ADDC

Desk and Derrick Journal

Association of Desk and Derrick Clubs

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Greater Knowledge – Greater Service

Inside this Issue

The Desk and Derrick Journal (DDJ) is the official publication of the Association of Desk and Derrick Clubs, an international energy education organization. Byline and credited articles represent the views of the authors. Publication in the DDJ neither implies approval of the opinions nor accuracy of the facts stated. The DDJ is published by the Association of Desk and Derrick Clubs to provide news of ADDC and the energy and allied industries to its members. Bulk mailing rate postage paid at Tulsa, OK.

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The Association of Desk and Derrick Clubs

The Association of Desk and Derrick Clubs (ADDC) is an international educational organization made up of individuals employed in or affiliated with the petroleum, energy, and allied industries.

Our Mission
Our mission is to enhance and foster a positive image to the global community by promoting the contribution of the petroleum, energy, and allied industries through education by using all resources available.

Our Purpose
The Association of Desk and Derrick Clubs (ADDC), an international non-profit organization, is a premier provider of energy education and professional development. ADDC's purpose shall be to promote the education and professional development of individuals employed in or affiliated with the petroleum, energy and allied industries, and to educate the general public about these industries as well as the companies and global communities the members serve.

Front Cover: Stacee Dover, Crude Oil Representative, photographer: We are hands on with crude oil in the Illinois Basin~ literally. A Countrymark Refining and Logistic's Gauger is gauging and certifying an Operators' tank of oil at a lease. A Gauger will check the API Gravity, Base Sediment and Water Contents in order to approve the marketability of the oil to the refinery. Along with the tank strapping and top/bottom measurements, these variables help establish the quantity of crude oil available to be sold. Gauging is a common practice in the purchase of crude oil in the Illinois Basin.

Letter from the Editor

Dear Members,

It is with great pleasure that I welcome you to the DDJ's first issue of 2017!
As we ponder the many changes in our industry, I ask each of you to take a moment today and take inventory of everything that you do in this thing called life! We should not only take inventory of ourselves, but the things that we prepare, publish or even our job performance. God, our family and health should be at the top of our priority list. What are your goals in life? What can we change or do better? You can either move or rust! What is your choice?
Where are, you going? Do you have the plans in place to accomplish your goals? Zig Ziglar [motivational speaker] often said many times during his speech, "If you don't aim for anything, you will hit it every time."
Are you plugged in or unplugged? I love the new age expression; 50 is now the new 40, 60 is now the new 50, and so on! It is never too late to start living and making a difference! No matter where you are, just start! Today is a brand-new day and it's yours! Make the most of it!
I challenge each of you to look within your Club, Region or ADDC to see how you can make a difference by volunteering! Your volunteer job could possibly turn into a new job, passion or purpose!

Peggy Loyd
2017 DDJ Editor

GREATER KNOWLEDGE is GREATER SERVICE.

Peggy Loyd (peggy@cortezoil.com)

ADDC President's Letter
Maggi Franks

Friends and Fellow members,

Through the years, the Desk and Derrick Journal has gone through many changes. We have come a long way from the Oil & Gas Gal that we once were; we have grown. Each editing team, each President put their own unique fingerprint on the publication. This year is no different.

The DDJ is no longer the only publication provided by the Association. In 2013 the Insight was born. It has become a means to provide information to membership on a timelier basis. In response to that, Editor Peggy Loyd suggested that we move away from using the DDJ as a newsletter, and start treating it as an industry magazine. The "New and Improved" magazine will have articles and industry information from not only the US and Canada, but from across the globe.

Peggy is working closely with Wayne Ammons and Mark Loch the co-editors of the Insight. Together our team will ensure that members are receiving current, accurate, and vital information from the Association, the Oil and Gas industries and all of the energy industries. Articles relating to ADDC activities, events, and member issues should be sent to Wayne and Mark at ADO. Industry news, changes, and suggestions for industry articles should go to Peggy.

By offering information on advances in the industry, the DDJ is becoming another venue for members to receive educational information. Share it with your co-workers, and your employers. In this magazine, you will be able to learn something new about fracing, about the Keystone pipeline, and something about industry activities in Russia. Where else can you find such diverse information about Energy?

Did you remember that you can advertise in the DDJ? The committee is diligently seeking advertisers. As this publication transitions into a platform for industry news, what better way to inform readers of what your company has to offer? Many of us own or are employed by small businesses. These businesses were hit hard by the down turn in the industry, and had to tighten their belts. The DDJ offers advertising at nominal fees.

Please enjoy this first issue of the Desk and Derrick journal. I hope you find it as educational and informative as I do.

Maggi Franks
2017 ADDC President

Maggi Franks

Border Tax Ideas Send Oil Market Into Tizzy

By Liz Hampton and Catherine Ngai - Reuters - Friday, January 27, 2017

As with many industries now fretting over the uncertain future of U.S. trade policy, the oil business is sizing up the potential impact of the various protectionist measures being bandied about Washington that have sent crude markets into a tizzy. The trade proposal with the most momentum may be the controversial tax reform, pushed by Republicans in Congress, that could slap a tax of up to 20 percent on all imports, including crude oil. That would spark a rise in fuel costs across the country that would hurt East and West Coast refiners more than those near the Gulf of Mexico. It would also hit the pocketbooks of drivers and airline passengers, as refiners pass on the nearly $30 billion that the tax could cost them each year on crude imports. "The consumer is really the one that suffers," Cynthia Warner, executive vice president for operations at refiner Tesoro Corp, said earlier this month at a conference in Houston. Tesoro operates seven refineries: two in California, two in North Dakota and one each in Utah, Alaska and Washington.

The "border adjustment" tax could also redraw trade maps for global flows of crude and refined products. U.S. crude producers would be the obvious beneficiaries as their overseas rivals bear heavy taxes on imports, which are used often by coastal refiners, especially those without direct access to U.S. pipelines. Higher prices for domestic crude would make pumping from more U.S. fields economically viable - encouraging higher output from the shale patch and giving more momentum to a nascent recovery in the U.S. shale industry after a brutal international price war. While that likely would not put a big dent in the 7.9 million barrels per day (bpd) that the U.S. imports, Goldman Sachs estimates that U.S. oil exploration and production firms would benefit to the tune of $20 billion from higher domestic crude price and increased production.

Crude markets have been buffeted by the public back-and-forth between President Donald Trump and the Republican party over various tax proposals. Contradictory signals from Trump sent the oil markets up and down in recent days. U.S. crude fell to its biggest discount to Brent crude in five months last week after Trump appeared to poured cold water on the idea as "too complex". The next day, he said the tax would be discussed - and U.S. crude rose relative to Brent. Traders had speculated on the tax with an options bet that the value of U.S. crude would rise above the global Brent crude benchmark. Trump's comments caused volatility in trade of those options, which in turn impacted benchmark oil prices.

Investment bank Goldman Sachs estimated in a report this week the border tax proposal had a 20 percent

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chance of passing. But White House chief of staff Reince Priebus seemed to move the President closer to supporting the border adjustment tax on Thursday, in the context of discussing how to make Mexico pay for a security wall on U.S. border with Mexico, his signature campaign promise. Asked if Trump favored a border adjustment tax, Priebus said such a tax would be "one way" of paying for the border wall.

$30 BILLION IN IMPORT COSTS

Border taxes are part of a broader tax reform plan that is being pushed by Republican House Speaker Paul Ryan as an alternative to a variety of protectionist trade policies discussed in a more ad hoc way by Trump. While Trump has threatened to impose tariffs on specific industries or countries in an effort to boost U.S. manufacturing, Ryan's border adjustment tax would tax all imports at 20 percent. Exports would be tax-free. That could add more than $30 billion to the annual import bill for U.S. refiners, assuming an oil price of $53 per barrel on the 7.9 million bpd of imports that fuel the world's largest economy.

A steep rise in import costs would squeeze the margins of refiners dependent on foreign crude shipments such as Chevron and PBF Energy. But all refiners would see feedstock prices rise if the tax pushed up domestic crude prices - and it would, because there is not enough U.S. crude to meet demand.

To cover the costs to refiners, retail gasoline prices would need to increase by 13 percent, or 30 cents a gallon, energy consultant Philip Verleger estimated in a report last month. Diesel would rise by 11 percent, or 27 cents a gallon. That would be the equivalent of adding $300 to $400 per year to the average consumers' gasoline tab, Barclays Capital said earlier this month.

Aside from oil refiners, automakers and retailers oppose the tax. Those against the measure include billionaire industrialists Charles and David Koch, who spend heavily to support Republican candidates and conservative policies and own a refinery that imports crude.

Republicans, who now control the House and Representatives and the Senate, say that if U.S. companies want the lower corporation tax from its current level of 35 percent - a move supported by both Trump and Ryan - then they have to accept the border tax on imports.

COSTS FOR COASTAL REFINERS

The refining industry as a whole opposes the tax, which would separate it from the global oil marketplace. But East and West Coast refiners have more reason to worry. Coastal refiners import more foreign oil and typically have a competitive advantage over inland counterparts in accessing imports because they can buy a wider range of crude oil in various qualities. That advantage would evaporate with the tax.

"Anybody who is importing crude and not exporting very much - mostly refiners on the East and West Coasts - is going to be in a worse position," said Sandy Fielden, director of oil and products research at Morningstar. "Their raw material cost will have gone up, and that will eat into their margins."

Chevron, which operates two refineries in California with capacity of more than 500,000 barrels per day, is the largest importer of foreign crude, according to government data from 2016. For the first ten months of 2016, Chevron imported some 213 million barrels, excluding Canadian imports. That's followed by Valero Energy, which imported 194 million barrels, and Phillips 66, which imported 130 million barrels. Phillips 66 said it was analyzing the potential impacts of such a law, while Chevron, Valero and PBF Energy did not respond to requests for comment.

West Coast refiners may feel the pinch less than those on the East Coast, because they have access to Alaskan crude cargoes. U.S. Gulf refiners would be on the best footing, traders say, because of their easy access to domestic and foreign supplies and proximity to export markets for tax-free fuel shipments out.

DON'T HOLD YOUR BREATH FOR $70 OIL

By Art Berman for Oilprice.com

It is more likely that oil prices will fall below $50 per barrel than that they will continue to rise toward $70. Prices have increased beyond supply and demand fundamentals because of premature expectations about the effects of an OPEC production cut on oil inventories.

Last week's 13.8 million barrel addition to U.S. storage was the second largest in history. It moved U.S. crude oil inventories to new record high levels.

Meanwhile, 130 horizontal rigs have been added to tight oil drilling since the OPEC cut was first announced in September. That means that U.S. output will surge and will continue to be a drag on higher prices.

Comparative inventory analysis suggests that the current ~$53 per barrel WTI oil price is at least $6 per barrel too high. Don't hold your breath for $70 oil prices.

INVENTORY IS THE KEY

Most analysts believe prices will increase steadily now that OPEC has decided to cut production. Their logic is that over-production caused lower oil prices and lower output should bring markets into production-consumption balance.

The problem is that production is not the same as supply and consumption is not the same as demand. Inventories lie in-between and modulate the flows from both sides of the production-consumption equation.

Inventory is clearly part of supply but is also a component of demand. Excess production goes into inventory when demand is less than supply. When consumption exceeds production, oil is withdrawn from inventory reflecting increased demand.

The International Energy Agency (IEA) reported last week that global liquids markets would move to a supply deficit by the first quarter of 2017 if OPEC production cuts take place as announced (Figure 1).

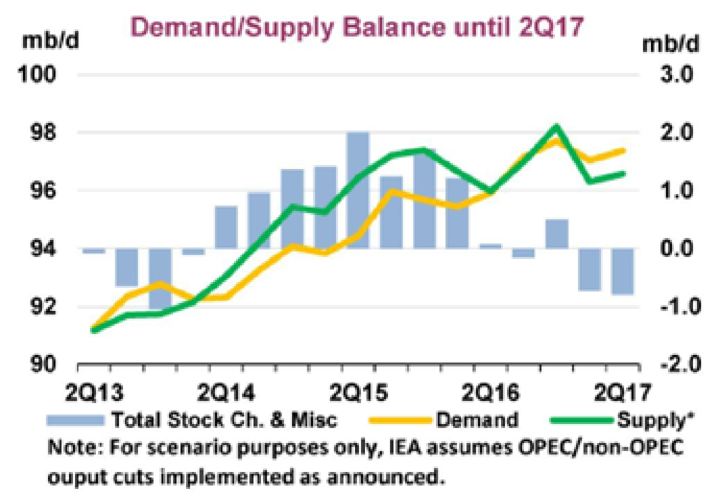

Figure 1. IEA Demand/Supply Balance until 2Q17. Source: IEA February 2017 Oil Market Report.

Yet the OECD inventories on which IEA's forecast is based have increased and are now more than 400 million barrels above the 5-year average (Figure 2). In order for a supply deficit to develop in the first quarter of 2017, those stocks would have to be drastically reduced over the next 6 weeks. Comparative inventory analysis provides some context for the necessary magnitude of that reduction.

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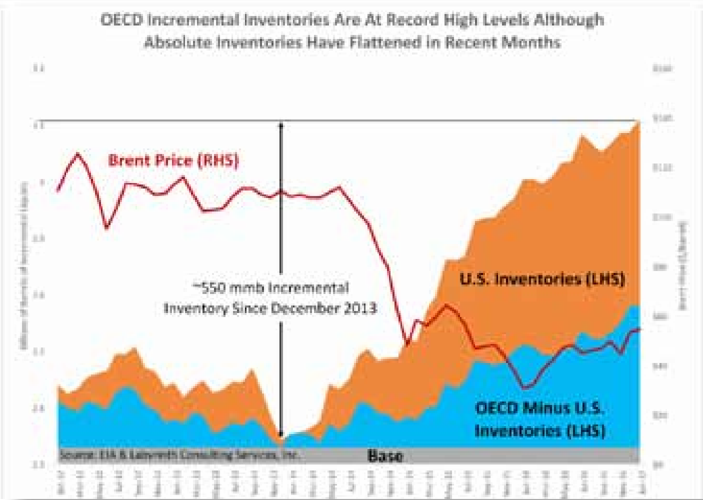

Figure 2. OECD Incremental Inventories Are At Record High Levels Although Absolute Inventories Have Flattened in Recent Months. Source: EIA and Labyrinth Consulting Services, Inc.

Comparative inventories index current storage levels against a moving average of values for the same calendar date over the previous 5 years. This provides the most reliable way of understanding oil-price trends by normalizing stock changes for seasonal variations and comparing them with 5-year average values.

Figure 3 shows that current OECD comparative inventories (C.I.) are at an all-time high level of more than 300 million barrels (absolute inventories are 3.1 billion barrels).

C.I. values around zero (+/- about 50 mmb) correspond to periods of high oil prices (>$80 per barrel) over the past decade. That suggests that comparative inventories need to fall approximately 200 to 300 million barrels to support $70 to $80 per barrel oil prices.

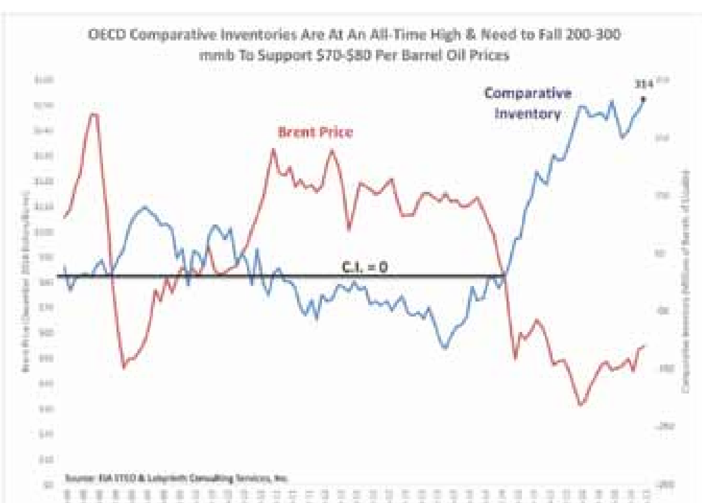

Figure 3. OECD Comparative Inventories Are At An All-Time High & Need to Fall 200-300 mmb To Support $70-$80 Per Barrel Oil Prices. Source: EIA STEO and Labyrinth Consulting Services, Inc.

What IEA is apparently showing in Figure 1 as a "demand/supply balance" is really a demand/production balance. If OPEC cuts move forward as announced, consumption will exceed production in the first two quarters of 2017 and withdrawals from storage will occur. That is a legitimate demand increase.

The billions of barrels of working capacity remaining in inventory are not considered supply in this calculation of balance. That distorts the supply-demand relationship.* At the very least, it does not treat that the ~550 million barrels of incremental inventory that has accumulated since December 2013 in Figure 2 as supply.

Inventory is like a savings account for oil. It may be in a separate account from checking but it is part of total available supply. This sort of confusion over definitions of supply and demand is easily avoided by considering comparative inventories.

RELATED: IS $60 OIL WITHIN REACH?

Figure 4 is a cross-plot of OECD comparative inventories and Brent prices. It shows that current prices of ~$55 per barrel are approximately $10 per barrel over-valued compared to the trend line. It further shows that comparative inventory levels must fall ~200 million barrels to support ~$70 per barrel oil prices.

