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Short-Term Energy Outlook Supplement: Key drivers for EIA's short-term U.S. crude oil production outlook

Crude oil production increased by 790,000 barrels per day (bbl/d) between 2011 and 2012, the largest increase in annual output since the beginning of U.S. commercial crude oil production in 1859. The U.S. Energy Information Administration (EIA) expects U.S. crude oil production to continue rising over the next two years represented in the *Short-Term Energy Outlook* (STEO).

U.S. crude oil output is forecast to rise 815,000 bbl/d this year to 7.25 million barrels per day, according to the February 2013 STEO. U.S. daily oil production is expected to rise by another 570,000 bbl/d in 2014 to 7.82 million barrels per day, the highest annual average level since 1988. Most of the U.S. production growth over the next two years will come from drilling in tight rock formations located in North Dakota and Texas. This paper explains the underpinnings of EIA's short-term forecast for crude oil production.

Increasing tight oil production is driven by the use of horizontal drilling in conjunction with multi-stage hydraulic fracturing, which provides both high initial production rates and high revenues at current oil prices. Additional technological and management improvements have increased the profitability of tight oil production, thereby expanding the economically recoverable tight oil resource base and accelerating the drive to produce tight oil. These technology and management improvements include, but are not confined to:

- Multi-well drilling pads
- Extended reach horizontal laterals up to 2 miles in length
- Optimization of hydraulic fracturing through micro-seismic imaging and enhanced interpretation
- Simultaneous hydraulic fracturing of multiple wells on a pad
- Drilling bits designed for specific shale and tight formations
- "Walking" drilling rigs

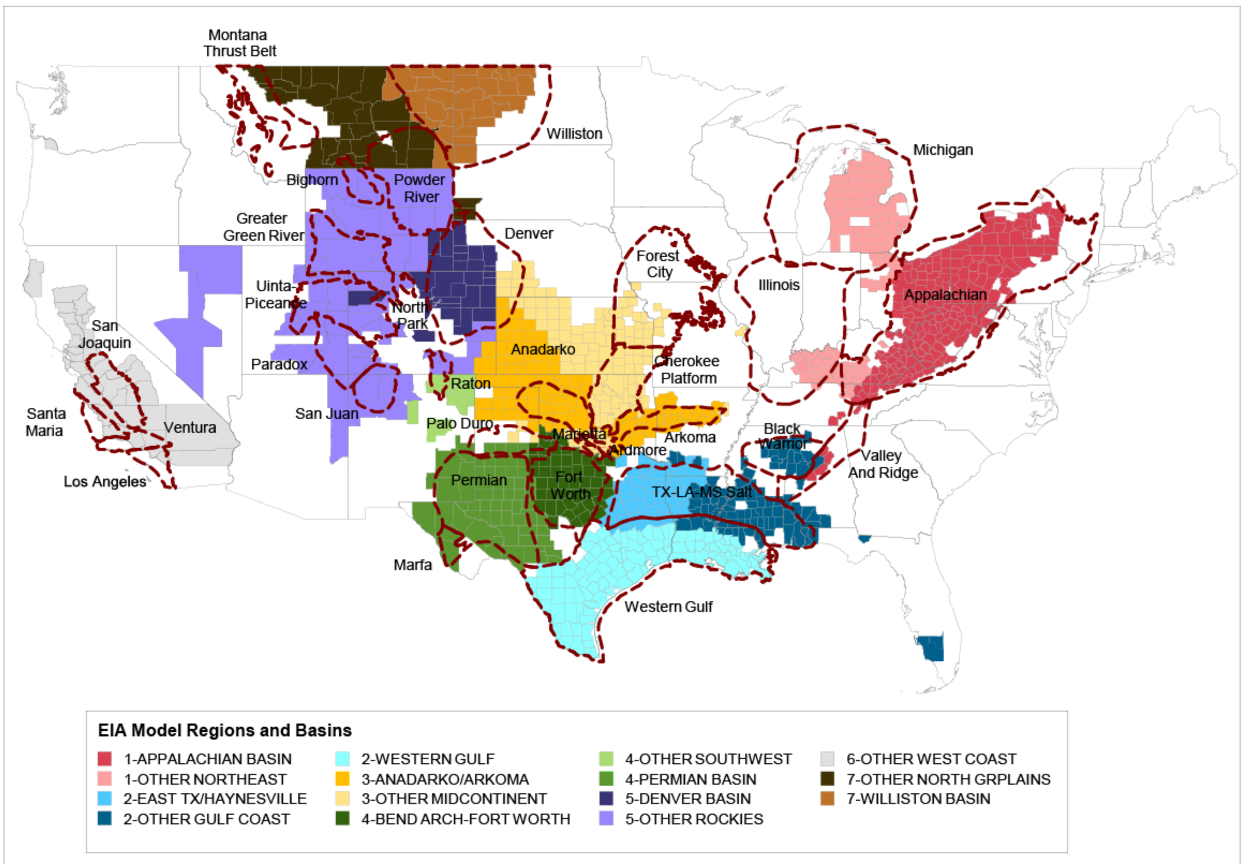
Further improvements in technology, such as selective fracturing along the horizontal lateral (the horizontal section of a well) to avoid zero or low production stages, based on local geologic characteristics, might further improve the economics of tight oil production. Even so, diminishing returns to scale and the depletion of the high-productivity "sweet spots" are expected to eventually slow the rate of growth in tight oil production. It is difficult to predict when that inflection point will be reached because it can be pushed farther into the future by increases in the number of drilling rigs and further technological change.

