By ALEX LONGLEY AND SHEELA TOBBEN on 3/20/2019

LONDON and NEW YORK (Bloomberg) -- For a glimpse into what the global oil price might look like one day, a good place to look is the Dutch port of Rotterdam. There, at a key hub for Europe’s oil trading and refining, crude imported from the U.S. is determining the price for an aspiring benchmark for North Sea oil one-third of the time, according to Argus Media.

That a U.S. grade is even considered for inclusion in a reference price for more than half the world’s crude underscores the sea change in global oil markets over the past decade.

America’s shale boom has driven the nation’s production up by about a third since 2016, with exports surging to Europe as well as Asia. At the same time, North Sea output has plateaued,
On the southwestern margin of the Williston Basin in Billings and Golden Valley counties in North Dakota, a 90,000-acre area previously considered marginal is being redelineated through advances in reservoir characterization and improved stimulation practices. The Elkhorn project area is geologically different than the central basin rocks where the thinner section is more heavily influenced by local subsurface structure and stratigraphy.

The unique geologic, stratigraphic and structural characteristics require a departure from the “bigger is better” approach to fracturing design that has become the norm in the Bakken/Three Forks and other plays (in which more fluid and proppant are pumped into more closely spaced clusters). To enhance well productivity and overall development economics in the Elkhorn project, NP Resources has adapted an engineered completions strategy to tailor customized and right-sized slickwater treatments based on variations in subsurface properties along the lateral. The initial horizontal wells that have been completed with the engineered treatments are achieving excellent results. In fact, the most recent wells have yielded productivities on the order of 300-400 percent higher than offsets, and their completion costs are substantially lower than wells completed with conventional large slickwater treatments similar to the standard designs in the Bakken/Three Forks.

Influenced heavily by the Beaver Creek Anticline, large through-going vertical and subvertical natural fractures are routine in the central basin. These tectonic fractures play a significant role in system mechanics and reservoir deliverability, as evidenced by production from legacy unstimulated vertical and horizontal wells. Legacy unstimulated open-hole horizontals did not reliably recover incremental reserves compared with the vertical wells, but did achieve more predictable production with a narrower distribution of production rates and estimated ultimate recoveries, reinforcing the interpretation of productive interconnected natural fractures in the Elkhorn area.

**LEGACY WELLS**

Elkhorn development began in the early 1960s with vertical penetrations targeting various intervals, including the Bakken and Three Forks. The first horizontal completions targeting the Bakken/Three Forks were drilled in the 1980-90s, and were primarily short uncedmented and unstimulated laterals completed with pre-perforated or slotted liners. A second generation of horizontal wells was completed in the project area between 2010 and 2014. They consisted of 10,000-foot laterals completed with uncedmented liners, external packers and sliding sleeves. The second-generation wells were hydraulically fractured primarily using a cross-linked fluid system and 3 million-4 million pounds of 40/70- and 20/40-mesh white sand in 10-35 stages.
‘ENGINEERED COMPLETIONS’ KEY TO ECONOMIC DEVELOPMENT OF PREVIOUSLY MARGINAL ELKHORN FIELD CONT’D

The unstimulated wells—both vertical and horizontal—produce very little water, with oil cuts typically exceeding 90 percent. In contrast, second-generation horizontals that have been hydraulically fractured generally yield maximum oil cuts of 60 percent, suggesting fracture growth into water-bearing strata above or below the lateral. Moreover, the second-generation horizontals are forecast to achieve EURs approximately equal to the unstimulated first-generation horizontals.

The stimulation histories of second-generation child wells show a correlation between the quality of the treatment execution and the producing oil cut. In particular, wells with the lowest oil cuts had a higher number of pressure increases during treatment and often had unintended screen-outs. One explanation is that near-wellbore proppant bridging and increased net pressure created undesired fracture height growth into surrounding water-bearing strata. An alternate mechanism is that proppant bridging redirected fluid injection into a localized portion of a stage rather than even distribution into multiple fractures, resulting in excessive height.

With a thin pay interval bounded by undesirable water hazards, NP Resources elected to design completions with tailored propped fracture spacing/sizing while honoring the vertical height growth constraints. Optimizing perforation cluster efficiency is critical using a combination of careful stage placement, engineered perforation locations within similarly stressed rock, aggressive extreme limited-entry perforating techniques and tailored proppant placement throughout the lateral.

