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Please fill in your manuscript title.	**Integration of Fracturing Pressure Diagnostics with Multi-Well Smart Tracer Program for Hydraulic Fracturing Stimulation and Diversion Efficiency Assessment**

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Abstract

Multi-stage hydraulic fracturing stimulation and completion programs now account for up to 70% of total well costs (Shokanov et al. 2019). Faced with unprecedented economic pressures on the entire oil and gas industry, upstream operations must take a serious look at increasing their efficiency regarding the use of completion money and ensuring that increased production results warrant the expenditure. Completion operations must develop systems and processes that deepen insight into complex reservoir performance, right-size well spacing, and focus on data-driven stimulation designs that optimize economics.

This paper highlights one such effort in the Tennessee Colony Field project in East Texas. A novel ultra-high-resolution nanoparticle tracer played a key role in delivering useful data that led to a comprehensive understanding of the reservoir response to stimulation efforts at a stage level. Additional multi-well studies in turn led to developing a full reservoir plan and optimizing well spacing.

The state-of-the-art ultra-high-resolution nanoparticle tracers were added before and after each diverter stage for flow profile mapping and diversion efficiency assessment. In addition, a sampling campaign of adjacent wells was initiated to identify potential communication between old and new wells. The tracers' data integration with fracturing pressure diagnostics helped to improve the target reservoir development approach and provided a live performance flow profile for the entire field. This data was used to optimize completion and workover strategies, achieve the best well productivities, and significantly enhance the understanding of the reservoir geology for the entire field.

This paper describes the project results including the hydraulic fracturing pressure diagnostics with a multi-well tracer program integration. Since tracers were analyzed over several months from numerous wells, the operator has gained insight into continuous flow profiles leading to optimizing well performance on a regular basis as new production-diagnostic results are received.

Introduction

Unprecedented power outages in the United States and the global demand-sapping Covid-19 pandemic have aggravated exponentially the economic pressures facing oil and gas companies. In this unprecedented environment, there is increased pressure upon oil and gas operators to deepen insight into complex reservoir performance, right-size well spacing, and focus on data-driven stimulation designs backed by stage-level production measurements to enhance production flow within the confines of ever-restricted budgets.

Any exercise directed at maximizing production and estimated ultimate recoveries (EUR) must now focus, more than ever, on the multi-stage hydraulic fracturing stimulation and completion programs, which together account for up to 70% of total well cost (Shokanov et al. 2019). The multi-stage hydraulic fracturing stimulation process can significantly increase production in vertical, deviated, and horizontal wells. The objective is to maximize reservoir contact by exposing vast quantities of surface area within the reservoir through fracturing stimulation that create and interconnect the hydraulic and natural fractures.

With current completion designs, the production results of multi-stage hydraulic fracturing treatments, when reported down to individual stage level, are significantly lower than many oil and gas companies expect. Several stage level production mapping studies across various shale basins in North America have reported that up to 30% of the stages and clusters do not produce (Lindsay et al. 2018).

In addition, the current geometric completion designs, rock heterogeneity, brute force approach using ever-increasing volumes of sand and water, and declining returns combine to pose a critical challenge to the economics of modern wells. For conventional and unconventional wells, especially, access to affordable stage-by-stage flow profiles to identify non-productive stages is an indispensable tool. A method to maximize production flow across the horizontal lateral will minimize unnecessary costs and reduce onsite emissions as multi-stage hydraulic fracturing operations eliminate non-economic fracture stages.

As many shale operators resume infill development amid ever-tightening well spacing and nebulous economics, frac-hit issues re-emerge as critical in asset development strategies. Industry statistics indicate frac-to-frac communication is responsible for upwards of $21 billion in lost production revenue and mitigation expenses over the past two years alone (Lindsay et al. 2018).

Unsurprisingly, direct frac hits account for only 12% of detected events and the majority of the remaining events, an estimated 82% of frac-hit signal characteristics are, in fact, fluid migration between the existing "parent" well and the newly drilled "child" well. Fluid migration not only has a minimal and short-lived effect on production, but without it, an inordinate area between the wells would be left unstimulated, leaving potentially significant reserves stranded. The key is to put detected inter-well flow communication events in the proper perspective (Shokanov et al. 2021).

However, save for a scant number of engineered "science" wells, data on these critical frac hits and stage-level production have been unavailable to more than 99% of completed land wells. Narrowing the wide economic gap between transitioning engineered science wells to the mainstream drove the development of a uniquely engineered portfolio of ultra-high-resolution nanoparticle tracers which were designed to provide the stage-level flow data once reserved for a select few wells.

The field-proven nanoparticle-based tracers consistently deliver accurate and near real-time detection, well beyond the capabilities of conventional chemical liquid tracers and DNA sequencing products, and at comparable costs that essentially equate to a fraction of the total cost of contemporary completions.

Uniquely abetted with the latest advances in artificial intelligence (AI) and machine learning (ML), the robust, non-radioactive, and non-hazardous tracers are engineered with subatomic spectroscopic measurement techniques to map the distribution of well production, the performance of each stage, cross-well interference, and reservoir condition.

Easily deployed, the distinctly tagged and non-intrusive nanoparticle tracers maintain stability at very high temperatures. Compared to standard, chemically based soluble tracers, these nanoparticle tracers remain intact within the fracture network, thereby enabling continuous on-site monitoring of the flow profile for up to 6 months.

The ultra-high-resolution nanoparticle tracers are able to convey much more information about the fractures in the reservoir, from the flow characteristics to the fracture's conductivity. Easily deployed, clearly tagged, safe, non-radioactive tracers can maintain stability at excessive reservoir temperatures (up to 2,000°F) and withstand the high closure stress (up to 10,000 psi) which compares very favorable to the limitations of standard chemically soluble tracers. Figure 1 shows the relative size to other tracers and gives some properties of the nanoparticle tracer. The nanoparticle tracers remain intact within the fracture networks, allowing continuous on-site monitoring of the flow profile.

