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DOE/ET/27081-8 Vol. I

GEOPRESSURED - GEOTHERMAL PROGRAM

MASTER

DOE/ET/27081--8 Vol. 1

DE82 007756

FINAL REPORT
CROWN ZELLERBACH WELL NO. 2
LIVINGSTON PARISH, LOUISIANA

VOLUME I
COMPLETION AND TESTING

TESTING GEOPRESSURED GEOTHERMAL RESERVOIRS IN EXISTING WELLS

PREPARED FOR
U.S. DEPARTMENT OF ENERGY
NEVADA OPERATIONS OFFICE
UNDER CONTRACT NO. DE-AC08-80ET27081

EATON OPERATING COMPANY, INC.
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HOUSTON, TEXAS 77027
713-627-9764

DISCLAIMER

FINAL REPORT

CROWN ZELLERBACH WELL NO. 2

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VOLUME II

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1.0 EXECUTIVE SUMMARY

The Crown Zellerbach Well No. 2, approximately 23 miles east of Baton Rouge, Louisiana, is the eighth successful test of a geopressured-geothermal aquifer under the DOE Wells of Opportunity program. Eaton Operating Company, Inc. assumed control of the site on February 20, 1981 after Martin Exploration Company had abandoned the well as a dry hole at a depth of 17,000 feet.

The well was tested through the annulus between 7-inch casing and 2-3/8 inch tubing. Two intervals of the Tuscaloosa Trend were tested. The lower zone was perforated from 16,720 to 16,750 feet and was tested separately. The upper zone, from 16,462 to 16,490 feet, was later perforated and tested together with the lower zone. Produced water was injected into the Crown Zellerbach Well No. 1, which was also a dry hole acquired from Martin Exploration Company and converted into a disposal well. The disposal well was perforated in a Miocene sand from 4833 to 4908 feet.

Two flow tests and one reservoir pressure buildup test were conducted on the lower zone during a 13-day period. A total of 12,489 barrels of water was produced. The highest flow rate achieved was about 3887 BWPD.

One flow test followed by a buildup period was conducted on the combined upper and lower zones during a 3-day period. A total of 4739 barrels of water was produced. The highest flow rate achieved was about 3000 BWPD.

The gas/water ratio measured during testing was about 32.0 SCF/BBL for the lower zone. The extrapolated laboratory data indicates that the solubility of the gas is 55.7 SCF/BBL. It appears that the reservoir brine is considerably undersaturated.

Chemical and physical differences between the produced fluids of the lower zone and the combined zones were slight.

The methane content of the flare line gas averaged 71.0 mole percent. The methane content is the lowest measured to date when compared to previous WOO tests. The CO_2 content averaged 23.5 mole percent, which is the highest to date relative to previous WOO tests. Liquid hydrocarbon production is estimated to have been in the range of 2 to 5 barrels of oil per 10,000 barrels of water and was much higher relative to brine production than on any prior WOO test with the exception of the G.M. Koelemay Well No. 1.

The original bottom-hole pressure of the lower zone was 10,114 psia, with a corresponding static surface pressure of 2900 psia. The reservoir temperature was 330°F. The highest surface temperature observed during flow was 201°F. The lower zone appeared to be a relatively tight sand with increasing sand thickness further from the wellbore. The permeability to reservoir fluids is approximately 14.1 millidarcies. Surface pressure drawdown data on the combined upper and lower zones indicates a surprisingly higher productivity of 2218 millidarcy-feet as compared to a productivity of 495 millidarcy-feet for the bottom zone alone. This conclusion cannot be supported by other physical or chemical data. In either case, the reservoirs were not capable of the high sustained production rates needed for commercial considerations. Crown Zellerbach Company carefully studied the commercial feasibility of using the well to produce energy for a wood-drying facility and decided against the project.

The total dissolved solids in the produced brine averaged 31,700 mg/l for the lower zone. Scaling and corrosion of the surface equipment were so light that no conclusion can be made concerning long-term chemical treatment requirements.

The lower zone produced solids at the rate of 20 to 190 pounds per 1000 barrels. The produced solids were predominately sand which accumulated in the separator. When the upper and lower zones were tested, solids production was very low. The reason for this is not clear.

Concentration of boron averaged 48 milligrams per liter. This concentration is extremely toxic to plant life. Long-term surface disposal of untreated brine would be precluded because of the boron content. The mercury content was less than 0.2 micrograms per liter and would probably not be a hazard to the environment during long-term surface disposal.

A two-page summary of test data follows on pages 1-3 and 1-4.

SUMMARY OF TEST RESULTS

CROWN ZELLERBACH WELL NO. 2

LIVINGSTON PARISH, LOUISIANA

(Lower Zone)

WELL DATA:

Total Depth of Well	17,000 Feet
Formation	Upper Cretaceous, Tuscaloosa Trend
Gross Sand Interval	36 Feet
Net Sand	35 Feet
Perforations	16,720-16,750 (8 HPF)
Original Reservoir Pressure	10,114 Psia
Original Reservoir Temperature	330°F
Original Shut-In Surface Pressure	2900 Psia
Average Porosity	17% (Density/Neutron Log)
Average Permeability	(No sidewall cores)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	31,700 mg/l
Chlorides	18,300 mg/l
pH	5.6

ANALYSIS OF FLARE LINE GAS:

Methane	71.0	Mole Percent
Carbon Dioxide	23.5	Mole Percent
Heavier Hydrocarbons	5.0	Mole Percent
Other	0.5	Mole Percent
Heating Value	823	BTU/SCF
H_2S in Gas	12-56	ppm

TESTS (From 6-5-81 to 6-17-81):

Test No. 1	A 4.55 day reservoir drawdown test producing 10,109 barrels of water followed by a 1.64 day reservoir buildup test.
Test No. 2	A 0.88 day flow test producing 2380 barrels of water.
Produced Dry Gas-to-Saltwater Ratio	32.0 SCF/STB
Total Water Produced While Testing	12,489 Barrels
Highest Flow Rate Achieved	3887 BWPD
Highest Surface Temperature Observed	201°F
Solids Production	High; at least 20 to 190 lb/1000 barrels
Corrosion	Very light, not measurable
Scaling	Very light, not measurable
Lowest Flowing Surface Pressure Observed	449 psia
Lowest Flowing Bottom-hole Pressure Measured	7378 Psia (extrapolated to perforations)
Test Well Productivity Index	2.09 barrels per day per psi
Maximum Explored Volume of Reservoir Water	16.4 million barrels
Maximum Distance Explored (BHP Instrument)	2971 Feet
Reservoir	Relatively tight with increasing sand thickness. At least 1 permeability barrier about 197 feet from the wellbore. Permeability to reservoir fluids is 14.1 millidarcies.
Disposal Well Gross Perforations	4833-4908 Feet (4 HPF)
Disposal System Pressure Range	40 to 175 psi

SUMMARY OF TEST RESULTS

CROWN ZELLERBACH WELL NO. 2

LIVINGSTON PARISH, LOUISIANA

(Lower and Upper Zones)

WELL DATA:

Total Depth of Well	17,000 Feet
Formation	Upper Cretaceous, Tuscaloosa Trend
Gross Sand Interval	64 Feet (36 + 28)
Net Sand	58 Feet (35 + 23)
Perforations	16,720-16,750 (8 HPF) and 16,462-16,490 (4 HPF)
Original Reservoir Pressure	10,007 Psia (estimated)
Original Reservoir Temperature	330° to 324°F
Original Shut-In Surface Pressure	2389 Psia
Average Porosity	17 and 13.7% (Density/Neutron Log)
Average Permeability	(No sidewall cores)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	29,900 mg/l
Chlorides	17,600 mg/l
pH	5.6

ANALYSIS OF FLARE LINE GAS:

Methane	70.0	Mole Percent
Carbon Dioxide	24.6	Mole Percent
Heavier Hydrocarbons	4.9	Mole Percent
Other	0.5	Mole Percent
Heating Value	813	BTU/SCF
H_2S in Gas	60	ppm

TESTS (From 6-23-81 to 6-25-81):

Test No. 1	A 2.36 day flow test producing 4,739 barrels of water. Followed by a 3.01 day pressure buildup period. (This is described as the third flow test in the text.)
Produced Dry Gas-to-Saltwater Ratio	33.0 SCF/STB
Total Water Produced While Testing	4739 Barrels
Highest Flow Rate Achieved	3000 BWPD
Highest Surface Temperature Observed	197°F
Solids Production	Low; about 7 to 23 lb/1000 barrels
Corrosion	Very light, not measurable
Scaling	Very light, not measurable
Lowest Flowing Surface Pressure Observed	280 psia
Lowest Flowing Bottom-hole Pressure Measured	Not applicable
Test Well Productivity Index	Not applicable
Maximum Explored Volume of Reservoir Water	42.8 million barrels
Maximum Distance Explored (BHP Instrument)	Not applicable
Reservoir	Surface pressure drawdown data apparently indicates a much higher productivity of 2218 md-ft as compared to a productivity of 495 md-ft for the bottom zone alone.
Disposal Well Gross Perforations	4833-4908 Feet (4 HPF)
Disposal Well Pressure Range	Produced to reserve pit

2.0 INTRODUCTION AND BACKGROUND

2.1 Events Leading to Project Initiation

This report covers the acquisition, completion, and testing of a geopressured-geothermal (GEO^2) well and reservoir by Eaton Operating Company, Inc., under contract with the United States Department of Energy, Division of Geothermal Energy (DOE-DGE). The work performed by Eaton is a continuation of the Wells of Opportunity (WOO) program. This program was initiated in 1977 to take advantage of the low cost of oil and gas wells previously drilled by industry to obtain short-term test data on the energy producing potential of underground aquifers. Geopressured-geothermal resources could make an important contribution to our nation's energy supply if it should become commercially feasible to produce saltwater reservoirs and to extract the dissolved hydrocarbons, heat, and kinetic energy.

The Crown Zellerbach Well No. 2, acquired for this particular test, was drilled by Martin Exploration Company at a cost of approximately $3,000,000. The well was temporarily abandoned as a dry hole at a depth of 17,000 feet and was offered to Eaton for GEO^2 testing. Contracts with Martin and Crown Zellerbach Corporation were finalized on January 16, 1981, and February 20, 1981, respectively, and field operations were initiated on April 17, 1981.

2.2 Location and Geography

The Crown Zellerbach Well No. 2 test site is located approximately 23 miles east of Baton Rouge, Louisiana and about 3 miles north of Interstate 12 near the town of Livingston, Louisiana. Baton Rouge is the capital of Louisiana and the center of the petrochemical industry along the Mississippi River. Livingston is a small town and the county seat of Livingston Parish. The principal industry in the Livingston area is the cutting and processing of pine timber by Crown Zellerbach Corporation.

Interstate 12 is a major interstate highway connecting Baton Rouge with other southeastern Louisiana towns and cities. The specific well location is 2530 feet from the south line and 500 feet from the east line of Section 19, Township 6 South, Range 5 East in Livingston Parish, Louisiana. The terrain is flat and about 45 feet above sea level. The land is covered with a thick forest of pine trees and some hardwood trees.

Exhibit 2-1 indicates the location of the Crown Zellerbach Well No. 2 in relation to other GEO^2 wells in Louisiana. Exhibit 2-2 is a topographic map of the area.

2.3 Operator Contracts and Agreements

Martin Exploration Company is the operator of the test well. Drilling of the test well was completed on May 31, 1980. Martin agreed to temporarily plug the well so that Eaton could move in a rig and complete the well for a GEO^2 test. Eaton's legal agreement with Martin can be found in Appendix "A."

2.4 Rig Contractor Agreements

Wilson Brothers Drilling Company was awarded the contract to complete the test well, and WellTech, Inc. was awarded the contract to complete the disposal well, Crown Zellerbach Well No. 1. Wilson Brothers Rig No. 8 and WellTech Rig No. 31 performed the completions. WellTech was later awarded another contract to workover the test well. WellTech Rig No. 8 performed the work. The rig descriptions and the drilling contracts can be found in Appendix "B."

WellTech Rig No. 168 was contracted to perform the plug and abandonment operations on the test well. This contract can also be found in Appendix "B."

DOE CONTRACT NO.
DE-AC08-80ET-27081

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
3104 Edloe, Houston, Texas 77027

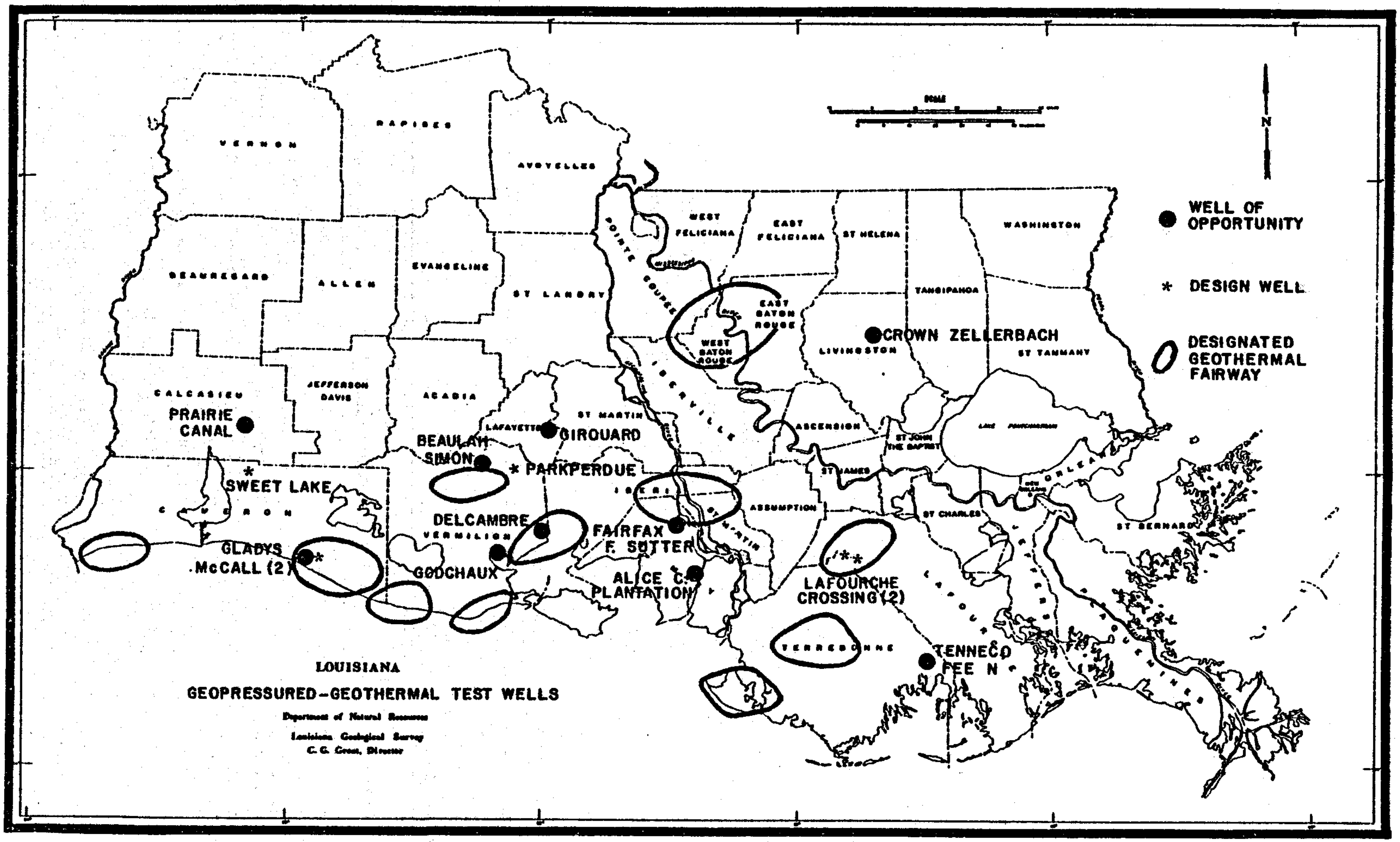
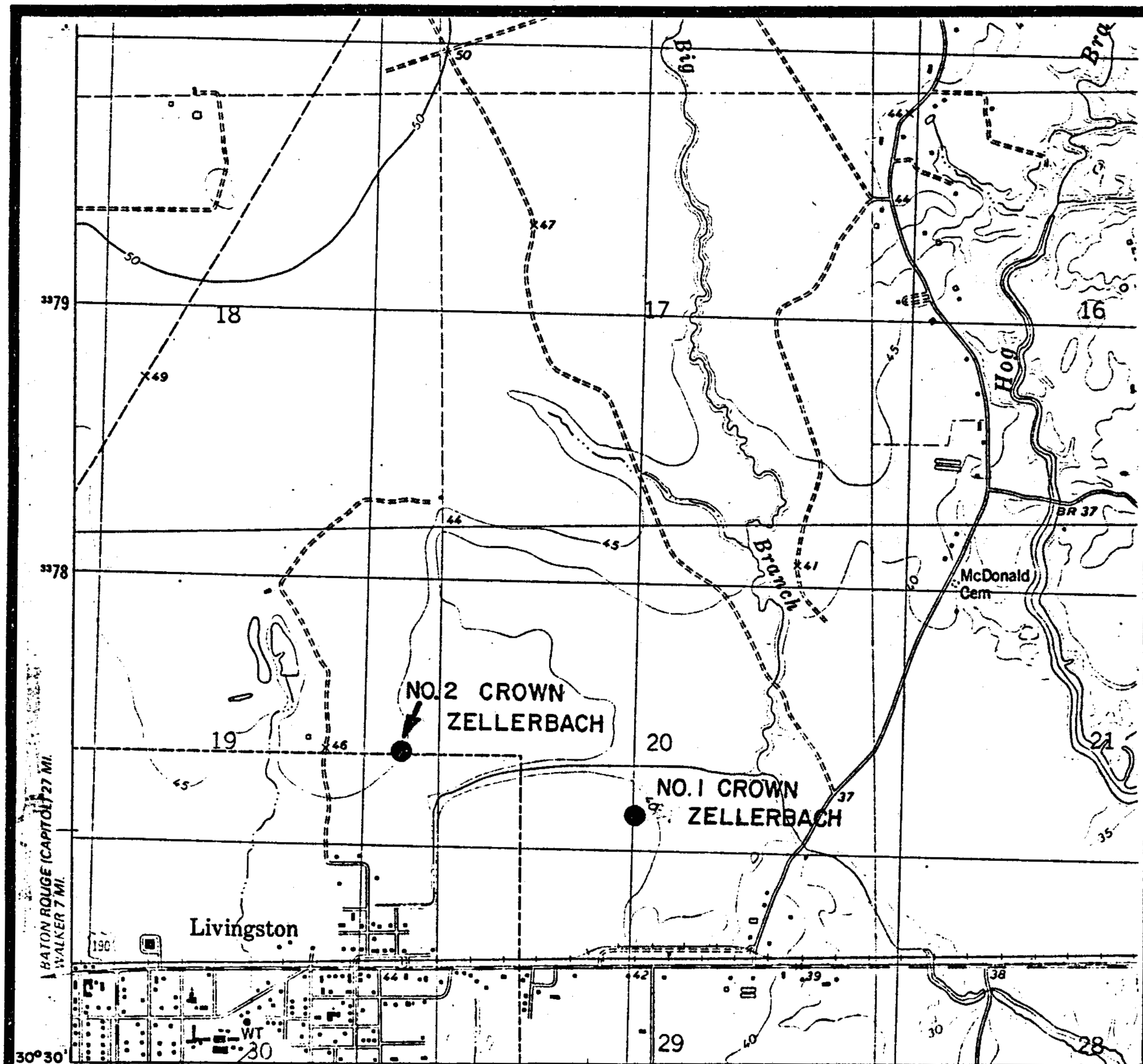


EXHIBIT 2-1



90°45' 63 FROST 7 MI 717 2 190 000 FEET 719 42

Mapped, edited, and published by the Geological Survey

TOPOGRAPHIC MAP

HOLDEN, LA.
SW/4 AMITE 15' QUADRANGLE
N3030—W9037.5/7.5

1974

AMS 7845 II SW—SERIES V885

ROAD CLASSIFICATION

Primary highway, hard surface

Light-duty road, hard or improved surface

Secondary highway, hard surface

Unimproved road

Interstate Route U. S. Route State Route

SCALE 1:24 000

1 ½ 0 1 MILE

1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

1 .5 0 1 KILOMETER

CONTOUR INTERVAL 5 FEET
NATIONAL GEODETIC VERTICAL DATUM OF 1929

Eaton Industries of Houston, Inc. **EXHIBIT 2-2**
Eaton Operating Co., Inc.

3.0 OBJECTIVES

The "Wells of Opportunity" program was designed to obtain short-term test data from several geopressured-geothermal aquifers in different geologic environments along the Gulf Coast region of Louisiana and Texas.

The task requires the capability to drill, complete, and test wells, the ability to interpret data, knowledge of the regional geology, communication and coordination with oil and gas operators, and a scouting system capable of locating potential GEO^2 wells.

The objectives of the WOO test program in general, and of the Crown Zellerbach Well No. 2 test in particular, were to obtain accurate, reliable, short-term information concerning the following:

- The characteristics of geopressured-geothermal reservoirs, including permeability and porosity, extent and distribution of sands and shales, degree of compaction, and rock composition.
- The aquifer fluid properties, including in-situ temperature, chemical composition, hydrocarbon content, and pressure.
- The behavior of fluid and reservoir under conditions of fluid production at moderate and high rates, including pressure/time behavior at different flow rates, fluid characteristics under varying production conditions, and other information related to the reservoir production drive mechanisms and physical and chemical changes that may occur with various production conditions.
- The evaluation of completion techniques and production strategies for geopressured-geothermal wells.
- Analysis of the long-term environmental effects of an extensive commercial application of geopressured-geothermal energy, to the extent determinable during testing.

4.0 GEOLOGY

4.1 Regional Setting

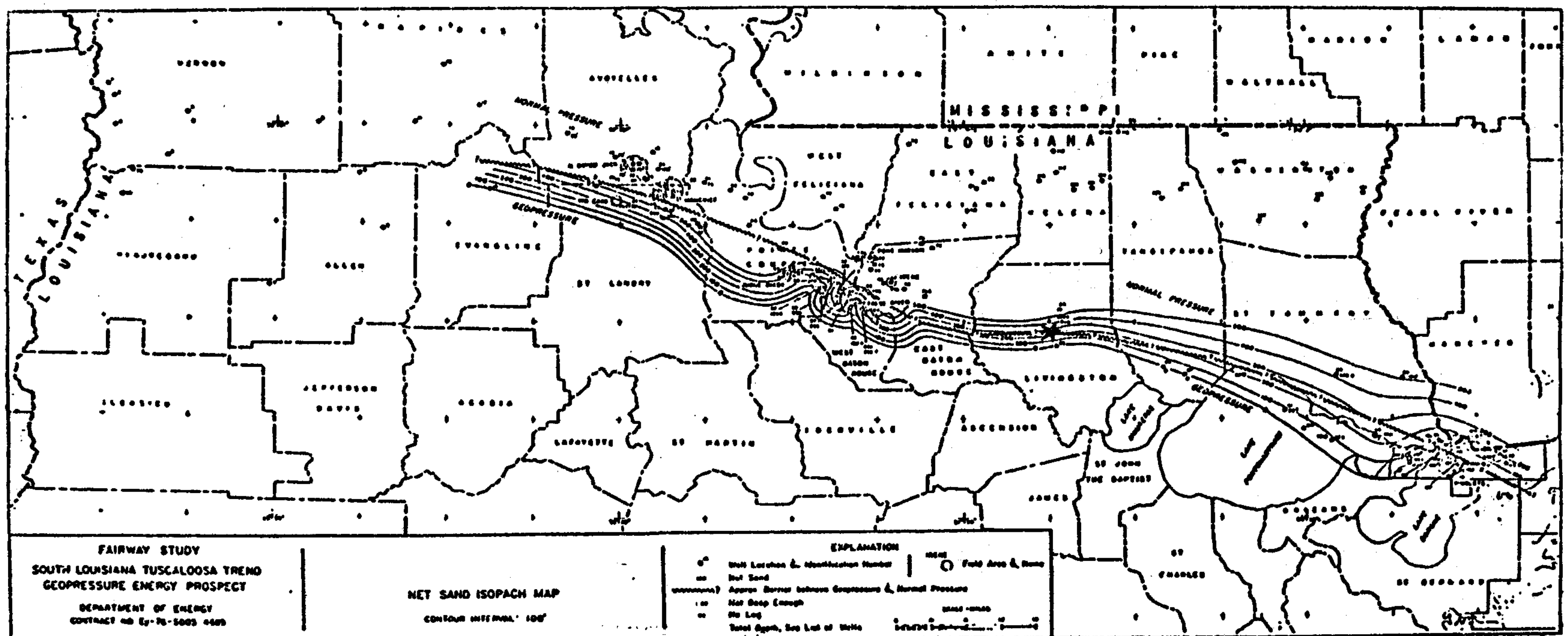
The Crown Zellerbach No. 2 geopressured-geothermal well was completed in a Tuscaloosa sand on the outskirts of Livingston in Livingston Parish, Louisiana. The tested reservoir is in the lower Tuscaloosa Trend of Upper Cretaceous Age. The lower Tuscaloosa is composed of alternating sands and shales, extending across Louisiana from St. Tammany Parish on the east to Beauregard Parish on the west. It varies from 2 to 12 miles in width. A net isopach map of a portion of the trend, which has been published by Zaki Bassiouni of the Louisiana State University Petroleum Engineering Department is shown in Exhibit 4-1 (Ref. 1).

Lower Tuscaloosa sediments were deposited in shallow water environments ranging from Fluvial to shallow marine. Paleontologic data indicated that water depths were less than 60 feet at the time of deposition, and that these sediments were deposited in high-constructive deltaic systems (Ref. 2).

The Tuscaloosa sediments are found below a depth of 16,000 feet, where temperatures approach 400°F and pressure gradients vary from 0.459 psi/ft to 0.96 psi/ft. Production tests have shown the presence of CO_2 and H_2S and have shown water salinity varying from 11,500 to 120,000 ppm NaCl. These salinity variations appear to occur both laterally and vertically (Ref. 37).

4.2 Local Geology

The Satsuma area, in which the test well was drilled, is situated down dip to the Edwards Reef Complex where the Tuscaloosa sands have a maximum development. A detailed seismic study was conducted in the Satsuma area. Since this area has very poor well control, the structure map (Exhibit 4-2) and the two cross-sections (Exhibits 4-3 and 4-4) are based primarily on the data from this seismic study. As indicated by these figures, the test well is located on an anticlinal fold between two down-to-the-coast growth faults. The throws are approximately 900 feet and 450 feet for the northernmost and southernmost faults, respectively. The two Tuscaloosa sands occur at a depth of 16,718-16,754 feet (Sand A) and 16,462 to 16,490 feet (Sand B). The maximum individual sand thickness ranges up to 36 feet (Exhibit 4-5).



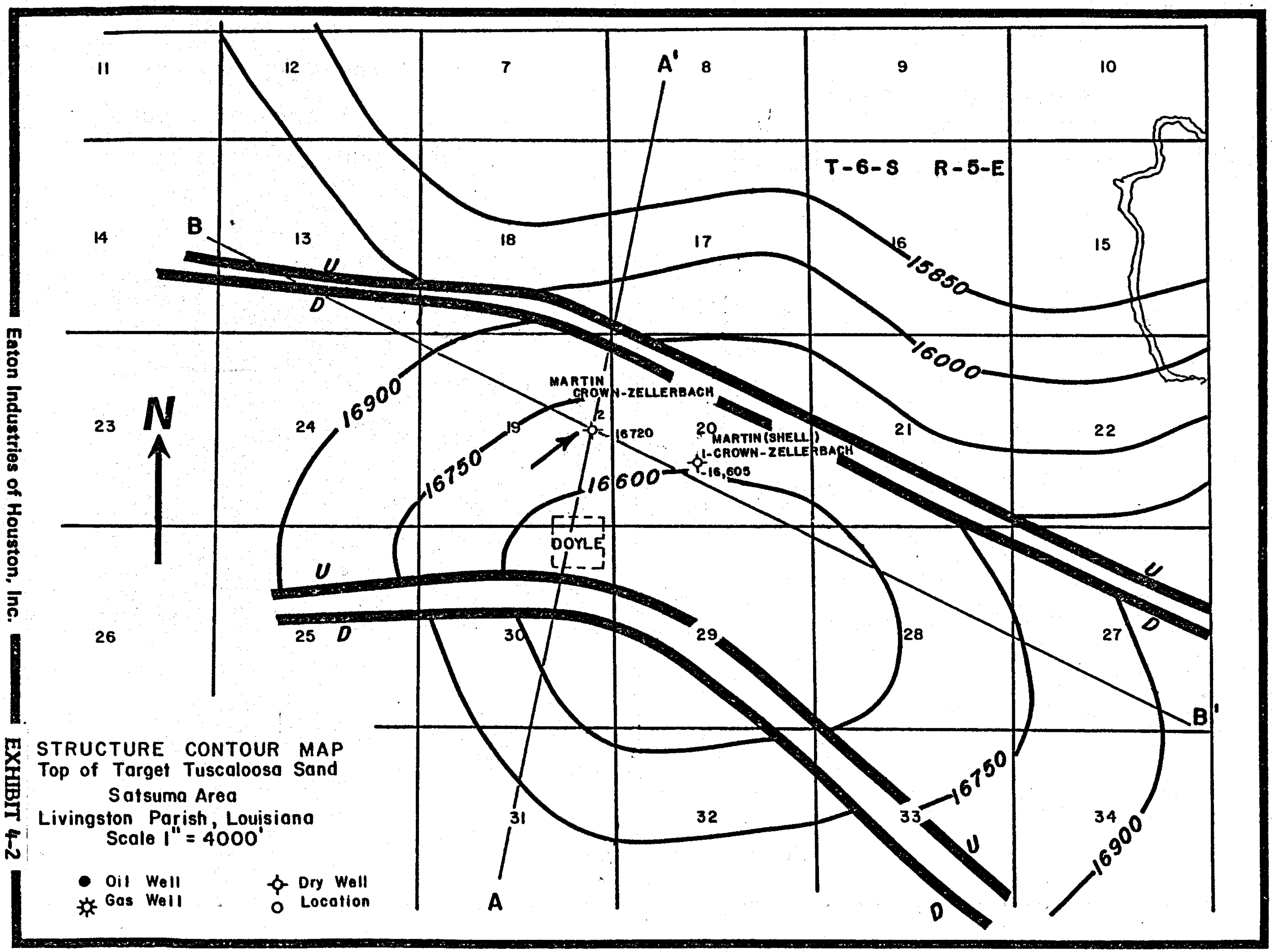
AFTER BASSIOUNI, 1979

NET SAND ISOPACH MAP
GEOPRESSURED TUSCALOOSA TREND

EXHIBIT 4-1

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

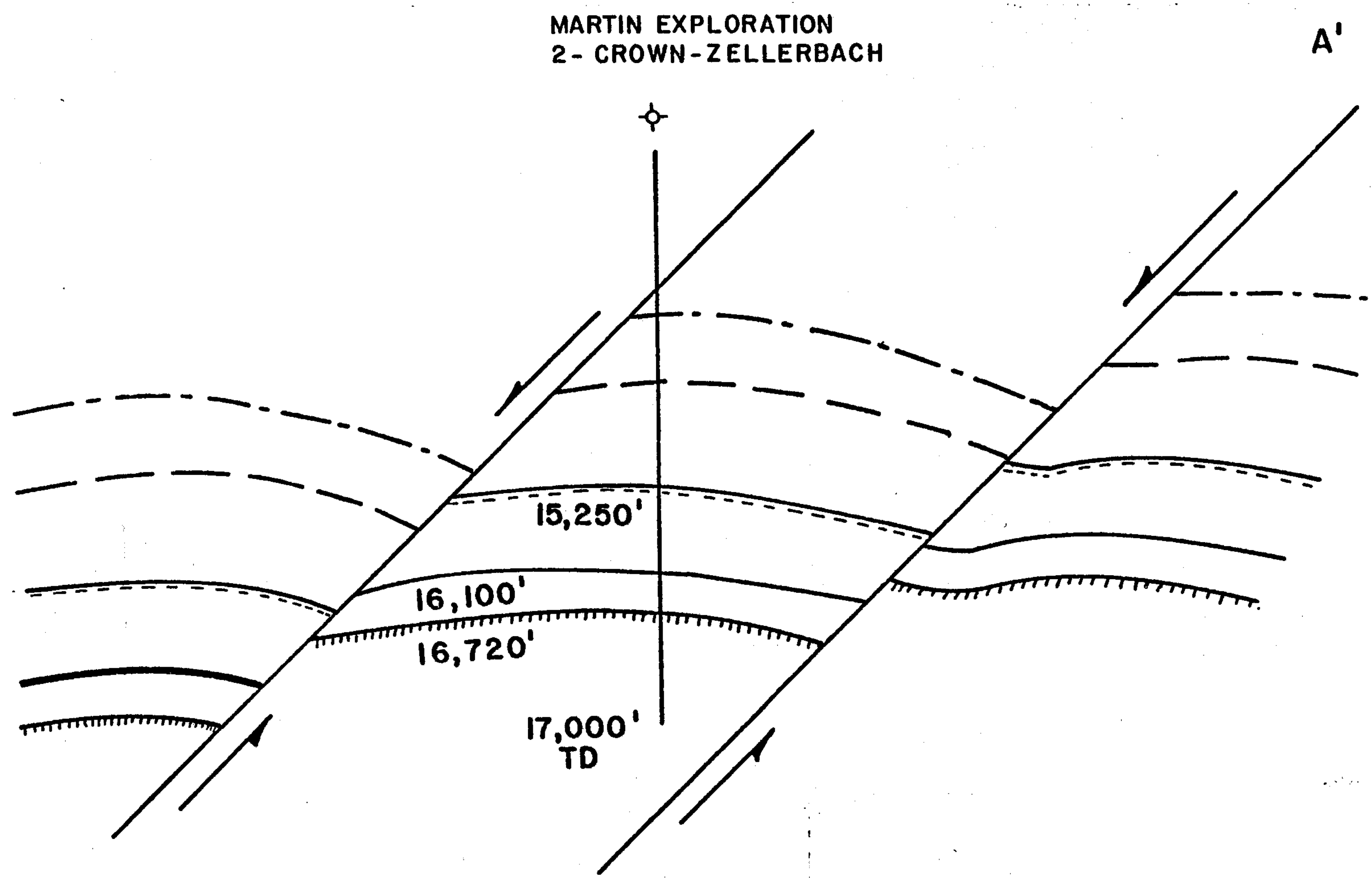
DOE CONTRACT NO.
DE-AC08-80ET-27081



STRUCTURE CONTOUR MAP
Top of Target Tuscaloosa Sand
Satsuma Area
Livingston Parish, Louisiana
Scale 1" = 4000'

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 4-2



BASE OF AUSTIN CHALK

TOP OF TUSCALOOA

MAP DATUM 'A' SAND (16,720')

FAULT; DIP & THROW

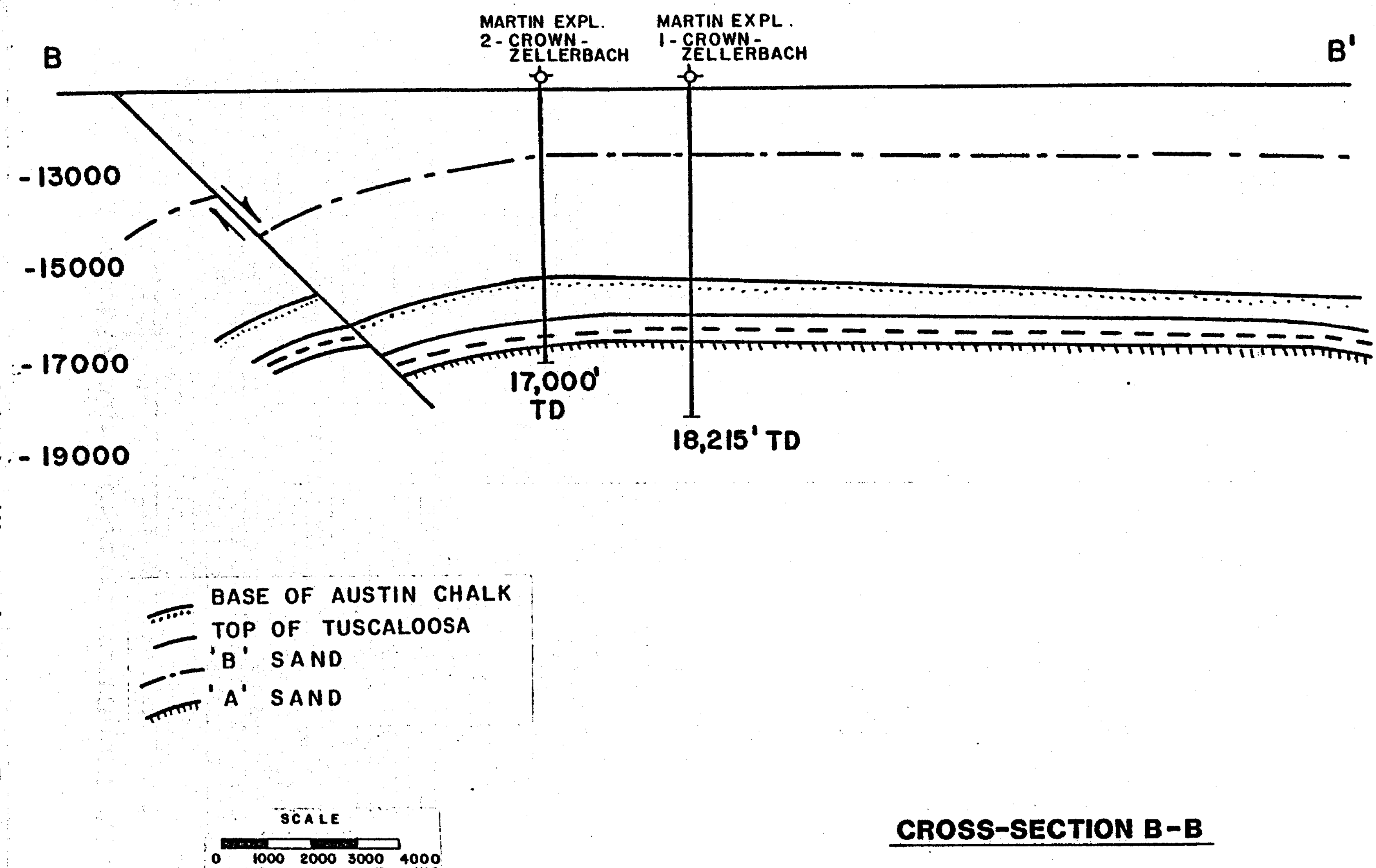
GENERALIZED CROSS-SECTION A-A'

SATSUMA AREA
LIVINGSTON PARISH LA.

HORIZONTAL & VERTICAL SCALE 1" = 2000'

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 4-3

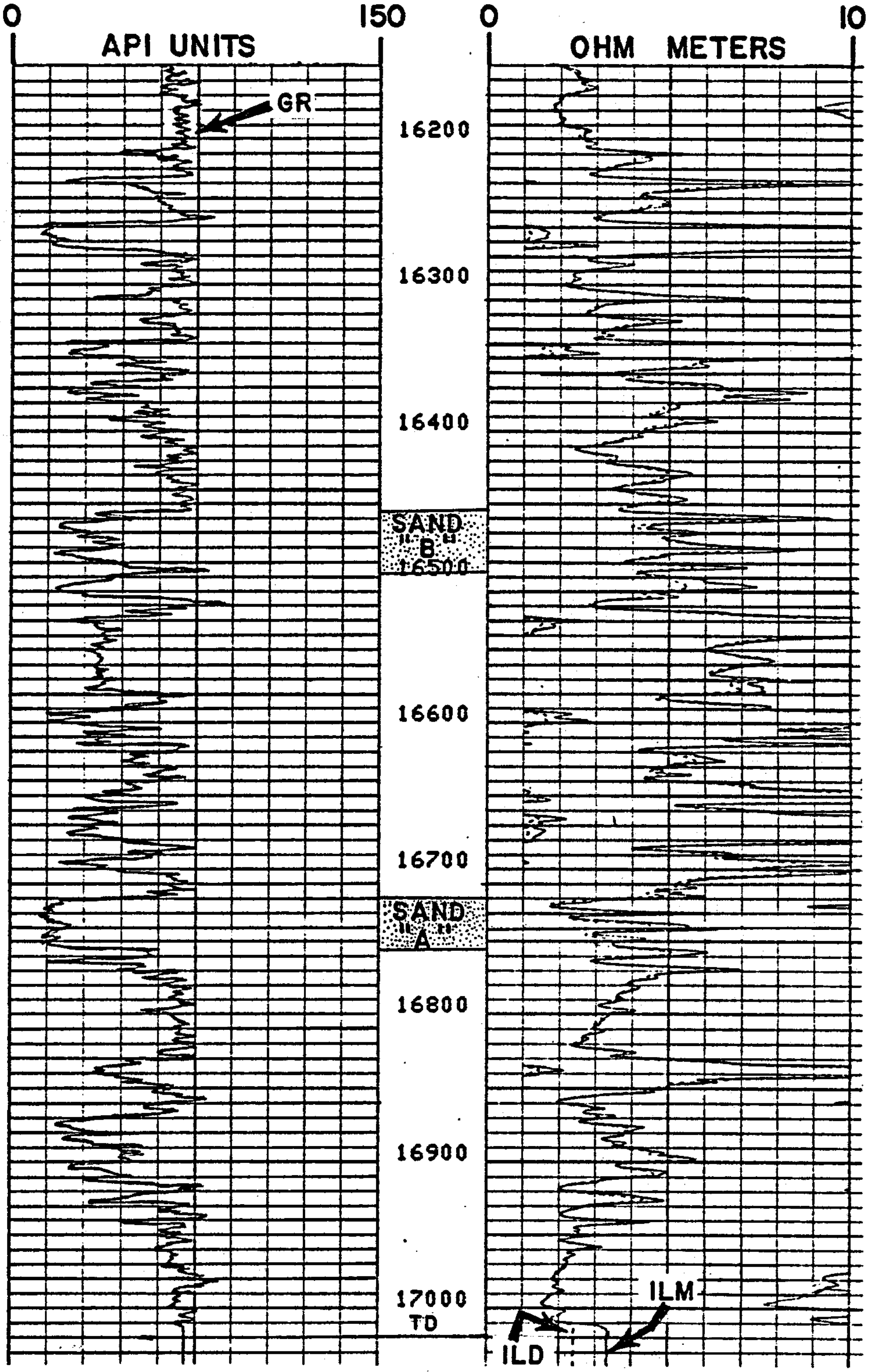


CROSS-SECTION B-B

SATSUMA AREA
LIVINGSTON PARISH, LA

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 4-4



DUAL INDUCTION/BOREHOLE COMPENSATED SONIC LOG
CROWN ZELLERBACH NO. 2 UPPER TUSCALOOSA

Eaton Industries of Houston, Inc. EXHIBIT 4-5
Eaton Operating Co., Inc.

DOE CONTRACT NO.
DE-AC08-80ET-27081

5.0 PETROPHYSICS

5.1 Open Hole Log Analysis - Test Well (Sand "A" and Sand "B")

During the drilling stages of the Crown Zellerbach Well No. 2, various downhole surveys were conducted for hydrocarbon evaluation. Upon the determination of a dry hole, the logs were made available to Eaton for use in reservoir evaluation for the Wells of Opportunity program of the Department of Energy. The following logs were used in this evaluation:

- Dual Induction Borehole Compensated Sonic Log, 1 inch. (Exhibit 4-6).
- Dual Induction Borehole Compensated Sonic Log, 5 inch. (Exhibits 5-1 & 5-4).
- Compensated Neutron-Formation Density, 5 inch. (Exhibits 5-2 & 5-5).

These logs contain information from which the following formation measurements could be determined:

- Gamma Ray
- Induction
- Neutron/Density Porosity
- Sonic Time Travel

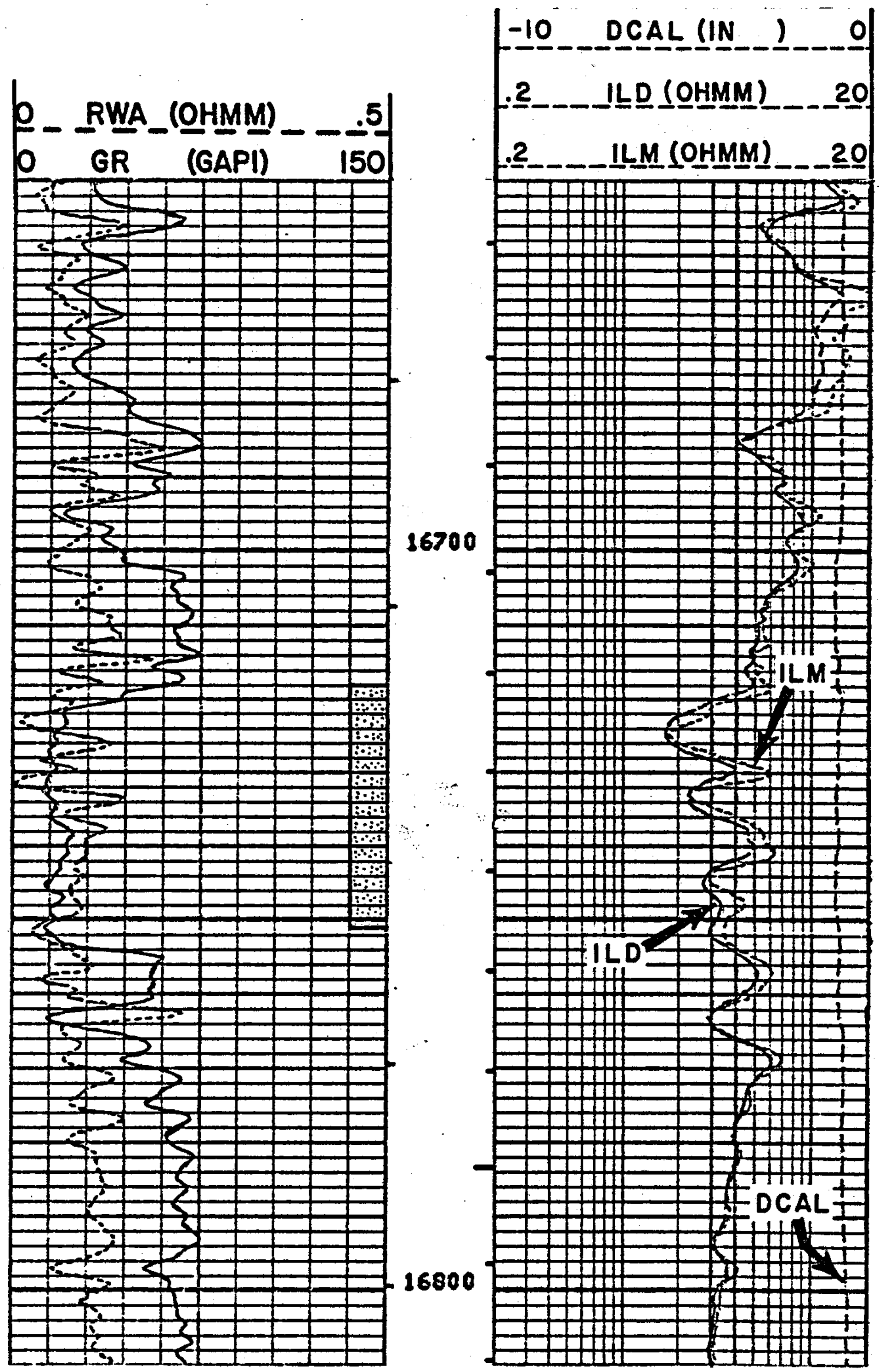
5.1.1 Porosity (Sand "A")

The average porosity of the net sand interval is 17% based upon analysis of the Neutron/Density log. The porosities in this interval ranged from 9% to 27% (Exhibit 5-2).

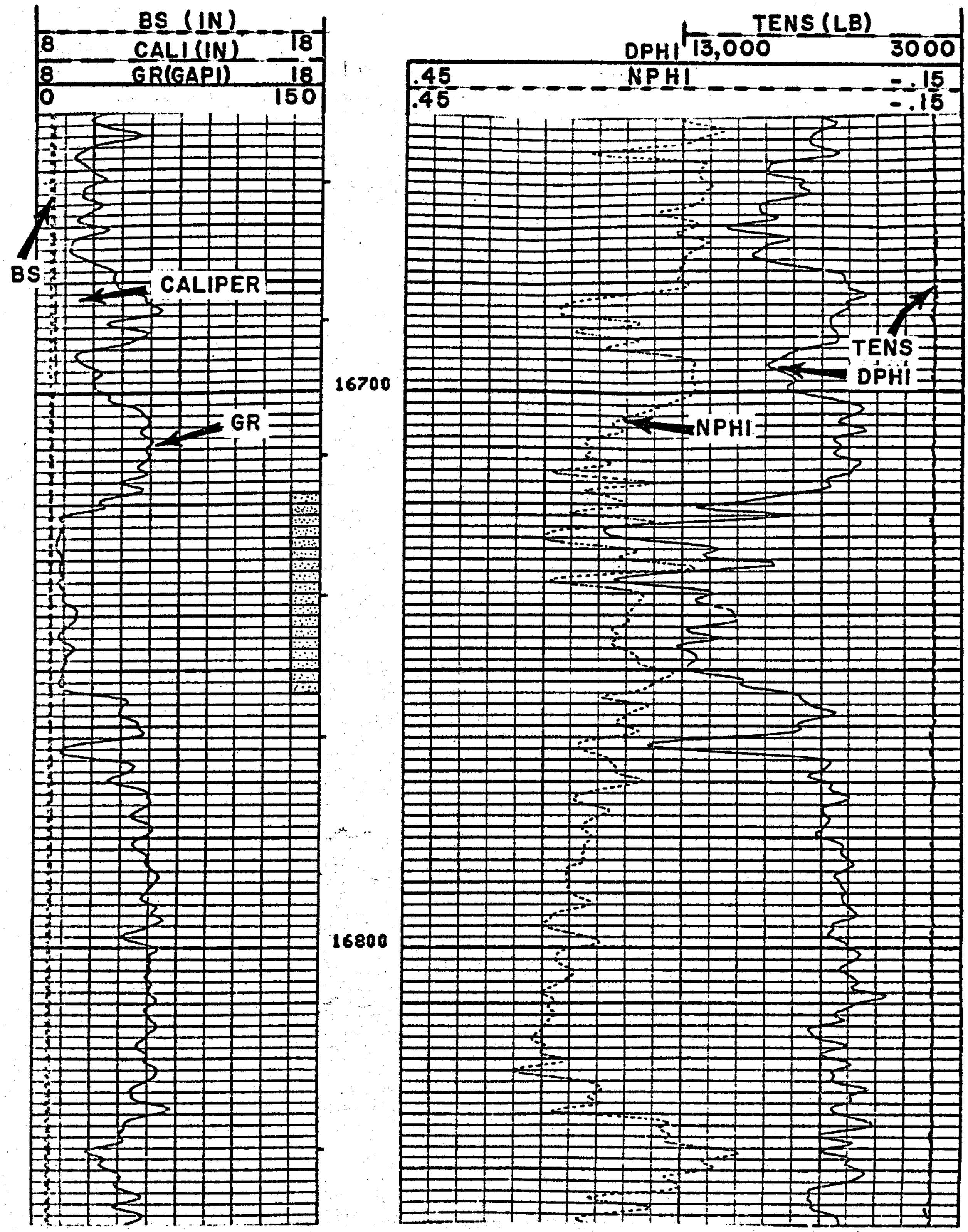
After considerable discussion with a representative of Schlumberger, it was determined that there were indications that the Compensated Neutron-Formation Density Log was inaccurate because of the heavy mud weight used. Therefore, the porosity appears to be 3-5% lower on the log than it actually is. To correct this error, a 4% correction factor was added to the apparent porosities.

5.1.2 Sand Thickness (Sand "A")

The gross sand thickness over the geopressured-geothermal reservoir interval of 16,718 to 16,754 feet is 36 feet (Exhibit 5-1). The total net sand thickness is 35 feet, based upon analysis of the Neutron/Density Log. A porosity cutoff of 9% was applied in the determination of the net sand (Exhibit 5-2).



DUAL INDUCTION BOREHOLE COMPENSATED SONIC LOG
SAND "A", CROWN ZELLERBACH NO. 2



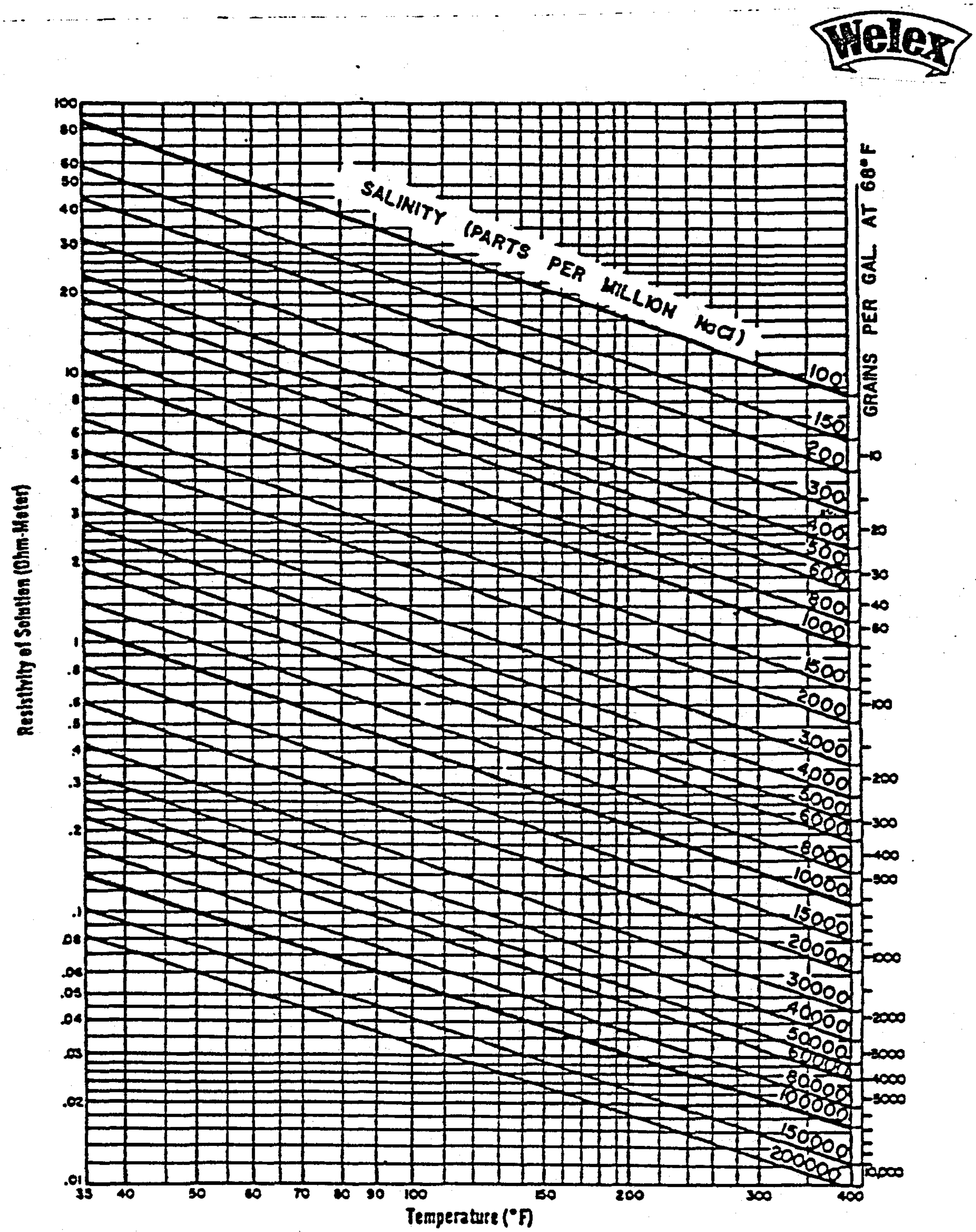
COMPENSATED NEUTRON-FORMATION DENSITY LOG

SAND "A", CROWN ZELLERBACH NO. 2

Eaton Industries of Houston, Inc. **EXHIBIT 5-2**

Eaton Operating Co., Inc.

DOE CONTRACT NO.
DE-AC08-80ET-27081



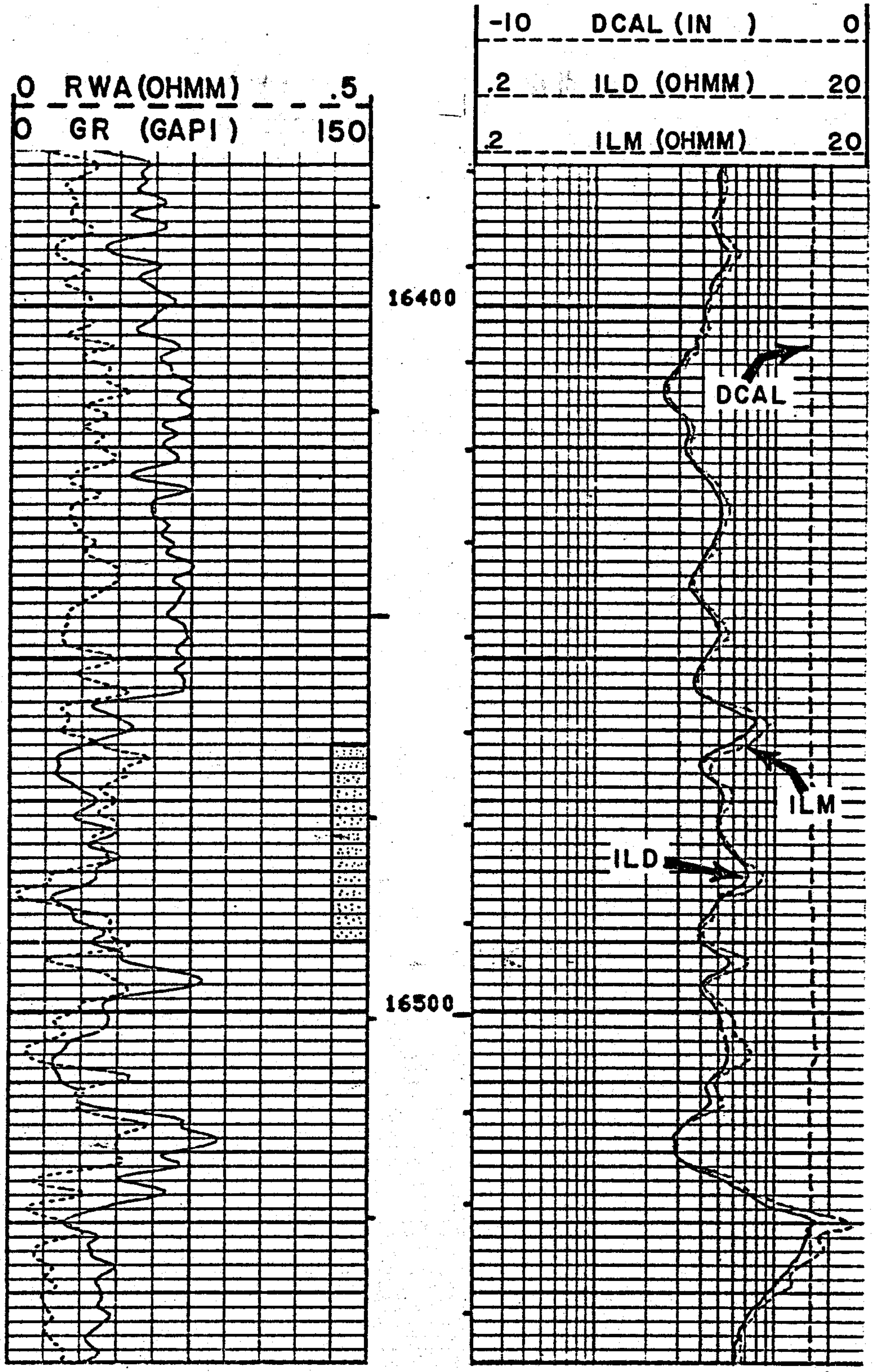
RESISTIVITY -SALINITY -

TEMPERATURE CHART

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 5-3

DOE CONTRACT NO.
DE-AC08-80ET-27081



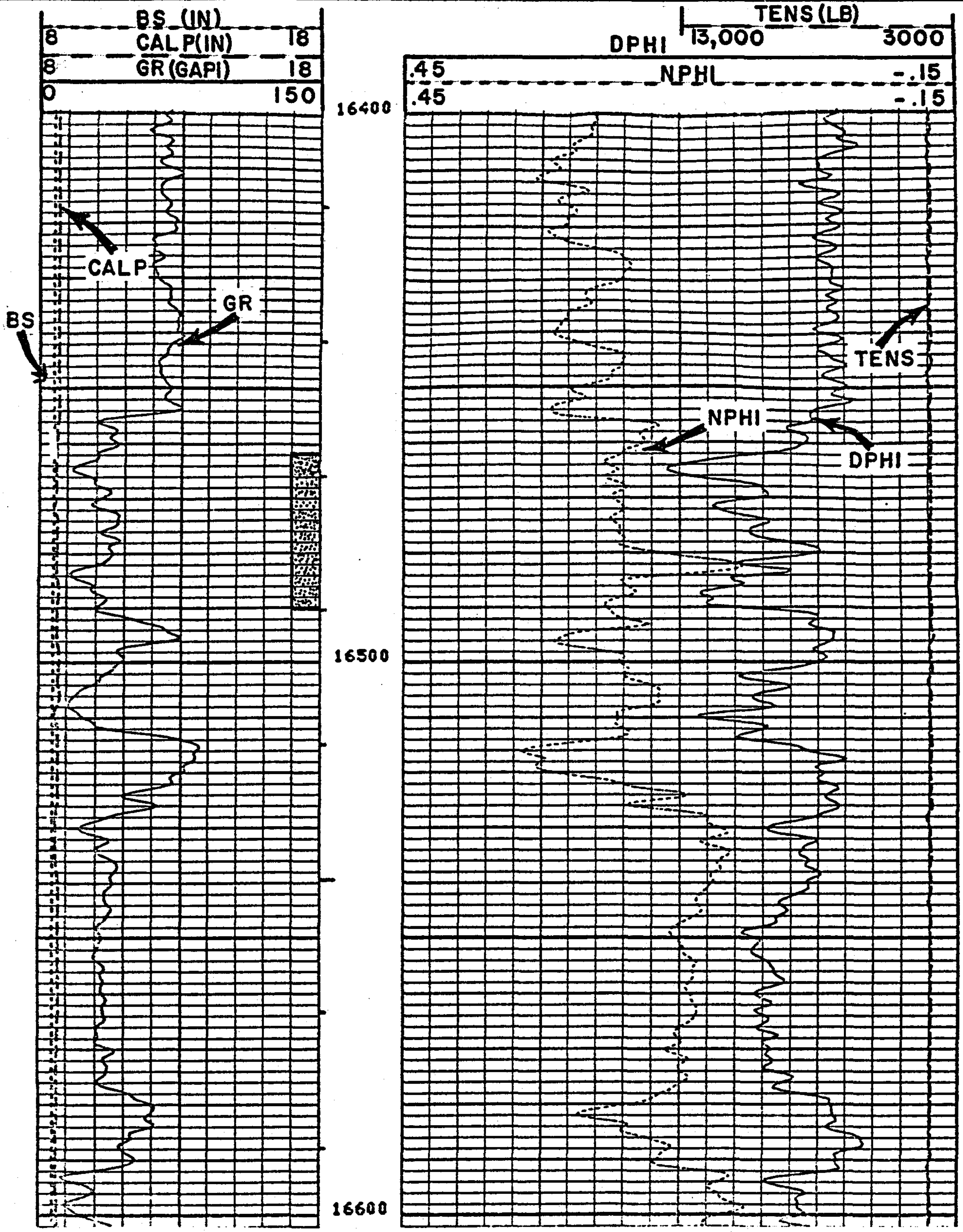
DUAL INDUCTION BOREHOLE COMPENSATED SONIC LOG

SAND "B", CROWN ZELLERBACH NO. 2

Eaton Industries of Houston, Inc. EXHIBIT 5-4

Eaton Operating Co., Inc.

DOE CONTRACT NO.
DE-AC08-80ET-27081



COMPENSATED NEUTRON-FORMATION DENSITY LOG
SAND "B", CROWN ZELLERBACH NO. 2

Eaton Industries of Houston, Inc. EXHIBIT 5-5
Eaton Operating Co., Inc.

DOE CONTRACT NO.
DE-AC08-80ET-27081

5.1.3 Permeability

The permeability, calculated from the drawdown of the reservoir test, is 14.1 millidarcies. The reservoir is relatively tight with at least one permeability barrier about 197 feet from the wellbore.

The permeability estimates of the geopressured-geothermal test zone were not available prior to the flow test. Conventional or sidewall cores were not obtained from the test zone during drilling operations. Also, empirical equations presented in logging literature for permeability estimation of various wireline logging devices have irreducible water-saturation values as a part of the mathematical statements. These equations, designed for saturated hydrocarbon formations, may not be applicable in 100% water-saturated sand.

5.1.4 Salinity (Sand "A")

The average actual formation water salinity, measured by IGT, is 31,700 ppm (total dissolved solids).

Since oil-based mud was used in the wellbore, the only method used in calculating the salinity was the modified Humble Method. Using this method the salinity is determined primarily as a function of porosity and true formation resistivity. The mathematical equation is as follows:

$$F = R_o/R_w \qquad \text{(Equation 1)}$$

$$F = 0.81/\phi^2 \qquad \text{(Equation 2)}$$

$$R_o/R_w = 0.81/\phi^2 \qquad \text{(Equation 3)}$$

$$R_w = R_o\phi^2/0.81 \qquad \text{(Equation 4)}$$

where:

F = formation factor-dimensionless

R_o = 100% water-saturated rock resistivity - ohm-m

R_t = true formation resistivity - ohm-m

R_w = formation water resistivity - ohm-m

ϕ = porosity - %

and:

R_t = 3.0 ohm-m

ϕ = 17.085%

Assuming a 100% water-saturated formation where $R_t = R_o$, Equation 4, and the previously listed log parameters, a formation water resistivity of 0.1081 ohm-m is obtained. Plotting the formation water resistivity on the Welex Resistivity Salinity graph (Exhibit 5-3) yields a calculated salinity of 16,000 ppm.

5.2 Sand "B"

Sand "B," 16,462 to 16,490 feet (Exhibit 5-4), was perforated after Sand "A" had been tested. Sand "A" and Sand "B" were then comingled into one test. Therefore, the "actual test results" were for both sand zones, not only Sand "B." The "calculated" parameters which follow are for only Sand "B." Calculations of the following were derived in the same way as those calculations of Sand "A" in Section 5.1.

	Calculated	Actual
• Porosity	13.74% (Exhibit 5-5)	N/A
• Gross Sand	28 feet	28 feet
• Net Sand	23 feet	23 feet
• Permeability	N/A	N/A
• Salinity	16,000 ppm	28,100 ppm (estimated)

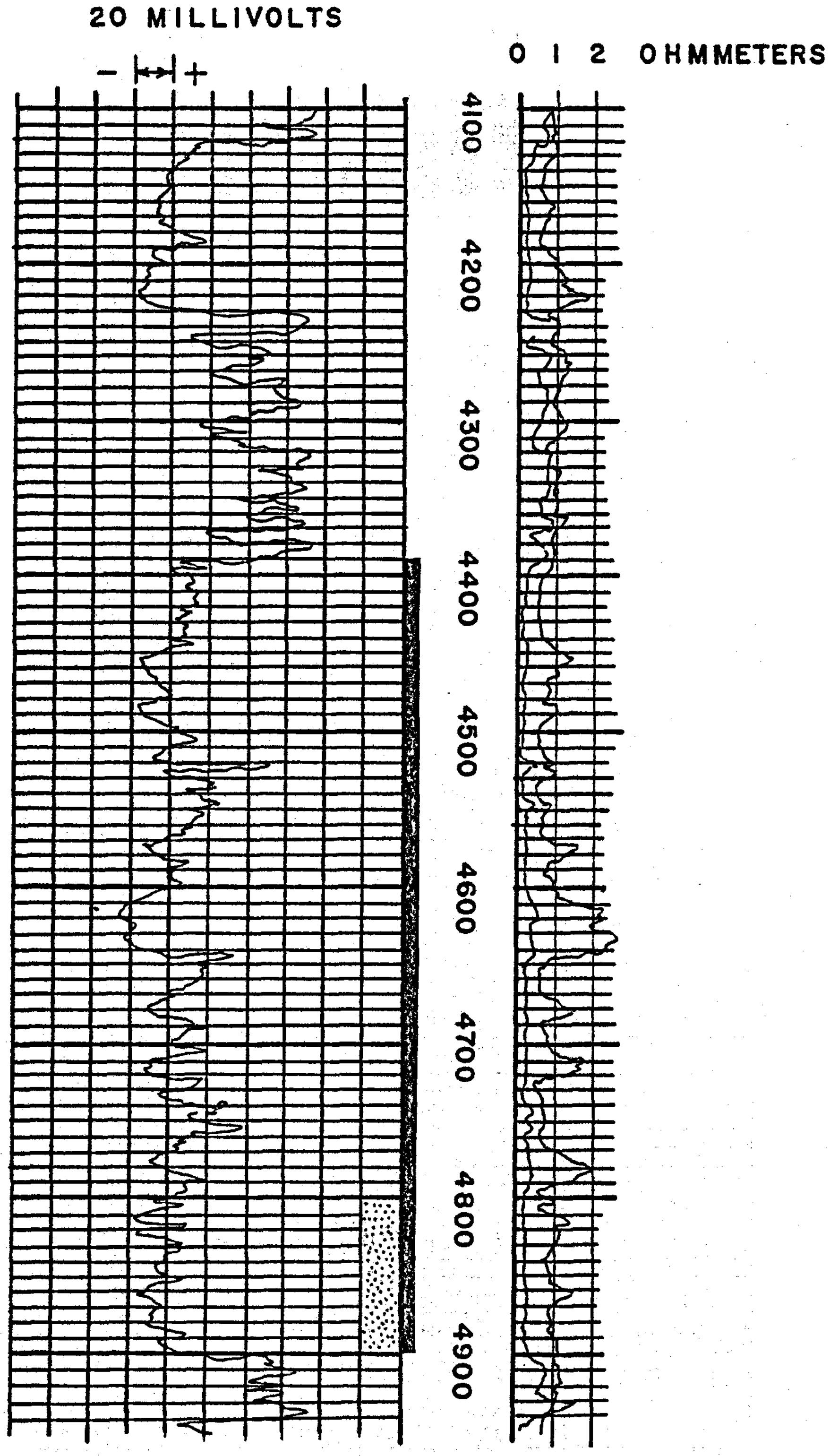
5.3 Open-hole Log Analysis - Disposal Well

The Crown Zellerbach Well No. 1 was re-entered and used as the saltwater disposal well. Three potential disposal sands were encountered (Exhibits 5-6 & 5-7) and are identified as follows:

Sand "A"	4390-4900	feet
Sand "B"	4120-4230	feet
Sand "C"	3625-3710	feet

The disposal well was completed in Sand "A" (Exhibit 5-6) from 4833 to 4908 feet. This sand exhibits the following log-derived parameters:

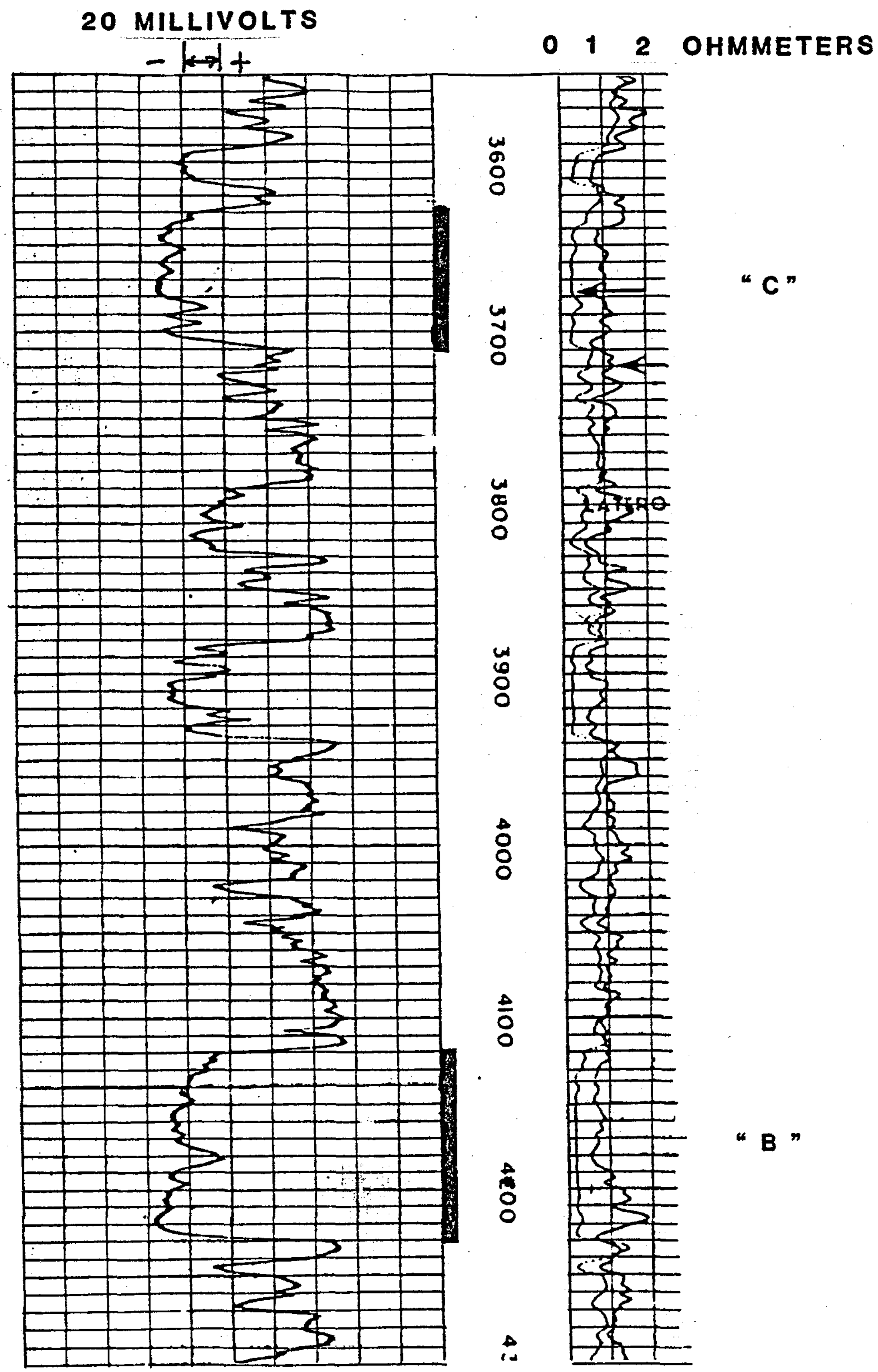
• Net Sand	75 feet
• Porosity	33%
• Pressure	2,279 psi
• Temperature	133°F
• Salinity	110,000 ppm



SP/ISF SONIC LOG SHOWING DISPOSAL SAND 'A'
CROWN ZELLERBACH NO.1

Eaton Industries of Houston, Inc. EXHIBIT 5-6
Eaton Operating Co., Inc.

DOE CONTRACT NO.
DE-AC08-80ET-27081



SP/ISF SONIC LOG SHOWING DISPOSAL SANDS "B" & "C"
CROWN ZELLERBACH NO. 1

5.4 Cased Hole Log Analysis - Test Well

An Acoustic Cement Evaluation Log was run in the test well after the cementing of the production string. This log gave Eaton the following data:

- Integrity of casing vs. cement and cement vs. formation bonding
- Correlation between open-hole and casing collars

Analysis of the test well Cement Evaluation Log (Exhibit 5-8) indicated that the Tuscaloosa sand was well bonded between 16,718 and 16,750 feet. The log was invalid above 16,500 feet due to tool malfunction.

5.5 Cased Hole Log Analysis - Disposal Well

An Acoustic Cement Evaluation Log was run in the saltwater disposal well which indicated good cement bonding in several sections from 4530 to 3050 feet. This cement was placed outside of the 9-5/8 inch casing by Shell and Martin Exploration Company during several squeeze jobs on perforations from 4390 to 4480 feet. The sand, which was used for disposal, is a very thick sand. The top of the sand is at 4390 feet and the bottom of the sand is at 4900 feet. As indicated on the log the injected saltwater should not have gone above 4500 feet because of the good cement bonding at that point (Exhibit 5-9).