EARLY EXPERIMENTS

The legacy wellbores offered a unique opportunity to observe how hydraulically induced fractures may distribute without mechanical isolation. A refrac was pumped in a 3,600-foot uncemented lateral that had been completed in 2008 with external water swellable packers and eight sliding sleeves. The original stimulation had placed a modest 837,000 pounds of proppant in 13,029 barrels of cross-linked fluid. After cleaning out the well to total depth with coiled tubing, it was restimulated with 1 million pounds of proppant and 48,000 barrels of slickwater in a bullhead injection.

A warm-back survey indicated that the unconstrained restimulation injection resulted in 30 discrete injection points with a median spacing of 110 feet (ranging between 50 and 400 feet) and confirmed that slurry entered all eight sleeves in the open hole. Although a bullhead restimulation is not equivalent to a staged completion, the results suggested that a fracture density greater than one per 110 feet (or two to three fractures a stage) may require isolation with cemented liners and additional diversion into a higher density of perf clusters.

Recognizing the presence of productive natural fractures in the project area, it was unclear how well these natural fractures interconnected over the large geographic area, or what storage capacity they offered. NP Resources initially attempted to contact and preserve these features with an un cemented lateral. Well 1 was completed using external water-swellable packers and three clusters per stage in a plug-and-perf sequence. No attempt was made to gather data in the lateral, adjust proppant mass by stage or deploy a limited-entry perforating scheme. The stimulation consisted of 200,000 barrels of slickwater and 5.6 million pounds of proppant with nearly even size distribution between the 35 stages. The early-time production response indicated a meaningful productivity improvement using slickwater and a larger proppant mass and fluid volume compared with legacy completions, but the water cut was significantly higher than offsets stimulated with smaller treatments.

SYSTEMATIC CHANGES

Four months later, Well 2 was completed adjacent to Well 1. A cemented completion was specified to evaluate whether controlled fracture fluid distribution would result in a lower water cut and improved oil productivity. The number of stages was identical and treatment volumes were similar to allow its production to be compared with that of Well 1. Although the wells are nominally parallel, the distances between them along the dominant fracture azimuth are 1,449-1,739 feet.

Well 2 was logged with a pulse neutron tool to characterize the lateral prior to cementing the 4 1/2-inch production liner. Then, Well 1 was shut in during Well 2’s stimulation, effectively leaving a downhole pressure gauge available to monitor the intensity and arrival times of the frac hits.

The treatment design on Well 2 incorporated systematic changes in the number of clusters (six versus three per stage), injection rates, and the use of degradable diverters and degradable balls. Frac hit arrival times and magnitudes were observed to evaluate diversion effectiveness. The apparent transit speed of frac fluid between the wells was analyzed to determine whether six perforation clusters would encourage the initiation of more fractures in each stage (thereby retarding fracture extension). All other factors being equal, frac extension from a stage that uniformly distributes frac fluid between six clusters instead of three should take twice as long to reach the observation well.

In addition to pressure observations, the fluids injected in Well 2 were tagged with unique oil and water chemical tracers in each of the 35 stages. Well 1 was returned to production after stimulating Well 2, and water and oil were sampled and analyzed periodically during the first 33 days to determine the degree of communication between the wellbores.

The initial post-frac water sample was collected from Well 1 after it produced only 65 barrels of flowback and showed significant concentrations of water-soluble tracer from 31 of the 35 stages in Well 2, indicating that well-to-well fluid transfer had occurred in most stages during or immediately following treatment. Only 19 of the oil-soluble tracers were identified in the initially collected sample, but during the first
downward growth may increase water cuts. Likewise, the carbonates and alternating shale streaks in the Lodgepole appear to provide a competent barrier to upward fracture growth in this region of the field.

These interpretations of acceptable height containment but poor diversion using contemporary perorating strategies and degradable diverters encouraged further investigation into stress variations along the lateral, and eventually led to more aggressive diversion schemes to generate 1,500–2,000 psi of pressure differential across the perforations.

STRESS VARIABILITY

In Well 2, the lateral’s relative stress differences were characterized with a dipole sonic log deployed on a wireline tractor. Refinements to data capture and interpretation were made on subsequent wells using stress-sensing equipment run on the drillstring. Stress data captured during drilling were integrated with minerology data captured from the pulse neutron tool to refine the stress model in the presence of changing minerology.

Variations in stress were measured as having differences of greater than 800 psi in 200-400 foot intervals (Figure 2). A 40–50 percent variation in stress relative to the applied differential presents a significant challenge. Therefore, the laterals were compartmentalized carefully into stages based on formation stress rather than uniform stage lengths.

For example, if rock stresses were consistent over a 500-foot interval, the number of clusters and limited-entry perforations were adjusted to cover the interval and generate 1,500–2,000 psi of perforation friction at a rate and pressure achievable by the frac equipment. Likewise, if the rock stresses were variable over a 500-foot interval, it was compartmentalized into smaller stage lengths.

