USL

THE DOW CHEMICAL COMPANY — UNITED STATES DEPARTMENT OF ENERGY

PARCERDUE GEOPRESSURE—GEOTHERMAL PROJECT

DOW — DOE No. 1 L.R. Sweezy

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SUBMITTED TO
UNITED STATES DEPARTMENT OF ENERGY
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**DOW-DOE
PARCPERDUE
GEOPRESSURE-GEOTHERMAL PROJECT**

**APPENDIX C
RESERVOIR ANALYSIS AND SIMULATION:
S-CUBED**

SUMMARY OF S-CUBED'S

RESERVOIR ANALYSIS AND SIMULATION

Twelve flow tests were made on the L. R. Sweezy No. 1 well. Short-term tests, Flow Test No. 1 through Flow Test No. 4 were designed to estimate formation properties and were conducted for drawdown periods measured in hours. Intermediate-term tests, Flow Test No. 5 through Flow Test No. 8, were for a few days and were designed to test for reservoir boundaries. Long-term tests, Flow Test No. 9 through Flow Test No. 12, were designed for drawdown periods of about 60 days in order to examine the depletion behavior of the reservoir.

Flow Test No. 3 was the first test in which the flow was sufficiently constant and downhole pressure measurements reliable enough to warrant detailed analysis. Downhole pressure measurements are also available for Drawdown Test Nos. 4 and 5 and Buildup Test Nos. 3, 4, 5, 8, 9, 10 and 11.

Multiple-rate analyses have been carried out for all of the three drawdown tests (i.e., Nos. 3, 4 and 5) for which downhole pressure data are available. The early part of the pressure drawdown data are dominated by wellbore storage; the log-log plot of pressure change versus drawdown time suggests that the semi-log behavior should start at about 0.5 hrs. The semi-log plot for Drawdown Test No. 5 is shown in Figure 1. It is possible to identify a straightline with slope $m' \approx 0.0088$, extending over at least two log cycles. The mobility kh/μ is given by:

$$\frac{kh}{\mu} = \frac{162.68}{m'} = 18,660 \frac{\text{md-ft}}{\text{cp}}$$

Flow Tests No. 3 and No. 4 give essentially identical values for the mobility.

The transition of the data from a straight line of slope $m' = 0.0088$ to one of slope $m' = 0.0335$ implies the presence of a reservoir boundary. The well geology (Figure 2) indicates that there are two faults close to the L. R. Sweezy No. 1 well (Fault C at ~600 ft and Fault A at ~1600 ft) at an average distance of ~1100 ft. Given the mobility kh/μ , the distance to the faults, and the transition time (Fig. 1), it is straightforward to estimate the total formation compressibility, C_T .

$$C_T = 10.4 \times 10^{-6} \text{ psi}^{-1}$$

It is worth emphasizing that the above estimate for C_T depends strongly upon the assumed distance to the barriers (we shall return to this question in the following discussion).

With kh/μ and C_T determined, it becomes possible to analyze the drawdown data for the skin factor, s . Analysis of Drawdown Test Nos. 3, 4 and 5 shows that the skin factor s varies linearly with the flow rate; this suggests the occurrence of a non-Darcy flow in the near-wellbore region.

Figure 3 presents the multi-rate Horner plot of the buildup data for Flow Test No. 5; the slope of the buildup data is changing throughout the buildup period. The Horner plots of the buildup data from Flow Test Nos. 3, 4 and 8 show a picture similar to that for Flow Test No. 5. Although it is possible to identify straightlines on buildup plots for Flow Test Nos. 9, 10 and 11, the kh/μ values inferred are substantially different (by an order of magnitude) from those given by the drawdown data. The conventional interpretation techniques are simply inadequate to analyze the buildup data from the L. R. Sweezy No. 1 well and to infer formation properties with any confidence.

The formation parameters inferred from the drawdown data were used together with the S-CUBED geopressured geothermal simulator MUSHRM (in its 2-D planar mode) to simulate the production history of the L. R. Sweezy No. 1 well. The calculated drawdown response, in general, displays excellent agreement with the measured downhole pressures; Figure 4 compares the calculated and measured data for Drawdown Test No. 5.

Figure 5 shows the calculated and measured buildup responses for Flow Test No. 5; the calculated pressure values generally lie below the measured values. As a matter of fact, the simulated buildup results display even poorer agreement with measured data for later flow tests (Flow Test Nos. 8 - 11).

In order to better understand the nature of the discrepancy between the calculated (P_{calc}) and the measured buildup pressure data (P_m), it is useful to plot ($P_{calc} - P_m$) against shutin time for each of the buildup tests; it is observed that ($P_{calc} - P_m$) is a linear function of log shutin time. This result suggests that the difference between P_{calc} and P_m is caused by some sort of diffusive phenomenon which is unaccounted for in the simulation.

An adequate reservoir model should be able to reproduce both the drawdown and buildup data. To improve the simulation model described above, a number of calculations incorporating various effects have been performed for Flow Test No. 3. More specifically, the calculations were designed to investigate the following phenomena:

1. Leakage from overlying/underlying shales.
2. Evolution of free gas in the aquifer.
3. Wellbore backflow due to sand settling to the bottom of the well on shutin.
4. Irreversible formation compaction.
5. Two producing zones with different formation properties (compressibility, permeability, skin factor, etc.)

It is possible to reproduce the observed drawdown/buildup response (Flow Test No. 3) by invoking two producing zones with no cross-flow. The two producing zones have different formation compressibilities (drawdown period) and skin factors (during buildup); in addition, it is also necessary to assume that the formation compacts irreversibly. In any event, it is important to point out that the resulting reservoir model is at best speculative and difficult to envision.

All of the S-CUBED reservoir analysis work so far has been based upon the well geology indicated in Figure 2. We were recently advised by Dow that the actual well geology (reservoir block volume, distance to boundaries, etc.) may be substantially different from that shown in Figure 2. The latter introduces a major uncertainty in the value for the formation compressibility (C_T) inferred earlier from Figure 1 and the distance from the well to the faults. A smaller distance to the boundary faults would imply a larger formation compressibility. A large formation compressibility during drawdown together with the irreversibility assumption may well be sufficient to reproduce the observed drawdown/buildup response. We are presently investigating this possibility.

Figure 1. Flow Test No. 5 Pressure Drawdown Multi-Rate Plot

Figure 2. Structure Map of Parcperdue Area (DOW [1982])

Figure 3. Flow Test No. 5 Pressure Buildup Multi-Rate Horner Plot

Figure 4. Comparison of Calculated and Measured Data for Test No. 5

Figure 5. Comparison of Calculated and Measured Responses for Flow Test No. 5

**DOW-DOE
PARC PERDUE
GEOPRESSURE-GEOTHERMAL PROJECT**

**APPENDIX F
CORE EXAMINATION AND MINERAL IDENTIFICATION:
DOW CHEMICAL COMPANY**

J. Hamilton
Houston Dow Center

XRD- 2105-2114
Oct. 5, 1981
Chs. 7573

Report of Analysis

Mineral Identification of Core Samples

This report describes the examination by x-ray diffraction (XRD) and energy dispersive x-ray fluorescence (EDX) of a set of core samples from a well in Louisiana. EDX data was collected with 20 kev accelerating voltage. This technique is only sensitive to elements of atomic number 11 (sodium) or greater, so lighter elements are undetected. All XRD data was collected using copper radiation. High-resolution Huber-Guinier films were obtained using monochromatized (Cu K-alpha-1) radiation and were used for most of the identification work. To identify the clay minerals, diffractometer scans were made using Cu K-alpha radiation, and scanning a limited region (4 to 20 deg.) in 0.02 to 0.03 degree steps with extended counting times to obtain the best possible signal to noise ratios. Montmorillonite and related clays were further tested in some of the samples by grinding the sample in ethylene glycol and scanning slowly from 2 to 20 deg. to ascertain if there had been a shift in any of the x-ray peaks, which would indicate an expansion of the layer spacings.

Each sample will be described separately, with a summary of all the results at the end of the report. Copies of pertinent x-ray patterns are attached.

Sample D-1, 13340 ft. XRD-2105 EDX-462

EDX shows mainly Si, with substantial Al and traces of Ti and Fe. Quartz is the predominant component, based on XRD results, with a significant amount of pyrite (FeS_2), (less than 25% as much as quartz), a trace of albite ($\text{NaAlSi}_3\text{O}_8$), and a small clay component. The clay component is about 70% kaolinite with the remainder about evenly split between illite or glauconite and montmorillonite or montmorillonite-illite.

Sample D-7, 13344 ft. XRD-2114 EDX-471

Si is the most intense element in the EDX spectrum for this sample, but there is a significant amount of Cl smaller amounts of Ca and Ti, and a trace of K. XRD shows mainly quartz, with a small amount of halite (NaCl) and possibly some anorthite ($\text{CaAl}_2\text{Si}_2\text{O}_8$).

Sample D-10, 13346 ft. XRD-2107 EDX-464

While the EDX of this sample shows a large amount of Si and smaller amounts of Fe and Al, the XRD pattern shows only quartz. This sample was the smallest in the set and its size prevented us from setting data of equal quality with the other samples.

Sample D-130, 13347 ft. XRD-2106 EDX-463

The EDX of this sample shows predominantly Si, with smaller

amounts of Al and Fe (but more Al and less Fe than D-10). Once again quartz is the predominant mineral in the XRD pattern, accompanied by a clay component. This clay component is mostly montmorillonite or montmorillonite-illite (about 2/3), with the remainder split 60:40 between kaolinite and illite or glauconite.

Sample D-33, 13364 ft. XRD-2113 EDX-470

EDX shows that this sample is principally Si with only a small amount of Al. XRD shows it to be almost entirely quartz, with a very small amount of kaolinite.

Sample D-43, 13373 ft. XRD-2112 EDX-469

This sample is predominantly Si, with traces of Al and Fe. XRD indicates that it is almost entirely quartz, with a trace of kaolinite, and a very small amount of pyrite.

Sample D-47, 13377 ft. XRD-2109 EDX-466

The elemental composition of this sample is nearly the same as D-43, with only slightly more Al and Fe. It is mostly quartz, with small amounts of albite and halite, and a clay component. This clay component is mostly kaolinite, with a small (<20%) amount of illite or glauconite and a slightly larger amount of another clay, possibly chlorite, with a major peak just slightly larger than kaolinite.

Sample D-51, 13381 ft. XRD-2110 EDX-467

This sample is primarily Si with small amounts of Al, Fe, and Ti, and a trace of K. XRD indicates that it is mostly quartz, with a small but significant clay component, pyrite, albite, and possibly halite present. The clay component is mostly kaolinite with about a sixth illite or glauconite.

Sample D-80, 13400 ft. XRD-2108 EDX-465

The elemental composition of this sample is primarily Si, with small amounts of Fe and Al. Mineralogically it is mostly quartz with small amounts of albite and kaolinite.

Sample D-87, 13405 ft. XRD-2111 EDX-468

EDX shows this sample to be predominantly Si, with small amounts of Al, Ti, and Fe. XRD indicates primarily quartz, with the largest amount of albite of any of the samples, a clay component, and possibly a trace of halite. The clay component is about 50% montmorillonite or montmorillonite-illite, 30% illite or glauconite, and 20% kaolinite.

As expected for these sandstone samples, they all have far and away more quartz than any other component. At first glance it would appear that there is some ambiguity in the identification of the clay minerals, as every time illite or glauconite occur, they are listed as a pair, as are montmorillonite and montmorillonite-illite. The reason for this ambiguity is that each of these pairs have very similar x-ray diffraction patterns, and are difficult to tell apart without a nearly pure phase sample, and impossible when the compound is a minor component

in a mixture like this. In the case of illite and glauconite, the similarity extends further, with the two minerals being nearly iso-structural.

The presence of halite (NaCl) in several of the samples may be surprising, but in two of the samples the diffraction evidence is virtually overwhelming (D-7 and D-47), and in one of these (D-7), halite furnishes the best explanation for the chloride observed by EDX.

Barbara Fisher
Alan Lisa

XRD 2108
Film # 108.2

Fe Radiation
Wavelength 1.93597

Front Reflection
High Resolution

Internal Standard:
SiO₂

by BHP
8/26/81

D-130 13347 (EDX463)

D-130 13347 (E 463)

13347 *ff*

XRD - 2100
Acct # 7543

Cu Radiation
Wavelength 1.54187

Diffraction Scan
for HAMILTON

Internal Standard
NOONE

by JNM
8/18/81

glye

SAMPLE D-130 13347 FT.

XRD - 2100
Acct # 7543

Cu Radiation
Wavelength 1.54187

Diffractometer Scan
For HAMILTON

Internal Standard
NONE

by C
9/22/81

Albite
Pleural - High

D-87 13405 (EDX468)

XRD 2111
Film # 111.2

Fe Radiation
Wavelength 1.93597

Front Reflection
High Resolution

Internal Standard:
SiO₂

by: BHP
8/27/81

13405

D-82 13405 (E 468)

XRD - 2111
Acct # 7543

Cu Radiation
Wavelength 1.54187

Diffraction Scan
for HAMILTON

Internal Standards
NONE

by JNM
9/18/81

D-87 13405

XRD - 2111
Acct # 7543

Cu Radiation
Wavelength 1.54187

Diffractionmeter Scan
from HAMILTON

Internal Standards
NONE

by: JNN
8/21/81

463

<ET>

Hamilton

0X10^0S 20.46 KEV

52 SEC

VS= 1K 1A+B M HS= 20EV 1AB

464
0X10^0S 0.12 KEV 309 SEC
US= 1K 1A+B M HS= 20EV 1AB
Hamilton
large pieces

464 <ET> Hamilton
0X10^0S 0.26 KEV 441 SEC
VS= 1K 1A+B M HS= 20EV 1AB

*small deposits between
large chunks*

465

<ET>

Hamilton

0X10^0S 20.38 KEV

48 SEC

VS= 1K 1A+B M HS= 20EV 1AB

466

<ET>

Hamilton

0X10^0S

20.46 KEV

52 SEC

VS= 1K

1A+B

M

HS= 20EV 1AB

467

<ET>

Hamilton

0X10^06

11 KEV

31 SEC

US = 1K

1A+B

M

HS = 20EV 1AB

468

<ET>

Hamilton

MX10^0S

20 15 KEV

77 SEC

VS = 1K

1A+B

M

HS = 20EV 1AB

469

< --- >

Hamilton

0X10^0S 20.46 KEV

30 SEC

VS= 1K 1A+B M HS= 20EV 1AB

470

Hamilton

0X10^0S 20.28 KEV

93 SEC

VS= 1K 1A+B M HS= 20EV 1AB

100_x

500_x

SAMPLE D-33, 13364 FT. XRD-2113 EDX-470

2k

2K

SAMPLE D-33, 13364 FT. XRD-2113 EDX-470

100_x

500_x

SAMPLE D-80, 13400 FT. XRD-2108 EDX-465

2K

5K

SAMPLE D-80, 13400 FT. XRD-2108 EDX-465

100_x

500_x

SAMPLE D-130, 13347 Ft. XRD-2106 .EDX 463

2K

5K

SAMPLE D-130, 13347 FT. XRD-2106 EDX-463

100_x

500_x

SAMPLE D-43, 13373 FT. XRD-2112 EDX469

5K_x

10K_x

SAMPLE D-43, 13373 FT. XRD-2112 EDX-469

100_x

500_x

SAMPLE D-47, 13377 FT. XRD-2109 EDX-466

2K_x

5K_x

SAMPLE D-47, 13377 FT. XRD-2109 EDX-466

10K_x

SAMPLE D-47, 13377 FT. XRD-2109 EDX-466

13340'

462

100x

100_x

462

500x

500_x

SAMPLE D-1, 13340 FT. XRD-2105 EDX-462

462
2K_x

2K_x

462
5K_x

5K_x

SAMPLE D-1, 13340 Ft. XRD-2105 EDX-462

462
10Kx

10 K_x

SAMPLE D-1, 13340 FT. XRD-2105 EDX-462

468

2K_x

2K_x

468

5K_x

5K_x

SAMPLE D-87, 13405 FT. XRD-2111 EDX-468

468
100x

13405'

100_x

468
500x

500_x

SAMPLE D-87, 13405 FT. XRD-2111 EDX-468

468

10Kx

10K_x

SAMPLE D-87, 13405 FT. XRD-2111 EDX-468

471

13344'

100x

100_x

471

500x

500_x

SAMPLE D-7, 13344 FT. XRD-2114 EDX-471

471
2K_x

2K_x

471
5K_x

2K_x

SAMPLE D-7, 13344 FT. XRD-2114 EDX-471

471

10Kx

10K_x

SAMPLE D-7, 13344 FT. XRD-2114 EDX-471

467-2
100x

13381'

100_x

467-2
500x

500_x

SAMPLE D-51, 13381 FT. XRD-2110 EDX-467

467-2

2K_x

2K_x

467-2

5K_x

5K_x

SAMPLE D-51, 13381 FT. XRD-2110 EDX-467

467 -2
10Kx

10K_x

SAMPLE D-51, 13381 FT. XRD-2110 EDX-467

**DOW-DOE
PARCPERDUE
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**APPENDIX G
CASING FAILURE REPORT:
GREAT LAKES ENGINEERING**

GREAT LAKES ENGINEERING INC.

2040 NORTH LOOP WEST
SUITE 212
HOUSTON, TEXAS 77018

TELEPHONE (713) 686-6700
TELEX 791816

RECEIVED

SEP - 8 1981

Oil & Gas Purchasing

September 4, 1981

Mr. Carl V. Rush
Dow Chemical U.S.A.
Oil and Gas Division
400 West Belt South
Houston, TX 77210

Re: 8-5/8" ABC-FL4S
Failure Analysis
L.R.Sweezy, No. 1

Gentlemen:

Relative to your inquiry concerning the delay in the preparation of the failure analysis report on the referenced well, please note the following:

As per your Purchase Order No. H-21498 and accompanying instruction letter, Great Lakes Engineering, Inc. was charged "to determine the cause of failure in this specific incidence only not with the merits or demerits of the thread or its history of failure or success." Our work was to "only include such items as the witnessing and confirmation of the results of the testing and analysis done as performed by Atlas Bradford." Consequently, the work progress of Great Lakes Engineering on this project was controlled by external factors.

In addition, when it became apparent that no failure scenario with conclusive engineering support data was forthcoming, Great Lakes Engineering, with your concurrence, began to pursue an additional avenue which could have precipitated or significantly contributed to the failure. On this aspect of the project some delay was incurred in the preparation and testing of the specimens since the services of three different machine shops and one metallurgical laboratory were required. Unfortunately, the data from this line of investigation did not help to establish the precise cause of failure.

Lastly, the data which finally established the most probable cause of failure was not received until September 2, 1981.

Page 2

I trust the above explanations provide a satisfactory answer to your inquiry on the delay in the preparation of the report.

If we can be of further assistance, please call.

Sincerely,

A handwritten signature in dark ink, appearing to read "David H. Dewar". The signature is fluid and cursive, with the first name "David" and last name "Dewar" clearly distinguishable.

David H. Dewar
President

DHD/bl
attachment

GREAT LAKES ENGINEERING INC.

2040 NORTH LOOP WEST
SUITE 212
HOUSTON, TEXAS 77018

TELEPHONE (713) 686-6700
TELEX 791816

RECEIVED

SEP- 8 1981

Oil & Gas Purchasing

FAILURE ANALYSIS
of
8-5/8" 44# P-110 ABC-FL4S
for
DOW
L.R. SWEEZY NO. 1

Mike Payne
Assistant Engineer

Erich F. Klementich, P.E.
Vice President & General Manager

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I. SUMMARY

Dimensional analysis on the failed specimens showed product variations which caused severe make-up conditions. The box involved would have very likely been found defective if exact gauging could have been applied post failure. Tapers on the members were revealed to be slow and probably out of tolerance for the failed pin. The above conditions were aggravated by ovalities present in both members, the result of which caused excessive plastic deformation upon make-up.

The failure occurred when the dynamic load reached the value of the reduced efficiency in the connection.

II. ANALYSIS DATA

A. Background

1. Material involved was 8-5/8" 44# P-110 FL4S R3 tieback casing run above a string of 7-5/8" LTC. The geolograph indicated a static load of approximately 420,000# at the time of failure.
2. The failure occurred 5 joints below the Kelly in 17.2 ppg mud; radial stresses (-183 psi) are negligible.
3. Failure occurred under the dynamic load created on lifting the casing.

B. Fundamental Dimensional Considerations

1. Obvious yielding occurred at both pin and box ends; it is thus necessary to reference only those dimensions which did not experience significant if any plastic deformation. Namely, these dimensions are the box seal I.D. and the pin large O.D. adjacent to the shoulder.
2. As yielding occurs, mainly if not entirely at the pin and box ends in a compressive and tensile manner respectively, the only effect yielding can have on tapers

is to increase it in the plastic region. It is thus justified to use the minimum tapers as measured post failure.

