FRACTURING FLUID ROCK INTERACTION

OF

COTTON VALLEY LIME FORMATION

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TR 78-60
October 1978

ABSTRACT

Laboratory analyses were performed on cores taken from Mitchell Energy Corporation (MEC) Muse-Duke Well #1, located in Cotton Valley Lime Formation, Limestone County, Texas, to determine fracturing fluid interaction with the host rock. All tests were conducted at simulated *in situ* conditions of 8800 psi confining pressure, 6400 pore pressure, 40% saturation and 285°F. Three candidate fracturing fluids were evaluated: Versagell (Halliburton); Stratafrac 400 (Dowell); Polaris 60 (Western). Tests were carried out to assess, (1) fracturing fluid damage to the rock permeability and (2) clean-up efforts required to return the host rock to its initial permeability. Irrespective of the initial, untreated permeability; post treatment permeability was in the tenths of microdarcies range. Initial permeability of the rock treated with Versagell and Stratafrac 400 was recovered in less than 2 hours. With Polaris 60, post fracture permeability appeared to stabilize at 60 percent of the initial permeability.

Further fracturing fluid/rock interaction tests will be performed with the above mentioned fracturing fluids on core samples from the same well and microscopic examination of the cores will also be done.

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INTRODUCTION

Degradation of permeability due to the application of hydraulic fracturing fluid has been postulated to be one of the reasons why some massive hydraulic fractures fail (Davis, 1975; Clark, 1977). Several previous studies (Simon, *et al.*, 1977; Davis, 1975; Haiwka, 1972; Buchholdt, *et al.*, 1978; Ahmed, *et al.*, 1978) have indicated that certain fracturing fluids are less damaging and behave differently to specific formation lithologies. Thus, it is necessary to experimentally determine the effect of different fracturing fluids on the host rock.

EXPERIMENTAL PROCEDURE

Core samples from Mitchell Energy Corporation (MEC) Muse-Duke Well No. 1 at depth 11313 feet were used in this investigation. All samples were one inch diameter by one inch long, with sample axes normal to the core axis. Permeability at atmospheric conditions for core at *in situ* saturation (40 percent) was first determined. Upon subjecting the samples to *in situ* pressures (8800 psia confining pressure, 6400 psia pore pressure) and temperature (285°F) permeability was again measured. While maintaining the confining pressure, pore pressure and temperature, fracturing fluid was flowed across one face of the sample for four hours at an injection pressure of 8700 psia (this particular fracture fluid flow time and pressure was used to simulate the field fracture job conditions). Shut in time of twelve hours was allowed to assure the fracture fluid was completely broken before backflow. On termination of shut in permeability measurements were taken to assess the amount of damage done.

Clean-up was simulated by introducing 6400 psi nitrogen at the sample back face and reducing pressure at the fracture face according to the following schedule:

Pressure Reduction at Fracture Face psi	Duration of Nitrogen Backflow hrs	Remarks
500	3	Monitor permeability until 100% damage was recovered or move on to the next step if damage recovery stabilized.
1000	2	Same as above
1500	2	Same as above
2000	2	Monitor permeability until 100% damage was recovered or stop test if damage recovery stabilizes.

The three different fracturing fluids evaluated were, Stratafrac 400 supplied by Dowell, Versagell supplied by Halliburton and Polaris 60 supplied by Western. All the fluids were premixed by the individual companies.

DISCUSSION OF RESULTS

The damage and the clean up data on the cores are presented in Table 1 and Figure 1 and 2. The initial *in situ* permeabilities of the samples interacted by Stratafrac 400 and Versagell were in the neighborhood of 25 μd, whereas the sample interacted by Polaris 60 was much higher (83 μd). The damaged permeability of all the samples at initiation of clean up were in the tenths of micro-darcy range, irrespective of the initial permeability of the sample and fluid used. There was no evidence of the fracturing fluid flowing totally through the sample.

