ENERGY OUTLOOK

2014 SPRING | SUMMER

With more than 100 years in the energy industry, BOK Financial is committed to helping you succeed. In this issue of the Energy Outlook, you'll learn more about the current environment and outlook for the energy industry, as well as emerging trends in oil, natural gas and contract drilling.

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OIL

NATURAL GAS

CONTRACT DRILLING

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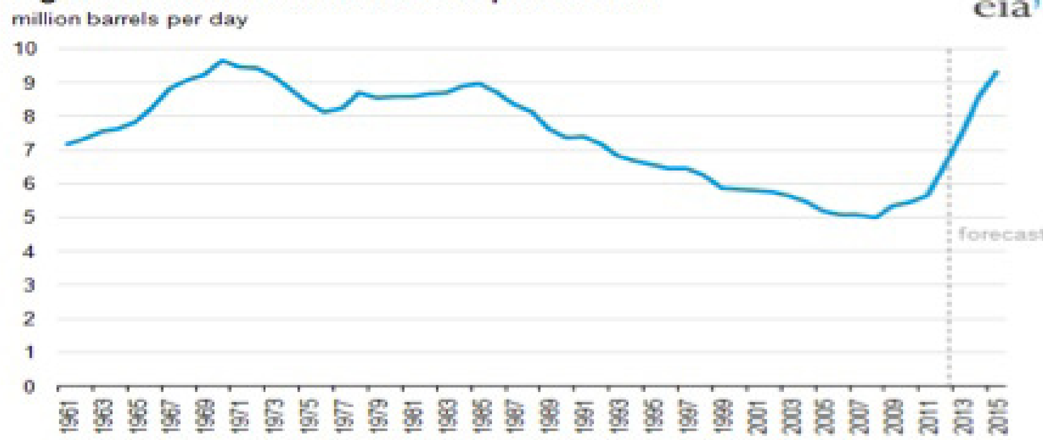
OIL

PRODUCTION

Crude oil production in the United States averaged 7.5 million barrels per day (bbl/d) in 2013, a 992,000 barrel per day increase over 2012 and the highest average production rate since 1989. Production in November and December 2013 was estimated to have been over eight million barrels per day. The nearly one million barrel per day increase in 2013 exceeded the increase of 836,000 barrels per day in 2012. The largest increase prior to that, of 751,000 barrels, was in 1951. In terms of percentages, 2013 represented a 15.3% increase over the prior year, which was the largest percentage gain since 1940. Increased production of shale oil has been the driving force behind five consecutive years of growth in U.S. oil production.

Production from tight oil formations spurred growth in crude oil production in recent years as companies learn how to apply hydraulic fracturing techniques more effectively and efficiently. More than 80% of crude oil (and lease condensate) production in the United States came from five states and the Gulf of Mexico in 2013. Texas led the U.S. in crude production at 35%, according to the U.S. Energy Information Administration (EIA). The second largest state producer was North Dakota (12%), followed by California and Alaska (7% each), and Oklahoma (4%). The federal offshore Gulf of Mexico produced 17%. Although Texas and North Dakota provided the majority of the growth in 2013, three other states experienced production growth rates in excess of 20% over the last three years. Colorado, with part of the Niobrara Shale, reported 93% growth in production from 2010 to 2013; Oklahoma, with the Woodford Shale, reported 62% growth; and New Mexico, which shares the Permian Basin with Texas, grew production 51%

Figure 1. Annual U.S. crude oil production



Source: U.S. Energy Information Administration, January 2014 Short-Term Energy Outlook.

Although onshore crude oil production is expected to comprise the majority of production increases through 2015, projected growth also includes offshore production from the U.S. federal Gulf of Mexico. After flat offshore Gulf of Mexico oil production of 1.3 million barrels per day in 2013, EIA estimates that Gulf of Mexico crude production will increase to 1.6 million bbl/d in 2015.

U.S. output, including natural gas liquids and biofuels, has increased roughly 3.2 million barrels per day since 2009. While still one of the largest consumers of fuel, increased crude available to refiners has turned the U.S. into a significant exporter of gasoline and distillate fuels. Growing domestic production in the United States has contributed to a sizeable decline in liquid fuel imports, including crude oil and petroleum imports. After peaking at 60% in 2005, U.S. liquids fuel consumption met by net imports fell to an average of 33% in 2013. Furthermore, EIA predicts the net import share will decline further to 24% in 2015.

