Laboratory Data in Support of Hydraulically Fracturing
EGSP OH Well #3

Work Completed for
Morgantown Energy Technology Research Center
Under Contract No. DE-AC08-79NV10066

Final Report
December, 1980

NOTICE

by

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INTRODUCTION

The objective of this work is to obtain data needed to apply advanced stimulation design concepts to Eastern Gas Shale Project (EGSP) wells. This report contains the results of laboratory tests on core samples from the EGSP OH Well #3. The samples tested were from organically rich shale, organically lean shale and the bounding formations. Pertinent properties are density, porosity, saturation, elastic moduli and the potential of damage to the matrix permeability and fracture conductivity by fracturing fluids. The permeability, elastic moduli and fracturing fluid damage potential were determined at simulated in-situ conditions.

SUMMARY AND CONCLUSIONS

Geologic and geophysical interpretations of data from the EGSP OH Well #3 show that an organically lean shale has a gradual transition with depth to an organically rich shale and that two layers (assumed barriers) bound each shale formation. The laboratory test program was designed to understand the containment and productivity of a hydraulic fracture induced in this well to enhance gas production from the shale.

The porosity in the formations of interest, including the upper barrier, the lower barrier, and the organic shales, varied from 6 to 10 percent. The porosity of each formation averaged about 8 percent. Densities and ultrasonic velocities were used to evaluate dynamic moduli. Over the tested intervals (organic shale and bounding layers) moduli consistently increased with depth. This indicates the possibility of upward migration of an induced fracture. Perforations, therefore, should be limited to the lower portion of the pay sand and it is also advisable to use low injection rates (i.e., less than 15 bpm).

Of the four fracturing fluids tested, the two code-named Dow II and Hal I caused, respectively, the least amount of matrix permeability damage to the organically lean and organically rich shales. However, the damage caused by the other fracturing fluids (except Dow III on organically rich shale) were not severe enough to cause any significant permanent reduction in well productivity. The fracture conductivity tests under the influence of fracturing fluids indicated that Hal I and Dow I caused, respectively, the least amount of multilayered fracture conductivity damage to the organically lean and organically rich samples. For monolayer fracture conductivities (edge of a fracture in the field job) Dow I caused least damage to the organically lean shale. With the exception of Dow III

all other fluids showed good results in the monolayer tests for organically rich shales. In the situation where both the lean and the rich shales are to be fractured together, the use of either Hal I or Dow I is indicated.

LABORATORY TEST RESULTS

Laboratory measurements were performed on samples from four distinct zones: the organically rich shale, the organically lean shale and two bounding formations around each organic shale. Sample footages are given in Table I. Pertinent properties were density, porosity, saturation, and elastic moduli (static and dynamic). In addition, the potential of damage to the matrix permeability and fracture conductivity by fracturing fluids were evaluated. The permeability, elastic moduli and fracture fluid damage potential were determined at simulated in-situ conditions as indicated also in Table I. Description of the equipment and test procedures are contained in References 1 through 5.

Physical Properties: Core samples were dried to 110°C for measuring the dry, bulk density (ρ_D). Grain density (ρ_g) was measured using crushed specimens. Porosity was calculated from the following relation:

$$\text{Porosity } (\phi) = 1 - \frac{\rho_D}{\rho_g}$$

Results of the physical property measurements are given in Table II. The porosity of all samples, including the barriers and the organic shales varied from about 6 to 10 percent. The porosity of each formation, however, averaged about 8 percent.

Ultrasonic Velocities: Both compression and shear wave velocities were measured on samples subjected to simulated in-situ conditions. Moduli and Poisson's Ratio derived from the measurements (assuming isotropic, elastic material) are presented in Table III. Over the tested intervals (organic shales and bounding formations) the Young's Moduli consistently increased with depth, from about 6×10^6 to 8×10^6 psi. The Poisson's Ratio over the tested interval remained fairly constant at about 0.2.

