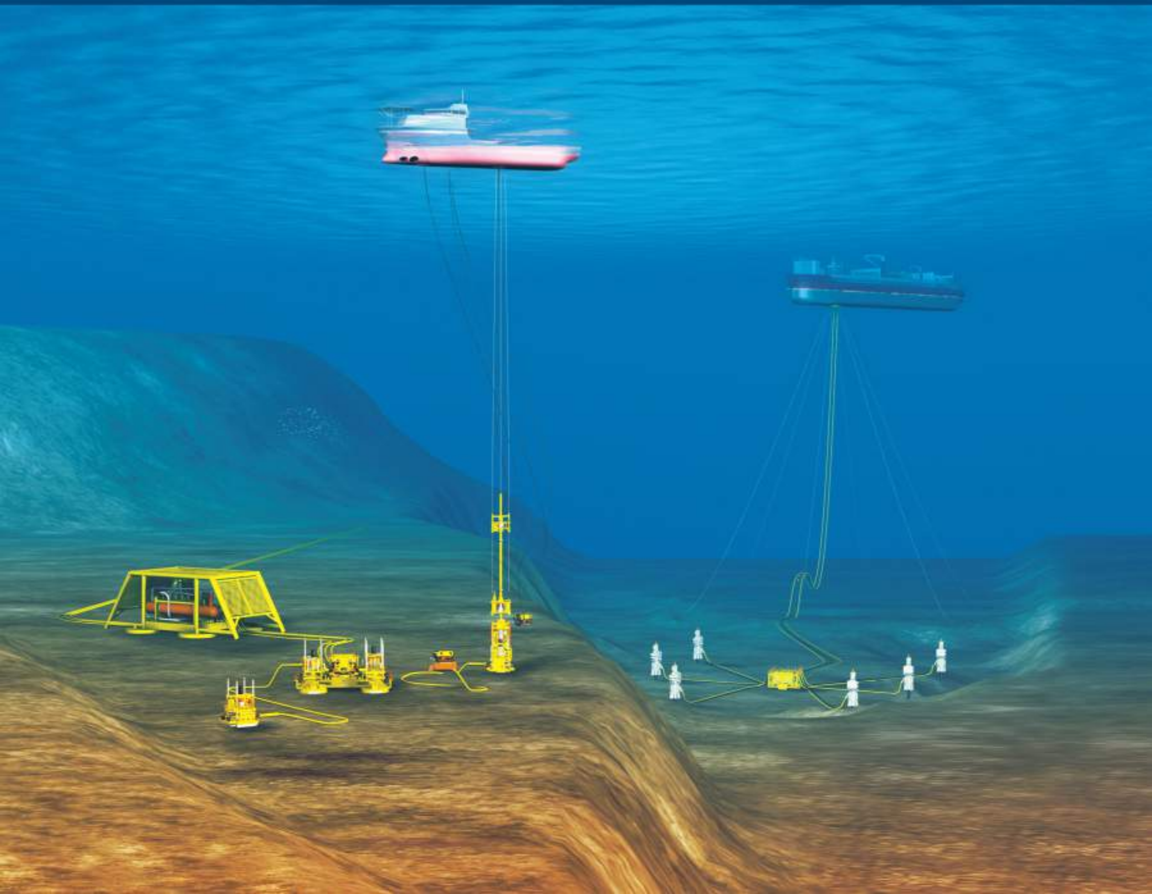
DEEPWATER PETROLEUM EXPLORATION & PRODUCTION

A NONTECHNICAL GUIDE | *2nd Edition*

WILLIAM L. LEFFLER • RICHARD PATTAROZZI • GORDON STERLING



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Foreword

Forewarned is forearmed.

—Miguel De Cervantes (1547–1616)
Don Quixote

We needed to hurry up and write this second edition. As with any foray into a new frontier, history and innovation have been happening almost every day since our first edition's publication date.

As in the first edition, our first two chapters bring you from the first geologic toe-in-the-water in California more than 100 years ago to stepping off the Outer Continental Shelf of the Gulf of Mexico into thousands of feet of water, as well as the plunge into the Campos Basin off the coast of Brazil. That journey is just the prelude to understanding present and even future deepwater operations.

To complete the setting, this edition adds a new complete chapter on geology and geophysics. To pull this off, we asked four accomplished scientists in the field, Stephen Sears, Fred Keller, Tim Garfield, and Mike Forrest, all with decades of experience with large exploration and production (E&P) organizations, to contribute chapter 3.

The processes for exploring, developing, and producing petroleum in the deepwater are about the same as for the shelf or, really, the onshore. From the outside, just four steps take place—explore, appraise, develop, and produce. From the inside, each of these processes takes many more steps, depending on how closely we look. And we look closer in chapters 4 through 13, even more closely than in the first edition. We examine in detail the engineering and scientific schemes that companies use in the deepwater, dealing especially with how they differ from shallower operations and the onshore. We have added other new chapters on the drilling rigs and service vessels used in the deepwater.

A theme underlies this book: how the upstream industry and companies learned their way into the deepwater. The first two chapters almost dwell on it. At the end of chapters 4, 5, 10, 11, and 13, case studies of prominent companies show how they climbed their own learning curves to success. Chapter 14 finishes off the theme by dubbing deepwater the "third wave."

We assumed something about your knowledge of E&P operations—onshore and offshore. Because you bought this book, which has the word "nontechnical" in the title, we treat each subject as if you have but a modicum of background. You should find almost everything easy to understand. If you need more depth, our publisher, PennWell, has a few other books, such as Raymond and Leffler's *Oil and Gas Production in Nontechnical Language* and Norm Hyne's *Nontechnical Guide to Petroleum Geology, Exploration, Drilling, and Production* to help you out.

This book is a collaborative effort of three industry veterans with more than 125 years experience in the industry. Despite that exhaustive and exhausting record, we needed the invaluable input from a throng of other industry experts and former colleagues. We have to recognize some of the many we consulted: Howard Shatto, Bruce Collipp, Mike Forrest, Jim Day, Dick Frisbie, John Huff, Ken Arnold, Doug Peart, George Rodenbusch, Alex van den Berg, Don Jacobsen, Harold Bross, Susan Lorimer, Jim Seaver, Bob Helmkamp, Franz Kopp, Dean Taylor, Mike Talbot, Joe Netherland, Bradley Beitler, Ken Dupal, Rich Smith, and Paul Wieg. Without their help, we could not have satisfied our own standards for a quality product. Still, we interpreted all they said and are therefore responsible for the way we presented it.

Introduction

My reaction when Rich Pattarozzi told me he was working on a nontechnical book about the development and production of oil and natural gas in deepwater has not changed: "At last. Without doubt, our industry needs this book. I could not be more enthusiastic about its content."

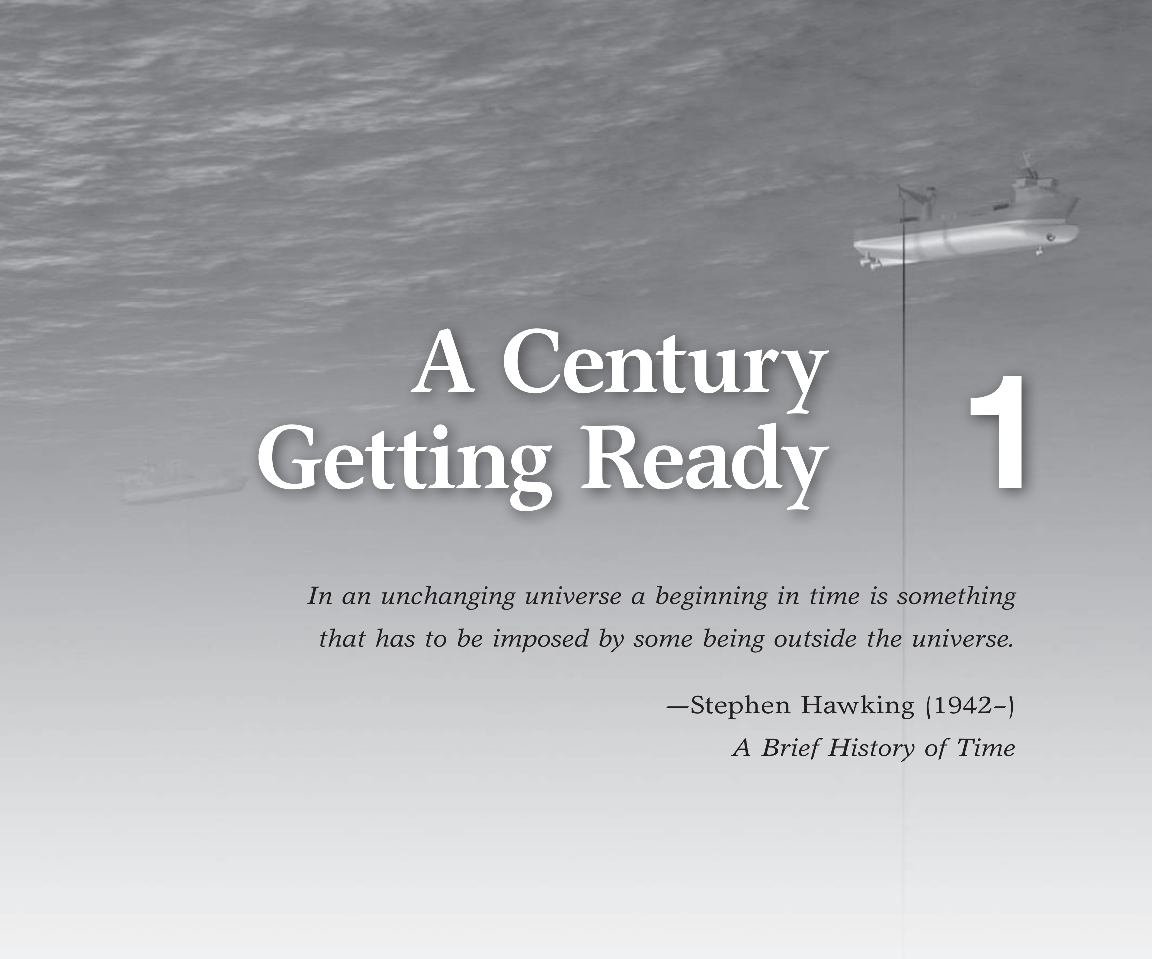
Going into the deepwater demands so much of so many that few individuals can grasp all of the intricate details and technical challenges that have to be overcome. I believe these three authors are unsurpassed in their ability to tell the story from start to finish in an understandable fashion.

Rich Pattarozzi, the talented senior executive at Shell Exploration and Production who created our deepwater organization, provided the dynamic leadership to take Shell where no oil and gas company had been. For Rich, technical and economic challenges were never roadblocks. They were merely opportunities for creativity and innovation that brought out the best in Shell's staff. Gordon Sterling pioneered many of the technical breakthroughs required to take our company on its incredible journey. Never afraid to question conventional engineering paradigms, he encouraged and nurtured the new and often radical approaches necessary to break through the technical barriers that inevitably occurred along the way. And finally, there is Bill Leffler, a long-time planner and strategic thinker at Shell, who has a gift of communicating through the written word. Despite his nontechnical background, Bill is able to transform complicated concepts into clear and concise words that are understandable for the expert and for the layperson.

While this book is all about the oil and gas companies' operations in deepwater, no doubt it will find a home on the desks and bookshelves of many non–oil company readers. Our industry has been most fortunate to have the thousands of dedicated service and supply personnel whose help and innovation in their area of expertise have made this deepwater story possible. Some of the key sectors that have made significant contributions are fabrication and construction, marine transportation, offshore drilling, producing systems, and oil and gas pipelines. Through this incredible journey, a vital partnership between the oil and gas operators and the service and supply industry has developed along the lines so evident in the more than 150-year history of the oil and gas industry.

I recommend this book to you, not only for its readability, but also for the story that it tells. It is the saga of thousands of men and women, working individually and together, both technical and business professionals, people who have accepted a challenge and created the systems that enable our industry to do what the naysayers said could not be done—to produce oil and gas in water depths 5,000 to 10,000 feet—safely, economically, and in an environmentally sound way.

Jack E. Little, President and CEO (retired)
Shell Oil Company
October 18, 2010



A Century Getting Ready 1

In an unchanging universe a beginning in time is something that has to be imposed by some being outside the universe.

—Stephen Hawking (1942–)
A Brief History of Time

Oily Beginnings

Most petrohistorians, from whom we have unabashedly borrowed much of this chapter, trace offshore exploration and production to Summerland, California. In 1897, at this idyllic-sounding spot just southeast of Santa Barbara, Summerland's founder, a spiritualist and sometimes wildcatter, H. L. Williams, boldly inched into the surf. With oil seeping from the ground back for hundreds of yards from the water's edge, Williams skipped the exploration stage and immediately build three wooden piers some 450 yards out from the shoreline. Water depths reached 35 feet (fig. 1–1). Over the next three years, he erected 20 derricks atop the piers. The power generators and other supporting equipment sat along the beachfront. Williams's crew, like most other drillers at that time, had not yet adopted rotary drilling rigs. Instead they set a steel pipe, called a *casing*, from the drilling platform down through the sandy bottom. Then they used cable tools to pound their way down 455 feet to two oil sands.

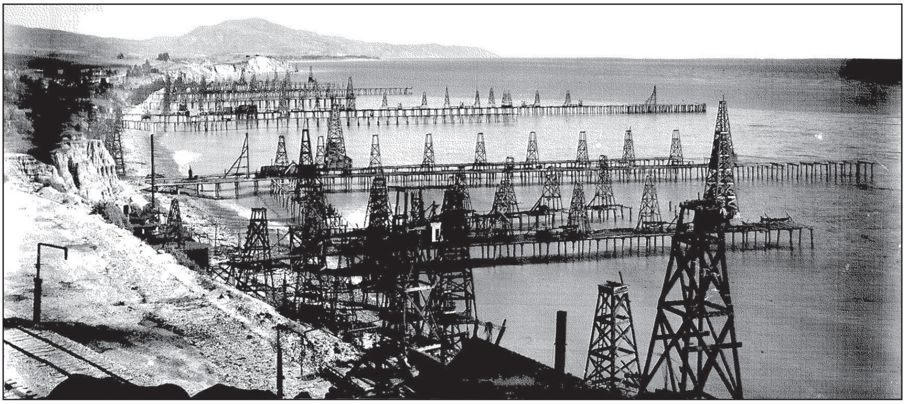


Fig. 1–1. Piers and derricks at Summerland, California, 1901. (Courtesy USGS.)

Bold as it was, the effort paled in comparison to its contemporary, Spindletop, the 80,000-barrels-per-day gusher drilled onshore near Beaumont, Texas. The most prolific well at Summerland reached only 75 barrels per day, the average well only two. Production peaked in 1902 and declined rapidly after that. Williams abandoned Summerland, the field, and his cult a few years later, leaving an ugly blight of piers and oily beach behind. The piers decayed slowly until 1942, when they finally succumbed to a violent tidal wave.

Scores of other venturers copied the pier and derrick technique along the California coast over the next ten years. At one, the Elwood field, the piers extended 1,800 feet from the shore, and still reached a water depth of only 30 feet. Not until 1932 did the Indian Oil Company courageously build a stand-alone platform in the shallow Pacific Ocean waters off Rincon, California.

The term *offshore* usually conjures up visions of vast expanses of water well beyond the pounding surf. However, the next important bit of offshore history happened in a more contained locale. In the area around Lake Caddo in East Texas over the years following 1900, wildcatters searching for oil continually stumbled on pockets of associated natural gas—to the chagrin of most. Gas cost much more to transport and required large discoveries and dense populations to create a market. Only one out of three of these conditions appealed to an East Texas wildcatter. In 1907, J. B. McCann, a scout for Gulf Oil Corporation, mulled over maps of the Lake Caddo area and thought about the gassy province that lay below. Late one night, he used a novel tool to prove his theories. He rowed across the lake, carefully touching lighted matches to the vapors bubbling from the waters. Besides successfully avoiding self-immolation, he convinced himself, and eventually W. L. Mellon in Gulf headquarters at Pittsburg, that a large oil and gas field crossed under the lake.

Gulf acquired the concession to drill 8,000 acres of lake bottom and brought new techniques to the area and to the industry. Starting in 1910, they towed up the Mississippi and Red Rivers a floating pile driver, a fleet of supply boats, and barges of derricks, boilers, and generators. In the lake, they drove pilings by using the abundant cypress trees felled along the shoreline. Atop they built platforms for their derricks (fig. 1–2) and pipe racks. Each drilling/production platform had its own derrick and gas-driven generator. Each pumped production down a 3-inch diameter steel flowline laid along the lake bottom to separation and gathering stations atop other platforms.

Over the next four decades Gulf drilled 278 wells and produced 13 million barrels of oil from under Lake Caddo, creating in the process a commercially successful prototype for water-based operations, the platform on piles.

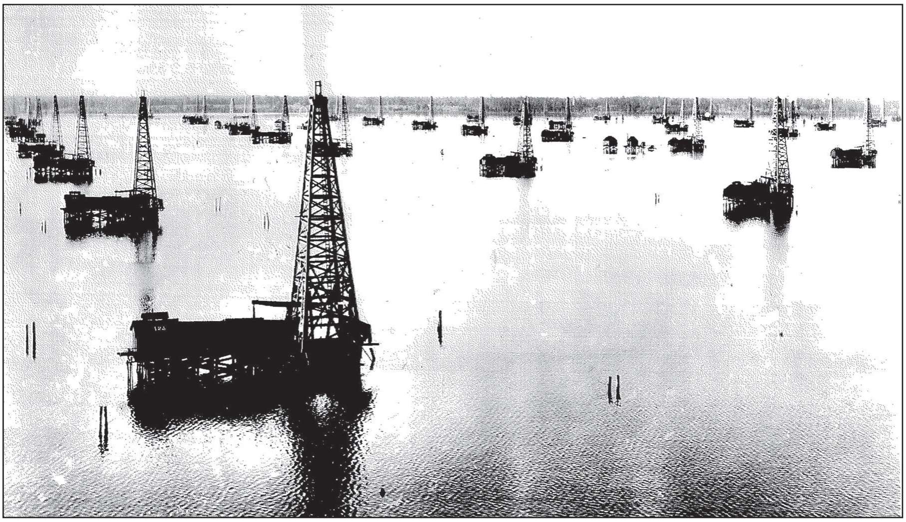


Fig. 1–2. Drilling from wooden pile platforms in Lake Caddo, Texas. (Courtesy Louisiana Collection, State Library of Louisiana.)

Concrete Progress

American notions aside, not all progress and innovation took place in the United States. Production in Lake Maracaibo, Venezuela, in the mid-1920s might have replicated Caddo Lake but for one thing, the dreaded teredo. These intrusive shipworms had pestered mariners since ancient times. In less than eight months these pesky parasites could chew through the wooden pilings that supported a Lake Maracaibo drilling platform, not allowing enough time to make a profit. Creosoted pine from the United States proved a technically effective antidote, but the expense made it an uneconomic solution.

In an instance of serendipity, the Venezuelan government had contracted with Raymond Concrete Pile Company to build a seawall on the lakefront near the oil fields, thereby underwriting an entire infrastructure necessary to make concrete platform pilings. Lago Petroleum (later Creole Petroleum, and then Esso, until the Venezuelan government nationalized it) tried using these concrete pilings in place of the wooden pilings. Soon they were fitting the pilings with steel heads to allow faster installation and tying them together with steel and wire rope for structural integrity. In the next thirty years industry erected nine hundred concrete platforms in Lake Maracaibo. By the 1950s, they used hollow cylindrical concrete piles with 5-inch walls and 54-inch diameters and lengths of 200 feet that were prestressed with steel cable.

Free At Last

At the same time Lago was developing Lake Maracaibo, the Texas Company, later Texaco, was searching for a better idea for their properties in the Louisiana swamps. Platforms on driven wooden pilings worked, but the expense left room for improvement. The idea of using a barge sunk in place as a drilling platform intrigued the Texas Company. In their own prudent way they first visited the U.S. Patent Office and discovered that Louis Giliasso, a merchant marine captain who had worked the Lake

Maracaibo fields, had already claimed the idea. After a Byzantine search, they found him in 1933, improbably running a saloon in Panama. Soon after, the Texas Company sank two standard barges, side-by-side, in a swampy section of Lake Pelto, Louisiana. With only a few feet of water to deal with, they had enough freeboard to weld a platform on top and install a derrick (fig. 1–3).

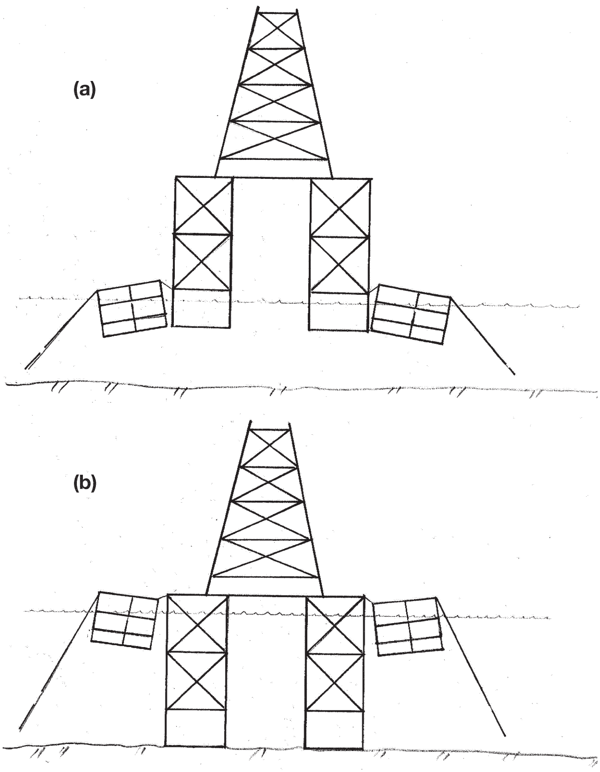


Fig. 1–3. The submersible *Giliasso* from the original U.S. patent application: (a) afloat; (b) submerged

In a magnanimous moment, they named the first submersible the *Giliasso* after its inventor. They sank another barge nearby with a boiler for power supply and proceeded to drill a well to 5,700 feet. Like most of their competitors by the 1930s, they used a rotary drill. Undaunted by finding no hydrocarbon and having to abandon the well, they pulled casing, refloated the barges, and quickly moved around the lake, drilling another five wells over a year's time. A triumph in innovation and efficiency, the *Giliasso* reduced lost time from completion of one well to drilling the next well from seventeen days to two. Mobile offshore drilling had begun.

Other Humble Beginnings

In the 1930s, the Pure Oil Company conducted onshore geophysical and seismic research near the coastal town of Creole, Louisiana. They concluded that the oil sands extended offshore. In 1937, they partnered with Superior Oil Company to test a 33,000-acre offshore concession they had acquired from the state of Louisiana. Brown & Root built for them an unprecedented 30,000 square foot platform atop timber pilings in 14 feet of water a record one mile from the beach. The platform stood 15 feet above the water. With vivid memories of the hurricane that had killed 6,000 people on Galveston Island just a few decades earlier, they reinforced the structure by sheer brute force using steel strapping and redundant piling. In an environment totally unprepared for a new offshore industry, the operator resorted to shrimp boats to tow the equipment barges to the site, to haul crews at the end of each shift, and as supply boats.

The first well, drilled to 9,400 feet, proved successful. Pure soon expanded the modest platform, drilled ten more wells directionally, and eventually pulled nearly four million barrels from the Creole Field.

Shortly after this pioneering step, the oil parade picked up momentum. Humble Oil tried a similar but unsuccessful operation off McFadden Beach on the upper Texas coast in 1938. However, Humble was still unwilling to abandon the onshore paradigm and built a trestle several thousand feet out from shore, inexplicably stopping almost 100 feet from the platform. On top they placed railroad tracks, which they used to haul equipment and supplies. In 1938, a hurricane ravaged the trestle. Unshaken, they rebuilt it, but for naught, because they ultimately found no commercial oil deposits and abandoned the whole scheme.

In 1946, Magnolia Petroleum Company vaulted to a point six miles from the Morgan City, Louisiana, coast. Offshore seismic and geological surveys convinced them that oil provinces unrelated to onshore finds lay in the Gulf of Mexico. Still, they worked in only 16 feet of water. They used a conventional design for their facility except for steel pilings under the area of the platform that supported the derrick, a concession to their concern about stability during harsh weather. Alas, their effort yielded no oil either.

Superior Approaches

The next year, Superior took another leap, technically, economically, and geographically. They moved 18 miles from the Louisiana coast, still in only 20 feet of water. They judged the pile-supported platform in their Creole field too expensive to build in the new, more remote site. Instead they had the J. Ray McDermott Company construct a steel tubular structure in an onshore yard and barged the prefabricated units to the site. Horizontal and diagonal members linked the tubulars like huge Tinker Toys. (See fig. 1–4.) With these innovative steps, Superior shortened installation time, improved structural integrity, reduced costs, improved safety conditions around installation, and, to the contractors' delight, created a new industry sector, prefabrication.

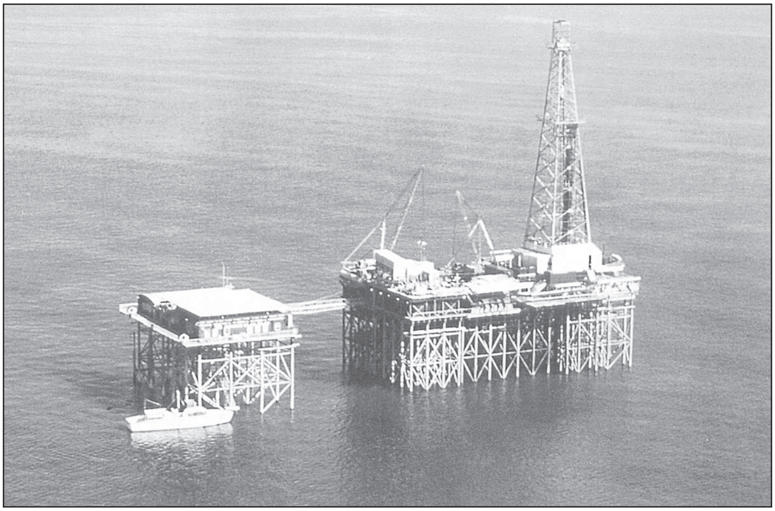


Fig. 1–4. Superior's prefabricated template platform. (Courtesy McDermott International, Inc.)

Superior would have received even more kudos had their first well not been a dry hole. A small Midwest independent preempted them before they could bring on their second and successful well.

Credit usually goes to Kerr-McGee Corporation for ushering in the great and enduring oil bonanza that the Gulf of Mexico has provided. A tortuous struggle from 1945 to 1947 with financial and technical problems led K-M to build only two bantam-sized platforms, one only 2,700 square feet, the other 3,600, in the Ship Shoal Area, 10 miles off the Louisiana coast. On October 14, 1947, K-M snatched the brass ring ahead of the well-financed but ponderous Superior, beating them by eight months to first oil from a well out of landsite.

For design and installation, K-M used Brown & Root, McDermott's arch rival and a company anxious to establish a position in offshore work. Ironically, the design, a platform set on steel and wood piles, predated Superior's. However their frugal but shrewd effort included the use of war surplus barges, air-sea rescue boats, and an LST for support vessels. They converted a 367-foot LST to a drilling tender, adding a living quarters, a 35-ton crane, and winches for mooring. (See fig. 1–5.)

Jackets and Templates

The unlikely term, *jacket*, came about when platform fabricators substituted steel frames for the wooden pilings supporting the decks. They manufactured the frames at onshore yards, towed them to the drilling location, and dropped them on the well site. To anchor the frame in place, the installers drove pilings, sometimes wood but later steel, through the legs of the frame, i.e., the *jackets*. The term was quickly extended to mean the entire structure that supported the platform. Later, as the frames grew to gorilla sizes, too large for a simple crane lift, the legs sometimes held ballasting tanks used to float the frames off the barges. *Templates* later became synonymous with *jackets* where pilings were driven using the legs as guides.

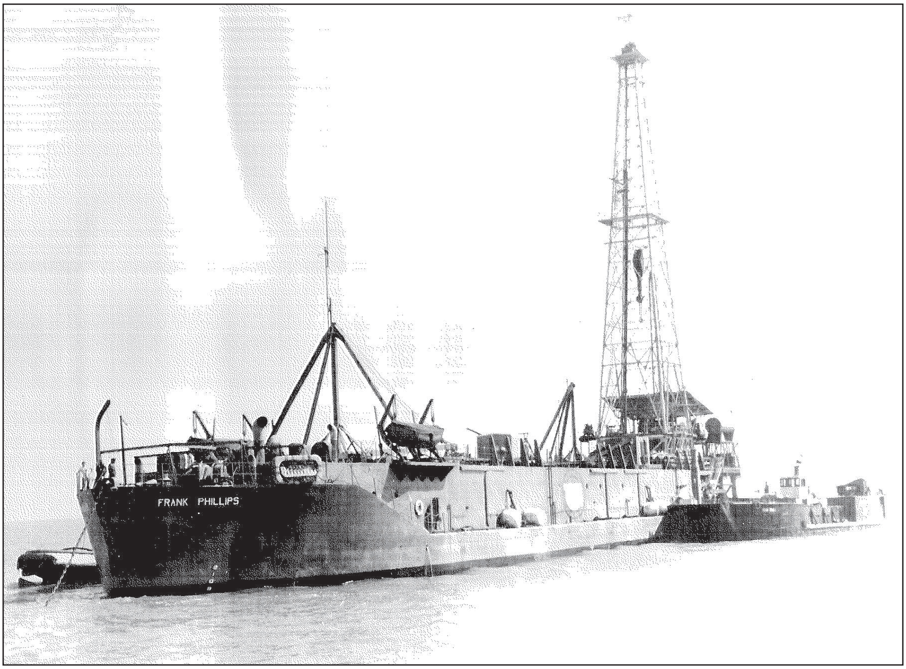


Fig. 1–5. Kerr-McGee's platform in the Ship Shoal area of the Gulf of Mexico with the drilling tender *Frank Phillips*, a converted U.S. Navy surplus LST butted up to it in 1947. (Courtesy Kerr-McGee Corporation.)

When K-M completed their first well at almost 500 barrels per day, the combination platform and drilling tender captured the imagination of the industry, eclipsing Superior's technically superior—but 20 times larger—platform design. K-M had created a paradigm that lessened exploration risks by using fixed platforms of minimal size and mobile drilling tenders. In the event of a dry hole, the bulk of the investment—the tender and the topsides—could be redeployed to another site. LSTs moved to the top of companies' wish lists. Even Humble Oil, not always known for its quick-step, bought 19 LSTs the next year for conversion to drilling tenders.

The boom had started, and numerous companies followed K-M's lead into the Gulf with platforms and tenders. But as they moved to deeper waters, they found that building even a small platform just to drill one or two exploratory wells became too expensive. Clearly they needed new concepts, and they found the next one in the Louisiana swamps.

Submersibles

Along came John T. Hayward, a marine engineer with the unlikely credentials of having supervised the first rotary-drilled oil well in Rumania in 1929. A partnership that included Seaboard Oil Company acquired a prospect in the Gulf of Mexico, without a clue as to the cost of drilling the six wells needed to explore it. In desperation, they turned to Hayward in 1948 for help. He mused about the barges that he had seen sitting on the bottom of the Louisiana swamps with drilling platforms welded on top. Simple linear scale-up for even 30-to-40-foot water depths would lead to 50-foot-high vessels that would drift away with only moderate tidal currents. Instead he designed a totally submerged, conventional-sized barge with columns high enough to support a platform at a safe above-water distance with manageable freeboard and no drift. Pontoons on either side of the barge provided both stability and displacement control.

Despite the initial, skeptical response of his clients, Hayward convinced them to build the prototype rig, the *Breton Rig 20* (fig. 1–6a). In early 1949, they used the rig to drill a half dozen exploration wells in the Gulf, moving 10 to 15 miles between each, drilling within a day or two of leaving the previous site.

The diciest step using *Breton Rig 20* came as the barge submerged—an untoward wave or current could flip it, especially in deeper water. Fortunately that didn't happen, and Kerr-McGee purchased the rig from the partnership. A. J. Laborde, their marine superintendent, still worried about stability but couldn't convince Kerr-McGee to buy an improved design of his. He quit and with Hayward formed a new company, ODECO. There they built *Mr. Charlie* (fig. 1–6b), a submersible designed to handle the stability problem. They rigged the barge with pontoons at each of the long ends. It operated like an old man getting in a car—butt first. They ballasted one pontoon until that end of the barge sat on the bottom. (They still operated in only 20 to 40 feet of water.) With the stability ensured, they filled the other pontoon until the barge rested on the bottom, topside-up every time. ODECO contracted with Shell Oil for *Mr. Charlie* to drill a well near the mouth of the Mississippi, and the rig went on to drill wells in the Gulf of Mexico for the next 30 years. (The venerable *Mr. Charlie*, now anchored of Morgan City, Louisiana, continues its offshore service as a museum and a training center for cooks, divers, and riggers.)

Meanwhile, companies tried design variations of these submersibles, pushing the water depths from scores to almost 200 hundred feet. Some had outrigger hulls; some had large cylindrical tanks in the platform corners. Kerr-McGee, the leading company in submersibles, built the largest and last one, *Rig 54* (fig. 1–6c), in 1963. The unusual-looking rig sported a triangular platform, bottle tanks at each apex 388 feet from each other, and could drill in 175 feet of water. Industry used the 30 submersibles built during this time until the 1990s. Meanwhile other keen minds worked on another innovation to reduce costs of exploration by eliminating the large amount of steel needed to fabricate barges, pontoons, tanks, and bottles.

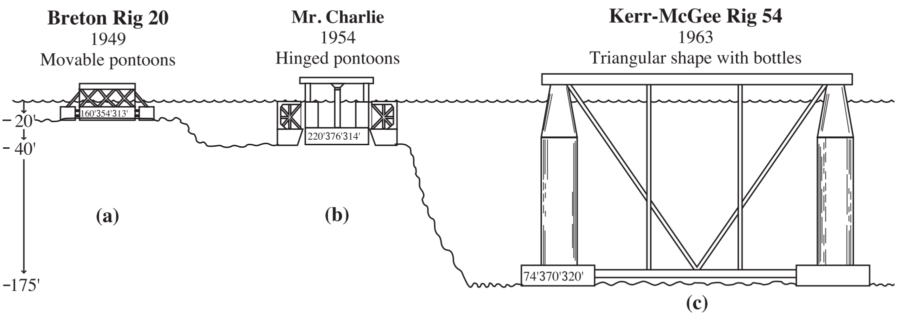


Fig. 1–6. Submersible rigs: a) *The Breton Rig 20* in 1949, the first submersible used offshore; b) Odeco's *Mr. Charlie*; c) Kerr-McGee's *Rig 54* a triangular platform with bottles a each apex. (Rendering after Richard J Howe.)

Bootstrapping

In its chronically assertive fashion, the oil industry stole a concept that had long languished in the marine industry, the *jack-up*. Naval architects and civil engineers had been installing jack-up docks in remote locations around the world for decades, even using them at Normandy during the

Allied invasion of Europe. At mid-century, Colonel Leon B. DeLong build the most famous jack-up, a platform for radar towers 100 miles off Cape Cod in 60 feet of water. For this engineering feat, remarkable at the time, history immortalized the Colonel by thereafter referring to the concept as the DeLong design. The idea was simple. On a barge or other floatable, install tall cylinders (or caissons) around the perimeter. Float the barge to a site and drop the caissons to the bottom like legs. Then jack the platform up the remaining length of the caissons as high above water as required.

In 1950, Magnolia Petroleum Company installed the first Delong-design platform in the Gulf of Mexico. It stood on six caissons in 30 feet of water. Ironically, they used it as a permanent production platform, but McDermott Company followed with a mobile rig the next year, the *DeLong-McDermott No. 1*. (See fig. 1–7.)

Not all efforts made one step forward. An embarrassing two steps back appeared in 1954 by the name of *Mr. Gus*, a design of Bethlehem Steel Company. *Mr. Gus* consisted of a barge, a platform above it, and four legs, all designed to operate in 100 feet of water. The platform stayed in place as the barge slid down the legs to the bottom—sort of a jack-down, not up—to serve as a base for the platform.

On its initial installation in 50 feet of water, the barge tilted, breaking pilings and damaging two legs. Undaunted, Bethlehem took *Mr. Gus* to the yards and repaired the design problem. They sent the rig back out to the Gulf, whereupon it capsized in rough seas and sank off Padre Island, Texas, ending any residual interest in jack-downs.

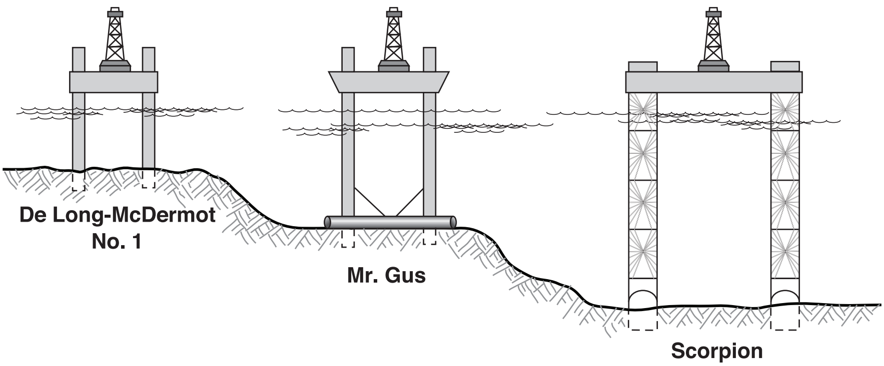


Fig. 1–7. Early jack-up rigs: the *DeLong-McDermott No.1*, *Mr. Gus*, and the *Scorpion*

In 1953, R. G. LeTourneau, who had made his fortune inventing modern earthmoving equipment, entered the offshore industry with a successful and enduring extension of the DeLong design. Rather than caissons around the perimeter, LeTourneau switched to steel truss-like legs. Borrowing from his experience with earth moving equipment, he designed the lifting mechanism with rack-and-pinion drives and electric motors.

The established oil companies showed little interest in the strange configuration that LeTourneau proposed. It took an upstart, Zapata Offshore Company, to underwrite LeTourneau. On March 20, 1956, LeTourneau delivered the *Scorpion* to George H. W. Bush, Zapata's president and founder (fig. 1–8). This jack-up had six 152-foot legs in two triangular sets and an eight-million-pound platform. The dumbbell shape of the platform, an object of more than one disparaging remark, gained scant industry enthusiasm, but almost all jack-ups built after that used the rack-and-pinion lift design with electric drive.

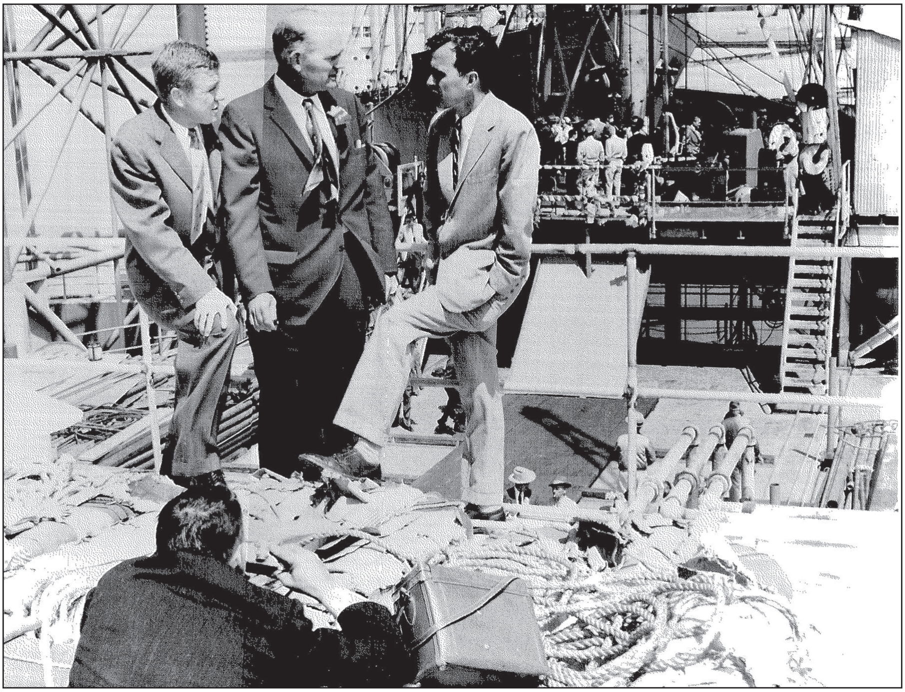


Fig. 1–8. Aboard the *Scorpion*, the first jack-up to use rack-and-pinion drives. (Courtesy George Bush Presidential Library and Museum.)

Floaters

What's better than adversity to stimulate creative juices? Oil companies long coveted the potentially prolific leases off the coast of Southern California. At the same time, Californians had never gotten over the unsightly morass at Summerland and countless other nearby aesthetic and environmental disasters. They raised strong objection to any additional permanent offshore platforms.

Continental, Union, Shell, and Superior Oil Companies formed a consortium, irreverently named the CUSS group, and commissioned the *Submarex*, a drilling ship. They converted yet another war surplus vessel, a patrol boat, by adding a drilling rig cantilevered over the port side amidships. In 1953, the rig drilled in depths of 30 to 400 feet, but vexing engineering problems quickly convinced the CUSS group that they and the *Submarex* were not yet ready for prime time and limited the operations to core sampling, not exploratory wells.

Still the CUSS group learned enough about stability, mooring, and drilling that they began design on *CUSS 1*, a purpose-built drilling vessel launched in 1961.

CUSS 1 had no self-propulsion. Tugs positioned it on a site; moorings held it in place. On board, a derrick perched above an access hole in the barge's center. Under that sat the key innovative mechanism, a birdcage structure on guide wires leading to a landing base on the ocean floor.

They started the drilling sequence with the birdcage on board. They ran surface pipe down through its center (fig. 1–9a), almost to the ocean floor. A drill string run through the surface pipe spudded the hole in the ocean floor. The surface pipe was sunk to a few feet. Blowout preventers were added to the birdcage, and lowered to the bottom. The pipe was cemented in place (figure 1–9b). Registry cones on the birdcage and the guide wires (fig. 1–9c) facilitated landing additional equipment for subsequent drilling and completion. The design would outlast the century.

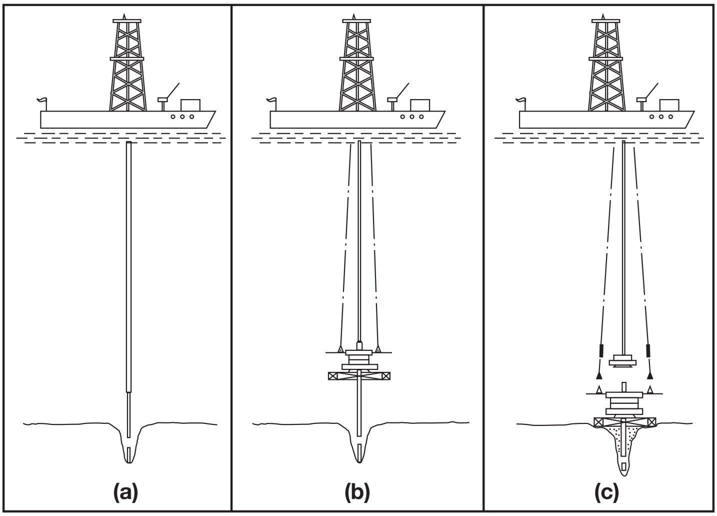


Fig. 1–9. The drilling sequence used aboard the *CUSS 1*

CUSS 1 performed successfully in waters up to 350 feet, drilling core holes down to 6,200 feet. At the same time, Standard Oil of California (Socal) and Brown & Root each experimented with derricks on barges similar to the *Submarex* and the *CUSS 1,* using them primarily for geological surveys. The Offshore Company made an obscure oil discovery in 1958 off the coast of Trinidad from a barge with a derrick. Still, most historians credit *CUSS 1* for starting a new class of exploratory drilling options, floating platforms.

Class Distinction

An obscure government office in New Orleans gave birth to the unlikely term *semi-submersible*. Before sailing, Shell had to apply to the Coast Guard for an operating license for the *Bluewater I*, the first of its class. Shell wanted to avoid using the term "ship," on the application, lest the maritime unions claim jurisdiction. Bruce Collipp, the design engineer, explained to the local Coast Guard Commandant how the *Bluewater I* operated like a submersible, but was only partially sunk. The Commandant wrote on the licensing application, "Type Vessel: Semi-submersible," thereby naming the new class of drilling rigs.

Much of the challenge around floating platforms centered on stability. Bruce Collipp, a naval architect and therefore an unlikely employee of an oil company, articulated all the movements that had to be accommodated while drilling from any floater—surge, sway, pitch, roll, heave, and yaw. His early diagram, shown in figure 1–10, is legend.

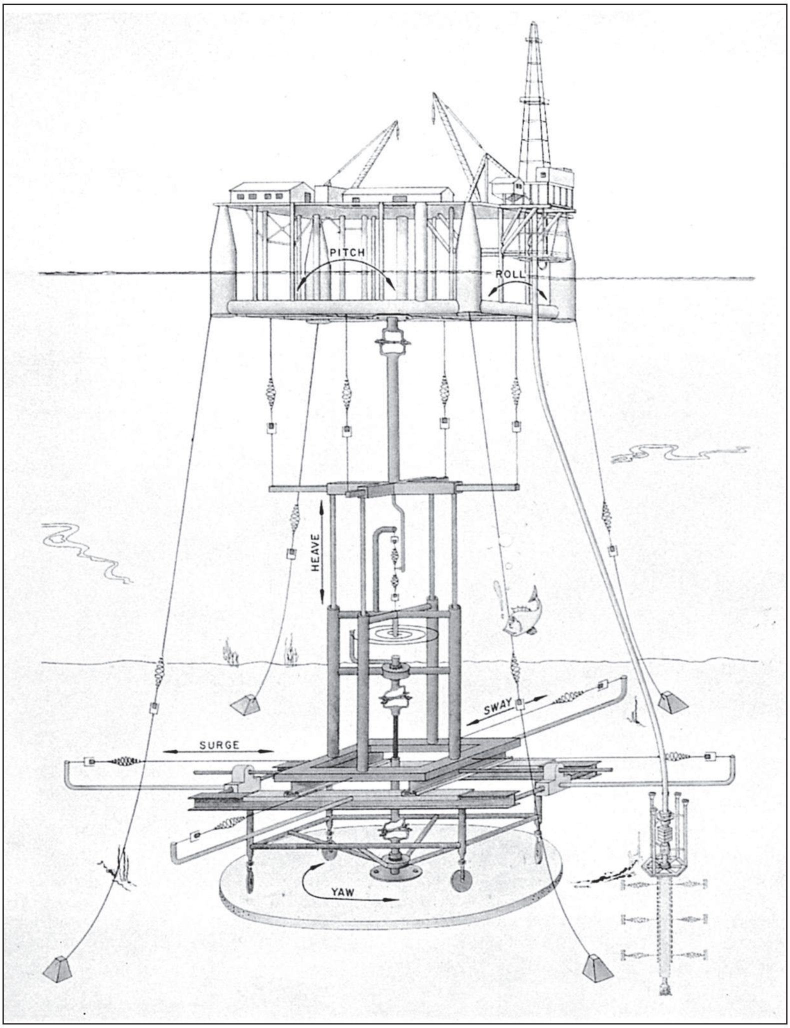


Fig. 1–10. Pioneer Bruce Collipp's DaVinciesque diagram used to explain the six types of motion ocean drillers have to cope with. This and his experience with the *CUSS 1* led to his invention of the semi-submersible. (Courtesy Bruce Collipp.)

While working at Shell, an inspiration came to Collipp when he was aboard an Odeco submersible. During a heavy seas episode, with the submersible under tow to a new location, the operator partially submerged the vessel to protect it from capsizing. Collipp noticed the immediate improvement in stability. He went on to design and patent the first large semi-submersible, the *Bluewater I*. This floating drilling platform started life as a bottle-type submersible, but Shell added additional ballast tanks and then only partially flooded the four bottles. The bottles then lay mostly beneath the water's surface, and their small profile at the water's surface reduced the effects of wave action and gave *Bluewater 1* the stability that hulled vessels could not achieve at the time.

Drillers of exploratory wells in deeper water came to love the semi-submersible in its various sizes and shapes. Some unusual designs included Odeco's *Ocean Driller,* which had a V-shaped platform with multiple caissons; The *Sedco 135* had a triangular platform with bottles at each apex.

This is not to say that companies lost their enthusiasm for drilling from self-propelled, hulled vessels. In parallel development, purpose-built drill ships went into service. In 1962, Sedco built the *Eureka* for Shell Oil (fig. 1–11). To deal with positioning, the *Eureka* had bow and stern propellers extending from the bottom of the ship. The propellers could be rotated 360 degrees to move the ship in any direction.

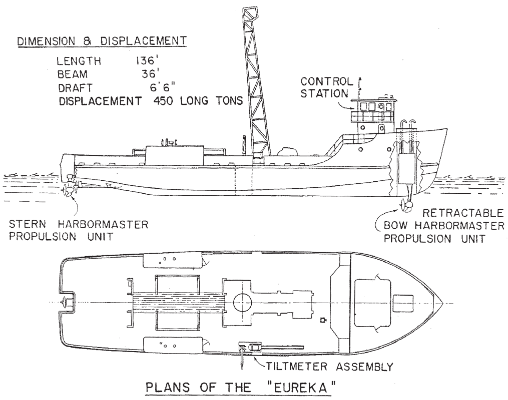


Fig. 1–11. The original 1961 drawings by H. L. Shatto and J. R. Dozier of the drillship *Eureka*. Bow and stern thrusters rotated 360 degrees to maintain the ship's position. (Courtesy Howard Shatto and Shell Oil Company.)

Shatto's Tale

Howard Shatto, a pioneer in drill ship stability, tells the story of maneuvering vessels to place a 15,000-ton platform section onto to a site in the Gulf of Mexico. In 1975, his employer hired a company to do the lowering using anchored barges. Shatto asked the marine captain how long it might take, once the platform was floated between the barges, to move it, say, 50 feet to center it over the selected site. The captain estimated that manipulating the twelve anchor lines through their respective winches would take about twelve hours.

Shatto knew two tide changes and their currents would push the platform around even more than the required 50 feet. After some consideration he pointed out that to move laterally 50 feet, the captain need only let out 50 feet from one restraining anchor line, take in 50 from its opposite, and adjust the other eight lines by the cosines of their angles.

The captain and even Shatto's colleagues mounted vigorous, if not rigorous, objections based on both the complicated mathematics of catenary–shaped anchor lines and twenty centuries of marine lore. In the end, they agreed to try it and found that, indeed, a foot of anchor line, or its cosine-adjusted equivalent, gives a foot of movement, and in about three minutes. Shatto revealed the logic behind his insight only after selling the calculation on magnetic strips for hand-held calculators to dozens of companies for $10,000 a copy.

(Shatto's aha!: At the bottom of the mooring line, more than a hundred feet of mooring line and anchor chain lies between the anchor and the point where the line starts its catenary-shaped rise to the vessel. Winching in one foot lifts one foot off the bottom and leaves the catenary shape unchanged.)

Up to that time, drilling from barges necessitated dropping buoys around the wellhead to give a clue about the approximate position. The barges had to be anchored in four directions; anchor lines had to be continually winched in and out to maintain the correct position over the well. The Eureka needed no anchors, but it did have a positioning device tied to the ocean floor, a thin wire that ran up through an onboard "tiltmeter." This mechanical device measured the angle of the wire and calculated the position of the ship relative to the wellhead. Operators then used a joystick to engage the forward and aft thrusters. Experience indicated the joysticks were about as stable as an arcade road racing game, and with about the same results. The designers quickly replaced them with automatic electromechanical devices (using vacuum tubes!) that performed much better.

Shell, the *Eureka* operator, limited the ship's use to drilling core samples, deeming this ship, like the *Submare*x and the *CUSS 1*, too experimental to drill exploratory wells. More than ten years passed before a purpose-built, dynamically positioned drill ship, *SEDCO 445*, appeared in 1971, ready to drill exploration wells. Rotating fore and aft thrusters seemed clever enough during the *Eureka's* design, but at sea the operators literally wore them out as they swung them to and fro to maintain position, and with voluminous use of fuel. The *SEDCO 445* had fixed thrusters, eleven along the port and starboard that gave lateral and heading control. The main screws provided fore and aft positioning. This simpler, more durable design became the standard for subsequent drillships.

Honing Tools of the Trade

Whether the drilling derrick sat on a semi-submersible or a dynamically positioned drillship, the driller continually asks, "Are we over the wellhead?" In shallow waters, for a while some companies anchored their vessels and continued to use variations of the *Eureka's* guide wires. In deeper waters where they could tolerate more movement, they moored buoys in a circle as guides, sometimes using a tiltmeter in parallel. Then they worked the anchor lines to move the vessel. Aboard the *Bluewater I*, substituting wire rope for anchor chain to make winching and positioning easier came as a welcome but forehead-slapping innovation in 1961.

Much deeper water made that method impractical because of the long mooring lines. The *SEDCO 445* used an acoustic positioning system. Pingers on the wellhead sent signals to the ship's hydrophones. A few trigonometric calculations gave the position, although the error due to uneven water speed could be plus or minus 1–2% of the water depth. (3,000-foot depths could give a 60-foot error!) Later operators switched to placing four transponders at some distance around the wellhead. The ship sent a signal, the transponders sent it back, and onboard computers triangulated (quadrangulated?), reducing the error to a more tolerable one-half percent.

A big leap in position determination came in the 1980s when enough satellites whizzed around the globe to give continuous line-of-sight coverage. The Global Positioning System (GPS) eventually let ships know where they were within a few feet.

Positioning by Chance

By 1986, the U.S. Government had enough satellites up to provide continuous signals in the Gulf of Mexico. But foreign enemies could use the Global Positioning System to lob missiles into America just as easily as the oil industry could use it to dynamically position their drill ships. In the name of national security, the government diddled with the signal to assure the bad guys would have inaccurate launch positioning. That also rendered the signal useless to the drillers.

Along came John Chance who figured he knew where he stood, so he could continuously calculate the diddle correction. He did, and he signed up the drillship companies and continuously transmitted to them the offsetting error, allowing them accurate GPS use.

Later, Chance's company, Starfix, switched to undiddled commercial satellites (which still needed some correction) and continued to provide tracking service to the decimeter to a growing fleet of dynamically positioned vessels. Eventually, with GPS technology maturing, Chance's company concentrated on application. It became a leading purveyor of subsurface topography surveys for positioning platforms and pipelines, for equipment location, and for aiding inspection, even after the company was absorbed by Fugro.

Divers and ROVs

From the beginning, drilling at sea called for subsea assistance—to locate wellheads, to make connections, to set platforms, to do inspections, and for many other tasks. Early efforts used divers who could operate efficiently down to about 100 feet. Pressures beyond that could turn divers dangerously silly due to nitrogen narcosis.

The U.S. Navy had discovered that using a mix of oxygen and helium instead of air could push divers' limits down past 200 feet. Helium replaced the nitrogen content of the air, eliminating the culprit that easily penetrates brain tissue, inducing narcosis, and causing divers to act like two-year olds. Of course, the helium made them sound like Donald Duck, but at least they knew what they were doing. In 1960 in the Gulf of Mexico, Shell sponsored the first use of oxygen/helium in offshore exploration.

Still, even using helium, diving required long and expensive periods of diver decompression. Industry needed a non-breathing, underwater assistant and began to experiment with robots. *Mobot*, the first remotely operated vehicle (ROV) used to complete an offshore well, went into service for Shell in January 1962. Long before George Lucas conceived R2D2 and C3PO, this elegant little robot (fig. 1–12) had four distinct features:

- Free-swimming self propulsion
- Onboard sonar that could find a wellhead
- A television camera that could see it
- A socket wrench that could connect a Christmas tree or a blowout preventer

Over the next ten years, *Mobot* successfully completed six subsea wells in the Molino Field off California, a discovery well in Cook Inlet, Alaska, and eighteen more exploration wells up and down the U.S. West Coast, all without the assistance of divers.

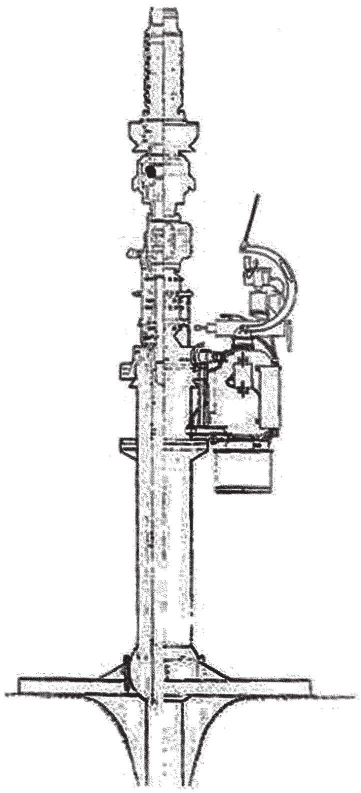


Fig 1–12. The original 1962 version of the *Mobot*, clinging to a wellhead. The profile shows, top to bottom, the tether, television camera, sonar apparatus, ratchet wrench, and wheels that permitted it to circle the wellhead. (Courtesy H. L. Shatto and Shell Oil Company.)

During that same time, other ROVs entered service with a variety of capabilities—articulated arms, grabbing devices, suction cups, high-pressure jets for cleaning, and other tools. Operators controlled them aboard the drilling vessel with joysticks, television receivers, and even early versions of virtual reality apparatus.

In parallel, the diving industry, led by Taylor Diving and Salvage Company, mastered "saturation diving," which permitted divers to stay onsite in hundreds of feet of water indefinitely, using pressurized habitats and carefully monitored decompression. In a 1970 experiment, five Taylor divers worked eighteen days from a pressurized vessel at simulated depths of 1,000 feet. In the ensuing decade, Taylor's crew broke successive commercial records, culminating in a pipeline job in 1978 for Norsk Hydro. Taylor divers welded two sections of 36-inch diameter pipe in 1,036 feet of water offshore from Western Scotland.

After that, the use of ROVs and diving converged, with divers handling the fine motor skill tasks and the somewhat clumsier ROVs doing the heavy-duty work, surveillance, and some specialty work.

Lift Power

Transporting and launching prefabricated production platforms required newly designed barges to haul them and mobile heavy-lifting equipment to get them in the water and correctly positioned. (See fig. 1–13.) Over the last half of the twentieth century, floating crane capacity increased dramatically (table 1–1) as industry pushed into deeper and rougher waters and jackets grew larger and heavier. Following the lead of the innovative and entrepreneurial P. S. Heerema, other companies upgraded their crane capacities, or built new crane vessels, as shown in table 1–1.

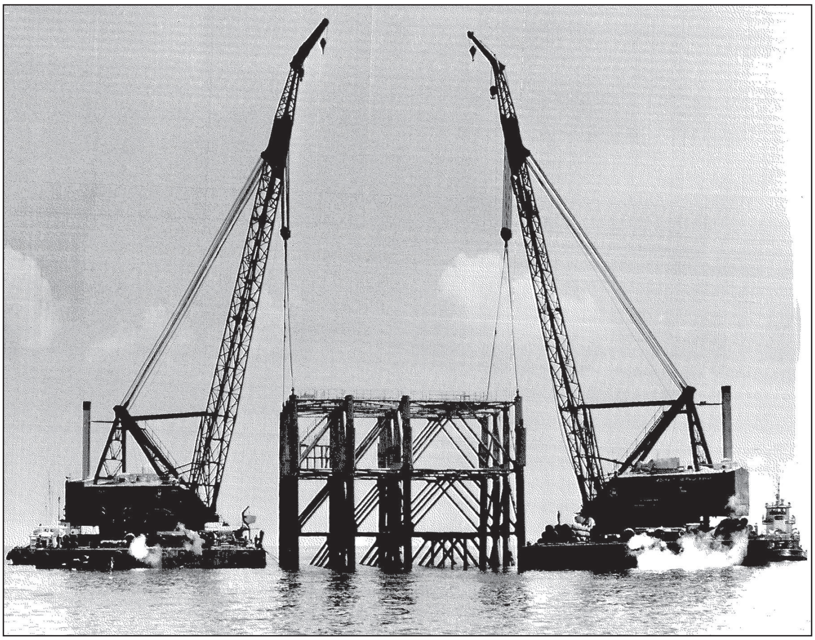


Fig. 1–13. Twin cranes lifting a jacket into place. (Courtesy Shell Oil Company.)

Table 1–1. Heavy lifting milestones

1948	75-ton crane lift of Superior's jacket at the Creole Field
1962	300-ton crane on Heerema's *Global Adventurer* into service
1968	800-ton crane on Santa Fe's *Choctaw*, a column stabilized catamaran
1972	2,000-ton crane on Heerema's *Champion* into Amoco's service in Suez
1973	2,000-ton crane on Heerema's *Thor* into BP's service at the *Forties* field in the North Sea
1976	3,000-ton crane on Heerema's *Odin* installs a platform on Shell's Brent *Alpha* jacket
1977	2,000- and 3,000-ton cranes installed on Heerema's *Balder* and *Hermod*
1985	*Balder* and *Hermod* crane capacities increased to 4,000 and 6,000 tons
	Twin 6,000-ton cranes installed on McDermott's *DB-102*
	Twin 7,000-ton cranes installed on Microperi's semi-submersible, which eventually became the *Saipem 7000*
2000	Heerema upgrades its *Thialf*, formerly McDermott's *DB-102*, to 14,200 tons of capacity

Geology, Geophysics, and Other Obscure Sciences

Ask a *geologist* a question about the offshore that includes the word *history* and you'll likely get a long answer that begins not a hundred years ago but a hundred million. You'll hear that the Gulf of Mexico, for instance, became so rich in hydrocarbons because ancient rivers, ancestors of the Mississippi, deposited a continent's worth of organic material, shales, and sands in long fairways running into the present Gulf Coast. The depth of the sands and weight of the shale created enough pressure and temperature to cook the organic matter, some into oil, some into gas. Along the coastline, wandering landmasses stranded seawater, which evaporated and left huge sheets and pillows of salt. The shale provided the source rock, sands provided the reservoirs, and cap rock or salt sealed the hydrocarbon.

The story then shifts to somewhat later, about 1920, when geologists began to realize the similarities between the onshore Gulf Coast and the Continental Shelf. After all, it was only around 1912 that exploration companies began to hire geologists. That year marked the first recorded discovery in Cushing Field, Oklahoma, directly resulting from a geologic survey.

But drilling deeper into a geologist's interest in the deepwater yields a simple statement that paraphrases the notorious 1920s banker robber, Willie Sutton: "Because that's where the oil is." Exploration of the deepwater has always been just a continuation of accumulated knowledge and a march into more challenging environments. It hardly ever depended on the concurrent abilities of production departments to develop and produce. The geologist's assumption, to paraphrase another famous mantra, has been, "Find it and they will come." The speed with which they pursued that has been limited only by the funds available from producing what they had found a decade or so earlier.

Ask a *geophysicist* the same question, and the history starts less than a hundred years ago. In 1924, Amerada Oil discovered the Nash salt dome in Brazoria County, Texas, using an early mapping tool, the torsion balance. Two years later, Amerada completed an oil well there, making the Nash field the first oil field credited to any geophysical method.

Incoming!

On both sides of the trenches of World War I, groups of mathematicians, physicists, and engineers used acoustic equipment to plot the locations of enemy artillery. They took readings at three or more locations to triangulate on enemy guns. In the 1920s some of these same people came to America and developed the seismic refraction and later seismic reflection techniques and with that they founded some of the earliest geophysical companies. One Frenchman had a name that now speaks for itself, Captain Conrad Schlumberger. Another, a German named Ludger Mintrop, founded Seismos, Limited, a firm ultimately absorbed by Schlumberger to form the core of their seismic services subsidiary.

Seismography developed at the same time. During its early stages in the shallow inland lakes and swamps and in the offshore, seismic crews planted geophones by hand, with locations measured by land sight. Recording apparatus sat on raft-like vessels. (See fig. 1–14.) Geophysicists at Teledyne credited their full-scale marine survey in 1934 for the discovery of Superior's Creole Field.

Within ten years, self-contained, 60-foot boats towed hydrophone cables into place, backed up a bit to let them settle, and then radioed the shooting boat to drop a dynamite charge and back off. Blessedly, the seismic waves they captured, despite having to travel through scores, then hundreds and eventually thousands of feet of water, behaved no differently from onshore waves.

Soon neutrally buoyant tubes with hydrophones allowed the boats to record while underway. Eventually the geoservices companies also bowed to the environmentalists and fishing industry who were understandably upset at the sight of a seascape of dead fish after a seismic shot. By the 1970s most seismic boats towed a steel cylinder charged with compressed air that, on release, sent a pressure wave as a signal, with as good a result as an explosive. No dead aquatic life has been reported.

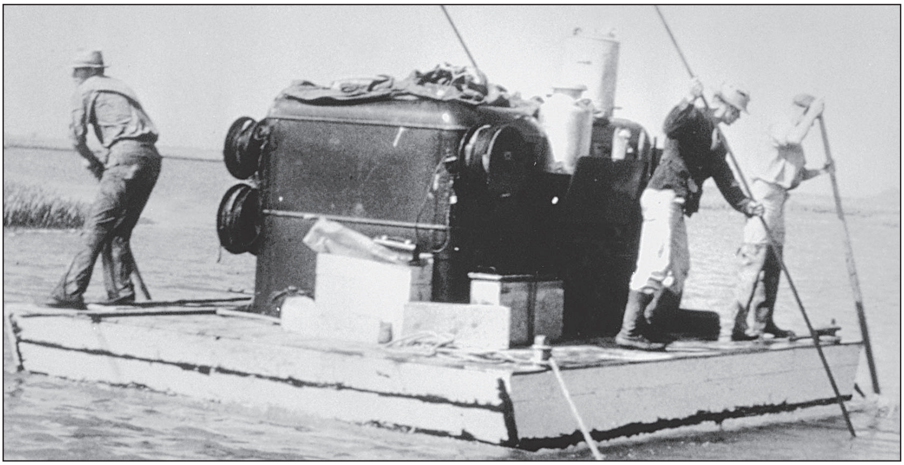


Fig. 1–14. Early offshore seismic collection. (Courtesy Western Geco.)

Seeing the Forrest

In 1967 a young geophysicist noticed a curious pattern in the seismic data shot in preparation for lease sales offshore Louisiana—an abrupt zone of low velocity reflections. The same phenomenon turned up a year later on a Bay Marchand prospect. When his company drilled wells through those zones shortly after, they confirmed commercial gas accumulations in each.

For another year he assembled more evidence, debated with skeptical colleagues, and pestered his management until his vice president agreed to see him and review his story. The geophysicist, Mike Forrest, convinced his management of the remarkable power of *bright spots*, a name coined during coffee room debates. They could use seismic data to do more than just geologic mapping. They could directly identify natural gas accumulations.

For the next few years he joined teams of geologists, petrophysicists, geophysicists, and computer scientists correlating *bright spots* with every other piece of evidence they could. As confidence grew, Forrest doggedly spurred his company, Shell, to win leases and ultimately prove with the drilling bit hundreds of millions of barrels of hydrocarbon in the GOM. Finding the 300 million barrel reserve on Prospect Cognac in 1975 using *bright spots* was only a prelude to the giant fields discovered in the deepwater in the next decade.

Seismic data interpreters were among the first disciplines to fully exploit contemporary computing power. In 1958, Geophysical Services, Inc. (GSI) fired up the first digital computer wholly dedicated to seismic processing. With that, paper recording gave way to analogue recording and eventually to digital recording.

At the annual meeting of the Society of Exploration Geophysicists in 1970, Exxon Production Research presented the results of seven years' efforts, their breakthrough on 3-D seismic. In another two decades, geophysicists sat at computer workstations and manipulated data, relaying it to Spielbergesque display rooms, where they sat with geologists surrounded by brilliantly colored displays of the subsurface. All this advanced the discovery and appraisal process and reduced the risk of dry holes.

To introduce yet another dimension, in the early 1990s oil companies and seismic companies started commercial application of 4-D or time-lapse seismic in both the North Sea and Gulf of Mexico. They compared two surveys of the same field run at an interval of about five years. With much interpretive effort, they could identify unswept areas of oil- and gas-containing reservoirs.

Permanence

As the geologists and geophysicists demystified the subsurface and mobile rigs drilled exploratory wells further from the shoreline, the demand grew for permanent, durable production facilities in ever-deeper water. Building onsite at sea became out of the question, and fabrication yards sprang up along the Gulf Coast.

Rediscovering the success of Superior in 1947, operators learned to love prefabricated jackets. The simple concept involved fabrication onshore, barging (or later floating) the jacket to the site, lifting it off the barge, and dropping it on the target. Driven piles made from open-ended steel tubes, eventually as large as 8 feet in diameter, held the jacket in place. Then came the topsides, lifted *in toto* or in parts from the transporting barges and fitted to the stubs of the jacket sticking out of the water.

No one would call progress in jacket development dramatic—until the 1970s and 1980s. For thirty years engineers had worked to increase strength and decrease weight and drag, keeping the cost of jacket installation profitable in ever-increasing depths (fig. 1–15), and in the case of the North Sea, more harsh weather conditions. The number of installed jackets and platforms increased steadily, with the largest concentration on the Gulf of Mexico's Continental Shelf. More than 1,000 platforms were installed there by 1963, 4,000 by 1996, and worldwide more than 6,000 by 2000.

In 1978 Shell Oil Company placed their Cognac Platform in record-breaking 1,023 feet of Gulf of Mexico water, but still on the Continental Shelf (fig. 1–15). Ten years later, Shell bested its own record by installing *Bullwinkle* in 1,354 feet of water, at a point where the Outer Continental Shelf begins its plunge down to the deepwater (figs. 1–16 and 1–17).

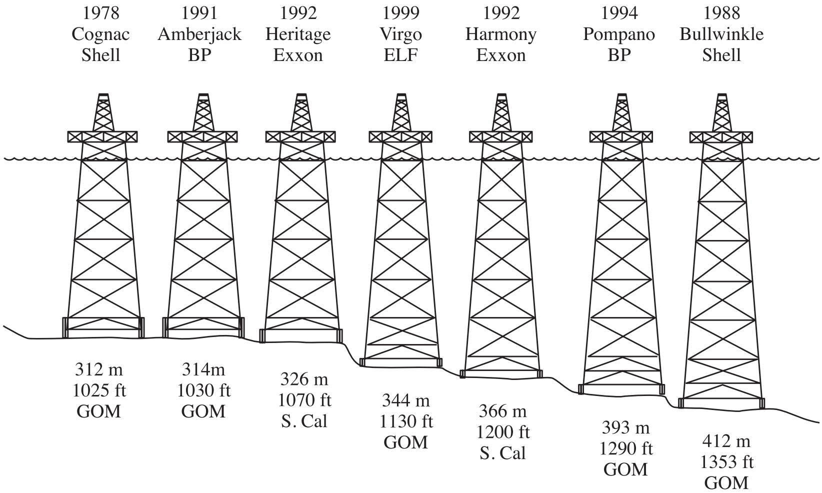


Fig. 1–15. Fixed platforms by installation year and installation company: two decades to the limit

Fig. 1–16. The *Bullwinkle Platform* being towed to sea. (Courtesy Shell International, Ltd.)

Fig. 1–17. The *Bullwinkle Platform* in place. (Courtesy Shell International, Ltd.)

Bullwinkle needed 44,500 tons of steel structure and 9,500 tons of pilings. The cost of fabrication and installation totaled nearly $250 million. Remarkably, the cost of *Bullwinkle* came in at less than the cost of the smaller, earlier Cognac. The learning curve was so steep in those days that progress in engineering and construction absorbed the period's 66.5% cumulative inflation and a 30% increase in size. Still, Shell and other companies looked toward the horizon and fretted over the economic viability of sinking even more steel and money into a conventional jacket in water any deeper.

The Learning Curve Bends Over

With *Bullwinkle*, the industry approached the top of the offshore learning curve. The onshore curve had taken much longer, languishing for thousands of years before it moved up at all. For eons, people had gleaned oil and gas from *seeps*, natural springs of hydrocarbon that made their way to the surface. As long ago as 3000 BC, Egyptians found tar oozing from rocks and preserved their mummies with it. Clever Chinese captured natural gas venting from the ground to light their imperial palaces around 800 BC. Archeologists have found evidence that American Indians used oil seeps to seal their canoes and baskets as early as 1300 AD.

Clever as these efforts might have been, they hardly caused anyone to think of their instigators as pioneer oilmen. Neither did those anonymous efforts accelerate the learning curve in any way. It took Colonel Edwin L. Drake, drilling a well in an area rife with oil seeps near Titusville, Pennsylvania, in 1859 to turn it upwards. The persevering Drake was not the first or the last oilman to triumph after staring into the face of total financial ruin without blinking. He was, however, the first to pound a casing pipe down his well as he drilled to keep the borehole from collapsing, and that simple morsel of technology made his well a producer and gave his reputation immortality.

Not far away, the next year, J. C. Rathbone drilled into a small hill at Burning Springs in West Virginia and brought in a well that produced ten times the rate of Drake's well. After that, a growing horde of wildcatters took note that oil seeps often occurred on natural surface bulges, later called *anticlines*. These natural formations, like the one at Spindletop, provided good geological mechanisms for trapping accumulations of oil and gas. Starting with this knowledge, waves of entrepreneurs, engineers, scientists, financiers, and fortune-seekers created massive practical and intellectual breakthroughs and pushed up the onshore learning curve for a century. Figure 1–18 shows only a few of the milestones, which continued well beyond the first ventures into the offshore.

The dynamic development of onshore exploration and production technology provided only the necessary backdrop. But moving offshore in the twentieth century needed the new paradigms and the new breed of oilmen to get from Summerland to *Bullwinkle*, the second wave shown in figure 1–18.

But to some, as the twentieth century drew to an end, even this learning curve had played itself out. The offshore industry needed a jump start.

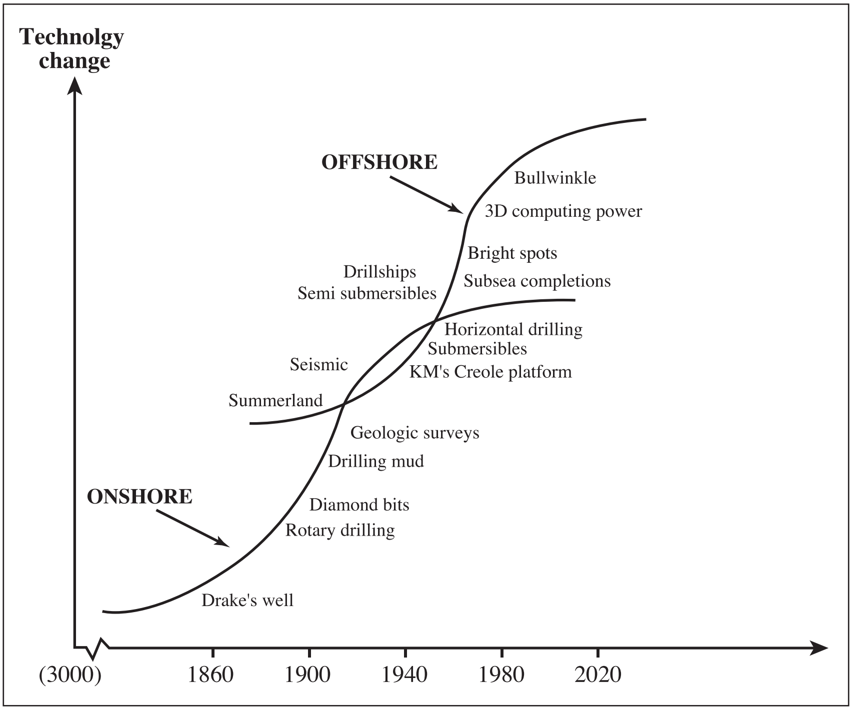
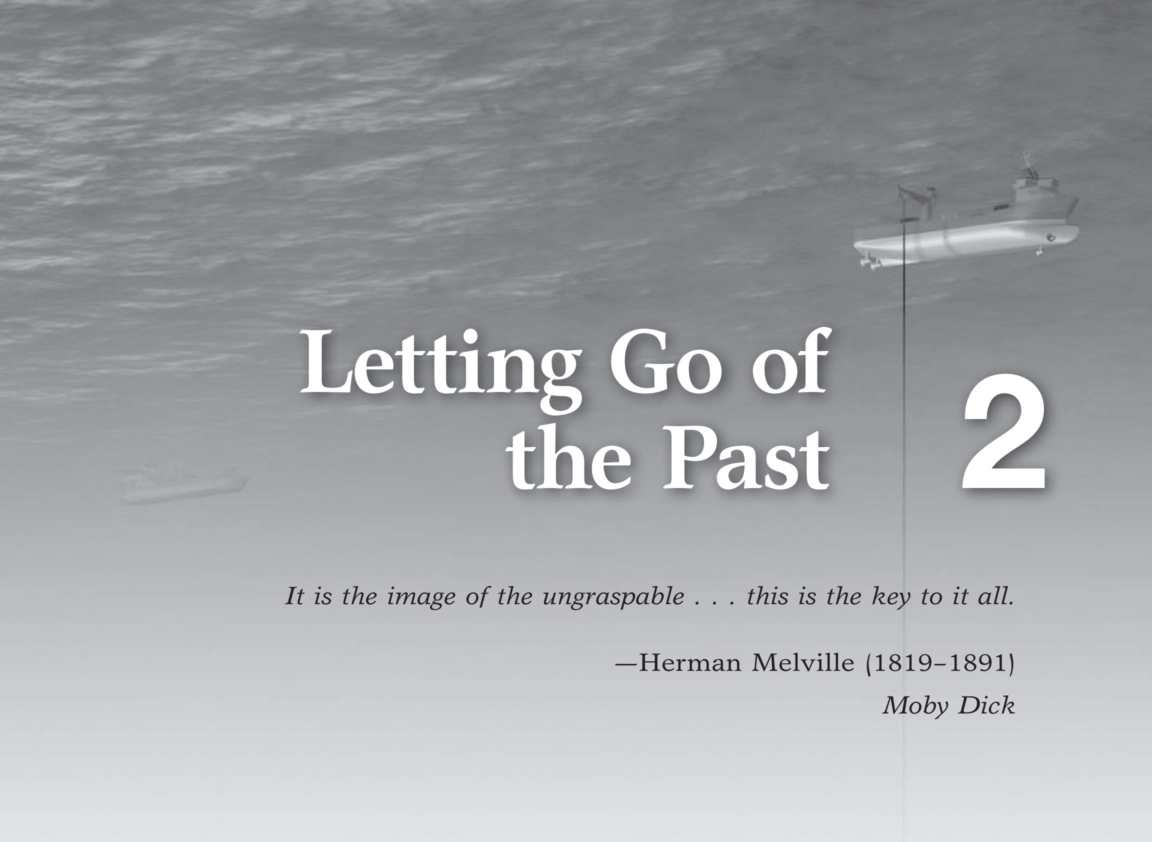


Fig. 1–18. Exploration and production—the first and second waves



Letting Go of the Past 2

It is the image of the ungraspable . . . this is the key to it all.

