THE USE OF ALCOHOL-WATER MIXTURES IN FRACTURE STIMULATION OF GAS WELLS

W.A. TINDELL, M.D. MISAK and E.H. GRAS
Halliburton Services

INTRODUCTION

The stimulation of gas wells presents many special problems. If the reservoir pressure is low and there is little fluid associated with the gas the problems become more complex. When these conditions exist, the formation may also be sensitive to water and have low permeability. Thus, the use of water-base fluids is not practical in many of these wells. Oil-base fluids, while eliminating some of these problems, may increase the fluid saturation and introduce a third phase to the reservoir. This can result in a reduction in relative permeability to the gas.

A fluid used for hydraulic fracturing of gas wells should have the following qualities:

1. Exhibit low surface tension
2. Be nondamaging
3. Have a low residue level
4. Be miscible with or soluble in formation fluids
5. Pump at low friction pressure
6. Be a good proppant transporter
7. Be compatible with carbon dioxide and/or nitrogen
8. Leave the formation water-wet.

Methyl alcohol used as the base fluid provides many of these advantages. While the benefits of this fluid have been known for years, only recently has technology advanced to the point where it may be used as the base component of fracturing fluids.[1] Since methanol is expensive and recently in short supply, a means was sought to take advantage of many of the good properties while incorporating the advantage of better economy. It is now possible to formulate base fluids utilizing various concentrations of methanol. The original fracturing stimulation with alcohol utilized 100% methanol as the base fluid. However, tests have shown that a mixture of 10-40% methanol in water retains most of the benefits of 100% methanol at a much lower cost.

FLUID CHARACTERISTICS

One of the primary benefits derived from methanol as a fracturing fluid is lowered surface tension. This benefit is due to a reduction in capillary pressure. Capillary pressure is a measure of the force with which a liquid is held in capillaries, which in this case are the pore channels of the formation and is a function of both surface tension and average radius of the channels. High capillary pressure can cause slow clean-up and, in extreme cases, may lead to a restrictive water-block condition. Thus, by employing a low surface tension fluid, less pressure and time should be required to produce the fracturing fluid from the formation. If a low surface tension fluid is commingled with interstitial water, fluid saturation may effectively be reduced along the fracture face. A plot of surface tension versus various methanol-water mixtures is shown in Fig. 1.

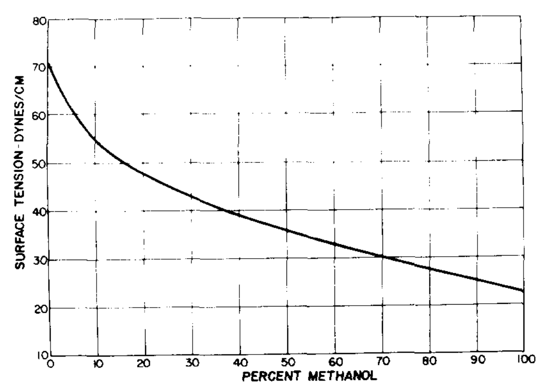

FIG. 1—SURFACE TENSION VS PERCENT METHANOL

In low porosity, low permeability formations containing low levels of connate fluid, the problems of regaining permeability may be more difficult. The created fractures are of little value if the capillaries leading to them remain totally or partially blocked to the produced gas.

Although extremely time consuming, tests can be performed on formation cores using a variety of treating fluids to indicate the rate at which permeability can be regained. Figure 2 is an example of results of this type testing. This example serves to illustrate the importance of surface tension in the role of removal of fluid after treatment to allow the rapid return of the well to production.

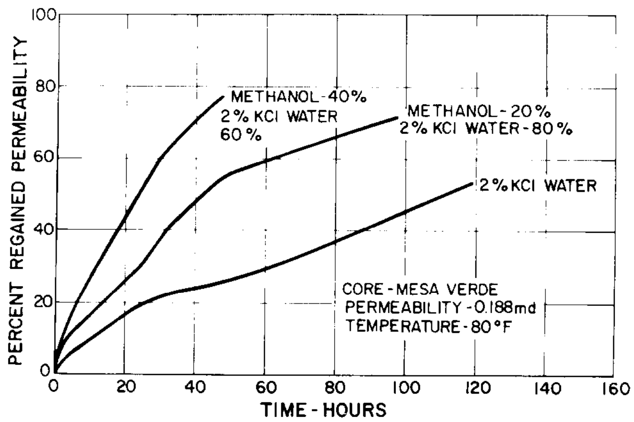

FIG. 2—PERCENT REGAINED PERMEABILITY VS TIME

A methanol-water solution has an additional advantage in that it aids in protecting water-sensitive formations from damage. This is especially true when the solution also contains a clay stabilizing chemical.[2] Compatibility of these systems with the various water-soluble clay-protecting chemicals is as important quality. Immersion tests and regained permeability tests indicate that clay swelling and/or migration is lessened considerably when combinations of these components are used in water-sensitive formations. The swelling of clays together with their release and migration reduce the size of capillaries, thus requiring higher pressures for removal of treating fluids.