Overview of the crude oil production forecast

The growth in U.S. crude oil production over the past several years has come largely from onshore basins in which exploration and production (E&P) companies are most active (Figure 1). Currently, the most important basins for production growth are:

- The Williston Basin in North Dakota and Montana, which includes the Bakken Formation
- The Western Gulf Basin in south Texas, which includes the Eagle Ford Formation
- The Permian Basin in West Texas and southeast New Mexico, which includes the Spraberry and Wolfcamp formations[1]

Figure 1. Key onshore crude oil production basins



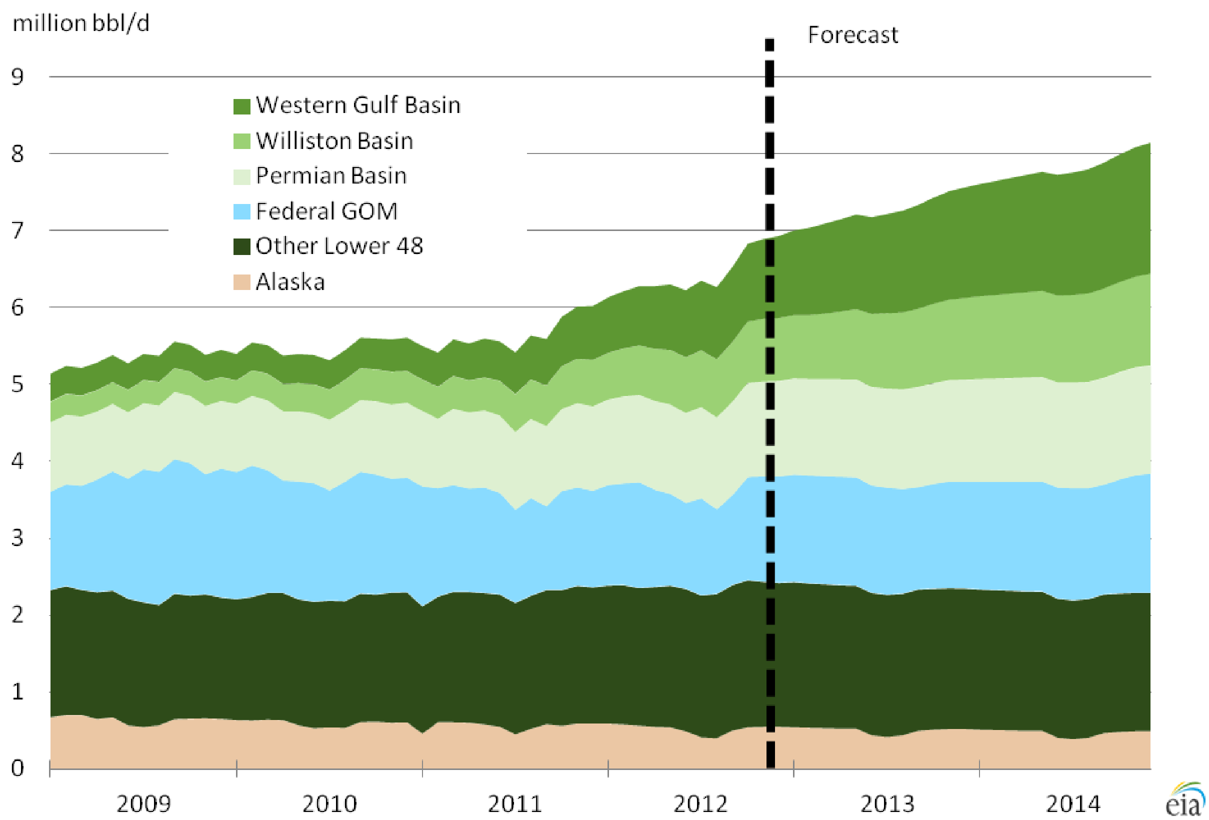
Note: Counties with at least one producing well from 2008 to present are shaded. Basins are represented with dashed outlines. The seven model regions are indentified with leading numbers in legend.
Source: U.S. Energy Information Administration analysis of data from DrillingInfo.

[1] The Denver Basin in Colorado and Wyoming and the Anadarko and Arkoma basins in north Texas, Oklahoma, and Arkansas, while currently producing much less than the other three oil basins, are prospects for significant production growth.

At present, drilling activity is focused mostly on "tight," or very low permeability, geologic formations, including shales, chalks, and mudstones. These formations are particularly attractive because the drilling and fracturing of long horizontal well laterals yields high initial production volumes and, therefore, strong cash flows.

EIA estimates that total U.S. oil production will increase from 6.89 million bbl/d in November 2012 to 8.15 million bbl/d in December 2014 (Figure 2). In the Lower 48 states, excluding the Gulf of Mexico Federal Offshore region (Federal GOM), production is forecast to rise from 4.97 million bbl/d to 6.10 million bbl/d over the same period, representing most of the increase in U.S. oil production. Oil production from offshore fields is expected to resume an upward trajectory as operators intensify exploration and development efforts in the deepwater portions of the Federal GOM. Federal GOM production increases from 1.37 million bbl/d in November 2012 to 1.55 million bbl/d in December 2014. At the same time, EIA expects that the contribution from Alaska and other mature onshore areas in the Lower 48 states will continue to wane over the next two years.