The average stage length in portions of laterals with consistent rock stresses range between 200 and 300 feet. However, by applying a perforating scheme adapted to the rock stress, the number of wireline runs can be kept to a minimum while maximizing cluster efficiencies. Significant efficiencies and cost savings can be achieved in the Elkhorn project area utilizing an engineered and customized staging/perforating strategy based on the wellbore stresses. Aggressive efforts are made to distribute fluid and proppant evenly into a large number of clusters to:
Cluster efficiency measured at the start of the stimulation routinely exceeded 90 percent. Step-rate tests in wells 5-7 showed near-wellbore friction ranging from 696 to 1,744 psi, with an average of 1,100 psi. The average perf friction was 822 psi and the number of holes open was 19, based on the start-of-treatment step-down data. This contrasts with earlier wells 3 and 4, which employed a more conventional limited-entry scheme with 60-degree phasing, standard perforating charges, and six-eight clusters with 36-38 perforations a stage. Wells 3 and 4 each had a much lower average cluster efficiency (50 percent) at the start of each stage, reinforcing the interpretation of poor diversion efficiency in similarly perforated Well 2.

Treatment responses and step-rate test data suggest that the extreme limited-entry perforation stages are more sensitive to minor changes in maximum proppant concentration, implying that narrower fracture apertures are likely to develop because of the cumulative stress shadow effect of numerous, closely-spaced fractures initiating simultaneously.

In the example shown in Figure 4, a change in proppant concentration from 1.25 to 1.50 pounds added per gallon was enough to generate a meaningful net pressure change. Step-rate tests run during this and other stages with similar responses showed high start-of-job cluster efficiency prior to pumping proppant and a reduced number of open perforations during the final step-rate test, indicating that proppant slugs were sanding off or screening out some of the fractures.

**PERFORATING STRATEGY**

Several perforating strategies are being incorporated at Elkhorn to improve the distribution of frac fluid and proppants, including:

- Extreme limited-entry perforating that targets a range of 1,500-2,000 psi of perforation friction to increase the percentage of perforations that break down and accept slurry;
- Uniform hole size and depth of penetration to improve breakdown efficiency; and
- Oriented perforating with 0- and 180-degree phasing to better align with the fracture plane and reduce near-wellbore friction/tortuosity.

Each stage has seven perf clusters (18-21 total perforations) and entry point spacing is approximately 40 feet between clusters, with two-four holes in a cluster. Figure 3 shows the perf friction generated as a function of rate. After adopting this extreme limited-entry approach in wells 5, 6 and 7, step-rate tests were run at the beginning and at the end of every other stage, offering a quantifiable measure of the number of open perforations.

Field observations indicate that aggressively placed cyclic proppant ramps, combined with extreme limited-entry perforating, can achieve diversion effectively while placing a desirable material in the fracture and avoiding concerns regarding degradation times associated with the previously utilized degradable diverters.

Completion Design

The wellbore and stimulation procedures continue to evolve based on the observations and lessons. The current wellbore architecture and completion design at Elkhorn consist of a 10,000-foot lateral completed with a 4½-inch cemented liner. The slickwater treatment is pumped down the 7-inch intermediate casing and 4½-inch tieback string at 50-70 bbl/minute, depending on a given stage’s wellbore and near-wellbore friction. A total of 24-35 stages is specified, consisting of 6-15 clusters a stage based on stress variations along the lateral.
or two stages that significantly outproduce other stages. This cumulative productivity monitored in long-term chemical tracer surveys has been sustained through the flowing periods and into production on artificial lift (Figure 7).

The pump schedule consists of four-six cyclic proppant ramps of alternating 100-mesh uncoated sand and 40/70-mesh curable resin-coated sand at a maximum concentration of 1.25-1.50 ppa. During treatment, the effect of maximum bottom-hole proppant concentration on observed net pressure is used to increase or decrease proppant concentration to improve the amount of diversion after the first 40/70 cycle. This helps achieve more even proppant distribution throughout the stage and reduces difficulties in pumping the full mass of the stage in the event the amount of diversion forces a significant rate drop.

As shown in Figure 5, the three wells completed at Elkhorn using this newest approach are as much as four times more productive than the second-generation horizontal wells completed in 2010-14. Moving from a cross-linked fluid to slickwater with more stages and increased fluid/proppant volumes generated a 250 percent base uplift. Extreme limited-entry perforating and an increased focus on stage placement tailored to the lateral’s variability has yielded an additional 150 percent improvement. This production uplift and the efficient allocation of a smaller capital investment translate to a meaningful return on investment for acreage once considered on the economic fringe.