According to the EIA, the world petroleum and other liquids supply is expected to increase by 1.4 million bbl/d in 2014 and 1.3 million bbl/d in 2015, with the majority of the growth coming from countries outside of the Organization of Petroleum Exporting Countries. The U.S. and Canada will account for much of this growth.

For 2014 and 2015, the United States is projected to produce 8.42 million bbl/d and 9.19 million bbl/d, respectively. According to the EIA, the 2015 forecast would be the highest annual average level of production since 1972. The EIA predicts that the majority of the growth in crude oil production through 2015 will stem from drilling in the Bakken formation in North Dakota and Montana, the Eagle Ford in Texas, and the Permian Basin in Texas and New Mexico.

The Paris-based International Energy Agency (IEA) indicated that U.S. is poised to become the world's largest producer of oil by 2015, five years sooner than last year's forecast. The boost to U.S. production came at an opportune time. The U.S. Energy Information Administration stated that unplanned global supply disruptions averaged 2.6 million bbl/d in 2013, which was 0.7 million bbl/d higher than 2012. Global disruptions peaked at 3.1 million bbl/d at the end of 2013 and remained at that level into 2014. Non-OPEC supply disruptions are centered in South Sudan, Syria, and Yemen, while OPEC supply disruptions are largely driven by Libya.

CONSUMPTION

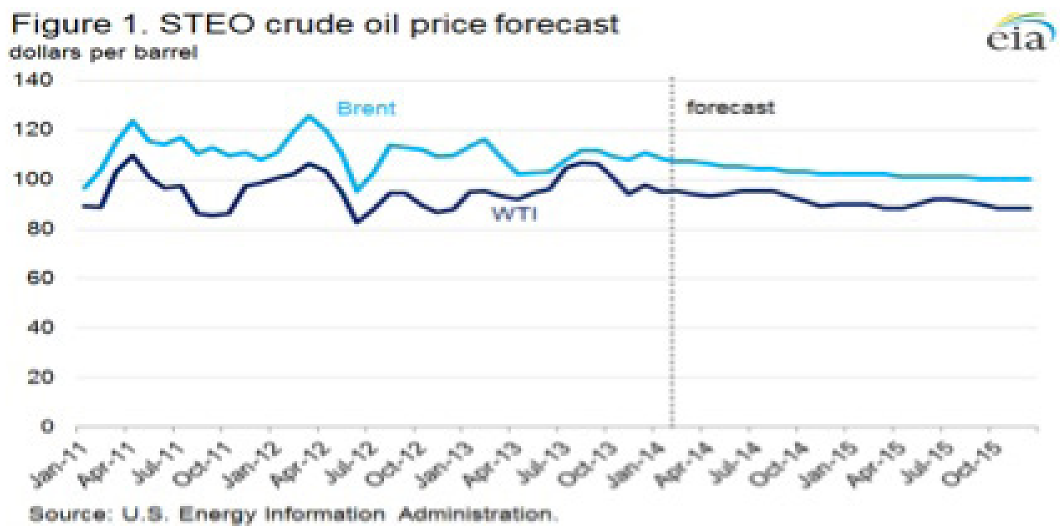
Total liquids fuel consumption in the U.S. increased 2.1% in 2013, with the biggest consumption gain reported by hydrocarbon gas liquids with a 6.4% increase. Meanwhile, motor gasoline reported a 1.1% increase (90,000 bbl/d) in consumption, the biggest increase since 2006. The increase in motor gasoline consumption was fueled by stronger than expected highway travel during the latter half of 2013. Distillate fuel consumption increased 2.5% during 2013 as a result of colder weather coupled with domestic economic growth. For 2014, total liquid fuels consumption in the U.S. is expected to remain flat.

Global consumption grew by 1.2 million bbl/d in 2013 and is expected to grow by a similar pace of 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Countries outside of the Organization for Economic Cooperation and Development (OECD) account for nearly all consumption growth for the next several years. The IEA estimated that the 34 countries comprising the OECD will consume less than half the oil used in the world in 2014. As recently as 2004, their share was over 60%. The projected decline in OECD consumption can be attributed in large part to Japan and Europe.

