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**LABORATORY INVESTIGATION OF FORMATION DAMAGE OF AN
ARTIFICIAL FRACTURE AT SIMULATED GEOTHERMAL CONDITIONS**

Final Report

By
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MASTER

March 1985

Work Performed Under Contract No. AC07-77ET28301

**Terra Tek Research
Salt Lake City, Utah**

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TR 85-24
March, 1985

A 910 6210

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INTRODUCTION

3 This report presents the results of a laboratory program performed to investigate formation damage mechanisms in a fracture-dominated geothermal reservoir through the use of simulated fractures. The experiments performed in this program systematically investigated fracture conductivity impairment resulting from exposure to three discrete fluid systems known to be sources of formation damage[1-4]. The fluids used included: 1) a clear brine containing suspended solids representative of those produced during drilling, 2) two clear brines of incompatible chemical composition which, when intermingled, produce carbonate scaling and precipitation, and 3) a colloidal drilling fluid containing bentonite clay as the colloid.

The test program concentrated on fracture conductivity impairment not matrix permeability impairment. The test procedures were designed to simulate the infiltration of drilling fluid into the natural fractures of the geothermal reservoir system. To assess fracture conductivity impairment incurred, a generic fractured rock system was developed. The reference fracture conductivity was made to 2% KCl brine in a direction to establish production from the well. Once the initial brine fracture conductivity was measured, the damaging fluid was flown through the fracture in a set direction to simulate invasion due to an overbalance drilling situation. Fracture conductivity was not measured during the damaging phase of the testing. After the fracture conductivity was impaired due to drilling fluid invasion, brine fracture conductivity was again measured in the direction chosen to simulate production from the reservoir. The testing procedures also had provisions for testing for fines migration and stimulation by acidization.

Testing included measurement of fracture conductivity before and after exposure to the conductivity impairing fluids. Samples tested in the program were prepared with artificially manufactured fractures of controlled geometry. Samples were prepared from Nugget sandstone which was selected as a generic homogeneous sandstone representative of a geothermal reservoir material.

The laboratory testing program was divided into five tasks:

- Task I Routine Physical Properties and Lithological Description.
Selection, routine characterization and detailed lithological description of the representative generic test material.
- Task II Development of Fracturing Technique and Preparation of Artificially Fractured Test Samples.
Develop a technique for manufacturing reproducible longitudinal fractures in the generic test material and prepare test specimens required in the program.
- Task III Formation Damage Resulting from Exposure to Suspended Particulates.
Measure changes in fracture conductivity in artificially fractured samples exposed to particulate contaminated brine.
- Task IV Formation Damage Resulting from Incompatible Fluid Interaction.
Measure changes in fracture conductivity in artificially fractured samples exposed to fluids producing carbonate scaling.
- Task V Formation Damage Resulting from Exposure to Colloidal Drilling Fluid.
Measure changes in fracture conductivity in artificially fractured samples exposed to a bentonite based colloidal drilling fluid.

A total of fourteen artificially fractured samples were tested in this program. An outline of the laboratory test matrix is provided in Table 1.

Table 1

Summary of Test Matrix

Sample I.D.	Fluid Type Used to Produce Formation Damage			Post Damage Acid Stimu- lation	Test Temperature	
	Brine with Suspended Solids	Incompatible Completion Fluid	Drilling Mud		200°F	350°F
1	x				x	
2	x				x	
3	x					x
4	x					x
5		x			x	
6		x			x	
7		x				x
8		x				x
9			x		x	
10			x		x	
11			x			x
12	x			x	x	
13	x			x	x	
14		x		x	x	

TASK I ROUTINE PHYSICAL PROPERTIES & LITHOLOGIC DESCRIPTION

Objective

Routine physical properties were measured to provide baseline data characterizing the Nugget sandstone used in all subsequent testing. This data base contains routine physical properties including bench condition gas permeability, bulk density, grain density, porosity, pore size distribution, and capillary pressure curve. Additionally, a detailed lithologic description, including thin section and Scanning Electron Microscope (SEM) micrographs, is provided.

Test Procedures

The samples for this testing were machined as required from available host stock material using compressed air as the cooling medium in all cutting operations. Bench porosity and bench gas permeability, capillary pressure, grain density, and bulk density were determined according to standard API recommended procedures. Pore size distribution was determined by a mercury injection technique. Lithological description was made by standard thin section and SEM analyses.

Test Results

Results of routine properties characterizations are summarized:

Bench Gas Permeability:	10 md
Porosity:	11.1%
Bulk Density:	2.23 gm/cc
Grain Density:	1.98 gm/cc
Pore Size Distribution:	Summarized in Appendix A
Capillary Pressure Curve:	Summarized in Appendix A

A detailed lithologic description of the Nugget Sandstone is presented in Appendix A. This description includes both thin section and SEM micrographs along with captions which describe salient features. For convenience, a brief summary of the lithologic description is provided below:

The Nugget sandstone is a well-sorted to fine grained subquartzarenite. The average grain size is approximately 0.20 mm and the predominate framework grain is monocrystalline quartz with polycrystalline quartz, feldspar and clay clasts also detected. An iron oxide rim was present on many of the framework grains and kaolinite was found to be the principle clay in the rock.

TASK II DEVELOPMENT OF FRACTURING TECHNIQUE AND PREPARATION OF ARTIFICIALLY FRACTURED TEST SAMPLES

Objective

This task was performed to develop a method by which longitudinal fractures could be introduced in cylindrical samples of Nugget Sandstone, 2 inches in diameter and 6 inches in length. It was necessary to subsequent testing in this program that the fractures be relatively consistent in geometry, tortuosity and surface roughness. Two general techniques of artificial fracture preparation were investigated: saw cutting with subsequent sand blasting to roughen the fracture faces, and tensile fracturing (Brazil technique).

Test Results

Experimental procedures were developed which made possible the introduction of artificial fractures, of consistent characteristics, using either technique. The surface texture of the tensile-fractured samples, was judged to be more representative of naturally occurring fractures; and therefore, the Brazil technique was chosen for sample preparation.

Sufficient samples were prepared for testing by the following technique. Longitudinal fractures were produced by machining two shallow diametrically opposed longitudinal grooves in the sample. A load was applied using a hydraulic press and two hardened metal wedges acting on the grooves in the sample in a manner similar to a Brazil tensile test. To preclude intimate remeshing of the fractured sample, the two half cylinders were off-set approximately 50×10^{-3} inches. The offset ends were then surface ground with an abrasive diamond wheel to be coplanar.

Photomicrographs of typical tensile fracture surfaces are presented in Figures 1 and 2. The two micrographs depict overall surface roughness of a typical sample. Figure 2 is a magnification of Figure 1.

Figure 1. Photomicrograph of Artificial Fracture Surface of Untested Sample. Note grain sized roughness and large undulations. Magnification 10x.

Figure 2. Photomicrograph of Artificial Fracture Surface of Untested Sample. Note roughness of surface. Magnification 20x.

TASK III FORMATION DAMAGE RESULTING FROM EXPOSURE TO SUSPENDED PARTICULATES

Objective

This task was performed to assess changes in fracture conductivity resulting from exposure to particulates generated during the drilling process. The use of clear brines as drilling fluids is becoming more common as concern about formation damage in geothermal systems becomes more widespread. However, the use of clear brines does not preclude exposure of the formation to particulates produced by drilling. Fractured specimens tested in the experiments performed in this task were exposed to clear brine containing suspended particulates from disaggregated Nugget sandstone. Fracture conductivity, before and after exposure to brine containing suspended particulates, was measured under test conditions simulating geothermal environments.

Table 2 outlines the testing performed in this task.

Table 2

Test Summary
Formation Damage from Brine with Suspended Solids

Test No.	Test Temp. (°F)	Back Flow Clean-Up	Post Damage Acid Stimulation
1	200	Yes	No
2	200	Yes	No
3	200	Yes	Yes
4	200	Yes	Yes
12	350	Yes	No
13	350	Yes	No

Test Procedure

Testing protocol used in these experiments was essentially the same for each of the six tests. In order to investigate specific damage effects and

to accommodate individual sample responses, some variations in procedure were required.

Testing protocol can be divided into four functional phases: (1) measurement of initial fracture conductivity (pre-damage), (2) exposure of the sample to brine containing suspended particulates (damage), (3) measurement of fracture conductivity in particulate damaged samples (post-damage), and (4) measurement of conductivity recovery and assessment of particulate mobility induced by clear brine backflow (reverse flow). An additional acid stimulation phase was included in the testing of two samples. This step was performed to assess recovery of fracture conductivity resulting from attempted acid stimulation of damaged specimens. Appendix B contains general test procedures for measuring fracture conductivity.

The fractured samples were prepared according to the established method outlined in Task II. Six samples were prepared for the suspended solids damage and brine clean-up portion of this task; two of these samples were additionally subjected to an acid stimulation procedure.