3. Diameter variations present in the thick sections of the pin and box, 0.012" and 0.017" respectfully, represent minimum diameter variations as residual stresses have a greater effect as the pipe section thins.
4. The pin and box lengths of 4.751" and 4.753" respectfully support visual evidence that proper shouldering occurred. For simplicity, however, this analysis will "remove" the 0.002" clearance and assume a pin and box length of 4.752".

C. Determination of Average Joint Characteristics

Prior to calculating the effects of ovality on make-up interference, it is necessary to define the average, meaning without ovality effects, interference along the length of the joint. The reference dimensions, the pin large O.D. and the box seal I.D. establish an average interference if nominal tapers are present.

The pin large O.D. was small by 0.005"; the box seal was small by 0.003". The interference at this point is thus 0.016" (nominal) - 0.005" + 0.003" or 0.014". However, since it is clear that both pin and box tapers were slow it is critical that the increase in interference be found by extrapolating the tapers from the known reference points. Referencing Appendix Ib, diametrical tapers of $0.08975 \frac{\text{in}}{\text{in}}$ and $0.08875 \frac{\text{in}}{\text{in}}$ will be used for the box and pin. (Nominal taper is 0.09375 ± 0.004).

The connection model appears below.

Working from the box I.D. reference point towards the box face, the increase in interference due to the slow box taper -

$$\begin{aligned}\Delta \delta_{\text{Box}} &= X[0.09375 - 0.08975] \\ &= X(0.004)\end{aligned}$$

Similarly for the effect of the slow pin taper -

$$\begin{aligned}\Delta \delta_{\text{Pin}} &= (4.752 - X) [0.09375 - 0.08875] \\ &= (4.752 - X) (0.005)\end{aligned}$$

Still omitting ovality effects, total average interference -

$$\delta_{\text{TAVE}} = 0.014 + \Delta \delta_{\text{Box}} (X) + \Delta \delta_{\text{Pin}} (X)$$

Upon simplification -

$$\delta_{\text{TAVE}} = 0.0378 - \left(\frac{X}{4.752}\right) (0.0047)$$

The above calculations indicate average make-up interference present in the failed specimen was greater than twice the nominal interference for which the joint was designed.

D. Determination of Ovality Effects

This analysis will conservatively assume a constant box I.D. variation 0.017" and a constant pin O.D. variation of 0.012".

As per conversations with Mr. Ed McWhorter of NL Atlas Bradford, the made up connection should have resulted close to the worst case of orientation of the pin and box ellipses as depicted below.

$$\delta_A = \delta_T (X) + \left(\frac{0.012 + 0.017}{2} \right)$$

$$\delta_B = \delta_T (X) - \left(\frac{0.012 + 0.017}{2} \right)$$

Another crucial pin dimension, the nose thickness, indicates that the thinnest section of the nose coincided with the largest O.D. Consequently, the thinnest pin section experienced the heaviest interference. This effect can be seen clearly in the photograph of the pin showing variations in I.D. clean-up.

All factors affecting make-up stresses have been defined.

E. The Dynamic Load of Raising the Casing String

Studies, conducted with strain gauge methods, of the dynamic loads experienced by rig components during the lifting of casing showed dynamic increases ranging from 110% to 136% of the static load. These loads must also be transmitted through the casing being lifted. Hence, an important factor in the

failure was the actual dynamic load increase experienced by this string. While an exact figure is undeterminable, the above figures provide a range to estimate a probable dynamic increase.

F. Residual Stresses

Laboratory measurements indicate that residual tensile hoop stresses in the members averaged 7,670 psi. While a residual stress of the magnitude is not unusual, it could be a possible factor in the stress analysis. Slight residual axial and radial stresses, although detected in the lab, will be neglected.

II.

MAKE-UP STRESS ANALYSIS*

X	PIN					BOX				
	A			B		A		B		
0	δ	52.3	δ	23.3	δ	52.3	δ	23.3		
	BP	8965	BP	5088	BP	8965	BP	5088		
	σ_H	308729	σ_H	126447	σ_H	91018	σ_H	51656		
	CE	0.97	CE	0.97	CE	100.0	CE	100.0		
1.0	δ	51.3	δ	22.3	δ	51.3	δ	22.3		
	BP	10253	BP	4688	BP	10253	BP	4688		
	σ_H	269460	σ_H	114148	σ_H	118907	σ_H	54368		
	CE	9.057	CE	9.057	CE	100.0	CE	100.0		
2.0	δ	50.3	δ	21.3	δ	50.3	δ	21.3		
	BP	11058	BP	4852	BP	110.58	BP	4852		
	σ_H	226850	σ_H	93796	σ_H	149058	σ_H	65403		
	CE	25.87	CE	25.87	CE	82.0	CE	82.0		
3.0	δ	49.3	δ	20.3	δ	49.3	δ	20.3		
	BP	11069	BP	4672	BP	11069	BP	4672		
	σ_H	187057	σ_H	75206	σ_H	177328	σ_H	74847		
	CE	47.39	CE	47.39	CE	57.75	CE	57.75		
4.0	δ	48.3	δ	19.3	δ	48.3	δ	19.3		
	BP	10367	BP	4214	BP	10367	BP	4214		
	σ_H	149453	σ_H	58302	σ_H	203674	σ_H	82790		
	CE	76.70	CE	76.70	CE	42.39	CE	42.39		
4.752	δ	47.6	δ	18.6	δ	47.6	δ	18.6		
	BP	9433	BP	3734	BP	9433	BP	3734		
	σ_H	122714	σ_H	46818	σ_H	222459	σ_H	88059		
	CE	100.0	CE	100.0	CE	34.04	CE	34.04		

*Symbols and conventions are detailed in Appendix IV

RESULTS OF MAKEUP STRESSES

DISCUSSION OF RESULTS

While precise evaluation of the stresses present in a joint with respective oval members would require finite element analysis, this analysis attempted to show as simply as possible the approximate effect of the make-up stresses in this connection.

The calculated critical efficiency of 54% would have resulted in a failure when an axial load of 575,100# was reached. This represents a dynamic increase of near 37%, a magnitude which could be expected. Moreover, had a stress analysis been performed under static axial loading, the increased combined stresses would have shown a failure possible at even lower dynamic increases.

Conclusively, severe make-up conditions and ovality caused plastic deformation in both pin and box members upon make-up. The reduced efficiency combined with the dynamic loading precipitated the failure.

APPENDIX I

DIMENSIONAL DATA ON FAILED SPECIMENS

I. Pin #1

A. Standoff = $\frac{26}{32}'' = 0.8125''$

(Nominal = 0.539 ± 0.031)

B. Large O.D. = 8.293 8.304
= 8.303 8.292

1. Average = 8.298

2. Variation = 0.012

(Nominal = 8.303 ± 0.004)

C. Small O.D. (Severely Yielded)

1. Min. = 7.798

2. Max. = 7.898

3. Ave. = 7.858

(Nominal = 7.870)

D. Overall Length = 4.751
0.015
(Nominal 4.752 ± 0)

E. Nose Seal Length = 0.310
(Nominal 0.312)

F. Nose Thickness = 0.114 0.123
= 0.156 0.158

1. Ave. = 0.138

2. Var. = 0.044

(Nominal Unknown)

G. Pin Bored I.D. (Yielded)

1. Ave. = 7.452

2. Var. = 0.044

(Nominal = 7.550)

II. Box #1

A. Standoff = 0.771
(Nominal = 0.790 ± 0.031)

B. Polished Seal I.D. = 7.834 7.823
 = 7.817 7.821

1. Ave. = 7.8238
2. Var. = 0.017
(Nominal = 7.826 ± 0.003)

C. Overall Length = 4.753
 0.015
(Nominal = 4.748 ± 0)

ANDERSON & ASSOCIATES, INC.

Consulting Metallurgical Engineers

PHONE: 713 / 481-5840

819 F. M. ROAD 1959

HOUSTON, TEXAS 77024

June 15, 1981

N.L. Atlas Bradford
P.O. Box 15197
Houston, Texas 77020

Gentlemen:

The following are results of hardness and tensile testing performed on the four casing samples submitted.

Hardness Testing

Location	*Rockwell "C" Hardness			
	P1	P2	B1	B2
Outside Diameter	31.5	32	30	32
Outside Diameter	29.0	36	32	32
Outside Diameter	29.0	34	30	35
Inside Diameter	28.5	32	28	31
Inside Diameter	27.5	34	27.5	31
Inside Diameter	30.0	36	28	31
Wall Thickness	27	34	30	30
Wall Thickness	32	33	32.5	35
Wall Thickness	30.5	32	32	35

Tensile Testing

Specimen	Ultimate Tensile Strength (p.s.i.)	Yield Strength (p.s.i.)	Elongation (% in 2")
P1	137,900	126,600	23.15
P2	138,700	128,300	21.30
B1	137,900	128,100	23.00
B2	143,400	134,100	20.90

Respectfully submitted June 15, 1981.

ANDERSON & ASSOCIATES, INC.

*NOTE: P1 = PIN #2
P2 = PIN #1
MP

Randy C. Anderson
Randy C. Anderson, Met. Tech.

TAPER Tolerance .004/in.

Page 11

ACTUAL BOX TAPERS

○ 1
△ 2
□ 3

BOX #1

ACTUAL PIN TAPERS

MEASURED IN
YIELOED PLANE

.004/in.
STD.
.004/in.

Small Taper End

THREADS

PIN #1

- STD
- 1
- △ 2
- 3

APPENDIX II

CONSTRUCTED STRESS STRAIN DIAGRAMS

APPENDIX III

8-5/8" 44# P-110 RESIDUAL STRESSES

	PIN			BOX		
	#1	#2	OD Machined	#1	#2	ID Machined
D ₁	8.726	8.693	8.248	8.710	8.711	8.669
	8.722	8.703	8.218	8.686	8.690	8.681
	8.693	8.695	8.215	8.686	8.688	8.691
	8.698	8.697	8.248	8.718	8.691	8.695
Ave.	8.710	8.697	8.232	8.700	8.695	8.684
t	0.496	0.503	0.282	0.528	0.508	0.266
	0.510	0.514	0.277	0.519	0.539	0.261
	0.532	0.517	0.254	0.473	0.464	0.256
	0.491	0.518	0.293	0.519	0.509	0.251
Ave.	0.5073	0.5130	0.277	0.510	0.505	0.259
R	4.1014	4.0920	3.978	4.095	4.095	4.213
s	0.046	0.049	0.048	0.048	0.047	0.044
a	0.140	0.258	0.368	0.140	0.066	0.118
a'	0.094	0.209	0.320	0.092	0.019	0.074
Res	6,768	15,286	13,349	6,676	1,366	2,573
t @Cut	0.486	0.514	0.254	0.472	0.462	0.248

APPENDIX IVSTRESS CALCULATION CONVENTIONS

- A. Symbols: δ - Interference (0.001")
 BP - Bearing Pressure (psi)
 σ_H - Average Hoop Stress (psi)
 CE - Cross-sectional Efficiency (%)

defined by:

$$100 \left[1 - \frac{\sigma_{H_A} - \sigma_Y}{\sigma_{H_A} - \sigma_{H_B}} \right]$$

where σ_{H_A} and σ_{H_B} are the respective hoop stresses and σ_Y is the yield stress for the respective member.

B. Conventions:

Both bearing pressure and hoop stress accounted for the ovality at the I.D. The contact radius was calculated by assuming equal pin and box strains; while this is admittedly an erroneous assumption, it was necessary to simplify the problem. Moreover, the error induced by this approximation is negligible in light of other uncertainties. The outer pipe radius was taken as 4.3125" and constant.

The above assumptions led to the formulation of bearing pressure constants of the form -

$$BP = K (0.001")$$

Along the joint length the results were as follows:

X	KA	KB
0	171.41	218.35
1	199.52	210.24
2	219.84	227.77
3	224.52	230.13
4	214.63	218.35
4.752	198.17	200.76

While the extreme calculated hoop stresses would never be reached in elastic/plastic behavior, their purpose was not to define concise stress states but rather to calculate what percent of the cross-sectional areas of the pin and box remained elastic after make-up.

APPENDIX V

**DOW-DOE
PARC PERDUE
GEOPRESSURE-GEOTHERMAL PROJECT**

**APPENDIX H
PALEONTOLOGICAL REPORT:
GEORGE MAY & ASSOC.**

RECEIVED
DOW-DOE GEOTHERMAL PROJECT
DATE 5/22/81

GEORGE N. MAY & ASSOCIATES

Consulting Geologists and Paleontologists

408 HEYMANN BLVD.

P. O. BOX 51858

LAFAYETTE, LOUISIANA 70505

WILLIAM E. GRUBB

(318) 234-2379

May 21, 1981

Dr. J. S. Wilson
Dow Chemical U.S.A.
Parcperdue Project
P. O. Box 53073
Lafayette, Louisiana 70505

Dear Sir:

I am enclosing herewith a paleo report on the Dow Chemical--
D.O.E., Lee Roy Sweezy # 1, Parcperdue Field, Vermilion Parish,
Louisiana.

If you need additional information, let me know.

Yours very truly,

George N. May
George N. May

/dmh

Enclosure

GEORGE N. MAY & ASSOCIATES

Consulting Geologists and Paleontologists

408 HEYMANN BLVD.

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LAFAYETTE, LOUISIANA 70505

WILLIAM B. GRUBB

ISBN 834-8379

PALEONTOLOGICAL REPORT

DOW CHEMICAL CO.--D.O.E.

LEE ROY SWEETZ # 1

SECTION 26-T11S-R4E

PARCERDUE FIELD

VERMILION PARISH, LA.

May 21, 1981

S U M M A R Y

SAMPLE RANGE 11500'	-----	13600'
IN SIPHONINA DAVISI	-----	11500'
CRISTELLARIA 47	-----	11900'
NODOSARIA VERTEBRALIS	-----	12170'
DISCORBIS GRAVELLI	-----	12780'
HET SP. (VERY RARE)	-----	12880'
CIBICIDES JEFFERSONENSIS	-----	13140'
BOLIVINA PERCA	-----	13490'

NO FURTHER DIAGNOSTIC FOSSILS WERE ENCOUNTERED.

Respectfully submitted

George N. May
George N. May

Samples worked by
George May & Bill Grubb

PALEOECOLOGICAL REPORT
DOW CHEMICAL CO. D.O.E.
LEE ROY SWEEZY # 1
SECTION 26-T11S-R4E
PARCPERDUE FIELD
VERMILION PARISH, LA.

May 21, 1981

S U M M A R Y

SAMPLE RANGE 11500'.....13600'
ZONE 2 WEAK.....11500'
ZONE 1-2.....11620'
ZONE 2-3.....11840'
ZONE 2 WITH STREASK OF 2-3 VERY WEAK.....12080'
ZONE 3.....12750'
UNZONED 13,340' DUE TO CONVENTIONAL CORING
(NO SAMPLES).
ZONE 313450'

DEPOSITIONAL RATE

SAMPLE RANGE 11500'.....13600'
D.R. 2.....11500'
D.R. 3.....12520'
D.R. 4.....12560'
D.R. 5.....12750'
D.R. 4.....12810'
D.R. 5.....13020'
D.R. 6.....13170'
UNZONES 13,340'-13,450'
D.R. 5.....13450'

Lee Roy Sweezy #1

11500-30	W.R.	Fine to medium quartz sand, shell fragments, siderite, pyrite, rare very fine sandstone and siltstone Robulus chambersi N. T., v.r.; sp. v.r. Trochammina sp. S., r. (1) Siphonina davisii V.S. Nonion sp. v. r. Textularia sp. S., r. (1) Elphidium rolshauseni S. (1) Amphistegina sp. tiny
11530-60 Ctgs.	W.R.	Similar; very fine-fine quartz sand (1) Siphonina davisii V.S. Nonion sp. r. (1) Discorbis "B"; (1) nomada (1) Globigerina sp. (1) Cibicides concentricus
11560-90 Ctgs.	W.R.	Similar Robulus chambersi v.r. Rotalia sp. f.n. (1) Siphonina davisii Trochammina sp. f.n.
11590-620	W.R.	Similar, increasing grey shale; very noticeable shell fragments (1) Eponides sp. Textularia sp. f. n. (1) Discorbis "B" Trochammina sp. n.
11620-50 Ctgs.	W.R.	Similar; rare shale, rare forams Cristellaria sp. S., v.r. (1) Siphonina davisii
11650-80 Ctgs.	W.R.	Mostly very fine quartz sand, siderite and pyrite
11680-710 Ctgs.	W.R.	Similar
11710-40 Ctgs.	W.R.	Similar
11740-70 Ctgs.	W.R.	Similar (1) Planulina sp. (probably reworked)
11770-800 Ctgs.	W.R.	Similar, rare forams
11800-10 Ctgs.	W.R.	Similar Siphonina davisii v. r.
11810-40 Ctgs.	W.R.	Grey-brown shale and fine loose quartz sand (1) Eponides sp. Nonion sp. v.r. (1) Textularia sp. (1) Discorbis nomada
11840-70 Ctgs.	W.R.	Similar (1) Cristellaria 47 M. (large beads) (1) Cristellaria cf. 47 F.S. Liebusella sp. f. n. Siphonina davisii v.r. Milliolids r. Textularia sp. r. Discorbis "B" v.r. Nonion sp. n.

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11870-900 Ctgs.	W.R.	Similar, common very fine quartz sand (1) <i>Cristellaria</i> cf. 47 F.S. <i>Liebusella</i> sp. n. <i>Discorbis</i> "B" f.n. <i>Eponides</i> sp. r. (1) <i>Planulina</i> "A"
11900-30	W.R.	Similar, increasing fine-very fine calcareous sandstone <i>Cristellaria</i> 47 F.L.-L., f.n. <i>Eponides</i> sp. v.r. <i>Robulus chambersi</i> v.r. <i>Liebusella</i> sp. f.c.
11930-60 Ctgs.	W.R.	Similar with medium to coarse quartz sand <i>Cristellaria</i> 47 v.r.
11990-020 Ctgs.	W.R.	Similar; fewer forams, less sandstone (1) <i>Cristellaria</i> 47 S. <i>Liebusella</i> sp. f.n.
12020-50 Ctgs.	W.R.	Similar <i>Cristellaria</i> 47 v.r.
12080-110	W.R.	Similar, increasing very fine "tite" sandstone and silt- stone aggregates (1) <i>Cristellaria</i> 47 (1) <i>Cytheridea collei</i>
12110-40 Ctgs.	W.R.	Similar, noticeable loose very fine sandstone and quartz <i>Robulus chambersi</i> v.r. <i>Discorbis</i> "B" r.
12140-70 Ctgs.	W.R.	Similar; fewer forams (1) <i>Bathysiphon</i> sp.
12170-200 Ctgs.	W.R.	Similar <i>Cristellaria</i> 47 M.-S., v.n. <i>Reophas</i> sp. r. <i>Lenticulina jeffersonensis</i> f.n. <i>Bathysiphon</i> sp. r. <i>Robulus chambersi</i> n. <i>Eponides</i> sp. r. (2) <i>Nodosaria vertebralis</i> fragments <i>Uvigerina</i> sp. S., r.
12200-30 Ctgs.	W.R.	Similar (1) <i>Nodosaria vertebralis</i> fragment <i>Uvigerina howei</i> type S., r.
12230-60 Ctgs.	W.R.	Similar <i>Nodosaria vertebralis</i> v.r. <i>Cristellaria</i> 47 S.-M.-F. L., v.n.
12260-90 Ctgs.	W.R.	Similar <i>Bathysiphon</i> sp. f. n.
12290-320 Ctgs.	W.R.	Similar <i>Cristellaria</i> 47 f.c. <i>Liebusella</i> sp. r. <i>Nodosaria vertebralis</i> fragments r. <i>Uvigerina howei</i> r.
12320-40 Ctgs.	W.R.	Similar

Lee Roy Sweezy #1

12340-80 Ctgs.	W.R.	Similar, increasing very fine sandstone, siltstone and loose quartz Cristellaria 47 v.n. Robulus chambersi f.c. Nodosaria vertebralis fragments v.r. Reophax sp. v.r.
12380-410 Ctgs.	W.R.	Similar, noticeable very fine sandstone and loose very fine quartz sand and silt; fewer forams Nodosaria vertebralis fragments r.
12410-50 Ctgs.	W.R.	Similar
12450-60 Ctgs.	W.R.	Grey shale, very fine quartz sand, rare very fine sand stone; some siltstone and lignite mud additive (1) Robulus chambersi S. (1) Cristellaria fragment S.
12460-70 Ctgs.	W.R.	Similar with increasing siltstone and very fine sandstone aggregates; rare shell fragments Cristellaria sp. v.r. Leibusella sp. v.r. (1) Nodosaria vertebralis S. fragment (1) Guttulina irregularis Uvigerina sp. S., r.
12470-80 Ctgs.	W.R.	Similar Robulus chambersi f.n. Discorbis "B" v.r. Nonion sp. v.r. Millolids v.r. Globigerinids v.r.
12480-90 Ctgs.	W.R.	Mostly grey shale, silt and lignite Robulus chambersi r. Uvigerina sp. r.
12490-500 Ctgs.	W.R.	Similar Lenticulina jeffersonensis f.n. (1) Liebusella sp. Robulus chambersi f.n.
12500-10 Ctgs.	W.R.	Similar Lenticulina jeffersonensis f.n. Eponides sp. f.n. Cytheridea isrealnyi v.r. Siphonia sp. v.r. Nonion sp. f. n.
12510-20 Ctgs.	W.R.	Similar; fewer forams
12520-30 Ctgs.	W.R.	Similar Cristellaria 47 r. Eponides sp. r. Uvigerina sp. S., v.r. Reophax sp. v.r. Globigerinids r.
12530-40 Ctgs.	W.R.	Similar

Lee Roy Sweezy #1

12540-50 Ctgs.	W.R.	Similar Nodosaria vertebralis v.r. Liebusella sp. v.r. Robulus chambersi n. Eponides sp. f.n. Cibicides moreyi v.r.
12550-60 Ctgs.	W.R.	Grey shale, siltstone, noticeable very fine quartz sand, lignite mud additive Robulus chambersi F.S., n; sp. r. Cristellaria 47 r. Nonion sp. n. (1) Cibicides concentricus
12560-70 Ctgs.	W.R.	Similar Cristellaria 47 f.n. Eponides sp. n. Robulus chambersi v.n. Globigerinids f.n.
12582 Ctgs. B.U.	W.R.	Similar, slight increase in siltstone and very fine sand- stone fragments Discorbis "B" S., r.
12582-90 Ctgs.	W.R.	Similar
12590-600 Ctgs.	W.R.	Similar Globigerinids n. Miliolids r. Amphistegina sp. v.r.
12600-10 Ctgs.	W.R.	Similar, increasing fine quartz sand aggregates, glauconite fairly noticeable Cristellaria 47 f. c. Liebusella sp. v. r. Robulus chambersi c. Eponides sp. n. Uvigerina cf. howei S., r. Globigerinids f. c. Cibicides moreyi r. Vulvulina ignava v.r. Nonion sp. n.
12610-20 Ctgs.	W.R.	Similar, soft grey shale flakes; increasing very fine quartz sand; rare glauconite and echinoid fragments
12620-30 Ctgs.	W.R.	Grey shale and siltstone, increasing pyrite; fewer, smaller forams
12630-40 Ctgs.	W.R.	Similar Lenticulina jeffersonensis n. Siphonina sp. f. n. Discorbis nomada n. Globigerinids n. Robulus sp. S., n.
12640-50 Ctgs.	W.R.	Similar Discorbis "B" r. Liebusella sp. S., r.
12650-60 Ctgs.	W.R.	Similar with some very fine quartz sand aggregates (1) Ellipsonodosaria sp. Eponides sp. n. Cibicides moreyi f. n. Nonion sp. f. c.