—Herman Melville (1819–1891)
Moby Dick

The Confusion of the Eighties

Nothing but promise appeared on oilmen's horizons in the early 1980s. OPEC provided a dizzyingly high oil price, rising at one point from $1.50 to over $40 per barrel. Rigs operating in the Gulf of Mexico increased to 231 in 1981, double that of 1975, and almost triple 1970's. (See fig. 2–1.)

Worried about energy security, the U.S. government stopped its piecemeal offerings of tracts and held its first Gulf of Mexico area-wide lease auction in 1983. They included broad expanses of tracts both on the Outer Continental Shelf plus ones extending into waters of 2,000-to-7,500-foot depth.

Advances in drilling technology, especially dynamically positioned drillships, anchored semi-submersibles, subsea completions, and the use of 3-D seismic, a costly but technologically superior advance over 2-D seismic, allowed drillers to test these deep waters. Rumors of a succession of elephant-sized discoveries abounded, huge in comparison to discoveries on the Continental Shelf (table 2–1). Conoco, Shell, British Petroleum, Exxon, and Oryx (who ultimately disappeared into Kerr-McGee, who was absorbed by Anadarko) pioneered exploration success in the new province.

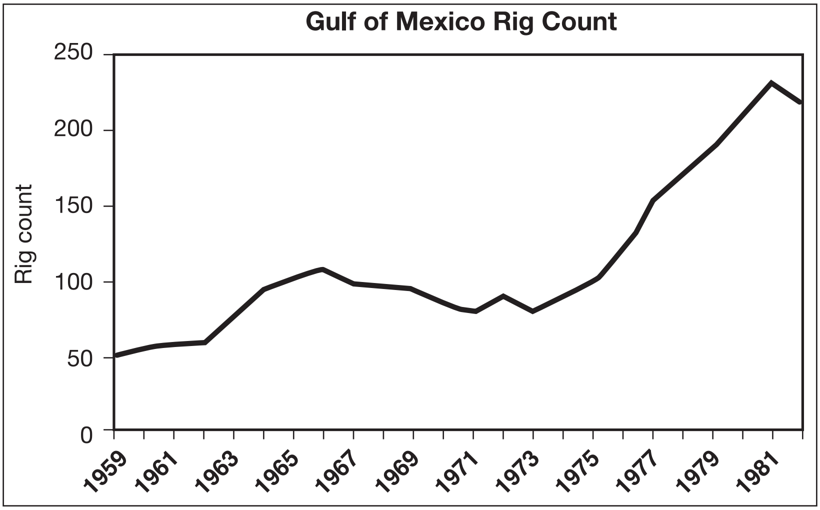


Fig. 2–1. Rig count in the Gulf of Mexico, 1959–1982

Table 2–1. Significant deepwater discoveries in the 1980s

Field	Volume Million barrels	Depth in feet	Company	Year
Joliet	65	1724	Conoco	1981
Pompano	163	1436	BP	1981
Tahoe	71	1391	Shell	1984
Popeye	85	2065	Shell/BP/ Mobil	1985
Ram-Powell	379	3243	Shell/Amoco/ Exxon	1985
Mensa	116	5276	Shell	1986
Auger	386	2260	Shell	1986
Neptune/Thor	108	1864	Oryx/Exxon	1987
Mars	538	2960	Shell/BP	1988

In the mid-1980s, ominously dark clouds floated over the Gulf of Mexico. OPEC learned that with $34 oil they had priced themselves out of many markets. Consumers found unprecedented ways not to use oil in their cars, industrial plants, and buildings. The oil price softened to $28 dollars in 1983 and collapsed to $10 in 1986.

Coincidentally, exploration success in the Gulf of Mexico Continental Shelf, the region in less than 1,000 feet of water, began to show signs of increasing age. The average size of discoveries declined by half from the previous decade to about 24 million barrels. (See fig. 2–2.) Despite the huge increases in rig activity, after twenty-five years of double-digit growth rates (with only a short pause in the 1970s), the production of oil and gas from the Gulf flattened out like the Cumberland Plateau. (See fig. 2–3.)

Oilmen searched in their files for the U.S. Department of Interior report from a decade earlier, which predicted that essentially all the potentially productive blocks up to 600 feet would have been already leased and development would have been completed by 1985.[1] Even more depressing, they began to refer to the Gulf of Mexico Continental Shelf as the "Dead Sea."

With the exception of Prudhoe Bay, Alaska, the notable lack of success for ten years by the major oil companies elsewhere in North America disheartened the most stalwart oilmen. Huge exploratory expenditures in the Norton and Navarin Basins in offshore Alaska and in Georges Banks, offshore East Coast, yielded no commercial hydrocarbons; discoveries on the entire onshore Lower 48 were puny; and environmental restrictions eliminated any new plays in the West Coast offshore. By 1986, the oil company annual reports began to announce new exploration strategies—a shift from the U.S. to the onshore and offshore areas of other continents, Asia, Africa, Australia, and South America.

That is not to say momentum didn't sustain some progress in the Gulf of Mexico. In 1984, Placid Oil, H.L. Hunt's intrepid independent company, announced a large discovery in 1,554 feet of water. They immediately undertook development of the field with subsurface wellheads producing back to a floating platform, a first of its kind in the Gulf. At the same time, Conoco mulled over developing its 1981 discovery, Joliet, in 1,760 feet.

[1] U.S. Department of Interior, Bureau of Mines, *Offshore Petroleum Studies Estimated Availability of Hydrocarbon to a Water Depth of 600 Feet from Federal Offshore Louisiana and Texas through 1985* (December 1973).

Conoco had developed some expertise in the North Sea by using a floating tension leg platform (TLP) to develop their Hutton field. Emboldened by that success, they installed the first TLP in the Gulf of Mexico in 1989.

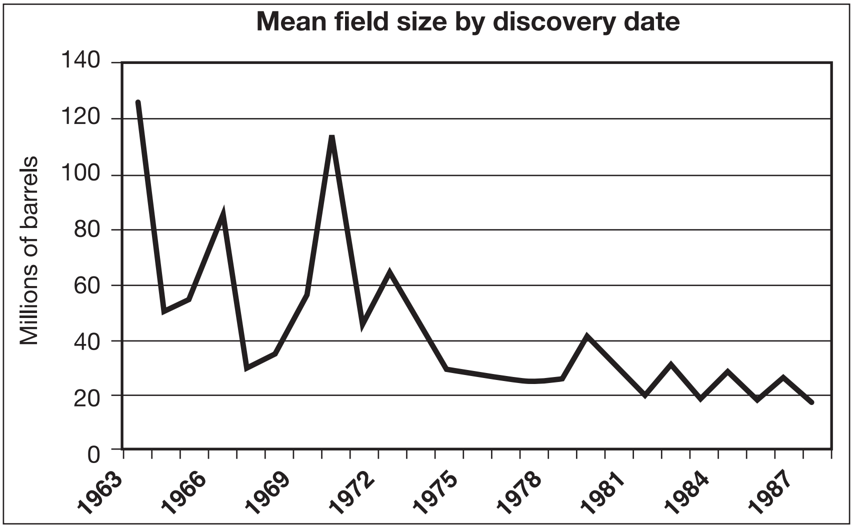


Fig. 2–2. Average size of fields discovered in the Gulf of Mexico

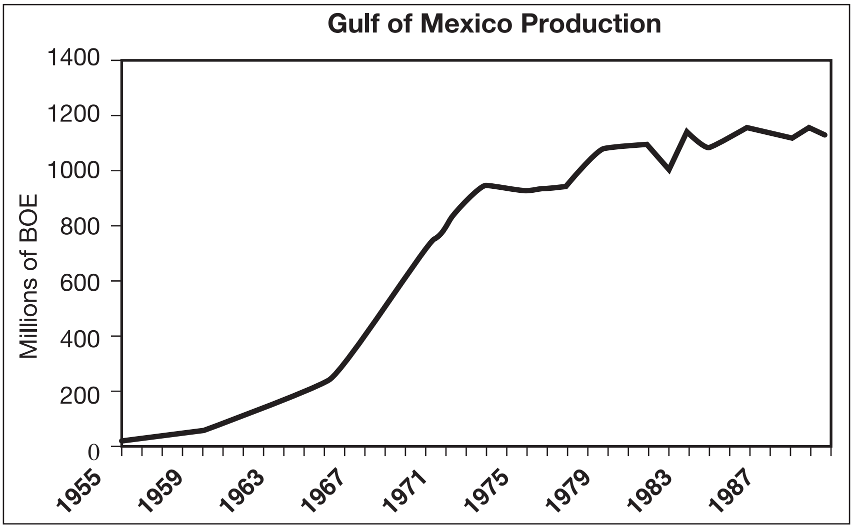


Fig. 2–3. Oil and gas production in the Gulf of Mexico

Disconcerting Signals

Then the petals fell off the technological bloom. Having installed *Bullwinkle*, a conventional fixed base platform, in 1,354 feet of water in 1988, Shell reached the economic limit for this configuration. Using more than its 54,000 tons of steel structure and pilings would strain the profitability of any conceivable project in deeper water. In addition, the pyramidal base measured some 400 by 480 feet, barely-manageable dimensions.

While Placid's and Conoco's approaches were less capital-intensive engineering successes, it became apparent that they had misjudged the geology of their fields. Poor performance of their wells led Placid to abandon their investment. Conoco's Joliet limped along, cash positive but with below-investment-grade performance.

At this point the U.S. offshore industry faced a crisis of confusion:

- Volatile and mediocre oil and gas prices
- Unpromising potential in the Gulf of Mexico Continental Shelf
- Apparent brighter opportunities in foreign plays
- Billions of barrels of hydrocarbons already discovered but not developed in the deepwater
- Uncertain deepwater reservoir performance that put development investment at risk
- Yet more federal lease sales scheduled

Oilmen pondered, *what should we do?*

Turning the Key

Coincidental and fortunate circumstances, only vaguely related to each other, occurred about that time. In 1974, Petrobras, the national oil company of Brazil, began exploring with modest success the Campos Basin off their northeast coast. Brazil, like many other countries, worried over energy security. Their oil imports ran at 70% to 80% of consumption. In the early 1980s, the Brazilian government challenged Petrobras to substantially reduce their dependence on foreign oil.

At their first commercially significant find in 1977, the Garoupa Field in 402 feet of water (fig. 2–4), Petrobras had used a conventional fixed-base platform. After that, in a burst of productivity and originality, they discovered Bonita, Enchova, Piraúna, Marimbá, Albacora, and Barracuda and produced them from subsea wells first into temporary and then permanent floating production systems (FPS). These FPSs, moored above the producing fields, provided a transit point for shuttle tankers to load the crude oil. Using FPSs avoided the construction time associated with both fixed-base platforms and subsea pipelines to shore and shortened the discovery-to-production-of-first-oil time from a typical nine year span to five to seven.

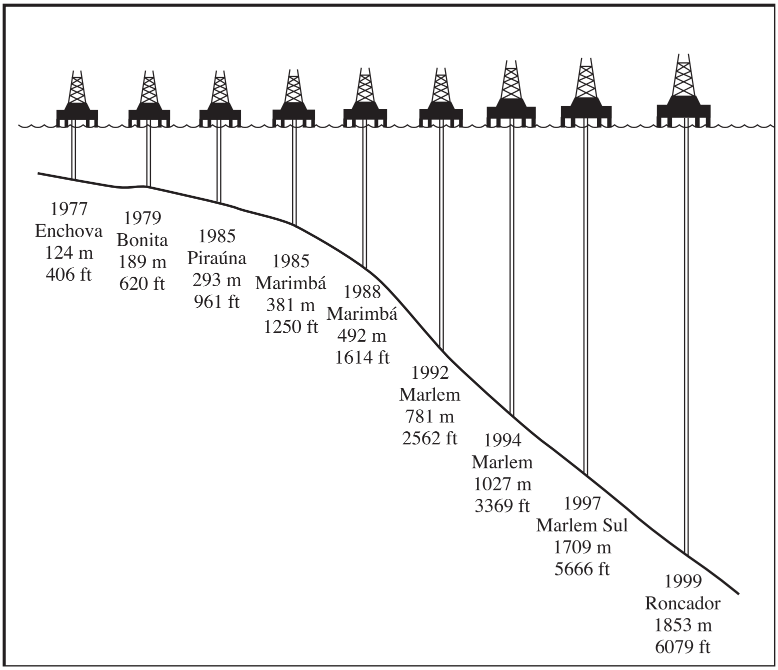


Fig. 2–4. Petrobras discoveries and drilling records

In 1985, they found the Marlim Field and in 1987, the Marlim Sul field, both two to three times larger than the elephantine discoveries in the Gulf of Mexico. Marlim sat under 2,500 feet of water, but the Marlim Sul reservoirs lay beyond the continental shelf in depths from 2,500 to 6,300 feet. Exploiting all they had learned from multiple applications of their Early Production System, Petrobras tapped Marlim Sul in 1994 with a subsea completion producing into the *FPSO II*, a converted tanker.

To the delight of the Petrobras staff, the wells proved so prolific, producing upwards of 12,000 barrels per day, that they justified accelerating their program of subsea development on Marlim and Marlim Sul using floating production, storage, and offloading ships (FPSOs) and FPSs. By 2000, they had 29 active FPSs and FPSOs in place in the Campos Basin.

Meanwhile, back in the United States, another company labored under the similar competitive constraints. Shell Oil Company was a wholly owned subsidiary of Anglo-Dutch giant Royal/Dutch Shell, but they operated autonomously at the time. However, their parents already covered most of the attractive prospects outside the United States, so Shell Oil chose not to divert substantial spending to foreign plays.

Like Petrobras, they turned to the offshore and embarked with single-minded purpose on an *elephant hunt*—discoveries whose size would warrant spending hundreds of millions of dollars in development expenditures. After a discouraging series of exploration failures off Alaska and the U.S. East Coast, they focused with abounding success on the waters beyond the Gulf of Mexico's Continental Shelf. Shell chose to develop their first, the Auger Field, which lay under 2,860 feet of water, using a tension leg platform. The TLP concept had already been demonstrated by Conoco in the North Sea and in the Gulf of Mexico. But even with Conoco's and Placid's deepwater experience in mind, the subsurface risk—well productivity—remained.

Three shrewd moves buoyed their success. First, at unprecedented expense, Shell ran 3-D seismic studies back and forth over the Auger prospect. That increased the reliability of their estimates of how much hydrocarbon the reservoirs might contain.

The second move took place not at Auger, but at *Bullwinkle*. There, Shell's production and reservoir engineers convinced their management to open the wells beyond any comparable shallow water producing rates. They had studied turbidite reservoirs around the world. They noted that these layers of sandstone had been deposited by turbid currents that washed away the finer grains of sand as they lay down. That made these sandstone formations more porous and permeable, qualities high on a reservoir engineer's wish list. The engineers convinced themselves that the turbidite sands below *Bullwinkle* would behave differently from the deltaic sands common to the adjacent Gulf of Mexico Continental Shelf.

If they misjudged, the rush of fluids could cause sand from the reservoir to plug up around the well bore, with irreversible harm to the wells—and their careers. As they opened the valves for a few tense hours, the production rate went from 3,500 to 7,000 barrels per day. Bottom hole pressures remained constant, a crucial sign. No other bad symptoms of well behavior occurred. The experiment confirmed that reservoirs in the turbidite sands of the deepwater could produce at several times the rates the industry had grown to expect. They immediately reworked their Auger development plans, counting on producing 8,000 to 10,000 barrels per day from each well, which happily they did. By having to drill only half the number of wells to drain the reservoir, they reduced Auger's cost by hundreds of millions of dollars—and lowered the worry about falling oil prices by at least half.

Third, like Petrobras, they accelerated development and reduced the interval to first oil. In this case, however, they predrilled the wells from readily available semisubmersible drilling rigs, the type normally used for exploration. Once the TLP was built and anchored in place, they completed the predrilled wells and started production.

Still, Auger took ten years from wildcat discovery to full production. Oil companies, in cooperation with their contractors, set their sights on cutting the cycle time to less than five years.

Closing the Door

With these bold steps, the doors to the past closed. Industry now had in hand the keys to unlock deepwater development:

- They realized the high productivity of turbidite sands, both in rates and ultimate recovery from the reservoirs.
- They could reduce uncertainty about reservoir configuration and the size of the hydrocarbon reserves through the use of 3-D seismic.
- They could use low cost, innovative development systems—TLPs, FPSs, FPSOs, and later compliant towers, spars, and long-reach tiebacks to existing facilities.
- They could compress the time from discovery to first production through rapid approval, pre-drilled wells and other parallel activities, and quick construction of simpler facilities.

The third wave had begun. (See fig. 2–5.)

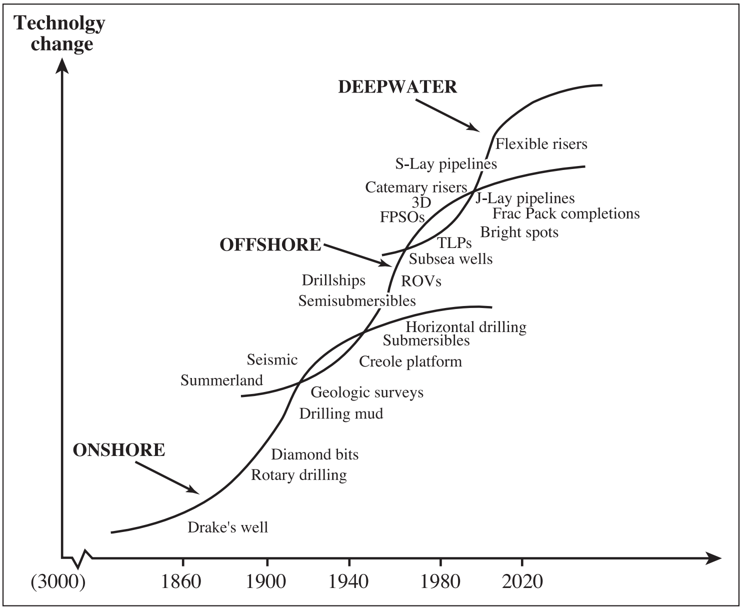


Fig. 2–5. Deepwater—the third wave

From time to time, Shell and Petrobras take victory laps for having pioneered the deepwater—and well they should. But scores of other enterprises contributed technology and technique to tapping hydrocarbon in the deepwater—drillers, mud companies, cementing services, fabricators, geoservice and seismic companies, maritime services, and more, not to mention the other oil companies. It would take another ten chapters to do them justice.

Geology and Geophysics 3

Never look down to test the ground before taking your next step; only he who keeps his eye on the far horizon will find the right road.

—Dag Hammarskjold (1905–1961)
Second Secretary General of the United Nations

The Geology of Deepwater

Dr. Stephen O. Sears, Chair, Department of Petroleum Engineering, Louisiana State University

Many people think that oil and gas occur in large cavern-like pools underground. Not so. To dispel this misconception, maybe a good starting point for this chapter is a photograph of a sandstone reservoir rock taken by an electron microscope. (See fig. 3–1.)

The picture shows void spaces called pores, about a tenth of a millimeter in diameter, between grains of solid rock about twice that size. Deep underground, these pores can be filled with water, oil, or gas. Other rocks have no pore space, and consist of solid minerals. One of the challenges of the geoscientist is to predict where rocks with a substantial amount of pore space occur, the ones capable of storing hydrocarbons.

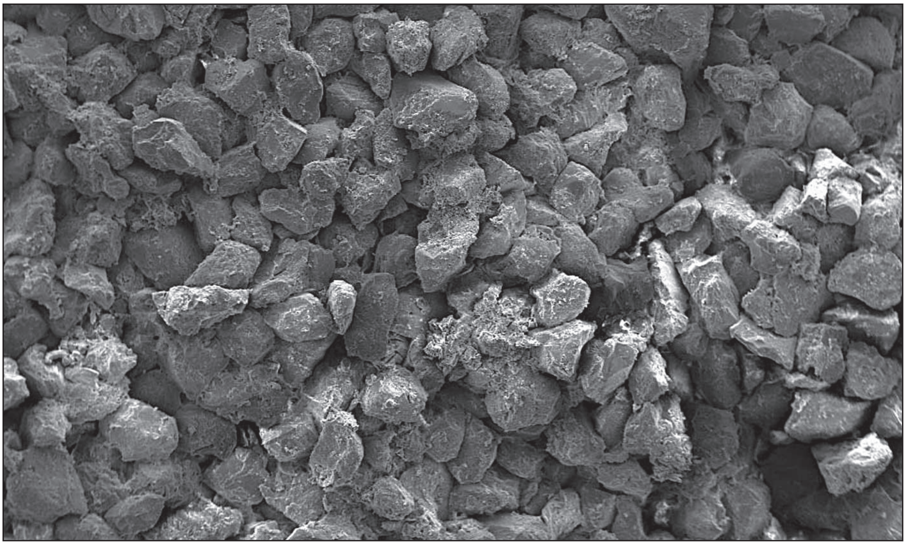


Fig. 3–1. Scanning electron microscope photograph of a sandstone reservoir rock

Geology fundamentals

Understanding the occurrence of hydrocarbon in deepwater fields rests on a few geological concepts and processes. Three of them are most important: the formation of sedimentary rocks, the warping, twisting, and breaking of rocks (structural geology), and chemical changes due to increases in temperature and pressure.

Geologic time. The earth is billions of years old, and geologists have divided this time period into different periods referred to as the geologic time scale. We are now living in the Holocene epoch, which was preceded by the Pleistocene, when man first appeared on Earth. The Pleistocene began about 2 million years ago. Both of these epochs were preceded by a 65-million-year period of time called the Tertiary, which began when a large meteor impacted the earth and caused widespread extinctions, at least so the story goes. The time before the Tertiary is referred to as the Cretaceous. Just before that were the well-known Jurassic and the Triassic periods. Geologists and the journals that cover their activities often refer, for example, to deepwater development as being in the Lower Tertiary or pre-salt Cretaceous, indicating the time the sediment was laid down.

Rocks. Geologists classify rocks into three main groups: igneous, metamorphic, and sedimentary. The only group that petroleum geologists are really concerned with is sedimentary rocks, since these form both the reservoirs and the sources of hydrocarbons. Sedimentary rocks, in turn, are divided into three groups, and they are all important in deepwater oil and gas development: sandstones, carbonates, and shales.

Sandstones are composed of sand grains derived from erosion of other rocks. These grains are deposited by rivers on beaches and other locations. Of particular interest to deepwater petroleum geologists are sandstones deposited by underwater currents called turbidity currents. These currents result when water mixes with sediment (it becomes turbid and dense) and then flows downslope to deeper water. These flows can exceed tens of miles per hour, and can transport large quantities of sand. Figure 3–2 illustrates the process of sand grains being produced by erosion of mountains and ultimately being transported to the deep sea floor by turbidity currents.

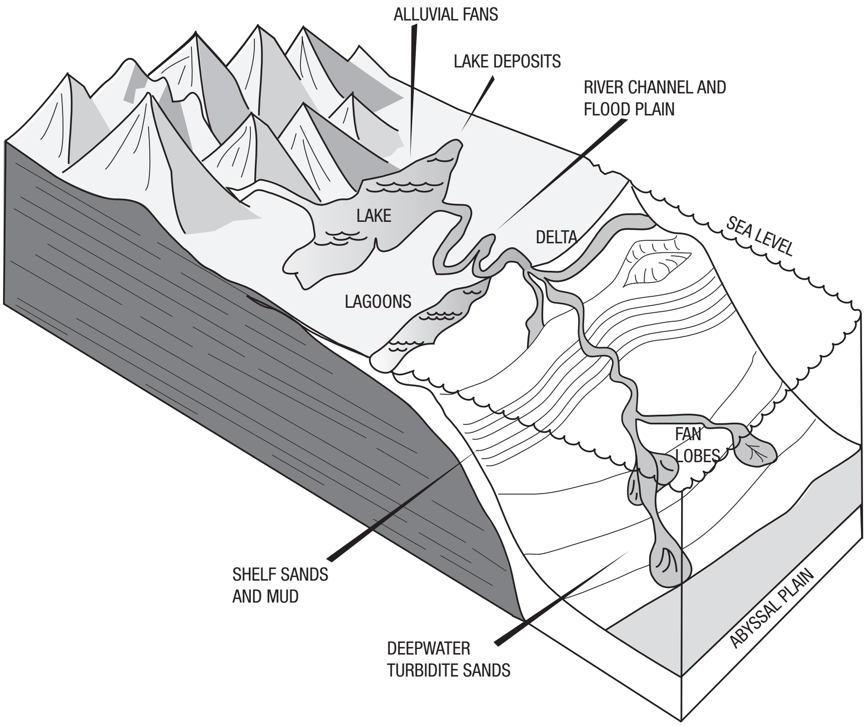


Fig. 3–2. The transport of sand from mountains to the deep sea floor by turbidity currents

Carbonates consist of limestones and dolomites. These rocks are the result of organisms like coral reefs, algae, clams, and sea urchins which precipitate calcium carbonate from sea water to form skeletons such as shells. They are called carbonates because their chemical composition is calcium carbonate (limestones) or calcium magnesium carbonates (dolomites). They are deposited in clear, shallow water.

Shales are very fine-grained sediments, consisting largely of clays. Some may also contain carbonate minerals. The composition of shales also includes a few percent organic material, micro-vegetable, and maybe some micro-animal matter. They are typically deposited by very slow moving currents, either rivers or turbidity currents. They are very important for two reasons: first, shales are the source rocks for almost all oil and gas, and second, they typically have very low permeability, which makes them an essential component for trapping oil and gas.

Structure. The study of the warping, twisting, and breaking of the earth is called structural geology. Layers of rock can either break (called faulting) or bend. This can be caused by a number of processes, but one that is of particular importance in many deepwater reservoirs is the presence of salt. In the Gulf of Mexico, for instance, in ancient times a thick layer of salt was laid down and eventually covered by sediment. Salt is less dense than other rocks, and it can bulge through the layers of overlying rock. As it does, it causes both faulting and bending. This can be beneficial for the formation of hydrocarbon reservoirs by forming traps that prevent the oil from continuing to migrate. However, it can also be detrimental by creating barriers within the reservoirs, preventing a single well from accessing all the hydrocarbons.

Another process that can cause faulting and bending results from the large scale movement of the earth's crust, called plate tectonics. The earth's crust consists of a number of individual plates that make up both land masses and areas of the sea floor. The plates drift around on top of the earth's mantle, and intersect at plate margins. When two plates push against each other (geologists would call it collide, but they march to a different beat), called an active margin, one plate can override the other, resulting in mountain ranges, earthquakes, and volcanoes. Where they are drifting apart, referred to as a passive margin, new crust is created. The California coast is an example of an active margin, the Brazilian coast a passive margin. Passive margins are excellent places for large, thick accumulations of sandstones and shales. The major deepwater development areas in the world are along passive margins, including the Gulf of Mexico, Brazil, and West Africa.

Other processes, not covered here, can result in the structural deformation of rocks on many different scales.

Diagenesis. Sedimentary rocks are deposited in the ocean or rivers, arriving there at surface temperature and pressure. Because the center of the earth is far hotter than the surface, as the rocks are buried, they encounter increased pressure and temperature. That combination plus accumulated time of burial leads to chemical transformation of the rocks called diagenesis by geologists. This has a number of positive and negative impacts. The first impact is beneficial, in that increased temperature is required for organic material deposited in shale to transform to oil and gas. However, with increased burial, reservoir rocks typically undergo a reduction in porosity and permeability, due to chemical changes and mechanical compaction. Younger sediments buried at shallower depths and exposed to more limited temperature increases are usually the best reservoir rocks.

The origin of an oil or gas field

An oil or gas field anywhere in the world, offshore or onshore, very shallow or deep below the surface of the earth, requires three essential components. (See fig. 3–3.)

1. **Source.** Oil and gas occur when organic material (mainly remains of algae) is buried to a depth where it is exposed to temperatures around 60–100°C, transforming it to oil or gas. Oil forms at lower temperatures than gas. As the organic material changes to oil or gas, it increases in volume, creating fractures in the rock. The pore spaces are normally filled with water. Since hydrocarbons are lighter than water, they migrate upward toward the surface through fractures and other pore space.

2. **Reservoir.** These consist of rock with pore spaces filled with oil, gas, and water, sometimes a combination of all three. The pore space, or porosity, typically amounts to 10% to 30% of the total volume of a reservoir, sometimes higher or lower. If the pores are well connected, the hydrocarbons can flow from one pore to another

and eventually to a well. The degree of connectivity is called permeability, and is expressed by a unit named after a nineteenth-century French engineer, Darcy. A very good reservoir may have a permeability of one Darcy. Typically, good reservoirs have permeabilities from 1/10 to 1/2 of a Darcy (100 to 500 millidarcies.) To understand permeability, try to blow air through a one inch cube of rock. If you can blow through it, it has permeability of a Darcy or more.

3. **Trap.** If there is no way to stop the oil and gas from continuing to migrate upward, eventually it will escape to the earth's surface, either at the sea floor or on land, as it does at the La Brea tar pits in Los Angeles. There are naturally occurring seeps on the sea floor all over the world, where oil and gas are continuing to escape to the ocean in small quantities. However, if a combination of rock with no permeability and the right geometric configuration intercept the upward flow of oil or gas, it may be trapped in a reservoir that can be produced by drilling wells.

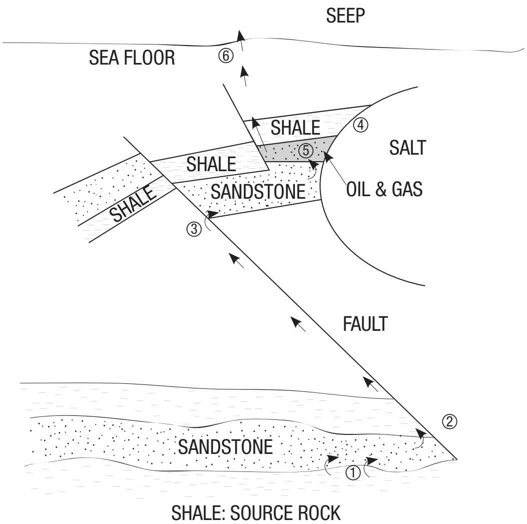


Fig. 3–3. The oil sequence. Oil forms in a source rock buried to a depth with temperatures of 60–100°C (1), causing small fractures to form in the rock. Oil migrates upward through these fractures into a porous sandstone and then laterally to a fault (2), then up the fault to another porous sandstone (3). At this point, some of the oil is trapped (5) and becomes a potential oil reservoir, while some leaks (6) up another fault to a seep on the sea floor.

The Gulf of Mexico

The various processes described in the previous section coincided to produce world-class oil and gas reservoirs, the Upper Tertiary Deepwater play in the Gulf of Mexico (GOM), one of the first areas (along with offshore Brazil) where deepwater development was accomplished as an economically viable venture, The word *play* is used by petroleum geologists to define a new area where they think hydrocarbons might be found, developed, and produced.

Upper Tertiary

The reservoir rock in this play consists of sandstones deposited by turbidity currents. While oilfields in the shallower waters of the Gulf of Mexico (located on the continental shelf) produce from sandstone reservoirs, these sandstones were deposited by ancient rivers in their deltas—deltaic sands. Reservoirs with a deltaic origin typically possess excellent porosity and permeability (25–30% porosity and 100–500 millidarcies), but the lateral size of a sand body in a delta is limited by the size of channels and river mouth sand bars. Well spacing in the GOM shelf oil and gas fields is typically about 40 acres per well, as much as can be drained by a single well.

The existence of turbidite sands in the modern day deepwater GOM had been confirmed by the scientific drilling of the Deepsea Drilling Project of 1968–1983. The presence of oil and gas reservoirs in turbidite sandstones was anticipated when the play began in the 1970s. The first discoveries of these fields confirmed the presence of high quality turbidite sandstone reservoirs, with porosity and permeability characteristics similar to those of the shelf deltaic sandstones. However, a major question was continuity—how large an area could be drained by one well? Because of the high development costs, well spacing of 40 acres would not be economical.

An extensive program of outcrop studies, coring, and shallow seismic in modern day turbidite sands on the present day sea floor, well test analysis, and analog studies confirmed that drainage areas of as much as 1,000 acres could be expected. This included the early production history of the

Bullwinkle field mentioned in chapter 1, a field with turbidite sandstone reservoirs in 1,354 feet of water developed in the late 1980s. The large drainage areas are due to two reasons:

1. The turbidity currents deposit sand on the open sea floor or in large depressions called minibasins. Either depositional site results in continuous sand bodies that can be thousands of feet in length, much larger than a channel or sand bar in a delta.

2. The different modes of salt occurrence in the shelf versus the deepwater environments in the GOM. In the Gulf of Mexico, the layer of salt formed during ancient times underlies the sandstone reservoirs. On the shelf, the oozing salt often formed almost vertical columns of salt called salt domes, breaking up the nearby oil reservoirs into small compartments by faulting. In the deepwater environment, the salt had less of an irregular surface, and it formed structures called minibasins bounded by salt. (See fig. 3—4.) Faulting is less pronounced in the deepwater minibasins and contributes to the larger drainage areas.

The sandstone reservoirs are relatively young in geologic time. They have not been subjected to very high temperatures or pressures, and so have high porosities and permeabilities. The combination of this with the large drainage areas gives very high-rate wells (up to 40,000 barrels per day) with each well draining as much as 30 million barrels of oil or 300 MMCF of gas.

The presence of sufficient source rock to charge reservoirs with oil and gas had been confirmed on the GOM shelf for years, and proved not to be a problem in the deepwater. Traps were formed by overlying impermeable shales, faults, and salt structures. This combination of reservoirs, source rocks, and traps created a geologic environment that could support the high costs of deepwater development. However, the very expensive wells required to find and produce the oil and gas required another technology, the geophysical techniques, especially 3-D seismic, described later in this chapter.

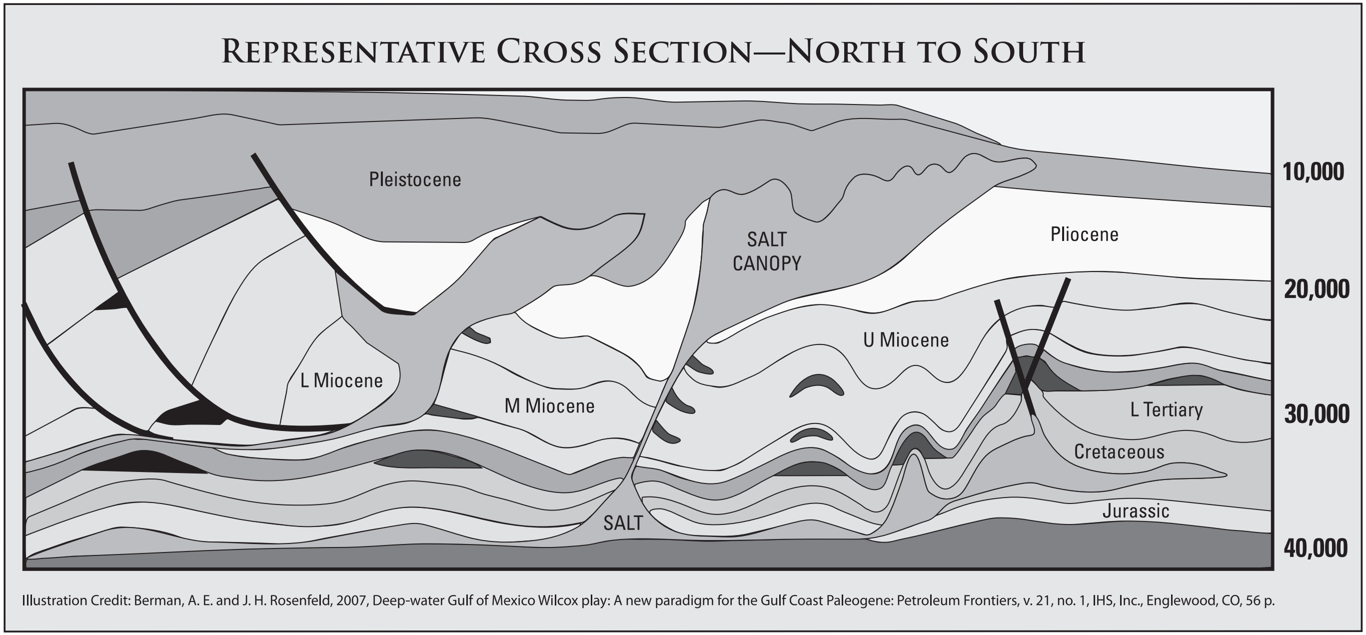


Fig. 3–4. A cross section showing typical Gulf of Mexico structures and their geologic ages. Note the reservoirs, from left to right, below impervious layers, butted up against a fault, butted against salt diapirs, and in various sedimentary layers distorted by mobile salt. (Courtesy A. Berman and J. Rosenfeld and HIS.)

Lower Tertiary Wilcox

The Lower Tertiary Wilcox play in the deepwater Gulf of Mexico is directed at fields consisting of very large traps. Some of them are easily distinguished on seismic, but some exist below a salt layer that partially or completely covers the trap (fig. 3–5), making seismic imaging a more complex exercise.

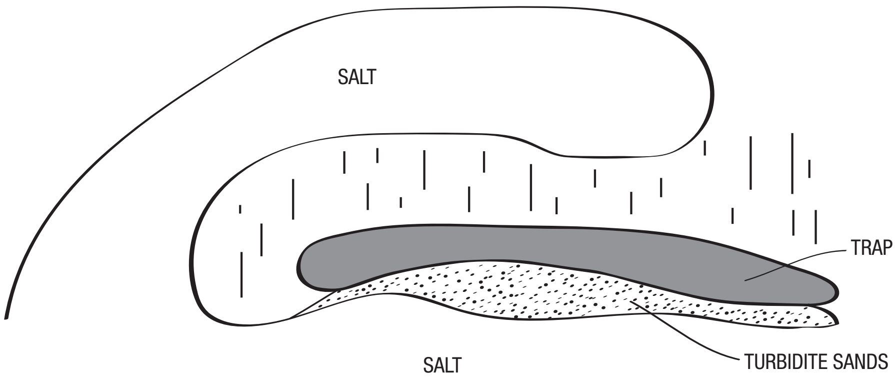


Fig. 3–5. Salt canopy overlying oil reservoirs in the Gulf of Mexico Lower Tertiary

As in the Upper Tertiary play, sufficient source rocks exist to fill the traps with oil and gas when they exist. The reservoir rocks are turbidite sandstones, deposited in a similar manner to those in the Upper Tertiary. However, the reservoir rocks in the Lower Tertiary are older, and have been exposed to higher temperatures and pressures. As a result, they exhibit lower porosities and permeabilities. In spite of that, new techniques to complete the wells have resulted in very high production rates.

The rocks beneath some limestone reservoirs have been deformed into areas that are topographically higher than the surrounding rock, pushing up the reservoir rock and allowing migration to accumulate hydrocarbon. This combination of a higher elevation, porous limestone for a reservoir rock, and an impermeable salt seal overlying the reservoir resulted in very large oil reservoirs being formed.

Accurately mapping these traps has become possible through an advance in reflection seismic technology called pre-stack depth migration, also discussed later. This technique for processing the seismic data requires close collaboration between geologists, geophysicists, and well logging specialists, but is capable of accurately delivering images of complex traps below the salt.

Brazil

Fred B. Keller, Shell Upstream Americas

Offshore exploration

The era of offshore exploration in Brazil began around 1947. A series of appraisal wells were drilled in the Reconcavo basin, extending the onshore Dom Joao oil field into the shallow ocean waters—an episode reminiscent of chapter 1's account of the dawn of the offshore industry in 1897 at Summerland, California. In 1968 Petrobras made its first offshore discovery in the Guaricema field in 80 meters of water.

In the 1970s, Petrobras pursued drilling in greater than 200 meters of water in the now prolific Campos, Santos, and Espirito Santo basins. They were testing the oil and gas potential of a thick interval of sediments, and also trying to understand the distribution of source rocks, reservoirs, seals, and their associated oil and gas fields, that is, defining the *petroleum systems*. (See the box of definitions on page 55 for all the italicized terms in this section.)

The offshore Brazil basins have two major petroleum systems—a pre-salt petroleum system, and a post-salt system, each with its own set of distinctive petroleum reservoirs.

The pre-salt petroleum system

This system occurs beneath a layer of evaporite sediments—salt, anhydrite, and other minerals formed by an ancient, massive evaporation of basin waters. (See fig. 3–6.) This layer of so-called "salt" occurs more or less continuously across much of the offshore Atlantic margin of both Brazil and West Africa, but is not present on the northern equatorial margin of Brazil. Beneath the salt layer, organic-rich and thermally mature source rocks occur in the centers of a series of rift basins created by the tectonic forces that pulled Africa and South America apart to create the South Atlantic Ocean during Cretaceous and younger times (beginning 145 million years ago.) The sub-salt reservoirs that capture the petroleum are divided into two groups:

- **Clastic** sediments, both *sandstone* and *conglomerate* that were eroded from the mountains that flank the rift basins
- **Carbonate** sediments, (porous *limestones* and some *dolostone* reservoirs) that were deposited in shallow water along the edges and crests of the mountains as they were eventually flooded and then buried by older sandstones and associated sediments

Above the reservoirs, the salt formed the top seal that trapped petroleum accumulations. Even deeper oil and gas accumulations may exist where shales and nonporous limestone interlayered with the reservoirs trapped oil and gas against the submerged mountain flanks or against faults that flank the mountains and penetrate the deeper parts of the basins.

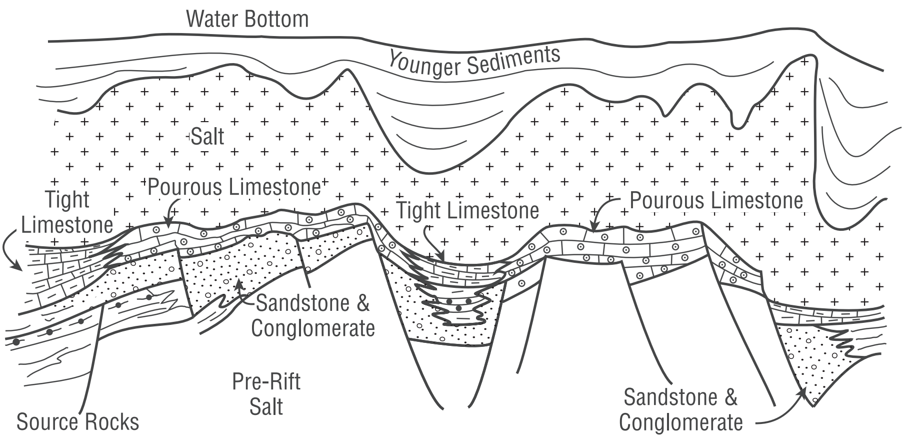


Fig. 3–6. The pre-salt petroleum system in offshore Brazil

Some Important Common Terms in Petroleum Geology

petroleum system. A geologic interval in a basin that relates the occurrence of a mature source rock (one that expels petroleum) with all the geologic elements that are essential for migrating and trapping petroleum within that system. Understanding petroleum systems allows better prediction of where, in a given interval of the basin, accumulations of oil and gas are most likely to occur.

clastic sediment. Sediment consisting of fragments of rock, transported from elsewhere and redeposited, forming another rock. *Clasts* are individual grains that make up the sediment.

conglomerate. Clastic sedimentary rock that contains mostly pebble-size rounded clasts. The space between the clasts is generally filled with smaller particles and/or chemical cement that bind the rock together.

carbonates. Sedimentary rock consisting mostly of calcium carbonate, $CaCO_3$ **(limestone),** and **dolomite,** $CaMg(CO_3)_2$. **Limestone, dolostone,** and **chalk** are carbonate rocks. Carbonates can be **clastic** but are more frequently formed by precipitation or the activity of coral, algae, or other organisms.

shale. A fine-grained sediment formed by consolidation of clay and silt particles into relatively thin but impermeable layers. Shales that contain a percent or so of organic material can become rich source rocks. The fine grain size of the shale makes for good cap rock for hydrocarbon traps.

salt diapir. A mass of salt, which is a plastic material that intrudes into preexisting rock, generally upward because of its buoyancy. Salt diapirs can cause faults and form domes and other shapes that make for good hydrocarbon traps.

grainstones. A kind of limestone composed of grains with cement called spar.

oncolites and oolites. Sedimentary rock containing spherical or egg-shaped grains composed of concentric layers of mostly calcium carbonate.

diagenesis. A physical, chemical, or organic change undergone by a sediment after its initial deposition; particularly associated with the transformation of organic material into oil and gas.

In the offshore Santos and Campos basins, the pre-salt *limestones* are found today well beyond the modern continental shelf edge in up to 2,000 or more meters of water and at distances up to 200 kilometers or more from the shoreline. Their occurrence is also unusual for a rift basin setting. During formation of the rift basins, the porosity of these limestone reservoirs may have resulted from deposition in higher energy (more movement) shallow water environments, like beaches and shallow water bars, where stronger waves and currents sorted larger grains and kept fine clay and carbonate particles from accumulating. Removal of the fine silt and clay-sized grains by currents is a process known as *winnowing*, leaving in place a coarser grained limestone, often referred to either as *grainstone* or as coquina if the rock is mostly composed of large sea shells. The grains in these rocks are rounded fragments of hard shells from special varieties of snails and bivalves (clams and ostracods) that do not occur in typical oceanic environments.

The absence of typical normal marine organisms like corals in these sediments has led some geologists to think that the pre-salt limestones were deposited in some far more restricted setting, or perhaps even within very large ancient lake environments called a lacustrine setting. Some of the porous and permeable nature of these reservoirs may also be due to deposition by various microbial organisms and chemical processes during burial (*diagenesis*), which can yield a limestone or *dolostone* with locally good porosity, often with numerous, abnormally large pores called vugs. (See fig. 3–7.) Examples of these types of deposits are found in modern tidal flats and other settings like lakes or shallow bays with restricted water circulation, as in, for example, Shark Bay, Australia. Where the limestone is fractured due to the stresses that build up around folds and fault surfaces, the fractures may connect both the reservoir pores and the vugs in the reservoir rocks, greatly improving the reservoir's overall permeability.

In recent years, major accumulations of oil and gas have been found in pre-salt limestone layers in the Santos and Campos basins. Some of these oil fields are among the largest found in the world. For example, the Tupi field in the Santos basin is a porous limestone oil accumulation that Petrobras, the operator, says may ultimately produce between 5 and 8 billion barrels of oil. This production, referred to as *recoverable* oil and gas, actually is only a fraction of the total amount of oil and gas trapped beneath the surface within the reservoirs, and is in most cases less than 40% of the total oil in place. The rest clings stubbornly to the rock granule surfaces. An important factor in exploring for petroleum from such deeply buried and unusual reservoir settings is the subsequent application of various production technologies that can provide more efficient extraction of petroleum from the reservoirs. The resulting increase in hydrocarbon recovery can make the development of a discovered field profitable, and so make these deep petroleum settings more attractive as exploration objectives. Application of production technologies that improve recovery by even a few percent can unlock tens to hundreds of millions of barrels of petroleum within these fields, depending on their sizes.

Fig. 3–7. Vuggy microbial limestone from a modern lake setting. (Courtesy Thomas C. Boronow, Shell International E&P.)

The post-salt petroleum system

The post-salt petroleum system in the Atlantic margin of Brazil lies *above* the regional salt layer and was deposited on the western margin of the growing South Atlantic Ocean under conditions of normal marine shelves and deepwater slopes. The post-salt system is divided into two major units:

- Shallow water carbonates, largely grainstones resting on top of the salt layer
- A younger *clastic* section, with local sandstone reservoirs in a variety of oil and gas traps

Structural traps in this system are associated with *salt diapirs* and "roll-over" structures (fig. 3–8) that were created by continued faulting, flexure, and vertical movements of the more mobile salt displaced under the weight of the sedimentary layers above. In addition, many of the clastic oil fields are formed by stratigraphic trapping, in which the edges of the fields coincide with the edges—or pinch-outs—of the sandstones, either along the flanks or the up-dip edges of the reservoir body. Oil and gas fields were formed where petroleum was generated and migrated either from a number of source rocks within the post-salt clastic section, or where it has leaked from the underlying pre-salt petroleum system through faults and "windows" in the salt layer. These windows occur where the salt was highly thinned or absent, either because it wasn't precipitated along the edges of the basin or because it was squeezed out by the weight of the overlying sediments.

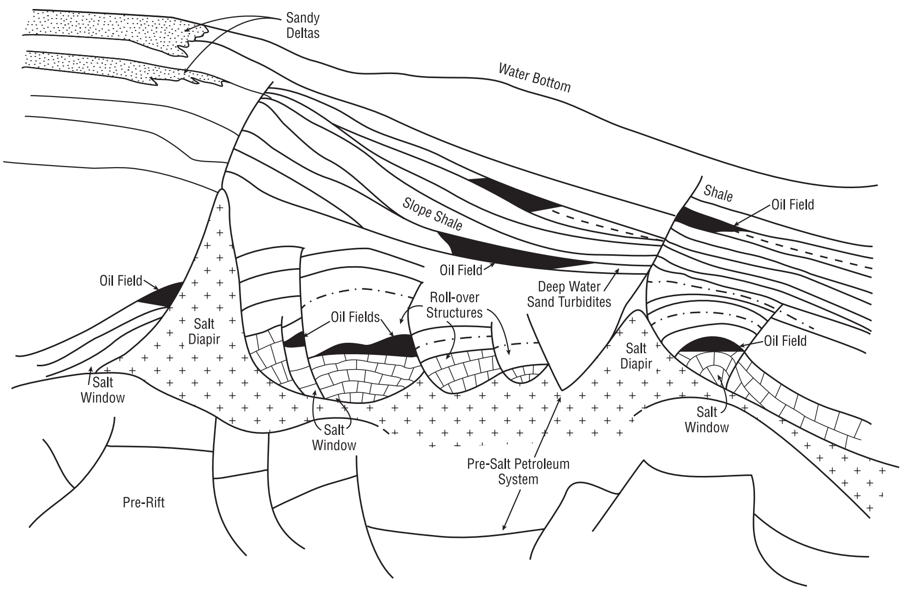


Fig. 3–8. The post-salt petroleum system in offshore Brazil. Salt windows provide a migration route to the post-salt section; other younger sediments provide more classic source rock, reservoirs, and traps.

Limestones in the post-salt petroleum system were deposited under normal marine conditions resulting from the opening of the South Atlantic Ocean during the Cretaceous Period. Many limestone beds contain an abundance of sand-sized *oolites* and *oncolites*. (See fig. 3–9.) These deposits can be clean and well sorted, and can be good reservoirs where burial-related chemical reactions have not deteriorated the properties. In 1974, the Garoupa Field in the Campos Basin became the first major offshore discovery in these post-salt limestones. Several other fields of this reservoir type also have been discovered in the same area of the Campos basin, in both the shallow and deepwater beyond the modern shelf edge. Deposits of similar age and depositional environments may also be found on the West African side of the South Atlantic Ocean, for example, the Cabinda limestones, offshore Angola.

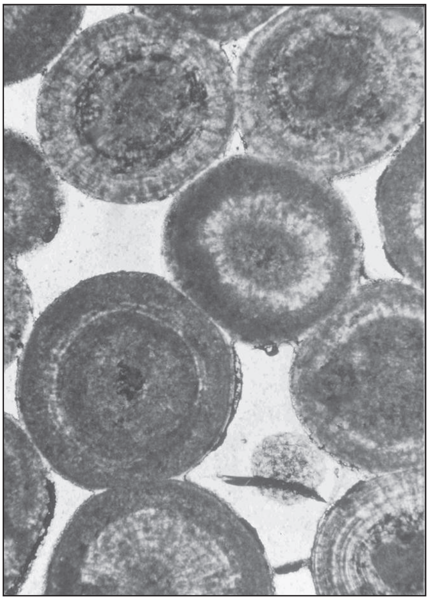


Fig. 3–9. Microscopic photograph of an ancient oolitic limestone. (Courtesy Thomas C. Boronow, Shell International E&P.)

Above the post-salt carbonates is the younger unit comprised of alternating layers of *sandstone* reservoirs and *shale* seals deposited by both seaward and landward migrations of sandy deltas and their equivalent deeper water sandstone turbidite deposits. Major seaward migrations (regressions) of the shoreline delivered considerable sand to the basin in the form of a series of major deltas at the shelf edge. Sand at that location was then transported into the deepwater slope and basin areas and was deposited as a variety of both channelized and sheet-like turbidite sequences. At other times, rapid landward migrations of the shoreline (transgressions) resulted in widespread deposition of fine-grained mudstone and shale over broad areas of the shelf and deepwater as water depths rapidly increased. These shaly deposits formed multiple seal layers for the sand sequences. Some of the largest oil fields in Brazil are found in such sealed turbidites and account for the majority of the oil and gas currently produced in offshore Brazil. The first of these was Namorado field, found in 1975 by Petrobras. This discovery was followed by very large discoveries at Albacora (1984), Marlim (1985), Albacora Leste (1986), Marlim Sul (1987), Marlim Leste (1987), and Roncador (1996). Stratigraphic trapping forms a major component in many of these fields.

In most of these fields, the petroleum occurrences in the reservoirs were initially identified by their seismic amplitude response as "bright spot" reflections, or as reflections exhibiting amplitude-versus-offsets anomalies (see the geophysics discussion in this chapter). Subsequent drilling confirmed the occurrence of the oil-bearing turbidites. In addition, major advances in drilling and production technologies—extended reach drilling, and subsea and floating production facilities, were crucial to this step outward into the deepwaters.

West Africa

Tim Garfield, Exxon Mobil E & P

Offshore exploration history

Shallow water drilling off the coast of West African began in the early 1960s with exploration successes in the offshore areas of the Niger Delta, Gabon, and the Congo. Production from shallow Nigerian waters started in 1965, and since then several hundred shallow water oil and gas fields have been brought on production in near offshore West Africa.

The first significant deepwater discoveries in offshore West Africa were made some 30 years later. These discoveries in water depths greater than

300 meters used high quality seismic data and specialized deep-water drilling and production equipment that had only recently been developed in the Gulf of Mexico and Brazil.

One of the first significant deep-water discoveries in West Africa was Mobil's Zafiro field, 40 miles offshore Equatorial Guinea on the eastern flank of the Niger Delta in 1995. Production began only 18 months later and demonstrated the high initial oil production capacity of the channelized deep-water reservoirs, ultimately peaking at nearly 300 thousand barrels a day with an expected ultimate recovery approaching 600 million barrels.

Bonga field in the west central part of the Niger Delta in 1996 by Shell/Exxon/Total/ENI in over 1,000 meters of water 120 kilometers offshore was followed by Bosi (1996), Ehra (1998), and Agbami (1998), establishing the area as a world class basin.

In 1996 Elf Aquitaine/Exxon/BP/Statoil discovered Girassol, the first major deepwater discovery in the geologic province known as the Lower Congo Basin, located offshore of Angola and the Congo. Subsequent drilling led to the nearby Dalia discovery and a string of smaller discoveries. In 1997, Chevron and its partners made the Kuito discovery. Exxon and partners drilled the Kissanje discovery in 1997, followed by Hungo, Dikanza, Marimba, and a string of smaller discoveries.

Several of the initial deepwater fields were major discoveries with estimated ultimate recoveries approaching a billion barrels of oil each. Together they defined the significance of two major petroleum systems—the deep-water Niger Delta and the Lower Congo Basin offshore Angola and Congo, both areas of prolific hydrocarbon generation from Tertiary marine source rocks. Since those mid-1990s discoveries, scores of fields were discovered offshore West Africa in water depths greater than 300 meters. West Africa had become one of the most rapidly expanding exploration and production centers in the world.

Geologic history

Offshore West Africa and the East Coast of Brazil are two of the world's most prolific deepwater producing regions, and the two have many geologic traits in common. At one time, in the early Mesozoic era (around 250 million years ago), both continents were part of a single great landmass called

Gondwana. In the earliest Cretaceous time (145 million years ago), the two regions were separated by great crustal rifts or troughs driven by the forces of plate tectonic motion. This rifting phase first resulted in the formation of basins where lakes formed and a variety of sediments were deposited, including algal-rich organic deposits that later formed source rocks. (*Algal*: rapidly formed bloom of algae.)

Continued extension and separation of the African plate from South America stretched and thinned the continental crust to the point of rupture—the beginnings of the South Atlantic oceanic basin. The first marine waters, laden with salt, entered this depression from the south, across a shallow shelf called the Walvis Ridge. This shallow sill separated the rapidly subsiding rift basin to the north from open oceanic waters to the south. The climate in this period (112 to 125 million years ago) was highly arid and desert-like. Evaporation of the marine waters entering the silled basin (one with a sill that prevents rapid replacement of the contents) occurred quickly and caused the salt content of the water to increase to the point of precipitation. This resulted in the rapid deposition of a thick salt deposit that is now present below some oil producing regions of both West Africa and Brazil, the so-called *pre-salt*. These thick salts behave like plastic when loaded by overlying sediment. Movement of the salt pushed some sedimentary layers into large ridges or domes, which created many of the structures that contain oil and gas in offshore Angola and Brazil (fig. 3–10).

Continued sea-floor spreading pulled the continents apart, dividing the salt basin in two: the South Atlantic Ocean basin had formed. The two continental margins were characterized by narrow shelves beyond which water depth rapidly increases across broad slopes to bathyal depths (3,300 to 13,000 feet) of the open ocean. On both sides of the Atlantic, deep-water oceanic conditions have existed in these areas since the end of the early Cretaceous Period. Onshore rivers dumped endless layers of sands, shales, and organic rich mudstones in these deep marine waters, producing the reservoir, seal, and source rocks essential to generate and trap oil and gas.

The oil and gas discovered in offshore West Africa fields like Girassol, Zafiro, and Bonga are contained within the pore space of sands and sandstone formations that were deposited in great water depths, on the bottom of the South Atlantic ocean in the Oligocene and Miocene periods (about 35–5 million years ago) of the Tertiary era. These types of deposits were not very well understood at the time these fields were discovered.

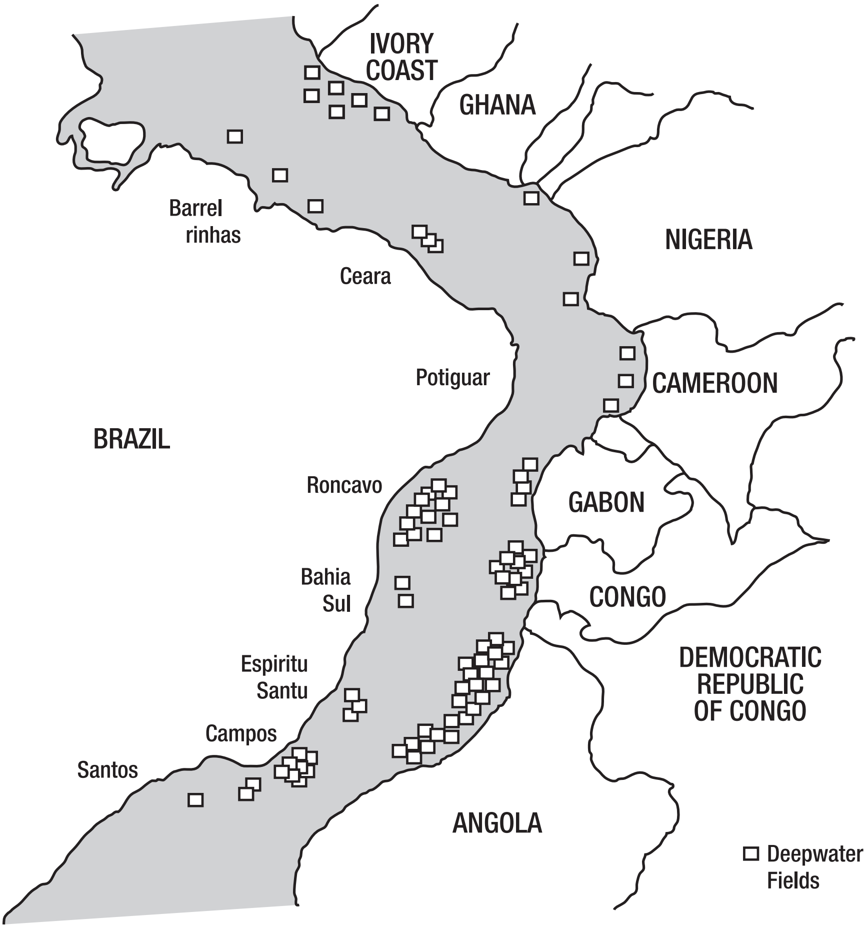


Fig. 3–10. Mirror images of oil fields off Brazil and West Africa

Exploration experience

Early models for deposition of deepwater sands were based on whatever data sets were available at the time. As a consequence, the models that geologists used to predict the nature and distribution of deep-water sands were, in hindsight, rudimentary. The classical models used to describe deepwater reservoirs such as those in the Gulf of Mexico were submarine fan models that depicted concentric sediment deposit belts radiating away from the mouth of a submarine canyon (fig. 3–11). These models suggested gradual down-fan decreases in reservoir sand thickness.

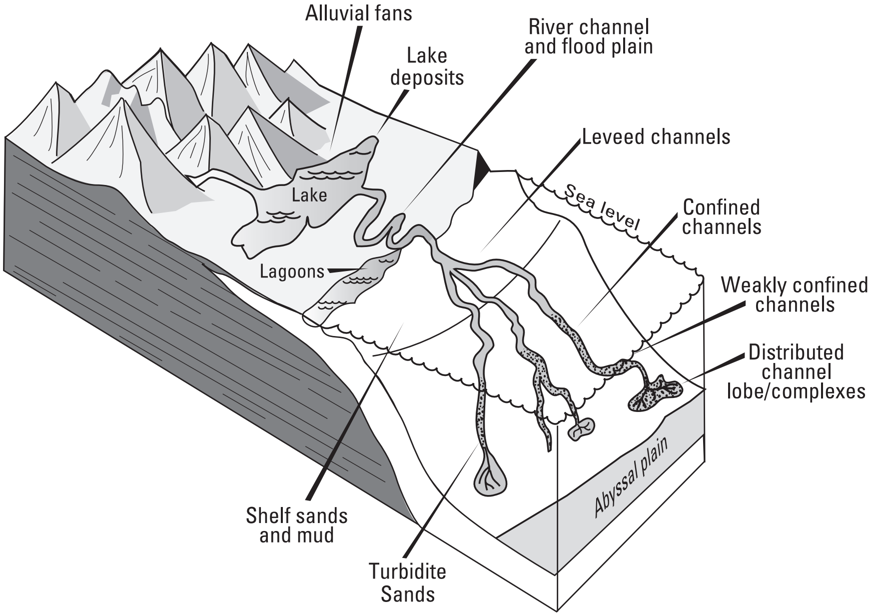


Fig. 3–11. Channelized fan model for West Africa

In many ways these models were not consistent with the reservoir types that were encountered by the early West Africa exploration drilling in deep-water settings. Girassol and Zafiro reservoirs in particular appeared to have much greater lateral variability in sediment type then the classical fan models would have predicted. The modern high-resolution 3-D now being used and the many wells and cores extracted to characterize these reservoirs suggest a much different mode of deposition and a much more complex reservoir and seal architecture then the classical fan models predicted.

Many West Africa deepwater reservoirs have geometries that resemble filled-in rivers and streams. The nature of the deposits of these submarine rivers or streams has been extensively studied by industry and academic geoscientists since the Girassol and Zafiro discoveries were made. They are now understood to have been formed by turbidity currents—deep currents laden with sediment pulled by gravity.

Turbidity currents form when sediments deposited near the outer edge of the continental shelf are reworked into deeper water by slope failures, storms, or surges in river discharge. The high concentrations of sediment in the water column are driven downslope by the force of gravity acting on the sediment, pulling the entrained water along to form a strong current. This is similar to a river where the force of gravity pulls the water downslope and the water entrains sediment. Sediment-gravity currents active in deepwater settings with sufficient slope can carry sediment as coarse as gravel or cobbles. These currents cut channels, build levees, and create meandering channel patterns just like rivers. (See fig. 3–11.) Sands deposited in the channel *thalweg* (the lowest continuous points of a river channel) or as levees form the reservoirs that are now being produced in West Africa. The reservoirs resulting from this action tend to be further downstream and in channel-related formations, in contrast to the fan shaped deposits of shown in figure 3–2.

Because of the complex distribution of reservoir (sand) and seals (shales or muds) associated with channelized deepwater reservoirs common in West Africa, successful development is largely dependent on high-resolution 3-D seismic data. This tool's resolution approaches meter scale and allows geologists to develop models that accurately map the old river beds in the subsurface. These models are used to accurately position development producer and water injection wells in locations that provide maximum sweep of the oil and gas in the reservoirs to the producing wells. This results in reduced well counts and higher per well producing rates and oil recovered per well, all critical economic factors.

Northwest Australia

Dr. Stephen O. Sears, chair, Department of Petroleum Engineering, Louisiana State University

The Exmouth Plateau off Northwest Australia represents another example of the development of deepwater technology enabling new plays in different geologic environments. The hydrocarbons in this area are predominantly gas. Reservoir rock includes sandstones that were deposited in river deltas as well as turbidite-derived sandstones. These rocks are considerably older than the Tertiary rocks described above in the Gulf of Mexico, or the rocks of pre-salt Brazil and West Africa. They are interpreted as having been deposited over 200 million years ago. Carbonate reservoirs consisting of reef rock, surrounded by muddy limestones and dolomites, are also possible in this area.

Traps in Northwest Australia include classic stratigraphic traps that are formed when impermeable shale layers are draped over porous sandstone, sequestering the hydrocarbons. Stratigraphic traps can occur when porous sandstone or limestone is deposited next to muddy sediments, either shale or muddy limestone (fig. 3–12.) After burial and some uplifting or tilting of the sedimentary layers, the muddy sediments form a barrier to further migration, and can form a trap with no need for a fault barrier of bending rocks. This type of trap is harder to identify on seismic data than structural traps, but can form very large hydrocarbon reservoirs.

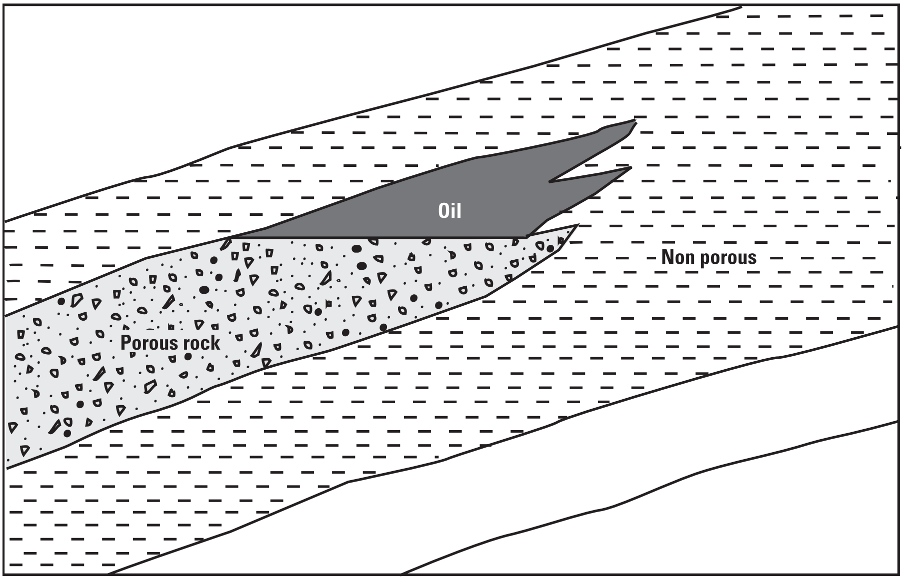


Fig. 3–12. A stratigraphic trap does not depend on faults or bending but on impermeable rock deposited about the same time as the reservoir rock.

Seismic Data

Michael C. Forrest, Geophysicist, Shell Oil (retired)

Seismic data, especially 3-D data, is one of a handful of vital enablers that has made deepwater exploration successful. No one ever *knows* what will turn up when the drill bit reaches target depth, but seismic data provides a quantum leap in improving the estimate of the probability of success before the well is drilled. With some deepwater wells costing more than $100 million, that's crucial.

Understanding and assessing seismic data may be more challenging than any other step in the process of finding and producing oil and gas. The professionals who work seismic—the geophysicists, geologists, mathematicians, computer specialists, and other proselytized scientists—have their own language. While there is little hope of totally demystifying seismic here, and at the risk of causing all of them to guffaw, a quick look at the mechanics and nomenclature follows.

Seismic data involves four steps: *acquisition, processing, display,* and *interpretation*. Oil companies usually outsource the seismic data acquisition and the initial processing and display. The final processing can be from service companies that have climbed up the seismic learning curve, but some oil companies do their own processing and display for most of their prospects. Other companies lean on vendors.

Acquisition

The object of the acquisition phase is to collect seismic data that presents a picture of the subsurface. Seismic vessels like the one in figure 3–13 tow *streamers,* plastic tubes that extend five to six miles in length behind the boat. The streamers float below the surface and have visible markers at the surface, placed intermittently to track the cables and to warn off vessels that might want to cross tracks and cut the cables.

Fig. 3–13. The seismic vessel *Seisquest.* (Courtesy Veritas DGC.)

The streamers each contain thousands of hydrophones (pressure change detectors). The vessel also tows air cans or guns, the seismic source, a short distance behind the boat. These guns are filled with compressed air, and when they open abruptly, they release the air with a bang, like a popped balloon. As that happens, the classic seismic data gathering takes place. (See fig. 3–14.)

The sound wave travels down through the water, more or less unimpeded. As it passes the sea floor into the subsurface, the sound wave echoes from the boundaries between various layers of seabed, back to the surface where the hydrophones pick up the echo. Each hydrophone records the reflected seismic signal from a different angle. Here is the essence: the deeper the layer, the longer the echo takes to reach a hydrophone. Moreover, and this is critical as well, the various layers of the subsurface have different acoustical properties. The unique velocity and density of each rock layer affects the strength of the echo.

Seismic records can be displayed in several different ways, such as black wiggly lines or color-coded cross sections. On the seismic record in figure 3–15, the intensity (or amplitude) of each line (geophysicists use the term *seismic trace*) measures the strength of the reflected signal. The interval between the strong amplitudes lines measures the time from one received signal to the next.

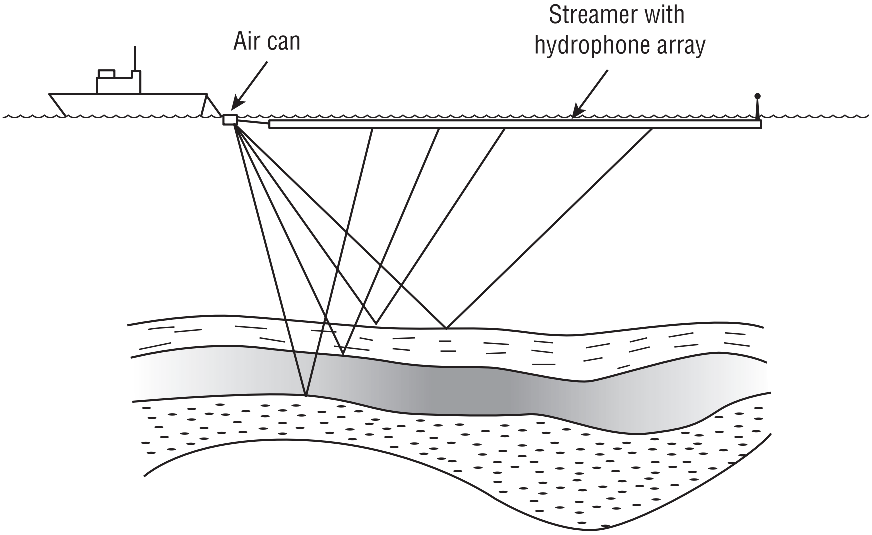


Fig. 3–14. Offshore seismic acquisition

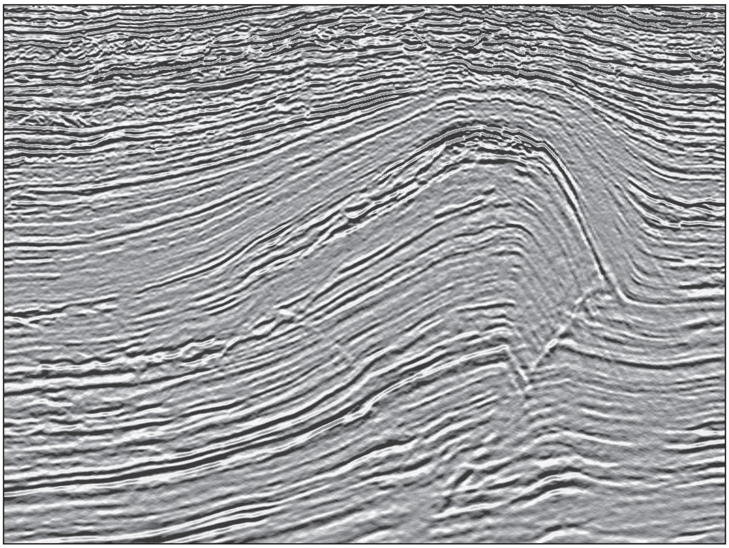


Fig. 3–15. A 2-D seismic display of a hanging wall anticline with direct hydrocarbon indicator (DHI), West Niger Delta. (Courtesy Veritas DGC.)

Multiple shots fire as the seismic vessel motors over a target area. All in all, the number of recorded sounds can add up to millions of millions. The seismic travel time for a reflection is variable depending on the velocity of the sedimentary layers. In some areas, 10,000 feet is about three seconds. A deepwater seismic record typically has about 12 seconds worth of data.

Since the hydrophones string out behind the seismic vessel in a straight line, the seismic record comes in 2-D format. The reflections primarily come from below the seismic cable. To create 3-D records, seismic vessels tow several parallel streamers. During later processing, the parallel records are transformed into a continuous three-dimensional block of data, often called a seismic cube.

Modern seismic cables convert the reflected sound waves into digital format using special modules in the cable. The digital data is transferred to the recording room on the boat. Some 3-D surveys capture and store several terabytes of data. (Measuring information goes byte, kilobyte, megabyte, gigabyte, then terabyte, or 10^{12} pieces of information.) Processing requires supercomputers dedicated to seismic work. Computing capacity is heading in the direction of petabytes (10^{15}).

Azimuthal seismic

Azimuth is a location parameter used in 3-D systems, including astrophysics (stars and such) and geophysics (oil and gas exploration). It is a measure of the angle from a base point to some point in x, y, and z (i.e., 3-D) coordinates.

After the big bang of the air gun, seismic echoes are picked up from the space in a 360-degree circumference around it, so the hydrophones capture echoes from multiple azimuths. In addition, the vessel may make multiple passes over the target. Figure 3–16 shows four different techniques for capturing increasingly rich azimuthal data. After correspondingly lengthy and complex processing, each can give a successively better picture of the subsurface.

- In **narrow azimuth seismic** (NAZ) the original 3-D approach, a single boat tows several cables, 100 to 200 feet apart, recording reflections primarily below the cables.

- In **multi-azimuth seismic** (MAZ) a single boat takes readings as it passes several times over the target in different directions.
- In **wide azimuth seismic** (WAZ) some companies use two vessels towing multiple cables and a third in the middle with the seismic source. That can give a spread of 3,000 to 4,000 feet. Other companies use one vessel with multiple passes.
- In **rich azimuth** (RAZ) a single tow making numerous circular paths within the target area gathers yet another step change in the amount and richness of the data collected and the quality of the processed image. But of course, it is that much more expensive to acquire and process.

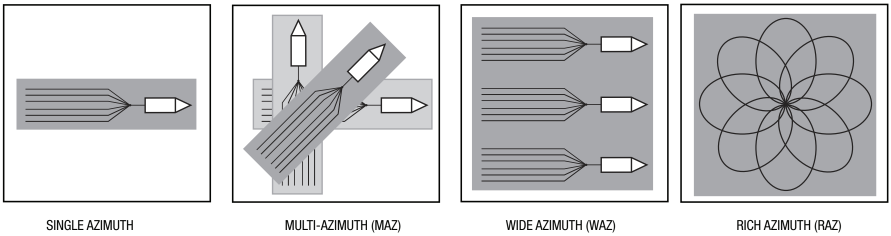


Fig. 3–16. Patterns used for capturing azimuthal seismic

The data sets from these increasingly extensive surveys grow by a factor of five or more, demanding a corresponding processing effort to ensure that the data from surveys precisely overlay each other after processing. All this multiplies the cost of WAZ seismic by a factor of four or five times NAZ, but still small in comparison to a $100 million dollar well cost.

