SPE 163824

Development and Use of High-TDS Recycled Produced Water for Crosslinked-Gel-Based Hydraulic Fracturing

R. LeBas, P. Lord, SPE, Halliburton; D. Luna, SPE, XTO Energy Inc.; and T. Shahan, SPE, Halliburton

This paper was prepared for presentation at the SPE Hydraulic Fracturing Technology Conference held in The Woodlands, Texas, USA, 4–6 February 2013.

Abstract

Large quantities of high-total dissolved solids (TDS) produced water are generated during oil and gas production in Eddy County, New Mexico (more than 164 million bbl in 2011). Most of the high-saline produced water is reinjected into disposal wells at an average cost of USD 0.75 to USD 1.00 per bbl. Caused in part by the persistent drought conditions in New Mexico, beneficial use of produced water is receiving attention in the oil and gas industry. One alternative being considered is the use of produced water for hydraulic fracturing operations. Typically, wells in the Delaware basin require 40,000 to 60,000 bbl of fresh water each for hydraulic fracturing job during well development. As such, reclaiming produced water as the base fluid for fracturing not only helps alleviate the industry's dependence on fresh water but can also lower the overall cost of the well stimulation treatment.

Using produced water exceeding TDS values of 270,000 ppm is key to reclamation and reuse programs in the Delaware basin. This paper discusses a project to (1) identify the critical parameters and the corresponding optimal ranges in the laboratory, that will allow use of treated produced water as a base fluid for crosslinked-gel-based hydraulic fracturing, and (2) evaluate the validity of the laboratory findings under actual field conditions.

High-TDS produced water from a Brushy Canyon producing well near Carlsbad, New Mexico was used as the base fluid for the bench-scale experiments. Crosslinked gels were formulated with carboxymethyl hydroxypropyl guar gum (CMHPG), a zirconium-based crosslinker, sodium chlorite breakers, and other ingredients. The apparent viscosity of the gels was measured using Chandler Model 5550 high-pressure/high-temperature (HP/HT) viscometers. The bottomhole temperature simulated in the experiments was approximately 140°F. The rheological effects of several parameters, including pH, salinity, and scaling tendencies, were evaluated. Other factors, including organics and suspended solids, are included in the discussion. In addition, a field test performed following the bench-scale experiments to validate the laboratory findings under the actual stimulation conditions is discussed. Results indicate that the fracturing treatment using high-TDS produced water successfully created a fracture network and transported sand into that fracture network.

Introduction

Produced water usually comprises both the formation water and injected fluids from previous treatments. It can contain hydrocarbons, high levels of TDS, suspended solids, and residual production chemicals. When stored on the surface for extended periods of time, produced water is subject to evaporation, which can further increase the salt concentration in the water. Traditionally, flowback and produced water generated during completion and production operations is typically disposed of down saltwater injection wells, which are typically regulated by state oil and gas agencies under the Underground Injection Control program of the Safe Drinking Water Act.

Using produced water for hydraulic fracturing has many benefits, such as reducing disposal of produced water, reducing fresh water consumption during completion and production operations, and economic benefits realized by the operator. If produced water is gathered at or near the site of production and a minimal treatment is applied for use in hydraulic fracturing fluids, recycling and reuse programs may become economical and environmentally beneficial. As hydraulic fracturing in shale plays continues to require large amounts of fresh water for oilfield operations (i.e., 4 to 6 million gal/well in some cases), reusing produced water reduces the consumption of fresh water. Fresh water is becoming more difficult to obtain from traditional sources because of increased restrictions on water availability from subsurface or surface sources (Gleick 1994).

The Delaware basin has undergone extensive development during the past few years. This has resulted in the discovery of many, mostly oil-producing, fields. A large percentage of the productive wells have produced water along with the oil. A significant amount of that produced water has TDS greater than 250,000 mg/L (low organic content). In 2011, approximately 164 million bbl of produced water were generated during oil and gas production in the Delaware basin (New Mexico EMNRD 2012). More than 90% of the produced water was reinjected into disposal wells at an average cost of USD 0.75 to USD 1.00 per bbl (Boysen et al. 2011). Although the use of produced water for oil and gas drilling and slickwater-based fracturing have been explored in the Delaware basin, little has been done to use the high-TDS produced water with linear-gel-based and crosslinked-gel-based hydraulic fracturing fluids (Erskine et al. 2002). Proper rheological effects of parameters pertinent to ionic species, including hydration time, ionic strength, and pH, were studied using bench-scale testing. A series of oilwell stimulations were performed in the Bone Springs formation in the Delaware basin to evaluate the validity of laboratory testing under field conditions.