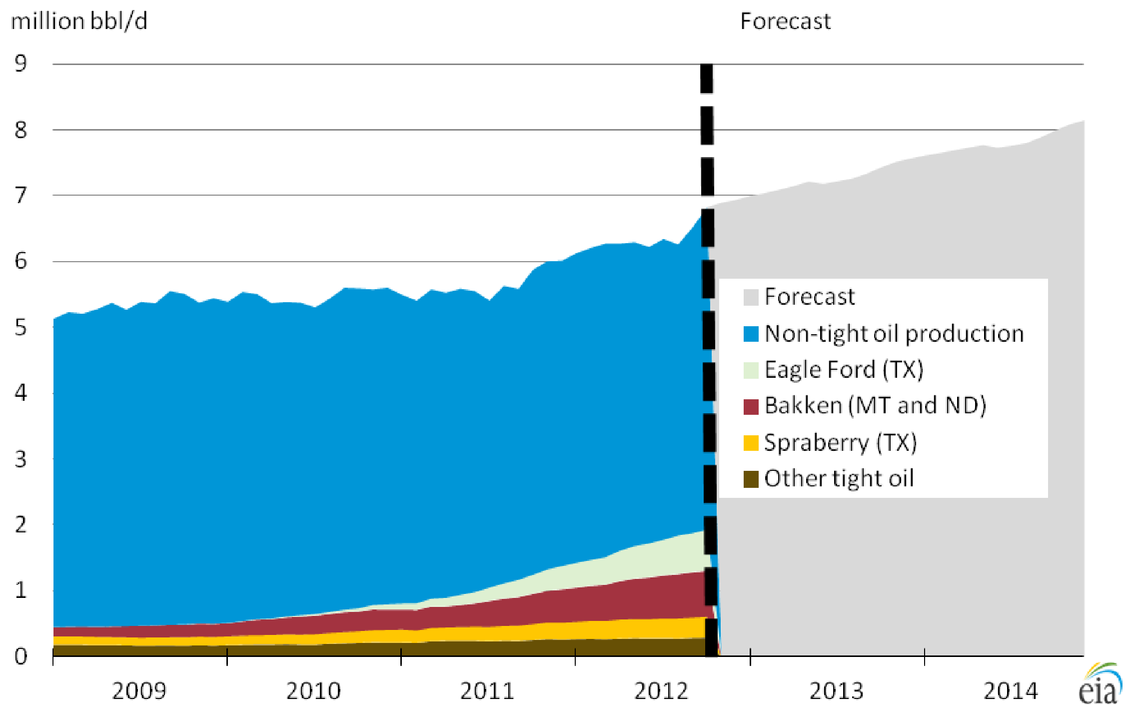
Figure 2. Regional oil production forecasts



Source: U.S. Energy Information Administration (EIA) analysis of data from DrillingInfo, through November 2012. EIA forecast through 2014.

It is expected that E&P companies will continue to focus primarily on existing and emerging tight oil formations where the combination of horizontal drilling and hydraulic fracturing generates high initial production rates. While oil production from other sources will continue to account for most of the country's output, production volumes from tight formations such as the Bakken, Eagle Ford, and Spraberry are forecast to steadily increase tight oil's production share, reaching about one-third of total U.S. oil production by 2014 (Figure 3).

Figure 3. Selected tight oil production history and U.S. oil production forecast



Source: Tight oil production estimated by U.S. Energy Information Administration (EIA) analysis of data from DrillingInfo, through August 2012, U.S. total oil production through November 2012 from EIA, EIA forecast through 2014.

Production growth follows drilling activity

Tight oil production growth is driven by the number of rigs drilling wells, how quickly those rigs can drill a well, how productive each well is initially, and how quickly production from each well declines. Forecasting this growth in production depends both on historical data and assumptions about potential changes to each of these factors.

Drilling activity is a leading indicator of future production growth because it is the most current data available. Drilling activity is measured by the number of rigs actively drilling for oil and/or natural gas within a specific region.

Drilling efficiency, the number of days required to drill a well or the number of wells drilled in a year, quantifies the speed of drilling wells. Drilling wells faster effectively increases the number of rigs. Drilling efficiency is estimated from the number of wells that start production over a certain time period compared with the number of rigs in operation, after accounting for an assumed lag to complete the wells.

EIA uses publicly available weekly and monthly rig counts from Baker Hughes and Smith Bits. This information, in conjunction with data regarding the average number of days a rig takes to drill a single well, provides an estimate of the number of wells that will be drilled and completed over a specific time period for a particular region.

Horizontal drilling and multiple-well pad drilling boost production in tight formations

In some basins, such as the Permian and Denver, producers often drill through, hydraulically fracture, and produce from multiple stacked tight formations, spanning hundreds to thousands of vertical feet. In contrast, producers in the Western Gulf and Williston Basins drill vertically into a single tight oil formation targeted for production, then drill horizontally through the formation. Horizontal wells expose thousands of feet of oil-bearing formation surface to achieve the same effect as fracturing thousands of feet of vertical depth through multiple formations using a vertical well. However, horizontal wells are more expensive.

In those tight oil formations where horizontal drilling is extensive, producers have gradually lengthened the horizontal lateral. In the Bakken, for example, horizontal laterals are now typically 10,000 feet in length with 30 fracturing stages. Long-lateral wells not only help reduce well costs per barrel produced and increase production, they also reduce producer risk by ensuring that a large cross-section of rock is exposed to production. This way, the highly productive stages in a lateral offset its low productivity stages. However, because horizontal laterals are more expensive to drill per foot than vertical well footage, there are diminishing returns to ever longer laterals.