What's this all about? This has been a boon in many deepwater prospects, especially in the Gulf of Mexico and offshore Brazil that occur beneath large accumulations of salt, sometimes thousands of feet thick. (See earlier figs. 3–5 and 3–6, for example.) Seismic wave fronts that pass through salt layers often result in distorted data as the signals bounce irregularly about the salt, in the same way that looking through a beveled-glass table top distorts anything below it. Also, the top and base of salt masses are often *rugose* (irregularly corrugated), and that causes the seismic energy to scatter is many directions. MAZ, WAZ, and RAZ seismic has helped improve seismic data in these areas in much the same way as walking around that beveled table top would. Many of these salt-prone areas will have been shot using multi-wide-rich acquisition.

Processing

Some processing usually takes place on the recording boat to organize the data, but most of it and all the subsequent reprocessing is performed using computers in the service company's or the oil company's processing centers.

Initial processing takes the form of "data preparation" to eliminate bad records, correct for unwanted shallow surface effects, and reduce the effect of multiple reflections (wave fronts that bounce around within geologic layers and then back to the surface). This work is done using a series of complex software programs developed from mathematical theory about seismic wave fronts traveling through the earth.

After the initial clean up, serious processing begins with a covey of techniques meant to produce accurate representations of the subsurface.

Stacking. One of the most important parts of processing is called stacking where 100 recordings (or more) at varying offset distances are combined to form one seismic *trace*. (See fig. 3–17.) The purpose of stacking is to enhance the quality of the signal, reduce noise ratio, suppress multiple reflections that come from reflections within a layer, and in general come up with a more accurate representation of the reflection sound waves from the surface to the subsurface and back to the surface.

Migration. The stacking process assumes each reflection is at the midpoint of the traveled distance (down, then up) between the *detector* (the hydrophone) and the sound source (the air gun), after bouncing off the layer. That's fine if all the layers are flat. Reflections from *dipping beds*, layers that run at an angle from the surface, can deliver a signal that can appear to be thousands of feet horizontally and hundreds of feet vertically away from reality. To correct the seismic records and restore the signals to their true spatial relationships, processors use a scheme called *migration* (also fig. 3–17), an unfortunate term not to be confused with the movement of hydrocarbon from the source rock to the reservoir.

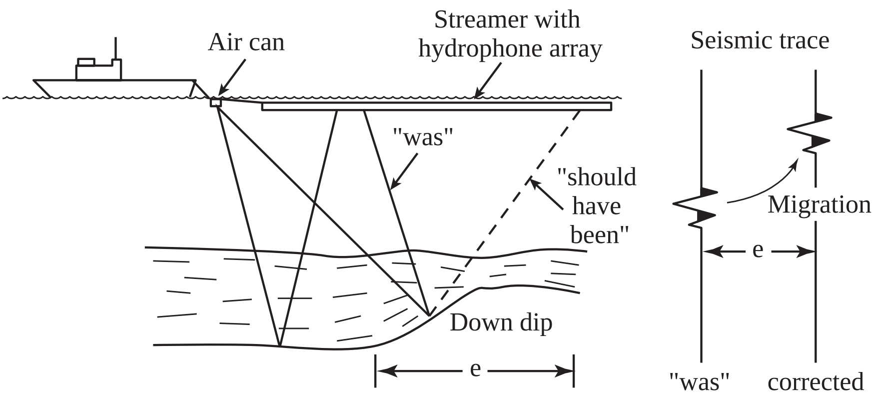


Fig. 3–17. Migration—reflections from updip location appear in the wrong place on a seismic record and must be corrected during processing to get the best approximation of where the reflection originated.

To do migration (seismic-talk type), the processing programs have to use the velocity of sound in the various layers. Geophysicists and geologists sometimes have the luxury of data from a nearby well to estimate the velocities. Well logs have accurate measurement of depths and the compositions of various geologic layers. Using mathematical analysis, they can also use seismic data to estimate the velocity of sound in each layer and approximate the depth/velocity relationship.

In some deepwater areas, the conversion can be tricky. The Gulf of Mexico, for example, has many salt domes and salt layers that have both been deformed by the heavy weight of accumulated sands and shales deposited from rivers. (See fig. 3–5.) In offshore Brazil, two layers of salt abound in some areas. (See fig. 3–8.) Sound travels about 15,000 feet per second in salt but only 8,000 to 12,000 feet in sediment. Seismic signals sometimes take a tortuous path through sediment and salt layers, and the seismic records can be very poor.

Prestack depth migration. This deals with the distortions caused by inconsistent and odd-angled layers. The data is migrated (corrected) before stacking and is measured in depth. The corrections to the data require accurate subsurface velocity data and massive computer processing, an expensive but effective way to adjust the data. A somewhat cheaper approach, *prestack time migration*, uses less rigorous velocity data and less computer processing.

Display

Results of the massive manipulation of seismic data must be displayed in a useful form. Processed 3-D seismic data cubes are stored in the computer. Simple 2-D vertical slices (fig. 3–18) provide first looks at the geology. Horizontal slices of the data cube, usually called time slices, can also be displayed on the computer screens. A 3-D cube can be rotated to get different views of the seismic image of the subsurface. Certain data characteristics such as strong seismic reflections can be isolated and displayed as a separate data cube using *voxel* technology. A voxel is the 3-D equivalent of the 2-D pixel used to display images on home TV sets.

Early on, interpreters found that the amount of data in black-and-white seismic lines overwhelmed the human eye. However, the eye can handle wide-ranging variations in color. Interpreters, even as late as the 1970s, used colored pencils to add another dimension to their displays. That sometimes led to disparaging but good-natured remarks about the sophistication of seismic interpreters. Eventually software programs differentiated amplitudes, spacing, and other characteristics of the seismic reflections with color arrays chosen at the pleasure of the interpreter. (See fig. 3–19.)

3-D seismic data along with geologic and engineering data can be displayed in visualization rooms, like that in figure 3–20. Images of the subsurface are shown on large high-resolution screens and appear on one or more walls to create an illusion of the viewer being present in the subsurface, looking at the data from different angles, sometimes using special 3-D glasses. In recent years, computer technology has advanced so visualization can be done on workstations in a geophysicist's office or on a laptop computer.

Interpretation

All this preparation is just foreplay to the final step: interpretation and making economic decisions. Teams that can include geophysicists, geologists, petrophysicists, and other professionals bring their special knowledge to the interpretation, as they search for the source rock, the reservoir, and the trap for direct indicators of hydrocarbon presence. That calls for intimate interaction to relate seismic data to the geologic and geophysical knowledge of the area. Experienced interpreters can recognize false signals given by bad processing and can order reprocessing with corrections.

Direct hydrocarbon indicators. DHI technology is related to the acoustic properties of an oil or gas reservoir and the overlying seal. Geophysicists look at seismic displays for DHIs to help predict hydrocarbon accumulations, usually on a probability of success basis. The operative word is *indicator*, not *identifier*. A more descriptive term for DHI is *seismic amplitude anomaly*, which refers to a change in seismic data that is calibrated to other known oil and gas accumulations and that can be used to predict new accumulations. The most common DHI, a "bright spot," is a strong seismic reflection caused by the lower velocity and density of oil or gas sands compared to water-bearing, nonproductive sands. Other forms of DHIs include "dim spots," "flat spots," and *amplitude versus offset (AVO)* (discussed below).

The processing schemes take care to preserve the relative amplitudes of the data that make recognizing DHIs possible. The trained eye of a geophysicist can sometimes locate possible oil and gas accumulations on a seismic display like figure 3–15, although the interpretation team always does more detailed analysis and measurements before they make a prediction. Factors that greatly influence DHI interpretation and risking are the quality of the seismic data and the rock physics data and the presence of multiple amplitude anomaly characteristics.

Amplitude versus offset. Geophysicists also use a related technique, amplitude versus offset (AVO), as a seismic amplitude anomaly characteristic to help predict (not just indicate) the presence of hydrocarbons. They have learned that changes in seismic signal amplitudes are affected by three factors:

1. The offset angle, which changes with the horizontal distance between the source and the receiver, versus
2. The acoustic properties (velocity and density) of the reservoir and the sealing rock above the reservoir
3. The content of the zone, i.e., oil, gas, or water

AVO is often more successful if calibrated with nearby well data. This includes modeling the gas, oil, or water in a reservoir. It is important to review the seismic gathers (the 100 or more seismic recordings that make up a stacked seismic trace) to assess seismic data quality and amplitude change with offset (technically it should be amplitude change with angle). There are many ways to display and study seismic AVO data in cross-plots, but all are based on the basic amplitude versus offset data.

An AVO anomaly alone does not equal hydrocarbons. It is part of the toolkit to risk exploration prospects but can be very important on some prospects. AVO studies are generally used in conjunction with other seismic amplitude anomaly characteristics. This includes conformance to down-dip structural contour (oil/water or gas/water contact), flat spots (possible oil or water level), and/or data from nearly wells.

4-D seismic. This technique adds the fourth dimension—time—to seismology and is used during the production phase of an oil or gas field. As oil or gas in a reservoir is evacuated during production, the acoustical image may be modified due to changes in the reservoir properties (related to velocity and density changes). These changes in reservoir properties and acoustic properties are monitored by multiple 3-D seismic surveys repeated every several years. Even permanent receiver stations can be employed that involve the use of remote-operated vehicles to place hydrophones on the seabed above the target. Useful data requires precise knowledge of the hydrophone locations and detailed seismic processing so the seismic shoot can be compared to the previous vintage. Some companies use towed cables for 4-D, but that complicates matching the data sets to previous ones. Either way, careful analysis of time-lapsed evacuation can locate pockets of oil or gas not being drained and can improve future development plans.

In the end, seismic work plays a critical role in the decision to drill a deepwater wildcat well, or even a delineation or development well.

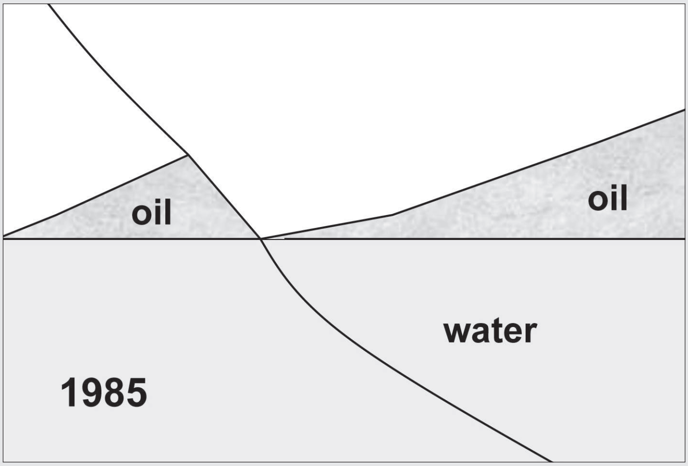


Fig. 3–21. Gullfaks 4-D survey—1986

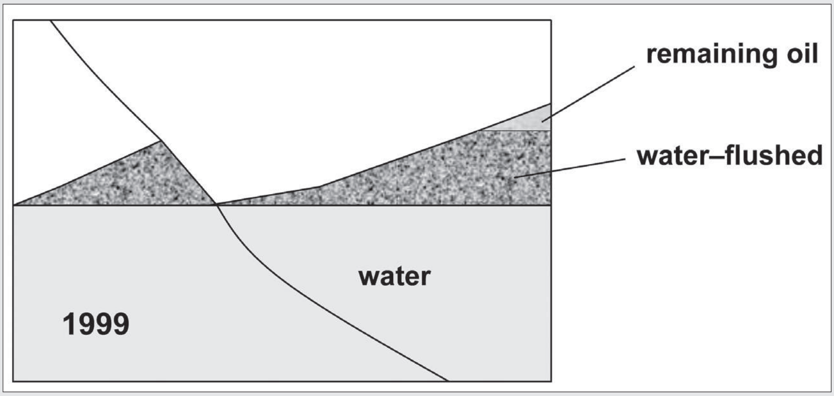


Fig. 3–22. Gullfaks 4-D survey—1999

Statoil, a big champion of 4D seismic (more than three-quarters of their fields are monitored), discovered the Gulfaks Field in the Norwegian side of the North Sea in 1978. They began producing in 1986. By 2001 Gulfaks reached peak production of 180 MB/D.

Statoil had followed up its initial 1986 pre-production 3D seismic survey (fig. 3–21 with subsequent surveys. By 1999 a survey showed an area of unswept oil (fig. 3–22) that was later drilled.

Complementary Technologies

Geoscientists use seismic data as their primary exploration tool for deepwater exploration. After a successful exploration well they are wont to say, "There's no substitute for a high quality seismic line." But there are complementary technologies such as CSEM and gravity gradiometry, which can be modeled and integrated with seismic data and in certain cases may increase the probability of success of an exploration well.

Controlled source electromagnetics

CSEM, often called EM, is a technique for measuring the resistivity of subsurface geobody that may be oil or gas but may also be carbonates, salt, volcanic rocks, or high resistivity shales. EM is based on the propagation of an electromagnetic field into the subsurface. The deepwater subsurface is filled, for the most part, with minerals and saltwater, which together have very low resistivity—they let electromagnetic fields pass through. Oil and gas are poor conductors of EM fields and have higher resistivity than the surrounding rock.

Acquisition. An EM source is towed about 60–120 feet above the sea floor, continuously emitting an EM field into the subsurface. Along the towing track on the sea floor are recording receivers that pick any EM fields reflected back to the subsurface—indications of high resistivity. (See fig. 3–23.)

Placement of the receivers is dictated by other knowledge of a possible hydrocarbon accumulation, mostly from seismic surveys. At least one receiver is placed outside the target.

Processing. After the receivers are retrieved and the massive amounts of data are downloaded, lengthy and intricate processing yields spatial locations of hydrocarbon sediments. EM and seismic technologies depend on totally different parameters: seismic comes from sound waves bouncing off sedimentary discontinuities; EM comes from field scatter from resistive or non-conductive matter. The EM locations have to be superimposed on the seismic data interpretation to show which traps may have hydrocarbon accumulations.

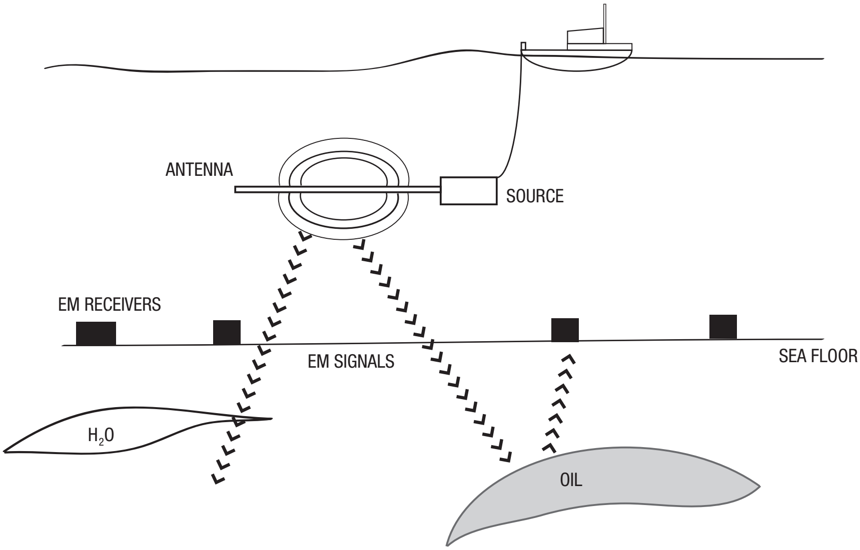


Fig. 3–23. Collecting electromagnetic data via sea floor receivers

In some deepwater areas, EM can be used to better understand and reduce the risk of deepwater prospects at depths up to 10,000 feet below the mudline. Thick resistivity zones are, not surprisingly, easier to identify than thin zones. EM technology is not applicable in the Gulf of Mexico deepwater subsalt play as the reservoirs are too deep and overlying salt is resistive. The technology is in the early stages of acceptance and use by oil companies, but the increase in EM knowledge and techniques has been rapid, just as it was for early stages of seismic.

Gravity gradiometry imaging

Another subsurface imaging technique has emerged to help clarify what lies beneath: gravity gradiometry imaging (GGI). A conventional gravity survey measures the change in the gravitational pull of the subsurface. GGI, an enhanced version of gravity measurements, can display three-dimensional measurements because it captures the rate of change of vertical components in the horizontal directions. This technique is sometimes referred to as full tensor gravity gradiometry (FTG). These gravity measurements can be especially useful for indicating the continuity of structural changes in the subsurface—faults and the nature of different sedimentary layers,

Gravity gradiometry can be useful as an aid to a seismic interpretation in mapping salt dome geometries because it can improve the structure interpretation under salt where seismic signals are difficult to resolve. GGI is also a useful complement to seismic analysis for enhancing interpretation where 3-D seismic is poor quality or not available. For example, a 2-D seismic survey might show two faults some distance apart. The interpreter drawing a map might be tempted just to connect the two to fill out a picture of the subsurface. Since GGI is more or less continuous, a more accurate path for the fault can be drawn.

GGI surveys can be taken with equipment mounted on a survey ship or even on an aircraft. In either case, the variability of the vessel's speed as it traverses the survey area can induce unwanted distortions in the received data.

Exploring the Deepwater 4

We must learn to explore all the options and possibilities that confront us in a complex and rapidly changing world.

—J. William Fulbright (1905–1995)
Speech in the U.S. Senate

The oil business starts with exploration and exploration geoscientists, geologists, and geophysicists, trained in the study of the earth, who carry the baton through the first lap. They take the responsibility of identifying oil or gas deposits of sufficient size to be drilled, developed, and produced. In this phase, the exploration geoscientists collaborate with a collection of other scientists, engineers, and professionals in the process shown in figure 4–1.

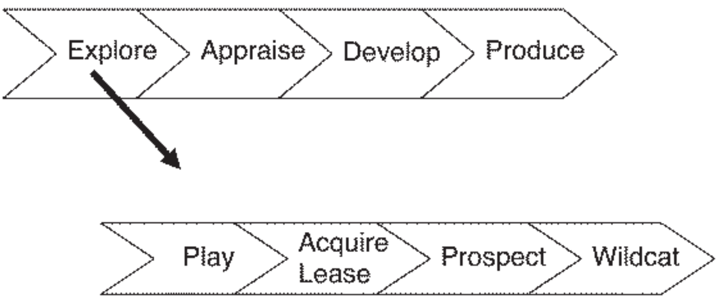


Fig. 4–1. The exploration process

Developing a Play

The exploration geoscientists start with a region or a basin such as the Gulf of Mexico, or the areas off the coast of Brazil, West Africa, or elsewhere, and develop a subsurface geological story, first for a basin, a large expanse of water that might contain scores of possible plays. They draw data from a rich body of knowledge and a broad slate of specialists.

- Geologists have developed a modern theory of plate tectonics. They say that the earth's surface is made up of a number of plates, about 60 miles thick, that are constantly moving, albeit in geologic speed measured in centimeters per year. As these plates drift around the globe, in some places they rub against each other, causing earthquakes, opening up fissures to deep, molten magma, otherwise known as volcanoes. In other places they squeeze large pieces of real estate, generally deforming the entire landscape into mountains and valleys. Over time the mountains erode and the rubble washes down rivers, carrying with it animal and vegetable micro-matter, the stuff from which petroleum develops. Subsequent tectonic plate movement and erosion material buries the organic stuff to depths where it, due to heat and pressure, transforms into oil and gas. Chapter 3 on geology and geophysics describes the results.
- Geochemists help the geologist identify the composition of underground formations as they search for adequate source rock where the organic material might have resided. Good source rocks are typically limestone and shale, and might contain 1% or more organic matter. Some fortunate explorationists find extremely rich source rock with as much as 10% organic matter.
- Geophysicists have become the eyes and ears of the exploration geologists, particularly during the preliminary evaluation stage, by contributing seismic information. The elaborate collection of data they bring to the party as described in the second half of chapter 3 forms the basis of detailed subsurface models tied to the geological history.

As the geoscientists begin to focus on specific areas of interest—individual plays—the story's plot line emerges as four dramatic and essential episodes:

- **Source rock.** A deep rock layer of limestone or shale where enough organic matter—microscopic animal or plant organisms—was deposited hundreds of millions of years ago. With the heat from below and pressure from the layers above, the organic material cooked into forms of petroleum—oil and gas.
- **Migration.** Gravity, perhaps water intrusion, *geologic* forces, or a combination of the three causes the oil and gas to seep from the source rock through pathways (faults, etc.) to the reservoirs.
- **Reservoir.** Adequately *porous* and *permeable* rock or sands that are available to receive the oil and gas.
- **Trap.** An impermeable sealing mechanism like shale, salt, or a fault keeps the oil and gas from leaking out of the reservoir.

This combination of source rock, migration, reservoir rock, and trap becomes the essential component for a play to be a viable exploration opportunity. With a technically sound story and viable play story, the exploration geoscientist can convince the decision makers in his company to commit real money to the next several steps in the exploration process.

Acquisition

Most enterprises that have any commitment to customer satisfaction and a sense of competition subscribe to the salesman's mantra, "Nothing happens until I make a sale." But exploration and production (E&P) companies in general have no preoccupation with that commitment. They sell their oil and gas into a faceless commodity marketplace. That is not to say they don't compete with other companies. They do, but mostly for the rights to drill for oil and gas. And that leads to the explorers' mantra, "Nothing happens until I get access."

At the early stage of developing a play, a company probably does not own or otherwise have the right to drill a well to confirm the existence of hydrocarbon in the alleged reservoir. In offshore waters throughout the world, the national governments own both the surface and subsurface rights and set the rules by which E&P companies can acquire them.

In the Gulf of Mexico and other waters that border the United States, the U.S. federal government administers control through an agency of the Department of the Interior called the Bureau of Ocean Energy Management Regulation and Enforcement. Periodically that bureau makes available to oil companies the opportunity to acquire the rights to explore and produce from leases in certain wide areas of the offshore, including the deepwater.

At these lease sales, E&P companies submit sealed bids for those rights, often as partnerships but always in competition with all others. Minimum bid for an offshore lease (a block 3 miles square or 5,760 acres) is typically $400,000. Historically some winning bids, or bonuses, have run in the tens of millions of dollars. Besides the bonus, a company agrees to pay a royalty of 12.5% to 16.0%, more or less, of the gross value of all the oil and gas produced by the company over the life of the lease. Leases generally run for an initial term of five to ten years, increasing with the depth of the water and therefore roughly with the cost and risk involved in drilling a well on the lease.

(For the United States *onshore*, unlike almost anywhere else in the world, both private parties and governments can own the mineral rights to oil and gas. An oil company interested in exploring and producing on lands involving private owners can negotiate directly with them without involving the government.)

If the company drills a successful well on the lease, it retains the rights to the lease as long as they continue to produce oil or gas. If the company does not drill a well on the lease within the initial lease period, it loses the lease, which reverts to the government. It goes without saying that the government keeps the original bonus money and may re-lease the block to another company.

What's In a Name?

Bullwinkle? Perdido? Where did these improbable names come from?

Working on a play (an exploration project) is a cause for super-secrecy in an oil company. For that reason, some use code names when deciding how much to offer for a lease, the rights to drill on a particular spot, particularly in the offshore. A federal offshore lease sale may involve ten or more prospects of interest to a company, so some companies use a list of like-minded names for that sale. The names stick with the successful projects. That's why *Popeye* and *Bullwinkle* could carry over from one lease sale, and *Cognac* and *Neptune/Thor* from two others.

The region of the Gulf of Mexico that borders Mexico up to a borderline agreed to in a Mexico/United States treaty is administered by the Mexican government. They, in turn, have historically granted Pemex, the National Oil Company, the exclusive right to explore and develop those opportunities. In almost all other international offshore plays, including in the deepwater off Brazil and the West African countries, the national governments typically have E&P companies submit more elaborate proposals for the rights to explore and produce, in this case more cavalierly called *concessions*. The proposal stipulates upfront fees (bonuses), explicit expenditure plans for seismic data acquisition, and the expected number of exploratory wells in the exploration phase. Terms also include what happens if commercial volumes of oil and gas are discovered. International concessions are typically ten to a hundred times the size of a Gulf of Mexico lease.

Many countries with less commitment to free enterprise than the United States also leverage their monopolistic ownership position by having their national oil company own interest in the concessions. That enables both financial opportunity for the national oil company when a well is successful plus technology transfer to the country. Some take this knowledge and use it in their own country or around the world.

Identifying the Prospect

Companies may have earlier gotten permission to run seismic surveys, or they may have acquired surveys from a third party. Either way they have used them to assess interest in specific plays. But once a lease or concession is acquired, real work starts for the exploration geoscientists and their team.

In some cases, most likely in shallow water prospects, the existing seismic data is good enough to allow the geoscientists to identify the specific prospect with a high enough probability to warrant drilling a wildcat well. However in almost all deepwater plays, hiring a geophysical service company to run a proprietary 3-D survey across the prospect in the manner covered in chapter 3 makes sense. After all, a big sum, maybe a $100 million, is at risk. It may take an additional 12 to 18 months to acquire, process, and interpret the new seismic data.

All this is the foreplay to drilling that $100 million-or-more wildcat well. The exploration geologist keeps in mind the famous quote of renowned football coach Darryl Royal of the University of Texas about forward passes: "Three things can happen when you throw a football downfield. Only one of them is good." The same principle holds for the results of running additional seismic. They can move the geoscientists to one of three conclusions—recommend a wildcat well, defer drilling the prospect, or even kill the prospect altogether.

Mapping

Anyone looking for a location not visited before benefits from having a good map, especially if there is no one to ask along the way. The same principle applies to exploration, but the maps are extraordinarily different from anything available on Mapquest or Google. All companies with sufficient resources to explore the deepwater have geologists who prepare maps, some more extensive than others, as part of the play evaluation process.

The mapping process uses information from seismic surveys, gravitometric surveys, wireline logs, cuttings analysis from other wells drilled nearby or afar, and any other relevant sources available. The mappers may enlist the aid of scientists with arcane specialties such as stratigraphy and sedimentology, structural geology, paleontology and bio-stratigraphy, and geochemistry. They produce maps that display many different characteristics of the subsurface. When considered together, these maps allow the explorationists to identify the most likely subsurface areas to find trapped hydrocarbons.

Some of the maps developed include:

- Geologic cross sections, as shown in figure 4–2
- Bathymetry maps that show water depths
- Hydrocarbon trend maps at the basin scale
- Source rock maturity maps
- Paleontology maps showing how sediment deposited
- Surface maps showing outcrops on the sea floor
- Subsurface structural maps
- Seismic amplitude maps, as discussed in chapter 3
- Reservoir thickness maps
- Optimal areas of porosity and permeability maps
- Sea floor hazards maps
- Shallow water flows area maps

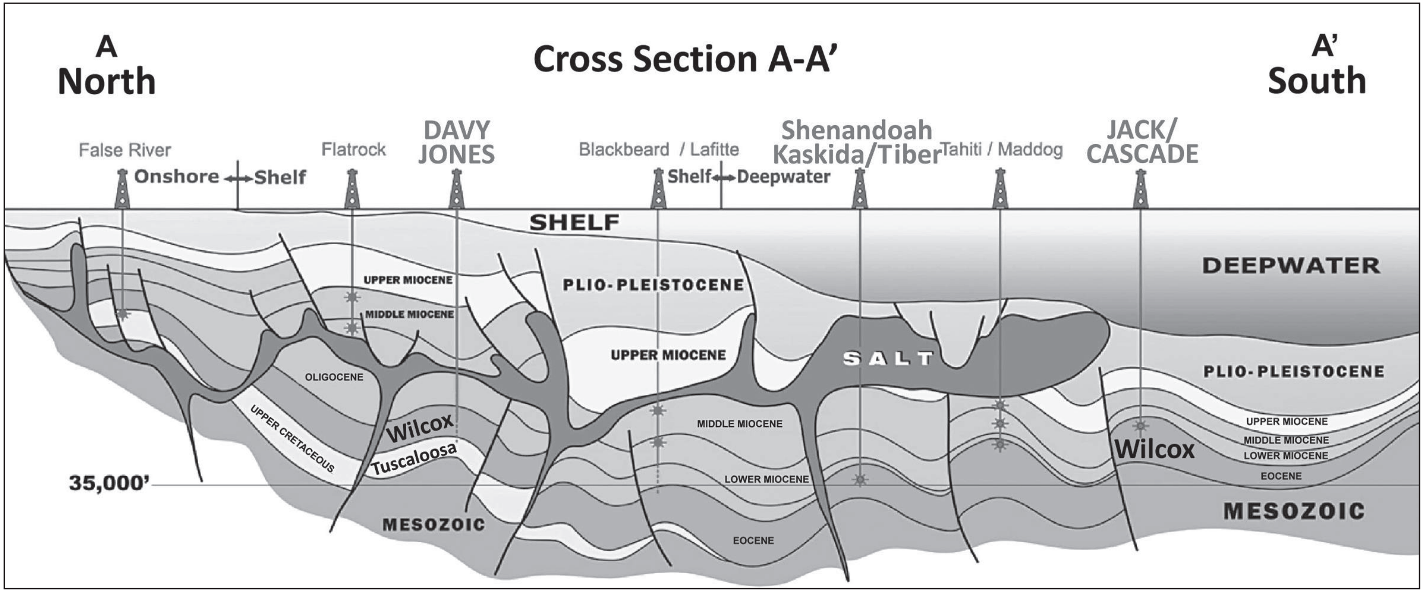


Fig. 4–2. Geologic age map: idealized structural cross section showing prospects and discoveries in Tertiary and Upper Cretaceous reservoirs. Modified from McMoran Exploration Company 3rd Quarter 2009 Conference Call, October 19, 2009. (Courtesy Arthur Berman, Labyrinth Consulting.)

Volume Prediction

The next step in the exploration process begins with the geoscientists, working with reservoir engineers to estimate the volume of hydrocarbons in place in the reservoir to be tested. They use a volumetric formula:

Hydrocarbons in place = GRV × N/G × Porosity × SH × FVF

Where

- GRV, gross reservoir volume, is the amount of rock in the reservoir above the oil/water contact.
- N/G is the net to gross ratio or percent of reservoir rock of total rock.
- Porosity is the percent of net reservoir rock occupied by pore space.
- SH is the hydrocarbon saturation in the pore space.
- FVF is the formation volume factor that converts the (compressed) reservoir oil and gas volumes to surface volume.

To estimate these factors the geoscientists use all relevant sources available—seismic data, offset well data, analogue fields, and more.

With a volumetric estimate in hand, they can estimate how much of the hydrocarbons in place can be produced. These recoveries vary from 10% to 50% for oil fields and 50% to 80% for gas fields. Most of the oil gets left in the ground; most of the gas does not. Deepwater fields are usually at the higher end of the ranges because of the excellent reservoir properties of the turbidite sands.

Given all that, the team can create a production model with production rates over time, ultimate recovery, and the cost of developing the field.

Risking the Play

All the input to the creation of the production model is uncertain. Despite how good the calculation results may look, all E&P companies apply risk factors to reduce the outcome to a realistic expectation.

Risking is based on very basic statistical theory: with a pair of dice, a throw can result in a 1 and 6, a 4 and 3, or a 5 and 2, the only combinations that give a 7. Only one combination can give a 2. So the likelihood of rolling a 7 is higher than a 2.

In exploration plays, it is generally recognized that the likelihood of finding hydrocarbon varies from play to play. Thus each of the play elements have to be carefully considered and a sober assessment made of the likelihood of each being as good as estimated. The probabilities are based on the accumulated knowledge of the E&P company and its staff.

One of the remarkable realities of the exploration business is that the predicted outcome for most exploration wells has less than even odds—most exploration wells are expected to fail! Consider the difficulty of recommending to management the drilling of a $100 million well in deepwater with "only" a 30% probability of success (or 70% chance of failure.) That's normal business for an E&P company.

The Exploration Well

All this is a purely theoretical game until the geoscientists reach a level of confidence where they recommend a wildcat well to their management, and these executives believe the potential reward justifies the significant risk and approve drilling the wildcat well.

To go forward, successful planning and drilling of the exploration well requires all this information be shared in an even larger team that includes the geoscientists, drilling engineers and operations personnel, petrophysical engineers, and more. In addition, the drilling contractor and its personnel and all the service companies have to understand the objectives of the well and be included in all pertinent meetings. On all critical wells—and *all* deepwater wells are critical—a predrill meeting has everyone in attendance to review the well plan and identify and discuss any potential drilling hazards and how they will be dealt with during the operation.

Finally, it is critical that everyone on the rig and in the office understand all the regulatory agencies' requirements and that all permits are in hand before any operation is undertaken by the rig. (In the United States the main actors include the Bureau of Ocean Energy Management, Regulation, and Enforcement, the Environmental Protection Agency, the Occupational Safety and Health Administration, and the Coast Guard.) Then drilling the well, as described in chapter 6, can begin.

Appraisal

The wildcat has been drilled. The electric logs run in the well indicate that hydrocarbons are present in the reservoir(s). The exploration geoscientists are thrilled with the success. But the excitement soon dissipates as management asks the critical questions, "How big is the accumulation? Are there enough reserves to justify appraisal wells or *any* further investment?"

As part of the planning process, the team members had already developed various scenarios dependent on the results of the well. If the well was successful, where would they drill an appraisal well, and what would be the objectives? Clearly the information derived from drilling the wildcat would have some bearing on the answers.

Based on the wildcat well information analyses, the team recommends one of several options, shown in figure 4–3:

- Plug and abandon the well because it has no further use in the appraisal process or in the development plans. Remarkably, this is often the case with a wildcat well.
- Plug back the lower portion of the well with cement: set a cement kick-off plug below the last string of casing. Sidetrack the well to a new bottom hole location to help determine the total size of the oil and gas accumulation.

- Temporarily abandon the well by setting cement plugs in the open hole and casing until further analysis can be done to determine how the well might be used in the appraisal or development process.
- In some cases, if there is a high probability that field development will go forward in a timely way and if the well is situated in a good spot, the well can be temporarily abandoned and later completed (as discussed in chapter 6) in the development phase.

The appraisal process can last a few months or more than three years, depending on the number of wells needed to be drilled and any new seismic data efforts needed. The end game of the appraisal process is a decision to either abandon the prospect or proceed with a drilling program to develop the field, again the subject of chapter 6.

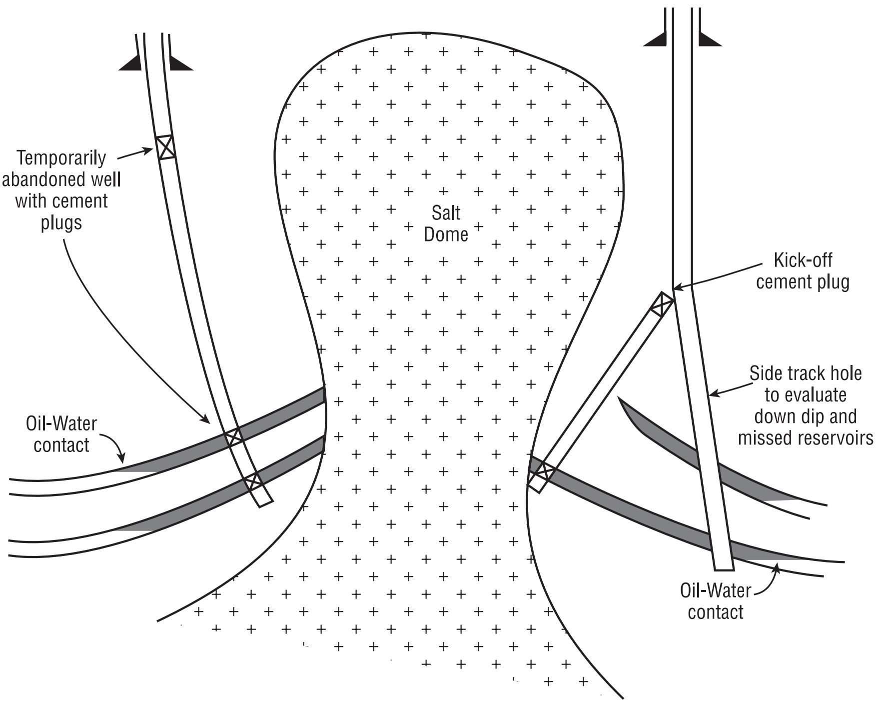


Fig. 4–3. Appraisal well options

Deepwater Exploration Plays in Context

The exploration process flow in figure 4–1 and the description may seem straightforward and linear, and in microcosm it is. But as most E&P companies contemplate the huge expenditures required to test a deepwater play, they may choose to spread their risks—they pursue in parallel a number of exploration plays in various basins that have different risk profiles to avoid the consequences of the "gambler's ruin." A deepwater play exposes large sums of investment up front, with not terrific probabilities of success but potentially huge rewards. Deepwater drilling is often on the technologic and geologic frontier and is not without all sorts of risks—unsatisfactory geologic understanding, meteorological and oceanographic uncertainty, and, as BP found out with *Macondo*, operational adversities. Other types of plays, that is, onshore or shallower water, might have lower potential rewards and have higher probabilities of success and more amenable downsides. In the big picture, commitment to an exclusive deepwater strategy could lead to financial ruin.

That was the story told in chapter 2 about Shell Oil Company, who pioneered the deepwater Gulf of Mexico in the 1970s and 1980s, but only in parallel with other domestic plays. In contrast, Petrobras had almost no alternatives to their low probability deepwater plays. At the same time they faced a national mandate to find *something* and develop it. In hindsight, of all the plays pursued by all the E&P companies in the U.S. lower 48 and in Brazil from about 1970 forward, the deepwater became the only continuing and substantial exploration successes in those countries. That is, until recently when new hydraulic fracturing technology unlocked onshore oil and gas in shale plays.

Case Study

Tira de Bota

The modest oil discovery in northeastern onshore Brazil in 1939 gave no clue to the path-finding explosive growth that took place starting 30 years later. For 25 years, Brazil remained a mediocre petroleum province, even after the federal government created the monopolist Petrobras in 1953. The company's mission was to make concerted efforts to improve domestic production. At the time, Brazil produced only 2,700 barrels per day of oil.

Petrobras began building its capability by hiring Walter Link, a Standard Oil Company geologist of some renown. In 1960, Link, who had risen to senior management status, opined in official documents that Brazil was so bereft of petroleum potential that it should pursue its business either in the offshore or in other countries.

After the hasty exit of Link, a victim of old age and some xenophobia, Petrobras began to consider the structures in the coastal basins. By that time, discoveries in the salt basins in the Gulf of Mexico, the North Sea, and elsewhere were well known. In 1968, in an effort reminiscent of 1900 Summerland plus Kerr-McGee's 1947 discovery (chapter 1), Petrobras followed the onshore trend in the Sergipe-Alagoa basin and drilled its first offshore well.

Unfortunately it was a dry hole, but it did confirm the existence of a large salt dome. The second well, a producer, encouraged the geologic surveys and analysis of what would come to be called the "three sisters," the Espiritu Santo, Campos, and Santos basins, north to south. (See fig. 4–4.)

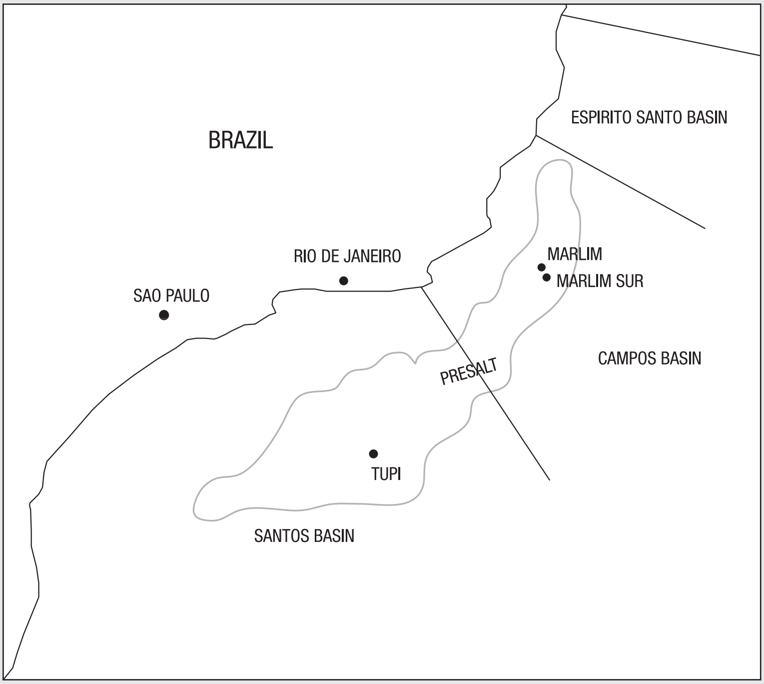


Fig. 4–4. Brazil's deepwater basins

The 1973 world oil disruption induced the Brazilian government to encourage even more intense exploratory efforts. Even though almost all petroleum technology had to be imported at that time, Petrobras moved further offshore in the Campos Basin. The next jump start came about in 1974 with the discovery of the beginning of a series of a dozen finds in ever-deeper water. Hundreds of million of barrels of petroleum lay discovered but untapped in the Campos Basin. Too impatient to wait for fixed platforms to be built, in 1977 Petrobras began a series of small subsea completions with "wet" trees. By the end of the year, Enchova, the first of the new fields, was producing 10,000 barrels per day from subsea wellheads into the semisubmersible *Sedco 1135D*, a drilling rig temporarily converted to a floating production platform. After that, subsea development with delivery into floating production vessels became a routine way to accelerate first oil. Many of the vessels became permanent installations.

Not all leaps landed on two feet. Petrobras tried installing "dry chambers" at eight subsea installations, i.e., dry trees encapsulated in a pressurized chamber on the sea floor. The high cost of the surface vessel and risky intervention techniques led them to abandon the idea and convert the wells to wet tree technology.

Subsea processing had its conception in Brazil with the installation of a sea floor manifold in 1982. Later Petrobras would install electric subsea pumping, and in 2010 sea floor separation and water reinjection.

By the late 1970s Petrobras was beginning to take full advantage of the world's accumulated subsurface knowledge: tectonic plate movement theory, especially the drift of South America away from Africa and the resulting rift, understanding the role of rivers and turbidite sedimentation, and the latest seismic reflection technology.

In 1984 Petrobras made its first real deepwater discovery, Albacore (150–1,100 meters of water), followed by Marlim (781 meters) in 1986 and Marlim Sul (1,709 meters) in 1987. These depths challenged existing development technology. Petrobras had mastered subsea completion and production to floating vessels, but only to about 400 meters. The company began its ambitious program, Deepwater Systems Technology Innovation Program (in Portuguese its acronym is PROCAP), in 1986, aimed at significantly reducing its offshore costs to make fields economical, as well as enabling itself to move into 1,000 meters of water and beyond. By 2006 it had thirty-three offshore fields being produced, though over 600 subsea trees to twenty-three floating and thirteen fixed platforms and the Roncador field had just been completed in 1,886 meters. Also that year Petrobras produced enough oil to make Brazil petroleum self-sufficient. Granted, the national program turning biomaterial into gasoline and diesel fuel helped, but crude oil production had risen to 2.3 million barrels per day.

The supergiant Tupi discovery in 2006 in the Santos Basin to the south demonstrated the need for even newer technologies. Tupi sits under a so-called pre-salt layer. Tupi lies below a water depth of 2,140 meters, and then a 2,000 meter-thick salt layer that itself is under as much as 5,000 meters of sand and rocks. The presalt layer provides the seal to trap massive accumulations of petroleum. Petrobras estimated after testing that Tupi contained 5–8 billion barrels. Both seismic imaging and drilling technology had been developed anew to penetrate these layers and develop this field, which produced its first oil in 2010.

Exploration and production activities in the Brazilian offshore are hardly at a peak. Newer technologies still need to be invented. Still impatient, Petrobras is now even exporting its capabilities to other countries where it can exploit its now-mature understanding of deepwater E&P. (See fig. 4–5.)

And apologies for the untranslatable expression “bootstrap” into the Portuguese, *tira de bota*.

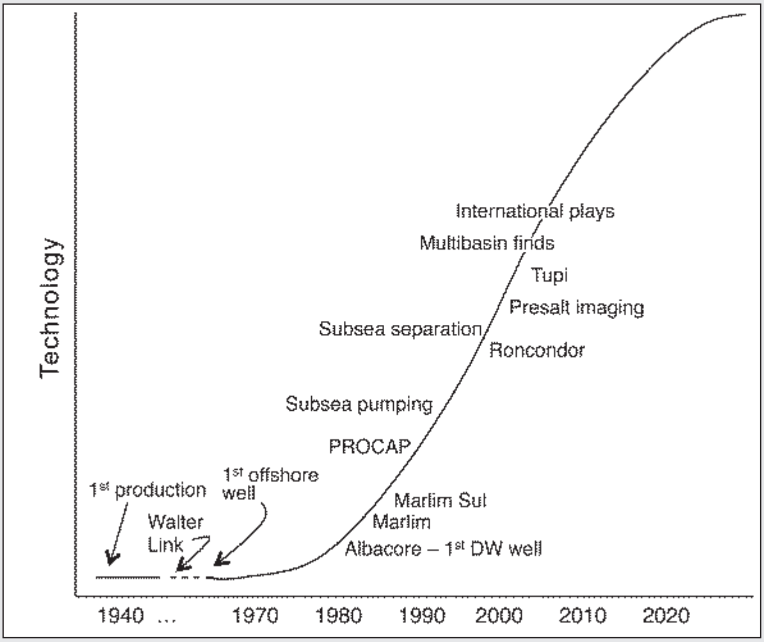
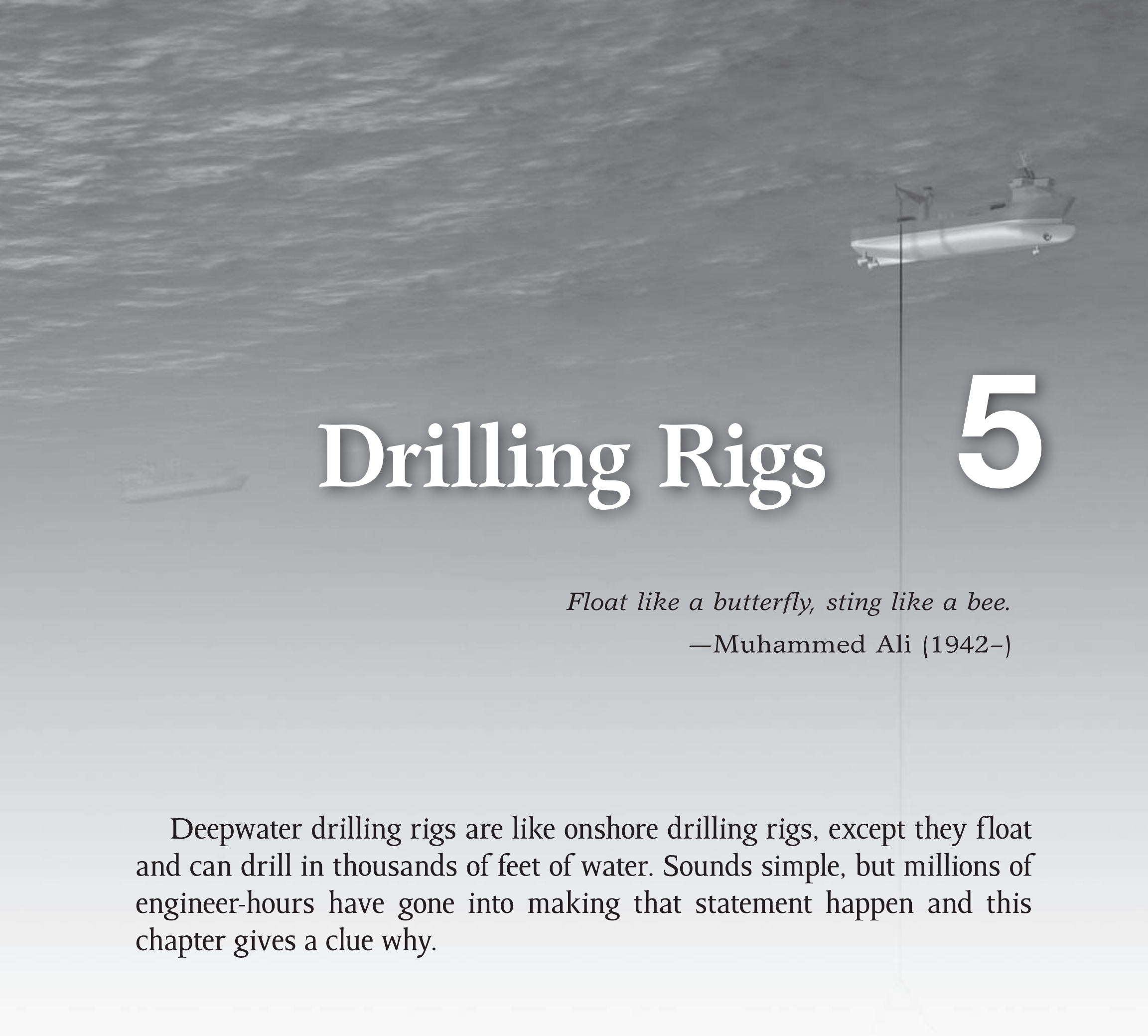


Fig. 4–5. The evolution of Petrobras



Drilling Rigs 5

Float like a butterfly, sting like a bee.
—Muhammed Ali (1942–)

Deepwater drilling rigs are like onshore drilling rigs, except they float and can drill in thousands of feet of water. Sounds simple, but millions of engineer-hours have gone into making that statement happen and this chapter gives a clue why.

Drilling Rig Essentials

All drilling rigs, onshore and offshore, have basic elements:

- Derrick
- Hoisting system—draw works, crown block, etc.
- Rig floor equipment
- Pipe racks and handling equipment
- Mud equipment
- Blowout preventers
- Safety systems

Derrick

The signature image of any drilling rig is the derrick, that tall pyramidal skeleton that supports the weight of the drill string while drilling. Drill pipe weighs in the neighborhood of 15 to 30 pounds per foot. The full weight of the drill pipe, drill collars, and drill bit when operations have reached the target well depth of 25,000 feet could exceed 750,000 pounds. Casing, which is larger in circumference and heavier per foot, weighs even more. In addition, the derrick sometimes has to handle larger and dynamic loads during the operation to remove or recover drill pipe or casing stuck downhole. So the derrick and drill system on deepwater rigs is sized to handle one to two million pounds or more.

Rig floor equipment

On most onshore drilling rigs, the drill pipe is connected to a *kelly*, a joint of pipe with an octagonal shape that can be grabbed effectively by the bushing in the rotary table, the mechanism that turns the drill pipe to "make hole." (See fig. 5–1.)

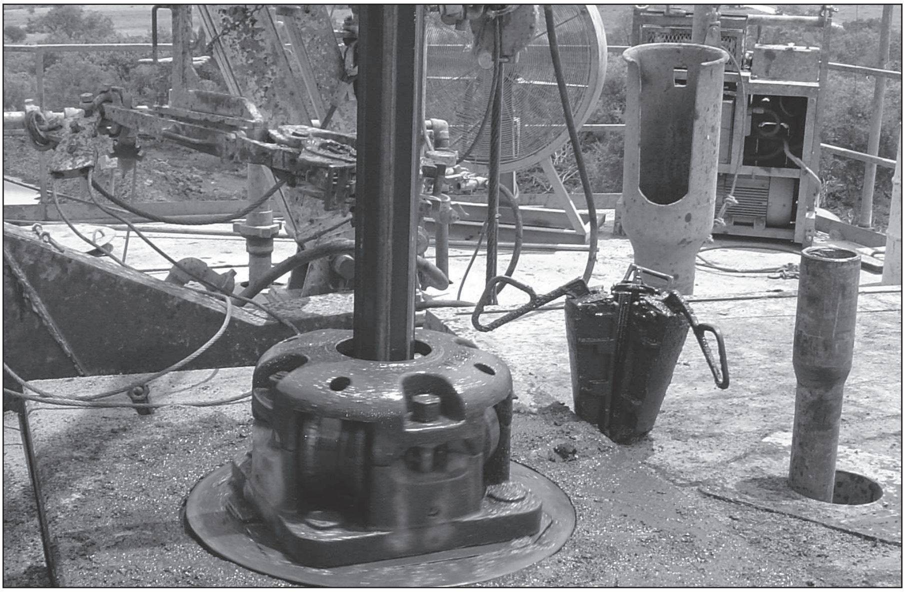


Fig. 5–1. Equipment on an onshore drilling rig floor—the kelly fits into a kelly bushing in the rotary table which turns the drill pipe and drill bit.

Nowadays, almost all deepwater rigs use a top drive (fig. 5–2), rather than a rotary table, a more cost efficient and safer mechanism. A track allows the top drive to move up and down the derrick while turning the drill pipe. Other pieces of equipment on the rig floor level help the rig personnel move, connect, disconnect, and handle different types of tubulars—drill pipe, casing, production tubing, and so on.

The driller, the person who orchestrates the rig floor operations, is located in an enclosed compartment that has a clear view of the entire rig floor. At a console, he controls all aspects of the drilling operation, the weight on the drill bit at the bottom of the hole, the mud pressure, and most importantly, operating the blowout preventer (BOP) if an emergency arises.

Fig. 5–2. A top drive on a track in the derrick. It moves up and down in the derrick and turns the drill pipe and drill bit.

Hoisting system

A large, powerful, drum-shaped winch, known as the *draw works*, does the duty of raising and lowering drill pipe, casing, or other tubulars in the well. (See fig. 5–3.) At the top of the derrick is the crown block with several sheaves (pulleys). The hoisting line from the draw works goes over the sheaves to the traveling block or the top drive.

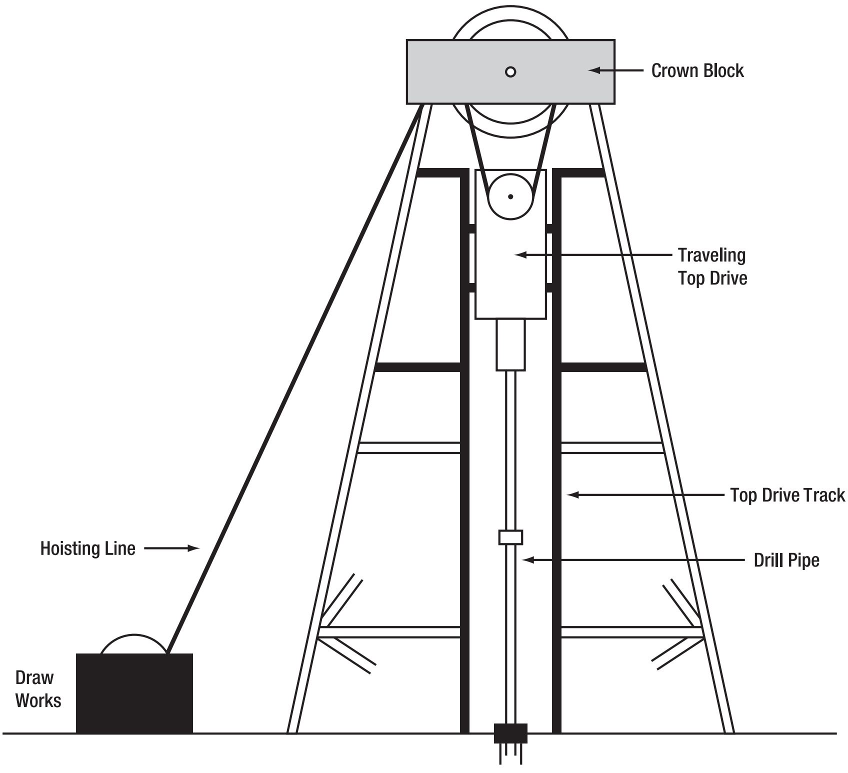


Fig. 5–3. Hoisting system with a top drive

Pipe racks and handling equipment

Various types of tubulars (drill pipe, drill collars, and all sizes of casing) are brought to an offshore rig in 30- to 45-foot joints by a supply vessel and stored on the rig's pipe racks. As the drilling proceeds and the well is deepened, the drilling rig crew picks up the individual pipe joints from the pipe rack and screws them into the top drive before attaching them to the drill pipe already hanging in the borehole. When the drill pipe is pulled out of the borehole to change a bit, log the well, run casing, or any other reason, it is unscrewed in 90- to 130-foot lengths and stacked in the derrick.

Because pipe handling can be dangerous and is so time consuming and cumbersome, recent generations of rigs have automated much of the pipe handling. Many newer generation offshore rigs have dual activity drilling systems. They have two complete drilling systems, including separate draw works, top drives, and pipe-handling facilities under one derrick. While one system is working the borehole, the other can be making up pipe or breaking it down.

Mud equipment

Drilling mud provides several functions:

- Removes the cuttings as the drill bit penetrates the earth
- Cools and lubricates the drill bit
- Offsets the earth's downhole pressure and prevents the borehole from collapsing

Mud is a mixture of water, barite, bentonite clay, and various chemicals. (In many deepwater wells, synthetic oil is used instead of water to better stabilize the borehole. Synthetic oil is, of course, much more expensive than water but it provides better and more consistent, cost-effective performance.) Barite is a very heavy mineral that gives the drilling mud the weight and therefore the ability to counteract the Earth's increasing pressure as the well is drilled deeper and to keep the borehole from collapsing. (The deeper the well is drilled, the more barite has to be added to compensate for higher subsurface pressures.) The bentonite clay provides the viscosity and carrying capacity so that the mud can be pumped and the cuttings transported back to the surface. Chemical additives are often used for corrosion prevention, lost circulation control, and other purposes.

Mud is stored in liquid tanks onboard a deepwater rig. High-pressure (10,000 to 15,000 psi) mud pumps deliver the mud via piping to a hose at the top of the swivel. (See fig. 5–4.) The mud proceeds down from the top drive or through the kelly into the drill pipe to the bottom where it squirts out the jets in the drill bit. The cuttings-laden mud then precedes up the space between the drill pipe and the borehole (the *annulus*), to the surface and out a line to a shale shaker and other mud cleaning equipment that separate the mud from the cuttings. Samples of the cuttings are saved for examination by the geologist to identify what geologic formations the drill bit has penetrated. After cleanup, the mud goes back to the mud tanks for recycling.

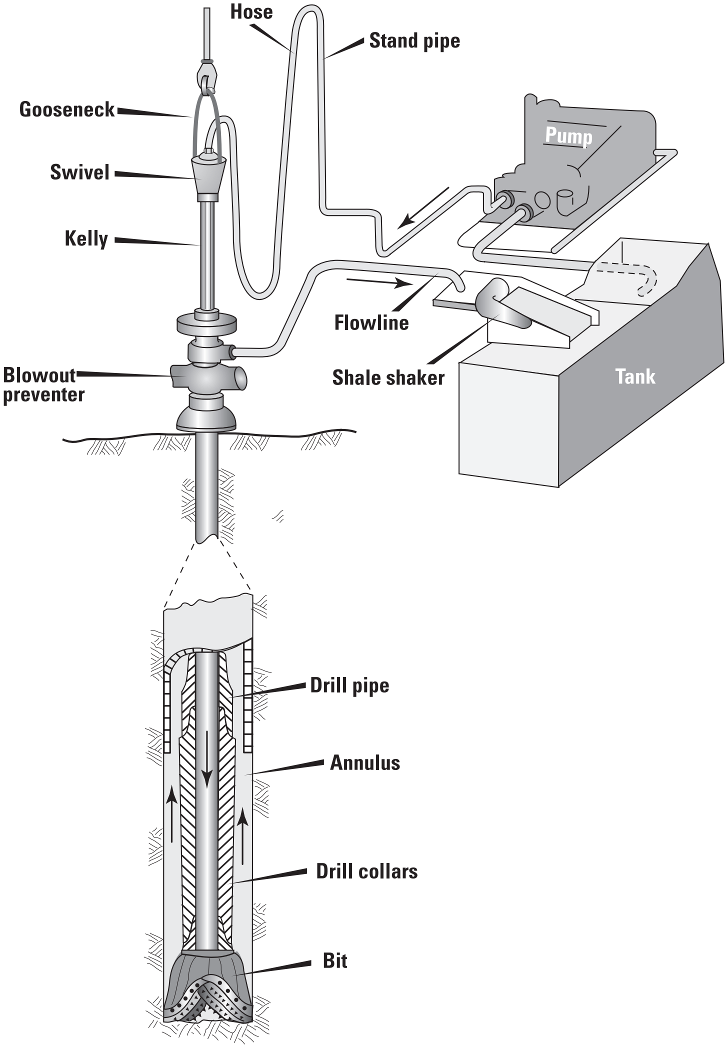


Fig. 5–4. The mud-handling system

Unique Deepwater Rig Equipment

An onshore rig has the luxury of completely stable footing—the Earth. An onshore rig has virtually unconfined space for equipment and supplies. When an onshore rig has finished at one site, trucks haul it to another site, positioning it exactly where the geologist says.

None of that is true for a deepwater rig, and two different species of rigs have evolved to compensate for some of those constraints, the semi-submersible drilling rig and the drillship.

Semi-submersible drilling rigs

The brilliant "aha!" that led to the first semi-submersible drilling rig, the *Bluewater Rig No.1*, was chronicled in chapter 1. The concept of ballasting large pontoons enough to submerge most, but not all, of a large mass gives semi-submersibles most of the stability needed for a drilling platform. (See fig. 5–5.)

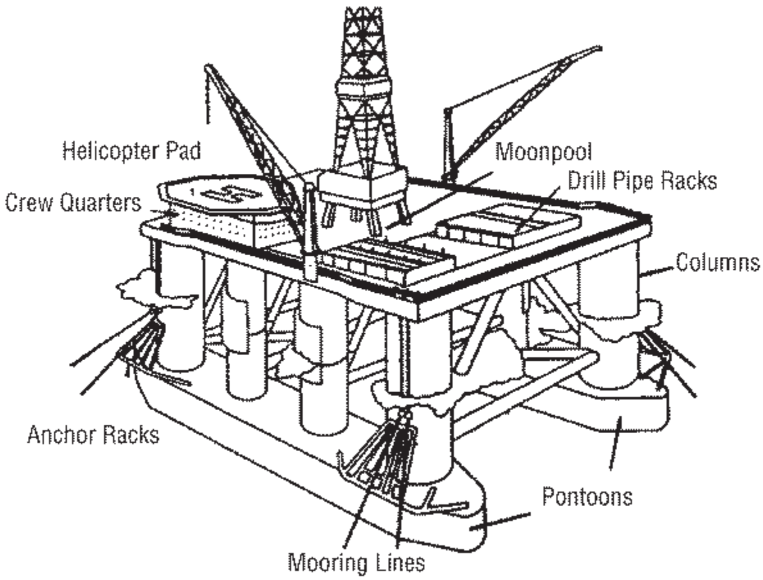


Fig. 5–5. Semi-submersible drilling rig

But several other innovations are needed to translate the onshore rig to deepwater duty. To keep the rig in position, the semi-submersible drilling rig can carry with it a set of eight to twelve anchors. Anchor-handling boats, in concert with the rig's winching system, handle anchor deployment. The anchor is connected to 100 feet or more of chain that lies on the sea floor, and then to wire or polyurethane rope, depending on the water depth.

Alternatively, a rig can use the more flexible but more expensive to install and operate dynamic position systems. These systems use geosynchronized satellite positioning signals fed to computers that control propellers or thrusters. The water shooting out the sides of the thrusters keep the rig in position over the drill site.

During any drilling operation the weight on the drill bit has to be carefully managed. If the full weight of 20,000 feet or more of drill pipe were allowed to rest on the drill bit, the bottom sections of the drill pipe would fail and the bit would be crushed. Heave compensators on the hoist take care of the inevitable bobbing caused by wind and wave action on the rig and help the driller control the weight on the bit.

Floor space and storage area are scarce on any offshore drilling rig, and deepwater rigs need more of everything—tubulars, mud, fuel storage, power generation, crew accommodations, cranes, and more. Deepwater rigs have multistoried levels to handle all this.

The industry has adopted the term *generation* to indicate the capability of semi-submersible rigs. The term also loosely relates to the construction vintage, as shown in table 5–1.

Table 5–1. Semi-submersible drilling rig generations

Generation	Era	Water Depth	Variable Deck Load
I	1960s	600 ft	–
II	Early 1970s	2,000 ft	2,000 T.
III	Early 1980s	3,000 ft	3,000 T.
IV	1990s	4,000 ft	5,000 T.
V	Early 2000s	7,500 ft	7,000 T.
VI	2010s	10,000 ft	8,000 T.

The progression implied by the table goes: the deeper the water and well depth, the larger and more sturdy the derrick required, the more powerful the hoisting system, the more high-pressure mud pumping capacity, the more storage capacity, and the greater the tubulars storage. That adds weight to the rig, which calls for larger pontoons and supports and anchors or dynamic positioning systems. That doesn't account for new control room technology and tubulars handling and other innovations. All that comes under the heading, *next generation*.

Drillships

Besides the key features of semi-submersible drilling rigs, drillships have a few unique characteristics. The most obvious is, of course, their ship-shaped design, which gives them mobility. A drillship can move quickly under self-propulsion from one drill site to another. Even more dramatically, a move from, say, the Gulf of Mexico to the Offshore Angola takes about 20 days. A semi-submersible drilling rig has to be towed by oceangoing tugboats and takes about 70 days for the same trip.

That mobility comes at a price, as drillship construction is more expensive than that of comparable semi-submersibles. In turn, owners charge higher day rates and get the benefit of lower idle time between assignments.

To allow drilling from a drillship, underneath the derrick is a *moonpool*, an opening through the hull covered by the rig floor. (See fig. 5–6.) Like the semi-submersibles, some of the newer drillships have larger masts (derricks) that allow dual activity operations, for example, simultaneous drilling and casing handling.

Over the years the industry has classified drillsites into different vintages, depending on their age and water depth, as shown in table 5–2. As shown in chapter 1, the first drillship, the *CUSS I*, had a mast suspended over the side of the deck. Most of the later designs adopted the moonpool feature as a better way to accommodate maritime instability. In figure 5–7, the contrast in size between the *Discoverer 534*, a 1975-vintage drillship, and the *Enterprise*, a 1999-vintage drillship with a dual handling system, is apparent.

Table 5–2. Drillship vintages

Drillship	Launch Date	Water Depth
CUSS I	1961	350 ft
Discoverer 534	1975	7,000 ft
Enterprise	1999	10,000 ft
Inspiration	2009	12,000 ft

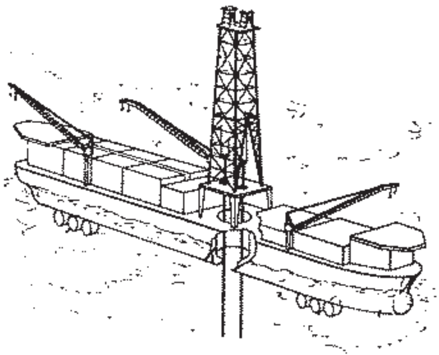


Fig. 5–6. A drillship, showing the moonpool and thrusters

Fig. 5–7. The larger drillship, *Discoverer Enterprise* has a dual activity facility. The smaller, earlier vintage drillship, is the *Discoverer 534*, alongside a supply boat.

Case Study

E Pluribus Unum

Many companies that arrive at the top of their industry are driven by a single charismatic or highly motivated individual. Not so Transocean, Ltd. It had the benefit of drivers from a half-dozen companies. All eventually saw the benefits of scale and consolidation.

Transocean is rooted in venerable corporate names—SONAT Offshore Drilling, SEDCO, Global Marine, Forex, Santa Fe, and the CUSS group, a consortium of Continental, Union, Superior, and Shell Oil companies—and some mostly forgotten—Danciger, Neptune Offshore, Louis N Westfall, and the Norwegian company, Transocean ASA. (See fig. 5–8.) Along the way, Schlumberger and the Kuwait Petroleum Company owned large pieces of the Byzantine history of Transocean.

The ancestral dip into the offshore came in 1951 when the CUSS group underwrote the *Submarex*, the prototype for floating offshore drilling, and began offshore coring. That awkwardly configured vessel, with the cantilevered drilling rig described in chapter 1 gave inspiration and confidence to several companies to initiate more suitable designs.

- Santa Fe entered offshore drilling in 1956 by adapting a land rig to a jack-up barge for a well in Trinidad.
- In 1958 Global Marine acquired the former CUSS assets, including the *CUSS I*. From what it learned from that floating drilling barge it upgraded in 1961 to the revolutionary (at the time) self-propelled version, *CUSS II*, and went on to build the III, IV, and V.
- SEDCO launched the *Eureka*, a purpose-built, hulled drillship with rotating thrusters for positioning. (See fig. 1–11.)

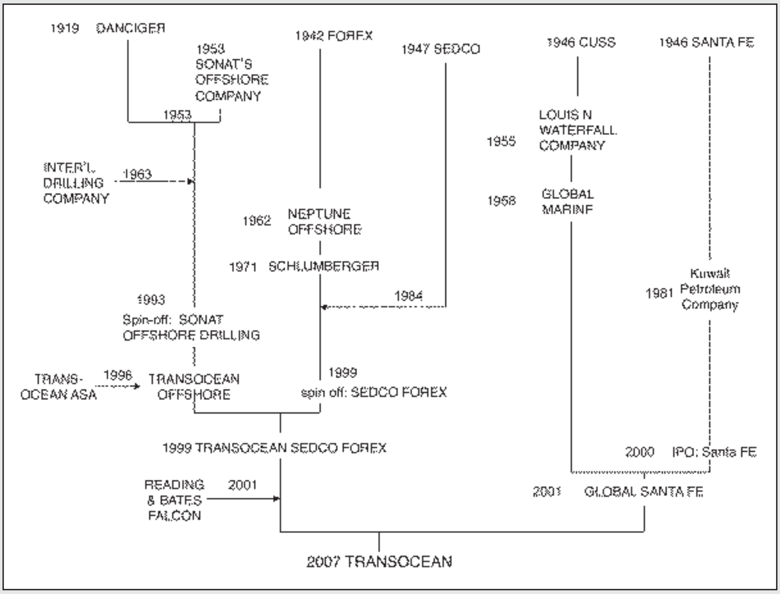


Fig. 5–8. Transocean, Ltd. mergers

In 1966 Sonat's Offshore Company put to work the *Orion*, the first jack-up rig capable of year-round drilling in the harsh North Sea waters.

- A group led by Forex produced the *Pentagone 81* in 1969, one of the first semi-submersible rigs.
- That same year, the Offshore Company produced the first self-propelled jack-up, the *Offshore Mercury*.

In the 1970s, as oil prices began a tumultuous rise, the Offshore Company, Forex, SEDCO, Global Marine, and Santa Fe, a latecomer to the offshore, all competed for jack-up and semi-submersible business in the rapidly growing market. They responded with the continuous technological improvement demanded by inexorable movement into deeper waters, leapfrogging each other constantly:

- 1971: SEDCO built the *SEDCO 445*, first truly dynamically positioned drillship with side thrusters to hold position; they drilled a well the next year off Brunei in 1,300 feet of water.
- 1977: That allowed SEDCO to follow with the *SEDCO 709*, the first dynamically positioned semi-submersible.
- 1983 Global Marine built heavy weather jack-ups *Moray Firth I, Labrador I,* and *Baltic I.*
- 1985: Sonat Offshore Drilling built the first fourth generation semi-submersible capable of drilling in 4,000 feet of water.
- 1996: Transocean Offshore's *Transocean Leader* was the first fourth-generation semi-submersible capable of year-round operation in the West of Shetlands in more than 4,000 feet.
- 1996: Glomar Marine fitted *Glomar Explorer* with dynamic positioning, giving capability to drill in 7,800 feet.
- 2000: The merged Transocean SEDCO Forex brought on three fifth-generation semis, *SEDCO Express, SEDCO Energy*, and the *Cajun Express,* capable of depths greater than 9,000 feet.
- 2003: The same company's *Discoverer Deep Seas* drilled in over 10,000 feet of water. Its *Polar Pioneer* constructed a world record 23,000-foot horizontal well off Norway.

During the late 1990s it became clear to some that the challenges of the emergent deepwater business required a new dual value proposition. The technological requirements called for depth in engineering and scientific capabilities; the expectations for a global business required breadth—relationships with local customers, both public and national oil companies. For that reason, five entities eventually pooled their resources and emerged as a single company. Transocean then had the scale to deliver that different value proposition to its customers.

For more than a half century, Transocean and its predecessors have grown, sometimes just survived, by responding to the demands of explorers' march into more treacherous and deeper waters. As a group they continually created new capabilities one step—sometimes one leap—at a time (fig. 5–9) as they implemented new technologies and advanced the scale of their rigs.

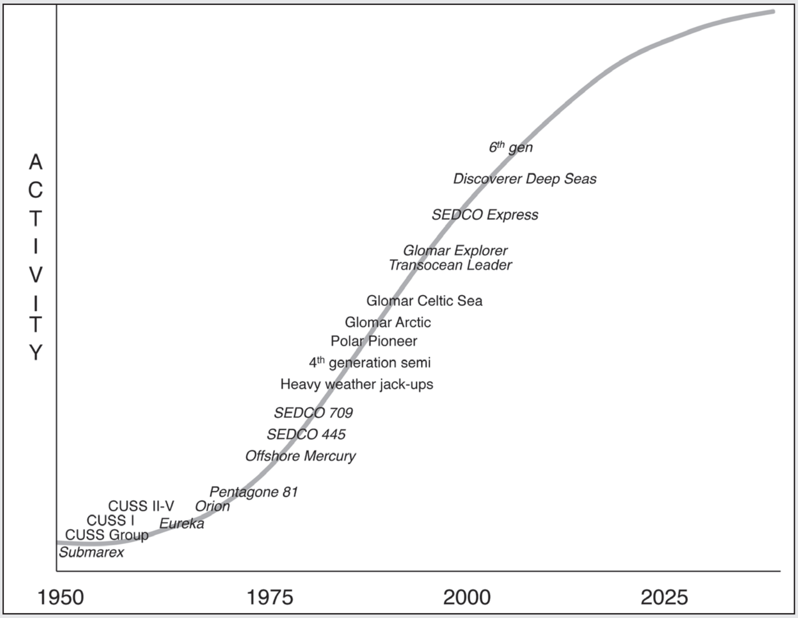
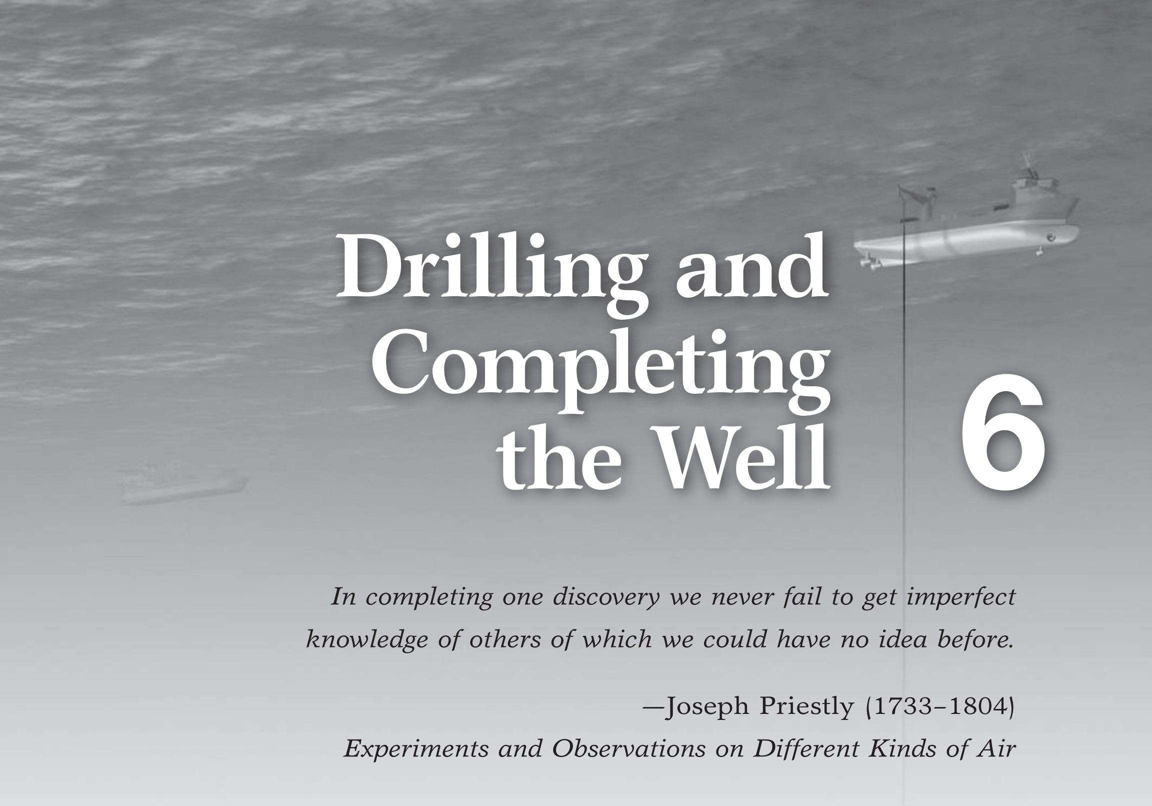


Fig. 5–9. The evolution of Transocean



Drilling and Completing the Well

6

In completing one discovery we never fail to get imperfect knowledge of others of which we could have no idea before.