Bench-Scale Testing

The bench-scale study was designed to determine the effectiveness of the produced water recycling and reuse program for hydraulic fracturing operations. The following considerations were studied:

- Detailed water analyses.
- Produced water treatment by electrocoagulation (EC).
- Scaling tendencies and dynamic scale loop tests.
- Customized fracturing fluid development.

Recycled produced water from a well near Carlsbad, New Mexico was used as the source water for the bench-scale experiment.

Materials. All materials are commercially available. The derivative guar, buffer, surfactant, phosphate-based scale inhibitor, breaker, breaker activator, and crosslinkers were obtained from commercial sources and used for evaluation in the bench-scale testing.

Influent Water Analysis. Influent water analysis was conducted using separate titrimetric procedures for the determination of chlorides, carbonates, bicarbonates, and hydroxides. The sulfate concentration was determined using a sulfate test strip. Analysis of various cations was performed using inductively coupled plasma (ICP) spectroscopy. For ICP analysis, the calibration standard solutions were prepared with mixtures of the metal species ranging from 1 to 100 ppm. The samples were diluted 1:10 and 1:100 before analysis. **Table 1** shows the average composition of the produced water.

TABLE 1—PRODUCED WATER ANALYSIS: INFLUENT SAMPLE

Source	Produced Water
Specific gravity	1.200
pH	4.83
Conductivity (μS/cm)	257
Turbidity (NTU)	182
Dissolved oxygen	8.24
Chloride	163,637
Sulfate	40
Aluminum	1.42
Boron	20.3
Barium	5.69
Calcium	29,222
Iron	34.6
Potassium	1,660
Magnesium	4,347
Sodium	70,342
Strontium	2,204
TDS	267,588
TSS (mg/L)	10,623
TPH (ppm)	>20

Measurements are expressed in ppm unless otherwise noted.

Electrocoagulation Treatment. EC is a water-treatment process whereby an electric current is applied across metal plates to remove various contaminants from water. Heavy metals (ions) and colloids (organics and inorganics) are primarily held in solution by electrical charges and particle size. By applying an electrical charge to a solution of contaminated water, it destabilizes the charges on the various particles and generates a coagulation reaction.

The produced water sample was treated using a bench-scale EC process. This step in the recycling program removes specific contaminants, including suspended solids, allowing the treated produced water to be used in future fracturing applications. **Fig. 1** shows a visual comparison of the untreated produced water to the treated produced water.

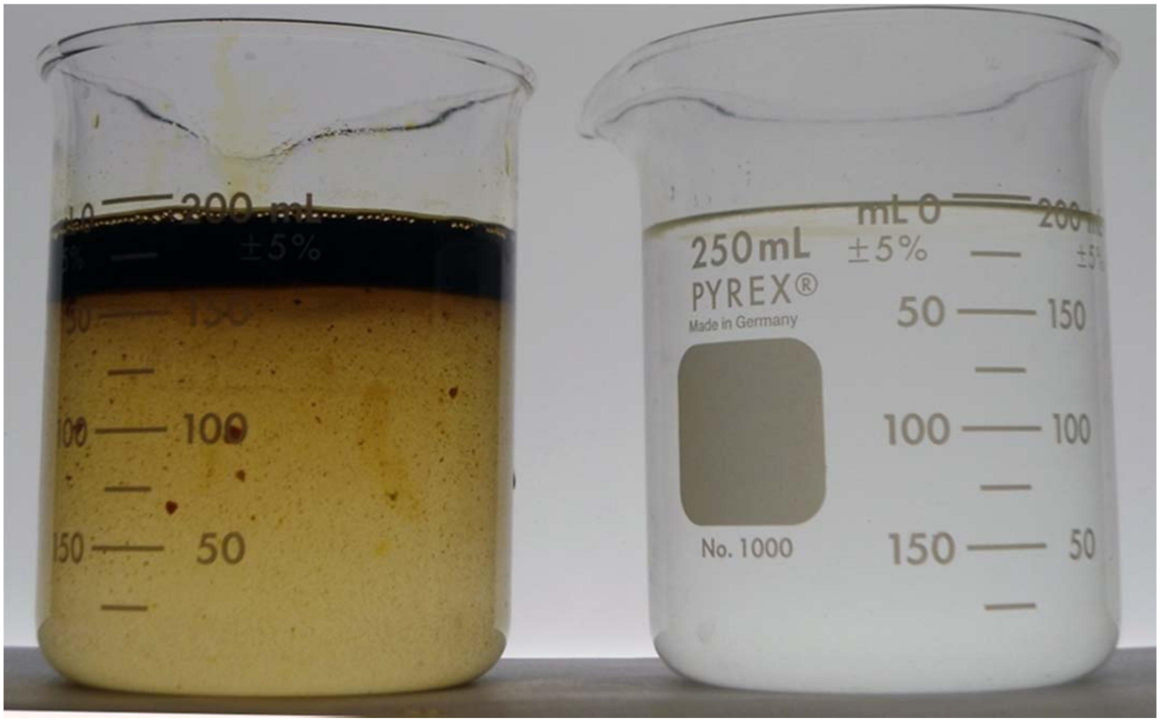


Fig. 1—Visual comparison of untreated and EC treated water.