PRICING

At $111/bbl, Brent crude oil spot prices averaged between $108/bbl and $112/bbl for the sixth consecutive month in December 2013. For the full year 2013, Brent spot prices averaged $109/bbl, down 3% from the prior year. Brent spot prices experienced downward pressure as increasing light sweet crude oil production reduced the need for U.S. imports, thus increasing the supply of Brent crude available on the global market. West Texas Intermediate (WTI) spot prices averaged $98 per barrel in 2013, the highest annual average since 2008 and a 4% increase over 2012. Transportation constraints eased with new pipeline and railroad infrastructure, alleviating some of the downward pressure on WTI.

The spread between West Texas Intermediate (Cushing) and Brent (North Sea) crude represents the difference between two crude benchmarks. Simply put, WTI represents the price oil producers receive in the U.S., and Brent is a leading global price benchmark for Atlantic basin crude oils and represents the price received internationally. Although the two crude oils are of similar quality and theoretically should price closely to each other, the two benchmark prices differed greatly because of a recent production surge in the U.S. resulting in a buildup of crude oil inventories at Cushing, OK, where WTI is priced. With commodity prices remaining fairly stable in 2013, the differential between WTI and Brent crude narrowed as pipelines came online, flow was reversed on existing pipelines to ease bottlenecks, and rail transportation of crude increased in the U.S. The spread between WTI and Brent averaged $18/bbl in 2012 before falling below $4/bbl in July 2013 only to increase to an average of $12/bbl during the fourth quarter of 2013.



Brent crude is expected to average $105/bbl and $102/bbl in 2014 and 2015, respectively, as non-OPEC supply growth exceeds global consumption. Meanwhile, WTI is expected to average $96/bbl in 2014 and $90/bbl in 2015. Although it averaged $7/bbl in March 2014, the discount of WTI to Brent is projected to grow in coming months to an average $9/bbl in 2014 and $11/bbl in 2015, reflecting the economics of transporting and processing the growing production of light sweet crude oil in the U.S. and Canadian refineries. Over the past decade (prior to the shale oil boom), refiners spent billions optimizing plants based on the assumption that crude oil supplies would be getting heavier and more sour. As it turns out, the wrong upgrades were made at the wrong time. After sinking a significant amount of capital to optimize plants for heavy crudes, refineries generally lack the capability to absorb the growing production of light sweet crude oil in North America.

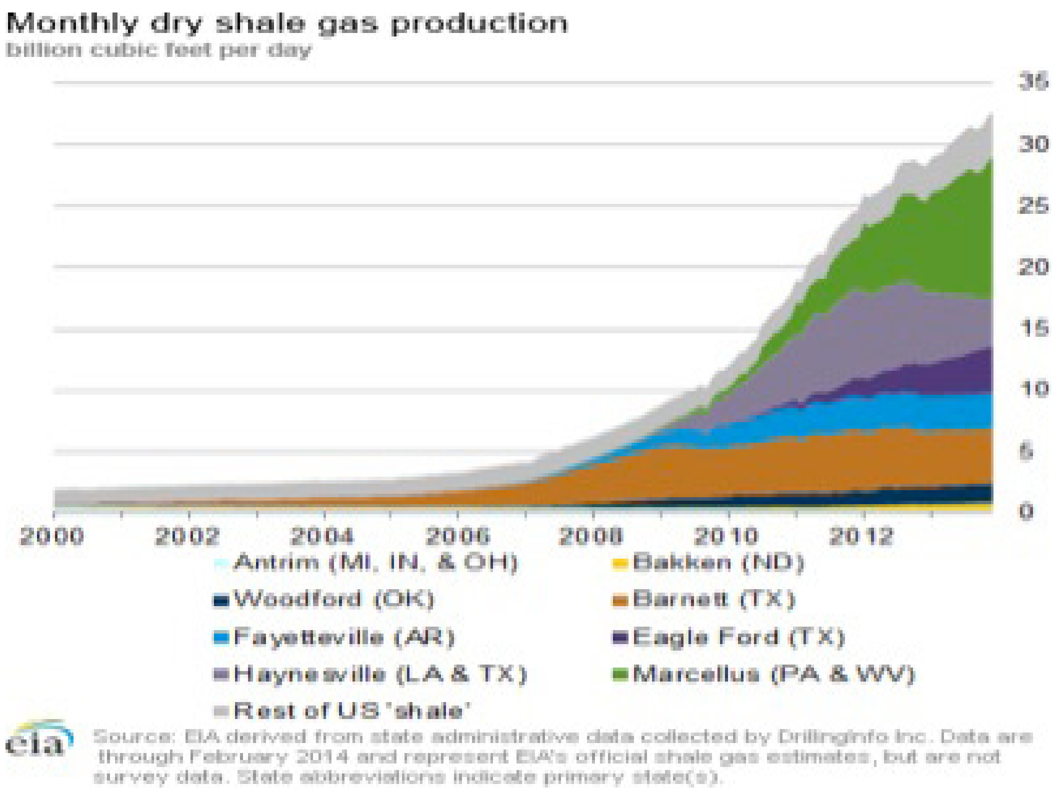
Raymond James predicts global oil supply will continue to outpace demand for the next several years. The United States has provided the most incremental growth over the last five years, a trend that is expected to continue into 2014 and 2015. With anticipated global inventories building by 1.5 MMbpd in 2014, the fundamental oil glut may result in downward pressure on prices. The 2014 price forecast provided by Raymond James indicates Brent will average $102/bbl in 2014, while WTI will average $90/bbl in 2014. Longer term, RJ predicts that the current U.S. supply growth rate will begin to fade, and the global economy will likely gain more traction, resulting in modest price increases in the second half of the decade as global oil demand should begin to outpace global oil supply growth.

