166
2-31-82
(10)

I-2244

①

Sh. 378

WESTERN GAS SANDS PROJECT STATUS REPORT

DOE/BC/10003-25
July—August—September 1981

FY81/4

DO NOT MICROFILM
COVER

MASTER

DISSEMINATION OF THIS DOCUMENT IS UNLIMITED

U.S. DEPARTMENT OF ENERGY
BARTLESVILLE ENERGY TECHNOLOGY CENTER

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

DISCLAIMER

"This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

Available from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161.

NTIS price codes

Paper copy: \$15.50

Microfiche copy: \$3.50

**WESTERN GAS SANDS PROJECT
STATUS REPORT**

For July-August-September 1981

DOE/BC/10003--25

DE82 009490

Compiled by

**CER Corporation
Las Vegas, Nevada**

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

**Alex Crawley, *Project Manager*
Bartlesville Energy Technology Center
P.O. Box 1398
Bartlesville, OK 74005**

**C. H. Atkinson, *Technical Project Officer*
Nevada Operations Office
P.O. Box 14100
Las Vegas, Nevada 89114**

NOTICE

**PORTIONS OF THIS REPORT ARE ILLEGIBLE.
It has been reproduced from the best
available copy to permit the broadest
possible availability.**

**Work Performed for the Department of Energy
Under Contract No. DE-AC08-79BC10003**

Date Published--March 1981

Published by

Bartlesville Energy Technology Center

UNITED STATES DEPARTMENT OF ENERGY

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

Contents

SUMMARY	1

SECTION 1

PROJECT MANAGEMENT	3
Technology Transfer	3

SECTION 2

RESOURCE ASSESSMENT	7
U.S. Geological Survey Activities	7
Survey of Basin Activities	7
Coring and Logging Program	15
C K GeoEnergy Corporation	24
Reservoir Simulation Model Development — CER Corporation	24
Gas Research Institute Sponsored Projects	51

SECTION 3

RESEARCH & DEVELOPMENT BY ENERGY TECHNOLOGY CENTERS & NATIONAL LABORATORIES	53
Bartlesville Energy Technology Center	53
Lawrence Livermore National Laboratory	79
Los Alamos National Laboratory	98
Sandia National Laboratories	102

SECTION 4

FIELD TESTS & DEMONSTRATIONS	123
Background	123
Colorado Interstate Gas Company	126
DOE Well Test Facility	128
Multi-Well Experiment	130
Sandia National Laboratories — WGSP Stimulation Research	141

Figures

Figure 2-1	Greater Green River Basin Showing Wells of Interest	10
Figure 2-2	Piceance Basin Showing Wells of Interest	13
Figure 2-3	Uinta Basin Showing Wells of Interest	16
Figure 2-4	Plot of SXOPHI Model for Northwest Exploration Langstaff No. 1 Well, Garfield County, Colorado	20
Figure 2-5	Example of Output from SXOPHI Computer Log Analysis Model, Wexpro Mesa Unit No. 1 Well, Sublette County, Wyoming	21
Figure 2-6a	Linear Relation of Water Saturation Far from Borehole	23
Figure 2-6b	Linear Relation of Water Saturation Adjacent to Borehole	23
Figure 2-7	Run I-1; Areal View of $10\mu\text{d}$ Rectangular Reservoir with a 1,500-ft Fracture along the Major Axis	26
Figure 2-8	Run I-2; Areal View of a $10\mu\text{d}$ Circular Reservoir with a 1,500-ft Fracture	27
Figure 2-9	Run I-1; Bottom-hole Pressure vs. Time for a $10\mu\text{d}$ Rectangular Reservoir having a 1,500-ft Fracture along the Major Axis	28
Figure 2-10	Run I-2; Bottom-hole Pressure vs. Time for a $10\mu\text{d}$ Circular Reservoir having a 1,500-ft Fracture	29
Figure 2-11	Composite Real Gas Potential Plots for Run I-1 Rectangular Fractured Reservoir and Run I-2 Circular Fractured Reservoir	31

Figures Continued

Figure 2-12	Run I-3; Areal View of a $10\mu\text{d}$ Rectangular Reservoir with a 200-ft Fracture along the Mean and Intersecting a Boundary	32
Figure 2-13	Run I-4; Areal View of a $10\mu\text{d}$ Rectangular Reservoir with a 200-ft Fracture along the Major Axis	33
Figure 2-14	Run I-5; Areal View of a $10\mu\text{d}$ Circular Reservoir with a 200-ft Fracture	34
Figure 2-15	Run I-3; Bottom-hole Pressure vs. Time for a $10\mu\text{d}$ Rectangular Reservoir having a 200-ft Fracture along the Minor Axis	35
Figure 2-16	Run I-1; Bottom-hole Pressure vs. Time for a $10\mu\text{d}$ Rectangular Reservoir having a 200-ft Fracture along the Major Axis	36
Figure 2-17	Run I-5; Bottom-hole Pressure vs. Time for a $10\mu\text{d}$ Circular Reservoir having a 200-ft Fracture	37
Figure 2-18	Run II-1; Areal View of a $50\mu\text{d}$ Rectangular Reservoir with a 1,500-ft Fracture	39
Figure 2-19	Run II-2; Areal View of a $50\mu\text{d}$ Circular Reservoir with a 1,500-ft Fracture	40
Figure 2-20	Run II-1; Bottom-hole Pressure vs. Time for a $50\mu\text{d}$ Rectangular Reservoir having a 1,500-ft Fracture along the Major Axis	41
Figure 2-21	Run II-2; Bottom-hole Pressure vs. Time for a $50\mu\text{d}$ Circular Reservoir having a 1,500-ft Fracture	42
Figure 2-22	Composite of Real Gas Potential Plots for Run II-1 Rectangular Fractured Reservoir and Run II-2 Circular Fractured Reservoir	44

Figures Continued

Figure 2-23	Run II-3; Areal View of a 50 μ d Rectangular Reservoir with a 200-ft Fracture along the Major Axis	45
Figure 2-24	Run II-3; Bottom-hole Pressure vs. Time for a 50 μ d Rectangular Reservoir having a 1,500-ft Fracture along the Minor Axis	46
Figure 2-25	Run II-4; Areal View of a 50 μ d Rectangular Reservoir with a 200-ft Fracture along the Major Axis	47
Figure 2-26	Run II-4; Bottom-hole Pressure vs. Time for a 50 μ d Rectangular Reservoir having a 200-ft Fracture along the Major Axis	48
Figure 2-27	Run II-5; Areal View of a 50 μ d Circular Reservoir with a 200-ft Fracture	49
Figure 2-28	Run II-5; Bottom-hole Pressure vs. Time for a 50 μ d Circular Reservoir having a 200-ft Fracture	50
Figure 3-1	Relative Flow Rates Through Capillaries having Elliptical and Rectangular Cross Sections of Equal Areas	56
Figure 3-2	Simulated Permeability as a Function of Overburden Pressure: Effects of Standard Deviation and Fraction of Channels That are Cracks	58
Figure 3-3	Simulated Permeability as a Function of Overburden Pressure	58
Figure 3-4	Simulated Permeability as a Function of Overburden Pressure	59
Figure 3-5	Effect of Temperature on Gas Permeability	61
Figure 3-6	Laboratory Measurements	66

Figures Continued

Figure 3-7	Experimental Results	66
Figure 3-8	Experimental Results	67
Figure 3-9	Experimental Results	67
Figure 3-10	Experimental Results	68
Figure 3-11	Experimental Results	68
Figure 3-12	Calculated vs. Experimental Settling Velocities for Hydroxypropyl Guar	69
Figure 3-13a	Modeled Proppant Distribution — 10, 20 and 50 Minutes after Start of Pumping Cycle	70
Figure 3-13b	Modeled Proppant Distribution — 5 and 10 Minutes after Pump Shut-In	71
Figure 3-14	Pressing Compaction Curves for Alumina Collector Fines and A-16 Superground Alumina	74
Figure 3-15	Variation of Non-Darcy Factor along Fracture with Flow Rate as Parameter	77
Figure 3-16	Variation of Non-Darcy Factor along Fracture with β as Parameter	77
Figure 3-17	Non-Darcy Flow and Klinkenberg Effects on Bottom-Hole Pressure	78
Figure 3-18	Non-Darcy Flow and Klinkenberg Effects on Bottom-Hole Pressure	79
Figure 3-19	Geometry of Fracture Partially Filled with Fluid for $-x_0 < x < x_0$, with Fluid Pressure $p(x)$	80
Figure 3-20	Pressure-Stress Distributions as a Function of Scaled Fracture Length	81

Figures Continued

Figure 3-21	Scaled Fracture Displacement as a Function of Scaled Fracture Length for the Pressure-Stress Distributions shown in Figure 3-20	82
Figure 3-22	Pressure-Stress Distributions for $p(x) = p_0 = \text{Constant}$ and for Several Values of σ_m^0/p_0 ; $P(x)$ was Varied with σ_m^0 to Maintain p_0 Constant	84
Figure 3-23	Wetted Fracture Length x_0/c as a Function of σ_m^0/p_0 for $p_0 = \text{Constant}$ and with the Pressure Distribution shown in Figure 3-22	84
Figure 3-24	Scaled Fracture Displacement as a Function of Scaled Fracture Length for the Pressure Distributions shown in Figure 3-22	85
Figure 3-25	Maximum Scaled Fracture Aperture for Increasing (σ_m^0/p_0) with p_0 Constant	85
Figure 3-26	Irregular Star Near a Curved Boundary	86
Figure 3-27	Isotherms, the Vertical Solid and Dotted lines, in a Grid which Becomes More Irregular as It Moves Away from the Boundary where $f = 1$ for Early Times	88
Figure 3-28	Isotherms, the Vertical Solid and Dotted lines, in a Grid which Becomes More Irregular as It Moves Away from the Boundary where $f = 1$ for Late Times	88
Figure 3-29	Fluid Flow Experiment	89
Figure 3-30	Failure Envelope of Mesaverde Sandstone from Wyoming, 3,510 m Depth, Loaded Parallel to Bedding	90

Figures Continued

Figure 3-31	Compressive Strength of Mesaverde Shale from Wyoming, 3,510 m Depth, Under 1-D Strain Loading Normal to Bedding	91
Figure 3-32	Compressive Strength of Mesaverde Sandstone from Wyoming, 3,510 m Depth, Under 1-D Strain Loading Normal to Bedding	91
Figure 3-33	P-V Behavior of Mesaverde Shale from Wyoming, 3,510 m Depth, Specimen Axis Parallel to Bedding	92
Figure 3-34	P-V Behavior of Mesaverde Shale from Wyoming, 3,510 m Depth, Specimen Axis Normal to Bedding	92
Figure 3-35	P-V Behavior of Mesaverde Sandstone from Wyoming, 3,510 m Depth, Specimen Axis Normal to Bedding	93
Figure 3-36	Stress Effect on Travel Time for a Radially Polarized Shear Wave	95
Figure 3-37	Stress Effect on Travel Time for a Tangentially Polarized Shear Wave	95
Figure 3-38	Transducer/Wedge Assemblage	96
Figure 3-39	Closup Transducer/Wedge Assemblage	96
Figure 3-40	Radial Shear Mode	97
Figure 3-41	Tangential Mode	97
Figure 3-42	First NMR Signal from a Water Saturated Western Gas Sands Core in the Double Helmholtz Coil Spectrometer Operating at 0.5 MHz	99

Figures Continued

Figure 3-43	Radial Normalized Magnetic Field Deviations at Opposite Azimuth Angles with Magnets Aligned	100
Figure 3-44	Radial Normalized Magnetic Field Deviations at 0° (a) and 180° (b) to Tilt Direction with Magnets Misaligned 2°	101
Figure 3-45	Revised 0.5 MHz Sine Wave Reference Signal Phase Shifter Covering Over 360° , for Use With Present Laboratory NMR System	103
Figure 3-46	Wakefield Test Site Configuration — Columbia Gas	106
Figure 3-47	Wakefield Pressure/Flow Profile — Columbia Gas	107
Figure 3-48	Data Files RAD1L1 and RAD2L1 Percentage Change from Mean Radial A12 — Columbia Gas	108
Figure 3-49	Columbia Gas	109
Figure 3-50	Schematic Showing Multiple Raypaths Linking the Same Shot Receiver Pair	112
Figure 3-51a	Intersection Depth vs. Angle	113
Figure 3-51b	Total Travel Time vs. Angle	113
Figure 3-52	Behavior of the Computed Effective Medium Permeability K_m for the Three-Element, $Z = 3$ Network as a Function of the Concentration of the High Permeability K_1 Element	116
Figure 3-53	Behavior of the Computed Effective Medium Permeability K_m for the Three-Element, $Z = 6$ Network as a Function of the High Permeability K_1 Element	117

Figures Continued

Figure 3-54	Topography Surrounding the MWX Site	118
Figure 3-55	Predicted Vertical Changes in Horizontal Stress for the 2-D Topography Shown in Figure 3-54	119
Figure 3-56	Depth Dependence of Principal Horizontal Stresses Predicted by the 3-D Calculation	120
Figure 3-57	Orientation of the Maximum Horizontal Principal Stress	121
Figure 4-1	MWX-1 Site, As Built	131
Figure 4-2	Plot of SXOPHI Model for Northwest Exploration Langstaff No. 1 Well, Garfield County, Colorado	133
Figure 4-3	Example of the Uppermost Fluvial Section Mapped at Rifle Gap	134
Figure 4-4	Example of the Composite Sandstone of a Meander Belt Seen in the Lower Part of the Fluvial Section Mapped at Rifle Gap	134
Figure 4-5	Seismic Shooting/Receiving Scheme Near MWX Site	135
Figure 4-6	Bottom-Hole Pressure Response for a Production Wellbore and a Remote Observation Well 160 ft Away, From a Drawdown of 9 MCFD in a 20-ft Thick, 3 μ d Reservoir	137
Figure 4-7	Bottom-Hole Pressure Response for a Production Wellbore and a Remote Observation Well 160 ft Away, From a Drawdown of 30 MCFD in a 20-ft Thick, 10 μ d Reservoir	138

Figures Continued

Figure 4-8	Bottom-Hole Pressure Response for a Production Wellbore and a Remote Observation Well 160 ft Away, From a Drawdown of 90 MCFD in a 20-ft Thick, 30 μ d Reservoir	139
Figure 4-9	Side View of Instrumentation Corehole Locations	142
Figure 4-10	Pressure Data in the Fracture	143
Figure 4-11	Width Data in the Fracture	144
Figure 4-12	Flow Rate and Injection Pressure	145
Figure 4-13	Plan View of First Perforation Experiment	146
Figure 4-14	Sample Pressure Records for First Perforation Experiment	147
Figure 4-15	Photograph of Perforation, Resultant Fracture and High Stress Halo	149
Figure 4-16	Plan View of Second Perforation Experiment	150
Figure 4-17	Pressure Records — 92 ft	151
Figure 4-18	Pressure Records — 82 ft	152
Figure 4-19	Pressure Records — 72 ft	153
Figure 4-20	Pressure Records — 62 ft	154
Figure 4-21	Pressure Records — 52 ft	155
Figure 4-22	Pressure Records — 42 ft	156
Figure 4-23	Pressure Records — 32 ft	157
Figure 4-24	Pressure Records — 22 ft	158

Figures Continued

Figure 4-25	ISIP Comparison	160
Figure 4-26	Fracturing Pressure as a Function of Charge and Number of Perforations	160
Figure 4-27	In Situ Stress Data from Open-Hole Fracturing	161

Tables

Table 2-1	Summary of Wells — Greater Green River Basin	9
Table 2-2	Summary of Drilling Activities — Greater Green River Basin	11
Table 2-3	Summary of Wells — Piceance Basin	12
Table 2-4	Summary of Drilling Activities — Piceance Basin	14
Table 2-5	Summary of Wells — Uinta Basin	15
Table 2-6	Summary of Drilling Activities — Uinta Basin	17
Table 2-7	Case Study I: 10 μ d Reservoir	30
Table 2-8	Case Study II: 50 μ d Reservoir	38
Table 3-1	Calculated Values	62
Table 3-2	Calculated Results	63
Table 3-3	Experimental Results for Sample W9177.2	64
Table 3-4	Chemical Analysis of Alumina Collector Fines	74
Table 3-5	Scaled Fluid Penetration Depth for the Scaled Pressure Distribution Shown and for $p_o/\sigma_m^o = 1$	82
Table 3-6	Summary of Anelastic Strain Recovery Data from Bossier Sandstone, Oakhill Field, Texas	111
Table 3-7	Dielectric Permittivity and Loss Tangent of Berea Sandstone Samples at 106.5 MHz	117

Tables Continued

Table 4-1	MHF Contract Location and Frac Data	124
Table 4-2	Ashfall Tuff Properties	145
Table 4-3	Perforations in PERF-3, Gearhart Industries Inc. Perforating Charges	150
Table 4-4	Data from Open Hole Minifrac	159
Table 4-5	Data from Perforation Minifrac	159

Summary

The progress during July, August and September, 1981, of government-sponsored projects which are directed toward increasing gas production from low permeability gas sands of the Western United States, is summarized in this edition of the WGSP Quarterly Status Report.

During the quarter, CK GeoEnergy completed the field work in the Rifle Gap area near Rifle, Colorado, as well as the Draft Phase VI report covering the prognosis about reservoir geometry in the Multi-Well site area. At CER, a number of case studies have been selected and modeled using the DOE/CER reservoir simulator to enhance the understanding of the effects of various reservoir and fracture parameters on well testing in low permeability gas reservoirs.

The improved pressure coring system project, tested by Sandia National Laboratories and sponsored by Bartlesville Energy Technology Center, officially terminated Sept. 30. Accomplishments included increased capabilities for the pressure core barrel, improvements in the low invasion fluid plus various laboratory core intrusion studies and improved designs for PDC drill bits. At Lawrence Livermore National Laboratory, the P²L² system described last quarter was evaluated further and the decision has been made to abandon further investigation. The Los Alamos National Laboratory Ceramics Materials Group is preparing to fabricate a ceramic sample with cylindrical pores of specified diameters. The NMR data on this type sample will contribute to a better understanding of the parameters affecting NMR relaxation rates in porous media.

During the quarter, modifications were made in the operating and application software of the DOE Well Test Facility, which will support additions to the PDP-11/10 computer system. The Multi-Well Experiment well was spudded on Sept. 13 and by Sept. 30, total depth was 3,358 ft. Coring operations are expected to begin at a depth of 4,150 ft. At the Nevada Test Site, Sandia National Laboratories completed four additional coreholes for the Fluid Mechanics/Proppant Transport Experiments.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

Section 1

Project Management

TECHNOLOGY TRANSFER

DOCUMENTATIONS AND REPORTS

The "Interim Economic Analysis of Natural Gas Production from Tight Formations in Selected Western Basins," Report No. DOE/BC/10003-23, was published during the quarter. This document uses production data from more than 900 hydraulically fractured wells in the tight gas sand basins of the western United States and applies an economic analysis methodology to determine the life-cycle economics of gas production from these wells. Where possible, inferences were made as to the effects of individual technological parameters, such as frac fluid volume, fluid type and geological parameters (e.g. formation depth, permeability) on well performance and production economics. The analysis focuses on the Wattenberg Field of Colorado and on the Washakie Basin of Wyoming. An improved method of decline curve analysis is derived and utilized.

PROJECT DATA BANK

The "WGSP Abstracts Information System," Report No. DOE/BC/10003-22, May, 1981, was published this quarter. This document contains abstracts of 713 technical reports and articles that are relevant to western tight gas sand activities. Technological, geographical, geological, environmental and economic topics are included. Approximately 30 percent of the papers abstracted were published by oil- and gas-oriented professional and technical journals, approximately 20

percent by geological associations and societies and the remainder by federal and state governments, WGSP contractors and other contractors. A keyword indexing system for facilitating search within the information system is also included.

ARTICLES AND PUBLICATIONS

The following is a discussion from an article of interest to the WGSP and is included in the bibliography.

*Depositional Environments and
Diagenesis of Some Non-marine
Upper Cretaceous Reservoir Rocks,
Uinta Basin, Utah*

by C. W. Keighin and T. D. Fouch
USGS

The purpose of this paper is twofold: to present new data on the sedimentology and mineralogy of the non-marine part of the Mesaverde Group in the Southman Canyon gas field in the Natural Buttes area of Utah, and to present our analysis of the data. We hope this will facilitate development of sedimentologic and diagenetic models that may prove useful in the exploration for hydrocarbons in continental rocks.

Discussion

We believe the cored rocks were deposited in fluvial channels, but limited information precludes our determining the geometry and size of the subaerial streams. If comparison to exposures along the Book Cliffs is reasonable, individual channels in the Tuscher-Farrer interval that were cored were probably no more than a few tens of meters wide, and those of the Neslen were less.

Although the basic physical and chemical characteristics of the rocks are established by the lithologic charac-

teristics related to their depositional history, these conditions may be subsequently modified, often dramatically, by diagenetic processes.

As would be expected in fine-grained sandstones, most of the observed pores are small, usually less than 60 μm . Many pores formed by leaching (thus forming secondary pores) are on the order of 0.1 - 10.0 μm . The smaller pores are very sensitive to modifications by subsequent diagenetic effects (e.g., linings, coating or bridging by authigenic clays), and pore throats may be easily plugged by movement of clay-size fines

Measured porosities for sandstones from the Shell Southman Canyon Unit No. 7 well range between about 3 and 13 percent. These values agree with the ranges determined by other investigators for stratigraphically similar sandstones in other parts of the Uinta Basin (U.S. Department of Energy, 1979, p. 27; 1980a, p. 23, 1980b, p. 21; Keighin and Sampath, 1980, Table 1). According to Beard and Weyl (1973), sediments with these characteristics have an initial porosity on the order of 35 percent and permeabilities of about 2 to 7 darcies. Although determination of modal (thin section) porosity is now commonly and easily done using thin sections impregnated with blue-dyed epoxy (Gardner, 1980), the modal values rarely agree with porosities measured in the laboratory. The reasons for lack of agreement are not clear, but it is common for modal porosities to be higher than measured porosities, often significantly. It is apparent that porosity may change dramatically over short vertical distances due to the variation in grain size, the degree of cementation and the presence of silt or clay laminae.

Several investigators (McLatchie and others, 1959; Vairogs and others, 1971; Thomas and Ward, 1972; Jones and Owens, 1979; Keighin and Sampath, 1980) showed that porosity decreases

only slightly (usually less than 5 percent) as confining stress is increased to approximate that of reservoir conditions. Permeability in low-permeability sandstones is, however, drastically reduced by increases in confining pressure. The permeabilities measured at surface conditions for the low-permeability sandstones in the Uinta Basin are commonly in the range of 0.02 to 1.0 md; these values decrease by as much as 80 percent when subjected to confining pressures of 34.5 MPa (5,000 psi). It appears that pore volume is not changed significantly, but pore throats, already small because of the nature of the detritus forming the rocks and because of subsequent diagenetic reactions, are reduced even further in size.

Another factor which probably reduces communication between pores is the presence of convoluted bedding. Whether due to bioturbation or to soft-deformation, induced irregularities in bedding surfaces, if extensive, further complicate reservoir drainage. Because of the limited availability of core material, we do not know the extent or continuity of these disturbed beds, but it seems reasonable that they are common in other fine-grained, channel-formed sedimentary deposits and should be considered when evaluating such rocks.

There is growing recognition that fine-grained authigenic minerals, which line pores and coat grains, thus altering pore geometry, may modify the response of resistivity logs and affect calculated water saturation and the interpretation of sonic and neutron logs (Almon, 1978). Investigations by Texas A&M (U.S. Department of Energy, 1980a, p. 23) show that carbonate cement also influences porosities calculated from sonic and/or density logs. If a standard sandstone matrix density (2.65 gm cc^{-1}) is used for porosity calculations from density logs in a highly carbonate-cemented zone, porosity will be underestimated. Conversely, if a higher (e.g.,

2.68 g, cc⁻¹) matrix density is used in the calculations, porosities will be overestimated in zones with little carbonate cement. The importance of knowing the mineralogic characteristics of the rocks seems obvious.

Apparent in all cores is the relation between borehole geophysical log response and lithology. In at least three of the four cores (no logs were available for the deepest core), the highest energy crossbedding seems to correspond with low-gamma ray and good SP. This is to be expected, and these logs could probably be used to delineate channel sandstones. However, these same higher energy sandstones also seem to be zones of the highest amounts of carbonate cement, which is displayed as zones of high resistivity. One normally expects the highest values of resistivity to occur in the lowest energy sandstones where clay minerals and carbonate cements are more common. These relations of the core to the logs may suggest that many higher energy beds (possibly with better initial porosity and permeability) are preferentially cemented by carbonate minerals and therefore are not good reservoirs. It is also probable, although the evidence is sparse, that these higher energy sandstones are preferentially fractured. To the extent that carbonate cements are found in higher energy beds, diagenesis may be related to sedimentologic setting. If this is true, then the higher energy beds, normally considered to be preferential exploration targets, may be poor choices, at least locally. If natural open fractures are present in the carbonate-cemented (and more brittle) sandstones, these fractures may enhance permeability by allowing communication between available pores.

Coal and carbonaceous claystone beds are abundant in some stratigraphic units, but they are absent in thick sequences of the Mesaverde Group in

the study area. However, even in the absence of coal and carbonaceous claystones, herbaceous organic matter exists in great quantities along laminae of many sandstones in core over most of the non-marine part of the Mesaverde Group. This organic matter is particularly abundant in convoluted sandstone and siltstone beds. We suggest that the herbaceous organic matter in the sandstone and siltstone units is a principal source of the gas recovered from these rocks.

Unfortunately, cores were not taken in producing intervals of the Southman Canyon well. However, sandstones of the Neslen that bound the cored intervals are productive. We, therefore, suggest that productive sandstone reservoir rocks are similar to those sandstone cores that we examined.

Field Study of Tight Gas Sands Reservoir Directional Characteristics

by C. F. Knutson, W. N. Hackenbracht
and L. T. Hodges
C K GeoEnergy Corporation

Three shallow wells were drilled, cored and logged to provide additional information on the seismic picture of the GC-1 area developed by Dr. Dobecki of Sandia (Dobecki, 1980).

The wells were drilled and cored without any appreciable problems. The orientation equipment used during the coring failed to provide data on a number of occasions, but fortunately none of these lapses were in the target areas identified by Dobecki.

The information from the various sources were in general agreement for some lenses, but the general scatter of results was somewhat disappointing.

	Outcrop	Oriented Core	Logs	Seismic
GC-1A-A Lens	146°	146°	30°-195°	45°-135°
GC-1B-B Lens	133°	169°	153°-169°	30°-90°
GC-1C-C Lens	144°	36°	164°-166°	30°-90°
GC-1C-C Lens	144°	—	95°-147°	30°-90°

The regional dip of 5° at an azimuth of 200° was removed from the logging calculations. This moved the average azimuth more than 90°, e.g. from 180° to 72°. However, the log calculations were very sensitive to the parameters used during the file compilation and computer analysis.

The site will be turned over to the state of Utah as a geological research area instead of plugging the wells and abandoning them. The wells will be filled with mud and locked, all the DOE and GRI reports and logs will be placed on file at the state Oil, Gas and Mining

Department Offices in Salt Lake City, Utah.

We would strongly recommend that an additional two-well program be initiated, with wells drilled within 50 ft of GRI GC-1B and 1C. The program would be in cooperation with the major logging companies (Dresser Atlas and Schlumberger) and with Christensen on the oriented coring. This program would include repeat logging of the new holes (with prototype equipment, varying parameters and technique and with the core laid out at the well site for comparison). This procedure should continue until consistent and repeatable results are achieved. The resulting new quantitative dipmeter technique could then be evaluated by relogging the GRI GC-1B and 1C hole. These results could then be compared with the results obtained from the original directional data as well as with the results obtained from the nearby new wells GRI 2B and 2C.

Section 2

Resource Assessment

U.S. GEOLOGICAL SURVEY

The following documents were published during the quarter.

Bucurel, H. G., "Subsurface correlations of some Upper Cretaceous and Tertiary rocks, Great Divide Basin, Wyoming," U.S. Geological Survey Open-File Report 81-981, 2 sheets, 1981.

This publication is a subsurface log cross section extending eastward from the northeast flank of the Rock Springs Uplift to the east flank of the Great Divide Basin. Drill stem test data and well completion intervals are shown for all wells.

Markochick, D. J., R. E. Lanham, H. G. Bucurel and B. E. Law, Summary chart of geological data from Amoco Tierney Unit 1 well, SW¼, SE¼, Sec. 15, T20N, R94W, Sweetwater County, Wyoming: U.S. Geological Survey Oil and Gas Investigations Chart OC-116 (in press), 1981.

This is a display of data obtained from analysis of core of the Upper Cretaceous Mesaverde Group. The display includes: core description; mineralogy; source rocks; permeability; porosity; and some geophysical well log traces.

Keighin, C. W. and T. D. Fouch, "Depositional Environments and Diagenesis of Some Non-marine Upper Cretaceous Reservoir Rocks, Uinta Basin, Utah," Society Economic Paleontologists and Mineralogists Special Publication No. 31, p. 109-125, August 1981.

Note: This paper is presented in the previous section.

The purpose of this paper is twofold: to present new data on the sedimentology and mineralogy of the non-marine part of the Mesaverde Group in the Southman Canyon gas field in the Natural Buttes area of Utah, and to present our analysis of the data. We hope this will facilitate development of sedimentologic and diagenetic models that may prove useful in the exploration for hydrocarbons in continental rocks.