Typically, the EC process generates approximately 3 to 5% waste by volume of fluid treated. **Fig. 2** shows a gravity separated-volumetric determination of solids removal. This is an unfiltered sample. The final volume is dry volume and is expected to be much less than 8%.

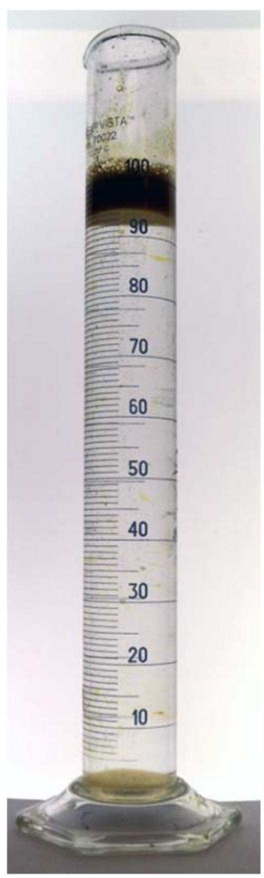


Fig. 2—Gravity separated-volumetric determination of solids removal.

Effluent Treated Water Analysis. Effluent treated water analysis was conducted using separate titrimetric procedures for the determination of chlorides, carbonates, bicarbonates, and hydroxides. The sulfate concentration was determined using a sulfate test strip. Analysis of various cations was performed using ICP spectroscopy. For ICP analysis, the calibration standard solutions were prepared with mixtures of the metal species ranging from 1 to 100 ppm. The samples were diluted 1:10 and 1:100 before analysis. **Table 2** shows the effluent EC-treated produced water.

TABLE 2—WATER ANALYSIS: EFFLUENT EC-TREATED PRODUCED WATER

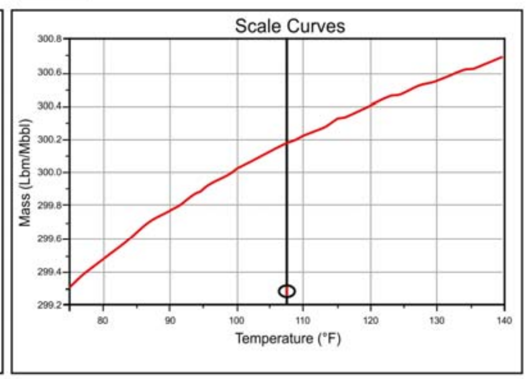
Source	EC Treated
Specific gravity	1.203
pH	8.00
Conductivity (µS/cm)	258
Turbidity (NTU)	15.4
Dissolved oxygen	8.45
Chloride	164,951
Sulfate	38
Aluminum	2.28
Boron	16.6
Barium	6.03
Calcium	28,845
Iron	0.264
Potassium	1,689
Magnesium	3,148
Sodium	75,517
Strontium	2,020
TDS	273,552
TSS (mg/L)	92
TPH (ppm)	Between 5 and 20

Measurements are expressed in ppm unless otherwise noted.

Scale Tendencies Determination. A software modeling program contains an algorithm for scale prediction using information obtained from the water analysis performed on field water samples. The concentration of each species detected in the water analysis was input into the software program along with the reservoir pressure and temperature. The program then generated the different scaling species expected under such conditions and the relative amounts expected to scale out of solution. This information was then used to determine if scale is likely to occur during the treatment. **Fig. 3** shows the results from the scale tendencies program.