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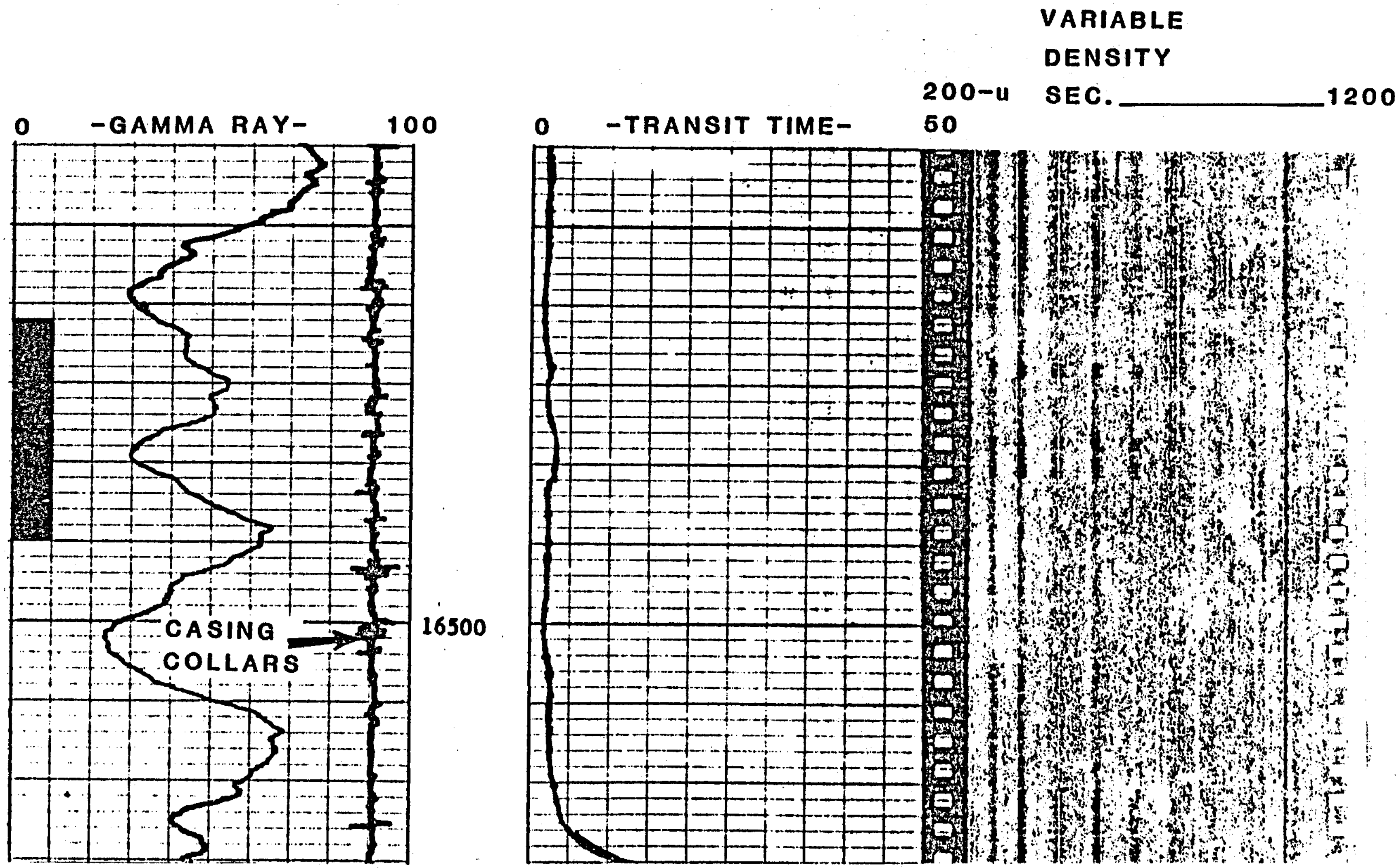
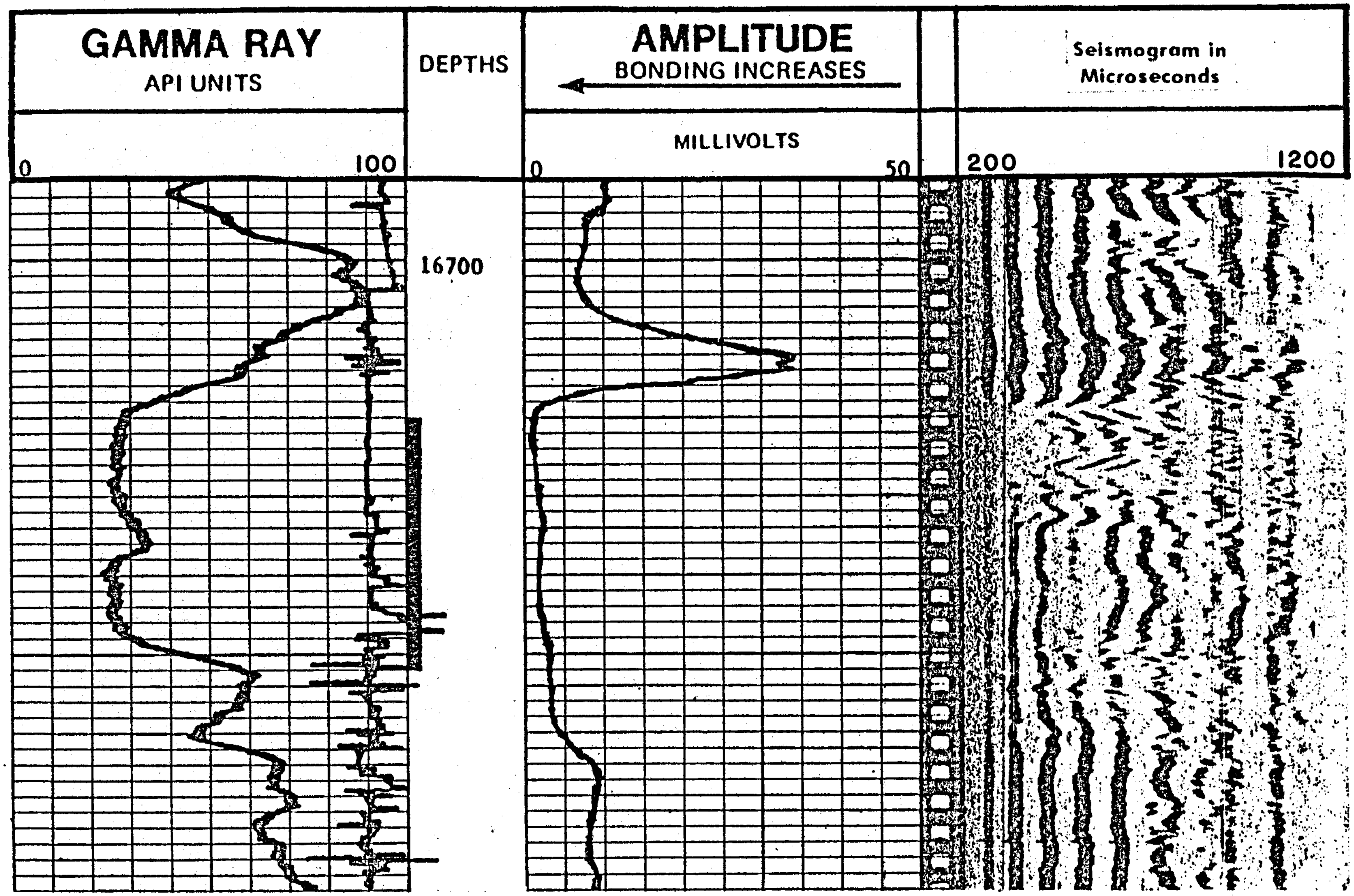


ACOUSTIC CEMENT BOND LOG - TUSCALOOSA "B" SAND

CROWN ZELLERBACH NO. 1

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 5-8



ACOUSTIC CEMENT EVALUATION LOG
CROWN ZELLERBACH NO. 2 SAND "A"

6.0 RE-ENTRY AND COMPLETION OPERATIONS - TEST WELL

6.1 Drill Site and Support Facilities

6.1.1 Site Layout

The location layout shown in Exhibit 6-1 accommodated conventional drilling and workover equipment used for the completion of the test well. The site was covered with boards for the support of rig operations. Prior to moving in the well testing equipment, a portion of the boards was replaced. The boards provided a good level working area for the testing operations.

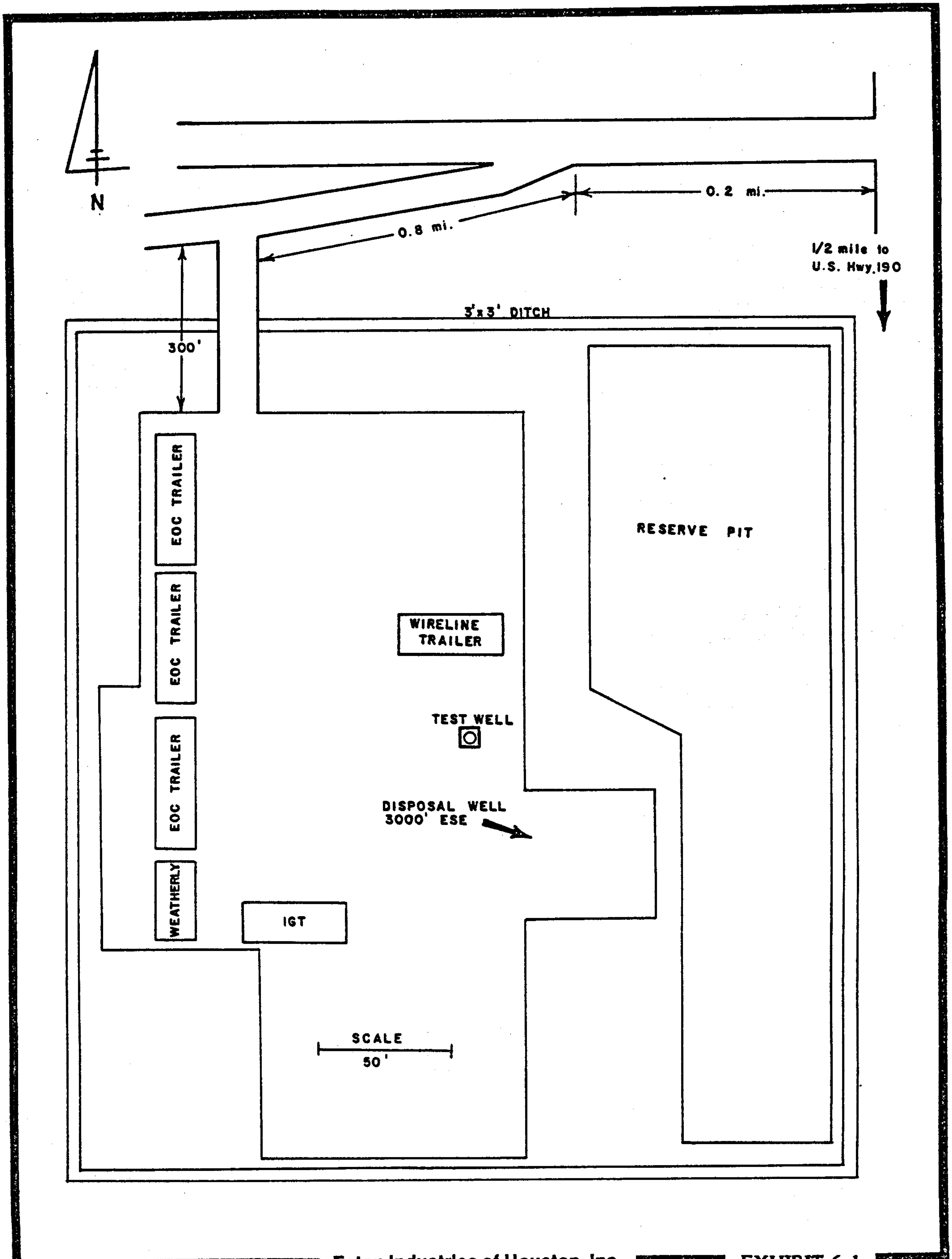
Rain water, waste oil, and grease spillage were trapped and drained into a ditch around the location for disposal. The ditch was pumped out into the reserve pit.

6.1.2 Living Facilities and Utilities

Air-conditioned living facilities were provided for 12 people. Weatherly Engineering, Energy Resource Measurement, and the rig contractors brought in living trailers for their personnel. Motel accommodations were available in Baton Rouge and Hammond, Louisiana.

Water for drilling and other operations was obtained from a fresh water well drilled on the site. Drinking water was brought to the site by a local water delivery service.

Two telephones were installed in the Eaton house trailers. Electrical power was obtained from a nearby commercial power source.



Eaton Industries of Houston, Inc. EXHIBIT 6-1
Eaton Operating Co., Inc.

DOE CONTRACT NO.
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6.2 Test Well Design

6.2.1 Initial and Testing Well Completion Status

Exhibit 6-2 is a schematic drawing of the test well, showing the well condition when Eaton took over operations from Martin. The lower portion of the well had been abandoned by setting a cement retainer at 13,912 feet and pumping cement below and above it. A second cement retainer had been set at 3586 feet and cement pumped on top of it. A surface plug of cement set had been down to a depth of 148 feet.

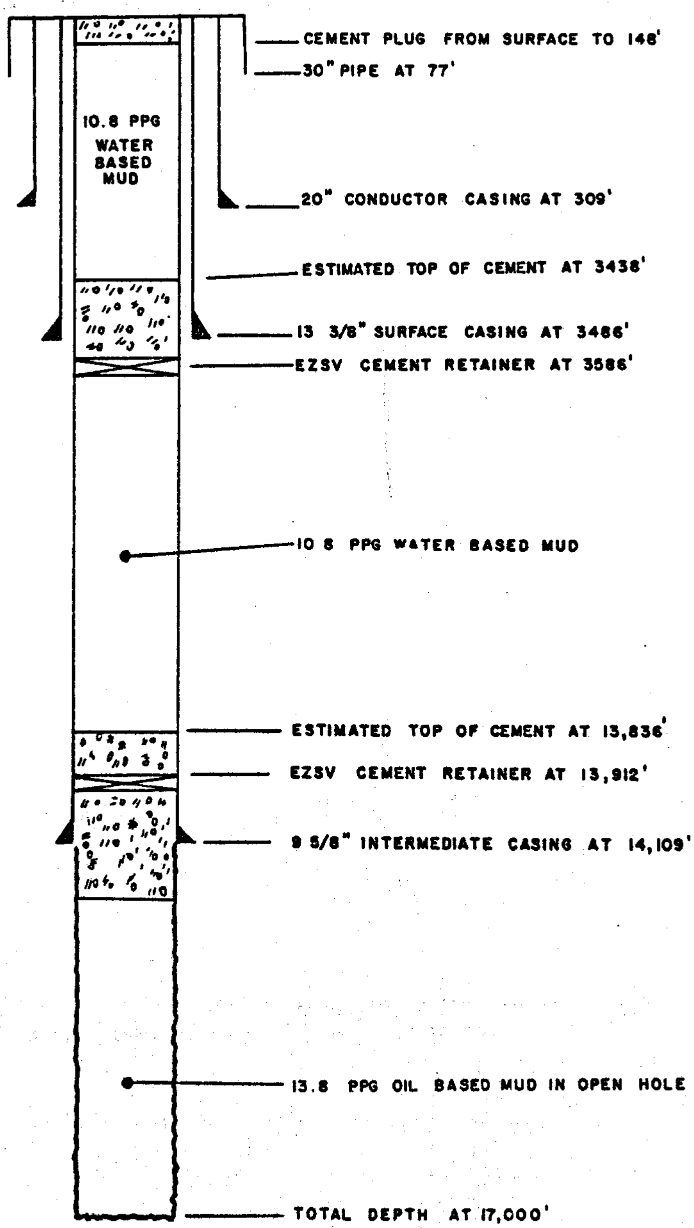

EXHIBIT 6-2 TEST WELL - CONDITION AT TIME OF EATON TAKEOVER

Exhibit 6-3 is a schematic diagram showing the tubular configuration of the well as completed for testing. A string of 2-3/8 inch tubing was run without a packer to 16,613 feet. The heavy mud was displaced with saltwater, and the well was perforated from 16,720 to 16,750 feet, using wireline perforating guns run through the tubing. After remedial operations, to remove a portion of the tubing string, an additional interval was perforated from 16,462 to 16,490 feet using wireline perforating guns run through the tubing. The tubing was rerun to 16,351 feet during remedial operations.

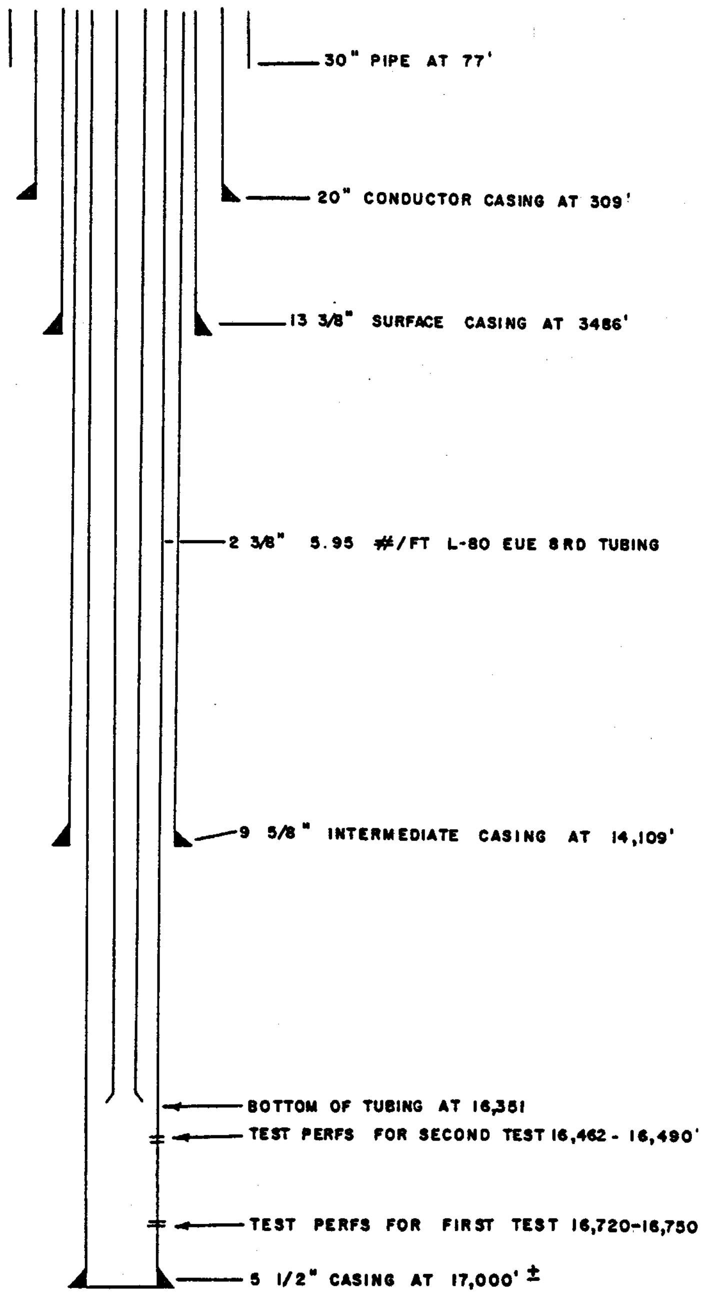

EXHIBIT 6-3 TEST WELL - CONDITION DURING TESTING

This is the fifth annular-flow tubular arrangement used in the WOO program. The annular-flow configuration has two advantages over the conventional tubing-flow completion: 1) wireline tools, such as the Hewlett-Packard downhole pressure gauge, are not exposed to the turbulence caused by flowing fluids outside the tubing, and 2) the well can be killed efficiently in an emergency simply by circulating heavy mud down the tubing and up into the annulus.

6.2.2 Tubular Goods Design

Engineering design and safety calculations were performed prior to completion of the well. Exhibit 6-4 shows the specifications for the tubular goods installed in the well, as well as hole sizes and design safety factors.

6.2.3 Wellhead Design

Exhibit 6-5 is a schematic of the wellhead and christmas tree used. The christmas tree was designed for annular flow of fluids. Produced fluids flowed up the casing-tubing annulus and exited through two outlets in the tubing head. Flow through each outlet was controlled by one 3-1/16 inch 10,000-psi working pressure, hand-operated gate valve, one 3-1/16 inch 10,000-psi working pressure, pneumatic-operated surface safety valve, and one 2-1/16 inch 10,000-psi working pressure, hand-operated gate valve. Two sections of 3-inch XX grade "B" API line pipe connected the tubing head outlets to a common "Y" block at the head of the flowline.

The upper section of the christmas tree consisted of one 2-1/16 inch 10,000-psi working pressure master gate valve, a tee with a 1-11/16 inch valve for a kill line connection, and a 2-1/16 inch "swab" valve for wireline accessibility.

6.2.4 Logging Program

The suite of open-hole logs and sidewall core data obtained by Eaton supplied adequate information for formation evaluation purposes. A casing caliper log was run in the 9-5/8 inch casing in the test well from 11,390 feet to the surface. After running the 7-inch production casing and cementing it in place, a gamma ray cement bond log was run from 16,920 to 12,000 feet. A gamma ray casing collar locator log was run in the test well for use as a reference for perforating operations. A cement bond log and gamma ray casing collar locator log were run in the saltwater disposal well.

6.3 Re-Entry Operations

The Wilson Brothers' Rig No. 8 was moved to the location on April 17, 1981, to commence completion operations on the test well. A blowout preventer stack, approved by Eaton, was installed on the well and tested. A cement mill was run in the hole to a cement plug at 266 feet. The cement plug was drilled out and the hole cleaned out to 3588 feet, where cement and a cement retainer were drilled out. The hole was cleaned out to 11,455 feet. A casing caliper log was run in the 9-5/8 inch casing from 11,390 feet to the surface. The casing appeared to be in good condition. Detector equipment for H_2S was installed and an H_2S safety school was conducted for all personnel. The

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Eaton Operating Co., Inc.

EXHIBIT 6-4

MARTIN-CROWN ZELLERBACH WELL NO. 2
TUBULAR GOODS SUMMARY

Tubular	O.D. Size (in.)	Depth From (Ft.)	Depth To (Ft.)	Weight lbs./Ft.	Minimum Drift (in.)	Casing Description Grade	Casing Description Thread	Casing Design Factors Burst	Casing Design Factors Collapse	Casing Design Factors Tension
Conductor Pipe	20	0	309	NA	NA	NA	NA	*	*	*
Surface Casing	13-3/8	0	3,486	61	12.359	NA	NA	*	*	*
Intermediate Casing	9-5/8	0	14,109	53.5	8.500	NA	NA	*	*	*
Production Casing	7	0	7,521	32	5.969	L-80	LT&C	1.96	**	1.56
		7,521	17,000	32	5.969	P-110	ABM	**	2.33	**
Tubing	2-3/8	0	16,351	5.95	1.773	L-80	DWS	**	**	1.57

CEMENTING SUMMARY

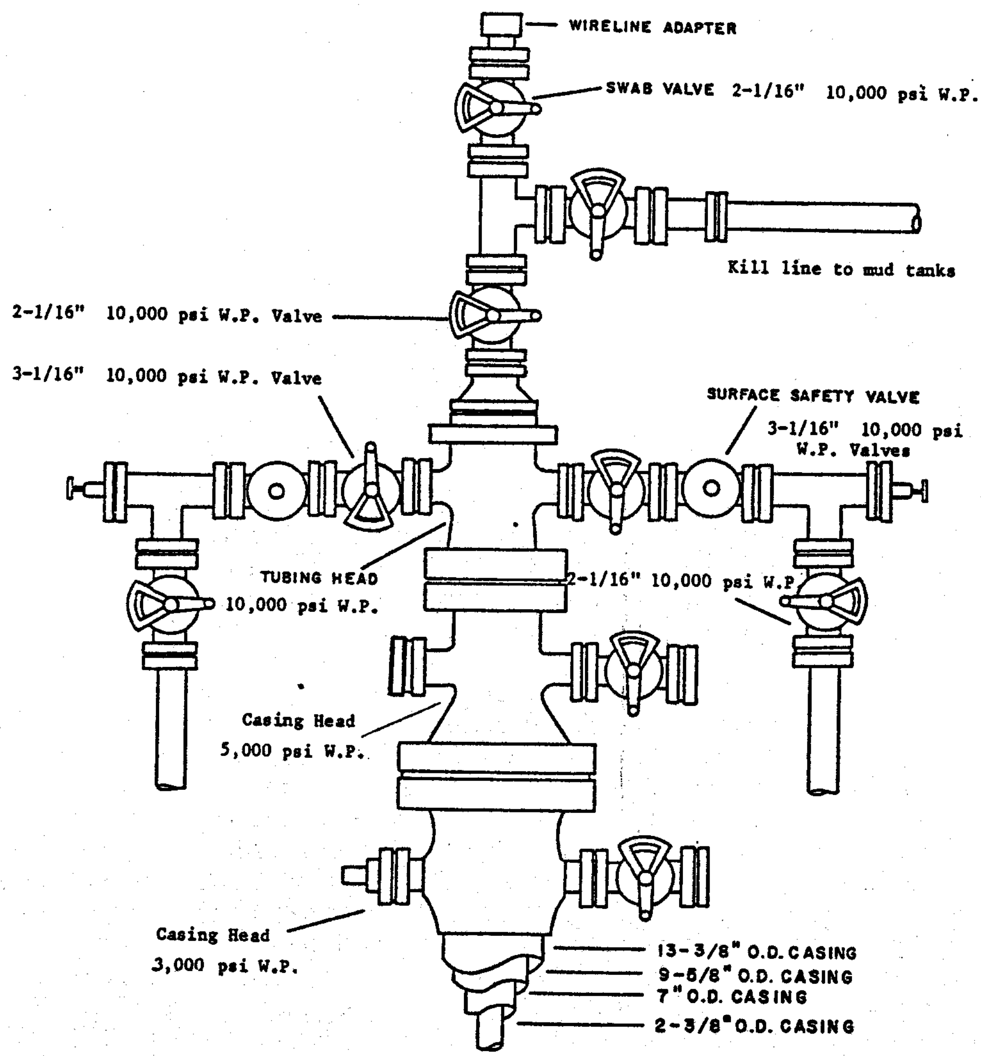
Casing	O.D. Size (in.)	Hole Size (in.)	
Surface	13-3/8	17-1/2	2,390 Sacks Lite cement with 3% salt followed by 400 sacks Class H cement.
Intermediate	9-5/8	12-1/4	1,500 Sacks HTLD cement with 1.7% halad 22-A, 0.2% Econolite, 0.25% Kwikseal and 0.6% HR-5, followed with 1,000 sacks class H cement with 35% silica, 0.75% CFR-2, 0.4% halad-22A and 0.3% HR-5. Cemented around top of 9-5/8" by 13-3/8" annulus with 1,000 sacks of cement.
Production	7	8-1/2	10 BBLS APS-1 Spacer at 15.0 lb/gal., 500 sacks Class H cement with 35% silica flour, 0.6% CF-6, 0.3% WR-6 at 15.9 lb/gal. followed by 5 BBLS APS-1 Spacer.

Note: All pipe except 7" casing was cemented and tested by Martin Exploration. The 7" casing was tested at pressures much higher than the 3,120 psi required by the State of Louisiana.

* Tubulars in place and/or will not be exposed to well bore conditions.

** Safety factors very high or no longer exposed to well bore conditions.

CHRISTMAS TREE SCHEMATIC



Eaton Industries of Houston, Inc. EXHIBIT 6-5
Eaton Operating Co., Inc.

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water-based mud was displaced with 13.8 ppg oil-based mud. Cement and a cement retainer were drilled out from 13,912 to 14,232 feet. The hole was cleaned out to 17,017 feet.

6.4 Completion Operations

A string of 7-inch O.D. casing, consisting of 227 joints of 32 lb/ft, grade P-110, FL4S, totaling 9477 feet and 172 joints of 32 lb/ft, grade L-80, modified LT&C, totaling 7521 feet, was run in the hole to 16,998 feet. A down-jet float shoe was installed on the end of the casing string, and a float collar was placed two joints up from the float shoe. Centralizers were installed on each joint from bottom up to 15,000 feet and one centralizer on every third joint from 15,000 to 13,000 feet. Torque-turn equipment was utilized while running the casing to insure proper and uniform make-up. The casing was cemented with 500 sacks Class H cement with 35% silica flour, 0.6% CF-6 (fluid loss additive), 0.3% WR-6 (Retarder) at 15.9 ppg. The cement was preceeded by 10 barrels APS-1 spacer at 15.0 ppg and followed by 5 barrels APS-1 spacer at 15.0 ppg. Drilling mud was used to displace the cement. The wiper plug was seated in the float collar with 2500 psi of pump pressure. The pressure was bled to 0 psi, indicating that the float valves were holding. The casing was set on casing slips with 420,000 pounds tension. The blowout preventers were removed, a casing head installed, and the blowout preventers installed. The casing was pressure-tested to 2400 psi for one hour with no leaks. A gamma ray cement bond log was run from 16,900 to 15,800 feet. The log indicated that good cement bonding had been achieved across all potential test zones. The log also indicated that the top of the cement was at 12,300 feet. A string of 2-3/8 inch O.D., grade L-80, 5.95-lb/ft tubing was run in the hole to 16,920 feet. The 13.8 ppg oil-base mud was displaced with 8.8 ppg saltwater. Ten joints of tubing were laid down, and the tubing was landed at 16,613 feet. A 1-5/8 inch O.D. gauge was run to total depth, and the tubing was found free of obstructions. The blowout preventers were removed, and a 7-inch tubing head was installed. The rig was released on May 13, 1981.

The location was cleaned up and repaired after the rig was moved off location, and production equipment was installed. The christmas tree flow loops and choke manifold were pressure-tested to 7000 psi, and the casing was tested to 3500 psi prior to perforating. An attempt to run a gamma ray collar locator log failed when the insulators on the tungsten weight bars burned out at 16,000 feet. The insulators were rebuilt, and a gamma ray collar locator log was run after two logging tool failures. A perforating gun was run in the hole, and the 7-inch casing was perforated from 16,730 to 16,750 feet with four holes per foot. A pressure of 3200 psi was held on the casing while perforating. No change in pressure occurred after perforating. The well was opened to the reserve pit after the perforating gun was pulled up into the tubing string. The well pressure dropped to 1450 psi and built up to 1750 psi while flowing at an estimated rate of 300 barrels per day. The choke size was increased, and the well pressure dropped to 800 psi, rose to 1200 psi, and stabilized at 900 psi, while producing at an estimated rate of 2700 barrels per day. Perforating gun number two was fired across the interval from 16,720 to 16,730 feet with 4 holes per foot. When the wireline was pulled from the tubing string, it was discovered that the perforating gun and collar locator had been blown off the wireline. A new rope socket, collar locator, and weights were rigged up, and the interval from 16,730 to 16,750 feet was perforated with an additional 4 holes per foot for a total density of 8 holes per foot. While attempting to perforate the interval from 16,720 to 16,730 feet with an additional 4 holes per foot, the perforating gun hit an obstruction in the tubing and became stuck but was worked free and pulled out of the hole. No further attempts were made to perforate the interval from 16,720 to 16,730 feet. A gauge tool was run through the tubing to the bottom of the perforations with no obstructions encountered.

The well was opened to flow during the perforating operations to lower the surface pressure and to clean the perforations. An estimated 1500 barrels of saltwater were produced during this period. The shut-in surface pressure was 2575 psi.

6.4.1 Tubing Cutting Operations

A decision to perforate an additional zone, 16,462 to 16,490 feet, in an attempt to improve producing rates, necessitated removal of approximately 200 feet of the 2-3/8 inch O.D. tubing, which was hung at 16,613 feet. In an effort to eliminate a costly rig move, it was decided to attempt to cut the tubing at approximately 16,416 feet, by using wireline tools and to allow the approximately 200 feet of tubing to fall to the bottom of the hole below the existing perforations.

A chemical cutter was run in the tubing on wireline and fired at 16,416 feet. The tool became stuck after firing. Attempts to work the tool free failed, and a pump truck was hooked up to the tubing and pressured it up to 6000 psi in an attempt to pump the tool out of the tubing. The wireline was pulled out of the rope socket during this operation, and the chemical cutter was left in the tubing. A new rope socket was made up, and a jet cutter was run in the hole and tagged the lost chemical cutter at 16,626 feet. The jet cutter was pulled up to 16,390 feet but fired prematurely and did not cut the tubing. Another jet cutter was run in the hole to 7036 feet at which point the wireline jumped off the sheave on the truck, necessitating cutting and splicing the wireline, pulling out of the hole, and replacing the wireline truck with another unit. A jet cutter was run in the hole to 16,390 feet and fired and failed to cut the tubing. A string shot was run in the hole to 16,390 feet and fired across the previous jet cut and also failed to cut the tubing. A jet cutter was run in the hole to 16,390 feet and fired, followed by another jet cutter fired at 16,386 feet, both of which failed to cut the tubing. The jet cutter fired at 16,386 feet was left in the tubing when the wireline pulled out of the rope socket. A slick line unit was rigged up with 30 feet of weight bars and run in the tubing to pound on the tools lost in the hole. No movement was observed as a result of pounding on the stuck tools. A heavy load chemical cutter was run in the hole and fired at 16,373 feet. This tool failed to fire because of a short in the wireline necessitating another unit to be brought on location. The chemical cutter was run in the tubing to the top of the stuck jet gun at 16,380 feet and fired. A perforating gun was run in the hole on the assumption the tubing had been cut but found the the tubing uncut and the top of the stuck jet cutter at 16,397 feet. The wireline unit was released, and the well flowed for 21 hours before the well was killed and a workover rig was moved in.

6.4.2 Workover of Test Well

The well was killed with 11.6-ppg calcium chloride water, and a wireline gauge tool was run to the top of the junk in the tubing to determine whether the tubing had parted during kill operations. The tubing was found to be still intact, and WellTech Rig No. 8 was moved on location on June 19, 1981. The christmas tree was removed, and a set of blowout preventers approved by Eaton was installed and tested. The 2-3/8 inch tubing string was pulled out of the hole and eight joints laid down. The chemical and jet cutters stuck in the tubing were recovered. The 2-3/8 inch tubing was run in the hole, and a 1-11/16 inch gauge tool was run through the tubing to 16,700 feet to insure the tubing was clear. The tubing was landed at 16,351 feet. The blowout preventers were removed and the christmas tree installed. The 11.6-ppg calcium chloride water was displaced with fresh water. The rig was released on June 23, 1981. A perforating gun was run through the tubing on wireline and perforated the interval from 16,462 to 16,490 feet with 4 holes per foot. The well was opened to flow to the reserve pit as soon as the perforating gun had been pulled into the tubing.

6.4.3 Tubing Conditions as Result of Cutting Operations

The wireline operator, N.L. McCullough, retrieved the tubing containing the stuck chemical and jet cutters, removed their tools, and sawed the tubing longitudinally for examination of the areas where the chemical and jet cutters were fired.

The first chemical cutter, shot at 16,416 feet, did not leave any external marks on the tubing and was therefore overlooked when sawing the tubing. The first jet cutter, fired at 16,390 feet, left an external ring bulge of about 1/4-inch height completely around the tubing at the point of impact but failed to penetrate the tubing at any point. The subsequent string shot at 16,390 feet resulted in deformation of the tubing to the extent of swelling the diameter of the tubing approximately 1-inch over a length of about 2 feet. The string shot also split the tubing longitudinally, in the area of deformation, in two places, with a length of approximately 15 inches per split. The second and third jet cuts deformed the tubing almost identically to the first jet cut. The second chemical cut apparently failed to function properly as it penetrated the internal wall of the tubing at only one point to a depth of about 1/8-inch. Photos 6-1 through 6-4 show the condition of the tubing described above.

The failure of the various tubing cutting operations is believed to be a combination of the following: 1) the wall thickness of the tubing, and 2) the tubing being in compression rather than tension at the firing points of the cutters. Chemical and jet cutters are designed primarily to cut casing or tubing in tension. Both types of cutters have a good success ratio cutting pipe which is in tension. The fact that the tubing had been hung open-ended without a packer precluded putting it in tension for the cutting operations.

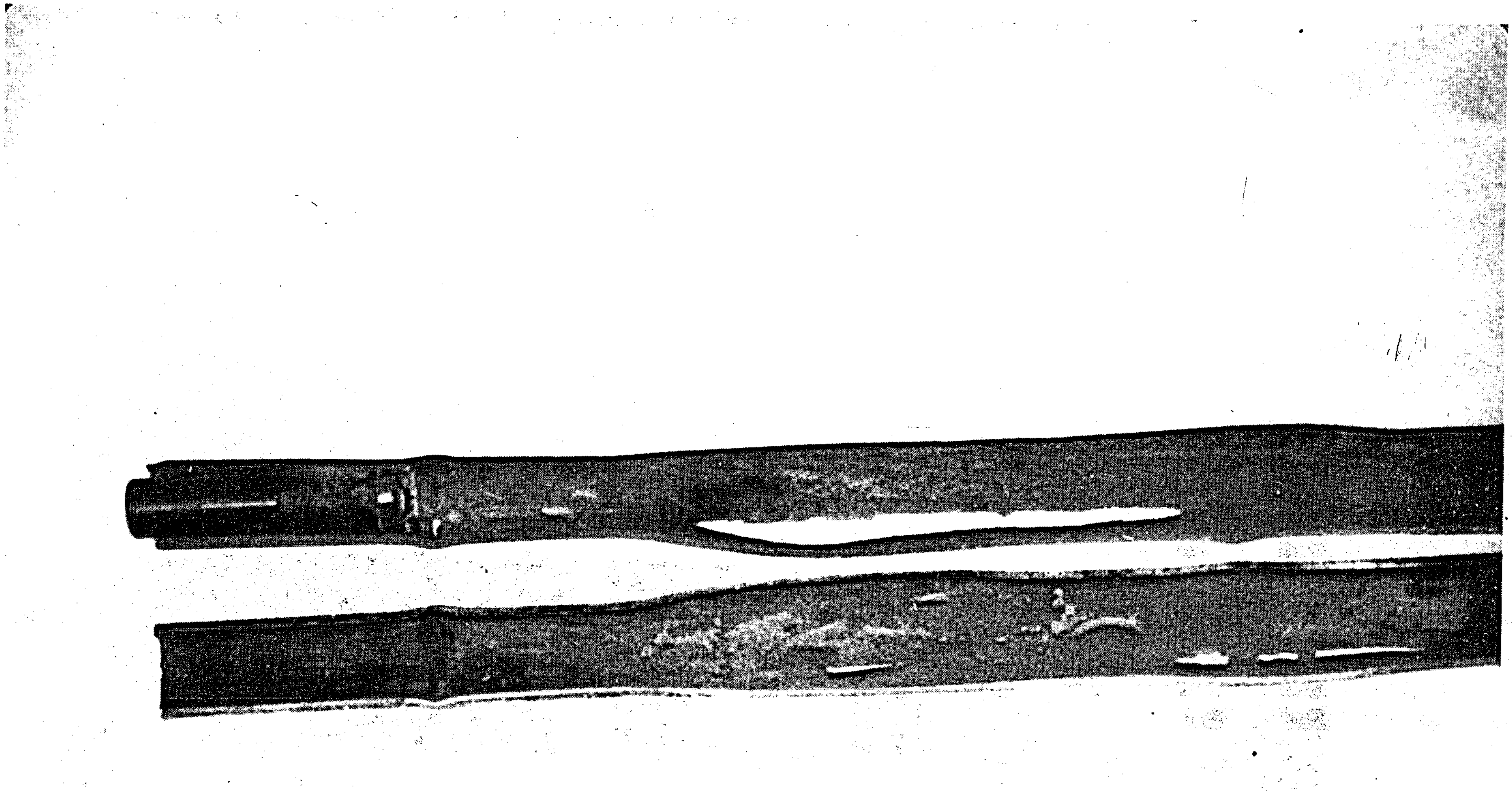

Photo 6-1: Effects of tubing-cutting operations: First jet cut and string shot

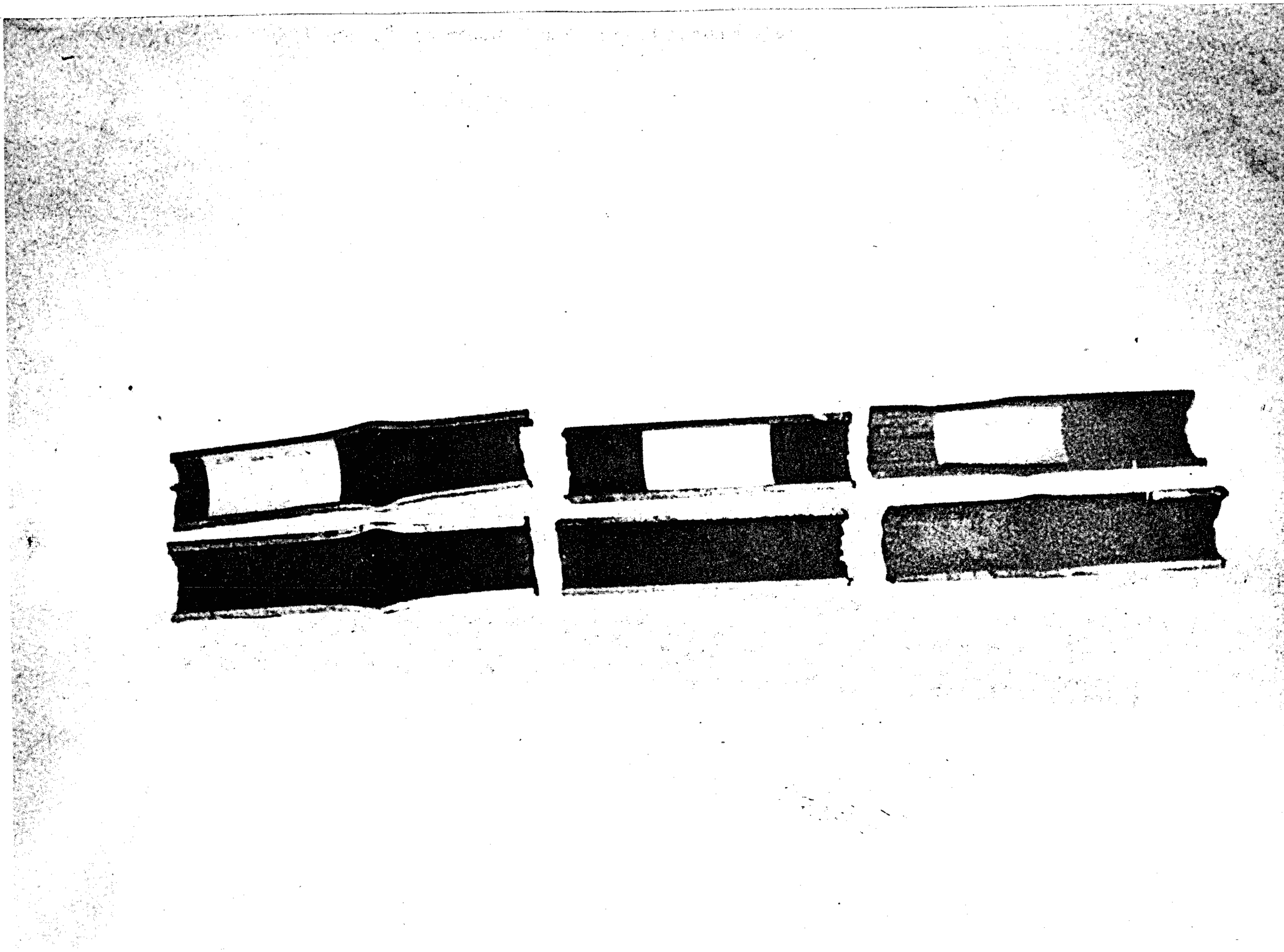

Photo 6-2: Effects of tubing-cutting operations: Second jet cut, second chemical cut, third jet cut

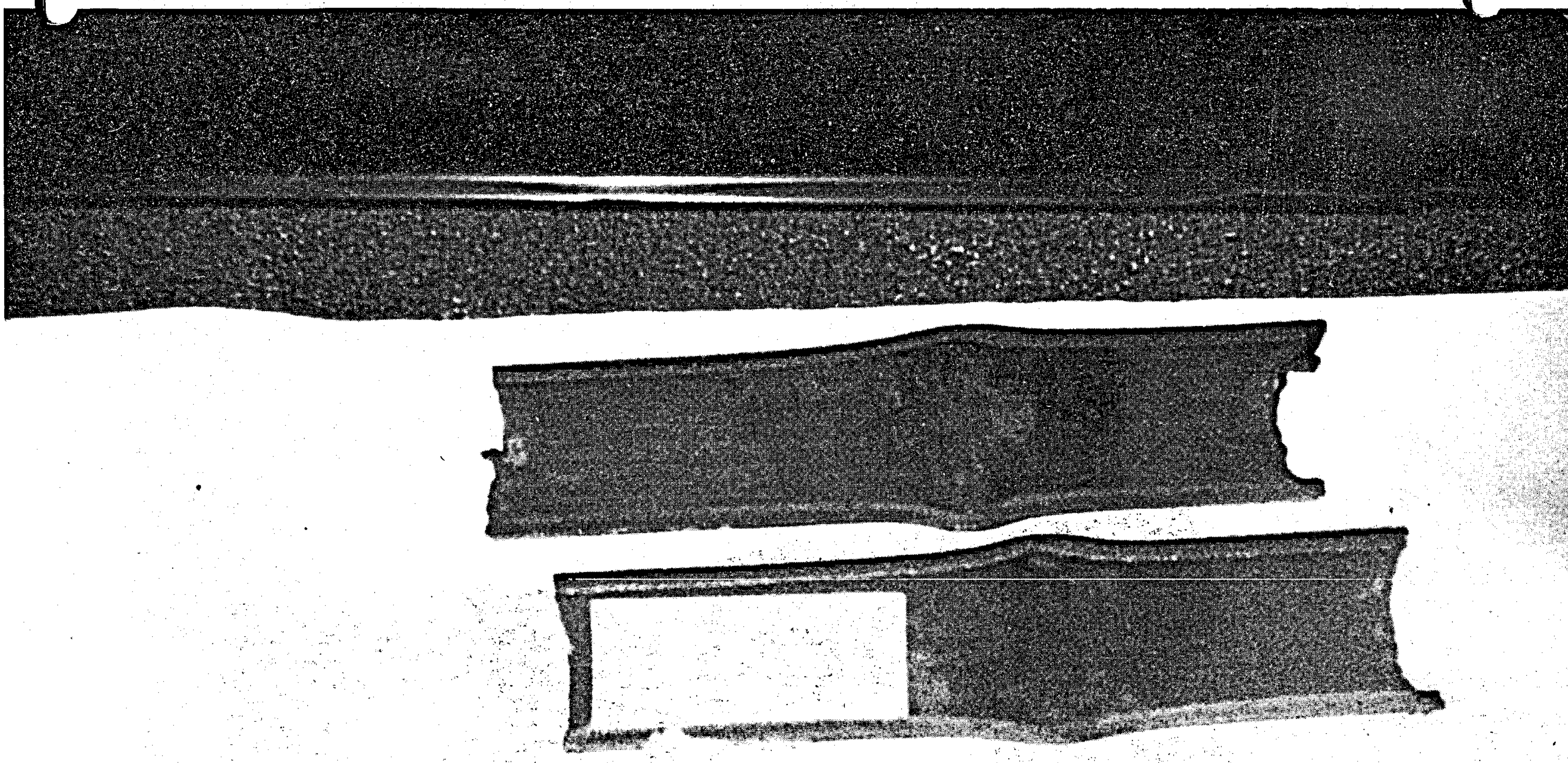

Photo 6-3: Closeup of second jet cut

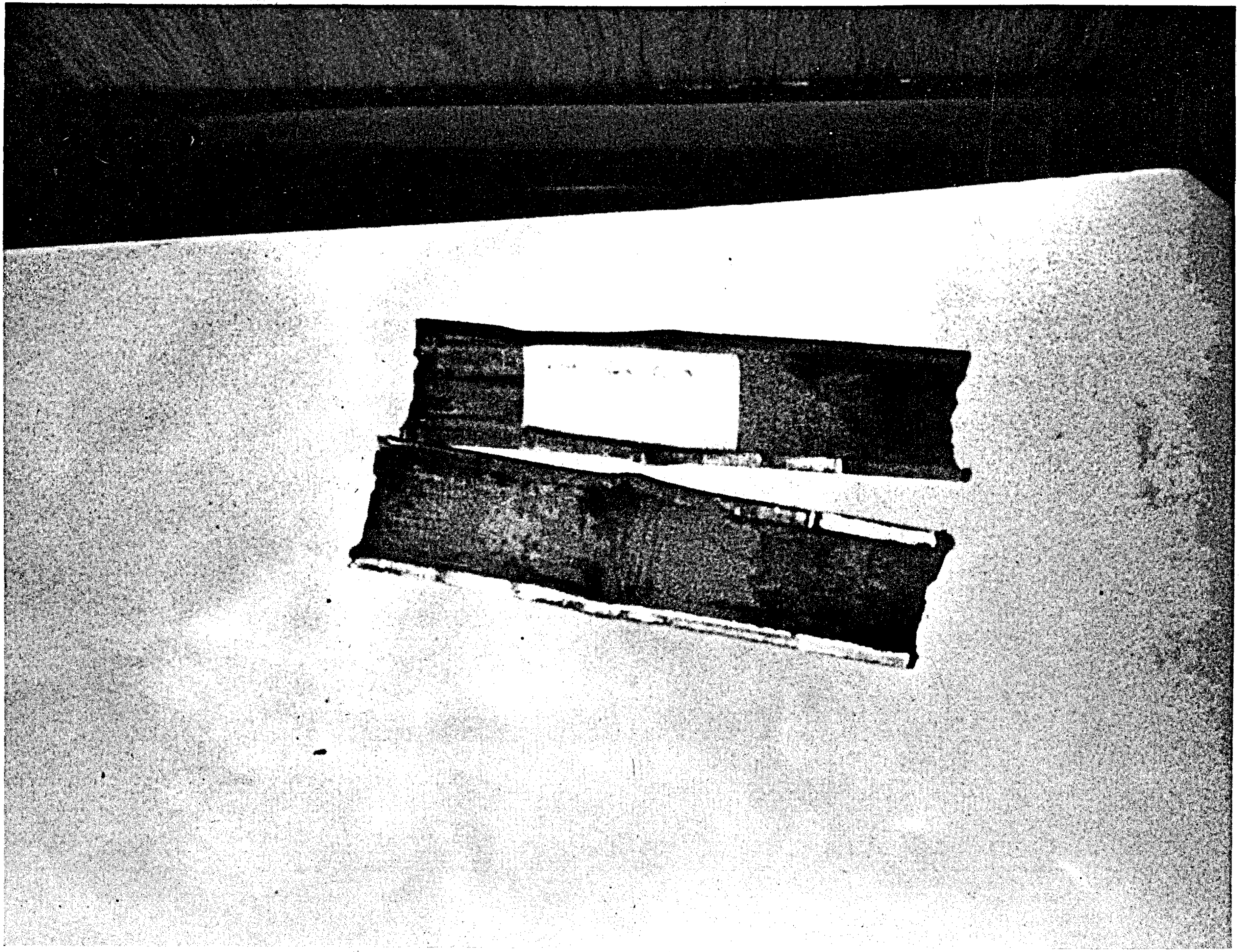

Photo 6-4: Closeup of third jet cut

7.0 RE-ENTRY OPERATIONS - DISPOSAL WELL

7.1 Location

The Crown Zellerbach Well No. 1, which was plugged and abandoned by Martin, was selected for use as a brine disposal well. This well was located about 3000 feet southeast of the test well. The well was surrounded by a board mat in a flat area which had been cleared of timber. Additional boards in the well cellar were the only improvements required on the location for rig operations or testing.

7.2 Disposal Well Design

A brine disposal well was desired for this test because of the large amount of water that was to be produced. The primary design requirements for the well were the following:

- An injection capacity of 15,000 barrels of water per day at an injection pressure below 500 psi.
- High temperature capability up to 300°F.
- A minimum disposal depth of 2500 feet, as specified by the Louisiana Department of Conservation.
- Protection of fresh and brackish water sands by proper completion methods using casing and cement for isolation of sands.

7.2.1 Initial and Actual Well Completion Status

Exhibit 7-1 is a schematic drawing of the disposal well showing the conditions when Eaton took over the operations from Martin.

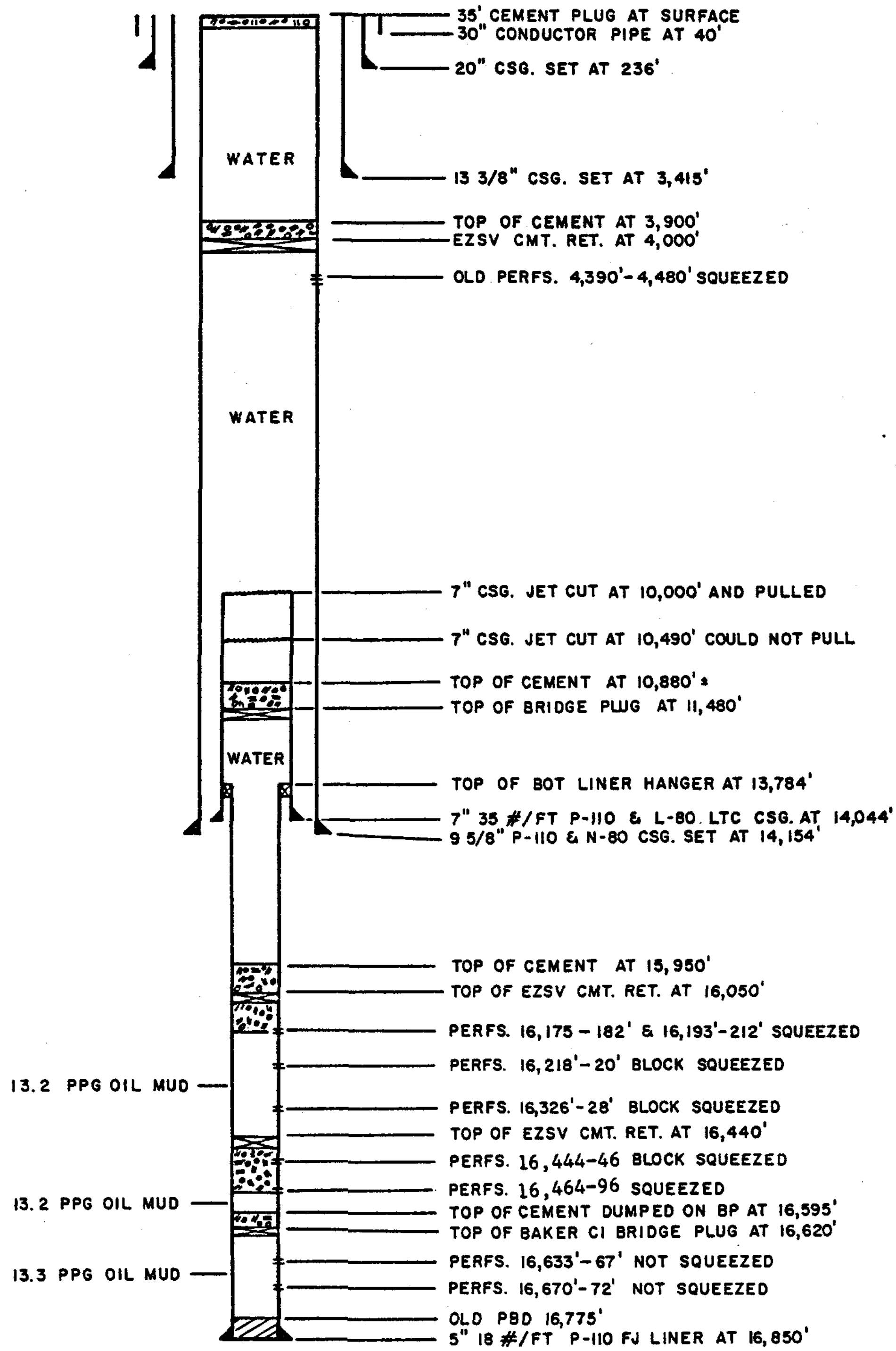

EXHIBIT 7-1: DISPOSAL WELL - CONDITION AT TIME OF EATON TAKEOVER

Exhibit 7-2 is a schematic diagram illustrating the wellhead design and the tubular configuration of the well as completed for disposal. The 7-inch casing was cut off below the disposal zone, and the 9-5/8 inch casing was squeezed above the disposal interval.

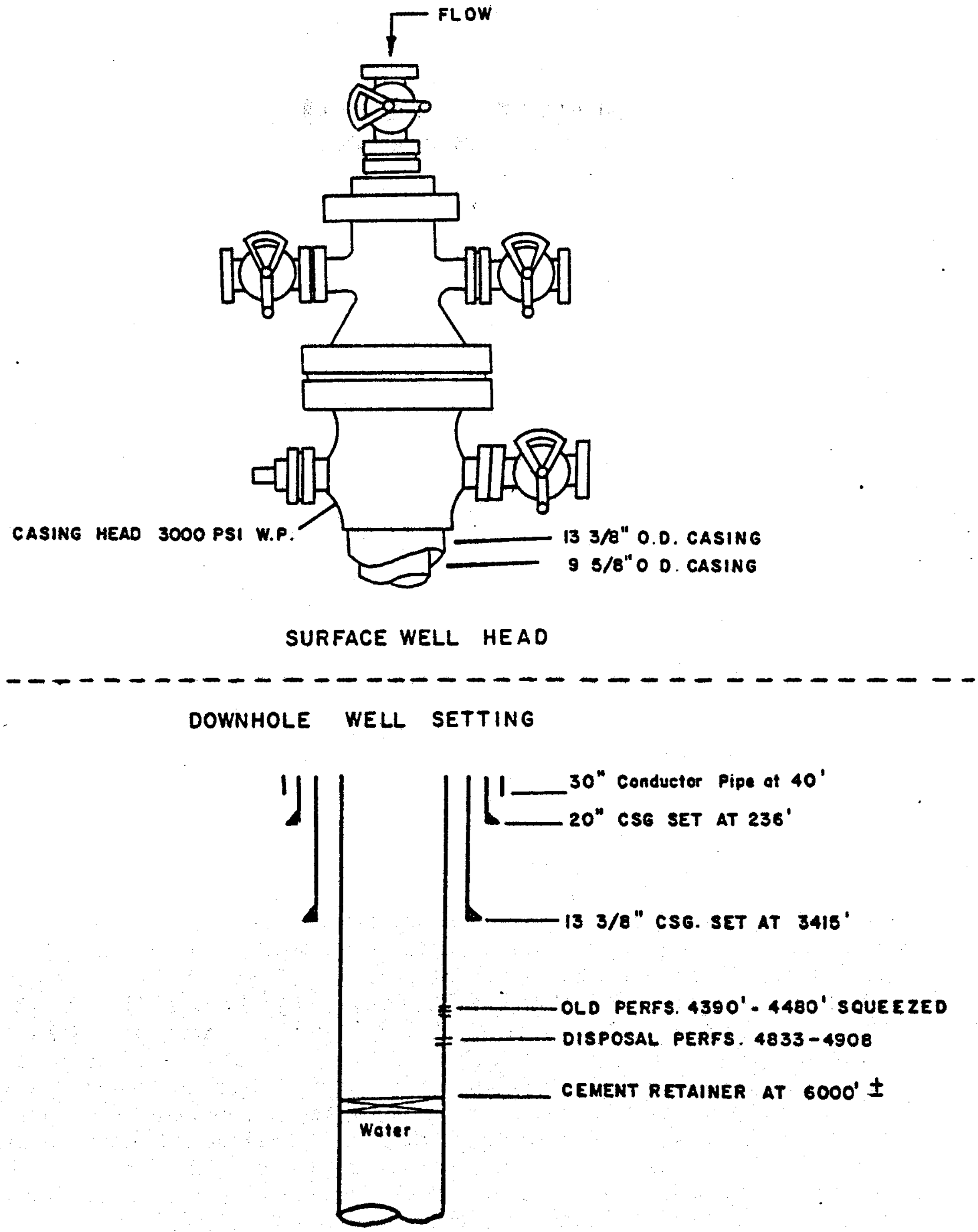

EXHIBIT 7-2: DISPOSAL WELL AS COMPLETED FOR DISPOSAL

7.3 Selection of Disposal Zone

The electrical log of the Crown Zellerbach Well No. 1 obtained from Martin indicated that the following potential disposal sands were available for injection.

Sand	Top	Bottom	Thickness	Average Porosity %
A	4390'	4900'	510'	26
B	4120'	4230'	110'	36
C	3625'	3710'	85'	26

The well was completed in Sand "A," and Sands "B" and "C" were reserved for additional disposal capacity.

7.4 Re-Entry Operations

The WellTech Rig No. 31 was moved on location on March 26, 1981 to commence completion operations on the disposal well. A blowout preventer stack, approved by Eaton, was installed on the well and tested. A cement mill was picked up and run in the hole. Cement was drilled from 346 to 376 feet. The hole was cleaned out to 3600 feet. Cement and a cement retainer were drilled out from 3600 to 3753 feet. The hole was cleaned out and circulated clean to 6000 feet. A cement retainer was set at 6000 feet and the casing tested to 1000-psi pressure. The blowout preventers were removed, and a 9-5/8 inch tubing head was installed. The rig was released on April 4, 1981.

7.5 Completion Operations

A wireline unit was moved on location on April 9, 1981. A gamma ray collar locator log was run from 5900 to 3500 feet. The well was perforated with 4 holes per foot from 4893 to 4908 feet.

7.5.1 Perforation and Injectivity Tests

A pump truck was rigged up to conduct injectivity tests. The first rate achieved was 1800 barrels of water per day for a 20 minute interval at 1450 psi, followed by a rate of 5400 barrels of water per day for a 20 minute interval at 1550 psi. The well was acidized with 20 barrels of clay fix, 2000 gallons of FE acid, 3000 gallons of HF acid, and 20 barrels of clay fix. The acid was displaced with 398 barrels of water at a rate of 3600 barrels per day at 1850 psi. The injection rate went to 21,600 barrels per day at 1550 psi when all of the acid was displaced. A pump truck was rigged up and pumped into the well at 23,400 barrels per day at 600 psi. The well then went on vacuum. A cement bond log was run from 5000 to 3000 feet. The log indicated good cement bonding in several sections from 4530 to 3050 feet. This cement had been placed outside of the 9-5/8 inch casing by Martin during several squeeze jobs on perforations from 4390 to 4480 feet. The log served as evidence that the injected salt water would not go above 4500 feet and that fresh water sands would be protected. The flowline was hooked up to the christmas tree and the reserve pits were pumped into the well at a rate in excess of 30,000 barrels of water per day at 200 psi.

8.0 TEST OBJECTIVES

The test equipment and procedures for the Crown Zellerbach Well No. 2 were designed to obtain the maximum information within the time and funds allotted.

Specific information desired was the following:

- Gas Content and Solubility
- Well Deliverability
- Formation Flow Capacity
- Aquifer Geometry
- Distance to Existing Boundaries
- Chemical Composition of Produced Fluids
- Physical Properties of Produced Fluids
- Performance of Downhole Equipment
- Performance of Surface Test Equipment
- Scaling and Corrosion Potential
- Formation Sand Production
- Disposal Well Injectivity

9.0 SURFACE TESTING FACILITIES

9.1 Design Requirements

The test facilities were designed to produce and inject the well effluent continuously and to obtain data at the points indicated on Exhibit 9-1. Design criteria were as follows:

- Wellhead Working Pressure 10,000 psi
- Flowline Shut-in Pressure 6,000 psi
- Temperature 350° F
- Brine Flow Rate 20,000 BWPD
- Separator Operating Pressure 1,200 psi
- Filter Operating Pressure 400-600 psi
- H_2S Resistance yes

9.2 Main Process Equipment

Exhibit 9-1 is a diagram of the surface test equipment. The well stream entered the flowline at the point where the two flow loops connected. The flow rate, pressure, and temperature were measured ahead of the choke manifold. Well effluent samples were obtained from a sampling port ahead of the choke manifold. The sampling port was positioned in the flow stream so that sampling could be performed at flowing wellhead conditions and before the scale inhibitor injection point. The main flow then passed through a choke manifold and through a data header. The data header incorporated a sonic sand detector and a scale and corrosion measuring coupons. The flow then entered a conventional horizontal 3-phase separator.

The separated gas was run through an Air Exchange Model 32 VVS air fan cooler. This cooler was capable of handling 1 MMCF per day at a maximum pressure of 1250 psi at 325°F. The fan was driven by a 5.0 horsepower electric motor at 1725 RPM. The unit was capable of cooling gas to within approximately 20°F of the ambient temperature. The gas then flowed from the air fan cooler through a small scrubber. The cooler/scrubber system was installed to remove as much as possible of the liquid still entrained in the gas. Removal of liquids not removed by the separator was desired for evaluation of gas measurement accuracy. After the gas left the scrubber, it was measured by an orifice meter and flared.

The separator brine passed through a flow meter manifold where water samples were obtained. The brine then flowed through a Ronningen-Petter 8-pod, 5-micron filter tower manifold which operated at maximums of 400 psi, 350°F, and 500 gallons of water per minute. The filtered brine flowed to the disposal well or reserve pit. Pressure and temperature were measured on the disposal line downstream of the filter system. Brine and solids from the filter backwash operation were collected in a 10-barrel tank for analysis. A 25-micron, 3-pod filter tower manifold was utilized as a back-up filter system.

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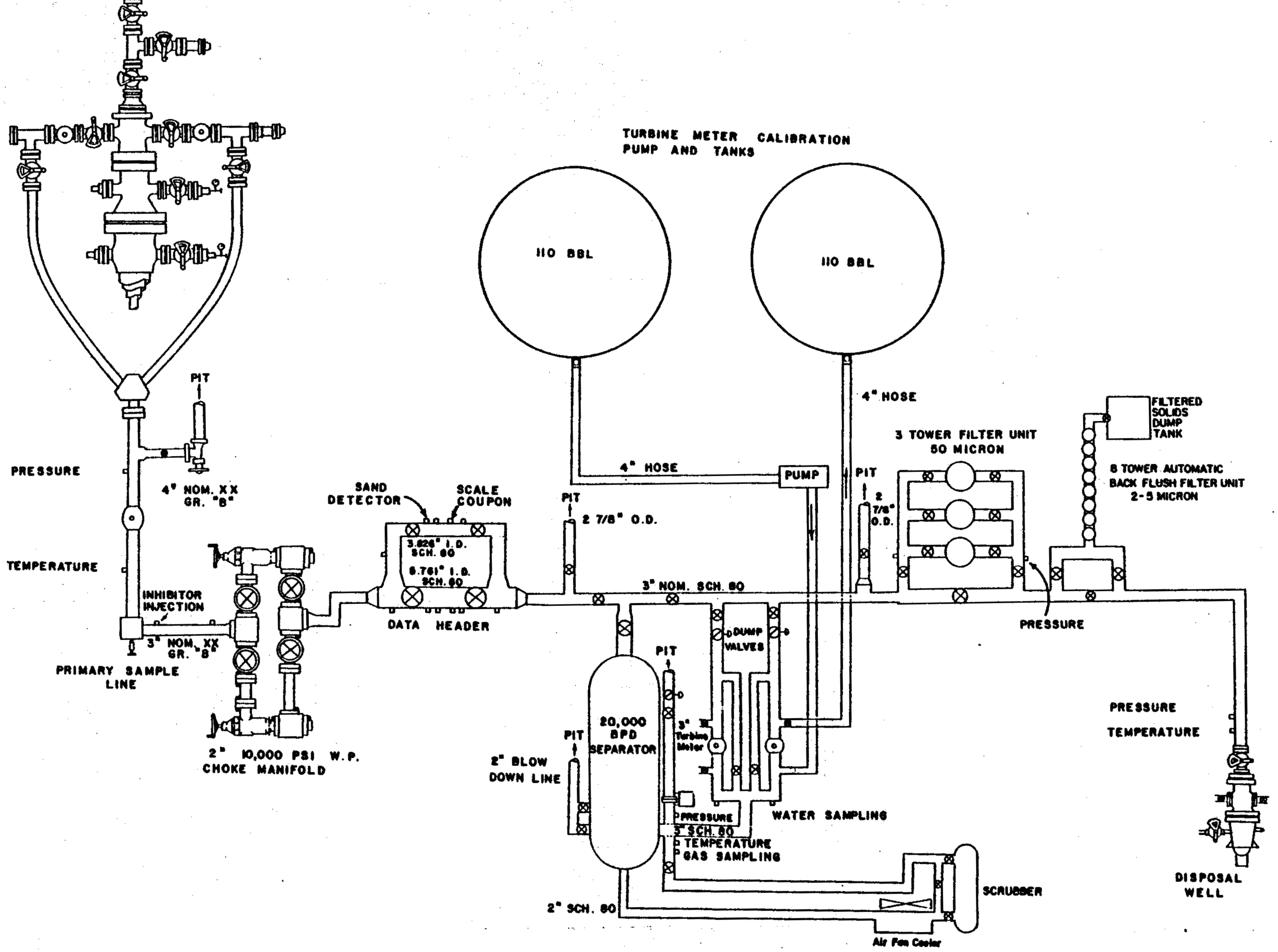
Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 9-1

SURFACE TEST SCHEMATIC



9.3 Safety Considerations

The test well christmas tree was equipped with two fail-safe pneumatic safety gate valves. The valves were set to close if the flow line pressure reached a low of 500 psi, separator pressure reached a high of 1200 psi, or the filter unit pressure reached a high of 600 psi. The pneumatic system could also be activated manually at a safe distance from the test well.

All test equipment was pressure-tested prior to flow. There were several relief and bypass lines to the pit. The separator had a pressure-relief burst plate.

Caution signs were posted to warn visitors of the high pressure and high temperature pipes and vessels. Personnel were given safety instructions and required to wear hard hats.

9.4 Data Recording

The following sub-contractors participated in recording of data for deducing the quantity and properties of produced fluids:

- Institute of Gas Technology (IGT)
- Energy Resource Measurement, Inc. (ERMI)
- Weatherly Engineering, Inc. (Weatherly)

Sensors installed and recording methods used by each are described in the following sections.

9.4.1 Data Recording (Institute of Gas Technology)

IGT was responsible for the majority of real-time electronic data collection and for the interpretation concerning the quantity and properties of produced fluids.

9.4.1.1 Sensors Provided by IGT: The following sensors were installed and provided data electronically recorded by IGT:

- **Wellhead Temperature:** Wellhead temperature was sensed by an Acromag 319-BX-4 temperature transmitter (0° to 400°F) installed in the high-pressure line between the wellhead choke and the choke manifold. In the four previous well tests by the Eaton team the temperature transmitter was installed in a thermal well recessed in a tee due to concern over sand erosion; this thermal well was in the flowing stream. Measured temperatures are a true representation of flowing brine temperature.

- **Wellhead Pressure (Annulus):** A Honeywell diffused silicon pressure transmitter (0 to 10,000 psig) was attached to a flange on the wellhead to determine pressure in the annulus. This 1/4% sensor provided backup to the higher resolution Panex gauge provided by ERMI.

- **Wellhead Pressure (Tubing):** A Honeywell diffused silicon pressure transducer (0 to 10,000 psig) was attached to ERMI's wellhead lubricator to provide a continuous record of static tubing pressure.

- **Wellhead Brine Production Rate:** IGT installed a pickup on the high-pressure wellhead turbine meter to provide flow rate recording.

- **Separator Pressure:** Separator pressure was sensed by a Honeywell diffused silicon pressure transmitter (0 to 1000 psig) installed on the downstream flange of the orifice meter.

- **Orifice Meter Differential Pressure:** A Statham-type differential pressure transmitter with a range of 0 to 400 inches of water was used.

- **Gas Temperature:** Gas temperature from a thermal well approximately 3 feet downstream from the orifice was detected by a Foxboro temperature transmitter with a range of 0° to 400°F.

- **Separator Brine Production Rate:** A separate pickup was installed on the separator brine turbine so that brine production could be electronically recorded by IGT.

- **Filter Differential Pressure:** The pressure drop across the filters was converted to electronic data using a Statham-type Gould diffused silicon differential pressure transmitter (0 to 100 psi).

- **Disposal Well Pressure:** Disposal wellhead pressure was not monitored directly due to its remoteness from the production well (about 3000 ft). A Honeywell diffused silicon pressure transmitter (0-1000 psig) was installed on the downstream side of the filter assembly instead.

- **Disposal Well Temperature:** An Acromag 319-BX-4 temperature transmitter (0° to 400°F) was mounted on the downstream side of the filter assembly to provide an indication of disposal wellhead temperature. The distance to the disposal well made this arrangement necessary.

9.4.1.2 **Data Recording by IGT:** Electrical outputs from the 11 sensors described above were directly transmitted to the recording location in the IGT trailer using four-conductor shielded cables with Amphenol 165-8 connectors at each end of the outside wiring. Output pulses from both of the turbines (separator and wellhead) were amplified and shaped using Tejas Controls Inc., "Big Tex II" amplifier units near the turbine meters. Each Big Tex II received 110 volts AC power from an extension cord. Output pulses from these amplifiers were transmitted to IGT's trailer using the same type field wire and connectors as the other data channels.

Inside the trailer, signal processing was provided by plug-in cards in an HP 6940B multiprogrammer controlled by an HP 85 computer through an HP 59500A multiprogrammer interface unit. For each of the 4-20 ma outputs of temperature and pressure transmitters a precision 250-ohm resistor was used to produce a voltage signal. The analog voltages were sequentially sampled using a relay actuator card, so that a single analog-to-digital converter card provided digitizing of all analog data. Direct counting of pulses from turbine meters was accomplished by use of counting cards in the multiprogrammer. Since counts were cumulative over the duration of a test, three cards were used in series for each turbine meter. This provided enough capacity to avoid overloading.

Control software provided for scanning of all analog channels every 5 seconds. Values measured for separator pressure and orifice differential pressure each 5 seconds were then square-root averaged over operator-selected time intervals for data recording. Linear averaging was performed for other analog channels. Time intervals for permanent records varied from 20 seconds at the beginning of each test up to as long as 5 minutes during long-term stable production or shut-in periods. Cumulative counts from the brine turbines were recorded at the time of each permanent record. Permanent records were produced both by real-time printouts and by storing of digital data on magnetic cartridge tapes. Backup strip chart recording of eight analog channels was provided.

9.4.2 Energy Resource Measurement, Inc.

9.4.2.1 Sensors Provided by ERMI:

- Preproduction Temperature Gradient
- Preproduction Pressure Gradient
- Bottom-hole Pressure
- Wellhead (Annulus) Pressure: Wellhead pressure in the annulus was sensed by a Panex quartz crystal pressure sensor.
- Brine Temperature: A temperature sensor was installed in the thermal well in the high-pressure flowline from the wellhead.

9.4.2.2 Data Recording by ERMI: While temperature and pressure gradients were being run, data recording was performed in the wireline truck. At each depth station the following actions were performed:

- Manual recording of depth as indicated by the wireline odometer.
- Observing a visual display of temperature until the value stabilized. Then manually recording temperature and pressure from the bottom-hole pressure gauge and entering these values into the HP 85 computer.

For production and buildup testing, ERMI's computer was moved to a trailer. All electrical signals from sensors provided by ERMI were transmitted to that trailer using four-conductor shielded cable without connectors outside the trailer.

Control software provided for measuring the value of each signal at the time of permanent recording. The time intervals between permanent records varied between 10 seconds at the time of change in choke settings to 5 minutes during stable flow or low rate of pressure buildup. Permanent records were produced by both real-time printing and digital recording on magnetic tape.

All ERMI raw data are represented in Appendix G.

9.4.3 Weatherly Engineering, Inc.

Weatherly provided continuous hand-recording of the following four channels of data:

- **Separator Pressure:** Separator pressure at the flange tap for the orifice meter was recorded on a 24-hour circular chart with a pressure range of 0 to 1500 psi.

- **Orifice Meter Differential Pressure:** Orifice meter differential pressure was recorded by a second pen on the same 24-hour circular chart with a differential pressure range of 0 to 100 inches of water.

- **Gas Temperature:** Gas temperature downstream of the orifice meter was recorded by a third pen on the same circular chart with a temperature range of 0^{o} to 400^{o}F.

- **Sand Detection:** The strip-chart recorder for an OIC Sand Systems, Inc., sonic sand detector provided a continuous record of sand detector output at all times during brine production.

Weatherly personnel also provided around-the-clock manual data logging of the following parameters:

- Separator pressure from the circular chart described above,

- Orifice differential pressure from the circular chart described above,

- Trends in gas production, calculated manually by multiplying the square root of the product of separator pressure and differential pressure by an orifice factor characteristic of 0.6 gravity gas at standard temperature and pressure,

- Temperature from a thermometer installed between the large choke manifold and the separator,

- Cumulative brine production from the counter on the brine turbine operating at separator pressure,

- Calculated brine production rate and gas-to-brine ratio derived from the difference in cumulative brine production at successive data logging times and the gas production estimate described above,

- Differential pressure across the filters between the separator and the disposal well,

Raw data logged manually by Weatherly is presented in Appendix E. Calculated values for gas production, brine production, and gas/water ratio in Appendix J differ from those logged manually in the field. This difference is caused by including gas temperature and composition in orifice interpretation and correcting brine flow rate to reflect brine volume at a temperature of 60^{o}F.