NATURAL GAS

PRODUCTION

U.S. dry natural gas production reported moderate growth in 2013, increasing from 65.7 billion cubic feet per day in 2012 to 66.5 Bcf/d in 2013 despite a 35% year-over-year increase in prices. This 1% increase in production represents the lowest annual growth since 2005 and was relatively flat when compared to the 5% and 7% increases reported in 2012 and 2011, respectively. Domestic production has satisfied approximately 88% of U.S. natural gas disposition since 2010. Natural gas imports in the U.S. have continued to decline over the last several years, with nearly 16% of natural gas needs met by imports as recently as 2007. Today, imports serve as a marginal source of supply, primarily during cold weather and pipeline maintenance outages.

The productivity of natural gas wells is steadily increasing in many basins across the U.S. primarily as a result of increasing precision and efficiency related to horizontal drilling and hydraulic fracturing in gas extraction. A number of resource-producing basins are experiencing higher yield over time in natural gas, namely the Marcellus and Haynesville. Although the geology of each resource play is diverse, and individual rig or well performance may vary considerably, drilling activity in the U.S. shale plays is now generally producing greater quantities of natural gas than in the past. The Marcellus Shale is leading in increased production of natural gas per rig, according to EIA. Data shows that a Marcellus Shale well completed by a rig in April 2014 can be expected to yield over six million cubic feet of natural gas per day more than a well completed by that rig in that formation in 2007. Northeastern portions of the basin are leading the growth in production, producing drier gas, where output has benefitted from gathering line and pipeline capacity expansions. Greater levels of natural gas output in the Marcellus Shale were the leading factor in the net increase in national production levels despite decreases in other basins.



With crude prices remaining mostly above $100/bbl, upstream operators were encouraged to target regions with wetter gas and higher returns on investment in 2013. The Haynesville Shale in Texas and Louisiana and the Barnett Shale in Texas are generally considered dry natural gas plays. Production in these shale plays declined by 27% and 9%, respectively, between 2013 and 2012. Meanwhile, the Fayetteville Shale in Arkansas and the nearby Woodford Shale in Oklahoma combined for a 3% production increase in 2013. The Baker Hughes active rig count reported a significant decrease in all four of these basins between 2011 and 2013, but it is important to note that some of the production declines in these fields are the result of normal decline or maturity of existing wells.