SURVEY OF BASIN ACTIVITIES

GREATER GREEN RIVER BASIN

American Quasar Petroleum has staked 36-33 State, Sec. 36, T28N, R102W, a scheduled 4,000-ft test in Wyoming's Fremont County. The new wildcat, which will be the first drilling in the township, is 22 miles north of Rim Rock Field, which produces from the Muddy, and 24 miles northwest of Lost Valley Field, where production is from the Mesaverde. The wildcat is about 10 miles northeast of Rainbow Resources's 1-34 Federal-Pacific Creek, Sec. 34, T27N, R103W, which set the Rock Mountain Region drilling-depth record at 25,764 ft. Operations are currently suspended at that well.

Sixty-four new wells were staked during the quarter — 37 development and 27 wildcat. Sixteen development wells were reported as completions and six wildcat wells were reported as discoveries during the quarter. Eight development and two wildcat wells were D&A. Total initial potential flow assigned to the producing wells was 12,138 MCFD, with the Frontier Formation again being the largest contributor. Other producing horizons included the Mesaverde undifferentiated, the Almond, Lewis, Fort Union and Frontier/Bear River commingled.

Amoco Production completed a new pay discovery in south central Wyoming's Continental Divide Field flowing 1,259 MCFD

of gas and 40 BBLS of condensate per day. The 1 Champlin-533 Amoco-B, Sec. 3, T22N, R93W, in Sweetwater County, produces from the Lewis 11,380-11,400 ft. The new producer is in the Red Desert area less than a mile northwest of the field's 1964 Fort Union oil discovery and 2¾ miles northwest of a Mesaverde gas discovery recently completed in the field by Amoco. Continental Divide Field is about 16 miles north-northeast of the town of Wamsutter.

Mountain Fuel Supply has completed a discovery eight miles south of the town of Pinedale in Sublette County, Wyoming, flowing 456 MCFD of gas from the Fort Union. The 2 Mesa Unit, Sec. 16, T32N, R109W, produced from perforations in a net 24 ft between 11,410 and 11,700 ft. Log top of the Fort Union is at 7,525 ft. Total depth is 12,190 ft. Mountain Fuel's discovery is 3 miles northwest of a Fort Union gas well in Pinedale Field and about 5 miles south a Fort Union gas well in Sec. 20, T33N, R109W.

Table 2-1 is a summary of wells and newly-staked tests of interest in the Greater Green River Basin; Figure 2-1 shows their locations. Table 2-2 is a quarterly drilling summary for the basin.

PICEANCE BASIN

Coors Energy has staked 1-32C USA, Sec. 32, T10S, R98W, a planned 5,540-ft test in western Colorado's Mesa County. This test is ½ mile southwest of an indicated discovery; Coors' 1-28C Cameo Land Co., Sec. 28, which is testing Cozzette and Corcoran Sands. Total depth of 1-28C was 5,450 ft. Closest drilling is 5 miles to the north in Craig Field; in addition, this new venture is 7 miles east of the Brushy Basin Field and 2½ miles north of the town of Palisade.

In Rio Blanco County, Stauffer will drill 1 Big Ridge-Federal, Sec. 19, T1S, R100W, which is 2½ miles northeast of Mancos gas production in the Philadelphia Creek Field and 4½ miles northwest of the Corral Creek

gas field, capable of producing from the Mesaverde and Mancos. A half mile to the east, Adolph Coors Co. has suspended operations at 1-20 USA-Philadelphia, Sec. 20. Total depth was 5,649 ft in the Mancos.

By the end of the quarter, 60 new field tests had been reported — 48 development and 12 wildcat.

Total initial potential flow reported during the quarter was 23,155 MCFD, with the Wasatch Formation producing the most. Other horizons, in order, include the Mancos undifferentiated, the Mesaverde undifferentiated, Mancos B, Cozzette/Corcoran commingled and Rollins/Cozzette/Corcoran commingled. Forty-seven wells contributed to the total: 42 development wells and 5 wildcat discoveries. In addition, 1 development and 2 wildcat wells were reported as D&A, 2 development wells were temporarily abandoned and 1 wildcat location was abandoned.

A sampling of completions and newly-staked wells is presented in Table 2-3 and their locations are shown in Figure 2-2. The quarterly activity summary is shown in Table 2-4.

UINTA BASIN

Total initial potential flow reported during the quarter was 16,130 MCFD. That came from 16 reported completions: 15 producing development wells and 1 wildcat discovery. Two development and 2 wildcat wells were D&A; in addition, 1 wildcat and 8 development locations were abandoned. The largest producer of gas reported during July, August and September was the Wasatch, which is usually the dominant horizon in the Uinta Basin. The Mesaverde contributed 2,300 MCFD.

Twenty new locations were staked during the quarter: 13 development and 7 wildcat. One of those wildcats was staked by Wexpro Co., 1 Whitmore, Sec. 17, T12S, R11E, a remote 3,500-ft test 9 miles northeast of the town of Helper in Utah's Carbon County. The wildcat will be the first test in the township.

Table 2-1 Summary of Wells — Greater Green River Basin

OPERATOR	WELL NAME	MAP INDEX NO. ¹	LOCATION SEC/T/R	HORIZON ² ft	FINAL TD	FRACTURE TREATMENT	STATUS	IPF In MCFD
Amoco Production	1 Champlin-337 Amoco-F	1	csw 19/19N/93W Tierney Field Carbon Cnty, WY	Almond 9,304-9,384 (gross)	9,910 PB: 9,747	Acidized w/3,192 gal; fractured w/ 202,986 gal emul, 377,000 lb sand, 25,000 scf nitrogen.	Wildcat outpost extension, comp. 2-15-81; spud 9-13-80. No cores or tests.	93
Belco Petroleum	76-14 Unit	2	nene 14/26N/113W Green River Bend Field Lincoln Cnty, WY	Frontier 7,213-7,538 (gross)	8,134 PB: 8,090	Fractured twice w/ total 70,310 gal water, 254,000 lb sand.	Develop. well, comp. 7-3-81; spud 3-22-81. No cores or tests.	1,699
Woods Petroleum	17-1 USA-Reardon	3	swne 17/28N/111W Wildcat Field Sublette Cnty, WY	Frontier 11,192-11,510 (gross) Bear River 11,841-11,998 (gross) (Commingle Production)	12,675 PB: 12,017	Acidized w/2,000 gal; fractured three times w/total 112,000 gal oil, 247,000 lb sand.	Wildcat field discovery, comp. 5-8-81; spud 6-2-80. No cores; drill stem tested 10 times.	61
Wexpro Company	1 The Mesa	4	nene 7/32N/109W Unnamed Field Sublette Cnty, WY	Fort Union 11,106-11,208 (gross)	12,050 PB: 11,390	86,170 gal gel, 156,000 lb sand, 280,000 scf nitrogen.	Wildcat field discovery, comp. 7-15-81; spud 9-6-80. Cored from intervals 9,651-9,802 ft, 10,486-10,604 ft, 11,195-11,314 ft, 11,880-11,961 ft. Drill stem tested. Two miles north-west of Wexpro's 2 Mesa Unit, Sec. 16, which flowed 456 MCFD.	1,452
Getty Oil	14-2 McPherson Springs	5	nwne 14/13N/94W McPherson Springs Field Sweetwater Cnty, WY	Mesaverde 11,680-12,934 (gross)	13,020	Acidized twice w/ total 5,000 gal; fractured twice w/ total 198,000 gal gel, 138,500 lb sand.	Wildcat deeper pool discovery, comp. 6-30-81; spud 9-28-80. No tests, cored from intervals 10,153-10,186 ft and 10,455-10,505 ft.	500
Amoco Production	1 Champlin-259 Amoco-B	6	cnw 1/20N/101W Unnamed Field Sweetwater Cnty, WY	Frontier 9,084-9,206 (gross)	10,350 PB: 9,500	Acidized four times w/total 16,220 gal.	Wildcat field discovery, comp. 8-81; spud 9-80. Cored 8,636-8,678; drill stem tested. Closest Frontier production three miles to west in Deadman Wash Field.	70
Wexpro Company	4-1 Haley-Federal	7	nwnw 4/17N/112W Bruff Field Uinta Cnty, WY	Frontier 12,064-12,098	12,833 PB: 12,510	227,500 gal water, 524,500 lb sand.	Develop. well, comp. 8-28-81; spud 4-6-81. No cores; drill stem tested.	1,336
Synder Oil	1-12 Chorney-Federal	8	n½nw 12/17N/92W Wildcat Field Carbon Cnty, WY	Almond 7,675			Wildcat field test, reported 7-29-81. 2½ miles S-SE of Mesaverde gas production in Standard Draw Field and 7 miles E of Coal Gulch Field.	

¹ Refer to Figure 2-1
² Projected Depth or Producing Interval

Figure 2-1 Greater Green River Basin Showing Wells of Interest (refer to Table 2-1)

Fiscal Year	Calendar Year	NO. OF WELLS				PRODUCING HORIZONS IN MCFD													
		Wildcats		Development		Total													
		D&A	Discovery	D&A	Producing														
							Fort Union (Almy)	Lance	Fox Hills	Lewis	Transition Zone	Undifferentiated	Almond	Ericson	Blair	Frontier	Bear River	Commingled	Total
3rd Qtr 1977	**2nd Qtr 1977	13	23	6	20	67	6,168	0	0	14,703	0	8,573	9,180	580	0	14,219	0	2,556 ¹	55,979
4th Qtr 1977	**3rd Qtr 1977	14	8	5	24	51	25	231	0	7,361	0	9,413	8,477	0	0	12,180	0	0	37,687
1st Qtr 1978	**4th Qtr 1977	24	5	8	23	60	0	0	0	7,648	0	20,282	8,372	3,982	1,298	14,018	0	0	55,600
2nd Qtr 1978	**1st Qtr 1978	9	9	6	22	45	725	0	0	11,100	2,191	4,292	2,999	0	0	7,455	0	14,650 ²	43,412
3rd Qtr 1978	**2nd Qtr 1978	9	7	7	31	54	532	53	0	16,061 ³	1,697	8,532	14,044	0	0	18,703	0	12,306 ⁴	71,928
4th Qtr 1978	**3rd Qtr 1978	15	9	5	32	61	628	0	540	16,110	0	12,122	4,327	1,389 ³	0	16,167	427	1,064 ²	52,774
1st Qtr 1979	**4th Qtr 1978	12	12	13	23	60	1,297	0	0	3,987	0	7,501	7,825	1,723	0	25,841	0	1,288 ⁵	49,462
2nd Qtr 1979	**1st Qtr 1979	17	9	11	27	64	1,154	0	0	15,757	0	11,238	2,897	0	0	25,507	2,000	807 ⁹	59,360
3rd Qtr 1979	**2nd Qtr 1979	14	7	6	31	58	708	0	0	2,315	0	13,014	22,636	461	0	18,350 ³	0	0	57,484
4th Qtr 1979	**3rd Qtr 1979	7	11	11	41	70	1,300	0	0	6,508 ³	0	20,714	14,275 ³	896	0	22,657	5,896	993 ¹⁰	73,239
1st Qtr 1980	**4th Qtr 1979	12	3	6	47	68	0	0	0	7,842	0	5,045	25,613	303	0	13,363	0	8,676 ²	60,842
2nd Qtr 1980	**1st Qtr 1980	6	7	1	17	31	3,700	0	675	1,709	618	4,878	5,094	0	0	6,152	0	4,290 ¹¹	27,116
3rd Qtr 1980	**2nd Qtr 1980	4	2	2	17	25	803	1,023	0	448	0	2,109	4,434	0	0	9,426	2,000	0	20,243
4th Qtr 1980	3rd Qtr 1980	3	4	2	28	37	3,700	0	110	9,564	0	6,559	5,095	0	0	14,491	472	0	39,991
1st Qtr 1981	4th Qtr 1980	17	11	5	56	89	2,241	1,454	0	4,690	128	6,890	17,426	0	0	36,403	7,643	1,505 ⁹	77,380
2nd Qtr 1981	1st Qtr 1981	9	4	6	31	50	0	0	0	6,802	0	10,709	8,433	1,255	0	17,599	7,647	7 ¹³	52,452
3rd Qtr 1981	2nd Qtr 1981	12	9	7	38	66	95	352	0	1,044	0	14,318 ³	14,250	0	0	27,331	427	1,371 ¹²	59,188
4th Qtr 1981	3rd Qtr 1981	2	6	8	16	32	1,452	0	0	930	0	3,694	1,478	0	0	4,523	0	61 ¹⁴	12,138

Legend

- ¹ Almond/Ericson/Table Rock/Rock Springs
Lewis/Almond 2,194
362
- ² Frontier/Dakota 400
Frontier/Bear River 1,176
Frontier/Mowry 2,200
Almond/Ericson 4,900
- ³ IPF not available from one well
- ⁴ Frontier/Bear River 11,457
Frontier/Hilliard 28
Mesaverde/Ericson 821
- ⁵ Ft. Union/Lance 499
Lewis/Lance 789
- ⁶ IPF not available from two wells
- ⁷ IPF not available from three wells
- ⁸ IPF not available from four wells
- ⁹ Almond/Ericson
- ¹⁰ Lewis/Ericson 193
Frontier/Muddy 800
- ¹¹ Frontier/Muddy 2,350
Frontier/Bear River 500
Frontier/Dakota 1,440
- ¹² Frontier/Bear River 550
Almond/Ericson 540
Frontier/Dakota 281
- ¹³ Almond/Ericson/Rock Springs
- ¹⁴ Frontier/Bear River

* Data compiled from P.I. Rocky Mountain Region Report "Completions"

** Revised figures

Table 2-2 Summary of Drilling Activities – Greater Green River Basin

Table 2-3 Summary of Wells — Piceance Basin

OPERATOR	WELL NAME	MAP INDEX NO. ¹	LOCATION SEC/T/R	HORIZON ² ft	FINAL TD	FRACTURE TREATMENT	STATUS	IPF In MCFD
Adolph Coors Company	2-6 LW Cowperthwaite	1	swnw 6/8S/97W Unnamed Field Garfield Cnty, CO	Mesaverde 2,342-2,362	4,355 PB: 2,820	Acidized w/500 gal; fractured w/ 50,000 gal gel water, 100,000 lb sand, 30 tons CO ₂ .	Wildcat field discovery, comp. 5-20-81. Spud 2-4-81. Log tops: Rollins 3,609; Cozzette 3,817; Corcoran 4,028; Mancos 4,237.	665
Northwest Exploration	13 Clough	2	sene 13/6S/94W Rulison Field Garfield Cnty, CO	Mesaverde 6,438-7,360 (gross)	7,700 PB: 7,654	Acidized w/1,218 gal; fractured w/ 56,448 gal gel, 88,240 lb sand, 940,800 scf CO ₂ .	Develop. well, comp. 10-14-80. Spud 8-26-80. No tests; cored from 7,400-7,489 ft.	410
Marlin Exploration Management	0-2 Ute-Water Federal	3	nese 0/10S/90W Shire Gulch Field Mesa Cnty, CO	Mancos 6,239-6,290	7,350	Fractured (no details available)	Wildcat new pool discovery, comp. 1-20-81. Spud 5-20-80. No cores or tests. Log tops: Mancos 6,237.	50
Coseka Resources	15-30 Federal	4	nwne 30/4S/103W Unnamed Field Rio Blanco Cnty, CO	Mancos 3,098-3,674 (gross)	3,932 PB: 3,861	131,800 gal foam, 273,560 lb sand.	Wildcat outpost extension, comp. 5-17-81. No cores or tests. Log tops include: Castlegate 2,197; Mancos 8 3,094.	111
CSG Exploration	397-8-4 Gov't	5	nesw 8/3S/97W Standard Draw Field Rio Blanco Cnty, CO	Mesaverde 8,976-9,986	10,050	Acidized twice w/ 2,500 gal; fractured twice w/total 122,262 gal gel, 299,442 lb sand.	Wildcat deeper pool discovery, comp. 5-14-81. Spud 11-7-80. Log tops include: Wasatch 3,460; Ohio Creek 6,887; Mesaverde 7,680. No cores or tests.	701
Teton Energy	18-2 Coury	6	swnw 18/10S/94W Plateau Field Mesa Cnty, CO	Rollins 4,969-5,091 Cozzette 5,352-5,403 Corcoran 5,509-5,586 (Commingled Production)	5,720 PB: 5,687	Acidized three times w/total 152,500 gal; fractured three times w/total 159,500 gal gel, 202,000 lb sand.	Develop. well, comp. 8-3-81; spud 5-7-81. No cores or tests.	814
Northwest Exploration	1 Theos & Son	7	sese 8/1N/92W Wildcat Field Rio Blanco Cnty, CO	Cretaceous test 10,000			Wildcat field test, reported 7-18-81.	
Pool Energy	4-2-8-90 Federal	8	nese 2/8S/90W Wildcat Field Garfield Cnty, CO	Mesaverde 6,000			Wildcat field test, reported 8-7-81.	

¹ Refer to Figure 2-2

² Projected Depth or Producing Interval

Figure 2-2 Piceance Basin Showing Wells of Interest (refer to Table 2-3)

Fiscal Year	Calendar Year	NO. OF WELLS				PRODUCING HORIZONS IN MCFD													
		Wildcats		Development		Total	Green River (Dolitas Creek)	Wasatch	Fort Union	Undifferentiated	Mesaverde				Mancos		Total		
		D&A	Discovery	D&A	Producing						Castlegate/Rollins	Cozzette	Corcoran	Undifferentiated	Mancos B/Emery	Commingled			
3rd Qtr 1977	**2nd Qtr 1977	0	2	2	18	22	0	3,815	10	0	0	0	0	0	4,490 ¹	634 ²	8,949		
4th Qtr 1977	**3rd Qtr 1977	8	1	3	21	33	2,000	3	0	0	120	0	0	1,159	2,839	4,605 ²	10,726		
1st Qtr 1978	**4th Qtr 1977	2	0	3	42	47	0	2,108 ³	0	3,132	0	0	0	2,267 ³	7,947	850 ²	16,304		
2nd Qtr 1978	**1st Qtr 1978	5	2	1	12	20	0	0	0	0	0	0	140	0	3,509	2,336 ⁴	5,985		
3rd Qtr 1978	**2nd Qtr 1978	6	3	3	16	28	0	250	0	0	0	0	1,167	489 ³	4,588	1,809 ²	6,012		
4th Qtr 1978	**3rd Qtr 1978	2	3	2	27	34	775	7,062	0	610	0	0	0	1,002 ¹	4,418 ³	1,787 ⁵	15,654		
1st Qtr 1979	**4th Qtr 1978	1	0	0	39	40	0	5,730	0	5,338	0	370	650	3,122	12,995 ³	1,178 ¹³	30,383		
2nd Qtr 1979	**1st Qtr 1979	0	5	4	14	23	0	0	0	0	0	0	1,775	0	4,162	0	5,937		
3rd Qtr 1979	**2nd Qtr 1979	1	1	1	10	13	0	170	0	4,131	0	0	0	805	158 ³	4,001 ⁷	9,265		
4th Qtr 1979	**3rd Qtr 1979	3	4	2	22	31	0	0	0	40	0	0	1,844	1,552	8,297	1,477 ⁹	13,210		
1st Qtr 1980	**4th Qtr 1979	2	0	0	27	29	0	0	0	500	0	0	4,210	0	6,118	2,671 ¹⁰	13,499		
2nd Qtr 1980	**1st Qtr 1980	1	2	2	22	27	0	0	0	77	0	76	725	270	6,720	2,049 ¹¹	9,917		
3rd Qtr 1980	**2nd Qtr 1980	2	2	1	16	21	0	2,570	0	7,335	0	0	0 ³	0 ³	614	3,198 ¹⁴	12,457		
4th Qtr 1980	3rd Qtr 1980	0	2	1	18	21	0	0	0	500	0	0	2,878	0	1,764	3,279 ¹²	8,421		
1st Qtr 1981	4th Qtr 1980	3	6	1	31	41	0	490	0	2,367	0	0	3,430	1,946 ³	6,436 ⁸	2,142 ¹⁵	16,811 ¹⁶		
2nd Qtr 1981	1st Qtr 1981	2	4	1	25	32	0	479 ³	0	3,848	0	0 ³	837	0	5,095	3,815 ¹⁷	14,074		
3rd Qtr 1981	2nd Qtr 1981	0	2	1	28	31	0	4,867	0	6,802	96	0	160	815	800	3,725 ¹⁸	17,265		
4th Qtr 1981	3rd Qtr 1981	2	5	1	42	50	0	6,796	0	4,162	0	0	0	5,732	3,194	3,271 ¹⁹	23,155		

Legend

¹ IPF not available from two wells

² Rollins/Cozzette/Corcoran

³ IPF not available from one well

⁴ Morapos/Alamos Cameo/Cozzette/Corcoran Rollins/Cozzette/Corcoran 481 460 1,395

⁵ Rollins/Cozzette/Corcoran Castlegate/Mancos B 1,734 53

⁶ IPF not available from five wells

⁷ Cozzette/Corcoran Mancos B/Dakota 1,573 2,428

⁸ IPF not available from three wells

⁹ Cozzette/Corcoran Rollins/Corcoran 1,152 325

¹⁰ Morapos/Mancos B Rollins/Cozzette/Corcoran Rollins/Corcoran Cozzette/Corcoran 409 677 1,145 440

¹¹ Cozzette/Corcoran Rollins/Cozzette/Corcoran 1,521 528

¹² Cozzette/Corcoran

¹³ Cozzette/Corcoran Rollins/Cozzette/Corcoran 845 333

¹⁴ Cozzette/Corcoran Rollins/Cozzette/Corcoran 2,569 629

¹⁵ Rollins/Cozzette/Corcoran Mesaverde/Rollins/Cozzette/Corcoran Cozzette/Corcoran 1,157 506 479

¹⁶ Two IPFs and producing intervals N/A

¹⁷ Rollins/Corcoran Cozzette/Corcoran Mesaverde/Rollins/Cozzette/Corcoran 418 2,364 1,033

¹⁸ Rollins/Cozzette Cozzette/Corcoran Rollins/Cozzette/Corcoran 1,050 1,439 1,236

¹⁹ Rollins/Cozzette/Corcoran Cozzette/Corcoran 814 2,457

Legend

¹ IPF not available from two wells² Rollins/Cozzette/Corcoran³ IPF not available from one well

⁴ Morapos/Alamos 481
 Cameo/Cozzette/Corcoran 460
 Rollins/Cozzette/Corcoran 1,395

⁵ Rollins/Cozzette/Corcoran 1,734
 Castlegate/Mancos B 53

⁶ IPF not available from five wells

⁷ Cozzette/Corcoran 1,573
 Mancos B/Dakota 2,428

⁸ IPF not available from three wells

⁹ Cozzette/Corcoran 1,152
 Rollins/Corcoran 325

¹⁰ Morapos/Mancos B 409
 Rollins/Cozzette/Corcoran 677
 Rollins/Corcoran 1,145
 Cozzette/Corcoran 440

¹¹ Cozzette/Corcoran 1,521
 Rollins/Cozzette/Corcoran 528

¹² Cozzette/Corcoran 845
 Rollins/Cozzette/Corcoran 333

¹³ Cozzette/Corcoran 845
 Rollins/Cozzette/Corcoran 333

¹⁴ Cozzette/Corcoran 2,569
 Rollins/Cozzette/Corcoran 629

¹⁵ Rollins/Cozzette/Corcoran 1,157
 Mesaverde/Rollins/Cozzette/Corcoran 506
 Cozzette/Corcoran 479

¹⁶ Two IPFs and producing intervals N/A

¹⁷ Rollins/Corcoran 418
 Cozzette/Corcoran 2,364

¹⁸ Mesaverde/Rollins/Cozzette/Corcoran 1,033

¹⁹ Rollins/Cozzette 1,050
 Cozzette/Corcoran 1,439
 Rollins/Cozzette/Corcoran 1,236

²⁰ Rollins/Cozzette/Corcoran 814
 Cozzette/Corcoran 2,457

* Data compiled from P.I. Rocky Mountain Region Report "Completions"

** Revised figures

Table 2-4 Summary of Drilling Activities — Piceance Basin

Table 2-5 Summary of Wells – Uinta Basin

OPERATOR	WELL NAME	MAP INDEX NO. ¹	LOCATION SEC/T/R	HORIZON ² ft	FINAL TD	FRACTURE TREATMENT	STATUS	IPF In MCFD
Coastal Oil & Gas	39 Natural Buttes Unit	1	swsw 29/10S/22E Natural Buttes Field Uintah Cnty, UT	Mesaverde 6,394-7,017 (gross)	7,100 PB: 7,034	Acidized w/2,800 gal; fractured w/ 100,000 gal gel, 200,000 lb sand.	Wildcat outpost extension, comp. 7-14-81; spud 6-3-81. No cores or tests. Log tops include: Wasatch 4,064; Mesaverde 6,392.	775
Conoco Inc.	5-14 Cesspooch et al	2	nese 5/9S/21E Natural Buttes Field Uintah Cnty, UT	Wasatch 6,114-6,652 (gross)	7,240 PB: 7,178	Acidized twice w/ total 1,400 gal; fractured w/ 102,650 gal emul, 241,000 lb sand.	Develop. well, comp. 7-18-81; spud 9-6-80.	956
Natural Gas Corporation of California	33-15 Argyle Unit	3	nwse 15/12S/14E Stone Cabin Field Carbon Cnty, UT	Mesaverde 6,875	7,206		Wildcat deeper pool test, comp. 3-23-81 D&A. Spud 12-24-80.	
Mapco Production	11-36B River Bend Unit	4	nesw 36/9S/19E Island Field Uintah Cnty, UT	Mesaverde 8,915	9,055	Acidized five times w/total 8,500 gal; fractured six times w/total 63,900 gal water, 443,000 gal gel, 790,588 lb sand.	Develop. field test, comp. 5-26-81 D&A; spud 6-17-79. No cores or tests. Log tops include: Wasatch 5,094; Mesaverde 8,291.	
Coseka Resources	14-15-15-24 Black Horse Canyon	5	nenw 15/15S/24E Wildcat Field Uintah Cnty, UT	Cretaceous test 8,179			Wildcat field test, reported 8-3-81.	
Natural Gas Corporation of California	14-18 Moccasin Trail-Federal	6	swsw 18/15S/25E Wildcat Field Uintah Cnty, UT	Cretaceous test 8,429			Wildcat field test, reported 7-9-81. One additional wildcat reported same day by same operator in same location.	
Cotton Petroleum	1-10 Hill-Federal	7	nesw 10/11S/20E Natural Buttes Field Uintah Cnty, UT	Mesaverde 5,900			Wildcat outpost extension, reported 7-14-81.	

¹ Refer to Figure 2-3
² Projected Depth or Producing Interval

It is 18 miles north-northeast of Farnham Dome Field, 20 miles north of shut-in gas production in Miller Creek Field and 25 miles northeast of Clear Creek Field. Closest drilling is a 3,154-ft dry hole, a little more than 4 miles to the west in Sec. 27, T12S, R10E. Mud without shows was recovered on drill-stem tests between 1,979 and 2,651 ft. Log tops included the Castlegate at 1,710 ft and the Mancos at 2,780 ft.

A summary of newly-staked and completed wells is presented in Table 2-5, and Figure 2-3 shows their locations. The quarterly activity summary is shown in Table 2-6.

CORING AND LOGGING PROGRAM

LOG INTERPRETATION-DEVELOPMENT OF TIGHT GAS SANDS – CER CORPORATION

Reservoir Geometry – Continuity

A study has been started to determine the degree of correlation of point-bar and channel sand deposits in the Upper Mesaverde section of late Cretaceous age in the Rulison Field of the southern Piceance Basin (Colorado). Logs

Figure 2-3 Uinta Basin Showing Wells of Interest (refer to Table 2-5)

Fiscal Year	Calendar Year	NO. OF WELLS				Total	PRODUCING HORIZONS IN MCFD							
		Wildcats		Develop-ment			Green River	Wasatch	North Horn	Mesaverde	Undifferentiated	Mancos		
		D&A	Discovery	D&A	Producing							Mancos B/Emery	Commingled	Total
3rd Qtr 1977	**2nd Qtr 1977	3	0	0	6	9	435	4,794	0	0	0	0	0	5,229
4th Qtr 1977	**3rd Qtr 1977	3	2	2	14	21	0	23,138	0	1,079	0	0	0	24,217
1st Qtr 1978	**4th Qtr 1977	1	1	0	8	10	0	13,264	0	0	314	0	0	13,578
2nd Qtr 1978	**1st Qtr 1978	0	0	0	12	12	0	13,985 ¹	0	697	0	0	750 ²	15,432
3rd Qtr 1978	**2nd Qtr 1978	1	2	0	16	19	963 ¹	14,837	0	1,612	0	288	7,750 ²	25,450
4th Qtr 1978	**3rd Qtr 1978	1	1	0	16	18	1,786	10,663 ¹	0	3,367	0	0	0	15,816
1st Qtr 1979	**4th Qtr 1978	1	3	2	23	29	1,660	9,973 ⁶	0	840	0	205	3,210 ³	15,888
2nd Qtr 1979	**1st Qtr 1979	0	0	2	21	23	0 ⁸	28,797 ⁸	0	0	0	0	750 ²	29,547
3rd Qtr 1979	**2nd Qtr 1979	0	0	1	10	11	0	13,293	0	0	0	0	1,161 ²	14,454
4th Qtr 1979	**3rd Qtr 1979	12	2	0	11	25	0	0	0	7,684 ¹	0	70	5,301 ⁵	13,055
1st Qtr 1980	**4th Qtr 1979	0	0	1	14	15	0	7,362	0	4,120	0	0	1,351 ²	12,833
2nd Qtr 1980	**1st Qtr 1980	0	3	1	11	15	1,200	9,732	0	5,382	0	0	0	16,314
3rd Qtr 1980	**2nd Qtr 1980	1	3	2	2	8	0	5,805	0	520	0	0	0	6,325
4th Qtr 1980	3rd Qtr 1980	1	1	5	13	20	0	11,298	0	1,650	0	0	272 ²	13,220
1st Qtr 1981	4th Qtr 1980	0	3	0	12	15	0	12,118	0	0 ¹	0	190	0	12,308
2nd Qtr 1981	1st Qtr 1981	0	4	0	6	10	0	8,436	0	520	0	191	0	9,147
3rd Qtr 1981	2nd Qtr 1981	0	2	0	12	14	0	14,679	0	0	0	0	0	14,679
4th Qtr 1981	3rd Qtr 1981	2	1	2	15	19	0	13,800	0	2,300	0	0	0	16,130

Legend

¹ IPF not available from one well

² Wasatch/Mesaverde

³ Mesaverde/Castlegate
Wasatch/Mesaverde 410
2,800

⁴ IPF not available for four wells

⁵ Mancos/Dakota
Wasatch/Mesaverde 3,500
1,801

⁶ No IPF available for nine wells

⁷ IPF not available from two wells

⁸ Dual Completion: Green River and
Wasatch, no IPFs available

* Data compiled from P.I., Rocky Mountain
Region Report "Completions"

** Revised figures

Table 2-6 Summary of Drilling Activities — Uinta Basin

from two closely-spaced wells are being used to ascertain how well the sand lenses correlate at the well spacing of approximately 300 ft. Thickness correlations are being used to help define the areal distribution and continuity of subsurface lenses in this area.

