THE AMERICAN OIL & GAS REPORTER®
DECEMBER 2019
The "Better Business" Publication Serving the Exploration / Drilling / Production Industry

Operators "Go Natural" To Understand Frac Flowback Water

By Patrick Travers,
Ben Burke
and Michael P. Dolan

WESTMINSTER, CO.–As producers operating in North American unconventional oil and gas plays strive for increased efficiency and optimization, collecting appropriate datasets during operations is essential for making intelligent, data-driven decisions on development plans or operations.

One example of this is a case study presented at the Unconventional Resources Technology Conference in July showing flowback and produced water data collected from horizontal Niobrara and Codell wells operated by HighPoint Resources, a Denver based operator working in Colorado's Denver-Julesburg Basin.

HighPoint applied the understanding it gained from this study to guide development decisions and completion strategies for Niobrara and Codell wells in the Hereford Field.

Although operators commonly track the volume of flowback and produced water closely, the sources of that produced water and how the contributions of those sources change throughout the life cycle of a well are not always well understood. Similarly, common industry practice is to monitor offset wells for pressure responses during nearby hydraulic fracturing to describe and measure fracture hits, but tracer studies measuring the physical transport of frac fluid from the active well to the passive offset well are rare.

HighPoint's geoscience team designed a study that was able to capture information on these and other phenomena occurring during operations using simple, naturally present tracers. The level of detail provided by this data represents a step change relative to many current industry practices.

Stable Isotope Analysis

The method that provided the key insights in this study is not novel, but is an innovative application of a well-known scientific technique: stable isotope analysis. All water shares a common molecular composition (H_2O). But at the more detailed atomic level, the relative abundance of the stable isotopes of hydrogen and oxygen can differentiate water that has undergone different physical processes or originated from different sources.

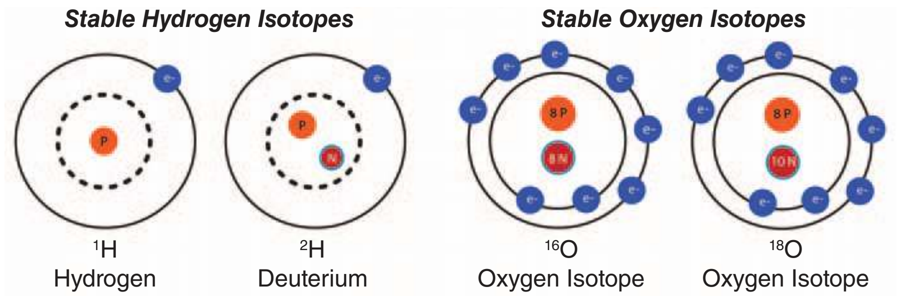
A specialized mass spectrometer such as those operated at Dolan Integration Group's (DIG) oil and gas fluids laboratory in Denver is used to measure the slight differences in isotopic abundances of waters collected in the oil field.

Stable isotope analysis was a sensible choice, given it has been used for decades to delineate the origin and mixing of distinct water sources in hydrogeologic studies, although its application to oil and gas studies has been more limited.

As shown in Figure 1, the relative abundances of the different stable isotopes of hydrogen and oxygen can be used as natural tracers of water molecules as they move through the subsurface. This is based on measuring the ratio of the "heavy" isotopes to the "light" ones, which contain fewer neutrons. The water-stable isotopes of hydrogen (^{1}H and ^{2}H) and oxygen (^{16}O and ^{18}O) are particularly useful as tracers because they occur naturally in all water.

