Securing America's Future Energy

Issue Brief

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U.S. Oil Supply Post-Macondo

High oil prices and improved drilling technologies have unlocked substantial new petroleum resources that could alter the U.S. energy security outlook for decades to come. In 2009 and 2010, the United States witnessed consecutive annual increases in domestic oil production for the first time since 1984-85.[1] These increases in production demonstrate that, despite a long history of development, the United States still possesses the resource base to be a prolific oil producer. The most recent forecasts from the Department of Energy (DOE) show a crude oil production growth rate of 0.4 percent annually between 2008 and 2035.[2] Meanwhile, net crude imports fall by 0.3 percent over the same period.[3] This outlook is dramatically different than what was expected as recently as three years ago.

Nonetheless, numerous challenges to future production growth certainly exist. Perhaps most notably, the U.S. oil industry has yet to return to normal operations in the Gulf of Mexico after last year's *Deepwater Horizon* incident. The blowout and resulting oil spill have set a series of regulatory reforms into motion, temporarily set back production in the Gulf, and created a great deal of uncertainty regarding the future of industry access to promising resources in other areas of the federal Outer Continental Shelf (OCS). Onshore, potential resource access issues are rapidly emerging as the industry deploys hydraulic fracturing technology with greater frequency. A handful of states have placed moratoriums on hydraulic fracturing, and a number of factors are combining to

1 U.S. Department of Energy (DOE), Energy Information Administration (EIA), "Crude Oil Production," available at http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm

2 DOE, EIA, *Annual Energy Outlook 2011* (AEO 2011), Table 11

3 Id.

jeopardize the future of both onshore shale gas and shale liquids. Finally, throughout the industry, the boom and bust cycle of oil prices may already be contributing to another economic downturn, which could lead to rapidly falling oil prices and forestalled investments.

Increased domestic oil production has clear economic and national security benefits. Recent domestic production increases aside, the United States still imports large volumes of crude oil and petroleum products. As oil prices have increased in recent years, U.S. imports have had a sharply negative impact on the current account deficit. Through the first 5 months of 2011 alone, the United States ran a $138.8 billion deficit in petroleum trade.[4] To the extent that domestic oil production offsets the need for imports, it can help to minimize the transfer of U.S. wealth abroad. From a national security perspective, increased self reliance would help minimize the exposure of the United States to a crippling disruption in oil supplies brought about by turbulence in the Middle East or any other oil-supplying region.

Of course, greater energy security must be built on lessons learned. Public policy and private sector investment should be developed within a broad framework designed to accomplish at least three core objectives: increase economic security, bolster foreign policy, and safeguard natural resources. The 2010 *Deepwater Horizon* disaster in the Gulf of Mexico clearly illustrates that future policy must carefully balance each of these three core objectives—achieving increased energy security while sacrificing the environment is not an acceptable outcome. And yet, events around the world, from the rise of China to the Arab Spring, suggest that the U.S. economy will continue to be at risk in the absence of comprehensive energy reform, including a pathway to increased domestic production of oil and gas.

1. Why Domestic Supply is Important

Petroleum meets nearly 40 percent of total U.S. primary energy needs, more than any other fuel source.[5] No doubt, the energy impact of reduced economic and industrial activity—as well as high unemployment—associated with the 2007-2009 recession has been significant. Total U.S. oil consumption averaged 20.6 million barrels per day (mbd) from 2003 to 2007, equal to approximately 25 percent of the global total.[6] High fuel prices and the recessionary conditions that began in 2007 drove oil demand down by nearly 10 percent—from 20.7 mbd in 2007 to 18.7 mbd in 2009, its lowest level since 1997.[7] In 2008 and 2009, oil consumption in the United States experienced two consecutive years of decline for the first time in 19 years.[8] Notably, the decline in domestic petroleum overwhelmingly affected import levels, which fell by 13 percent between 2007 and 2009.[9]

However, total U.S. petroleum consumption rebounded to 19.1 mbd in 2010 and is expected to reach 19.4 mbd in 2012.[10] A stronger economic recovery that featured more robust job growth

4 U.S. Department of Commerce (DOC), Census Bureau and Bureau of Economic Analysis, "April 2011 Form FT900," Exhibit 9
5 BP, plc. *Statistical Review of World Energy 2011*, at 41
6 Id., at 9
7 Id., at 9
8 DOE, EIA, *Annual Energy Review 2009* (AER), Table 5.1
9 Id.
10 DOE, EIA, *June 2011 Short Term Energy Outlook*, Figure 15

could certainly increase those figures. Over the long term, the growth rate of U.S. liquid fuel consumption is somewhat uncertain. The Department of Energy expects U.S. oil consumption to increase by 3.0 mbd between 2010 and 2035. At the same time, high fuel prices and increasingly stringent automotive fuel-economy standards appear likely to reduce the oil intensity of the U.S. economy—that is, the amount of oil required to fuel economic growth.[11]

FIGURE 1
U.S. OIL DEMAND BY SECTOR (2009)

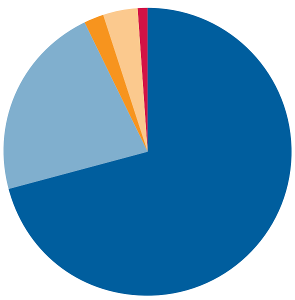
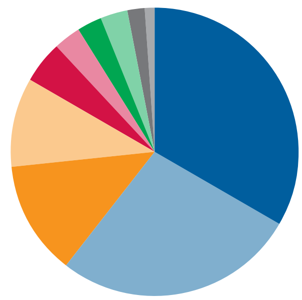


FIGURE 2
U.S. TRANSPORTATION OIL DEMAND (2009)



Source: Figure 1—DOE, EIA; Figure 2—Oak Ridge National Laboratory

In either case, the United States will rely heavily on petroleum for the foreseeable future. In large part, this is because the nation's transportation system is still the world's largest and most dynamic. At more than 13 million barrels per day, this sector alone currently consumes more oil than any other individual national economy in the world.[12] There are more than 230 million light-duty vehicles on U.S. roads today, accounting for approximately 40 percent of total national oil consumption.[13] Freight trucks add another 8.7 million vehicles, equaling roughly 12 percent of oil demand.[14] All told, the transportation sector accounts for 71 percent of aggregate U.S. oil consumption.[15] Despite significant efforts to drive alternative fuels into the marketplace, 94 percent of delivered energy in the transport sector is still petroleum-based today.[16]

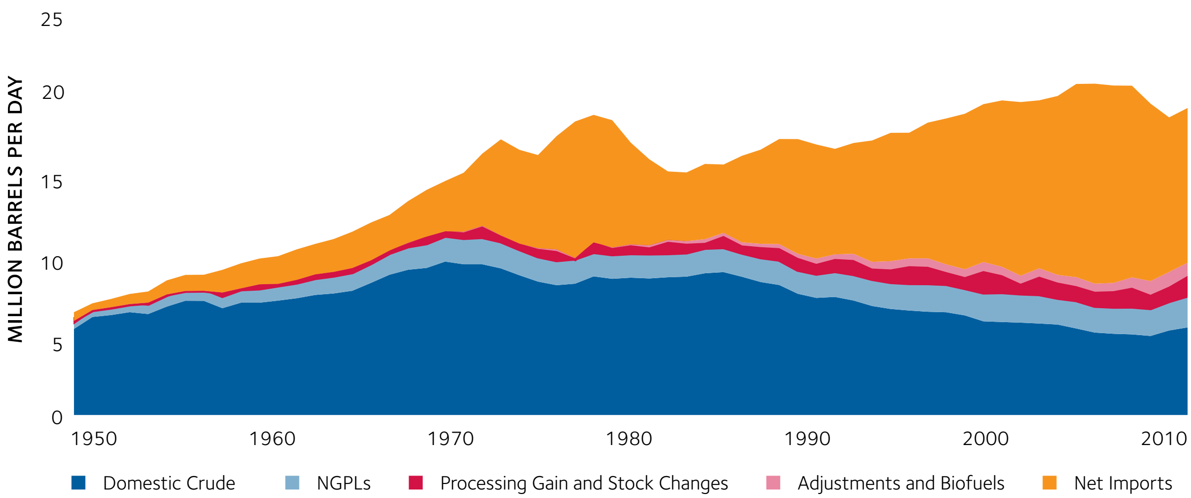
For a number of economic and national security reasons, the United States should seek to maximize domestically produced petroleum as a share of total oil consumed. Rising oil prices and high import levels weaken the American economy and export U.S. wealth abroad. At the same time, high dependence on imports increases the exposure of the United States to a crippling physical supply disruption brought about by turmoil in the global oil market. It is important to note that this goal is perfectly consistent with efforts to maximize the efficiency of the nation's automobile fleet. Indeed, these two approaches—increasing domestic oil production while reducing aggregate demand—should form the core of any national strategy for energy security.

11 DOE, EIA, *AEO 2011*, Table 11
12 DOE, *AER 2009*, Table 5.13c
13 DOE, EIA, *AEO 2011*, Table A-7 and online supplemental Table 58
14 DOE, EIA, *AEO 2011*, online supplemental Table 67
15 DOE, EIA, *AER 2009*, Figure 5.0
16 DOE, EIA, *AER 2009*, Table 2.1e

A. Economic Security

Despite promising increases in domestic oil production in 2009 and 2010, America currently imports approximately half of the oil it consumes at tremendous cost to the current account balance.[17] In 2007, the U.S. trade deficit in crude oil and petroleum products was $295 billion. In 2008, as oil prices reached all time highs, that figure increased to $388 billion.[18] The figures for 2009 and 2010 were somewhat muted based on a combination of reduced import levels (due to the economic recession) and relatively lower petroleum prices. However, based on current levels of oil imports and petroleum prices, the U.S. trade deficit in crude oil and petroleum products is on pace to return to pre-crisis levels above $300 billion in 2011.[19]

FIGURE 3 · U.S. PETROLEUM SOURCE BY ORIGINATION (HISTORICAL)



Source: DOE, *Annual Energy Review 2010*

Because price increases have outpaced the reduction in import levels, the share of petroleum trade in the overall U.S. trade deficit has increased considerably in recent years. Since December 2007, crude oil and petroleum products have routinely accounted for more than half of the monthly U.S. trade deficit.[20] For the full year, oil trade accounted for 56 percent of the total U.S. trade deficit in 2008 and 55 percent in 2009.[21] As oil prices have spiked in the first half of 2011, that figure has risen to 59 percent.[22] In other words, oil now typically accounts for a greater share of the U.S. trade deficit than trade with any single bilateral or regional trade partner, such as China, NAFTA or the European Union.

Perhaps more importantly, while more than 30 percent of net U.S. imports are sourced in North America, 48 percent originate with members of the Organization of the Petroleum Exporting Countries (OPEC), nations with which the Unites States has little else in terms of an economic

17 DOE, EIA, *June 2011 Short Term Energy Outlook*
18 DOE, EIA, *AER 2011*, Table 3.9
19 DOC, Census Bureau and Bureau of Economic Analysis, "April 2011 Form FT900," Exhibit 9
20 DOC, Census Bureau and Bureau of Economic Analysis, "Form FT900," Exhibit 1 and Exhibit 9; SAFE Analysis
21 Id.
22 Id.

relationship.[23] A significant share of the dollars sent abroad to purchase oil from OPEC states is not recycled into the U.S. economy, amounting to a simple transfer of wealth. Recent research has suggested that America's one-dimensional relationship with its oil suppliers makes the U.S. economy more vulnerable to oil price volatility than it would be if the trade were reciprocal.[24] To the extent that increased domestic oil production offsets the need for oil imports and minimizes the transfer of U.S. wealth abroad, it would clearly have a beneficial economic impact.

FIGURE 4

SHARE OF PETROLEUM TRADE IN U.S. TRADE DEFICIT

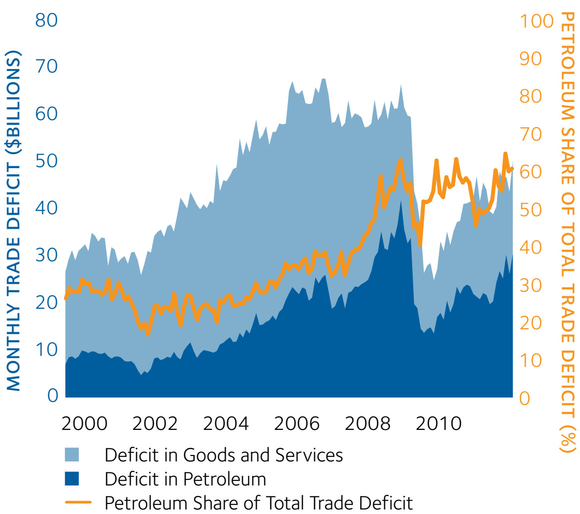
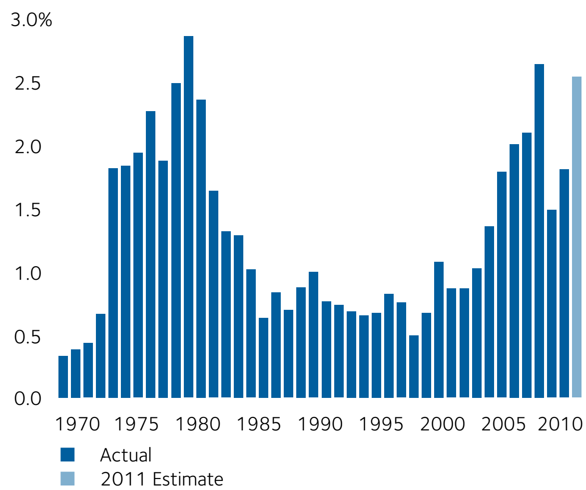


FIGURE 5

NET OIL IMPORTS AS A PERCENT OF U.S. GDP



Source: Figure 4—U.S. Census Bureau, Office of Foreign Trade Statistics; Figure 5—DOE, EIA; World Bank; International Monetary Fund; SAFE Analysis. 2011 estimate based on DOE forecasts for refiner acquisition cost of crude oil and net U.S. imports, and IMF forecast of GDP growth.

B. National Security

A crippling disruption to global oil supplies ranks among the most immediate threats to the United States today. A prolonged interruption due to war in the Middle East or the closure of a key oil transit route would lead to severe economic dislocation. U.S. leaders have recognized this for decades, and have made it a matter of stated policy that the United States will protect the free flow of oil with military force.[25] Still, policy alone has consistently fallen short of complete deterrence, and the risk of oil supply interruptions has persisted for nearly 40 years.

To mitigate this risk, U.S. armed forces expend enormous resources protecting chronically vulnerable infrastructure in hostile corners of the globe and patrolling oil transit routes. This engagement benefits all nations, but comes primarily at the expense of the American military and ultimately the American taxpayer. A 2009 study by the RAND Corporation placed the ongoing cost of this burden

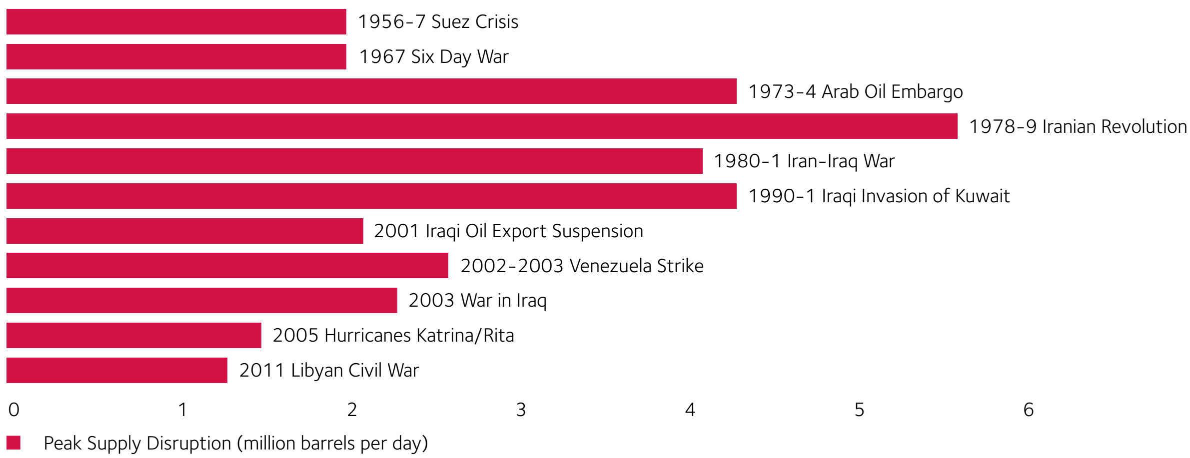
23 DOE, EIA, *AER 2009*, Table 5.7

24 Matthew Higgins, Thomas Klitgaard, and Robert Lerman, "Recycling Petrodollars," Federal Reserve Bank of New York, *Current Issues in Economics and Finance*, Vol. 12, Number 9, (2006)

25 RAND Corporation, "Imported Oil and U.S. National Security," at 60-62 (2009)

at between $67.5 billion and $83 billion annually, plus an additional $8 billion in military operations.[26] In proportional terms, these costs suggest that between 12 and 15 percent of the current defense budget is devoted to guaranteeing the free flow of oil.

FIGURE 6 · MAJOR WORLD OIL SUPPLY DISRUPTIONS



Source: IEA

Oil is a fungible commodity, and a supply interruption anywhere will almost always affect prices everywhere. In this sense, oil supply disruptions affect the economies of all oil consumers by driving up benchmark crude oil prices in unexpected and volatile ways. Nonetheless, the role of oil in the U.S. economy coupled with America's dependence on foreign suppliers over the past 40 years has elevated concerns regarding supply disruptions. The resulting foreign policy posture has arguably unduly burdened America's armed forces, who have been implicitly tasked with being the world's oil police, a role that manifests itself through operations ranging from direct military engagements to security force training. With this in mind, increased self reliance in terms of oil supplies would certainly have a positive impact on military and national security.