Multiple-well pad drilling, in which multiple wells are drilled from a single surface location, is assisted by the availability of horizontal drilling technology. Multiple-well pad drilling decreases the site preparation and remediation costs associated with single-well drilling pads, while also reducing the environmental impacts with a smaller drilling footprint. Multiple-well pads also allow producers to operate at greater economies of scale because they can handle larger production volumes at a single site, thereby reducing operating and maintenance costs. Another recent time- and cost-saving innovation being employed by tight oil producers is the walking drilling rig, which can move between wells on the drilling pad without having to be disassembled and reassembled.

Lease strategies can also contribute to drilling efficiency

For some tight formations, such as the Bakken and Eagle Ford, where the most desirable acreage has already been leased, producers are now achieving further economies of scale by buying, selling, and trading leases to increase the size of their contiguous lease acreage. This allows their drilling and production crews to operate within fewer and larger leaseholds rather than across a dispersed set of smaller-sized leases. The North Dakota Industrial Commission's unitization of leases in a 1-mile-by-2-mile grid pattern should create long-term infrastructure efficiencies whereby service roads are oriented along the axes.

Future efficiency gains may be more gradual

The well drilling and completion efficiency gains that have been achieved over the last few years not only improve the well profitability of the tight formation sweet spots but also turn portions of the formation that were not previously profitable to produce into profitable acreage. So the net effect of all these efficiency gains is to increase the size of the economically recoverable tight oil resource base.

Although oil producers have greatly improved the economic efficiency of drilling and completing tight oil wells, the rate of change in efficiency improvements is expected to slow down in the future and become more representative of the overall rate of technological improvement experienced by the oil and gas industry as a whole. For example, Bakken well laterals are typically 10,000 feet long with 30 hydraulic fracturing stages; a Schlumberger research report indicates that this is the optimal number of fracturing stages for a Bakken well of that lateral length.[2] The easy improvements in tight oil well drilling and completion efficiency (e.g., longer laterals, pad drilling) have apparently been achieved; therefore, future improvements to existing technology are likely to occur at a more measured pace.

Moreover, as the high-productivity portions of the tight oil formations (i.e., sweet spots) are depleted, drilling activity will have to focus on the less-productive portions of the tight formations, requiring more well completions just to maintain oil production. A slower future rate of technological improvements, combined with drilling activity that moves into less-productive areas, will require the dedication of more drilling rigs either to increase or maintain tight oil production.

Onshore forecast assumptions

EIA's short-term crude oil production model forecasts liquids production in the major onshore basins. In each basin, the number of new oil wells drilled each month is estimated from a forecast of oil-directed rig count and rig efficiency. Rig efficiency, or the number of wells drilled per rig each year, is derived from the recent number of new oil wells starting production in a basin compared to the number of drilling rigs operating in that basin. Forecast rig efficiency also takes into consideration the degree of technological and management improvements that are expected to occur over time.

New well production profiles are also estimated for each basin (Figure 4). Initial well production (IP) rates and monthly decline rates of the new wells are estimated using recent historical data for the wells producing in each of the three key basins. The IP rate is an estimate of the average daily flow rate over the first 30 days the well is flowing. Because some wells come online at the beginning of the first month while others come online in the middle or at the end of that month, the first month of production for the average well is generally half the estimated IP. Subsequent months are full production months, so the second month of production is greater than the first month of production.

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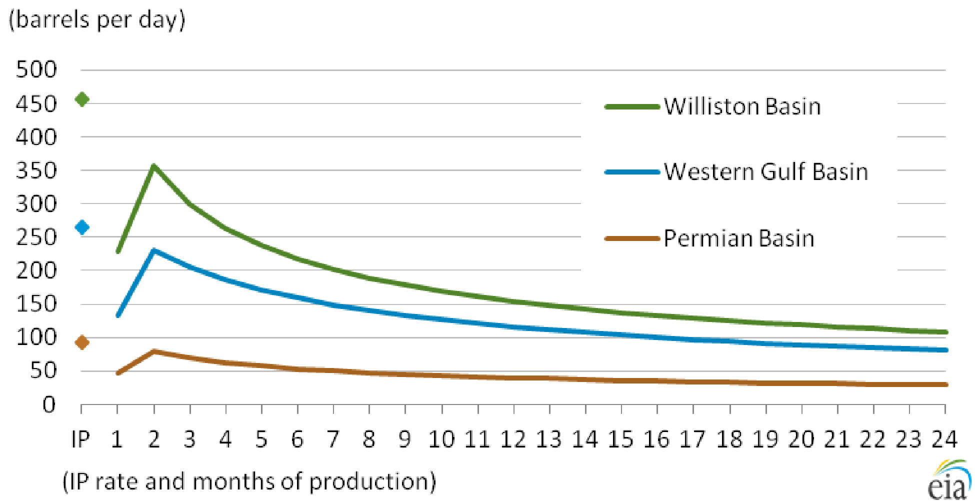
[2] Society of Petroleum Engineers, "Has the Economic Stage Count Been Reached in the Bakken Shale?," by Jason Baihly, et.al., SPE Document Number 159683, presented in Alberta, Canada, September 24-25, 2012.

Figure 4. Production profile of average wells in three key basins, 2011 to present



Source: U.S. Energy Information Administration (EIA) analysis of DrillingInfo data

In the Western Gulf Basin, the rig count declined during the second half of 2012, but is forecast to increase moderately during 2013 and 2014 (Table 1). While a rig typically takes longer than a month to drill a new well, the increased use of pad drilling, as described below, is expected to increase rig efficiency to about one well per rig per month in 2013 and 2014. Based on the rig count rising to about 360 in 2014, about 8,400 total new wells would be drilled in 2013 and 2014 in the Western Gulf Basin.