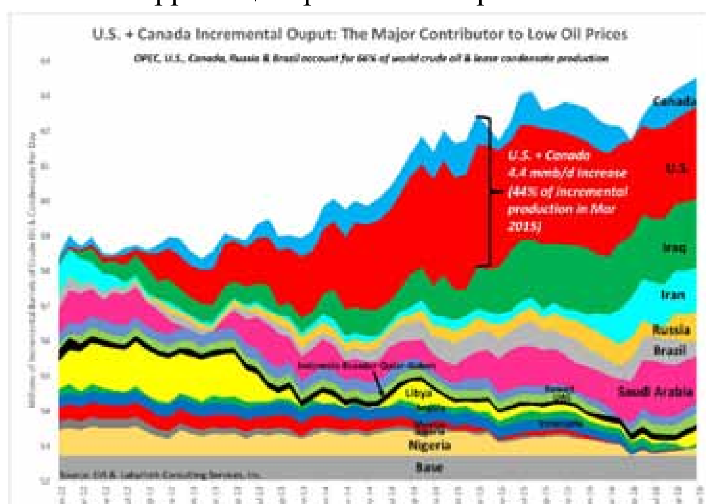

Figure 4. OECD Comparative Inventories At Record Highs–Comparative Inventory Suggests That Current Prices Are ~$10/Barrel Over-Valued. Source: EIA and Labyrinth Consulting Services, Inc

Movement toward market balance cannot help but accelerate as a result of OPEC production cuts. Still, the massive stock reductions necessary to support higher oil prices will only occur over a much longer period.

It will take at least a year to reduce OECD inventories 400 mmb down to the 5-year average. This assumes that

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all OPEC cuts take place as announced and continue beyond the 6-month term of those agreements. It also assumes that non-OPEC production declines or at least remains static.

U.S. PRODUCTION WILL NOT REMAIN STATIC

It is worth recalling that over-production by the U.S. and Canada was the trigger for the global oil-price collapse in 2014 (Figure 5). These two countries accounted for almost half (44%) of the incremental increase in crude oil and lease condensate production in the world as of March 2015 peak production levels.

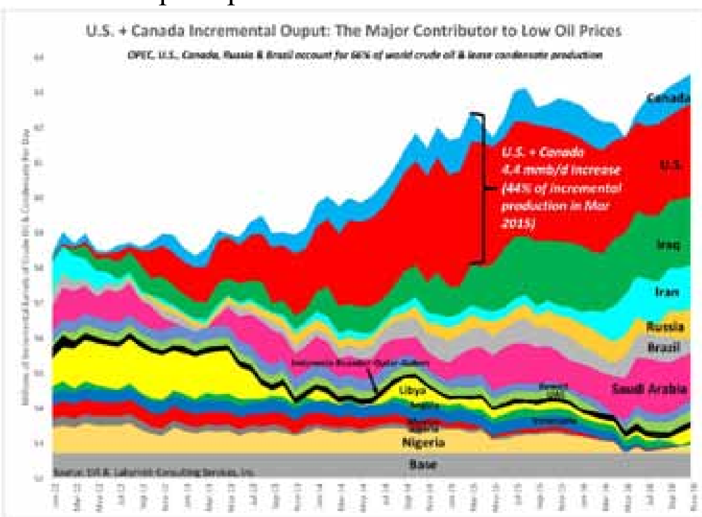


Figure 5. U.S. + Canada Incremental Ouput: The Major Contributor to Low Oil Prices. Source: EIA and Labyrinth Consulting Services, Inc.

U.S. production fell more than 1 million barrels per day (mmb/d) from April 2015 through September 2016 but is now recovering because of higher oil prices (Figure 6). EIA forecasts that field production will increase to 9.28 mmb/d by the end of 2017 and will reach almost 10 mmb/d by December 2018.

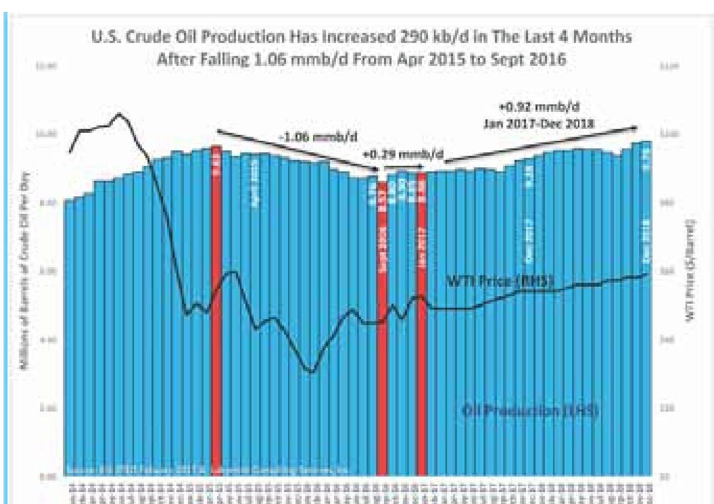
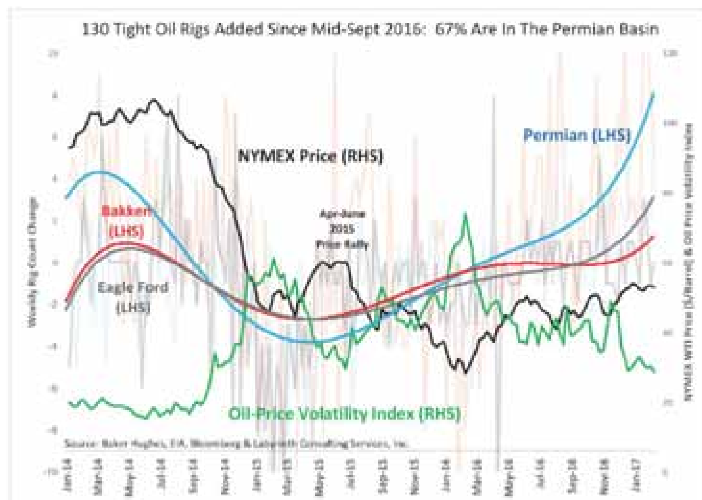


Figure 6. U.S. Crude Oil Production Has Increased 290 kb/d in The Last 4 Months After Falling 1.06 mmb/d From Apr 2015 to Sept 2016. Source: EIA February 2017 STEO and Labyrinth Consulting Services, Inc.

EIA does not predict that WTI oil prices will exceed $60 per barrel throughout this 2-year period. It is interesting to note that EIA shows prices falling below $50 per barrel in February 2017 and remaining at that level through mid-year.

RELATED: ENERGY STORAGE SET TO BOOM IN 2017

After OPEC announced that a production cut agreement was evolving in September 2016, the U.S. horizontal tight oil rig count accelerated. Since then, 130 rigs have been added and 67% have been in the Permian basin tight oil play (Figure 7). In recent weeks, the Eagle Ford play rig count has made impressive gains and the Bakken rig count has steadily increased also.



This reflects a massive flow of capital into these plays that will certainly result in production increases. Approximately $10 billion was spent in 2016 on Permian basin drilling and completion costs for horizontal tight oil wells. An additional $28 billion was spent on Permian land acquisitions.

DON'T HOLD YOUR BREATH FOR $70 OIL PRICES

Traders, analysts and the press have consistently looked for every possible reason to anticipate higher prices since the collapse in 2014. Expectation of an OPEC production cut or freeze has provided an artificial lift to oil prices for at least a year and now, probably accounts for at least $6 per barrel of current $53 per barrel NYMEX futures prices.

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A recent Wall Street Journal article noted a new record in long crude oil futures positions during the last week in January. It went on to speculate that this meant a possible end to the over-supply of oil and that prices should increase.

That observation is not supported by history. In fact, record long positions are commonly followed by a drop in oil prices. Notable examples shown in Figure 8 include price declines around the 2008 Financial Collapse, the 2014 world oil-price collapse, and the brief rally to $60 prices in the Spring of 2015.

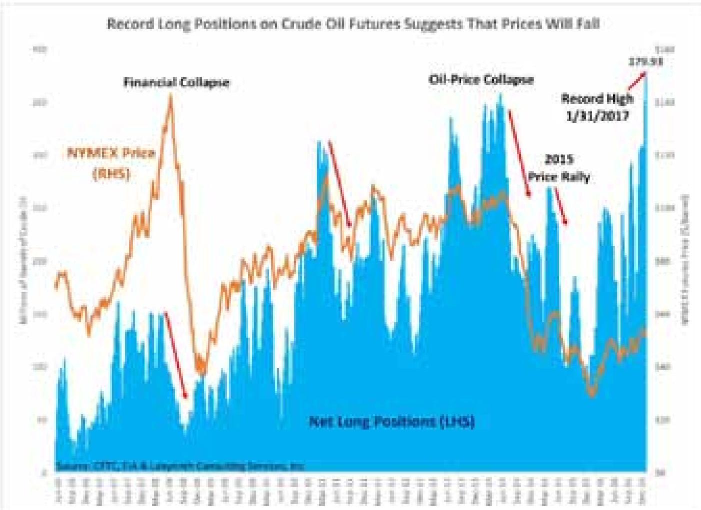

Figure 8. Record Long Positions on Crude Oil Futures Suggests That Prices Will Fall. Source: CFTC, EIA and Labyrinth Consulting Services, Inc.

Inventory data provides compelling evidence that present oil prices are over-valued. Last week, 13.8 million barrels (mmb) were added to U.S. crude oil storage. That's the second highest weekly addition ever--the highest was 14.2 mmb on October 28, 2016 when WTI prices were about $5 per barrel lower.

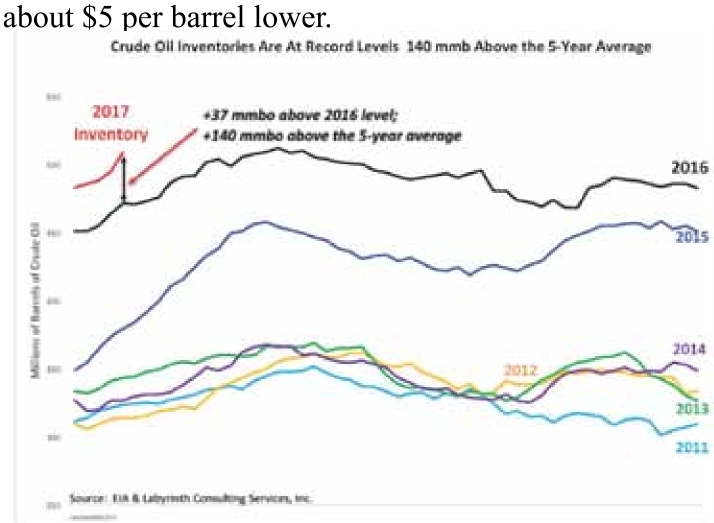

Figure 9. Crude Oil Inventories Are At Record Levels 140 mmb Above the 5-Year Average. Source: EIA and Labyrinth Consulting Services, Inc.

Comparative inventories are also near record highs (Figure 10). When C.I. was at this level in March 2016, WTI prices were around $39 per barrel. When C.I. was slightly lower in August 2016, prices were about $47 per barrel. The trend line in Figure 10 shows that oil prices are probably about $6 or $7 per barrel over-valued.

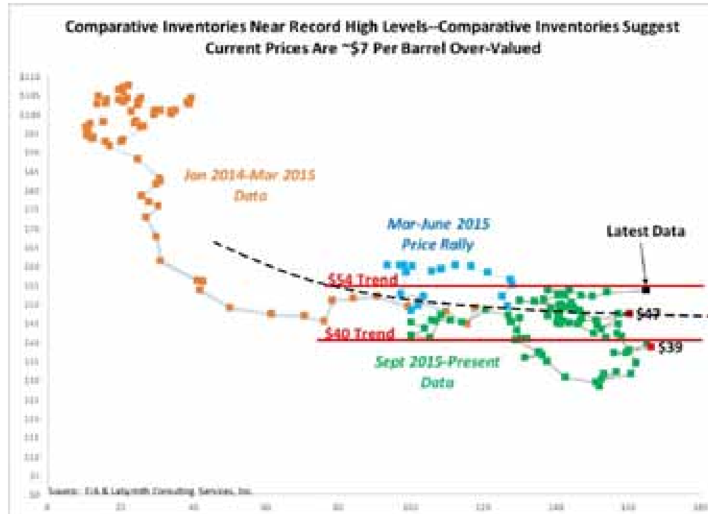

Figure 10. Comparative Inventories Near Record High Levels--Comparative Inventories Suggest Current Prices Are ~$7 Per Barrel Over-Valued. Source: EIA and Labyrinth Consulting Services, Inc.

Oil prices do not always reflect underlying fundamentals but markets eventually adjust because of them. Comparative inventory analysis suggests that current oil prices are over-valued. It is possible that markets have already priced in anticipated uplift from OPEC production cuts. If so, prices may not increase much beyond present levels and expectations of $70 prices any time soon are improbable.

OPEC cuts have almost certainly put a floor under oil prices but volatility will continue to characterize markets as it has for the past 2 years. U.S. production is a wild card that will almost certainly be a drag on upward price movement. My guess is that WTI prices are likely to move below $50 per barrel until effects of OPEC production cuts are reflected in falling global inventories.

To its credit, IEA shows 2016 inventory declines reaching the maximum levels of the 2011-2015 average. That doesn't change the fact that current stock levels are 400 mmb above the 2012-2016 5-year average. That's why comparative inventories are essential.

TransCanada Tries Again for Nebraska's Approval of Keystone Pipeline

By LYNN COOK
Updated Feb. 16, 2017 6:13 p.m. ET

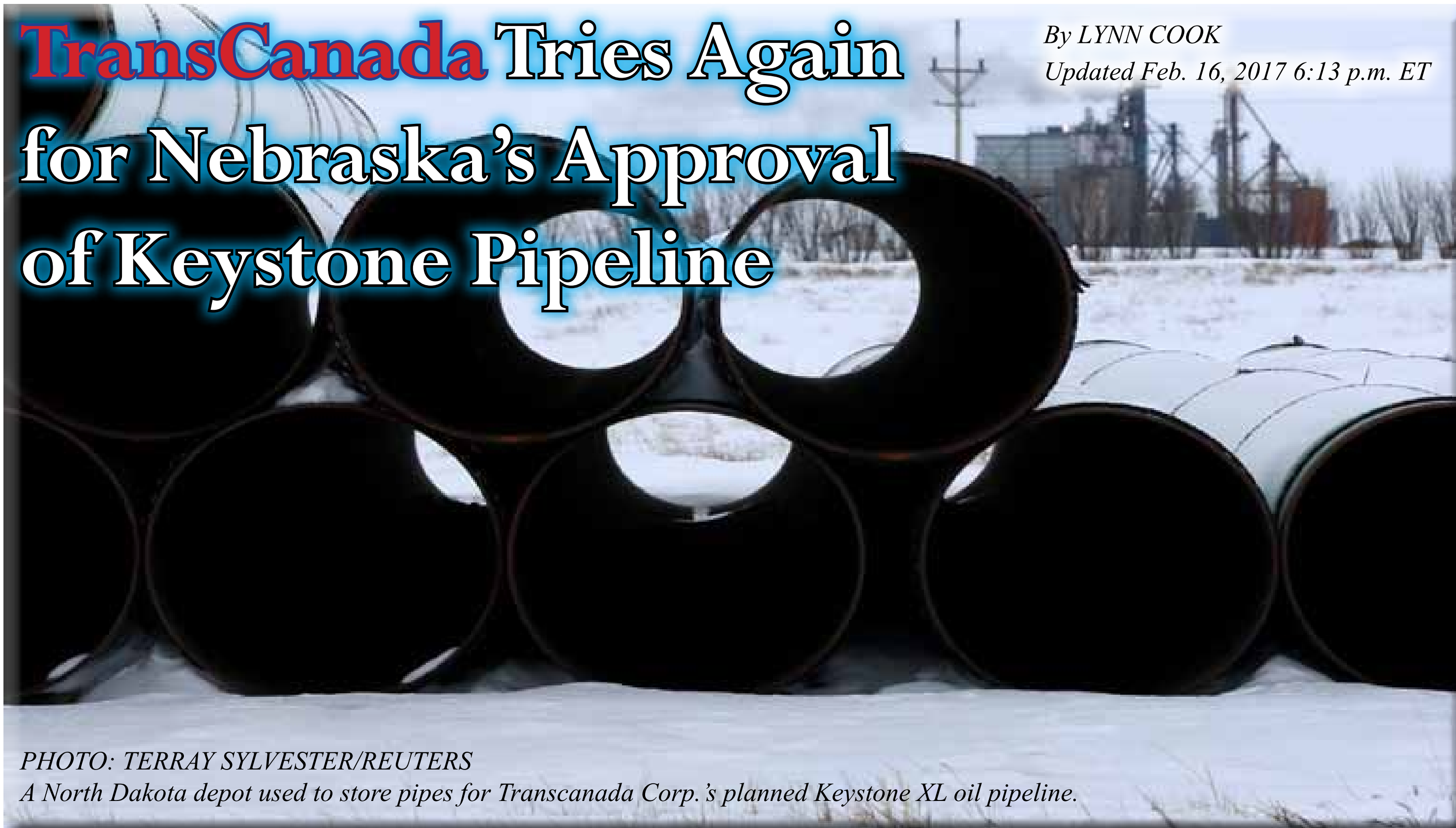

PHOTO: TERRAY SYLVESTER/REUTERS
A North Dakota depot used to store pipes for Transcanada Corp.'s planned Keystone XL oil pipeline.