To date, individual sand bodies in the two wells have been identified and correlated. The Farrer Facies of the Upper Mesaverde is divided into three zones: an upper zone composed of thick sandy units interbedded with shale; a middle zone which has thin, discontinuous sand lenses between thick shale beds; and a lower zone, with characteristics similar to the upper zone. The thicknesses of sand units from well to well were crossplotted for each zone. A combined plot of the upper and lower zones was also made.

Correlation coefficients were derived for each plot. In the upper and lower zone plots, plus the combined plot, the coefficient is above 0.5. The number gives a measure of the dependence of one variable on the other, i.e. how well they correlate. The lower zone exhibits the strongest thickness correlation with a coefficient of .67.

The sand units generally correlate favorably at a distance of nearly 300 ft. However, some deposits thin out or do not extend at all to the adjacent well. Location of a hole within a reservoir boundary is difficult to determine. A single log can be deceiving, for if the edge of a lens is penetrated, or if what appears to be a single thick deposit is really two stacked lenses which extend laterally at different azimuths, it is not readily apparent. Study of two or more adjacent wells may aid in the identification of these situations.

A rough draft report has been completed and is being reviewed. The report contains a general discussion on the nature of point-bar deposition, which will facilitate understanding of the geometry of point-bar reservoirs in the Rulison Field. Correlation data and estimates of probable reservoir sizes are included also.

This study has potential as an extended research effort if additional wells are studied. When the data base is expanded, the conclusions will have a broader application. The Multi-Well Experiment offers a unique opportunity to study the reservoirs in three dimensions. There are many other closely-spaced wells with logs available for further study.

Log-Core Correlations

A computer model has been developed for use with the CER LOGCALC software program to facilitate log-core correlations. Averages are utilized in this technique to decrease statistical "noise" in the data. The model will calculate averages for any depth-incremented data available and will crossplot any of these together. The distribution statistics of the plot are also displayed, and further statistics are available. The ease with which data can be plotted and manipulated (when needed) by this model makes possible a more detailed examination of log-core correlations. The organization of the LOGCALC program allows results from other models to be used by the crossplotting model, or the crossplotting model can solve equations and display the results if the base data is provided. Typical plots are: core porosity vs. calculated log porosity; gamma ray vs. cation exchange capacity (CEC) and core porosity vs. horizontal permeability.

In order for core data to be used with the LOGCALC analysis, it must be manually inputted and added to the log data. Currently, this has only been done for the PTS 3-10A and Mesa Unit No. 1 wells.

Core data from Mesa Unit No. 2 well is being depth correlated to log data as it is received. However, a final report of core analysis has not been received.

For the two wells with edited core data, many crossplots have been prepared using LOGCALC. One of the most useful thus far has been a plot of CEC vs. gamma ray. By

extrapolation it is possible to get a minimum gamma ray value at the point where CEC equals 0.0 (y-intercept). Another plotting technique is comparison of density porosity vs. core porosity and effective porosity (Kukul, SPE/DOE paper 9856) vs. core porosity. These crossplots show that the effective porosity calculations give a better porosity value (i.e. better agreement with core data). Crossplots of water saturations vs. effective porosity indicate that tighter rocks have higher water saturations.

Computer generated crossplots of log data vs. core data from the Mesa Unit No. 1 well have enabled interpretation of clay mineralogy in tight sands. Crossplots of CEC vs. gamma ray and CEC vs. potassium (from natural gamma spectroscopy data) indicate that the predominant clay type in the interval 8,700 to 12,000 ft is illite.

Log Interpretation Model Development

The computer model SXOPHI (Kukul, SPE/DOE paper 9856) was modified to provide greater accuracy in formation evaluation. One development is an equation which curve fits temperature and pressure changes and provides a more accurate formation water density which is used in calculating S_{xo} . Another improvement is the addition of three R_w equations. One of these calculates R_{wa} from the total shale equation, one calculates R_w from the total shale equation (if the formation is uninvaded) and the other one is a first attempt to get R_w from the SP curve. Calculating R_w from the SP is a method having limited success in the Rocky Mountain area and continued research in this area may enable better R_w calculations.

RWUISS (clay corrected formation water resistivity in an uninvaded formation) is calculated by an equation that was developed by G. C. Kukul during August:

$$RWUISS = \frac{\phi_e^2 S_{xo}^2}{\frac{1 - V_{cl} - S_{xo}}{R_t} \frac{R_{cl}}{.81 (1 - V_{cl})}}$$

where

- ϕ_e = effective porosity;
- S_{xo} = average water saturation in the volume investigated by the density and neutron tools;
- R_t = true formation resistivity;
- V_{cl} = clay content, fraction of bulk volume; and
- R_{cl} = resistivity clay $\approx$ resistivity shale.

The equation was derived by combining the ideas presented in SPE 9856 (Kukul, 1981) and the total shale equation (Schlumberger, 1972). This calculation has been made a part of the SXOPHI interpretation scheme and is presented along with the other calculations in Figures 2-4 and 2-5. These figures are discussed in a later part of this report.

Additional equations were developed during August and September to add to the SXOPHI Model as presented in SPE 9856 (Kukul, 1981). The relationships were developed to enable the interpretation of V_{clay} and ϕ_{nclay} (neutron response to clay) from logs. The basic premise of the technique is that ordinary shales in fluvial formations of the Mesa-verde Group of Wyoming and Colorado do not consist of 100 percent clay but rather approximately 60 percent clay and 40 percent silt. Also of consideration is the fact that both sandstones and shales have porosity and this feature must be taken into account.

The new equations for the calculation of V_{clay} are:

$$V_{cl} = \frac{\frac{GR_{zone}}{1 - \phi_e} - GR_{silt}}{GR_{clay} - GR_{silt}}$$

where

- GR_{zone} = gamma ray response to the zone being evaluated;
- GR_{silt} = gamma ray response to the non-clay fraction of a formation

Figure 2-4 Plot of SXOPHI Model for Northwest Exploration
Langstaff No. 1 Well, Garfield County, Colorado

Figure 2-5 Example of Output from SXOPHI Computer Log Analysis Model, Wexpro Mesa Unit No. 1 Well, Sublette County, Wyoming

$$= \frac{GR_{min}}{1-\phi_e};$$

GR_{min} = gamma ray response to clean sand as read from log;

ϕ_e = effective porosity of zone;

GR_{clay} = gamma ray response to clay

$$= \frac{GR_{max}}{1-\phi_{esh}} - .4 GR_{silt}$$

GR_{max} = gamma ray response to shale;

ϕ_{esh} = porosity of shale

$$= \frac{\rho_{gr sh} - \rho_{b sh}}{\rho_{gr sh} - 1.0}$$

$\rho_{gr sh}$ = grain density of shale as measured from core analysis of shale in the same formation and at similar depth; and

$\rho_{b sh}$ = bulk density of shale from log.

Similar equations can be developed for any spectral component of the gamma ray response (potassium, potassium + thorium).

The new equation for neutron response to clay is:

$$\phi_{n clay} = \frac{\phi_{nsh} - \phi_{esh}}{.6}$$

where ϕ_{nsh} is read directly from the log in shale (borehole corrected) and ϕ_{esh} has already been defined.

These new equations have been included in the CER LOGCALC SXOPHI model. Using the Mesa Unit No. 1 well as an example, a CEC value is calculated for 100 percent clay to be 24 meg/100g. The potassium content of 100 percent clay calculates 4.5 percent. These values are within the limits of published data for the clay mineral illite.

The log interpretation computer model SXOPHI was applied to the Mesa Unit No. 1 and Mesa Unit No. 2 wells in Sublette

County, near Pinedale, Wyoming. Both of these wells have tight reservoir sands in the 11,000 to 12,000 ft interval.

The Mesa Unit No. 1 well was completed in July 1981, with initial production reported as 1,452 MCFD after fracture. A pre-fracture flow rate was gauged at 35 MCFD.

The SXOPHI model was applied to this well to determine if the degree of invasion, as indicated by water saturation near the borehole, could be used as an index to permeability. Such an index in conjunction with other parameters would then lead to an interpretation of hydrocarbon producibility.

The results of the computer analysis indicate that nearly all the sandy intervals from 11,000 to 12,000 ft exhibit some degree of invasion. Figures 2-6a and 2-6b clearly illustrate this point. The crossplot in Figure 2-6a shows the linear relation of water saturation by the total shale equation (SWTOSH) and effective porosity (PHIEFF). This plot can be regarded as the profile of water saturation far from the borehole, thus, distant from the effects of filtrate flushing. Figure 2-6b, however, shows that a large group of points have moved toward higher water saturation in the zone immediately adjacent to the borehole (flushed zone). The water saturation of the zone adjacent to the borehole (SXOCAL) was calculated with ideas presented in SPE/DOE paper 9856 (Kukul, 1981). Points which remain near the original best-fit line represent no invasion. Points which are highly invaded fall close to or on the axis representing 100 percent water saturation of the zone adjacent to the borehole. Between these two points are the majority of points which are partially invaded.

The degrees of invasion, shown as the amount of separation between SWTOSH and SXOCAL, were illustrated in Figure 2-4. Analysis of the curve traces in these plots leads to an interpretation of which zones may be naturally gas productive and which zones may be stimulation candidates.

Figure 2-6a *Linear Relation of Water Saturation Far from Borehole*

Figure 2-6b *Linear Relation of Water Saturation Adjacent to Borehole*

The Mesa Unit No. 2 well was completed in late June 1981, as a gas well, producing 456 MCFD after fracture.

Computer processing of the Mesa Unit No. 2 well with the SXOPHI model is proceeding at this time and interpretations of the results are pending.

Technology Transfer

Revisions have been completed on SPE 7920, "Formation Evaluation and Gas Detection in Shallow, Low-Permeability Shaly Sands of the Northern Great Plains Province," by G. C. Kukal. The paper is scheduled to appear in the October 1981 issue of the Journal of Petroleum Technology.

A draft report by K. E. Simons of CER, which discusses the reservoir geology and areal distribution and continuity of lenticular sands in Rulison Field of the southern Piceance Basin, has been prepared and is being reviewed internally.

A paper is currently in preparation by G. C. Kukal, R. E. Peterson and R. E. Hill dealing with the applications of the SXOPHI model for the log interpretation of low-permeability gas reservoirs in the Wyoming and Colorado Mesaverde Group.

A paper documenting a new technique for the determination of volume clay in shaly sands as discussed in this report is in the early stages of preparation. The validity of the new equations will be tested during the next few months by comparison to core data and by comparison of the calculated values to those computed using other log interpretation techniques.

C K GEOENERGY CORPORATION

During the quarter, field work in the Rifle Gap area near Rifle, Colorado, was completed as well as the Draft Phase VI report covering the field work and the prognosis about

reservoir geometry in the Multi-Well Site area south of Rifle, Colorado.

The final Phase V report covering the Wyoming field and core work and the Phase III report covering the logging and coring of the Grand County corehole GC-1 were completed. This last report had been delayed pending the receipt of log calculations on the dip of the strata encountered in the borehole.

RESERVOIR SIMULATION MODEL DEVELOPMENT — CER CORPORATION

To enhance the understanding of the effects of various reservoir and fracture parameters on well testing in low permeability gas reservoirs, a number of case studies have been selected and modeled using the DOE/CER reservoir simulator.

In the first two case studies, permeability, fracture length and orientation and the geometry of the non-productive boundaries surrounding the gas-producing reservoir were varied. In these case studies, the bottom-hole pressure at the producing wellbore was viewed as well as the pressure response of the reservoir at various distances and angles from the fracture azimuth. Analysis is continuing of several other case studies that involve simulating the effects of fracturing from one productive gas lens through a non-productive boundary such as shale and intersecting a second gas-producing reservoir. The results of these case studies will be presented in the next quarterly report.

For each of the case studies presented here, the reservoir body consists of a 20-ft thick gas-producing interval with a gas porosity of 6.5 percent. Initial reservoir pressure was established at 3,200 psia. The areal dimension and permeability of the reservoir varied from case to case.

The induced fracture was taken as a .25 in. wide propped fracture. The proppant was 20/40 mesh sand and the effects of non-darcy flow and proppant compaction according to

published lab data within the fracture were included during each simulation run. The vertical fracture assumed a symmetrical shape with respect to the wellbore and extended over the entire 20-ft interval of the reservoir. Productive fracture length and direction varied from case to case.

The first two case studies centered on deriving some insight into the effects the reservoir boundaries would have on well testing, particularly in a low permeability ($10 \mu\text{d}$) lenticular reservoir and further, to establish some relation between test times and the possible position of an offset well (MWX No. 2). The first sets of simulation runs in Case I involved production of a $10 \mu\text{d}$ reservoir, while the second set of runs in Case II produced from a $50 \mu\text{d}$ reservoir. In both cases, the fracture was oriented either along the long axis or short axis of a rectangular (lenticular) reservoir. In the case of the circular reservoir, the radial boundary of the reservoir was fixed as having the same length as the long axis of the rectangular reservoir. The simulated test consisted of production for 1,000 hours (41 days) followed by 1,000 hours of shut-in, for a total testing period of almost three months.

Case Study I

For these simulations, the reservoir permeability was taken to be $10 \mu\text{d}$. The lenticular reservoir areal dimensions were taken to be a $4,000 \times 400$ ft rectangle while the circular reservoir had a diameter of 4,000 ft.

Figures 2-7 and 2-8 represent an areal view of the fractured reservoir along with pressure vs. time plots for the wellbore and various points or offsets within the reservoir. Figures 2-9 and 2-10 are a composite of the pressure response for each wellbore and its offsets. These graphs will aid in comparing the pressure differences from one run to the next, both for the wellbore and offset locations and offer much more dimensional definition than do the areal figures. The pressure plots for the offsets represent the pressure response that

would be seen in MWX No. 2, if in fact, it was located at any of those positions. Each of the offsets is located an equal distance (160 ft) from the producing wellbore but at various angles to the fracture azimuth. The degree of inclination is noted on each plot. Table 2-7 lists some of the pertinent information for each of the simulation runs contained in Case Study I. In run I-1 (Figure 2-7), there is a fractured rectangular reservoir, and in Run I-2, (Figure 2-8) there is a circular reservoir. Both runs had fracture half lengths, X_f , of 1,500 ft and were produced at a rate of 1,000 MCFD for 1,000 hours and then shut in for 1,000 hours.

The pressure response at the wellbore for both cases is very similar and in fact, rather indistinguishable. Furthermore, the pressure response at the offset locations can be seen to be quite similar and thus, would present no additional information by which one could ascertain the extent or location of the reservoir boundaries. Although the boundaries are not distinguishable even with these lengthy testing periods, the extent or length of the productive fracture could be readily simulated given these pressure histories, previous reservoir perturbation and initial conditions.

Although the wellbore pressure has dropped from 3,200 psi to about 1,200 psi in both runs, the offset well farthest away from the fracture (72°), which is located near the boundary for the rectangular Case I-1, has dropped only about 300 psi during the 1,000 hours of production. Thus, at that time, the perturbation at this boundary location did not have a significant enough effect to indicate either at the wellbore or at any of the chosen offset locations that a boundary had been reached.

A log-log plot of the wellbore pressure data presented as real gas potential ($\Delta\psi$) for the rectangular Case I-1 and circular Case I-2 is shown in an overlay in Figure 2-11. Here again, no distinguishable change, i.e., variation in slope, occurs that would permit a distinction to be made between these two cases.

Figure 2-7 Run I-1; Areal View of 10μd Rectangular Reservoir with a 1,500-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions during a 1,000 MCFD drawdown and buildup test.

Figure 2-8. Run I-2; Areal View of a 10 μ d Circular Reservoir with a 1,500-ft Fracture. Pressure responses are for the producing wellbore and several offset positions during a 1,000 MCFD drawdown and buildup test.

Figure 2-9 Run I-1; Bottom-hole Pressure vs. Time for a 10μd Rectangular Reservoir having a 1,500-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions during a 1,000 MCFD drawdown and buildup test.

Figure 2-10 Run I-2; Bottom-hole Pressure vs. Time for a 10 μ d Circular Reservoir having a 1,500-ft Fracture. Pressure responses are for the producing wellbore and several offset positions during a 1,000 MCFD drawdown and buildup test.

Table 2-7 Case Study I: 10 μ d Reservoir

Simulation Run No.	Reservoir Geometry	Reservoir Dimensions, ft	Production Rate, MCFD	Fracture Half Length (X_f), ft	Remarks	Figures
I-1	Rectangular	4,000 x 400	1,000	1,500	Fractured along major axis	2-7, 2-9
I-2	Circular	$r_e = 2,000$	1,000	1,500	---	2-8, 2-10
I-3	Rectangular	4,000 x 400	200	200	Fractured along the minor axis to the boundary	2-12, 2-15
I-4	Rectangular	4,000 x 400	200	200	Fractured along the major axis	2-13, 2-16
I-5	Circular	$r_e = 2,000$	200	200	---	2-14, 2-17

The next three simulation runs, I-3, I-4 and I-5, are shown respectively in Figures 2-12, 2-13 and 2-14. Figures 2-15, 2-16 and 2-17 are composites of the pressure response. The fracture half length, X_f , for these runs is reduced to 200 ft and production rate or drawdown was established at 200 MCFD for 1,000 hours. For I-3, the 200-ft fracture extended along the minor axis of the lens and intersected a non-productive boundary. For the I-4 run, the 200-ft fracture extended parallel to the major axis. Finally, in I-5 the fracture was a 200-ft extension in a 2,000-ft circular reservoir.

Considering first the circular run, I-5, and the long axis run, I-4, it can be seen from Figures 2-13 and 2-14 that the pressure data at both the wellbore and the offsets offer no apparent differences between these two cases that would aid in defining reservoir geometry. This is not so startling, considering the previously presented runs that produced a more significant perturbation to the same type reservoirs and were nevertheless, indistinguishable from one another.

Runs I-3 and I-4 have fractures which are normal to and parallel to the major axis, respectively. The wellbore pressures from Figures 2-12 and 2-13 indicate a change between these differing runs in final bottom-

hole pressure at the end of the 1,000 hour drawdown. The difference amounts to about 300 psi: 1,050 psi for the short axis run and 1,350 psi for the long axis run.

For the long and short axis runs, corresponding offsets also display pressure differences. The offset wells close to the fractures (3 $^{\circ}$ and 8 $^{\circ}$) tend to follow closely the pressure of their respective wellbore and the pressure difference between runs remains about 300 psia. However, for the offset wells farthest from the fracture (45 $^{\circ}$ and 72 $^{\circ}$), the pressure difference between runs becomes minimal. At the 72 $^{\circ}$ offsets, the pressure differences between the long and short axis run are less than 20 psia. For the 45 $^{\circ}$ offsets, the pressure difference between runs amounts to about 50 psia. The pressure difference for the 30 $^{\circ}$ offsets is about 200 psia.

It can be seen that in a fractured 10 μ d reservoir, it may be possible with lengthy pressure testing to determine whether the fracture extends along the major axis of a lens or cuts across it and intersects a boundary. The offset (MWX No. 2) position should then be judiciously selected to provide the greatest amount of additional information beyond that acquired at the producing wellbore. It has been shown that if the offset was placed within 10 $^{\circ}$ of the fracture

Figure 2-11 Composite Real Gas Potential Plots for Run I-1 Rectangular Fractured Reservoir and Run I-2 Circular Fractured Reservoir

Figure 2-12 Run I-3; Areal View of a 10 μ d Rectangular Reservoir with a 200-ft Fracture along the Mean and Intersecting a Boundary. Pressure responses are for the producing wellbore and several offset positions during a 200 MCFD drawdown and buildup test.

Figure 2-13 Run I-4; Areal View of a 10 μ d Rectangular Reservoir with a 200-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions during a 200 MCFD drawdown and buildup test.

Figure 2-14 Run I-5; Areal View of a 10 μ d Circular Reservoir with a 200-ft Fracture. Pressure responses are for the producing wellbore and several offset positions during a 200 MCFD drawdown and buildup test.

Figure 2-15 Run I-3; Bottom-hole Pressure vs. Time for a $10\mu d$ Rectangular Reservoir having a 200-ft Fracture along the Minor Axis. Pressure responses are for the producing wellbore and several offset positions during a 200 MCFD drawdown and buildup test.

Figure 2-16 Run I-1; Bottom-hole Pressure vs. Time for a 10 μ d Rectangular Reservoir having a 200-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions during a 200 MCFD drawdown and buildup test.

Figure 2-17 Run I-5; Bottom-hole Pressure vs. Time for a $10\mu\text{d}$ Circular Reservoir having a 200-ft Fracture. Pressure responses are for the producing wellbore and several offset positions during a 200 MCFD drawdown and buildup test.

Table 2-8 Case Study II: 50 μ d Reservoir

Simulation Run No.	Reservoir Geometry	Reservoir Dimensions, ft	Production Rate, MCFD	Fracture Half Length (X_f), ft	Remarks	Figures
II-1	Rectangular	4,000 x 400	1,750	1,500	Fractured along the major axis	2-18, 2-20
II-2	Circular	$r_e = 2,000$	1,750	1,500	---	2-19, 2-21
II-3	Rectangular	4,000 x 400	400	200	Fractured along the minor axis to the boundary	2-23, 2-24
II-4	Rectangular	4,000 x 400	400	200	Fractured along the major axis	2-25, 2-26
II-5	Circular	$r_e = 2,000$	400	200	---	2-27, 2-28

azimuth, it was so influenced by the effects of the fracture that it was not presenting additional data that differed significantly from the wellbore data. Similarly, when the offset was placed beyond about 45 $^{\circ}$, it was not significantly influenced, even with these lengthy tests and thus, did not permit a distinction to be made between these two dissimilar fracture cases.

In summary, this case study has shown that substantially long testing periods (on the order of thousands of hours), are required to perturb a fractured 10 μ d reservoir. It was found that it was difficult to distinguish reservoir geometry or boundaries when the fracture was remote or distant from a boundary. However, if the fracture extended to or penetrated the boundary, then by using data from the wellbore and offset, it may be possible to determine at least a portion of the reservoir geometry. If the reservoir permeability and the production history are known, then fracture length could be simulated from well test data, assuming that the testing periods are sufficiently long and that the offset data provides added information for near boundary conditions.

Case Study II

This set of simulations for Case Study II was similar to those presented in Case Study I, except that the reservoir permeability was increased to 50 μ d. Production rates were increased in correspondence to the enhanced permeability. Table 2-8 lists some of the pertinent information from the five simulation runs contained in Case Study II. The first two simulation runs considered a 1,500-ft fracture along the major axis of a fractured rectangular reservoir, Run II-1, and a 1,500-ft fractured circular reservoir, Run II-2. The production rate was taken to be 1,750 MCFD for 1,000 hours and was followed by a 1,000-hour buildup. Bottom-hole pressure data are depicted for these two runs in Figures 2-18 and 2-19, respectively. Figures 2-20 and 2-21 are composites of the pressure response. The difference in wellbore pressure response between these two simulations is clearly discernable. In addition, all the selected offset positions indicate substantial pressure differences between the simulations. Pressure differences amounting to about 400 psi were seen at the wellbores and at the 72 $^{\circ}$ offsets. Pressure differences of about

Figure 2-18 Run II-1; Areal View of a 50μd Rectangular Reservoir with a 1,500-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions along a 1,750 MCFD drawdown and buildup test.

Figure 2-19 Run II-2; Areal View of a 50 μ d Circular Reservoir with a 1,500-ft Fracture. Pressure responses are for the producing wellbore and several offset positions during a 1,750 MCFD drawdown and buildup test.

Figure 2-20 Run II-1; Bottom-hole Pressure vs. Time for a 50 μ d Rectangular Reservoir having a 1,500-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions during a 1,750 MCFD drawdown and buildup test.

Figure 2-21 Run II-2; Bottom-hole Pressure vs. Time for a 50 μ d Circular Reservoir having a 1,500-ft Fracture. Pressure responses are for the producing wellbore and several offset positions during a 1,750 MCFD drawdown and buildup test.

200 psi occur between the runs for the 3°, 8° and 30° offsets. Pressure responses from boundary effects for the rectangular Case II-1 are clearly discernable from those in the circular Case II-2. This is especially evident at the end of the buildup (2,000 hours) where it can be seen that the pressure in the circular case continues to rise whereas the pressure gradient in the rectangular case tends toward a constant.

A composite log-log plot of the wellbore pressure data for both runs presented in real gas potential ($\Delta\psi$) is shown in Figure 2-22. The data for these two cases can be seen to diverge at about 500 hours where the slope of the rectangular data approaches one-half. The differences, however, are not very significant.

Thus, it can be seen that this increase in permeability (50 μ d) permitted a substantially higher production rate or drawdown to be advanced than was achieved with the 10 μ d reservoir tests. This, in turn, perturbed the reservoir at a greater distance from the wellbore. The boundary effects of the rectangular case create a substantially different pressure signature than those of the circular case.

The last three simulation runs, II-3, II-4, and II-5 represent 200-ft fractured reservoirs and are shown respectively in Figures 2-23 and 2-24, 2-25 and 2-26, 2-27 and 2-28. The production rate was fixed at 400 MCFD for 1,000 hours and was followed by a 1,000-hour buildup. In Run II-4, the 200-ft fracture was oriented along the major axis of a rectangular reservoir, whereas, in Run II-3, the fracture extended along the minor axis and intersected a nonproductive boundary. Simulation Run II-5 represents a 200-ft fractured circular reservoir. Each of the runs shows substantially dissimilar pressure/time histories.

Considering the circular case, II-5, and the long axis case, II-4, it can be seen that there are substantial differences between these two pressure/time histories and that the differences become more evident at late time.

Although the magnitude of these differences is not as substantial as seen in the two previous runs where the fractures were substantially longer (1,500 ft), these cases are nonetheless distinguishable. The boundary effects for the long axis case are clearly having an effect on the pressure history. However, they occur late in time or well into the buildup.

The pressure/time histories of the short axis case, II-3, and the long axis case can be seen to be dissimilar. Once again, the boundary effects for the long axis case have a substantial effect upon the pressure histories, particularly for the offsets that are remote from the fracture and close to the boundaries.

The offset wells in close proximity to the fracture, 3° and 8°, tend to closely follow the pressure/time history of their respective wellbores. The offsets remote from the fracture, 45° and 72°, for the long axis case are substantially influenced by their proximity to the boundaries.

In summary, it can be seen from this case study that a fractured 50 μ d reservoir can be substantially perturbed such that the effects of nearby boundaries are distinguishable to some degree at the wellbore. Although it may be difficult to make a quantitative analysis of geometry or the boundaries surrounding the reservoirs, their effects are significant enough to indicate that non-productive zones have either been reached or penetrated. The addition of bottom-hole pressure data from an offset well will tend to enhance the analysis and lead to a more definitive explanation of the distance and possibly the geometry of that boundary.

In addition, it can be seen that fracturing across the minor axis can be distinguished from fracturing along the major axis of a gas producing reservoir. Thus, if a massive fracture cuts across the reservoir and penetrates a non-productive zone, although the initiated fracture may be 1,000 ft long, the productive area that it is in contact with may be substantially shorter by several

Figure 2-22 Composite of Real Gas Potential Plots for Run II-1 Rectangular Fractured Reservoir and Run II-2 Circular Fractured Reservoir

Figure 2-23 Run II-3; Areal View of a 50 μ d Rectangular Reservoir with a 200-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions during a 400 MCFD drawdown and buildup test.

Figure 2-24 Run II-3; Bottom-hole Pressure vs. Time for a 50μd Rectangular Reservoir having a 1,500-ft Fracture along the Minor Axis. Pressure responses are for the producing wellbore and several offset positions during a 400 MCFD drawdown and buildup test.

Figure 2-25 Run II-4; Areal View of a 50μd Rectangular Reservoir with a 200-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions during a 400 MCFD drawdown and buildup test.

Figure 2-26 Run II-4; Bottom-hole Pressure vs. Time for a 50 μ d Rectangular Reservoir having a 200-ft Fracture along the Major Axis. Pressure responses are for the producing wellbore and several offset positions during a 400 MCFD drawdown and buildup test.

Figure 2-27 Run II-5; Areal View of a 50 μ d Circular Reservoir with a 200-ft Fracture. Pressure responses are for the producing wellbore and several offset positions during a 400 MCFD drawdown and buildup test.