—Joseph Priestly (1733–1804)
Experiments and Observations on Different Kinds of Air

The exploration geologist and the team of subsurface professionals have completed their technical work in their prospective area; they have identified a high quality prospect; and they have recommended it be drilled to their management, who has approved it in principle, meaning everything is a go depending on the detailed plan. At this point the exploration organization gives the go ahead to start the formalized well-planning process shown in figure 6–1 by requesting a cost estimate and a detailed well plan from another in-house specialist, the drilling engineer.

At this point in many companies, team leadership passes to the drilling engineer who takes the lead in the well-planning process. The new team leader's first responsibility is working with the organization's management to ensure the right people are assigned to the team to plan the drilling of the well. Often some members of the previous team carry over to the new team, particularly the exploration geologist. Next the team develops a detailed well design basis that takes into account all the critical aspects of the well objectives, the estimated time and cost, the risks, and the government regulations.

The Process to Drill a Well

Key Process Steps	Responsible Party
Define the well *objectives*	Geologist/geophysicist
Estimate the downhole pressures	Geologist/geophysicist
Establish the well evaluation criteria	Geologist/geophysicist
Specify the downhole logging program	Petrophysical engineer
Identify any special issues	Everyone involved
Prepare the well plan	Drilling engineer
Estimate the well cost	Drilling engineer
Survey the drilling rig options	Drilling engineer
Select the drilling rig	Drilling engineer
Select service providers	Everyone involved
Drill the well	Drilling operations
Evaluate the well	Everyone involved
Complete or abandon the well	Drilling operations

Fig. 6–1. The drilling process

The Well Plan

Early on, the drilling engineer leads the effort in the preparation of the *drilling program* for the well, a document of 20 or more pages that covers all the details and activities of the proposed drilling of the planned well. Figure 6–2 shows a typical cover sheet for the planned well. The drilling program lays out in detail the job responsibilities, specifications and material, and the equipment to successfully drill the well. It includes the specifics critical to the drilling plan:

- The well location
- The water depth

- The vertical depth and the total measured depth of the well. (Vertical depth is measured from the rig floor straight down to the target level; total measured depth is the distance the drill bit travels to the bottom of the well—different from the vertical if the well is a directionally drilled long reach well.)
- Well bore stability issues as detailed by geomechanical modeling
- Lost circulation plans
- Special casing designs such as expandable tubulars
- The depths of expected *reservoir sands* (often there are several)
- Downhole reservoir pressures and any unusual pressure zones or changes, plus potential depleted zones in developed fields
- The expected hydrocarbons: oil or gas or both
- The presence of H_2S (hydrogen sulfide) or CO_2 (carbon dioxide) in the gas
- Evaluation needs (mud logs, electric logs, drillstem test, etc.)
- Special drilling problems such as loop currents, shallow hazards, or shallow water flows
- Recommended industry practices
- Specific government regulations that apply
- Critical risk identification
- Estimated time and cost to drill and evaluate the well

The drilling program also specifies the final disposition of the well:

- If the well is an expendable well (once it is drilled and evaluated), it will be permanently plugged and abandoned (P&A) with cement according to industry practices and government regulations. The well will also be permanently P&A if it is a dry hole, i.e., no commercial hydrocarbons have been found.

- If the prospect has multiple potential hydrocarbon zones, the well may include a sidetrack or two. Once the original wellbore has been evaluated, the well is plugged back to a specific depth and then drilled off in a different trajectory to evaluate other potential reservoirs.
- In the case where hydrocarbons are discovered in the original wellbore or in the sidetrack locations(s), it may be decided to keep the well for future use. In that scenario, casing would be run to the total depth of the well and cemented in place. Temporary cement plugs would then be placed in the casing string, according to government regulations, and a temporary tree placed on the well until the well is again needed, probably during the development phase.

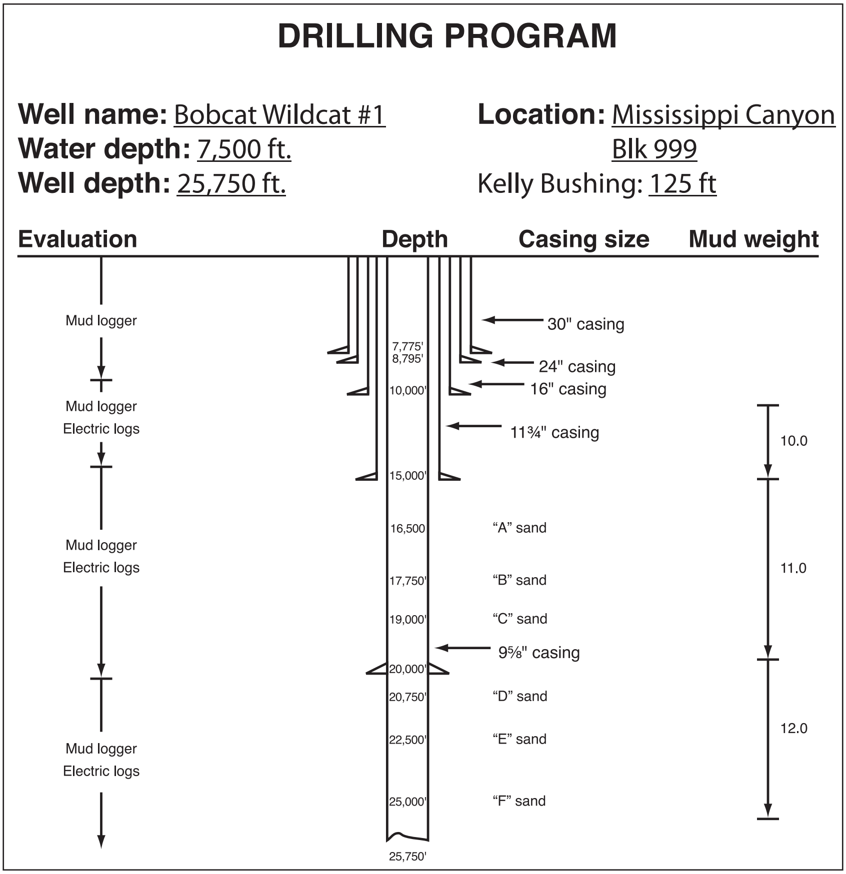


Fig. 6–2. Cover sheet for a drilling program

At this point the drilling engineer and the exploration geologist present the drilling program to their joint management for their authorization for expenditure (AFE) to drill the well.

Rig Selection

Rigs that can drill the deepwater have come a long way from the *CUSS I,* the first drillship, highlighted in chapter 1. The drilling organization nowadays has the choice of more than 300 semi-submersibles and drillships that can handle water depths of 1,500 feet or more. Rigs like the semi-submersible *Nautilus* in figure 6–3 and the drillship *Discoverer Clear Leader* in figure 6–4 and others in the fleet can drill wells down more than 30,000 feet in water up to 12,000 feet deep.

Fig. 6–3. The semi-submersible *Nautilus*

Fig. 6–4. The drillship *Discoverer Clear Leader*, showing the dual activity mast

To narrow the choices, the drilling engineer lists the project requirements the rig must meet:

- Water depths and well depths
- Pressure ratings, riser sizes, blowout preventer specifications
- Deck space and variable load capacity
- Drilling mud weight and delivery capacity
- Hook load capacity (how much pipe or casing the derrick can handle—typically 2 million pounds or more)
- Remote operated vessel (ROV) capability
- Ability to complete single and multilateral wells and smart wells
- Safety and environmental performance records
- Communications capabilities, including real-time transmission of well and rig sensor data
- Mobilization costs

- Day rate—the dollars per day to use it
- Length of contract
- Availability—windows of opportunity

With these criteria, the drilling engineer and drilling superintendent choose a group of companies that have rigs that meet the demands, and either get bids for the work, or negotiate a short- or long-term contract for several wells. In many cases the operator already has a rig under long-term contract and the drilling organization can match up the best rig for the job. If not, the potential contractors are asked to submit the formal bids. The drilling superintendent and his team select the rig operator who they believe can drill the well in the safest and most cost-effective way. After that, the rig contractor works with the operator to monitor and document the safety performance, risk assessment, and well planning and execution.

Some deepwater wells are drilled in the development stage from the production platforms—a fixed platform, a compliant tower, a tension leg platform, or a spar. The drilling rigs used for those wells are given the generic name *platform rigs*. They have all the hydraulic, electrical, and load capacity of the floating rigs, but come packaged to sit on the deck of a production system, and not on their own exclusive hull.

Drilling

With the AFE in hand and the rig contract signed, the time to spud the well (begin drilling) arrives. If the rig contract calls for a semi-submersible, a large anchor-handling boat tows it to the location and assists with the mooring. Satellite-fed signals assist in the initial positioning of the semi and in the continuous monitoring during drilling operations. After all, as any deepwater driller will boast with the least bit of encouragement, drilling a well in 5,000 feet of water is comparable to standing on top of the Sears Tower trying to stick a long straw into a bottle of Coke sitting on South Wacker Drive. Success in one case delivers the refreshing joy of a cola and, in the other, whatever hydrocarbon riches a reservoir can deliver.

If the rig contract calls for a drillship, it moves to the drill site under its own power and locates itself via dynamic positioning by using its external thrusters on the fore, aft, and sides, and the aid of continuous satellite geopositioning.

Many semi-submersibles also have dynamic positioning. Others need to be moored on site; some carry their own mooring rigging with them, and anchor-handling boats assist in setting anchors around the drill site to hold the rig in place.

As semis grew in size to handle deeper waters, the kit required to moor them increased to mammoth proportions, demanding more deck space and flotation. In a forehead-slapping insight, rig companies began hiring separate work boats to haul the mooring apparatus ahead of time to the drill site and set the anchors. When the semi arrived, hook-up took only hours, not days, and anchor boat day rates substituted for semi-submersible rates, saving about 80% of the mooring cost.

The crewmembers that operate the drilling rig or drillship are employees of the drilling company that provides the rig. Onboard also are other employees of other service companies that run testing, drilling mud operations, or other special functions. The representation from the E&P company, ironically referred to as the *operator*, usually consists of one or two drilling foremen. The operator's representatives have the final word on how the well is drilled, but the drilling and service companies are expected to run a safe and efficient operation.

The petrophysical engineer, or another professional who plays that role, takes the lead in the well evaluation, both as the drilling proceeds and after the target depth is reached. In the drilling program, the petrophysical engineer orders intermittent or continuous electric logs and mud logs. (The drilling program in figure 6–2 shows the logging requirement on the left.) The *Measure While Drilling* (MWD) tool assesses the lithology and determines the presence of hydrocarbons as the drill bit penetrates. Electric logs run at each casing point and at the total depth help assess the nature of the drilled-through layers, the presence of oil and gas in the reservoir sands, and the quality of the reservoir sands. Mud logs provide a record of the well cuttings and any hydrocarbon content as the well is being drilled. Usually, service companies (Schlumberger, Halliburton, or dozens of smaller companies) perform these logging tests for the petrophysical engineer, who then interprets the logs as part of the process to determine if the well is a success or failure.

Drilling Mud

Pressure control sits at the top of the list of worries for the drilling engineer. As the drill bit goes deeper, it encounters increasing pressure in the formation, due to the weight of the various rock layers and the column of water above it. Pressures increase more or less predictably in many areas, but in the deepwater, abnormal geopressures are often encountered.

As the well is drilled, drilling mud is circulated down the drill pipe and up the borehole annulus, the space between the drill pipe and the walls of the well. The weight of the mud is tuned to the pressures at the bottom of the hole. Three things can happen as the weight of the mud is varied. If the mud is not heavy enough to contain the pressures encountered, the well bore may cave in, or worse, the oil and gas may come uncontrollably spewing up the well bore, forcing the drillers to close the blowout preventer. If the mud is too heavy, it may overwhelm the strength of the rock, fracture the sides of the well, and leak off into the formation. If the mud is just right, the well bore maintains its integrity, and any hydrocarbons encountered are kept in the formation until the well can be evaluated and completed.

As the mud flows down the drill pipe, out the jets on the drill bit, and up the borehole annulus, it performs two other functions. It cools the drill bit and carries away the drilling cuttings. The mud logger monitors the cuttings as they are separated from the mud at the surface. The cuttings help determine the nature and age of each layer drilled through, including the presence of hydrocarbons.

As the well goes deeper, heavier mud is needed to offset the higher pressures encountered. The weight of the mud has to be increased. But the mud is homogeneous, and the heavier it is to accommodate pressures at the bottom of the hole, the more pressure it puts on the well bore at lesser depths. In fact, the weight of the mud may eventually increase to the point where it could fracture the rock uphole, at intermediate depths. To prevent that, steel casing is run in the well to preselected depths (after the drill pipe is pulled out of the well bore), and cemented in place. The steel casing can readily handle the higher mud weight pressure, and protects the weaker rock formations from fracturing.

The petrophysical engineer provides the drilling engineer with the *formation fracture gradient* information to determine when casing should be run. As the well proceeds, casing has to be run several times to cover weak formations and allow the drill bit to reach the targeted total depth. The geometry of the well forces each new string of casing to have a smaller diameter—it has to fit inside the previously run casing to get to the bottom of the borehole. The schematic on the drilling program cover sheet in figure 6–2 shows the general plan for running casing. In that sketch, the well starts with 30-inch *surface casing*. By the time the well reaches 20,000 feet, four more sets of casing, each of decreasing size, are put in place. Setting casing for the final 5,750 feet of well bore depends on whether the well contains hydrocarbons and is to be completed.

Blowout Preventers

As another precaution against unusual and even catastrophic surges in well bore pressure, every well is fitted with a *blowout preventer* (*BOP*) system. The BOP can seal off fluid flow from the well through one or more devices activated from the drilling rig control room. The choice of which one to use depends on the severity of the situation, but all are present to protect the drilling operations, personnel, and the environment.

For a well being drilled from a semi-submersible or a drillship, the BOP is placed on the well casing head at the sea floor. For a platform rig on a stable drilling platform like a fixed-to-bottom platform, a tension leg platform, or a spar, the BOP can be located at the surface, just below the drilling rig.

The rig's subsea BOP stack has four or more sets of hydraulic devices, as shown in figure 6–5. The first line of defense is one or two Hydrils or annular preventers. On activation, a donut-shaped rubber-steel composite closes off the annular space between the drill pipe and the casing. The Hydril is closed by the driller as soon as he sees any sign of a surge in the drilling mud flow. That indicates a higher-pressure zone has been penetrated and mud weight needs to be increased.

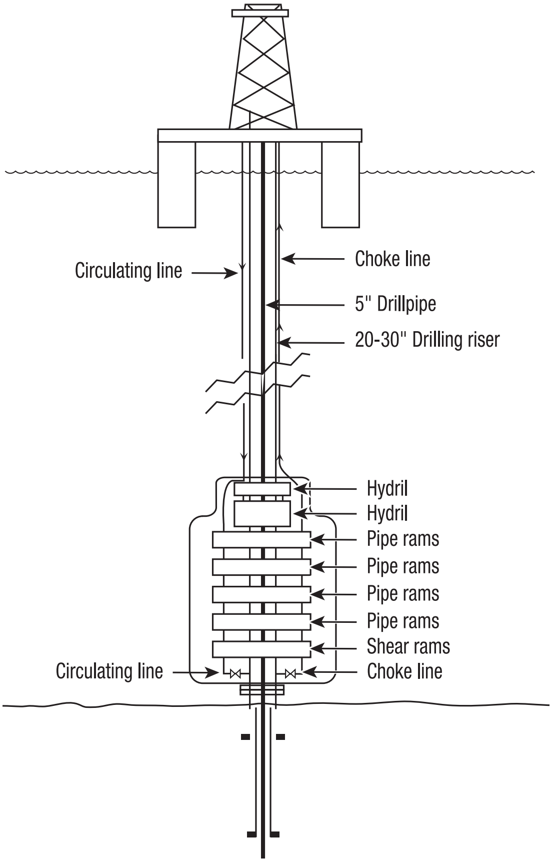


Fig. 6–5. A blowout preventer system

If the pressures exceed what the Hydril can control or if the Hydril has been damaged, the next safeguards are the four different types of pipe rams, made of steel and rubber and contoured to fit around the drill pipe and seal off the annulus. With the Hydril or the pipe ram closed, the valve on the choke line is opened. That allows heavier weight drilling mud to be circulated down the drill pipe and back up the section of the annulus below the BOP stack, and then up the choke line to the surface. Once the heavier weight mud controls the higher reservoir pressures, the pipe rams and Hydril can be reopened safely.

In extraordinary circumstances, *shear rams* provide the last resort. These steel blinds cut through the walls of the steel drill pipe and seal off both the annulus *and* the drill pipe. Using the shear rams causes irreversible damage to the drilling sequence. The well will have to be re-entered; the pressure will have to be overcome; the severed drill pipe will have to be removed. All this can add costly days to the drilling operation.

Drilling crews test the BOP system on rigorous schedules to ensure that it always functions. Company policies and local government agencies determine the frequency and testing procedures.

Evaluating the Well

After the drill bit reaches the target depth (TD), the bit and the drill pipe are pulled, and the drilling engineer and his team evaluate the well. A drill stem test (see box below) may evaluate the flow rates of hydrocarbons from the zones not yet covered by casing. Integrating this data with the logs and other tests leads to the completion decision. The drilling vessel can stand by while this decision is being mulled, or the well can be "temporarily abandoned" by placing cement plugs in the well bore and then disconnecting at the BOP. The vessel then moves on to another assignment.

Drillstem Test

"A procedure to determine the productive capacity, pressure, permeability, or extent (or a combination of these) of a hydrocarbon reservoir. While several different proprietary hardware sets are available to accomplish this, the common idea is to isolate the zone of interest with temporary packers. Next, one or more valves are opened to produce the reservoir fluids through the drill pipe and allow the well to flow for a time. Finally, the operator kills the well, closes the valves, removes the packers and trips the tools out of the hole. Depending on the requirements and goals for the test, it may be of short (one hour or less) or long (several days or weeks) duration and there might be more than one flow period and pressure buildup period." (From "Schlumberger Glossary of Oilfield Terms" at www.glossary.oilfield.slb.com/.)

Completing the Well

Another decision point arrives for the subsurface and drilling teams—whether or not to complete the well. Depending on the circumstances, well completion can start as soon as the approval for expenditure can be signed. In the case of a wildcat, creating a complete development plan may delay completion of the well for two or three years.

So what's left to complete? To produce oil and gas effectively, a well has to have additional casing run; tubing, through which the production flows, has to be put in place; the casing has to be perforated below the tubing so the oil and gas can flow; a tree has to be installed at the top of the well; safety devices need to be put in place; and at any reservoir sands where hydrocarbon is to be produced, a kit has to be installed to keep sand from clogging up the well. The process to carry out these few steps, shown in figure 6–6, differs from onshore and shallow water completions primarily in the complexity and cost.

Process Steps	Responsible Party
Create a reservoir model	Geologist and reservoir engineer
Specify reservoir pressures and temperatures	Reservoir engineer
Estimate well rates and ultimate recovery	Reservoir engineer
Identify any special issues	All involved
Develop a completion plan	Completion engineer
Estimate the completion cost	Completion engineer
Approve the rig company capabilities	Completion superintendent
Select service providers	All involved

Fig. 6–6. Well completion process

Even before the drilling phases finishes, the geologist and reservoir engineer have raw data to help them work on the first three steps in the well completion process, defining how the reservoir behaves. Their information, plus input from the petrophysical engineer, the geophysicist, and others become the fodder for a completion plan.

Once again, the baton passes in most companies to a completion (or production) engineer, usually a mechanically inclined person. The first chore of the completion engineer is the preparation of a Completion Program (fig. 6–7). Details of the work plan include the following:

- Who is involved and what their responsibilities are
- Type of completion
  - Single conventional
  - Multiple smart well
- Procedures for completion
- The mechanicals
  - Completion fluid type and weight
  - Hardware specifications
    - Perforation type and depth
    - Tubing size
    - Packer type and locations
    - Subsurface safety valve type and depth
  - Smart well technology for multiple completions
  - Artificial lift considerations
  - Tree specifications
  - Rigless intervention capabilities
  - Downhole measurement requirements
- Procedures for start-up

The well completion program becomes the basis for the preparation of the AFE to obtain approval of the well completion funds.

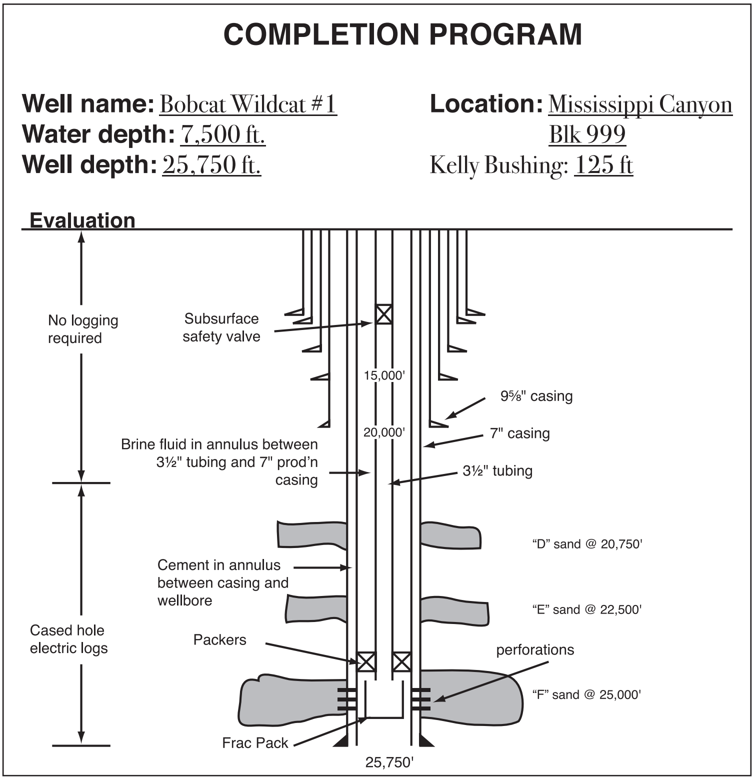


Fig. 6–7. Cover sheet for a well completion program

The Mechanicals

The first and most critical decision made by the completion engineer, working with the other subsurface specialists, is to determine the type of completion to be used on the well. Depending on the number of reservoirs ultimately to be drained, the complexity of the completion process, the potential for future rig interventions, and the ultimate total cost, the completion team will pick what it thinks is the optimum completion process for the well, as in figure 6–7.

After all the completion logs have been run (cement bond log, pressure log, etc.), all completions, whether a single or multiple zone smart well, begin the completion process by first displacing drilling mud in the casing with completion fluid. Completion fluid is a brine composed of water and either sodium chloride, calcium chloride, or zinc bromide in concentrations that mimic the weight of the drilling mud being displaced. The brine performs the same pressure control function as drilling mud while still allowing other completion work to be done in the well bore. Also during this step, it is possible that some of this fluid might leak into the subsurface formations, which warrants the environmentally friendly characteristics of these mixtures and calls for a fluid that does not damage the reservoirs.

During the drilling phase, protective casing had been run down the hole, probably about 80% of the way. In most cases, if the well was considered a keeper, then the production casing was run to total depth, below the deepest reservoir that contains hydrocarbon. The first operational item is running production casing inside the existing casing, down below the deepest reservoir that contains hydrocarbon. This casing is the smallest in diameter, from 5 to 9½ inches, depending on the casing already installed above it (fig. 6–7), so the production tubing is even narrower.

Smart or Intelligent Wells

The oil and gas industry generally thinks of smart or intelligent wells as having installed downhole in the well:

- Monitoring equipment like pressure and temperature sensors
- Completion components such as downhole valves and mandrels that can be adjusted to optimize production either automatically or remotely by an operator's intervention

Since this downhole equipment could be operated at the surface, these wells were initially conceived as alternatives to costly or potentially technically difficult drilling rig interventions at inordinately higher costs.

These wells do save the cost of a well intervention, but over time they have become more important for their ability to enable production from different reservoirs in the same wellbore or through the use of multilaterals and ultimately increase the recovery of hydrocarbons from these reservoirs. (See fig. 6–8.) As this technology continues to build a history of reliability, the number of smart/intelligent well installations increases.

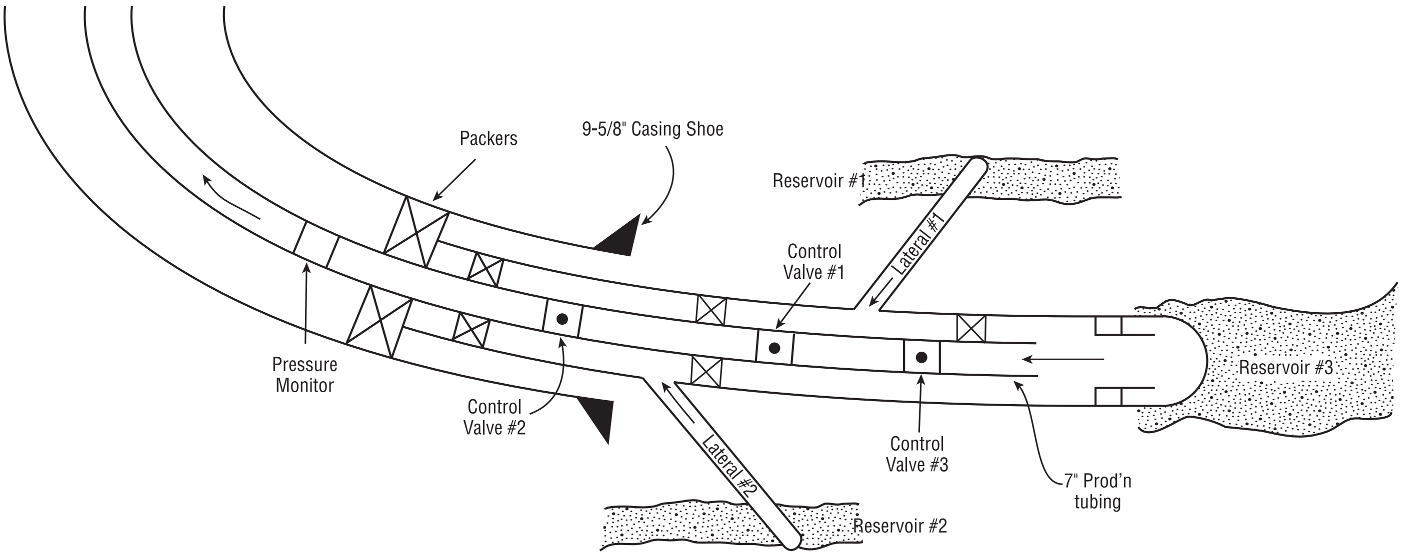


Fig. 6–8. A multilateral smart/intelligent well. Flows from the laterals tapping into the three reservoirs are pressure controlled from the surface using packers, control valves, and pressure monitors to control flow from multiple reservoirs.

The sequence of tasks that follows includes:

- Cement the production casing in place.
- Run a tubing workstring.
- Displace the drilling mud with brine through the workstring.
- Perforate the casing.
- Set the *gravel pack* or the *frac pack*.
- Replace the workstring with production tubing and a packer.
- Displace the completion fluid with a permanent, corrosion-resistant fluid.
- Remove the BOP.
- Set the tree.

Christmas Trees—Wet Trees—Dry Trees

In the beginning at onshore fields, the device at the surface of a well consisted of a central stem plus a few valves, nozzles, and handles, often wider at the bottom and sometimes resembling a tree. Oil patch legend has it that in Oklahoma and Texas oil field hands festooned them with lights and garlands during the Yuletide season, begging for the enduring name, *Christmas tree,* and later just *tree*.

People seldom mistake today's surface devices for a forest product, and the self-contained apparatus used on subsea wells has no resemblance at all. In the offshore, *dry trees* sit on a production platform where the crew can use their hands to work them. *Wet trees* sit on the wellhead at the sea floor. An operator works them from a production platform connected through an *umbilical*. Chapter 10 describes the system in more detail.

As one of many safety devices, a few thousand feet below the seabed a subsurface safety valve is located in the well bore. (Refer to fig. 6–7.) This failsafe valve closes automatically when the pressure holding it open drops precipitously. That stops the flow of oil and gas from the well if a catastrophic event occurs such as the tree or the platform being destroyed.

Downhole

The completion engineer has to specify in the completion program the downhole completion system. Its purpose is to prevent sand from the reservoir from flowing into the well bore with the hydrocarbons. Geologists usually refer to reservoirs as rock, but in fact many are unconsolidated sands. Because of the multiple layers of sediment above them, they all have high geopressures waiting to be released. The prolific turbidites in the deepwater allow fluids to gush into the well bore at rates of 5,000 to 30,000 (or even more) barrels per day. At those rates, sand can easily fill up the well bore or act like a sandblaster, eating away the innards of the well. In either of these unwanted circumstances, the well stops producing and the operator faces the choice of abandonment or a multimillion-dollar recompletion.

The challenge for the completion engineer is not only to avoid or stop the production of sand but also to maintain a high well productivity. Shutting off sand flow is worthless if it kills the oil flow. A number of methods are available to control sand production in wells, but the three most commonly used are the conventional gravel pack, the frac pack, and wire-packed screens.

Gravel pack

In gravel pack operations, shown in figure 6–9, a steel screen is lowered into the well and the surrounding annular space between the screen and the production casing is packed with gravel and sand of a specific size and gradation, selected to prevent the influx of reservoir sand and silt. The mesh in the screen is sized to retain the gravel and sand pack yet also to minimize any restriction to production.

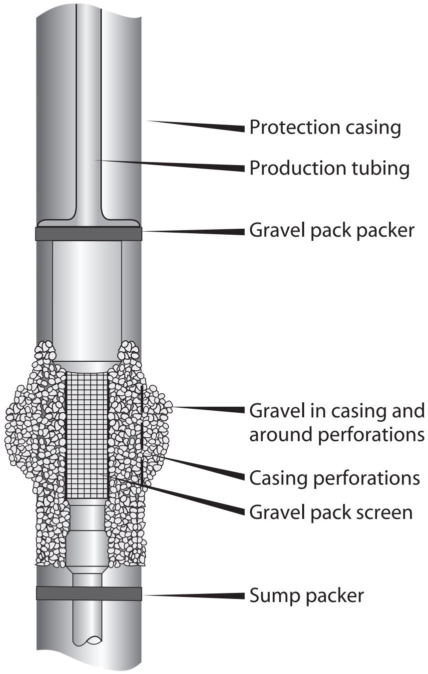


Fig. 6–9. Downhole gravel pack

Frac pack

In a frac pack installation, specially formulated slurry containing selected sand and gravel is pumped under high pressure and rate into a well reservoir interval. That causes a vertical fracture to occur, splitting the reservoir open on both sides of the well. The sand in the slurry fills up the fractures. When the pressure is removed and the slurry flows out, the sand remains to "prop" open the fracture. The process creates a plane of high permeability in this fissure, an avenue from the reservoir through which the well fluids can flow. A frac pack also includes a downhole gravel pack to filter out the sand.

Wire packed screens

In wire-packed screen applications, wire mesh holding gravel in place is wrapped around a perforated liner for several turns and then welded to it. All this is done before the production tubing goes in the well.

Final Steps

As nearly the last step in the completion phase, the blowout preventer has to be removed and replaced with a tree, the device that controls the flow of the well. To ensure the integrity of the well, BOP removal and replacement with a tree have to be done at the same time.

With all the equipment in place, the completion fluid is removed by pumping water treated to prevent corrosion (or sometimes diesel fuel) down the production tubing, displacing the brine through the annulus. A packer is set near the bottom of the production tubing (but above the perforations and sand control apparatus), sealing off the annulus so that hydrocarbons flow through the production tubing, not up the annulus. The treated fluid remains in the annulus permanently. As the pressure at the top of the production tube is reduced, hydrocarbon pushes the completion fluid out the production tubing as the well comes on stream. The completion engineer has reached the finish line and he hands the baton to the operations personnel.

Special Problems in the Deepwater

As E&P companies moved into deeper water, they encountered geologic and environmental obstacles never seen before. Other operating issues they ran into were not new but were more complicated to resolve because of the water depths and subsea conditions. Some still vex them.

The Loop Current and eddies

A clockwise current of water from the Caribbean Sea into the Gulf of Mexico between Cuba and the Yucatan creates a flow known to ocean scientists and meteorologists as the Loop Current. Panel 1 of figure 6–10 shows three stages of the Loop Current as it extends further into the Gulf.

The movement of this current is more or less random both in timing and the extent to which it penetrates the Gulf. On its exit from the Gulf, it changes name to the Florida Current, a tributary of the Gulf Stream.

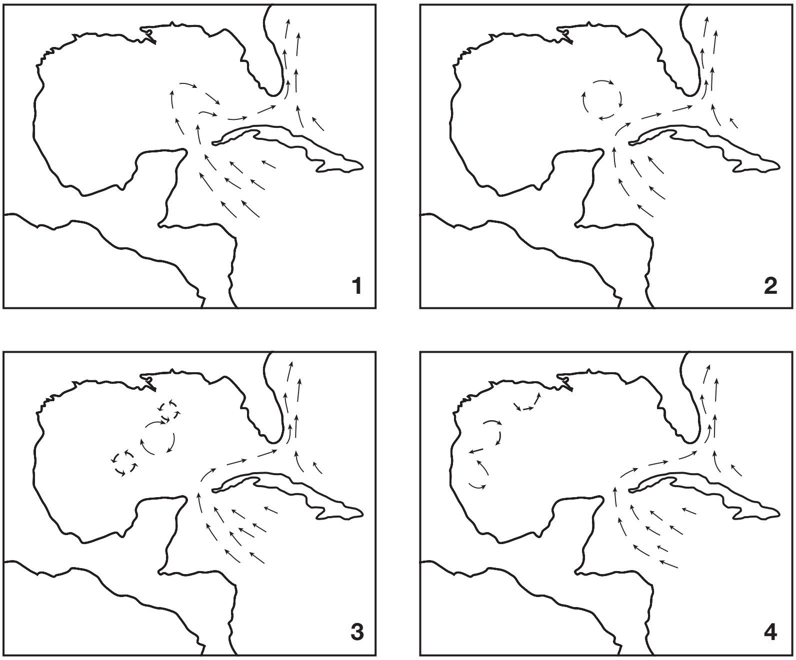


Fig. 6–10. The Loop Current and eddy currents in the Gulf of Mexico

As in panel 2, *eddy currents* spin off the Loop Current and work their way westward as a huge column of warm water, spinning in a clockwise fashion. In panel 3, the larger eddy current creates smaller, cold-water eddies, rotating in a counterclockwise direction. Eventually, both the cold and warm water eddies move westward into shallow water (panel 4) and dissipate.

The velocity of the current as the eddy spins can be 2 to 4 knots. As the eddies pass by an oil and gas drilling or producing operation, they subject the facilities to unusual stress and vibration. In addition, depending on the position of the platform and the eddy, the current may increase in one direction and then perhaps change to the opposite some time later.

The swirling eddy currents drift slowly westward in the Gulf at about one knot. Their diameters vary. As a result, a platform or drilling operation may see the effects of one eddy current for a day and the next one for perhaps a week or a month.

During an eddy current episode, the drilling riser from a semi-submersible or a drillship may bend or bow from the current to such an extent that the vessel has to change positions to stay connected. In some cases, the distortion can be so exaggerated that the drill pipe rubs against the drilling riser, a situation that warrants shutdown of operations before failure. At a producing operation an eddy can cause a riser to vibrate, inducing worries about metal fatigue and ultimate failure. Some mechanical devices can deflect the vibration effect of the currents on risers, but add to the drag.

The random nature of the eddy currents vexes the industry and begs for mechanical solutions to mitigate its effects. No known method to prevent the eddy currents themselves is on the horizon or even likely. E&P people just learn to live with them.

Shallow hazards

Occasionally drillers run into drill sites that have special geologic problems at depths of less than 1,000 or 2,000 feet below the sea floor—excessive faulting makes drilling and well control more difficult; thin layers of gas can disrupt what should be easy drilling.

Special processing of seismic data helps identify the presence of these hazards, and when they are found, the solution is often to spud the well in an offset location and directionally drill the well around them to the target bottom hole location. Eliminating the delays that these shallow hazards sometimes cause usually offsets the extra cost of the directionally drilled well.

Shallow water flows

Another geologic quirk prevalent in the Gulf of Mexico happens when sand layers in the first 2,500 feet became slightly over-pressured during their original deposition. As the drill bit penetrates these layers, the contained water wants to flow into the well bore. Increasing the weight of the drilling mud is the normal antidote to prevent inflows, but often the rock and sands at these depths are very young geologically and therefore have little strength. The extra mud weight can fracture other layers in the vicinity of the shallow water flows, causing loss of drilling mud and other well control problems. The situation calls for carefully setting casing at selected depths to isolate the troublesome sands, a time consuming and costly solution, but a necessary procedure if the well is to reach the target depth.

Reservoir complexity

Many deepwater reservoirs have much more compartmentalization within themselves—more faulting, less homogeneous sediment and less continuity. That results in a larger number of smaller reservoirs, making the field development more difficult and costly. Using multiple completion or multilateral wells and smart well technology in these cases can reduce the number of wells and total cost.

Many deepwater reservoirs are also very young in geological age. As they are produced, the reservoir pressure drops and the sands can compact due to the weight of the overlying rock. The result can be a discouraging reduction of the porosity and permeability and the productivity of the well, as well as the ultimate recovery. This phenomenon can even cause subsidence on the ocean floor, threatening the integrity and safety of a platform. Engineers pay careful attention to possible subsidence in the design phase of both fixed and floating platforms above or near these reservoirs.

Reservoir performance

In some reservoirs, even as deep as they are, the pressure is so low that artificial lift is required from the beginning of production, as in Shell's Perdido Field in about 8,500 feet of water. See details in chapter 10.

In other installations, gas is pumped down the annulus between the production tubing and the casing and injected into the production tubing at predetermined ports. The gas reduces the density of the fluid moving upward. That lowers the pressure needed to push the oil to the surface and facilitates flow from the reservoir and allows longer life and higher ultimate recovery.

Gas pressure issues

Water temperatures at the deepwater sea floor are typically less than 40°F, sometimes as low as 32°F. For wells with high proportions of water and natural gas, the formation of gas hydrates, a crystalline form of methane with the behavior of icy slush, can block wellheads and flowlines. If the equipment is designed for it, injection of chemicals such as methanol can revert these hydrates back to gaseous form. Other techniques are discussed in chapter 10.

Drilling and completing wells in the deepwater continually encounters new problems and challenges. All have to be dealt with in real time, and all lead to incremental learning in preparation for the next well.

7 Development Systems

"The time has come," the Walrus said, "To talk of many things: of shoes—and ships—and sealing wax—Of cabbages—and kings—And why the sea is boiling hot—And whether pigs have wings."

—Lewis Carroll (1832–1898)
Through the Looking Glass

The exploration team has found a field, appraised it to the satisfaction of its management, and recommends development. In some companies, the explorers hand off this work to a development team in the production organization. In others, some members of the original exploration team follow the work and join the development team, in which case, a subsurface reservoir engineer or construction engineer leads this step. With the Explore and Appraise phases of the overall development cycle completed (fig. 7–1), the Develop phase begins. The team then defines a concept or concepts consistent with the field architecture requirements, designs the system or systems, selects contractors to build and install them, integrates the entire operation with the probable ongoing drilling operations, and finally commissions the completed product and hands it over to operations.

Of course, before they ever spent money on the appraisal step, the geologists and engineers of the exploration team had given some thought to how they would produce the field. Otherwise how would they estimate the ultimate profitability of the venture? While figure 7–1 shows a linear sequence, reality is a bit messier than that. Still, when the appraisal effort indicates a viable opportunity, work on the first step of development—selecting a system—escalates.

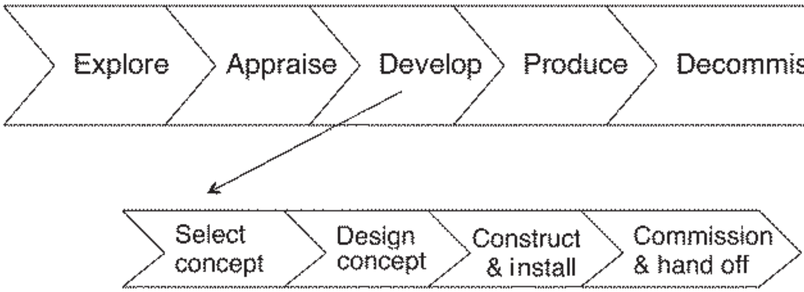


Fig. 7–1. Life cycle of field development processes

Development System Choices

The options available to develop and produce oil and gas in water a thousand feet or deeper fall into three broad groups: fixed to the sea floor, moored and tethered floating systems, and subsea systems, as shown in figure 7–2.

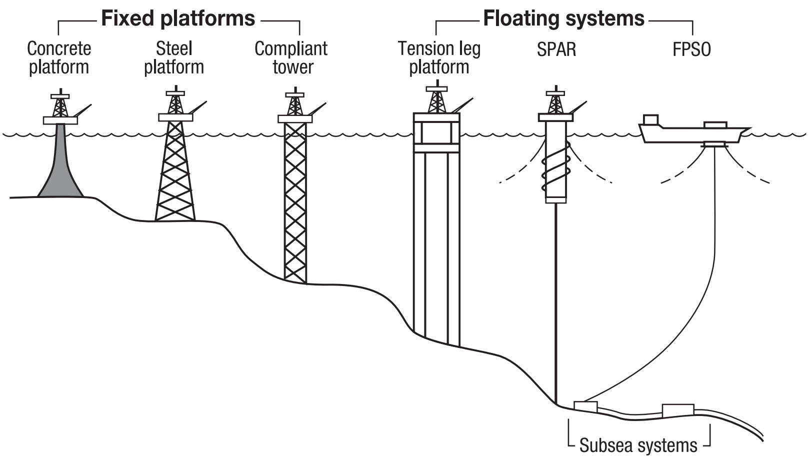


Fig. 7–2. Development system options for deepwater projects

Fixed to the sea floor

These structures physically sit on the bottom. They are held in place either by the sheer weight of the structure or by steel piles driven into the seabed and affixed to the structure. The group includes:

- **Fixed platforms**, which consist of a jacket and a deck. The jacket is the tall, vertical section built from tubular steel members and is locked to the seabed by driven piles. The deck placed on top holds the topsides' production equipment, utilities, crew quarters, and drilling rigs.
- **Compliant towers**, which, like the fixed platform, are made of tubular steel members and are fixed to the bottom with piling and support a deck with topsides. By design, compliant towers sustain more lateral deflection than do the more massive and rigid fixed platforms.
- **Gravity platforms**, which are built from reinforced concrete. With their substantial weight, plus the weight of the topsides, gravity platforms rely on gravity to hold them in place. Gravity platforms are used in up to 1,000 feet of water, but the seabed has to be especially firm to ensure no creep over time.

Floating systems

These include tension leg platforms and moored floating production systems of several shapes. All have to be held in place with steel pipe tendons, or moored in place with chains on the seabed attached to wire or polyester rope.

- **Tension leg platforms (TLP)** have floating hulls made of buoyant columns and pontoons. Steel pipe tendons hold the hulls down below their natural level of flotation, keeping the tendons in tension and the hulls in place. Even so, the platforms experience some lateral motion in heavy seas. TLPs most often have dry trees on the platform, but wet-tree subsea tiebacks are also common. Like the fixed systems, TLPs can accommodate drilling operations from the deck. A variation of the TLP design, the smaller mini-TLP accommodates smaller deepwater reserves.

- **Spar platforms** get their flotation from large-diameter cylinders, weighted at the bottom to keep them upright. Eight to sixteen wire or synthetic rope-and-chain combinations moor the hulls to the seabed. Because of their huge masses, spars have very little vertical heave, even in heavy seas, but there can be lateral offsets due to winds and currents. Like TLPs, either dry trees or wet trees can be used on spars.
- **Floating production systems (FPS)** consist of ship-shaped or semi-submersible hulls with production facilities onboard. Wire or synthetic rope and chain moor them in place. FPSs are quite free to move both laterally and vertically, so only wet trees can be accommodated. No drilling either. The significant motion during heavy seas and currents calls for special equipment to accommodate the risers that get the oil and gas from the sea floor wet trees to the production facilities on the deck.
- **Ship-shaped floating production, storage, & offloading systems (FPSO)** are made from converted tankers or new ship construction. They are moored with rope and chain. Like FPSs, FPSOs have no drilling capability. They process production from subsea wells and store large crude oil volumes, accumulated for later transport by shuttle tankers. A variation, **floating storage and offloading systems (FSO),** receives processed oil from nearby platforms, often FPSs, and stores it for subsequent transport by shuttle tankers. (These units are also often referred to as floating storage units or FSUs.) An FPS and FSO or FSU together are the equivalent of an FPSO. Water depths present no limitation to FPSOs and FSOs.
- **Cylindrical-hull FPSOs** have double-bottom, double-sided hulls with enough ballast to make them resistant to motion from wave, wind, and current. Conventional mooring spreads anchor them in place. The symmetrical hull eliminates the expensive turret necessary for some ship-shaped vessel. This innovative solution does have limitations in that it cannot store the high volumes of oil that a ship-shaped FPSO can. These vessels can accommodate deepwater drilling rigs.

- **Floating drilling production storage and offloading systems (FDPSO)** are another variation of the FPSO, and they can be either ship-shaped or cylindrical hulls. They accommodate a drilling operation on board.
- **Floating liquefied natural gas systems (FLNG)** break the stranded-gas dilemma by converting the natural gas vapor to liquid, storing it, and then offloading it to an LNG carrier for delivery to market.

Subsea systems

This option can have a single or multiple wellheads on the sea floor connected directly to a host platform or to a subsea manifold. The systems include connections by flowlines and risers to fixed or floating systems or to a land base that could be miles away. Subsea systems can be set in water of any depth.

More complete descriptions of each of these options follow in the next three chapters. This overview sets those chapters up by looking at the criteria for selecting among them.

Choosing Development Systems

Criteria

Offshore fixed structures and floating systems provide platforms for further well construction and servicing, production processing, and utility equipment used to explore, develop, and produce oil and gas fields. As the water depth increases and environmental conditions become more challenging, the cost of providing the needed space becomes an increasingly large and dominant item in the overall field development cost. The well construction and processing options selected for field development are major factors in determining the needed platform size. Considerations for providing a safe working environment for staffed facilities further increase the need for deck space and platform size.

Altogether, the functions of platforms for oil and gas developments can be summarized as follows:

- Provide adequate surface area to install and safely operate all the equipment.
- Structurally support the weight of all the equipment and fluids and the structure that provides the deck space.
- Elevate the deck above storm waves.
- Withstand the wave, wind, and current forces on the structure.
- Transfer all the weight and environmental loads to the foundations or provide adequate buoyancy to safely support all loads.
- Remain in safe and serviceable condition against corrosion and structural deterioration.

These platforms may be open-framework steel structures (fixed platforms) with piling foundations, large concrete structures with gravity-based foundations, or floating vessels with either vertical tendons or spread moorings.

In a subsea system, everything except the flowline riser and surface control system is wet (underwater). Subsea systems are often a viable alternative to dry-tree developments in which the well and other components are installed on a topside deck. Since production from a subsea system moves to a host facility for processing, some components may be located several to many miles from the host facility. Nevertheless, they can be economical in water depths ranging from very shallow to 10,000 feet or more. They are in widespread use in very deep water.

The function and purposes of subsea components are essentially the same as their counterparts on a surface wellhead dry tree platform. However, the components of a subsea system must be designed to deal with internal pressures associated with deepwater wells and still function under the external pressures and corrosive saltwater environment. Because subsea components are placed on the sea floor, they are more costly and time consuming to repair or replace.

Selection

Selecting the right development systems involves assessment of the usual list of physical circumstances—water depth, reservoir configuration and location, access to oil transportation, and, separately, gas transportation—plus the constraints placed by the local government and the institutional preferences of the investing operator. Figure 7–3 shows schematically the many issues—technical, risk, environmental, investment, and social—that need to be addressed and resolved in selecting the right option for a field development system.

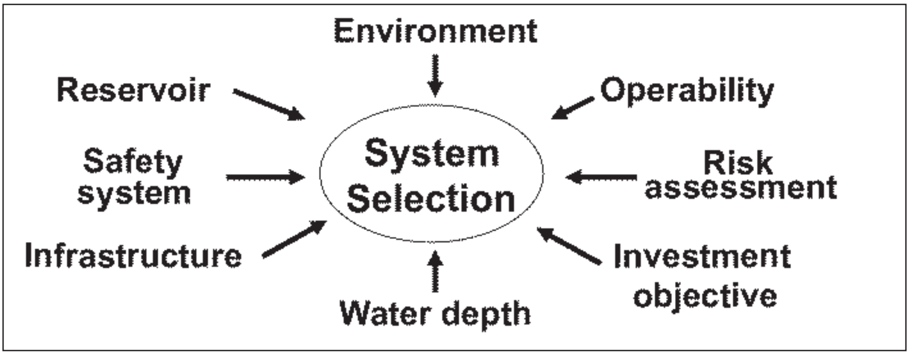


Fig. 7–3. Selecting a system

Companies may each arrive at different conclusions for the same circumstances, reflecting their own predilections or biases. In some areas of the world, producers would rather not bring oil ashore, so they choose floating production systems that offload into tankers. Regulatory agencies have to be convinced as well. For years, the (former) U.S. Minerals Management Service was hard-pressed to allow the floating production systems that offload into tankers in the Gulf of Mexico; they preferred floating systems tied to pipelines. At the same time, the UK government had no problem with floating production systems and shuttle tankers in the North Sea.

Water depths. The realities of the laws of physics and the limited strength and flexibility of materials make water depths the first cut in choosing a development system. In round numbers, the maximum water depths for each of the options fall as follows:

• Fixed platforms	up to about 1,500 feet
• Gravity platforms	1,000 feet
• Compliant towers	1,000 feet to 3,000 feet
• Tension leg platforms	5,000 feet
• Spars	unlimited
• Floating production systems	unlimited
• Subsea systems	unlimited

At first glance, the water depth would seem to be related to the amount of materials necessary to build the system. That may be true, but beyond that, the other maritime conditions—wind, waves, currents, ice loadings in some areas, and the competency of the seabed to support heavy loads—figure importantly. Winter storms in the North Sea and the Atlantic off Nova Scotia sometimes generate winds of 125 miles per hour and create waves 90 feet high. Hurricanes in the Gulf of Mexico can deliver 150-miles-per -hour winds and 80-foot waves. In the more serene areas off the coast of West Africa, winds seldom exceed 75 miles per hour; waves reach only 25 feet.

Thinking even more deeply, the extremely hard clay soil of the North Sea bottom provides fine support for gravity-based structures. In contrast, the under-consolidated, soupy clay soils in the Gulf of Mexico would have platforms slipping and sliding around if they weren't nailed down with deep-driven piles.

Oil transportation. The next cut at choosing development systems comes from the oil-transportation options available. The Gulf of Mexico and the North Sea already have a web of pipelines in place. For many new discoveries, the option of tying into one of these lines might look attractive, even if miles of new subsea pipe have to be laid.

Sometimes the prohibitive cost of laying a new pipeline calls for floating production systems with oil storage onboard or floating nearby. In areas as remote as West Africa, West of the Shetlands, or the Faroe Islands, the complete lack of oil pipeline infrastructure calls for FPSOs.

Gas disposition. Deepwater gas can provide good news or bad news in the selection of development systems. First of all, if the prospect has associated gas dissolved in the oil, and virtually all of them do, something besides flaring has to be done with the gas as it is produced. Almost every offshore jurisdiction prohibits or restricts continuous flaring. Gas is good news when a gas pipeline infrastructure presents itself in some proximity. The good news is then compounded when the reservoir is predominantly gas, with just some associated liquids. Gas flows in a rather frictionless way through miles of flowline with minimal loss of pressure. For example, the designers of the *Mensa* development, a gas reservoir in 5,400 feet of Gulf of Mexico water, shrewdly avoided the expense of any onsite platform. They did a subsea development and tied it via flowline to a host platform 63 miles away, powered just by the reservoir's pressure with no boosting. (See fig. 7–4.) The receiving station happens to be a fixed platform in 350 feet of water already delivering gas to the onshore via pipeline. In contrast, oil might flow under those conditions *only* 15 to 20 miles.

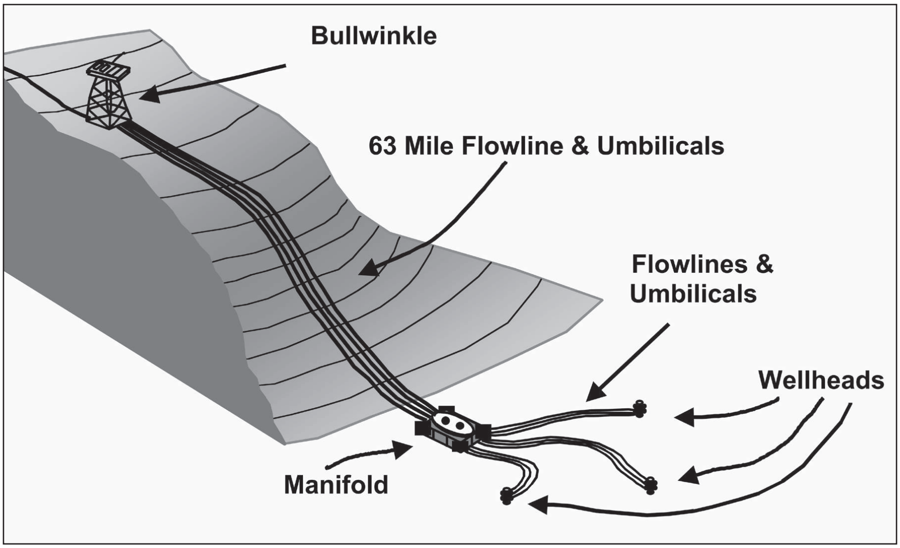


Fig. 7–4. The *Mensa Field,* a subsea development. (Courtesy Shell.)

But what if no pipeline infrastructure for the gas exists in the region? In that case, if it is a gas-only well, traditionally nothing happens. The E&P company can hang a sign on it that reads "Stranded Gas" and wait for the market to develop; or they can embark on the construction of an FLNG vessel. (See fig. 7–5.) These vessels separate the oil from the gas, convert the natural gas vapor to liquid using supercooling facilities onboard, and store it in a frigid state until LNG tankers come to offload the gas in the same way shuttle tankers service FPSs.

If the gas is associated with oil, and if the oil alone presents itself as an economically viable project, the gas can be reinjected (carefully) into the reservoir whence it came or into another convenient reservoir. There it sits indefinitely, like the rest of the stranded gas in the world. The good news is, however, that it does add energy to the reservoir, enhancing production rates and ultimate recovery. Reinjection facilities on the producing facility consist primarily of compressors to force the gas back into the reservoirs.

In some cases, the volume of associated gas is small enough that the power requirements on the platform—generating electricity for pumps, compressors, heat, and light—consume all of it.

Fig. 7–5. FLNG ship design. (Courtesy Shell.)

Development Examples

1. An oil and associated gas field located in 3,000 feet of water 20 miles from an existing shallow-water platform with pipelines to the onshore

   Probable solutions:

   - A TLP, a spar, or a compliant tower with dry trees; separate oil and gas pipelines to the nearby platform

   Possible alternatives:

   - Floating production system with wet trees; separate oil and gas export pipelines to the nearby platform
   - Subsea development (wet trees) with a single flow line back to the nearby platform.

   Criteria:

   - Costs
   - Technical and commercial risk assessment
   - Timing
   - Experience and learning curve
   - Producer's bias toward various systems

2. An oil field with associated gas located in 8,000 feet of water 60 miles from any other infrastructure, and further from any market

   Probable solution:

   - A floating production storage and offloading system, FPSO with subsea trees, shuttle tankers for the oil, and reinjection of the gas

   Possible alternatives:

   - Spar with dry or wet trees, topsides production and treatment equipment, supplying treated oil to a nearby FSO via a sea floor or mid-depth floating transfer pipeline. Shuttle tankers take the oil to market. The gas is reinjected.

   Criteria:

   - Depth
   - The high cost of building export pipelines eliminates other alternatives
   - No viable transport options for the gas

Reservoir proximity. Often development opportunities can include more than one reservoir. In that case, the proximity of the various reservoirs can dictate the scheme selected. If they are relatively close to each other, say within two miles, directional drilling from one location makes sense. Each well can then be produced through a dry tree on a platform, making production operations less complicated. That arrangement favors a fixed platform, a tension leg platform, a spar, or a compliant tower, but doesn't exclude development with subsea wet trees. If the reservoirs range over many miles, subsea wells connected via flowlines to a fixed or floating station make more sense. As exploration in an area proceeds, various combinations of both wet and dry trees often emerge.

With these selection criteria now laid out, the next chapters examine the devil in the details, taking a close look at the design of fixed structures and floating and subsea systems.

8 Fixed Structures

We were the first that ever burst into that sea.

—Samuel Taylor Coleridge (1772–1834)
"The Rime of the Ancient Mariner"

From the get-go, offshore operations employed fixed structures, secured to the seabed by pilings. Even exploratory wells were drilled from fixed platforms in the early days. Today E&P companies use fixed structures up to the threshold of deepwater for both drilling and subsequent production of oil and gas.

Conventional Platforms

The fixed structure installed most often around the world consists of the following, as shown in figure 8–1:

- The *jacket,* the steel structure that rises from the seabed to above the waterline
- The *deck*, where the drilling and production equipment (the topsides) sits, located atop the jacket

- The *pilings*, steel cylinders that secure the platform to the seabed
- The *conductors* or *risers*, steel pipes through which the wells are drilled, completed, and produced

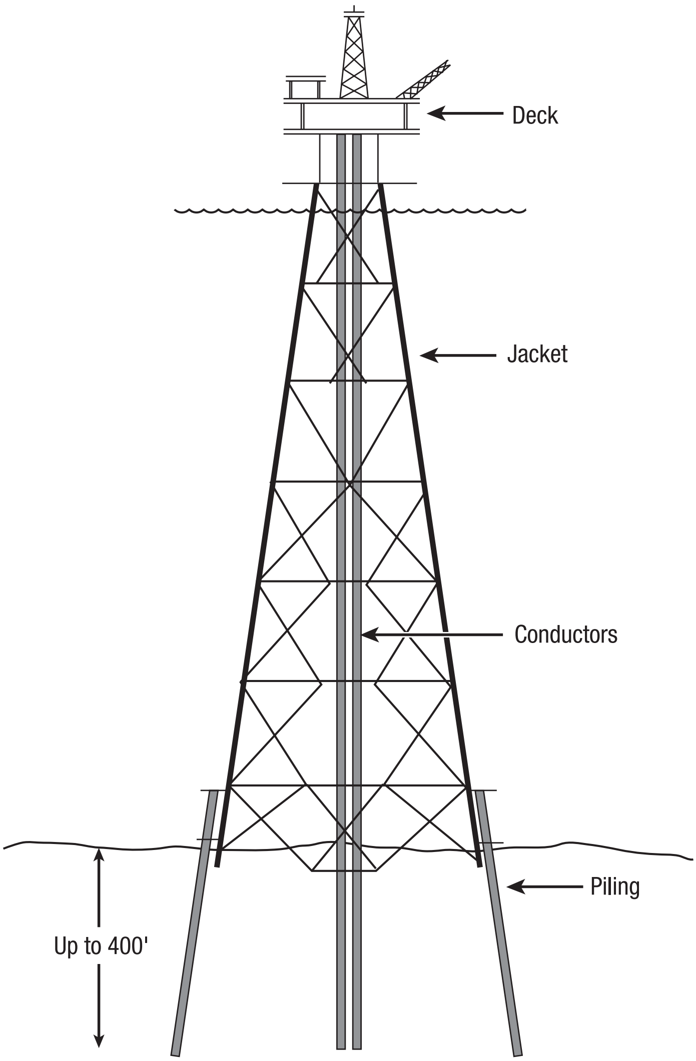


Fig. 8–1. A fixed steel platform

In contrast to onshore structures, the platform is built from tubular steel members, not structural shapes. These cylindrical shapes create the lowest resistance to waves and currents, reducing the amount of steel and ultimately the weight and the bill for the platform. The deck legs, which connect to the jacket, are typically tubular, to allow for easier geometric fit. Additionally, in many cases, the deck legs extend downward to near the waterline and are vulnerable to wave action in high seas. The deck itself is above water, so traditional square-edged structural pieces are as common as those found on an onshore operation or any heavily loaded high-rise building.

The steel jackets are typically built on their side, that is, rotated 90 degrees from their final installed position. This keeps the construction yard heights under control, but does require an innovative approach to load-out and launch of these structures.

Concrete Platforms

In the 1970s another form of fixed structure started to dot the seascape of the North Sea: steel reinforced concrete platforms. The unusually hard clay seabed of much of the North Sea allowed these heavy structures to plop down and stay in place by their sheer weight, despite the large profile they presented to waves and currents. Few have any pilings driven into the seabed.

Both these fixed structures, steel and concrete, rely on brute force and huge footprints to resist wind, wave, and current forces. The *Troll* platform in the North Sea, a concrete gravity structure, has a base approximately 500 feet in diameter. When it landed on the seabed, it penetrated tens of feet into the bottom. (See fig. 8–2.) In contrast, the *Bullwinkle* platform in 1,354 feet of water of the Gulf of Mexico has a base of 400 feet by 480 feet. Twenty-eight steel pilings hold the jacket in place. Each cylindrical piling is 7 feet in diameter with 2-inch thick walls and is driven 400 feet into the sea floor.

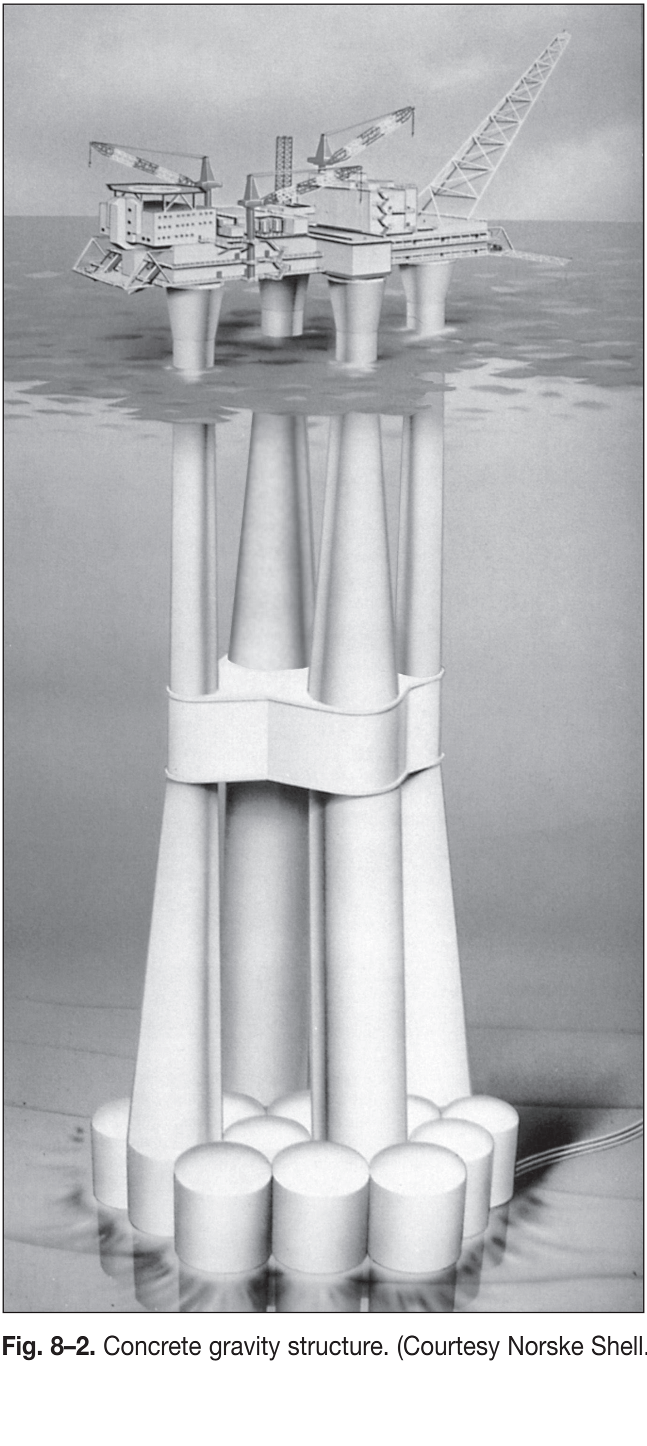


Fig. 8–2. Concrete gravity structure. (Courtesy Norske Shell.)

Compliant Towers

As oil and gas development moved into waters beyond 1,500 feet deep, steel platforms and certainly concrete platforms required more materials and cost than the ventures could economically bear. The problem wasn't engineering. The base of the structures just became too large. Along came the idea of compliant towers, tall structures built of cylindrical steel members, but slender in shape. Pilings tie it to the seabed, but in a small footprint. A typical compliant tower in 1,650 feet of water in the Gulf of Mexico covers only 140 by 140 feet at its base. (See fig. 8–3.) With such a narrow base, the compliant tower has none of the brute strength of the steel platform or concrete structure. In fact it sways with the currents, waves, and winds, as much as 10 to 15 feet off center in extreme cases, but during normal operating conditions the motions are very slight.

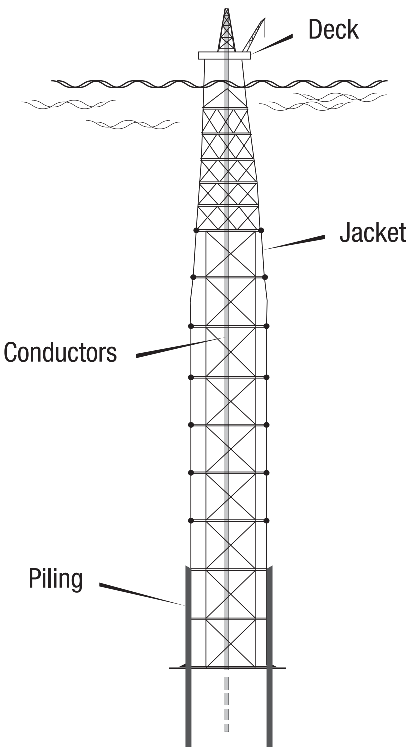


Fig. 8–3. A compliant tower

Compliant towers are designed to have considerable "mass" and buoyancy in their upper regions. The net result is that they have a very sluggish response to any forcing function. The typical 10- to 15-second-cycle waves pass through the structural frame before it can respond, something like a water reed in a wave environment. (An early version of the compliant tower was named the *Roseau*, the French word for reed.)

While fixed platforms have a technical and commercial limit of about 1,500 feet of water—it just takes too much steel to go deeper—compliant towers can be used to about 3,000 feet before the increasingly thicker steel members at its base make the concept infeasible. Ironically, compliant towers have a lower water limit of about 1,000 feet. In shallower water, the flexibility needed for deeper water disappears.

Construction

Steel platforms and compliant towers

Building steel platforms and compliant towers requires tedious fabrication of the cylindrical members. Steelworkers take flat steel plates and form them into cylindrical shapes of various diameters and lengths of 5 to 15 feet. Next, they *stalk* (weld together) these individual *cans* into tubular members. Then they *cope* (cut to shape) each end to fit up against other cylindrical members and form the prescribed and complex geometry of the structure. Coping becomes crucial. In the next step, they weld these intricate shapes to form the panels or sides of the structure. (See fig. 8–4.)

A variation on this approach is to fabricate structure nodes, or joint cans, in a shop with stub members in the correct orientation. The full brace members are then connected via girth welds in the yard. This approach, very common for North Sea structures, is used when the residual stresses caused by welding need to be relieved by heat treating the joint node. Heat treating a node in the shop is much simpler and cheaper than doing a heat treatment on a full already built-in joint.

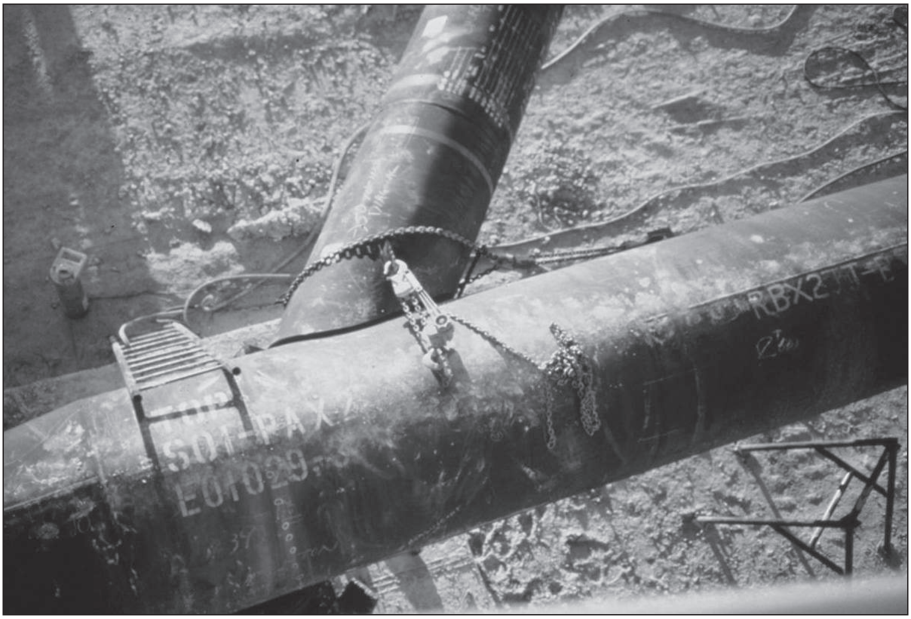


Fig. 8–4. Coped brace welded to larger tubular member. (Courtesy P. W. Marshall.)

Once the fabricated panels have been completed on the ground, construction cranes roll them up for connection with each other by welding and addition of more cylindrical steel members. Figure 8–5 shows cranes rolling up a panel for a completed jacket on its side, ready to be loaded out and taken offshore. Tall as it is when upright, the structure typically lies on its side in the construction yard to accommodate construction access and, more importantly, transit to the offshore well site. Sites for the construction and assembly of these platforms have to be on waterways that allow access to the sea. There will be more later on the transport of these structures, ungainly as they are out of water.

In round numbers, a steel platform in 300 feet of water requires about 3,000 tons of steel for the main structure and another 1,000 tons of steel pilings. For a steel platform in 1,500 feet of water, the main structure increases to about 50,000 tons of steel and 15,000 tons of pilings.

The steel jacket legs for a 300-foot water-depth structure are about 54 inches in diameter, with the truss work made up of 24- to 36-inch cylindrical braces. For a 1,500-foot water-depth case the legs are 80 to 100 inches in diameter, the braces 30 to 60 inches, and the piling about 70 or 80 inches.

Big stuff! A compliant tower has individual members of the same dimensions as a fixed platform, but does not take as much overall steel because of its slenderness. A compliant tower in 1,700 feet of water requires about 30,000 tons of structural steel and 7,000 tons of piling, considerably less than the 1,500-foot fixed platform.

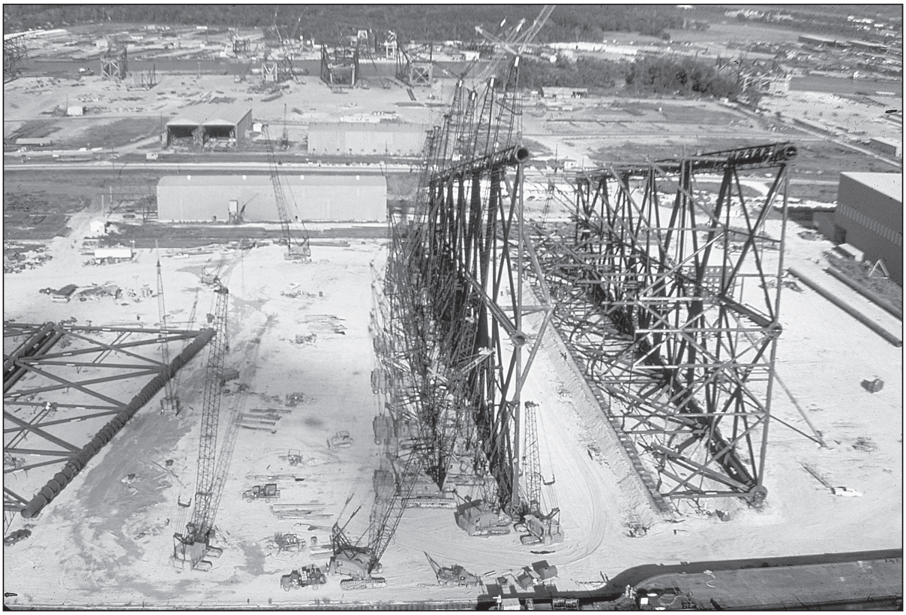


Fig. 8–5. Construction cranes rolling up a steel frame for a deepwater jacket. (Courtesy Shell E&P.)

Gravity platforms

Using concrete for gravity structures came about because of a happy confluence of marine topography and geologic history in the North Sea. The seabed above reservoirs like Brent and Ekofisk consists of firm, hard clay. Not far away, on the eastern side of the North Sea, deep fjords cut into the mountainous coastline.

Concrete structures have to be built like concrete buildings, from the bottom up, using reinforcing steel embedded in the concrete. Whereas buildings rise toward the sky as they form, concrete platforms sink into the water. The platforms are formed by pouring concrete into platform-shaped forms, *lift* by *lift*, that is, one 20-foot level (or so) at a time. As the concrete cures, the structure is ballasted and lowered into the deep water of a fjord. That way work continues at the same elevation throughout the construction process, with only a few dozen feet of platform showing above the waterline.

The outer walls of a concrete platform might be 18 inches thick at the top, but as much as 3 feet thick at the bottom. The *Troll* concrete structure is located in 994 feet of water. It was installed in 1995 and remains today the deepest water gravity structure in the world. It weighs about 700,000 tons, with 110,000 tons being steel reinforcing rods. This "concrete" platform has fifteen times the amount of steel in the Eiffel tower and 1½ times the steel weight of the world's deepest fixed steel platform, *Bullwinkle*.

Jacket and Topside Design Conditions

An offshore production system is designed to support the topsides facility load and to withstand brutal environmental forces. (See fig. 8–6.) In addition, the design must consider the stresses of all phases of the structure's life cycle, including fabrication, load-out, transportation, installation, in-place operating, and, eventually, decommissioning.

- **Environmental forces and loads.** Winds, waves, currents, tidal, ice movement, earthquakes, and sea floor movement such as soil slides.
- **Dead loads.** Loads that are a part of the permanent system, such as the weight of the structure itself, weights of equipment, hydrostatic forces, and buoyancy forces.
- **Operating live loads.** Imposed by operations conducted on the structure, such as produced fluids, weight of temporary equipment or material, ballast, forces generated by the operating equipment, weight of liquid consumables, helicopter landing loads, variations in derrick loading during the drilling and completing of wells, forces generated during crane operations, etc.
- **Construction loads.** Temporary loads and twisting and turning forces imposed on the structure during its fabrication, load-out,

transportation, and installation. These forces often account for a significant portion of the design requirements for offshore structures and in some cases are the controlling design cases for given areas and members.

In addition, during the design phase a typical series of in-place load cases to determine the design limits for all structural elements includes the following:

- Dead loads plus normal operating environmental loads plus maximum operating live loads
- Dead loads plus normal operating environmental loads plus minimum operating live loads
- Dead loads plus extreme environmental loads (e.g., hurricane, earthquake, swells) and the maximum live operating loads that would be expected as well
- Dead loads plus extreme environmental loads plus minimum operating live loads

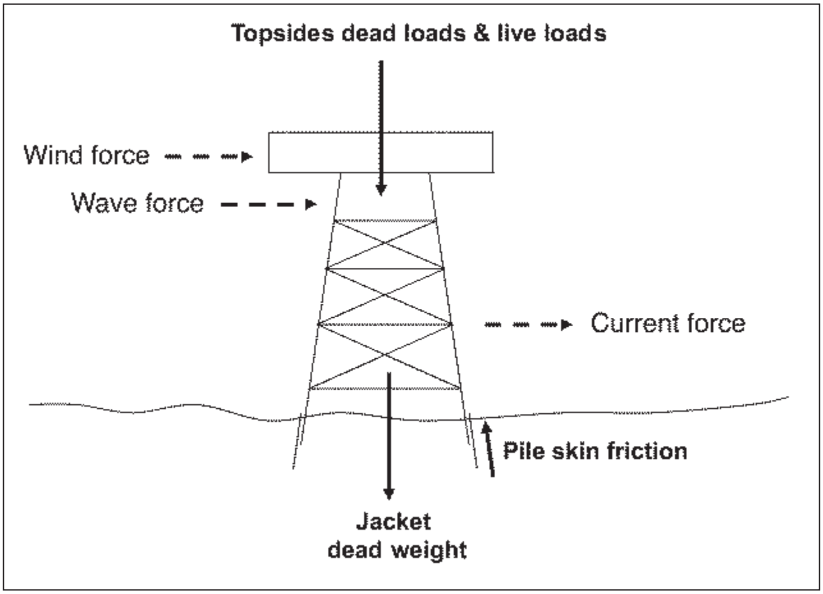


Fig. 8–6. Load system on a fixed platform

The intent of these operating cases is to combine loads in a manner that is consistent with the most extreme conditions that a structure may actually experience. In a similar manner, load cases are developed for all phases of fabrication, load-out, transport, and installation. For example, a review of environmental data and the associated level of risk leads to a series of load cases, for example, a sudden ten-year storm for which the structure needs to be analyzed during the transport and installation phases. Another more routine example deals with the wind speed and forces generated during yard fabrication lifts.

To design offshore structures, data from other disciplines such as equipment weights, operating loads, and space requirements must be provided to the structural engineers.