Table 1. Forecast assumptions for liquids production in three key basins

	2012	2013	2014
Western Gulf Basin			
Average Drilling Rig Count	352	338	361
Rig Efficiency (wells/rig-year)	9	12	12
New Well Count	3,042	4,061	4,337
Well Initial Production (bbl/d)	331	290	269
Production (million bbl/d)	0.89	1.28	1.58
Permian Basin			
Average Drilling Rig Count	506	492	523
Rig Efficiency (wells/rig-year)	10	10	10
New Well Count	5,063	4,925	5,228
Well Initial Production (bbl/d)	93	93	93
Production (million bbl/d)	1.18	1.29	1.37
Williston Basin			
Average Drilling Rig Count	208	196	184
Rig Efficiency (wells/rig-year)	10	12	12
New Well Count	2,079	2,348	2,213
Well Initial Production (bbl/d)	458	435	414
Production (million bbl/d)	0.72	0.95	1.13

Source: U.S. Energy Information Administration

In 2012, the majority of new wells drilled in the Western Gulf Basin were horizontal wells. In 2013 and 2014, the proportion of horizontal wells is expected to increase as the Eagle Ford formation is further developed. As a result, the production profile of an average well in this basin will closely resemble the profile of an Eagle Ford horizontal well, with high initial production rates followed by a steep decline. The IP rate of a Western Gulf Basin well is forecast to be 290 bbl/d in 2013. The IP rate declines to 269 bbl/d in 2014, as some of the Eagle Ford sweet spots are completely drilled and producers move into areas with lower well productivity. Overall, these changes result in Western Gulf Basin oil production increasing from 890,000 bbl/d in 2012 to 1.28 million bbl/d in 2013 and 1.58 million bbl/d in 2014. By December 2014, oil production is forecast to reach 1.71 million bbl/d, making this basin the largest domestic oil producer at the end of 2014.

The Williston Basin, which contains the Bakken formation, is forecast to slow production growth from 2013 to 2014. Similar to the Western Gulf Basin, EIA forecasts rig efficiency to rise to about one well per rig per month through 2014. As the horizontal wells in this region are generally longer than in other regions, and one drilling pad can develop oil from a larger area, rig counts are forecast to decline from an average of 208 rigs in 2012 to about 196 in 2013 and 184 in 2014, with over 4,500 new wells being drilled through 2014.

In the Williston Basin, almost all new wells are horizontal, and this trend will continue in 2013 and 2014. Williston Basin wells have very high IP rates, averaging 435 bbl/d in 2013 and declining to 414 bbl/d in 2014 as the basin's sweet spots are fully drilled. Although Williston IP rates are very high, with fewer wells forecast to be drilled, Williston Basin oil production is not forecast to grow as much as in the Western Gulf Basin. Williston Basin oil production increases from 720,000 bbl/d in 2012 to 950,000 bbl/d in 2013 and 1.13 million bbl/d in 2014, with December 2014 production averaging just under 1.19 million bbl/d.

Winter weather is contributing to a delay in completing wells after they are drilled and thus is currently slowing the growth in Williston Basin oil production. The spring thaw and weight restrictions on roads may also slow production growth. However, once the weather improves, production is forecast to surge as the backlog of wells waiting for completion is worked off.

Permian Basin wells have different production and spacing characteristics than wells in the Western Gulf and Williston basins because of the large proportion of vertical wells drilled in that basin. In 2012, there were an average of 506 rigs in the basin, drilling slightly less than one well per rig per month. Permian Basin production growth is driven by the large number of new wells drilled during 2013 and 2014, with about 10,150 new wells drilled through 2014.

Vertical wells in the Permian Basin have lower IP rates (Figure 4). Forecast new wells in 2013 and 2014 have an average IP rate of 93 bbl/d. Although each well produces less oil initially, the large magnitude of new wells increases production from an average of 1.18 million bbl/d in 2012 to 1.29 million bbl/d in 2013 and 1.37 million bbl/d in 2014. In December 2014, production is forecast to be 1.41 million bbl/d.

Crude Oil Pipeline Infrastructure

The rapid growth of production from tight oil plays in the U.S. mid-continent, as well as the development of oil sands in Canada, have dramatically changed the balance of flows at Cushing, Oklahoma, which was historically the distribution hub of imported and West Texas produced crude oil for Gulf Coast refineries. Over the last three years, pipeline capacity for delivering crude oil to Cushing increased by about 815,000 bbl/d (solid lines on Figure 5). The key development was the construction of the 590,000 bbl/d TransCanada Keystone pipeline that originates in Hardisty, Alberta, Canada. Phase 1 of the Keystone pipeline, which runs from Hardisty to Steele City, Nebraska, and on to Patoka, Illinois, was completed in June 2010. Phase 2 of the Keystone pipeline, which extended the pipeline from Steele City to Cushing, was completed in February 2011.

Table 2. New Pipeline Projects Delivering Crude Oil to Cushing, Oklahoma (2010 – 2012)

Pipeline Project	New Capacity (bbl/d)	In-Service Date	Description
Hawthorn	90,000	Jan 2010	New 17.5-mile, 12-inch pipeline serving rail facility in Stroud, Oklahoma
TransCanada Keystone	590,000	Feb 2011	New pipeline from Nebraska delivering crude oil from Hardisty, Canada and Williston Basin
White Cliffs Pipeline expansion	40,000	3Q 2011	Pipeline from Colorado expanded from 30,000 bb/d to 70,000 bbl/d
Plains All American Medford-to-Cushing conversion	25,000	Jul 2012	Pipeline from Mississippian Lime formation converted from LPG service
Plains All American Basin pipeline expansion	50,000	1Q 2012	Pipeline from Permian Basin expanded from 400,000 bbl/d to 450,000 bbl/d
Parnon Great Salt Plains pipeline	20,000	Oct 2012	New 115-mile, 8-inch pipeline from Cherokee in the Mississippian Lime formation