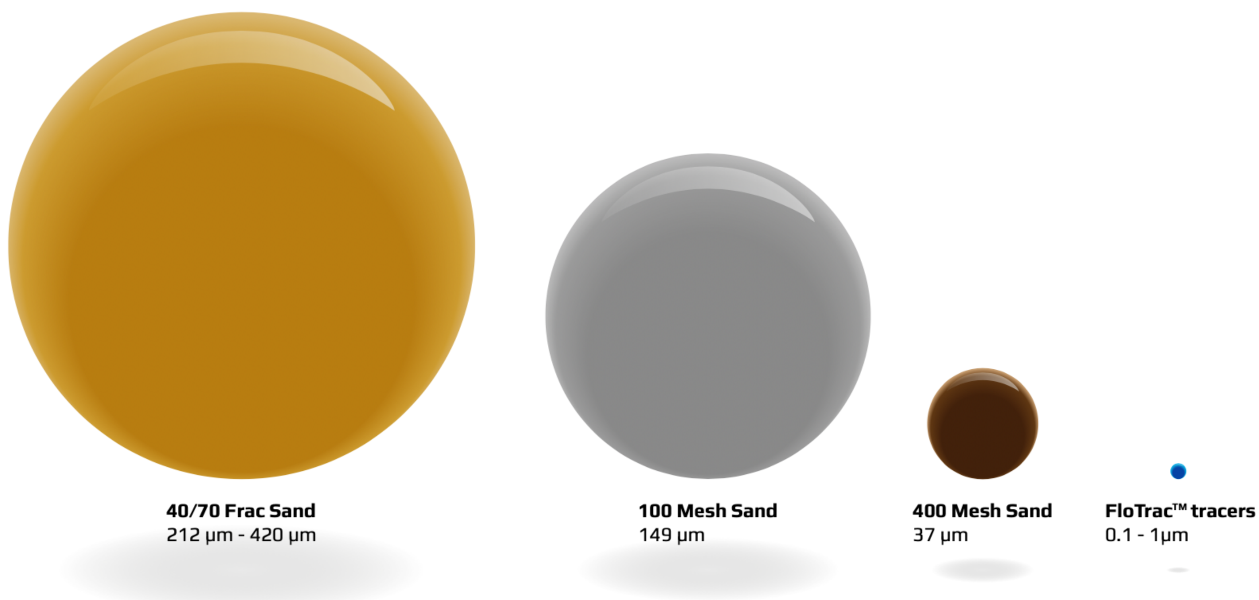

Figure 1: Ultra-high-resolution nanoparticle tracer technology shown in comparison to sizes of popular fracture sands.

The ultra-high-resolution nanoparticle tracer technology enables operators to decrease the multi-stage hydraulic fracturing cost and significantly reduce environmental impact. It also bolsters the environmental friendliness and ultimately provides better oil and gas production via focused usage of fracture materials and water to actionable stages with overall lower CO_2 emissions. All these factors are combined with state-of-the-art subatomic measurements coupled with advanced geomechanics, onsite laboratory analysis, and big-data analytics to create critical value for oil and gas operators which ensures the most accurate, affordable, and actionable stage performance and production data along with an integrated workflow from tracer inter-well interference mapping to intelligent completion diagnostics.

The benefits of the ultra-high-resolution nanoparticle tracers provide accurate, actionable, performance-flow-profile data and allow oil and gas companies to optimize well placement and field development strategies while reducing well completion and multi-stage hydraulic fracturing stimulation costs (Shokanov et al. 2019).

Flow Profiling Landscape

Conventional liquid chemical tracers, based on water- or oil-soluble chemical substances, have been used as reservoir surveillance tools for decades. Tracers with fluorescent properties, DNA fingerprints, ionic, organic materials, or radioactive diagnostic isotopes are used to evaluate fracturing performance, ostensibly to control the effectiveness of multi-stage hydraulic fracturing stimulation. Owing to obvious environmental deficiencies and disposal concerns, tracers incorporating radioactive isotopes have largely fallen out of favor.

Given their soluble characteristics, conventional chemical tracers must be tailored for individual fluid types, thereby requiring more, and often exotic, chemical formulations for a single stage, increasing the chemical tracer costs appreciably for a modern multi-stage hydraulic fracturing completion. Given the inherent heterogeneity and complexity of shale rock along a typical horizontal lateral and the assorted fluid streams, the different types of chemical tracers required could add an additional $250,000 or more in incremental costs per well.

Furthermore, once liquid-based tracers have been pumped, they dissolve, disseminate quickly, and are flushed from the conductive proppant pack, thus shortening the effective stage-level production monitoring period significantly. Therefore, because of cost, occasionally inconclusive accuracy, cross-well contamination, and downhole temperature restrictions (limited to 350°F), the use of contemporary chemical tracers is realistically limited to “science” wells.

Conventional tracer testing, likewise, is severely restricted by the time required to obtain a comprehensive interpretation of the test results. This is normally accomplished from an offsite analytical laboratory with a minimum three-week turnaround on average, given the longer sample preparation time, very expensive instrumentation, sensitive sample dissolution process, and specialized costly reagents needed for analysis.

Perhaps one of the more glaring drawbacks with conventional tracers is the frequent instigation of unnecessary signals to what is erroneously perceived and known as “frac hits”. A frac hit is typically described as a fracture-driven inter-well 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.

