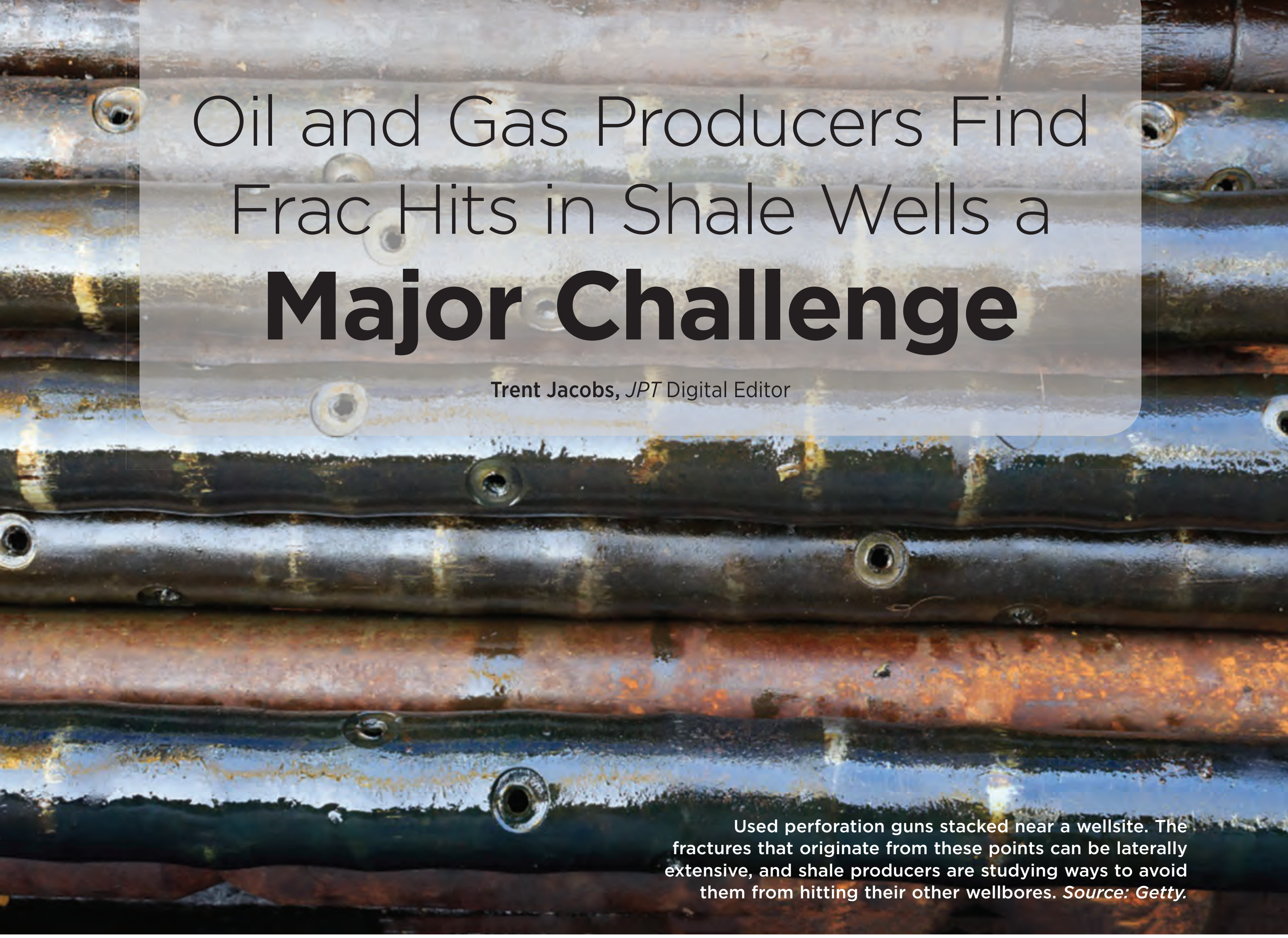


Oil and Gas Producers Find Frac Hits in Shale Wells a **Major Challenge**

Trent Jacobs, *JPT* Digital Editor

Used perforation guns stacked near a wellsite. The fractures that originate from these points can be laterally extensive, and shale producers are studying ways to avoid them from hitting their other wellbores. *Source: Getty.*

In North America's most active shale fields, the drilling and hydraulic fracturing of new wells is directly placing older adjacent wells at risk of suffering a premature decline in oil and gas production.

