TECHNOLOGY AND METHODS USED TO REDUCE WATER PRODUCTION IN THE LOWER DELAWARE SANDS OF SOUTHEASTERN NEW MEXICO AND WEST TEXAS

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ABSTRACT
Producing hydrocarbons from the lower Delaware Formation in SE New Mexico and West Texas is often associated with a high water production. In the Matthews Field in West Texas (Reeves County), an operator was encountering water production of over 600 bbl per day from the treated wells. It was decided to modifying the stimulation techniques and processes. To improve the production results, multiple-stage treatments using coiled tubing (CT) with selective placement controls and reduced rates were performed to lower the fracture height growth in an attempt to reduce water production. This method included using conventional fracturing fluids, specialized coiled-tubing perforating and controlled fracturing placement, and a relative permeability modifier (RPM). The RPM was used in the treatment for its capability to modify the relative permeability by coating the formation rock, thereby reducing the potential for water production. This paper will detail how these operations were performed.

INTRODUCTION
The operator has produced from the Delaware pays in the Matthews Field (Fig. 1) for several years with a steady production of oil. The production decline in the field was rather flat, with an estimated reserve life of 25 to 30 years. Following the last completions, the average well produced approximately 300 BWPD of produced water along with hydrocarbons. Upon acquisition of this field some time ago, a disposal well readily available in the field soon was utilized. The produced water was injected into a nonproductive zone in this disposal well. Because the field is remote from the nearest disposal facility, transporting the water to an offsite location would be expensive. Therefore, use of the disposal well was beneficial. Over time, the high production of water also added significant costs for lifting, additional facilities, etc. The operator obviously needed a method to reduce the water-oil ratio (WOR).

The geological makeup of the Matthews Field and the methodology used to derive the applied treatment are covered in this paper. Included as well are (1) a general discussion of how RPMs work, and (2) details regarding the application in this particular case. The stimulation design and treatment is surveyed, including subsequent production results. In addition, an economic analysis of a drilled and completed well in this field is also provided. This paper illustrates how the RPM and other new technology can help decrease the WOR and increase the gas-oil ratio (GOR), thereby adding value for the operator.

GEOLOGY
The pay intervals of interest in this field are the Lower Delaware sands of Brushy Canyon and Cherry Canyon. Cherry Canyon is the more productive and is also noted for its high clay content and high water production. Its primary makeup is fine-grained sandstone with carbonate consolidation.[1]

A variety of stimulation techniques has been used in this area, including fracturing with water and foamed fluids energized with either carbon dioxide or nitrogen. In this project, a conventional crosslinked fluid system was used.

Stimulation treatments in the Brushy and Cherry sands are usually straightforward, but it is common for significant amounts of sand and water to flow back after treatments. A possible solution to this flowback problem entails pumping resin-coated sand, which has significant bonding capability. Use of this type of treatment in the subject well however was eliminated because of its high cost. Instead, a conductivity-enhancing additive was used to coat the proppant to help prevent sand flowback and fines migration. An RPM was also added to the treatment as a pre-flush to help combat water production.

RPM TECHNOLOGY

Controlling water production has been an objective of the oil industry almost since its inception. Produced water has a major economic impact on the profitability of a field. Producing 1 bbl of water requires as much or more energy as producing the same volume of oil. Often, each barrel of produced water represents some lesser, but significant, amount of unproduced oil. In addition, water production causes other related problems such as sand production, the need for separators, disposal and handling concerns, and corrosion of tubulars and surface equipment. Many methods are available to mitigate water production problems. Among the chemical methods, both sealing and nonsealing systems have been in use for many years.[2-4]

Nonsealing systems are also referred to as bullheaded placement systems. These systems develop into either disproportionate permeability modifiers (DPMs) or RPMs. These nonsealing systems (referred to in this study as RPMs) are typically dilute polymer solutions that perform by adsorption onto the pore walls of formation flow paths. Numerous polymer systems of this type have been promoted through the years, and a large volume of literature has been devoted to this topic. It is widely believed that these systems are best applied to layered, heterogeneous formations without reservoir crossflow.[5,6]

