Emerging from the downturn, optimism from Bakken-industry players highlights why most see the play as another opportunity waiting to happen.

By Patrick C. Miller | June 18, 2018

The rising tide of oil prices has lifted the Bakken shale play to the lofty position of No. 1 in netback per well drilled, which has not only resulted in predictions of a new oil production record for North Dakota this summer, but also a renewed sense of optimism among industry insiders about the play’s future.

The annual Williston Basin Petroleum Conference—sponsored by the North Dakota Petroleum Council—attracted more than 2,500 people from 40 states, three countries and six Canadian provinces. Many of the event’s participants outlined their plans while explaining why they considered the Bakken one of the top plays in the U.S.

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(Continue on Page 2)

08 August 2018

In early 2018, with the drilling of two lateral wells that hit lengths of 17,875 ft and 18,129 ft, respectively, Range Resources once again broke the record for longest laterals drilled in the Marcellus play—an area that includes Ohio, West Virginia, and Pennsylvania. It was an important new milestone for the company, but not because they broke a record.

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GEO PRODUCT INTRODUCTION

THE PERFFLOW® SYSTEM

A One-Trip Fluid for Reservoir Drill-In and Completion Applications

GEO drilling Fluids’ PERFFLOW system is an effective reservoir drillin fluid designed to lower overall completion costs while optimizing both initial and longterm production rates. PERFFLOW acts as a drilling fluid while insulating production zones against drill-in damage. As a standard drilling fluid, PERFFLOW provides lubricity, inhibition, solids suspension, cuttings removal, and improved wellbore stability. In its protective role, PERFFLOW controls filtration, remains intact during completion, and is easily removed with production. The system’s excellent performance has made it effective in a number of wellsite applications. These applications include its use as a coring fluid, fluid loss pill, underreaming fluid, and a kill fluid. In addition, PERFFLOW has been used to efficiently control fluid leakoff during openhole gravel packs.

DRILL-IN FLUID APPLICATIONS

The PERFFLOW system is designed to meet our clients' drilling fluid needs in a wide range of wellsite applications. These include:

Reservoir Drill-In Fluid - PERFFLOW can be used to drill through older skin damage, effectively establishing new production in previously damaged wellbores.

Extended reach wells - PERFFLOW protects large areas of exposed reservoir while providing excellent lubricity and hole cleaning.

Coring Fluid - PERFFLOW delivers efficient leak off control, providing core samples that closely resemble their native state.

Fluid Loss Pill - PERFFLOW’s filter cake quickly seals formations, reducing fluid losses in both drillin and completion applications.

Underreaming Fluid - PERFFLOW may be used when utilizing hole openers to protect the newly exposed production surfaces.

Completion Fluid Applications - In addition to utilizing PERFFLOW as a drillin fluid, it can perform effectively in a number of completion fluid applications including:

Open-Hole Gravel Packs - PERFFLOW protects against fluid leak off while circulating open-hole gravel packs. In addition, the filter cake is removed by the production FLOW without acidizing or specialized cleanup measures.

Kill Fluid - The density of a PERFFLOW fluid can be modified with weighting materials for well control.

(Continue on Page 7)
In fact, in early 2017 when Range drilled its first well that exceeded 15,000 lateral ft, the team didn’t realize it had set a record-setting length until 2 months afterward. “It’s exciting when something like that happens, but our true objective is to continue lowering our cost per lateral ft (CPLF).”

As Robinson explains it, natural gas drillers have traditionally used cost per ft (CPF) as their most important Key Performance Indicator (KPI). “It’s a number that is simply derived by dividing the total drilling cost by the measured depth of the well, and it’s been the standard by which drillers have measured their efficiency and productivity.”

But now, with technological advancements that are allowing drillers to achieve lateral lengths that would have been considered unattainable just a few short years ago—that metric no longer works. “How do you compare a $1.3 million, 7,000-ft lateral length well to a $2.2 million, 15,000-ft lateral length well?” said Robinson.

A drilling team is tasked with providing lateral footage that is then handed over to a completions group to be hydraulically fractured (fracked.) “Drilling’s objective is to provide each lateral ft at the lowest possible cost; while utilizing precise targeting and steering to keep the wellbore in the sweet spot of the formation. After that, a properly cemented production string is required to maximize the effectiveness of the hydraulic fracturing. With that in mind, all operators must now focus on minimizing their cost per lateral ft (CPLF), the new drilling KPI,” said Robinson.