Figure 2-28 Run II-5; Bottom-hole Pressure vs. Time for a 50 μ d Circular Reservoir having a 200-ft Fracture. Pressure responses are for the producing wellbore and several offset positions during a 400 MCFD drawdown and buildup test.

hundred feet. This case can be distinguished from a case where a lengthy fracture, on the order of 1,000 ft, is extended totally within the gas producing zone. However, various conditions such as large fracture skins, proppant compaction or crushing, may leave an effective fracture length of only several hundred feet.

Conclusions

Long testing periods were required to significantly draw down these low-permeability reservoirs. Bottom-hole pressure data from an offset or observation well provided useful information to aid in defining reservoir geometry. The position of this observation point with respect to the fracture azimuth is functionally dependent upon reservoir permeability. The length of the productive fracture can be assessed using a simulator, provided that the reservoir permeability, initial pressure and previous production histories are known. This is particularly true for the low permeability case ($10 \mu\text{d}$) where it was shown that the extent or boundaries of the reservoir did not have the influence on wellbore pressure history that the fracture length had.

For the more permeable case using $50 \mu\text{d}$, boundary effects were perturbing the reservoir responses and would therefore slightly complicate the extraction of productive fracture length from wellbore pressure data alone. The position of the observation well with respect to fracture azimuth was shown to be more critical for the $10 \mu\text{d}$ case than for the $50 \mu\text{d}$ case. This follows from the fact that much smaller pressure disturbances occur at the boundaries in the low permeability case than for the higher permeability case; therefore, the information obtained from the most remote observation point, 72° , contained little, if any, pertinent information.

In addition, it was seen that it was possible to distinguish between the case where the fracture extended beyond the reservoir and entered a non-productive zone from the

case where the fracture of equal length was contained totally within the gas producing reservoir.

GAS RESEARCH INSTITUTE SPONSORED PROJECTS

PROJECT PROPOSALS

In August, the GRI Project Manager, Tight Gas Sands, and the CER Project Manager met with USGS personnel to discuss a proposed subcontract with the Texas Bureau of Economic Geology (BEG) for basin comparison studies in the Rocky Mountain region. The USGS will not enter into a subcontract arrangement but will furnish assistance, data, etc. to the BEG for the studies. In September, a draft subcontract (\$104,850) for the BEG to perform basin comparison studies was prepared and transmitted to GRI for review. By the end of the quarter, execution of the BEG subcontract was pending an audit by GRI. This work would be to compare tight gas sands basins in the contiguous United States for consideration by GRI in its selection of primary and secondary basins per the draft program plan. CER-recommended basin selection considerations were furnished to GRI and the BEG for comparing geologic and engineering aspects of tight gas sands basins.

PROJECT IMPLEMENTATION

At the end of the quarter, two copies of CK GeoEnergy Corporation's final report on the Uinta Basin channel sands study were transmitted to GRI. This transmittal had been delayed to provide for augmentation of the abstract and conclusions portions of the report. The report is entitled "Field Study of Tight Gas Sands Reservoirs Directional Characteristics," and its abstract in Section 1.

As indicated in the study report by CK GeoEnergy, the various methods for determining the azimuth of channel sands (outcrop, oriented core, logs, seismic) do not present

common results. However, the two logging companies involved (Schlumberger and Dresser Atlas) and the oriented core participant (Christensen) are understood to be interested in continuing the work with prototype equipment. CK GeoEnergy recommends that an additional two-well program be initiated at the Book Cliffs site to resolve results and to evaluate new tools and techniques.

Hunter Geophysics has started work on the subcontract entitled "Determination of Propped Fracture Length by Detection of Injected Magnetic Material with Surface Superconducting Magnetometers." This sub-

contract amounts to \$249,199. Hunter Geophysics has directed its initial efforts toward:

- characterization of a subsurface magnetic anomaly and the resulting surface magnetic field with an appropriate theoretical model;
  - determination of a suitable magnetic source material; and
  - devising a reliable method of measurement of surface magnetic fields of very small magnitude.
-

Section 3

Research and Development by Energy Technology Centers and National Laboratories

---

BARTLESVILLE ENERGY TECHNOLOGY CENTER

IMPROVED PRESSURE CORING SYSTEM — SANDIA NATIONAL LABORATORIES

Objective

The overall program objective has been to develop a system that will retrieve a core at in situ conditions. In FY 1978, a design was formulated for an improved pressure coring system. Since then, Sandia's involvement has been in developing and making improvements in the core retriever mechanism and associated hardware, in high speed coring bits which incorporate polycrystalline diamond compact (PDC) cutters, and with low invasion coring fluids. Specific objectives for FY 1981 were to fluid test a pilot-type core bit, to develop a low invasion fluid suitable for use in coring tight gas sands, and to assist existing contractors in completing mechanical developments such as a longer core barrel, high pressure capability and a core orientation feature. Most of the objectives were met and work is continuing on others, as indicated in the following.

Summary of Technical Progress

The project was officially terminated on Sept. 30, 1981. Accomplishments included increased capabilities for the pressure core barrel (longer cores, underpressured reservoirs, unconsolidated sands and deviated holes), improvements in the low invasion fluid (composition and methods of preparation and handling) plus various laboratory core intrusion studies and improved designs for PDC drill bits. Items presently under development, such as a high pressure coring capability, fielding of the core orientation device and testing the two-piece pilot bit, will be carried on by Pressure Coring, Inc.

Core Retriever Design and Testing

Advancements were made during the quarter to improve the capabilities of the core retriever mechanism. PCI now has the capability to pressure core deviated holes and to core unconsolidated sand formations. They are able to take conventional cores, if required, and are also rapidly developing a high pressure (7,500 psi vs. 5,000 psi) coring capability. The core orientation device has not yet been made operational but is still under development and will be completed at the earliest opportunity.

The long (15 ft) core barrel, available only a short time, is performing successfully in the field. The demand for long pressure cores has been even greater than expected. Consequently, a large effort has been placed on conversion of short (10 ft) core barrels into long ones and in fabricating the parts required to perform the conversion.

A steel ball bearing has been installed as a lower swivel bearing in the pressure core barrel. It serves to support the inner core barrel at the lower end so that deviated holes may be pressure cored. An added benefit is that core washing has been reduced so unconsolidated cores may be cut.

An elastomeric core catcher has been designed and tested by PCI. Its incorporation into the pressure core barrel will assist in the taking of cores from unconsolidated formations.

The core barrel chamber is being modified with a bleed valve to relieve excess core pressure during cutting which is caused by slow exit flow of the low invasion fluid. This modification will allow pressure coring of fine-grained unconsolidated formations.

In order to provide a high pressure coring capability, a new high pressure reservoir has been fabricated and laboratory tested. An improved pressure regulator has also been placed in service which has increased pressure capability. Rupture discs are being installed to provide personnel safety. Also, a stable electronic amplifier/digital readout has been fabricated by Sandia so that core pressures may be measured without undue exposure of personnel to handling hazards.

Sandia contractor, Larry Russell, has had difficulties with the compass bearings of the core orientation device. A large amount of bearing friction has caused the needle to stick. Modifications are being tested at this time and the solution seems imminent. The core orientation device will be fielded by PCI when available.

Coring Fluid Testing

Experiments performed at Sandia indicate that the penetration of an oil-base mud/salt water gel mixture into a Tennessee Sandstone core (a material with similar permeability to the Mesaverde horizon at the Multi-Well Experiment site) is very slight at 50 psi differential pressure. The rate of penetration is greater at 250 psi differential pressure and starts to become a significant factor influencing proper well completion. A balanced pressure drilling condition is required. The use of oil-base mud allows a balanced pressure to be approximated.

The oil-base drilling mud contains about 10 percent water as an invert emulsion. If water from the mud becomes a factor in the determination of water saturation values for the western tight gas sands formations, an all-organic low invasion fluid made of hydroxypropyl cellulose (HPC) and propylene glycol is available for use with pressure coring equipment which will preserve the water saturation values.

Bit Design and Fabrication

A core bit with a large ID (7-27/32 in. OD by 3-3/8 in ID) was designed and fabricated by PCI. The bit provides a conventional coring capability when used with a special core barrel.

A core bit having improved internal hydraulics was also fabricated by PCI. Unfortunately, the bit was wrecked by junk in the hole the first time it was placed in service so operational information was not obtained.

Polycrystalline Diamond Core Bit Tests

The two-piece bit with removable pilot section is presently scheduled to be tested during the fourth quarter of 1981 or early 1982. The one piece bit design continues to be the bit of choice by the operators in the field.

FORMATION EVALUATION STUDIES

Relationship of Pore Structure to Fluid Behavior in Low Permeability Gas Sands — New Mexico Institute of Mining and Technology

Three Dimensional Network Analysis of Interconnected Circular and Slit-Shaped Pores

The presence of silt-shaped pores has been suggested as a possible explanation of the sensitivity to overburden observed for low

permeability gas sands. Three-dimensional networks of interconnected circular and slit-shaped pores have therefore been investigated as models of tight sands.

The arrangement of bonds (capillaries and/or cracks) was defined by considering flow through a cubic lattice such that the general direction of flow is from one corner to the opposite corner. Both the injection and exit faces would be 111 planes of the lattice. A rectangular prism is defined such that those injection and exit faces are two of its faces, each of which contains 25 pores—5 rows and 5 columns—experiencing the injection or exit pressure. Internally, there are four planes, each of which contains 25 pores—5 rows and 5 columns. Thus, there are $6 \times 5 \times 5 = 150$ pores and $4 \times 5 \times 5 = 100$ unknown pressures.

The coordination number of the pores near the center of the network is six. However, many of the pores at the boundary have smaller coordination numbers—some as small as two.

There are 313 bonds (throats, necks or capillaries and cracks) in this network. These bonds are defined as having circular or elliptical cross sections. The flow rate, Q , through such a capillary can be calculated¹ by

$$Q = \frac{\Delta P}{4 \mu L} \cdot \frac{\pi a^3 b^3}{(a^2 + b^2)} \quad (1)$$

where

ΔP = pressure at entrance—pressure at exit,

μ = viscosity of fluid,

L = length of capillary, and

a, b = semi-axes of elliptical cross section.

This equation has been derived for flow rate, Q , through a capillary having a rectangular cross section of length, C , and height, H :

$$Q = \frac{\Delta P}{128 \mu L} \left\{ (C-H)^4 \ln \frac{C+H}{C-H} - 2C^3H + 8C^2H^2 - 2CH^3 \right\} \quad (2)$$

In this equation, ΔP , μ and L have the same meanings as before.

Relative flow rates through capillaries having the same cross sectional areas are compared in Figure 3-1. This figure shows that the flow rate through a nearly circular capillary is appreciably greater than that through a nearly square capillary having the same ratio of long dimension to short dimension. However, the flow rate through a capillary whose cross section is a long, narrow ellipse is nearly the same as that through a capillary whose cross section is a rectangle having the same ratio of long dimension to short dimension. (Dimension refers to length or width for a rectangle, and to a semi-axis for an ellipse.) Therefore, it appears that very similar results would be obtained from using cracks having either elliptical or rectangular cross sections. In this study, elliptical cross sections are used.

Equations in the literature² were used (after inserting a factor of π , which apparently had been omitted by mistake, into the numerator of the right hand side of Equation 13 in Reference 2) to obtain:

$$b = \text{Maximum of} \begin{cases} b_0 - \frac{3\beta f(\nu)a}{4\pi} p \\ \text{and } 0 \end{cases} \quad (3)$$

where a and b are the major and minor semi-axes, respectively, of an elliptical cross section, p is external pressure, b_0 is the value of b when $p = 0$, β is the compressibility of solid material, and the function of ν , the Poisson ratio, is given by (from Reference 2):

¹ Lamb, Sir Horace, "Hydrodynamics," 6th edition, Dover Publications, New York, 1932, 587.

² Walsh, J. B., "The Effect of Cracks on the Compressibility of Rock," Journal of Geophysical Research 70 (2), pp. 381-389, 1965.

Figure 3-1 *Relative Flow Rates Through Capillaries having Elliptical and Rectangular Cross Sections of Equal Areas*

$$f(\nu) = \begin{cases} \frac{16}{9} \frac{1-\nu^2}{1-2\nu} & \left(\begin{array}{l} \text{penny-shaped} \\ \text{crack} \end{array} \right) \\ \text{or } \frac{4\pi}{3} \frac{1-\nu^2}{1-2\nu} & \left(\begin{array}{l} \text{elliptical crack:} \\ \text{plane strain} \end{array} \right) \\ \text{or } \frac{4\pi}{3(1-2\nu)} & \left(\begin{array}{l} \text{elliptical crack:} \\ \text{plane strain} \end{array} \right) \end{cases} \quad (4)$$

Values used by Brower³ also have been used here for $f(\nu)$ and β .

Since lengths of the minor semi-axes could be calculated as a function of the simulated overburden pressure, permeability could then be calculated as a function of the simulated overburden pressure.

Data have been simulated for populations whose logarithms are normally distributed. These data represent both cracks and circular capillaries. The minor semi-axes of structures that are either cracks or circular capillaries at zero overburden pressure are calculated according to Equation (3). Examples of results are shown in Figures 3-2 through 3-4. These plots stop at the point at which all of the cracks have been closed. At this point, the permeability is due entirely to the capillaries that were circular under zero pressure in this model.

The simulated data whose results are plotted in Figure 3-2 initially consist of

- 118 cracks and 195 originally circular capillaries (top dashed line),
- 69 cracks and 244 originally circular capillaries (top solid line),
- 133 cracks and 180 originally circular capillaries (bottom dashed line), and
- 55 cracks and 258 originally circular capillaries (bottom solid line).

In each case, the semi-axes of the cracks at zero pressure represent a population whose logarithms of a and b in cm are normally distributed with means -1.0 and -3.0, and the radii of the circular capillaries at zero pressure represent a population whose logarithms of lengths in cm are normally distributed with -3.0 as the mean. The population standard deviations of the logarithms for both cracks and circular capillaries are 0.4 for lines 1 and 2 and 0.2 for lines 3 and 4. This illustrates that a larger variance tends to lead to greater permeability (than does a smaller variance with identical means). This is expected, as a larger variance leads to the largest channels being larger and the smallest channels being smaller. Not much fluid flow is expected through the smallest channels, but the difference in quantity of fluid flowing through the largest channels is significant. Comparing the slopes of the solid vs. dashed lines suggests that the networks containing the higher proportion of cracks are usually more sensitive to increases in overburden pressure. This behavior is also expected.

In all of the simulated data used in Figures 3-2, 3-3 and 3-4, the circular capillaries can be thought of as ellipses whose major and minor semi-axes both represent the same populations from the minor semi-axes of the cracks. Owing to the small size of these networks compared with actual porous rock, these simulated curves display some lack of smoothness.

Results using the simulated data are plotted in Figure 3-3 and 3-4. Simulations initially consist of:

- 132 cracks with semi-axes representing a population whose logarithms of a and b in cm are normally distributed with means of -0.5 and -3.0 and standard deviation 0.3, and
- 181 capillaries with radii representing a population whose logarithms of lengths in cm are normally distributed with -3.0 for the mean and 0.3 for the standard deviation.

³ Brower, K. R., "Effects of Pressure on Coal Liquefaction and Natural Gas Production," presented at ACS Meeting, Washington, D.C., June 1981.

Figure 3-2 *Simulated Permeability as a Function of Overburden Pressure: Effects of Standard Deviation and Fraction of Channels That are Cracks*

Figure 3-3 *Simulated Permeability as a Function of Overburden Pressure*

Figure 3-4 Simulated Permeability as a Function of Overburden Pressure

Work is continuing in the attempt to simulate models whose results mimic experimental observations. These efforts are helping to gain better understanding of low-permeability porous media that contain cracks.

Permeability of Synthetic Tight Sands Consolidated Under Load

Studies to date have yielded no evidence that microcracks, sufficient in number to affect permeability, are formed when samples

are unloaded. In tests to date, samples have been loaded up to and well in excess of approximations of their in situ stress condition. Because of the possibility that cementation under load is a key feature of unloading behavior, tests have been performed on artificial and reconstituted tight sands formed at overburden.

Samples of concrete formed from several types of sand were allowed to set at pressures from 11,000 to 15,000 psi and at ordinary pressure. In no case was there a significant

difference in permeability, pressure coefficient of permeability, average pore radius or compressibility resulting from a difference in setting pressure. Typically, an overburden pressure of 4,000 psi reduced the permeability by approximately 20 percent. Therefore, there was no indication of conduction through thin cracks which might have resulted from unloading the samples formed at high pressure. The coefficient of compressibility of the pore space was typically $2 \times 10^{-4} \text{ atm}^{-1}$, whereas the coefficient of a pressure-sensitive rock was $12.8 \times 10^{-4} \text{ atm}^{-1}$. Permeabilities were in the microdarcy range and pore radii ranged from .086 to .152 microns.

A strip of nitrocellulose film 5mm wide and 25 microns thick was positioned lengthwise in a cylindrical split mold and surrounded by concrete containing 30 percent cement and local sand. A core was drilled so that the strip was located along the axis and exposed at each end. The core was dried and heated under vacuum to 250°F. The nitrocellulose did not completely gasify as had been hoped. It does deflagrate when not surrounded by a solid matrix. However, the crack opened partially and appeared under the microscope to have a width of about 5 microns. The flow rate was sensitive to pressure to the degree expected. A confining pressure of 3,000 psi decreased the permeability by a factor of 3.5. This sensitivity indicated an aspect ratio of approximately 500 according to experiments with a glass model. The aspect ratio based on microscopic examination would appear to be approximately 1,000. The thickness calculated from the flow rate using

$$Q = \frac{wh^3 dP/dx}{12\eta}$$

is 6.4 microns. The slope of the Klinkenberg plot gives 1.3 microns using

$$h = \frac{48(2)^{1/2} (RT/M)^{1/2} K_{\infty}}{5\pi^{1/2} B}$$

Another specimen was prepared using .001

in. tin foil. The sample was heated to 250°F to melt the foil which extruded to a considerable degree to form a globule at each end of the specimen. The sensitivity of flow rate to pressure was similar to that above.

Further work is now in progress using cores having cracks formed from random distribution of small flakes of nitrocellulose film.

Combined Effect of Overburden and Temperature on Permeability of Tight Gas Sands

Work has begun on examining the effects of temperature on permeability. The first set of data obtained is shown in Figure 3-5 for an Old Man Mountain 2 core taken from a depth of 4,498 ft. The observed decrease in permeability with temperature is qualitatively consistent with previously reported results for sandstones of much higher permeability.

Measurement of Formation Characteristics for Western Tight Sands — Institute of Gas Technology

Recently obtained data^{4,5} showed that the ratio of maximum to minimum permeability was only of the order of 1.5 as measured on four sandstone samples where bedding and cross-beddings were quite marked. The definitive work of Bear⁶ showing how bedding gives rise to anisotropy makes it interesting as to exactly how the thickness and permeability contrasts of the adjacent layers affect the directional trends.

Muskat⁷ showed in 1949 that when the ratio

⁴ Rose, W., S. Keikar and M. Mazumder, "A New Method to Measure Directional Permeability," offered for publication as a JPT Forum Note, Journal of Petroleum Technology, April, 1981.

⁵ Rose, W. and M. Mazumder, "Measuring Directional Permeability of Arbitrarily Oriented Samples," offered as a Geologic Note in Bulletin of the American Association of Petroleum Geologists, June, 1981.

⁶ Bear, J., Dynamics of Fluids in Porous Media, Elsevier (Amsterdam), 1972.

⁷ Muskat, M., Physical Principles of Oil Production, McGraw Hill (New York), 1949.

Figure 3-5 Effect of Temperature on Gas Permeability
(Old Man Mountain Core Sample)

of the maximum to minimum permeability is less than 10, ignoring it would not introduce serious error when accounting for the production performance even of a partially penetrating well. Conversely, both laboratory and field state-of-the-art methods of measurement are quite complicated and serious ambiguities frequently are encountered in the interpretation of the data^{8,9}. It is as though sediment heterogeneity due to spatial variations in permeability and porosity, rather than anisotropy, is the principal factor to take into consideration when simulations are undertaken as a step towards history-matching (past) and predicting (future) well and reservoir (field) performance¹⁰.

Simplistic mathematical modeling more often

⁸ Marcus, H., "The Permeability of a Sample of an Anisotropic Medium," Journal of Geophysical Research, v. 67, pp. 5212 ff, 1962.

⁹ Rose, W., Discussion of the Marcus (1962) paper, Journal of Geophysical Research, v. 68, pp. 4881 ff, 1963.

¹⁰ Greenkorn, R. A., "Steady Flow through Porous Media," AIChE Journal, v. 27, No. 4, pp. 529 ff, 1981.

leads to predictions of limited utility. Still, useful and surprising results occasionally can be obtained with them. A case in point will be illustrated here. The main assumption to be made is that 2-D anisotropy cases are to be considered which occur as a consequence of the bedding and cross-bedding of layered sediments. The second assumption is that there are alternating layers made up of otherwise uniform strata of contrasting permeabilities and thicknesses. If within any given representative region, all bedding planes are more-or-less parallel with each other, it can be shown that the maximum and minimum permeabilities are given by:

$$K_{\max} = K_2 (AB+1)/(B+1) \quad (1)$$

$$K_{\min} = K_2 A(B+1)/(A+B)$$

where $A = (K_1/K_2)$ and $B = (T_1/T_2)$, and where the K s and T s are the permeabilities and thicknesses of the repeating layers.

Table 3-1 Calculated Values

A	B	$K_{\max}/K_2$	$K_{\min}/K_2$	$K_{\max}/K_{\min}$
1	1.0	1.000	1.000	1.000
2	1.0	1.500	1.333	1.125
5	1.0	3.000	1.667	1.800
10	0.1	1.818	1.089	1.669
10	1.0	5.500	1.818	3.025
10	10.0	9.182	5.500	1.669
37.974	1.0	19.487	1.9486	10.000
10^3	10^3	999.002	500.500	1.996
10^3	10^{-3}	1.998	1.001	1.996
10^4	10^4	9,999.001	5,000.500	1.9996
10^4	10^6	9,999.990	9,901.000	1.010
10^4	10^5	9,999.910	9,091.000	1.100
10^5	10^4	99,990.000	9,091.818	10.998
10^5	10^3	99,990.101	991.089	100.789
10^5	1.0	50,000.500	2.000	25,000.500

From Equation (1) it follows that the ratio of maximum to minimum permeability will be given by:

$$K_{\max}/K_{\min} = (AB+1)(A+B)/(B+1)^2A. \quad (2)$$

Two curious consequences of Equation (2) are that the $K_{\max}/K_{\min}$ ratio will be a maximum for all values of A when $B = 1$ and that the $K_{\max}/K_{\min}$ ratio has the same value for A and B^{-1} as it does for A and B for each value of B. In other words, while for each value of A the magnitudes of $K_{\max}$ and

$K_{\min}$ in Equation (1) are very much influenced by the absolute magnitude of the parameter B, the ratio as calculated according to Equation (2) is unaffected by whether B or its reciprocal, B^{-1} , is considered. These consequences are shown by examining the calculated values given in Table 3-1 for various cases.

For the cases where $B = 1$, it is seen in Table 3-1 that the $K_{\max}/K_{\min}$ ratio increases as A increases and whenever A is larger than 10, the ratio is approximately equal to one-fourth the value of A. For example, for

Table 3-2* Calculated Results

A	K ₁ , md	B	T ₁ , cm	K _{max} /K _{min}
10 ⁴	1	10 ⁴	1.0	1.9996
10 ⁴	1	10 ⁵	10.0	1.1000
10 ⁴	1	10 ⁶	100.0	1.0100
10 ⁵	10	10 ⁴	1.0	10.9980
10 ⁵	10	10 ³	0.1	100.7890

* In these computations it is being assumed that K₂ = 10⁻⁴ md and T₂ = 1 micron.

K_{max} to be 10 times larger than K_{min}, the interbedded layers of equal thickness (viz. B = 1) must have a contrast in permeability of almost 40 (viz. A = 37.974). When the interbedded layers have a tenfold permeability contrast, the K_{max}/K_{min} ratio at most can be little more than three.

The cases of A = B = 10³ and A = B = 10⁴ are of special interest since they describe reservoir situations where more-or-less homogeneous blanket sands are broken by thin shale laminae of minimal thickness. For example, suppose that these laminae have a permeability such as K₂ = 0.1 μd (=10⁻¹⁵ cm²), then K_{max}/K_{min} is of the order of 2 only while K_{max} will range from 0.1 to 1.0 md for the two cases under discussion. If the shale partings (laminae) themselves are of the order of 1.0 micron in thickness, this implies that they are separated by 0.1 cm of intervening sand for the A = B = 10³ case and by 1.0 cm of intervening sand for the A = B = 10⁴ case. On the other hand, if it is imagined that the 1.0 micron laminae are separated by 10 to 100 cm (viz. B = 10⁵ and B = 10⁶, respectively), the K_{max}/K_{min} ratios are only slightly greater than unity. In other words, the conclusion can be drawn that permeability anisotropy is of negligible

importance in many cases, as shown by Table 3-2, except when either A >> B or A >> B⁻¹.

IMPROVED LOGGING TECHNIQUES

Interface Conductivity: Effect of Ion Type

As reported last quarter, the influence of ion-type on interface conductivity and therefore, on electric logging, has been expanded to include Ca⁺⁺. The electrical conductivity of a tight sandstone core from Mesa Unit No. 1 well, Sublette County, Wyoming (Sec. 7, T32N, R109W), at a depth of 9,177.2 ft, was measured at 23°C and 70°C using various concentrations of K⁺, Na⁺ and Ca⁺⁺ brines. The data for the Na⁺ and Ca⁺⁺ brines are incomplete since the core seal failed, allowing oil to penetrate the core. Some of the data are still being analyzed to determine exactly when the core damage occurred. Results from experiments with Na⁺ and K⁺ at 23°C and with K⁺ at 70°C will be given here. Results from multiple salinity plots (C₀ vs. C_w) are summarized in Table 3-3.

Table 3-3 Experimental Results for Sample W9177.2

Brine	Temperature, °C	Formation Factor, F*	C _x , (OHM-M) ⁻¹
Na ⁺	23	197	1.38
K ⁺	23	202	1.15
K ⁺	70	222	3.04

If the formalism of Waxman and Smits¹¹ is used, then for a completely water-saturated core,

$$C_0 = \frac{1}{F^*} (C_w + BQ_v), \quad (1)$$

or when $C_0 = 0$ (extrapolation of the linear portion of $C_0 - C_w$ plot),

$$-C_w = C_x = -BQ_v. \quad (2)$$

C_0 is the conductivity of the brine-saturated core, C_w is the conductivity of the brine, F^* is defined as the formation factor, B is the counterion equivalent conductance and Q_v is a measure of the cation exchange capacity (CEC). By writing Equation (2) for K⁺ and Na⁺ at a given temperature, the following expression can be written relating B_{Na^+} and B_{K^+} :

$$\frac{B_{K^+}}{B_{Na^+}} = \frac{C_x, K^+}{C_x, Na^+}, \text{ constant } T \quad (3)$$

Therefore, at 23°C, $B_{K^+}/B_{Na^+} = 0.83$ or the equivalent conductance for K⁺ is 17 percent less than Na⁺. A similar equation can be written for the temperature dependence:

$$\begin{aligned} B_{23^\circ} &= C_x, 23^\circ Q_v, 70^\circ \\ B_{70^\circ} &= C_x, 70^\circ Q_v, 23^\circ \end{aligned} \quad (4)$$

If it is assumed that $Q_v, 70^\circ = Q_v, 23^\circ$ (there is evidence to the contrary in soils chemistry), then $B_{23^\circ}/B_{70^\circ} = .378$. Therefore, the equivalent conductance of K⁺ at 70°C is 2.6 times larger than at 23°C.

Sonic and Electrical Properties of Partially Saturated Tight Gas Sands — Stanford University

Sonic V_p/V_s , Q_p/Q_s and Gas Saturation in Tight Sands

As the search for natural gas intensifies, increasing reliance is placed on high resolution geophysical techniques. New techniques are required which not only indicate the presence of gas, but also yield information concerning the degree of partial gas saturation. It is well established that in unconsolidated sands, compressional velocity is very sensitive to the presence of small amounts of gas in the pores. During the 1970s, bright spots made a significant contribution to the recovery of natural gas from unconsolidated sands in the Gulf of Mexico and other basins. However, bright spot interpretation is not without pitfalls and shear waves have been proposed to aid in distinguishing "true" bright spots from lithologic discontinuities.

Much of the original technical motivation for the deployment of these techniques resulted from laboratory measurements made in unconsolidated sands by Domenico (1974, 1976, 1977) and Elliott and Wiley (1975) at high ultrasonic frequencies. Unfortunately, in consolidated sandstones of both high and low porosities, similar measurements — again at high ultrasonic frequencies — apparently indicate a less promising situation. That is, these measurements suggest that in consolidated sandstones, the effects of partial gas saturation are too small for good reso-

¹¹ Waxman, M. H. and L. J. M. Smits, "Electrical Conductivities in Oil-Bearing Shaly Sands," Society of Petroleum Engineers Journal (June, 1968), 107-122. Presented as paper SPE 1863-A at SPE 42nd Annual Fall Meeting, Houston, Texas, October 1-4, 1967.

lution in field measurements, as shown in Figure 3-6. However, it has been found that velocities are frequency dependent and that measurements taken at high ultrasonic frequency are measuring unrelaxed values. Dispersions as large as 15 to 20 percent affect not only the magnitude of the velocities, but the qualitative dependence on partial gas saturation. In fact, the sensitivity to gas of both V_p and V_p/V_s is far stronger at low acoustic frequencies than at ultrasonic frequencies. Moreover, the attenuation associated with the stress relaxation may provide significant information about the degree of partial gas saturation.