Move had been expected since Trump said he'd allow it, after Obama had blocked project

TransCanada Corp. has rebooted its effort to build the Keystone XL oil pipeline across Nebraska, where it had met with opposition before it withdrew its application when the Obama administration denied the company a federal permit in late 2015.

The company filed an application Thursday with the state's Public Service Commission, executives said on a conference call with investors and analysts to discuss earnings. Nebraska had been at the center of opposition to the pipeline, largely based on environmental concerns.

TransCanada's latest move had been expected since Donald Trump was elected U.S. president. One of his first orders of business was to invite TransCanada to reapply for a permit from the U.S. State Department to allow the line to cross the border with the U.S. The company did so last month.

Keystone XL's tentative route calls for it to originate in Alberta's oil sands region, cross the U.S. border into Montana and run through South Dakota to Steele City, Neb., where it would link to existing pipelines to Gulf Coast refineries and ports.

Nebraska's permitting process, which requires a series of public hearings, could take up to a year and is expected to again draw strong opposition from residents, ranchers and farmers, as well as environmental groups. Landowners had expressed concern about use of eminent domain to seize land in the path of the pipeline.

TransCanada has said the Gulf Coast is the natural destination for heavy Canadian oil because the many refineries in Texas and Louisiana are geared to process the sludgy crude into gasoline, diesel and other fuels. The company said it is working with potential shippers on the oil pipeline to assess demand for space on Keystone XL, with some customers wanting less than they did a few years ago and others signaling they may want more.

Bold Alliance, a Nebraska-based group that opposes the line, has long maintained that Keystone makes the U.S. little more than a conduit to funnel foreign oil into the U.S. and south to ports for export, with risks of spills along the way.

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"Keystone XL is a foreign-owned pipeline, using foreign steel headed to the foreign export market," said Jane Kleeb, president of the Bold Alliance. "Keystone XL is and always will be all risk and no reward."

In the years that Keystone XL was hamstrung in regulatory limbo during former President Barack Obama's tenure, the entire energy market changed. U.S. shale producers have unleashed a new wave of crude in places like Texas and Oklahoma, which are closer to the Gulf Coast, making transportation less costly than Keystone. And many refineries made long-term arrangements to buy heavy crude from countries other than Canada or from TransCanada's pipeline rival Enbridge Inc., which also operates cross-border oil pipelines from Canada.

Paul Miller, TransCanada's president of liquids pipelines, said discussions with potential customers are ongoing but have taken on a new urgency. Keystone XL's $8 billion price tag will be revised later this year, he said.

TransCanada could have the permits it needs to build Keystone by around the end of the year, but construction is unlikely to move forward until well into 2018. Building the pipeline would then take at least two years, Mr. Miller said.

The company on Thursday posted a loss for its latest quarter on a hefty charge related to the sale of its Northeast U.S. renewable-power generation business, but results still beat Wall Street expectations. TransCanada also raised its quarterly dividend 11% to 62.5 Canadian cents per share.

For the three months ended Dec. 31, the company recorded a net loss of 358 million Canadian dollars, or 43 Canadian cents a share, compared with a loss of C$2.5 billion, or C$3.47 a share, in the year-earlier period. TransCanada attributed the loss to the C$870 million write-down related to the sale of the U.S. Northeast power business.

Excluding that charge and other items, adjusted earnings rose to 75 Canadian cents per share from 64 Canadian cents for the same period in 2015. Revenue surged 27% to C$3.62 billion. Analysts polled by Thomson Reuters had expected an adjusted 72 Canadian cents a share on C$3.5 billion in revenue.

Corrections & Amplifications
The Dakota Access Pipeline is primarily owned by Energy Transfer Partners. An earlier version of this article incorrectly stated that it was owned by TransCanada.

High costs, low prices and tough new environmental rules forcing companies to cancel plans to produce oil

A new era of low crude prices and stricter regulations on climate change is pushing energy companies and resource-rich governments to confront the possibility that some fossil-fuel resources will remain in the ground indefinitely.

In a signal that the prospect is growing more likely, Exxon Mobil Corp. has said that as many as 3.6 billion barrels of oil that it planned to produce in Canada in the next few decades is no longer profitable to extract. A disclosure is expected in the coming week.

The step stems from U.S. regulations that require companies to take oil reserves off their books if they aren't profitable at existing prices or can no longer be included as part of five-year development plans.

The acknowledgment by Exxon, after the company spent about $20 billion to put the oil sands at the center of its growth plans, highlights how dramatically the prospects of the region have dimmed.

Once considered a safe bet, Canada's vast deposits are emerging as a prominent case of reserves being stranded by a combination of high costs, low prices and tough new environmental rules.

"For a lot of reasons the oil sands look like a prime candidate for eventual abandonment," said Jim Krane, an energy fellow at Rice University's Baker Institute. "One problem is that costs are persistently higher. The high carbon content only makes it worse."

In addition to the oil sands' high costs, extracting and refining the region's heavy oil or bitumen is on average a more carbon-intensive process than almost any other type of extraction. The Alberta and Canadian governments have introduced new rules, including a cap on emissions and a carbon tax

During most of the past decade, Exxon and other giant oil companies spent billions of dollars in Canada as part of a global quest for new sources of supply, as analysts cautioned about "peak oil," or the idea that production would start declining as resources ran out. Prices surged to $140 a barrel.

Companies worked feverishly to replenish their reserves of oil and gas, especially as investors have traditionally considered reserves a key indicator of future success.

But now, the worry is more about "peak demand." Amid a glut of supply that led to a price collapse in 2014 and

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a tepid recovery, investors and executives at some of the world's biggest energy producers are considering the possibility that oil demand will top out in the coming decades.

The shift from a preoccupation with future supply to worries about demand has altered investment priorities away from high-cost opportunities in the Arctic, ultradeep waters and the oil sands.

Such projects can require billions of dollars in upfront investment and seven to 10 years, or even more, to bring returns. Now companies are turning to new sources of crude oil, such as shale, that don't require the same massive investment of time and money to bring to production.

"Barring some geopolitical catastrophe that really changes the outlook…all these other projects are going to take the wind out of the oil sands," said Amy Myers Jaffe, executive director for energy and sustainability at the University of California, Davis.

Canada was once thought to hold the world's third-largest trove of crude, enough to meet U.S. demand for almost 30 years, largely due to the oil sands in northern Alberta—giant deposits of crude with the consistency of a hockey puck. Today, only about 20% of those reserves, or about 36.5 billion barrels, are capable of being profitable, according to energy consultancy Wood Mackenzie.

In the decade leading up to the 2014 price collapse, companies spent as much as $200 billion building megaprojects to extract heavy oil in Alberta's boreal forest.

Canada, despite its high costs, was attractive to companies like Exxon for its stability and proximity to the U.S.

For its Kearl oil sands project in Alberta, Exxon invested more than $20 billion, designing a less carbon-intensive process by which the oil could be extracted without the use of a high-emitting plant called an upgrader.

The project was supposed to unlock 4.6 billion barrels of crude over 40 years and produce as much as 300,000 barrels a day. Production came online in 2013 and was expanded significantly two years later. The plant produced an average of about 169,000 barrels a day last year, according to an Exxon subsidiary.

The reserves Exxon is about to take off its book are a casualty of the price collapse that has foiled more than 17 oil sands projects, representing about 2.5 million barrels a day of production, according to ARC Financial Corp.

Global companies such as Statoil ASA and Royal Dutch Shell PLC that raced to build massive industrial projects in Canada have been forced to lower the value of their oil sands investments. Since 2012, the write-downs from those companies and Canadian producers have exceed $20 billion.

Exxon isn't forecasting an oil demand peak through 2040 despite the action it is taking on its reserves.

"Even though we make that transfer, there is no change to our operations or how we manage the business, those assets, going forward," Jeff Woodbury, Exxon's vice president of investor relations, told investors last month.

U.S. Securities and Exchange Commission rules require companies to evaluate their prospects based on the average oil price in the previous year—about $43 a barrel in the U.S. for 2016.

Exxon isn't the only company taking steps that underscore the tenuousness of oil reserves. In its annual energy outlook published earlier this year, BP PLC warned that an abundance of already discovered oil resources and slowing demand growth will likely mean some barrels are never recovered.

Exxon Mobil, along with Chevron Corp., is pouring billions into expanding their footprint in shale oil, turning to projects that can ramp up quickly to fill the void left by a lack of larger, costlier developments.

Many of Canada's biggest producers are planning to rein in spending this year, even as spending in parts of the U.S. is starting to rise.

According to the Canadian Association of Petroleum Producers, capital investment in the oil sands fell about 30% in both 2015 and 2016 and is expected to slide another 11% this year.

To be sure, oil output isn't expected to fall in Canada as it has in the U.S. Fully invested oil-sands projects may go forward because the cash cost of producing barrels once a project is up and running is low.

DISSOLVABLE FRAC PLUGS

Brammer Broadcast" November 2016 issue numner 2016.5 and the author is Michael Randle, Production Engineer

Dissolvable frac plug technology offers a solution for overcoming the obstacles of reaching deeper, more extended depths in longer lateral wells. Replacing the traditional composite frac plug in the toe section of the lateral with a dissolvable frac plug option eliminates the need to reach the toe section during plug drill-out operations. Dissolvable plugs are made from advanced dissolvable metal and dissolvable rubber material. Dissolvable frac plug technology relies on a combination of three main downhole variables; time, temperature, and/or salinity. There are many different types of dissolvable plugs offered by many different service companies. The dissolution rate for certain plugs may depend more on temperature while others will depend more on salinity. It is important to choose the plug that best fits downhole well conditions. In optimal conditions most plugs will dissolve in 7-10 days. Upon complete dissolution full wellbore ID is recovered for optimal flow conditions during production and for future operations. Most dissolvable plugs are limited to 4.5", 5", or 5.5" casing with a differential pressure rating of 10,000 psi.

Advances in drilling and completion technology are resulting in improved recoveries through longer horizontal lateral lengths and larger well stimulation designs. During the early years of the Haynesville Shale development the typical lateral length was 4,500 feet and stimulation designs targeted 1,200 pounds of proppant per lateral foot. Operators in the Haynesville Shale are catching up with the trends prevalent in other basins to drill longer laterals and increase the proppant loading per lateral foot. With today's technology, the typical lateral length has extended to 8,500 feet and in some cases up to 10,000 plus feet with stimulation designs targeting anywhere from 3,000 to 4,000 pounds of proppant per lateral foot. One of the latest developments in completion tool technology is the dissolvable frac plug. The purpose of this article is to provide general details on dissolvable frac plug technology and the operational and economic benefits when used in longer horizontal laterals.

One of the major obstacles during the completion portion of a horizontal lateral that extends past 8,000 feet is accessing the toe of the lateral with completion tools for the Plug Drill-Out. Even with the advantages of larger OD coil tubing units, extended reach tools such as agitators, and chemicals used to decrease pipe on pipe friction it can be difficult and in some cases impossible to get coiled tubing conveyed tools to a desired depth in longer laterals. Wellbore conditions will have an impact on the difficulty of accessing the toe section of the lateral during drill-out operations. For example, the lateral will have 40-60 frac plugs along with residual proppant from multiple stimulation stages; combine those conditions with the friction points from undesired doglegs in the lateral and the probability of reaching the desired depth to drill-out the toe stage plugs can be diminished greatly.

Dissolvable frac plugs cost 3-4 times as much as traditional composite frac plugs which potentially equate to several thousand additional dollars associated with plug cost. However, a large portion, and in many cases all of the additional plug cost, will be offset by the reduced amount of lateral that needs to be drilled-out. Decreasing the time of coiled tubing operations associated with running dissolvable plugs will reduce the following costs: coil tubing charges, motor/mill charges, drill-out chemical volumes, fluid volumes, disposal volumes, and all the other associated cost with decreasing the total days of operations. Avoiding extended reach drill outs will also reduce the chances of coiled tubing fishing jobs which can be quite costly and in the worst cases can junk all or a portion of the lateral.

In conclusion, Brammer Engineering has experience applying dissolvable plug technology in horizontal wells. We strive to continue to expand our knowledge of all of the latest technological advances in an effort to better serve our clients and meet the demands of the latest trend of longer horizontal lateral wells. For more information, please contact Michael Randle, Production Engineer.

Russia Overtakes Saudi Arabia as World's Top Crude Oil Producer

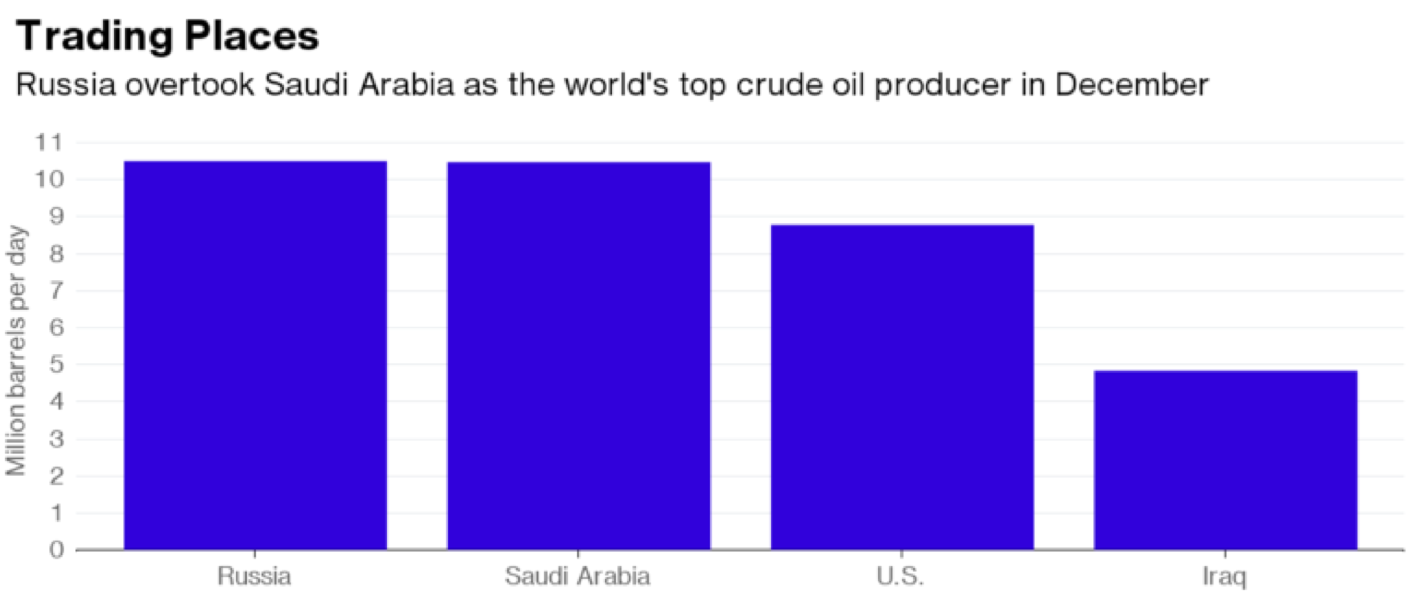
by Claudia Carpenter

Russia overtook Saudi Arabia as the world's largest crude producer in December, when both countries started restricting supplies ahead of agreed cuts with other global producers to curb the worst glut in decades. Russia pumped 10.49 million barrels a day in December, down 29,000 barrels a day from November, while Saudi Arabia's output declined to 10.46 million barrels a day from 10.72 million barrels a day in November, according to data published Monday on the website of the Joint Organisations Data Initiative in Riyadh. That was the first time Russia beat Saudi Arabia since March.

Saudi Arabia and fellow producers from the Organization of Petroleum Exporting Countries decided at the end of November to restrict supplies by 1.2 million barrels a day for six months starting Jan. 1, with Saudi Arabia instrumental in the plan. Non-member producers, including Russia, pledged additional curbs. Brent crude prices have climbed about 20 percent since the end of November.

The U.S. was the third-largest producer, at 8.8 million barrels a day in December compared with 8.9 million barrels a day in November, according to JODI. Iraq came in fourth at 4.5 million barrels a day, followed by China at 3.98 million barrels a day, the data show.

Saudi Arabia's crude exports declined to 8 million barrels a day in December, from 8.26 million barrels a day, the biggest outflow for any month since May 2003, according to JODI data.