The underlying issue has been coined as a "frac hit." And though they have long been a known side effect of hydraulic fracturing, frac hits have never mattered or occurred as much as they have recently, according to several shale experts who say the main culprit is infill drilling.

"It is a very common occurrence—almost to the point where it is a routinely expected part of the operations," said Bob Barree, an industry consultant and president of Colorado-based petroleum engineering firm Barree & Associates.

He added that frac hits are also an expensive problem that involve costly downtime to prepare for, remediation efforts after the fact, and lost productivity in the older wells on a pad site.

A frac hit is typically described as an interwell communication event where an offset well, often termed a parent well in this setting, is affected by the pumping of a hydraulic fracturing treatment in a new well, called the child well. As the name suggests, frac hits can be a violent affair as they are known to be strong enough to damage production tubing, casing, and even wellheads.

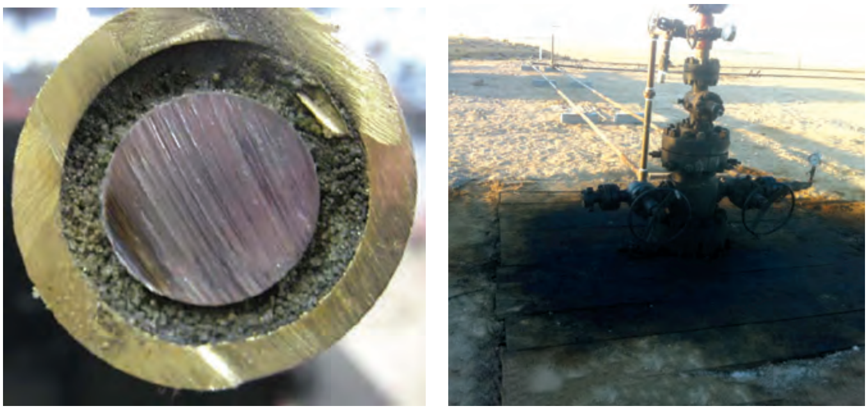
Claudio Virues, a senior reservoir engineer with CNOOC Nexen, said frac hits have become a top concern in the shale business because they can affect several wells on a pad, along with those on nearby pads too. Based on his experiences in Canada and in south Texas, the question is no longer if a frac hit will happen, but how bad will it be.

"You usually have two scenarios," he said. "One may be that you have a temporary loss of production, but you will recover to the trend that you had before. The other will be really bad for your production and reserves."

He is alluding to the fact that some wells impacted by frac hits never fully recover and, in the worst cases, permanently stop producing after taking frac hits. The frequency of these outcomes are unknown as there are no publicly available statistics. In a small minority of cases, and in select formation types, frac hits have been known to increase production in the impacted well, but this is unusual.

A Rising Profile

Operators have been meeting behind closed doors for years to collaborate on best practices for dealing with frac hits. One of the first things they agreed upon was to notify other nearby operators of an impending hydraulic fracturing oper-



Two examples of what may happen during a frac hit. Rod tubing, left, is shown filled with proppant sand, while a remediated wellhead is shown post-frac-hit. ***Sources: Marathon Oil/Eagle Ford Training San Antonio.***

ation so those firms could prepare for any potential frac hits.

Shale producers are sharing what they know about frac hits at conferences and in technical papers more frequently. The bulk of SPE papers focusing on frac hits have been published since 2015. This may show that unconventional operators are gaining a better grasp of the situation, yet concrete solutions remain elusive.

In recent years, lawsuits between oil and gas companies and occasional frac-hit-induced blowouts have also attracted varied degrees of scrutiny from industry regulators in the US and Canada.

The US state of Colorado adopted rules in 2013 that require oil and gas companies to notify other operators within 1,500 ft of a proposed wellbore at least 90 days before a scheduled hydraulic fracturing operation takes place. Colorado also mandates that all offset wells within that designated area have 5,000-psi-rated wellheads to prevent a frac hit from turning into a well control event. Earlier this year, Oklahoma regulators proposed a mandatory reporting requirement for when one operator initiates a frac hit against another operator's wells.

