National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling

---Draft---

Staff Working Paper No. 1[1]

A Brief History of Offshore Oil Drilling

The BP Deepwater Horizon explosion in April 2010 occurred after a dramatic, three-decade-long reconfiguration of how the United States and several other nations drill for oil. Technology, law, and geology pushed oil exploration farther from U.S. shores, as land-based exploration became less fruitful, and the global demand for energy ramped up. Oil production off American coasts began well over a century ago, but the move into deepwater and ultra-deepwater is a relatively recent phenomenon.

Developing the Shallow Waters

Offshore drilling for oil began off the coast of Summerfield, California, just south of Santa Barbara, in 1896. Closely resembling boardwalks in appearance, rows of narrow wooden piers extended up to 1,350 feet from the shoreline, their piles reaching 35 feet to the floor of the Pacific. Using the same techniques as then used on land, steel pipes were pounded 455 feet below the seabed. The hunt for oil ultimately produced only a modest yield. The field's production peaked in 1902, and the wells were abandoned several years later. The project left behind a beach blackened by oil and marred by rotting piers and derricks, the latter

[1] Staff Working Papers are written by the staff of the BP Deep Horizon Oil Spill Commission for the use of the members of the Commission. They are prepared before the conclusion of the Commission's work and are subject to further refinement and updating.

providing ugly reminders of the pioneering effort that stood until a strong tidal wave wiped out the remaining structures in 1942.

Another offshore milestone was achieved in 1947, when Kerr-McGee Oil Industries drilled the first productive well beyond the sight of land, located 10.5 miles off the Louisiana coast, but still in water depths of only about 18 feet. By that time, drilling technology had advanced far beyond the methods used to dig the first wells in Summerfield. Sophisticated rotary rigs had replaced unidirectional pile drivers. Increasingly, firms chose steel over wooden drilling structures, recognizing the metal's greater structural integrity for rigs and its lower costs over the life of the well. Offshore operators, such as Texaco and Shell, had recently pioneered "barge drilling," the practice of towing small mobile platforms to new locations at the end of drilling jobs.[2] As the oil companies grew more comfortable operating in the offshore environment, they adapted land-drilling methods – especially in the uniquely shallow continental shelf in the Gulf of Mexico.

Just as advances in technology opened up large swathes of the offshore to the possibility of drilling, a legal impasse of major proportions brought exploration and development to a virtual halt in 1950. Leases for subsea drilling were being offered by the States of California, Texas, and Louisiana, yet President Harry Truman had asserted exclusive federal jurisdiction over the entire continental shelf in 1945. The U.S. Supreme Court in 1947 and 1950 subsequently upheld Truman's claim.[3] But because no then-existing federal law conferred authority on the Department of Interior to issue offshore leases, neither the federal government nor the states possessed power to authorize offshore drilling. When Congress proved unable to resolve the matter with new legislation, leasing on the continental shelf came to a virtual halt by the end of 1950.[4]

---

[2] Tyler Priest, *The Offshore Imperative: Shell Oil's Search for Petroleum in Postwar America* (Texas A&M Press, 2007), 34. A good survey of the early history of offshore drilling can be found in Leffler, Pattarozzi, and Sterling, *Deepwater Petroleum Exploration & Production: A Nontechnical Guide* (Tulsa, Oklahoma: PennWell Corporation, 2003), pp. 1-8.
[3] See United States v. California, 332 U.S. (1947); United States v. Texas, 339 U.S. 707 (1950); United States v. Louisiana, 339 U.S. (1950).
[4] John Whitaker, *Striking a Balance: Environment and Natural Resources Policy in the Nixon-Ford Years* (American Enterprise Institute/Hoover Institution Policy Studies, 1976), p. 260.

This so-called “Tidelands dispute” over who should control offshore drilling became an issue in the 1952 presidential election, when General Dwight Eisenhower pledged to restore the leasing authority coastal states had lost in the courts. His election led to the passage of the Submerged Lands Act of 1953, which gave states the right to lease up to three nautical miles from the coast. Some states could lease up to nine nautical miles, if justified by the boundaries documented when states entered the union or by a subsequent action by Congress. After lengthy battles in the courts, only Florida and Texas won the right to the nine-mile limit.

Eisenhower’s elevation to the presidency also helped facilitate the passage of the Outer Continental Shelf Lands Act (OCSLA) of 1953, which gave the federal government (Department of Interior) the authority to issue leases in coastal areas beyond state jurisdiction. The federally administrated area became known as the Outer Continental Shelf, or OCS – a legal designation more reflective of legislative negotiations, than the actual geology of the seafloor. After the implementation of the OCSLA, leasing activity on federal submerged lands began in 1954.

Offshore production of oil in 1954 stood at only 133,000 barrels of oil a day (2 percent of total U.S. production at that time).[5] With legal disputes mostly resolved, offshore production rose steadily to reach 1.7 million barrels a day, roughly 20 percent of U.S. production, in 1971, when the industry was still recovering from a watershed event.