Scale Name: Calcite

S No.	Temp °F	Pressure psi	pH	Si	Precipitate lbm/Mbbl
1	75	15	8.0	4.17	299
2	82	15	8.0	4.17	300
3	88	15	7.9	4.17	300
4	95	15	7.9	4.17	300
5	101	15	7.9	4.17	300
6	108	15	7.9	4.17	300
7	114	15	7.8	4.16	300
8	121	15	7.8	4.16	301
9	127	15	7.8	4.15	301
10	134	15	7.8	4.14	301
11	140	15	7.8	4.14	301



Scale Name: Siderite

S No.	Temp °F	Pressure psi	pH	Si	Precipitate lbm/Mbbl
1	75	15	8.0	0.68	0
2	82	15	8.0	0.71	0
3	88	15	7.9	0.74	0
4	95	15	7.9	0.76	0
5	101	15	7.9	0.78	0
6	108	15	7.9	0.79	0
7	114	15	7.8	0.81	0
8	121	15	7.8	0.82	0
9	127	15	7.8	0.83	0
10	134	15	7.8	0.83	0
11	140	15	7.8	0.84	0

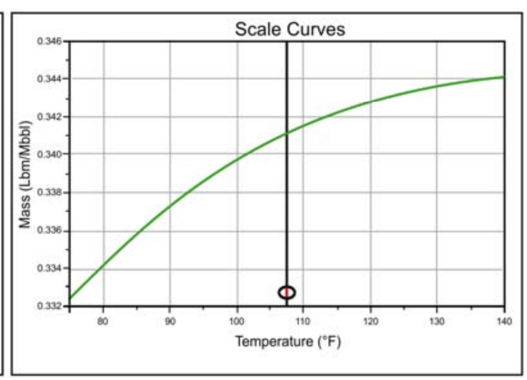


Fig. 3—Scaling tendencies: program results.

Dynamic Scale Loop. The minimum effective dose (MED) is the minimum concentration of an additive (scale inhibitor in this case) required to prevent scale formation over the test period and is specific to test conditions. Such a test is mainly used to obtain a performance ranking of different chemicals under specific conditions. The dynamic scale loop tests were conducted using a HP/HT Scale Rig 5000™ loop. The test consisted of injecting the anion and cation brines individually and at equal rates by means of two pumps into the system. Each brine was passed through a heating coil within the oven, which was set to the required test temperature. Then, the brines were mixed at a T-junction and the mixture (scaling brine) flowed into the scaling coil under pressure. This pressure was regulated by use of a pressure relief valve. The pressure difference (DP) across the scaling coil was continuously monitored and recorded. As the cations (such as calcium and barium) and anions (such as carbonate and sulfate) reacted and formed scale inside of the scaling coil, brine flow was restricted. This led to an increase in DP. First, the scaling time for brine without inhibitor was determined. To determine the MED of the scale inhibitor, the test was repeated with the scale inhibitor dosed at various concentrations. The test period was generally two to three times that of the baseline brine without inhibitor or a minimum 30 minutes. The results of the test indicated that the MED of a phosphate scale inhibitor to inhibit scale formation was 35 ppm under the final test conditions. **Fig. 4** shows the results of the dynamic scale loop test.

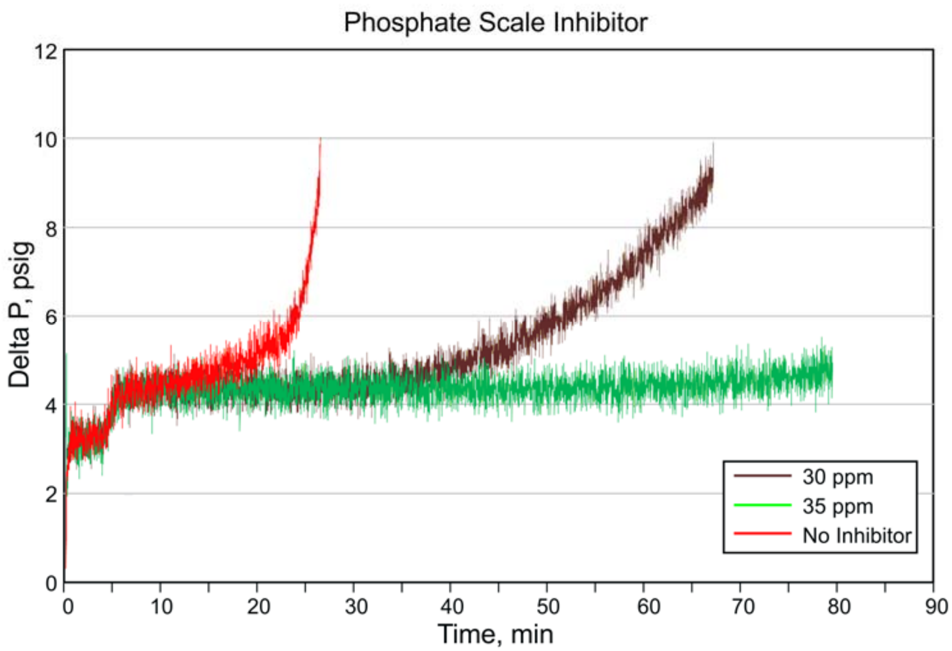


Fig. 4—Dynamic scale loop results.

