Offshore Permanent Well Abandonment

Worldwide, government and regulatory officials are informing the offshore oil and gas industry that unproductive wells must be immediately sealed to permanently remove these potential environmental threats. Service companies are developing tools and methods to limit the economic impact of fulfilling these obligations.

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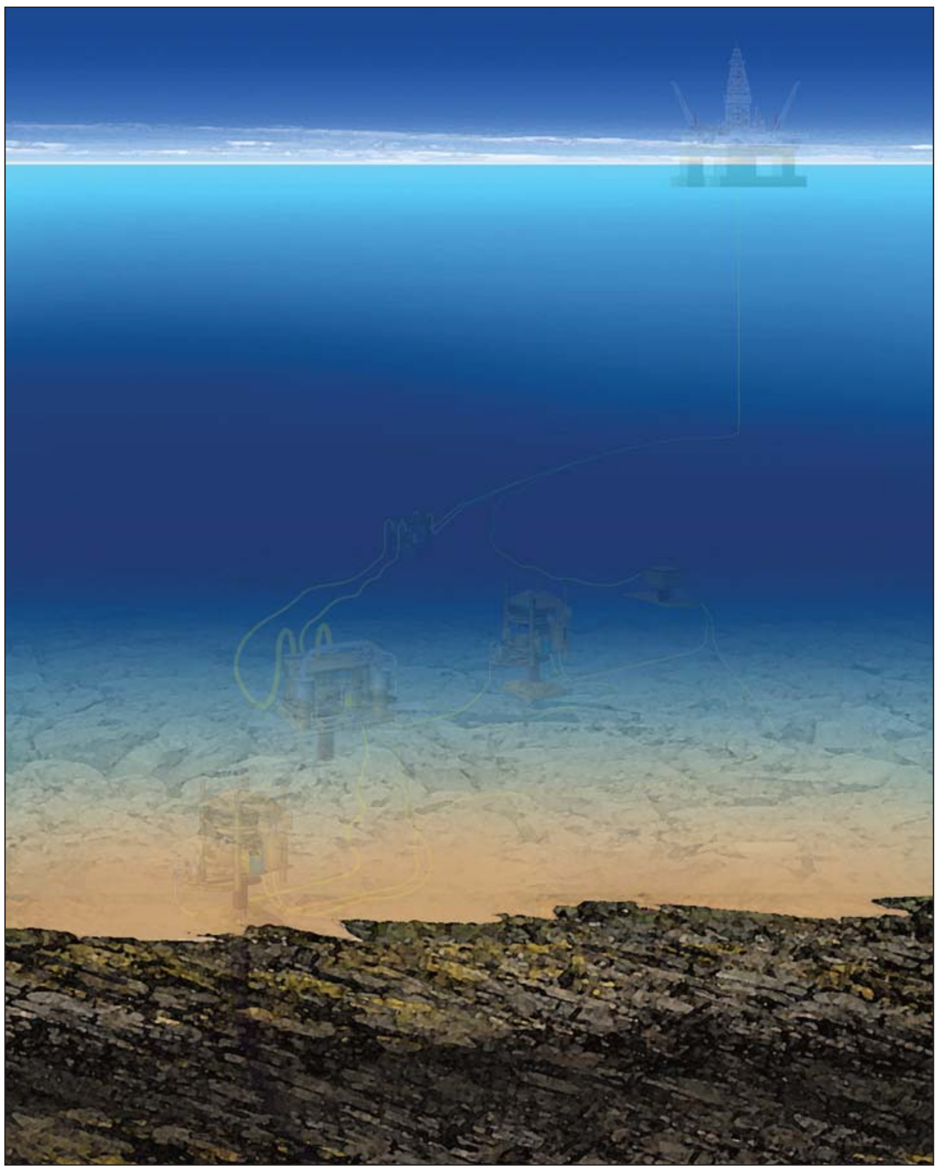

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For help in preparation of this article, thanks to Hani Ibrahim and Eric Wilshusen, Houston.

1. Smith I, Olstad E and Segura R: "Heightened Regulations Create Demand for Well Abandonment Services," *Offshore* 71, no. 10 (October 2011): 70–73.
2. King GE: "Plug and Abandonment—Producing Well," George E. King Engineering, Inc. (March 14, 2009), http://gekengineering.com/Downloads/Free_Downloads/Plug-and_Abandonment_Basics.pdf (accessed March 14, 2012).

Subsea fields are reaching the end of their productive lives in the North Sea and the Gulf of Mexico, where the offshore oil and gas industry first moved into waters deep enough to require floating drilling and production units. As a consequence, and spurred by environmental concerns and official regulatory agencies, operators are poised to plug and abandon (P&A) a substantial number of wells in both those regions in the next few years.

This proliferation of present and future P&A needs is turning what has been a niche market into a multibillion dollar industry for offshore service companies. In the UK sector of the North Sea alone, it is estimated that more than 500 structures with about 3,000 wells are slated for permanent abandonment in the near future. By some estimates, as many as 12,000 wells are no longer producing in the Gulf of Mexico, qualifying them all as P&A candidates.[1] In the Norwegian sector of the North Sea, more than 350 platforms and more than 3,700 wells eventually must be permanently abandoned. Additionally there are more than 200 structures slated for decommissioning offshore the Netherlands, Denmark, Ireland, Spain and Germany.

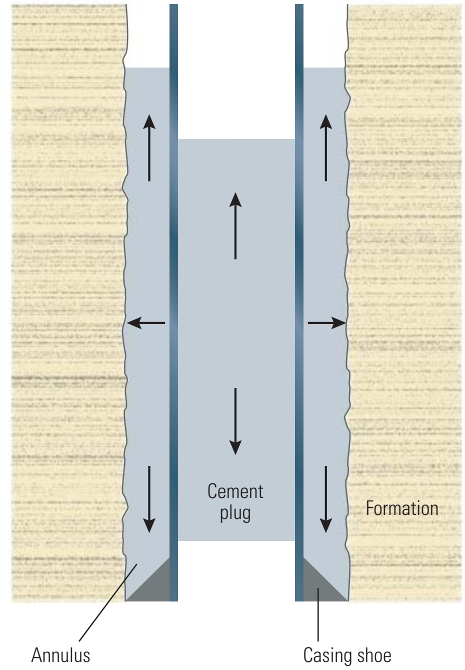
The basics of P&A operations vary little, whether the well is on land or offshore. Operators remove the completion hardware, set plugs and squeeze cement into the annuli at specified depths across producing and water-bearing zones to act as permanent barriers to pressure from above and below in addition to protecting the formation against which the cement is set (above right). Operators remove the wellhead last. Today, regulators are increasingly demanding that operators remove sections of casing so that a cement plug may be set that is continuous across the entire borehole in a configuration often referred to as rock to rock.