Consider, for example, a multi-zone well stimulated with a zipper frac, where most of the pay zones are hydraulically fractured sequentially with one well pumping while the other well is performing wireline operations. A typical stacked pay shale well would have the predominate fracture with sand proppant, along with a discrete secondary fracture network having very small apertures or open fissures. Chemical tracers tend to percolate deeper into these often-microscopic fissures, usually resulting in the multiple “false positives” wrongly signaling that all the fractures are communicating and drawing down production. However, owing to residual proppant-fracture conductivity, once pumping has ceased, the sand-packed fracture is the only fracture actually contributing to production, while the natural fractures immediately re-seal, meaning little inter-well communication had been achieved (Figure 2).

Obtaining post-fracture flow profiles, especially critical in optimizing multi-stage hydraulic fracturing programs, has up to now been mostly unavailable and, if available, usually a cumbersome and enormously costly proposition. Along with requiring specialized and downhole modifications, most standard diagnostic methodologies also generate inferred, rather than direct, measurements of the flow profile.

Production logging tools, for instance, require a wireline intervention, while providing only a medium level of detection accuracy for multi-phase flow especially for comingled flow in the horizontal lateral and a very short snapshot for production profiling during wireline intervention. Microseismic completions generate rock shear failure datapoints during hydraulic fracturing propagation that can measure fracture geometry, but is unable to provide direct answers for the production profile or severity of inter-well communication. DNA sequencing products are only appliable in the localized near-wellbore area but require a high-cost extensive drill cuttings sampling and analysis process.

Figure 2: The various types of frac hits and their respective impact on production and EUR (Shokanov et al. 2021).

Conversely, fiber-optic-enabled distributed temperature surveys (DTS) and distributed acoustic sensing (DAS) deliver a high degree of detection accuracy and long-term production profiling. However, DAS and DTS systems, which must be installed as part of the completion operation, necessitate extensive modifications downhole with specialized oriented perforations and require extra caution with each perforation phasing and cement integrity. Unfortunately, these systems typically report a high failure rate due to fiber damage/signal disruption during plug-and-perf operations. All these come at very high cost, well beyond the resources of most oil and gas operators, especially with today's severe economic regime and considering the high risk of obtaining limited data at best. Depending on the complexity, the permanent installation of fiber optic DAS and DTS systems can add $1 million per well to the completed total costs.

The limitations and often prohibitive costs of conventional tracer and current diagnostic technologies encouraged the development of the next-generation innovative ultra-high-resolution nanoparticle tracers and "intelligent" flow-diagnostic workflows. The aim is to develop new-generation tracer technology with a costing model that will fit within the economic capabilities of all operators (Table 1).

	Production Logging (PLT)	Chemical Tracer	Fiber Optic (DAS & DTS)	Nanoparticle Tracer
Type of Technology	Logging	Chemical	Downhole Fiber Optics	**Smart Particles**
Temperature Limit	700°F	350°F	500°F	**2,000°F**
Detection Accuracy	Medium	Low	Very High	**High**
Production Profiling Timeline	Short-Term	Middle-Term	Long-Term	**Long-Term**
Deployment Requirements	Intervention with Logging	Multiple Tracers per Stage	Downhole with Completion	**Single Tracer per Stage**
Mobile lab with Onsite Analysis	Yes	No	Yes	**Yes**
Results Turnaround Time	2 Weeks	3 Weeks	3 Weeks	**Near Real-Time**
Precision in "frac hits" Mapping	No	Medium	No	**Very High**
Cost to E&P Operators	High	High	Very High	**Low**

Table 1: Current landscape of flow-profiling technologies.

Tennessee Colony Project

The operator acquired the East Texas asset in 2019 with the acquisition of 2,680 net acres and eight operating wells. The Tennessee Colony Field wells (Figure 3) were producing oil, dry gas, and natural gas liquids from carbonate reservoirs through legacy vertical wells.