Lee Roy Sweezy #1

12660-70 Ctgs.	W.R.	Similar (1) Gyroidina vicksburgensis	Uvigerina howei S., r.
12670-80 Ctgs.	W.R.	Similar, increasing light grey shale, glauconite and fine very fine quartz sand; less siltstone	
12680-90 Ctgs.	W.R.	Similar Uvigerina howei r. Reophax sp. v. r.	(1) Nodosaria vertebralis fragment
12690-700 Ctgs.	W.R.	Similar; fewer forams	
12720-50 Ctgs.	W.R.	Abundant cement; noticeable fine-medium quartz sand and grey shale; no forams noted	
12750-80 Ctgs.	W.R.	Similar, increasing very fine sandstone Cristellaria 47 c. (2) Discorbis cf. gravelli Uvigerina howei c. Siphonina sp. thick n.	Robulus chambersi c. (1) Spiroloculina sp. Globigerinids c.
12780-810 Ctgs.	W.R.	Similar, very noticeable glauconite; abundant forams Discorbis gravelli c. Cristellaria 47 v.c. Uvigerina howei v.c.	Liebusella sp. n. Nodosaria Vertebralis r. Gyroidina hannah r.
12810-20 Ctgs.	W.R.	Similar, increasing very fine sandstone, siltstone and fine quartz sand Discorbis gravelli c.	Textularia mornhinvegi
12820-50 Ctgs.	W.R.	Predominantly grey-brown shale; noticeable very fine quartz sand and rare glauconite Discorbis gravelli f.n. Robulus chambersi c.	Lenticulina jeffersonensis r. Uvigerina howei c.
12850-80 Ctgs.	W.R.	Similar	
12880-900 Ctgs.	W.R.	Similar; faunal increase Discorbis gravelli c. Sorites sp. r. (2) Miogypsina sp. S. (1) Het sp. S. (fragment) Cibicides moreyi r.	Amphistegina sp. f. n. Cristellaria 47 v.n. Robulus chambersi v.c. Uvigerina howei v.c.
12900-30	W.R.	Similar, increasing fine hard sandstone fragments Miogypsina sp. S., v.r. Sorites sp. v.r. Liebusella sp. S., r.	Textularia mornhinvegi r. Spiroloculina sp. r. Gyroidina hannah several

Lee Roy Sweezy #1

12930-60 Ctgs.	W.R.	Similar with very noticeable fine to coarse quartz sand and cement fragments (1) Het sp. V.S. (juvenile)	
12960-90 Ctgs.	W.R.	Similar, increasing grey shale	
12990-020 Ctgs.	W.R.	Similar	
13020-50 Ctgs.	W.R.	Similar (1) Het sp. Globigerinids f. c.	Liebusella sp. f. c. Nodosaria vertebralis v. r.
13050-70 Ctgs.	W.R.	Similar (1) Uvigerina isreaelskyi; howei r.	Liebusella sp. n.
13070-100 Ctgs.	W.R.	Similar with common fine to medium quartz sand, hard silt-stone aggregates, siderite fragments, shell fragments and cement Uvigerina howei c.	
13100-10 Ctgs.	W.R.	Coarse extraneous quartz sand, mud additives, forams noticeable Uvigerina howei c. Cristellaria 47 v.r.	Liebusella sp. r. Eponides sp. r.
13110-20 Ctgs.	W.R.	Similar Sorites sp. v. r.	Discorbis gravelli v.r.
13120-30 Ctgs.	W.R.	Similar Cibicides moreyi v. r.	
13130-40 Ctgs.	W.R.	Similar Sorites sp. r.	
13140-50 Ctgs.	W.R.	Similar (1) Cibicides jeffersonensis	Sorites sp. r.
13150-60 Ctgs.	W.R.	Similar Cibicides jeffersonensis (larger) c. Globigerinids v. c. Uvigerina howei v. c. Textularia mornhinvegi	Discorbis gravelli c. Liebusella sp. f. c.
13160-70 Ctgs.	W.R.	Similar Cibicides jeffersonensis c.	
13170-80 Ctgs.	W.R.	Similar, very abundant forams (95% forams) Cibicides jeffersonensis a. Discorbis gravelli a. Uvigerina howei v. a.	Globigerinids <u>flood</u> Liebusella sp. c. Cristellaria 47 c.

Lee Roy Sweezy #1

13180-90 Ctgs.	W.R.	Similar
13190-200 Ctgs.	W.R.	Similar, similar forams common
13200-10 Ctgs.	W.R.	Similar with common fine pyrite fragments, pyritized siltstone and very fine quartz sand Globigerinids a. Liebuseella sp. n.
13210-20 Ctgs.	W.R.	Similar Liebuseella sp. F. S., f.c. Cibicides jeffersonensis v.c.
13220-30 Ctgs.	W.R.	Mostly grey shale, forams, very fine quartz sand; some siltstone, pyrite and glauconite; similar forams less noticeable
13230-40 Ctgs.	W.R.	Similar, abundant forams Cibicides jeffersonensis a. Globigerinids a. Uvigerina howei a.
13240-50 Ctgs.	W.R.	Similar, increasing grey shale fragments, noticeable fine silt aggregates
13250-60 Ctgs.	W.R.	Similar, very abundant forams Globigerinids flood Textularia mornhinvegi v. n. Uvigerina howei flood Vulvulina ignava v. n.
13260-70 Ctgs.	W.R.	Similar Cibicides jeffersonensis v. c.
13270-80 Ctgs.	W.R.	Similar, very noticeable increase in very fine to fine angular to sub-rounded, frosted quartz sand; increasing hard siltstone aggregates; forams less abundant Liebuseella sp. n. Globigerinids c.
13280-90 Ctgs.	W.R.	Much less quartz sand; very common forams
13290-300 Ctgs.	W.R.	Similar (1) Bolivina sp. reticulate Nonion cf. chappaotense v.r. Cibicides jeffersonensis c.
13300-10 Ctgs.	W.R.	Similar, increasing very fine to fine loose quartz sand and fine hard silt fragments
13310-20 Ctgs.	W.R.	Similar, abundant forams Cibicides jeffersonensis a.; 10 S., f.n. Liebuseella sp. f. c. Globigerinids a. Uvigerina howei a. Sorites sp. v.r.
13320-30 Ctgs.	W.R.	Similar; fewer forams Cibicides 10 S.-M., f. n.; jeffersonensis v.c.

Lee Roy Sweezy #1

13330-40 W.R. Similar, increasing echinoid fragments, glauconite, pyrite and very fine quartz sand; abundant forams
Cristellaria 47 var. v. n. Discorbis gravelli v.n.
Nonion cf. chapapotense n.

Gap in samples from 13340' to 13450'

13450-60 Ctgs.	W.R.	Similar Cibicides jeffersonensis v.n.	
13460-70 Ctgs.	W.R.	Similar Globigerinids c.	Cibicides jeffersonensis c.
13470-80 Ctgs.	W.R.	Similar	
13480-90 Ctgs.	W.R.	Similar	
13490-500 Ctgs.	W.R.	Similar Bolivina perca n.	
13500-10 Ctgs.	W.R.	Similar Bolivina perca v. n.	
13510-20 Ctgs.	W.R.	Similar Bolivina perca c.	
13520-30 Ctgs.	W.R.	Very fine sand and silty shale fragments	
13530-40 Ctgs.	W.R.	Similar	
13540-50 Ctgs.	W.R.	Similar	
13550-60 Ctgs.	W.R.	Similar	
13560-70 Ctgs.	W.R.	Similar	
13570-80 Ctgs.	W.R.	Similar with sideritic silt Bolivina perca c.	
13580-90 Ctgs.	W.R.	Similar Bolivina perca v.c.	
13590-600 Ctgs.	W.R.	Similar with limestone fragments Bolivina perca c.	

**DOW-DOE
PARC PERDUE
GEOPRESSURE-GEOTHERMAL PROJECT**

**APPENDIX I
ACID SOLUBILITIES AND SIEVE ANALYSIS
DOWELL**

APPENDIX B

ACID SOLUBILITIES
and
SIEVE ANALYSES
of
PRODUCTION ZONE SAND

DOW/D.O.E. L.R. SWEEZY NO.1

DOWELL DIVISION OF DOW CHEMICAL U.S.A.

Report No.: 810003

May 5, 1981

Dow Chemical
Sweezy #1
Vermilion, Louisiana

Originator: Dave Swoffer
Lafayette, Louisiana

W. H. Bolivar - Chemist
Dan Maxwell - Lab Assistant

Distribution:

Lafayette Lab (2)
Regional Engineering Manager (1)
Ron Thomas (1)
Dave Swoffer (2)

Requested Information

Analysis of formation samples have been requested for purpose of preparing sand control recommendations. The analysis should specifically include acid solubilities and sieve analysis.

Sample Grouping Procedure

Submitted samples were cleaned formation samples and should be representative of zones of interest. In order to have adequate and representative samples to work with, we combined portions of each sample thought to be representative of a particular sand segment. Samples for acid solubilities were prepared in approximately ten foot intervals and include both clay and sand segments. Sieve analysis samples were prepared only on those thought to be representative of sand segments.

Acid Solubility Tests

These tests were run gravimetrically. One gram samples were placed in 100 ml of 15x and Mud Acid and heated for one hour at 150°F. The residue was filtered, dried and weighed. The amount of soluble material was then calculated and is reported as per cent by weight.

<u>Depth</u>	<u>Percent Solubility</u>	
	<u>15x</u>	<u>Mud Acid</u>
13,340.5	4.7	63.6
13,342.5	4.0	15.0
13,346.5	1.3	31.7
13,352.7	1.9	11.0
13,360.5	9.4	15.8
13,365.5	1.7	9.1
13,370.5	1.6	16.1
13,375.5	1.4	11.8
13,380.9	8.0	47.2
13,381.5	11.2	66.5
13,390	3.6	21.9

Acid Solubility Tests (cont)

<u>Depth</u>	<u>Per Cent Solubility</u>	
	<u>15x</u>	<u>Mud Acid</u>
13,394.5	3.9	31.1
13,395.2	4.6	63.4
13,397.5	6.2	15.7
13,400	10.6	45.1
13,405	6.3	38.9
13,410	11.7	66.8
13,415	12.7	53.9
13,418	12.7	59.9
13,419	9.6	53.5
13,420	13.6	61.9
13,425	14.2	63.0
13,430	11.2	63.5
13,435	11.9	66.3
13,438	10.2	64.3
13,450	15.8	52.4
13,456	15.3	67.7
13,460	15.4	68.2
13,491	12.8	70.9

Sieve Analysis

Sieve Analysis was run using screens sized according to the U. S. Standard Sieve Series. Approximately 50-75 grams of sample were placed on the top screen, the stack of screens was then placed on a Tyler Shaker and shaken for 15 minutes. The amount of sample retained on each screen was recorded and is presented below as the per cent of the total sand weighed back.

Depth 13,342.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	16.4	21.2	21.2
70	48.7	63.1	84.3
100	12.0	15.5	99.8
140	0.1	0.2	100.0
200	0.0	0.0	100.0
270	0.0	0.0	100.0
Pass	0.0	0.0	100.0

Depth 13,346.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	4.0	6.3	6.3
70	27.7	44.0	50.3
100	27.4	43.5	93.8
140	2.4	3.8	97.6
200	1.0	1.6	99.2
270	0.5	0.8	100.0
Pass	0.0	0.0	100.0

Depth 13,352.7

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	3.5	5.4	5.4
70	21.6	33.4	38.8
100	33.7	52.1	90.9
140	4.7	7.3	98.2
200	1.0	1.5	99.7
270	0.2	0.3	100.0
Pass	0.0	0.0	100.0

Depth 13,360.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	18.8	24.1	24.1
70	35.6	45.7	69.8
100	21.3	27.3	97.1
140	1.6	2.1	99.2
200	0.4	0.5	99.7
270	0.2	0.3	100.0
Pass	0.0	0.0	100.0

Sieve Analysis (cont)

Depth 13,365.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	9.8	16.6	16.6
70	19.4	32.9	49.5
100	22.5	38.2	87.7
140	6.0	10.2	97.9
200	1.00	1.7	99.6
270	0.2	0.4	100.0
Pass	0.0	0.0	100.0

Depth 13,370.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	13.1	17.9	17.9
70	39.7	54.2	72.1
100	17.7	24.2	96.3
140	1.4	1.9	98.2
200	1.1	1.5	99.7
270	0.2	0.3	100.0
Pass	0.0	0.0	100.0

Depth 13,375.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	1.7	2.9	2.9
70	11.4	19.4	22.3
100	40.5	68.9	91.2
140	3.4	5.8	97.0
200	1.5	2.6	99.6
270	0.3	0.4	100.0
Pass	0.0	0.0	100.0

Depth 13,380.9

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	5.4	10.6	10.6
70	15.8	31.1	41.7
100	15.7	30.9	72.6
140	4.2	8.3	80.9
200	3.5	6.9	87.8
270	5.2	10.2	98.0
Pass	1.0	2.0	100.0

Sieve Analysis (cont)

Depth 13,390

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	5.6	9.8	9.8
70	3.3	5.6	15.4
100	17.4	29.7	45.1
140	8.5	14.5	59.6
200	18.3	31.2	90.8
270	4.5	7.7	98.5
Pass	0.9	1.5	100.0

Depth 13,394.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	4.7	7.6	7.6
70	3.1	5.0	12.6
100	13.9	22.3	34.9
140	13.5	21.7	56.6
200	18.8	30.2	86.8
270	6.6	10.6	97.4
Pass	1.6	2.6	100.0

Depth 13,397.5

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	6.9	8.4	8.4
70	11.5	14.0	22.4
100	28.5	34.6	57.0
140	11.0	13.3	70.3
200	18.8	22.8	93.1
270	5.0	6.1	99.2
Pass	0.7	0.8	100.0

Depth 13,405

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	8.5	15.0	15.0
70	4.1	7.2	22.2
100	20.7	36.6	58.8
140	10.0	17.7	76.5
200	8.2	14.5	91.0
270	3.8	6.7	97.7
Pass	1.3	2.3	100.0

Sieve Analysis (cont)

Depth 13,419

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	12.8	24.4	24.4
70	8.7	16.6	41.0
100	15.3	29.1	70.1
140	4.4	8.4	78.5
200	2.3	4.4	82.9
270	5.5	10.5	93.4
Pass	3.5	6.6	100.0

Depth 13,438

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	15.7	36.7	36.7
70	10.6	24.8	61.5
100	8.5	19.8	81.4
140	2.1	4.9	86.3
200	1.9	4.4	90.7
270	3.6	8.4	99.1
Pass	0.4	0.9	100.0

Depth 13,450

<u>Screen #</u>	<u>Mass</u>	<u>% Retained</u>	<u>% Cumulative</u>
50	13.3	29.0	29.0
70	7.9	17.2	46.2
100	10.8	23.6	69.8
140	2.6	5.7	75.5
200	4.1	9.0	84.5
270	5.8	12.7	97.2
Pass	1.3	2.8	100.0

LOGARITHMIC PROBABILITY PLOT OF SCREEN ANALYSIS

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LOGARITHMIC PROBABILITY PLOT OF SCREEN ANALYSIS

**DOW-DOE
PARC PERDUE
GEOPRESSURE-GEOTHERMAL PROJECT**

**APPENDIX J
GEOCHEMICAL ANALYSIS:
GEOCHEM LABORATORIES INC.**

GEOCHEMICAL ANALYSES
SOURCE ROCK EVALUATION

CRUDE OIL—SOURCE ROCK CORRELATION

CRUDE OIL CHARACTERIZATION
GEOCHEMICAL PROSPECTING

1143 - C BRITTMORE ROAD • HOUSTON, TEXAS 77043 • 713/467-7011

July 30, 1981

Mr. Jack Hamilton
Senior Exploration Geologist
Oil and Gas Division
DOW CHEMICAL COMPANY
P. O. Box 4322
400 West Belt South
Houston, Texas 77210

RE: GeoChem Job No. 2062
DOW-DOE No. 1 Sweezy Geopressed Well

Dear Mr. Hamilton:

Enclosed please find the results of the organic geochemical analyses performed on three (3) core samples from the DOW-DOE No. 1 Sweezy Geopressed Well, drilled in Vermillion Parish, Louisiana.

Upon arrival at GeoChem the samples were assigned the GeoChem Job Number 2062, and submitted to the following analytical program:

<u>TYPE OF ANALYSIS</u>	<u>TABLE</u>
Total organic carbon determination and gross lithological description	I
Pyrolysis analysis	II
C ₁₅ + Soxhlet extraction, deasphalting and complete liquid chromatographic separation of hydrocarbon and non-hydrocarbon fraction	III-A,-B,-C
C ₁₅ + paraffin-naphthene gas chromatography	IV-A,-B; Figure 1-A,-B,-C
Visual Kerogen assessment	V
Vitrinite reflectance analysis	VI; Figure 2-A,-B
Palynological examination	VII

DISCUSSION OF THE RESULTS

A. Thermal Maturity of Sediments

Based on kerogen coloration, the thermal maturity of the two (2) core samples from this well is an immature Maturation Index Stage 1+ to 2- (Table V). The results of the vitrinite reflectance analyses also indicate an immature thermal maturation for these sediments, with an average %Ro of 0.41% and 0.40%, respectively (Table VI; Histograms).

The high odd-carbon preference exhibited in the C₁₅₊ paraffin-naphthene gas chromatograms of these samples is further evidence of a thermally immature sedimentary sequence.

At this immature level of thermal maturation, the rocks from this well interval would be expected to have only generated varying amounts of biogenically-derived methane (C₁) gas.

B. Hydrocarbon Source Characterization of Sediments

The sediments analysed from this well interval (13418' to 13448') have an immature, poor hydrocarbon source character.

This interpretation is based on the poor amounts of organic matter (% TOC; 0.24% to 0.27%; Table I) and the poor amounts of free hydrocarbon yield (S₁-0.00 mg/g to 0.13 mg/g; Table II) and poor hydrocarbon generating potential (S₂-0.00 mg/g to 0.13 mg/g; Table II).

These sediments are within the geopressured gas-saturated sands in South Louisiana. On the basis of the data presented in this study, we do not believe that these shales are the source for the gas in this pressured zone. The palynological data presented on Table VII indicates that these shales were deposited in a near shore environment, which apparently was void of large accumulations of organic matter. However, since these sediments were deposited near the coast line, it is likely that there are adjacent sediments, deposited in a marsh environment, wherein large accumulations of organic matter (lignite) exist.

Should this be the case, then these organic-rich sediments would be the probable source for the large concentrations of gas found in this geopressured zone.