Similarly, both onshore and offshore, the decision to P&A a well is invariably based on economics. Once the production rate has fallen below the economic limit—that point at which production levels deliver income that is less than or equal to operating expenses—it becomes prudent to abandon the well. In some instances, although considerable reserves may remain, the cost to repair a well problem is more than the projected income from potential production from a reworked well. On the other hand, in some offshore wells, engineers are able to permanently plug an offshore completion below a certain depth, remove one or more intermediate casing strings and set a whipstock. The operator is then able to reenter the original mother bore and drill a sidetrack well off the whipstock to an untapped section of the reservoir.

The steps required of operators to qualify their offshore wells as permanently abandoned vary widely with regulatory jurisdiction. For example, an offshore platform well in Norway is far more costly to abandon than one in the Middle East because meeting the standard of permanency set by regulators of the former requires more expensive operations than do those of the latter.

As a consequence of the high cost of offshore operations, prudent operators consider the cost of permanently abandoning a well and its supporting infrastructure during the field planning stages. Abandoning subsea wells can cost millions of dollars per well, particularly when the task must be performed from a deepwater drilling vessel. Operators planning to permanently abandon a well are therefore driven by the sometimes competing interests of safety and economics.

This article discusses the final steps of abandonment operations unique to offshore wells and describes the tools being developed to meet the needs of permanency while providing cost efficiencies. Because official governing bodies of the North Sea and Gulf of Mexico recently have made decommissioning a priority and because the two represent the largest mature offshore arenas in the world, this article focuses on operations in those areas. Similarly, legislators governing operations in the North Sea and Gulf of Mexico are themselves more experienced in this work than are their counterparts elsewhere around the world. Consequently, these official bodies are likely to both drive and incorporate new technology in future regulations that are realistic in terms of the operators' bottom lines while ensuring that taxpayers not be burdened with repair costs for wells that, decades later, turn out not to be truly permanently abandoned.



^ Basic plug. A requirement for a permanent well barrier is that it must include all annuli, extending to the full cross section of the well and seal both vertically and horizontally. In this illustration, the cement plug is sealing vertically inside the casing and sealing both horizontally and vertically in the casing-formation annulus above the casing shoe.

Attacking the High Cost of P&A

The inability to recover 100% of all the oil and gas trapped in formation rocks is due in part to economics and in part to constraints imposed by technology and geology. In all cases, some hydrocarbon will be left behind because the cost to bring it to surface is higher than the price it will bring at market; other pockets of oil and gas remaining in the reservoir will never be recovered because even technologies such as water injection, which are used to force hydrocarbons to the wellbore after natural drives are depleted, eventually become ineffective or uneconomic.

When operators abandon a well, they are obliged to leave it in a condition that protects both the downhole and surface environment in perpetuity. In all parts of the world, sometimes numerous regulatory bodies of overlapping responsibilities define procedures and qualifications of a permanent well abandonment. In the Gulf of Mexico, for example, depending on distance from shore and water depth, operators may have to meet requirements set by agencies from both federal and state jurisdictions.

Despite disparities between regulators around the world, the intent of all P&A operations is to achieve the following:

- isolate and protect all fresh and near freshwater zones
- isolate and protect all future commercial zones
- prevent leaks in perpetuity from or into the well
- remove surface equipment and cut pipe to a mandated level below the surface.[2]

Situation	Procedure
Zones in open hole	Set cement plug(s) from at least 100 ft [30 m] below the bottom to 100 ft above the top of oil, gas and freshwater zones to isolate fluids in the strata.
Open hole below casing	Perform one of the following: • Set, by the displacement method, a cement plug at least 100 ft above and below the deepest casing shoe. • Set a cement retainer with effective backpressure control 50 ft [15 m] to 100 ft above the casing shoe, and a cement plug that extends at least 100 ft below the casing shoe and at least 50 ft above the retainer. • Set a bridge plug 50 to 100 ft above the shoe with 50 ft of cement on top of the bridge plug for expected or known lost circulation conditions.
Perforated zone that is currently open and not previously squeezed or isolated	Perform one of the following: • Use a method to squeeze cement to all perforations. • Set, by the displacement method, a cement plug at least 100 ft above to 100 ft below the perforated interval, or down to a casing plug, whichever is less. • If the perforated zones are isolated from the hole below, use any of the five plugging methods specified below instead of the two specified in this section, immediately above. ▪ Set a cement retainer with effective backpressure control 50 to 100 ft above the top of the perforated interval and a cement plug that extends at least 100 ft below the bottom of the perforated interval with at least 50 ft of cement above the retainer. ▪ Set a bridge plug 50 to 100 ft above the top of the perforated interval with at least 50 ft of cement on top of the bridge plug. ▪ Set, by the displacement method, a cement plug at least 200 ft [60 m] in length, with the bottom of the plug no more than 100 ft above the perforated interval. ▪ Set a through-tubing basket plug no more than 100 ft above the perforated interval with at least 50 ft of cement on top of the basket plug. ▪ Set a tubing plug no more than 100 ft above the perforated interval topped with a sufficient volume of cement so that it extends at least 100 ft above the uppermost packer in the wellbore with at least 300 ft [90 m] of cement in the casing annulus immediately above the packer.
Casing stub with the stub end within the casing	Perform one of the following: • Set a cement plug at least 100 ft above and below the stub end. • Set a cement retainer or bridge plug at least 50 to 100 ft above the stub end with at least 50 ft of cement on top of the retainer or bridge plug. • Set a cement plug at least 200 ft long with the bottom of the plug no more than 100 ft above the stub end.
Casing stub with the stub end below the casing	Set a plug as specified in the openhole sections, above, as applicable.
Annular space that communicates with open hole and extends to the mudline	Set a cement plug at least 200 ft long in the annular space; for a well completed above the ocean surface, pressure test each casing annulus to verify isolation.
Subsea well with unsealed annulus	Use a cutter to sever the casing; set a stub plug as specified in casing stub sections, above.
Well with casing	Set a cement surface plug at least 150 ft [45 m] long in the smallest casing that extends to the mudline with the top of the plug no more than 150 ft below the mudline.
Fluid left in the hole	Maintain fluid in the intervals between the plugs that is dense enough to exert a hydrostatic pressure that is greater than the formation pressures in the intervals.
Permafrost areas	Leave, in the hole, fluid that has a freezing point below the temperature of the permafrost and a treatment to inhibit corrosion and use cement plugs designed to set before freezing and that have a low heat of hydration.