Methane Rule Inappropriately Targets Marginal Wells

By Susan Ginsberg

WHILE MARGINAL WELLS ARE DEFINED AS THOSE PRODUCING 15 BARRELS A DAY OF OIL OR LESS, OR 90 MCF OF GAS A DAY OR LESS, THESE WELLS ARE FAR FROM MARGINAL IN THEIR CONTRIBUTION TO AMERICA'S ENERGY PRODUCTION. THERE ARE MORE THAN 1.1 MILLION OIL AND NATURAL GAS WELLS IN THE UNITED STATES; APPROXIMATELY 760,000 ARE MARGINAL WELLS. THESE SMALL WELLS ACCOUNT FOR ABOUT 20 PERCENT OF U.S. OIL PRODUCTION AND 13 PERCENT OF ITS NATURAL GAS PRODUCTION.

Because of the declining nature of oil and natural gas wells, "new" wells ultimately will become "marginal." Because marginal wells will continue to be part of America's energy production, it is crucial for regulators to grasp their operating characteristics. While many state regulators have years of experience in regulating marginal wells, actions by the U.S. Environmental Protection Agency demonstrate a lack of understanding. EPA issued a final rule on May 12 to amend its New Source Performance Marginal WellsBy Susan Ginsberg. Methane RuleInappropriately TargetsStandards to reduce methane leaks from new and modified oil and gas facilities. These rules, which build on EPA's 2012 requirements to reduce volatile organic compounds, pull in some sources not previously covered: marginal wells. When EPA proposed these changes last September, it recommended low-producing wells be exempt. In comments submitted in early December, the Independent Petroleum Association of America and the American Exploration & Production Council supported that exemption, noting the minimal incremental emissions from marginal wells, and arguing the cost of reducing those emissions were likely to make many marginal wells uneconomic."The opportunity cost or value of that lost production is not offset by the minimal emission reductions achieved by regulating existing sources," the associations contended.But instead, EPA relied on comments indicating that "low production well sites have the potential to emit substantial amounts of fugitive emissions," and that "a significant number of wells would be excluded from fugitive emissions monitoring, based on this exemption. We believe the emissions from low production and non-low-production well sites are comparable."Such a conclusion flies in the face of logic. Energy in Depth explored this abrupt change in agency thinking and the counterintuitive "evidence." EPA relied on comments submitted by the Clean Air Task Force (CATF), which was launched in 1996 with a single goal: to enact federal policy to reduce the pollutants from America's coal-fired power plants that caused respiratory death and disease, smog, acid rain and haze. According to its website, "CATF has continued to apply its technical and policy know-how to aspects of the climate challenge in cutting-edge ways."One apparently novel way was to persuade EPA, through an Environmental

"Continued on page 17"

Top Five Facts

1. Methane emissions have fallen dramatically as natural gas production has skyrocketed.
2. EPA consistently finds methane emissions are declining.
3. Methane emissions are declining in major oil and gas basins across the U.S.
4. Research shows climate benefits of natural gas are not erased by emissions.
5. Industry's 'voluntary reductions' led to dramatic decline in methane emissions.

Courtesy of Energy in Depth For more info, visit http://energyindepth.org/wp-content/uploads/2015/01/MethaneEmissions.pdf

"Continued from page 16"

Defense Fund study, that the focus should be on methane as a percent of production, not on sites emitting large quantities of methane. Using that construct, the EDF study found that "lower production sites … are almost twice as likely to be among the top 5 percent of emitters, relative to sites with an order of magnitude higher rates of production."Some examples in the study showed a well in which half of its extraction was lost in emissions. The study concluded that "the conventional definition of super-emitters would be biased toward the highest producing sites." What a shock!This inaccurate portrayal of emissions from oil and gas sites does not explain to how these enormous emissions were calculated. Was this a single-day occurrence, such as a liquid unloading operation? Otherwise, it is difficult to explain how a producer would allow so much of a valuable product to be wasted.EPA‘s bias against marginal wells is also present in its 2016 Greenhouse Gas Inventory (GHGI), which abruptly reversed EPA's estimate of declining methane emissions from the oil and natural gas industry. The 2015 inventory indicated urethane emissions from natural gas systems had dropped 11 percent since 2005. But after revising the 2015 data, this year's GHGI found the reductions in methane emissions from natural gas to be less than one percent. Further, the 2016 data show a 29 percent increase in methane emissions from petroleum systems since 2005.Part of EPA‘s focus on marginal wells can be seen In the GHGI. EPA acknowledges that 70 percent of smaller oil and natural gas production facilities do not report and, therefore, are not part of the GHGI. EPA appears to assume that these smaller facilities are releasing emissions comparable to those of larger producing facilities. And EPA intends to pursue this line of thinking by requiring marginal wells to monitor leaks.Marginal wells should not be marginalized in the implementation of environmental regulations. These wells, which are operated primarily by smaller producers, provide a significant portion of America's energy. New rules should not encourage producers to shut in those resources.

SUSAN GINSBERG is vice president of crude oil and nat ural gas regulatory affairs for the Independent Petroleum Association of America. She covers legislation and regula tion, focusing on the CFTC and FERC. Her experience in natural gas regulatory affairs spans 25 years.

Some major food companies in the United States and in Europe are looking to fossil fuels to produce animal feed — an idea that's understandably being viewed as somewhat controversial. Although the feed has already been approved by the European Union (EU) for livestock and farmed fish, approval is still underway in the United States and could potentially be expanded to include dogs, cats and even humans.

The process being exploited is not new. In fact, it first evolved billions of years ago, even before photosynthesis, as methanotrophs (microbes that feed on methane) began feasting on the methane that seeps through cracks in the sea floor into ponds and marshes. These organisms basically burn methane for energy and combine with other complex organic molecules to produce a high-protein food product that can be dried and turned into pellets. But along the way, one of the by-products is carbon dioxide, which, on a large scale, could actually exacerbate global warming.

Proponents of the technology claim that the reduced need for land to grow livestock feed and lower demand for wild fish to feed farmed fish would counteract the effect of increased CO2 emissions. They also propose that the process will reduce hazardous gas flares, which currently release nearly 140 billion cubic meters (5.3 trillion cubic feet) of natural gas into the atmosphere every year. But opponents argue that using non-renewable fossil fuels in lieu of sunlight is an environmentally unsound approach to long-term food production.

Emily Patsy, Hart Energy Wednesday, February 15, 2017 - 12:45pm
[Editor's note: This story was updated at 8:55 a.m. CT Feb. 24.]

HOUSTON—The oil and gas industry is coming back to life across U.S. shale plays, with the still Permian Basin leading the way.

Despite the Permian's A&D and capex already sizeable lead —the basin has already seen at least $14 billion in deals in the first two months of 2017 and increased spending—Robert Clarke, research director at Wood Mackenzie, doesn't discount the return of other shale plays.

Clarke said he would put his money on the Powder River Basin for the exploration play of the year, though he's already concerned about the speed of the rebound so far.

"It is very aggressive—more aggressive than we've seen in prior cycles," Clarke said during the 2017 NAPE Summit business conference on Feb. 15.

Driven by the recent stability of oil prices at $50 a barrel, Clarke said the best U.S. energy companies are looking at double digit growth for 2017. However, the effect of such accelerated development might lead to higher costs and less efficiency for producers.

A leading indicator of the growing optimism in the industry is the rig count, which has been shooting upward for the past 14 weeks.

During the week of Feb. 10, U.S. drillers added eight oil rigs, bringing the total count up to 591—the most since October 2015, according to Baker Hughes Inc. (NYSE: BHI). Overall, the monthly rate of rig additions in the U.S. over the past four weeks is the highest it's been since 2012.

"I think we're at a point now where it's going to be a bit challenging. It's not that we can't continue to add more [rigs], but costs are going to go up and that's going to impact breakevens," Clarke said.

As a result, Clarke predicts the industry could be entering a period where massive efficiency gains achieved during the downturn slow down.

On a brighter note, Clarke said opportunities are emerging for operators outside the "Delaware buzz."

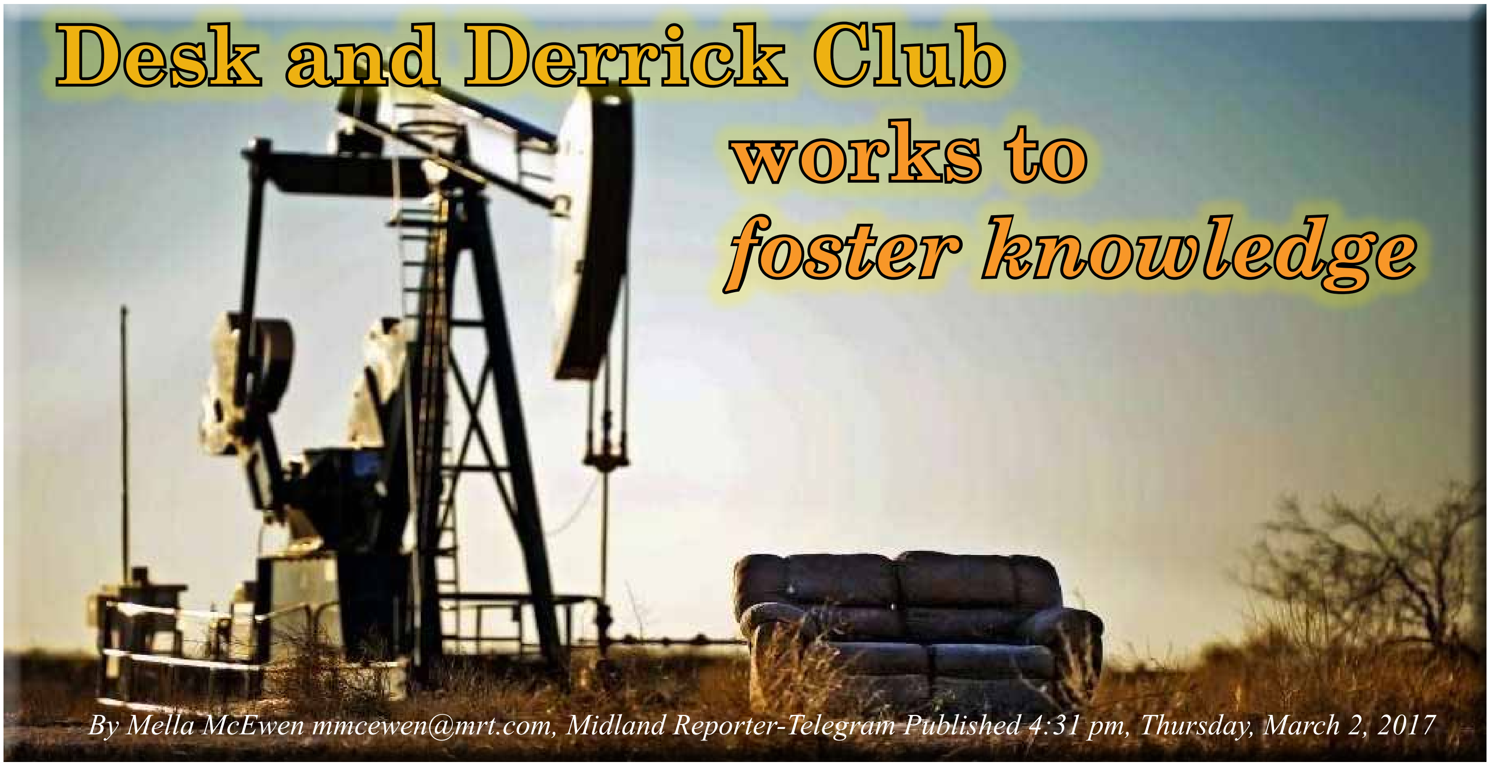
"The recovery is just not in the core of the core, it's just not in the Permian. Plays like the Eagle Ford don't die a quiet death," he said.

As the industry recovers, Wood Mackenzie projects that 30% of all rigs added in the U.S. will go into the Permian. This leaves 70% of rig additions across multiple basins and multiple plays, Clarke said.

Going forward, Clarke said a modest demand growth is leading to a growing call on U.S. Lower 48 supply. Outside of the Lower 48 onshore production, supply is projected to be broadly flat to 2020, creating an opportunity for U.S. shale producers.

"The gap between global demand and non-U.S. global supply… that's ours to go for," Clarke said. "We want to provide a lot barrels for the global market, but we don't want to be that last barrel because that last barrel sets the price."

Emily Patsy can be reached at epatsy@hartenergy.com.



Education is the foundation of the Association of Desk and Derrick Clubs.

"Our motto is Greater Knowledge, Greater Service," said Joyce Nolly, president of the Desk and Derrick Club of Midland.

Each March, the association's 50-plus chapters are asked to raise public awareness of the organization, what it does and its benefits. Last year, as part of those efforts, local members handed out "Bit of Fun" activity books to children at Music City Mall in Odessa.

Nolly said the association's purpose is to promote the education and professional development of those involved in the petroleum, energy and allied industries and to educate the public about the contributions of those industries.

More from Oil Report

Oil exports hit 1 million barrels, opening door for West Texas producers

PetroLima founders trying their hand at exploration, production

European oil analyst sees opportunities, challenges for Permian

Chapter meetings often include presentations on topics that may fall outside the scope of a member's job description. For example, Sheryl Ryan, assistant vice president and information security officer for First Capital Bank Texas, will address cyber security at the local chapter's March 9 dinner at Ranchland Hills Golf Club. Previous topics have included electric submersible pumps from Schlumberger and vapor recovery units from Hy-Bon. In April, members will take a field trip to a wind energy farm.

Nolly said membership benefits the career path of members, their employers and the community.

"It helps re-energize and jump-start your career. Your company can see you can use your membership as part of training. With so many cutbacks lately, it can be difficult to get training," she said.

The association offers certification programs in geology, land and leasing, drilling, completion and production, marketing and accounting. It also offers cross training in other areas.

"A production analyst like myself isn't exposed to engineering or geology," noted Nolly, a ConocoPhillips employee. "It's effective because once you understand other departments and their needs, it helps you meet their needs better."

Desk and Derrick Club members also publicize their companies when they volunteer at various events. Local volunteers help with monthly Permian Basin Petroleum Association luncheons and at the Petroleum Museum's Family Science Night. Members have long assisted with registration at the Permian Basin International Oil Show and helped with the American Petroleum Institute's annual golf tournament. The chapter also hosts the Black Gold golf tournament to raise scholarship funds.

The local chapter, which currently has 30 members, is one of 10 in the association's Region V (there are seven regions in the U.S. and Canada). Nolly said the group is looking to increase membership.

Desk and Derrick Club of Midland and the parent association marked their 65th anniversary in November.

The Beginning of the End For The Bakken Shale Play

By Arthur Berman

The decline in Bakken oil production that started in January 2015 is probably noThe decline in Bakken oil production that started in January 2015 is probably not reversible. New well performance has deteriorated, gas-oil ratios have increased and water cuts are rising. Much of the reservoir energy from gas expansion is depleted and decline rates should accelerate. More drilling may increase daily output for awhile but won't resolve the underlying problem of poorer well performance and declining per-well reserves.

December 2016 production fell 92,000 barrels per day (b/d)–a whopping 9% single-month drop (Figure 1). Over the past two years, output has fallen 285,000 b/d (23%). This was despite an increase in the number of producing wells that reached an all-time high of 13,520 in November. That number fell by 183 wells in December.

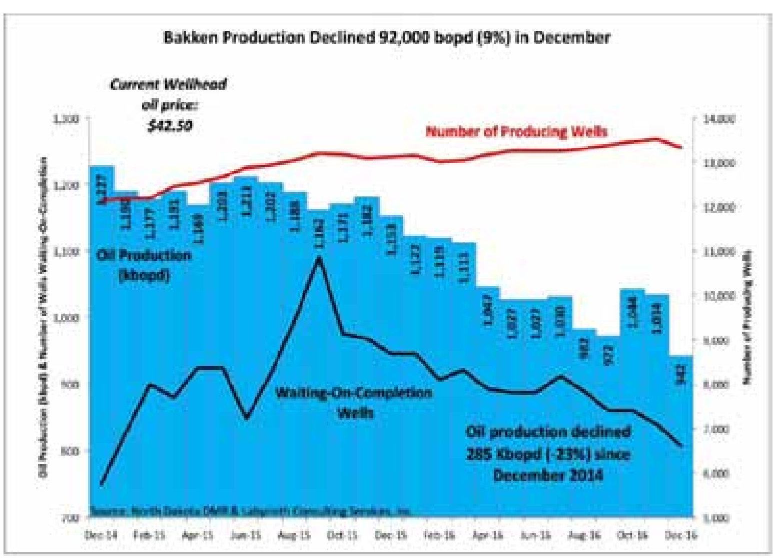


Figure 1. Bakken Production Declined 92,000 bopd (9%) in December. Source: North Dakota Department of Mineral Resources and Labyrinth Consulting Services, Inc.

Well Performance Is Declining

Well performance was evaluated for eight operators using standard rate vs. time decline-curve analysis methods. These operators account for 65% of the production and also 65% of producing wells in the Bakken play (Table 1).

OPERATOR	CUMULATIVE OIL PRODUCTION	TOTAL PRODUCING WELLS	2012-2015 WELLS USED FOR DCA
WHITING OIL AND GAS CORPORATION	256,346,497	1,757	995
CONTINENTAL RESOURCES, INC.	187,381,729	1,657	775
HESS BAKKEN INVESTMENTS II, LLC	185,106,777	1,382	818
XTO ENERGY, INC.	126,073,289	980	509
EOG RESOURCES, INC.	172,746,920	976	260
STATOIL OIL & GAS LP	99,420,181	719	408
BURLINGTON RESOURCES OIL & GAS CO	107,349,533	677	394
MARATHON OIL COMPANY	105,585,646	575	276

Source: Drilling Info & Labyrinth Consulting Services, Inc.