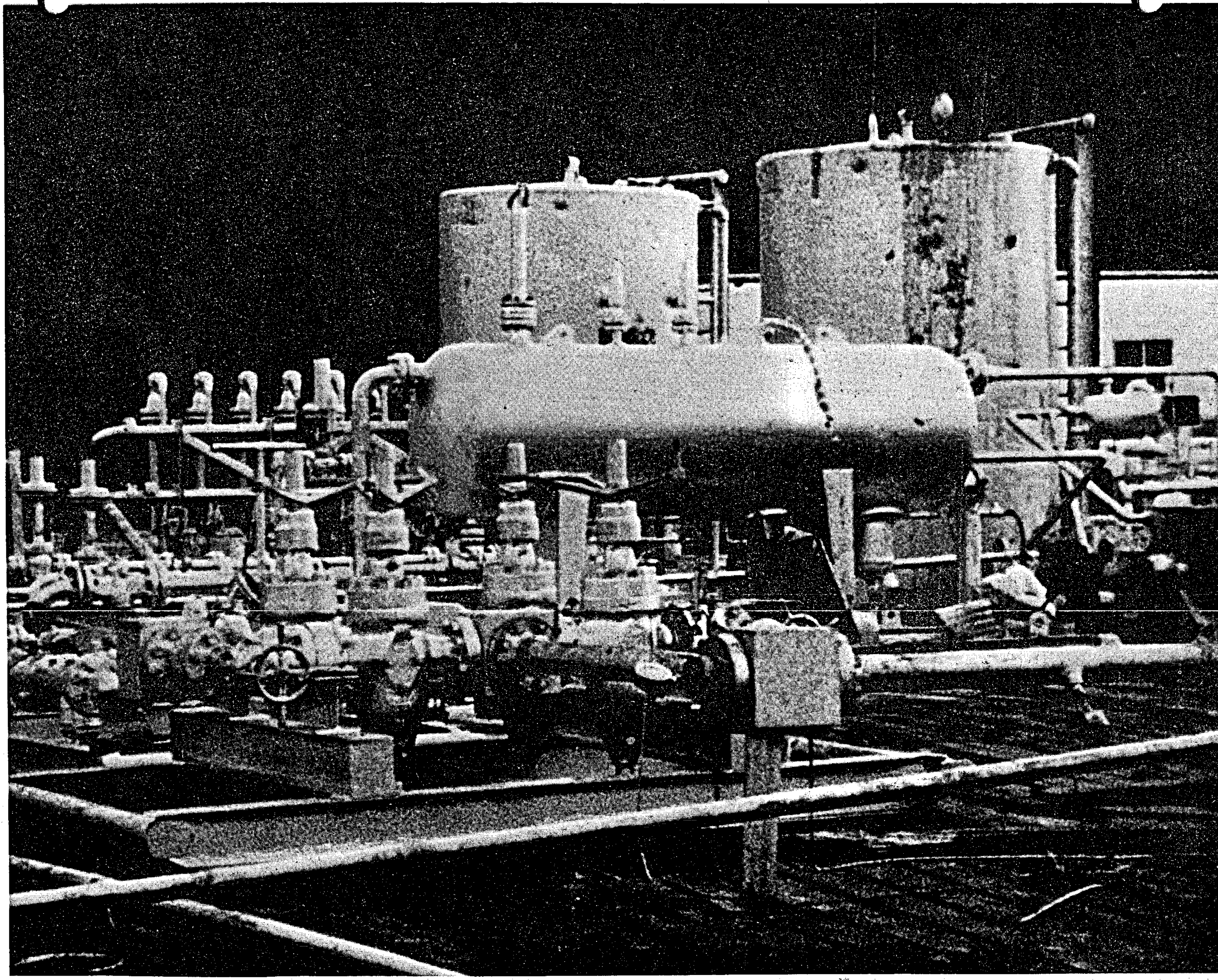


Photo 9-1: High-pressure sampling block, choke manifold, separator, and turbine meter calibration tanks

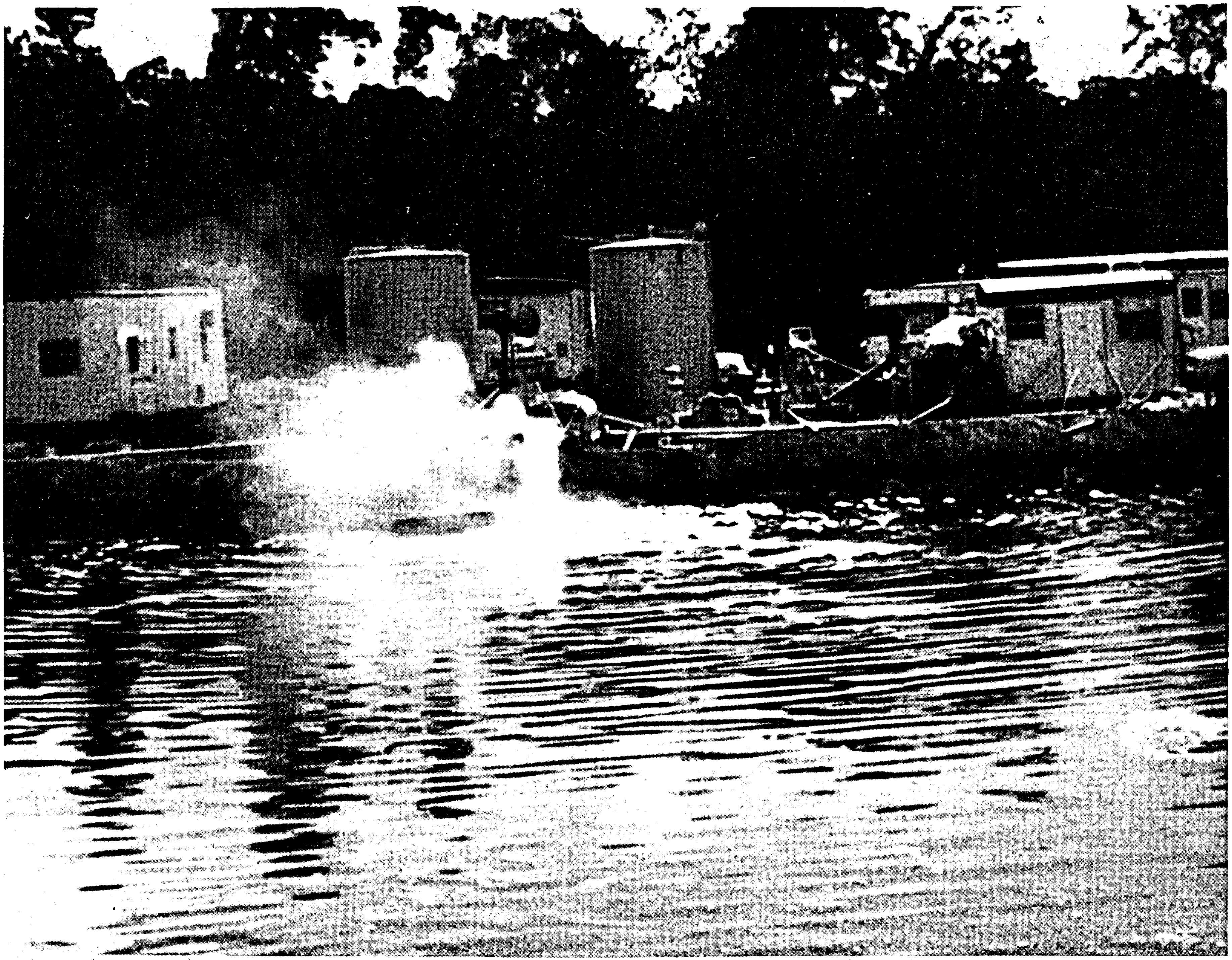


Photo 9-2: Disposal water being diverted momentarily to reserve pit. IGT test trailer is on extreme right.

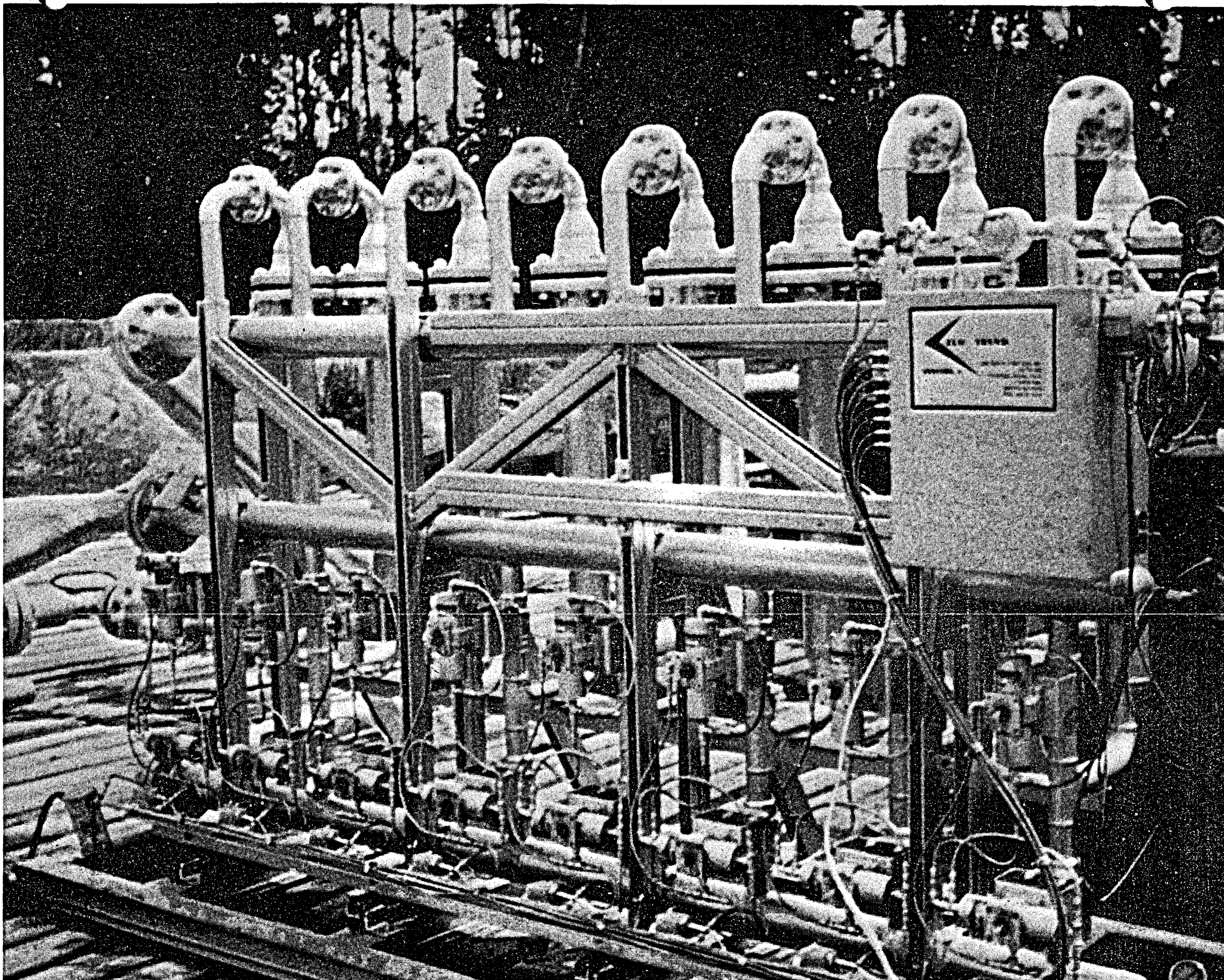


Photo 9-3: Custom-built 5-micron self-cleaning filter system, which performed well.

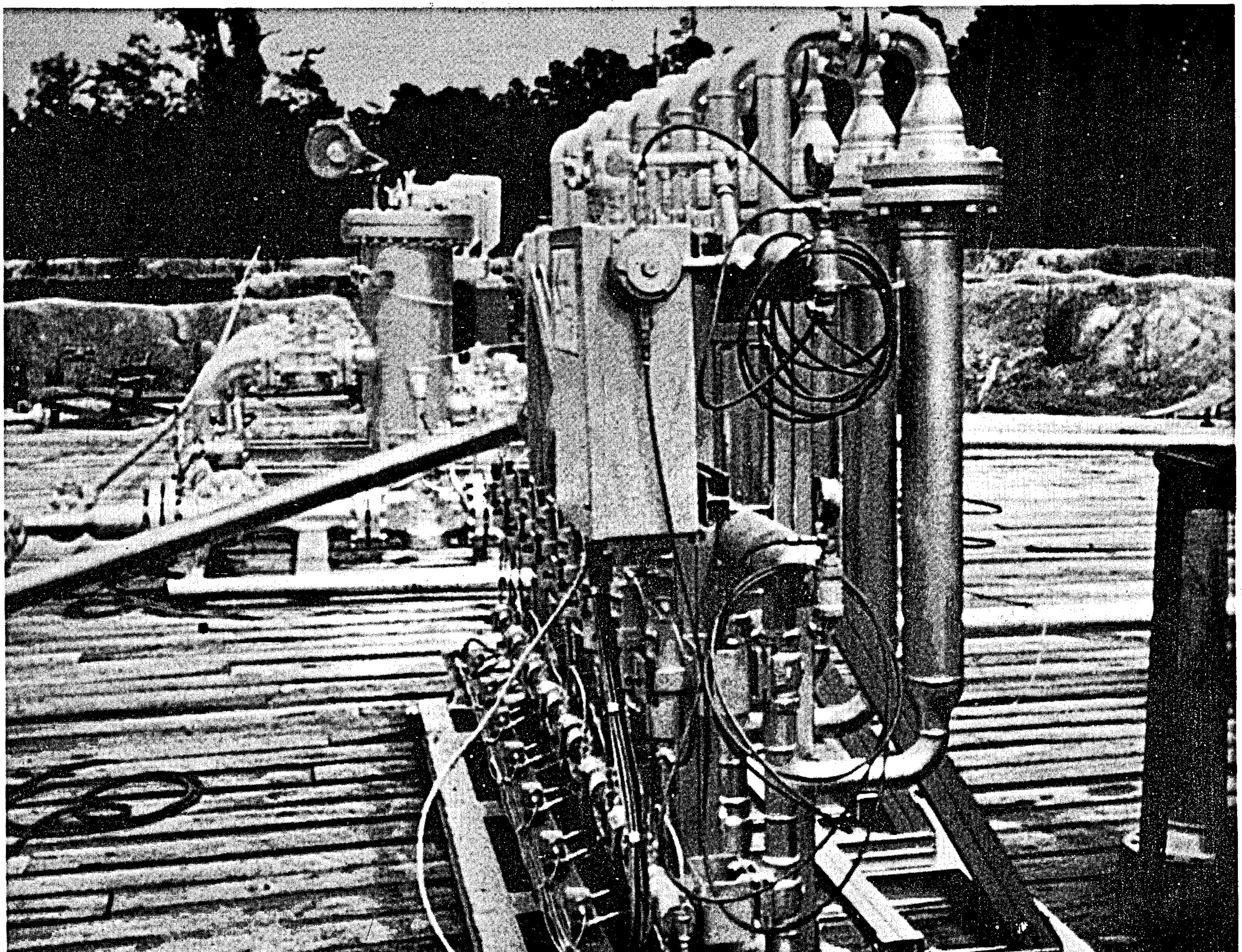


Photo 9-4: View of both filter units. Nowata 25-micron filter system is in background.

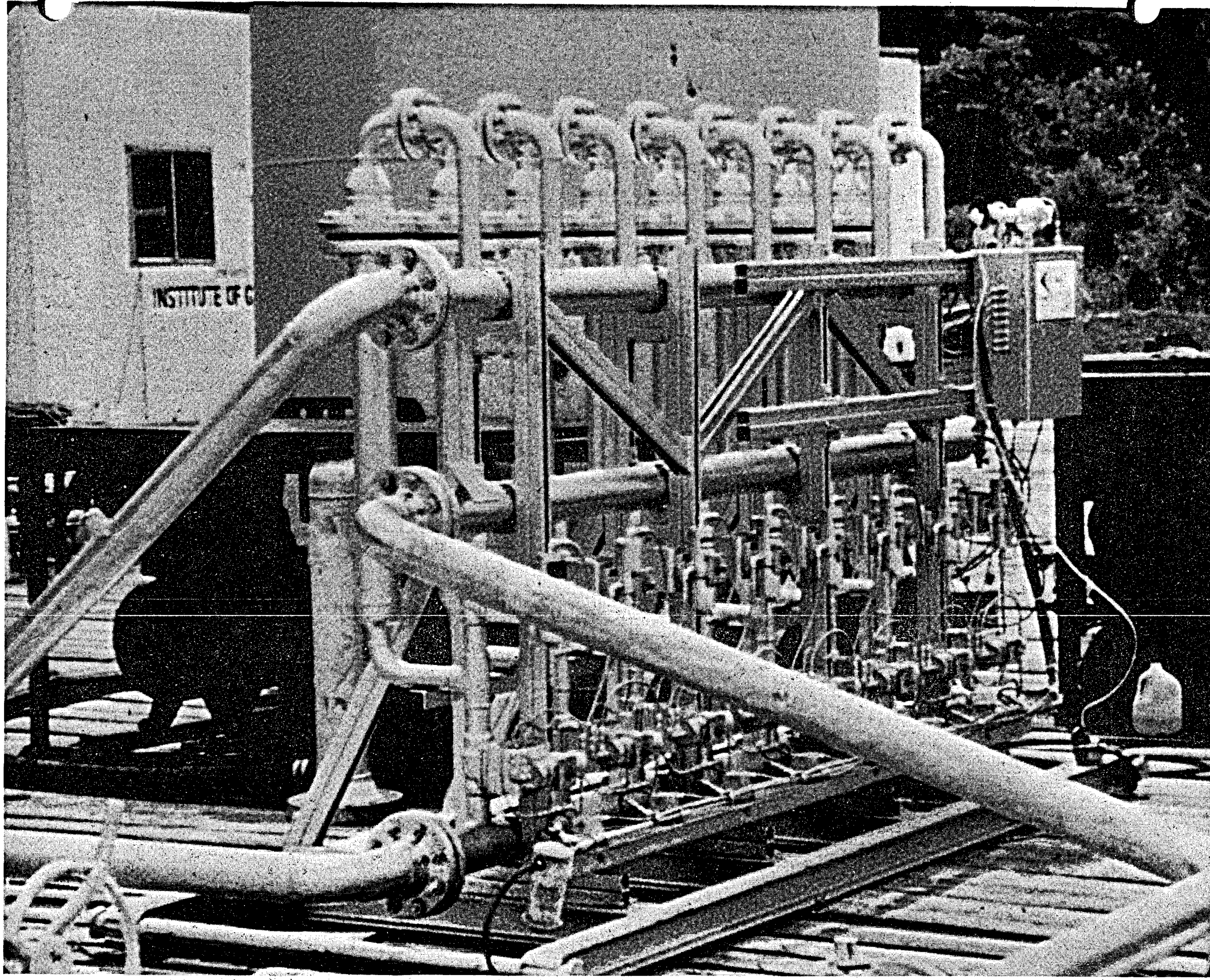


Photo 9-5: Disposal water enters filter system through center pipe. Filtered water exits through top pipe. Back-flush discharges through bottom pipe.

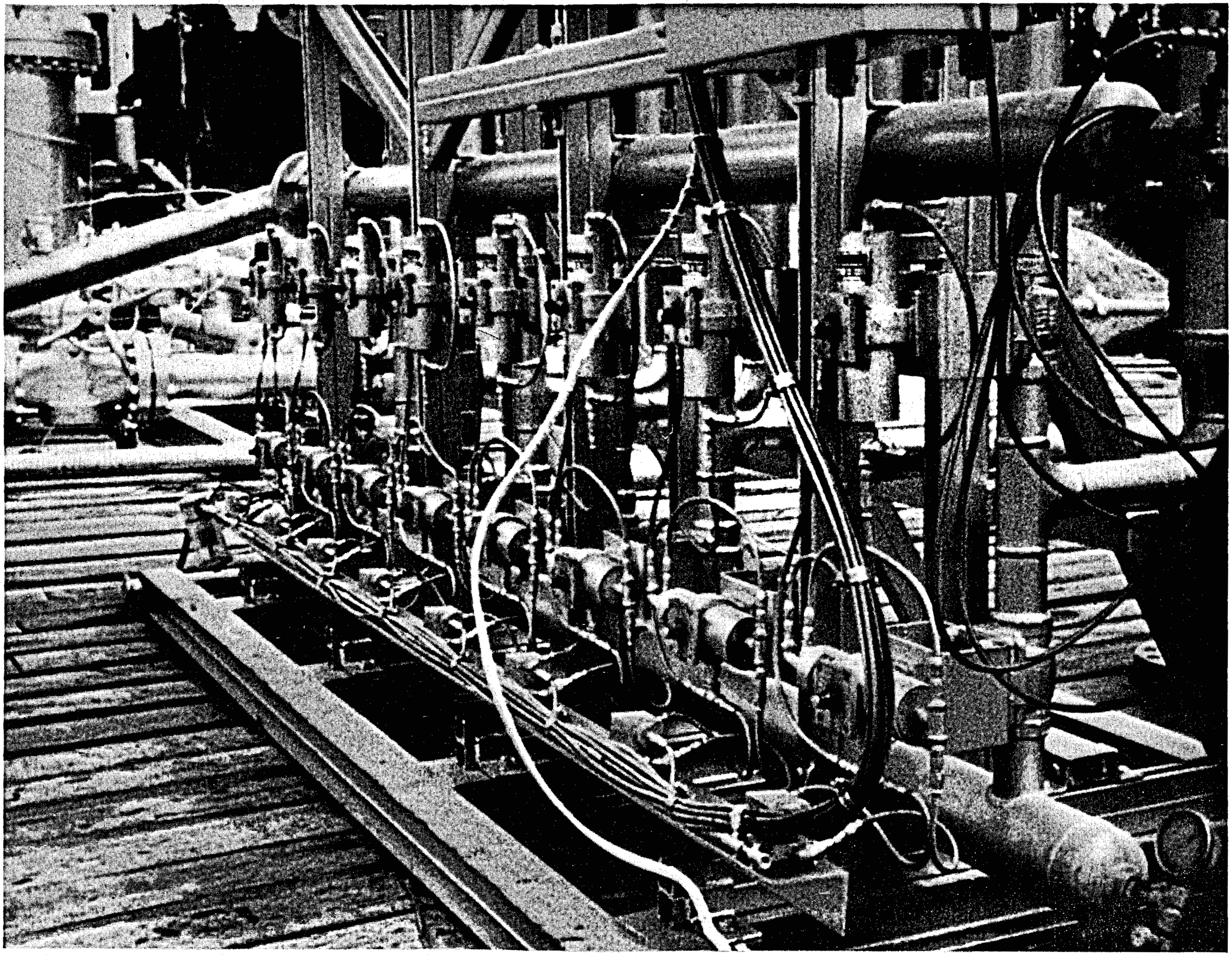


Photo 9-6: Closeup of pneumatic switching valves which allow each filter pod to be back-flushed individually

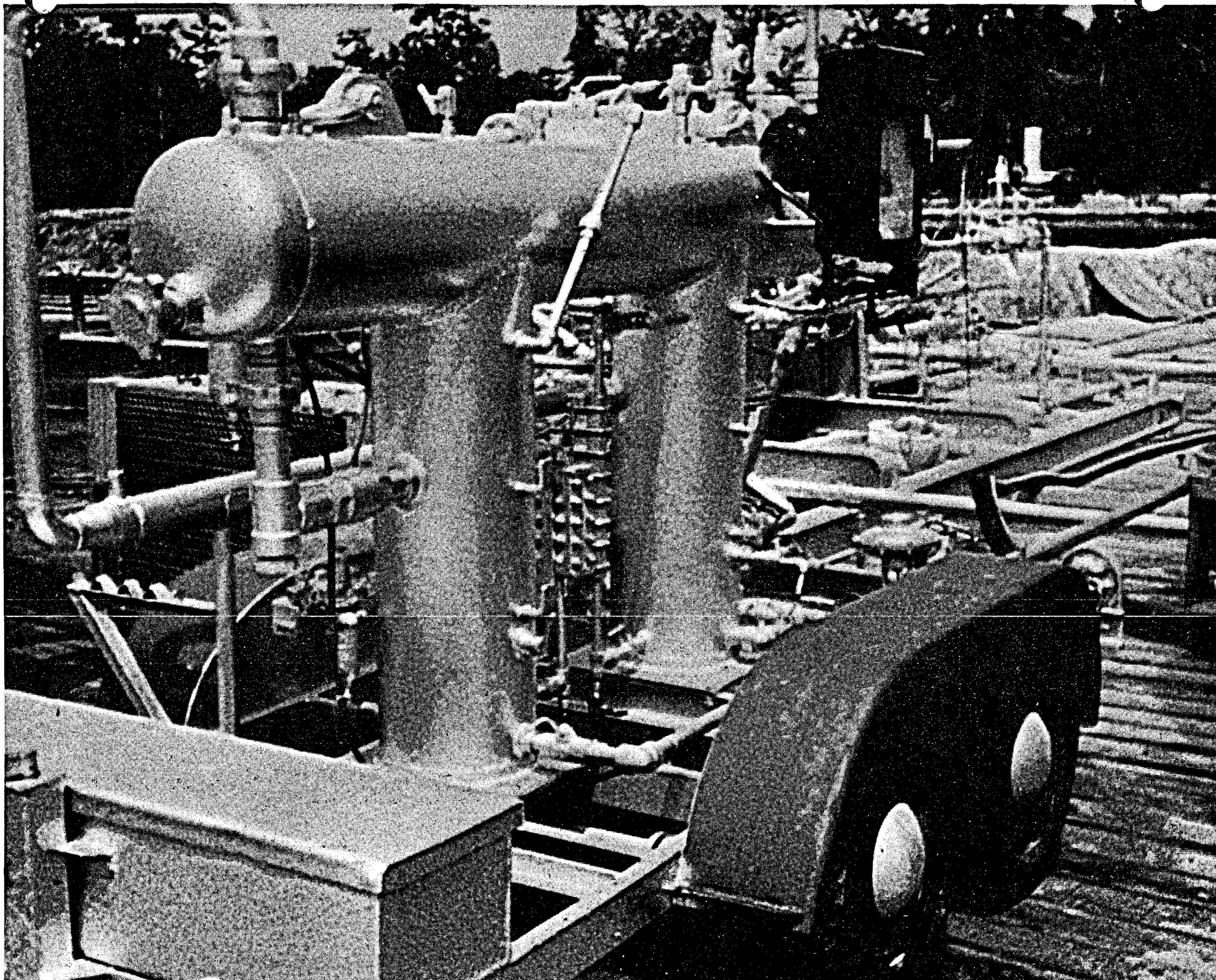


Photo 9-7: This small test separator was used as a scrubber to remove fluids from the gas line upstream of the meter run.

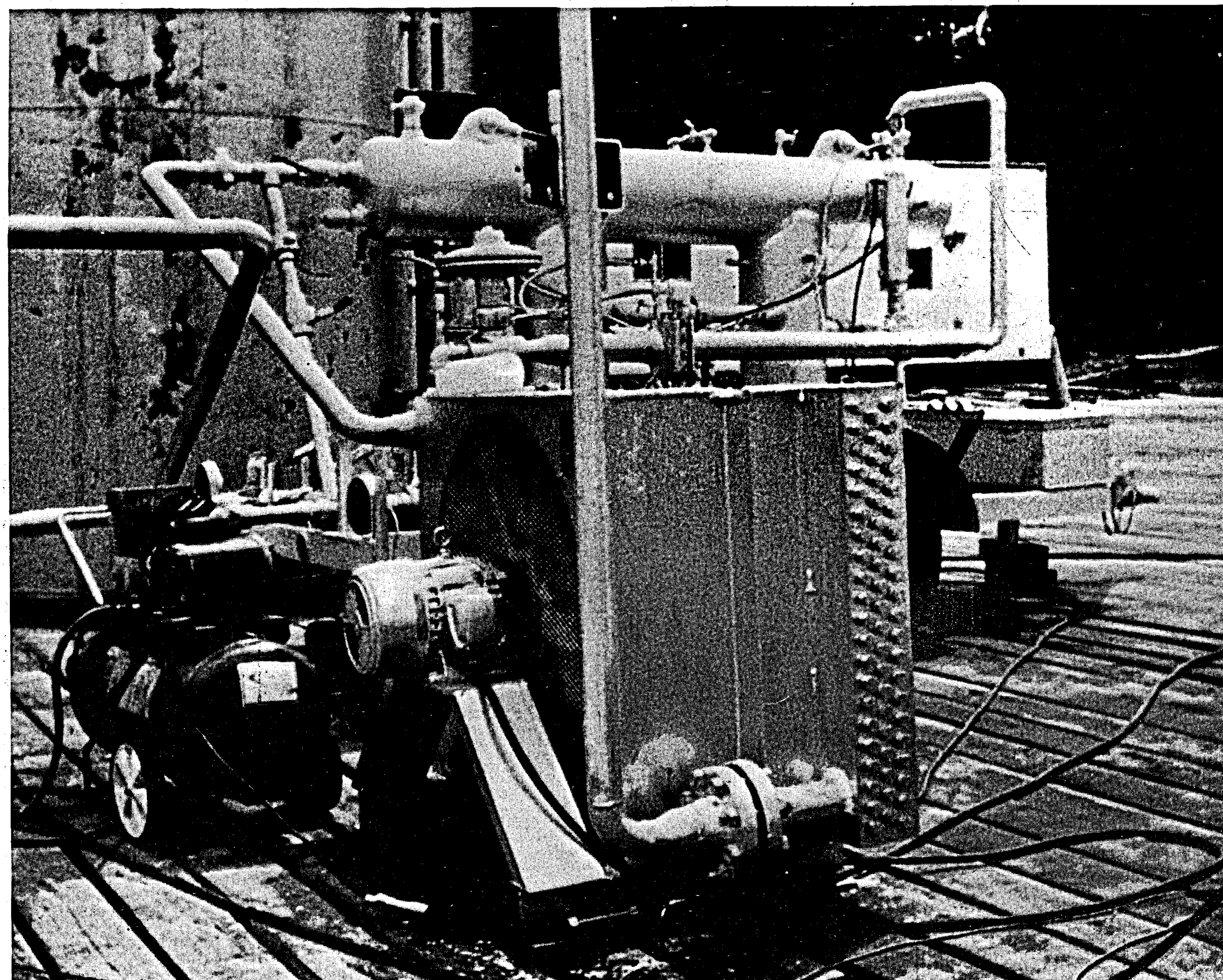


Photo 9-8: Gas entering the scrubber was first cooled by this air fan cooler.

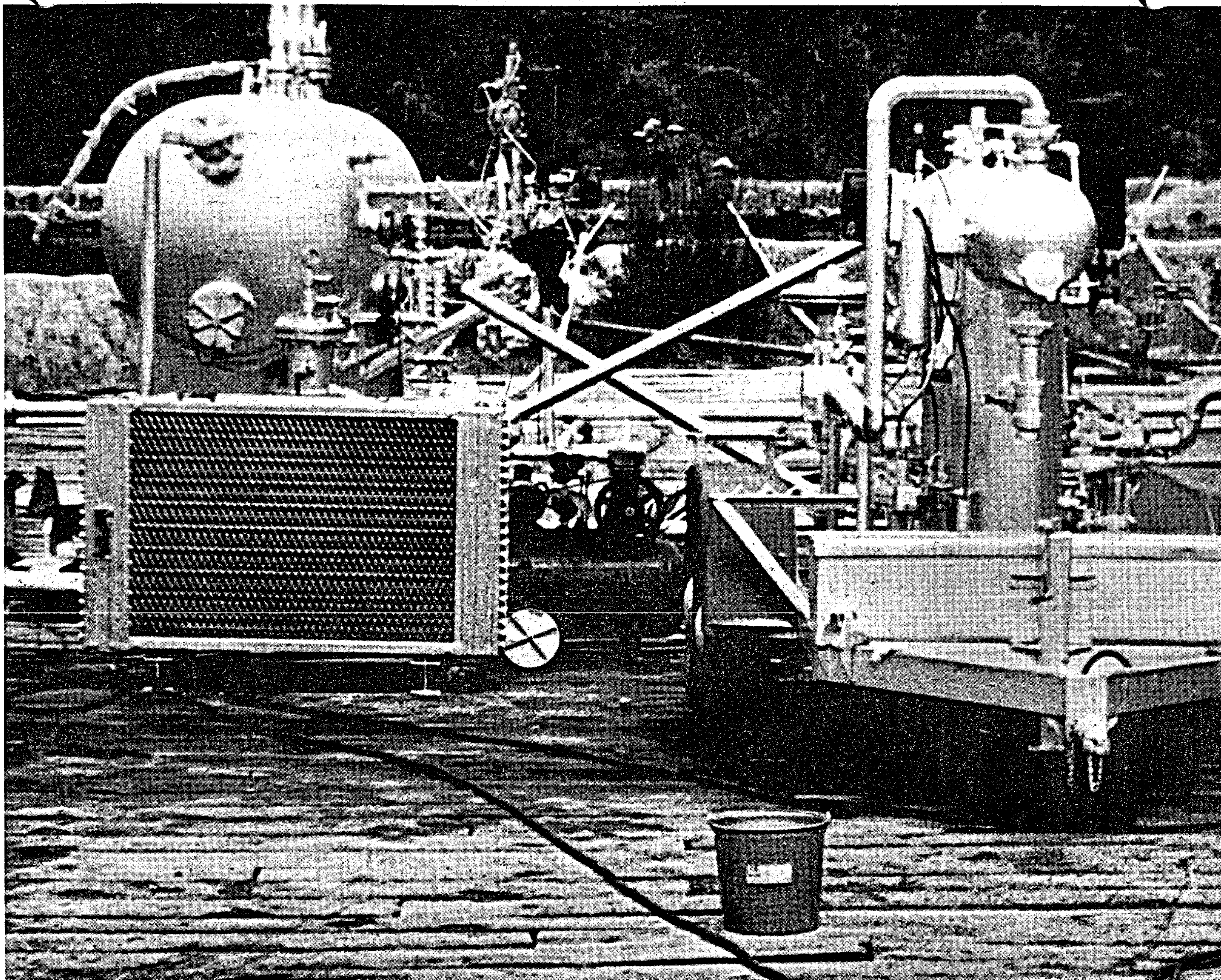


Photo 9-9: Front view of air fan cooler and scrubber

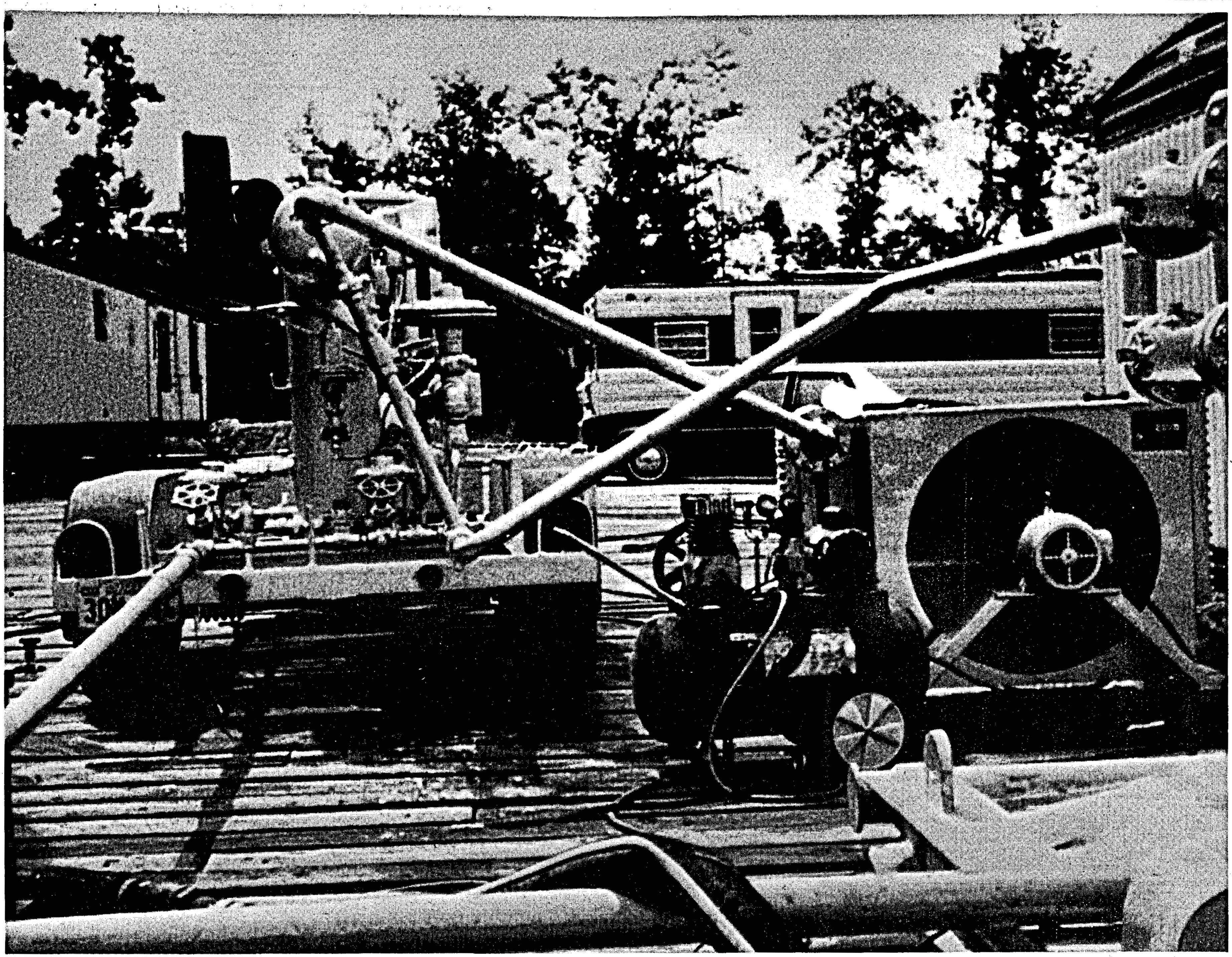


Photo 9-10: Rear view of air fan cooler and scrubber

10.0 PRE-TEST OPERATIONS

10.1 Completion and Wellbore Cleaning

The well was prepared for perforating by displacing the 13.8-ppg oil-based mud with 8.8-ppg brine water. Perforating operations were performed from May 28, 1981 through May 30, 1981. The first interval was perforated with an estimated 1150 psi pressure differential between the formation and the wellbore in the 7-inch casing by placing 3200 psi pressure on the casing. This differential was based upon the predicted bottom-hole pressure of 12,010 psi. A 20-foot through-tubing gun was used to perforate from 16,730 to 16,750 feet with 4 shots per foot. There was no change in the surface pressure when this perforating gun was fired. The well was allowed to flow, and an estimated 75 barrels of water were produced while retrieving the first perforating gun and perforating the second interval from 16,720 to 16,730 feet with 4 shots per foot. Flowing the well served the purposes of cleaning the newly perforated interval of debris and lowering the tubing pressure during perforating operations. When the well was opened to flow, the 3200 psi being held on the casing dropped to 800 psi, rose to 1200 psi and finally stabilized at 900 psi, indicating the bottom-hole pressure was lower than predicted. A measured bottom-hole pressure taken prior to the well test was found to be 10,114 psi at a datum of 16,735 feet, the midpoint of the perforations. An increase in the choke size was made after the well flowed for several hours. The new rate of approximately 2700 barrels of water per day was maintained during this period, and the well still flowed while the perforating operations were being completed. An additional gun was run to perforate the interval 16,730 to 16,750 feet with an additional 4 holes per foot. While attempting to perforate from 16,720 to 16,730 feet with an additional 4 holes per foot, the perforating gun became stuck in the tubing at 15,823 feet. The gun was worked free and pulled out of the hole. The additional perforations in this interval were not made since the benefit to the producing rate would have been minimal considering the operational risks.

The total production during the above pre-test operations is estimated to have been 1500 barrels of formation water.

10.2 Preliminary Wellbore Pressure and Temperature Recordings

Preliminary information on the Tuscaloosa formation indicated that the reservoir temperature would probably exceed the 305°F limitation placed on the Hewlett-Packard downhole pressure instrument. Energy Resource Measurement, Inc., contracted to conduct the downhole pressure and temperature measurements, had the new Panex downhole pressure and temperature instruments. The Panex probes were designed for temperatures in excess of 350°F. Two of these instruments were tested in the Brazoria-Pleasant Bayou Well No. 2 with a bottom-hole temperature of 308°F and pressures above 11,000 psia. These two new pressure probes appeared to meet all requirements for the high temperature and pressure expected in the Crown Zellerbach Well No. 2. A Hewlett-Packard quartz crystal gauge was also placed on standby basis.

The Panex probe No. 1 was placed in the wellhead lubricator at 13:00 hours on June 2, 1981. The wellhead pressure was measured at 2657.05 psia and the wellhead temperature was 90.2°F. A companion Panex surface pressure recording instrument had a reading of 2664.54 psia at the same time. Pressure and temperature measurements were recorded with stops at every 1000-foot interval as the pressure probe descended through the tubing of the well. The pressures and temperatures recorded for the gradient plots are listed in tabular form on Exhibit 10-1 and graphically plotted on Exhibit 10-2. The complete printout and record of pressures and temperatures are found in Appendix G.

The pressure probe reached a depth of 16,636 feet at 21:22:00 hours on June 3, 1981. The pressure after about 28 minutes at this depth was 10,074.58 psia, with a temperature of 327.2°F. This datum is still 99 feet above the center of perforations, or 16,735 feet. The calculated pressure at the center of perforations, using the pressure gradient equation listed on Exhibit 10-11, would be 10,113.61 psia. The temperature at this depth calculated at 329.7°F.

The pressure readings started falling off rapidly, after about one hour at the datum depth. The well was still shut in, which suggested a pressure leak in the instrument. The pressure dropped to 9394 psia within 29 minutes. The Panex No. 1 probe was removed from the well, and the No. 2 probe was readied for replacement.

The Panex No. 2 probe was run into the well on June 4, 1981 and was at datum depth of 16,536 feet at 08:31:00 hours. The pressure was recorded at 10,111.11 psia and 317.1°F upon reaching datum depth. The pressure and temperature readings continued to increase to a maximum of 10,127.50 psia and 320.2°F at 08:41:00. This is a normally expected instrument adjustment for this period of time. The pressure then started to drop off and at 12:50:00 or in about 4 hours, was 10,070.35 psia with the temperature reading constant at 320.8°F. This again indicated a pressure leak and a possible weld failure. The instrument was left in the well while the Hewlett-Packard quartz gauge was being transported to the well site. The H.P. gauge arrived around midnight on June 4, 1981. The temperature gauge in the well was relatively steady at 320.6°F just prior to removing it from the well.

The H.P. gauge was run into the wellbore, without a temperature element attached, starting at 03:11 hours on June 5th. The pressure element reached the datum of 16,566 feet at 05:45. The pressure reading at the datum depth of 16,566 feet at 08:12:30 was 9864.13 psia with a surface pressure reading of 2736.11 psia. The surface temperature was 87.9°F. The pressure recorded by the Panex No. 1 on June 2 was 10,041.73 psia, or 117.6 psi higher than this new reading. The earlier surface pressure was 2901.39 psia, or 165.28 psi higher than this recent pressure measurement. The same pressure element was used for both surface readings, which supports an actual change in both datum pressure and surface pressure during the shut-in period while pressure probes were changed out.

This variation in datum and surface can be explained by reviewing the well operations during the changing out of pressure probes. The opening of the well to the lubricator and movement of the cable through the lubricator allowed loss in wellhead pressure. This reduction does not affect the flow test, since interpretations are based upon rate of pressure change at the sand face while flowing.

The well was opened for the flow test at 08:12:30 on June 5, 1981. The H.P. instrument indicated a fairly stable pressure reading prior to the start of the flowing phase of the test. The reservoir temperature, being approximately 25°F above the reported range of operation of the H.P. gauge, did suggest delay be avoided in carrying out the production flow test. Instrument failure was expected during the flow period.

On June 7th, between 06:00 and 06:30 hours, loss of communication between the downhole computer and surface receiver occurred. The surface voltage output to the instrument was increased to its maximum, and pressure read-out returned. This suggested that the problem was increased resistence in the wireline as the flowing temperature increased. This adjustment worked for about 2 hours until, with increasing flowing temperature at the surface and resistence in the cable, the signal was again lost. The probe was then raised about 100 feet up the tubing, shortening the length of cable affected by the hot brine. This again gave temporary response.

The next plan called for moving the probe an additional 1000 feet up the tubing. During the operation of pulling 1000 feet of cable from the wellbore, a break occurred in the cable, requiring replacement. A wireline truck was sent from Houston with a new cable. The rigging up of the new cable started about 22:00 on June 8, 1981. The flow rate was maintained during this period of trouble and surface pressure monitoring continued.

The same H.P. pressure gauge was rerun on the new cable and reached the datum depth of 16,536 feet at 10:33 hours on June 9th. Pressures were monitored at this depth until 11:40:30, at which time the probe was pulled up the tubing 1000 feet to a depth of 15,536 feet. This was expected to allow continuous pressure readings for the remainder of the flow test and through the end of the scheduled buildup testing. The pressure recordings did continue to 14:00 on June 11, 1981, when the prescribed pressure buildup test was completed, and the pressure element was removed.

PRESSURE & TEMPERATURE MEASUREMENTS

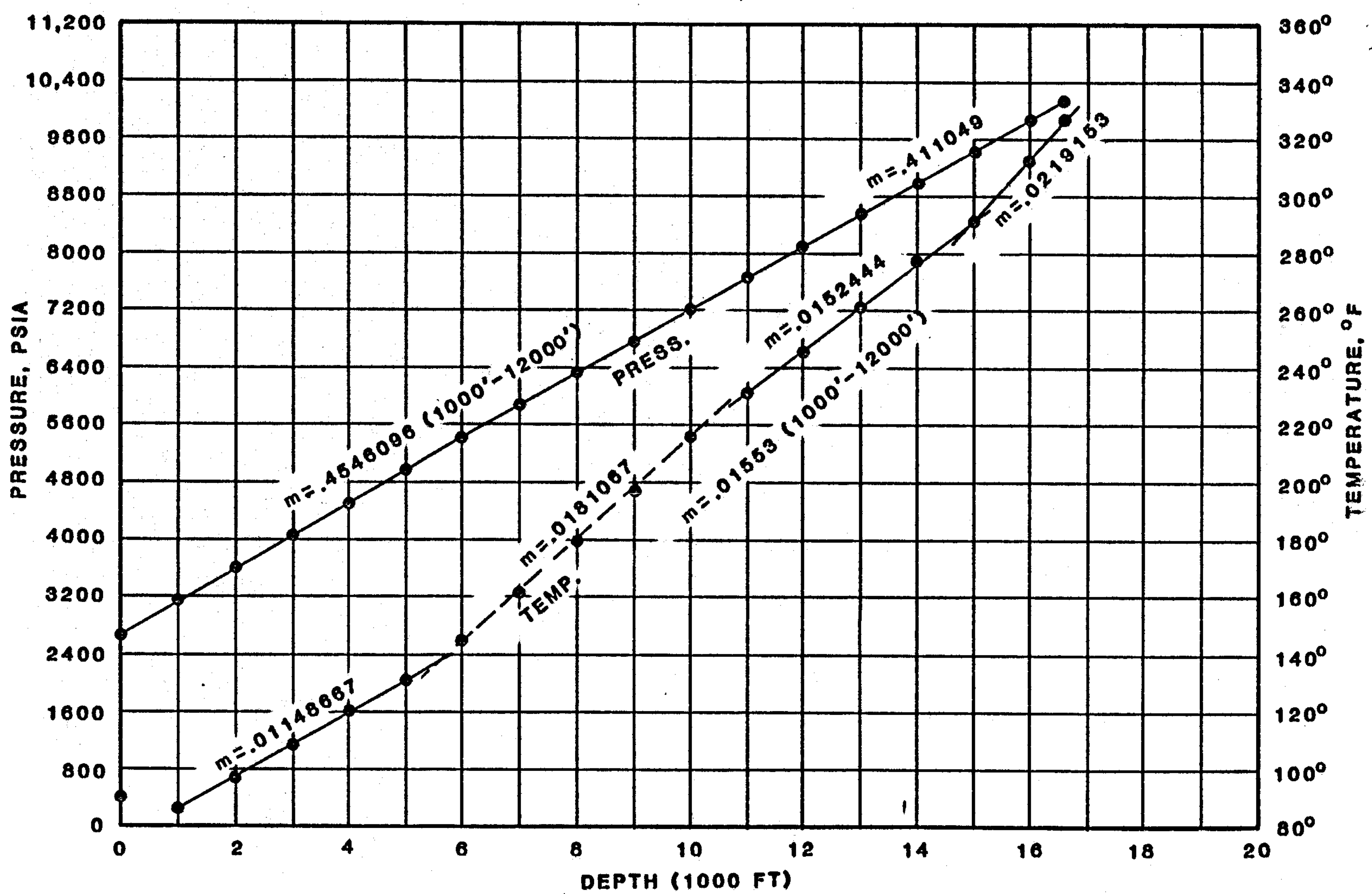
WELLBORE GRADIENTS

TIME (24 hr.)	DEPTH (Feet)	PRESSURE Psia	TEMPERATURE ^{o}F	GRADIENTS Psi/Ft	$^{o}F/Ft$
1325	0	2,657.05	90.2		
1351	1,000	3,116.70	85.6	0.4546096	0.0114867
1417	2,000	3,578.16	96.4	0.4546096	0.0114867
1442	3,000	4,039.90	107.9	0.4546096	0.0114867
1507	4,000	4,501.77	120.0	0.4546096	0.0114867
1539	5,000	4,962.66	130.7	0.4546096	0.0114867
1602	6,000	5,422.86	144.9	0.4546096	0.0181067
1624	7,000	5,882.63	161.3	0.4546096	0.0181067
1658	8,000	6,337.16	179.0	0.4546096	0.0181067
1723	9,000	6,783.39	197.7	0.4546096	0.0181067
1749	10,000	7,228.98	216.3	0.4546096	0.0181067
1817	11,000	7,674.43	231.3	0.4546096	0.0152444
1844	12,000	8,117.67	246.5	0.4546096	0.0152444
1913	13,000	8,552.69	261.0	0.4110490	0.0152444
1948	14,000	8,986.30	278.3	0.4110490	0.0152444
2018	15,000	9,429.19	292.0	0.4110490	0.0152444
2057	16,000	9,809.83	313.2	0.4110490	0.0219153
2125	16,636	10,074.58	327.2	0.4110490	0.0219153
2300	16,536	10,024.17	325.6	0.4110490	0.0219153

P (psia) = 0.4110490(16,735 ft) + 3234.707 = 10,113.61 psia

T (^{o}F) = 0.0219153(16,735 ft) - 37.09^{o}F = 329.66^{o}F

PANEX PRESSURE ELEMENT NO. 1
13:15 PM TO 23:39 PM, JUNE 3, 1981
PRESSURE & TEMPERATURE GRADIENTS
CROWN ZELLERBACH WELL NO. 2
LIVINGSTON PARISH, LOUISIANA



DOE CONTRACT NO.
DE-AC08-80ET-27081

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 10-2

11.0 TEST SEQUENCE

The test sequence for the Crown Zellerbach Well No. 2 included the short flow periods required for cleaning the wellbore after perforation. Following these preliminary cleaning flow periods, two flow tests and one buildup test were conducted.

11.1 First Flow Test

The initial reservoir pressure drawdown was conducted for 4.55 days, during which time 10,109 barrels of reservoir brine were produced. This test provided the bottom-hole pressure information for determining reservoir characteristics.

11.2 Buildup Test

The flow test was followed by a bottom-hole pressure buildup test of 1.64 days. This was sufficient to provide confirming information gained from the flow test. The bottom-hole pressure element was removed from the hot wellbore, and surface tubing pressure readings were continued after 1.54 days.

11.3 Second Flow Test

The second flow test was conducted for 0.88 days without the pressure element in the wellbore. This test was conducted to give IGT additional flow measurements and reservoir fluids for chemical analyses. A total of 2380 barrels of water was produced during this test.

11.4 Sand "A" and Sand "B" Flow Test

The previous tests were conducted on the deep primary sand, Sand "A." An upper sand, found between 16,462 and 16,490 feet, was designated as a secondary target and was called Sand "B." Sand "B" was perforated on June 23, 1981, and flow-tested jointly with Sand "A" for 2.36 days, during which 4739 barrels of water were produced. This test was conducted using only surface measurements. The purpose of this comingled test was to see if well productivity could be improved by adding this second geopressured water sand.

12.0 TEST RESULTS AND ANALYSIS

12.1 First Flow Test

The initial plan was to open the well to a flow rate of 2500 barrels of water per day, using about 30 seconds to open the adjustable choke. The rate was to remain as nearly constant as possible during the first phase of the flow test.

The Hewlett-Packard pressure element was at a datum depth of 16,536 feet within the 2-3/8 inch tubing. The reservoir fluid would flow to the surface through the annular space between the 7-inch casing and 2-3/8 inch tubing. A regular conductor cable was used for transmission of pressure data to the surface for recording.

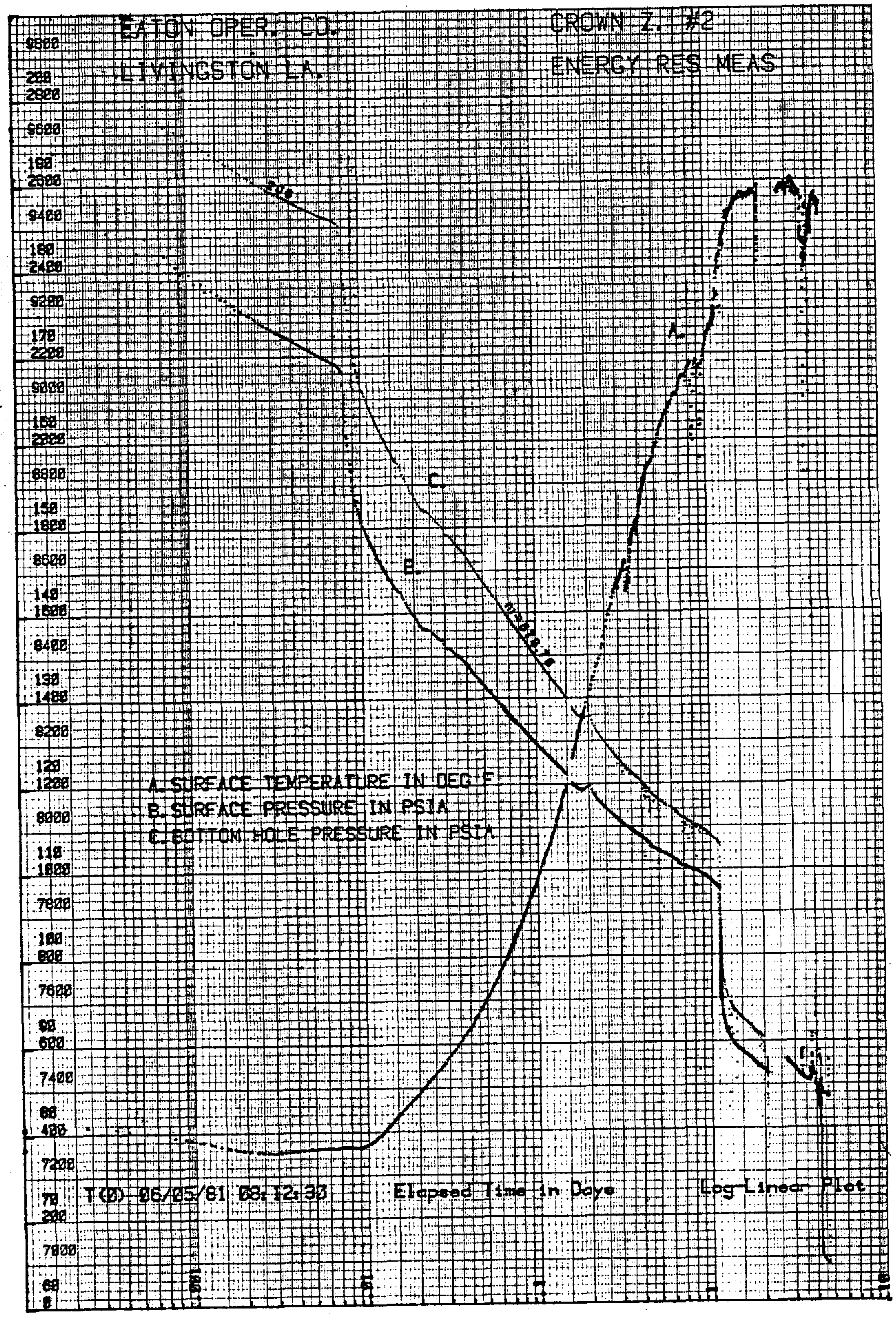
During the first opening of the adjustable choke, there appeared to be some restriction or plugging in the choke. The backup choke was then opened to the estimated flow rate. The flow meter impellers appeared to be stuck and required jarring to start movement. Some 15 minutes passed without flow readings and final adjustment of choke position. This result is depicted on the plot of bottom-hole and surface pressures on Exhibit 12-1. The starting time of effective reservoir fluid flow was depicted at 08:12:30 hours on June 5, 1981, on Exhibit 12-1 and started at 08:23:35, or 11 minutes and 5 seconds later, on Exhibit 12-1a.

The actual time that flow starts at the reservoir sand face for drawdown test interpretation is very critical during the early flow period. Exhibits 12-1 and 12-1a illustrate this very well. Notice, on Exhibit 12-1, the sudden rate of pressure drop at 0.0077 days (about 11.09 minutes), when the pressure appeared to register the effect of the second choke opening. This plot depicts a hyperbolic-type curve for the first 24 hours, with no distinct or sharp straight-line plot. The plotting of starting time at 08:23:35 hours, or where the second opening of choke occurs, gives two distinct straight-line plots of 310 psi per cycle and 521 psi per cycle in the early time. This is depicted on Exhibit 12-1a and can be interpreted as a permeability barrier close to the wellbore.

Consideration was given at this time to the question whether to shut the well in and start the drawdown test over, or to continue the test at a constant rate. The high bottom-hole fluid temperature of 329°F caused concern as to how long pressure readings from an element restricted to an operating temperature below 305°F could continue. It was already evident that this formation was relatively tight, and a long time would be required for complete buildup. The data could be confirmed in the early part of the buildup test; therefore, the decision was made to continue this flow test.

The pressures recorded at the start of the test at 08:12:30 June 5, 1981, were 2736.11 psia at the surface and 9864.12 psia at the 16,536 foot datum. Temperatures were 87.9°F and 321°F at the surface and at datum depth, respectively. At 08:23:35 surface pressure was 2163.65 psia, and it was 9302.45 psia at datum depth. The flow rate from the meter, when it became operational, appeared to be around 2779 barrels of water per day. The first corrected reading from the separator, by Weatherly, was 2352 BWPD at 11:00 a.m. or over 1.79 hours after initial opening.

The production rate of 2779 barrels of water per day, used in calculations with the first drawdown slope of 310 psi per cycle, was arrived at by studying several sources of data



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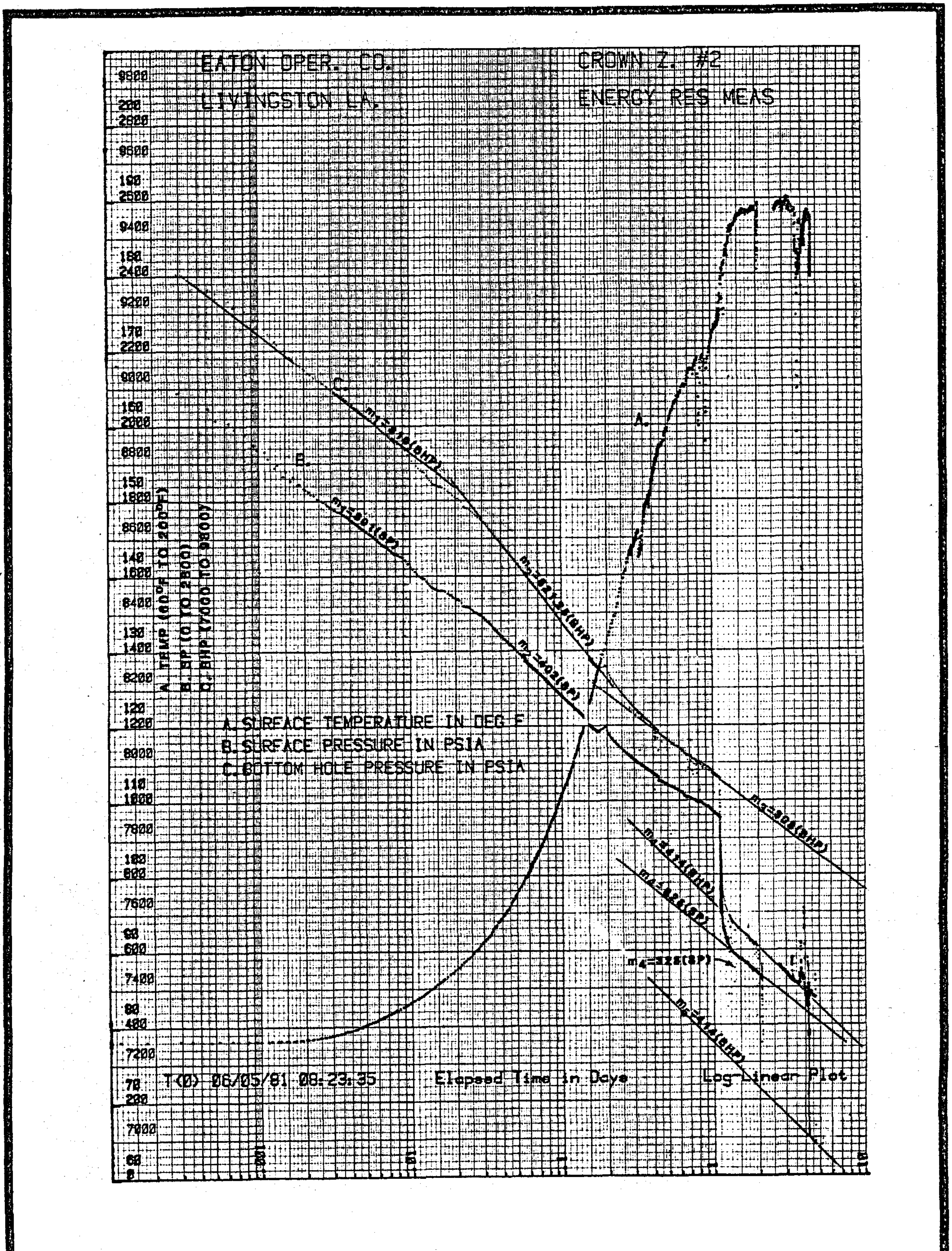
Eaton Operating Co., Inc.

EXHIBIT 12-1

DOE CONTRACT NO.
DE-AC08-80ET-27081



Eaton Industries of Houston, Inc. EXHIBIT 12-1a
Eaton Operating Co., Inc.

DOE CONTRACT NO.
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tabulated during the early flowing test period. Weatherly records depicted 66 barrels of water produced prior to 10:30 hours, or their first recorded production. This would correspond to 3168 barrels of fluid per day for this first 30-minute flow period. Weatherly's rate of production for the next 30-minute period was 2352 barrels of water per day, or a mean average for the first hour of 2760 BWPD. This is comparable to the first available metered rate registered at 2779 BWPD, during the time of the first slope of 310 psi per cycle.

The production rate occurring during the second flow slope of 521 psi per cycle declined from 2460 to 2210 BWPD, for an average rate of 2335 BWPD. If the rate had been constant, the change in slope would have been expected to be 620 psi per cycle, or doubled for a permeability barrier. Instead the decreased flow rate produced a correlative slope of only 521 psi per cycle. The first rate presented by IGT, and tabulated in Appendix K, "Well Test Analysis," was 2475.1 BWPD at separator temperature and pressure and 2462.2 BWPD at standard temperature and pressure. This value is listed at 10:30 a.m. or about 1.3 hours after reservoir flow began, which is equivalent to 0.054 days, or well into the time plot of the second drawdown slope. This fact supports the need to have a flow meter recording in front of the separator and as near the well as possible to measure these early flow rates from the well.

The interpretation of the drawdown test for the first slope of 310 psi per cycle will give the fundamental reservoir data for all interpretations that will follow. Exhibits 12-2 and 12-2a depict the basic calculations for this first flow test. The radial flow slope of 310 psi per cycle allows a reservoir productivity of 495.27 md/ft. The permeability is 14.15 mds for 35 feet of net sand. This information is sufficient for an early conclusion that this reservoir is not capable of producing at rates above 2500 BWPD for any extended period of time.

The skin effect calculation on Exhibit 12-2 is shown as a negative 1.65. This again shows the effect of not having a constant producing rate from the beginning of the flow test through this first radial flow period. To eliminate the negative value, the slope would have to be reduced, and the pressure at 1 hour on the slope would also be smaller. This would allow a larger value for the actual drawdown for the first part of the skin effect equation. In other words, the starting time adjustment between Exhibits 12-1 and 12-1a was fair but still not accurate enough to eliminate the negative skin factor. The buildup test that will be discussed later will present additional information on this phase of the interpretation.

The intercept of the 310 and 521 psi per cycle slope occurs at about 0.02 days or about 197 feet from the wellbore. This is interpreted as the distance to the first permeability barrier. This radial distance encloses a radial area of about 2.8 acres. With 35 feet of net sand and 1230 barrels per acre/foot, for porosity of 17 percent, the volume of water in this area would be 120,540 barrels. Exhibit 12-2a shows that the calculation of water explored using the drawdown slope of 310 psi per cycle is 132,169 barrels. The two methods give reasonably close values for correlation of range of accuracy.

The value of explored water at the end of the 521 psi per cycle slope at 0.4 days is 1,321,547 barrels. The distance explored in 0.4 days is 880 feet from the wellbore. A radial area of 880 feet would comprise 55.85 acres. This would support 2,404,343 barrels of water or nearly twice that from the drawdown slope. Therefore, the barrier is a positive condition to reduce the pore volume to the value seen from the slope calculation. Please note that the rate of production for this drawdown slope was 2335

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST

FOR

GEOTHERMAL-GEOPRESSURED WELL

Test date: June 5-9, 1981 Type Test: Drawdown Lease and Well No. Crown Zellerbach No. 2

Producing Formation: Tuscaloosa-Upper Cretaceous, Sand "A" Field: Wildcat (Livingston Parish)

Hole size: ____ Casing Size: 7" Tubing Size: 2 3/8" State: Louisiana

Cumulative Production: ____ Gas Gravity: ____ Z: ____

Constant Rate Production: 2779 (bbls/day) Water Salinity: ____ PPM Total Solids

Total Production Life: 0 days Porosity, ϕ: 0.17 Gas-Water Ratio: 32.07 ft^3/bbl

Reservoir Temperature: 329.7 ^oF Net Pay: 35 ft. Perforations: 16,720-16,750 ft

μg ____ cps μw 0.3169 cps Bw 1.0722 R.B./B. Bg ____ R.B./MCF

C_T 3.43 $X10^{-6}$ Cg ____ $X10^{-6}$ Cw 3.12 $X10^{-6}$ C_r 1.5 $X10^{-6}$

m 310 psi/cycle P at 1 hour: 8535 Sg 0.0 Sw 1.00 Pi 10,113.61 psia @ 16,735 ft.

Pf ____ psia @ 16,536 ft.

Pi ____ psia @ 16,536 ft.

I. Calculation of kh (md-ft) and k (md):

kh = 162.6 (Q)(B)(μ)/(m)

kh = 162.6 (2779) (1.0722) (0.3169) / (310) = 495.27 md-ft

k = (495.27) md-ft / (35)ft = 14.15 mds

II. Bg = (Pb)(Tf)(Z)(1000)/(5.61)(520)(P_R) =

Bg = ( ) ( ) ( ) .34279/( ) = ____ Res. bbl/ MCF

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP skin

$$s = 1.151\left[\left(\frac{Pi - P_{1hr}}{m}\right) - \log\left(\frac{K}{\phi\mu C_t r_w^2}\right) + 3.23\right]$$

$$s = 1.151\left[\left(\frac{(9864)-(8535)}{(310)}\right) - \log\left(\frac{(14.15)\,10^6}{(.17)(.3169)(3.43)(.085)}\right) + 3.23\right] = -1.65$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)( )( ) = ____ psi

IV. Diffusivity, η

η = .006328 (k) /$\phi\mu$ C_T =

η = .006328 (14.15) / (.17)(.3169)(3.43) 10^{-6} = 484,571 ft^2/day

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: June 5-9, 1981 Type Test: Drawdown Lease and Well No. Crown Zellerbach No. 2

Calculation of Productivity Index (B/D-psi) and Completion Efficiency, CE

$$J\ (\text{actual}) = \frac{Q_w}{P_i - P_f} = \frac{(2779)}{(9864 - 8535)} = \underline{2.09}\ \text{bbls/D-psi}$$

$$J\ (\text{ideal}) = \frac{Q_w}{(P_i - P_f) - \Delta P\ \text{skin}} = \frac{(2779)}{(9864 - 8535) - (\quad)} = \underline{\qquad}\ \text{bbls/D-psi}$$

$$CE = \frac{J\ (\text{actual})}{J\ (\text{ideal})} = \frac{(\quad)}{(\quad)} = \underline{\qquad} \quad \text{or} \quad \underline{\qquad}\ \%$$

Distance to Barriers or Discontinuities, d $\qquad d = 2\sqrt{\eta t}$

$$d = 2\sqrt{(484571)} \times \sqrt{t} = (1392)\sqrt{t}$$

time, days	SBWPD Q_w	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
.0021	2779	64	310	360°	21.9402	13,878
.02	2779	197	310	360°	2.2617	132,169
.03	2335	241	521	180°	3.01596	99,116
0.4	2335	880	521	180°	.226197	1,321,547
0.4	2160	880	308		.144555	2,067,933
1.1	2160	1460	308		.052565	5,686,812
1.3	2408	1587	414		.0536286	5,574,073
2.0	2408	1969	414		.0348586	8,575,497
4.2	2019	2853	414		.0197975	15,099,766
4.555	2019	2971	414		.0182545	16,375,614

BWPD. This is the average of the decline in production rate from 2460 BWPD to 2210 BWPD. In other words the well could not maintain the rate without continuous adjustment of the production choke.

The next slope change occurred between 0.4 and 1.1 days of time on the log scale and the slope was reduced to 308 psi per cycle from the 521 psi per cycle. The production during this period of time was relatively constant at about 2160 BWPD. The rate change from 2334 to 2160 would account for only 7.5 percent of the slope change or a change only to 482 psi per cycle. The slope change was a 59 percent reduction, which indicates improved productivity at about 880 feet from the well. This is interpreted as the result of increase in net sand from about 35 feet to about 60 feet of net sand. The acreage explored for a distance of 1460 feet with one barrier is approximately 77 acres. Thirty-five feet of net sand at 1230 barrels per acre/foot would be 3,315,000 barrels of water. The "Y" function or slope calculations depict 5,687,000 barrels of water. A net sand of 60 feet for 77 acres at 1230 barrels per acre/foot would allow 5,683,000 barrels of water.

The reservoir values having been established, the decision was made to increase the production rate to around 2400 barrels of water per day. This dropped the pressure to between 7500 and 7400 psia and developed a slope of approximately 414 psi per cycle. The ratio of the slope change for the increase in rate should have allowed a slope of 343 psi per cycle. The slope might have continually decreased to this value if the test could have continued. But at about 05:30 hours on Sunday, June 7th, the H.P. pressure element started losing signal to the surface. The voltage was adjusted to maximum and improved signal response temporarily, which indicated that the increasing flowing temperature up the wellbore increased the cable's resistence and led to loss of signal.

The pressure element was moved up the wellbore 100 feet, thereby shortening the wire resistence between the pressure probe and the surface. This brought a strong signal back and pressure monitoring continued.

The flowing wellbore temperature again gave resistence problems in the cable, so it was decided to move the pressure element up an additional 400 feet, 500 feet above the original datum of 16,536 feet. During this operation it was found that the cable was frayed after about 430 feet had been pulled through the lubricator.

The decision was made to pump heavy salt water into the tubing and equalize the 529 psi surface pressure. This would make it possible to strip out the cable at zero pressure on the tubing head, while still maintaining the flowing drawdown test with casing flow. The chance of losing the pressure element and cable in the hole would be minimized.

A field examination of the cable did not find the effect of any type of chemical reaction or damage. The cable had gone in and out of the well about four times without problems. This portion of the cable had not been in other wellbores prior to this test. Therefore it was concluded that the upper flow tube was just sufficiently large to handle a cold wireline, but after flowing for two days the wellhead temperature of 198°F was sufficient to expand the cable enough to cause binding as it passed through the upper flow tubes.

The cable was stripped from the well and another cable brought to the well site. The replacement cable was at the well site on June 9, 1981. Exhibits 12-1 and 12-1a have missing bottom-hole pressures during this period of changing out conductor cables.

Before the pressure element was returned to the wellbore, the heavy salt water in the tubing was displaced with fresh water. The same Hewlett-Packard pressure probe that had been operating successfully at these high temperatures was rerun into the tubing. The pressure element was run into a depth of 16,536 feet and left for one hour to allow pressure correlation with previous data at this depth. After the one-hour period, the element was raised to a new datum of 15,536 feet, 1000 feet above the previous datum. The purpose was to shorten the cable subjected to the high temperature and thereby allow the additional operating time to complete the initial test.

The plan was to continue the drawdown test at a constant rate for an additional 12 hours and then shut the well in for the buildup test. This was planned to allow a minimum of 48 hours of buildup pressure measurements if desired. The temperature with the well flowing was expected to be around 319°F at the probe depth of 15,536 feet.

The next bottom-hole pressure reading that can be used for interpretation occurred between 4.2 and 4.555 days. The flowing pressures at instrument depth were between 6930 and 6882 psia with a drawdown slope of approximately 414 psi per cycle. As can be seen on the log scale, this is a very short plotting period and interpretation of this slope is subject to considerable error. The pressure element being some 1000 feet up the hole from previous measurements would explain the decrease in pressure for that datum. The slope of 414 psi per cycle can easily be passed through these points, probably indicating no change in slope.

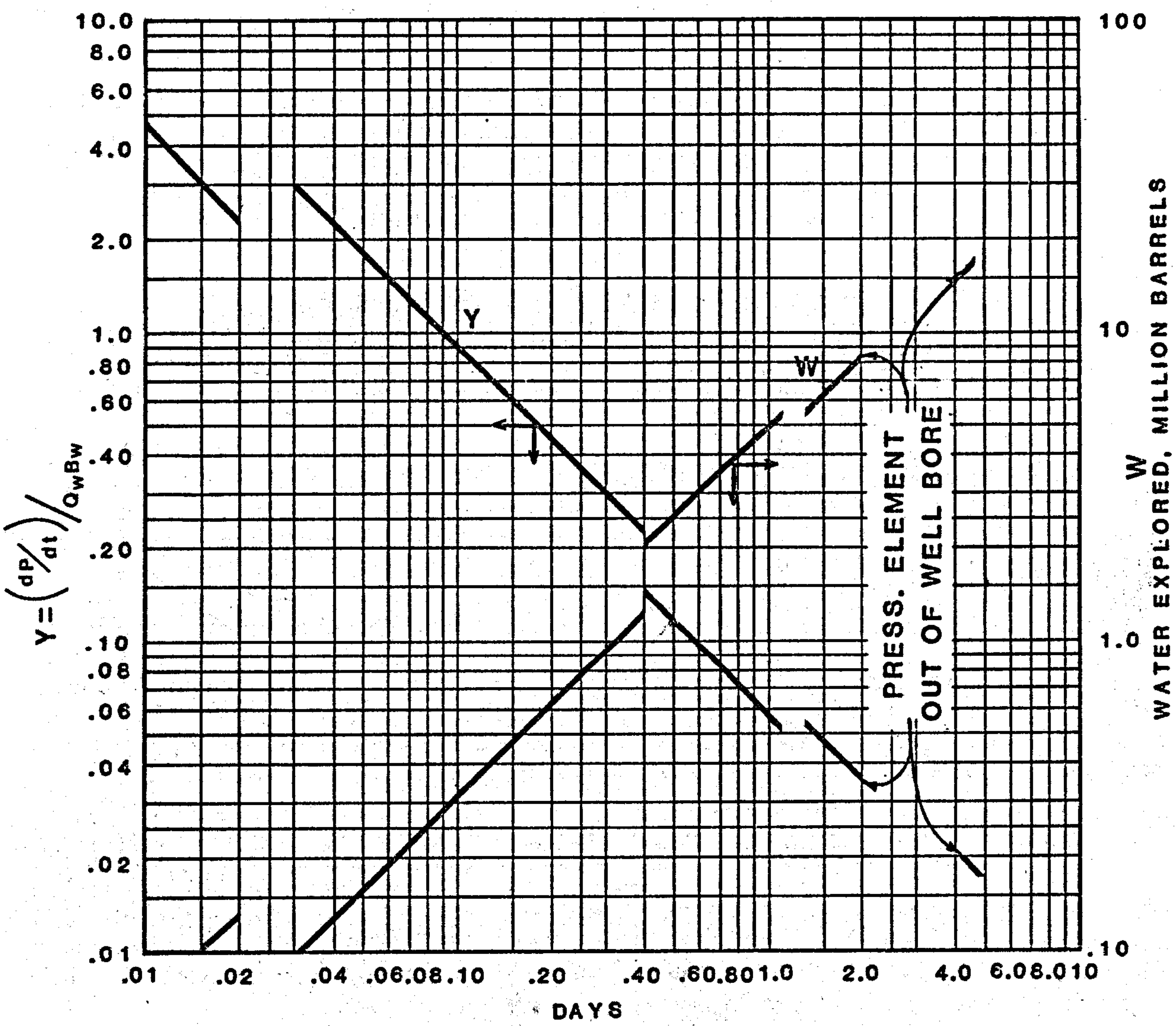
The 12-hour flow period prior to shutting the well in averaged 2019 standard barrels of water per day. The rate was reasonably steady with maximum variance between 1973.3 and to 2053.1 BWPD. The average gas/water ratio during this period was 32.04 cubic feet per barrel of water. This is very close to the total cumulative average ratio of 31.65 cubic feet per barrel. The slope of 414 psi per cycle would allow a calculated explored volume of aquifer of 16,375,614 barrels at the end of 4.555 days of testing. The radial distance tested to this time would be 2971 feet. No additional permeability barriers were detected, but this is not to suggest that additional barriers could not exist. The missing pressure data prevents detailed evaluation during that period. One permeability barrier would suggest an explored area of about 318 acres. Dividing 16,375,614 barrels of explored aquifer by 1320 barrels per acre/foot and 35 feet of net sand would suggest 354.5 acres. This probably is not additional area but could be the additional net sand that gives the additional productivity.