A number of hypotheses have been advanced regarding the operative mechanism(s) responsible for the disproportionate permeability reducing capability of these systems. In 1992, J. Liang, H. Sun, and R.S. Seright began extensive experimentation on disproportionate reduction in gel treatments.[7-9] Their initial testing revealed a number of behavioral patterns arising from the use of various modification gels.[7] These findings led to further study. In 1995, the same team of experts was able to discredit, or at least cast doubt upon, the theories that the gravity, lubrication, wettability, or swelling/shrinking effects of the gel play a major role in the phenomenon of disproportionate permeability.[8]

Further research by Liang and Seright in 1997 focused on the segregated pathway theory, which speculates that, on a microscopic scale, water-based gelants pass through water pathways more readily than through oil pathways. Results of their tests of Berea core samples supported the theory for oil-based gels, but not for water-based gels. Additional work in this battery of tests found that a balance between capillary and elastic forces is a factor in disproportionate permeability reduction, but only in flow tubes and micro-models, not in porous rock.

A previous paper described an RPM polymer that consisted of polydimethylaminoethyl methacrylate derivatized with methoxypolyethylene glycol.[10] This system was shown to provide significant permeability reduction in relatively low-permeability sandstone cores at 100% water saturation, as well as, at residual oil saturation. The hydrophobically modified, water-soluble polymer described in that paper was found to provide a minimum of 80% brine permeability reduction in sandstone cores in a broad range of permeabilities, while showing minimal effect on oil permeability. Further, the chemical was not shear-sensitive, which lent itself readily to the possibility of placement under fracture stimulation conditions.

HYDROPHOBICALLY MODIFIED WATER-SOLUBLE POLYMERS

The solution properties, such as rheology and viscosity, of both ionic and nonionic water-soluble polymers, are uniquely modified when hydrophobic groups are introduced into the polymer chains.[11-14] The primary factor responsible for the property modification is the associative tendency between the hydrophobic groups when placed in aqueous medium.

The associative interactions of the hydrophobic groups may lead to either lower or higher solution viscosities, depending on the polymer concentration, which determines whether intra- or inter- molecular interactions dominate. These attractive interactions are often depicted as transient and reversible crosslinks among polymer chains that form under static or low shear conditions but rupture at high shear rates. At concentrations that produce higher viscosity of the solutions under low shear conditions, the polymer solutions still behave as traditional shear-thinning fluids under high shear. This property is useful in oilfield applications requiring particle transport, such as fracturing or transport of drill cuttings.

Another unique property of hydrophobically modified, water-soluble polymers is their behavior in aqueous brines. The shear-dependent rheological properties of these polymers can be modified without altering their behavior towards salts by the addition of surfactants. The adsorption behavior of hydrophilic, water-soluble polymers can also be modified in a unique manner by the introduction of hydrophobic groups. Rather than reaching a plateau adsorption isotherm, as is common for hydrophilic polymers, hydrophobic modification appears to continue the increase in adsorption with an increase in polymer concentration. This behavior is attributed to associative adsorption of polymer chains on previously adsorbed layers of polymers.[13]

In general, hydrophobic modification of water-soluble polymers adds new properties to RPM-type applications while retaining features typical for historically applied hydrophilic polymers. The extent of these new properties can be controlled by the synthesis method, polymer concentration, hydrophobe type and amount, the quality of the solvent, and the monomer distribution along the polymer chain. Based on their unique properties, especially the adsorption and associative properties, this class of compounds was chosen for investigation as an improved RPM.