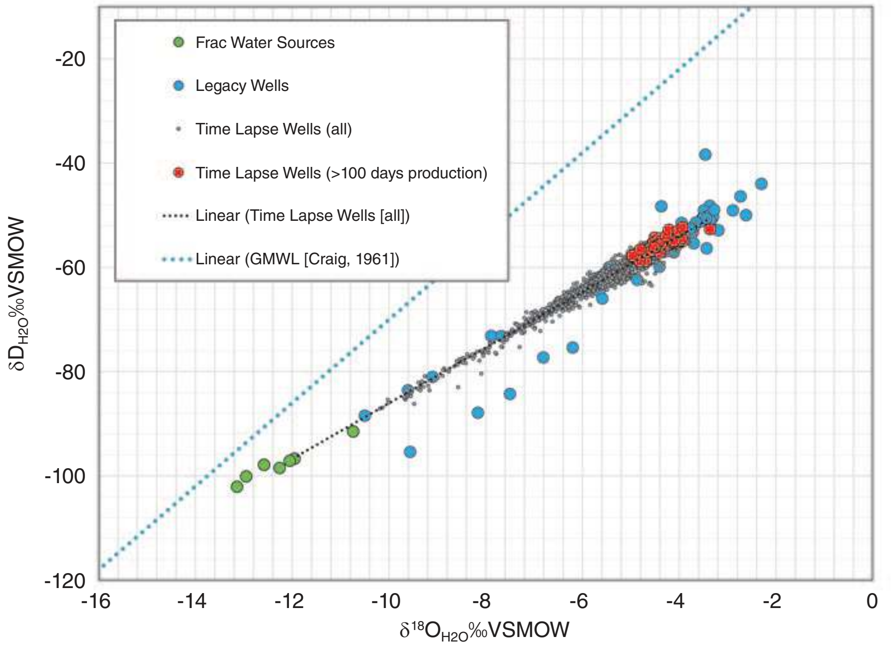
Reliable samples can be collected easily at the surface from the separator or wellhead using minimal equipment. Because these tracers exist naturally, they can be utilized on wells in any stage of flowback or production, even if a tracer

FIGURE 1



By measuring the ratio of "heavy" isotopes to the "light" ones, which contain fewer neutrons, the relative abundances of the different stable isotopes of hydrogen and oxygen can be used as natural tracers of water molecules as they move through the subsurface.

FIGURE 2



This plot shows all stable hydrogen and oxygen water isotope data collected, along with the Global Meteoric Water Line after Craig, 1961.

study had not been planned.

Sampling Program

An extensive time-lapse water geochemistry sampling and analysis program was executed by HighPoint Resources throughout 2017 and 2018. This study is unique in its expansive temporal and spatial resolution ($n > 1,600$ samples), and the number ($n > 80$) and diversity of wells sampled.

In addition, sampling was planned carefully around the completions of offset wells in order to capture information about well-to-well fracture-driven interactions, more commonly known as frac hits. HighPoint was able to use the results of the study to guide completion strategies, carefully document frac hits and how wells recover from them, and influence development strategy and well-spacing decisions.

With a few exceptions, wells sampled all were located in the Hereford Field in the Northern DJ Basin, near where the original EOG Resources Jake 2-01H horizontal Niobrara well was drilled in 2009, which opened the horizontal Niobrara play in the DJ Basin.

Hereford Field is an ideal field-scale laboratory to apply these techniques because there are a number of legacy horizontal wells that have been producing for several years, such as the Jake well, along with new horizontal Niobrara and Codell wells drilled, completed and brought on production in 2017 and 2018.

During this period, 1,603 time-lapse water samples were collected from 22 wells during hydraulic fracturing flowback and production. Sample density for the time-lapse sampling was highest (twice a day) during the first month of flowback. Subsequent sample frequency was reduced to daily or every other day.

The level of effort required in the field to collect such frequent samples can be substantial, but the excellent temporal resolution of the dataset, as well as the careful sampling prior to and immediately after shut-ins for operations or offset completions, proved to be key to the study's findings.

In addition to time-lapse samples, legacy wells were spot-sampled with the intent to provide end-member compositions of native Niobrara and Codell formation waters. Samples also were collected and analyzed from the groundwater wells and surface ponds used to source the water injected during hydraulic fracturing in order to characterize another critical end-member: the source water used to fracture the new wells.

Isotope Analysis

Water samples from all sites were collected and shipped to the laboratory for stable hydrogen and oxygen isotope analysis. Figure 2 shows a cross plot of the results of the water stable isotope analyses. It shows distinct isotopic signatures of the three main types of samples collected:

- Hydraulic fracturing source water;
- Produced water from legacy Niobrara and Codell wells; and
- Time-lapse produced water samples collected from newly completed horizontal Niobrara and Codell wells during flowback and production.

