DEEPWATER TECHNOLOGY: Exploration, Production, and Blowout Prevention

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Introduction

As the search for new oil and gas resources in the United States continues, the deepwater areas off our shores become more and more geologically interesting. This interest has stimulated the oil industry into designing and developing the equipment and expertise necessary for successful exploitation of deepwater resources. Although much of the technology is still on the drawing boards, industry has consistently stated that lack of opportunities and economics have limited the actual undertaking of deepwater operations, not the limitations of technology. The following sections describe the various types of equipment proposed for exploration and production of deepwater oil and gas resources.

Deepwater Exploration

Presently there are several operational drilling facilities capable of exploring for oil in water depths as great as 8000 feet or more. Drillships and semi-submersibles are most commonly used for deepwater drilling. The drillship Discoverer Seven Seas, operated by the Offshore Company, recently set the current deepwater record by operating in just under 5000 feet of water. The French consortium of CFP and Elf Aquitaine have contracted the Discoverer Seven Seas to spud an exploration well in the French Mediterranean in a water depth of 6000 ft. late in 1982 or early 1983. If the wells reveal the area to be economically attractive plans will be drawn for the drilling of wells in 10,000 ft. of water. The consortium's aim is to eventually reach targets as great as 23,000 ft. below sea level (Steven, 1981). Global Marine's Glomar Explorer, equipped with a recently developed free-standing drilling riser, is reportedly presently capable of drilling in 13,000 feet of water. Sedco International also has a series of drillships designed to explore for oil and gas in up to 8000 foot water depths.

Semi-submersible rigs, although they offer less storage capacity in terms of weight than drillships, are inherently more stable and thus more applicable in certain areas and weather conditions. Roll seldom exceeds 5° on a properly found vessel, even in the most severe seas (U.S. Dept. of Interior, BLM, 1980). The Sedco 709 semi-submersible rig is equipped with features which will enable it to operate in 8000 foot water depths.

Several innovations in equipment and technology are responsible for the extreme deepwater capabilities of the presently available equipment. Modifications and improvements to existing blow-out preventers (BOP) and marine risers have been partially responsible. The BOP is a high-pressure valve, usually hydraulically operated, fitted to the top of the casing of a drilling well to prevent an accidental blow-out of oil or gas (Bank of Scotland, 1975). The BOP must be capable of fast response to potential well control problems regardless of water depth. BOPs designed for shallow water operation exhibited undesirable reaction times for preventer activation. Development of new electro-hydraulic control systems for activating the ram and annular preventers of the BOP resulted in quicker response times. The BOP must also be designed and manufactured to tolerate the large loads imposed on it by the deepsea risers. The BOPs found on several of Sedco's drillships are 39 feet tall and weigh approximately 400,000 pounds.
Marine riser systems also had to undergo modification to alleviate the up and down wave movement associated with floating drilling operations. The marine riser is a tube running from the BOP, which is situated on the sea-bed, to the drilling rig at the surface, enabling drilling fluid to be returned to the surface (Bank of Scotland, 1975). This problem was dealt with by installing slip-joints in appropriate locations of the riser and by installing riser tensioning units to balance out the rising and falling motions of the rig or vessel.

Two of the most significant innovations in the development of deepwater drilling technology have been the use of guidelineless re-entry and dynamic positioning. Guidelineless re-entry uses acoustical/subsea television equipment to guide the drill string into a wellhead funnel thousands of feet below the surface of the water (McNally and Hale, 1979).

Dynamic positioning, the concept of remaining in one spot at sea without anchors, was originally proposed for the National Science Foundation Project Mohole to drill through the earth's inner mantle underlying ultra deep 20,000 foot water depths. Today, dynamic positioning is being applied to the deepwater search for natural resources. Advances in control sophistication, reliability, and power output allows present dynamic systems to keep rigs on station for extended periods.