Table 1. Operators, Cumulative Oil Production, Total Producing Wells and 2012-2015 Wells Used for Decline-Curve Analysis (DCA) in this study. Source: Drilling Info and Labyrinth Consulting Services, Inc.

Estimated ultimate recovery (EUR) decreased over time for most operators and 2015 EUR was lower for all operators than in any previous year (Figure 2). This suggests that well performance has deteriorated despite improvements in technology and efficiency.

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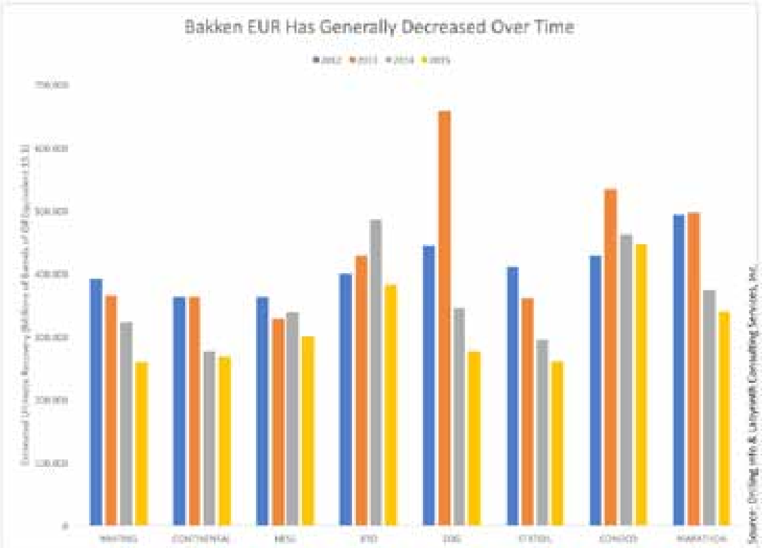

Figure 2. Bakken EUR (Estimated Ultimate Recovery) Has Generally Decreased Over Time. Source: Drilling Info and Labyrinth Consulting Services, Inc.

Figure 3 shows Bakken EUR and the commercial core area in green. The map on the left shows all wells with 12-months of production history and the map on the right, all wells with first production in 2015 and 2016.

Most 2015-2016 drilling was focused around the commercial core area. The fact that EURs from these core-centered locations were lower than earlier, less favorably located wells indicates that the commercial core is showing signs of depletion and well interference.

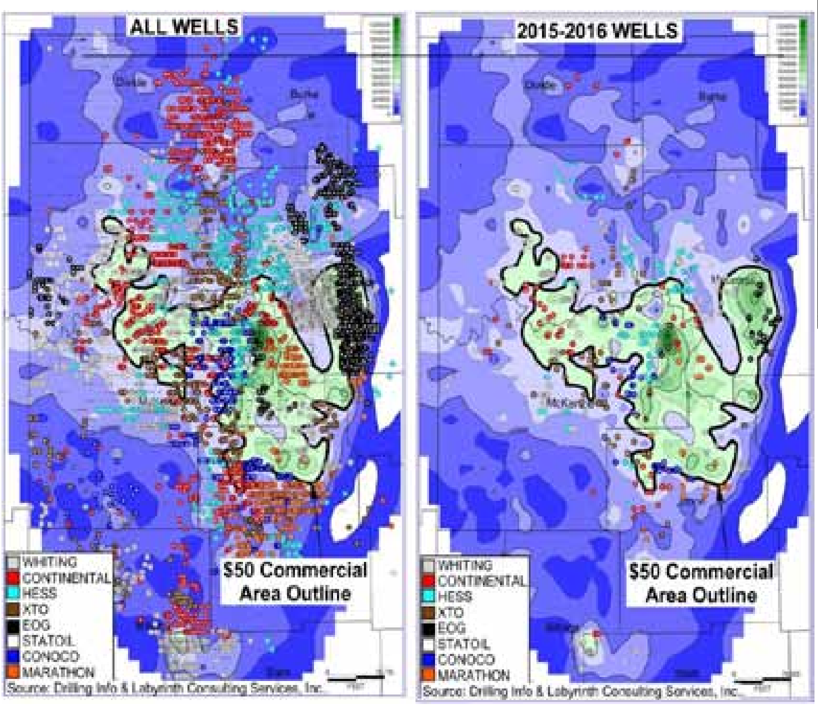

Figure 3. Bakken EUR map showing all wells with 12-months of production and all wells with first production in 2015 and 2016. Source: Drilling Info and Labyrinth Consulting Services, Inc.

Well-level analysis indicates a fairly systematic steepening of decline rates over time. Figure 4 shows Continental Resources wells with first production in 2012 and 2015. 2012 wells have a shallow, super-harmonic (b-exponent = 1.3) decline rate but 2015 wells have a steeper, weakly hyperbolic (b-exponent=0.2) decline rate.

Oil reserves for 2012 wells averaged 343,000 barrels but only 229,000 barrels for 2015 wells–a 33% decrease in well performance. Steeper decline rates result in lower EURs.

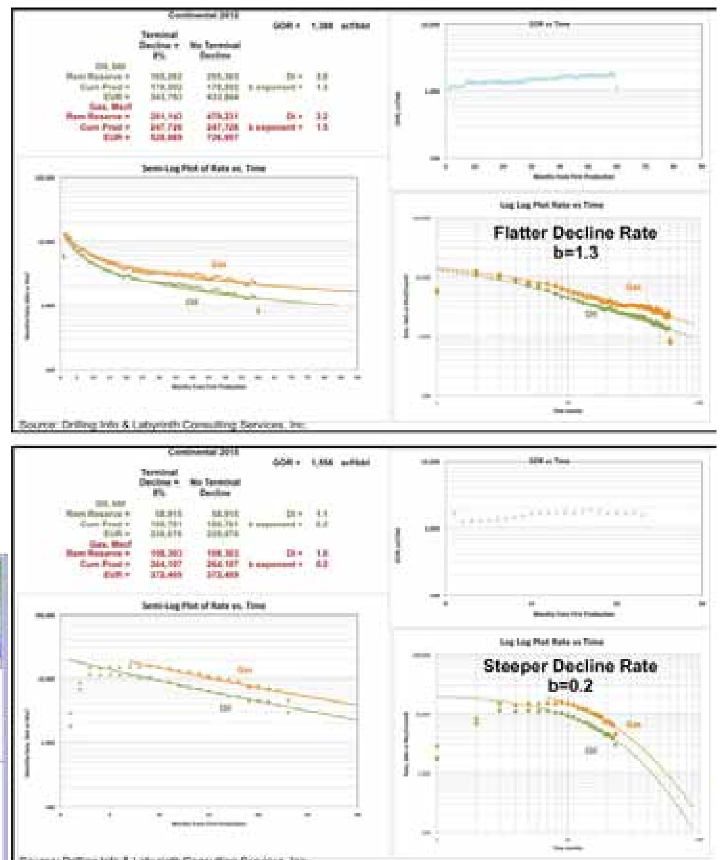

Figure 4. Well-level analysis shows steeper decline rates for more recent wells than for older wells. Source: Drilling Info and Labyrinth Consulting Services, Inc.

Gas-oil ratios (GOR) for most operators increased from 2012 through 2014 and then, decreased for wells with first production in 2015 (Figure 5).*

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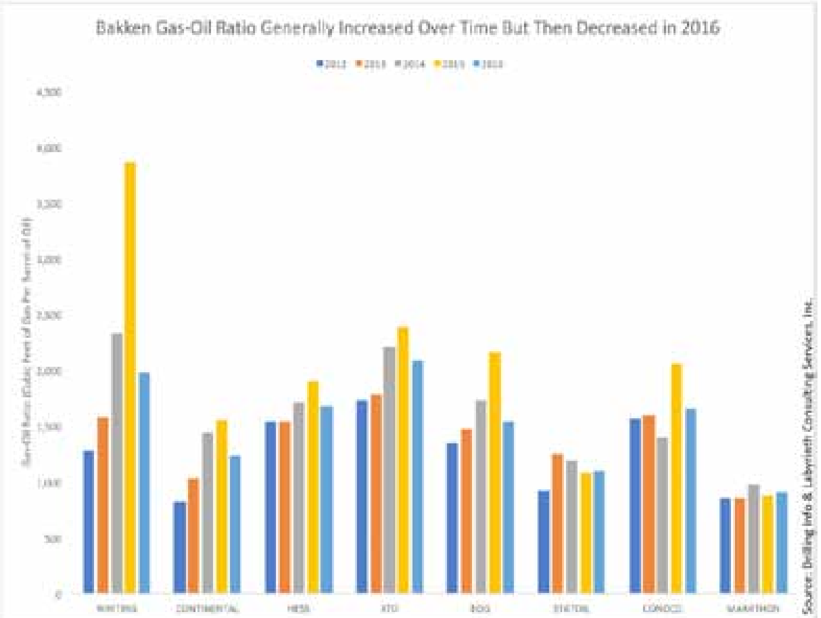

Figure 5. Bakken gas-oil ratios generally increased over time but then decreased in 2016. Source: Drilling Info and Labyrinth Consulting Services, Inc.

Changing GOR is important because it suggests decreasing reservoir energy. The Bakken has a solution gas drive mechanism. Initially, oil is produced by liquid expansion across the pressure drop from the reservoir to the well bore. Later, gas dissolved in the oil expands and this is the mechanism that lifts oil to the surface.

Rapidly increasing GOR in the Bakken probably indicates partial reservoir depletion and subsequently decreasing GOR suggests more advanced depletion accompanied by declining reservoir pressure, declining oil production and increasing water cut (Figure 6).

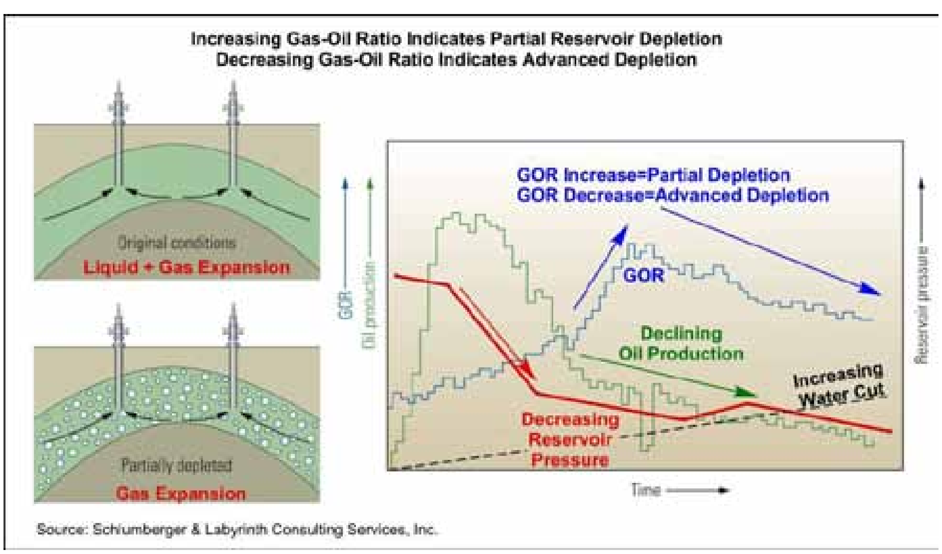

Figure 6. Increasing gas-oil ratio indicates partial reservoir depletion–Decreasing gas-oil ratio indicates advanced depletion. Source: Schlumberger and Labyrinth Consulting Services, Inc.

The sequence of events summarized in Figure 6 is demonstrated in Bakken field production shown below in Figure 7. Gas increased before oil production peaked in December 2014 and continued increasing through March 2016, and then declined.

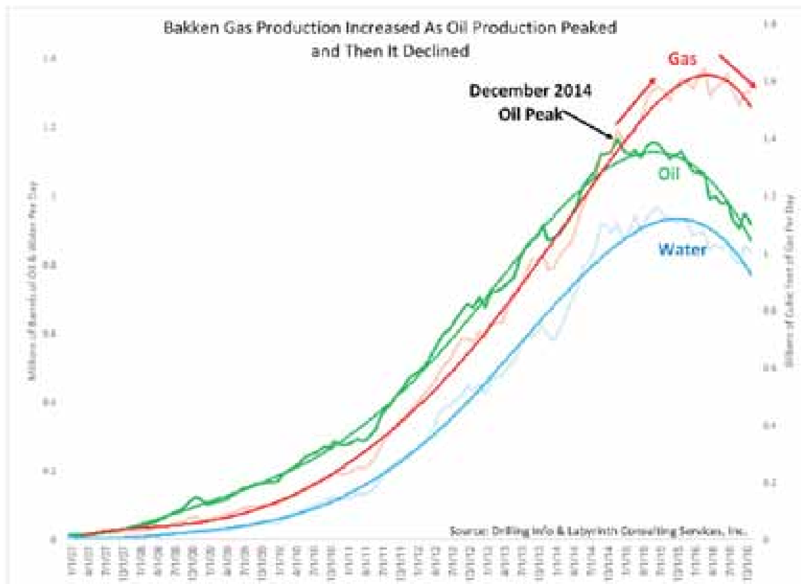

Figure 7. Bakken gas production increased as oil production peaked and then it declined. Source: Drilling Info and Labyrinth Consulting Services, Inc.

Water cut—water as a percent of total liquid produced—has increased for most operators over time (Figure 8) and this provides additional support for progressive Bakken depletion.

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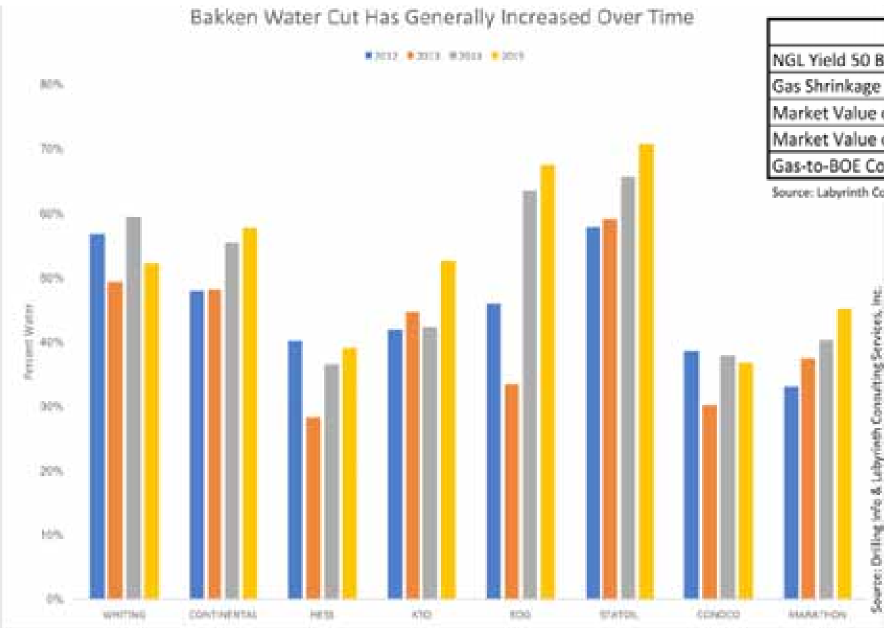


Figure 8. Bakken water cut has generally increased over time. Source: Drilling Info and Labyrinth Consulting Services, Inc.

Company Performance, Break-Even Prices and Future Drilling Locations

Well performance for the 8 key operators shown above in Table 1 above provides a framework for company performance and break-even prices for the Bakken play.

Reserves were estimated for more than 4,400 wells with first production in 2012 through 2015 using standard rate vs. time methods. Decline-curve analysis (DCA) was used to evaluate wells with at least 12 months of production history for key operators. Production group DCA was done separately by operator and year of first production for oil, gas and water.

Results are summarized in the following tables.

	GROUP	WHITING	CONTINENTAL	HESS	XTO	EOG	STATOIL	CONOCO	MARATHON
WTD AVG EUR BOE 15	368,593	339,387	318,035	331,495	422,861	449,721	348,102	470,653	433,889
BREAK-EVEN OIL PRICE	$54.98	$59.85	$63.80	$61.30	$47.96	$45.09	$58.30	$43.08	$46.75

Source: Drilling Info & Labyrinth Consulting Services, Inc.

Break-Even Wellhead Price ($/Barrel)	EUR MBOE 15	Economic Assumptions
$45	451	$7 MM Well Cost
$50	406	80% Net Revenue Interest
$55	369	11% Severance Tax
$60	338	50 Barrels NGL per Mmcf
$65	312	OPEX $12/BOE
$70	290	8% Discount

Source: Drilling Info & Labyrinth Consulting Services, Inc.