Two years earlier (Jan. 28, 1969), a blowout at a Union Oil Company well located in the Santa Barbara Channel had resulted in an 800-square-mile slick of oil that blackened an estimated 30 miles of Southern California beaches and soaked a substantial number of sea birds in the gooey mess. The blowout lasted 11 days and ultimately released approximately 80,000 barrels of oil. Before the BP Deepwater Horizon blowout, Santa Barbara stood as the greatest offshore drilling accident in American waters.   Although Santa Barbara is often remembered as an isolated incident, the next two years saw three more blowouts and one major fire on rigs off American shores. Though each individual incident was smaller than

[5] One barrel equals 42 gallons. Basic energy data taken from Energy Information Administration, U.S. Department of Energy.

Santa Barbara, one blowout could not be contained for more than four and a half months, and the cumulative loss of oil – as reported by the oil companies – was greater than Santa Barbara.[6]

The Santa Barbara incident had a rapid impact on federal environmental and regulatory policy. Ten days after the accident, Secretary of the Interior Walter Hickel, with the support of President Richard Nixon, issued a moratorium on all drilling and production on offshore rigs in California waters. On February 11, 1969, Nixon directed his Presidential Science Advisor, Dr. Lee A. DuBridge, a physicist, to assemble an advisory team and recommend measures to restore the affected beaches and waters. Nixon also requested that DuBridge "determine the adequacy of existing regulations for all wells licensed in past years now operating off the coast of the United States [and] to produce far more stringent and effective regulations that will give us better assurance than the Nation now has, that crises of this kind will not recur." With DuBridge at his side, Nixon remarked three months later, when unveiling his new Environmental Quality Council that "The deterioration of the environment is in large measure the result of our inability to keep pace with progress. We have become victims of our own technological genius."[7]

In April, Hickel completed a preliminary assessment of the leases affected by the moratorium and allowed five of the seventy-two lessees to resume drilling or production. By the late summer, the Department of Interior issued completely new regulations on OCS leasing and operations – the first update since the program's start fifteen years earlier. These were the first rules in which the Department claimed authority to prohibit leasing in areas of the continental shelf where environmental risks were too high. Although a small amount of drilling continued off the coast of California, the Santa Barbara accident furthered an existing trend of almost exclusive reliance on the Gulf of Mexico for U.S. offshore oil production.

---

[6] Whitaker, pp. 264-66. There is some expert opinion that oil companies greatly underestimated the volumes of these spills, and the leaked oil may have been much greater than reported. See Steve Mufson, "Federal Records Show Steady Stream of Oil Spills in Gulf since 1964," *Washington Post*, July 24, 2010.
[7] All Presidential statements can be found at John T. Woolley and Gerhard Peters, *The American Presidency Project* [online], Santa Barbara, CA, available at http://www.presidency.ucsb.edu/.

After U.S. domestic oil production peaked in 1970, making the nation increasingly dependent on imported oil, the Organization of Arab Petroleum Exporting Countries' embargo of 1973-1974 escalated fears of dependence on foreign oil.[8] Public interest in development of OCS oil and gas resources grew accordingly. Presidents Nixon, Ford, and Carter advocated the expansion of offshore drilling, while also emphasizing the need for environmental safeguards, but the results were meager. The Santa Barbara blowout and the transformed regulatory environment had little immediate effect on offshore production, but they did have a lagged impact. By 1981, offshore production levels had dropped to two-thirds of its peak production, just ten years before.

Although no other blowout in American waters reached the scale of the Santa Barbara incident, accidents at rigs in other counties reached magnitudes far surpassing the volumes of oil released at Santa Barbara. These occurred in the Persian Gulf and the Niger Delta in 1980, and the North Sea and the Mexican waters of the Gulf of Mexico in 1979. The Ixtoc I blowout off Mexico's Bay of Campeche took nine months to cap and released an estimated 3.5 million barrels of oil. The Hasbah platform blowout in the Persian Gulf killed 19 workers on the rig.

In 1982, President Ronald Reagan's Interior Secretary James Watt issued a five-year leasing plan for federal waters that greatly expanded the area available for leasing and quickened the pace of sales. Watt called the Outer Continental Shelf "America's great hope of reducing our dependency on foreign sources" of petroleum. The revised leasing plan projected estimated incomes of $40 billion to $80 billion for the federal government – revenues needed to offset an ambitious series of tax cuts passed by the Congress. Watt maintained that except for the Santa Barbara blowout, offshore drilling had been conducted with little environmental damage.[9] The new plan, known as "area-wide leasing," brought a

[8] In the early months of the embargo, some non-Arab members of OPEC increased production in response to the shortage. By the end of 1973, however, there was broader OPEC support for higher prices resulting from production cuts by the Arab members. See Jay Hakes, *A Declaration of Energy Independence* (Wiley and Sons, 2008), pp. 24-35.

[9] *Congress and the Nation 1981-1984* (Congressional Quarterly, 1985), pp. 347-48.

renewed burst of activity. One sale in the Central Gulf of Mexico reaped a record bid of $4.5 billion.

The expanded program for OCS leasing drew sharp criticism from environmental groups, officials from some coastal states, and others who argued the value of the tracts would be diluted if so many were on the market at the same time. In response, Congress began writing provisions into the yearly appropriations bills to place limits on drilling off the shores of California, New Jersey, Florida, and Massachusetts. After Watt left Interior in October of 1983, his successor, William Clark, scaled back the 1982 leasing plan.