Once the fractured sample was jacketed in teflon tubing for isolation from the confining fluid, the sample was installed in the permeameter and simulated geothermal reservoir conditions were established: 7500 psi confining stress (overburden), 3000 psi pore fluid pressure, and either 200°F or 350°F. When the sample had reached mechanical and thermal equilibrium at the simulated reservoir conditions, an initial fracture conductivity measurement was performed using 2% KCl brine as the permeating fluid. Fracture conductivity was measured using a steady-state flow technique in which flow rate, pressure drop, and sample geometry are measured. Fracture conductivity was measured at discrete intervals until reaching pseudo-equilibrium. Although difficult to generalize because of individual

sample variations, pseudo-equilibrium was typically reached after 1 to 2 hours of steady-state flow.

Once initial fracture conductivity was measured, particulate contaminated brine was injected into the fractured sample. The particulate bearing brine was an aqueous 2% KCl brine with suspended solids prepared from disaggregated Nugget sandstone source material. The solids were mixed with the brine, agitated for 15 minutes, and then allowed to settle for 5-10 minutes, after which the brine with the remaining suspended solids was decanted and retained.

During the damage phase of testing, 500 ml of brine with suspended solids was flowed through the fracture. Flow rates did not exceed 5 ml/min and were typically much lower as the fracture plugged. The direction of flow during damage was opposite that used during the initial fracture conductivity measurement. The flow directions were intended to simulate reservoir processes of production and drilling brine invasion.

Once the fracture had been damaged by the brine containing suspended solids, clear 2% KCl brine was injected in the opposite direction to the flow during which damage occurred. This procedure simulated backflow clean-up of a well in which brine is produced in an effort to flush particulate plugged fractures. In the laboratory testing, flow of clear brine was sustained until stable fracture conductivities were measured. Although there was substantial variation among tests, typical backflow periods lasted 1 to 2 hours.

To qualitatively test the mobility of particulates which had impaired the conductivity of the sample fractures, direction of clear brine flow was reversed during the experiments. Should the particulates be mobile, a transient increase in fracture conductivity is likely to occur at the onset

of flow reversal. The duration of this transient increase can be highly variable lasting only seconds or as long as several hours. Variability of duration is dependent upon many variables including: fracture size, surface roughness, particulate size distribution, permeating fluid viscosity, and fluid velocity. Because of the complexity of the governing mechanisms, only qualitative information about particulate mobility was sought from the flow reversal procedure.

Acid treatments, applied to particulate damaged fractures, were performed on two samples. The volume of acid injected into the damaged samples was equivalent to a field treatment volume of 75 gal/ft. Two acid systems were used to assess the potential for stimulation of the damaged fractures; 7.5% HCl and 3%/12% HF/HCl.

Metered volumes of acid were injected into particulate damaged samples at a rate not exceeding 10 ml/min. At the completion of injection the samples were flushed with approximately 100 ml of clear brine. Once the sample was purged of acid, fracture conductivity was measured using a technique identical to that used in providing the initial conductivity measurements.

Test Results

Tables 3-6 summarize the results of fracture conductivity testing performed on four samples exposed to brine with suspended solids but not subjected to acid stimulation. The tables detail the fracture conductivity data, elapsed test time and directions of brine flow during the testing. Figures 3-6 detail the data graphically.

Tables 7 and 8 summarize the fracture conductivity data for the two samples which were damaged and then treated with acid. The tables detail

the fracture conductivity, elapsed time and directions of brine flow during the testing. Figures 7 and 8 depict this data graphically.

Figures 9-14 are photomicrographs of a typical sample after testing. Figure 9 is a side view of a fractured sample and shows typical fracture geometry. Figures 10-14 show particulates distributed on the fracture face of the sample. The four samples tested for damage with backflow clean-up (samples 1-4) showed an average decrease in brine conductivity of 95.5% with little to no increase in brine conductivity due to the reverse in flow direction. The two samples tested for damage with acid clean-up (samples 12 and 13) had an average decrease in brine conductivity of 76.35%. Sample 12 was acidized with 7.5% HCl with an increase in brine conductivity of 38.63% or an equivalent of 68.51% of the initial conductivity. The sample had a reverse in flow direction which resulted in a decrease in brine conductivity probably due to mobile fines. The final brine conductivity was decreased by 67.18%.

Sample 13 was acidized with 3% HF/12% HCl acid with an increase of over 100% in brine conductivity. The final brine conductivity was approximately 847 md-cm or 191.6% of the initial conductivity.

Table 3

Summary of Fracture Conductivity Data for Sample #1

Permeating Fluid: 2% KCl with
Suspended Solids
Temperature: 200°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow ^a	Post-Damage Flow ^b	Reverse Flow
3	2390	--	--
5	2040	--	--
6	1900	--	--
8	2360	--	--
10	2300	--	--
11	2290	--	--
12	2490	--	--
1035	--	282	--
1038	--	153	--
7902	--	--	326 ^c
7907	--	--	319
7913	--	--	223 ^d
7940	--	--	270
7942	--	--	186

- a - Initial fracture conductivity measurement to 2% KCl. Flow was reversed during the 1 hr damage phase which followed measurement, then shut-in under in-situ conditions for 16 hrs.
- b - Brine clean-up conducted in the same direction as initial flow. Flow was then reversed again and shut-in under in-situ conditions for 113 hrs.
- c - Reverse flow (opposite initial flow direction).
- d - Reverse flow (initial flow direction).

Table 4

Summary of Fracture Conductivity Data for Sample #2

Permeating Fluid: 2% KCl with
Suspended Solids
Temperature: 200°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow ^a	Post-Damage Flow ^b	Reverse Flow ^c
2	2600	--	--
4	2140	--	--
7	1700	--	--
15	1650	--	--
18	899	--	--
21	913	--	--
24	979	--	--
1045	--	64	--
1047	--	59	--
1049	--	52	--
1051	--	51	--
1053	--	50	--
1056	--	48	--
1063	--	46	--
1071	--	57	--
1101	--	65	--
1161	--	47	--
1166	--	44	--
1174	--	--	41
1179	--	--	47
1185	--	--	37
1190	--	--	45
1196	--	--	36
1202	--	--	43

a - Initial fracture conductivity measurement to 2% KCl. Flow was reversed during the 1 hr damage phase which followed measurement; sample was then exposed to suspended solids during 16 hr shut-in.

b - Brine clean-up conducted in the same direction as initial flow.

c - Reverse flow (opposite initial flow direction).

Table 5

Summary of Fracture Conductivity Data for Sample #3

Permeating Fluid: 2% KCl with
Suspended Solids
Temperature: 350°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow	Post-Damage Flow	Reverse Flow ^e
2	940 ^a	--	--
4	799	--	--
5	724	--	--
10	767	--	--
13	990	--	--
15	798	--	--
19	629	--	--
22	604	--	--
25	606	--	--
28	307	--	--
35	404	--	--
38	327	--	--
42	357	--	--
44	386	--	--
49	641	--	--
62	518	--	--
1029	226 ^b	--	--
1032	281	--	--
1038	332	--	--
1043	228	--	--
1049	341	--	--
1050	405	--	--
1053	394	--	--
1056	371	--	--
1185	--	40 ^c	--
1191	--	42 ^d	--
2007	--	19	--
2010	--	19	--
2011	--	18	--
2017	--	--	35
2021	--	--	33
2024	--	--	35
2038	--	--	51
2060	--	--	30
2066	--	--	32
2076	--	--	33
2078	--	--	30

a - Initial fracture conductivity measurement to 2% KCl, followed by 16 hr in-situ shut-in.

b - Fracture conductivity measurement to 2% KCl.

c - Damage phase, conducted for 1 hr with reverse flow and exposure to suspended solids, was followed by brine clean-up in the same direction as initial flow.

d - After a 13.5 hr in-situ shut-in, brine clean-up was conducted in the same direction as initial flow.

e - Reverse flow (opposite initial flow direction).

Table 6

Summary of Fracture Conductivity Data for Sample #4

Permeating Fluid: 2% KCl with
Suspended Solids
Temperature: 350°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow ^a	Post-Damage Flow ^b	Reverse Flow
1	1095	--	--
2	1270	--	--
4	1570	--	--
7	--	1900	--
10	--	2100	--
11	--	2700	--
71	--	--	53 ^c
72	--	--	54
74	--	--	57
75	--	--	56
80	--	--	70 ^d
89	--	--	66
104	--	--	65
113	--	--	61
119	--	--	66
135	--	--	62
136	--	--	96
137	--	--	89
138	--	--	82
139	--	--	80

- a - Initial fracture conductivity measurement to 2% KCl followed by 15 hr shut-in.
- b - Fracture conductivity measurement to 2% KCl with reverse flow (opposite initial flow direction).
- c - Exposure to suspended solids during 1 hr damage phase, followed by brine clean-up in direction of initial flow.
- d - Reverse flow (opposite initial flow direction).