A differential pressure of 500 psi was adequate for the clean up of the samples damaged by Stratafrac 400 and Versagell. The sample damaged by Polaris 60 cleaned up about 50 percent on a 500 psi differential pressure; permeability appeared to stabilize at this level even after 3 hours of backflow. Upon increasing the differential up to 2000 psi there was a 10 percent increase in damage recovery.

FRACTURING FLUID/ROCK INTERACTION
MEC.: Muse-Duke Well No. 1
11,313'

Fracturing Fluid	Permeability at Atmospheric Condition, K_a µd	Permeability at *in situ* conditions. Before Fracturing Fluid Flow, K_i µd	Permeability after Fracturing Fluid Flow, K_s, µd	Time of Nitrogen Backflow hrs, Δp of				Final Permeability K_f, µd	Recovery Fraction K/K_i, Δp of				Estimated 100% Recovery Time, hrs
				500	1000	1500	2000		500	1000	1500	2000	
Stratafrac 400	159	23	0.2	2	--	--	--	22	.96	--	--	--	2.2
Versagell	991	31	0.3	1.5	--	--	--	25	.81	--	--	--	1.7
Polaris 60	811	83	0.1	3	0.5	--	0.5	48	.49	.54	--	.58	Inconclusive

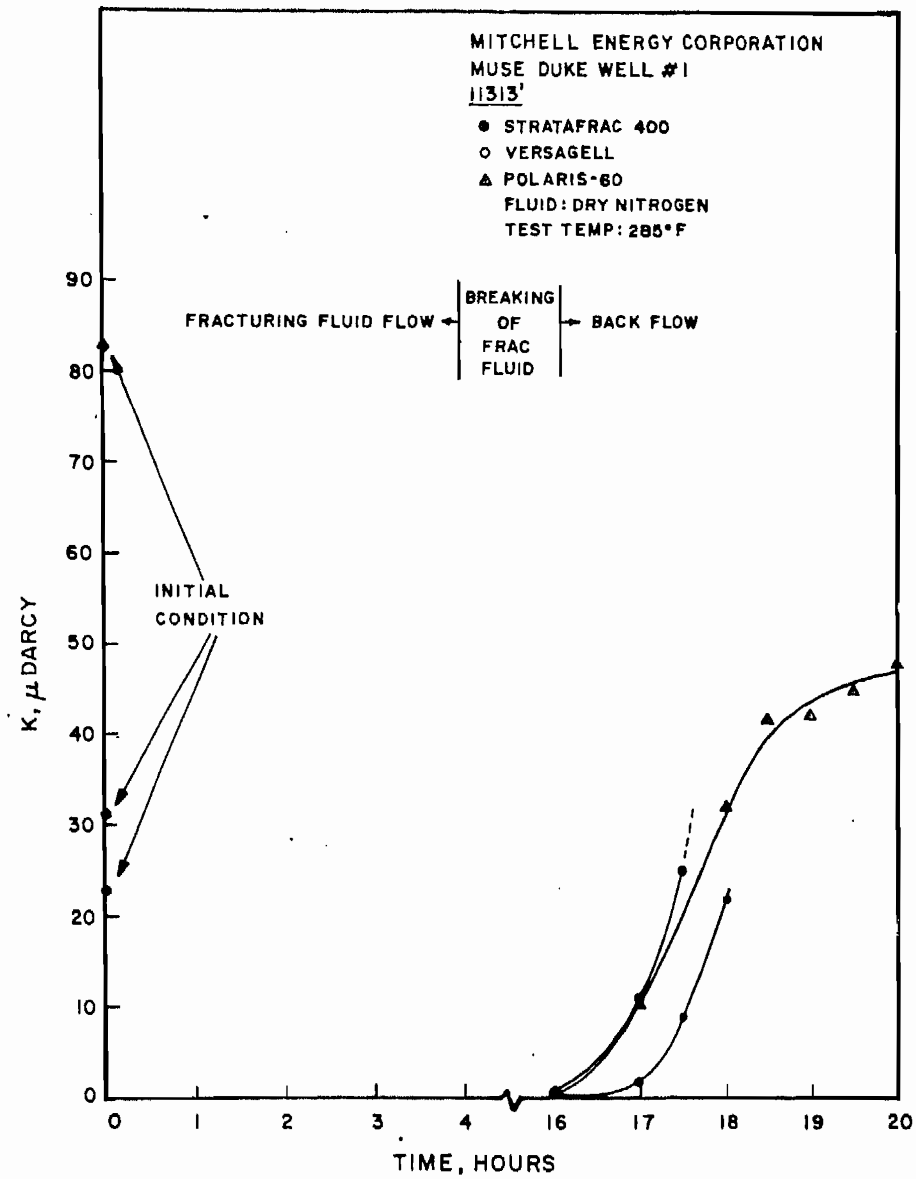

Figure 1. Change in permeability during damage and clean up.