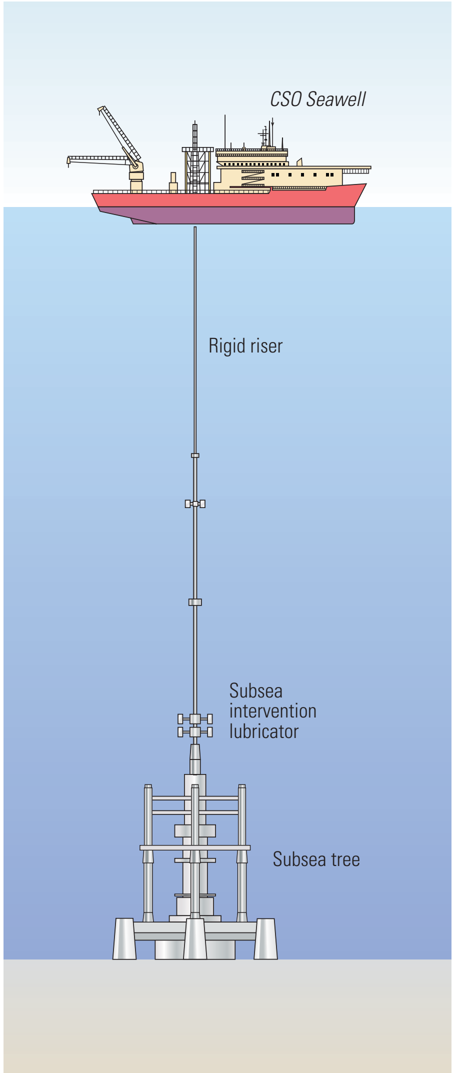
^ US P&A regulations guide. Depending on a well's location, depth, condition and other parameters, operators are obliged to perform and document specific steps that are outlined by the regulating body for the area. This table shows samples of the procedures to be performed so that a well in the Gulf of Mexico is deemed permanently plugged. The procedure called for depends primarily on the well configuration prior to plugging and is set by the US Bureau of Safety and Environmental Enforcement. [Adapted from the Electronic Code of Federal Regulations: "Permanent Well Plugging Requirements," http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=06d320a6f4723641d7d1b83be409c10d&rgn=div8&view=text&node=30:2.0.1.2.2.17.93.11&idno=30 (accessed March 28, 2012).]

P&A operations offer permanent solutions to wells that are no longer profitable or that have developed problems that cannot be economically repaired. However, offshore, it is a common practice for operators to permanently abandon the zones within a well before completing and producing others. Additionally, offshore development plans often call for lower sections of depleted wells to be permanently abandoned to free a slot in subsea templates and platforms through which another well may be drilled to an untapped section of the reservoir. This practice is termed slot recovery.

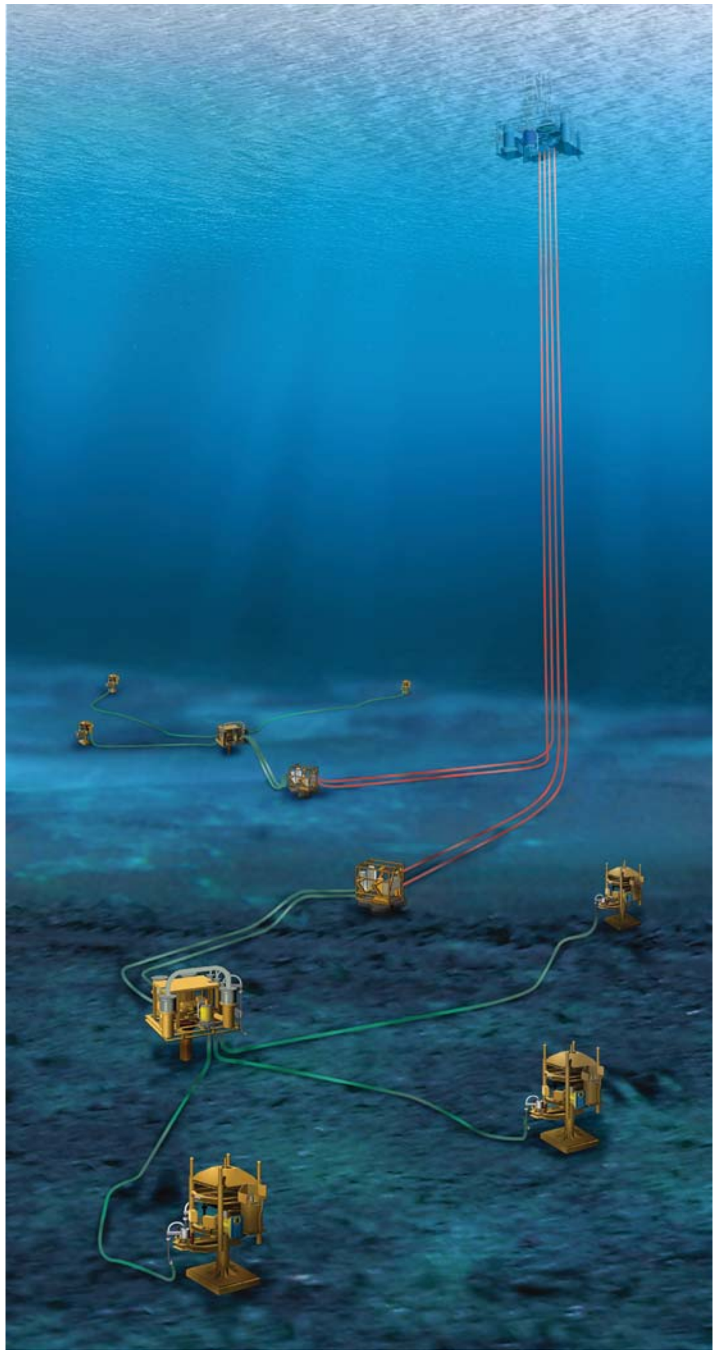
To permanently abandon a well, operators must leave behind a wellbore that is configured according to local regulations for plug type, length and depth (left). Operators remain responsible for an abandoned well long after the wellbore has been cemented and the surface equipment removed. In the event a seal fails and well fluids leak to the surface or crossflow is detected, the operator is liable for the problem.

To meet P&A obligations, the oil and gas industry has developed methods and materials designed to provide long-term zonal isolation even when downhole conditions change over time.[3] In efforts aimed at reducing the expense of offshore abandonment operations, operators and regulators continue to change the way traditional P&As are performed, and service companies strive to stay abreast of these changes and to develop tools and techniques to facilitate them. Minimizing these costs, without sacrificing the integrity of the abandoned well, is critical to operators who must make these significant investments with no hope of financial return.