Fixed steel platforms are still by far the most used platform structures for offshore oil and gas development in water depths of less than 1,000 feet. These structures are held in place by long steel piling. The previous discussion and figure 8–6 show the loading conditions that the piling must withstand. The piling is designed to resist both vertical loads, such as axial loads causing compression and tension, and lateral loads that can cause high bending stresses at the pile-structure intersection.

Almost all of the piling used for offshore fixed platforms is composed of large steel pipe cylinders. (See fig. 8–7.) These are driven deeply into the soil, sometimes as much as 500 feet into the sea floor. The piling is referred to as "friction" pile. As the vertical load is applied, it gains almost all of its resistance from the adhesion of the soil to the skin of the pile. (See fig 8–8.) The load-carrying capacity of the pile is determined by calculating the friction components along the sides of the piles. Adding them all up gives the total load bearing capacity.

Fig. 8–7. A 96-inch diameter steel pile in fabrication yard

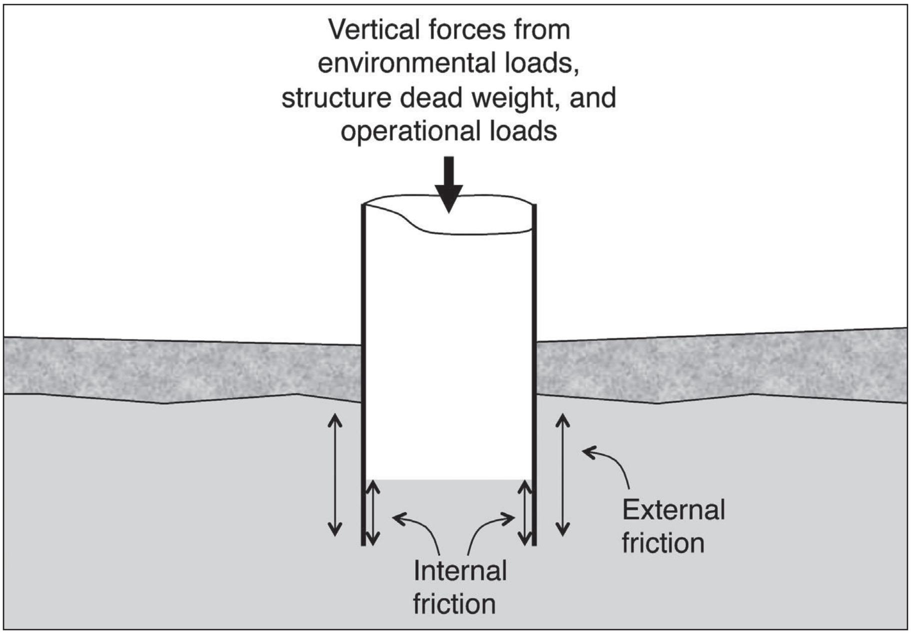


Fig. 8–8. Forces on a friction piling

From Here to There

Moving a steel jacket from the construction yard to the drill site requires a launch barge, a vessel specially suited—and sometimes specially built—for the job. During the load-out onto the barge, the platform is moved along skid ways onto the launch barge. Motive power comes from a series of hydraulic jacks pushing or winches with block and tackle pulling. The lateral push or pull force runs 5% to 10% of the total structure weight. A 3,000-ton platform requires 150 to 300 tons of jacking or winching force. The agonizingly slow load-out process typically takes up to a day—the bigger the platform, the longer the day.

As the platform moves onto the barge, the crew pumps water into some and out of other barge compartments, changing the buoyancy to accommodate the weight and position of the platform. Once the platform is properly positioned on the barge, it is elaborately welded to the barge using additional structural members. Losing a platform overboard could abruptly end an otherwise illustrious engineering career. Some platforms have been hauled as far as from a fabrication yard in Japan to the California coast.

Several seagoing towboats haul the barge/platform combination to the vicinity of the drill site. For *Bullwinkle,* a platform that weighed 40,000 tons and required a launch barge 850 feet long and 180 feet wide, three tugs pulled and two tugs followed to provide braking, if needed. (See fig. 1–16.) The capricious nature of inland waterways, and even some offshore locations, demands a careful depth survey of the route between the fabrication yard and the drill site. A loaded launch barge can draw as much as 45 feet of water. Going aground also does little for an engineer's otherwise unblemished résumé.

A concrete structure, already sitting in the deep water of a fjord because of its manner of construction, needs a few towboats to haul it to the drill site. The several hundred feet of platform that sit below the water's surface demand more towing power and braking power than needed for a launch barge. Typically, a concrete platform has to be raised some by partially deballasting to reduce the drag and to clear through shallower waters. Considering the massive size of these concrete monsters, it takes husky tugboats to tow them to location. Ten of the world's largest and most advanced tugs moved the *Troll* platform 174 miles (322 km) from its construction site to the final resting site. (See fig. 8–9.) Each vessel had bollard pulls of 150 to 200 tons and ratings of 12,000 to 16,000 horsepower. (*Bollards:* the posts to which the towlines are tied.)

Fig. 8–9. Concrete gravity structure *Troll* being towed to its North Sea installation site. (Courtesy Norske Shell.)

Installing Conventional Platforms or Compliant Towers

As the launch barge and its precious cargo near the drop site, the crew uses burning torches to remove the tie-down welds in preparation for launching the platform. The crew pumps the barge ballast around carefully to give the barge a slight nose-down tilt, then hydraulic jacks or winches on the barge move the platform slowly toward the stern, and at some point the platform begins to slide off the barge on its own. (See fig. 8–10.)

Because of their hollow cylindrical shape, the members that make up the platform structure typically displace more water volume than they weigh; that is, they provide net upward buoyancy, so the jacket floats when it leaves the launch barge, in the case shown in figure 8–11, on its side like a sunning whale. Obviously this is a carefully analyzed and designed-in attribute of each jacket to ensure that they do float as they clear the launch barge. If there is not enough natural buoyancy, additional tanks are added to ensure flotation at this stage. After the jacket is installed, those temporary tanks are removed.

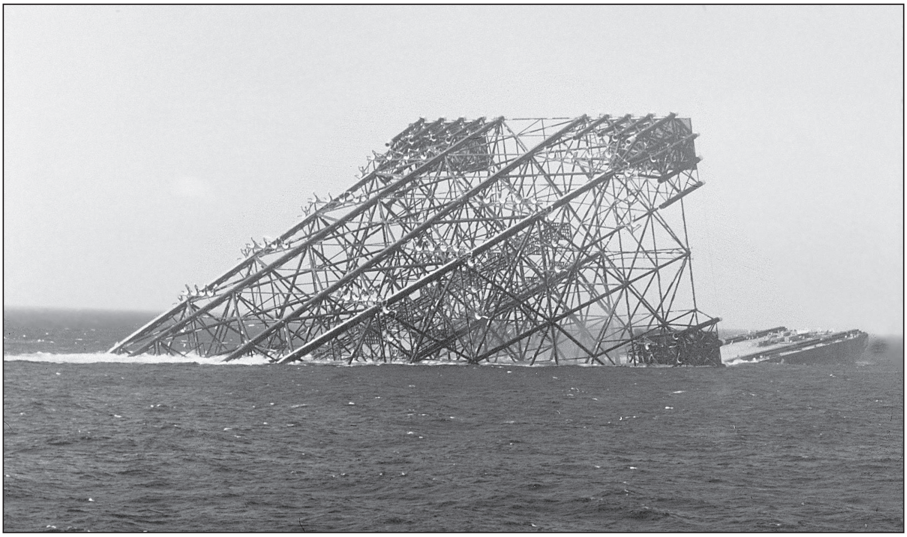


Fig. 8–10. Steel jacket launching from a barge. (Courtesy Shell E&P.)

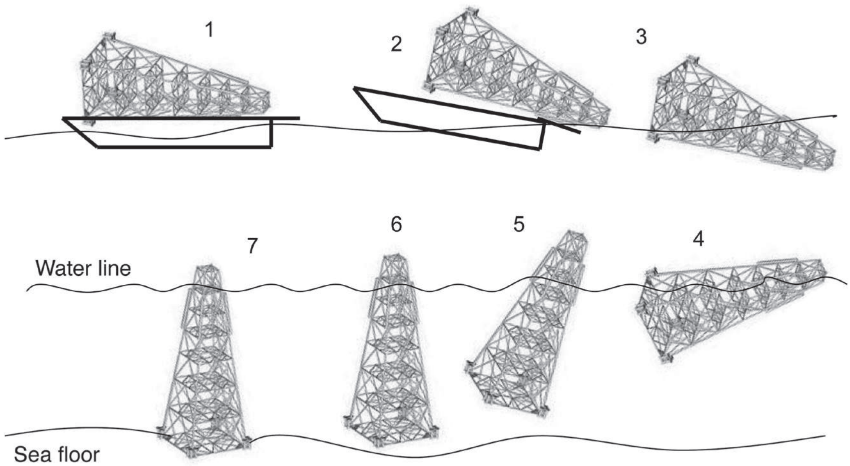


Fig. 8–11. Progression from jacket launching to settling on the bottom

In the case shown in figure 8–11, which is quite typical, the launch crew opens valves on some of the cylindrical members, allowing water to enter. If they did their calculations right, the entire structure slowly rotates to an upright position with the top of the platform poking 20 to 50 feet out of the water, enough for a few feet of clearance above the sea floor. The tugs tow the platform over the drop site, guided by satellite positioning, the remaining floodable members are filled, and the platform slowly drops into place. The progression goes from floating on the barge to self floating, uprighting, and setting down. Following the steps in figure 8–11:

1. The jacket arrives on location, and the sea fastening tie-downs are cut loose.
2. The launch barge is ballasted down at the stern. Hydraulic jacks or winches start the jacket moving on the greased skid-ways toward the stern. The stern of the barge tilts downward even more. At some point the forward component of the weight causes to jacket to move forward on its own.
3. When the center of gravity of the distributed forces passes the end of the barge, the entire jacket rotates on the tilt or rocker beams and slides into the water.

4. The jacket floats on its side.

5. Valves are opened.

6. The jacket uprights and floats several feet above the sea floor, and it is towed to its set-down point.

7. More water is added, and the jacket sets down on location.

The rocker beams on the barge stern serve to allow a smooth transfer of the jacket from the barge to the sea, without damage to either the structure or the barge. In some cases the buoyancy calculations are so accurate that the jacket will be allowed to upend itself to the vertical and then the valves opened to add water weight to set it down on the seabed.

Sometimes mud mats, large wooden or metal rugs, are placed under the bottom of the platform to ensure that it stays in place until the pilings can be driven to make a permanent connection to the sea floor.

For fixed platforms in less than 400 feet of water, the piles may be driven with surface pile drivers and long extensions to the pile being driven. In deeper water the situation changes. Here the piling is dealt with in one piece, perhaps as much as 550 feet long. This calls for cranes with heavy-lifting and long-reach capabilities. For construction in shallower water, the pile drivers are open to the air (fig. 8–12) and powered by diesel, steam, or hydraulic fluid. In deepwater construction, underwater pile drivers are totally enclosed to hold out the seawater, and are operated by hydraulic fluid. (See fig. 8–13.)

After a few piles secure each leg, the construction crew straightens the platform by ballasting and deballasting some platform segments and perhaps by having a crane hoist one side or another. The crew then permanently attaches the platform to the piles. They can either weld the piles directly to the platform (typical for shallow water structures) or attach them using cement grout, most commonly used in deepwater. (See fig. 8–14.) With the platform permanently secured by a few piles, the rest are slipped into their sleeves, driven into place, and permanently attached to the platform. That completed, the platform awaits its deck.

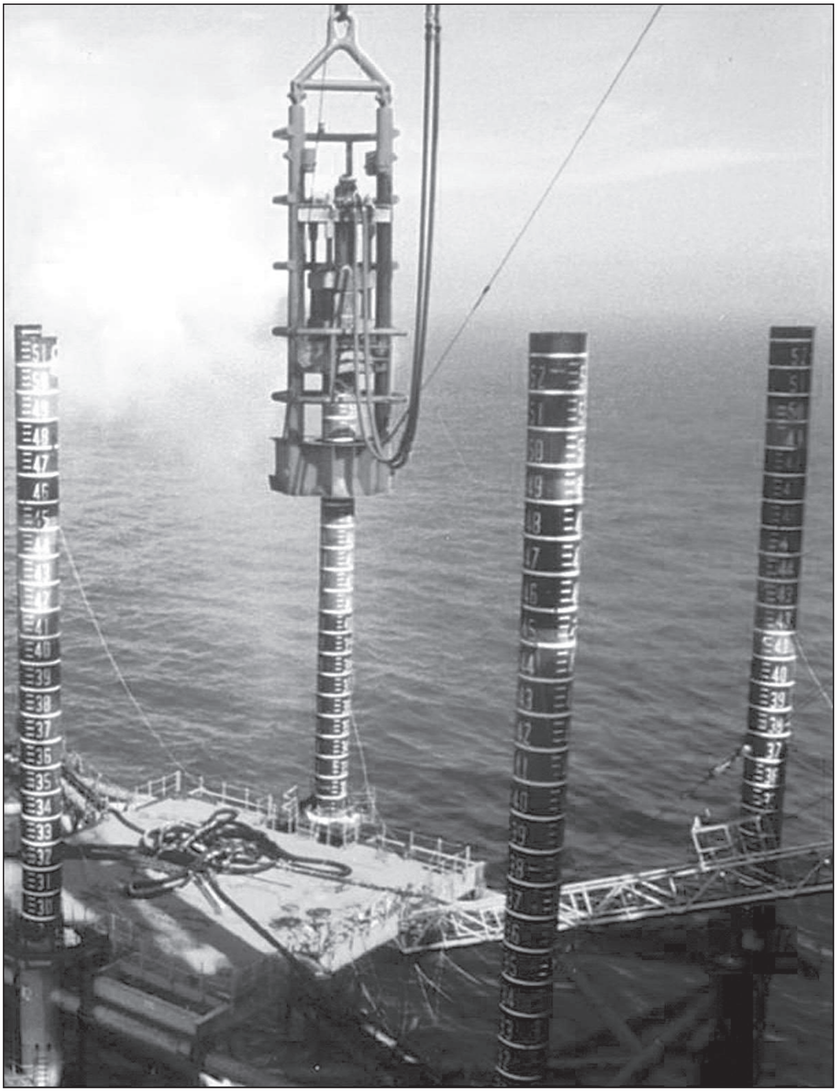


Fig. 8–12. Surface steam hammer at work. (Courtesy Heerema Marine Contractors.)

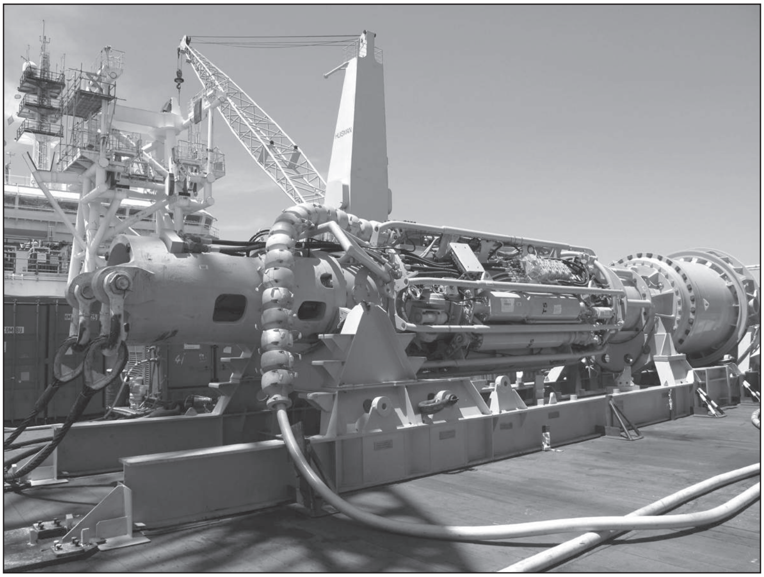


Fig. 8–13. Underwater hydraulic hammer. (Courtesy MENCK GmbH.)

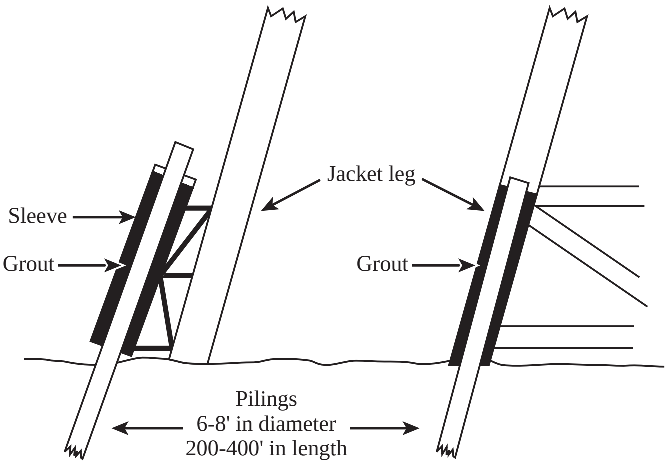


Fig. 8–14. Steel jacket connected to piling with grout

Installing Concrete Gravity Platforms

A concrete platform arrives at the drop site already in the upright position. Operators slowly increase the volume of water in the base by controlled flooding; the platform sinks down and pushes itself into the sea floor, perhaps several tens of feet, depending on the soil characteristics. The underside of the concrete base often has large structural ribs several feet deep. Seen from the inside, there is a rib extending around the perimeter, then some laterals creating cavern-like rooms. As the base contacts the sea floor, the foundation is pushed into the hard clay, much like a cookie cutter into dough. To avoid blowing out the water around the rib edges, valves on the top of the foundation can be opened to let the entrapped water out. Sometimes the water is pumped out to create downward suction force to aid in the leveling and installation.

As the huge structure is slowly and carefully lowered onto and into the sea floor, settling into the hard bottom is controlled to ensure that the base remains level and the columns vertical. Water can be added inside the structure to increase the weight; additional water can be pumped from the rib caverns to provide more downward suction forces. Once the structure has reached its required position and is within the specified tolerances for levelness, the base may be weighted with concrete or iron ore to achieve a predetermined on-bottom force. Because of the variations in bottom conditions, the detailed design for each Gravity Based Structure is different. Indeed, in some areas of the world the base penetrates very little into the sea floor. The subsoil conditions are extensively explored and the appropriate design chosen for those specific conditions. For example, the Malampaya Gravity structure in the Philippines was set down onto a bed of pre-laid rocks and gravel and then was weighted down further with iron ore. More rock was placed around the edges to control any tendency for scouring from currents.

Setting the Deck

If all goes well, the steel topsides deck for the steel platform or compliant tower arrives atop a transport barge not long after the final integrity checks of the installed platform. The same cranes used to set the platform lift the deck into place, either as a complete unit or in sections. (See fig. 8–15.) Pre-designed deck legs mate with the top of the platform. Welding them together makes the final connection.

Fig. 8–15. Saipem 7000 heavy-lift crane vessel setting a deck. (Courtesy Saipem.)

In many cases the decks come complete with drilling and production equipment. That allows the crews at the fabrication yard to make all the pipe, electrical, hydraulic, or other connections. Alternatively, the equipment arrives piecemeal, and an army of welders, fitters, laggers, instrument technicians, and other craftsmen go aboard to install, connect, and prove readiness. Preinstallation is usually much cheaper, but the availability of cranes with enough capacity to lift the extra load can limit the choices.

A concrete structure is usually transported to the site upright, so the deck installation can take place in the fjord, before transport to the drill site. Floating the deck over the concrete platform is the most common way to mate the two. In the fjord, protected from wind and waves, the concrete platform is ballasted so the top is almost at water level. One or two barges with the deck sitting on top float to a point where either the barges straddle the submerged platform or the platform straddles the single barge. By slowly ballasting the barges, the deck comes to rest on the platform, where the connections are made. Once the load transfers to the platform, the barges float away. Figure 8–16 shows the topsides for the Malampaya structure being moved via barge into place to be transferred to a pre-positioned gravity based structure.

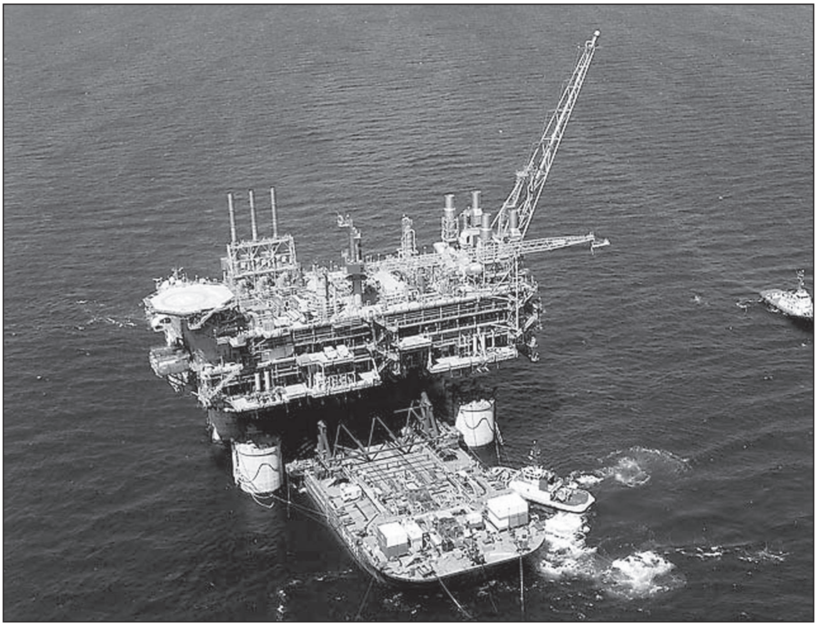


Fig. 8–16. Malampaya deck being floated in to be lowered onto the structure legs. (Courtesy Philippines Exploration BV.)

Corrosion Mechanics and Protection

Most structural alloys corrode merely from exposure to moisture in the air—they rust. Steel structures in the ocean create an excellent environment for corrosion to occur.

A design of structures in the ocean has to take into account three distinct areas of corrosion:

1. **Atmospheric area.** The area above the waterline and above the area that waves commonly splash. It is normally protected by paint or coatings.
2. **Splash zone.** The area of the platform that is alternately in and out of the water due to waves, tides, and currents. The alternate wetting and drying of the steel members can accelerate corrosion. Basic corrosion control methods, each with several variations, deal with this zone. It can be painted or coated; the wall thickness of the members can be increased to add more steel; or an additional steel plate sleeve, called a doubler plate, can be welded to the member.
3. **Immersion zone.** Below the splash zone level, the steel is left bare and the structural corrosion is controlled by a cathodic protection system. Cathodic protection (CP) controls corrosion of a metal surface by making that surface a cathode of an electrochemical cell. Galvanic action causes current to flow from a specially placed anode to the structure. These galvanic or sacrificial anodes are made in various shapes using alloys of zinc or aluminum. The anode corrodes instead of the structure. For some larger structures, galvanic anodes cannot economically deliver enough current to provide complete protection. In those cases, Impressed Current Cathodic Protection (ICCP) systems using anodes connected to an onboard DC power source are needed.

In a marine cathodic protection system, the efficiency of the node/cathode system and the resulting quality of the protection are dependent on many factors including the following:

- Water depth
- Dissolved oxygen
- Temperature
- Salinity
- pH

- Ocean currents
- Pressure from water depth
- Fouling

Each of these parameters impacts the design of the cathodic protection system, some more, some less. For example, dissolved oxygen varies considerably with water depth, with geographic location, and with the seasons. Some data (Thomason and Fischer, 1991 OTC Paper 6588) show the dissolved oxygen content at 1,300 feet of water as 8 parts per million (ppm) in the Norwegian Sea, 7 ppm in the North Atlantic, 4 ppm in the Gulf of Mexico, and 1 ppm in Southern California. Data from locations a few miles away may well have been substantially different. The point is that considerable care has to be taken to get enough data for location and over time to allow a proper design.

For most offshore systems, the cathodic protection system is designed for 20 to 40 years. Indeed, many Gulf of Mexico systems removed after 30 or more years have still been dealing quite effectively with corrosion. Figure 8–17 shows several passive anodes on a fixed steel platform.

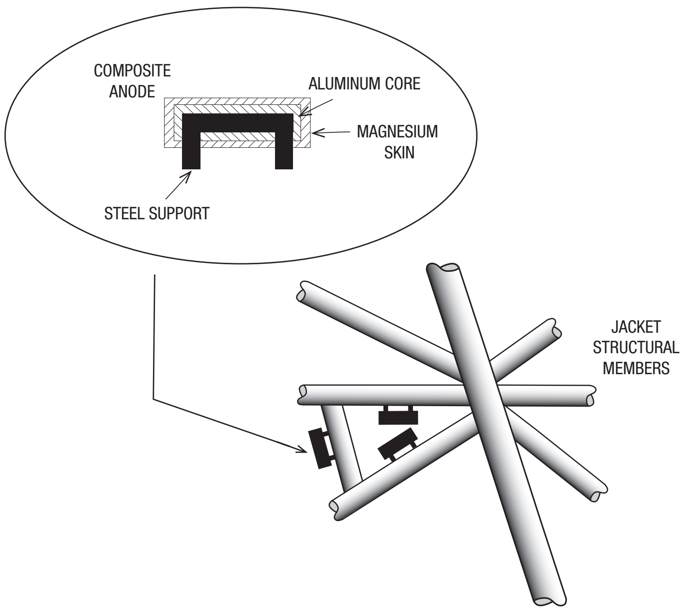


Fig. 8–17. Sacrificial aluminum anodes of a fixed platform

Setting the Pipeline Riser

Sometimes the plan calls for a platform to tie into one or more export pipelines, inbound or outbound. As a last task, the crane vessel picks up the end of each pipeline for attachment to a riser, a vertical line attached to the platform and connected to piping on the deck. There is more on this in chapter 10. At this point, the operating crews can begin to drill wells or complete the predrilled wells and start production.

Floating Production Systems 9

On such a full sea are we now afloat, And we must take the currents when it serves, Or we lose our venture.

—William Shakespeare (1564–1616)
Julius Caesar

By their nature and training, explorers look for hydrocarbons wherever, and often that can lead them to most inhospitable places. Practical development and production schemes may not always be high on their list of concerns. But drillers and production engineers continually rise to the occasion when explorers present opportunities that are continually deeper and otherwise less pleasant. Most often, they even encourage explorers to push on to the forbidding.

Once offshore operations extended beyond practical fixed platform limits, the production engineers borrowed concepts devised by the drilling engineers who had responded to the needs of the explorers with semi-submersibles and drillships as they moved out of shallow water. Thus floating production systems (plus, in many cases the subsea completions covered in the next chapter) now provide viable options in deepwater.

Floating production systems come in many sizes and shapes. (See fig. 9–1.) Some provide more functions than others. In every case, they differ from fixed systems by what holds them up—the buoyancy of displaced water, not a steel understructure. There are many variations within each generic category—but they can all be included in one of four groupings:

1. Tension leg platform (TLP)
2. Spar
3. Floating production system (FPS)
4. Floating production storage and offloading system (FPSO)

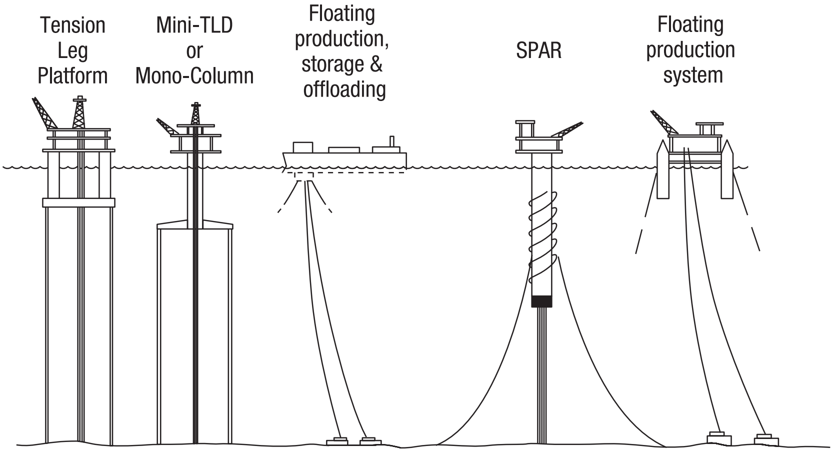


Fig. 9–1. Floating system options for deepwater projects

These floating systems have many common elements (See figs. 9–2, 9–3, 9–4, and 9–5):

- **Hull.** The structure that provides buoyancy to support the deck, topsides, mooring loads, and riser loads. On TLPs and FPSs this includes the columns and pontoons. For spars, the hull is essentially the central column. FPSOs have a ship's hull or a cylindrical shape.
- **Column.** On TLPs and FPSs, large members, rectangular or round, support the topsides deck and connect to the pontoons. On spars, a central column serves as the hull.

- **Pontoon.** TLPs and FPSs have large structural members called pontoons that connect the bottom of the columns together to form part of the hull. The pontoons and columns provide the necessary displacement to carry the vertical loads on the system.
- **Deck.** The structure on top of the hull that provides support for the topsides.
- **Topsides.** The decks and all of the production, drilling, and ancillary equipment plus the quarters for the crew are collectively known as the topsides.
- **Piles.** The steel cylinders driven, drilled, or forced by suction into the sea floor are used as anchors for the mooring system.
- **Risers.** The steel pipe that connects the subsea wellhead and blowout preventer to the deck of the floating host during well construction and servicing operations is called a drilling riser. For subsea wells that are drilled directly under the floating host, once production is established, the production riser is a steel casing or pipe that is used to connect the subsea wellhead to the surface Christmas tree. The production risers serve a very similar function as conductors do on fixed platforms. For subsea wells that transport their production via flow lines to the host, the section of line from the sea floor up to the floating platform is called a flowline riser. Processed oil and gas is transported *down* through export risers to pipelines. Chapter 12 has more detail on risers.
- **Mooring.** All the equipment, including wire rope, polyester line, chain, and anchors, that holds the floating system at the desired location. In the case of the TLP, they are held in place by steel pipe tendons, with a very small footprint on the sea floor. (See fig. 9–6.) In other cases, the lateral mooring spread can take up miles of real estate. (See fig. 9–7.)

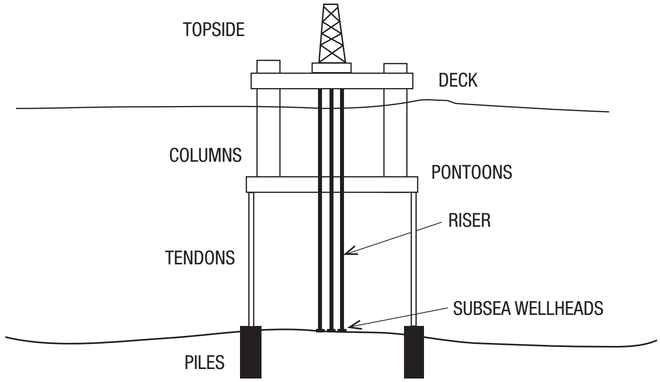


Fig. 9–2. Hull, topsides, mooring (tendons), and risers for TLP

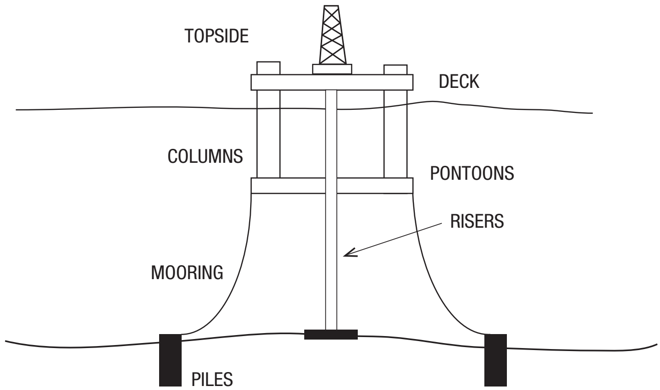


Fig. 9–3. Hull, topsides, mooring, and risers for FPS

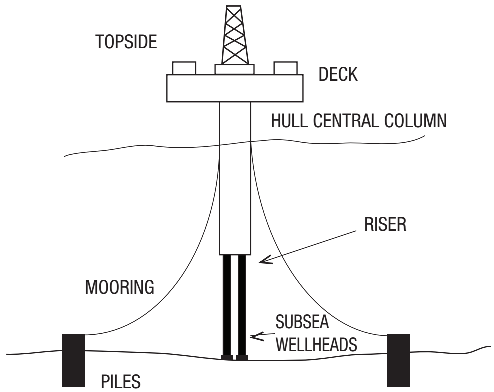


Fig. 9–4. Hull, topsides, mooring, and risers for a spar

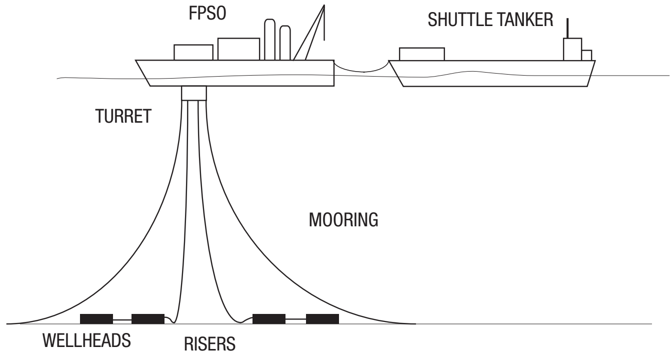


Fig. 9–5. Hull, topsides, mooring, and risers for an FPSO

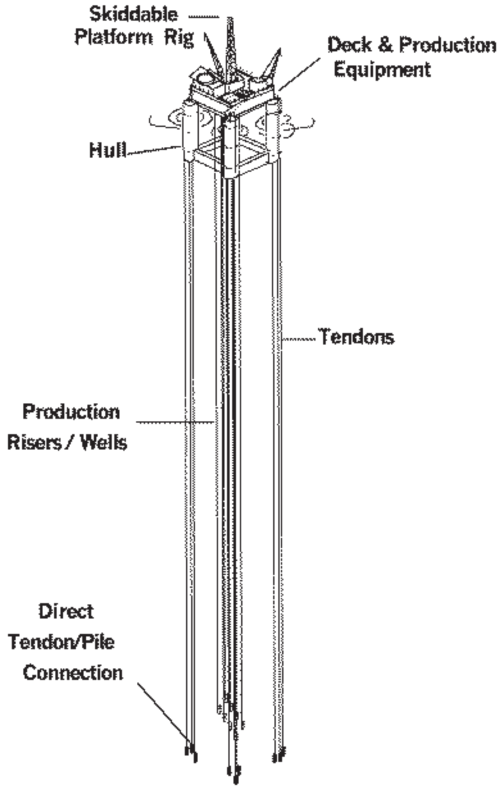


Fig. 9–6. TLP for the *Brutus* field in the Gulf of Mexico. (Courtesy Shell E&P.)

Fig. 9–7. A rendition of the TLP Auger, sometimes called "the TLP that ate New Orleans." (Courtesy Shell E&P.)

Tension Leg Platforms

The semi-submersible, used for years only as a drilling platform, begat TLPs. By similar design, the buoyancy of a TLP comes from a combination of pontoons and columns. (See figs. 9–2 and 9–6.) Vertical *tendons* from each corner of the platform to the sea floor foundation piling hold the TLP down in the water. Vertical risers connected to the subsea wellheads directly below the TLP bring oil and gas to dry trees on the deck.

The vertical loads on a TLP are carried entirely by the buoyancy available in the hull. Thus, at all times the dead and live loads (see chapter 8 for a discussion on dead and live loads) and tendon tensions of the system are in balance with the displacement. The upward force on the tendons is achieved by holding the TLP at a draft below the displacement that would come from the dead and live loads only, thereby keeping them in constant tension. As a consequence, rigid body vertical (heave) motions are eliminated. The only vertical motions come from the elastic stretch in the tendon pipes themselves, which is very minor. Lateral motions do occur, of course, and this causes the TLP to set down in the water as it moves laterally from its centerline position. The additional buoyancy caused by that "set-down" results in additional upward force that helps to push the TLP back toward its centerline.

Tendon tensions are set within a predetermined design and operating range. If the operations require a change in the live loads, for example adding or subtracting a large supply of drill pipe, the tension in the tendons is maintained within that range by adding or subtracting ballast, such as pumping water into or out of the TLP hull. The vertical tendons are steel tubes, generally 24 to 32 inches in diameter with wall thicknesses of 1 to 2 inches.

The typical uses of TLPs in oil and gas developments are as surface wellhead platforms (dry tree units), as production platforms, and as full drilling and production platforms. They are often selected over other types of floating systems because of their superior motion performance in severe environmental conditions and the small footprint they require on the sea floor. The advantage of a small sea floor footprint is that future drilling, seismic, and construction opportunities are not hindered by extensive mooring systems as is needed for FPSs, FPSOs, and spars. TLPs provide stable work platforms in relatively deep water with seas and wind from any direction. Under normal conditions, TLP motions are very limited and may feel much like being on a fixed platform. They are economical options in water depths as shallow as about 1,000 feet, and depending on the local meteorological and oceanographic (metocean) conditions and the desired payload, TLPs can be attractive in as much as 5,000 feet of water. As the technology develops for more cost-effective materials for tendons, they may be viable in even deeper water.

Conventional TLP hulls are composed of columns and pontoons in a four-sided shape. Example dimensions for medium size TLP columns are 75 feet (25 meters) or so in diameter and 170 feet (52 meters) in height with pontoons on the order of 30 feet (9 meters) deep and 40 feet (12 meters) wide. The columns and pontoons may be either circular or rectangular in shape.

Installation of a conventional TLP

While a TLP is being constructed at an onshore construction yard, a floating drilling rig is often busily drilling several of its wells at the offshore location. The drilling operation leaves behind subsea wellhead assemblies, which are each later connected to the production risers.

TLP hulls are often built in shipyards that have experience in fabrication of vessels using large steel plates and have large lifting capacities, dry docks, quayside facilities, etc. However, some have been built in large fabrication yards and then are skidded onto barges or heavy lift ships to be transported to another location.

TLP hulls are fabricated separately from the topsides, although both may be done in the same yard. There are a variety of ways to mate the hull and the topsides:

- If the hull and deck/topsides have been built in the same yard, they can be mated and integrated before the entire system is transported to the commissioning site.
- Often the hull and topsides are built in different yards in different countries. In that case, the two sections—hull and topsides—are brought to a common integration point and the mating occurs there.
- A possible but seldom-used method is to install the hull and then set the topsides at sea with heavy-lift marine cranes.
- The topsides can be set onto the hull using a variety of methods—heavy lift cranes, a special truss system lifting device that floats in over the hull and installs a completely integrated deck (fig. 9–8), or onshore lifting devices, such as stiff legs (fig. 9–9) or strand jacks.

The integrated and commissioned hull/topsides system is then towed from the integration site to the installation site for connection to the tendons and final installation operations.

Fig. 9–8. A truss lift system that floats over a platform to set a topsides. (Courtesy Versabar.)

Fig. 9–9. Integrating topsides with hull using an onshore special lifting device. (Courtesy Shell E&P.)

Some weeks or months prior to the arrival of the commissioned hull/topsides system at the installation site, the piling that will hold the completed TLP in place will have been installed using heavy lift marine cranes and the underwater pile drivers discussed in chapter 8. The tendons are then installed in segments on the order of 200 feet in length, with mechanical connectors between each section. (Welding the sections together would take way too much time.)

There are two ways to mate the tendon to pile and tendon to hull connections—the co-installation and the pre-installation methods.

- Co-installed tendons are installed in long sections, about 200 feet, using the cranes on a semi-submersible crane vessel (SSCV). The tendons are installed one by one and hung off from each corner of the hull while the TLP is held laterally in place with tugs and with the SSCV. After four tendons have been done this way, they are, one by one, connected to the sea floor piling via a predesigned and prebuilt mechanical connector, with aid of a remotely operated vehicle (ROV) to help guide the tendon into the pile. This makes the TLP "storm safe" for relatively heavy sea conditions. Once a tendon on each corner is connected, this process is repeated until all tendons, typically twelve to sixteen, are connected. Then the TLP is deballasted, causing upward force to put the tendons into tension, as much as 2,000 tons per tendon. This ensures that the tendon legs never go slack under any environmental or operating conditions.
- In the pre-installation method, the tendons are inserted into the sea floor piling some days or weeks before the hull/topsides arrive on location. The tendons are kept upright by large buoyancy tanks (temporary buoyancy modules or TBMs), which maintain a constant uplift load and keep them in position for the TLP to be connected. The hull is then brought over the tendon grouping and lowered by flooding several compartments until the top of the tendons slide through the predesigned and prebuilt connection slots in the hull. The final connection is via hydraulic jack and mechanical latches. Figure 9–10 shows a schematic of a pre-installed tendon being connected to the TLP hull. When all of the tendons at all four corners have been installed, water is

pumped out of the hull, causing a natural uplifting force of considerable magnitude and putting the tendon legs into tension. The TBMs are then removed.

In both cases, the tendons must be fabricated to exceptionally high material and geometry specifications to ensure a long-lived facility. The end results are very stable platforms that have limited lateral movement and usually insignificant vertical motions. In the extreme case for a hurricane design storm, a Gulf of Mexico TLP will move from its center point by as much as 8% of the water depth. For example, Shell's *Ursa* TLP in 4,000 feet (1,220 meters) of water could move as much as 320 feet (98 meters) laterally during a design level hurricane. At that much offset, the hull would be pulled down in the water about 12 feet (3.5 meters). This is acceptable and will not cause damage, as the deck is set at a high enough level to avoid waves hitting lower deck equipment. The lateral movement of TLPs in other areas of the world depends on the wind and wave conditions. For West Africa, as an example, the lateral motions are substantially less than the Gulf of Mexico's 8%.

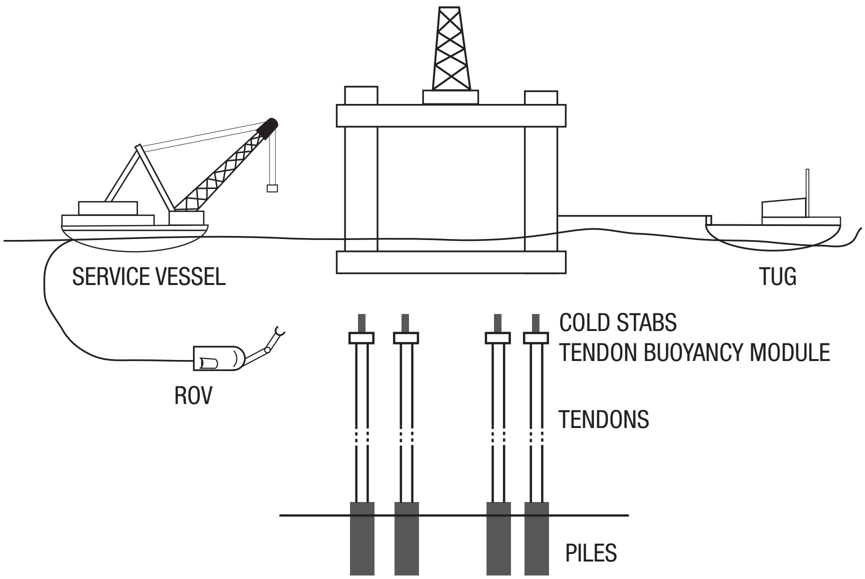


Fig. 9–10. TLP hull being connected to pre-installed tendons

Drill pipe can accommodate the lateral movement that comes from moderate winds or ocean current changes. In heavy seas that push the TLP towards its limit, no drilling takes place anyway.

With the TLP secure, the drilling rig onboard has to connect (or reenter) the predrilled wells by attaching a riser (or connector pipe) to the subsea wellheads, one at a time. Since the TLP is not directly above each well, one method is to lower a small structural frame on wirelines and connect it to the subsea wellhead. An ROV guides the frame into place and manipulates the locking device to secure it. The riser (or connector pipe) then uses the wirelines as a guide to reach the wellhead, where a remote operated vehicle assists in the mechanical connection.

Without being directly above the wellhead, how does the riser achieve a square, tight fit? As a frame of reference, imagine a 10-foot-long steel rod, say ⅛ inch in diameter, hanging from the ceiling. Moving the bottom of the rod sideways 10 inches is the same scale as the 240-foot offset for the tendons and risers in 3,000 feet during a design storm. Bending the 10-foot rod to make a connection at the bottom deforms its shape imperceptibly. Not easy, but doable. Even better, pushing the bottom of the rod only a couple of inches is analogous to the maneuvering the ROV deals with during the alignment process.

Dry trees on the deck of the TLP control the flow of oil and gas production coming up through the conductor pipes. However, like other floating systems TLPs can receive production from risers connected to remote subsea wet tree completions. Most TLPs have subsea riser baskets, which are structural frames than can hold the top end of risers coming from subsea completions.

Installation of monocolumn and extended-leg TLPs

In shallower water or for smaller deposits in deepwater, and where no more drilling is planned, some companies use smaller variations of the TLP. These proprietary versions are named:

- Mini-TLP, a monocolumn TLP, or sometimes a Sea Star
- Extended leg TLP (ETLP)

The names monocolumn and Sea Star (a proprietary label) come from the underwater configuration of the flotation tank, a large central cylinder with three star-like arms extending from the bottom. (See fig. 9–11.) The cylinder measures about 60 feet in diameter and 130 feet in height. The arms reach out another 18 feet.

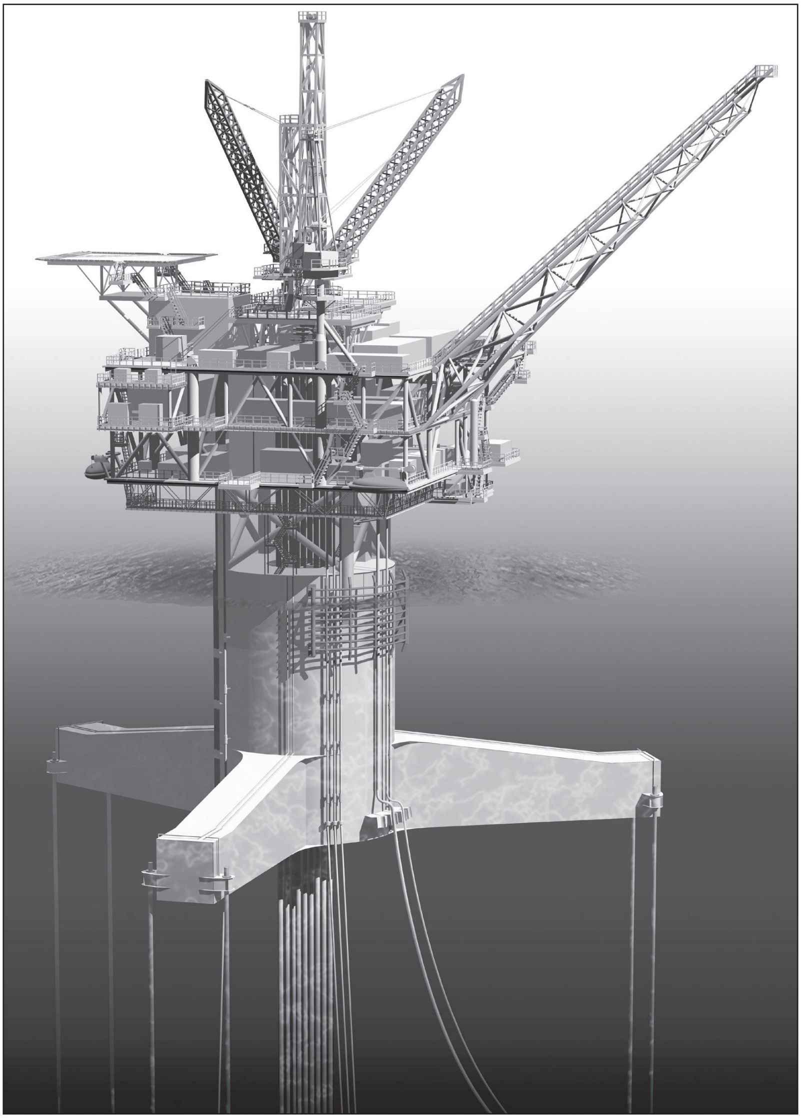


Fig. 9–11. TotalFinaElf's *Matterhorn Sea Star*, a monocolumn TLP. (Courtesy Atlantia Offshore.)

As with other TLPs, tendons secure the substructure to the sea floor, in this case two from each arm. The mooring system, risers, and topsides are similar to those of any other TLP, except for more modest sizes. The absence of drilling equipment onboard helps lower the weight of the topsides and allows this scaled down version.

The extended leg TLP (ETLP—a proprietary label) keeps the four corner columns, but adds an extension to the pontoon sections at each column. The ETLPs, smaller than the conventional TLPs (CTLP), can still have all the capabilities, albeit at a smaller scale than the CTLPs. That is, they can be used for the following:

- Full drilling, production, and quarters platforms
- Wellhead platforms
- Tender-assisted drilling
- Either dry-tree or wet-tree production

Floating Production Storage and Offloading

From 400 yards away, most FPSOs are indistinguishable from oil tankers. In fact, while many FPSOs are built from scratch, the rest are oil tankers converted to receive, process, and store production from subsea wells. FPSOs do not provide a platform for drilling wells or maintaining them. They do not store natural gas, but if gas comes along with the oil, facilities onboard an FPSO separate it. If there are substantial volumes, they are sent back down a riser for reinjection in the producing reservoir or some other nearby subsurface home.

Moored in place by various systems, FPSOs are effective development solutions for both deepwater and ultra-deepwater fields. From multiple subsea wells FPSOs receive oil through in-field flowlines and risers and often through a turret-and-swivel system discussed later. (See fig. 9–12.)

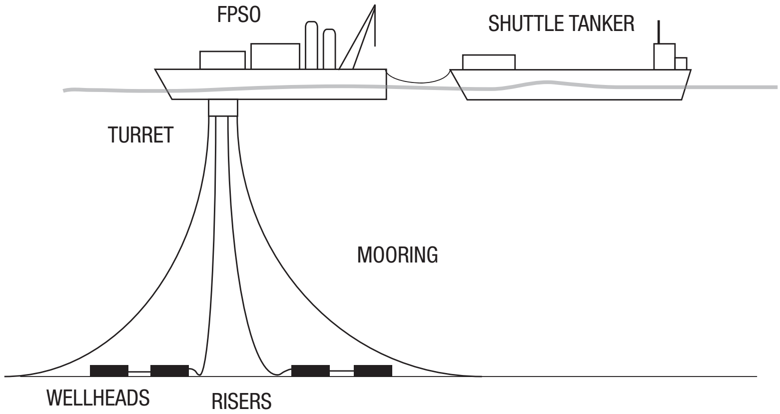


Fig. 9–12. Oil from the well to FPSO to a shuttle tanker

Shell installed the first FPSO, a tanker conversion, in 1977 to produce from the small Castellon field in the Mediterranean Sea. Since then the industry has found scores of remote or hostile environments that call for the FPSO design:

- At sea where no pipeline infrastructure exists
- Where weather is no friend, such as offshore Newfoundland or the northern part of the North Sea
- Close-to-shore locations that have inadequate infrastructure or market conditions or local conditions that may occasionally discourage intimate personal contact
- Where the oil accumulation is too small to warrant a platform. (See fig. 9–13.)

As an FPSO sits on station, wind and sea changes can make the hull want to weathervane, that is, turn into the wind like ducks on a pond on a breezy day. As it does, the risers connected to the wellheads, plus the electrical and hydraulic conduits, could twist into a Gordian knot. Two approaches deal with this problem, the cheaper way and the better way, respectively:

- Spread-mooring systems permanently anchor the vessel in one orientation.

- A central weathervane mooring system allows the vessel to rotate freely to best respond to weather conditions.

Fig. 9–13. The FPSO *Anasuria* in the North Sea. (Courtesy Shell International.)

In areas of consistent mild weather, the FPSO moors, fore and aft, into the predominant wind. On occasion the vessel may experience quartering or broadsides waves, sometimes causing the crew to shut down operations. Figure 9–14 shows the *Bonga* FPSO offshore Nigeria that is permanently "spread moored" with eight mooring lines. The operator has taken advantage of the wind and wave conditions offshore West Africa—they are relatively mild, consistently from the same direction, and predictable. The minimal downtime caused by ship motion in nonroutine waves is a good trade off to save the expense of a weathervane system.

In harsher environments, the more expensive FPSOs have a mooring system that can accommodate weathervaning. Mooring lines attach to a revolving turret fitted to the hull of the FPSO. As the wind shifts and the wave action follows, the FPSO turns into them. The turret might be built into the hull or cantilevered off the bow or stern. (See figs. 9–15 and 9–16.) Either way, the turret remains at a permanent compass setting as the FPSO rotates about it.

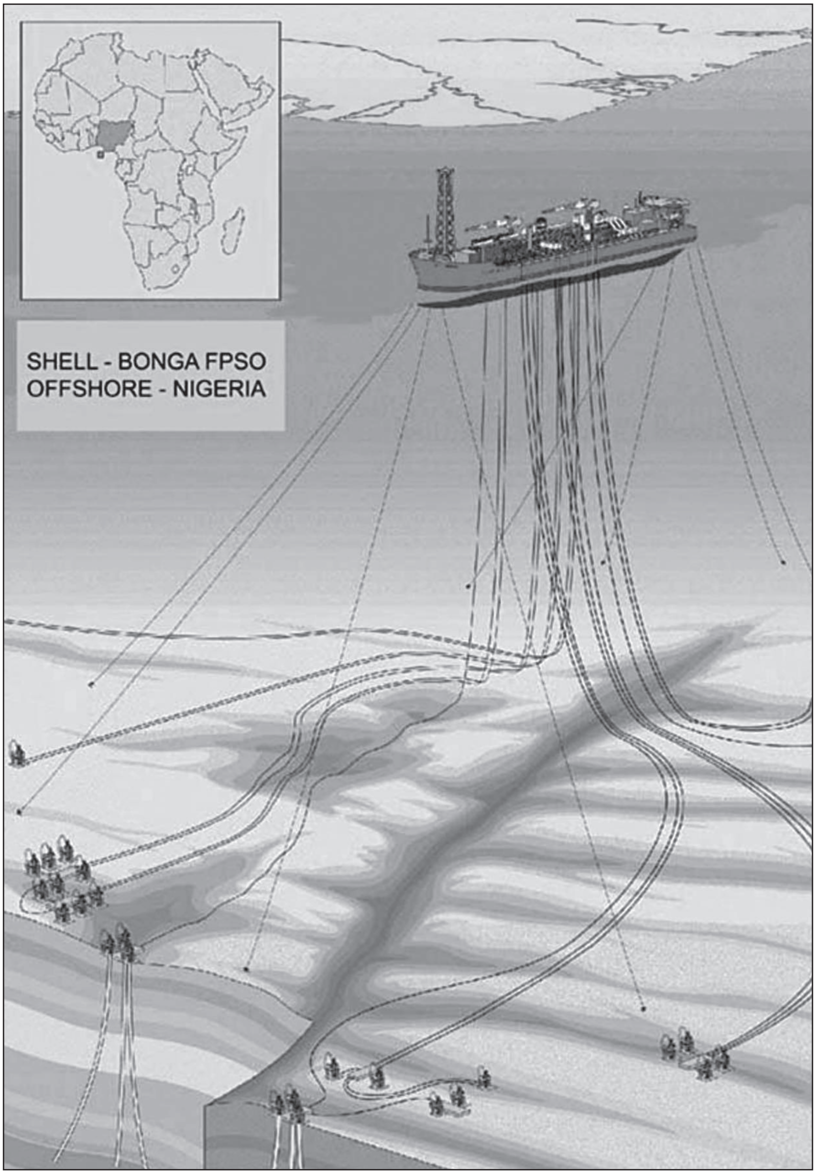


Fig. 9–14. *Bonga* FPSO mooring spread. (Courtesy Shell International.)

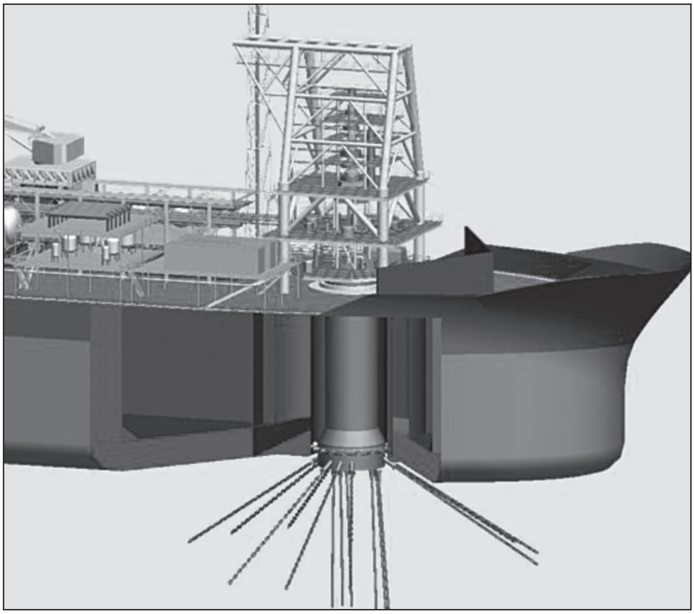


Fig. 9–15. Weathervane/internal turret/swivel mooring system. (Courtesy SBM Offshore.)

Fig. 9–16. Weathervane, external turret, and swivel system. (Courtesy SBM Offshore.)

The turret also serves as the connecting point between the subsea systems and the topsides production equipment. Everything between the seabed and the FPSO is attached to, or through, the turret—production risers; export risers; gas reinjection risers; hydraulic, pneumatic, chemical, and electrical lines to the subsea wells; as well as the mooring lines.

Turrets contain a swivel stack, a series of fluid flow and electronic continuity paths that connect the seaside lines with the topsides. As the FPSO swings around the turret, the swivels redirect fluid flows to new paths, inbound or outbound. Other swivels in the stack handle pneumatics, hydraulics, and electrical signals to and from the subsea systems. Figure 9–17 shows the internal workings of a swivel. In some designs, the FPSO can disengage from the seabed (after shutting in the production at the wellheads) to deal with inordinately rough seas or other circumstances that might worry the ship's captain, like an approaching iceberg. A spider buoy, the disconnectable segment of the turret with the mooring, the riser, and the other connections to the subsea apparatus, drops and submerges to a predesignated depth as the vessel exits the scene.

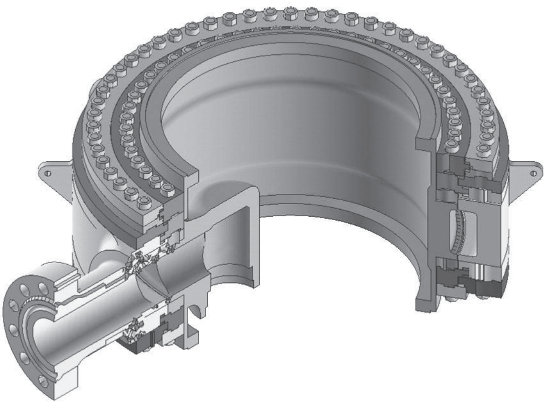


Fig. 9–17. Swivel for fluid flow; the outer ring is attached to the FPSO process piping; the inner core is connected to the turret. (Courtesy SBM Offshore.)

The full turret aboard PetroCanada's FPSO *Terra Nova* weighs more than 4,400 tons and is 230 feet high. The turret assembly includes a spider buoy, 65 feet in diameter and 1,400 tons, with connections for nine mooring lines and nineteen risers. On disconnect, which takes only fifteen minutes, the mooring lines, risers, and conduits remain tethered to the spider buoy, until the FPSO returns and fishes it out of the water, reconnects, purges the lines, and restarts operations.

After the oil moves from the reservoir to the FPSO via the turret, it goes through the processing equipment and then to the storage compartments. The fifteen storage tanks on the *Bonga* FPSO can hold two million barrels of oil. Like all new oil tanker construction, the *Bonga* FPSO has a double hull. The oil storage sits in the inner hull, separated by air space from the outer hull. That reduces the risk of an oil spill should an accident pierce the outer hull.

Shuttle tankers periodically must relieve the FPSO of its growing cargo. Even FPSOs that can store up to two million barrels onboard may still need a shuttle tanker visit every week or so because of high production rates.

Mating an FPSO to the shuttle tanker to transfer crude oil calls for setting up in one of several positions:

- The shuttle tanker can connect aft of the FPSO via a mooring hawser and offloading hose. The hawser, a few hundred feet of ordinary marine rope, ties the shuttle tanker to the stern of the FPSO and the two vessels weathervane together about the turret. (See fig. 9–16.)
- The shuttle tanker can moor at a buoy a few hundred yards off the FPSO. Flexible lines connect the FPSO through its turret to the shuttle buoy and then to the shuttle tanker.
- Some shuttle tankers have dynamic positioning, which allows them to sidle up to the FPSO and use thrusters fore, aft, and on the sides to stay safely on station, eliminating the need for an elaborate buoy system. The shuttle tanker drags flexible loading lines from the FPSO for the transfer.

Oil then flows down a 20-inch (or so) offloading hose, giving a turnaround schedule for the shuttle tanker of about one day.

Cylindrical FPSOs

A novel cylindrical FPSO has been developed by Sevan. The cylindrical shape allows it to be moored without regard to wave directionality, thereby avoiding the need for expensive turret and swivel systems. Figure 9–18 shows the Sevan *Piranema,* installed in 2007 by Petrobras on the Piranema field in Brazil. It is capable of deployment in 3,000 to 5,000 feet of water and can store up to 300,000 barrels of oil.

Fig. 9–18. Sevan's *Piranema* circular FPSO. (Courtesy Petrobras.)

Floating Drilling Production Storage and Offloading

The concept of an FDPSO vessel was realized in 2009 when a subsidiary of Murphy Oil installed *Azurite* offshore the Congo. (See fig. 9–19.) The vessel is spread moored—taking advantage of the rather benign wind and wave conditions in West Africa—and does the drilling through a moon pool. During the drilling phase the FDPSO is moved laterally from well site to well site by using its own spread moor system. In addition to the drilling capability, *Azurite* can process 40,000 barrels of oil per day or more, has storage for 1,400,000 barrels, and can offload up to 150,000 barrels per hour.

Fig. 9–19. The first FDPSO, *Azurite.* (Courtesy Prosafe Production.)

Floating Storage and Offloading Units

This specialty vessel stores crude from a production platform, fixed or floating, where no viable alternatives for pumping oil via pipeline exist. FSOs almost always had a former life as an oil tanker and generally have little or no treating facilities onboard. As with the FPSO, shuttle tankers visit periodically to haul the produced oil to market.

Floating Production System

In theory, an FPS can have a ship shape or look like a TLP, with pontoons and columns providing buoyancy. In reality, almost all are in fact the column and pontoon type. Either way, the FPS stays moored on station to receive and process oil and gas from subsea wet trees, often from several fields. After processing, the oil and gas can move ashore via export risers, or the gas can go into reinjection and the oil to an FSO.

At a typical operation, for example the Shell-BP Na Kika project in the Gulf of Mexico, the FPS is designed to handle six oil and gas fields, several miles away. Production arrives at the FPS from subsea completions through flexible and catenary risers (more on this in chapter 10) and goes through treating and processing before it leaves via export risers towards shore. The FPS provides a home for the subsea well controls that are connected via electrical and hydraulic umbilicals.

Petrobras led the industry up the FPS learning curve in the 1990s. They developed most of their deepwater fields with subsea wellheads, using FPSs as nodes on a gathering system and subsequently pumping the oil and gas onshore or the oil to a nearby FSO.

Spars

Even though the name *spar* comes from the nautical term for booms, masts, and other poles on a sailboat, spars exhibit the most graceless profile of the floating systems. An elongated cylindrical structure, up to 700 feet in length and 80 to 150 feet in diameter, the spar floats like an iceberg—it has just enough freeboard to allow a dry deck on top. (See fig. 9–20.) Additionally, the enclosed cylinder acts as protection for risers and equipment, making spars a good choice for deepwater developments.

Atop the spar hull sits the topsides, which can be comprised of drilling equipment, production facilities, and living quarters. Drilling is performed from the topsides through the hollow-cylinder hull alongside import/export and production risers. Wells connect to dry trees on the platform by risers, also coming through this core. Risers from subsea systems and export risers also pass through the center.

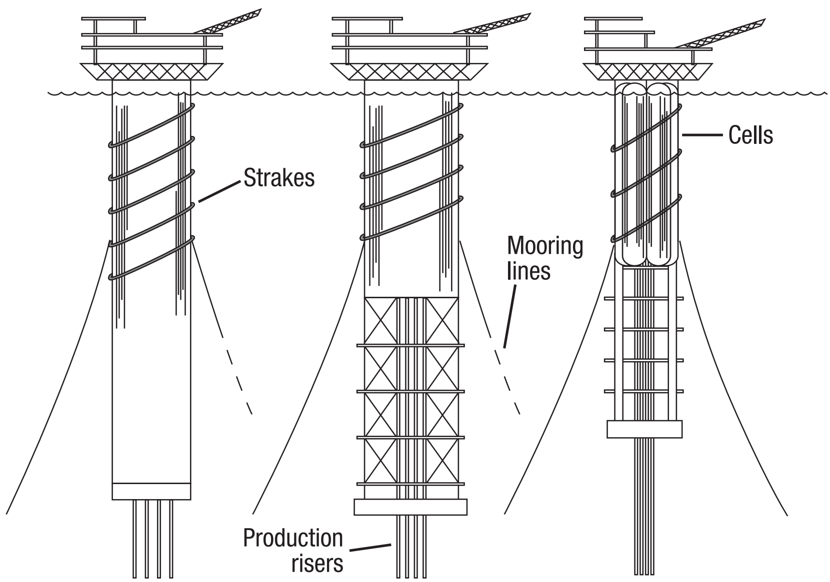


Fig. 9–20. Three spar options—conventional, truss, and cell

The mooring system uses steel wire or polyester rope connected to chain on the bottom. The polyester has near neutral buoyancy in water and adds little to no weight to the spar, eliminating having to build an even bigger cylinder. Because of its large underwater profile, the huge mass provides a stable platform with very little vertical motion. To ensure that the center of gravity remains well below the center of buoyancy (the principle that keeps the spar from flipping), the bottom of the spar usually has added ballast of some heavier-than-water material like magnetite (iron ore). The unique design of the spar, with the center of gravity located below the center of buoyancy, ensures that the facility will not topple even in heavy weather-induced catastrophes or if the moorings are not connected.

Because of the large underwater profile, spars are vulnerable not only to currents but also to the vortex eddies that can cause vibrations. The characteristic *strakes*, fins that spiral down the cylinder (apparent in figure 9–21), shed eddies from these ocean currents. The strakes add even more profile and cause increased lateral forces during high waves and currents, which calls for additional mooring capacity.

Spars have evolved through several generations of design including the original spar design, truss spars, and cell spars. The original design was created in the mid 1990s for the Gulf of Mexico consisting of a single cylindrical hull.

Fig. 9–21. The *Genesis* spar en route to the well site. Note the spiral strakes. (Courtesy Chevron.)

The next rendition, the truss spar, has three sections: a shortened "tin can" section; below that truss frame (saving weight); and below that a keel or ballast section filled with magnetite. The truss section has several large, horizontal, flat plates that provide damping of vertical movement due to wave action. Like the original, the cylindrical tank provides the buoyancy for the structure and contains variable ballast compartments.

The third generation, the cell spar, is a scaled down version of the large truss spar and is suitable for smaller, economically challenged fields. The design takes advantage of the economies of mass production. A cell, a bundle of tubes that looks like six giant hot dogs clustered around a seventh, makes up the flotation section extending below the decks. This concept uses more easily fabricated pressure vessels, with each of the separate cylinders being about 20 feet in diameter and 400 to 500 feet long. Structural steel holds the package together, extends down to the ballast section, and can include heave plates.

Spars do not, as a rule, have significant oil storage capabilities. Ironically, the most notorious, the *Brent* spar had a useful life as a storage vessel until the *Brent* platform in the North Sea gained full access to an oil export system. The *Brent* spar disposal saga beginning in 1995 became an epoch lesson in business/societal relations.

Construction

Ship-shaped hulls

FPSOs, FSOs, and the ship-shaped FPSs present no inordinate technological challenges to shipyards around the world, with the exception of the turret systems. Consequently, turrets are usually built by specialty constructors and moved to the shipyards for installation.

Like all ship-shaped hulls nowadays, construction takes place in a dry dock on blocks with the usual list of craftsmen—steelworkers, welders, pipefitters, laggers, and electricians. When the hull reaches satisfactory integrity, the dry dock is flooded and the hull is floated to a dockside. Equipment installation and outfitting continues there, especially the turret or special anchor points and winches for a mooring system.

Caisson and pontoon hulls

TLP and FPS hulls look much alike, but the mooring details differ. Both have large volume pontoons and columns (or caissons) that provide buoyancy to carry the deck, riser, and mooring line loads.

Many FPS hulls are built in construction yards rather than shipyards, avoiding the need for expensive dry docks. The physical shape of the finished product allows the steel work and assembly to take place on a flat spot in the yard. These behemoths use thousands of tons of steel and require several hundred craftsmen for months. The Shell *Ursa* TLP, built in Italy (fig. 9–22) and installed in the Gulf of Mexico in 3,800 feet of water, has four 85-foot diameter columns, each 177 feet tall, connected by four ring pontoons, each 38 feet wide and 29 feet deep. The hull alone weighs 28,000 tons. Total steel, including the deck, hull tendons, and foundation piling adds up to 63,000 tons. Large mobile cranes handle the pieces as the overall structure comes together.

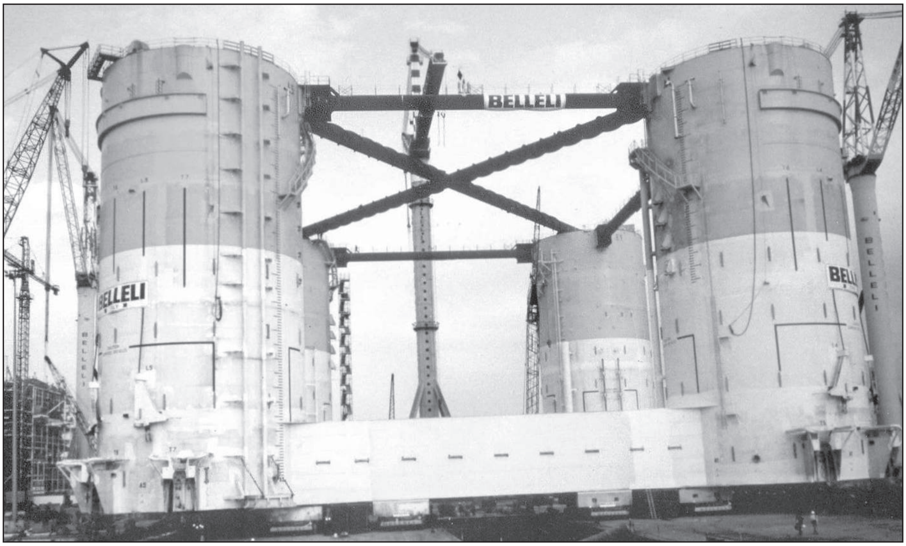


Fig. 9–22. The TLP *Ursa* hull under construction at an Italian yard. (Courtesy Shell Oil Company.)

Spars

Construction of a spar requires similar yard facilities to the TLP and FPS hulls. The design of the flotation cylinder requires internal stiffening pieces to accommodate the hydrostatic forces from the surrounding water and to carry the deck and mooring loads.

The spars are built in blocks that can be handled by the yard cranes and transporters. These blocks are then sequentially welded together to form the finished hull. (See fig. 9–23.)

Spars are massive structures. The ChevronTexaco *Genesis* hull is 122 feet in diameter and 705 feet deep, and used 26,600 tons of steel. It was fabricated in two sections in Finland and then carried to a Gulf of Mexico yard on a large lift vessel, where they were offloaded. Then the two pieces were welded together to form the large hull in figure 9–21. The *Genesis* hull incorporates a center well bay that is 58 by 58 feet and accommodates twenty wells.

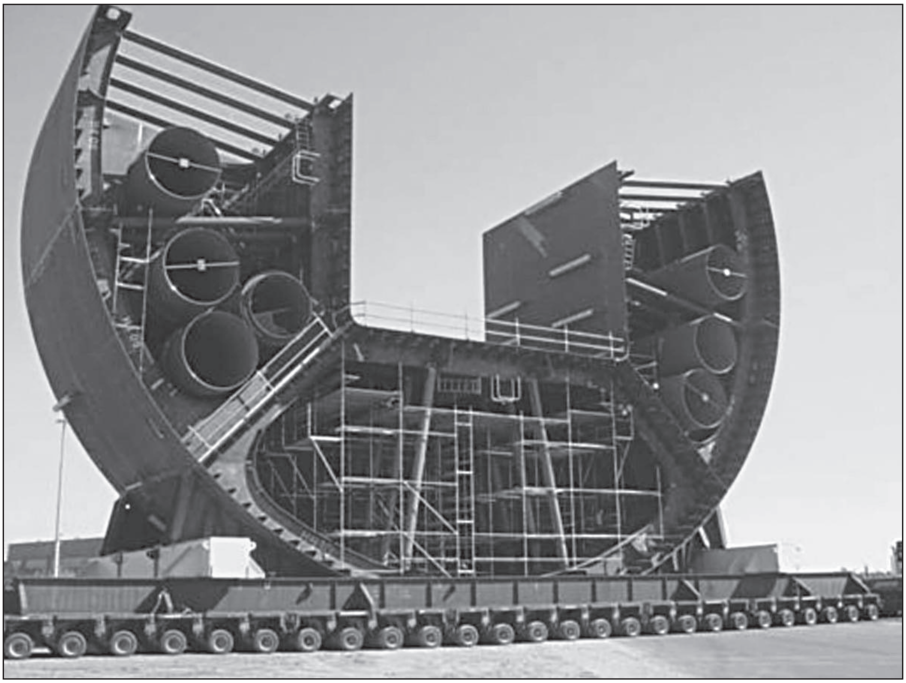


Fig. 9–23. Spar blocks being put together in a Finnish yard. (Courtesy Jack Kenny.)

The Shell *Perdido* spar is operating in 7,817 feet of water in the Gulf of Mexico. The original design of this truss spar had six slots for direct vertical access to twenty-two wet trees and the capability to handle another twelve.

From Here to There

The floating systems are built, of course, many miles from their final destination. For example, most of the TLP hulls for the Gulf of Mexico came from Italy and Korea. Finland specializes in spar hulls. Ship-shaped hulls come from all over the world.

For the ship-shaped hulls, transportation is straightforward—literally. The hull either drives itself to the location, if it has its own engine power, or seagoing tugs tow it. Since their mission is more or less stationary, most FPSOs and FPSs do not have their own motoring facilities.

The pontoon/caisson hulls are moved to the well site either by wet tow or dry tow. For a wet tow, tugboats drag the hull at an agonizing three to four knots. Transport from Italy to the Gulf of Mexico takes about 90 days.

The dry tow method involves placing the hull on a vessel with heavy lift capability and a more nautical-friendly shape, sometimes self-powered, sometimes towed. In either case, speeds of 10 to 12 knots cut the Italy/Gulf trip to about 25 days.

The quayside water may not be deep enough to float a pontoon/caisson hull. It may be deep enough so that the hull can be dragged out of the construction yard on skids right on to a transport vessel. If the waterway is not deep enough, shallow draft transit barges might have to be pressed into service to carry the hull to deeper, but still protected waters. At that point, the barges are lowered by ballasting until the hull floats. The larger, deeper draft, heavy lift vessel is ballasted enough to come under the hull, where it is deballasted, lifting the hull. Figure 9–24 shows the *Brutus* TLP hull en route on a heavy lift vessel. In this case, the hull was offloaded at a quayside in Ingleside, Texas. The deck and topsides were installed there, the system was integrated and commissioned, and the entire hull/topsides combination was wet towed to location where it was connected to tendons as described earlier in this chapter.

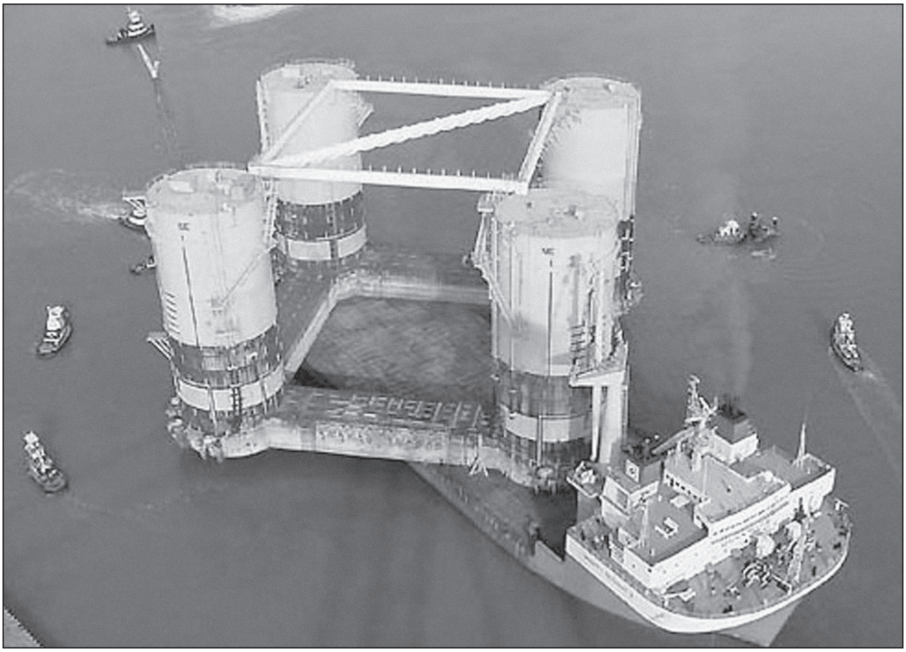


Fig. 9–24. Hull of the TLP *Brutus* on a heavy lift vessel en route to installation. (Courtesy Dockwise USA.)