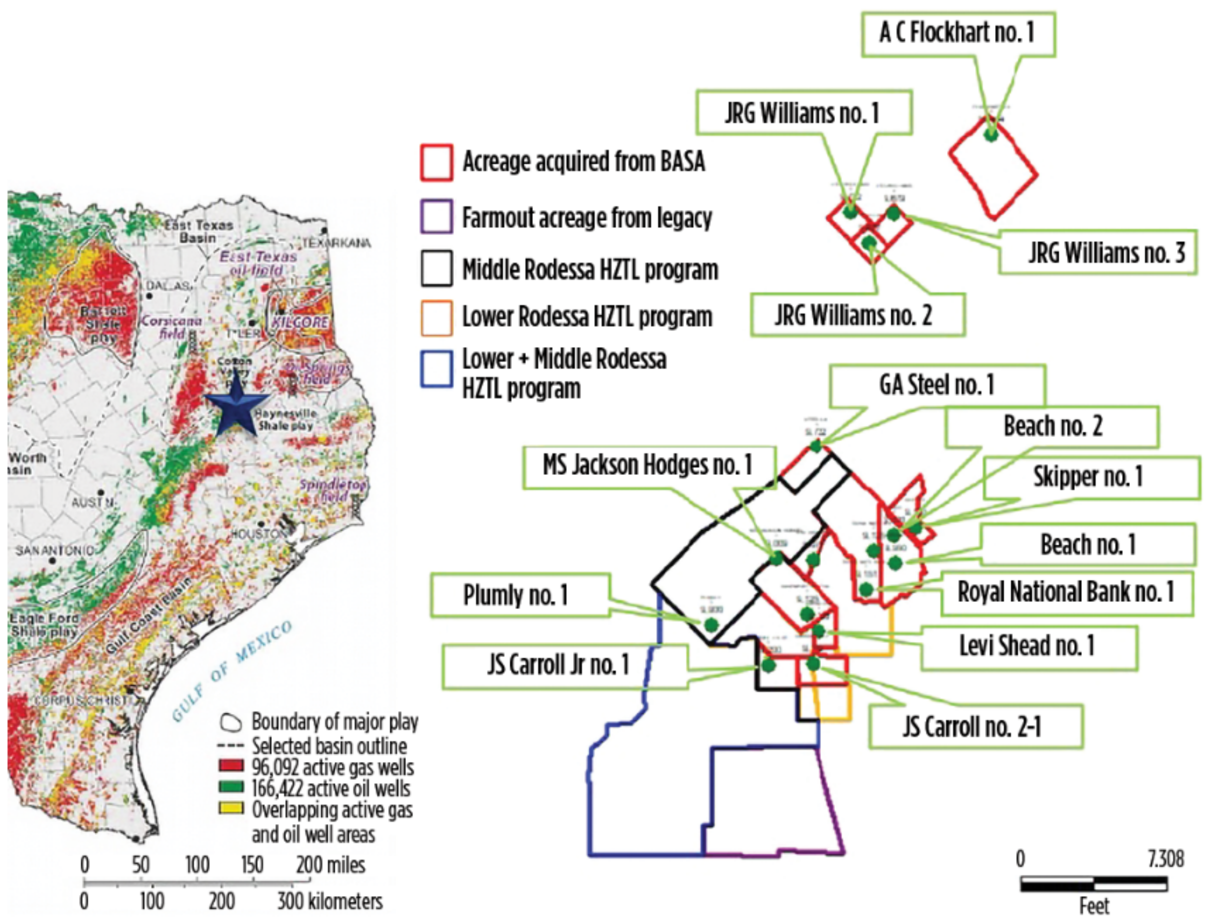

Figure 3: East Texas location of the multi-well Tennessee Colony Field Development Project (Shokanov et al. 2020).

After identifying at least two bypassed prospective pay zones in the Middle and Lower Rodessa Formation productive layer, the operator orchestrated a comprehensive re-development and hydraulic fracturing stimulation strategy for the Tennessee Colony core field and adjacent areas. The targeted reservoir has 5 to 18% porosity, 0.01 to 100 mD permeability, and 50% water saturation.

The immediate objectives were to quadruple the three-stream production rates from legacy wells; verify geological, reservoir and geomechanical assumptions; identify prospects for new development zones; and optimize well spacing for the new wells at the acreage. The operator structured this work as a Phase I – Field Rehabilitation Project.

Following the completion of Phase I – Field Rehabilitation, the operator further scheduled three additional workover opportunities for current wells and plans to drill one new horizontal well for increased production from the targeted reservoir. In addition, the operator entered into a farm-out agreement for 2,460 acres contiguous to the existing field to expand the well count, increase the wells EUR, and add surface production facilities.

The first phase of the strategy comprised a series of workovers and acid hydraulic fracturing stimulation treatments, followed by the deployment of specialized diverters and tracers. The infill development program was initiated with a workover on a first well with an existing perforation and cement bond squeezes for previous perforation intervals.

The perforation of a new pay zone was to be followed by the hydraulic fracturing program entailing three continuous pumping cycles of hydrochloric acid (HCl), water, and 75-lb rock salt diverters. The treatment pumping and decline fracturing pressures were continuously recorded with a surface digital pressure sensor.

Because there is no conventional liquid chemical tracer developed and available that works efficiently with the formulated acid, the operator decided to proceed with the nanoparticle-tracer portfolio. Three distinctively tagged ultra-high-resolution nanoparticle tracers were added before and after each diverter stage to assess the efficiency of the fracture diverters in creating multiple fractures and effectively increase the reservoir contact area and flow paths as shown in Table 2.

Pumping Procedure:	
Acid Frac Pumping Schedule	**Smart Nano Tracers Injection Schedule**
1. Establish injection rate w/ customer supplied water	1. Monitor the surface frac pressure
2. Pump 800 gallons Acid	2. Stand ready for water injection
3. **Pump 900 gallons Water**	**3. Inject 850 grams of Smart Nano Tracer #1**
4. Pump 100 gallons Water w/ 75# Rock Salt	4. Stand ready for water injection
5. Pump 800 gallons Acid	5. Stand ready for water injection
6. **Pump 900 gallons Water**	**6. Inject 1400 grams of Smart Nano Tracer #2**
7. Pump 100 gallons Water w/ 75# Rock Salt	7. Stand ready for water injection
8. Pump 800 gallons Acid	8. Stand ready for water injection
9. **Pump 900 gallons Water**	**9. Inject 1100 grams of Smart Nano Tracer #3**
10. Pump 100 gallons Water w/ 75# Rock Salt	10. Monitor the surface frac pressure
11. Displace to bottom perf + 5 bbls w/ Water	11. Monitor the surface frac pressure
add in 5 gal non emulsifier.	

Table 2: Pumping schedule with HCl, water, diverters, and tracers.

Pressure Diagnostics

The pumping and post shut-in decline pressures were evaluated during each cycle to characterize the hydraulic fracture response, diversion efficiency, closure behavior, and in-situ stress. Figure 4 illustrates the pressure response and post shut-in decline data collected.

