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DOE/ET/27081-6 Vol. I

GEOPRESSURED - GEOTHERMAL PROGRAM

DOE/ET/27081--6 Vol. 1

DE82 006124

FINAL REPORT
PRAIRIE CANAL WELL NO. 1
CALCASIEU 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.
3104 EDLOE, SUITE 200
HOUSTON, TEXAS 77027
713-627-9764

DISCLAIMER

FINAL REPORT

PRAIRIE CANAL WELL NO. 1

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

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

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1.0 EXECUTIVE SUMMARY

The Prairie Canal Company, Inc. Well No. 1, approximately 8 miles south of the city of Lake Charles, Louisiana, is the seventh successful test of a geopressured-geothermal aquifer under the DOE Wells of Opportunity program. Eaton Operating Company, Inc. assumed control of the site on October 20, 1980, when Houston Oil and Minerals Corporation abandoned the well as a dry hole at a depth of 15,636 feet.

The well was tested through the annulus between 5-1/2 inch casing and 2-3/8 inch tubing. The interval tested was from 14,782 to 14,820 feet. The geological section was the Hackberry Sand, a member of the Oligocene Frio formation. Produced water was injected into a disposal well which was perforated in several Miocene Sands from 3070 to 4600 feet. The interval tested was not the primary zone in the well. Original plans were to test a section of the Hackberry sand from 14,976 to 15,024 feet. This primary zone, however, produced a large amount of sand, shale, gravel, and rocks during early flow periods and was abandoned in favor of the secondary zone.

Four pressure drawdown flow tests and three pressure buildup tests were conducted during a 12-day period. A total of 36,505 barrels of water was produced. The highest sustained flow rate was approximately 7100 BWPD.

The gas-to-water ratio, measured during testing, ranged from 41 to 50 SCF/BBL. There is disagreement among the contributors to the report as to the saturation value of the reservoir brine, which may be between 43.3 and 49.7 SCF/BBL.

The methane content of the flare line gas averaged 88.4 mole percent. The CO_2 content averaged 8.4 mole percent. Measured values of H_2S in the gas were between 12 and 24 PPM.

The separator's efficiency was independent of brine residence time, for residence times of two minutes or longer. The efficiency is not necessarily an inherent characteristic of the separator hardware; it is mainly a function of brine temperature, gas composition, produced gas/brine ratio, and separator operating pressure. Thermal energy recovery from brine before the separator would improve the quality of gas recovered at any specific separator pressure. Or conversely, in the particular case of a gas having the composition observed at the Prairie Canal well, prior cooling of brine may well increase marketable gas from single-stage separation by 2-4 SCF per barrel of brine.

The original bottom-hole pressure was 12,942 psia, with a corresponding static surface pressure of 6440 psia. The reservoir temperature was 294°F. The highest surface temperature observed during flow was 250°F. The reservoir appeared to be a thin sand zone, restricted by close-by permeability barriers which reduced the flow area to 40°. The permeability to reservoir fluids is approximately 93 millidarcies. Pressure transient analysis indicated that the reservoir was not capable of the high sustained production rates needed for commercial considerations.

The total dissolved solids in the produced brine averaged 43,400 mg/l. Very light scaling and corrosion of the surface equipment was detected. Calcium carbonate scaling would be the predominate treatment problem for long-term production.

Concentrations of mercury in the produced brine averaged 0.79 micrograms per liter. This value is above the 0.10 micrograms per liter upper limit recommended by the U.S. Environmental Protection Agency for protection of aquatic organisms and for human consumption. Concentrations of boron averaged 55 milligrams per liter. This concentration is extremely toxic to plant life. Long-term surface disposal of the produced brine would be precluded because of the mercury and boron concentrations.

It is estimated that over 2700 pounds of formation sand and silt were produced during testing. This well produced more solids than any previous WOO test well. Long-term production would be impossible without sand control at the perforations.

A one-page summary of test data follows on page 1-3.

SUMMARY OF TEST RESULTS

PRAIRIE CANAL COMPANY INC. WELL NO. 1

CALCASIEU PARISH, LOUISIANA

WELL DATA:

Total Depth of Well	15,636 Feet
Formation	Hackberry, Upper Frio
Gross Sand Interval	25 Feet
Net Sand	14 Feet
Perforations	14,782 - 14,820 Feet (8 HPF)
Original Reservoir Pressure	12,942 Psia
Original Reservoir Temperature	294°F
Original Shut-In Surface Pressure	6440 Psia
Average Porosity	22.5% (Log)
Average Permeability	(No sidewall cores)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	43,400 mg/l
Chlorides	24,800 mg/l
pH	6.0

ANALYSIS OF FLARE LINE GAS:

Methane	88.4	Mole Percent
Carbon Dioxide	8.4	Mole Percent
Heavier Hydrocarbons	2.9	Mole Percent
Other	0.3	Mole Percent
Heating Value	949	BTU/SCF
H_2S in Gas	12-24	ppm

TESTS (From 2-21-81 to 3-05-81):

Test No. 1	A 2.51-day reservoir drawdown test, producing 4455 barrels of water, followed by a 0.14-day reservoir buildup period.
Test No. 2	A 1.21-day reservoir drawdown test, producing 4953 barrels of water, followed by a 0.93-day pressure buildup period.
Test No. 3	A 4.00-day flow test, producing 23,202 barrels of water, followed by a 2.00-day buildup period.
Test No. 4	A 1.17-day flow test, during which 3895 barrels of water were produced.

Produced Dry Gas-to-Saltwater Ratio	41 to 50 SCF/STB
Total Water Produced While Testing	36,505 Barrels
Highest Flow Rate Achieved	7100 BWPD
Highest Surface Temperature Observed	250°F
Solids Production	High, rough estimate is 100 to 200 lb per 1000 BBLS
Corrosion	Very light, not measurable
Scaling	Very light, not measurable
Lowest Flowing Surface Pressure Observed	805 psia
Lowest Flowing Bottom-hole Pressure Measured	7031 psia
Test Well Productivity Index	1.94 BBLS per day per psi
Maximum Explored Volume of Reservoir Water	22.4 million barrels
Maximum Distance Explored (BHP Instrument)	4741 Feet
Reservoir	A thin sand zone restricted in drainage area by close-by permeability barriers which reduce the flow area to 40°. The permeability to reservoir fluid is 93 mds.
Disposal Well Gross Perforations	Zone 1: 4490-4600 feet Zone 2: 3070-3130 and 3350-3410 feet
Disposal Well Pressure Range	100-1400 psi

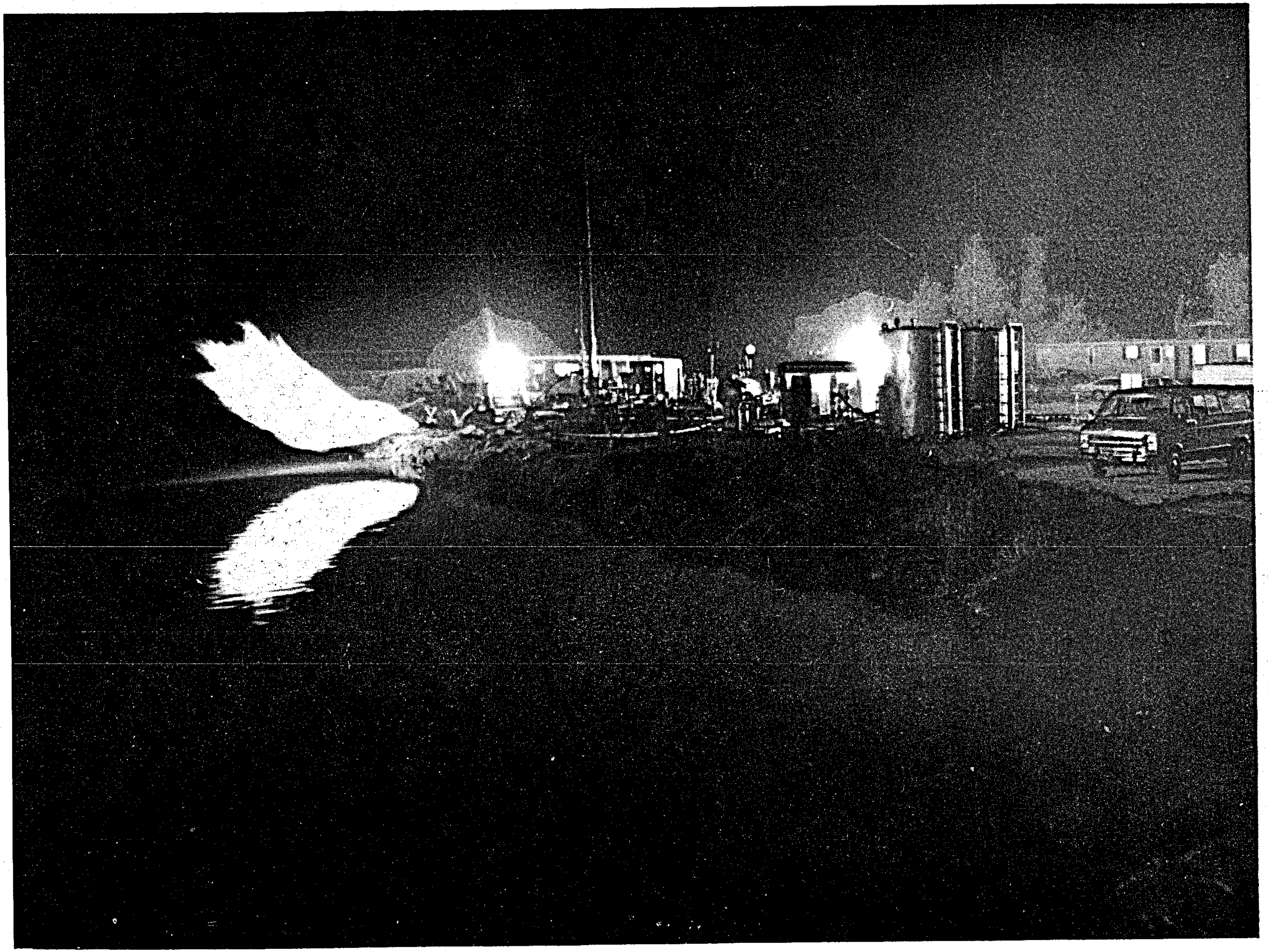


Photo 1-1 Well producing approximately 300,000 ft^3 of gas per day.

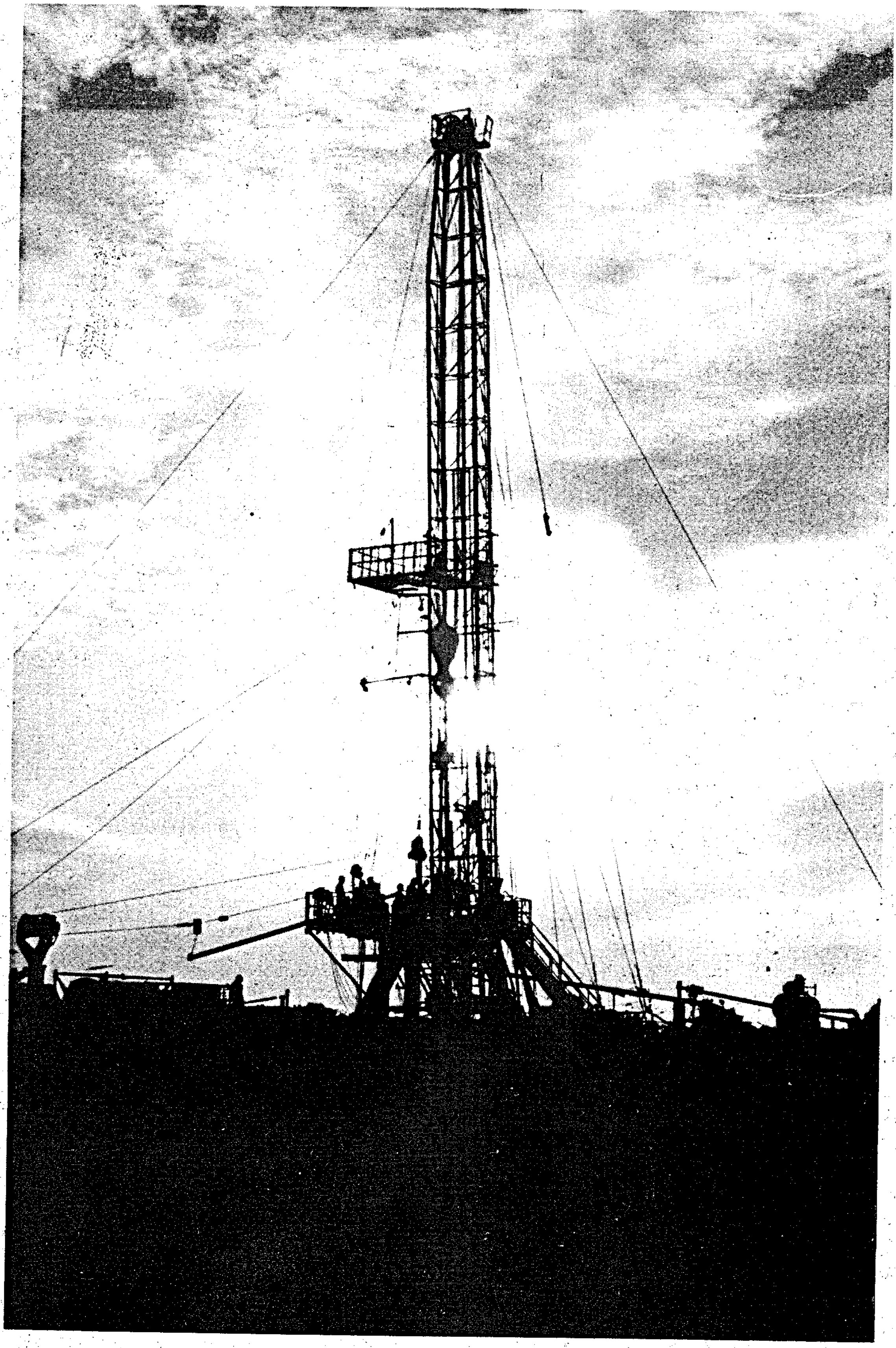


Photo 1-2 WellTech Rig No. 61 performing completion operations on the test well.

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. (Eaton) 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 Prairie Canal Company Well No. 1, acquired for this particular test, was drilled by Houston Oil and Minerals Corporation (H.O.&M.) at a cost of approximately $3.1 million. H.O.&M. temporarily abandoned the well as a dry hole at a depth of 15,636 feet, and offered the well to Eaton for GEO^2 testing. Contracts with H.O.&M. and the landowners were finalized on October 20, 1980, and field operations were initiated on October 24, 1980.

2.2 Location and Geography

The Prairie Canal Company Well No. 1 test site is 8 miles south of Lake Charles, Louisiana, a major city with a population of approximately 92,000. It is an industrial city, the main industries being refining, petrochemical production, and trade.

The specific well location is 2200 feet from the east line and 2300 feet from the north line of section 21, township 11 south, range 8 west, Calcasieu Parish, Louisiana. The terrain is flat and is about 7 feet above sea level. The land is normally used for soybean production.

Exhibit 2-1 indicates the location of the well in relation to other GEO^2 test wells in Louisiana. Exhibit 2-2 is a topographic map of the area.

2.3 Operator Contract and Landowner Agreement

Houston Oil and Minerals Corporation was the operator and principal working interest owner of the test well. Drilling of the well was completed on October 4, 1980. Electric logs and sidewall core analyses indicated no commercial hydrocarbon potential. H.O. & M. agreed to temporarily plug the well so that Eaton could later complete it for a GEO^2 test. Eaton's agreement with H.O.&M. can be found in Appendix "A."

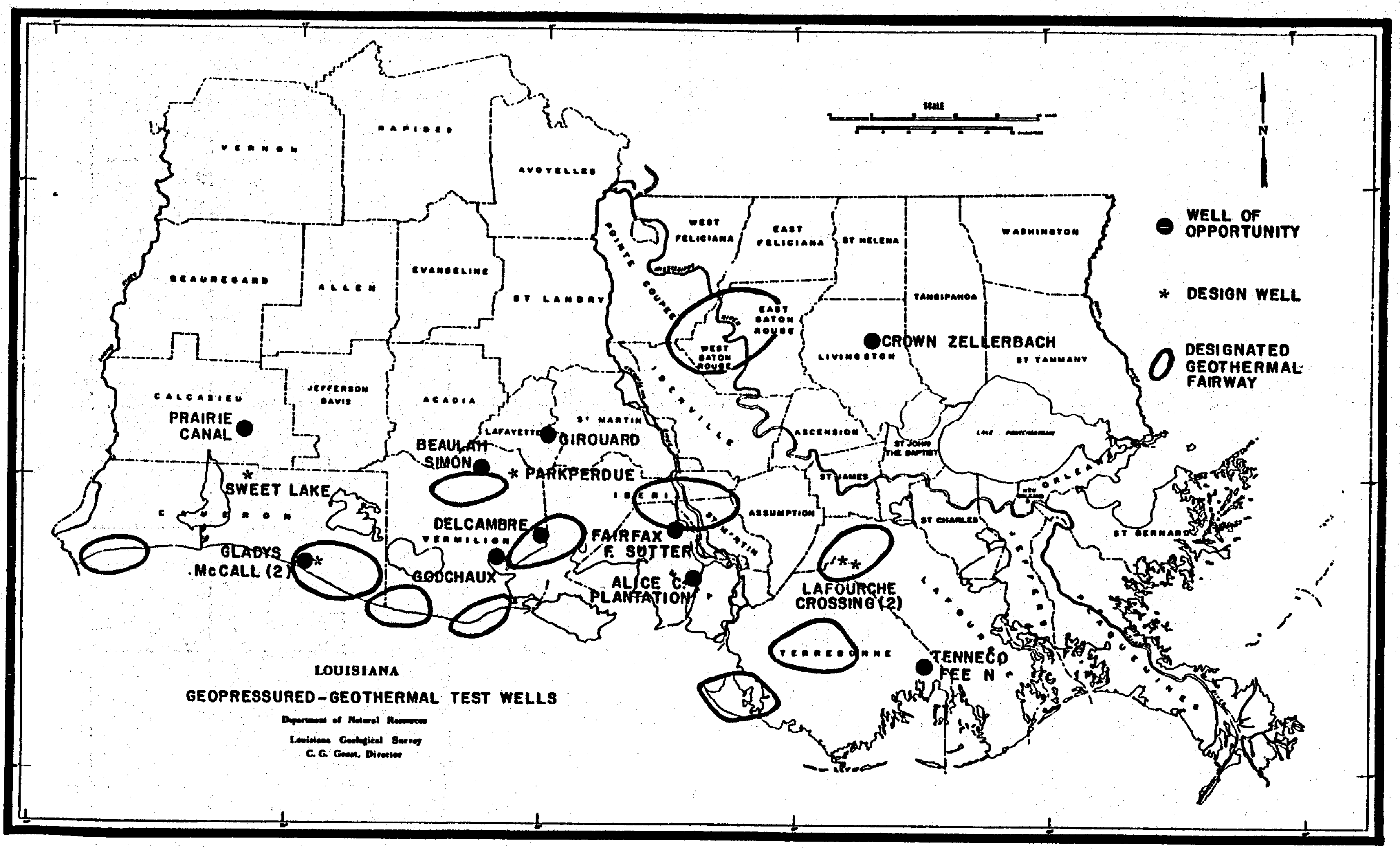
An agreement was also made with the land and minerals owner, Prairie Canal Company, Inc. Permission to drill a disposal well on the site and to conduct testing operations was obtained in a letter agreement with Prairie Canal Company, which is also in Appendix "A."

2.4 Rig Contractor Agreements

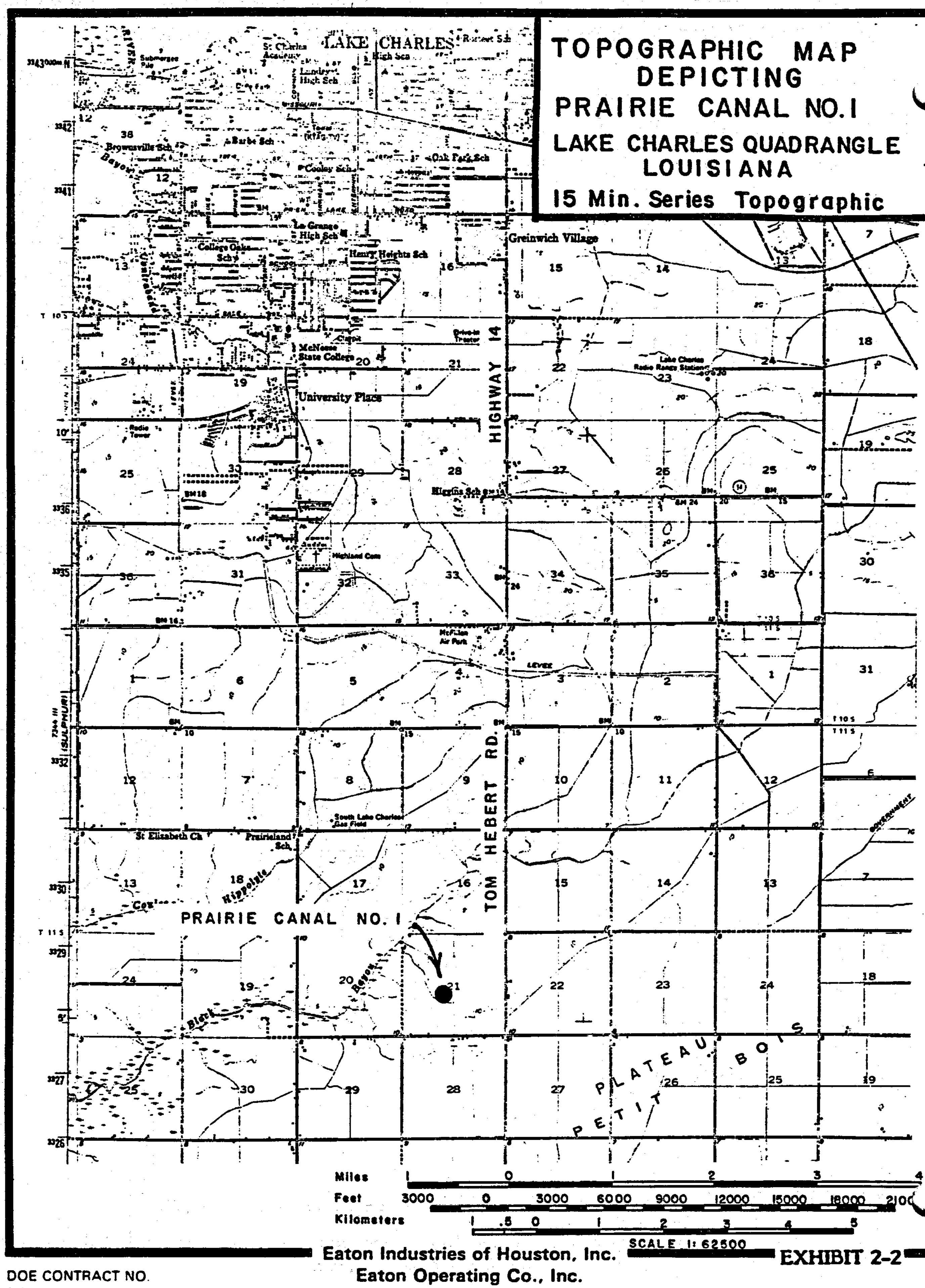
WellTech, Inc. was awarded the contract to complete the test well and drill the disposal well. Rig No. 61 moved onto the location on October 24, 1980 and was released on December 12, 1980. The rig description and partial drilling contract can be found in Appendix "B."

During testing operations, two workovers were required on the test well. The first workover was accomplished using WellTech Rig No. 9 to remove obstructions in the well. The second workover, by WellTech Rig No. 5, was performed to plug the well back to another zone. Descriptions of both rigs and partial drilling contracts are in Appendix "B."

The rig contract for plug and abandonment operations was also awarded to Well Tech, Inc. Rig operations were completed by Rig No. 31 on March 25, 1981. A description of the rig and a partial contract are in Appendix "B."



GEOPRESSURED-GEOTHERMAL TEST WELLS IN LOUISIANA



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

EXHIBIT 2-2

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

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 Prairie Canal Company Well No. 1 test in particular, are to obtain accurate, reliable, short-term information concerning the following:

A. The aquifer fluid properties, including in-situ temperature, chemical composition, hydrocarbon content, and pressure.

B. The characteristics of geopressured-geothermal reservoirs, including permeability and porosity, extent and distribution of sands and shales, degree of compaction, and rock composition.

C. 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.

D. The evaluation of completion techniques and production strategies for geopressured-geothermal wells.

E. 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 Houston Oil & Minerals Corporation, Prairie Canal Company, Inc. No. 1 Well was tested in the Hackberry sand. This sand is a member of the Oligocene Frio formation.

The Hackberry sand is present in southeast Texas and southwest Louisiana in an area designated the Hackberry embayment (Berg and Powers, 1980). The Oligocene Frio Hackberry embayment is filled by a southward thickening wedge of sediment which contains a deep water fauna and extends from Acadia Parish, Louisiana, to Chambers County, Texas (Benson, 1971).

The Hackberry embayment can be divided into two parts. The upper section ranges in thickness from zero to more than 3000 feet and consists of shale containing an outer-neritic (deep water) microfaunal assemblage. Several thin, erratically distributed lenticular sandstone bodies are present. The lower section ranges in thickness from zero to 700 feet and consists primarily of sandstone (Paine, 1968).

The lower Hackberry sandstones were the first reservoirs in the Gulf Coast to be recognized as turbidites. A distinctive assemblage of deep marine origin, the Hackberry microfauna greatly aided in designating the Hackberry sandstones as turbidites. It is believed that these turbidites were deposited in a submarine channel which was controlled by an erosional surface and later filled by channel sands and overlying outer-shelf and upper-slope shales (Berg and Powers, 1980).

4.2 Local Geology

The geopressured-geothermal test well is located in South Lake Charles field. Paleontological studies were used in the determination of this Hackberry sand in the Prairie Canal No. 1 Well (Exhibit 4-1). Ammonbaculites nummus and Gyroidina scalata define the top of the Hackberries, whereas the base is defined by the presence of Nonion struma. Nodosaria blanpiedi is the next lower zone represented (Berg and Powers, 1980).

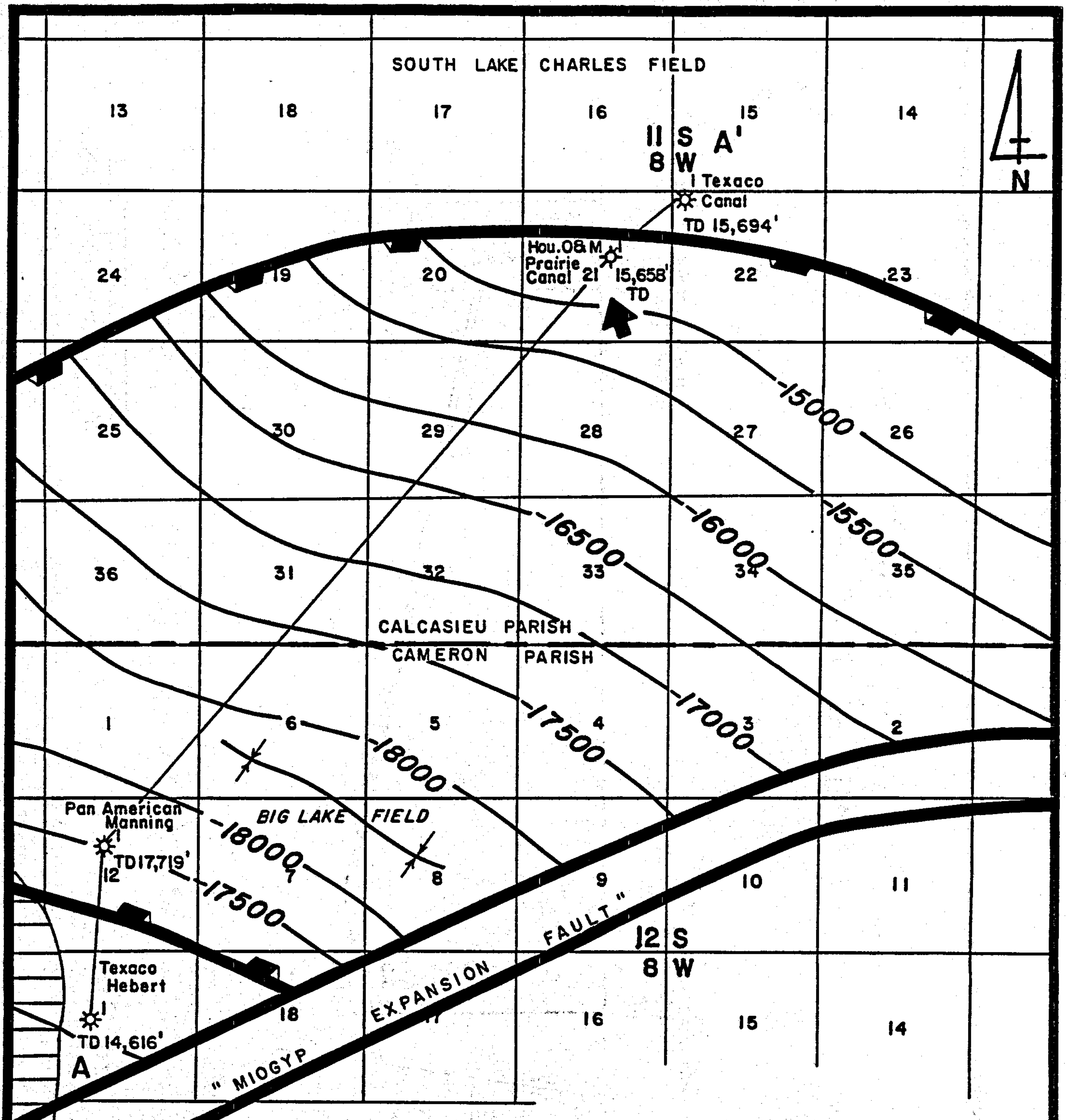
Approximately four miles to the south of the Prairie Canal No. 1 Well, there is a well-known "Miogyp Expansion Fault" extending from approximately Section 18, Township 12S and Range 8W in Cameron Parish, easterly toward Section 33, Township 11S and Range 7W in Calcasieu Parish, Louisiana. Between this southern "Miogyp Expansion Fault" and a small fault immediately north of the candidate well, there appears to be no major faulting, based on analysis of proprietary seismic data. The well penetrates the north flank of an east-west trending fault structure with an expansive drainage area dipping toward the south (Exhibit 4-2 and 4-3).

HOUSTON OIL AND MINERALS

PALEO IDENTIFICATION

PALEONTOLOGICAL SUMMARY PRAIRIE CANAL #1

9,100'	FIRST SAMPLE (in Anahuac)
9,520'	DISCORBIS GRAVELLI
10,000'	BOLIVINA PERCA (low)
10,540'	MARGINULINA HOWEI
10,840'	CAMERIAN (A) PAUNA
11,920'	CYCLAMMINA SPECIES
12,070'	CRISTELIARIA (H)
12,580'	HACKBERRY (poorly developed)
13,030'	HACKBERRY (good)
13,330'	UVIGERINA CANARYENSIS
13,570'	BULIMINA VAR. JACKSONENSIS
15,460'	NODOSARIA BLANPIEDI & DISCORBIS (D)
15,634'	LAST SAMPLE (Vicksburg not reached)



HOUSTON OIL & MINERALS
PRAIRIE CANAL NO. 1
STRUCTURE CONTOUR MAP
HACKBERRY SAND
South Lake Charles Field
Calcasieu Parish, Louisiana
Contour Interval: 500'
Scale 1" = 1 Mile

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

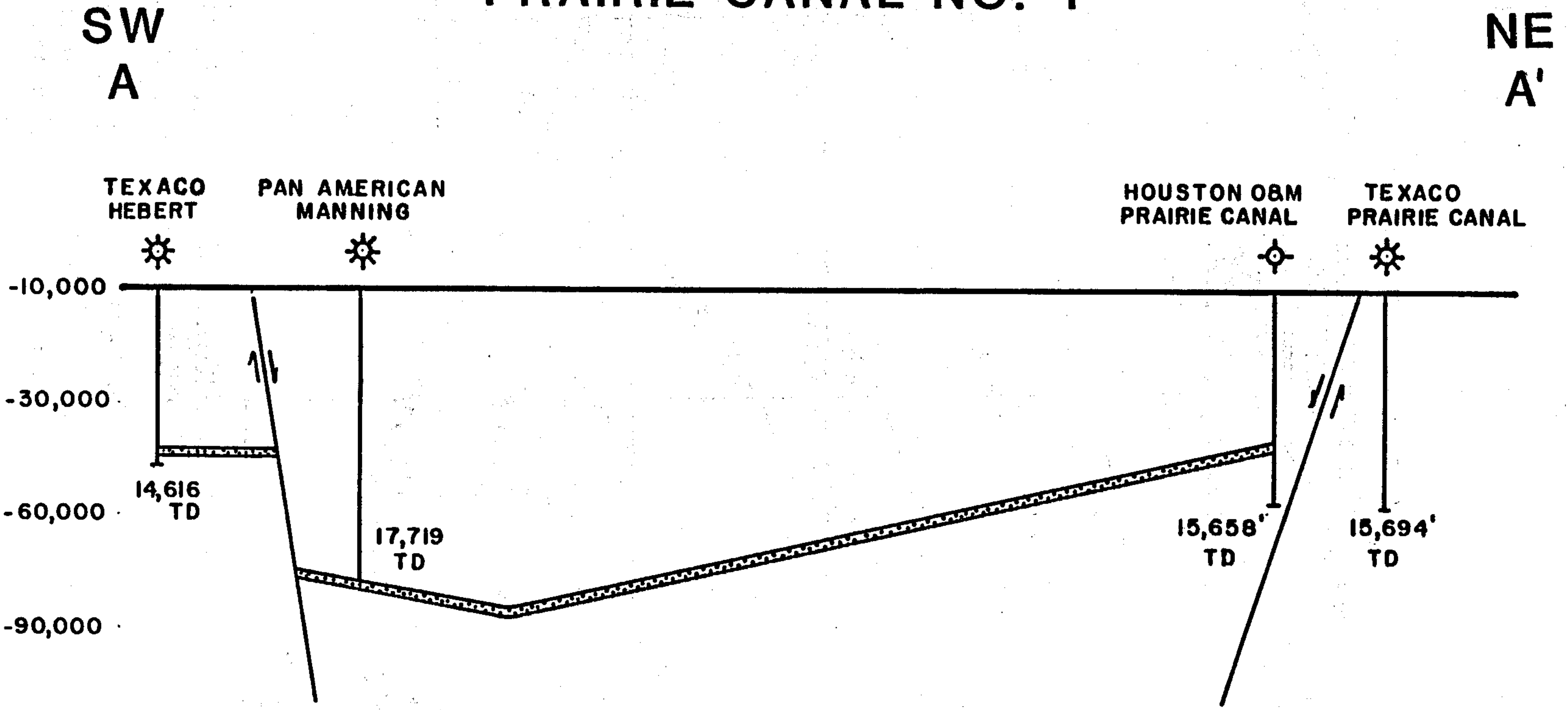
EXHIBIT 4-2

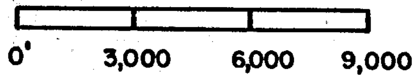
DOE CONTRACT NO.
DE-AC08-80ET-27081

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

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

HOUSTON OIL & MINERALS
PRAIRIE CANAL NO. 1





CROSS-SECTION
HACKBERRY SAND
TEST ZONE 14,782 - 14,822
SOUTH LAKE CHARLES FIELD
CALCASIEU PARISH, LA

EXHIBIT 4-3

5.0 PETROPHYSICS

5.1 Open Hole Log Analysis - Test Well

Houston Oil & Minerals Corporation conducted several logging surveys for hydrocarbon evaluation during the drilling of their Prairie Canal No. 1 Well. The logs were made available to Eaton for use in reservoir evaluation for the DOE's Wells of Opportunity program upon the determination that the well was a non-producer of hydrocarbons. The following logs were used in the evaluation of Eaton's target reservoir:

1. ISF/Sonic Log - 1-inch (Exhibit 5-1)
2. ISF/Sonic Log - 5-inch (Exhibit 5-2)

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

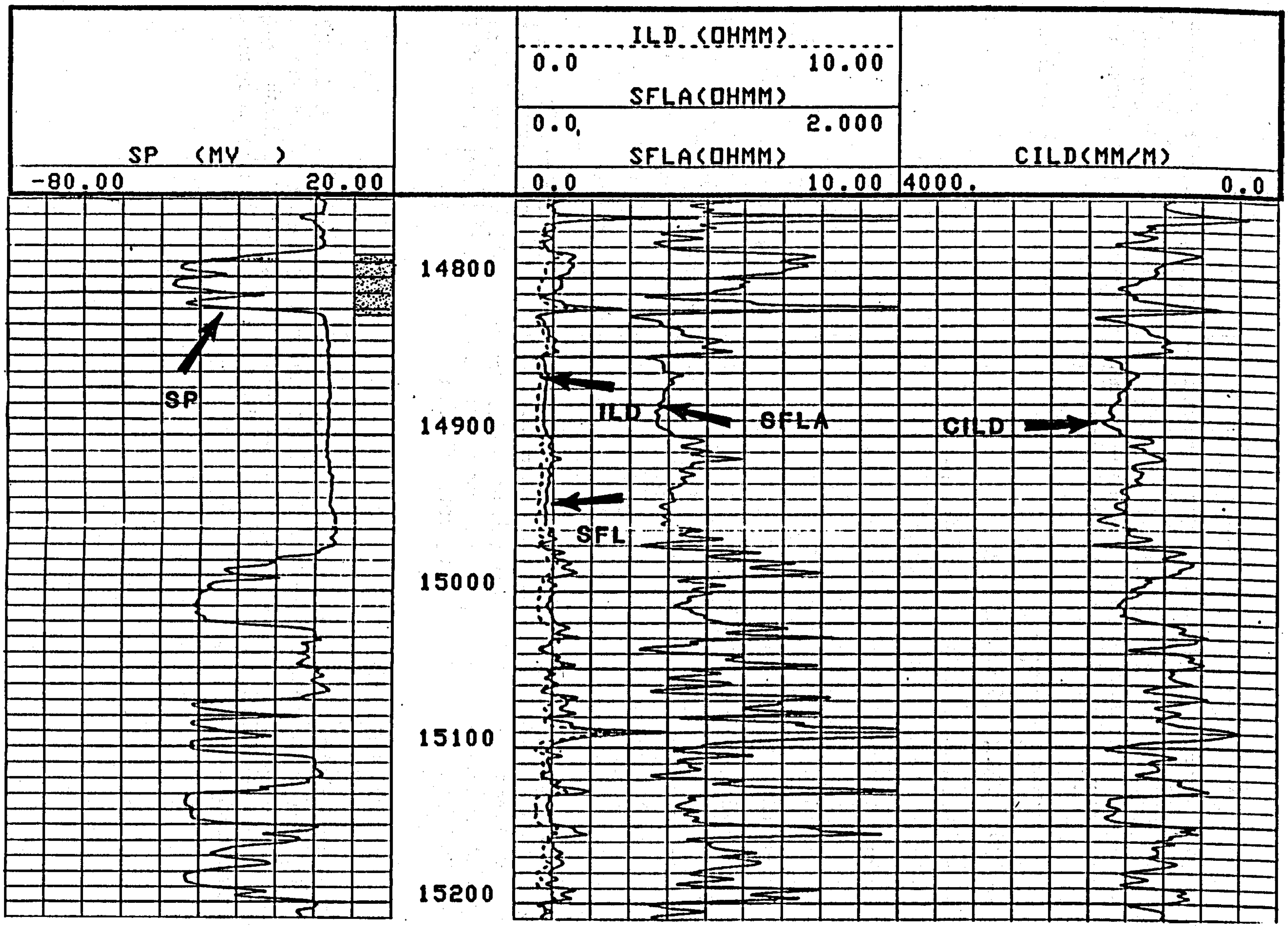
1. Spontaneous Potential
2. Gamma-Ray
3. Induction
4. Sonic Time Travel
5. Computed Apparent Water Resistivity

5.1.1 Porosity

The mean porosity of the net pay sand was 22.5%, with a range of 12% to 29%. These values were determined from the Sonic Log (Exhibit 5-2) and the Welex "Compaction Correction Chart" (Exhibit 5-3). The porosity value was obtained by a sampling of the sonic travel time on a two-foot interval basis. An observed sand travel time of 90 microseconds/ft was used in the porosity determination.

5.1.2 Sand Thickness

The gross sand thickness of the geopressured-geothermal test zone interval, 14,782-14,822 feet is 40 feet. The net sand thickness is estimated to be 30 feet. This value is based upon analysis of the Gamma-Ray Log. A cutoff point of 40 "API Gamma-Ray Units" was used. All given sand between 0 and 40 "API Gamma-Ray Units" was counted as net sand (Exhibit 5-4).

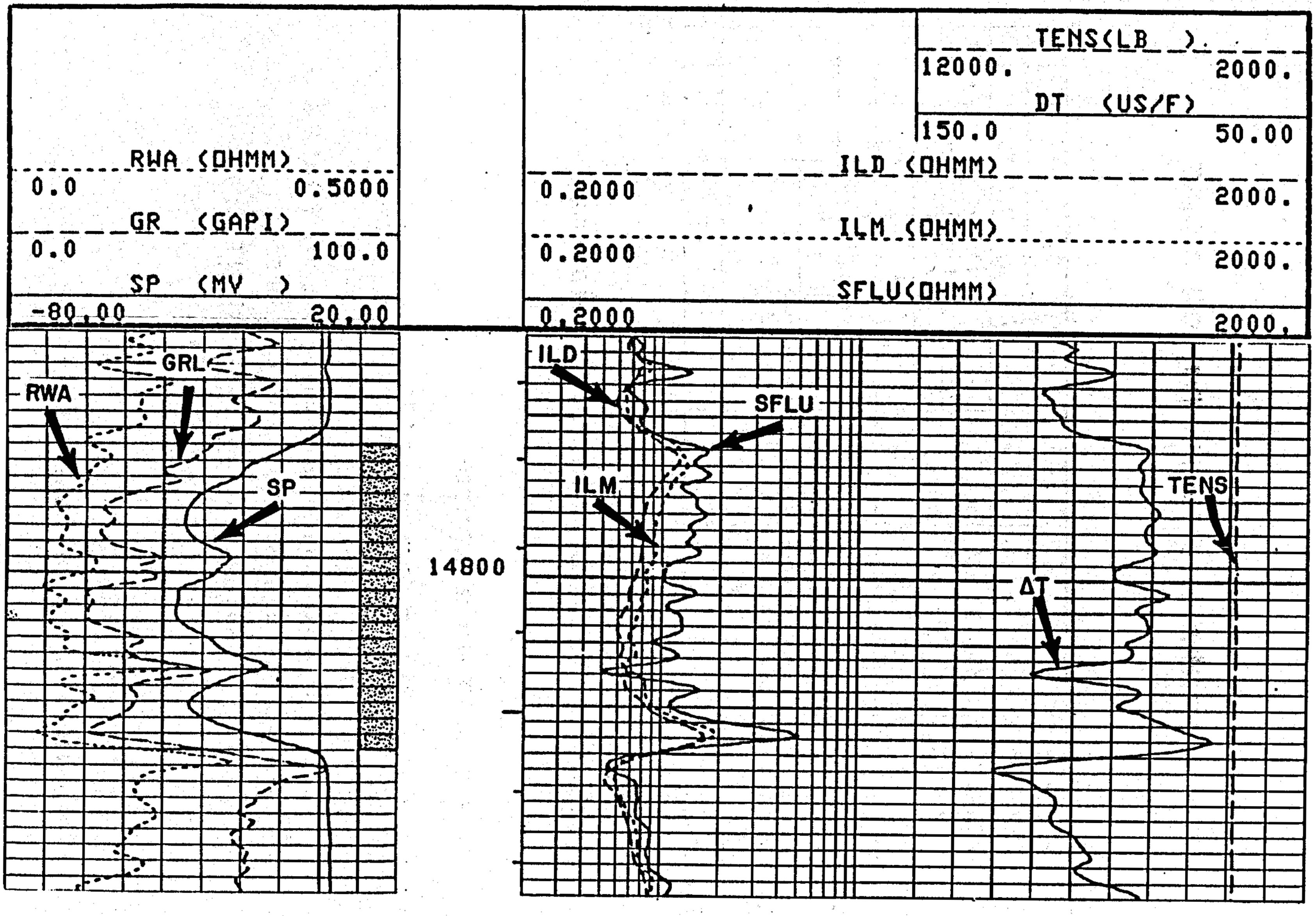


ISF/SONIC LOG-HACKBERRY SAND
PRAIRIE CANAL NO. 1

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

EXHIBIT 5-1

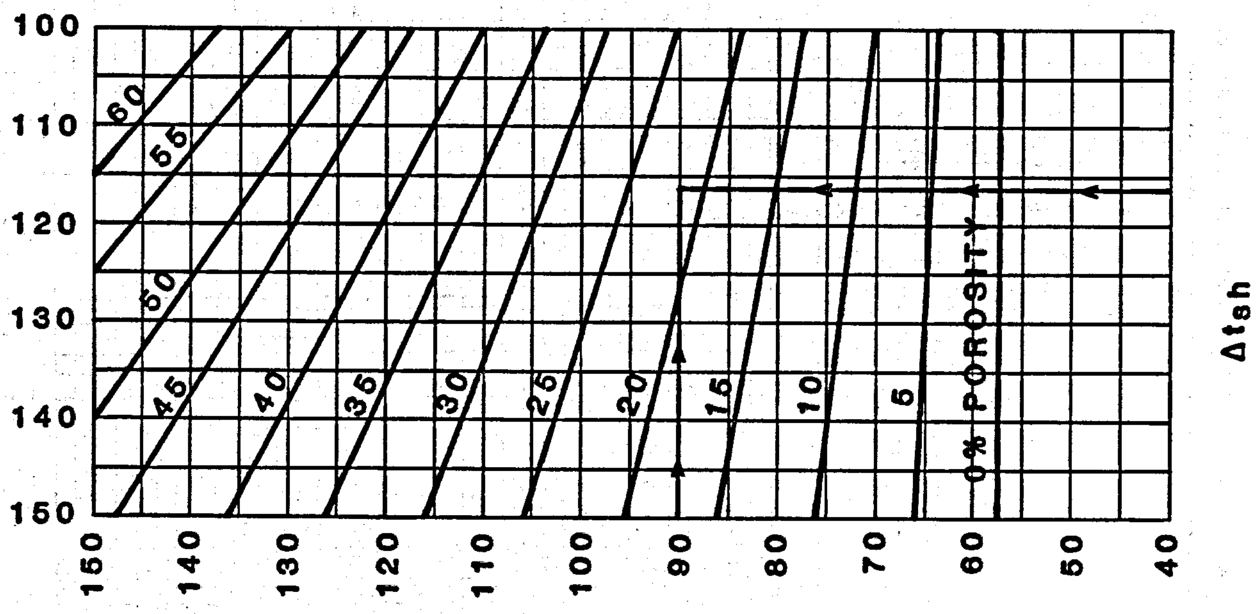
EXHIBIT 5-2



ISF/SONIC 5 INCH LOG - HACKBERRY TEST SAND

PRAIRIE CANAL NO. 1

COMPACTION CORRECTION CHART



TRANSIT TIME (Δt) IN MICROSECONDS PER FOOT

EQUATION GRAPHED:

$$\phi = \left[\frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_m}\right] \frac{100}{\Delta t_{sh}}$$

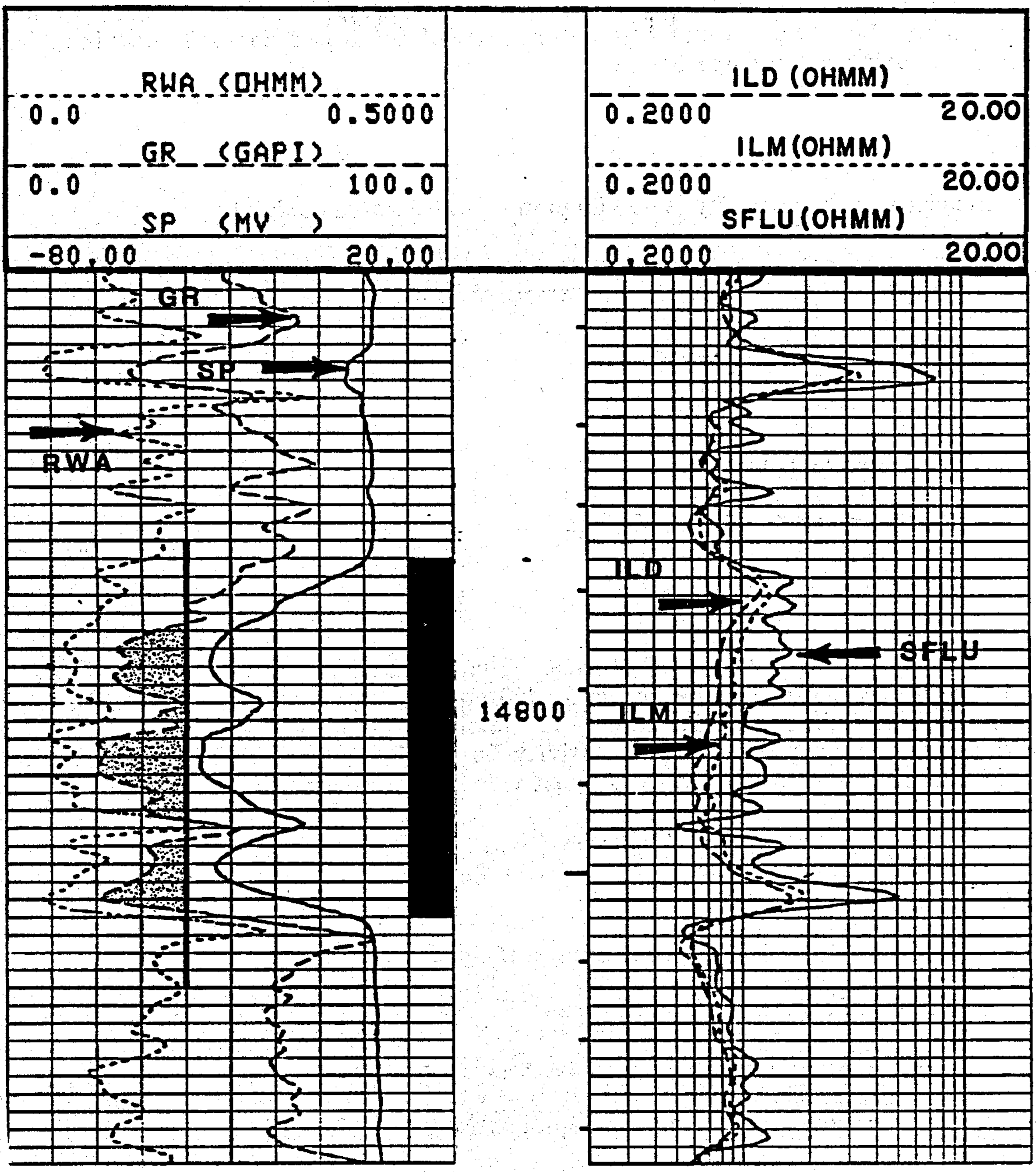
Δt_{sh} = ACOUSTIC TRANSIT TIME IN SHALES NEAR ZONE OF INTEREST

Δt_{ma} = MATRIX ACOUSTIC TRANSIT TIME, MICROSECONDS/FOOT

APPLICATION:

WHEN: $\Delta t_{ss} = 90$ AND $\Delta t_{sh} = 116$

THEN: $\phi = 22.5\%$



ISF/SONIC LOG HACKBERRY TEST ZONE

NET SAND CONTENT

EXHIBIT 5-4

5.1.3 Permeability

The permeability calculated from the drawdown of the reservoir test is 93 millidarcies. Permeability estimates of the geopressured-geothermal test zone were not available prior to the flow test. Conventional or sidewall cores had not been obtained from the test zone during drilling operations.

5.1.4 Salinity

The measured water salinity is 43,400 ppm (total dissolved solids).

The estimated formation water salinity based upon log analysis ranges from 37,000 ppm to 68,000 ppm. These values were determined using the following methods:

1. Conventional SP Method
2. R_{wa} Method
3. Dunlap's "K_f" Method
4. Conductivity - Salinity Method
5. Shale Resistivity Method

5.1.4.1 **Conventional SP Method:** The estimated salinity using the Conventional SP (spontaneous potential) method is 37,000 ppm. This value was determined by solving for formation fluid resistivity using the maximum SP value from the induction log and then plotting it on the Welex "Resistivity Salinity" graph (Exhibit 5-5). The equation used in determining formation fluid resistivity is as follows:

$$SSP = -(60 + 0.133T_f) \log R_{mf}/R_{we} \quad \text{(Equation 1)}$$

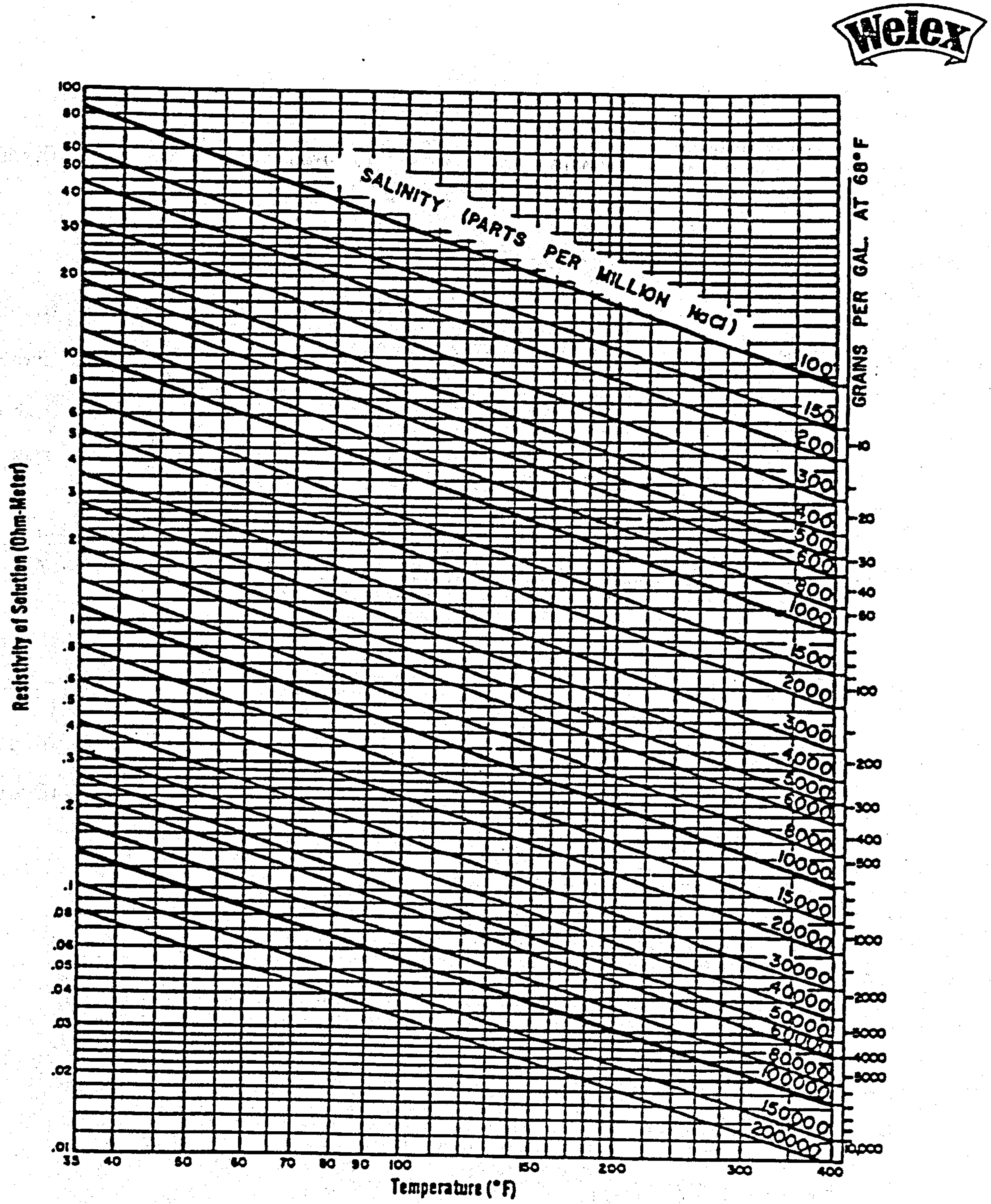
where:

SSP = Static spontaneous potential - millivolts

T_f = Formation temperature - °F

R_{mf} = Resistivity of mud filtrate - ohm-m

R_{we} = Equivalent formation fluid resistivity - ohm-m



RESISTIVITY — SALINITY — TEMPERATURE CHART

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

EXHIBIT 5-5

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

and

Maximum SP (uncorrected)	=	-40 mv	
Corrected SSP	=	-40 mv	(Exhibit 5-6)
Temperature	=	294° F	
R_{mf}	=	0.49 ohm-m at 70°F	
R_{mf}	=	0.13 ohm- at 294°F	(Exhibit 5-5)
R_{we}	=	0.05 ohm-m	(Exhibit 5-7)
R_w	=	0.05 ohm-m	(Exhibit 5-8)
Salinity	=	37,000 ppm	(Exhibit 5-5)

5.1.4.2 R_{wa} Method: An estimated salinity of 42,500 ppm was calculated using the R_{wa} Method and was primarily determined as a function of porosity and true formation resistivity. The mathematical applications follow:

$$F = R_o/R_w \qquad \text{(Equation 2)}$$

$$F = .81/\phi^2 \qquad \text{(Equation 3)}$$

$$R_o/R_w = .81/\phi^2 \qquad \text{(Equation 4)}$$

$$R_w = R_o\phi^2/.81 \qquad \text{(Equation 5)}$$

where:

F = Formation factor - dimensionless

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

R_t = True formation resistivity - ohm-m

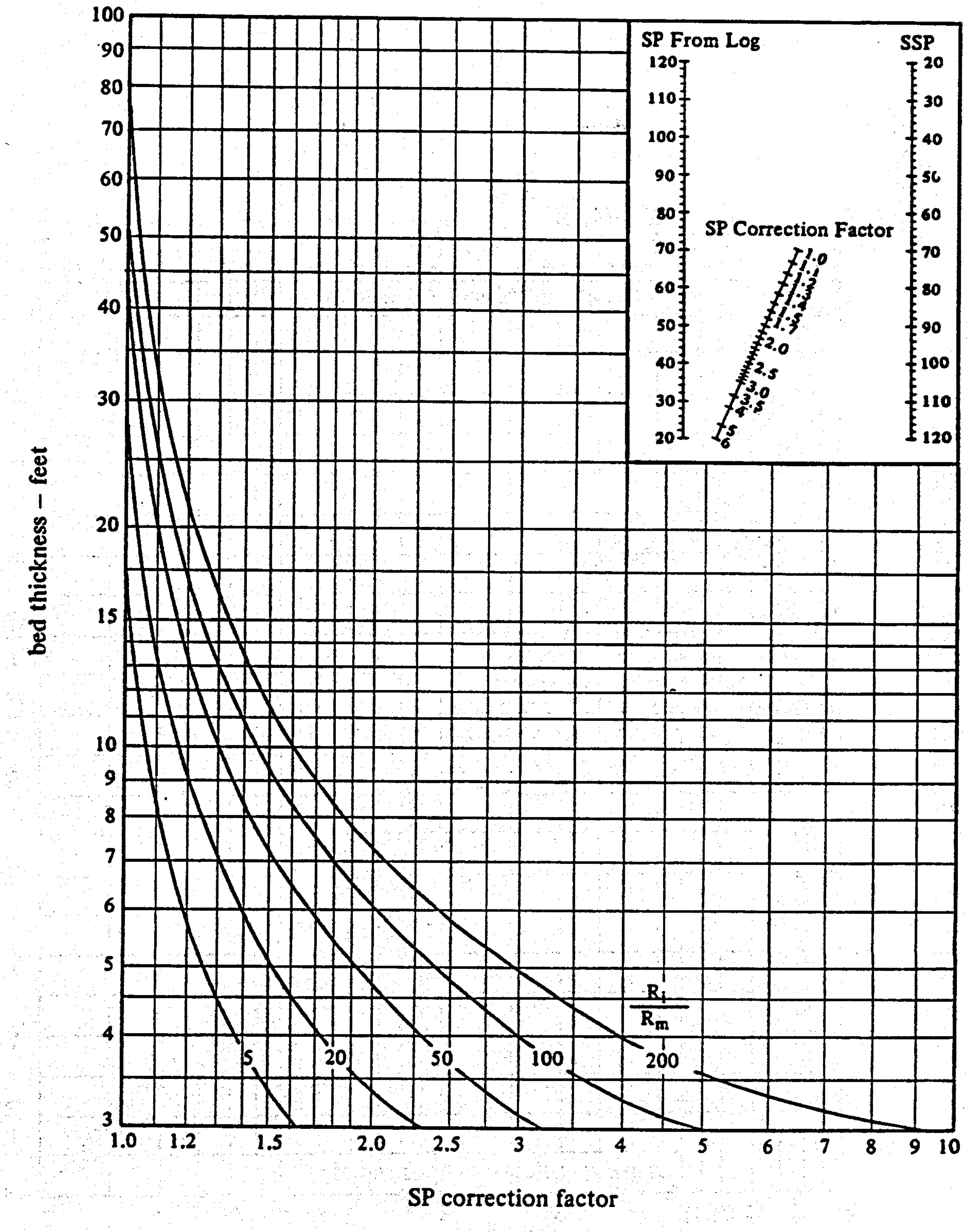
R_w = Formation water resistivity - ohm-m

ϕ = Porosity (%)

and:

R_t = 0.7 ohm-m

ϕ = 22.5%



SP CORRECTION CHART — DRESSER ATLAS

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

EXHIBIT 5-6

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

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

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

SP—Temperature—Rmf/Rwe Chart

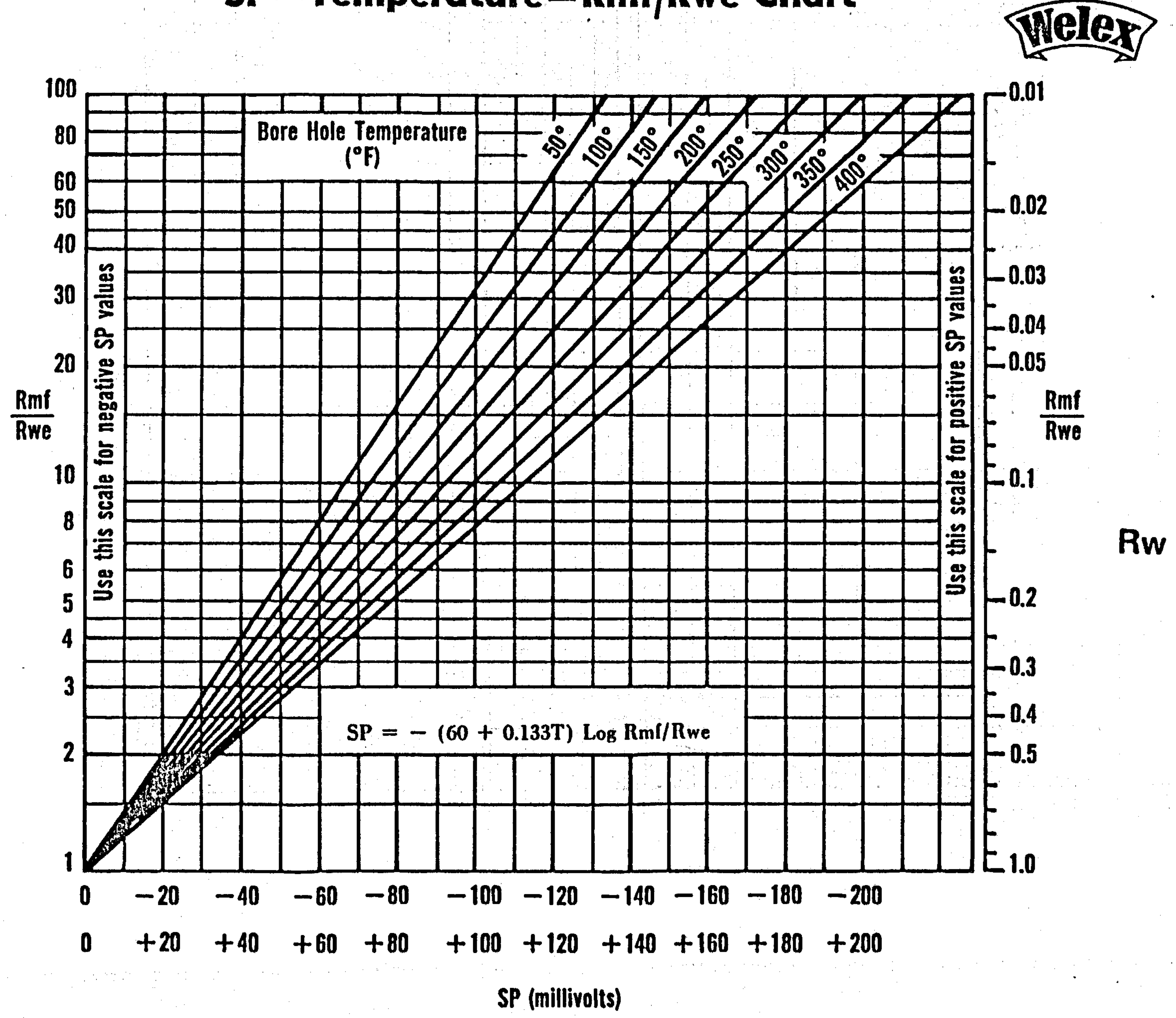
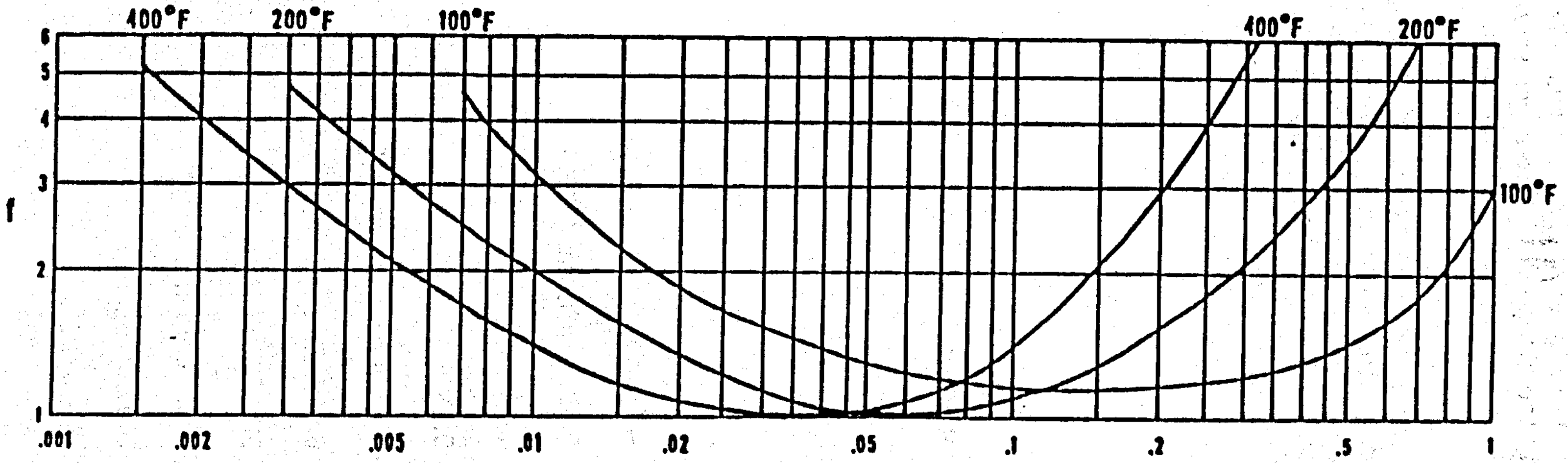


EXHIBIT 5-7

Rwe Correction Chart



($Rw = f \times Rwe$)

APPLICATION

From Exhibit 5-7

When: SP = −40mv

T = 294°F

Rmf = .13 ohm-meter

Then: Rmf/Rwe = 2.6

and Rwe = .13 ÷ 2.6 = .05 ohm-meter

Using this Exhibit, f = 1

Then: Rw = 1 x .05 = .05 ohm-meter

Assuming a 100% water-saturated formation, where $R_t = R_o$, and assuming Equation 5 and the previously listed log-derived parameters, an apparent formation water resistivity of 0.044 ohm-m is obtained. Plotting the formation water resistivity on the Welex "Resistivity Salinity" graph (Exhibit 5-5) yields a salinity of 42,500 ppm.