2. Emerging Opportunities in the Domestic Petroleum Industry

U.S. domestic field production of crude oil and associated natural gas liquids peaked in 1970 at 11.3 mbd.[27] A precipitous decline in output left domestic production at just 9.7 mbd in 1976.[28] The discovery of oil in Prudhoe Bay, Alaska, contributed to a temporary resurgence in the late 1970s and early 1980s, with production reaching a second peak of 10.6 mbd in 1985. For decades after that, however, production generally declined, hitting 6.7 mbd in 2008. Over the same period, U.S. oil consumption increased by more than 25 percent, from 15.9 mbd in the period 1980-85 to 19.9 mbd in 2005-2010.[29]

26 RAND Corporation, "Imported Oil and U.S. National Security," at 71 (2009)
27 DOE, EIA, *AER 2009*, Table 5.1
28 Id.
29 DOE, EIA, online statistics, "Product Supplied," available at http://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_m.htm

Declining rates of reserves replacement, falling well productivity, and rising industry costs all contributed to the decline in U.S. production between the 1970s and 2000s. Increased consumption of petroleum products and resulting development of domestic resources has far outpaced net proved reserves additions since the 1950s.[30] Although proved reserves only provide a snapshot of recoverable reserves based on cost and economics, it is instructive to note that the U.S. has not seen a net increase in reported reserves for any decade since the 1950s.[31] At the same time, the cost of incremental reserves additions has soared since the mid-1990s.[32]

FIGURE 7
CHANGE TO U.S. PROVED RESERVES BY DECADE

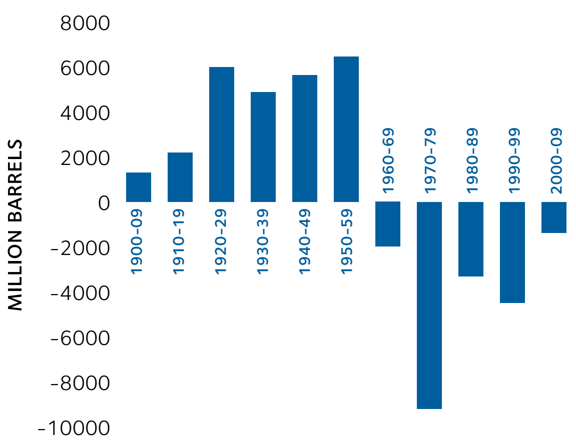
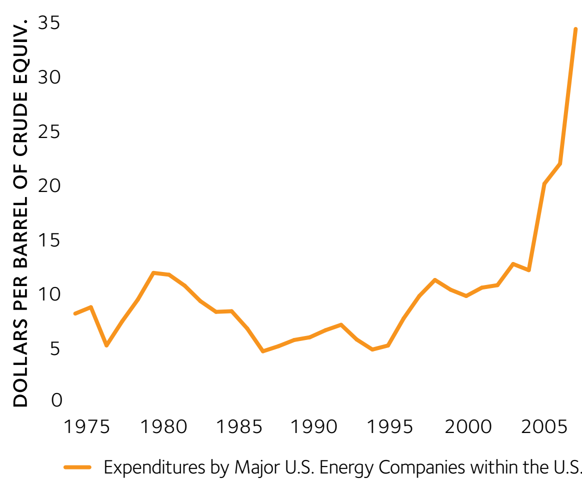


FIGURE 8
EXPENDITURES PER BARREL OF RESERVES ADDITIONS



Source: Figure 7—DOE, EIA; Figure 8—DOE, EIA

In addition to costly reserves replacement, declining productivity from new wells served to stall U.S. oil output in recent decades. More than 530,000 oil producing wells averaged 18.1 barrels of oil production per day in 1970.[33] This figure plummeted to 9.4 barrels per well per day for 526,000 producing wells in 2008.[34] At the same time, the cost of drilling new development and production wells increased substantially. Most recently, between 2000 and 2008, real costs per well drilled in the United States increased by a factor of nearly six.[35]

There are, however, reasons for optimism regarding the future of domestic petroleum production in the United States. While the levels of conventional oil output reached in the 1970s are not likely to return, several factors indicate that the United States could increase domestic production of petroleum to levels that would reduce the need for oil imports and thereby significantly enhance economic security.

30 DOE, EIA, online statistics, "Crude Oil Proved Reserves, Reserves Changes, Production" last accessed June 29, 2011
31 Id.
32 DOE, EIA, *AER 2009*, Table 4.9
33 Id., Table 5.2
34 Id.
35 Id. Table 4.8

High and rising oil prices since approximately 2003 have provided strong incentives to the petroleum industry to increase oil production. In fact, high prices have encouraged important developments on multiple fronts. In general, sustained high oil prices incentivize the industry to increase spending on exploration and development, thereby leading to organic reserves growth in the near term and incrementally higher production in the future. Perhaps more importantly, high prices incentivize and support investment in research and development. By developing the necessary means to produce oil and gas from unconventional resource deposits, the energy industry has expanded the range of economically attractive resources available for development, and the United States is clearly benefiting.

A. Gas Shales and a Return to Growth in Onshore Liquids

In 2009 and 2010, the United States witnessed consecutive annual increases in domestic oil production for the first time since 1984-85.[36] Excluding natural gas plant liquids, domestic field production of crude oil was 4.9 mbd in 2008.[37] It was 5.4 mbd in 2009 and 5.5mbd in 2010.[38] The increases in production were the direct result of several converging trends in the onshore and offshore oil industry.

Onshore, the story begins in the mid-2000s not with oil, but with the massive increase in development of unconventional natural gas. For decades, industry geologists were aware of the existence of natural gas resources deep in underground shale formations.[39] However, the resource was viewed as technologically difficult to access and economically unattractive. In essence, unconventional reservoirs are defined by reduced porosity vis-à-vis conventional reservoirs.[40] This reduced porosity made it difficult to collect commercial quantities of natural gas without expending tremendous capital.

Throughout the 1990s, the public and private sectors each invested significantly in research and development efforts designed to improve existing drilling technologies in order to profitably unlock shale gas.[41] A 1999 report from the Office of Fossil Energy noted that the DOE-led Natural Gas and Oil Technology Partnership promoted a number of advances in hydraulic fracturing.[42] The report also cites advances made by the DOE-funded Gas Research Institute during the 1990s, including better diagnostics and greater ultimate recovery. Beginning in 2003, surging natural gas prices added a final incentive for the industry to focus on achieving commercial production of natural gas from unconventional reservoirs.[43] After averaging $3.96 per million Btu (MMBtu) in 2001 and $3.36/MMBtu in 2002, prices rose to average $5.47 and $5.89/MMBtu in 2003 and 2004 respectively.

By 2008, rising prices and better application of drilling technology resulted in a virtual revolution in the natural gas industry. Proved reserves increased by 54 percent between 2000 and 2009—from 177 trillion cubic feet (tcf) to 273 tcf.[44] Moreover, proved reserves present only part of the picture.

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36 DOE, EIA, online statistics, "Crude Oil Production" last accessed June 29, 2011
37 Id.
38 Id.
39 DOE, Office of Fossil Energy and National Energy Technology Laboratory, "Modern Shale Gas Development in the United States: A Primer," at 13 (April 2009)
40 Id., at 14
41 *See, e.g.*, Massachusetts Institute of Technology, *The Future of Natural Gas*, at 73-75 (2010)
42 Department of Energy, *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology*, Drilling and Completion technology fact sheet, at 7 and 8, (1999), available at http://fossil.energy.gov/programs/oilgas/publications/environ_benefits/Environmental_Benefits_Report.html
43 DOE, EIA, online statistics, "Natural Gas Spot and Futures Prices (NYMEX)" last accessed June 29, 2011
44 DOE, EIA, online statistics, "Dry Natural Gas Proved Reserves" last accessed June 29, 2011

The Colorado School of Mines Potential Gas Committee estimates that potential U.S. gas reserves could now be closer to 2,000 tcf, resulting in a theoretical reserves-to-production ratio of nearly 100 years at today's consumption levels.[45]

The technology that the industry used to unlock shale resources is known as hydraulic fracturing. Although the concept of fracturing existed in the industry for decades, its combination with new drilling techniques and other process improvements proved revolutionary. In order to extract natural gas from deep shale reservoirs, hydraulic fracturing over-pressurizes the source rock, creating multiple fractures in which gas supplies can accumulate. The fracturing process is typically achieved using fluids (like water under high pressure) along with viscosity-enhancing chemical agents (surfactants). In addition, producers typically inject a proppant, or propping agent, into the well to keep the fractures from closing when pressure is reduced.[46] Instead of using traditional vertical wells, hydraulic fracturing and recovery take place via horizontal wells, which increase exposure of the well bore to the gas-producing zone.

FIGURE 9

U.S. PROVED RESERVES, DRY NATURAL GAS

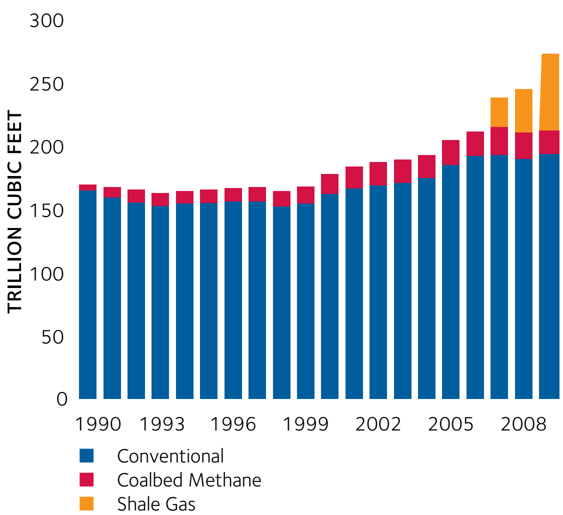
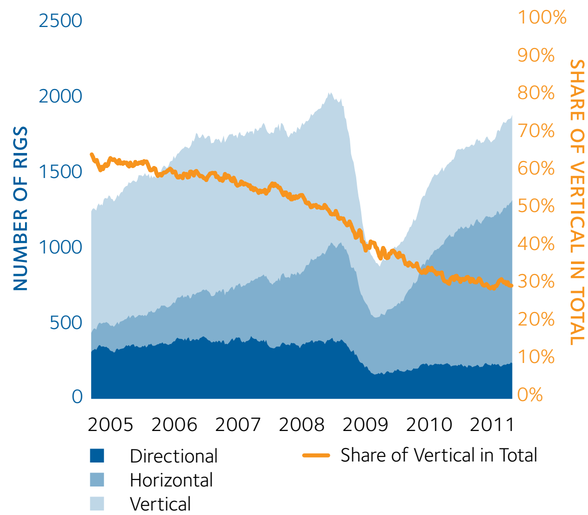


FIGURE 10

WEEKLY U.S. RIG COUNT BY TYPE



Source: Figure 9—DOE, EIA; Figure 10—Baker Hughes

The growing attractiveness of horizontal drilling starting in 2005 is reflected in the U.S. well count. The number of horizontal and directional wells drilled began expanding slowly in 2005. By 2008, high and rising natural gas prices drove an influx of investment in natural gas production, and the horizontal well count surged. In the first week of January 2005, 127 horizontal wells were drilled. For the same period in 2006, the number was more than 320. In the week ending December 5, 2008, 625 horizontal wells were drilled in the United States.[47]

45 Potential Gas Committee, "Potential Supply of Natural Gas in the United States," December 31, 2010

46 Environmental Protection Agency, Underground Injection Control Program, "Hydraulic Fracturing," available online at www.epa.gov/ogwdw/uic/wells_hydrofrac.html, last accessed on August 28, 2009

47 Baker Hughes, "North America Rotary Rig Count: Baker Hughes Drilling Type" last accessed June 29, 2011

In 2009, however, the full impact of the global financial crisis and a deepening recession led to sharply reduced energy demand throughout the U.S. economy. While the decline in economic activity affected both oil and gas, the recession was ultimately more significant for natural gas than for oil. Natural gas prices had also reached extremely high levels in mid-2008, topping out at more than $13 per MMBtu.[48] The financial crisis resulted in a steady decline in Henry Hub prices through December, when natural gas spot prices averaged $5.81/MMBtu, levels last seen in much of the early- and mid-2000s.[49] However, the decline in natural gas prices was to continue for some time. Prices in 2009 averaged $3.91/MMBtu, with the monthly average falling as low as $2.99/MMBtu in September.[50] Prices in 2010 averaged $4.37/MMBtu.[51]

Unlike oil prices, natural gas prices in the United States today are generally insulated from developments around the world. The physical properties of natural gas historically made it difficult to ship overseas and, therefore, prevented the development of a global market. In recent decades, technology to liquefy and store gas as liquefied natural gas (LNG) emerged, and LNG plays a significant role in the energy economies of a number of countries, particularly in East Asia. However, the United States has been able to rely on domestic production supplemented by limited imports from North American suppliers, thus effectively insulating it from price volatility in LNG spot markets.[52]

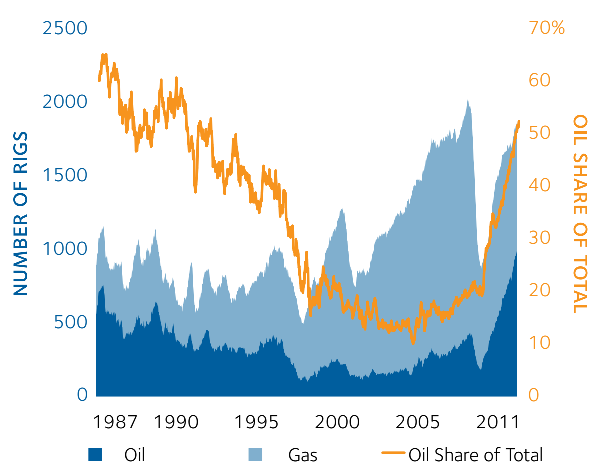
The main driver of domestic natural gas prices, therefore, is the domestic economy. The prolonged nature of the 2007-2009 recession led to a substantial decline in demand for natural gas in key sectors. In particular, industrial gas demand fell by 7.4 percent between 2008 and 2009, from 6.7 tcf to 6.2 tcf.[53]

FIGURE 11

RATIO OF CRUDE OIL TO NATURAL GAS PRICE

FIGURE 12

U.S. RIG COUNT: OIL/GAS SPLIT



Source: Figure 11— DOE, EIA; Figure 12—Baker Hughes

48 DOE, EIA, online statistics, "Natural Gas Spot and Futures Prices (NYMEX)" last accessed June 29, 2011
49 Id.
50 Id.
51 Id.
52 DOE, EIA, *AER 2009*, Table 6.3
53 DOE, EIA, online statistics, "Natural Gas Consumption by End Use" last accessed June 29, 2011

This stands in marked contrast to the petroleum industry, where prices are directly determined by the net effect of changes in supply and demand in every country around the world. The global nature of the oil industry contributed directly to a rapid recovery in oil prices after the financial crisis. Even during 2009, much of which was characterized by high unemployment and weak economic growth in the United States, oil prices bounced back to average between $60 and $80/bbl throughout much of the year.[54] A fast return to high rates of demand growth in emerging markets and other global market fundamentals trumped a slow recovery in the developed world in terms of oil price impact.

Beginning in early 2009, companies that had been active in unconventional gas production began to shift capital and drilling programs toward liquids production. Compared to persistently low natural gas prices, the high and rising oil prices provided an attractive target. Many of the most significant unconventional gas plays also contained sizeable liquid-bearing formations. Fortunately, the investments in drilling technology and equipment that had been so central to the expansion in shale gas production—horizontal drilling and multi-stage hydraulic fracturing—were also directly applicable for producing liquids from these formations. As companies shifted capital and labor assets out of gas and into liquids, mature oil-producing regions of the United States experienced a renaissance in production. The Permian basin in Texas has arguably led the way.[55] In addition, large quantities of shale oil in North Dakota and Montana could be developed using the same techniques.

During the height of the shale gas boom between 2005 and 2008, the U.S. oil rig count had fallen below 500, and oil rigs accounted for less than 15 percent of the total U.S. rig count. An expanding spread between oil and natural gas prices lead to a surge in oil drilling that would rapidly change this dynamic. The number of rigs drilling in the Permian basin increased from 68 in June 2009 to 350 in June 2011.[56] This year, Chevron alone plans to drill 350 wells in the Permian compared to 200 last year. Similarly, Apache will drill 550 Permian wells compared to 263 last year.[57]

Merger and acquisition activity has also reflected the shift to liquids and the elevated the status of U.S. shale liquids to a world-class resource. Chesapeake Energy, perhaps the premier independent operator active in shale gas development, inked a series of billion dollar joint venture deals with Total, Statoil, and CNOOC in liquids-rich U.S. shale plays, including the Barnett and Eagle Ford in Texas.[58] Also of note, the share of natural gas in Chesapeake capital spending fell from 90 percent in 2009 to 70 percent in 2010, and company estimates report that the gas share will fall to 25 percent in 2012—elevating liquids investments to 75 percent of projected capex spending.[59] In 2011, Devon Energy, a major U.S. gas producer, will reportedly spend roughly 90 percent of its $5 billion budget on liquids.[60]

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54 DOE, EIA, online statistics, "Oil Spot Prices," last accessed June 29, 2011
55 Sheila McNulty, "Advances spark new rush for black gold," Financial Times, June 24, 2011
56 Sheila McNulty, "Fresh ground for U.S. groups in Texas renaissance," Financial Times, June 24, 2011
57 Id.
58 Sui-Lee Wee and Paritosh Bansal, "CNOOC to Pay $1.1 Billion for Stake in Chesapeake Unit," Reuters, October 10, 2010
59 Chesapeake Energy, *May 2011 Investor Presentation*
60 Daniel Gilbert, "As natural gas prices fall, the search turns to oil," Wall Street Journal, May 23, 2011

FIGURE 13

CHESAPEAKE ENERGY CAPEX BUDGET

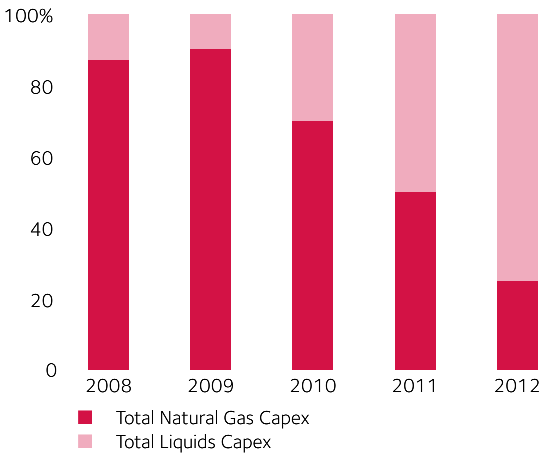
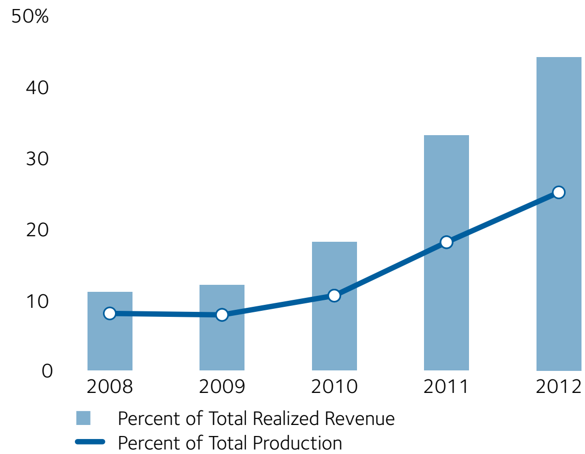