The $\delta^{18}O_{H2O}$ and δD_{H2O} values of samples collected from the shallow (200- to 400-foot) water wells and surface ponds holding frac source water form a distinct population near the Global Meteoric Water Line (GMWL), indicating that they are waters sourced by geologically recent precipitation.

This signature is distinct from the spot samples collected from legacy producing Niobrara and Codell wells in the field, which plot well below the GMWL and yield generally enriched $\delta^{18}O_{H2O}$ and δD_{H2O} values. Importantly, the time-lapse hydrogen and oxygen isotope data from the new wells co-vary and fall on a linear trend between the frac water and legacy-well produced water end-member populations.

Given the mixing trend evident in Figure 2, the isotopic composition of each discrete, time-lapse produced water sample can be understood in terms of a simple two-component mixing model in which the produced or flowback water at any given time is interpreted as a mixture of the source water injected during hydraulic fracturing (frac water) and the long-term produced Niobrara or Codell formation water in the reservoir, base-lined from the legacy EOG wells at Hereford Field.

Combining this mixing model with the produced and flowback water volumes, HighPoint and DIG were able to calculate the relative contributions of each water source with time, as shown in Figures 3A and 3B. These plots show time-lapse data–shown as actual water volume in Figure 3A and as a percentage of produced water volume in Figure 3B–collected from a single Niobrara horizontal well that was hydraulically fractured in March 2017, sampled twice daily for the first 10 days of flowback and then daily through the first five months of production.

Key Observations

By calculating the fraction of frac

FIGURE 3A

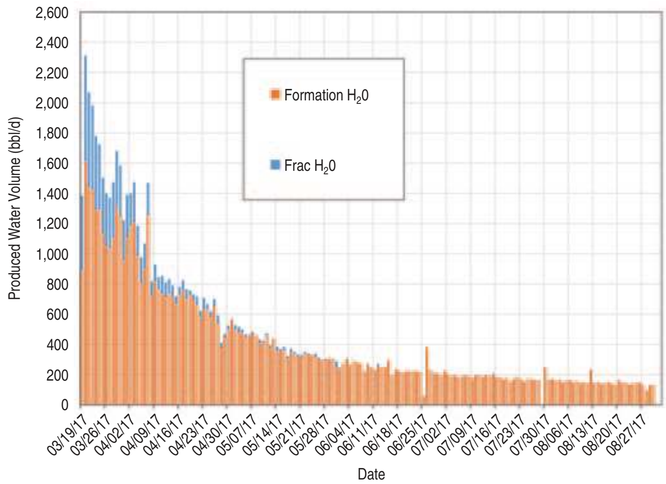
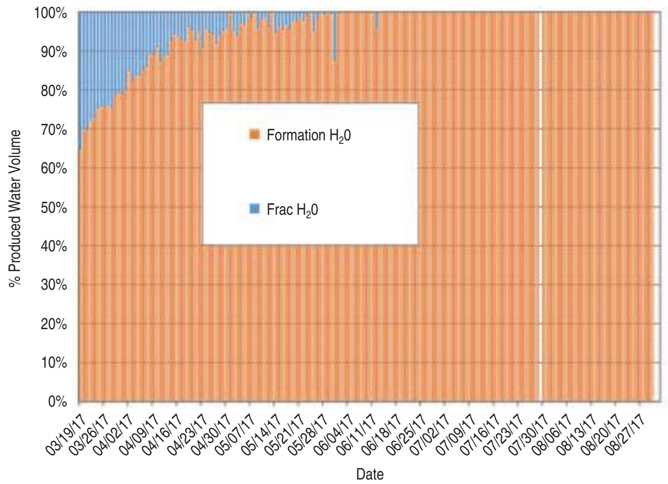


FIGURE 3B



An example of the mixing model combined with produced water volumes is shown in barrels a day at left and as a percentage of produced water volume at right. Time lapse water isotope data allowed for the calculation of relative contributions of frac versus formation water.