Depending on water depth, offshore well abandonment can be staged from a fixed platform such as jackup rig, from a large floating platform such as a semisubmersible drilling rig or from a support vessel with dynamic positioning. In UK waters, abandonment from a fixed platform is the least expensive—about US$ 1 to 2 million per well. By contrast, abandonment operations using a semisubmersible or dynamically positioned floating drilling unit typically cost operators US$ 5 to 6 million per well, and the cost of support vessel–based abandonments falls between those two extremes (next page, left).[4] In Norway, the cost of permanent well abandonment is significantly higher to meet both the operators' self-imposed standards and regulators' requirements.



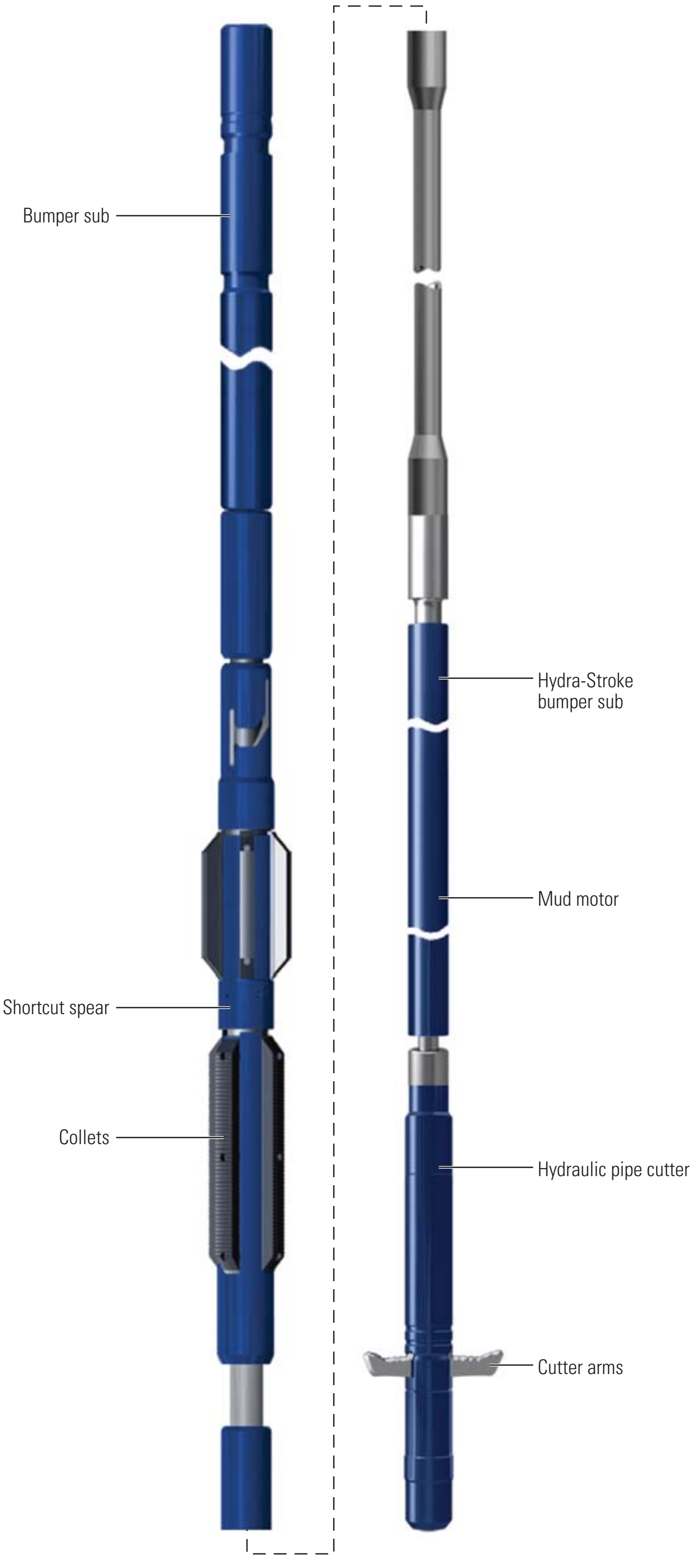
^ Subsea lubricator. In the 1970s, Schlumberger introduced a subsea intervention lubricator that could be landed on a subsea tree and connected via a rigid riser to a dynamically positioned vessel. This allowed operators to perform light slickline, wireline or coiled tubing well interventions without deploying a costly offshore floating drilling unit. The capability to cost effectively reenter subsea wells greatly reduced well maintenance costs and allowed engineers to perform necessary work more frequently, thus extending well life.



^ Subsea completions. To minimize demands on surface support facilities in deep water, operators place subsea wellheads (yellow) on the ocean floor. Bundled flowlines and umbilicals (green) carry production and electric and hydraulic control and monitoring signals between wellheads; fluids and signals travel to the production facility at the surface via risers (red). This system allows engineers to deploy smaller and fewer high-end deepwater support vessels for service in large areal fields.

As the upstream oil and gas industry moved into deeper water, it sought ways to temper steeply rising capital and operating expenditures. In deep water, where numerous satellite jackets are impractical, one approach is to complete subsea wells with wellheads that are on the seabed and connected to a field platform via flowlines strung along the seafloor. Subsea wellhead valves and instruments are monitored and manipulated through bundled hydraulic and electric lines called umbilicals (above right).

3. For more on P&A procedures: Barclay I, Pellenbarg J, Tettero F, Pfeiffer J, Slater H, Staal T, Stiles D, Tilling G and Whitney C: "The Beginning of the End: A Review of Abandonment and Decommissioning Practices," *Oilfield Review* 13, no. 4 (Winter 2001/2002): 28–41.
   For more on long-term zonal isolation: Bellabarba M, Bulte-Loyer H, Froelich B, Le Roy-Delage S, van Kuijk R, Zeroug S, Guillot D, Moroni N, Pastor S and Zanchi A: "Ensuring Zonal Isolation Beyond the Life of the Well," *Oilfield Review* 20, no. 1 (Spring 2008): 18–31.
4. Liversidge D, Taoutaou S and Agarwal S: "Permanent Plug and Abandonment Solution for the North Sea," paper SPE 100771, presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Adelaide, South Australia, Australia, September 11–13, 2006.



^ Cut and pull. The Shortcut deepwater P&A system uses a hydraulic cutter to sever the casing and a spear to latch it. The collets of the Shortcut spear are extended to engage the casing near the cut point until the cut is complete. The spear is then released and pulled to the top of the casing section where it is reengaged. This ability to change the position of the spear allows it and the drillstring it is run on to be racked out of the way while the casing is being pulled. The cutter arms are rotated by fluid pumped through the mud motor. The bumper sub attachment allows the rig operator to jar the casing if necessary.