12.2 Exploration Drawdown Evaluation

The results of the first flow test can be summarized as volume of explored brine and this is depicted graphically on Exhibit 12-3. The "Y" function is the calculated pressure loss per day per reservoir barrel of fluid produced. Exhibit 12-3 has plotted the "Y" value of the drawdown of each semilog slope previously discussed and depicted on Exhibit 12-1a. The log-log plot of "Y" as a function of flow time is an additional aide to interpretation. Theoretically the slope of this plot should also be 45 degrees. When a flowing pressure transient reaches a permeability barrier the plot will shift upward in value but still remain a 45-degree straight line plot.

The first data plotted would be the pressure-production data to 0.02 days. This is the same information that developed the 310 psi per cycle plot found on Exhibit 12-1a. The "Y" function is used to calculate "W," the water explored at a particular flow time. This equation is as follows:

EXPLORATION DRAWDOWN
RESERVOIR BRINE
CROWN ZELLERBACH WELL NO. 2
LIVINGSTON PARISH, LOUISIANA



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$W = (S_w)/(B_w)(Y)(C_w)$ = Standard barrels of water explored

Where:

S_w = the fraction of water saturation in the pore space

B_w = the formation volume factor for the reservoir brine

C_w = the compressibility of the reservoir brine

$Y = (dp/dt)/(Q_w B_w)$, or psi per day per reservoir barrel

The plot of water explored, "W", versus time of flow in days, is the inverse plot of the "Y" function and will always plot 45 degrees going up with time. This means that as the pressure transient moves out from the sand surface at the wellbore, a greater volume of water is being explored.

The second slope on Exhibit 12-3 has shifted upward as a "Y" function plot and follows another 45-degree declining slope. This is expected when a permeability barrier is reached. The corresponding water explored "W" plot also shifts at this time, but its shift is downward, showing the rate of increase in water explored has been reduced with time. This is as it should be, since a permeability barrier reduces the area of water to be explored.

The third slope on the "Y" plot is a 45-degree plot, but shifting down, the opposite to that for a barrier. This could happen for a less viscous fluid such as a gas cap, or as in this case, it appears to be from an increase in explored volume of aquifer. This was interpreted previously as a net pay increase from 35 feet to 60 feet. A fluid having a viscosity of around 0.187 cps would be required if the other interpretation was valid. This would suggest a very very rich gas condensate or a volatile oil in the critical range of the hydrocarbon phase envelope. Therefore, a zone of higher kh, or productivity, is the most feasible interpretation. The geological environment would suggest that an increase in net sand thickness would be the most logical conclusion to meet the conditions depicted.

The next shift in the plots occur between 1.3 and 2.0 days. This is an upward shift in the "Y" function and a downward shift in the "W" or explored water volume. This would again suggest a permeability barrier but not a great loss of flow angle. This was not a definite conclusion from the drawdown graph on Exhibit 12-1a, since an increase in production occurred during this period. The missing data between 2 days and 4.2 days is during the period when the damaged cable was being replaced.

The final slope occurred during the last 12 hours of the flow period, after the pressure element was returned to the wellbore. The production rate continued to fall off, but the semilog plot could be parallel to the previous 414 psi/cycle slope. This plot gives an explored value at 4.2 days of 15,099,776 barrels of brine, and at the final point of 4.555 days the explored volume was 16,375,614 barrels of brine. This is tabulated in Exhibit 12-2a. The total brine produced during this flow test was 10,109 barrels, with 320 MCF of gas; the average gas/water ratio was 31.65 cubic feet per barrel.

12.3 Pressure Buildup

The well was shut in at 22:42:05 on June 9, 1981, with the flowing pressure at a datum of 15,536 feet of 6883.10 psia. The surface flowing pressure at this time was 474.28 psia, with a wellhead temperature of 187.3 psia. The rate of flow during the final hour was approximately 1987 standard barrels of brine per day. The well had been completely shut in at 22:45:00 or in less than three minutes. The well was producing at a relatively constant rate of 2019 barrels per day during the final 12 hours of flow. The rate varied between a low of 1973.3 and a high of 2053.1 BWPD during this final period. The average gas/water ratio during this 12-hour period was 32.04 cubic feet per barrel. This is very close to the total cumulative average ratio of 31.65 cubic feet per barrel.

The estimated gas required for total brine saturation at 10,113.61 psia and 329.7°F is 55.68 cubic feet per barrel at standard conditions (14.73 psia and 60°F). These calculations used the Weatherly PVT data presented in this report. This engineering interpretation indicates the reservoir was undersaturated by about 24.03 cubic feet (320,000 MCF/10,109 bbls = 31.65 cu. ft/bbl) (55.68-31.65 = 24.03).

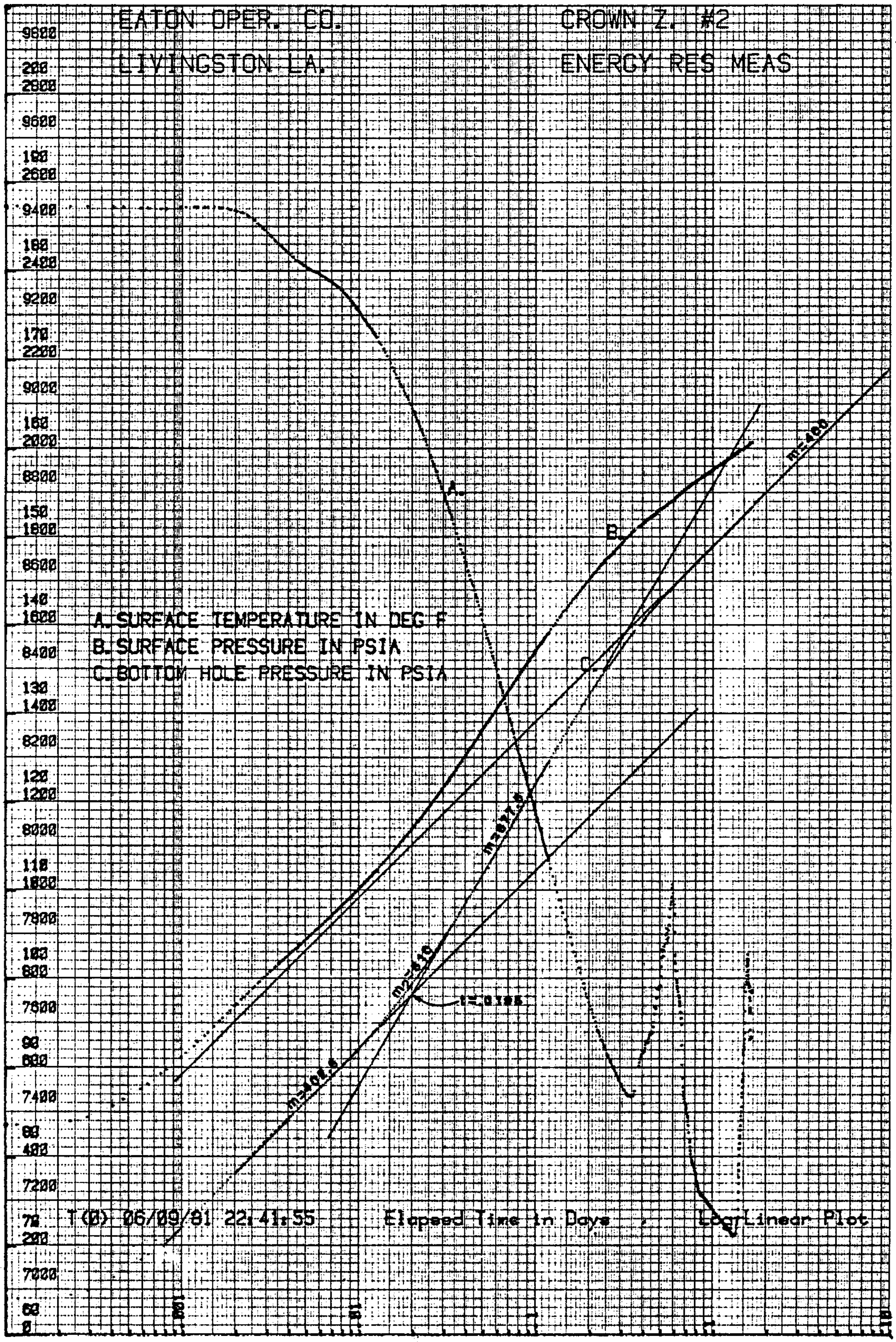
The well was flowed for 4.555 days during the first flow test period. (This does not include prior wellbore cleaning flows.) The first buildup slope was 402.5 psi per cycle and is depicted on Exhibit 12-4. The straight-line portion of this plot is found between 0.0012 and 0.012 days. The next slope is depicted as 677.5 psi per cycle and was found between 0.03 and 0.23 days. The ratio between the slopes is 1.6832. The equivalent early drawdown slopes of 310 to 521 psi per cycle have a ratio of 1.6806. This is extremely close for a check of values. This might suggest that the fault intercept is not a straight line barrier but is curving away from the well, reducing the restriction of the flow angle of 180 degrees. The effective flow angle could be 193.5 degrees.

The decrease in slope to 400 psi per cycle seen between 0.6 days and 1.64 days may have three interpretations. The reduced slope may be from the previously postulated increase in net pay, the existence of a very, very rich gas condensate cap some 880 feet from the well, or a very volatile oil having less viscosity than water. If the latter two conditions are feasible, the permeability barrier (or sealing fault) shown in geological mapping is not in the updip position. The permeability barrier is 241 feet from the well. All three conditions are possible, but the increased productivity is the preferred interpretation, when the undersaturated aquifer condition is considered.

Calculations of reservoir data are presented in Exhibits 12-5 and 12-5a. The buildup test gives a much lower value of kh, 277.13 mds, which would place permeability at 7.92 mds. This is about 56 percent less than the 14.15 mds calculated from the drawdown. In either case, the productivity is much too low to be considered for geopressured-geothermal economics.

The final buildup pressure readings were concluded at 1400 hours on June 11, 1981. The pressure measured at the 15,536-foot datum was 8668.42 psia, with surface pressure of 2013.98 psia. The total shut-in time for these measurements was 1.6369 days.

The Horner-type buildup plot is presented as Exhibit 12-6. This is the pseudo plot of flow time plus shut-in time divided by shut-in time on the log scale versus pressure. The linear extrapolation of the final plotted points to the log value of one presents an interpreted pressure of 8940 psia. These pressures were measured 1199 feet above the center of perforations. Therefore to correlate this pressure with the original reservoir



Eaton Industries of Houston, Inc. EXHIBIT 12-4
Eaton Operating Co., Inc.

DOE CONTRACT NO.
DE-AC08-80ET-27081

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST

FOR

GEOTHERMAL-GEOPRESSURED WELL

Test date: June 9-11, 1981 Type Test: Buildup Lease and Well No. Crown Zellerbach No. 2

Producing Formation: Tuscaloosa-Upper Cretaceous, Sand "A" Field: Wildcat (Livingston Parish)

Hole size: ______ Casing Size: 7" Tubing Size: 2 3/8" State: Louisiana

Cumulative Production: 10,109 Gas Gravity: ______ Z: ______

Constant Rate Production: 2019 (bbls/day) Water Salinity: ______ PPM Total Solids

Total Production Life: 4.6 days Porosity, ϕ: 0.17 Gas-Water Ratio: 32.07 ft^3/bbl

Reservoir Temperature: 329.7°F Net Pay: 35 ft. Perforations: 16,720-16,750 ft

μg ______ cps μw 0.3169 cps Bw 1.0722 R.B./B. Bg ______ R.B./MCF

C_T 3.43 $X10^{-6}$ Cg ______ $X10^{-6}$ Cw 3.12 $X10^{-6}$ C_r 1.5 $X10^{-6}$

m 402.5 psi/cycle P at 1 hour: 7695 Sg ______ Sw 1.00 Pi 10,113.161 psia @ 16,735 ft.

Pf 6883.10 psia @ 15,536 ft.

I. Calculation of kh (md-ft) and k (md):

kh = 162.6 (Q)(B)(μ)/(m)

kh = 162.6 (2019) (1.0722) (.3169) / (402.5) = 277.13 md-ft

k = (277.13) md-ft / (35)ft = 7.92 mds

II. Bg = (Pb)(Tf)(Z)(1000)/(5.61)(520)(P_R) =

Bg = ( ) ( ) ( ) .34279/( ) = ______ Res. bbl/ MCF

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP skin

$$s = 1.151\left[\left(\frac{Pi - P_{1hr}}{m}\right) - \log\left(\frac{K}{\phi\mu C_t r_w^2}\right) + 3.23\right]$$

$$s = 1.151\left[\left(\frac{(\ 7695\ )-(\ 6883\ )}{(\ 402.5\ )}\right) - \log\left(\frac{(\ 7.92\ )10^6}{(\ .17\ )(.3169\ )(\ 3.43\ )(.085\ )}\right) + 3.23\right] = -3.97$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)( )( ) = ______ psi

IV. Diffusivity, η

η = .006328 (k) /$\phi\mu$ C_T =

η = .006328 (7.92) / (.17)(.3169)(3.43)10^{-6} = 271223 ft^2/day

Eaton Industries of Houston, Inc. EXHIBIT 12-5

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Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 12-5a

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: June 9-11, 1981 Type Test: Buildup Lease and Well No. Crown Zellerbach No. 2

Calculation of Productivity Index (B/D-psi) and Completion Efficiency, CE

$$J\ (\text{actual}) = \frac{Q_w}{P_i - P_f} = \frac{(\quad\quad)}{(\quad - \quad)} = \_\_\_\_\_\_\_\_ \text{bbls/D-psi}$$

$$J\ (\text{ideal}) = \frac{Q_w}{(P_i - P_f) - \Delta P\ \text{skin}} = \frac{(\quad\quad)}{(\quad - \quad)-(\quad\quad)} = \_\_\_\_\_\_\_\_ \text{bbls/D-psi}$$

$$CE = \frac{J\ (\text{actual})}{J\ (\text{ideal})} = \frac{(\quad\quad)}{(\quad\quad)} = \_\_\_\_\_\_\_\_ \quad \text{or} \quad \_\_\_\_\_\_\_\_ \%$$

Distance to Barriers or Discontinuities, d $\quad d = 2\sqrt{t\eta}$

$$d = 2\sqrt{(271223)} \times \sqrt{t} = (1042)\sqrt{t}$$

time, days	$\sqrt{t}$	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
.0012	.0346	36	402.5	360°		
.012	.1095	114	402.5	360°		
.0195	.1396	145	intercept			
.029	.1703	177	677.5			
.23	.4796	500	677.5			
.58	.7616	794	400.0			
1.6369	1.2794	1333	400.0			

DOE CONTRACT NO.
DE-AC08-80ET-27081

CROWN ZELLERBACH NO. 2 WELL

HORNER TYPE BUILDUP PLOT

SHUT-IN AT 22:42:05 ON JUNE 9, 1981

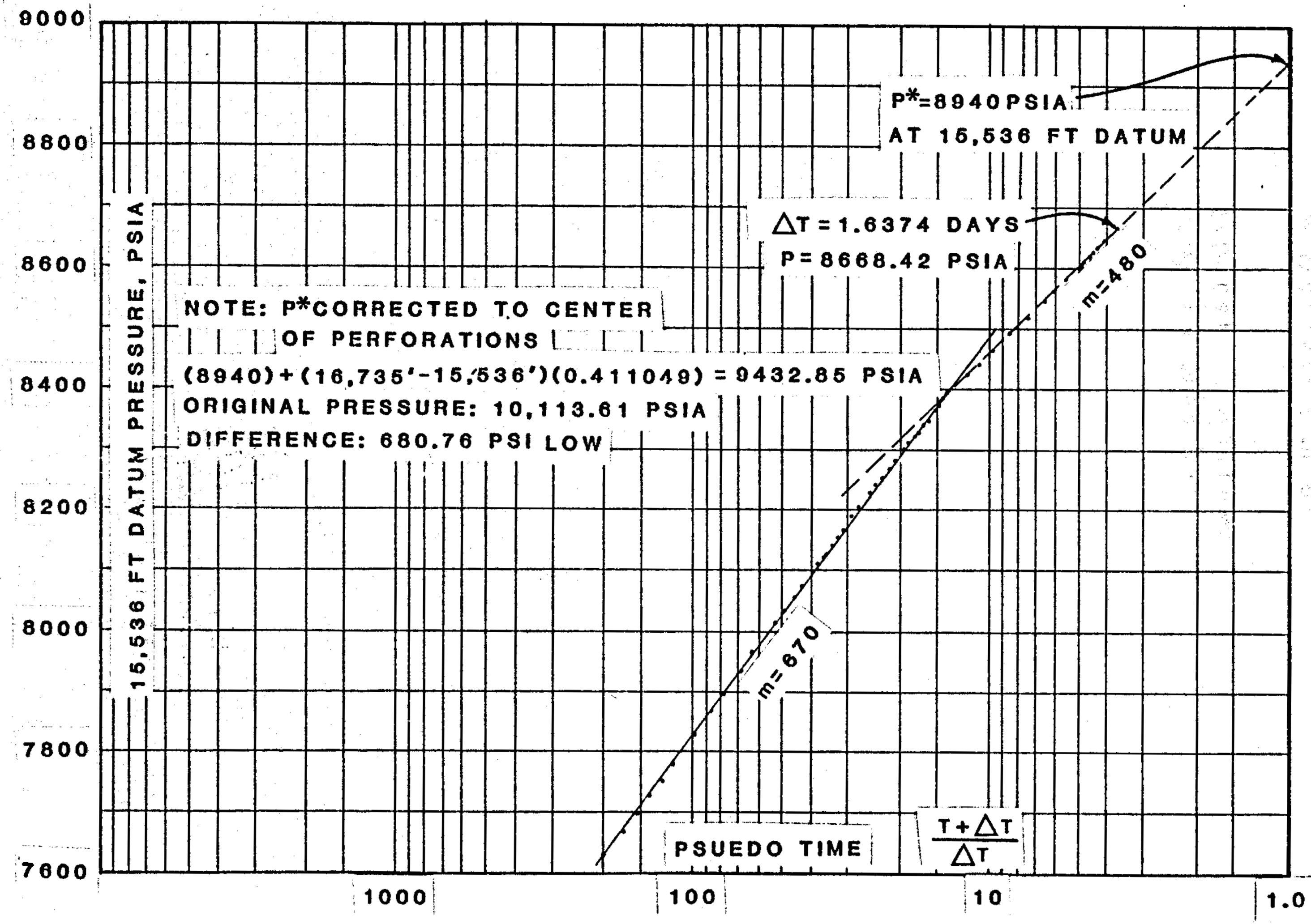

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EXHIBIT 12-6

pressure a datum correction is necessary. The calculated original pressure gradient between 13,000 and 16,636 feet was 0.411049 psi per foot. Therefore:

$$(16{,}735 \text{ ft} - 15{,}536 \text{ ft})(0.411049)+(8940) = 9432.85 \text{ psia}$$

This corrected pressure is 680.76 psi below the original pressure of 10,113.61 psia. This is not to be used as the basis for a conclusion that the reservoir lost this much pressure during the drawdown production test. The purpose of using the Horner-type buildup on a new reservoir is to determine the original static reservoir pressure. This is a good example of the inaccuracy of the use of this type of graphical extrapolation.

12.4 Second Flow Test

The second flow test was conducted while awaiting a workover rig to remove tubing before perforating an additional upper sand zone. This test was conducted between 19:30 on June 16 and 14:30 on June 17, 1981. This production test was for the purpose of gathering additional reservoir fluids for analysis by IGT. The results of this test are reported in Appendix K, "IGT Well Test Analysis." Bottom-hole pressure measurements were not conducted during this second flow test.

The total production during this flow test was 2380 barrels of water and 75 MCF of gas with an average produced gas/water ratio of 31.51 cubic feet per barrel. The cumulative total for all tests to this time was 12,489 barrels of brine and 395 MCF of gas with a cumulative gas/water ratio of 31.63 cubic feet per barrel.

12.5 Dual Reservoir Flow Test (Comingled Flow Test)

The original well test proposal presented two Tuscaloosa sands as targets for testing. The primary target, Sand A, is found at a depth between 16,718 to 16,754 feet. The test of this sand has been discussed. The secondary target sand, or reservoir, presented as Sand B in the original proposal, is found between the log depths of 16,462 and 16,490 feet. There are 228 feet of separation between the base of one sand and the top of the other. This should allow a good test of the effect of completing an additional sand in an effort to improve productivity of a geopressured-geothermal well. Sand A had a total productivity of 495.27 md-ft. This sand was not capable of producing more than 2000 barrels of brine per day for a sustained period.

The workover rig was removed from the well, and Sand B was perforated between 16,462 and 16,490 feet on June 23, 1981. The log analysis indicated porosities in this sand zone ranging from 9% to 20% with an average porosity of 13.74%. The net sand for the perforated interval was estimated at about 23 feet.

Bottom-hole pressure equipment was not run into the well for this comingled test. It was believed that sufficient information could be obtained using surface pressure measurements that could be correlated with the earlier tests. This would help lower the cost of this test.

Exhibits 12-7 and 12-7a present the flowing surface pressure and temperature measurements of the comingled test (the third flow test). The well was perforated around 01:00 hours on June 23, 1981. Energy Resource Measurement's surface-recording

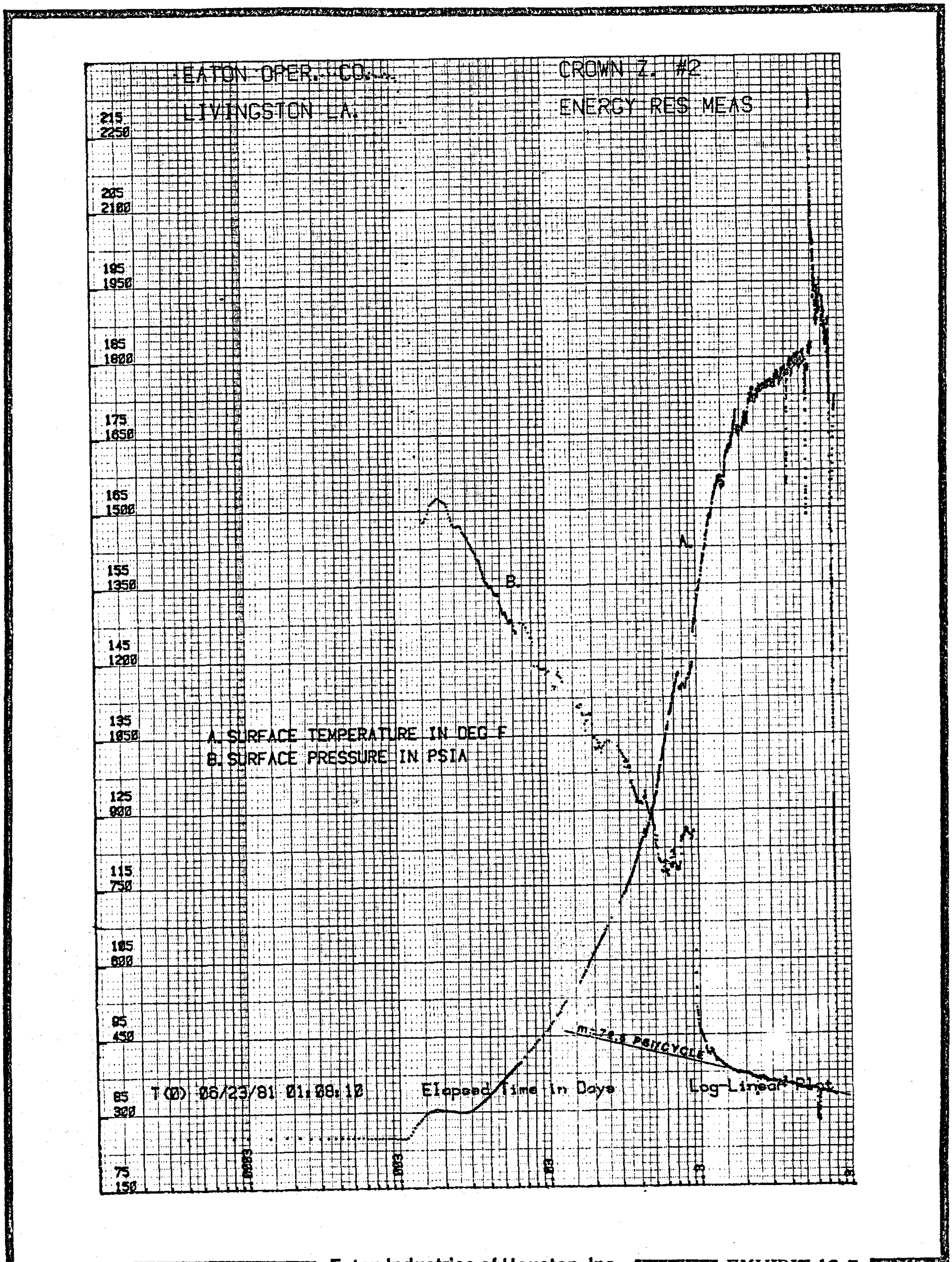

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EXHIBIT 12-7

DOE CONTRACT NO.
DE-AC08-80ET-27081

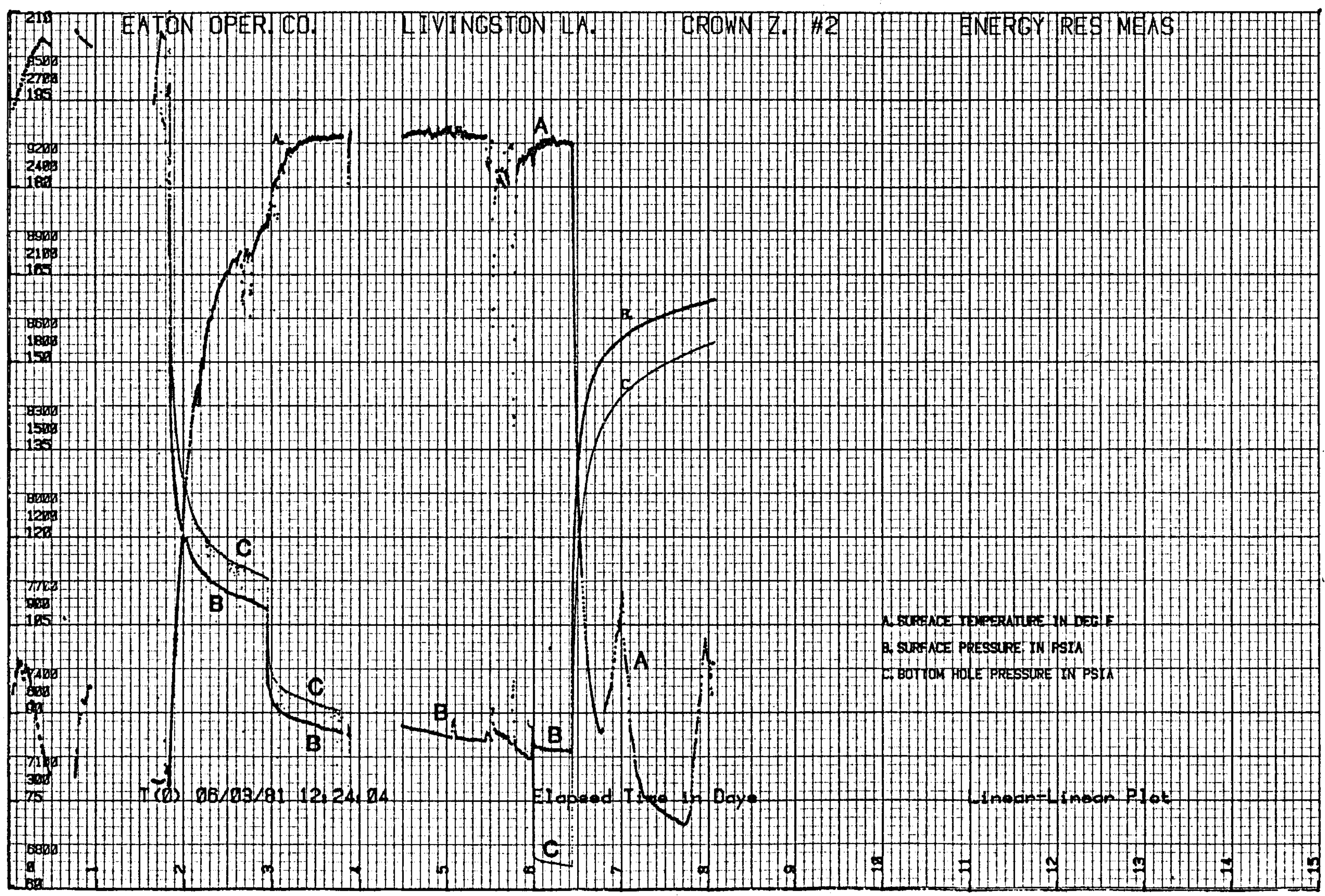

EXHIBIT 12-7a

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Panex instruments started recording surface wellhead temperature and pressure at 01:08:10 hours. This detailed data is found in Appendix G.

The first surface pressure recorded was 2371.00 psia with 81.9°F surface temperature. This is a higher pressure than the 2163.65 psia recorded prior to the first flow test on June 5th. The surface pressure cannot be correlated directly with previous surface pressure and the bottom-hole pressure due to the variation of the density of the fluid in the tubing. Fresh water had been placed in the tubing for wire line operations. Flow was through the annular space between tubing and casing; therefore any change in the amount of fresh water and formation brine in the tubing affected the surface pressure reading. A comparison of the rate of change or drawdown slope should be correlative.

The surface pressure, prior to the well flowing, varied between a high of 2389.49 psia and a low of 2363.28 psia. The well was open to flow to the surface pits at about 01:13:00 hours on June 23rd. The last shut-in surface reading was 2363.28 psia and 82.1°F. After flowing one minute and 50 seconds, or at 01:14:50, the surface pressure had dropped to 1477.97 psia, with a flowing temperature of 85.2°F. This is the low point seen at 0.0035 days on Exhibit 12-7.

The surface pressure declined continuously while the well was cleaning into the pits. A noticeable change in the pressure plot occurred at about 05:00 in the morning. This could indicate the time of the final cleaning of the wellbore.

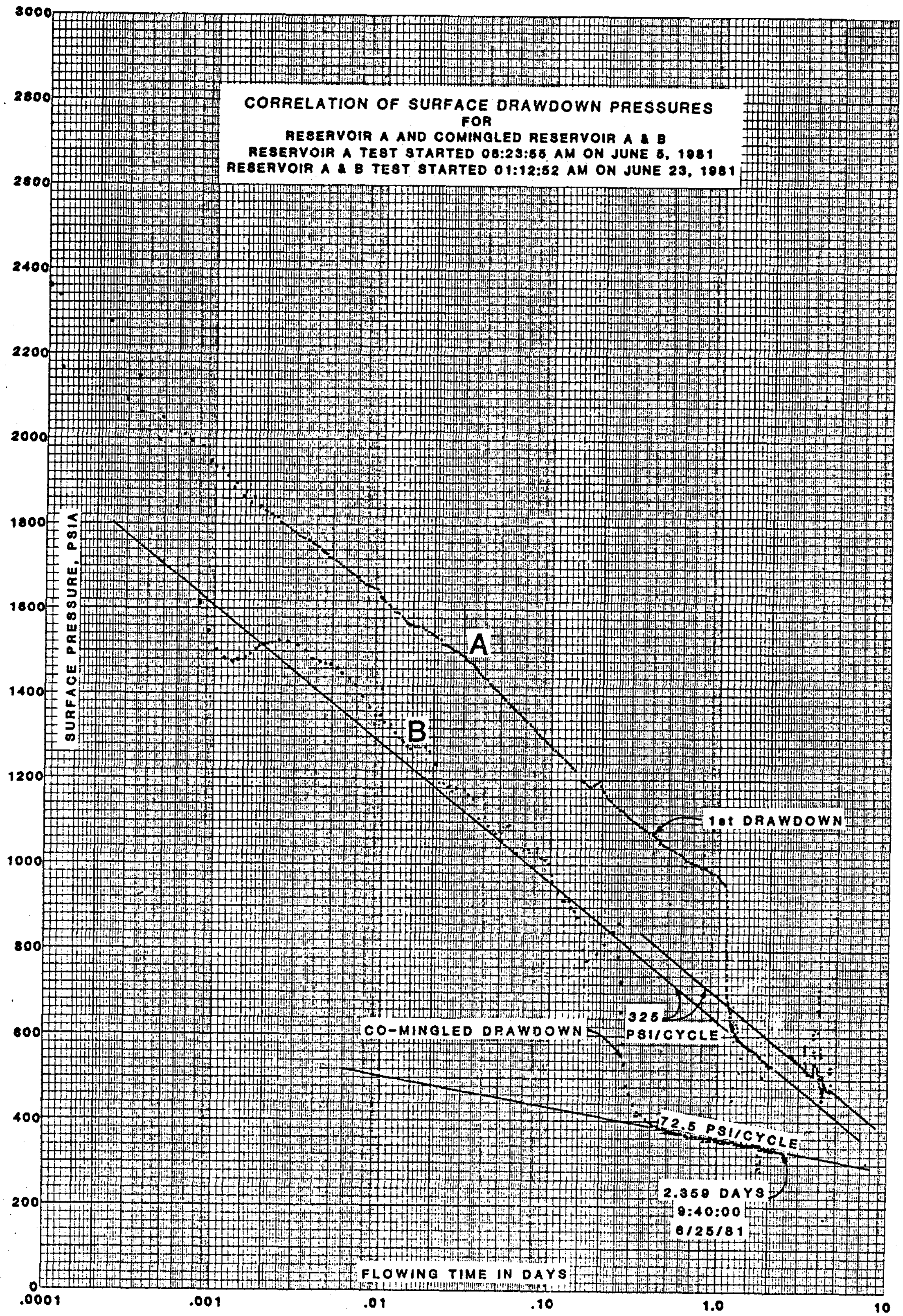
The well flow was turned into the separator and the choke was opened to a flow rate of about 3000 BWPD at about 07:52 on June 23rd. The average production rate dropped to around 2815.9 SBWPD by 09:00. The surface pressure at 09:01 was 416.76 psia with a wellhead temperature of 157.7°F. The rate of pressure drawdown thereafter remained uniform at 72.5 psia per cycle with a mean average production of about 2300 SBWPD.

Exhibit 12-8 was prepared to depict a comparison of drawdown between the previous Sand A flow and the combined Sand A and B flow. The plot designated "B" on the graph is for the comingled flow. The two drawdown slopes exhibit very similar trends for the first six hours or 0.25 days. The plot "A" flow period started at 08:23:55 on June 5, while plot "B," the comingled flow, started at 01:12:52 on June 23, 1981.

The final drawdown slopes on Exhibit 12-8 are the portion of the test that should allow comparative engineering analyses. These slopes occur after the transient effect of the permeability barrier, previously discussed, has been passed in flow time.

The flow slope between 1.2 and 4.6 days for Sand A is around 325 psi per cycle. The upward shift of the plot at 2.7 days occurs after the pressure element was removed from the well, the tubing displaced by pumping in fresh water, and then the pressure element was run back into the tubing. The lighter fluid in the tubing gives the increased surface pressure.

The slope depicted for the comingled A and B sands is 72.5 psi per cycle. This lower slope indicates a very good increase in well productivity. In order to present a realistic evaluation, the production rates for the flow periods need to be considered. The average flow rate at various intervals along the interpreted drawdown slopes are tabulated as follows:



Eaton Industries of Houston, Inc. EXHIBIT 12-8
Eaton Operating Co., Inc.

DOE CONTRACT NO.
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Sand "A"		
0.8 days	-	2100 SBWPD
1.5 days	-	2441 SBWPD
2.0 days	-	2324 SBWPD
2.7 days	-	2250 SBWPD
4.5 days	-	2000 SBWPD
Average:	-	2229 BWPD
Ave. Gas/ Brine Ratio	-	31.636 Ft^3/Bbl.

Comingled Sand "A" & "B"		
0.4 days	-	2648 SBWPD
0.5 days	-	2553 SBWPD
0.6 days	-	2468 SBWPD
0.8 days	-	2398 SBWPD
1.0 days	-	2291 SBWPD
2.4 days	-	2142 SBWPD
Average:	-	2274 BWPD
Ave. Gas/ Brine Ratio	-	32.142 Ft^3/Bbl.

Sand "A": Cumulative brine at 13:30 a.m., 6-6-81, was 2565 Bbls and at 22:30 a.m., 6-9-81, was 10,088 Bbls. (7523 Bbls ÷ 3.375 days) = 2229 SBWPD.

Sands "A" & "B": Cumulative brine at 13:30 p.m., 6-23-81, was 550 Bbls and at 9:30 a.m., 6-25-81, was 4719 Bbls. (4169 Bbls ÷ 1.833 days) = 2274 SBWPD.

The engineering interpretation needs to explain the reason for the difference in the slope of 325 psia per cycle for the Sand A drawdown and 72.5 psia per cycle for the comingled Sand A and B drawdown. The production rates were very similar, as shown in the tabulation, the combined Sand A and B average rate being about 2274 SBWPD and the produced gas/water ratio being 32.142 cu ft per bbl. The original Sand A produced 2229 SBWPD and a gas/water ratio of 31.636 cu ft per bbl. The gas/water ratio difference is 0.506 cubic feet per bbl or about 1.6 percent difference. The production rate difference of 45 SBWPD is only about a 2-percent variation in rate. The slope difference was 252.5 psi per cycle, 77.69 percent less slope, or a 4.48 ratio in slope reduction.

Using a pressure and temperature gradient presented in Exhibit 10-1 for a mean depth of 16,476 feet (center of "B" sand perforation) the mean pressure was estimated at 10,007 psia with reservoir temperature of 324°F for Sand B. The buildup plot on Sand A indicated that the sand face pressure at the time Sand B was perforated would have built up to a pressure less than 9200 psia at the sand face. In other words, there was approximately an 800-psi differential into the wellbore when Sand B was perforated. This would suggest that there would never be flow from Sand B to Sand A during this test period, since during production drawdown testing the two sand face pressures would equalize.

The drawdown slopes are direct effects of formation productivity. The difference of 414 psi per cycle from sand face pressure drawdown and 325 psi per cycle for surface pressure drawdown for Sand A is 78.5 percent. This is close to what would be expected for the combined flow. Assuming this is correct, the corresponding bottom-hole pressure drawdown slope would correct from the 72.5 psi per cycle to about 92.4 psi per cycle.

The kh value for Sand A was 495.27 md-ft. The Kh value for Sand B and Sand A should be 4.48 times as large or about 2218 md-ft. The difference from the expected would suggest Sand B productivity of about 1724 md-ft.

The comingled test ended after 2.359 days on flow. If one assumes the same physical fluid properties of the brine from Sand A, the water explored at the end of 2.359 days is equivalent to 42,798,000 standard barrels of reservoir brine. The ratio of increased productivity also suggests that 77.7 percent of the fluid produced came from Sand B. Therefore, the slight increase of 0.506 cubic feet per barrel in gas/brine ratio would indicate little or no variation in the amount of gas in solution in the brine from either sand.

The 448 percent increase in productivity would not offer sufficient improvement to consider these two sands within the range of possible geopressured-geothermal economics. The daily production rate and sand face pressure was still declining at the end of the 2.359 day flow test. In other words, production rates of 2200 barrels of reservoir fluid per day cannot be sustained for long periods of flow. Surface flowing temperatures could not be expected to be maintained above 200°F. Production of 2200 SBWPD at 32.142 ft^3/bbl would allow only 70.7 mcf per day of total gas, of which about 62 mcf per day could be separated efficiently for market.

12.6 Summary of Reservoir Engineering Data

Two separate sand reservoirs were tested in the Crown Zellerbach Well No. 1. The first test was conducted on the deeper Sand A. This sand was tested for 4.555 days and produced a total of 12,489 barrels of reservoir brine and 395 mcf of solution gas. The second sand, Sand B, was perforated while Sand A was shut-in and pressure had built up through open perforations. The comingled reservoir drawdown test was conducted using surface production and pressure measurements only. The total production from the comingled test over 2.359 days of flow testing was 4739 barrels of brine and 152 mcf of gas. Exhibit 12-9 is a graphical plot of the comingled well test, depicting surface flowing pressure and surface flowing temperature plotted versus time in days. The total production from all tests was 17,228 barrels of brine and 547 mcf of gas, giving an average gas/brine ratio of 31.75 cubic feet per barrel. A tabular summary of basic reservoir data from Sand A and comingled Sands A and B is seen on Exhibit 12-10. A comparison of the rate of surface pressure drawdown of Sand A and the comingled sands was analyzed. The data tabulated under the Sand B column is the estimate of expected contribution of Sand B to the combined improved flow productivity. The improvement of the drawdown slope from 325 psi per cycle for Sand A to 72.5 psi per log cycle for the combined sands, at nearly equal production rates, would be a direct result of the additional Sand B.

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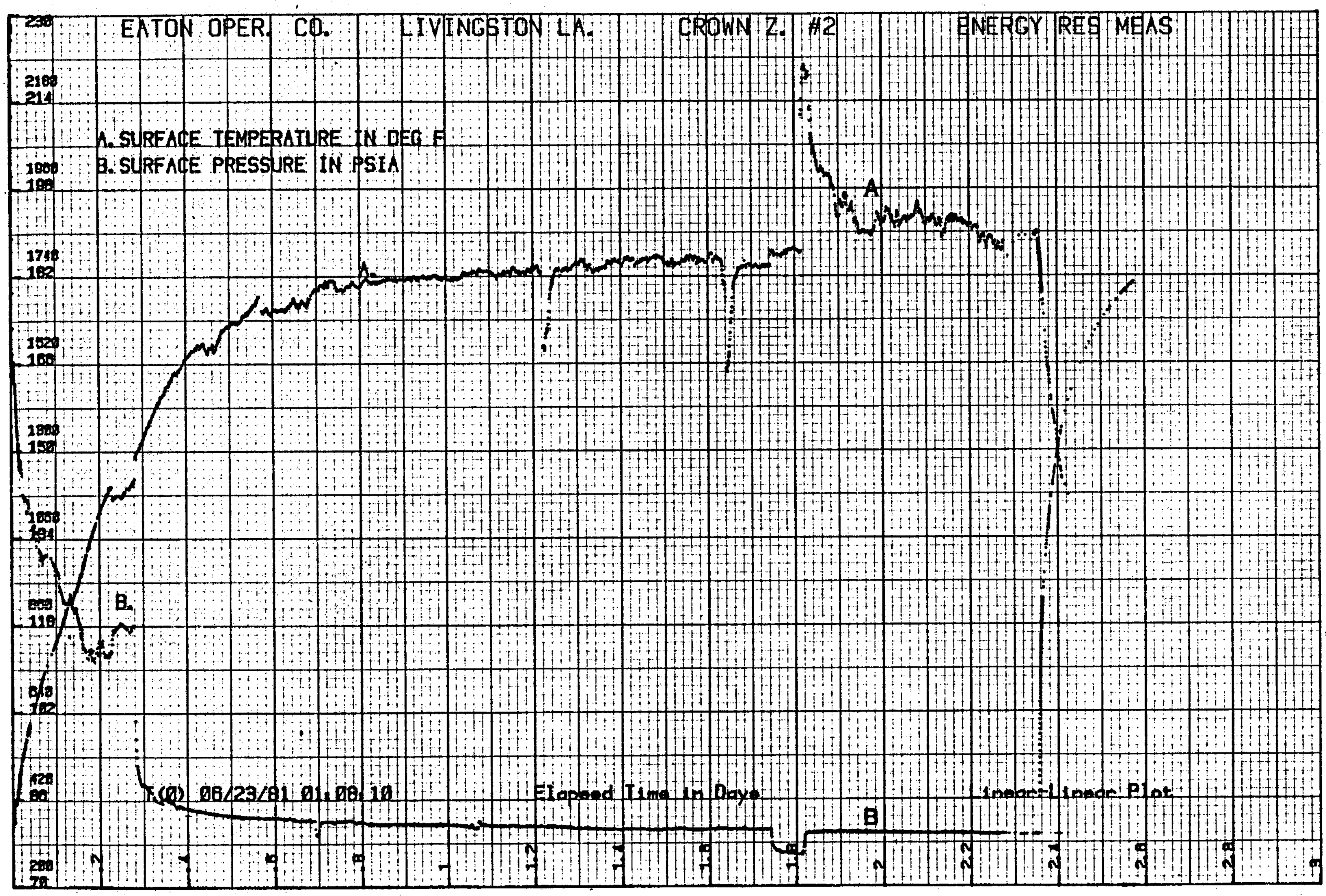

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Eaton Operating Co., Inc.

EXHIBIT 12-9

DOE CONTRACT NO.
DE-AC08-80ET-27081

Eaton Industries of Houston, Inc.
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EXHIBIT 12-10

Reservoir	Sand A	Combined Flow Sand A & B	Sand B (Est.)
Perforated Interval, Feet	16,720-16,750	(16,720-16,750) (16,462-16,490)	16,462-16,490
Date of Test	June 5, 1981	June 23, 1981	June 23, 1981
Length of Test, days	4.555	2.359	2.359
Initial Reservoir Pressure, psia	10,114	not measured	10,007 e
Reservoir Temperature, °F	329.7	329.7 to 324	324
Shut-in Surface Pressure, psia	2736.11	2371	2371 e
Porosity, percent	17 e	17 e	13.7 e
PVT DATA by Weatherly Laboratories:			
Saturated Brine Compressibility, $C_W \times 10^{-6}$	3.12	3.12 e	3.12 e
Brine Formation Volume Factor, B_W	1.0722	1.0722 e	1.0722 e
Viscosity of Reservoir Brine; U_W, cps	0.3169	0.3169 e	0.3169 e
Productivity, kh, md-ft	495.27	2218	1724 e
Permeability, K, mds.	14.15	38.2	75 e
Net Sand, Ft.	35	(35 + 23) = 58	23
Brine Salinity, ppm	31,700	29,900	28,100 e
Productivity Index, Bbls per day per psi	2.09	NA	NA
Completion Efficiency, Percent	NA	NA	NA
Max. Vol. of Aquifer Explored, Million Bbls.	16.375	42.8	26.4 e
Maximum Area Explored, Acres	318	933	933
Max. Radial Distance Explored, Feet	2971	4923	4923
Total Brine Production, Bbls	10,109	4,739	3,682
Average Produced Gas/Brine Ratio, Cu ft/Bbl	31.65	32.074	32.196
Average Production Rate, Bbls/day	2219.3	2008.9	NA
Number of Permeability Barriers Detected	1	1	NA
Maximum Production Rate, Bbls/day	3,887	3,000	NA

Note: "e" stands for estimated

12.7 Quantities and Properties of Produced Fluids

Details of field data, sample collection, sample analysis, and data interpretation concerning produced fluids are presented in the following subsections. The order of presentation for specific topics has been chosen to provide an orderly development of the results obtained. Discussions of the test sequence and real time test data obtained provide background for the discussion of hydrocarbon production. Conclusions regarding hydrocarbon chemistry are reflected in the calculation of gas production rates as well as the ratio of produced gas to produced brine. Details of brine chemistry are then presented as background for the subsequent section, "Solids Production, Scaling, and Corrosion."

12.7.1 The Test Sequence

The following chronological summary provides an overview of test activities most relevant to interpretation of well performance in terms of quantities and properties of produced fluids:

- **5/27-28/81:** The depth interval of 16,730 to 16,750 feet was perforated with eight shots per foot, and the interval of 16,720 to 16,730 feet was perforated with four shots per foot, using multiple runs of a 1-11/16 inch through-tubing carrier gun. An estimated 600 barrels of brine were produced through the annulus to clean up the new perforations. During cleanup, wellhead pressure was drawn down to 800 psi.
- **6/3/81:** Pressure and temperature gradients through the tubing were measured by ERMI. Reported pressure and temperature at the center of the perforated interval (16,735 feet) were 10,075 psia and 327°F.
- **6/5/81, 0811 hours:** Began opening the choke for the first flow test, with the bottom-hole pressure gauge at a depth of 16,536 feet. The choke was opened to provide an initial flow rate of about 2500 BPD. By 1130 hours on 6/6/81, producing annulus pressure had dropped to 980 psig, and brine rate had declined to below 2100 BPD. The choke was then opened further to insure a brine rate high enough to stay in the linear range of the 3-inch turbine meters.
- **6/6/81, 1100 hours:** Choke opening adjustment was made to increase flow rate from about 2500 to about 4000 BPD.
- **6/6/81, afternoon:** Samples of separator gas and brine were collected for laboratory studies of recombination and differential liberation.
- **6/7/81, 1500-2200 hours:** Killed tubing with $CaCl_2$ brine to remove inoperative bottom-hole pressure gauge and frayed wireline.
- **6/8/81, 2300 hours - 6/9/81, 0700 hours:** Displaced $CaCl_2$ brine down tubing with fresh water after rerunning the bottom-hole pressure gauge to 16,536 feet and then pulling up to15,536 feet.
- **6/9/81, 2245 hours:** Shut in well to record pressure buildup.

- **6/9/81, 2245 hours to 6/11/81, 1400 hours:** Recorded buildup pressures. When the bottom-hole gauge assembly was removed at the end of this period, pressure at a depth of 15,536 feet was 8669 psia. Using the reported gradient of 0.413 psi/ft for the interval 14,000 to 16,636 feet adjusts this value to 9165 psia at the perforation midpoint (16,736 feet). This is 910 psi less than original bottom-hole pressure. Surface pressure was 2014 psia or 890 psi less than the highest recorded original value.

- **6/11/81, 1400 hours to 6/16/81, 1900 hours:** Several attempts to cut the tubing at about 16,400 feet so that casing could be perforated to co-mingle production from a second aquifer at 16,462-16,490 feet were unsuccessful. During these attempts a few barrels were produced at each of eleven different times.

- **6/16/81, 1900 hours to 6/17/81, 1613 hours:** Opened well on 3/4" choke to start second flow test. Wellhead pressure declined to about 325 psia for most of this test. At test conclusion flow rate was down to under 2500 BPD.

- **6/18/81, 1600-2200 hours:** Killed well with 11.6 ppg calcium chloride brine so tubing could be pulled.

- **6/23/81, 0120 hours to 6/25/81, 0943 hours:** Third flow test started 15 minutes after perforating the interval from 16,462 to 16,490 feet with four shots per foot using one perforating gun. Calcium chloride brine had previously been displaced from the well with fresh water. At the time of perforation, wellhead pressures were 2325 psig on the tubing and 2050 psig on the annulus.

  An initial two-phase flow rate to the pit of about 3000 BPD dropped wellhead pressure to 750 psig by 0800 hours. The 3/4-inch adjustable choke was then opened all the way. At that time, production of muddy water from perforation cleanup had ended, and separator operation was commenced. For the remainder of the test, wellhead pressure averaged about 350 psig and flow rates were very similar to those experienced before perforating at the depth of the second aquifer.

- **6/25/81 0942 hours:** The well was shut in for recording buildup of surface pressure.

- **6/28/81 1000 hours:** Real-time data recording ended.

12.7.2 Real-Time Production Data

The quality of electronically recorded real time production data was affected by weather-associated difficulties with instrumentation, problems with surface equipment, and at certain times, operation of the salt water injection well. In general these problems were of the following nature:

- Condensation of moisture in both computer equipment and electrical connections.

- Computer program interruptions thought to be induced by humidity and/or heat.

- Brine flow through the orifice meter and out the flare line (separator upset), usually as a result of increased injection well pressure.

These circumstances made editing of certain data files necessary to present a realistic portrayal of well performance. Fortunately, the redundant and versatile nature of the instrumentation system allowed a continuous record of all pertinent well parameters to be maintained. This is particularly true of the four most critical parameters (orifice differential pressure, separator static pressure, gas temperature, and brine flow rate) which are the determinants of gas and brine produced and the primary component of the gas/brine ratio. Erroneous data was replaced by measurements from the following sources in the indicated order of precedence:

- Digitized values from IGT's backup recording system

- Values recorded by other contractors on location

- The average values of the parameters that were recorded by IGT just before and just after the time interval involved. This practice was used only when other data indicated that flowing conditions of the well had been constant during the time interval.

Parameters affected and data sources used in the above fashion are tabulated in Exhibit 12-11.

This combined cross-checking/editing process resulted in raw data collected by IGT, ERMI, and Weatherly being combined into a single data set which provided a basis for interpretation by IGT. The resultant data set is considered most likely to be truly representative of the producing characteristics at each instant of time. The complete compiled data set is provided in Appendix F. In addition, graphical portrayals and discussions are provided in subsections 12.7.2.1 through 12.7.2.6 below.

12.7.2.1 **Production Well Pressures:** Exhibit 12-12, Parts I, II, and III, show bottom-hole, tubing, and annulus pressures representative of actual values throughout the test sequence. Significant observations regarding each of these pressures are provided below.

- **Bottom-hole Pressure:** Values shown between start of recording on 6/5/81 and failure of the instrument during 6/7/81 were recorded at a datum of 16,536 feet, 200 feet above the center of perforations. For a few hours after the instrument was rerun during 6/9/81, pressures were recorded at this same depth. Then, the instrument was pulled up the hole to a new datum of 15,536 feet. Recording of bottom-hole pressure was stopped during 6/11/81 to prepare for additional perforations.

- **Annulus Pressure:** With the exception of the time between killing the well with $CaCl_2$ brine during the evening of 6/17/81 and production of the first annulus volume of fluid on 6/23/81, the annulus was filled with produced fluids throughout the test sequence. Thus, this data provides an overall picture of production well pressure history.

  The low pressures shown just before the start of bottom-hole pressure data on Exhibit 12-12, Part I reflect drawdown due to a small valve leak on the wellhead.

DATA EDITING PERFORMED

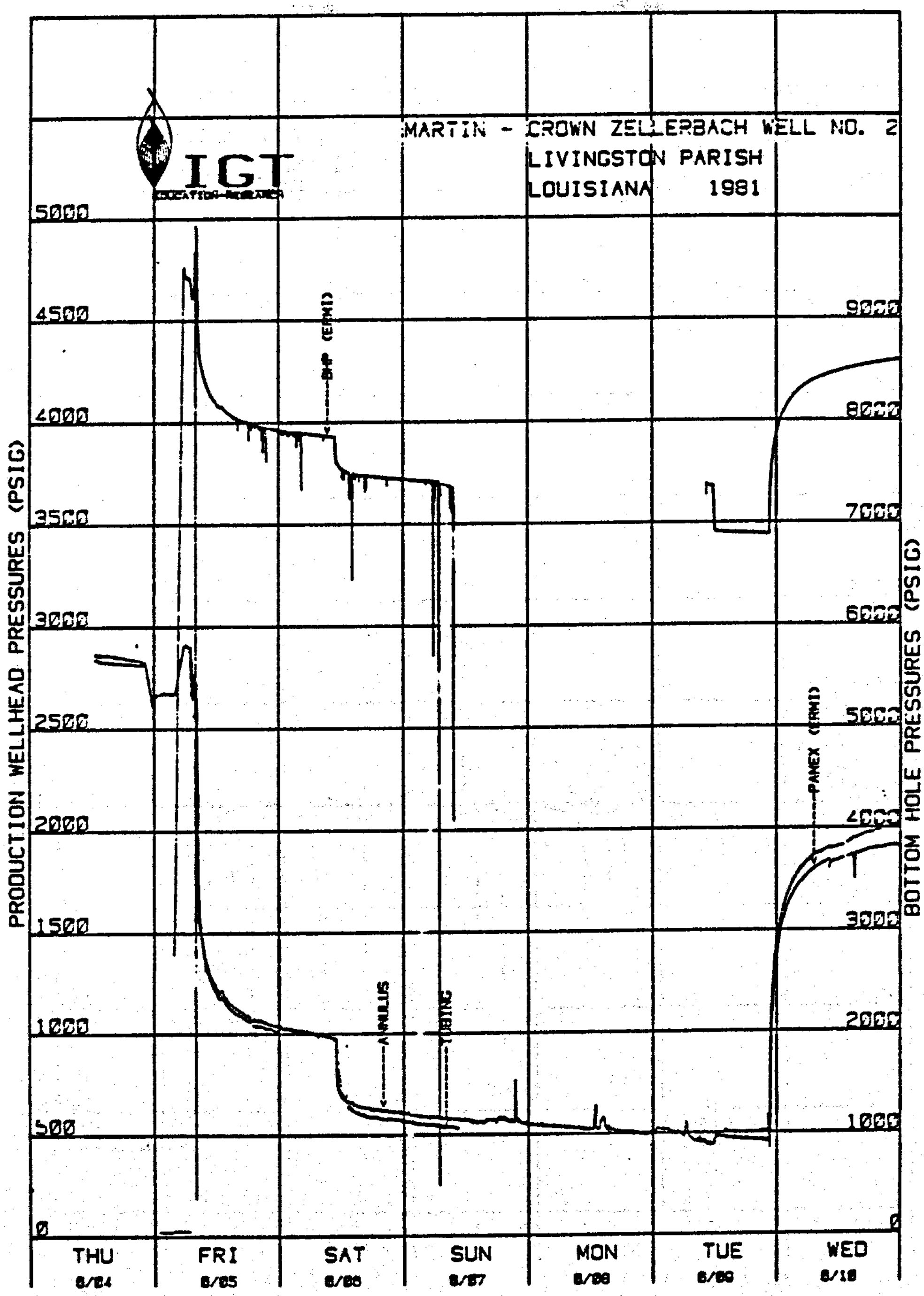
Date/Time	Affected Instrumentation Channel	Occurrence	Reason	Actions Taken
6/5/81 0950-1400	Separator Turbine	Underranged	Back pressure from experimental filter assembly during back-wash cycle.	Substituted values recorded by Weatherly Engineering.(1)
6/5/81 1115	ΔP, P_s, Separator Turbine	Separator upset	Increase in disposal well pressure.	Substituted mean values of before and after recorded data.(2)
6/5/81 1840-2015	ΔP, P_s, Separator Turbine	Separator upset	Increase in disposal well pressure.	Substituted mean values of before and after recorded data.(2)
6/6/81 1350-2030	P_s	Erratic reading	Moisture/corrosion in electrical connection.	Used data based on Weatherly recorded values.(1)
6/7/81 0915	P_s	Erratic reading	Moisture/corrosion in electrical connection.	Used data based on Weatherly recorded values.(1)
6/7/81 2120-2205	ΔP, P_s, Separator Turbine	Separator upset	Separator air supply lost.	Substituted mean values of before and after recorded data.(2)
6/8/81 0200-1200	P_s	Signal attenuation	Poor connection in multiprogrammer.	Substituted values recorded by Weatherly Engineering.(1)
6/8/81 1251	Separator Turbine, Wellhead Turbine	Shut down counting circuitry	To repair connection in multiprogrammer.	Substituted mean values of before and after recorded data.
6/8/81 1315	T_s	Erratic response	Moisture in electrical connection.	Used data based on Weatherly recorded values.(1)
6/8/81 2130 to 6/9/81 0900	All	Computer program halted	Unknown	Digitized data from IGT backup recording system.(3)
6/10/81 0100-1000	$P_{annulus}$	Erratic response	Improperly positioned valve.	Substituted ERMI recorded data.
6/23/81 1533-1730	ΔP, P_s, Separator Turbine	Bypassed separator	To drain flare stack.	Substituted mean values of before and after recorded data.(2)
6/23/81 1745-2325	All	Computer program halted	Halt key inadvertently pressed.	Digitized data from IGT backup recording system.(3)
6/24/81 1855-2100	ΔP, P_s, Separator Turbine	Bypassed separator	To repair leak in flare line weld.	Substituted mean values of before and after recorded data.(2)

Notes:

(1) Values recorded manually by Weatherly Engineering at half-hour intervals formed the basis of substituted IGT edited data for these channels during the times indicated.

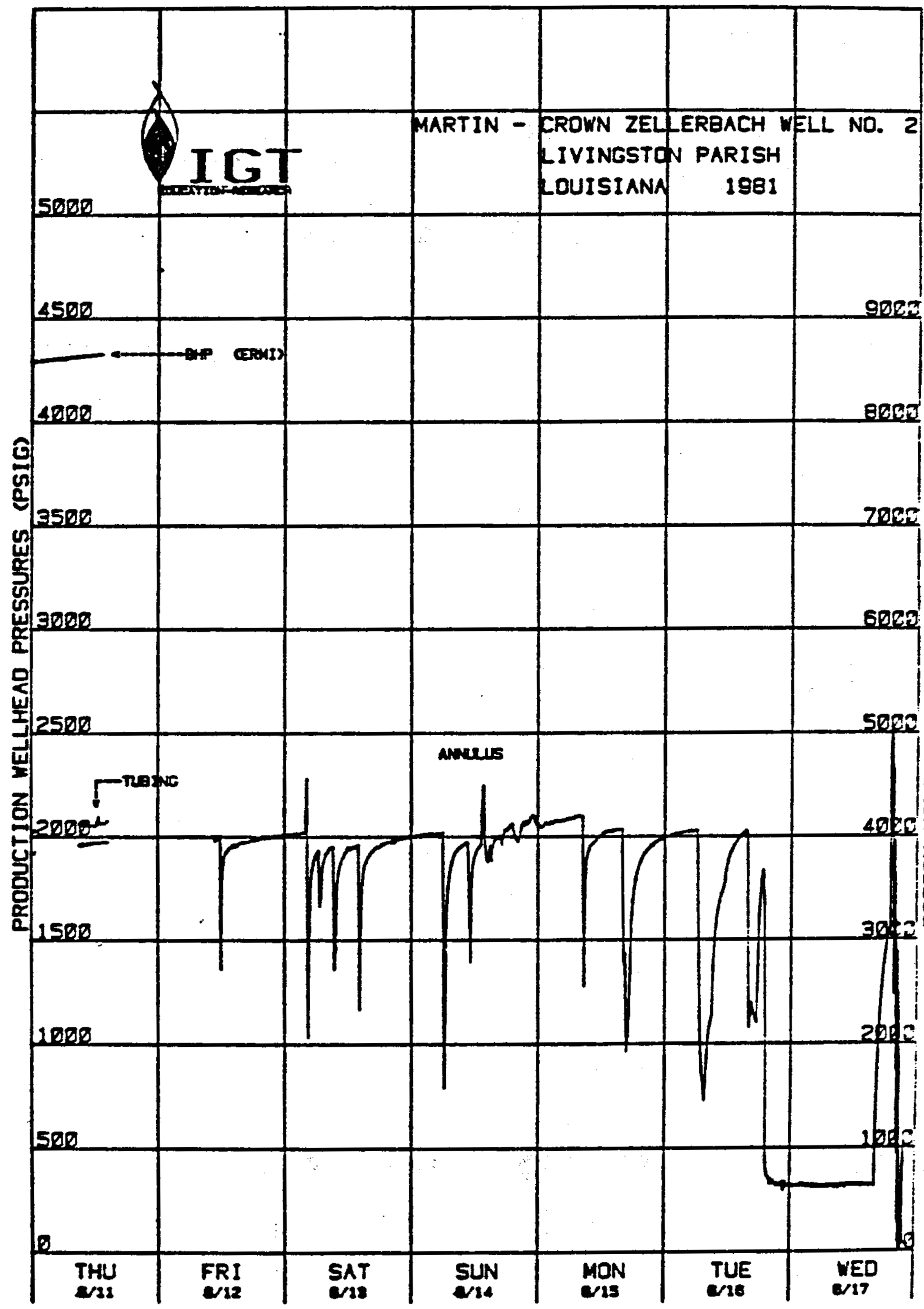
(2) Substituted values are the averages of production figures obtained just before and just after the indicated times. The static nature of the flowing conditions of the well, evidenced by wellhead pressure and turbine data, make these values a reasonable estimate of the measurements that would have been made had the upset not occurred.

(3) Hand digitized data from strip chart recordings, averaged over 30-minute intervals, permitted the interpolation of this data into a form acceptable by IGT's interpretive software, thus maintaining the continuity of the brine and gas production records for the well.



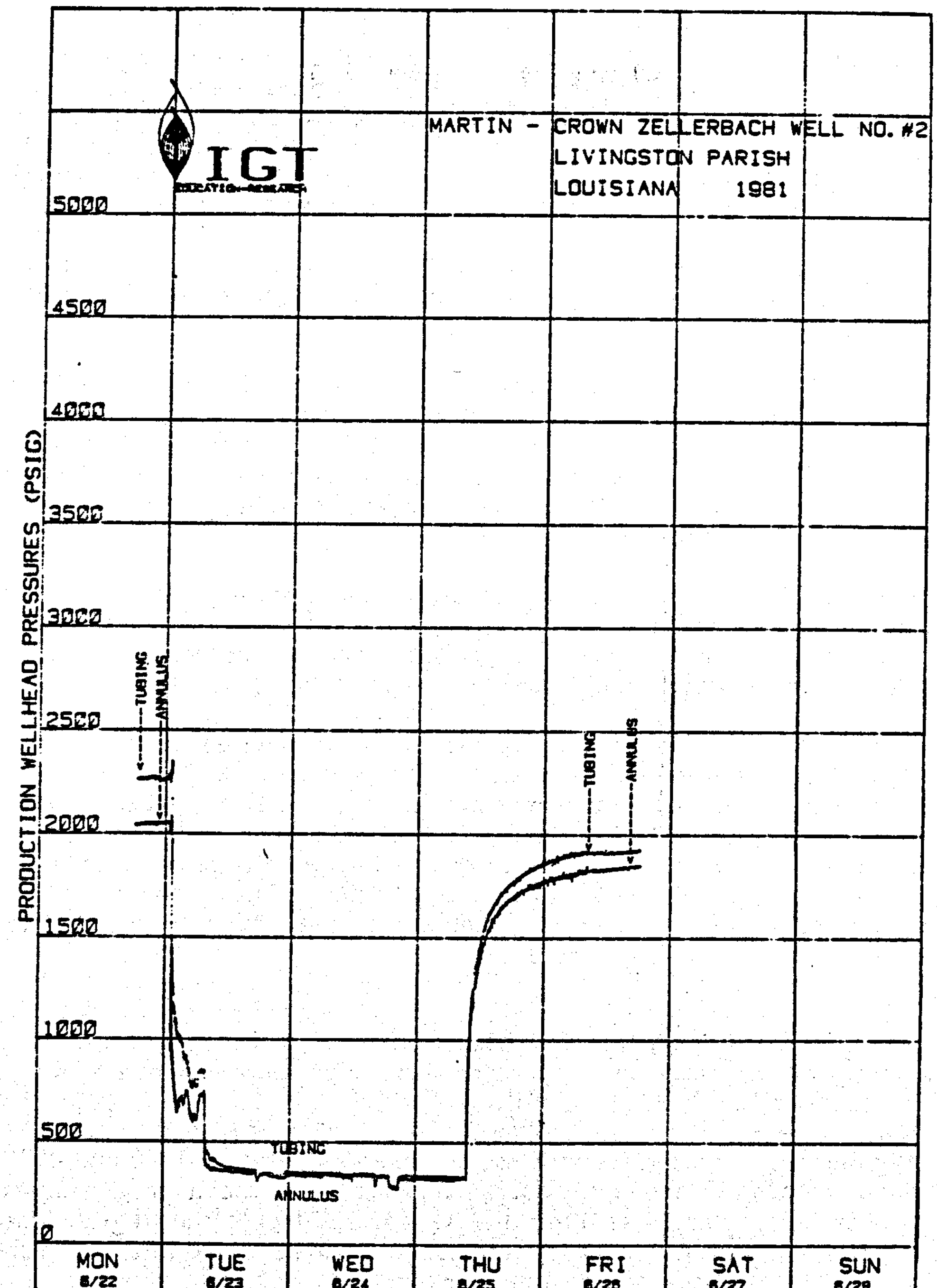
PRODUCTION WELLHEAD PRESSURES
(Part I)

EXHIBIT 12-12



PRODUCTION WELLHEAD PRESSURES
(Part II)

EXHIBIT 12-12



PRODUCTION WELLHEAD PRESSURES
(Part III)

EXHIBIT 12-12

The peak of about 2900 psig is the annulus pressure reading corresponding to initial reservoir pressure. For the brine rates achieved, friction drop in the flowing annulus was less than the ± 25 psi accuracy of the IGT recording channel used for the majority of annulus pressure data.

The variations in annulus pressure between 6/12/81 and start of production during 6/16/81 are due to brief periods of production from, or pumping into, the tubing with the annulus shut-in. These actions were in conjunction with unsuccessful attempts to cut and drop the bottom three joints of tubing. Nevertheless, it is noteworthy that the maximum annulus pressure observed during this time was only about 2100 psig or about 800 psig less than initial shut-in annulus pressure. This difference suggests a very small reservoir volume.

The unusual pressures shown between 1600 hours and 2400 hours on 6/17/81 are due to killing of the well with $CaCl_2$ brine, starting with injection into the annulus.

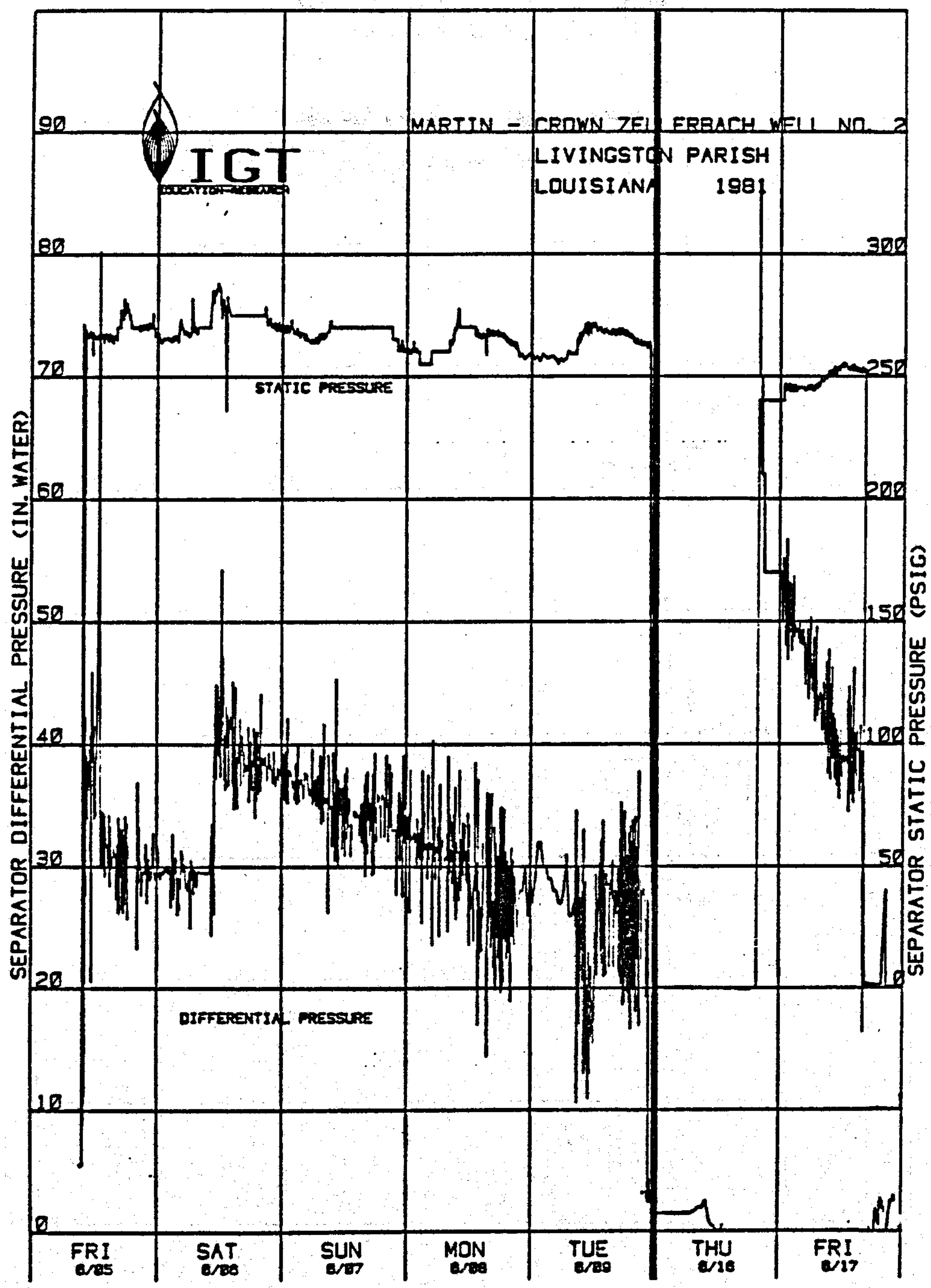
- **Tubing Pressure:** Reservoir fluids were not produced through the tubing at any time during this well test. Prior to disconnecting the sensor so that the bottom-hole pressure gauge could be pulled during 6/7/81, the tubing contained the NaCl brine used to flush mud from the wellbore prior to perforating. Since this brine was more dense than produced brine, measured tubing pressure was less than measured annulus pressure.

  Replacing the bottom-hole instrument required killing the tubing with $CaCl_2$ brine. This brine was then displaced from the tubing with fresh water. Since the fresh water was less dense than produced brine, recorded tubing pressure was greater than recorded annulus pressure during 6/9-11/81.

  Similarly, on 6/22/81 the $CaCl_2$ brine was circulated from the wellbore by pumping fresh water into the tubing. The relatively large difference in tubing and annulus pressure between start of recording on 6/22/81 and start of production during 6/22/81 is due to a small amount of $CaCl_2$ brine remaining in the annulus. This was flushed from the well by production, so that the difference was much less after a few hours of production. During the first few hours of production, pulling perforating equipment up the tubing contributed to the high recorded values of tubing pressure.