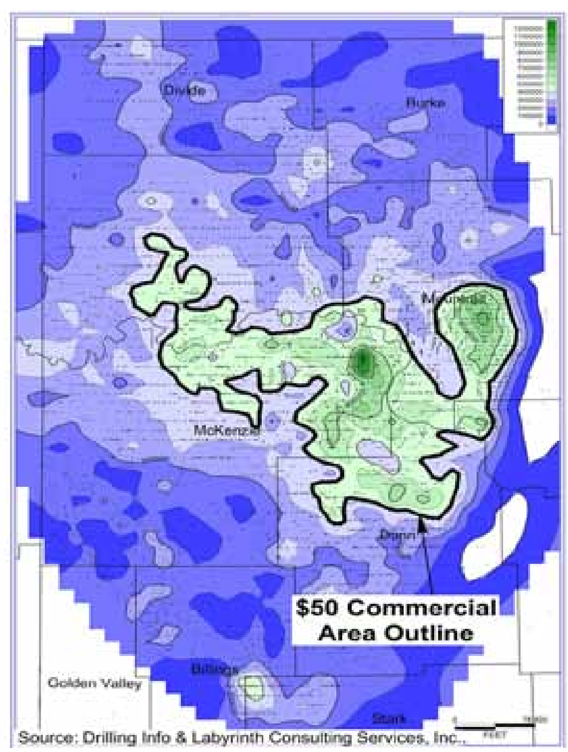
	Per Mcf	Price Per Unit	Assumptions
NGL Yield 50 BPM	0.05	$0.90	NGL value is 40% of $45/bbl
Gas Shrinkage 86%	0.86	$2.15	Assumes $2.50/Mcf
Market Value of Gas/Mcf		$3.05	NGL/Mcf + Shrunk Gas/Mcf
Market Value of Condensate		$45.00	$45/bbl
Gas-to-BOE Conversion Factor	15	15 Mcf/BOE	$45 oil price/$3.05 NGL-adjusted gas price

Source: Labyrinth Consulting Services, Inc.

Table 2. Summary tables of key operator EUR and break-even prices and economic assumptions. Source: Drilling Info and Labyrinth Consulting Services, Inc.

None of the key operators' average well breaks even at current Bakken wellhead prices of $42.50 per barrel although ConocoPhillips ($43.08 break-even price) is very close. EOG, XTO and Marathon all break even at prices less than $50 per barrel but other operators need higher oil prices to break even. It is worth noting that Bakken wellhead prices are about $10 per barrel less than WTI benchmark prices.

Current well density was calculated by measuring the area of the $50 commercial area (406,000 BOE cutoff) and dividing by the number of horizontal wells within that area. There are 5,500 producing wells within the 1.2 million acre commercial area shown in Figure 9. That equates to a current well density of 215 acres per well.



	Acres	Wells	Well Density
$45 Commercial Area	1,182,401	5,500	215

Source: Drilling Info & Labyrinth Consulting Services, Inc.

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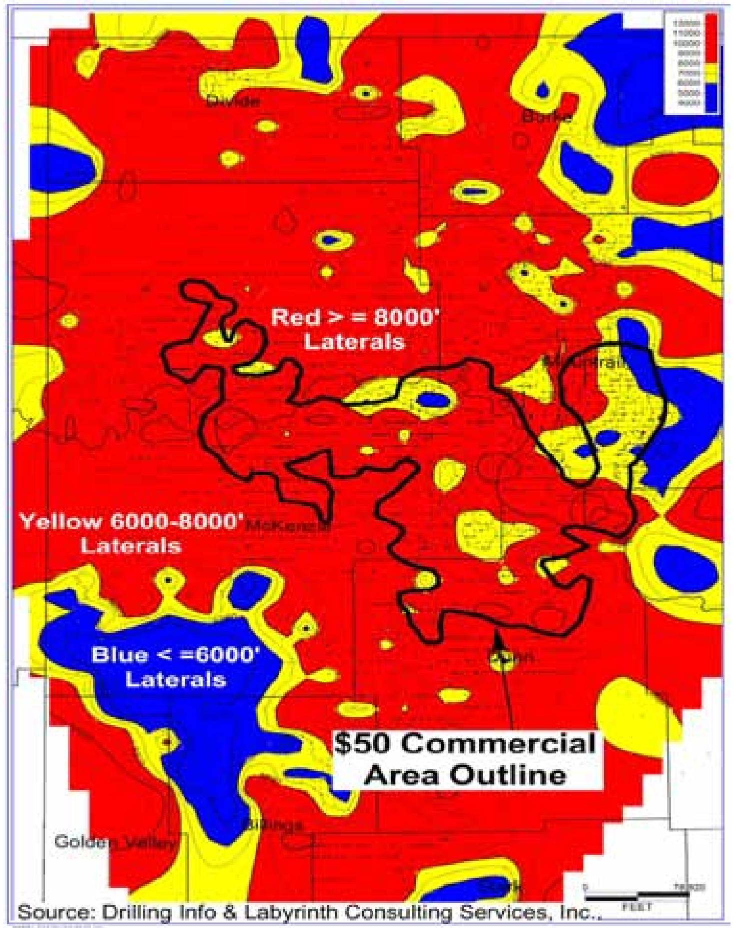
Figure 9. Bakken EUR map showing the $50 (406,000 BOE EUR) commercial area and well density table. Source: Drilling Info and Labyrinth Consulting Services, Inc.



Tight oil operators describe infill spacing of 40 to 120 acres per well favoring the lower end of that range. Current well density in the Bakken core of 215 acres per well suggests substantial infill locations remain yet declining EURs, increasing water cut and falling GOR do not support further infill drilling.

The Bakken is unique because of the extraordinary lengths of lateral wellbores compared with other tight oil plays. Laterals are commonly more than 10,000 feet in length and often approach 12,000 feet.

Figure 10 shows lateral lengths in the Bakken. It is clear that within the commercial core area, most laterals exceed 8,000 feet. Available evidence suggests that current well density is sufficient to fully drain reservoir volumes. That implies that further drilling will not result in producing new oil volumes but will interfere with and cannibalize production from existing wells.

IPAA
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

From the President and CEO

Barry Russell

Dear IPAA Member: ***March 29, 2017***

Yesterday, I had the opportunity to attend President Donald Trump's signing ceremony of the Energy Independence Executive Order, which includes a number of IPAA recommendations made to the transition team and new administration. Also attending were Vice President Pence, Interior Secretary Zinke, Energy Secretary Perry and EPA Administrator Pruitt. It was an honor to represent IPAA at the signing event and we're pleased IPAA is being recognized as playing a vital role in strengthening our nation's energy security and getting Americans back to work. Yesterday's executive actions include:

Withdrawing the social costs of carbon executive order, a concept that had been used to justify new regulations in the Obama Administration.

Rescinding the National Environmental Policy Act guidance on greenhouse gases that made climate change a consideration in the permitting process.

Ordering the Bureau of Land Management (BLM) to review the hydraulic fracturing rule that attempted to limit the practice on federal and tribal lands.

Reviewing the new source standard for methane from new oil and gas operations.

Reviewing the BLM's venting and flaring regulations.

Revoking the presidential memorandum on mitigating the impacts on natural resources from development and encouraging related private investment.

USGS: Oklahoma's earthquake threat now equals California's due to man-made temblors

By Rong-Gong Lin 2nd Los Angeles Times

LOS ANGELES — The earthquake risk for Oklahoma and southern Kansas is expected to remain significant in 2017, threatening 3 million people with seismic events that can produce damaging shaking, according to a new U.S. Geological Survey forecast released Wednesday.

The seismic risk is forecast to be so high that the chance of damage in Oklahoma and southern Kansas is expected to be similar to that of earthquakes in California, USGS scientists writing in the journal Seismological Research Letters said Wednesday.

In 2016 alone, Oklahoma experienced several damaging earthquakes, including a magnitude 5.0 temblor in November near the central oil town of Cushing — which proclaims itself the "Pipeline Crossroads of the World" — that dislodged unreinforced bricks in chimneys and storefronts, sending them tumbling onto the sidewalks.

Oklahoma also saw the largest quake ever recorded in the state in 2016, when a magnitude 5.8 earthquake struck near Pawnee.

The earthquakes are thought to be the result of the disposal of wastewater deep underground from fracking, a method used to extract petroleum. Injecting the wastewater underground is not thought to trigger earthquakes everywhere it is practiced — in North Dakota, for example — but is widely believed by scientists to be a problem in Oklahoma.

According to scientists, there were only about two earthquakes a year of magnitude 2.7 or greater in Oklahoma between 1980 and 2000. But that number jumped to 2,500 in 2014, and soared to 4,000 a year later.

There has recently been a decrease in wastewater being injected deep underground, either because of regulatory actions or because oil and gas extraction has declined due to falling petroleum prices. That might be a reason for the decrease in the number of Oklahoma earthquakes last year, to 2,500.

In a statement, Mark Petersen of the USGS said the amount of injected wastewater in some areas has been reduced by up to 40 percent in 2016.

But the USGS report says the forecast earthquake hazard in 2017 "is still significantly elevated" compared to the seismic risk before 2009.

The Oklahoma Geological Survey's director, Jeremy Boak, said in a statement that he expects that state directives to curtail wastewater injection rates and low oil prices "should result in further declines in the seismicity rate and limit future widespread seismic activity."

A spokeswoman with a research and education program of the Independent Petroleum Association of America, Katie Brown, said in an email the reduced number of earthquakes "is a clear sign that the collaborative efforts between industry, scientists and regulators are working."

Largest U.S. refinery now belongs to Saudi Arabia

Charles Kennedy, Oilprice.com

Royal Dutch Shell and Saudi Aramco appear to be getting a divorce, breaking up their joint venture in U.S.-based refining assets.

The two companies joined together to create Motiva Enterprises LLC in 1998, a 50-50 joint venture that operated three refineries on the U.S. Gulf Coast. But Shell and Saudi Aramco have seen their interests head in different directions. "It is now time for the partners to pursue their independent downstream goals," said Abdulrahman Al-Wuhaib, a senior vice president of Saudi Aramco's downstream unit.

Oil Prices Jump As Dollar Hits 5-Month Lows | OilPrice.com

Reuters reported that the relationship started to fray after Motiva announced a $10 billion expansion of the Port Arthur refinery, doubling its capacity to 603,000 barrels per day, making it America's largest refinery. It produced gasoline, diesel and jet fuel. A leak shortly after the expansion was completed in 2012 led to ballooning costs, exacerbating tension between Shell and Aramco. A 2015 workers strike also sparked anger between the two companies.

The two companies signed a nonbinding letter of intent, a plan that would divide up Motiva's refineries between them. The refineries have a combined capacity of 1.1 million barrels per day and are all located close to each other. The breakup will allow Saudi Aramco to take over the Port Arthur refinery and 26 distribution terminals, and Aramco will also hold onto the Motiva brand name. Shell will take over the other two refineries, Convent and Norco, both located in Louisiana. Shell said that it would operate the two refineries as one plant with a combined throughput of 500,000 barrels per day.

Oil Prices Rally To 2016 Highs On Weaker Dollar | OilPrice.com

The split will hand the largest U.S. refinery to the state-owned Saudi oil company. The Wall Street Journal speculates that it could also pave the way for some sort of listing of Aramco's assets in a public offering, something that Saudi officials have alluded to for several months. Few expect Aramco to list its upstream production assets in Saudi Arabia; downstream assets are much more likely to be offered up.

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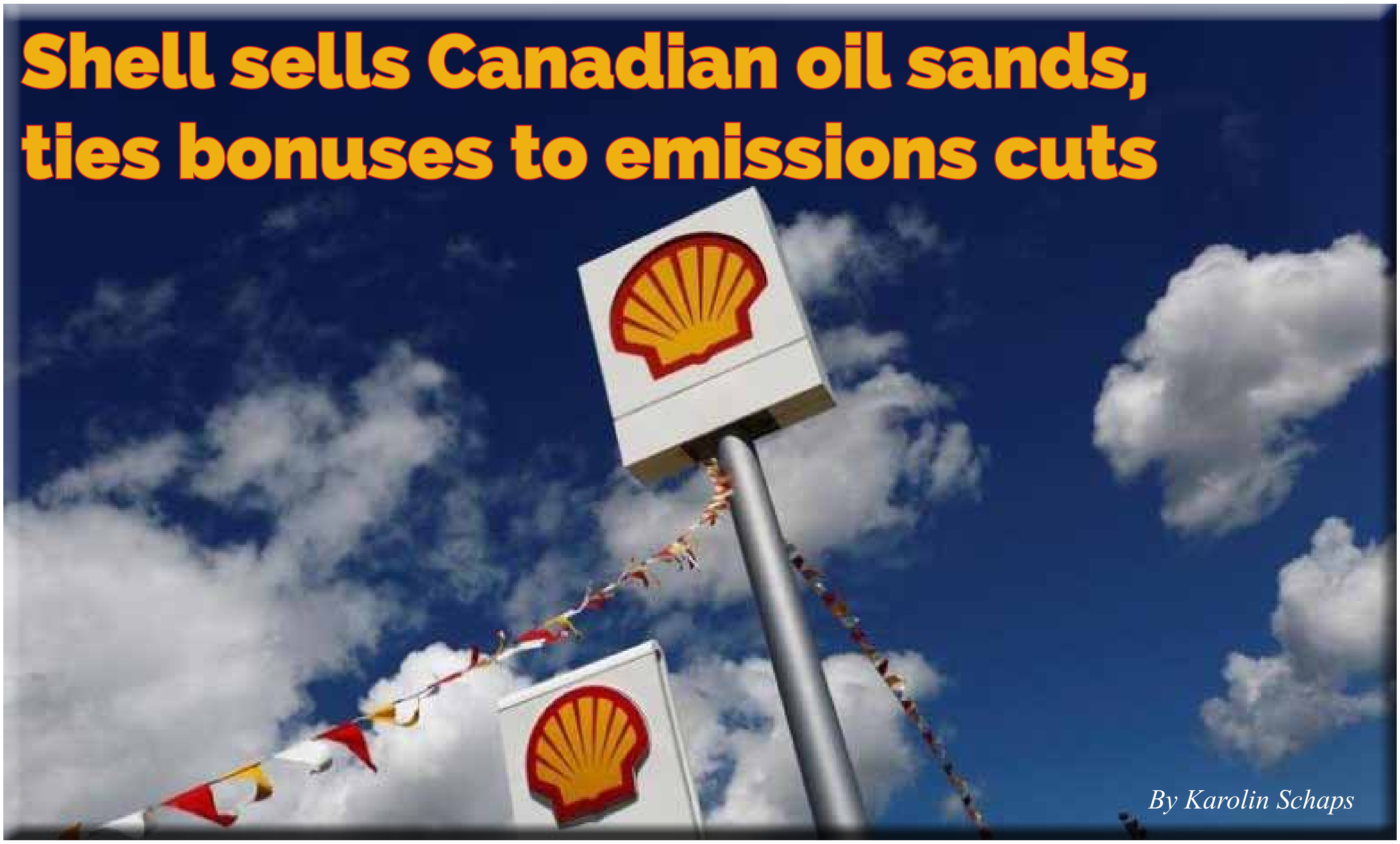
Shell sells Canadian oil sands, ties bonuses to emissions cuts



By Karolin Schaps

Royal Dutch Shell has agreed to sell most of its Canadian oil sands assets for $8.5 billion, the latest international oil major to withdraw from the costly projects, which are among the most carbon heavy.

Shell is trying to sell assets totaling $30 billion to cut debt following its $54 billion acquisition of BG Group and is under investor pressure to mitigate climate change risks.

As well as revealing the Canadian oil sands sale, Shell also said on Thursday that ten percent of directors' bonuses will now be tied to how well it manages greenhouse gas emissions in refining, chemical and upstream.

Analysts welcomed the deal, under which Shell has agreed to sell its existing and undeveloped Canadian oil sands interests to Canadian Natural and to cut its share in the Athabasca Oil Sands Project (AOSP) from 60 to 10 percent.

"This significant divestment should help de-gear Shell's balance sheet over 2017 and help remove concerns around the dividend," Biraj Borkhataria of RBC Capital Markets said.

Shell is also buying half of Marathon Oil Canada Corporation which brings the deal's value to Shell to $7.25 billion and its divestment plan total to around $20 billion as it works towards its target of $30 billion by late 2018.

Other oil firms including Exxon Mobil, Conoco Phillips and Statoil have written down or sold their Canadian oil sand assets.

Shell said it would remain as operator of the AOSP Scotford upgrader and the Quest carbon capture and storage project.

Shares in Shell were trading 1.1 percent lower at 0852 GMT, in line with the sector index that was down 1.2 percent.

The company is also replacing earnings per share in directors' long-term incentives with free cashflow, saying its disposals program had made it a more important metric.

In its annual report, Shell said its Chief Executive Ben van Beurden saw his pay jump 60 percent to 8.263 million euros ($8.7 million) in 2016, the year he pulled off the BG purchase.