THEORIZED RPM MECHANISM

The governing mechanism for DPR is segregated flow of oil and water (Fig. 2).[15] Because of pore size restriction, a DPR fluid placed in a porous media will selectively restrict the flow of the phase it is soluble in. This mechanism applies to both gel systems and single-polymer systems that demonstrate retention. The location of retained DPR fluid in the pore space is governed by wettability in the same way as the preferred pathways for water and oil. In water-wet media, the water pathways are mainly located close to the surface and in the smallest pores where entrance pressure restricts the flow of oil. In oil-wet media, the water pathways are mainly in the middle of the largest pores and pore channels.

LABORATORY PROCEDURE

Laboratory testing was conducted to determine the effect of a hydrophobically modified, water-soluble polymer chemical treatment on a formation containing layers of water and oil stringers without reservoir crossflow. The following conditions were applied:

- Temperature—testing was performed at 175°F
- Water flow stabilized—API brine (9% NaCl + 1% $CaCl_2$) was used to stabilize the flow of water through the cores of aqueous fluids
- Oil phase—kerosene constituted the oil phase
- Treatment solution—a conventional 25-lb/Mgal crosslinked guar fracturing gel/breaker package containing 2,000 ppm (active) RPM solution
- Pressure—all flow studies were performed behind a backpressure (system pressure) of 400 psi
- Multi-pressure tap flow cells (Fig. 3)—two used, each contained a Berea sandstone core
- Water core—Sw of 100%

The following procedure was then performed:

1. The oil core was first stabilized to the flow of brine, then stabilized to the flow of oil until a state of irreducible water was achieved.
2. After determining the initial permeabilities of the two cores, the core cells were plumbed together to allow a treatment to be "bullheaded" into the two cores simultaneously in the reverse-flow direction.
3. A crosslinked guar fracturing gel containing the RPM solution was diluted to form a 25-lb/Mgal fracturing gel containing a standard borate crosslinker and breaker package.
4. The gel was pumped in the reverse-flow direction into the respective cores at a pressure of 1,000 psi, which was maintained for 30 minutes. The volume of filtrate passing through each core was captured and recorded.
5. Following the fluid "leakoff" of the filtrate, the two core cells were shut in at temperature overnight to allow reaction of the breakers on the crosslinked filter cake of the gel.
6. Following RPM fracturing of the simulated layered formation, the regained permeabilities of the two cores to their respective fluids (oil and water) in the normal flow direction were determined. To escape "end-effects," only the two inner segments were used to evaluate the fluid systems. The results are shown in Figs. 4 and 5.

METHODOLOGY

With multiple stringers of the Delaware Brushy Canyon sands to produce from, the stimulation technique had to allow the treatment of small net pays while simultaneously attempting to keep fracture height under control. As witnessed by the operator, when too much height was created, more water production resulted. The goal was to apply multiple fracturing treatments in each selected zone with limited height generation. Based on ongoing research and field developments, the best fracturing technique for this well was through coiled tubing with selective placement controls.

Compared to conventional fracturing techniques used on similar reservoir characteristics, coiled-tubing fracturing with placement controls has resulted in better initial production rates. CT fracturing increases well deliverability and recoverable gas reserves.[16] Using CT, it is possible to stimulate multiple zones in one day without the use of a wireline unit to set plugs between stages. CT also enables the operator to begin flowback of the well from all zones immediately after the treatments rather than waiting on a unit to drill out isolation plugs. This process has saved operators time and money because wireline units and/or pulling units have not been needed.

The operator in this field had been fracture-stimulating down coiled tubing while isolating untreated formations with a packer. This process requires a wireline unit to perforate all of the proposed intervals at once before the fracturing operation. Having a wireline company perform these perforations entails additional expense. Furthermore, the opening of all zones prior to treatments could cause the operation to become differentially stuck between stages if a communication between pay intervals developed during the treatment.