FIGURE 14

CHESAPEAKE ENERGY LIQUIDS SHARE OF REVENUE



Source: Figure 13—Chesapeake; Figure 14—Chesapeake

From a financial perspective, the shift to liquids is paying off for companies. While liquids production made up just 10 percent of Chesapeake's 2010 output, it accounted for nearly 20 percent of the company's revenue that year.[61] For 2011, company estimates suggest a 20 percent liquids share will account for approximately one-third of total realized revenue.[62]

Horizontal drilling for oil shales like the Eagle Ford and Barnett in Texas and the Bakken in North Dakota is delivering substantial new oil production in the United States. Oil production in the Bakken shale increased from just a few thousand barrels per day in 2005 to more than 230,000 b/d in 2010.[63] North Dakota ranked fourth on the list of oil production by state in 2010 and ranks fifth when including the federal Gulf of Mexico.[64] Liquids production in the Eagle Ford in Texas increased from negligible levels in 2008 to nearly 30,000 b/d in 2010.[65]

More importantly, shale oil resources could be positioned to provide a steady source of liquids production growth for the United States in the short and medium term, particularly in a high oil price environment. Some recent estimates place liquids output from the Bakken shale as high as 1.0 mbd by 2020.[66] Output from the Eagle Ford could be as high as 400,000 b/d by mid-decade. Proved oil reserves in both Texas and North Dakota experienced notable increases between 2008 and 2009, largely as a result of shale oil resources. In North Dakota, oil reserves increased by 481 million barrels to 1.1 billion barrels.[67] Oil reserves in Texas increased by 529 million barrels, reaching a total of 5.5 billion barrels.[68]

61 Chesapeake Energy, *May 2011 Investor Presentation*, at 14
62 Id.
63 DOE, EIA, "This Week in Petroleum," April 27, 2011
64 DOE, EIA, online statistics, "Crude Oil Production," last accessed June 29, 2011
65 DOE, EIA, "This Week in Petroleum," April 27, 2011
66 Clifford Kraus, "Shale Boom in Texas could increase U.S. Oil Output," New York Times, May 27, 2011
67 DOE, EIA, "Summary: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves," Table 6
68 Id.

FIGURE 15
U.S. RIG COUNT BY PLAY

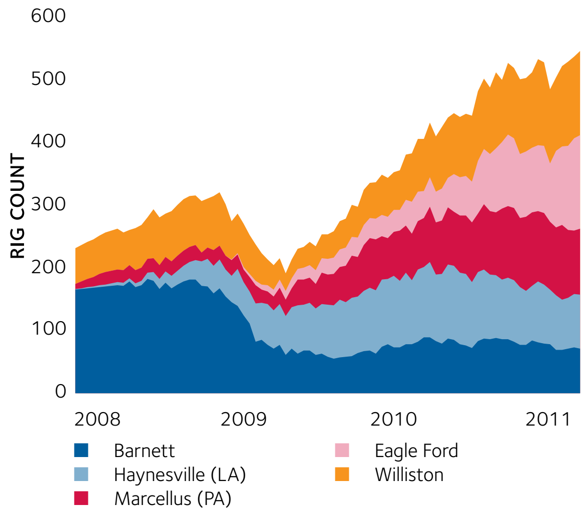
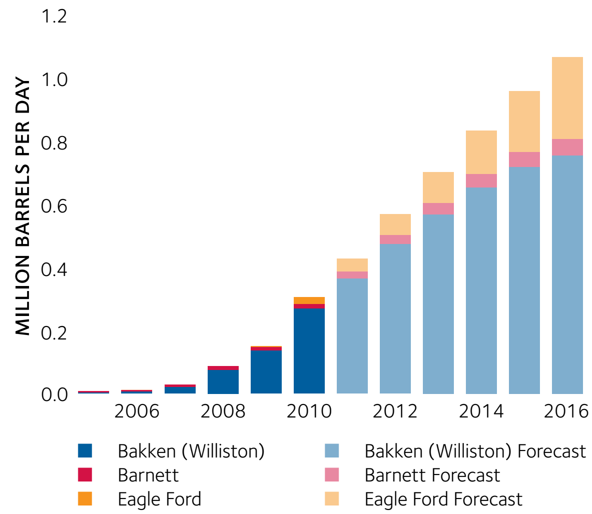


FIGURE 16
U.S. PRODUCTION OF SHALE LIQUIDS (HISTORICAL & FORECAST)



Source: Figure 15—Bernstein Research; Figure 16—Historical data is through 2010 from DOE, EIA. Forecast is from IEA, *Medium-term Oil Market Report 2011*

It is important to note that many of these resources carry higher structural production costs than a typical onshore conventional play. But the medium-term outlook for oil markets suggests buoyant price support for unconventionals, and the United States possesses very few resources at the bottom end of the cost curve today. Even from a global perspective, the IEA recently forecast conventional crude resources to provide less than 40 percent of the increase in liquids production between 2011 and 2016.[69] In fact, the attractiveness of the spread between oil and gas prices has even led some in the industry to suggest that shale gas utilized in gas-to-liquids (GTL) projects could soon make economic sense in the United States.[70]

B. Enhanced Oil Recovery

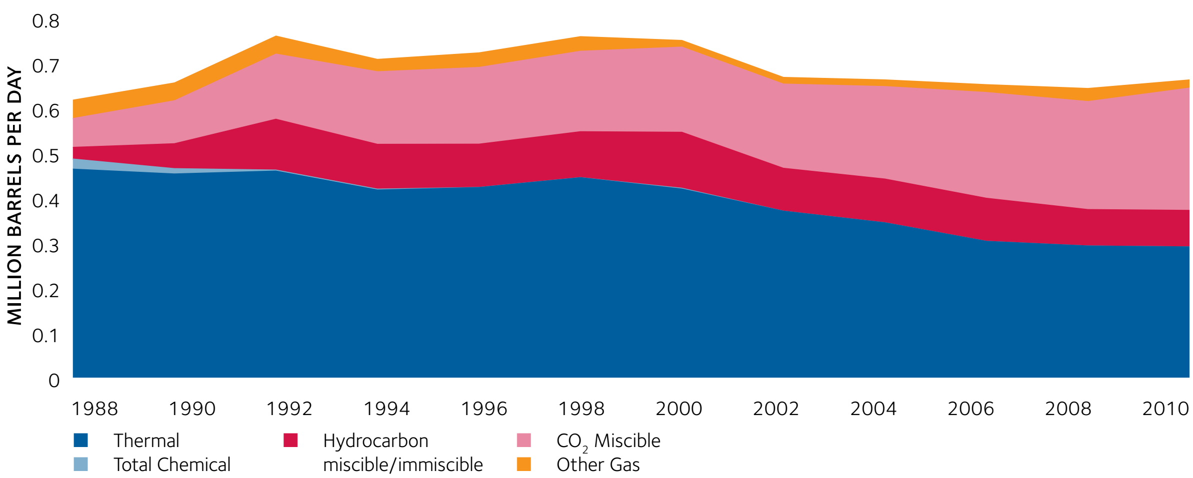
As bright as the future of onshore oil production from shales looks today, enhanced oil recovery techniques could also deliver profound production growth in the future. Throughout its productive life, an oil reservoir transitions through three distinct recovery phases. In the primary phase, naturally existing gas pressure and gravity deliver oil to the wellhead where it can be pumped to the surface. Typically, primary recovery techniques yield 10 percent of the oil in place (OIP). During secondary recovery, the reservoir is subjected to water flooding or injection of additional natural gas to maintain pressure and continue the flow of oil to the wellhead. These secondary recovery techniques (which in practice are often utilized as primary recovery techniques) can increase the total recovery rate to as high as 50 percent. Still, this leaves as much as half of the original OIP behind, or 'stranded'.[71]

69 IEA, *Medium Term Oil and Gas Markets 2011* (June 2011)
70 Eduard Gismatullin, "Shell's U.S. shale gas may be refined into jet fuel, diesel," Bloomberg, May 19, 2011
71 DOE, Enhanced Oil Recovery/CO_2 Injection Program, available online at http://www.fossil.energy.gov/programs/oilgas/EOR/index.html

In an effort to develop the remaining 50 percent of OIP that exists after primary and secondary recovery, oil producers can turn to tertiary recovery, also known as enhanced oil recovery (EOR). EOR techniques attempt to reduce the viscosity of non-flowing oil by subjecting it to heat and pressure or by mixing it with supercritical gases, increasingly CO_2. In 2010, total oil produced from all EOR projects in the United States averaged 663,431 barrels per day—about 12 percent of U.S. production.[72]

Historically, the injection of steam, known as thermal EOR, has been the most widely applied method. In 1990, there were 154 individual thermal EOR projects in the United States, yielding incremental production of over 450,000 barrels per day. Over time, as new and more effective methods have become available, thermal use has declined—in 2010 there were just 60 such projects yielding production of just 292,000 barrels per day.[73]

FIGURE 17 · U.S. OIL PRODUCTION FROM ENHANCED OIL RECOVERY



Source: Oil and Gas Journal

Over the same time period, more advanced EOR methods have become available and been put into practice. When subjected to increased pressure and reduced temperature, CO_2 can retain the properties of a gas while reaching the density of a liquid. In this 'supercritical' state, CO_2 injected into a reservoir essentially mixes with liquid hydrocarbons, reducing viscosity and increasing flow to the wellhead. The first commercial CO_2 EOR project was initiated in 1972 in Texas. In 1990, there were 52 EOR projects in the United States utilizing this 'miscible' CO_2 technique, resulting in incremental oil production of 96,000 barrels per day. By 2010, the number of such projects had doubled and output reached 272,000 b/d.[74]

On average, CO_2 EOR increases oil field recovery by an additional 5 to 15 percentage points, although some pilot projects have increased that figure to 22 percent.[75] Recent estimates place the

72 Oil and Gas Journal, *Survey of Enhanced Oil Recovery Projects*

73 Id.

74 Id.

75 DOE, National Energy Technology Laboratory (NETL), *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Solution,* March 2010, at 14

amount of technically recoverable oil from CO_2 EOR at 84.8 billion barrels (more than 10 years of total U.S. consumption at the current rate and more than double current proved reserves), assuming some policy support and appropriate market conditions.[76]

Oil production using CO_2 EOR is currently inhibited by its limited access to CO_2 supplies and by capital costs. Carbon dioxide for use in enhanced oil recovery has historically been sourced from naturally occurring reservoirs in Colorado and New Mexico along with a small but growing number of energy and industrial facilities that service the EOR market.[77] The cost of delivering the CO_2 from such sources is significant. Industry has spent more than $1 billion on 2,200 miles of CO_2 transmission and distribution pipeline infrastructure in support of CO_2 flooding in the Permian Basin.[78] EOR projects also require significant investment at the well site, including drilling or reworking wells to serve as both injectors and producers and installing a CO_2 recycle plant and corrosion resistant field production infrastructure.[79] The largest cost, however, is typically the purchase of the CO_2 itself.

High oil prices make CO_2 EOR economically attractive, assuming necessary CO_2 supplies are available. One DOE estimate suggests that oil prices at $70/bbl can deliver a $15-$25/bbl pre-tax profit margin for an average CO_2 EOR project.[80] At this price, a 2010 study by Advanced Resources International found that 48 billion barrels of incremental oil would be economically recoverable via CO_2 EOR in the United States, assuming adequate CO_2 access.[81] In the current price environment, and given the scale of the stranded oil resource base of the United States, a more robust market for CO_2 would likely lead to a significant increase in the number of CO_2 EOR projects and consequently to an increase in oil production.

EOR and Carbon Mitigation

The vast majority of the CO_2 used in EOR projects is either sequestered in the reservoir or recycled for further use.[82] There is no net carbon emissions benefit from an EOR project that uses naturally occurring CO_2 to extend the productive life and improve the yield of an oil reservoir. However, if CO_2 is captured and transported from large-point anthropogenic emitters—such as power plants and certain industrial facilities—there is a potential for environmental benefits. Oil produced by means of an integrated EOR carbon capture and storage (CCS) system could carry upstream emissions that are between 40 and 80 percent lower than conventionally produced oil.[83]

The electric power sector, particularly coal-fired electric power plants, represents the most significant stationary source of CO_2 emissions in the United States. A conventional one-gigawatt coal plant produces roughly six million tons of CO_2 per year. Advanced combined cycle coal plants utilizing gasification technologies could provide a ready-made source of marketable CO_2 for storage in oil and gas fields as part of enhanced oil recovery. This CO_2 presents the United States with an important opportunity to increase energy security while addressing concerns about carbon emissions.

76 Advanced Resources International (ARI), report for the NETL, "Storing CO2 with enhanced oil recovery," (2008), at 27
77 DOE, NETL, at 10
78 Id., at 11
79 Id., at 13
80 Id., at 13
81 ARI, "U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage," March 2010
82 DOE, NETL, at 17
83 ARI, "Storing CO2" at 7;, National Petroleum Council, "Working Paper #17: Carbon Capture and Storage," (2007) at 44

Ultimately, EOR utilizing CO_2 will only offer a small fraction of the required offsets in carbon emissions envisioned by most climate change abatement scenarios, but these projects can function as a learning and proving ground for more ambitious CCS technologies while significantly increasing oil production. It should also be noted that the sale of CO_2 from advanced coal power generation facilities to EOR projects could offer a significant cost offset. While estimates vary according to assumed feedstock prices and capital costs, a number of recent analyses point to the benefits of EOR in offsetting lifecycle costs of CCS in power generation.[84]

C. Deepwater OCS

While high oil prices and new technology have created opportunities onshore, the Gulf of Mexico region of the federal Outer Continental Shelf has provided the most meaningful increases in U.S. domestic oil production since the mid-1990s. Today, the federal Gulf of Mexico (GOM) is the largest individual petroleum-producing region in the United States, alone accounting for 1.64 mbd, or 29.8 percent, of crude production in 2010.[85] Production from the rest of the Gulf Coast region—Petroleum Administration for Defense District (PADD) 3—totaled 1.6 mbd.[86] Production in PADD 2, which includes California and Alaska, totaled 1.2 mbd.[87] Growth in production from the federal GOM was the key driving factor behind the overall growth in U.S. crude production in 2009 and 2010.

The Gulf has a track record of successful production growth. Between 1970 and 1990, the oil industry produced a cumulative 6.6 billion barrels of crude oil in the federal Gulf of Mexico, equal to approximately 10 percent of total domestic crude production.[88] The vast majority of Gulf activity from 1950 through 1990 was in less than 1,000 feet of water—referred to as shallow water. Between 1984 and 1991, shallow water development accounted for 94 percent of Gulf OCS oil production.[89]

The first commercial discoveries in the deepwater Gulf occurred in the mid-1970s. In 1975, Shell announced a 100-million barrel reserve in 1,000 feet of water in the Central Gulf off the coast of Louisiana.[90] Still, the discoveries were relatively small and development costs were high. Moreover, the technical capability to produce oil at such depths was barely existent. By the early 1980s, improvements in drilling technology and advancements in geophysical exploration techniques began to drive stronger interest in deepwater Gulf. In a series of federal lease sales held between 1983 and 1985, more than 22 percent of the tracts sold were in waters greater than 1,000 feet.[91]

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84 United Nations Intergovernmental Panel on Climate Change, "Carbon Capture and Storage," (2005), at 9

85 DOE, EIA, online statistics, "Crude Oil Production," last accessed on June 29, 2011

86 Id.

87 Id.

88 U.S. Department of Interior (DOI), Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE), "Production by Planning Area with Daily Production Rates," available online at http://www.gomr.boemre.gov/homepg/fastfacts/pbpa/pbpamaster.asp

89 DOE, EIA, "Gulf of Mexico Proved Reserves and Production by Water Depth," (2009)

90 National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (Deepwater Commission), "Deepwater: The Gulf Oil Disaster and the Future of Offshore Oil Drilling," (2011), at 31

91 Id. at 33

High and rising oil prices between 1973 and 1985 played a strong role in incentivizing oil companies to explore in the deepwater, just as high prices have incentivized activity both onshore and offshore again today. However, an oil price crash in 1985 forced most companies to postpone developments in the deepwater Gulf. In the latter half of the 1980s, deepwater development moved forward slowly, with just a handful of companies experimenting with expensive projects in a low-price environment. As seismic imaging and other exploration technology continued to improve, the massive resource potential of the deepwater Gulf came into greater focus. Commercial resources were believed to exist in turbidite sandstone formations throughout the Outer Continental Shelf. Still, high costs and oil price uncertainty provided a weak incentive to many in the industry.