During the same period, coastal states made a hard push for a share of OCS revenues. The Mineral Leasing Act of 1920 granted states 50 percent of Interior mineral leasing revenues from onshore federal lands within their borders, but the OCSLA of 1953 made no provision for sharing revenues with states adjacent to oil and gas production in federal offshore waters. The idea went as far as a House-Senate conference committee, but stalled because of concerns with revenue sharing's potential adverse impact on the federal budget deficit and the threat of a presidential veto. States received another setback in 1984, when the Supreme Court rejected California's argument that Interior decisions to lease OCS tracts could be blocked if inconsistent with state coastal zone management plans.[10]

A collapse in world oil prices in the mid-1980s stalled the expansion of onshore and offshore drilling and struck a devastating blow to the economies of Louisiana and Texas. By 1990, offshore production stood at only 1.1 million barrels a day – just 5 percent more than a decade earlier.

The safety record in American waters improved during the decade, but in 1988, offshore drilling suffered another major calamity, this time in the North Sea. The Piper Alpha – a platform about 110 miles north-east of Aberdeen, Scotland,

[10] *C&N*, pp. 350, 358-59. The federal Coastal Zone Management Act (CZMA) provides that each federal agency shall conduct its activities "directly affecting the coastal zone in a manner which is, to the maximum extent practicable, consistent with approved state managements plan. See 16 U.S.C. § 1456(c) (1). . In Secretary of Interior v. California, 464 U.S. 312 (1984), the U.S. Supreme Court held that OCS leasing falls outside the CZMA's consistency requirement because OCS leasing does not "directly affect" the coastal zone within the meaning o f the CZMA.

producing oil and gas -- suffered two fires and an explosion leading to the death of 167 workers. It was the deadliest accident in oil rig history and, at the time, the insurance industry's costliest man-made catastrophe.

The Move into Deepwater

The relatively stable levels of offshore production in the 1980s masked a major shift occurring in the Gulf of Mexico. Production in shallow waters rose and fell in tandem with boom and bust cycles in the broader oil and gas industry. There were some highly prospective plays in shallow water but they proved too challenging given the seismic limitations. The shelf was heavily gas prone so the economics were more difficult for small pockets. Those two factors led to the greater exploration for larger fields in deeper waters.

The first discovery in deepwater (depths of 1,000 feet or more, though definitions vary) came at Shell Oil Company's *Cognac* field in 1975. Technology had yet to evolve from shallow to deepwater, just as it took a while to develop from land to sea. Cognac adapted the fixed platform technology from shallow water, which proved economically impractical for moving much further from the coast.

Nonetheless, with the emergence of new technologies, the 1980s witnessed several pioneering discoveries. Shell's parallel deepwater work on its *Augur* (1987) and other sites discovered in the 1980s advanced the potential of deepwater more than *Cognac*. *Augur* used a tension leg (non-fixed) platform, which was better suited to deepwater conditions than fixed platforms. More importantly, geologists working on these sites came to better understand the deposition of the turbidite sands and the complex relationships to subsea salt. Turbid (i.e. murky) currents had washed away the finer grains of sand in the sandstone, making them more porous and permeable – in the words of Leffler, "qualities high on a reservoir engineer's wish list."[11] The deepwater turbidite reservoirs turned out to be even better than imagined.

While good wells on the shelf produced a few thousand barrels of oil a day, deepwater fields were developed with flow rates commonly exceeding 10,000

---

[11] Leffler, p. 33.

barrels per day. The *Auger* platform was originally designed with an estimated production capacity of 40,000 barrels per day. Once the well reached full production, its capacity grew beyond 100,000 barrels per day. The *Auger* field was developed with fewer than half the number of wells originally envisioned, which reduced capital costs. “High rate-high ultimate” wells became the standard for deepwater developments and one of the most critical factors for deepwater project success. Shell’s MENSA field, completed in1986, was located in depths of more than 5,000 feet, a threshold often defined as “ultra-deepwater”.[12]

Shell was not alone in making significant discoveries in the deepwater Gulf of Mexico in the 1980s. Conoco (later merged with Phillips), British Petroleum (later BP), Mobil (later merged with Exxon), Amoco (later merged with BP), Oryx (later merged with Kerr McGee), and Exxon moved further offshore to find new oil and gas. Petrobas – founded by the government of Brazil in 1953 – was moving into deepwater off the coast of Brazil.

Advances in exploring the deepwater of the Gulf of Mexico relied in large part on improvements in seismic technology. As a result of these advances, the percentage of wells drilled in the Gulf where 3-D seismic technology was employed increased from 5 percent in 1989 to 80 percent in 1996. The success rate of exploratory offshore wells shot up once 3-D seismology and other improvements became common. Between 1985 and 1997, the offshore exploratory success rate for the major U.S. companies increased from 36 percent to 51 percent.[13]