5.1.4.3 **Dunlap's "K_f" Method:** Using Henry Dunlap's "K_f" Method, an estimated salinity of 47,000 ppm was calculated. This value was calculated by obtaining a corrected R_{mf} using Dunlap's $K_f = R_{mf}/R_m$ vs. mud weight, the Geologic Age Salinity Correction Chart I, and the Salinity Correction Chart II (Exhibits 5-9, 5-10, and 5-11). The equations used in correcting R_{mf} are as follows:

$$K_f = R_{mf}/R \qquad \text{(Equation 6)}$$

Solving for R_{mf}:

$$R_{mf} = K_f R_m \qquad \text{(Equation 7)}$$

where:

R_{mf} = mud filtrate resistivity - ohm-m

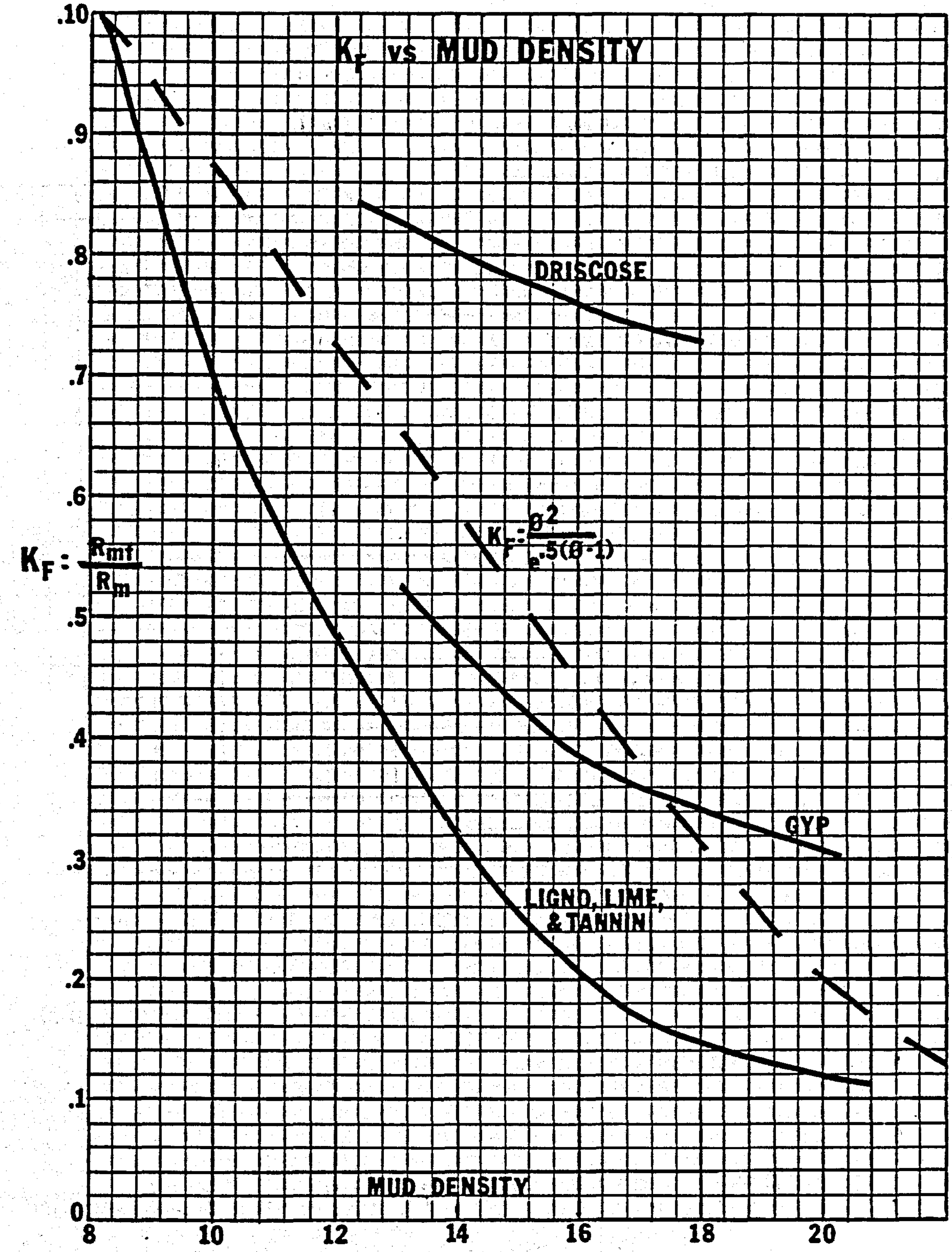
R_m = mud resistivity - ohm-m

K_f = constant - dimensionless

MD = mud density - ppg

and:

SP (corrected)	=	-40 mv	
R_m (uncorrected)	=	0.99 ohm-m at 70°F	
MD	=	17.3 ppg	
K_f	=	0.16	(Exhibit 5-9)
R_{mf}	=	0.1584 ohm-m at 70°F	(Equation 7)
R_{mf}	=	0.043 ohm-m at 294°F	(Exhibit 5-5)
R_{we}	=	0.017 ohm-m	(Exhibit 5-7)
R_w	=	0.022 ohm-m	(Exhibit 5-8)
Salinity (uncorrected)	=	100,000 ppm	(Exhibit 5-5)
Salinity (corrected I)	=	60,000 ppm	(Exhibit 5-10)
Salinity (Corrected II)	=	47,000 ppm	(Exhibit 5-11)



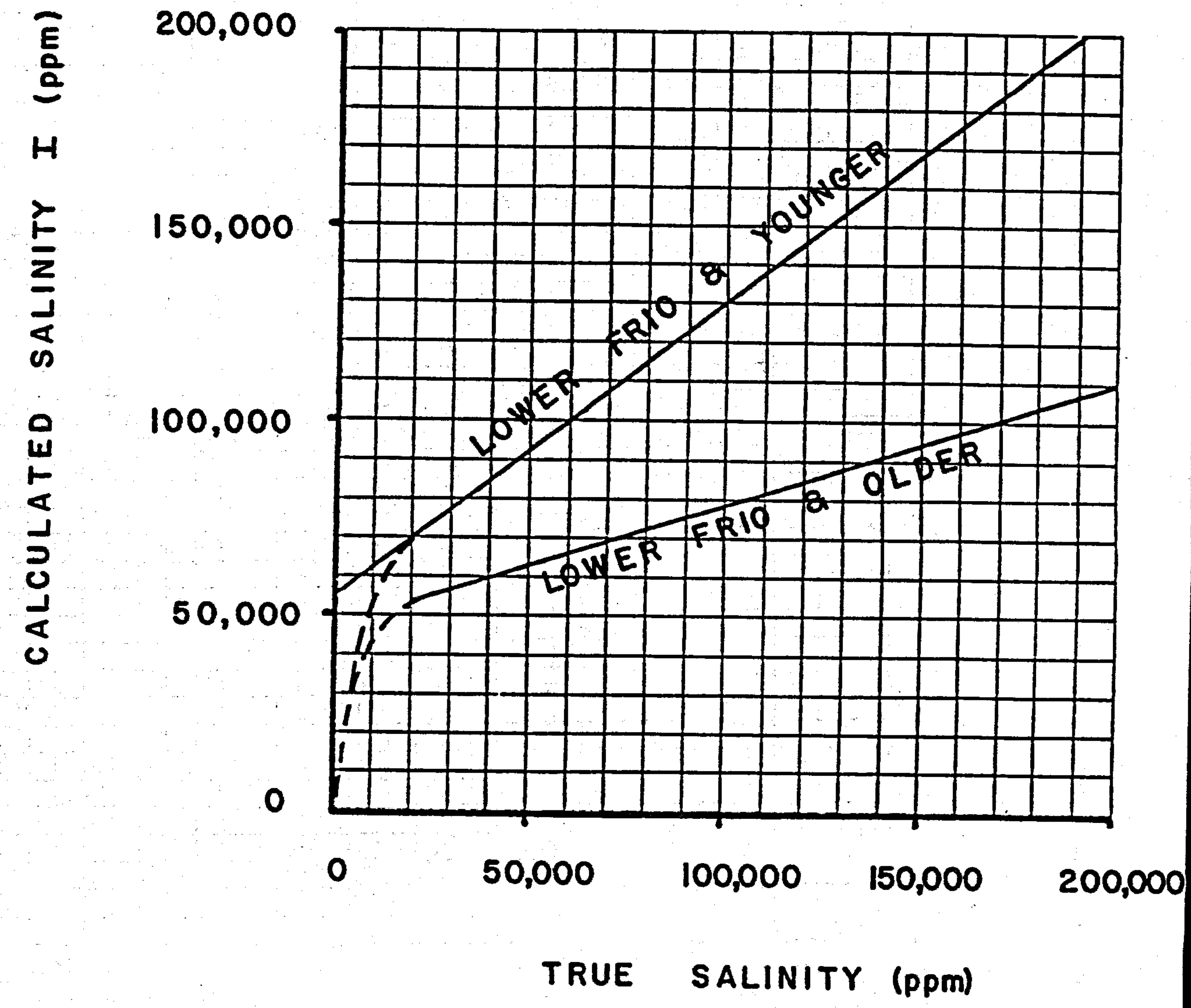
MUD RESISTIVITY CORRECTION CHART

H. F. DUNLAP — AUGUST 1980

Eaton Industries of Houston, Inc. EXHIBIT 5-9

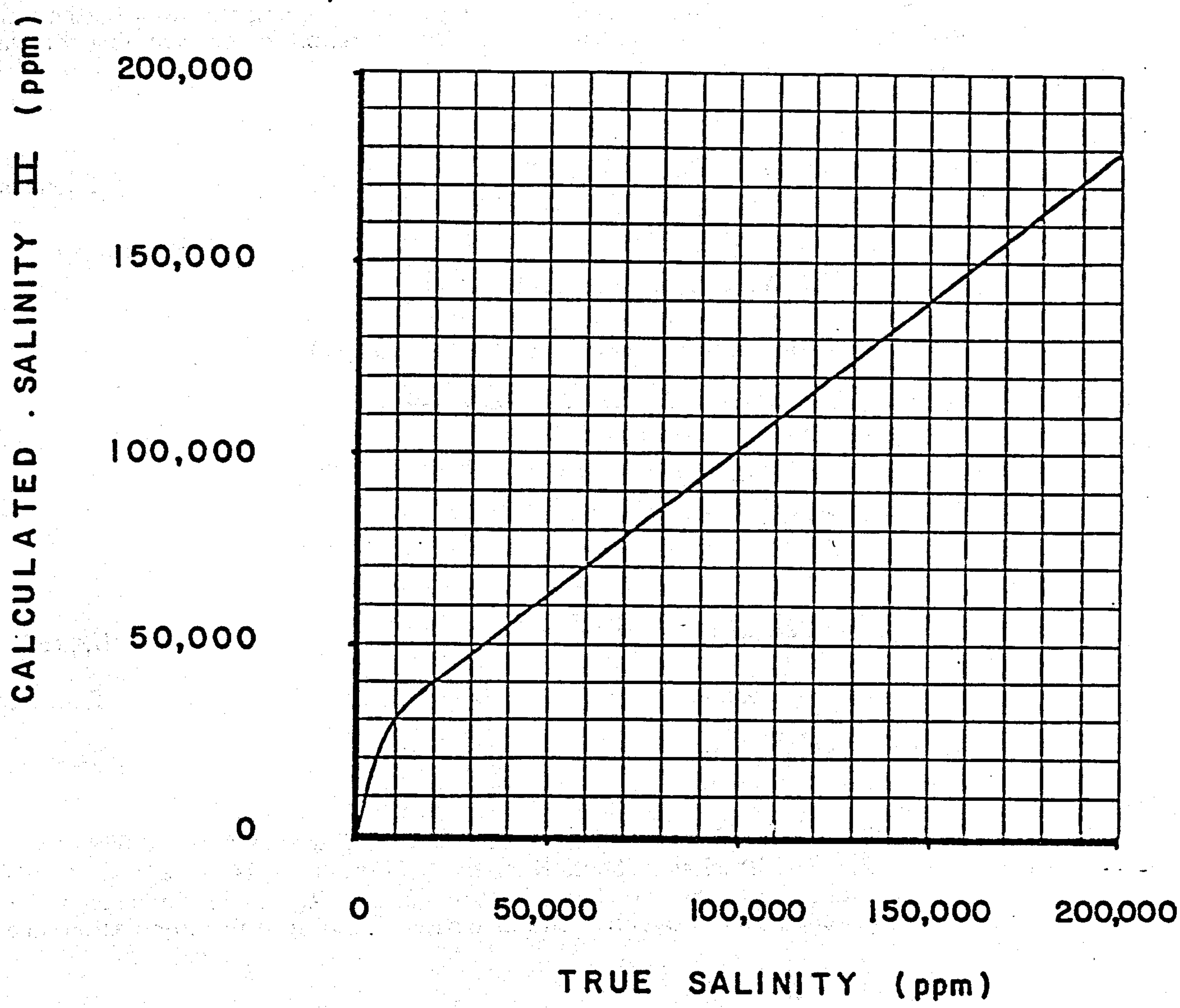
Eaton Operating Co., Inc.

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



GEOLOGIC AGE SALINITY CORRECTION

H.F. DUNLAP , FEBRUARY 1981



SALINITY CORRECTION CHART II

H.F. DUNLAP - MARCH 1981

5.1.4.4 **Conductivity-Salinity Method:** A salinity of 44,000 ppm was calculated using the Conductivity-Salinity Method, which is a variation of the R_{wa} Method. In this approach true formation resistivity is back-calculated from the conductivity of the formation. Once the true formation resistivity is known, applying the R_{wa} Method gives an additional value for formation water salinity. The equation for determining this value is as follows:

R_t = 1000/C (Equation 8)

where:

R_t = true formation resistivity - ohm-m

C = conductivity - mmhos/m (1500 mmhos/m)

T_f = formation temperature - ^oF (294^oF)

and:

ϕ = 22.5%

Then:

R_t = 0.667 ohm-m (Equation 8)

R_w = 0.042 ohm-m (Equation 5)

Salinity = 44,000 ppm (Exhibit 5-5)

5.1.4.5 **Shale Resistivity Method:** A salinity measurement of 68,000 ppm was estimated using Dr. Zaki Bassiouni's Shale Resistivity Method. This value was calculated by using parameters from the SP log and solving for R_w using Bassiouni's "Shale Resistivity-SP" graph (Exhibit 5-12). The equations used in this calculation are as follows:

$\left[R_{sh}/R_{mf}\right]$ @ T_f (Equation 9)

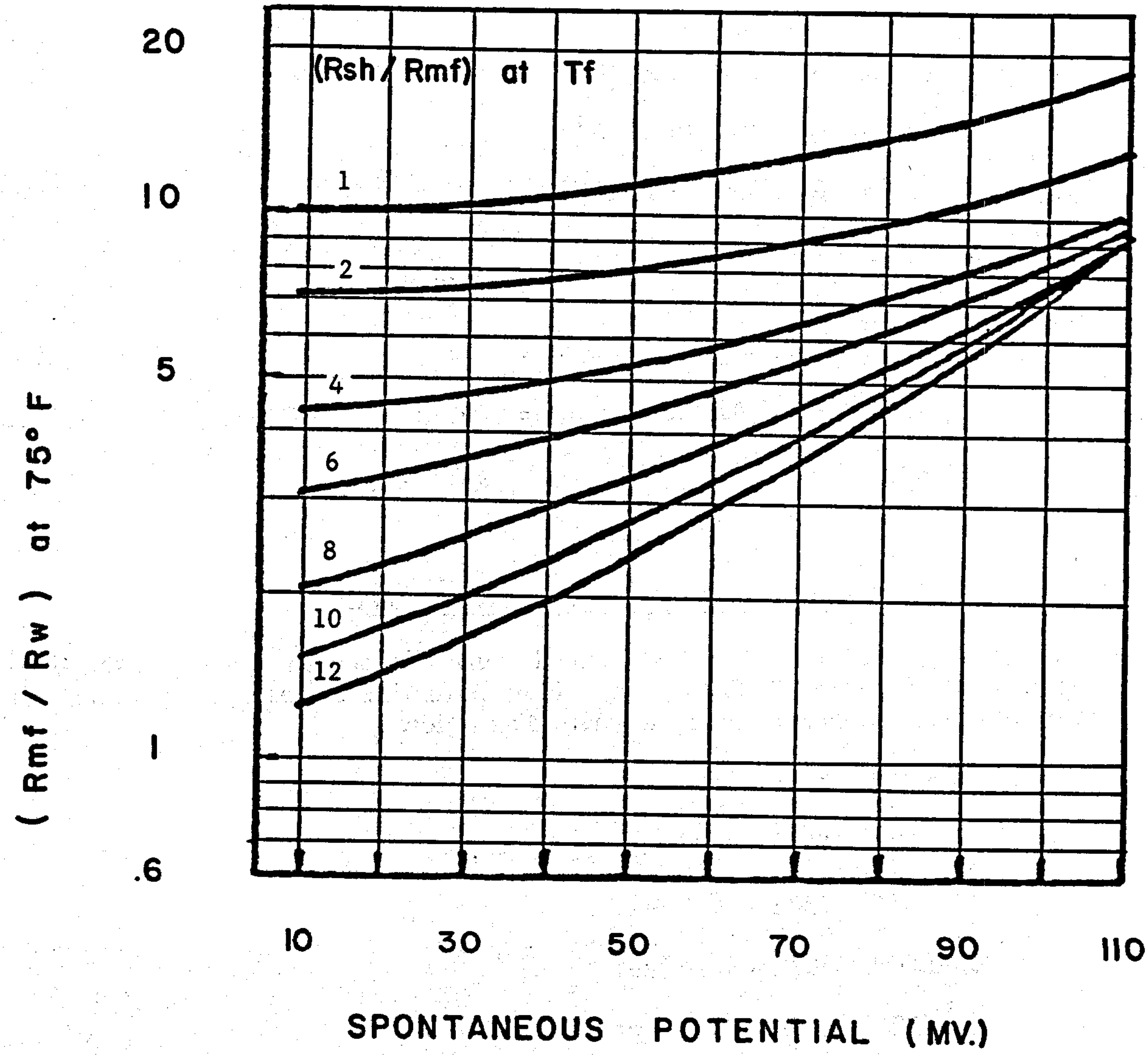
$\left[R_{mf}/R_w\right]$ @ 75^oF (Equation 10)
(Exhibit 5-12)

where:

R_{sh} = shale resistivity - ohm-m

R_{mf} = mud filtrate resistivity - ohm-m

R_w = formation water resistivity - ohm-m



NEW SP CHART

SILVA AND BASSIOUNI JUNE 1981

and:

SP = -40 mv

R_{sh} = 0.6 ohm-m

T_f = 294^oF

R_{mf} = 0.49 ohm-m at 70^oF

= 0.47 ohm-m at 75^oF

= 0.13 ohm-m at 294^oF (Exhibit 5-5)

$\left[0.6/0.13\right]$ @ 294^oF = 4.62 (Equation 9)

$\left[R_{mf}/R_w\right]$ @ 75^oF = 4.6 (Exhibit 5-12)

R_w @ 75^oF = 0.47/4.6 = 0.102 (Equation 10)

Salinity = 68,000 ppm (Exhibit 5-5)

5.2 Open Hole Log Analysis - Disposal Well

The Prairie Canal Company SWD No. 1 well was drilled for saltwater disposal to a logger's total depth of 5284 feet. Five potential disposal sands were encountered (Exhibits 5-13 and 5-14) and are identified as follows:

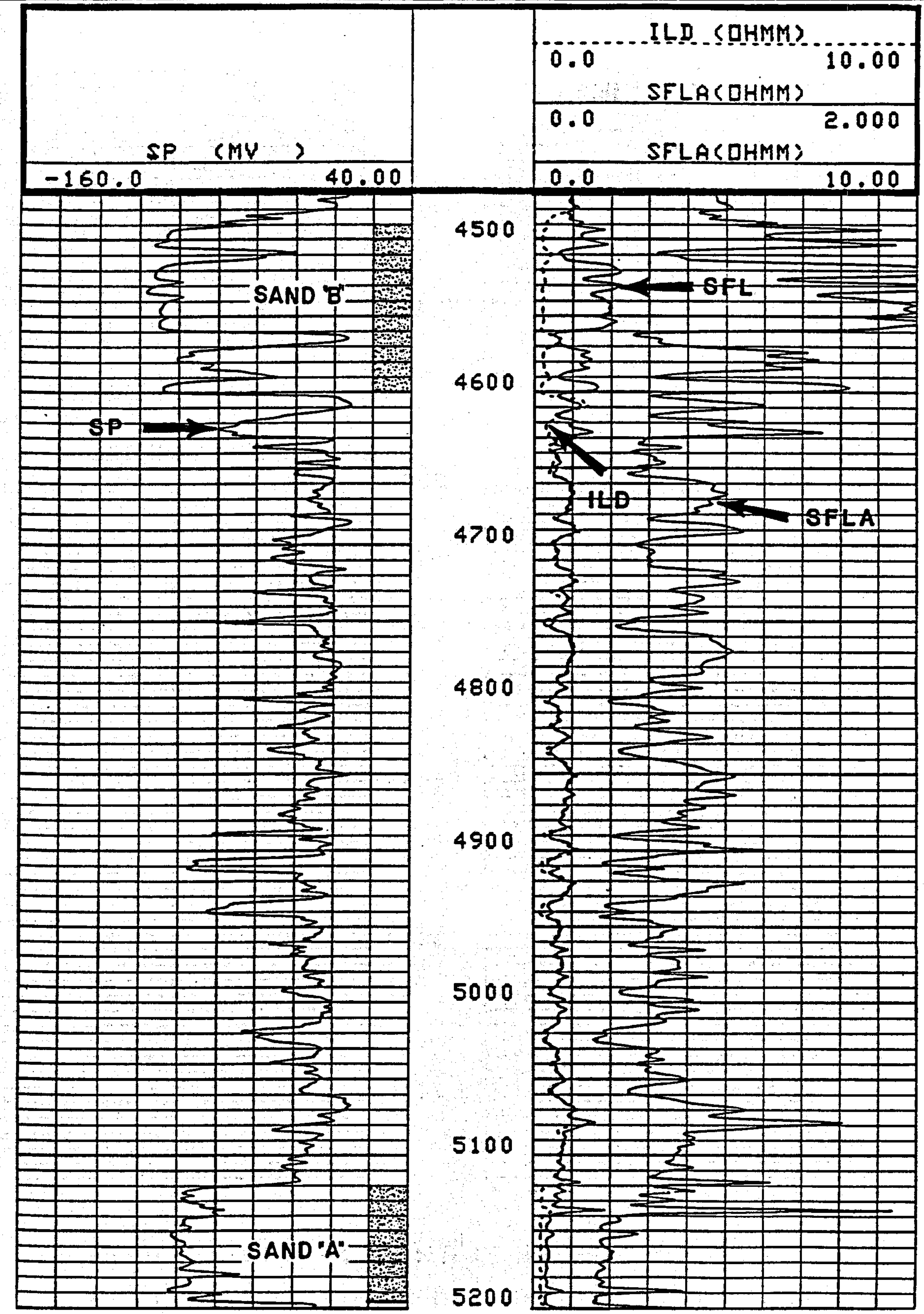
Sand "A" 5121 - 5196 feet

Sand "B" 4490 - 4602 feet

Sand "C" 3342 - 3412 feet

Sand "D" 3070 - 3130 feet

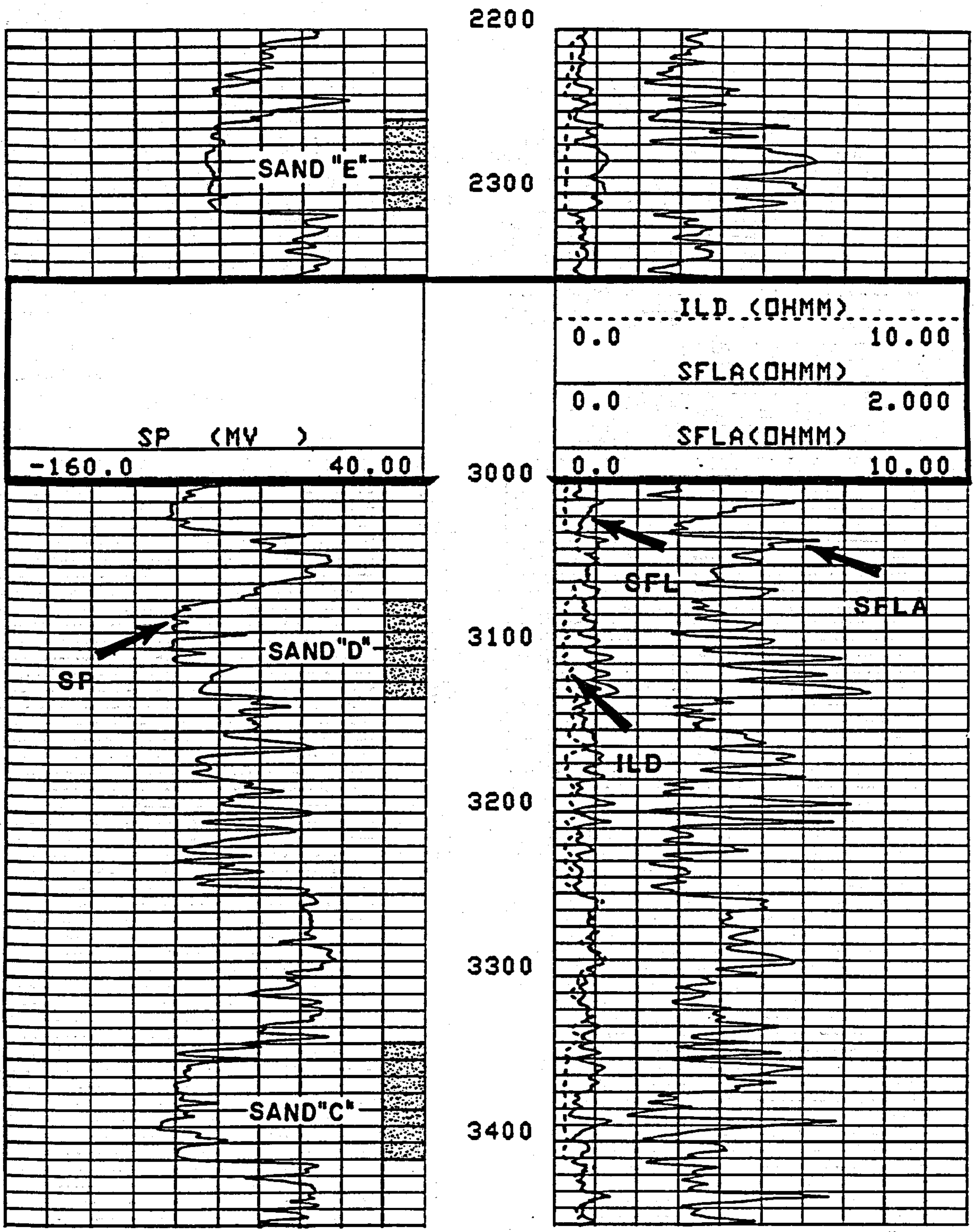
Sand "E" 2256 - 2312 feet



INDUCTION-SFL FORMATION DENSITY LOG
SAND 'A' AND SAND 'B' SWD ZONES

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

EXHIBIT 5-13



INDUCTION-SFL FORMATION DENSITY LOG
SAND "C", SAND "D" AND SAND "E" SWD ZONES

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

EXHIBIT 5-14

Sand "A" was too close to the bottom of the well to allow for solids accumulation during testing, so it was decided to complete the well in Sand "B." Following disposal complications with Sand "B," the well was plugged back and disposal was made into Sands "C" and "D" (Exhibits 5-15 thru 5-17). These sands exhibit the following log-derived parameters:

	Sand "B"	Sand "C"	Sand "D"
• Net Sand	60 feet	55 feet	50 feet
• Porosity	33%	35%	37%
• Salinity	110,000 ppm	50,000 ppm	50,000 ppm
• Temperature	132^{o}F	115^{o}F	112^{o}F
• Pressure	2202 psi	1632 psi	1497 psi

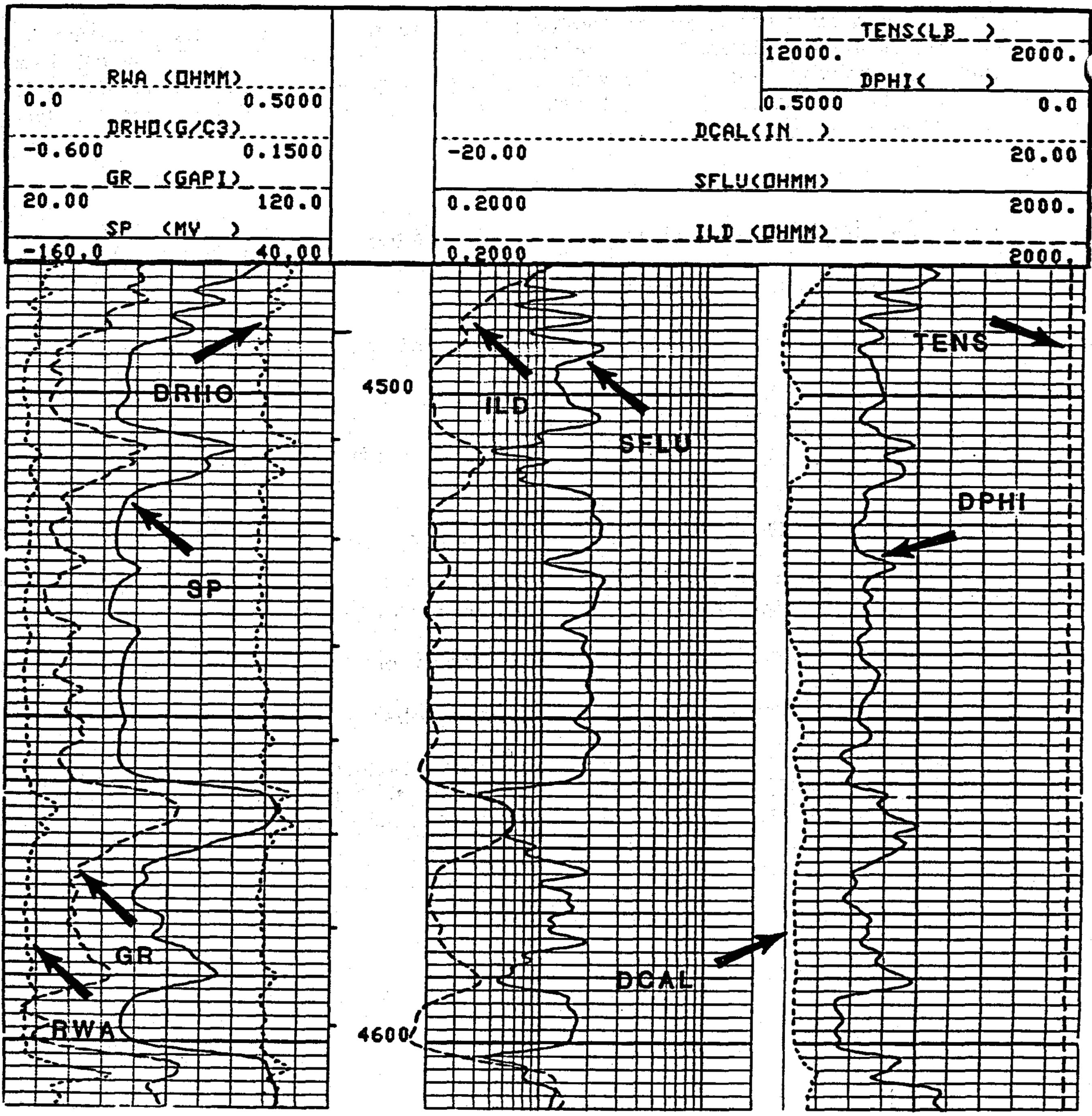
5.3 Cased Hole Log Analysis - Test Well

A variable density cement bond log was run in the well after the cementing of the 5-1/2 inch production string. This log gave Eaton the following data:

1. Integrity of casing vs cement and cement vs formation bonding.

2. Correlation between open hole and casing collars.

Analysis of the test well cement bond log (Exhibit 5-18), which was run 87 hours after cementing and under 1500-psi pressure, indicated that the Hackberry sand (14,782 - 14,820 feet) was bonded fairly well in and around the target sand.



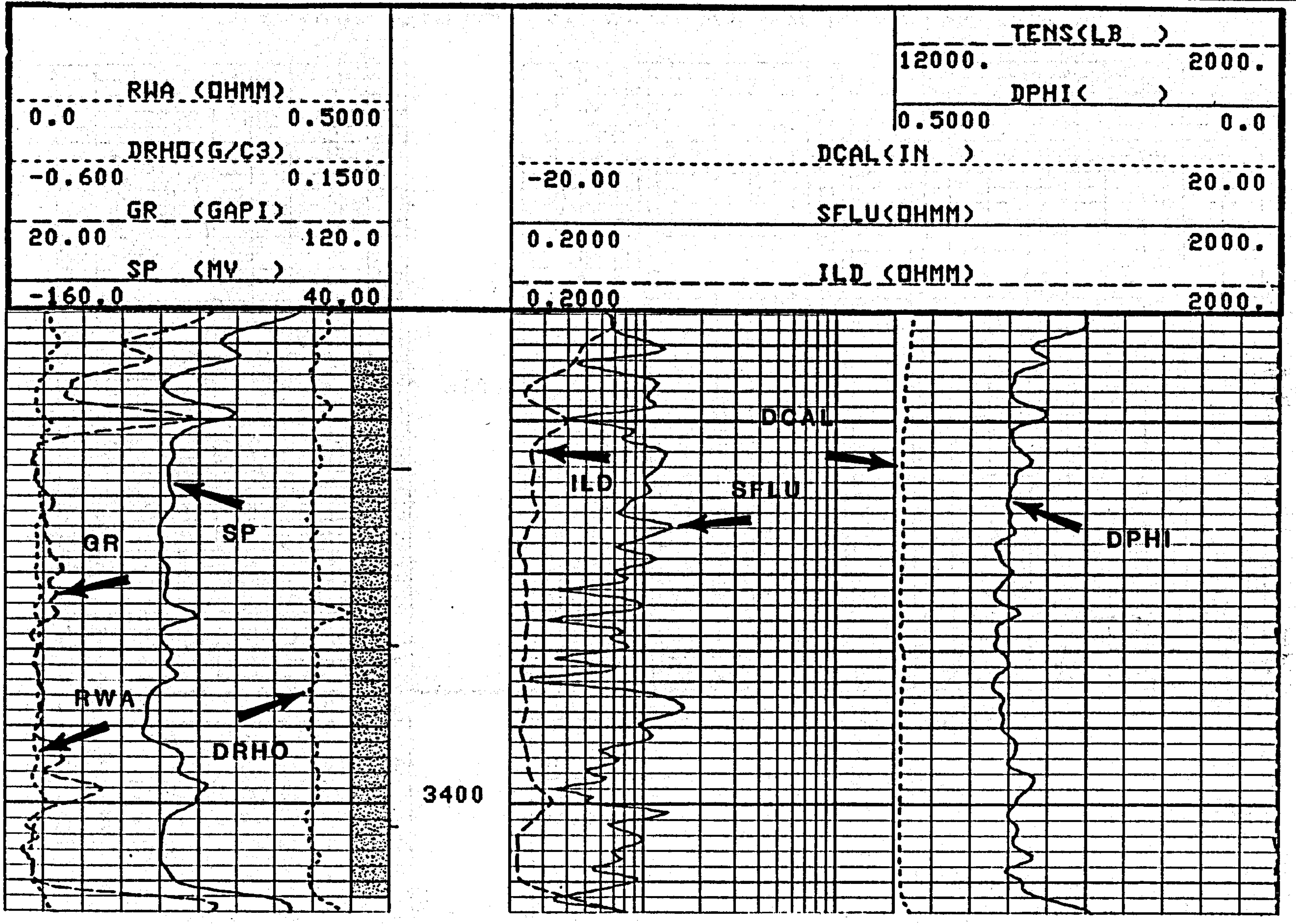
INDUCTION-SFL FORMATION DENSITY

SWD SAND B

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

EXHIBIT 5-15

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

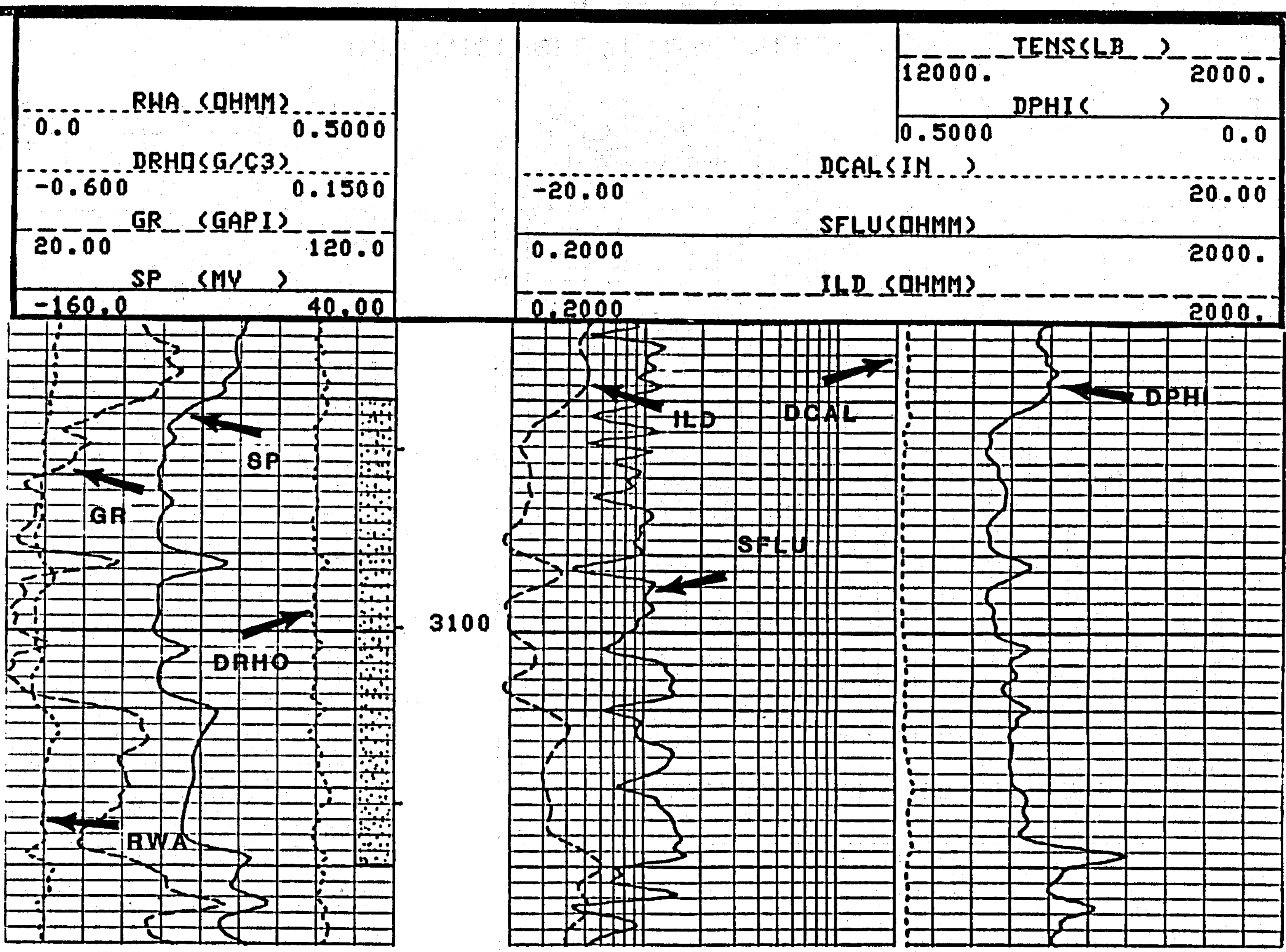


INDUCTION-SFL FORMATION DENSITY

SWD SAND "C"

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

EXHIBIT 5-16

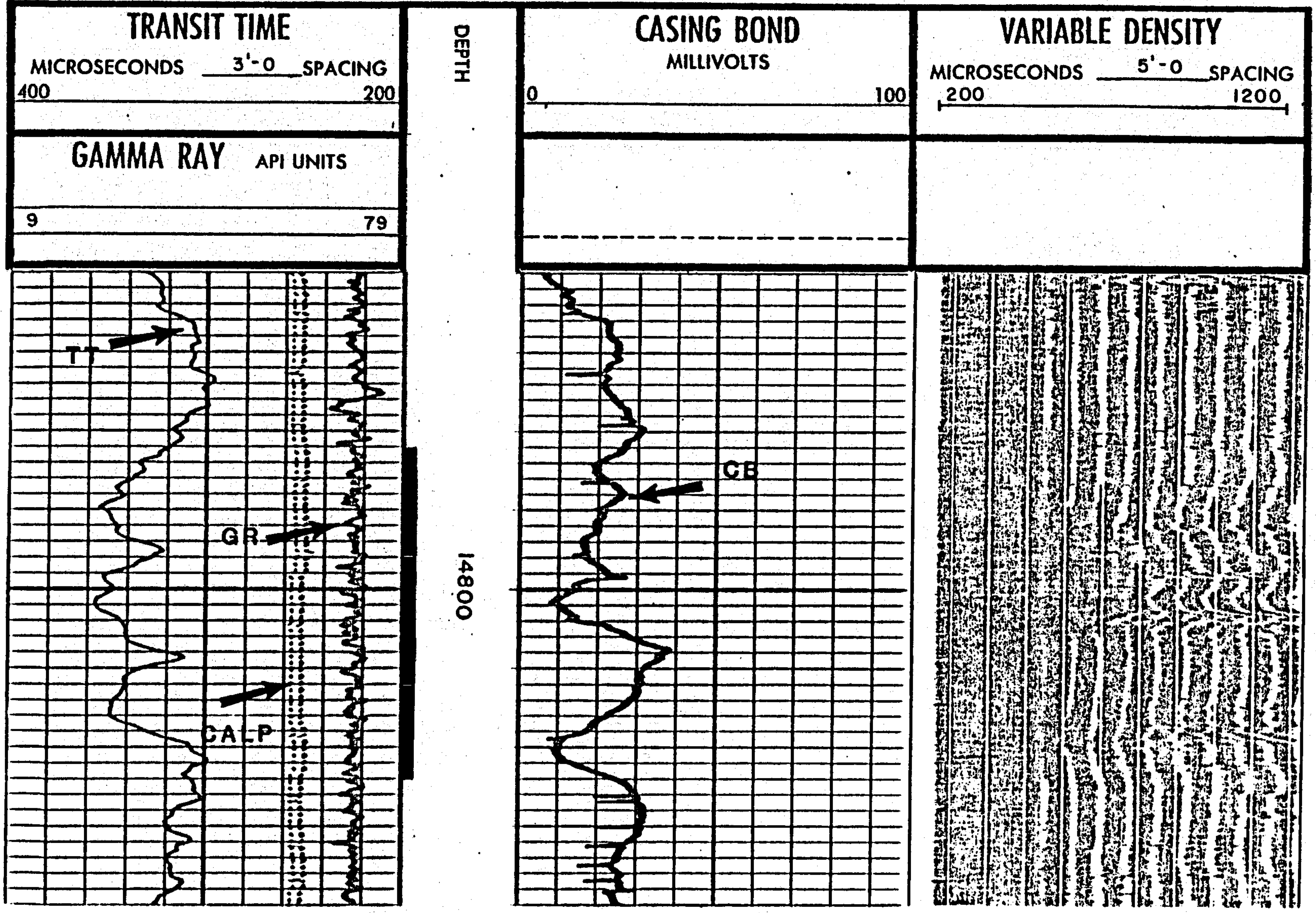


INDUCTION - SFL FORMATION DENSITY

SWD SAND "D"

EXHIBIT 5-17

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



CEMENT BOND LOG-VARIABLE DENSITY
HACKBERRY TEST ZONE

EXHIBIT 5-18

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

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 and the drilling of the disposal 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 location was covered with another layer of boards. 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.

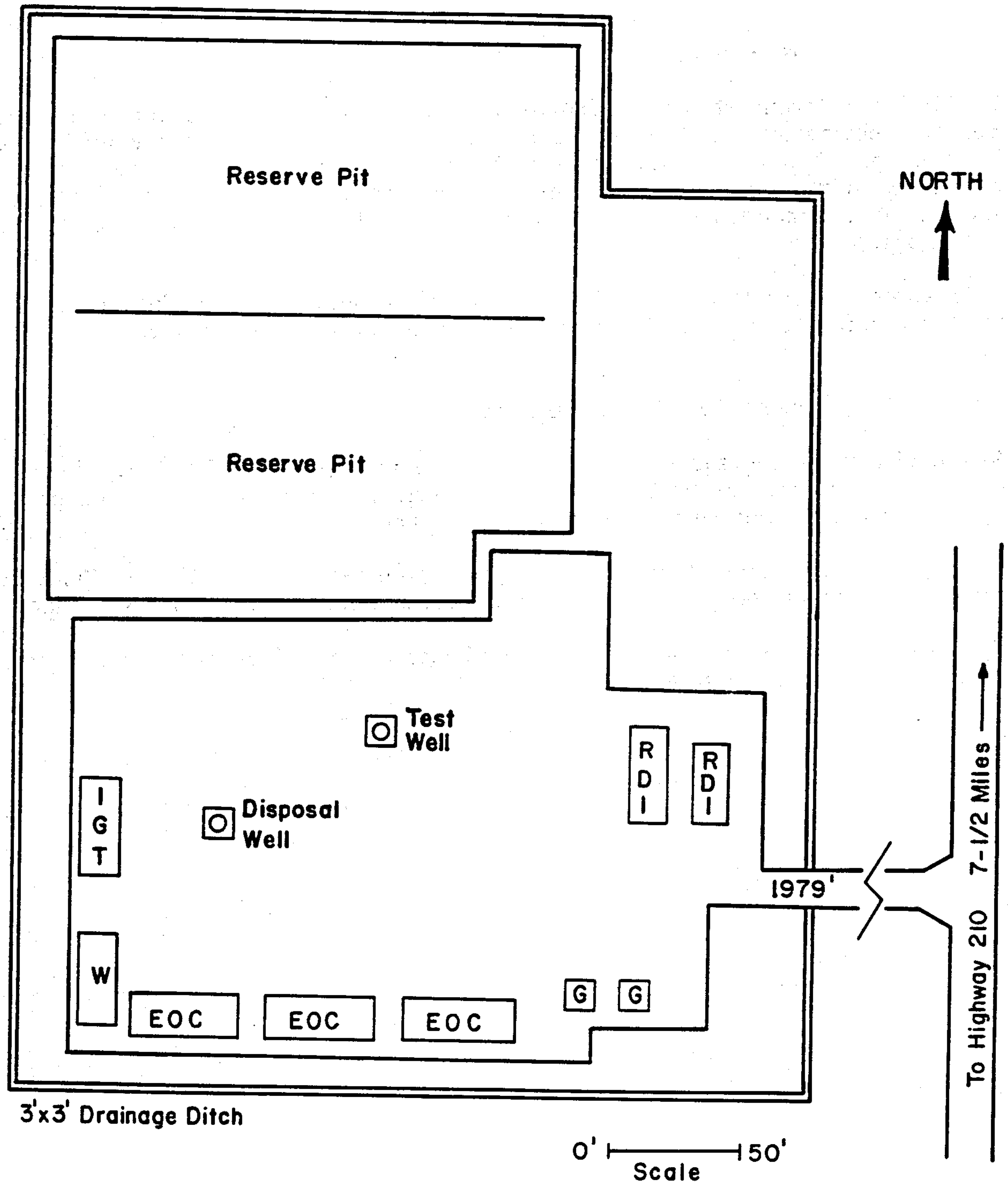
6.1.2 Living Facilities and Utilities

Air-conditioned living facilities were provided for 10 people. Weatherly Engineering, Reservoir Data, Inc., and the rig contractor brought in living trailers for their personnel. Motel accommodations were available in Lake Charles, Louisiana.

Water for drilling and other operations was obtained from a drilling fluids supply company. Drinking water was brought to the site by a local water delivery service.

Two telephones were installed in the Eaton house trailer. Two rented generators were used to supply electrical power.

TEST SITE LOCATION LAYOUT



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

EXHIBIT 6-1

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

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 completion when Eaton took over operations from Houston Oil and Minerals Corporation. The uncased portion of the hole was abandoned by setting a cement retainer at 14,011 feet and placing cement from 14,057 to 13,782 feet. A water-based drilling mud weighing 17.3 ppg was left in the well.

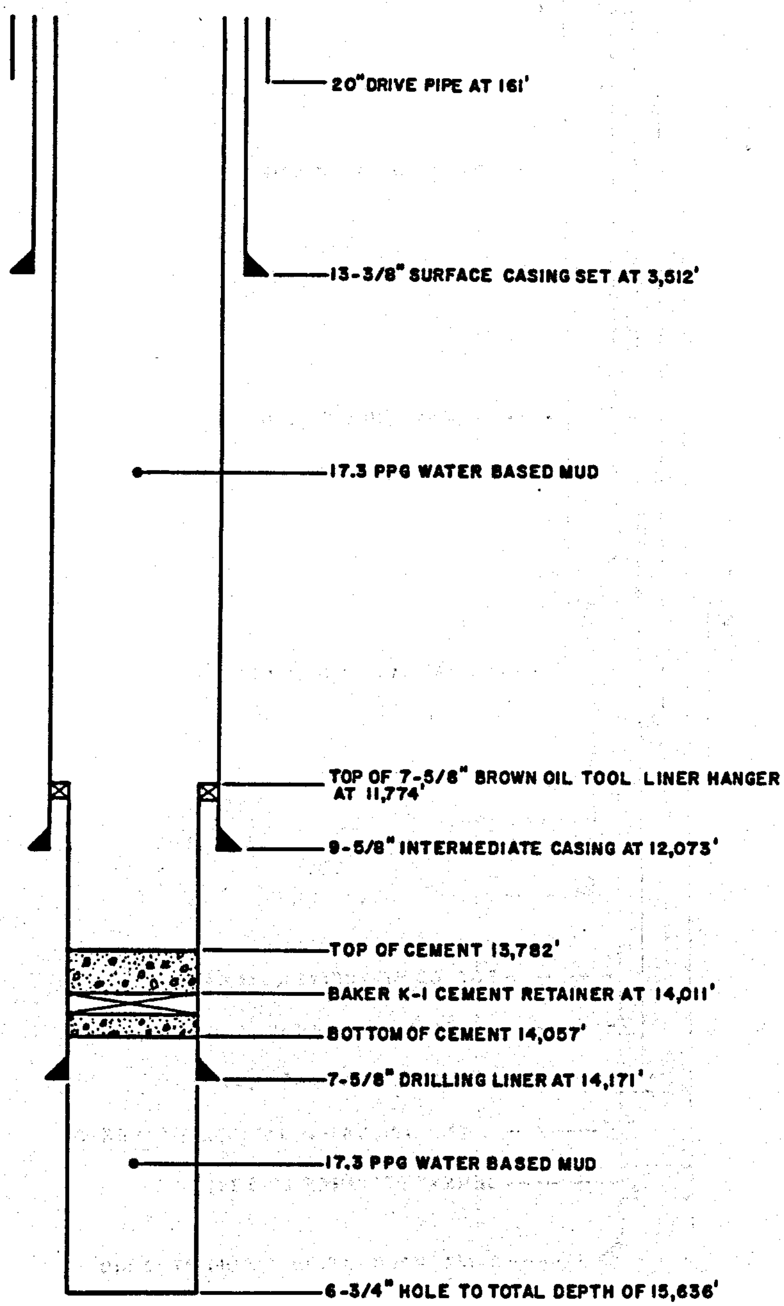


EXHIBIT 6-2 CONDITION AT TIME OF EATON TAKEOVER

Exhibit 6-3 is a schematic diagram of the tubular configuration of the well as completed for testing. A full string of 5-1/2 inch casing was set and cemented at 15,610 feet. A string of 2-3/8 inch tubing was run without a packer to 14,644 feet. Two sets of perforations are shown on the diagram. The lower set was initially perforated as the primary test zone. The zone produced large amounts of sand and gravel and was immediately abandoned. The upper set of perforations was subsequently tested.

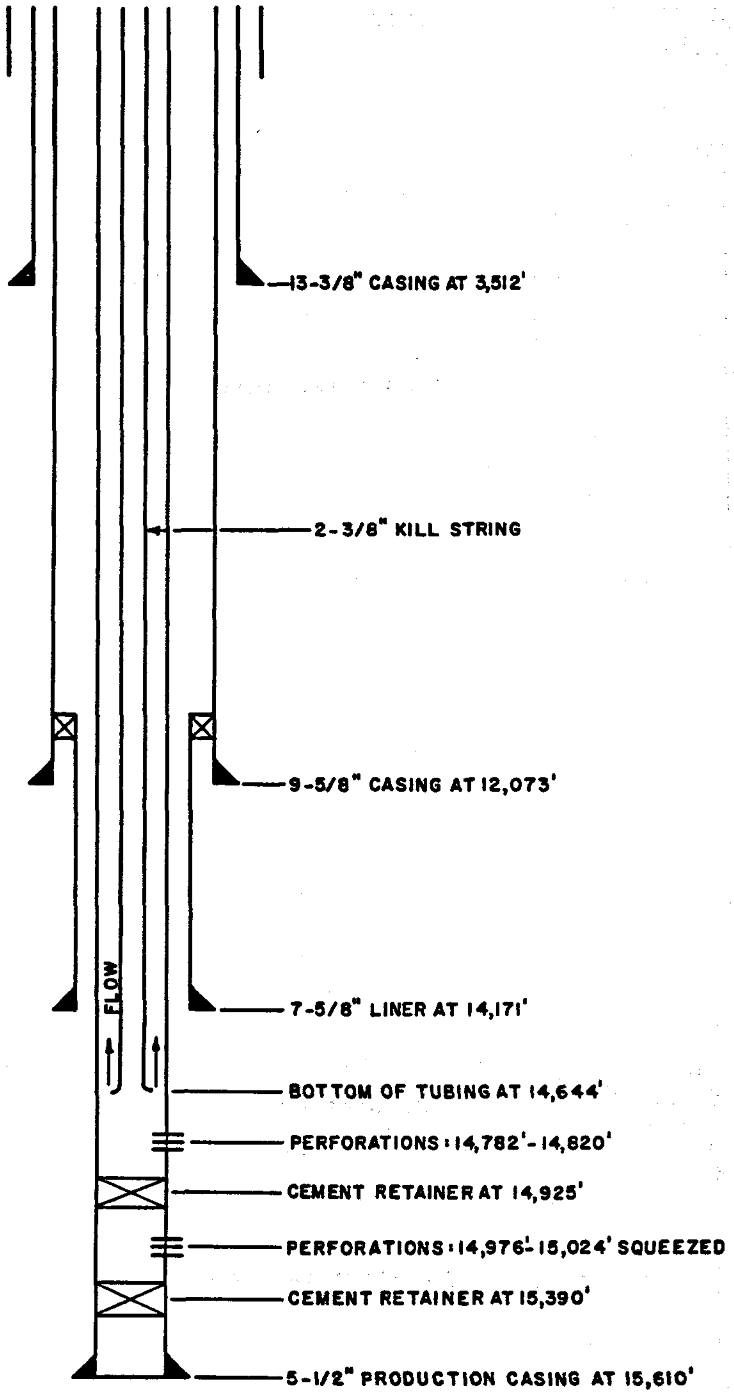


EXHIBIT 6-3 CONDITION DURING TESTING

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 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 flow line. The upper section of the christmas tree consisted of one 3-1/16 inch, 10,000-psi working pressure master gate valve, a "tee" with a 1-13/16 inch, 10,000-psi working pressure gate valve (for a kill line connection), and a 2-1/16 inch, 10,000-psi working pressure "swab" valve (for wireline accessibility).

Since there was a possibility that a leak in the 5-1/2 inch casing would allow excessive well pressure to reach the 9-5/8 inch casing, a remotely operated choke was installed on one outlet of the 9-5/8 inch casing head. This installation served as an additional safety feature on the christmas tree.

6.2.4 Logging Program

The ISF-Sonic open hole log and sidewall core data obtained by Eaton was adequate for formation evaluation purposes. The logs run by Eaton during re-entry and completion operations included a casing inspection log of the 9-5/8 inch casing, a gamma-ray cement bond log in the 5-1/2 inch casing, and a casing inspection log of the 5-1/2 inch casing.

6.3 Re-Entry Operations

The WellTech Rig No. 61 was moved to the location on October 24, 1980, to commence re-entry operations on the test well. A blowout preventer stack approved by Eaton was installed on the well and tested. An attempt was initially made to run a mechanical-type casing inspection log in the 9-5/8 inch casing and the 7-5/8 inch liner. However, the 9-5/8 inch tool would not pass through the blowout preventers, and the 7-5/8 inch tool would not go down the hole, because the mud viscosity was too high. A 6-3/4 inch cement mill was run in the hole to the top of the cement at 13,782 feet. The cement and the cement retainer were drilled up. The mud was circulated and conditioned at a depth of 14,171 feet, and the mill was pulled out of the hole.

An electromagnetic casing thickness inspection log was run in the 9-5/8 inch casing from 11,750 to 3500 feet and in the 7-5/8 inch liner from 14,150 to 12,034 feet. The electromagnetic tool was used because it is smaller than a mechanical inspection tool

HO&M PRAIRIE CANAL COMPANY, INC. WELL NO. 1
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	161	1/2" W.T.	19.0	NA	Welded	*	*	*
Surface Casing	13-3/8	0	1,675	54.5	12.459	J-55	STC	*	*	*
		1,675	3,512	68.0	12.259	J-55	STC	*	*	*
Intermediate Casing	9-5/8	0	2,412	47.0	8.525	N-80	LTC	(1)	*	*
		2,412	2,795	43.5	8.599	S-95	LTC	(1)	*	*
		2,795	10,243	43.5	8.599	P-110	LTC	(1)	*	*
		10,243	12,073	43.5	8.599	S-95	LTC	(1)	*	*
Drilling Liner	7-5/8	11,774	14,171	29.7	6.750	S-95	SFJ	(1)	*	*
Production Casing	5-1/2	0	11,469	20.0	4.653	S-95	LTC (MOD)	1.62	**	2.09
		11,469	15,610	20.0	4.653	S-95	SFJ	**	1.51	**
Tubing	2-3/8	0	14,644	4.7	1.995	N-80	8 RD	**	**	1.67

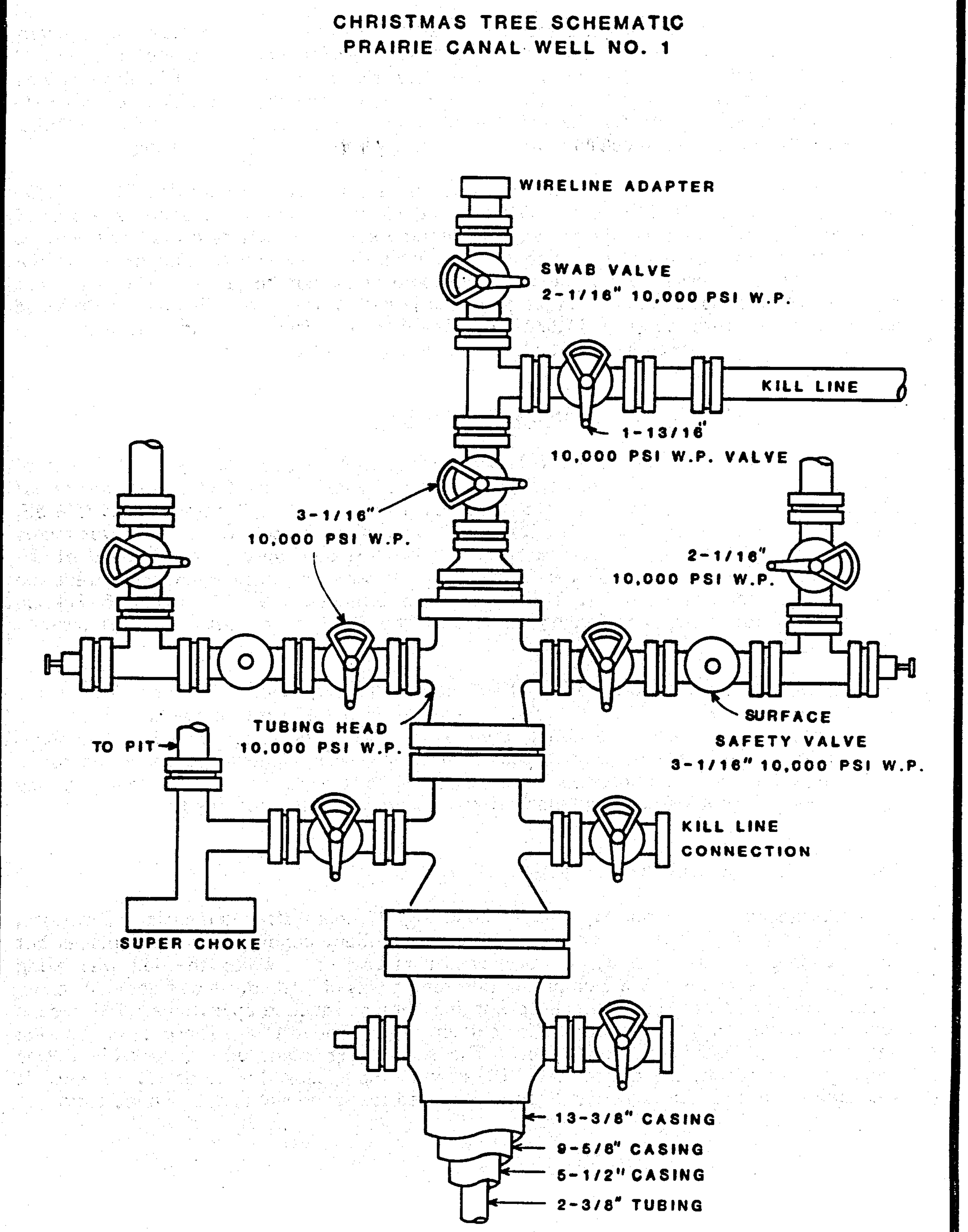
CEMENTING SUMMARY

Casing	Size (in.)	O.D. Hole Size (in.)	
Surface	13-3/8	17-1/2	Cemented with 1,200 sacks Class H + 3% A-2 followed with 500 sacks Class H. No cement returns to surface. Recemented from 0 - 150' with 100 sacks Class H.
Intermediate	9-5/8	12-1/4	Cemented with 350 sacks Trinity light weight and 240 sacks Class H.
Liner	7-5/8	8-1/2	Cemented with 300 sacks Class H + 35% sand + 0.6% Halad 22A + 1% CFR-2 + 1.5% Hi Dense No. 3 + 0.1% HR-5 mixed at 17.2 ppg. Squeezed top of liner with 250 sacks Class H + 0.3% CFR-2 + 0.7% HR-5 mixed at 16.7 ppg.
Production	5-1/2	6-3/4	Cemented with 750 sacks class H + 35% SF + 1% CFR-2 + 0.6% Halad 22A + 0.4% HR-5 + 3 lbs/sx Hi Dense No. 3 mixed at 17.4 ppg.

* Tubulars in place and no longer exposed to well bore conditions.

** Safety factors very high.

(1) Safety factors acceptable assuming no production casing leaks.