Source: U.S. Energy Information Administration

Until mid-2012, there was only one pipeline that could deliver crude oil from the Midwest to the Gulf Coast. The 96,000-bbl/d ExxonMobil Pegasus pipeline between Patoka, Illinois and Nederland, Texas originally shipped crude oil northward. The pipeline was reversed in 2006 in order to ship Canadian heavy oil to the Gulf Coast. The growing supply of crude oil into Cushing quickly exceeded the capacity of Midwest refineries to process it. As a result, the 150,000-bbl/d Seaway pipeline carrying imported crude oil from the Gulf Coast to Cushing was reversed in May 2012. Because it takes four years or longer to plan, obtain permits, and build new interstate pipelines, major expansion of new pipeline capacity to deliver the fast-growing mid-continent crude oil production to the Gulf Coast is just now nearing completion. The Enbridge/Enterprise Seaway Expansion brought 250,000 bb/d of new capacity into service on January 11, 2013. A new pipeline with 700,000 bbl/d of capacity is expected to be completed in the fourth quarter of 2013 and an additional 450,000 bbl/d of capacity is expected to be added in 2014 (Table 3).

Table 3. New Pipeline Projects from Cushing, Oklahoma to the Gulf Coast (2013 – 2014)

Pipeline Project	New Capacity (bbl/d)	Planned In-Service Date	Description
Enbridge/Enterprise Seaway expansion	250,000	Jan 11, 2013 completed	Expand existing pipeline from 150,000 bbl/d to 400,000 bbl/d
TransCanada Gulf Coast project	700,000	4Q 2013	New 485-mile, 36-inch pipeline to Nederland, Texas
Enbridge/Enterprise Seaway twin	450,000	1Q 2014	New 512-mile, 30-inch pipeline parallel to existing Seaway pipeline

Source: U.S. Energy Information Administration

In anticipation of the new pipeline take-away capacity from Cushing, 1,225,000 to 1,315,000 bbl/d of new pipeline capacity to deliver crude oil into the Cushing hub is also planned (Table 4).

Table 4. New Pipeline Projects Delivering Crude Oil to Cushing, Oklahoma (2013 – 2014)

Pipeline Project	New Capacity (bbl/d)	Planned In-Service Date	Description
Plains All American Mississippian Lime	175,000	Mid-2013	New 170-mile pipeline from Mississippian Lime formation in the Anadarko basin
SemGroup/Gavilon Glass Mountain	140,000	Fall 2013	New 210-mile, 20-inch pipeline from Mississippian Lime and Granite Wash formations in the Anadarko basin
White Cliffs pipeline expansion	80,000	1H 2014	Expansion from 70,000 bbl/d to 150,000 bbl/d
Enbridge Flanagan South	600,000	Mid-2014	New 600-mile, 36-inch pipeline paralleling existing Spearhead line
Tallgrass Pony Express conversion	230,000 - 320,000	3Q 2014	Convert 430 miles of existing natural gas pipeline from Bakken and Denver-Julesburg basins and construct 260-mile extension to Ponca City, Oklahoma and Cushing, Oklahoma

Source: U.S. Energy Information Administration

Crude oil production in the Permian Basin faces the same transportation constraints as Canadian imports and producers in the mid-continent. Two pipelines currently transport crude oil from the Permian Basin to Cushing: the Plains All American Basin pipeline, which was expanded from 400,000 to 450,000 bbl/d in early 2012; and the 175,000 bbl/d Oxy Centurion pipeline. A third pipeline, the Sunoco Logistics West Texas Gulf pipeline, has the capacity to transport 300,000 bbl/d from the Permian Basin to Longview, Texas, where it connects with the Mid-Valley pipeline to Samaria, Michigan. Because the existing pipelines are nearly fully utilized and deliver crude into the over-supplied Midwest market, six pipeline projects that include pipeline reversals, expansion, and new lines would provide 355,000 bbl/d of new capacity to move crude oil from the Permian Basin to the Gulf Coast in 2013, and 478,000 bbl/d of new capacity in 2014 (Table 5).