To a lesser extent, methyl alcohol offers some benefit in reduced clean-up time due to its higher vapor pressure and lower density which reduces the hydrostatic pressure on the formation.

Nonresidue gelling agents are now available which may be used to gel alcohol-water mixtures to almost any viscosity range desired.[3] Rate of gelation may also be controlled in order to maintain or increase gel viscosity as bottomhole temperatures increase.

The base fluid may be pre-gelled on the surface to provide the desired viscosity for the bottomhole conditions of the well (see Fig. 3). An alternative to this is to prepare a base gel initially on the surface, so that there is sufficient viscosity to carry the sand down the tubing. The balance of the gelling agent (in a retarded form) is then added continuously during the job so that it does not develop its viscosity until it reaches the bottom of the well.[4,5] This provides viscosity needed to transport sand in the fracture without expending additional hydraulic horsepower that would be required to pump a highly viscous gel from the surface. By use of a similar type gelling agent together with the addition of the crosslinker, a good sand transport fluid is transformed into a perfect sand transport fluid. Viscosities, no longer measurable on the Fann VG Meter, are in excess of 2000 cp. It is often possible to maintain adequate viscosity at lower gel concentrations and reduced cost. This allows the placement of much higher sand concentration in the fracture than can be obtained with conventional gels.[6] Regardless of the type of gelling agent selected, all are residue-free and compatible with carbon dioxide and nitrogen.

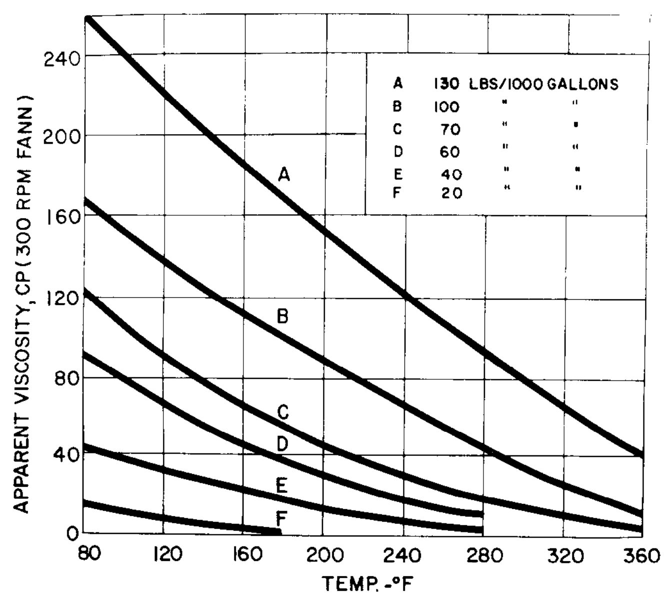

FIG. 3—VISCOSITY VS TEMPERATURE

FIELD STUDY

An extensive field study was undertaken in order to determine the viability of these types of methanol solution systems. A formation was chosen that was gas-bearing, had a long history of production, was thick in section and had a well-documented history of various types of stimulation treatments. Complete analysis was performed on various core samples available (Table 1). Various base fluids were run in order to determine fluid compatibility, and immersion tests were run.

TABLE 1—CORE ANALYSIS TRAVIS PEAK

Core Depth Feet	Porosity Percent	Air Permeability (md) Horiz.	Vert.	Solubility Percent
7502	13.2	<1.0	<1.0	4.0
	10.8	2.0	<1.0	2.0
	14.9	2.6	<1.0	4.0
to	11.9	<1.0	<1.0	5.0
7509	12.8	3.2	2.7	3.0

The formation chosen was the Travis Peak in Northeast Texas. This formation is productive in a large area covering primarily Gregg, Henderson, Upshur and Panola Counties. The formation in this area is primarily a gas producer but does produce oil in some other geographical locations. It usually varies in thickness of from 1000 to 1500 feet at depths ranging from 6000 to 10,500 feet. It grades from sandy shale to shaly sand. Generally, the formation may be considered mildly water-sensitive due to its clay content. X-ray diffraction analysis shows from very small to moderate amounts of montmorillonite and mixed layer clays (Table 2).