The factor that most substantially altered this dynamic was the realization that deepwater reserves were not only massive, but they would also flow at very high rates. Some of the first deepwater wells brought online in the early 1990s flowed at more than 10,000 barrels per day.[92] Beginning in 1994, production from waters greater than 1,000 feet deep began to take on greater significance, rising from just 12 percent of total Gulf output to 60 percent in 2003.[93] In September 1999, a well on a Shell-owned project flowed at more than 50,000 barrels per day. By 2009, the shallow water share of Gulf output had fallen to just 20 percent, as a decline in deepwater production was more than offset by development in ultra deepwater—areas in greater than 5,000 feet of water.[94]

FIGURE 18

GULF OF MEXICO OIL PRODUCTION

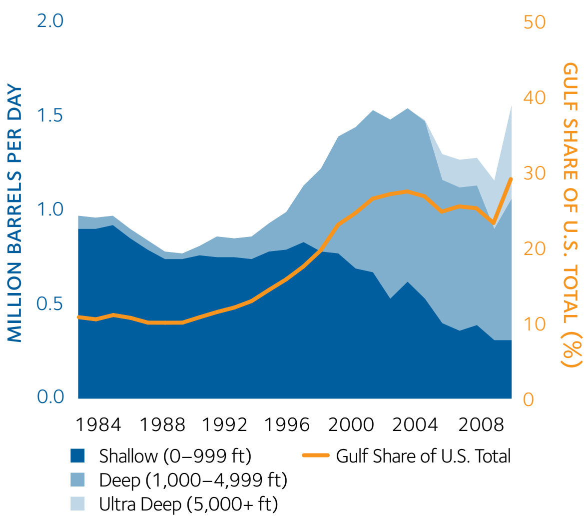
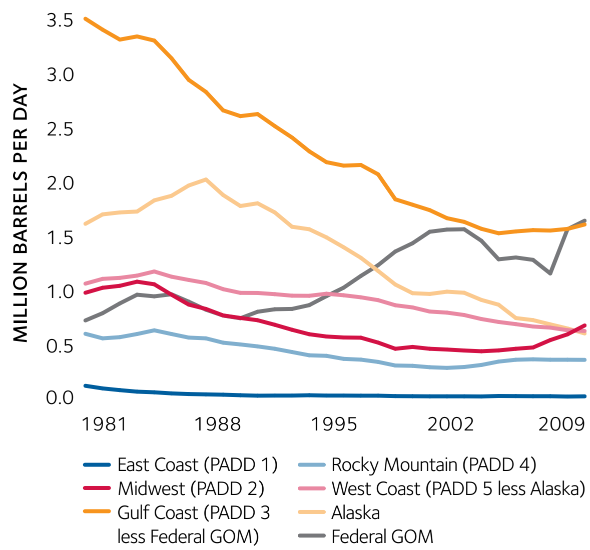


FIGURE 19

U.S. CRUDE OIL PRODUCTION BY PAD DISTRICT



Source: Figure 18—National Commission on the Deepwater BP Oil Spill; SAFE analysis; Figure 19—DOE, EIA

92 Deepwater Commission, at 38

93 DOE, EIA, "Gulf of Mexico Proved Reserves and Production by Water Depth," (2009)

94 Id.

Between 2008 and 2009, the United States recorded a gross increase in crude output of 475,000 b/d. Production in the federal Gulf increased by 407,000 b/d, or 86 percent of the total growth.[95] Additional increases in the Midwest and Gulf Coast were offset by decreases in Alaska and elsewhere on the West Coast, leaving the net U.S. increase at 410,000 b/d. Between 2009 and 2010, gross increases totaled 204,000 b/d, of which the federal Gulf accounted for 79,000 b/d—or 39 percent of the total.[96] Significant increases in the Midwest and Gulf Coast, which were generally driven by expanding output from shale oil, were once again offset by continued declines in Alaska and the West Coast.

More generally, during a period when oil production in much of the rest of the country has been either declining or plateauing, production in the federal OCS has exhibited strong growth. Devastating hurricane seasons in 2005 and 2008 certainly impacted growth, and the impact of the *Deepwater Horizon* oil spill and subsequent moratorium on exploration and development drilling have yet to be fully realized. However, the resources for future growth in oil production in the Gulf of Mexico and other areas of the federal OCS almost certainly exist, and development of these resources will be absolutely necessary if the United States is to continue to increase domestic production in the future.

FIGURE 20

CRUDE AND LEASE CONDENSATE RESERVES BY DEPTH, FEDERAL GOM

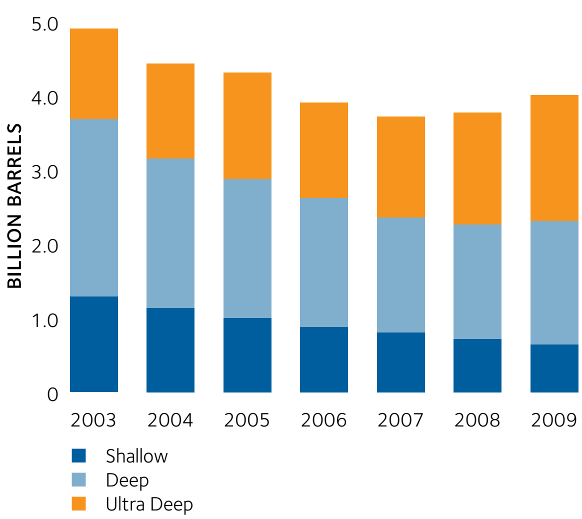
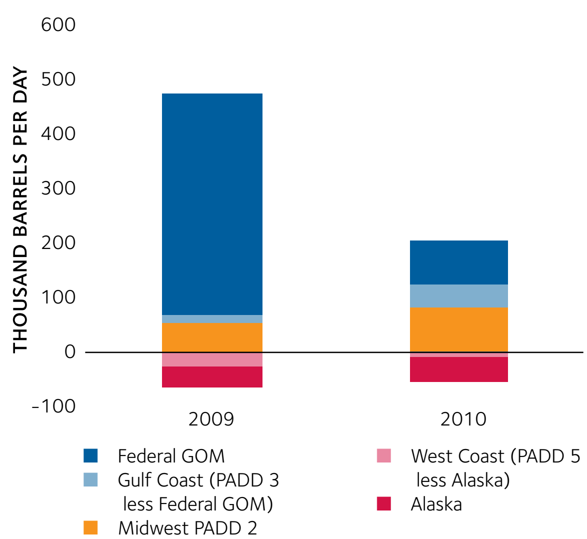


FIGURE 21

CHANGE IN CRUDE PRODUCTION BY REGION



Source: DOE, EIA

In addition, there is significant resource potential in areas of the federal Outer Continental Shelf beyond the Gulf of Mexico. The full federal OCS spans areas on the East, West and Gulf coasts as

95 DOE, EIA, online statistics, "Crude Oil Production," last accessed on June 29, 2011
96 Id.

well as off the coast of Alaska. Many of the areas outside of the Western and Central Gulf of Mexico have been withheld from development for a variety of reasons over the past several decades. Nonetheless, federal government resource assessments have consistently pointed to the likelihood that billions of barrels of petroleum resources are likely to exist in much of the OCS, particularly in the Pacific and Alaskan OCS.[97] In areas off the east and west coasts and in the eastern portion of the Gulf of Mexico, the size of the resources base is somewhat speculative due to the fact that inventory data is based on decades-old seismic data. Many in the industry believe that a modern geophysical survey would reveal even larger deposits. Access to these resources would further increase the production potential of the federal offshore.

4. Challenges to Future Growth

In spite of the numerous reasons for optimism, the domestic oil and gas industry will also face challenges over the coming years. Many of these will be familiar issues. The exuberance generated by high oil prices is driving up industry-wide equipment and operating costs, just as occurred in the late 1970s and early 1980s. Coupled with the capital-intensive nature and higher costs of unconventional resources like shale oil and gas, the industry will depend on sustained high prices in order to expand production. The ability of American consumers to adapt to such an environment is not guaranteed, as periods of high prices have often ultimately been recessionary.

Regulatory issues such as access to the most promising resources and the social impact of expanded operations will also continue to play an important role for the industry. In fact, in the case of shale oil and gas development, the impact of industry on surrounding communities may come to play a more important role than it has in recent history, as many of the most promising resources rest in heavily populated areas.

For the oil industry, the regulatory uncertainty that exists as a result of the April 2010 *Deepwater Horizon* incident poses a long-term challenge. Not only has the fallout from the incident significantly reduced prospects for expanded leasing in frontier areas of the OCS, it has also altered some observers' expectations of the future of the Gulf of Mexico.

Fiscal and tax issues—currently the subject of intense debate—also pose a threat to the industry. At a time of record profits due to high oil prices, there is strong pressure on the nation's political class to repeal industry tax incentives. In many cases, carefully tailored public policy could increase federal revenues while also ensuring the industry receives the support it needs to invest in cutting edge prospects. However, blanket repeals of industry incentives that fail to account for differences between the natural gas and oil industries—as well as the differences between small- and mid-sized independents and the majors—could stunt future growth.

97 *See, e.g.*, DOI, Minerals Management Service, "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf," 2006

A. Oil Prices, Investment Costs, and Stability

During the run-up in oil prices that occurred between 2003 and 2008, industry-wide equipment and operating expenses soared to extremely high levels. As major upstream companies bid for new tracts and invested in exploration and development designed to capitalize on the record petroleum price, competition for drilling equipment and other assets became intense. Field services companies scrambled to keep up with customer needs. The day rates for shallow water jack-up rigs reached levels as high as $180,000 per day in 2008, after having averaged just $40,000 to $60,000 for most of the period between 2000 and 2004.[98] Global utilization of deepwater drilling ships was at or near 100 percent through much of 2007 and 2008, forcing day rates for semisubmersibles and deepwater drill ships to levels above $500,000.[99] In turn, these rising costs contributed to the rising marginal costs of production for the incremental non-OPEC barrel of oil.

FIGURE 22

U.S. PRODUCER PRICE INDEX FOR OIL AND GAS

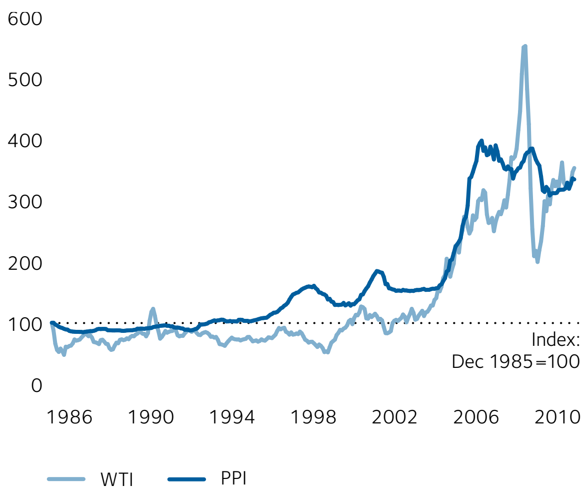
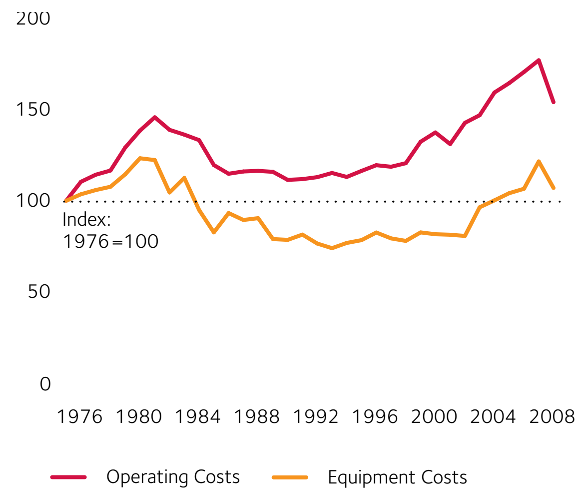


FIGURE 23

GDP DEFLATED ESTIMATES OF U.S. OIL FIELD COSTS



Source: Figure 22—IMF; Figure 23—DOE, EIA

Between January 2003 and January 2007, the U.S. Producer Price Index for Oil and gas increased by 142 percent.[100] Even when adjusting for economic growth, the surge in oil field costs between the early 2000s and 2008 was high by historical standards. According to data produced by the Department of Energy, U.S. oil field equipment costs reached nearly the same level in 2008 that they had during the 1979-81 energy crisis. Indexed operating costs for all U.S. oil fields actually exceeded the levels at any point in recent history.[101]

98 Vantage Drilling Company, Presentation at DnB NOR Offshore & Shipping Management Access Conference, March 4, 2009

99 ODS-Petrodata, Day Rate Index, available online at http://www.ods-petrodata.com/odsp/day_rate_index.php; for semisubmersible day rate, see e.g., David Phillips, "Higher Rig Day Rates at Diamond Offshore Drilling," Bnet, October 24, 2011

100 International Monetary Fund, *World Economic Outlook*, April 2011, at 99

101 DOE, EIA, "Oil and Gas Lease Equipment and Operating Costs 1994 Through 2009," (2010)

The financial crisis, recession, and resulting reduced oil demand growth brought relief for equipment and operational costs in 2009. Industry investments in new upstream projects were temporarily postponed and in some cases cancelled.[102] Declining upstream costs were frequently cited as contributing to the stable oil prices witnessed throughout much of 2009 and 2010.[103]

The surge in oil prices that occurred in late 2010 and into the first half of 2011 has placed renewed pressure on upstream oil field costs. There is evidence, particularly in terms of capital/equipment costs, that levels are once again on an upward trajectory. Managing rising pressure on costs as the industry continues to invest in capital-intensive projects in deepwater areas offshore and unconventional resources onshore will be an important challenge. Consumers in the OECD generally adapted to stable oil prices in the $70 to $80/bbl range throughout 2009 and 2010, but a renewed cycle of rising demand for oil in emerging markets combined with high industry costs could once again put further upward—and unsustainable—pressure on prices.

FIGURE 24
IHS UPSTREAM OPERATING COST INDEX

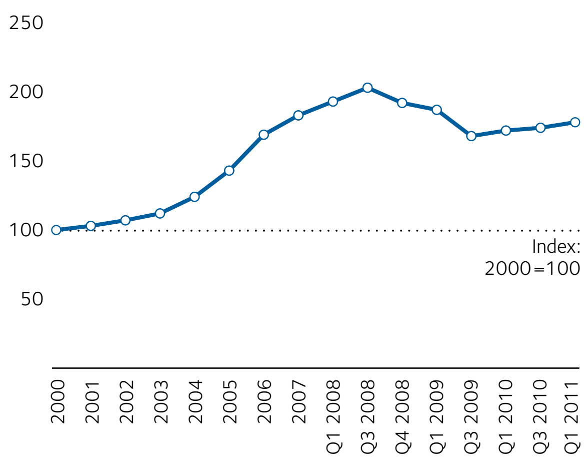
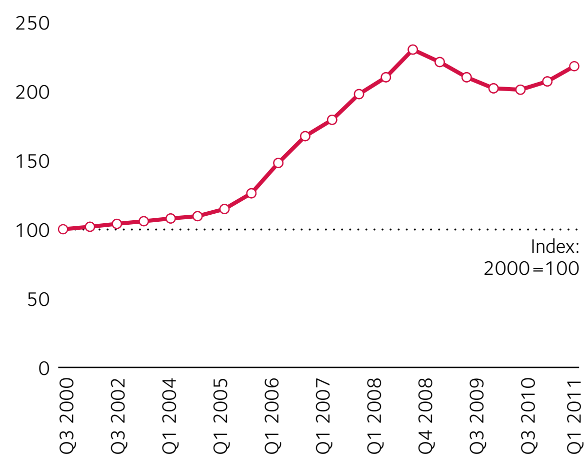


FIGURE 25
IHS UPSTREAM CAPITAL COST INDEX



Source for Figure 24 and 25: IHS

Price Volatility

As has often been the case in the past, the boom and bust cycle of oil prices is perhaps the most important structural risk to the industry—and the stability of the macro economy more generally. During the 1970s, high oil prices drove a substantial increase in efforts to find and develop crude oil fields. Between 1975 and 1985, non-OPEC oil production increased by 50 percent—from 19.7 mbd to 29.6 mbd.[104] This increase was largely driven by a substantial increase on OECD oil production, from 13.7 mbd in 1975 to 20.1 mbd in 1985.[105] However, by the end of

102 *See, e.g.*, International Energy Agency, "Impact of the Financial Crisis on Global Energy Investment," at 3 (Background paper for the G8 Energy Ministerial Meeting, Rome, Italy, 24-25 May, 2009)
103 IEA, *World Energy Outlook 2009*, at 448-450
104 BP plc., *Statistical Review of World Energy 2011*, online statistical supplement
105 Id.

1985, rising non-OPEC supply forced a breakdown in OPEC cartel discipline, with Saudi Arabia and other members pumping above quota levels to maintain market share as the global supply pool increased. The result was a crash in oil prices, which averaged $27.56/bbl in 1985 but just $14.43 in 1986.[106]

Low oil prices throughout the late 1980s and much of the 1990s helped sow the seeds of the 2003-2008 oil price spike by reducing the incentive for the oil industry to aggressively invest in new upstream capacity. By the time rising oil demand in emerging markets had begun to tighten markets in 2003 and 2004, the industry was unprepared. Upstream investment is characterized by long lead times between exploration and production, and large swings in oil prices can undermine the long-term commitment to upstream investment in the industry as a whole.

In mid-2011, the industry is once again in a period of high and rising oil prices characterized by aggressive upstream investment. However, there are warning signs indicating that destructive price volatility is on the horizon. The International Energy Agency suggested that OECD commercial inventories of crude oil and petroleum products are likely to experience a significant drawdown in 2011 to levels at or below the 2006-2010 range.[107] The expected stock drawdown is the result of numerous factors. The loss of Libyan production has not been fully compensated by other OPEC members, and oil demand growth, while not as robust as in 2010, is still expected to be 1.3 mbd in 2011 (less than half of the 2.8 mbd increase in 2010).[108]

Assuming OPEC production remains at current levels for the remainder of the year, the IEA has repeatedly warned of significant market tightening and oil price volatility by year-end 2011. In fact, commercial stock levels in Asia have been trending below the five-year average since mid-2009, and tightness is rapidly emerging in Europe as well. This is in stark contrast to the comfortable levels witnessed in 2010, when a well-supplied market generally kept OECD inventories full and oil prices relatively stable. Saudi Arabia has promised to break ranks with other OPEC members and ensure that the oil market is "well supplied," but the exact meaning of this and consequences of the recent discord within the cartel have yet to be fully determined. Saudi crude production did increase by 700,000 b/d in June. Although half the incremental supply went to domestic power generation, the uptick brought Saudi output to its highest level since February 2006.

Highly volatile and destabilizing prices benefit neither oil consumers nor oil producers. Retail gasoline prices rose by 29 percent between the first week of January and the first week of May 2011, surpassing $4.00 per gallon on average for the first time since the summer of 2008.[109] Diesel and jet fuel prices experienced a similar spike, affecting the broader economy from shipping and logistics to commercial aviation. First quarter U.S. GDP growth came in at a near-contractionary 0.4 percent annualized rate, and second quarter growth underwhelmed at 1.3 percent. While a number of factors probably played a role, rapidly escalating fuel prices certainly had an impact in driving exceptionally weak consumer spending levels.