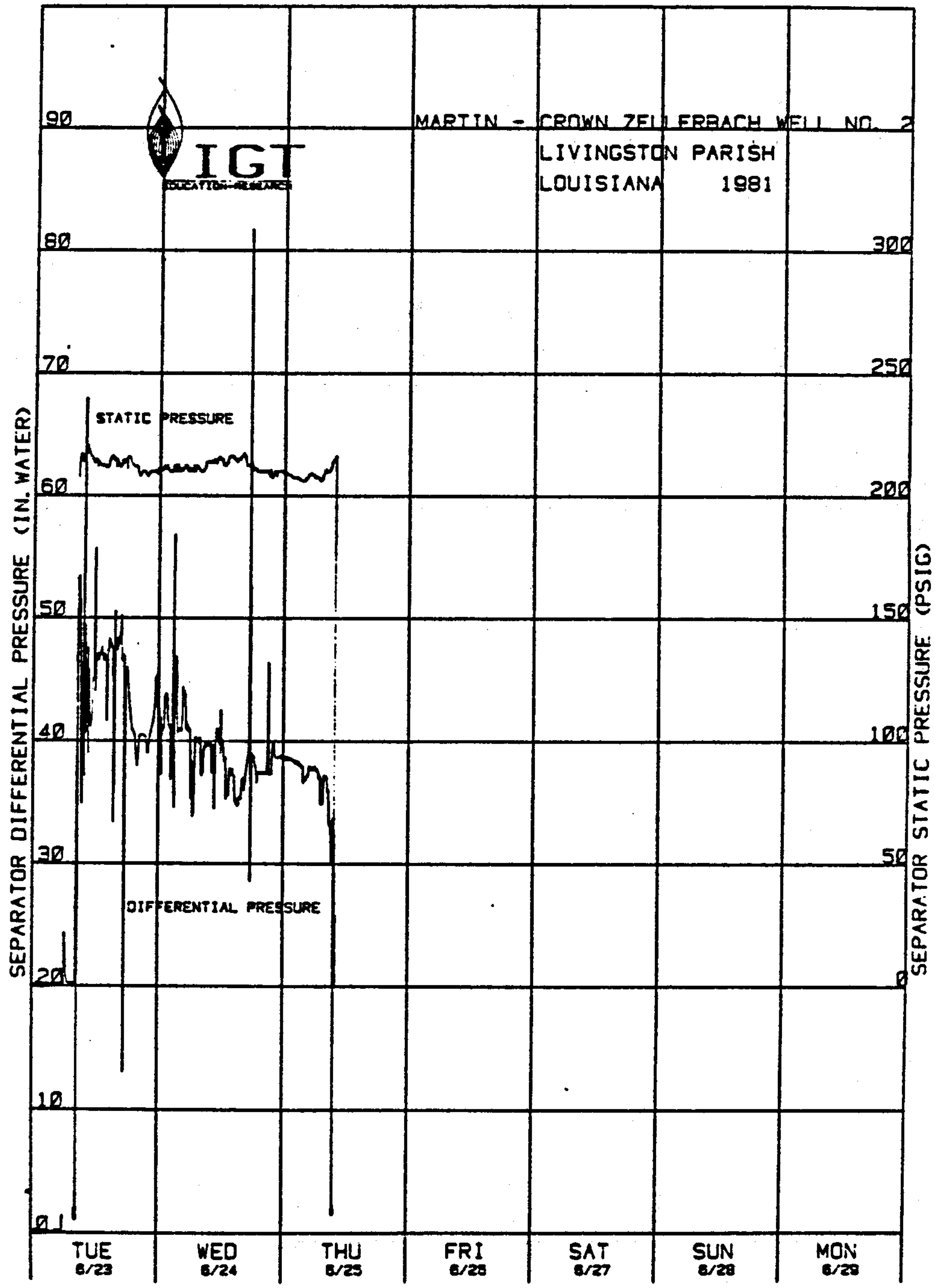
12.7.2.2 Separator Static and Orifice Differential Pressures: IGT data for the orifice differential pressure and separator static pressure channels are presented graphically in Exhibit 12-13, Parts I and II.

The steady values of separator static pressure observed between 1350 and 2030 hours on 6/6/81 and between 0955 and 2100 hours on 6/7/81 are the average values of data recorded by Weatherly over these intervals. Original IGT data shown graphically for the 48-hour period, along with other surface pressure channels in Exhibit 12-14, indicates a malfunction in the separator pressure network, as the excursions shown could not have occurred without associated change in either wellhead or disposal line pressures. The problem appears to have been due to shorting of amphenol connectors with brine spray during collection of brine samples.



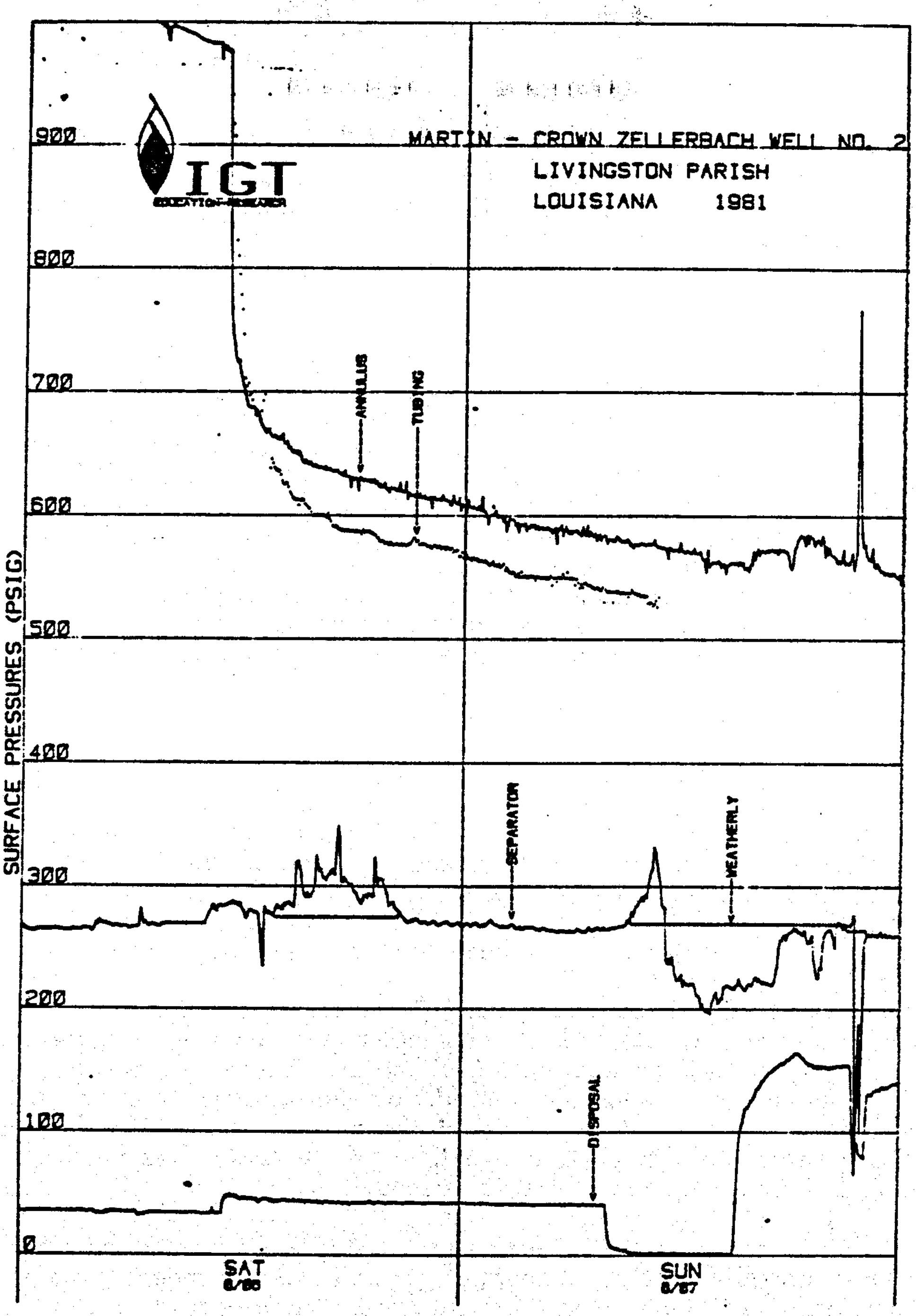
SEPARATOR STATIC AND ORIFICE DIFFERENTIAL PRESSURES (Part I)

EXHIBIT 12-13



SEPARATOR STATIC AND ORIFICE DIFFERENTIAL PRESSURES
(Part II)

EXHIBIT 12-13



PRESSURE RECORDINGS 6/6/81 AND 6/7/81

EXHIBIT 12-14

The second flow test started at 1845 hours on 6/16/81, approximately 15 hours ahead of schedule. Due to a conflict in plans, IGT field personnel were returning from an energy conference in New Orleans during the first few hours of the test. For this reason the orifice differential pressure and the separator pressure channels were not recording data until shortly after midnight when the conferees returned to location. Computations of gas production during this interval have as their basis values recorded by Weatherly Engineering for both of these parameters.

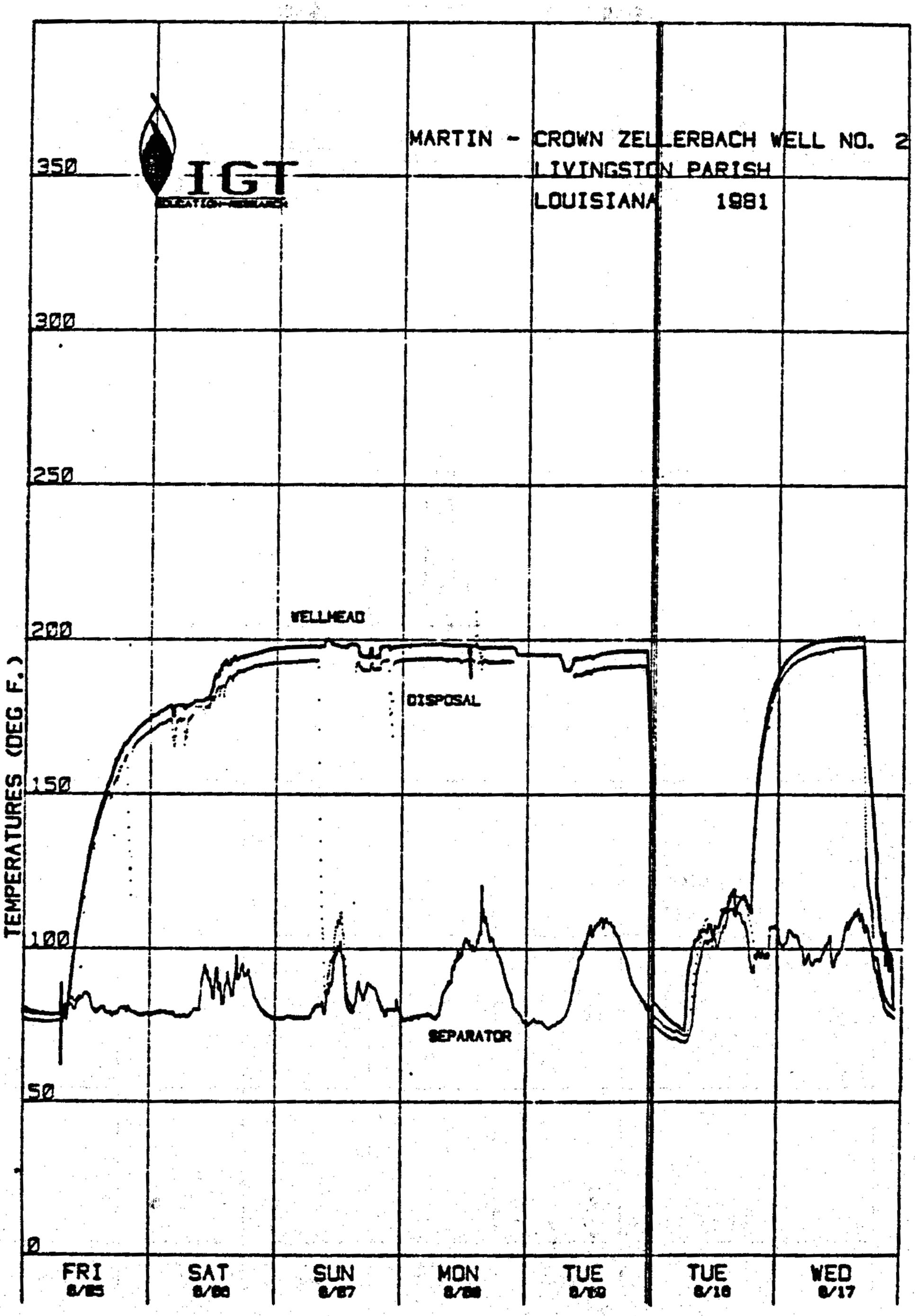
Manual editing of data was also performed between 1900 hours and 2050 hours on 6/24/81. During this time interval, the separator was bypassed for repair of a leak at a weld between the separator and the orifice meter. Values used were the average of those recorded before and after the repair. This is believed to be a reasonable approximation because wellhead pressure change associated with the bypassing was only about 30 psi.

Unedited portions of orifice differential pressure data during the first flow test show larger, more rapid oscillations than during the second flow test (Exhibit 12-13, Part I). The second test in turn shows more rapid differential pressure fluctuations than the third flow test (Exhibit 12-13, Part II). The fluctuations during the first test are consistent with experience on prior well tests. They are due to stepwise changes in dump valve setting and associated interaction with gas line back-pressure control changes. For the second flow test, filters were in use, but brine was delivered to a reserve pit at the disposal well location. The much lower incidence of fluctuations during the third test correlates with production of brine to a reserve pit at the disposal well location without use of filters. This apparently indicates that fluctuations normally observed are due in large part to interaction between dump valve setting and back-pressure due to filters and injection pressure.

12.7.2.3 **Temperature Data:** Exhibit 12-15, Parts I and II, shows temperatures recorded from the sensors 1) at the production wellhead, 2) at the entry to the line to the disposal well, and 3) at the orifice meter. The production wellhead temperature sensor was in the flowing brine stream and is believed to have provided accurate data. (The temperature sensor in previous tests was mounted in a thermal well in the side of the pipe.) Although flow rate was only 2000-2500 STB/D for this well test, brine flow through the surface facilities was accompanied by a temperature drop of only about 5°F.

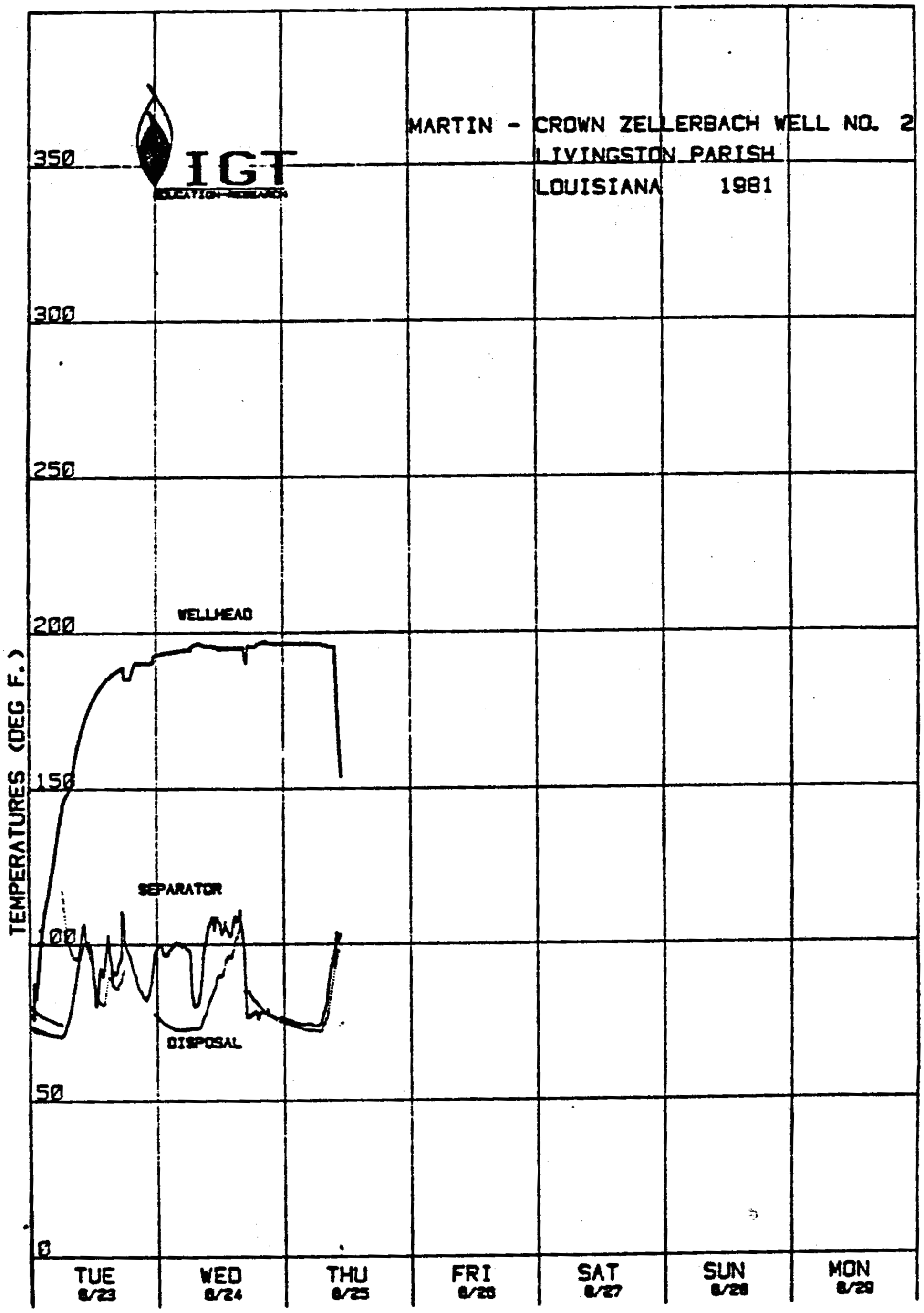
Gas temperature at the orifice meter, labeled "separator" on Exhibit 12-15, was much lower than brine temperature due to the cooler and the small separator (scrubber) between the primary separator and the orifice meter. The small separator was operated continuously, and the air cooler fan was operated intermittently during the first flow test. Recorded gas temperature was essentially the same as ambient air temperature. The small separator was bypassed, and the fan on the cooler was not used during the second flow test. Gas temperature stayed at about 100°F.

At the sart of the third flow test, the small separator was bypassed, and the fan for the cooler was not turned on. After 12 hours of gas production, condensed water was found to be accumulating in the line to the vertical flare. Therefore, the cooler fan and small separator were actuated at 1730 hours on 6/23/81. Although the fan was operated intermittently, brine accumulation in the line to the vertical flare stack was observed 24 hours later. The small separator was drained, and then both it and the fan were operated for the rest of the third flow test.



TEMPERATURES
(Part I)

EXHIBIT 12-15



TEMPERATURES
(Part II)

EXHIBIT 12-15

The disposal line temperature sensor was bypassed during the third flow test. Values shown are mostly ambient temperature.

12.7.2.4 Brine Production Rate: Recorded brine turbine data is presented graphically in Exhibit 12-16, Parts I and II. Both IGT and ERMI had problems in recording two-phase flow data from the turbine at wellhead pressure. Only the portions of data from this turbine that may be valid are shown. No editing was performed, because stable, reliable operation of the separator output turbine provided data needed for interpretation.

The separator output turbine data shown has been corrected for pressure and temperature at the turbine as described in Section 12.7.4.2.

12.7.2.5 Filter Differential Pressure and Sonic Sand Detector Signal: Data from both the filter differential pressure transmitter and the sonic sand detector are presented graphically in Exhibit 12-17, Parts I and II. For plotting, 50 has been added to the sand detector data for the second and third flow tests. This is because the majority of data was slightly negative and therefore would not have been shown.

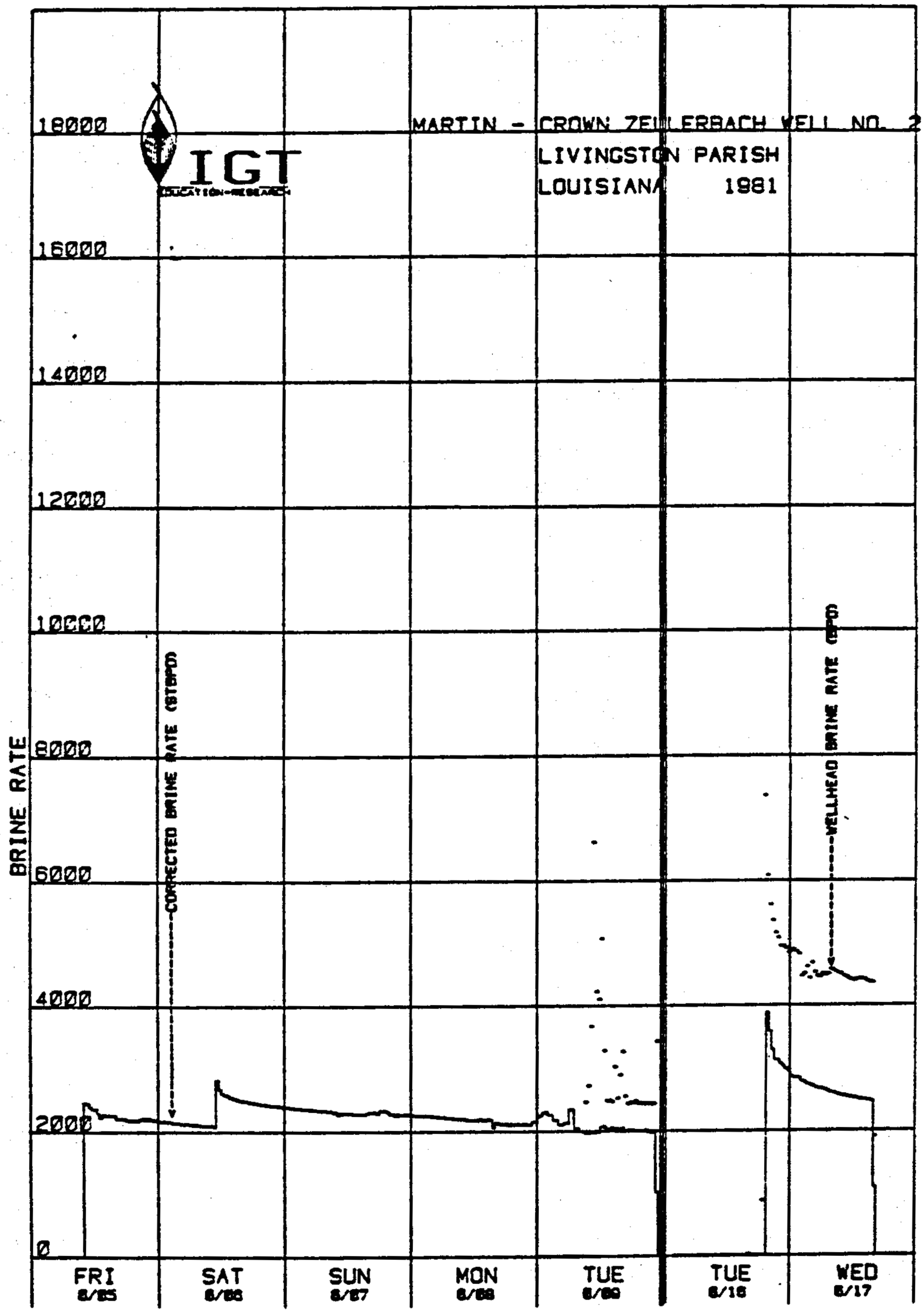
The negative spike recorded on the filter pressure drop curve at 1030 hours on 6/5/81 is the result of a valve position which prevented pressure from being sensed by the high pressure side of the gauge. Bottoms-up is clearly visible on this graph as the sharp rise in pressure at about 1300 hours on the same day. Two types of filtering assemblies were used at different times during this test to remove solids from the brine prior to injection into the disposal well. During the first five days of production a unit was used which automatically back-washed the filter elements whenever the pressure drop across these elements exceeded a certain predetermined value. The excursions observed during this interval on the Filter Pressure Drop curve result from solids production of sufficient magnitude to cause plugging of the filter elements. The sharp drops in this pressure were caused when the back-wash cycle was activated, removing the solids from the filter elements.

The high values of filter pressure drop displayed on 6/16/81 are anomalies caused by solar heating of trapped brine inside the surface plumbing during a non-flowing period. The low pressure side of the transmitter was open to the atmosphere at that time.

For the second flow test, the filter unit used on all previous Wells of Opportunity experiments was employed. All filters were bypassed for the third flow test.

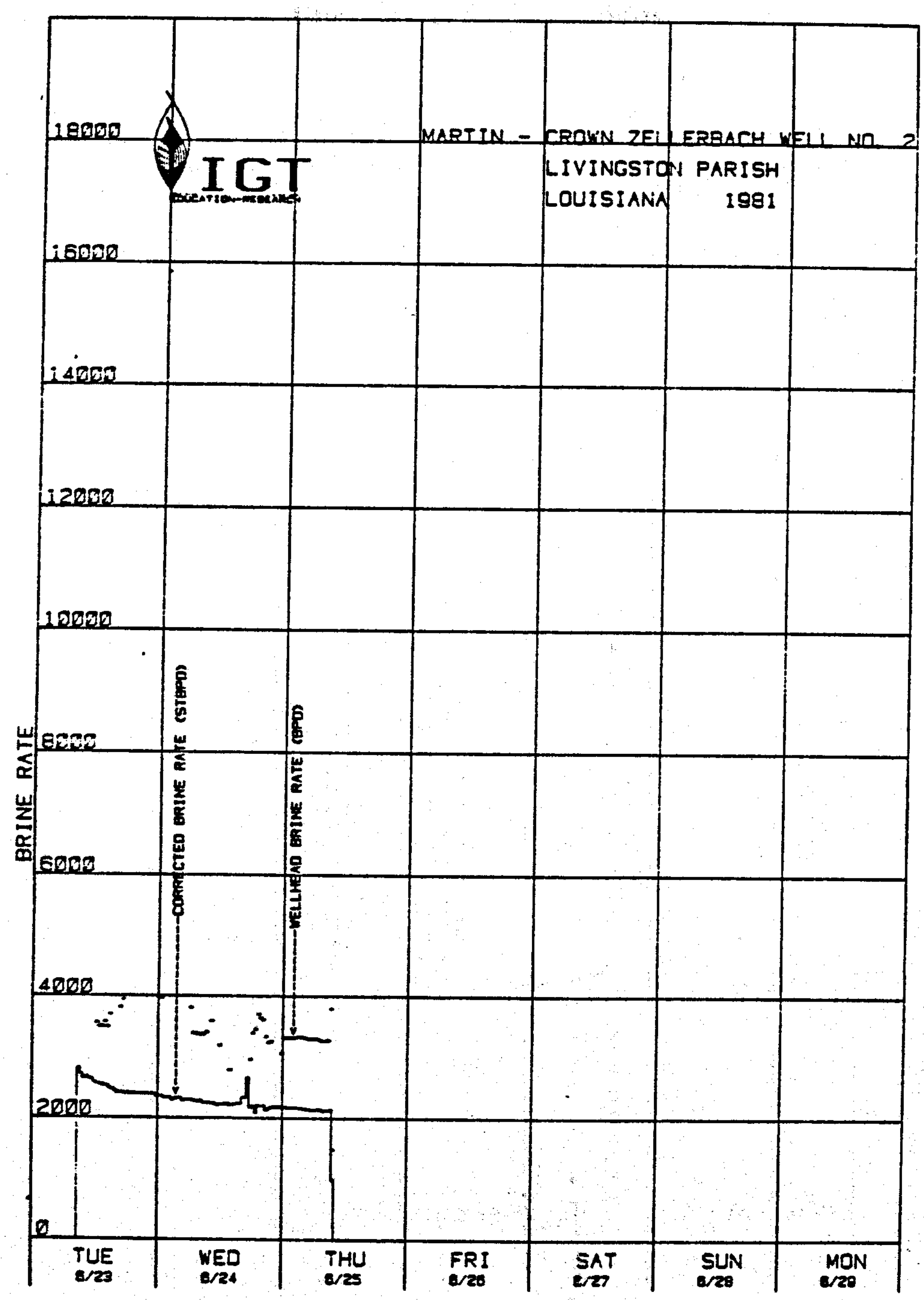
The sonic sand detector signal, shifted by 50 for the second and third flow tests to enhance curve distinguishability, shows no appreciable departure from an arbitrary "no sand" baseline. However, conclusive evidence of significant sand production exists in both the filter pressure drop data and the fact that about 200 lb of sand was removed from the separator at the termination of the test.

The detection sensitivity of the sonic sand detector is a function of both the amount of produced sand per unit volume of fluid and the velocity of the fluid. With a flow rate of 3000 bpd and an inside pipe diameter of 3.83 inches, the velocity at the metering point was 2.4 ft/sec. Using interpretation charts from the sand detector manual, the minimum amount of sand detectable at this low flow rate is 100 lb/1000 bbls of brine. Since over



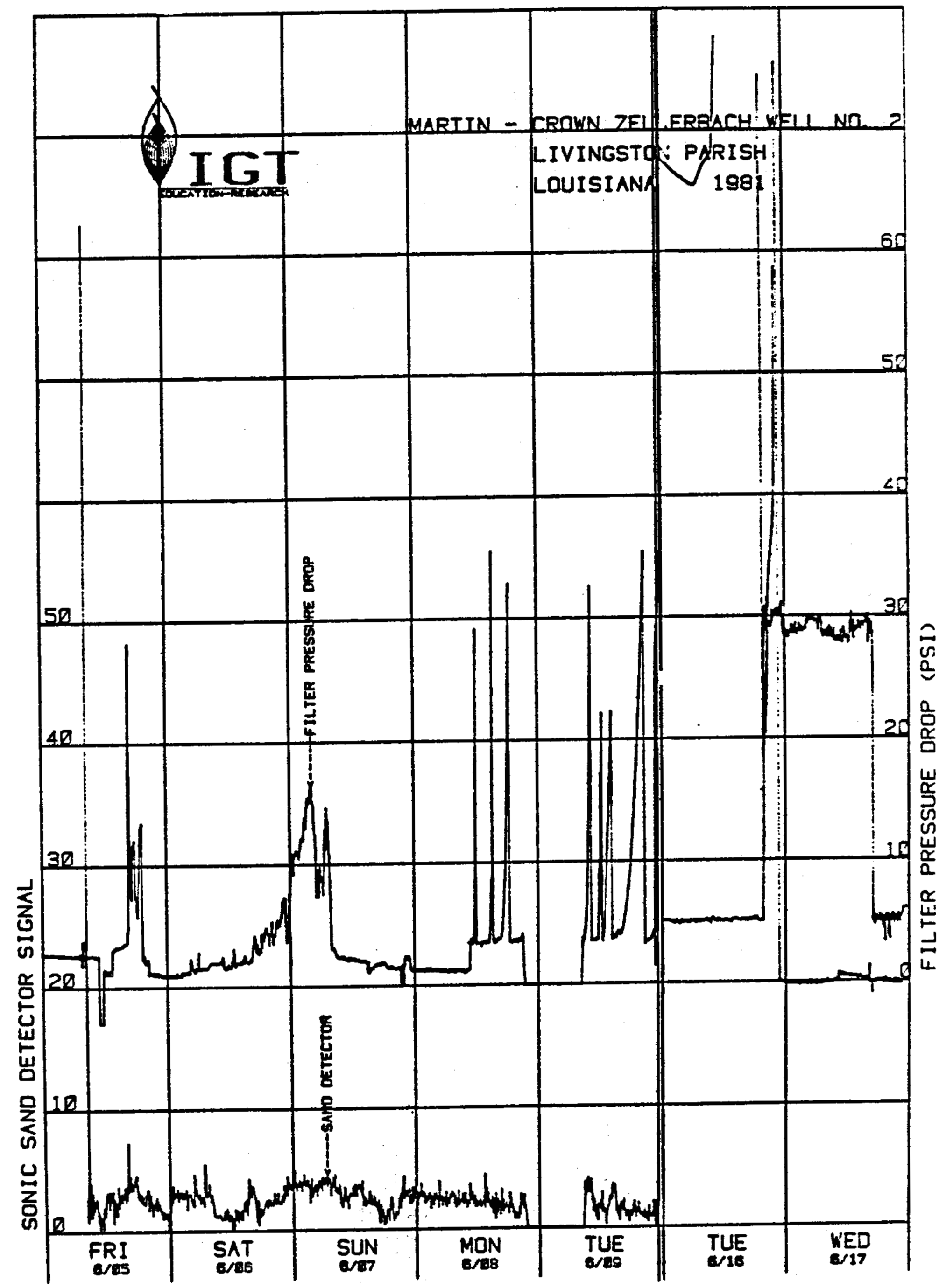
BRINE RATES
(Part I)

EXHIBIT 12-16



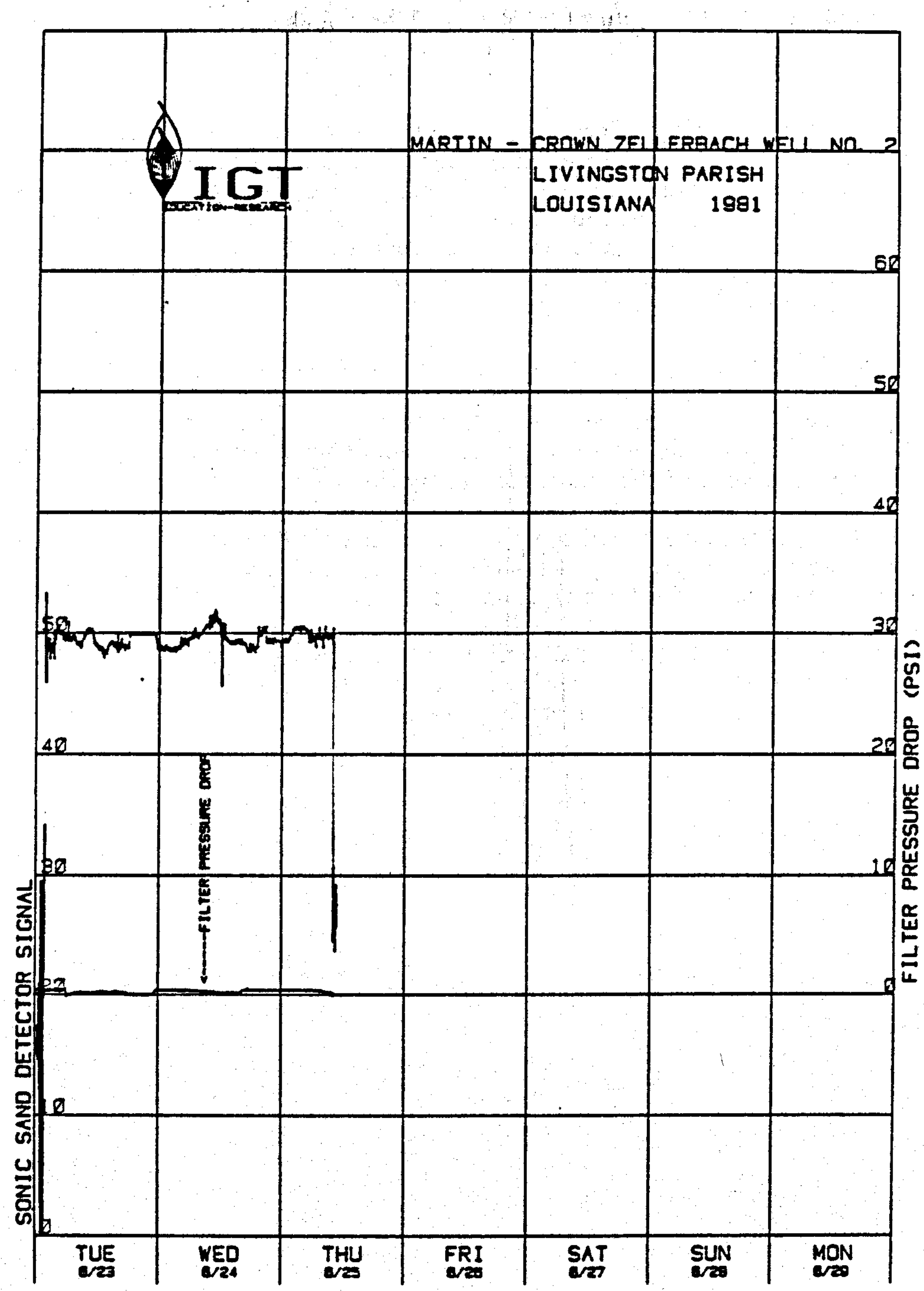
BRINE RATES
(Part II)

EXHIBIT 12-16



SONIC SAND DETECTOR SIGNAL AND
FILTER DIFFERENTIAL PRESSURE
(Part I)

EXHIBIT 12-17



SONIC SAND DETECTOR SIGNAL AND FILTER DIFFERENTIAL PRESSURE (Part II)

EXHIBIT 12-17

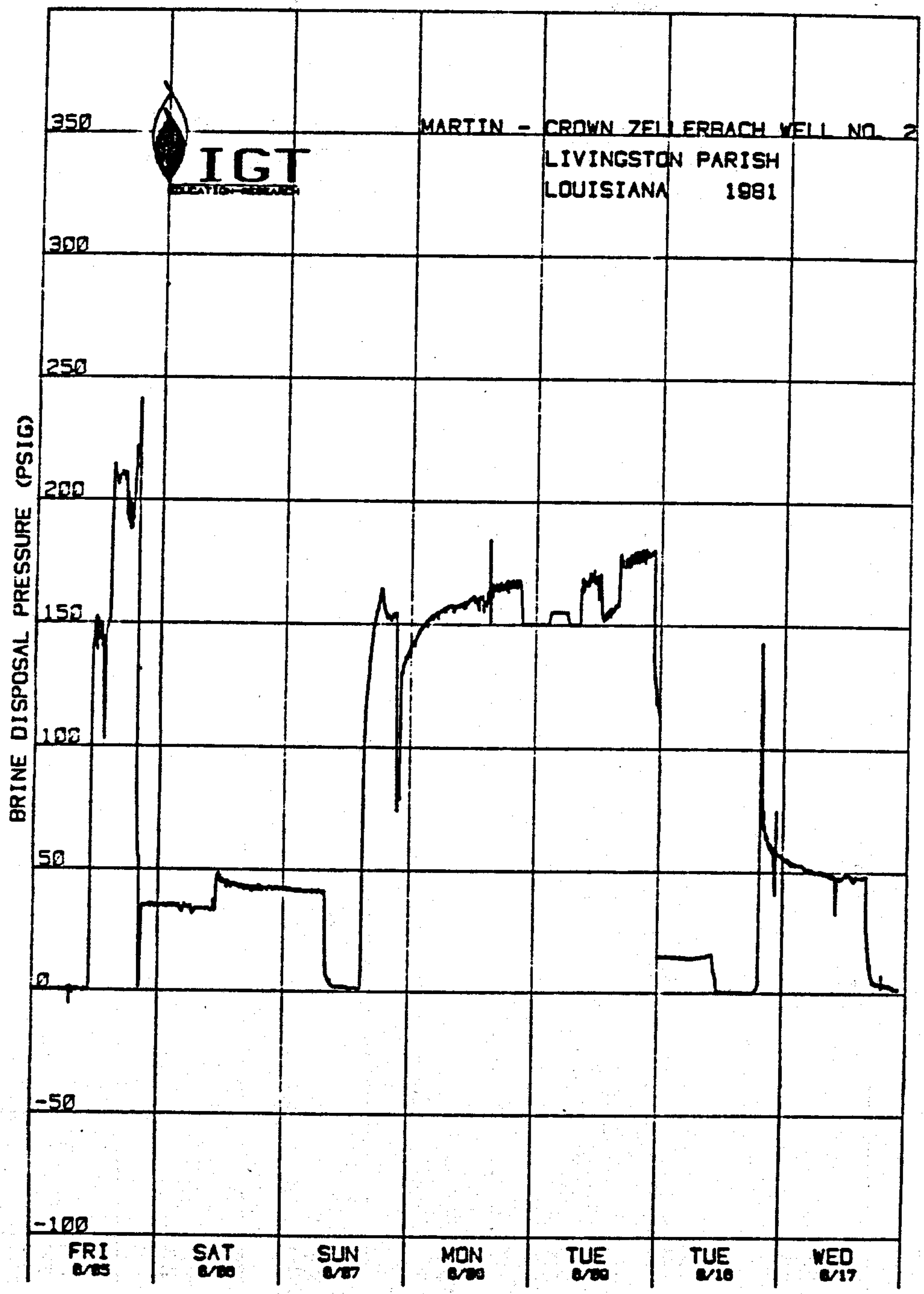
17,000 bbls of brine were produced during this test, up to 1700 pounds of sand could theoretically have been produced without detection by the sonic sand detector. To increase the sonic sand detector sensitivity the velocity of the brine must be increased, either by reducing the pipe diameter through the metering point or by increasing flow rate.

12.7.2.6 **Brine Disposal Pressure:** Exhibit 12-18 shows brine disposal pressure at the outlet of the filter systems. Pressures shown correspond to three different modes of brine disposal. When pressure was above 100 psig, brine was passing through about 3000 feet of pipe and being injected into the disposal well. Pressures in the range of 40-60 psig were measured when brine was flowing through the 3000 feet of pipe to a reserve pit at the disposal well location. Pressures near zero occurred during brine flow to the reserve pit at the production well location.

During the first day of production (6/5/81), brine was switched from the disposal well to the disposal well reserve pit, because separator pressure was not high enough to drive the brine through the filters, pipeline, and disposal well. Separator pressure could not be increased, because orifice differential pressure would have become too low for 2-percent accuracy in measurement of the small gas production rate.

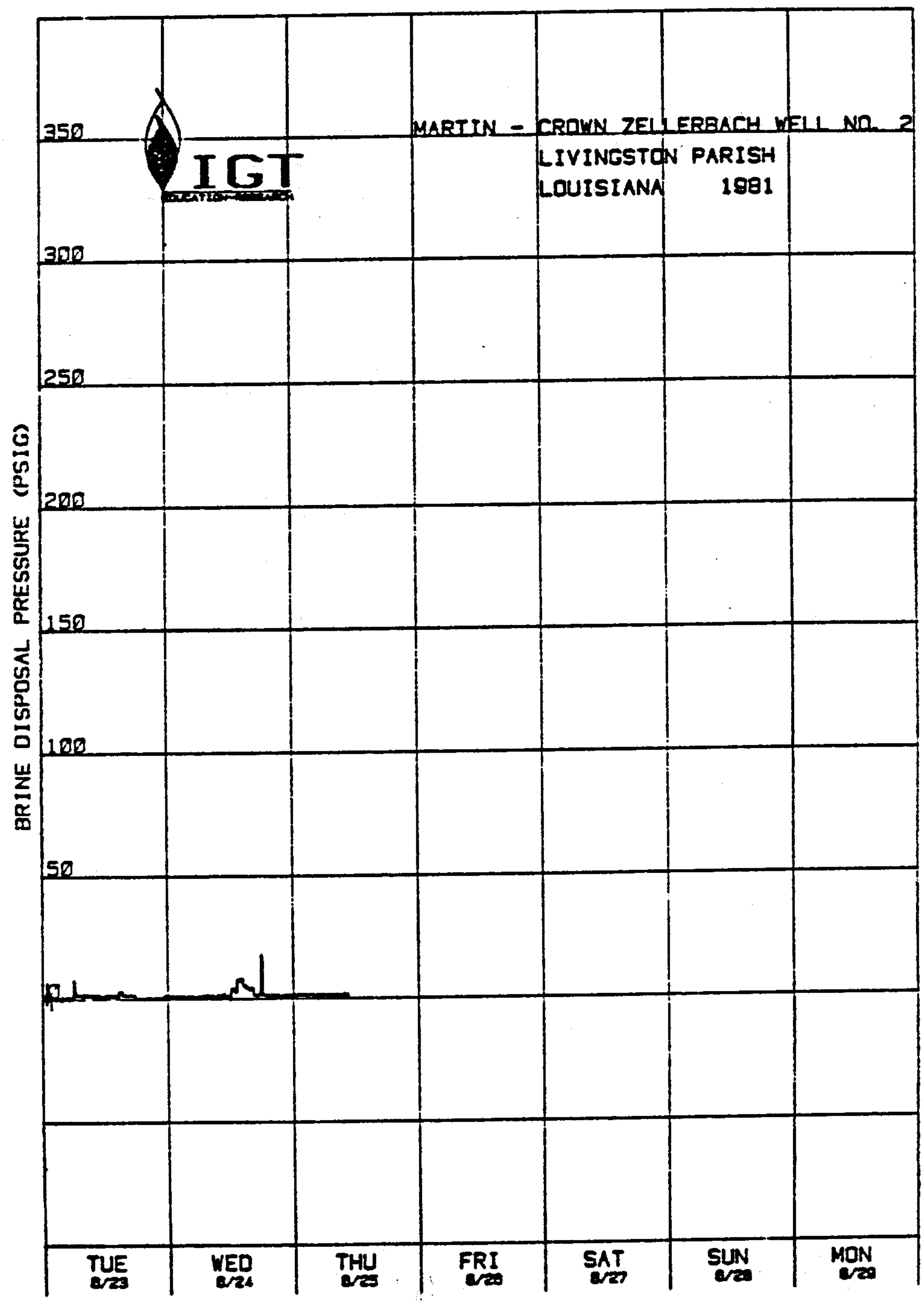
After perforating the additional disposal sand in the depth interval 4833 to 4893 feet, direct brine injection to the disposal well was resumed during 6/7/81. Such injection continued until the end of the first flow test on 6/9/81.

Direct brine injection to the disposal well was not attempted during the second and third flow tests. Pressures for the third flow test are not shown in Exhibit 12-17, because both the filters and the pressure sensor were bypassed.



BRINE DISPOSAL PRESSURE
(Part I)

EXHIBIT 12-18



BRINE DISPOSAL PRESSURE
(Part II)

EXHIBIT 12-18

12.7.3 Characteristics of Produced Hydrocarbons

Collection and analysis of flare line gas samples is described in Section 12.7.3.1. Similar information for gas remaining in post-separator brine is provided in Section 12.7.3.2. Results of analyses by parties other than IGT are presented in Section 12.7.3.3. Collection and analysis of liquid hydrocarbon samples is described in Section 12.7.3.4. Discussion of the sample analysis results, in the context of the question of saturation of aquifer brine and source of hydrocarbons, is presented in Section 12.7.3.5. Judgments made in selecting gas compositions for interpretation of orifice meter data to determine the time dependence of gas production to the flare line are presented in Section 12.7.3.6.

12.7.3.1 Flare Line Gas Samples: Flare line gas samples were collected from a sampling point between the orifice meter and the back-pressure controller. All samples were collected at separator pressure. The gas temperature at the sampling point was much lower than the flowing brine temperature. This was due to the introduction, on this well test, of an air-cooled heat exchanger between the primary separator and the orifice meter, which reduced the flowing gas temperature to near ambient temperature. Liquids that condensed from the gas as a result of the temperature reduction were removed with a small second separator (scrubber). Procedures used for 1) flare line gas sample collection, 2) gas chromatography analyses in the field, 3) Draeger apparatus analysis, and 4) mass spectrometry analysis in IGT's Chicago laboratories are as follows:

- **Sample Collection:** A clean 300-ml Telfon-lined stainless steel cylinder with #316 stainless steel valves was evacuated, sealed, and placed in an oven. The cylinder was heated to a temperature greater than the brine temperature (and above 100°C) to discourage droplets of water from adhering to the sides of the cylinders. Before sampling, the sample line was purged at a high flow rate to establish thermal equilibrium with the flare line. The sample line valve was then turned off, and the hot evacuated cylinder was attached to the sample port. All valves were then opened in sequence, starting with the sample port valve, and the system was flushed with gas at a high flow rate for 10 seconds. The valves were then turned off in reverse sequence and the cylinder removed. If the analyses were not to be performed immediately on-site, the cylinder was doubly sealed with Swagelock caps.

- **Field Gas Chromatograph Analyses:** These analyses were performed using a Carle Model 111-H gas chromatograph. The instrument uses a thermal conductivity detector and was housed in the IGT instrumentation trailer on location.

  The gas chromatograph was used to measure the hydrocarbons from C_1 to C_5. A C_{6+} peak was also eluted, but a water vapor peak swamped it, making quantification difficult. The chromatograph also separated carbon dioxide, nitrogen, oxygen, and hydrogen.

  The area under each peak was integrated by an on-line Perkin Elmer integrator. The area of each peak was then multiplied by the response factor of that component from a standard gas and the composition normalized to 100%.

Samples of flare line gas were bled from the collection cylinders to the heated inlet of the gas chromatograph within minutes after sample collection. Thus, samples were not cooled before field analysis.

Results of the field gas chromatograph analyses are presented in Exhibit 12-19. With the exception of C_{6+}, the maximum uncertainties in reported values are estimated to be as follows:

% Component	% Uncertainty
0.01 to 0.09	50
0.1 to 0.9	10
1.0 to 90	5

The second digit after the decimal point is not significant for methane or carbon dioxide but is reported for normalization purposes. The uncertainty in C_{6+} content is as great as, or greater than, the values shown above.

Natural gas liquids (NGL) content for ethane through pentane has been calculated for each gas analysis using values for SCF per gallon of liquid from Table 16-1 of the 1974 revised edition of the Engineering Data Book published by the Gas Processor's Suppliers Association in cooperation with the Gas Processor's Association (Ref. 11). The quantity of ethane through pentane NGL per MCF of total gas is also shown in Exhibit 12-19. The C_{6+} components are not included because of the large uncertainty in gas chromatograph results for these components.

- **Draeger Apparatus Analyses:** Hydrogen sulfide concentrations shown in Exhibit 12-20 were determined using Length of Stain Tubes (Draeger apparatus). The sampling port was the same as that used to collect samples for hydrocarbon analysis. The procedure used was the Gas Processor's Association "Tentative Method of Test for Hydrogen Sulfide in Natural Gas using Length of Stain Tubes," (Appendix H). Carbon dioxide, ammonia, and mercury contents were also determined using this procedure. At 1040 hours on 6/6/81, a Draeger tube that responds to both H_2S and SO_2 was used. The result was 25 ± 5 ppm. Since a tube responsive only to H_2S indicated 21 ppm, no conclusive evidence resulted regarding SO_2 in the gas.

  Mercury and ammonia contents throughout the test were, in every case, below the minimum detectable limits (less than 3 ppm ammonia and less than 0.05 mg/m^3 mercury). Results for CO_2 were consistent with those from gas chromatograph analysis and are not reported.

- **Mass Spectrometer Analyses:** Samples for mass spectrometric analysis were collected in Teflon-lined stainless steel cylinders using the procedures described previously. After collection, the 300 cc sample vessels were doubly sealed using Swagelock caps.

  Immediately before analysis with IGT's DuPont Model 21-104 mass spectrometer, each sample vessel was checked for leakage while removing the Swagelock caps.

FIELD GAS CHROMATOGRAPH ANALYSES OF FLARE LINE GAS
MARTIN-CROWN ZELLERBACH WELL NO. 2

Date	Time	Separator Pressure (psia)	Brine Temperature (°F)	C2-C5 NGL (gal/MCF)	Gas Composition (mole %) Nitrogen	Carbon Dioxide	Methane	Ethane	Propane	n-Butane	i-Butane	Pentanes	C6+[1]
5 June 81	1320	280.4	137.4	1.4493	0.51	16.91	77.12	4.62	0.71	0.04	0.03	0.00	0.06
5 June 81	1438	280.7	146.1	1.3333	0.48	20.04	74.45	4.24	0.68	0.03	0.02	0.00	0.06
6 June 81	0827	284.7	180.0	1.2867	0.45	22.58	72.17	3.92	0.69	0.08	0.06	0.02	0.03
6 June 81	1040	295.0	180.7	1.2926	0.46	22.59	72.10	3.94	0.69	0.07	0.06	0.03	0.06
6 June 81	1957	289.7	195.5	1.2910	0.44	23.33	71.40	3.91	0.69	0.08	0.07	0.03	0.05
7 June 81	1000	284.7	199.6	1.2882	0.46	23.58	71.13	3.91	0.68	0.08	0.07	0.03	0.06
7 June 81	1028	284.7	198.9	1.2850	0.46	23.55	71.17	3.91	0.68	0.08	0.06	0.03	0.06
8 June 81	1001	284.7	198.1	1.2818	0.46	23.71	71.02	3.91	0.68	0.07	0.06	0.03	0.06
8 June 81	1514[2]	279.9	197.3	1.2883	0.43	24.14	70.60	3.90	0.69	0.08	0.07	0.03	0.06
8 June 81	1612	282.1	197.4	1.2743	0.46	23.73	71.03	3.87	0.68	0.08	0.06	0.03	0.06
9 June 81	0845	277.9	193.9	1.3022	0.45	22.88	71.79	3.93	0.70	0.09	0.07	0.03	0.06
9 June 81	0945	281.3	193.9	1.3076	0.44	23.33	71.33	3.94	0.71	0.09	0.07	0.03	0.06
9 June 81	2102	277.1	196.2	1.2841	0.45	23.59	71.14	3.91	0.69	0.08	0.06	0.02	0.06
17 June 81	1049	268.2	200.4	1.2814	0.45	24.24	70.51	3.90	0.69	0.08	0.06	0.02	0.05
23 June 81	1035	230.8	172.2	1.1980	0.46	24.01	71.03	3.78	0.55	0.04	0.07	0.01	0.05
23 June 81	1517	229.1	185.8	1.2476	0.46	24.30	70.56	3.85	0.64	0.07	0.06	0.01	0.05
23 June 81	1652	229.3	187.7	1.2438	0.45	24.59	70.29	3.86	0.64	0.06	0.05	0.01	0.05
24 June 81	1012	228.4	195.5	1.2642	0.46	24.84	69.96	3.82	0.68	0.08	0.07	0.03	0.06
24 June 81	1038	229.0	195.4	1.2641	0.43	24.87	69.96	3.83	0.67	0.08	0.07	0.03	0.06
25 June 81	0915	229.0	195.3	1.2542	0.45	24.88	69.96	3.82	0.68	0.07	0.06	0.02	0.06

1 Uncertainties in C6+ values exceed reported (measured) values.

2 This gas sample was taken from a port on the top of the primary separator.

EXHIBIT 12-19

DRAEGER APPARATUS ANALYSES OF FLARE LINE GAS
MARTIN-CROWN ZELLERBACH WELL NO. 2

Date	Time	H_2S (ppm)	Hg (mg/m^3)	NH_3 (ppm)
5 June 81	1040	<1		
5 June 81	1458	12		
5 June 81	1610	14	N.D.	N.D.
6 June 81	1040	21		
6 June 81	1240		N.D.	N.D.
7 June 81	1028	34		
8 June 81	1020	43		
9 June 81	0845	48	N.D.	N.D.
9 June 81*	0900	52		
9 June 81	2104	55		
17 June 81	1050	56		N.D.
25 June 81	0923	60		

N.D. = None detected, below minimum detection limits

EXHIBIT 12-20

Samples were rejected if the space between the valve and cap was found to be pressurized. Acceptable sample vessels were connected to the mass spectrometer inlet system and heated to a temperature greater than the temperature of the separator gas stream at the time of sample collection. A small amount of gas was then injected into the mass spectrometer.

The mass spectrometer analysis quantifies all gases from Z = 2 to Z = 114. The detection limit is 0.01 mole percent composition. Analysis results are presented in Exhibit 12-21 for all components detected with concentrations greater than 0.01 mole percent. Gases that would have been detected and reported if concentrations exceeded this value include hydrogen, oxygen, argon, octanes, and nonanes.

The NGL content calculated for each analysis is also shown in Exhibit 12-21. This calculation is reported for ethane through pentane only, as well as for all hydrocarbons above the detection threshold. This breakdown facilitates the comparison of gas chromatograph and mass spectrometer analyses.

12.7.3.2 **Gas Flashed from Brine to the Disposal Well:** Samples for determination of the quantity and composition of gas in brine from the separator were collected from the brine sampling point at the inlet end of the brine metering skid. Samples were collected at the same time as flare line gas samples.

The sample collection point was at the midpoint of the horizontal 3-inch ID pipe and only about two pipe diameters downstream from the last of three right-angle changes in flow direction. This position discriminates against collection of gases or solids entrained in the brine stream. The sampling point was at separator pressure. Sample collection and flashing were performed as follows:

- Connecting a 500-ml, Teflon-lined, stainless steel cylinder to the sampling point with the outlet end of the vessel above the inlet end.
- Opening valves and flowing brine though the sample vessel for at least 60 seconds and until the vessel was hot to the touch.
- Closing the sample vessel outlet valve.
- Closing the sample vessel inlet valve.
- Closing the sample port valve.
- Disconnecting the sample vessel from the sampling point and immersing it in water until it cooled to the field laboratory ambient temperature (about 25°C). Cooling by water immersion provided the advantage that any sample vessel exhibiting leakage by bubble formation could be rejected.
- After cooling, connecting the sample vessel to a 500 cc syringe with less than 5 cc of air-filled dead volume in connecting tubing, fittings, and the syringe itself.
- Opening the sample vessel to allow gas flashed from brine in the pressure vessel to move vertically into the large syringe.

FLARE LINE GAS COMPOSITION FROM MASS SPECTROMETRIC ANALYSES
MARTIN-CROWN ZELLERBACH WELL NO. 2

Date	7 June 81	25 June 81
Time	1038	0911
Separator Pressure (psia)	284.7	229.1
Brine Temperature (°F)	198.8	195.3
Composition (mole %)		
Nitrogen	0.50	0.44
Helium	0.03	0.02
CO_2	24.21	26.51
Methane	70.13	67.86
Ethane	3.99	4.00
Propane	0.73	0.75
n-Butane	0.08	0.07
i-Butane	0.08	0.07
Pentanes	0.02	0.02
Hexanes	0.02	0.01
Heptanes	0.01	0.01
Benzene	0.10	0.12
Tolulene	0.09	0.11
Xylenes	0.01	0.01
NGL (gal C2-C5/MCF)	1.3229	1.3246
Total NGL (gal/MCF)	1.4175	1.4316

EXHIBIT 12-21

- Striking the cylinder repeatedly to ensure that the carbon dioxide has reached equilibrium between the gas and liquid phases.

After quantitative determination of the amount of gas entering the syringe at atmospheric pressure, the gas from the syringe was injected into the gas chromatograph for analysis. Results from this procedure are reported in Exhibit 12-22. A duplicate sample was collected for determination of hydrogen sulfide in this flashed gas. Results of these analyses are presented in Exhibit 12-23.

The most striking feature of all this data is the unexpectedly large quantity of gas remaining in the brine after the separator. On past well tests, IGT had used an algorithm developed by System Science and Software to predict the amount of gas in the brine at a given pressure. This algorithm was developed to match the data of Culberson and McKetta for methane solubility in water (Ref. 6) and was used by IGT because it empirically matched results of gas liberations from many prior well tests. This algorithm has satisfactorily agreed with field measurements on every prior Well of Opportunity the EOC/IGT team has tested, as well as on the Pleasant Bayou Well No. 2 and the MG-T/DOE Amoco Fee Well No. 1.

As illustrated in Exhibit 12-24, however, measured values showed an extreme divergence from predicted values for the Crown Zellerbach Well No. 2. The apparent cause for this is the very high carbon dioxide content in the produced brine of the subject well. This is demonstrated by comparing well test data for Crown Zellerbach with that obtained from other wells, as shown in Exhibit 12-25. This exhibit shows results from analyses of single brine samples collected at roughly similar separator pressures and temperatures from each of the five wells tested by the EOC team. The larger amount of gas liberated from the Crown Zellerbach separator brine samples was predominately CO_2. It is interesting that the measured hydrocarbon content of liberated gas is close to 60 percent of the calculated solubility for all five samples shown. Understanding of reasons for this has not been pursued. Nevertheless, this empirical observation is judged an adequate basis for use of the computer algorithm to estimate hydrocarbon energy production for this well.

12.7.3.3 **Hydrocarbon Samples Analyzed by Parties Other than IGT:** Several parties other than IGT collected and/or analyzed gas samples. Representatives of the following organizations collected their own samples on location or were provided with samples from IGT:

- Weatherly Laboratories, Inc.
  Lafayette, LA

- McNeese State University
  Lake Charles, LA

- USGS Gulf Coast HydroScience Center
  NSTL Station, MS

- U.S. Geological Survey
  Federal Center
  Lakewood, CO

COMPOSITION AND AMOUNT OF GAS LIBERATED FROM BRINE AFTER THE SEPARATOR
MARTIN-CROWN ZELLERBACH WELL NO. 2

Date	Time	Separator Pressure (psia)	Brine Temperature (°F)	Amount (SCF/STB)	Composition (mole %)							
					Nitrogen[1]	Carbon Dioxide	Methane	Ethane	Propane	n-Butane	i-Butane	Pentanes
5 June 81	1436	279.6	145.6	6.35	0.21	73.25	25.13	1.26	0.15	0.00	0.00	0.00
6 June 81	1040	295.0	180.7	5.04	0.24	71.84	26.57	1.19	0.14	0.01	0.01	0.00
6 June 81[2]	—	—	—	5.1	—	64.86	33.58	1.40	0.14	0.01	0.01	0.00
6 June 81	1957	289.7	195.5	4.71	0.32	69.68	28.58	1.25	0.15	0.01	0.01	0.00
7 June 81	1028	284.7	198.9	4.69	0.28	70.37	27.95	1.24	0.14	0.01	0.01	0.00
8 June 81[3]	1001	284.7	198.1	4.39	—	59.95	38.59	1.29	0.15	0.01	0.01	0.00
8 June 81	1612	282.1	197.4	4.59	0.14	74.27	24.41	1.04	0.12	0.01	0.01	0.00
9 June 81	0845	277.9	193.9	3.88	0.12	66.76	31.51	1.42	0.17	0.01	0.01	0.00
9 June 81	2102	277.1	196.2	4.54	0.14	70.06	28.37	1.26	0.15	0.01	0.01	0.00
17 June 81	1049	268.2	200.4	4.01	0.13	71.59	26.92	1.20	0.14	0.01	0.01	0.00
23 June 81	1040	231.2	172.8	4.55	0.17	74.05	24.52	1.11	0.13	0.01	0.01	0.00
23 June 81	1655	227.8	187.8	3.49	0.15	68.70	29.59	1.37	0.17	0.01	0.01	0.00
24 June 81	1040	228.1	195.5	3.14	0.18	65.95	32.21	1.46	0.18	0.01	0.01	0.00
25 June 81	0925	229.3	195.3	3.39	0.21	68.46	29.63	1.43	0.22	0.02	0.02	0.01

1 Nitrogen analyses uncertain due to air contamination of samples during liberation process.

2 Sample collection, gas liberation, and analyses performed by Weatherly Laboratories.

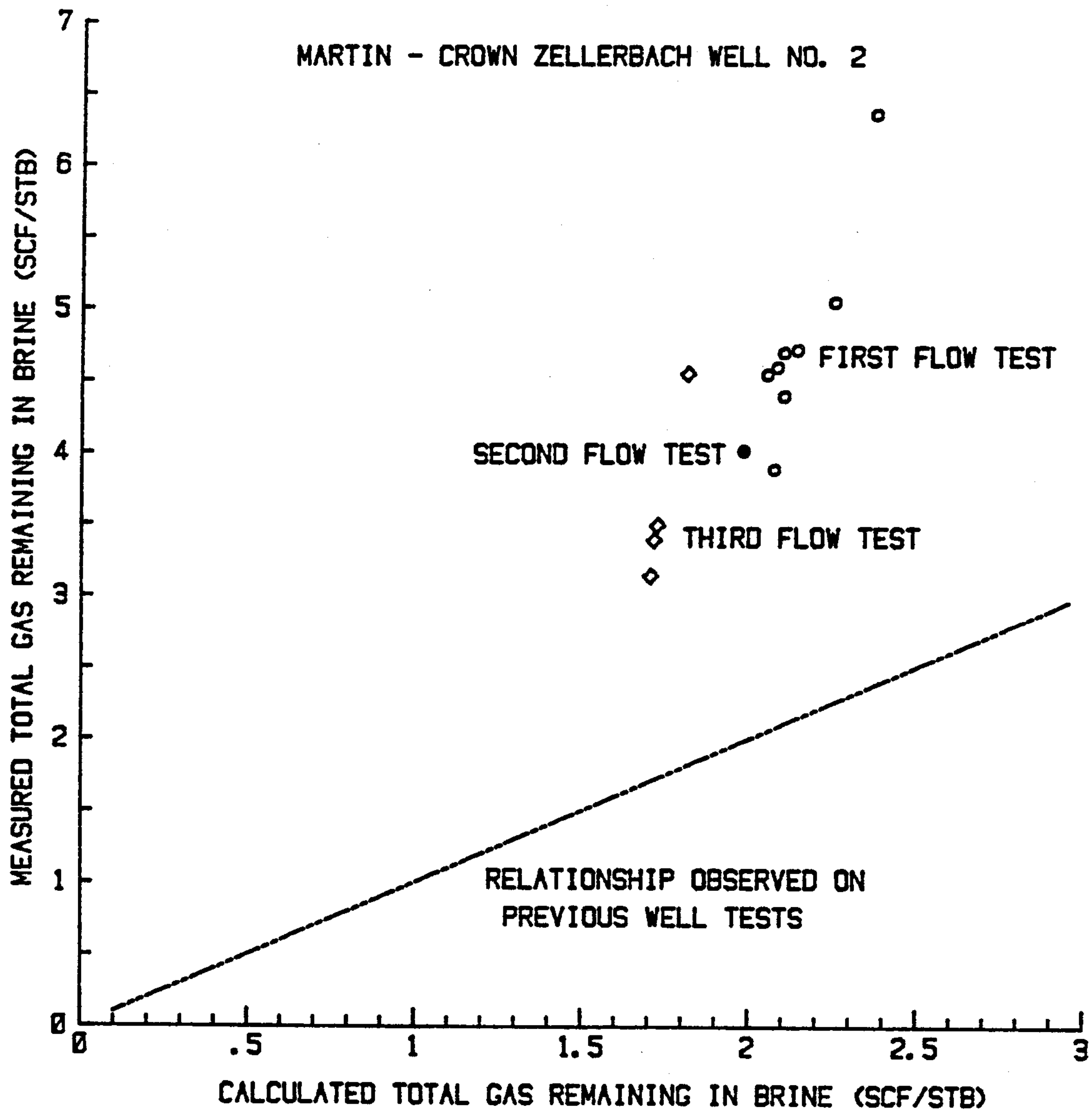
3 Nitrogen analysis not possible due to baseline upset of gas chromatograph.

EXHIBIT 12-22

DRAEGER APPARATUS ANALYSES OF GAS LIBERATED FROM BRINE AFTER THE SEPARATOR
MARTIN-CROWN ZELLERBACH WELL NO. 2

Date	Time	Separator Pressure (psia)	Brine Temperature (°F)	Amount of Gas (SCF/STB)	H_2S (ppm)
5 June 81	1438	281	146	6.06	130
6 June 81	1040	295	181	4.47	140
7 June 81	1028	285	199	4.44	125
8 June 81	1020	285	198	4.39	120
9 June 81	0845	278	194	3.23	45
9 June 81	2102	277	196	4.16	230
17 June 81	1049	268	200	3.23	80
23 June 81	1040	231	172	3.66	65
23 June 81	1655	228	189	3.25	40
24 June 81	1040	229	195	2.70	70
25 June 81	0923	229	195	3.32	200

EXHIBIT 12-23



COMPARISON OF MEASURED AND PREDICTED TOTAL GAS REMAINING IN BRINE AFTER THE SEPARATOR

EXHIBIT 12-24

GAS LIBERATED FROM BRINE AFTER THE SEPARATOR FOR FIVE WELLS OF OPPORTUNITY

	Wainoco-P.R. Girouard Well No. 1	Lear-G.M. Koelemay Well No. 1	Riddle-Saldana Well No. 2	HO&M Prairie Canal Co., Inc. Well No. 1	Martin-Crown Zellerbach Well No. 2
Date	7/23/80	9/18/80	11/22/80	3/5/81	6/9/81
Time	1230	1850	1345	1008	2102
Separator Pressure (psig)	259	244	203	251	262.4
Brine Temperature (°F)	210	201	216	187	196
Measured Gas Liberation (SCF/STB)					
Hydrocarbons	1.13	.98**	.97	1.16	1.35
CO_2	.18	.26**	.56	.55	3.18
Total†	1.31	1.24**	1.59	1.71	4.54
Calculated Gas Solubility (SCF/STB)*					
	1.99	1.91	1.59	2.00	2.05
Measured Hydrocarbon Content as a Percentage of Calculated Solubility					
	57	51**	61	58	66

* Calculated using the algorithm developed by S. K. Garg, et al (1978) to fit the data published by Culberson, O. L. and J. J. McKetta (1951) for solubility of methane in distilled water.

** Values may be low due to leakage from the sample cylinder.

† Differences from sum of hydrocarbons plus CO_2 are due to N_2.

EXHIBIT 12-25

Other organizations invited to participate in sampling and analysis included The University of Texas at Austin, Lawrence Berkeley Laboratory, Louisiana State University, and the U.S. Geological Survey at Menlo Park, California.

A combined sample log showing times of sample collection, location and type of samples collected, tests performed on location, and tests intended to be performed off location is presented as Appendix I.

Results of other-party hydrocarbon analyses that have been provided to IGT since the test are presented below:

- **USGS Gulf Coast HydroScience Center:** Results from analyses of gas samples for ^{222}Radon were provided in a letter from Mr. Thomas F. Kraemer dated October 22, 1981. Results of gas chromatograph/mass spectrometer (GC/MS) analyses and carbon isotope ratio analysis for a sample by Dr. George Claypool, USGS, Denver, were also contained in that letter. These are presented in Exhibit 12-26. Mr. Kraemer observed that the Radon content is fairly typical for gas from geopressured-geothermal brines.

  The value reported for the methane $\delta^{13}C$ isotope ratios is the difference between the $^{13}C^{12}C$ isotope ratios obtained for the sample and for an international standard. Values for gas of thermogenic origin usually range from -40 to -55, more mature gases having more positive values (closer to -40). The values for biogenic gases usually fall between -60 and -100. Thus, the value of -47.1 suggests that the produced methane is primarily of thermogenic origin.

- **Weatherly Laboratories, Inc.:** Representatives of this organization collected samples of gas and brine from the primary separator during the afternoon of 6/6/81. Their report covering comprehensive reservoir fluid analyses is provided in Appendix J. Only those portions of that report most relevant to quantity and composition of produced hydrocarbons is summarized in the paragraphs immediately below.

  Flare line gas analyses by Weatherly and IGT provided virtually identical results. The most notable difference was in C_{6+} components. The Weatherly gas chromatograph analysis included 0.11 mole percent of C_{6+} components whereas the mass spectrometric analysis of samples collected later in the test sequence revealed 0.23-0.25 mole percent C_{6+}. The difference is primarily due to benzene and toluene.

  Weatherly measurements of quantity and composition of gas liberated by pressure reduction after cooling separator brine gave results very close to those obtained by IGT. The data are included in Exhibit 12-22.

  Four recombinations of separator gas and brine to determine bubble points were performed. Results are shown in Exhibit 12-27(A). The gas/brine ratios shown were calculated from data in Appendix J, as follows:

GAS ANALYSIS REPORTED BY THE USGS GULF COAST HYDROSCIENCE CENTER

Radon Analysis:

Date	Time	^{222}Rn (dpm/L @ STP)
6/8/81	14:20	73.7 ± 3.7
6/25/81	09:25	78.6 ± 4.0

GC — MS Analysis:*

Date: 6/8/81 14:20

Component	Volume %
Methane	71.58
Ethane	4.13
Propane	0.76
i Butane	0.08
n Butane	0.06
i Pentane	0.02
n Pentane	0.01
CO_2	22.92
N_2 ± air	0.44
$\delta^{13}C$ (per mil)	-47.13

* Analyses performed by Dr. George Claypool, USGS, Denver Co.

EXHIBIT 12-26

RECOMBINATION AND DIFFERENTIAL LIBERATION ANALYSES
BY WEATHERLY LABORATORIES

(A) Recombination Data at 327°F

Gas in Solution* (SCF/STB)	Bubble Point Pressure (psia)
15.50	1501 ± 32
25.82	2878 ± 31
38.77	5584 ± 45
46.44	7538 ± 40
55.68 (extrapolated)	10075

(B) Differential Liberation Data

Pressure Step (psia)	5584–4000	4000–2500	2500–1000	1000–15
Gas Liberated (SCF/STB)**	4.08	6.02	9.69	18.97

Dry Gas Composition (mole percent):

CO_2	8.85	11.05	19.36	63.31
Methane	82.61	82.78	76.66	35.24
Ethane	6.56	5.09	3.54	1.35
Propane	1.46	.83	.38	.10
i-Butane	.22	.10	.03	—
n-Butane	.18	.09	.03	—
Pentanes	.12	.06	—	—
C6+	—	—	—	—

* Values differ from those reported in Appendix J due to:

- o Adding gas content of separator brine
- o Changing the gas pressure base from 15.025 psia to 14.73 psia
- o Dividing brine volume by 0.9679 to correct for shrinkage from separator pressure and temperature to one atmosphere and 60°F.

** Gas pressure base of 14.73 psia

EXHIBIT 12-27

- The reported $5.1 \dfrac{\text{SCF gas @ 15.025 psia and 60}^{\circ}}{\text{bbl brine @ 0 psig and 60}^{\circ}\text{F}}$ was multiplied by the separator shrinkage factor (0.9679) to give

$$4.93 \ \frac{\text{SCF gas @ 15.025 psia and 60}^{\circ}\text{F}}{\text{bbl brine @ 270 psig and 191}^{\circ}\text{F}}$$

- The above $4.93 \dfrac{\text{SCF gas @ 15.025 psia and 60}^{\circ}\text{F}}{\text{bbl brine @ 270 psig and 191}^{\circ}\text{F}}$ was added to the recombined gas/brine ratio

- The result was divided by the separator shrinkage factor to give brine volume at 0 psig and 60°F.

- This was then multiplied by $\dfrac{15.025}{14.73}$ to correct gas volume to the pressure-base used in this report.

The recombination at a gas/brine ratio of 38.77 SCF/STB in Exhibit 12-27(A) corresponds to the produced gas/brine ratio at the time of sampling as calculated by Weatherly using data from manual logging. This recombination revealed a bubble point of only 5584 ± 45 psia. In contrast, original reservoir pressure was reported by ERMI to be 10,075 psia. Extrapolating the recombination data to this pressure suggests that gas saturation at reservoir conditions would be 55.68 SCF/STB. Flowing bottom-hole pressure at the time of sample collection for recombination studies was 7475 ± 25 psia or about 1800 psi greater than the measured bubble point. Thus, it appears that the reservoir brine was well below saturation with natural gas.

A differential liberation analysis was performed using a sample recombined to the bubble point of 5584 ± 45 psia (38.77 SCF/STB), which corresponds to the produced gas/brine ratio calculated from Weatherly data. Results are shown in Exhibit 12-27(B). Volumes liberated differ from those reported in Appendix J due to change to the gas pressure-base of 14.73 psia used in this report. As is normal for geopressured aquifers, gas liberated in the first pressure step (5584-4000 psia) was rich in natural gas liquids (2.32 gal/mcf) and contained relatively little CO_2 (8.85 mole percent). In contrast, the gas from the last pressure step contained a very large amount of CO_2 (63.31 mole percent) but was lean in natural gas liquids (0.39 gal/mcf).

12.7.3.4 Collection and Analysis of Liquid Hydrocarbon Samples: Samples of liquid hydrocarbons were obtained from both the separator and the scrubber at various times during the test. In addition, collected brine samples were all observed to develop an oil film. Near the end of the test, bubbles of oil were observed to develop in the body of the sample and then float to the surface.

Only the lower limit of oil production can be estimated. This is because neither separator nor scrubber was rigged for three-phase operation. Thus, oil accumulated at the interface between gas and brine. In the case of the primary separator, an unknown amount of oil may well have been lost to the brine dump. In addition, the larger separator was blown to the reserve pit before being opened for inspection after each flow test. Nevertheless, about 1/2 gallon of black oil was recovered each time the separator was opened. In addition, black material was observed blowing to the pit between the brine and gas flows during the blowdown after the second flow test. Since solids remaining in the separator were white, the black material is assumed to have been roughly 0.5 to 1.0 barrels of oil. Since the primary separator was cleaned after the first flow test, it is estimated to have accumulated this quantity of oil from the 2380 STB of brine produced during the second flow test. With this assumption, and assuming no oil out the brine dump before the separator had been blown down, the primary separator oil/brine ratio is estimated to be in the range of 2 to 5 barrels of oil per 10,000 barrels of brine.

Level controllers were not in use for either the oil or brine dumps on the scrubber in the gas line. Rather, liquids condensed from the gas were periodically drained by manual opening of valves. Three such drainings appear to have provided condensate with minimal oil contamination due to carryover from the primary separator. In these cases, the majority of liquid hydrocarbons recovered were light in color but contained a suspension of red or orange material, possibly rust. Estimates of liquid hydrocarbon recovery from the scrubber lie in the range of 2 to 8 barrels of condensate per 100,000 barrels of produced brine.

Samples of recovered liquid hydrocarbons were sent to Mr. Leigh Price, USGS, Denver, for analysis. At the time of writing this report, only a small portion of his planned analyses have been completed. Nevertheless, his preliminary data provides two observations of interest. These are:

- The C_2 through C_7 portion of liquids from both vessels contains about 25 weight percent benzene and 40-60 weight percent toluene. This observation at least supports the detectable quantity of these species observed in nearly all of IGT's mass spectrometric analyses of flare line gas samples from tests of geopressured aquifers.

- The C_7 compounds exclusive of toluene are 70-85 percent cyclic hydrocarbons. Normal and branched C_7 hydrocarbons each constitute less than 15 percent of C_7 compounds exclusive of toluene. In contrast, normal crude oil usually contains a small fraction of cyclic compounds. This observation suggests that the observed oil may well have been in solution in brine in the reservoir.

12.7.3.5 **Discussion of Hydrocarbon Analyses:** The analyses presented in Sections 12.7.3.1 through 12.7.3.4 reveal three characteristics that differ substantially from prior tests of brine production from geopressured-geothermal reservoirs. These are:

- CO_2 content of produced fluids is the highest observed to date.

- Methane content of produced brine is the lowest to date relative to laboratory studies of methane solubility of brine.

- Liquid hydrocarbon production is much higher relative to brine production than on any prior test except the G.M. Koelemay Well No. 1.