TABLE I

Tested Sample Intervals and Simulated In Situ Conditions

METC: EGSP OH WELL #3

Formation	Zone	Core Sample Interval, ft.	Simulated In Situ Pressures, psi			Simulated In Situ Temperature, °F
			Confining	Pore	Fracturing	
Upper Barrier	1	569-600.6	600	290	--	82
	2	637-648.6	640	305	--	82
	3	840-852.6	850	410	--	85
Organically Lean Shale	4	901-901.4	900	430	630	86
	5	937-937.4	940	450	660	87
	6	967-971.5	970	465	680	87
Organically Rich Shale	7	1039-1039.7	1040	500	725	88
	8	1052-1052.6	1050	504	735	88
	9	1105-1105.8	1105	530	774	89
Lower Barrier	10	1164-1164.7	1165	560	--	90
	11	1204-1204.8	1205	578	--	90

Table II
Physical Properties
METC: EGSP OH WELL #3

Formation	Sample Depth (ft)	Density (gm/cm ³)			Porosity (percent)
		As Received	Dry	Grain	
Upper Barrier	569	2.071	2.669	2.901	8.0
	637	2.537	2.472	2.708	8.7
	840	2.571	2.500	2.701	7.4
Organically Lean Shale	901	2.566	2.504	2.768	9.6
	971	2.657	2.588	2.782	7.0
Organically Rich Shale	1052	2.463	2.421	2.697	10.3
	1105	2.465	2.423	2.597	6.7
Lower Barrier	1164	2.651	2.586	2.838	8.9
	1204	2.668	2.602	2.834	8.2
	1204	2.721	2.647	2.890	8.4

Table III
Dynamic Elastic Properties
METC: EGSP OH WELL #3

Formation	Sample Depth (ft)	Moduli ($\times 10^6$ psi)				Poisson's Ratio
		Young's	Bulk	Shear	Constrained	
Upper Barrier	637	6.07	3.96	2.44	7.21	0.24
	852	6.31	3.54	2.62	7.04	0.20
Organically Lean Shale	901	6.33	3.76	2.60	7.22	0.22
	967	6.73	3.82	2.79	7.54	0.21
Organically Rich Shale	1052	7.33	3.66	3.14	7.85	0.17
	1105	7.04	3.71	2.97	7.67	0.18
Lower Barrier	1164	7.50	3.90	3.18	8.14	0.18
	1204	7.90	5.22	3.16	9.44	0.25

Triaxial Tests: Samples used in the triaxial compression tests were cylinders one inch diameter by one and one-half inches long. Table IV lists the results of the measurements. The elastic moduli quoted were determined from the initial slope of the stress-strain curves. As expected, the static moduli were lower than the dynamic moduli for the samples tested, but trend of increasing moduli with depth is repeated.

Fracturing Fluid Interaction: Four fracturing fluids were used to determine their damaging effect on the pay zone permeability and the propped fracture conductivity. Two of the used were water foams and two were cross-linked, refined, water-gelled guar gum. They were supplied by the Halliburton and Dowell Companies. Table V lists the fracturing fluids along with their suppliers and the code names of each (these names will be used in further discussion).

The system used to measure permeability and propped fracture conductivity of the tight reservoir rocks at in-situ stress levels and temperature is shown schematically in Figure 1. Figure 2 illustrates the four phases of pressurization used in the tests to simulate the four phases of the fracture process (fracturing, shut-in, clean-up and production). A detailed description of the testing procedure can be found in Reference 2. The transient technique for permeability determination^{6,7} was used because of the very low permeability of the cores.

Figures 3 and 4 show, respectively, sample assembly schematics for the matrix permeability and the fracture conductivity tests. During testing, the sample assembly is placed in the high pressure, high temperature vessel. Sample permeability (horizontal only) at room conditions was first determined. After the samples were subjected to in-situ effective pressure and temperature conditions, the effective permeability was again determined. While the confining

Table IV
Static Elastic Properties

METC: EGSP OH WELL #3

Formation	Sample Depth (ft)	Modulus (10^6 psi)	Poisson's Ratio	Maximum Compressive Strength ($\times 10^3$ psi)
Upper Barrier	840	3.2	0.26	8.8
	840	3.2	0.18	8.3
Organically Lean Shale	901	3.3	0.24	8.9
	967	3.0	0.16	8.5
Organically Rich Shale	971	3.4	0.19	7.1
	1052	3.6	0.25	18.4
	1105	3.5	0.15	15.7
Lower Barrier	1164	3.6	0.24	14.2
	1204	4.2	0.25	8.5