Pennsylvania Natural Gas Production is Expected to Grow Significantly Over Next Decade and Beyond

Pennsylvania is the second-largest producer of natural gas in the country - with production up more than 2,400% between 2005-2014 - but our natural gas market extends beyond production. Natural gas usage fits into many aspects of our economy, including heat, power, downstream manufacturing, and electricity generation. Other natural gas uses, such as compressed natural gas, offer inexpensive transportation fuel to companies who locate in the state. With Royal Dutch Shell's planned ethylene plant and a local, reliable, and inexpensive source of feedstock, plastics products manufacturing stands to grow exponentially.

Natural gas and natural gas liquids (NGLs) – particularly ethane and propane – are powering our economy. These resources can be used in a variety of ways, including as fuel for heat and electricity generation, transportation fuel, and as valuable feedstock for downstream manufacturing of plastics and chemicals

An independent study produced by IHS Markit states that the Marcellus and Utica region has the supply and the means to recover enough ethane to support the development of an additional four world-scale ethane crackers to produce polyethylene (PE), a key resin and foundational building block for a wide variety of plastics products. This would be in addition to the planned Shell ethane cracker plant in Southwestern Pennsylvania announced in 2016.

Dakota Access Oil Line Outlasts Protests, Readies for Service

by Tim Loh , Sheela Tobben , and Ari Natter

In the end, the pipeline won.

Dakota Access, which became a rallying point for tens of thousands of anti-fossil fuel and Native American-rights protesters, is preparing for service, a court filing on Monday showed. Now that the last segment built underneath Lake Oahe has been filled with oil, it's only a matter of time before the line delivers crude from North Dakota's once-booming Bakken shale region. That'll be a boon to drillers there who've lost market share amid low oil prices to rivals in Texas and elsewhere with better access to Gulf Coast refineries and terminals.

"No doubt, this makes the Bakken more competitive," said Rob Thummel, managing director at Tortoise Capital Advisors.

The filing, by Dakota Access's developer, came just three days after the State Department issued a presidential permit approving the controversial Keystone XL oil pipeline, which when completed would run from Canada into America's heartland. President Donald Trump's support of both pipeline projects represents a dramatic reversal from former President Barack Obama's opposition to them on environmental grounds.

Until now, Bakken crude has had to travel through a circuitous network of other pipelines and by pricier rail, one reason production has fallen in North Dakota as explorers shifted their focus to cheaper Texas reserves.

It's been a long and ugly fight bringing to life one of the most contentious pipeline projects in recent memory. Just a few years ago, the Bakken was the Wild West of oil, with boom towns, man camps and casinos fueled by speculative plays on soaring oil prices. Following the crash in prices, drillers of the remote northern plains hoped new transport options like Dakota Access would help them remain competitive -- only to be stymied by fierce protests.

In early 2016, members of the Sioux nation and hardy environmentalists began camping out along the proposed route in protest. Their ranks swelled in late summer after construction crews bulldozed a site sacred to Native Americans. Hollywood celebrities including Mark Ruffalo and Leonardo DiCaprio flocked to the Standing Rock reservation to lend support. Shailene Woodley was arrested and led away in handcuffs. It all went viral on social media.

Prepping for Service

Energy Transfer is commissioning its controversial Dakota Access oil pipeline after months of protests, regulatory setbacks and two U.S. presidents weighing in.

But after Trump's election, the government swept away protesters, at one point with high-pressure water hoses in the icy North Dakota winter. And soon thereafter Trump signed an executive order clearing the way for the pipeline's final segment to be built.

$3.8 Billion

Now, finally, Energy Transfer Partners LP, the company behind the $3.8 billion project, is commissioning the 1,172-mile (1,886-kilometer) pipeline with crude. Once at full capacity, it'll be able to ship 570,000 barrels a day across four states to Patoka, Illinois, where the fuel can be diverted to markets across the Midwest and Gulf Coast.

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"Dakota Access is currently commissioning the full pipeline and is preparing to place the pipeline into service," the company said in the court filing released Monday.

The Standing Rock Sioux tribe that has protested the project for months said in a statement March 24 that it would continue to fight it in court and "stand with the many tribes threatened" by the Keystone XL pipeline too.

Once the poster-child for America's shale boom, Bakken oil output tumbled 23 percent from its peak, reaching the lowest in almost three years in December. With Dakota Access in place, the spread between Bakken crude prices and that for U.S. benchmark West Texas Intermediate could disappear as soon as June 1 because of the "sheer number of committed shippers," Andy Lipow, president of Lipow Oil Associates, a Houston-based consulting company, said by phone. That could spur more production in North Dakota as the fuel gets increasingly transported by pipe instead of rail out of the region, Lipow said.

By Rail

Dakota Access will reduce the need to ship 150,000 barrels a day by rail, according to Tony Scott, a managing director at BTU Analytics in Colorado.

"It should lower the cost for everyone in the system," Scott said in a phone interview, citing oil companies including Hess Corp. as beneficiaries since they're so heavily invested in the Bakken.

As more supplies are shipped south on Dakota Access, oil prices in Texas may fall, opening markets overseas, said Dominic Haywood, a London-based analyst for Energy Aspects Ltd.

"Producers may look to export Dakota Access crude rather than sell on the Gulf Coast," Haywood said by email.

Bakken crude priced for delivery at Clearbrook, Minnesota, was trading at $47.98 per barrel on Monday, according to data compiled by Bloomberg. West Texas Intermediate was at $47.73.

17 Banks

For months before the Trump administration cleared the way for Dakota Access, the pipeline became a symbol in the broader environmental movement to curb fossil fuels. Opponents included politicians from New York City Mayor Bill de Blasio to Seattle's city council, which called on banks to pull out of the project. Kelcy Warren, Energy Transfer's chief executive officer, said he'd underestimated the power of social media.

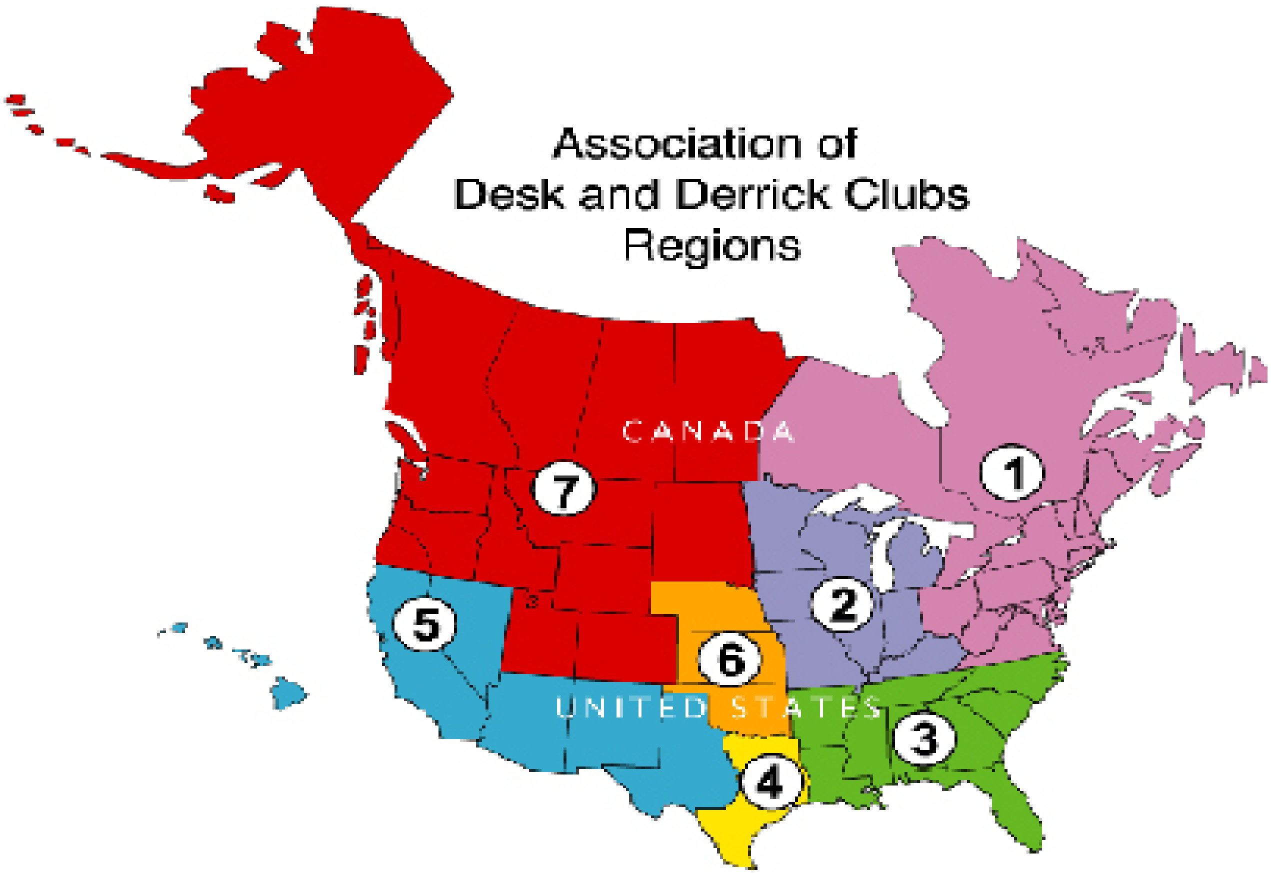
Ultimately, 17 banks including Wells Fargo & Co. and Citigroup Inc. that were contractually obligated to finance the project did so. Energy Transfer, which spearheaded the project, sold off minority stakes in it to companies including Enbridge Inc. and Marathon Petroleum Corp.

"Some of the biggest infrastructure names in the U.S. want a piece of this pipeline," said Thummel. "They all obviously think this is a critical pipeline."

The thinking, Thummel said, is the line will be operational for decades. The U.S. shale industry has established itself as a permanent and substantial supplier to global markets.

"Yes, Bakken has some economic challenges, especially with oil below $50 a barrel," he said. "But the Bakken will be relevant again at some point in the future and this pipeline is one that will help."

Association of DESK and DERRICK Clubs



Regional Meetings

Region I Meeting

Dates: May 18 – 21, 2017

Host: Penn-York Oil & Gas Affiliates Club

City: Niagra Falls, NY

Hotel: Sheraton at the Falls

REGISTRATION INFORMATION:

Region I Registration Packet

Region II Meeting

Dates: March 30 – April 1, 2017

Host: Olney Club

City: Terre Haute, IN

Hotel: Holiday Inn

REGISTRATION INFORMATION:

Region II Registration Packet

"Continued on page 32"

"Continued from page 31"

Region III Meeting

Dates: April 26 – 30, 2017

Host: El Dorado, Arkansas, Club

City: El Dorado, AR

Hotel: Holiday Inn Express

REGISTRATION INFORMATION:

Region III Registration Packet

Region IV Meeting

Dates: May 3 – 6, 2017

Host: Corpus Christi Club

City: Corpus Christi, TX

Hotel: Holiday Inn Downtown Marina

REGISTRATION INFORMATION:

Region IV Registration Packet

Region V Meeting

Dates: April 20 – 22, 2017

Host: San Angelo Club

City: San Angelo, TX

Hotel: Courtyard Marriott

REGISTRATION INFORMATION:

Region V Registration Packet

Region VI Meeting

Dates: April 27 – 30, 2017

Host: Tulsa Club

City: Tulsa, OK

Hotel: Postoak Lodge

REGISTRATION INFORMATION:

Region VI Registration Packet

GEOLOGY CERTIFICATION FLYER

Region VII Meeting

Dates: June 1 – 3, 2017

Host: Grande Prairie Club

City: Grande Prairie, AB

Hotel: Pomeroy Hotel & Conference Centre

REGISTRATION INFORMATION:

RegionVII Registration

PACKET REGION VII UPDATED ITINERARY FOR THURSDAY AND FRIDAY

"REGISTRATION PACKETS CAN BE FOUND ON-LINE AT

http://www.addc.org/about/regions-and-clubs/regional-meetings/

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Convention

66TH ANNUAL ADDC CONVENTION (2017)

San Antonio, Texas
September 19 - 24, 2017

67TH ANNUAL ADDC CONVENTION (2018)

Evansville, Indiana
September 18 - 23, 2018

68TH ANNUAL ADDC CONVENTION (2019)

Kansas City Missouri
Dates to be determined

65TH ANNUAL ADDC CONVENTION

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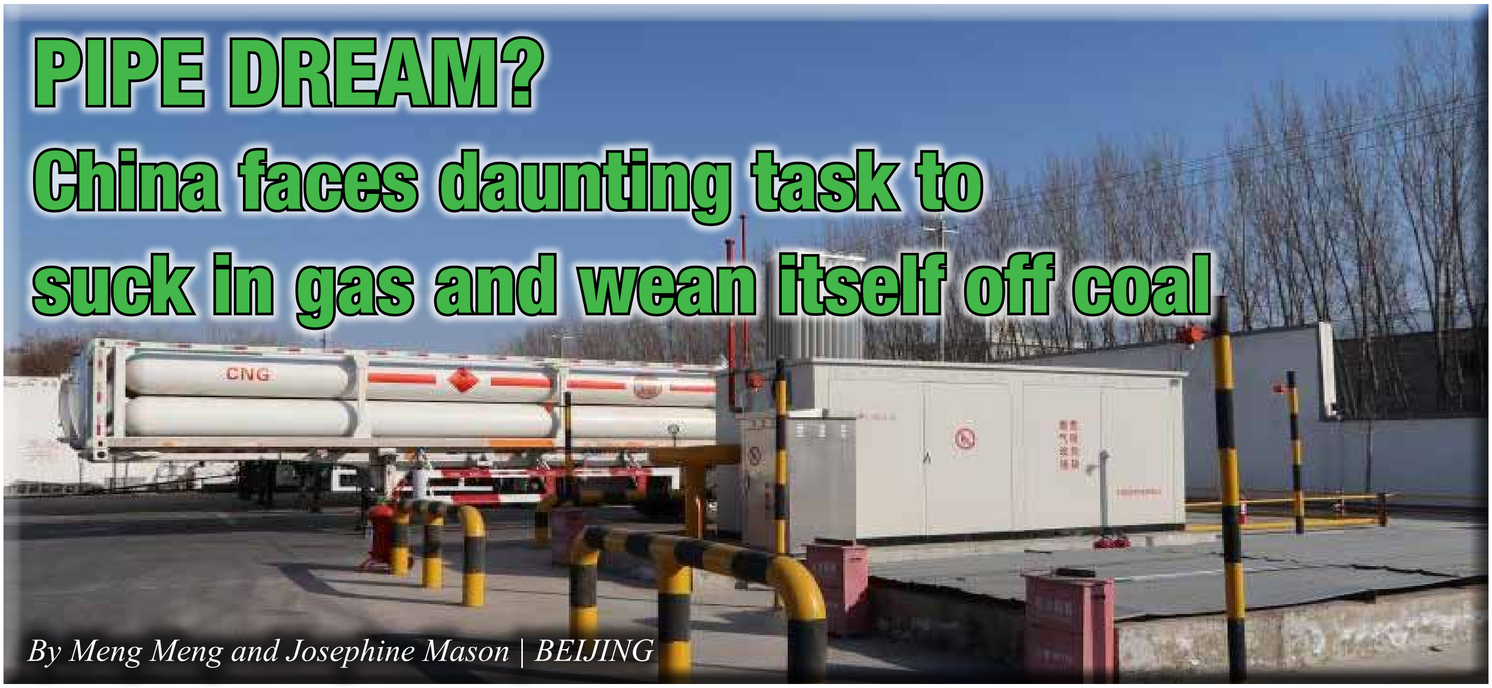
PIPE DREAM?

China faces daunting task to suck in gas and wean itself off coal



By Meng Meng and Josephine Mason | BEIJING

China has set itself a staggering task to cure its smothering pollution: switching coal-fired boilers and heating systems in at least 1.2 million households in 28 of its smoggiest northern cities to run on gas or electricity. By October.

Beijing's latest crackdown on pollution, outlined in a policy document dated Feb. 17 and seen by Reuters this week, dangles a potentially game-changing carrot for the country's saturated global natural gas market.

The projected extra needs would inflate China's gas demand by a quarter, according to consultancy Wood Mackenzie - some 50 billion cubic metres (bcm), more than the whole of France consumes in a year. That would offer the prospect of boosting prices in a seller's market and surging liquefied natural gas (LNG) imports.
There's a large, expensive catch. Such expansion is all but impossible without investing in doubling underground storage capacity, building thousands of miles of pipeline to carry the gas in the west to the eastern cities, and installing pump stations in rural villages - all of which is supposed to be complete within a meager seven months.

"The magnitude of this policy is unprecedented," said Guo Zihua, head of a rural development department at Beijing city hall that deals with villages surrounding the capital - now on the front line of the battle for cleaner air.

"The central government has given us very little time to remove coal heating in rural villages. We are under tremendous pressure to reach the target," said Guo, speaking during a tour on Thursday of Beijing's outskirts designed to highlight the scale of the task.

The radical plan comes as Beijing ramps up its years-long war on pollution by attempting to wean the nation off coal, its favorite fuel but one that chokes the north during China's cold winter months. Most power plants run on coal.

The speed at which the project turned from a draft, issued in January, into an order suggests the government is determined to tackle the problem - at any cost. The issue of pollution has become a political hot potato that will be a major topic during China's upcoming annual parliament meeting, starting on Sunday.