Most subsea wells are completed with three or more casing strings of progressively smaller diameters and are usually bonded to each other by a cement sheath in the annulus. Typically, during the abandonment process, three or more drillpipe trips are required to remove each casing string. The first trip is made to retrieve the casing and hanger seals from the wellhead. The casing is then cut during a second trip, and a third trip is required to pull the casing and casing hanger from the well. Following recovery of these intermediate strings, the conductor casing is cut and the wellhead retrieved.

Rig time for these operations is considerable; in deep water, each trip commonly takes 8 to 10 hours.[5] To reduce time and thus cost of cutting and pulling strings of intermediate casing from a subsea well, SERVCO has developed the Shortcut deepwater plug and abandonment system (left). It is designed to latch and retrieve the seal assembly and then sever a single string of casing, engage it for removal and retrieve the wellhead seal assembly in a single operation.

The Shortcut system is run in the hole on drillpipe and has a mechanical spear fishing tool that can be engaged near the point at which the cut is being made. Once the casing is cut, the fishing tool can be released and moved to the top of the severed casing string and reset. The recovered casing is hung in the rotary table while the spear is released and the workstring is racked back out of the way, which allows the casing to be handled safely and efficiently as it is being removed from the wellbore. A retrieval tool may be included in the system to enable removal of the wellhead seal assembly. A key component of the system is the SERVCO hydraulic cutting tool, whose knives can extend the maximum sweep diameter created by the often eccentric configuration of cemented pipe (next page, top).

To cut and pull a string of casing, engineers first engage the wellhead seal assembly with the retrieval tool and strip the seal assembly up into the riser. The casing cutter is then positioned at the appropriate depth and the spear is engaged and used to place the string in tension. Pumps are turned on and drillstring rpm rates are slowly increased to turn the mud motor rotor, which rotates the cutter.

The driller monitors the differential pressure across the positive displacement motor; when data indicate a fluid pressure drop, the cut is complete. The driller then slacks off and manipulates the drillpipe to disengage the spear, which is pulled to just below the wellhead where it is reengaged. The casing is then pulled from the well, and the seal assembly and retrieval tool are laid out on the surface. The driller continues to pull out of the hole until the casing hanger is landed on the rotary and the spear can be disengaged and racked back in the derrick so that casing lay down may proceed.

A similar tool, the SERVCO 2M cut-and-pull system, is also a single-trip system primarily used to cut and retrieve 20- and 30-in. casings and subsea wellheads. This tool is able to pull the casing alone or the casing and wellhead together, and because it is designed to latch the wellhead and casing in noncritical areas and thus avoid seal bores in casing hangers, the recovered parts need not be machined before reuse.

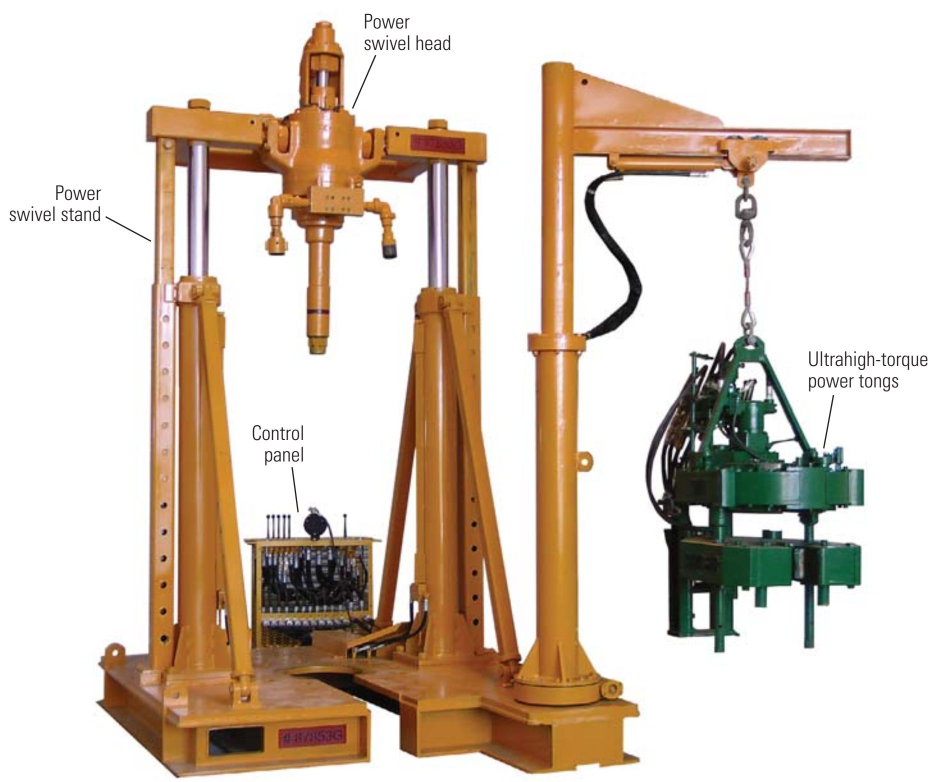
Because the cutting assembly may be run on a single stand of 8-in. drill collars, the 2M system reduces workstring handling time and eliminates the need for a marine swivel typically required for these operations (below right). The cut-and-pull system consists of a standard or rotating spear, hydraulic pipe cutter and nonrotating stabilizers placed above and below the pipe cutter.