The system provides a means of automatically maintaining the position of a free-floating vessel within specific tolerances by using thrust vectors to counter the forces of wind, waves, and currents that tend to displace a vessel from a desired location. The dynamic positioning system consists essentially of a position referencing unit, a dynamic positioning controller, and the thrusters. The taut wire position referencing unit uses a weighted line extending from the sea floor to a two-axis inclinometer that reads the rope angle as it deviates from the vertical. The resulting data is fed to the controller unit. Acoustic referencing is accomplished by either the short-base, ultra short-base, or long-base configuration. The short-base system uses an acoustic beacon (transponder) on the ocean bottom and several hydrophones on the vessel. The beacon transmits pulses (at regular intervals) which are received at the same instant by the hydrophones when the rig is exactly on-station. As the vessel drifts off-station the acoustic wave is received at different times as individual hydrophone-to-transponder distance varies. Vessel pitch, roll, and heave, is compensated for by a Vertical Reference Unit which applies appropriate corrections to the data prior to transmittal to the controller. The converse of the short-line system is the long-line system in which the hydrophones are mounted on the ocean bottom and the beacon located on the vessel. This arrangement eliminates pitch and roll inaccuracies, and, since the baseline between transponders is large, it is very accurate. A variation on the short-line system is the ultra short baseline or phase comparison system. This system determines direction from a measurement of the phase of the acoustic signal received by three closely spaced sensors within a single assembly. The basic configuration of the three reference systems is shown on Figure 1.
Figure One: Acoustic position referencing systems
The data from the reference systems are fed into the error compensators that generate error signals which are proportional to the difference between actual and desired position. These data are in turn fed into the Dynamic Position Controller. The computers of the controller unit analyze the input data, apply modifications or add information through software, and act as the system interface to the thrusters. The thrusters (either fixed or omni-directional) are positioned and actuated by the commands from the controller. The thrusters develop up to 3000 hp for station-keeping.

In the event that a computer malfunction, weather conditions, or other factors result in a "driveoff" of a dynamically positioned drilling vessel (a condition in which the vessel moves away from its position over the well), provisions are aboard for disconnection of the upper BOP package and riser from the lower BOP stack (Albers, 1980). A programmed sequence of events results in the closing of certain valves on the lower stack and unlocking of the riser connector. Several deep water drilling vessels are equipped also with riser recoil preventor systems which prevent the slip joints of the riser system from slamming together and transferring the impact energy of the system to the drilling vessel structure.

There are currently several deepwater facilities equipped with dynamic positioning systems. Among this group are the Sedco 709 semi-submersible, the three drillships of the Sedco 400 series, the Glomar Explorer, and the Offshore Company's drillship Discover Seven Seas. As prospects for deep ocean oil and gas increase, more deepwater exploration drilling rigs and ships equipped with dynamic positioning systems will undoubtedly be manufactured and utilized. To date, no unusual problems have been encountered in any present deep-water exploratory drilling operations.

Deepwater Development and Production

Production capability for deepwater extraction of hydrocarbons generally lags some eight years behind exploration technology, according to one industry expert (Albers, 1980). However, new designs and models for deepwater production are now being developed. Some technically innovative equipment is presently or will soon be available for application.

To date, conventional fixed platforms have been used for major deepwater discoveries in water depths to just over 1000 feet. Figure 2 reflects the growth in offshore production platform size, from 1974 through 1978. Shell's Cognac platform lying in approximately 1025 feet of water fifteen miles from the mouth of the Mississippi River, is presently the world's tallest and heaviest steel production platform. With drilling rigs atop, it stands 1265 feet tall and weighs approximately 59,000 tons. (Shell Oil Company, 1979). The Cognac platform is unconventional in that it was fabricated in three sections and set one on top of the other at the site, due to the fact that no facilities were available where a one piece section of that size could be built.

An innovative new rig design for production is Exxon's guyed tower. It is a bottom-founded structure that differs significantly from conventional
Figure Two: Evolution of offshore production platforms
platforms in several aspects. It is a "compliant" structure in that it moves in response to applied forces. It also is a trussed structure with constant cross-section from top to bottom and, though it is bottom mounted, it does not utilize a system of piles for stability (Power et al., 1978).

The tower essentially consists of a blunt-nosed, truss-reinforced spud can that is forced into the sea floor during installation, the constant cross-section tower jacket, and the deck - much like that of a conventional platform. The tower is held in the vertical by a series of radial guy-wires that attach to the deck by wedge-type clamps that also serve as tensioners. The lines then pass down the side of the structure to fairleads about 50 feet below the water line, and (at about a 30° angle) to clump weights on the ocean floor. Design criteria call for the clump weights to partially lift off the bottom during passage of storm waves, while under extreme weather conditions they may lift entirely. Beyond the weights, the guy system terminates at anchor piles. Figure 3 shows the general configuration of the system.

