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

Work Completed for
Morgantown Energy Technology Research Center
Under Contract No. DE-AC08-79NV1066

Final Report
December, 1980

by

U. Ahmed
G. C. Swartz
J. F. Schatz

Submitted to:

METC
Collins Ferry Road
Morgantown, W. Va. 26505
Attn: C. A. Komar

Submitted by:

Terra Tek, Inc.
420 Wakara Way
Salt Lake City, Utah 84108

TR 80-100
December, 1980

TABLE OF CONTENTS


| | Page |
|---|---|
| List of Figures | ii |
| List of Tables | iii |
| Introduction | 1 |
| Summary and Conclusions | 2 |
| Laboratory Test Results | 4 |
| Physical Properties | 4 |
| Ultrasonic Tests | 4 |
| Triaxial Tests | 8 |
| Fracturing Fluid Interaction | 8 |
| Matrix Permeability | 13 |
| Fracture Conductivity | 13 |
| References | 19 |
| Acknowledgement | 20 |

LIST OF FIGURES


| Figure | Title | Page |
|---|---|---|
| 1 | Schematic of the Laboratory System. . . . . | 10 |
| 2 | Four Stages of Pressure Treatment . . . . . | 10 |
| 3 | Fracture Face Permeability Measurement Sample Assembly. . . | 11 |
| 4 | Fracture Conductivity Measurement Sample Assembly . . . . . | 11 |
| 5 | Fracture Conductivity Variation: Organic Lean . . . . . | 17 |
| 6 | Fracture Conductivity Variation: Organic Rich . . . . . | 18 |

LIST OF TABLES


| Table | Title | Page |
|---|---|---|
| I | Tested Sample Interval and Simulated In-Situ Conditions . . | 5 |
| II | Physical Properties . . . . . | 6 |
| III | Dynamic Elastic Properties. . . . . | 7 |
| IV | Static Elastic Properties . . . . . | 9 |
| V | Fracturing Fluids Considered for Stimulation. . . . . | 9 |
| VI | Fracturing Fluid/Rock Interaction (Matrix Permeability) . . | 14 |
| VII | Fracture Conductivity/Fracturing Fluid Interaction (Multilayer Fracture Width) . . . . . | 15 |
| VIII | Fracture Conductivity/Fracturing Fluid Interaction (Monolayer Fracture Width). . . . . | 15 |

# 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 (Knox County, Ohio). The samples tested were from organic rich zones, organic lean zones 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 Knox County, Ohio well show that an organic lean zone has a gradual transition with depth to an organic rich zone and that two layers (assumed barriers) bound each pay 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 pay zones.

The porosity in the formations of interest, including the upper barrier, the lower barrier, and the organic zones, 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 zone 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 zone 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 organic lean and organic rich pay zones. 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 organic lean and organic rich samples. For monolayer fracture conductivities (edge of a fracture in the field job) Dow I caused least damage to the organic lean zone. With the exception of

Dow III all other fluids showed good results in the monolayer tests for organic rich pay zones. In the situation where both the lean and the rich pay zones 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 organic rich pay zone, the organic lean pay zone and two bounding formations around each organic zone. 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 ($\rho_D$). Grain density ($\rho_g$) 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 zones 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 zones and bounding formations) the Young's Moduli consistently increased with depth, from about $6 \times 10^6$ to $8 \times 10^6$ 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: Knox County, Ohio

| 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 |
| Organic Lean Zone | 4 | 901-901.4 | 900 | 430 | 630 | 86 |
| | 5 | 937-937.4 | 940 | 450 | 660 | 87 |
| | 6 | 967-971.5 | 970 | 465 | 680 | 87 |
| Organic Rich Zone | 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: Knox County, Ohio

| 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 | 8.0 |
| | 637 | 2.537 | 2.472 | 2.708 | 8.7 | |
| | 840 | 2.571 | 2.500 | 2.701 | 7.4 | |
| Organic Lean Zone | 901 | 2.566 | 2.504 | 2.768 | 9.6 | 8.3 |
| | 971 | 2.657 | 2.588 | 2.782 | 7.0 | |
| Organic Rich Zone | 1052 | 2.463 | 2.421 | 2.697 | 10.3 | 8.5 |
| | 1105 | 2.465 | 2.423 | 2.597 | 6.7 | |
| Lower Barrier | 1164 | 2.651 | 2.586 | 2.838 | 8.9 | 8.5 |
| | 1204 | 2.668 | 2.602 | 2.834 | 8.2 | |
| | 1204 | 2.721 | 2.647 | 2.890 | 8.4 | |

