of the mixture is usually sand and water. Many states are now requiring companies to disclose the chemicals used in the fracking process.

Finding oil and gas used to be as much an art as a science, but advances in computer-processing power now allow geologists to interpret seismic surveys with greater accuracy and to produce three-dimensional images and underground maps of hydrocarbon-bearing formations that may exist in thin layers of rock (less than 50 feet thick), 5,000 to 10,000 feet or more below the surface. Think of the subsurface as a multiple-tiered layer cake, with the hydrocarbon-bearing layer (the pay dirt) being the thin layer of chocolate fudge frosting holding the two bottom cake layers together. New directional drilling technologies, including horizontal drilling, allow companies to turn corners and follow thin hydrocarbon-bearing formations for thousands of feet in a mostly horizontal direction to reach more oil and gas from one spot. Hydrofracking can then be done at multiple locations along a horizontal borehole to stimulate the recovery of greater quantities of oil and gas from one well.

With today's technology dry holes are becoming far less prevalent. Technological advances have reduced drilling costs and financial risk and have allowed for greater recovery efficiencies that make it possible for companies to go after previously uneconomic, unrecoverable reserves like deep shale oil and gas.

Hydrofracking requires huge amounts of water (up to five million gallons per well) that is scarce in many locations, and concerns have been raised about possible contamination of drinking water. At most sites, however, fracking occurs far below the water table at depths of 3,000 feet or more that are separated from the aquifer by solid geological barriers. Nevertheless, there are instances currently under investigation where some older, shallow wells have been subjected to hydrofracking in and below the aquifer in close proximity to drinking water.

Another issue involves the recovery, treatment and disposal of the wastewater and chemicals used in the fracking process. Some states used to allow wastewater from fracking operations to be sent to municipal wastewater treatment plants for treatment and discharge, but that practice has largely been stopped. In many states, wastewater must now be captured, treated and reused wherever possible, which makes sense where water is scarce. In the eastern states, wastewater is disposed of in deep injection wells drilled just for the purpose of disposing the fracking liquids. There have also been some instances of well blowouts where fracking fluids have spilled out on the surface to pollute farmland, lakes, ponds and streams.

Industry standards and state and federal regulations governing hydrofracking are evolving rapidly to deal with these issues. The Environmental Protection Agency (EPA) is conducting a broad study of the fracking process with a view toward developing standards for the process itself and for the capture, treatment and disposal of wastewater, but preliminary results are not due until 2013. In May of 2011, EPA Administrator Lisa Jackson, testifying before the House Oversight and Government Reform Committee, said, I'm not aware of any proven case where the fracking process itself has affected water.although there are investigations ongoing. She also testified that Natural gas creates less air pollution than other fossil fuels so increasing America's natural gas production is a good thing.

The U.S. shale oil story is good news for many reasons. We are the world's largest consumer and importer of oil and the world's third-largest oil producer behind Saudi Arabia and Russia. U.S. production of crude oil peaked at about 9.6 million barrels per day (mmbd) in 1970, and then declined steadily to a low of 5.0 mmbd in 2008. Total U.S. liquid fuel production, which includes not only crude oil but also other liquid fuels like condensates, natural gas liquids and biofuels, was 7.5 mmbd in 2008. Since 2008, however, total U.S. liquid fuel production has risen by about 1.2 mmbd, with the increase in crude oil accounting for the largest share. Half of the rise in U.S. crude oil production was from the deep-water Gulf of Mexico, and half was from new shale oil developments in North Dakota, Texas and other places.

Minor shale oil production began in North Dakota almost 50 years ago, but shale's potential could only be realized when high oil prices and the cost-effective application of horizontal drilling and hydraulic fracturing allowed production to rise from 10,000 bpd in 2003 to 500,000 bpd today. Today, North Dakota is about to pass California to become the nation's third largest oil-producing state behind Texas and Alaska. The rise in shale oil production will take over from the deep water Gulf of Mexico as the largest incremental source of crude oil production growth in the next 10 years, adding a total of about 2.0 mmbd to U.S. production between now and 2020. This growth, coupled with smaller gains in deep water production, biofuels, and natural gas liquids will help to offset continued production declines in older fields and help us limit our dependence on oil imports

Our dependence on oil imports reached a peak of over 60% in 2005, but it has since declined to just 49% in 2010, partly as a result of increased domestic production. In 2010, almost half of our net oil imports came from the Western Hemisphere (Canada, Mexico, Venezuela and others), and less than one-fifth of our imports came from the Persian Gulf. While the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) expects U.S. oil demand to resume growing slowly over the long term, the expected increases in our domestic production of all liquid fuels together, including shale oil, may further limit our dependence on oil imports to just over 40% of our expected consumption in 2035. While shale oil and increased imports from Canada and other friendly suppliers will help to limit our dependence on potentially unreliable sources of oil, we will still be part of the global oil market and economically vulnerable to supply disruptions and price hikes.

The natural gas story is even more dramatic. The U.S. is the world's largest producer and consumer of natural gas, but our production of gas was fairly stagnant for years up to about 2006. In the early 2000s, our imports of natural gas, primarily coming by pipeline from Canada, reached a level of nearly 20 % of our consumption, and there was a great expectation that U.S. gas imports would continue to grow. Canadian gas production was also stagnating, and Canada began to use more of its own gas in the production of syncrude. As a result, just a few years ago the U.S. was perceived as a growing market for liquefied natural gas (LNG) imports from many international suppliers. In 2004, the Federal Energy Regulatory Commission (FERC) was entertaining more than 40 requests for siting permits to build LNG receiving terminals along the U.S. coastline. Gas producers in many parts of the world invested billions of dollars in gas liquefaction plants, export terminals and ships to supply the U.S. market, only to see U.S. demand for imports dry up in the space of a few years because of increased U.S. production.

High natural gas wellhead prices stimulated the industry to experiment with a combination of horizontal drilling and hydraulic fracking in the Barnett shale in Texas. Early success with the technique in the Barnett led the industry to focus on other shale plays in Haynesville (La.), Fayetteville (Ark.), Marcellus/Utica (Penn., Oh., NY, W.Va.), and others. The rest is history. Shale gas production went from 0.3 trillion cubic feet (Tcf) in 2000, to almost 5.0 Tcf today, and it now accounts for almost 25 % of our total gas production. Our imports have dropped to about 10 %, and wellhead and spot natural gas prices have declined by more than half, to a level around $3.00 per thousand cubic feet (Mcf) today from more than $8.00 per Mcf in 2008.

The DOE/EIA now expects shale gas production to continue rising to more than 12 Tcf by 2035, when it will account for nearly 50 % of our total gas production. The EIA also expects natural gas prices to stay below the highs experienced earlier, which could allow it to gain market share, primarily at the expense of coal in electricity generation (but also nuclear and renewables like solar and wind), and possibly in the transport sector, at the expense of oil, as a fuel for trucks and buses. On an energy equivalent basis, the wellhead price of natural gas today is roughly only about 20 % of the cost of oil. Abundant supplies of inexpensive natural gas couldn't have arrived at a better time. The EPA's new utility regulations on emissions of mercury, acid gases and soot, coupled with their proposed regulations on emissions of carbon dioxide could lead to the closure of about 20 % (or about 60,000 megawatts) of our coal-fired electricity generating plants between now and 2016. This capacity is likely to be replaced by new, clean-burning, efficient, combined-cycle natural gas plants that produce the lowest-cost power available today.

(Continued on page 6)