Data from this well departs so much from prior field and laboratory experience that it is not clear whether the reservoir brine is "saturated." Hydrocarbon production is clearly disappointing in relation to predictions based upon laboratory studies of the methane/NaCl brine system. However, the academic question of saturation must be approached from the experience of the negative result from G.M. Koelemay Well No. 1 recombination analyses (Ref. 8). That work included the observation that adding a volume fraction of 5×10^{-4} of produced oil to NaCl brine increased the bubble point for methane from 9585 ± 35 psia to greater than 10,995 psia at a temperature of 260°F. This raises the question of how much the small amount of heavy hydrocarbons observed on this well test could reduce methane solubility. It is conceivable that combined effects of CO_2 and liquid hydrocarbons could suppress methane solubility to such an extent that the reservoir tested could not naturally contain any more methane.

An alternate hypothesis is that the source of CO_2, methane, and liquid hydrocarbons is adjacent shales that are at an early stage in hydrocarbon maturation. This would contrast with previously tested reservoirs, where the source of natural gas appears to be upward migration from much greater depth. The measured value of -47.1 per mil for $\delta^{13}C$ further suggests less thermal maturity than the values in the range of -42.5 to -45 for methane from the tests of the P.R. Girouard Well No. 1, Saldana Well No. 2, and Prairie Canal Well No. 1. With this hypothesis, the brine could be below saturation with methane due to lack of methane generation in the adjacent shales.

12.7.3.6 **Gas Composition for Gas Production Calculations:** Interpretation of orifice meter raw data to determine the rate of natural gas flaring is dependent on the composition of the gas flowing through the meter. The data presented in Section 12.7.3.1 reveal modest day-to-day variations in composition after the first day of the test. The carbon dioxide content of flare line gas gradually increased, probably because the brine temperature increased. This temperature change is small and is also partially dependent on other factors, including the weather. A single analysis may not be representative of a full day's flow because of these variations, and average compositions were deemed satisfactory for an entire flow test. For production calculations, therefore, separate compositions were selected for each of three different time intervals, as shown in Exhibit 12-28.

The gas compositions for each time interval reflect the average of field gas chromatograph values for N_2, CO_2, and methane through pentane hydrocarbons. Data from 6/5/81 was excluded from these computations since the results were not thoroughly understood, probably coming from a period of rapidly changing compositions.

The selected gas compositions were then renormalized to include a C_{6+} component on the basis of mass spectrometric analyses. Mass spectrometer data indicated a C_{6+} component equal to 0.23 mole percent for the first flow test and 0.26 mole percent for the third flow test. A value of 0.24 mole percent was used during the short, second flow test, because no mass spectrometric analyses were performed on samples collected during this test.

FLARE LINE GAS COMPOSITIONS SELECTED FOR PRODUCTION CALCULATIONS
MARTIN-CROWN ZELLERBACH WELL NO. 2

Composition (mole %)	Time Interval: 5 June 81 to 9 June 81	16 June 81 to 17 June 81	23 June 81 to 25 June 81
N_2	0.48	0.45	0.47
CO_2	23.24	24.09	24.64
Methane	71.29	70.47	69.99
Ethane	3.90	3.89	3.83
Propane	0.69	0.69	0.66
n-Butane	0.08	0.08	0.07
i-Butane	0.06	0.07	0.06
Pentanes	0.03	0.02	0.02
C6+	0.23	0.24	0.26

EXHIBIT 12-28

12.7.4 Produced Gas and Gas/Brine Ratio

Sections 12.7.4.1 through 12.7.4.3 provide details of raw data interpretation to deduce flare line gas production, brine production, and the total produced gas/brine ratio. Values from a number of these intermediate steps are tabulated under the appropriate columns in Appendix K. Specific columns will be referenced in the detailed discussions in these first three sections. Sections 12.7.4.4 and 12.7.4.5 examine changes in gas/brine ratio and production of individual gaseous species in relation to producing conditions. Section 12.7.4.6 then presents the comparison of produced gas/brine ratio and laboratory data on gas solubility.

12.7.4.1 **Flare Line Gas Production:** Flare line gas compositions representative of various time intervals during the test were selected as discussed in Section 12.7.3.6 and tabulated in Exhibit 12-28. The steps used to calculate the time dependence of gas production to the flare line, with those gas compositions, are as follow:

- Calculating the specific gravity and heating value for the average gas composition for each time interval, using the method prescribed in ANSI/ASTM D 3588-77. This ANSI/ASTM procedure assigns the physical properties of normal hexane to all C_{6+} hydrocarbons. Resulting calculated values are shown for each 1/2-hour of production in columns 3 and 4 of Appendix K.

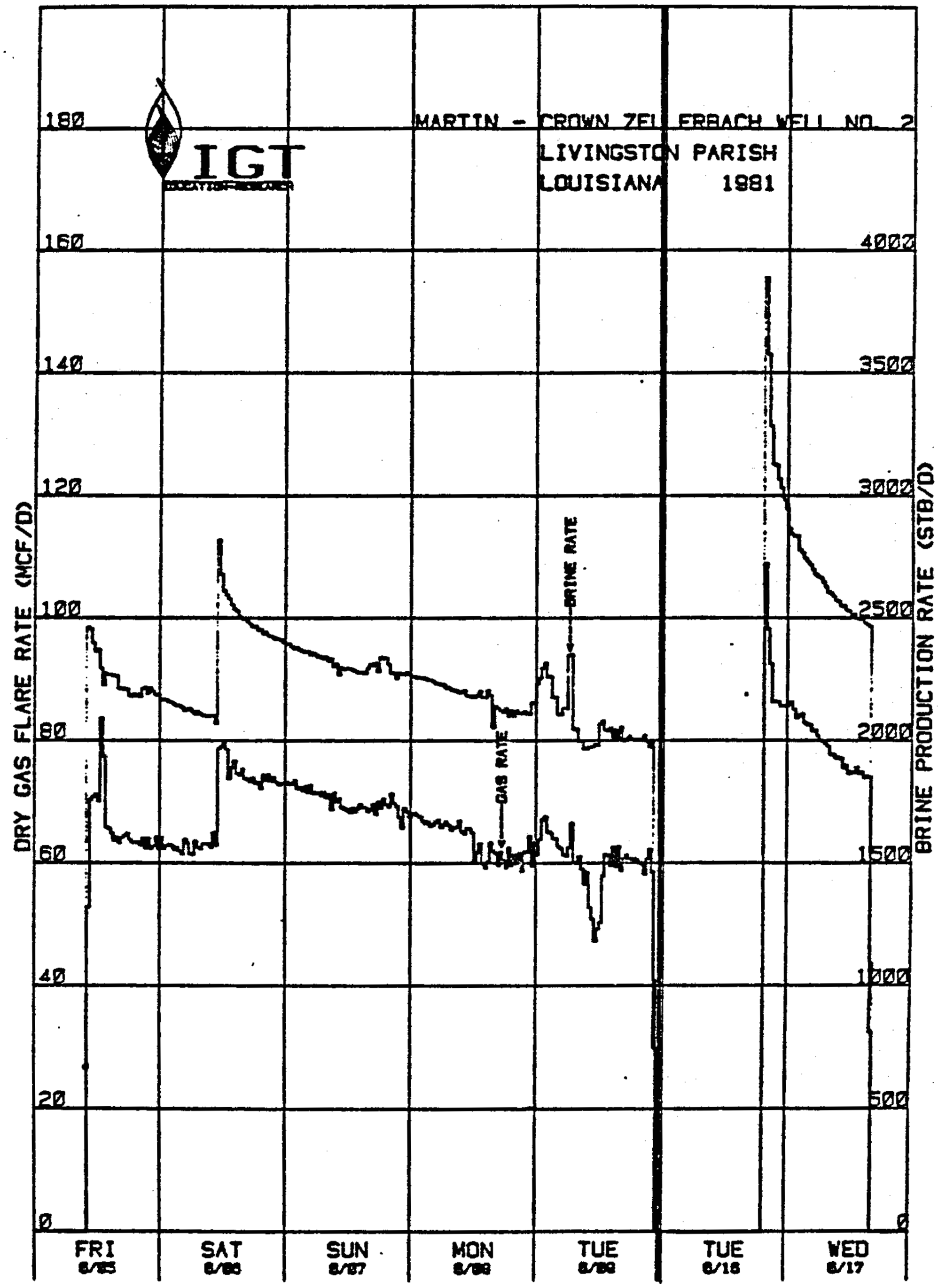
- Calculating gas production to the flare line for each line entry of raw data using methodology prescribed in A.G.A. Gas Committee Measurement Report No. 3. Implementing this methodology requires values for super-compressibility ($F_{pv} = \sqrt{1/z}$). The values of z used for interpretation were calculated for various separator pressures and temperatures, using a computer program developed by IGT for a different project. Results of this calculation of F_{pv}, for each 1/2-hour of production, are shown in the fifth column of Appendix K.

- Summing the gas production from each entry of raw data to determine total gas production in each 1/2-hour, and then expressing this as a daily rate for that 1/2-hour time interval. Results of this calculation for each 1/2-hour are reported in column 6 of Appendix K.

- Reducing calculated gas production for each 1/2-hour by an amount corresponding to the ratio of partial pressure of water at the orifice meter to separator absolute pressure. The resultant calculated dry gas production is tabulated for each 1/2-hour in column 7 of Appendix K. Dry gas flare rates are also shown graphically in Exhibit 12-29, Parts I and II.

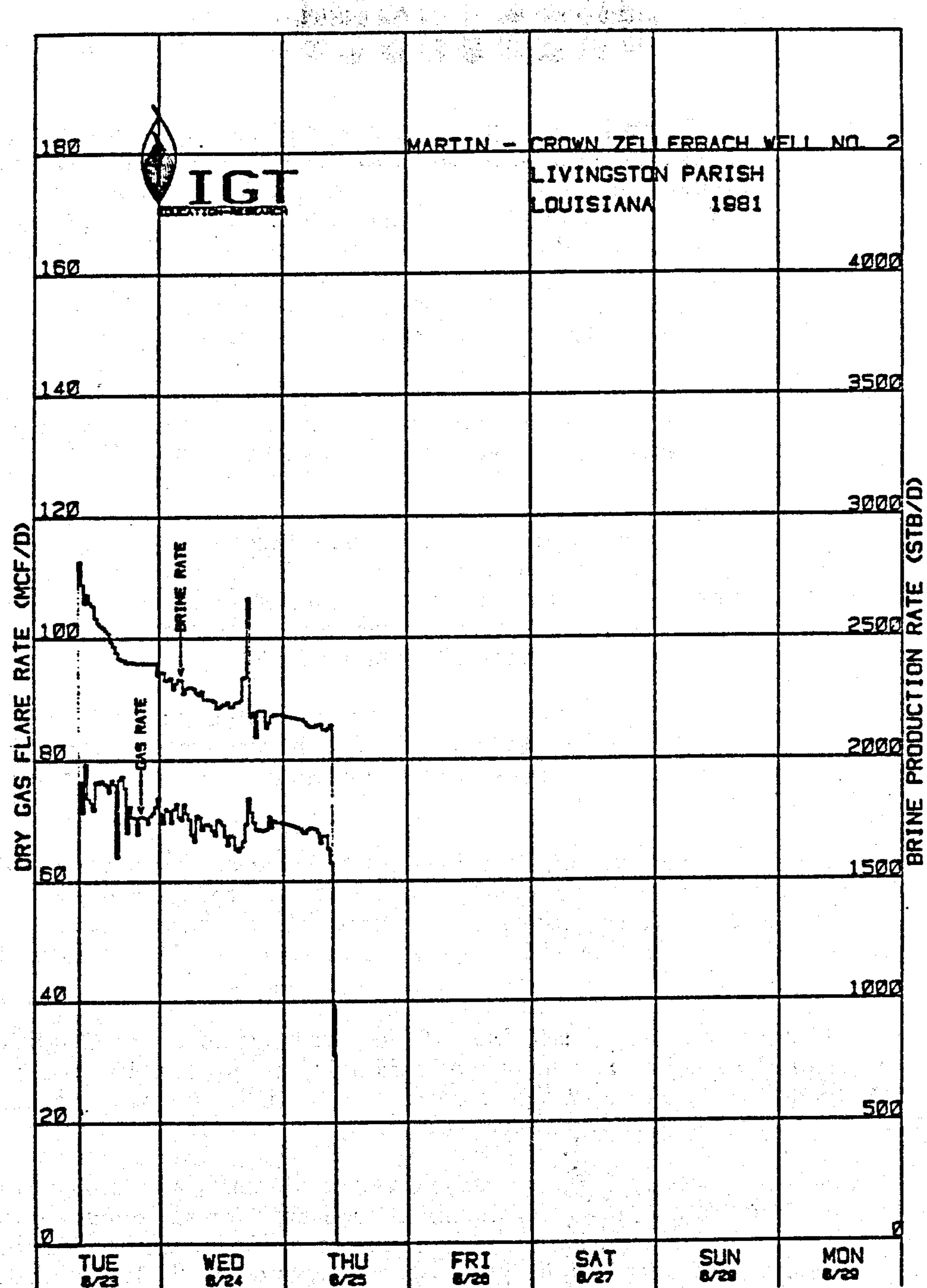
- Calculating hydrocarbon gas production by excluding the portions of produced dry gas that are nitrogen and CO_2. Hydrocarbon gas production rate for each 1/2-hour is shown in column 8 of Appendix K.

12.7.4.2 **Brine Production Rate:** Section 12.7.2 and Exhibit 12-11 provide a description of raw data on brine production rate measured just beyond the separator and a procedure for estimating brine production through periods of separator upsets and at other times that this information could not be obtained directly.



DRY GAS FLARE RATE AND BRINE PRODUCTION RATE
(Part I)

EXHIBIT 12-29



DRY GAS FLARE RATE AND BRINE PRODUCTION RATE
(Part II)

EXHIBIT 12-29

For each 1/2-hour, the calculation of brine rate was performed by using the same computer program that performed the gas production rate calculations described in the preceeding section. Inputs to each 1/2-hour calculation are the 1/2-hour averages for separator turbine rate, separator pressure, and brine temperature. Brine rate at 14.73 psia and 60°F was then calculated for each 1/2-hour time interval. Results are tabulated in column 10 of Appendix K and presented graphically in Exhibit 12-29, Parts I and II.

12.7.4.3 Produced Gas/Brine Ratio: Total produced gas is the sum of gas to the flare line plus gas remaining in solution in brine to the disposal well. As discussed in Section 12.7.3.2, gas content of brine leaving the separator was substantially greater than for prior tests of Wells of Opportunity by the EOC team. However, as shown in Exhibit 12-25, the excess gas is CO_2. Hydrocarbon content of separator brine is consistent with prior experience. Therefore, the previously used calculation procedure has been used to approximate total production of gas with heating value and gravity similar to flare line gas. This has been estimated using the following steps:

1. Dividing the previously discussed flare line dry gas production rate for each 1/2-hour by the previously discussed brine production rate at 14.73 psia and 60°F for that 1/2-hour to determine the flared dry gas/brine ratio. These results are tabulated in column 11 of Appendix K.

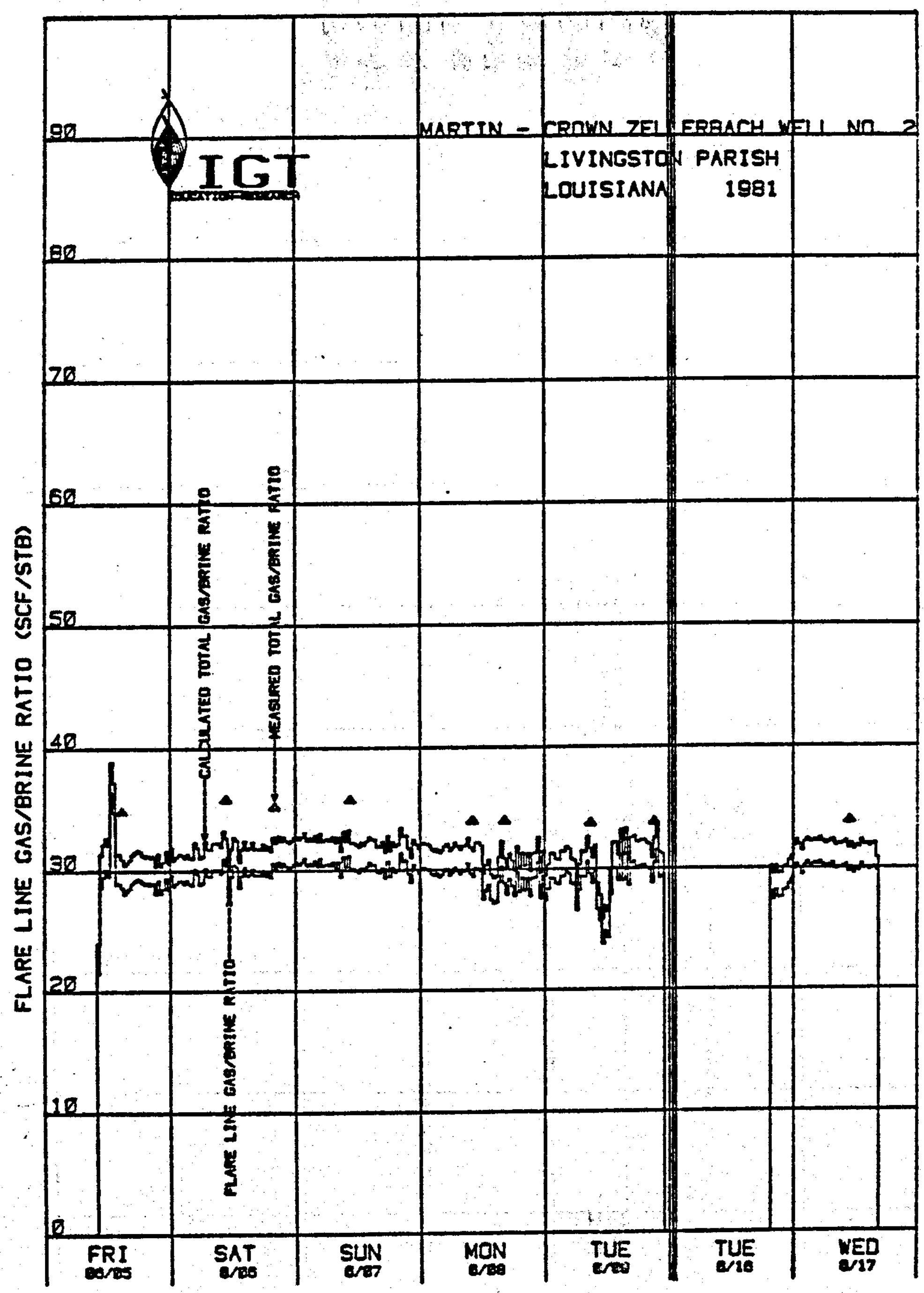
2. Estimating the gas/brine ratio in brine to the disposal well using the algorithm developed by System Science and Software to fit the data of Culberson and McKetta for methane solubility in distilled water (Ref. 6). Results of this calculation using 1/2-hour averaged values for separator pressure and brine temperature are reported in column 12 of Appendix K.

3. Adding flare line dry gas/brine ratio to the estimated disposal well gas/brine ratio to estimate the total gas/brine ratio for the production well. Results of this addition are tabulated in column 13 of Appendix K and are shown graphically in Exhibit 12-30.

Exhibit 12-30 also shows the ratio of flare line gas to brine production and data points for the gas/brine ratio determined by adding gas liberated by reducing pressure on brine samples to one atmosphere after cooling to the flare line gas/brine ratio. These data points at times of sample collection will be discussed in more detail in Section 12.7.4.5.

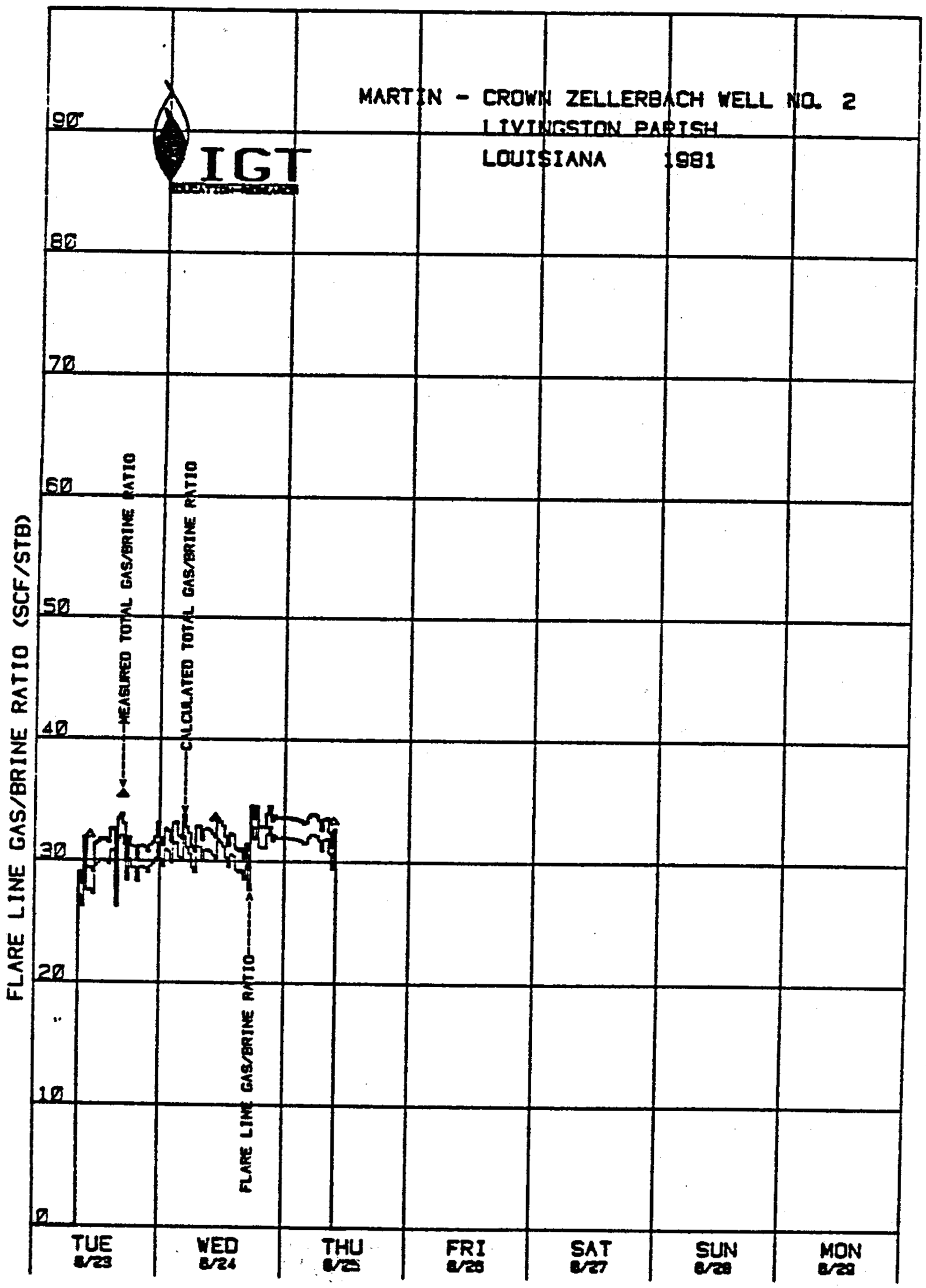
12.7.4.4 Correlation of Gas/Brine Ratio with Producing Conditions: The variations in calculated gas/brine ratio shown in Exhibit 12-30, Parts I and II, have been carefully examined in relation to producing conditions. This examination revealed many of these to be due to human activity. Most noteworthy of these are:

- **Midday 6/8/81 - Midday 6/9/91:** The low values of gas/brine ratio correlate with (a) bleeding liquids and gas from the small separator for sampling, (b) displacing gas-free brine down the tubing and into the produced stream to kill the tubing for removal of the bottom-hole pressure gauge, and (c) displacing the gas-free $CaCl_2$ brine down the tubing and into the produced stream after running a new bottom-hole pressure gauge.



FLARE LINE GAS/BRINE RATIO
(Part I)

EXHIBIT 12-30



FLARE LINE GAS/BRINE RATIO
(Part II)

EXHIBIT 12-30

- **Midday of 6/24/81:** The decrease in gas/brine ratio is due, at least in part, to loss of gas through a leak in the line upstream of the orifice meter.

Additional variations in gas/brine ratio were due to phenomena that are reasonably well understood and take place after brine leaves the reservoir and enters the wellbore. These are:

- **Midday 6/5/81 - Midday 6/6/81:** The increase of about 1 SCF/STB over this time interval correlates with increasing surface temperature. It is believed due to temperature-dependent changing partitioning of CO_2 between the gas and brine phases in the separator. Such change was documented during the test of the Prairie Canal Well No. 1 (Ref. 14).

- **Evening of 6/16/81:** The low gas/brine ratio was observed only prior to production of the first well volume of brine. A portion of the gas originally contained in this brine had previously migrated to the wellhead.

With the above observations in mind, the majority of production during the first and second flow tests was characterized by production of 30.0 ± 0.5 SCF/STB to the flare line and calculated production of 32.0 ± 0.5 SCF/STB of total gas. Gas/brine ratio with all produced CO_2 taken into account will be discussed in Section 12.7.4.5. The high gas/brine ratio (38.1 SCF/STB) during a one-hour period on 6/5/81 will be discussed in Section 12.7.4.6.

In contrast to the first two flow tests, the gas/brine ratio for the third flow test contains numerous variations of a few percent that are not understood in detail. However, the lowest values do correlate with manual draining of liquids from the small separator meter run and flare stack. Changes in producing characteristics due to perforating an additional reservoir before the third flow test appear to be only (a) a slight increase in calculated gas/brine ratio from 32.0 to about 33.0 SCF/STB, and (b) an increase in volatile oil/brine ratio by a factor of about two or three as deduced from liquids removed from the small separator.

These small changes are of no significance in relation to energy production economics. Rather, this detailed search for correlations and the examination of production of individual species in Section 12.7.4.5 below have been motivated by the suprisingly small gas/brine ratio.

12.7.4.5 Production of Specific Gaseous Species: The paragraphs below combine results of various measurements and analyses to define total content of specific gaseous species in each barrel of produced brine. Results are tabulated for the times of simultaneous collection of gas and brine samples. Separate discussions of volatile hydrocarbons, CO_2, H_2S, and total produced gas are presented:

- **Volatile Hydrocarbon Species:** Exhibit 12-31 provides tabulations of content of all gaseous species detected by mass spectrometric analysis of gases in each stock tank barrel of brine produced from the reservoir. Steps used to develop this table were:

VOLATILE HYDROCARBON CONTENT OF PRODUCED BRINE

Sample		Amount of Species Shown (SCF/STB)								
Date	Time	Methane	Ethene	Propane	n-Butane	i-Butane	Heptanes, Hexanes Plus Pentanes,	Benzene	Toluene Plus Xylene	Total Hydrocarbons
First Reservoir Tested:										
5 Jun 81	1436	22.85	1.290	0.204	0.009	0.006	0.009	0.026	0.026	24.42
6 Jun 81	1040	23.57	1.275	0.220	0.022	0.019	0.018	0.031	0.031	25.19
6 Jun 81	1957	23.15	1.253	0.218	0.025	0.022	0.018	0.031	0.031	24.75
7 Jun 81	1028	23.47	1.276	0.218	0.025	0.019	0.018	0.031	0.031	25.09
8 Jun 81	1001	22.74	1.216	0.208	0.021	0.018	0.018	0.030	0.030	24.28
8 Jun 81	1612	22.04	1.187	0.206	0.024	0.018	0.018	0.029	0.029	23.55
9 Jun 81	0845	22.72	1.232	0.216	0.027	0.021	0.018	0.030	0.030	24.29
9 Jun 81	2102	22.16	1.204	0.209	0.024	0.018	0.015	0.029	0.029	23.69
17 Jun 81	1049	22.19	1.216	0.212	0.024	0.018	0.015	0.030	0.030	23.74
Mean Values of Above:		22.77	1.239	0.212	0.022	0.018	0.016	0.030	0.030	24.33
Standard Deviation: (% of Mean)		2.5	2.9	2.8						2.5
Comingled Production From Two Reservoirs:										
23 Jun 81	1040	19.62	1.092	0.157	0.012	0.020	0.009	0.033	0.033	20.97
23 Jun 81	1655	23.48	1.281	0.210	0.020	0.016	0.010	0.038	0.038	25.09
24 Jun 81	1040	22.10	1.200	0.208	0.024	0.021	0.015	0.036	0.036	23.64
25 Jun 81	0925	21.95	1.192	0.211	0.022	0.019	0.012	0.036	0.036	23.48

EXHIBIT 12-31

1. Combine field gas chromatograph analyses from Exhibit 12-19 with C_{6+} hydrocarbon contents from the mass spectrometric analyses in Exhibit 12-21 and then renormalize to 100 percent as described in Section 12.7.3.6.

2. Multiply the result from Step 1 by the flared gas/brine ratio from column 11 of Appendix K for the time of flare line gas sample collection.

3. Add the quantity of each gaseous species liberated from simultaneously collected separator brine by pressure reduction to one atmosphere. This was calculated from data in Exhibit 12-22.

- **Produced CO_2:** Under separator operating conditions, CO_2 is present in several forms. These are gaseous CO_2, CO_2 in solution in brine, CO_2 contained in bicarbonate (HCO_3^-) ions in solution in brine, carbonate ($CO_3^=$) ions in solution in brine, and possibly in precipitates such as $CaCO_3$. Partitioning of CO_2 between species in this $CO_2/HCO_3^-/CO_3^=$ system is dependent upon pressure, temperature, and time.

Means have not yet been developed for defining partition of the $CO_2/HCO_3^-/CO_3^=$ inside the separator. However, total CO_2 content of produced brine plus an upper limit on the quantity present as CO_2 molecules was estimated by the following procedures:

1. Determine CO_2 content of flare line gas and gas liberated from cooled separator brine using the same procedures as described above for hydrocarbons. These portions of CO_2 and their sums are shown in Exhibit 12-32.

2. While draining a portion of brine sample from the cooled sample vessel at one atmosphere, simultaneously stabilize the remaining $CO_2/HCO_3^-/CO_3^=$ content with sodium hydroxide. Then treat with acid while purging with nitrogen and trapping liberated CO_2. Adding this CO_2, expressed as SCF/STB, to the results of Step 1 provides a measure of total CO_2 content of produced brine including all components of the $CO_2/HCO_3^-/CO_3^=$ system. Acid liberated CO_2 and total produced CO_2 for each suite of samples are tabulated in Exhibit 12-32.

3. A second aliquot of brine from the sample vessel is titrated with acid to an observed pH endpoint between 3.5 and 4.0 that corresponds to conversion of all HCO_3^- to CO_2. Since $CO_3^=$ content of produced brine is very small compared to HCO_3^-, subtracting results of this titration from the result of Step 2 provides an estimate of molecular CO_2 content of produced brine. Results of the titration and subtraction are tabulated for each suite of samples in Exhibit 12-32.

- **H_2S:** Production of H_2S is similar to production of CO_2 in that partition among a variety of species is involved. However it differs from CO_2 in that sulfide ions are much more reactive with tubular goods, so that only a portion of the sulfide ions in reservoir brine reaches the surface.

CO_2 CONTENT OF PRODUCED BRINE

Sample		Separator		Amount of CO_2 From Source Shown (SCF/STB)						
Date	Time	Pressure (psia)	Temperature (Deg F)	Flare Line	Brine at One Atmosphere	Sum	Acid Liberation	Total $CO_2/HCO_3^-/CO_3^=$	Alkalinity Titration	Total Minus Alkalinity
First Reservoir Tested:										
5 Jun 81	1436	280	146	5.72	4.65	10.37	5.50	15.87	1.73	14.14
6 Jun 81	1040	295	181	6.97	3.62	10.59	3.99	14.58	1.83	12.75
6 Jun 81	1957	290	196	7.12	3.28	10.41	4.44	14.85	1.99	12.86
7 Jun 81	1028	285	198	7.33	3.30	10.63	4.57	15.20	1.76	13.44
8 Jun 81	1001	285	198	7.03	2.63	9.66	5.14	14.80	1.88	12.92
8 Jun 81	1612	283	197	6.99	3.41	10.40	4.08	14.48	1.79	12.69
9 Jun 81	0845	281	194	6.85	2.59	9.44	6.56	16.00	1.74	14.26
9 Jun 81	2102	279	196	6.92	3.18	10.10	5.47	15.57	1.73	13.84
17 Jun 81	1049	269	200	7.26	2.87	10.13	5.84	15.97	1.76	14.21
Mean Values of Above:				6.91	3.28	10.19	5.07	15.26	1.80	13.46
Standard Deviation: (% of Mean)				6.8	18.9	4.0	17.0	4.0	4.8	5.0
Comingled Production From Two Reservoirs:										
23 Jun 81	1040	231	173	6.62	3.37	9.99	5.32	15.31	1.29	14.02
23 Jun 81	1655	228	188	7.85	2.40	10.25	4.87	15.12	1.83	13.29
24 Jun 81	1040	228	196	7.50	2.07	9.57	4.93	14.50	1.86	12.64
25 Jun 81	0925	229	195	7.45	2.32	9.77	4.17	13.94	1.83	12.11

Total produced H_2S was determined by procedures similar to those described previously for CO_2. Sulfide concentrations in produced brine were measured for 1) flare line gas, 2) gas liberated from cooled post-separator brine by pressure reduction to 1 atmosphere and ambient temperature, and 3) sulfide remaining in brine after gas liberation by pressure/temperature reduction. Analytical results obtained by these procedures are presented in Exhibit 12-33. This exhibit reveals an increase in total sulfide (expressed as mg H_2S/liter) during each flow test. Thus, sulfide content of brine in the reservoir may well exceed the highest measured value of 1.55 mg H_2S per liter of brine.

12.7.4.6 Comparison of Observed Gas/Brine Ratios with Laboratory Data on Gas Solubility: Exhibit 12-34 provides a comparison of recombination and differential liberation data developed using separator samples with methane solubilities calculated using algorithms by Blount (Ref. 19) and Haas (Ref. 13) to approximate laboratory data on methane solubility in NaCl brine. The recombination and differential liberation points shown were calculated from the report in Appendix J and are tabulated in Exhibit 12-27.

As discussed in Section 12.7.3.3, the gas content shown for the recombination data points includes the quantity of gas liberated by reducing pressure on cooled separator brine samples to one atmosphere. However, additional CO_2 remaining in the $CO_2/HCO_3^-/CO_3^=$ system in cooled brine was not included. This additional CO_2 has been considered in conjunction with detailed comparison of recombined and produced gas compositions.

Exhibit 12-35 shows the concentrations of species recombined by Weatherly Laboratories, Inc. at 5584 ± 45 psia and the actual produced concentrations from Section 12.7.4.5. The exhibit reveals that the recombination at 5584 psia included about 3.4 SCF/STB more hydrocarbons than actually produced. Thus, the actual reservoir bubble point was probably lower than that chosen for differential liberation studies.

If all CO_2 present in the $CO_2/HCO_3^-/CO_3^=$ system had been included in the Weatherly analysis, reported gas content for each recombination would have been higher by about 5.0 SCF/STB. Reported total solubility at 5584 psia would then have been about 25 percent greater than calculated using the two algorithms. Hydrocarbon content of brine would have been 25 percent less. These departures are consistent with preliminary laboratory data on the effect of CO_2 upon methane solubility (Ref. 32).

These observations combine to provide strong evidence that reservoir brine is below saturation with natural gas and that the bubble point pressure is only about one-half the measured reservoir pressure of 10,075 psia. However, this conclusion is not drawn because:

- The one-hour spike in gas/brine ratio during 6/5/81 and the composition of the flare line gas sample collected at 1320 hours during that spike both suggest that pressure near the wellbore dropped to below the reservoir bubble point during the initial drawdown.

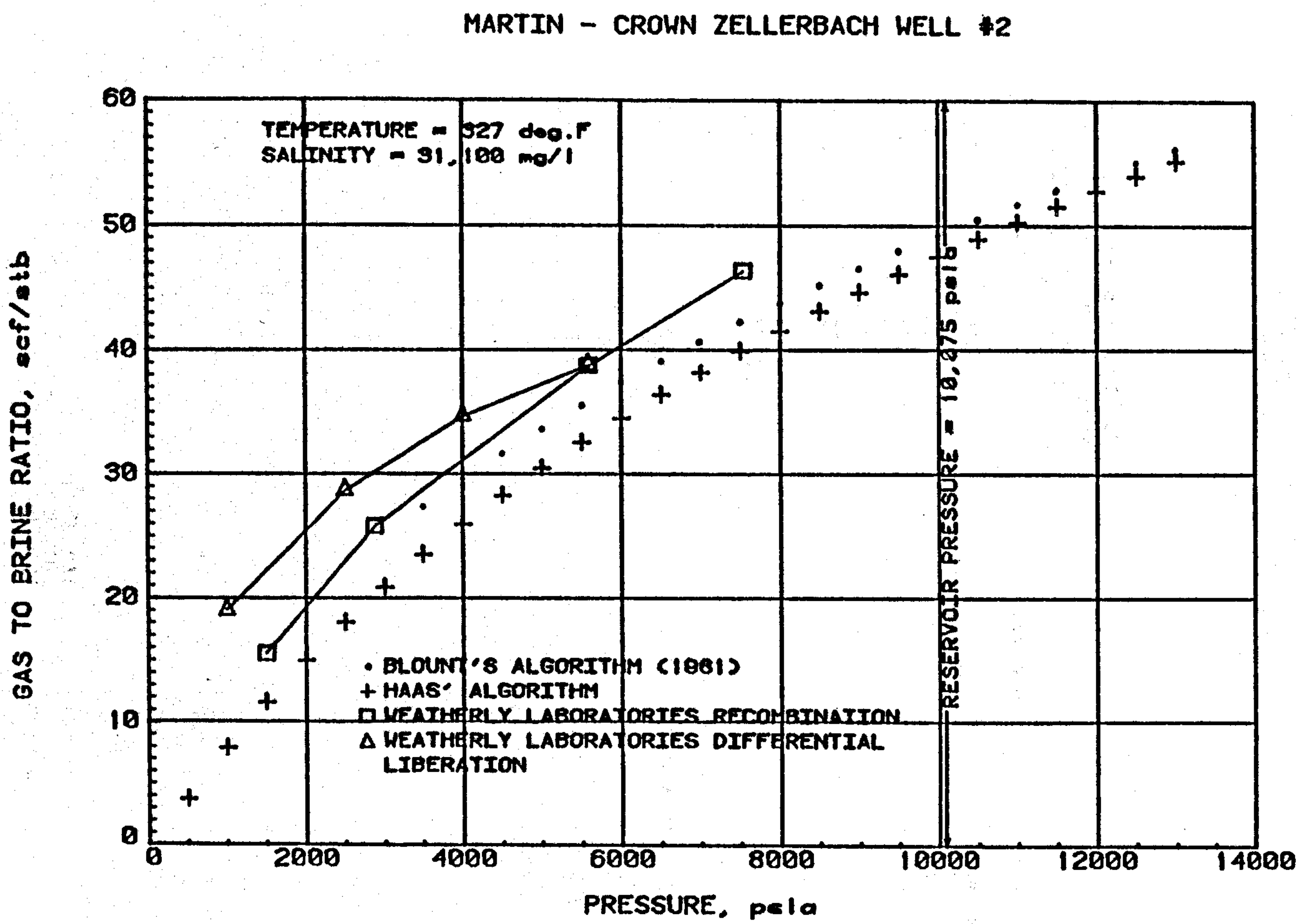
- The observed effect of the liquid hydrocarbons upon gas solubility has not been defined.

SULFIDE PRODUCTION

Sample		Sulfide From Each Analysis (mg H_2S/l)			
Date	Time	Flare Line Gas	Released From Brine	Brine Analysis	Total*
First Flow Test:					
6-5-81	1458	0.10	0.22	0.33	0.65
6-6-81	1040	0.19	0.18	0.50	0.87
6-7-81	1028	0.29	0.16	0.60	1.05
6-8-81	1020	0.37	0.15	0.60	1.12
6-9-81	0845	0.42	0.04	0.53	0.99
6-9-81	2102	0.45	0.27	0.83	1.55
Second Flow Test:					
6-17-81	1050	0.49	0.07	0.50	1.06
Third Flow Test:					
6-23-81	1040	0.12	0.07	—	—
6-23-81	1655	0.36	0.11	0.83	1.30
6-24-81	1040	0.50	0.05	0.83	1.38
6-25-81	0925	0.53	0.19	0.77	1.49

* The second digit after the decimal point may not be significant.

EXHIBIT 12-33



COMPARISON OF RECOMBINATION AND DIFFERENTIAL LIBERATION
DATA WITH LABORATORY DATA ON METHANE SOLUBILITY IN NaCl BRINE

EXHIBIT 12-34

COMPARISON OF GAS RECOMBINED AT 5584 PSIA WITH PRODUCED GAS COMPOSITION

	Gas Content of Brine (SCF/STB)	
	Recombination at 5584 psia	Well Test Data Interpretation
Gases liberated at one atmosphere		
Methane	26.10	22.77
Ethane	1.35	1.24
Propane	0.20	0.21
Butanes	0.05	0.04
C5+	0.05	0.08
Subtotal Hydrocarbons	27.75	24.34
CO_2	10.94	10.19
N2+He	0.09	0.15
Total	38.78	34.68
CO_2 liberated by acid	N.D.	5.07
Total		39.75
CO_2 as Alkalinity	N.D.	1.80
Difference		37.95

NOTE: N.D. = Not Determined

EXHIBIT 12-35

12.7.5 Brine Sample Collection and Analysis

Section 12.7.5.1 below provides details for the collection and analysis of surface brine samples by IGT. Mass balance calculations for these analyses are presented in Section 12.7.5.2. Then, results of analyses by others are provided in Section 12.7.5.3. A discussion of brine analytical results is presented in Section 12.7.5.4.

12.7.5.1 Surface Brine Sampling and Analysis by IGT: Surface samples for brine analysis were collected by IGT from a tap at the inlet to the brine metering skid. This tap is downstream of the separator vessel by about 15 feet of 3-inch piping and upstream of the separator dump valves. The sampling point is at the same temperature and pressure as the separator.

Brine samples were collected and analyzed using the IGT procedures described in Appendix L, which are in accordance with the intent of the "Standard Sampling and Analytical Methods for Geopressured Fluid" by McNeese State University. (Ref. 27)

Complete laboratory analyses were performed on three suites of samples. Results of the daily field analysis, commencing 12 hours after flow was initiated, plus the three complete laboratory analyses are shown in Exhibit 12-36. Two samples (17 June 1981, 1250 hours; 17 June 1981, 1515 hours) were collected prior to and during the inhibitor injection studies by Rice University. These results were single filtered samples that were neither diluted nor acid treated in the field to stabilize content of specific species. Results of laboratory analyses of these samples, performed for the Gas Research Institute, are also shown in Exhibit 12-36.

Several additional brine samples were analyzed in the field only for alkalinity, acid liberated CO_2, and sulfide. These additional samples were collected simultaneously with gas samples and analyzed as a step in determination of total CO_2 and sulfide (expressed as H_2S) content of produced brine. Results were previously reported in Section 12.7.4.5.

12.7.5.2 Brine Material Balance Calculations: A computer program has been developed at IGT to calculate the balance between measured cations and anions in geopressured-geothermal brine. Several basic assumptions were used in developing the program. They are the following:

1. All significant anions and cations have been measured and are included in the calculations.

2. The measured alkalinity is due only to carbonate-containing species (CO_3^{2-}, HCO_3^-, and H_2CO_3) and their concentrations are predictable from the solution's pH and the appropriate equilibrium constants.

3. The boron measured exists in solution as borate ion ($H_2BO_3^-$), and its concentration is predictable from the solution's pH and the appropriate equilibrium constant.

4. The measured silica is molecular in solution and is excluded from the charge balance calculations, as it does not contribute to the solution's ionic balance.

RESULTS OF SURFACE BRINE ANALYSIS BY IGT FOR SAMPLES FROM THE MARTIN-CROWN ZELLERBACH WELL NO. 2

Component	Units	5 June 81 1437 hrs	6 June 81 1040 hrs	7 June 81 1028 hrs	8 June 81 1001 hrs	17 June 81 1250 hrs*	17 June 81 1515 hrs†	23 June 81 1040 hrs	23 June 81 1655 hrs	24 June 81 1040 hrs	25 June 81 0925 hrs
Temperature	°C	59	58	73	78			75		87	78
pH	--	5.6	5.6	5.6	5.6			5.4		5.6	5.6
Specific Conductance	μmhos/cm	36,000	39,000	38,400	38,600			44,800 **		38,700	38,700
Suspended Solids	mg/ℓ	93	19	11	15			130		23	134
Dissolved Solids	mg/ℓ	32,300	32,300	31,000	31,200			37,400 **		30,200	29,600
Alkalinity	mgHCO_3^-/ℓ	790	840	810	860	780	760	600	840	850	840
Total CO_2	mgHCO_3^-/ℓ	2,530	1,830	2,090	2,360			2,440	2,240	2,260	1,910
NH_3	mg/ℓ	18	17	22	21			21		15	42
SiO_2	mg/ℓ	180	160	170	170			180		180	200
Cl^-	mg/ℓ	19,600	18,800	18,200	18,100	17,600	17,500	21,200 **	18,210	17,800	17,300
F^-	mg/ℓ			0.74		0.60	0.62			0.74	0.66
S^{2-}	mg/ℓ	0.3	0.5	0.6	0.6				0.8	0.8	0.8
SO_4^{2-}	mg/ℓ			9.6		35	32			16	14
As	μg/ℓ			5.8		2.6	2.3			<2	<2
B	mg/ℓ			54		44	39			45	46
Ba	mg/ℓ			15		24	25			18	17
Ca	mg/ℓ			460		370	400			400	380
Cd	μg/ℓ			0.60		<0.2	<0.2			0.40	2.8
Cr	μg/ℓ			10		9.5	5.0			5	45
Cu	μg/ℓ			3.5		1.4	0.7			<2	4.6
Fe	mg/ℓ			20		6.7	5.4			12	12
Hg	μg/ℓ			0.2		<0.2	<0.2			<0.2	<0.2
K	mg/ℓ			97		89	91			93	90
Mg	mg/ℓ			39		36	36			36	35
Mn	mg/ℓ			1.03		0.77	0.72			0.59	0.61
Na	mg/ℓ			11,000		10,100	10,200			10,700	10,500
Pb	μg/ℓ			4.1		<3	<3			<3	<3
Sr	mg/ℓ			38		36	36			35	35
Zn	mg/ℓ			<0.06		<0.06	<0.06			<0.06	<0.06

* Sample from upstream of separator prior to inhibitor injection.

† Sample from upstream of separator during inhibitor injection.

** High values are probably due to $CaCl_2$ brine used to kill well.

EXHIBIT 12-36

The program converts the concentration of each constituent to the gravimetrically equivalent weight of calcium carbonate. A sum is computed for the weights due to the anions and cations, and they are compared to each other. A total dissolved solids (TDS) value is also calculated by summing the weight of all ions. Measured SiO_2 content of brine is added, and the value is compared with the experimentally measured TDS content.

The data for the three completely analyzed samples shown in Exhibit 12-36 were used for mass balance calculations. The results are shown in Exhibit 12-37. Good balances were obtained for all three samples, within the limits of the experimental errors and assumptions made. The calculated and measured values for TDS were also in close agreement.

12.7.5.3 **Brine Samples Analyzed by Parties Other than IGT:** Representatives of the following organizations collected their own brine samples on location or were provided with samples by IGT.

- Weatherly Laboratories, Inc.
  Lafayette, LA

- McNeese State University
  Lake Charles, LA

- USGS Gulf Coast HydroScience Center
  NSTL Station, MS

- Rice University
  Houston, TX

Other organizations invited to participate in sampling and analysis included The University of Texas at Austin, Lawrence Berkeley Laboratory, Louisiana State University, and the U.S. Geological Survey at Menlo Park, California.

A combined sample log showing times of sample collection, location and type of samples collected, tests performed on location, and tests intended to be performed off location is presented as Appendix I.

Results of other-party hydrocarbon analyses that have been provided to IGT since the test are presented by organization below.

- **Weatherly Laboratories, Inc.:** This organization collected separator brine samples for recombination and physical properties measurement only. No chemical analyses of brine were performed. The complete Weatherly Laboratories report is provided in Appendix J.

- **USGS Gulf Coast HydroScience Center:** Results from ^{226}Ra, U, and $^{234}U/^{238}U$ activity ratio analyses by this organization are tabulated in Exhibit 12-38.

MATERIAL BALANCE CALCULATIONS FOR SURFACE BRINE SAMPLES FROM THE MARTIN-CROWN ZELLERBACH WELL NO. 2

	7 June 81 1028 hrs	24 June 81 1040 hrs	25 June 81 0925 hrs
pH:	5.6	5.6	5.6
A. Charge Balance:			
	Equivalent Concentrations of Brine Constituents ($mgCaCO_3/\ell$)		
<u>Cations</u>			
NH_4^+	64	44	124
Na^+	23,932	23,279	22,844
K^+	124	119	115
Ca^{2+}	1,149	999	949
Mg^{2+}	161	148	144
Sr^{2+}	43	40	40
Ba^{2+}	11	13	12
Fe^{3+}	54	32	32
<u>Anions</u>			
Cl^-	25,690	25,126	24,420
CO_3^{2-}	0	0	0
HCO_3^-	278	292	288
SO_4^{2-}	10	17	15
Total			
Cations	25,538	24,675	24,261
Anions	25,978	25,435	24,723
Difference (Cations-Anions)	-440	-760	-462
Difference (% of Cations)	-1.72%	3.08%	-1.90%
B. Mass Balance:			
	Total Dissolved Solids (mg/ℓ)		
Measured	31,000	30,200	29,600
Calculated	31,248	30,506	29,843
Difference (measured-calculated)	-248	-306	-243
Difference (% of measured)	-0.8%	-1.0%	-0.8%

EXHIBIT 12-37

Exhibit 12-38. Brine Analyses for ^{226}Ra and Uranium by the USGS Gulf Coast HydroScience Center

Sample Point: Downstream from Separator at Separator Pressure

^{226}Ra Analyses

Date	Time	^{226}Ra (dpm/l)
6/5/81	14:37	133.7 ± 10.5
6/6/81	10:40	101.3 ± 3.7
6/7/81	10:28	123.4 ± 11.0
6/8/81	10:01	130.3 ± 11.4
6/9/81	10:19	130.4 ± 11.4

Uranium Analyses

Date	Time	U (μg/l)	U Activity Ratio
6/8/81	14:20	0.0068	1.23

In his data transmittal letter, T.F. Kraemer observed that:

"The ^{226}Ra values seem pretty stable and are consistent with the salinity-radium relationship I have seen in other Wells of Opportunity. Uranium is at a low value, with an activity ratio just above unity, both fairly typical for geopressured-geothermal brines."

- **Rice University:** During the afternoon of June 17, 1981 (second flow test), Rice personnel analyzed three brine samples on location in conjunction with inhibitor testing. Measured concentrations of specific species, extracted from the report in Appendix M, are tabulated in Exhibit 12-39. Values from IGT analyses of companion samples are shown in parenthesis on this table.

12.7.5.4 Discussion of Brine Analyses: The sample at 1040 hours, June 23, 1981 was collected after minimal flushing of $CaCl_2$ kill fluid from the wellbore. The high values of conductance, dissolved solids, and Cl^- concentration, as well as the low alkalinity value, are believed due to residual $CaCl_2$. For this reason, these reported measurements are ignored in the discussion which follows.

EXHIBIT 12-39. RESULTS OF BRINE ANALYSES BY RICE UNIVERSITY

Sample Date:	6/17/81	6/17/81	6/17/81
Sample Time:	1250	1505	1605
	Concentration (mg/l)		
Alkalinity (as HCO_3^-)	854 (780)*	780 (760)*	817
Ca^{++}	462 (370)	464 (400)	461
Cl^-	17,700 (17,600)	18,300 (17,500)	17,000
Fe (total)	8.5 (6.7)	9.6 (5.4)	16
Fe^{++}	7	6	11
SiO_2	135	-	-
PO_4^{---}	1.2	1.9	1.8
Phosphonate (measured)	-	4.3	2.1
Inhibitor (AMP-2) added (metered)	-	4	2

*Values in parenthesis are from IGT analyses of companion samples (Exhibit 12-36).

Measured concentrations for several constituents of produced brine were reasonably constant throughout the test sequence. For this reason, the average of reported concentrations, with the exception of the 1040 hours, 6/23/81 sample, are believed representative of reservoir brine for the following:

• Dissolved Solids	• F^-	• Mg
• NH_3	• B	• Na
• SiO_2	• Hg	• Sr
• Cl^-	• K	• Zn

Several additional constituents of produced brine were found to have higher concentration on June 7, 1981 than in subsequent samples. These high concentrations are believed due to materials introduced by man during drilling and completion of the well. The lower concentrations reported are therefore believed closest to representative of reservoir brine for the following species:

• As	• Cr	• Pb
• Cd	• Mn	

Measured concentrations of several other species exhibited variations or absolute values that warrant specific comment. These are the following:

- **Alkalinity:** Values measured in IGT's Chicago Laboratory for samples collected on June 17, 1981 are 2.6% to 8.7% lower than those measured in the field on companion samples by Rice personnel. Also, Rice field measurements yielded values consistent with IGT field measurements on other days. Similar differences existed for Ca^{++} concentrations. It is hypothesized that low values from the Chicago analyses may be due to a small amount of precipitation of $CaCO_3$ during long-term, low-pressure storage of samples that had not previously been acidified with HCl.

- **CO_2:** Variations in "Total CO_2" reported in Exhibit 12-36 are believed due to variations in partitioning between components of the $CO_2/HCO_3^-/CO_3^=$ system. Results previously reported in Exhibit 12-32 are more meaningful.

- **$S^=$:** Partitioning of sulfide between species varied from sample to sample. Exhibit 12-33 and the discussion thereof are more meaningful than results shown in Exhibit 12-36 alone.

- **$SO_4^=$:** The June 17, 1981 samples were collected from a "Tee" on the bottom of the flow line between the choke skid and the separator. It is hypothesized that the high $SO_4^=$ and Ba concentrations for these samples may be due, in part, to insufficient flushing of accumulated drilling mud residue before sampling. This suggests that 9.6 mg/l is the best measure of $SO_4^=$ concentration from the first reservoir tested and that the higher values of 14-16 mg/l from the third flow test are due to a real difference between the fluids from the two reservoirs.

- **Ba:** Variations in concentrations were in the same directions as the variations in $SO_4^{=}$ concentrations discussed above. However, percent changes were less. Barium concentration on 6/7/81 was consistent with $SO_4^{=}$ concentration. However, the 6/17/81 samples contained only 40% to 45% of the amount of Barium required to balance the measured $SO_4^{=}$ concentration. Samples from the third flow test contained 65% to 70% of the Barium required to balance the measured $SO_4^{=}$ concentration.

- **Ca^{++}:** Values measured on location by Rice personnel on 6/17/81 were consistent with the IGT analysis of the 6/7/81 sample that had been acidified with HCl before transport. It is therefore believed that some Ca^{++} had been lost as $CaCO_3$ precipitation during transport of the 6/17/81 sample. Thus the Ca^{++} concentration in brine from the first reservoir tested is believed to be 460 mg/l. The decrease to 380-400 mg/l for comingled production of both reservoirs may reflect a real difference.

- **Cu:** Reasons for the observed variations in concentrations have not been pursued.

- **Fe:** Values from analyses of IGT's 6/17/81 samples are probably low due to precipitation from the samples before analysis. Thus the lowest credible values are the 8.5 and 9.6 mg/l determined by Rice during the second flow test. If 9.0 mg/l of Fe is from corrosion of tubulars, weight loss would be about 2300 lb/year for production at the maximum rate of 2000 bpd. Whether the increase to 12 mg/l during the third flow test is due to iron from the second reservoir or due to exposing tubing to air between the second and third flow tests cannot be resolved.

One of the measured constituents, boron, has a mean concentration of 48 mg/l which should be noted due to its environmental significance. This concentration precludes surface disposal of the brine because of boron's phytotoxicity unless massive dilutions can be made. In contrast to prior tests of Wells of Opportunity which had higher mercury concentrations, mercury content of produced brine from this well was less than 0.2 μg/l after five days of production. Actual concentration may have been below the 0.1 μg/l limit recommended by EPA for protection of fresh and marine aquatic organisms.

12.8 Solids Production, Scaling and Corrosion

As with prior Wells of Opportunity tested by EOC, substantial quantities of solids were produced during the test of the Crown Zellerbach Well No. 2. The vast majority of quantitative data discussed below resulted from work separately funded by the Gas Research Institute.

Real-time data on solids production is presented in Section 12.8.1. Section 12.8.2 describes work performed to evaluate scaling and corrosion. Sections 12.8.3 and 12.8.4 provide details of direct observation and sampling of solids after each flow test plus results of sample analyses. Finally, Section 12.8.5 combines all data into a scenario for solids production.

12.8.1 Real-time Data on Solids Production:

Data relevant to time and rate of solids production was provided by (1) visual observation of direct production to the reserve pit for well cleanup or for separator blowdown, (2) recording of data by an Oceanography International Corporation (OIC) sonic sand detector, (3) recorded pressure drop across filters, and (4) suspended solids collected on 0.45-micron filter paper as a part of brine sampling. Data from each of these sources is provided below.

12.8.1.1 Observation of Brine Flow to the Reserve Pit: About 1.2 times the wellbore volume was flowed after initial perforation of the depth interval 16,720-16,750 feet with four shots per foot. A modest quantity of solids was observed after displacement of the tubulars. After an additional 100 barrels had been produced, flow to the pit appeared to be clean, gassy brine. Therefore no additional cleanup was performed after perforating the interval 16,730-16,750 feet with an additional four shots per foot.

The next documented direct observation of solids content of flowing brine was during separator blowdown after the second flow test. Blowdown of each end of the separator commenced with a slug of "dirty" water. The quantity of solids was estimated to be less than the volumes of the sumps (about 0.5 ft^3 each) at each end of the separator. Blowdown brine was then clear until slugs of oil were observed between the brine and gas portions of the blowdown.

Prior to perforating the additional reservoir and starting the third flow test, the $CaCl_2$ brine used to kill the well was displaced with fresh water. Returns from the annulus commenced after pumping 60 to 70 barrels into the tubing. During the displacement, back-pressure was controlled with a choke in an effort to eliminate fluid transport through perforations.

When the additional reservoir was perforated, shut-in wellhead pressure increased about 50 psi. Production was started 11 minutes later. Throughout production of 1.2 well volumes of brine, brine flow to the pit was clear, but gas content was still too low for separator operation. Then production of dirty, gassy brine commenced. Produced brine still contained dark-colored fine solids when separator operation was commenced after flowing about 200 barrels of dirty brine to the pit.

12.8.1.2 **Sonic Sand Detector Data:** An OIC sonic sand detector sensor was installed in the data header between the choke manifold and the separator. This sensor was installed in 4-inch Schedule 80 pipe with an inside diameter of 3.826 inches. This installation provided very low sensitivity for the flow rates used in the experiment.

Exhibits 12-40 and 12-41 provide a basis for estimating the detection threshold for the sonic sand detector. These exhibits are from the installation and operation manual for the OIC sonic sand detector. Exhibit 12-40 reveals that non-linearity of the AC-DC converter in the unit greatly decreases sensitivity for output signals of less than 5-10 millivolts. At the same time, recorded sand detector signal (shown graphically in Exhibit 12-17, Parts I and II) revealed that changes in background noise due to changes in separator pressure were of this same order of magnitude. Thus, the minimum detectable signal due to sand would have a corrected value of about 20 millivolts.

The maximum brine production rate during this experiment was only about 3500 bpd. For this rate, flow velocity at the sonic sand detector was only 2.85 feet per second, and the 20-millivolt corrected value for sand detection would correspond to production of about 350 pounds of sand per 1000 barrels of produced fluid. For the brine rate of about 2000 bpd characteristic of most of the production, the threshold for sand detection is roughly 1000 pounds of sand per 1000 barrels of production.

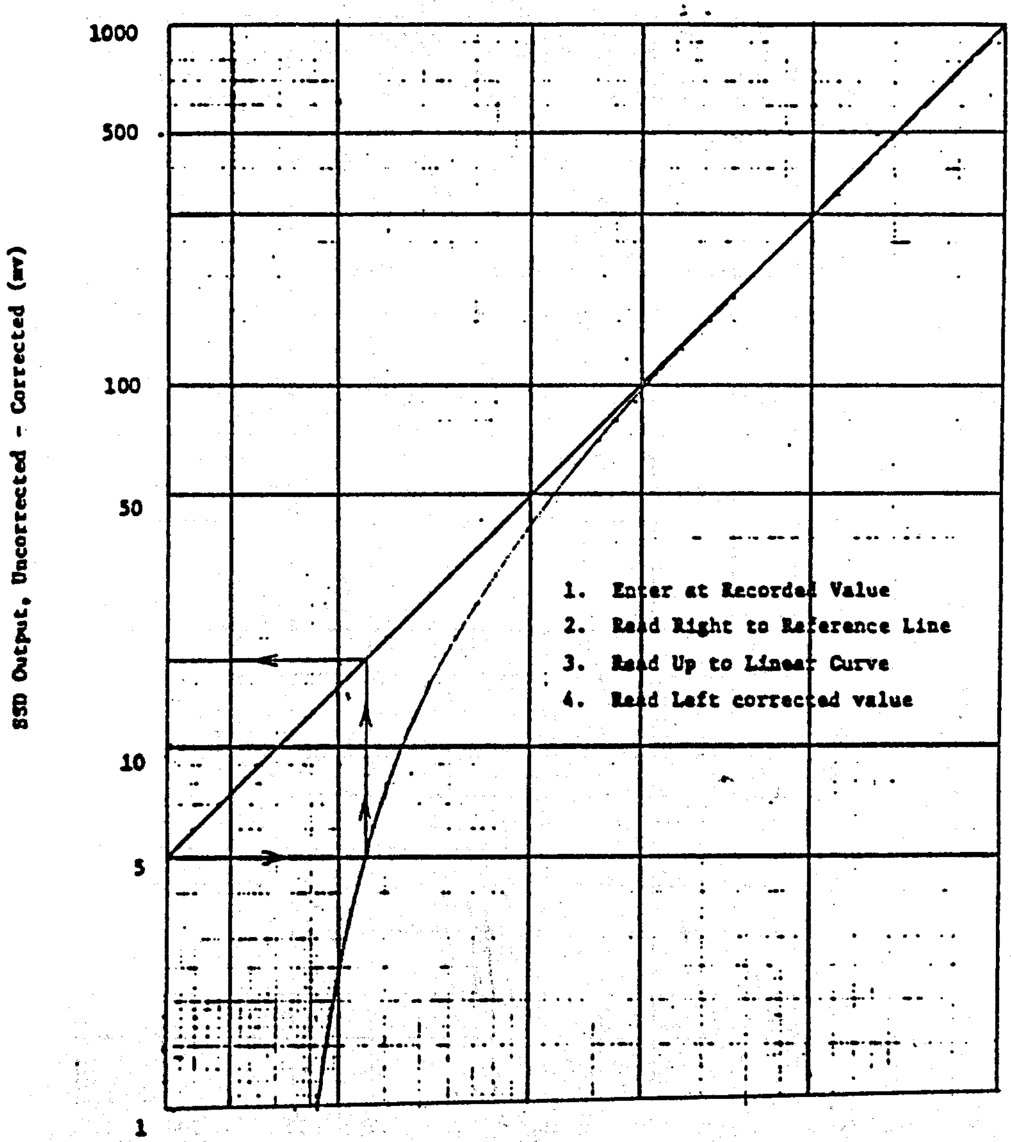
No sand detector signals clearly due to sand production were observed. However, because of the low detection sensitivity, several tons of sand could theoretically have been produced without detection by the sonic sand detector.

12.8.1.3 **Pressure Drop Across Filters:** A new filter system was installed between the separator and the disposal well for this test. The new system consisted of eight separate 5-micron filters in parallel. The volume of each filter unit was about 3-1/2 gallons. When pressure drop reached about 45 psi, the filters were automatically back-flushed, one at a time, with about 7-8 gallons each. This unit was installed in parallel with the cartridge filter units used on prior wells, with valves such that either system could be used. The cartridge units contained elements designed to catch 25-micron particles.

Since cleanup flow to the pit after perforating had produced reasonably clean fluids, production through the separator and new filter units for the first flow test was commenced before producing an amount of brine equal to the well volume (bottoms-up). Shortly after bottoms-up, very rapid automatic back-flushing of the 5-micron filter elements began. Back-pressure was found to be too high for proper control of separator brine level and accurate brine metering. After three hours, brine was diverted to the cartridge filter units. No pressure buildup was observed on these units between 1300 and 1500 hours on 6/5/81. At 1500 hours, production through the new filter unit was resumed. Back-flushing occurred about every 15 minutes until separator back-pressure resulted in a separator upset at 1900 hours. Brine disposal was then diverted from the disposal well to the pit at the disposal well location.

Recorded filter pressure drop data between 1900 hours on 6/5/81 and 1045 hours on 6/8/81 is not understood. It appears likely that a valve was closed to one side of the pressure transducer. Nevertheless, the real-time strip chart recording reveals the times of back-flush cycles. The time interval between back-flushes increased from about 1/2-hour to 1-1/2 hours during this time. As previously shown in Exhibit 12-17, only four filter back-flush cycles occurred during the last twelve hours of the first flow test.

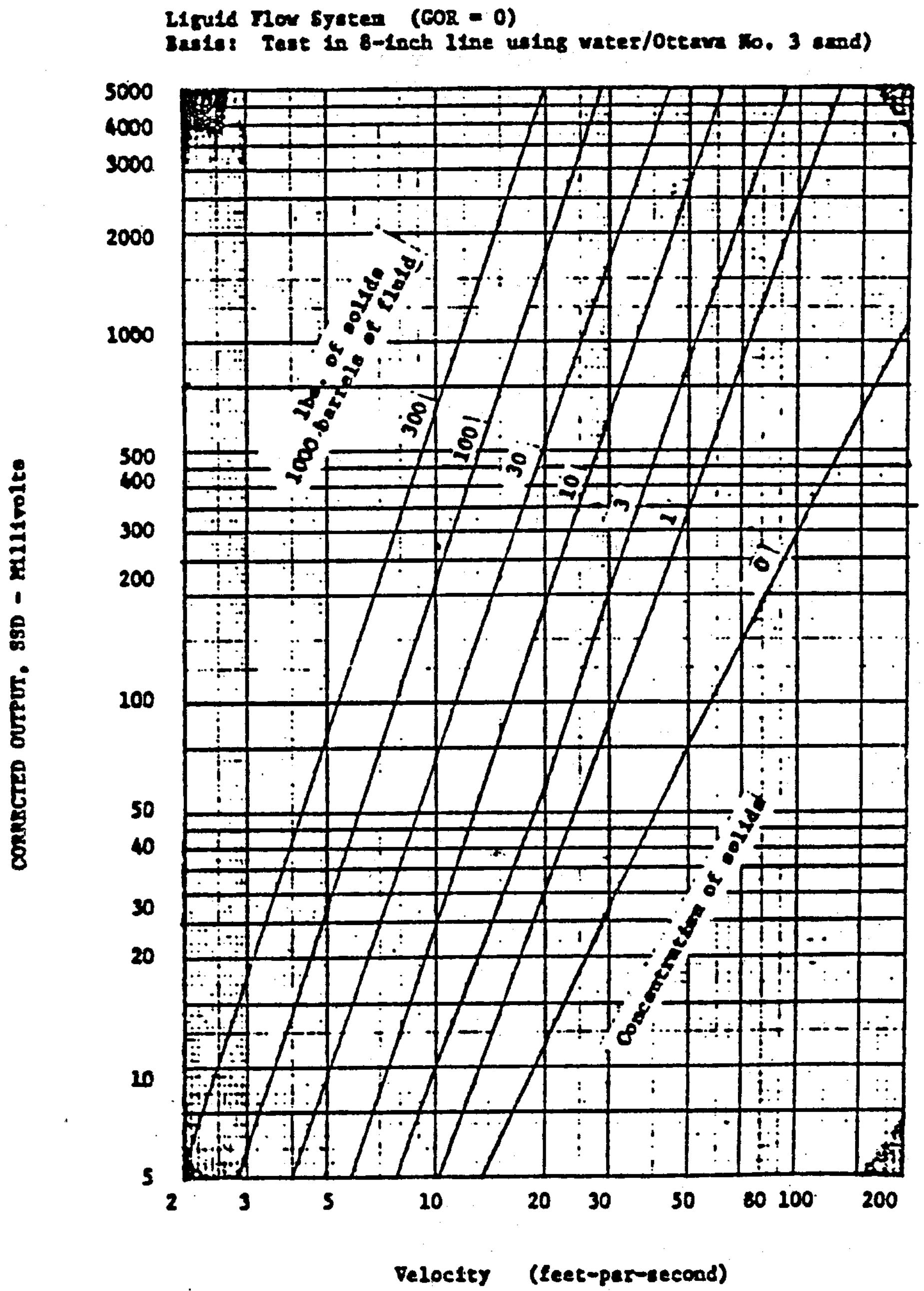
Basis: Bench Test July, 1976



Source: Oceanography International Corporation, "Sonic Sand Detector, Model 582-SSD, Model 563-SSD," Appendix A. College Station, Texas, Revised April 1980.

CORRECTION FOR NONLINEARITY OF AC-DC CONVERTER

EXHIBIT 12-40



Source: Oceanography International Corporation, "Sonic Sand Detector, Model 582-SSD, Model 563-SSD," Appendix A. College Station, Texas, Revised April 1980.

PROBE CALIBRATION

EXHIBIT 12-41

In summary, the increase in time between filter back-flush cycles suggests that concentration of produced solids too fine for collection in the separator gradually decreased by a factor of about 20 during the first flow test. Since all filters were bypassed for the second and third flow tests, no filter pressure drop data was obtained.

12.8.1.4 **Suspended Solids:** Collection of each suite of brine samples included filling 1-liter sample bottles with brine that had been filtered through 0.45-micron filter papers. Quantity of solids collected on each filter paper was determined by weight difference between the previously weighed dry filter paper and the weight after use and oven drying. In units of pounds of solids per 1000 barrels of brine, the data previously presented in Exhibit 12-36 becomes:

Date	Time	Suspended Solids (pounds per 1000 barrels)
6/5/81	1437	32.6
6/6/81	1040	6.7
6/7/81	1028	3.9
6/8/81	1001	5.3
6/23/81	1040	45.6
6/24/81	1040	8.1
6/25/81	0925	47.0

The above tabulated values are not a true representation of solids content of produced brine. This is because of the following:

- The samples were collected downstream from the separator and therefore could not contain any solids that settled out and remained in the separator.
- The sampling point geometry probably discriminated against collection of the larger sizes of solid particles.

Thus, the utility of the above values is as a qualitative indication of relative content of the smallest grain size solids in the various samples.

12.8.2 Scaling and Corrosion

Prior to the flow tests a small area inside piping both upstream and downstream of the separator was cleaned of the small scale accumulation stemming from use on prior tests. After each of the three flow tests, inspection of these locations revealed no new scale. The only visible change was a fine layer of rust.

On 7/17/81, during the second flow test, personnel from Rice University performed inhibitor tests. Brine samples collected prior to inhibitor injection and while injecting AMP-20 at concentrations of 4 and 2 ppm revealed no evidence of scale formation at separator pressure and temperature. Their complete report is provided in Appendix M.

12.8.3 Observed Quantities and Sampling of Produced Solids

Prior to the start of tests on this well, all solids from prior tests were flushed from all surface equipment. Then surface facilities were examined for solids after each of the three flow tests. The only significant accumulations found were in the separator and the tank used to collect material from automatic back-flushing of the new filter system. Details of these accumulations and sampling thereof are described in Sections 12.8.3.1 and 12.8.3.2.

12.8.3.1 Solids Retained in the Separator: Solids observed inside the separator after each flow test were as follows:

- **First Flow Test:** The inlet end of the separator contained a uniform layer of white sand about 3-1/2 to 4 inches deep. Total amount is estimated to be 2-1/4 to 3 cubic feet. Assuming a bulk sand density of 100 lb/cu ft, 225 to 300 pounds of sand were washed from this end of the separator. Samples were collected for analysis by reaching inside the inspection port of the inlet end of the separator. The outlet end of the separator contained only a few pounds of black sludge that appeared to be a mixture of clays, oil, and brine. Samples collected were allowed to gravity separate. The oil-phase was provided to Dr. Leigh Price of USGS. Solids from the outlet end of the separator were not analyzed.

- **Second Flow Test:** The inlet end was again found to contain a large amount of white sand. However, distribution inside the separator was very different from after the first flow test. Samples were collected while manually digging through a solid wall of sand inside the inspection port. Thickness of solids decreased rapidly with distance from the inlet. Total sand washed from the inlet end is estimated to be in the range of 150 to 500 pounds. Conditions at the outlet end of the separator were similar to those after the first flow test.

- **Third Flow Test:** The observed character and amount of solids at the inlet end of the separator was very different from that after the first flow test. Only a uniform 1.5 to 2.5-inch layer of mixed solids, oil, and brine was observed. After gravity separation, solids appeared to have a much greater clay content than after the earlier flow tests. The outlet end of the separator had contents similar to the inlet end. Total solids observed in both ends is estimated to be about 20-60 pounds. No analyses of these solids were performed.

12.8.3.2 Solids From Filters: Filters were used for only the first of the three flow tests. During the second and third tests, filters were bypassed and brine was flowed to a surface pit at the disposal well location.

The 25-micron cartridge filters were used for two hours during the first day of the first flow test, because solids concentration was too high for the new 5-micron units. Pressure drop across filters did not increase significantly during this time, and about a pound of sludge accumulated in the filter holders. This was not sampled because more representative samples were obtained from the tank used to collect solids back-flushed during use of the new 5-micron filter system.

The water from the automatic back-flushing of the new 5-micron filters was diverted to a cubical holding tank, four feet on an edge. Each time the holding tank became nearly full, about half of the water was siphoned off from a midpoint elevation. After the first flow test, the remaining liquid was siphoned off. All solids in the tank were then collected and dried, yielding 16.5 poinds of sample. These solids were black in color and had a very fine texture in sharp contrast to the larger grains of the white sand recovered from the separator.

Recognizing that some very fine grain size material remained in suspension in the siphoned brine, this 16.5-pound sample constitutes the majority of the weight of solids leaving the separator during the first flow test.

12.8.4 Analyses of Samples of Solids

A series of physical and chemical analyses were performed to determine the portions of produced solids that were (1) introduced by man (i.e. drilling mud), (2) formation sand, (3) formation fines (i.e clays), and (4) precipitated from species that were in solution in brine in the reservoir. Analyses performed consisted of x-ray analysis, chemical analysis of the acid-soluble portion of solids, particle size distribution measurements, and microscopic analyses. Results of each of the first three types of analyses are described in Sections 12.8.4.1 through 12.8.4.3 below. Results of microscopic analysis are included in the discussion of each sample in Section 12.8.4.5.

12.8.4.1 X-ray Analyses: Both X-ray diffraction (XRD) and X-ray fluorescence (XRF) analyses were performed on samples of suspended solids as well as samples collected from the separator and filter back-flush tank. The XRD analyses provide identification of crystalline species in the solids and the XRF analyses provide identification of the most abundant atomic species. Elements as light as sodium (atomic weight 23) are not identified with the XRF equipment used.

Results from x-ray analyses of three samples of suspended solids are shown in Exhibit 12-42. These were collected in conjunction with the suites of brine samples from the first and third flow tests that were analyzed in detail. The NaCl in each sample crystallized during drying of the filter paper. Since measured sodium content of brine (Exhibit 12-36) averaged only 10,500 mg/l, the brine could not have been saturated with NaCl.

The only substantive differences between the sample from only one reservoir (6/7/81) and the samples from comingled production of two reservoirs are that (a) clay minerals were identified only in the first sample and (b) calcite was identified only in the third sample. Since alkalinity and Ca^{++} concentrations measured for the third sample are similar to values for the other two, XRD identification of calcite may have occurred only because this suspended solids sample was much larger than the other two (134 mg vs 11 and 23 mg), thereby increasing calcite to above the detection level.

Exhibit 12-43 presents results from x-ray analyses of the samples of solids collected from the separator and back-flush tank as observed in Section 12.8.3. XRD analysis was performed on portions of each sample, as received, and after treatment with boiling 6N HCl to remove all acid-soluble components. XRF analysis was performed only on portions previously treated with boiling 6N HCl. Again, the reported NaCl undoubtedly precipitated during drying of the received samples.

COMPOSITION OF SUSPENDED SOLIDS SAMPLES FROM THE MARTIN-CROWN ZELLERBACH WELL NO. 2

Sample Date and Time	Components Identified (XRD)		Elements Identified (XRF)		
	Major	Minor	Major	Minor	Trace
7 June 81 1028 hrs	NaCl	Clay Minerals* α-Quartz Barite	Cl Si	Ti Ba,Fe,S K,Ca,Zn	Br
24 June 81 1040 hrs	α-Quartz NaCl Barite		Si Cl Ba,S	Fe Ti,Ca K	Zn
25 June 81 0925 hrs	Barite α-Quartz, NaCl	Calcite	Fe,Si,S,Ba,Cl	Ca K,Zn,Sr,Ti	Br,As,I

Approximate concentration ranges: Major 1-100%; Minor 0.01-1%; Trace <0.01%

Entries on the same line are approximately equal.
All constituents listed in probable order of decreasing abundance.