*Calculated

Table III

Dynamic Elastic Properties

METC: Knox County, Ohio

| Formation | Sample Depth (ft) | Moduli ($x10^6$ 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 |
| Organic Lean Zone | 901 | 6.33 | 3.76 | 2.60 | 7.22 | 0.22 |
| | 967 | 6.73 | 3.82 | 2.79 | 7.54 | 0.21 |
| Organic Rich Zone | 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: Knox County, Ohio

| Formation | Sample Depth (ft) | Modulus ($10^6$ psi) | Poisson's Ratio | Maximum Compressive Strength (x $10^3$ psi) |
|---|---|---|---|---|
| Upper Barrier | 840 | 3.2 | 0.26 | 8.8 |
| | 840 | 3.2 | 0.18 | 8.3 |
| Organic Lean Zone | 901 | 3.3 | 0.24 | 8.9 |
| | 967 | 3.0 | 0.16 | 8.5 |
| Organic Rich Zone | 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: Knox County, Ohio

| 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 |

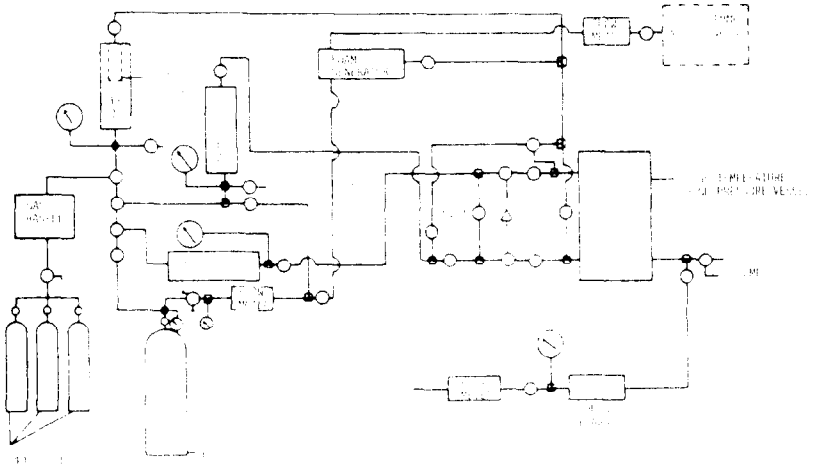

Figure 1. Schematic of the Laboratory System

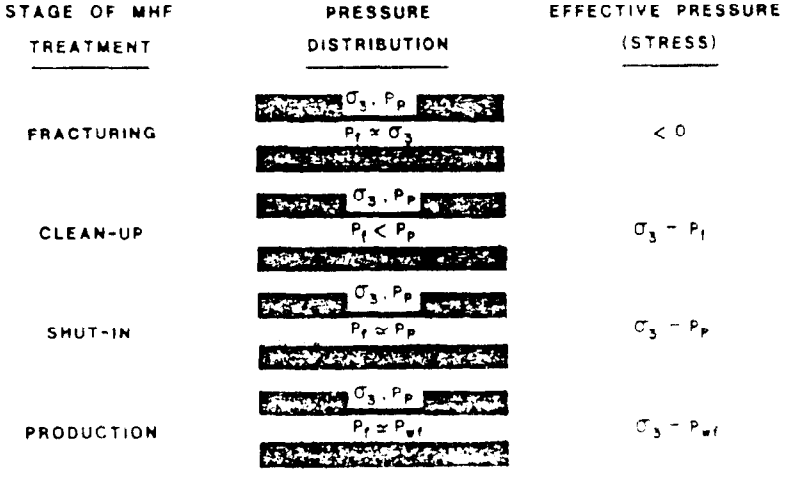


Figure 2. Pressures During Four Stages of Simulation

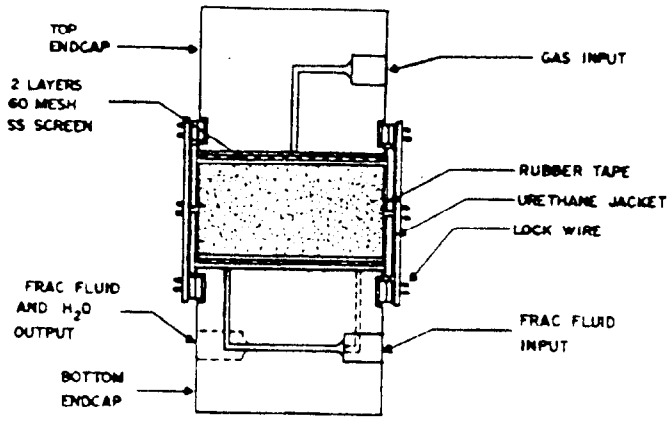


Figure 3. Fracture Face Permeability Measurement Sample Assembly

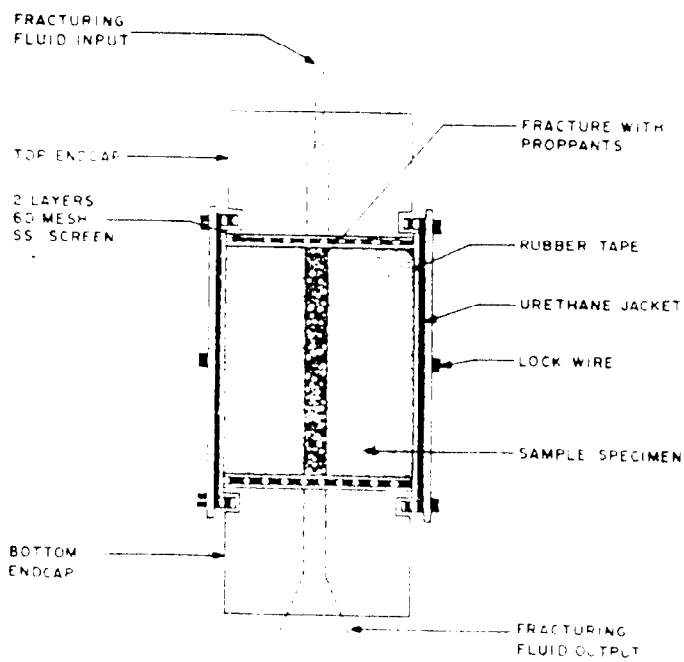


Figure 4. Fracture Conductivity Measurement Sample Assembly

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 $lb/ft^2$). 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 organic lean zone, the damaged permeabilities of all the organic pay zone samples were of the order of tenths of microdarcies. The Dow I fracturing fluid across the organic lean pay zone 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 organic lean and organic rich pay zone.

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 organic lean and organic rich samples. There was little change in fracture width between damage