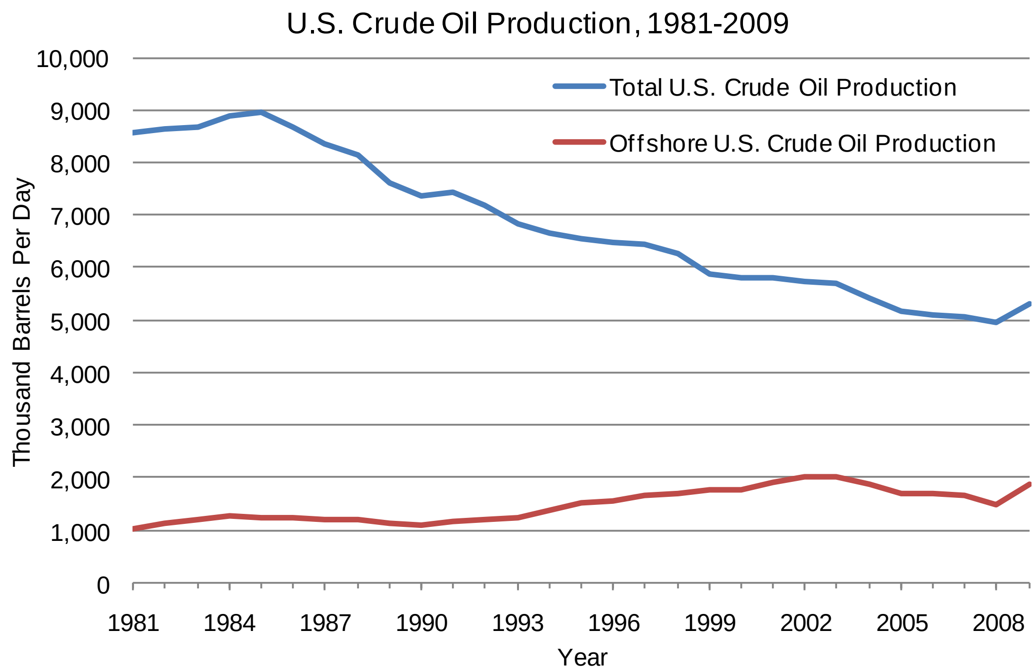
Propelled by advances in rig technology and seismology and a better understanding of the potential of turbidite reservoirs, offshore production in 1991 started a string of thirteen consecutive years of increased production, which by 2002 topped 2 million barrels per day. Since onshore production continued to decline during this period, the share of offshore in total domestic supply took on increasing importance. (See Fig. 1 below.)

---

[12] The story of Shell’s role in these developments can be found in Tyler Priest, *The Offshore Imperative*.

[13] U.S. Energy Information Administration, http://www.eia.doe.gov/emeu/finance/usi&to/upstream/index.html#n9

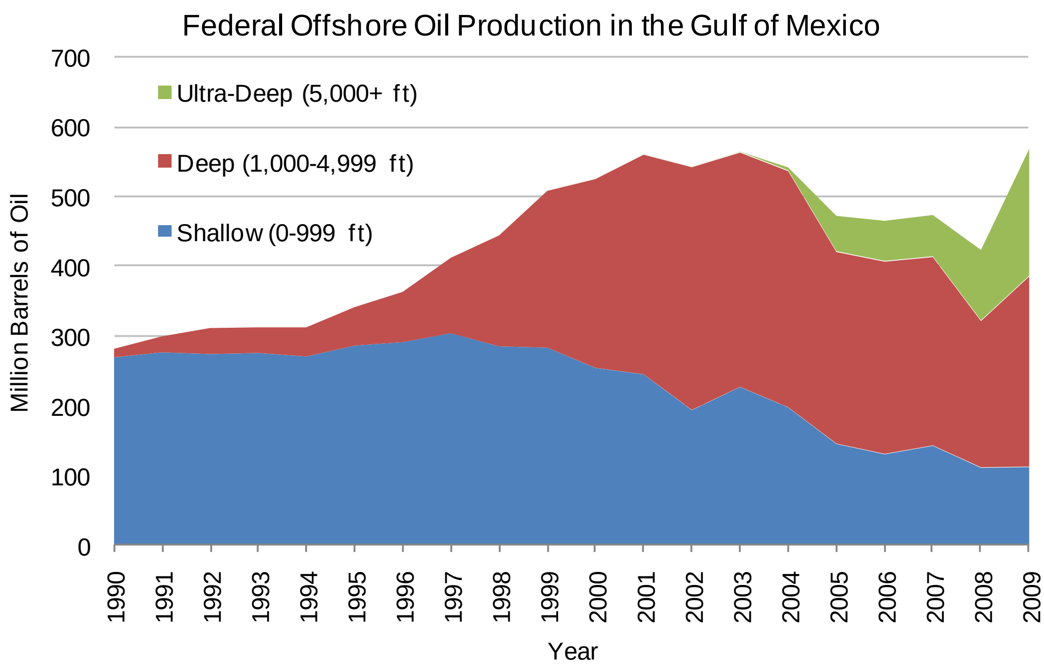
Fig. 1.



Source: Commission staff, adapted from U.S. Energy Information Administration

Attention quickly shifted to offshore assets, as discoveries in deepwater in the 1980s developed into producing wells in the 1990s. By the end of the decade, production in deepwater – a minor factor just ten years earlier – surpassed that in shallow water for the first time. Just five years later, deepwater was producing twice as much as shallow water. An increasing amount of oil was coming from ultra-deepwater (5,000 feet and deeper). (See Fig. 2 below.)

Fig. 2.