If Beijing official Guo's calculations are anything to go by, that cost will be enormous: by October, the capital must convert boilers serving around 300,000 residents to run on gas or electricity rather than coal, and is plowing 10 billion yuan ($1.45 billion) into funding the switch.

And for provinces that aren't as advanced as the capital, the challenge will be much more difficult and costly, said an official at the city's coal department on Thursday.

HUGE QUESTIONMARKS

As well as a matter of improving national health, curbing

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pollution is a key part of a strategy of upgrading the economy by shifting away from heavy industry like public construction projects and tackling overcapacity.

Yet analysts say the plan's fate will rest on a massive, breakneck infrastructure build-out including LNG terminals, storage tanks and pipelines.

"If you look at the pollution in China, it's clearly a massive problem so it's not a surprise they want to do this," said Neil Beveridge, senior oil and gas analyst at Sanford C Bernstein. "The big question is: how are they going to achieve it?"

Underground storage capacity needs to increase to around 40 bcm, or 20 percent of annual demand, to support the boost in demand. That'd be up at least more than double an estimated current capacity 10-20 bcm.

ALSO IN COMMODITIES

Oil majors reverse decade of stalled growth to beat supply crunch fears

ChemChina says Syngenta deal filing accepted by Beijing

The daunting scale of the plan leaves huge questionmarks over the prospects of its success. But in the meantime, construction and energy companies are gearing up for a windfall.

Some, like China National Petroleum Corp [CNPET.UL] (CNPC), were already at work on extending the country's gas infrastructure. CNPC is building the fourth Shaanxi-Beijing gas pipeline, a critical 1,114 kilometer line with 25 bcm capacity reaching China's northeastern region.

The existing three lines with 35 bcm are already operating at full capacity. Whether by coincidence or design, the new pipe is due to come into operation by October this year.

(Reporting by Meng Meng and Josephine Mason; Editing by Kenneth Maxwell)

On July 7, 1919, a group of U.S. military members dedicated Zero Milestone – the point from which all road distances in the country would be measured – just south of the White House lawn in Washington, D.C. The next morning, they helped to define the future of the nation.

Instead of an exploratory rocket or deep-sea submarine, these explorers set out in 42 trucks, five passenger cars and an assortment of motorcycles, ambulances, tank trucks, mobile field kitchens, mobile repair shops and Signal Corps searchlight trucks. During the first three days of driving, they managed just over five miles per hour. This was most troubling because their goal was to explore the condition of American roads by driving across the U.S.

Participating in this exploratory party was U.S. Army Captain Dwight D. Eisenhower. Although he played a critical role in many portions of 20th-century U.S. history, his passion for roads may have carried the most significant impact on the domestic front. This trek, literally and figuratively, caught the nation and the young soldier at a crossroads.

Returning from World War I, Ike was entertaining the idea of leaving the military and accepting a civilian job. His decision to remain proved pivotal for the nation. By the end of the first half of the century, the roadscape – transformed with an interstate highway system while he was president – helped remake the nation and the lives of its occupants.

For Ike, though, roadways represented not only domestic development but also national security. By the early 1900s it become clear to many administrators that petroleum was a strategic resource to the nation's present and future.

At the start of World War I, the world had an oil glut since there were few practical uses for it beyond kerosene for

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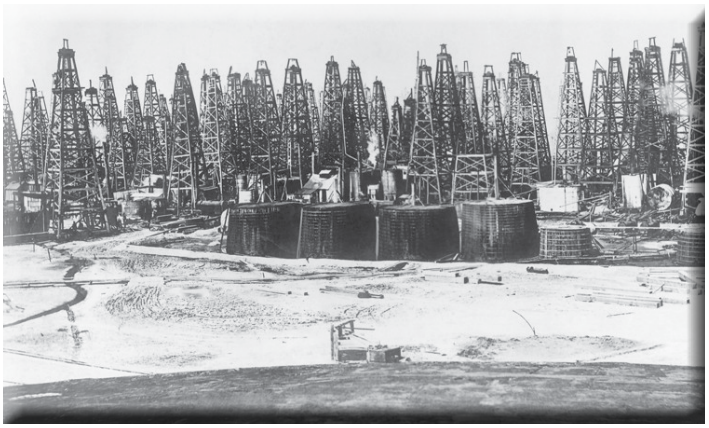
lighting. When the war was over, the developed world had little doubt that a nation's future standing in the world was predicated on access to oil. "The Great War" introduced a 19th-century world to modern ideas and technologies, many of which required inexpensive crude.



Prime movers and national security

During and after World War I, there was a dramatic change in energy production, shifting heavily away from wood and hydropower and toward fossil fuels – coal and, ultimately, petroleum. And in comparison to coal, when utilized in vehicles and ships, petroleum brought flexibility as it could be transported with ease and used in different types of vehicles. That in itself represented a new type of weapon and a basic strategic advantage. Within a few decades of this energy transition, petroleum's acquisition took on the spirit of an international arms race.

Even more significant, the international corporations that harvested oil throughout the world acquired a level of significance unknown to other industries, earning the encompassing name "Big Oil." By the 1920s, Big Oil's product – useless just decades prior – had become the lifeblood of national security to the U.S. and Great Britain. And from the start of this transition, the massive reserves held in the U.S. marked a strategic advantage with the potential to last generations.

As impressive as the U.S.' domestic oil production was from 1900-1920, however, the real revolution occurred on the international scene, as British, Dutch and French European powers used corporations such as Shell, British Petroleum and others to begin developing oil wherever it occurred.

During this era of colonialism, each nation applied its age-old method of economic development by securing petroleum in less developed portions of the world, including Mexico, the Black Sea area and, ultimately, the Middle East. Redrawing global geography based on resource supply (such as gold, rubber and even human labor or slavery) of course, was not new; doing so specifically for sources of energy was a striking change.

Crude proves itself on the battlefield

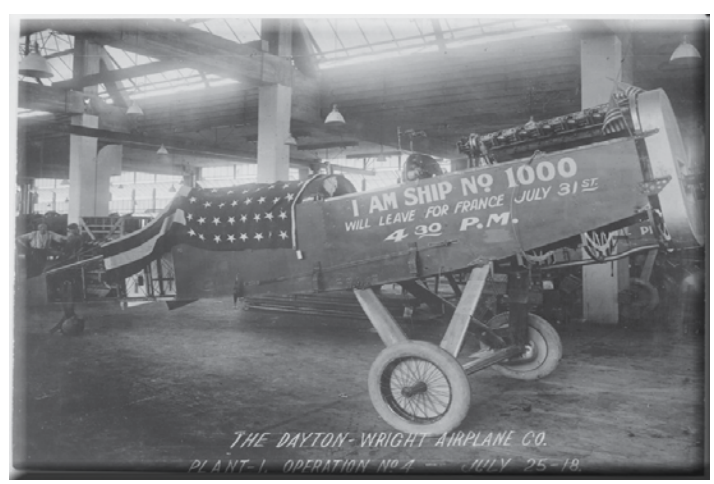
"World War I was a war," writes historian Daniel Yergin, "that was fought between men and machines. And these machines were powered by oil."

When the war broke out, military strategy was organized around horses and other animals. With one horse on the field for every three men, such primitive modes dominated the fighting in this "transitional conflict."

Throughout the war, the energy transition took place from horsepower to gas-powered trucks and tanks and, of course, to oil-burning ships and airplanes. Innovations put these new technologies into immediate action on the horrific battlefield of World War I.

It was the British, for instance, who set out to overcome the stalemate of trench warfare by devising an armored vehicle that was powered by the internal combustion engine. Under its code name "tank," the vehicle was first used in 1916 at the Battle of the Somme. In addition, the British Expeditionary Force that went to France in 1914 was supported by a fleet of 827 motor cars and 15 motorcycles; by war's end, the British army included 56,000 trucks, 23,000 motorcars and 34,000 motorcycles. These gas-powered vehicles offered superior flexibility on the battlefield.

In the air and sea, the strategic change was more obvious.



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By 1915, Britain had built 250 planes. In this era of the Red Baron and others, primitive airplanes often required that the pilot pack his own sidearm and use it for firing at his opponent. More often, though, the flying devices could be used for delivering explosives in episodes of tactical bombing. German pilots applied this new strategy to severe bombing of England with zeppelins and later with aircraft. Over the course of the war, the use of aircraft expanded remarkably: Britain, 55,000 planes; France, 68,0000 planes; Italy, 20,000; U.S., 15,000; and Germany, 48,000.

With these new uses, wartime petroleum supplies became a critical strategic military issue. Royal Dutch/ Shell provided the war effort with much of its supply of crude. In addition, Britain expanded even more deeply in the Middle East. In particular, Britain had quickly come to depend on the Abadan refinery site in Persia, and when Turkey came into the war in 1915 as a partner with Germany, British soldiers defended it from Turkish invasion.

When the Allies expanded to include the U.S. in 1917, petroleum was a weapon on everyone's mind. The Inter-Allied Petroleum Conference was created to pool, coordinate and control all oil supplies and tanker travel. The U.S. entry into the war made this organization necessary because it had been supplying such a large portion of the Allied effort thus far. Indeed, as the producer of nearly 70 percent of the world's oil supply, the U.S.' greatest weapon in the fighting of World War I may have been crude. President Woodrow Wilson appointed the nation's first energy czar, whose responsibility was to work in close quarters with leaders of the American companies.

Infrastructure as a path to national power

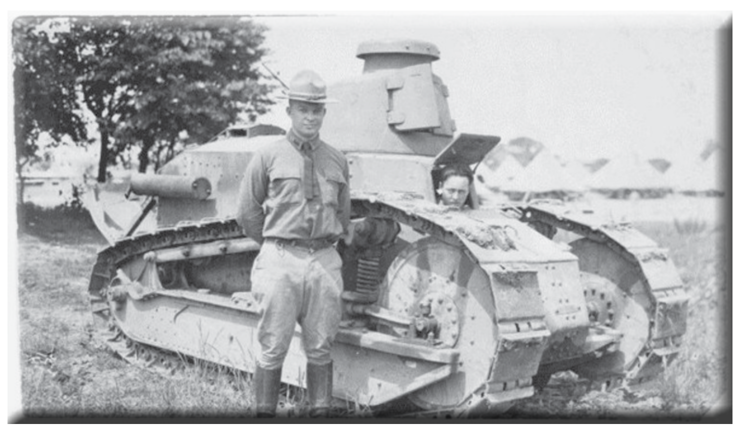
When the young Eisenhower set out on his trek after the war, he deemed the party's progress over the first two days "not too good" and as slow "as even the slowest troop train." The roads they traveled across the U.S., Ike described as "average to nonexistent." He

"In some places, the heavy trucks broke through the surface of the road and we had to tow them out one by one, with the caterpillar tractor. Some days when we had counted on sixty or seventy or a hundred miles, we could do three or four."

Eisenhower's party completed its frontier trek and arrived in San Francisco, California on Sept. 6, 1919. Of course, the clearest implication that grew from Eisenhower's trek was the need for roads. Unstated, however, was the symbolic suggestion that matters of transportation and of petroleum now demanded the involvement of the U.S. military, as it did in many industrialized nations.

The emphasis on roads and, later, particularly on Ike's interstate system was transformative for the U.S.; however, Eisenhower was overlooking the fundamental shift in which he participated. The imperative was clear: Whether through road-building initiatives or through international diplomacy, the use of petroleum by his nation and others was now a reliance that carried with it implications for national stability and security.

Seen through this lens of history, petroleum's road to essentialness in human life begins neither in its ability to propel the Model T nor to give form to the burping plastic Tupperware bowl. The imperative to maintain petroleum supplies begins with its necessity for each nation's defense. Although petroleum use eventually made consumers' lives simpler in numerous ways, its use by the military fell into a different category entirely. If the supply was insufficient, the nation's most basic protections would be compromised.



After World War I in 1919, Eisenhower and his team thought they were determining only the need for roadways – "The old convoy," he explained, "had started me thinking about good, two lane highways."

At the same time, though, they were declaring a political commitment by the U.S. And thanks to its immense domestic reserves, the U.S. was late coming to this realization. Yet after the "war to end all wars," it was a commitment already being acted upon by other nations, notably Germany and Britain, each of whom lacked essential supplies of crude.

OIL COMPANIES' MODEST PRIZE: BREAKING EVEN

By SARAH KENT
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A Shell oil rig near Mentone, Texas. While Shell and Exxon notched stronger quarters late last year, analysts point to challenges ahead. PHOTO: MATTHEW BUSCH/BLOOMBERG NEWS

The world's biggest oil companies are struggling just to break even.

Despite billions of dollars in spending cuts and a modest oil-price rebound, Exxon Mobil Corp. , Royal Dutch Shell PLC, Chevron Corp. and BP PLC didn't make enough money in 2016 to cover their costs, according to a Wall Street Journal analysis.

To calculate each companies' free cash flow—the excess cash remaining after costs—the Journal deducted the firm's dividends and capital expenditures from its cash from operations. All four firms fell short of cash flow for the year, although Exxon said it broke even by its own metrics, which exclude dividends. The analysis also showed that the four companies ended last year with more debt than they began it.

The firms are showing signs of improvement. For example, Shell and Exxon notched stronger quarters late last year. However, analysts point to challenges ahead as oil prices hover around $50 a barrel. BP says it will need oil at $60 a barrel to balance cash generation against capital expenditures and dividends, while Chevron is targeting $50 a barrel with the help of asset sales. Investment bank Jefferies estimates neither Shell nor Exxon require more than $50 a barrel, though those companies don't disclose break-even prices.

For companies once known as profit machines—whose executives were hauled before Congress in 2005 to explain their enormous earnings—their cash problems demonstrate just how unprepared they were for a historic crash and tepid recovery in oil prices. They have maintained the same large dividends they had when oil prices were over $100 a barrel, piling on debt and selling off assets to prioritize shareholders above all else.

The result is that spending on dividends and capital investments has ballooned above cash generated from their businesses. The issue has worried investors who expect those steady dividends because oil giants don't have the capacity to grow much. Exxon, Shell and their competitors are under pressure to show they can drum up cash to keep shelling out dividends.

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"Since the oil price collapsed, it's been all about who's fastest down the road to breaking even," said Iain Reid, a senior analyst at Macquarie Capital. "In the short term, it's all about cash flow because people are still worried about the dividend."

Exxon, Shell and their peers spent much of the past three years scrambling to reassure investors that their dividends were safe amid the oil-price crash. These companies were already struggling to live within their means at elevated oil prices.

In response to the tumble in prices, the companies laid off thousands of workers, slashed billions in spending and piled on debt to protect the payouts. Despite disappointing profits last year, they say that medicine is now working.

Both Exxon and Shell managed to break even in the final quarter last year. In the fourth quarter, Exxon generated $400 million more than it spent and Shell made $1.2 billion over its outlays, according to the Journal's analysis. However, for the full year, Exxon spent nearly $7 billion more on developing new projects and dividends in 2016 than it generated in cash. Shell's costs last year were around $11 billion above its cash generation, the Journal's analysis shows.

"We are right in the middle of transforming the company," Shell Chief Executive Ben van Beurden told the CERAWeek conference in Houston in March. "We are going to be able to produce a free cash flow that is going to be more than twice as high as it was in the $90 era, but this time in a $60 world."

In a sign that investors remain fixated on companies' cash flow position, BP's share price tumbled around 4% when the company upgraded its break-even oil price to $60 a barrel in February.

International benchmark Brent crude hasn't hit that level since the middle of 2015.

"The ultimate goal of the company is to generate excess free cash flow," BP Chief Executive Bob Dudley said in a March interview in Houston. The company has seven new projects starting up this year and nine more under way that will add 800,000 barrels a day of new production by the end of the decade, pushing up returns.

BP expects to drive its break-even price back down toward $55 a barrel by the end of the year from about $60 now.

"The message going forward is good," Chevron Chief Executive John Watson told analysts in January. "Four years ago, I wouldn't have thought that would be the case at moderate prices."

But all of the companies' ability to break even rely on forces outside their control, especially oil prices.

In February, investment banks predicted oil prices would average about $57 a barrel this year, according to a Wall Street Journal poll. Analysts said prices could fall short of that mark depending on how quickly U.S. shale producers ramp back up and whether the Organization of the Petroleum Exporting Countries can maintain its agreement with other major oil producers to reduce output.

Chevron's $50-a-barrel break-even threshold relies in part on support from asset sales. Shell also is leaning heavily on plans to divest $30 billion of assets by next year to help it bring down its elevated debt levels. At the end of last year, the four companies' combined net debt amounted to $186.3 billion.

"This is the year when their credibility will be tested," said Jefferies analyst Jason Gammel, referring to big oil companies. "Some are more capable than others."

Even Exxon, the world's biggest publicly traded oil company, is showing rare signs of weakness. The company wrote down the value of more than $2 billion in U.S. assets earlier this year and shaved a chunk off its reserves estimates because of Securities and Exchange Commission rules. It ended 2016 with net debt totaling $39.1 billion—the highest debt level in the company's history.

Exxon said its balance sheet remains stronger than those of competitors.

—Bradley Olson contributed to this article.

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