Table VI

Fracturing Fluid/Rock Interaction
(Matrix Permeability)

METC: Knox County, Ohio

| 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 $(K_i-K_f)/K_i$ |
|---|---|---|---|---|---|---|
| Organic Lean Zone | 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 |
| Organic Rich Zone | 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

Fracture Conductivity/Fracturing Fluid Interaction
(Multilayer Fracture Width)

METC: Knox County, Ohio

| Formation | Fracturing Fluid | Fracture Conductivity (md-ft), Fracture Width (in.) | | | |
|---|---|---|---|---|---|
| | | Ambient Condition | In-Situ Condition | Following Damage | Final Clean-up |
| Organic Lean Zone | 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 |
| Organic Rich Zone | 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

Fracture Conductivity/Fracturing Fluid Interaction
(Monolayer Fracture Width)

METC: Knox County, Ohio

| Formation | Fracturing Fluid | Fracture Conductivity (md-ft), Fracture Width (in.) | | | |
|---|---|---|---|---|---|
| | | Ambient Condition | In-Situ Condition | Following Damage | Final Clean-up |
| Organic Lean Zone | Dow I | 682, .0116 | 676, .0112 | 231, .0112 | 653, .0112 |
| | Dow III | 464, .0114 | 413, .0114 | 23, .0112 | 420, .0112 |
| Organic Rich Zone | 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 |

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 organic lean and rich 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 $B^1$, $C^1$, $D^1$ and $E^1$. 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 organic lean zones; and Dow I, Dow II and Hal I all caused less fracture conductivity damage to the organic rich samples than Dow III.