The service company proposed a new technology in which perforations are cut at the time of the fracturing treatment. This process involves hydra-jetting holes in the casing with sand-laden fluid at a substantial rate (12 bbl/min in this case). Immediately following the hole cutting, treatment of that zone would begin. In this zone, which would be isolated by a packer assembly, only the section just cut is stimulated (Fig. 6). After the stimulation treatment is flushed, the CT unit pulls uphole, resets the packer, cuts new perforations by hydra-jetting, and stimulates the new section. This method saves the time and costs associated with perforating by wireline.

Unlike some techniques, this process pumps the treatment down the annulus rather than down the coil. This new method allows a higher pump rate and produces less friction. It also enables personnel to use the CT as a dead string to monitor the downhole treating pressure. Smaller diameter CT can also be used, thus allowing more availability of units.

ECONOMIC INDICATORS

It is difficult to determine the effect of one treatment on a single well in a field of this magnitude. The early evaluation shows a slight reduction in water production compared to the offset. Typical water production is over 300 BWPD, while the treated well has leveled off at approximately 200 BWPD. Based on a lifting cost of $0.40 per bbl, with the produced water injected into a disposal well, the money saved is approximately $40/day ($14,600/year). If the disposal well were not utilized, trucking would have cost $1.00 to $1.25/bbl. If the water had been transported to a disposal facility, the cost of trucking would have been $113/day ($41,000/year). A lower water production rate would also result in less wear on the rod pump.

An interesting effect created by this treatment was a higher-than-usual gas production. The GOR has increased by almost 20% compared to an offset. Prior production numbers from the offset indicated average production of 25 Mscf gas per day and 15 BOPD. Production figures from the treated well in this case have leveled off to approximately 50 Mscf gas per day and 23 BOPD.

Another factor that made it difficult to evaluate the effectiveness of the treatment was the early drawdown or unloading of the fracturing operation just after treatment was completed. Considering the proppant pack that was pumped, the treatment that was added to it, and the addition of the RPM, an ideal shut-in period would have been 24 hours. The well was immediately shut in after the treatment, but not for 24 hours. The longer shut-in time could have provided better results as well.

SUMMARY

The treated well was an ideal candidate for this new technology because of its reservoir characteristics and the production history from this field. A combination of new technology and services was applied to save the customer money while adding value to the well. The RPM was designed to save the operator money over the life of the well by reducing water production. This cost reduction potential combined with the advanced treatment produced better than normal production, indicating success with room for improvement.

CONCLUSIONS

Based on the results of this case study, the following conclusion are made:

- The new technology helped decrease WOR for an operator
- Fracturing using CT with placement controls was the best method for treatment in this field
- Perforating by hydra-jetting saved the operator time and money
- Fracturing down the annulus enables a faster rate, causes less friction, and provides a dead string to monitor downhole treating pressure
- An RPM was pumped with the treatment to help reduce post-treatment water production
- A conductivity-enhancing sand additive was added to the proppant to reduce sand flowback and fines migration

ACKNOWLEDGEMENTS

The authors thank Halliburton for their support and permission to publish this work.

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Table 1—Physical Properties of Berea Sandstone Cores Used in Testing

Core No.	Fluid Saturation	Length (cm)	Diameter (cm)	Porosity (%)
1	Water core (control)	13.2	2.5	15
2	Oil core (control)	14.1	2.51	15
3	Water core (test)	13.96	2.54	15
4	Oil core (test)	13.96	2.54	15

Table 2—Crosslinked Fracturing Gel Laboratory Formulations

Fracturing gel concentrate	25 lb/Mgal guar fracturing gel
780 ml Water	310 ml Fracturing gel concentrate
200 ml RPM concentrate	690 ml Water
.036 g BE-3S additive	10 ml Breaker
.036 g BE-6 additive	1 ml CAT-3 activator
100.2 g KCl	0.1 ml 10% CAT-4 activator
20 ml Liquid guar concentrate	1.22 ml buffer
	pH 5.98