Fracturing Fluid and Rheology Performance. An effective fracturing fluid must have these characteristics: easy preparation, low fluid loss, good proppant transport capacity (viscosity), low pipe friction, efficient recovery from the reservoir, and low gel residue. Through the use of gelling agents, fluids achieve excellent viscosity. For water-based fluids, guar-gum and their derivatives, such as hydroxypropyl guar (HPG) and CMHPG, can be used. The derivative guars generally have less residues and faster hydration compared to non-high-yield guars. Borate crosslinkers or metal-based crosslinkers, such as zirconium, titanium, or aluminum, generate a significant viscosity increase in the guar-polymer gels.

Crosslinked fluids have a greater capacity to transport proppants than uncrosslinked fluids. This transport capacity is measured using a rheometer in which fluid is tested at specific temperature conditions and shear rates. In these tests, it is possible to observe the transporting elastic regime and proppant settling. A minimum transport capacity of 400 cp at 40 1/sec with a B2 bob is desired. This value was used as a reference for fracturing fluid tests developed using the rheometer (Harris and Walters 2000).

The fluid system employed in this study is a proprietary fluid system designed to hydraulically fracture the Brushy Canyon formation (~6,800 ft TVD). It consisted of a CMHPG gum, zirconium-based crosslinker, sodium chlorite breaker, breaker catalyst, and a non-emulsified surfactant. The bottomhole temperature simulated in the experiment was 140°F. As can be seen in **Fig. 5**, the CMHPG crosslinked fluid with 100% EC treated produced water retained greater than the desired minimum viscosity of 400 cp for the required pump time of 60 min.

Ingredients of the hydraulic fracturing fluid were obtained from a service company in Hobbs, New Mexico and mixed using a Waring® commercial blender. 30-lbm gel was used in the experiments, unless otherwise noted.

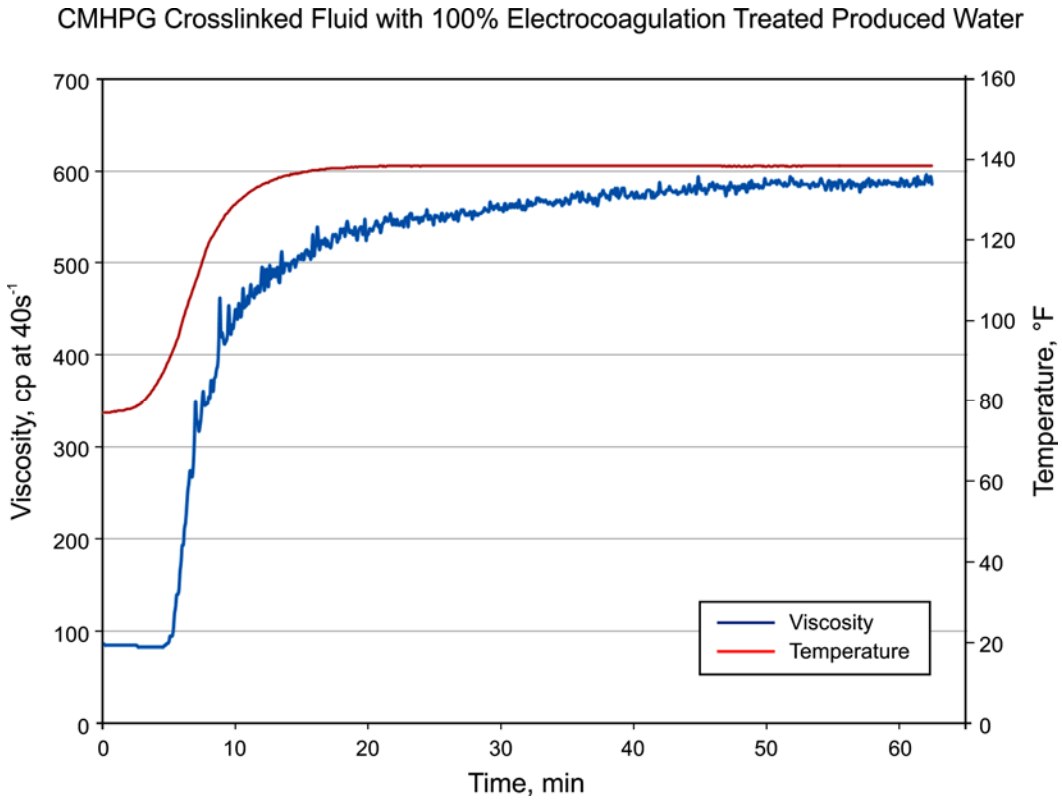


Fig. 5—Fluid rheology: CMHPG crosslinked fluid system with 100% EC-treated produced water.