Table V
Fracturing Fluids Considered for Stimulation

METC: EGSP OH WELL #3

Supplier	Code Name	Description
Halliburton	Hal I	Water foam
Dowell	Dow I	Water foam
Dowell	Dow II	J-266-40, shallow wells; low residence time.
Dowell	Dow III	J-160-40; low pressure reservoirs

Figure 1. Schematic of the Laboratory System

STAGE OF MHF TREATMENT	PRESSURE DISTRIBUTION	EFFECTIVE PRESSURE (STRESS)
FRACTURING	σ_3, P_p $P_f \approx \sigma_3$	< 0
CLEAN-UP	σ_3, P_p $P_f < P_p$	$\sigma_3 - P_f$
SHUT-IN	σ_3, P_p $P_f \approx P_p$	$\sigma_3 - P_p$
PRODUCTION	σ_3, P_p $P_f \approx P_{wf}$	$\sigma_3 - P_{wf}$

Figure 2. Pressures During Four Stages of Simulation

Figure 3. Fracture Face Permeability Measurement Sample Assembly

Figure 4. Fracture Conductivity Measurement Sample Assembly

pressure, pore pressure and temperature were held constant, the fracturing fluid was then flowed for four hours either across one face of the sample (matrix permeability damage evaluation) or through a propped fracture (fracture conductivity damage) at an appropriate injection pressure (the particular fracturing fluid, flow time, and pressures were chosen to simulate the field fracture job). A shut-in time of twelve hours was then used to assure that the fracturing fluid was completely "broken" before backflow. On terminating shut-in, permeability measurements were taken to assess the amount of damage. Clean-up was simulated by introducing nitrogen into the system at a pressure equal to the reservoir pressure and then reducing fracture face pressure. This pressure reduction is equivalent to introducing the differential pressure between the field bottom hole flowing pressure and the reservoir pressure. Tests were stopped upon reaching the maximum reduction pressure of the well being simulated even if recovery was not complete. At the termination of the tests, samples were microscopically inspected to determine sand embedment, sand crushing, fracture face chipping, clay flocculation and whether or not the fracturing fluid had completely penetrated the core.

Fracture conductivity tests used whole core samples, saw-cut in half and propped with 20/40 mesh Ottawa sand. Proppant concentrations were in a range representative of concentrations expected in the field job, that is, in a range from a monolayer to between 2-3 ppg (0.3-0.5 lb/ft²). Initially, the cores were subjected to confining pressures of 0.7 MPa (100 psi) for the proppants to settle in place. By flowing nitrogen gas through the propped channel, conductivity measurements were then taken. Flow rates were low enough to avoid non-Darcy flow. This was checked by performing tests at several pressures (all low compared to the capillary pressure) and extrapolating measurements to zero flowrate. Cantilevers were placed across the sample to monitor fracture width changes during the course of the experiment.

Matrix Permeability: The permeability and the clean-up data on the cores from the organically lean and rich shale zones are presented in Table VI. Irrespective of the initial permeability and the fracturing fluid and with the exception of Dow I in lean shale, the damaged permeabilities of all the organic shale samples were of the order of tenths of microdarcies. The Dow I fracturing fluid across the organically lean shale yielded about 8 microdarcies. Following clean-up, the percentage of permeability reduction as compared to the virgin sample ranged from 20 to 99 percent. These results show that a fracturing fluid can be selected for each formation such that permanent damage is not significant enough to cause any adverse effect on the productivity of the well.⁸ Dow II and Hal I caused the least amount of damage, respectively, to the organically lean and organically rich shale.

The differing levels of permeability reduction are attributed to the fact that different fracturing fluids leave different solid and liquid residues in the sample pores.² Nitrogen backflow helps remove some of these residues. However, even after backflow at unrealistically high differential pressures, and long times, some residual damage always remains.

Fracture Conductivity: The effect of the fracturing fluids on the fracture conductivities of the organically lean and rich samples are presented in Tables VII and VIII. Table VII shows multilayer fracture width, and Table VIII shows monolayer fracture width. Included in the tables are the fracture conductivity and fracture width values during initial ambient conditions (100 psi effective stress and room temperature), in-situ conditions, following fracturing fluid damage, and following final clean-up.