For the past 6 years, the drilling team at Range has steadily increased lateral lengths, leading to significant decreases in cost per lateral ft. The performance has also included improvements to rate of penetration (ROP) and reduced flat time, together with reductions in connection time and trip time. Avoiding the loss of directional assemblies has also been key, along with carefully managing the impacts of fluctuating service costs.

The difference in the lateral lengths being drilled today as opposed to 6 years ago is substantial. In 2012, Range’s average lateral length was 3,123 ft; by 2018 their lateral length had increased by 324% to 10,133 ft. Put another way, one well drilled in 2018 is the approximate equivalent of 3.2 wells drilled in 2012. In 2018, a full 78% of Range’s wells have exceeded 8,000 lateral ft, and 18% of this year’s wells have exceeded 14,000 ft.

The effort to reduce the cost per lateral ft has been consistent. “Five years ago, when we were first plotting comparisons of lateral lengths drilled in 2012 versus 2013 and evaluating drilling cost per lateral ft, we immediately realized the true value of longer laterals,” said Robinson. “By spending another day or two we could essentially double the lateral footage, which was the equivalent of drilling a second well in two days. In 2013, a 27% increase in average lateral length reduced our costs per lateral ft by 24%.”

Today, Range and other operators are continuing to push their laterals out to nearly 3.5 miles, a trend Robinson points to as an indicator of the increased value in longer horizontal wells. Range also has an advantage with regard to the company’s “blocked-up” acreage position in southwestern Pennsylvania—a circumstance that can more freely allow for the drilling of wells at or in excess of 18,000 ft. However, while Robinson makes it clear he believes there is a limit to lateral lengths, he also says they haven’t hit it so far.

“The curve is definitely flattening out. We saw our annual reduction in cost per ft peak at 26% in 2016, it dropped to 16% last year, and it’s expected to be in single digits this year. But by all appearances, lateral lengths will continue to increase until there is no further CPLF reduction. And once that happens, drillers will likely seek new and better technology to solve that issue. In the meantime, the logic behind drilling an 18,000 ft or longer lateral length well is simple math. When you consider that back in 2012 the drilling of a 3,000 ft lateral length well was costing nearly $2 million per well, and in 2018 you can drill an 18,000 ft lateral length for well under $3 million, then it becomes obvious that you’ve experienced a major game changer.”
DRILLING FOR MILES IN THE MARCELLUS: LATERALS REACH NEW LENGTHS CONT’D

Last year, the number of horizontal rigs Range had working was down 5% from 5 years prior, while the number of wells the company drilled was down 9%. However, even with those slight decreases, the number of lateral feet drilled jumped from less than 400,000 in 2012, to over 1.1 million in 2017—an increase of 280%.

Longer laterals also have major surface footprint benefits; as drilling companies can now significantly reduce the number of drill sites needed to produce the same volumes that would have previously required additional wells. In a state like Pennsylvania, where hilly terrain often requires sophisticated and costly site preparation, the cost savings and reduced impact on the environment and local communities that come with drilling fewer sites is a significant value add for numerous stakeholders.

RIG CHANGES
As longer laterals have become the norm, adaptations continue to be made industrywide.

“Operators continually seeking improvements have created some challenges for the industry’s drilling contractors,” said Robinson. “As the play has evolved, rig requirements have continued to change. Over time, modifications have included walking packages, more powerful pumps, stronger top drives, and more rack back capacity. Now, most operators require 7500 psi rated pumps and an increasing number of operators also require a third pump along with an additional generator.”

Range is among the operators that have increased the pump pressure rating from 5000 psi working systems to 7500 psi due to longer laterals. The 1600 horsepower (hp) pumps had been the norm for the Marcellus wells but two of the rigs working for Range now utilize 2,000 hp pumps. That allows for a needed increase in maximum pressure from 5,000 psi (which was sufficient for laterals up to 12,000 ft) to the 6,000 to 7,000 psi working pressure that is required for extending the laterals. Robinson explained that added pressure is needed to clean the hole by increasing annular velocities and provide the additional power required for rotary steerable tools.

DRILLING FLUIDS CHANGES
As drillers have encountered added friction in wells with laterals that stretch out more than three miles, they’ve had to make some changes with regard to drilling fluids. In the Marcellus, the vast majority of operators are utilizing oil-based muds that provide superior lubrication and improved inhibition for wellbore stability, compared to water-based muds that were the previous standard.