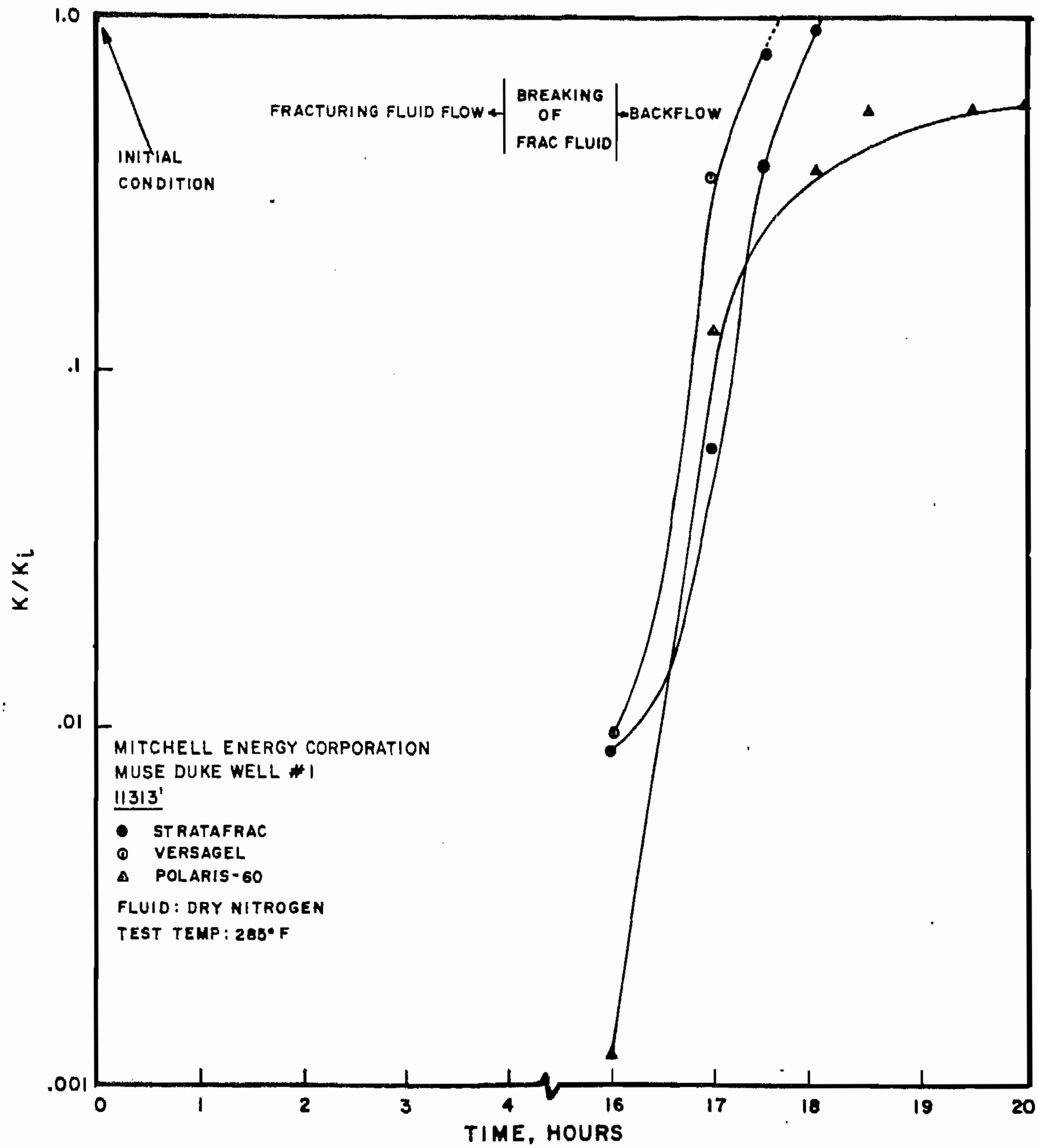

Figure 2. Trend of permeability fraction during damage and clean up.

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APPENDIX A

PERMEABILITY MEASUREMENT

PERMEABILITY MEASUREMENTS

The transient technique has been used to measure the permeability of the samples obtained from MEC-Muse-Duke Well No. 1. The transient method imposes a step increase in pressure in a known volume across a sample. The permeability can be calculated from the time-dependent decay of this imposed pressure step. This method is more adaptable to tight sandstone, granite and shale where the permeabiliteis are in the tens of microdarcies or lower.

Figure A1 shows a typical test set-up of the transient method to measure permeability after fracturing fluids flowed along the face of the core. Figure A2 shows the sample assembly. The sample is placed in a pressure vessel and the pore-pressure inlet and outlet are connected to external fittings through the base plug. With this geometry, the sample can be subjected to hydrostatic loading or triaxial compression prior to testing. Pore-pressure in the sample can be set at any value less then the confining pressure and desired backflow pressure can be applied.

Figure A3 shows fluid reservoirs on either side of the sample that can be hydraulically connected to allow the pore-pressure to equalize. When the sample has reached equilibrium, the volumes are disconnected by closing a valve. The pressure in volume one is then raised slightly. This pressure step should be limited to a small percentage (less than five percent) of the absolute pressure in the reservoir volumes. Through the use of a differential pressure transducer the pressure step decay is accurately monitored.

A brief outline of the theory involved in measuring permeabilities using the transient technique is given below. Detailed treatment of this analysis is presented by Brace, *et al.*, (1968).