Figure 3. Summary of Fracture Conductivity Variations Due to Exposure to a Fluid with Suspended Particulates, Sample 1.

CONDUCTIVITY IMPAIRMENT DUE TO SUSPENDED SOLIDS

CLIENT: DOE
 FORMATION: NUGGET SANDSTONE
 SAMPLE: 1
 PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI
 PORE PRESSURE: 3000 PSI
 TEMPERATURE: 200 F

Figure 4. Summary of Fracture Conductivity Variations Due to Exposure to a Fluid with Suspended Particulates, Sample 2.

CONDUCTIVITY IMPAIRMENT DUE TO SUSPENDED SOLIDS

CLIENT: DOE
 FORMATION: NUGGET SANDSTONE
 SAMPLE: 2
 PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI
 PORE PRESSURE: 3000 PSI
 TEMPERATURE: 200 F

Figure 5. Summary of Fracture Conductivity Variations Due to Exposure to a Fluid with Suspended Particulates, Sample 3.

CONDUCTIVITY IMPAIRMENT DUE TO SUSPENDED SOLIDS

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 3
PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 350 F

Figure 6. Summary of Fracture Conductivity Variations Due to Exposure to a Fluid with Suspended Particulates, Sample 4.

CONDUCTIVITY IMPAIRMENT DUE TO SUSPENDED SOLIDS

CLIENT: DOE

FORMATION: NUGGET SANDSTONE

SAMPLE: 4

PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI

PORE PRESSURE: 3000 PSI

TEMPERATURE: 350 F

Table 7

Summary of Fracture Conductivity Data for Sample #12

Permeating Fluid: 2% KCl with
Suspended Solids
Temperature: 200°F
Acid: 7.5% HCl

Time (min)	Fracture Conductivity (md-cm)			
	Pre-Damage Flow - a	Post-Damage Flow - b	Reverse Flow - c	Post-Treatment Flow
1	863	--	--	--
3	1002	--	--	--
9	941	--	--	--
12	899	--	--	--
15	832	--	--	--
18	826	--	--	--
21	811	--	--	--
24	750	--	--	--
27	736	--	--	--
29	635	--	--	--
32	567	--	--	--
35	580	--	--	--
38	555	--	--	--
40	563	--	--	--
1062	--	107	--	--
1064	--	120	--	--
1068	--	168	--	--
1070	--	197	--	--
1072	--	334	--	--
1075	--	215	--	--
1081	--	211	--	--
1085	--	200	--	--
1093	--	218	--	--
1095	--	237	--	--
1100	--	--	138	--
1102	--	--	101	--
1105	--	--	151	--
1110	--	--	192	--
1115	--	--	173	--
1120	--	--	171	--
1125	--	--	168	--
1127	--	--	157	--
1130	--	--	167	--
1192	--	--	--	409 ^d
1194	--	--	--	426
1196	--	--	--	307
1198	--	--	--	429
1200	--	--	--	387
1202	--	--	--	377
1204	--	--	--	358
1206	--	--	--	165 ^e
1207	--	--	--	158
1209	--	--	--	167
1212	--	--	--	173
1214	--	--	--	199
1217	--	--	--	184
1219	--	--	--	178
1270	--	--	--	182

a - Initial fracture conductivity measurement to 2% KCl. Measurement was followed by a 1 hr damage phase with reverse flow and exposure to suspended solids, then a 16 hr shut-in.

b - Brine clean-up in the same direction as initial flow.

c - Reverse flow (opposite initial flow direction).

d - Acid flush for 1 hr (opposite initial flow direction) followed by brine clean-up in direction of initial flow.

e - Reverse flow (opposite initial flow direction).

4500

Table 8

Summary of Fracture Conductivity Data for Sample #13

Permeating Fluid: 2% KCl with
Suspended Solids
Temperature: 200°F
Acid: 3% HF/12% HCl

Time (min)	Fracture Conductivity (md-cm)			
	Pre-Damage Flow	Post-Damage Flow	Reverse Flow - e	Post-Treatment Flow - f
6	640 ^a	--	--	--
50	639	--	--	--
62	617	--	--	--
67	579	--	--	--
74	611	--	--	--
86	533	--	--	--
98	519	--	--	--
110	527	--	--	--
122	529 ^b	--	--	--
128	456 ^b	--	--	--
140	414	--	--	--
143	444	--	--	--
146	442	--	--	--
149	439	--	--	--
220	--	679 ^c	--	--
221	--	712	--	--
222	--	696	--	--
223	--	688	--	--
225	--	582	--	--
227	--	480	--	--
229	--	437	--	--
231	--	437	--	--
233	--	396	--	--
234	--	372	--	--
235	--	359	--	--
236	--	313	--	--
237	--	362	--	--
239	--	321	--	--
240	--	313	--	--
241	--	273	--	--
242	--	264	--	--
243	--	257	--	--
244	--	251	--	--
245	--	209	--	--
246	--	205	--	--
248	--	665	--	--
250	--	605	--	--
322	--	67.4 ^d	--	--
325	--	60	--	--
328	--	63	--	--
338	--	--	132	--
341	--	--	70	--
344	--	--	71	--
347	--	--	85	--
350	--	--	76	--
353	--	--	77	--
356	--	--	77	--
422	--	--	--	394
428	--	--	--	362
431	--	--	--	327
443	--	--	--	782
446	--	--	--	829
449	--	--	--	770
452	--	--	--	852
455	--	--	--	799
458	--	--	--	890

a - Initial fracture conductivity measurement to 2% KCl.

b - Reverse flow.

c - Exposure for 1 hr to suspended solids was followed by brine clean-up (initial flow direction).

d - Re-damage phase initiated with suspended solids for 1 hr (opposite initial flow direction) was followed by brine clean-up (initial flow direction).

e - Reverse flow.

f - Acid flush exposure for 1 hr was followed by flow reverse and brine clean-up (initial flow direction).

95%

Figure 7. Summary of Fracture Conductivity Variations Due to Exposure to a Fluid with Suspended Particulates, Sample 12.

CONDUCTIVITY IMPAIRMENT DUE TO SUSPENDED SOLIDS

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 12
PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 200 F
ACID TREATMENT: 7.5% HCL

Figure 8. Summary of Fracture Conductivity Variations Due to Exposure to a Fluid with Suspended Particulates, Sample 13.

CONDUCTIVITY IMPAIRMENT DUE TO SUSPENDED SOLIDS

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 13
PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 200 F
ACID TREATMENT: 3% HF/12% HCL

Figure 9. Photomicrograph Showing Side View of Fracture in Sample 1. Shown are typical features of the artificial fractures. Magnification 25x.

Figure 10. Photomicrograph Showing Exposed Face of Fracture, Sample 1. The lighter areas in the central portion of the micrograph are deposits of particulates captured in the fracture. Magnification 50x.

Figure 11. Photomicrograph Showing Plan View of Fracture Face of Sample 1.
Magnification 50x.

Figure 12. Photomicrograph Showing Plan View of Fracture Face of Sample 1.
Magnification 50x.

Figure 13. Photomicrograph of Sample 1. Lighter areas are captured particulates. Magnification 50x.

Figure 14. Photomicrograph of Sample 1. Lighter areas are captured particulates. Magnification 50x.

TASK IV FORMATION DAMAGE RESULTING FROM INCOMPATIBLE FLUID INTERACTION

Objective

This task was performed to assess the effect of precipitate and scaling, resulting from the interaction of incompatible fluids, upon fracture conductivity. During the course of the drilling and completion of a well a wide variety of solutions come into contact with the fluids native to the reservoir. Because of the complex chemistry of these man-made and native fluids there is the possibility of fluid interactions which could result in precipitation, scaling or flocculation. Interaction of incompatible fluids within a fracture system can, therefore, be a source of significant formation damage. The testing performed in this task systematically investigated impairment of fracture conductivity resulting from carbonate precipitation within an artificial fracture. The carbonate precipitation was produced by reacting two potassium chloride brines, one of which contained a small amount of potassium bicarbonate and the other contained small amounts of calcium chloride. Testing was performed under conditions simulating those of geothermal environments.

Table 9 outlines the testing performed in this task.

Table 9

Test Summary
Formation Damage From Incompatible Fluid Interaction

Test Number	Test Temp. (°F)	Back Flow Clean Up	Post-Damage Acid Stimulation
5	200	Yes	No
6	200	Yes	No
7	350	Yes	No
8	350	Yes	No
14	200	Yes	Yes

Test Procedure

Testing protocol used in these experiments was, in general, identical for each of the five tests. In order to investigate specific damage effects and to accommodate individual sample responses, some variations in procedure were observed.