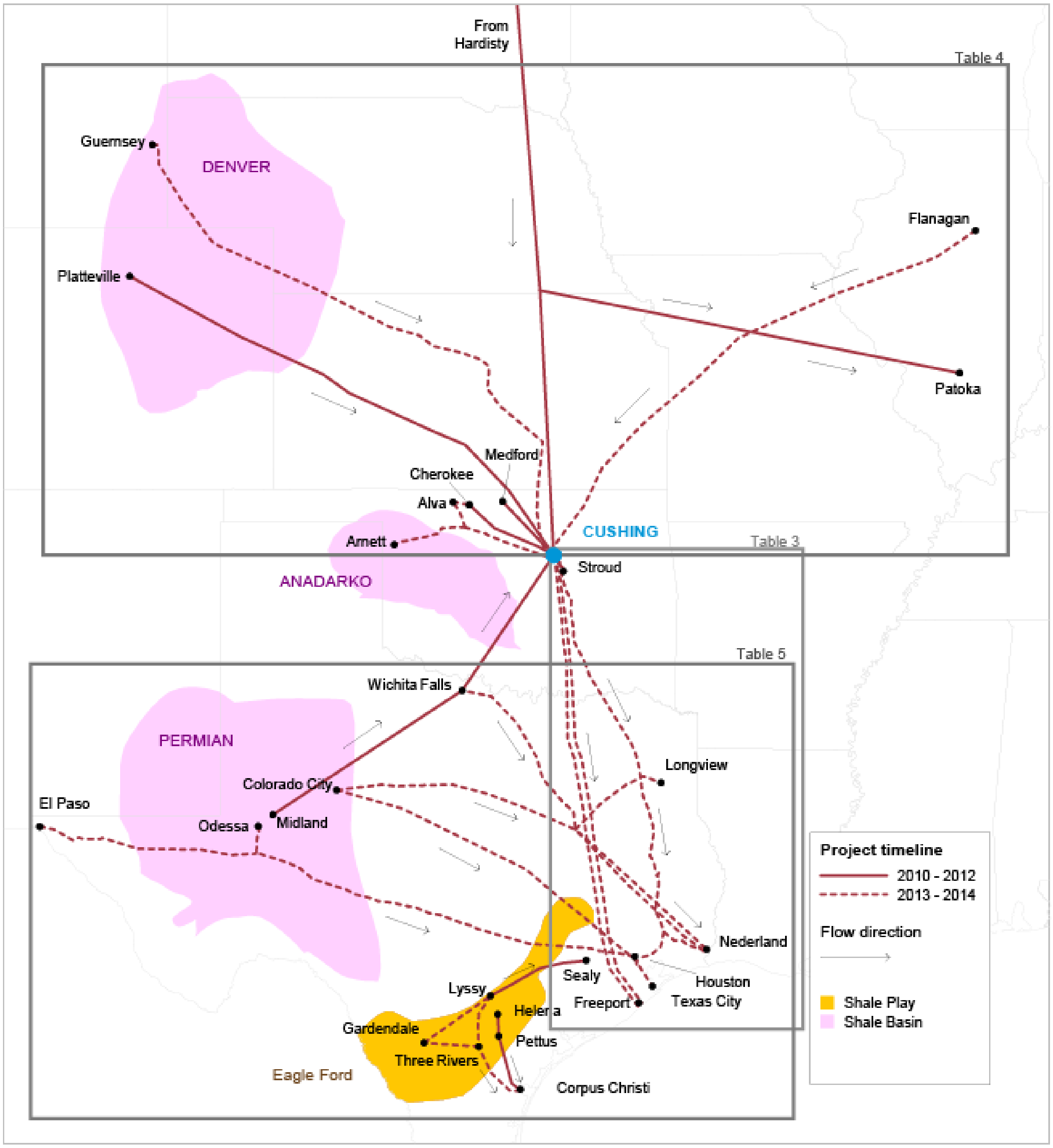
Table 5. Planned New Pipelines from the Permian Basin to the Gulf Coast

Pipeline Project	New Capacity (bbl/d)	Planned Completion	Description
Sunoco Logistics West Texas Gulf	40,000	1Q 2013	Connection, expansion, extension, and reversal of West Texas Gulf pipeline
Magellan Longhorn reversal	135,000	Early 2013	Conversion and reversal of Longhorn refined products pipeline from Crane to Houston, Texas
Magellan Longhorn expansion	90,000	Mid-2013	Expand capacity of the Crane-to-Houston pipeline
Sunoco Logistics Permian Express	90,000	1Q 2013	Reversal of existing pipeline and new pipeline alongside existing West Texas Gulf pipeline. Capacity is expandable to 150,000 bbl/d
Sunoco Logistics Permian Express phase 2	200,000	2H 2014	Expansion of West Texas Gulf pipeline from Colorado City, Texas to Nederland, Texas
Magellan/Oxy BridgeTex	278,000	Mid-2014	New 400-mile pipeline from Colorado City, Texas to Texas City, Texas

Source: U.S. Energy Information Administration

Over the past three years, almost 815,000 bbl/d of new pipeline capacity delivering crude oil to Cushing was added. Over the same period, only 400,000 bbl/d of new pipeline take-away capacity was added. During the next two years an additional 1,190,000 bbl/d of pipeline capacity for delivering crude oil from Canada and the mid-continent to Cushing is planned, but this is balanced by 1,150,000 bbl/d of planned pipeline capacity additions to deliver crude oil from Cushing to the Gulf Coast. In addition, about 830,000 bbl/d of new pipeline capacity is planned to move crude oil from the Permian Basin to the Gulf Coast (Figure 5).

Figure 5. Map of recently completed and planned pipelines in and out of Cushing, Oklahoma and Eagle Ford shale play



Source: U.S. Energy Information Administration

Offshore Federal Gulf of Mexico (Federal GOM)

During 2012, oil production in the Federal GOM is projected to have increased from about 1.31 million bbl/d in January to about 1.39 million bbl/d in December (up 6 percent). This Federal GOM oil production increase was driven by the initiation of production at 13 new deepwater fields with a combined peak production of about 195,000 bbl/d, as well as the restarting of the Mad Dog Field, which had been offline since April 2011 (Table 6).