Canadian rules are more involved and require that a single hydraulic fracturing operation coincide with a multiwell surveillance operation.

"In the old days, guys like me would watch three or four charts on one well that we were treating with a fracture," said Tim Leshchyshyn. "But now, you have an additional 10 or 12 other screens on that are just for watching those wellhead pressures."

Leshchyshyn, president of the Calgary-based consultancy FracKnowledge, said that the Canadian government became involved in frac hits after they were blamed for a number of surface releases, mostly involving damage to low-pressure wellheads and older vertical wells.

Calculating Lost Reserves Not So Easy

Aside from preparation and prevention, the third piece to the frac hit issue involves trying to assess both the economic and physical damage caused. In terms of quantifying lost production, it is not as straightforward as one might imagine.

Engineers in BP's unconventional program recently developed a way to calculate such losses using rate transient analysis (RTA). The caveat to this diagnosis method is that it has only been tested on shale gas wells because their single-phase flow is more reliably assessed with RTA compared with oil wells which involve more complex multiphase flow.

Siyavash Motealleh, a reservoir engineer at BP and coauthor of a technical paper on the subject (SPE 184812), said the traditional method has been to use decline curves to estimate the impact to estimated ultimate recovery—which importantly, does not take into account the role of pressure.

In cases where production has dropped post-frac-hit, this analysis tries to answer whether open fractures were closed (representing a permanent loss of stimulated reservoir volume) vs. the development of superficial skin damage.

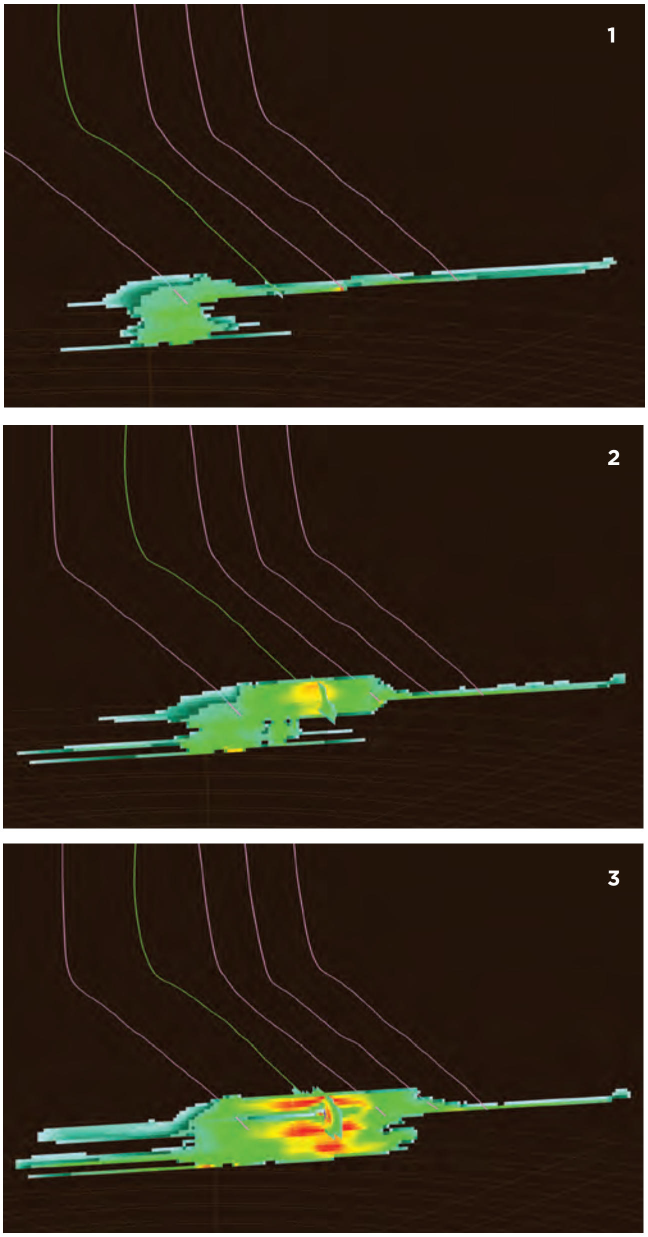
The major benefit RTA offers an operator is a probability that the well damage is either irreparable or can be addressed with a coiled tubing cleanout. "But if you use only the decline curve, you won't know to do that; you will only know your productivity went down and you won't know why," explained Motealleh.