106 BP plc., *Statistical Review of World Energy 2011,* online statistical supplement
107 IEA, *Monthly Oil Market Report*, May 12, 2011, at 5
108 IEA, *Medium Term Oil and Gas Market Report 2011*, June 2011, at 36
109 DOE, EIA, online statistics, "Weekly Gasoline and Diesel Prices," last accessed June 29, 2011

High fuel prices and weak economic growth almost inevitably coincide with demand destruction, a formula which has played out in early- and mid-2011.[110] The IEA reported in May that global oil demand was essentially flat in March, registering its smallest monthly increase since mid-2009.[111] In the United States, total petroleum product supplied was down 0.6 percent through the first 6 months of 2011 compared to the same period in 2010.[112]

Based on the combination of these oil market and economic factors, benchmark crude oil prices (WTI) fell by nearly $15 per barrel on May 4 and 5, from $113/bbl to less than $100/bbl.[113] Stronger than expected unemployment claims coupled with rising concerns about inflation and broader macro economy accelerated the selloff, which surpassed $10 per barrel on May 5 alone.[114] Then, on June 23rd, the International Energy Agency announced a coordinated release of government-owned oil stocks totaling 60 million barrels. Targeted for 30 days, the additional oil amounted to a temporary surge of 2.0 million barrels per day. The IEA action prompted another sell off that brought oil prices nearer to $90/bbl.[115]

The industry—particularly outside of OPEC—has little ability to control end-user prices. The IEA speculates that "producers could adopt a more relaxed view on spot sales and greater flexibility in pricing to coax refiners."[116] Strong policies aimed at increasing efficiency in the United States and elsewhere in the OECD would have a positive impact on prices in the medium term, as would a more aggressive stance on expanding acreage available to domestic production. The elimination of rampant fuel subsidies in much of emerging Asia, the Middle East, and Latin America could also have an impact. In the short term, however, avoiding another bust at the end of the current boom will be a major challenge for the industry.

B. Resource Access

United States proved conventional oil reserves were 30.9 billion barrels at year-end 2010, or about 2.2 percent of the world total.[117] Proved natural gas reserves were 272.5 tcf, or about 4.1 percent of the world total.[118] Based on 2010 estimates, these figures placed the U.S. reserves-to-production ratio at 11.3 years for oil and 12.6 years for natural gas. At first blush, this data is frequently used to argue that the United States is resource-poor, and that continued growth in production is infeasible.

In reality, this is not the case. While proved reserves do provide a snapshot in time of a country's technologically and economically feasible production potential, U.S. proved reserves never

110 Barbara Powell, "Gas poised to decline as $4 drives down demand," Bloomberg, May 25, 2011
111 David Blair, "Oil demand flattens as prices spike," Financial Times, May 12, 2011
112 DOE, EIA, *Weekly Petroleum Status Report*, May 25, 2011
113 DOE, EIA, online statistics, "Oil Spot Prices," last accessed June 29, 2011
114 Id.
115 Rachel Graham, "Crude Oil Falls on Slowing U.S. Consumption, IEA Reserve Release," Bloomberg, June 24, 2011
116 IEA, Monthly Oil Market Report, April 2011
117 BP, plc., *Statistical Review of World Energy 2011*
118 Id., at 20

exceeded 40 billion barrels in the period between 1980 and 2009—yet the domestic industry produced 94 billion barrels of oil over the same period.[119] The fact is that proved reserves alone present an incomplete and inaccurate picture of a nation's total resource potential. Reserves classification is a multifaceted endeavor and depends heavily upon underlying assumptions regarding technology, energy prices, and government regulations.

In the Oil and Gas Supply Module for *Annual Energy Outlook 2011*, the Department of Energy estimated total technically recoverable U.S. oil resources to be 218.9 billion barrels. This figure consists of proved reserves of 20.6 billion barrels, inferred reserves of 62.5 billion barrels, and undiscovered technically recoverable reserves (UTRR) of 135.8 billion barrels.[120] Importantly, the total resource assessment *did not* include areas off limits to production, such as the Eastern Gulf of Mexico or Arctic National Wildlife Refuge (ANWR). The DOE supply module placed total technically recoverable natural gas resources at more than 2,500 trillion cubic feet.

Several government resource assessments have also indicated that the United States possesses significant amounts of undiscovered technically recoverable resources of both oil and natural gas.[121] According to a congressionally-mandated 2007 inventory of these resources, total (onshore and offshore) undiscovered recoverable conventional and unconventional natural gas resources at the time were at least 1,100 trillion cubic feet. Undiscovered conventional oil resources were approximately 140 billion barrels.[122] As the industry has recently demonstrated, the ability to develop these resources is primarily a question of technology and cost. However, it is also a question of access.

Both offshore and onshore, important portions of the resource base are restricted from oil and gas development. Offshore, statutory restrictions limit access to the Eastern Gulf of Mexico and certain areas of the Alaska OCS. Onshore, development is restricted in certain areas of Alaska and the Mountain West. Moreover, as the unconventional gas industry moves into populated regions in the Midwest and Northeast, new access issues are emerging rapidly. No doubt, environmental preservation and conservation goals should play an important part in determining when and where the industry can operate. However, any scenario for future U.S. oil and gas production is highly dependent on the ability of the industry to access the most attractive proportions of the resource base.

Resource access issues tend to be controversial and intensely debated, and they often attract the lion's share of attention dedicated to energy policy by national policymakers. Industry advocates argue that the country has little prospect for increasing domestic production if the most promising resources are held off the table. Opponents argue that some areas are too pristine to be disrupted by the industry footprint. In fact, these familiar talking points oversimplify what has increasingly become a very complex set of issues.

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119 Id., online statistical supplement

120 DOE, EIA, AEO 2011, Oil and Gas Module, available online at http://www.eia.gov/forecasts/aeo/assumptions/pdf/oil_gas.pdf

121 *See, e.g.,* DOI, Minerals Management Service, "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf," 2006

122 DOI, "Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to their Development," (2007)

TABLE 1 · SELECT UNDISCOVERED, TECHNICALLY RECOVERABLE PETROLEUM RESOURCES AND ACCESS STATUS (BILLION BARRELS)

Region	Status	Mean Estimate	Recoverable at $60/barrel	Recoverable at $80/barrel
Offshore				
Beaufort Sea	No statutory restrictions; leases granted, but development delayed by litigation	8.2	6.0	6.9
Chukchi Sea	No statutory restrictions; leases granted, but development delayed by litigation	15.4	8.4	12.0
Eastern Gulf of Mexico	Access restricted by Congressional Moratoria through 2022	3.9	3.1	3.3
Atlantic OCS	No statutory restrictions; leasing delayed by DOI until 2017	3.8	2.6	2.8
Pacific OCS	No statutory restrictions; leasing delayed by DOI until 2017	10.5	8.2	8.9
Western & Central Gulf of Mexico	Post-Macondo moratorium expired in October 2010; first permits issued in February 2011	41.0	35.1	36.9
Total Offshore		**85.9**	**65.6**	**73.4**
Onshore				
Federal Lands within ANWR	Access restricted by law	7.7	NA	NA

Source: DOE, EIA; DOI, BOEMRE

Offshore Access Issues

As recently as 2008, offshore access issues were defined by congressional and presidential actions that withheld broad swaths of the federal Outer Continental Shelf from being leased and developed for mineral extraction. Today, however, the offshore issues are much different.

On April 20, 2010, while completing work on an exploratory well in the Macondo Prospect approximately 50 miles off the coast of Louisiana, the semi-submersible drilling rig *Deepwater Horizon* experienced a catastrophic blowout, leading to several crippling explosions and an uncontainable fire that resulted in the deaths of 11 rig workers. Two days later, the rig sank in approximately 5,000 feet of water.[123] The accident severed the rig's connection to the seafloor, and the blowout preventer experienced a complete failure, allowing oil from the reservoir to plume into the Gulf of Mexico. The federal government estimates that the *Deepwater Horizon* incident released 4.9 million barrels of crude oil into the Gulf of Mexico before the damaged well was stabilized on July 15, making it the single worst offshore incident in U.S. history.[124]

While only a year has passed since the disaster in the Gulf, it is already clear that the incident has

123 Rigzone, "Deepwater Horizon Sinks Offshore Louisiana," April 22, 2010
124 *See, e.g.*, http://www.restorethegulf.gov/release/2011/04/10/one-year-later-press-pack

led to some significant changes in terms of the regulation of offshore oil and gas production in the United States. The first notable change was with the identity and makeup of the regulator itself. On May 19, 2010, the Secretary of Interior issued Secretarial Order No. 3299, eliminating the Minerals Management Service and replacing it with three new agencies: the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and the Office of Natural Resource Revenue (ONRR).[125] The order specified that the Bureau of Ocean Energy Management would be responsible for managing the core conventional (i.e. oil and gas) and renewable energy functions of the former MMS, including resource evaluation, planning, and leasing. The Bureau of Safety and Environmental Enforcement would have the authority to inspect and investigate OCS activities, including calling witnesses, levying penalties, and canceling or suspending activities. The Office of Natural Resource Revenue would assume all former MMS activities related to royalties and revenues.[126]

The changes reflected the Department's response to a primary criticism of its functions in the past, namely that a regulator that was also responsible for revenue collection was inherently conflicted. On one hand, MMS was supposed to be responsible for guaranteeing safe and secure operations on the Outer Continental Shelf. In theory, this meant that MMS would carefully evaluate the environmental and socioeconomic impact of lease sales and other OCS activities, balancing the costs and benefits of further development. On the other hand, there was a perception among many critics that the revenue management functions of MMS gave it a direct incentive to increase and expedite OCS development, thereby hampering its regulatory neutrality.

The changes to MMS were significant, affecting the more than 1,000 workers at the agency. At the same time, the agency came under intense public fire. Critics argued that MMS had been hiring unqualified staff who failed to keep pace with the rapidly evolving offshore oil and gas industry and that the industry had essentially captured the regulator. Charges of corruption were also an issue. A September 2008 report from the Interior Department's Inspector General detailing abuses among a handful of staff in the Denver revenue management office still affected the public perception of the agency.[127, 128]

On May 27, amid the initial uncertainty regarding the causes of the blowout, the difficulty of a major reorganization, and heavy public criticism, Interior announced a six-month moratorium on new deepwater drilling at depths greater than 500 feet in the Gulf of Mexico.[129] The ban halted approval of any new permits for deepwater drilling and suspended drilling of 33 exploratory wells in the Gulf.[130] On June 21, a federal judge in New Orleans temporarily reversed the administration's decision, finding that Interior had failed to "cogently" explain its rationale.[131] After a series of

125 DOI, Office of the Secretary, Order 3299, available at http://www.eenews.net/public/25/15769/features/documents/2010/05/19/document_pm_03.pdf
126 Noelle Straub, "Interior Unveils Plan to Split MMS into 3 Agencies," New York Times, May 20, 2010
127 Derek Kravitz and Mary Pat Flaherty, Report Says Oil Agency Ran Amok," Washington Post, September 11, 2008
128 DOI, Office of the Inspector General, *Investigative Report: Oil Marketing Group—Lakewood*, available online at http://www.doioig.gov/images/stories/reports/pdf//RIKinvestigation.pdf
129 United Press International, "U.S. announces drilling moratorium details," May 30, 2011
130 Michael Kunzelman, "Judge blocks Gulf offshore drilling moratorium," Associated Press, June 22, 2010
131 Laurel Brubaker Calkins and Margaret Cronin Fisk, "Deepwater Drilling Ban Lifted by New Orleans Federal Judge," Bloomberg News, June 22, 2010

appeals, the drilling moratorium was restored on July 12, 2010, when Interior adjusted the ban to focus on specific types of drill ships as opposed to water depth.[132, 133]

In late September 2010, Interior released a series of revised regulations for offshore drilling. One drilling safety rule detailed the proper cementing, casing and drilling fluid procedures that drillers should use in order to maintain wellbore integrity while drilling.[134] The new rules also strengthened oversight of equipment, like blowout preventers, used to shut off the flow of oil and gas.[135] In addition, a new workplace safety rule required operators to have a comprehensive safety and environmental impact program in place to reduce organizational errors that could cause accidents or spills.[136]

On October 12, Interior lifted the moratorium on issuing drilling permits in the Gulf of Mexico.[137] However, a November 2010 notice to lessees indicated that the Department would not be issuing new permits until the industry could demonstrate that it was capable of deploying equipment that could successfully contain future spills.[138] Interior established a set of industry requirements that it deemed necessary to demonstrate that future spills—particularly blowouts of the magnitude of the *Deepwater Horizon* spill—could be more rapidly contained and cleaned up than that disaster, during which the ruptured well gushed oil for 57 days, with a peak rate that exceeded 60,000 b/d.[139]

In the days immediately following the incident, it became clear that neither the companies involved nor the industry as a whole had realistic plans in place for containing a disaster of the scale presented by the Macondo blowout.[140] Though the operators were ultimately able to cap the wellhead and then seal the well itself, the series of trial-and-error attempts directed at stopping the initial leak damaged both the environment and the public's confidence in the industry. Early shortfalls in necessary oil cleanup equipment led critics to charge that the industry response process had evolved very little since the Exxon Valdez disaster decades earlier.[141]

Anticipating that the industry would now have to demonstrate enhanced capabilities, several large integrated companies formed the Marine Well Containment Company (MWCC) in July of 2010. Shell, ExxonMobil, ConocoPhillips, and Chevron announced that the consortium would be funded by $1 billion in member contributions.[142] The purpose of the MWCC was to design and make available a technology system that would be "flexible, adaptable…able to begin mobilization within 24 hours and [that] can be used on a wide range of well designs and equipment, oil and natural gas

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132 Frederic K. Frommer, Administration hopes new drilling moratorium can survive," Associated Press, July 13, 2010

133 Mark Clayton, "Offshore drilling moratorium: good for the Gulf, bad for the economy?" Christian Science Monitor, July 27, 2010

134 DOI, BOEMRE, *Drilling Safety Rule*, available at http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&PageID=45792 (fact sheet only)

135 Katie Howell and Patrick Reis, "Interior issues new rules, holds firm on moratorium," Greenwire, September 30, 2010

136 DOI, BOEMRE, Workplace Safety Rule, available at http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&PageID=45791 (fact sheet only)

137 Neela Banerjee, "U.S. lifts moratorium on deep-water drilling in Gulf of Mexico," LA Times, October 13, 2010

138 DOI, BOEMRE, "NTL No. 2010-N10," available at http://www.gomr.boemre.gov/homepg/regulate/regs/ntls/ntl_lst2.html

139 Joel Achenbach and David Fahrenthold, "Oil spill dumped 4.9 million barrels into Gulf of Mexico, latest measure shows," Washington Post, August 3, 2010

140 Holbrook Mohr, Justin Pritchard, Tamara Lush, "BP's gulf oil spill response plan lists the walrus as a local species," Christian Science Monitor, June 9, 2010

141 Henry Fountain, "Advances in Oil Spill Cleanup Lag Since Valdez," New York Times, June 24, 2010

142 Angel Gonzalez, "Oil Firms to Deploy New Containment Device for Deepwater Spills," Wall Street Journal, April 15, 2011

flow rates and weather conditions." The pre-engineered system was targeted toward being able to contain a blowout in 10,000 feet of water at a peak discharge rate of 100,000 b/d.[143]

Since introduction, six new companies have joined the MWCC (BP, Apache Corp., Statoil ASA, BHP Billiton, Anadarko Petroleum, and Hess Oil). Member companies claim to represent 70 percent of deepwater wells drilled in the Gulf.[144] Nonmembers can lease the MWCC system for a fee.

At the same time, a larger group of more than 20 independent oil and gas companies active in deepwater exploration and production formed the Helix Well Containment Group (HWCG). The group works in partnership with Helix Energy Solutions Group (HESG), a field services company active in the Gulf of Mexico. In fact, HESG was hired as part of the effort to stem the flow of oil from the ruptured Macondo well, and at one point was successfully collecting up to three-fourths of the oil flowing from the well before it was capped.[145]

The two industry-led containment systems are somewhat different. The MWCC's interim spill containment device is a 30-foot tall, 100-ton capping stack unit designed to be lowered onto a ruptured seafloor well and either kill the well or divert flow to ships at the surface. The interim unit, introduced in early 2011, is engineered to be used in deepwater depths up to 8,000 feet and has capacity to contain 60,000 barrels per day of liquid, according to the MWCC.[146] The advanced containment unit, to be available in mid-2012, still targets the MWCC's original goal of 10,000 feet and 100,000 b/d.[147] In the meantime, the MWCC has commissioned specialized ships for storing and transporting oil to augment the final system.

The HWCG system builds on existing components used during the containment of the Macondo blowout. The system includes its own version of the capping stack, but also utilizes HESG technology that can rapidly deploy ships to new sites on short notice. HWCG has also partnered with Clean Gulf Associates, a nonprofit consortium that has provided spill response equipment since 1972, and has established agreements with third-party suppliers that will provide firefighting, pressure testing and chemical dispersants at the site of an accident. Clean Gulf Associates' 20 largest members now have access to the Helix Fast Response System, which claims to be able to reach any of their Gulf wells and collect oil and gas at full capacity within 10 days and as fast as three to four days in the right conditions.[148, 149] Members pay a one-time fee to join the HWCG and then a quarterly retainer.[150]

The HWCG argues that its approach relies on service ships already staffed, equipped, and operat-

143 MWCC, "New Oil Spill Containment System to Protect Gulf of Mexico Planned By Major Oil Companies," July 21, 2010
144 MWCC, "Marine Well Containment Company Establishes Membership," April 19, 2011
145 David Hammer, "Latecomer to Gulf oil spill cleanup says it now has the answer in any future disasters," The Times-Picayune, February 27, 2011
146 MWCC, Interim Containment Unit, available online at http://marinewellcontainment.com/interim_system.php
147 Angel Gonzalez, "Oil Firms to Deploy New Containment Device for Deepwater Spills," Wall Street Journal, April 15, 2011
148 David Hammer, Times Picayune (February 27, 2011)
149 Katie Howell, "New Containment Technologies Jump-Start Offshore Drilling but Fail to Quell Oil Spill Concerns," New York Times, April 25, 2011
150 Id.

ing in the Gulf on normal projects, and that it has been successfully deployed in a spill already.[151] Of course, the Gulf-specific nature of such a system raises questions about the ability of the industry to adequately respond to a blowout in other OCS areas. As of April 8, 2011, the HWCG system was capable of containing 55,000 b/d of liquids in up to 8,000 feet of water. Helix estimates that it will be capable of deploying a system at 10,000 feet as soon as mid-summer 2011, and that its system ultimately could be upgraded to contain flows in excess of 100,000 b/d.[152]

On February 28, 2011, satisfied that the industry was more capable of containing future blowouts, BOEM approved the first permit to drill in the deepwater Gulf of Mexico since the Macondo blowout.[153] Though the rate of permit approvals increased in the following weeks, BOEMRE did not grant its 10th permit until April 8. Of the first 11 permits approved, six cited the Helix containment system, and none of the first seven permits granted by BOEM were for activities in more than 8,000 feet of water.[154,155]

There is considerable debate over whether the existence of two separate industry-sponsored containment entities, HWCG and MWCC, is either useful or necessary. Anecdotally, HWCG is populated by smaller, independent companies, and MWCC is a partnership among much larger, integrated international oil companies. Some observers have suggested that the HWCG is positioned to respond to a blowout at a mid-sized well and that the MWCC system is clearly designed for a much larger incident. This dichotomy would seem to imply that the two systems are equally important. Indeed, there has been some discussion of the groups working together in the future.[156]

It is important to note that both the HWCG and the MWCC are generally targeted toward responding to incidents in the U.S. Gulf of Mexico. An early criticism of this approach was that the industry was ill-prepared for subsea blowouts in other areas of the OCS, or indeed globally. To respond to this issue, nine of the world's largest oil companies announced the formation of the Subsea Well Response Project (SWRP) in May of 2011.[157] SWRP members include BG Group, BP, Chevron, ConocoPhillips, ExxonMobil, Petrobras, Shell, Statoil and Total. Shell was announced as the project leader. The SWRP is apparently designing a separate capping tool of its own, and will exist to respond incidents in different regions of the world.