Conversely, production activity in wetter shale basins replaced some of the drop-off in production from their drier counterparts. For instance, the Eagle Ford Shale in south Texas averaged daily gas production of 3.3 Bcf/d in 2013, a 54% increase over the previous year. Operators target a combination of crude oil, condensate, and natural gas liquids in the Eagle Ford. Furthermore, production grew by 33% in the Bakken Shale in North Dakota and Montana, where operators predominantly target crude oil. The shift in focus was also evident in terms of the increase in the percentage of new wells that produced both gas and oil. In 2010, roughly 57% of all new natural gas producing wells produced both gas and oil. By 2013, this grew to 68%.

Natural gas marketed production is expected to increase by an average rate of 3.0% in 2014 and 1.5% in 2015, according to EIA's Short Term Energy and Summer Fuels Outlook. Growing domestic production over the last several years has displaced a portion of imports from Canada, while exports to Mexico have increased. United States net imports are projected to total approximately 3.7 Bcf/d in 2014 and 3.0 Bcf/d in 2015, which would be the lowest level since 1987.

CONSUMPTION

Domestic consumption in 2013 increased 2% in spite of the decrease in natural gas consumption for electric generation (power burn) in 2013. Natural gas consumed for electric generation in 2013 was 2.6 Bcf/d lower than the prior year as coal regained some of its market share in response to higher natural gas prices and cooler summer temperatures resulted in reduced total electric generation demand. However, increased winter natural gas demand offset the decline in electric generation, leading to a net increase in consumption for the full year.

EIA projects total natural gas consumption will average 72.1 Bcf/d in 2014, a 0.7 Bcf/d increase over 2013 as a result of increased residential, commercial, and industrial use offsets declines from the electric power sector related to higher natural gas prices. In 2015, total natural gas consumption is projected to decline by 0.4 Bcf/d as reductions in residential and commercial consumption more than offset consumption growth in industrial and power growth sectors.

STORAGE

The U.S. winter withdrawal season, which spans November through March, is a significant driver of natural gas storage levels as higher heating tends to pull down inventory. Natural gas working inventories fell by 97 Bcf to 2,974 Bcf during the week ended December 27, 2013. Increased heating demand associated with colder than normal temperatures during the month prompted sizeable withdrawals, including the highest withdrawal on record (285 Bcf). Natural gas inventory at the end of 2013 was 562 Bcf lower than the prior year and 289 Bcf lower than the five year average for that time of year.

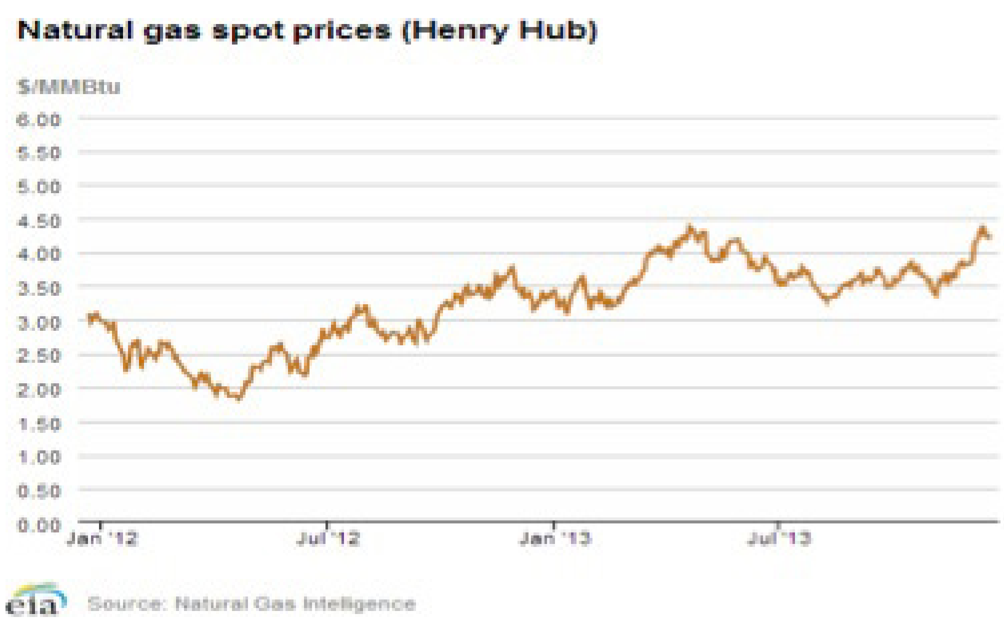
U.S. natural gas producers added more than 35 tcf of reserves in 2013, according to the American Gas Association. Total U.S. reserves were estimated at 330 tcf or more at year end 2013. The majority of reserve additions were associated with unconventional resources, including the Marcellus Shale and the Eagle Ford Shale. Improved prices over the $2.75/MMbtu range seen in 2012 likely contributed to the increased attraction of dry gas plays.