For the multilayer fracture width tests, Hal I and Dow I caused, respectively, the least amount of fracture conductivity reduction to the organically lean and organically rich samples. There was little change in fracture width between

Table VI

Fracturing Fluid/Rock Interaction
(Matrix Permeability)

METC: EGSP OH WELL #3

Formation	Sample Depth (ft)	Fracturing Fluid	Permeability at In-Situ Condition Prior to Frac Fluid Flow, K_i , μ darcy	Permeability After Frac Fluid Flow K_d , μ darcy	Stabilized Permeability Following Clean-up K_f , μ darcy	Estimated Permeability Damage, Percentage $(K_i - K_f)/K_i$
Organically Lean Shale	901.0	Hal I	2.0	<0.1	0.4	80.0
	901.5	Hal I	6.0	0.4	0.4	93.3
	937.0	Dow II	1.0	<0.1	0.3	70.0
	967.0	Dow I	652.0	8.2	63.0	90.3
Organically Rich Shale	1039.0	Hal I	1.0	0.2	0.8	20.0
	1052.0	Dow I	0.6	0.1	0.1	83.3
	1052.5	Dow III	475.0	0.2	2.5	99.5
	1105.0	Hal I	2.4	0.2	0.3	87.5

Table VII

METC: EGSP OH WELL #3
Fracture Conductivity/Fracturing Fluid Interaction
(Multilayer Fracture Width)

Formation	Fracturing Fluid	Fracture Conductivity (md-ft), Fracture Width (in.)			
		Ambient Condition	In-Situ Condition	Following Damage	Final Clean-up
Organically Lean Shale	Hal I	489, .0822	454, .0816	104, .0816	453, .0816
	Dow I	579, .0827	524, .0827	357, .0825	475, .0825
	Dow II	501, .0823	455, .0817	83, .0815	274, .0815
	Dow III	616, .0817	596, .0817	31, .0816	502, .0816
Organically Rich Shale	Hal I	471, .0874	467, .0819	92, .0823	376, .0823
	Dow I	443, .0879	442, .086	79, .0863	410, .0863
	Dow II	459, .0854	456, .0818	32, .0806	144, .0805
	Dow III	487, .0865	478, .0852	3.5, .083	3.8, .083

Table VIII

METC: EGSP OH WELL #3
Fracture Conductivity/Fracturing Fluid Interaction
(Monolayer Fracture Width)

Formation	Fracturing Fluid	Fracture Conductivity (md-ft), Fracture Width (in.)			
		Ambient Condition	In-Situ Condition	Following Damage	Final Clean-up
Organically Lean Shale	Dow I	682, .0116	676, .0112	231, .0112	653, .0112
	Dow III	464, .0114	413, .0114	23, .0112	420, .0112
Organically Rich Shale	Hal I	604, .0113	504, .0113	128, .0113	524, .0113
	Dow I	493, .0113	425, .0113	148, .0113	427, .0113
	Dow II	489, .0113	473, .0111	53, .0105	591, .0099
	Dow III	555, .0113	437, .0113	33, .0113	345, .0113

damage and clean-up, even though there was a substantial change in fracture conductivity. This indicates that a process of residue clean-up occurred. Figures 5 and 6 illustrate, respectively, the changes of fracture conductivity during the course of the test for the organically lean and rich shale samples. The curves for the virgin samples are the fracture conductivities versus effective stress relationships at in-situ temperature. The gentle slope of the curves indicate that the reduction in fracture conductivity with stress is principally due to the packing of proppants and embedment at the fracture face. In both figures, point A is the average fracture conductivity at in-situ conditions. Points B, C, D and E represent the lowest fracture conductivity values at maximum damage due to the different fracturing fluids. The stabilized values of fracture conductivity after the nitrogen flow clean-up procedure are shown as points B¹, C¹, D¹ and E¹. These values represent the expected fracture conductivity in the field for multilayer fractures after the well has been opened for backflow.

For the monolayer fracture width tests, Dow I caused the least fracture conductivity reduction for the organically lean shale; and Dow I, Dow II and Hal I all caused less fracture conductivity damage to the organically rich samples than Dow III.

Figure 5. Fracture Conductivity Variation: Organically Lean Shale

Figure 6. Fracture Conductivity Variation: Organically Rich Shale

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