TABLE 2—X-RAY DIFFRACTION ANALYSIS—TRAVIS PEAK

Sample Depth (Ft.)	8351-52	8372-73	8380-81
Quartz	major	major	major
Feldspars	small	very small	small-moderate
Calcite	moderate-large	trace	small
Dolomite	-	-	very small
Kaolinite	very small	-	small
Illite	-	small	very small
Montmorillonite	-	very small	very small
Mixed Layer Clays	small-moderate	moderate	small-moderate

Immersion tests performed indicated that all base fluids used, (with the exception of kerosene and a 30% methanol-70% water solution containing 2% potassium chloride) released some fines (Table 3).

Wells may contain as many as 40 producing intervals and are often difficult or impossible to correlate from well to well. However, some zones are pressure connected. Well spacing has been reduced in some areas from 640 to 160 acres by in-field drilling over a period of years.

Upon completion, wells usually show a small, inconclusive, natural blow. Typically, clean-up acid treatments (500-3000 gal.) result in only slight improvement. The only sustained increase in production is obtained by properly designed hydraulic fracturing treatments.

A search of the records revealed a fairly

TABLE 3—IMMERSION TESTS—TRAVIS PEAK

Effects of immersion under vacuum at 160°F (est. BHT) for one hour in the following:

Depth Feet	Fresh Water	10% NaCl	2% Kcl	2% Clayfix	Mix-ture*	7-1/2% MCA	6% HF	Kero-sene
8351-52	NFR	NFR	NFR	NFR	NFR	MAF	MAF	NFR
8372-73	V-SAF	V-SAF	V-SAF	V-SAF	NFR	NFR	V-SAF	NFR
8380-81	V-SAF	V-SAF	V-SAF	V-SAF	NFR	V-SAF	NFR	NFR

NFR = No fines releases.
MAF = Moderate amount fines.
V-SAF = Very small amount fines.
* = The mixture consists of 30% methanol and 70% water containing 2% potassium chloride.
MCA = Mud cleanout agent.
HF = Mixture of hydrochloric and hydrofluoric acids.

extensive use of water with 30-50 lb per 1000 gal. of guar gum in volumes from 20,000 to 50,000 gal. Injection rates were from 12-30 BPM with an average sand concentration of 3/4 ppg.

Some limited entry jobs were performed, but formation coverage was usually attempted by use of the perforation ball sealers to separate the treatment into stages. The usual problem encountered, however, was that only a few of the many zones perforated were properly treated. Clean-up time varied from 3 to 7 days with estimated treating fluid returns of from 30-50%.

With the advent of the alcohol-water base fracturing fluid, slight modifications were made in treating procedures. Average job size was increased to a range of 40,000 to 80,000 gal. and, since this fluid exhibited somewhat better temperature stability and sand transport qualities, average sand concentration was increased to 1-1/2 ppg. Increased use of the limited entry technique was employed using rates of 14-32 BPM into from 6 to 14 of the better intervals. By use of this fluid, clean-up time was dramatically reduced to from 18 to 36 hours. Treating fluid recovery correspondingly increased to an estimated 70%.

Results of these treatments in three different fields are illustrated in Figs. 4, 5, and 6. Comparable wells within each of these fields were chosen where the wells were completed in a like manner, development of the producing intervals was approximately the same, and treatment parameters were similar.

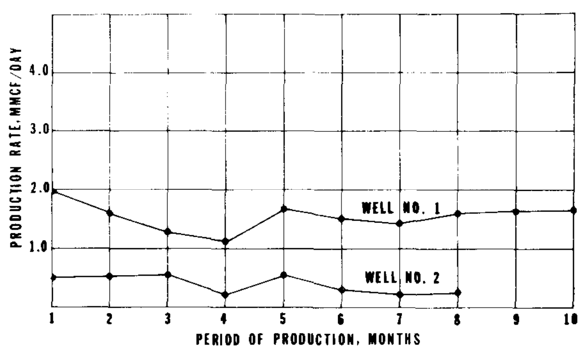

FIG. 4—PRODUCTION CURVE—FIELD "A" FOLLOWING TREATMENT

Approximately 17 wells have been studied in Field "A". Five new wells and two old wells were treated with the gelled methanol-water solution and compared with two new and eight old wells treated with gelled water. Figure 4 is an illustration of the results obtained when treating two comparable wells. Well No. 1 was treated with 54,000 gal. gelled methanol-water containing an average proppant concentration of 1-1/2 ppg. Injection rate was 17 BPM. Well No. 2 was treated with 30,000 gal. gelled water, average proppant concentration of 3/4 ppg and injection rate of 18 BPM.

Figure 5 is an illustration comparing three new completions in Field "B". In this comparison, Wells No. 1 and No. 2 respectively, were treated with 60,000 gal. and 89,000 gal. of crosslinked methanol-water solution. Injection rates were 27 and 35 BPM. Average proppant concentrations were 1-1/2 and 1-1/4 ppg. Well No. 3 was treated with 40,000 gal. gelled water at an injection rate of 17 BPM and average proppant concentration of 3/4 ppg.