Testing protocol can be divided into four functional phases: 1) measurement of initial fracture conductivity (pre-damage), 2) exposure of the sample to brine containing calcium chloride which would react with the potassium bicarbonate within the sample (damage), 3) measurement of fracture conductivity in sealed samples (post-damage), and 4) measurement of conductivity recovery and assessment of particulate mobility induced by clear brine backflow (reverse flow). An additional acid stimulation phase was included in the testing of one sample. This step was performed to assess recovery of fracture conductivity resulting from attempted acid stimulation of the damaged sample. Appendix B contains general test procedures for measuring fracture conductivity.

The fractured samples were prepared according to the established method outlined in Task II. Five samples were prepared for the incompatible fluid damage and brine clean-up portion of this task; one sample was additionally subjected to an acid stimulation procedure.

Once the fractured sample was jacketed in teflon tubing for isolation from the confining fluid, the sample was installed in the permeameter and simulated geothermal reservoir conditions were established: 7500 psi closure stress (overburden), 3000 psi pore fluid pressure, and either 200°F or 350°F temperature. When the sample had reached mechanical and thermal equilibrium at the simulated reservoir conditions, an initial fracture conductivity measurement was performed using 2% KCl with potassium bicar-

bonate as the permeating fluid. Fracture conductivity was measured using a steady-state flow technique in which flow rate, pressure drop, and sample geometry are measured. Fracture conductivity was measured at discrete intervals until reaching pseudo-equilibrium. Although difficult to generalize because of individual sample variations, pseudo-equilibrium was typically reached after 1 to 2 hours of steady-state flow.

Once initial fracture conductivity was measured, the incompatible fluid was injected into the fractured sample. The incompatible fluid was a potassium chloride brine with calcium chloride present. Appendix C contains detailed fluid compositions and chemical reaction equations.

During the damage phase of testing, 500 ml of potassium chloride brine with calcium chloride was flowed through the fracture. Flow rates did not exceed 5 ml/min and were typically much lower as the fluids interacted and calcium carbonate precipitated in the fracture system. The direction of flow during damage was opposite that used during the initial fracture conductivity measurement. The flow directions were intended to simulate reservoir processes of production and drilling brine invasion.

Once the fracture had been damaged by the brine containing calcium chloride, clear 2% KCl brine was injected in the opposite direction to the flow during damage. This procedure simulated backflow clean-up of a well in which brine is produced in an effort to flush scaling precipitate from the fractures. In the laboratory testing, flow of clear brine was sustained until stable fracture conductivities were measured. Although there was substantial variation among tests, typical backflow periods lasted 1 to 2 hours.

To qualitatively test the mobility of the precipitate which had impaired the conductivity of the sample fractures, direction of clear brine flow

was reversed during the experiments. Should the precipitate be mobile, a transient increase in fracture conductivity is likely to occur at the onset of flow reversal. The duration of this transient increase can be highly variable lasting only seconds or as long as several hours. Variability of the duration is dependent upon many variables including: fracture size, surface roughness, precipitate and/or scaling of sample, permeating fluid viscosity, and fluid velocity. Because of the complexity of the governing mechanisms, only qualitative information about precipitate mobility was sought from the flow reversal procedure.

Acid treatment, applied to the precipitate damaged fractures, was performed on one sample. The volume of acid injected into the damaged sample was equivalent to a field treatment volume of 75 gal/ft. The acid system used to assess the potential for stimulation of the damaged fracture was 7.5% HCl acid.

Metered volumes of acid were injected into the precipitate damaged sample at a rate not exceeding 10 ml/min. At the completion of the injection the samples were flushed with approximately 100 ml of clear brine. Once the sample was purged of acid, fracture conductivity was measured using a technique identical to that used in providing conductivity measurements.

Test Results

Tables 10-13 detail the results of fracture conductivity testing performed on four samples exposed to brine with calcium chloride but not subjected to acid stimulation. The tables detail the fracture conductivity data, elapsed time and directions of brine flow during the testing. Figures 15-18 detail the data graphically.

Table 14 summarizes the fracture conductivity data for sample 14, as well as the fracture conductivity, elapsed time and directions of brine flow during testing. Figure 19 depicts the data graphically.

Figures 20-25 are photomicrographs of a typical sample after testing for damage from exposure to calcium chloride. Figures 20 and 21 depict the fracture and show the calcium carbonate deposit. Figures 22-25 show the calcium carbonate being deposited along the inundations on the fracture face. The four samples showed an average decrease in fracture conductivity of 84.25%. The samples tested at 200°F showed a 94.5% decrease in fracture conductivity with an additional decrease of 1% with the flow reversal. This showed that the precipitate was mobile and the sample incurred further damage. The samples tested at 300°F had less fracture conductivity damage which was not expected. The initial decrease in fracture conductivity due to damage with the calcium chloride was an average of 74.0%. The fracture conductivity again decreased with the flow reversal to an average reduction of 78.0%.

The sample which was treated with 7.5% HCl acid had an initial decrease in fracture conductivity of 92.2% due to exposure to calcium chloride. The final fracture conductivity after treatment was 502 md-cm, equivalent to more than a 400% increase in fracture conductivity compared to the initial undamaged fracture conductivity.

Table 10

Summary of Fracture Conductivity Data for Sample #5

Permeating Fluid: Aqueous 2% KCl Brine
with 7% CaCl_2
Temperature: 200°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow ^a	Post-Damage Flow ^b	Reverse Flow ^c
1	1570	--	--
5	1670	--	--
6	1500	--	--
7	1500	--	--
9	1500	--	--
10	1370	--	--
11	1440	--	--
12	1480	--	--
78	--	69	--
81	--	94	--
90	--	58	--
117	--	65	--
162	--	--	79
176	--	--	73
204	--	--	76
207	--	--	72
210	--	--	71

a - Initial fracture conductivity measurement to 2% KCl with bicarbonate.

b - Exposure to 2% KCl with CaCl_2 during a 1 hr damage phase with reverse flow (opposite initial flow direction) was followed by brine clean-up with 2% KCl (initial flow direction).

c - Reverse flow (opposite initial flow direction).

Table 11

Summary of Fracture Conductivity Data for Sample #6

Permeating Fluid: Aqueous 2% KCl Brine
with 7% CaCl_2
Temperature: 200°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow ^a	Post-Damage Flow ^b	Reverse Flow ^c
4	1600	--	--
5	1600	--	--
9	1300	--	--
10	1150	--	--
11	1160	--	--
13	1160	--	--
16	1090	--	--
18	960	--	--
79	--	51	--
80	--	51	--
82	--	50	--
83	--	63	--
84	--	68	--
85	--	77	--
86	--	--	92
87	--	--	76
88	--	--	65
98	--	--	51
106	--	--	45
113	--	--	41
122	--	--	38
124	--	--	43
131	--	--	34
135	--	--	41

a - Initial fracture conductivity measurement to 2% KCl with bicarbonate.

b - Exposure to 2% KCl with CaCl_2 during a 1 hr damage phase with reverse flow (opposite initial flow direction) was followed by brine clean-up with 2% KCl (initial flow direction).

c - Reverse flow (opposite initial flow direction).

Table 12

Summary of Fracture Conductivity Data for Sample #7

Permeating Fluid: Aqueous 2% KCl Brine
with 7% CaCl_2
Temperature: 350°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow	Post-Damage Flow ^c	Reverse Flow ^d
2	4700 ^a	--	--
3	6800	--	--
4	2000	--	--
5	2200	--	--
7	2000	--	--
908	4000 ^b	--	--
910	4000	--	--
911	3000	--	--
972	--	1400	--
988	--	1700	--
996	--	1200	--
1022	--	1250	--
1023	--	1150	--
1024	--	1800	--
1025	--	1200	--
1026	--	1500	--
1027	--	2000	--
1042	--	--	388
1066	--	--	1000
1087	--	--	363
1088	--	--	303
1089	--	--	383

a - Initial fracture conductivity measurement to 2% KCl with bicarbonate.

b - Following 15 hrs shut-in (at in-situ conditions) fracture conductivity measurement to 2% KCl with bicarbonate.

c - Following 1 hr damage phase with reverse flow direction, sample exposed to 2% KCl with CaCl_2 ; brine clean-up was instigated with 2% KCl flow in the initial flow direction.

d - All conditions except flow remained constant.