In Figures 3-7 through 3-11, a set of experimental results is presented which demonstrate these effects in Cotton Valley Sandstone (CV 9594) and Fort Union Sandstone.

HYDRAULIC FRACTURING AND FRACTURE CONDUCTIVITY

Fracture Fluid Induced Formation Damage — Regained Permeability

After preliminary experiments measuring the regained permeability of western tight gas sands core, several minor modifications to the system were performed.

- The fracturing fluid was preheated just before entering the cell to simulate heat transferred to the fluid as the fluid is pumped downhole.
- A cooling device, similar to a condenser, was installed in the fluid/gas exit line to protect equipment downstream and to allow accurate gas flow measurements to be made.
- A differential pressure transducer was installed across the core to be used in conjunction with a back pressure regulator placed at the core exit to permit flow rates to be measured at low-differential pressure (10 to 50

psi rather than 1,000 to 2,000 psi). This modification will allow the Klinkenberg-corrected permeability to be measured at various times during the experiment without disturbing the regained permeability process.

- Autoranging electronics were installed to allow flow rates varying over at least two orders of magnitude to be measured automatically. Flow rates of 0.2 cc/sec to 2,000 cc/sec can be measured, with any two orders of magnitude being able to be performed automatically. If needed, the autoranging could be extended over 10^4 and flow rates as low as .005 cc/sec could be measured. The upper limit is also extendable.

Proppant Transport in Massive Hydraulic Fracturing — University of Tulsa Laboratory Studies

Work on uncrosslinked and boric acid cross-linked gels was completed this quarter. Comparison of the measured and calculated data is shown in Figure 3-12. The data indicate that crosslinking, even at low-crosslinker concentrations, has a dramatic effect on the settling velocity of proppant particles. In addition to this work, preliminary settling data have been gathered on metal ion cross-linked gels. Both sand and bauxite have been tested. Observations of erratic particle movement reported by Harrington et al¹² have been verified for fully-crosslinked gels. Particles falling in partially-crosslinked gels do not appear to exhibit the same behavior. The particles fall without appreciable horizontal movement (perpendicular to the direction of shear). Studies are underway to isolate the source of the horizontal velocity component.

¹² Harrington, L. J., R. R. Hannah and D. Williams, "Dynamic Experiments on Proppant Settling in Crosslinked Fracturing Fluids," presented at SPE 8342 at the 54th Annual Fall Technical Conference and Exhibition, Las Vegas, Nevada, September 23-26, 1979.

Figure 3-6 Laboratory Measurements

Figure 3-7 Experimental Results

Figure 3-8 Experimental Results

Figure 3-9 Experimental Results

Figure 3-10 Experimental Results

Figure 3-11 Experimental Results

Figure 3-12 Calculated vs. Experimental Settling Velocities for Hydroxypropyl Guar (HPG)

Fracture Conductivity Model

The results of some initial runs using the model are shown in Figures 3-13a and 3-13b.

These figures represent proppant moving down a fracture as the fracturing fluid and proppant are pumped into a fracture for 50 minutes. At the end of 50 minutes, pumping is stopped and the fracture begins to close. After an additional 10 minutes, the fracture has closed and the distributions of settled and suspended sand are shown.

A verification study of the computational proppant transport model is being undertaken. A laboratory model described in SPE 6814¹³ and results reported in SPE/DOE

9865¹⁴ will be used in the verification study.

Feasibility of Fabricating Light Weight Proppants for Application in Gas and Oil Well Stimulation - Terra Tek, Inc.

Several alternative methods for forming experimental proppants were investigated during the last quarter. Both porous and hollow spheres were fabricated by outside vendors. A relatively high strength porcelain composition (50 percent alumina, 30 percent kaolin clay and 20 percent nepheline syenite) was sent to three different manufacturers for pelletization.

¹³ Clark, P. E., M. W. Harkin, H. A. Wahl and J. A. Sievert, "Design of a Large Vertical Prop Transport Model," presented as SPE 6814 at the 54th Annual Fall Technical Conference and Exhibition, Las Vegas, Nevada, September 23-26, 1979.

¹⁴ Sievert, J., P. Clark, M. Harkin and H. A. Wahl, "Prop Transport in a Large Vertical Model," presented as SPE/DOE 9865 at Symposium on Low Permeability Gas Reservoirs, Denver, Colorado, May 27-29, 1981.

Figure 3-13a Modeled Proppant Distribution — 10, 20 and 50 Minutes after Start of Pumping Cycle

Figure 3-13b Modeled Proppant Distribution – 5 and 10 Minutes after Pump Shut-In (55 and 60 minutes after start of pumping cycle)

Tests using a disc pelletizer did not produce spherical particles. Disc pelletization was tried because of its relatively short retention time as compared to a high intensity mix-pelletizer commonly used for commercial proppant fabrication. The particles produced had a Krumbein roundness of 0.5 to 0.7 which is comparable to sand but not bauxite. Another disadvantage of disc pelletization is that internal pores are generally larger than those produced by a high energy pelletizer, which results in larger pores in the sintered proppant. No further testing using disc pelletization is planned.

Proppants comparable in roundness (Krumbein roundness ≥ 0.9) to commercial bauxite were produced in a M-5-G mix-pelletizer manufactured by Littleford Brothers in Florence, Kentucky. Both the high strength porcelain composition and A-16 superground Alcoa alumina were pelletized using this machine. The M-5-G Littleford mixer is similar in operation to the Eirich R02 but is horizontal during operation instead of vertical. Water was used as a binder during pelletization and was most successful in producing round pellets when it was introduced as a very fine mist.

Alumina and porcelain proppants produced using the M-5-G pelletizer were polished with diamond paste and compared to commercial bauxite. Both alumina and bauxite proppants have relatively large pores (20 to 30 μm in diameter) which result from poor particle packing even in the high intensity mixers. It is obvious that appropriate binders could be investigated which, when added during pelletization, would limit the size of the pores to less than 0.1 μm . Since large pores greatly decrease the strength of the proppants when compared to proppants with minimal porosity, it is evident that the strength of commercially available proppants can be substantially increased as needed.

The alumina composition was single phase while at least three phases were detected in the bauxite spheres due to its high impurity content. Since single phase ceramics are

usually stronger than multiphase ceramics, it is predicted that for similar sizes and sphericities, there will be less crushing and therefore higher conductivity for A-16 super ground alumina than bauxite proppants. Porcelain proppants showed almost no porosity due to the flow of a second phase into pores during sintering. Since the second phase is likely to be glassy and therefore brittle, it is not suspected that the strength of these proppants will be comparable to bauxite but rather intermediate between sand and bauxite. The density of the porcelain is between 2.8 and 3.0 g/cc.

Conductivity tests will be run on this material during the next quarter. Sand, when polished, shows a single phase, as expected, with minimal porosity. The strength limitations of sand are caused by the large crystal size and low sphericity as compared to alumina-based proppants.

One limitation for making multicomponent ceramic proppants such as mullite, cordierite and the porcelain composition discussed previously, is the high cost of alumina as compared to bauxite. An inexpensive source of alumina, called alumina collector fines by Alcoa, has been investigated to determine if it is suitable for use in proppant fabrication. Typical chemical composition of alumina collector fines is given in Table 3-4 along with an analysis of a sample received by Terra Tek and analyzed by Coors spectro-chemical laboratory.

Alcoa reports a typical loss on ignition of 5 to 15 weight percent. Impurities are relatively low except for soda, which is known to cause exaggerated grain growth in alumina ceramics. Therefore, it may be necessary to fast fire these proppants, a technique which could both limit grain size as well as decrease energy costs.

The surface area of the alumina collector fines was measured as $104.56 \pm 1.16 \text{ m}^2/\text{g}$ after heating to 300°C, indicating a very fine ultimate particle size. X-ray identification of the collector fines revealed the presence of a

significant amount of aluminum hydroxide ($\alpha\text{-Al}(\text{OH})_3$) or Gibbsite in the as-received collector fines with the major constituent being alpha-alumina ($\alpha\text{-Al}_2\text{O}_3$). Alcoa has detected Boehmite ($\alpha\text{-Al}_2\text{O}_3(\text{OH})_2$) in the collector fines but not Gibbsite although their characterization has been limited.

The cost of the collection fines is \$0.11 per pound for orders exceeding 42,000 pounds, so the cost is only slightly higher than bauxite. The higher cost may be offset by eliminating some of the crushing and grinding steps currently necessary for bauxite ore. The degree of agglomeration in the alumina collector fines was determined by measuring the pressing pressure as a function of grain density and comparing it to A-16 superground alumina.

As is illustrated in Figure 3-14, the slope of the pressing pressure-theoretical density plot changes between 6.0 MPa and 14.0 MPa for both aluminas, indicating that soft agglomerates exist in both materials. Another change in slope occurs above 70 MPa which may indicate hard agglomerates in this material which would require dry grinding. The offset in theoretical density between the two aluminas is thought to be due to the large difference in particle size. Work is presently in progress to evaluate the collector fines in mullite, cordierite and porcelain.

Hollow spheres are being produced using bauxite, as a raw material, and resin, based on 3M's patent (U.S. No. 4,111,713). Although hollow spheres have been fabricated indicating the feasibility of the approach, neither the economics of the process nor the strength of the proppants and their corresponding density have been determined at this time.

Stochastic Model of Massive Hydraulic Fracturing — Oral Roberts University

A sector model of hydraulic fracture expansion in 3-D is being developed to study the effect of inhomogeneities in stress or rock properties on fracture shape and bottom-hole

pressure. Such inhomogeneities will initially include vertical stress variations from layer to layer and also stochastic variations within layers.

In this quarter, the research has been directed at an approximate solution for the 3-D problem of fracture expansion, which is difficult to solve in its fullness (e.g., see Clifton¹⁵). The approach is based on a "quasi-radial approximation" (QRA), in which an expanding fracture is broken up into a number of azimuthal sectors (e.g., 128) and a number of time intervals (e.g., 200). Fluid flow equations and the elasticity equations, which must be simultaneously satisfied, are solved during each time interval. A new fracture perimeter and bottom-hole pressure is found at the end of each time interval. Initially, Newtonian flow and no leakoff are assumed.

Previously, an approach was tried in which the fluid front and the crack front were assumed to be the same (quasi-static approximation), and the stress intensity factor

$$K_i = \frac{2}{\sqrt{\pi R}} \int_{R_0}^R \frac{r [P(r) - S(r)] dr}{\sqrt{R^2 - r^2}}$$

was used to predict the new front.

Influenced by the arguments of Clifton¹⁵, a different approach is being tried, in which the fluid mechanics defines the fluid front while the fracture tip stands off a little way, the standoff distance being adjusted so that $K_i = K_c$. This means primary emphasis must be placed on the fluid mechanics of the problem:

- The fluid flow is radial (i.e., non-radial gradients in fluid pressure are neglected in sectors which are

¹⁵ Clifton, R. J. and A. S. Abou-Sayed, A Variational Approach to the Prediction of the Three-Dimensional Geometry of Hydraulic Fractures, SPE/DOE 9879.

Figure 3-14 Pressing Compaction Curves for Alumina Collector Fines and A-16 Superground Alumina

Table 3-4 Chemical Analysis of Alumina Collector Fines

Chemical Composition	Alcoa Typical Properties, percent	Coors Analysis, percent by weight based on sample ignited at 1,000°C
Al ₂ O ₃	85 - 95	Balance
Na ₂ O	0.25 - 0.70	1.2000 ± 0.0050
Fe ₂ O ₃	0.05 - 0.07	0.0390 ± 0.0040
SiO ₂	0.02 - 0.20	0.0350 ± 0.0040
MgO	N.I.*	0.0100 ± 0.0010
TiO ₂	N.I.*	0.0045 ± 0.0005
CaO	N.I.*	0.0470 ± 0.0050

* N.I. -- No information on impurity levels

taken to be independent of each other. Taking, for the moment, the width to be constant, $w_i(r) = w_i$, the average pressure in a sector and the pressure at the wellbore are:

$$(\bar{P} - \bar{S})_i = \frac{6\mu q_i}{\pi \bar{w}_i^3} \quad (1)$$

$$(P_o - \bar{S})_i = \frac{12\mu q_i}{\pi \bar{w}_i^3} \ln \frac{R_i}{R_o} \quad (2)$$

where q_i = vol/sec/radian in the i th sector, S_i is average rock stress and R_i is radius of sector.

- For the case of a pay zone between two zones of higher stress, the average widths, $\bar{w}_i$, are determined from $\bar{w}_i/w_o = 2/3 - f$, where:
  - $f = 0$ for sectors in the pay zone. This is an approximation guided by the width function in an elliptical fracture under static conditions.
  - $f = f(S_1, S_2, R', R, P)$ for a sector which penetrates a higher stress zone (S_2), where R' is distance along the sector from origin to higher stress zone, and R is length of sector. In 3-D, the solution for f involves integrals which have no analytic solution. However, in 2-D, a solution can be adapted from a related solution¹⁶ and it is assumed that this describes the 3-D solution adequately in the approximate approach (note the solution for f still requires a numerical integration).
- The fluid front is defined by the condition that the bottom-hole pressure

P_{oi} in each sector has the same value (i.e., pressure drop from borehole to fluid front be the same in each sector).

- A correction needs to be made to the equations to account for the fact that the sectors are not independent of each other. One way to do this is to modify the $(P - \bar{S})$ terms in Equations (1) and (2) by a "shape factor" that depends on where the sector lies in the overall fracture shape. Such a correction factor is being tested.

After these fluid mechanics considerations, the solution for the new fluid front at the end of each time cycle is obtained by an iteration which is similar to the approach used by Daneshy¹⁷:

- A new set of R_i is guessed.
- Knowing the shape of each sector $\bar{w}_i/w_o$ and the volume of injected fluid (no leakoff) gives the new width w_o at the borehole (same for all sectors).
- The increase in fluid volume in each sector then gives a new flow rate, q_i .
- A new borehole pressure, P_{oi} , is calculated for each sector.
- This cycle is repeated until the P_{oi} s are all the same.
- The above iteration cycle can give an R_i distribution which is consistent, but another condition appears required, presumably a consistency check on $(\bar{P} - \bar{S})_i$ and the corresponding width $\bar{w}_i/w_o$ in each sector. This is being studied.

The iterations are very complicated when a

¹⁶ Christianovich, S. A. and Y. P. Zheltov, Formulation of Vertical Fractures by Means of Highly Viscous Liquid, Fourth World Petroleum Congress, Rome, 1955.

¹⁷ Daneshy, A. A., "On the Design of Vertical Hydraulic Fractures," J. Pet. Tech., January, 1973, p. 83.

large number of sectors are employed, but should be orders of magnitude simpler than the full 3-D solution by finite elements.¹⁵

In summary, it is anticipated that the sector simulator described above will be able to predict an approximate 3-D fracture profile (and 2-D fluid flows) for the basic three — stress — zone situation. The simulator will have to be tested and validated against other known solutions. In the next stage of the work, other stress variations will be incorporated (e.g. horizontal or stochastic) in a more general approximate model.

RESERVOIR SIMULATOR STUDIES

Development of a Multi-Faceted Well Simulator — University of Oklahoma

During the quarter, efforts were directed toward the completion of the 2-D lenticular reservoir well simulator program. In addition, work continued on modifying the existing 3-D model to include the effects of non-Darcy flow, Klinkenberg, wellbore storage and fracture storage. A new, more powerful subroutine for solving the coupled finite difference equations between the reservoir and fracture nodes has been developed. This subroutine will be incorporated into the 2-D model and will improve the stability of the solutions. Completion of this latter step will provide a final version of the 2-D model and it should be ready for publication before the end of the next reporting period.

In assessing wellbore/fracture storage effects in low permeability formations, it appears that for massive hydraulic fracture stimulation programs, fracture volume can be of the same order of magnitude as the wellbore volume. Therefore, even if wellbore storage is minimized, fracture storage could significantly influence pressure buildup tests. However, no runs have been made to date where these two effects are isolated for analysis purposes. The preliminary conclusion was made by doing an order of magnitude calculation to assess the importance of each.

To determine the applicability of the modeling effort, an assessment of non-Darcy flow and Klinkenberg effects were investigated for the reservoir and the fracture. Non-Darcy flow effects are expressed in terms of a non-Darcy flow number F_{nd} defined according to

$$F_{nd} = \frac{1}{1 + \frac{\beta \rho k}{\mu} |\vec{v}|} \quad (1)$$

where

- β = inertial resistance coefficient of the porous media,
- ρ = fluid density,
- k = permeability of the porous media,
- μ = fluid viscosity,
- $\vec{v}$ = fluid velocity, and
- $F_{nd} = 1$ implies Darcy flow.

Figures 3-15 and 3-16 demonstrate the effects of non-Darcy flow in propped fractures. From these figures, it is clear that non-Darcy flow effects should be included when modeling fractured low permeability formations. In these types of formations, most of the fluid produced from the reservoir enters the wellbore via the fracture. Furthermore, non-Darcy flow is greatest near the wellbore. This means that pressure buildup and draw-down tests may be significantly affected by non-Darcy flow in the fracture. In addition, non-Darcy flow effects may be significant in the region of the reservoir next to the fracture. In the attempts to assess non-Darcy flow effects, a sensitivity analysis was done using the β factor as a parameter. Figure 3-16 reveals that non-Darcy flow effects are extremely sensitive to this factor. This is particularly true since small quantities of water in the fracture can change the β factor by a factor of ten¹⁸. Therefore, since little or no work has been done on the experimental determination of β factors under partial water saturation conditions, serious errors could be introduced in well testing and simulation of fractured gas wells using β values which are given in the literature for dry gas cores.

¹⁸ Wong, S. W., "Effect of Liquid Saturation on Turbulence Factors for Gas-Liquid System," J. Cdn. Pet. Tech., (Oct-Dec. 1976) 274.

Figure 3-15 Variation of Non-Darcy Factor along Fracture with Flow Rate as Parameter

Figure 3-16 Variation of Non-Darcy Factor along Fracture with β as Parameter

Figure 3-17 Non-Darcy Flow and Klinkenberg Effects on Bottom-Hole Pressure

In assessing Klinkenberg effect, it became readily apparent that flow in the fracture is essentially independent of this effect. This is true because of the high permeability of propped fractures. However, Klinkenberg effect appears to be significant in the low permeability reservoir. The Klinkenberg and non-Darcy flow effects for hypothetical low permeability reservoirs are shown in Figures 3-17 and 3-18. It can be seen from these figures that Darcy flow with Klinkenberg effects is dominant in a low permeability formation. Therefore, any model developed for low permeability formations should include the Klinkenberg effect. The data in Figures 3-17 and 3-18 were generated utilizing the model given by Evans and Carroll¹⁹ which was modeled after the

work of Jones and Owen²⁰.

In conclusion, it is clear that models of low permeability lenticular gas reservoirs must include lenticularity, non-Darcy flow and Klinkenberg effects if one is to adequately predict fluid movement and pressure data for these types of formations.

The 2-D model should be ready for publication, including the computer code and sample output, by the end of the next report period. Hence, most of the future effort will be directed toward developing the multi-phase 3-D model to include all the effects inherent in the 2-D model.

¹⁹ Evans, R. D. and H. B. Carroll, "Stochastic Modeling of Fractured Gas Wells Completed in Low Permeability Non-continuous Lenticular Reservoirs," SPE/DOE Joint Symposium on Low Permeability Gas Reservoirs, Denver, Colorado, May 27-29, 1981. SPE Paper 9884.

²⁰ Jones, F. O. and O. W. Owen, "A Laboratory Study of Low Permeability Gas Reservoirs," SPE Symposium on Low Permeability Gas Reservoirs, Denver, Colorado, May 20-22, 1979, SPE Paper 7551.

Figure 3-18 Non-Darcy Flow and Klinkenberg Effects on Bottom-Hole Pressure

LAWRENCE LIVERMORE NATIONAL LABORATORY

THEORETICAL ANALYSES

Analysis of Fracture Shape

Previous calculations and experiments²¹ have indicated that the in situ stresses can play an important role in the control of the created fracture geometry. Simplified models have been developed to analyze the combined effects of the in situ stresses and the pressure profile in the crack. Two-dimensional equations²² which describe the fracture characteristics in an isotropic-elastic continuum have been applied.

²¹ Hanson, M. E., G. D. Anderson, R. J. Shaffer and L. D. Thorson, "Some Effects of Stress, Friction and Fluid Flow on Hydraulic Fracturing," Report UCRL-85003, Lawrence Livermore National Laboratory, also SPE/DOE 9831 (1981).

²² Sneddon, I. N. and M. Lowengrub, "Crack Problems in the Classical Theory of Elasticity," The SIAM Seminar in Applied Mathematics, John Wiley, New York (1969).

These equations,

$$u_y(x,0) = b \int_{x/c}^1 \frac{t q_1(t) dt}{\sqrt{t^2 - (x/c)^2}}$$

$$q_1(t) = \frac{2}{\pi} \int_0^t \frac{p_1(u) du}{\sqrt{t^2 - u^2}}, \quad (1)$$

and

$$b = \frac{2(1-\nu^2)p_0 c}{E}$$

describe the displacement $u_y(x,0)$ of the crack face for a pressure-stress distribution imposed on an arbitrary crack. In these equations, the pressure in the crack $p(x)$ can be normalized by taking $p(x) = p_0 p_1(x)$ in the crack where p_0 is the maximum pressure in the crack and $0 \leq p_1(x) \leq 1$; c is the half crack length and E, ν are the Young's modulus and Poisson's ratio of the continuum containing the crack. A closure or failure

Figure 3-19 Geometry of Fracture Partially Filled with Fluid for $-x_0 < x < x_0$, with Fluid Pressure $p(x)$ (fracture length is $2c$)

condition^{23,24}

$$\int_0^c \frac{\sigma(x) dx}{c^2 - x^2} = 0, \quad (2)$$

$$\text{for } \sigma(x) = \begin{cases} P(x) - \sigma_m(x) & 0 < x < x_0 \\ -\sigma_m(x) & x_0 < x < c \end{cases} \quad (3)$$

has been combined with Equations (1). Equations (2) and (3) imply that the elastic rock mass cannot support a tensile stress for the scale of the field problems considered. A significant consideration of the hydraulic fracturing problem is that the viscous fluid, which is pumped to create the fracture, does not fill the crack completely. There remains a free part of the crack on both ends of the wetted area as shown in Figure 3-19. In Equations (2) and (3), the matrix stress is the only load that is imposed on the crack between the end of the wetted area, x_0 , and the tip.

Using these relationships, the limits, defined by Equation (3), can be used to develop a relationship for the ratio, $\eta = c/x_0$, as a function of the effective pressure in the crack $p(x) = P(x) - \sigma_m(x)$ and the matrix stress. For the results presented, it is assumed that the matrix stress does not vary with x , e.g., $\sigma_m = \sigma_m^0$; the following is obtained,

$$\frac{1}{\eta} = \frac{x_0}{c} = \left(\sin \left(\frac{\pi}{2} - P_0/\sigma_m^0 \right) \int_0^1 \frac{P_1(\beta) d\beta}{\sqrt{\eta^2 - \beta^2}} \right), \quad (4)$$

where $\beta = x/x_0$ and the other variables are as defined before. Since η appears on both sides of the equation, Equation (4) is solved by iteration.

Equations (1) and (4) have been applied for the case of

$$\left| P_0/\sigma_m^0 \right| = 1$$

for various normalized pressure/stress distributions,

²³ Barenblatt, G. I., "Mathematical Theory of Equilibrium Cracks," in *Advances in Applied Mechanics*, Vol. VII (1962).

²⁴ Daneshy, A. A., "Opening of a Pressurized Fracture in an Elastic Medium," *Petroleum Society of CIM*, Paper No. 7616 (1971).

Figure 3-20 Pressure-Stress Distributions as a Function of Scaled Fracture Length (for $\sigma_m^0/p_0 = 1$). (For Cases II through VI the wetted length x_0/c was calculated.)

$$p_1(x) = [P(x) - \sigma_m]/p_0.$$

Figure 3-20 shows the normalized pressure/stress distributions as a function of the normalized crack coordinate x/c . Equation (4) was applied to calculate the fluid penetration depth x_0/c for all the analyses except Case 1 where $p_1(x)$ was taken as a constant over the entire crack length and equal to p_0 . Table 3-5 shows the pressure distribution and the scaled fluid penetration depth, x_0/c , of the fracture for each pressure distribution.

Figure 3-21 shows the scaled fracture displacement as a function of scaled fracture length. On this plot, it is needed only to show the fracture displacements in the upper right quadrant (see Figure 3-19) because of symmetry. The crack face displacement has been normalized by dividing the calculated displacements by the b term from Equation (1).

In Table 3-5 and Figures 3-20 and 3-21, Case 1 is included for comparison. For Case 1, the pressure is simply held constant for the entire length of the crack and η not calculated. The resulting crack takes on the classical elliptical shape²² and has a maximum displacement of one in the scaled coordinates. In Cases 2 through 6, the penetration depth of the fluid was calculated. For Case 2, the pressure in the crack was constant from $x = 0$ to $x = x_0/c$; for Cases 3 through 5, the pressure behaves like various pressure law fluids; and for Case 6 the pressure varies linearly from the wellbore to x_0/c . The pressure distribution for Case 6 behaves like a constant flow of a Newtonian viscous fluid in a narrow constant width aperture. It is obvious that for the fluids with the largest area under the positive part of the curve (Figure 3-20), the scaled fluid penetration depth is the smallest. It was also noted that the maximum fracture aperture occurs for the fluids with the

Figure 3-21 Scaled Fracture Displacement as a Function of Scaled Fracture Length for the Pressure-Stress Distributions shown in Figure 3-20.

Table 3-5 Scaled Fluid Penetration Depth for the Scaled Pressure Distribution Shown and for $p_0/\sigma_m^0 = 1$

Case	Scaled Fluid Penetration Depth x_0/c	Scaled Pressure Distribution to x_0/c
1	1.0000	$p_1(x) = p_0$ to $x_0/c = 1$
2	0.7071	$p_1(x) = p_0$ to x_0/c
3	0.7502	$p_x(x) = \sqrt{1 - (x/x_0)^4}$
4	0.7803	$p_1(x) = \sqrt{1 - (x/x_0)^2}$
5	0.8216	$p_1(x) = \sqrt{1 - x/x_0}$
6	0.8856	$p_1(x) = 1 - x/x_0$

greatest area under the positive part of the pressure/stress curve. It should be emphasized that scaled distances and apertures are being compared and that the actual crack lengths would undoubtedly be different.

Also analyzed are cases where the matrix stress σ_m^0 (see Figure 3-19) was increased but the pressure in the crack $P(x)$ was also increased so that p_0 remained constant. The pressure-stress distributions, $\sigma(x)/p_0$, for these calculations are shown in Figure 3-22. From this figure, it is noted that the pressure in the wetted area of this crack was held constant and also that $\sigma_m(x) = \sigma_m^0$ was held constant for each calculation. The ratio of the matrix stress σ_m^0 to the magnitude of the effective crack pressure, p_0 , in this case constant, e.g., σ_m^0/p_0 was varied from 0.25 to 4.5. In Figure 3-22, the vertical step from the normalized pressure of unity to the negative matrix stress represents the point, x_0/c , the length of the wetted area of the fracture. Figure 3-23 displays the variation of x_0/c as a function of σ_0/p_0 when the value of p_0 is held constant by increasing $P(x)$ as σ_0 is increased. It is obvious that as the matrix stress increases, the ratio of the portion of the wetted length x_0/c of the crack increases. It is also seen that as the ratio of σ_0/p_0 increases, the aperture u of the crack increases and undergoes a change to a more elliptical shape, as shown in Figure 3-24. This occurs because as the ratio of the matrix stress, σ_0 , to the effective pressure in the crack, p_0 , increases, the wetted area also increases (Figure 3-23) and causes the fracture surfaces to experience a larger load above the matrix stress. To emphasize the fact that the scaled fracture aperture increases with the ratio of σ_0/p_0 when p_0 is held constant, the maximum fracture displacement has been plotted as a function of the ratio, σ_0/p_0 , which is shown in Figure 3-25. The maximum scaled fracture displacement occurs at the center of the crack, the point $x = 0$ in Figure 3-19.

From the above analyses, it can be seen that the inclusion of a fracture closure or failure condition also has an effect on the fracture

shape and area contacted by the pressurized fluid. Some of the simpler loading conditions have been displayed, e.g., the function p_0 was taken as a boxcar function for the discussion of the effects due to changes in the ratio of σ_0/p_0 when p_0 is made to be constant. Other more complex pressure distributions have also been analyzed, e.g., power law fluid pressure distribution, which show the same trends. It should be emphasized that scaled variables have been plotted and that the inclusion of real reservoir parameters will have to be applied to interpret the actual fracture geometries. While those simplified formulations can provide an indication of the relationships between pressure distribution in the fractures and matrix stress, the flow characteristics of the fracturing fluid to predict fracture lengths and geometries have to be included. These flow descriptions are currently under development.

Analysis of Fluid Flow in Fractures

In the last quarterly report, an instability was discussed that occurred when a constant pressure boundary was applied. It was hypothesized that it was a result of an inadequate specification of the free surface condition. The actual cause and hence solution is much simpler. As is well known, the explicit solution technique that is being used requires the cell Reynolds number to be greater than one for stability. This is not a hard and fast rule, since it is always violated at the free surface. However, it appears that this must hold for "most" of the zones in the problem. It was found that for the pressure inlet condition, the cell Reynolds number was less than one for all zones after computation was well underway. What is found is that the velocity starts out high at the inlet but slowly drops off. It is this slow velocity decay that is the cause of the instability. The ultimate resolution is to incorporate an implicit solution technique into the codes.