Following preliminary analysis of the concept, a 1/5 scale model of the tower (intended for 1500 foot application) was fabricated and installed in 293 feet of water in the Gulf of Mexico. Installation was completed utilizing conventional offshore construction equipment and procedures that would be employed for a full-scale prototype. However, the test tower was fabricated and installed in one section whereas a full-scale one would be completed in two or more sections, floated to the site, and joined prior to implantation on the bottom. Analysis of acquired data on tower motions compared well with analytical predictions based on measured wave profiles. Also, measured maximum guy-wire tensions compared well against predicted tensions. The practicality of the design has been indicated by the performance of the model since installation in October 1975. Exxon is considering the guyed tower as one alternative for producing deepwater tracts in the Mississippi Canyon area of the Gulf of Mexico. Present plans call for installation of a guyed tower in 1200 feet of water 65 miles southeast of Grand Isle, Louisiana, in the same general location as Shell's Cognac platform. Exxon feels the guyed tower concept can be extended into waters 2500 to 3000 feet deep (Bleakley, 1980).

Another innovative concept for deepwater production (and probably the most feasible fixed platform design for extreme water depths) is Conoco's tension leg platform. This platform is scheduled for operation on the Hutton Field in the North Sea by 1984 and installation has already begun. The TLP is basically a semi-submersible, although it will be larger than any presently available semi-submersible. Figure 4 shows the general configuration of a tension leg platform.

Conoco's platform will be attached to the ocean floor by 12 tethered or tension legs 9 inches in diameter. The tension legs will be in four groups, comprised of 3 tension legs at each corner of the platform. They will be attached to the seafloor by anchoring templates, previously drilled and cemented in. The tension legs can be reduced or lengthened. At each end of the tether is a locking assembly fitted with a flex joint. The locking
Figure Three: Guyed Tower
(After Kraft, Campbell, and Ploessell, 1979)
Figure Four: Tension Leg Platform
(After Kraft, Campbell, and Ploessel, 1979)
feature will allow the TLP to connect its 12 tethers to the seafloor anchoring systems by stabbing them into the locking mechanism, without diver assistance. Later, they can be automatically released and recovered for replacement, maintenance, or relocation of the rig. Once anchored the TLP is pulled down on the tethers, resulting in 1000 tons of tension on each of the 12 tethers. The legs will be in tension rather than compression like bottom supported platforms and their length will have far less structural significance. When tension is applied the platform will have virtually no vertical motion, although the flex joints will permit approximately 79 feet of lateral motion in heavy weather. At this point, the force on the tethers will be nearly 200 tons each, acting to restore the legs to a vertical position. Conoco's TLP is designed to withstand effects of the 100-year northern North Sea storm, with a 98 foot wave and 98 mph wind, although most of the waves expected to be encountered will be of smaller magnitude and shorter periods (Ives, 1980). Although Conoco's design has an expected maximum depth capability of 2000 feet, oil industry experts feel that the tension leg platform could be operated in 6000 feet of water with some experience and additional engineering (Rogers, 1980).

Gulf Research and Development and British Petroleum have both recently come up with their own radical modifications to Conoco's basic TLP design. Gulf's modification to the TLP configuration incorporates a hexagonal leg hull with wells through each leg and a track encircling the deck upon which the rotary rig rests. The tensioning members are incorporated in each of the legs. Gulf engineers feel that the hexagonal hull configuration will be less sensitive to wind and wave direction and severity (Offshore, 1980). The BP design utilizes a four-leg hull of square configuration also with separate tensioning members in each of the four legs. In addition to the guyed tower and TLP, Shell Oil is experimenting with new designs which they feel are feasible to water depths of about 6000 ft. (Shell Oil - personal communication).

A major contribution to deepwater oil and gas production may be made by the subsea completion/production systems now in various stages of design, development, and installation. An ideal system for extreme deepwater production should be able to be installed and operated without the use of divers.

The most common type of subsea completion is the satellite well system. This is basically a single well completed on the sea floor and connected by flow lines to a remote central facility. Satellite well systems may be either "wet" or "dry". A wet system consists of a Christmas tree and other components which are exposed to ambient sea floor conditions. Wet subsea completion systems have been made diverless by the development of through-flow-line/pump down tool systems (TFL/PDT). These systems provide a method for conducting operations by pumping tools through flow lines and into and out of tubing strings. A closed hydraulic system is used with fluid pressure providing energy to a piston attached to a service tool string (Morrill, 1980). Figure 5 shows a subsea tree equipped for TFL
Figure Five: Satellite well system
(From Mason, 1980)
maintenance and diverless installation. Diverless flowline pull-in and connection systems are contained in this set-up, as well as a diverless control module, and a pop-up buoy system which allows for the reestablishment of guidelines in deep water (Mason, 1980). Oil industry personnel claim a system such as this can be installed at any water depth.