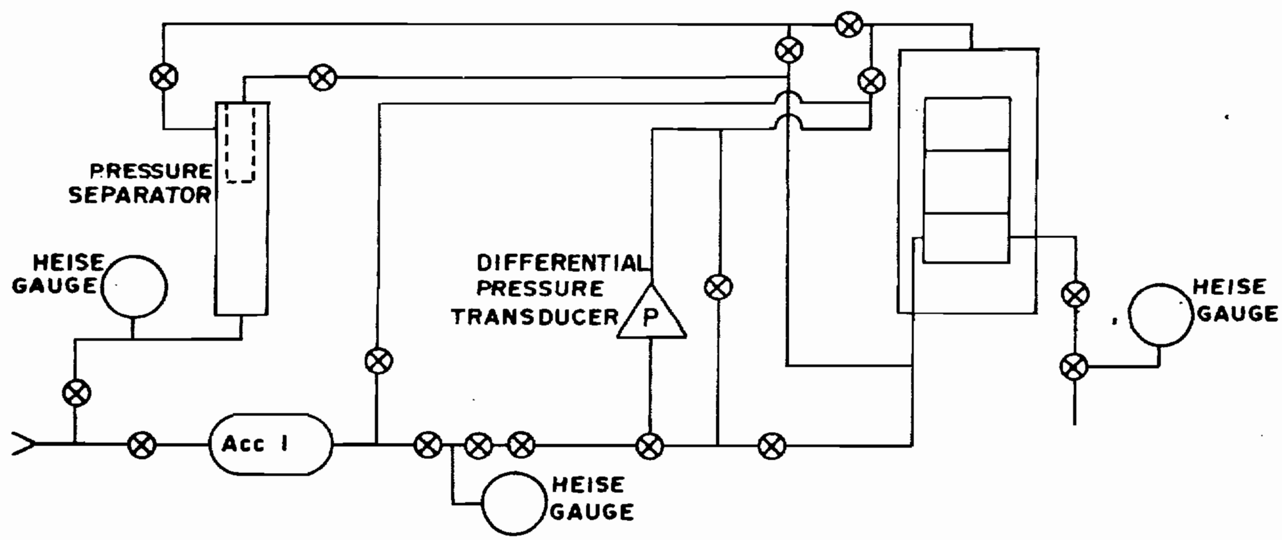

Figure A1. Pulse Permeability System

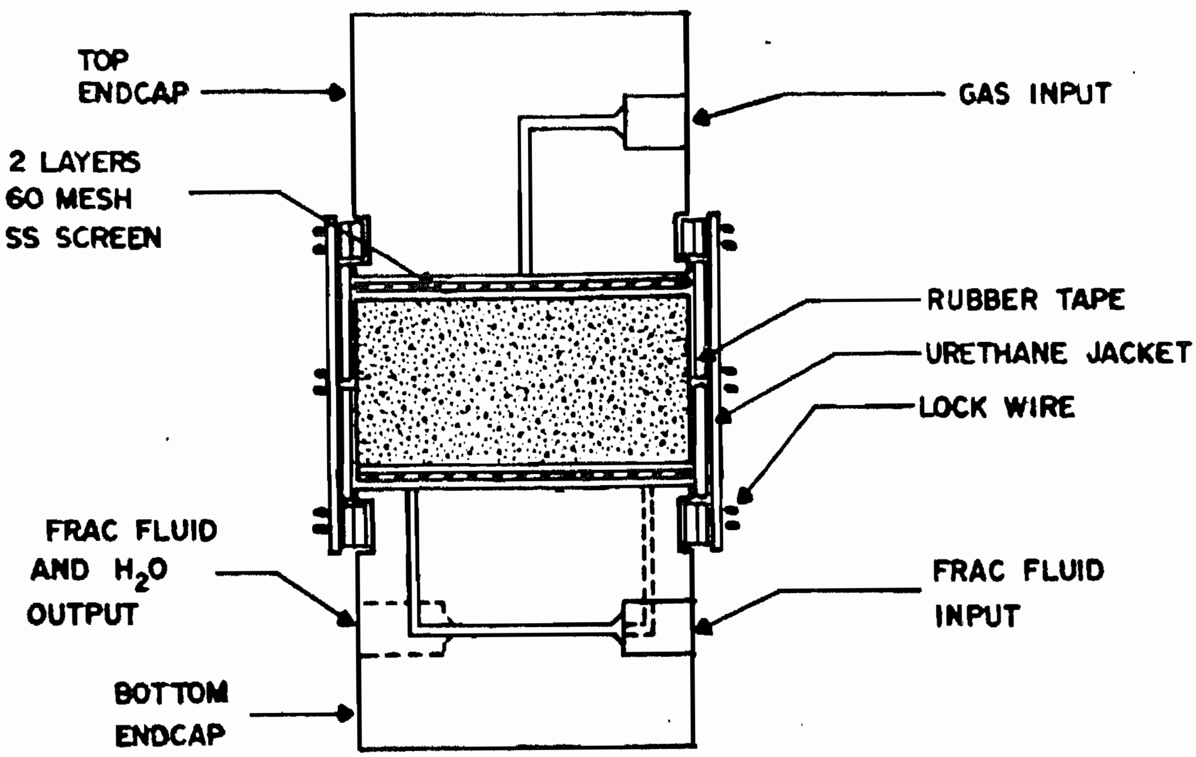

Figure A2. Fracturing Fluid Interaction Sample Assembly

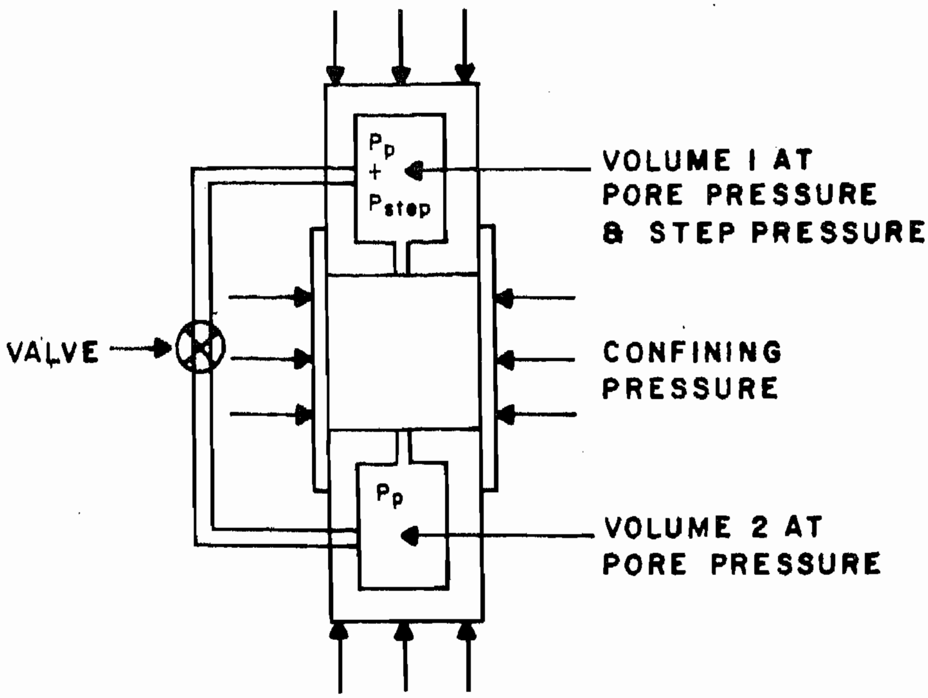

Figure A3. Schematic Drawing of a Permeability Test Using the Transient Technique.

The flow of a compressible fluid through a media of constant compressibility is represented by,

$$\nabla^2 p = \frac{\mu \beta}{K} \; c \; \frac{\partial P}{\partial t} \qquad \text{(A1)}$$

where,

P = pressure

μ = fluid viscosity

β = fluid compressibility

c = compressibility of the rock matrix

K = permeability

t = time

Assuming:

1. The fluid flow is laminar
2. Darcy's law is valid