A new technique was incorporated into the code to handle the free surface. To be rigo-

Figure 3-22 Pressure-Stress Distributions for $p(x) = p_0 = \text{Constant}$ and for Several Values of σ_m^0/p_0 ; $P(x)$ was Varied with σ_m^0 to Maintain p_0 Constant (the vertical lines represent the wetted fracture length x_0/c)

Figure 3-23 Wetted Fracture Length x_0/c as a Function of σ_m^0/p_0 for $p_0 = \text{Constant}$ and with the Pressure Distribution shown in Figure 3-22

Figure 3-24 Scaled Fracture Displacement as a Function of Scaled Fracture Length for the Pressure Distributions shown in Figure 3-22 (change in fracture shape and displacement is shown for increasing σ_m^0/p_0)

Figure 3-25 Maximum Scaled Fracture Aperature for Increasing (σ_m^0/p_0) with p_0 Constant

rously correct it is required that the free surface satisfy:²⁵

$$\phi - 2\mu \left[n_x n_x \frac{\partial u}{\partial x} + n_x n_y \left(\frac{\partial u}{\partial y} + \frac{\partial u}{\partial y} \right) + n_y n_y \frac{\partial u}{\partial y} \right] = 0 \quad (5)$$

$$\mu \left[2 t_x n_x \frac{\partial u}{\partial x} + (t_x n_y + t_y n_x) \left(\frac{\partial u}{\partial y} + \frac{\partial u}{\partial x} \right) + 2 t_y n_y \frac{\partial u}{\partial y} \right] = 0 \quad (6)$$

where

- ϕ = pressure,
- μ = viscosity,
- n_i = the normal in i direction,
- t_i = the tangent in i direction,
- u = x velocity, and
- v = y velocity.

These conditions have been applied in the past,²⁶ however, a simplified version is being used at present.

The original MAC method sets the pressure to zero in a zone that is cut by the free surface. This has been modified²⁷ to set the pressure to zero on the free surface itself. This is a better approximation and seems to smooth out the pressure field near the free surface.

Following Chan and Street²⁷ an "irregular" star near the free surface is incorporated, as shown in Figure 3-26. The objective in the figure is the pressure at ϕ_{ij} ; ϕ_1 and ϕ_4 are behind the free surface; ϕ_2 and ϕ_3 are on the free surface. The η 's are the respective dis-

Figure 3-26 Irregular Star Near a Curved Boundary

pressure, ϕ_1 , ϕ_2 , ϕ_3 and ϕ_4 . It can be shown that

$$\phi_{ij} = \frac{\eta_1 \eta_2 \eta_3 \eta_4}{2(\eta_2 \eta_4 + \eta_1 \eta_3)} \frac{\eta_3 \phi_1 + \eta_1 \phi_3}{\eta_1 \eta_3 \frac{(\eta_1 + \eta_3)}{2}} + \frac{\eta_4 \phi_2 + \eta_2 \phi_4}{\eta_2 \eta_4 \frac{(\eta_2 + \eta_4)}{2}} + R_{ij} \quad (7)$$

tances from ϕ_{ij} to the known values of where R_{ij} is a term which includes derivatives of both velocity and the divergence of the velocity.

Finally, the first steps to solve for the fluid flow given a real crack shape are being made. A real crack will not have nice parallel walls, i.e., a slot, as has been assumed up to now. Rather there will be some curvature and in fact, the walls will move outward. This requires a more involved and careful handling of the difference equations. The intention is to allow the crack face to move over a background of rectangular zones as it opens. This alleviates the creation of zones inside the crack and thus interpolation of velocity and pressure values over the new set of zones.

²⁵ Catchelor, G. K., F.R.S., "An Introduction to Fluid Dynamics," Cambridge, at the University Press, 1967.

²⁶ Nichols, B. D. and C. W. Hirt, "Improved Free Surface Boundary Conditions for Numerical Incompressible-Flow Calculations," J. Comp. Phys. 8, 434-448 (1971).

²⁷ K-C Chan, R. and R. L. Street, "A Computer Study of Finite-Amplitude Water Waves," J. Comp. Phys. 6, 68-94 (1970).

However, this method will give rise to non-rectangular zones for which the present difference equations will give erroneous answers. As a first step, consider the Poisson equation for pressure

$$\nabla^2 \phi = R \quad (8)$$

This is the same as Equation (7). To solve this, Kershaw's²⁸ method of solving the diffusion equation is followed:

$$\nabla^2 \phi = \frac{\partial \phi}{\partial t} \quad (9)$$

Equation (8) can be looked at as the steady-state solution of Equation (9) with R acting as a source term. The solution technique considers the problem as consisting of two grid systems. The first is a logical grid in (k, l) space. The difference equations are written for this system which is very regular. In fact, it can be considered a rectangular system. Associated with this system is a physical system, (R, z) space, which is the actual physical problem to be solved for. There is a one-to-one correspondence between the two systems. This requires information to specify the needed transformation from (R, Z) to (k, l) . The diffusion equation can be written in a more general fashion as

$$\nabla \cdot (D \nabla f) = \frac{\partial f}{\partial t} \quad (10)$$

where D is the diffusion coefficient and f is, for example, temperature. Accounting for the transformation, the left hand side becomes

$$\begin{aligned} \nabla \cdot (D \nabla f) = & \frac{1}{jR} \left(\frac{\partial}{\partial k} \left[\left(\frac{DR(R_L)}{j} \right)^2 \frac{\partial f}{\partial k} \right] \right. \\ & \left. + \frac{\partial}{\partial l} \left[\left(\frac{DR(R_K)}{j} \right)^2 \frac{\partial f}{\partial l} \right] \right) \end{aligned}$$

$$\frac{\partial}{\partial k} \left[\left(\frac{DR(R_K)}{j} \right)^2 \frac{\partial f}{\partial k} \right] + \frac{\partial}{\partial l} \left[\left(\frac{DR(R_L)}{j} \right)^2 \frac{\partial f}{\partial l} \right],$$

where

$$j = \det \begin{pmatrix} \frac{\partial R}{\partial k} & \frac{\partial R}{\partial l} \\ \frac{\partial Z}{\partial k} & \frac{\partial Z}{\partial l} \end{pmatrix} \quad (11)$$

$$R_K = \begin{pmatrix} \frac{\partial R}{\partial k} \\ \frac{\partial Z}{\partial k} \end{pmatrix} \quad \text{and} \quad R_L = \begin{pmatrix} \frac{\partial R}{\partial l} \\ \frac{\partial Z}{\partial l} \end{pmatrix}$$

It is this equation which is differenced. The details are sketched out in Kershaw's paper and so will not be shown here.

The method was coded and a test problem run that has an analytic solution, a rectangular-like region with insulated boundaries at top and bottom, the left hand side is held at $f = 1$ and the right at $f = 0$. The late time or steady state solution is a linear drop in " f " from left to right. Figures 3-27 and 3-28 show the grid used and isotherms at early and late times, respectively. In Figure 3-28, the linear drop is easily seen.

Several points about both the problem and difference scheme are important:

- The difference scheme is a 9-point one which involves all the neighbors. With a rectangular grid, it reduces to the usual and expected 5-point scheme.
- The usual 5-point scheme applied to this problem will give isotherms which follow the bends in the grid system. Clearly, Kershaw's scheme results in the expected parallel isotherms.

The grid system used makes a more difficult problem than is anticipated in crack flow but is a good test of the method.

This furnishes a means for solving Equation (9) given a real crack shape. Work still must be done to properly incorporate the source term, R , given a distorted grid.

²⁸ Kershaw, D. S., "Differencing of the Diffusion Equation in Lagrangian Hydrodynamic Codes," Lawrence Livermore Laboratory, Journal of Computational Physics 39, 375-395 (1981).

$f = 1$

Figure 3-27 Isotherms, the Vertical Solid and Dotted lines, in a Grid which Becomes More Irregular as It Moves Away from the Boundary where $f = 1$ for Early Times.

$f = 1$

Figure 3-28 Isotherms, the Vertical Solid and Dotted lines, in a Grid which Becomes More Irregular as It Moves Away from the Boundary where $f = 1$ for Late Times.

LABORATORY EXPERIMENTS

Fluid Flow in Cracks

During the past quarter, development work continued on the PMMA frame for the study of fluid flow in a crack. The design has been described earlier.²⁹ The two surfaces, which act as sides of the crack, were lapped flat and a strip of shim stock of known thickness was placed along each edge of the crack prior to assembly so that the crack width was known. Pressure gauges were installed at the fluid inlet and at three positions along the crack. Distance markers were placed along each edge of the crack so that the position of the fluid front could be recorded as a function of time. The rate of fluid flow into the crack was controlled by a micrometer valve. In the preliminary tests run so far, a crack width of 0.002 in. has been used. The fluid used is glycerol colored with India ink for better visibility. As expected, it has been found that for a given opening of the micrometer valve, the rate of flow of the glycerol through the crack is sensitive to the ambient temperature due to the change of viscosity of the glycerol with temperature. With a crack opening of 0.002 in. and an 0.025 in. setting of the micrometer valve, a typical experiment at an ambient temperature of about 70°F requires approximately 30 minutes for the fluid front to propagate the 18-in. length of crack.

A photograph of a typical experiment is shown in Figure 3-29. The fluid inlet is at the bottom and the fluid front propagates upward. The lower gauge measures the inlet pressure and the other three gauges record the pressure along the crack. In this figure, the fluid front is visible just below the upper gauge. A graduated cylinder at the upper end of the crack collects fluid so that the steady state flow rate can be measured after the fluid front reaches the end of the crack. Experiments are planned in which the fluid

Figure 3-29 Fluid Flow Experiment

front velocity is measured as a function of crack width, inlet pressure, flow rate and fluid viscosity.

Rock Properties Measurements

Current methods for predicting fracture intensity, geometry and extent resulting from fracturing stimulation (using either high explosive or hydraulic means) of an initially low permeability natural gas bearing rock require certain equation-of-state (EOS) measurements as input data to the calculation codes.

The core samples used contain alternating sections of sandstone, shale and mixtures of the two. The bedding planes between sandstone and shale are horizontal (perpendicular to the axis of the core sample). However, within sections of pure shale, the bedding is not obvious. The sandstone section contains thin layers of black material. The colors of the sandstone and shale are

²⁹ LLNL Gas Stimulation Quarterly Report for January to March, 1981.

light gray and dark gray, respectively. The sandstone is fine to very fine grained.

In the last quarter, the determination of uniaxial stress compressive strength of the Mesaverde sandstone was completed. The sample, which was loaded parallel to bedding, was slightly weaker than that loaded normal to bedding. Results of this study are shown in Figure 3-30 as strength vs. pressure.

Figure 3-30 Failure Envelope of Mesaverde Parallel to Bedding Sandstone from Wyoming, 3,510 m Depth, Loaded

Measurement was also completed of the one-dimensional strain loading (in compression) for the Mesaverde shale and sandstone loaded normal to bedding. The results of this measurement are shown in Figures 3-31 and 3-32 in the form of shear stress, $(\sigma_1 - \sigma_3)/2$, vs. confining pressure, σ_3 , when the radial strain of a specimen is kept at zero. The strength of the sandstone is about 2 to 2.5 times that of the shale.

The pressure/volume behavior of the Mesaverde shale was also determined. Figures 3-33 and 3-34 show examples of volumetric strain of the shale as a function of pressure. The volumetric strain/pressure curve of a specimen with its longitudinal axis parallel to bedding (Figure 3-33) is slightly more compressible (about 10 percent) than that normal to bedding (Figure 3-34). The determination of pressure/volume behavior of the sandstone specimens with their longitudinal axis normal to bedding has also been completed. One example of the volumetric strain/pressure curve is shown in Figure 3-35. The sandstone is about 15 percent more compressible than the shale.

In this quarter, a paper entitled "Mechanical properties of Mesaverde shale and sandstone at high pressure," was presented at the 8th International Conference of AIRAPT, Uppsala, Sweden.

ULTRASONIC IN SITU STRESS TOOL FEASIBILITY STUDY

Pulsed Phase Locked Loop Technique (P2L2)

The P2L2 system described in the last quarterly report was evaluated further during this reporting period. Problems which became apparent are discussed below.

In a borehole configuration, a technique for measuring in situ stress levels and orientation of the principal stresses relies on relative measurements of tangential and radial shear wave components at several locations around the borehole. With the P2L2 system, the lock-in frequency for a particular mode depends on the travel time between source and receiver transducers, Δt , the frequency range setting of the pulse generator, the gated width of the pulse, the setting of the sampling point, as well as other environmental factors such as temperature and the nature of the coupling between the sample and transducers. In summary, the variables are such that for a given set of environmental conditions, the

Figure 3-31 Compressive Strength of Mesaverde Shale from Wyoming, 3,510 m Depth, Under 1-D Strain Loading Normal to Bedding

Figure 3-32 Compressive Strength of Mesaverde Sandstone from Wyoming, 3,510 m Depth, Under 1-D Strain Loading Normal to Bedding

Figure 3-33 P-V Behavior of Mesaverde Shale from Wyoming, 3,510 m Depth, Specimen Axis Parallel to Bedding

Figure 3-34 P-V Behavior of Mesaverde Shale from Wyoming, 3,510 m Depth, Specimen Axis Normal to Bedding

Figure 3-35 *P-V Behavior of Mesaverde Sandstone from Wyoming, 3,510 m Depth, Specimen Axis Normal to Bedding*

lock-in frequency is not repeatable. Hence, measurements must be made at several integral intervals of in-phase frequency in order to determine the absolute velocity, as shown in the last report. The repeatability and accuracy of this method has been tested in the laboratory. The results show that even though the system can detect changes in velocity of one part in six or better, the ability to measure absolute velocity is limited by the variability in lock-in frequency to about one percent. For the present experiment, this results in the unacceptably high uncertainty in travel time of about $\pm 1.0 \mu s$.

Another problem involved with the P2L2 system, as used in the laboratory, is mode contamination. The P2L2 requires that the sampling point is in the same mode during the experiment. Since refracted waves are generated at the interface between the wedge

and the sample, there are many modes present. If a smaller wedge is used, the difference in the travel time for different modes inside the wedge becomes very small and mode contamination becomes a serious problem.

Because of the limitations described and because a resolution of $0.1 \mu s$ in pulse timing with the pulsed technique can be approached (as described in the previous quarterly report), further investigation of the P2L2 system has been abandoned.

Pulsed Technique

During this period the following new hardware was received:

- HP3497A Data Acquisition/Control Unit,

- DIGITAL VT1000 Terminal-Display Unit,
- DATA SYSTEMS — Hard disc memory and floppy disc drive, and
- RT11 Version IV computer.

The capability of monitoring horizontal and vertical loads and displacement voltages from the biaxial press is now available with the acquisition of this equipment. There is also a channel available to monitor strain gauge voltage to calibrate the system. In addition, the same capability to digitize the acoustic waveforms continues. However, by using the foreground-background modes in the computer, it is possible to automatically monitor load and displacement at the same time a waveform for a particular load is being digitized.

This system was used to calibrate the pressure gauges for the horizontal and vertical loads in the biaxial system. The operation of the boxcar integrator was modified so that the initiation of the boxcar scan of the waveform and the digitization of the data takes place simultaneously. This was done by tying the trigger which starts digitization in the ADR program to the initiation of the scan by the boxcar integrator. Previously, the digitization would start only in ADR when the signal level reached some arbitrarily set value. The present configuration, relative to the system trigger, assures that the starting point is the same in every file. This allows two different modes to be measured separately, added into one file and then the time delay calculated as discussed in the previous quarterly report.

Figures 3-36 and 3-37 show the stress effect on the travel time for Nugget Sandstone under biaxial loading. The error bar indicates the 95 percent confident interval calculated from the pulse timing technique. Figure 3-36 is the stress effect of a radially polarized shear wave with the stress in the polarization direction fixed at 250 psi with the stress normal to the polarization direction varying from 0 to 600 psi. Thus, the effective stress

is compressional and the velocity increases with the load. The calculated velocity/stress coupling coefficient is 2.53×10^{-5} km/sec/psi. Figure 3-37 is the stress effect of a tangentially polarized shear wave with the stress in the polarization direction fixed at 300 psi with the stress normal to the polarization direction varying from 0 to 600 psi. Thus, the effective stress is tensional and the velocity decreases with the load. The calculated velocity/stress coupling coefficient is 5.85×10^{-5} km/sec/psi, about twice the value for a radially polarized shear wave.

When only one pure mode is measured at a time, measurement of different modes or different directions in the borehole requires cyclic loading which may permanently change the microcrack characteristics of the sample. To avoid this problem, a new transducer/wedge assemblage, using four pairs of small shear transducers and fixed angle wedges, has been designed and built, as shown in Figures 3-38 and 3-39, so that all four shear waves, i.e., V_{zr} ($\theta = 0^\circ, 90^\circ$) and $V_{z\theta}$ ($\theta = 180^\circ, 270^\circ$) will be generated under a specific loading condition without changing the transducer location or the polarization direction.

Testing of the new transducer/wedge assembly indicated that there were mode interference problems due to the smaller size of the wedges. Experiments have been performed with various wedge materials and bonding agents in an attempt to achieve better mode separation and wave amplitude. Lead, brass and copper wedges were tried. Lead wedges resulted in very high signal attenuation, brass wedges were somewhat better, but copper wedges gave best results.

Copper has a high Poisson's ratio with low signal attenuation, so that compressional wave velocity in the wedge is faster and shear wave velocity in the wedge is slower. However, because of the high acoustic impedance mismatch between copper and rock, more energy is confined within the wedge and less is coupled to the rock.

Experiments have also been performed with

Figure 3-36 Stress Effect on Travel Time for a Radially Polarized Shear Wave

Figure 3-37 Stress Effect on Travel Time for a Tangentially Polarized Shear Wave

Figure 3-38 Transducer/Wedge Assemblage

Figure 3-39 Closeup – Transducer/Wedge Assemblage

Figure 3-40 Radial Shear Mode

↑ $t = 70 \mu\text{sec}$

Figure 3-41 Tangential Mode

↑ $t = 69 \mu\text{sec}$

various materials to improve the coupling at the transducer-wedge interface. What is desired is a non-permanent, hard, brittle bond. Phenyl salicylate was initially tried, but it was difficult to maintain a thin, uniform bond without laborious preparation. Presently, Eastman 910 glue is being used, which gives fairly good results. With the copper wedges and glue for a wedge-transducer bond and using honey for the wedge-rock bond, a very good radial shear mode can be generated and detected, as

shown in Figure 3-40. However, the tangential mode is still very weak and presently, attempts are being made to correct this problem, as shown in Figure 3-41.

It becomes apparent that the ideal wedge material to match both the velocities and the acoustic impedance has not yet been found. One way to solve this problem is to mix two or more components together to meet these critical requirements. Experiments are proceeding with the idea of mixing

epoxy with high density, high velocity powder such as aluminum oxide to produce more suitable wedge material.

Once the ability is developed to generate a good measurable tangential shear mode in the four transducer pair configuration, the experiment will be ready for measurement of V_{zr} ($\theta = 0^\circ, 90^\circ$) and $V_{z\theta}$ ($\theta = 80^\circ, 270^\circ$) as a function of total load and differential stress.

LOS ALAMOS NATIONAL LABORATORY

INSTRUMENTAL AND LOGGING TOOL DEVELOPMENT

Double Helmholtz-Pair NMR Spectrometer

The Double Helmholtz-pair NMR spectrometer was placed in operation after it was shielded by a Faraday cage and other noise reduction techniques were completed. Preliminary test spectra have been obtained at tool frequency (0.5 MHz) in preparation for measuring saturated WGSP core NMR relaxation properties. Figure 3-42 shows the first NMR signal obtained from a water-saturated western gas sands core in the Helmholtz-pair spectrometer. The large width of the free induction decay and spin echo are evidence of good magnetic field homogeneity. Initial measurement will be at atmospheric pressure. Design for a pressurizing cell is in progress, which will allow investigation of the effect of in situ confining pressure on pore structure by monitoring changes in the NMR response.

Four-Inch Permanent Magnet Tool Mockup

The magnetic field of the 4-in. permanent magnets of the laboratory tool mockup has been mapped in two configurations: one with the magnets properly aligned and the other with one magnet slightly tilted (2°). The results are shown in Figures 3-43 and

3-44. Figure 3-43 shows the measured magnetic field at region of the peak (homogeneous) field at about 114 mm from the magnet axis with the magnets aligned. Figure 3-44 is the corresponding result with the magnets misaligned 2° . The small variation evident in Figures 3-43a and 3-43b is due to the laboratory ambient field. It is evident that the field configuration is visibly affected by misalignment of the magnets by this amount, but experimentally the NMR spin-echo signal is not affected.

Six-Inch Permanent Magnet Tool Prototype

The 6-in. permanent magnets for the prototype tool have been received after being remagnetized at the factory. The magnetic field magnitude in the homogeneous region, which occurs at approximately 7.5 in. from the magnet axis, has been measured to be 120 Gauss.

Superconducting Magnet Tool

The superconducting magnet pair is being fabricated for a laboratory mockup of a superconducting version of the NMR logging tool. These magnets are designed to produce a region of uniform 120 Gauss magnetic field 12 in. from the central axis. A vacuum pumping station and provisions for handling the magnets are in preparation.

Data Acquisition and Analysis

Software has been written for computer control of the tool electronics and data acquisition using an Interface Technology timing simulator. The 4-in. laboratory mockup has been operated in this mode and NMR relaxation time measurements have been made under computer control.

Improved Receiver Design

An improved receiver design is being developed with the intent to replace the present

Figure 3-42 First NMR Signal from a Water Saturated Western Gas Sands Core in the Double Helmholtz Coil Spectrometer Operating at 0.5 MHz

Figure 3-43 Radial Normalized Magnetic Field Deviations at Opposite Azimuth Angles with Magnets Aligned

Figure 3-44 Radial Normalized Magnetic Field Deviations at 0° (a) and 180° (b) to Tilt Direction with Magnets Misaligned 2°

commercial preamplifier, receiver and detector equipment used in the laboratory demonstration system. The new receiver will be optimized for the 0.5 MHz operating frequency.

The new preamplifier will use capacitive feedback to produce a low input impedance for rapidly damping the NMR probe circuit while still keeping the signal-to-noise ratio (SNR) advantage of a "noise-matched" amplifier. The main amplifier incorporates a linear phase band pass filter to establish the system bandwidth. The detection system will have a true phase-sensitive detector to reject the quadrature noise components and thereby improve the system's SNR. The probe/preamplifier interface circuitry will include a switched attenuator to avoid receiver overload when rf power is applied to the probe.

A variable delay circuit centered around $2\mu\text{sec}$ (0.5 MHz) has been designed, built and tested to provide a controlled-phase reference signal for the receiver phase sensitive detector, shown in Figure 3-45. The circuit uses only passive components and therefore, introduces no extraneous noise. Use of the present commercial variable-phase circuit has the disadvantages of incurring a detectable amount of additional noise (from its logic circuitry) and of a variation in output level with delay setting.

A test of the new delay circuit with the present detector showed a slight improvement over standard envelope detection at low SNR conditions. However, the present unit is not a true phase-sensitive detector and better results may be found with the new receiver system.

STUDIES ON NMR PROPERTIES OF FLUIDS IN POROUS MEDIA

Western Gas Sands Project Core

Eighteen cylinders ($1\frac{1}{2}$ in. diameter x $1\frac{3}{4}$ in. long) have been cut from a new WGSP core

and are being prepared for T_1 and T_2 measurements in the 4-in. magnet laboratory logging tool mockup as well as in the Double Helmholtz-pair magnet at tool frequency. This tool-frequency data will provide further basis for interpretation of logging tool measurements.

Synthetic Samples

The Los Alamos Ceramics Materials Group is preparing to fabricate a ceramic sample with cylindrical pores of specified diameter. The NMR data on this type sample will contribute to a better understanding of the parameters affecting NMR relaxation rates in porous media and will aid in the interpretation of the logging tool data. In addition, previously run samples of sintered ceramic powder, which showed nearly uniform pore structure by NMR relaxation experiments, are being investigated by acoustic techniques in collaboration with researchers at Harvard University. These data will provide further corroboration of the NMR relaxation data in determining pore structure of these simple materials. As a final step, these same samples will be subjected to thin sectioning and photomicrography for verification of the actual pore structure resulting from the sintering process.

SANDIA NATIONAL LABORATORIES

FRACTURE DIAGNOSTICS

Borehole Seismic System

A hydrofracture experiment involving three wells was performed by Sandia Laboratories for Cities Service (CITCO) near Madison, Kansas. Two wells (F6 and B6) were fractured while a third well (D4) was used for observation. Well F6 is approximately 600 ft east of well B6, and well D4 is about 600 ft north of F6 and B6. Both wells were fractured with approximately 250 gallons of clear water. This experiment represented the

Changes over Previous Circuit should
Decrease Variations in Output Level
and Input Loading with Delay Setting

Revised 500 kHz Sine Wave Reference
Signal Phase Shifter Covering over 360 $^\circ$
for Use with Matec NMR System

Figure 3-45 Revised 0.5 MHz Sine Wave Reference Signal Phase Shifter Covering Over 360 $^\circ$, for Use With Present Laboratory NMR System

shut in and signals were recorded on the hydrophone system in 50 meter intervals down to the fracture zone. Approximately 20 minutes were allocated for recording at each location.

Because of the relatively high formation velocities involved and the 10-ft spacing of the linear array of the phones, the mathematical modeling indicates that an extremely accurate measurement must be made to obtain good fracture oriented acoustic source location. The reduction of data obtained to date has indicated that the signal to noise ratio is not sufficiently high to give acceptable source location results. However, it is felt that some meaningful information is available and certainly can be obtained from future data. The acceptable source location here is meant to be fracture height information.

The system has undergone rigid environmental testing. The maximum pressure encountered in Canada was very nearly 10,000 psi which occurred during peak pumping. From approximately 30 Hz to 2,000 Hz, the sensitivity of the hydrophone transducers appears to be very good. During operation, the high static pressures encountered do not appear to reduce the sensitivity or quality of the system. The majority of signals received in all the tests are clean and readable. In most cases, a clear difference in arrival time can be measured.

Until a complete analysis of the data collected to date has been made, future activities for the hydrophone system cannot be planned.

Surface Electrical Potential

The data from the Wakefield test well have been under analysis. Sandia completed the hydraulic fracture mapping experiment with Columbia Gas on October 7, 1980. The test site, located at Belden, Ohio, south of Cleveland, was located on an 86-acre farm 0.6 miles west of town. The gas well casing was perforated between depths of 816 and 1,050 ft in the Devonian Shale. For this experiment,

Sandia fielded the surface electrical potential system (SEPS), the borehole seismic system and the borehole hydrophone system. The tiltmeter fracture mapping system was also fielded by M. D. Wood, Inc. under contract to Sandia.

The SEPS acquired two separate sets of data during the main fracture. The first data set was acquired by monitoring the surface electrical potential between 24 stakes (which were placed at a 450-ft radius around the fracture well) and the reference stake (which was located approximately 2,550 ft from the fracture well on an azimuth of 166°), as shown in Figure 3-46. The second set was acquired by monitoring the surface electrical potential between the stake sets at the 450- and 636-ft radii. The test site was pulsed by SEPS between the fracture well casing and another well casing located at an azimuth of 267°, approximately 5,000 ft away.

On October 2, the well had undergone a series of small volume breakdowns designed to produce the seismic data acquired by the borehole seismic system. Thus, on October 7, some degree of formation fracturing had already occurred.

Pressure and flow data, shown in Figure 3-47, relate to the main fracture treatment. An earlier treatment (not shown) occurred at 1445 hrs. The pumping pressure ranged from a peak of 3,470 psi to approximately 795 psi after 61 minutes. Flow rates during the main treatment began at 4 BPM two to three minutes into the treatment, and increased in a stepping fashion 37 minutes when a flow rate of approximately 34 BPM was reached. This flow rate continued until 1612 hrs.

The shape of the 24 radials vs. time within each of the two data files is nearly identical. Figure 3-48 illustrates the two data types. The influence of the fracture process is evident in the RAD2C1 data. The influence on the RAD1L1 data is more subtle, but indicates a gradual increase in magnitude during the main treatment. A gradual decrease in magnitude occurred after shut in.

first time that the partner (CITCO) reimbursed Sandia for expenses. Also, this represented the first time the borehole seismic package was utilized in conjunction with an EOR project (fracturing to aid a micellar-polymer flood).

A total of four brittle fracture seismic type signals were recorded by the unit in well F6 during the fracture experiment in that well, along with a large number of non-brittle fracture type signals. No signals were recorded in well D4 during this experiment stage. Three of the four seismic signals indicate a fracture of 25° to 205° . The fourth seismic signal was at an azimuth of 135° . The non-seismic signals were observed at azimuths of 30° and 135° .

A total of fourteen seismic signals were recorded during the well B6 experiment along with a large number of non-seismic signals. Thirteen of the seismic signals indicated an azimuth of 38° to 218° for the fracture. The fourteenth signal was at an azimuth of 136° . One seismic signal was recorded in well D4 during the fracture in well B6. The azimuth of this signal was 38° and at a distance of approximately 70 ft from the wellbore. Considering the small volume pumped during the fracture, the signal recorded in well D4 must have been produced by local activity and not from the B6 fracture, especially since this signal is at the same bearing as that observed in B6 and cannot intercept the fracture.

If all of the signals observed are averaged, it can be concluded that induced hydraulic fractures in this producing field are oriented in a plane 32° to 212° .

Borehole Hydrophone

About 1975, El Paso Natural Gas Company performed an experiment in New Mexico, where acoustic signals in the 100 Hz to 2,000 Hz frequency range were detected by a downhole hydrophone immediately following a hydraulic fracture operation. Since then,

experiments have been performed using both seismic and hydraulic acoustic instrumentation. However, until recently all systems tested made use of surface or near surface detectors. Systems developed and now new systems are being tested that place transducers downhole in the vicinity of the fracture. One of these systems is the downhole hydrophone tool.