Exxon Production Research has developed a 'wet' Subsea Production System (SPS) which has undergone extensive land and subsea tests. The system consists of a large template supporting several subsystems designed for various functions of oil and gas production. The system is capable of deepwater operation and can be serviced by remote controlled manipulators.

The template is a large tabular structure used to carry all of the subarea equipment to the sea floor and to provide for easy alignment of the wells and pipelines to the manifold. Enclosed by the template are the various subsystems - the manifold, pump and separator, the completed wells and Christmas trees. The main component of the system is the rectangular production manifold containing the piping to carry out the various operations. It is fail-safe (all valves close on loss of hydraulic pressure) and designed for use with pump-down tools for well tests and other assignments. The manifold is ready to handle production from the time the wells start to flow until the field is abandoned. All joints are either metal-to-metal or 100% x-rayed welds for long-life and reliability. The SPS is designed to permit replacement of malfunctioning components without need for divers. This is carried out by a 68,000 pound Maintenance Manipulator (remotely operated via surface support vessels) that brings a new piece of equipment down to the unit, replaces the faulty gear, and returns to the surface with the old one. The manipulator maneuvers within the SPS template on tracks that bring all replaceable components within reach. It carries TV equipment and lights to aid in surface controlled operation of the unit. The only components of SPS that are not bottom replaceable are the sea floor template and the wellheads. An overall view of the SPS System is shown on Figure 6.

The piping of the manifold surrounds the wells that are to be produced by the system. They are rigged for pump-down tools, are equipped with down-hole safety valves below the mudline, and have conventional fail-safe master valves in the Christmas tree.

After extensive land tests, a complete SPS was installed in West Delta Block 74 off Louisiana. Three wells were tapped by the unit that in turn processed the 500 barrel/day oil flow and transferred it to a nearby platform. During the test (that lasted over two years) the SPS was maintained by the Remote Manipulator lowered from surface support vessels. The manipulator successfully completed more than 50 work missions during the test. The long-term test was designed to demonstrate the ability of the SPS to function successfully in the ocean environment, to perform reliably over a period of time, and to provide data on the economic feasibility of the design. Future operation and modification of the
Figure Six: Exxon Subsea Production System (SPS) (From Snyder and McKinney, 1978)
Exxon SPS may allow for its placement in unlimited water depths. At the present time Exxon Production Research believes the system can be safely operated in depths of 6000 ft. or more (personal communication-Exxon).

Subsea completion systems may also be "dry" systems. A dry completion is one in which the wellhead equipment is enclosed within a chamber and is accessible by attachment of a manned bell (especially designed to mate with the subsea unit) lowered by surface support vessels. An advantage of the dry system is that well control lines and the flowline can be connected from inside the chamber (U.S. Dept. of Interior, BLM, 1980). Water depth is not critical in the installation of dry systems as the chamber wall thickness can always be increased accordingly. As submersible technology expands to greater depths, dry subsea completions become more economically feasible.

Shell Oil Company and Lockheed Petroleum Services joined efforts to develop and field test a dry ocean floor completion system for completing and producing several wells as a single system. The system is based on the concept of housing more or less standard equipment in one-atmosphere chambers. Components of the subsea system include wellhead cellars, distribution lines, and the Production Manifold. This manifold (also a one-atmosphere unit) is the core of the system. It acts as the central gathering point for the wells in the field, and contains all equipment necessary to transfer the gas and oil to a floating or fixed platform facility for further processing. Connecting lines between the wellheads and production manifold are connected to the units through an inclined opening in the sides of the chambers called the 'bullnose port'. Flexible oil/gas lines are pulled into the ports via a cable and winch system inside the wellhead cellar or manifold. The system is completely diverless and all components are maintained at one atmosphere of pressure. It is fully automated for remote operation, is capable of through-flow-line (TFL) tool operation, and can be designed for any water depth (ETA Offshore Seminars, Inc.). Two examples of the Lockheed system wellhead equipment are shown in Figure 7.