“When we first started drilling lateral lengths over 10,000 ft, we quickly recognized that we were going to have to bite the bullet and make some changes,” said Robinson. “We could no longer run lower cost water-based mud, we had to switch to more costly oil-based mud.”
Once the company made the switch, they began using oil-based mud on all their laterals, longer and shorter, finding that route to be more practical than changing the type of mud from well to well. As a result, incremental costs were increased by an amount approximately equivalent to adding two days to the cost of the well. However, the decrease in both risk and potentially expensive consequences has been considered an appropriate offset to any of the additional drilling fluid expenditures.

ELIMINATING “TRAIN WRECKS”

According to Robinson, the most likely cause for dramatically overspending a Drilling AFE (Authority for Expenditures) is the loss of a costly directional drilling assembly in the hole, whether by twisting off, or getting stuck and becoming irretrievable.

“In 2013 we lost a number of directional assemblies. It’s very expensive, the cost for losing just the tools was typically somewhere between $600,000 to $1 million per incident, and then you have the added amount of the hole you lost on top. It’s the type of loss that makes you feel like you’ve had a bad month, and it only takes a couple of ‘train wrecks’ to negatively impact your cost per lateral ft.”

After those directional assembly losses in 2013, Range took what some might consider drastic action—idling rigs and putting a stop to drilling for nearly a week as the company investigated what went wrong. Afterward, measures were put in place that have since sharply reduced the number of similar incidents. “We actually expected to experience a greater frequency of lost directional assemblies as we’ve continued drilling longer laterals, but that hasn’t happened. We do take extra precautions to avoid problems as we extend our laterals. Trust me, you don’t want to lose 18,000 ft of lateral hole along with the directional tools if there was something you could have done to prevent it,” Robinson added.

In 2017 the team experienced a stuck tool on one of Range’s first 15,000 ft laterals; which led to additional efforts to make sure the hole is clean, and to ensure the rig crew “is never in too big of a hurry after we’ve received some obvious warning signs,” said Robinson. “If you cannot get the casing to the bottom and perform an adequate cement job, you really haven’t accomplished anything.”

Today, wellbore stability remains a primary objective, with the team focused on maintaining sufficient mud weight, monitoring pump pressure and torque, and constantly monitoring the cuttings coming across the shaker to head off any potential problems.

“Rubble is your enemy when you are trying to drill a lateral hole,” said Robinson. “When we see large, baseball–sized chunks of shale coming across the shaker or a massive amount of cuttings piling up on the shakers, we know we have to get things settled down prior to resuming drilling.”

Unchanged Goal

As he looks toward the future of drilling, Robinson anticipates that lateral lengths for all operators will continue to grow. And while he can’t be sure where the cut-off lies, he emphasizes that no matter how many feet Range and other operators may ultimately hit, the most important question will remain the same, “At what cost per lateral foot?” In the meantime, “We’re excited about the lateral lengths we’re drilling, and we’re constantly testing new ideas and exploring new technology to become even more efficient.”
WHY CALIFORNIA OIL PRODUCTION NEEDS TO RAMP UP CONT’D

HAGIN Investment Management. California’s extensive shale reserves and diatomite formations have yet to be fully exploited by independents and remain largely untapped. California has not permitted a new offshore well since 1969.

While investors often mistakenly believe that California is a difficult state to work in because of its tighter regulatory framework, the state ranks third in oil refining capacity as of January 2017 with 18 refineries, according to the EIA.

“The perception is that it’s too risky because of the regulations, but California is an overlooked opportunity for producers despite the hurdles,” he said.

As demand in California continues to rise, production has dipped, giving California’s main producers an opportunity to benefit from higher oil prices with some companies receiving a premium to WTI and Brent prices for their crude oil. The cost to transport oil into California is high due to a shortage of transportation infrastructure including rail.

While California used to import more oil from Alaska, that state is also producing less oil. California is importing its oil from Canada, Saudi Arabia and other countries from the Middle East and South America.

“Alaskan oil production has dropped dramatically due to low crude oil prices, high drilling and operating costs and the recent changes in the state’s tax rebate policies,” Morris said.

One advantage of drilling in California is that many of the fields have more sand thickness in their composition and less rock, making drilling 10,000-ft wells less costly at an average of $1.2 million to $2 million per well, said Rod Eson, CEO of Foothill Energy, which owns and operates oil and gas properties in Texas and California and produces 200 barrels of oil per day (bbl/d) within 3 sq. mi. in California.

Eson says states like Colorado and Louisiana also have their barriers to entry because their state regulations can be strict while Texas has its drawbacks because it is highly competitive.