Mr. Jack Hamilton

Page 3

July 30, 1981

Should you have any questions concerning this study, or if we may be of further service, please feel free to contact us.

Sincerely,

Paul Tybor
GEOCHEM LABORATORIES, INC.

lf

Enclosures

Table I

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

GeoChem Sample Number	Well Interval (Feet)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
2062-001 -A	13418.4	100% Shale, noncalcareous, very slightly silty, slightly micromicaceous, very slightly pyritized, subcentimetric silt intercalated, slightly bedded, chunky, moderately soft, olive gray.	5Y 4/1	0.24
2062-002 -A	13424	100% Shale, noncalcareous, very slightly carbonaceous, glauconitic, very slightly micromicaceous, massive, chunky, moderately soft, olive gray.	5Y 4/1	0.23; 0.24R
2062-003 -A	13448.5	100% Shale, noncalcareous, very slightly carbonaceous, glauconitic, very slightly micromicaceous, massive, chunky, moderately soft, olive gray.	5Y 4/1	0.27

Table II
RESULTS OF ROCK-EVAL PYROLYSIS

T.O.C. = Total organic carbon, wt. %
 S1 = Free hydrocarbons, mg HC/g of rock
 S2 = Residual hydrocarbon potential
 (mg HC/g of rock)
 S3 = CO2 produced from kerogen pyrolysis
 (mg CO2/g of rock)
 S1+S2 = Genetic hydrocarbon potential
 (mg HC/g of rock)
 Hydrogen
 Index = mg HC/g organic carbon
 Oxygen
 Index = mg CO2/g organic carbon
 S1/S1+S2 = Transformation ratio
 Tmax = Temperature Index, degrees C.

GeoChem Sample No.	Depth Interval ()	T.O.C. (wt.%)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1+S2 (mg/g)	Hydrogen Index	Oxygen Index	S1/S1+S2	Tmax (C)
2062-001	0 - 13418	0.24	0.13	0.13	0.31	0.26	54	129	0.50	514
2062-002	0 - 13424	0.24	0.04	0.03	0.71	0.07	13	296	0.57	418
2062-003	0 - 13448	0.27	0.11	0.00	0.48	0.11	0	178	1.00	0

Table III

**Summary of C15+ Soxhlet Extraction, Deasphalting
and Liquid Chromatography**

A. Weights of Extracts and Chromatographic Fractions

GeoChem Sample Number	Well Interval	Weight of Rock Extd. (grams)	Total Extract (grams)	Precipitated Asphaltenes (grams)	N-C5 Soluble (grams)	Sulfur (grams)	Paraffins- Naphthenes (grams)	Aromatics (grams)	Eluted NSO'S (grams)	Noneluted NSO'S (grams)
2062-001	-13418	100.0	0.0046	0.0033	0.0013	N.D.	N.D.	N.D.	N.D.	N.D.
2062-003	-13448	100.0	0.0027	0.0013	0.0014	N.D.	N.D.	N.D.	N.D.	N.D.

B. Concentration of Extracted Materials in Rock

GeoChem Sample Number	Well Interval	Total Extract (ppm)	-----Hydrocarbons-----				-----Nonhydrocarbons-----			
			Paraffin- Naphthene (ppm)	Aromatic (ppm)	Total (ppm)	Sulfur (ppm)	Precipitd. Asphaltene (ppm)	Eluted NSO'S (ppm)	Noneluted NSO'S (ppm)	Total (ppm)
2062-001	-13418	46	-	-	-	-	33	-	-	-
2062-003	-13448	27	-	-	-	-	13	-	-	-

C. Composition of Extracts

GeoChem Sample Number	Well Interval	-----Hydrocarbons-----				-----Nonhydrocarbons-----					
		Paraffin- Naphthene %	Aromatic %	PN/Arom	Sulfur %	Eluted NSO'S %	Noneluted NSO'S %	Precipitd. Asphaltene %	Asph/NSO	HC'S %	HC/Non HC
2062-001	-13418	-	-	-	-	-	-	71.7	-	-	-
2062-003	-13448	-	-	-	-	-	-	48.1	-	-	-

Table IV-A

Saturate Hydrocarbon Analyses

Summary of Paraffin-Naphthene Distribution

GeoChem Sample Number	Well Interval	% Paraffin	% Isoprenoid	% Naphthene	C-P Index A	C-P Index B	ip19/ip20
2062-001	13418	36.0	0.4	63.6	1.24	1.29	0.67
2062-003	13448	39.5	0.7	59.8	1.21	1.70	1.33

Table IV-B

Saturate Hydrocarbon Analyses

Normalized Paraffin Distribution

GeoChem Sample Number	Well Interval	% nC15	% nC16	% nC17	% ip19	% nC18	% ip20	% nC19	% nC20	% nC21	% nC22	% nC23	% nC24	% nC25	% nC26	% nC27	% nC28	% nC29	% nC30	% nC31	% nC32	% nC33	% nC34	% nC35
2062-001	13418	0.0	0.0	0.2	0.4	1.3	0.7	3.2	5.2	7.9	9.2	9.8	8.9	10.3	8.5	12.6	7.3	1.1	4.0	7.1	1.0	1.0	0.1	0.1
2062-003	13448	0.0	0.0	0.4	1.0	1.5	0.7	3.1	4.5	6.2	7.7	9.0	8.2	9.3	7.5	10.4	6.4	10.1	3.7	7.2	1.2	1.5	0.2	0.2

FIGURE 1A

2062-001

13418.4

FIGURE 1B

**2062-003
13448.5**

FIGURE 1C
STANDARD

TABLE V
VISUAL KEROGEN ASSESSMENT WORKSHEET

[illegible]

Table VI

VITRINITE REFLECTANCE SUMMARY

GEOCHEM SAMPLE NUMBER	DEPTH (feet)	TYPE OF SAMPLE	POPULATION	NUMBER OF READINGS	MINIMUM REFLECTANCE (% Ro)	MAXIMUM REFLECTANCE (% Ro)	MEAN REFLECTANCE (% Ro)	STD. DEV. (% Ro)	REMARKS
2062-001	13418	C	(1)	28	0.32	0.50	0.41	0.049	
			(2)	7	0.53	1.21	0.78	0.268	
2062-003	13448	C	(1)	5	0.34	0.46	0.40	0.043	
			(2)	3	0.77	0.92	0.86	0.081	

FIGURE 2A

GEOCHEM NO. 2062-001 TYPE OF SAMPLE: CORE DEPTH / SAMPLE NO. _____

CLIENT'S NAME DOW CHEMICAL CO. WELL NAME _____

(NO. OF READINGS = 35) 0.32 0.34 0.34 0.35 0.36 0.36 0.36 0.37 0.37 0.37 0.38 0.39 0.40 0.40
0.40 0.41 0.42 0.43 0.43 0.43 0.44 0.44 0.45 0.46 0.46 0.49 0.49 0.50 0.53 0.54 0.58 0.67
0.95 0.99 1.21

<u>POPULATION</u>	<u>NO. OF READINGS</u>	<u>MIN. Ro (%)</u>	<u>MAX. Ro (%)</u>	<u>MEAN Ro (%)</u>	<u>STD. DEV. (%)</u>	<u>REMARKS</u>
(1)	28	0.32	0.50	0.41	0.049	
(2)	7	0.53	1.21	0.78	0.268

VITRINITE REFLECTANCE HISTOGRAM

FIGURE 2B

GEOCHEM NO. 2062-003 TYPE OF SAMPLE: CORE DEPTH/SAMPLE NO. _____

CLIENT'S NAME DOW CHEMICAL CO. WELL NAME _____

(NO. OF READINGS = 8) 0.34 0.39 0.39 0.41 0.46 0.77 0.90 0.92

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	5	0.34	0.46	0.40	0.043	
(2)	3	0.77	0.92	0.86	0.081

Table VII

Interpretation of Environment of Deposition

GeoChem Sample Number	Depth (Ft.)	Environment of Deposition
2062-001	13418	Near shore subaerial marine environment, in an area of rapid currents.
2062-003	13448	Very near shore subaerial marine environment, in an area of quiet water.

The two samples contain similar kinds of organic material. While both samples are rich in fungal debris (spores and hyphae) indicating a source for organic material that is probably in a swamp, the presence of micro-foraminiferal linings is indicative of deposition in a marine environment. The distance from shoreline and relative current speeds are inferred from condition of preservation and particle sizes.

**DOW-DOE
PARC PERDUE
GEOPRESSURE-GEOTHERMAL PROJECT**

**APPENDIX K
PVT ANALYSIS:
WEATHERLY LABS**

RESERVOIR FLUID ANALYSIS

For

DOW CHEMICAL U.S.A., PARCPERDUE PROJECT

L. R. Sweezy Well No. 1
Parcperdue Field
Vermilion Parish, Louisiana

J. E. Weatherly, Jr.
President

WEATHERLY LABORATORIES, INC.
223 Georgette Lafayette, Louisiana 70506
Phone (318) 232-4877
(318) 232-4604 24 Hours

John D. Neal
Vice President

Petroleum Engineers

August 26, 1982

Dow Chemical U.S.A., Parcperdue Project
P. O. Box 53073
Lafayette, LA 70505

Attention: Mr. J. R. Hamilton

Re: Reservoir Fluid Study
L. R. Sweezy Well No. 1
Parcperdue Field
Vermilion Parish, Louisiana

Gentlemen:

Attached are the results of the analysis of the chemical and physical characteristics of a recombined reservoir fluid sample from the subject well. Surface separator samples were collected from this well by a representative of Weatherly Laboratories, Inc. on May 12, 1982. The gas-liquid ratio measured on this test, 10.01 cubic feet of separator gas per barrel of separator liquid, was used as the basis for one recombination. The resultant reservoir fluid exhibited a bubble point of 5037 psia at the reservoir temperature 237.4°F.

Subsequent tests indicate that a gas-liquid ratio of 17.0 SCF/Bbl. is more representative of the reservoir fluid. This reservoir fluid would exhibit a bubble point of 8870 psia at 237.4°F. This interpolated bubble point pressure has a possible error of $\pm 0.4\%$.

We wish to thank you for this opportunity of serving you. Should there be any questions concerning this report, please contact us.

Very truly yours,

John Neal

Lab. No. N-1657

Geopressure/Geothermal Project Sampling and Laboratory Procedure

- 1) Water vapor content of separator gas was determined by flowing gas from a metering valve on the separator gas meter run through a weighing tube (indicator Drierite (CaSO_4) weighed to 0.1 milligram) to a G.C.A./Precision Scientific wet test meter. Separator gas samples were taken from the same place into evacuated 1 gallon stainless steel (S.S.) cylinders after thorough purging of transfer line at separator pressure. Separator liquid sample cylinders (500 ml. S.S.) were first charged with separator gas to full separator pressure. The liquid cylinders were then connected to the separator water sampling point by a S.S. tube long enough to loop through a cooling bath. The water transfer line was then slowly and thoroughly purged at the cylinder. Separator water was let into the cylinder by slow slowly bleeding gas from the top valve. At no time was the water caught in the cylinder allowed to drop below separator pressure.
- 2) Flash liberation of gas from separator water was accomplished by using a weighed separator flask. This separator flask was connected to the outlet of a separator water cylinder by a short capillary line. Gas from the separator flask passed through a weighed drying tube through a glass cylinder (~ 300 ml.) to a Ruska Gasometer. A vacuum valve and a mercury manometer was connected to the gas manifold between the drying tube and the gasometer. Before commencing the flash, the entire flash gas manifold was evacuated and then filled with Helium to atmospheric pressure. A known volume of separator water was pushed out of the sample cylinder at a pressure slightly above field separator pressure by use of a calibrated mercury pump. The volume of stock tank water produced was determined by its weight and density. The volume of dry gas evolved was determined with the gasometer. This gas volume was subject to $\pm 2\%$ error due to the very small amounts measured. The gas was charged to a chromatograph for analysis from the glass cylinder.
- 3) Physical recombination of separator effluents:
Dry separator gas was charged into a temperature controlled cell. The volume of this windowed cell is known for any pressure and temperature. The pressure of the gas in the cell was measured with a mercury manometer and a barometer. This calculated gas volume was subject to a $\pm 1\%$ error due to the small amount charged to the cell. A volume of separator water was charged into the windowed cell by use of a calibrated mercury pump. The water was metered and measured at a pressure slightly above field separator pressure. Four recombinations were done in order to produce a saturation pressure-vs-gas-water ratio curve. A fifth recombination was done using the produced gas-water ratio at the time of sampling.

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- 4) Pressure-volume relations of recombined reservoir fluid at reservoir temperature:
Each datum of pressure-volume relations was corrected for mercury pump calibration, manifold expansion, cell expansion, mercury compressibility and mercury thermal expansion. Liquid volume percent was determined by calibrated cathetometer and by data interpretation.
- 5) Differential liberation of reservoir fluid at reservoir temperature:
Gas from each pressure decrement of the differential liberation was analyzed in the same manner as described in 2), (flash liberation). Differential liquid changes were noted.
- 6) Viscosity of reservoir fluid was measured by Mr. J. R. Comeau of Weatherly Laboratories. A description of Mr. Comeau's experimental procedures is given below:
Geothermal water viscosities were measured using an E.L.I. Rolling Ball Viscometer with an electronic detection system to prevent electrolysis. The detection system consists of a sensitive audio amplifier with a positive feedback adjusted just below oscillation. Feedback was turned on by an automatic switch as the viscometer was inverted at the beginning of the cycle and turned off when the ball made contact. Part of the signal was used to turn the digital timer on and off. Times were measured to 1/100th of a second and averaged. The viscometer was calibrated at each of the three angles using several known viscosity standards which were checked against Cannon-Fenske Viscometers and the results ($t\Delta\rho$ vs. μ) plotted. The viscometer was recalibrated using distilled water at several temperatures. These results were used along with previous results to obtain new calibration curves.

t = roll time, (second)

$\Delta\rho$ = density difference between ball and reservoir fluid, (gm./ml.)

μ = viscosity, (centipoise)

The viscometer was charged with reservoir fluid and run at 237.4°F at 1000 lb. intervals. The viscosities had a probable error of ± 0.002 centipoise.

Field Data for Weatherly Laboratory Investigation

Well Record

Company	Dow Chemical U.S.A.
Well	L. R. Sweezy No. 1
Field	Parcperdue
Parish and State	Vermilion, Louisiana

Field Characteristics

Formation Name	
Sand Name or Designation	
Date Completed	
Original Reservoir Pressure	Shut in 5-12-82 11408 psia

Well Characteristics

Original Produced Gas-Liquid Ratio

Perforations	
Elevations	
Total Depth	
Last Reservoir Pressure	Flowing 5-12-82 11000 psia
Reservoir Temperature	237.4 °F

Sampling Conditions

Date Sampled	(on 24/64 choke)	5-12-82	
Tubing Pressure, Flowing		5013	psig
Primary Separator Temperature		122	°F
Primary Separator Pressure		614	psig
Primary Separator Gas Rate		64259	SCF/day
Separator Liquid Rate (2nd. Stage @ 60 psig)		6417.6	Bbls./day
Gas-Liquid Ratio		10.013	SCF/Bbl. 60# Liq.
Shrinkage Factor (Vol. 60# Liq. @ 122°F / Vol. 614# Liq. @ 122°F)		1.0001	
Gas-Liquid Ratio		10.014	SCF/Bbl. 614# Liq.
Shrinkage Factor (Vol. S.T. Liq. @ 60°F / Vol. Sep. Liq. @ 614# & 122°F)		0.9865	
Gas-Liquid Ratio		10.151	SCF/Bbl. S.T. Liq.
Pressure Base		15.025	psia @ 60°F

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CALCULATION OF GAS RATE, 5-12-82 TEST

(Factors from GPSA Engineering Data Book)

$\sqrt{H_w P_f}$	=	76.0710	H_w	=	9.2	"H ₂ O, P_f	=	629	psia
F_b	=	28.393	D	=	2.626	"	, d	=	0.375 "
F_{pb}	=	0.9804			15.025	psia			
F_r	=	1.0010	b	=	0.0792				
Y_2	=	1.0001	H_w/P_f	=	0.015	, d/D	=	0.143	
F_g	=	1.3010	Gravity	=	0.5908	, F_g	=	$\sqrt{1 / 0.5908}$	
F_{tf}	=	0.9452	Temp.	=	122 °F,	F_{tf}	=	$\sqrt{520 / 582}$	
F_{pv}	=	1.0271	ρ_{Tr}	=	1.665	, ρ_{Pr}	=	0.938	, z = 0.9479
			F_{pv}	=	$\sqrt{1 / 0.9479}$				

$$Q = \sqrt{H_w P_f} \times F_b \times F_{pb} \times F_r \times Y_2 \times F_g \times F_{tf} \times F_{pv} \times 24$$

$$Q = 64,259 \text{ SCF/day @ } 15.025 \text{ psia @ } 60^\circ\text{F}$$

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Reservoir Fluid Summary - Produced GWR

Reservoir Temperature, °F.	237.4
Saturation Pressure at 237.4 °F, Psia	5037 ± 23
Compressibility of Reservoir Oil at 237.4°F	
Vol. per Vol. per Psi x 10 ⁶	
From 5037 Psia to 7000 Psia	2.55
From 7000 Psia to 9000 Psia	2.46
From 9000 Psia to 11408 Psia	2.43
Saturated Oil at 5037 Psia, 237.4 °F	<u>Diff. Lib.</u>
Density, Gms. per Ml.	1.0327
Lbs. per Bbl.	361.96
Specific Volume, Cu.Ft. per Lb.	0.015511
Viscosity, Centipoise	0.415
Formation Volume Factor, Bbls. per Bbl.	
"Residual Stock Tank Oil" at 60°F	1.0539 *
Solution Gas-Oil Ratio, Cu.Ft. per Bbl.	14.1 *
"Residual Stock Tank Oil" at 60°F	13.5 *
	1.0491
	17.1 Wet
	13.5 Dry
Reservoir Oil at 11408 Psia 237.4 °F	
Density, Gms. per Ml.	1.0492
Lbs. per Bbl.	367.74
Specific Volume, Cu.Ft. per Lb.	0.015267
Viscosity, Centipoise	0.437
Formation Volume Factor, Bbl. per Bbl.	
"Residual Stock Tank Oil" at 60°F	1.0326
Thermal Expansion at	Psia, % per °F

Note: References to 'oil' above should read 'water'.
This summary is based on reservoir fluid recombined to
10.01 SCF sep. gas/Bbl. sep. water. See page 7 for
interpolated summary data for a 17.0 SCF/Bbl. recombination.

* Based on separator water flash.

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Reservoir Fluid Summary - Subsequent GWR

Reservoir Temperature, °F	237.4
Saturation Pressure at 237.4 °F, Psia	8870
Compressibility of Reservoir Oil at 237.4 °F Vol. per Vol. per Psi x 10 ⁶ From 8870 Psia to 11408 Psia	2.50
From Psia to Psia	
Saturated Oil at 8870 Psia, 237.4 °F	1.0427
Density, Gms. per Ml.	365.47
Lbs. per Bbl.	0.015362
Specific Volume, Cu.Ft. per Lb.	~0.42
Viscosity, Centipoise	
Formation Volume Factor, Bbls. per Bbl.	1.0447
"Residual Stock Tank Oil" at 60°F	
Solution Gas-Oil Ratio, Cu.Ft. per Bbl.	
"Residual Stock Tank Oil" at 60°F	20.5
Reservoir Oil at 11408 Psia 237.4 °F	
Density, Gms. per Ml.	1.0494
Lbs. per Bbl.	367.81
Specific Volume, Cu.Ft. per Lb.	0.015265
Viscosity, Centipoise	~0.43
Formation Volume Factor, Bbl. per Bbl.	
"Residual Stock Tank Oil" at 60°F	1.0381

Thermal Expansion at Psia, % per °F

Note: Ref. to 'oil' above should read 'water'.

This summary is based on reservoir fluid recombined to 17.0 SCF sep. gas/Bbl. sep. water. Interpolated values for F.V.F. and Sol. GWR (SCF total gas/Bbl. S.T. water) are based on the separator water flash.

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COMPOSITE LABORATORY DATA AT 237.4°F

Recombination (1): 30.00 SCF Sep. Gas @ 15.025 psia & 60°F/Bbl. Sep. Water @ Sep. Conditions.

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION		
	RELATIVE VOLUME V/V_{sat} Bt	SPECIFIC VOLUME cu. ft. Per Pound	Liquid Volume Percent		FORMATION VOLUME FACTOR B_o **	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO
							Per Barrel Stack Tank Oil @ 60°F Dry **

6000 ~B.P. 1.000 0.01511 100 1.0289 33.8 34.0

1408 Res.	1.0129	0.015301	99.92
0000	1.0179	0.015376	99.79
9000	1.0219	0.015437	99.66
8000	1.0265	0.015506	99.46
7000	1.0320	0.015589	99.19
6000	1.0395	0.015703	98.72
5000	1.0490	0.015846	98.07
4000	1.0615	0.016035	97.16
3000	1.0778	0.016281	95.94
2000	1.1020	0.016647	94.07
1000	1.1653	0.017603	89.18
539	1.2753	0.019265	81.90
91	2.9814	0.045037	34.94
59	4.7588	0.071886	21.89

NOMENCLATURE:

V/V_{sat} . is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B_o is the volume of oil at reservoir temperature and indicated pressure relative to the volume of equivalent stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 15.025 psia at 60°F, per barrel of residual oil at 60°F.