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

DOE CONTRACT NO.
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and more likely to go past tight places in the hole. (The electromagnectic tool, however, will not provide an effective log on casing that is surrounded by an outer string of casing.) The log indicated that no damaged or defective pipe was present in either casing string, that negligible-to-minimal corrosion was present, and that the pipe was in a safe and satisfactory condition for the anticipated operating conditions. Some heavier joints of the 9-5/8 inch casing were found to be intermingled with the lighter casing.

A bit was then run in the well. The hole was washed and reamed from 14,171 to 15,534 feet. At that point a failure in the rig's control system caused a shut-down for 10 minutes. During that time the drill string became stuck. An oil base mud was pumped down and spotted around the outside of the bottom-hole assembly. The next day the shaft in the drawworks failed, and the stuck pipe could not be jarred. The shaft was replaced 47 hours later, and the stuck pipe was jarred loose. The hole was then reamed and washed to a total depth of 15,684 feet. The mud was circulated and conditioned at a weight of 17.4 ppg in preparation for the running of production casing.

6.4 Completion Operations (Primary Zone)

The drill pipe was laid down and 5-1/2 inch production casing (consisting of 4141 feet of 20 lb/ft, S-95, SFJ pipe, followed by 11,409 feet of 20 lb/ft, S-95, LT&C pipe) was set at 15,610 feet. The casing was cemented with 750 sacks of class "H" cement plus 35% SF, 1% CFR-2, 0.6% Halad 22A, 0.4% HR5, and 3 lb/sx of Hi Dense. The cement was mixed at a density of 17.4 ppg. Fifteen barrels of SAM-5 spacer were pumped ahead of the cement, and 5 barrels of the spacer followed the cement. Rubber cement plugs were run ahead of and behind the cement. The cement was displaced with 345 barrels of 17.4 ppg mud. The wiper plug was landed on top of the float collar with 1500-psi surface pressure.

The cement was allowed to set for 24 hours before operations were resumed. The casing was pressure-tested to 1500 psi. The blowout preventers were removed. Additional tension of 50,000 pounds was added to the casing, and it was landed with 280,000 pounds on the slips. (The additional 50,000 pounds of tension was added to partially neutralize the elongation which would occur as a result of heat expansion of the casing during production.) The tubing head and blowout preventers were then installed on the well.

6.4.1 Cement Bond Logs

Schlumberger ran a gamma-ray cement bond log, 49 hours after cementing operations, from 15,478 to 11,000 feet. The log indicated excellent bonding in several places but poor bonding in the area of the proposed perforations. While the log was being evaluated, some of the 2-3/8 inch production tubing was picked up. It was decided to run another log under pressure, before attempting cement squeeze operations. The second cement bond log was run 87 hours after cementing and under 1500-psi pressure. The log was run from 15,487 to 11,000 feet. The second log indicated considerably better bonding in and around the target sand. The cement top appeared to be at 11,780 feet. It was decided that cement squeezing of the proposed test zone would not be necessary.

6.4.2 Production Tubing

The 2-3/8 inch, 4.7 lb/ft, N-80, EUE 8 RD tubing was run in the hole to 15,526 feet. The drilling mud was displaced with 9.0 ppg brine. The tubing was then pulled up and landed in the tubing head with the bottom of the wireline guide at 14,850 feet. The blowout preventers were removed, and the christmas tree was installed. The casing and christmas tree were tested to 7500 psi for 30 minutes. No leaks were found. The rig was released on November 20, 1980.

6.4.3 Tubing Obstruction

While the rig was being moved off the location, it was discovered that pressure had built up in the well. (It is now believed that this pressure originated in the area of the float collar, which was set at 15,528 feet). An attempt was made to bleed off the pressure over a 20-minute period, but after a large amount of air and water had been flowed, the pressure remained on the well. A pressure gauge and an adjustable choke were then installed on the well. After the equipment was installed, there was still 1530 psi of pressure on the well. The pressure was reduced to 0 psi over a 90-minute period by bleeding air and water through the choke.

Forty days later, after the disposal well had been drilled, the location had been prepared for testing, and the test equipment had been installed, an attempt was made to perforate the well. The perforating gun would not go past 13,572 feet (1278 feet above the bottom of the tubing). Several unsuccessful attempts were made to clear the obstruction using wireline tools and pump pressure. A coiled tubing unit was then used in an effort to drill up the obstruction with a downhole rotating motor and a mill. Several pieces of red rubber were recovered during the milling operation, and the tubing was cleaned out to 14,826 feet (24 feet above the bottom of the tubing). The coiled tubing then parted at 5580 feet, and it was decided that the production tubing would have to be pulled out of the well to remove the obstruction.

6.4.4 Workover to Remove Tubing Obstruction

The WellTech Rig No. 9 was moved to the location on January 8, 1981. Blowout preventers were installed on the well, and the 2-3/8 inch tubing was pulled out of the hole. The coiled tubing was recovered, and several pieces of rubber and cement particles were pumped out of the tubing. The wireline guide and several joints of tubing were found to be damaged. A 4-5/8 inch mill was run in the well, and the hole was washed from 14,227 to 15,464 feet. Rubber, cement, shale cuttings, and some light mud were recovered. The rubber was identified as probably pieces of the top and bottom cement wiper plugs. A cement retainer was then set at 15,390 feet to isolate any bad casing below the retainer. The 2-3/8 inch tubing was run back in the well and set at 14,860 feet. The blowout preventers were removed, and the christmas tree was installed. The rig was released on January 16, 1981.

6.4.5 Probable Cause of the Tubing Obstruction

A slow leak probably developed at the 5-1/2 inch casing float collar at 15,528 feet after the drilling mud was displaced with brine. The pressure and wellbore fluids pushed the rubber wiper plugs up the hole. The plugs damaged the bottom of the tubing, and some of the rubber entered the tubing, causing the obstruction. The leak in the area of the float collar was probably related to poor cementation at that location.

It has also been speculated that the rubber which was found in the well may have been foreign matter pumped into the hole along with the brine used to displace the drilling mud. However, the serial numbers found on the rubber fragments were those of Halliburton top and bottom 5-1/2 inch casing wiper plugs. It is also unlikely that the large rubber pieces recovered from the hole would have passed through the pumps used to displace the mud.

6.4.6 Completion Perforations (Primary Zone)

Perforating operations were performed without a rig on location. Through-tubing 1-11/16 inch, zero-phase, "Hyperdome" guns were used. The shot density was 4 holes per foot. Since a surface pressure of about 6300 psi was expected when the target sand was perforated, the casing was pressured up to 5000 psi to minimize the surge of fluids into the well. The first interval perforated was from 14,999 to 15,024 feet. The pressure quickly increased to 6000 psi when the gun was detonated. The well was allowed to flow at about 3200 BWPD and produced approximately 355 barrels of saltwater before the second gun run. Shut-in pressure, with the lighter formation water in the well, was 6500 psi.

The second interval perforated was from 14,976 to 14,999 feet. The well was then flowed at a rate of about 8200 BWPD and produced approximately 540 barrels of brine. The well was next flowed out the tubing for a short time to remove the completion brine from the tubing and to establish a clean downhole environment for bottom-hole sampling operations. The well was shut in with 6500-psi surface pressure.

6.4.7 Attempt to Obtain Bottom-hole Sample

A Gearhart Industries bottom-hole sampler was run in the hole on January 20, 1981. The sampler appeared to work properly, and a sample was obtained at the top of the perforations. While pulling the tool out of the hole, the wireline became stuck in the lubricator, with the tool 200 feet below the surface. The wireline could not be pulled free, and the wireline blowout preventor rams could not be closed. The tubing was filled with 60 barrels of 17.0 ppg mud to kill the tubing pressure so that the lubricator could be removed. When the lubricator was pulled off, it was found to be full of frozen methane and water vapor. The cold ambient surface temperature and high well pressure had created a condition which allowed these hydrates to form in the lubricator. The hydrates were removed, and the wireline was pulled out of the hole. It was then discovered that the sampler tool, casing collar locator, and weight bars had been sheared off the line during pumping operations and had fallen to the bottom of the well. It was decided to suspend bottom-hole sampling operations and to begin testing the well.

6.4.8 Attempted Testing Operations (Primary Zone)

The well was produced for short periods between January 24 and 26, 1981, to reduce the surface pressure and provide easier access for the bottom-hole pressure and temperature gauges. When the wireline instruments were lowered into the well, they encountered solid material at 14,961 feet (perforations were 14,976-15,024 feet).

Prior to opening the well up for testing, it was noted that the bottom-hole pressure was 13,157 psia and the bottom-hole temperature was 297°F.

The well was flowed for approximately 10 minutes and produced a large amount of sand and gravel. The well was then shut in to repair a malfunctioning surface recorder. While the recorder was being repaired, the choke manifold was inspected. One choke insert and choke body were badly cut out. Sand and gravel were found in the lines. It was decided that the well was producing too many solids, and safe testing could not be conducted. The wireline instruments were removed from the well, and the well was killed by circulating 17.5 ppg mud down the tubing and out of the annulus. The location was prepared to accept a workover rig.

6.4.9 Workover to Inspect Casing and Locate Source of Solids Production

The WellTech Rig No. 5 was moved to the location on February 1, 1981. The upper part of the christmas tree was removed, and blowout preventers were installed. The 2-3/8 inch tubing was then pulled out of the hole. The next 7 days were spent washing out the sand, gravel, and shale in the well and attempting, unsuccessfully, to recover the bottom-hole sampling tool.

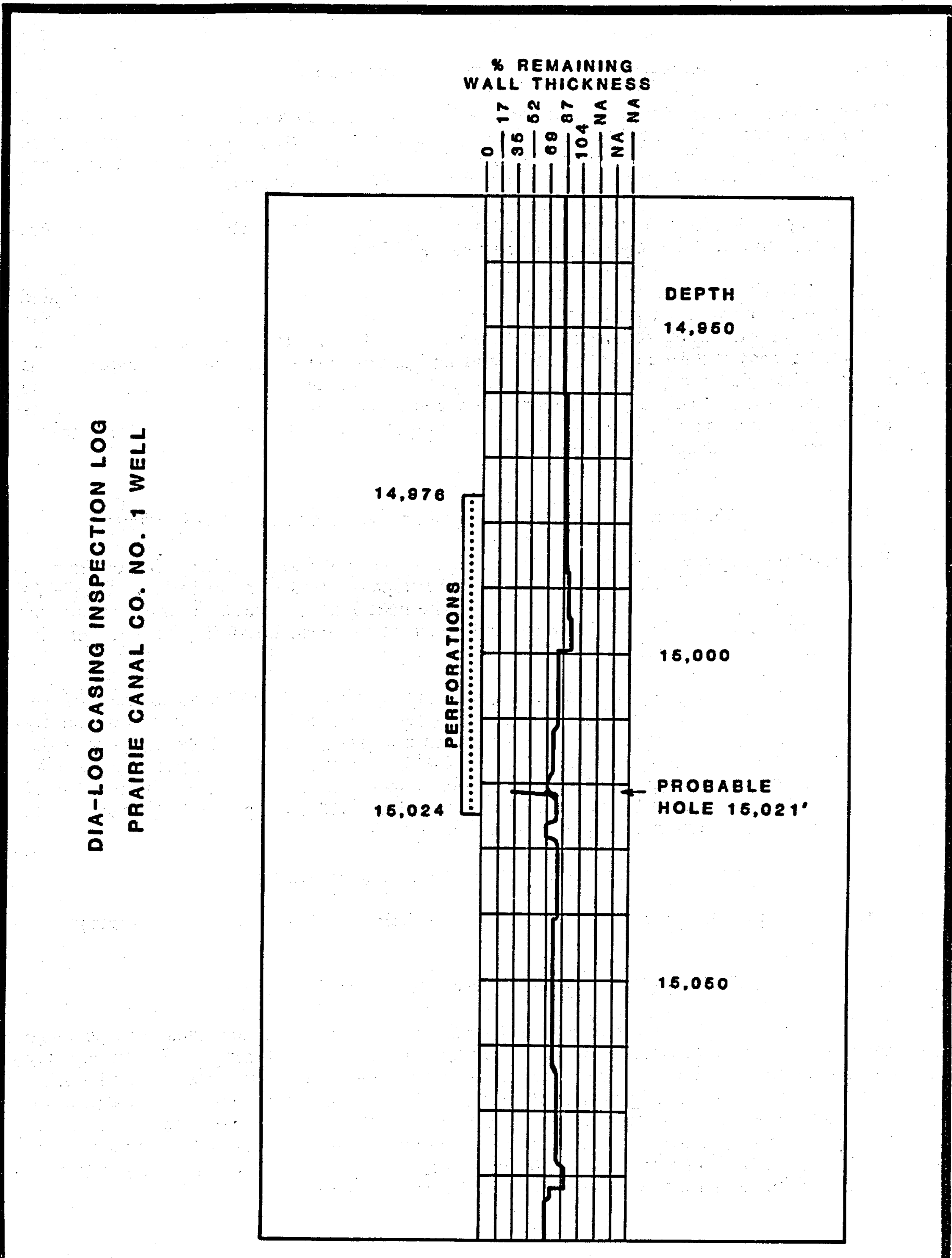
A mechanical-type casing inspection log was then run from 15,167 feet to the surface. The log indicated that there was an 8-foot-long tight spot in the casing at approximately 3800 feet and a significant loss of casing wall thickness (probably a hole) just above the bottom of the perforated interval. Exhibit 6-6 is a section of the inspection log. An attempt was made to run an electronic casing inspection log to confirm the findings of the mechanical log, but the tool would not go below 4060 feet, probably because of its large size and the high viscosity of the mud in the hole.

It was then decided to plug the well back and test an alternate sand.

A final attempt was made to recover the bottom-hole sampling tool, without success.

6.4.10 Probable Cause of Solids Production from Primary Zone

Considering all of the above events and findings, the most probable cause of the large amount of sand, gravel, and shale production is the following: A particularly unconsolidated section of formation initially produced small amounts of sand during cleanup flow. The cutting action of the sand enlarged a perforation and allowed more sand and some gravel to pass through the hole. As the well was being flowed to lower the surface pressure for wireline entry, the hole became even larger, allowing more sand, larger gravel, and some shale to enter the wellbore. A formation strength log cannot be developed, because there was no formation density log run in the open hole.



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

EXHIBIT 6-6

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

6.5 Completion Operations (Secondary Zone)

A cement retainer was set at 14,925 feet, about 51 feet above the primary test sand. The perforations were squeezed off with 250 sacks of cement. The 2-3/8 inch tubing was run back into the well to 14,920 feet, and the 17.3 ppg mud was displaced with 9.0 ppg brine. The tubing was then pulled up to 14,644 feet, and the christmas tree was installed and tested to 8000 psi. The workover rig was released on February 15, 1981.

6.5.1 Completion Perforations (Secondary Zone)

Perforating operations were performed without a rig on location. Through-tubing 1-11/16 inch zero-phase, "Hyperdome II" guns were used. The shot density was 8 holes per foot. The casing was initially pressured up to 5600 psi prior to perforating to minimize the surge of fluids into the well. The first interval was perforated from 14,795 to 14,820 feet. The pressure slowly increased from 5600 to 6000 psi after perforating. Approximately 500 barrels of water were flowed from the well. The well was then perforated from 14,782 to 14,795 feet. The shut-in surface pressure prior to testing was 6420 psi. Exhibit 6-3 is a schematic diagram showing the well as finally completed for testing.

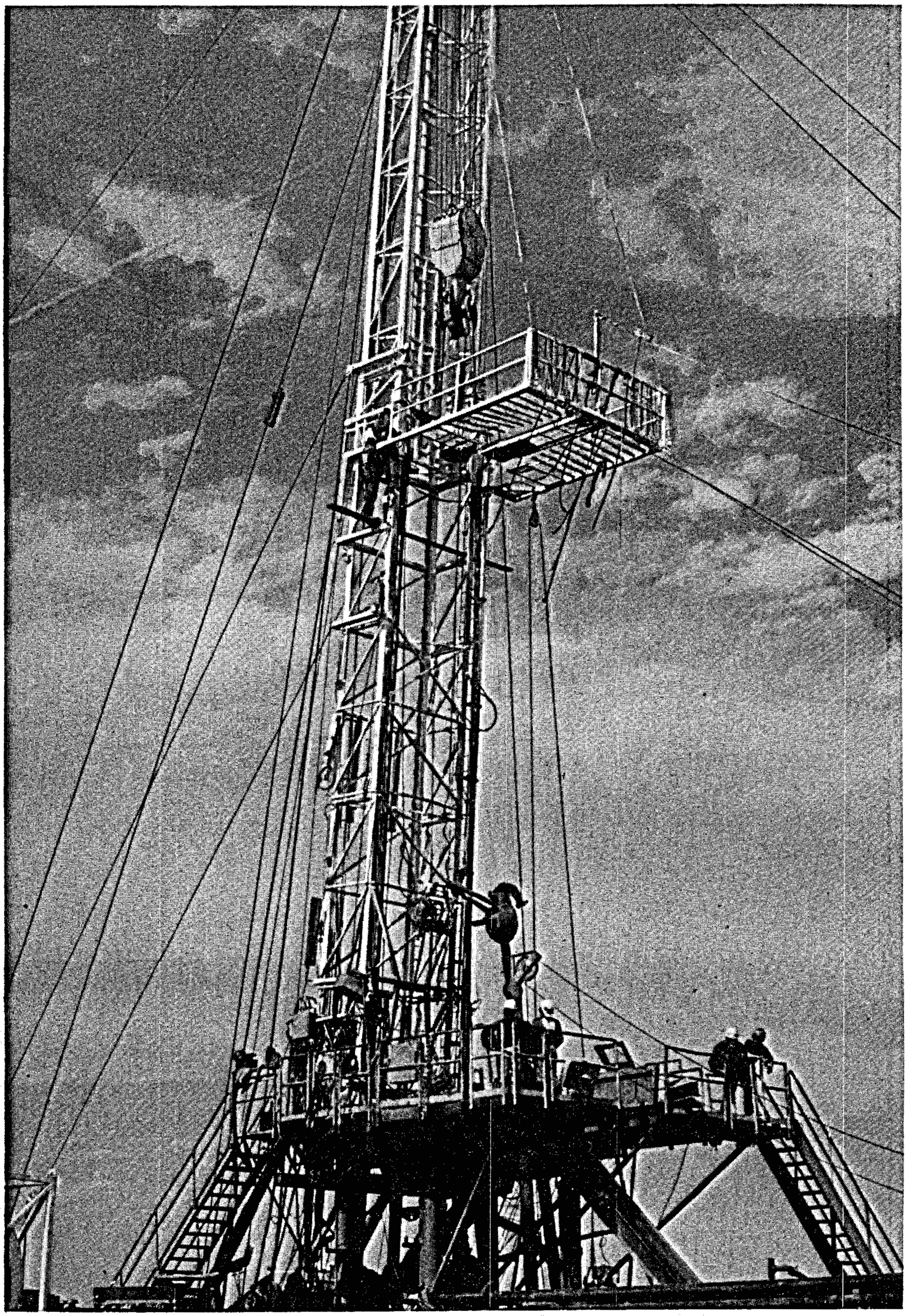


Photo 6-1 Welltech Rig No. 61 prior to running production casing.

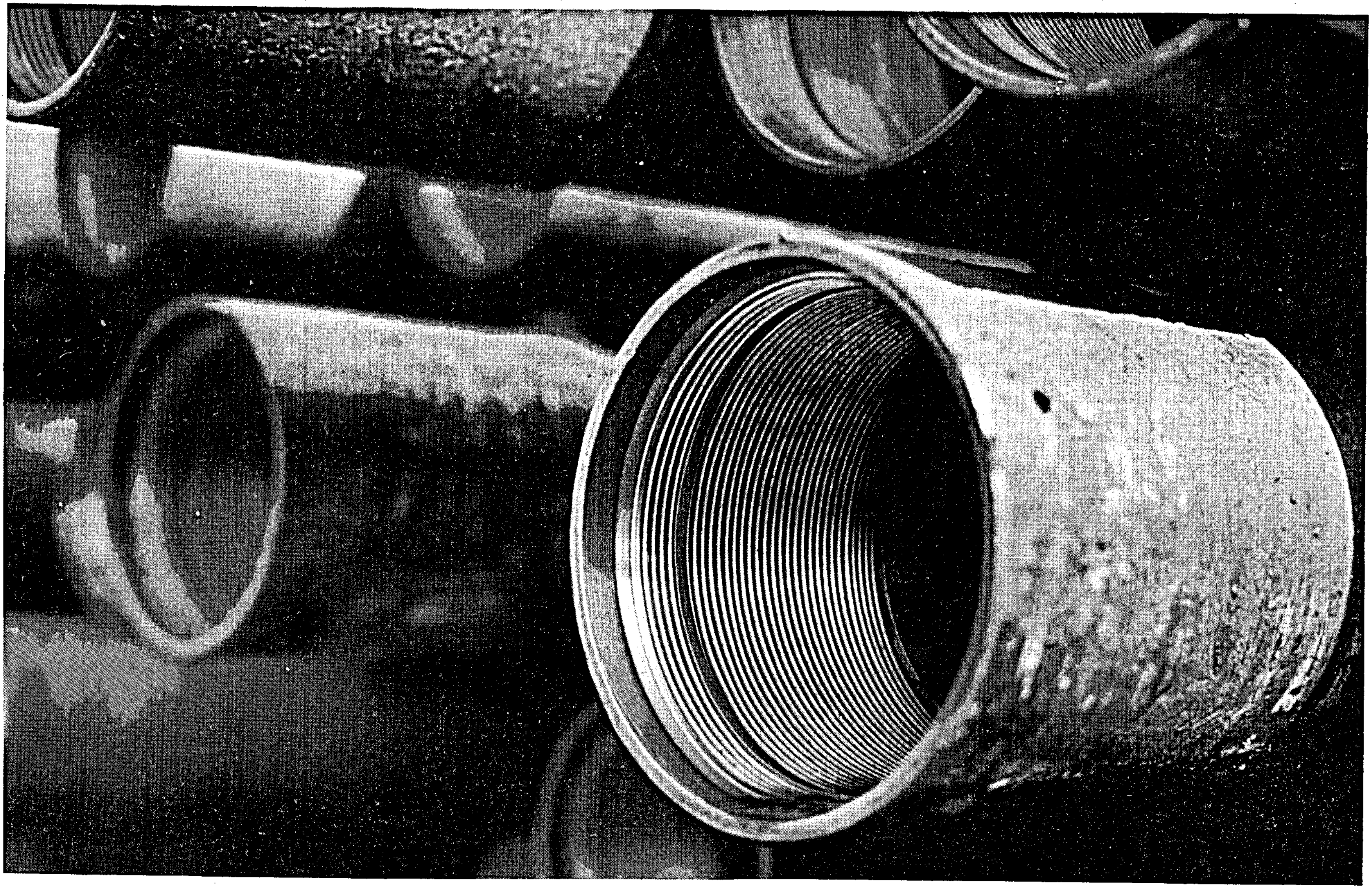


Photo 6-2 Note the seal rings on the modified API 5½-inch casing couplings.

Photo 6-3 Computer make-up torque analysis was used while running the 5½-inch casing in the well.

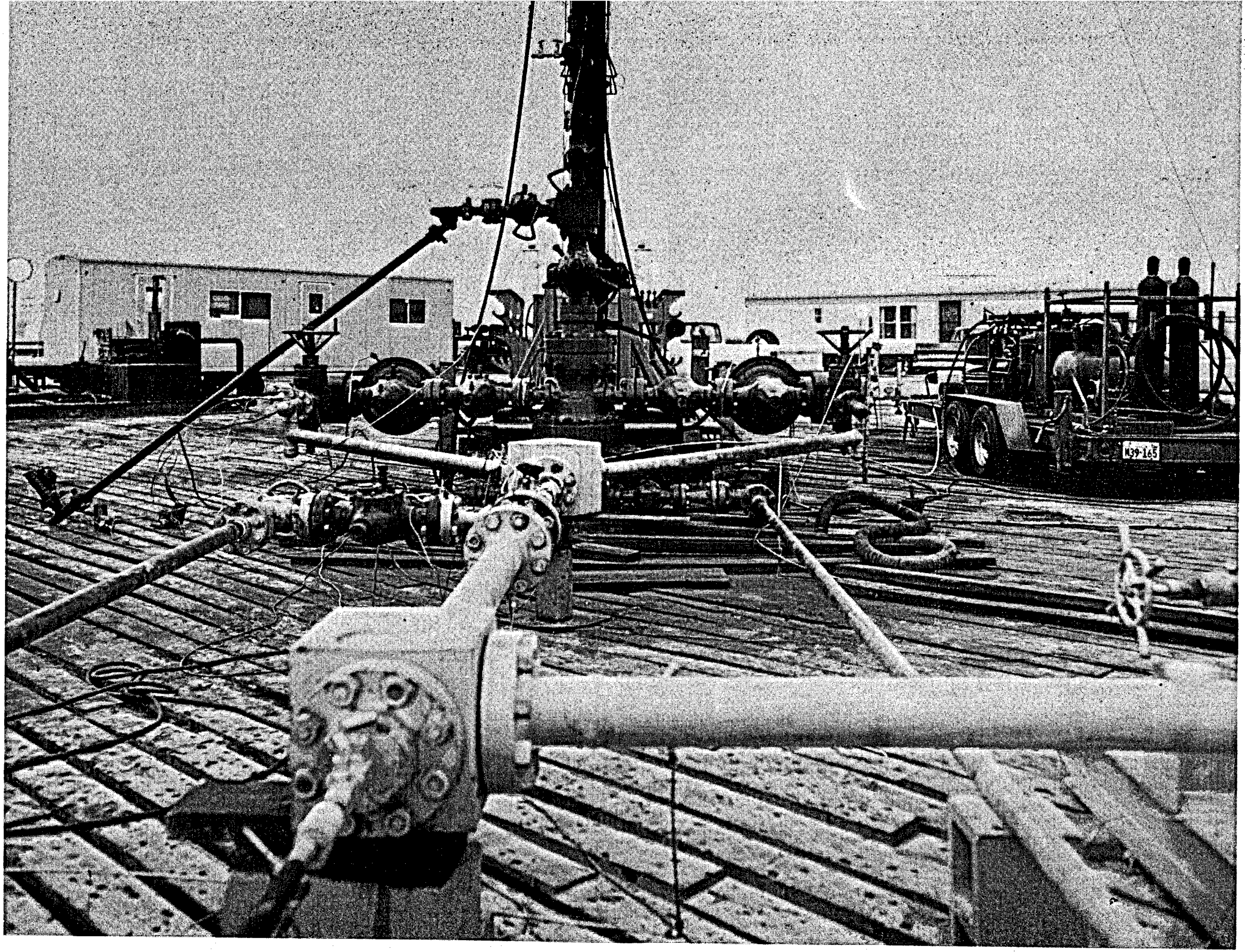


Photo 6-4 10,000-psi working pressure annular flow Christmas tree and flow line.

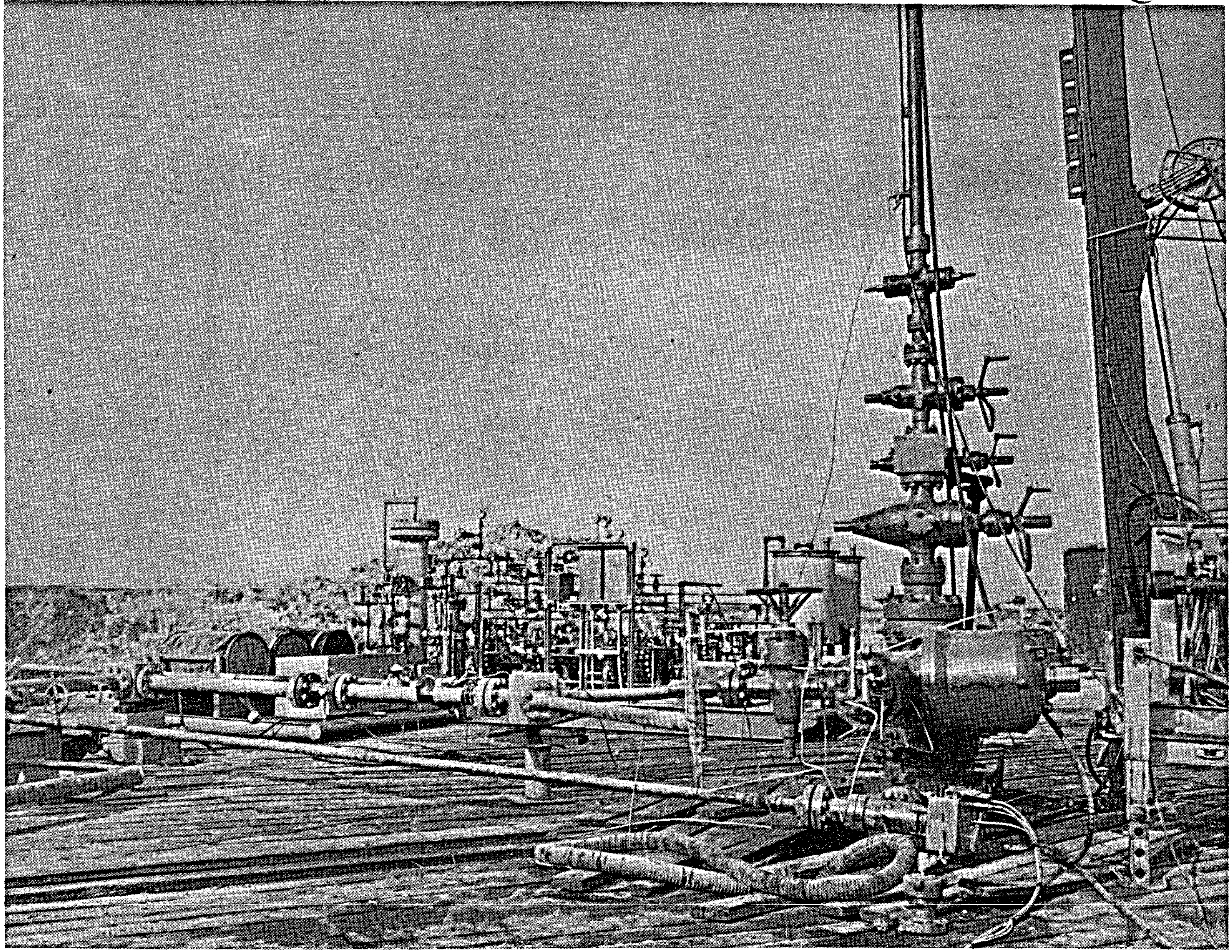


Photo 6-5 Side view of Christmas tree and flow line. Note remote control pressure choke base of Christmas tree.

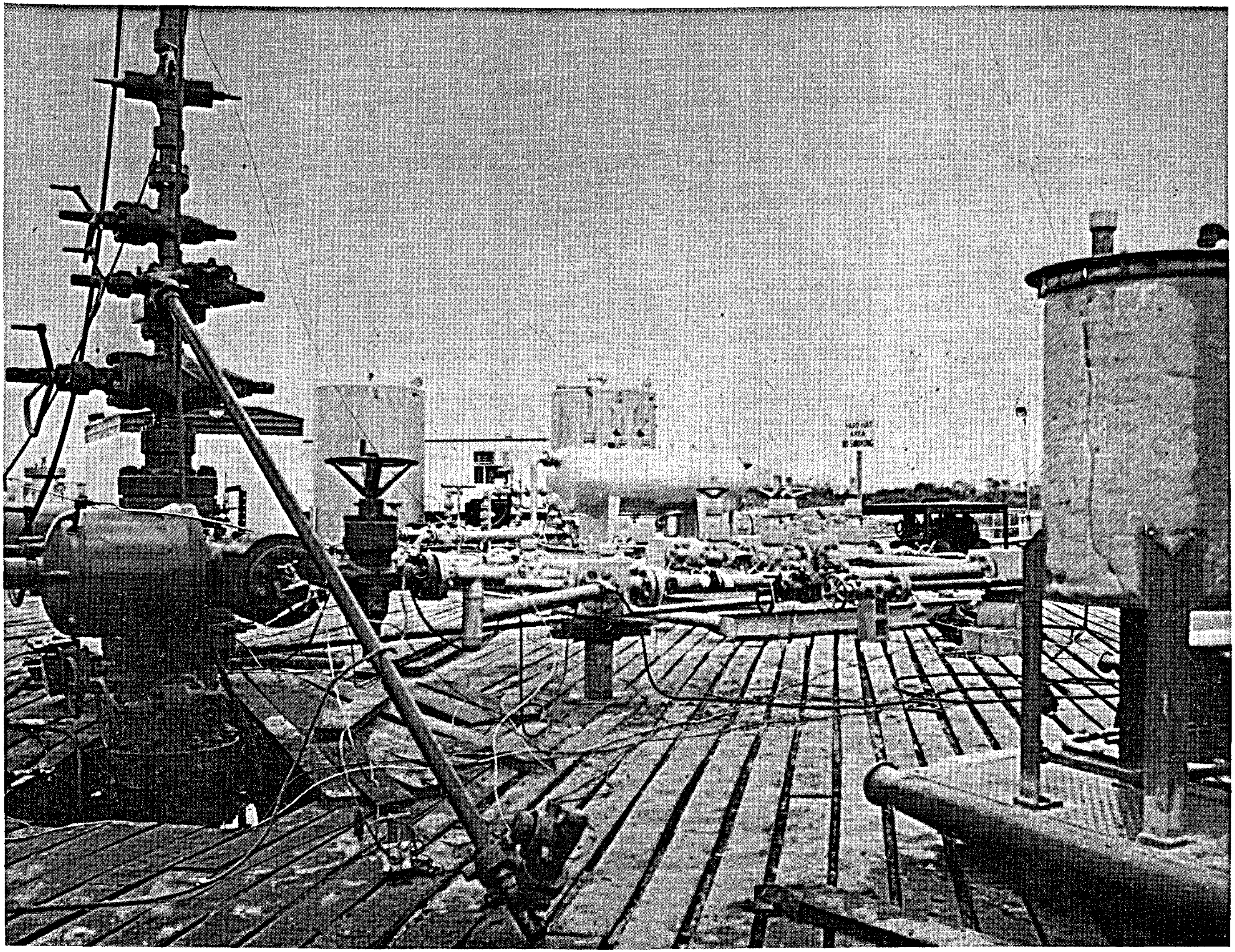


Photo 6-6 Note kill line connected to tubing wing valve on Christmas tree.

7.0 DRILLING AND COMPLETION OPERATIONS - DISPOSAL WELL

7.1 Location

The brine disposal well was 90 feet southwest of the test well. Exhibit 7-1 is a surveyor's plat of the location.

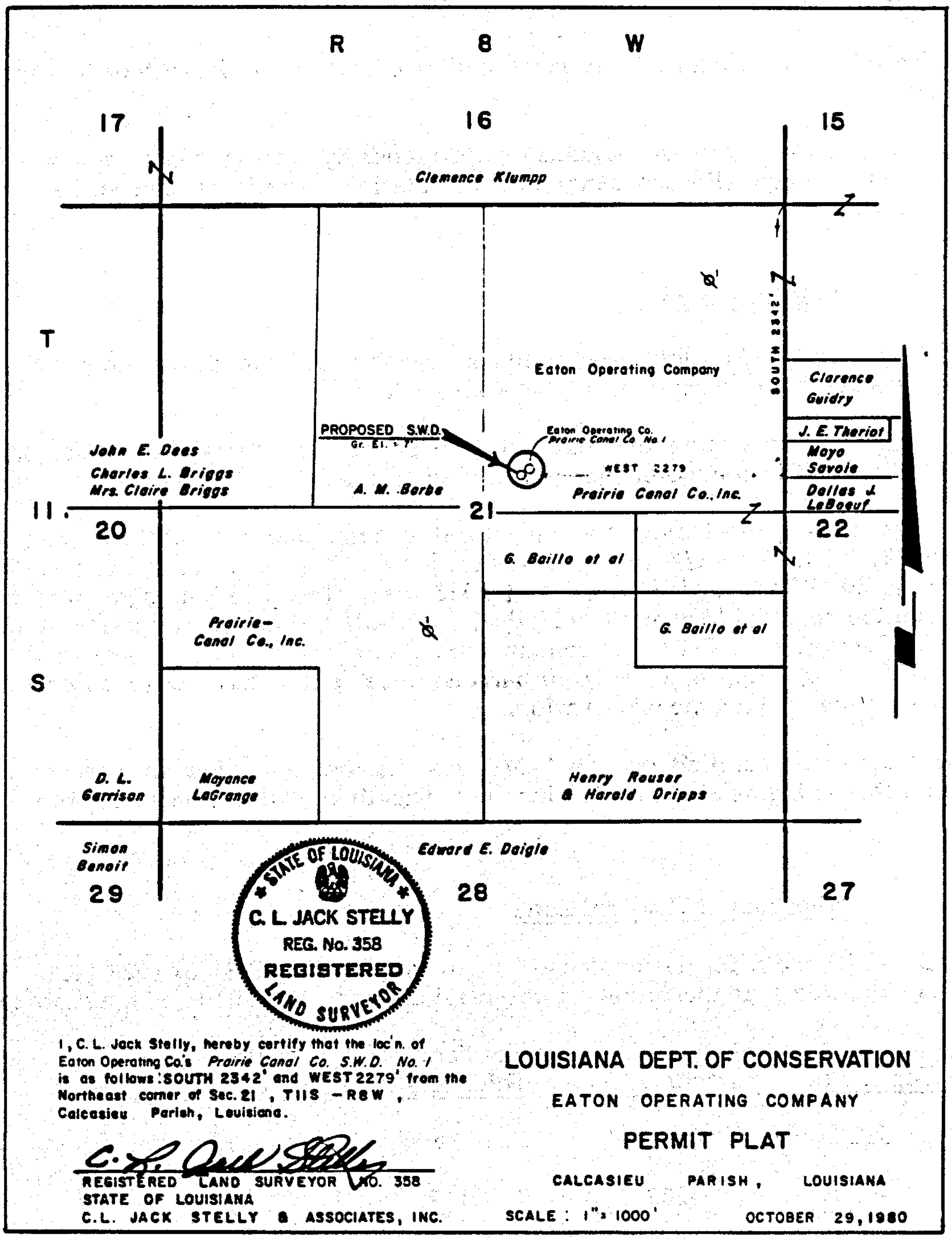


EXHIBIT 7-1 SURVEYOR'S PLAT OF LOCATION

7.2 Design Requirements

A brine disposal well was required for the test because of the large volumes of water to be produced. The primary design requirements for the well were the following:

- An injection capacity in excess of 15,000 barrels per day at an injection pressure not to exceed 500 psi.
- High temperature capability of up to 300°F.
- The minimum acceptable disposal aquifer depth below all fresh or brackish water sands.
- Protection of fresh and brackish water sands by setting two complete strings of casing through all such sands and circulating cement to the surface on both strings.

7.3 Drilling Operations

The WellTech Rig No. 61, which was used for re-entry and completion operations on the test well, was selected for drilling the disposal well.

While the rig was completing the test well, the 14-inch structural casing was driven for the disposal well. The conductor pipe was driven to a depth of 115 feet.

The rig was then moved over the structural casing, and the well was spudded on November 28, 1980. A 12-1/4 inch hole was drilled to 1528 feet. A string of 9-5/8 inch, 43.5 lb/ft, N-80, LT&C casing was set at 1528 feet. The pipe was cemented with 600 sacks of Halliburton "light" cement, mixed with 3% salt and having a density of 12.7 ppg, followed by 300 sacks of Class "H" cement mixed with 1% calcium chloride and having a density of 15.6 ppg. Approximately 60 barrels of cement returns were observed at the surface during the displacement operation.

A casing head was installed on the 9-5/8 inch casing, and blowout preventors were installed on the casing head. An 8-1/2 inch hole was then drilled to a total depth of 5282 feet.

7.4 Selection of Disposal Zone

An induction-SFL and a formation density log were run from 5281 to 1524 feet. Analysis of the logs indicated that the following potential disposal sands had been penetrated:

Sand	Top (Ft.)	Bottom (Ft.)	Net Sand Thickness (Ft.)	Porosity (%)
A	5121	5196	75	37
B	4490	4602	112	33

C	3342	3412	70	35
D	3070	3130	60	37
E	2256	2312	56	37

Sand "A" was too close to the bottom of the well to allow room for solids accumulation during testing, so it was decided to complete the well in Sand "B" and reserve the upper sands for additional disposal capacity.

7.5 Completion Operations

A string of 5-1/2 inch, 15.5 lb/ft, grade K-55, ST&C casing was run in the hole to 5260 feet. The casing was cemented with 805 sacks of Halliburton "light" cement, having a density of 12.7 ppg, followed by 500 sacks of class "H" cement mixed at a density of 15.6 ppg. Saltwater was used to displace cement, and approximately 50 barrels of cement returns were observed at the surface. The blowout preventors were removed, and a tubing head was installed on the 5-1/2 inch casing. The rig was released on December 10, 1980.

7.5.1 Logging, Perforation and Injectivity Test

A gamma-ray cement bond log was run on December 14, 1980 from 5070 to 3050 feet. The log indicated that good bonding had been achieved. The well was then perforated from 4570 to 4600 feet and from 4490 to 4560 feet with 2-1/8 inch Schlumberger "Hyperdome" guns, at 4 holes per foot.

An injectivity test was performed after the perforating operations were complete. The disposal zone was so tight that it would only accept water at the low rate of 1400 BPD at 1000-psi surface pump pressure. Stimulation of the disposal well was necessary.

7.5.2 Disposal Well Stimulation

To improve acceptance of water by the well, it was treated with 5000 gallons of Halliburton "FE" acid, with a diverting agent and other additives, followed by 10,000 gallons of regular HF acid with some additives. The acid was followed by 2000 gallons of a "clayfix" solution to stabilize the formation clays. After the acid treatment, the well accepted saltwater at higher rates. Exhibit 7-2 is a graph illustrating the improved injection rate versus injection pressure. The well was considered capable of accepting 10,750 BWPD at the maximum filter pressure operating limit of 600 psi. No additional perforating or stimulation was planned. It was decided to first flow test the producing well to see if the well would produce at rates in excess of 10,750 BWPD.

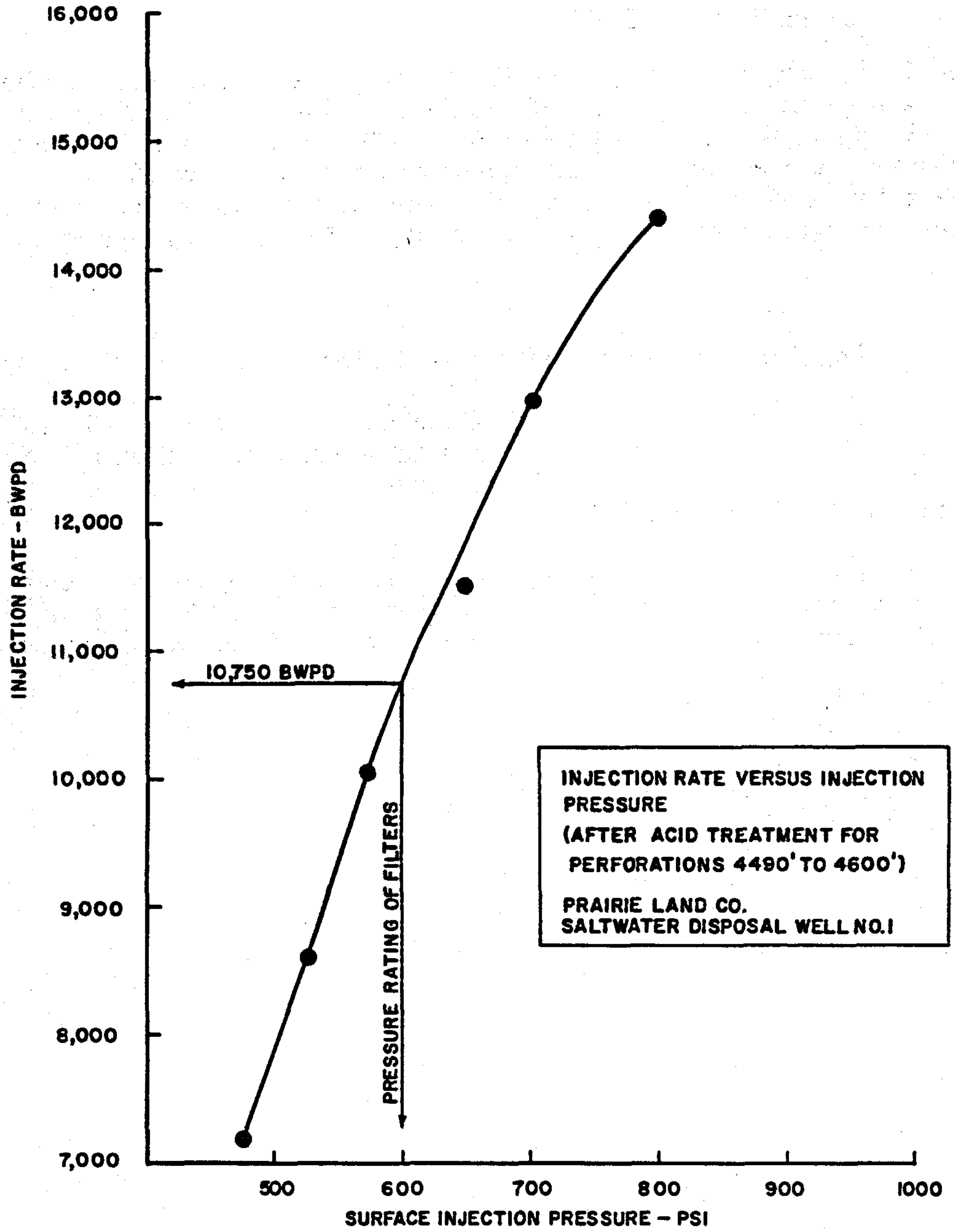


EXHIBIT 7-2 INJECTION RATE VS INJECTION PRESSURE

7.5.3 Well Setting and Christmas Tree

Exhibit 7-3 is a schematic diagram of the actual disposal well completion and wellhead. Three sets of perforations are shown in the diagram. The upper two sets were added during the test operations when additional disposal capacity was required. The work is discussed in the following paragraph.

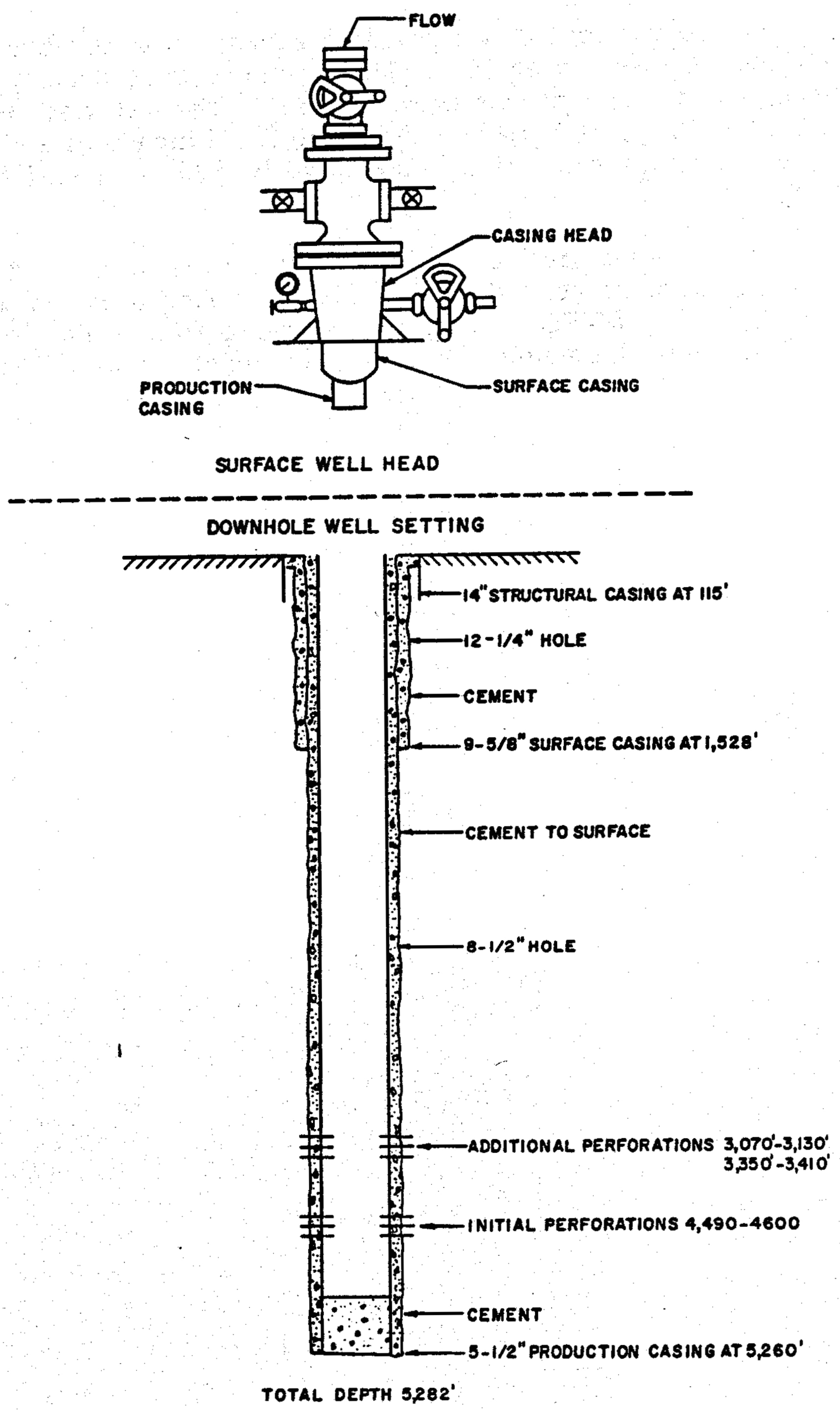


EXHIBIT 7-3 DISPOSAL WELL COMPLETION AND WELLHEAD

7.5.4 Plug Back to Alternate Sands

During the second flow test period, the disposal well injection pressure began to exceed 600 psi. It is believed that the high pressure was caused by a combination of a poor disposal zone with insufficient solids removal at the filter unit. It was decided to plug the well back to Sand "C" and Sand "D."

To obtain effective stimulation of the two proposed zones it was necessary to plug off the first disposal zone. Approximately 35 sacks of cement were pumped down to the existing perforations, and the cement was allowed to set. The well was then perforated from 3350 to 3410 feet and from 3070 to 3130 feet with 2-1/8 inch guns at four holes per foot. The newly perforated intervals were acidized with 5000 gallons of "FE" acid and 10,000 gallons of regular HF acid.

The recompleted disposal well performed satisfactorily during most of the subsequent testing. However injection pressures did exceed 600 psi during a period when disposal rates were greater than 6500 BWPD. Formation plugging from solids in the disposal water is believed to have been the main cause of the high injection pressures.

8.0 TEST OBJECTIVES

The test equipment and procedures for the Prairie Canal Company Well No. 1 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 continously and to obtain data at points indicated on Exhibit 9-1. Design criteria were the following:

• Wellhead Working Pressure	10,000 psi
• Flow Line Shut-In Pressure	8,800 psi
• Temperature	350° F
• Brine Flow Rate	20,000 BPD
• Separator Operating Pressure	1,200 psi
• Filter Operating Pressure	600 psi
• Resistance to Hydrogen Sulfide	Yes

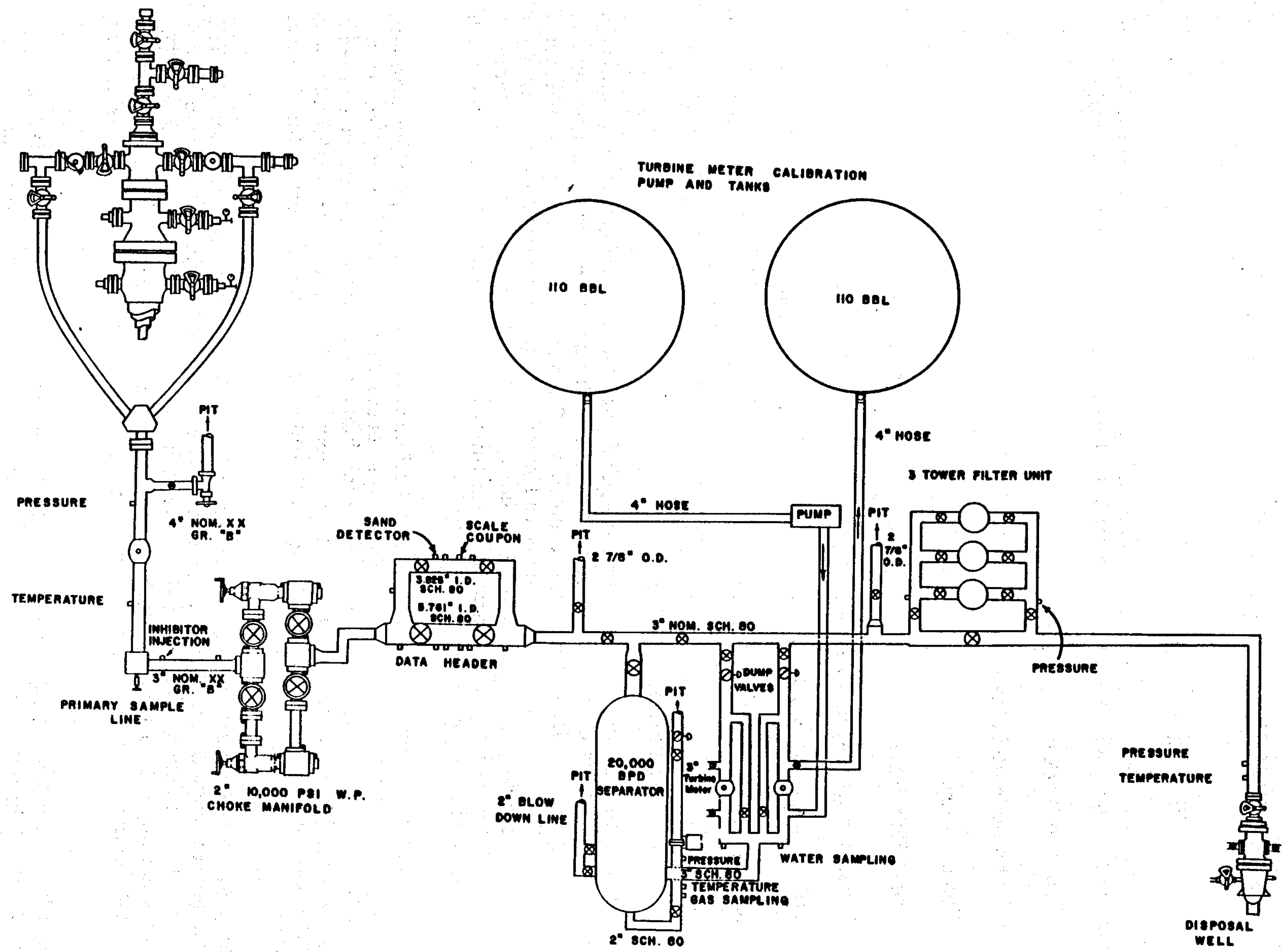
9.2 Main Process Equipment

Exhibit 9-1 is a diagram of the surface test equipment. Most of the equipment was skid-mounted for easy assembly and transportation. The well stream entered the flow line at the point where the two flow loops connected to a "Y" block. The pressure, temperature, and flow rate (water and gas) were measured ahead of the choke manifold. Effluent samples were obtained from the sampling block, which contained a 1/2-inch diameter tube that protruded into the flow stream. Steel fin-type mixing blades (turbolizers) were located ahead of the sampling tube.

A chemical inhibitor injection point was installed down-stream of the sampling tube and upstream of the choke manifold. Flow rate and pressure drop were controlled at the choke manifold by two adjustable chokes. The fluids then entered a data header at a lower pressure. The data header incorporated a sonic sand detector and scale/corrosion measuring coupons. The main flow then entered a conventional horizontal 3-phase separator.

The gas leaving the separator was measured by an orifice meter and then flared. The brine passed through a liquid-metering skid. The skid was composed of two 3-inch turbine meters and two pneumatically operated brine flow discharge valves. The manifold was designed so that the turbine meters could be separately calibrated at any time during testing. Two 110-barrel tanks and a pump were used to check the turbine meters.

The brine leaving the water-metering skid passed through a 25-micron cartridge filtering unit before entering the disposal well. Pressure and temperature were measured at the disposal wellhead.



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 1000 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.

An active mud system was maintained at the location. Mud of sufficient weight and quantity to kill the well was thus immediately available for pumping down the tubing through a kill line.

All test equipment was pressure-tested prior to flow. There were several relief and by-pass 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 were required to wear hard hats.

9.4 Data Recording

The following subcontractors participated in recording of real time data relevant to deducing the quantity and properties of produced fluids:

- Institute of Gas Technology (IGT)
- Reservoir Data, Inc. (RDI)
- 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 quantities and properties of produced fluids.

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

- **Wellhead Temperature:** Wellhead temperature was sensed by an Acromag 319-BX-4 temperature transmitter (0^{o} to 400^{o}F) installed in the high-pressure line between the wellhead choke and the choke manifold. This sensor was mounted in a tee on the side (45 degrees below horizontal) of the high-pressure line to sense liquid temperature and to avoid problems resulting from sand erosion. Temperature values were a few degrees low, because the thermal well was not in the flowing stream.

- **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 RDI.

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

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

- **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 meter, was detected using 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 used 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 Honeywell diffused silicon differential pressure transmitter (0 to 100 psi).

- **Disposal Well Pressure:** Disposal wellhead pressure was converted to electronic data by a Honeywell diffused silicon pressure transmitter (0 to 1000 psig).

- **Disposal Well Temperature:** An Acromag 319-BX-4 temperature transmitter (0° to 400°F) was used on the disposal well wellhead.

9.4.1.2 **Data Recording by IGT:** Electrical outputs from 9 of the 11 sensors described above were directly transmitted to the recording location in the IGT trailer, using four-conductor shielded cables. Output pulses from the brine turbines were amplified and shaped using Tejas Controls, Inc., "Big Tex II" units near the turbine meters. The "Big Tex II" units received 110-volt a-c power from extension cords. Output pulses were transmitted to IGT's trailer, using the same type field wire as the other data channels.

Digital recording of a twelfth channel of data, the sand detector signal, commenced during the production test. The 4-20 ma output of the OIC Sonic Sand Detector was used. Since neither side of this signal detector could be grounded, voltages above ground to each side of a 250-ohm resistor were separately digitized. Software was then used to duplicate the actual sand detector reading for permanent digital recording.

Inside the IGT trailer, signal processing was provided by plug-in cards in an HP 6940B multiprogrammer that was controlled by an HP 85 computer through an HP 59500A multiprogrammer interface unit. For each of the 4-20 ma outputs of the temperature and pressure transmitters, a precision 250-ohm resistor was used to produce a voltage signal. The analog voltages were sampled sequentially, using a relay actuator card, so that a single analog-to-digital convertor 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 are 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 at 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 of all data except the sand detector signal were produced both by real-time printouts and by storing of digital data on magnetic cartridge tapes. Backup strip-chart recording of nine analog channels was provided. Permanent records of sand detector signals were on strip-chart and magnetic tape only.

The field printout of IGT raw data for the production test is presented in Appendix F.

9.4.2 Wireline Company Recording

RDI was responsible for data recording for analysis of reservoir behavior. Data sensing and recording by RDI consisted of the following:

- **Pre-production Temperature Gradient:** Temperature was measured at depth increments of 1000 feet and near the zone tested. The temperature sensor was a thermistor-type Gearhart-Owens 1-7/16 inch differential temperature tool. Temperature, digitally displayed at the surface, was logged by hand.

- **Pre-production Pressure Gradient:** Pressure from a Hewlett-Packard downhole pressure gauge was recorded digitally at depth increments of 1000 feet and near the zone tested.

- **Bottom-hole Pressure:** During flow and buildup test, pressure at the 14,611-foot gauge datum, 33 feet above the end of the tubing string, was sensed using a Hewlett-Packard quartz crystal pressure sensor.

- **Wellhead (Annulus) Pressure:** Wellhead pressure in the annulus was sensed with a Panex quartz crystal pressure sensor.

- **Wellhead Brine Production Rate:** A three-inch Camco turbine meter and pickup were installed in the high-pressure flow line from the wellhead to determine the total rate of two-phase brine and gas production at wellhead temperature and pressure.

- **Brine Temperature:** A thermistor-type temperature sensor was installed in a thermal well in the high-pressure flowline from the wellhead. The sensor was recessed to avoid possible sand erosion.

While running temperature and pressure gradients, data recording was performed in the wireline truck. At each depth station the following actions were performed:

- Manually recording depth indicated by the wireline odometer.

- Observing a visual display of temperature until the value stabilized. Then manually recording temperature and setting that value into the HP computer on the HP bottom-hole pressure gauge.

- Switching the downhole tool to pressure recording and then manually logging the stabilized value indicated on the computer display.

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

Electronic chassis procured from suppliers of the Panex surface pressure gauge and HP's downhole pressure gauge provided digital outputs compatible with the HP 9825 computer used for system control and permanent data recording. Neither brine rate nor brine temperature was successfully digitized and recorded by RDI during this well test. Values provided by IGT were manually entered onto the RDI recording.

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 changes in choke settings up 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.

RDI data for the production test is presented 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 for 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 recorded on 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.

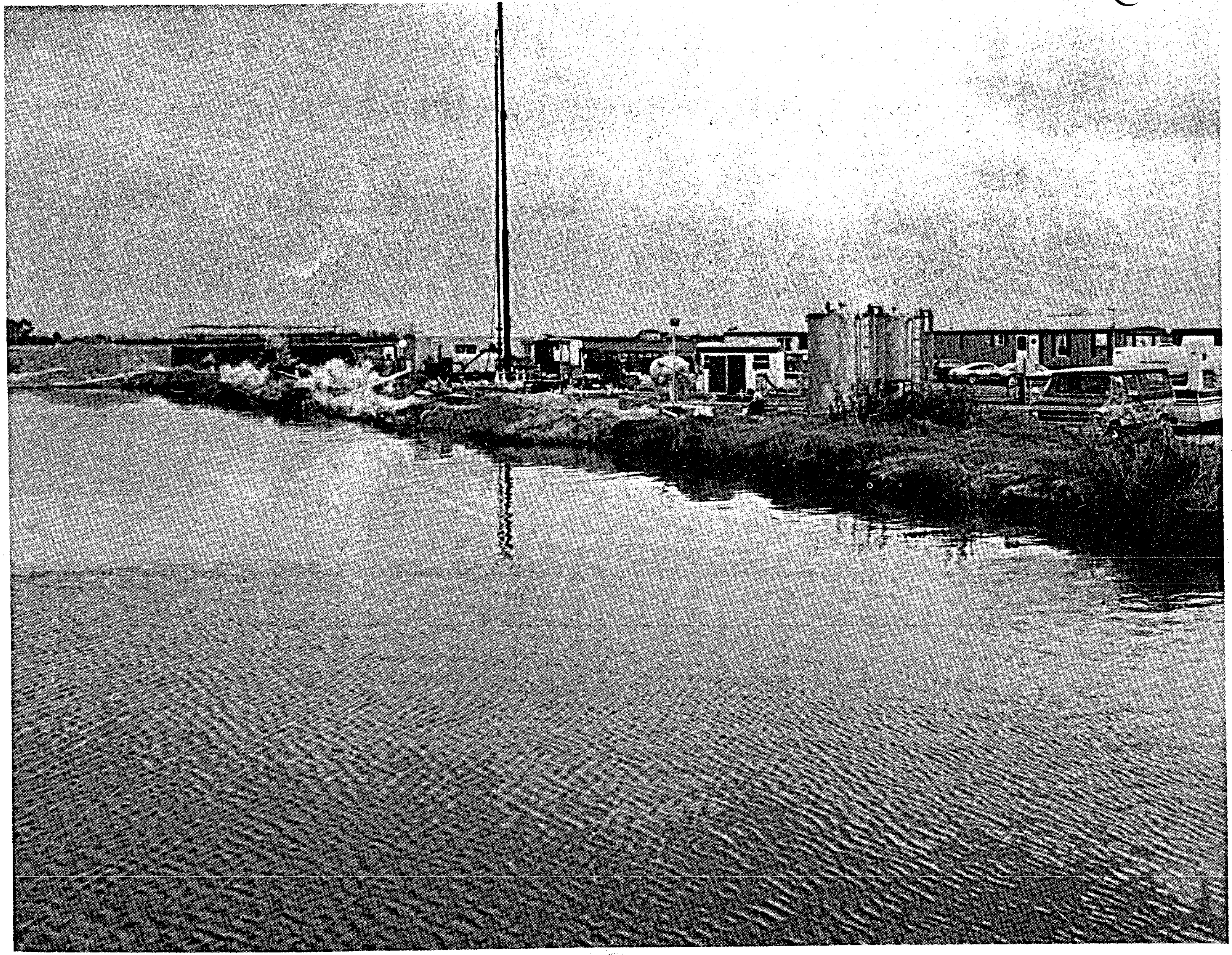


Photo 9-1 View of testing equipment and location from reserve pit.