These subsea completion systems can be linked by pipelines to production and storage facilities in shallower water or to facilities directly on land. Alternatively, these systems can be linked to floating production systems as discussed later in this report.
Figure Seven: Lockheed One-Atmosphere Subsea Completion System

a. For wellhead installation where TFL tools are not required.
b. A wellhead cellar designed to enclose the TFL tubing loop.

Source: Lockheed Petroleum Services, Ltd.
The majority of actual working subsea completion systems to date have been installed in low pressure, shallow water environments (less than 85 feet). More than 300 subsea completions have been made in Lake Erie since the first known underwater North American completion was made there in 1943. One hundred-six subsea completions were made worldwide between 1960 and 1974 (U.S. Dept. of Interior, BLM, New Orleans, 1980). Lockheed Petroleum currently holds the world deep-water record after installation of a subsea production system at a depth of 198 m (620 ft) offshore Brazil. There were approximately 21 subsea wells completed on the sea floor in 1979 and about 59 subsea trees are presently on order (Mason, 1980). No operating or safety-related problems have been encountered under actual working conditions of the subsea networks operating presently.

If hydrocarbons in economically producible quantities are found in the deeper portions of the U.S. Outer Continental Margin, facilities for transportation of the oil or gas to onshore facilities for processing must be made available. The oil/gas products may either be transported to land by tankers after being pumped to the surface or transported by pipelines.

Pipelines may be installed using several different techniques. Two of the most applicable approaches to deepwater placement of pipelines would seem to be the use of either a reel barge or a dynamically positioned semi-submersible platform. The semi-submersible barge is similar to a conventional lay barge in that it is equipped with a production ramp, welding station, facilities for coating the welded joints, tensioners, devices for lowering the pipe overboard, etc., and is self-propelled. The semi-submersible, however, is able to perform in more severe weather and wave conditions. With dynamic positioning aboard, the platform can maintain a more accurate and precise position while pipe is being laid. As the vessel advances by using anchoring lines, position is maintained by thruster control. This negates the effects of yaw or turning tendencies which normally might be present. A general configuration of this set-up is illustrated in Figure 8.

The traditional method of laying marine pipelines is to join the sections of pipe on the lay vessel. In this method the pipe is placed aboard in 40 to 80 foot sections. During lay operations several sections are positioned and the joints welded simultaneously on a long, gently curved production ramp. The joints are then x-rayed and protectively coated. When these operations are complete, the vessel is moved forward by winching in on the anchoring lines. The pipe leaves the vessel via the stinger, a device designed to help limit the stress imposed on the pipe as it is laid. Tensioners along the production ramp provide a hold-back force, which limits the curvature of the pipe string, holding the strain on the pipe to a minimum. For deepwater laying operations a curved stinger or ramp must be used. This allows the pipe to leave the vessel at a steeper angle, and settle to the bottom in a 'J' curve greatly reducing pipe stress. Shallow water operations place the pipe on the bottom in an 'S' curve. The differences in these configurations are illustrated in Figures 9A and 9B. Figure 9B shows a variation or extension of the stinger method for deeper water. This variation utilizes an inclined ramp in place of the stinger. The ramp is hinged to the lay vessel and thus the angle can be adjusted as water depth changes. It is presently believed that the inclined ramp method could be effective to water depths as great as 9000 feet (Weaver, 1980a).
Figure Eight: Dynamically-positioned semisubmersible lay barge

(After Gorden and Rochelle, 1976)
Figure Nine A: Lay barge with stinger showing 'S' curve developed during lay operation.
(After Gordon and Rochelle, 1976)

Figure Nine B: Inclined ramp/curved stinger 'J' curve developed during lay operation.
(After Gordon and Rochelle, 1976)
The dynamically-positioned semi-submersible Castoro VI, operated by the Saipem Co., recently established a world's record in deepwater pipelaying by laying a 20 inch gas line across a 608 m deep (2000 ft) section of Mediterranean seabed along the trans-Mediterranean route from Tunisia to Sicily. A recent report by the Bechtel Co. indicates that a semi-submersible rig such as the Castoro Sei, equipped with a rotary rig for vertical laying of pipeline would be feasible beyond water depths of 3000 ft. (Offshore, July, 1980). Saipem officials feel confident that the Castoro Sei presently has the capabilities to lay pipe to depths of 6000 to 7000 ft. (Hale, 1980).