Note: ** Based on separator water flash.
Ref. to 'oil' should read 'water'.

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COMPOSITE LABORATORY DATA AT 237.4 °F

Recombination (2): 25.000 SCF Sep. Gas @ 15.025 psia & 60°F/Bbl. Sep. Water @ Sep. Conditions.

PRESSURE. PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/V _{sat} B1	SPECIFIC VOLUME cu. ft. Per Pound	Liquid Volume Percent		FORMATION VOLUME FACTOR Bo **	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO	
							Per. Barrel Stock Tank Oil at 60°F Dry **	Wet **
13300 ~B.P.	1.000	0.01520	100		1.0347		28.7	29.0
11408 Res.	1.0052	0.015281	99.98					
10000	1.0095	0.015346	99.92					
9000	1.0130	0.015400	99.83					
8000	1.0170	0.015460	99.71					
7000	1.0219	0.015535	99.48					
6000	1.0278	0.015625	99.17					
5000	1.0352	0.015737	98.72					
4000	1.0460	0.015901	97.94					
3000	1.0600	0.016114	96.90					
2000	1.0820	0.016449	95.17					
1000	1.1443	0.017396	89.81					
500	1.2515	0.019025	82.19					

NOMENCLATURE:

V/V_{sat}. is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B_o is the volume of oil at reservoir temperature and indicated pressure relative to the volume of equivalent stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 15.025 psia at 60°F, per barrel of residual oil at 60°F.

Note: ** Based on separator water flash.
Ref. to 'oil' should read 'water'.

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COMPOSITE LABORATORY DATA AT 237.4 °F

Recombination (3): 20.000 SCF Sep. Gas @ 15.025 psia & 60°F/Bbl. Sep. Water @ Sep. Conditions.

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION		
	RELATIVE VOLUME V/V _{sat} B ₁	SPECIFIC VOLUME cu. ft. Per Pound	Liquid Volume Percent		FORMATION VOLUME FACTOR B _o **	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO
							Per Barrel Stock Tank Oil at 60°F Dry **
11408 Res.	0.9977	0.015267					
10500 B.P.	1.0000	0.015302	100.00		1.0410		23.5 24.0
10000	1.0012	0.015320	bubble				
9000	1.0038	0.015360	99.99				
8000	1.0067	0.015405	99.96				
7000	1.0100	0.015455	99.88				
6000	1.0147	0.015527	99.67				
5000	1.0210	0.015623	99.31				
4000	1.0305	0.015769	98.64				
3000	1.0433	0.015965	97.67				
2000	1.0620	0.016251	96.19				
1000	1.1061	0.016926	92.59				
500	1.2013	0.018382	85.03				

NOMENCLATURE:

V/V_{sat} . is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B_o is the volume of oil at reservoir temperature and indicated pressure relative to the volume of equivalent stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 15.025 psia at 60°F, per barrel of residual oil at 60°F.

Note: ** Based on separator water flash.
Ref. to 'oil' should read 'water'.

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COMPOSITE LABORATORY DATA AT 237.4 °F

Recombination (4): 15.000 SCF Sep. Gas @ 15.025 psia & 60°F/Bbl. Sep. Water @ Sep. Conditions.

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION		
	RELATIVE VOLUME V/V _{sat} B ₁	SPECIFIC VOLUME cu. ft. Per Pound	Liquid Volume Percent		FORMATION VOLUME FACTOR B ₀ **	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO
							Per Barrel Stock Tank Oil at 60°F Dry **
11408Res.	0.9910	0.015265					
10000	0.9944	0.015318					
9000	0.9969	0.					
7780B.P.	1.0000	0.015404	100.00		1.0473		18.5 19.0
7500	1.0007	0.015415	bubble				
7000	1.0022	0.015438	99.98				
6500	1.0038	0.015463	99.94				
6000	1.0056	0.015490	99.89				
6500	1.0077	0.015523	99.80				
5000	1.0103	0.015563	99.67				
4500	1.0134	0.015610	99.49				
4000	1.0173	0.015670	99.23				
3500	1.0218	0.015740	98.91				
3000	1.0277	0.015831	98.47				
2500	1.0348	0.015940	97.92				
2000	1.0440	0.016082	97.17				
1500	1.0573	0.016287	96.07				
1000	1.0797	0.016632	94.19				
500	1.1483	0.017688	88.67				
198	1.4121	0.021752	71.78				

NOMENCLATURE:

V/V_{sat}. is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B₀ is the volume of oil at reservoir temperature and indicated pressure relative to the volume of equivalent stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 15.025 psia at 60°F, per barrel of residual oil at 60°F.

Note: ** Based on separator water flash.
Ref. to 'oil' should read 'water'.

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COMPOSITE LABORATORY DATA AT 237.4°F

Recombination (5): 10.014 SCF Sep. Gas @ 15.025 psia & 60°F/Bbl. Sep. Water @ Sep. Cond.(Produced)

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	FORMATION VOLUME FACTOR Bo **	Differential Liberation		
	RELATIVE VOLUME V/Vset B1	SPECIFIC VOLUME cu. ft. Per Pound	Liquid Volume Percent			Formation Volume Factor Bo	SOLUTION GAS-OIL RATIO	
							Per Barrel Stock Tank Oil at 60°F	
							Dry	Wet
11408 Res.	0.9843	0.015267		0.437		1.0326		
10000	0.9877	0.015320		0.432		1.0362		
9000	0.9901	0.015357		0.428		1.0387		
8000	0.9926	0.015396		0.425		1.0413		
7000	0.9950	0.015433		0.422		1.0439		
6000	0.9976	0.015474		0.418		1.0466		
5037 B.P.	1.0000	0.015511	100.00	0.415	1.0539	1.0491	13.5	17.1
5000	1.0001	0.015513	bubble					
4500	1.0018	0.015539	99.96					
4000	1.0036	0.015567	99.89	0.412				
3500	1.0059	0.015603	99.76			1.0527	10.6	13.8
3000	1.0086	0.015644	99.59	0.409				
2500	1.0122	0.015700	99.31					
2000	1.0174	0.015781	98.88	0.407		1.0554	7.3	9.6
1500	1.0249	0.015897	98.20	0.406				
1000	1.0437	0.016189	96.48	0.407				
500	1.1009	0.017076	91.50	0.412		1.0566	2.8	3.3
279	1.1994	0.018604	84.00					
100				0.419				
15								
15*						1.000	0.0	0.0

NOMENCLATURE:

V/Vsat. is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

Bo is the volume of oil at reservoir temperature and indicated pressure relative to the volume of equivalent stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 15.025 psia at 60°F, per barrel of residual oil at 60°F.

Note: * Indicates value measured at 60°F.

** Based on separator water flash.

(Solution gas in res. fld. based on sep. water flash, 13.5 dry & 14.0 wet SCF/Bbl. S.T. water @ 60°F).

Ref. to 'oil' above should read 'water'.

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Effect of Gas-Water Ratio Upon Bubble Point Pressures @ 237.4°F

Gas-Water Ratio (SCF Dry Sep. Gas @ 15.025 psia & 60°F) (Bbl. Sep. Water @ 614 psig & 122 °F)	Bubble Point (PSIA)
30.000 extrapolated	~16000
25.000 extrapolated	~ 13300
20.000	10500
* 17.0 interpolated	8870
15.000	7780
10.014 produced	5037

* Subsequent tests indicated that a GWR of 17.0 was more representative.

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Separator Water Flash to 0 psig & 68°F

Solution Gas-Water Ratio, dry = 3.4

, wet = 4.0 $\frac{\text{SCF gas @ 15.025 psia \& 60°F}}{\text{Bbl. water @ 0 psig \& 60°F}}$

Shrinkage = 0.9865 $\frac{\text{vol. S.T. water @ 60°F}}{\text{vol. Sep. H}_2\text{O @ 614psig \& 122°F}}$

Stock Tank Water Density = 1.0693 Gm./Ml. @ 60°F

Gas Gravity, dry = 0.6765 (see analysis)

, wet = 0.6673

Produced May 12, 1982:

GWR = 10.1 + 3.4 = 13.5 $\frac{\text{SCF total dry gas @ 15.025 psia \& 60°F}}{\text{Bbl. Stock Tank Water @ 60°F}}$

GWR = 10.1 + 4.0 = 14.1 $\frac{\text{SCF total wet gas @ 15.025 psia \& 60°F}}{\text{Bbl. Stock Tank Water @ 60°F}}$

Dow Chemical U.S.A.
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Parcperdue Field

Separator Gas Sampled:
May 12, 1982 @
614 psig & 122°F

Chromatographic Analysis

	Dry	Wet
	<u>Mole %</u>	
Water		0.13
Carbon Dioxide	2.20	2.20
Nitrogen	0.29	0.29
Methane	95.24	95.11
Ethane	1.88	1.88
Propane	0.28	0.28
Iso-Butane	0.07	0.07
N-Butane	0.03	0.03
Iso-Pentane	0.01	0.01
N-Pentane	0.00	0.00
Hexanes	0.00	0.00
Heptanes Plus	<u>0.00</u>	<u>0.00</u>
TOTAL	100.00	100.00
Gravity (Air=1.00)	0.5908	0.6135

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Solution Gas From
Separator Water Flash
@ 0 psig & 68°F
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		15.00
Carbon Dioxide	11.79	10.02
Nitrogen	-----	-----
Methane	86.80	73.78
Ethane	1.29	1.10
Propane	0.11	0.09
Iso-Butane	0.01	0.01
N-Butane	0.00	0.00
Iso-Pentane	0.00	0.00
N-Pentane	0.00	0.00
Hexanes	0.00	0.00
Heptanes Plus	0.00	0.00
	<u>100.00</u>	<u>100.00</u>
TOTAL		
Gravity (Air=1.00)	0.6765	0.6673

Dow Chemical U.S.A.
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Solution Gas From
3500 psi sample -
Differential Liberation
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		13.86
Carbon Dioxide	2.50	2.15
Nitrogen	----	----
Methane	94.77	81.64
Ethane	2.15	1.85
Propane	0.52	0.45
Iso-Butane	0.05	0.04
N-Butane	0.01	0.01
Iso-Pentane	0.00	0.00
N-Pentane	0.00	0.00
Hexanes	0.00	0.00
Heptanes Plus	<u>0.00</u>	<u>0.00</u>
TOTAL	100.00	100.00

Gravity (Air=1.00) 0.5943 0.5982

Gas Deviation Factor (Z) = 0.958 @ 3500 psia & 237.4°F

Bbls. Gas in Res./MMSCF (Bg) = 982 @ 3500 psia & 237.4°F

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Parcperdue Feild

Solution Gas From
2000 psi sample -
Differential Liberation
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		27.21
Carbon Dioxide	1.78	1.30
Nitrogen	-----	-----
Methane	95.49	69.51
Ethane	2.21	1.61
Propane	0.36	0.26
Iso-Butane	0.10	0.07
N-Butane	0.04	0.03
Iso-Pentane	0.02	0.01
N-Pentane	0.00	0.00
Hexanes	0.00	0.00
Heptanes	<u>0.00</u>	<u>0.00</u>
TOTAL	100.00	100.00
Gravity (Air=1.00)	0.5877	0.6220

Gas Deviation Factor (Z) = 0.936 @ 2000 psia & 237.4°F

Bbls. Gas in Res./MMSCF = 1,679 @ 2000 psia & 237.4°F

Dow Chemical U.S.A.
L. R. Sweezy Well No. 1
Parcperdue Field

Solution Gas From
500 psi sample -
Differential Liberation
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		39.99
Carbon Dioxide	3.56	2.14
Nitrogen	-----	-----
Methane	94.74	56.84
Ethane	1.51	0.91
Propane	0.14	0.08
Iso-Butane	0.03	0.02
N-Butane	0.01	0.01
Iso-Pentane	0.01	0.01
N-Pentane	0.00	0.00
Hexanes	0.00	0.00
Heptanes Plus	<u>0.00</u>	<u>0.00</u>
TOTAL	100.00	100.00
Gravity (Air=1.00)	0.5977	0.6074

Gas Deviation Factor (Z) = 0.980 @ 500 psia & 237.4°F

Bbls. Gas in Res./MMSCF (Bg) = 7,032 @ 500 psia & 237.4°F

Dow Chemical U.S.A.
L. R. Sweezy Well No. 1
Parcperdue Field

Solution Gas From
15 psia sample -
Differential Liberation
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		17.85
Carbon Dioxide	11.75	9.65
Nitrogen	-----	-----
Methane	87.01	71.48
Ethane	1.19	0.98
Propane	0.05	0.04
Iso-Butane	0.00	0.00
N-Butane	0.00	0.00
Iso-Pentane	0.00	0.00
N-Pentane	0.00	0.00
Hexanes	0.00	0.00
Heptanes Plus	<u>0.00</u>	<u>0.00</u>
TOTAL	100.00	100.00
Gravity (Air=1.00)	0.6736	0.6644

Company Dow Chemical U.S.A.

Well L. R. Sweezy No. 1

Reservoir

Field Parcperdue

Fig. 1: Effect of Gas-Water Ratio on Bubble Point Pressure @ 237.40°F

GWR = $\frac{\text{SCF Sep. Gas @ 15.025 psia \& 60}^\circ\text{F}}{\text{Bbl. Sep. Water @ 614 psig \& 122}^\circ\text{F}}$
Lab. No. N-1657

Company Dow Chemical U.S.A.
Reservoir _____

Well L. R. Sweezy No. 1
Field Parcperdue

Fig. 2: Liq. Vol. % vs. Pressure-Res. Water @ 237.4°F GWR = 10.01

Company _____
Reservoir _____

Well _____
Field _____

Fig. 3: Diff. Liberation of Reservoir Water @ 237.4°F GWR = 10.01

Company Dow Chemical U.S.A.
Reservoir _____

Well L. R. Sweezy No. 1
Field Parcperdue

Fig. 4: Formation Volume Factor & Solution Gas-Water Ratio (based on Sep. Water Flash) @ 237.4°F

Company Dow Chemical U.S.A.
Reservoir _____

Well L. R. Sweezy No. 1
Field Parcperdue

Fig. 5: Specific Volume of Saturated (Bubble Point) Water @ 237.4°F

Company Dow Chemical U.S.A.
Reservoir _____

Well L. R. Sweezy No. 1
Field Parcperdue

FIG. 6: Viscosity of Reservoir Water @ 237.4°F. GWR = 10.01

**DOW-DOE
PARCPERDUE
GEOPRESSURE-GEOTHERMAL PROJECT**

**APPENDIX L
GRAVEL PACK FAILURE REPORT:
COMPLETION TECHNOLOGY INC.**

COMPLETION PROCEDURES AND ANALYSIS
OF GRAVEL PACK FAILURE
L. R. SWEETZ NO. 1

6/83
CTC # 174-83-01
DERREL GURLEY

9.10 COMPLETION PROCEDURES AND ANALYSIS OF GRAVEL PACK FAILURE
L.R. SWEETZ NO. 1

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9.10 COMPLETION PROCEDURES AND ANALYSIS OF GRAVEL PACK FAILURE - L.R. SWEETZ NO. 1

9.10.1 Introduction

The Dow/DOE Sweetz No. 1, located at Parc Perdue, Louisiana (south of Lafayette) was a research and development well designed to study the feasibility of producing gas which was dissolved in a geopressured brine reservoir. The concept was to produce the brine at a rate that would create a pressure sink near the wellbore allowing flashing and production of brine accompanied by gas. The Parc Perdue location was chosen because there was a volumetrically well defined reservoir in the Cibb Jeff sand at 13,342-13,406 feet. The reservoir was located in a small fault block of 939 acres. Massive shale sections lie above and below the reservoir sand and the lateral extent is limited by faulting. Location of the faults is believed to be known with a high degree of certainty. Fault cuts were determined using data from eight neighboring wells and seismic lines that intersect the fault block at 11 points.

The Cibb Jeff interval includes approximately 50 net feet of permeable formation having an average porosity of 29%. The reservoir volume is approximately 106 million barrels. Original reservoir pressure was approximately 11,423 psig. Production of the reservoir was planned at 20,000 bbls of brine per day to allow complete depletion in as short an interval of time as practical. Core data indicated permeability of the very clean Cibb Jeff sand approaching 3,000 md. A sand of this vertical extent and permeability can easily produce at this rate.

However, the Cibb Jeff sand is unconsolidated and sand control measures were required to control sand production. Using present technology, gravel packing is the only practical method of controlling sand in an interval of this vertical extent and allow production rates of 20,000 bbls per day. A gravel pack was installed in the L.R. Sweezy No. 1 but it was not possible to produce at 20,000 bbls per day without producing large quantities of formation sand. In fact, the well produced sand from a very early point in its life and produced large quantities of sand, even when the production rate was restricted to less than 10,000 bbls/day, until the gravel pack failed catastrophically February 5, 1983.

The objectives of this study are to learn why the L.R. Sweezy No. 1 failed to produce at the desired rate and to make recommendations for successful completions of future high rate wells.

9.10.2 Need for Sand Control

In the U.S. Gulf Coast and other geologically similar areas, many of the young, deltaic deposited sand formations are either unconsolidated or are weakly consolidated by clays. The unconsolidated formations usually produce sand even at low oil production rates. The weakly consolidated formations may produce sand-free at restricted production rates.

Most of these sands are water wet. The interfacial tension of residual water helps to keep the formation consolidated. However, if the formation begins water production, the wetting phase moves and disturbs the cohesive forces of interfacial tension and the clay bonding. Sand

production may begin at this point and increase with increased water saturation and production rate. The Cibb Jeff sand in the Sweezy No. 1 is an extremely clean, unconsolidated sand and is saturated with the brine wetting phase. This was clearly indicated in core samples taken from the bore hole. For this reason, sand production was inevitable if the well was to produce brine at high rates.

9.10.3 Sand Control History

Gravel packing wells to prevent sand production has been used for several hundred years with records of use by early Egyptians in water wells. There have been other methods of sand control used with limited success in the past 40 years. In the 1940s, Dow Chemical Company first developed a method of controlling sand production by injecting plastic into the formation to chemically bond the formation particles. The process essentially consisted of three steps following perforating of the casing.

1. Cleaning the formation - This process usually consisted of injecting various acid formulations followed by oil based spacers designed to displace any residual acid leaving an environment compatible with plastic which was to follow.
2. Consolidation - Following the cleaning phase, plastic was injected to form a chemical bond. Many different types of plastic solutions were used. Some contained a high percentage of plastic to assure adequate strength development even in dirty (high clay content) sands. Others contained low resin content to assure maximum permeability retention. The resins varied in type including phenolics, epoxies and furans.

3. Overflush - Following the plastic, an overflush of oil was used to sweep away excess resin leaving maximum permeability. (One epoxy system containing only 18% active resin did not require this step.) The overflush usually had a matched oil to plastic viscosity to provide uniform displacement of excess resin. In addition, overflush sometimes contained chemicals which accelerate setting of plastic and enhanced final strength.

The 1960s saw the development of several other in situ consolidation schemes. One of these was a metallic plating process developed by Shell Oil where either nickel or aluminum solutions were used to plate and consolidate the formation particles. Another method used a coking process where the formation oil was burned in place to consolidate the formation.

In addition to these methods, a method was developed where gravel (usually US 20-40 sand) was coated with liquid plastic and injected into the perforations in a manner very similar to cement squeezing. The plastic then hardened leaving a permeable mass in the perforations and casing. After the resin coated sand hardened, the portion left in the casing was drilled out leaving plastic coated sand only in the perforations.

All of these methods have one common weakness which has never been solved. For the technique to be successful, the entire interval must be consolidated. If one perforation is plugged with debris preventing injection of the consolidating material, there is a potential failure.

To combat this problem, the treated intervals are usually limited to 10 feet or less. Even with all possible precautions, the long term success ratio of in situ consolidation seldom exceeds 50 percent. As a result, most of these processes have been abandoned. Plastic consolidation is probably used on less than 30 wells per year and the resin coated gravel systems are used only slightly more frequently. For these reasons and others, in situ consolidation was not considered applicable in L.R. Sweezy No. 1.

9.10.4 Gravel Packing

As stated earlier, gravel packing has been in use for several hundred years. However, its use has increased in the oil industry since 1938 when Coberly published research findings on sizing of gravel to control sand movement.¹ Its use accelerated in the late 1960s and 1970s when the sizing techniques were improved and with the advent of clean fluids and improved placement techniques. At the present time, the success ratio of gravel packing exceeds 90 percent even including jobs that are performed ignoring the most rudimentary gravel packing principles.

There are two types of wells that demand close attention to design and procedural techniques if a successful job is to be expected. These are wells requiring very small gravel (US 40-60 or smaller) and high rate wells. Experience by field technicians in wells of this type is limited and the principles are not always understood. As a result, many of the gravel pack failures are in wells falling in these categories. In order to explain these principles, this report will outline the process used in designing and performing gravel packs in wells requiring high

performance efficiency. The design procedure starts after casing is set and assumes that the producing interval has been well isolated by primary cement job.