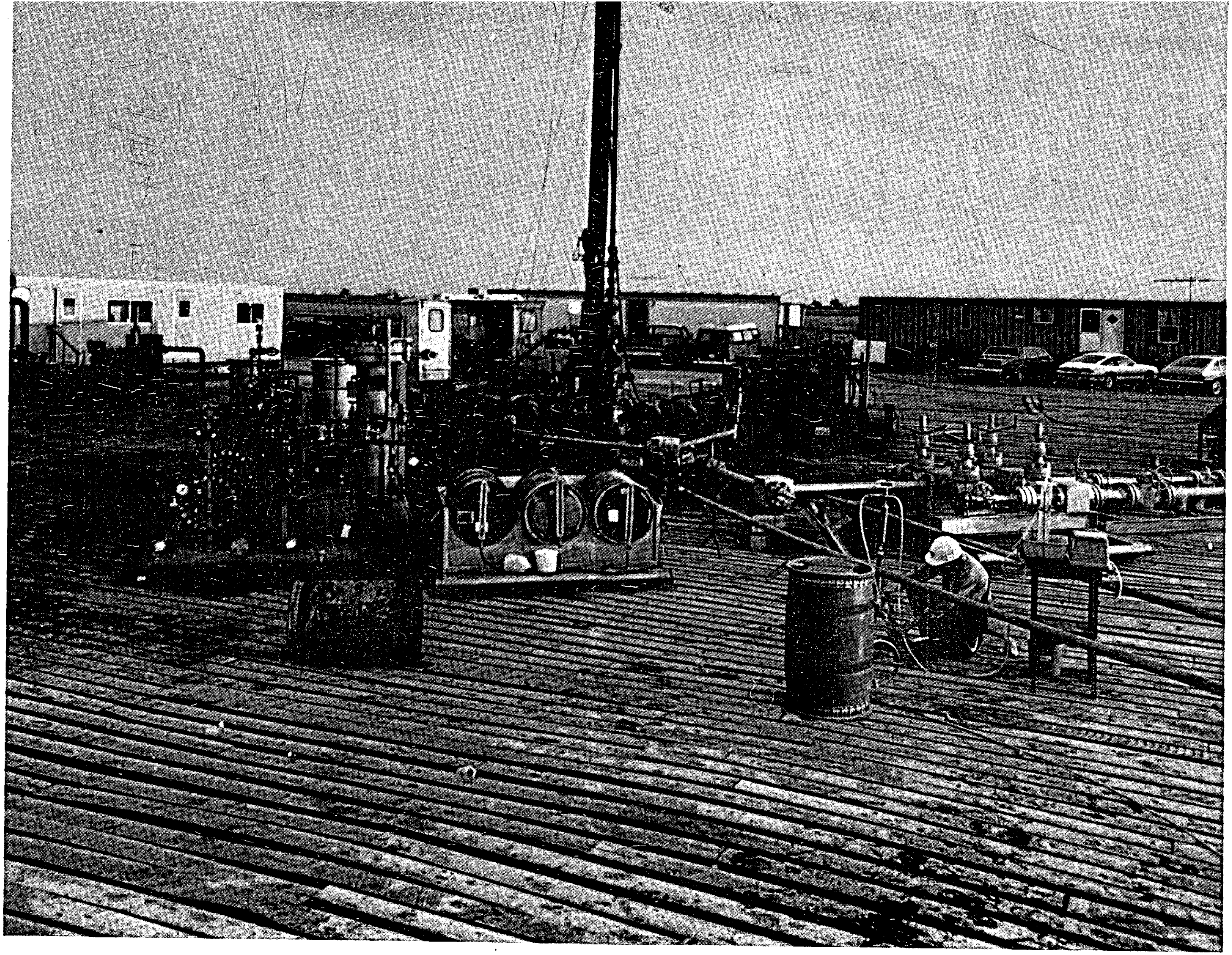


Photo 9-2 The unit with three chemical drums includes two high-pressure chemical inhibitor injection pumps.

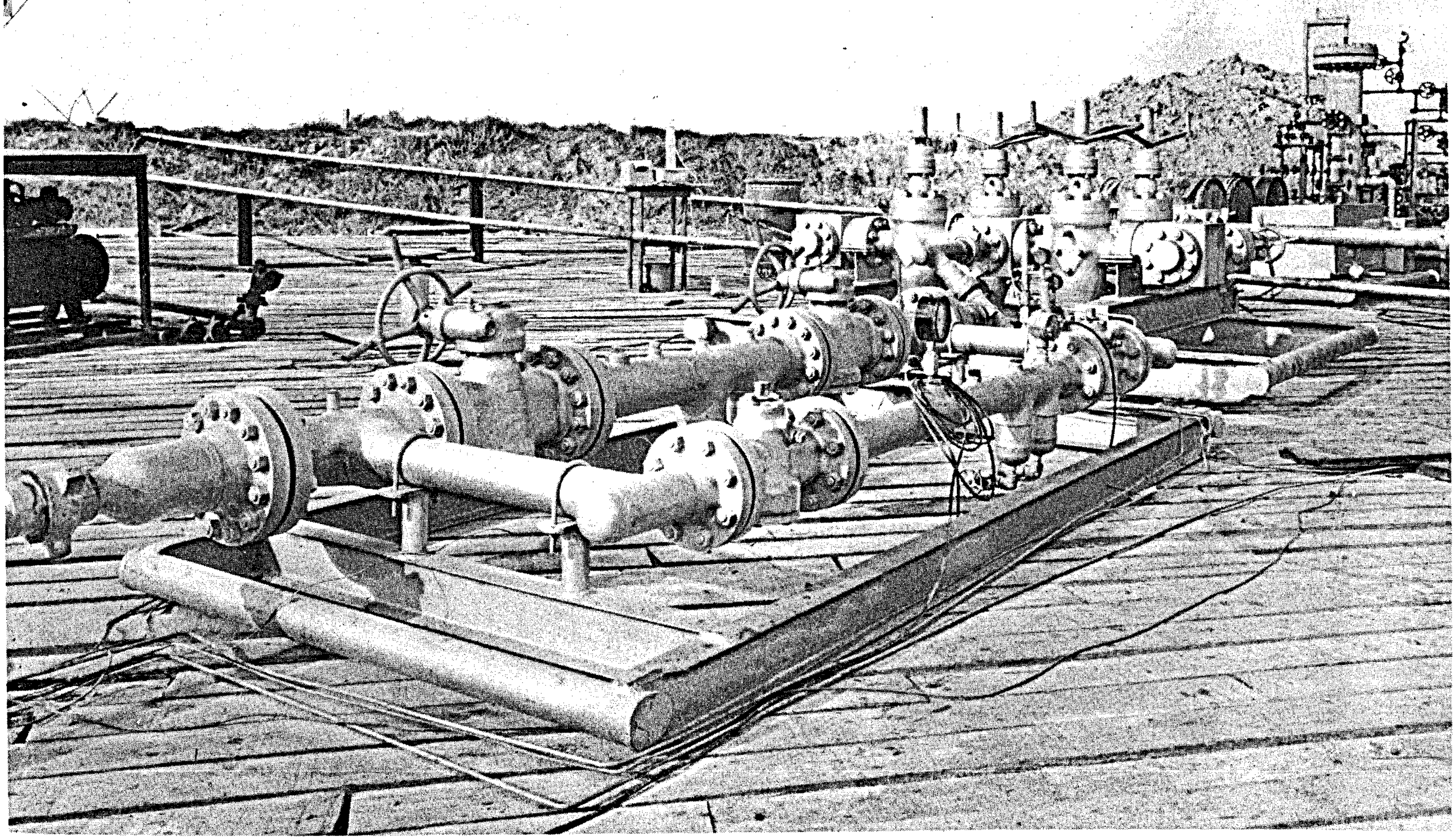


Photo 9-3 Data header with choke manifold to the right of center.

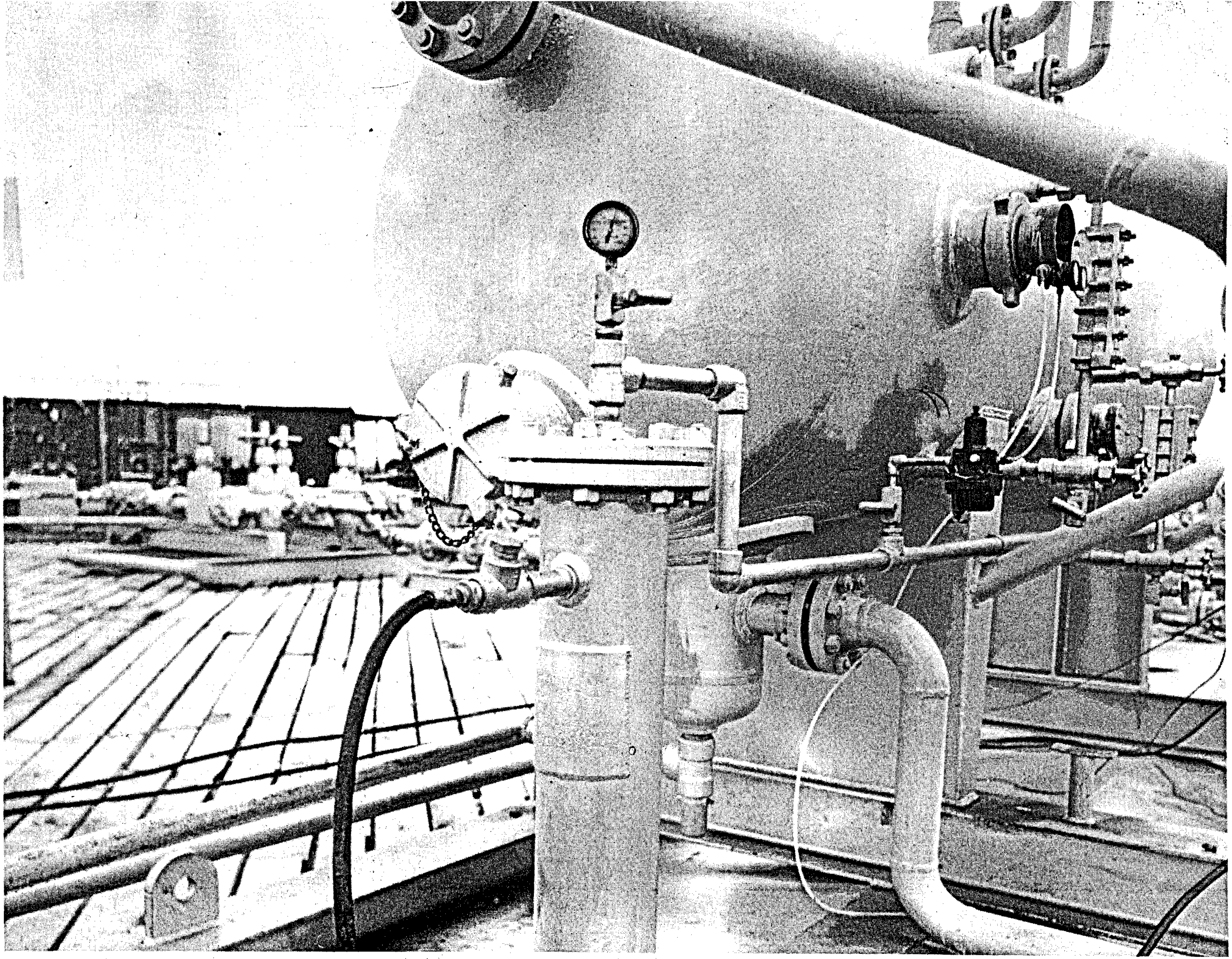


Photo 9-4 Gas leaves the separator through the 2-inch pipe at top center. Water leaves through the 3-inch pipe at bottom right.

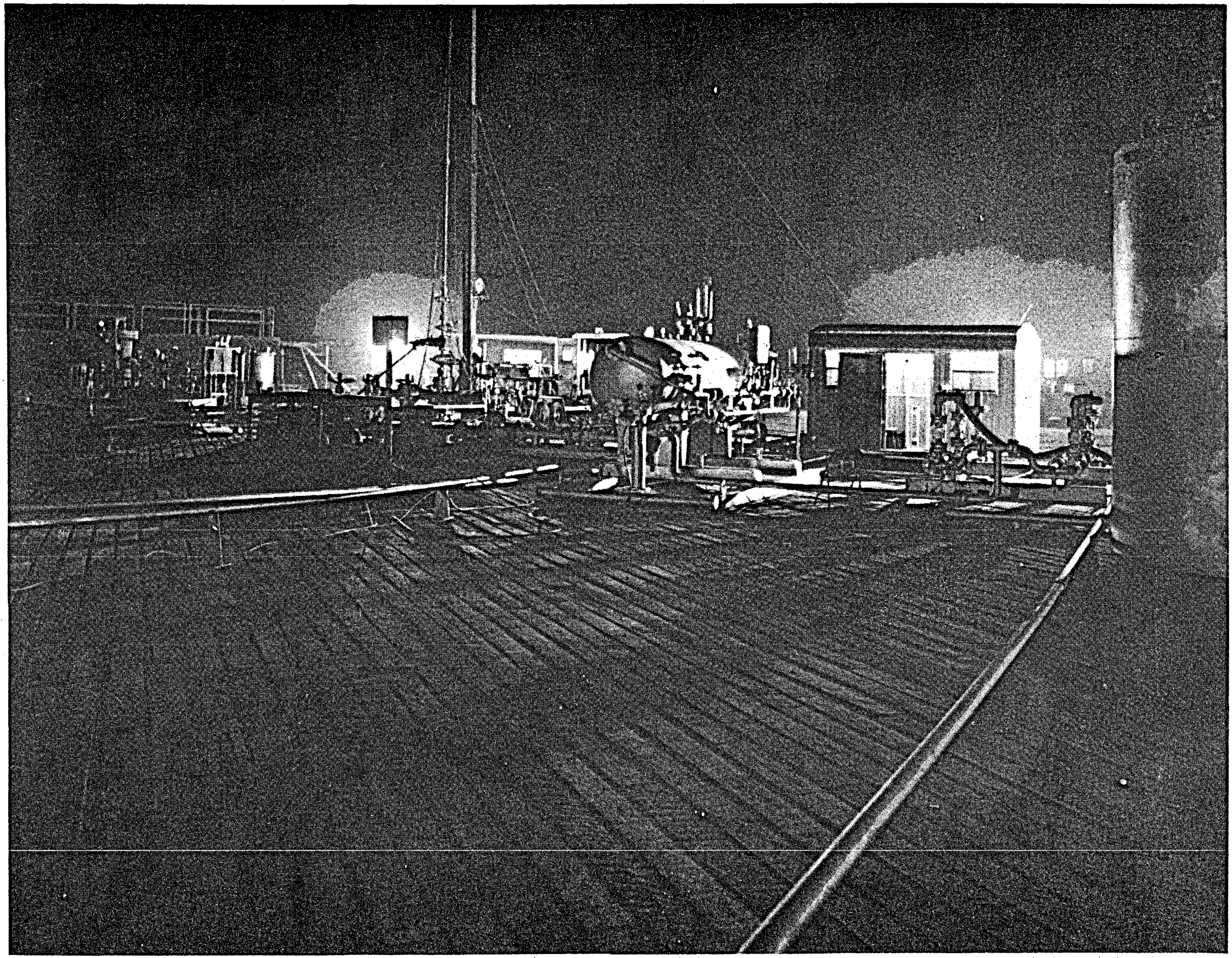


Photo 9-5 Separator and Weatherly's test house.

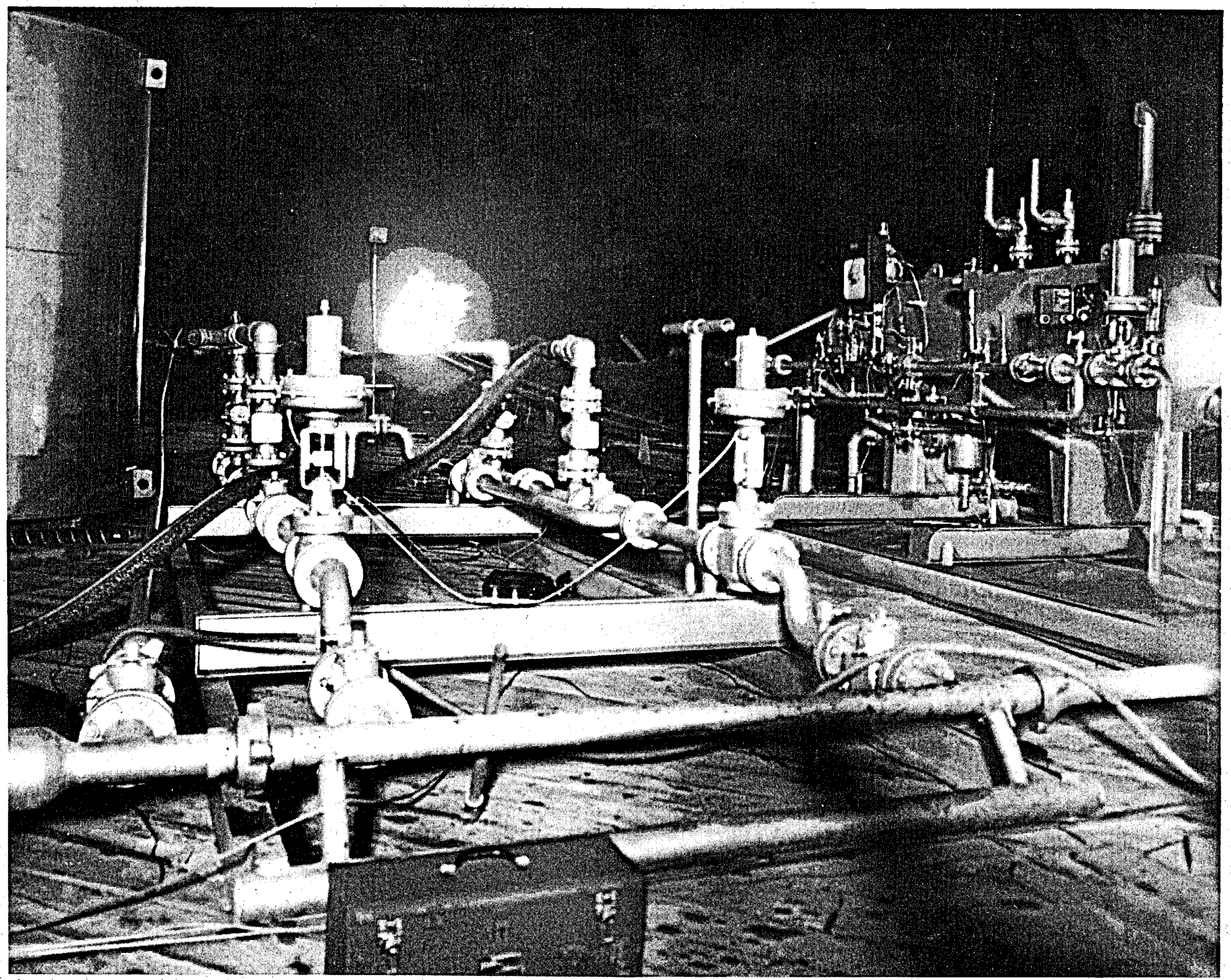


Photo 9-6 110-barrel calibration tank, water metering manifold, and separator.

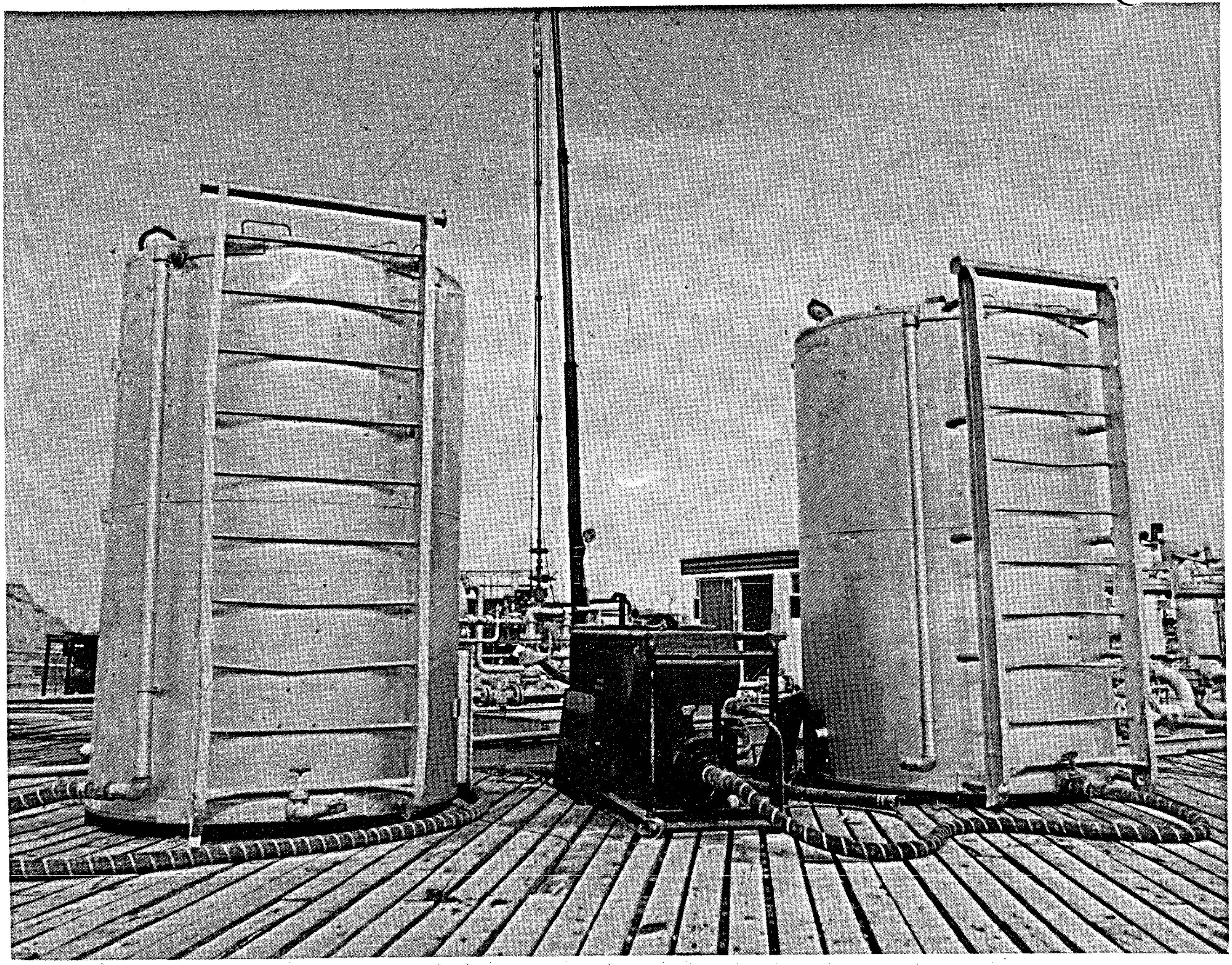


Photo 9-7 Pump and two 110-barrel tanks were used to calibrate the turbine meters.

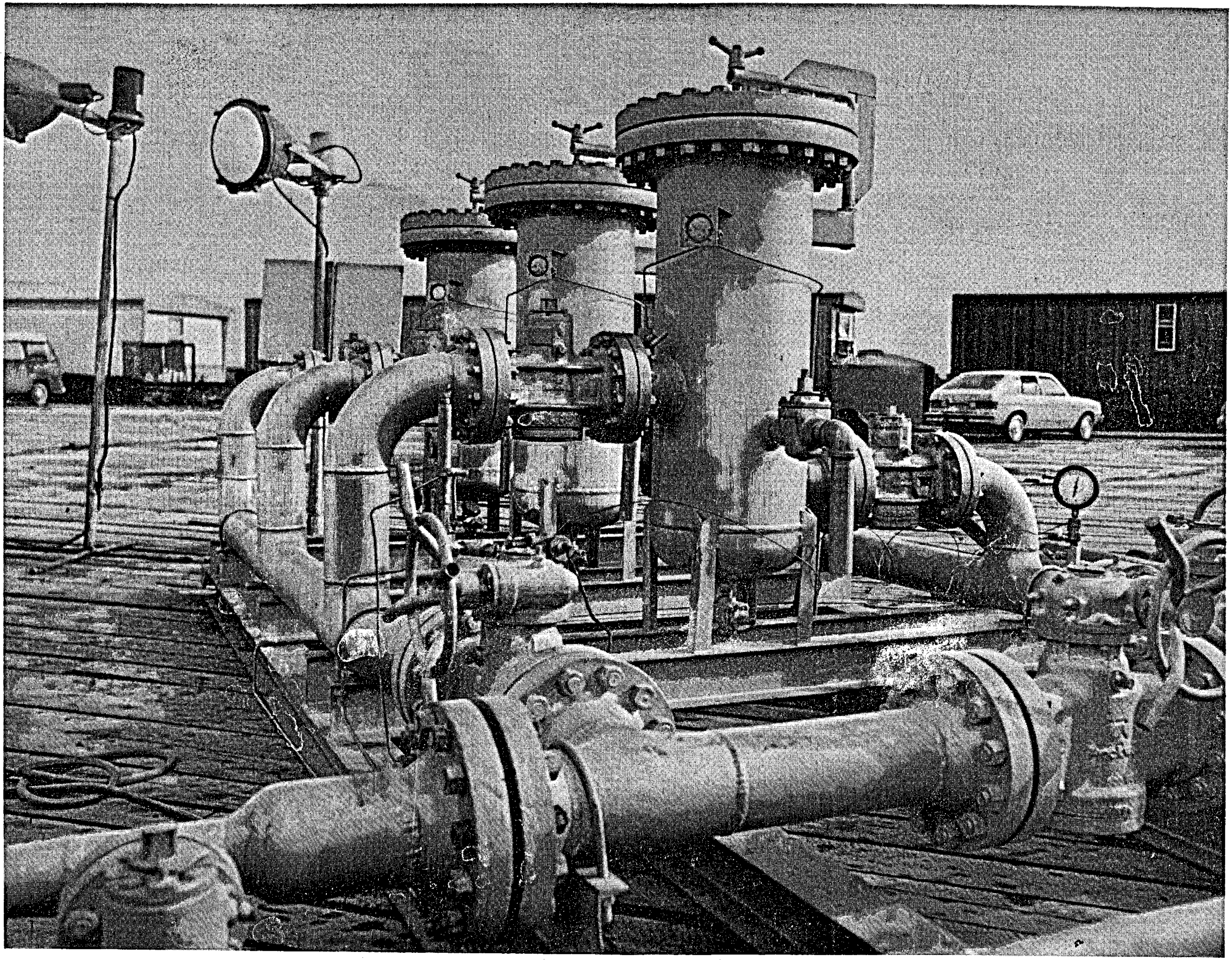


Photo 9-8 Three-tower filter unit with 25-micron filters. Flow capacity of each tower is 20,000 BWPD.

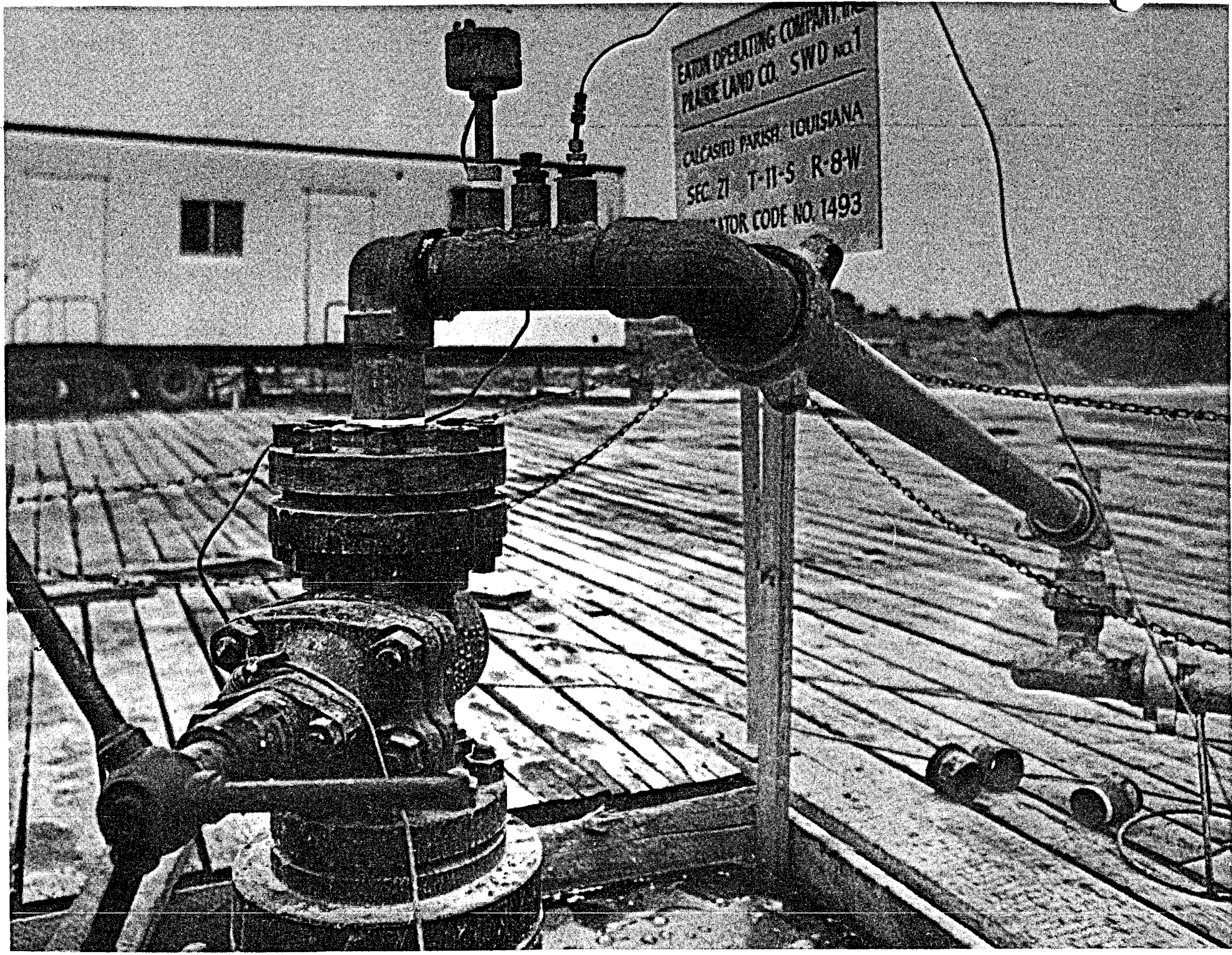


Photo 9-9 Pressure and temperature sensors mounted on top of disposal well.

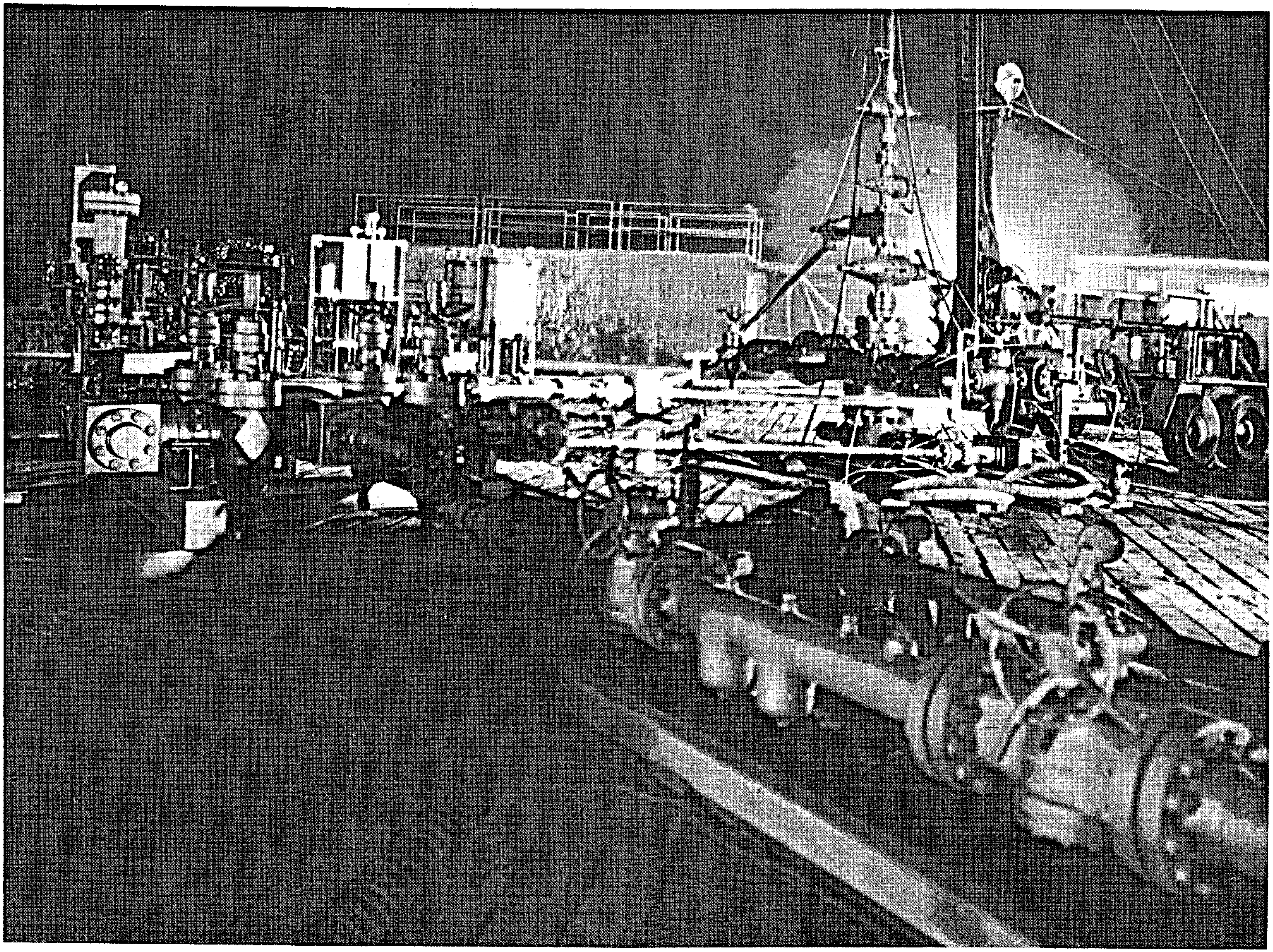


Photo 9-10 Test well, choke manifold, and data header. Drilling fluid storage tanks are in the background.

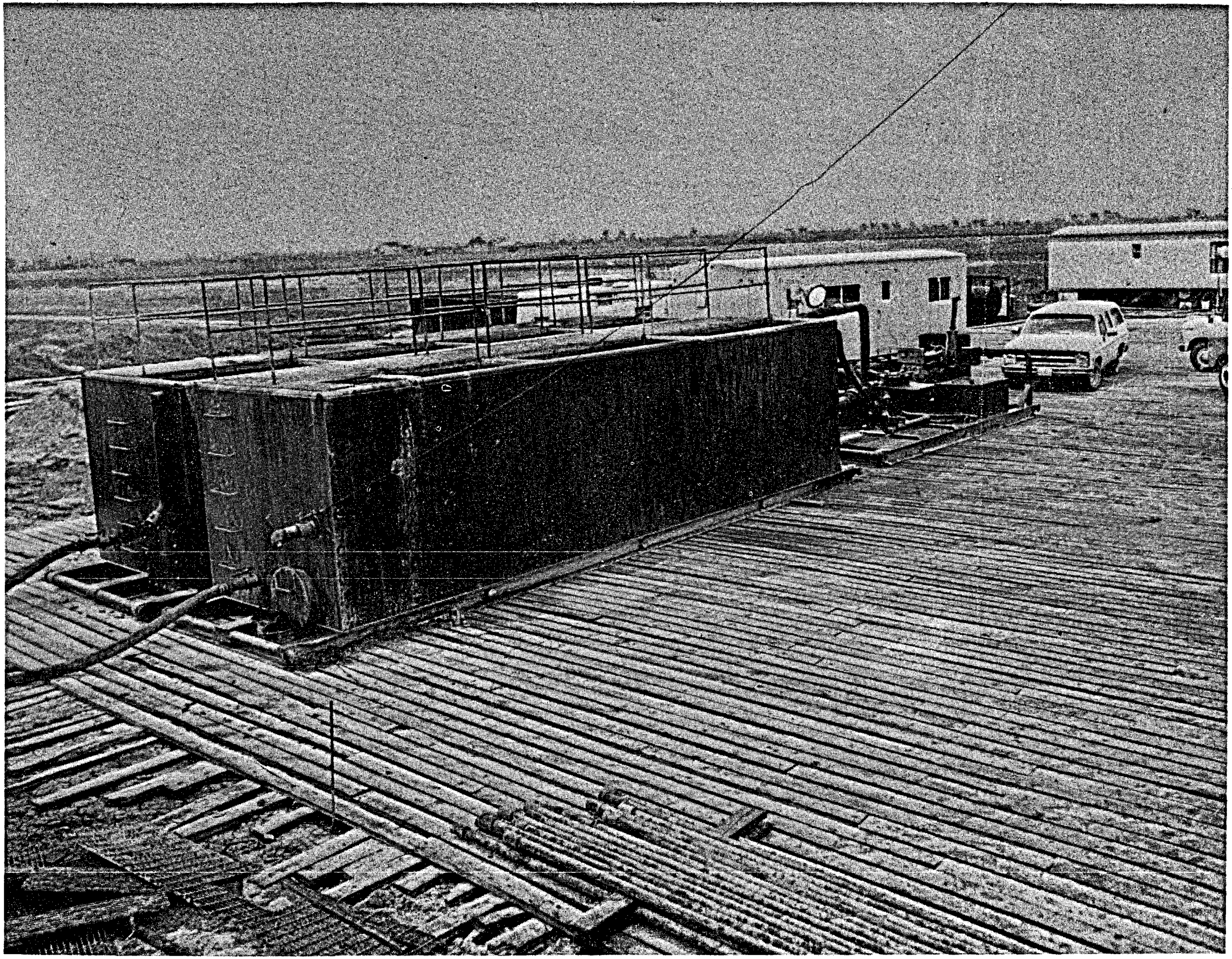


Photo 9-11 Drilling fluid of sufficient weight and quantity to kill the well was stored at the location for safety.

10.0 PRE-TEST OPERATIONS

10.1 Perforating and Wellbore Cleaning

The secondary test sand was first perforated on February 19, 1981. The depth interval was perforated from 14,782 to 14,820 feet with 8 holes per foot, using 1-11/16 inch "Hyperdome II" zero-phase perforating guns. A total of four perforating trips were made, each run into the hole providing four holes per foot over an interval of either 13 feet or 25 feet. When the first gun was fired in the interval from 14,795 to 14,820 feet, the surface pressure increased from 5600 to 6000 psi. The well was allowed to flow at about 1500 BWPD for 20 minutes. During this period the surface pressure decreased to 4600 psi. The interval from 14,795 to 14,820 feet was re-perforated with 4 holes per foot. The well was flowed for 30 minutes at about 500 BWPD. The surface pressure decreased from 6000 psi to 5600 psi. The well was then flowed for a few minutes at 3200 BWPD. During this period the surface pressure fell to 2200 psi. The rate was then reduced, and the well was allowed to produce with a surface pressure of 5500 psi until the formation water reached the surface. The total volume of water produced from the interval 14,795 to 14,820 feet was about 500 barrels. Produced brine was dirty at the termination of cleanup flow.

The interval from 14,782 to 14,795 feet was then perforated with two guns for a total of 8 holes per foot. The well was flowed for 4 hours at 1440 BWPD and a flowing pressure of 5400 psi. Approximately 240 barrels of water were produced.

A deliberate effort was made to keep flow rates low and produce a minimal amount of water from the well during the wellbore cleaning operations because of concern over possible sand production, as experienced from the primary zone.

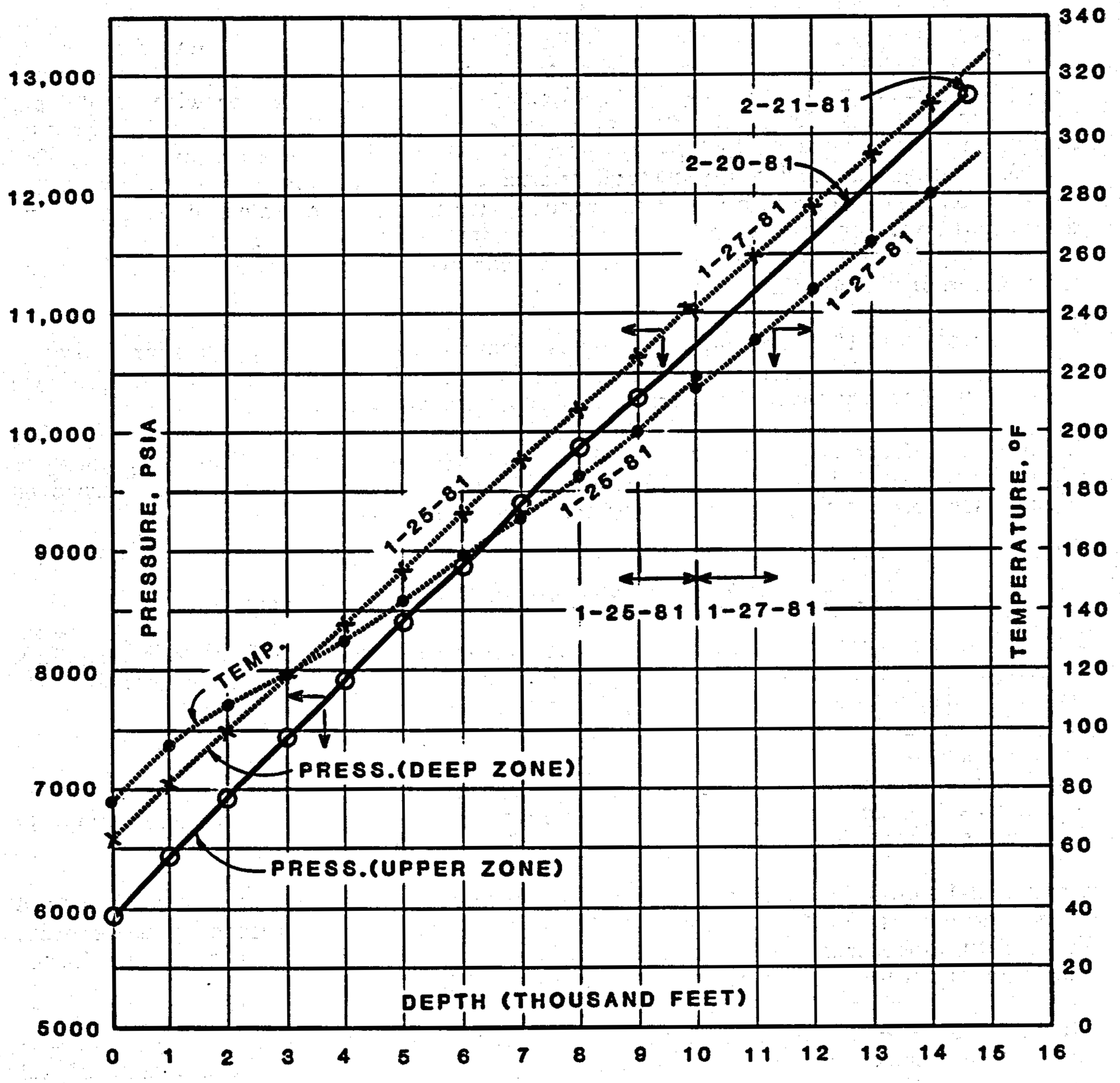
10.2 Preliminary Wellbore Pressure and Temperature Recordings

Static wellbore pressure and temperature readings were obtained by Reservoir Data, Inc. on January 26, 1981 while attempting to test the primary zone. A Hewlett-Packard quartz crystal pressure gauge and a Gearhart Thermistor-type tool were used to measure temperature and pressure at 1000-foot depth increments. At each depth the temperature was recorded first, because the temperature reading stabilized faster then the pressure reading. After recording the temperature, the selector switch was turned to the pressure recorder. The pressure value was allowed to stabilize for approximately 20 minutes at each depth before a pressure reading was taken.

Exhibit 10-1 shows the measured wellbore pressures and temperatures graphically plotted as a function of depth. Exhibits 10-2 and 10-3 are the tabulations of these data. Temperature measurements were conducted during the preceding January for the deeper sand zone and were not needed for this upper reservoir sand.

Static wellbore temperature readings were not taken when the secondary zone was ready for testing, because the data was already on file. The Hewlett-Packard quartz crystal pressure gauge was lowered into the well to a depth of 14,611 feet on February 21, 1981. The bottom-hole pressure at that depth was 12,858 psia. The pressure at the midpoint of the perforations was projected to be 12,942 psia. The temperature of the reservoir was interpreted to be 294°F from earlier data.

PRESSURE & TEMPERATURE VS DEPTH
PRAIRIE CANAL CO. NO. 1 WELL
JAN. 25, 27 AND FEB. 20-21, 1981



NOTE: SOLID LINE IS FOR PRESSURES CONDUCTED ON SAND AT 14,782' TO 14,820'

DOTTED LINES FOR SAND AT 14,976'-15,024'

Eaton Industries of Houston, Inc. EXHIBIT 10-1
Eaton Operating Co., Inc.

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

PRESSURE AND TEMPERATURE VERSUS DEPTH
PRAIRIE CANAL CO. WELL NO. 1
Lower Sand Zone
January 25, 27, 1981

Depth (feet)	Pressure (psia)	Pressure Gradient (psi/ft)	Temperature (°F)
January 25, 1981			
0	6,603.09	----	74
1,000	7,050.01	0.447	96
2,000	7,498.30	0.448	108
3,000	7,945.65	0.447	118
4,000	8,393.27	0.448	129
5,000	8,839.96	0.447	142
6,000	9,306.73	0.447	157
7,000	9,753.31	0.447	170
8,000	10,195.65	0.442	185
9,000	10,653.63	0.458	200
10,000	11,074.82*	0.421	219

Bad place in cable detected and instruments removed from wellbore.

Depth (feet)	Pressure (psia)	Pressure Gradient (psi/ft)	Temperature (°F)
January 27, 1981 (New cable)			
10,000	11,040.83*	----	215
11,000	11,474.65	0.434	232
12,000	11,905.75	0.431	247
13,000	12,334.23	0.428	264
14,000	12,761.12	0.427	282
14,950	13,156.68	0.396	292

*Difference in pressure and temperature at same depth is caused by insufficient time at this depth for all instruments to equilibrate for higher temperature. During previous run, instrument was stopped at each datum for 15 minutes to allow temperature to come to equilibrium.

PRESSURE AND TEMPERATURE VERSUS DEPTH
PRAIRIE CANAL CO. WELL NO. 1
Upper Sand Zone
February 20-21, 1981

Depth (feet)	Pressure (psia)	Pressure Gradient (psi/ft)	Temperature (°F)
February 20, 1981			
0	5,936.87	----	85.3
1000	6,440.18	0.503	95.5
2000	6,932.87	0.493	107.3
3000	7,424.39	0.492	118.5
4000	7,916.55	0.492	129.5
5000	8,404.80	0.488	141.1
6000	8,893.55	0.489	153.8
7000	9,380.11	0.487	167.5
8000	9,865.31	0.485	181.3
9000	10,347.23	0.482	195.5
February 21, 1981			
14,644	12,858.40*	0.397	----

*Unable to process signal from elements when below 9000 feet. Instruments were pulled out of well and temperature gauge removed and the pressure element run to datum depth of 14,644 feet. Therefore pressure at 14,644 feet was measured some 24 hours after previous readings. Pressures were measured on completions at the upper sand. Previous readings on February 25 and 27 were conducted with lower sand completion.

11.0 TEST SEQUENCE

The discussion below concerns the secondary sand only (14,782-14,820 feet).

The test sequence for the Prairie Canal Company Well No. 1 included two short flow periods to clean the hole during perforating operations. Approximately 740 barrels of water were produced from the perforations. Following this preliminary flow period, a sequence of flow and buildup tests was carried out to evaluate reservoir parameters, produced fluids, and flow characteristics.

11.1 First Flow Test

The initial reservoir pressure drawdown flow test began on February 21, 1981 and lasted 2.51 days. During the test 4455 barrels of water were produced, at an average rate of 1775 BWPD. This test provided quick early information on reservoir characteristics and properties of produced fluids.

11.2 Short First Buildup Period

The first flow test was followed by a 0.14-day reservoir pressure buildup test. This test provided additional early information on reservoir parameters.

11.3 Second Flow Test

The second reservoir pressure drawdown flow test lasted 1.21 days, during which 4953 barrels of water were produced, at rates ranging from 2000 to 6500 BWPD. The test was terminated when injection pressures at the disposal well became excessive. It was decided to discontinue flow testing while the disposal well was recompleted in another zone.

11.4 Second Buildup Period

The test well was shut in for 0.93 days while the disposal well was being recompleted. The bottom-hole pressure and surface pressure were continuously recorded during this time.

11.5 Third Flow Test

The third flow test was 4.00 days long. The well was produced at flow rates ranging from 4500 to 7200 BWPD, for a total of 23,202 barrels of water. During this flow test, severe oscillations in separator conditions occurred, and disposal well pressure became too high for filter operation.

11.6 Third Buildup Period

The final reservoir pressure buildup survey was conducted for 2.00 days while plans were made for a special flow test to study the effects of separator operating pressure on gas and brine properties. The well remained shut in to record bottom-hole pressures until March 4, 1981 when the Hewlett-Packard pressure gauge was removed from the hole.

11.7 Fourth Flow Test

The final flow test lasted 1.17 days, during which 3895 barrels of water were produced at rates ranging from 1600 to 6300 BWPD. Samples of brine and gas were obtained at various separator pressures during this test. The well was shut in on March 5, 1981, with all testing completed.

12.0 TEST RESULTS AND ANALYSIS

12.1 Pre-Test Flow Period

The flow period before the first flow test was occupied by running original pressure and temperature gradients. A problem developed in maintaining electrical communication between the Hewlett-Packard pressure element and the surface recording instruments before the instruments had reached total depth. The cause was probably additional current resistance due to the temperature gauge also installed on the wireline system. The temperature gradient for the wellbore had already been obtained while attempting to test the deeper sand zone; so the temperature gauge was removed from the wireline, and the pressure element was run to a datum of 14,611 feet, with good operational results.

The pressure at 14,611 feet was 12,858.41 psia, with a temperature of 291°F. The corrected pressure, calculated to the center of perforations, or 14,801 feet, was 12,941.72 psia. The temperature for the center of perforations was 294°F. This temperature was used in all pressure computation by the computer system for the flowing temperature at the datum of 14,611 feet, the datum selected for the pressure element for all flow tests. At this depth, the temperature at the pressure element approached reservoir temperature shortly after the well was placed on flow.

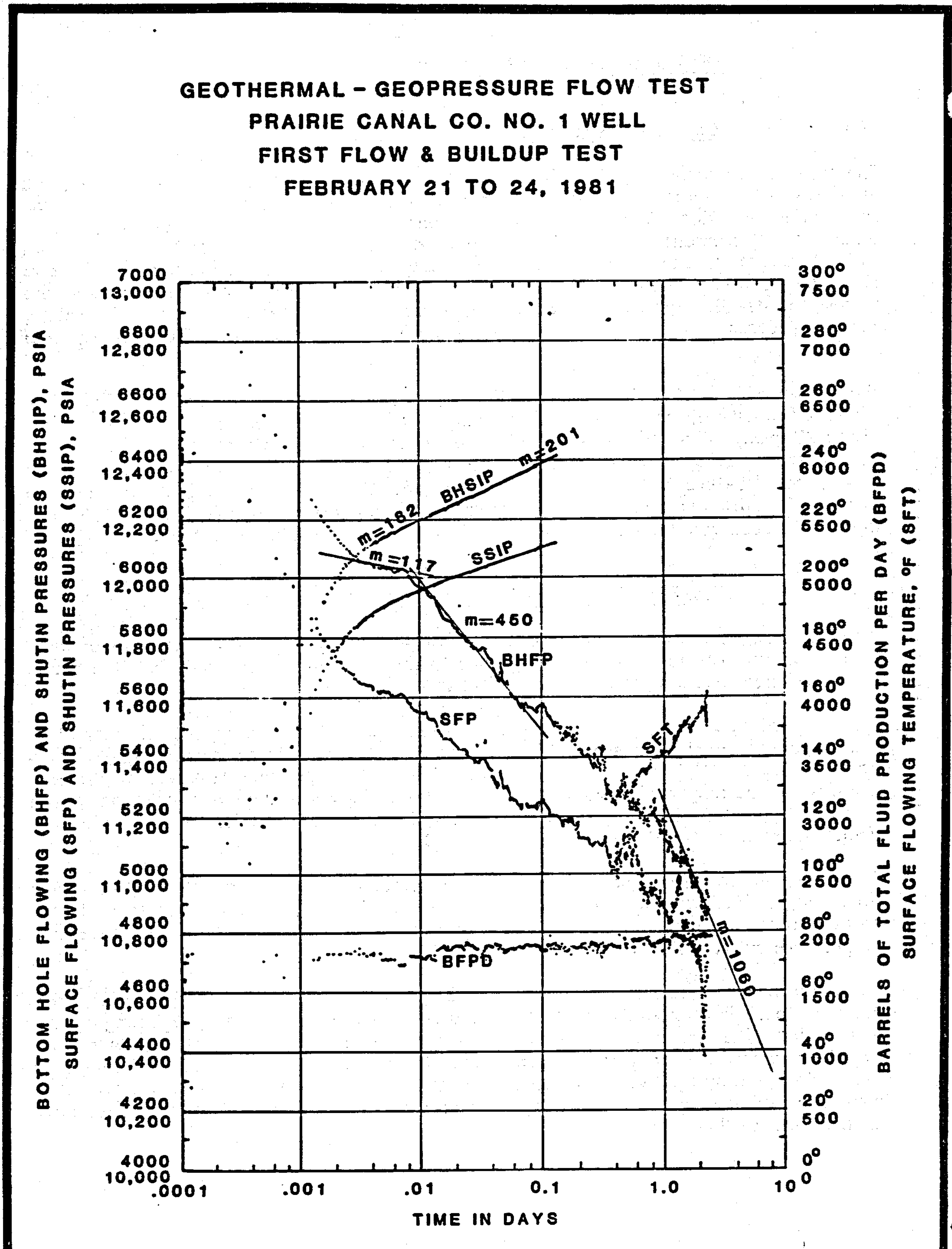
12.2 First Flow Test Period

The first flow period was designed as a constant-production-rate flow test to gain basic reservoir data. The test plan was to gradually and uniformly open the adjustable choke to a production rate of approximately 2000 barrels of water per day.

The wing valve, just ahead of the choke manifold in the flow system, was opened at 21:56:00 hours on 21 February 1981. This caused the pressure at instrument datum to drop from 12,858.41 psia to 12,854.63 psia. The start of the flow test was at 21:58:30 hours, when the adjustable flow choke at the mainifold was opened very uniformly. The pressure dropped to 12,065 psia within 4.5 minutes, for a total loss of 790 psi. The production rate appeared uniform at 1800 BWPD.

The adjustable choke was not changed for the remainder of the first flow test, which continued to 10:14:30 hours on 2-24-81, or a total of 2.511 days. Exhibit 12-1 is a semilog graphical plot depicting sand face pressure drawdown, production flow rate, and the pressure buildup that followed.

The flow meter was located ahead of the gas-water separator, to give equivalent reservoir total fluid flow rates at 10-second intervals from the very beginning of the flow period. The production rate plot and the pressure drawdown plot show erratic variations in rate and pressure. These variations are partially affected by cleaning of perforations and by reservoir lithological variations. The variations in lithology could be from minor thickening and thinning of the sand intervals as the pressure transients move out from the wellbore.



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

EXHIBIT 12-1

DOE CONTRACT NO.
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The production rate plot depicts a general increase in flow rate with time. There is also a continuous increase in surface flowing temperature from 69° to 180°F during the 2.511 days on flow. The temperature effect would cause an increase in surface volume or in the metered production rate, without a noticable increase in sand face flow rate. The cleaning of the sand around the wellbore is depicted by a sharp increase in pressure and then following of the same pressure drawdown slope but at a higher pressure position on the graphical plot. The final flow meter production rate was approximately 1950 BWPD, or 150 barrels per day, higher than the initial flow rate.

The flow rates discussed are the values read from the flow meter installed ahead of the production choke and separator, in other words values of the full well stream. IGT has prepared a table of corrected produced standard (14.73 psa to 60°F) volume of brine in Appendix K. This table represents production after the separator was filled with brine, starting at 23:00 hours, or 61.5 minutes after production started. This is equivalent to 0.0427 days on the graph in Exhibit 12-1.

Basic reservoir calculations must be accomplished prior to the end of the first radial drawdown slope, which occurred at 0.0074 days (10.66 minutes). The flow meter was set to average flow rates every 10 seconds. These 10 second rates are plotted on Exhibit 12-1.

The calculation of permeability requires these measured flow rates to be converted to reservoir volumes at reservoir temperature and pressure. The surface pressure was 6407.53 psia, with surface temperature at 69°F. The well had been static for several days, with no free gas in the wellbore; therefore, the early flow rate for the first 10 minutes should have had little or no gas flowing past the meter and a temperature close to standard conditions. This would support a metered volume that would need little or no correction for a standard volume and a sand face flow rate at near reservoir volume. This would allow the use of the early metered volume to arrive at a reasonable sand face rate for this early flow time.

The first radial flow drawdown slope is found on the graph, Exhibit 12-1, between 0.0030 and 0.0074 days. The pressure drawdown rate was 117 psi per cycle at a producing rate of 1800 standard barrels of fluid per day. The productivity calculated for this radial flow period was 1296.06 md-ft. This would convert to 92.6 mds permeability, if 14 feet of net effective sand is used.

The skin effect is +1.731, with a pressure loss due to skin of 176 psi. The productivity index (PI) was 1.9397 barrels per day per psi. The ideal PI, assuming no skin effect, would be 2.3936, which would result in a completion efficiency of 81.03 percent. The corrected total of standard barrels of reservoir brine produced during the 2.511 days of flow was 4455 barrels. The prior production was 750 barrels, for a cumulative total of 5205 barrels of brine. The 208 MCF of gas produced with the 4455 barrels of brine would give an average gas/brine ratio of 46.69 cubic feet per barrel.

The total radial distance explored in 2.511 days was calculated to be 3897 feet. The first permeability barrier was detected at a distance of 212 feet from the wellbore. The degree of slope change for this barrier would reduce the flow angle to 93.6 degrees around the wellbore. This would indicate more than one barrier equidistant from the wellbore. The interpretation could be two intersecting sealing faults, or possibly a sand lense type permeability pinch-out closing the flow angle to 93.6 degrees.

The next permeability barrier was detected in 1.6 days of flow time and reduced the productive flow angle to 39.7 degrees. This would allow an explored area of about 120.9 acres. The drawdown slope of 1060 psi per cycle for 2.511 days, with an average producing rate of 1825 BWPD, would allow an explored volume of aquifer of 4.38 million barrels. The pore volume for 120.9 acres, with 14 feet of net sand, would only account for 3.061 million barrels. This is not as close a check as one would like. These calculations are found on the calculation data sheets, Exhibits 12-2a and 12-2b.

12.3 First Buildup Test

The pressure buildup test that followed the primary flow test was conducted between 10:14:30 and 13:30:50 hours on 24 February 1981. This is a shut-in period of 3 hours, 16 minutes and 20 seconds, (196.33 minutes; 0.1363 days). The plot of the buildup pressures are also found on Exhibit 12-1. The mechanics of closing the flowing well were very smooth, and the straight line slope occurred at about 0.005 days, or 7.2 minutes, on the log of time plot.

The plot depicts a buildup slope of 182 psi per cycle, with an increase to 201 psi per cycle at 0.06 days. This does not compare to the data from the drawdown test. Frequently the virgin well test of a reservoir will present a mirror image effect between the initial constant-rate drawdown and the buildup test that follows. On Exhibit 12-1 the early slope of 117 psi per cycle seen on the drawdown plot is not depicted on the buildup plot. The drawdown slope of 450 psi per cycle occurs on the same time scale as the 182 and 201 slope seen on the buildup plot.

Plotting the pressure buildup and drawdown on the same graph is a fundamental method of improving engineering interpretation of the basic reservoir data. Figure 12-1 presents an erratic plot of pressures recorded during the production drawdown and a very smooth plot of the buildup pressures that followed. The drawdown pressure data is very sensitive to the sand face production rate as the pressure transients move further into the static reservoir. The buildup test is effected by the pressure buildup at the sand face and also by the effect of the prior production pressure transients still moving farther into the reservoir. This dual effect creates an averaging or smoothing of the pressure changes at the sand face.

The interpretation of the pressure buildup is found on Exhibits 12-3a and 12-3b. The buildup pressure slope of 182 psi per cycle allows a calculated 844.75 md-ft of reservoir productivity. The permeability, using 14 feet of net effective sand, is 60.3 mds. This is about 65 percent of the 92.6 mds determined from the drawdown test. A skin factor of 2.06 would be equal to a pressure loss from skin or partial penetration of 326 psi.

Note that the slope of 182 psi per cycle occurs on the log plot of time at the same position at which that the second slope of 450 psi per cycle occurred on the prior drawdown plot. Is this really the first slope, or was the first slope missed in the buildup and is the 182 psi per cycle really the second slope? The other postulation would assume the first drawdown slope of 117 psi per cycle is in error, and the 450 slope is the true full radial drawdown slope. This could not be true, since this value would calculate a negative skin, which is not logical from the completion method. In other words, the buildup test in this case is not reliable for gaining good reservoir data.

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST

FOR

GEOTHERMAL-GEOPRESSURED WELL

No. 1

Test date: Feb. 21-24, 1981 Type Test: Drawdown Lease and Well No. Prairie Canal Co. No. 1

Producing Formation: Hackberry Sand, Upper Frio Field: South Lake Charles

Hole size: ______ Casing Size: 5 1/2" Tubing Size: 2 3/8" State: Louisiana

Cumulative Production: 750 Bbls Gas Gravity: .6278 Z: ______

Constant Rate Production: 1800 (bbls/day) Water Salinity: 42,600 PPM Total Solids

Total Production Life: ± .5 days Porosity, ϕ: .246 Gas-Water Ratio: 49.7 ft^3/bbl

Reservoir Temperature: ____ ^oF Net Pay: 14 ft. Perforations: 14,782-14,820 ft

μg ______ cps μw .491 cps Bw 1.0552 R.B./B. Bg ______ R.B./MCF

C_T 3.21 $X10^{-6}$ Cg ______ $X10^{-6}$ Cw 2.72 $X10^{-6}$ C_r 1.5e $X10^{-6}$

m 117 psi/cycle P at 1 hour: 11,930 Sg ______ Sw 1.00 Pi 12,941.72 psia @ 14,801 ft

Pf 10,863.29 psia

Pi 12,858.41 psia @ 14,611 ft

Pressure Element Datum

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

kh = 162.6 (Q)(B)(μ)/(m)

kh = 162.6 (1800) (1.0552) (.491) / (117) = 1296.06 md-ft

k = (1296.06) md-ft / (14)ft = 92.6 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

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

$$s = 1.151\left[\left(\frac{(12858)-(11930)}{(117)}\right) - \log\left(\frac{(92.6)\,10^6}{(.246)(.491)(3.21)(.0525)}\right) + 3.23\right] = +1.731$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)(1.731)(117) = 176 psi

IV. Diffusivity, η

η = .006328 (k) /$\phi\mu$ C_T =

η = .006328 (92.6) / (.246)(.491)(3.21)10^{-6} = 1,511,317 ft^2/day

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

No. 1

Test Date: Feb. 21-24, 1981 Type Test: Drawdown Lease and Well No. Prairie Canal No. 1

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

$$J\ (\text{actual}) = \frac{Qw}{P_i - P_f} = \frac{(1800)}{(12858 - 11930)} = 1.9397 \text{ bbls/D-psi}$$

$$J\ (\text{ideal}) = \frac{Qw}{(P_i - P_f) - \Delta P\ \text{skin}} = \frac{(1800)}{(12858 - 11930) - (176)} = 2.3936 \text{ bbls/D-psi}$$

$$CE = \frac{J\ (\text{actual})}{J\ (\text{ideal})} = \frac{(1.9397)}{(2.3936)} = .8103 \quad \text{or} \quad 81.03\ \%$$

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

$$d = 2\sqrt{(1511317)} \times \sqrt{t} = (2459)\sqrt{t}$$

time, days	Qw	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
.0030	1800	135	117	360°		
.0074	1800	212	117	360°	3.619253	115,350
.50	1776	1739	450	93.6	.208803	1,999,413
1.60	1825	3110	1060	39.7	.149575	2,791,131
2.511	1825	3896	1060	39.7	.095305	4,380,492

(7758)(.246)/(1.0552) = 1808.6 Bbls/Ac-Ft

$(212)^2\pi/(43560)$ = 3.24 Acres

(3.24 Ac)(14 Ft)(1808.6 Bbls/Ac-Ft) = 82,038 Acres

$(3896)^2\pi/(43560)$ = 1094.7 Ac (117/1060) = 120.8 Ac for 39.7° flow area

(120.8 Ac) (14 Ft)(1808.6 Bbls/Ac-Ft) = 3,058,704 Bbls

(3,058,704)/(4,380,492) = .70 or 70% of value from drawdown slope

(4,380,492 Bbls)/(1808.6)(14) = 173 Acres required

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST
FOR
GEOTHERMAL-GEOPRESSURED WELL
No. 1

Test date: Feb. 24, 1981 Type Test: Buildup Lease and Well No. Prairie Canal Co. No. 1
Producing Formation: Hackberry Sand, Upper Frio Field: South Lake Charles
Hole size: ____ Casing Size: 5-1/2" Tubing Size: 2-3/8" State: Louisiana
Cumulative Production: 5,205 Gas Gravity: .6278 Z: ____
Constant Rate Production: 1825 (bbls/day) Water Salinity: 42600 PPM Total Solids
Total Production Life: 2.511 days Porosity, ϕ: .246 Gas-Water Ratio: 49.7 ft^3/bbl
Reservoir Temperature: 294 ^oF Net Pay: 14 ft. Perforations: 14,782-14,820 ft
μg ____ cps μw .491 cps Bw 1.0552 R.B./B. Bg ____ R.B./MCF
C_T 3.21 $X10^{-6}$ Cg ____ $X10^{-6}$ Cw 2.72 $X10^{-6}$ C_r 1.5 $X10^{-6}$
m 182 psi/cycle P at 1 hour: 12,325 Sg ____ Sw 1.00 Pi 12,858.41 psia
Pf 10,863.29 psia

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

kh = 162.6 (Q)(B)(μ)/(m)

kh = 162.6 (1825) (1.0552) (.491) / (182) = 844.75 md-ft

k = (844.75) md-ft / (14)ft = 60.3 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

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

$$s = 1.151\left[\left(\frac{(12325)-(10863)}{(182)}\right) - \log\left(\frac{(60.3)10^6}{(.246)(.491)(3.21)(.0525)}\right) + 3.23\right] = + 2.06$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)(2.06)(182) = 326 psi

IV. Diffusivity, η

η = .006328 (k) /$\phi\mu$ C_T =

η = .006328 (60.3) / (.246)(.491)(3.21) 10^{-6} = 984,152 ft^2/day

Eaton Industries of Houston, Inc. EXHIBIT 12-3a
Eaton Operating Co., Inc.