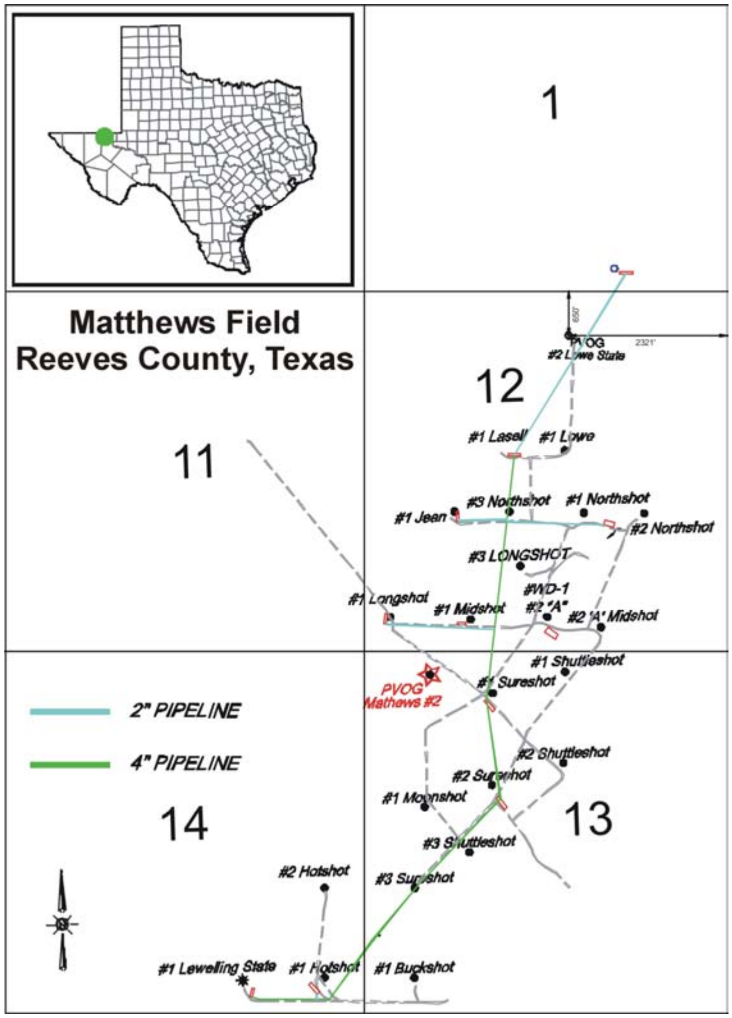


Figure 1—Matthews Field, Reeves County, Texas

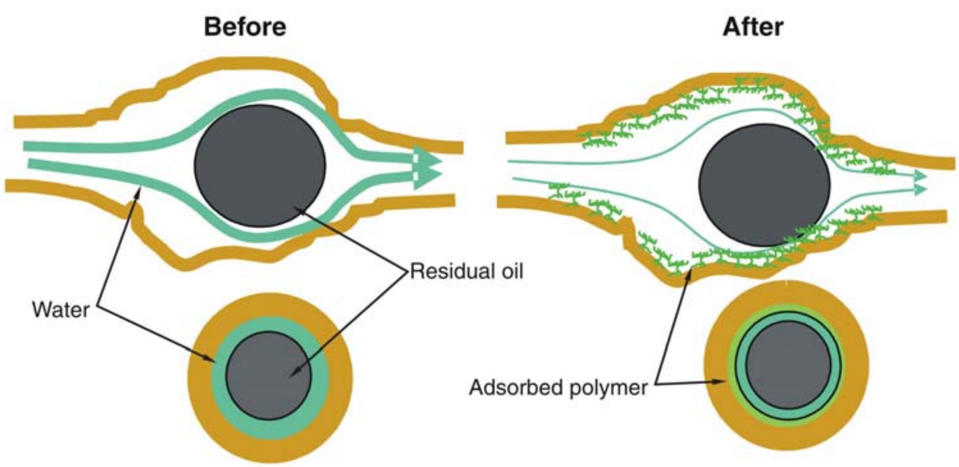
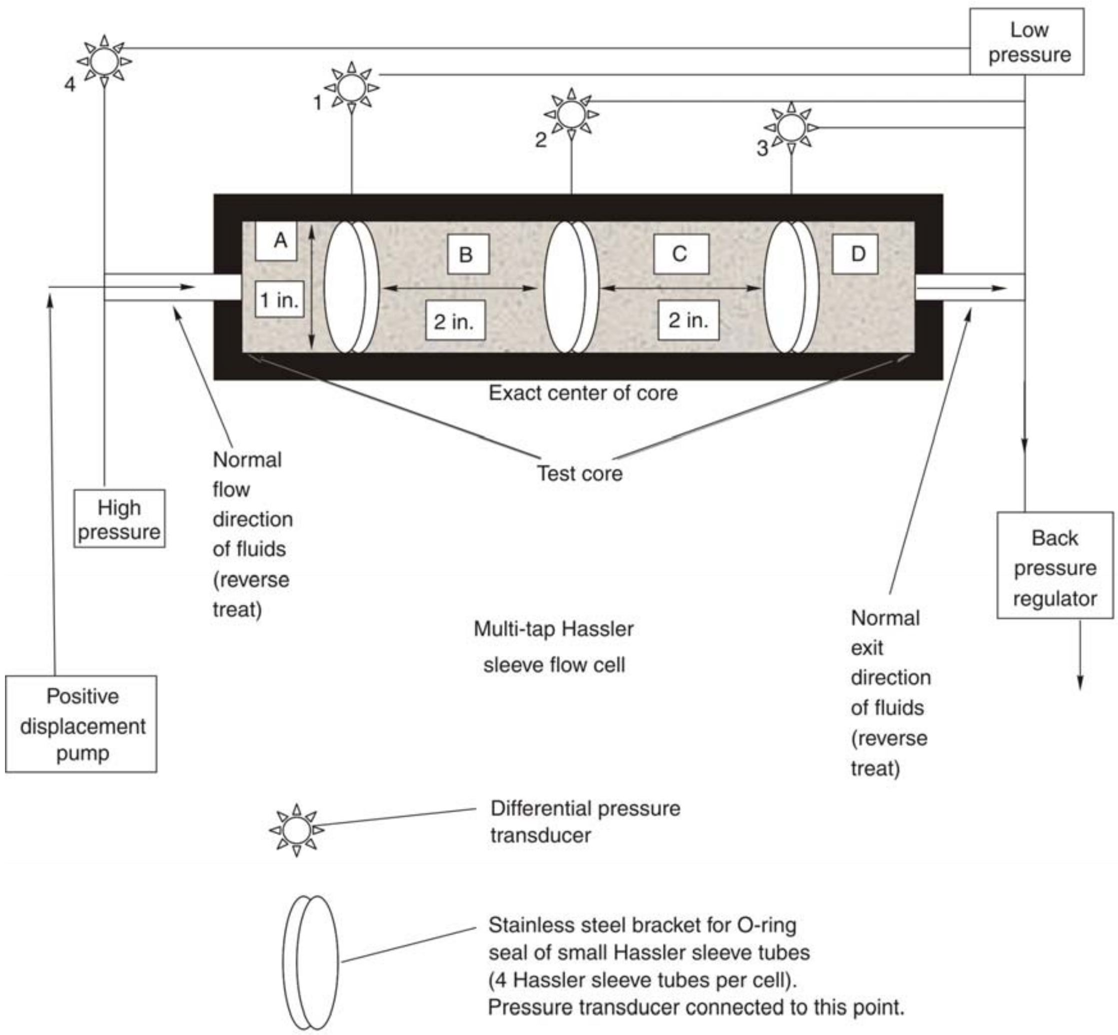


Figure 2—Proposed RPM Mechanism



Core segments B and C are 2 in. exactly. Core segments A and D are one-half the length left over from the total core.