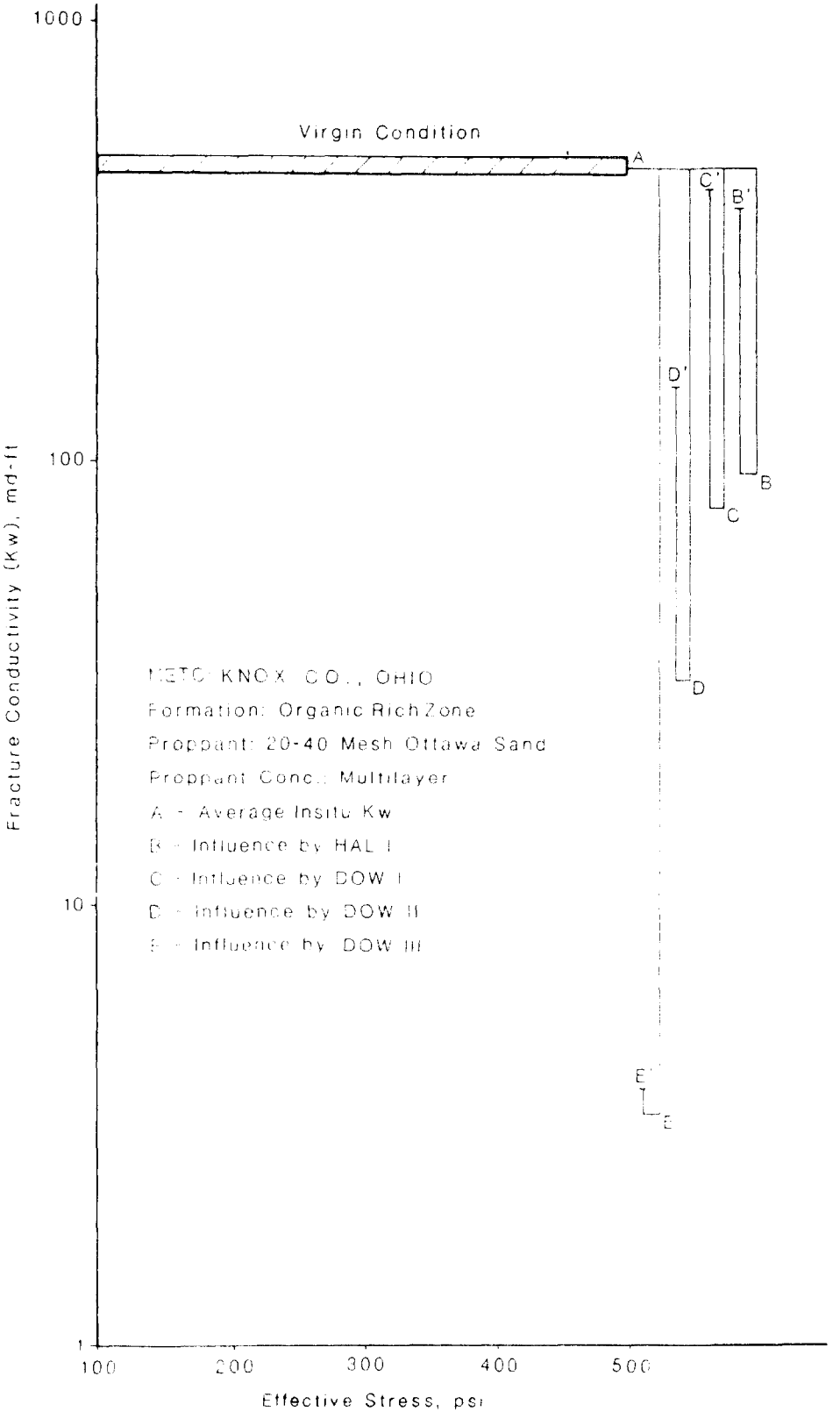


Figure 5. Fracture Conductivity Variation: Organic Lean Zone

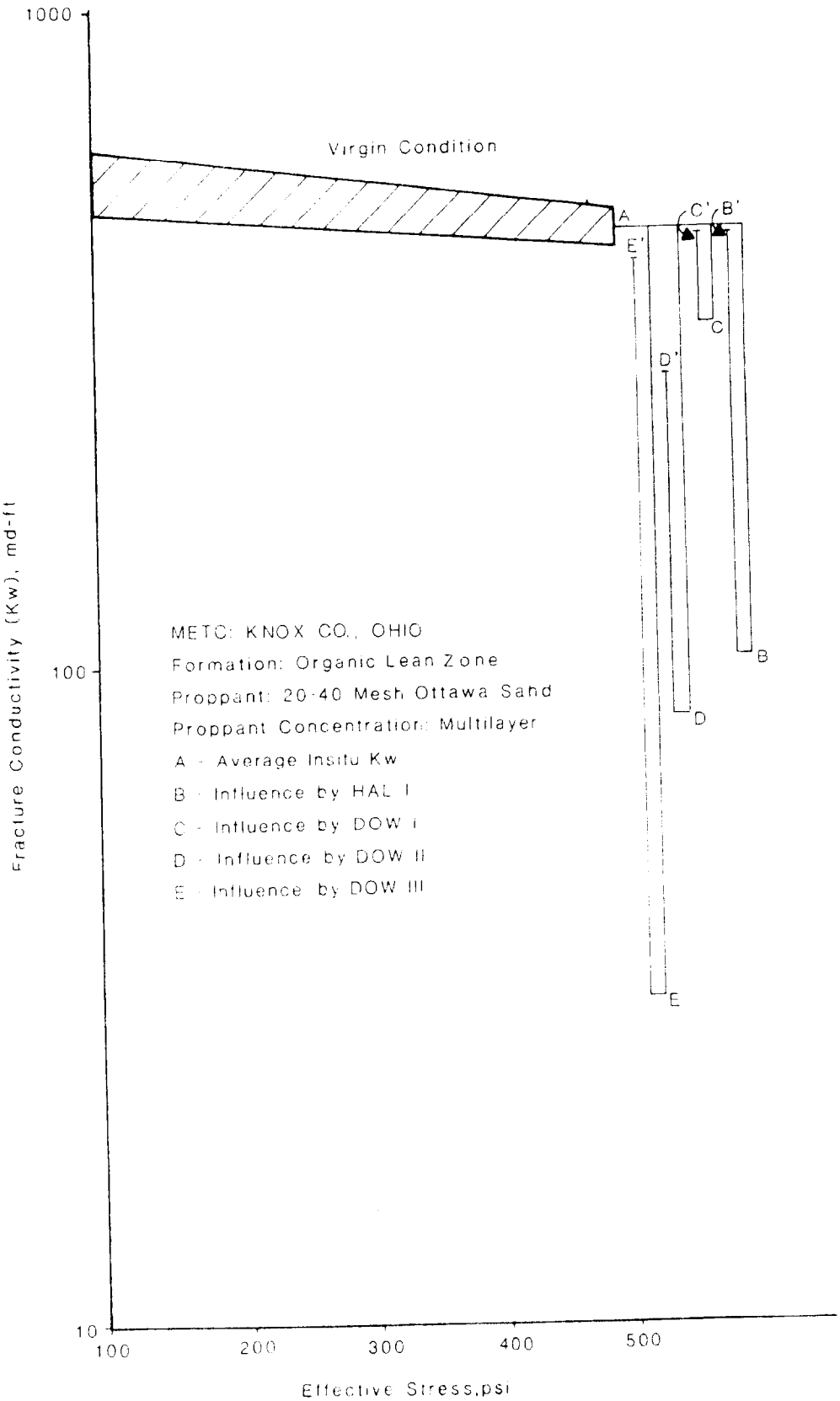


Figure 6. Fracture Conductivity Variation: Organic Rich Zone

## REFERENCES


1. Simonson, E.R., Abou-Sayed, A.S., and Clifton, R.J., "Containment of Massive Hydraulic Fractures, "Society of Petroleum Engineers Journal, (February, 1978), Vol. 18, No. 1, pp. 27-32.

2. Ahmed, U., Abou-Sayed, A.S., and Jones, A.H., "Experimental Evaluation of Fracturing Fluid Interaction with Tight Reservoir Rocks and Propped Fractures," SPE paper 7922, proceedings of the 1979 SPE Symposium on Low Permeability Gas Reservoirs, Denver, Colorado, May 20-22, 1979, pp. 109-126.

3. Brechtel, C.E., Abou-Sayed, A.S., and Jones, A.H., "An Evaluation of Fracture Containment within the Castlegate Sand," Terra Tek Report TR 77-24, (March, 1977).

4. Brechtel, C.E., Abou-Sayed, A.S., and Jones A.H., "Fracturing Containment Analysis Conducted onthe Benson Pay Zone in Columbia Well 20538-T," Second Eastern Gas Shales Symposium, Vol. 1, U.S. Department of Energy (METC), Morgantown, WV, (October, 1978), pp. 264-272.