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

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

No. 1

Test Date: Feb. 24, 1981 Type Test: Buildup Lease and Well No. Prairie Canal Co. No. 1

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

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

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

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

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

$d = 2\sqrt{(\ 984{,}152\ )} \times \sqrt{t} = (\ 1984\ )\sqrt{t}$

time, days	$\sqrt{t}$	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
.005	.0707	140	182	360°		
.06	.2449	486	182			
.06	.2449	486	201			
.1363	.3692	732	201			

The additional calculation that can be derived from the buildup test, although it is not reliable, is presented on the calculation data sheets, Exhibits 12-3a and 12-3b.

12.4 Second Flow Test Period

The well was opened to conduct the second flow test at 13:29:00 hours on 24 February 1981. The well had been shut in for 0.1363 days, or 3.2712 hours, and the shut-in pressure was 12,430.86 psia. This is 427.55 psi below the initial datum pressure of 12,858.41 psia. Since the pressure at the sand face was still building up at the time the second flow started, the drawdown pressure slope depicted on Exhibit 12-4 will have been affected.

The second flow test was planned to determine the maximum producing rate that the well and the reservoir could sustain. The well was initially opened to a metered rate of about 4800 barrels of fluid per day within one and one half minutes. The rate could not be maintained, and the rate of pressure decline and production decline is depicted by graphical plot on Exhibit 12-4.

There is a noticeable change in pressure decline at a graphical time of 0.0065 to 0.01 days (9.4 to 14.4 minutes). The production rate appeared to hold between 4250 to 4350 barrels of fluid per day. Additional erratic variations in production rate and sand face pressures are seen until 0.115 days (2.78 hours). The erratic fluctuations are caused by reservoir adjustments for the first flow period and the new pressure transients created during this flow period.

The disposal well started to pressure up slightly after about 2 hours and 45 minutes (0.115 days). The well flow stream was turned into an open pit for about 5 minutes, while the No. 3 sand filter pot was changed . The rate was then reduced from about 4000 BFPD to around 2000 to 2200 BFPD. This is depicted on Exhibit 12-4 between the time interval of 0.115 to 0.182 days. The sand face pressure increased from 9650 to 11,000 psia during the drop in production rate.

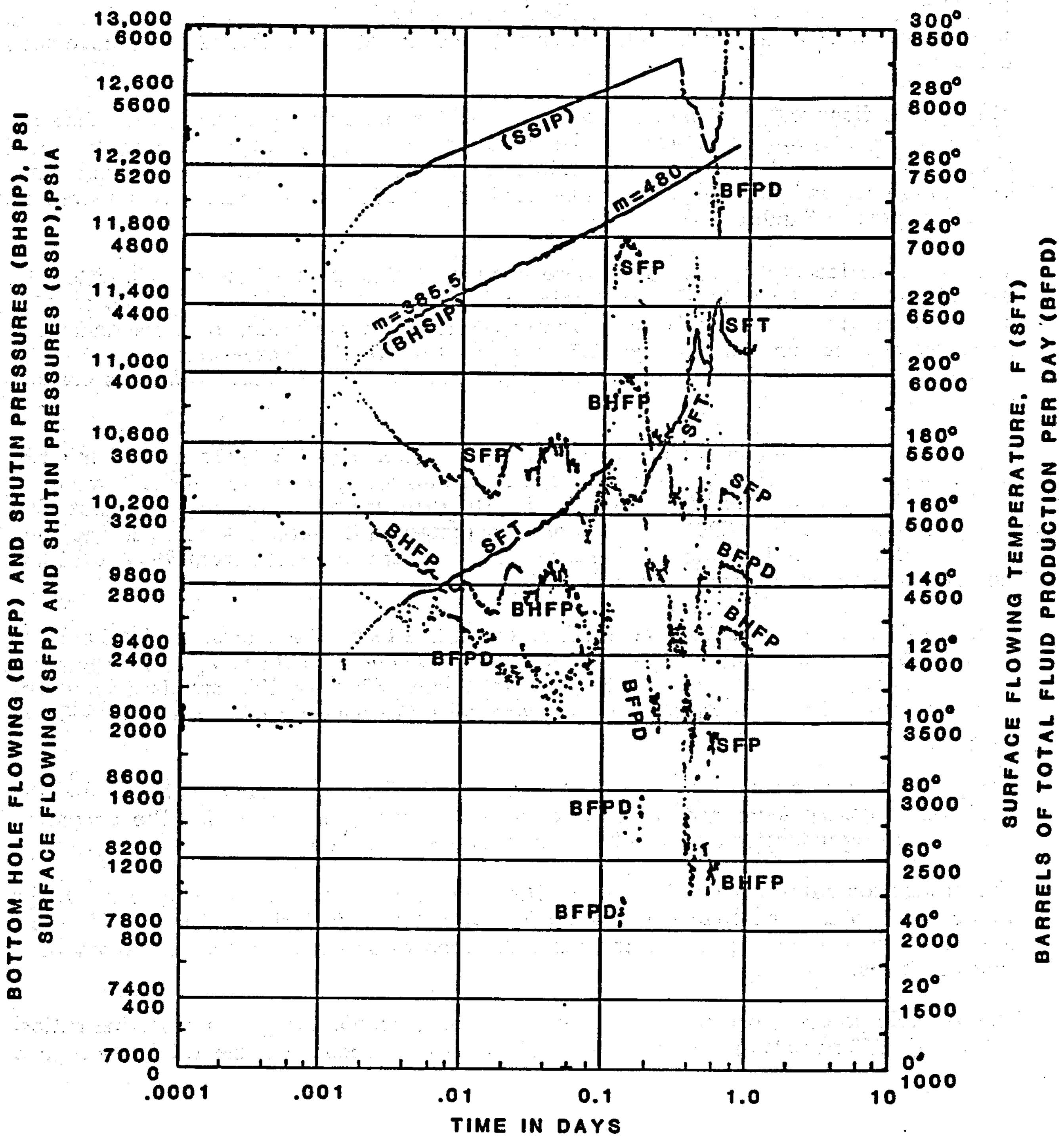
Production rates were varied several times during this test. The highest production rates occurred between 0.60 and 0.70 days (04:00 and 06:00 hours on February 25th). The rates varied between 7850 and 7000 BFPD, or between about 7043 and 6280 standard barrels of brine per day. These rates dropped the sand face flowing pressure to around 8000 to 8200 psia.

The production rate was cut back to 4650 to 4500 BFPD for the final 12 hours, and the sand face pressure increased to 9570 to 9440 psia during this period. The corrected standard brine production rate was between 4211 and 4075 STBPD.

The production rates during the second flow period were not sufficiently constant or stable to allow any reasonable additional reservoir data calculations. The test did show the reservoir was not capable of the sustained production rates needed for commercial considerations.

The variable production rate did not depict any appreciable changes in gas/brine ratios. A total of 4953 barrels of corrected reservoir brine was produced in the 1.208-day second

GEOTHERMAL – GEOPRESSURE FLOW TEST
PRAIRIE CANAL CO. NO. 1 WELL
SECOND FLOW & PRESSURE BUILDUP TEST
FEBRUARY 24 TO 26, 1981



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

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

flow test. The estimated gas produced during this flow period was 206.0 MCF, for an average gas/water ratio of 41.6 cubic feet of dry gas per barrel. The cumulative total of water produced at the end of this test was 10,158 bbls.

12.5 Second Pressure Buildup Test

The second pressure buildup is plotted on Exhibit 12-4 along with the immediately preceding production drawdown data. The final 12 hours of production averaged about 4143 standard barrels of reservoir brine per day. The first slope obtainable was 385.5 psi per cycle. It appears that the first radial buildup slope was not seen in this plot. The first point on the straight line occurred after 0.004 days or 5.8 minutes.

The second flow test, preceding the second buildup test, started at a pressure of 12,430 psia, or 428 psia below the original pressure of 12,858 psia. Therefore, the first buildup pressure transients are mixed into this buildup pressure plot. The total effect on the buildup is shown, but it cannot be broken out. Therefore, the calculated values arrived at on Exhibit 12-5 are not completely reliable.

The buildup slope of 385.5 psi per cycle and the average production rate of 4143 barrels per day would allow a calculated kh value of 905.4 md-ft. The permeability would then be 64.7 mds. The resulting negative skin of -0.973 does indicate the error of these figures for true reservoir values. Missing the first slope and pressure transients, as mentioned above, would create this invalid interpretation.

12.6 Third Flow Test Period

The third flow test began on February 26th at 16:42:40 hours, with a datum bottom-hole pressure of 12,365.33 psia. This pressure is 493.09 psia lower than the initial datum pressure of 12,858.41 psia. The well was opened to flow by slowly opening the production choke to about 2425 BFPD. During the initial flow period of 1 hour and 43 minutes the fluid production rate declined to 2250 BFPD. Exhibit 12-6a depicts the pressure drawdown plot of this test.

The first drawdown slope of 164 psi per cycle occurred between 0.0036 and 0.0095 days (5.1 and 13.68 minutes). The plot of the production flow rate indicates a relatively constant rate of about 2425 BFPD, or about 2343 STBPD of brine per day, corrected. The slope then increased to 210 psi per cycle, and the production rate decreased at a rate of about 150 barrels per day per log cycle. This change occurred over the next 1-1/2 hours of flow.

The reservoir data that would be calculated from this drawdown test would be subjected to the additional effect of the reservoir still building up from previous flow tests. The factor giving the major change would be how the skin effect equation would be solved. For example:

$$Kh = (162.6)(2343)(1.0552)(0.491)/(164) = 1203.55 \text{ md-ft.}$$
$$K = (1203.55 \text{ md-ft.})/(14 \text{ ft.}) = 86.0$$

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST

FOR

GEOTHERMAL-GEOPRESSURED WELL

Test date: Feb. 24-25, 1981 Type Test: 2nd Buildup Lease and Well No. Prairie Canal Co. No. 1

Producing Formation: Hackberry Sand, Upper Frio Field: South Lake Charles

Hole size: ______ Casing Size: 5-1/2" Tubing Size: 2-3/8" State: Louisiana

Cumulative Production: 10,158 Gas Gravity: 0.6278 Z: ______

Constant Rate Production: 4143 (bbls/day) Water Salinity: 42,600 PPM Total Solids

Total Production Life: 3.72 days Porosity, ϕ: .246 Gas-Water Ratio: 49.7 ft^3/bbl

Reservoir Temperature: 294 °F Net Pay: 14 ft. Perforations: 14,782-14,820 ft

μg ______ cps μw .491 cps Bw 1.0552 R.B./B. Bg ______ R.B./MCF

C_T 3.21 $X10^{-6}$ Cg ______ $X10^{-6}$ Cw 2.72 $X10^{-6}$ C_r 1.5e $X10^{-6}$

m 385.5 psi/cycle P at 1 hour: 11,490 Sg ______ Sw 1.00 Pi 12,941.72 psia @ Res.

Pf 9397.89 psia

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

kh = 162.6 (Q)(B)(μ)/(m)

kh = 162.6 (4143) (1.0552) (.491) / (385.5) = 905.4 md-ft

k = (905.4) md-ft / (14)ft = 64.7 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

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

$$s = 1.151\left[\left(\frac{(11,490)-(9393)}{(385.5)}\right) - \log\left(\frac{(64.7)\,10^6}{(.246)(.491)(3.21)(.0525)}\right) + 3.23\right] = -.973$$

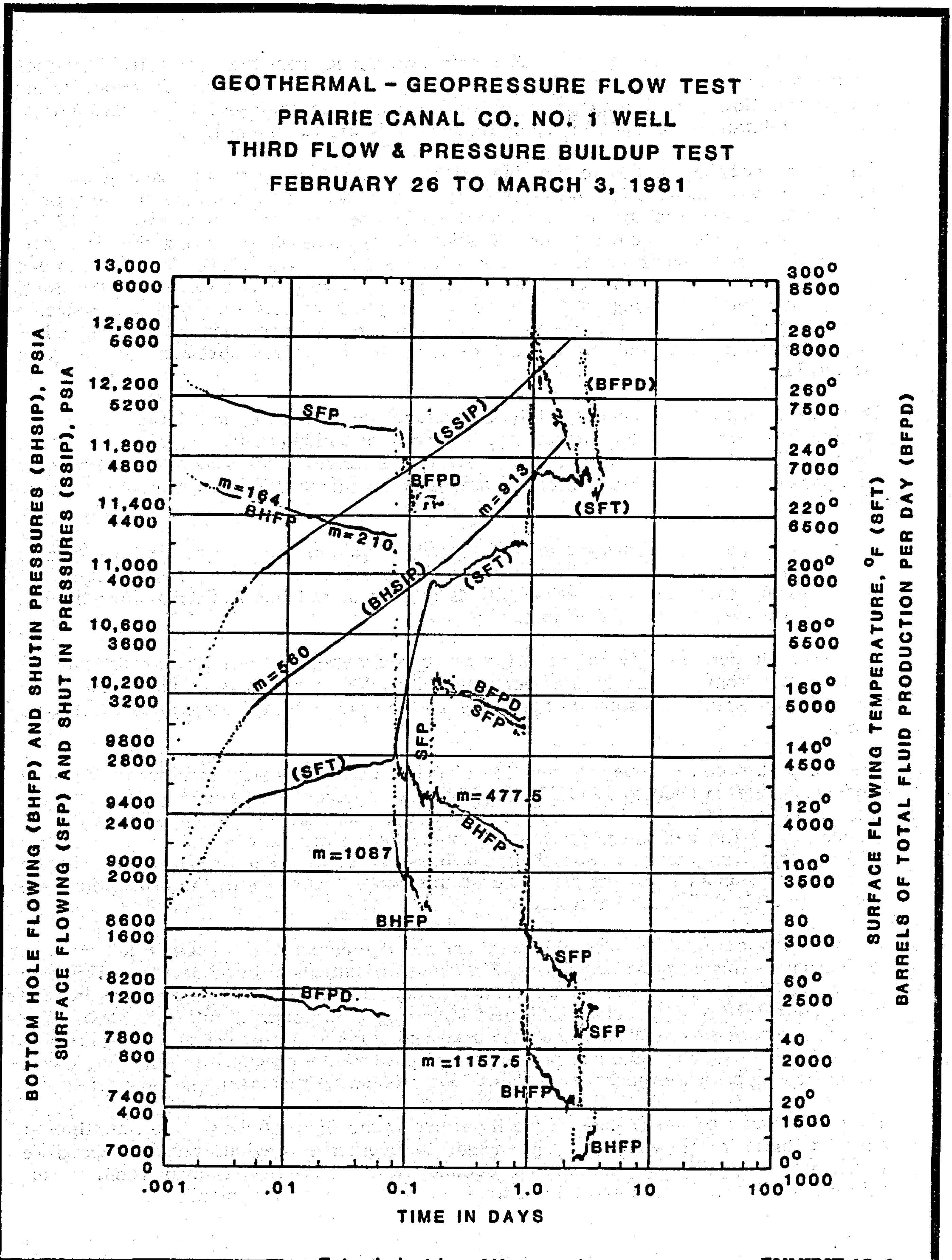
ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)( )( ) = ______ psi

IV. Diffusivity, η

$\eta = .006328\ (k)\ /\phi\mu\ C_T =$

$\eta = .006328\ (64.7)\ /\ (.246)(.491)(3.21)10^{-6} =$ 1,055,964 ft^2/day



Eaton Industries of Houston, Inc. EXHIBIT 12-6a

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The 86.0 mds is 6.6 mds below the 92.6 mds determined from the first test. This does not mean that the reservoir has lost permeability, but rather that the conditions during the second flow period did not fully provide the data required for true evaluation. Additional details of calculation can be found on Exhibits 12-6b and 12-6c.

The same reasoning applies to the skin effect. If the initial pressure used in the skin calculation was 12,858 psia, the original measured datum pressure, the skin effect is 3.362. Should one use the pressure measured before this flow test started, or 12,365 psia, the skin factor becomes a minus 0.098. The skin calculated during the first flow test, which meets conditions of the derived flow equation, was 1.731. Therefore, in one case it would appear that the damage around the wellbore nearly doubled. In the other case it improved, as though the interval was fracture-stimulated. Both cases are in error. In other words, the calculated values do not meet the conditions of the original or virgin drawdown test, and the amount of error in the values obtained can be quite substantial.

These data suggest the need to fully understand the derivation and definitions of the original flow equations when interpreting drawdown or buildup tests. Valid data is gained when the flow test starts from a static reservoir pressure. The closer the starting sand face pressure is to the static reservoir pressure, the more valid the results of the flow test.

In this case, the original drawdown test appeared reliable, and no attempt was made to keep the well shut in long enough to reach or approximate the original pressure of 12,858 psia. Testing cost continues during periods of shut in and this additional time did not appear to be needed for this well test.

The reservoir permeability to the brine of approximately 90 mds is equivalent to air permeability from core analysis of between 400 to 500 mds. (Amyx et al, 1960.) This places this reservoir sandstone in the above average productivity category of Gulf Coast sands.

The third drawdown slope of this flow period occurred after increasing the well production rate to 6500 to 7250 BFPD. This rate reduced the datum flowing pressure below 9000 psia for a two-hour flow period. The pressure drawdown rate was about 1087 psi per cycle. The well was not capable of maintaining a constant production rate at this choke setting, so the rate was then cut back to about 5000 BFPD. The pressure drawdown was about 477.5 psi per cycle at this choke setting, with the production rate declining at 525 BFPD per log cycle.

The rate was increased to over 8000 total barrels of fluid per day at about 15:00 hours on 27 February. This is equivalent to over 7000 standard barrels of brine per day. This high rate required full opening of the production choke. The surface flowing pressure dropped from about 2970 psia to below 1000 psia in the next 42 hours at full open flow. The surface pressure was allowed to drop to a low pressure of about 500 to 600 psia, which still allowed sufficient separator pressure to dispose of the produced brine. The lowest datum flowing pressure reached was about 7050 psia during this maximum flow rate.

The production rate was changed three times during the final 1.6 days. The flow time at each of these rates was not long enough to overcome previous reservoir pressure transients and allow an established decline rate for reservoir evaluation. This information is seen in Exhibit 12-6a at the later portion of the graphical plot.

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST

FOR

GEOTHERMAL-GEOPRESSURED WELL

No. 3

Test date: Feb. 26-Mar. 2, 1981 Type Test: Drawdown Lease and Well No. Prairie Canal Co. No. 1

Producing Formation: Hackberry Sand, Upper Frio Field: South Lake Charles

Hole size: ______ Casing Size: 5-1/2" Tubing Size: 2-3/8" State: Louisiana

Cumulative Production: 10,158 Bbls Gas Gravity: ______ Z: ______

Constant Rate Production: 2343 (bbls/day) Water Salinity: 42,600 PPM Total Solids

Total Production Life: 3.719 days Porosity, ϕ: .246 Gas-Water Ratio: 49.7 ft^3/bbl

Reservoir Temperature: 294 °F Net Pay: 14 ft. Perforations: 14,782-14,820 ft

μg ______ cps μw .491 cps Bw 1.0552 R.B./B. Bg ______ R.B./MCF

C_T 3.21 $X10^{-6}$ Cg ______ $X10^{-6}$ Cw 2.72 $X10^{-6}$ C_r 1.5 $X10^{-6}$

m 164 psi/cycle P at 1 hour: 11330 Sg ______ Sw 1.00 Pi 12,365 psia

P_o 12,858 psia

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

kh = 162.6 (Q)(B)(μ)/(m)

kh = 162.6 (2343) (1.0552) (.491) / (164) = 1203.55 md-ft

k = (1203.55) md-ft / (14)ft = 86.0 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

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

$$s = 1.151\left[\left(\frac{(12365)-(11330)}{(164)}\right) - \log\left(\frac{(86.0)10^6}{(.246)(.491)(3.21)(.0525)}\right) + 3.23\right] = -0.098$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)( )( ) = ______ psi

IV. Diffusivity, η

η = .006328 (k) /$\phi\mu$ C_T =

η = .006328 (86) / (.246)(.491)(3.21)10^{-6} = 1,403,600 ft^2/day

Negative skin caused by not letting pressure at sand face completely build up before starting third drawdown test. If Pi was 12,858 instead of 12,365 psia, skin would be + 3.362.

Eaton Industries of Houston, Inc. EXHIBIT 12-6b

Eaton Operating Co., Inc.

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

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

No. 3

Test Date: 2/26-3/2/81 Type Test: Drawdown Lease and Well No. Prairie Canal Co. No. 1

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

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

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

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

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

$d = 2\sqrt{(1,403,600)} \times \sqrt{t} = (2369)\sqrt{t}$

time, days	Qw	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
4.004	6800	4741	1027	?	.0155419	22,418,000

$(4741)^2 \pi/(43560) = 1621$ Acres

(1621 Ac)(14 Ft)(1808.6 Bbls/Ac-Ft) = 41,044,000 Bbls, if no barriers

The well was shut-in at 16:47:50 on 2 March, with a bottom-hole flowing pressure of 7271.03 psia and a surface flowing pressure of 1143.89 psia. This total flow period had lasted for 4.004 days. The final maximum producing rate was about 6800 barrels of total metered fluid per day or about 5800 barrels per day, corrected to standard measurements. The produced gas/brine ratio reported by IGT appeared to range from 40 to 43 standard cubic feet per barrel. The total water produced was 23,202 barrels for a cumulative test total of 33,360 barrels of brine. The total gas produced was 975 MCF for an average gas/brine ratio of about 42 cubic feet per barrel.

The drop in produced gas/brine ratio from 46.69 cubic feet per barrel in the first test to 42.02 cubic feet per barrel during this third flow test requires some reservoir engineering comment. This could be compared to undersaturated oil reservoirs that produce at exact solution ratio until the bubble point or saturation pressure is reached. When the bubble point pressure of the reservoir oil is reached, a noticeable drop below solution gas/oil ratio is detected in the produced ratio. The gas/oil ratio remains low until the critical gas saturation, or permeability to the gas phase, is reached in the reservoir, and then the produced gas/oil ratio begins to increase. This comparison would indicate that the extrapolation of the Weatherly fluid analysis from 33.8 ft^3/bbl @ 6000 psia to 48.7 ft^3/bbl at 12,858 psia is reasonable. The lower produced gas/water ratio would then be from a reservoir brine that was at or close to a saturated gas condition, with no original free gas saturation. The loss in reservoir pressure would allow a minor amount of gas to come out of solution in the brine and remain as free gas saturation in the reservoir. Matthews has discussed the probable amount of gas that would have to come out of solution to insure sufficient pore saturation to have permeability, or flow, in the gas phase, (References 27 & 28).

This could explain why, at the higher producing rates and lower pressure around the wellbore, the measured produced-gas/water ratio decreased. This data does not support the conclusion that the brine was fully saturated with gas at the original reservoir conditions. In fact it could have been slightly undersaturated, with the same results. The Weatherly extrapolation of 48.7 at 15.025 psia or 49.7 at 14.73 psia appears to be of the proper order of magnitude.

The maximum distance tested in the 4.004 days is 4741 feet. The explored volume of reservoir brine is equivalent to 22.418 million barrels or an area equivalent to about 885 acres. The total production for this test phase was 23,202 barrels of brine for a cumulative total of 33,360 barrels of brine.

12.6.1 Explored Volumes of Aquifer

The first flow test supported about 4.4 million barrels of explored aquifer. The third flow test, of some 4 days, supported an additional volume of explored brine in the reservoir. Exhibit 12-6a depicts two distinct drawdown slopes, between 0.16 days and 2.4 days, that meet conditions for exploration drawdown calculations. Exhibit 12-7a is a log-log graphical plot of the explored values derived.

The "Y" function plotted is the rate of pressure drawdown of the produced reservoir fluid in psi per day per reservoir barrel of fluid. This data should always drawdown at a slope of 45 degrees. A permeability barrier would cause a shift to the right of the plotted data but it would remain at a 45-degree slope.

The "W" value of volume of explored water or reservoir brine is in millions of barrels explored. These values will plot a 45-degree slope perpendicular to the Y slope at the same corresponding times; in other words, as the pressure transient moves further into the reservoir, additional volumes of aquifer are affected. Three basic sets of data are needed for these calculations. One is an accurate recording of pressure changes at the sand face while flowing. The second is accurate recorded measurements of rate of production of the reservoir fluid. The third value is an accurate analysis of the compressibility or expansibility of the total reservoir fluid. Physical properties of the reservoir matrix, distance to permeability barriers, etc., are not a part of this direct method of determining reservoir fluid explored with time. - The ability to convert surface-measured fluids at various surface temperatures and pressures to reservoir volumes at reservoir temperature and pressure is important.

Exhibit 12-7b is a tabulation of the measured and calculated data used for construction of Exhibit 12-7a in a graphical form. At the end of the first slope, at 0.894 days, the explored volume of aquifer is 6.790 million barrels. The end of the second slope, at 2.4 days, depicts a volume of explored aquifer of 10.088 million barrels. The reason for two distinct slopes is found during the "First Flow Period," when a permeability barrier was detected between 0.9 and 1.4 days.

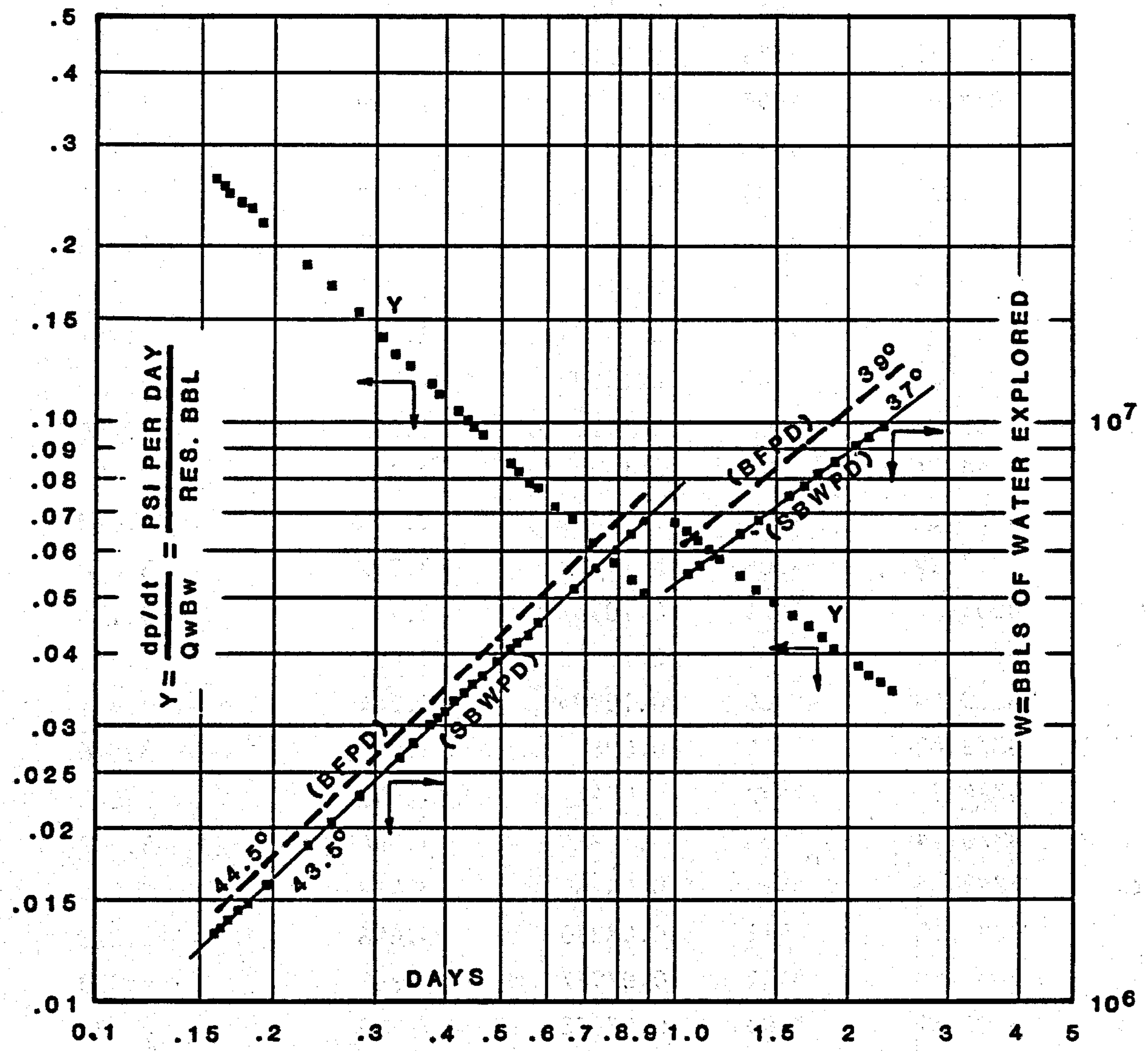
The dashed line (BFPD) found on Exhibit 12-7a is from the same type of calculations, but using the fluid flow meter recordings of production measured prior to separation of free gas and brine. The slopes of explored water are closer to the theoretical 45-degree plot but somewhat higher in explored volume than the slopes corrected to standard metered volumes. The producing rates for the second slopes were much higher and the surface flowing temperatures were also much higher. This would account for the greater separation between the corrected standard volumes and the fluid metered volumes. It would also suggest that the effect of surface temperatures in correcting the standard volumes may be slightly in error.

One other condition previously discussed was the effect of prior production and shut-in pressure transients upon these drawdown slopes. This would probably account for the major deviation from the theoretical 45-degree slope. This would again lead back to an earlier conclusion, that to gain the most accurate reservoir data from well testing, the pressure at the sand face should be the original reservoir pressure. In other words, be sure that the pressure at the start of the first flow period is at the static reservoir conditions. If additional data is needed in subsequent flow tests, the well should be shut

THIRD DRAWDOWN TEST

PRAIRIE CANAL CO. NO. 1 WELL

FEB 26 TO MARCH 3, 1981



NOTE:

BFPD IS BARRELS OF FLUID PER DAY (DIRECT METER READING PRIOR TO SEPARATOR)

SBWPD IS STANDARD BARRELS OF WATER PER DAY (CORRECTED TO 14.73 PSIA AND 60°F)

Eaton Industries of Houston, Inc. EXHIBIT 12-7a

Eaton Operating Co., Inc.

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

Third Flow Test Period
Third Flow Slope
m = 477.5 psi per cycle

Cum. Time	Flow Rate		Corrected	Million Bbls of Aquifer Explored	
Days	BFPD	SBWPD	$Y = \frac{m/2.3t}{QwBw}$	W (uncorrected)	W (Corrected)
0.160	5110.12	4672	0.263201	1.448	1.324
0.164	5093.66	4657	0.2576	1.470	1.352
0.168	5113.95	4675	0.2505	1.521	1.391
0.175	5094.33	4657	0.2414	1.579	1.443
0.183	5005.70	4576	0.2349	1.622	1.483
0.193	5088.01	4657	0.2189	1.739	1.592
0.206	5064.55	4636	0.2060	1.848	1.691
0.216	5065.23	4636	0.1965	1.937	1.773
0.231	5005.03	4587	0.18568	2.047	1.876
0.250	5010.52	4592	0.1714	2.218	2.033
0.281	5002.93	4584	0.15274	2.490	2.281
0.307	4999.04	4581	0.1399	2.718	2.490
0.329	4981.88	4565	0.1310	2.903	2.660
0.350	4943.57	4521	0.1243	3.064	2.802
0.378	4934.29	4504	0.11556	3.303	3.015
0.388	4937.29	4506	0.11254	3.392	3.096
0.402	4903.66	4475	0.10937	3.491	3.186
0.423	4894.48	4467	0.10412	3.666	3.346
0.437	4889.49	4460	0.10095	3.784	3.451
0.450	4878.42	4450	0.09825	3.888	3.546
0.467	4884.91	4447	0.09474	4.040	3.678
0.499	4870.44	4433	0.08894	4.304	3.917
0.520	4863.35	4415	0.085699	4.478	4.065
0.540	4858.17	4411	0.08260	4.646	4.218
0.561	4849.84	4402	0.07967	4.863	4.373
0.582	4841.21	4403	0.07678	4.990	4.538
0.624	4829.63	4400	0.07166	5.337	4.862

0.665	4809.88	4370	0.0677	5.664	5.146
0.728	4795.51	4359	0.0620	6.182	5.620
0.790	4769.27	4335	0.05745	6.672	6.065
0.853	4723.28	4289	0.053778	7.135	6.479
0.894	4723.18	4289	0.05131	7.478	6.790

Fourth Flow Test Period
Fourth Flow Slope
m = 1157.5 psi per cycle

Cum. Time	Flow Rate		Corrected	Million Bbls of Aquifer Explored	
Days	BFPD	SBWPD	$Y = \frac{m/2.3t}{QwBw}$	W (uncorrected)	W (Corrected)
1.00	8125.0	7118	0.0670	5.936	5.200
1.05	8050.3	7053	0.0644	6.175	5.410
1.10	7979.1	6969	0.0622	6.412	5.600
1.15	7911.0	6900	0.0601	6.646	5.797
1.20	7845.9	6833	0.0582	6.878	5.990
1.30	7723.4	6709	0.0547	7.335	6.371
1.40	7609.9	6594	0.05166	7.783	6.744
1.50	7504.3	6486	0.04902	8.223	7.107
1.60	7405.5	6386	0.04669	8.656	7.463
1.70	7312.7	6291	0.04460	9.082	7.813
1.80	7225.2	6201	0.04273	9.501	8.154
1.90	7142.4	6118	0.04103	9.914	8.492
2.00	7063.9	6038	0.03949	10.321	8.822
2.10	6989.2	5962	0.03809	10.722	9.146
2.20	6918.0	5889	0.03681	11.118	9.465
2.30	6849.9	5819	0.03564	11.509	9.777
2.40	6784.8	5754	0.03454	11.896	10.088

in and allowed to build back to the original pressure. The closer the starting flow pressure is to the original, the more accurate the resulting calculations.

12.7 Third Buildup Period

Pressure buildup measurements continued until 16:55:00 hours on 4 March 1981, or for a total of 2.005 days. RDI removed the pressure element from the well at this time. The pressure had built up from a flowing pressure of 7271.03 psia to 11,948.24 psia in the two days. This is about 900 psi below the initial pressure.

The first buildup slope occurred between 0.005 and 0.15 days, at about 560 psi per cycle. The second slope was 913 psi per cycle between 0.5 days and 2.005 days. The Kh for the first slope, using an average rate of 6800 STBWPD, was 1022.96 md-ft. This would convert to permeability of 73.1 mds.

The pressure buildup data is plotted on Exhibit 12-6a with the prior pressure drawdown for comparison.

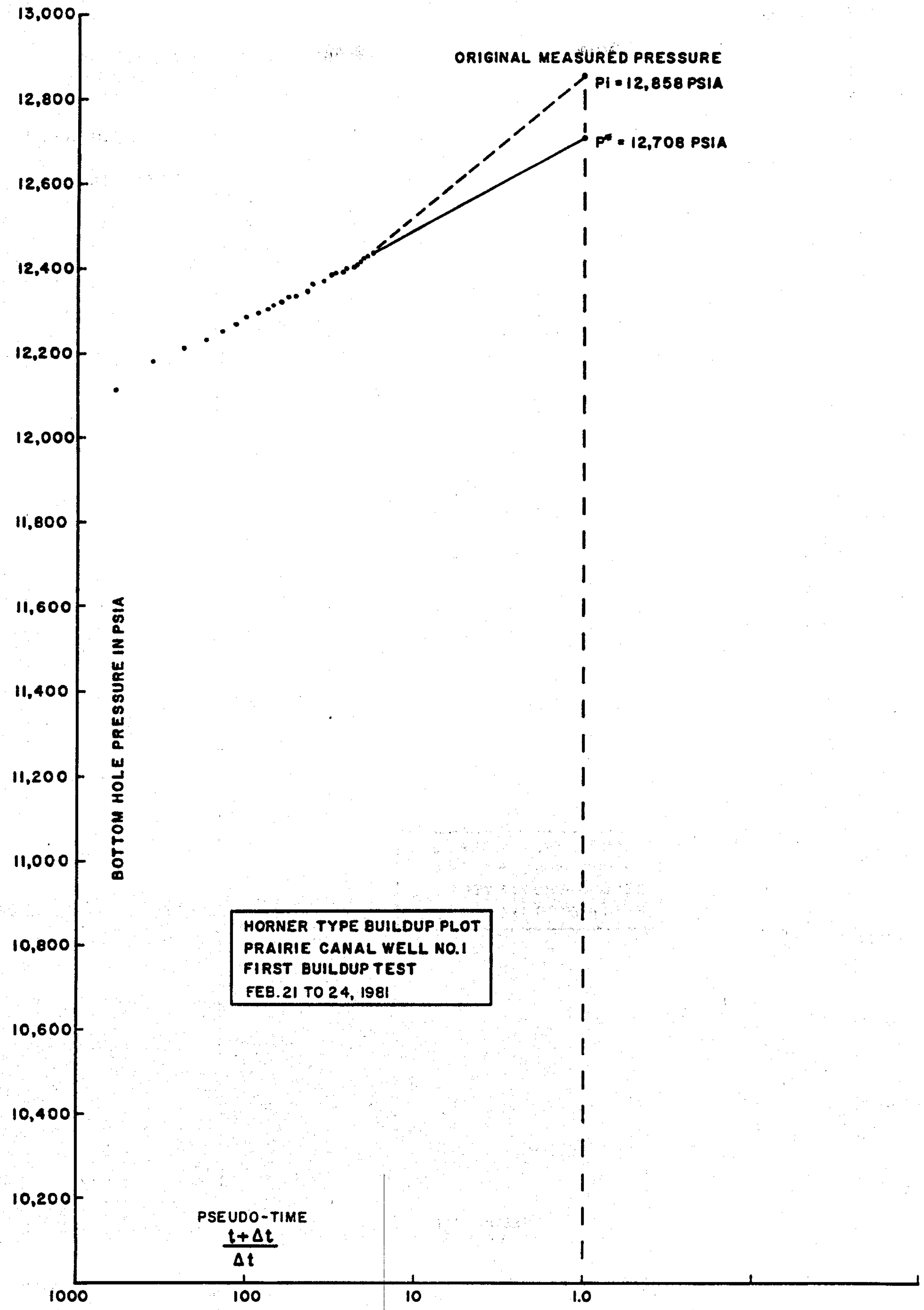
12.8 Horner-type Buildup Extrapolations

The Horner-type buildup plot is a pseudo flow time semi-log graph of flowing time plus shut-in time divided by shut-in time on the inverse log scale versus the measured pressure. This type of pressure buildup plotting was designed to obtain an original static reservoir pressure when one was not originally measured. This method appeared to work reasonably well when only the bourdon tube type pressure element was available. The three buildup tests conducted in this well have been plotted by this method and are shown on Exhibits 12-8a, 12-8b, 12-8c and 12-8d.

The pressures for these graphs were all measured at a datum depth of 14,611 feet, and the original reservoir pressure was measured at 12,858.41 psia. Exhibit 12-9 is a tabulation of data that was derived from the buildup test plotted by the Horner method. The extrapolated P*, or the theoretical static original reservoir pressure, is not very close to the measured original pressure. The lowest value is off by 385 psi, and the closest value is 12,750 psia, or within 108 psi of the original pressure. The 108-psi and 385-psi differences are within 0.84 and 2.99 percent, respectively, of the actual original pressure. This is closer than the accuracy of the old-type Amerada pressure gauge, but not close enough for detailed reservoir evaluations.

12.9 Fourth Flow Test

This flow test started at about 19:30 hours on 4 March and continued until 23:30 hours on 5 March 1981, or a total of approximately 1.167 days. A total of 3895 barrels of brine and 167 MCF of gas were produced during this test. The average produced gas/brine ratio was 42.88 cubic feet per barrel. The cumulative total production from the well for all cleaning and testing was 37,255 barrels of reservoir brine. The total time of flow for all tests was 8.89 days, for a mean average producing rate of 4190.66 barrels per day.



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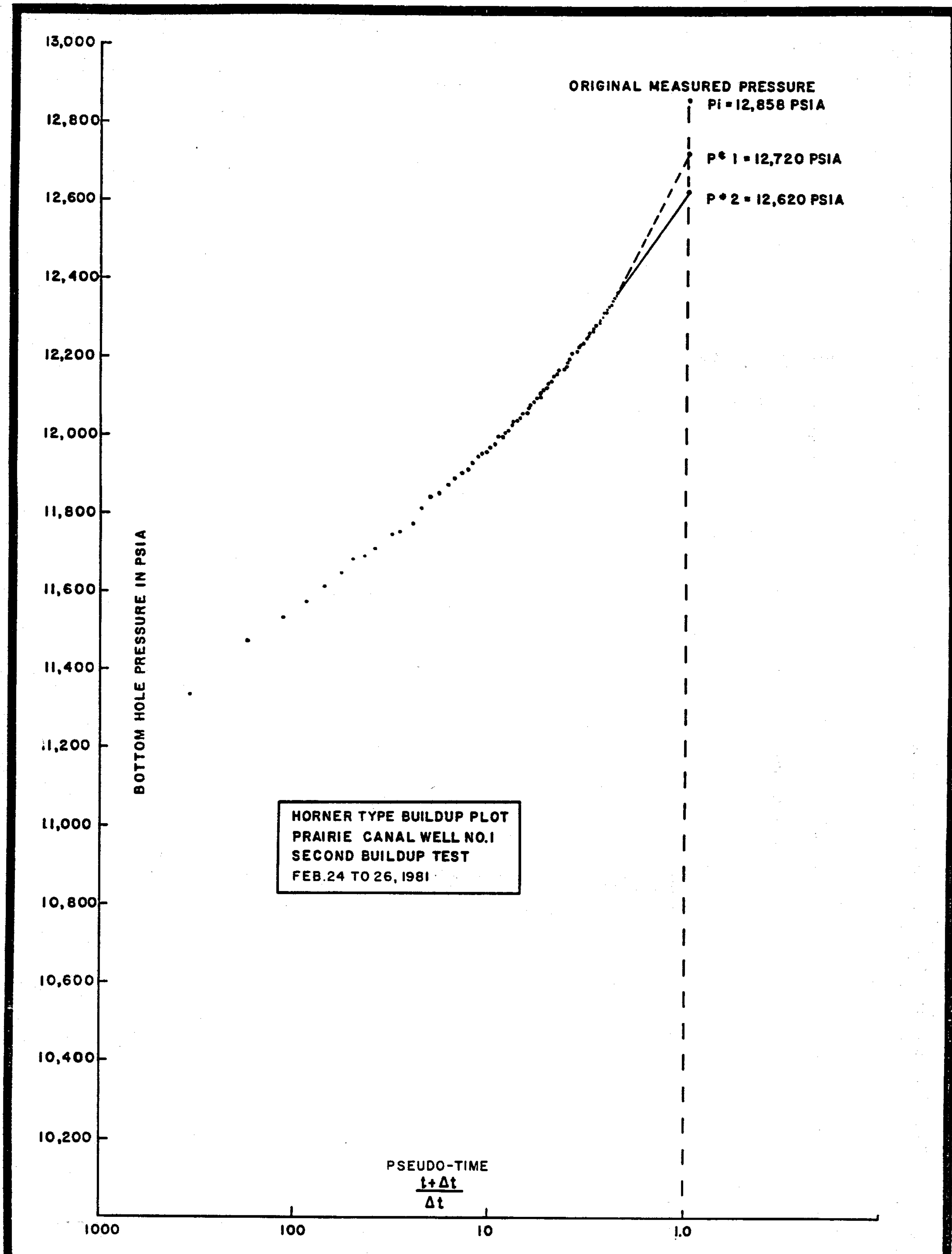
Eaton Operating Co., Inc.

EXHIBIT 12-8a

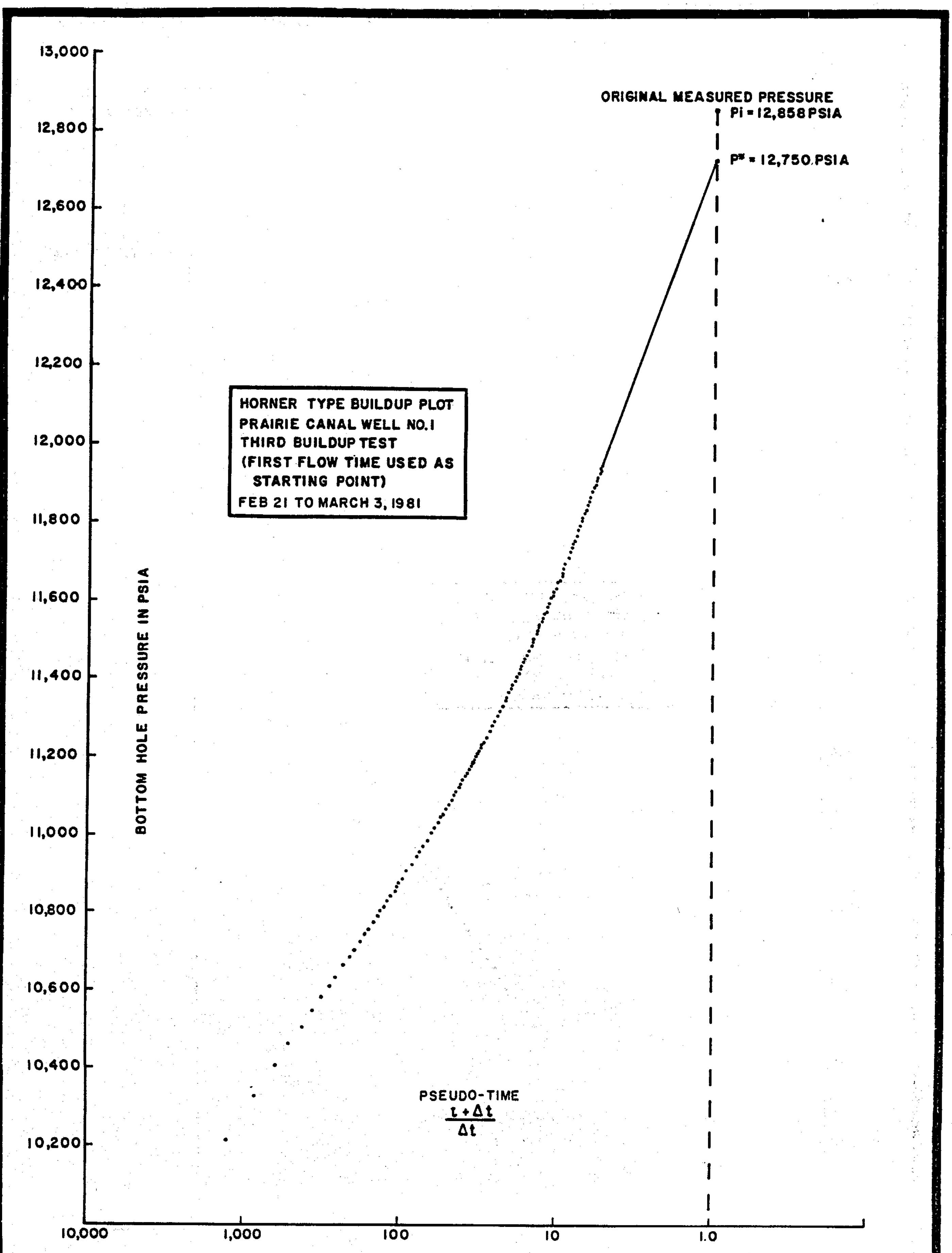
DOE CONTRACT NO.
DE-AC08-80ET-27081



Eaton Industries of Houston, Inc. EXHIBIT 12-8b

Eaton Operating Co., Inc.

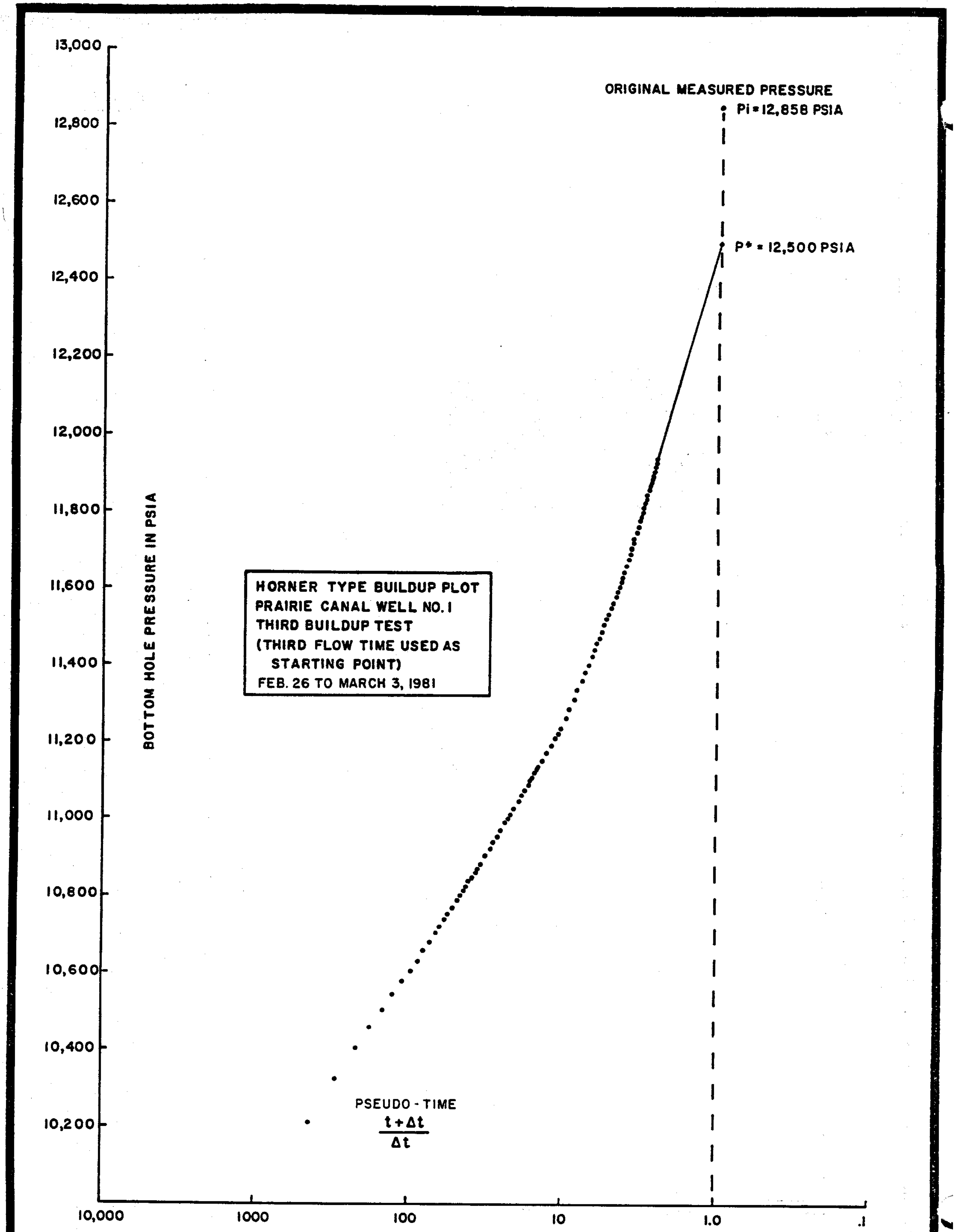
DOE CONTRACT NO.
DE-AC08-80ET-27081



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

EXHIBIT 12-8c

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



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

EXHIBIT 12–8d

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

Horner Buildup Interpreted

Reservoir Data

Prairie Canal No. 1 Well Tests

	M psi/cycle	Qw STBWD	t Days	Kh Md-Ft	K Mds.	S Skin	P*, psia @14,611 Ft.
1st B.U.	205	1774.2	2.511	729.1	52.1	1.086	12,708
2nd B.U.	375	4100.2	1.208	921.1	65.8	-0.009	12,620
3rd B.U.	595	5800.5	4.004	821.2	58.7	-0.712	12,500
3rd B.U.	590	3797.7	8.784	542.3	38.7	-0.312	12,750

Note: The final buildup test tabulated assumes starting flow time on 2-21-81 at 21:58:30, the start of the first flow period, for a total of 8.784 days of total flowing time.

Basic Data Used:

Bw = 1.0552 Bbl./Bbl

μ_w = 0.491 cps

Ct = 3.21 X 10^{-6} Bbl/Bbl psi

ϕ = 24.6%

Rw^2 = 0.0525

h = 14 ft.

Pi = 12,858 psi @ 14,611 Ft.

This final test was conducted without a pressure element in the well and was requested by IGT to gain additional surface production measurements. Production rates were varied between 1596 and 6324.5 STBWPD, for an average production rate for the test of 3337.6 STBWPD. Gas/brine ratios varied between a reported low of 24.6 scf/bbl and a high of 71.2 scf/bbl (IGT Well Test Analysis, Appendix K). The mean producing gas/brine ratio was 42.88 scf/bbl.

12.9.1 Summary of Reservoir Engineering Data

Certain measured and calculated data are given below to summarize the previous discussions. Exhibit No. 12-1 is a graphical plot of the original flow test that developed the fundamental reservoir data. Exhibits 12-2a through 12-9 contain supplementary data that was used for various final conclusions. Four flow tests were conducted between February 21 and March 5, 1981. The first three flow tests and buildup test were conducted with pressure elements in the wellbore, allowing reservoir engineering interpretation. The final or fourth flow test was conducted using surface measurements only. The production tests started at 2156 hours on 21 February and continued to 2330 hours on 5 March 1981. The period includes 8.890 days of well flowing and 3.142 days of shut-in time.

- **Total Test Time:** 12.032 days, February 21 through March 5, 1981.
- **Initial Reservoir Pressure:** 12,941.72 psia at 14,801 feet.
- **Reservoir Temperature:** 294^{o}F at 14,801 feet.
- **Initial Surface Pressure:** 6440 psia measured in lubricator.
- **Porosity:** 24.6 percent estimated from log and average of 9 sidewall cores of similar sand.
- **Pvt Data by Weatherly Laboratories:**

  C_w = 2.72 x 10^{-6} Vol/Vol. per psi @ 12,942 psia and 294^{o}F

  B_w = 1.0552 Vol/Vol. @ 12,942 psia, 294^{o}F and saturated with 49.7 ft^3 of dry gas (14.73 psia)

- **Viscosity of Reservoir Fluid:** 0.491 cps @ 12,942 psia, 294^{o}F, and saturated with 49.7 ft^3 of dry gas. (Geothermal water viscosities were measured using an E.L.I. Rolling Ball Viscometer, with an electronic detection system to prevent electrolysis, at Weatherly Laboratories.)

- **Calculated Reservoir Data:**

  Kh = 1296.06 md.-ft

  K = 92.6 mds., using 14 feet of net effective pay

S = 1.731 skin and/or partial penetration

ΔP (skin) = 176 psi

P.I. = 1.9397 Bbls. per day per psi

Completion Efficiency: 81.03 percent

- **Maximum Volume of Water Explored:** 22.418 million bbls.
- **Maximum Area Explored:** 885 acres
- **Maximum Radial Distance Explored:** 4741 feet (4.004 days)
- **Total Well Production:** 37,255 barrels of reservoir brine
- **Average Produced Gas/Brine Ratio:** 42.88 cu.ft/bbl.
- **Mean Average Production Rate:** 4190.66 bbls./day

12.10 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 (12.10.1) and real time test data obtained (12.10.2) provide background for the discussion of fluids production. Collection and analyses of gas samples are described in 12.10.3. Conclusions regarding gas chemistry are reflected in the calculation of gas production rates as well as of the ratio of produced gas to produced brine (12.10.4). An analysis of separator performance and produced CO_2 is presented in 12.11. Finally, details of brine chemistry are presented in 12.10.5 as background for the subsequent section, 12.12 "Solids Production, Scaling, and Corrosion."

12.10.1 The Test Sequence

The test of the original target aquifer (14,976-15,024 ft.) was aborted after a few minutes of flow because of the production of chunks of formation material. Nevertheless, several observations significant to well completion and production on future wells were made. These are discussed in Section 12.10.1.1. Section 12.10.1.2 then provides a chronological summary of the test activities most relevant to interpretation of well performance in terms of quantities and properties of produced fluids for the aquifer actually tested, 14,782-14,820 feet deep).

12.10.1.1 Relevant Data From the Aborted Test: An estimated 2570 barrels of brine were produced between perforation of the depth interval 14,976-15,024 feet and the decision to abandon the planned production test. This production was accompanied by collection of data relevant to interpretation of the test actually performed and to the conduct of future tests of geopressured aquifers. These data are described under subheadings which follow:

- **Brine Composition:** By the afternoon of 1/18/81, production of an estimated 1440 barrels of brine to the reserve pit had resulted in sufficient cleanup for initiation of the production test. A sample of this flowing brine was collected. Field analyses revealed a Cl^- content of 27,800 mg/l and a total dissolved solids content of 41,000 mg/l. These are reasonably close to values subsequently measured during the production test of the aquifer in the depth interval 14,782 - 14,820 feet.

- **Hydrate Formation in the Wellhead:** After producing an estimated 120 barrels of reservoir brine through the tubing, a Gearhart Industries Inc. bottom-hole sampler was run to a depth of 13,690 feet. Then, with the sampler inside the tubing, an additional 10 barrels were produced through the annulus, and the sampler was lowered to 14,965 feet. The sampler was then fired, left in position for 15 minutes to fill and then uneventfully retrieved to a depth of 220 feet.

  After stopping for about 15 minutes at a depth of 220 feet, the filled sampler would move neither up nor down. No leakage was observed when grease injector pressure was reduced to below wellhead pressure, and the wireline rams on the lubricator could not be closed. These problems were outside the realm of prior experience of all personnel on location.

After several hours of unsuccessful attempts to move the filled sampler, equipment was mobilized to kill the tubing by pumping heavy mud into a wellhead "Tee" below the lubricator. Initial pumping caused noise on the collar locator on the downhole assembly. This suggested that the wireline was stuck at the wellhead and that the filled sampler was free. The noise ceased before completion of pumping of heavy mud.

After the tubing had been killed, the lubricator was removed from the wellhead. A short, strong blow occurred when the "O" ring unseated. Then solid white material, similar to crushed ice, stained with lubricator grease slowly extruded from the lubricator. After about one hour, the material had sublimated, the wireline moved freely through the lubricator, and the wireline rams operated properly. Unfortunately, the bottom-hole sampler was not recovered with the wireline. It is believed to have been "pumped off" while the tubing was being killed with heavy mud.

The solid material that filled the lubricator is believed to have been methane hydrate. Prior production through the tubing undoubtedly released gas by differential liberation. Such gas would then have migrated into the lubricator as small bubbles while the sampler was being run to total depth. Thus, both gas and low-salinity brine were present in the lubricator. Temperature at the time of the problems was in the range of 40-45°F and wellhead pressure was in excess of 6000 psig. This combination of temperature and pressure is well within the regime of hydrate stability.

Although the reason for losing the bottom-hole sample was clearly understood, no additional sampling attempt was authorized.

After rigging down the wireline unit used for bottom-hole sampling, the heavy mud was displaced down the tubing by pumping fresh water while simultaneously producing the annulus to the reserve pit so that heavy mud would not reach the perforations. Before starting wireline operations for bottom-hole pressure and temperature measurement, vegetable oil was pumped into the near-surface portion of the tubing to assure that hydrate problems would not recur.

These actions effectively eliminated hydrate problems in the tubing. However, monitoring of annulus pressure continued to be plagued by blockage of small stainless steel lines to pressure transducers by hydrate formation. This problem was mitigated by use of electric heating tapes.

- **Collection of Samples of Formation Material:** After the heavy mud had been displaced from the tubing with fresh water, cumulative production from the perforations was estimated to have reached 2230 barrels. The high pressure line and choke were then opened for visual inspection. Both a "dead end" in the high pressure line and the housing of the choke used for flow to the reserve pit were found to contain "rocks" with linear dimensions as great as 1/2 inch. Samples of these were collected on 1/21/81 for subsequent analysis.

After producing additional brine on several occasions due to problems associated with bottom-hole pressure measurement, production through surface equipment was attempted on 1/27/81. When wellhead valves to the annulus were opened, recorded annulus pressure had a very low value, presumably due to hydrates in the annulus portion of the wellhead. Since tubing pressure drop was only about 60 psi, production was continued. This production was through the choke manifold to be used for testing and then to the reserve pit through a bypass line at the separator.

After about a minute of strong gas flow and then slugging production of black liquid, the well was shut in due to loss of bottom-hole pressure data. Subsequent inspection of the choke previously used during cleanup and of the high pressure "isokinetic" sampling point revealed that more than 1 pound of "rocks" had smashed the turbine of the high pressure turbine meter as well as the turbolizers and sampling tube at the isokinetic sampling point. One of these rocks had linear dimensions in excess of 1 inch. Samples of these rocks were added to those previously collected for laboratory analysis.

Results of scanning electron microscope and x-ray analyses of these samples of formation material are discussed in Section 12.12.2.

- **IGT Recording Stability Check:** Installation of the IGT sensors and recording equipment described in Section 9.4.1 was completed on 1/23/81. This hardware was then operated continuously until the initial test was aborted during the afternoon of 1/27/81. The resulting 3-plus days of operation provided an important test of overall system stability. Conclusions from playback of magnetically recorded data are as follows:

a. Data from the differential pressure gauges (orifice meter and filter) were constant to ± 1 digitizing step. The digitizing step used was 1/400 of full scale for each transducer. Thus demonstrated stability was ± 0.25%. This is the same as the manufacturer's specification for linearity of the transmitters used.

b. The 1000-psi pressure transmitters used for separator pressure and disposal wellhead pressure similarly demonstrated stability to ± 1 digitizing unit or ± 0.25%.

c. The three temperature transmitters responded to daily temperature fluctuations between extremes of 34°F and 80°F. Maximum deviation between recorded temperatures at any time was less than 5°F. Whether the modest differences were real, or merely reflections of truly different temperatures at each thermal well, was not examined, since observed agreement was adequate for all uses of temperatures during data interpretation.

d. Quantitative conclusions regarding stability of pressure transmitters used on the production well annulus and tubing were not warranted due to variations in recorded values caused by changes in valve positions associated with wireline activities. However, comparison with deadweight tester and Panex gauge data on previous wells, and during the subsequent test of this well, has left little doubt that recorded data is accurate to ± 0.25% of full scale for the 10,000 psig pressure transmitters used.

12.10.1.2 Chronological Summary of Production Test Activities: The following chronological summary provides an overview of test activities most relevant to interpretation of well test performance in terms of quantities and properties of produced fluids.

- **2/21/81:** An initial brine production rate of about 1850 BPD was established by smoothly opening the choke over a one-minute time interval, while monitoring the rate meter on the wellhead turbine Big Tex II.

- **2/22-23/81:** The first flow test proceeded smoothly, with only two minor increases in separator pressure caused by increasing injection pressure on the disposal well.

- **2/24/81:** The first flow test was terminated by closing the choke smoothly over about a 30-second interval at 1015 hours. After a three-hour shut-in to record bottom-hole pressure buildup, the choke was adjusted in increments to see what rate the well would produce. Although sand detector response was negligible, the buildup in filter differential pressure and disposal well pressure were excessive after three hours of production at 3500 to 4000 BPD. At 1600 hours, the disposal well line was opened to the pit for ten minutes to "back-surge" the perforations. During this time, brine production rate was reduced to about 2000 BPD and then left constant for two hours. Although injection pressure continued to build up, pressure drop across a new filter unit remained negligible.

  At 1815 hours brine rate was again increased to 3500 to 4000 BPD. The choke was opened further at 2245 hours, with an increase in brine production rate to about 5500 BPD (two-phase wellhead turbine rate of about 6500 BPD). By midnight, injection and separator pressures were 490 and 600 psig respectively.

- **2/25/81:** At 0100 hours, the filter units were bypassed to avoid exceeding the working pressure rating of 600 psig and the flow rate was reduced from about 5500 BPD to about 4500 BPD. Injection pressure continued to increase. Shortly after 0300 hours the separator and associated instrumentation were bypassed, and the choke was opened all the way to see if the disposal well would break loose. By 0500 hours, injection pressure had increased to in excess of 1400 psig at a two-phase wellhead turbine rate of 7500 BPD (actual peak brine rate is estimated to have been 6500 to 7000 BPD). Shortly before 0600 the brine production rate was decreased to a two-phase wellhead turbine rate of about 4600 BPD. Injection pressure declined slowly but was still in excess of 1250 psig ten hours later.

  At 1630 hours production was switched from the disposal well to the separator and reserve pit to measure gas and brine production rates. The production well was shut in at 1815 hours to wait for recompletion of the disposal well.

- **2/26/81:** After the original disposal zone had been cemented off and a new zone in the disposal well had been perforated, production testing was resumed at 1640 hours. The initial rate of about 2200 BPD produced a constant injection pressure of 175 psig for 2 hours, without acid treatment of the new disposal zone. The choke was then opened wide, with a rate increase to about 6500 BPD, after 1830 hours. After bottoms-up, the filter developed enough pressure-drop to require switching. Injection pressure increased to about 400 psig when brine produced at high rate hit the disposal zone perforations. Production rate was decreased to about 5000 BPD at 2030 hours. This reduced rate arrested the rapid buildups in filter differential and injection pressures.

- **2/27/81:** No adjustments in choke setting were made until after separator brine flow was diverted to the reserve pit at 1440 hours so that acid could be pumped into the disposal well.

  Oscillations by a factor of two in orifice differential pressure, with a period of about two minutes, occurred during more than half of the 18 hours of flow at 4500 to 5000 BPD. Two intervals of stable separator operation, each about 2-1/2 hours in duration, were characterized by high gas/brine ratios.

  At 1500 hours the choke was again opened to provide a flow rate of about 7000 BPD. Sonic sand detector signals commenced at bottoms-up from the rate increase. Then, at 1700 hours, separator brine output was switched from the pit to the filters and the disposal well, immediately behind the acid. By midnight, the second filter unit since 1700 hours was approaching its rated maximum pressure drop of 50 psi, and injection pressure had increased to over 400 psig.

- **2/28/81-3/2/81:** High-rate production continued until the well was shut in at 1645 hours on 3/2/81. Changes in surface hardware during these three days consisted of (1) fully opening the choke at 0940 hours on 3/1/81 (brine rate increased from 5900 STB/D to 6700 STB/D), (2) adjusting separator pressure 12 times, and (3) bypassing the filters due to high injection pressure at 0550 hours on 3/2/81. Before the well was shut in at 1645 hours on 3/2/81, injection pressure had increased to 900 psig, and separator pressure had been increased to 1015 psig.