Spars move more or less the same way, though some are transported in two or three pieces to an assembly site where they are joined then wet towed to the installation site.

Installation of FPSs, FPSOs, and Spars

If all goes well, by the time a floating system arrives on site, the anchoring system is in place. In the case of an FPS, FPSO, FSO, and spar, mooring lines and chain have also been installed and are waiting on the sea floor. A large crane vessel fishes the mooring lines out and transfers them to the hull, one at a time. The lines are winched to the right tension and position and locked in place.

Hauling a 600-foot or more spar out to sea calls for a long wet tow to the installation site. On location the crews carefully flood the spar's compartments so that it rotates to the upright position, mostly submerged. (See fig. 9–25.) Heavy-lift cranes resurrect the mooring system and assist with the connections to the spar.

Fig. 9–25. The *Genesis* spar uprighting from its floating position. (Courtesy Chevron.)

Setting the deck

Expertise and craftsmen for hull and deck are different enough that topsides for TLPs, spars, FPSOs, or FPSs are usually constructed at different yards than the hull. For all systems except the spar, the hull and the deck can be mated onshore at an outfitting and commissioning site or at sea. Either way, the deck can come whole or in several pieces.

Whether at an integration land site or at sea, heavy lift cranes can place the deck or its pieces on top of the moored hull. Alternatively, the *float-over* method can be used. The deck on two or more parallel barges is floated over a ballasted floater hull. The water is pumped out of the floater, allowing it to rise and pick up the deck from the float-over barges.

Most FPSs, FPSOs, and TLPs have their topsides deck equipment set at an onshore or near-onshore location. Spars, with their awkward 600-foot or so height, have their decks set after being uprighted on site. Heavy marine lift vessels do the transfer of the topsides, which often come in one unit.

Mooring spreads

A typical mooring spread for FPSOs, FPSs, and spars has steel wire or polyester rope, stretching down to heavy chain links. For the *Ursa* TLP in 4,000 feet of water, each chain link weighs 1,320 pounds and stands 3 feet high. Figure 9–26 shows a smaller chain—only 500 pounds per link! The chains connect at the seabed to an anchor system, usually made up of steel piling. These foundation piles can be driven into the seabed by underwater hydraulic hammers. Alternatively, they can be installed by the suction pile method.

Fig. 9–26. A 500-pound chain link for a mooring chain. (Courtesy Offspring International.)

Like rubber boots stuck in the mud, suction piles rely on the sediment around them to hold them in place. The installation is a bit more complicated than donning footwear. Suction pile sizes vary, but the *Na Kika* project piles and installation serve as an example. A 14-foot diameter tubular about 80 feet long with a top cover was lowered to the sea floor. As the bottom edge touched the soil, the enclosed water escaped through valves left open on the top. The weight of the steel suction pile was enough to cause the pile to penetrate about 40 feet into the soil. As it penetrated, the water was ejected out the top, preventing any escape of water around the bottom. Otherwise the soil in the area might have washed out, causing a loss in load-carrying capacity.

After about 40 feet, the tubular weight was not enough to cause further penetration. A pump, operated via an ROV, sucked more water from the top of the tubular, causing downward suction that caused the piling to move slowly down for the full 80 feet. The valves were closed and the piling was permanently in place, held by suction akin to that rubber boot, but stuck in 80 feet of mud. Figure 9–27 shows the process of installing a suction pile. Literally hundreds of these have been used to moor both drilling and production vessels.

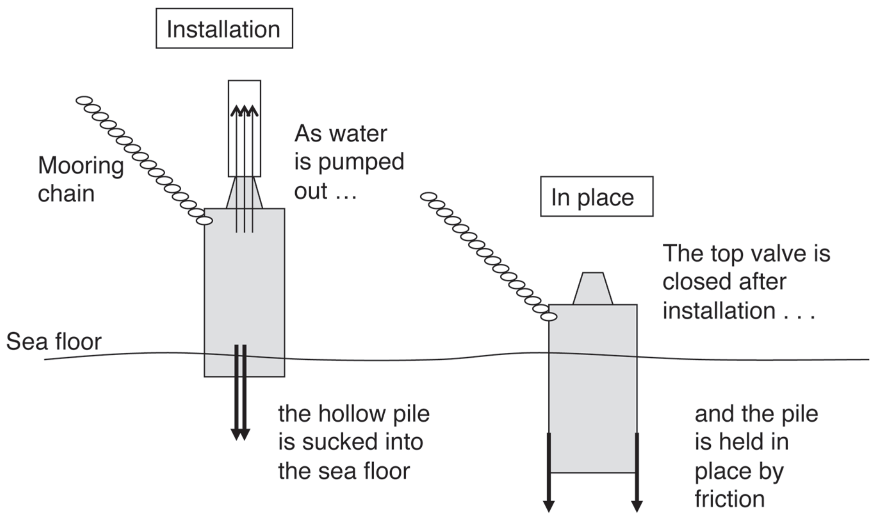


Fig. 9–27. Suction pile installation

Mooring spreads usually have at least eight separate legs coming from the floating system; some have up to sixteen. Like most stable anchoring system at sea, the length of the anchor line runs one and a half to two times the water depth. For the FPS used in the *Na Kika* project in 6,500 feet of Gulf of Mexico water, Shell/BP used 9,600 feet of wire and 1,750 feet of chain for each of 16 separate legs. The suction piles sit a mile and a half from the FPS. (See fig. 9–27.)

Service companies install the foundation piles and the rope and chain before the arrival of a floating system, leaving the ropes on the seabed (in satellite-identified locations so they can find them) until hook-up time arrives. Then they use global positioning systems and subsea acoustic beacons again to find the loose ends. With the assist of remote operated vehicles, they attach the ends to heavy-lift cranes that hoist them to the connect points on the floater.

Most of the early mooring systems for FPSs, FPSOs, and spars were made up of steel wire rope and chain segments, as shown for the *Na Kika* systems. (See fig. 9–28.) Nowadays, however, polyester rope sections often displace the wire rope. Each leg of the mooring system for the *Perdido* spar, located in 7,820 feet of water in the Gulf of Mexico, was made up of chain/polyester segments averaging more than two miles in length, with the majority being 9.6 inches in diameter polyester. (See figs. 9–29 and 9–30.) The top of each line is comprised of a short length of chain called the platform chain, which is connected to the spar. The platform chain is held firmly at the deck level and runs down through a below-water fairlead on the outside of the spar. There the polyester rope is connected to the platform chain, and the rope spans most of the water depth and connects on the bottom end to the ground chain some distance above the mudline. The bottom end of the ground chain is connected to the suction pile via a mooring shackle.

Polyester lines meet the strength and stiffness requirements for holding the spar in place and they provide the valuable benefit of reducing the download on the spar that steel rope would create.

The length of the ground chain is chosen so that the polyester will never touch the sea floor and be subject to sediment friction and abrasion. However, the rope is jacketed anyway to guard against abrasion and silt ingress.

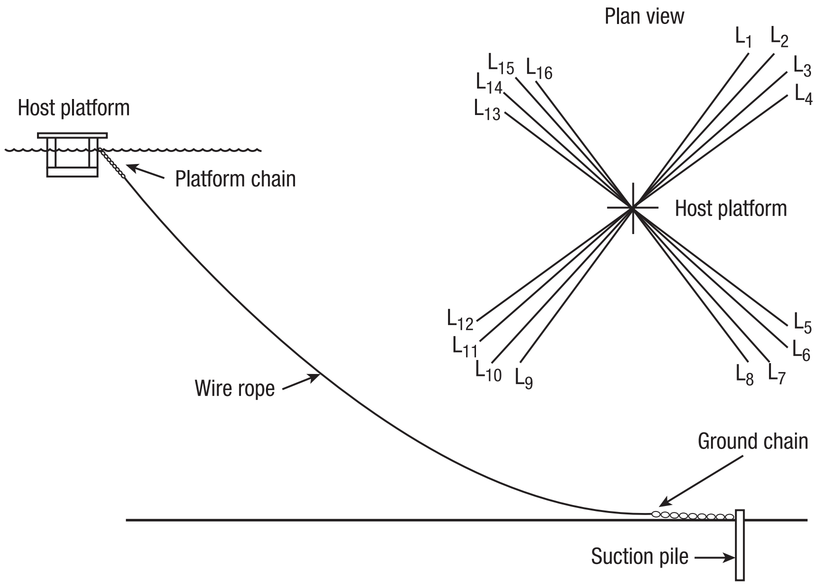


Fig. 9–28. Mooring spread for the *Na Kika* FPS

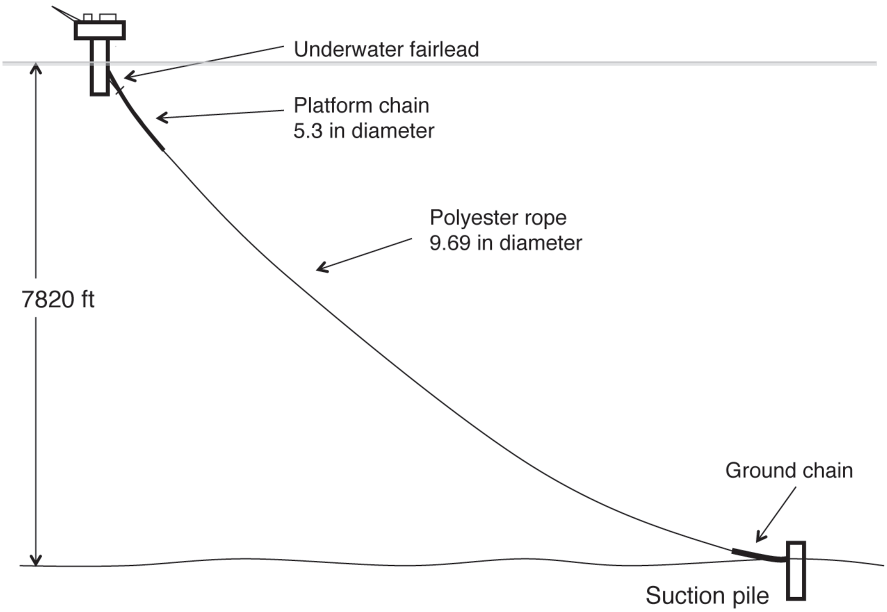


Fig. 9–29. Mooring spread for the *Perdido*

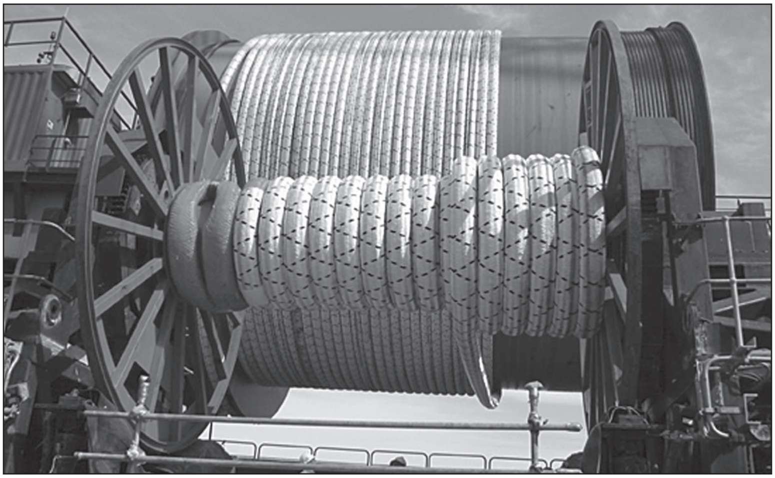


Fig. 9–30. Polyester rope used for the *Perdido* mooring lines. (Courtesy Heerema Marine Contractors.)

Because of the concern about abrasion, the installation procedures for the polyester rope are somewhat different from those for wire rope discussed previously. The suction pile anchors with the ground chain attached are still set months before the spar, FPS, or FPSO arrives at the site. However, the polyester rope section is brought out only a week or two in advance of the floater. These ropes are attached to the ground chain using mechanical connectors with the help of ROVs, and then the top end is buoyed off waiting for arrival of the floater, when it will be mechanically connected to the platform chain.

Risers

Floating production systems connect to subsea wells by a combination of production risers and flowlines along the bottom. Chapter 12 treats them in detail.

Subsea Systems 10

Below the thunders of the upper deep;
Far, far below in the abysmal sea.

—Alfred, Lord Tennyson (1809–1892)
The Kraken

People sit in climate-controlled offices surrounded by multicolored electronic displays, control panels, and communication links. A transient signal crosses a screen and an un-ignorable alarm seizes the attention of an operator who punches changes into a keyboard *in staccato* and then watches the screen intently. Is this the Johnson Space Center? The White House Command Center? No, it's a control room aboard a deepwater platform where oil and gas from subsea wells miles out and a few thousand feet below on the sea floor is managed. Advancing subsea technology now approaches the sophistication of outer space and military surveillance.

The first subsea completion was installed by Shell in the Gulf of Mexico in 1961. The 55-foot water depth was well within the range of divers, and the installation was a test case for application in deeper water. Subsea came into common use in the 1980s led by Petrobras in Brazil, and by various North Sea operators. Initially subsea developments were one or two well step-outs from an existing infrastructure of fixed platforms. Later they developed into clustered wells with subsea (wet) trees tied back to a fixed structure or floating system host facility or directly to a shore base.

Technological improvements have continued to provide viable designs for increased water depths. Now, subsea system technology has a critical, sometimes dominant economic role in the oil and gas industry's portfolio of new field developments and is used throughout the world.

Subsea systems have gained prominence by allowing the development of small satellite fields located some distance from surface facilities. Increasing density of surface developments has also helped to reduce the cost of subsea systems by providing ready access to existing infrastructure for use as host facilities.

Early in the 1990s, subsea-system utilization accelerated in tandem with developments in deeper water. Entire fields were developed with subsea systems where widely dispersed reservoirs would have presented cost barriers to development from multiple surface locations.

Developments in remotely operated vehicles (ROVs) have had a crucial role, making subsea developments practical in water depths not accessible by divers. The technology and complexity of subsea systems continue to advance, driven by the need to reduce capital expenditures and life-cycle cost, to minimize subsea-intervention costs, and to improve system reliability.

Industry uses subsea systems to tap oil and gas fields in two ways:

- Subsea systems can be part of the initial plan for the development of a field. In those situations, the host facility is purpose-built to accommodate optimized subsea field architecture and systems. The *Na Kika* system, in the Gulf of Mexico, mentioned in chapter 9, and shown again in figure 10–1, is an example of a development that was purpose-built to optimize subsea architecture and systems. These smaller fields, close to each other but not all reachable from one location by directional drilling and each not large enough to support its own platform, were developed entirely with a subsea system and a new, common platform.

- The need for a subsea development is often recognized after the host facility has been designed and is in operation. In this case, the subsea architecture and systems are adapted to fit the limitations of the existing host facility. The *Angus* field in the Gulf of Mexico has effectively used the existing *Bullwinkle* infrastructure as a host (fig. 10–2).

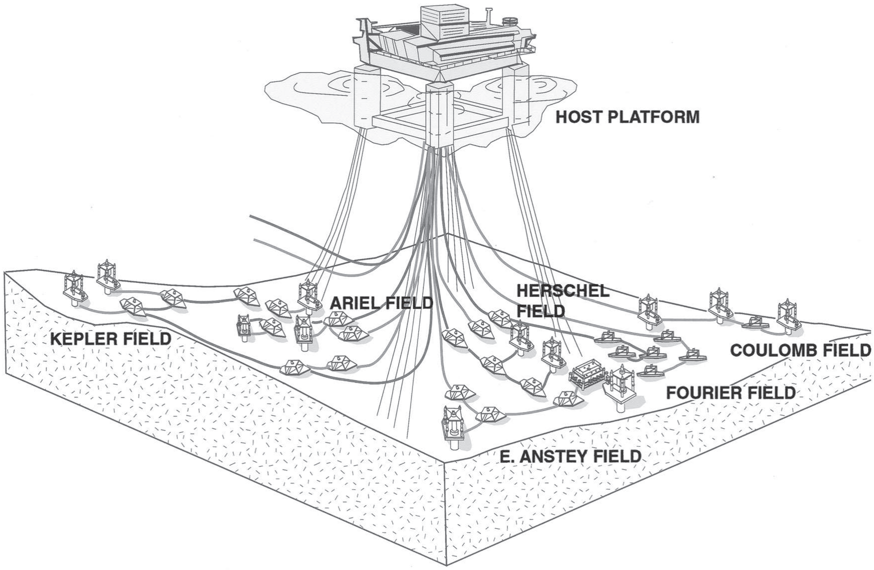


Fig. 10–1. The *Na Kika* development scheme for six subsea fields. (Courtesy Shell Oil Company.)

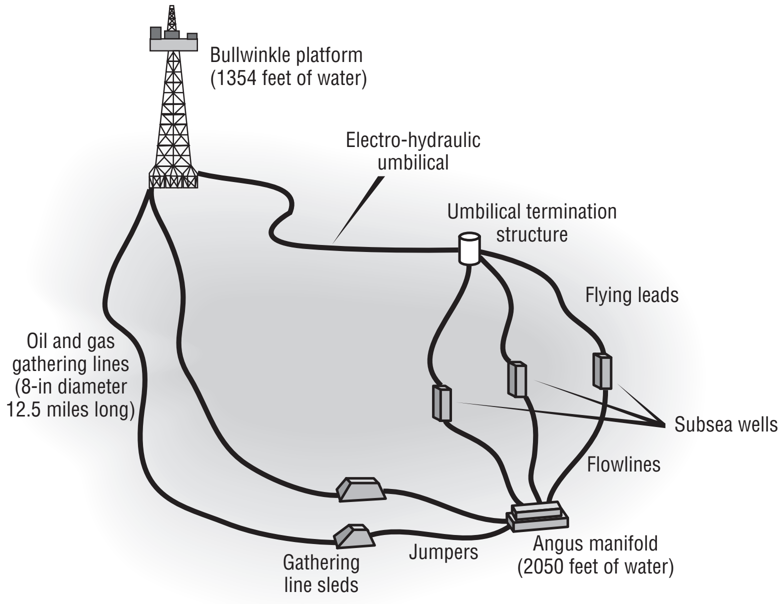


Fig. 10–2. Subsea development scheme for *Angus*, hooked up to *Bullwinkle.* (After INTEC.)

Subsea Field Architecture

Field architecture refers to the layout and configuration of key elements of a subsea system—the wells and their locations, the flowlines, manifolds, and umbilicals, and the host facility. In the process of deciding the appropriate combination of these components, three are addressed—bathymetry, flow assurance, and host facility capabilities and location.

Bathymetry

Water depth contours can change quite dramatically in relatively short distances and have a significant influence on the routing of flowlines and the placement of wells and subsea facilities. In many areas the sea floor is relatively smooth with very little vertical relief. But there are also many times when the routing of flowlines and connections between the fields traverse canyons, rises, and unstable soil conditions. Figure 10–3 shows the deepwater bathymetry off the coast of Norway. This weathered topography is the result of a gigantic sea floor movement, the Storegga slide, which occurred about 7,000 years ago. The *Ormen Lange* gas development had to address the issues caused by this irregular bathymetry.

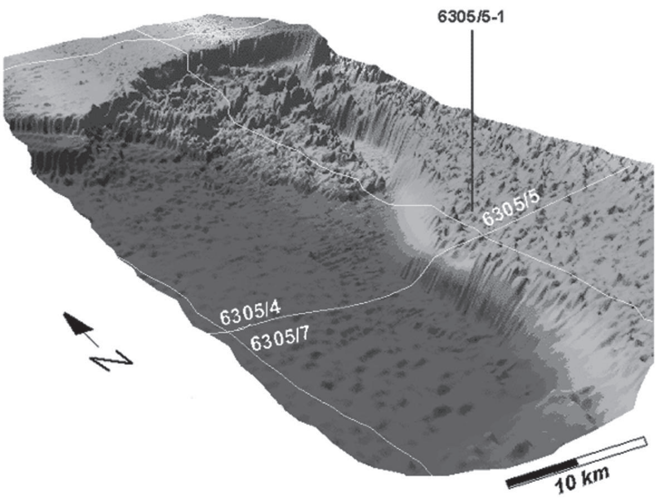


Fig. 10–3. Deepwater bathymetry of offshore Norway after the Storegga slide about 7,000 years ago

Flow assurance

Keeping the oil and gas moving in the lines sometimes presents important engineering problems. Is one flowline enough, or are two or more needed? Will low temperatures result in the formation of hydrates or paraffin accumulation? Will pigging be required?

Host tieback

Any subsea well must be tied back to a host, whether it is a fixed platform, a floater, or a shore base. Space and load carrying capacity, operational and topsides limitations, and even host ownership have to be addressed. For example, existing limitations on a given host facility may limit the options for hanging off dual flowlines or umbilicals. There may be bottlenecks in onboard processing of the crude oil and gas.

In addition to these three considerations, the potential for future expansion, overall system reliability, and the attendant economics have to be considered as well.

Field architecture considerations can sometimes be simple. For instance, a single well subsea development may simply include a single flowline and umbilical connected back to a host. In the case of only a few wells, a clustered configuration, as shown for the three well *Angus* field in figure 10–2, is often the solution chosen.

For a large number of wells, a well-pad approach may be used, wherein several wells at each pad are connected to a common gathering line and then through a manifold to a common flowline to the host.

Difficult as it usually is, potential opportunities for future expansion can be considered, including having the layout, sizing, and extras designed and/or built in for both the subsea and the surface hardware additions.

Given all these design considerations, subsea field layouts can be characterized as three generic types:

- **Single tiebacks to a host.** Wells directly connected via a flowline to a host.
- **Daisy chain.** Two or more wells linked together by a flowline from the host in a daisy chain fashion and then returned to the host

to complete the chain. This allows production to be sent either of two ways to the host. In addition, the entire loop can be pigged. (Pigging is discussed in chapter 12.)

- **Cluster.** Several wells clustered around a manifold. The individual wells flow into the manifold via jumpers or flowlines; commingled fluid is then transported from the manifold to the host via one or two flowlines.

Figure 10–2 is an example of a cluster system. Figure 10–1 shows a much bigger and more complex system that includes daisy chains as well as cluster groups in the development architecture.

Field Architecture and System Design Process

The development of an optimum field layout requires the involvement and expertise of many people with diverse talents and backgrounds. These will include personnel from at least the following technical and business areas:

- Geology and geosciences
- Drilling
- Reservoir
- Subsea
- Flow assurance
- Pipelines and flowlines
- Production
- Legal and commercial
- Process
- Project management

- Installation and marine operations
- Host facility technical and commercial representatives

Subsea Components

The hardware components that make up the subsea portion of the system include the following, as shown in figure 10–4:

- Wells
- Subsea trees
- Manifolds and sleds
- Flowlines
- Jumpers and flying leads
- Electric and hydraulic umbilicals
- Subsea and surface controls

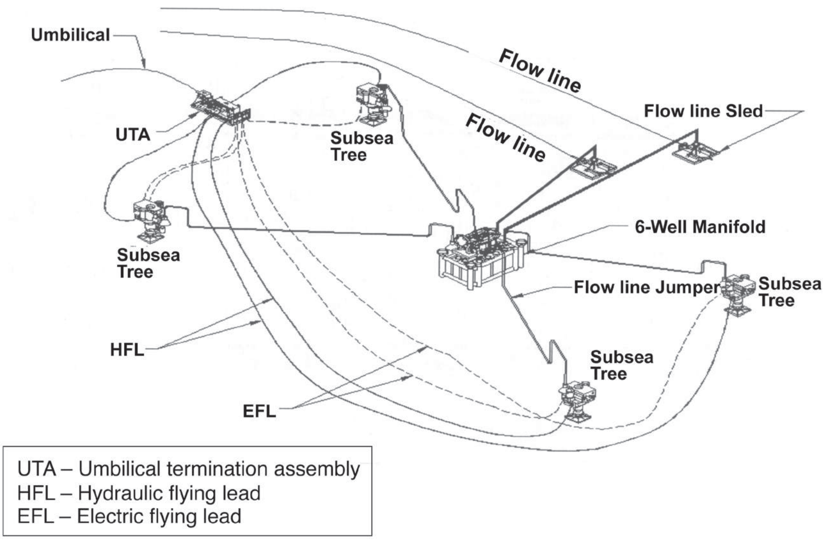


Fig. 10–4. Subsea components

Figure 10–5 follows a barrel of fluid from the well to the host. The fluid from each well flows from the reservoir up through the well bore to the tree, then via the tree-to-manifold jumper to the manifold where it is joined by the production from two other wells. The commingled and combined flows then transit from the manifold to the flowlines via the manifold-to-flowline jumper. From there the production flows through the flowlines, up the steel catenary riser (more in chapter 12) to the production topsides facility (more in chapter 11) for processing and treatment.

Sensors on the trees and manifold provide electrical signals that are sent to the host via the electrical umbilical and converted to data, which can include well temperature, pressure, flow rates, etc. In addition, the umbilical can supply chemicals for hydrate and paraffin inhibition as well as hydraulic fluid and pressure to open and close valves, reset chokes, and so on. This enables control of the entire operation from the host, which may be miles away from the subsea system.

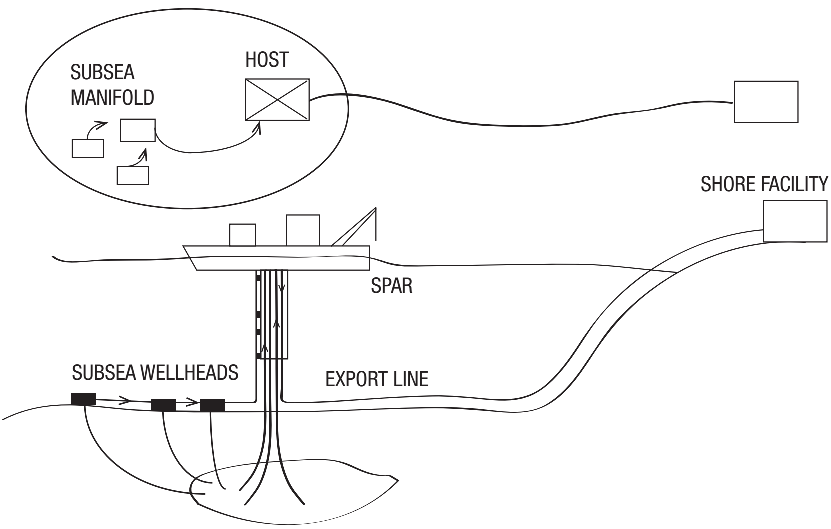


Fig. 10–5. Flow from the reservoir to shore terminal

Wells

The designs and specifications of all the subsea components—trees, manifolds, umbilicals, and so on—are a function of the characteristics of the well. For example, some subsea wells have high shut-in pressures, greater than 10,000 pounds per square inch (psi), while others are less than 5,000 psi. Some with very low reservoir pressure may require downhole pumps to move the fluids to the surface. The functions of the trees and other downstream components are similar in all cases, but the hardware and various control devices differ in strength, materials, controls, instrumentation, and installation. Nonetheless, the pieces fit together as a system to accommodate the reservoir characteristics and the well parameters.

Trees

Subsea trees sit on top of the well at the sea floor. Although they have little visual resemblance to the original onshore Christmas trees, they provide essentially the same functions. They furnish the flow paths and primary containment for the oil and gas production and the valves needed for both operation and safety. Operators on the host platform actuate hydraulically controlled valves on the trees and monitor feedback from sensors on the tree and in the well.

Remote and inaccessible as subsea trees (and other subsea equipment) are, they demand robust design, built-in redundancy, vigilant manufacturing quality control, and thorough testing of the finished product to reduce the worry of equipment failure. Even then, nothing is perfect, and components sometimes have to be disconnected and brought back to the surface for repair.

Subsea trees normally have the external handles and fixtures evident in figure 10–6. They enable ROVs to physically turn valves and activate other control functions, sometimes during normal operations, other times as a backup if something fails. An important ROV capability is to provide hydraulic pressure to open or close various valves in the event a primary electro-hydraulic system misfires. In addition, ROVs hook up, disconnect, and otherwise change around control lines. They also install rigging and do other miscellaneous maintenance activities. And as important as any function, ROVs provide visual confirmation that what was supposed to happen did happen. Design of subsea components takes all these factors into consideration.

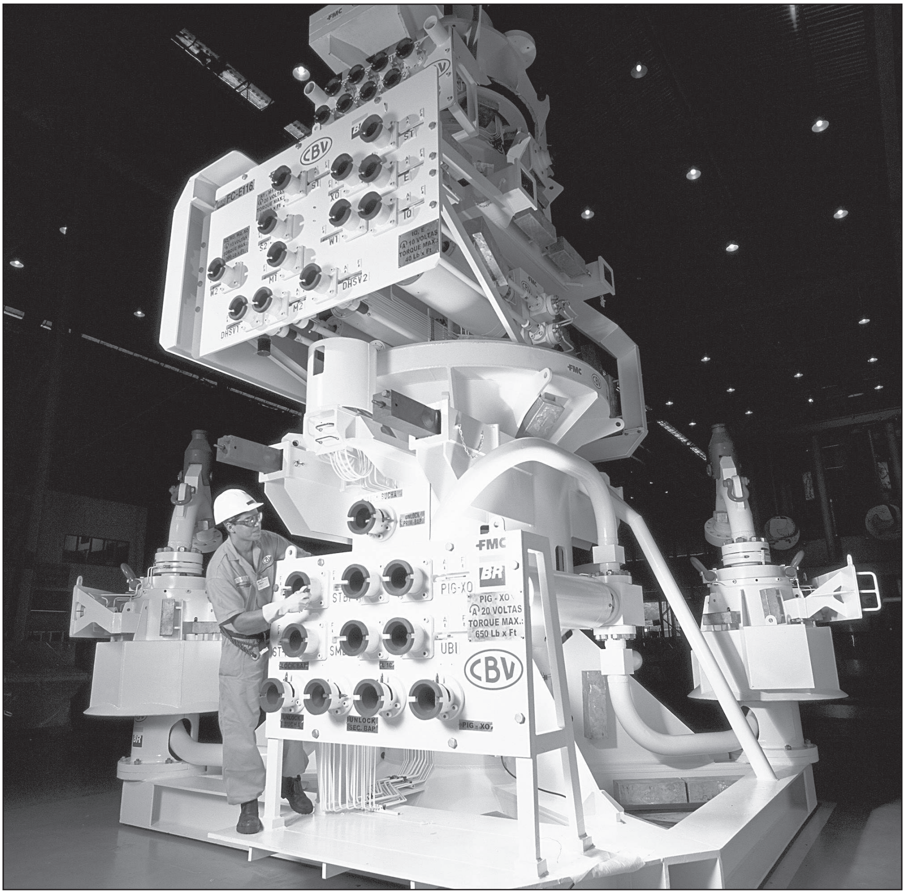


Fig. 10–6. A subsea tree with ROV-friendly connections

Manifolds and sleds

A manifold is quite simple in concept—it provides the node where the fluids from the individual wells commingle before moving in a flowline to the host platform. A sled is another node where a flowline or gathering line connects to a subsea well or manifold. (See fig. 10–4.) Using sleds facilitates installing complex architectures.

In the simplest case, a single-well development, the oil and gas production moves from the subsea tree via a short jumper to a flowline sled, into a flowline and then directly to the host platform. However, in many fields, several flow lines converge and are connected to a central subsea manifold with jumpers. Often several wells are clustered around and linked directly to a common manifold. In many cases, manifolds have extra slots for future wells or for tie-ins from other fields that might not warrant full subsea development on their own.

Manifold and sled designs vary in sophistication and complexity. (See fig. 10–7.) Some are "dumb" steel structures that anchor the flowlines and collect the produced oil and gas for transport to the host platform. Others have complex control and distribution systems. Those give operators located at host platforms the ability to isolate flow from individual wells or fields and provide well flow data for reservoir surveillance and management.

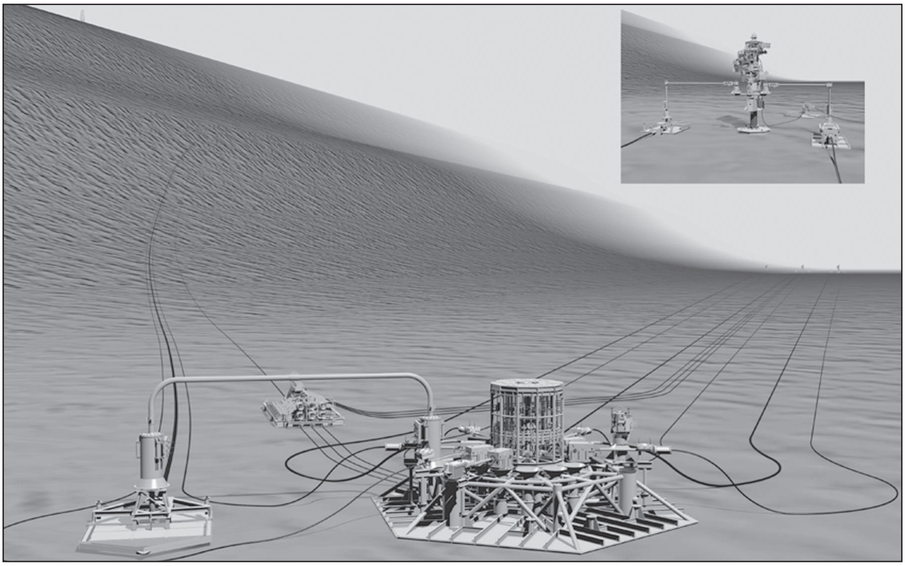


Fig. 10–7. The Mensa subsea field manifold, jumpers, flying leads, and sled

Flowlines, jumpers, and gathering lines

The topics of pipelines and flowlines are covered in depth in chapter 12, but for completeness, a brief explanation here doesn't hurt. The oil and gas flow from the wells to a manifold via a jumper if it is close, 50 feet or so, or through a flowline if not. A jumper is a prefabricated section of steel pipe (fig. 10–8a), or a length of flexible composite line (fig. 10–8b), specially configured to make a structural, mechanical, and pressure-tight connection at each end. The precise measurements that determine the jumper shape—length, orientation, relative offset, and angles between the termination points—can be taken only after the sleds, wells, and manifolds are in place.

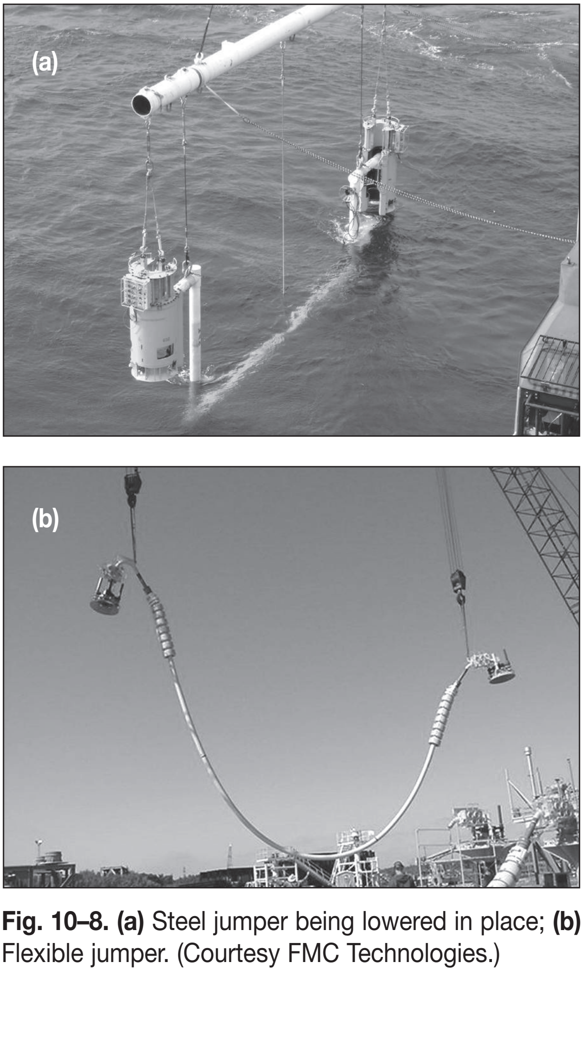


Fig. 10–8. (a) Steel jumper being lowered in place; **(b)** Flexible jumper. (Courtesy FMC Technologies.)

The *Mensa* field, a high-pressure gas development in 5,400 feet of Gulf of Mexico water (fig. 10–7), uses short jumpers from each tree to sleds on individual well gathering lines. Three separate lines then proceed about five miles to a common manifold. From there the commingled production is transported via a common flowline to a platform 63 miles away for treatment and processing.

In some cases (fig. 10–2), two flowlines come from a subsea manifold. This allows the operators on the host platform to control the volume delivered from each line. If maintenance is required on one flowline, production can continue through the other. In the event a production well temporarily requires special flowing conditions (different pressures from the other wells), it can be directed to one flowline with the other wells directed to a different flowline, allowing production to continue with little or no interruption.

Umbilicals and flying leads

Like their namesakes in the animal kingdom, umbilicals conduct the flows necessary to keep the system alive. They provide the connecting medium for electrical, hydraulic, chemical injection, and fiber optic lines between the topside facilities on the host platform and various subsea items—the manifold, sleds, termination assemblies (fig. 10–4), subsea trees, and controls.

The number and the character of umbilicals vary according to specific system needs and development plans. Umbilicals may be single function, e.g., a hydraulic line only. They are more commonly multifunction integrated umbilicals that provide hydraulic tubes, electrical lines, and tubes that carry chemicals to the manifolds and trees. Figure 10–9 shows a cutaway section of a full service umbilical. Steel tubes in the outer ring can be used to pump chemicals to the production stream. Others can deliver hydraulic fluid to actuate subsea valves. Some umbilicals have thermoplastic tubing for low-pressure chemical injection service.

The center of the umbilical in figure 10–9 has several electrical conductors that transmit signals from instrumentation on the subsea components (temperature, pressure, integrity checks) back to the control center. Electrical power can move through an umbilical to operate solenoid valves on the subsea control pods, which in turn control hydraulic pressure supplied to the subsea valves on the manifolds, trees, or sleds. In some cases, power is also supplied to operate well bore or subsea pumps.

Fig. 10–9. Cutaway view of an electro-hydraulic umbilical. (Courtesy Oceaneering Multiflex.)

Combining multiple services into a single umbilical can save manufacturing and installation costs. However, distance, depth, and weight may require multiple umbilicals. In the *Na Kika* development, several umbilicals lie on the sea floor between the host platform and the various trees, manifolds, and sleds.

The subsea end of an umbilical has a termination head that connects to a distribution structure, the umbilical termination assembly or UTA. (Sometimes the connection piggybacks instead on a manifold.) From there the umbilical services are distributed to trees or any other miscellaneous equipment in the vicinity by flying leads, sort of subsea extension cords. (See fig. 10–10.) The smaller and shorter of these can be "flown" by ROVs and plugged into waiting receptacles. However, simple as it sounds, the umbilical cord and plug are considerably more sophisticated than a rubber-covered copper wire with a two-prong connection.

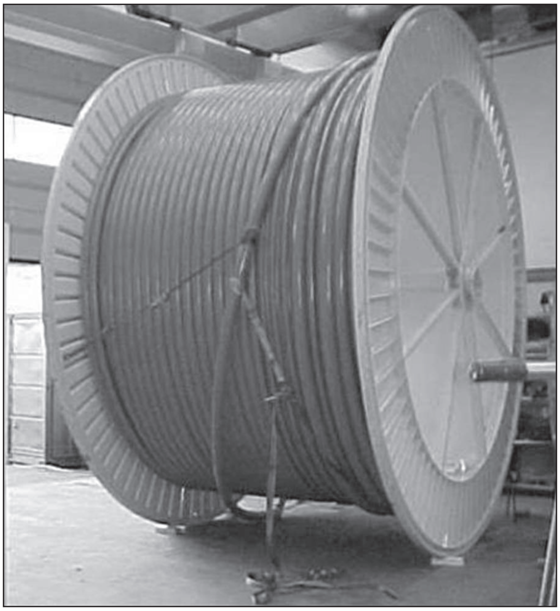


Fig. 10–10. Reel of steel flying leads. (Courtesy Oceaneering Multiflex.)

Control system

The ability to monitor and control wells and manifold functions from the host facility with confidence and safety is critical to overall subsea system performance. Trees and manifolds have control pods, modules that contain the electro-hydraulic controls, logic software, and communication signal devices. Redundancy is built into the systems to provide alternate ways to retrieve and transmit data and commands. Most control pods are designed so that if they fail they can be replaced. Collaborating with a surface vessel that has an onboard winch, an ROV can fly in, disconnect the pod from its support structure, and connect the lifting slings so the winch can pull the pod to the surface. This is more or less a subsea version of changing a card in a computer.

The master computer in the host platform control room communicates with the subsea control pods. The pods then operate the valves and other functions on the manifold to increase or reduce flow rate or to shut in the flow entirely, if needed. In addition, the system contains failsafe devices to shut in automatically if certain parameters are exceeded, such as large increases in well pressure that might indicate a plug in the system or an abrupt pressure drop that might indicate a flowline or other component failure. As a sometimes last but slow resort, an ROV can fly down and mechanically open and close valves or perform other functions.

For normal (and predominant) operations, the control room operators monitor and tweak the system based on feedback from the electronic monitoring devices, just as they would for more accessible dry tree systems.

Flow Assurance

Fluids from wells are a mixture of gas, oil, condensate, and water, perhaps with suspended solids such as hydrates, paraffin, asphaltenes, scale, and just plain dirt—sand and silt. The potential for paraffin, scale, and hydrates to build up in trees, flowlines, and risers is a significant problem for subsea production systems, which are entombed in a very cold environment, usually hovering around 32°F in deep water.

Hydrates are a crystallized combination of water and natural gas (methane). They look and behave like snow or slush and can form a solid plug under certain conditions of temperature and pressure. Hydrates can form rapidly with sudden depressurization such as occurs with flow across a valve, or slowly as in a cooling of subsea lines and equipment during a shutdown of well flow. Hydrates will not occur if any of the three required elements—temperature, pressure, and water—are not within the formation range. This leads to design attention on heat containment and dealing with co-produced water.

Wax and paraffin components are a natural part of crude oil composition. As the fluid flows, wax crystals can precipitate out as the temperature drops to the wax appearance temperature, which is dependent on the unique characteristics of every crude oil. At low enough temperatures, the waxy paraffin in some crude oils can deposit on the pipeline wall, constricting flow or even blocking it entirely.

These two issues, hydrates and wax, consume a considerable amount of time for the flow assurance team. To the extent possible, the team early on analyzes fluid samples to assess the likelihood and proclivity for hydrates and wax to form. They consider the life cycle of the field. As the reservoir pressure declines, the fluid composition changes. With less oil and gas and more water, for example, the conditions that cause hydrates or wax might recede or advance. Transient periods—shutdown and start-up, planned and unplanned, add complexity to the design and operations planning.

Figure 10–11 shows some failures to address these issues properly, a hydrate plug being removed from a pig catcher and a cutout section of a pipe plugged with paraffin. Subsea system designers and operators have plugged lines near the top of their worry list.

To avoid the wax/paraffin and/or hydrates issues, subsea systems are designed to retain the natural heat in the fluids as they exit the well, to add heat, to inject chemicals additives, or all three. The chemicals change the hydrate formation temperature or modify the wax appearance temperature.

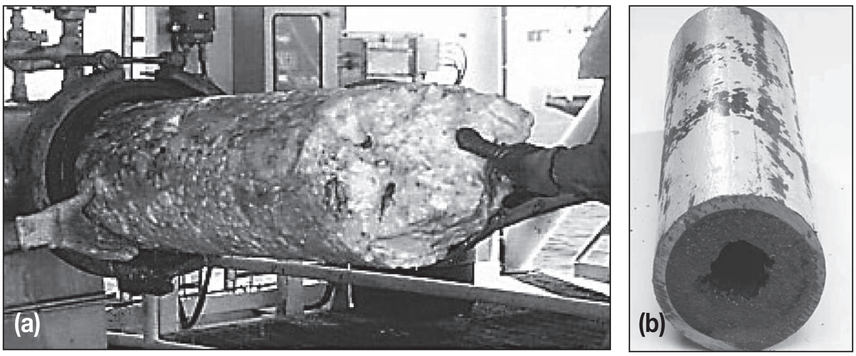


Fig. 10–11. (a) A hydrate plug; **(b)** A paraffin plug being removed from a cut out section of pipeline. (Courtesy Chevron.)

Heat retention alternatives

To mitigate a temperature drop, the flowlines and other subsea components have insulation. An effective insulation system for flowlines, used in cases where there is a high potential for constriction or plugging, is the pipe-in-pipe flowline. The space between the pipes is partially evacuated and then filled with insulating material such as a polymer. The result behaves like an elongated thermos bottle, eliminating most of the heat loss from the well fluids as they pass through. These efficient insulation systems allow the well fluid to be transported great distances while maintaining almost all their original heat, preventing the formation of both hydrates and wax.

Some other common approaches to heat retention and the relative effectiveness of each are shown in figure 10–12a:

- Insulating with a material such as polymer that can withstand the flowline installation process
- Burying the already insulated or even bare pipe flowline so that the surrounding soil acts as an insulator
- Pipe-in-pipe bundles use of flexible pipes that have inherent insulating characteristics due to their composition

Where heat retention techniques are not enough, the pipeline can also be heated from an external source. Direct electrical heating applies an electrical current along the flowline, where electrical resistance to the current causes direct heating of the flowline—sort of a subsea toaster. In another technique, hot fluids are circulated inside a pipe bundle. The heat permeates and transfers to the produced fluids.

The decision on the level of heat retention needed is controlled by the assessment of risk and the capital cost. The most expensive option is the pipe bundle, which naturally is the most effective at heat retention. This is followed in cost and effectiveness by the pipe-in-pipe, and so on, as shown in figure 10–12b.

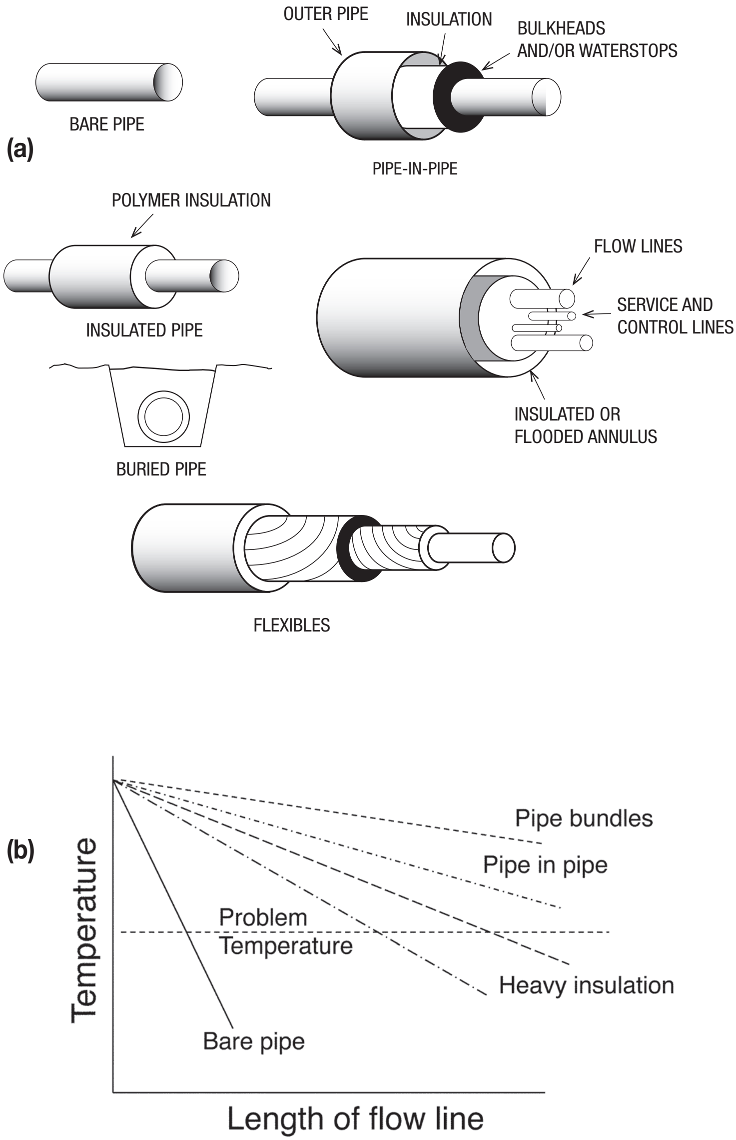


Fig. 10–12. (a) Methods for heat retention in pipelines; **(b)** Notional heat retention in a flowline by various methods

The flow assurance team often has limited real information on the reservoir characteristics to help it address the level of heat retention that needs to be provided. Consequently, even with one of the heat-retention methods mentioned here, they design most subsea wells with chemical flow assurance (as opposed to the non-chemical methods mentioned earlier), pumping hydrate and paraffin inhibitors to the trees via the umbilical or by a separate tube.

So, after a decision is made on heat retention, the flow assurance team has to address the volume and types of chemicals to be injected into the well stream. Methanol is often used for hydrate control. The injection point is also important—it may be best done at the manifold, at the tree, or downhole in the production tubing. All this implies added cost, and while it reduces the risk of plugging, it adds some level of risk of mechanical failure.

Like any other oil and gas producing facility, from time to time subsea facilities have to be shut in. During that time, nonflowing, stagnant fluids sit in the flowlines and gathering lines. Even the best insulation—be it pipe-in-pipe, polyester coating, or pipe bundles—doesn't prevent flowline cooling indefinitely. Several methods deal with the long shut-in challenge:

- Slugs of chemicals can be injected into the production stream just prior to the shut-in, using either the umbilical or a separate chemical injection line. Methanol or glycol in amounts of 25% to 50% of the water content serves as antifreeze by depressing the freezing point below the seabed temperature, preventing hydrate formation.
- Where the water content of gas is high, methanol or glycol injection is expensive. In that case operators may depressurize the flowlines, moving the ambient conditions out of the hydrate-forming zone.
- The flowlines can be purged with dry oil pumped down through an umbilical-type connection.
- The flowline can be electrically heated. One electrical heating system now in use in the Gulf of Mexico uses the two pipes in a pipe-in-pipe flowline as the circuit that carries the electric current needed for heating.

- Chemical additives can be injected into the well stream to keep paraffins and waxes from solidifying or depositing on the pipe wall.

In addition to paraffins and hydrate plugging problems, deposition of inorganic scales, precipitation of organic molecules known as asphaltenes, and corrosion problems can undermine flow assurance. The solution to these irritations is usually chemical additives. While effective, operators have found that these chemicals are expensive and take extensive adjustment to ensure continuous, problem-free, minimum-cost flow.

Installation of System Architecture

In the early days, subsea development systems were built with rigid, hard-plumbed templates. They were installed and connected in a given sequence using a limited number of installation vessels and project-specific tools and equipment.

Nowadays, subsea systems are designed with installation flexibility as a core requirement. Over time, engineers have created flexible but reliable modular systems for the deepwater environment. The main components and modules—trees, manifolds, flowlines, umbilicals—can be separately built and then separately installed in the target location. Each of these components will be outfitted with devices to aid in subsea measurements and with hardware to allow one component to be connected with another *in situ*. Jumpers and flying leads with specifically designed connections are then used to tie these components and modules together. In addition the ability to connect components subsea provides options for choosing vendors, installers, and equipment. That provides opportunities to improve project scheduling and to control interdependency conflicts during the installation cycle. Using sleds, jumpers, and other termination structures allows major work modules to proceed on independent work schedules. Installing wells and manifolds and laying pipe can happen as vessels and equipment become available, a significant cost savings.

Subsea metrology

Modularity depends on the ability to measure distances, elevations, and vertical and horizontal offsets and tilts subsea in order to manufacture the jumpers to precise dimensions and angles and to install them subsea and effect structural, mechanical, and leak-proof connections.

Metrology is the science of measurement. Subsea metrology is the uncanny extension to achieve accurate and timely acquisition of distance, angles, and tilt measurements in a cold, wet, and entirely dark underwater world. The common method of acquiring the needed measurements in the subsea uses acoustic transponders located on each component and module. An ROV equipped with acoustic pingers and data recording equipment sends signals to each transponder. By knowing the speed of the signals in water, and after a multitude of interrogations, mathematical analyses give the measured distances and angles with considerable precision.

Other techniques—including direct measurements via calibrated steel tapes (taut-wire metrology), laser technology, photogrammetry, and inertial metrology offer complementary ways to get the final needed measurements. The end result is a high degree of confidence that allows the jumper's final dimensions to be precisely fabricated, and then for the jumper to be installed.

Subsea connectors

Subsea fields have utilized a variety of connections for the jumpers, umbilicals, and flying leads. Sizes vary from 2 to 36 inches, but they can be broadly categorized into two types, vertical and horizontal.

Vertical connections are tied directly to a preinstalled hub in one operation. The pulldown stroking and final connection are done by the connector itself with either externally provided hydraulic power or a tool being carried by an ROV. The vertical jumper connector mates with the upward-looking receiving configuration and effects mechanical, structural, and pressure integrity (or perhaps electrical or fiber-optic) seal. Often an ROV provides visual and mechanical assistance.

Horizontal connectors are first set in a preinstalled socket, and then the termination head is pulled using a subsea winch or pushed hydraulically, laterally into a mating connection. Horizontal connectors result in a straight line for the flowline or umbilical. Depending on the sizes involved, many of these connectors can be installed with standard work class ROVs.

Manifolds

Because they come in many sizes and shapes, manifolds are lowered to the sea floor in a variety of ways. Drilling rig cranes have installed many, but a more economical method is usually to employ a crane vessel. The crane lifts the manifold from the deck of the transport vessel and sets it in the water. (See fig. 10–13.) Sometimes the crane continues to lower the manifold, but in deepwater, the drop requires more wire rope than a crane normally carries. In that case, the load is then transferred to a winch that lowers the manifold as it plays out supporting wire rope from a spool. In some cases, the manifold is lowered to the sea floor by controlling the buoyancy so that a very low load capacity winch with plenty of lowering cable can be used. Some designs can be launched from the back of workboats and then sunk under controlled conditions with a light winch line providing guidance to the sea floor target.

The vessel used to lower the manifold into place, whether drilling rig, crane vessel, or workboat, locates itself using a global positioning system. (See chapter 1.) The location of the manifold, or any other item for that matter, being lowered is determined by placing acoustic transponders on the sea floor, on the manifold, and on the vessel. By pinging from the vessel and using the known speed of sound in water, distances and angles between the sea floor, the manifold, and the vessel transponders are determined. Using triangulation, the location of the manifold can be followed as it is lowered. Since the manifold is not hanging directly under the vessel because of deep ocean currents, the surface vessel has to move in iterative steps to get the manifold to the desired set-down spot. With meticulous patience but remarkably little time, the manifold can be put right on target with the correct orientation. Typical specifications call for the manifold to be placed within 5 feet of the designated spot, within 5 degrees orientation, and less than 5 degrees off level.

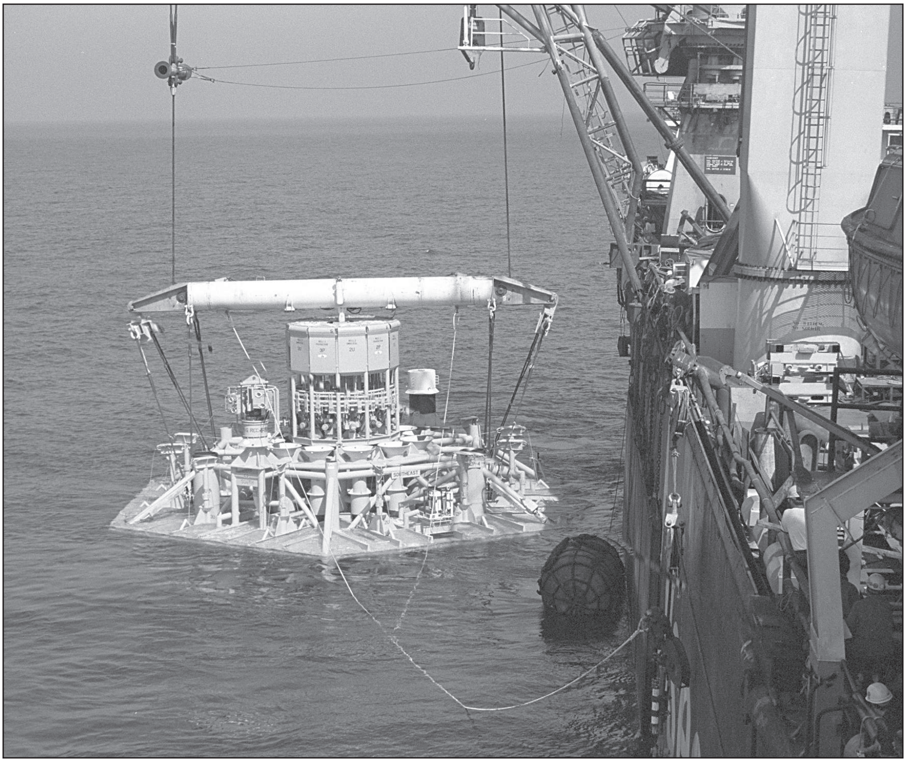


Fig. 10–13. A crane vessel lowering a subsea manifold. (Courtesy FMC Technologies.)

Umbilicals

Shipped from the factory on large steel reels, an umbilical is installed from the back of a work boat by unwinding it from the spool and lowering it to the sea floor. (See fig. 10–14.) Although short segments of an umbilical are stiff, over the long distance from the host platform to the manifold an umbilical flexes into a catenary shape on the way down and can snake around obstacles without buckling or otherwise losing integrity. ROVs do the subsea connections for umbilicals the same way as for the jumpers. The host end of the umbilical is then transferred from the installation vessel to the platform, where the connection is made on the deck in a blessedly dryer and more accessible environment.

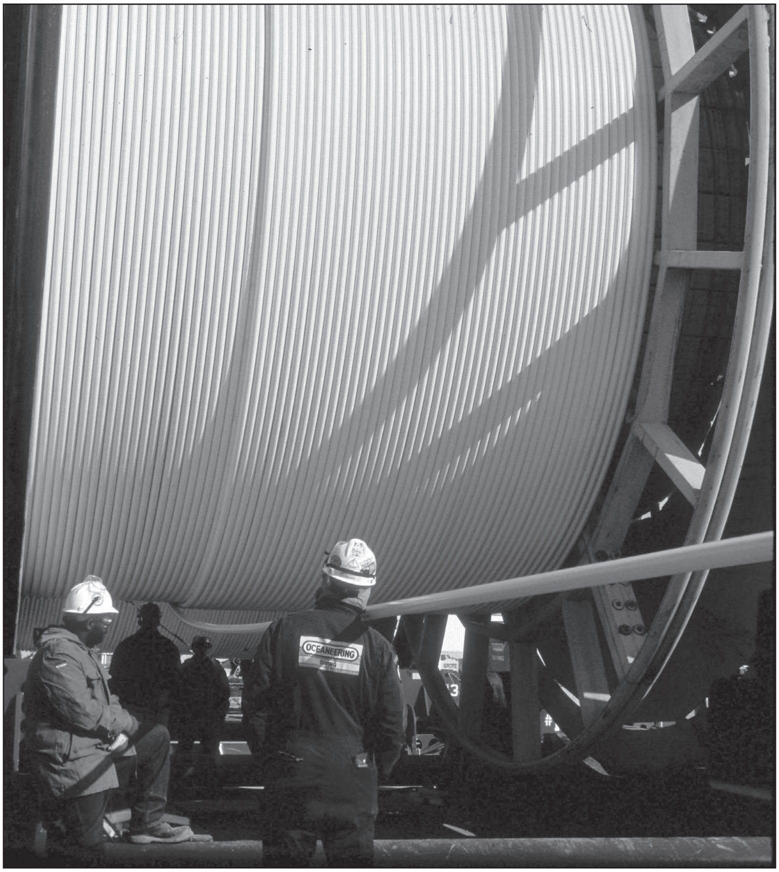


Fig. 10–14. Umbilical on a reel. (Courtesy Oceaneering.)

In many cases, only electrical or hydraulic or chemical lines need to be connected to a well or sled from the manifold, without the rest of the communications or other umbilical services. A smaller umbilical can be installed by having the ROV "fly" each end to its place, plug it in, and do the mechanical and integrity checks.

Choreography

Subsea systems involve many elements, so system designers work hard to reduce the work vessel schedule interdependencies during installation and to minimize the logistical effort involved in choreographing the time and space needs of the various work vessels. For example, a particular subsea system plan might have the following installation sequence: (a) install all subsea trees; then (b) install all flowlines; then (c) install the manifold; then (d) install gathering lines and umbilicals; and then (e) install jumpers and flying leads. If the need arises, with proper design and appropriate planning, the sequence could be modified to other combinations, as long as (e) is last. This flexibility allows for inevitable but unforeseeable schedule problems and gives the opportunity to use a wide range of vessels on an opportunity basis. The scheduling and implementation of these multiple efforts creates a new role in the process, the installation coordinator, the impresario of a safe and efficient project, who most certainly needs the cooperative innovation of the designers and contractors.

System Reliability

Because the subsea elements are way down there and hard to get to, designers and builders emphasize redundancy and reliability—not unlike the space industry. But as with space vehicles, items do fail and need replacement. The control pods on the tree and many other parts of the system are modularized so that they can be removed and replaced relatively easily. Though an ROV contractor is never satisfied that enough is done, system designers build in extensive ROV-friendly connections and contact points that make the ROV intervention simple and straightforward.

The operational uptime of the average subsea systems is remarkably good, approaching that of more accessible surface facilities in many areas. Subsea well problems are usually related to reservoir issues, not hardware problems.

Subsea Processing, Pumping, Compression, and Metering

Companies are incessantly addressing ways to do more on the sea floor to achieve two main advantages:

- Reduction of the capital for the offshore host facility, and the operational expense that accompanies it
- Increase in the ultimate recovery, thereby improving the economics

For any naturally flowing oil and/or gas well, there is a point when the reservoir pressure reduces to the extent that the well cannot overcome the system pressure—friction and head losses in the well bore, in the flowlines, and in the processing equipment—and it stops producing. There remains, in some cases, a significant amount of oil in the well. The only way to get it out is to reduce the back pressure to allow the well to flow again.

Onshore, thousands of so-called stripper wells have mechanical pumps run by pump jacks, the ubiquitous horse heads (or "nodding donkeys" in some parts of the world) that enable production. By directly pumping the oil from the reservoir the back pressure of the well bore is overcome, allowing more oil to flow to the well bore. The oil is then pumped to the surface.

What is the analogy for the offshore? Putting pump jacks on the sea floor or even on platforms is totally impractical, but pumps and compression facilities at the wellhead can overcome the back pressure from the thousands of feet of fluid between the sea floor and the surface. Furthermore if the oil, gas, and water can be separated at the sea floor, even better pressure conditions in the well bore can be achieved. (See fig. 10–15.) The resulting percentage increase in oil and gas recovery from a reservoir varies from case to case and with water depth, length of flowlines, and inlet pressure at the receiving facility. In some fields, the opportunity to achieve an increase of 20% to 30% in reserves exists. Recovery increases have to be traded off against capital and operating expense. Further, in some cases the initial production rate increases, adding quicker payback and more present value to the proposition (fig. 10–16). In any event, each case has to be analyzed closely.

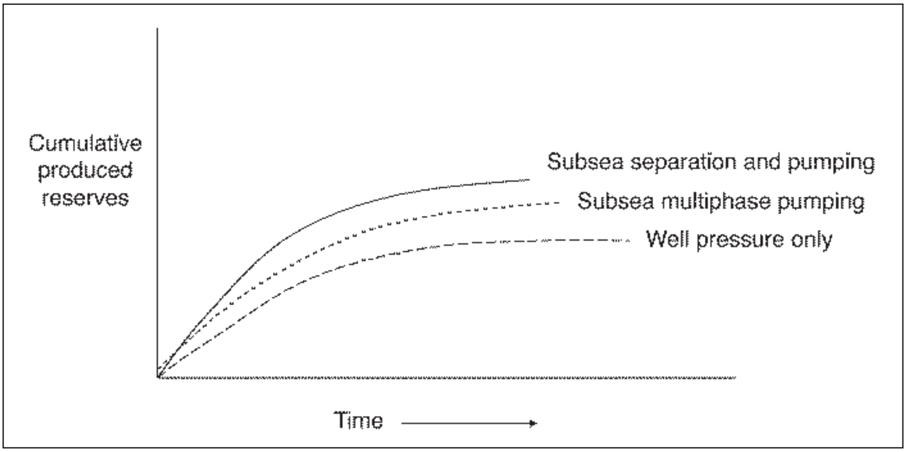


Fig. 10–15. Increased reserves from subsea pumping and separation

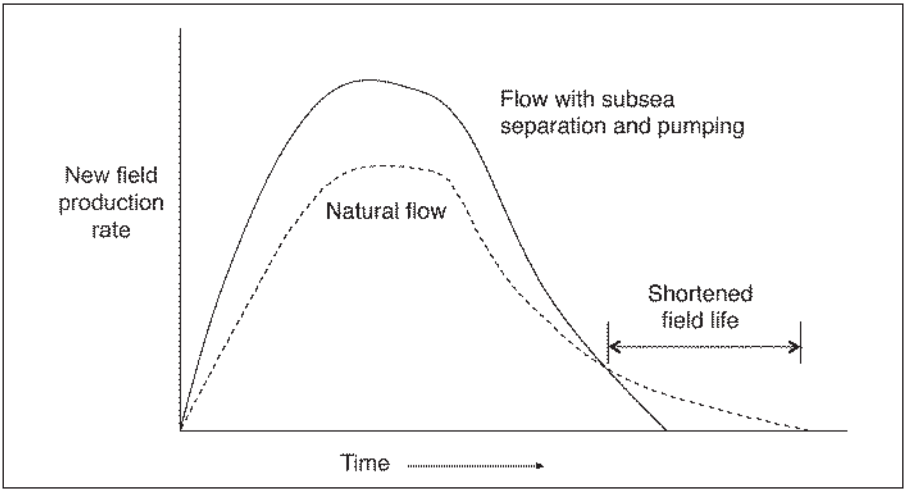


Fig. 10–16. Accelerated recovery with subsea pumping and separation

Subsea pumping

Research and development has progressed on the development of multiphase pumps—ones that can move a mixture of vapor and liquids and even some solids. Under selected combinations of liquid and gas, multiphase pumps have been very successful. Besides the increase in flow and ultimate recovery, subsea multiphase pumps reduce the amount of equipment and space needed on the host, which can impact venture profitability.

Subsea separation

Subsea separation followed by pumping the produced fluids to the surface complements the benefits of multiphase pumps, including reducing topsides equipment and space. The provision of the separation equipment on the sea floor, however, comes at a cost and risk, and is not always the most profitable solution.

The designs at Shell's *Perdido* field in the Gulf of Mexico and the *Parque das Conchas* field offshore Brazil use a vertical caisson 3 feet in diameter and 350 feet tall. Production from several wells commingles in each caisson, which is, in essence, a cylindrical cyclonic separator, relying on centrifugal force to separate the liquid and gas as the raw well fluid swirls down the outer walls. An electrical submersible pump (ESP) deployed inside lifts the liquid up through a riser to the host facilities for further treatment. Figure 10–17 shows the separator caisson concept used at *Perdido*. The gas and liquids from the caisson go to a single riser of three components. The outer annulus allows the relatively dry gas to flow to the surface; the middle annulus provides the corridor for the produced liquids being pumped by the ESP; and the small diameter pipe in the middle is there to carry liquid down to cool, and prime if needed, the submersible pump.

Since the ESP can handle a moderate amount of gas with the liquid, it is not necessary to get complete gas-liquid separation in the caisson. This design can handle a wide range in well flow characteristics, especially the gas/oil ratio, and water cut, that is likely to occur over field life.

The *Tordis* field in the North Sea has another approach. A separator was installed on the sea floor where the oil, water, and gas are separated. (See fig. 10–18). The water is reinjected, and the oil and gas are remixed and pumped to the surface by a multiphase pump. The expected increase in producible reserves at *Tordis* is on the order of 35 million barrels of oil, a 12% increase from natural depletion.

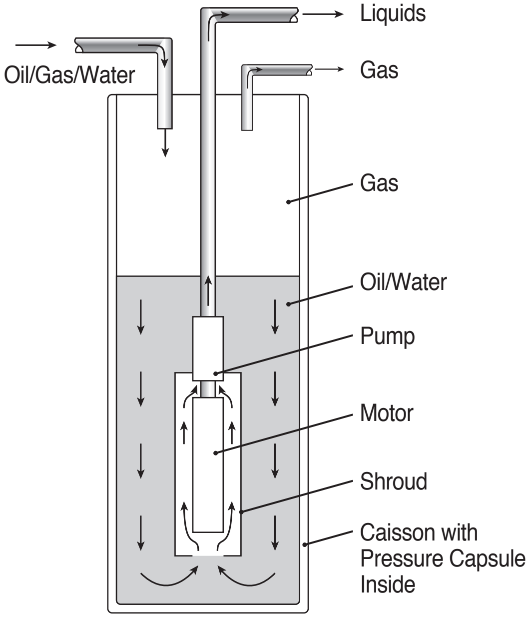


Fig. 10–17. Electric submersible pumping equipment used at *Perdido*

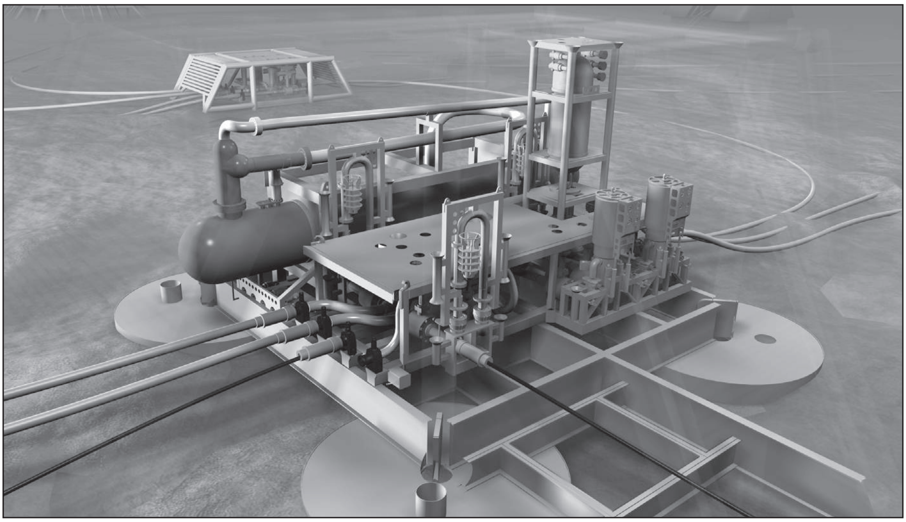


Fig. 10–18. Tordis subsea separation module with multiphase pumps and flow meters. (Courtesy FMC Technologies.)

Sea floor gas compression

This technology is applicable for long-distance offshore gas fields, perhaps connected to a shore base without an intermediate offshore platform serving as host. It can also be used in harsh environmental conditions where a subsea pipeline is preferred to a platform of any kind and for low-pressure reservoirs that need a boost to get the gas to market. Potential applications for this technology are in the Arctic and in deepwater, long distance step-outs worldwide.

Subsea multiphase metering

The normal way to determine the volume of oil, gas, and water being produced from each well is to measure the output after the well fluid has been separated into its three components. This is accomplished, as discussed in chapter 11, by using test facilities to determine how much of the total fluid and its components are being produced from each well. The data are needed for reservoir surveillance and reservoir management activities. Additionally, since it is not unusual to have different ownerships in the subsea fields served by a common host, these data are needed to allow a fair allocation of income. Further, the characteristics of the flow from each well would be of great use to the reservoir engineers and operations staff as they do their best to maximize the output from the field.

In most cases, several subsea wells are being produced into a common manifold and thence to a flowline. A good approximation of the actual production well by well can be achieved if individual wells are metered or continually production tested (which is not the usual case). But even though multiphase flow meters have been in operation in subsea fields for a while, their level of accuracy and reliability is well below single-phase meters. Even so, they are often the only means to provide a continuous picture of the well flow. Continuing research and development (R&D) and field pilots are advancing the technology and art of multiphase metering, and this will be an important component in future subsea developments.

Power

Subsea production stations have electrically driven pumps and perhaps even gas compression to deliver the gas and oil to hosts or shore bases miles away. That requires sophisticated and hardy electrical and distribution systems supplied from a distant host or a land base. Electrical issues involved with any long distance tiebacks need considerable testing and improvements. The esoteric and challenging subjects of parallel harmonic resonance in the power cables, whether to use AC or DC, and distribution losses all increase in importance as the host-to-field distance increases.

Subsea Intervention

The growth rate of the already thousands of subsea wells in the world created an opportunity to improve the efficiency of access for remediation. Traditionally this work has been and is being done by submersibles or drillships, with all the attendant issues of contract duration, slow mobilization, and, of course, cost. In many cases the need for a riser during subsea intervention requires a large semi-submersible or drillship. However there are many tasks, similar to those routinely performed on land wells or dry tree on hosts, that do not need the full service capabilities of a huge drilling rig. Zone isolation, re-perforating, chemical treatment for scale and wax removal, logging, and other downhole remediation can be done with light well intervention (LWI) units. (See fig. 10–19.) These vessels, which do riserless access to wells, have capabilities somewhere between the drillship and the semi-submersible drilling units in chapter 5 and the work boats discussed in chapter 13. These ship-shaped vessels have rapid deployment and dynamic positioning, which adds to their benefits and utility.

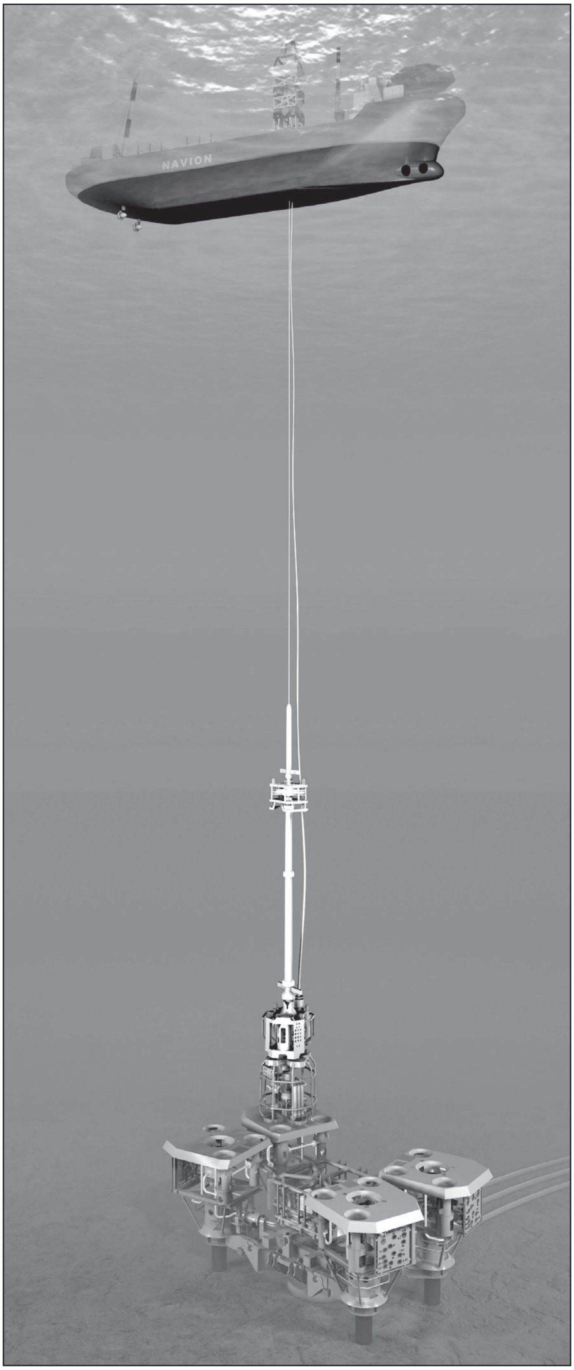


Fig. 10–19. Riserless light well intervention. (Courtesy FMC Technologies.)

Case Study

Subsea Springboard

Some beginnings are more humble and seemingly inexplicable than others. FMC Technologies' genesis was in 1884 when John Bean patented his high-pressure, continuous-action spray pump, designed for agricultural insecticide applications. For the next 100 years, the Bean Spray Company, then Farm Machinery Company, then FMC Corporation, grew to a world-class farm machinery manufacturer. Along the way, in the 1930s FMC extended one of its core competencies by buying a manufacturer of deep well pumps for irrigation, a precursor to its later offshore activities.

In the 1950s, when conglomerate building became so fashionable, FMC ventured into amphibious vehicles for the military, petroleum exploration and production, airport de-icing and cargo handling systems, fiber, film, and agricultural chemicals, and wellhead flow control assemblies, also known as Christmas trees.

Over the next decade, FMC leveraged its knowledge of fluid flow machinery to develop and deliver equipment for early applications of subsea wellheads. Soon after, to bring together all its related capabilities, it established a separate division for mechanical equipment development and manufacture.

By the 1980s FMC had established product lines for inclusive subsea completion systems, and with the acquisition of Kongsberg Offshore in 1993, became the world's largest subsea engineering, procurement, and construction company. A series of other acquisitions—National Oilwell's Fluid Control Systems, Smith Meters, the leading name in oil measurement, and CBV Subsystems—gathered related capabilities around the company's subsea efforts. (See fig. 10–20.) To these businesses FMC brought a culture percolated in mechanical engineering principles and machine tool applications.