U.S. NATURAL GAS PRICES

Average wholesale (spot) prices for natural gas in the U.S. increased significantly in 2013. Henry Hub prices hit $4.44/MMBtu in mid-December, the highest level since July 2011. The average wholesale price for natural gas at Henry Hub increased to $3.73 per million British thermal unit in 2013. As a result, natural gas prices were roughly $0.50 to $1 per MMBtu higher at the end of 2013 than at the start of the year.

Nevertheless, with the exception of 2012, prices in 2013 were at their lowest level since 2002. Shale gas production over the last few years led to depressed natural gas prices as a record amount of production came online. With natural gas falling below $2/MMBtu in the spring of 2012, many wells became unprofitable to drill, and producers shifted their focus from dry natural gas to wet gas and increasingly into unconventional oil production.

Contracts for future delivery of natural gas rose 26% in 2013, their biggest one year gain since 2005 and the largest percentage gain for any commodity in 2013. The gains appear to be largely weather driven. Following a relatively mild winter in 2012, the 2013 winter started off unusually cold and remained that way for an extended period of time. Additionally, the gas price rebound can be attributed to improved demand growth prospects and the shift in energy companies' focus towards liquids production.



EIA Natural Gas Weekly Update, release date December 19, 2013

One of the keys to gas prices is the amount of gas-to-coal switching needed to fill storage. Historically, there has been a high correlation between year over year changes in gas prices and fuel switching. Natural gas demand may be challenged in 2014 as incremental share gains from coal prove more difficult. If gas prices remain at current levels, the larger and more structural market share gains from the Appalachia coal region may not be repeated in 2014, while the Powder River, Unita, and Illinois basins present opportunities for new coal-to-gas switching. In order to make the switch economical in these areas, it is estimated that gas prices would need to drop below $3/MMBtu.

Future levels of natural gas prices depend on a number of factors, including macroeconomic growth rates and expected rates of resource recovery from natural gas wells. Higher economic growth tends to result in increased consumption of natural gas, causing more rapid depletion of natural gas resources and a more rapid increase in the cost of developing new production, which push natural gas prices higher. The converse is true in low economic growth. Furthermore, as natural gas production is expected to remain buoyant in 2014, a warmer than expected winter withdrawal season may result in supply overwhelming demand and downward pricing pressure.

At the recent 2014 Oil & Gas Investment Symposium, gassier companies in attendance were running their sensitivities around gas in the $4.25-4.50/MMBtu range for 2014 and generally also saw those gas prices holding steady into 2015. Structurally, $4/MMBtu gas appears to be viewed more as a floor than as a ceiling, and the recent performance of gas-leveraged Ultra Petroleum, Comstock Resources, and PetroQuest, among others, appears to support that.

EIA projects that the Henry Hub natural gas spot price, which averaged $3.73/MMBtu in 2013, will average $4.44/MMBtu in 2014 and $4.11/MMBtu in 2015. The Raymond James forecast indicates natural gas prices will average $4.75/Mcf for 2014 and $3.75/Mcf for 2015. Henry Hub averaged $4.95/MMBtu in the first quarter of 2014, the highest quarterly average in four years.

NATURAL GAS PRICE SEASONALITY

North American natural gas markets exhibit seasonality, with generally higher prices in winter because of increased heating demand. However, this seasonal variation appears to be easing. Research indicates that over the past four years, the spread between the natural gas price for delivery in February compared to November has decreased from an average of $0.65/MMBtu in October 2010 to an average of $0.24/MMBtu in October 2013. The price spread represents the market's expectations of prices in the peak winter month compared to prices in an autumn month, with a lower spread indicating less seasonal variation. A number of factors are contributing to the reduction in natural gas seasonality, including:

- Increased natural gas production, particularly in consuming regions like the Northeast, has generally lowered the amount of supply needed to be withdrawn from storage. Net withdrawals from inventory decreased during the winter of 2012-13 compared to the prior winter, despite higher levels of consumption and lower net imports.