  More than half of the time during three days of high-rate production, oscillations in separator conditions occurred that were so severe that gas production to the flare line was zero for half of each minute. Stable operation was achieved for times in excess of 30 minutes on 12 occasions. The longest of these was three hours.

- **3/3/81-3/4/81:** The well remained shut in to record bottom-hole pressure buildup until 1700 hours on 3/4/81. The Hewlett Packard gauge was then removed from the well.

  At about 1915 hours, an injection pump, to be used to pump brine from the pit to the injection well, was tested for six minutes. Injection pressure was 115 psig.

At 1940 hours brine production was resumed so that brine and gas could be collected simultaneously and analyzed at a variety of separator pressures. An initial flow rate of about 4000 STB/D was selected as the maximum practicable for increasing surface temperature without excessive sand production. Since there was no indication of sand after bottoms-up, and since injection pressure was a modest 165 psig, the brine flow rate was increased to 4300 STB/D at 2215 hours on 3/4/81.

- **3/5/81:** The sequence of changes to collect and analyze simultaneous gas and brine samples at six different separator pressures was as follows:

  0230 hours: With the brine flow rate remaining at about 4200 STB/D, increasing separator pressure from 345 to 470 psig.

  0510 hours: Decreasing the brine flow rate to 1800 STB/D and decreasing separator pressure to 245 psig.

  1230 hours: Without changing the brine flow rate, decreasing separator pressure to 125 psig. (This required diversion of post-separator brine from the disposal well to the pit, because injection pressure was 110 psig).

  1605-1635 hours: Increasing the brine flow rate to about 4300 STB/D, increasing separator pressure to 615 psig.

  1720 hours: Resuming brine injection to the disposal well.

  2000 hours: Increasing the brine flow rate to about 6200 STB/D and increasing separator pressure to 1015 psig.

  2306 hours: Shut in production well.

  Stable separator operation was achieved for four of the six separator pressures. The last rate and pressure were again accompanied by separator oscillations so large that flare line gas production was zero for half of each minute.

  While brine from the separator was flowing to the pit, pumped injection of pit brine into the disposal well was commenced at 1315 hours. Such injection was continued through the remainder of the test and thereafter until the pit was drained. Injection pressure was constant at 175 psig when 4300 STB/D from the separator was added at 1720 hours. Injection pressure then continuously increased to a maximum of 525 psig, for a total injection rate of about 14,500 BPD at the end of the test. One hour after the production well was shut in at 2306 hours, injection pressure was 340 psig, with waste water still being injected from the pit.

- **3/6/81:** When digital recording was stopped at 0950 hours, injection pressure was 425 psig with pit brine disposal still in progress.

Samples of scale and produced solids were collected in conjunction with disassembling the surface test equipment. Both ends of the separator contained sand about 14 inches deep.

12.10.2 Real Time Production Data

High quality test data was recorded continuously from all sensors in use on this test. The few minor exceptions were at times when other data channels provided a basis for manual editing with a high degree of confidence. The data and characteristics relevant to interpretation in terms of produced fluids are discussed in subsections which follow.

12.10.2.1 Production Well Pressures

Data from three of the four channels of digitally recorded production well pressures are presented graphically in Exhibit 12-10, Parts I and II. These are bottom-hole pressures from RDI's Hewlett Packard gauge at a depth of 14,611 feet, plus tubing and annulus pressures recorded by IGT. Data from the fourth sensor, RDI's Panex gauge on the annulus, is not shown but would not be distinguishably different from IGT's data on the scale used in Exhibit 12-10.

The following characteristics of the data should be noted:

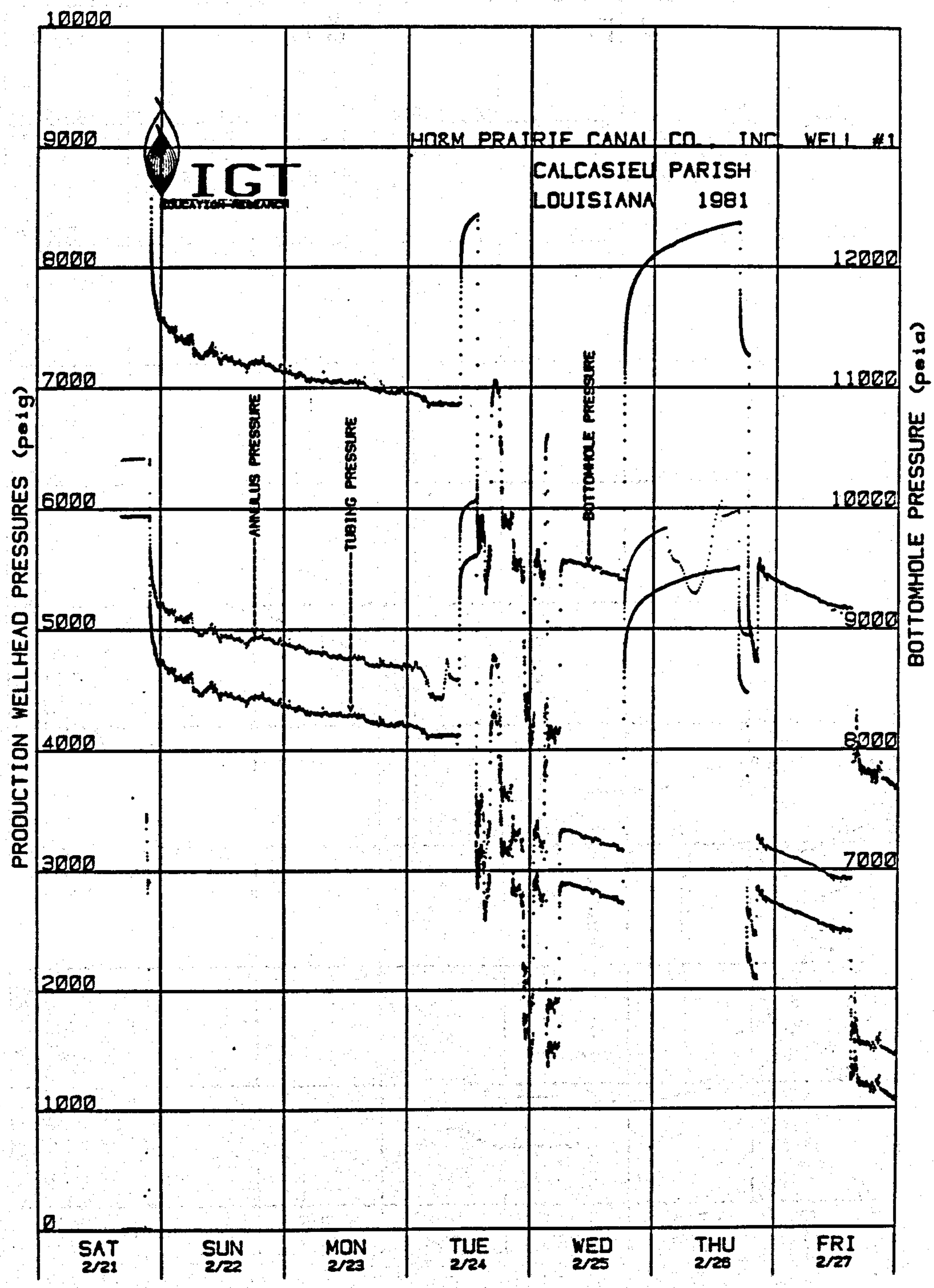
- The "zero" for bottom-hole pressure is depressed. The scale is on the right-hand side of the exhibit.
- Tubing pressure is lower than annulus pressure because the tubing was filled with 9 ppg NaCl brine.
- The vast majority of minor pressure fluctuations were simultaneously observed at all three sensor locations.

Individual pressure sensors provided data inconsistent with the other two on three separate occasions. These were annulus pressures during the morning hours of 2/24/81 and 2/26/81 and tubing pressure during 3/4/81. The first two of these are believed to have been caused by hydrate formation in the tubing between the wellhead and the sensor. The inconsistent tubing pressure probably resulted from increased grease injection into the wireline lubricator before pulling the bottom-hole pressure gauge.

Credibility of the hydrate hypothesis is supported by factual data on 2/26/81. Temperature data to be presented in Section 12.10.2.3 reveals a temperature minimum of 50°F during the deviation in recorded annulus pressure. However, hydrates form in a methane/water mixture at a temperature of roughly 75°F at the pressure that existed in the annulus during the recorded pressure variation on that date (Reference 26).

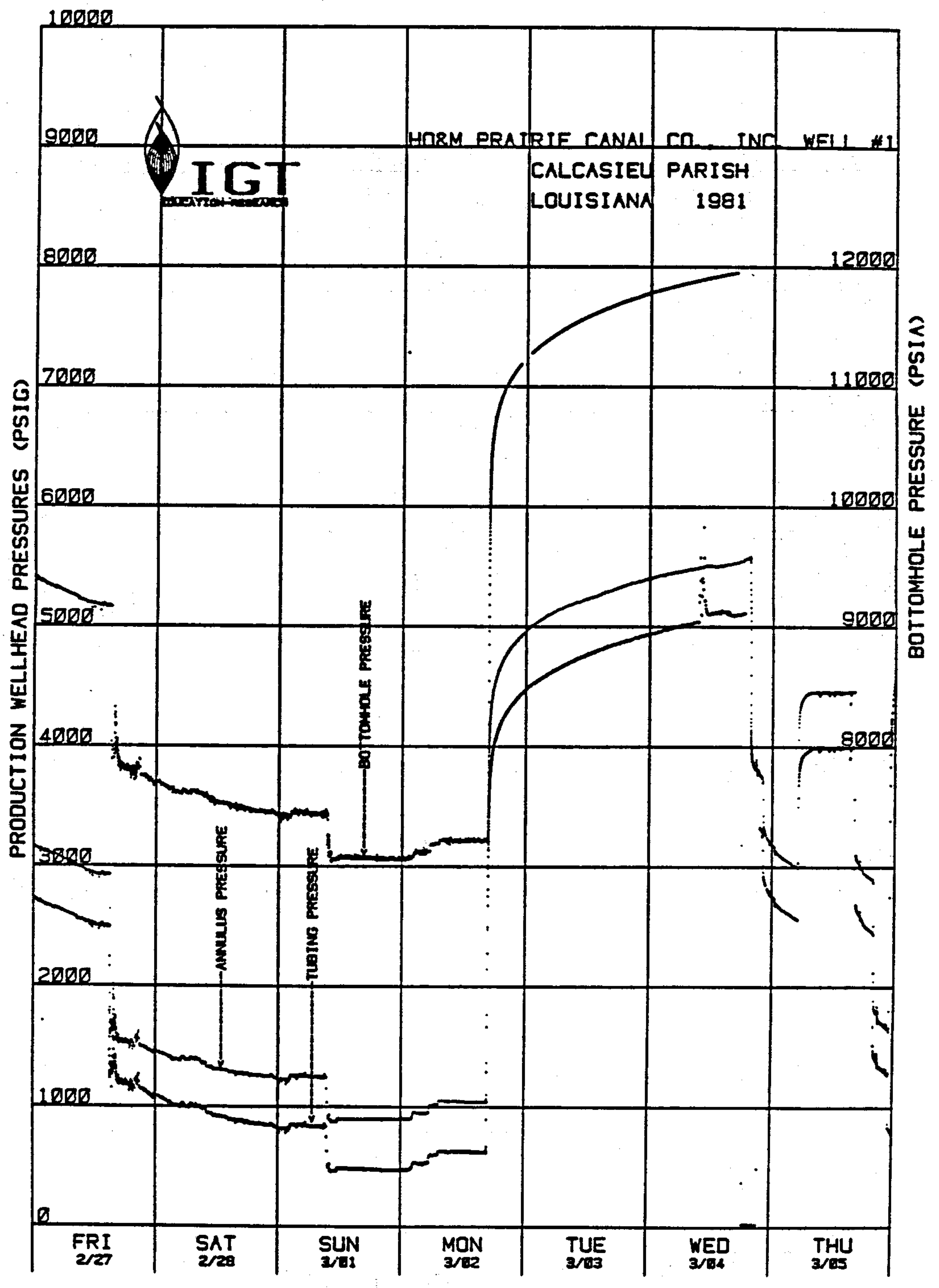
12.10.2.2 Brine Production Rate Data

Raw data from the two turbine meters, expressed as average rate for 1/2 hour time increments, is shown in Exhibit 12-11, Parts I and II. The rate recorded from the production wellhead turbine is always higher due to two-phase (gas and brine) flow. Gaps appear in the data for times when data was not recorded due to damage to signal wires by heavy equipment or, on one occasion, due to an accidental disconnection of the power cord to the "Big Tex II" on the wellhead turbine.



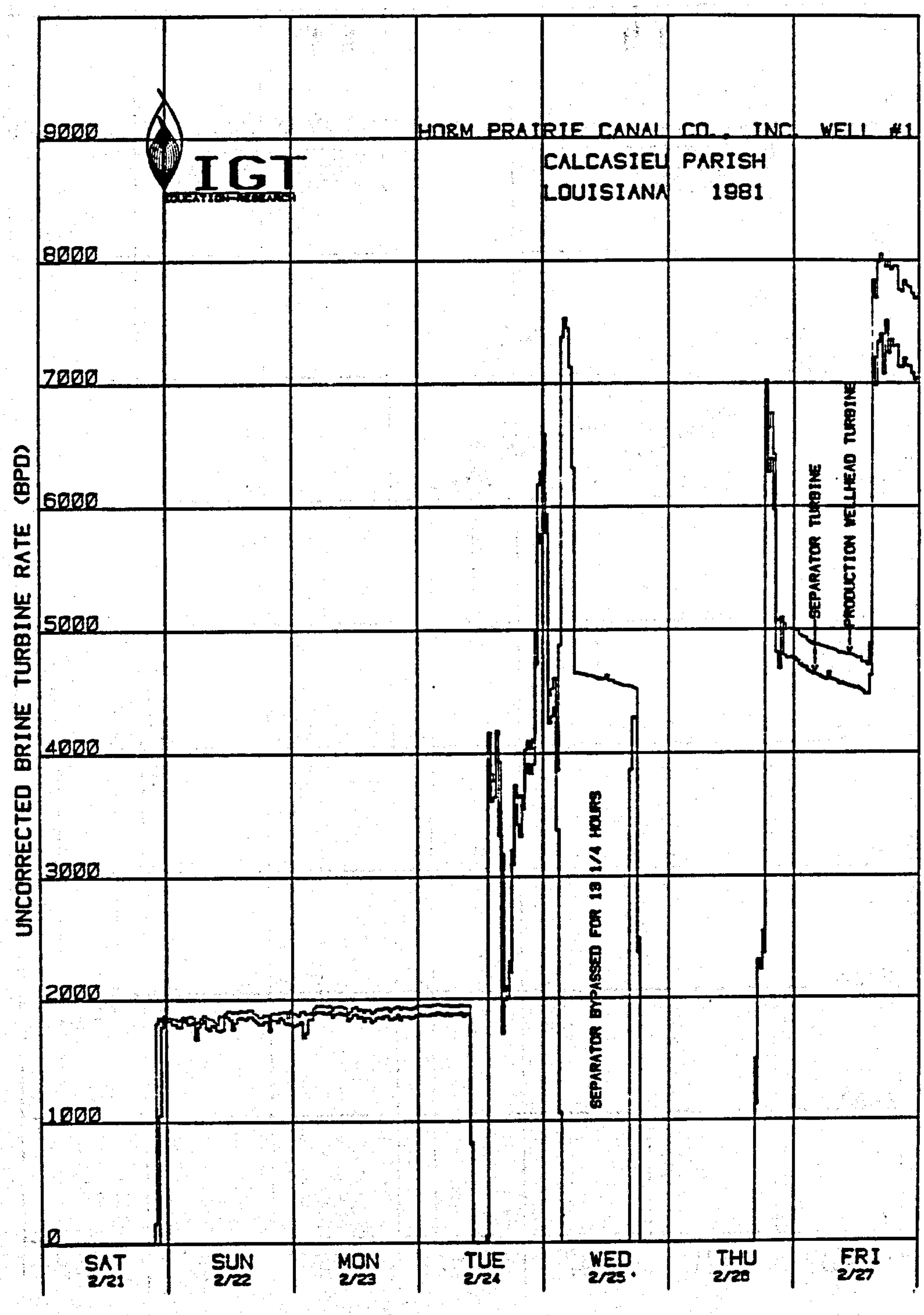
PRODUCTION WELL PRESSURES
(Part I)

EXHIBIT 12-10



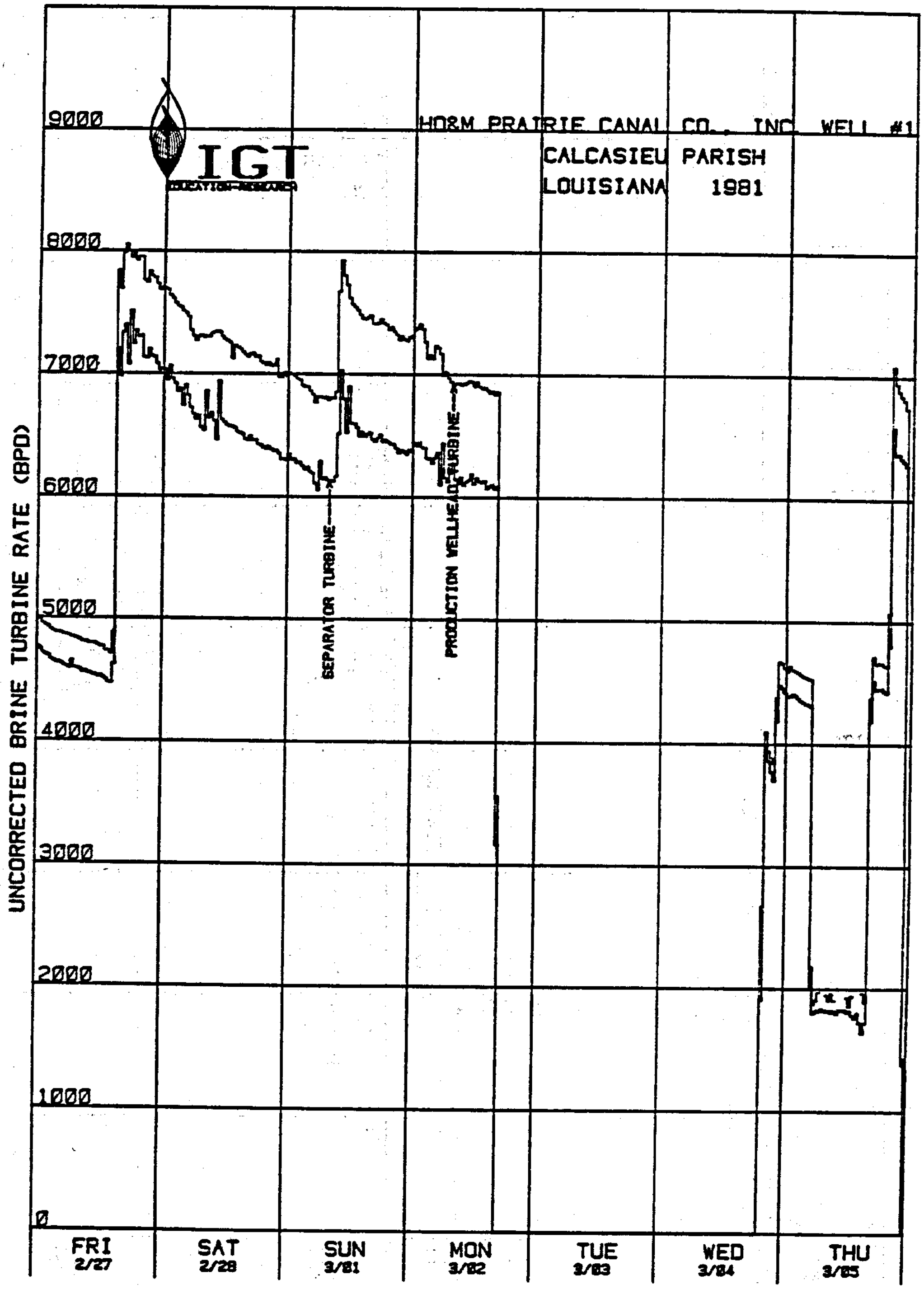
PRODUCTION WELL PRESSURES
(Part II)

EXHIBIT 12-10
(cont'd)



TURBINE METER FLOW RATES
(Part I)

EXHIBIT 12-11



TURBINE METER FLOW RATES
(Part II)

EXHIBIT 12-11
(cont'd)

As will be discussed in more detail in Sections 12.10.2.4 and 12.10.2.5, the frequent changes in rate during the afternoon of 2/24/81 and the early morning hours of 2/25/81, were due to sand production and rapid increase in injection pressure to the disposal well at the higher brine rates. On 2/25/81 the separator was bypassed for 13-1/4 hours because of high injection pressure, and therefore no fluid passed through the separator brine output turbine during that time. For the last hour before shut-in on 2/25/81, brine was flowed through the separator to the reserve pit so that the gas/brine ratio could be determined.

12.10.2.3 Brine Temperature Data

Data from IGT's brine temperature sensors in the line from the production well and on the wellhead of the disposal well are shown in Exhibit 12-12, Parts I and II. The recorded production wellhead temperatures during brine flow are low because the sensor was installed in a "T" in the line rather than in the flowing brine stream. Thus it was cooled by atmospheric convection whenever brine temperature exceeded ambient air temperature.

In data interpretation, brine temperature is used only for correction of brine volume to standard temperature and pressure and for calculation of thermal energy production. Since the brine volume correction is only a few percent and since some thermal energy loss would be incurred before practical use is made of it, the higher of the two measured temperatures at each instant is used for interpretation. Thus, data interpretation uses the erroneously low production well temperature during times of brine flow to the pit when the disposal wellhead was bypassed.

12.10.2.4 Filter Differential Pressure and Sonic Sand Detector Signal

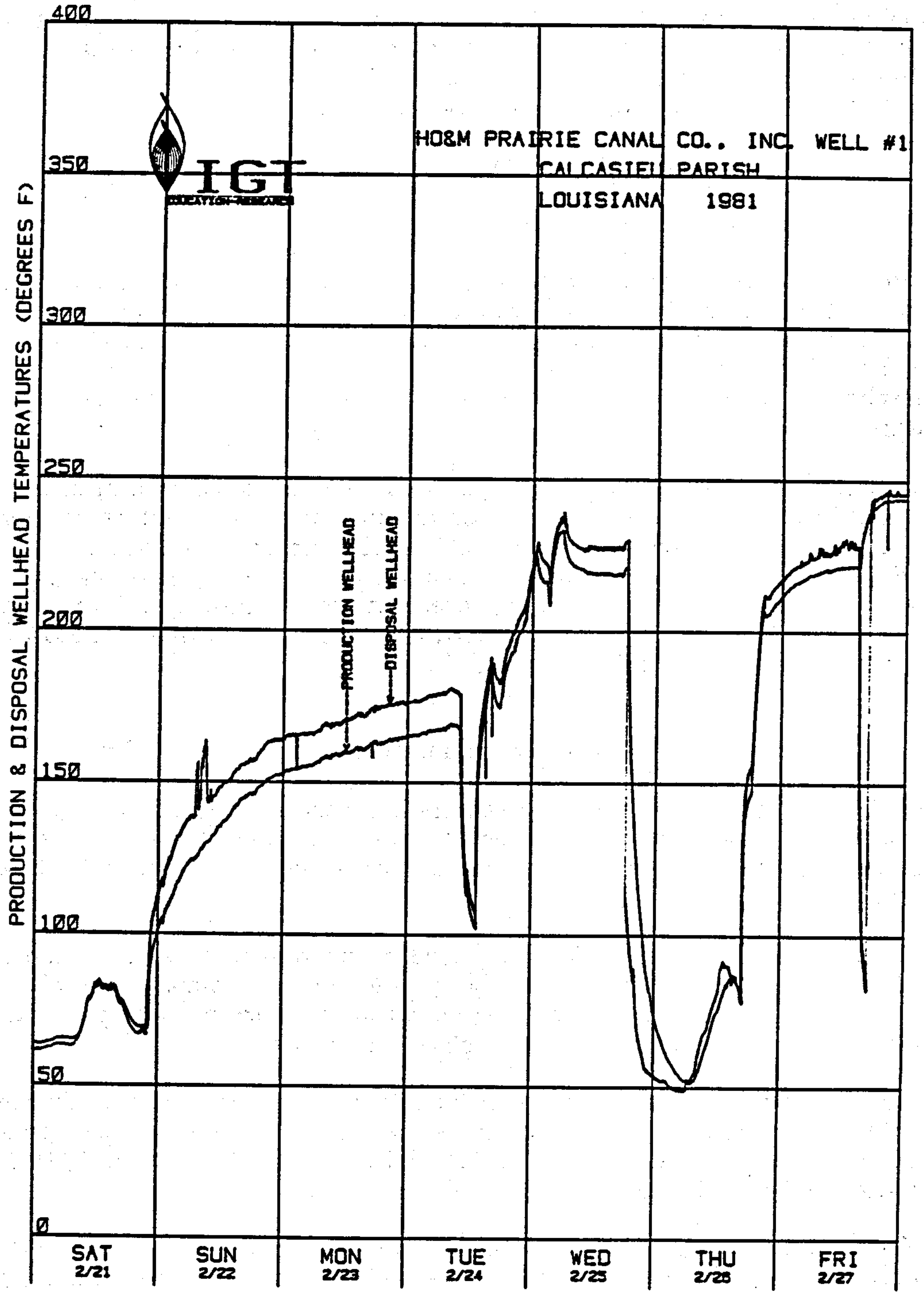
Digitally recorded data from these two sensors is presented graphically in Exhibit 12-13, Parts I and II. The scale for pressure drop across the nominal 25 micron filters used is on the left. Zero for the sand detector signal is halfway up the chart, and the scale is on the right side.

Detailed examination of data concerning sand production will be presented in Section 12.12. However, several observations are presented here in summary form, because sand production caused problems so severe that conclusions regarding fluid production cannot be reached for portions of the test. Those observations are:

- Most of the step-wise changes in Exhibit 12-13 correlate with changes in flow rate or separator pressure. However, the rapid decreases in filter pressure drop of more than 20 psi during 2/24/81, 2/26/81, 2/27/81, and 2/28/81 are due to switching brine flow to new filter units.

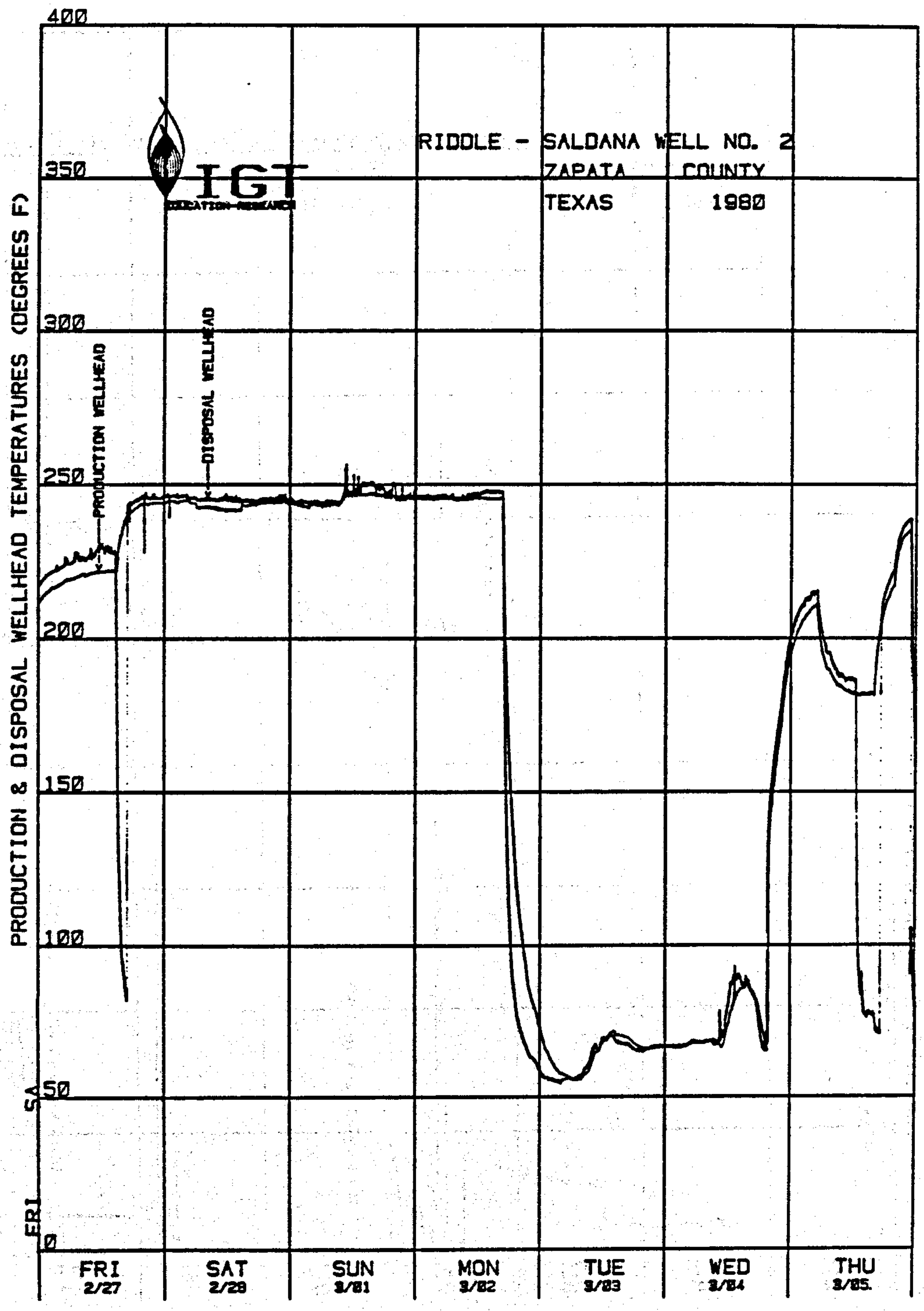
- The rapid loading of filters and subsequent switching on 2/26/81-2/28/81 correlates with increases in flow rate and probably reflects washing previously produced sand from the separator.

- At the initial flow rate of less than 2000 BPD, a sand production rate in excess of 500 pounds per day was required for detection by the sonic sand detector.



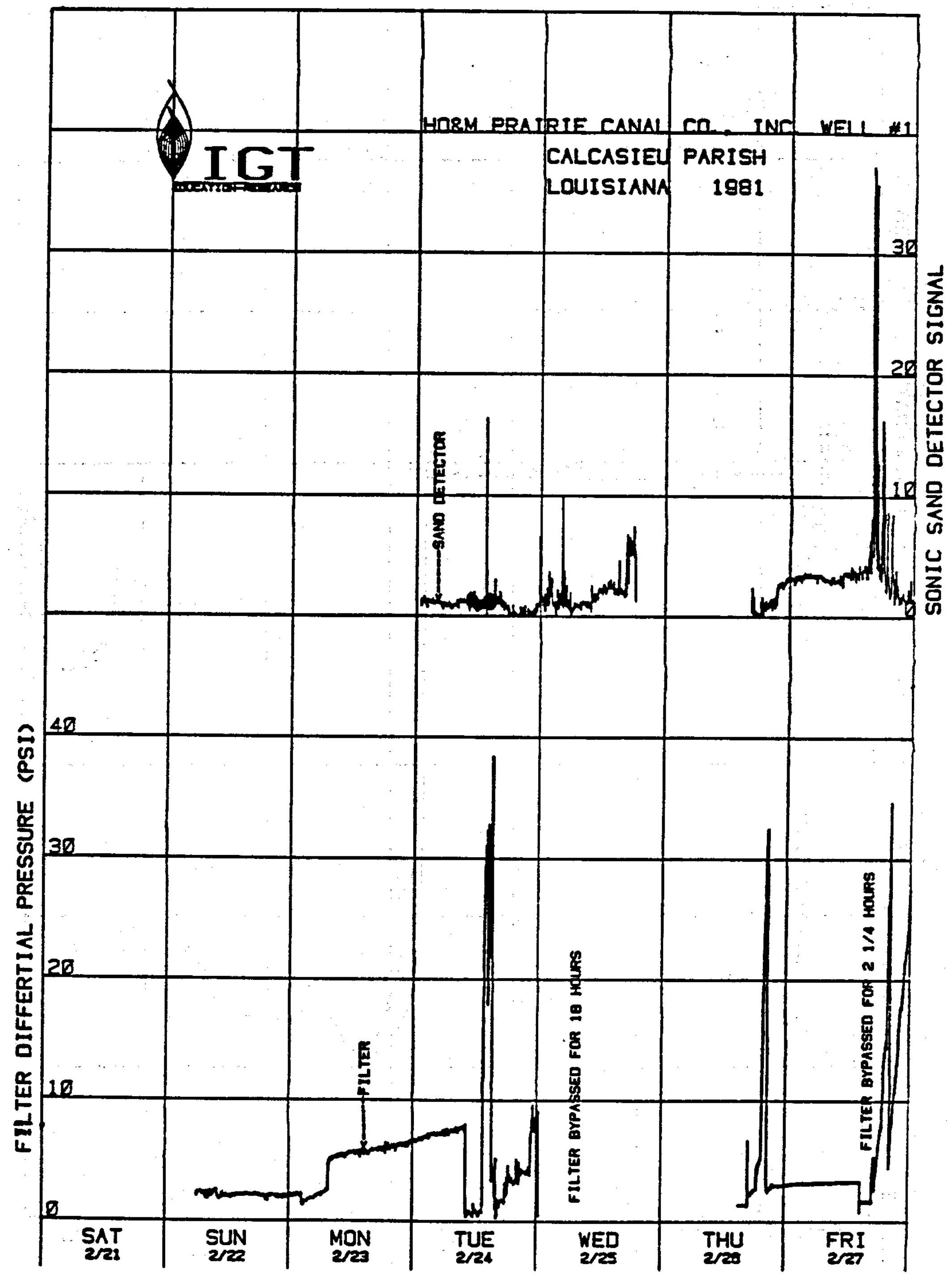
BRINE TEMPERATURES
(Part I)

EXHIBIT 12-12



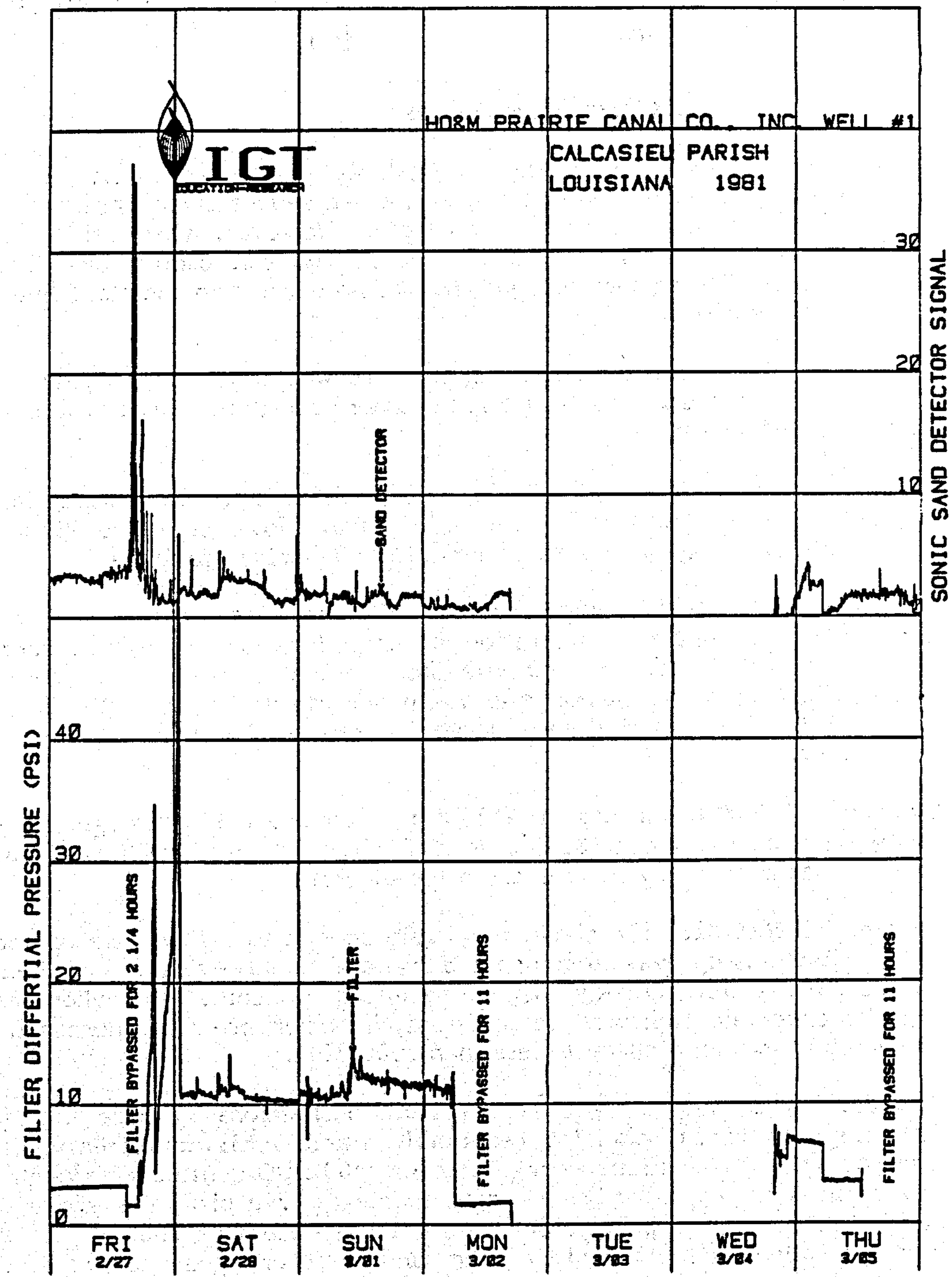
BRINE TEMPERATURES
(Part II)

EXHIBIT 12-12
(cont'd)



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

EXHIBIT 12-13



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

EXHIBIT 12-13
(cont'd)

- The fast sonic sand detector signals in excess of 2 units above background are definitely due to sand. This is supported by a correlation observed at the test site between variations in injection pressure and transit time from the sand detector to the injection well perforations following observed small variations in sand detector signal.

12.10.2.5 Separator and Injection Pressures

These pressures are portrayed graphically in Exhibit 12-14, Parts I and II. With the exception of times when brine was produced to the pit, separator pressure had to be high enough to provide the required injection pressure. However, whenever pressure drop across the separator dump valves exceeded about 100 psi, oscillations in separator performance occurred. During such oscillations, gas production to the flare line was zero for about 1/2 of each minute.

The net result was that separator operating pressure was dictated by injection pressure for the majority of the test. In chronological order, additional observations regarding Exhibit 12-14 are as follows:

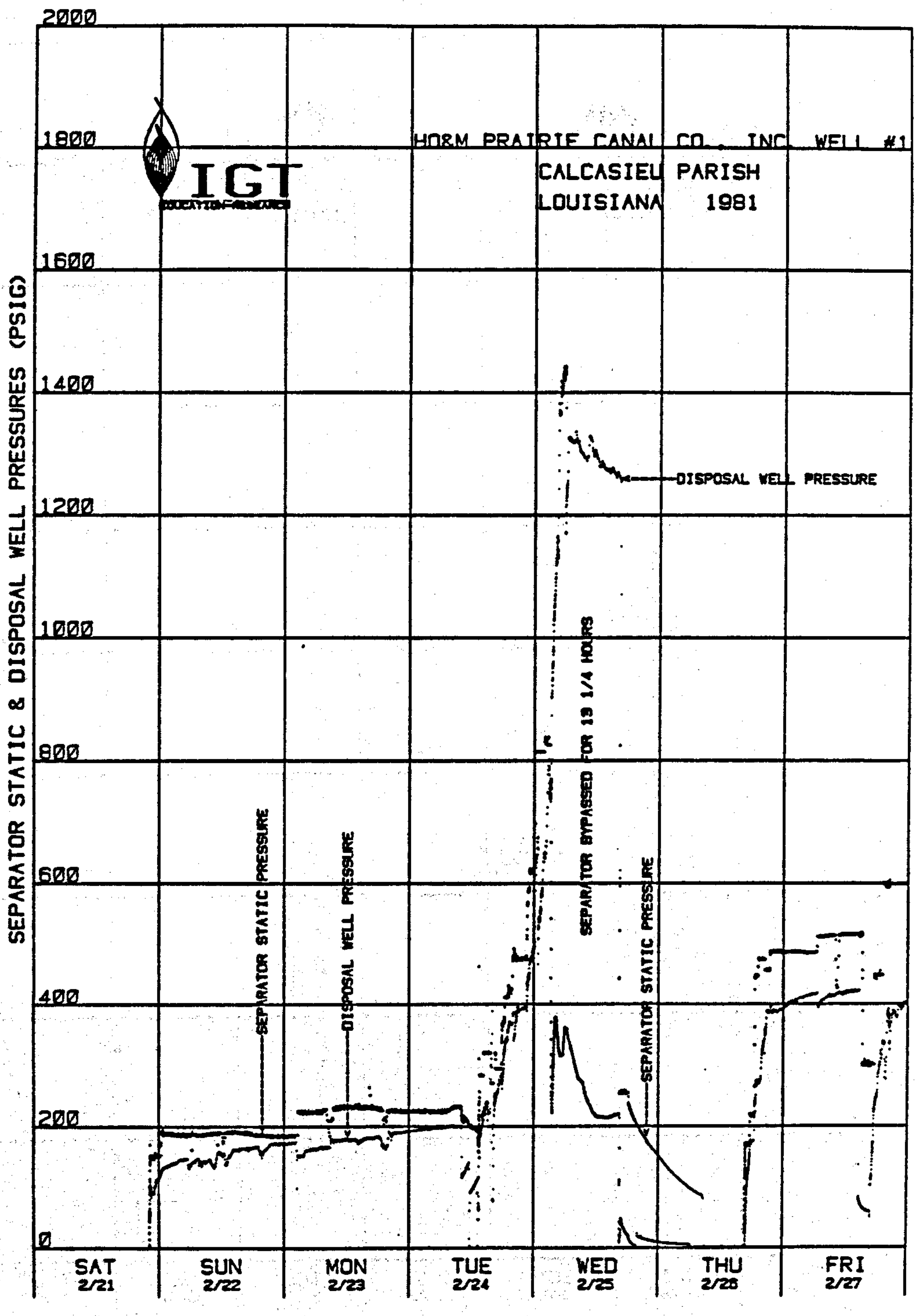
- **2/21/81 through morning of 2/24/81:** No significant problems were encountered during the initial flow test at about 1800 BPD. However, up to 500 pounds per day of fine sand may have been accumulating in surface facilities.

- **Afternoon of 2/24/81 through most of 2/25/81:** After a few hours shut in to obtain buildup data for augmentation of initial drawdown data for reservoir limit analysis, the choke was opened with the intent of stepping up to the maximum possible flow rate. However, this intent was thwarted when the first step, to about 3800 BPD, resulted in a large increase in filter pressure drop before bottoms-up.

- **Evening of 2/25/81 and most of 2/26/81:** After producing through the separator to the pit from 1645 until 1815 hours on 2/25/81, the production well was shut in for perforation of a new zone in the disposal well.

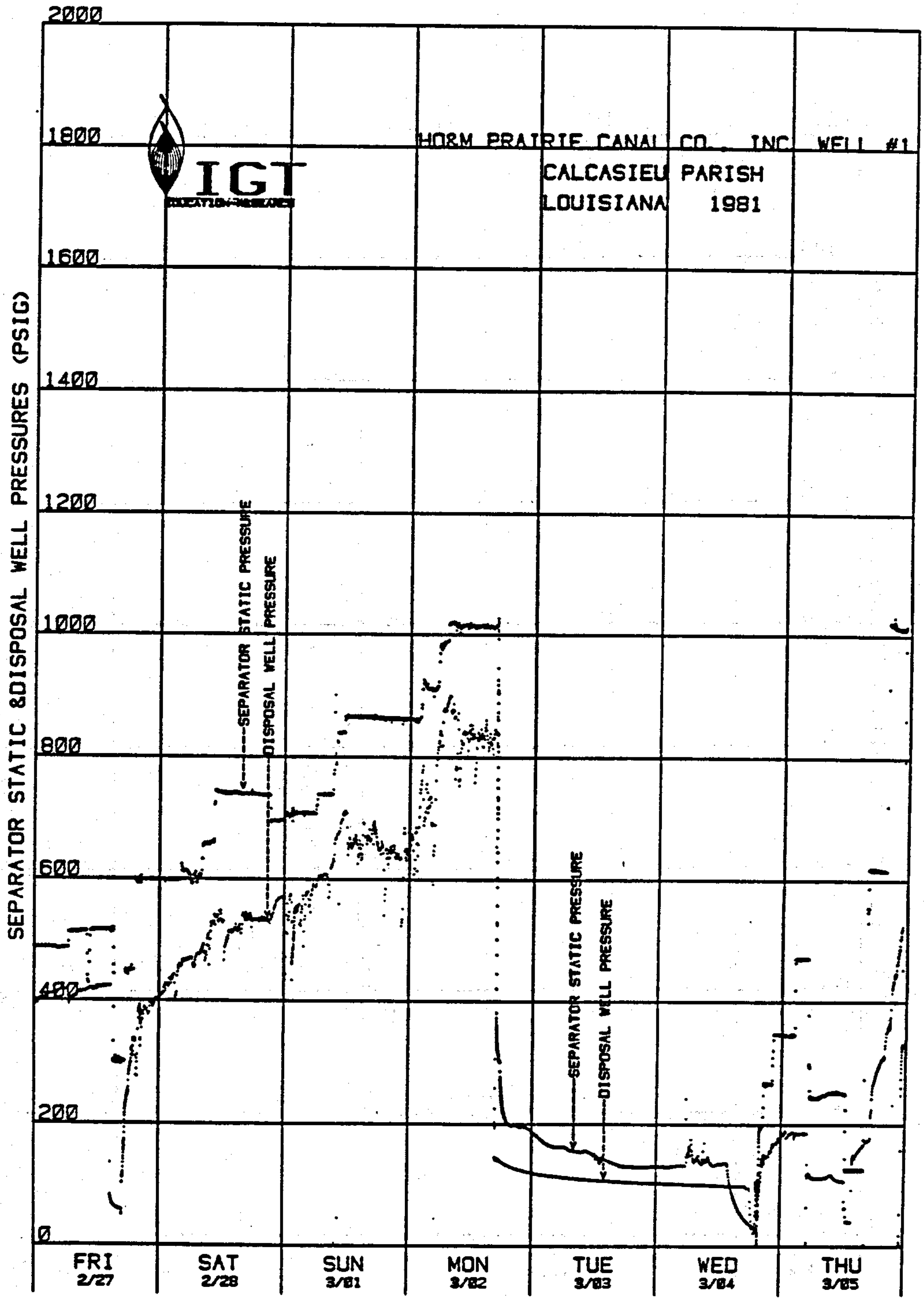
- **Evening of 2/26/81:** The choke was again opened to a flow rate of about 6500 BPD. Bottoms-up was accompanied by additional evidence of heavy sand production. Filters quickly loaded, requiring switching, and when sand-laden fluid reached injection well perforations, injection pressure increased rapidly. Brine rate was then reduced to less than 5000 BPD.

- **2/27/81:** With the exception of periodic oscillations in flare line gas rate, operating conditions remained reasonably stable until acid treatment of the disposal well. Production testing at about 4500 BPD continued through the acid treatment with separator brine output to the reserve pit. The choke was then opened to provide a brine production rate in excess of 7000 BPD. Although bottoms-up was accompanied by sonic sand detector signals of 1/3 of the most sensitive scale and filters loaded rapidly, production at maximum rate from the 14 feet net pay remained the overall objective.



SEPARATOR AND INJECTION PRESSURES
(Part I)

EXHIBIT 12-14



SEPARATOR AND INJECTION PRESSURES
(Part II)

EXHIBIT 12-14
(cont'd)

- **2/28/81 through 3/2/81:** Maximum rate testing continued. During 3/1/81, the choke was opened the rest of the way. For the last several hours before shut-in on 3/2/81, separator pressure had to be in excess of 1000 psig, and extreme surging of flare gas rate was continuous, with a period of about one minute.

- **Evening of 3/2/81 through most of 3/4/81:** The production well remained shut in for recording of pressure buildup. Disposal well pressures shown on Exhibit 12-14 are shut-in pressures.

- **Evening of 3/4/81 through 3/5/81:** Production was for the purpose of obtaining simultaneous gas and brine samples at a variety of separator pressures, so that the relationship to CO_2 content of gas could be definitively established. The highest separator pressure, and required high flow rate, were deferred until the end of the test in anticipation of the observed rapid increase in injection pressure.

12.10.2.6 Orifice Differential Pressure and Gas Temperature

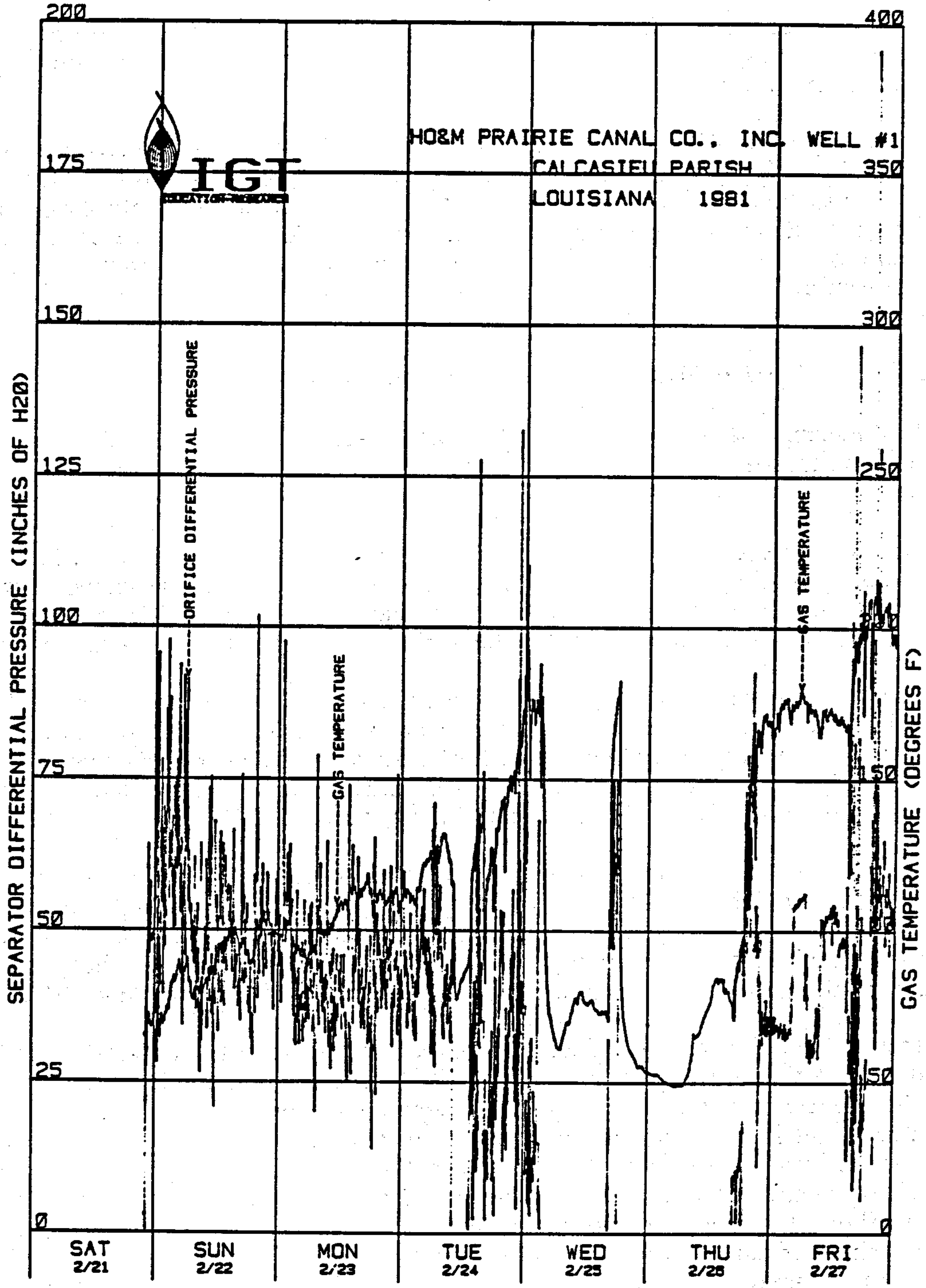
Digitally recorded data is shown in Exhibit 12-15, Parts I and II. The scale for differential pressure is on the left and the temperature scale is on the right of this exhibit.

Gas temperatures shown are the values downstream of the orifice meters that are used to calculate gas flow. They are substantially lower than the brine temperatures previously shown in Exhibit 12-12. This is due to cooling by air convection around roughly 15 feet of 2-inch pipe between the separator vessel and the meter orifice.

To the maximum extent practicable, orifice sizes were selected to maintain differential pressure in excess of 20 inches of water. This is because the "zero" level varies with time by as much as plus or minus one inch of water. Since gas rate is proportional to the square root of differential pressure, values in excess of 20 inches of water provide gas rate measurement accuracy of better than 2.5 percent.

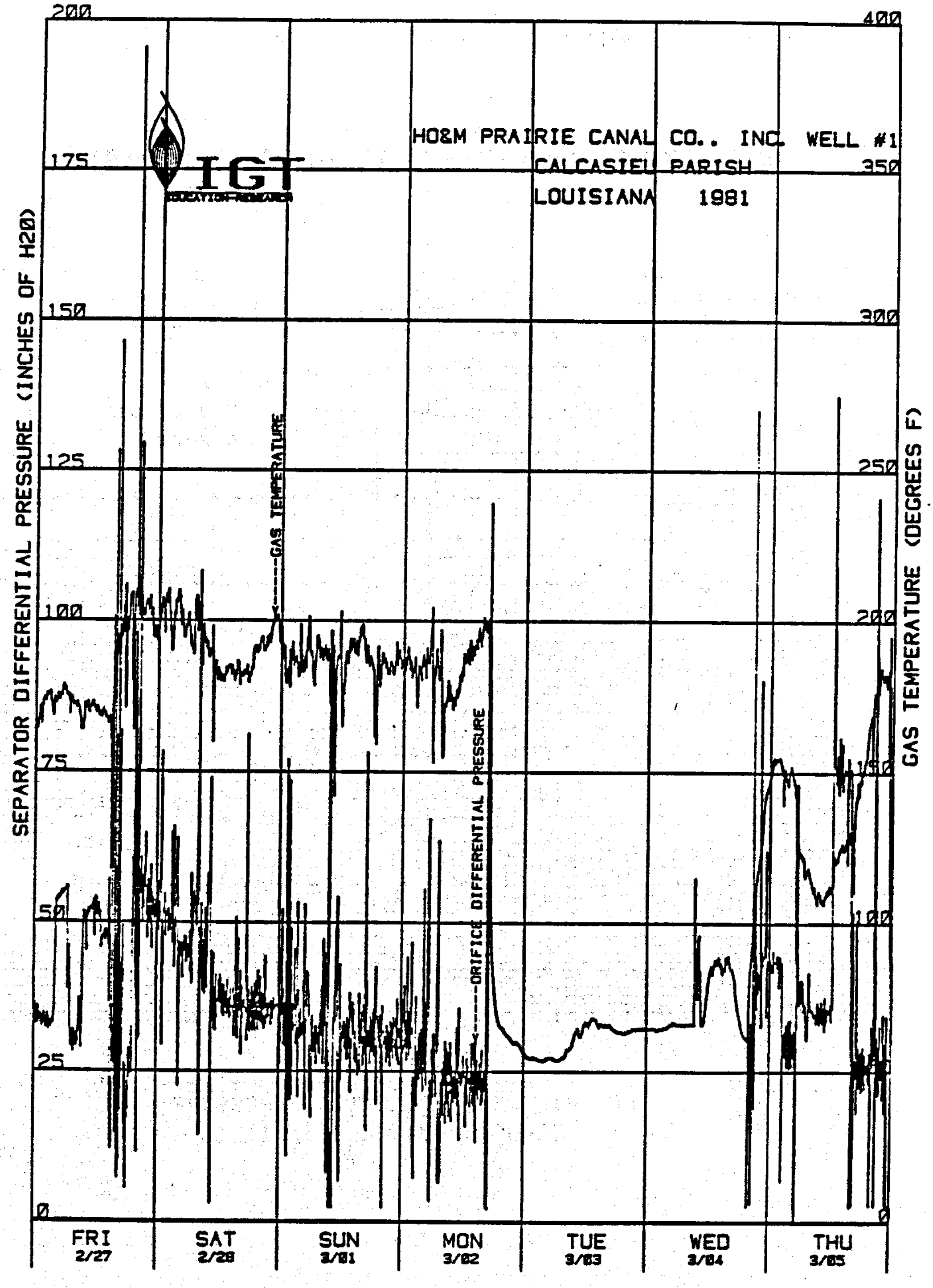
In actual practice, very short-term variations in differential pressure were much greater than suggested by Exhibit 12-15. For example, Exhibit 12-16 is a high-speed strip chart recording of orifice differential pressure at 2030 hours on 3/5/81. In this exhibit, the flat base of each cycle corresponds to zero differential pressure. The positive offset from zero on the chart is to avoid negative values during long-term slow drift.

The reason that Exhibit 12-15 does not reveal these violent short-term oscillations is programming of the digital data recording. The digital equipment is programmed to read orifice differential pressure and take the square root every five seconds. Times of such readings are indicated by the tick marks at the zero signal level on Exhibit 12-16. The square root values for every five seconds are then added over the time interval desired between permanent records. At the time of each permanent record, the sum is divided by the number of readings to obtain an average. This average is then squared before producing the permanent record. Most permanent records are made at five-minute intervals and therefore reflect square root averaging of sixty individual readings. The result is the relatively smooth data shown in Exhibit 12-15.



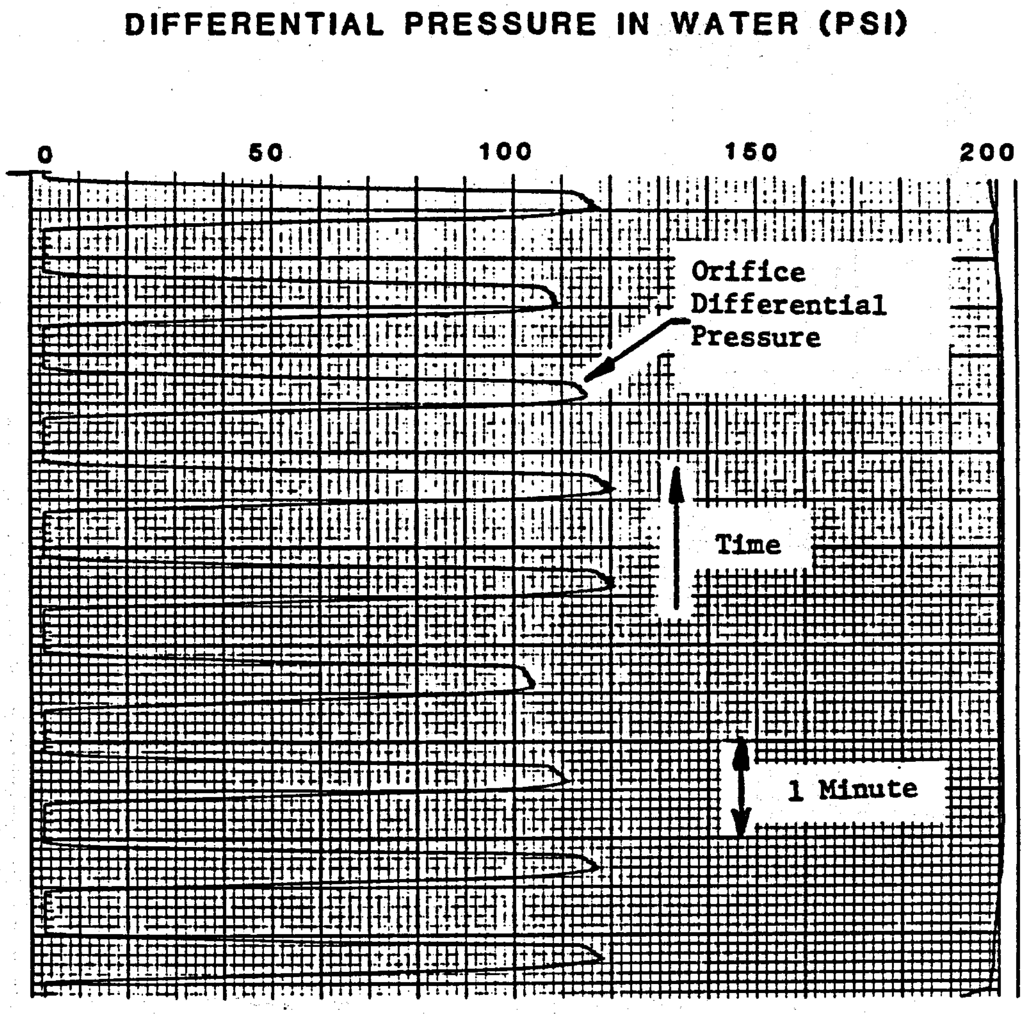
ORIFICE DIFFERENTIAL PRESSURE
AND GAS TEMPERATURE
(Part I)

EXHIBIT 12-15



ORIFICE DIFFERENTIAL PRESSURE
AND GAS TEMPERATURE
(Part II)

EXHIBIT 12-15
(cont'd)



HIGH-SPEED STRIP CHART RECORDING
OF ORIFICE DIFFERENTIAL PRESSURE
(2030 Hours on 3/5/81)

EXHIBIT 12-16

12.10.3 Characteristics of Produced Gases

Collection and analysis of flare line gas samples is described in Section 12.10.3.1. Similar information for gas remaining in post-separator brine is provided in Section 12.10.3.2. Results of analyses by parties other than IGT are then presented in Section 12.10.3.3. Finally, Section 12.10.3.4 presents judgments made in selecting gas compositions for interpretation of production test data to determine the time-dependence of gas production.

12.10.3.1 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 several degrees lower than the flowing brine temperature due to atmospheric convective cooling on the roughly 15 feet of two-inch pipe between the separator vessel and the orifice.

Procedures used for 1) 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 Teflon-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 the C_{6+} peak, making quantification difficult. The chromatograph also separated carbon dioxide, nitrogen, oxygen, and hydrogen. The nitrogen values are uncertain, because a baseline upset occurred with valve switching within the instrument. The hydrogen peak is not quantified, because an adequate standard had not been run. A small peak appearing with a retention time similar to that of hydrogen has been determined to be an anomalous "leak peak." This "leak peak," however, severely lessened the ability of the chromatograph to detect hydrogen.

The area under the 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 and the composition normalized to 100% for N_2, CO_2, and methane through pentane hydrocarbons.

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. 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.

- **Draeger Apparatus Analyses:** Hydrogen sulfide concentration was determined using Length of Stain Tubes (Draeger apparatus). The sampling port was the same as was 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 (See Appendix H). Carbon dioxide, ammonia, and mercury contents were also determined using this procedure. Results of mercury and ammonia analyses on 2/22/81 at 0245 hours were below minimum detectable limits--less than 3 ppm ammonia and less than 0.05 mg/m^3 mercury. Results of CO_2 analyses were consistent with gas chromatographic analyses--7% at 1100 hours on 2/20/81 and 8.2% at 0245 hours on 2/22/81.

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

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

Results of field analyses are tabulated in Exhibit 12-17. Collection times are shown for the 51 gas samples analyzed with the field gas chromatograph. Results of Draeger apparatus analyses are added to the column closest in time to that of gas chromatograph analyses. In all cases, the separator pressures and brine temperatures shown are also representative of the time of Draeger apparatus analyses.

Cursory examination of Exhibit 12-17 reveals substantial variations in gas composition. Mole fractions of both CO_2 and propane vary by a factor of almost two. Fraction of butanes varies by a factor of four. Analyses to be presented in later sections of this report will reveal that the dominant reason for variation in CO_2 content of flare line gas was changes in separator pressure. The higher contents of C_{2+} hydrocarbons will be shown to correlate with produced gas/brine ratios in excess of gas solubility in reservoir brine and, therefore, to reflect the existence of a free gas phase in the reservoir.

Results of mass spectrometric analysis of three gas samples are tabulated in Exhibit 12-18. The three analyses provide verification of field gas chromatograph analyses performed in the field and provide an estimate of content of C_{6+} components that will be used in Section 12.10.3.4, "Gas Composition for Orifice Meter Data Interpretation."

12.10.3.2 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. The sample collection point was horizontal at the midpoint of the 3-inch pipe and only about two pipe diameters downstream from the last three right-angle changes in flow direction. The sampling point was at separator pressure. The sample collection and flashing procedures were 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 through the sample vessel for at least 60 seconds and until the vessel is 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.