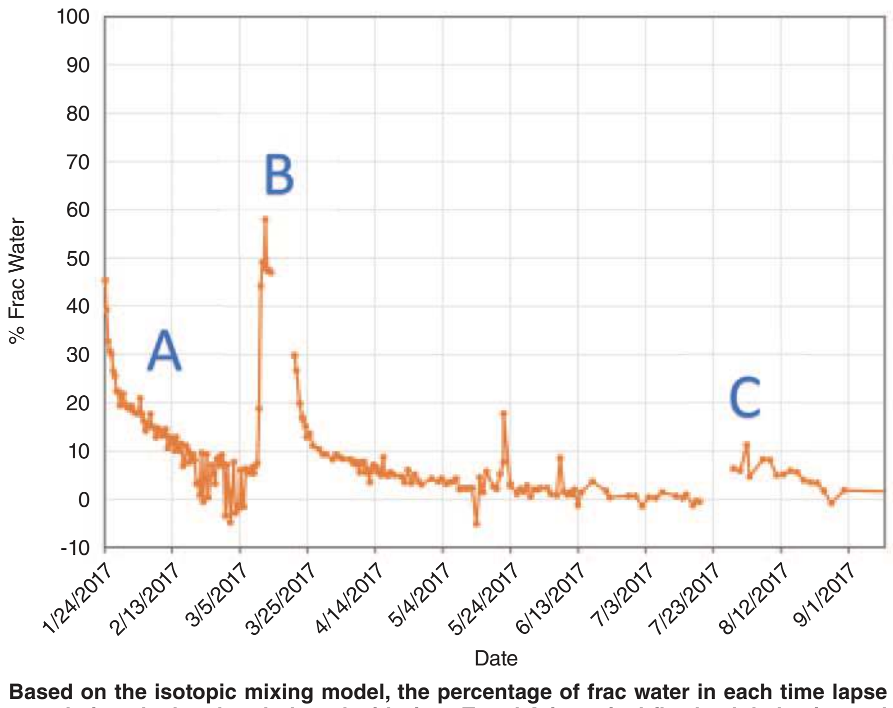
water present in each time-lapse sample collected from this and 21 other new wells with time series data, several key observations were made about the dynamic nature of the produced water and its sources:

- Produced water collected at the very beginning of flowback is a mixture of frac water and native Niobrara/Codell formation water. The initial breakdown of frac versus formation water varies well to well, but samples collected at the start of flowback on average were 46% returned frac water (maximum 68%, minimum 31%).
- The contribution of frac water to the overall produced water stream decreases sharply once flowback begins, indicating that these wells clean up quickly after stimulation, and formation water begins to dominate the production stream. Within three-four weeks, almost all sampled wells were producing water with less than a 10% frac water contribution.
- The isotopic composition of the produced water stabilizes with time. This equilibrated composition is consistent for Niobrara and Codell wells in the field and overlaps with many of the legacy wells that were sampled after seven-eight years of production. Consequently, this signature is hypothesized to be representative of predominantly Niobrara/Codell formation water or a mixture of connate and frac water that equilibrates during the imbibition process, but more work is being done to test this theory.
- Finally, the amount of frac water that ultimately is returned to the surface during flowback and production is relatively low in these wells. An average of 3.5% of the frac water injected returned during flowback and production (maximum 6.7%, minimum 1.9%).

Quantifying Frac Hits

The individual well data shown in Figures 3A and 3B was collected from the last well completed in that area, and thus does not show any shut-in periods during the hydraulic fracturing of nearby offset wells. It also shows a predictable decrease in the frac water contribution through time. This is in contrast to many of the other wells selected for time lapse

FIGURE 4



Based on the isotopic mixing model, the percentage of frac water in each time lapse sample is calculated and plotted with time. Trend A is typical flowback behavior and shows a decreasing contribution of frac water with time once flowback begins. Event B shows a dramatic increase in frac water because of a frac hit from a nearby well sited heel to heel on the same pad. Event C shows a smaller frac hit from a toe-toe offset well.

sampling, which were subject to shut-ins while nearby wells were being completed. Sampling these wells immediately before shut-in and immediately after provides a unique opportunity to study the produced water chemistry response during well-to-well fracture interactions.