The tool consists of a vertical array of four pressure sensitive hydrophones with 10-ft spacing. The diameter of the tool is $1\frac{1}{2}$ in. and it contains both the hydrophone transducer and its associated electronics. The line to the surface is a single conductor armor shielded cable designed to operate up to 250°F and to a pressure of 10,000 psi. It is now being evaluated for downhole detection of passive acoustic signals for the purpose of hydraulic fracture mapping.

Most of the work this quarter involved the continuation of reducing the data collected in the Wakefield and Kernridge tests. In examining the data already collected, it appeared that a redesign of the amplifiers was in order. The change in the design was minor in that only the gain and a minor change in the amplifier low pass filter was made. The gain was reduced approximately 3 db and the filter altered to produce a consistent relative phase change in the four amplifiers. Also, a commercial plus or minus 15V power supply was used in place of the in-house design, which simplified the overall package design. The electronics were then tested, including temperature tests, and the entire package was assembled and checked for use in the hydrofracture tests to be made in Canada by Exxon.

The hydrophone tool was included in the practice operation conducted by Exxon on a well located near Rocky Mountain House, Alberta, Canada. The depth of the fracture zone was approximately 2,200 meters. Before the fracture operation, the tool was lowered to a depth of 2,050 meters and remained at that location during the fracture operation. After the fracture, the well was

Figure 3-46 Wakefield Test Site Configuration — Columbia Gas

Figure 3-47 Wakefield Pressure/Flow Profile — Columbia Gas

Figure 3-48 Data Files RAD1L1 and RAD2L1 Percentage Change from Mean Radial A12 – Columbia Gas

Figure 3-49 Columbia Gas

The RAD2L1 data was produced by the surface electrical potentials between the 450- and 636-ft radii. This gradient data appears to be sensitive to the depth of the equivalent center of the current injection. Prior to 1445 hrs, the fracture well casing was injecting a large portion of the total current at and near the surface. The magnitude of all 24 radials was highest at this time. During the attempt at 1445 hrs, the fluid-filled well casing caused the current injection center to move downward. This was due to the well casing filling with conductive fluid and/or conductive fluid entering the in-place fractures to a limited degree. The wellhead retained a residual pressure of approximately 240 psi. The start of the main treatment at 1517 hrs pushed the current injection center still deeper. The full depth was achieved in a short period of time, indicating that only a small volume of fracture fluid was needed. The full depth of the current injection center was assumed to lie above the range 840 to 1,030 ft since this depth range is known to have taken fluid. The equivalent center of current injection would tend to be located

above this depth range due to the influence of the well casing and hydrostatic loading fluid. The current injection center remained at depth during the main treatment with a very slight rise toward the surface. At 1611 hrs, after approximately 55 minutes, the surface radial tilt began to subside, as shown in Figure 3-49 (M. D. Wood). Coincident to this, the RAD2C1 data indicated the beginning of a large current redistribution within the current injection electrode (fracture well), shown in Figure 3-48. The equivalent current injection center moved significantly upward toward the surface.

The magnitude of injection current remained essentially constant between 1611 and 1617 hrs. After 1620 hrs, the RAD2L1 data remained essentially constant until the SEPS shut down. Evidence of current redistribution is seen in the RAD1L1 data at 1615 hrs, when a large increase in magnitude occurred. The mechanism for this apparent change in injection electrode-geometry and subsequent current redistribution would seem to be

explained by the closure across the 1611 to 1617 hrs time interval of the vertical conduit feeding the horizontal fracture located above 840 ft (M. D. Wood). The possibility of the gradient data (RAD2L1) containing vertical fracture height information will be pursued.

The RAD1L1 data was produced by the surface electrical potential between the 450-ft radii and the reference stake at 166⁰, 2,550 ft from the well. Present analysis indicates that these data are more responsive to the vertical fracture progress. The present status of the mathematical model does not consider the presence of a horizontal fracture above the vertical fracture(s) of interest. Within the constraints implied by this, strong evidence of vertical fracture growth began at 1548 hrs at an azimuth of 181⁰. The magnitude of this vertical presence increased beyond shut in at 1618 hrs and reached a maximum amplitude at 1622 hrs. The azimuth at this time was 182⁰. It has not been established yet whether this maximum vertical fracture amplitude resulted from fracture growth, from the current redistribution, or other mechanisms.

At 1604 hrs, Figure 3-48, a significant continuation of vertical fracture growth occurred. This is evident in the azimuth data (185⁰ indicated) and in the SEPS loop impedance data. The SEPS loop impedance, composed in part by the fracture well contact resistance (and thus the area and geometry of this fracture well or electrode), began a gradual downward trend continuing through 1636 hrs. At this time, the loop impedance downward trend reversed. The magnitude of the vertical fracture(s) data began an upward trend (Figure 3-48), which would seem to indicate vertical fracture(s) closure and current redistribution within the fracture well electrode. The depth of this closure(s) is approximated by extrapolating the minimum principal stress at 1,000 ft (1,150 psi, M. D. Wood) across the decaying pressure profiles at 840, 875, 980, 1,015 and 1,030 ft after shut in. This is then correlated with the time

position in which the SEPS loop impedance reversal occurs (Figure 3-49). Assuming the fractures close at or near the wellbore, good matches occur for the 1,015- and 1,030-ft depths with a preference for 1,015 ft. It seems that an improved method of monitoring the SEPS loop impedance should be added.

Anelastic Strain Recovery Measurements

A reliable method of predicting the orientation of massive hydraulic fractures in low-permeability formations is of great importance to the gas industry. An accurate prediction of the fracture orientation would allow optimum well location and spacing for increased recoveries in a developing field. In order to predict the azimuth of a hydraulic fracture, it is necessary to know the direction of the minimum horizontal principal stress, because a hydraulic fracture propagates perpendicular to this stress direction. A strain relaxation technique is currently being investigated as a possible method of determining directions and the ratio of the maximum and minimum horizontal strains (stresses) from oriented core and thus predict the fracture orientation.

The procedure for the technique was presented in a previous quarterly report with initial relaxation measurements from the NTS on volcanic tuff and unoriented sandstone core from the Piceance Basin. Recently, new relaxation measurements were made on Bossier Sandstone from the Cotton Valley Trend in East Texas.

Strain relaxation measurements were made on four sections of oriented core from a depth greater than 9,000 ft. As seen in Table 3-6, all four cores showed significant relaxation. The ratio of E_1/E_2 (maximum to minimum horizontal stress) ranged from 1.50 to 1.71. The azimuth of E_1 was consistently oriented, with a mean orientation of N69E+7⁰ (69⁰ + 7⁰).

Table 3-6 Summary of Anelastic Strain Recovery Data from Bossier Sandstone, Oakhill Field, Texas

Core*	Final Principal Strain Magnitudes		Ratio of E_1/E_2		Azimuth of E_1^{**}		Recovery Time, hrs
	E_1 , wE	E_2 , wE	Range	Mean	Range, deg.	Mean $\pm$ Std. Dev.	
A	268	156	1.62 - 1.80	1.71	55-67	62 ± 4	11.4
B	309	171	1.50 - 1.89	1.70	68-86	77 ± 6	10.8
C	208	135	1.58 - 1.71	1.65	63-79	72 ± 6	10.8
D	246	149	1.39 - 1.61	1.50	61-71	66 ± 3	9.7
						69 ± 7	

* Core from a depth that is greater than 9,000 ft

** Azimuth is given as $0^\circ = N$, $90^\circ = E$, $180^\circ = S$, and $270^\circ = W$

FORMATION MAPPING

Mathematical Procedure for Inverting Cross Borehole Traveltime Data

During the past quarter, modifications have been made to the forward model (raytrace) segment of the computer program in an effort to find the entire set of possible raypaths which link a given shot point to a given receiver point through a set velocity model. From the set of raypaths, the one having the minimum travel time is selected for comparison to the field data which is to be inverted. The ultimate scheme will be to model all possible raypaths for every possible shot-receiver pair and determine the minimum time raypath for each pair.

As an example, included are model results based on a velocity model presented by Bois, et al³⁰ for raypaths from a single

shot point at a given depth (150 m). The receiver well is 450 m away from the shot. The variable parameter, shown in Figure 3-50, is the initial launch angle. For a given angle, the ray eventually goes out the top of the model, goes out the bottom, or intersects the receiver well. For those that intersect the well, total travel time can also be determined. The two parts of Figure 3-51 show intersection depth vs. angle and total time vs. angle. From such a set of curves, it is possible to select those rays (equivalently initial launch angle) which reach a desired geophone (depth point). Given this set of angles, travel times can be compared to determine which is the minimum. The intercept vs. angle plot has some very steep segments. This requires an adaptive iteration scheme to insure the angular increment is halved or halved again until the criterion is satisfied. Current work involves trying to automatically find the minimum time raypath.

³⁰ Bois, P. M., N. LaPorte, M. Lavergne and G. Thomas, Geophysical Prospecting, pp 42-83, No. 1, V. 19, 1971.

Figure 3-50 *Schematic Showing Multiple Raypaths Linking the Same Shot Receiver Pair. [The rays are distinguished by their initial launch angle (a).]*

FORMATION EVALUATION

Inversion of Sonde Responses

Logging tools measure the response of a formation after it has been subjected to some stimulus. For example, resistivity tools measure the voltage induced in a formation when it is subjected to a known current. To deduce the resistivity of the formation from this information requires the solution of an inverse problem. Inverse problems are more difficult to solve than forward problems. For the present example, the corresponding forward problem would be to find the voltage-given radii of the borehole and the invasion zone and all

pertinent resistivities. Traditionally, inverse problems have been attacked by first solving many forward problems and compiling the solutions in charts. Then the inverse problem involves a chart look-up and interpolation procedure. This technique may be applied to simple logs in simple situations, e.g., resistivity logs in formations with thick horizontal layers.

When more complicated logs are considered, chart techniques become cumbersome, if not impossible to use. Dielectric logs fall into this category since more parameters are involved; each zone of the forward solution involves both the high frequency resistivity and the dielectric permittivity. Another example is several logs being examined simultaneously. In both cases, a form of multi-dimensional, non-linear regression analysis is required.

A simple example of regression analysis is fitting a set of data to a line by a least squares technique. If the problem is non-linear, iterative techniques must be adopted. In these techniques, the data are compared in a least-squares fashion with the solution of a trial forward problem. If the convergence is not satisfactory, the techniques indicate the direction in which the model parameters should be adjusted to obtain a better fit. Iterations proceed until a satisfactory fit is obtained. Since each iteration involves solutions of a forward problem, regression techniques require fast, real time forward solutions or a set of tables generated from slower forward solutions.

Fast forward solutions for high frequency dielectric logging sondes are discussed in the next section of this report. Low frequency electrical logs are of interest since they can determine the depth of the invasion front (which may be related to the formation permeability) and low frequency resistivities of the invaded and virgin zones (which will aid in evaluating dielectric logs).

Low frequency forward problems involve only the solution of Laplace's Equation since the wavelength of the radiation is

Figure 3-51a Intersection Depth vs. Angle

Figure 3-51b Total Travel Time vs. Angle

longer than any formation or tool dimension. Laplace's Equation has been solved for non-layered formations, including borehole effects, using conventional techniques. More realistic formations are layered and the solution is more complicated. Conventional techniques yield a set of coupled integral equations that may be slow to solve, even on a large computer. Thus, a finite element heat flux code was modified to solve the problem of a horizontally and radially layered formation. While not very fast (each iteration requires a few minutes on a CDC 7600 and a complete regression analysis requires about ten iterations), it is sufficiently fast to use in logging operations of demonstration importance. However, for routine applications, faster forward solutions will be required. Modifications to yield faster forward solutions are being made.

Limitations and Extension of Dielectric Logging

Dielectric logging seeks to determine the dielectric properties of formation rocks. Subsequently, the production parameters of reservoir rocks are obtained from the dielectric properties. This two-step effort is motivated by the fact that the dielectric properties of rocks vary with the constituent composition (gas, oil, matrix material) and structural arrangement of the pores.

The formation is interrogated by a dielectric-logging sonde consisting of transmitting and receiving coils aligned coaxially along a wellbore. There is usually mud in the wellbore and invasion of mud filtrate into the formation. The basic idea of sonde modeling is to build a good analytical model for the interrogated environment and to fit the model with measurable responses.

In situ measurable responses will vary with four sets of parameters:

- transmitting terminal parameters (transmitting current, coil size, etc.);

- receiving terminal parameters (receiver spacing, voltage and phase, etc.);
- constitutive parameters (formation dielectric constant and resistivity); and
- geometrical parameters (thickness of invasion zone, etc.).

The first two sets are known or measured, and the last two sets are designated as desired (or to-be-determined) parameters.

Due to difficulties in practical instrumentation and/or inadequacies in analytical modeling, simplifying assumptions are made in sonde modeling. Assumptions always entail limitations. Several of these limitations are reviewed for the purpose of extending the capabilities of dielectric logging.

Present dielectric logging theory assumes that the current on the transmitting (Tx) coils and the fields on the receiving (Rx) coils are of importance. If this assumption is to have an amplitude error of less than 15 percent, the diameter of logging coils would have to be less than 0.03 in medium wavelengths. For interrogating typical formations, using a coil diameter of 5 cm, logging frequencies would have to be less than 30 MHz. To extend dielectric logging with frequencies up to 100 MHz, an extended logging theory should include electric-dipole and magnetic-quadrupole couplings. This extended theory is being investigated.

Dielectric logging theory also employs an assumption that a formation with mud-filtrate invasion effects is piecewise homogeneous and circumferentially symmetric around the axis of the wellbore. As a result, the undetermined formation can be modeled as a tandem network consisting of individually defined transfer functions for all zones of different radii and dielectric properties. A common practice in actual dielectric logging is to measure only the transfer impedance of the modeled network. This practice entails an ambiguity in the network function.

To eliminate this ambiguity, another transfer function (e.g., transfer admittance) is needed. One possibility is to measure the short circuit as well as the over circuit voltage induced in the receiver coils. This extended measurement requirement helps to eliminate the ambiguity of overall network function. Whether it would enhance the uniqueness of inverting the individual transfer functions of the network is being investigated with parameter-inversion techniques.

The immediate goal in dielectric logging is to uniquely invert the dielectric properties and the thickness of individual zones (assigned to model the unknown formation with invasion effects). Questions to be answered include: how many receiving coils are needed to assure unique inversion? How should they be spaced? And, how far should they be placed from the transmitting coil? Analytically, for a CW logging source frequency, the unknown formation of several zones is modeled as a spatial filter function. This model allows the determination of a spatial-filter bandwidth. It also permits developing bandlimited sampling criteria according to resolution requirements in parameter inversion. Specifications of parameter-inversion resolution are made with realistic needs consistent with designed capabilities of a logging system.

Pore Microstructure and Flow Modeling

During the last quarter, theoretical studies of fluid flow in porous media have been pursued. Main efforts have been in modeling the flow using a hybrid network approach. According to this idea, the porous medium is imagined to be composed of microelements, each of which is describable by a macroscopic flow parameter, permeability. Each element may be as small as a single pore, or as large as a set of interconnected pores having the same size. Previous efforts have shown that NMR techniques can be used to deduce effective fluid permeabilities for these elements.

The network approach is then used for combining the elemental permeabilities of the medium to yield an overall macroscopic medium permeability. The mathematical formalism used for the random, series-parallel interconnection network is that of effective medium theory. The resultant effective medium permeability for a three-component network has been examined as a function of the elemental permeability magnitudes K , and their concentrations P , and of the node coordination number Z for the network. This solution exhibits threshold behavior near the onset of percolation, the point where an interconnected path is just created through the medium.

For non-zero component permeabilities, percolation is characterized by curvature rather than by an abrupt transition in the medium permeability. This behavior is shown by the computed permeability curves in Figure 3-52. For this $Z = 3$ (y-type junction) network, percolation occurs when the primary permeability component K_1 , with a normalized permeability of unity, reaches a concentration $P_1 = P_c = 0.67$. In this example, the elemental permeabilities each differ by two orders of magnitude. This is typical of the component permeabilities found by the NMR experiments on western tight gas sand core. Figure 3-52 shows that the transition for probability ratios between components 2 and 3 varying from 0.01 to 100. The transition from K_2 permeability elements to K_1 is smoother than from K_3 elements to K_1 , as expected.

Figure 3-53 shows the medium permeability for a $Z = 6$ (cubic junction) network as a function of the primary element probability. The percolation threshold for this network occurs at $P_1 = P_c = 0.33$. For these curves, the ratio $P_3/P_2 = 0.1$ and the K_2 elemental permeability varies between 0.1 and 0.001 of the normalized K_1 . Again, when K_2 and K_3 are small compared to K_1 , the transition is sharp; whereas when $K_2/K_1 = 0.1$, the computed medium permeability varies smoothly over the entire range of K_1 concentrations.

Figure 3-52 Behavior of the Computed Effective Medium Permeability K_m for the Three-Element, $Z = 3$ Network as a Function of the Concentration of the High Permeability $K1$ Element. (The three curves show increasing curvature around the percolation threshold P_c for decreasing concentrations of the low permeability element $K3$).

These figures demonstrate that the effective medium solution to the three-component network model behaves appropriately for various proportions and magnitudes of elemental permeabilities. In particular, the solution makes physical sense at the percolation threshold.

Dielectric Rock Properties

Experiments with the dielectric permittivity measurement apparatus have been progressing to better understand what the apparatus is measuring and to locate possible sources of error. An amplifier has been designed and constructed which can provide a high input impedance (18 to 20 ohms) and a large frequency bandwidth (up to 4 MHz before

the gain begins to decrease). Tests have been run using combinations of capacitors and resistors to simulate the sample cells. The voltages and phase shifts of these circuits have been accurately measured, thus demonstrating the proper operation of the electronics and computer software. However, measurements of high resistivity fluids in the cells have indicated a problem due to the capacitance of the connections between the amplifiers and the cell electrodes. Effects have been made to solve this problem by reducing the length of the connections and floating the amplifiers to eliminate the ground reference.

For high frequency measurements (i.e., above 100 MHz), a cavity technique will be used. The cavity design, first proposed by

Figure 3-53 Behavior of the Computed Effective Medium Permeability K_m for the Three-Element, $Z = 6$ Network as a Function of the High Permeability $K1$ Element (the ratio of element concentrations $P3/P2$ is held constant and the magnitude of the permeability element $K2$ is varied)

Karpova³¹ and since modified by Moyer³², consists of a reentrant cavity with a center conductor in which some section of this center conductor has been replaced by the unknown sample. The sample consists of a cylinder which must be accurately machined to be inserted into the cavity. The length may be adjustable but the diameter of the sample must match the diameter of the center conductor.

Three cavities at frequencies near 100 MHz, 500 MHz and 1.1 GHz have been built or are nearing completion. To test these cavities, six Berea Sandstone samples have been prepared.

Measurements of the dry rocks at a frequency of 106.5 MHz are shown in Table 3-7. Dry- and water- (or saline solution) saturated

Table 3-7 Dielectric Permittivity and Loss Tangent of Berea Sandstone Samples at 106.5 MHz

Sample	E'	Tangent
B1	3.94	0.0345
B2	3.87	0.0301
B3	3.97	0.0339
B4	3.83	0.0279
B5	4.09	0.0390
B6	4.07	0.0359

³¹ Karpova, O. V., Soviet Physics, (Solid State) 1, 220-228, 1959.

³² Moyer, R. D., Toward More Accurate Loss Tangent Measurements in Reentrant Cavities, SAND80-0365, May, 1980.

Figure 3-54 Topography Surrounding the MWX Site

samples will be measured in each of these cavities.

ANALYSIS AND MODELING

Prediction of In Situ Stresses

Topographic relief in certain gas producing areas can sometimes be 5,000 ft or more. This makes it likely that stresses due to topographic loading will be an important component of the in situ stress state. Theoretical predictions of topographic stress effects were the major thrust of this quarter's work. The Multi-Well Experiment (MWX) site near Rifle, Colorado, has significant topographic relief: it sits in the Colorado River Valley at approximately 5,200 ft bounded by Mamm Peak ($> 11,000$ ft) and Battlement Mesa on the south and by Anvil Points (9,000 ft) and the Roan Plateau on the north. The modeling effort thus focused upon the topographic stress effects at the MWX site.

Both two- and three-dimensional calculations were performed with the usual simplifying assumptions of homogeneous, elastic rock. The 2-D calculations were done analytically for a simple topography (represented by a cosine function) and numerically for the actual topography shown in Figure 3-54 by both Fourier transform and finite element calculations. A comparison of the predicted horizontal stress from the two numerical methods is shown in Figure 3-55: both predict tension in the upper 1,000 ft and increasing horizontal stress with depth. The three factors contributing to the stress are also shown in Figure 3-55:

- the normal component is that due to the topographic force in the direction of gravity;
- the "spreading" component, usually rarely considered in problems of this type, is the result of the spreading of the mountain under its own weight; and

Figure 3-55 Predicted Vertical Changes in Horizontal Stress for the 2-D Topography Shown in Figure 3-54. (The finite element results and the Fourier transform results marked "total" are compared.)

- the uniaxial strain component is for the base case that is unperturbed by topography. The sum of these components gives the total stress.

A Green's function approach was used in the 3-D calculation and the results were checked for serious error against the 2-D results. The predicted variation with depth of the three principal stresses is shown in Figure 3-56. Note that the vertical stresses are about 400

psi greater than expected for the case of no topographic relief. At the 7,500-ft depth, the horizontal stresses are equal, indicating that at this depth, a hydraulic fracture would have no preferred orientation. This effect is shown in Figure 3-57, which shows that in the absence of a tectonic stress, the orientation of the maximum horizontal principal stress (which is the same as the azimuth of a hydraulic fracture) rotates with increasing depth through approximately 90° , from roughly parallel to, to perpendicular to the valley.

Figure 3-56 Depth Dependence of Principal Horizontal Stresses Predicted by the 3-D Calculation

When a tectonic stress is imposed upon the topographic stress components, such a "cross over" doesn't occur. Furthermore, the varia-

tion in azimuth decreases with increases in tectonic stress.

Figure 3-57 Orientation of the Maximum Horizontal Principal Stress (the length of the lines indicates the difference in magnitude of the two horizontal principal stresses)

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

Section 4

Field Tests and Demonstrations

BACKGROUND

Field tests are essential to verify the findings of laboratory tests and modeling studies. The field test and demonstration program involves cooperation between industry and govern-

ment and also interacts geologic studies with laboratory research and development. The following projects are active in the WGSP:

- a dry gas injection experiment in the Wattenberg Field, Colorado, by Colorado Interstate Gas Company,
- multi-well field test for production technology research in Colorado, and
- a mineback testing program by Sandia Laboratories.

Table 4-1 summarizes WGSP MHF treatments. Progress of these projects is presented in the following sections.

Table 4-1 MHF Contract Location and Frac Data

Company Basin & Formation	Location T/R/Sec	Well	Interval Fractured ft	Fracture Date	Fracture Treatment Lb of Sand	Injected Fluid 10 ³ Gal	Production Rates MCFD		Ratio
							Before	After	
AUSTRAL Piceance, Mesaverde	7S/94W/Sec 3 Garfield Cty, Colorado	Federal 3-94	6,198-6,333	8-13-76	420,000	226 Gel	35	62	1.8
			5,170-5,630	8-25-76	720,000	316 Gel			
CONSORTIUM MANAGED BY CER CORPORATION Piceance, Mesaverde	3S/98W/Sec 11 Rio Blanco Cty, Colorado	RB-MHF-3	8,048-8,078	10-23-74	400,000	117 Gel	60	60	—
			7,760-7,864	05-02-75	880,000	285 Gel	—	40	—
			5,925-6,016	04-04-76	815,000	400 Gel	42	160	3.8
			5,851-5,869	11-03-76	448,000	228 Gel	57	70	1.2
DALLAS PRODUCTION Fort Worth, Bend Cong.	Ben D. Smith Survey A-779 Wisc Cty, Texas	Ferguson A-1	5,957-6,194	09-16-76	506,000	139 Foam 198 Emul.	40	15	—
EL PASO NATURAL GAS Northern Green River, Fort Union	30N/108W/Sec 5 Sublette Cty, Wyoming	Pinedale Unit No. 5	10,950-11,180	07-02-75	518,000	183 Emul 8 Gel	150	340	2.3
			10,120-10,790	10-20-75	1,422,000	459 Gel	—	150	—
GAS PRODUCING ENTERPRISES, INC. Uinta, Wasatch and Mesaverde	10S/22E/Sec 10 Uintah Cty, Utah	Natural Buttes No. 18	6,490-8,952	09-22-76	1,480,000	745 Gel	—	1,400	—
	10S/21E/Sec 21 Uintah Cty, Utah	Natural Buttes No. 19	8,909-9,664 7,224-8,676	09-21-76 09-28-76	424,000 784,000	280 Gel 364 Gel	—	166	—
	9S/21E/Sec 22 Uintah Cty, Utah	Natural Buttes No. 14	6,646-8,004	03-15-77	1,093,000	544 Gel	38	800	21.0
	9S/21E/Sec 28 Uintah Cty, Utah	Natural Buttes No. 20	8,498-9,476	06-22-77	826,000	322 Gel	75	1,200	16.0
	10S/22E/Sec 18 Uintah Cty, Utah	Natural Buttes No. 22	6,838-8,550	11-21-77	1,151,000	499 Gel	—	700	—
	9S/22E/Sec 19 Uintah Cty, Utah	Natural Buttes No. 9	5,661-8,934	03-27-78	554,000	349 Gel	140	540	3.9
	10S/21E/Sec 29 Uintah Cty, Utah	CIGE No. 2	9,237-9,653 7,251-8,774	06-22-78 08-08-78	170,500 1,965,000	203 Gel 722 Gel	—	Water Water	—
	10S/22E/Sec 7 Uintah Cty, Utah	Natural Buttes No. 23	5,080-6,294	10-04-78	470,000	240 Gel	—	800	—
MITCHELL ENERGY Cotton Valley, Limestone Trend	Limestone Cty, Texas	Muse-Duke No. 1	11,235-11,418	11-15-78	2,800,000	891 Gel	2,000	6,600	3.3
MOBIL Piceance, Mesaverde	2S/97W/Sec 13 Rio Blanco Cty, Colorado	F31-13G	10,549-10,680	06-22-77	580,000	316 Gel	300	800	2.7
			9,392-9,538	08-24-77	600,000	260 Gel	700	2,600	3.7
			8,765-8,972	05-10-78	388,000	150 Gel	479	430	—
			8,163-8,650	07-06-78	660,000	288 Gel	—	360	—
			7,704-7,794	09-07-78	218,000	120 Gel	—	180	—
			7,324-7,476	11-15-78	700,000	365 Gel	1,000	2,000	2.0
PACIFIC TRANSMISSION Uinta, Mesaverde	8S/23E/Sec 25 Uintah Cty, Utah	Federal 23-25	NO FRACTURES PERFORMED						
RIO BLANCO NATURAL GAS Piceance, Mesaverde	4S/98W/Sec 4 Rio Blanco Cty, Colorado	Federal 498-4-1	6,150-6,312	10-22-76	766,000	276 Gel	57	130	2.3
			5,376-5,960	11-30-77	243,000+ 22,500 Beads	164 Gel	80	350	4.4
WESTCO Uinta, Mesaverde	10S/19E/Sec 34 Uintah Cty, Utah	Home Fed. No. 1	10,014-10,202	12-21-76	500,000	248 Gel	33	155	4.7
			7,826-9,437	10-01-76	600,000	412 Gel	40	Water	—

WATTENBERG FIELD

DE-AC08-77ET12046

Colorado Interstate Gas Company
Colorado Springs, Colorado
Status: Active

Contract Date: September 1, 1977

Anticipated Completion Date: March 1, 1981

Total Project Cost (estimated):	DOE	\$ 75,000
	CIG	\$392,340
	Total	\$467,340

Principal Investigator: David Wilson
Technical Project Officer for DOE: C. H. Atkinson

OBJECTIVE

Cyclic injection of dry natural gas is the method to be used to increase production of tight gas sands.

COLORADO INTERSTATE GAS COMPANY

During the quarter, CIG issued a final report of the project "Cyclic Dry Gas Injection," by D. L. Wilson and G. W. Gettman of CIG and P. T. Branagan and G. Cotner of CER Corporation. This work, performed under Contract DE-AC08-77ET12046, has been completed.

ABSTRACT

Cyclic dry gas injection was the technique used to determine if reducing interstitial water saturation in a wet reservoir would improve the permeability of tight formations

and the productivity of gas wells in these formations. Two existing gas wells were connected and after an initial shut-in period to measure initial bottom-hole pressure buildup, dehydrated gas produced from one was injected into the other. Periodically, the direction of production and injection were reversed. A number of unforeseen technical problems were encountered with freezing, regulating low gas flow and assuring continuous dehydration. The calculated effect of the first six-month cycling phase was a substantial improvement in formation permeability. No further improvement was discernable after the second six-month cycling phase. Post cyclic production failed to confirm any significant, long-term improvement in formation permeability. Water probably re-entered the formation adjacent to the wellbore soon after cyclic dry gas injection ceased.

**DOE WELL
TEST FACILITY**

DE-AC08-79-BGO1569

CER Corporation
Las Vegas, Nevada

Status: Operational

Principal Investigator:
Technical Advisor for DOE:

R. L. Mann
C. H. Atkinson

OBJECTIVE

The DOE Well Test Facility, consisting of two vehicles, will provide a deep well instrumentation and investigation system to monitor and evaluate the productive potential of all types of wells.