Field Testing

A field trial was performed in which seven wells with a total of 97 fracturing stages were tested using 100% EC-treated produced water. The well stimulations were performed to evaluate the validity of the laboratory test findings under actual field conditions. The presented data is from one well in the field trial and is located in XTO's Nash Draw (ND) field in Eddy County, New Mexico. The depth of the well was approximately 6,800 ft TVD (11,300 ft MD) with a 3,800-ft horizontal lateral in the Brushy Canyon formation, and the bottomhole temperature was roughly 140°F. The fracturing fluid system was a 30-lbm CMHPG crosslinked gel. The 30-lbm CMHPG crosslinked fluid was also used in the bench-scale testing.

Dynamic Break Tests. Dynamic break tests of a 30-lbm crosslinked gel with treated produced water as the base fluid were conducted in the laboratory using a Fann 35 viscometer to help ensure proper fluid rheology before stimulation. CMHPG was hydrated in the treated produced water at a pH of 5.0 before a sodium chlorite breaker and breaker activators were added, and the gel was crosslinked using a zirconium-based crosslinker at 140°F. Breaking of the crosslinked gel was optimized by adjusting the amounts of crosslinker and breakers used, as seen in **Fig. 6.**

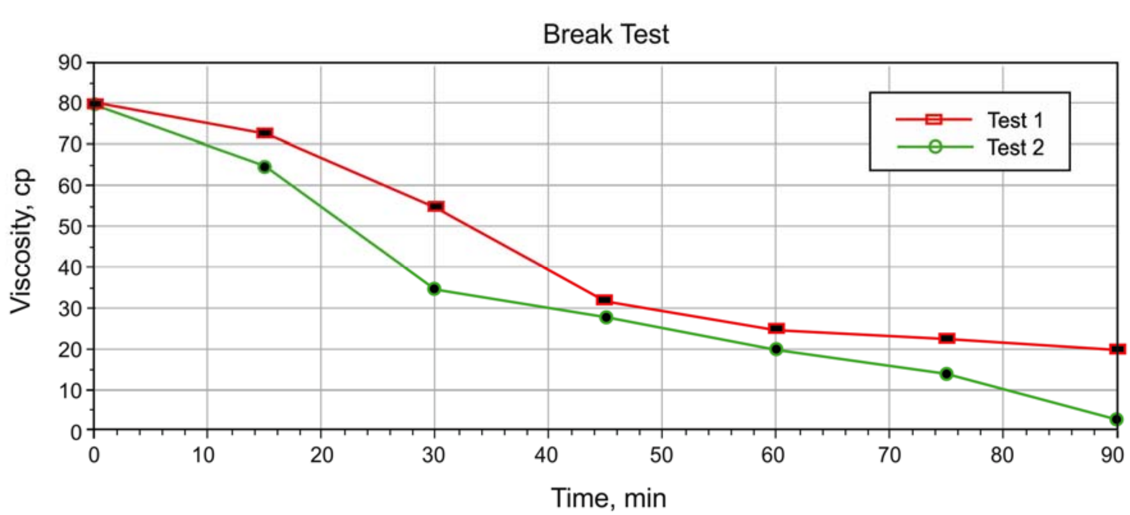


Fig. 6—Dynamic break tests performed before fracturing treatment.

ND Trial Well 5 Well Stimulation. The ND Trial Well 5 was stimulated using 1.4 million gallons of treated produced fluid and approximately 1.7 million lbm of proppant placed in 17 treatment stages. The average treatment pressure was 1,911 psi and the average treatment rate was 47 bbl/min. The pump time for each stage was approximately 55 minutes and consisted of pad and proppant stages with an average maximum proppant concentration of 4.4 lbm/gal. No mechanical failure or screening out was encountered during the stimulation. The job summary for a single treatment stage for the ND Trail Well 5 is shown in **Fig. 7.** Treating pressure trends observed were as modeled with 2% KCl water as the base fluid, indicating no adverse effects on the treatment pressure or ability to place proppant when using high-TDS treated produced water of 270,000 ppm.