“The environmental guidelines are tougher than other places, but reasonable and companies just need to work with the counties and cities,” he said. “It’s easy to drill in California—it’s a give and take, and we have learned how to work with the regulators.”

Since the refiniers in California need light oil to blend, producers are reaping the rewards of higher oil prices.

“There are opportunities in California—the newer technology in the rigs has reduced costs,” Eson said. “We can live with oil being $50 to $60 a barrel because we can still make a profit.”

Despite the perception that working in California is more challenging, oil companies can thrive in the state as long as they budget for more time to obtain permits and other regulatory approvals, said Trem Smith, CEO of Berry Petroleum, a Bakersfield, Calif., exploration and production company which emerged from the Linn Energy bankruptcy in March 2017 with new management and board members. Berry’s oil and natural gas reserves are located in the San Joaquin Basin in Kern County, Calif., the Uinta Basin in Utah, the Piceance Basin in Colorado and the East Texas Basin in Texas.

The company is focused on California since 70% of its total fourth quarter 27,000 boe/d production is derived from the state.

“It is certainly manageable, but do not pretend your company can do it faster than the law allows you to,” he said. “Having prior overseas experience myself, I find it refreshing to have rules. If you don’t like it, then there are probably better places for you to be.”

California is not unique its regulatory and environmental requirements, says Smith. “California is not exempt,” he said. “Texas, Utah, Colorado and Pennsylvania have their own regulatory issues. There is always pressure and politicians trying to change things.”

The state is a growth opportunity for Berry since the San Joaquin Basin still has a tremendous amount of untapped oil to be recovered since it is known as a “Super Basin,” Midway-Sunset, Kern River, South Belridge and the Elk Hills fields have produced approximately 8.5 Bbbl or oil.

While most industries fear more competition, Smith says the addition of more producers than the existing ones would be good for the industry. California has historically had few operators and the current landscape is dominated by Chevron, CRC, Aera Energy, a joint venture of Shell Oil and ExxonMobil, and Sentinel Peak.

“One of the producers in California are producing from existing oil fields and are not actively looking to grow,” he said. “We view that as an opportunity and it would be nice to have more operators in the basin.”

Berry has been focused on increasing their production and reported a 3% fourth quarter increase compared to third quarter in 2017.
WHY CALIFORNIA OIL PRODUCTION NEEDS TO RAMP UP CONT’D

“We turned around a significant inherited production decline of 20% in 2017,” Smith said. “Production is moving up and our wells have a low natural decline.” While California is not a “walk in the park,” once investors see the data, they tend to change their mind, he said. Since the basins have conventional, shallow wells, drilling can be completed for $300,000 to $500,000 within seven days and is typically cheaper than hydraulic fracturing.

The decline in production in the state needs to be reversed.

“We have lots of opportunities to expand in the Belridge, Midway Sunset and McKittrick oil fields,” Smith said.

The chronic energy deficit in California needs to be changed, said Todd Stevens, CEO of California Resources Corp. (NYSE: CRC), a Los Angeles-based oil and natural gas exploration and production company which produces 126,000 bbl and is the largest operator in the state.

“California is misunderstood and like an island since transporting oil by rail is too costly,” he said. “However, our crude oil has less impurities and is better for refiners.”

Production in the state remains high—Kern County, which includes Bakersfield, produces more crude oil than the state of Oklahoma.

As oil prices have rebounded, investors have shifted their attention to CRC’s inventory and how the company will add value.

“Investors now realize the opportunities are there and California is not dramatically different from Colorado or Pennsylvania,” said Stevens. “It would help to have competition.”

MUDMEN’S CORNER

GEO’S MUD SCHOOL

Kevin Helms – Tech Manager GEO Drilling Fluids, Inc.

GEO conducts an in-house Mud School for all our Drilling Fluids Specialist (DFS), or Mud Man for short. As a graduate of GEO Drilling Fluids Mud School, you will be well responsible for the execution of drilling fluid activities at the well site in a professional and organized manner. Supporting clients drilling activities at various sites you will be required to determine client’s fluid requirements, establish effective relationships with key rig site personnel and ensure all daily and post job reports are correctly completed and distributed to the relevant personnel. Our DFS are responsible for the maintenance of drilling fluid properties via chemical and physical treatment as dictated by the customer and supervision of all mud treatment ensuring the correct use and maintenance of solids control equipment. GEO’s Mud School is typically 6-8 weeks depending on previous experience.