The *Deepwater Horizon* event and subsequent fallout had a profound effect on the offshore oil and gas industry in the United States. The processes and norms for regulating the industry have already changed significantly, and additional changes are almost surely forthcoming. The National Commission on the Deepwater Horizon Oil Spill and Offshore Drilling released its report in January 2011.[158] The report presented a thorough analysis of the events leading up to the spill and the process of managing the consequences of the blowout. The report issued a series of recommen-

151 Anna Driver, "Helix readying Gulf oil spill containment system," Reuters, December 8, 2010
152 Katie Howell, New York Times, April 25, 2011
153 Phil Taylor, "Interior Issues First New Deepwater Permit," New York Times, February 28, 2011
154 Katie Howell, New York Times, April 25, 2011
155 Ryan Dezember, "Helix Oil Spill Group Expanding Reach To Stop Runaway Wells," Dow Jones Newswire, March 31, 2011
156 Ayesha Rascoe, "U.S. oil spill containment firms may work together: BP," Reuters, April 19, 2011
157 Sheila McNulty, "Oil industry tries to prove it can drill responsibly," Financial Times, May 17, 2011
158 Deepwater Commission, available at http://www.oilspillcommission.gov/

dations for reforming the regulatory process in the United States, subject matter which is sure to be considered by Congress in 2011.

Of course, the spill and moratorium also had a measurable impact on U.S. energy security and domestic energy production. While the moratorium ended in October 2010, the first permits to drill exploration and development wells were not granted until February 2011. In essence, exploration and development activity was halted in the Gulf of Mexico for a full year. To be sure, the moratorium did not impact the production of oil and gas on production platforms at existing fields. But the act of halting exploration and development drilling will have a meaningful impact on oil production in the Gulf of Mexico in both the near term and long term.

First, the halt in exploration drilling—and the slow, incremental return to exploration—has meant that new oil discoveries did not occur in much of 2010 or the first quarter of 2011. The absence of new discoveries today is likely to translate into reduced production levels in the future.

Perhaps more importantly, the inability to drill development wells during the moratorium will appreciably harm production levels at existing oil fields in the very near future. Development wells are crucial for managing reservoir pressure and reducing oil field natural decline rates. In the absence of such investment, field production levels simply decline at a faster rate. The manifestation of this fact in the Gulf of Mexico has recently been borne out in a number of analyses from a wide range of sources. One recent analysis from consultancy Wood Mackenzie estimated that the moratorium and slower permitting will reduce GOM deepwater oil production by 375,000 b/d in 2011.[159]

FIGURE 26

ESTIMATED GOM DEEPWATER OIL PRODUCTION

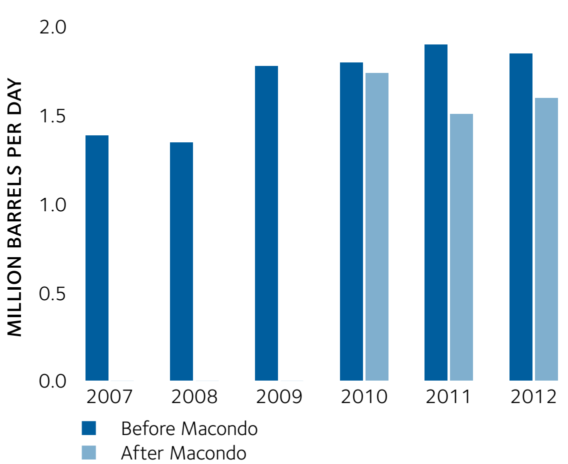
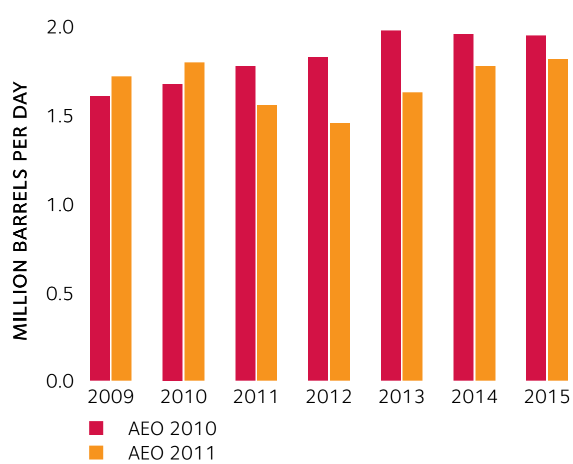


FIGURE 27

LOWER-48 OFFSHORE OIL PRODUCTION



Source: Figure 26—Wood MacKenzie; Figure 27—DOE, EIA

159 Angel Gonzalez, "Spill's Toll on Oil Output Grows Clearer," Wall Street Journal, April 20, 2011

A comparison of pre- and post-disaster forecasts from the U.S. Department of Energy illustrates the medium-term impact of the disaster and subsequent moratorium. In its *Annual Energy Outlook* for 2010, DOE forecast a steady increase in lower-48 offshore oil production between 2009 and 2015, driven largely by surging deepwater production in the Gulf of Mexico. In the six years after 2009, AEO 2010 forecast lower-48 OCS production to increase by 340,000 b/d, from 1.6 mbd to 1.94 mbd.[160] The 2011 iteration of the Outlook, released in April 2011, reveals a starkly different trend. After exceeding previous estimates of production for 2009 and 2010, the post-Macondo scenarios project a sharp drop in oil production from the lower-48 OCS in 2011 and 2012. After reaching 1.79 mbd in 2010, production falls to 1.55 mbd in 2011 and 1.45 in 2012, before beginning to recover in 2013.[161] Notably, however, production does not return to previously forecast levels until after 2015.

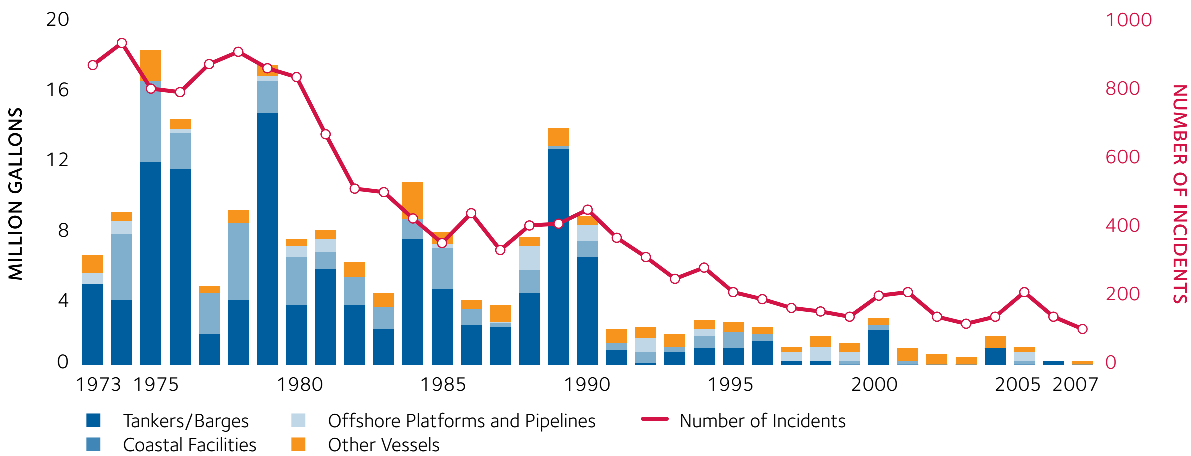
These data should not necessarily be construed as a criticism of Interior or of the moratorium. However, the data certainly indicate that decisions made by the industry and by government regulators have a direct, tangible impact on American energy security. Each incremental barrel of oil not produced on the OCS is likely to be replaced by a barrel of imported oil. Whether such oil originates in traditionally stable North American suppliers or less friendly regimes elsewhere, it increasingly has a negative impact on the American trade balance, resulting in exported wealth and reduced economic opportunity at home.

Achieving greater production growth from promising resources like the deepwater Gulf of Mexico may not be possible with the status quo dynamic between industry and regulator, and increasing production from frontier regions such as the Alaskan and Atlantic OCS planning areas appears to be a near impossibility, with new development stalled by bureaucratic wrangling and excessive litigation.

The fact is that the industry can produce oil from offshore regions in a safe manner. In fact, the *Deepwater Horizon* has largely overshadowed two decades of remarkable progress in reducing oil spills due to offshore development. According to the Department of Interior, the offshore oil and gas industry produced 10.2 billion barrels of oil between 1985 and 2007 with a spill rate of just .001 percent.[162] The industry argued that as technology had improved, so had built-in safety systems. The rate of incidents did, in fact, steadily decline. The annual number of oil spills in U.S. coastal waters declined dramatically between the early 1990s and 2000s. In fact, between 1990 and 1999, nearly two-thirds of the oil that entered North American coastal waters came from natural seeps, with only 5 percent coming from oil extraction and transportation.[163]

160 DOE, EIA, *Annual Energy Outlook 2010*, Table 14
161 DOE, EIA, *AEO 2011,* Table 14
162 SAFE Analysis; DOI, MMS, "Spills: Statistics and summaries," available at http://www.boemre.gov/incidents/spills1964-1995.htm
163 Congressional Research Service (CRS), "Oil spills in U.S. coastal waters: background, governance, and issues for Congress," August 2007, at 30

FIGURE 28 · U.S. ANNUAL VOLUME & NUMBER OF OIL SPILLS FROM SELECTED SOURCES (1973–2007)



Source: CRS

The turbulent 2005 Atlantic hurricane season—when Hurricanes Katrina and Rita tore through the Gulf of Mexico—was in some ways a demonstration of the industry's capabilities. Approximately 75 percent of the 4,000 federal OCS oil and gas facilities in the Gulf of Mexico were subjected to 175 mile-per-hour winds and other hurricane conditions. Despite serious damage to 168 platforms, 55 rigs, and more than 560 pipeline segments, the U.S. Coast Guard and Department of Interior reported no major oil spills.[164] Total OCS petroleum spillage was estimated at 14,676 barrels—about the size of a single Olympic swimming pool—of which the vast majority (90 percent) was released and dispersed during the storms.[165]

Onshore Access Issues

In addition to reserves of oil and gas held off-limits on the Outer Continental Shelf, the United States possesses significant reserves in onshore federal lands which are also not available for production. The Energy Policy and Conservation Act of 2000 directed the Department of Interior to conduct a comprehensive review of all onshore oil and gas resources and to identify the impediments to their development. In 2008, a multi-agency process that integrated analyses from the Departments of Interior, Energy, and Agriculture, as well as the Environmental Protection Agency, produced an inventory of the entire onshore United States.[166]

The study estimated total UTRR beneath federal lands to be approximately 30.1 billion barrels of oil and 230.1 trillion cubic feet of natural gas. Of these totals, 62 percent of the oil and 41 percent of natural gas resources were fully inaccessible due to regulatory restrictions. Many of the reserves surveyed by the federal government coincide with ecosystems and natural geological structures of tremendous scientific and national significance. Nonetheless, certain onshore areas likely possess

164 The Coast Guard defines "major spills" as those in excess of 2,400 barrels

165 DOI, BOEMRE, "Petroleum spills of one barrel or greater from Federal OCS facilities resulting from damages caused by 2005 hurricanes Katrina and Rita including post-hurricane seepage through December 2007," (2008)

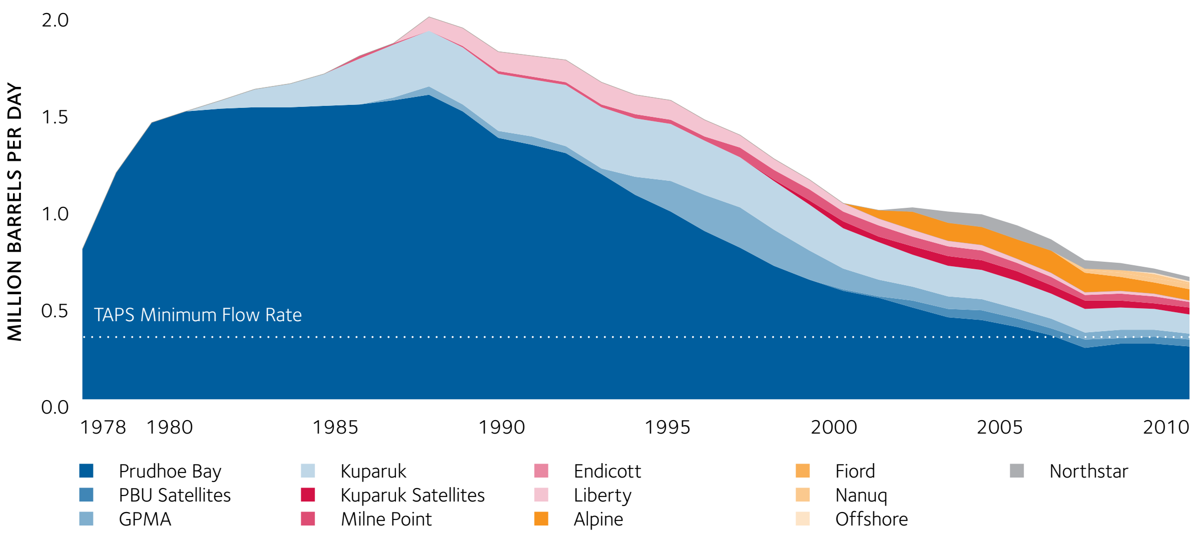
166 DOI, "Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to their Development," (2007)

large quantities of conventional resources. In particular, of all the areas surveyed by the federal government, Northern Alaska is notable for possessing extremely large resources in a relatively confined space. While off-limits lands in the Northern Alaska Study Area represent just 11 percent of the fully inaccessible federal territory, these lands hold more than two-thirds of the inaccessible onshore UTRR oil resources (13.3 billion barrels).[167]

Historically, crude oil production from the accessible areas of Alaska's North Slope (ANS) has played an important role in overall U.S. output. Production began in the late 1970s and peaked in 1988 at more than 2.0 mbd, much of this from the mammoth Prudhoe Bay oil field, which had estimated oil in place of at least 25 billion barrels and has yielded cumulative production of approximately 14 billion barrels.[168] As Prudhoe Bay has gone into natural decline and potential replacement resources have been held off-limits, total ANS crude oil production has quickly trended downward, falling below 650,000 barrels per day in State Fiscal Year 2010.[169]

Opening limited areas of Northern Alaska to oil and natural gas production could reverse this trend and improve U.S. energy security. Specifically, of the 13.3 billion barrels of technically recoverable federally restricted oil in the Northern Alaska Survey Area, 7.7 billion barrels fall within the 1.9 million acres of the 1002 Area of the Arctic National Wildlife Refuge.[170] An additional 2.7 billion barrels are on state and native lands within the 1002 Area.[171]

FIGURE 29 · ALASKA NORTH SLOPE PRODUCTION BY FISCAL YEAR



Source: Alaska State Department of Revenue

167 DOI, "Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to their Development," (2007), at 117

168 DOE, NETL, "Alaska north slope oil and gas: a promising future or an area in decline?" (August 2007), Fig. 3.1 and Table 3.1

169 Alaska State Department of Revenue, Tax Division, *Crude Oil Production History*, available at http://www.tax.alaska.gov/sourcesbook/AlaskaProduction.pdf

170 ANWR was created by the Alaska National Interest Lands Conservation Act (ANICLA) of 1980. Section 1002 of ANILCA deferred a decision on the management of oil and natural gas exploration and development in the coastal plain of ANWR. The coastal plain area—the 1002 Area—represents about 8 percent of the total area of ANWR.

171 DOE, EIA, "Analysis of crude oil production in the Arctic National Wildlife Refuge," (May 2008)

In 2008, an analysis by the Department of Energy posed three cases for development of oil and natural gas resources in the Coastal Plain of the Arctic National Wildlife Refuge. The estimates were derived from USGS survey data. The mean resource case assumed 10.4 billion barrels; the low resource case assumed 5.7 billion barrels; and the high resource case assumed 16.0 billion barrels.[172] In the mean resource case, the Department of Energy estimated increased U.S. incremental oil production from opening ANWR would be 780,000 barrels per day in 2027 and 710,000 in 2030. Total Alaska production would be over 1.0 mbd in 2030 compared to just 300,000 b/d in the base case.[173] The increased production would significantly extend the life of the Trans-Alaska Pipeline System, which is currently closing in on its minimum flow rate of 300,000 b/d.

Hydraulic Fracturing: An Emerging Access Issue?