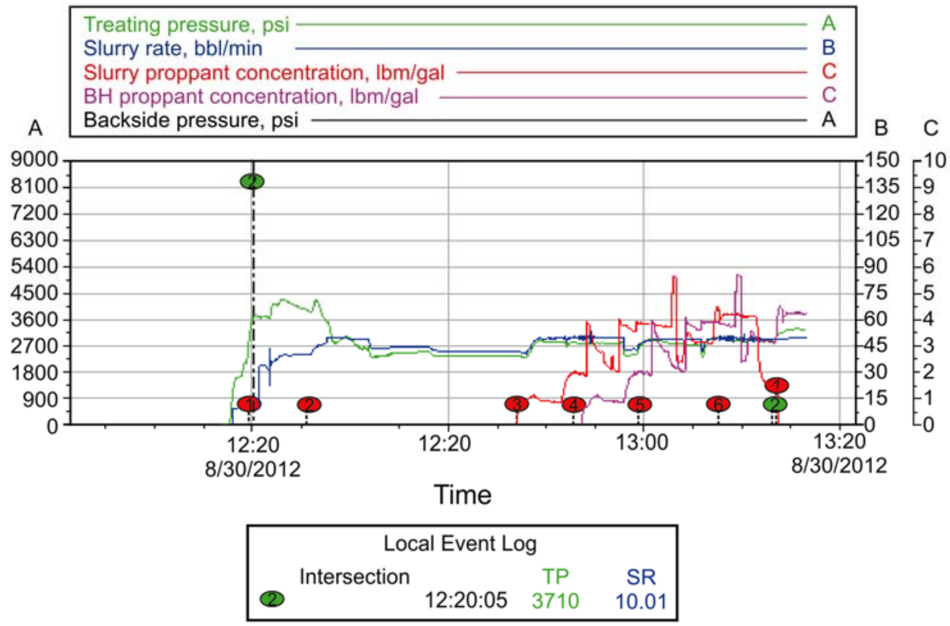


Fig.7—ND Trail Well 5 treatment summary.

Results and Discussion

The objective was to demonstrate the feasibility of using treated produced water with 270,000 ppm TDS water from Carlsbad, New Mexico as the base fluid for hydraulic fracturing. The maximum apparent viscosity of the crosslinked gel at a shear rate of 40 sec^{-1} was evaluated first without the addition of sodium chlorite breakers. Solution pH and hydration time were variables of the experiments. Once the proper settings were identified, breakers were introduced to examine the overall rheological performance of the fluid, as can be seen in Fig. 6. The fluid using 100% treated produced water was successfully developed in the lab and replicated in the field.

Initial production data from the ND Trail Well 5 is shown in **Fig. 8.** The well was brought online in October 2012, with an initial oil production rate of 591 BOPD and an initial gas production rate of 566 Mscf/D. For comparison, production data from an offset well is shown in **Fig. 9.**

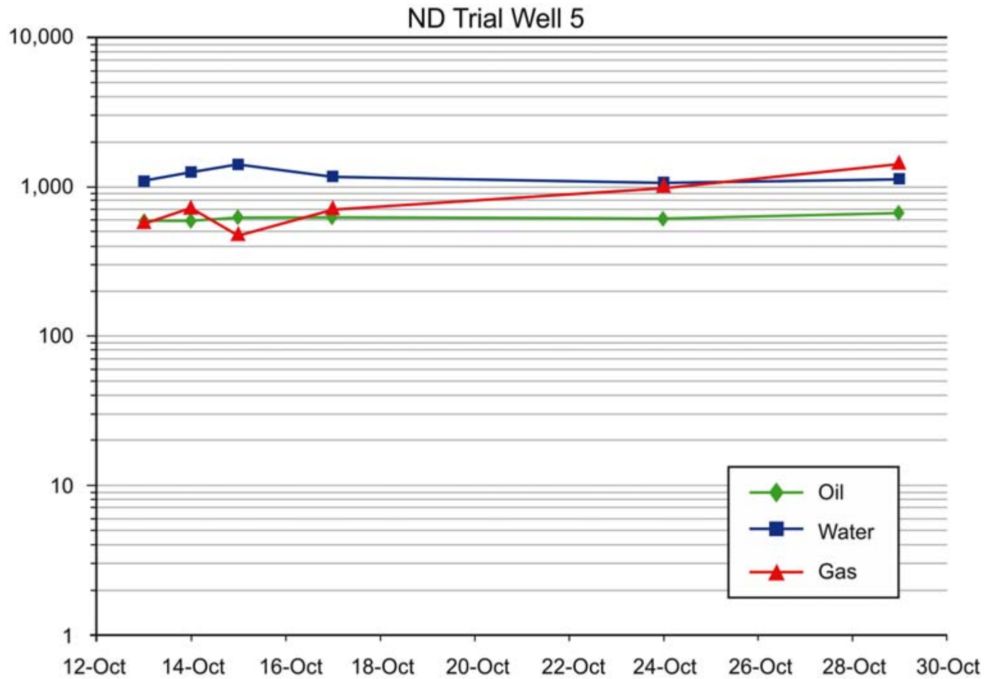


Fig. 8—ND Trial Well 5 production data.