Mud School Topics:

- **FUNCTIONS AND TESTING OF DRILLING FLUIDS**: Density of Fluid Weight, Viscosity, Sand Content, Liquid and Solid Content, Hydrogen-Ion Concentration (pH), Filtration, Chemical Analysis
- **ENGINEERING DATA AND CALCULATIONS**: System Volumes, Pump Outputs, Solids Analysis
- **COMPOSITION AND PROPERTIES OF CLAY-WATER MUDS**: Clay Chemistry, Factors Affecting the Yield of Clays
- **FLOW CHARACTERISTICS AND GEL STRENGTHS**: Rheology, Chemical Treatments
- **FILTRATION AND FLUID LOSS CONTROL AGENTS**: Factors Affecting Filtration, Additives for Filtration Control
- **POLYMER TECHNOLOGY**: Polymer Chemistry, Polymer Types, Polymer Application
- **INHIBITIVE MUDS**: Calcium Treated Systems, Lignosulfonate Systems, Salt Systems
- **CHEMICAL CONTAMINATION**: Contaminants, Symptoms of Various Contaminants and Treatment
- **SOLIDS CONTROL**: Techniques, Equipment
- **HYDRAULICS**: Particle Slip Velocity Calculation, Reynolds Number Calculation, Annular Pressure Loss Calculation
- **LOST CIRCULATION**: Causes, Preventive and Corrective Measures, Mud Additives and Squeezes, Procedures
- **STUCK PIPE**: Mechanically Stuck Pipe, Causes, Preventative Measures
- **DIFFERENTIALLY STUCK PIPE**: Causes and Symptoms, Preventative Measures, Methods and Techniques to Free Stuck Pipe
- **SHALE PROBLEMS**: Characteristics and Composition of Shale, Pressured Shales, Stressed Shales, Mud Making
- **SHALES, EROSION OF SHALES**
- **PRESSURE CONTROL**: Origin of Pressures, Pressure Indicators, Basic Science, Preplanning, Types of Blowout Control, Kill Procedures, Special Problems
- **COMPETITIVE MUD PRODUCTS**: Current Catalog, Research and Development
THE BAKKEN BETTER THAN EVER CONT'D

PRESENTING THE MOOD

“The conference speakers and enthusiasm by the attendees sent a valuable message that our industry has a bright future and that the Williston Basin’s oil and gas resources play a critical role in the world’s energy future,” noted Ron Ness, NDPC president. Echoing the conference’s “Bakken now” theme, Lynn Helms, director of the North Dakota Department of Mineral Resources, said, “The Bakken is now, and we need to be thinking about what’s next because the Bakken is going to go on for decades and generations.”

Throughout the conference, speakers made comparisons between the Bakken and the nation’s hottest shale play, the Permian Basin in Texas and New Mexico. Helms said attention had become so focused on the Permian that some referred to the condition as “Permania.”

“Two or three years ago, you couldn’t get investors’ attention on the Bakken,” said Greg Hill, chief operating officer of Hess, which has a 50-year history of Williston Basin operations. “Everybody had turned to the Permian. All people wanted to talk about was, ‘When are you going to get in the Permian? What’s your position in the Permian? How come you don’t have a position in the Permian?’” We kept returning people back to the Bakken, saying the Bakken has as good or better economics as a large part of the Permian.”

According to Hill, the Permian Basin is suffering from many of the growing pains that plagued the Bakken several years ago, which include lack of infrastructure, the high cost of acreage, an insufficient workforce, bottlenecks in moving oil and gas to market and traffic congestion.

“What that means now is that the Bakken is the place to be,” he said. “If you look at netbacks alone, WTI plus about $2 is what’s going on in the Bakken. If you look at the Permian, it’s WTI minus $9 or $10 because of all those bottlenecks. We’ve got the infrastructure, we’ve got a great regulatory framework here and we’ve got higher netbacks. So, the Bakken is the place to be.”

Brad Holly, president and CEO of Whiting Petroleum, gave a talk titled “Why the Bakken?” in which he proceeded to answer his own question. Noting that the Bakken accounts for 10 percent of U.S. oil production, he cited a regulatory environment in North Dakota that provides certainty to investors. Whiting is bullish on moving oil out of the Williston Basin, Holly said, but also added that additional investment is needed to respond to the challenge of increased gas production.

“The Bakken has performed very nicely on oil differentials compared to the Permian,” Holly stressed, adding that Whiting expects differentials in the play to steadily improve.