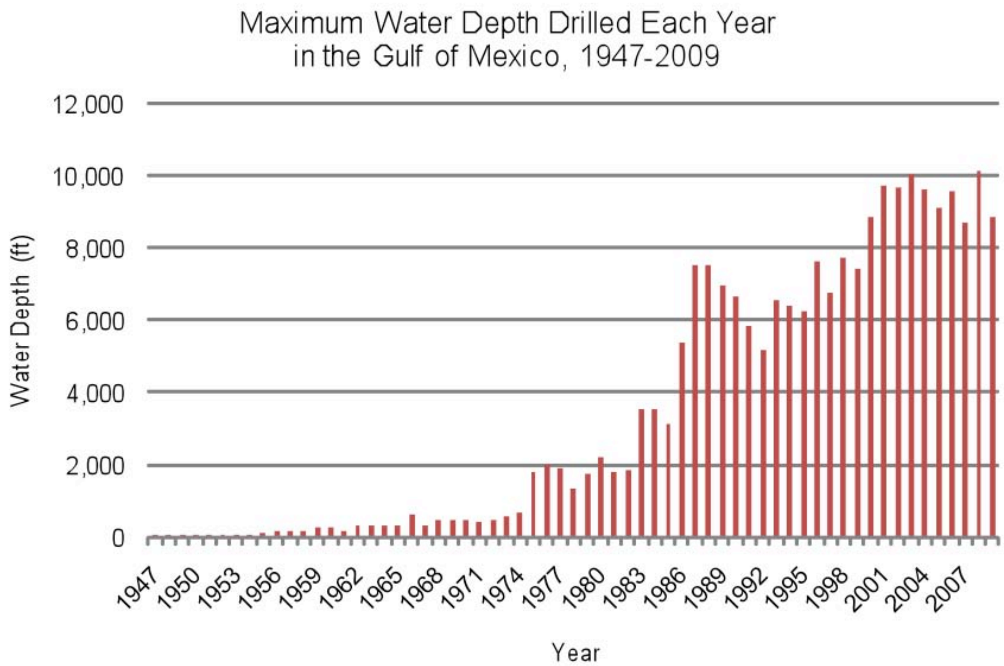


Source: Commission staff, adapted from U.S. Energy Information Administration

The move to deepwater was not gradual, as companies quickly leapfrogged each other to go deeper and deeper for new oil and gas. (See Fig. 3 below.) The move into the deepwater was a rare, dramatic era in American energy history, comparable in some ways to the early emergence of civilian nuclear power and the opening of drilling in Prudhoe Bay Alaska and subsequent rapid construction of a 600-mile pipeline through permafrost.[14]

[14] The first civilian nuclear plant began operation in 1957; by 1967, most orders for new plants were nuclear. Legislation authorizing the Alaska oil pipeline passed late in 1973; oil began reaching Valdez in the summer of 1977, and the pipeline was delivering well over a million barrels a day by the following year.

Fig. 3.



Source: Commission staff, adapted from Bureau of Ocean Energy Management, Regulation and Enforcement

The Outer Continental Shelf Deep Water Royalty Relief Act of 1995 provided additional impetus to accelerated drilling in the Gulf. Up to specified volumes (which were larger for greater depths), the Act eliminated royalty payments on new deepwater leases issued from 1996 to 2000 and allowed different levels of relief for leases issued before and after these dates. The Administration took the position: "Even the largest energy companies are often unable to make substantial investments in long-term, high-risk R&D, which is why the government supports energy industries through appropriate tax treatment and invests at all stages of technological development to ensure that Americans will have clean and affordable energy in the future."[15] Critics in Congress countered that royalty relief was unnecessary because "improved economics, better technology, and growing experience have already facilitated development of productive areas in the Gulf of Mexico without the industry first winning forgiveness of royalties, which are an important source of revenue for the Treasury."[16]

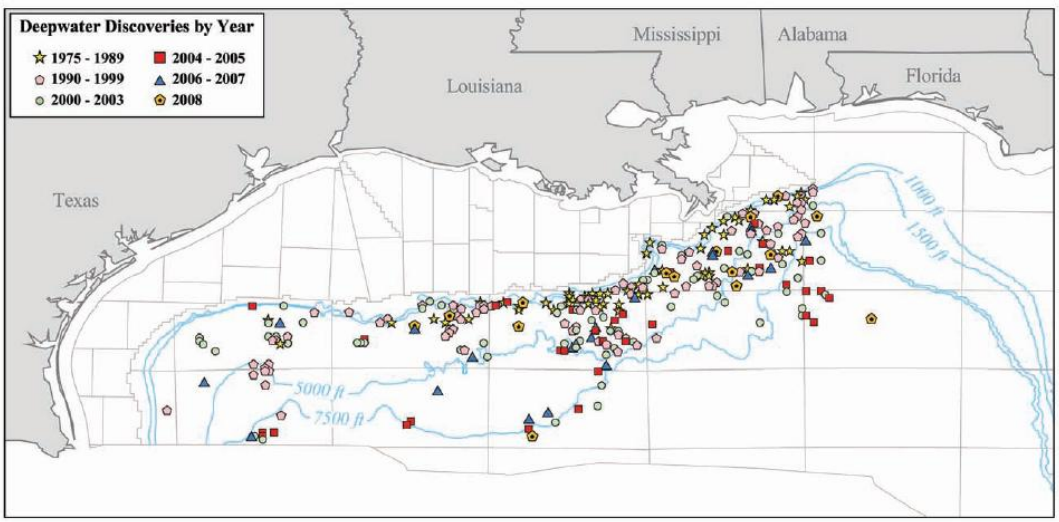
---

[15] Hazel O'Leary, "Unlocking Energy, Not 'Corporate Welfare,'" *Washington Post*, Nov. 25, 1995.
[16] George Miller, "No Royalty Relief for Oil Companies," *Washington Post*, April 24, 1995.