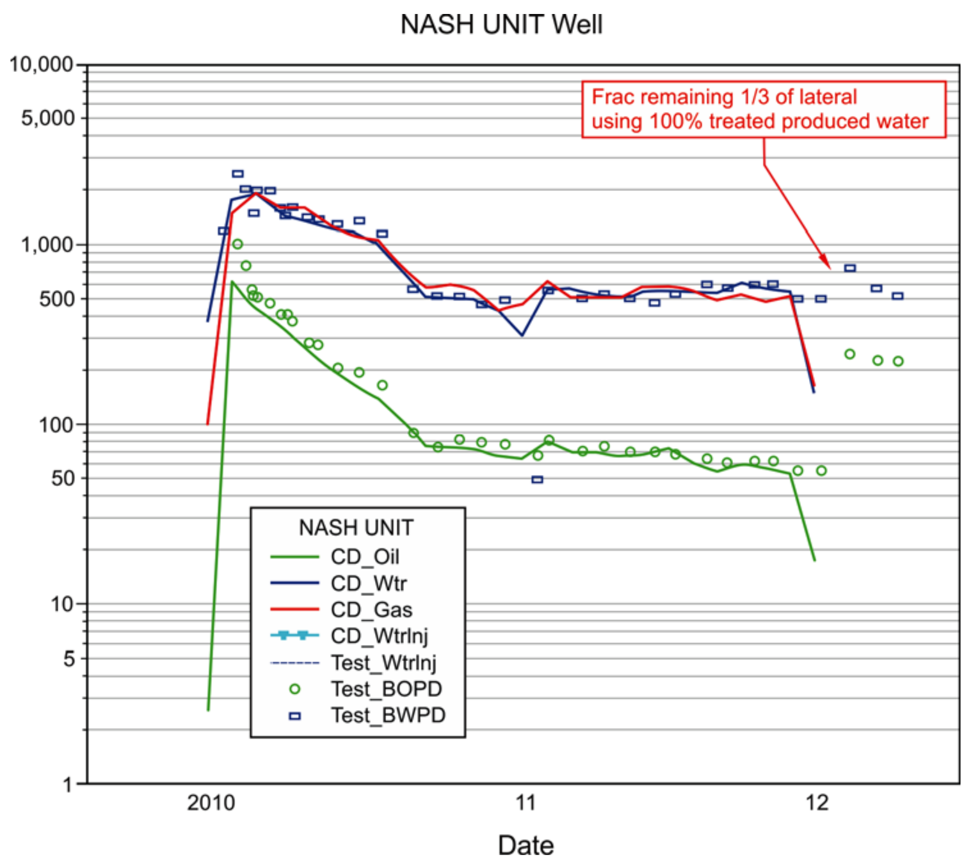


Fig. 9—Offset well production data.

Conclusion

The laboratory and field results of this study demonstrate that under the conditions evaluated it is feasible to use treated produced water as the base fluid for crosslinked-gel-based hydraulic fracturing. In this trial, produced water with TDS up to 285,000 ppm was shown to generate proper crosslinked rheology for hydraulic fracturing. Initial results indicate that production aligns with that from offset wells that were fractured using 2% KCl as the base fluid.

Additionally, the operator realized the following benefits from the seven-well recycling and reuse program:

- Used over 8 million gal of produced water replacing fresh water.
- Reduced trucking ~1,400 loads of fresh water from off-lease.
- Water management cost verses purchasing and transporting fresh water—USD 70,000 to 100,000 reduction per well (USD 500,000 to 700,000 total program cost savings).

Acknowledgements

The authors thank XTO Energy Inc. and Halliburton for permission to publish this paper and for all the support provided during its development.

References

Boysen. D., Boysen, J., and Larson, T. 2011 Produced Water Management Handbook. GRI-03-0016. Gas Research Institute, II.

Erskine, D.W., Bergman, P.W., and Wacker, D.L. 2002. Use of Produced Water for Oil and Gas Drilling in the San Juan Basin. Paper presented at the Proceedings of the 9th Annual Petroleum Environmental Conference, Albuquerque, New Mexico, 22–25 October.

Gleick, P.H. 1994. Water and Energy. *Annu Rev Energy Environ* **19**: 267–299.

Harris, P. and Walters, H. 2000. Real Time Control of Low Polymer Fracturing Fluids. Paper SPE 63238 presented at the SPE Annual Technical Meeting, Dallas, Texas, USA, 1–4 October. doi: 10.2118/63238-MS.

New Mexico EMNRD 2012. New Mexico Energy Minerals and Natural Resources Department, http://www.emnrd.state.nm.us/index.html (accessed 22 October 2012).