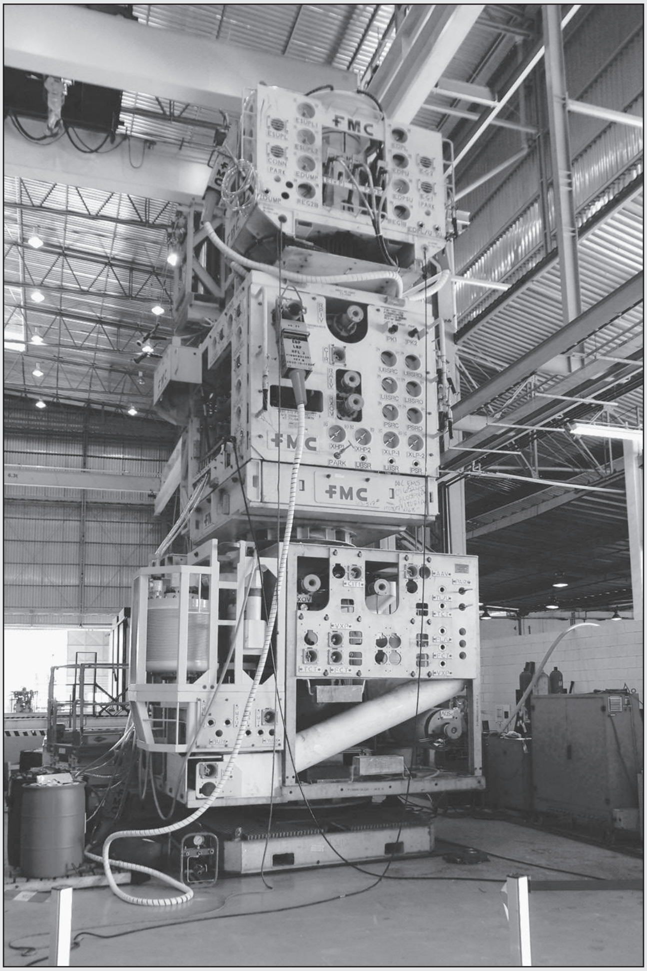


Fig. 10–20. Deepwater vertical tree. (Courtesy FMC Technologies.)

Eventually the complexity of the offshore business that demanded such intense management attention led to two corporate schisms. In 2001 FMC Technologies separated itself from its conglomerate parent, FMC. In 2008 FMC Technologies in turn spun off the farm machinery and airport systems operations as John Bean Technologies, returning that enterprise to its original and titular roots.

In the 2000s FMC Technologies rolled out a series of advanced subsea designs, most for deepwater—electric chokes and manifolds; high pressure, high temperature trees; submersible pumps; subsea compression; subsea separation; multiphase flow meters; through-tubing drilling; light well intervention systems; and remote operated vehicles. ROV development was enhanced by investment in Schilling Robotics, experts in packaging hardware and software for ROV toolsets and subsea packages. To augment its pace of technological innovation, FMC Technologies acquired its longtime ally, CDS Engineering, a developer of unique subsea oil/gas separation technology.

Meanwhile, the company pursued alliances with a few E&P companies, key players in the deepwater. That gave it the opportunity to develop and implement new subsea components and capabilities not otherwise possible by speculative efforts.

Timing is everything, of course, and in the 1990s and beyond, FMC Technologies caught the wave as subsea completions became the technology of choice by oil companies moving into deeper water. By providing both new capabilities and cheaper solutions, FMC Technologies helped lower the economic threshold of commercially attractive discovery sizes.

FMC Technologies' steep climb to success featured one critical strategy—single-minded commitment to exploiting core capabilities built around its mechanical engineering culture, while continually clearing management's mind of unrelated organizational clutter. (See fig. 10–21.)

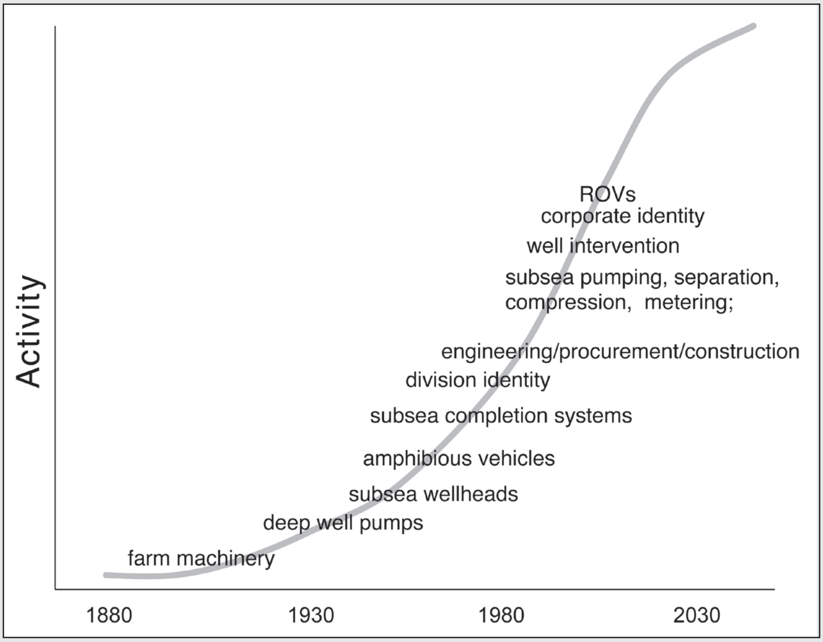
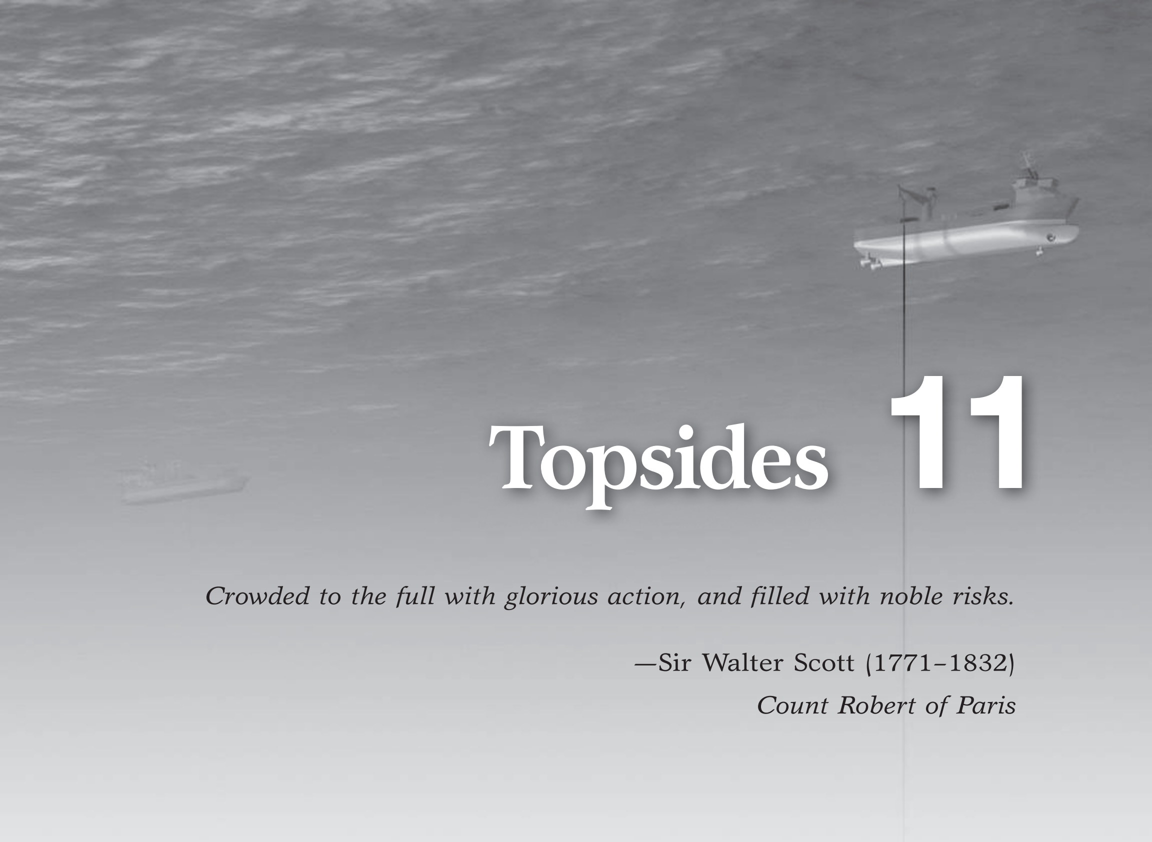


Fig. 10–21. The evolution of FMC Technologies



Topsides 11

Crowded to the full with glorious action, and filled with noble risks.

—Sir Walter Scott (1771–1832)
Count Robert of Paris

The name says it all. *Topsides*—the place atop the platform where the drilling and processing equipment sit, where scores of auxiliaries continuously labor away, and where the crew makes its temporary home. Topsides for FPSOs may look remarkably different from other floating systems and fixed platforms, but the list of necessities remains the same.

Production engineers wish that oil and gas would come out of the ground ready for sale, but most reservoirs disappoint them. In almost every case, a cocktail of oil, gas, water, and solids comes up through the riser to the platform. The mixture could be predominantly oil with some gas or the reverse. In either case, water usually accompanies the hydrocarbon. Since the designers have a wide range of possible realities when they are planning the facility, the actual topsides configuration and capacities have to be very flexible.

The term *topsides facilities* refer to the equipment and systems installed on the deck of a structure that accomplish the following processes and functions:

- Separation and stabilization of oil, gas, water
- Treatment of oil, gas, water

- Well testing to aid reservoir surveillance
- Compression
- Gas dehydration
- Metering
- Personnel accommodation (quarters)
- Utilities and auxiliary systems
- Safety systems
- Controls and power systems
- Well construction and servicing
- Exporting treated oil and gas to a delivery point for transport to market

The fluid from the oil wells is first separated into its main three components: oil, gas, and water. The gas phase may need to be treated, compressed, and dehydrated before being sent via pipeline to a market. The oil phase will need to be treated, primarily to remove even more water, and perhaps to remove salts, inorganic scales, and sand, dirt, scale, and corrosion products.

After treatment, the oil is sent to onboard storage and then shipped via either pipeline or marine vessels. The water is treated so that it can be disposed of safely either into the sea or back into the reservoir. Then an environmentally acceptable home must be found for the leftover trash. The basic process schematic is shown in figure 11–1.

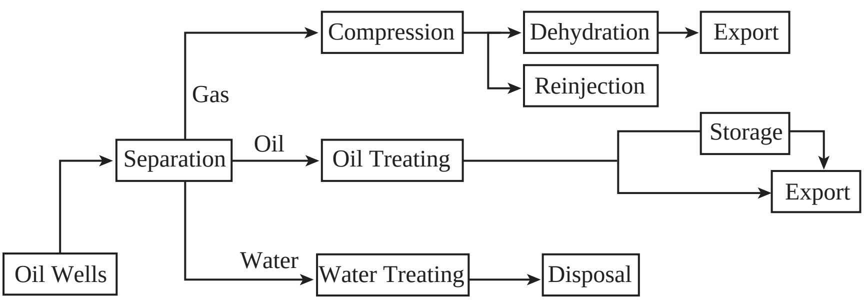


Fig. 11–1. Crude oil processing on deepwater platforms. (After Paragon Engineering.)

Fortunately, through a geological quirk, most offshore natural gas has minimal content of carbon dioxide (CO_2), hydrogen sulfide (H_2S), and other acid gases common to many onshore areas. With these small concentrations, the expensive apparatus to remove them is not needed. However, if much water vapor is present in the natural gas, even the small amounts of acid gas can dissolve in it and create corrosive compounds that attack topsides equipment and wreak havoc with pipelines. In that case, chemicals are added to inhibit corrosion before processing or transportation. Some cases even call for processing equipment fabricated from special, corrosion-resistant alloy steel.

Deepwater crude oils are mostly sweet; that is, most have less than 1.5% sulfur. Even for those that contain more, the sulfur does not present the potential for corrosivity that the acid gases in natural gas do. Sulfur in oil comes in the form of various complex hydrocarbon compounds that usually do not readily react to form corrosive compounds, so the oil goes through no treatment on the platform to sweeten it, leaving the refineries to handle that problem

Marketable oil, a loose specification negotiated with the pipeline or tanker company transporting it, generally needs a basic sediment and water (BS&W) content of no more than 0.5% to 3.0%. This BS&W can be "salty," having a salt content several times higher than that of ordinary seawater. Sometimes, however, there is an additional requirement that the salt content of the oil cannot exceed 10 to 25 pounds per thousand barrels. Facilities at the receiving refineries clean up the rest.

Topsides facilities are customized for every development. For some deepwater developments, very little processing equipment may be needed if the production is transported to a hub facility for processing. In other fields, the facilities may support only the drilling rig and/or wellheads. The optimum topsides will depend on the overall field architecture, proximity to existing infrastructure, and the operator's risk and cost tolerance. The design of the topsides facilities begins once the field architecture has been decided.

An important step in process facility design is selecting the basic process option for use in the field development. The range includes the following:

- **Minimum Wellhead Facilities.** All well fluids to be transported to other facilities (either onshore or offshore) for processing.

- **Medium Wellhead Facilities.** Well fluids are separated into the gas and liquid phase, and then transported to other facilities for processing.
- **Minimum Process Facilities.** Well fluids are separated into a gas stream, hydrocarbon liquid streams, and a water stream. Gas and hydrocarbon liquids streams are transported to other facilities for further processing. The water stream is cleaned and disposed of at the originating facility.
- **Full Processing Facilities.** Well fluids are separated and fully treated to market-ready gas stream and hydrocarbon liquid streams. The water stream is cleaned and disposed of at the originating facility.

Regional practices and existing infrastructure can significantly influence the amount of offshore processing to be done. In the Gulf of Mexico, the general practice is to process the hydrocarbon liquids to sales quality and to transport to market in common carrier pipelines. The gas is usually dehydrated and then transported to onshore gas processing plants. In other areas of the world different approaches are often taken, depending on offshore infrastructure and onshore capabilities. For example, in much of the North Sea, the liquids, which are delivered to onshore processing plants, still have some natural gas and natural gas liquids in them. The exported natural gas stream is often fully treated and transported directly to sales markets.

Oil Treatment

Every platform is designed to accommodate the unique combination of fluids expected to be coming up the riser, including anticipated future production from other fields and subsea developments. Of course the designers don't always get it right. Newly discovered fields nearby might be tied in; production from new zones in existing fields might have different characteristics. This might require retrofitting topsides facilities to handle different volumes and compositions over the lifetime of a platform.

Even though the topsides processing facilities are often complex and costly, they are not as complex as refineries or gas treating and chemical plants. The topsides facilities perform only relatively basic functions of separating, treating and measuring produced oil, gas, and water. In a refinery, sophisticated processes separate and crack the oil into marketable products such as gasoline, kerosene, fuel oil, diesel, aviation fuel, lubricants, and asphalts. Similarly, at onshore gas processing plants, gas is further processed beyond the offshore treatment to separate methane from the natural gas liquids, ethane, propane, butanes, and natural gasoline. However, the size of the offshore topsides facilities, the extensive number of separate systems that need to be designed and installed, the need to provide local power, and house people, all in a limited space, make the topsides design detailed and complicated.

Separation

For this section, think of the hydrocarbon coming from the riser as mostly oil with some associated gas. The first block in figure 11–1 involves separating the gas from the liquids. The well stream from the riser flows into a separator, a cylindrical pressure vessel, sometimes vertical, sometimes on its side. The sudden increase in volume and decrease in pressure causes the "beer bottle" effect. Just as the carbonation starts to leave the beer when the top is popped, the natural gas *flashes* or separates from the oil. Gravity pushes the gas to the top, where it is drawn off, and leaves the liquids at the bottom.

Actually, liquid/gas separation often takes place in several stages. (See fig. 11–2.) Even with the sudden drop in pressure, and even if the associated gas comprises only a small percent of the total, some gas may remain dissolved in the oil. Liquid flows from the first stage, a high-pressure separation, to a second stage and third stage, where pressure reductions cause more gas to flash. In the first two stages, the liquid is a combination of oil and water. Any entrained water follows the oil path. Everyone knows oil and water don't mix, and conveniently, in the third stage the water—or most of it—drops to the bottom of the separator, leaving the oil in the middle. The three separated phases leave the separator through separate nozzles, heading for the next phase of treatment.

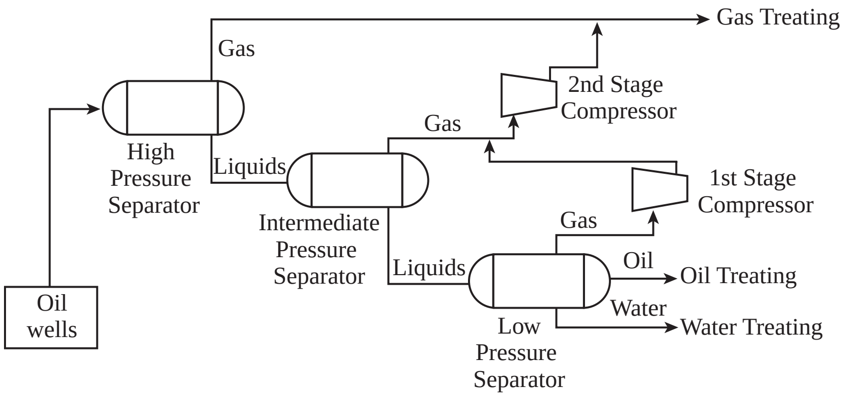


Fig. 11–2. Gas separation on deepwater platforms. (After Paragon Engineering.)

By that stage, live oil has transformed into dead oil. For arcane reasons having to do with vapor/liquid phase equilibrium, reducing the pressure of the well stream fluids in multiple stages results in a better gas/oil split than a single separator would and results in dead oil with a lower vapor pressure, which is good for transportation purposes. The first stage, where most of the gas comes off, runs at a pressure higher than the export riser requirement. That way, most of the gas, even with pressure drops through downstream treating, can flow with no boosting to an export line. Reinjection of the gas would require additional compression. The gas coming from the latter stages has to go through compressors to reach the pressure necessary to commingle it with the first stage gas.

There are, as one can imagine, many variations of the above separation system. While three are common, some systems have two and even four and five stages of separation, depending on the fluid characteristics from the well bore and transport facilities. In addition, some separators are "two-phase," and some are "three-phase." The two-phase separators separate the well fluids into a liquid stream and a gas stream. Three-phase separators go one step further with the liquid stream and separate it into oil and water. In the example discussed above, the system had a pair of two-phase separators and a single three-phase separator.

Three-phase separators are either horizontal or vertical, large-diameter steel tube pressure vessels. The horizontal vessel (fig. 11–3) is more common than vertical separators offshore, but variations abound. Indeed an entire niche industry specializes in the technology of this simple concept.

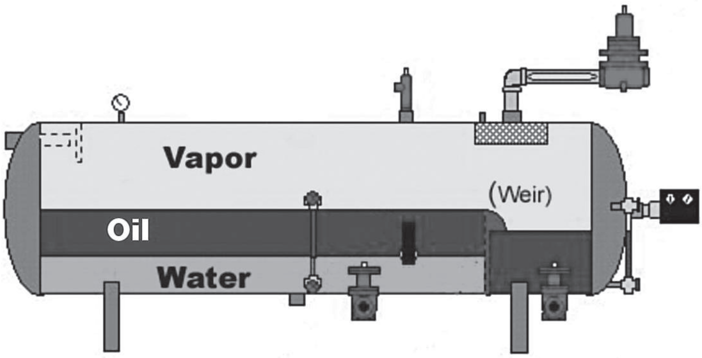


Fig. 11–3. Three phase horizontal separator. (Courtesy United Vessel.)

As the well fluids flow into the vessel, they splash against a steel plate to absorb the energy. The sudden change of pressure causes much of the liquid/gas separation. The gas rises to the top of the vessel, and the liquid drops to the bottom. The water and oil are, of course, immiscible, and gravity forces and density difference cause the water and oil to separate. The vessel is sized large enough to allow time for the oil/water separation to occur. The oil flows over a weir into an oil containment area, and the water stays on the bottom of the vessel from where it is removed via piping. Mechanical or electronic devices control the liquid levels and open and close dump valves to allow the water and oil to be drained off.

The gas flows laterally through a mist extractor, which collects oil droplets in the gas flow and allows them to fall down into the oil phase, then into a flowline at the top via the pressure control valve that maintains a constant pressure in the vessel.

Mist extractors come in a variety of types and materials. Common ones are woven wire mesh, made of steel or other materials. The droplets of liquid still in the gas phase strike the wires, coalesce, and drip back into the oil phase.

Treaters

The settling-and-flashing technique of a separator, rudimentary as it is, may not quite do the water/oil split, especially for very viscous crude oils. If the water content remains too high, the oil is sent to a water-removal treater. (See fig. 11–1.) Many different designs are available. The treaters lower the viscosity or break oil/water emulsions by heating, electric current, agitation, or other means to increase droplet size of the water contained in the crude oil. This in turn is followed by quiescent sections where the water settles to the bottom.

From the treaters, the dry oil, or as dry as it has to be given the BS&W specification, flows to a rundown tank, where a pump moves oil continuously into the export riser or to a larger tank for transport in large batches to a shuttle tanker.

Most streams arriving at most deepwater platforms have only moderate amounts of solids in them, but where they occur they have to be separated using sedimentation settlement tanks, hydrocyclones, and filters. The solids can then be cleaned sufficiently by washing with relatively oil-free produced water and disposed of overboard or hauled from the platform in workboats to onshore disposal sites.

Water Treatment

Just as the oil from the separators still contains water, water from the separator still contains some oil. The logical destination of the water is overboard, but its quality and environmental concerns may call for reinjection into the subsurface. In either case, the oil needs to come out of the water, and solids removal may be also required.

One of several types of processes, skimmers use a long residence time in a vessel with a large surface area to allow the small droplets of oil to rise. The top layer, heavy with oil, passes over a weir or is skimmed mechanically. Sometimes stubborn oil emulsions that hold in the water call for chemical additives to speed the separation process.

Plate coalescers, an alternative separation process, use closely spaced electrostatic charged plates to attract or repel the water and oil ions, causing separation. These close plates reduce the distance that the small oil droplets must rise before being captured by the plate and channeled to the top for skimming.

Another innovative device is the hydrocyclone. The water/oil mix is squirted into the inside of a cone at high velocity via a tangential inlet. This causes the fluid to "spin" at a high rate of speed in a cyclonic manner, forcing the heavier water down and out along the inside surface of the cone and to exit the bottom. The lighter oil moves upward and inward to the center axis of the cone and out the top. Often the topsides have two or more of these processes in series to progressively reduce the oil content of the water.

The requirement for allowable oil concentrations in water that will be discharged back into the sea as of the year 2008 in various parts of the world is shown in table 11–1.

During the various oil/water separation processes, some natural gas comes off. A line from the top of the vessels moves it to a convenient injection point in the gas treatment section.

Table 11–1. Maximum allowable oil concentrations in discharged water as of 2008

Location	Maximum Concentration (mg/l), monthly average measurement
North Sea	30
USA Offshore	29 avg/42 max
NE Atlantic & Arctic	40
Mediterranean Sea	10–15
Caspian Sea	20 (under review)
Red Sea	15
Nigeria	15 (creeks) 30 offshore
Indian Ocean	48
Western Australia	30 (50 max)

Gas Treatment

Heating

A typical gas well has several thousand pounds per square inch of pressure at the wellhead, much higher than needed to treat it on the platform and export it. As the gas moves through the choke, a carefully designed constriction in the flowline, the pressure drops, and the volume expands, and following Boyle's Law, the temperature drops precipitously. Residential and commercial air conditioners depend on this same principle: the temperature drop of an expanding gas.

As the temperature drops, whether the wellhead is located on the seabed or at topsides, the water in the gas stream can turn to liquid or, worse, form hydrates. Snow or slush-like in appearance under close examination, hydrates form as methane trapped in icy crystals. They can easily plug a flowline. Hydrates can form at any temperature between 30°F and 80°F if the line pressure and water content of the gas is just right.

When hydrates plug a wellhead or flowline, defrosting them can be difficult and perilous. Hoping that once the flow stops the hydrates will disassociate is akin to thawing frozen water pipes in Alaska: wait until spring . . . maybe. And when the hydrates do melt and release the backed-up pressure, equipment downstream can get a sudden and dangerous jar.

To avoid hydrate formation and the plugging that goes along with it, the chokes and a segment of the flowlines from a topsides wellhead are enclosed in a heated water bath kept at a high enough temperature so that the gas is always above the hydrate-formation temperature. (See fig. 11–4.)

Separation

Even if the gas coming from the riser originated in a gas well, it runs through a separator to remove condensate and water in the same way described for oil. Water drops out the bottom, oil from the middle, and gas from the top. Though not shown in figure 11–4, the separation can be run in the three stages of figure 11–2. Condensate has the composition and other characteristics of very light crude oil.

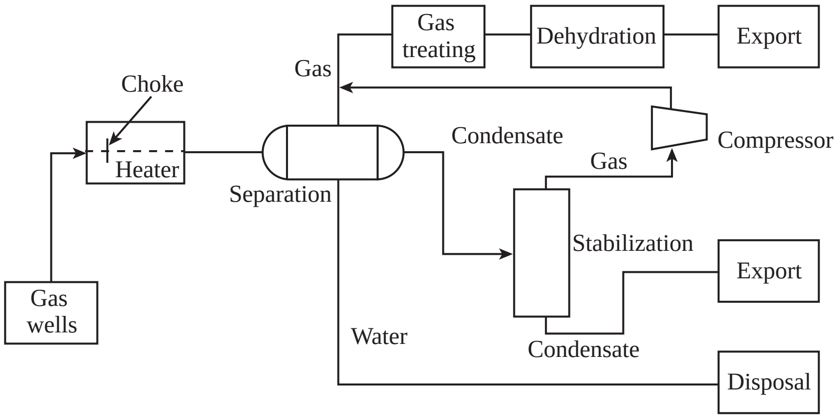


Fig. 11–4. Natural gas processing on deepwater platforms. (After Paragon Engineering.)

Stabilization

Sometimes the multistage separation process is not sufficient to stabilize the condensate—the oil/condensate coming out of this simple piece of equipment could still have more volatile gases than desired dissolved in it. Since the condensate gets stored in a tank aboard the topsides, at least momentarily and sometimes for a day or more, the volatility presents a hazardous condition. The vapor pressure of the condensate, a measure of the content of light gases such as butane, propane, ethane, and even methane, can be reduced by passing the condensate through a stabilizer. The condensate first goes through a heater and then flows into the middle of a column, maybe 30 feet tall, with perforated trays or packing inside. The light gases work their way to the top, wringing out any liquids, which fall toward the bottom. As the liquids fall to the bottom, the sloshing action through the trays or packing agitates any volatiles out and toward the top. Because of these two actions, wringing out and agitation, on each tray or level of packing additional separation occurs. That is, the concentration of heavier hydrocarbons dissolved in the gas reduces as the gas moves upwards, and the concentration of volatile gases dissolved in the oil decreases as the oil drops to the bottom.

The gas from this step goes through a compressor and then commingles with the high-pressure gas stream for treatment and dehydration.

Gas dehydration

Gas going into the export riser has to meet maximum water content. Otherwise, the water could condense and accumulate in low spots, form hydrates, or otherwise constrain flow. Furthermore, water combined with small amounts of any acid gases can cause a slow but corrosive reaction with almost everything it touches, such as pipelines, treaters, compressors, and all the other equipment aboard.

A glycol dehydration system is most often used to remove the water from the gas stream. The gas flows into the bottom of a column with trays or packing. (See fig. 11–5.) Triethylene glycol (TEG) or a similar chemical enters the top of the column. TEG has an affinity for water, and as it sloshes past the gas, it absorbs most of the water and carries it out the bottom of the column. Dehydrated gas exits the top. Dehydrated gas is not to be confused with *dry gas*, which is natural gas with the *natural gas liquids* (propane, butane, and natural gasoline) removed.

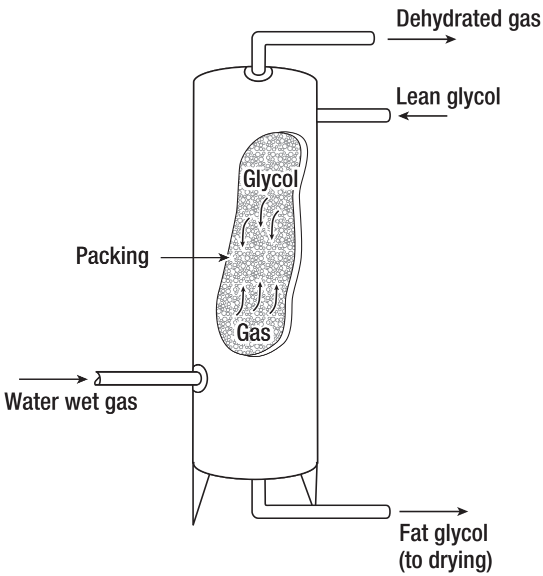


Fig. 11–5. Gas dehydration column

The TEG then goes to a regeneration step. First it goes to a separator, where any entrained oil can be skimmed off. Then it goes to a heater where the temperature is raised to about 400°F. This causes the water to vaporize, leaving behind the TEG, whose boiling temperature is 549°F. The regenerated TEG goes back to the top of the contact column for reuse. The water vapor goes either to the atmosphere or to a cooler to condense and capture any hydrocarbons that made it through the entire process.

In an alternative dehydration process, a desiccant or absorbent like silica or alumina gel in two parallel steel tanks captures the water. The gas stream flow is alternated between the tanks: while the absorbent in one tank is heated to drive the collected water off to the atmosphere, gas passes through the other tank to have the water removed. In some cases refrigeration or membrane permeation systems do the dehydration.

Once the gas is properly treated, it is sent into the export riser, on its way to market. In most deepwater environments the sea floor temperature runs at 30°F to 35°F. Since the gas export riser and the pipeline run along the sea floor, the temperature of the gas soon drops to the surrounding temperature. Typically the water content (in vapor form) is limited to three or four pounds per million cubic feet of gas. At the normal operating pressure of the export line (1,000 to 1,100 psi), with that much water, the gas has a dew point of about 0°F. (Dew point is the temperature at which water begins to condense in the form of droplets. Dew point varies with pressure.) That gives a +30°F to 35°F safety margin to keep the water in the vapor phase.

Well Testing

To properly do reservoir surveillance and reserve management and to diagnose well problems as needed, keeping track of the gas, oil, and water production from each well is essential. In some cases, the ownership of the individual wells varies, so a method to effectively allocate total production back to individual wells is needed for fiduciary reasons. A typical method to get data is to provide a system in which each well is periodically tested. The total production can then be allocated to each well on a percentage basis, based on the tests. The frequency of well tests depends on several factors. Common ownership of all the wells and reservoir management call for less; fiduciary issues call for more.

A test system has the same type of three-phase separator vessels, albeit smaller, as employed in the full operation. Valid tests call for the same well conditions as producing into the common flow. Test separators have to be operated at the same pressures and temperatures, and so on, as the flows from the commingled wells.

For onshore wells, or for offshore dry tree locations, it is a relatively straightforward process to routinely test every well in the field over a monthly schedule. The fluids from the test separator are put back into the downstream flow with the rest of the platforms production, so there is no loss of overall production. For subsea production, however, the only way to do similar testing would be to shut down other wells to allow the test flow full access to the flowlines or to provide dedicated flowlines to each well—an unacceptable cost.

As discussed in chapter 10, multiphase meters, even with their limitations, are the fallback for subsea wells. Indeed, they are now being used on some surface facilities as well, and as they improve in accuracy they will replace the test separator entirely. The data will be continuous and complete over the life of each well, not intermittent as is the case for the well test. In addition, multiphase meters require less topsides space and piping.

Metering

Sending oil and gas into the export risers can be like pumping money overboard if accurate metering doesn't take place. For oil, a lease automatic custody transfer (LACT) unit measures volume. LACT units come in many sizes and levels of sophistication. The larger units have built-in meter provers, devices that automatically and periodically recalibrate the meter. Most LACT units also have probes to monitor BS&W content. Some even block the flow to the meter if the crude oil fails to meet the BS&W specification. After all, who wants to pay full oil prices for water and sediment?

The mechanism in a LACT unit is most often a positive displacement (PD) meter, a direct measurement device. It divides the flow into discrete packets and counts the number passing through the meter. A PD meter operates by having the flowing oil drive its internals of vanes, pistons, or rotors, which displaces a known and specific amount for each revolution.

The revolutions are counted, either by a mechanical device or more commonly by reading electrical pulses, measuring the total volume. Readout devices provide a continuous update of status.

Another type, the turbine meter, measures volume flow indirectly. It belongs to the "inferential" family of meters. Turbine meters infer the volume by measuring the rotation speed of a turbine suspended in the flow stream. PD meters are more widely used for custody transfer, but if they are properly calibrated and maintained, both work.

Another form, the ultrasonic meter, uses the transit time principle. Signals emitted from transducers travel faster when moving with the flow than when moving against the flow. The difference in transit time is used to calculate the flow rates. Ultrasonic meters have found some use in gas pipeline applications. They have been developed to the level of reliability and accuracy so as to be used as fiscal meters in some applications.

For gas, *orifice meters* are used often to measure the flow. An orifice meter has three essential elements: (1) a conduit or pipe through which the gas flows; the conduit contains (2) an orifice plate, which is a flat steel plate with a precise hole in the middle; and (3) a means to measure the difference in pressure caused by the disturbance created by the orifice plate, from its upstream side to its downstream side. This differential pressure is proportional to the square of the flow velocity, and so it follows that the flow rate can be calculated from the pressure differential. Orifice meters have a long history dating back to the Italian physicist Giovanni Venturi. They are reliable and accurate, with a range of plus and minus 0.05%, and hardly anyone argues about that precision.

Topsides Construction Options

Topsides come in many sizes and shapes but can be loosely categorized into three main types:

1. Skid-mounted equipment
2. Integrated decks
3. Modularized decks

In the early days, the most effective way to build topsides was to have a structural deck fabricated first. The process equipment was then brought to the deck fabrication site and installed on and in the deck. Each item—compressors, quarters buildings, heliport landings, etc.—had to have enough structural support steel to provide the strength and rigidity needed to transport and install it. That is, each piece was mounted on its own skid so that the skid steel for each equipment item did not share in the load-carrying needs of the entire deck.

Many of these equipment skids did require considerable structural steel to allow them to be lifted into place, either offshore or at the deck yard site. Much of the necessary flowlines, pressure piping, and electrical, pneumatic, and hydraulic lines could already be installed on each component skid when it arrived. The rest would be added after the skids were set; for example, the skids were "hooked up" to each other—which often occurred offshore. One advantage of this design was that the structural deck could first be used to accommodate the drilling and completion rigs and then later receive the production skids. A disadvantage was the reality that doing offshore hookups cost 5 to 15 times as much as those done onshore.

For integrated deck and topsides, the individual pieces of process equipment are placed in the structural deck as it is being fabricated, with the steel structural deck members directly integrated into the support system for each piece of equipment. The electrical, pneumatic, and pressure piping systems are fabricated and installed for the entire set of equipment, not just a hook-up of individual skids. That saves structural steel and overall topsides weight. However, the equipment and structural work scheduling is much more intense, given the limited deck space.

As the deepwater decks became larger and larger, it was a necessity to split the deck into smaller, liftable pieces and to allow them to be built more cost effectively by niche contractors. Topsides were modularized by function—compressor modules, well bay modules, quarters modules, and so on. This version had some of the characteristics of both the skid-mounted and the integrated deck topsides and varied considerably from project to project.

The Mars TLP topsides (fig. 11–6) was built in five major modules by five specialty contractors and then installed module by module at the quayside. (See fig. 11–7.) The module setting was then followed by several weeks of intra-module hookup, testing, and commissioning.

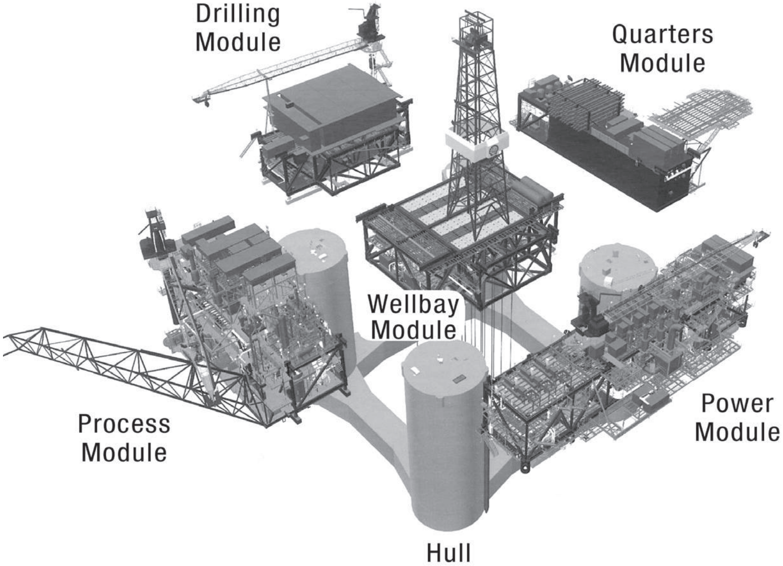


Fig. 11–6. Exploded view of Mars TLP topsides. (Courtesy Shell E&P.)

Fig. 11–7. Deck module being lifted onto the Mars TLP. (Courtesy Shell E&P.)

Hook-Up and Commissioning

Hook-up and commissioning field work is initiated when all the topsides modules or skids are placed on the host structure. Successful projects plan these activities from the early stages of concept development. Even though the modules shown in figure 11–6 may well be individually complete and functionally tested, there will remain a ton of intra-module connections and testing to do before the entire system is integrated and fully functionally confirmed. Under the overall guidance of construction engineers, numerous technicians, specialists, and craftsmen—electrical, pneumatics, hydraulics, computers, structural welders, structural fitters, pipe welders, pipe fitters, welding x-ray and ultrasonic technicians, crane operations, safety coordinators, corrosion specialists, and more assemble and test it all.

The best place to do this work is onshore or at a quayside, before the facility is moved to its offshore location. TLPs, FPSs, FPSOs, and concrete gravity–based platforms may all have their topsides decks and facilities fully integrated before they leave the quayside on their way to the installation site. Spars and fixed platforms always have their topsides modules set after they are in place. This requires that some of the hook-up and commissioning be done offshore, at a considerable cost premium. Dealing with a large workforce on one structure, with all of its attendant scheduling, organization, and safety issues is challenging at an onshore location. Doing the same work offshore adds the issues of offshore quartering and feeding of people, delivery of needed materials by boat and helicopters, and the need to plan for contingencies well beyond that required onshore.

The availability of sleeping accommodations, for example, may well limit the number and type of craft people who can be scheduled. Hotel ships have been employed to increase the available staff, but this comes at high cost.

Successful projects begin their hook-up and commissioning planning activities at the early stages of concept development. Engineering and operations staff, working closely with the design and construction teams, develop and modify the path forward as the project progresses to ensure readiness and a smooth transition from fabrication to hook-up and commissioning.

Personnel and Their Quarters

Complement

The crew size on an offshore facility depends on the number and complexity of wells, the equipment, and the overall philosophy of the operating company. Some platforms have advanced electronic and computer-assisted controls that run much of the operation; others are more reliant on people to operate. As an example, say a certain facility needs a full-time operating crew of 60 to operate and maintain—40 during the daytime and 20 at night. (Some jobs require only a daylight shift.) Another 60 are on their days off and about 15 more have to be available for vacation coverage, sick leave, and other contingencies. All in, the complement adds up to 135 people, about 2¼ times the daily contingent.

Shifts

For most offshore operations, the crews stay onboard and operate the facility for one week, working 12-hour shifts, then have one week off. In the deepwater arena, the crews may do two weeks on and two weeks off. In remote locations, it is common for the schedule to be four weeks on and four weeks off.

Quarters

All these qualified people need a place to spend their off-duty time on the platform. They need sleeping accommodations, food service, fresh water, electricity, laundry, stores, medical facilities, relaxation rooms, and workout rooms. Figure 11–8 shows the dining features in the crew's quarters on the *Ram Powell* TLP in the Gulf of Mexico. For obvious safety reasons personnel facilities sit as far from the drilling, the wellheads, and the hydrocarbon handling equipment as possible. No one questions that the design, comfort, and safety features of these facilities lend themselves to the efficiency and effectiveness of the operation.

Fig. 11–8. Crew quarters on a deepwater platform. (Courtesy Shell E&P.)

The galley on a production platform typically serves four meals daily—the normal three plus a midnight meal for the night crew. Snacks are set out often during the day. In a typical week during peak times, the *Ram Powell* galley serves 2,600 meals using 160 dozen eggs, 1,350 pounds of meat, 500 pounds of potatoes, and the crew does 840 loads of laundry.

Personnel transportation

For most deepwater platforms, crews move to and from in large helicopters, sometimes carrying as many as 24 passengers. Even so, large facilities need several round trips during a shift change. A helicopter-landing platform sits on the top deck, generally above the crew's quarters, because it too needs to be as far from the operating equipment as possible for safety reasons. Some deepwater operations are close enough to shore bases and have calm enough waters that personnel can move in cheaper crew boats. Crews transfer from the boat to the platform in a "Billy Pugh" basket lifted by the platform crane.

Safety Systems

The safety of people working around complex equipment, in an environment that is itself quite volatile, demands the full attention of the system designers and the actual operations staff as well.

If process controls always worked, if equipment never failed, and if personnel were always careful, safety would not have to be systemic. But they don't, so it is. The design stage for equipment and facilities integrates safety with operations. In practice, that calls for measuring pressure and temperature and other operating parameters at many places on the platform, with feedback loops to allow corrections or shutdowns if the process gets beyond safe limits. It also means fire retardant material covering structural members, wash stations where they might be needed, hazard detection systems, sprinkling systems, and other damage-control apparatus.

Operating procedures call for periodically maintaining, testing, and calibrating the safety devices. Industry organizations such as the American Petroleum Institute, the Norwegian Petroleum Directorate, the United Kingdom Offshore Operators Association, and the International Standards Organization publish well-vetted guidelines for all aspects of safety. In the end, the most important safety feature is pervasive safety awareness.

During the design phase, hazardous operation reviews evaluate a thorough list of "what if" questions. Suppose a certain valve malfunctions. How is a ruinous failure averted? What if a pressure monitor fails? What's the backup? What if a pressure relief valve pops? And so on.

Also during design, while the crew goes through operations training, they learn how to watch for the development stages of dangerous conditions and how to react to a full array of calamities. The money spent on attention to safety during the design phase easily reaches 50% of the topsides costs.

Large platforms have a last escape route—crew capsules. Designs vary, but they are the equivalent to lifeboats on a passenger ship. If a serious failure occurs—explosion, uncontainable fire, or the failure of the platform—the crew flees to the capsule and leaves the platform. Capsules sit in several strategic places around the platform, with access paths clear at all times as part of the safety program. Figure 11–9 shows a 40-person escape capsule. Normally a platform has enough capsule capacity to handle one and half times the onboard complement of workers.

Fig. 11–9. Survival capsule aboard a TLP. (Courtesy Survival Systems International.)

Auxiliary Systems

Extensive (and expensive) as the main functions just summarized are, the auxiliary systems supporting them often require more engineering time and effort and capital expenditures. Figures 11–10 and 11–11 show possible overall layouts of topsides on a fixed platform and on an FPSO. Again, the general rule is that the living quarters are kept as far from the process area as possible.

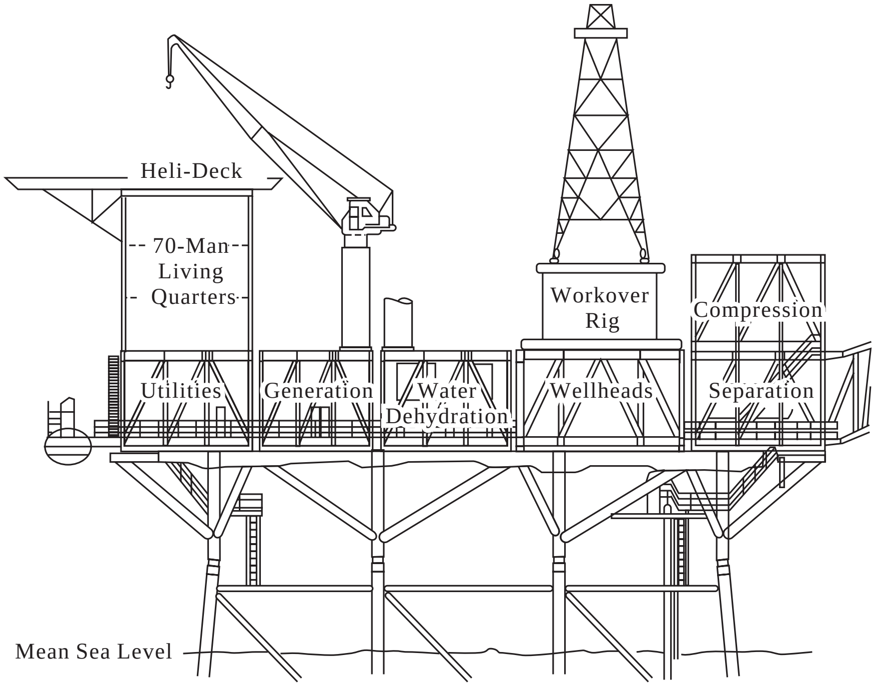


Fig. 11–10. Topsides layout of a fixed platform. (After Paragon Engineering.)

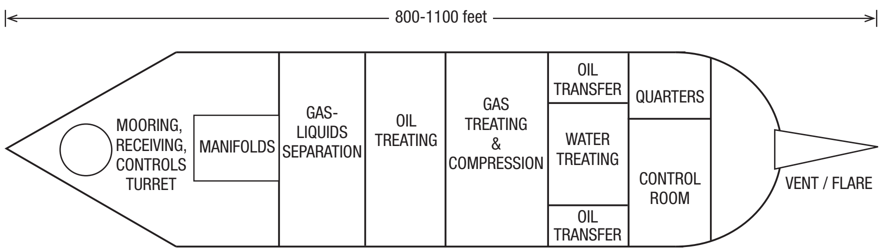


Fig. 11–11. Topsides layout on an FPSO

Auxiliaries

As extensive as the main functions are, the auxiliary systems that support them take even more time and capital and, often, maintenance expense. They can be grouped into two types, major auxiliaries and secondary support.

Major auxiliaries

- Power
- Pumps
- Cranes
- Emergency flaring
- Control centers
- Electrical switch gear rooms
- Instrumentation
- Crew quarters
- Export pipeline
- Compression
- Fire detection and protection
- Emergency shutdown

Secondary support

- Fuel gas treatment
- Instrument air
- Diesel storage
- Laundry
- Potable water
- Sewage treatment
- Pigging capabilities
- Boiler feed water
- Re-injection water
- Steam boilers

- Waste-heat recovery systems
- Glycol regeneration
- De-salters
- Gas lift
- Chlorination
- De-aeration
- Chemical injection
- Hydraulic systems
- Pneumatic systems
- Health and wellness
- Heating, ventilation, and air conditioning
- Rain water drains and treatment
- Injection systems: water, gas
- Maintenance and repair shops
- Electronics repair

Not all the auxiliary systems are needed on every platform, and on some a few of the secondary supporters might well be major. Each and every system, major or secondary, will call for significant engineering and operational knowledge to design, build, install, integrate into the overall topside, hook up, commission, and operate. The successful topsides are truly an integrated system—including the human worker—that are built on and by an extremely broad base of technologies, materials, and systems.

Power

Most equipment on board is powered by electricity—pumps, lighting, personnel facilities, ice cream machines, and computers. The odd gas-fired or diesel engine shows up occasionally on topsides, but the design, installation, maintenance, and operation of electricity-driven equipment make the most sense.

For platforms with an adequate supply of natural gas, gas-fired electric generators are always chosen. The next best alternative, a diesel-fired generator, requires that the diesel fuel be transported to the platform and stored onboard. Even then, turning diesel fuel into electricity to drive rotating equipment, such as compressors and pumps, makes more sense than placing direct drive gas-fired or diesel engines around the platform. For that reason, gas-fired or diesel engines rarely find a home onboard except for electricity generation and for large compressors (greater than 1,000 horsepower) and pumps.

During peak activity levels, electricity consumption can chew up large volumes of gas or diesel. The *Ram Powell* TLP in the Gulf of Mexico, during its drilling and completion phase, generated enough electricity to have supplied 7,000 homes. The various turbines and engines around the *Ram Powell* topsides have the equivalent power capabilities of about 225 big Ford pick-up trucks, the Model 350 V8s.

Pumps

The ubiquitous piece of equipment on the topsides is the pump. Big pumps move oil into the LACT unit, water to reinjection or disposal, and oil to treating. Smaller pumps move skimmed oil, methanol, cooling water, firewater, and so on.

Cranes

Most of the equipment, maintenance supplies, and sustenance need to arrive at a deepwater facility by supply boat. Platforms have at least one crane, and some two or three, to offload their supplies.

Flares

Almost all regulatory jurisdictions require natural gas flaring on a continuous basis to be kept to a minimum. Still, safety and engineering design call for an outlet for the natural gas, especially for emergency conditions, since it cannot be stored in a surge tank like oil.

Piping from the affected equipment is run across the topsides and goes up a riser into a flare tower or a flare boom. That takes the flare flame away from both the facilities and the people. A flare has both an ignition system and a constantly lit pilot to ensure instantaneous response to emergencies.

Produced water injection

Disposing of the water produced and then separated from the well stream requires a complete set of piping, pumps, valves, and operational savvy. The water can be directed to either the producing formation or to another formation.

To avoid loss of injection capacity by plugging the reservoir's pore volume, additional treating of the water beyond the oil removal discussed earlier may be required. This may involve extra equipment and will definitely involve some type of chemical scale inhibition treatment before the water is pumped back down into a reservoir.

Process control system

The entire topsides process, including the auxiliaries, can be controlled and operated via either a simple or a complex process control system. Many existing platforms have controls local to the equipment. They may be either electronic or pneumatic or a combination of both. Newer systems rely more on centralized computerized controls, with feedback loops, trend projections, and forward-looking diagnostics to help the operators anticipate as well as react. From this central location the operator can operate valves, level settings, and other controls without leaving the control room. (Even so, it is a good idea to have knowledgeable and competent technicians walking the system to provide visual confirmation of what is going on.)

Emergency shutdown system

When the ESD button is pushed the entire facility shuts down in a quick but well-designed sequence. On older platforms these systems were driven by pneumatics. More modern facilities utilize a combination of pneumatic and electronic computerized systems, and it can be initiated from the control room, rig floor, and certain safe havens, such as the quarters or lifeboat stations.

Fuel-gas system

Almost all large offshore platforms develop their own power. A few have electrical cables from shore providing the needed power, but that is unlikely for deepwater platforms. Fuel for the power generation and other smaller systems has to be provided. Platforms with gas production solve their own problem—natural gas fuel. In lieu of that, diesel has to be delivered by service vessel.

The major fuel-gas consumers on a typical offshore facility include the following:

- Gas turbines for power generation
- Gas turbines for compressor drivers and/or other large equipment
- Drilling and workover rigs

The fuel-gas quality is dictated by the equipment with the pickiest requirements, calling for treaters to prepare the fuel gas for onboard consumption, perhaps at a quality above that of the gas being exported. The treatment is designed to protect the fuel gas system from carryover of liquids or entrained solids from the upstream process. In addition, the system will often be sized to provide several seconds of gas "retention time" so the dual fueled power generation turbines can switch to diesel in the event that the fuel gas supply is interrupted.

Waste heat recovery

The major needs for heat on a topsides facility are in the following areas:

- Oil/water/gas heating to promote separation and crude stabilization
- Glycol regeneration
- Fuel gas processing
- Quarters HVAC system (often indirect via glycol/water)
- Distillation-type freshwater maker

The main heat source on most offshore facilities is the gas turbine exhaust. Heat transfer fluids with a wide variety of different physical and thermal properties are available, and are carefully handled and stored onboard.

Potable water

Fresh potable water is, of course, an absolute necessity for normal personal use in hygiene, food, laundry, and eye wash, and safety showers, engine coolant, and even for some uses for drilling fluids. Potable water can be delivered by service vessel and pumped onboard. Fresh water can be made from seawater using one of two technologies, vacuum distillation or the more common reverse osmosis.

Rainwater collection

The topsides deck is typically provided with an open-drain gravity system that guides the rainwater and wash-down water to a low point collection sump. The collected liquid contains oil and dirt from deck areas, equipment drip trays, accidental deck spills, and so on. Oily water from the sump is usually recycled back to the processing scheme for treatment.

Fire protection

Many offshore platforms have fire retardant and/or firewater systems installed. The firewater system typically has a ring main with nozzles directed at the most likely sources and with pumps of enough capacity to operate the various spray and deluge nozzles at the farthest reaches of the system. Protective insulation is used on critical structural members. This extends the time it takes for the steel members to lose structural integrity and thereby allows more time to get the fire under control.

Export connections

The topsides separation and treatment facilities transform the fluids that come in through the riser (that by now may sound like a witch's brew—oil, gas, water, acid gases, sediment, sand, and more) to market-quality hydrocarbons that flow into the export risers. Chapter 12 continues the story with a look at risers, pipelines, and flowlines.

Case Study

Heavy Lifting Dynasty

Over four decades, Pieter Heerema built a business that dominated platform installation around the world. At the same time he raised two sons who created their own successful offshore construction and installation companies.

The “old man,” as his business colleagues called him, started his serious entry into the offshore at the water’s edge in 1948, modestly building piers, quays, and bulkheads along Lake Maracaibo, plus an occasional oil platform. His innovative and superior design for pre-stressed, hollow concrete pilings in 1956 won him entrée to eventual construction and installation of some 100 platforms there.

By the 1960s Heerema could see that Lake Maracaibo was approaching maturity. He returned to his native Holland just as the giant Groningen Field was discovered. Seeing that flat-bottom barges used for platform installation were ill-equipped for the rough North Sea waters, in 1969 he built the *Global Adventurer*, a ship-shaped crane vessel (SSCV) with a lifting capacity of 800 tons. Its immediate success led him to increase the SSCV’s capacity two years later and follow that with SSCVs of ever-increasing lift capacity—*Thor* and *Odin*. The *Odin* had the world’s largest pile driving hammer at the time as well.

In 1986, after surveying the accumulated technology that industry had already developed, Heerema designed and built two giant semi-submersible crane vessels, the *Balder* and the *Hermod*, which eclipsed all other crane vessels in the industry, including his own. The two SSVCs each had lift capacity, eventually, of 14,000 tons, enough to hoist and set entire topsides. With this extension, Heerema changed the standard construction model from multiple, pre-fab modules for assembly on a platform to onshore, completed assemblies. That reduced topsides installation from a whole season to a few weeks. Producers began to time their construction schedules to the availability of a lift by Heerema.

Meanwhile, the Heerema Group moved further upstream through acquisition of construction yards for steel jackets and topsides, as well as bridges and lock gates. The *Balder* and the *Hermod* were back-fitted with Pieter Heerema's own design for J-lay pipeline installation. In 1992 the Heerema Group did the first J-lay pipeline installation in 360 feet of water off the coast of New Zealand.

The addition to the fleet in 1997 of the *Thialf,* the largest lift vessel in the world, capable of lifting 14,200 tons, tightened the Heerema Group's grip on heavy lift activity (fig. 11–12). They purchased it even as they shed business and activities (e.g., Hermac, a joint venture with McDermott and Willbros Group) that distracted them from focus on their core business.

Fig. 11–12. Heerema's lift vessel *Thialf*. (Courtesy Heerema Marine Contractors.)

After the end of his career, three of the "old man's" sons, Pieter, Edward, and Hugo, leveraged their own salty genes. In the 1980s Pieter Jr. bought out his brothers and assumed control of the Heerema Group. Edward became the head of Allseas, a premier offshore pipeline installation and subsea construction company, and invested in the world's largest pipelay vessel, the *Pieter Schelte*, named after his father. Hugo's Bluewater Group started as an engineering company specializing in designing and providing offshore mooring systems, and then under his direction expanded into FPSO design, construction, installation, and leasing. (See fig. 11–13.)

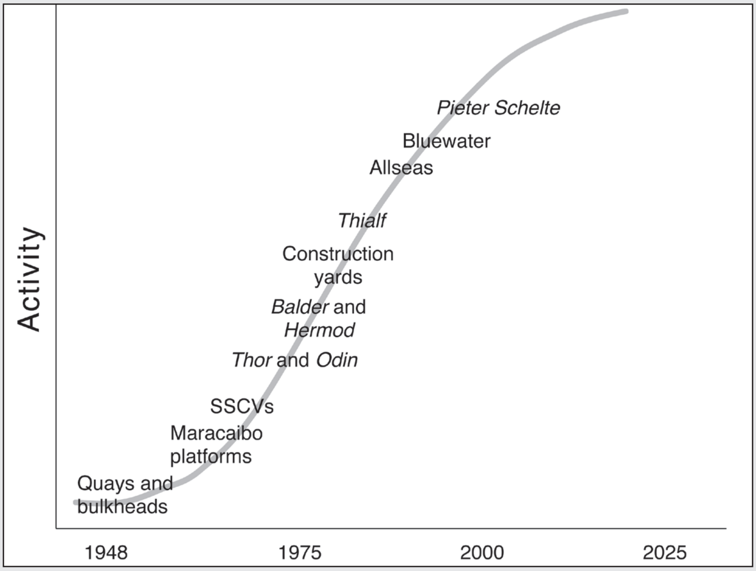
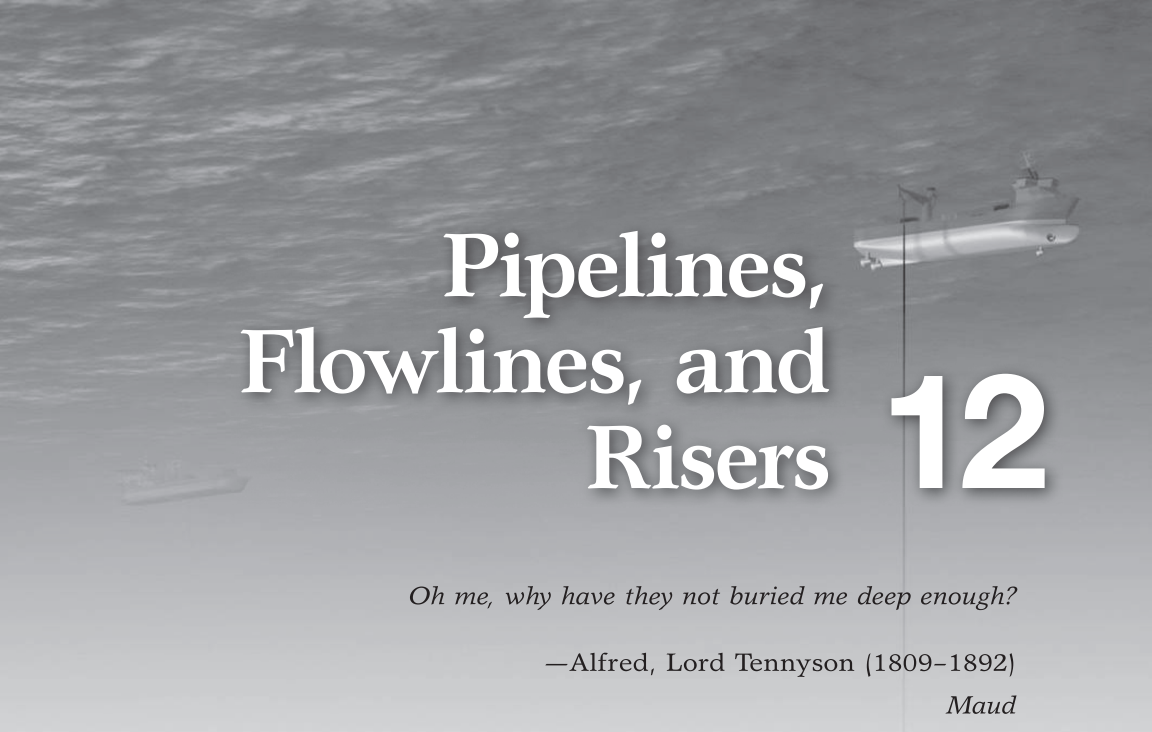


Fig. 11–13. The evolution of Heerema

Among them, the Heerema family members have positioned the dynasty to exploit the fastest growing sector of the oil and gas industry.



12 Pipelines, Flowlines, and Risers

Oh me, why have they not buried me deep enough?

—Alfred, Lord Tennyson (1809–1892)
Maud

"Nothing happens until we get our lines in place," say the subsea pipeline line engineers, and they are right. Oil and gas have to get from the reservoir to a refinery or a gas transmission system to make investments in the well, the platform, and the topsides pay off.

The logical way to deal with this subject is to follow figure 12–1. The fluids flow from the wellhead through a *jumper* to a manifold. From the manifold, the admixed fluids move through a *flowline,* which could be up to 70 miles or longer for gas or 10 to 20 miles for oil, to a *production riser*. That line moves the fluids to a production platform where processing takes place. Outbound from the platform, the fluids move through an *export riser* to a *subsea pipeline* and on to shore, which may be many miles away.

While they have different names, flowlines, and pipelines differ from each other mostly in size. Other characteristics and installation techniques are similar. Jumpers, which are discussed in chapter 10, and risers, which are discussed in this chapter, have their own issues.

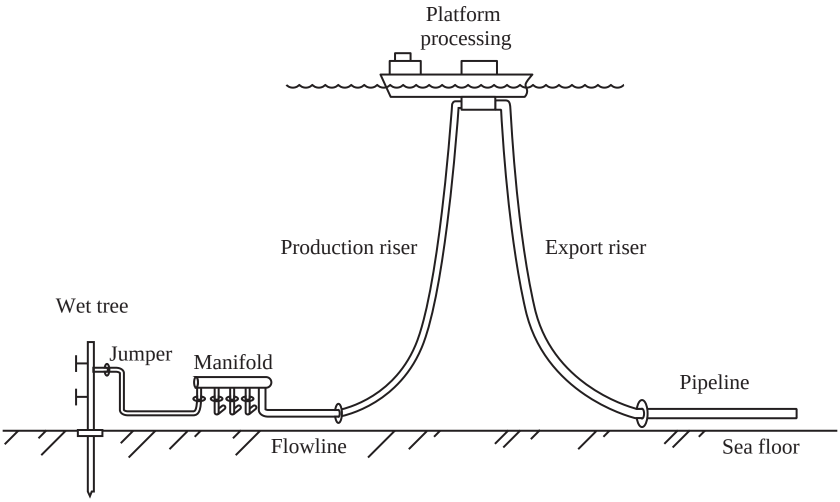


Fig. 12–1. Well production from the wellhead to the shoreline connectors

Pipeline System Architecture

The fluids carried in the offshore flowline/riser/pipeline systems are determined by reservoir analysis and predictions early in the development cycle. Of course, the nature, composition, and volume of the fluids—gas, water, and oil—will change over the life of the field, and need to be considered in the design phase. In some cases the entire pipeline-to-market system will be entirely new and therefore somewhat independent, for example, "Greenfield," and thereby controlled only by its own designed-in capabilities. In other cases, though, the export line will connect to exiting infrastructure with its existing constraints and limitations.

The layout of the entire system needs to consider these issues:

- Flow capacity
- Storage
- Pumping
- Compression

- Metering
- Pigging
- Communications

Hydraulics

The expected volume and characteristics of fluid from the wells, and the projected change over the life of the field in that volume and those characteristics, is the starting point for the sizing of the flowlines, risers, and pipelines. The amount of product that can move through a pipeline is determined in large part by the inlet pressure, the internal diameter of the pipe, the viscosity and temperature of the fluid, the elevation changes and sea floor profile that line must traverse, the attendant pressure loss due to friction on the pipe walls as the fluid moves forward, and the back pressure on the pipeline exerted by the receiving facilities. Taking all these parameters into consideration, the end result, for export lines for example, is one in which the oil has a velocity of 3 to 15 feet per second, and where gas moves at 10 to 30 feet per second. The inlet pressure on the multiphase flowlines is determined by the available reservoir pressure or by the subsea pumping design if used; the back pressure on the flowline is determined by the process and treatment trains on the receiving host; and the internal diameter is calculated using all the parameters mentioned here.

As noted in chapter 11, the separation and treatment process lowers the pressure on the clean oil (in most cases) to atmospheric pressure, and so pumps are used to move the oil through the export line. This requires some level of storage on the offshore host to provide suction for the pumps. This is usually only a few hundred to a couple thousand barrels.

For gas, the initial separation phase conserves as much gas as possible above the export line pressure. The gas released from the second, third, and subsequent phase separators is compressed back up above the export line pressure and joins the phase-one gas in the pipeline.

In some cases, if the line is long and/or tortuous enough, there may be so much friction pressure loss (which is related to fluid velocity, pipe wall roughness, and fluid viscosity) that an intermediate pumping, or compression, station will be introduced to boost the pressure back up to an appropriate level and send the oil or gas on its way to the receiving terminal. (See fig. 12–2.)

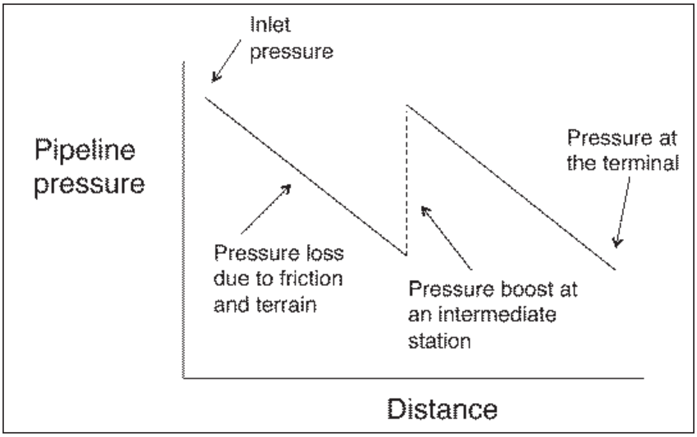


Fig. 12–2. The need for pumping or compression along a pipeline

Mechanical

In many ways the design of the flowline, riser, or pipeline for its in-place pressure regime, for example, internal fluid pressure and external hydrostatic pressure caused by the weight of sea water, is relatively straightforward. Design conditions related to installation and operational loads are discussed later in this chapter. It is not uncommon for the installation conditions to require a thicker wall pipe than for the in-place design. Figure 12–3 shows the "in-place" pressure conditions that will decide the minimum wall thickness for the line.

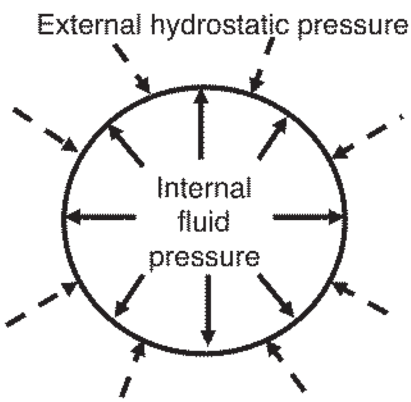


Fig. 12–3. Pressure on a subsea pipe

The selection of the steel grades to be used in the manufacture of the pipe is dependent on many parameters. In addition to the pressure regime and the corrosive components of the fluids, the system's expected life and ease of installation must be considered. For shallow water lines, lower grade materials are often used, especially for low pressure lines. For deeper water, higher strength pipe allows the use of thinner, therefore less weighty pipe to be used, which generally means faster and cheaper installation. The extra cost of the higher grade material is returned many times by the improved productivity during installation.

Installation

Marine pipeline laying comes in four generic, self-descriptive, methods: S-lay, J-lay, reel-lay, and tow-in. In all of these cases, the pipe from the steel mill arrives in 40-foot sections to be butt-welded together into miles and miles of finished line.

S-lay

An S-lay vessel has on its deck several welding stations where the crew welds together 40- or 80-foot lengths of pipe in a dry environment away from wind and rain. The pipe, either for a flowline or a pipeline, is eased off the stern as the vessel moves forward. It curves downward through the water as it leaves until it reaches the touchdown point. After touchdown, as more pipes is played out, the pipe assumes the nominal S-shape shown in figure 12–4.

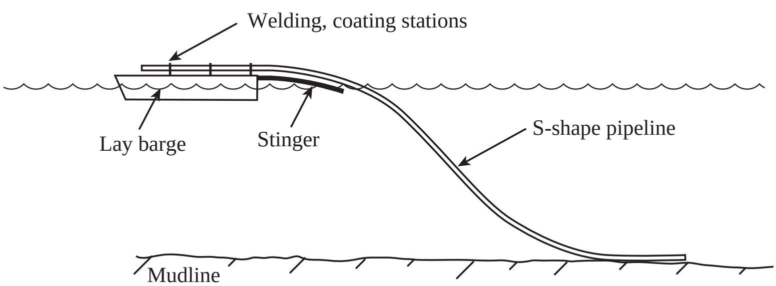


Fig. 12–4. S-lay method for deepwater pipelines

To control the pipe curvature as it leaves the barge, a stinger, a long steel structure attached to the stern of the barge, supports the pipe. Some stingers extend out 300 feet. Some barges have articulated stingers with controllable hinges that change the shape of the stinger, managing the trajectory of the pipeline. That gives those S-lay barges vessels flexibility to operate in a variety of water depths, shallow to deep.

The double curvature S-shape requires careful control of the lay barge position relative to the touchdown point. The barge must hold the pipe at the right level of tension, otherwise the curvature can become severe enough for the pipeline to buckle, a disastrous event. Tensioning rollers and controlled forward thrust provide the appropriate tensile load.

The assembly line process, feeding, welding, coating, and laying is supported with loads of pipe arriving on transport barges as the work progresses. S-lay barges can lay as much as four miles per day of pipeline. S-lay has been used to water depths of 8,000 feet, with stated capabilities even deeper. Figure 12–5 shows a world-class S-lay vessel getting ready for a job. This vessel, the *Solitaire,* owned by Allseas, is 300 meters long, excluding the stinger, can accommodate 420 people. It has two pipe transfer cranes, two double jointing plants where 40-foot pieces are joined, seven welding stations, one quality control station, and two coating stations. It has the capacity to hold up to 580 tons tension on the pipeline, and to lay pipe from 2 to 60 inches. It can carry an inventory of 15,000 tons of pipe, which allows it to lay miles of pipeline before being restocked.

Fig. 12–5. S-lay vessel *Solitaire.* (Courtesy Allseas.)

J-lay

To avoid some of the difficulties of S-laying (tensile load, forward thrust, double curvature), J-lay barges drop the pipe down almost vertically until it reaches touchdown. After that, the pipe assumes the nominal J-shape in figure 12–6.

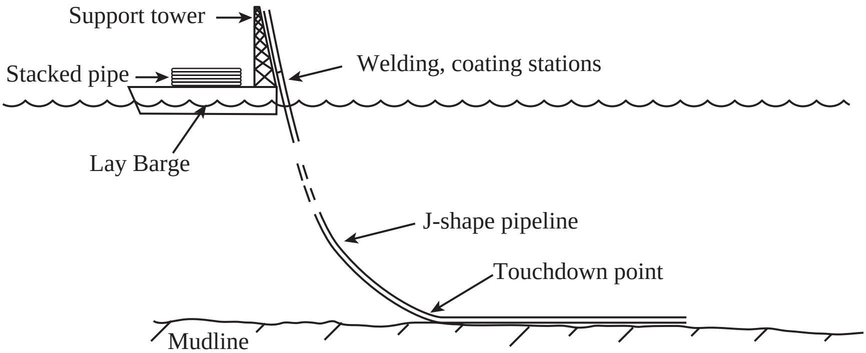


Fig. 12–6. J-lay method for deepwater pipelines

J-lay barges have a tall tower on the stern or over the side where lengths of pipe are stacked, joined, welded, and coated before they slip into the sea. The tall towers mean that, realistically, only one welding station can be used, so the pipe arrives on transport barges in long, pre-welded lengths up to 240 feet.

With the simpler pipeline shape, J-lay can be used in deeper water than S-lay. During the lay procedure, the pipeline can tolerate more motion from barge movements and underwater currents that could lead to buckling. Figure 12–7 shows a J-lay vessel working from the large crane vessel, *Balder*.

Fig. 12–7. J-lay tower on the crane vessel *Balder.* (Courtesy Heerema Marine Contractors.)

Pipeline tensioners

The pipe is held in tension for the S- and J-lay process by hydraulic or electric driven treads that look a lot like the tracks from a bulldozer. (See fig. 12–8.) The vertical pressure on the pipe creates a force that resists the horizontal pull for the S-lay case and the vertical weight for the J-lay case. An alternate way to carry the load in the J-lay system is the use of upset collars on each long section. This precludes the need for tensioners but does add to the onshore welding time.

Reel-lay

Contrary to casual perceptions, a long section of steel pipe is quite flexible. While a 40-foot length may seem totally rigid, an unsupported 24-inch, 5,000-foot length droops like a fly rod with a 10-pound trout on the hook. Even more remarkable, and continuing the angler's analogy, the same pipe can be wound around a reel for transport and later unwound during installation.

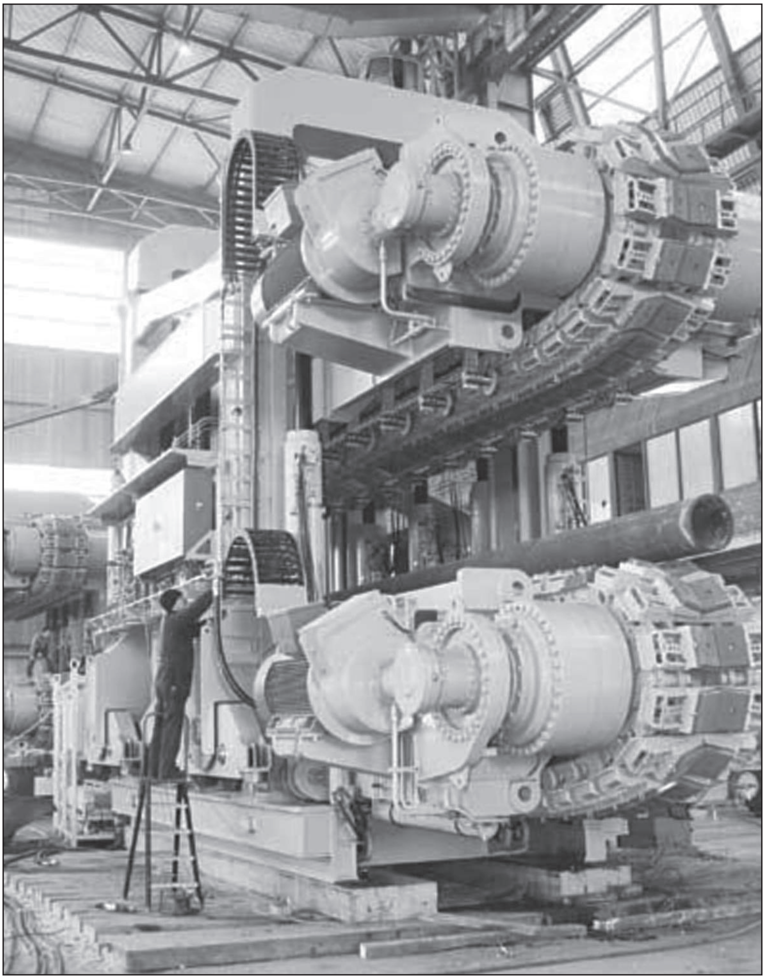


Fig. 12–8. Caterpillar track tensioner closing down on a length of pipe. (Courtesy SAS Gouda BV.)

During the second World War, a group of British engineers developed the initial version of pipe reeling. Seventeen small diameter lines (4 inches) were laid from England to the continent to supply petrol to the Allied armies, by a variation of the modern day reel approach. Today's version is much more advanced in design and equipment capabilities, but the idea born of necessity during the war lives on.

Once they realized they could wind pipe around a reel like fishing line, pipeliners began to transport it and deliver over the stern of lay vessels that way. Some reels unwind horizontally, some vertically. (See figure 12–9.) The horizontal reels lay pipe with an S-lay configuration. Vertical reels most commonly do J-lay, but can also do S-lay.

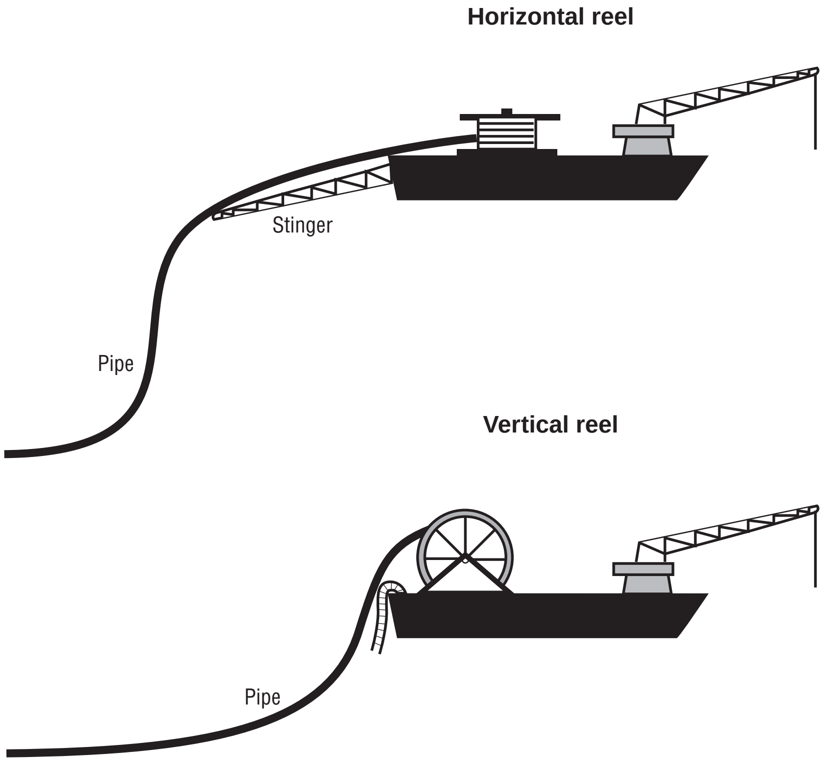


Fig. 12–9. Vertical and horizontal reel barge methods

Most of the welding and coating for reeled pipe takes place onshore where costs are much less. The onshore operation requires long sections of property adjoining good dockage, as seen in figure 12–10. There the reel barge prepares to load up with the pre-welded pipe stretched out onshore. Figure 12–11 shows the Global Industries' reel barge, *Hercules,* laying pipe in the Gulf of Mexico.