Pressure 1= P4 - P1 for core segment A
Pressure 2= P2 - P1 for core segment B
Pressure 3= P3 - P2 for core segment C
Pressure 4= P3 for core segment D

For reverse-flow, three-way valves are used to keep pressure readings using the same transducers. Pressure is calculated using absolute values to take care of negative values generated during reverse flow.

Figure 3—Schematic of Multiple-Pressure Tap Flow Cell

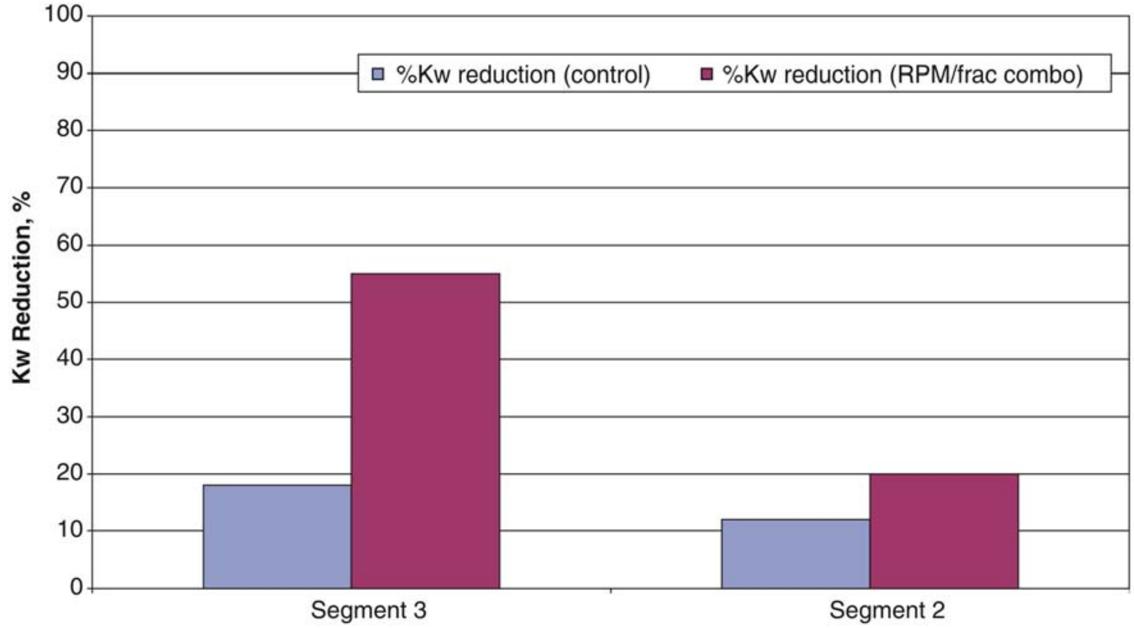


Figure 4—Comparison of %Kw Reduction with and Without RPM Frac Combo in a Multipressure Tap Core Flow Cell