Table 13

Summary of Fracture Conductivity Data for Sample #8

Permeating Fluid: Aqueous 2% KCl Brine
with 7% CaCl_2
Temperature: 350°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow	Post-Damage Flow ^c	Reverse Flow ^d
1	541 ^a	--	--
2	487	--	--
3	434	--	--
4	575	--	--
5	416	--	--
6	469	--	--
7	512	--	--
8	421	--	--
9	318	--	--
10	344	--	--
11	408 ^b	--	--
914	305 ^b	--	--
915	305	--	--
916	276	--	--
917	351	--	--
918	381	--	--
920	335	--	--
922	294	--	--
923	383	--	--
985	--	49	--
986	--	50	--
987	--	56	--
988	--	45	--
990	--	50	--
991	--	57	--
993	--	43	--
999	--	--	55
1000	--	--	39
1002	--	--	36
1004	--	--	40
1006	--	--	41
1012	--	--	39
1013	--	--	38
1014	--	--	40
1022	--	--	40
1037	--	--	44
1039	--	--	43
1040	--	--	39
1041	--	--	41
1042	--	--	46

a - Initial fracture conductivity measurement to 2% KCl with bicarbonate.

b - Shut-in under in-situ conditions for 15 hrs was followed by fracture conductivity measurement to 2% KCl with bicarbonate.

c - Exposure to 2% KCl with CaCl_2 during a 1 hr damage phase with reverse flow (opposite initial flow direction) was followed by brine clean-up with 2% KCl (initial flow direction).

d - Reverse flow (opposite initial flow direction).

Figure 15. Summary of Fracture Conductivity Variations Due to Exposure to an Incompatible Fluid, Sample 5.

CONDUCTIVITY IMPAIRMENT DUE TO INCOMPATIBLE FLUID INTERACTION

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 5
PERMEATING FLUID: 2% KCL BRINE W/
BICARBONATE SOLUTION

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 200 F

Figure 16. Summary of Fracture Conductivity Variations Due to Exposure to an Incompatible Fluid, Sample 6.

CONDUCTIVITY IMPAIRMENT DUE TO INCOMPATIBLE FLUID INTERACTION

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 6
PERMEATING FLUID: 2% KCL BRINE W/
BICARBONATE SOLUTION

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 200 F

Figure 17. Summary of Fracture Conductivity Variations Due to Exposure to an Incompatible Fluid, Sample 7.

CONDUCTIVITY IMPAIRMENT DUE TO INCOMPATIBLE FLUID INTERACTION

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 7
PERMEATING FLUID: 2% KCL BRINE W/
BICARBONATE SOLUTION

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 350 F

Figure 18. Summary of Fracture Conductivity Variations Due to Exposure to an Incompatible Fluid, Sample 8.

CONDUCTIVITY IMPAIRMENT DUE TO INCOMPATIBLE FLUID INTERACTION

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 8
PERMEATING FLUID: 2% KCL BRINE W/
BICARBONATE SOLUTION

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 350 F

Terratek Research

CUMULATIVE TIME (MINUTES)

Table 14

Summary of Fracture Conductivity Data for Sample #14

Permeating Fluid: Aqueous 2% KCl Brine
with 7% CaCl_2
Temperature: 200°F

Time (min)	Fracture Conductivity (md-cm)		
	Pre-Damage Flow ^a	Post-Damage Flow ^b	Post-Treatment Flow ^c
1.5	359	--	--
3	210	--	--
5	183	--	--
9	160	--	--
12	132	--	--
14	86	--	--
18	74	--	--
20	61	--	--
22	54	--	--
24	230	--	--
28	51	--	--
30	124	--	--
32	116	--	--
34	119	--	--
106	--	40	--
115	--	21	--
121	--	125	--
124	--	104	--
128	--	6	--
130	--	12	--
132	--	7	--
133	--	10	--
142	--	8	--
206	--	--	712
207	--	--	491
208	--	--	581
210	--	--	504
212	--	--	415
214	--	--	412
215	--	--	506
216	--	--	474
218	--	--	421
219	--	--	523
220	--	--	504
222	--	--	521
224	--	--	540

a - Initial fracture conductivity measurement to 2% KCl with bicarbonate.

b - Exposure to 2% KCl with CaCl_2 during a 1 hr damage phase, followed by brine clean-up with 2% KCl (initial flow direction).

c - No reverse flow was performed. Brine clean-up with 2% KCl (initial flow direction).

Figure 19. Summary of Fracture Conductivity Variations Due to Exposure to an Incompatible Fluid, Sample 14.

CONDUCTIVITY IMPAIRMENT DUE TO INCOMPATIBLE FLUID INTERACTION

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 14
PERMEATING FLUID: 2% KCL W/
BICARBONATE SOLUTION

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 200 F
ACID TREATMENT: 7.5% HCL

Figure 20. Photomicrograph Showing Side View of Fracture in Sample 5, Magnification 50x.

Figure 21. Photomicrograph Showing Side View of Fracture in Sample 5, Magnification 50x.

Figure 22. Photomicrograph Showing Exposed Face of Fracture of Sample 5, Magnification 50x.

Figure 23. Photomicrograph Showing Exposed Face of Fracture of Sample 5, Magnification 50x.

Figure 24. Photomicrograph Showing Plan View of Fracture Face of Sample 5, Magnification 50x.

Figure 25. Photomicrograph Showing Plan View of Fracture Face of Sample 5, Magnification 50x.

TASK V FORMATION DAMAGE RESULTING FROM EXPOSURE TO COLLOIDAL DRILLING FLUID

Objective

This task was performed to assess the effect of exposure to a colloidal drilling fluid upon fracture conductivity. Common drilling fluids frequently are colloidal systems designed to hydrostatically balance reservoir pressures, lubricate the drilling bit and control fluid loss to the reservoir. Although a well designed colloidal drilling fluid can control fluid loss while causing little formation damage, performance of these fluids can be problematic in a fracture dominated reservoir. Fracture specimens tested in the experiments performed in this task were exposed to colloidal drilling fluid which was injected into the artificial fracture. Fracture conductivities of samples before and after exposure to the drilling fluid were measured under conditions simulating geothermal environments.

Table 15 outlines the testing performed in this task.

Table 15
Test Summary
Formation Damage from Exposure to
Colloidal Drilling Fluid

Test No.	Mud Type (colloid constituent)	Temperature (°F)
9	Bentonite/ Attapulgate	200
10	Bentonite	200
11	Bentonite	350

Test Procedure

Testing protocol used in these experiments, in general, was identical for each of the three tests. In order to investigate specific damage

effects and to accommodate individual sample responses, some variations in procedure were observed.

Testing protocol can be divided into four functional phases: 1) measurement of initial fracture conductivity (pre-damage), 2) exposure of the sample to the colloidal mud system (damage), 3) measurement of fracture conductivity in a filtrate and mud particulate damaged samples (post-damage), and 4) measurement of conductivity recovery and assessment of particulate mobility induced by clear brine backflow (reverse flow). Appendix B contains general test procedures for measuring fracture conductivity.

The fractured samples were prepared according to the established method outlined in Task II. Three samples were prepared for the colloidal drilling system damage and brine clean-up portion of this task.

Once the fractured sample was jacketed in teflon tubing for isolation from the confining fluid, the sample was installed in the permeameter and simulated geothermal reservoir conditions were established: 7500 psi confining pressure (overburden), 3000 psi pore fluid pressure, and either 200°F or 350°F temperature. When the sample had reached mechanical and thermal equilibrium at the simulated reservoir conditions, an initial fracture conductivity measurement was performed using 2% KCl brine as the permeating fluid. Fracture conductivity was measured using a steady-state flow technique in which flow rate, pressure drop, and sample geometry are measured. Fracture conductivity was measured at discrete intervals until reaching pseudo-equilibrium. Although difficult to generalize because of individual sample variations, pseudo-equilibrium was typically reached after 1 to 2 hours of steady-state flow.

Once initial fracture conductivity was measured, colloidal drilling fluid was injected into the fractured sample. The colloidal system was a bentonite based drilling mud with attapulgite added for protection from degradation due to high temperature. Table 16 is a summary of the drilling fluid composition. Appendix D has a detailed property analysis.

Table 16
Summary of Drilling Fluid System

Component	Recommended Mixture	Actual Amount Used
Water	2.5 l	2.5 l
Caustic	1/4-1/2 lb/bbl	4 g
Bentonite	5-8 lb/bbl	57 g
Attapulgite	10-15 lb/bbl	107 g
Thinner	2-6 lb/bbl	50 g

During the damage phase of testing, 500 ml of colloidal drilling fluid was flowed through the fracture. Flow rates did not exceed 5 ml/min and were typically lower as the fracture plugged. The direction of flow during damage was opposite that used during the initial fracture conductivity measurement. The flow directions were intended to simulate reservoir processes of drilling.

Once the fracture had been damaged by the colloidal system, clear 2% KCl brine was injected in the opposite direction the the flow during damage. This procedure simulated backflow clean-up of a well in which brine is produced in an effort to flush drilling particles and filtrate out of the plugged fractures. In the laboratory testing, flow of clear brine was sustained until stable fracture conductivities were measured. Although there was substantial variation among tests, typically backflow periods lasted 1 to 2 hours.