The reel lay method utilizes a continuous string of pipe that has been joined ashore and wound onto a reel on the vessel. Reel diameter is such that only plastic deformation of the pipe occurs. At location, the end of the previously laid pipe is attached to the pipe on the reel. The pipe is then fed from the reel through a gear that straightens the pipe before it goes overboard. Maximum pipe diameter for laying by the reel method is presently 16 inches.

A new concept in the laying of deepwater pipelines by the reel method is the construction of Santa Fe's self-propelled, vertical reel layship Apache, which recently laid and connected four flowlines and two control umbilicals for British Petroleum. An illustration of the Apache can be seen in Figure 10. The ship is 404 feet long and can carry 2000 tons of pipe 5000 miles at 12.5 knots. In addition, it is dynamically positioned by four 800 hp thrusters for lay operations (Jorgensen, 1980). The Apache is presently capable of laying 16 inch pipe in water depths around 610 meters (2000 ft.) and smaller lines in water depths of 915 m (3000 ft).

Deepwater pipelines may also be laid by the flotation method - a 10 inch line was laid in Lake Geneva at 1100 feet using flotation. In this method the pipe is welded ashore in long sections, flotation is attached to counteract pipe weight, and the pipe is then towed to location and joined to previous sections of pipe. Submergence of the pipe may take place via conventional stinger methods or by regulating the flotation to gradually lower the string to the bottom.

It is also possible to install pipe by pulling long strings of it along the bottom - at times into pre-trenched channels. As in the flotation method the pipe is assembled in a nearby facility, welded, and then pulled (rather than floated) to final location.

In addition to pipe stress, the problems of fatigue, buckling, etc., must be overcome in deepwater pipeline operations. Dynamic analysis of pipeline installation is a necessity for deepwater. Sea state, vessel motions, pipe diameter and weight, stinger configuration, pipe tension etc., must be considered in evaluating any pipelaying operation (Mason, 1980). Concentrated industry research and effort have led to development of complex and sophisticated computer codes for dynamic analysis of deepwater operations.
Figure Ten: Apache reel pipelay ship
(After Friman, Uyeda, and Bidstrup, 1978)
In many cases it is desirable (or required by regulations) to protect the laid pipeline from environmental effects such as scour, and man-induced damage due to fishing or vessel anchoring. The classic method of pipe burial has been jetting air and water at up to 25,000 psi on the bottom adjacent to the previously laid pipe. The pipe would then sink into the depression. However, this method is not always effective and it may cause the soils to lose normal structural properties. A unique approach to deepwater trenching has been undertaken by Norway's state-owned oil company, Statoil. They have developed a remote trenching unit, connected by umbilical cords to a surface ship. The system utilizes acoustic position-referencing systems and computer interfacing. Figure 11 shows the general operation of this unit. A dual narrow-beam scanning sonar unit serves as the basic sensor for locating the pipe and aligning the vehicle with it during mating. Subsea televisions serve as backup to the sonar for trenching purposes. Deepwater testing of the system has been completed and no problems were encountered.

An extremely interesting and feasible concept for deepwater production is the semisubmersible or floating production system (see Figure 12). This concept utilizes and unitizes several of the deepwater technologies previously mentioned in this report.

The floating production system utilizes a semisubmersible which has been converted from a drilling rig to a production platform. The semisubmersible is kept on station by means of a conventional chain and wire rope mooring or by dynamic positioning. For small reservoirs a manifold is placed on the seafloor connecting the flow of oil or gas from several satellite wells. The product is subsequently routed through a production riser up into the semisubmersible for processing. The processed product is then flowed down the riser, through a sea floor pipeline, up a single point mooring structure and into a shuttle tanker for transport to market (Mason, 1980). The single point mooring structure can be any of several types of tanker loading configurations, depending on water depth and wind and wave conditions (see Figure 13).

Several variations on the above mentioned system are feasible. For large reservoirs the manifold can be replaced by a seafloor template similar in appearance to Exxon's SPS. This template could not only handle several wells located in the immediate vicinity, but could also be tied into a significant number of satellite wells. Exxon envisions their SPS being located in deepwater with the product being flowed through pipelines into shallower water, where it would be routed up a production riser into a ship-shape vessel which has been converted into a production/storage vessel.