Table 6. Federal GOM Producing Projects

Project Name	Start	Peak date	Peak mbbl/d
Morgus	Feb-12	Mar-12	7
South Raton	Feb-12	May-12	4
Pyrenees	Feb-12	Mar-12	2
West Tonga	Mar-12	May-12	29
Caesar	Mar-12	Jul-12	20
Cascade	Feb-12	Jun-12	6
Tahiti Phase 2*	Apr-12	Nov-12	30
Wide Berth	Apr-12	May-12	3
Isabela*	Jun-12	Jul-13	18
Santiago*	Jun-12	Jan-13	15
Santa Cruz*	Jun-12	Jan-13	15
Mandy*	Jun-12	Jan-13	11
Chinook*	Jul-12	Apr-13	35

* Expected peak date and production volume

Source: U.S. Energy Information Administration

Also contributing to the increase in 2012 offshore oil production is the start-up of the Tahiti Phase 2 redevelopment project, as well as those deepwater fields that began production in 2011 but continued to increase production during 2012. On an annualized basis, however, Federal GOM oil production for 2012 will likely be below its 2011 level, in part because of the production shut-ins that occurred during Hurricane Isaac. The hurricane also delayed development activities at several locations throughout the Gulf of Mexico, likely pushing some late-2012 scheduled production starts into 2013.

EIA expects Federal GOM production to increase from an average 1.27 million bbl/d in 2012 to an average 1.39 million bbl/d in 2013. Much of that increase is the result of new projects that started producing in 2012 but do not reach peak production until late 2012 or early 2013. Adding to Federal GOM production in 2013 will be a combination of six new field start-ups with a combined peak production of about 45,000 bbl/d, and the Na Kika Phase 3 redevelopment project (Table 7).

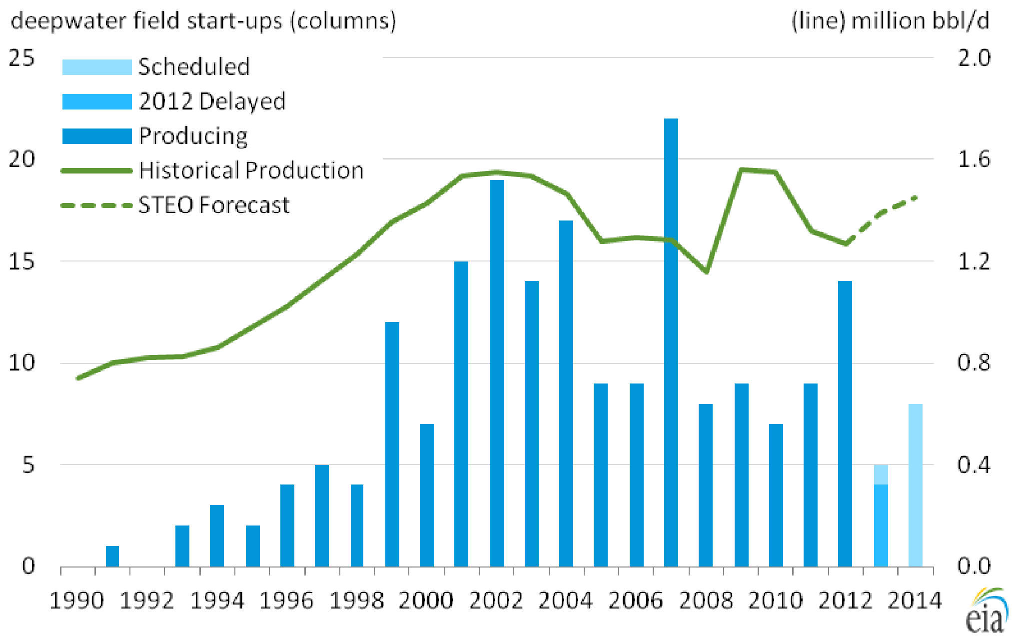
Table 7. Federal GOM Developing Projects

Project Name	Start	Peak	Peak mbbl/d
Clipper	Feb-13	Sep-13	10
Goose	Feb-13	Sep-13	5
Bushwood (Noonan)	Feb-13	Sep-13	1.5
Nancy	Feb-13	Sep-13	0.5
Danny II	Feb-13	Sep-13	3
Knotty Head	Jan-13	Aug-13	25
Na Kika Phase 3	Sep-13	Apr-14	40
Jack	Jan-14	Aug-14	50
St. Malo	Jan-14	Aug-14	50
Entrada	Mar-14	Oct-14	3
Dalmatian	Mar-14	Oct-14	7
Big Foot	Jun-14	Jan-15	50
Tubular Bells	Jun-14	Jan-15	40
Lucius	Sep-14	Apr-15	70
Atlantis Phase 2	Sep-14	Apr-15	50
Hadrian South	Sep-14	Apr-15	5

Source: U.S. Energy Information Administration

Projected Federal GOM production continues to increase in 2014, averaging 1.45 million bbl/d, as several relatively high-volume deepwater projects are expected on stream, including the Jack-St. Malo joint field development, Big Foot, Tubular Bells, and Lucius (Table 7). Also expected on stream during 2014 is the Atlantis Phase 2 redevelopment project. Combined peak oil production could be in the range of 300,000 to 350,000 bbl/d (although later-2013 scheduled start-ups may not reach peak volumes until 2014). The timing and volumetric contribution from these projects is based on publicly available project schedules, but typically the actual project schedules and volumes will likely be different than what is currently projected. Figure 6 shows historical and anticipated future deepwater field start-ups in the Federal GOM, along with oil production over the corresponding period.

Figure 6. Federal GOM: deepwater field start-ups and total oil production



Source: U.S. Energy Information Administration, Bureau of Ocean Energy Management (BOEM), industry reporting.

Alaska

EIA estimated that Alaska oil production was 526,000 bbl/d in 2012. With the exception of the initiation of production at the Point Thomson condensate field in 2014 at 10,000 bbl/d, no new oil projects are expected to begin operations in 2013 and 2014. Overall, Alaska oil production is projected to decline in both 2013 and 2014, with continuing declines in production from existing wells. EIA projects that production will average 504,000 bbl/d in 2013 and 474,000 bbl/d in 2014.