Himanshu Yadav, a reservoir engineer at BP and the paper's lead author, related a case in which a frac hit was misdiagnosed in such a manner. After the affected well was brought back on production, field engineers determined that because its gas flow rate returned to normal, there was minimal damage.

However, when Yadav looked at the well data he found that the field engineers had increased the choke size, which allowed more gas to be produced while hiding the fact that wellhead pressure was down by more than 1,000 psi.

"This is the classic case of where if you just use decline curve averages, you are not looking at the entire picture and might be fooling yourself," he said.

The authors point out that this method also may not be optimal for ultralow-permeability shale formations, based on their limited research into the issue. The simulations used to validate the RTA approach were based on shut-in times of 30 days, while in very tight formations an adequate pressure buildup may take as long as a year.



Frame 1 of a modeling sequence shows a hydraulic fracture may contact a depleted reservoir section of multiple parent wells—inducing a frac hit across the pad. A larger fracture network develops around the child well only after the fracturing fluids have filled that depleted area, shown in frames 2 and 3. *Source: Barree & Associates.*

The directive regarding interwell communication also calls for operators to do upfront modeling to estimate the radius of the potential strike zone. Companies not implementing such due diligence are subject to being shut down.

Leshchyshyn further explained that in Canada, if the pressure in an offset well exceeds the maximum threshold, the pumping units must shut down—virtually ensuring that particular stage of the child well will not be optimally stimulated. This highlights that frac hits should not only be viewed from the perspective of a parent well, since they can have direct implications on the child well too.

Closer Than Ever

The main reason frac hits are becoming a rule rather than the exception in North American shale fields is because of infill drilling and downspacing programs. Shale producers are drilling new wells closer together, and closer to older wells, all in an effort to drain as much of the available reservoir area as possible.

For perspective, many shale wells drilled in 2010 were at least 1,000 ft apart. Today, many well spacing designs include a range from 550 ft to 250 ft. Leshchyshyn stressed that with such tight well spacing, "You are always going to have frac hits."

Added to the equation is that the shale sector has now adopted hydraulic fracturing treatments that use two or three times the volume of water and sand used when many of the parent wells were initially completed.

The higher volumes of water, more so than the increased amounts of sand, are thought to be creating fractures longer than desired. If operators can create shorter fractures, they may avoid punching into depleted reservoir zones where large volumes of oil, gas, and water have been produced over the years.

As Leshchyshyn explained, it is the relative low pressure of these depleted zones that turns them into a vacuum "that sucks in both sides of the wellbore's fracturing network."

With individual fracture stages being placed tens of feet apart instead of hundreds, as was the norm a few years back, this vacuum effect can predestine fractures stimulated subsequent to a frac hit to a fate of low productivity and the potential of causing more frac hits.

How Bad Can It Be?

On the mild end of the frac hit severity spectrum are what engineers call pressure hits. These have been recorded in wells more than a mile away from a hydraulic fracturing operation but may only result in a small pressure spike of 10 psi. Such instances are not thought to result in large, if any, production losses but they do demonstrate the extensive interconnectedness of fracture networks—both induced and natural.

Other instances of interwell communication are thought to be short-lived and thus not very harmful to production. So while a frac hit may have connected two adjacent wells, in a few weeks or months the connective fracture network between them may pinch off, ending the interference.

In the meantime though, operators may notice they are pumping out more produced water from an impacted parent well than before. Production could also fall off temporarily before returning to a normal rate.