Countless other variations revolve around this concept, but they all have one significant goal in common: the replacement of the conventional fixed production platform with that of a floating production platform. Two actual working semisubmersible production systems exist presently. These are located in the Argyll field in the North Sea and the Garoupa field offshore Brazil. Although located in shallow water, industry officials are confident that the concept can successfully be extended into deepwater environments.
Figure Eleven: Operation of Statoil's deepwater pipeline burial system
(After Petroleum Engineer International, July, 1979)
Figure Twelve: Floating (semisubmersible) production system
(From Mason, 1980)
TANKER LOADING - SINGLE POINT MOORINGS (SPM)

FLOATING

1. CALM
2. ELSBM
3. SALM -1

FIXED OR MOORED

4. SALM -2
5. ALP
6. SPAR

Figure Thirteen: Single point mooring systems
(From Coleman, 1980)
Deepwater Drilling and Blowout Prevention

Blowouts are the most costly and dangerous hazard associated with the operation of an oil or gas platform. A blowout is an accidental escape of oil or gas from a well caused by a sudden loss of control in underground pressures (Bank of Scotland, 1975).

The USGS has maintained a computerized file of all blowouts which have occurred on the OCS since 1971 (Danenberger, 1980). During the 8-year period from 1971-78, 46 blowouts, all in the Gulf of Mexico, occurred: 17 during exploratory operations, 13 during development drilling, 5 during production, 8 during workover activities, and 3 during completion activities. Most of these blowouts had short durations and involved minimal amounts of oil spillage. In cases of blowouts occurring during development drilling for natural gas, wells have been known to release gas around the outside of the surface casing for several months after the blowout. In most cases, however, well control was reestablished within a relatively short period of time with minimal gas loss. The most severe blowout in U.S. waters during this time period occurred during operations (nondrilling) on Gulf of Mexico Eugene Island Block 215 in 1971 when an oil pump on the platform exploded, destroyed the platform and resulting in a fire which burned for 55 days.

Controlling and/or preventing blowouts during deepwater operations is not significantly different than in shallow water operations. In most cases, proper analysis and continuous and/or intermittent surveillance of the mud system being employed can detect small changes in subsurface pressure before they become visually apparent (ETA Offshore Seminars, Inc. 1976). Should monitoring of the "mud in" and "mud out" indicate an oncoming increase in pressure, the pumping down of mud can in most cases, prevent a blowout.

In deepwater drilling operations precise monitoring and maintenance of the mud system is particularly necessary to protect against the fracturing of surface sedimentary formations when drilling in shallow gaseous zones. Fracturing of these formations may result in a sudden influx of over-pressured shallow gas into the well bore. Danenberger (1980) notes that this can be a problem in deepwater drilling because of the relatively greater increase in pressure exerted by the mud column than the increase in pressure exerted by the overburden.

Blowouts may also be controlled through the drilling of relief wells and/or the activation of the blow-out-preventor (BOP). Relief wells are drilled to establish direct connection with the wild-well bore hole (ETA Offshore Seminars, Inc. 1976). During offshore operations within roughly the last decade, none of the blowouts which have occurred in U.S. waters required a relief well to re-establish control of the well. Many of these blowouts have "bridged" or sealed off through natural processes.
The drilling of relief wells involves the injection of heavy mud into the overpressured bore hole at a rate greater than the lifting capacity of the blowing well, until control is established. In certain cases, bottom hole pressure of the reservoir is such that it exceeds a pressure capable of being balanced by feasible mud injection rates. In this situation, the relief well may be deliberately aimed off the wild well landing point so that mud can be injected into the reservoir to plug the passageways open to the escaping reservoir fluids (ETA Offshore Seminars, Inc., 1976).

After relief well operations succeed in bringing the wild-well under control, final plugging operations are still necessary to gain permanent well control. Relief well techniques are expensive to implement, as an additional drilling rig is necessary to actually drill the relief well. At the present time, drilling rigs capable of operating in water depths as great as 6000 to 8000 ft. are extremely scarce. Only 3 dynamically positioned drillships (Discoverer Seven Seas, Sedco 471, Sedco 472) and 1 dynamically positioned semisubmersible (Sedco 709) are rated to operate at these extreme depths. Thus, rig availability is a limiting factor in the implementation of relief well techniques should a blowout occur within the proposed sale area. The timely activation of the rams on the blowout preventor (BOP) stack of the drilling system will, in most cases, prevent a catastrophic blowout from occurring. The BOP's purpose, in general, is to quickly close the well bore in the event that the well starts a "kick", a "kick" being an indication of oncoming pressure increase and influx of fluid from the formation. The quicker the response of the BOP, the faster the well can be brought under control.