Common industry practice is to monitor offset wells for pressure responses during nearby completions to describe and quantify frac hits. Time-lapse water stable isotope data provides an additional level of detail; this data can show the physical transport of frac water from a nearby completion into the existing fracture network of a parent well.

These types of responses in the water stable isotope data during the nearby completions were seen in at least six of the sampled wells. An example well where interwell fracture communication is evident during the hydraulic fracturing of offset wells is shown in Figure 4.

The well shown in Figure 4 initially shows typical flowback behavior with the frac water contribution decreasing sharply once flowback begins, followed by a large increase in frac water contribution occurring in March 2017. This behavior is coincident with the hydraulic fracturing of an offset well that sits heel to heel on the same pad.

This increase in frac water is indicative of a significant frac hit impacting the well; it goes from producing almost entirely formation water (<10% frac water) to almost 60% frac water. The most likely source of the surge in frac water is the hydraulic fracturing of the offset well.

A smaller frac hit also is shown to occur in July 2017. This one is driven by fracture interaction from the completion of a well sited toe to toe. The increase in frac water contribution is small (5%-10%), but measurable using isotopic data.

Time To Heal

Another important piece of information revealed by the data is how long and how quickly wells heal from frac hits. The decline of the frac water contribution after a frac hit behaves similar to initial flowback decline in these wells, returning to native Niobrara or Codell formation water within three-four weeks. Both water and oil production rates normalize after this time, so although frac hits are evident, they do not have long-term adverse effects on the production rates of the wells impacted.

Produced water contains naturally present tracers in the oxygen and hydrogen stable isotopes, which are diagnostic of the water's origin. By utilizing this naturally occurring phenomenon, this innovative case study was able to:

- Differentiate water injected during stimulation from native formation waters;
- Determine the mix of frac water versus formation water produced during flowback and production;
- Track the magnitude and duration of well cleanup after completion;
- Quantify the severity of frac hits and track how wells heal from them; and
- Predict which wells intersect major fault and fracture networks.

The large differences in the isotopic composition of surface waters sourced by precipitation and formation brines mean these techniques may be useful tools in other basins as well. Further study will include connecting this data with additional operational variables such as completion designs and well performance data to further optimize completion strategies. ❐

PATRICK TRAVERS

Patrick Travers is the general manager and a partner at Dolan Integration Group (DIG), a geochemical consulting and laboratory services company providing innovative solutions to companies and individuals actively exploring, developing or producing oil and gas resources. He manages DIG's team, projects and the day-to-day operation of DIG's fluid geochemistry laboratory in Denver. Travers graduated with a degree in chemical and biological engineering from the University of Colorado and has been with DIG since 2012, when he was brought in to help develop DIG's isotope ratio mass spectrometry laboratory. Prior to DIG, he was a technician in laboratories at the University of Colorado and the National Ecological Observatory Network.

BEN BURKE

Ben Burke is the geoscience adviser at HighPoint Resources in Denver. He has worked a number of international and domestic oil and gas plays during his tenure with Exxon Mobil Upstream Companies, Noble Energy, Fidelity Exploration & Production, Fifth Creek Energy, and HighPoint. Burke holds an A.B. magna cum laude from Bowdoin College in geology and Russian language, an M.B.A. in general management from Texas A&M University, and a Ph.D. in earth sciences (geomorphology and trace metals geochemistry) from Dartmouth College.

MICHAEL P. DOLAN

Michael P. Dolan is a geoscientist and co-founder of Dolan Integration Group and QuickStartX. He is an AAPG-certified petroleum geologist (No. 6085) and a graduate of the Colorado School of Mines with an M.Sc. in geochemistry. Dolan specializes in organic geochemistry, and has 21 years of oil and gas industry experience as an oil finder for DIG, Mobil and ExxonMobil.