9.10.4.1 Design Procedure

The design procedure includes the following steps:

- . Gravel sizing
- . Selection of completion method (open hole or perforated)
- . Selection of screen
- . Completion fluid consideration
- . Gravel placement techniques

All of these steps are equally important and will be summarized to explain considerations involved in the design.

a. Gravel Sizing

As stated earlier, Coberly was one of the early researchers reporting on optimum gravel sizing to control movement of formation particles. The work reported by Coberly was applicable in widely sorted formation particles of the type found in California. The sizing method was not as successful in the very fine but uniform sands found in Gulf Coast Miocene sands. These sands were so fine that they would penetrate a pack designed using Coberly's guidelines. Invasion of the pack by formation sand results in reduced flow capacity.

In 1974, Saucier reported on a gravel sizing method developed by Shell Development Company.² This work resulted in the use of smaller gravel which prevented invasion of the pack by the fines.

Summarizing the method reported by Saucier, the following guidelines are used.

1. Formation particles are sieved and the results plotted on semilog paper (Figure 1).
2. The formation median grain diameter (D_{f50}) is determined from the plot.
3. Saucier found that gravel having a median grain diameter (D_{g50}) not exceeding 5 times the formation (D_{f50}) would prevent invasion of the pack by formation particles. Using this guide, determine gravel median grain diameter required and select a commercially available gravel meeting the criteria.

Once the gravel median diameter requirements are determined and the gravel is selected, calculations may be made to determine pressure loss through the gravel pack while producing at the desired production rate. Results of these calculations will be used in selecting the type completion.

b. Selection of Completion Type

There are two gravel pack completion types -- open hole and perforated. In the open hole completion, the producing interval is not cased or the casing is removed by milling and the interval underreamed and gravel packed. The advantage of this type completion is reduced pressure loss through the pack. This becomes extremely important when the gravel required to control the formation sand is very small and when production rates are extremely

Fig. 1—Representative sieve analysis.

high. There are two primary disadvantages; hole stability is difficult to maintain with non-damaging fluids; and zone selectivity is more complicated.

In perforated casing completions, zones may be selectively perforated and gravel packed while hole stability problems are minimized. Pressure loss through perforated gravel pack completions is greater than in open hole packs. And all perforations must be fully packed with gravel if the pressure loss is minimized. In long intervals, complete packing is very difficult to achieve and special procedures are required to maximize the number of perforations packed.

In evaluating pressure loss in gravel packs, there are two types of flow to consider -- radial and linear. As fluid is produced through the formation, velocity increases as it flows radially toward the wellbore. Since velocity is greatest just before entering an open hole wellbore, the greatest pressure loss is near the wellbore. Radial flow is present in both open hole and perforated completions; but in a perforated completion, the velocity increases dramatically as fluid funnels into perforation tunnels extending through the cement sheath and casing. It is in this area where velocity increases linearly with a reduction in perforation area or increased production rate.

Since the velocity in an open hole pack does not increase at the same rate as in perforations, the pressure loss is much lower. In fact, the open hole area of a 6-1/2 inch hole is approximately 40 times greater than the area of twelve 0.8 inch perforations that are

frequently used in high rate perforated completions. Pressure losses in perforated gravel pack completions 100 times greater than open hole packs are not unusual.

As stated earlier, smaller gravel results in decreased permeability and increased pressure loss. Most sand producing formations can be controlled with US 20-40 gravel. However, some of the younger sands are much finer and require finer gravels. Permeability of some of the commonly used gravels are listed below.

US 20-40	121 darcies
US 40-60	45 darcies
US 50-70	30 darcies

Equations used in making the pressure loss calculations in open hole and perforated gravel packs are shown below.

Open Hole Pack Pressure Loss Equation

$$\Delta P_r = \frac{\mu Q \ln \frac{r_2}{r_1}}{7.08 Kh}$$

Where: ΔP_r = Pressure loss through open hole pack, psi
 Q = Flow rate, bbls/day
 μ = Viscosity, centipoise
 K = Gravel permeability, darcy
 h = Vertical extent of pack, feet
 r_2 = Open hole radius, inches
 r_1 = Screen radius, inches

Packed Perforation Pressure Loss Equation

$$\Delta P_l = \frac{0.888 L \mu Q}{KA} + 9.1 \times 10^{-13} \beta \frac{Q^2}{A}$$

Where ΔP_1 = Pressure loss through perforation pack, psi
 Q = Flow rate, bbls/day
 μ = Viscosity, centipoise
 K = Gravel permeability, darcy
 A = Perforation area, feet²
 B = Drag coefficient,
 $10^{(6.5 - .95 \log K)}$

These equations should always be applied when selecting the completion method.

The original gravel pack design for Sweezy No. 1 used twelve 3/4 inch perforations per foot and a total of 288 perforations. At 20,000 bbls/day, the pressure drop was predicted by predesign calculation to be 31 psi with gravel having a permeability of 90 darcies. The calculation appears to have been in error and the calculated pressure loss should have been 231 psi.

The actual diameter of the perforations used was 0.68 inches but there were 600 perforations. Table 1 shows calculated pressure loss for rates up to 20,000 bbls/day for 600 perforations and gravel with only 60 darcies permeability. At these conditions, pressure losses were borderline acceptable for 12 holes/foot.

Calculations in Table 1 also show the pressure loss expected if the perforations were filled with 2 darcy formation sand. It is clear that an open hole pack has much lower pressure losses. But a perforated completion even with gravel having 60 darcies permeability is acceptable if all perforations are packed. However, if a high percentage are filled with formation sand, the pressure loss would not be acceptable.

TABLE 1
Gravel Pack Pressure Loss

Produced Fluid Density - 1.09 kg/liter or 68.01 lbs/ft³

Produced Fluid Viscosity - 0.5 centipoise; Screen OD - 4-1/2"

Perforation Tunnel Length - 2 inches; Perforation Diameter - 0.68 inches

Producing Interval - 50 feet

<u>Production Rate (BPD)</u>	<u>Gravel Permeability (darcies)</u>	<u>Open Hole Completion (psi)</u>	<u>Perforated Completion</u>	
			<u>8 holes/ft (psi)</u>	<u>12 holes/ft (psi)</u>
5,000	60	0.08	22.5	11.3
10,000	60	0.16	77.8	37.2
15,000	60	0.24	165.8	77.8
20,000	60	0.32	286.7	132.8
5,000	2	2.4	598	306
10,000	2	4.9	2,026	981
15,000	2	7.3	4,283	2,026
20,000	2	9.8	7,370	3,439

Figure 2 was developed to visually indicate the minimum number of gravel packed perforations required for a given production rate. It is a series of production rate curves plotted versus pressure loss and number of perforations. These curves were developed using the Packed Perforation Pressure Loss Equation. This series of curves allows a quick estimate of the number of perforations required to produce at a certain rate under the conditions stated on the figure. For example, if the pressure loss at the perforations is to be limited to 100 psi, there must be approximately 508 0.68" diameter perforations packed with gravel having a permeability of 120 darcies to produce at 20,000 bbls/day. And if only 33% of the perforations (153) are packed, the differential pressure will be at an unacceptable level of 865 psi.

c. Screen Selection

There are two basic types of screens -- wire wrapped and saw slotted liners. Wire wrapped screens are manufactured by wrapping a special keystone shaped wire around a joint of drilled tubing or casing. Saw slotted liners are manufactured by sawing slots in a joint of tubing or casing. The number of slots possible in saw slotted liners are limited to only a fraction of the slots in wire wrapped screens. This leads to plugging, especially when the slots are gauged to filter US 20-40 or smaller gravel.³

Saw slotted screens are used in low rate producing wells where sand can be controlled with US 10-20 gauge or larger gravel. The slot size is just small enough to stop the gravel. A slot of 0.025" is commonly used with US 10-20 gravel.

FIGURE 2

In selecting a screen, the important factors are slot width, slot area, screen diameter and type steel. The maximum diameter allows a minimum radial clearance of 3/4 inch. The slot width is just small enough to stop the smallest gravel and slot area is largest practical especially when using slots small enough to control US 20-40 sand.

In the Sweezy No. 1, a 4" OD wire wrapped screen with .012 wire spacing was used in 7-5/8" casing. This screen allowed approximately 1.4" of gravel around the screen and maximum slot area.

Ordinarily, Type 304 stainless steel wire is used with J55 base pipe in the construction of wire wrapped gravel pack screens. Type 304 is susceptible to chloride stress cracking in some environments and may not be recommended in high temperature brines.⁴ Although Type 304 wire was used in the Sweezy No. 1, based on well performance, CTC does not believe that chloride stress cracking contributed to the failure of the well to perform properly.

d. Completion Fluids

Completion fluids used for gravel packing will provide minimum pack damage if they are solids-free. In the oil industry, "solids-free" is a relative condition. Most oil operators have different definitions but the trend is toward reduced solids with many operators striving for less than 50 ppm solids finer than 2 micron.

Clean fluids are necessary to prevent deposition of solids in the perforation tunnels and mixing with the gravel. Both of these conditions result in productivity impairment.

When using clean brines and after purging the perforations, loss of fluid to the formation is increased. For this reason, use a minimum overbalance to control the well while keeping safety in mind. An overbalance of 150 psi is commonly used, and this is CTC's recommendation. Brine density must be adjusted to compensate for the well temperature effect.

9.10.4.2 Gravel Placement Techniques

The gravel placement techniques used in open hole gravel packing are quite different than those used in perforated completions. Since an open hole pack was not used on the Sweezy No. 1, details of open hole gravel placement techniques will not be discussed except to say that the open hole is underreamed to provide maximum matrix flow area and the gravel is placed by circulating the gravel laden slurry through the screen filtering out the gravel.

In perforated completions, gravel placement must be performed in a manner that will assure maximum number of perforations filled with gravel. Perforations filled with formation particles will be restricted severely (See Table 1). Restriction of these perforations diverts production through the remaining perforations at increased velocity and differential pressure. If the velocity and differential pressure is high, perforations packed with gravel will be invaded by formation particles further restricting the productivity and increasing the rate at which complete plugging of the pack will occur. There is evidence from well test data in the Dow/DOE Sweezy No. 1 that ± 500 psi skin leads to increased formation particle production.

Prior to injecting gravel into the perforations, they must be purged of formation particles. In addition, the formation matrix must be permeable so that the gravel carrier fluid can be squeezed into the matrix leaving the gravel in the perforation tunnel.

a. Perforation Purging

There are at least three methods used to purge perforations. The most commonly used is the washing technique using opposed swab cups to circulate between perforations. This may result in purging less than half the perforations as the fluid will follow the path of least resistance. Surging and underbalanced perforating subject all the perforations to instantaneous pressure differential.

Surging was developed by Shell and is used extensively in the Gulf Coast.

Underbalanced perforating is an emerging technique and has become more widely used in the past three years. Industry is divided on which method of perforation purging is best. At the present time, the majority of operators use the perforation wash technique.

b. Acidizing

Acidization of the perforations is extremely beneficial to proper placement of gravel. As slurry is injected into perforations, the carrier fluid must be squeezed out of the slurry leaving gravel in the perforation tunnels. For this to occur, the formation matrix near the perforations must be permeable. Matrix acidization is normally applied to remove formation permeability damage and improve matrix fluid injectivity.

The acid treatment normally consists of three acid stages. A preflush of 7-1/2% hydrochloric acid is injected to remove calcium carbonate and to flush brines away from the wellbore. Following the weak acid, a solution of hydrochloric/hydrofluoric acid is injected to remove clay and silt particles that were not soluble in the 7-1/2% hydrochloric. And since hydrochloric/hydrofluoric acid is not compatible with brines, a spacer of 7-1/2% acid is injected following the hydrochloric-hydrofluoric acid.

c. Stage Packing

In high rate wells, it is necessary that most if not all of the perforations are filled with gravel. This is difficult if not impossible in long perforated intervals. The problem lies in non-uniform effective permeability. The gravel slurry enters the perforations opposite the highest matrix permeability and dehydrates leaving gravel in the perforations and a sand bridge in the screen casing annulus. Perforations opposite less permeable matrix below this point will not be fully packed allowing formation sand invasion of the tunnel.

Matrix acidization has been used in conjunction with diverting agents to obtain uniform permeability. This approach has provided only limited success and alone is not a solution to the problem.

One approach that has been used very successfully is to perforate a series of short intervals (10-15 feet) then purge, acidize, and pack in stages. This is an expensive approach because multiple perforation runs, purge procedures and pack procedures are required. This, coupled with the rig time sometimes appears to be

an unjustified expense. It is, however, the only effective approach to maximize the number of packed perforations. This was the approach recommended in the Sweezy No. 1 by Dowell.

9.10.5 What Caused Failure of Sweezy No. 1

There have been several possible causes or contributing factors to the failure discussed with Dow personnel familiar with the well. Those listed by Dow include:

1. Perforations not prepacked
2. Single stage pack rather than three-stage (original Dowell recommendation proposed four stages)
3. Inability to bring the well in slowly during initial production stages
4. Perforating the more unconsolidated portion
5. Possible improper sizing of gravel
6. Oil coning

In our analysis of the well test data, it appears that factors 1, 2 and 3 could have had a severe impact. Factor 5 is a possible cause but gravel was sized using sieve analysis from whole cores and Saucier's criteria. Pack failure occurred prior to oil coning so while it may have caused additional problems, it probably did not cause initial failure.

9.10.5.1 Analysis of Data

Dow furnished well test data taken at several intervals during the producing life of the Sweezy No. 1. The test data (summarized in Table 2) shows skin factor, reservoir permeability, and differential

pressure due to skin calculated at a given flow rate. The differential pressure due to skin was very likely a measurement of the pressure loss of brine flowing through the gravel and formation filled perforations.

CTC has prepared a series of pressure loss versus perforation flow rate plots for perforations filled with materials of various permeability. These plots are in Figure 3. The conditions used to prepare these plots were similar to those in Sweezy No. 1.

Perforation Diameter	- .68 inches
Perforation Length	- 2 inches
Brine Specific Gravity	- 1.09
Brine Viscosity	- 0.5 centipoise

Several different packing material permeabilities were used starting with permeability plots of 1,000 and 2,000 millidarcies that may be used to simulate perforations filled with formation materials. Then followed a series of plots with permeabilities varying from 40 to 120 darcies. These plots represent gravel filled perforations. The gravel used on the Sweezy No. 1 was US 20-40. Laboratory measurements indicate a permeability of 121 darcies for US 20-40. However, field testing has indicated that the permeability of the gravel is considerably less after placing in a well. One series of tests indicated 80,000 millidarcies after being pumped around a screen using filtered water and a triplex pump. The permeability is further damaged when mixed with dirtier water and displaced to the bottom of a well.

Using these plots and permeabilities estimated to simulate well conditions, it is possible to calculate the number of perforations filled with gravel and the number filled with formation material.

FIGURE 3

Gravel permeability for these calculations was estimated to be 60,000 millidarcies. Laboratory data indicated formation permeability of 2,000 to 3,000 millidarcies. However, well tests by Otis (Table 2) indicated permeability in the range of 476-1,246 millidarcies. CTC selected 1,000 millidarcies to represent permeability of the formation material filling the perforation.

The number of gravel and formation packed perforations was calculated for the differential pressures due to skin in each of the Otis tests. An explanation of the calculations follows.

Buildup Test No. 2 (April 28, 1982) was the first recorded test after production was started on April 26, 1982. This test indicated a skin of 544.7 psi when calculated at a flow rate of 13826.8 BWPD. Figure 3 shows that the flow rate through a single perforation filled with 1 darcy material is 8 BWPD at 544.7 psi differential; and through a gravel filled perforation with 60 darcy permeability, the rate is 70 BWPD.

Then it is possible to write two simultaneous equations to solve for the number of perforations of each permeability. These equations assume that all perforation charges effectively penetrated the formation and a total of 600 perforations were present. This is an optimistic assumption. The equations are:

$$x + y = \text{Total perforations}$$

Where:

x = the number of gravel filled perforations

y = the number of formation filled perforations

and

$$Q_{gp}x + Q_{fp}y = Q_{total}$$

Where: Q_{gp} = Flow rate BWPD through gravel filled perforation at a given pressure loss

Q_{fp} = Flow rate BWPD through formation filled perforation at the same given pressure loss

Q_{total} = Total flow rate from well tests at that pressure loss (P_{skin}) Table 2

Using Buildup Test No. 2 data, the equations then are

$$x + y = 600 \text{ perforations}$$

$$70x + 8y = 13826.8 \text{ BWPD}$$

Solving then shows 145 perforations filled with gravel and 455 perforations filled with formation material.

Table 2 shows the calculated data for each of the Otis well tests. The columns labelled "Calculated Number of Perforations" shows the number of formation filled and gravel filled perforations. While the data is indicative of probable perforation condition, it should not be interpreted as literal fact.

In Figure 4, the production rate per psi pressure loss due to skin $PI (Skin)$ is plotted for each of the buildup tests shown in Table 2. This plot illustrates the decreasing $PI (Skin)$ through Test No. 5. After Test No. 5, there was increasing $PI (Skin)$. This is a good indication that the formation sand and gravel were being purged from the perforations. If the screen had not already failed, flow may have been going up the annulus of the screen assembly and back into the tubing through the open crossover ports of the Model 16 packer. Sand production was controlled only by the cohesiveness of the formation from this point in time.

CALCULATED NUMBER OF GRAVEL FILLED & FORMATION SAND FILLED PERFORATIONS

Test	Skin Factor	Reservoir Perm md	ΔP Skin psi	Flow Rate bpd	PI (Skin) bpd/psi	Calculated Rate per Perf-bpd		Calculated No. of Perfs	
						Gravel Filled	Fmt. Filled	Gravel Filled	Fmt. Filled
Build Up Test #2 4/28/82	22.7	732	544.7	13826.8	25.38	70	8	145	456
Build Up Test #3 5/13-17/82	31.7	764	335.08	6361.8	18.95	62.5	6	57	543
Build Up Test #4 5/18-20/82	36.18	749	528.26	8608.7	16.29	68.75	7.75	65	535
Build Up Test #5 5/26-6/2/82	48.19	763	863.42	10766.8	12.47	88.5	10.5	58	542
Build Up Test #8 6/28-7/6/82	23.83	476	593.95	9363.1	15.76	73	8.3	67	532
Build Up Test #9 8/27-30/82	29.47	1246	277.92	9257.4	33.31	49.4	5	141	459
Build Up Test #10 11/2-15/82	18.02	1015	188	8350	44.41	40.2	3.8	167	433
Build Up Test #11 1/19-23/83	16.3	1150	148.77	8270.2	55.59	35	3.25	199	401
Draw Down Test #11 11/15/82-1/19/83	104	656	1614.51	8017	4.96	122	15.5	-	612+

Conditions: Total Perforations - 600 Diameter - .68 in Length - 2 in
 Perforations Filled with FMT Sand - Perm = 1000 md Perforations Filled with Gravel - Perm = 60000 md
 Produced Brine - Viscosity - 0.5 cps Brine Density - 1.09 Kg/liter

TABLE 2

PRODUCTIVITY INDEX OF SKIN VERSUS TIME

FIGURE 4

9.10.5.2 Conclusions

Analysis of data in this table leads to the following conclusions.:

- 1) Since the prepack was performed in one stage, initially, there were only ± 150 perforations filled with gravel.
- 2) Due to the high skin created by poor packing, gravel was flowed out of some of the perforations and replaced by formation sand causing an increased Differential Skin Pressure of 863.42 psi and a Skin Factor of 48.19 in Buildup Test No. 5. This is also reflected by reduced Productivity Index (Skin), plotted in Figure 4.
- 3) Increased Differential Pressure probably completely purged some of the perforations and most of the flow was coming from only a few perforations starting after Buildup Test No. 6.
- 4) During Drawdown Test No. 11, all perforations filled with sand causing almost complete plugging.
- 5) Flowing after that date probably for the most came from only a few perforations until the screen was blasted through and a complete failure occurred on February 5, 1983.
- 6) There is evidence that the well was in trouble from the initial test. However, a rework at that time would have been very expensive and involved because it would have been virtually impossible to have affected a complete pack of all the perforations without stage packing.

Other conclusions based on well experience are:

- 1) It would probably be less expensive to drill a new well than to attempt a high risk workover.
- 2) There is a good possibility that the casing is buckled in the producing zone due to reduced reservoir pressure and sand production removing lateral support.

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4. Dillon, C.P. and Associates, "Guidelines for Control of Stress-Corrosion Cracking of Nickel-Bearing Stainless Steels and Nickel Base Alloys", The Materials Technology Institute of the Chemical Process Industries, Inc., Material Manual No. 1, Table 2.3, pp. 23 and 125.