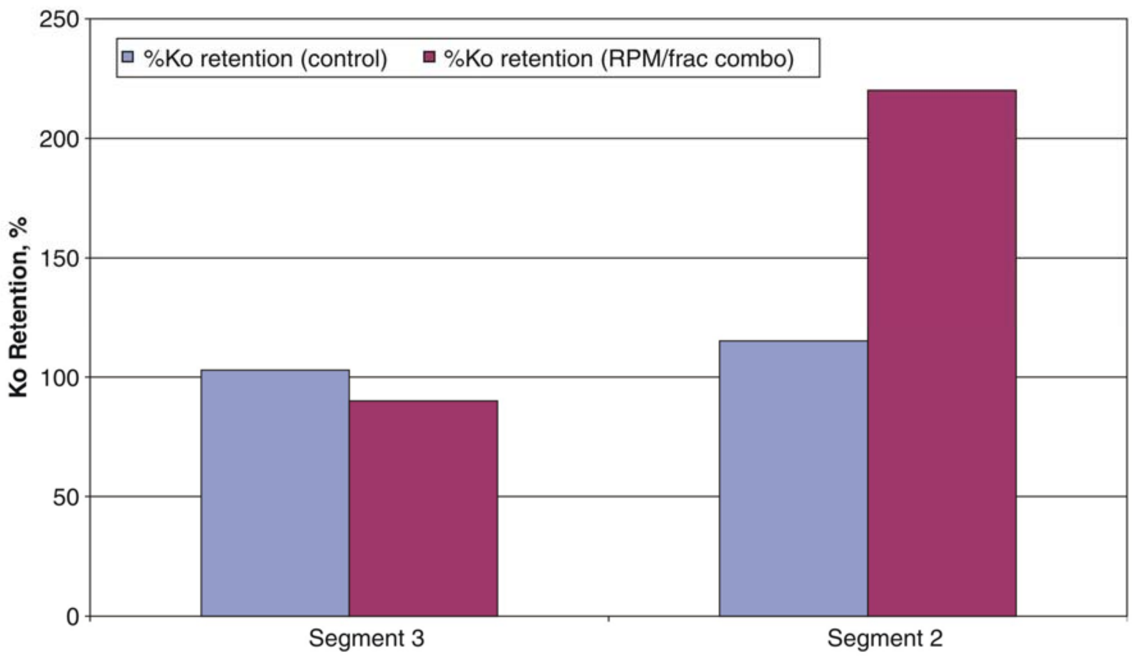


Figure 5 — Comparison of %Ko Reduction with and without RPM Frac Combo

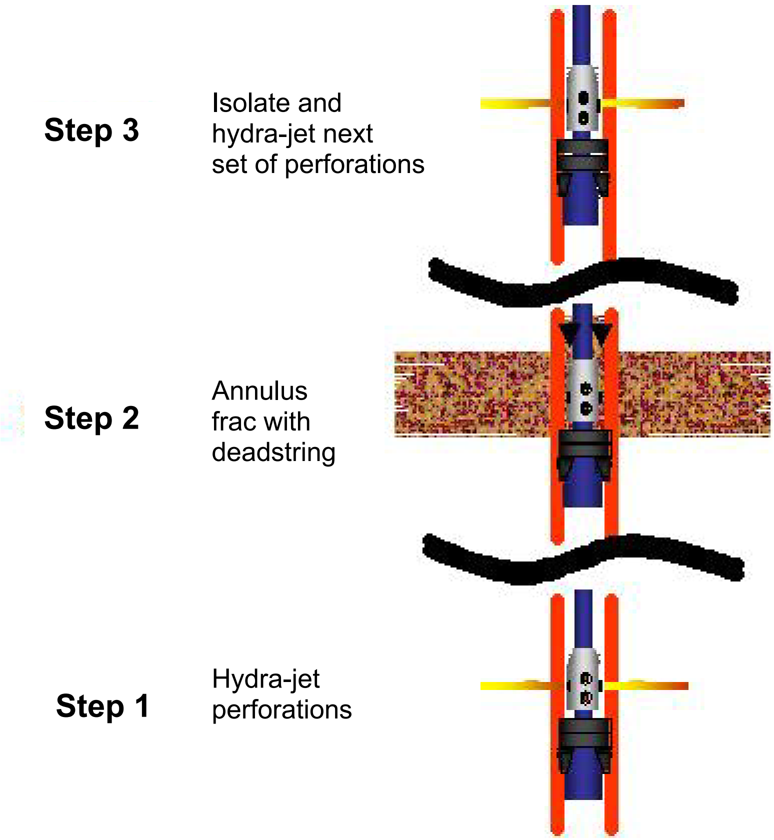


Figure 6 —The Hydra-jetting Process