Holly was one of three producers on a panel with Ness who discussed the next moves for the Williston Basin. Erec Isaacson, vice president of the ConocoPhillips Rockies Business Unit, said that by reducing costs and spending, improving efficiencies and focusing on its best resources, the company is moving forward from its low point two years ago. In spite of the improvement in oil prices, he noted that the industry remains in a period of volatility. “The key takeaway is that we need to maintain resilience in the face of volatility,” he emphasized.

Thomas Nusz, chairman and CEO of Oasis Petroleum, said the 15 years of experience in the Williston Basin helped the company become one of the first producers to go cash-flow positive during the downturn. As the fourth largest producer in the basin, Nusz said Oasis plans to spend $1 billion in the Bakken this year, 75 percent on upstream and 25 percent on downstream.

FIELD-LEVEL OPPORTUNITIES

One of the key opportunities for the Bakken lies in enhanced oil recovery (EOR) technology. Helms revealed that there will be four EOR projects in the Williston Basin this summer testing the technology. Mark Pearson, president and CEO of Liberty Resources, discussed the company’s Stomping Horse EOR Project which is expected to begin in July north of Tioga, North Dakota. He used long straws and two two-liter bottles of “conventional” Coke and “unconventional” Diet Coke to demonstrate the process.

Pearson noted that the Bakken has greater oil reserves than Saudi Arabia. The difference is that currently, only a small portion of the Bakken’s reserves are considered economically recoverable. In the 1970s, experiments began using carbon dioxide (CO2) as a miscible fluid—a fluid that will mix with oil—to create a higher displacement of oil. Working with the University of North Dakota Energy & Environmental Research Center, Liberty will test a technique that could recover 40 percent or more of the Bakken’s oil resources. “That is the opportunity for the Bakken,” Pearson said.

The problem with using CO2 for EOR is that it’s expensive. “It’s a big project that small companies like mine could never take on,” Pearson explained. “You’ve got to drill the wells for the resource. You’ve got to pipeline it in chrome alloy pipes because of corrosion issues. And you have to change out all your tubulars in your injection wells because of carbonic acid and corrosion that go on there,” he said.

What the Bakken offers is gas with high levels of natural gas liquids (NGL) that can be used as a miscible liquid instead of CO2. Pearson said Liberty’s gas is typically 80 percent methane, 20 percent ethane and 10 percent propane.
THE BAKKEN BETTER THAN EVER CONT’D

“It’s those components of ethane and propane that excite us about the potential for enhanced oil recovery in the Bakken,” he said. “We have the potential to take the produced gas—with the NGLs in it—and reinject it back into the ground to increase the oil production coming out.

“I don’t know what the results are going to be, but it definitely has the potential of being a gamechanger in terms of our total recovery,” Pearson continued.

“I think the future is bright for the Bakken, but I think it’s time for what I would call some EBOR—enhanced Bakken oil recovery.”

EXPORTING FROM NORTH DAKOTA

According to Brady Cook, Koch Industries Inc. senior vice president for oil and trading, the Bakken is ripe to benefit from export opportunities. While U.S. shale oil production is surging, refinery capacity in the U.S. is growing slowly. In contrast, Asian refining capacity for sweet, light crude is rapidly expanding. U.S. refiners will continue to import quantities of medium and heavy crude to meet their needs.

“Lighter crude will grow in value versus heavier grades,” Cook predicted. “Bakken oil is well-positioned for this compared to common water-borne crudes for refiners in Europe and Asia. The market is recognizing the scale of the refining problem coming its way. The value for Bakken goes up compared to refiners’ other crude alternatives.”

Both Hill and Helms emphasized that beginning with the oil price downturn, investment in the oil and gas industry has lagged far behind where it should be to keep pace with demand. To catch up, an annual investment of $540 billion is needed through 2040, according to Hill.

Helms labeled the $1 trillion underinvestment in the oil and gas industry that’s occurred since the downturn began in 2015 a huge concern. “What that means is that sometime not too long after 2020, prices have to make a correction to bring that investment back and bring that production back,” he noted. “But in 2021 when we see that price correction, we see rigs coming back really, really intensely.”

ANOTHER BAKKEN RUSH LOOMING

Helms expects North Dakota to set a new production record this summer, eclipsing the previous record of nearly 1.23 million barrels per day set in December 2014. With that comes record levels of gas production as well.

In North Dakota, Helms said lack of infrastructure to capture and process gas will likely be a problem this year when state regulations raise the level of gas capture required from 85 percent to 88 percent. Although the oil and gas industry has invested $127 billion in the state, he estimates that another $350 billion of investments will be needed over the next 20 years.