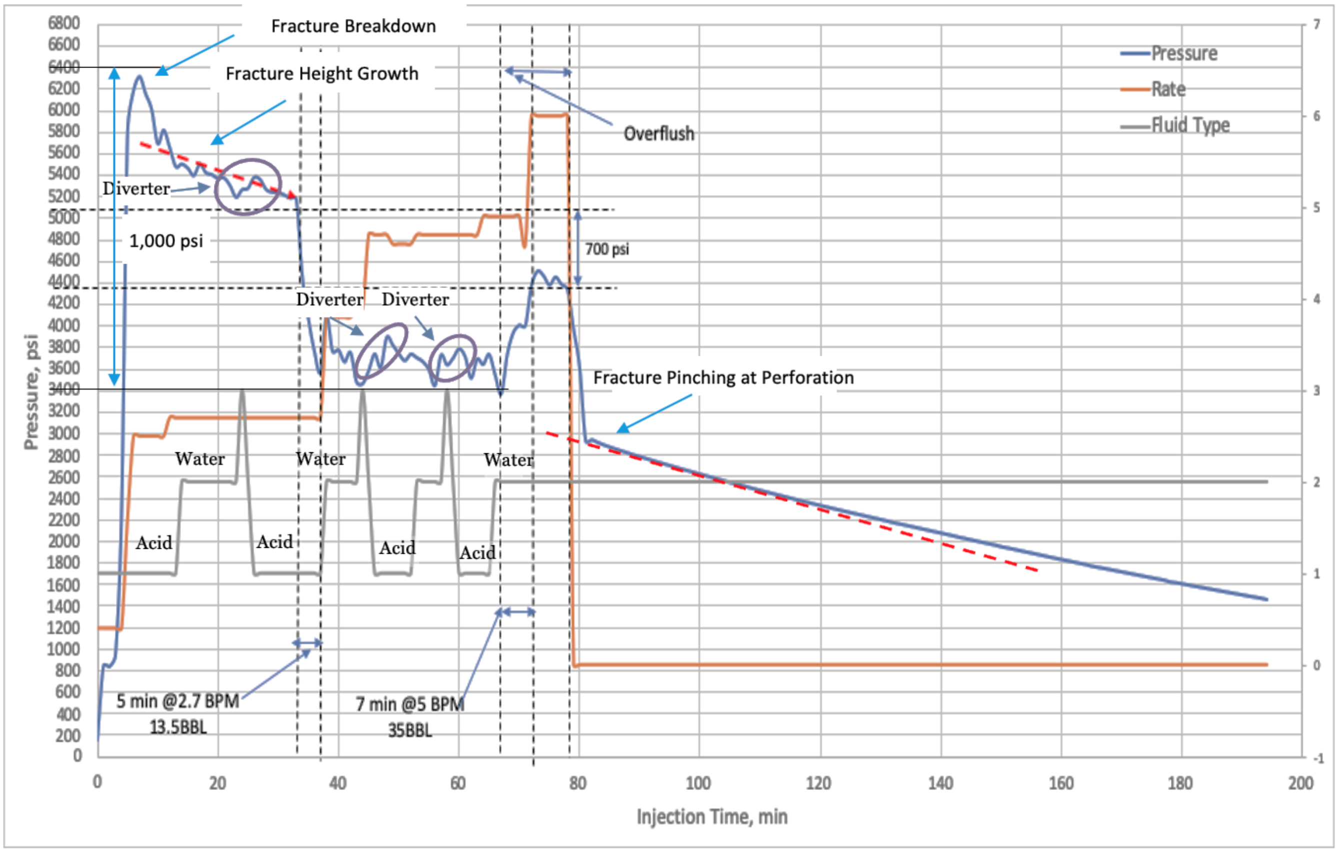

Figure 4: Pressure response during pumping and post shut-in decline.

The first pumping cycled commenced with pumping acid at 2.7 bbl/min and a breakdown pressure of 6,300 psi. The surface injection pressure was gradually decreased after initial pressure breakdown during pumping. The estimated well volume was about 36 barrels according to the final well completion diagram. The surface pressure decrease during the first 14 minutes of pumping is related to fluid displacement of the less-dense completion fluid by the heavier acid in the wellbore, and possibly also the gradual fracture vertical height growth or propagation into lower in-situ stress layers above.

Considering legacy wireline open-hole log data and lithology sequence, the geologic cross-section represents the alteration of carbonate and shale layers. In this case, the lower in-situ stress zone can be correlated with layers located above the perforation interval.

A significant surface pressure drop was observed during the second pumping cycle after 33 minutes of total pumping time (Figure 4). The surface pressure dropped from 5,180 to 3,580 psi, or a total drop of 1,600 psi within a 5-minute period. Several plausible scenarios for this drop include:

- Cement quality and bonding issues
- Upward hydraulic fracture propagation into the depleted interval located above the current perforation interval

A review of the cement bond log indicated cement quality and bonding issues in several intervals located above the perforation interval (Figure 5). In addition, the scenario for fracture propagation into the depleted interval was both plausible and supported by rapid fracture closure with a straight-line post shut-in pressure decline behavior (aka "fracture storage response") and fracture pinching during the closure of the current perforation interval.