**DOW-DOE
PARC PERDUE
GEOPRESSURE-GEOTHERMAL PROJECT**

**APPENDIX M
ANALYSIS OF FLUIDS:
U.S.L.**

FINAL REPORT

ANALYSIS OF FLUIDS FROM THE
DOW-DOE L.R. SWEETZ NO. 1
GEOPRESSURED ENERGY WELL

SUBCONTRACT: #CT-3939-P68

CONTRACT: #DE-AC08-70ET27255

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10. Chemical Analyses

The chemical and physical analysis of fluids from the L. R. Sweezey well was carried out by the University of Southwestern Louisiana (USL) in Lafayette, Louisiana.

10.1 Facilities

The analyses were performed at two of the University's Laboratories and at an on-site laboratory trailer. The laboratory trailer contained the following major items of analysis equipment:

Varian	Gas Chromatographic System
Varian	Atomic Absorption Spectrometer
Bausch & Lomb	Spectrophotometer
Beckman	Conductivity Bridge
Orion	Ion Selective Electrode System
Corning	pH meter

The University preparatory laboratory provided:

- wet chemistry facilities
- solvent extraction system
- sample dryers
- sample mounting

USL's Acadiana Research Laboratory provided the

3MV van de Graaff accelerator and its

- associated proton beam handling equipment
- sample irradiation chambers
- x-ray detection equipment
- γ -ray detection equipment
- data link to USL's Multics computer

10.2 Laboratory Procedures

The various procedures used will be discussed in the sections dealing with particular fluids.

10.3 Sampling Procedures

Three different fluids were sampled: the brine, the exsolved gas and the condensables from the gas stream. The sampling points are shown in figure 10.3-1.

10.3.1 Brine Sampling

The brine samples were removed from the brine stream through a sampling point just downstream from the choke system. The hot brine, normally about 96°C was passed slowly through a coil of 3/8" stainless steel tubing immersed in an ice bath to reduce its temperature. This cooling was designed to reduce the loss of volatile compounds. This procedure is a standard one suggested by several authors.^{1,2} Normally about eight (8) liters of brine was taken on the sampling schedule shown in Table 10.3-1 which included both the early short term flow tests and the long term tests. Table 10.3-1 also lists the cumulative brine production on the sample dates. Some large volume samples were also taken for extraction of trace materials in the brine.

TABLE 10.3-1

BRINE SAMPLING SCHEDULE

SAMPLE #	DATE(Time)	CUMULATIVE BRINE VOLUME in kilobarrels
1.	5-12-82 (1258)	-
2.	5-12-82 (1700)	4
3.	5-13-82 (0902)	8
4.	5-13-82 (1717)	11
5.	5-17-82	15
6.	5-18-82	18
7.	5-18-82	20
8.	5-20-82	23
9.	5-21-82	37
10.	5-22-82	47
11.	5-23-82	58
12.	5-24-82	70
13.	5-25-82	80
14.	6- 8-82	135
15.	6-11-82	160
16.	6-14-82	187
17.	6-17-82	216
18.	6-21-82	255
19.	6-25-82	309
20.	7- 7-82	329
21.	7-14-82	395
22.	7-19-82	442
23.	7-26-82	507
24.	8- 2-82	567
25.	8- 9-82	636
26.	8-16-82	701
27.	8-23-82	767
28.	9- 1-82	825
29.	9-13-82	868
30.	9-27-82	996
31.	10- 4-82	1060
32.	10-11-82	1123
33.	10-18-82	1186
34.	10-25-82	1248
35.	11- 2-82	1300
36.	11-16-82	1320
37.	11-22-82	1360
38.	11-29-82	1421
39.	12- 6-82	1481
40.	12-20-82	1585
41.	12-27-82	1652
42.	1- 3-83	1718
43.	1-10-83	1783
44.	1-16-83	1840
45.	1-25-83	1856
46.	2- 2-83	1928

The regular samples were divided into five (5) parts as follows:

TABLE 10.3-2
Brine Samples

1. Raw, unacidified (RU)
2. Raw, acidified (RA)
3. Filtered, unacidified (FU)
4. Filtered, acidified (FA - HNO_3)
5. Filtered, acidified (FA - HCl)

The various sample fractions were used as listed in section 10.4.

10.3.2 Gas Sampling

A standard double-valved, teflon-lined gas sampling bomb was attached to a gas sampling port at the top of the gas-brine separator and both inlet and outlet valves opened. After a time long enough to insure that the sampler was flushed by the gas flow, the outlet valve was closed and after a moment, for the pressure to equilibrate, the inlet valve closed. The gas from the separator was sampled on essentially the same schedule as brine samples.

10.3.3 Condensable Hydrocarbon Sampling

The condensable materials in the gas stream were collected seven times during the course of testing the well. The apparatus used to collect these samples consisted of a two stage regulator which reduced the

pressure and a series of traps and a flow meter. The gas stream passed through an ice-water cooled trap to remove some moisture from the stream. The stream then passed through two "dry ice" - acetone traps and finally through a wet test meter to record the total volume of gas which passed through the system.

10.4 Brine Chemistry and Physical Properties

The following analyses were performed on the regular brine samples. In each case the type of pre-treated brine sample and a short synopsis of the procedure is given. When the method required a comparison to standard samples, the standards were prepared using the same matrix--a solution of sodium chloride of the same ionic strength as the well brine. These standards will be referred to as "matrix-matched".

10.4.1 Procedures

I. Physical Methods

A. Density

The density of the brine was determined by weighing a standard volume (usually 50 ml) contained in a pycnometer which was equilibrated in a constant temperature bath at 25.0°C.

B. Viscosity

The viscosity of the brine was determined by timing the flow of a standard volume brine through the calibrated orifice of a Ostwald viscosimeter maintained at 25.0°C. The equation used was:

$$\text{viscosity} = 0.8928 \rho_x \left(\frac{t_x}{t_{H_2O}} \right)$$

ρ_x = density of the brine

t_x = flow time for the brine

t_{H_2O} = flow time for H_2O

C. Conductivity

The conductivity of the brine was measured directly using a Beckman conductivity bridge and a calibrated immersion-type conductivity cell. The cell and the brine were maintained at 25.0°C in a constant temperature bath.

D. pH

The pH of the brine was measured directly using a standard pH meter and a combination pH electrode. The pH was measured soon after the sample was taken and the value reported is the equilibrium value, i.e., when no further change was observed.

II. Chemical Methods

A. Chloride

The Chloride ion concentration was measured by titration; the Mohr method.

B. Sulfate

The sulfate ion concentration was determined turbidimetrically using FA-HCl brine. Comparison was made to matrix-matched standards.

C. Hydrogen Carbonate

Hydrogen carbonate was determined using a specific

ion electrode and a fresh sample of RU brine.

D. Fluoride

Fluoride was determined using a specific ion electrode. A sample of FU brine was compared to matrix-matched standards.

E. Alkalinity

The total alkalinity was determined by potentiometric titration of an RU brine sample using standard HCl solution.

F. Hardness

The total hardness of the brine was determined by titration with ethylenediaminetetracetic (EDTA) acid to an Erichrome Black-T end point.

G. Dissolved Solids

A sample of FA-HCl brine was evaporated to dryness and the residue weighed.

H. Dissolved Silica

Silica was determined using the spectrophotometric molybdate method on an RU brine sample.

I. Ammonia

Ammonia was determined using a specific ion electrode. A sample of FU brine was compared to matrix-matched standards.

J. Boron

Boron was determined using the spectrophotometric curcumin method.

K. Atomic Absorption Methods

The following elements were determined using atomic absorption spectrometry. Except for sodium all

determinations were in comparison to matrix-matched standards.

- a. zinc
- b. sodium
- c. potassium
- d. magnesium
- e. iron
- f. calcium

L. Bromine

Bromine was determined using proton induced x-ray emission.

M. Strontium

Strontium was determined using proton induced x-ray emission.

10.4.2 Results of Brine Analyses

Several parameters and constituents changed during the course of the sampling. The results reported in Table 10.4-1 are the asymptotic ones; the average of many essentially unchanging values. The values which changed with time are reported graphically in Figures 10.4-2 through 10.4-4. For reference, the unchanging values of total solids and chloride are shown in Figure 10.4-1. The analysis of the changes are discussed in section 10.8. The standard deviation, $\sigma_{\bar{x}}$ reported in Table 10.4-1 is calculated by the expression

$$\sigma_{\bar{x}} = \sqrt{\frac{\sum (x_i - \bar{x})^2}{n(n-1)}}$$

where x_i is a particular value of a set of n values and
 $\bar{x}$ is the mean value of the set.

TABLE 10.4-1
Brine Analysis

<u>DETERMINATION</u>	<u>MEAN VALUE</u>
Density @ 25°C	1.062 ± 0.000 g/mL
Conductivity @ 25°C	121700 ± 641 μ mhos/cm
Viscosity @ 25°C	1.045 ± 0.001 ep
pH (equilibrium)	6.37 ± 0.02
alkalinity	1540 ± 23 mg/L
total dissolved solids	99700 ± 240 mg/L
total hardness (as CaCO ₃)	5410 ± 140 mg/L
sodium	33890 ± 170 mg/L
potassium	176 ± 4 mg/L
magnesium	262 ± 3 mg/L
boron	60.2 ± 0.6 mg/L
manganese	1.1 ± 0.09 mg/L
silica	68.4 ± 1.1 mg/L
ammonia	48.0 ± 0.8 mg/L
iron	2.10 ± 0.09 mg/L
zinc	1.92 ± 0.16 mg/L
calcium	1710 ± 30 mg/L
strontuim	245 ± 11 mg/L
chloride	55720 ± 140 mg/L
hydrogen carbonate	380 ± 13 mg/L
sulfate	522 ± 4 mg/L
carbonate	0.04 ± 0.003 mg/L
Fluoride	1.65 ± 0.07 mg/L
bromide	110 ± 15 mg/L
iodide	36.3 ± 1.6 mg/L

10.5 Gas Analyses

A small portion of the gas sample was removed through a fixed volume sampling loop and injected into the gas chromatograph equipped with a seven foot PORPAK-Q column. The sample was carried by chromatographic grade helium. The column was heated and its temperature varied in a programmed sequence. The mole percent of each component is calculated in the following manner.

$$N_i = \frac{A_i R_i}{\sum A_i R_i} \times 100$$

N_i = the normalized (mole) percent of component i

A_i = the integrated peak area for component i

R_i = the relative response factor for component i

The mean results and the standard deviations of the mean are given in Table 10.5-1.

TABLE 10.5-1

Gas Analyses

<u>DETERMINATION</u>	<u>MOLE PERCENT</u>
N ₂	0.39 ± 0.03
CO ₂	2.45 ± .12
C ₁	94.17 ± .16
C ₂	2.48 ± .02
C ₃	.35 ± .02
i - C ₄	.09 ± .003
n - C ₄	.03 ± .003
i - C ₅	< .01
n - C ₅	< .01
C ₆ ⁺	< .01

10.6 Trace Elements

The trace element concentration of the samples were measured using a technique which used solvent extraction to isolate elements or groups of elements from the brine and then analysis of the group by proton induced x-ray emission (PIXE). It was hoped that these trace indicators would provide information concerning changes in the source of the waters having sampled.

In the PIXE method of analysis a proton beam with an energy of about 2 MeV is directed into a sample. The proton beam has quite sufficient energy to remove the innermost electrons around the atoms of the sample. When an electron vacancy is created in a particular shell of an atom, the excited atom may stabilize by filling the vacancy with an electron from a higher shell and the emission of a photon of electromagnetic radiation. When the vacancies occur in the K or the L shell the photons are usually in the x-ray region. The designation of these x-rays are as follows

VACANCY IN _____ Shell	ELECTRON FILLING THE VACANCY FROM _____ Shell	X-RAY DESIGNATION
K	L	K_{α}
K	M	K_{β}
L	M	L_{α}
L	N	L_{β}
L	O	L_{γ}

The energies of the x-rays from particular elements are known from atomic physics calculations. The observation of particular x-ray energy groups provides a unique means of identifying the presence of elements in a sample. See for example Figure 10.6-1; the abscissa is proportional to x-ray energy. This is an energy spectrum from the bulk solids from the brine. The germanium peaks result from a standard added to the samples. Quantitative measurements of elemental concentrations can be accomplished by comparison to standard samples or by such techniques as standard addition.

Interfering background, the generally unstructured events of figure 10.6-1, which tends to obscure smaller x-ray peak results primarily from three sources: Compton scattering of higher energy gamma rays produced from proton-nucleus reactions, pile-up of signals in the detection electronics when two x-rays arrive at the detector at essentially the same time and bremmsstrahlung (German for breaking radiation) x-rays which are produced in the deceleration of electrons in the sample which were ejected by the proton beam. The second source can be reduced by simply counting for a longer time at a slower rate and by electronically rejecting some pulses which occur too close together in time. Of the other two sources, the last is the most serious, best dealt with by using thin samples so that the electrons produced do not decelerate in the sample but pass through.

Solvent extraction of complex ions of various elements is a technique long employed for separation. Since PIXE can detect the presence of many elements simultaneously, techniques which extract groups of elements leaving behind the bulk of a sample are particularly useful.

To accomplish this extraction, brine samples were adjusted to a pH of 4 and a small amount of sodium diethyldethiocarbamate (NaDDTC) added. The metal complexes produced were extracted into a few milliliters of chloroform. This chloroform was evaporated leaving a very thin sample containing the trace elements of interest. The bulk of the sample-sodium, potassium, calcium and magnesium salts is not extracted.

Figure 10.6-2 is a portion of an x-ray energy spectrum of a thin sample extract described above. The peaks corresponding to vanadium, manganese, iron, nickel, copper and zinc are shown. Vanadium and nickel are not found in the brine. This particular spectrum represents a sample to which 100 parts per billion (ppb) of each of vanadium and nickel was added. Further, an addition of as little as 5 ppb produced a peak which was discernable above the background events. Not all of the elements of interest are extracted efficiently into NaDDTC, however, cupferron is an excellent agent for Cr, Cu and Pd among others. Table 10.6-1 list the results of the extraction/PIXE measurements for two representative brine samples.

TABLE 10.6-1

<u>ELEMENT</u>	<u>CONCENTRATION</u>	
	Brine Sample: <u>8-2-82</u>	<u>2-2-83</u>
V	< 5 ppb	< 5 ppb
Cr	< 10 ppb	< 10 ppb
Mn	1.1 ppm	1.0 ppm
Fe	2 ppm	1.6 ppm
Ni	< 5 ppb	< 5 ppb
Cu	< 10 ppb	< 10 ppb
Pd	< 10 ppb	< 10 ppb
Pb	50 ppb	40 ppb

10.7 Hydrocarbon Production

Early in our testing of the fluids from the DOW-DOE L. R. Sweezy #1 geopressured well in Vermilion Parish, Louisiana, we detected the presence of a small amount of condensable hydrocarbons in the separator gas from the well. These hydrocarbons were trapped from a small amount of the separator gas by means of a series of "dry ice" -- acetone traps. Analysis of this condensate showed it to be largely aromatic in nature. The production of this primarily aromatic condensate continued over the lifetime of the well. Furthermore, the production of hydrocarbons increased during the lifetime of the well. A "drip pot" trap in the gas line from the separator to the flare began to collect a light oil where before only water had been present. About one month before the demise of the well, due to excessive sand production, the well began to produce heavy oils. The production of these hydrocarbons could inject a new dimension into the economic equation for geopressured-geothermal brine production.

Interest in the presence and significance of this aromatic condensate in the L. R. Sweezy well prompted us to undertake the task of determining if similar condensates could be obtained from the Pleasant Bayou #2 geopressured-geothermal well in Brazoria County, Texas, and/or from the Gladys McCall #1 geopressured-geothermal well in Cameron Parish, Louisiana. We were interested in correlating any

hydrocarbons we collected from these wells with that already obtained from the L. R. Sweezy well.

Experimental Results

We have found that the three wells sampled all contain very similar, primarily aromatic, hydrocarbons in the gas exsolved from the brine. Figure 10.7-1 shows gas chromatographs of these condensates. The six major components are labeled: B = benzene, T = toluene, E = ethylbenzene, and O, M, and P, for ortho-, meta-, and para-xylene respectively. Table 10.7-1 gives the mole percents of the six compounds from each of the three wells. Our early semiquantitative results indicated that the amounts of condensate in the separator gas from the wells are: L. R. Sweezy #1 = 15mL/MCF, Gladys McCall #1 = 86mL/MCF, and Pleasant Bayou #2 = 123mL/MCF. It should be noted that the condensates from the sampled wells are very much different in character than a condensate sample taken from a producing gas well whose producing zone is in the same sand as the L. R. Sweezy #1 well, but across a fault.

TABLE 10.7-1

COMPOUND	MOLE PERCENT			
WELL:	Sweezy	Gladys McCall	Pleasant Bayou	
BENZENE	32.96	66.94	51.05	
TOLUENE	36.04	23.44	33.91	
ETHYLBENZENE	7.53	2.51	2.96	
o-XYLENE	11.19	2.62	4.07	
m-XYLENE	10.39	3.85	6.87	
p-XYLENE	1.89	0.65	1.14	

10.8

Discussion of Results

The detailed analytical chemistry, both inorganic and organic, that was performed on the L. R. Sweezy Well, provided the basis for the understanding of some of the processes which were active during the production of the well. Without vigilant attention to the chemistry much information of interest would have been missed. Four results, in particular, need to be discussed here.

1. Elution of completion fluids from the formation.

The several brine samples from the early short term flow tests of the well and the weekly samples of the long term tests revealed a sharp decrease in concentration of calcium and zinc (figures 10.4 - 3,4). Subsequent bromine analysis yielded a similar pattern.

A reasonable explanation for this phenomenon lies in the fact that the Dowell Hevi-water^R completion fluid was left standing in the well for about 2½ months. The well was left in this condition while repairs were being made to the special "christmas tree" which failed due to a valve malfunction on initial installation. The Hevi-water^R is a solution of calcium bromide (CaBr_2) and zinc bromide (ZnBr_2) in proportions to provide the desired density - which varied during completion of this well. This solution is assumed to have diffused into the formation during the time it remained in the well.

The elution of the CaBr_2 - ZnBr_2 from the formation does not follow a pattern indicative of simple diffusion

into the formation. If only one, simple diffusion process was involved, one would expect the concentrations eluted would decrease in a simple exponential fashion, and a graph of the logarithm of the concentration as a function of elution volume would then be a straight line. Figure 10.8-1 shows that this is not the case. However, as analysis of this graph reveals, it can be decomposed into three straight line components representing three separate diffusion rates.

The equation for the elution (chi-squared) is rather mixed, but informative units is:

$$C_{Zn} = 208.6e^{-0.54V} + 162.0e^{-0.0099V} + 18.3e^{-0.0027V}$$

The concentration of zinc, C_{Zn} is in units of mg/L and V is the cumulative volume produced in thousands of barrels (42 gallons per barrel). A background of 2 mg/L of zinc, determined from the long term limit of the concentration, was subtracted from all the data to account for the natural zinc in the formation.

The coring from the sand showed that the production formation was separated into two distinct zones, the upper and the lower. Further, the upper zone is cut by siltstone "stingers". The average permeability of the lower zone is 20 millidarcies, while that in the middle of the upper zone ranges from about 100 millidarcies to about one darcy. The upper portion of the upper zone was sparsely measured and only one figure of 44.8 millidarcies is reported.³ It is suggested that the Hevi-water⁵ stand-

ing in the well diffused at different rates into the different regions of the production zone and the elution function reflects this fact.

The elution function was integrated over the total volume removed and it was found that 4.3×10^3 kilograms (9540 pounds) of zinc was removed from the formation; as zinc bromide 1.5×10^4 kilograms were removed. The Hevi-water^R was on the average about 10% ZnBr₂ (weight-weight), so about 1.5×10^5 kilograms of solution were removed. Separate calcium analysis confirms this number to within 10%. Furthermore this amount of Hevi-water^R corresponds to about 130 barrels which is in satisfactory agreement with the "somewhat over 100 barrels" reported lost during completion operations.⁴

A paper on this subject has been prepared and is being submitted for publication.

2. Analytical Methodology

Tried and true standard methods of analysis are hallmarks of good analytical chemistry. Most of the analytical methods chosen in this work were standard and taken from

Hankins¹ and Watson².

Analytical chemistry is not, however, a static and unchanging science and better methods and/or techniques can often be developed. Two such developments need to be stressed here:

A. Ion selective electrode analysis for:

1. Fluoride

Although ion selective electrode analysis is a recommended procedure¹ for fluoride

ion, there are no details for a proper methodology available for reference 1 or elsewhere for use of this type of electrode in brine. The technical, report attached as Appendix A (Section 10.10) contains the details of this technique.

2. Ammonia and Carbon Dioxide

Methods have been developed to utilize these gas sensing ion selective electrodes to determine the ammonium and bicarbonate ions in brine. The use of reconditioning buffers is the key to reproducibility. The technical report attached as Appendix B (Section 10.9) contains the details of this method.

B. Proton Induced X-ray Emission Analysis (PIXE) of Strontium and Bromine

The PIXE analysis technique described in Section 10.6 for determining trace elements proved also to be an excellent technique for determining bromide and strontium. Dried samples of the solids from measured amounts of brine containing a reference element were bombarded with protons and the characteristic x-rays measured. An x-ray energy spectrum for these elements appears as figure 10.6-1 in this report. Here the reference element is germanium to provide consistency from sample to sample.