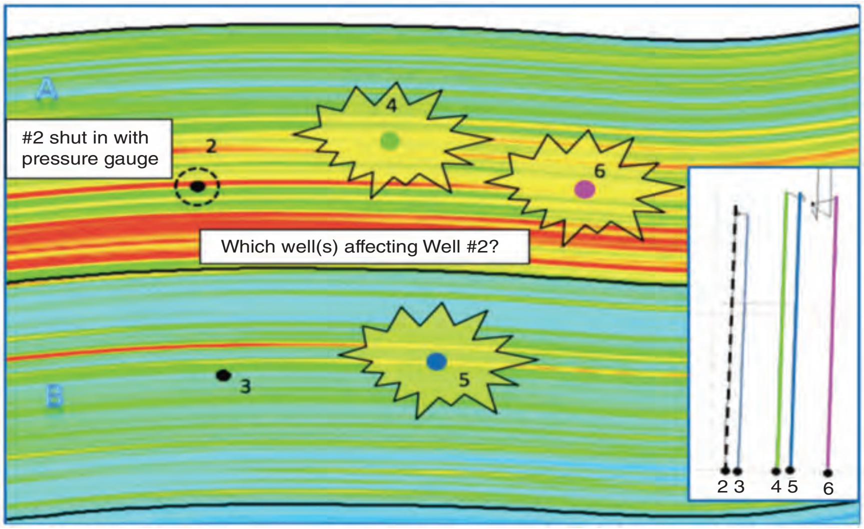
However, trying to quantify the production permanently vs. temporarily lost remains a subject of research. This means some companies may be unaware that they have lost oil and gas reserves.

On the far end of the spectrum is well-bashing. "I picture that as the full boat," said Barree, who reserves usage of that term for when a well has taken in fluid and proppant from a fracture that directly hit the parent well and maintains long-term direct communication with it. "That's where you usually get the most severe damage," he said.

When sand is forced into a parent well, the tendency is for it to settle in the low spots of the wellbore and plug off production. This is called being "sanded in." A cleanout is possible, but Barree said that if the sand enters toward the toe section of a well, it is likely beyond the reach of coiled tubing.

Excess water communication can also harm production by waterflooding the proppant pack, which ends the continuous flow of oil and gas into the wellbore. Instead, the hydrocarbon flow regime becomes dominated by residual droplets that are discontinuous.

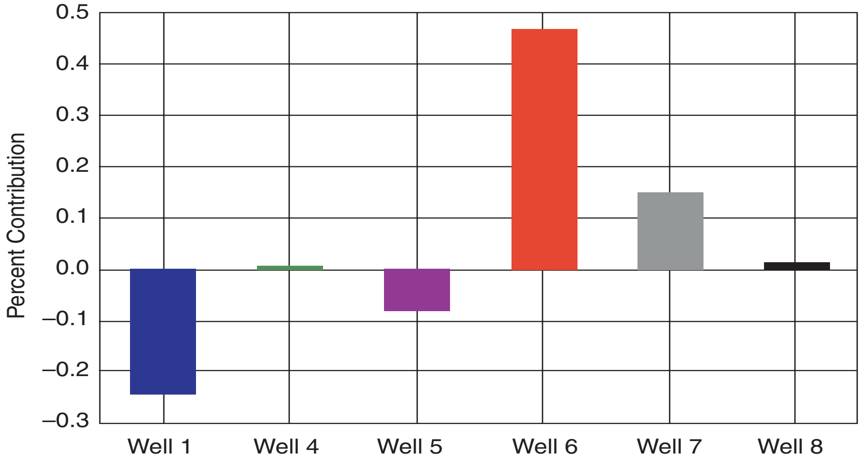
Barree said water imbibition can also drop the conductivity of producing fractures by 10- to 50-fold. If such extreme damage occurs, it is doubtful that production will ever recover. "You put the well back on production and you've lost your pressure, the velocity, the inflow capacity, and the well is just dead," he said.



This diagram shows the location of well #2 in relationship to wells #4, #5, and #6. Because those wells were completed around the same time, the operator was left guessing which one caused a frac hit. *Source: EP Energy.*

Practicing Self-Defense

Independent oil and gas explorer EP Energy published a technical paper at the SPE Hydraulic Fracturing Technology Conference (SPE 184869) this year detailing its use of an emerging DNA diagnostic technology to conduct a frac hit post-mortem in its operations in the Permian Basin of Texas.