Slot Recovery

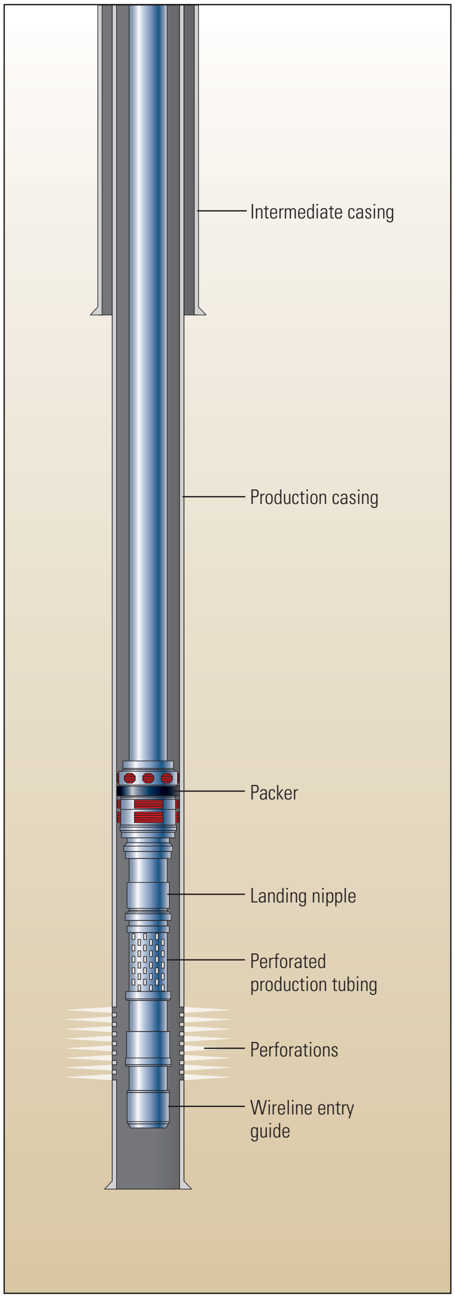
Most P&A operations are an unavoidable cost of doing business and offer no return on the capital invested in them. However, slot recovery operations are a different story because such operations provide access to untapped reserves that will extend the life of the field. Not only does this operation result in more revenue from production, but as the field ages it helps extend the life of the platform and other infrastructure that represent very large preproduction capital expenditures. Because slot recovery is performed in maturing fields, operators tend to be concerned with cost cutting when accessing these secondary targets. One key to controlling the costs of these new wells is reining in the P&A portion of slot recovery costs by reducing the number of trips required to cut and retrieve the multiple casing strings that prevent installation of a new well.

5. Going WS and Haughton D: "Using Multi-Function Fishing Tool Strings to Improve Efficiency and Economics of Deepwater Plug and Abandonment Operations," paper SPE/IADC 67747, presented at the SPE/IADC Drilling Conference, Amsterdam, February 27–March 1, 2001.

^ Eccentric casing. Cutting two strings of casing can be complicated when the distance from center to casing wall is extended by eccentricity. In this case, a 7-in. casing is inside a 9⅝-in. casing string. When the two are perfectly centered (*left*), the largest diameter the cutting knife must reach is 10.62 in. In extreme cases, the 7-in. casing is tightly pressed against the inner wall of the 9⅝-in. casing (*right*), thus the knife must sweep a 13.68-in. diameter.



^ Rigless well abandonment package. The SERVCO power swivel stand consists of hydraulic jacks with 445-kN [100,000-lbf] pulling capacity power swivel, control panel, power tongs and a mast with which to swing the tongs in and out of position. The stand is positioned over the well; once a string of casing is pulled to the surface by a spear fishing tool, it is connected to the power swivel head. The hydraulic jacks lift it out of the well to the next connection; the power tongs break the connection. The stand allows the crew to rack back the spear and drillstring. This system replaces the alternative method using a spear and drillstring to retrieve each stand of casing.



^ Offshore completion. Lower completions that must be pulled from the hole as part of slot recovery procedures typically consist of packers to isolate production zones and the tubing-casing annulus, landing nipples for deploying slickline intervention tools and perforated production tubing.

Typically, in addition to the conductor, or surface, casing string, offshore wells include intermediate and production casing strings, production tubing and a production packer (above). The section of the well below the packer is referred to as the lower completion. Slot recovery consists of plugging and abandoning the lower completion—which often includes working through collapsed tubing—and sidetracking from a kickoff point some distance above this new plug, which must be across all annuli and sealed against the formation. A simplified version of the procedure requires the following:

- installing a pressure barrier—usually one or more cement plugs—in the production tubing below the packer
- removing production tubing above the packer
- installing a second barrier above the lower completion inside the production casing
- cutting and pulling and, if necessary, milling the production casing to below the kickoff point
- sidetracking the well through intermediate casing.

Conventional systems for this work involve multiple trips to run cutting and fishing tools and retrieve casing sections. Usually, the well has been in place for many years, so cutting and pulling the casing may be difficult because of a firm cement bond, barite settling from drilling fluid in the annulus or a combination of the two.[6] Pulling units may be unable to overcome the strong bonds created by cement or barite. As a result, the cutting and pulling operation may require several trips and cuts for each string before an interval is found that is free of binding cement or barite.

To address this possible eventuality, a team of engineers reviewed the conventional tools used for these jobs. They found that the standard kit could make only a limited number of cuts downhole. Based on these findings, the team designed a pipe cutting tool with three sets of tungsten-carbide cutters, which can be activated individually and remotely. This capability allows operators at least three attempts to cut the casing without having to pull out of the hole for fresh knives. An indicator in the tool confirms to observers on the surface that the cut is completed. A hydraulic spear and packer assembly being developed for future inclusion in the BHA will allow engineers to pull and circulate fluid behind the production casing.[7]

The product of this design effort is the multicycle pipe cutter (MCPC) system (next page, top). It incorporates an indexing piston assembly that moves in response to applied drilling fluid pressure and is used to engage and guide the tool's axial and rotational movements. A combination of an indexing mechanism and flow fluctuations allows the engineer to selectively activate one of three sets of cutters and the hydraulic spear and packer assembly. Those cutters not engaged are securely collapsed within the body of the tool.

A pressure drop indicator at the top end of the tool consists of a stationary stinger within the piston bore. Initially the stinger remains in the piston bore, creating a flow restriction and a higher activation pressure. When the cut is complete, the piston moves downward, resulting in removal of the flow restriction and a drop in pressure of 1.4 to 2.1 MPa (200 to 300 psi) that is displayed at the surface.

Developers used proprietary tungsten carbide inserts positioned on the cutters to provide the optimal cutting angle. They also designed the tool for an operational sequence—complete the cut and activate the spear to grip and pull the casing segment—that was repeatable in a single downhole trip. To do this, engineers developed a hydraulic spear compatible with the MCPC tool that is activated at a higher flow rate than that required to activate the MCPC. This ensures that only the spear is activated and the correct cut-pull sequence will take place.

The tool was field tested on a slot recovery operation on the Norway Continental Shelf. Rather than test the viability of the single trip method, the operator chose to cut and pull 9⅝-in. casing in two trips. Initial cuts were made at 861 m [2,825 ft] and 983 m [3,225 ft] using a standard SERVCO pipe cutter. The first section, from wellhead to 861 m, was pulled successfully with an overpull of 320,000 lbf [1,420 kN]. The second section from 861 m to 983 m was pulled successfully with 700,000 lbf [3,110 kN] overpull using a downhole pulling tool.

The operator's next objective, based on the previous two cuts, was to validate the selective cutting capabilities of the MCPC with six cuts in a single run at 1,602; 1,509; 1,409; 1,300; 1,068 and 1,031 m [5,256; 4,951; 4,623; 4,265; 3,504 and 3,383 ft] using the MCPC tool.