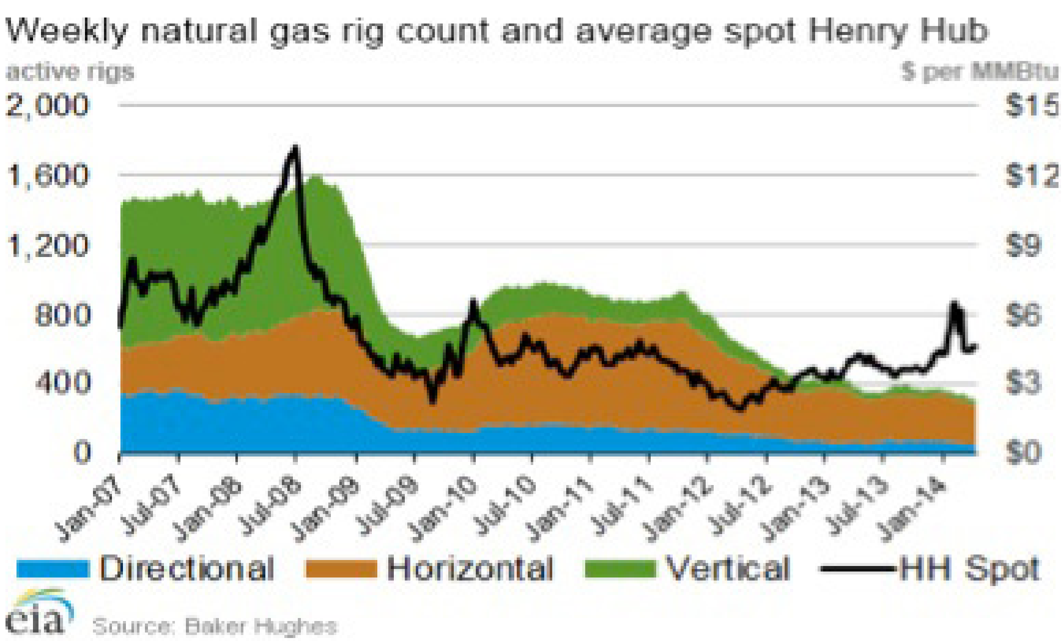
- Gas displacement of coal for electricity generation has reduced seasonality of natural gas in the power sector. However, when natural gas markets tighten, coal-fired power plants become more economically competitive than some of their natural gas-fired plant counterparts, releasing gas to other customers.

- Consumption in November through February as a share of yearly natural gas consumption declined from 41% in 2010-11 to 39% in 2012-13, illustrating the fact that gas consumption is increasing in other months of the year for other uses, such as electricity generation during the summer.

Although the declining spread indicates an expectation for less seasonal variability in natural gas prices, it is important to note that the eventual price will often be determined more by supply and demand when the physical natural gas is sold. Regardless of the short-term factors impacting natural gas prices, long-term trends continue to reduce the seasonality of natural gas markets.

CONTRACT DRILLING

The number of rigs engaged in exploration and production in the U.S. totaled 1,757 as of year-end 2013. This nationwide rig count is more than double the lowest level reached in recent years though it is still below the prior year level of 1,763. Rig count reached a 22-year high in 2008 at 2,031 rigs. According to Baker Hughes, rigs engaged for land operations declined to 1,676 in 2013, while offshore drilling and inland waters activity were relatively flat at 61 rigs and 20 units, respectively. Of the 1,757 rigs at year end 2013, vertical rigs comprised 22% of the total, while horizontal/directional rigs comprised 78%.



EIA Natural Gas Weekly Update, release date April 24, 2014

The natural gas rig count ended the year at approximately 374, with gas directed rigs down 53.9% from the peak in 2012. Furthermore, the year end 2013 gas rig count remained 76% below its all-time high of 1,606 reached in the summer of 2008. Oil rig count, which reached a record high of 1,432 in August 2012, fell to 1,382 by year end 2013.