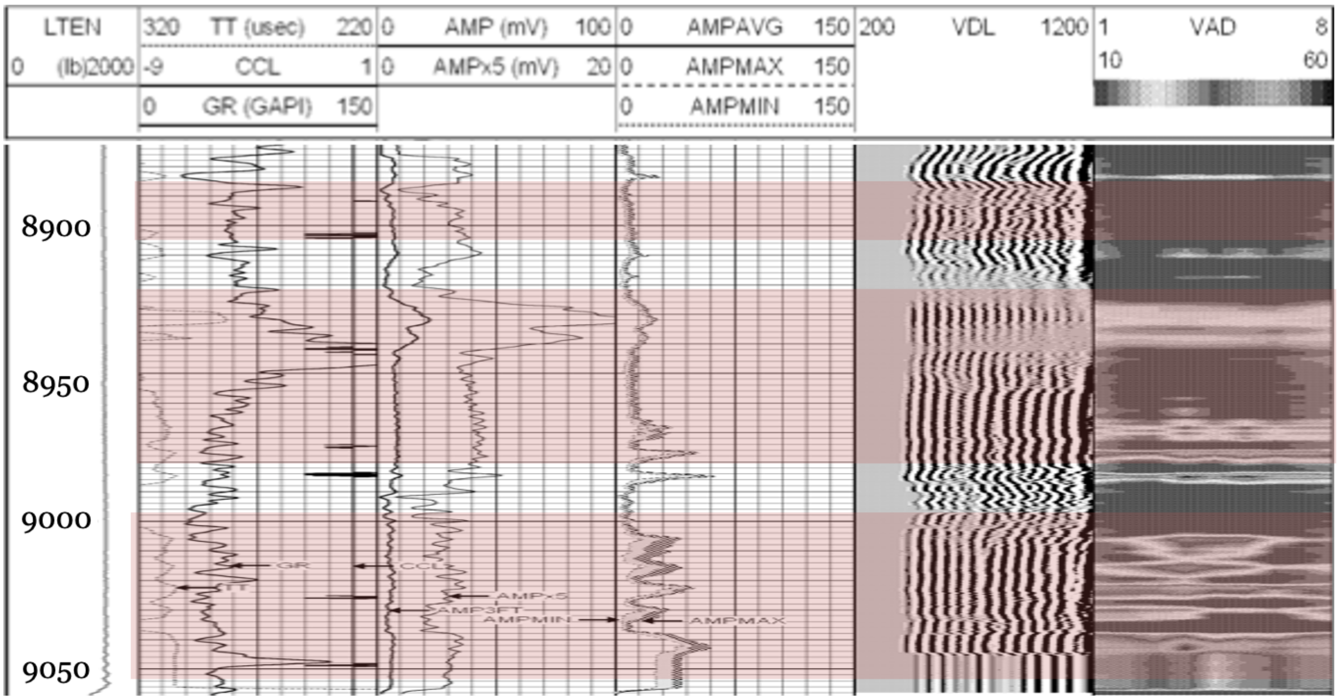

Figure 5: Cement bond log for the traced well.

It is also noted that the interval above had depleted reservoir pressure which correlated well with this pressure response. The reservoir pressure in the depleted zone was estimated to be at around 880 psi. With Poisson's Ratio (PR) of 0.3 and overburden gradient of 1.0 psi/ft in the carbonates, that would result in minimum in-situ stress value in the depleted layer of approximately 4,400 psi (converted to surface pumping pressure). This is assuming very limited or no tectonic stresses in the area. The minimum in-situ stress at the new perforated interval with the same assumptions would be about 6,200 psi. The in-situ stress difference between depleted and new zone correlates closely with the observed surface pressure drop during the pumping (Figure 4).

Diversion Efficiency Assessment

Diverter pumping during the three cycles indicates a surface pressure change of approximately 400 psi. Industry best practice indicates (Fragachan et al. 2020) that effective diverter placement that leads to new hydraulic fractures initiation (as intended by design) should result in a pressure increase of 800 to 1,000 psi. This is mainly due to the pressure required to initiate the new hydraulic fracture from the wellbore and as a result of plugging the existing fracture aperture with diverter material.

The observed pressure behavior (Δ400 psi) signifies little or no effect from diverter placement creating secondary fracture initiation during the pumping. The most likely scenario is that pumping was performed into a single large bi-wing hydraulic fracture with vertical height growth which is further supported by the tracer analysis during flowback. The surface pressure readings, taken after the diverters were pumped, suggested diversion may not be occurring with that incremental surface pressure.

Three distinctively tagged ultra-high-resolution nanoparticle tracers were added before and after each diverter stage to assess the efficiency of the fracture diverters in creating multiple fractures from the wellbore to increase the reservoir contact area and flow paths. The flowback samples were taken from the wellhead and tested onsite for 10 consecutive days during production to measure the subsequent recovery rate of the ultra-high-resolution nanoparticle tracers. Ideally, if the diverters were performing as designed, near uniform recovery rates would be observed for all the tracers (Figure 6).