Using diagnostic firm Biota Technology's DNA surveillance and analysis, EP Energy conclusively determined that well #6 was responsible for frac hits on well #2. ***Source: EP Energy.***

The pilot project analyzed the DNA signatures of several wells on a pad site and was able to single out the child well that initiated a frac hit on a parent well during a multiwell zipper fracturing operation. The culprit well was landed around the same depth as the impacted well, which prompted EP Energy to begin staggering wells at different depths to lessen the occurrence of inducing a frac hit.

One frac hit protection technique involves pumping fresh water into parent wells along with diverting agents to temporally plug off the perforations that serve as access points. A paper (SPE 184851) authored by engineers at Abraxas Petroleum detailed the use of this strategy in North Dakota's Bakken Shale.

BHP Billiton and Chevron have said that, in certain areas, they manage the risk of frac hits by first conducting hazard reviews of nearby wells.

In addition to installing high-pressure wellheads on offset wells, some operators take the extra step to remove downhole completions components from producing wells, including the artificial lift system, and then install packers downhole to isolate unwanted pressures.

A Marathon Oil presentation from 2014 said these "full decompletions" are applied to horizontal wells parallel to and within about 500 ft of an offset hydraulic fracturing treatment.

Is Prevention Possible?

The current understanding of how frac hits develop is so limited that there is no consensus on how to prevent them. Many of the ideas tested so far have shown mixed results, according to those familiar with field operations.

Barree questioned the practice of loading up producing wellbores with water, believing that this could cause the same type of damage that operators are trying to avoid. Also, it may not be adequate enough to form a protective pressure shield around parent wells. "You can't reverse the years of pressure depletion, and you can't re-stress the rock or re-pressurize the well," he added.

Another idea is to recharge the offset wells using gas, either natural gas or carbon dioxide, neither of which should lead to well damage. Though Barree is not aware of any companies that have tested this approach, he said "there is a good chance that it could help."

If gas compression facilities are available, operators could continuously pump natural gas into offset wells to increase their local pore pressure to ward off an oncoming fracture.

Barree said the potential of this approach is supported by instances where wells have been shut in prior to an offset hydraulic fracturing operation and were shown to have built up enough pressure to reduce the frequency or severity of frac hits.

A similar approach, though more involved and costlier, is to refracture a parent well prior to the initial hydraulic fracturing of a child well. Schlumberger is among the service companies marketing refracturing as a method of frac hit protection.

Virues said he has observed that refractured wells tend to experience less severe frac hits and thinks it is because refracturing enhances the parent well's local stress regime—the same idea behind the other injection techniques but involving much more fluid.

Barree emphasized that a new fracturing fluid design may be the shale sector's best option for avoiding damaging frac hits. Use of high-concentrated friction reducer (HCFR) in slickwater fluids is trending upward as it is seen as an affordable alternative to gel-based fluids and has shown productivity benefits as well.

Barree said testing has also shown that HCFR can also enable operators to pump high loads of sand to keep fractures open while using far less water, which should generate less-extensive but high-producing fractures. "Forget about trying to reach out with the fractures," he advised. "Focus on near-wellbore stimulation." **JPT**

For Further Reading

SPE 184869 Applying Subsurface DNA Sequencing in Wolfcamp Shales, Midland Basin *by Peter Lascelles, EP Energy et al., Biota Technology.* https://doi.org/10.2118/184869-MS

SPE 184812 Improving Quantitative Analysis of Frac-Hits and Refracs in Unconventional Plays Using RTA *by Himanshu Yadav and Siyavash Motealleh, BP.* https://doi.org/10.2118/184812-MS

SPE-178509 Is That Interference? A Work Flow for Identifying and Analyzing Communication Through Hydraulic Fractures in a Multiwell Pad *by Ali Awada, IHS et al. and Claudio Virues, CNOOC Nexen.* https://doi.org/10.2118/178509-PA

SPE 184851 Re-Designing from Scratch and Defending Offset Wells: Case Study of a Six-Well Bakken Zipper Project, McKenzie County, ND *by Peter Bommer, Abraxas* Petroleum Corporation et al., https://doi.org/10.2118/184851-MS

SPE 184837 Reservoir and Completion Considerations for the Refracturing of Horizontal Wells *by Robert (Bob) Barree, Barree & Associates et al., and Jennifer Miskimins, Colorado School of Mines.* https://doi.org/10.2118/184837-MS