DOE WELL TEST FACILITY

Support of the DOE Well Test Trailer Facility has continued through this quarter. Modifications made in the operating software and application software will support additions to the PDP-11/10 computer system. These new additions include the dual RKO 5 disc systems and the nine track magnetic tape transport. Additional PDP system software is being obtained from Sandia Laboratories at this time.

Additional application software is being written to support the file structure necessary for data transmission between the test facility, Sandia-Albuquerque and the DOE NVOO CDC computer systems. Next quarter more pieces of application software will be written for system operation in the trailer and field evaluation of the software will take place. Work continues on developing software for the 8080 micro-processor display system in the trailer.

Trailer modifications for this quarter include the addition of a 3-ton air conditioner for the instrumentation portion of the trailer. Changing the hydraulic motor on the slick line winch was accomplished, which permits a one-third speed reduction and much greater safety in the operation of this unit.

Designing of the operator's console for the stress test program is continuing. Initial designs show that both a TV monitor and analog readout will be necessary to properly control the equipment and monitors. The

following are some of the parameters that will be measured and recorded within the facility during Multi-Well Experiment (MWX) stress testing: bottom-hole pressure, bottom-hole temperature, surface pump pressure, surface flow rate and annulus pressure. The stress test pump system has been designed and will include remote-control of the start and stop of the system and speed control of the hydraulic motors. Pressure and temperature warning indicators will be remote to the operator's panel for his convenience in operating this system. Instrumentation for this system will include strain gauge pressure transducers, high pressure turbine flow meters and safety limit switches. A commercial high pressure test manifold will be incorporated into the pump system to allow several high pressure ports to inject different fluids into the system during the stress tests. The multiple valve system in this manifold will be monitored remotely from the test facility to assure the proper positioning of the valves before and during the test runs. This system has been designed but will not be fabricated until delivery of the manifold system, which is expected the first quarter of 1982.

Laboratory support this quarter has consisted mainly of training new technicians in the operation of both water analysis equipment and gas chromatographic equipment; instructions for operating this equipment are continuing. Modifications and testing of the multiplex downhole temperature tool are continuing with a successful test of 12 days at 310°F and 1,000 psig. Additional high temperature components will be procured in the next quarter to continue this testing program and permit replacement of weak or faulty components, particularly in the temperature tools.

MULTI-WELL EXPERIMENT PICEANCE BASIN, COLORADO

Bartlesville Energy Technology Center
Bartlesville, Oklahoma

Objective: To characterize lenticular gas sand reservoirs and to evaluate technology for their production.

Start of Field Operations:

August, 1981

Anticipated Completion:

July, 1986

Estimated Cost:

\$20 million

DOE Technical Project Officer:

Charles H. Atkinson

Technical Coordinator for Project:

Sandia National Laboratories
Albuquerque, N. Mexico

Principal Investigators:

David A. Northrop
Allan R. Sattler

Contractor for Management of Operations:

CER Corporation
Las Vegas, Nevada

Manager:

Robert L. Mann

Asst. Manager:

John C. Schillo

MULTI-WELL EXPERIMENT

The Multi-Well Experiment (MWX) is a research-oriented field laboratory and is the major production technology activity in the Western Gas Sands Project (WGSP). The overall MWX objectives are to characterize lenticular gas sand reservoirs and to evaluate technology for their production.

MWX PLANNING

Stimulation Experiments

A series of stimulation experiments for the MWX has been defined to serve as the basis for further discussions and to address specific MWX goals. This definition must be generic at this time since the actual geology and log, core and well test data will dictate the actual interval selection and experiments. Two wells were considered: MWX-1 for stimulation-production and MWX-2 for stress and interference data.

A MWX budget review was held at BETC in September. Budgets for MWX-1 and MWX-2 activities were reviewed. Alternatives to MWX-3 were discussed and submitted, through BETC, to DOE Headquarter.

Site Preparation

The Superior Oil Company and Northwest Exploration Company land swap agreement was completed in August 1981. A Declaration of Pooling was filed and recorded in Garfield County, Colorado, on Aug. 31, 1981.

The MWX environmental statement prepared by Lawrence Livermore National Laboratory was approved by the Environment, Safety and Program Support Division of DOE's San Francisco Office.

Agreements were reached with three land-owners for surface rights to allow a high resolution seismic survey in conjunction with site construction. Agreements for subsequent diagnostic instrumentation during stimulation were reached with two of the three land-owners. These latter agreements allow access and equipment installation and use.

Construction

Site preparation commenced August 10, 1981. Contracts were prepared for drilling, drilling fluid, mud logging, coring, cementing and testing. A water well permit was issued by the Colorado Water Quality Control Board for the MWX project and the well was completed on Aug. 28, 1981. A plan of the site as constructed is shown in Figure 4-1.

The design and fabrication of a core photographic system for the MWX facility in Colorado was completed this quarter and has been field tested on site. This camera system consists of an Olympus 5mm camera with motor drive, 250 frame film pack and trolley assembly to allow a strip film procedure to be used by the geologists. Final assembly of the core gamma measurement system in the facility in Colorado was also completed this quarter by a team of Sandia and CER technicians. This system consists of a slow speed conveyer, a strip chart recorder, six channels of scintillation counters and an electronics bay to process the data displayed on the strip chart recorder.

A building permit for the Core Handling Facility to be built on site could not be obtained from Garfield County. Through the help of DOE's Laramie Energy Technology Center, a building at the Anvil Points Oil Shale Center was obtained and is being modified. The building is approximately eight miles by road to the MWX site.

CER technicians installed the antenna and base station radio for communications between the site, Anvil Points core processing facility and the general Rifle-Glenwood

MWX-1 LAYOUT

KEY TO MWX-1 LAYOUT

1. Reserve Pit
2. 400 BBL Mud Storage Tank
3. 400 BBL Mud Storage Tank
4. 400 BBL Mud Storage Tank
5. 400 BBL Mud Storage Tank
6. Mud Pit
7. Self Contained Trailer — Mud Engr.
8. Self Contained Trailer — Coring Engr.
9. Self Contained Trailer — Sandia Lab.
10. Commercial Electric Power Substation
11. Office/First Aid Trailer
12. Septic Tank
13. CER Drilling Engr. Trailer
14. Sandia Office Trailer
15. CRC Drilling Company Trailer
16. MWX-1 Well
17. CRC Drilling Rig
18. Five Strand Barbed Wire Fence
19. CRC Drilling Company Camp
20. Storage Area
21. Water Well with Shed
22. 400 BBL Water Storage Tank
23. Ranchers Pond
24. Flare Pit

P.P. = Commercial Electric Power Pole
C.G. = Cattle Guard

Scale 1/2" = 100'

Figure 4-1 MWX-1 Site, As Built

Springs area. This system consists of one 100-watt base station and two hand-held portable units.

Drilling

The drilling contract for MWX-1 was negotiated and awarded to Crutcher Resources Corporation and the CRC-Colorado Well Service Rig No. 140 was moved on site on Sept. 4, 1981. The well spudded on Sept. 13, 1981 at 10:00 p.m.

On Sept. 30, 1981, total depth was 3,358 ft. The drilling of MWX has been slower than anticipated. The upper portion of the hole was comprised of basalt and lavas and boulders were encountered between 800 and 2,000 ft. The use of a packed hole assembly, including a short drill collar and blade stabilizers, resulted in severe torquing and reduced penetration rates, but allowed a straight hole to be drilled. Lost circulation was encountered at various intervals from surface to 2,000 ft. Coring operations will begin at a depth of 4,150 ft, anticipated for mid-October.

RESERVOIR CHARACTERIZATION

Core Program and Analysis

Core will be field processed (photographed, described, core gamma logged, measured, sampled and boxed) at the Anvil Points facility prior to shipment to the MWX library at DOE's Grand Junction facility.

Intervals for oriented core are being determined. The data from the oriented core and fast track strain relaxation data are necessary for fracture design and for locating MWX-2.

Logging Program and Analysis

Log Interpretation Development for MWX

Log tapes were obtained for Northwest Exploration's Langstaff No. 1 and Clough

No. 2 wells in the vicinity of the MWX. The tapes were edited and the CER LOGCALC model SXOPH1 was run on both wells. Figure 4-2 is an example plot showing two tight reservoir sands in the 6,100 to 6,300 ft interval of the Langstaff No. 1 well. The two zones are interpreted as tight sands having marginal reservoir quality (i.e., $S_{XO} = S_W$; therefore the formation is uninvaded and relative permeability to water must be very low). Effective porosity is presented in track 1 and S_{XO} and S_W from the total shale equation are presented in track 3. Note that the S_{XO} calculation is generated without R_W or any resistivity data by the technique discussed in SPE/DOE paper 9856 (Kukul, 1981). RWUISS gives an independent value for R_W and verifies the assumptions used in the calculation of S_W using the total shale equation.

The Langstaff No. 1 and Clough No. 2 analyses have proved useful in interpreting model variables appropriate for the MWX area. Also, they are being used to assign priorities to core intervals for the MWX well.

Outcrop Studies

Sedimentology Study of the Mesaverde Group Near MWX

The sedimentology study of the Mesaverde Group in the vicinity of the MWX site continued this quarter with work in three areas. The first area was a geologic literature search to determine the extent of previous studies and their bearing on MWX-related aspects. It was found that the stratigraphy of the formation, as well as its generalized paleogeographic setting, has been well documented. (There is, however, continued question as to the age and nature of the upper contact of the Mesaverde in this location.) The nature of the lower blanket sands, the Sego, Corcoran, Cozzette and Trout Creek, is well understood; they were shallow marine-shoreline deposits. There has been no study of the sedimentology of the paludal and fluvial sections of the Mesaverde. Paleogeographic studies, however,

Figure 4-2 Plot of SXOPHI Model for Northwest Exploration
Langstaff No. 1 Well, Garfield County, Colorado

Figure 4-3 Example of the Uppermost Fluvial Section Mapped at Rifle Gap (Actual Outcrops Nearly Vertical). The lower sand body displays distinctive lateral accretion (point-bar) deposits; stippled pattern is fine-grained sandstone and white is probably mudstone.

Figure 4-4 Example of the Composite Sandstone of a Meander Belt Seen in the Lower Part of the Fluvial Section Mapped at Rifle Gap (Actual Outcrops Nearly Vertical)

Figure 4-5 Seismic Shooting/Receiving Scheme Near MWX Site

have shown a 90° shift in shoreline trends (and, by inference, in basin and river system orientations) between the early and late Mesaverde deposition.

The second phase was field studies, principally in the Rifle Gap Mesaverde exposures along the Grand Hogback about 10 miles northeast of the MWX site. Preliminary attempts were made to map the shapes and sizes of the sandstone bodies from the paludal and fluvial zones, specifically noting small- and medium-scale sedimentary structures where they were unobscured. These results suggest that the sands are erratically-oriented, irregularly-shaped sandstone bodies which were deposited as laterally-migrating point bars in a meandering fluvial system. Sandstones containing point bar lateral accretion beds ("epsilon crossbedding") were found and an example is shown in Figure 4-3. Also, the sands containing abandoned channel deposits with reactivation were observed. Meander-belt horizons with concentrations of sandstones were also found and these are shown in Figure 4-4. Finally, the uppermost sandstones in the section have evidence which suggests short-lived returns to marine deposition at the end of Mesaverde time in this area.

The third phase of the work was interaction with fluvial sedimentologists and other interested geologists from the USGS and companies represented on the Technical Review Panel. Visits and discussions with these individuals have been productive in helping formulate the concepts and modeling of the Mesaverde Group.

Seismic Program and Analysis

Seismic Reflection Mapping Project

The contract for 3-D seismic data acquisition and processing was awarded to the Exploration Research Laboratory (ERL) at the Colorado School of Mines (CSM). A shooting-receiving scheme, shown in Figure 4-5, was designed which placed a large number of vibroseis (source) locations along the County Road 320.

Walkaway noise tests made in early August determined the following acquisition parameters for production shooting.

Receivers — single 18 Hz vertical geophone (one per channel).

Source — Vertical Vibroseis; 18 to 102 Hz sweep; sweep 12 secs, listen 3 secs; 10 sweeps per shot point.

Three-dimensional data acquisition began on Sept. 2, 1981, and continued through conclusion on Sept. 17. An additional CDP line (2-D) was shot along the county road on Sept. 19 and 20 to add longer offset data for better velocity control for advanced data processing steps. These seismic data are currently being processed at the CSM-ERL processing facility in Golden, Colorado.

MODEL DEVELOPMENT

Simulated Interference Tests

A number of computer simulation runs were made to model the pressure responses for non-fractured tight gas reservoirs that might be representative of the MWX testing

program. Three figures depict simulated bottom-hole pressure vs. time for several non-fractured reservoirs with varying permeabilities. Figure 4-6 represents bottom-hole pressure response at the producing wellbore for 3 μ d reservoir with an insert showing the response at an offset or observation well 160 ft away. Production rate during the drawdown period was 9 MCFD. Figure 4-7 is a similar case where the reservoir permeability was taken as 10 μ d and the production rate was increased to 30 MCFD. Finally, in Figure 4-8 the response from a 30 μ d reservoir is shown where the production rate was increased to 90 MCFD. It can be seen in all cases that the pressure response at the observation well was small, less than 10 psi, and that the slope for the best case (30 μ d) was only slightly greater than one psi per day. These pressure responses will be difficult to measure in the field and considerable care will need to be taken during interference tests of this type.

Figure 4-6 Bottom-Hole Pressure Response for a Production Wellbore and a Remote Observation Well 160 ft Away, From a Drawdown of 9 MCFD in a 20-ft Thick, 3μ d Reservoir

Figure 4-7 Bottom-Hole Pressure Response for a Production Wellbore and a Remote Observation Well 160 ft Away, From a Drawdown of 30 MCFD in a 20-ft Thick, 10μ d Reservoir

Figure 4-8 Bottom-Hole Pressure Response for a Production Wellbore and a Remote Observation Well 160 ft Away, From a Drawdown of 90 MCFD in a 20-ft Thick, 30 μ d Reservoir

---

**NEVADA TEST SITE
NYE COUNTY, NEVADA**

Mineback Testing

Sandia Laboratories
Albuquerque, New Mexico
Status: Active

Principal Investigator:

D. A. Northrop

OBJECTIVE

To develop an understanding of the fracturing process for stimulation and thereby improve the production of natural gas from low-permeability reservoirs. This will be accomplished by conducting controlled fracture experiments which are accessible by mineback for direct observation and evaluation.

**SANDIA NATIONAL LABORATORIES –
WGSP STIMULATION RESEARCH**

**IN SITU HYDRAULIC FRACTURING
EXPERIMENTS (MINEBACK)**

**Fluid Mechanics/Proppant Transport
Experiments**

The initial phase of this program is a series of experiments to develop and apply instrumentation for measuring pressure and width of various locations in a propagating hydraulic fracture. An initial test of pressure transducers and displacement (width) gauges grouted into six coreholes (one of each gauge in all coreholes) was completed last quarter and resulted in only 5 of 12 gauges functioning properly. Subsequently, four additional coreholes were completed this quarter and a pair of transducers was grouted into each of three holes while a crack detector was grouted into the fourth.

Figure 4-9 shows a side view of the apparent fracture shape and the locations of the instrument coreholes. The fracture appears to be confined above and below by high stress regions. New width and pressure detectors were grouted into Holes No. 22, No. 23 and No. 26 and a crack detector was grouted into Hole No. 27. No fracture was found in Holes No. 26 or No. 25.

The second fracturing test to check the instrumentation was performed in August. The zone was fractured at 20 gpm for approximately 7 min. during which time data were continuously obtained from the transducers. The five transducers which functioned on the first test as well as the six newly emplaced transducers all recorded data on this trial. The data have not been completely reduced but preliminary results are shown

in Figures 4-10 and 4-11. The decrease in pressure along the length of the fracture can be clearly seen in Figure 4-10 by observing the pressure changes from Instrument Hole (IH) No. 19 through IH No. 26, IH No. 22 and IH No. 23. These transducers were spaced at 10-ft intervals along one wing of the fracture, as seen in Figure 4-9. The rise in pressure just after shut-in in IH No. 26 and IH No. 23 appears to be an instrument problem where, for some unknown reason, the gain of the transducers was altered. This problem is being investigated.

The width data are somewhat less clear in this preliminary form. As seen in Figure 4-11, there appears to be an oscillation in width during fracturing which is not readily apparent in the pressure data. However, it should be remembered that the pressure opening the fracture is the ΔP over the in situ stress base level (300 to 500 psi in this case). Thus, the small oscillations in pressure which can be observed in Figure 4-10 at least in three holes (IH No. 22, No. 23 and No. 26) are 20 to 30 percent of the fracturing ΔP and can easily account for the width oscillations. There may also be pressure oscillations in IH No. 17, but this will not be determined until the data are fully reduced and the noise filtered out. As seen in Figure 4-12, there also appear to be fluctuations in the flow rate and injection pressure. The width transducer in IH No. 19 does not make any sense in view of the other data. Whether this is a failure or a recording problem has yet to be determined. Nevertheless, the decrease in width along the length of the fracture can be seen clearly. Further correlations between pressure, width and injected volume will be made when the reduced data have been obtained.

After the data have been carefully analyzed and all problems have been corrected, this zone will be refractured at several different flow rates and if possible, with several different fluids, probably in the first quarter of FY 1982.

Figure 4-9 Side View of Instrumentation Corehole Locations

Figure 4-10 Pressure Data in the Fracture

Figure 4-11 Width Data in the Fracture

Figure 4-12 Flow Rate and Injection Pressure

In Situ Stress Measurements by Hydraulically Fracturing Through Perforations

It is established that in situ stress distribution strongly affects the geometry of a hydraulic fracture. Of particular importance is the vertical distribution of the minimum principal compressive stress because of its controlling influence on the height of the fracture. Measurement of this stress distribution would be extremely valuable for fracture design.

Presently, the only viable technique for accurately measuring stress at depth in a borehole is hydraulic fracturing. The instantaneous shut-in pressure (ISIP) is equivalent to the minimum, principal, compressive, in situ stress (σ_{min}) and generally, this parameter can be measured quite accurately. However, this has only been shown for open-hole fracturing. In many cases, it is impractical or impossible to conduct a large number of these minifrac open hole in a given well. For example, in the MWX experiment, 50 to 100 of these fractures will be conducted at various locations over a 4,000-ft interval during a four-year time period.

The only practical method of conducting these tests is to fracture through perforations. However, it has never been proven that conducting minifrac through perms will result in accurate or meaningful stress measurements. The effects of the casing, cement

annulus, explosive damage and random perforation orientation are impossible to predict theoretically. To evaluate the accuracy and reliability of these measurements, a set of fracture tests was conducted at DOE's Nevada Test Site (NTS). These tests compared stress measurements by fracturing through perforations with those obtained by fracturing open hole.

The tests were conducted in ashfall tuffs having the properties shown in Table 4-2. This material probably is a more difficult

Table 4-2 Ashfall Tuff Properties

Dry Density	1.63 gm/cc
Grain Density	2.52 gm/cc
Porosity	31%
Saturation	> 92%
Young's Modulus	0.68×10^6 psi
Poisson's Ratio	0.31
Compressional Wave Velocity	8,800 ft/sec
Shear Wave Velocity	5,000 ft/sec
Uniaxial Compressive Strength	2,500 psi (unconfined)
Permeability	.02 md

Figure 4-13 Plan View of First Perforation Experiment

test than sandstone or shale because of its low Young's modulus and strength and high porosity and Poisson's ratio. This results in a greater susceptibility to crushing and the resultant damage and residual stress formation associated with detonations in rock.

An initial test was conducted a little more than a year ago by fracturing comparable zones in two horizontal, parallel holes — one cased and perforated and one open hole. This test is shown in Figure 4-13, in plan view. The detailed results are not given here but, essentially, it was found that accurate, reproducible, stress measurements could not be made. Fracturing pressures through the

perfs were about 2,400 psi vs. about 900 psi open hole and it was very difficult to pick an ISIP.

The apparent ISIPs through the perforations were about 1,100 to 1,200 psi compared to 800 to 900 open hole — about a 40 percent error. An example of the pressure records from the two holes at the same location is shown in Figure 4-14. The flow rates are the same, about 6 GPM of dyed water.

There were two possible reasons for this discrepancy in measurement. First, large shaped charges were used — about 26 gm — and this resulted in considerable crushing of the tuff in the vicinity of the perf. This was

Figure 4-14 Sample Pressure Records for First Perforation Experiment

obvious from visual observation during mineback. It is known that explosions in rock masses result in a damage zone around the cavity (perf) which has a high residual stress field associated with it. Apparently, this high residual stress did not allow the fracture to initiate from the end of the perf, but rather through the cement annulus. Figure 4-15 shows a photograph of one of these perfs. The high stress region around the perforation is obvious because of the halo around it in which there was no dye and no obvious fracture initiation from the perf. This is probably the reason for the large fracturing pressures and may account for the high ISIP.

The second possible problem was the orientation of the boreholes. They were meant to be closely aligned with the stress field. During mineback, it was found that they were about 40° off from being aligned with the stress field. This resulted in the fractures initiating parallel to the borehole and then turning as they propagated farther out. This orientation change may have resulted in erroneously high ISIPs; however, it has been found that this never affects the ISIP in open holes (although it does affect the fracturing pressure) and there should be no reason that it would do so in a cased hole.

A second test was planned that would investigate both of these possible problems. Again, two parallel holes were drilled and one was cased and perforated, as shown in Figure 4-16. This was performed in a region where the stress orientation was absolutely certain so the holes would be correctly aligned. Eight different zones were perforated with the shaped charges, as given in Table 4-3. The 37 gm charge was chosen so there would be severely crushed perfs, but with good enough penetration that frags might be initiated through them. The 22.7 gm charge was similar to the first experiment and the perfs were to be oriented in different directions. The 12 gm charge was the best bet to give reduced crushing with good penetration and the 2 gm charge was picked to avoid crushing entirely, although penetration would be marginal.

Each zone was fractured at a nominal 10 GPM with a total volume of 2 to 5 gallons of dyed water. They were then refractured at 10 GPM (1 to 3 gallons) and several zones were fractured a few more times at higher flow rates. Beginning with the deepest zone (42 ft), the pressure records of the eight fracture tests of the second PERF experiment are shown in Figures 4-17 through 4-24. The open-hole pressure data of each zone are shown on the left side of the figures and most of the perf frags are given on the right side. Selected data from the cased and open-hole fractures are given in Tables 4-4 and 4-5, together with calculated σ_{max} values for the open-hole tests.

In all eight tests, it can be seen that the open-hole fracture pressures are seldom more than 50 psi over σ_{min} because of the low rock modulus and the low viscosity frac fluid (water). Note the difficulty in determining ISIP values in Figures 4-17 and 4-18 compared to the small charge cases.

The change in slope at the beginning of each pumping through perforations is due to the accumulator on the pump and is in no way associated with the fracture process. In Figure 4-18, the pressure in the third pumping through perfs went off scale and was approximately 2,450 psi. The initial pressure spike of the second pumping through perfs in Figure 4-19 is due to opening of a valve; fracturing began a few seconds later. The same is true of the second open-hole pumping in Figure 4-18.

Figure 4-25 shows the measured ISIP for the eight zones. There is very good agreement between the two measurements, with the exception of the deepest two zones — these were perforated with the 37 gm charges. The 62-ft and 72-ft zones used 22.7 gm charges, yet there appeared to be little crushing effect. The slight increase in stress at the 22-ft zone is the result of the stress concentrations around the nearby tunnel. It is not known why the stresses suddenly decrease at the 92-ft zone. It is clear from these data

Figure 4-15 Photograph of Perforation, Resultant Fracture and High Stress Halo

Figure 4-16 Plan View of Second Perforation Experiment

Table 4-3 Perforations in PERF-3, Gearhart Industries Inc. Perforating Charges

Zone, ft	Number of Perfs	Charge, gm	Type	Phasing, deg.	Remarks
92	4	37.0	Glass Sabre Jet	180	Deep Penetration Significant Crushing
82	2	37.0	(Steel Strip)	180	
72	4	22.7	Aluminum Strip	180	Similar to Previous Test
62	4	22.7	Jet	180	Orientation Change
52	8	12.0	DML Densi-Jet XII	120	Reduced Crushing
42	4	12.0	Hollow Steel Carrier	120	Good Penetration
32	6	2.0	Gowinder Circulation	180	Reduced Crushing
22	10	2.0	Charges	180	Reduced Penetration

Figure 4-17 Pressure Records - 92 ft

Figure 4-18 Pressure Records — 82 ft

72-ft Zone
 4 Perfs — 180°
 22.7 gm Charge

Figure 4-19 Pressure Records — 72 ft

Figure 4-20 Pressure Records — 62 ft

52-ft Zone
8 Perfs — 120°
12 gm Charge

Figure 4-21 Pressure Records — 52 ft

Figure 4-22 Pressure Records - 42 ft

Figure 4-23 Pressure Records — 32 ft.

Figure 4-24 Pressure Records — 22 ft

Table 4-4 Data from Open Hole Minifrac

Zone, ft	FIRST PUMP			SECOND PUMP			THIRD PUMP			FOURTH PUMP			AVG. ISIP, psi
	P _c , psi	ISIP, psi	Q, GPM	P _c , psi	ISIP, psi	Q, GPM	P _c , psi	ISIP, psi	Q, GPM	P _c , psi	ISIP, psi	Q, GPM	
22	1,575	610	10	820	640	15	1,050	600	22	815	610	25	615
32	1,550	600	10	1,050	570	10	1,050	560	20	---	---	---	575
42	1,720	580	10	1,200	560	10	1,025	580	15	1,200	560	25	570
52	1,390	520	15	670	550	10	---	---	---	---	---	---	535
62	1,220	600	10	975	600	10	1,000	550	15	---	---	---	585
72	1,250	560	15	840	580	9	---	---	---	---	---	---	570
82	1,770	---	7	2,100	800	10	2,300	700-900	25	---	---	---	(800)
92	1,250	---	7	1,240	---	7	1,250	560	35	---	---	---	(560)

Table 4-5 Data from Perforation Minifrac

Zone, ft	FIRST PUMP			SECOND PUMP			CALCULATED			
	P _c , psi	ISIP, psi	Q, GPM	P _{op} , psi	ISIP, psi	Q, GPM	ISIP AVG, psi	$\sigma_{\max}$ from P _c , psi	$\sigma_{\max}$ from P _{op} , psi	
22	820	590	12	690	570	25	580	1,350	1,020	
32	930	540	11	610	520	12	530	1,090	950	
42	1,030	530	11	620	510	11	520	960	910	
52	800	530	10	630	530	12	530	1,190	960	
62	1,290	540	10	660	560	12	550	730	1,020	
72	1,320	570	10	750	590	11	580	790	1,020	
82	1,040	580	12	700	570	12	575	1,100	1,010	
92	1,250	510	8	700	460	8	485	680	780	

Figure 4-25 ISIP Comparison

Figure 4-26 Fracturing Pressure as a Function of Charge and Number of Perforations

Figure 4-27 In Situ Stress Data from Open-Hole Fracturing

that accurate ISIP values were obtained with reasonably-sized perforation charges. With the exception of the 37 gm charge zones, the error is less than 50 psi (< 10 percent). Since the open-hole stress measurements are accurate only to about ± 20 psi, this is very acceptable agreement.

Although it was planned to observe the effect of the perf orientations on the ISIP measurements, it was not possible to accurately position the shaped charges during perforating. It was difficult to locate the perfs with a borehole TV camera, so presently the orientations are not known of any of the perfs. If these tests are mined back at a later date, that correlation will be made. If the perforations were randomly oriented, it appears that this had little effect on the stress measurement.

Figure 4-26 shows the fracturing pressure vs. the perforation charge for these tests. Indicated also is the number of perforations for each data point. It is apparent that increasing the perf charge results in higher fracture pres-

ures, probably because of the crushing and residual stress cage. On the other hand, decreasing the charge size below a certain point also results in increasing fracturing pressures. This may be because of the reduced penetration. It also can be seen that the number of perforations has some effect on the fracturing pressure. Although these trends are based on limited data, they may be very important because excessively large fracturing pressures often make it difficult to accurately choose an ISIP. In addition, the optimum charge size of 12 gm obtained from Figure 4-26 will not generally apply to sedimentary rocks because of the large difference in properties.

Finally, as an interesting note, it is useful to try to determine the maximum, principal, compressive, in situ stress (σ_{max}) from the open hole data. This is shown in Figure 4-27 and is taken from the fracturing data given in Table 4-5. Calculating σ_{max} from the breakdown pressure (P_c)

$$\sigma_{max} = 3\sigma_{min} - P_c + T$$

where T is the tensile strength, results in scattered data. However, calculating $\sigma_{\max}$ from the initial reopening pressure (P_{op}) of the second pumping by

$$\sigma_{\max} = 3\sigma_{\min} - P_{\text{op}}$$

results in very consistent data. Thus, in wells where it is possible to conduct minifrac open hole, accurate measurements of the maximum stress may also be possible. On the other hand, no way could be found to back out information on $\sigma_{\max}$ from the minifrac through the perfs.

In summary, accurate, reproducible stress measurements were obtained by conducting minifrac through perforations. A reasonable number of medium charge perforations should be sufficient for obtaining good data. Excessive perforation charge and borehole deviation appear to be the major problems.

The second experiment has not yet been mined back, and it may not be due to budget constraints. A final report on both of these tests will be postponed pending final decisions on the mineback.

UNITED STATES DEPARTMENT OF ENERGY
BARTLESVILLE ENERGY TECHNOLOGY CENTER
P.O. BOX 1398
BARTLESVILLE, OKLAHOMA 74003

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, \$300

POSTAGE AND FEES PAID

UNITED STATES
DEPARTMENT OF ENERGY

Return this sheet to above address, if you
do NOT wish to receive this material ☐,
or if change of address is needed ☐ (indi-
cate change, including ZIP code).