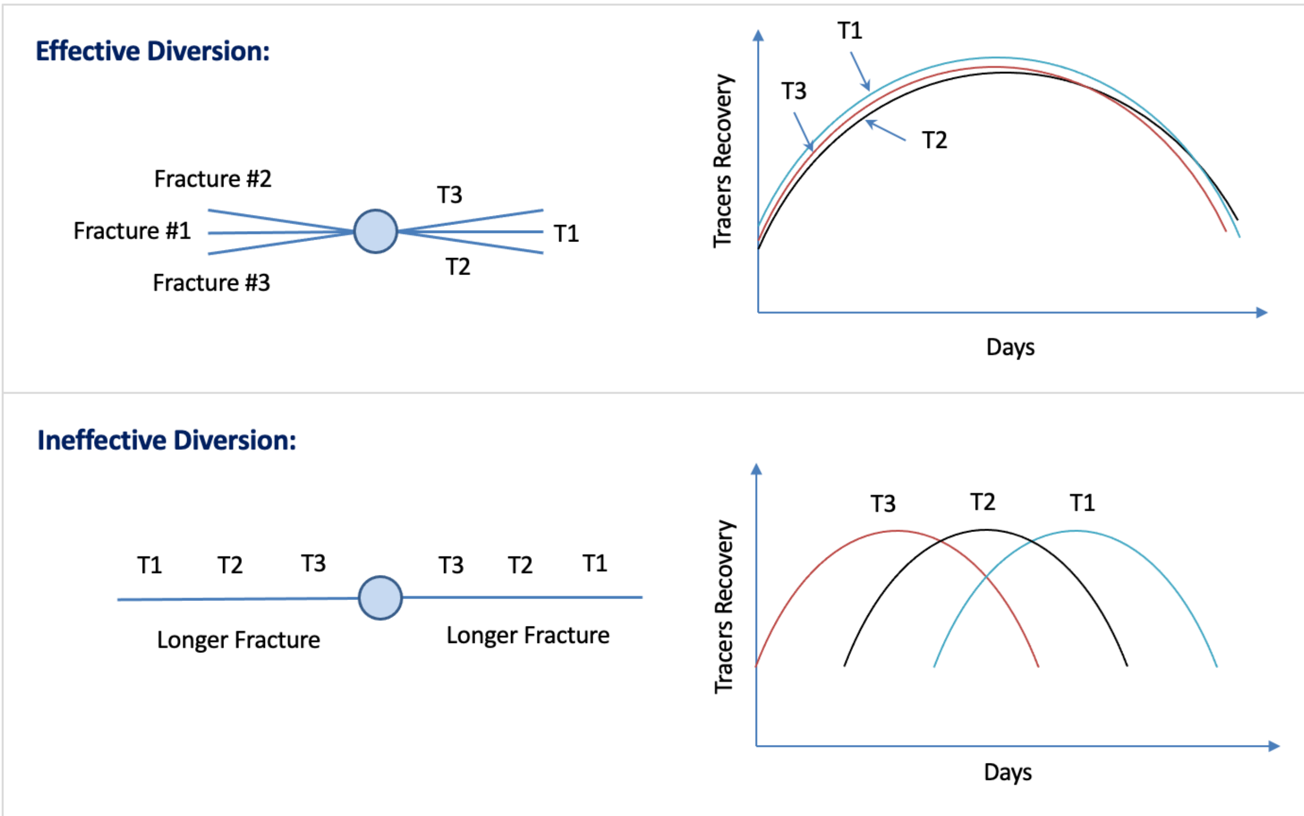

Figure 6: Diversion assessment for vertical well: effective vs. ineffective diversion.

However, one set of the tagged ultra-high-resolution nanoparticle tracers placed during third cycle of pumping came back in a comparably larger quantity, confirming that diversion was not occurring and recoveries were coming only from one large bi-wing fracture, rather than the multiple flow paths/fractures as intended (Figure 7).

Validation of the pressure reading reinforced the critical value of the ultra-high-resolution nanoparticle tracers in assessing diverter efficiency, or in this case, inefficiency. Given the resulting data, the operator saved approximately $100,000 per well by eliminating ineffective parts of a re-completion diversion strategy. This type of cost savings is critical for execution successes and supported the cost reduction and increased efficiency efforts for the re-development program.

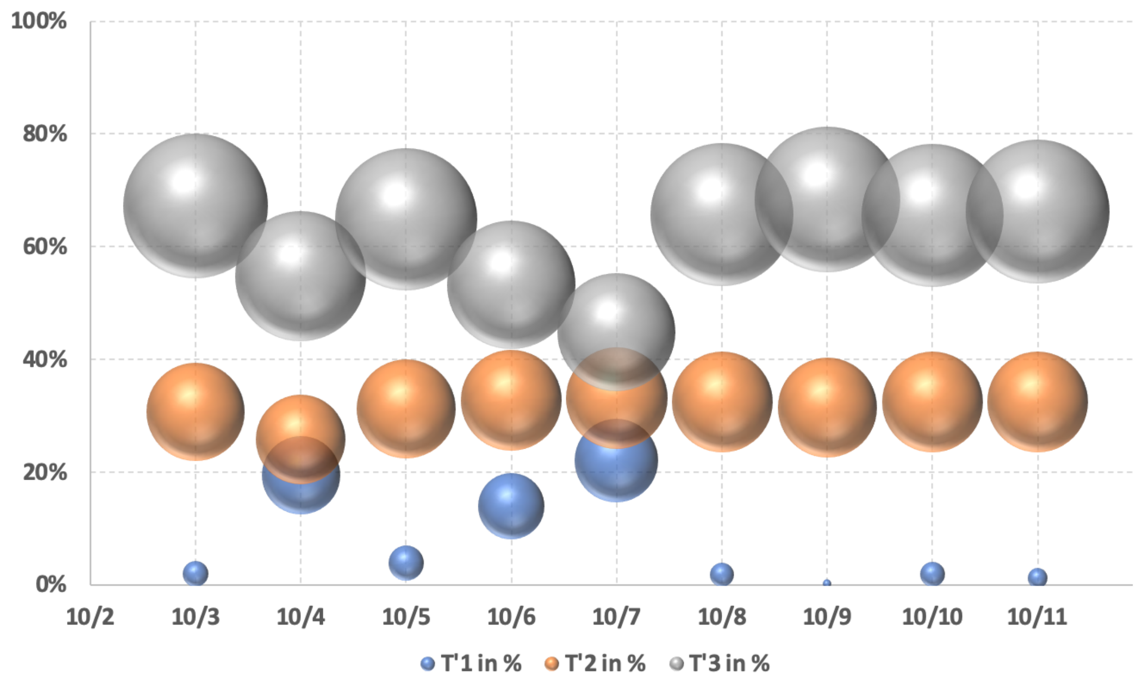

Figure 7: Flow profiling from three distinctively tagged ultra-high-resolution nanoparticle tracers. Size of sphere indicates relative volume of tracer recovered. Note the variation in blue spheres indicates the recovery of the tracer was not uniform over time.

Tracer Offset Wells Analysis

After the tracer study detailed above, the operator requested production sampling and analysis on four offset wells from the traced well to gain a better understanding of the reservoir, insofar as inter-well communication was concerned. The resulting data provided valuable spacing insights, communication information, and the reservoir flow pathway critical to the company's plan to drill additional development wells in the Tennessee Colony Field of East Texas.

Hydraulic fracturing of a vertical well is unique, in that the induced fractures are inherently planar, as they are not subjected to the tortuous path of an unconventional well, but rather follow a so-called preferred fracture plane (PFP). PFP is oriented in a direction perpendicular to the least principal in-situ stress. With this distinction in mind, samples were taken from four offset wells to determine surface recovery rates and potential communication.