3. The change in fluid volume in the pores of the rock due to the step pressure change is negligible compared to the amount of fluid flowing through the sample during a test.
4. The pressure step is small compared to the absolute pore pressure so that the physical constants of the fluid (viscosity and compressibility) can be considered constant in all parts of the sample.

The solution to Equation A1 is given by

$$P - P_f = \Delta P \frac{V_2}{V_1 + V_2} e^{-\alpha t} \tag{A2}$$

where

- P = Initial pressure
- P_f = Final pressure
- ΔP = Initial pressure step
- $V_1 (V_2)$ = Volume reservoir 1 (reservoir 2).

In Equation A2, α is defined as the slope of the semilog of the natural log of the decaying pressure versus time, *i.e.*,

$$\alpha = \frac{KA\left(\frac{1}{V_1} + \frac{1}{V_2}\right)}{\mu \beta L} \tag{A3}$$

and the permeability K is given by

$$K = \frac{\alpha\mu\beta L}{A \frac{1}{V_1} + \frac{1}{V_2}} \tag{A4}$$

where,

L = the sample length

A = cross-sectional area of the sample

Thus, the permeability can be accurately determined for very tight samples with no direct measurement of the flow rate. Another major advantage of this method is the capability for making permeability measurements at high pore pressures.

Permeability Recovery Fraction

One of the ways to ascertain the damaging effect of fracturing fluids on the formation is to get an idea of recovery fraction. Quantitatively,

$$R_F = \frac{K_s}{K_i} \tag{A5}$$

where,

R_F = Recovery fraction

K_s = damaged permeability or final permeability, μd

K_i = initial permeability, μd