Hurricanes and the cycles of the oil and gas industry led to a 30 percent drop in offshore oil production from 2003 to 2008, to approximately 1.4 million barrels a day. Within the industry, however, this drop was viewed as a pause rather than a new trend. In 2008 alone, exploration efforts resulted in fifteen new discoveries. In 2008-2009, new lease sales opened up areas that had been closed to drilling for twenty years.[17] To find new resources, drillers continued to go further and further offshore. (See Fig. 4 below.)

Fig. 4.

Deepwater Discoveries by Year



Source: Minerals Management Service, *Deepwater Gulf of Mexico 2009: Interim Report of 2008 Highlights*

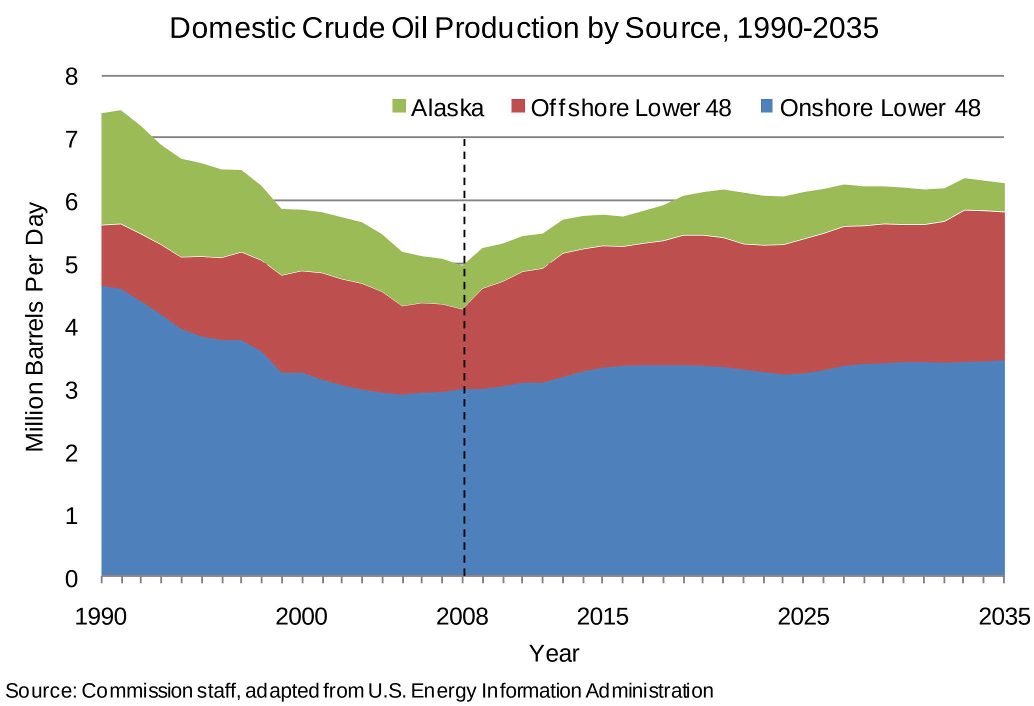
As of last year, there were fifteen new mobile offshore drilling units being built and contracted for use in the ultra-deepwater Gulf of Mexico, all of which are scheduled for operation over the next two to three years. They will be capable of operating in water depths up to 12,000 feet and drilling an additional 28,000 feet below the seabed. All modern rigs are highly sophisticated and powerful, capable of lifting one million pounds or more, a substantial advance on the original offshore operation in Summerfield. Some new deepwater projects cost

[17] Mineral Management Service, *Deepwater Gulf of Mexico 2009: Interim Report of 2008 Highlights*, p. 3-5.

approximately $4 billion dollars. Despite high initial costs, these projects can pay off in several years, or even months, due to flow rates exceeding 200,000 barrels per day of oil plus associated gas.