Fig. 12–10. Reel barge at dock. (Courtesy Global Industries.)

Fig. 12–11. Reel barge *Hercules* laying pipe. (Courtesy Global Industries.)

The length of pipe that a reel can handle depends on the pipe diameter. Over 30,000 feet of 6-inch pipe, the type used for some flowline applications, can fit on a reel. In many cases that is sufficient for a barge to lay several flowlines. Pipe up to 18 inches in diameter is successfully reeled, but at much smaller lengths. Some lay barges have cranes that can lift loaded reels off transport barges and return the empties. Others have to make the round trip to shore to do the exchange, a time consuming interruption if the pipeline or flowline are not nearby the supply depot.

The boon and bane of buoyancy

During the installation of a pipeline, as the pipe reaches from the stern of a lay barge to the seabed, the entire vertical load of the pipe weighs on the barge. Take as an illustration a 24-inch steel pipeline with a 1-inch thick wall. One foot of that line weighs about 250 pounds on the barge deck. In the water it weighs only 50 pounds, and the buoyancy effect provides the counteracting upward 200-pound force. Suppose a barge was laying that pipe in 3,000 feet of water. It has to support more than 150,000 pounds of weight off its stern—actually more, because the trajectory from the lay barge to the touchdown point of the pipe is more than the water depth. If the line suddenly flooded with water because it buckled or some other nightmare occurred, the load on the system would jump to more than 750,000 pounds. That sudden increase could cause the loss of the pipeline or damage to the lay barge. Worse, as the water depth increases, in 10,000 feet of water the barge would be in peril if it had no quick disconnect capability. For that reason, the laying procedure includes careful and continuous monitoring of the configuration of the outstretched pipeline to ensure structural integrity.

Ironically, once on the sea floor a pipeline needs more net *downward* force to keep it from drifting. Oil, so much heavier than air, adds to the weight of the steel pipe. Gas, however, doesn't provide the extra weight that oil does. Depending on the line size, extra ballasting might be needed to hold the line in place. In shallow water the most cost-efficient way to add weight is coating the pipe with concrete. In deeper water the pipe wall thickness required to resist hydrostatic pressure is often enough to provide the needed weight.

Tow-in

There are four basic variations of the towed pipeline method, as shown in figure 12–12. For the *surface tow* approach, the pipeline has some buoyancy modules added so that it floats at the surface. Because of the length involved, at least two tug or towboats are required to control the pipe as it is being taken to location. Once on site, the buoyancy modules are (carefully) removed or flooded, and the pipeline settles to the sea floor.

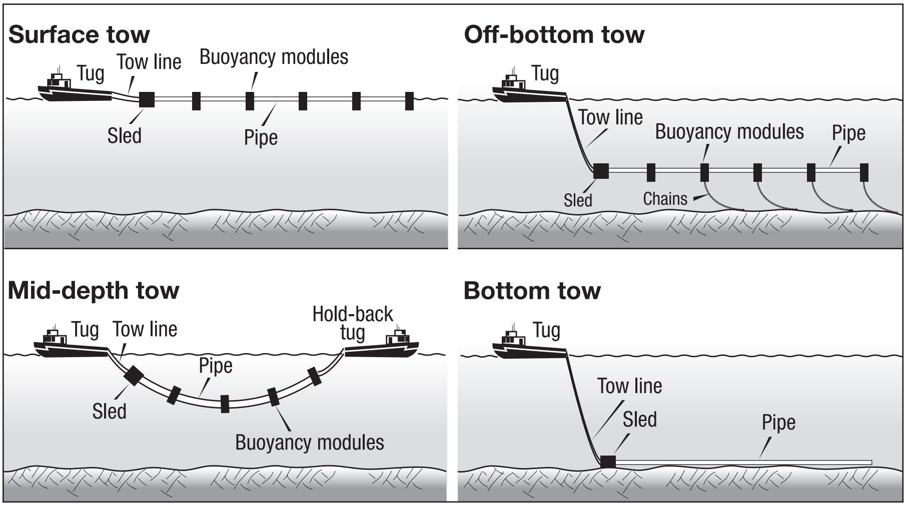


Fig. 12–12. Variations on pipeline tow-in installation

The *mid depth tow* also requires some buoyancy modules, but fewer. Both the depth of submergence and the shape of the pipeline are controlled by the forward speed of the tow. In this case the pipeline settles to the bottom on its own when the forward progression ceases.

The third case, the *off bottom tow*, involves both buoyancy modules and added weight in the form of chains. The chains cause the pipeline to sink to near the bottom, but as the chain links pile up on the sea floor, their weight reduces and the buoyancy holds the pipe at a given distance above bottom. Again, once on location, the buoyancy is removed, and the line settles to the sea floor.

The last variation is the *bottom tow*. In this case, the pipeline is allowed, or caused, to sink to the bottom, and then towed along the sea floor. In all of these approaches, the ends of the pipelines are configured with termination structures, often called sleds, so that one end can be connected to subsea manifolds, and the other to the host platform riser system, using the previously discussed jumper method. (See chapter 10.)

All of these methods have been used, and are a way to do much work onshore and to limit exposure to offshore weather conditions. However, a long tow distance also has its own weather, shipping, and other risks.

Installation and Operational Loads

During the installation process, the pipeline feels the full pressure of the weight of water above it at a time when the internal pressure is zero. This may create a situation where the wall thickness selected for pressure containment is not sufficient. Unless the pipe wall thickness is increased, the external pressure would cause the pipe to collapse. In addition, during the laying process, S-lay, J-lay, or reel-lay, the pipe will be under high tensile stresses as well as high bending stresses and high external pressure causing increased potential for instability, such as collapse or failure due to overstress.

If, during the laying, the pipeline buckles because of the complex loadings discussed above (changes from a tube shape to a flat shape, suddenly), the buckle will propagate all along the line until it reaches a water depth where the external pressure is less than the pressure needed to cause a buckle. Unless some means to prevent that propagation are employed, this means that miles of pipe could be rendered useless by one mistake that caused a local buckle.

To avoid this situation, pipelines in deep water are fitted with *buckle arrestors*. This can be as simple as increasing the wall thickness every so often to exceed the propagation pressure or using steel rings or sleeves welded to the pipe. The space between the arrestors is a judgment call on the part of designer and installer—their evaluation of the cost/risk of that particular installation.

The end result is that the internal diameter of the pipe is chosen by hydraulics consideration, the material grade is often driven by fluid corrosivity criteria, and the wall thickness is controlled by installation issues.

Flexible Pipe

Although the lion's share of pipelines and flow lines are steel pipe, there is an alternative, flexible pipe, fabricated from helically wound metallic wires interspersed with thermoplastic layers. Each layer has a specific function. (See fig. 12–13.) These *flexibles*, as they are called, have excellent bending characteristics and are often used where steel pipe would be too rigid. The flexible pipes have more use as risers, which are discussed later, but they also have served as flowlines and jumpers.

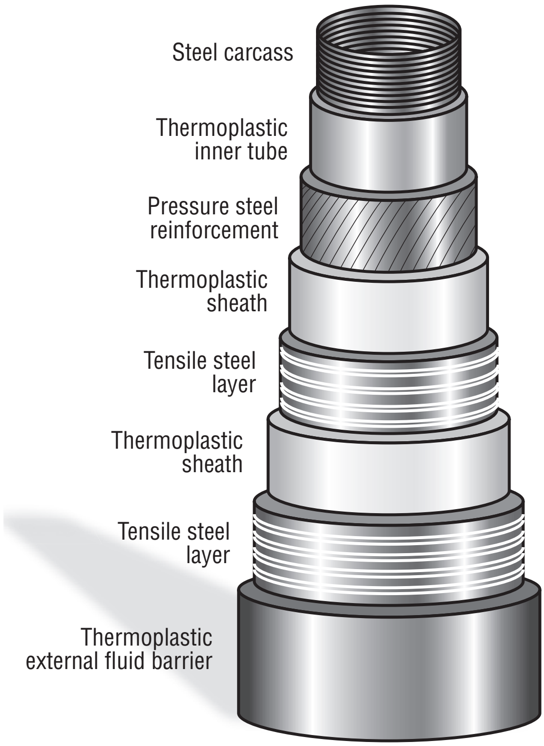


Fig. 12–13. Flexible pipe. (Courtesy Wellstream.)

In chapter 10 there is a discussion of ways to retain heat—insulation, pipe in pipe, pipe bundles, or direct electric heating. The installation techniques discussed in this chapter can be utilized for all of these systems. Laying clean pipe without any of these heat retention systems will obviously move faster and be less costly, but every one of the insulation methods discussed can be installed by the four generic pipe lay methods.

Coatings and Corrosion Protection

Steel pipelines in the salty sea water will corrode if they're not protected. In practice this almost always results in a pipeline with both a protective coating and an effective cathodic protection system. Simple but rugged bracelet anodes, which can withstand the installation-handling insults, and which are compatible with the chosen coating, are welded to the pipe at intervals. The distance between anodes is specified by various codes and is dependent on a clear understanding of coating conductance.

There is a wide variety of coating systems available, from coal tar/asphalt, which has been used for on-land and immersed lines for over 100 years, to epoxy, polyethylene, polypropylene, thermal sprays, and foam coatings.

For all of the installation methods discussed for deepwater lines, there is always a need to field apply a short segment of coating at connections. For S-lay this occurs every double joint, or 80 feet. For J-lay it occurs every 240 feet or so, and for reel-lay and tow-in installations the field joint will occur at connection points. Whatever the pipe lay method, considerable attention must be given to this often routine field coating operation to ensure that it does not become the weakest part of the protection system. Various methods have been devised to make this field joint—coal tar, tape wrap polypropylene, heat shrink sleeves, epoxy, injection-molded polypropylene, or polyethylene.

Consideration of Bottom Conditions

To pipeline engineers, the ideal subsea terrain has a continuous flat seabed of soft clay or mud. In many deepwater areas they find that, but not always. The features of the ocean floor vary as much as the onshore, with gullies, outcrops, ravines, hills, and escarpments. The precursor to any pipeline or flowline installation is a survey done by a contractor using depth-finding sonar and even an ROV to establish the safest and most economical route.

Even small undulations of the seabed cause worry. As the pipeline passes over an extended dip in the surface, it has an unsupported span where the pipeline does not rest firmly or perhaps even touch the bottom. Bottom currents can lead to serious vibration in long unsupported spans.

Strong currents find the gaps prime targets for scouring even longer expanses, making the pipeline more vulnerable. ROVs search for these unsupported spans. Additional weights or screw-type anchors can be added to push the line down, or at least hold it steady. Alternatively, the spans can be outfitted with vortex-shedding strakes to prevent vibration from occurring.

Other potential deepwater sea floor hazards to the pipeline are slope instability, gravity flows, and turbidity flows. Evidence of these will usually be in past occurrences as shown in the route survey data conducted of the sea floor, indicators of possible future occurrences. In many cases the best solution is to seek an alternate, almost certainly longer, route for the pipeline to avoid the bad areas. If that is not possible, or if the risk evaluation does not warrant it, careful design of the orientation of the line can at least reduce the potential harm. For example, the impact on a pipeline from soil or turbidity flows would be substantially less along the line rather than broadside to it.

Burial

Once the pipelines are laid on the seabed, they are sometimes buried. Some jurisdictions require this in shallow (less than 500 feet) water to avoid having lines damage trawling fishing nets. In deeper water the burial may be continuous to help in heat retention, as discussed in chapter 10. In other situations the burial may be intermittent to smooth out the bottom profile and reduce or eliminate the number of unsupported spans.

The right approach to digging a trench depends on the nature of the sea floor. The simplest and oldest technique uses a unit placed on the pipeline towed by a surface vessel. (See fig. 12–14.) It cuts out a trench with high-pressure water jets and/or mechanical cutting heads. As the trencher moves forward, the line settles into the trench. The burial can take place over time as bottom currents cause local sediments to cover the line, or it can be done by dumping sediment directly onto the line and filling the trench. In any case, the ubiquitous ROV is, again, an important contributor, as it follows the trencher and displays to the operating crew the real sea floor situation of the trenching and burial operations.

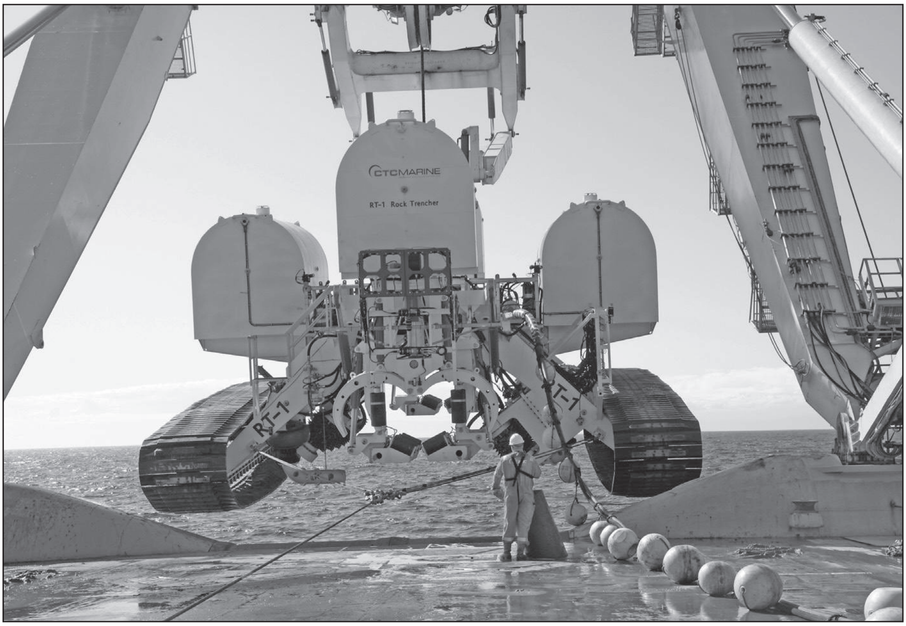


Fig. 12–14. Trencher for burial of pipelines. (Courtesy CTC Marine.)

Soft sea floors can be trenched using towed plows. These units require vessels that have high pulling capacities. The plow modules, which can weigh in excess of 200 tons in air, have buoyancy tanks to allow weight adjustments in the water. For tough hard pan, rocks, and boulders, special equipment (perhaps designed for that project only) may be developed. Rock or gravel beds may be laid down to smooth out and cover over the obstructions.

Control and Safety Systems

Supervisory Control and Data Acquisition, SCADA, computer-based equipment used to remotely monitor and operate equipment and facilities, allows operators to remotely monitor and control system operating parameters (temperatures, pressures, flow rates, vessel fluid levels, valve open/close position) and make adjustments as needed. These control systems are normally located on the offshore platform and are commonly integrated with the controls for operations systems on the structure.

In addition to providing day-in and day-out operating information, many such systems have instruments and control systems to monitor two major items of interest—overpressure and leak detection. Overpressure conditions can result from well surge pressures, thermal pressure buildup in shut-in lines, failure of process and treatment controls, and so on. The automatic control for overpressure is for relief valves to vent the line to a flare system for gas or to an onboard vessel for liquids. The technology of leak detection systems is still in the early stages, and therefore any such installation needs to be operated and the data analyzed with care to identify leaks without having excessive numbers of false alarms.

Risers

To and from the production platform, production and export risers take six different forms: attached risers, pull tube risers, steel catenary risers, top tensioned risers, flexible riser configurations, and tower risers.

Attached risers

Fixed platforms, compliant towers, and concrete gravity structures often have the risers clamped to the outside structure, as the right side of figure 12–15 shows. The riser is pre-built in sections. The sea bottom end of the riser is attached to the nearby inbound flowline or outbound pipeline, then assembled piece by piece and inserted into pre-placed clamps on the structure. ROVs with electro-hydraulic tools make the connections or divers do the work.

Pull tubes

In this installation, shown on the left side of figure 12–15, a flowline or a pipeline becomes the riser as it is literally dragged up through a tube in the center of the structure. The pull tube, a few inches wider than the flowline or pipeline, is generally pre-installed in the structure. A flowline or pipeline laid on the seabed floor is attached to a wire rope threaded through the pull tube. The wire rope is winched up the pull tube to the topsides, at which point the flowline or pipeline inside the tube becomes the riser. This procedure works best, of course, when the pipe is pulled directly from the lay barge and fed into the pull tube.

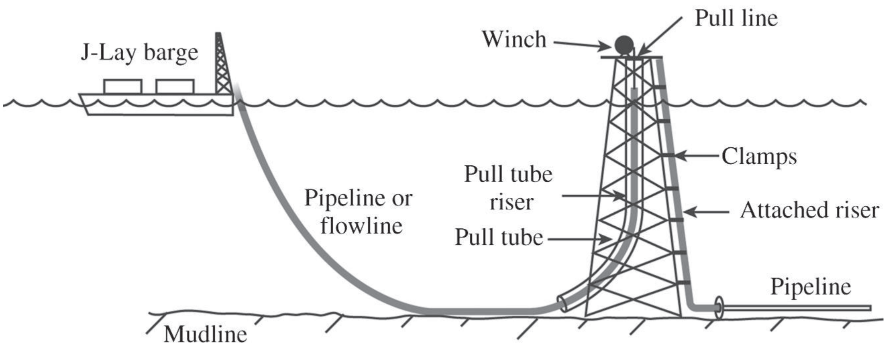


Fig. 12–15. Attached and pulled-in tube risers

Steel catenary risers

Some of the world's most graceful bridges, including the Golden Gate in San Francisco and the Verrazano Narrows in New York, exhibit a classic geometric shape. The cables that are strung from the end towers and support the bridge deck form a *catenary*. Another imposing and classic catenary, this time inverted, is the Gateway Arch in St. Louis, Missouri. Designed by Eero Saarinen, it towers 630 feet above the Mississippi River. The steel catenary riser shown schematically in figure 12–1 has a similar albeit abbreviated shape from the seabed to the production platform. As with the bridge cables, the more tension on the riser, the less sag in the system, and in the case of risers, the further out the touchdown point.

Steel catenary risers are an elegant solution to the riser challenge of connecting to floating production platforms in deepwater. These risers can be installed by laying a predetermined length of pipe, making the connections easier. They tolerate a certain amount of movement of the production platform, making them useful for TLPs, FPSs, FPSOs, and spars, as well as fixed platforms, compliant towers, and gravity structures. However, excessive motion can cause metal fatigue at or near the touchdown point and at or near the top support.

Top tensioned risers

For some TLP and spar applications, top tensioned risers provide a good solution. In this application, the flowline or pipeline terminates at a junction point beneath the structure. (See fig. 12–16.) A straight riser is run down from the platform and either terminates in the same junction structure or in its own junction structure, in which case a short pipe section installed with the aid of an ROV connects the riser and flow line.

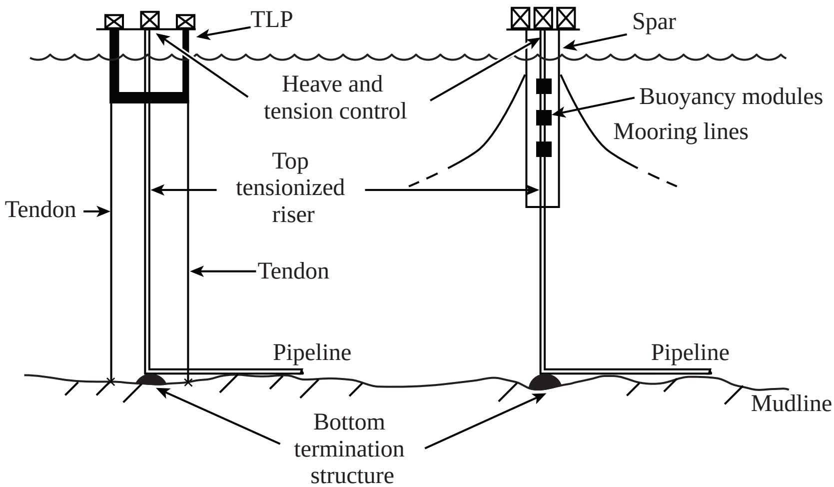


Fig. 12–16. Top tensioned riser

Since the riser is fixed to the sea floor, and the TLP or spar is free to move laterally under the influence of winds, waves, and currents, there is vertical displacement between the top of the riser and the point where it connects to the TLP or spar. To accommodate this motion within allowable stresses in the riser, a hardware device known as a motion compensator is integrated into the top tensioning system. This piece of hardware is made up of a hydraulic cylinders, and nitrogen-charged vessels known as accumulator bottles. (See fig. 12–17.) An almost constant tension is maintained on the riser by the expansion-contraction action of the hydraulic fluid as it moves between the cylinders and the accumulator bottles. For spars, a simpler approach is often employed, using buoyancy cans around the outside diameter of the riser.

The Christmas tree on top of the riser is, in either case, connected to the facilities manifold using flexible pipe, as seen in figure 12–18, going from the motion compensator to the topsides facilities.

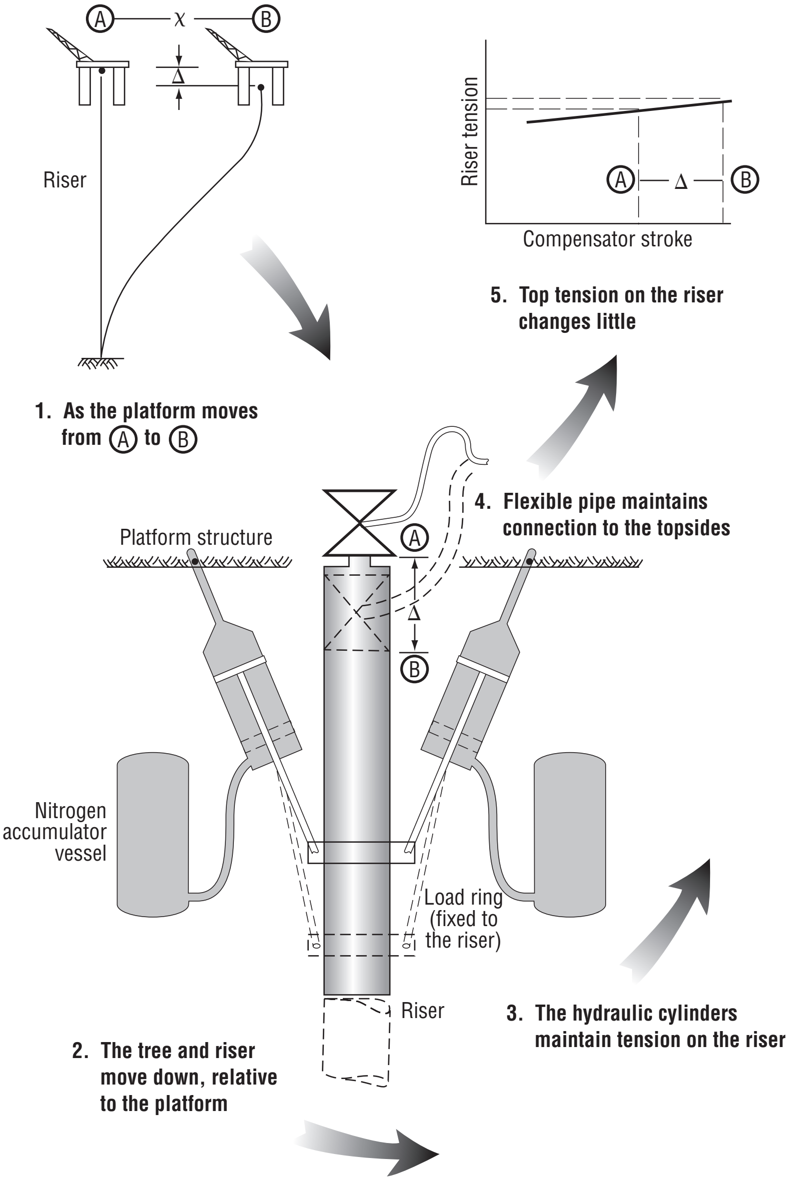


Fig. 12–17. Motion compensator mechanism for top tension riser

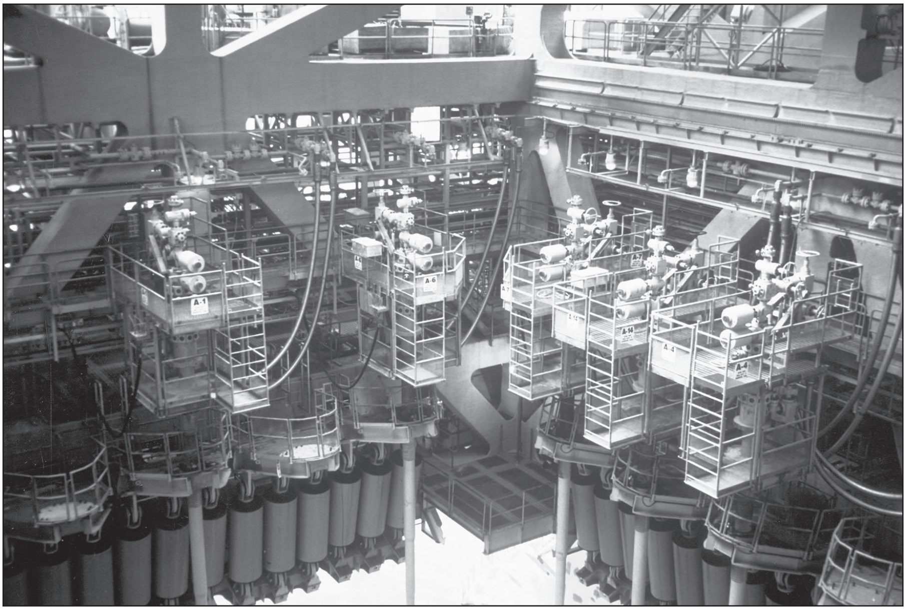


Fig. 12–18. Riser connections at the *Auger* TLP. Note the flexible hoses between the motion compensators. (Courtesy FMC.)

Riser tower

At the *Girassol Luanda* project offshore Angola, TotalFinaElf used the first riser towers. In this application, three steel column towers, each 4,200 feet tall are anchored to the sea floor in 4,430 feet of water. The towers each have four production risers, four gas lift risers, two water injection risers, and two service line risers. The tower is topped with a buoyancy tank, 130 feet long and from 15 to 26 feet in diameter. The upward force generated by the buoyancy tank holds the tower vertically stable. (See fig. 12–19.)

Flowlines connect from the subsea wells to the tower base, and flexible lines from the nearby FPSO connect to the various risers at the tower top.

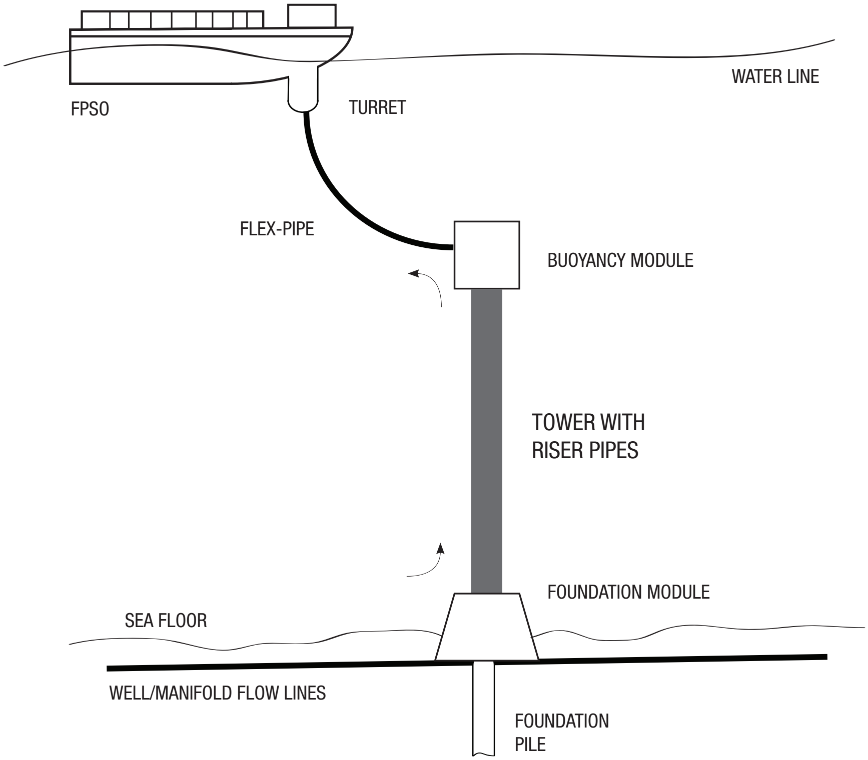


Fig. 12–19. Riser tower held upright by a buoyancy module, connected via a flexible pipe jumper

Flexible risers

Petrobras pioneered the use of flexible pipe as risers starting in 1978. Because of the bending characteristics, flexibles are most appropriate for floating systems that experience significant vertical and/or horizontal movement.

Flexible pipe, because of its beneficial bending characteristic, is often used to make the connections from the production equipment on floating systems to the production and export risers. Because of these same bending characteristics, these flexibles are also finding more and more use as the primary risers.

Besides the usual, free-hanging catenary riser, figure 12–20 shows several other configurations: lazy S, steep S, steep wave, and lazy wave. The specific selection depends on the expected motions of the production vessel and available installation equipment. All configurations involve providing buoyancy modules or cans at selected locations on the flexible pipe to force a given shape, and they all have the net effect of reducing the stress and wear and tear on the pipe at both the touchdown point and at the platform connection.

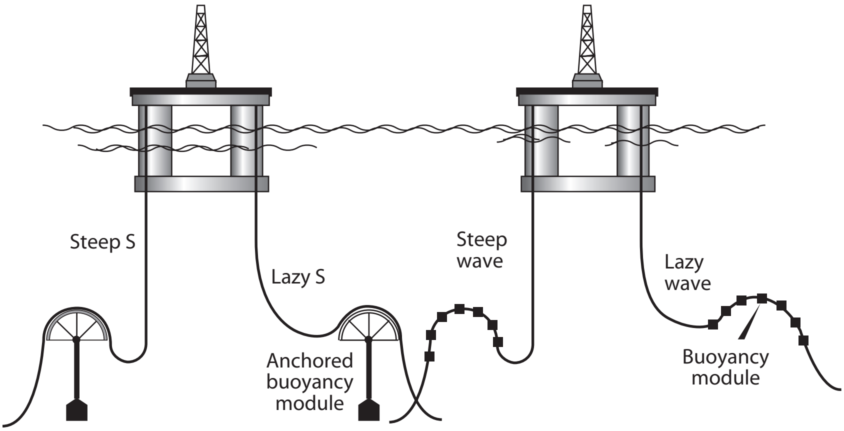


Fig. 12–20. Some flexible riser configurations

Selecting a Riser System

For the various development systems, some risers predominate. For fixed platforms and compliant towers, the attached and the pull tube risers are most common. For concrete gravity structures, attached and pull tube risers make most sense. For the floating systems, FPS, TLP, FPSO, and spar, the attached riser and pull tube don't work because they cannot accommodate the lateral excursions. For the floater, the steel catenary riser and flexibles work for almost all occasions. The top tensioned riser works for the TLP and spar only. The riser tower method, which also has many variations, can be used with all floating systems, particularly for ultra deepwater.

Pipeline System Operations

Once all the lines are hooked up, the valves are opened up, and oil and gas are moving to market, *flow assurance*, keeping the fluids moving through the lines, moves towards the top of the watch list on the platform. Operating crews monitor pressures and flows, watch for potential plugging, and inject inhibiting chemicals when necessary. From time to time, operators sweep out flowlines and pipelines by sending a *pig,* a specially designed sphere or short cylinder, down the line to sweep out the line. They are constructed of hard rubber-like materials (fig. 12–21), polyurethane, and steel or other metals with polyurethane cups for sealing (fig, 12–22). The pressure of the oil or gas drives the pig as it scrapes layers of paraffin off the pipeline walls or pushes ahead of it hydrates, water, and accumulated sand or other trash. Pig launch and recovery facilities that are aided by ROVs handle the start and finish. Pigs can be simple constructs of polyurethane or smart pigs that not only clean but also have sensors to measure wall thickness, monitor corrosion, and check for faults and leaks. Pigs used for inspections may be several pipe diameters in length and are constructed with sensors, recording equipment, batteries, and so on to perform their functions. Figure 12–23 shows an example of a high tech multifunction pig.

Pig launchers and receivers are used to install and remove the pig from the pipeline. They include special arrangements of piping and valves to allow inserting and removing the pig with little disruption to ongoing pipeline operations. The receiver will also include a pig trap to catch any fluids or solids removed by the pig as it moves through the pipeline.

Since explosive gases may be released to the atmosphere during removal of the pig, receiver and pig traps must be carefully located to minimize the risk of explosions or fires. In addition, well-thought-out procedures must be in place to ensure pigging operations are safely conducted and to prevent liquid spills.

Fig. 12–21. Rubber pigs. (Courtesy Statoil.)

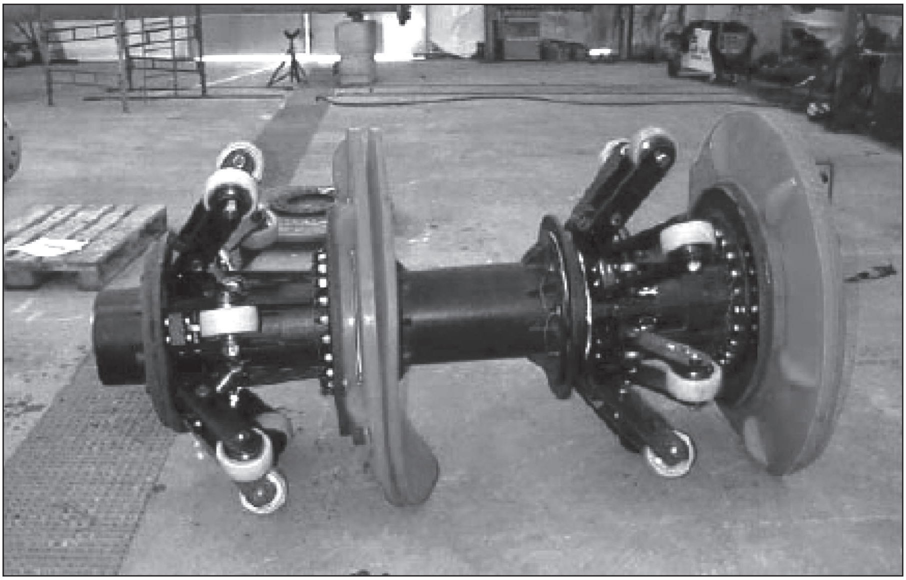


Fig. 12–22. A scraper pig with polyurethane cups. (Courtesy Statoil.)

Fig. 12–23. Multifunctional smart pig. (Courtesy Baker Hughes.)

PIGS?

Where did the name come from? An expert in the field, Andrew Marwood of Pipeline Engineering Company offers two possibilities:

- PIG, a Pipeline Injected Gadget
- In the early days of pipelining, leather balls were used to swab pipelines. As they moved down the line they squealed—like a pig.

Marwood suggests that both undocumented possibilities may be more a myth of mirth than a matter of fact.

Offshore Support Vessels 13

The vessel may give off several branches in succession, and still continue as the main trunk.

—Henry Grey (1827–1861)
Grey's Anatomy

Food, water, diesel fuel, equipment, and people—they are all mission-critical to every offshore rig. As offshore exploration and production activities detached themselves from the onshore, the offshore supply boat industry hatched. At the beginning, the industry hired whatever boat was handy—shrimp boats, trawlers, tow boats. By the time Kerr-McGee made its historical discovery out of landsight in 1947, the industry began pressing into service surplus U.S. Navy LCTs (Landing Craft, Tank) and the much larger LSTs (Landing Ship, Tank). (See fig. 13–1.)

Expedient as these boats were, it became evident that they were not particularly suitable for loading and unloading at sea. Along came Alden "Doc" Laborde in 1955, fresh from his accomplishments with *Mr. Charlie* (refer to chapter 1). He envisioned what other vessels lacked: a pilot and wheel house in the bow, maximum space amidships and aft for flat cargo space, and maneuverability for stable aft docking at a rig or platform.

Laborde designed the *Ebb Tide* to meet those specifications and launched his company, Tidewater Marine. (See the case study beginning on page 321.)

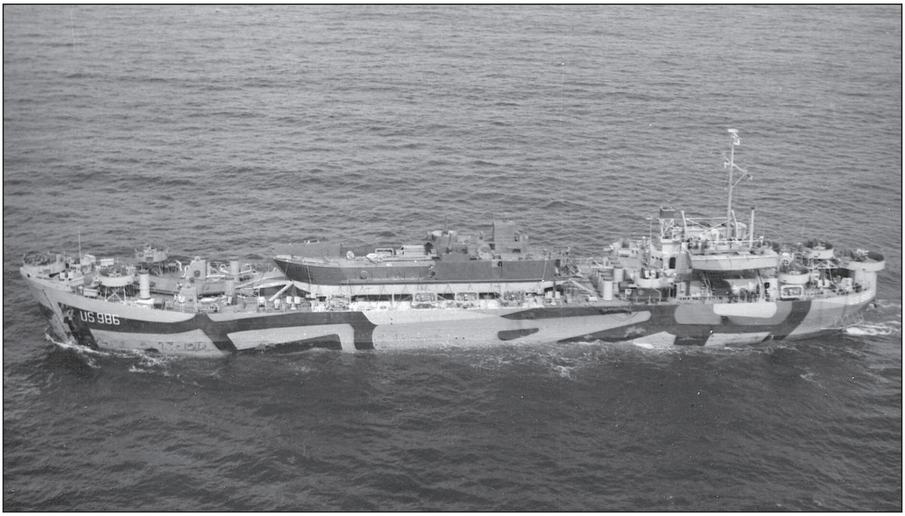


Fig. 13–1. The USS *LST-986* underway off the coast of California with *LCT-1018* cradled on her main deck, 2 July 1944. (© David Buell.)

The Fleet

The offshore service vessel industry has scores of companies, many with offices and operations around the world, wherever operators need them. More than 6,000 vessels of all types make up the worldwide industry fleet. The largest number of vessels, the platform supply vessels (PSVs), still look remarkably like the *Ebb Tide* and perform most of the supply service. Other types include fast crew boat supply vessels (FCSVs), anchor handling towing supply vessels (AHTSs), tugboats, heavy lift vessels (HLVs), and a variety of specialty vessels. PSVs, AHTSs, and FCSVs are often used interchangeably.

Platform supply vessels

The PSV is specially designed to supply construction sites, offshore rigs, platforms, FPSOs, and their satellites or tenders. These boats range in length from about 65 to 360 feet. They haul dry goods and equipment on their flat aft deck. Below deck they have tankage for drilling mud, cement, potable and nonpotable water, and diesel fuel. Many have dry storage and tankage for chemicals and liquids used for the drilling and completion process. They may also supply methanol used for flow assurance in subsea wells and flowlines.

A recent vintage PSC might have these carrying capacities:

- 150,000 gallons of diesel fuel
- 12,000 barrels of liquid drilling mud
- 250,000 gallons of water
- 1,200 tons of dry cargo on deck

PSVs haul supplies, equipment, and, at times, personnel to the drilling, completion, and construction operations and then haul it all back when those functions are completed. Rig and platform operators in most parts of the world send their trash and garbage back to shore on PSVs as well.

Deepwater PSVs have dynamic positioning capability to ensure that they will not collide with the platform or rig during loading and unloading. This is especially critical in deepwater operations, which are generally longer distances from shore and more vulnerable to weather changes. A costly collision caused by an unstable PSV could be a commercial relationship breaker.

Dynamic positioning systems have three main components:

- Geosynchronous positioning systems (GPS) that capture from satellites location data with just a few feet of tolerance.
- Pumps and thrusters below the waterline that can move the vessel laterally. Typically electric pumps drive port and starboard thrusters (called Z-drives). The propulsion system provides the forward/reverse capability.
- Computers that drive the thrusters and ship's propulsion in response to the GPS signals.

Transfer of dry goods and equipment from the PSV to the rig or platform is generally the responsibility of the rig operator, who uses a crane on its own facility. Pumping liquids is generally done by the PSV.

Anchor handling towing supply vessels

As the industry rig experience evolved, it became apparent that setting anchors was a function that should be outsourced. Rather than use a cumbersome and expensive rig to maneuver and drop an anchor in a correct position, operators hired the nimble AHTSs at a fraction of the cost.

Many semi-submersibles and FPSOs are towed to their drilling sites using one or more AHTSs (fig. 1–16 in chapter 1). Once they have positioned the vessel by GPS, anchor handling begins. A typical semi-submersible has eight to twelve anchors, depending on the size and water depth. Each anchor chain is made up of links that can be huge. For example, on Shell's Perdido spar, they are about 3 feet high and weigh 1,320 pounds. The chain is attached to a wire or polyester rope tied to a winch on the semi-submersible. After each anchor is dropped and set by the AHTS, the rig uses its own winches for fine-tuning the tension on the anchor to its final position. (See fig. 13–2.)

Diesel engines connected to electric generators (gensets) provide the power for towing rigs to their destinations. Towing capability is measured in bollard pull. (Bollard: a vertical post, generally wider at the top, used to secure hawsers, the towing lines.) A large AHTS might have a 25,000 horsepower diesel set and have a bollard pull of more than 100 tons.

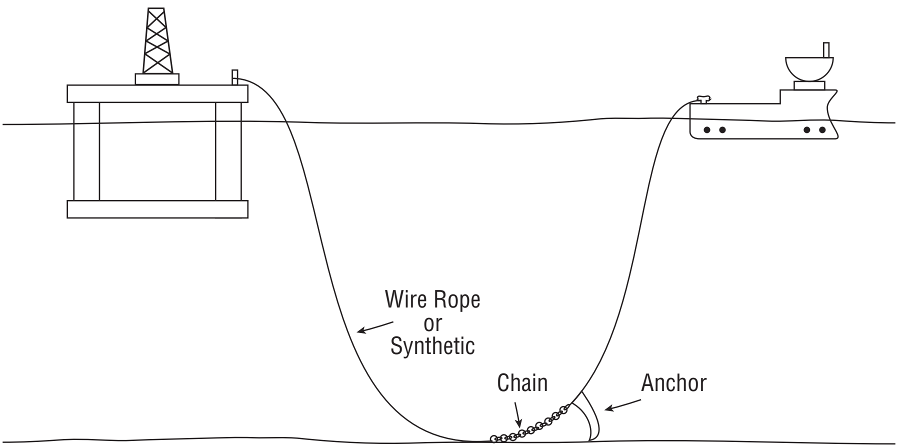


Fig. 13–2. An AHTS and a semi-submersible setting an anchor

For longer hauls, oceangoing tugboats sometimes provide towing services for semi-submersibles and FPSOs and for moving floating production platforms during the positioning phase.

Crew boats

Rig and platform crews change out on a typical two weeks on/two weeks off schedule. Dozens of people need transportation to and from shore. FCSVs are outfitted to haul anywhere from 10 to 150 people, and like any other local taxi service, may visit more than one installation on a trip for drop-off and pick-up. FCSVs travel at up to 35 knots (fig. 13–3) to accommodate the impatience of both the crew and the operator. Some FCSVs have bunks for overnight and long-distance hauls.

Fig. 13–3. The crew boat *Vickie Tide.* (Courtesy Tidewater.)

As the distance to the offshore structure increases, operators are more likely to use helicopters. Local operators provide the aircraft. The helicopters range in size from 4 to 30 or more passengers. Some have capacity for additional supplies and equipment in emergency situations. Crew and passengers are trained for emergency ditching at sea in both cold and warm water.

Heavy lift vessels

During the construction phase of a production platform (TLP, semi-submersible, SPAR, etc.), sometimes one construction yard fabricates the hull flotation section and another yard does the topsides or production facilities. The hull may be towed to its location by an oceangoing tug or an AHTS or loaded on and transported by a special oceangoing carrier, an HLV or heavy lift vessel. (See fig. 13–4.)

The topsides could be lifted at the construction yard onto the hull or put on an HLV to be placed on the hull at the ultimate location. In either case, heavy lift cranes are used.

Fig. 13–4. Hull of TLP *Brutus* en route to installation on a heavy lift vessel. (Courtesy of Dockwise USA.)

Specialty vessels

A variety of offshore operations are performed by some of the vessels mentioned previously or by purpose-built ones:

- Seismic acquisition support, especially placing receivers on the sea floor
- Well intervention and maintenance, especially wireline services through a moon pool in the hull (fig. 13–5)
- Remote operated vehicle operations
- Workboats for deploying subsea equipment (manifolds, jumpers, processing modules, etc.) at the sea floor. These vessels generally have cranes and ROV capability.
- Diving operations support
- Line handling
- Platform maintenance
- Cable laying
- Umbilical laying
- Trenching support vessels covered in chapter 12

Fig. 13–5. The light well intervention vessel *Sarah*. (Courtesy Marine Subsea.)

Many of these vessels look like PSVs, but when outfitted with cranes, heliports, GPS, derricks, and other equipment they can handle many other jobs.

In figure 13–6, several support vessels provide services to a final construction and deployment operation.

Fig. 13–6. Several vessels working simultaneously at the *Crosby* project. (Courtesy Shell.)

Case Study

Rising Tide

The nascent offshore industry of 1950 depended on a menagerie of small vessels—wooden fishing boats, idle shrimp trawlers, oyster luggers, war surplus LSTs, tugs, and barges—to transport its needs for tubular goods, mud, fuel, food, fresh water, equipment, and people. Along came A. J. “Doc” Laborde who designed the first purpose-built offshore supply vessel (OSV). He and his brother, John Laborde, formed Tidewater Marine and launched the *Ebb Tide* in 1955. (See fig. 13–7.) This vessel, with a bow wheelhouse and a large flat deck in the aft, allowed stern positioning for easy unloading to platforms and floaters, even in rough seas. That set the standard for OSV design for the next 50 years. (See fig. 13–8.)

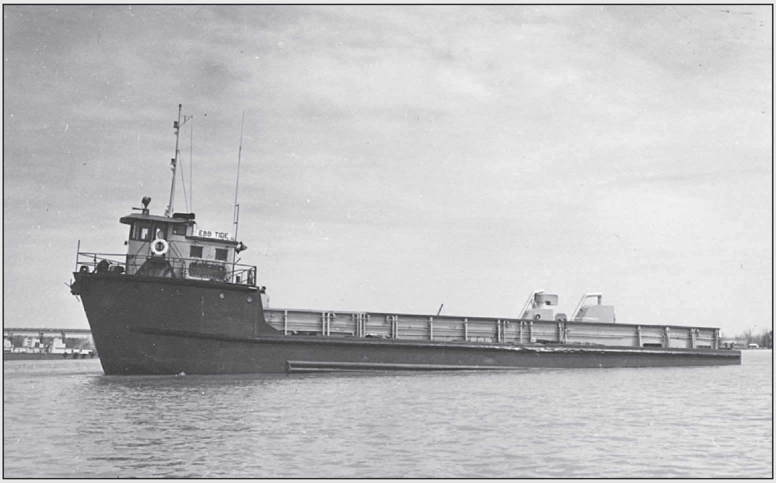


Fig. 13–7. The *Ebb Tide*—1955. (Courtesy Tidewater.)

Fig. 13–8. The *Damon Bankston*—2006. (Courtesy Tidewater.)

Growing activity in the Gulf of Mexico wasn't enough to keep John Laborde busy after he assumed leadership of Tidewater. He quickly realized that operations already underway in Lake Maracaibo presented opportunities for an even larger fleet of his newly designed OSVs. By 1966 Tidewater built its fleet to 200 vessels and operated in the Gulf of Mexico, South and Central America, West Africa, and Australia. Special designs accommodated not only transport and transfer of people and goods, but anchor setting, hook-ups, and towing.

In a burst of self-confidence, and to keep up with opportunity, starting in 1968 Tidewater embarked on an expansive acquisition program—the OSV companies Twenty Grand Marine and O.I.L. Ltd; McDermott's offshore construction vessels; Hornbeck Offshore Services; Ensco's offshore fleet; gas compression companies; and oil and gas interests, including Hilliard O&G. At the same time it continued its own new-build activity, even back integrating by acquiring a shipbuilding facility in Houma, Louisiana. In 1992 John Laborde made his most dramatic acquisition and doubled his fleet size. He bought Zapata Marine, which itself was a conglomeration of Tidewater's most important competitors.

Like many other companies, Tidewater ultimately reconsidered the revenue growth they had achieved through laterally extending into related businesses, away from its core. By 1997 it had sold off its oil and gas interests and compression operations to focus on the OSV business.

By 1997 Tidewater owned and operated more than 700 vessels as the largest OSV company in the world. In the following decade, Tidewater expended hundreds of millions of dollars per year for new builds to recapitalize its fleet with new, more productive and versatile vessels. At the same time it retired aging ones, reducing the fleet size to less than 400, but concurrently increasing revenues to record levels. Meanwhile, to “follow the money,” Tidewater shifted over 75 percent its fleet from Gulf of Mexico international waters. In an industry of 700 companies and 6,000 vessels, Tidewater grew to become the largest competitor. Tidewater’s growth came about through a strategy of step-wise organic growth plus opportunistic acquisitions. (See fig. 13–9.) Tidewater was not often a first mover in technology, but rather a fast follower when the market for the technological change demonstrated its profit potential. That positioned it for comparatively better financial stability, particularly during hard times when the opportunities came along.

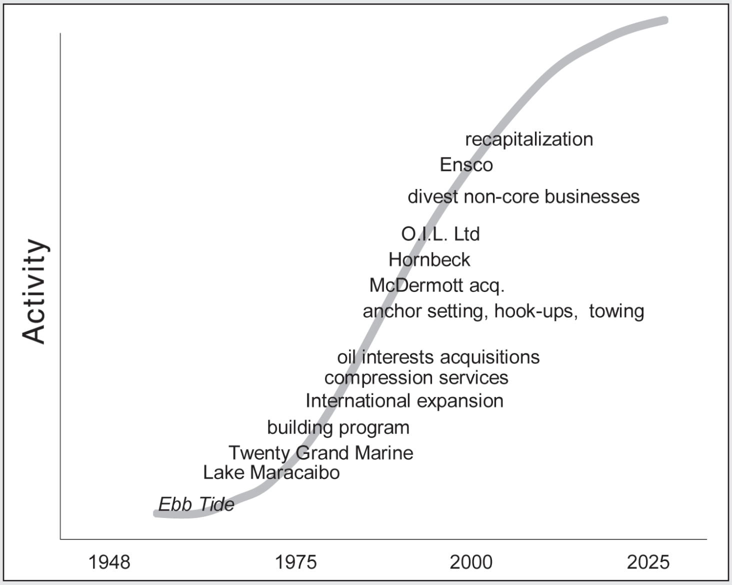


Fig. 13–9. The evolution of Tidewater

Remotely Operated Vehicles

How does a tree get bolted to the wellhead in 7,000 feet of water? How does the crew of a lift barge find the end of a mooring line? How does anyone replace a damaged seal ring on the bottom of a BOP being put in place? And how does anyone know it's damaged anyway? The answer to all these questions, and the *sine qua non* for subsea systems, is ROVs, remotely operated vehicles.

Almost every deepwater drilling rig has a sidekick ROV assigned to it. In most cases, a company other than the rig operator provides and operates it. That's how specialized ROV technology is.

ROVs in E&P service fall into two general categories, *inspection* and *work class*. Inspection ROVs are smaller, cheaper, and provide only a set of eyes in the submerged depths. Work class ROVs can carry some 400 pounds of payload—hydraulic and electro-mechanical tools and supporting supplies. (See fig. 13–10.)

Fig. 13–10. Work class ROV. This ROV operates down to 10,000 feet. (Courtesy Oceaneering.)

Inspection class ROVs can do their surveillance on wellheads, underwater structures, and pipelines using a camera on the fly. They can also stop and connect their sensors to check cathodic protection or structural integrity. Connected to pipelines, they can check wall thickness and listen for sand particles and other plugging problems.

The work class ROV, a subsea handyman, does more diverse tasks. In fact, a work class ROV can have its own tool rack nearby where it stows wrenches, torque tools, cable cutters, awls, pincers, and other devices. *Manipulators*—articulated arms—will pick them up and drop them off as the job demands. Manipulators typically have the seven degrees of movement—turning, elbowing, hinging, grabbing, rotating, and so on—that the human arm has.

The supplies in the payload can include, for example, a cargo of hydraulic fluid that the ROV delivers into a waiting tank of seabed equipment that has an ambient pressure of 10,000 psi or more.

An ROV has lights and a television camera that relays a reasonable image back to an operator's console onboard the rig or platform. The image provides the operator a 2-D view of a 3-D underwater work environment—challenging, but adequate. For some jobs, a work class ROV brings along a buddy, an inspection ROV. That provides a camera view from another angle, not quite 3-D but useful for obscured or especially touchy approaches.

Maneuvering. Propellers driven by electric motors or by electric-activated hydraulic pumps provide propulsion. The 75- to 100-horsepower motors deliver about a 1,000 pounds of thrust. The ROVs are nearly neutrally buoyant, so most ROVs do their vertical traveling to and from the target depths in cages suspended by cables with umbilicals (fig. 13–11) to allow rapid transit and minimal deviation from a straight line that currents might cause. At the target depth, the ROV exits the cage, to which it remains connected by a tether. It can roam the length of its tether, some up to 3,000 feet. On return the ROV uses its tether, sonar, and a transponder on the cage to find its way home. The operator reels in the tether and the ROV pops back in the cage like a well-trained Labrador retriever.

Fig. 13–11. ROV in its cage being launched. (Courtesy Oceaneering.)

Wonderful as that sounds, ROVs have limited dexterity. The problem arises when they have no stable platform. Doing precise work with an ROV is analogous to threading an earthbound needle from a hovering helicopter. For that reason, connections between an ROV and a subsea fixture are designed as crudely as possible to accommodate the underdeveloped gross motor skills of the ROV. Most of the time, an ROV has to lock on to a subsea fixture (a wellhead, a manifold, a tree) before it can switch to its finer motor skills. The ROV can use one of the manipulators to grab the structure. Alternatively, if the engineers who designed the target equipment have done it right, the ROV can lock into a waiting receptacle and immediately start turning valves or doing whatever the task might be. Figure 13–12 shows the sequence of tasks as an ROV attaches a pipeline to a subsea manifold.

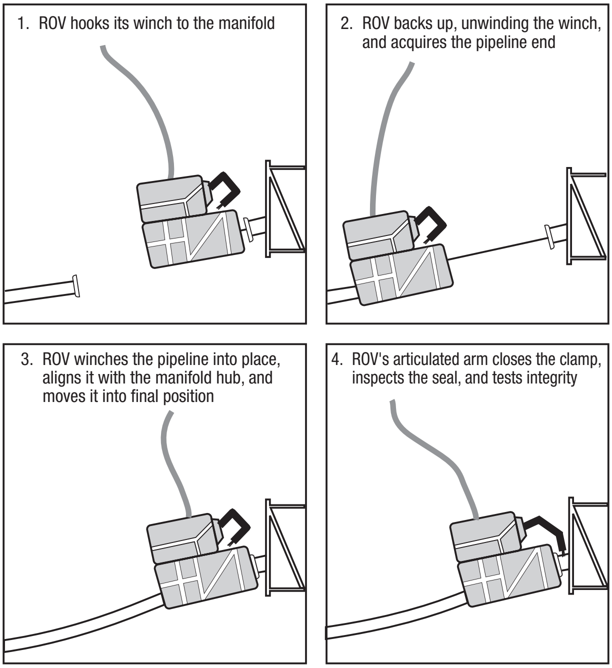


Fig. 13–12. Sequence of an ROV attachment of a pipeline to a subsea manifold. (After Oceaneering.)

Umbilicals and tethers. The ROV connects to the cage through a tether; the cage connects to the controller on the surface through an umbilical. Wires run through both to deliver electrical power. All the signals to and from the ROV are digitized, as are the camera images, and all travel through fiber optic cables in the tether and umbilical. Hydraulic fluids that run ROV devices don't move via the umbilical. They are stored in hydraulic reservoirs on the ROV. Electric motors onboard turn the hydraulic pumps.

Besides doing transmission, the umbilical also acts as the winched line to lower and raise the ROV and cage. The steel *armor shield*, the umbilical cover, bears the weight. As the ROV moves to greater depths, the weight of the umbilical is self-limiting. At 10,000 feet the umbilical approaches the limit at which the armor shield can hold up its own weight with acceptable assurance. At 15,000 feet, Kevlar, the same polymeric material used for personal armor, is substituted for steel. It weighs less and needs less strength for the same length. It is, however, more than four times as expensive as steel and requires more careful handling.

Operators. The operator maneuvers the vehicle with a joystick, watching screens on a console that relay information from sonar and the camera on the ROV as well as the transponders on the seabed or equipment being serviced. The sonic guidance system has an inherent error of plus or minus a half percent of the water depth, so the operator has to rely on both the sonar/transponders and the television images. ROV operators say that getting the vehicle to the right spot is akin to landing a helicopter underwater at night. As pilots do, they train on simulators to establish their proficiency (fig. 13–13).

Fig. 13–13. ROV training simulator. (Courtesy Oceaneering.)

Most of the time ROV operators work under air traffic controller–type stress. First, the subsea environment is filled with physical obstacles to success: equipment, flowlines, jumpers, flying leads, and even the ROV tether. Second, ROVs tend to be painfully slow anyway because of the sluggish environment they work in, the limited visibility, and because they are, well, remotely operated. Finally, the operators realize that every moment they spend doing their specialized work—connecting, fixing, adjusting, or whatever—the cash register of an idled million-dollar-per-day drilling rig is ringing. An ROV manager will tell you that the ideal operator is a former Nintendo adolescent who grew up to be a helicopter maintenance technician and who scuba dives as a hobby.

Case Study

Into the Forbidding

Three old hands in the diving business, Mike Hughes, Lad Handleman, and Phil Nuyten, decided in 1969 that their three companies could do better as one. They formed Oceaneering and began a long history of going where most others preferred not to—far below the water's surface. For many years Oceaneering's core business came from inspecting tanker hulls and producing platform legs in the Gulf of Mexico. All the while, they increased the depth their divers could reach by adopting and sometimes pioneering new technologies, such as saturation and mixed gas diving, and eventually diverless operations.

Increasing knowledge, successful growth, and a promising reputation convinced the principals that there was even more opportunity under the waves and that a fast track to growth should include acquisitions related to their business:

- 1981: Commercial Dive Center, which it renamed the College of Oceaneering and trained its own divers and others
- 1982: Marinav, an offshore surveying company
- 1983: Steadfast Marine, a marine search company whose largest client was the U. S. Navy
- 1984: Solus Ocean Systems, the underwater services division of Ensearch

The robust growth of the 1973–1983 period, when oil prices and offshore activity soared, had underwritten the enthusiasm of these acquisitions. But when the doldrums arrived in the late 1980s, Oceaneering had to rely heavily on expanded U. S. Navy work to stay afloat.

It also found during those years that the technologies and capabilities it had assembled could be applied to other, non-oilfield areas. Notable research-and-recovery projects included the space shuttle Challenger, Korean Air Lines Flight 007, and later, the Confederate submarine *Hunley*.

In the late 1980s, as an extension of diving activities, Oceaneering began to deploy a few ROVs purchased from a third party. At the same time it began to apply the special skills that divers brought to that operation—spatial cognizance, mechanical aptitude, entrepreneurship, and risk affinity. That led to rapid growth not only in inspection and maintenance, but in repair of oil producers' mission critical subsea facilities. Their first purpose-built vessel to deliver ROVs in 1993 was followed by growth to a fleet of eight Oceaneering boats and an active ROV airfreight delivery operation to crisis hotspots.

In 1991 a new division, Oceaneering Technology, deployed what they knew about platform legs to the inland counterparts—bridges, towers, and other structures. A few years later another division, Oceaneering Space Systems, applied its competence in diving apparatus, life support systems, and retrieval and repair to the analogous environment in space.

But the acquisitions in 1993–1994 of the Space Systems Division of Dover, Eastport International, and Multiflex defined Oceaneering's place in the offshore. Eastport was also an undersea search-and-recovery firm, but more importantly a pioneer in the development of ROVs; Space systems had been designing robotic tools; Multiplex was a leading producer of umbilicals. With these capabilities, the company began offering the equipment "outside the wellhead," the manifolds, the jumpers, the flying leads, the umbilicals to control them all, and the ROVs to install and maintain them. All these depended on developing complicated hydraulic, electrical, and electronic systems and power controls. By the mid-1990s, Oceaneering had assembled a fleet of sixty ROVs that brought together all these technologies, just as deepwater exploration and development took off. (See fig. 13–14.) In 2004, it acquired another 44 ROVs from Stolt Offshore and secured market positions in Africa, Brazil, and Norway.

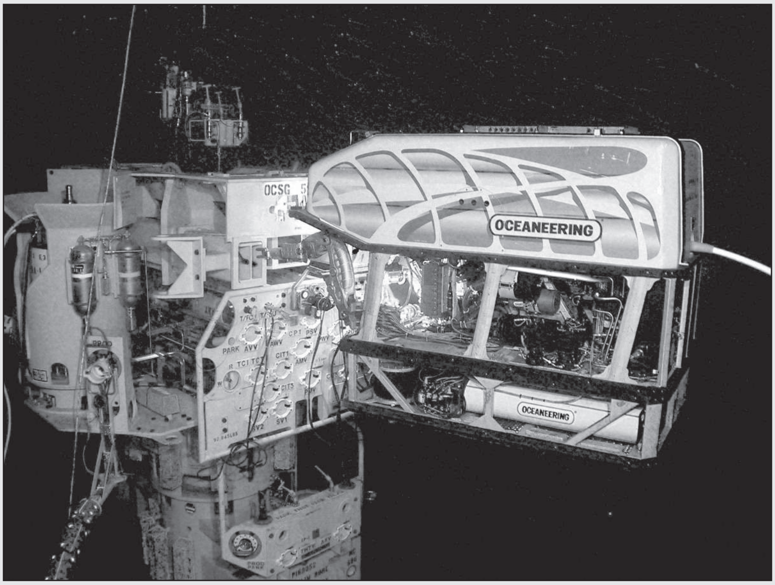


Fig. 13–14. ROV servicing a wellhead. (Courtesy Oceaneering.)

Some companies achieve successful growth by delivering world-class performance in a focused market. In Oceaneering's case, that might have led to financial ruin, as the offshore market collapsed in the late 1980s. It took a different course—it assembled its core capabilities by both organic growth from its humble beginnings and by acquisition of closely related competencies. Along the way it exploited diverse markets, but ones that had critically common characteristics that matched Oceaneering's capabilities. (See fig. 13–15.)

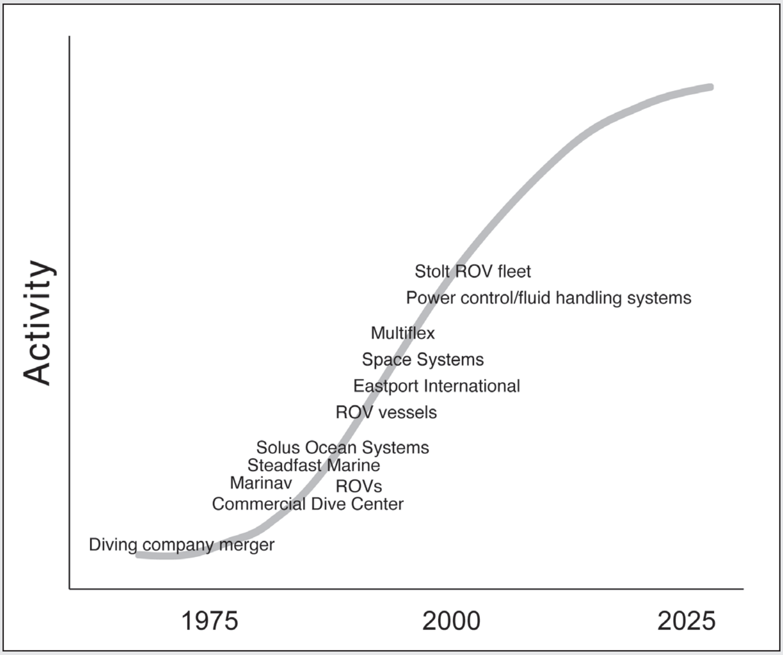
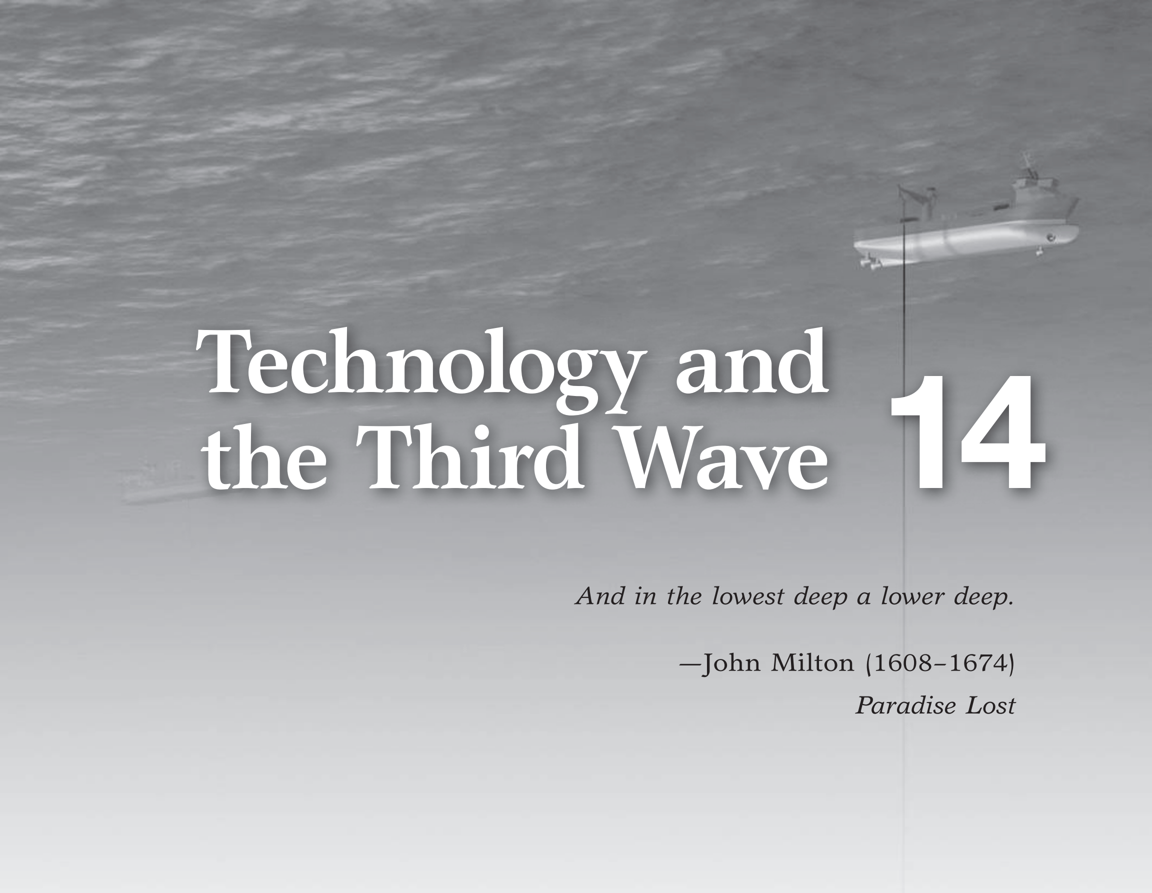


Fig. 13–15. Evolution of Oceaneering



Technology and the Third Wave 14

And in the lowest deep a lower deep.

—John Milton (1608–1674)
Paradise Lost

It took the petroleum industry 50 years of inching up the offshore learning curve before Kerr-McGee placed their historic *Creole* platform in 30 feet of Gulf of Mexico waters in 1947. In the next half century, a remarkable technology story unfolded as the industry soared nearly to the top of the curve, to the point where Shell began production from a platform in 1,354 feet of water.

Even before the curve started to flatten out, offshore pioneers leaped ahead. Within a decade they routinely produced oil and gas from wells in 2,000 to 3,000 feet of water in the Gulf of Mexico and the Campos Basin. Soon they drilled wells in 5,000 to 10,000 feet. The oil and gas industry had moved to the steep part of the deepwater learning curve, the third wave.

The previous 13 chapters have documented the most recent accomplishments in the years 1970 to 2011, all vital to success in the deepwater. Some belong to the mature offshore wave, some to the fully ripened first wave, the onshore, and some only just being used in the deepwater:

- Horizontal wells
- Bright spots

- High-capacity computing
- 4-D seismic
- Subsea wells
- Tension leg platforms
- Spars
- FPSOs and FPDSOs
- J-lay pipeline vessels
- S-lay pipeline vessels
- Large capacity lift barges, supply boats, and service vessels
- Taut anchoring systems
- Catenary risers
- Frac pack completions
- Suction piles
- Dual activity rigs
- Smart/intelligent wells
- Light well intervention
- Subsea separation and pumping

Even as this book reaches publication, technologies continue to emerge or are being perfected:

- **Shear seismic.** Shear waves, oscillations of particles perpendicular to the sound source (and to the p-waves generally used in offshore seismic), do not transmit through water. Capturing s-waves allows more detailed description of subsurface properties.
- **Riserless drilling.** The weight of the drilling mud in the riser annulus increases the frequency that casing has to be run. Pumping the returning mud separately from the sea floor to the drilling platform eliminates part of the weight.

- **Composite materials.** Using composite materials—polymers and reinforced resins—reduces weight in platforms, casing, risers, anchor lines, and other applications.
- **Smart/intelligent wells.** Wells that have analytical apparatus in the wellbore or in multiple completions and are controlled from remote locations.
- **Expandable, monobore tubulars.** An elastic casing that can be expanded after it is inserted in the well bore permits a well of uniform diameter, top to bottom. Elimination of the need for wider casing in the upper sections of the well reduces materials and cost.
- **Dual activity drilling rigs.** Drilling and setting wellheads simultaneously improves the rig efficiency.
- **Subsea pumping.** Pumps on the sea floor, connected to a power source on a remote platform, extend the range of subsea completion options and make smaller reservoirs economical.
- **Subsea separation.** Placing oil/gas/water separators on the sea floor increases the options for where and how those fluids get handled at the surface and increases total oil and gas recovery.
- **Subsea compression.** Placing gas compressors on the sea floor rather than on the topsides.
- **Surface blowout preventer.** Having the BOP on the platform makes maintenance (unjamming rams, replacing seals, etc.) more efficient but requires high-pressure risers and subsea failsafe devices.
- **AUVs.** Not having an umbilical, the autonomous underwater vehicle is unencumbered in depth and maneuvering; only battery capacity limits the range. An AUV gets recharged without returning to the surface by connecting to a seabed station linked to a platform that provides electrical power.
- **Light well intervention.** Using a specially designed PSV rather than using a drilling rig, at much lower cost.

And as operating companies deliver those technologies to deepwater sites, research organizations of a few oil and gas companies and scores of service companies aggressively pursue the means to bring hydrocarbon from ever-more inhospitable locations and conditions in the deep- and ultra-deepwater:

- **Direct detection of hydrocarbons below salt.** Dealing with the distortions as seismic waves pass through salt
- **Real time seismic acquisition, processing and interpretation.** Cutting the cycle time from acquisition to decision
- **Light weight, zero-discharge rigs, and processing facilities.** Addressing increasing demands of regulatory agencies
- **Totally composite structures.** Stronger, lighter, less expensive facilities replacing steel
- **Exploiting gas hydrates.** Recovering the trillions of cubic feet of methane locked up in deep methane hydrate deposits
- **Tapping small accumulations.** The combination of multiple technologies allowing efficient access and evacuation
- **Subsea production facilities.** Doing the complete job at the sea floor rather than require any topsides equipment
- **Floating gas liquefaction plants and gas-to-liquids technology.** Exploiting stranded gas accumulations around the world using an economic means of transport to market, either
  - by liquefying the methane and moving it as LNG
  - by chemically converting it to a diesel range oil

As dynamic as the offshore industry is, it doesn't change as rapidly as, say, the electronics industry, where Moore's Law still has the speed of microchips doubling every 18 to 24 months. The authors reviewed the list of emerging technologies from the first edition eight years ago. What a surprise to find that today's lists have more or less the same items as that one. Yes, progress has been made on all, but they can hardly be called mature technologies.

Prospects

Despite continuing advances, deepwater is still an immature frontier. As this book goes to print, the oil industry has discovered more than seventy billion barrels, is producing over eight million barrels per day from the deepwater, about ten percent of world oil production, with the Gulf of Mexico, offshore Brazil, and offshore West Africa accounting for most of the volume. A score of other prospective areas around the world remain mostly underexplored (fig. 14–1), especially:

- The Faroe Islands, the West of Shetlands, and Greenland,
- Morocco, Egypt, the Adriatic, and eastern Mediterranean
- South Caspian
- Trinidad to the Falklands
- Nova Scotia
- Tanzania and Mozambique
- Northwest and West South Africa
- Northwest Australia, South Australia, and New Zealand
- West and East India
- Borneo and the Philippine Sea
- Sakhalin

Some of these areas are down-dip (further out, in deeper water and deeper sediment) from existing producing areas, both onshore and shallow offshore. Others are brand new prospects. Many should have the same, wonderfully productive turbidite reservoirs that have made existing deepwater ventures so successful.

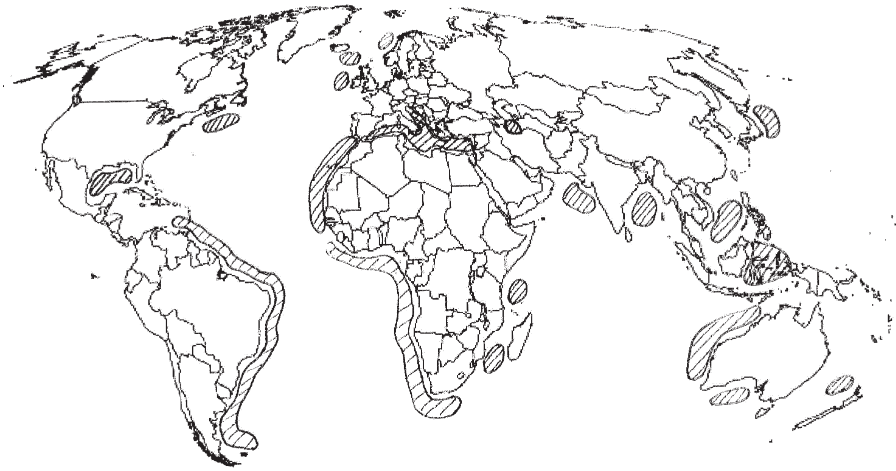


Fig. 14–1. Deepwater areas with hydrocarbon potential

Ultimately . . .

M. King Hubbert, a brilliant but irascible geophysicist, forecasted in 1956 that U.S. oil production would peak in 1970, plus or minus a couple years, following the trajectory of a bell-shaped curve. At the time, of course, he was looking at only the upside of that curve, the left-hand side. Incredibly enough, U.S. production began to decline in 1971. Hubbert's curve, as it to be known, amazed and excited petroleum economists around the world.

In ensuing years, Hubbert and his disciples used his notions about finite resources to predict that *world* oil production would peak by 2000. The *Hydrocarbon Age* would be over. As that date approached, appraisals of the ultimately recoverable oil, the area under Hubbert's curve, increased and Hubbert subscribers postponed their gloomy prognoses further into the future. Many predicted peak world oil production in the first decade of the twenty-first century.

The technology learning curve, the wave used so enthusiastically in this book, is mathematically, of course, the integral of a bell-shaped curve. That lends some support to Hubbert's theory, but only to the extent that oilmen embark on no new waves, no new learning curves. In an interminable public debate with Hubbert subscribers, Professor Morris Adelman and his colleagues at the M.I.T Center for Energy and Environmental Policy have argued that what limits the supply of oil and gas is not any finite resource theory but only the ingenuity of the people searching for and producing them. And that, they maintain, is limitless. Perhaps the deepwater wave is just one of a series that could keep us in the Hydrocarbon Age indefinitely.

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NEW TO THIS EDITION

- New chapters on geology and geophysics, rigs, and service vehicles
- Engineering and scientific schemes used in deepwater covered in greater detail
- Final chapter presents the latest technology used in the "third wave" of industry evolution

ABOUT THE BOOK

The second edition of this best-selling book is the most comprehensive and authoritative text available on the business, engineering, science, and technology of this multibillion-dollar industry. Readers will find extensive coverage of all aspects of deepwater operations—including historic background and an outlook to future deepwater operations. The authors compare and contrast offshore operations to the shelf and onshore operations throughout the text.

Packed with pictures, graphs, and illustrations, *Deepwater Petroleum Exploration and Production: a Nontechnical Guide, 2nd Edition*, is a handy reference that readers will turn to many times throughout their careers for valuable information on:

- Deepwater geology
- Deepwater exploration
- Drilling rigs
- Drilling and completing wells
- Fixed and floating systems
- Subsea systems
- ROVs and service vessels
- Topsides
- Pipelines, flowlines, and risers

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