* Probably Amesite: $2(MgFe)O\cdot Al_2O_3\cdot SiO_2\cdot 2H_2O$; and/or
Cronstedtite: $Fe(II)_2Fe(III)_2SiO_5(OH)_4$.

EXHIBIT 12-42

IDENTIFICATION OF SOLIDS RECOVERED FROM THE SURFACE EQUIPMENT OF THE MARTIN-CROWN ZELLERBACH WELL NO. 2 BY X-RAY DIFFRACTION AND FLUORESCENCE

Sample Description	As Received Compounds Identified (XRD)		Residue Insoluble in 6N HCl Compounds Identified (XRD)		Residue Insoluble in 6N HCl Elements Identified (XRF)	
	Major	Minor	Major	Minor	Major	Minor
Solids from Inlet Side of Separator 10 June 81	α-Quartz (82) Barite (16)	NaCl	α-Quartz Barite		Si Ba,S,Al	Fe Sr,Ti,K
Solids from Inlet Side of Separator 17 June 81	α-Quartz (88)	NaCl Barite (<0.5)	α-Quartz		Si	Ti,Al Fe Zr
Solids from Back-flush tank 12 June 1981	α-Quartz (25) Barite (18)	NaCl Calcite Clay Minerals*	α-Quartz Barite	Albite ($NaAlSi_3O_8$)	Si Ba,S Al	Fe K,Sr Ti

Approximate concentration ranges: Major 1-100%; Minor 0.1-1%; Values in parentheses are quantitative XRD determinations of wt.% quartz and barite in as-received samples.

Entries on the same line are approximately equal.
All constituents listed in probable order of decreasing abundance.

* Probably Amesite: 2 $(Mg,Fe)O \cdot Al_2O_3 \cdot SiO_2 \cdot 2H_2O$ and/or
Cronstedtite: $Fe(II)_2Fe(III)_2SiO_5(OH)_4$.

The 6/10/81 separator sample and the 6/12/81 back-flush sample both reflect solids accumulation during the first flow test. The x-ray results are consistent with visual observations that the separator contained clean white sand whereas the filter back-flush contained clays. Barite was present in both samples.

The sample from the separator after the second flow test differed from those after the first flow test in that barite was not observed after acid treatment. This suggests that the majority of barite may have been from drilling mud that was flushed from the vicinity of the wellbore during the first flow test. The substantial fraction of barite in suspended solids from the third flow test would then have come from the second reservoir.

XRD data from all six sample analyses reported in Exhibits 12-42 and 12-43 were examined to determine whether the reported titanium actually existed or was erroneous identification of Barium L-series x-rays. The titanium and barium x-rays were clearly resolved by the equipment used, and the titanium is believed to have actually existed in the samples.

12.8.4.2 Chemical Analyses of Separator and Filter Back-flush Samples: The samples from the separator and back-flush tank after the first flow test and from the separator after the second flow test were analyzed using a multistep procedure. Steps used and results of each are described below:

1. Determination of Initial Weight

   The portion of each sample to be analyzed was dried and then weighed to establish initial weight.

2. Acid Liberation of CO_2

   The weighed sample was placed in a closed system and treated with boiling 6N HCl. This treatment breaks down all carbonates and drives all CO_2 off the system. The liberated CO_2 was trapped on previously weighed Ascarite. The Ascarite was then weighed again to determine the weight of CO_2 liberated from the sample by the acid. This weight was then divided by initial sample weight and expressed as weight-percent CO_2 of the total sample. Results are tabulated in the first column of Exhibit 12-44(A).

3. Separator Solid Residue from Acid Solution

   This separation was performed by filtering. Subsequent work on the solid and liquid fractions is described below.

4. Analysis of Solid Residue

   The solid residue from filtering each sample in Step 3 was dried and then weighed. The weight-percent residue was calculated using the initial weight from Step 1 and is tabulated in the last column of Exhibit 12-44(A).

   The previously described x-ray diffraction analysis was then performed to identify compounds in crystalline form in the samples. In addition to quartz, the

ESTIMATED COMPOSITION OF ACID SOLUBLE SOLIDS FROM THE MARTIN-CROWN ZELLERBACH WELL NO. 2

A. Analysis of Samples

Sample Description	Wt.% of Total Sample in 6N HCl Soluble Solids								Wt.% 6N HCl Insoluble Residue	Calculated Wt.% CO_2 to Balance Ca+Mg
	CO_2	Na	K	Ca	Mg	Sr	Ba	Fe		
Solids from Separator 6/10/81	0.60	0.17	0.029	0.60	0.77	0.021	0.23	1.09	93.4	2.05
Solids from Separator 6/17/81	0.07	0.31	0.014	0.10	0.52	0.015	0.08	0.38	98.6	1.05
Solids from Backflush Tank 6/12/81	4.88	0.79	0.067	3.0	4.7	0.044	0.49	10.7	64.6	11.80

B. Additional Analyses

Sample Description	Wt. % of Total Sample in 6N HCl Soluble Solids			
	Al	Si	$SO_4^{=}$	Cl^{-}
Solids from Separator 6/10/81	0.21	0.20	0.07	0.88
Solids from Separator 6/17/81	0.16	0.16	<0.04	0.52
Solids from Backflush Tank 6/12/81	1.30	0.56	0.20	1.73

C. Calculated Material Balance

Sample Description	Calculated Wt. %								Residue	Total
				Clay Minerals						
	(Na, K)Cl	$(Ca,Mg)CO_3$	$(Ba,Sr)SO_4$	CaO	MgO	FeO	Al_2O_3	SiO_2	Wt.%	Wt.%
Solids from Separator 6/10/81	0.49	1.26	0.43	0.46	1.00	1.40	0.40	0.43	93.4	99.3
Solids from Separator 6/17/81	0.81	0.15	0.17	0.09	0.83	0.49	0.30	0.34	96.8	100.0
Solids from Backflush Tank 6/12/81	2.14	10.22	0.92	1.09	5.56	13.77	2.46	1.20	64.6	102.0

EXHIBIT 12-44

separator and back-flush samples from the first flow test were found to contain barite in excess of solubility in hot 6N HCl. Although the acid dissolved most of the tentatively identified clay minerals in the back-flush tank sample, albite ($NaAlSi_3O_8$) remained after the acid treatment. In contrast, only quartz was identified after hot acid treatment of the separator sample collected after the second flow test. Barite content of this sample was apparently low enough for all of it to dissolve.

5. Analysis of Acid Solution

The volume of the acid solution from Step 3 was measured. The solution was then analyzed by atomic absorption spectrophotometry (AAS) to determine concentrations of Na, K, Ca, Mg, Sr, Ba, and Fe. The weight of each of these species was calculated by multiplying the concentration of each species (expressed in mg/l) by the volume of the acid solution. This weight was in turn expressed as weight-percent of the initial sample by dividing by the weight determined in Step 1. Results are tabulated in the remaining columns of Exhibit 12-44(A).

6. Calculated Fraction of CO_2 from $CaCO_3$ and $MgCO_3$

In contrast to prior well tests by EOC, the quantity of CO_2 liberated by acid was less than half the amount that would have been observed if all of the Ca and Mg had existed as carbonate in the samples of solids. This made necessary additional analyses before attempts to calculate a material balance were warranted. Additional analyses performed are described in Steps 7 and 8.

7. Determination of Al, Si and $SO_4^=$ Content of the Acid Solution

Results of these additional analyses by AAS of the solutions obtained by treating solids with boiling 6N HCl are shown in Exhibit 12-44(B).

8. Determination of Soluble Cl^- Content of Solids

A separate dried, weighed portion of each sample of solids was treated with a measured volume of dilute nitric acid. After separation from residue by filtering, the Cl^- content of this solution was determined. The result, as weight-percent of solids, is shown in Exhibit 12-44(B) for each of the three samples.

9. Calculation of Material Balance for Solids

The analytical results in Exhibit 12-44(A) and 12-44(B) contain a surplus of cations. It was therefore assumed that oxygen provided the missing anions required for charge balance and that the oxide species existed in acid-soluble clay minerals. Exhibit 12-44(C) presents results of mass balance calculations using this assumption. Results are consistent with the accuracy of analytical procedures used and suggest that clay minerals constitute the following portion of each sample:

Sample	Clay Mineral Content, Wt. %
Separator (6/10)	3.3
Separator (6/17)	2.1
Back-flush Tank (6/12)	24.1

Only the back-flush tank sample contained a significant amount of calcium and magnesium carbonates (10.2%). The minimal carbonates in the separator samples are consistent with Rice University's conclusion regarding lack of scaling at separator pressure and temperature. Carbonates observed in back-flush tank solids are believed to have precipitated from solution after the brine was placed in the back-flush tank.

12.8.4.3 **Particle Size Distribution Measurements:** Size distributions were determined for portions of the two samples from the separator and the sample from the back-flush tank.

The samples were pretreated before determining particle size. One portion of each sample was washed with deionized water to remove water-soluble salts precipitated through evaporation of the reservoir brine. A second portion of each sample was washed with 1N hydrochloric acid to remove the same salts and to disperse any carbonate-bound particles by dissolving the carbonate. The procedure used for each particle size distribution measurement was as follows:

1. A dried, weighed portion of each sample was pretreated with either deionized water or 1N HCl.
2. The slurry was washed through a series of weighed standard mesh sieves. The solids passing through the last sieve (325-mesh or 45-micron) were retained on a weighed Whatman 2 (8-micron) filter paper.
3. All fractions were dried and weighed to determine the weight of material in each sieve fraction and on the filter paper.
4. The size distribution of the material retained on the filter paper was determined using a Coulter counter.
5. The data from Steps 3 and 4 above were combined to provide the weight-percent of particles in each size range as tabulated in Exhibit 12-45. In this process, multiple Coulter counter steps were combined as required to give about a factor of two increase in particle diameter for each size interval reported.
6. A separate portion of each sample was dried, leached with 1N hydrochloric acid and filtered to determine the weight-percent of the sample insoluble in acid. The result of this measurement is also tabulated in Exhibit 12-45 for each sample.

Whatman 2 filter paper was used to filter the wash liquid from the sieves to recover the very fine material (less than 45 microns). Whatman 2 filter paper is rated 98% efficient

PARTICLE SIZE DISTRIBUTIONS OF SOLIDS RECOVERED FROM THE SURFACE EQUIPMENT OF THE MARTIN-CROWN ZELLERBACH WELL NO. 2 BEFORE AND AFTER TREATMENT WITH 1N HYDROCHLORIC ACID

Size Fraction (microns)	Solids from Inlet Side of Separator: 10 June 81		Solids from Inlet Side of Separator: 17 June 81		Solids from Backflush Tank: 12 June 81	
	As Rec'd	HCl Insol.*	As Rec'd	HCl Insol.*	As Rec'd	HCl Insol.*
> 1180	0.31 wt.%	0.24 wt.%	0 wt.%	0 wt.%	1.53 wt. %	1.94 wt.%
1180 to 600	0.50	0.43	0.02	<0.01	1.78	1.65
600 to 300	4.12	5.16	2.03	1.86	2.17	2.26
300 to 150	44.31	44.70	77.39	79.12	2.42	2.36
150 to 75	22.85	19.57	19.28	17.64	3.84	5.36
75 to 32	14.00	8.31	1.08	0.96	17.68	16.68
32 to 16	3.02	4.95	0.14	0.25	27.21	24.25
16 to 8	6.20	8.58	0.04	0.10	25.85	24.70
8 to 4	4.69	8.06	0.02	0.07	17.52	20.80
Insoluble Residue*	94.68		97.90		72.65	

* Insoluble in room temperature 1N HCl.

for retention of particles 8 microns or larger in diameter. During use, however, particles lodge in the filtering channels, restricting their effective diameter. This causes particles smaller than 8 microns in diameter to be retained.

The particle size distribution of the filtered fines was determined using a Coulter counter. The Coulter counter electronically sorts particles by size into 12 channels, from 4 to 64 microns. Particles greater than 45 microns are retained and determined by sieving. However, no direct information can be gathered on particles smaller than 4 microns in diameter. The instrument assumes a spherical shape for these particles and calculates the volume percent in each of the 12 size ranges. To convert the data from volume-percent distribution to weight-percent distribution, the assumption is made that the particles are of uniform density.

Each size distribution weight-percent listed in Exhibit 12-45 is based on the cumulative weights of size fractions for each sample. Each column adds to 100%. If size fractions of the 1<u>N</u> HCl insoluble portion of samples are desired in units of weight-percent of total sample, tabulated values must be multiplied by the fraction of each sample that is insoluble in 1<u>N</u> HCl. This fraction is shown in Exhibit 12-45 for each sample.

Exhibits 12-46 through 12-48 provide a graphical portrayal of measured particle size distributions for each sample. In these exhibits, the size fractions for the 1<u>N</u> HCl washed portion are shown as weight-percent of original weight for each sample. Significant observations based upon these exhibits are:

- **6/10/81 Separator Sample:** This sample was 94.7% insoluble in room temperature 1<u>N</u> HCl. Exhibit 12-46 indicates that some of the larger particles are made up of smaller particles cemented together with carbonate salts. The 1<u>N</u> acid wash resulted in the disappearance of larger particles and an increase in the fractions of very small ones.

- **6/17/81 Separator Sample:** Exhibit 12-47 shows no change in particle size distribution due to the acid wash of this sample, which was 97.9% insoluble in 1<u>N</u> HCl. Virtually all the particles are between 75 and 600 microns, and most are between 150 and 300 microns. This is also the highest populated range for the 6/10/81 separator sample.

- **6/12/81 Back-flush Tank Sample:** This sample was 72.7% insoluble in 1<u>N</u> HCl. This size distribution shows little change in relative size of particles due to acid washing. With the exception of the 75-150 micron size range, the most notable effect was a general decrease in population of all size ranges.

Comparison of Exhibits 12-46 and 12-47 with Exhibit 12-48 shows that more of the larger particles are being trapped in the separator and more of the smaller particles are being trapped on the filters. This is not surprising. It also shows that the 5-micron filters in the field and 8-micron filters in the lab are stopping at least some of the particles in the 4 to 8-micron range. No means were available, at reasonable costs, to define the weight-percent of unobserved particles smaller than 8 microns actually produced with the brine, but it is considered negligible. This is because electron microscope examination of cores from other wells generally reveals low amounts of such particles.

PARTICLE SIZE DISTRIBUTION OF
6/9/1981 SEPARATOR SAMPLE

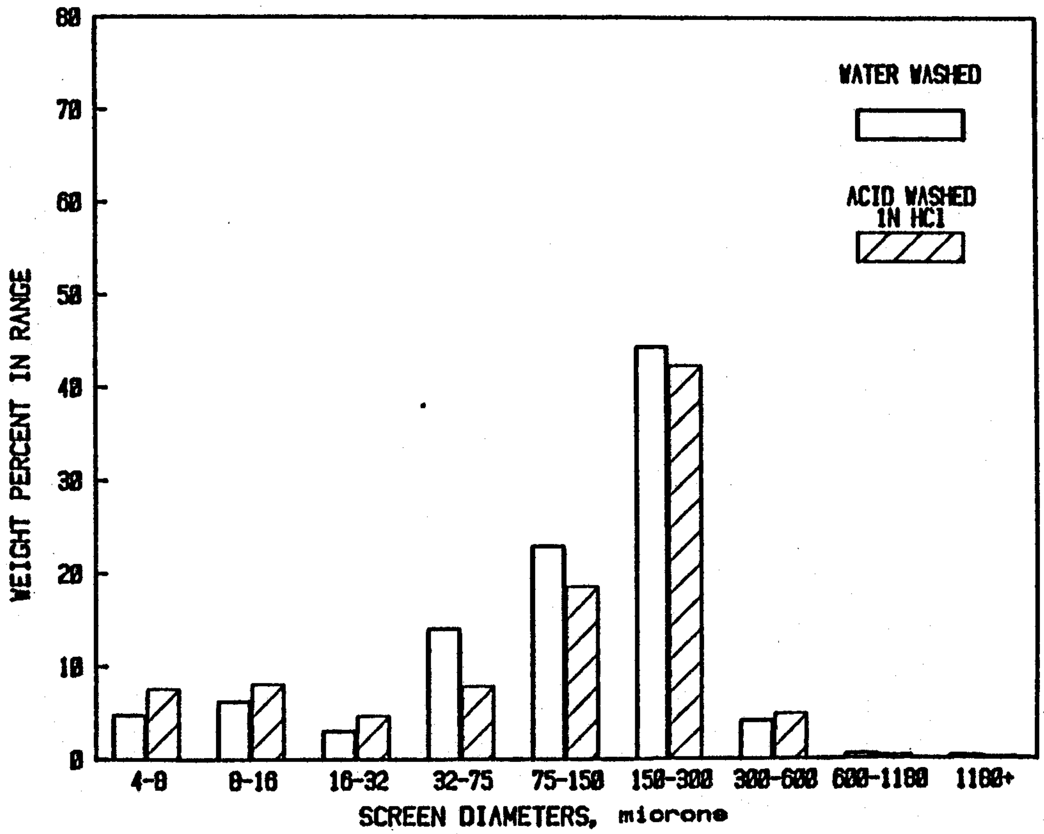


EXHIBIT 12-46

PARTICLE SIZE DISTRIBUTION OF
6/17/1981 SEPARATOR SAMPLE

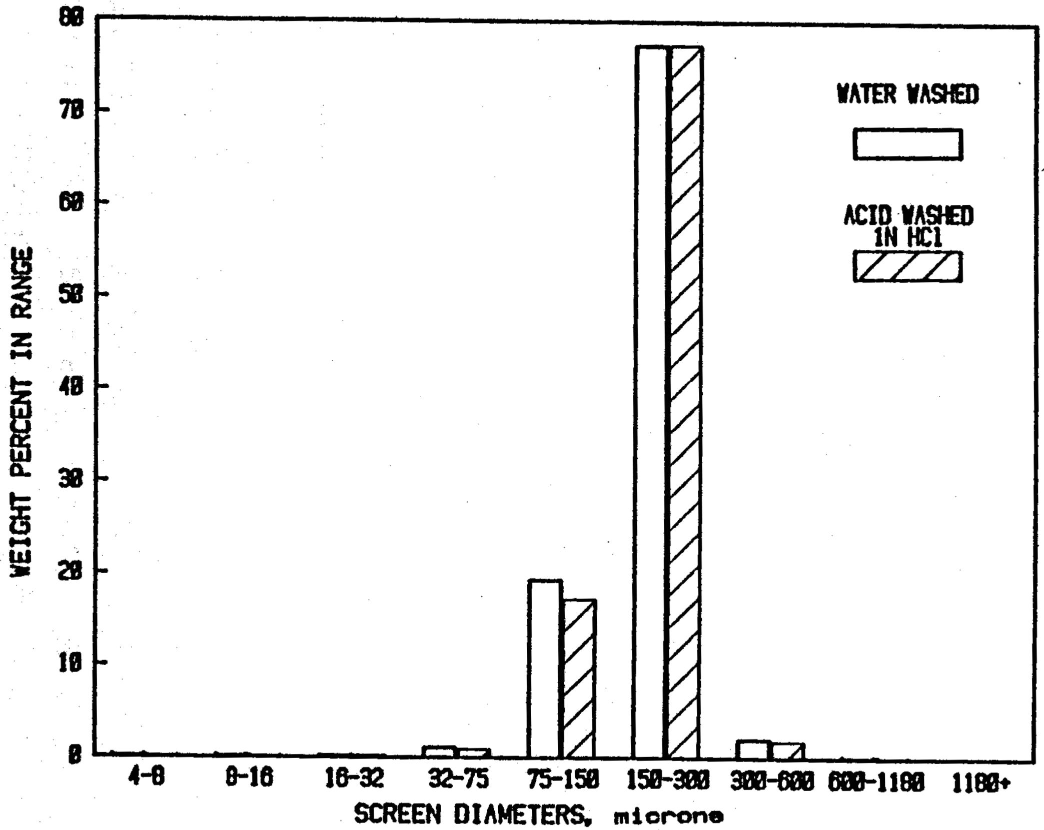


EXHIBIT 12-47

PARTICLE SIZE DISTRIBUTION OF
BACKFLUSH TANK SAMPLE

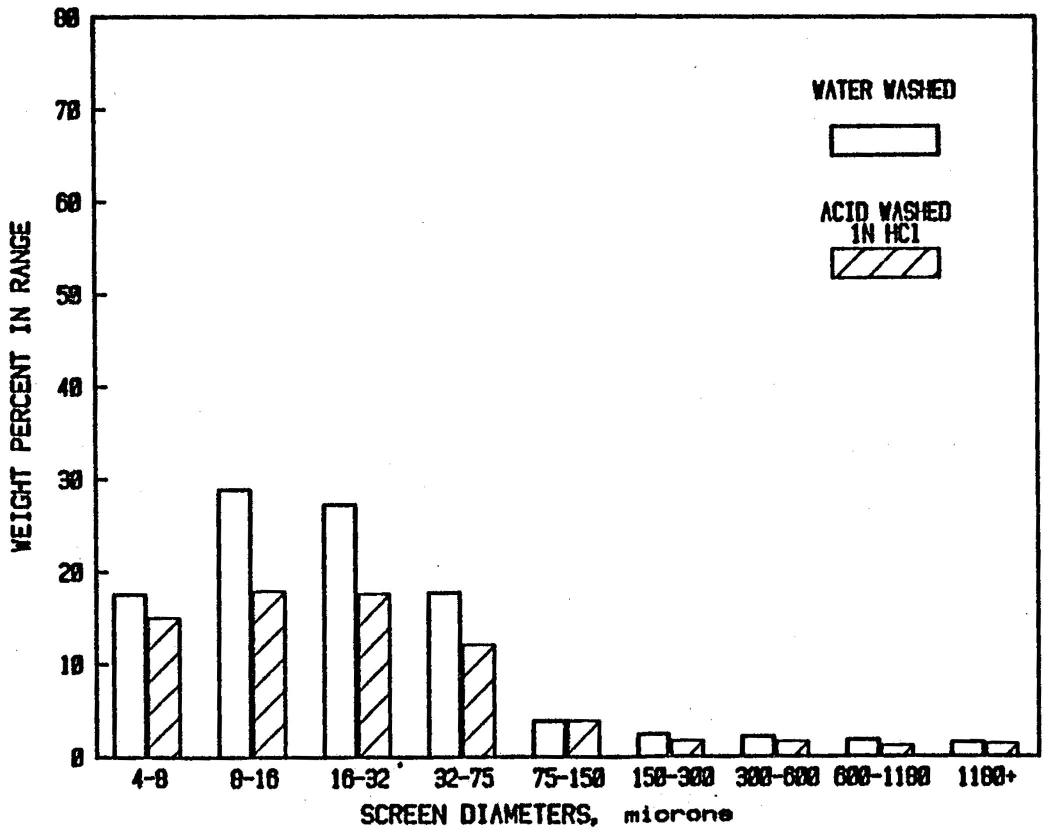


EXHIBIT 12-48

12.8.4.4 **Discussion of Detailed Solids Analyses:** All data from analyses of the two separator samples clearly indicate that produced solids were predominately sand. This was confirmed by low-power microscope examination that revealed sand grains with sharp, well-defined edges.

Although neither calcite crystals nor carbonate bonding of very small particles was indicated by x-ray analysis and visual observation, the chemical analyses and grain size distributions strongly suggest such bonding in the 6/10/81 separator sample. Since 1<u>N</u> HCl treatment increased weight-percent only for sizes less than 32 microns, it is likely that clay particles, rather than sand grains, were bonded by carbonates. Assuming all acid-liberated CO_2 was from calcite, the calcite bonding the clays in the 6/10/81 sample constituted only 1.4 weight-percent of the sample.

The major differences between the two separator samples are a much lower content of particles smaller than 75 microns, and of carbonates, in the 6/17/81 sample. One possible reason is that the higher flow rates during the second flow test washed such materials from the separator. However, this still leaves a major question as to why sand did not accumulate in the separator during the third flow test.

An alternative hypothesis for collection of a large amount of uniform sand in the separator during the second flow test, and virtually none during the third flow test, is that all observed sand actually entered the wellbore during the first test. This possibility has been examined by comparing the settling velocity of sand grains with the fluid velocity up the producing annulus.

Assuming spherical, 150-micron diameter, density 2.67 gr/cc particles in brine with a viscosity of 0.25 centipoise, the Reynolds' number is about 250 or in the transition region between Stokes' Law and Newton's Law settling behavior. Using the methods set forth in Reference 3, settling velocity is calculated to be about 0.25 ft/sec. For a 300-micron sphere, calculated settling velocity is about 0.42 ft/sec. In contrast, flow velocity in the 2-3/8 inch tubing by 7-inch casing annulus is 0.76 ft/sec. at a production rate of 2000 bpd. Below the tubing, flow velocity at this production rate is 0.64 ft/sec.

In practice, the sand grains are not spherical. For Reynolds numbers in the vicinity of the calculated value of 250 for 150-micron spheres, all non-spherical shapes have terminal settling velocities less than those calculated above. It therefore appears that sand entering the wellbore during the first flow test could only have remained until the higher rate second test if stored in low fluid velocity areas. Such areas exist near annulus walls, behind tubing collars and below the shallowest flowing perforations.

Casing volume in the depth interval of 30 feet between shallowest and deepest perforations was about 6 cubic feet and, assuming a bulk density of 100 lb/cu ft, could hold about 600 pounds of sand. Since only 150-500 pounds of sand was found in the separator after the second flow test, it is conceivable that this sand had actually entered the wellbore during the first flow test and was then produced to the surface during the higher rate second flow test.

Solids collected from the back-flush tank after the first flow test had carbonate and iron contents almost 10 times as high as solids from the separator after the first flow test. Under the microscope, no particles appeared to be calcium carbonate scale. However, there were rust-colored particles of assorted sizes that reacted with 1<u>N</u> sulfuric acid to produce slight effervescence. Apparently, as the brine was being held in the holding tank, there was a reaction between the carbonated brine, the iron tank walls, and possibly the dissolved calcium carbonate, the product being a mixture of iron oxide, iron carbonates, and precipitated calcium carbonate.

The brine analyses previously presented in Section 12.7.5.1 are consistent with the conclusion that carbonates in the back-flush tank precipitated after the brine entered the tank. If all bicarbonates in the brine became $CaCO_3$, the total amount of $CaCO_3$ from a single filling of the back-flush tank would exceed the amount of carbonate observed.

Shiny black spheroids, which were readily attracted by a magnet, were also observed in microscopic examination of back-flush solids. These appeared to be the solidified molten metal spray from the electric arc welder used in the tank's construction.

Along with the bits of rust and welding spray were round clumps of sand. These clumps of sand were bound together tightly enough to resist crumbling into much smaller components during measurement of particle size distribution. Still, they were soft enough to be easily crushed by a needle. These sand clumps were present in both the water-washed and acid-washed size fractions. Since a test of the clumps with acid produced no effervescence, it is concluded that the sand clumps were bonded together by some means other than by carbonates. Clay minerals or lubricator grease falling into the open tank are possibilities.

The observed rust, magnetic spheroids, and sand clumps are included in the particle size distributions reported for the back-flush tank. Even with their presence, over 88 weight-percent of reported solids from the tank were smaller than 75-micron diameter. The shape of the distribution suggests that additional undocumented particles smaller than 4 microns were also present.

12.8.5 Scenario for Solids Production

The largest problem in constructing a scenario consistent with all data is explaining the large variations in sand content of the separator after each of the three flow tests. Assuming observed solids in the separator were 100% sand for the first two flow tests and 50% sand after the third flow test, observed sand in the separator would have required average concentrations in brine of:

Flow Test	Sand to Separator (pounds/1000 barrels)
First	22-30
Second	60-200
Third	2-6

Further, a scenario must explain the narrow range in size distribution and very high sand content of separator solids observed after the second flow test.

The other key observation of time-dependence of solids production is the decrease in suspended solids concentration after the separator during the first flow test and the subsequent increase during the third flow test.

The favored scenario is that virtually all of the produced sand passed through perforations and entered the wellbore during the first flow test. However, at the low flow rate of 2000-2500 STB/D, a substantial fraction of sand grains larger than 100 microns were not transported to the surface. Total sand remaining in the wellbore after the first test would have to have been sufficient to fill the wellbore from total depth to a level between the top and bottom perforations. The higher flow rate of about 3500 STB/D at the start of the second test is then believed to have transported sand from adjacent perforations to the surface.

With this scenario, total sand entering the wellbore during the first test would have been the 225-300 pounds observed in the separator plus 3600 to 4100 pounds to fill the casing from total depth of 16,920 feet to a depth in the top 2/3 of the perforations (16,740-16,720 feet). With this scenario, the average concentration of sand in brine entering the wellbore during the first flow test would have been about 400 pounds of sand per 1000 barrels of brine. However, in practice, this average would have to reflect a much higher concentration at the start of the test, and a concentration of only about 2-6 pounds per 1000 barrels at the end of the test.

Exhibit 12-49 provides an estimate of production of various solids into the wellbore and to the surface for each of the three flow tests. For each species of solids, judgments made in developing this estimate were:

Sand: Estimated quantities to the surface are equal to the prior estimates of solids content of the separator. The minimal sand content of the back-flush tank after the first test clearly shows that the separator is highly efficient for sand collection at the flow rates used. Estimated sand production to the wellbore for the first flow is the observed amount on the surface plus the amount required to fill casing from total depth to the upper 2/3 of the perforated interval. The estimate for the third flow test assumes a static sand level in the wellbore and all sand entering the perforations being transported to the surface. The second test estimate assumes the same sand concentration as the third test.

Clay: It was assumed that all clays entering the wellbore were transported to the surface. The estimates for the first test are actual quantities deduced from analysis of separator and back-flush tank solids. The second test estimate consists of the amount deduced from analysis of separator contents plus that calculated from the ratio of back-flush tank to separator clays from the first test. For the third test, clay concentration is assumed five times as high as in the second test. The basis for this is observation of 200 barrels of dirty brine to the pit before starting separator operation plus measured suspended solids concentrations 2 to 10 times higher than at the end of the first test. The excess clays are assumed from the additional perforated interval.

Carbonates: It was assumed that carbonates observed in separator samples were either associated with clays or had particle sizes so small that all carbonates entering the wellbore were promptly transported to the surface. Estimates for the first two flow tests are from the analysis of separator samples. Carbonates observed in the back-flush tank were not included due to belief that they precipitated after the brine was placed in the tank. The third test estimate assumed concentration twice as high

ESTIMATE OF PRODUCED SOLIDS

Test and Species of Solids	Pounds Produced	
	To Wellbore	To Surface
First Flow Test (10,109 STB)		
Sand	3800-4400	185-250
Clays	11-15	11-15
Carbonates	3-4	3-4
Barite	35-50	35-50
Second Flow Test (2,380 STB)		
Sand	5-15	130-440
Clays	4-15	4-15
Carbonates	0.2-0.8	0.2-0.8
Barite	0.3-1.0	0.3-1.0
Third Flow Test (4,739 STB)		
Sand	10-30	10-30
Clays	20-75	20-75
Carbonates	3-4	3-4
Barite	90-140	90-140
Total (17,228 STB)		
Sand	3815-4445	325-720
Clays	35-105	35-105
Carbonates	6-9	6-9
Barite	120-190	120-190

EXHIBIT 12-49

as the first test due to carbonates produced with clays from the additional perforated interval.

Barite: Quantity produced to the surface on the first flow test was calculated from total solids in the separator and back-flush tank plus quantitative XRD determinations of weight-percent barite. For the second test the 0.17 weight-percent of separator solids deduced from chemical analysis was used because 6N HCl reduced the barite in residue to below the threshold for x-ray detection. The value was then increased by 10 percent on the basis of the relative amounts of barite observed in the back-flush tank and in the separator after the first test. Barite concentration for the third test was assumed five times that for the first test, because barite was identified as a major component in x-ray diffraction analysis of suspended solids, whereas it had been a minor component of the suspended solids sample from the first test. The extra barite is presumed to have been produced from the additional perforations. It was assumed that all barite entering the wellbore was transported to the surface, because very little barite was present in solids believed to have been flushed from the wellbore during the second test. This is consistent with expectations considering the very small particle size of barites used in drilling mud.

12.9 Test Equipment Performance

12.9.1 Digital Recording System

The quality of electronically recorded production data was adversely affected by several problems, including weather-associated difficulties. Editing of certain data files was necessary to present a realistic portrayal of well performance. Fortunately, the redundant and versatile instrumentation system provided a continuous record of all pertinent well parameters with the exception of bottom-hole pressures. Additional discussion on this subject can be found in Section 12.7.2.

12.9.2 Panex Bottom-hole Pressure Gauges

The Crown Zellerbach Well No. 2 is the first Well of Opportunity on which Panex instruments were used to record downhole pressures and temperatures. A pressure leak developed in the first Panex probe after one hour on bottom. A second instrument was run in the well, replacing the first, and it also developed a leak after four hours on bottom. A Hewlett-Packard gauge was then used for the remainder of the testing program.

Inspection of the Panex instruments revealed that the leaks were caused by failures in a critical welded section. The welds are believed to have been weakened when the tools were performance tested in the corrosive fluid environment of the Pleasant Bayou Well No. 2. Corrective welding procedures should eliminate the problem for future tests.

12.9.3 Hewlett-Packard Bottom-hole Pressure Gauge and Wireline

During the testing period on June 7, 1981, the surface receiver began losing signal from the Hewlett-Packard gauge. The voltage was increased to maximum, and this action improved the surface signal temporarily, which indicated that the increasing flowing temperature in the wellbore was increasing the wireline's electrical resistance. The pressure element was moved up the hole 100 feet, thereby reducing the resistance between the pressure gauge and the surface. This action restored a strong surface signal temporarily.

To further lower the resistance in the wireline, the pressure probe was moved up the hole about 1000 feet. During that operation the cable stuck and became frayed as it was being pulled through the lubricator. A field examination of the cable did not indicate that there was any damage due to corrosion or embrittlement. The cable had gone in and out of the well about four times without problems. It was concluded that the upper flow tubes in the lubricator were sufficiently large to handle a cool wireline, but the high flowing surface temperature of 198°F expanded the diameter of this wireline enough to cause binding in the flow tubes. The problem was eliminated when another wireline was run in the hole. The electrical resistance problem was overcome by placing the Hewlett-Packard pressure probe about 1000 feet higher than the depth at which the signal problem first occurred.

12.9.4 Self-Cleaning Disposal Brine Filter System

The Ronningen-Petter 5-micron, self-cleaning pressure filtration system performed well during the testing and provided some valuable data on fine solids production. The filter system improves disposal water quality because it removes the finer solids, which pass through the 25-micron filter elements in the Nowata filter system. The Ronningen-Petter system can become overloaded quickly, however, when a well is producing of solids at high rates.

12.9.5 Sonic Sand Detector

The OIC sonic sand detector was installed in a section of 4-inch schedule-80 pipe with an inside diameter of 3.826 inches. This installation provided very low sensitivity for the flow rates achieved during testing. For the brine rate of about 2000 BWPD, characteristic of most of the production, the threshold for sand detection was about 1000 pounds of sand per 1000 barrels of produced water. Because of the low detection sensitivity, several tons of sand could theoretically have been produced without detection by the sonic sand detector. A modification in the installation point may be required to obtain improved detector readings for future low flow rate wells.

13.0 PLUG AND ABANDONMENT OPERATIONS

13.1 Plugging of Test Well

The test well was killed on October 24, 1981, by pumping 650 barrels of 12.5-ppg mud down the tubing and around the annulus.

The WellTech Rig No. 168 was then moved to the location. The christmas tree was removed and blowout preventers were installed. The 2-3/8 inch tubing was pulled out of the hole, and a cement retainer was set at 16,130 feet. The perforations were squeezed off by pumping 165 sacks of cement below the retainer. About 10 sacks of cement were then spotted on top of the retainer.

A bridge plug was next set at 12,400 feet in the 7-inch casing, and the casing was cut at 11,800 feet and pulled out of the hole. A second bridge plug was set at 11,685 feet in the 9-5/8 inch casing. The 9-5/8 inch casing was then perforated at 2985 feet, and 200 sacks of cement were pumped into the perforated interval and displaced to a depth of 2471 feet. Cement was then spotted from 210 feet to the surface in the 9-5/8 inch casing.

The 9-5/8 inch and 13-3/8 inch casing, and drive pipe were then cut off below ground level and removed along with the wellhead equipment. The rig was released on November 5, 1981.

13.2 Plugging of Disposal Well

The disposal well was abandoned on December 23, 1981. A total of 1315 sacks of cement was pumped into the well, filling the 9-5/8 inch casing with cement from 4908 feet to the surface. The 9-5/8 inch and 13-3/8 inch casing and drive pipe were then cut off below ground level and removed, along with the wellhead equipment.

14.0 CONCLUSIONS

- Extrapolated laboratory recombination data indicates that the solubility value of the produced gas is 55.7 SCF/BBL. Since the actual produced gas/water ratio is about 32.0 SCF/BBL (for the lower zone) it appears that the reservoir brine is considerably undersaturated.

- The methane content of the produced gas is the lowest to date when compared to the previous WOO tests. The CO_2 content is the highest to date relative to previous WOO tests. Liquid hydrocarbon production was much higher relative to brine production than on any prior WOO test, with the exception of the G.M. Koelemay Well No. 1.

- The disposal brine contained about 4.54 SCF/BBL of gas, which is more than twice the 2.09 SCF/BBL solubility value of the gas at disposal conditions. The excess gas in the disposal brine was CO_2.

- Pressure transient analysis of the lower zone indicates that the reservoir is relatively tight with increasing sand thickness further from the wellbore. Surface pressure drawdown data on the lower and upper zones together indicates a surprisingly higher productivity as compared to the lower zone alone. This conclusion cannot be supported by other physical or chemical data. In either case, the reservoirs were not capable of the high sustained production rates needed for commercial considerations.

- Scaling and corrosion were so light that a statement concerning long-term chemical treatment requirements cannot be made.

- The lower zone produced solids at rates of 20 to 190 pounds per 1000 barrels. The produced solids were predominately sand which accumulated in the separator. When the upper and lower zones were tested, solids production was very low. The reason for this is not clear.

- Concentrations of boron averaged 48 milligrams per liter. This concentration is extremely toxic to plant life, and long-term surface disposal of untreated brine would be precluded. The mercury content was less than 0.2 micrograms per liter and probably would not be a hazard to the environment during long-term surface disposal.

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APPENDIX A

OPERATOR AND LANDOWNER CONTRACTS

MARTIN EXPLORATION COMPANY CONTRACT

EATON OPERATING COMPANY, INC.
3100 Edloe, Suite 205
Houston, Texas 77027

January 19, 1981

Martin Exploration Company
3501 N. Causeway Boulevard
Suite 901
Metairie, Louisiana 70002

Attention: Mr. Charles Romano

Re: Martin Exploration Company
Crown Zellerbach Corporation
Well No. 1
Section 19 and 20, T6S-R5E
Livingston Parish, Louisiana

Gentlemen:

Subject to the approval of the United States Department of Energy, Eaton hereby agrees to purchase all of the right, title and interest, inclusive of all geological history, log data and salvage rights, owned by Martin in the following described well, to-wit:

Martin Exploration Company-Crown Zellerbach Corporation Well No. 1, as above described, for the sum certain of EIGHTY-FIVE THOUSAND ($85,000.00) Dollars.

Upon payment of said sum Martin, its legal representatives, successors and assigns shall have no further interest in said described well.

Upon completion of certain geothermal-geopressure testing, Eaton shall clean up and restore the location, pursuant to Eaton's agreement with the landowner, Crown Zellerbach.

Martin shall be the sole corporation liable to fairly and equitable distribute the payment made by Eaton to other working interest owners, if any, and Martin herein agrees to hold Eaton harmless from such distribution, if any, by Martin.

Attached hereto and marked Exhibit I and Exhibit II, are certain documents incorporated herein as if fully written in this agreement.

If the above conforms to your understanding of this agreement, please sign and return four copies to us.

Sincerely yours,

EATON OPERATING COMPANY, INC.

BY: B A Eaton
B. A. EATON, President

ACCEPTED AND AGREED TO this

19th day of January, 1981

MARTIN EXPLORATION COMPANY

BY: Charles Romano
CHARLES ROMANO
Senior Vice President-Legal

EXHIBIT I

TERMS AND CONDITIONS OF PURCHASE ORDER

1. INSPECTION AND ACCEPTANCE — Inspection and acceptance will be at destination, unless otherwise provided. Until delivery and acceptance, and after any rejections, risk of loss will be on the Contractor unless loss results from negligence of the Purchaser.

2. VARIATION IN QUANTITY — No variation in the quantity of any item called for by this contract will be accepted unless such variation has been caused by conditions of loading, shipping, or packing, or allowances in manufacturing processes, and then only to the extent, if any, specified elsewhere in this contract.

3. DISCOUNTS — Discount time will be computed from date of delivery at place of acceptance or from receipt of correct invoice at the office specified by the Purchaser, whichever is later. Payment is made, for discount purposes, when check is mailed.

4. FOREIGN SUPPLIES — This contract is subject to the Buy American Act (41 CFR-1-6.10405).

5. CONVICT LABOR — In connection with the performance of work under this contract, the Supplier agrees not to employ any person undergoing sentence of imprisonment except as provided by (41 CFR-1-11.204).

6. OFFICIALS NOT TO BENEFIT — No member of, or delegate to, Congress, or resident commissioner, shall be admitted to any share or part of this contract, or to any benefit that may arise therefrom; but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

7. COVENANT AGAINST CONTINGENT FEES — The Supplier warrants that no person or selling agency has been employed or retained to solicit or secure this contract upon any agreement or understanding for a commission, percentage, brokerage, or contingent fees, excepting bona fide employees or bona fide established commercial or selling agencies maintained by the Supplier for the purpose of securing business. For breach or violation of this warranty the Purchaser shall have the right to annul this contract without liability or in its discretion to deduct from the contract price or consideration, or otherwise recover the full amount of such commission, percentage, brokerage, or contingent fee.

8. FEDERAL, STATE AND LOCAL TAXES — Except as may be otherwise provided in this contract, the contract price includes all applicable Federal, State, and local taxes and duties in effect on the date of this contract but does not include any taxes from which the Purchaser, the Supplier on this transaction is exempt.

9. Goods must be shipped as per instructions; otherwise any extra handling charge will be billed back to seller.

Approved By: ______________________

Title: ______________________

Date: ______________________

EXHIBIT II

ADDITIONAL
TERMS AND CONDITIONS OF PURCHASE ORDER

Except where the word "Contractor" is used, substitute the word "Subcontractor", and where the word "Government is used, substitute the word "Purchaser".

Applies to Subcontracts or purchase orders which exceed $2,500

1. "Employment of the Handicapped" (41-CFR-1-12.904)

Applies to Subcontracts or purchase orders which exceed $10,000

1. "Notice and Assistance Regarding Patent and Copyright Infringement" (41-CFR-9-9.104)

2. "Utilization of Small Business Concerns" (41-CFR-1-1.710-3)

3. "Utilization of Labor Surplus Area Concerns" (41-CFR-1-1.805-3)

4. "Utilization of Minority Business Enterprises" (41-CFR-1-1.1310.2)

5. "Equal Opportunity" (41-CFR-1-12.803.12)

6. "Disabled Veterans and Veterans of the Vietnam Era"

7. "Termination for Convenience of the Government"(41-CFR-1-8.705-1)

"Pricing Adjustment"(41-CFR-1-7.102-20)

"Walsh Healy Public Contracts Act"(41-CFR-1-12.605)

Applies to Subcontracts or purchase orders which provide for the performance of Service

1. "Contract Work Hours and Safety Standard Act - Overtime Compensation" (41-CFR-1-12.303)

2. "Service Contract Act of 1965 - As Amended" (41-CFR-1-12.904)

Applies to Subcontracts or purchase orders which exceed $100,000

1. "Cost Accounting Standard" (41-CFR-1-3.1204-1)

2. "Authorization and Consent" (41-CFR-9-9.102-1)

3. "Examination of Records" (41-CFR-1-7.103-3)

4. "Audit and Record" (41-CFR-1-3.814.2)

5. "Subcontractor Cost and Pricing Data" (41-CFR-1-3.814-3)

6. "Price Reduction for Defective Cost or Pricing Data" (41-CFR-1-3.814-1)

7. "Notice of Labor Disputes"

CROWN ZELLERBACH CORPORATION CONTRACT

DOE CONTRACT NO.
DE-AC08-80ET-27081

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
3104 Edloe, Houston, Texas 77027

CrownZellerbach

January 27, 1981

Mr. Dan Langford
Eaton Operating Company, Inc.
3100 Edloe, Suite 205
Houston, Texas 77027

Subject: Shell Oil Company - Crown Zellerbach Corporation No. 1, Martin Exploration Co. - Crown Zellerbach No. 2, Section 19 and 20, Township 6 South, R5E, Livingston Parish, Louisiana

Dear Mr. Langford:

Attached are two (2) signed copies of the Eaton/Crown Zellerbach contract for the Department of Energy "wells of opportunity" program. I will be looking forward to working closely with you in the evaluation of the geopressured/geothermal potential.

I will plan on visiting with you in the very near future to review your method of determining "wells of opportunity" with the hope that some of the other wells that have been drilled on Crown property will be considered for further evaluation.

Very truly yours,

E. G. Tonn

E. G. Tonn
Assistant to the Vice President
Research and Development

/c

Attachment

One Bush Street, San Francisco CA 94119

EATON OPERATING COMPANY, INC.

CROWN ZELLERBACH

JAN 19 1981

SOUTHERN ENERGY RESOURCES

January 16, 1981

Crown Zellerbach Corporation
One Bush Street
San Francisco, California 94104

Attention: Dr. E. G. Tonn

Re: Shell Oil Company - Crown Zellerbach Corporation No. 1, Martin Exploration Co. - Crown Zellerbach No. 2, Section 19 and 20, Township 6 South, R5E, Livingston Parish, Louisiana

Dear Dr. Tonn:

Eaton Operating Company, Inc. (hereinafter referred to as "EATON"), a Texas corporation, is a party to a written contract with the Department of Energy (hereinafter referred to as "D.O.E.") which calls for EATON to carry out research, field testing and evaluation of well sites in the Louisiana-Texas Gulf Coast area where reservoir and production data can be obtained to assess the energy potential of the Gulf Geopressured-Geothermal Aquifers.

Eaton is seeking well locations which, if they are not presently productive of oil or gas, can be taken over for a short test when the operator has made the decision to plug and abandon such a well.

Crown Zellerbach Corporation (hereinafter referred to as "CROWN") is the owner of two (2) tracts of land located in Sections 19 and 20, respectively, of Township 6 South, Range 5 East, Livingston Parish, Louisiana, upon which there have been drilled two (2) wells in search of hydrocarbons in a liquid or gaseous state, which wells are identified more specifically as the Martin Exploration Company-Crown Zellerbach Corporation No. 2 Well, located in Section 19, and the Shell Oil Company-Crown Zellerbach Corporation No. 1 Well located in Section 20, (hereinafter referred to as "Subject Wells"), which wells, and the lands owned by Crown in the vicinity thereof committed to this agreement, are outlined in red on the plat attached hereto and made part hereof as Exhibit A.

Under the proposed operation plan outlined herein, EATON has acquired from MARTIN EXPLORATION COMPANY (hereinafter referred to as "MARTIN") all of the right, title and interest in and to the salvage rights to the Subject Wells, which are reserved to Martin under Paragraph 8 of that certain Mineral Lease

PHONE 713-627-9764
TWX 910-881-1793
EDEC-HEC-HOU

3100 EDLOE, SUITE 205
HOUSTON, TEXAS 77027

U.S. DEPARTMENT OF ENERGY
CONTRACT NO.
DE-AC08-80ET27081

dated May 29, 1975, executed by Crown, as lessor, in favor of Shell, as lessee, as supplemented by agreement dated July 5, 1977 (hereinafter referred to as "Shell Lease") pursuant to which the Subject Wells were drilled. Eaton will use the Subject Wells, and the drill sites outlined in red on Exhibit "A", to perform temperature, pressure and gas content measurements at various flow rates, evaluate same and make written reports thereon to the United States Department of Energy.

CROWN will provide EATON with:

(i) the necessary access to the drill sites shown on Exhibit "A", and

(ii) a right-of-way for an "8" inch or less pipeline which will connect the Subject Wells during the term of this agreement.

This letter, when accepted and agreed to by CROWN, which shall be the effective date hereof, shall, subject to the conditions stipulated herein, evidence the agreement between EATON and CROWN, as follows:

(1) EATON, at its sole cost, risk and expense, will make its best effort to enter the Subject Wells and complete said wells for geothermal testing. Should this reentry prove unfeasible, then EATON shall restore and clean up the drill sites shown on Exhibit "A" and this agreement shall terminate as to both parties.

(2) Should EATON succeed in reentering the Subject Wells so as to commence further operations as stated above, then, at that point, EATON shall pay to CROWN, for the right to perform such testing, measurements and evaluation of geopressured-geothermal reservoirs, the sum of Thirty Thousand Dollars ($30,000.00) cash.

(3) The right granted to EATON for such consideration shall include the right, at EATON's election, to utilize the Shell Oil Company-Crown Zellerbach No. 1 Well as a saltwater disposal well and the right to lay a temporary water line between the Subject Wells.

(4) In connection with all its operations, including but not limited to reentry of the wells, and creating a saltwater disposal well, EATON shall:

(a) Provide insurance coverage, naming CROWN as an insured party, on all of its operations hereunder with limits of not less than Eighty Million Dollars ($80,000,000.00) for liability and Twenty-Five Million Dollars ($25,000,000.00) for cost of well control; and

(b) Obtain all federal, state and local governmental permits required for its operations and perform all such operations in accordance with reasonable industry standards and in compliance with applicable governmental and regulatory agency requirements.

(c) Should EATON find it unfeasible to reenter the Subject Wells for the purposes hereof, EATON at its sole expense, shall plug and abandon said wells in compliance with applicable governmental regulations and shall restore and clean up the drill sites shown on Exhibit "A".

(5) As part of the consideration to CROWN hereunder, in the event EATON succeeds in entering the Subject Wells, which entry shall be accomplished no later than one hundred and eighty (180) days from the effective date hereof, then upon EATON notifying CROWN in writing that it has completed or ceased its testing, measuring and evaluation operations, which shall be finalized within one hundred eighty (180) days from the date of actual entry by EATON, CROWN shall have one hundred and twenty (120) days from the date of notice within which to elect, by written notice to EATON, to receive from EATON, without necessity of any further consideration, the full ownership of the Subject Wells, with all casing in either or both of said wells. EATON shall not plug and abandon either of the Subject Wells during said period unless CROWN has notified EATON in writing that it does not elect to receive said wells, or either of them. Upon CROWN notifying EATON that it elects not to receive either or both said wells, upon expiration of said period of one hundred twenty (120) days without CROWN having given notice of election to receive either or both of said wells, then EATON shall, at its sole risk and expense, plug and abandon, in accordance with the rules and regulations of the Louisiana Department of Conservation, and other applicable governmental regulations, either or both of said wells which CROWN shall have elected not to receive, either by notice to EATON or by non-action within said period. If CROWN elects to receive either or both said wells, EATON shall convey what interest it (EATON) has thereto to CROWN with the casing therein. Upon such conveyance as to the well or wells CROWN shall elect to receive, and/or the plugging and abandoning of either or both said wells which CROWN does not elect to receive, EATON shall vacate the drill sites shown on Exhibit "A" and shall have no further liability hereunder except for previously and accrued obligations.

(6) Also as part of the consideration to CROWN hereunder, EATON will furnish to CROWN, directed to Dr. E. G. Tonn, Crown Zellerbach Corporation, 1 Bush Street, San Francisco, California 96104, all test well data, analyses, information and evaluation obtained from EATON's operations, including pressures, temperatures, flow rates, recervoir limit test information and analyses,

and chemical and physical analyses of both the brine and the gases, and consisting in general of the same information that will be provided by EATON to D.O.E. under Contract DE-AC08-80ET27081.

(7) CROWN's agreement hereto is made expressly subject to the following conditions:

(a) All hydrocarbons recovered and sold by EATON as the result of the operations to be conducted by EATON hereunder shall be the property of CROWN.

(b) All rights of EATON hereunder shall terminate within one hundred and eighty (180) days of the date on which EATON succeeds in entering the Subject Wells for the purpose hereof, except that any previously accrued obligations of EATON shall survive said termination.

(c) That oil, gas and mineral lease dated January 5, 1981, executed by Crown Zellerbach Corporation as lessor, in favor of Pennzoil Producing Co., as lessee, which lease specifically excludes the right to conduct geothermal operations.

(8) The rights granted EATON hereunder, shall not be assigned, surrendered or otherwise transferred without the prior written consent of Crown Zellerbach.

(9) Attached hereto are the following documents entitled "Terms and Conditions of Purchase Order" and "Additional Terms and Conditions of Purchase Order," which are marked Exhibit I and Exhibit II; which, are incorporated by reference herein as if fully set out in total context and made a part hereof.

(10) EATON further expressly states herein that any and all portions of this agreement shall be subject to the approval of the United States Department of Energy; and, should said agency disapprove any of this agreement in whole or in part, then said agreement shall be null and void.

(11) Notices hereunder shall be in writing and shall be deemed to have been given if sent by telegram, certified or registered mail, or delivered by hand, addressed to the respective parties, as follows:

If to EATON:

Eaton Operating Company, Inc.
3100 Edloe, Suite 205
Houston, Texas 77027

Attention: Mr. B. A. Eaton
Telephone: 713/627-9764

If to Crown:

Crown Zellerbach Corporation
One Bush Street
San Francisco, California 94104

Attention: Dr. E. G. Tonn
Telephone: 415/951-5240

This letter is executed on behalf of EATON in triplicate copies. If the provisions hereof conform to your understanding of the agreement between us, please execute and return two (2) copies to us.

Yours very truly,

EATON OPERATING COMPANY, INC.

B. A. Eaton, President

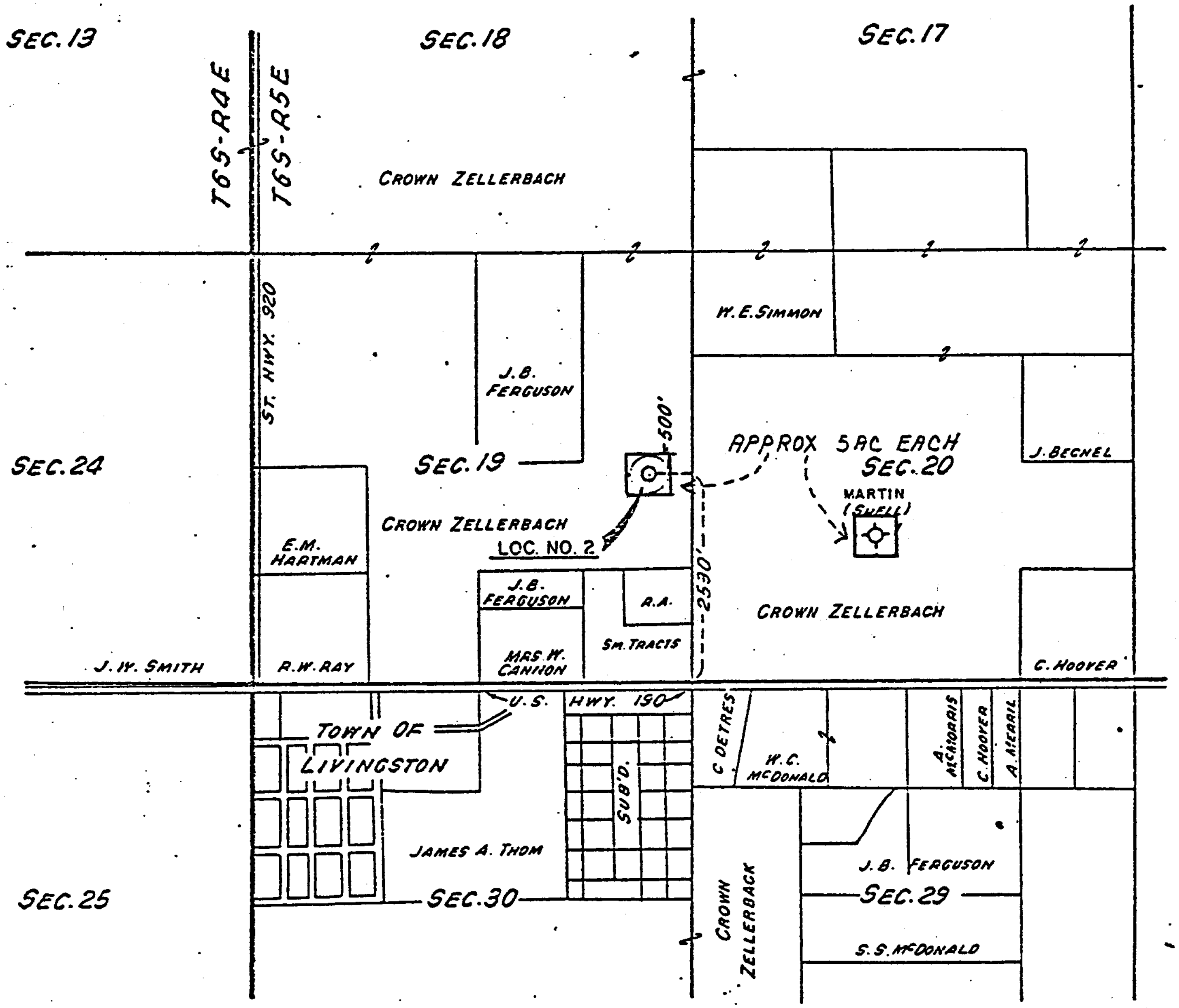
ACCEPTED AND AGREED TO this

______day of ______________, 1981.

CROWN ZELLERBACH CORPORATION

By______________________
M. S. Denman, Executive Vice President

EXHIBIT "A"



N

STATE OF LOUISIANA
AUBREY G. BURKE
REG. NO. 184
REGISTERED
LAND SURVEYOR

MARTIN EXPLORATION CO.
CROWN ZELLERBACH
LOC. NO. 2
SEC. 19 T6S-R5E
LIVINGSTON PH., LA.
SCALE 1"=2000' MARCH 1980

Aubrey G. Burke

AUBREY G. BURKE, SURVEYOR
REG. NO. 184 N. O., LA. 70112

EXHIBIT I

TERMS AND CONDITIONS OF PURCHASE-ORDER

1. INSPECTION AND ACCEPTANCE — Inspection and acceptance will be at destination, unless otherwise provided. Until delivery and acceptance, and after any rejections, risk of loss will be on the Contractor unless loss results from negligence of the Purchaser.

2. VARIATION IN QUANTITY — No variation in the quantity of any item called for by this contract will be accepted unless such variation has been caused by conditions of loading, shipping, or packing, or allowances in manufacturing processes, and then only to the extent, if any, specified elsewhere in this contract.

3. DISCOUNTS —Discount time will be computed from date of delivery at place of acceptance or from receipt of correct invoice at the office specified by the Purchaser, whichever is later. Payment is made, for discount purposes, when check is mailed.

4. FOREIGN SUPPLIES — This contract is subject to the Buy American Ace (41 CFR-1-6.10405).

5. CONVICT LABOR — In connection with the performance of work under this contract, the Supplier agrees not to employ any person undergoing sentence of imprisonment except as provided by (41 CFR-1-11.204).

6. OFFICIALS NOT TO BENEFIT — No member of, or delegate to, Congress, or resident commissioner, shall be admitted to any share or part of this contract, or to any benefit that may arise therefrom; but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

7. COVENANT AGAINST CONTINGENT FEES — The Supplier warrants that no person or selling agency has been employed or retained to solicit or secure this contract upon any agreement or understanding for a commission, percentage, brokerage, or contingent fees, excepting bona fide employees or bona fide established commercial or selling agencies maintained by the Supplier for the purpose of securing business. For breach or violation of this warranty the Purchaser shall have the right to annul this contract without liability or in its discretion to deduct from the contract price or consideration, or otherwise recover the full amount of such commission, percentage, brokerage, or contingent fee.

8. FEDERAL, STATE AND LOCAL TAXES — Except as may be otherwise provided in this contract, the contract price includes all applicable Federal, State, and local taxes and duties in effect on the date of this contract but does not include any taxes from which the Purchaser, the Supplier on this transaction is exempt.

9. Goods must be shipped as per instructions; otherwise any extra handling charge will be billed back to seller.

Approved By: ______________________

Title: ______________________

Date: ______________________

EXHIBIT II

ADDITIONAL
TERMS AND CONDITIONS OF PURCHASE ORDER

Except where the word "Contractor" is used, substitute the word "Subcontractor", and where the word "Government is used, substitute the word "Purchaser".

Applies to Subcontracts or purchase orders which exceed $2,500

1. "Employment of the Handicapped" (41-CFR-1-12.904)

Applies to Subcontracts or purchase orders which exceed $10,000

1. "Notice and Assistance Regarding Patent and Copyright Infringement" (41-CFR-9-9.104)
2. "Utilization of Small Business Concerns" (41-CFR-1-1.710-3)
3. "Utilization of Labor Surplus Area Concerns" (41-CFR-1-1.805-3)
4. "Utilization of Minority Business Enterprises" (41-CFR-1-1.1310.2)
5. "Equal Opportunity" (41-CFR-1-12.803.12)
6. "Disabled Veterans and Veterans of the Vietnam Era"
7. "Termination for Convenience of the Government"(41-CFR-1-8.705-1)
8. "Pricing Adjustment"(41-CFR-1-7.102-20)
9. "Walsh Healy Public Contracts Act"(41-CFR-1-12.605)

Applies to Subcontracts or purchase orders which provide for the performance of Service

1. "Contract Work Hours and Safety Standard Act - Overtime Compensation" (41-CFR-1-12.303)
2. "Service Contract Act of 1965 - As Amended" (41-CFR-1-12.904)

Applies to Subcontracts or purchase orders which exceed $100,000

1. "Cost Accounting Standard" (41-CFR-1-3.1204-1)
2. "Authorization and Consent" (41-CFR-9-9.102-1)
3. "Examination of Records" (41-CFR-1-7.103-3)
4. "Audit and Record" (41-CFR-1-3.814.2)
5. "Subcontractor Cost and Pricing Data" (41-CFR-1-3.814-3)
6. "Price Reduction for Defective Cost or Pricing Data" (41-CFR-1-3.814-1)
7. "Notice of Labor Disputes"

APPENDIX B

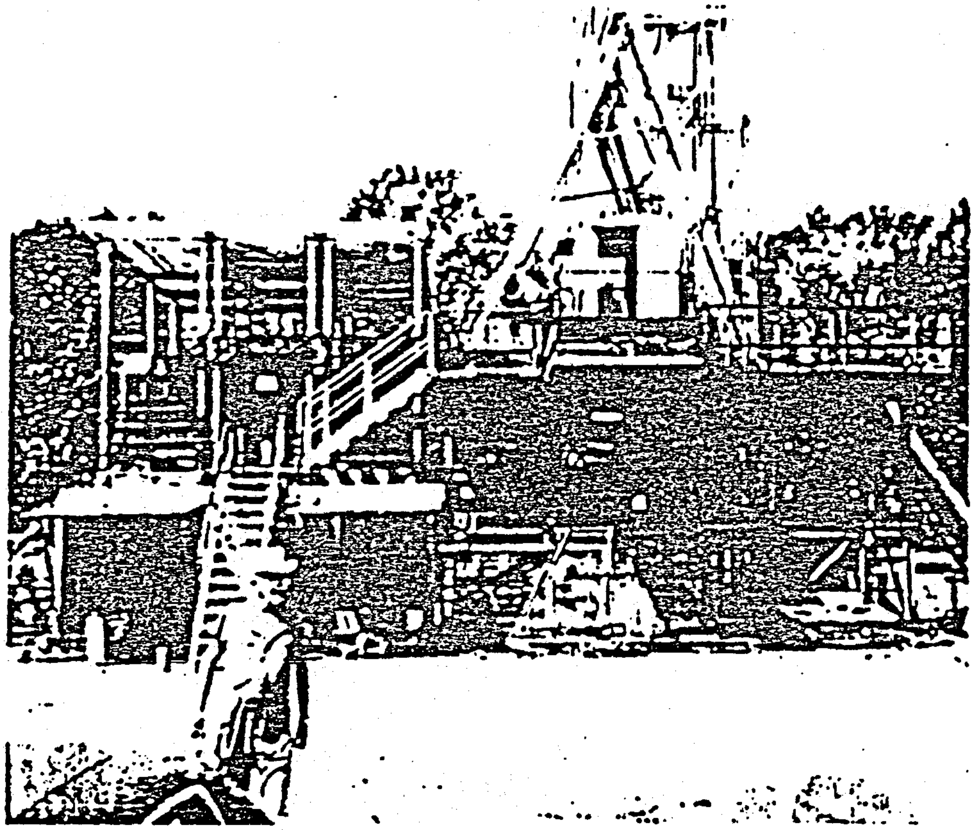
RIG CONTRACTS

WILSON BROTHERS DRILLING COMPANY CONTRACT

WILSON BROTHERS DRILLING COMPANY

RIG No. 8

EFFICIENT DRILLING
TO 16,000 FT.



DRAWWORKS
NATIONAL 110
GROOVED DRUM FOR 1⅛" DRILL LINE
SAND REEL ASSEMBLY
PARKERSBURG 46" HYDRAMATIC BRAKE

DERRICK
LEE C. MOORE
142 FT. JACKKNIFE
1,025,000 LB. CAPACITY

SUBSTRUCTURE
LEE C. MOORE
1KRT. 21 FT.

ENGINES F2896DSU Diesel
(3) WAUKESHA ~~CR2BU 800 H.P. (GAS-~~
BUTANE), DRIVING DRAWWORKS COMPOUND AND TWO PUMPS
(2) WAUKESHA ~~62-H5~~; LOW PRESSURE SYSTEM
F674DSU

PUMPS
(1) NATIONAL N-1100 7¼" X 16" 1100 H.P.
(1) National 9 P 100 Triplex, 1000 hp.
(2) 6" MISSION CENTRIFUGAL LOW PRESSURE MIXING

DRILL PIPE
16,000 FT. GRADE "E" 4½" DRILL PIPE WITH
X-hole ~~H-90~~ TOOL JOINTS
6¾" OR 7" DRILL COLLARS AS REQUIRED

PREVENTERS
HYDRIL GK SERIES 1500
CAMERON QRC SERIES 1500 (PIPE)
CAMERON QRC SERIES 1500 (BLIND)
PAYNE PRESSURE OPERATED CLOSING UNIT

OTHER EQUIPMENT
ROTARY - National 27½"
TRAVELING BLOCK – EMSCO R-52-6, 450 TON
SWIVEL – IDEAL N-615
HOOK – BJ 4300
SHALE SHAKER – RHUMBA 4960-B
LOW PRESSURE MUD SYSTEM
STEEL MUD TANKS
BUNK HOUSE
DESANDER
KELLY SPINNER
EQUIPPED WITH DUAL A.C. LIGHT PLANTS, AIR COMPRESSORS, WATER PUMP, AND ALL OTHER TOOLS, FITTINGS, APPLIANCES, LINE PIPE AND OTHER EQUIPMENT NECESSARY FOR DRILLING TO 16,000 FEET.

Subcontract No. 0517-80

OFFER

In compliance with the Solicitation, the undersigned offers and agrees, if this offer is accepted within ______ calendar days (60 calendar days unless a different period is inserted by the offeror) from the date for receipt of offers specified in the Solicitation, to furnish any or all items upon which prices are offered at the price set opposite each item, within the time specified in the schedule.

Discount for prompt payment:

______% 10 calendar days; ______% 20 calendar days; ______% 30 calendar days;

______%___ calendar days

NAME AND ADDRESS OF OFFEROR: (Street, City, County, ZIP Code, Area Code, and Telephone)

Wilson Brothers Drilling Company
P O Drawer 53628
217 East Kaliste Saloom Road
Lafayette, LA 70505

NAME AND TITLE OF PERSON AUTHORIZED TO SIGN OFFER (Type or Print)

Pete Wilson	Vice President
Typed Name	Title
Pete Wilson	April 1, 1981
Signature	Offer Date

RECEIPT OF AMENDMENTS: The undersigned acknowledges receipt of the following amendments of the invitation for bids, drawings, and/or specifications, etc. (Give number and date of each):

____

Subcontract No. 0517-80

AWARD

Amount $293,600.00

Submit Invoices (Four Copies Unless Otherwise Specified) to Address:

Eaton Operating Co., Inc.
3104 Edloe, Suite 200
Houston TX 77027

Administered By:

Eaton Operating Co., Inc
3104 Edloe, Suite 200
Houston TX 77027

Payment Will be Made By:

Eaton Operating Co., Inc

Awarded By:

Eaton Operating Co., Inc.

W. E. Rose
Name

W. E. Rose
Signature

Purchasing Manager
Title

27 May 81
Award Date

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number Crown Zellerbach #2 County Livingston Par
State Louisiana Field Name Wildcat Well Location and
Land Description 2530' from the South Line and 500' from the East Line of
Section 19, Township 6S and Range 5E - Livingston Parish, La.

CTP-02. COMMENCEMENT AND COMPLETION

The Subcontractor shall complete mobilization within five (5) calendar days after the date of receipt of Notice to Proceed and shall complete the entire work under the Unit Price Schedule ________ days after the date of receipt of Notice to Proceed. The contract completion date will be extended by the amount of time spent on Contractor-Directed Operations and Standby, to the extent that is deemed necessary.

CTP-03. STATEMENT OF WORK

A. General Description of Work. The Subcontractor's work consists of furnishing all personnel, equipment, materials and services, and supplies as specified herein, for conducting the following work: See Tentative Drilling Program, Attachment ____

B. Minimum Equipment and Services. The minimum equipment, facilities, services, and items required to complete the work is specified in CTP-07. All contractor-furnished items will be delivered to and picked up from the drill site by others. The minimum equipment and services designated to be furnished and operated by the Subcontractor will be at no additional cost to the Contractor.

C. Workweek and Personnel Requirement. The Subcontractor shall furnish minimum three man qualified drilling crew, including toolpusher, to maintain a 24-hour day, 7-day week operation.

CTP-04. MUD PROGRAM

Contractor agrees to furnish all mud additives and chemicals and will arrange to purchase all necessary engineering services. Mud program will be designed as dictated by hole conditions.

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

CTP-07. MINIMUM EQUIPMENT AND SERVICES

		To Be Provided By And At Expense Of	
		Contractor	Subcontractor
1.	Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location.		XX
2.	Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3.	Fishing tool services and fishing tool rental.	XX	
4.	Derrick timbers.		XX
5.	Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)		XX
6.	Conventional drift indicator.		XX
7.	Earthen mud pits and reserve pits.	XX	
8.	Steel mud tanks if required.		XX
9.	Necessary pipe racks and rigging up material.		XX
10.	Normal storage for mud and chemicals.		XX
11.	Necessary spools, flanges and fittings to connect blowout preventers.		XX

	To Be Provided By And At Expense of	
	Contractor	Subcontractor
2. Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	XX	
13. Staked, levelled and compacted location, including earth pits.	XX	
14. Rat and mouse holes to meet subcontractor's requirement.		XX
15. Test tanks with pipe and fittings.	XX	
16. Separator with pipe and fittings.	XX	
17. Labor to connect and disconnect Subcontractor's mud tank.		XX
18. Labor to disconnect and clean test tanks and separator.	XX	
19. Drilling mud, chemicals, lost circulation materials and other additives.	XX	
20. All tubular goods, miscellaneous line pipe and fittings.	XX	
21. All testing tools including inflatable and retrievable packers.	XX	
22. Special tools, casing scraper, etc.	XX	
23. Special mud pump capacity in excess of rig requirements.	XX	
24. Wireline split and conventional core barrels and wireline core catchers: two each ten-feet long split core barrel; one each twenty-feet long conventional barrel.	N/A	
25. Conventional core bits, barrels and catchers.	XX	
26. Diamond wireline core bits.	N/A	
27. Cement and cementing service.	XX	
28. Logging services.	XX	

		To Be Provided By And At Expense Of	
		Contractor	Subcontractor
9.	Directional, caliper, or other special services.	XX	
30.	Gun or jet perforating services.	XX	
31.	Core boxes, wrapping supplies, and storage facilities.	XX	
32.	Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33.	Equipment for drill stem testing.	XX	
34.	Mud Logging Services.	XX	
35.	Sidewall Coring Services.	XX	
36.	Welding Service (Except for Subcontractor's equipment).	XX	
37.	Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38.	Casing scratchers and centralizers.	XX	
39.	Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40.	Water at Source and Water Hauling Service.	XX	
41.	Water storage tanks 1000 gallon capacity.		XX
42.	Fuel and lubricants for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel in excess of ______ per gallon.	XX	
43	Drill pipe. Per Inventory		
44.	Drill collars. Per Inventory		
45.	Handling tools, clamps, etc., for each drilling assembly.	XX	
46.	Weight indicator.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
47. If applicable, drill pipe protectors for Kelly joint and each joint of drill pipe running inside of casing for use with normal strings of drill pipe.	XX	
48. Automatic driller (Optional).	N/A	
49. Materials for "boxing in" rig and derrick.	N/A	
50. Conventional core barrel.	XX	
51. Drilling recorder-minimum 2-pin.	XX	
52. Extra labor for running and cementing casing.	XX	
53. Casing tools.	XX	
54. Running of casing-conductor.	XX	
55. Running of casing-surface.	XX	
56. Running of casing protection, if applicable.	XX	
57. Running of casing production, if applicable.	XX	
58. Running of casing liner, if applicable.	XX	
59. Power casing tongs.	XX	
60. Tubing tools.	XX	
61. Power tubing tong.	XX	
62. Swabbing unit with swabbing line	XX	
63. Swab.	XX	
64. Swab lubricator.	XX	
65. Swab rubbers.	XX	
66. Light plant-adequate capacity for night-time operations, Subcontractor requirements.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
67. Drill rig-minimum failing 1500 rotary rig or approved equal for continuous wireline coring and drilling to ± 1500 feet.	N/A	
68. Two adequate circulating pumps and adequate mud mixing pumps.		XX
69. 1000 gallon water truck with driver for hauling water within two miles of work sites.	N/A	
70. Minimum of one two-way communications system.	N/A	
71. IADC Daily Drilling Report, Bit Record and Tally Forms.		XX

The above Subcontractor designated items are the minimum acceptable requirements for the Subcontractor drilling equipment. This is not intended to be a complete list of items to be furnished by the Subcontractor. The Subcontractor is required to furnish all drilling maintenance tools, materials, and equipment not herein designated, but which are normal components for a complete drilling rig required for drilling and testing operations described in these specifications.

CTP-08. UNIT PRICE SCHEDULE ITEMS DEFINED

Paragraph headings in this Special Condition correspond to items of the Unit Price Schedule.

1. Mobilization. The Subcontractor shall move in and rig up his equipment, rig up any lower-tier Subcontractor's equipment, and pick up first drilling assembly. Mobilization shall be considered complete when all the equipment is on location and rigged up ready to spud. The Subcontractor shall be paid for the above mobilization work under Item 1 of the Unit Price Schedule.

2. Contractor-Directed Operations. Operations under this category shall include, but are not limited to: Contractor-furnished surveying, plug backs, drilling, coring, reaming, hydrologic testing, inserting and retrieving casing, placing cement and regaining lost circulation. All operations will be done as directed by the Contractor. All work on an hourly rate basis shall be performed with a full complement of operating personnel and at the direction of the Contractor. If it becomes necessary to shut down Subcontractor's rig for repairs while performing work on an hourly rate basis, Subcontractor shall be allowed compensation for such repair time at the applicable hourly rate. The number of hours devoted to repair work for which the Subcontractor may be compensated shall be limited to an accumulated total of 12 hours for each 15 day period.

Contractor-directed operations will be paid for Item 02. of the Unit Price Schedule.

3. Standby Ready. When directed by the Contractor, the Subcontractor shall cease all operations and standby in a ready condition. A full complement of personnel and equipment shall be maintained at the work site ready to resume operations immediately. Operations under this category shall include Geophysical Logging, Cement Hardening Time, or any operations not requiring the use of rig engines or drill assembly. Standby ready time will be paid under Item 03. of the Unit Price Schedule.

4. Demobilization. Upon completion of the work under this Subcontract, the Subcontractor shall remove all rubbish and debris from the drill site and shall remove all of his equipment within ten calendar days. The Subcontractor will not be responsible for levelling the work site or draining and backfilling pits. Demobilization will be paid under Item 04. of the Unit Price Schedule.

CTP-09. RECORDS AND OBSERVATIONS

Providing the following records and observations shall be a part of the Subcontractor's general responsibility for which no additional payment will be made.

1. A Daily Drilling Report shall be kept on the IADC official Standard Daily Drilling Report. The Unit Price Schedule quantities for pay estimate purpose will be taken from the IDAC Daily Drilling Report. The general remarks section shall contain an accurate record of hole conditions, work performed, and time required for all work to the nearest quarter-hour. The original and two copies of the Daily Drilling Report shall be submitted to the Contractor or his authorized representative.