All cuts were completed, requiring from 10 to 14 min each. The pressure drop displayed on the rig floor pressure gauge clearly indicated at every cut that the tool had functioned as intended and that the casing was cut. Based on inspections of the tool at the surface, it was clear that all three sets of cutters had been deployed.

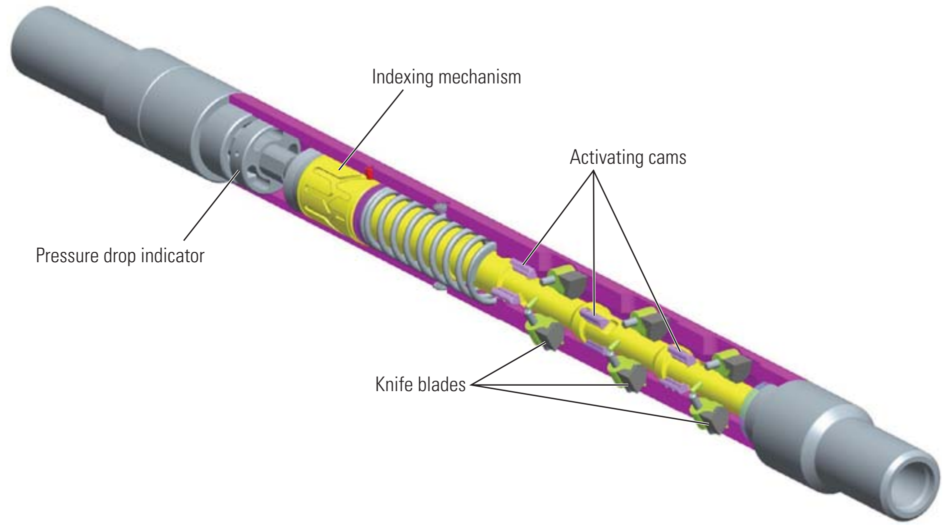
The casing from 983 m to the cut at 1,031 m was then pulled free and removed from the wellbore with an overpull of 940,000 lbf [4,180 kN] using a standard spear and a hydraulic jacking unit. The casing section from 1,031 m to 1,068 m was again pulled free using the same spear and a downhole jacking unit, but this time saw an overpull of 640,000 lbf [2,850 kN]. Again, this section was pulled to surface and the spear assembly was run once more to retrieve the 1,068- to 1,300-m section. It was confirmed, however, after pulling a maximum of 1,052,000 lbf [4,680 kN] that the casing section was too long to allow retrieval in one piece and had to be subsequently cut at 1,104 m [3,622 ft] and 1,202 m [3,944 ft]. These two cuts were performed with a standard pipe cutter.

The three resulting sections of casing were pulled free using the standard spear and downhole jacking unit with an overpull of 820,000; 930,000 and 440,000 lbf [3,650; 4,180 and 1,960 kN], respectively.

When attempting to pull the 1,300- to 1,409-m section of casing, engineers discovered that the casing would not pull free with a maximum of 1,052,000 lbf overpull.

The team then decided to make six more cuts to shorten the remaining pieces of casing to be removed. These cuts were performed with the MCPC in one run at 1,570; 1,545; 1,472; 1,436; 1,372 and 1,335 m [5,151; 5,069; 4,829; 4,711; 4,501 and 4,380 ft]. As with the first six cuts, the MCPC tool performed as intended, and cutting times were between 6 and 14 min each. In all, engineers estimated using the MCPC method delivered to the operator a savings of about 1.5 days and US$ 200,000 over conventional methods.

The remaining pieces have not yet been retrieved from the wellbore because the customer decided to temporarily suspend operations on this well for various reasons not related to the MCPC operations. The operator will return to the well and continue pulling the remaining sections in the near future.

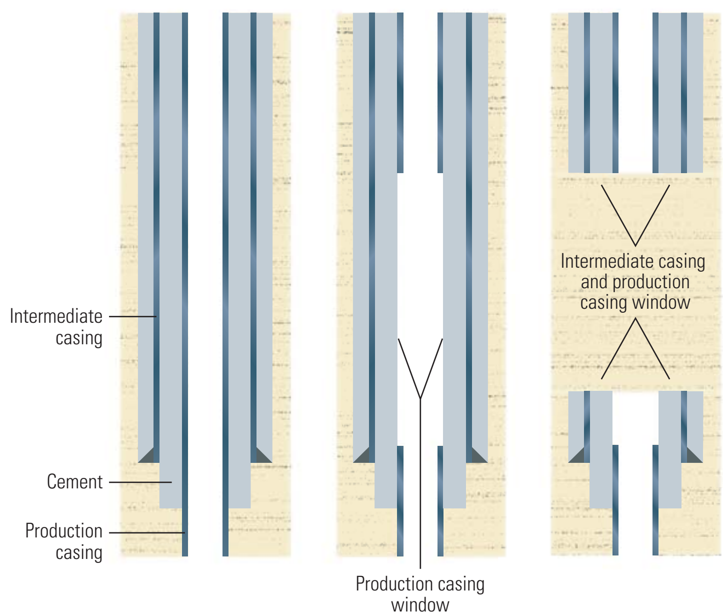


^ Multicycle pipe cutter (MCPC). Through changes in pump pressure, operators are able to position activating cams so that they act to extend one set of knife blades on the MCPC while the others remain retracted. Varying mud pulse signals cause the cycle indexing mechanism to engage a hydraulically activated, mechanically actuated casing spear (not shown) while simultaneously retracting all blades. When the cut is complete, a piston moves downward to a piston stop (not shown), creating a larger flow area through the pressure drop indicator. The resulting pressure drop is displayed at the surface, serving as confirmation that the cut is complete.

Perforate, Wash and Cement

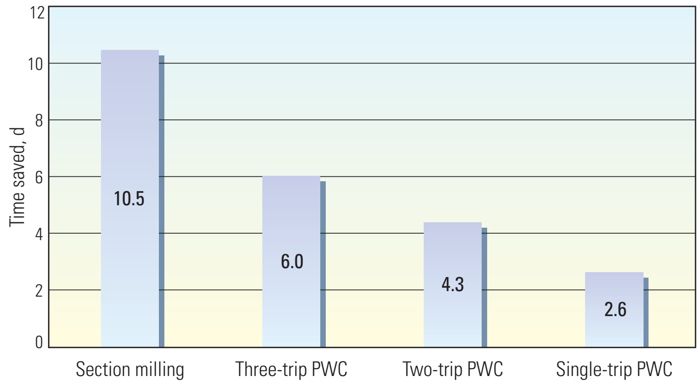
A crucial requirement of a permanent abandonment procedure is placement of a cement plug across the wellbore and in the annuli of the lower casing sections remaining in the well once upper sections have been pulled. In the majority of these cases, the procedure is to mill a window through all casing strings through which cement may be pumped into the annuli and against the exposed formation (right). This procedure also removes any cement, settled mud or other debris from between the casing and the formation that could prevent the required multidirectional sealing.