5. Abou-Sayed, A.S. Brechtel, C.B., and Clifton, R.J., In-Situ Stress Determination by Hydrofracturing - A Fracture Mechanics Approach," Journal of Geophysical Research, Vol. 83, No. B6 (June, 1978).

6. Brace, W.F., Walsh, J.B., and Frangos, W.T., "Permeability of Granite Under High Pressure," Journal of Geophysical Research, (1968), Vol. 69, pp. 259-273.

7. Yamada, S.E., and Jones, A.H., "Analysis of Pulse Technique for Permeability Measurement," Terra Tek Report, TR 79-8 (January, 1979), in preparation for publication.

8. Holditch, S.A., "Factors Affecting Water Blocking and Gas Flow from Hydraulically Fractured Gas Wells," SPE paper 7561 presented at SPE 53rd Annual Fall Meeting, Houston, Texas (October 1-3, 1978).

ACKNOWLEDGEMENTS

This work was done by Terra Tek, Inc. for Morgantown Energy Technology Center (METC) under a United States Department of Energy Contract No. DE-AC08-79NV1066.

The authors appreciate the close cooperation of C. A. Komar and Karl Frohne of METC, the Dowell and Haliburton companies, and D. Enniss and R. Winzenried of Terra Tek for their significant efforts in the laboratory testing phase of this work.