Quantitative results were obtained using the method of standard additions. In most methods the large excess of chloride and calcium ions would interfere with the bromide and strontium ion analyses; this poses no problem in this method.

3. Trace Chemistry

It has been found in this work that the already very sensitive technique of proton induced x-ray emission can be greatly facilitated by combining it with solvent extraction of groups of elements. The methods developed proved very useful for brine samples where the overwhelming bulk of sample interferes with the elements of interest. Sensitivity of a few parts per billion were achieved.

It was hoped in this work to use changes in the trace element inventory of the brine to shed light on the intrusion of other waters into the production formation. If these waters came from the surrounding shales one would expect that the different chemical history of these waters would cause changes in composition of the produced brine. No changes were observed in the trace elements which were followed in this work.

Increases in the trace content would have been taken as evidence for the intrusion of new waters. The lack of change does not support the counter point since less than 2% of the estimated volume of the formation water was removed during the production period. Further, there is no direct information concerning the shale water composition, nor is there any idea as to the degree to which

other waters would mix with those in the formation and find their way to the well bore.

4. Hydrocarbon Condensates and Oils

It would be satisfying to state unequivocally, the source of the condensates we have observed. Unfortunately, at this juncture, that is not possible. All we can do is to present several reasonable hypotheses. These hypotheses are consistent with the following chemical facts:

1. At a given temperature and pressure, aromatic hydrocarbons, in general, are more soluble in water (or brine) than are aliphatic compounds of equal numbers of carbon atoms (eg: benzene, C_6H_6 vs. hexane, C_6H_{14}).⁵
2. At a given temperature and pressure, if two or more phases of a multicomponent system remain in contact (ie.: share a common interface) for a sufficient period of time, then the components must partition themselves between these phases so as to give the overall system a minimum Gibbs Free Energy. This is the thermodynamic requirement for equilibrium in such a system.

With only these facts and our observations of the behavior of the L. R. Sweezy #1 well (This is the only well to date which has flowed over a substantial portion of its possible lifetime.); we propose two simple hypotheses (ie: models) that are consistent with the above scientific facts and our observations to date.

Hypothesis 1. In this model we visualize a system, excluding sand structure, in which the formation brine is still in contact with either a liquid petroleum phase, or a petroleum-rich gas phase, or possible both. Furthermore, the contact between the phases has existed for a sufficient period of time for the components that comprise the condensate to be in a state of equilibrium partition between the two of more phases.

Hypothesis 2. In this model we visualize a system, again excluding sand structure, in which either liquid petroleum, or a petroleum-rich gas phase, or possibly both; at some point in geologic time contacted the formation brine and allowed for partition of the components that comprise the exsolved condensate. [Note: Equilibrium partition is not a requirement of this model, but in view of movement restrictions imposed by porosities and permeabilities we would tend to believe it was at least approximated.]

Hypothesis #1 probably offers the best explanation of the events at the L. R. Sweezy #1 well. It was not until after the production of large quantities of brine, that dramatic changes occurred in the hydrocarbon production. Since the hydrocarbon production was rather small (estimated at a few gallons/day) compared to the brine production (approximately 8,000 bbls/day) we can not opt for either a liquid hydrocarbon phase or a petroleum-rich gas phase as the source. The petroleum-rich gas phase to which we refer could be similar

to that observed by Price, et.al.,⁶ in laboratory studies.

For the Pleasant Bayou #2 and the Gladys McCall #1 wells, either hypothesis is a plausible model at this point in time. Both wells are producing essentially the same kind of condensate as did the L. R. Sweezy #1 well prior to the onset of oil production. However, as was previously stated, the condensate yield per MCF of gas varies in amount by a factor of eight between the 15mL/MCF of the L. R. Sweezy #1 well and the 123mL/MCF of the Pleasant Bayou #2 well. There are a number of possible explanations of the variation in condensate yield. If one assumes a relatively constant aromatic content in the original oils, then the implication is that a greater relative amount of oil is now, or was, in contact with the brine in the Pleasant Bayou #2 production zone.

In view of the history of the L. R. Sweezy #1 well, we believe that there should be a continuing study of the condensates from the remaining DOE geopressured-geothermal wells. This recommendation is based primarily upon the belief that should hypothesis 1 prove to be the correct interpretation of geopressured-geothermal formations, it could inject a new dimension into the economic equation for geopressured-geothermal brine production.

A paper on the hydrocarbons is to be submitted to the Oil and Gas Journal.

In conclusion, some general comments on research in the development of geopressured energy are in order.

There has been a tendency on the part of some involved in the geopressured program to focus myopically on only the simple mission objective of the production testing of an existing resource. A flowing geopressured brine well is not just a potential energy source, it is a small window through which a view of the subsurface can be taken. Such a research opportunity should be exploited to its fullest if only because it is an opportunity. Research, like drilling a 2½ mile deep hole in the ground, is a risky business; blind alleys are going to be found -- the trace element analysis led to no new knowledge about shale dewatering. Sometimes, often quite by chance, a result is obtained which may provide greater understanding--the aromatic hydrocarbon condensate discovery may be just such a result.

A thorough research effort is but a fraction of the cost of drilling a geopressured well and worth the investment.

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10.10

Appendices

Appendix A

THE ANALYSIS OF FLUORIDE IN GEOTHERMAL-GEOPRESSURED BRINES

KEY WORDS: Fluoride, ion selective electrode, geothermal brines

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Abstract

Fluoride ion was determined by means of a fluoride ion selective electrode on geothermal-geopressured brines obtained from the DOW-DOE L. R. Sweezy #1 Well. The values decrease from 7.8ppm to a plateau value of 1.6 - 1.8 ppm.

Introduction

One of the most used and most studied electrodes is the fluoride solid state ion selective electrodes. Some of the many possible applications include the analysis of fluoride in carbonated beverages, chrome plating bath, dental plaque, toothpaste, coal, rocks and minerals, feeds, fish, household products, rainwater, biological fluids, sludge and wine.¹ The use of an ion selective electrode to monitor fluoride in geothermal-geopressured brines is recommended²; however, no details are given on the procedure to be followed. Studies³ have been made on the effect of interfering ions and it has been found that the addition of 0.1M sodium chloride to a solution containing 10^{-4} M fluoride ion results in a 7mv decrease in fluoride potential. In the presence of 1M sodium chloride, the potential of the fluoride solution (10^{-4} M) is depressed by about 20mv. In general, chloride ions do not interfere up to the ratio of

5.6×10^6 to 1 and the response is nernstian if the millivolt readings are corrected for the difference in fluoride ion activity coefficients and liquid junction potentials.

Geothermal-geopressured brines are complex fluids which have a high saline content (the one we are analyzing contains 90 g/l of sodium chloride) and are obtained in the vicinity of oil and gas fields. It is thought that these superheated fluids which have natural gas dissolved in them have the potential for use as an alternative energy source.

This paper will report on the procedure and analysis of geothermal-geopressured brines obtained from The Dow Chemical - Department of Energy, L. R. Sweezy Well Number 1 located in the North Parc Perdue gas field located in Vermilion Parish, Louisiana. The reservoir we were looking at has capacity of 40 to 80 million barrels of brine (depending on the method of calculation with the upper figure preferred) and we were able to monitor the fluoride level from May 12, 1982 until February 2, 1983 at which point 1,928,000 barrels of brine had flowed.

Experimental

An Orion fluoride ion selective electrode (Model 94-09) and an Orion ion selective electrode meter (Model 901) were used to take measurements. ACS Reagent grade sodium fluoride and sodium chloride were used to prepare the standards.

A TISAB solution was added to all samples before measurement not to control the ionic strength (because all solutions, samples and standards are essentially 0.9 g/100 ml NaCl) but to control the pH and to provide a complexing agent to complex with ions which

might complex with fluoride. TISAB was prepared by dissolving 58 g NaCl, 57 ml of concentrated acetic acid and 4.0 g of EDTA in 300 ml of distilled water. The pH was adjusted to pH 5.5 and the solution diluted to a volume of 1 liter.

The standards were all made up with 0.9 g NaCl/100 ml to match the chloride concentration of the diluted brine samples (1:10 dilution). Ten ml of TISAB was added for every 100 ml of sample.

Results

Calibration curves for fluoride were done in pure water, 9.0 g/l NaCl and 90 g/l NaCl matrixes. The results are shown in Table 1. Similar results to reference 3 were observed; however, it was found that for a 10^{-4} Molar Fluoride solution the millivolt readings were 58.6mv in water, 40.3mv in 9 g/l NaCl. This can partly be explained by the fact that the activity coefficients in solutions of high ionic strength can be greater than one.⁴ The slopes of the log concentration versus mv curves were: 61.1mv (H_2O), 54.0mv (9 g/l NaCl) and 54.5mv (90 g/l NaCl). The Nernstian value is 58.1mv. It was decided to use a 1 in 10 dilution of brine so all the standards were made up containing 0.9 g/l of sodium chloride.

To confirm the validity of the procedure studies were made of reproducibility and of accuracy. When 5 different aliquots of the same brine sample were measured, the millivolt values obtained had a standard deviation of ± 0.23 mv. The method of known addition⁵ was used to check the values obtained by the standard curve procedure as detailed above. Two samples of brine yielded values of 1.59 and 3.80 ppm when read off the standard curve and 1.60 and 3.61 ppm by use of the known addition method.

Forty-five samples were taken between May 12, 1982 and February 2, 1983 and analyzed for fluoride. The cumulative brine volumes ranged from 4,000 barrels to 1,928,000 barrels. The values decreased from a value of 7.76 ppm to a value at a plateau of 1.6 to 1.8 ppm fluoride at about 500,000 barrels. The fluoride results are shown in Table 2. Fitting of the raw data to a power curve of the form $y = ax^b$ yielded: Fluoride concentration (ppm) = $11.95 (\text{cumulative brine volume in K Barrels})^{-0.28}$ with a R^2 value of 0.92. It is thus obvious that long term values for fluoride ion in brine may be elevated and in error if insufficient brine volume has flowed to yield a steady state value. The source of the high initial fluoride values is unknown but one possible cause may be the leeching out of fluoride from the concrete used in the well completion.

Acknowledgments

This work was done under a subcontract awarded by The DOW Chemical Company -Department of Energy to the University of Southwestern Louisiana. The technical assistance of Mrs. Rhonda Fotaides is also gratefully acknowledged.

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Table 1

VALUES FOR CALIBRATION CURVES FOR
FLUORIDE IN DIFFERENT ENVIRONMENTS

-log concentration (Molar)	mv Readings		
	H ₂ O	9g/l NaCl	.90g/l NaCl
1	-111.3	-130.3	
2	- 53.2	- 72.3	
3	+ 3.2	- 15	- 63.4
4	+ 58.6	+ 40.3	- 5.6
5	+107.3	+ 89.9	+ 49.8
6	+148.5	+120	+100.1
slope	61.1 mv	54.0 mv	+135
Theoretical:	58.1 mv		54.5 mv

RAW DATA OF F⁻ CONCENTRATION AND
CUMULATIVE BRINE VOLUME FROM
THE DOW-DOE L. R. SWEETZ WELL

Sample Number	Cumulative Brine Volume (K Barrels)	F ⁻ (ppm)	Sample Number	Cumulative Brine Volume (K Barrels)	F ⁻ (ppm)
1 May 12, 1982	4	7.76	24	635	1.78
2	8	7.08	25	701	1.41
3	11	6.31	26	767	2.00
4	15	6.31	27	825	1.12
5	18	6.31	28	868	1.78
6	20	5.62	29	996	1.94
7	23	5.50	30	1060	1.68
8	37	4.79	31	1123	1.96
9	47	4.14	32	1186	1.96
10	58	3.98	33	1248	1.96
11	70	3.63	34	1315	1.97
12	80	3.23	35	1320	1.68
13	135	3.02	36	1360	1.68
14	160	3.02	37	1420	1.78
15	187	2.69	38	1480	1.99
16	216	2.40	39	1585	1.55
17	255	2.24	40	1652	1.58
18	309	2.14	41	1718	1.51
19	329	2.37	42	1783	1.59
20	345	1.78	43	1836	1.58
21	442	1.70	44	1860	1.73
22	507	1.99	45 Feb. 2, 1983	1928	1.70
23	567	1.78			

Appendix B

ANALYSIS OF HIGH IONIC STRENGTH SALT SOLUTIONS FOR AMMONIA AND CARBON DIOXIDE BY MEANS OF GAS SENSING ION SELECTIVE ELECTRODES

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Abstract

In the course of working with geothermal-geopressured brines, we have developed a relatively rapid and simple procedure using ion selective electrodes to determine carbon dioxide and ammonia. The pH of our brines range from 5.8 to 6.3, therefore all the carbon dioxide is present essentially as bicarbonate ion and the ammonia as ammonium ion.

The procedure we have developed works well for solutions of ionic strength below 0.4 and has a linear range which is greater than that cited by Orion³. The use of a reconditioning buffer is the key to reproducibility. Concentration values obtained from the calibration curves were further confirmed by the method of standard addition^{1,2} and by measurements made on spiked samples of brine from which the CO₂ or NH₃ had been removed.

Method Reagents and Apparatus

(A) Ammonia

- (a) 50% Sodium Hydroxide
- (b) Ammonia standard - 1000mg/l as NH₃. 0.7867g ACS analytical reagent grade ammonium chloride was dissolved in water and made up to volume in a 250 ml volumetric flask. (See section on preparation of standards).

- (c) Ion Selective Electrode filling solution - Orion Catalog number 95-10-02
- (d) ACS Analytical grade Sodium Chloride was used to adjust the ionic strength of the standards to match that of the samples.
- (e) Orion Ammonia Ion Selective Electrode (catalog number 95-10, available from Orion Research Inc, 840 Memorial Drive, Cambridge, MA 02139).
- (f) Conditioning Buffer - A 0.1M citrate buffer, pH 4.5, was used to condition the electrode before and between samples.
- (g) Orion Model 901 digital mv/pH meter
- (h) Magnetic Stirrer with a 1.5cm Teflon coated stirring bar. (Use an asbestos pad or foam mat to insulate the sample from motor heat).

(B) Carbon Dioxide

- (a) Acidizing Buffer - A 1M Sodium Citrate, pH 4.5 buffer was used to liberate carbon dioxide. This was used in preference to the commercial acetic acid - acetate buffer of the same pH (Orion 95-02-10) because the instruction manual³ says that acetic acid interferes with the electrode.
- (b) Hydrogen Carbonate Standard - 1000mg/l Dissolve 1.377g of dried ACS analytical grade sodium bicarbonate in water and make up to volume in a 1 l volumetric flask. (See section on preparation of standards)
- (c) Ion Selective Electrode filling solution - Orion Catalog number 95-02-02.
- (d) ACS analytical grade Sodium Chloride - was used to adjust the ionic strength of the standards to match that of the samples.
- (e) Orion Carbon Dioxide Ion Selective Electrode (catalog number 95-02, available from Orion Research Inc, Cambridge, MA 02139).
- (f) Conditioning Buffer - 0.1M Sodium Phosphate, pH = 10
- (g) Orion Model 901 digital mv/pH meter
- (h) Magnetic stirrer with a 1.5cm Teflon coated stirring bar. (Use an asbestos pad or foam mat to insulate the sample from motor heat).

Preparation of Standards and Sample

Our geothermal brine has approximately 10% dissolved solids (mainly sodium chloride at a level approximately 87g/l) with an ionic strength of 1.76. Orion recommends dilution of high ionic strength solutions to below the ionic strength of the internal filling solution (0.4). Because of this we dilute our brines (1 to 10) and matrix match our standards with sodium chloride.

PREPARATION OF STANDARDS FOR CARBON DIOXIDE

Concentration
(mg/l as HCO_3^-)

10
40
100
200
400

Preparation from 100mg/l HCO_3^-

2.5ml + 2.17g NaCl diluted to 250ml
10ml + same as above
25ml + same as above
50ml + same as above
100ml + same as above

PREPARATION OF STANDARDS FOR AMMONIA

Concentration
(mg/l as NH_3)

100
10
1
0.1

Preparation from 1000mg/l NH_3

25ml + 2.17g NaCl diluted to 250ml
25ml of 100mg/l standard + same as above
25ml of 10mg/l standard + same as above
25ml of 1mg/l standard + same as above

PREPARATION OF BRINE

Dilute 5ml of brine to 50ml in a volumetric flask.

Procedure:

(A) CO_2 Electrode

1. Replace the membrane and/or refill the carbon dioxide electrode as needed.

2. Suspend electrode at a slight angle in about 50 ml of conditioning buffer, (Phosphate solution) and allow electrode to condition until meter reads - 135 mV. (It takes about 8-10 min. to recover).
3. Rinse electrode with deionized water.
4. Suspend electrode at a slight angle in exactly 50 ml of standard or sample, add 5 ml of acidifying buffer (pH = 4.5), stir and read lowest stable mV value. (About 1 to 1½ min. from of acidifying buffer).
5. Rinse electrode with deionized water, and proceed as in step 2 followed by next standard or sample.

(B) Ammonia

The procedure above works for the ammonia electrode, too.

1. Replace the membrane and (or refill the ammonia electrode as needed.
2. Suspend the electrode at slight angle in about 50 ml of conditioning buffer (citrate solution) and allow electrode to condition until meter reads about +140 mv.
3. Rinse electrode with deionized water.
4. Suspend electrode at a slight angle in 50 ml of sample, add 0.5 ml of 50% NaOH stir and read the lowest stable value. (about 2 to 4 minutes)
5. Rinse electrode with deionized water and proceed as in step 2 followed by next standard and/or sample

Calculations

1. Plot the mV readings for the standards versus the log of the concentration of carbon dioxide (as bicarbonate) or ammonia

ie	mg/l bicarbonate	log concentration	mg/l ammonia	log concentration
	10	1.0	0.1	-1
	40	1.60	1	0
	100	2.00	10	1
	200	2.30	100	2
	400	2.60	1000	3

2. Read the log concentration of gas from the graph which corresponds to the millivolt value of the unknown.
3. Convert to concentration and multiply x 10 to get the value in the original brine.

Results

Both electrodes consist of a pH electrode surrounded by an internal filling solution and separated from the external solution by a membrane. Addition of acid (in the case of CO_2) or base (in the case of NH_3) release the gas which migrates across the membrane to the filling solution. This causes a change in pH which is proportional to the gas concentration.

It is important to control several factors: First, the rate of delivery of the releasing agent and the speed of the stirrer should be kept constant. The filling solution should be reasonably fresh. The first few runs on a new filling solution will not be reproducible but after a few runs reproducible values can be obtained. The electrode design of the Orion electrode limits precision to about $\pm 5\%$.

It was found that one of the problems with previous procedures was that the electrode was not restored to its initial condition between samples and this left residual gas in the internal filling solution thus leading to inaccurate unreproducible values and nonlinear calibration curves. The use of a conditioning buffer was found to alleviate this problem. See Figure 1 for plots of mv versus time for both sample and reconditioning curves. These curves are representative of the response of these systems. It is also worthy of note that the use of a reconditioning buffer enabled us to extend the lower limit of linearity of the ammonia electrode.

Typical values for calibration curves are shown in Table 1. Studies were carried out to determine the precision and accuracy of this method. The first check was to use known addition^{1,2} and to compare the result to that obtained by the standard curve method.

Values obtained for HCO_3^- were 490 mg/L by the standard curve 471 mg/L by the known addition technique, and for ammonia were, 59.5 mg/L by the standard curve and 60.4 by the known addition technique. Samples of brine were spiked with bicarbonate and ammonia and then analyzed. For ammonia, the value obtained was 176.9 ± 3 mg/L (6 samples) for a 175.9 mg/L standard and for carbon dioxide, the value obtained was 1014 ± 49.3 mg/L (10 samples) for a 1000 mg/L standard. These results indicate fine accuracy with a precision $\pm 5\%$. Typical values for our geothermal geopressured brines were 40-50 mg/L ammonia and 470-500 mg/L HCO_3^- .

Acknowledgments

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3. Orion Research Instruction Manual for the Carbon Dioxide Electrode Model 95-02.

Table 1

TYPICAL MILLIVOLT VALUES FOR STANDARDS

<u>log concentration of Ammonia (mg/L)</u>	<u>mv</u>
3	-134.2
2	- 77.4
1	- 19.5
0	+ 36.3
-1	+ 84.4

slope = 56.8 mv

<u>log concentration of Carbon Dioxide (mg/L)</u>	<u>mv</u>
1.0	- 84.3
1.6	- 61.9
2.0	- 44.9
2.30	- 30.7
2.60	- 17.4

slope = 42.6 mv

Figure 1: Curves of the Responses of Gas Sensing Ion Selective Electrodes

- (A) Sample Response Curve of the Ammonia Electrode,**
- (B) Regeneration Curve of the Ammonia Electrode After Immersion in Conditioning Buffer,**
- (C) Sample Response Curve of the Carbon Dioxide Electrode and**
- (D) Regeneration Curve of the Carbon Dioxide Electrode After Immersion in Conditioning Buffer**