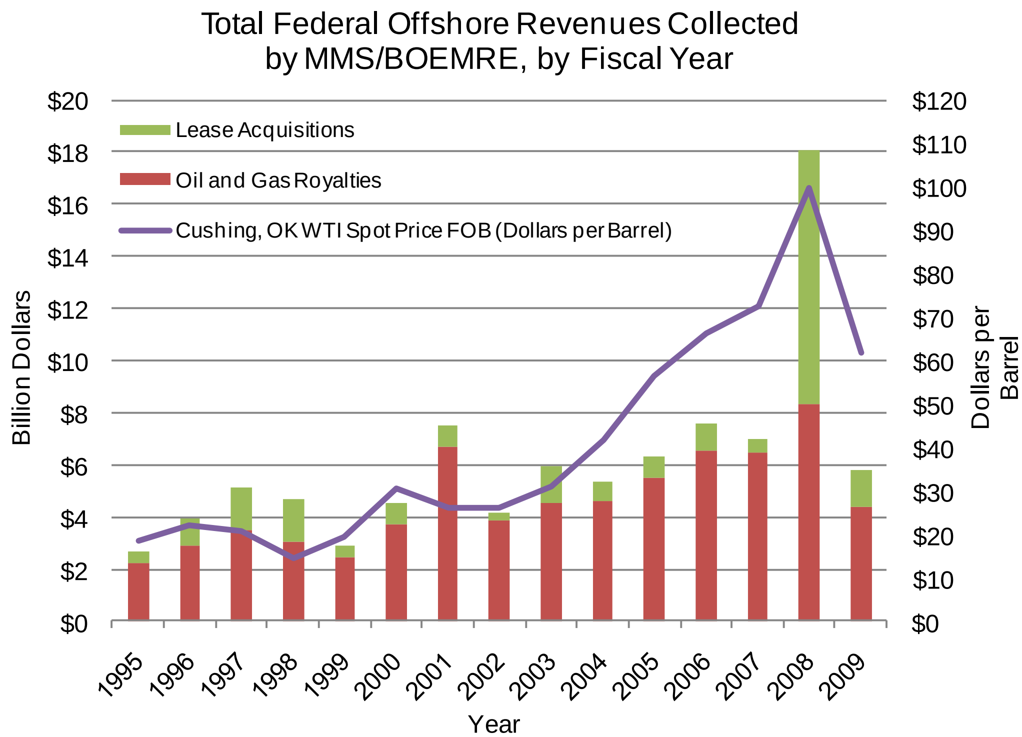
Investments in offshore drilling have contributed to the reversal of a long-term drop in U.S. oil production. Total U.S. oil production recorded year-on-year growth in 2009 for the first time since 1991, and the U.S. Energy Information Administration has projected additional increases in the coming years. (See Fig. 5 below.)

Fig. 5.



The boom in offshore drilling has produced considerable revenue for the federal government, most coming from the Gulf of Mexico. In recent years, the leasing and royalty programs have yielded about $6 billion to $18 billion a year, the higher-end figures coming at the time of big lucrative lease sales. (See Fig. 6 below.)

Fig. 6.



Source: Commission staff, adapted from Bureau of Ocean Energy Management, Regulation and Enforcement

Compensation to coastal states revived as an issue during the George W. Bush presidency. The Energy Policy Act of 2005 established the Coastal Impact Assistance Fund. Under this program, the Minerals Management Service within the Department of Interior awarded funds to OCS oil and gas producing states to offset the impacts of energy development. A total of $250 million was to be split among Alabama, Alaska, California, Louisiana, Mississippi, Texas, and the states' coastal counties each year.

Nonetheless, some coastal states wanted a greater share of Gulf of Mexico oil and gas revenue and more authority over how to spend it. In 2006 – the year following Hurricane Katrina – new legislation allotted Texas, Louisiana, Mississippi, and Alabama a 37.5 percent share of the revenues derived from leasing activity in the so-called 181 South area off the coast of Alabama. For Phase 2 beginning in 2017, the bill expands the areas from which the four states receive their 37.5 per cent share. Subject to a cap, the states will divide the revenue based on individual distance from each lease.[18] In Fiscal Year 2009, Alabama, Louisiana, Mississippi, and Texas and their eligible local governments received a total of $25 million dollars.

<u>Deepwater as the New Frontier</u>

The share of deepwater production in the current U.S. and world energy mix understates its importance for the future, at least as it was understood before the BP Deepwater Horizon accident. With high per-capita energy demands in the developed economies and dramatically rising levels of consumption in emerging economies, most experts project the world's appetite for oil and other fuels to grow for the foreseeable future. The role of deepwater oil and gas in providing that energy is also likely to grow.

According to a recent report by IHS-CERA , global deepwater production capacity has more than tripled since 2000. Ten years ago, capacity stood at 1.5 million barrels per day in water depths over 2,000 feet. By 2009 it had risen to over 5 million barrels per day. Deepwater discoveries also comprise a significant portion of new finds. In 2008 total oil and gas discovered in deep water globally exceeded the volume found onshore and in shallow water combined.[19]

The Gulf of Mexico has been only a part of the global offshore boom. Substantial exploration and development has also taken place off the coasts of Brazil and the West Africa. Interest in other, more challenging areas has been growing. Oil companies are looking to expand American production into new offshore areas, particularly Alaska and Virginia. Russian oil and gas companies are reviewing plans to develop areas in the Arctic, while Norway and Canada are assessing similar projects.

There are two key hurdles to new ultra-deepwater drilling. First, oil companies must be willing to invest substantial amounts of capital on generally challenging projects. Second, they must identify sites with significant resources and very high

[18] http://www.boemre.gov/offshore/GOMESARevenueSharing.htm

[19] James Burkhard, Peter Stark, and Leta Smith, "Oil Well Blowout and the Future of Deepwater E & P," IHS CERA, May 2010.

potential flow rates to justify such large capital expenditures. However, companies have had great success finding such sites. According IHS-CERA, the average size of a new deepwater discovery in 2009 was about 150 million barrels of oil equivalent compared with an onshore average of only 25 million barrels.