While the state now has excess railroad and pipeline capacity to ship the crude it produces, Helms expects that situation to change by 2020 when even an expanded Dakota Access Pipeline will reach full capacity. That means either increased crude by rail or planning for another oil pipeline.

“My message to you—you’re mainly upstream and midstream folks—is when somebody comes to you with a proposal for an export pipeline, commit barrels. Get the pipeline built because there is no time to get that project started and permitted,” Helms stressed.

In addition, he emphasized the need to build more gas gathering pipelines and gas processing plants to deal with an increasing gas-to-oil ratio. Since 2016, the industry has laid between 700 and 900 miles of new gas pipeline annually, a trend Helms said must be reversed. “If we go back to the number of completions that we anticipate, then we need to be building 2,000 miles of pipeline every single year from now to 2025,” Helms stated. “There is no time like the present to get your right-of-ways.”

In addition, even though five new gas processing plants representing a $3 billion investment should come online in late 2018 and 2019, Helms said they’re expected to meet industry’s needs only through 2020 or 2021. Another $6 billion of investments in gas processing plants will soon be needed to handle increasing production, he said. More infrastructure to transport NGL will also be needed in the next three years, Helms noted.

Expanded oil and gas production, combined with the need for more infrastructure, means that the workforce will also need to expand. Helms estimates that the 56,000-people employed by the industry at its peak in 2014 will need to grow from the current 36,000 jobs to 63,000 by 2020.

“We need to be talking to our western communities about how they’re planning for these people to come back because they’re all coming back—plus another 7,000,” Helms said. “These people are young and they’re diverse. We used to be a state that was No. 1 in retired people—growing older and a shrinking population. We are now No. 1 in millennials.”
THE BAKKEN BETTER THAN EVER CONT’D

CORE EXPANSION

The good news Helms brought to the conference was that increasing oil prices have enabled Bakken producers to once again begin operating outside the play’s core areas.

“At today’s oil prices, the economics reach way beyond the core and all the way to the Canadian border,” he said. “The entire Bakken is at play again. Sixty-five rigs are drilling today. In less than a week, we’ve added five rigs in the state of North Dakota. That’s great news for the royalty owners, for the working-interest owners and to the operators out in those parts of the world.”

Hill said that despite predictions of electric cars reducing the demand for oil, the demand for petrochemicals and the need for long-haul fuels for trucks, ships, trains and aircraft ensures that oil and other fossil fuels will continue to meet 75 percent of the world’s energy needs through 2040.

“Not only is the Bakken helping the state of North Dakota, it’s helping the United States of America,” Hill said. “And more importantly, it’s helping to change the lives of millions of people around the world as they come into prosperity—prosperity that so many of us have enjoyed.”

Author: Patrick C. Miller

Staff Writer, North American Shale magazine

GEO PRODUCT INTRODUCTION CONT’D

HORIZONTAL VS. VERTICAL: THE IMPORTANCE OF DRILL-IN FLUIDS

One reason for the growing importance of drillin fluids is the expanding number of horizontal wells being drilled. In these wells, producing formations have a greater tendency to be damaged by the drilling process than those in vertical wells.

AMONG THE REASONS ARE:

- Drilling fluid is in contact with the reservoir much longer.
- Most horizontal wells are completed open hole without casing and perforation. Shallow fluid invasion may result in skin damage which can reduce production.
- Long, exposed production zones can result in difficulty obtaining uniform drawdowns to clean up damage.
- Flow mechanics in horizontal wells differ from those in vertical wells, as do the horizontal and vertical permeabilities of most formations. These differences result in greater productivity impairments in horizontal wells exposed to equivalent damage.

LOWER COMPLETION COSTS

The system’s simplified cleanup procedures reduce rig days during well completion. While other commercially available drillin fluids require costly steps for cleanup, PERFFLOW doesn’t require breakers or acids to dissolve bridging solids. Removal is accomplished by simply flowing the well. However, the PERFFLOW components are acid soluble if an acid remediation treatment is desired.

INCREASED PRODUCTION

The system’s bridging agent design and unique polymer chemistry form a thin filter cake to protect the reservoir against damage from fluid and particulate invasion. The PERFFLOW filter cake is efficiently removed with low breakout pressures, optimizing well cleanup and production. Return permeability tests on cores exposed to the fluid range from 86% to 100%. In the field, PERFFLOW production systems have delivered initial increases of more than double the operator’s anticipated production.