To qualitatively test mobility of drilling particulates which had impaired the conductivity of the sample fractures, direction of clear brine flow was reversed during the experiments. Should the particulates be mobile, a transient increase in fracture conductivity is likely to occur at the onset of flow reversal. Also, under the new conditions the duration of this transient increase can be highly variable lasting only seconds or as long as several hours. Variability of duration is dependent upon many variables including: fracture size, surface roughness, particulate size, permeating fluid viscosity, and fluid velocity. Because of the complexity of the governing mechanisms, only qualitative information about particulate mobility was sought from the flow reversal procedure.

Test Results

Tables 17-19 detail the fracture conductivity testing performed on three samples exposed to the colloidal drilling fluid. The tables detail the fracture conductivity, elapsed time and directions of brine flow during the testing. Figures 26-28 depict the data graphically.

Figures 29-34 are photomicrographs of a typical sample exposed to the colloidal drilling fluid. Figures 29 and 30 depict the fracture itself and the carbonized, thermally degraded drilling fluid filtrate. Figures 31-34 depict the fracture faces and the extended degradation of the mud system most likely due to the temperature.

All of the samples had less than 1 md-cm of fracture conductivity during clean-up flow. The two samples tested at 200°F had fracture conductivities of 11 and 7 md-cm respectively, which is a 99.99% and a 99.8% reduction in fracture conductivity. The sample tested at 350°F had 100% fracture conductivity reduction.

Table 17

Summary of Fracture Conductivity Data for Sample #9

Permeating Fluid: Bentonite Mud
with Attapulgite
Temperature: 200°F

Time (min)	Fracture Conductivity (md-cm)	
	Pre-Damage Flow	Post-Damage Flow ^c
10	1300 ^a	--
13	848	--
16	916	--
19	868	--
937	1200 ^b	--
940	1300	--
943	1100	--
946	1200	--
1096	--	9
1099	--	11

a - Initial fracture conductivity measurement to 2% KCl.

b - Shut-in under in-situ conditions for 15.25 hrs was followed by fracture conductivity measurement to 2% KCl.

c - Following 1 hr damage phase (reverse flow direction) with exposure to Bentonite Mud with Attapulgite, brine clean-up was conducted with 2% KCl (initial flow direction). Post-damage flow was less than 1% of initial flow, and therefore no reverse flow was performed.

Table 18

Summary of Fracture Conductivity Data for Sample #10

Permeating Fluid: Bentonite Mud
with Attapulgite
Temperature: 200°F

Time (min)	Fracture Conductivity (md-cm)	
	Pre-Damage Flow	Post-Damage Flow ^c
2	3100 ^a	--
3	3180	--
6	2990	--
12	1980	--
13	2250	--
1082	3600 ^b	--
1085	3600	--
1090	3900	--
1151	--	8
1154	--	6
1157	--	7

a - Initial fracture conductivity measurement to 2% KCl.

b - Shut-in under in-situ conditions for 17.8 hrs was followed by fracture conductivity measurement to 2% KCl.

c - Following 1 hr damage phase (reverse flow direction) with exposure to Bentonite Mud with Attapulgite, brine clean-up was conducted with 2% KCl (initial flow direction). Post-damage flow was less than 1% of initial flow, and therefore no reverse flow was performed.

Table 19

Summary of Fracture Conductivity Data for Sample #11

Permeating Fluid: Bentonite Mud
with Attapulgite
Temperature: 350°F

Time (min)	Fracture Conductivity (md-cm)	
	Pre-Damage Flow ^a	Post-Damage Flow ^b
961	2800	--
962	2500	--
963	3100	--
966	2600	--
971	2500	--
972	2500	--
1032	--	Unmeasurable

a - Shut-in under in-situ conditions for 16 hrs was followed by initial fracture conductivity measurement with 2% KCl.

b - Damage phase, with exposure to Bentonite Mud for 1 hr with Attapulgite (opposite initial flow) was followed by brine clean-up with 2% KCl (initial flow direction). Post-damage flow was less than 1% of initial flow, and therefore no reverse flow was performed.

Figure 26. Summary of Fracture Conductivity Variations Due to Exposure to a Colloidal Drilling Fluid, Sample 9.

CONDUCTIVITY IMPAIRMENT DUE TO DRILLING FLUID CIRCULATION

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 9
PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 200 F

Figure 27. Summary of Fracture Conductivity Variations Due to Exposure to a Colloidal Drilling Fluid, Sample 10.

CONDUCTIVITY IMPAIRMENT DUE TO DRILLING FLUID CIRCULATION

CLIENT: DOE

FORMATION: NUGGET SANDSTONE

SAMPLE: 10

PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI

PORE PRESSURE: 3000 PSI

TEMPERATURE: 200 F

Figure 28. Summary of Fracture Conductivity Variations Due to Exposure to a Colloidal Drilling Fluid, Sample 11.

CONDUCTIVITY IMPAIRMENT DUE TO DRILLING FLUID CIRCULATION

CLIENT: DOE
FORMATION: NUGGET SANDSTONE
SAMPLE: 11
PERMEATING FLUID: 2% KCL BRINE

CONFINING PRESSURE: 7500 PSI
PORE PRESSURE: 3000 PSI
TEMPERATURE: 350 F

Figure 29. Photomicrograph Showing Side View of Fracture in Sample 11, Magnification 25x.

Figure 30. Photomicrograph Showing Side View of Fracture in Sample 11, Magnification 50x.

Figure 31. Photomicrograph Showing Exposed Face of Fracture of Sample 11, Magnification 50x.

Figure 32. Photomicrograph Showing Exposed Face of Fracture of Sample 11, Magnification 50x.

Figure 33. Photomicrograph Showing Plan View of Fracture Face of Sample 11, Magnification 50x.

Figure 34. Photomicrograph Showing Plan View of Fracture Face of Sample 11, Magnification 50x.

DISCUSSION

Three types of formation damage were investigated in this special core analysis program. These were: contamination by a clear brine containing suspended drilling solids, contamination by incompatible completion fluids and contamination by a colloidal drilling fluid.

Of the three contaminating fluids, the samples damaged with the colloidal drilling fluid experienced the greatest degree of conductivity damage. The decrease in conductivity was nearly 100%. None of the samples were exposed to stimulation through acidization and therefore no information is available for analyzing the reversibility of this observed damage. Acidization tests were not performed on the samples damaged with colloidal drilling fluid because of the severe damage incurred. Flow through the samples was not possible at the restricted low pressures to work with acid.

The samples damaged with the incompatible completion fluids had approximately an 84.25% decrease in initial conductivity due to the exposure to 2% KCl brine with CaCl_2 . The samples tested at 200°F had greater damage than the samples tested at 350°F which was unexpected. The damage observed at 200°F was approximately 95% where the damage observed at 350°F was approximately 74%.

It was observed that flow reversal within the artificial fracture resulted in a further decrease in fracture conductivity. This indicated that mobile fines were present to some degree. Since the further decrease in conductivity was slight, 1-4%, indications are that the major damage was due to scaling with some precipitate present and mobile.

One sample was acidized with 7.5% HCl acid after being damaged with the 2% KCl brine with CaCl_2 at 200°F. The acidization resulted in a large

increase in conductivity, improving fracture conductivity by more than 400%. This indicated that the scaling and precipitate was soluble to 7.5% HCl acid.

The samples damaged with the clear brine with suspended solids had approximately 95.5% decrease in fracture conductivity due to the exposure. The samples were exposed to a flow reversal with little change in fracture conductivity indicating little to no mobile fines. The temperature also seemed to have little effect on the degree of fracture conductivity decrease.

Two samples were acidized after damage was induced by the clear brine with suspended solids. Both of the samples were tested at 200°F; one being acidized with 7.5% HCl and the other being treated with 3% HF/12% HCl acid. The sample treated with the 7.5% HCl acid had an approximate increase of fracture conductivity of 38.63%. The sample treated with 3% HF/12% HCl had an increase in fracture conductivity of over 190% of its initial conductivity. This indicates that the suspended solids were more soluble in 3% HF/12% HCl acid than in the 7.5% HCl acid, although it was not determined whether or not the hydrofluoric acid or the combination of acids was responsible for the improved response.

In conclusion, the colloidal drilling fluid induced the greatest damage to the fracture conductivity. Due to the total loss in conductivity in all three samples, it is not possible to ascertain the effect of the attapul-gite for temperature stabilizing effects. Through visual inspection though, post-analysis, the sample tested at 300°F had a blackening of the colloidal system which wasn't present in the lower temperature tests. This indicates that the colloidal system is not stable at 300°F.

In general, the studies into colloidal drilling fluid damage were not inclusive enough to draw any definitive conclusions and further investigation should be initiated.