Risks in Offshore Drilling

The BP Deepwater Horizon oil spill is appropriately requiring a dramatic reassessment of the risks associated with offshore drilling. Before April 20, many believed that drilling might be safer in deep than in shallow waters. Since deepwater rigs worked farther off the coast, it would take longer for spilt oil to reach shore, giving more time for intervention to protect the coast. Moreover, the companies working in the deeper waters were seen as the "big guys" who utilized more advanced technologies than the smaller firms working near the coast, which presumably made them more adept at handling challenging conditions.

Even the severe hurricanes of the previous decade seemed, on balance, to provide validation that offshore facilities were safe. Substantial damage did occur, but caused less serious problems than might have been expected. The companies and the Minerals Management Service embarked on projects to make damage less likely during violent weather.

Any offshore drilling had the added advantage of displacing foreign oil which (except for Canada) arrived by tanker. Many of the visible damages from oil spills over the years came from tanker accidents, most notably the collision of the Exxon Valdez that led to between 260,000 and 750,000 barrels of oil leaking out and wreaking havoc on Alaska's coastline. If offshore drilling reduced the use of tankers, that seemed like a good thing.[20]

The dominant image of Exxon Valdez became itself a problem in assessing the risks of a major accident in the deepwater and the requirements for robust contingency plans. Because the tanker accident in Alaska was the largest oil spill in history and received heavy American media coverage, it became the picture of a worst case scenario for planning purposes. From that perspective, the worst

[20] Some oil from offshore is transferred to shore by tanker, but most arrives via pipeline.

case, if it occurred in the Gulf of Mexico, seemed far more manageable because the oil from such a spill would naturally be dispersed over a much wider area. Yet there was no logical reason that the accident in Prince William Sound should have been considered the worst case scenario. The blowout at the Ixtoc I well had produced a spill much larger than Exxon Valdez, a precedent that should have signaled a potential danger from an offshore well for a spill much greater than Exxon Valdez. Still there had been no major blowouts (greater than 1,000 barrels) in federal offshore waters since 1970, which made the chances of another one seem remote.

Another problem for appropriate risk assessment was the failure to adequately consider published data on recurring problems in offshore drilling. These included powerful “kicks” of unexpected pressures that sometimes led to a loss of well control, failing blowout preventer systems, and the drilling of relief wells -- the last lines of defense for a troublesome well. These problems were not great considering the large number of wells around the world and were usually more minor as threats than they sounded. However, these issues, known to petroleum engineers, did demonstrate that wells do not perform in a flawless manner.

Loss of well control, blowout preventer failure, or the need for relief wells can also occur in shallow water or on shore. Are some risks greater in the deep water? Both the velocity and irregularity of underwater currents as well as extreme pressures and temperatures put extra stress on subsea equipment in the deep. Pressure control becomes more difficult as the drill bit descends because of the greater likelihood of encountering abnormal geopressures.[21]

In the deeper water, sophisticated robotics increasingly substituted for human inspections and other tasks. According to Leffler (2007), “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 items do fail, he noted, which is why extensive robot-friendly connections and contact points are installed to make robotic intervention as simple and straightforward as possible.[22]

[21] Leffler et al, pp. 59, 66-68.
[22] Leffler, p. 119.

It was also recognized within the petroleum industry that deepwater conditions create special challenges for critical equipment, including the blowout preventer. In a 2007 article in *Drilling Contractor*, Melvyn Whitby of Cameron's Drilling System Group described how blowout preventer (BOP) requirements got tougher as drilling went deeper. "Today," he said, "a subsea BOP can be required to operate in water depths of greater than 10,000 ft, at pressures of up to 15,000 psi and even 25,000 psi, with internal wellbore fluid temperatures up to 400° F and external immersed temperatures coming close to freezing (34° F)." One possible enhancement he discussed involved taking advantage of advances in metallurgy to use higher-strength materials in ram connecting rods or ram-shafts in the BOP. He suggested that "some fundamental paradigm shifts" were needed across a broad range of BOP technologies to deal with deepwater conditions.[23]

Working further below the surface of the ocean creates myriad problems after a loss of well control or a blow out. Containment problems become much more challenging and real-time decisions become more difficult when so little is known about the deep ocean. Up to the BP Deepwater Horizon accident, little attention was devoted to containment of a blown out well in the deepwater, largely because its occurrence was considered so unlikely.

Perhaps the greatest risk factor was the very feature that made the deepwater boom so big in the first place. The prodigious flow rates in the deepwater help create "elephants," industry slang for wells whose production is considered especially high by historic standards. Such fields have very high daily output and good overall economics. But in cases of an uncontrolled blowout, high flow rate becomes the enemy as great volumes of oil and gas are spewed into the environment. This special risk of the turbidite reservoirs was both obvious and largely ignored in public discussions before April 2010.

[23] Melvyn Whitby, "Design Evolution of a Subsea BOP: Blowout Preventer Requirements Get Tougher as Drilling Goes Ever Deeper," *Drilling Contractor* (May, 2007).