DRILLING PERFORMANCE

In addition to reduced cleanup costs and enhanced production, PERRFLOW provides excellent drilling fluid properties, consistent with those of a polymer-based system. The fluid’s rheological properties can be modified to meet specific hole cleaning requirements.

ADDITIONAL SYSTEMS

Two additional PERFFLOW systems can be utilized to meet specific operational requirements.

These systems are:

- PERFFLOW 100 - engineered for specialized, low temperature cleanup in low temperature (<100°F / 38°C) reservoirs.
- PERFFLOW CM - Custom engineered drill-in fluid to meet specific needs.
The bridging agent used in the PERFFLOW system is a very pure calcium carbonate with a specified particle size distribution. The particle size distribution of our MILCARB and FLOWCARB series have been carefully selected to effectively bridge the pore throat openings in formations with permeabilities ranging from a few millidarcies to more than 10 darcies. The concentration of bridging solids is carefully engineered utilizing our Bridgewise® custom bridging analysis calculator to ensure optimum system performance. The BHDF GEO Bridgewise calculator converts permeability to pore size, determines target particle distribution for various bridging rules and finds a resultant particle size distribution for blends of the MILCARB series and FLOWCarb series to help you plan your well for optimum bridging of pore throats.

This bridging agent, combined with polymer viscosifiers and filtration control agents, forms a thin filter cake at the surface of the exposed formation. The filter cake forms quickly on the exposed surface of the wellbore to provide instantaneous leakoff control. This feature of the PERFFLOW system protects producing formations from damage by limiting fluid loss, fine solids migration, clay swelling, and solids invasion.

Several additional techniques can be applied to custom design our drillin fluid systems to meet the ultimate common objective: preservation of rock permeability and maximized hydrocarbon recovery.

PERFFLOW CM designs have included the selection of biopolymers and starch additives based on temperature, brine type, planned clean up technique, and other parameter adjustments to ensure productivity. In addition, special surfactants to improve filtrate compatibility, such as MULFREE RS maybe added to the DIF to prestimulate the porematrix, pronate improved mobility, and reduce the initial pressure.

Reduced Completion Costs The maximum particle size of the PERFFLOW filter cake’s calcium carbonate bridging agent was chosen to allow for its passage through a 40–60 gravel pack without requiring special cleanup procedures to dissolve the particles. The system’s polymer blend was selected for its ability to coat the bridging particles. The polymer coating provides low fluid leakoff rates, depositing a very thin filter cake on the formation face, allowing it to “break apart” for easy removal when the well is produced. The filter cake’s easy removal results in a savings of both time and money in cleanup costs for our clients.

The protective nature of a PERFFLOW filter cake is evident in return permeability studies where the fluid is exposed to sandpacks and natural cores. The PERFFLOW system has the characteristics required of a good drilling fluid. The waterbase polymer fluid is shear thinning, providing good hole cleaning properties which can be adjusted, as needed, to meet specific wellbore requirements. PERFFLOW’s polymer blend can be utilized effectively in both low density and high density brines to achieve desired rheological properties. Because it contains polymers, the PERFFLOW system is naturally lubricious. Additionally, the filter cake’s polymer coating imparts surface lubricity - minimizing torque and drag. This feature is especially critical in horizontal wells.

To measure leak-off control and return permeability performance of PERFFLOW systems, we developed the Sandpack Permeameter. This testing device allows us to evaluate the effectiveness of these systems against a wide range of permeabilities. By “custom-blending” sands to match the grain sizes present in target formations, this device enables our field services staff to select the proper PERFFLOW formulation to meet our clients’ specific reservoir needs. A similar device, the Hassler Cell Permeameter, analyzes consolidated sandstones to determine the least damaging fluid design for use in these formations.
## U.S. RIG COUNTS

### Current Week

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**US Rigs By Target**

- **Oil**: 924 (934, 829, -10, 95)
- **O/G**: 19 (19, 19, 0, 0)
- **Gas**: 214 (211, 223, 3, -9)
- **Total US**: 1157 (1164, 1071, -7, 86)

**US Rigs By Location**

- **Land**: 1126 (1133, 1041, -7, 85)
- **Inland/State Water**: 3 (3, 4, 0, -1)
- **Offshore**: 28 (28, 26, 0, 2)

**US Rigs By Direction**

- **Horizontal**: 958 (956, 857, 2, 101)
- **Directional**: 54 (58, 73, -4, -19)
- **Vertical**: 114 (119, 111, -5, 3)
- **% Horizontal**: 85.1% (84.4%, 82.3%)

**Major US Basins**

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<th>Prior Year</th>
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