The results showed two of the offset wells achieved detectable ultra-high-resolution nanoparticle tracer recovery rates on surface, while the remaining two offset wells had zero recovery. A consequent geological examination of faults and the preferred orientation of the hydraulic fracture revealed the fault and induced fracture were propagating in the direction of the two wells with full tracer recovery. Figure 8 pinpoints the relative location of the four offset wells analyzed for the tracer's recovery. The two offset wells with detectable tracer recovery are shown in blue. The recovered flow aligned with PFP orientation and azimuth in the reservoir.

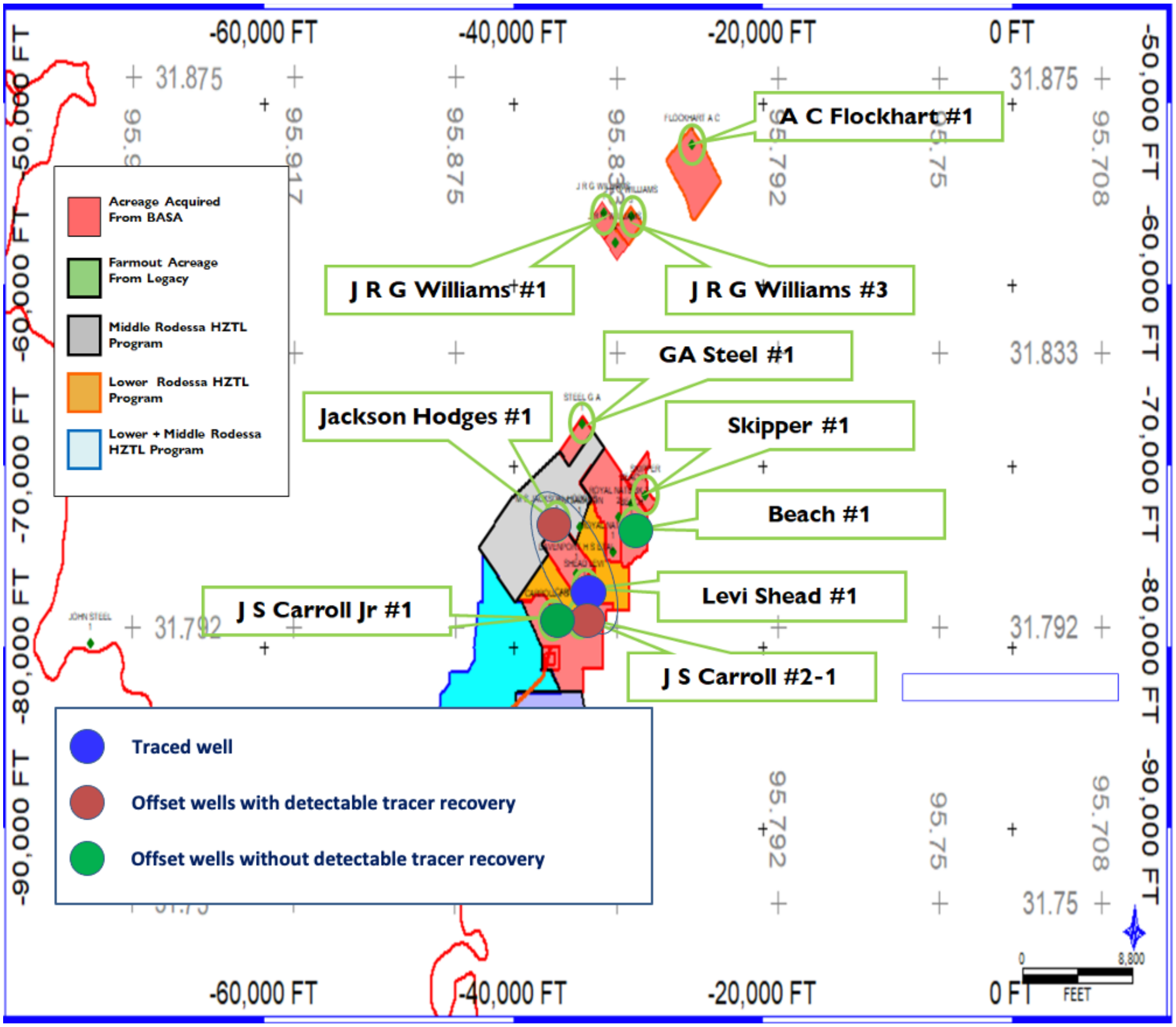

Figure 8: Two offset wells (in red) had detectable tracer recovery as contrast with the two offset wells (in green) with zero tracer recovery. Tracer flow aligned with PFP orientation.

Another imperative finding is the observed surface pressure and production rate increase in two offset wells with ultra-high-resolution nanoparticle tracer recovery. The created communication path connected the depleted low-pressure layer with the newly pressured zone. This created a constant water flow from higher pressure interval to the depleted zone indicating communication, and the reported higher water cut on both offset wells aligned with the tracer's recovery.

This comprehensive tracer data acquisition and integration of pressure diagnostics, diversion assessment, tracer flow mapping, and subsurface evaluation enabled the operator to map the entire Tennessee Colony asset and optimize future hydraulic fracturing designs, wells spacing, and avoid inter-well communication for future development prospects, all positive steps to help ensure maximum production.

Conclusions

As the Tennessee Colony Field Development Project illustrates, the capacity of the ultra-high-resolution nanoparticle tracers to enhance well performance and stimulation design, and reduce costs, represents a step change advancement in the industry's universal transition to stimulations of the future.

The tracers' data integration with hydraulic fracturing pressure diagnostics is a powerful tool to improve the target reservoir development strategy and provide live performance flow profile data for the entire asset. The results were used to optimize completion and workover strategies, to achieve the best wells EUR, and to significantly enhance reservoir understanding.

The lessons learned from ultra-high-resolution nanoparticle tracer data analysis and reservoir flow mapping reduced the learning curve and refined geological and geomechanical assumptions for the entire asset.

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