2. Bit Records shall be maintained daily and posted in the doghouse. A complete bit record shall be furnished the Contractor at the completion of a hole. Records must show bit types, sizes, footages, depths, rotary speeds, bit weights, manufacturer, and serial number.

3. Accurate Pipe Tallies shall be the Subcontractor's responsibility and shall be available at the drill site for inspection at all times. Copies of steel tape measurements of drill pipe and casing shall be furnished by the Contractor.

CTP-10. SUBSURFACE INFORMATION

1. The subsurface information and data furnished both in these specifications and at the Contractor's office are not intended as representations or warranties, but are furnished for information only.

2. It is anticipated that the information contained herein generally represents the conditions that will be encountered in the performance of the Subcontract; however, any interpretation or conclusion reached by the Subcontractor in preparing his Unit Price Schedules will be his sole responsibility.

CTP-11. ACCOMMODATIONS

The Subcontractor will be required to make his own arrangements with his employees for housing and feeding. The Subcontractor may locate toolpusher's house trailer near the drilling location, as designated by the Contractor.

CTP-12. DERRICK MISALIGHMENT

If, at any time, the Subcontractor's derrick becomes misaligned over a hole, the Subcontractor shall be required to commence realignment operations within eight hours of the misalignment. If such misalignment occurs as the result of fault or negligence on the part of the Subcontractor, the Subcontractor shall receive no compensation for the time or cost spent in realignment. If the misalignment is not the fault of, or caused by, Subcontractor negligence, the Subcontractor shall be compensated under Item 2. of the Unit Price Schedule.

CTP-13. LOSS OF HOLE

A hole shall be termed "lost" if the Contractor determines that the condition of the hole will prevent its successful completion, or if for any reason the Contractor deems it impractical to continue drilling. If the Contractor determines that a hole has been lost before required depth has been attained, and that further attempts to complete it will be impractical, he shall order work on the hole stopped, shall investigate the circumstances in contributing to its loss, and shall notify the Subcontractor of his decision in writing. The Contractor may, at his option, order the commencement of work at an alternate location.

Contractor shall assume liability, while work is being performed under Contractor-directed operations, for loss of, damage to, or destruction of the hole, Subcontractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, subs, stabilizers, and bits, unless such loss, damage, or destruction shall be caused by the Subcontractor's fault or negligence.

CTP-14. ABANDONMENT

In the event that, prior to completion of the work required, a hole covered by this Subcontract is abandoned, upon direction of the Contractor, the Subcontractor will be paid for work performed under the applicable items of the Unit Price Schedule.

The term "abandonment" as used in this paragraph shall mean abandonment to suit the convenience of the Contractor, as directed by the Contractor, under conditions which do not come within the scope of the paragraph entitled "Loss of Hole" of these specifications.

CTP-15. STANDARD FOR PRESSURE VESSELS

All Subcontractor's compressed air equipment and accessories shall be designed, fabricated, inspected, and certified in accordance with the SAME Boiler and

Pressure Vessel Code, Section VIII. For equipment fabricated under the 1968 Code, either Division I or Division II (but not both) of the Code may be used.

CTP-16. PRESERVATION OF ANTIQUITIES, WILDLIFE, AND LAND AREAS

Federal law provides for the protection of antiquities located on land owned or controlled by the U. S. Government. Antiquities include Indian graves, or campsites, relics, and artifacts. The Subcontractor shall control the movements of his personnel and his Subcontractor's personnel at the jobsite to ensure that any existing antiquities discovered thereon will not be disturbed or destroyed by such personnel. It shall be the duty of the Subcontractor to report the existence of any antiquities so discovered. The Subcontractor shall also preserve all vegetation except where such vegetation must be removed for survey or construction purposes. Further, all wildlife shall be protected.

CTP-17. RESPONSIBILITY FOR LOSS OF OR DAMAGE TO EQUIPMENT

1. Subcontractor's Surface Equipment. Subcontractor shall be liable at all times for damage to or destruction of Subcontractor's surface equipment including all drilling tools, machinery, and appliances for use above the surface and for any other type of equipment including in-hole equipment when such in-hole equipment is above the surface, regardless of when or how such damage or destruction occurs. The Contractor shall be under no liability to compensate the Subcontractor for any such loss except loss of damage thereto caused by negligence of the Contractor, its agents, or employees.

2. Loss of Tools in the Hole

   a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.

      i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.

      ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor

will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

b. <u>Contractor-Furnished Equipment</u>. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor. R.W.

CTP-18. CONTRACTOR MINIMUM EQUIPMENT REQUIREMENTS AND STANDARDS

The following American Petroleum Institute Standards and Recommended Practices of the latest issue, as of the date of bid opening, are a part of these specifications whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structures
3.	API Std. 7	Specification for Rotary Drilling Equipment
4.	API Std. 8A	Specification for Hoisting Equipment
5.	API Std. 9A	Specification for Wire Rope
6.	API RP-5C1	Recommended Practice for Care and Use of Casing, Drill Pipe and Tubing
7.	API RP-9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service
8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

WELLTECH, INC. CONTRACTS

WellTech, Inc.

Louisiana Division
Post Office Box 51933, O.C.S.
Lafayette, Louisiana 70505
318/232-3413

R I G # 31

Wilson Model "75", self propelled back-in Winchmobile, powered by two (2) 450-HP 12V-71N GM Diesel engines. Selective controls permit operation of either engine if desired or should loss of one engine occur. Engines are compounded and equipped with 11,500 series 3-stage Allison torque converters, with an additional 2 speed chain box air clutch auxiliary transmission. The unit is equipped with 1 1/8" drill line, water circulating brakes, one V-80 Parkersburg Hydrotarder. The mast is 110' angular, with hook load of 300,000#, hydraulically raised and telescoped. Racking capacity in doubles: 20,000' 2 7/8" drill pipe or 28,000' 2 3/8" tubing. The crown consists of five (5) sheaves allowing 8 line string up. Installed is one hydraulically operated breakout cylinder.

2	Gardner Denver 310 HP PJ-8 Triplex Pump powered by 8V-71N Series GM Diesel engine, 10,000 Series Twin Disc torque converter and 8542A Spicer transmission.
1	Harrisburg 5" X 6" mud mixing pump powered by 3-71 GM Diesel engine.
1	Gardner Denver 2½" X 2½" centrifugal fresh water transfer pump powered by Lister Diesel engine.
1	18' high X 20' X 17' hydraulically raised sub-structure equipped with 17½" Oilwell rotary.
1	Baash Ross 4 sheave, 150 Ton Shorty traveling block.
1	PC-150 Oilwell Swivel.
1	3" X 40' Rotary Hose, 3000# working pressure.

WellTech, Inc.

Louisiana Division
Post Office Box 51933, O.C.S.
Lafayette, Louisiana 70505
318/232-3413

R I G # 31 continued

1	6" Series 1500 Cameron Type "U" double blowout preventers, with one 2 3/8", 2 7/8" and blind rams - 4" and 2" series 1500 flanged outlets between rams.
1	6" 1500 Hydrill Type "GK" annular blowout preventer.
1	Ross-Hill Accumulators with 15 gallon capacity and 3000# working pressure.
1	Advance Model "C" air spider with 2 3/8" and 2 7/8" slips.
1	Type "FS" Martin Decker weight indicator with Hercules model 118 wireline anchor.
2	60 KW light plants, powered by 3-71 GM Diesel engines.
1	Shale Shaker Brandt 2' X 4'.
2	200 barrel mud tanks with mud hopper and mud mixing lines installed.
1	Set Foster hydraulic tubing tongs.
1	Baash Ross 38' kelly with 2 7/8" I.F. 4½" API LH box connection.
2 sets	Pipe racks, ramp, and catwalk.
1	set 2 3/8" and 2 7/8" Tubing elevators
1	Air conditioned living quarters
	All necessary mud lines and hand tools.

Subcontract No. 0521-80

OFFER

In compliance with the Solicitation, the undersigned offers and agrees, if this offer is accepted within ______ calendar days (60 calendar days unless a different period is inserted by the offeror) from the date for receipt of offers specified in the Solicitation, to furnish any or all items upon which prices are offered at the price set opposite each item, within the time specified in the schedule.

Discount for prompt payment:

______% 10 calendar days; ______% 20 calendar days; ______% 30 calendar days;

______%____ calendar days

NAME AND ADDRESS OF OFFEROR: (Street, City, County, ZIP Code, Area Code, and Telephone).

WellTech, Inc.
700 Rusk Avenue
Houston, Texas 77002
Harris County
(713) 225-5555

NAME AND TITLE OF PERSON AUTHORIZED TO SIGN OFFER (Type or Print)

Christian N. Seger	Vice-President
Typed Name	Title
Ch Seger	3-23-81
Signature	Offer Date

RECEIPT OF AMENDMENTS: The undersigned acknowledges receipt of the following amendments of the invitation for bids, drawings, and/or specifications, etc. (Give number and date of each):

____

Subcontract No. 0521-80

AWARD

Amount $60,840.00

Submit Invoices (Four Copies Unless Otherwise Specified) to Address:

EATON OPERATING COMPANY, INC.
3100 EDLOE, SUITE 205
HOUSTON, TEXAS 77027

Administered By:

Eaton Operating Company, Inc.

Payment Will be Made By:

Eaton Operating Company, Inc.

Awarded By:

Eaton Operating Company, Inc.

W. E. Rose
Name

W. E. Rose
Signature

Purchasing Manager
Title

3-24-81
Award Date

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

CTP-07. MINIMUM EQUIPMENT AND SERVICES

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
1. Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location. To be rebilled at subcontractor's cost		XX
2. Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3. Fishing tool services and fishing tool rental.	XX	
4. Derrick timbers.		XX
5. Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)	XX	~~XX~~
6. Conventional drift indicator.	XX	~~XX~~
7. Earthen mud pits and reserve pits.	XX	
8. Steel mud tanks if required.		XX
9. Necessary pipe racks and rigging up material.		XX
10. Normal storage for mud and chemicals.		XX
11. Necessary spools, flanges and fittings to connect blowout preventers.		XX

JHW

		To Be Provided By And At Expense of	
		Contractor	Subcontractor
12.	Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	XX	
13.	Staked, levelled and compacted location, including earth pits.	XX	
14.	Rat and mouse holes to meet subcontractor's requirement.	XX	
15.	Test tanks with pipe and fittings.	XX	
16.	Separator with pipe and fittings.	XX	
17.	Labor to connect and disconnect Subcontractor's mud tank.		XX
18.	Labor to disconnect and clean test tanks and separator.	XX	
19.	Drilling mud, chemicals, lost circulation materials and other additives.	XX	
20.	All tubular goods, miscellaneous line pipe and fittings.	XX	
21.	All testing tools including inflatable and retrievable packers.	XX	
22.	Special tools, casing scraper, etc.	XX	
23.	Special mud pump capacity in excess of rig requirements.	XX	
24.	Wireline split and conventional core barrels and wireline core catchers: two each ten-feet long split core barrel; one each twenty-feet long conventional barrel.	N/A	
25.	Conventional core bits, barrels and catchers.	XX	
26.	Diamond wireline core bits.	N/A	
27.	Cement and cementing service.	XX	
28.	Logging services.	XX	

		Contractor	Subcontractor
29.	Directional, caliper, or other special services.	XX	
30.	Gun or jet perforating services.	XX	
31.	Core boxes, wrapping supplies, and storage facilities.	XX	
32.	Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33.	Equipment for drill stem testing.	XX	
34.	Mud Logging Services.	XX	
35.	Sidewall Coring Services.	XX	
36.	Welding Service (Except for Subcontractor's equipment).	XX	
37.	Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38.	Casing scratchers and centralizers.	XX	
39.	Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40.	Water at Source and Water Hauling Service.	XX	
41.	Water storage tanks <u>1000 gallon</u> capacity.		XX
42.	Fuel and lubricants for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel in excess of ______ per gallon.	XX	
43	Drill pipe.	XX	
44.	Drill collars.	XX	
45.	Handling tools, clamps, etc., for each drilling assembly.		
46.	Weight indicator.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
47. If applicable, drill pipe protectors for Kelly joint and each joint of drill pipe runnin- inside of casing for use with normal strings of drill pipe.	XX	
48. Automatic driller (Optional).	N/A	
49. Materials for "boxing in" rig and derrick.	N/A	
50. Conventional core barrel.	XX	
51. Drilling recorder-minimum 2-pin.	XX	
52. Extra labor for running and cementing casing.	XX	
53. Casing tools.	XX	
54. Running of casing-conductor.	XX	
55. Running of casing-surface.	XX	
56. Running of casing protection, if applicable.	XX	
57. Running of casing production, if applicable.	XX	
58. Running of casing liner, if applicable.	XX	
59. Power casing tongs.	XX	
60. Tubing tools.	XX	
61. Power tubing tong.	XX	
62. Swabbing unit with swabbing line	XX	
63. Swab.	XX	
64. Swab lubricator.	XX	
65. Swab rubbers.	XX	
66. Light plant-adequate capacity for night-time operations, Subcontractor requirements.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
67. Drill rig-minimum failing 1500 rotary rig or approved equal for continuous wireline coring and drilling to ± 1500 feet.	N/A	
68. Two adequate circulating pumps and adequate mud mixing pumps.		XX
69. 1000 gallon water truck with driver for hauling water within two miles of work sites.	N/A	
70. Minimum of one two-way communications system.	N/A	
71. IADC Daily Drilling Report, Bit Record and Tally Forms.		XX

The above Subcontractor designated items are the minimum acceptable requirements for the Subcontractor drilling equipment. This is not intended to be a complete list of items to be furnished by the Subcontractor. The Subcontractor is required to furnish all drilling maintenance tools, materials, and equipment not herein designated, but which are normal components for a complete drilling rig required for drilling and testing operations described in these specifications.

CTP-08. UNIT PRICE SCHEDULE ITEMS DEFINED

Paragraph headings in this Special Condition correspond to items of the Unit Price Schedule.

1. Mobilization. The Subcontractor shall move in and rig up his equipment, rig up any lower-tier Subcontractor's equipment, and pick up first drilling assembly. Mobilization shall be considered complete when all the equipment is on location and rigged up ready to spud. The Subcontractor shall be paid for the above mobilization work under Item 1 of the Unit Price Schedule.

2. Contractor-Directed Operations. Operations under this category shall include, but are not limited to: Contractor-furnished surveying, plug backs, drilling, coring, reaming, hydrologic testing, inserting and retrieving casing, placing cement and regaining lost circulation. All operations will be done as directed by the Contractor. All work on an hourly rate basis shall be performed with a full complement of operating personnel and at the direction of the Contractor. If it becomes necessary to shut down Subcontractor's rig for repairs while performing work on an hourly rate basis, Subcontractor shall be allowed compensation for such repair time at the applicable hourly rate. The number of hours devoted to repair work for which the Subcontractor may be compensated shall be limited to an accumulated total of 12 hours for each 15 day period.

will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

b. Contractor-Furnished Equipment. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor.

CTP-18. CONTRACTOR MINIMUM EQUIPMENT REQUIREMENTS AND STANDARDS

The following American Petroleum Institute Standards and Recommended Practices of the latest issue, as of the date of bid opening, are a part of these specifications whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structures
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4.	API Std. 8A	Specification for Hoisting Equipment
5.	API Std. 9A	Specification for Wire Rope
6.	API RP-5C1	Recommended Practice for Care and Use of Casing, Drill Pipe and Tubing
7.	API RP-9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service
8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

Pressure Vessel Code, Section VIII. For equipment fabricated under the 1968 Code, either Division I or Division II (but not both) of the Code may be used.

CTP-16. PRESERVATION OF ANTIQUITIES, WILDLIFE, AND LAND AREAS

Federal law provides for the protection of antiquities located on land owned or controlled by the U. S. Government. Antiquities include Indian graves, or campsites, relics, and artifacts. The Subcontractor shall control the movements of his personne and his Subcontractor's personnel at the jobsite to ensure that any existing antiquities discovered thereon will not be disturbed or destroyed by such personnel. It shall be the duty of the Subcontractor to report the existence of any antiquities so discovered. The Subcontractor shall also preserve all vegetation except where such vegetation must be removed for survey or construction purposes. Further, all wildlife shall be protected.

CTP-17. RESPONSIBILITY FOR LOSS OF OR DAMAGE TO EQUIPMENT

1. Subcontractor's Surface Equipment. Subcontractor shall be liable at all times for damage to or destruction of Subcontractor's surface equipment including all drilling tools, machinery, and appliances for use above the surface and for any other type of equipment including in-hole equipment when such in-hole equipment is above the surface, regardless of when or how such damage or destruction occurs. The Contractor shall be under no liability to compensate the Subcontractor for any such loss except loss of damage thereto caused by negligence of the Contractor, its agents, or employees.

2. Loss of Tools in the Hole

a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.

i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.

ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor

CTP-11. ACCOMMODATIONS

The Subcontractor will be required to make his own arrangements with his employees for housing and feeding. The Subcontractor may locate toolpusher's house trailer near the drilling location, as designated by the Contractor.

CTP-12. DERRICK MISALIGNMENT

If, at any time, the Subcontractor's derrick becomes misaligned over a hole, the Subcontractor shall be required to commence realignment operations within eight hours of the misalignment. If such misalignment occurs as the result of fault or negligence on the part of the Subcontractor, the Subcontractor shall receive no compensation for the time or cost spent in realignment. If the misalignment is not the fault of, or caused by, Subcontractor negligence, the Subcontractor shall be compensated under Item 2. of the Unit Price Schedule.

CTP-13. LOSS OF HOLE

A hole shall be termed "lost" if the Contractor determines that the condition of the hole will prevent its successful completion, or if for any reason the Contractor deems it impractical to continue drilling. If the Contractor determines that a hole has been lost before required depth has been attained, and that further attempts to complete it will be impractical, he shall order work on the hole stopped, shall investigate the circumstances in contributing to its loss, and shall notify the Subcontractor of his decision in writing. The Contractor may, at his option, order the commencement of work at an alternate location.

Contractor shall assume liability, while work is being performed under Contractor-directed operations, for loss of, damage to, or destruction of the hole, Subcontractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, subs, stabilizers, and bits, unless such loss, damage, or destruction shall be caused by the Subcontractor's fault or negligence.

CTP-14. ABANDONMENT

In the event that, prior to completion of the work required, a hole covered by this Subcontract is abandoned, upon direction of the Contractor, the Subcontractor will be paid for work performed under the applicable items of the Unit Price Schedule.

The term "abandonment" as used in this paragraph shall mean abandonment to suit the convenience of the Contractor, as directed by the Contractor, under conditions which do not come within the scope of the paragraph entitled "Loss of Hole" of these specifications.

CTP-15. STANDARD FOR PRESSURE VESSELS

All Subcontractor's compressed air equipment and accessories shall be designed, fabricated, inspected, and certified in accordance with the SAME Boiler and

Contractor-directed operations will be paid for Item 02. of the Unit Price Schedule.

3. Standby Ready. When directed by the Contractor, the Subcontractor shall cease all operations and standby in a ready condition. A full complement of personnel and equipment shall be maintained at the work site ready to resume operations immediately. Operations under this category shall include Geophysical Logging, Cement Hardening Time, or any operations not requiring the use of rig engines or drill assembly. Standby ready time will be paid under Item 03. of the Unit Price Schedule.

4. Demobilization. Upon completion of the work under this Subcontract, the Subcontractor shall remove all rubbish and debris from the drill site and shall remove all of his equipment within ten calendar days. The Subcontractor will not be responsible for levelling the work site or draining and backfilling pits. Demobilization will be paid under Item 04. of the Unit Price Schedule.

CTP-09. RECORDS AND OBSERVATIONS

Providing the following records and observations shall be a part of the Subcontractor's general responsibility for which no additional payment will be made.

1. A Daily Drilling Report shall be kept on the IADC official Standard Daily Drilling Report. The Unit Price Schedule quantities for pay estimate purpose will be taken from the IDAC Daily Drilling Report. The general remarks section shall contain an accurate record of hole conditions, work performed, and time required for all work to the nearest quarter-hour. The original and two copies of the Daily Drilling Report shall be submitted to the Contractor or his authorized representative.

2. Bit Records shall be maintained daily and posted in the doghouse. A complete bit record shall be furnished the Contractor at the completion of a hole. Records must show bit types, sizes, footages, depths, rotary speeds, bit weights, manufacturer, and serial number.

3. Accurate Pipe Tallies shall be the Subcontractor's responsibility and shall be available at the drill site for inspection at all times. Copies of steel tape measurements of drill pipe and casing shall be furnished by the Contractor.

CTP-10. SUBSURFACE INFORMATION

1. The subsurface information and data furnished both in these specifications and at the Contractor's office are not intended as representations or warranties, but are furnished for information only.

2. It is anticipated that the information contained herein generally represents the conditions that will be encountered in the performance of the Subcontract; however, any interpretation or conclusion reached by the Subcontractor in preparing his Unit Price Schedules will be his sole responsibility.

WellTech, Inc.

Louisiana Division
Post Office Box 51933, O.C.S.
Lafayette, Louisiana 70505
318/232-3413

RIG #3

Wilson Model "65", self-propelled back-in Winchmobile, powered by two (2) 8V-92N GM Diesel engines. Selective controls permit operatio of either engine if desired or should loss of one engine occur. Engines are compounded and equipped with 11,500 Series 3-stage twin-disc torque convertors. The unit is equipped with 1" drill line, water-circulating brakes, rotary drive, V-80 Parkersburg hydrotarder. The mask is 110' angular, with hook load of 300,000# hydraulically raised and telescoped. Racking capacity in doubles 20,000' 2-7/8" drill pipe or 28,000' 2-3/8" tubing. The crown consist of five (5) sheaves allowing 8-line string up. Installed is one hydraulically operated break-out cylinder.

2	Gardner Denver 310 HP PJ-8 triplex pumps with 4" liners powered by 8V-71N GM Diesel engine, 10,000 Series Twin Disc Torque convertors, 85-42A Spicer transmission.
1	Mission 5" x 6" Mud mixing pump powered by 4-71N GM Diesel engine.
1	Harrisburg 2" x 3" centrifugal fresh water transfer pump powered by single cylinder Lister Diesel engine.
1	18' high x 20' x 17' hydraulically raised substructure equipped with 17-1/2" Oilwell rotary.
1	Baash Ross 4-sheave 150 ton Shorty Traveling Block.
1	PC-150 Oilwell Swivel.
1	3" x 40' Rotary Hose, 3,000# working pressure.
1	6" Series 1500 Cameron Type "U" Blowout Preventers with one 2-3/8", 2-7/8" and blind rams, 4" and 2" series 1500 flanged outlets between rams.
1	Series 1500 Choke Manifold.
1	6" Series 1500 Hydril Type "GK" preventers.
1 set	Koomey Accumulators with 30-gallon capacity, 3000# working pressure.
1	Advance Model "C" Air spider with 2-3/8" or 2-7/8" slip inserts.
1	Martin Decker type "FS" Weight Indicator.

WellTech, Inc.

Louisiana Division
Post Office Box 51933, O.C.S.
Lafayette, Louisiana 70505
318/232-3413

RIG #8 - Continued

2	60 KW light plant, powered by 3-71N GM Diesel Engine.
1	Brandt "Junior" Shale Shaker.
1 set	Vapor proof fluorescent lighting system.
2	200-barrel mud tanks with mud hopper and mud mixing lines installed.
1 set	Foster Hydraulic tubing tongs.
1	Baash Ross 3" x 38' square Kelly with 2-7/8" I.F. Pin x 4-1/2' API L. H. box connections.
1	Ramp, Catwalk and (2) sets pipe racks.
1	Air-conditioned living quarters.
1 set	2-3/8" and 2-7/8" tubing elevators.

All necessary mud lines and hand tools.

SOLICITATION AND OFFER NO: ~~0626-80~~
Subcontract No.

NAME AND LOCATION OF PROJECT:

Crown Zellerbach Well

~~Livingston Parish, LA~~

ISSUE DATE:

6/19/81

ISSUED BY:

A. Eaton Operating Co., Inc.

3104 Edloe, Ste 200

Houston TX 77027

ADDRESS OFFER TO:

B. WellTech Inc.

700 Rusk Avenue

Houston TX 77002

Your offer in original and one copy for performing the work described in the Schedule, Drawings, Conditions, and Technical Specifications may be mailed to address A., or if hand carried, will be received at the Reception Desk at address B. above, until the bids are opened at ______ Time ______ Zone

______. Date

CAUTION-LATE OFFERS, see paragraph 4 of Solicitation Instructions and Conditions.

DESCRIPTION OF WORK
Furnish all (except Government-furnished items) equipment, materials, supplies, transportation, and services necessary for drilling WIPP No. 16.

FOR INFORMATION ON THE TECHNICAL PROVISIONS OF THIS PROCUREMENT, WRITE OR CALL:

Doug Graham

c/o Eaton Operating Co., Inc.

3104 Edloe, Ste 200

Houston TX 77027

Telephone: (713) 627-9764

Subcontract No. 0626-80

AWARD

Amount $34,440.00

Submit Invoices (Four Copies Unless Otherwise Specified) to Address:

Eaton Operating Co., Inc.
3104 Edloe, Ste 200
Houston TX 77027

Administered By:

WellTech Inc.
700 Rusk Avenue
Houston TX 77002

Payment Will be Made By:

Eaton Operating Co., Inc.

Awarded By:

Eaton Operating Co., Inc.

Doug Graham	[signature]
Name	Signature
Purchasing Manager	6/19/81
Title	Award Date

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number Crown Zellerbach #1 County Livingston Parish State Louisiana Field Name Wildcat Well Location and Land Description 2530' from the South line and 500' from the East line of Section 19, Township 6S and Range 5E - Livingston Parish, La.

CTP-02. COMMENCEMENT AND COMPLETION

The Subcontractor shall complete mobilization within five (5) calendar days after the date of receipt of Notice to Proceed and shall complete the entire work under the Unit Price Schedule ________ days after the date of receipt of Notice to Proceed. The contract completion date will be extended by the amount of time spent on Contractor-Directed Operations and Standby, to the extent that is deemed necessary.

CTP-03. STATEMENT OF WORK

A. General Description of Work. The Subcontractor's work consists of furnishing all personnel, equipment, materials and services, and supplies as specified herein, for conducting the following work: See Tentative Drilling Program, Attachment ____

B. Minimum Equipment and Services. The minimum equipment, facilities, services, and items required to complete the work is specified in CTP-07. All contractor-furnished items will be delivered to and picked up from the drill site by others. The minimum equipment and services designated to be furnished and operated by the Subcontractor will be at no additional cost to the Contractor.

C. Workweek and Personnel Requirement. The Subcontractor shall furnish minimum three man qualified drilling crew, including toolpusher, to maintain a 24-hour day, 7-day week operation.

CTP-04. MUD PROGRAM

Contractor agrees to furnish all mud additives and chemicals and will arrange to purchase all necessary engineering services. Mud program will be designed as dictated by hole conditions.

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

CTP-07. MINIMUM EQUIPMENT AND SERVICES

		To Be Provided By And At Expense Of	
		Contractor	Subcontractor
1.	Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location.		XX
2.	Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3.	Fishing tool services and fishing tool rental.	XX	
4.	Derrick timbers.		XX
5.	Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)	XX	
6.	Conventional drift indicator.	XX	
7.	Earthen mud pits and reserve pits.	XX	
8.	Steel mud tanks if required.		XX
9.	Necessary pipe racks and rigging up material.		XX
10.	Normal storage for mud and chemicals.		XX
11.	Necessary spools, flanges and fittings to connect blowout preventers.		XX

	To Be Provided By And At Expense of	
	Contractor	Subcontractor
12. Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	XX	
13. Staked, levelled and compacted location, including earth pits.	XX	
14. Rat and mouse holes to meet subcontractor's requirement.	XX	
15. Test tanks with pipe and fittings.	XX	
16. Separator with pipe and fittings.	XX	
17. Labor to connect and disconnect Subcontractor's mud tank.		XX
18. Labor to disconnect and clean test tanks and separator.	XX	
19. Drilling mud, chemicals, lost circulation materials and other additives.	XX	
20. All tubular goods, miscellaneous line pipe and fittings.	XX	
21. All testing tools including inflatable and retrievable packers.	XX	
22. Special tools, casing scraper, etc.	XX	
23. Special mud pump capacity in excess of rig requirements.	XX	
24. Wireline split and conventional core barrels and wireline core catchers: two each ten-feet long split core barrel; one each twenty-feet long conventional barrel.	N/A	
25. Conventional core bits, barrels and catchers.	XX	
26. Diamond wireline core bits.	N/A	
27. Cement and cementing service.	XX	
28. Logging services.	XX	

		To Be Provided By And At Expense Of	
		Contractor	Subcontractor
29.	Directional, caliper, or other special services.	XX	
30.	Gun or jet perforating services.	XX	
31.	Core boxes, wrapping supplies, and storage facilities.	XX	
32.	Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33.	Equipment for drill stem testing.	XX	
34.	Mud Logging Services.	XX	
35.	Sidewall Coring Services.	XX	
36.	Welding Service (Except for Subcontractor's equipment).	XX	
37.	Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38.	Casing scratchers and centralizers.	XX	
39.	Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40.	Water at Source and Water Hauling Service.	XX	
41.	Water storage tanks 1000 gallon capacity.		XX
42.	Fuel and lubricants for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel in excess of ______ per gallon.	XX	
43	Drill pipe. ________	XX	
44.	Drill collars. ________	XX	
45.	Handling tools, clamps, etc., for each drilling assembly.		
46.	Weight indicator.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
47. If applicable, drill pipe protectors for Kelly joint and each joint of drill pipe running inside of casing for use with normal strings of drill pipe.	XX	
48. Automatic driller (Optional).	N/A	
49. Materials for "boxing in" rig and derrick.	N/A	
50. Conventional core barrel.	XX	
51. Drilling recorder-minimum 2-pin.	XX	
52. Extra labor for running and cementing casing.	XX	
53. Casing tools.	XX	
54. Running of casing-conductor.	XX	
55. Running of casing-surface.	XX	
56. Running of casing protection, if applicable.	XX	
57. Running of casing production, if applicable.	XX	
58. Running of casing liner, if applicable.	XX	
59. Power casing tongs.	XX	
60. Tubing tools.	XX	
61. Power tubing tong.	XX	
62. Swabbing unit with swabbing line	XX	
63. Swab.	XX	
64. Swab lubricator.	XX	
65. Swab rubbers.	XX	
66. Light plant-adequate capacity for night-time operations, Subcontractor requirements.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
67. Drill rig-minimum failing 1500 rotary rig or approved equal for continuous wireline coring and drilling to ± 1500 feet.	N/A	
68. Two adequate circulating pumps and adequate mud mixing pumps.		XX
69. 1000 gallon water truck with driver for hauling water within two miles of work sites.	N/A	
70. Minimum of one two-way communications system.	N/A	
71. IADC Daily Drilling Report, Bit Record and Tally Forms.		XX

The above Subcontractor designated items are the minimum acceptable requirements for the Subcontractor drilling equipment. This is not intended to be a complete list of items to be furnished by the Subcontractor. The Subcontractor is required to furnish all drilling maintenance tools, materials, and equipment not herein designated, but which are normal components for a complete drilling rig required for drilling and testing operations described in these specifications.

CTP-08. UNIT PRICE SCHEDULE ITEMS DEFINED

Paragraph headings in this Special Condition correspond to items of the Unit Price Schedule.

1. Mobilization. The Subcontractor shall move in and rig up his equipment, rig up any lower-tier Subcontractor's equipment, and pick up first drilling assembly. Mobilization shall be considered complete when all the equipment is on location and rigged up ready to spud. The Subcontractor shall be paid for the above mobilization work under Item 1 of the Unit Price Schedule.

2. Contractor-Directed Operations. Operations under this category shall include, but are not limited to: Contractor-furnished surveying, plug backs, drilling, coring, reaming, hydrologic testing, inserting and retrieving casing, placing cement and regaining lost circulation. All operations will be done as directed by the Contractor. All work on an hourly rate basis shall be performed with a full complement of operating personnel and at the direction of the Contractor. If it becomes necessary to shut down Subcontractor's rig for repairs while performing work on an hourly rate basis, Subcontractor shall be allowed compensation for such repair time at the applicable hourly rate. The number of hours devoted to repair work for which the Subcontractor may be compensated shall be limited to an accumulated total of 12 hours for each 15 day period.

Contractor-directed operations will be paid for Item 02. of the Unit Price Schedule.

3. Standby Ready. When directed by the Contractor, the Subcontractor shall cease all operations and standby in a ready condition. A full complement of personnel and equipment shall be maintained at the work site ready to resume operations immediately. Operations under this category shall include Geophysical Logging, Cement Hardening Time, or any operations not requiring the use of rig engines or drill assembly. Standby ready time will be paid under Item 03. of the Unit Price Schedule.

4. Demobilization. Upon completion of the work under this Subcontract, the Subcontractor shall remove all rubbish and debris from the drill site and shall remove all of his equipment within ten calendar days. The Subcontractor will not be responsible for levelling the work site or draining and backfilling pits. Demobilization will be paid under Item 04. of the Unit Price Schedule.

CTP-09. RECORDS AND OBSERVATIONS

Providing the following records and observations shall be a part of the Subcontractor's general responsibility for which no additional payment will be made.

1. A Daily Drilling Report shall be kept on the IADC official Standard Daily Drilling Report. The Unit Price Schedule quantities for pay estimate purpose will be taken from the IDAC Daily Drilling Report. The general remarks section shall contain an accurate record of hole conditions, work performed, and time required for all work to the nearest quarter-hour. The original and two copies of the Daily Drilling Report shall be submitted to the Contractor or his authorized representative.

2. Bit Records shall be maintained daily and posted in the doghouse. A complete bit record shall be furnished the Contractor at the completion of a hole. Records must show bit types, sizes, footages, depths, rotary speeds, bit weights, manufacturer, and serial number.

3. Accurate Pipe Tallies shall be the Subcontractor's responsibility and shall be available at the drill site for inspection at all times. Copies of steel tape measurements of drill pipe and casing shall be furnished by the Contractor.

CTP-10. SUBSURFACE INFORMATION

1. The subsurface information and data furnished both in these specifications and at the Contractor's office are not intended as representations or warranties, but are furnished for information only.

2. It is anticipated that the information contained herein generally represents the conditions that will be encountered in the performance of the Subcontract; however, any interpretation or conclusion reached by the Subcontractor in preparing his Unit Price Schedules will be his sole responsibility.

CTP-11. ACCOMMODATIONS

The Subcontractor will be required to make his own arrangements with his employees for housing and feeding. The Subcontractor may locate toolpusher's house trailer near the drilling location, as designated by the Contractor.

CTP-12. DERRICK MISALIGHMENT

If, at any time, the Subcontractor's derrick becomes misaligned over a hole, the Subcontractor shall be required to commence realignment operations within eight hours of the misalignment. If such misalignment occurs as the result of fault or negligence on the part of the Subcontractor, the Subcontractor shall receive no compensation for the time or cost spent in realignment. If the misalignment is not the fault of, or caused by, Subcontractor negligence, the Subcontractor shall be compensated under Item 2. of the Unit Price Schedule.

CTP-13. LOSS OF HOLE

A hole shall be termed "lost" if the Contractor determines that the condition of the hole will prevent its successful completion, or if for any reason the Contractor deems it impractical to continue drilling. If the Contractor determines that a hole has been lost before required depth has been attained, and that further attempts to complete it will be impractical, he shall order work on the hole stopped, shall investigate the circumstances in contributing to its loss, and shall notify the Subcontractor of his decision in writing. The Contractor may, at his option, order the commencement of work at an alternate location.

Contractor shall assume liability, while work is being performed under Contractor-directed operations, for loss of, damage to, or destruction of the hole, Subcontractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, subs, stabilizers, and bits, unless such loss, damage, or destruction shall be caused by the Subcontractor's fault or negligence.

CTP-14. ABANDONMENT

In the event that, prior to completion of the work required, a hole covered by this Subcontract is abandoned, upon direction of the Contractor, the Subcontractor will be paid for work performed under the applicable items of the Unit Price Schedule.

The term "abandonment" as used in this paragraph shall mean abandonment to suit the convenience of the Contractor, as directed by the Contractor, under conditions which do not come within the scope of the paragraph entitled "Loss of Hole" of these specifications.

CTP-15. STANDARD FOR PRESSURE VESSELS

All Subcontractor's compressed air equipment and accessories shall be designed, fabricated, inspected, and certified in accordance with the SAME Boiler and

Pressure Vessel Code, Section VIII. For equipment fabricated under the 1968 Code, either Division I or Division II (but not both) of the Code may be used.

CTP-16. PRESERVATION OF ANTIQUITIES, WILDLIFE, AND LAND AREAS

Federal law provides for the protection of antiquities located on land owned or controlled by the U. S. Government. Antiquities include Indian graves, or campsites, relics, and artifacts. The Subcontractor shall control the movements of his personnel and his Subcontractor's personnel at the jobsite to ensure that any existing antiquities discovered thereon will not be disturbed or destroyed by such personnel. It shall be the duty of the Subcontractor to report the existence of any antiquities so discovered. The Subcontractor shall also preserve all vegetation except where such vegetation must be removed for survey or construction purposes. Further, all wildlife shall be protected.

CTP-17. RESPONSIBILITY FOR LOSS OF OR DAMAGE TO EQUIPMENT

1. Subcontractor's Surface Equipment. Subcontractor shall be liable at all times for damage to or destruction of Subcontractor's surface equipment including all drilling tools, machinery, and appliances for use above the surface and for any other type of equipment including in-hole equipment when such in-hole equipment is above the surface, regardless of when or how such damage or destruction occurs. The Contractor shall be under no liability to compensate the Subcontractor for any such loss except loss of damage thereto caused by negligence of the Contractor, its agents, or employees.

2. Loss of Tools in the Hole

   a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.

      i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.

      ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor

will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

b. Contractor-Furnished Equipment. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor.

CTP-18. CONTRACTOR MINIMUM EQUIPMENT REQUIREMENTS AND STANDARDS

The following American Petroleum Institute Standards and Recommended Practices of the latest issue, as of the date of bid opening, are a part of these specifications whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structures
3.	API Std. 7	Specification for Rotary Drilling Equipment
4.	API Std. 8A	Specification for Hoisting Equipment
5.	API Std. 9A	Specification for Wire Rope
6.	API RP-5C1	Recommended Practice for Care and Use of Casing, Drill Pipe and Tubing
7.	API RP-9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service
8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

RIG #168
24 HOUR WORKOVER

Wilson model "75" drive-in, self-propelled winchmobile powered by two (2) 450-Hp 12V-71N Detroit diesel engines. Selective controls permit operation of either engine if desired or should loss of one engine occur. Engines are compounded and equipped with 1-1/8" drill line, water circulating brakes, rotary drive, V80 Parkersburg hydrotarder. The mast is 116' angular with hook load capacity of 354,000#. Hydraulically raised and telescoped. Racking capacity in doubles: 24,000 ft. 2-7/8" tubing, or 21,000 ft. 2-7/8" drill pipe or 16,000 ft. 3½" drill pipe. The crown consists of six (6) sheaves allowing 10-line string up.

2	Gardner Denver PJ-8 triplex mud pumps powered by Detroit 12V-71N diesel engine.
1	2½" X 2" centrifugal fresh water transfer pump powered by single cylinder Lister diesel engine.
1	5" X 6" centrifugal mud mixing pump powered by Detroit 4-71N diesel engine.
1	27' high substructure with 20' X 17' working area, rated at 350,000#. Substructure may also be worked at 18' height.
1	Gardner Denver 17½" rotary table, 300 ton capacity.
1	B.J. unimatic 4 sheave 15 ton w/B?J? 150 ton hook
1	IDECO swivel, 200 ton capacity.
1	3" X 45' rotary hose, 5,000 # working pressure.
2	Cameron Type "U" double blowout preventers, 6" - 1500 series, flanged top and bottom, H_2S trim with (1) 3" flanged outlet and (1) 2" flanged outlet.
1	Hydril "GK" annular blowout preventer, 6" - 1500 series, studded top, flanged bottom, H_2S trim.
1	Shaffer "DB" gate valve, 3" - 1500 series, hydraulic operated, flanged, and H_2S trim.
1	Choke manifold 2" - 1500 series, flanged, Howco plug valves, adjustable chokes, gas buster, all necessary lines, skid mounted H_2S trim.
1	Koomey five station closing unit with air and electric pumps, three eleven gallon accumulators with remote control panel which may be operated 100 ft. from the unit.
1	Canvis type "F" air operated spider slips with inserts for 2-3/8" and 2-7/8" tubing.
1	Martin Decker type "FS" weight indicator with Hercules model 118 anchor.

2 140 KW generators powered by Detroit 6-71N diesel engines skid mounted along with 8' X 12' steel doghouse.
1 Brandt junior unit single screen shale shaker.
2 225 BBL mud tanks, equipped with mud mix hopper, 30 BBL slugging tank, and bottom mud guns.
1 4700 gal. water tank to be used for water circulating brakes and the hydromatic brake.
1 1850 gallon diesel fuel tank.
1 Set Foster 58-93-R hydraulic tongs with jaws for 2-3/8" and 2-7/8" tubing.
1 3½" O.D. square Kelly Baash Ross.
1 Baash Ross Kelly drive bushing for 3½" O.D. square kelly.
1 Set each 175 ton center latch elevators for 2-3/8" and 2-7/8" tubing.
1 40 Ft. long catwalk.
4 28 Ft. long pipe racks.
1 Air Conditioned skid mounted house. Accomodations for WellTech Pusher and two others.
2 Hydraulically operated breakout and make-up cylinders installed in mast.

SOLICITATION AND OFFER NO: 0726-80
Subcontract No.

NAME AND LOCATION OF PROJECT:

Crown Zellerbach Well

Livingston, Louisiana

ISSUE DATE:

ISSUED BY:

A. Eaton Operating Company, Inc.

3104 Edloe, Suite 200

Houston, Texas 77027

ADDRESS OFFER TO:

B. WellTech Inc.

700 Rusk

Houston, Texas 77002

Your offer in original and one copy for performing the work described in the Schedule, Drawings, Conditions, and Technical Specifications may be mailed to address A., or if hand carried, will be received at the Reception Desk at address B. above, until the bids are opened at ______ Time ______ Zone

______ Date.

CAUTION-LATE OFFERS, see paragraph 4 of Solicitation Instructions and Conditions.

DESCRIPTION OF WORK
Furnish all (except Government-furnished items) equipment, materials, supplies, transportation, and services necessary for drilling WIPP No. 16.

FOR INFORMATION ON THE TECHNICAL PROVISIONS OF THIS PROCUREMENT, WRITE OR CALL:

Doug Graham

c/o Eaton Operating Company, Inc.

3104 Edloe, Suite 200

Houston, Texas 77027

Telephone: (713) 627-9764

Subcontract No. 0726-80

AWARD

Amount $87,840.00

Submit Invoices (Four Copies Unless Otherwise Specified) to Address:

Eaton Operating Company, Inc.
3104 Edloe, Suite 200
Houston, Texas 77027

Administered By:

WellTech Inc.
700 Rusk Avenue
Houston, Texas 77002

Payment Will be Made By:

Eaton Operating Company, Inc.

Awarded By:

Eaton Operating Company, Inc.

Doug Graham	Doug Graham
Name	Signature
Purchasing Manager	10/23/81
Title	Award Date

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number Crown Zellerbach # 2 County Livingston Parish
State Louisiana Field Name Wildcat Well Location and
Land Description 1800' from the South Line and 2400' from the West Line of
Section 20, Township 6S and Range 5E - Livingston Parish, LA.

CTP-02. COMMENCEMENT AND COMPLETION

The Subcontractor shall complete mobilization within five (5) calendar days after the date of receipt of Notice to Proceed and shall complete the entire work under the Unit Price Schedule ________________ days after the date of receipt of Notice to Proceed. The contract completion date will be extended by the amount of time spent on Contractor-Directed Operations and Standby, to the extent that is deemed necessary.

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B. Minimum Equipment and Services. The minimum equipment, facilities, services, and items required to complete the work is specified in CTP-07. All contractor-furnished items will be delivered to and picked up from the drill site by others. The minimum equipment and services designated to be furnished and operated by the Subcontractor will be at no additional cost to the Contractor.

C. Workweek and Personnel Requirement. The Subcontractor shall furnish minimum three man qualified drilling crew, including toolpusher, to maintain a 24-hour day, 7-day week operation.

CTP-04. MUD PROGRAM

Contractor agrees to furnish all mud additives and chemicals and will arrange to purchase all necessary engineering services. Mud program will be designed as dictated by hole conditions.

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

CTP-07. MINIMUM EQUIPMENT AND SERVICES

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
1. Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location.		XX
2. Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3. Fishing tool services and fishing tool rental.	XX	
4. Derrick timbers.		XX
5. Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)	XX	
6. Conventional drift indicator.		XX
7. Earthen mud pits and reserve pits.	XX	
8. Steel mud tanks if required.		XX
9. Necessary pipe racks and rigging up material.		XX
10. Normal storage for mud and chemicals.		XX
11. Necessary spools, flanges and fittings to connect blowout preventers.		XX

	To Be Provided By And At Expense of	
	Contractor	Subcontractor
12. Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	XX	
13. Staked, levelled and compacted location, including earth pits.	XX	
14. Rat and mouse holes to meet subcontractor's requirement.		XX
15. Test tanks with pipe and fittings.	XX	
16. Separator with pipe and fittings.	XX	
17. Labor to connect and disconnect Subcontractor's mud tank.		XX
18. Labor to disconnect and clean test tanks and separator.	XX	
19. Drilling mud, chemicals, lost circulation materials and other additives.	XX	
20. All tubular goods, miscellaneous line pipe and fittings.	XX	
21. All testing tools including inflatable and retrievable packers.	XX	
22. Special tools, casing scraper, etc.	XX	
23. Special mud pump capacity in excess of rig requirements.	XX	
24. Wireline split and conventional core barrels and wireline core catchers: two each ten-feet long split core barrel; one each twenty-feet long conventional barrel.	N/A	
25. Conventional core bits, barrels and catchers.	XX	
26. Diamond wireline core bits.	N/A	
27. Cement and cementing service.	XX	
28. Logging services.	XX	

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
29. Directional, caliper, or other special services.	XX	
30. Gun or jet perforating services.	XX	
31. Core boxes, wrapping supplies, and storage facilities.	XX	
32. Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33. Equipment for drill stem testing.	XX	
34. Mud Logging Services.	XX	
35. Sidewall Coring Services.	XX	
36. Welding Service (Except for Subcontractor's equipment).	XX	
37. Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38. Casing scratchers and centralizers.	XX	
39. Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40. Water at Source and Water Hauling Service.	XX	
41. Water storage tanks 1000 gallon capacity.		XX
42. Fuel and lubricants for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel	XX	
43 Drill pipe. ______		
44. Drill collars. ______		
45. Handling tools, clamps, etc., for each drilling assembly.		
46. Weight indicator.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
47. If applicable, drill pipe protectors for Kelly joint and each joint of drill pipe running inside of casing for use with normal strings of drill pipe.	XX	
48. Automatic driller (Optional).	N/A	
49. Materials for "boxing in" rig and derrick.	N/A	
50. Conventional core barrel.	XX	
51. Drilling recorder—minimum 2-pin.	XX	
52. Extra labor for running and cementing casing.	XX	
53. Casing tools.	XX	
54. Running of casing-conductor.	XX	
55. Running of casing-surface.	XX	
56. Running of casing protection, if applicable.	XX	
57. Running of casing production, if applicable.	XX	
58. Running of casing liner, if applicable.	XX	
59. Power casing tongs.	XX	
60. Tubing tools.	XX	
61. Power tubing tong.	XX	
62. Swabbing unit with swabbing line	XX	
63. Swab.	XX	
64. Swab lubricator.	XX	
65. Swab rubbers.	XX	
66. Light plant-adequate capacity for night-time operations, Subcontractor requirements.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
67. Drill rig-minimum failing 1500 rotary rig or approved equal for continuous wireline coring and drilling to ± 1500 feet.	N/A	
68. Two adequate circulating pumps and adequate mud mixing pumps.		XX
69. 1000 gallon water truck with driver for hauling water within two miles of work sites.	N/A	
70. Minimum of one two-way communications system.	N/A	
71. IADC Daily Drilling Report, Bit Record and Tally Forms.		XX

The above Subcontractor designated items are the minimum acceptable requirements for the Subcontractor drilling equipment. This is not intended to be a complete list of items to be furnished by the Subcontractor. The Subcontractor is required to furnish all drilling maintenance tools, materials, and equipment not herein designated, but which are normal components for a complete drilling rig required for drilling and testing operations described in these specifications.

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Paragraph headings in this Special Condition correspond to items of the Unit Price Schedule.

1. <u>Mobilization</u>. The Subcontractor shall move in and rig up his equipment, rig up any lower-tier Subcontractor's equipment, and pick up first drilling assembly. Mobilization shall be considered complete when all the equipment is on location and rigged up ready to spud. The Subcontractor shall be paid for the above mobilization work under Item 1 of the Unit Price Schedule.

2. <u>Contractor-Directed Operations</u>. Operations under this category shall include, but are not limited to: Contractor-furnished surveying, plug backs, drilling, coring, reaming, hydrologic testing, inserting and retrieving casing, placing cement and regaining lost circulation. All operations will be done as directed by the Contractor. All work on an hourly rate basis shall be performed with a full complement of operating personnel and at the direction of the Contractor. If it becomes necessary to shut down Subcontractor's rig for repairs while performing work on an hourly rate basis, Subcontractor shall be allowed compensation for such repair time at the applicable hourly rate. The number of hours devoted to repair work for which the Subcontractor may be compensated shall be limited to an accumulated total of 12 hours for each 15 day period.

Contractor-directed operations will be paid for Item 02. of the Unit Price Schedule.

3. Standby Ready. When directed by the Contractor, the Subcontractor shall cease all operations and standby in a ready condition. A full complement of personnel and equipment shall be maintained at the work site ready to resume operations immediately. Operations under this category shall include Geophysical Logging, Cement Hardening Time, or any operations not requiring the use of rig engines or drill assembly. Standby ready time will be paid under Item 03. of the Unit Price Schedule.

4. Demobilization. Upon completion of the work under this Subcontract, the Subcontractor shall remove all rubbish and debris from the drill site and shall remove all of his equipment within ten calendar days. The Subcontractor will not be responsible for levelling the work site or draining and backfilling pits. Demobilization will be paid under Item 04. of the Unit Price Schedule.

CTP-09. RECORDS AND OBSERVATIONS

Providing the following records and observations shall be a part of the Subcontractor's general responsibility for which no additional payment will be made.

1. A Daily Drilling Report shall be kept on the IADC official Standard Daily Drilling Report. The Unit Price Schedule quantities for pay estimate purpose will be taken from the IDAC Daily Drilling Report. The general remarks section shall contain an accurate record of hole conditions, work performed, and time required for all work to the nearest quarter-hour. The original and two copies of the Daily Drilling Report shall be submitted to the Contractor or his authorized representative.

2. Bit Records shall be maintained daily and posted in the doghouse. A complete bit record shall be furnished the Contractor at the completion of a hole. Records must show bit types, sizes, footages, depths, rotary speeds, bit weights, manufacturer, and serial number.

3. Accurate Pipe Tallies shall be the Subcontractor's responsibility and shall be available at the drill site for inspection at all times. Copies of steel tape measurements of drill pipe and casing shall be furnished by the Contractor.

CTP-10. SUBSURFACE INFORMATION

1. The subsurface information and data furnished both in these specifications and at the Contractor's office are not intended as representations or warranties, but are furnished for information only.

2. It is anticipated that the information contained herein generally represents the conditions that will be encountered in the performance of the Subcontract; however, any interpretation or conclusion reached by the Subcontractor in preparing his Unit Price Schedules will be his sole responsibility.

CTP-11. ACCOMMODATIONS

The Subcontractor will be required to make his own arrangements with his employees for housing and feeding. The Subcontractor may locate toolpusher's house trailer near the drilling location, as designated by the Contractor.

CTP-12. DERRICK MISALIGHMENT

If, at any time, the Subcontractor's derrick becomes misaligned over a hole, the Subcontractor shall be required to commence realignment operations within eight hours of the misalignment. If such misalignment occurs as the result of fault or negligence on the part of the Subcontractor, the Subcontractor shall receive no compensation for the time or cost spent in realignment. If the misalignment is not the fault of, or caused by, Subcontractor negligence, the Subcontractor shall be compensated under Item 2. of the Unit Price Schedule.

CTP-13. LOSS OF HOLE

A hole shall be termed "lost" if the Contractor determines that the condition of the hole will prevent its successful completion, or if for any reason the Contractor deems it impractical to continue drilling. If the Contractor determines that a hole has been lost before required depth has been attained, and that further attempts to complete it will be impractical, he shall order work on the hole stopped, shall investigate the circumstances in contributing to its loss, and shall notify the Subcontractor of his decision in writing. The Contractor may, at his option, order the commencement of work at an alternate location.

Contractor shall assume liability, while work is being performed under Contractor-directed operations, for loss of, damage to, or destruction of the hole, Subcontractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, subs, stabilizers, and bits, unless such loss, damage, or destruction shall be caused by the Subcontractor's fault or negligence.

CTP-14. ABANDONMENT

In the event that, prior to completion of the work required, a hole covered by this Subcontract is abandoned, upon direction of the Contractor, the Subcontractor will be paid for work performed under the applicable items of the Unit Price Schedule.

The term "abandonment" as used in this paragraph shall mean abandonment to suit the convenience of the Contractor, as directed by the Contractor, under conditions which do not come within the scope of the paragraph entitled "Loss of Hole" of these specifications.

CTP-15. STANDARD FOR PRESSURE VESSELS

All Subcontractor's compressed air equipment and accessories shall be designed, fabricated, inspected, and certified in accordance with the SAME Boiler and

Pressure Vessel Code, Section VIII. For equipment fabricated under the 1968 Code, either Division I or Division II (but not both) of the Code may be used.

CTP-16. PRESERVATION OF ANTIQUITIES, WILDLIFE, AND LAND AREAS

Federal law provides for the protection of antiquities located on land owned or controlled by the U. S. Government. Antiquities include Indian graves, or campsites, relics, and artifacts. The Subcontractor shall control the movements of his personnel and his Subcontractor's personnel at the jobsite to ensure that any existing antiquities discovered thereon will not be disturbed or destroyed by such personnel. It shall be the duty of the Subcontractor to report the existence of any antiquities so discovered. The Subcontractor shall also preserve all vegetation except where such vegetation must be removed for survey or construction purposes. Further, all wildlife shall be protected.

CTP-17. RESPONSIBILITY FOR LOSS OF OR DAMAGE TO EQUIPMENT

1. Subcontractor's Surface Equipment. Subcontractor shall be liable at all times for damage to or destruction of Subcontractor's surface equipment including all drilling tools, machinery, and appliances for use above the surface and for any other type of equipment including in-hole equipment when such in-hole equipment is above the surface, regardless of when or how such damage or destruction occurs. The Contractor shall be under no liability to compensate the Subcontractor for any such loss except loss of damage thereto caused by negligence of the Contractor, its agents, or employees.

2. Loss of Tools in the Hole

   a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.

      i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.

      ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor

will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

b. Contractor-Furnished Equipment. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor.

CTP-18. CONTRACTOR MINIMUM EQUIPMENT REQUIREMENTS AND STANDARDS

The following American Petroleum Institute Standards and Recommended Practices of the latest issue, as of the date of bid opening, are a part of these specifications whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structures
3.	API Std. 7	Specification for Rotary Drilling Equipment
4.	API Std. 8A	Specification for Hoisting Equipment
5.	API Std. 9A	Specification for Wire Rope
6.	API RP-5C1	Recommended Practice for Care and Use of Casing, Drill Pipe and Tubing
7.	API RP-9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service
8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

APPENDIX C

RE-ENTRY OF TEST WELL

DOE CONTRACT NO.
DE-AC08-80ET-27081

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
3104 Edloe, Houston, Texas 77027

APPENDIX "C"

SUMMARY OF RIG OPERATIONS

RE-ENTRY OF TEST WELL

Daily Drilling Report Date	Day No.	Operation
4/17/81	1	Prepared location for drilling rig. Started moving in Wilson Brothers Rig No. 8.
4/18/81	2	Moved in rig and started rigging up pumps; generators, and mud tanks spotted.
4/19/81	3	Repairing drawworks.
4/20/81	4	Repairing drawworks.
4/21/81	5	Repairing drawworks. Cut off 9-5/8 inch casing. Dressed casing for wellhead and seal.
4/22/81	6	Repairing drawworks. Cut 13-5/8 inch casing. Lowered bradenhead 3-1/2 inches. Centered 9-5/8 inch casing and started nippling up blowout preventers.
4/23/81	7	Repairing drawworks. Changed "R" seal and tested. Seal failed. Nippled down blowout preventers. Set drawworks and put derrick on stands. Changed "R" seals. Tested wellhead to 4500 psi. Top seals tested okay. Had leak at bottom seal and 12 X 900 inch Series flange. Tightened flange. Pumped pack-off fluid into casing spool. Bottom seal held 3500 psi. Dug out cellar and reconstructed 12 X 900 inch Series base plate and welded to 20 inch pipe.
4/24/81	8	Raised derrick, rigged up floor, and drilled rathole. Nippled up choke manifold and blowout preventers.
4/25/81	9	Tested casing to 3500 psi. Tested Hydril to 3500 psi. Tested blowout preventers, choke manifold, and kill line to 5000 psi. Found leak around stem on 4-1/2 inch pipe rams and on bonnet seal on blind rams at 600 psi. Changed pipe rams and bonnet seal on blind rams. Found leaking grease fitting on 2-inch kill line valve and on both ends of choke line at 2400 psi. Leak at bottom flange on blowout

Daily Drilling Report Date	Day No.	Operation
4/25/81	9	preventers and on weld on choke line at 3400 psi. Leak on both ends of choke line and bottom flange of blowout preventers at 5000 psi. Leak on bottom flange of Hydril at 2800 psi. All leaks repaired. Blowout preventers, choke, and kill system all tested to 5000 psi. Hydril tested and casing tested to 3500 psi. Wellhead tested to 5000 psi.
4/26/81	10	Rigged up Strip-O-Matic. Welded flow line. Picked up 8-3/8 inch mill and 7-inch drill collars. Tagged cement plug at 266 feet. Drilled cement and cleaned out to 3300 feet.
4/27/81	11	Drilled cement and EZSV retainer at 3588 feet. Penetration rate at 3642 feet almost zero. Pulled out of hole. Repaired air line. Recovered junk in mill. Worked on brakes. Went in hole and milled from 3642 to 3643 feet. Found pressure under cement plug. Weight indicator went from 82,000 to 25,000 pounds. Had slight fluid flow. Circulated possible kick (small air or gas bubble). Cleaned hole to 3680 feet. Picked up 4-1/2 inch drill pipe.
4/28/81	12	Picked up 4-1/2 inch drill pipe. Washed and reamed to 11,455 feet. Started pulling out of hole. Installed H_2S detector equipment. Conducted H_2S safety school at crew change.
4-29/81	13	Finished pulling out of hole. Mill disfigured. Waiting on Dia-Log to run casing caliper. Ran casing caliper in 9-5/8 inch casing from 11,390 feet to surface. Cleaned mud pits and waited on bit. Started in hole with J-4 rock bit. Started converting over to oil-base mud.
4/30/81	14	Finished displacing water-base mud with oil-base mud. Drilled cement retainer at 13,312 feet. Picked up additional drill pipe and continued in hole. Circulated bottoms-up. Drilled to 13,913 feet, slugged pipe, and started pulling out of hole.
5/01/81	15	Finished pulling out of hole. Picked up 8-3/8 inch mill. Went in hole with bottom-hole assembly and 23 stands of drill pipe. Cut drill line and hooked up reserve pit pump. Finished going in hole. Drilled cement and retainer from 13,913 to 14,232 feet. Circulated mud. Stagged to 14,500 feet.

Daily Drilling Report Date	Day No.	Operation
5/02/81	16	Washed and reamed from 14,450 to 16,505 feet. Mud weight dropped from 13.8 to 13.3 ppg. Circulated and conditioned mud. Mud weight up to 13.5 ppg. Pipe trying to stick.
5/03/81	17	Pulled out of hole and laid down drill collars. Waited on new bottom-hole assembly. Stacked 7-inch casing in running order. Unloaded new bottom-hole assembly. Picked up new bit and went in hole to 14,000 feet while reaming hole.
5/04/81	18	Washed and reamed from 16,505 to 17,017 feet. Circulated and slugged pipe. Pulled out of hole to liner shoe. Strung up 12 drill lines.
5/05/81	19	Finished stringing up 12 lines. Went in hole to 17,017 feet. Circulated and rigged up lay-down machine. Laid down drill pipe and bottom-hole assembly. Changed blowout preventer rams to run 7-inch casing.
5/06/81	20	Rigged up to run 7-inch casing. Began running 7-inch casing.
5/07/81	21	Finished running 7-inch casing to total depth. Casing string consisted of 227 joints of 32 lb/ft, P-110, FL4S, totalling 9477 feet, and 172 joints of 32 lb/ft, L-80 LT&C modified, totalling 7521 feet. Total casing length 16,998 feet. Float shoe set at 16,998 feet, float collar at 16,911 feet. Torque-turn equipment used for make-up. Centralizers installed on each joint from bottom of casing to 15,000 feet and one very third joint from 15,000 to 13,000 feet. Circulated approximately 800 barrels of mud to clean hole, and reciprocated casing. Cemented casing with 10 barrels APS-1 spacer at 15 ppg, 500 sacks Class H plus 35% SF plus 0.6% CF-6 (Fluids Loss Additive) and 0.3% WR-6 (Retarder) at 15.9 ppg, and 5 barrels APS-1 spacer at 15 ppg. Bumped plug with 2500 psi. Shoe and float held okay. Waited for cement to set. Set casing slips with 420,000 pounds.
5/08/81	22	Waited for cement to set. Nippled down Strip-O-Matic and blowout preventers. Made rough cut on casing. Made final casing cut, installed wellhead, and tested to 400 psi.

Daily Drilling Report Date	Day No.	Operation
5/09/81	23	Nippled up blowout preventers. Loaded out casing tools and Strip-O-Matic. Attempted to test casing to 3400 psi but relief valve shearing at 2800-3000 psi. Pressured up to 2400 psi for one hour and it held okay. Picked up 3 joints of 2-3/8 inch tubing, and tong controls malfunctioned. Torque gauge was not working. Waited for new tongs. Nippled down bell nipple and flow line. Rigged up CRC Wireline lubricator and pressure head. Attempted to run cement bond gamma ray log but gamma ray was not working properly. Went in hole to 2500 feet and collar locator stopped working. Pulled out of hole with logging tool.
5/10/81	24	Ran cement bond and gamma-ray log to 16,920 feet while logging down. Top of cement indicated at 12,300 feet, with good bond across proposed completion zone. Logged 16,900 to 15,800 feet, and tool malfunctioned. Held 2800 psi on casing while logging up the hole. Nippled up bell nipple and flow line. Ran 200 joints of 2-3/8 inch tubing.
5/11/81	25	Finished running 565 joints of 2-3/8 inch, L-80, 0.95 lb/ft tubing to 16,920 feet. Rejected 24 joints which would not drift, one joint short-threaded, and one bent joint. Rigged up Halliburton and tested lines to 7000 psi. Displaced 400 barrels 13.8 ppg oil-base mud with 8.8-ppg saltwater. Maximum pressure reached was 6400 psi. Took on two loads brine water and loaded out two loads oil-base mud.
5/12/81	26	Finished displacing oil-base mud with 8.8-ppg brine. Laid down 10 joints of tubing. Landed tubing at 16,613 feet. Ran CRC 1-5/8 inch by 30-foot gauge to total depth with no obstructions encountered. Cleared oil-base mud from location and loaded out rental equipment. Nippled down blowout preventers and Hydril. Nippled up tubing head. Tree adapter "O" ring failed at 2000 psi. Waited on packing while cleaning mud tanks and laid down swivel.
5/13/81	27	Rigged up Loomis and tested casing to 6000 psi. Tested tubing head to 10,000 psi. Released rig and began rigging down.

Daily Drilling Report Date	Day No.	Operation
5/14/81	28	Loaded out drilling rig except drill pipe and racks and one trailer house.
5/15/81	29	Loaded out drill pipe and racks and rig trailer house. Cleaning location and working on loose boards.
5/16/81	30	Worked on substructure floor in cellar on disposal well.
5/17/81	31	Waiting for orders.
5/18/81	32	Waiting for orders.
5/19/81	33	Begin rebuilding both well cellars and pumping out Well No. 2 ring ditch.
5/20/81	34	Pumped out rig ditch, pits, and cellars. Put in septic tank, cleaned site, and replaced boards.
5/21/81	35	Built new cellar for Well No. 2. Cleaned location and pumped pits.
5/22/81	36	Cleaned location and replaced boards.
5/23/81	37	Cleaned location. Installed christmas tree.
5/24/81	38	Rigged up flow loops, Y-block, and choke manifold. Cut and welded risers to christmas tree. Made x-rays of welds.
5/25/81	39	Completed hooking up production equipment. Had to cut and weld flowline from riser to Y-block. Pressure-tested christmas tree and piping to 7000 psi. Pressured up on casing to 3500 psi prior to perforating.
5/26/81	40	H&G x-rayed new welds and checked Brinnell hardness. CRC Wireline rigged up to run gamma ray and collar locator log. Insulators on tungsten bars burned out at 16,000 feet. Waited for new insulators. Rebuilt connectors on weight bars. Started logging.
5/27/81	41	Gamma-ray tool shorted out. Attempted third run and tool failed. Obtained gamma ray on fourth run. Repaired disposal line. Rigged up to perforate.

Daily Drilling Report Date	Day No.	Operation
5/28/81	42	Perforated 16,730 to 16,750 feet with 4 holes per foot with gun #1. Perforated 16,720 to 16,730 feet with 4 holes per foot with gun #2. Perforated with 3200 psi on casing with gun #1, with no pressure change after perforating. Flowed well. Pressure dropped to 1450 psi and built up to 1750 psi. Flow rate was approximately 300 barrels of water per day. Increased choke size, and pressure dropped to 800 psi and rose to 1200 psi. Pressure finally stabilized at 900 psi at approximately 2700 barrels of water per day. When gun #2 fired, it blew the perforating gun and collar locator off the wireline. Waited for new equipment. Rigged up new rope socket, collar locator, and weights.
5/29/81	43	Rigged up perforating gun. Perforated 16,730 to 16,750 feet with gun #3, with 4 holes per foot for a total density of 8 holes per foot. Started in hole with gun #4. Hit obstruction at 15,823 feet. Stuck perforating gun and worked it free. Pulled out of hole and recovered all perforating equipment. Rigged down CRC and did not attempt to shoot additional 4 holes per foot in interval 16,720 to 16,730 feet. Waited for wireline unit to run in tubing.
5/30/81	44	Rigged up and ran slick line to bottom of perforations at 16,750 feet. Rigged up production equipment.

APPENDIX "C"

CROWN ZELLERBACH WELL NO. 1

REMEDIAL OPERATION OF TEST WELL

Daily Drilling Report Date	Day No.	Operations
6/19/81	1	Ran Cudd wireline gauge to 16,354 feet but could get no deeper. Pulled out of hole and rigged down wireline unit. Cleared location for rig. Started moving in WellTech Rig No. 8. Pumped waste water from Well No. 2 pit to Well No. 1 pit.
6/20/81	2	Rigged up WellTech Rig No. 8. Pumped four barrels 11.6-ppg calcium chloride water down tubing and 20 barrels of 11.6-ppg calcium chloride water down casing. Removed christmas tree and installed 7-1/16 inch 5000-psi blowout preventers. Rigged up floor structure.
6/21/81	3	Finished rigging up. Repaired kill line. Tested blowout preventers. Pulled out of hole with 2-3/8 inch tubing. Replaced brake water line on rig. Finished pulling out of hole. Laid down 8 joints of tubing and recovered McCullough chemical and jet cutters. Started in hole with 2-3/8 inch tubing.
6/22/81	4	Finished going in hole with 2-3/8 inch tubing. Repaired rig hydromatic. Rigged up Cudd wireline and made dummy gun run to 16,700 feet with 1-11/16 inch gauge tool. Rigged down Cudd. Landed 2-3/8 inch tubing. Nippled down blowout preventers and nippled up christmas tree. Rigged up Western and displaced 11.6-ppg calcium chloride water with fresh water. Recovered calcium chloride water for resale.
6/23/81	5	Moved out WellTech Rig No. 8. Rigged up McCullough. Logged bottom of tubing at 16,351 feet. Perforated 16,462 to 16,490 feet with 4 holes per foot. Pulled out of hole and rigged down McCullough.

APPENDIX "C"

Summary of Rig Operations

Martin-Crown Zellerbach Well No. 2

Plugging and Abandonment

TEST WELL

Daily Drilling Report Date	Day No.	Operations
10/24/81	1	Broke out and changed valve and flange on christmas tree and installed choke line to kill well. Rigged up Western and pumped 650 barrels of 12.5-ppg mud to kill well. Shut in well and waited on rig.
10/25/81	2	Rigging up WellTech Rig No. 168.
10/26/81	3	Completed rigging up. Nippled down christmas tree and nippled up 7-inch 5000-psi blowout preventers.
10/27/81	4	Finished nippling up blowout preventers and fabricated bell nipple. Tested blowout preventers, pipe rams, blind rams, choke manifold, and all valves and lines to 250-psi low pressure and 5000-psi high pressure. Tested hydril to 250-psi low and 5000-psi high pressure. Circulated and conditioned mud. Pulled tubing out of hole measuring with wireline.
10/28/81	5	Finished pulling tubing out of the hole. Made up retainer with 25-foot shear sleeve. Went in hole. Laid down 2 bad joints of 2-3/8 inch tubing. Set cement retainer at 16,130 feet and pulled off. Rigged up Western. Mixed 225 sacks, 55 barrels, and squeezed 165 sacks below retainer. Dumped 10 sacks on top of retainer. Reversed out 50 sacks. Pulled out of hole and laid down 20 joints of 2-3/8 inch tubing.
10/29/81	6	Finished pulling out of hole. Nippled down blowout preventers. Rigged up casing pulling jacks. Rigged up Dia-Log. Made junk basket run and set 7-inch bridge plug at 12,400 feet. Rigged down Dia-Log. Nippled up blowout preventers. Picked up blowout preventers to weld casing.

Daily Drilling Report Date	Day No.	Operations
10/30/81	7	Welded 7-inch lifting nipple to 7-inch casing. Nippled up blowout preventers. Rigged up casing jacks and braces. Attempted to test blowout preventers. Tightened bottom flange and retested to 3500 psi. Rigged up casing tongs and laid down machine. Modified hydraulic line to jacks. Rigged up Dia-Log. Went in hole with 7-inch casing jet cutter to 11,800 feet and cut casing. Pulled out of hole and rigged down Dia-Log. Broke circulation. Pumped approximately 15 barrels of mud before obtaining returns. Allowed well to equalize between casing and casing annulus. Picked up joint of 7-inch casing to allow for jack extension. Attempted to jack up casing. Slips would not pull free. Jack stand failed. Leveled jacks and built new brace. Laid down joint of 7-inch casing. Rigged down tongs and started nippling up blowout preventers.
10/31/81	8	Rigged down jacks, broke bolts on blowout preventers, cut casing at casing head, and nippled down blowout preventers. Rigged up jacks on surface, welded casing together and, cut braces for casing jacks. Rigged up Western, pulled 450,000 lb with jacks, but without movement. Heated casing head slips, pulled casing free with 450,000 lb, and started jacking casing. Jacked 29 joints of 7-inch 32 lb/ft casing, with 360,00 lb on jacks.
11/01/81	9	Jacked casing until string weight equaled 265,000 lb, then pulled 7-inch casing with rig. Pulled total of 140 joints of 7-inch casing.
11/02/81	10	Pulling and laying down 7-inch casing. Rigged down casing jacks and welded straps on 7-inch crossover. Picked up and cut same. Continued laying down casing. Finished pulling and laying down casing, total of 274 joints of 7-inch, 32 lb/ft P-110 and L-80 flush joint casing. Rigged down lay-down machine. Nippled up blowout preventers and rigged up floor. Laid down 7 joints of 2-3/8 inch tubing and started in hole with bridge plug.
11/03/81	11	Went in hole with bridge plug and set it at 11,685 feet. Equalized 68 sacks of Class H with 35% SF4, 0.5% WR15 on top of bridge plug. Pulled 10 stands of tubing. Finished pulling out of hole with tubing. Rigged up Dia-Log and shot 4-1/2 inch holes at 2985 feet. Went in hole with 2-3/8 inch tubing.

Daily Drilling Report Date	Day No.	Operations
11/03/81	11	Rigged up Western and established breakdown at 1450 psi at 2-1/2 barrels per minute.
11/04/81	12	Mixed and pumped 200 sacks Class H cement at 2985 feet. Waited for cement to set. Tripped in hole and tagged cement at 2471 feet with 82 joints of 2-3/8 inch tubing. Pulled out of hole and laid down 91 joints of 2-3/8 inch tubing. Rigged up Western. Mixed and pumped 68 sacks of Class H cement with 2% calcium chloride, from surface to 210 feet. Rigged down Western and laid down 7 joints of 2-3/8 inch tubing. Nippled down blowout preventers and loaded out rental equipment. Pumped and dug out cellar to collar to cut casing head and weld plug for top of casing.
11/05/81	13	Rigged down WellTech Rig No. 168. Cleaned mud pits. Cleaned out cellar around casing. Cut off casing below wellhead. Welded 1/2-inch plate to top of 13-3/8 inch casing.

APPENDIX D

RE-ENTRY OF DISPOSAL WELL

APPENDIX "D"

CROWN ZELLERBACH WELL NO. 1

RE-ENTRY OF DISPOSAL WELL

Daily Drilling Report Date	Day No.	Operations
3/26/81	1	Finished moving in rig. Started rigging up.
3/27/81	2	Finished rigging up.
3/28/81	3	Nippled up blowout preventers. Unloaded drill collars and drill pipe handling tools. Rigged up tongs, picked up kelly, and dug rathole and mouse hole. Tested blowout preventers to 1000 psi. Built viscosity to 45 and picked up drill collars. Drilled cement and picked up drill pipe.
3/29/81	4	Drilled cement from 346 to 376 feet. Kelly started moving up hole. Lined up choke manifold and closed Hydril. Attempted to circulate. Changed choke line from blind rams to pipe rams. Failed to circulate. Racked back kelly and pulled out of hole. Recovered plastic around mill. Went in hole with mill to 326 feet and circulated hole clean. Continued in hole with 2-7/8 inch drill pipe. Strapped pipe while picking up pipe. Drilled cement and retainer at 3600 feet.
3/30/81	5	Continued to mill cement from 3648 to 3753 feet. Retainer started falling and was pushed to bottom. Circulated hole clean. Picked up additional drill pipe and went in hole to 6000 feet. Circulated and conditioned hole. Attempted to pull out of hole but had flow back. Pulled out of hole with 8-1/2 inch mill. Picked up cement retainer and went in hole. Set cement retainer at 6000 feet. Tested casing with 1000 psi. Set kelly back and pulled out of hole laying down drill pipe.
3/31/81	6	Continued pulling out of hole laying down 2-7/8 inch drill pipe, 8 drill collars, and kelly. Nippled down and loaded out all pipe and rental tools. Welded extension on 9-5/8 inch casing for pack-off. Landed tubing head and found it would not pull down. Pulled off extension, which was not centered.

Daily Drilling Report Date	Day No.	Operations
4/01/81	7	Removed hanger and shortened 9-5/8 inch casing stub. Installed hanger and tested pack-off to 2000 psi. Checked all flanges. Released rig. Rigged down rig.
4/02/81	8	Moved rig off location.
4/08/81	9	CRC Wireline ran gamma-ray and collar locator log from 5900 to 3500 feet. Perforated disposal zone from 4893 to 4908 feet with 4 holes per foot.
4/09/81	10	Rigged up Halliburton and pumped in at a rate of 1/2 barrel per minute for 20 minutes at 1450 psi. Pumped 1-1/2 barrels per minute for 20 minutes at 1550 psi.
4/10/81	11	Rigged up Halliburton. Pumped out cellar. Acidized well with 20 barrels of clay-fixed water, 2000 gallons FE acid, 3000 gallons HF acid, 20 barrels clay-fixed water. Displaced with 398 barrels of water. Pumped at 1 barrel per minute at 1850 psi prior to acid hitting formation. Started pumping 3 barrels per minute and increased to 6 barrels per minute at 1550 psi at end of acid job.
4/11/81	12	Hooked up flow line to disposal well. Rigged up Halliburton and pumped 310 barrels of brine in well at rate of 6-1/2 barrels per minute at 600 psi. Well went on vacuum. Pulled tree off well. Rigged up CRC to run cement bond log. Went in hole and logged 200 feet. No bond from 5000 to 4800 feet. Completed running log up hole.
4/12/81	13	Completed running cement bond log and rigged down CRC. Hooked up tree and flow line. Began pumping pit into disposal well.
4/13/81	14	Pumping reserve pits to disposal well at 300 barrels per minute at 200 psi.
6/08/81	15	Perforated 4833 to 4893 feet with 4 holes per foot.