An important feature of deepwater drilling operations is that the BOP is normally situated on the seafloor. This prevents a fire from reaching the wellhead and also limits the loss of the structural integrity of the iron on the wellhead (Weaver, 1980b).

The French companies CFP (Compagnie Francaise des Petroles) and Elf Aquitaine have noted that controlling a "kick" by the normal method of circulating it out may be practical only to water depths of about 6500 ft. In deeper water, it may be necessary to treat the riser and the well as two separate kicks. Consequently, it may be necessary to insert what amounts to an inverted BOP in the base of the riser to be able to separately control the kick inside it and also to facilitate an emergency disconnect. Extra service lines may be required for proper circulation of the mud within the riser (Steven, 1981).

Most B.O.P. systems to date have employed hydraulic control signals for activation of the rams for deepwater operations, hydraulic systems could be too slow in response time and thus ineffective in terms of blowout control. Thus, electromechanical systems have been developed for rapid BOP activation.

Cameron Iron Works, Inc. has developed a highly reliable, electrically operated blowout preventer system exclusively for use in deep water (Miller and Sowers, 1977). The system utilizes interconnecting cable harnesses which are oil-filled, pressure balanced, and activated by a
low-voltage power input from the instrumentation and control circuits situated on the platform. Testing of the system proved it to be rapid, safe, and most of all, highly reliable. In addition, the cable industry has responded favorably to the BOP user's need for durable umbilicals having a fast response time (Kerr and Sawin, 1977).

A BOP system such as the one described above will probably be used on any platforms placed within a deepwater area. In addition, designs for production platforms such as the tension leg platform (TLP) call for the installation of other safety devices. The TLP will be equipped with a safety block valve on the sea floor template. This valve, with dual fail-safe operators, will be the primary control point for each well, and provides for maximum security for well control (Falkner and Franks, 1978). Rapid "shutting in" of the well at the seafloor will be possible during emergency procedures.

Available data from U.S.G.S. failure records from the Gulf of Mexico, along with A.P.I. - sponsored tests, manufacturer's field tests, etc. indicate that certain types of subsurface safety valves are extremely effective in shutting off the flow of produced oil or gas in the event of excessive pressure in (and flow from) the producing zone (Purser, 1977). There are basically two types of subsurface safety valves: "subsurface controlled" and "surface controlled".

"Surface controlled" valves close by virtue of hydraulic, pneumatic, or electrical signals sent to it through control lines from the surface. "Subsurface controlled" valves close automatically at a predetermined mass flow rate through the valve. Subsurface safety valves can be placed at any vertical location between the wellhead and the well completion zone, but USGS regulations require that the device be installed at a depth of 30m (98 ft) or more below the ocean floor.

Analysis of failure rates for subsurface safety valves indicates that "subsurface controlled" valves have a significantly lower rate of failure than "surface controlled" valves (Purser, 1977). The most frequent cause of failure, by far, was erosion of the valve by sand particles (sand cutting) from produced sand. These sand particles can destroy the metal and result in leaks and failures anywhere in the system. Purser (1977) notes that many actual blowouts could have been prevented had effective, sand-resistant, "subsurface-controlled" subsurface safety valves been installed at or near the well completion zone. Thus, the installation of such a system would be highly recommended for deep-water operations.

Predictions of the probability of a blowout occurring during deepwater operations in a specific area is impossible. Danenberger (1980) has pointed out that differences in local geology (from both hazards and resource considerations) operating conditions, human factors, and technological changes make forecasting of blowouts from analysis of historical records highly misleading and inaccurate. This is especially true for frontier areas.
Improvements in detection and control of shallow gas can be expected, however, certainly in deepwater areas where drilling and operating costs are high. Additional improvements can also be expected in measurement-while-drilling (MWD) technology, in combating lost circulation, in mud measurement, in understanding the frictional effects related to gas influxes, in well-control training programs and from advances in subsurface-safety valves, completion and workover techniques (Danenberger, 1980).

Deepwater Production and Development Conclusion

The oil and gas industry appears ready and willing to explore and develop resources within the deepwater regions of the United States OCS. The equipment already available, plus the development of prototype and drawing board equipment, methodologies, etc., indicate that the potential is not far from reality. However, only the discovery or indication that economic quantities of oil or gas are present in the deepwater regions will spur industry into actually undertaking such an enormous venture.
References


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