FIELD ANALYSES OF FLARE LINE GAS
HO & M PRAIRIE CANAL CO., INC. WELL NO. 1
(Part I)

Date	2/22/81	2/22/81	2/22/81	2/22/81	2/22/81	2/23/81	2/23/81	2/23/81	2/24/81
Time	0230	0305	0835	1105	2005	0750	1350	2320	0837
Separator Pressure (psig)	189	188	187	188	185	226	234	224	232
Separator Temperature (°F)	125	129	140	146	161	169	172	175	181
Composition by Gas Chromatograph Analyses (mole %)*									
Methane	88.32	88.04	87.60	87.67	87.19	87.59	87.84	87.40	87.25
Ethane	2.80	2.54	2.55	2.67	2.71	2.65	2.73	2.64	2.52
Propane	0.44	0.37	0.39	0.43	0.44	0.43	0.45	0.43	0.39
n-Butane	0.06	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
i-Butane	0.03	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.02
Pentanes	0.01	<0.01	<0.01	0.01	0.01	<0.01	<0.01	<0.01	<0.01
Nitrogen	0.31	0.32	0.32	0.31	0.27	0.32	0.32	0.34	0.32
Carbon Dioxide	8.02	8.67	9.09	8.85	9.32	8.94	8.59	9.05	9.47
Draeger Apparatus Analyses, (ppm):									
Hydrogen Sulfide+	12		16			20			22

Date	2/24/81	2/24/81	2/24/81	2/24/81	2/24/81	2/24/81	2/24/81	2/25/81
Time	1502	1540	1630	2000	2205	2346	2358	0100
Separator Pressure (psig)	320	320	301	448	478	623	621	814
Separator Temperature (°F)	180	187	189	198	206	220	221	230
Composition by Gas Chromatograph Analyses (mole %)*								
Methane	87.36	87.80	84.76	88.27	88.50	89.23	88.92	89.87
Ethane	2.39	2.51	2.51	2.47	2.51	2.96	2.65	2.58
Propane	0.41	0.39	0.40	0.38	0.39	0.42	0.45	0.40
n-Butane	0.04	0.03	0.03	0.02	0.03	0.03	0.04	0.03
i-Butane	0.04	0.03	0.03	0.02	0.03	0.03	0.03	0.03
Pentanes	0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.01	<0.01
Nitrogen	0.29	0.33	0.31	0.33	0.33	0.08	0.32	0.31
Carbon Dioxide	9.47	8.80	11.96	8.50	8.21	7.24	7.58	6.77
Draeger Apparatus Analyses, (ppm):								
Hydrogen Sulfide+		24						14

* Gas chromatographic results are normalized to 100% for the species listed

\+ Hydrogen sulfide analyses are listed under the gas chromatograph analyses which were closest in time to the H_2S analyses. Mercury and ammonia were looked for, using appropriate Draeger tubes, at 0245 hours on 2/22/81. The results were below minimum detectable limits — less than 3 ppm ammonia and less than 0.05 mg/meter^3 mercury. Draeger CO_2 analyses were performed at 1100 hours on 2/20/81 and at 0245 hours on 2/22/81. The results were 7% (volume) and 8.2% respectively, and consistent with the gas chromatographic analyses.

EXHIBIT 12-17

FIELD ANALYSES OF FLARE LINE GAS
HO & M PRAIRIE CANAL CO., INC. WELL NO. 1
(Part II)

Date	2/25/81	2/25/81	2/26/81	2/26/81	2/27/81	2/27/81	2/27/81	2/28/81	2/28/81
Time	1705	1800	1930	2012	0855	1023	1555	1207	1245
Separator Pressure (psig)	258	255	476	476	513	528	301	739	739
Separator Temperature (°F)	228	230	192	208	226	227	234	246	246
Composition by Gas Chromatograph Analyses (mol %)*									
Methane	86.41	86.39	88.53	88.44	88.53	88.77	86.62	89.81	89.41
Ethane	2.43	2.44	2.76	2.59	2.50	2.44	2.85	2.32	2.45
Propane	0.36	0.36	0.47	0.41	0.37	0.36	0.57	0.32	0.35
n-Butane	0.02	0.02	0.04	0.03	0.02	0.02	0.06	0.02	0.02
i-Butane	0.02	0.02	0.04	0.03	0.02	0.02	0.05	0.02	0.02
Pentanes	<0.01	<0.01	0.01	<0.01	<0.01	<0.01	0.01	<0.01	<0.01
Nitrogen	0.34	0.34	0.32	0.35	0.34	0.27	0.33	0.29	0.32
Carbon Dioxide	10.42	10.41	7.84	8.16	8.22	8.12	9.50	7.22	7.43
Draeger Apparatus Analyses (ppm)									
Hydrogen Sulfide+	22						18		15

Date	2/28/81	3/1/81	3/1/81	3/1/81	3/1/81	3/2/81	3/2/81	3/2/81	3/5/81
Time	2115	0905	0945	1802	2236	0945	1300	1620	0035
Separator Pressure (psig)	736	738	778	864	860	1014	1013	1013	345
Separator Temperature (°F)	245	244	244	249	246	245	247	247	204
Composition by Gas Chromatograph Analyses (mol %)*									
Methane	89.39	89.14	89.47	89.77	89.66	90.22	90.27	90.34	87.70
Ethane	2.43	2.49	2.49	2.49	2.48	2.54	2.52	2.48	2.28
Propane	0.34	0.34	0.34	0.35	0.35	0.36	0.35	0.35	0.27
n-Butane	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
i-Butane	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
Pentanes	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Nitrogen	0.33	0.28	0.24	0.30	0.31	0.29	0.30	0.28	0.36
Carbon Dioxide	7.46	7.70	7.42	7.05	7.16	6.55	6.51	6.50	9.36
Draeger Apparatus Analyses (ppm)									
Hydrogen Sulfide+	16		16					12	

* Gas chromatographic results are normalized to 100% for the species listed.

\+ Hydrogen sulfide analyses are listed under the gas chromatograph analyses which were closest in time to the H_2S analyses

FIELD ANALYSES OF FLARE LINE GAS
HO & M PRAIRIE CANAL CO., INC. WELL NO. 1
(Part III)

Date	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81
Time	0125	0223	0328	0453	0453	1006	1009	1212	1340	1340	1520	1815	1933	2112	2112	2238
Separator Pressure (psig)	345	347	472	472	472	253	251	250	126	126	125	618	615	1014	1014	1010
Separator Temperature (°F)	209	211	213	215	215	187	187	186	186	186	186	216	221	235	235	238
Composition by Gas Chromatograph Analyses (mol %)*																
Methane	87.58	87.95	88.44	88.34	88.47	87.21	87.54	87.16	85.59	85.63	85.47	89.16	88.54	89.97	90.00	90.11
Ethane	2.31	2.05	2.39	2.41	2.36	2.34	2.28	2.36	2.32	2.31	2.31	2.59	2.54	2.93	2.92	2.73
Propane	0.28	0.28	0.29	0.29	0.29	0.27	0.27	0.28	0.27	0.27	0.27	0.35	0.34	0.49	0.49	0.41
n-Butane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.02
i-Butane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.02
Pentanes	<0.1	<.01	<.01	<.01	<.01	<.01	<.01	<.01	<.01	<.01	<.01	<.01	<.01	0.01	0.01	<.01
Nitrogen	0.30	0.07	0.30	0.30	0.36	0.30	0.32	0.30	0.30	0.33	0.32	0.31	0.40	0.30	0.34	0.32
Carbon Dioxide	9.51	9.62	8.56	8.62	8.49	9.05	9.59	9.87	11.49	11.43	11.61	7.56	8.14	6.23	6.19	6.36
Draeger Apparatus Analyses (ppm)																
Hydrogen Sulfide⁺							20									

* Gas chromatograph results are normalized to 100% for the species listed

+ Hydrogen sulfide analyses are listed under gas chromatograph analyses which were closest in time to the H_2S analyses.

EXHIBIT 12-18. FLARELINE GAS COMPOSITION FROM MASS SPECTROMETRY ANALYSES

Date	22 Feb 81	25 Feb 81	5 Mar 81
Time	1157	1700	1045
Separator Pressure (psig)	191.4	257.5	254.2
Separator Temperature (°F)	148	219	187
Composition (mole percent)*			
Methane	87.58	86.94	87.84
Ethane	2.29	2.29	2.17
Propane	0.31	0.30	0.23
n-Butane	0.02	0.02	0.01
i-Butane	0.03	0.03	0.01
Pentanes	<0.01	<0.01	<0.01
Hexanes	<0.01	<0.01	<0.01
Benzene	0.02	0.02	0.03
Toluene	0.01	0.01	0.02
Nitrogen	0.16	0.11	0.12
Carbon Dioxide	9.36	10.06	9.35
Hydrogen	0.22	0.22	0.22
Gas Properties:			
NGL (gallons/MCF)	0.7208	0.7180	0.6633
Heating Value (Btu/SCF)	914	918	923
Specific Gravity	0.660	0.667	0.659

*Additional species that would have been reported if present to 0.1 mole percent or greater are: hydrogen, helium, oxygen, argon, octanes, nonanes, and xylene.

- Opening the sample vessel to allow gas flashed from brine in the pressure vessel to move vertically into the large syringe.

- 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 12-19a. This exhibit shows both the quantity of gas liberated by reducing pressure to one atmosphere after cooling the brine and the composition of that gas. The additional gas remaining in solution in the brine at one atmosphere is not tabulated in Exhibit 12-19a. The analyses tabulated, plus the additional CO_2 remaining in the brine, will be discussed in detail in Section 12.11, "Separator Evaluation."

This is the first well test since the test of the Wainoco P.R. Girouard Well No. 1 to involve a wide range of separator pressures. The measured amounts of gas liberated from brine provide a check on the computational procedure used to estimate that quantity. Exhibit 12-19b presents that comparison. The abscissa is the measured amount of gas released, from Exhibit 12-19a. The ordinate is the value calculated using the algorithm by S.K. Garg, et al., (Reference 16), for methane solubility in distilled water, using the values of separator pressure and brine temperature tabulated for each sample in Exhibit 12-19a.

The deviation from a slope of one is caused by the facts that (1) the computer algorithm calculates total gas solubility whereas roughly one SCF/STB of gas (predominately CO_2) remains in solution after the measurement and (2) the portion of total CO_2 remaining in separator brine is greater at high separator pressure.

12.10.3.3 Gas Analyses 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.

- Weatherly Laboratories
  Lafayette, LA.
- U.S. Geological Survey
  NSTL Station, MS.
- McNeese State University
  Lake Charles, LA.
- U.S. Geological Survey
  Menlo Park, CA.

Other organizations invited to participate in sampling and analysis included The University of Texas at Austin, Lawrence Berkeley Laboratory, and Louisiana State University.

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.

Part I.
ANALYSES OF GAS OFF BRINE AFTER SEPARATOR
HO & M PRAIRIE CANAL CO., INC. WELL #1

Sample Collection Date	2/20/81	2/22/81	2/23/81	2/24/81	2/24/81	2/24/81	2/24/81	2/24/81	2/25/81	2/27/81	2/28/81	3/1/81	3/1/81
Sample Collection Time	1100	1030	1353	0845	1630	2000	2205	2345	1700	0900	1230	0950	1835
Separator Pressure (psig)	155	188	232	231	201	488	479	619	258	514	739	864	864
Brine Temperature (°F)	74	145	172	181	189	198	206	219	228	226	246	248	248
Gas to Brine Ratio (SCF/STB)	1.58	1.08	2.47	1.88	1.93	2.88	3.80	4.55	1.99	4.05	5.61	6.73	7.50
Composition (mole %)													
Methane	67.03	62.48	70.38	64.16	68.08	65.94	67.16	67.75	70.11	70.27	67.78	67.88	68.76
Ethane	1.71	1.58	1.89	1.60	1.54	1.52	1.61	1.64	1.57	1.62	1.45	1.44	1.47
Propane	0.14	0.15	0.22	0.16	0.15	0.14	0.16	0.18	0.16	0.15	0.12	0.12	0.13
Butanes	0.01	0.01	0.02	0.01	0.01	0.01	0.02	0.02	<0.01	0.01	0.01	0.01	0.01
Nitrogen*	1.81	4.44	--	0.97	0.33	0.17	0.30	0.17	0.87	0.08	0.20	0.11	0.17
Carbon Dioxide	29.30	31.33	27.23	33.10	29.88	32.22	30.75	30.25	27.30	27.87	30.42	30.43	29.46

* Nitrogen values are not significant due to air contamination.

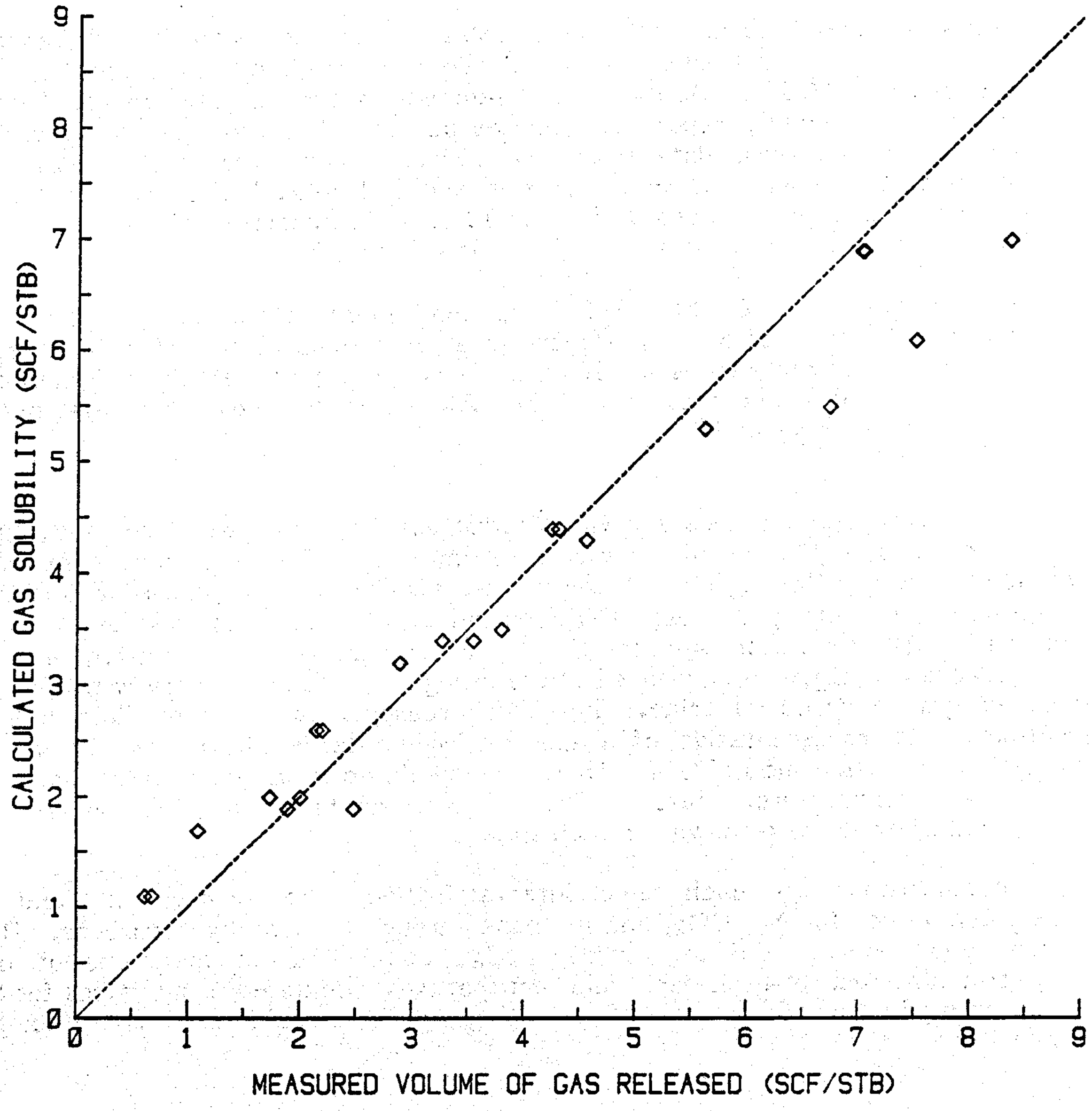
EXHIBIT 12-19a

Part II.
ANALYSES OF GAS OFF BRINE AFTER SEPARATOR
HO & M PRAIRIE CANAL CO., INC. WELL #1

Sample Collection Date	3/2/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81	3/5/81
Sample Collection Time	0955	0040	0045	0330	0453	1008	1340	1520	1815	1933	2112	2238
Separator Pressure (psig)	1014	345	345	470	472	251	125	125	617	615	1014	1010
Brine Temperature (°F)	245	204	204	213	215	187	187	187	216	221	235	238
Gas to Brine Ratio (SCF/STB)	8.35	2.14	2.19	3.54	3.26	1.71	0.60	0.66	4.30	4.28	7.00	7.02
Composition (mole %)												
Methane	70.75	58.70	65.19	63.51	63.09	65.98	70.83	69.34	63.46	64.40	66.93	69.81
Ethane	1.45	1.22	1.39	1.36	1.34	1.46	1.60	1.50	1.42	1.43	1.53	1.58
Propane	0.11	0.08	0.10	0.09	0.09	0.11	0.12	0.11	0.11	0.11	0.13	0.14
Butanes	0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.01	0.01	<0.01	<0.01	<0.01	0.01
Nitrogen*	0.22	0.29	0.29	0.29	0.29	0.31	0.41	0.53	0.17	0.14	0.17	0.17
Carbon Dioxide	27.45	39.70	33.03	34.74	35.18	32.14	27.03	28.51	34.84	33.90	31.23	28.29

* Nitrogen values are not significant due to air contamination.

EXHIBIT 12-19a
(cont'd)



COMPARISON OF CALCULATED AND MEASURED VALUES FOR GAS RELEASED FROM SEPARATOR BRINE BY PRESSURE REDUCTION TO 1 ATMOSPHERE AFTER COOLING TO AMBIENT TEMPERATURE

EXHIBIT 12-19b

Results of hydrocarbon analyses by other parties, that have been provided to IGT since the test, are presented by organization below:

- **USGS Gulf Coast HydroScience Center:** Flare line gas samples collected by this organization were analyzed for radioactivity by T.F. Kraemer of the USGS Gulf Coast HydroScience Center and for gas analysis and stable isotope analysis by George Claypool, of the USGS, Denver. Results shown in Exhibit 12-20 were transmitted to IGT in a letter report dated July 29, 1981. The gas analysis results are consistent with those obtained by IGT.

- **Reservoir Fluid Studies: Weatherly Laboratories (Mr. John Neal):** Weatherly Laboratories, Inc., collected samples of separator gas and brine during high rate production on 2/28/81. At the time of sampling, separator pressure was 750 psig. Weatherly's complete report of analyses performed is provided in Appendix J. Only the gas analysis data from that report is considered in the paragraphs immediately below. The recombination and differential liberation portions of the report will be discussed in Section 12.10.4, "Comparison of Gas/Brine Ratio from Field Data with Results from Laboratory Studies."

  On a dry gas basis, 6.3 SCF/STB of gas was liberated from separator brine by pressure reduction to one atmosphere at a brine temperature of 70°F. Results from gas chromatograph analysis of this gas and simultaneously collected flare line gas are tabulated in Exhibit 12-21. All reported values are consistent with those from analyses by IGT.

12.10.3.4 Gas Compositions 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. However, gas composition was found to change with time during the test. CO_2 content of flare line gas was found to vary systematically with separator pressure and brine temperature. In addition, although small, the fraction of C_{2+} hydrocarbons in flare line gas was found to vary with the ratio of produced gas to produced brine. For these reasons, 23 different flare line gas compositions, each representative of a specific time interval, have been chosen for interpretation of orifice meter data. These are tabulated in Exhibit 12-22. Separator pressure, gas temperature, natural gas liquids content, heating value, and supercompressibility are also shown for each time interval.

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. These have then been renormalized to include a C_{6+} component on the basis of mass spectrometric analyses. Natural gas liquids content was calculated using values for SCF per gallon of liquid from Reference 15. Heating value was calculated as set forth in Reference 39.

GAS ANALYSIS PERFORMED BY USGS GULF COAST HYDROSCIENCE CENTER

	2/22/81 @ 16:02 Vol. %	2/28/81 @ 16:49 Vol. %
Methane	87.75	89.24
Ethane	2.49	2.55
Propane	0.33	0.31
n - Butane	0.06	0.09
i - Butane	0.04	0.09
n - Pentane	------	------
i - Pentane	------	------
CO_2	9.12	7.22
N_2	0.08	0.10
$\delta^{13}C$	-45.03 per mil	-45.07 per mil
^{222}Rn	127.0 d/m/L*	112.0 d/m/L*

*Disintegrations per minute per liter

GAS ANALYSES BY WEATHERLY LABORATORIES

Sample Date	2/28/81
Sample Time	midday
Separator Pressure	750 psig
Brine Temperature	210°F
Dry Gas Flashed from Separator Brine	6.3 SCF/STB

Gas Composition (mole %)

	Flare Line Gas*	Gas From Brine
Methane	91.15	66.20
Ethane	2.30	1.10
Propane	0.26	0.10
Iso-Butane	0.02	0.00
n-Butane	0.02	0.00
Iso-Pentane	0.00	0.00
n-Pentane	0.00	0.00
Hexanes	0.00	0.00
Heptanes Plus	0.02	0.00
Nitrogen	0.13	----
Carbon Dioxide	6.10	32.60
	100.00	100.00
Gravity (Air = 1.0)	0.6278	0.8750

*Average of three analyses.

Part I.
FLARE LINE GAS COMPOSITIONS FOR PRODUCTION CALCULATIONS
HO & M PRAIRIE CANAL CO., INC. WELL #1

Time Interval								
Start	2/21/81; 2055 hrs		2/23/81; 0000 hrs		2/24/81; 0000 hrs		2/24/81; 1100 hrs	
End	2/22/81; 2400 hrs		2/23/81; 2400 hrs		2/24/81; 1100 hrs		2/24/81; 2400 hrs	
Separator Pressure (psia)	165-195		240		240		205-835*	
Gas Temperature (°F)	70-90		105		125		140	
Composition (mole fraction) and Natural Gas Liquids Content (gal/MCF)								
Gas	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF
Nitrogen	0.0032	--	0.0033	--	0.0032	--	0.0033	--
Carbon Dioxide	0.0889	--	0.0899	--	0.0947	--	0.0820	--
Methane	0.8773	--	0.8751	--	0.8722	--	0.8849	--
Ethane	0.0259	0.6907	0.0265	0.7067	0.0252	0.6720	0.0250	0.6667
Propane	0.0039	0.1072	0.0043	0.1182	0.0039	0.1072	0.0039	0.1072
Iso-Butane	0.0002	0.0065	0.0003	0.0098	0.0002	0.0065	0.0003	0.0098
n-Butane	0.0003	0.0094	0.0003	0.0094	0.0003	0.0094	0.0003	0.0094
Pentanes	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C6+	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123
Total	1.0000	0.8262	1.0000	0.8564	1.0000	0.8075	1.0000	0.8054
Heating Value (Btu/SCF)	944.5		944.7		938.11		950.9	
Supercompressibility	1.01217-1.01255		1.01403		1.01223		1.02165	

* Detailed interpretation reflecting the five rate changes and nine separator pressure changes during the afternoon and evening of 2/24/81 is not warranted.

EXHIBIT 12-22

Part II.
FLARE LINE GAS COMPOSITIONS FOR PRODUCTION CALCULATIONS
HO & M PRAIRIE CANAL CO., INC. WELL #1

Time Interval								
Start	2/25/81; 0000 hrs		2/25/81; 1630 hrs		2/26/81; 1630 hrs		2/27/81; 0000 hrs	
End	2/25/81; 0330 hrs		2/25/81; 1830 hrs		2/26/81; 2400 hrs		2/27/81; 0635 hrs	
Separator Presure (psia)	830		270		475		500	
Gas Temperture (°F)	170		170		165		170	
Composition (mole fraction) and Natural Gas Liquids Content (gal/MCF)								
Gas	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF
Nitrogen	0.0031	--	0.0034	--	0.0033	--	0.0033	--
Carbon Dioxide	0.0677	--	0.1041	--	0.0840	--	0.0840	--
Methane	0.8985	--	0.8638	--	0.8848	--	0.8833	--
Ethane	0.0258	0.6880	0.0244	0.6507	0.0265	0.7067	0.0250	0.6667
Propane	0.0040	0.1100	0.0036	0.0990	0.0045	0.1237	0.0037	0.1017
Iso-Butane	0.0003	0.0098	0.0002	0.0065	0.0003	0.0098	0.0002	0.0065
n-Butane	0.0003	0.0094	0.0002	0.0063	0.0003	0.0094	0.0002	0.0063
Pentanes	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C6+	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123
Total	1.0000	0.8295	1.0000	0.7748	1.0000	0.8619	1.0000	0.7935
Heating Value (Btu/SCF)	966.3		927.1		955.0		948.1	
Supercompressibility	1.02867		1.01019		1.01797		1.01816	

EXHIBIT 12-22 (cont'd)

EXHIBIT 12-22 (cont'd)

Part III.
FLARE LINE GAS COMPOSITIONS FOR PRODUCTION CALCULATIONS
HO & M PRAIRIE CANAL CO., INC. WELL #1

Time Interval										
Start	2/27/81; 0635 hrs		2/27/81; 1517 hrs		2/27/81; 1736 hrs		2/27/81; 1912 hrs		2/28/81; 1030 hrs	
End	2/27/81; 1517 hrs		2/27/81; 1736 hrs		2/27/81; 1912 hrs		2/28/81; 1030 hrs		3/01/81; 1035 hrs	
Separator Pressure (psia)	530		315		460		600		750	
Gas Temperature (°F)	175		195		200		205		190	
Composition (mole fraction) and Natural Gas Liquids Content (gal/MCF)										
Gas	**Mol. Frac.**	**Gal/MCF**	**Mol. Frac.**	**Gal/MCF**	**Mol. Frac.**	**Gal/MCF**	**Mol. Frac.**	**Gal/MCF**	**Mol. Frac.**	**Gal/MCF**
Nitrogen	0.0030	--	0.0033	--	0.0031	--	0.0033	--	0.0031	--
Carbon Dioxide	0.0820	--	0.1000	--	0.0860	--	0.0800	--	0.0737	--
Methane	0.8856	--	0.8707	--	0.8820	--	0.8855	--	0.8951	--
Ethane	0.0250	0.6667	0.0220	0.5867	0.0245	0.6533	0.0260	0.6933	0.0240	0.6400
Propane	0.0037	0.1017	0.0033	0.0907	0.0037	0.1017	0.0044	0.1210	0.0034	0.0935
Iso-Butane	0.0002	0.0065	0.0002	0.0065	0.0002	0.0065	0.0002	0.0065	0.0002	0.0065
n-Butane	0.0002	0.0063	0.0002	0.0063	0.0002	0.0063	0.0003	0.0094	0.0002	0.0063
Pentanes	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C6+	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123
Total	1.0000	0.7935	1.0000	0.7025	1.0000	0.7802	1.0000	0.8426	1.0000	0.7586
Heating Value (Btu/SCF)	950.5		929.1		945.9		954.2		957.5	
Supercompressibility	1.01848		1.00984		1.01352		1.01909		1.02245	

Part IV.
FLARE LINE GAS COMPOSITIONS FOR PRODUCTION CALCULATIONS
HO & M PRAIRIE CANAL CO., INC. WELL #1

Time Interval										
Start	3/01/81; 1035 hrs		3/02/81; 0230 hrs		3/02/81; 0545 hrs		3/02/81; 0745 hrs		3/04/81; 1900 hrs	
End	3/02/81; 0230 hrs		3/02/81; 0545 hrs		3/02/81; 0745 hrs		3/02/81; 1700 hrs		3/05/81; 0232 hrs	
Separator Pressure (psia)	875		920		1000		1030		210-365	
Gas Temperature (°F)	190		185		185		190		80-153	
Composition (mole fraction) and Natural Gas Liquids Content (gal/MCF)										
Gas	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF
Nitrogen	0.0031	--	0.0030	--	0.0030	--	0.0029	--	0.0033	--
Carbon Dioxide	0.0710	--	0.0690	--	0.0675	--	0.0652	--	0.0943	--
Methane	0.8968	--	0.8988	--	0.8999	--	0.9026	--	0.8759	--
Ethane	0.0249	0.6640	0.0250	0.6667	0.0253	0.6747	0.0251	0.6693	0.0230	0.6133
Propane	0.0035	0.0962	0.0035	0.0962	0.0036	0.0990	0.0035	0.0962	0.0028	0.0770
Iso-Butane	0.0002	0.0065	0.0002	0.0065	0.0002	0.0065	0.0002	0.0065	0.0001	0.0033
n-Butane	0.0002	0.0063	0.0002	0.0063	0.0002	0.0063	0.0002	0.0063	0.0001	0.0031
Pentanes	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C6+	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123	0.0003	0.0123	0.0005	0.0206
Total	1.0000	0.7854	1.0000	0.7880	1.0000	0.7988	1.0000	0.7907	1.0000	0.7173
Heating Value (Btu/SCF)	961.1		963.3		965.2		967.3		935.2	
Supercompressiblity	1.02569		1.02783		1.02984		1.02923		1.0144-1.0166	

Part V.
FLARE LINE GAS COMPOSITIONS FOR PRODUCTION CALCULATIONS
HO & M PRAIRIE CANAL CO., INC. WELL #1

Time Interval					
Start	3/05/81; 0232 hrs	3/05/81; 0518 hrs	3/05/81; 1233 hrs	3/05/81; 1625 hrs	3/05/81; 2060 hrs
End	3/05/81; 0518 hrs	3/05/81; 1233 hrs	3/05/81; 1625 hrs	3/05/81; 2006 hrs	3/05/81; 2400 hrs
Separator Pressure (psia)	485	257	140	630	1025
Gas Temperature (°F)	150	110	128	155	180

Composition (mole fraction) and Natural Gas Liquids Content (gal/MCF)

Gas	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF	Mol. Frac.	Gal/MCF
Nitrogen	0.0030	--	0.0031	--	0.0032	--	0.0035	--	0.0032	--
Carbon Dioxide	0.0859	--	0.0972	--	0.1151	--	0.0785	--	0.0626	--
Methane	0.8835	--	0.8732	--	0.8552	--	0.8880	--	0.9000	--
Ethane	0.0240	0.6400	0.0231	0.6160	0.0231	0.6160	0.0256	0.6827	0.0286	0.7627
Propane	0.0029	0.0797	0.0027	0.0742	0.0027	0.0742	0.0035	0.0962	0.0046	0.1265
Iso-Butane	0.0001	0.0033	0.0001	0.0033	0.0001	0.0033	0.0002	0.0065	0.0002	0.0065
n-Butane	0.0001	0.0031	0.0001	0.0031	0.0001	0.0031	0.0002	0.0063	0.0003	0.0094
Pentanes	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C6+	0.0005	0.0206	0.0005	0.0206	0.0005	0.0206	0.0005	0.0206	0.0005	0.0206
Total	1.0000	0.7467	1.0000	0.7172	1.0000	0.7172	1.0000	0.8123	1.0000	0.9257

Heating Value (Btu/SCF)	944.9	932.4	914.2	954.4	974.9
Supercompressibility	1.02032	1.01445	1.00709	1.02517	1.0320

EXHIBIT 12-22
(cont'd)

12.10.4 Produced Gas and Gas/Brine Ratio

Sections 12.10.4.1 through 12.10.4.3 provide details of raw data interpretation used to deduce flare line gas production, brine production, and the total produced gas/brine ratio. Values from a number of the intermediate interpretive steps are tabulated under the appropriate columns in Appendix K. Specific columns will be referenced in the detailed discussions in these first three sections. Section 12.10.4.4 examines changes in gas/brine ratio in relation to producing conditions. The correlation of gas/brine ratio with natural gas liquids content is discussed in Section 12.10.4.5. Section 12.10.4.6 presents a possible scenario for observed variations in gas/brine ratio and NGL content which is consistent with IGT's conclusion that the reservoir contained free gas in excess of saturation in brine. The gas/brine ratio obtained from field data is compared to relevant laboratory data on gas solubility in brine in Section 12.10.4.7.

12.10.4.1 Flare Line Gas Production: Flare line gas compositions representative of various time intervals during the test were selected, as discussed in Section 12.10.3.6 and tabulated in Exhibit 12-22. The steps used to calculate the time-dependence of gas production to the flare line, with those gas compositions, are as follows:

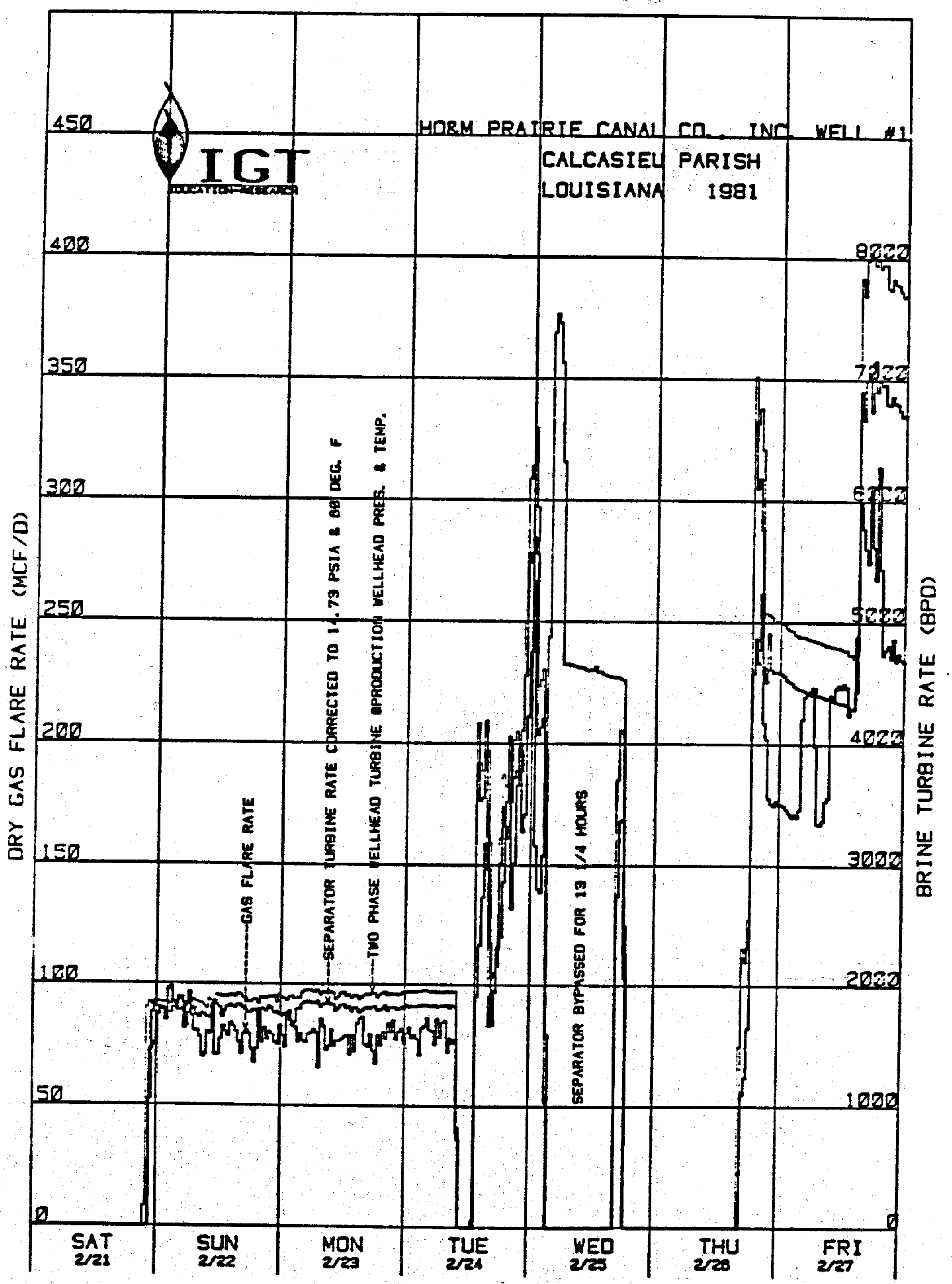
- Calculating the specific gravity and heating value for the average gas composition for each time interval, using the method prescribed in ANSI/ASTM D 3588-77. This ANSI/ASTM procedure assigns the physical properties of normal hexane to all C_{6+} hydrocarbons. Resulting calculated values are shown in Exhibit 12-22 for each gas composition. Total NGL content is also shown in that exhibit. In addition, gas gravity for each 1/2 hour of production is shown in column 4 of Appendix K.

- Calculating gas production to the flare line for each line entry of raw data using the method prescribed in A.G.A. Gas Committee Measurement Report No. 3. Using this method 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, 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.

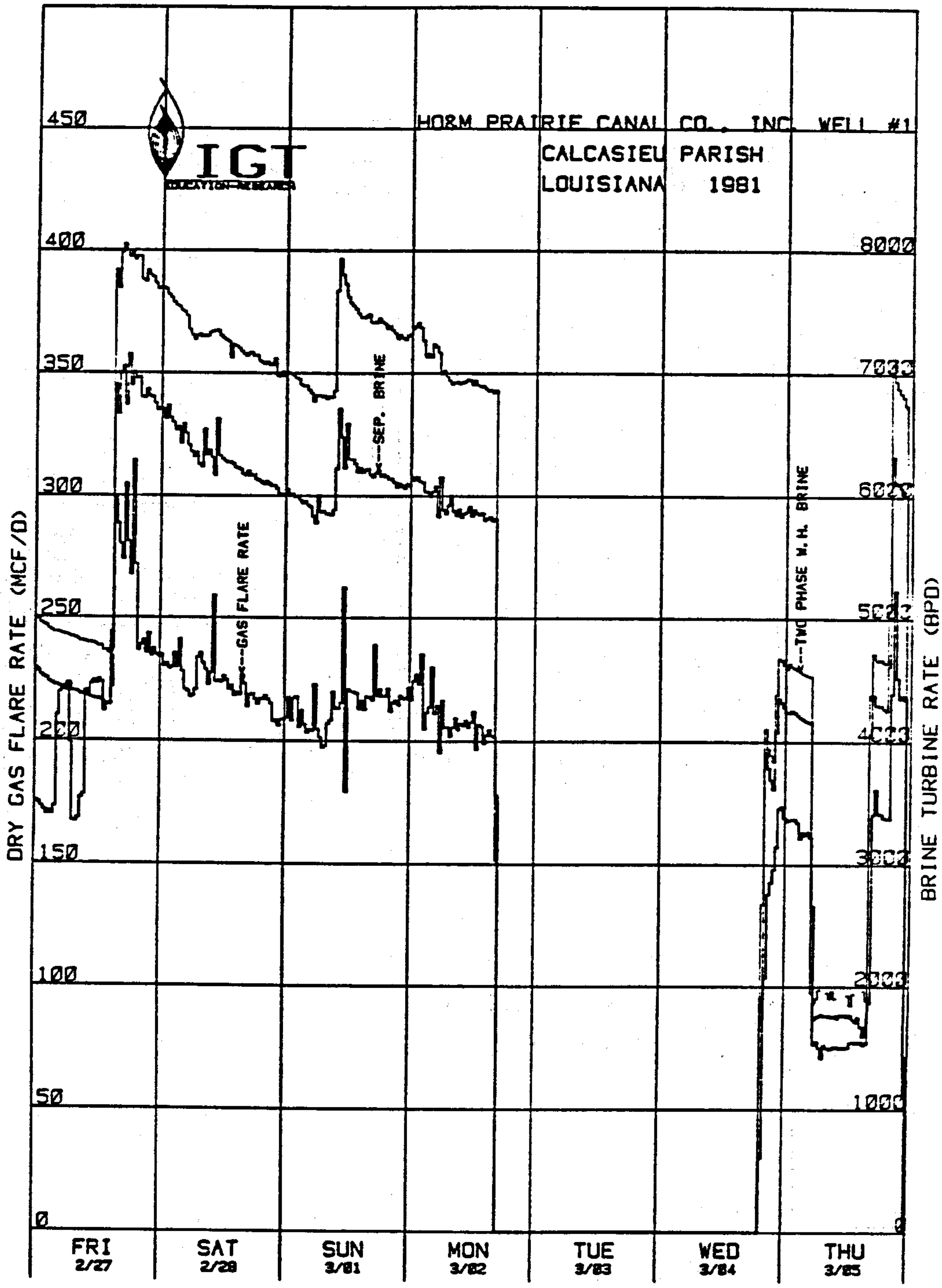
- Reducing calculated gas production for each 1/2 hour by an amount corresponding to the ratio of partial pressure of water at the orifice meter to absolute separator pressure. The resultant calculated dry gas production tabulated for each 1/2 hour is presented in column 7 of Appendix K. Dry gas flare rates are also shown graphically in Exhibit 12-23, 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.



DRY GAS FLARE RATE
(Part I)

EXHIBIT 12-23



DRY GAS FLARE RATE
(Part II)

EXHIBIT 12-23
(cont'd)

12.10.4.2 Brine Production Rate: Raw data from the separator output data was reduced to Stock Tank Barrels per Day (STB/D) for successive 1/2-hour time intervals by the following two-step procedure:

- Subtracting cumulative brine production at 1/2-hour time intervals and then expressing the difference as barrels per day at separator pressure and brine temperature.

- Correcting to STB/D by calculating brine rate at 14.73 psia and 60°F for each 1/2-hour time interval. Correction factors used are those for gas-free distilled water. In making the correction, brine temperature was assumed to be the higher of the two recorded values, as previously discussed in Section 12.10.2.3.

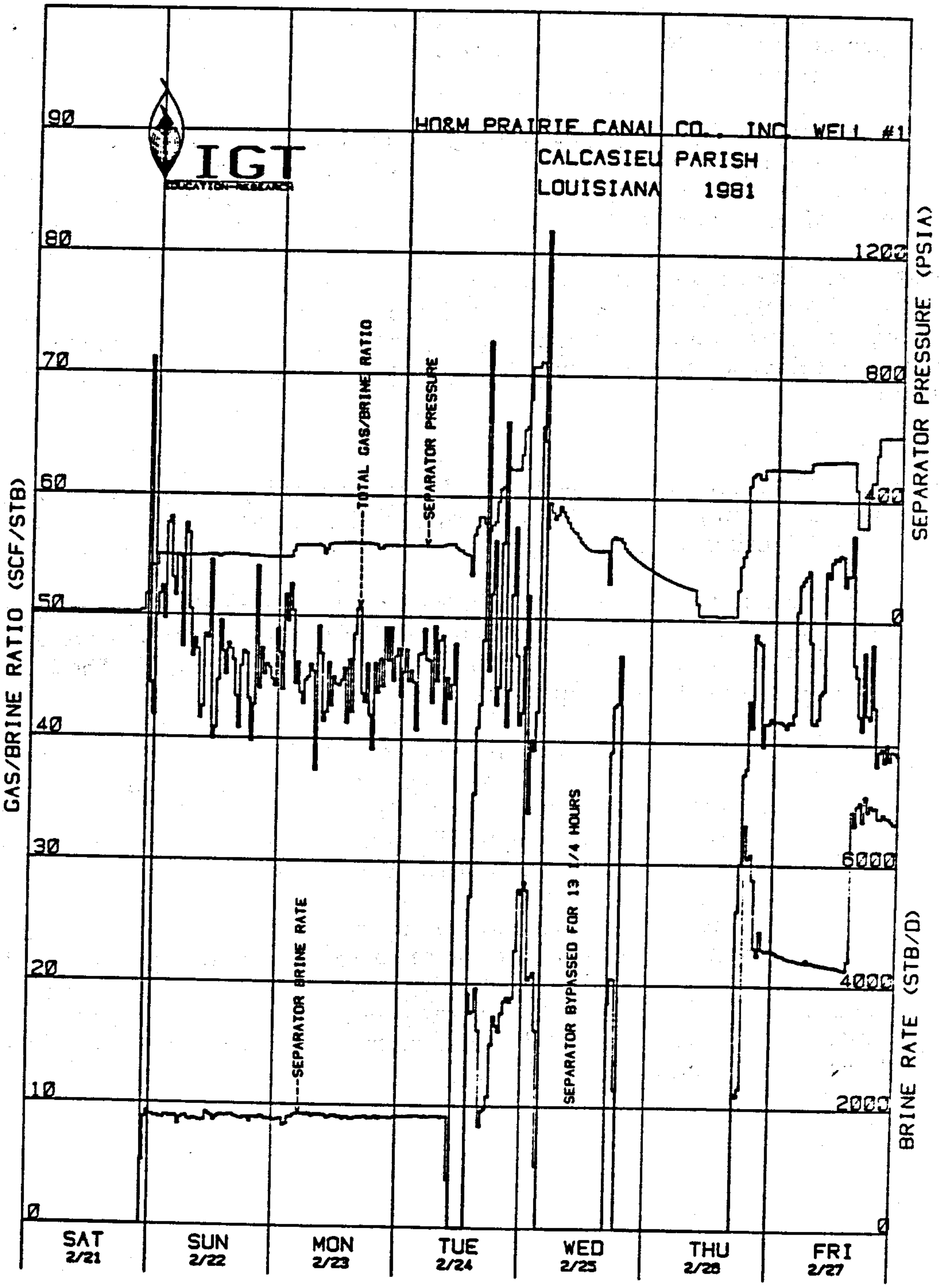
Measured brine rate at separator pressure and temperature is tabulated in column 9 of Appendix K. Calculated brine rates at standard conditions are shown in column 10 of that appendix and are shown graphically in Exhibit 12-23. Uncorrected rates recorded by the wellhead turbine, which experienced two-phase flow, are also shown in Exhibit 12-23, Part I and II.

12.10.4.3 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. Total produced gas has been estimated using the following steps:

- 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.

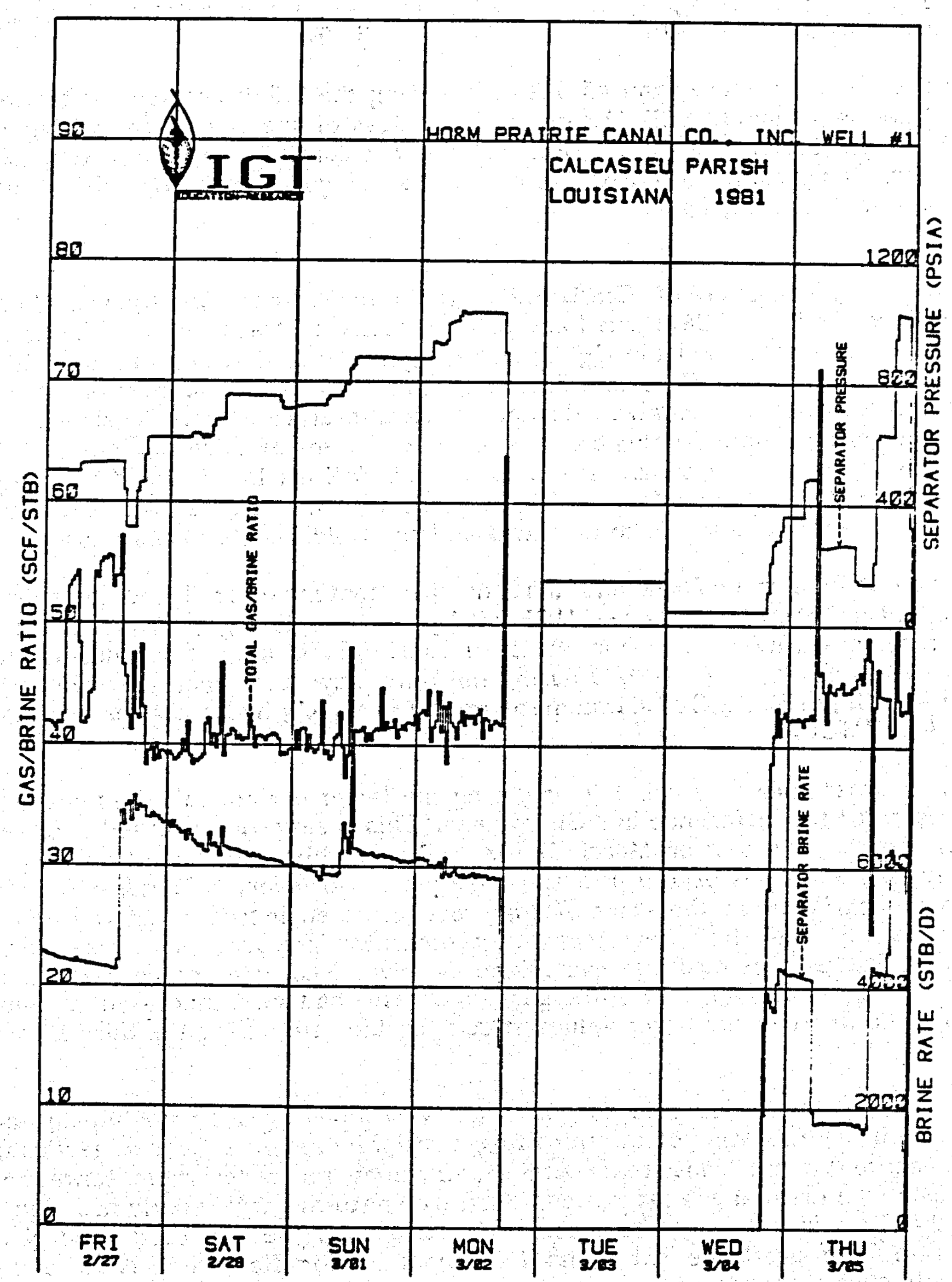
- Estimating the gas/brine ratio in brine to the disposal well using the algorithm developed by Systems Science and Software to fit the data of Culberson and McKetta for methane solubility is distilled water (Ref. 8). Results of this calculation, using 1/2-hour averaged values for separator pressure and brine temperature, are reported in column 12 of Appendix K.

- 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 12-24, Parts I and II. Separator pressure and corrected brine flow rate are also shown in Exhibit 12-24 to facilitate the correlation of gas/brine ratio with producing conditions which follows.



GAS/BRINE RATIO
(Part I)

EXHIBIT 12-24



GAS/BRINE RATIO
(Part II)

EXHIBIT 12-24
(cont'd)

12.10.4.4 Correlation of Gas/Brine Ratio with Producing Conditions: Average gas/brine ratios for 14 different time intervals are tabulated in Exhibit 12-25. This exhibit also shows energy production per barrel of brine for both natural gas energy and thermal energy. A temperature base of 120°F was used for calculating thermal energy content of produced brine.

The contrast between more than 45 SCF/STB during the 2.5 day first flow test at about 1800 BPD and less than 42 SCF/STB during the 3 days of the third flow test at rates at 6000 BPD is particularly puzzling. Possible reasons for this contrast will be set forth after the following examination of the correlation of gas/brine ratio with natural gas liquids content of produced gas.

12.10.4.5 Correlation of Gas/Brine Ratio with Natural Gas Liquids Content of Produced Gas: Exhibit 12-26, Parts I and II, graphically portrays the time dependence of produced gas/brine ratio and the C_2-C_5 natural gas liquids (NGL) content of the C_1-C_5 portion of each sample of flare line gas analyzed. This particular portion of produced gas has been selected to maximize relevance of data interpretation. Considering only C_1-C_5 components accomplishes this because (a) CO_2 content of flare line gas is dependent on separator pressure and temperature, as will be defined in Section 12.11, Separator Performance Evaluation, and (b) the C_{6+} content of produced gas was not accurately determined for each sample due to limitations of the field gas chromatograph.

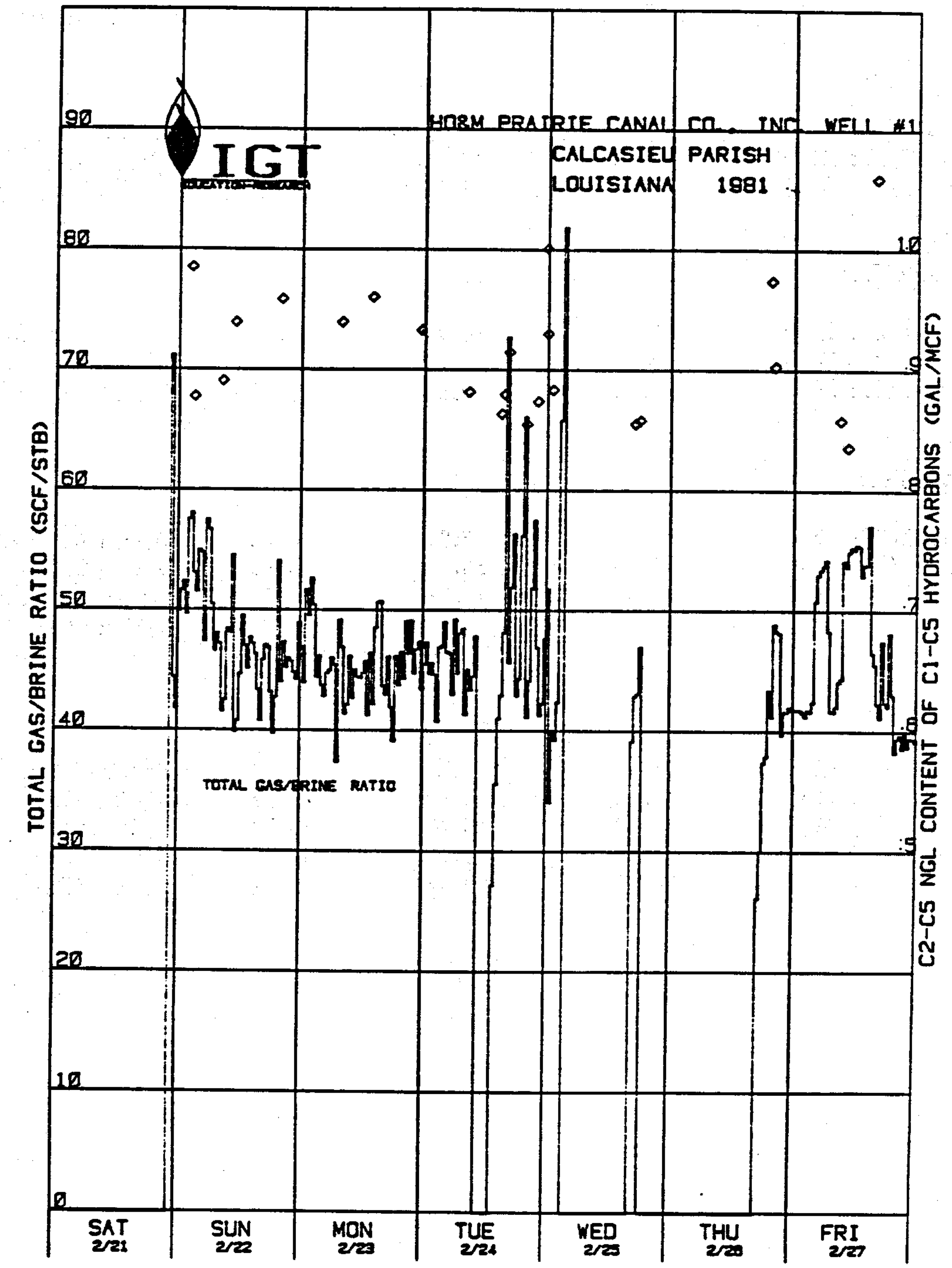
Examination of Exhibit 12-26 reveals that the NGL content of produced gas averaged in excess of 0.9 gallons of C_2-C_5 per MCF of C_1-C_5 flare line gas during the first flow test, when the gas/brine ratio was in excess of 45 SCF/STB. In contrast, during the three days of rates in excess of 6000 BPD during the third flow test, when gas/brine ratio was less than 42 SCF/STB, C_2-C_5 NGL content of flared C_1-C_5 hydrocarbons averaged only about 0.84 gal/MCF.

Although separator pressure was higher during the latter period, this does not appear to be the reason for the difference in NGL content. This observation is based upon behavior during the fourth flow test on March 5, 1981. During this date, separator pressure was varied between extremes of 140 psia and 1029 psia. However, NGL content started at less than 0.8 gal/MCF at the start of that test and then increased to the high values representative of the first flow test after separator pressure and brine rate were increased to values previously characterized by lower NGL content on 2/28/81 through 3/2/81. At the final 6000 BPD rate, gas/brine ratio had also increased to almost 45 SCF/STB, in contrast to the lower values at comparable rate during the third flow test.

12.10.4.6 Possible Scenario for Observed Variations in Gas/Brine Ratio and NGL Content: With the exception of the third flow test, observed variations in gas/brine ratio and NGL content were consistent with expectations for a reservoir containing free natural gas at the critical gas saturation. Such free natural gas normally has higher NGL content than gas in solution in brines. Accepting this, the expected —and observed— variations in both gas/brine ratio and NGL content for flow test 1, 2, and 4 are qualitatively consistent as follows:

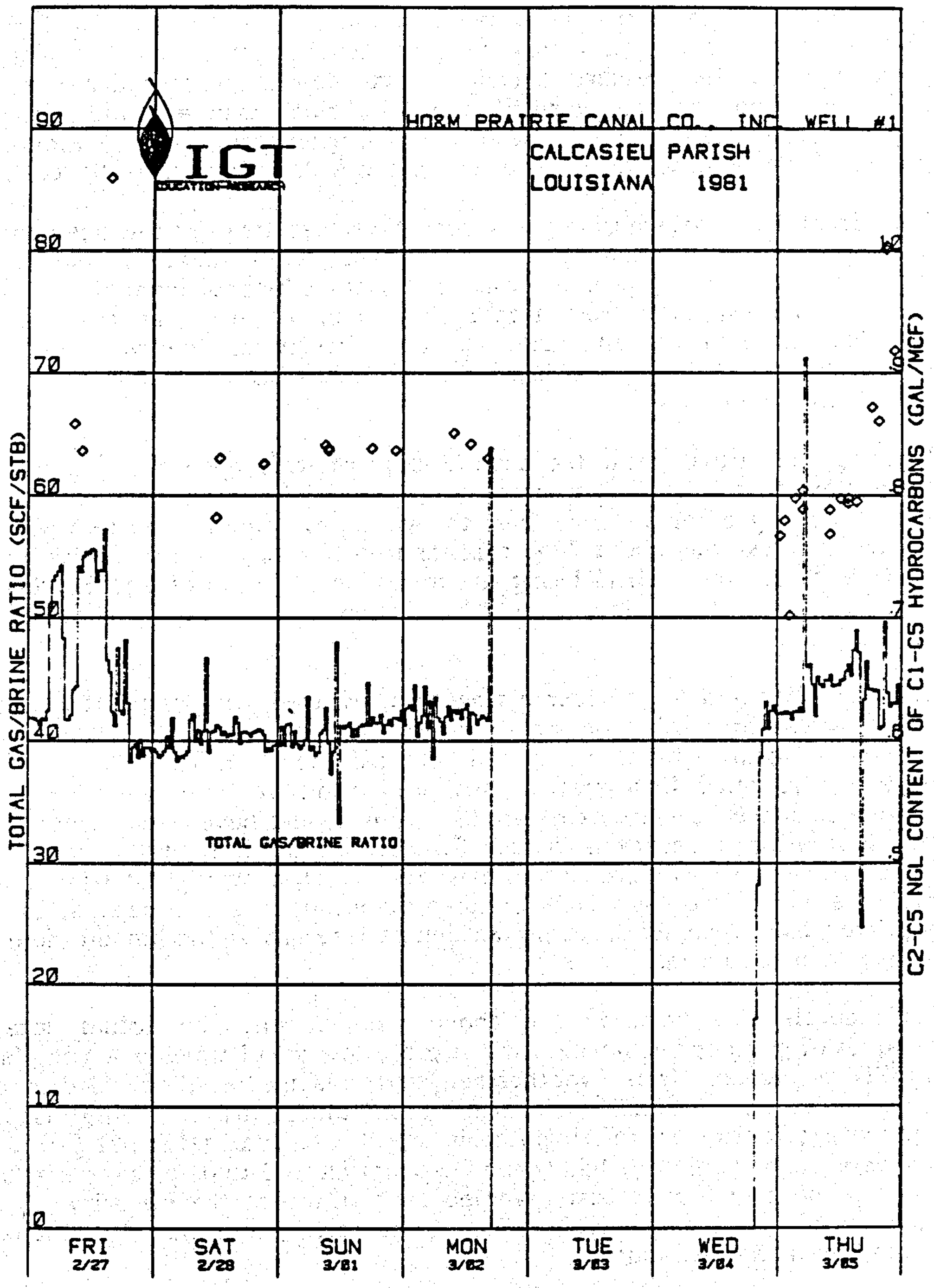
GAS AND ENERGY PRODUCTION RATES FOR VARIOUS TIME INTERVALS

Time Interval	Produced Gas SCF/STB	Gas Energy MMBTU/STB	Thermal Energy MMBTU/STB	Comments
First Flow Test				
2/21; 2230-2/22; 0130	50.43	47.85	---	Before bottoms-up
2/22; 0130-2/22; 1200	49.96	47.40	7.01	GWR peak
2/22; 1200-2/24; 1030	45.61	43.21	17.14	Rest of first test
Second Flow Test				
2/24; 1400-2/25; 0300	46.83	44.92	29.58	Six rate changes
2/25; 0300-2/25; 1700	---	---	---	Separator bypassed
2/25; 1700-2/25; 1800	43.02	40.07	38.01	Last hour of test
Third Flow Test				
2/26; 1800-2/27; 1500	46.91	44.81	34.26	About 4500 BPD
2/27; 1530-3/01; 1000	40.54	36.86	43.76	6000+ BPD
3/01; 1000-3/02; 1700	41.81	40.46	44.58	After opening choke to hold 6000+ BPD
Fourth Flow Test				
3/04; 2000-3/04; 2200	37.57	35.26	14.44	Before bottoms-up
3/04; 2200-3/05; 0530	43.16	40.65	29.69	4200 BPD
3/05; 0530-3/05; 1630	43.24	40.30	23.92	1800 BPD
3/05; 1630-3/05; 2030	43.38	41.73	33.48	4300 BPD
3/05; 2030-3/05; 2330	44.50	43.57	40.42	6000+ BPD



Part I. PRODUCED GAS/BRINE RATIO AND
C2-C5 NGL CONTENT

EXHIBIT 12-26



Part II. PRODUCED GAS/BRINE RATIO AND C2-C5 NGL CONTENT

EXHIBIT 12-26 (cont'd)

- The initial drawdown of bottom-hole pressure from 12,858 psia at gauge depth to less than 11,500 psia permits expansion of gas near the wellbore to above critical saturation so that flow of nearby free gas, in addition to the saturation gas content of brine, provides initial "flush" production with both a high gas/brine ratio and a high NGL content.

- Continuing drawdown to a recorded bottom-hole pressure of 10,862 psia during the remainder of the first flow test was accompanied by additional free gas production as the pressure drawdown extended to greater distance from the wellbore. The observed variations in gas/brine ratio and the correlation of higher NGL content with high values of gas/brine ratio are very similar to those previously documented during the test of the Riddle-Saldana Well No. 2.

- The higher flow rates during the second flow test involved recorded bottom-hole pressures as low as 8100 psia. Bottoms-up after most of the increases in drawdown of reservoir pressure was accompanied by additional "flush" production as would be expected from further expansion of free gas that had not yet exceeded critical gas saturation in the vicinity of the wellbore. The one exception was at the highest brine rate of 5500 BPD which was accompanied by heavy sand production.

- Ignoring the actual data, the several days of wide open production during the third flow test would have been accompanied by production of free gas to substantially greater distance from the wellbore. Minimum bottom-hole pressure during this test was about 7050 psia, and bottom-hole pressure was below 8000 psia for three days. Then during the following two days of buildup, any free gas remaining near the wellbore would have been compressed to below critical gas saturation.

- The first 24 hours of the fourth flow test involved brine rates of less than 4500 BPD. Thus although bottom-hole pressure was not recorded, it would have been above 9000 psia. This is more than 1000 psi above the value for the last three days of the third flow test. Thus production of free gas should not have occurred, and NGL content of produced gas should have been representative of gas in solution in reservoir brine. This is consistent with the data. Further, when brine rate was increased to over 6000 BPD, providing additional drawdown near the end of the test, NGL content of produced gas increased, as would be expected from resumption of production of free gas at the bottom-hole pressure of less than 8000 psia.

The major inconsistency between the above scenario and the actual data is that measured values of produced gas/brine ratio are too low at all times when the brine rate was 6000 BPD or higher. It is hypothesized that this inconsistency is due to loss of hydrocarbons, in excess of solubility in brine, from the separator to the disposal well. Major contributing factors to this hypothesis are the factual data that (a) 6000+ BPD brine rates were accompanied by heavy sand production and that (b) examination of the separator after the fourth flow test revealed sand filling of the majority of separator brine volume. This sand may have reduced brine residence time in the separator at 6000+ BPD to less than one minute.

Two additional factual observations support the hypothesis of loss of gas in the form of bubbles in brine to the disposal well. These are:

- A sample of separator brine collected at 1550 hours on 3/2/81 liberated more than 27 SCF/BBL when pressure was reduced to one atmosphere after cooling the brine sample. This excessive amount of gas resulted in loss of the gas sample before analysis. At the separator pressure and temperature of 1013 psig and 248°F at the time of sample collection, about 7.0 SCF/BBL of gas should have been in solution in brine. The excess of more than 20 SCF/BBL would have occupied a bubble volume larger than 30 ml in the 500 ml sample vessel.

- At about 20 different times during production at 6000+ BPD, disposal well injection pressure suddenly dropped by 50-150 psi and then recovered in the time required for fluid movement from the injection wellhead to the perforations in the injection well. Reasons for this are not understood. However, similar behavior was observed during times when slugs of hydrocarbons were known to be entering the disposal well during the test of the G.M. Koelemay Well No. 1.

This scenario is consistent with the conclusion that the saturation gas/brine ratio at reservoir temperature and pressure was about 43.3 SCF/STB and that the reservoir contained free gas in excess of saturation of brine. The next section compares this conclusion with relevant laboratory data on gas solubility in brine.

12.10.4.7 Comparison of Gas/Brine Ratio From Field Data with Results From Laboratory Studies: Initial reservoir pressure and temperature for the sand tested were 12,942 psia and 294°F respectively. The average of six measurements of total dissolved solids was 43,370 mg/l. For these conditions, the March 1981 equations of C. Blount and the procedure of J.L. Haas provide calculated estimates of 45.6 and 44.9 SCF of methane per STB of NaCl brine. These values are in agreement with the value of 43.3 SCF/STB from deduced field test data in the previous section of this report.

Although this agreement is within the accuracy of the field data and calculations, it is interesting to observe that agreement would be within 1 percent at a pressure 1000 psi lower or at a temperature 10°F lower.