Unique oil and water chemical tracers run in each stage indicate that the most productive wells achieve a consistent production profile throughout the lateral (Figure 6). These highly productive wells vary in the cumulative recovery of chemical tracer along the entirety of the lateral, but are not dominated by one

Because these wells are equipped with ESPs and downhole pressure gauges, it is possible to accurately normalize well production for the applied drawdown. The uplift in the productivity of total fluid normalized by drawdown suggests the completions have sustained a greater contact area with the reservoir compared with legacy completions, despite accelerating production with high-volume artificial lift.

The insights captured in the Elkhorn project have proven significant upside potential in an area outside the central Bakken/Three Forks development. Understanding changes in regional reservoir characteristics has become the foundation of the engineered completions approach, with reservoir variations dictating the customization necessary to improve oil recovery and development economics substantially. While initial wells completed with this approach are demonstrating highly compelling results, the treatment designs at the Elkhorn continue to evolve and additional improvements are anticipated that will drive further productivity and economic benefits.
DENVER’S ADAMS COUNTY APPROVES MORATORIUM DUE TO SB 181
3/21/2019

DENVER – Despite an overwhelming public response from Adams County residents who spoke out against a temporary ban on oil and natural gas permits, Adams County Commissioners voted 5-0 to approve a new six-month moratorium. The county gave only 24 hours notice before today’s meeting.

The following is a statement from Dan Haley, president and CEO of the Colorado Oil & Gas Association:

"Politics trumped policy as the uncertainty surrounding Senate Bill 181 spilled out of the statehouse and led to its first moratorium. The flaws within this bill are apparent and must be corrected, or we’ll see this uncertainty and confusion spread.

"Colorado’s oil and natural gas workforce is second to none, adhering to the toughest regulations in the country, and if our elected leaders pause long enough to look at the data, they would see that ours is one of the safest industries in the nation, and that we are in fact part of the climate solution, as emission numbers continue to drop.

"The temporary ban — passed before SB 181 has even cleared the statehouse — wasn’t needed. It sends a negative message to businesses and workers in Adams County and could have a chilling effect on the economy. Our members have worked openly and cooperatively with Adams County in the past on such matters and we hope that they include us in their discussions in the coming months. Oil and natural gas production is important to Adams County, its economy and its tax base and we shouldn’t play these types of games with something that important."

GEO’S MUDMEN’S CORNER
PRODUCTION SCREEN TESTER

The flow-back characteristics of drill-in fluids are critical to the productivity of a well. If the fluid plugs the production screen, it will not only slow down production, but it could also lead to screen erosion and costly remediation.

The PST is designed to test flow-back of completion fluids on the rig site. It is no longer necessary to ship fluid samples back to the lab and delay the completion operation for days or weeks. Field fluids can be tested in real time with samples of the actual production screen being used down hole.

The PST now makes it possible to determine if the fluid remaining in the annulus will flow back through the production screen.

The Production Screen Tester is like the standard API filter press both in appearance and operation. The user assembles a test cell with a sample of the production screen at the bottom. After filling the cell with fluid, he applies pressure and opens a valve at the bottom. The test will very quickly show whether the screen and fluid are compatible, or if plugging is a possibility. And the apparatus is simple enough that new screen samples can be installed and tested quickly and easily.
AS U.S. OIL SUPPLY GROWS, SO DOES ITS INFLUENCE ON GLOBAL PRICES CONT’D

European producers will have to face increased competition from the U.S. either way. Occidental Petroleum, one of the largest drillers in the Permian, is already exporting 10% of its production, its CEO said last week. With U.S.’s production forecast at 12.3 MMbpd this year, it will far eclipse supply from the likes of the U.K. and Norway.

The U.K. production sank from about 3 MMbpd in the late 1990s to 1.1 MMbopd last year, according to the U.K. Oil and Gas Authority. Norway pumped 1.5 MMbpd last year, compared with 1.7 MMbpd in 2011. That dynamic will only make U.S. crude more important -- as a source of supply and as a way to determine prices.

“WTI is already being factored into the price of North Sea and West African crudes,” says Sandy Fielden, analyst at Morningstar, based in Austin, Texas. “As long as there is too much WTI in the U.S., it will get demand from overseas.”

Traders and analysts have long argued that the global oil industry’s main reference price, which is based on cargoes loaded in the North Sea, needs an overhaul to reflect weaker regional production. But there are no signs that Platts’ Dated Brent is about to cede its dominant position as a benchmark any time soon. Multiple oil-producing countries the world over link the price of their bbl to Platts’ assessment, while crude futures are ultimately tied to it as well.