For decades, one of the most common metrics for estimating crude oil and natural gas production has been rig count. However, in the last few years, oil and gas production continues to flourish even as oil field services company Baker Hughes' reliably predictive rig count declines. New drilling technologies are severing the link between production and rig count as producers are able to drill more wells for every rig. In the past, U.S. producers drilled one well per rig into large, predictable sandstone formations that declined 3% a year on average. Formations in North Dakota's Bakken Shale, by contrast, decline 6% on average every month, driving the need for more timely data.

In an effort to provide data that reflects this change in the industry, the Energy Information Administration, the U.S. Energy Department's independent analytic arm, began issuing a new report in late 2013 in which it combines the rig count with a new calculation that includes the number of wells that each rig drills, the productivity of those wells, and the well depletion rates for the country's six major shale plays. Predicting production trends has become more complex, and it requires an understanding of drilling efficiency measures as operators boost the number of wells they can drill, shorten the time between drilling wells, increase drill hole widths, and extend the reach of horizontal wells. Drilling from temporary rig foundations called pads, for instance, allows rig operators to drill groups of wells more efficiently because improved rig mobility reduces the time it takes to move from one well location to the next while reducing the overall surface footprint. A drilling pad is a location that houses the wellheads for a number of horizontally drilled wells, allowing operators to drill multiple wells in a shorter time frame than they might with just one well per site.

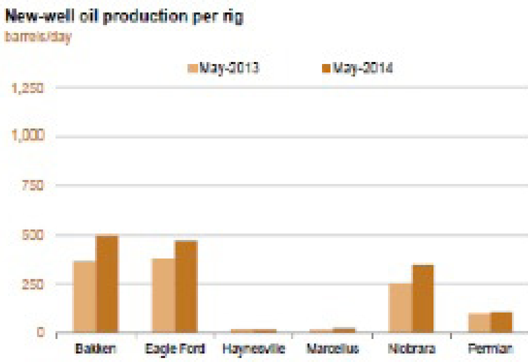
A summary of the April 2014 Drilling Production Report is shown on the following page. The report uses recent data on the total number of drilling rigs in operation along with estimates of drilling productivity and estimated changes in production from existing oil and natural gas wells to provide estimated changes in oil and natural gas production for six key fields. Currently, the EIA focuses on the six most prolific areas, which are located in the lower 48 states. These six regions (Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, and Permian) comprised roughly 90% of domestic oil production growth and virtually all domestic natural gas production in 2011-2012.

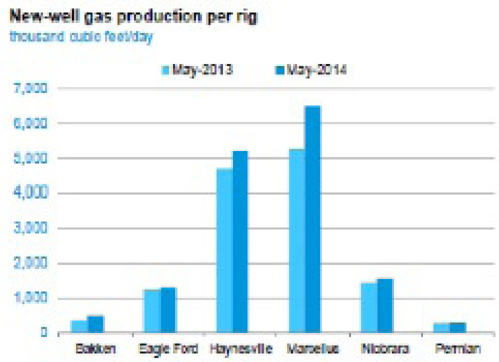
	New-well oil production per rig barrels/day			**New-well gas production per rig** thousand cubic feet/day		
Region	**April 2014**	**May 2014**	**Change**	**April 2014**	**May 2014**	**Change**
Bakken	492	499	7	497	505	8
Eagle Ford	463	470	7	1,279	1,285	6
Haynesville	23	23	-	5,168	5,230	62
Marcellus	30	30	-	6,455	6,501	46
Niobrara	344	352	8	1,540	1,554	14
Permian	109	110	1	273	276	3
Rig-weighted average	259	262	3	1,369	1,343	(26)

Source: EIA Drilling Productivity Report, April 2014

The table above indicates that for the Bakken region, for instance, the new well oil production from one average rig increased 7 bbl/d from April 2014 to May 2014. Overall, month over month new well oil production from one average rig in the six key fields was 23 bbl/d higher in May 2014 than April 2014, while rig count increased by 3. From a gas production standpoint, the rig weighted average for the six regions decreased by 26, while new well gas production from one average rig increased a total of 139 thousand cubic feet per day, month over month.

A comparison of the new well oil and gas production per rig from May 2013 to May 2014 is shown below.





Source: EIA Drilling Productivity Report, April 2014