The samples tested with incompatible fluids at 350°F had the least amount of fracture conductivity damage with this damage being the easiest to reverse through acidization with 7.5% HCl acid. It was anticipated that the higher temperature would induce the greater damage but the 200°F tests had greater conductivity impairment than the 300°F tests. This may be due to the reaction rate of the precipitating calcium carbonate. It may be that for the 200°F tests the damage was due to precipitate which was mobile and therefore removable through normal production whereas the damage in the 300°F tests was due to scaling and therefore permanent. This, although, is not conclusive due to the scope of this analysis.

The samples tested with suspended drilling solids had approximately 95.5% decrease in fracture conductivity. The drilling particles apparently bridged over portions of the flow paths since no apparent increase in fracture conductivity was observed with flow reversals. The acidization techniques used were a 7.5% HCl acid and a 3% HF/12% HCl acid. The former acid had little effect on increasing the damaged fracture conductivity whereas the latter dissolved not only the suspended solids but evidently portions of the matrix to improve fracture conductivity by over 190%. It is therefore rather conclusive that 3% HF/12% HCl acid is more effective in repairing drilling solids damage of this type than 7.5% HCl acid.

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APPENDIX A

PETROGRAPHIC EVALUATION OF NUGGET SANDSTONE

PETROGRAPHIC EVALUATION
Of a Nugget Sandstone Sample
for Terra Tek Research

One (1) sample of Nugget Sandstone was submitted for petrographic evaluation (thin section and scanning electron microscopy) by Terra Tek Research. The sample is a moderately- to well-sorted fine grained sub-quartzarenite. The average grain size, as determined from thin section and SEM is approximately 0.20mm. The predominant framework grain is monocrystalline quartz with polycrystalline quartz, feldspar and clay clasts also detected. An iron oxide rim on many of the framework grains imparts a reddish-brown color to the rock. Kaolinite is the principal clay in the rock, and it was found infilling porosity and coating framework grains.

The porosity and permeability values of the sample used for the mercury injection - capillary pressure analysis were 11.4% and 10md, respectively. The primary porosity in this sandstone was reduced by the combined effects of mechanical compaction (physical rearrangement of grains in response to increasing overburden pressure), chemical compaction or pressure solution and quartz overgrowth development. Some secondary porosity was created by the partial dissolution of clay clasts and feldspars.

Mercury injection - capillary pressure data shows that the threshold pressure is relatively low at 23.2 psi. Up to approximately 40% mercury saturation, the pore throats are relatively well sorted ranging from 4.6 μ m to 2.5 μ m. Beyond 40% mercury saturation a more heterogeneous distribution of pore throats is evident in the sample, as seen in the pore throat size histogram. This heterogeneous distribution of pore throats is due to the fine porosity associated with pore-filling clays and leached grains.

THIN SECTION PHOTOMICROGRAPHS

- A. General view of fabric showing distribution and sorting of framework quartz (q) grains. A thin iron oxide rim (arrows) on the framework grains imparts a reddish-brown color to the rock. x65 (Plane-polarized light)
- B. General view of fabric showing undulose and slightly sutured quartz grain boundaries (arrows) indicative of chemical compaction or pressure solution. x65 (Crossed-polars)
- C. Detail of fabric showing quartz overgrowths (o) and undulose grain boundaries (arrows) indicative of pressure solution. The combined effects of compaction and overgrowth development reduced the primary porosity in this sandstone. Note that the iron oxide rim is coating the detrital nuclei, suggesting that overgrowth development post-dated the development of these rims. x250 (Crossed-polars)
- D. Detail of fabric showing a pore (dark area in center) bounded by quartz overgrowths (o). The smooth overgrowth faces tend to reduce the tortuosity of the pore system. Compaction resulted in the plastic deformation of the grain (g) seen at lower center. x250 (Crossed-polars)

A

B

C

D

Thin Section Photomicrographs - Page 2

- E. Detail of fabric showing a microcline (m) or potassium feldspar grain compacted between more competent quartz grains. Note the undulose grain boundary (arrow) indicative of pressure solution. x250 (Crossed-polars)

- F. Detail of fabric showing a polycrystalline quartz grain (g) compacted between more competent monocrystalline quartz grains. Overgrowth development is generally limited on polycrystalline grains due to the abundant nucleating sites. x250 (Crossed-polars)

E

F

SEM MICROGRAPHS

- A. Overview of fabric of a fine-grained sandstone showing the sorting of framework grains and the variability in the size, shape and distribution of porosity. The majority of framework grains are monocrystalline quartz which possess some authigenic overgrowths (o). Some leaching and partial dissolution of unstable grains is evident (arrow). x50
- B. General view of fabric showing porosity infilled with authigenic quartz (q) and kaolinite (k). Kaolinite is irregularly distributed throughout the pore system of the rock. x200
- C. High magnification of pore-filling kaolinite seen in micrograph B. The individual kaolinite booklets are tightly packed in the pore and they have a corroded appearance. Note the microporosity associated with this clay fabric. x2500
- D. General view of fabric showing minor secondary porosity created by the partial dissolution of a detrital potassium feldspar (f) grain. Note the overgrowth development (o) on surrounding quartz grains. x500

A

B

C

D

SEM Micrographs - Page 2

- E. Overview of fabric showing packing of framework grains and a reduction in visible macroporosity when compared with that portion of the sample seen in micrograph A. The primary porosity was reduced mainly by the combined effects of compaction and quartz overgrowth development. Some leached and corroded grains are also evident. x70
- F. Detail of fabric showing a pore partly infilled with authigenic quartz (q) and kaolinite (k). Migration of kaolinite and subsequent reduction in permeability can occur if the flow velocity in the pore system exceeds the critical value necessary to initiate migration. x750
- G. General view of fabric showing variability in quartz overgrowth development. The large blocky overgrowths (o) form on monocrystalline quartz grains with the orientation of the overgrowth conforming to the crystallographic c-axis of the host grain. On microcrystalline grains such as chert, which have numerous nucleating sites, overgrowth development is generally not extensive and consists of small crystals of differing optical continuity. x450
- H. Detail of fabric showing a pore partly infilled with authigenic quartz (q). The smooth surfaces of the quartz grains reduce the tortuosity of the pore system. Note the remnants of a leached clay clast (c) at lower left. x700

E

F

G

H

MERCURY INJECTION/CAPILLARY PRESSURE
PORE THROAT SIZE
PORE ENTRY DISTRIBUTION

TEST OBJECTIVES

This test program is designed to acquire data from samples of Nugget Sandstone to determine capillary pressure by mercury injection analysis. Information required for the preceding tests are bench condition permeability to nitrogen, porosity and pore volume.

From the measured mercury injection/capillary pressure data the injected mercury (non-wetting phase) volume is plotted versus the injection pressure. The resulting capillary pressure curve provides values for threshold pressure, irreducible water saturation and pore geometry as a function of pore throat size distribution.

SAMPLE PREPARATION

The test plug prepared from a full diameter core sample was cut parallel to the core axis using a diamond core bit with water as the bit coolant and lubricant. The plug was 1 inch in diameter and approximately 1.5 to 2.0 inches in length. Porosity was measured by combining the Archimedes (mercury) displacement method for bulk volume and the Boyle's Law (helium) method for grain volume. Ambient condition permeability to nitrogen was measured in a Hassler sleeve using an orifice manometer and flowing meniscus to monitor downstream flow. The sample was convection dried at 100° C prior to porosity and permeability measurements.

TEST PROCEDURE

Mercury Injection/Capillary Pressure

The cleaned, air-dried core sample was enclosed and submersed in a pressure tight mercury chamber and evacuated to a pressure of less than ten microns of mercury. Mercury was then introduced into the interstices of the core at a series of increasing stabilized pressures by means of injecting nitrogen gas into the system. The amount of mercury injected into the core at a pressure increment was recorded. This mercury injection cycle is also known as the drainage cycle since the non-wetting (mercury) phase desaturates the wetting (air) phase. The injection cycle was terminated at a specified maximum pressure of 5,000 psia.

Pore Throat Size

Pore throat size was calculated from the mercury/nitrogen injection data with the following formula:

$$P_c = \frac{2\sigma \cos\theta}{r} \quad (1)$$

where P_c is the mercury/nitrogen (capillary) pressure, r the pore throat radius, σ the surface tension between mercury and nitrogen (estimated to be 480 dynes per centimeter) and θ the contact angle of mercury (estimated to be 140°).