Platts said late last year that it would consider including new grades, including WTI, in its Dated Brent assessment. Last month, after a consultation, it said that there were no immediate plans to do so, instead considering the value of North Sea crude delivered to Rotterdam.

There’s little doubt the influence of American crude is growing in the region. Shipments to Europe averaged 560,000 bpd last year, up from about 100,000 in 2016, according to U.S. Census Bureau data. The five North Sea grades that make up the Dated Brent benchmark produced 960,000 bpd on average in 2018.

Global Benchmark

Some traders especially those with U.S. bbl previously said they would favor a global benchmark that incorporated both WTI and Brent. Others, mindful that the 660,000 bpd Johan Sverdrup field in the North Sea is due to produce its first oil later this year, oppose such a widening.

GEO PRODUCT INTRODUCTION STOP LOSS CONT’D

Drillout of GEO STOP LOSS is not as damaging to a fresh water based mud system as a cement plug would be. While the pH of the plug is 12.3 and the filtrate pH is 12.1, the Pf of the filtrate is only 1.2. Most of the alkalinity is lost to the formation as the plug dewaters. Lower pH and Calcium levels than cement allow Bentonite to continue to function as a viscosity and fluid loss agent after drillout. The risk of sidetracking the hole is reduced because this material though hard does not have compressive strength great enough to cause a sidetrack. dewaters. Lower pH and Calcium levels than cement allow Bentonite to continue to function as a viscosity and fluid loss agent after drillout. The risk of sidetracking the hole is reduced because this material though hard does not have compressive strength great enough to cause a sidetrack.

GEO STOP LOSS cake from development series.

Rubble stabilization is also an appropriate application. By gently squeezing the material into the coarse spaces between unconsolidated rubble a new and stronger matrix material is substituted for the original. Because of its lower alkalinity this plug has a minimal effect on formations that are prone to swell or slough when exposed to hydroxyl ions.
Simulation of the plugging action at the surface is not as simple as allowing a cement plug to harden. Allowing a sample of the pill to sit in a container will not result in dewatering and production of a cake. In order to observe the nature of the cake deposited, a sample of the finished mix should be placed in a filter press and filtered at 30 psi. In a matter of minutes all the free water will be expelled and a sample of the cake can be observed.

1. **GEO STOP LOSS** is a high solids/high filtration lost circulation squeeze. It will not suspend well without agitation although it does not settle out hard or set up if held unagitated for prolonged periods.

2. Select a mixing pit that has excellent agitation and a good suction directly to the mud pump. Remove any drilling fluid or Gel based LCM. The more mud left behind the less effective the GEO STOP LOSS will be. Fill the pit with water or oil to 83% of the final desired volume, leaving space for expansion while adding material.

3. Add 100 pounds per barrel GEO STOP LOSS. For 50 bbls of finished volume start with 41 bbls of water (or oil) and mix 5,000 pounds (200 of the 25-pound sacks) of GEO STOP LOSS blended LCM material.

4. For a weighted pill see the table below. Mix GEO STOP LOSS first, then add Barite.

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<th>To Build 50 bbls of GEO STOP LOSS</th>
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<td>STOP LOSS</td>
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<td>Barite</td>
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9. Flush the mixing pit with water (or mud or oil). This may be used as part of the displacement fluid.

10. Pull the drill pipe above the theoretical top of the plug and flush the pipe. Trying to fill the hole at this point may help gently squeeze the plug into the formation. If the loss is due to natural fractures in a competent formation, squeezing with up to 200 psi is effective in getting the material away from the well bore and into the fractures. In weak formations where the loss is pressure induced do not squeeze (shut in).

11. To gently squeeze calculate the volume of squeeze to leave in the hole. For instance 100 lineal feet in 12 ¼” hole would be 14.6 bbls. Pump no more fluid than the pill volume less the amount to be left in the hole. Thus for a 50 bbl pill as above, only 35.4 bbls would be pumped. Too much volume may propagate the fractures as well as initiating new fractures and push the plug so far from the well bore that it loses its effectiveness.

12. Allow the GEO STOP LOSS plug to dewater. This reduces the volume by approximately 50% and may require an additional pill to fill the loss zone.

13. Wait 2–4 hours before drilling out to allow the plug to dewater.

14. Treat for calcium contamination with Bicarb if needed while drilling out. Many times this is unnecessary so wait until seeing signs of contamination before treating.

15. GEO STOP LOSS may also be used as a sweep in whole mud or as a pill spotted on trips.
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