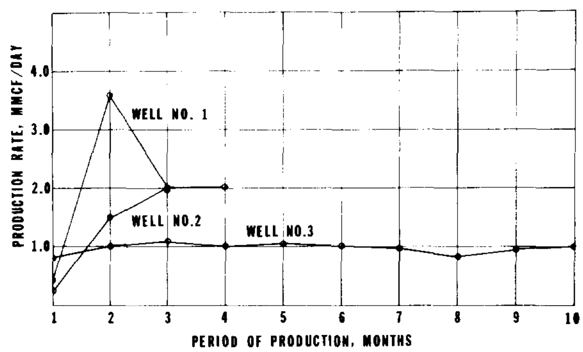

FIG. 5—PRODUCTION CURVE—FIELD "B" FOLLOWING TREATMENT

Figure 6 compares treatment of an old well and a new completion in Field "C". Both wells were treated with the gelled methanol-water solution. Well No. 1 (new completion) was treated with 53,000 gal. at 21 BPM and average proppant concentration of 1-1/4 ppg. Well No. 2 (old well) was treated with 48,000 gal. containing an average proppant concentration of 1 ppg at an injection rate of 9 BPM.

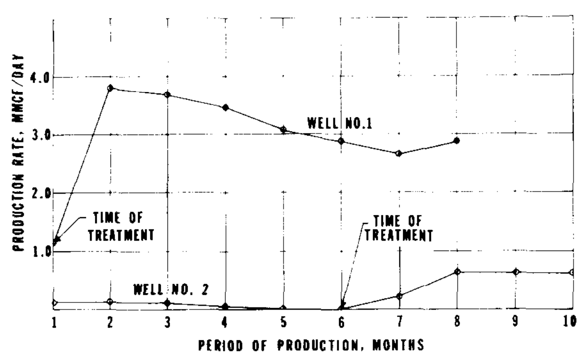

FIG. 6—PRODUCTION CURVE—FIELD "C"

Treatment results from several other wells in these fields and a variety of other tight gas-bearing formations in other areas are given in Table 4.

TABLE 4—FIELD RESULTS WITH ALCOHOL-WATER GELS

Formation	State	Depth Feet	Total Volume Gallons	Total Proppant Pounds	Rate BPM	Production Rate-Mcf/D Before	Production Rate-Mcf/D After
Travis Peak	E. Texas	9,555	60,000	63,000	18	show	2,600
Travis Peak	E. Texas	8,006	35,000	27,100	10	show	2,470
Travis Peak	E. Texas	8,010	58,500	62,200	19	new	3,100
Travis Peak	E. Texas	8,032	54,000	51,000	16	new	3,119
Travis Peak	E. Texas	8,084	52,000	62,500	24	new	4,200
Travis Peak	E. Texas	7,625	20,000	19,800	10	750	2,500
Travis Peak	E. Texas	9,264	53,000	59,000	21	new	5,400
Travis Peak	E. Texas	8,585	35,000	39,000	15	new	2,500
Berea	W. Virg.	3,900	39,500	30,000	47	150	2,700
Big Injun	W. Virg.	2,100	20,000	23,000	27	30	1,652
Brown Shale	W. Virg.	4,897	30,000	35,000	47	26	112
Berea	Virginia	4,900	25,000	30,000	23	146	2,200
Clinton	Ohio	3,650	11,000	7,000	29	969	1,393
Clinton	Ohio	3,650	15,000	8,500	30	118	192
Dakota	Colo.	2,100	30,000	22,500	-	233	2,100
Carpenter	W. Ark.	3,316	12,000	6,500	16	786	3,750
Spiro	E. Okla.	6,771	30,000	21,000	15	2,619	8,628
Strawn	Texas	5,843	13,400	15,000	13	30	500
Canyon	W. Texas	7,700	30,000	40,000	20	show	1,500
Canyon	W. Texas	3,045	10,000	8,000	20	show	200

CONCLUSIONS

As the petroleum industry continues the search for added energy sources in less productive formations the importance of maintaining original formation conditions becomes more apparent. Factors to consider in order to reduce formation damage and maintain a high level of permeability and effective flow capacity are:

1. Proper selection of fracturing fluid based on laboratory tests in order to reduce damage to water-sensitive formations
2. Utilization of low surface tension fluids to reduce fluid retention after treatment
3. Incorporation of artificial gas lift aids such as carbon dioxide and nitrogen to assist in quick return of treating fluids
4. Use of low or no-residue gelling agents to reduce the possibility of decreasing matrix permeability
5. Use of gelled water-methanol (5% to 40%) containing clay stabilizing chemicals.

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