Perhaps the most important issue facing the domestic oil and gas industry from an access perspective is currently heating up. As unconventional gas exploration, development, and production reached peak levels in 2008 and 2009—and as increased drilling activity led to increased exposure to local populations—an increasing focus developed on a range of possible externalities associated with hydraulic fracturing. For the most part, concerns have focused on the impact of chemicals used as part of the fracturing process—surfactants and other additives that typically account for less than 1 percent of the injected fluid volume.[174] However, additional concerns have been raised regarding methane contamination due to faulty drilling and well casing procedures.

Fresh water and proppants (such as sand) make up the vast majority of fracturing fluid. Still, hydraulic fracturing of an individual well can consume several million gallons of fluid, meaning that even at 0.5 percent the chemicals in a 5 million gallon job could amount to 25,000 gallons.[175] Identifying the makeup of chemicals used in hydraulic fracturing has been a source of contention. Industry representatives have often argued that the mixture of chemicals is proprietary. Critics of the industry have suggested that the chemicals used included some that pose known health risks, including benzene.[176] In 2003, one company signed an MOU with the Environmental Protection Agency agreeing to discontinue the use of diesel fuel—which contains benzene—as an injection fluid in coal bed methane projects that employed hydraulic fracturing.[177] More recently, in an effort to respond to public concerns and rising political pressure, a number of companies active in shale development agreed to voluntarily disclose some (but not all) of the chemicals used in fracturing.[178]

The primary environmental concerns stem from the fact that production of natural gas from shales can mean drilling past underground drinking water aquifers or very near to rural drinking water wells. In general, shale wells are drilled thousands of feet below drinking water reservoirs,

172 DOE, EIA, "Analysis of crude oil production in the Arctic National Wildlife Refuge," (May 2008), at 1

173 Id., Table 2

174 DOE, "Modern Shale Gas Development in the United States: A Primer," at 62

175 Bryan Walsh, "Could Shale Gas Power the World," Time Magazine, March 31, 2011

176 Tom Gjelten, "Water contamination concerns linger for shale gas," NPR, September 23, 2009

177 Memorandum of Agreement between BJ Services Co., Halliburton Energy Services Inc., and Schlumberger Technology Co., available online at http://www.epa.gov/ogwdw000/uic/pdfs/moa_uic_hyd-fract.pdf

178 *See, e.g.*, Mike Soraghan, Company's disclosure decision could change fracking debate," E and E News, July 15, 2010; and Interstate Oil and Gas Compact Commission, "National Registry Provides Public and Regulators Access to Information on Chemical Additives," April 11, 2011; the industry website is available at http://fracfocus.org/

meaning the actual process of hydraulic fracturing occurs far removed from drinking water supplies. For example, the average depth of drinking water wells in northeast Pennsylvania is 60 to 90 meters, whereas the Marcellus shale in that area runs an additional 900 to 1,800 meters farther below ground.[179] Industry supporters point out that there has never been a confirmed case of drinking water contamination associated with hydraulic fracturing.[180] A 2011 study released by researchers at Duke University supported this argument based on samples taken from dozens of Pennsylvania wells near wells that had been developed using hydraulic fracturing.[181]

However, the possibility of improper well completion and cementing procedures—concepts made all the more real by the 2010 *Deepwater Horizon* incident—has raised fears that human error associated with natural gas drilling could contaminate drinking water in other ways. The Duke University study found "systematic evidence for methane contamination of drinking water associated with shale gas extraction."[182] The study points to three possible mechanisms for such contamination, but implies that leaky well casings are a likely possibility. These and other contaminating issues may occur at just a small percentage of the thousands of fracturing jobs that take place each year. They nonetheless have made local populations more skeptical of the industry in many cases.

While concerns about drinking water contamination focus on drilling risks below the ground, challenges exist above ground as well. In 2009 and 2010, the Pennsylvania Department of Environmental Protection reported numerous discharges and other violations that occurred at shale development sites.[183] In fact, in 2010 the Pennsylvania department of environmental protection issued 1,218 violations out of 1,944 inspected Marcellus wells.[184] Many of the documented violations were relatively minor, but a handful of more serious accidents occurred as well.[185] In April 2011, a blowout at a shale gas well in Pennsylvania spewed fracturing fluid above ground for more than 12 hours.[186]

Moreover, well fracturing is not simply a one-time, low frequency event. Over the course of its lifetime, an individual shale well is typically fractured multiple times. This is because shale wells have steep decline rates. According to published company reports, the first-year decline rate for a typical well in the Haynesville shale play is 81 percent; the second-year rate is 34 percent and the third-year rate is 22 percent.[187] These rapid decline rates mean that steady production requires ongoing capital investment in stimulating existing wells and drilling new wells. Throughout its lifecycle, a single shale well can result in as much as 1 million gallons of produced water—fracturing fluid that returns to the surface bearing original chemicals as well as materials picked up in the well.[188] These materials can include heavy metals and other toxic

179 Stephen G. Osborn et. al., *"Methane contamination of drinking water accompanying gas well drilling and hydraulic fracturing"*, Proceedings of the National Academy of Sciences, approved April 14, 2011

180 Ian Talley, "EPA Official: State Regulators Doing Fine on Hydrofracking," Wall St. Journal, Feb. 15, 2010

181 Osborn et al.

182 Id.

183 Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management, lists available online at http://www.dep.state.pa.us/dep/deputate/minres/oilgas/OGInspectionsViolations/OGInspviol.htm

184 Bryan Walsh, "Could Shale Gas Power the World," Time Magazine, March 31, 2011

185 *See e.g.* Abrahm Lustgarten, "Frack Fluid Spill in Dimock Contaminates Stream, Killing Fish," ProPublica, September 21, 2009

186 Mike Soraghan, Pa. Well Blowout Tests Natural Gas Industry on Voluntary Fracking Disclosure," New York Times

187 *See e.g.* Chesapeake Energy, 2008 Investor and Analyst Meeting, presentation entitled, "Haynesville Shale Overview," slide 19

188 Bryan Walsh, "More problems with fracking—and some solutions," Time, April 20,2011

substances that could severely impact everything from clean water to farmland and livestock if improperly handled.

The transport and disposal of produced water raise additional issues. In many cases, particularly in Pennsylvania, waste water is transported over the road to water treatment facilities. In 2009 and 2010, a handful of accidents involving trucks carrying wastewater from shale development resulted in spills that damaged surrounding ecosystems. Recent press reports have suggested that some of the wastewater treatment facilities receiving produced water from shale drilling are not equipped to properly treat the fluids before releasing them.[189] In April 2011, state authorities in Pennsylvania requested that the industry voluntarily begin shipping recycled water to more sophisticated treatment facilities.[190]

The debate about the environmental impact of unconventional natural gas production has generated heightened political attention at both the state and federal level. Congress exempted hydraulic fracturing from federal regulation as part of the Energy Policy Act of 2005.[191] However, as the industry has expanded its operations and come into closer contact with local populations, there have been escalating calls for the Environmental Protection Agency to be given authority to regulate hydraulic fracturing at the national level under the Underground Injection Control Program and the Safe Drinking Water Act.[192] Fracturing wastes are not regulated as a hazardous waste under the Resource Conservation and Recovery Act.[193]

With federal regulators currently unable to deal directly with hydraulic fracturing on private lands, state regulators have been developing independent approaches to regulation.[194] In regions where oil and gas production have been commonplace in recent decades, the regulatory framework is generally well-developed and pro-production (e.g., Texas, Louisiana, and Oklahoma). It is, however, worth noting that on May 13, the Texas state House of Representatives passed legislation requiring companies to disclose fracturing fluids.[195] The bill cleared committee in the Texas state Senate, and was signed into law in June, 2011.[196] Its passage made Texas the first state to enact such a proposal.

In areas where unconventional gas production would significantly expand upon current activity—or indeed represent the first drilling activity in many decades—the response has been less positive. In November 2010, the New York state assembly passed a temporary moratorium on shale development in New York State through May of 2011.[197] More recently, the governor of Maryland issued

189 Ian Urbina, “Wastewater Recycling No Cure-All in Gas Process,” New York Times, March 1, 2011
190 Robbie Brown, “Gas Drillers Asked to Change Method of Waste Disposal,” New York Times, April 19, 2011
191 EPAct 2005 at § 322
192 *See e.g.*, “Face Off Over Fracking: Water Battle Brews on Hill,” National Public Radio Press, (May 27, 2009), available online at www.npr.org/templates/story/story.php?storyId=104565793, last accessed on August 28, 2009
193 Osborne et al.
194 Ian Talley, “EPA Official: State Regulators Doing Fine on Hydrofracking,” Wall St. Journal, Feb. 15, 2010
195 Texas Legislature Online, HB 3328, available at http://www.capitol.state.tx.us/BillLookup/History.aspx?LegSess=82R&Bill=HB3328
196 Editorial, “State must be clear on gas drilling,” Poughkeepsie Journal, May 23,2011
197 Mireya Navarro, “New York Assembly Approves Fracking Moratorium,” New York Times, November 30, 2010

an executive order banning hydraulic fracturing during a three-year study period.[198] The state assembly had previously voted against installing a moratorium on the drilling technique. The city of Pittsburgh banned hydraulic fracturing within city limits in 2010.[199]

The broader issue of freshwater access is likely to emerge as a challenge for the industry, particularly in the Western United States. Water use for unconventional gas recovery is significant—for example, the average deep well in the Barnett shale region of Texas requires 3.4 million gallons of fresh water to complete the initial drilling and fracturing process and create a producing well.[200] Industry supporters argue that this initial water requirement is largely one-time.[201] Water treatment options also certainly exist, but recycling is not currently the norm in regions outside of Pennsylvania, and it comes with its own set of issues, as mentioned above. Recycling is also viewed as a potentially costly addition to industry procedures in places where underground storage is an option.[202]

The environmental impact of unconventional gas production needs to be transparently assessed and managed. EPA is in the process of conducting a comprehensive study, but the results will not be known until late 2012, and the full report is not scheduled for release until 2014.[203] The preponderance of existing data suggests that there is little if any threat to drinking water from hydraulic fracturing itself, but instances of contamination due to inadequate drilling safety and water treatment procedures have created real access risks for both shale gas and shale oil production. The pressure on state and federal regulators to strictly regulate activity will likely remain substantial. Proactive steps that could be taken by the industry—including more binding disclosure requirements and establishing a mechanism for sharing and deploying best practices—would be an important step toward creating the most cooperative regulatory regime possible. This sentiment was surely the driving factor behind a series of investor-driven proposals on fracturing fluid disclosures voted on by shareholders of major publicly held U.S. energy companies like ExxonMobil and Chevron in mid-2011.[204] Proponents of the measures argued they "want to know more about what companies are doing to minimize shareholders' exposure."

Managing onshore access for hydraulic fracturing is critical to the nation's energy security and economic growth. Natural gas holds immense promise as a low-carbon fuel for power generation, transportation, and home heating. Low domestic prices could also catalyze the reemergence of a domestic petrochemicals industry, meaning new jobs and economic growth. Shale oil is providing new growth opportunities for domestic petroleum production, offsetting the need for imports and improving the nation's balance of trade. Capturing, these benefits, however, will require a regulatory framework that safeguards the environment and builds public trust through verification and transparency.

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198 John Wagner, "O'Malley orders study of natural gas drilling in Western Maryland," Washington Post, June 6, 2011

199 Steve LeVine, "Will shale gas be a shake or a mere stir?" Foreign Policy, June 20, 2011

200 *See, e.g.*, Chesapeake Energy, Water Use in the Barnett Deep Shale Gas Exploration, Fact Sheet, May 2009. Also, askchesapeake.com, Natural Gas Production, available online at www.askchesapeake.com/Barnett/Multimedia/Brochures/Water%20Use%20in%20Barnett%20Deep%20Shale%20Gas%20Exploration%20May%202009_Rev%201.pdf, last accessed on August 25, 2009

201 Op. Cit., Chesapeake Energy, *Water Use in the Barnett Deep Shale Gas Exploration*, Fact Sheet

202 *See, e.g.* Chesapeake Energy's discussion of water recycling at askchesapeake.com, Natural Gas Production, available online at www.askchesapeake.com/Barnett/Production/Pages/WaterManagement.aspx, last accessed on August 25, 2009

203 EPA, *Draft Hydraulic Fracturing Study Plan*, available online at http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm

204 Ben Casselman, "'Fracking' Disclosure Is Urged: Shareholders to Decide Whether Gas Producers Should Release More Information," Wall Street Journal, May 24, 2011

5. Policy Recommendations: Balancing the Possible with the Practical

The oil and gas industry, like nearly any other heavy industry, carries with it an environmental footprint. Exploration and production of hydrocarbons can impact local ecologies and communities by bringing industrial activity into areas not accustomed to it. They can also impact the local physical environment in terms of both air and water quality. For these and other reasons, there will always be areas that federal, state, and local government—as well as private land owners—deem inappropriate for development.

At the same time, the United States needs traditional energy. There is simply no alternative liquid fuel available at scale that can substitute for petroleum in the near or even medium term. After decades of investment, biofuels still only accounted for 860,000 barrels per day of liquid fuel in 2010—534,000 b/d in oil equivalent terms.[205] This represents less than 5 percent of total consumption. Commercialization of alternative transportation technologies, including hybrid and electric drive trains, are probably the surest path to improved energy security in the long term. But even the most bullish penetration scenarios do not envision such technologies reaching more than 50 percent of the private light-duty vehicle fleet before 2030.[206]

In the meantime, enhanced energy security and economic stability will require increased domestic production of oil and natural gas. Higher levels of self sufficiency in energy supply, coupled with greater efficiency standards that are already coming into effect between 2011 and 2016—and those that are being developed for 2017-2025—will keep billions of dollars from being exported out of the country each year.[207] But moving forward with development of domestic resources—both in areas already accessible to the industry and in frontier areas—will require a partnership between the public and private sector as well as a thoughtful and more nuanced approach by regulator and industry alike.

Leveraging Technology in New Frontiers

Technology can certainly help minimize the industry footprint in many cases. There have been remarkable advances in offshore oil and gas production techniques in recent decades. Subsea well heads and long distance tie-backs allow for a minimum surface presence throughout the life-cycle of a project and also provide more flexibility to site infrastructure. Today, a single platform can produce oil and/or natural gas from a number of wells over substantial distances. A temporary surface presence is required for exploration and development drilling, but current technologies offer the possibility of offshore oil and gas production without the burden of numerous surface-level platforms. StatoilHydro is one company that has successfully deployed a 'small footprint' strategy repeatedly in order to minimize exposure to harsh operating environments in the Barents and North Seas. At its Snohvit field in the Barents, subsea structures have

205 DOE, EIA, Monthly Energy Review, Table 10.3 (June 2011)

206 Electrification Coalition, *Electrification Roadmap*, November 2009

207 *See, e.g.*, SAFE, "Oil Savings from Proposed Fuel Economy Standards," (May 2011), available at http://www.secureenergy.org/policy/oil-savings-proposed-fuel-economy-standards

been tied to onshore facilities 100 miles away.[208] The project utilizes no surface-level structures offshore and sequesters separated CO_2 from produced natural gas.[209]

In fact, oil and gas projects around the world are demonstrating that existing and emerging technologies can be leveraged in order to access significant resource volumes while maintaining a minimal environmental footprint. For fields close to the shore, for example, extended-reach drilling allows many different deposits to be drilled from a single onshore pad by drilling wells horizontally under the seabed. The longest such wells—over seven miles long—have been drilled by ExxonMobil on Russia's Sakhalin Island. Because the drilling does not puncture the seabed, it sharply reduces the possibility of oil discharges into the sea. This technique has been used to drill Poole Harbor in the UK, an ecologically sensitive and archeologically important area, from a disguised onshore drilling pad.[210] The same technology is being used to develop a 100 million barrel oil reserve in the ecologically sensitive shallow coastal waters of Alaska's Beaufort Sea. The $1 billion project will feature extended reach horizontal wells up to 8 miles long and produce up to 40,000 barrels of oil per day by 2013.[211]

In the second half of 2011, partners Total, Statoil, ExxonMobil, and BP expect to reach the initial production phase from a deepwater project known as Pazflor, nearly 100 miles off the coast of Angola.[212] The project is expected to ultimately produce 220,000 barrels per day.[213] It will be developed from a single ship, a first-of-its-kind floating processing, storage, and offloading (FPSO) unit capable of processing two different grades of oil and housing 240 employees.[214] The FPSO will process the oil produced by a system of 49 subsea wells at a depth of nearly 4,000 feet. The total subsea production system, linked by a network of 109 miles of pipelines and 51 miles of umbilicals, will be spread over a vast expanse of 232 square miles—six times larger than the city of Paris.[215]

More Effective Regulation

Ultimately, no technology can substitute for a culture of safety surrounding oil and gas operations within individual companies. In part, such a corporate culture comes about as the result of internal dynamics such as historical standards and leadership. But safe operating conditions and positive outcomes are also determined by effective regulation. For the U.S. domestic oil and gas industry to capitalize on recent advances and high oil prices in a way that enhances American energy security, it will need to prove to the public and skeptical lawmakers that it can do so safely and responsibly, and it will need to do so in concert with a key partner: its regulator.

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208 Statoil, http://www.statoil.com/en/OurOperations/ExplorationProd/ncs/snoehvit/Pages/default.aspx

209 Statoil, "The Snøhvit field in the Barents Sea supplies gas to the world's first LNG plant with carbon capture and storage," http://www.statoil.com/en/technologyinnovation/newenergy/co2management/pages/snohvit.aspx

210 BP, plc., "UK Upstream Asset Portfolio: Wytch Farm," available at http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/U/uk_asset_wytch_farm.pdf

211 BP, plc., "Reaching Out to Liberty," available at http://www.bp.com/liveassets/bp_internet/us/bp_us_english/STAGING/local_assets/downloads/l/final_liberty70808.pdf

212 Total, "Pazflor, a world first in technology," available at http://www.total.com/en/our-energies/oil/exploration-and-production/projects-and-achievements/pazflor-940850.html

213 Id.

214 Joel Parshall, "Pazflor Project Pushes Technology Frontier," Journal of Petroleum Technology, January 2009

215 Id.

RECOMMENDATION ONE

Initiate a pilot program in cooperation with the State of Alaska to demonstrate extended reach drilling in the 1002 Area of the Arctic National Wildlife Refuge.

After decades of debate, federal protections that restrict industry development of the 1002 Area of the Arctic National Wildlife Refuge remain unlikely to be altered. The cultural, environmental, and political significance of these lands are such that, even in the current energy security environment, strong opposition remains entrenched. However, recent developments may provide an opportunity for industry to leverage technology to access oil resources with minimal incremental increase in footprint. Both sides in the debate should view this as an opportunity.