Pore Size Distribution

Following the method of Purcell¹ of investigating capillary pressures in reservoir rocks, Ritter and Drake² developed a theory for the calculation of pore size distribution from mercury-injection capillary pressure data. Burdine et al³ adapted the method of Ritter and Drake to the determination of pore-size distribution of reservoir rocks and also presented a method of calculating permeability from the distribution analysis. For the penetration of a "non-wetting" liquid into a porous solid, equivalent pore radius and distribution function could be calculated using the following equations:

$$P_{c_i} R_i = 2\sigma \cos\theta \quad (1)$$

$$D(R_i) = \frac{P_{c_i}}{R_i} \cdot \frac{d(V_0 - V)}{d P_{c_i}} \quad (2)$$

where: P_{c_i} = capillary pressure (psi, kPa)
 R_i = pore entry radius (microns)
 σ = interfacial tension (dynes/cm-mN/m)
 θ = contact angle (degrees)
 $D(R_i)$ = Distribution function (cm^2)
 V_0 = total pore volume (cm^3)
 V = volume (cm^3)

The calculations usually assume an air-mercury contact angle of 140° and interfacial tension of 480 dynes/cm., respectively, which are representative of most reservoirs. A pressure-volume curve is plotted from experimental data and by graphical differentiation of this curve, values of the derivative required to evaluate $D(R_i)$ are readily obtained. For a number of values of P_{c_i} , the pressuring curve is differentiated to obtain $d(V_o-V)/dP_{c_i}$, R_i is calculated from Equation 1 and $D(R_i)$ from Equation 2. Plotting $D(R_i)$ against R_i gives the desired distribution curve. The value of $D(R_i)$ may also be determined directly from the pressure-volume curve, where $D(R_i)$ is the average value of the distribution function in the radii interval R_i to $R_i + \Delta R_i$. The area under the distribution curve to a given pore entry radius is the fraction of the pore volume having pores larger than the given radius.

It has been recognized for some time by the petroleum industry that a determination of pore size distribution for porous reservoir rocks offered promise of increased understanding of fundamental flow processes in the porous matrix, and therefore of petroleum reservoir performance in general.

From the point of view of geological correlation, a study of pore size distribution data normally shows that distribution curves for samples from a particular geological formation generally have similar characteristics, whereas distribution curves from another formation may have very little in common. Differences can be related to the amounts of clay and various chemical compounds included in the formation.

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3. Burdine, N. T., Gournay, L. S. and Reichertz, P.P. 1950, Pore size distribution of petroleum reservoir rocks; Transactions of the AIME, volume 189, page 195.

Terra Tek Core Services

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SUMMARY OF CAPILLARY PRESSURE DATA

TERRA TEK RESEARCH

Well Name: N/A

Location: N/A

Nusset Sandstone

TTCs File No. 577

Sample	Depth	Perm	Porosity	Pore Throat Size			Irreducible	Maximum	Threshold	Residual	Hg Recovery
Number	(ft)	(md)	(%)	Hg Saturation			Water Sat.	Saturation	Pressure	Hg Sat.	Efficiency
				25%	50%	75%	(%)	(%)	(psi)	(%)	(%)
1	N/A	10	11.14	3.23	1.63	0.12	18.3	81.7	23.2	---	---

MERCURY INJECTION/PORE THROAT SIZE DATA

COMPANY: TERRA TEK RESEARCH

County, St.: Location: N/A

WELL: Well Name: N/A

TTCS File No.: 377

Sample Number	Depth Interval	Permeability md	Porosity %
1	N/A	10.3	11.1

Injection Pressure kPa	PSIA	Pore Throat Radius microns	Injection Phase Mercury Saturation 1
10	1.5	73.322	0.00
20	2.9	36.761	0.00
40	5.8	18.380	0.00
60	8.7	12.254	0.00
80	11.6	9.190	0.00
101	14.6	7.279	0.00
120	17.4	6.127	0.00
140	20.3	5.252	0.00
160	23.2	4.595	0.00
180	26.1	4.085	6.88
200	29.0	3.676	19.09
300	43.5	2.451	40.66
400	58.0	1.838	48.02
550	79.8	1.337	53.94
700	101.5	1.050	56.74
1400	203.1	0.525	64.37
2100	304.6	0.350	66.95
3500	507.6	0.210	70.88
5200	751.2	0.141	73.35
6900	1000.8	0.107	75.88
8600	1247.3	0.085	77.06
10300	1493.9	0.071	78.09
12100	1754.9	0.061	78.73
13800	2001.5	0.053	78.95
17250	2501.9	0.043	79.86
20700	3002.3	0.036	80.40
24150	3502.6	0.030	80.72
27600	4003.0	0.027	80.94
31000	4496.1	0.024	81.42
34500	5003.8	0.021	81.74

MERCURY INJECTION / CAPILLARY PRESSURE

TERRA TEK RESEARCH

Well Name: N/A

*Back
6/10/12*

PORE ENTRY DISTRIBUTION FUNCTION

TERRA TEK RESEARCH

Well Name: N/A

SCAL No. 577

APPENDIX B

EXPERIMENTAL PROCEDURE

MEASUREMENT OF FRACTURE CONDUCTIVITY

GENERAL TEST PROCEDURE

The prepared samples, 2.00 inches in diameter by 6.00 inches in length, were offset by 50×10^{-3} inches to preclude testing a fitted fracture. A schematic cross-section of the test sample assembly is shown in Figure 1. Sixty mesh Hastelloy* screens were placed at each end of the assembled cylindrical sample to retain the proppant pack. The sample assembly was placed between Hastelloy endcaps and enclosed in silicone rubber (to prevent sidewall leakage) and a teflon sleeve. The test sample was then placed within the test apparatus shown in Figure 2.

Figure 1. Fracture Permeability Measurement Assembly.

*Hastelloy is a low corrosion alloy used to minimize free iron contamination of the permeating fluid.

Figure 2. Test Apparatus for Permeability Measurements.

A vacuum was established in the flow lines and the sample to remove gas from the system. With a vacuum pump, a previously degassed 2% KCl brine pore fluid was drawn through the pore lines and the proppant pack. Pore pressure was then adjusted to 500 psi to avoid a phase change of the brine during the testing. Temperature of the permeating fluid was maintained constant by flowing the brine through a Hastelloy heat exchanger within the test cell prior to entry into the sample. A 0.45 micron filter was placed upstream of the sample to prevent sample contamination by foreign particulates.

Flow rate through the sample and a resulting differential pressure were recorded for conductivity calculations. Three flow rates were employed in

testing, approximately 2, 5 and 10 ml/min. Linear flow* in the sample, requisite for the application of Darcy's law, was verified at each of these flow rates. Verification was accomplished by measuring differential pressure at the specified flow rates and confirming constant values for the ratio of these two variables. This procedure was performed using a representative sample subjected to stress states typical of the test matrix. Non-linear flow within the fracture system will result in conductivity data which are artificially low.

*Linear flow is the portion of the laminar flow regime in porous media in which inertial phenomena do not contribute significantly to pressure drop.

APPENDIX C

CHEMISTRY OF CARBONATE SCALING FLUIDS

COMPOSITION OF TEST SOLUTIONS

Saturating Fluid

<u>Constituent</u>	<u>Desired Conc. (ppmV)</u>	<u>MEQ</u>
Potassium	10489	268.25
Bicarbonate	3000	49.17
Chlorine	7767	219.08
TDS	21256	
Sum Cations		536.49
Sum Anions		536.49
Cations-Anions		0.00

Permeating Fluid

<u>Constituent</u>	<u>Desired Conc. (ppmV)</u>	<u>MEQ</u>
Potassium	10489	268.25
Bicarbonate	400	19.96
Chlorine	10218	288.21
TDS	21107	
Sum Cations		576.41
Sum Anions		576.41
Cations-Anions		0.00

Chemical Reaction

APPENDIX D

PROPERTIES OF COLLOIDAL DRILLING FLUID

Standard Mud Properties of
Bentonite Based Mud with Attapulgite

Test Temperature	150°F
Plastic Viscosity	3 cp
Yield Point	3 lbf/100 sqft
Apparent Viscosity	4.5 cp
10 Sec Gel	2 lbf/100 sqft
pH	10.0
Density	8.45 lb/gal

APPENDIX E

SUMMARY OF TURBIDITY DATA

Turbidity measurements were performed by nephelometric methods, and yielded values of Nephelometric Turbidity Units. Turbidity is attributed to suspended solids such as clay and silt, etc. Turbidity is an expression of the optical property that causes light to be scattered and absorbed rather than transmitted. There is not a universal correlation between turbidity and weight concentration of suspended matter.

Turbidity Data from Damage Flow Line

Sample I.D.	Test Description	Early Time Turbidity (NTU's)	Late Time Turbidity (NTU's)
1	Suspended Solids	200+	106
5	Incompatible Fluids	2.6	0.9

Chemical Analysis Data for Incompatible Fluid Analysis

Compound	Early Time Flow (ppm)	Late Time Flow (ppm)
Suspended Solids	<0.01	<0.01
Ca	432	40
K	10480	10450
Cl	10200	10200
HCO ₃	269	72
pH	7.65	7.15