A potential drawback to this practice arises from the fact that a highly viscous drilling fluid must be used during the milling operation to lift the metal cuttings, commonly known as swarf, to the surface. Swarf-laden fluids have a density that is usually considerably greater than the formation can withstand before fractures are induced. The resulting equivalent circulating density (ECD) is more than sufficient to cause lost circulation



^ Milled windows. Casing strings of lower completions that are poorly cemented but cemented in a manner that renders them irretrievable (*left*), must be milled. One trip is required to mill the production casing (*middle*) and then separate trips are required for any intermediate casings (*right*) until all annuli and the formation are exposed. This allows the operator to cement each annulus according to permanent P&A requirements before drilling the sidetrack.

6. Hekelaar S, Gibson K and Desai P: "Increasing Reliability of Cutting/Pulling Casing in a Single Trip," paper SPE 145494, presented at the Offshore Europe Oil and Gas Conference and Exhibition, Aberdeen, September 6–8, 2011.
7. Hekelaar et al, reference 6.



^ Time saved during perforate, wash and cement (PWC). With continual operational improvements, engineers reduced the average plug-setting time from 10.5 days to 2.6 days for a single run PWC plug. Over the history of 20 jobs, engineers estimated a savings of 124 rig days. (Adapted from Ferg et al, reference 9.)

problems in the exposed zones.[8] Additionally, surface equipment may be easily damaged when metal-laden fluid passes through it.

As a consequence, these operations are time consuming and can be difficult to perform safely and effectively. Additionally, it is difficult to test the effective plug seals through the two methods typically deployed in section milled casing: leaving the top of the cement inside the casing above the milled window and leaving the top of the cement in the open hole.

To test the former, the plug is tagged, weight tested and then pressure tested. These tests assess the quality of cement inside the casing and make no determination of quality of cement in the casing annulus or in the open hole. In the latter test, the plug can be tagged to verify position, but in most cases, it is impossible to pressure test it.

One response to these challenges has been the introduction of a system known as perforate, wash and cement (PWC). This technique removes debris from the annulus through perforations, which eliminates milling debris and a high ECD to remove swarf.

The PWC method uses a tool made of pipe-conveyed perforating guns attached below a wash tool, which is below a cement stinger. The PWC tool is run to plug-setting depth where the guns are fired and automatically dropped. Fluid is then circulated and conditioned to match wellbore pore pressure conditions. A ball is dropped, which seals off the bottom of the wash tool and opens a sliding sleeve to direct circulation between the wash cups. Washing is done across the perforated interval from top to bottom. Circulating fluid cleans the annular space through the perforations between the wash cups and the annular space above the top wash cup.

When the tool reaches the bottom perforation, the washing continues while the tool is moved upward. The wash tool is then run back to the bottom of the perforations and a cement spacer is pumped between the wash tool cups and into the annular space as the tool is pulled upward. A ball is dropped and landed, disconnecting the wash tool from the cement stinger. The wash tool is then pushed to below the perforations. The wash tool cups are designed to maintain contact with the casing inner wall and are then used as a base for cementing operations. The cement stinger is pulled above the top perforation and the casing cleaned a final time through the workstring before the interval is cemented through the stinger. The cement is then squeezed into the perforations.

The workstring can then be used to wash downward to the top of the cement for tagging and pressure testing. If the plug needs to be tested, the operator can drill out the cement plug, pressure test the annulus and then set a plug inside the casing, which can be tagged and tested according to regulators' requirements.

By August 2011, operator ConocoPhillips had completed 20 PWC plug installations in the North Sea. Through experience and operational improvements using the PWC method, the operator progressively whittled down time required to set a permanent plug to 2.6 days. By comparison, in the course of six conventional operations, the operator required an average of 10.5 days to set a permanent downhole plug (left). As a result, the company calculated a savings of 124 rig days over the course of the 20 PWC wells.[9]

A New Timeline

Because of increasing concerns over the many wells no longer in production but not yet permanently sealed, regulators in the mature offshore areas of the Gulf of Mexico and the North Sea are pressing for action. This promises to immediately create enormous demand for abandonment services in those markets. The overall cost of decommissioning on the UK Continental Shelf is estimated at about US$ 48.6 billion by 2050, with US$ 7.2 billion expected to be spent in the next five years. Well plugging will account for more than US$ 2.6 billion spent by 2016.[10] North Sea operators have indicated these are modest estimates and that they expect to pay tens of millions of dollars in P&A costs per well plus the cost of decommissioning surface facilities and other infrastructure.

Because there is no profit to be gained from abandoning a well, operators look to service companies to limit the economic downside of these obligatory operations. And because the tangibles, such as cement and reamers, are relatively inexpensive and nearly fixed in amount and quality, the service industry challenge is to develop advantages by improving the intangibles—the methods that save time and money during permanent abandonment exercises.

The number of wells ready for these final procedures may rise with time because while operators work to permanently abandon their backlog of idle wells, many wells being drilled today will have a shorter productive life than wells drilled in the past. Earlier offshore wells captured hydrocarbons from large accessible reservoirs, while many of the remaining reservoirs are substantially smaller and will have shorter life spans that will make them abandonment candidates after fewer years of production than their predecessors. Additionally, regulators have made it clear that the time between the end of a well's life and its permanent sealing will now be shorter than in the past. Given these new parameters, it behooves operators to plan for a well's final days even as they spud it. —RvF

8. For more on lost circulation: Cook J, Growcock F, Guo Q, Hodder M and van Oort E: "Stabilizing the Wellbore to Prevent Lost Circulation," *Oilfield Review* 23, no. 4 (Winter 2011/2012): 26–35.
9. Ferg TE, Lund H-J, Mueller D, Myhre M, Larsen A, Andersen P, Lende G, Hudson C, Prestegaard C and Field D: "Novel Approach to More Effective Plug and Abandonment Cementing Techniques," paper SPE 148640, presented at the SPE Arctic and Extreme Environments Conference and Exhibition, Moscow, October 18–20, 2011.
10. Chesshyre M: "Braced for the North Sea 'Bow Wave'," *Offshore Engineer* 36, no. 11 (November 2011): 33–37.