In early 2010, ExxonMobil drilled and cased its first development well on the Point Thompson project in Alaskan State lands approximately 60 miles east of Prudhoe Bay and directly adjacent to the 1002 Area of ANWR. The Point Thompson project features an onshore drilling pad with extended reach directional wells that extend 1.5 miles offshore in the Beaufort Sea.[216] First production is expected in 2014 from a reservoir containing 8 tcf of natural gas and 200 million barrels of condensate. (It is worth noting that production timelines have been subject to slippage due to repeated federal delays in granting a NEPA-related EIS on noise impacts as they relate to nearby ANWR.[217])

The existence of the Point Thompson project so close to the 1002 Area provides an opportunity for the industry to use extended reach drilling to develop ANWR oil without establishing a surface presence in ANWR itself and without necessarily adding substantially to the existing industry footprint on state lands. In a recent Senate Energy and Natural Resources Committee hearing, a representative from Alaska's Department of Natural Resources suggested that extended reach drilling from Point Thompson into the 1002 Area could have a major impact on production. [218] In fact, debate is already underway regarding possible development of a 100 million barrel field within the Point Thompson unit that likely extends into the 1002 Area.[219]

The Department of Interior should initiate a pilot project in cooperation with industry to demonstrate the feasibility of extended reach drilling into the 1002 Area from Alaskan State lands. The state is supportive of development, and would likely prove a willing partner. Such a project should begin in an extremely limited fashion, with the right to drill a single ERD well from Point Thompson, assuming all NEPA-related requirements are met. Within two years of initial production, Interior should produce a report detailing any successes and failures of the project, and whether to move forward with additional ERD leasing from adjacent lands into the 1002 Area.

216 Rigzone, "ExxonMobil cases first Point Thompson well," February 8, 2010

217 Wesley Loy, "Thompson statement delayed once more," Anchorage Daily News, January 15, 2011

218 Nick Snow, "Obstacles beyond technology may limit U.S. production, lawmakers told," Oil and Gas Journal, May 16, 2011

219 Kay Cashamn, "Fortune Hunt Alaska: Tapping ANWR from Point Thompson," Petroleum News, May 8, 2011

RECOMMENDATION TWO

Implement comprehensive reform of the U.S. offshore regulatory approach, shifting from a rule-based to a goal-based approach.

The first step toward increased OCS oil production and enhanced U.S. energy security must be reform of the U.S. regulatory approach for offshore energy production. Before new areas of the OCS can be opened, it will be critical that local populations—and equally importantly, national lawmakers— have increased confidence in industry safety.[220] The current rules-based approach to regulating oil and gas production may no longer be suitable, given the complex nature of the offshore industry. Implementing a goal-based approach to regulation would require U.S. regulators, in particular the Department of Interior, to:

Establish clear goals that operators must meet: Operators need to take responsibility for the safety of their operations. Establishing clear goals for safety performance will make it clear to operators that, on its own, simply following the rules is not adequate.

Shift from detailed technical requirements to performance-based standards: Detailed technical requirements can easily be superseded as technology develops. Performance-based standards, however, will always be relevant as they identify a specific level of performance that an operator must achieve, and they can be written in relation to the best available technology rather than a minimum standard. Of course, technical guidance similar to today's technical requirements can accompany the standard, but the performance-based nature of the standard should make it clear that implementing the technical guidance is neither necessary nor sufficient if it fails to deliver the performance standard. This approach encourages innovation by incentivizing firms to find new ways to meet and exceed performance standards, and it makes it easy to tighten the standard as technology improves. Specific technical solutions might be correct for today's technology, but they are unlikely to be appropriate for future technologies.

Establish clear requirements to employ best available control technology consistent with global best practices: This is a particularly important example of the shift to performance-based standards. There is a real risk that new regulation may seek to specify detailed engineering requirements for well safety equipment. Whereas rules-based technical regulations focus on inputs to safety performance (e.g., number of sheer rams and specific tests of blow-out preventers), performance-based regulations measure success through outputs of safety performance (e.g. low quantitative risk assessment, low projected failure rates, and independent assessments that technological best practice is being implemented).

Implement the use of a safety case as a basis for dialogue with operators: A shift to goal-driven regulation will require regular dialogue in which operators explain to regulators the techno-

220 SAFE has also modeled the impact of the moratorium on Gulf of Mexico oil drilling. We estimate that the cumulative loss of production caused by the moratorium and the regulatory uncertainty that has followed it will amount to between one and two years of Gulf of Mexico production. http://www.secureenergy.org/sites/default/files/SAFE_Intelligence_Report_3-13--2010.10.25.pdf

logical choices they intend to make, and BOEMRE challenges those choices to ensure that operators develop the safest possible solutions. Production of a safety case will also force operators themselves to think through the safety implications of design and organizational choices early in the process.

RECOMMENDATION THREE

Increase funding for BOEMRE to attract highly trained engineers and enable BOEMRE to engage with operators on equal footing.

The shift to a goal-based approach to regulation will help foster a stronger safety culture. However, such an approach will only work if operators respect BOEMRE at a professional level. In order to have a dialogue with operators about safety, BOEMRE needs to have a similar level of technical expertise as the operators. Key technical personnel on both sides need to respect one another as colleagues. This can only happen if BOEMRE has the budget to attract and retain the same quality of engineering talent as the industry does. Moreover, expanded dialogue with operators will imply a larger role for BOEMRE, which will require a larger technical staff.

RECOMMENDATION FOUR

Use the new regulatory approach to open frontier areas and use the experience of frontier areas to refine the new regulatory approach.

Shifting to a goal-based approach in the Gulf of Mexico will be difficult, because current approaches and ways of working are deeply ingrained. As such, this regulatory transformation might be most easily applied either in a frontier area, such as the Atlantic planning areas, the Eastern Gulf of Mexico, and the Alaska OCS, or in a well understood area that is currently closed to new production, such as certain Pacific planning areas. In any of these areas, this new approach could be trialed with a relatively small number of companies to refine the approach and demonstrate its credibility before, or in conjunction with, rolling it out in the Gulf of Mexico.

By opening a portion of the OCS as a trial area for the new approach, BOEMRE can make clear that companies will only be allowed to participate in the new area if they take adopting the new approach seriously. Once the new approach has been demonstrated to work in one new area of the OCS, it can be extended to open other new areas.

RECOMMENDATION FIVE

Implement distance-from-shore provisions designed to minimize the footprint of offshore oil and gas development in all frontier areas.

In order to minimize the impact of oil and gas operation in frontier areas of the OCS, Interior should establish a strict zoning framework that clearly sets out what is—and what is not—allowable in terms of footprint. Such a framework would place the onus on individual companies to provide innovative technology solutions that meet the goal. OCS activity in frontier areas should be subject to the following development constraints:

Prohibition of surface presence within 15 miles of a state's seaward boundary: Regulations should prohibit the presence of any surface infrastructure related to the extraction of oil and gas resources within 15 miles of a state's seaward boundary in the Oregon-Washington planning area, the Northern, Central, and Southern California Planning Areas, the Eastern Gulf Planning Area, or the Northern, Central and Southern Atlantic Planning Areas. However, where individual State Coastal Zone Management Plans allow for it, the Secretary could offer leases that can be developed using extended reach drilling technologies that only occupy surface acreage onshore.

In some areas of the OCS, in particular the Pacific OCS, oil and gas resources are believed to be concentrated nearer to shore. At the same time, these areas are proximate to coastal vistas and other potentially sensitive offshore areas. For these resources, extended reach drilling allows many different deposits to be drilled horizontally under the seabed from a single onshore drilling pad. The longest such wells currently reach more than seven miles, but technology and economics should allow for a farther each in the coming years. Because the drilling does not puncture the seabed, it dramatically reduces the already exceptionally low possibility of oil spills.

Allowance of temporary surface presence between 15 miles of a state's seaward boundary and 25 miles of a state's coastline: Regulations should allow only a temporary surface presence in certain federal OCS areas between 15 and 25 miles of a state's seaward boundary. A surface presence of no more than 90 days in any 365-day period should be permitted in this mileage range for leases that are in the Oregon-Washington planning area, the Northern, Central, and Southern California Planning Areas, the Eastern Gulf Planning Area, or the Northern, Central and Southern Atlantic Planning Areas.

This approach aims to protect ocean sightlines that are critical for tourism. But it balances that need with the importance of providing industry with some flexibility to access oil and gas reserves. In the area beyond 15 miles of a state's seaward boundary (roughly 18 miles from the shoreline), but within 25 miles of the coastline, industry can erect a temporary drilling structure in order to install subsea components necessary to access an oil and gas reservoir and transport hydrocarbons. A subsea wellhead can be operated in two distinct ways. It can be operated by an offshore platform farther afield in the OCS, or by a facility onshore. In the Barents Sea, Norwegian oil company Statoil Hydro is setting the state of the art for developing offshore reserves in geologically challenging areas via subsea wellheads and long-distance subsea transport infrastructure. Snohvit, an offshore gas field, is tied to a land-based plant on Melokoya Island via several links. The largest of these, the gas pipeline, is 143 kilometers long.

RECOMMENDATION SIX

Initiate an "inventory-to-lease" program in frontier areas of the Outer Continental Shelf, subject to goal-based regulation.

Policymaking involving the OCS is fundamentally handicapped by a lack of geological understanding in many areas. Estimates of the scale and recoverability of OCS resources vary massively and are speculative at best, because the geological data necessary to make accurate estimates has not been gathered. The Energy Policy Act of 2005 required the Department of Interior to publish a comprehensive inventory of OCS resources using best available technology.[221] However, the final report, published in 2006, used probability modeling based on existing data, much of which was collected in the 1970s and 1980s, particularly in the Eastern Gulf of Mexico and the Atlantic planning areas.

Better data will arguably inform clearer energy policy decisions. One recent example highlights how this might work in practice. Although a lease sale was scheduled off the coast of Virginia as part of the 2007-2012 Five Year Plan, it was cancelled in the aftermath of the *Deepwater Horizon* incident.[222] The Obama Administration subsequently announced that the lease sale might be included in the 2012-2017 Five Year Plan. For that to happen, however, a long-delayed environmental impact states (EIS) on seismic activity in the Atlantic planning areas will need to be completed and find that significant resources exist.[223] This approach, which uses information gathering to facilitate leasing, could be a template for action in multiple OCS regions.

In May 2011, the Senate Energy Committee debated a bill that would fund a comprehensive OCS inventory to be conducted in three phases. The bill authorized up to $100 million each year between 2012 and 2017, and up to $50 million annually from 2018 to 2022.[224] This approach and level of funding seem adequate to gather necessary information, but the timeline is not workable. The industry has indicated that is willing and able to gather data on OCS resources in frontier areas—that is, those areas outside the Western and Central Gulf of Mexico and the Alaska OCS—with little or no expense to the government. Of course, this is likely to occur most rapidly in areas where industry believes it will be granted access to lease sales in a timely fashion.

To expedite information gathering, Interior should designate a specific number of frontier areas in which seismic inventory will take place between 2012 and 2014. If commercially producible reserves of oil and/or natural gas are discovered in those areas, at least one lease sale should immediately be included in the existing Five Year Plan (2012-2017). The program should be repeated every two years through 2020 and be subject to a midstream review in 2016.

221 EPAct 2005, Section 357
222 *See, e.g.*, DOI, BOEMRE, "Salazar Announced Revised OCS Leasing Program," December 1, 2010
223 Id.
224 S. 916 in the 112th Congress, Oil and Gas Facilitation Act of 2011, introduced on May 9, 2011, Title II

RECOMMENDATION SEVEN

Implement a system of progressive royalties for new OCS leases.

The value of the mineral resources beneath federal lands is a direct function of the market price of those resources. When much of the legislation that created today's oil and gas revenue management system was implemented, the incredible price volatility and high fossil fuel prices of today were probably not comprehensible. Yet, as oil prices have soared to record highs in recent years, the federal government's share of the resource value has remained the same.

In 2009, the Government Accountability Office reported that the U.S. government 'take' of oil and gas revenues on federal lands is often much less than the take of state governments and other countries.[225] Progressive royalties are designed to ensure that the federal government receives fair market value for federal resources developed by private corporations, especially as oil prices rise.

The Secretary of the Interior should conduct a pilot program under which royalty rates for oil or natural gas leases in frontier areas are based on a sliding scale that is price and volume sensitive (in a manner similar to the scale recommended by the Royalty Review Panel of the Province of Alberta, Canada).[226] If the program can document success by the end of the Five Year Plan in which it is implemented, it should be established as a standard approach for all future OCS leases.

Alternative Option: Some analysts have proposed alternative systems for managing offshore leasing in a manner that would increase federal revenues. One such system would require companies to not only submit a bonus bid, but also bid on royalty rates in a sealed envelope auction. The Secretary of the Interior would then award the lease to most attractive comprehensive bid package (bonus and royalty rate). The result would be to force bidders closer to their maximum acceptable royalty rate, thus increasing government revenues.

RECOMMENDATION EIGHT

Create loan guarantees for the construction of CO_2 pipelines from major economic and industrial centers to regions populated with oil and gas fields for use in EOR projects.

The progress enhanced oil recovery projects in the Permian Basin has been significantly aided by supportive public policy to date. A 15 percent federal tax credit applicable to all costs associated with installing a CO_2 flood, the purchase cost of CO_2, and CO_2 injection costs has existed since 1986. A handful of U.S. states also provide incentives, with Texas ranking as probably the most supportive (oil production from CO_2 EOR projects in Texas is exempted from severance tax).

225 Government Accountability Office (GAO), "Oil and Gas Royalties: A Comparison of the Share of Revenue Received from Oil and Gas Production by the Federal Government and Other Resource Owners," May 1, 2007

226 Alberta Royalty Review Panel, "Our Fair Share," September 2007, at 10

Federal research and development efforts have also supported the growth of CO_2 EOR for decades. The Department of Energy's advanced CO_2 injection program is focused on enabling "enhanced recovery of the nation's stranded oil resources." DOE's program focuses on evaluating possible candidate locations for future CO_2 injection enhanced oil recovery, utilizing CO_2 from industrial sources, as well as geologic sources.[227]

Despite incentives and other support, CO_2 EOR projects are viewed as financially risky in many regions of the country outside of Texas, despite the existence of oil fields that could be amendable to additional recovery via CO_2 flood. Uncertainty regarding the availability of CO_2 is a key issue in many places, a concern borne out by the experience of operators in Texas. According to a recent Department of Energy report, estimates point to as much as 500 million cubic feet (25,974 metric tons) per day of pent-up demand for CO_2 from oil field operators seeking to implement economic CO_2 EOR projects in Permian Basin alone.[228]

To capitalize on the potential of advanced EOR projects to enhance U.S. energy and environmental security, EOR projects utilizing CO_2 flooding should be eligible for federal loan guarantees applied toward building incremental pipeline capacity. Only projects that commit to sequestering a substantial portion of purchased CO_2 volumes should be eligible. In addition, 10 percent of the federal tax revenue derived from CO_2 EOR projects should be diverted to an Enhanced Oil Recovery Trust Fund. Eligible uses of the fund's capital should be limited to lowering perceived risks by conducting research, pilot tests and CO_2 EOR field demonstrations in geologically challenging fields.

RECOMMENDATION NINE

Establish a comprehensive approach to ensure regulatory stability for unconventional oil and gas production while also giving operators the certainty to move forward.

Pressure to establish federal regulation of hydraulic fracturing under EPA's Underground Injection Control Program is gaining momentum. Industry has long argued that state officials are dedicated public servants capable of regulating hydraulic fracturing and natural gas drilling. They point to the fact that fracturing has been used for decades and has yet to result in a single documented case of drinking water contamination with fracturing fluids or brines. However, the expansion of natural gas drilling that occurred between 2005 and 2009 created a fundamental departure from the world that existed prior to 2005. With gas drilling—and hydraulic fracturing—proliferating throughout shale-rich regions of the country, industry's exposure to local populations is increasing.

Inevitably, issues and violations will occur. Even if such violations overwhelmingly occur above ground or during well completion, they invariably reflect poorly on hydraulic fracturing, which the public and media have latched onto as an environmental risk—rightly or wrongly. With each

227 DOE, Enhanced Oil Recovery Program, available at http://fossil.energy.gov/programs/oilgas/eor/

228 DOE, National Energy Technology Laboratory (NETL), *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Solution,* March 2010, at 11

blowout, truck accident, and water recycling plant shortfall, public confidence is decreasing, and state officials are under growing pressure to penalize the industry. Today, this is largely confined to the northeast and developments in the Marcellus and Utica shales, but that is no strategy for containment. By insisting on state regulation and strictly voluntary disclosure of fracturing fluids, the industry is contributing to a volatile state of regulatory affairs that risks severely stunting the potential of shale gas as well as shale oil in the United States.

EPA regulatory authority already extends to hundreds of thousands of wells that inject fluids underground today.[229] This includes nearly 150,000 class II wells related to oil and gas activity, including wells for enhanced oil recovery, disposal wells, and hydrocarbon storage wells.[230] There is scarce logic behind exemption of wells used for hydraulic fracturing, except that state regulators can approve permits faster. Industry argues that federal regulation will result in a curtailment of natural gas drilling due to more extensive permitting requirements and bureaucracy. To a degree, this is surely valid. But EPA should have little interest in draconian actions, such as banning fracturing. In fact, the attainment of the CO_2 mitigation goals sought by many environmentalists will depend heavily on shale gas production. By sacrificing a measure of independence from federal regulators, industry would do much to minimize its exposure to serious and growing risk at the state level.

This report does not establish a position on this issue. Too much research remains in the pipeline phase, and both EPA and DOE have yet to release evaluations of the regulatory path forward. However, from an energy security standpoint, it is critically important to ensure that any new regulation does not become an unnecessary, duplicative impediment to future oil and gas production and weaken energy security. If, in fact, the federal government moves forward with regulation of hydraulic fracturing, states should be preempted from banning hydraulic fracturing and preempted from constructively banning it through regulations that make production uneconomic.

229 EPA, Underground Injection Control Program, "Classes of Wells," available at http://water.epa.gov/type/groundwater/uic/wells.cfm
230 Id., "Oil and Gas Related Injection Wells," available at http://water.epa.gov/type/groundwater/uic/class2/index.cfm

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