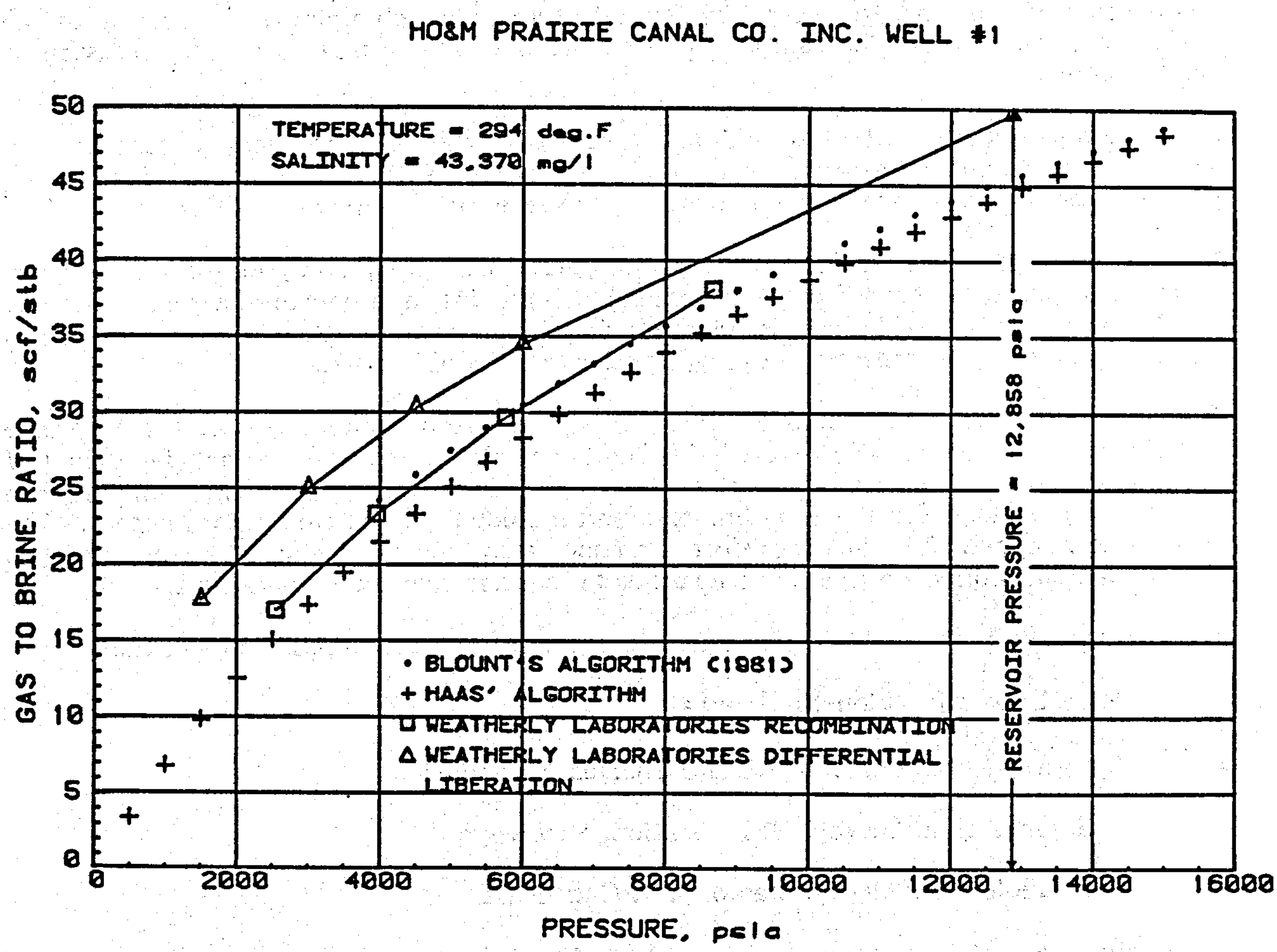
The Weatherly Laboratories report in Appendix J provides an estimate of solubility of 48.7 SCF of gas at a pressure base of 15.025 psia per STB of brine. Converting to the gas pressure base of 14.73 psia used in this report increases this value to 49.7 SCF/STB. However, careful scrutiny of that report removed the discrepancy between this value and the 43.3 SCF/STB deduced from field data.

First it is important to recognize that a bubble point was not observed for recombination at reservoir pressure. This is because that pressure exceeded the limits of the laboratory facilities. Thus in fact, the value 49.7 SCF/STB reflects only the sum of flare line gas/brine ratio plus the gas/brine ratio observed by reducing pressure on cooled separator brine to one atmosphere. The flare line gas/brine ratio in turn used gas production calculated from manual reading of a 24-hour circular chart during a time of wide oscillation in orifice differential pressure. As a result, the calculated separator dry gas rate of 267.3 MCF/D at the time of sampling was substantially greater than the value of about 225 MCF/D subsequently deduced from IGT's digital recording with square-root averaging of orifice differential pressure read every 5 seconds during the one-minute oscillations. This difference alone could have reduced the Weatherly Laboratories estimate of produced gas/brine ratio at that time to about 43 SCF/STB. However there is no a priori reason to believe that brine being produced at the time of sampling was saturated with gas at initial reservoir pressure and temperature.

A more meaningful conclusion is provided by comparing the actual recombination bubble points measured by Weatherly Laboratories with values calculated using C. Blount's March, 1981 equations (Ref. 22) and the J.L. Haas procedure (Ref. 17). This comparison is shown in Exhibit 12-27. The four bubble points actually observed by Weatherly Laboratories are plotted as squares and lie between values calculated using the two procedures. These four plotted points were derived from Appendix J by converting gas volumes to a pressure base of 14.73 psia and adding gas liberated from separator brine by pressure reduction to the amount of separator gas recombined with separator brine at each bubble point.

Differential liberation data from Appendix J are shown as triangles in Exhibit 12-27. The point at 49.7 SCF/STB and 12,858 psia reflects initial charging of the cell on the basis of orifice meter data as discussed previously. A bubble point was not actually observed due to pressure limitations on the laboratory equipment. The differential liberation points are 4.5-6.0 SCF/STB above the recombination data. A portion of this difference occurred because more than 80% of the total CO_2 in the cell was liberated in the last pressure reduction from 1500 psia to one atmosphere. The CO_2 portion of the 17.6 SCF/STB liberated in this step was 6.3 SCF/STB. Additional contributions to the high values reported during differential liberation may have been due to supersaturation of brine or tiny gas bubbles that did not move to the top of the cell until the final pressure drop.

With these observations taken into account, the laboratory and field data agree to within 5% on gas content of reservoir brine. Further, the overall gas/brine ratio of 46.04 SCF/STB after bottoms-up on the first flow test slightly exceeds the gas solubility at reservoir conditions from laboratory studies.



COMPARISON OF GAS/BRINE RATIOS

EXHIBIT 12-27

12.10.5 Brine Sample Collection and Analysis

Section 12.10.5.1 provides details of the collection and analysis of surface brine samples by IGT and other groups. Results of the analyses of these samples are discussed in Section 12.10.5.2. Section 12.10.5.3 presents the mass balance calculations for the IGT analyses of brine samples.

12.10.5.1 Surface Brine Sampling: 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 2-inch piping and upstream of the separator dump valves. The sampling point is at the same temperature and pressure as the separator.

These samples were collected and analyzed using the IGT procedures described in Appendix M, which are in accordance with the intent of the uniform plan for testing geopressured aquifers under development by McNeese State University (McNeese).

As directed by the DOE Project Manager, complete laboratory analyses were performed on three samples selected from the beginning, midpoint, and end of the test sequence. Results of the daily field analysis, commencing 12 hours after flow was initiated, plus the three complete laboratory analyses, are shown in Exhibit 12-28.

One of the samples (1520 hours on 2/22/81) was selected because it was the McNeese coordinated test sample. However, IGT's field analysis for this sample included only 4 of 11 parameters. The results of the field analysis of an earlier (1030 hours) sample were essentially the same for these parameters and included six additional parameters. The results shown for 2/22/81 are therefore a composite of the field and laboratory analysis for two samples collected five hours apart under similar producing conditions.

Representatives of the following organizations collected brine samples on location:

- Rice University, Houston, Texas
- McNeese State University, Lake Charles, Louisiana
- U.S. Geological Survey, NSTL Station, Mississippi
- U.S. Geological Survey, Menlo Park, California

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

Results of analyses by three of these organizations have been provided to IGT and are as follows:

- **Rice University:** Rice University personnel collected brine samples from upstream of the separator, at separator pressure, as a part of their Gas Research Institute-funded scaling and corrosion research. Their complete report of work

RESULTS OF SURFACE BRINE ANALYSIS BY IGT FOR SAMPLES FROM THE PRAIRIE CANAL WELL NO. 1

Component	Units	22 Feb 81 1520 hrs*	24 Feb 81 0845 hrs	24 Feb 81 1630 hrs	25 Feb 81 1700 hrs	28 Feb 81 1230 hrs	5 Mar 81 1008 hrs
Sample Temperature	°C	60	76	79	95	90	81
Separator Pressure	psig	192	230	200	258	741	251
Flow Rate	BPD	1840	1886	1718	3866	6580	1816
pH	--	6.1	6.0	6.0	6.3	5.8	5.7
Specific Conductance	μmho/cm	50,900	48,900	49,800	48,900	53,000	51,900
Suspended Solids	mg/l	370	35	200	20	30	153
Dissolved Solids	mg/l	42,600	44,100	44,000	43,300	44,200	42,000
Alkalinity	mgHCO_3^-/l	960	920	880	870	820	890
Total CO_2	mgHCO_3^-/l	--	1580	1360	1290	1510	1370
NH_3	mg/l	22	25	25	25	24	20**
SiO_2	mg/l	120	110	120	120	120	110**
Cl^-	mg/l	24,200	25,400	24,600	25,600	25,400	23,600**
S^{2-}	mg/l	0.8	1.2	0.6	0.7	0.5	--
F^-	mg/l	1.00			1.36		1.10
SO_4^{2-}	mg/l	150			140		140
As	μg/l	3.0			3.4		1.2
B	mg/l	55			54		56
Ba	mg/l	2.6			3.2		4.4
Ca	mg/l	890			880		880
Cd	μg/l	<0.5			4.4		<0.5
Cr	μg/l	57			61		48
Cu	μg l	<5			<5		<5
Fe	mg/l	98			59		76
Hg	μg/l	0.54			0.98		0.84
K	mg/l	112			107		110
Mg	mg/l	84			85		81
Mn	mg/l	1.04			0.62		0.75
Na	mg/l	14,900			15,100		14,500
Pb	μg/l	9.3			3.3		<3.0
Sr	mg/l	96			98		96
Zn	mg/l	<0.03			<0.03		<0.03

*Field - 1030 hours; laboratory - 1520 hours, see text.

**Laboratory analysis due to time constraints on location.

on this test well is provided in Appendix N. Results of Rice University brine analyses for samples taken when inhibitors were not being injected into the brine are reproduced in Exhibit 12-29.

- **USGS Water Resources Division, Menlo Park, California:** A single suite of brine samples was collected during the afternoon of 2/27/81. Results of analyses for these samples are tabulated in Exhibit 12-30.

- **USGS Gulf Coast HydroScience Center, NSTL Station, Mississippi:** This organization performed analyses of brine samples collected downstream of the separator to determine ^{226}Ra and Uranium content. Results are tabulated in Exhibit 12-31. In his transmittal letter, T.F. Kraemer observed that "Radium is quite variable over time in this water, and Uranium content is typically low."

EXHIBIT 12-29. RESULTS OF SURFACE BRINE ANALYSES BY RICE UNIVERSITY FOR SAMPLES THAT DID NOT CONTAIN INHIBITOR**

Parameter or Component	Units	22 Feb 81 1300 hrs	23 Feb 81 1000 hrs	24 Feb 81 0940 hrs	24 Feb 81 1700 hrs	25 Feb 81 1100 hrs
Temperature	^oF	150	169	179	187	228
Separator Pressure	psia	200	234	247	256	1300*
Flow Rate	BPD	1800	1800	1800	2000	4500
pH	--	6.8	6.7	6.5	6.6	6.4
Specific Conductance	μmho/cm	52,000	52,000	53,000	51,000	51,000
Alkalinity	mgHCO_3^-/l	939	966	878	854	854
SiO_2	mg/l	--	127	124	125	125
Cl^-	mg/l	23,000	23,200	23,300	22,400	26,900
$SO_4^=$	mg/l	180	200	185	192	175
Ba	mg/l	2	2	N.D.	N.D.	3
Ca	mg/l	907	886	848	862	869
Fe (total)	mg/l	108	79	70	58	60
Mg	mg/l	71	76	68	43	--

*Disposal wellhead pressure. Separator was bypassed.

**See Appendix N for the complete Rice University Report

RESULTS OF BRINE ANALYSIS BY THE USGS WATER RESOURCES DIVISION, MENLO PARK, CA.

Sample Collection Time: Afternoon of 2/27/81

Sample Point: Upstream from Separator at Separator Pressure

Sample Type	Analytical Results		
Raw Untreated Brine	pH*	6.65	
	H_2S*	0.4	mg/l
	Alkalinity as HCO_3^-*,	750	mg/l
Filtered, Untreated Brine	NH_3*	30	mg/l
	F^-	1.5	mg/l
	Cl^-	25,000	mg/l
	Br	7.2	mg/l
	SO_4^{--}	160	mg/l
	SiO_2	113	mg/l
Filtered, HCl-acidified Brine	Li	11.9	mg/l
	Na	14,700	mg/l
	K	112	mg/l
	Rb	0.91	mg/l
	Cs	2.52	mg/l
	Mg	82.8	mg/l
	Ca	823	mg/l
	Sr	77	mg/l
	Ba	3.3	mg/l
	Mn	0.63	mg/l

*Analysis performed at wellsite.

EXHIBIT 12-31. RESULTS OF BRINE ANALYSES FOR ^{226}Ra AND URANIUM BY USGS GULF COAST HYDROSCIENCE CENTER

Sample Point: Downstream from Separator at Separator pressure.

Date	Time	^{226}Ra Analysis Brine Rate (STB/D)	^{226}Ra d/m/l*
2/22/81	1030	1720	320.3 ± 4.0
2/24/81	0900	1810	111.2 ± 5.3
2/25/81	1700	4100	122.8 ± 1.4
2/28/81	1230	4340	287.5 ± 8.9

Uranium Analysis

Date	Time	U, µg/l
2/23/81	2030	0.03 ± 0.001

*Disintegrations per minute per liter

There is no apparent correlation between the variation in ^{226}Ra content of the brine and either changes in brine composition or producing conditions.

12.10.5.2 Discussion of the Analytical Results: The reported concentrations for several constituents were reasonably constant throughout the test sequence. Results from different groups were also consistent. The average of the reported concentrations is probably representative of brine in the reservoir for the following constituents:

- Cl^-
- SiO_2
- K
- F^-
- As
- Hg
- S^{2-}
- B
- Na
- SO_4^{2-}
- Cu
- Zn
- NH_3

The following three species exhibited a reasonably consistent decrease with time:

- Cr
- Mn
- Pb

The decrease in the concentrations of Cr, Mn, and Pb is probably the result of the purging action of the flowing brine through the wellbore and plumbing. These metals are probably of anthropogenic origin and their lowest values are the most probable upper limits for their concentrations in the reservoir brine.

Several other species exhibited variations or values that warrant the following specific comments:

- **Fe:** The decline in concentration from 98-108 mg/l on 2/22/81 to 59 mg/l on 2/25/81 is consistent with the decline observed early on previous well tests. The higher initial value is believed to originate in wellbore tubular goods. However the trend of the next two values for brine without inhibitor, 34.9 mg/l by USGS on 2/27/81 and 76 mg/l by IGT on 3/5/81 is not understood. The possibility of a systematic difference between laboratories has not been pursued. Another possibility is that the iron originates from continuing reaction with wellbore tubulars, rather than from the reservoir. In this event, flow rate and resultant residence time in the wellbore may be responsible for observed fluctuations. If this is the case, roughly 50 mg/l of iron is being dissolved from wellbore tubulars, and production of 5000 BPD for only one year would dissolve 32,000 pounds of iron. This is more than 100 times the maximum corrosion rate observed on the test of the Wainoco P.R. Girouard Well No. 1.

- **pH:** Outside limits of reported values for pH are 5.8 and 6.8. However, the significant point is that all reported values are less than the value inside surface piping at the sample point. This is due to CO_2 loss from the sample to the atmosphere before pH measurement. Values reported by IGT are lower than those reported by Rice University or USGS because IGT collects and cools its samples in pressure vessels to minimize, though not actually eliminating, CO_2 loss whereas other researchers allow the sample to cool at one atmosphere pressure before pH determination.

- **Alkalinity:** Although minor differences exist between values reported by IGT and Rice University, the significant point is that both organizations reported a decrease of about 10 percent as surface brine temperature increased to greater than 200°F. The Rice University report (Appendix N) reveals the decrease in alkalinity as due to $CaCO_3$ scale formation. The reason for the lower value reported by USGS, Menlo Park, (750 mg HCO_3^-/l vs 850-970 mg HCO_3^-/l) has not been determined.

- **Ca:** Average values reported by IGT and Rice University are very close. However, the reason why IGT's data does not exhibit the variations interpreted by Rice University in terms of $CaCO_3$ scaling is not understood. Understanding of the lower concentration (823 mg/l vs 848-907 mg/l) reported by USGS, Menlo Park, has not been pursued.

- **Mg and Sr.:** Understanding has not been pursued of the variations as great as 20% between organizations nor of the 40% decline apparent in the Rice University data.

- **Cd:** The concentration of 4.4 µg/l in the 2/25/81 sample is anomalously high compared to the other two values of <0.5 µg/l for the 2/22/81 and 3/5/81 samples. The reason for this high value, other than possible contamination, is not understood.

- **Ba:** Concentrations of barium increased slightly over the test period. This is contrary to experience and the previously held assumption that the major source of barium had been residues of barium sulfate from the drilling mud.

- **Suspended Solids:** Quantities measured during the test period varied widely. Relationship to well test conditions will be examined in Section 12.12, "Solids Production, Scaling, and Corrosion." The lower values (mean of 28 mg/l) measured on 2/24/81, 2/25/81, and 2/28/81 are most probably the upper limit of suspended solids which would be produced during a prolonged production run of this well.

- **Br, Li, Rb, and Cs:** Concentrations of these constituents of 72.0, 11.9, 0.91, and 2.52 mg/l, respectively, were reported by USGS, Menlo Park. Determination of these concentrations is not included in "Standard Sampling and Analytical Methods for Geopressured Fluids." (Ref. 43).

Two of the measured constituents have concentrations that should be noted due to their environmental significance, as follows:

- **Boron:** Although lower than in previous wells, the mean concentration of 55 mg/l still precludes surface disposal of the brine because of boron's phytotoxicity, unless massive dilution could be made.

- **Mercury:** Concentrations exceed the 0.1 µg/l limit recommended by EPA for protection of fresh and marine aquatic organisms. This would also preclude surface disposal of the brine unless massive dilution could be made.

12.10.5.3 **Brine Mass Balance Calculations:** A computer program has been developed at IGT by Dr. Sherman Chao to calculate the balance between measured cations and anions in geopressured-geothermal brine. Several basic assumptions were used in developing the program. They are:

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

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

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

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

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 weights of all ions. This value is compared with the experimentally measured TDS concentration.

The data for the three completely analyzed samples shown in Exhibit 12-28 were used for mass balance calculations. The results are shown in Exhibit 12-32. Good balances were obtained for all three samples, within the limits of the experimental errors and assumptions made. Further, the result that one calculation (2/21/81 sample) revealed a surplus of anions, whereas the other two revealed a surplus of cations, enhances confidence that the analyses have not overlooked single species present in amounts greater than the differences of up to 1000 mg/l gravimetrically equivalent weight of $CaCO_3$.

Including the Ba, Li, Rb, and Cs concentrations reported by USGS, Menlo Park, for 2/27/81 in calculations for the IGT analyses of 2/25/81 and 3/5/81 samples had a very small effect upon calculated differences in ionic balance. For the 2/25/81 sample the difference changed from -1072 to -989 and for the 3/5/81 sample it changed from +869 to +952.

Calculated and measured values for total dissolved solids are in reasonable agreement. However, for all three analyses, the calculated values were less than the measured values. Adding the 87 mg/l due to the four additional constituents in the USGS, Menlo Park, analysis does not change this observation.

EXHIBIT 12-32. MASS BALANCE CALCULATIONS FOR SURFACE BRINE SAMPLES FROM THE PRAIRIE CANAL WELL NO. 1.

	Equivalent Concentrations of Brine Constituents ($mgCaCO_3/l$)		
	22 Feb 81 1520 hrs.	25 Feb 81 1700 hrs.	5 Mar 81 1008 hrs.
pH	6.1	6.3	5.7
Cations			
NH_4^+	65	74	59
Na^+	32,417	32,852	31,547
K^+	143	137	141
Ca^{2+}	2222	2197	2197
Mg^{2+}	346	350	333
Sr^{2+}	110	112	110
Ba^{2+}	2	2	3
Fe^{3+}	263	159	204
Anions			
Cl^-	34,160	36,136	33,313
CO_3^{2-}	0	0	0
HCO_3^-	567	673	267
SO_4^{2-}	156	146	147
Total Cations	35,568	35,883	34,595
Anions	34,883	36,955	33,726
Difference (Cations less Anions)	+685 +(1.94%)	-1072 -(2.94%)	+869 +(2.54%)
TDS (observed)	42,600	43,300	42,000
TDS (calculated)	41,682	43,157	40,566

12.11 Separator Performance Study

The three flow tests to determine reservoir and fluid properties of the Prairie Canal Well required numerous increases in separator pressure due to increasing injection pressure required by the disposal well. Field data interpretation during those tests revealed substantial variations in CO_2 content of gas from the separator plus variations in total produced gas/brine ratio that appeared to correlate with separator pressure rather than with production well conditions.

During the first two flow tests, a Rice University team headed by Drs. John Oddo and Mason Thomson was on location performing inhibitor studies. Their evaluation of scaling potential required knowledge of separator efficiency for CO_2 removal. The IGT and Rice University personnel developed mutual understanding of the importance of equilibria between CO_2, HCO_3^-, and $CO_3^=$ ($CO_2/HCO_3^-/CO_3^=$ system) in relation to both removal of CO_2 gas by the separator and the formation of carbonate scale. It was recognized that total inorganic carbon in this sytem should be constant but that the partition amongst species in the $CO_2/HCO_3^-/CO_3^=$ system may well depend upon operating conditions. This in turn led to definition of a practicable sample collection and analysis procedure to provide relevant quantitative data.

An additional flow test was performed so that the sample collection and analysis procedure could be implemented for a wide range of separator pressures. Details of that flow test, presentation of data obtained, and interpretation of that data are covered under subheadings below.

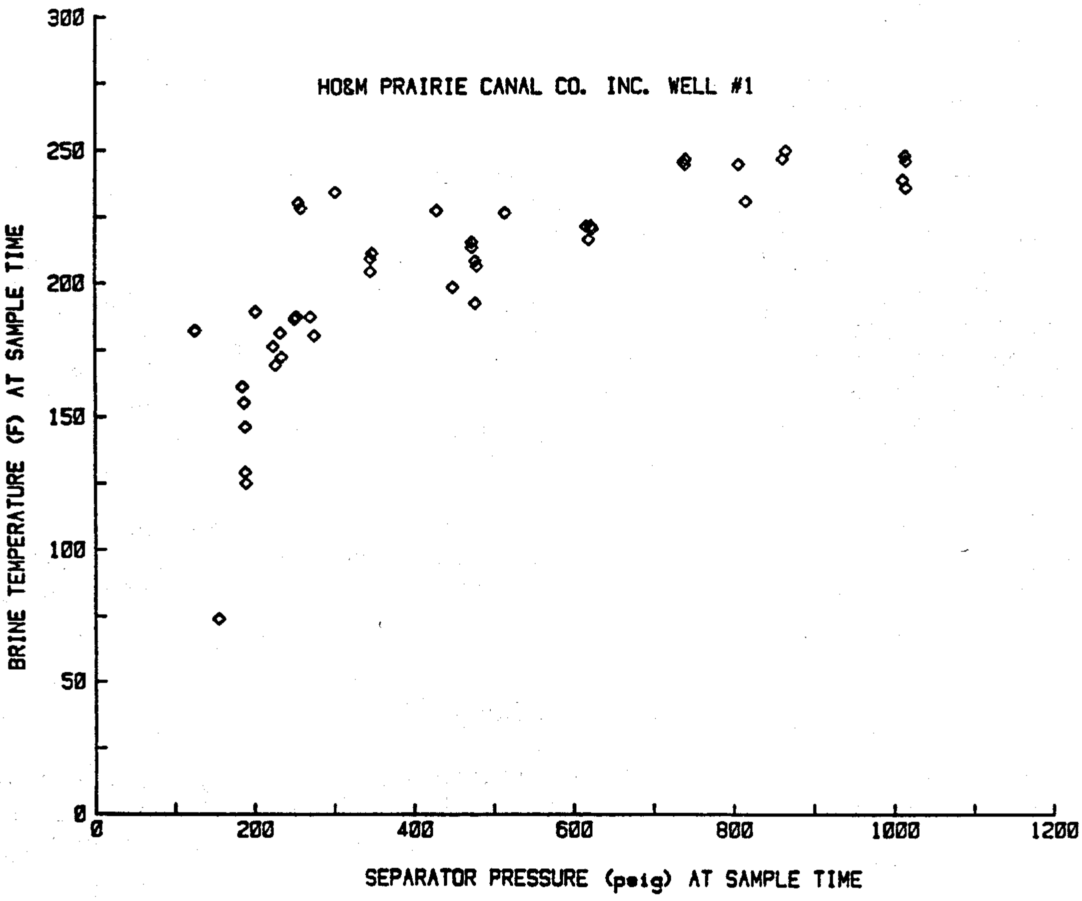
12.11.1 Operational Constraints and Sample Collection

The March 5, 1981 study of separator performance was preceded by about eight days of production, involving three flow tests between February 21, 1981 and March 2, 1981. This operating experience defined operational constraints on the proposed conduct of the separator study. The most significant of these were:

- Brine rates in excess of 4500 bpd were accompanied by substantial sand production and rapidly increasing injection pressure at the disposal well.
- Operation at separator pressures less than 250 psig would require brine flow to the reserve pit, and this flow would have to be minimal because the remaining pit capacity was limited.
- Reasonably stable operation was only possible in the range of separator pressures and temperatures encompassed by the points shown in Exhibit 12-33. These points represent the brine temperatures and separator pressures at the times of collection of 52 gas samples analyzed during the entire sequence of well tests.

The overall effect of these constraints was that operation at low separator pressure required low production rates and that high separator pressure required high rates. This in turn resulted in higher brine temperatures for the higher separator pressures.

Production for the separator study commenced at 1940 hours on March 4, 1981. Since the wellhead had been cooling during the preceding two-day shut-in period, an initial



BRINE TEMPERATURES AND SEPARATOR PRESSURES AT GAS SAMPLE COLLECTION TIMES

EXHIBIT 12-33

flow rate of about 4500 bpd was selected to provide the fastest heating possible, without excessive sand production and buildup of disposal well injection pressure. By 0030 hours on March 5, 1981, surface brine temperature had increased to above 200°F, and reasonably stable operation had been achieved. Therefore the first suite of gas samples was collected at that time.

Changes in operating conditions for the separator study during March 5, 1981 are portrayed graphically in Exhibit 12-34. Collection of suites of samples for analysis, after changes in brine production rate, was delayed until after "bottoms up" following each change. In addition, an hour of consistent production following each change in separator pressure was a prerequisite for sample collection. Two suites of samples were collected for each of six different separator pressures. However, one of the samples collected at 266 psia was lost, due to a leaky valve on the sample vessel.

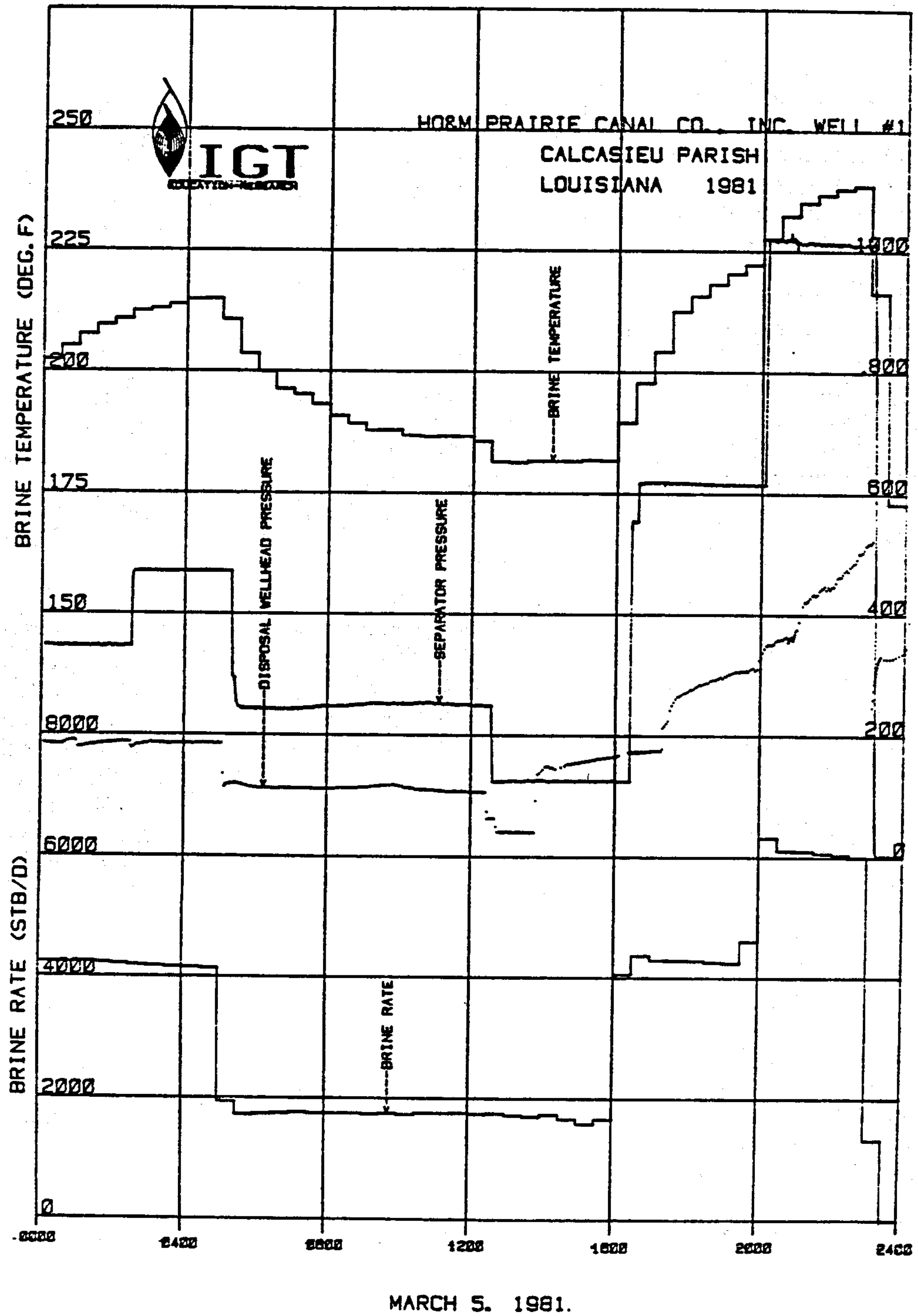
12.11.2 Total Produced Gas/Brine Ratio

Determination of total gas content of produced brine involved three distinct steps. The first step, determination of the ratio of flare line gas to produced brine is discussed in Section 12.11.2.1. The additional portion of produced gas liberated from brine leaving the separator by pressure reduction after cooling is discussed in Section 12.11.2.2. Finally, Section 12.11.2.3 covers gas remaining in brine at ambient pressure and temperature.

12.11.2.1 Flare Line Gas/Brine Ratio: Procedures used to determine the ratio of flared gas to produced brine were previously described in detail in Sections 12.10.4.1 through 12.10.4.3. Gas compositions used to analyze orifice meter data at each separator pressure were from analysis of samples collected at that pressure. The resulting 1/2-hour averages of the ratio of flared gas to produced brine for March 5, 1981 are portrayed graphically on an expanded scale in the upper half of Exhibit 12-35. The large positive peak at 0500-0530 hours and the negative swing at 1600-1630 hours are due to substantial changes in quantity of gas stored in the separator due to simultaneous changes in brine rate and separator pressure. Similar, but smaller, fluctuations are also apparent at the times of most separator pressure changes. Flared gas/brine ratios at the time of collection of samples for analysis are also tabulated in Exhibit 12-36.

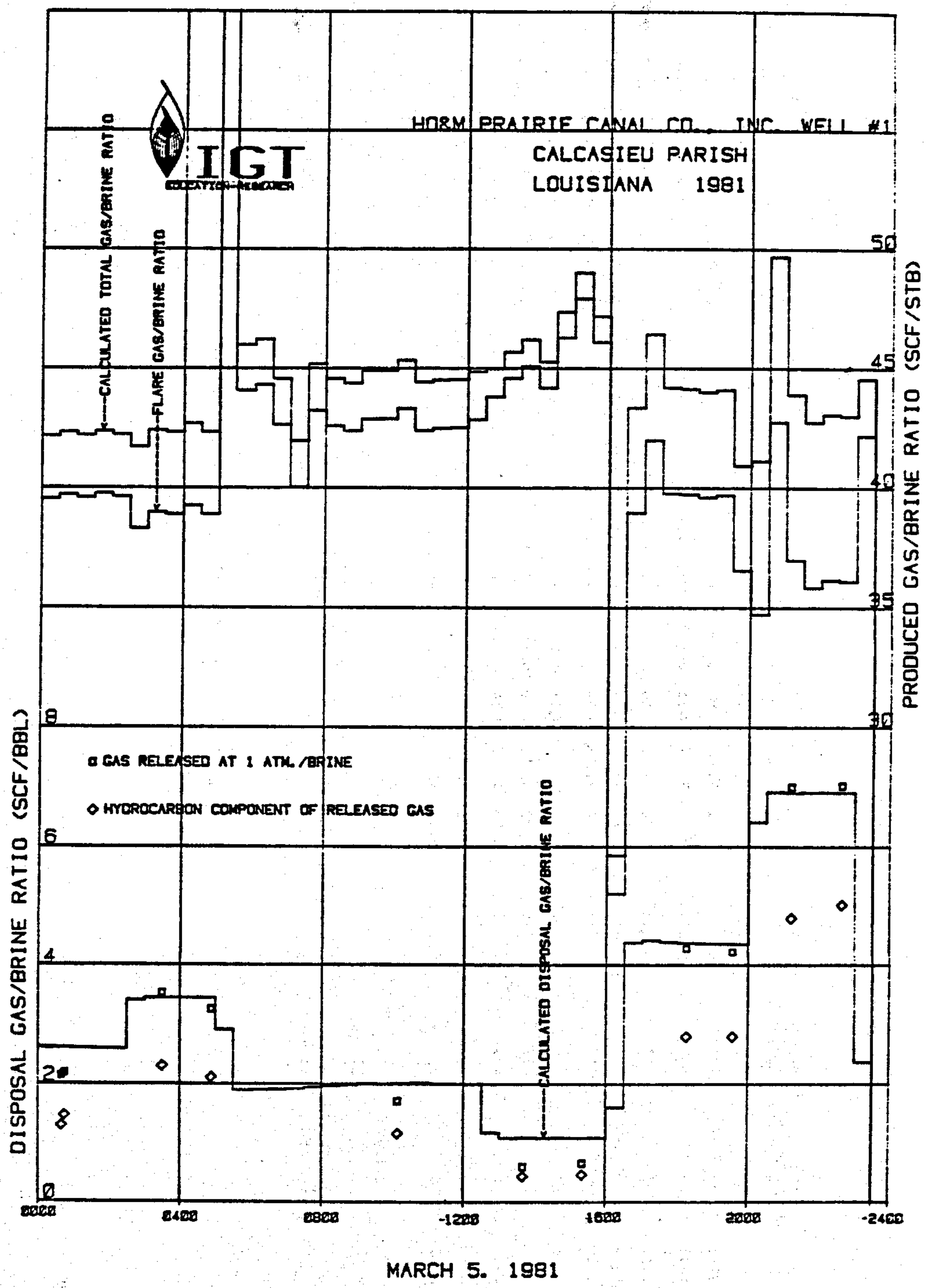
12.11.2.2 Additional Gas Liberated by Reducing Pressure on Post-Separator Brine to One Atmosphere After Cooling: Details of procedures used to collect samples of post-separator brine in pressure vessels, cool the samples, determine gas liberated by pressure reduction to one atmosphere, and analyze that gas were previously described in Section 12.10.3.3. Results of using that procedure during the separator performance study are shown as data points in the lower half of Exhibit 12-35 and are tabulated in Exhibit 12-36.

Data points both for total gas liberated from cooled samples and for the hydrocarbon portion of such gas are shown in the lower half of Exhibit 12-35. Also shown are the results of calculating methane solubility in distilled water using the algorithm developed by S.K. Garg et al. (Ref. 16) to fit the data of O.L. Culberson and J.J. McKetta (Ref. 8). The agreement between calculated values and measurements of total gas liberated



OPERATING CONDITIONS FOR SEPARATOR STUDY, 3/5/81

EXHIBIT 12-34



GAS/BRINE RATIOS DURING SEPARATOR PERFORMANCE STUDY

EXHIBIT 12-35

Date	Time	Flow Rate (STB/Day)	Separator Pressure (psia)	Brine Temperature °F	Flare Line (SCF/STB) CO_2	CH_4	C_2H_6	C_3+	Total	Disposal Well Brine (SCF/STB) CO_2	CH_4	C_2H_6	C_3+	Total	Sum (SCF/STB) CO_2	CH_4	C_2H_6	C_3+	Total*
5 Mar 81	2238	6050	1025	238	2.24	31.80	0.96	0.166	35.17	1.99	4.91	0.111	0.011	7.02	4.23	36.71	1.07	0.18	42.19
5 Mar 81	2112	6110	1029	235	2.12	30.59	1.00	0.194	33.90	2.19	4.69	0.107	0.011	7.00	4.31	35.28	1.11	0.21	40.91
5 Mar 81	1933	4260	630	221	3.05	33.14	0.95	0.150	37.29	1.44	2.73	0.061	0.005	4.24	4.49	35.87	1.01	0.16	41.53
5 Mar 81	1815	4300	632	216	2.89	34.07	0.99	0.157	38.11	1.50	2.73	0.061	0.006	4.30	4.39	36.80	1.05	0.16	42.40
5 Mar 81	1520	1730	140	187	4.98	36.65	0.99	0.133	42.75	0.19	0.46	0.010	0.001	0.66	5.17	37.11	1.00	0.13	43.41
5 Mar 81	1340	1790	140	187	4.64	34.58	0.94	0.125	40.29	0.16	0.43	0.010	0.001	0.60	4.80	35.01	0.95	0.13	40.89
5 Mar 81	1008	1760	266	187	3.81	34.27	0.91	0.122	39.11	0.55	1.13	0.025	0.002	1.71	4.36	35.40	0.94	0.12	40.82
5 Mar 81	0453	4160	487	215	3.22	32.99	0.90	0.123	37.23	1.15	2.06	0.044	0.004	3.26	4.37	35.05	0.94	0.13	40.49
5 Mar 81	0330	4180	485	213	3.09	31.89	0.86	0.119	35.96	1.23	2.25	0.048	0.004	3.53	4.32	34.14	0.91	0.12	39.49
5 Mar 81	0045	4240	360	204	3.46	32.44	0.84	0.115	36.86	0.72	1.43	0.030	0.003	2.18	4.18	33.87	0.87	0.12	39.04
5 Mar 81	0040	4240	360	204	3.46	32.44	0.84	0.115	36.86	0.85	1.26	0.026	0.002	2.14	4.31	33.70	0.87	0.12	39.00
		Mean Value													4.45	35.36	0.98	0.14	40.93
		Standard Deviation													0.29	1.18	0.08	0.03	1.41
		Standard Deviations as Percent of Mean Value													6.5	3.3	8.2	19	3.4

GAS LIBERATED BY PRESSURE REDUCTION

EXHIBIT 12-36

by pressure reduction, including CO_2, is excellent for separator pressures in excess of 300 psia. At lower separator pressures, measured values of total liberated gas, including CO_2, are lower than calculated values by about 0.5 SCF/STB.

The top curve in Exhibit 12-35 is the sum of the flare line gas/brine ratio plus the calculated ratio of gas to brine leaving the separator. With the exception of transients due to changes in operating conditions, this curve should be flat if the gas/brine ratio and composition of gas produced from the reservoir were constant and if all gas were properly accounted for. However, the higher values during production at the two lowest separator pressures of 266 and 140 psia clearly indicate that this is not true. As will be shown below, this is partly due to the larger amount of CO_2 gas liberated at low separator pressure.

The right-hand portion of Exhibit 12-36 shows the sum of flare line gas/brine ratio plus the similar ratio for gas liberated from brine samples by pressure reduction to one atmosphere for the time of collection of each sample. Relevant observations regarding these sums are:

- CO_2 recovered at a separator pressure of 140 psia was about 1 SCF/STB greater than for higher separator pressures. (The value of 5.17 SCF CO_2/STB is believed more accurate than the value 4.80 SCF CO_2/STB due to the time required to achieve equilibrium in composition of gas in the separator.)
- Natural gas liquid content of produced gas was increasing with time during the separator study.
- Values for "total" gas/brine ratio for the flare line and the sum in Exhibit 12-36 are slightly less than plotted in Exhibit 12-35 because the nitrogen and C_{6+} components of produced gas are not included in Exhibit 12-36.
- The standard deviation of 1.18 SCF/STB, or 3.3 percent of the mean concentration for methane, is a reasonable measure of overall accuracy.

12.11.2.3 Gas Remaining in Brine at 75°F and One Atmosphere Pressure: After liberation of CO_2 by the separator and by pressure reduction to one atmosphere on cooled brine, a substantial quantity of CO_2 remained in the brine in the forms of:

- Dissolved CO_2
- Bicarbonate (HCO_3^-)
- Carbonate ($CO_3^=$) ions

All these species must be taken into account in relation to both gas production and formation of carbonate scale. Brine from this well had two characteristics that greatly facilitate understanding concerning gas production. These are:

- The calcium and magnesium content of produced brine was too low for significant carbon loss due to carbonate scale formation at any of the pressure and temperature conditions of the experiment.

- The alkalinity titration did not reveal end-points suggestive of interference from other chemical species.

Exhibit 12-37 augments the previous sum of gases liberated by pressure reduction to one atmosphere. This augmentation consists of also taking into account the CO_2 remaining in brine after pressure reduction to one atmosphere. Such CO_2 is in HCO_3^- and $CO_3^=$, in addition to CO_2 gas remaining in solution. Total CO_2 content of the produced brine is the sum of that from analysis of flare line gas, plus that from analysis of gases liberated from brine samples by pressure reduction to one atmosphere plus the CO_2 liberated from the remaining brine by acid. It averages 7.53 SCF/STB with a standard deviation of only 1.9 percent of this average.

The column labeled "Total CO_2 plus Hydrocarbons" gives the total quantity of gas that could be recovered from produced brine by acid treatment. The column labeled "Total Gaseous Species" is total gas recoverable from the brine without breakdown of HCO_3^- and $CO_3^=$. As revealed in the last column, this gas would contain about 13.4 percent CO_2. For the Prairie Canal well, these last two columns provide upper limits on possible gas recovery from a conventional separator and the CO_2 content of such recovered gas.

12.11.3 Effect of Separator Static Pressure on Gas Remaining in Brine After the Separator

The relationship between the volume of gas remaining in the brine leaving the separator, including CO_2 in HCO_3^- and $CO_3^=$, is shown graphically as a function of separator pressure in Exhibit 12-38. The volume of gas increases approximately linearly with increasing pressure, but the Y-intercept does not equal zero. Determining the quantity of each gaseous species resolves this apparent anomaly.

Exhibit 12-39 is a plot of the volume of methane liberated from the separator brine by a pressure reduction to one atmosphere after cooling versus the partial pressure of methane in the separator. The data form a straight line ($r^2 = 0.994$) with a Y-intercept of -0.21 SCF/STB. This negative intercept is primarily due to the amount of methane remaining in the brine after the pressure reduction. The partial pressure of methane above the brine varies from 8.65 psia to 10.43 psia after the pressure reduction, which would leave about 0.10-0.13 SCF/STB still dissolved in the brine (Ref. 42), assuming Henry's law is valid in this range.

Another factor which lowers the Y-intercept is the previously discussed coupling of separator pressure and brine temperature due to operational constraints on this experiment. Samples collected at the lower separator pressures had lower temperatures due to the low brine production rates. Similarly, high separator pressures required high flow rates and therefore involved higher brine temperatures.

Exhibit 12-40 is a plot of the volume of ethane liberated from brine after the separator by a pressure reduction to one atmosphere after cooling versus partial pressure of ethane in the separator. The data form a straight line ($r^2 = 0.989$) with a Y-intercept of +0.0002 SCF/STB. The same factors that affect the slope of the methane plot should also affect the ethane plot. The values are much smaller than those for methane. Exhibit 12-41 is a similar plot of the sum of propane, butanes, and pentanes liberated from the disposal brine by reduction of pressure to one atmosphere. The plotted data form a straight line ($r^2 = 0.974$) with a Y-intercept equal to +0.0004 SCF/STB.

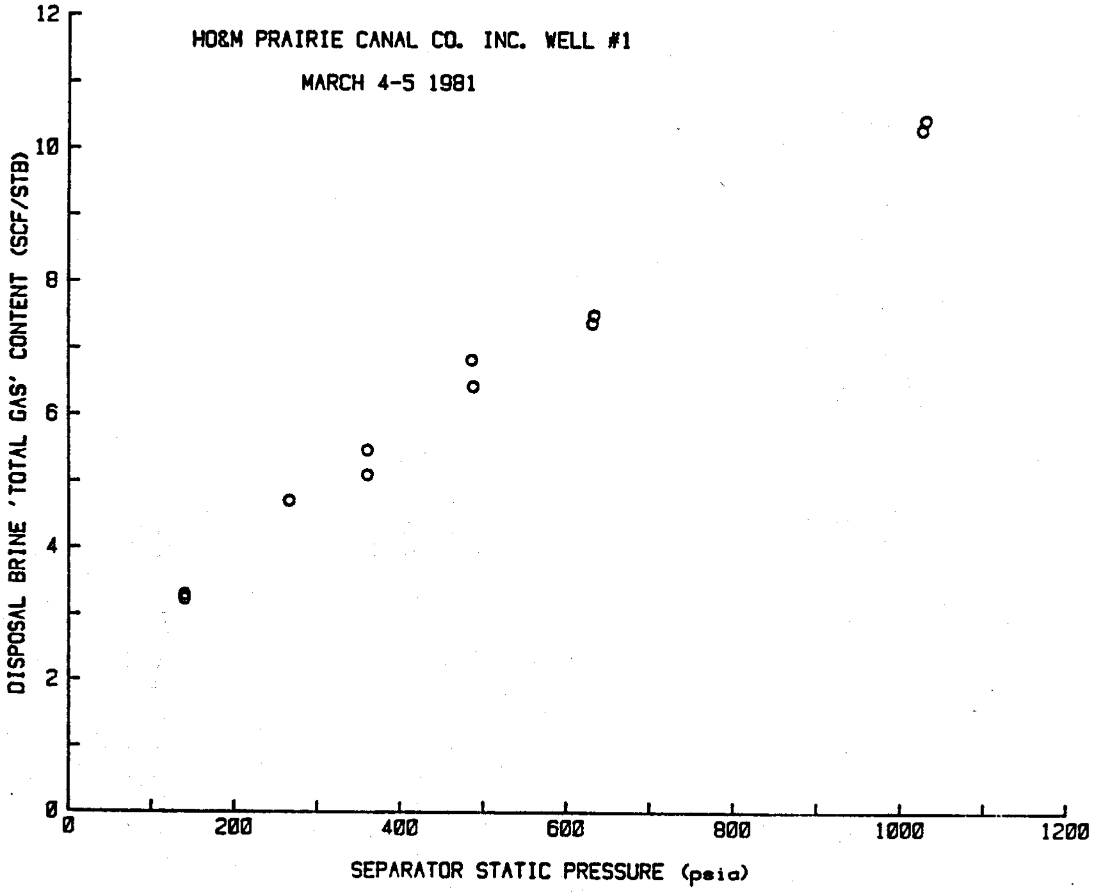
Date	Time	Flow Rate (STB/Day)	Separator Pressure (psia)	Brine Temperature °F	Gas Liberated From Cooled Brine by Pressure Reduction to One Atmosphere (SCF/STB)					Acid Liberated CO_2 (SCF/STB)	"Total" CO_2 (SCF/STB)	Alkalinity Biocarbonate as CO_2 (SCF/STB)	Gaseous CO_2 (SCF/STB)	Total CO_2 Plus Hydrocarbons* (SCF/STB)	Total Gaseous Species† (SCF/STB)	Gaseous CO_2 in Total Gas (Mole %)
					CO_2	CH_4	C_2H_6	C_3+	Total							
5 Mar 81	2238	6050	1025	238	4.23	36.71	1.07	0.18	42.19	3.24	7.47	1.81	5.66	45.43	43.62	13.0
5 Mar 81	2112	6110	1029	235	4.31	35.28	1.11	0.21	40.91	3.41	7.72	1.84	5.88	44.32	42.48	13.8
5 Mar 81	1933	4260	630	221	4.49	35.87	1.01	0.16	41.53	3.13	7.62	1.86	5.76	44.66	42.80	13.5
5 Mar 81	1815	4300	632	216	4.39	36.80	1.05	0.16	42.40	3.19	7.58	1.89	5.69	45.59	43.70	13.0
5 Mar 81	1520	1730	140	187	5.17	37.11	1.00	0.13	43.41	2.56	7.73	1.94	5.79	45.97	44.03	13.2
5 Mar 81	1340	1790	140	187	4.80	35.01	0.95	0.13	40.89	2.68	7.48	1.92	5.56	43.57	41.66	13.3
5 Mar 81	1008	1760	266	187	4.36	35.40	0.94	0.12	40.82	2.99	7.35	1.94	5.41	43.81	41.87	12.9
5 Mar 81	0453	4160	487	215	4.37	35.05	0.94	0.13	40.49	3.16	7.53	1.86	5.67	43.65	41.79	13.6
5 Mar 81	0330	4180	485	213	4.32	34.14	0.91	0.12	39.49	3.28	7.60	1.81	5.79	42.77	40.96	14.1
5 Mar 81	0045	4240	360	204	4.18	33.87	0.87	0.12	39.04	3.28	7.46	—	—	42.32	40.45	13.8
5 Mar 81	0040	4240	360	204	4.31	33.70	0.87	0.12	39.00	2.96	7.27	—	—	41.96	40.09	13.5
Mean Value					4.45	35.36	0.98	0.14	40.93		7.53	1.87	5.69	44.01	42.13	13.4
Standard Deviation					0.29	1.18	0.08	0.03	1.41		0.14	0.05	0.14	1.34	1.33	0.4
Standard Deviation as Percent of Mean Value					6.5	3.3	8.2	18.9	3.4		1.9	2.7	2.5	3.0	3.2	2.9

* Hydrocarbons, plus CO_2 gas, plus acid liberated CO_2.

† Hydrocarbons, plus CO_2 gas, plus acid liberated CO_2, minus alkalinity CO_2 (mean values used where none others were available.

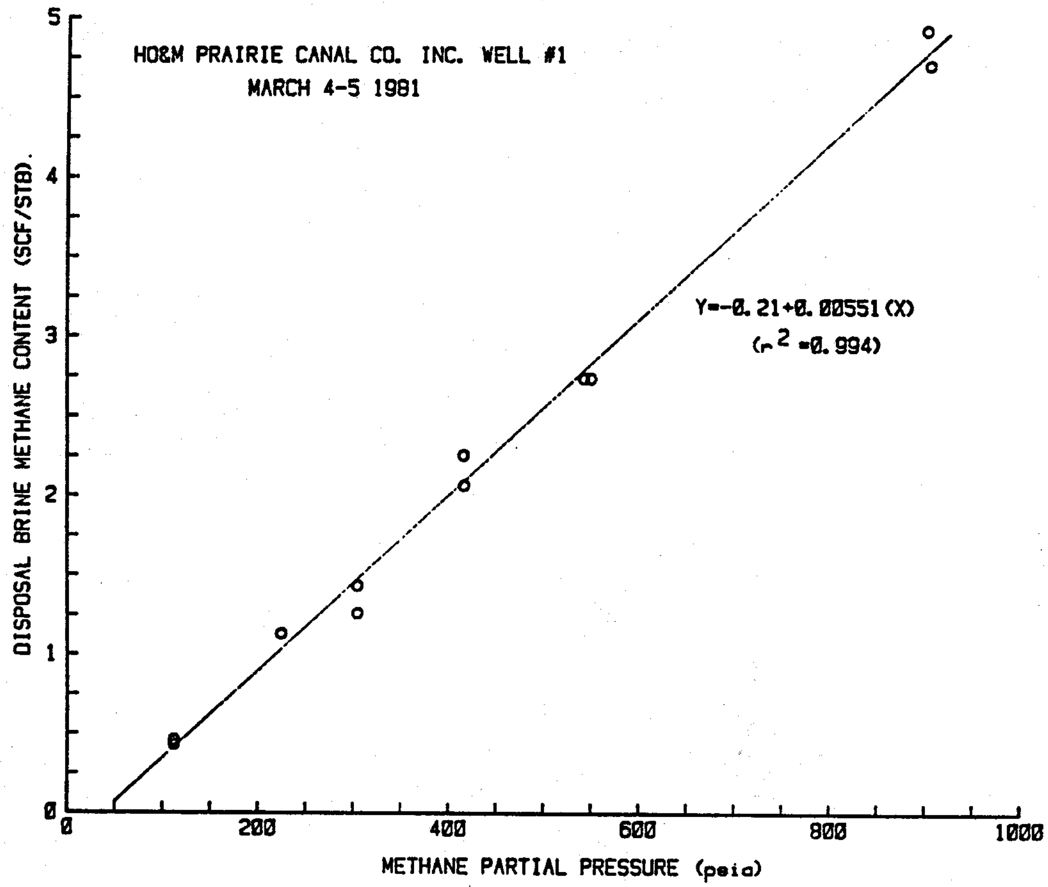
GAS CONTENT OF BRINE, INCLUDING ALL CARBON DIOXIDE
HO&M PRAIRIE CANAL CO., INC. WELL NO. 1

EXHIBIT 12-37



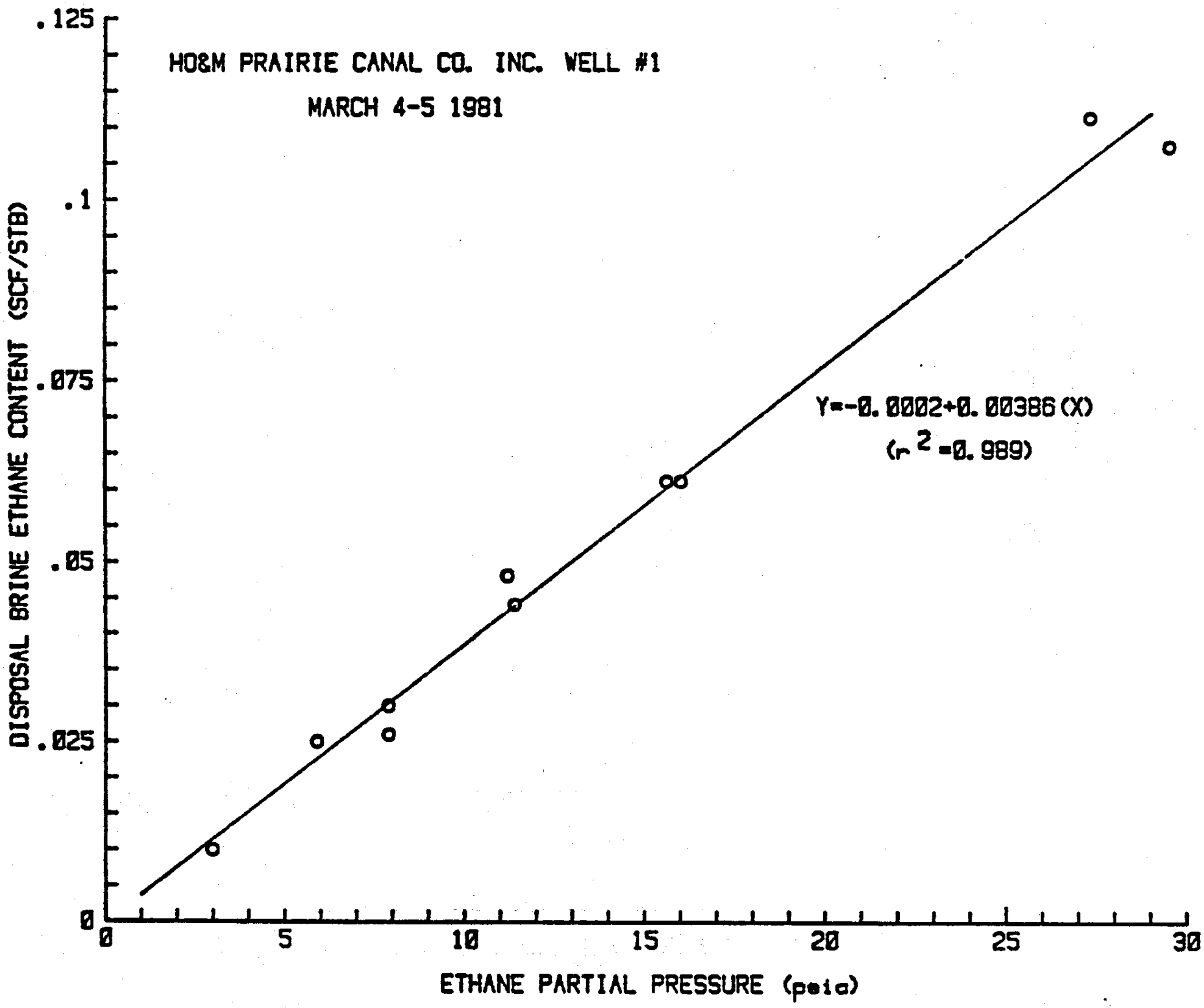
DISPOSAL BRINE 'TOTAL GAS' CONTENT
VS. SEPARATOR STATIC PRESSURE

EXHIBIT 12-38



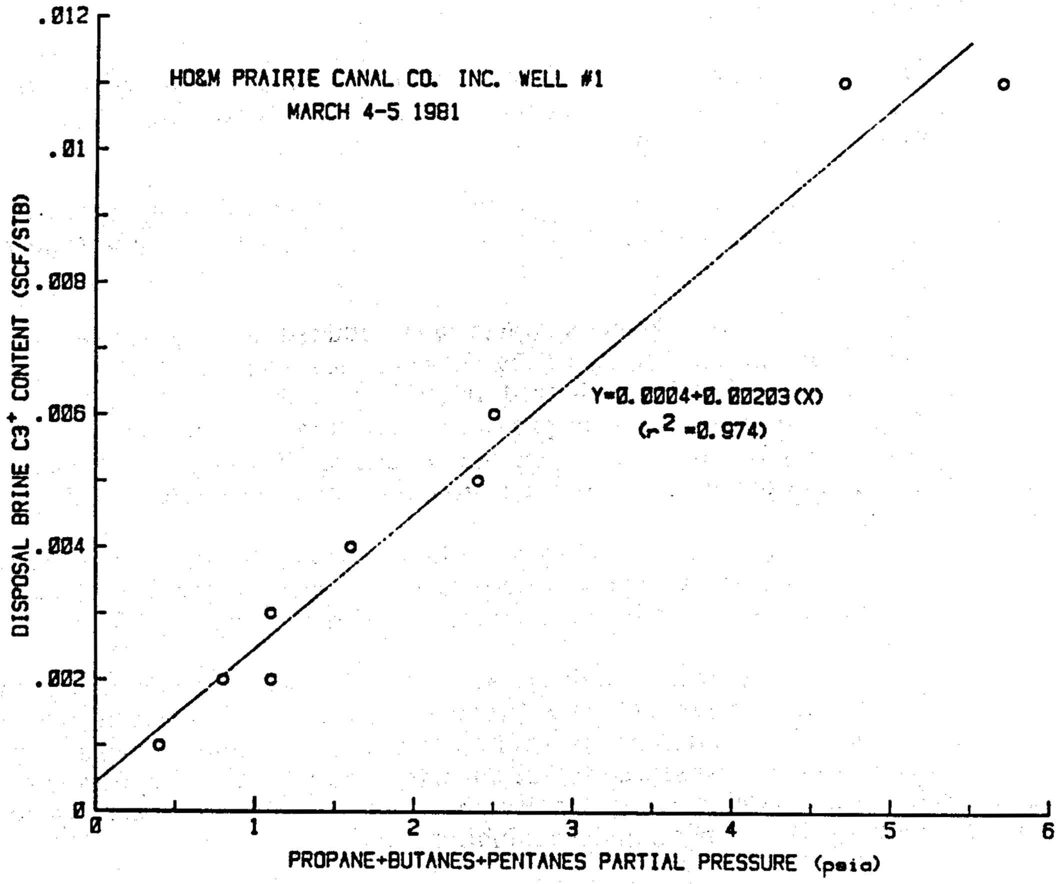
DISPOSAL BRINE METHANE CONTENT
VS. METHANE PARTIAL PRESSURE

EXHIBIT 12-39



DISPOSAL BRINE ETHANE CONTENT VS. ETHANE PARTIAL PRESSURE IN SEPARATOR

EXHIBIT 12-40



DISPOSAL BRINE C3+ CONTENT VS. C3+ PARTIAL PRESSURE

EXHIBIT 12-41

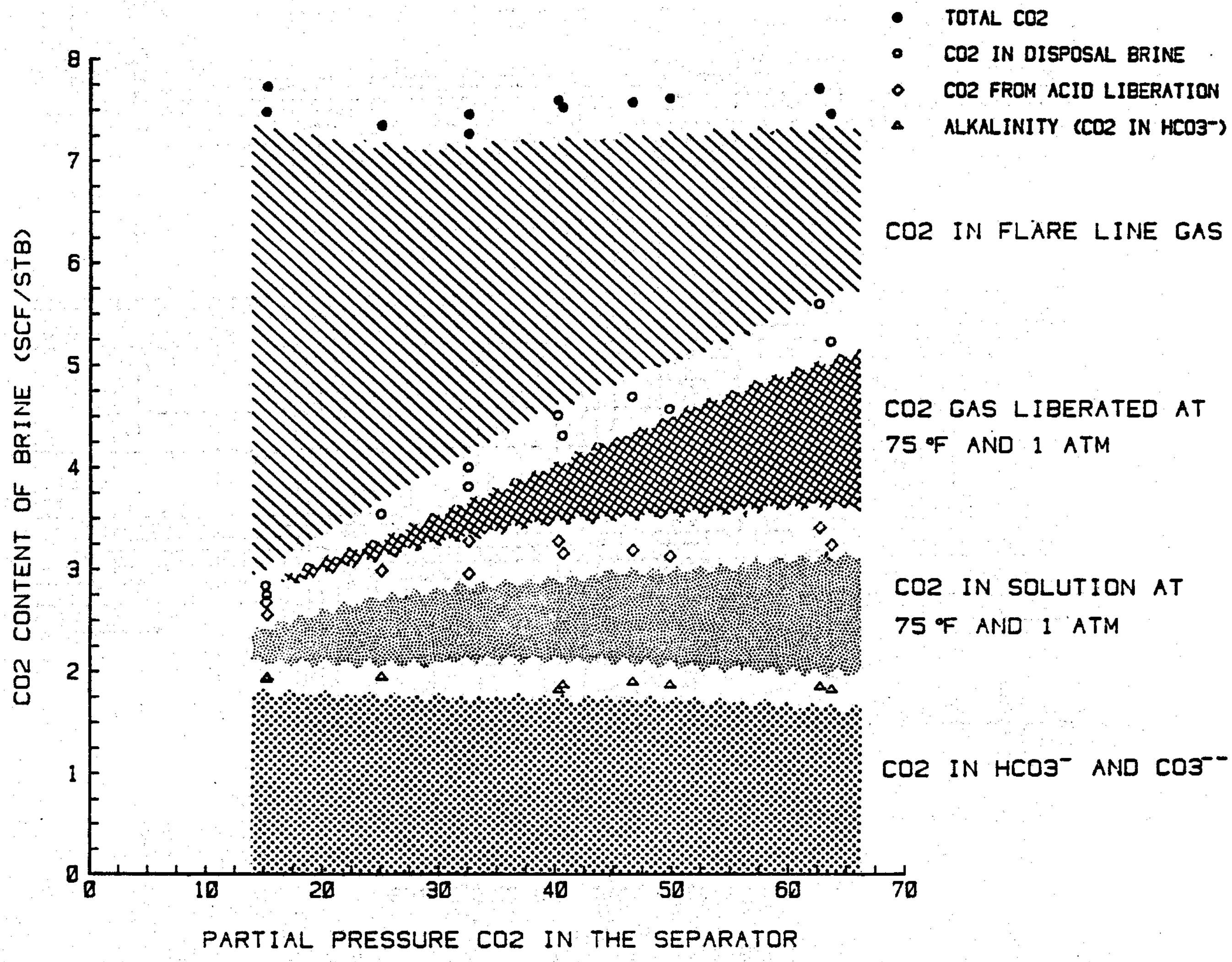
The data in Exhibits 12-39, 12-40, and 12-41 clearly indicate that the quantities of hydrocarbons liberated from disposal brine are primarily dependent on the partial pressure of each hydrocarbon species in the gas phase of the separator. In addition, there is very little deviation from simple Henry's law plots that would consist of straight lines passing through the origin.

The behavior of carbon dioxide is very different from that of hydrocarbons. Exhibit 12-42 is a graphical presentation of the partition of CO_2 according to the various experimental steps. This exhibit reveals that:

- The partition of CO_2 between the gas and brine streams by the separator varied between extremes of 63% in gas/37% in brine at 140 psia and 30% in gas/70% in brine at 1025 psia.
- When pressure on cooled brine samples was reduced to one atmosphere after cooling, variations in partition of CO_2 between gas and liquid phases was even more extreme. For samples collected at 1025 psia, about 2.0 SCF/STB, or 40%, was liberated as free gas by this pressure reduction. On the other hand more than 90% of the CO_2 in the brine in the separator at 140 psia remained in the brine when sample pressure was reduced to one atmosphere after cooling.
- CO_2 in the form of HCO_3^- and $CO_3^=$ was slightly lower for the highest separator pressures. This suggests a very small amount of carbonate precipitation at those pressures and the associated brine temperature of more than 200°F.

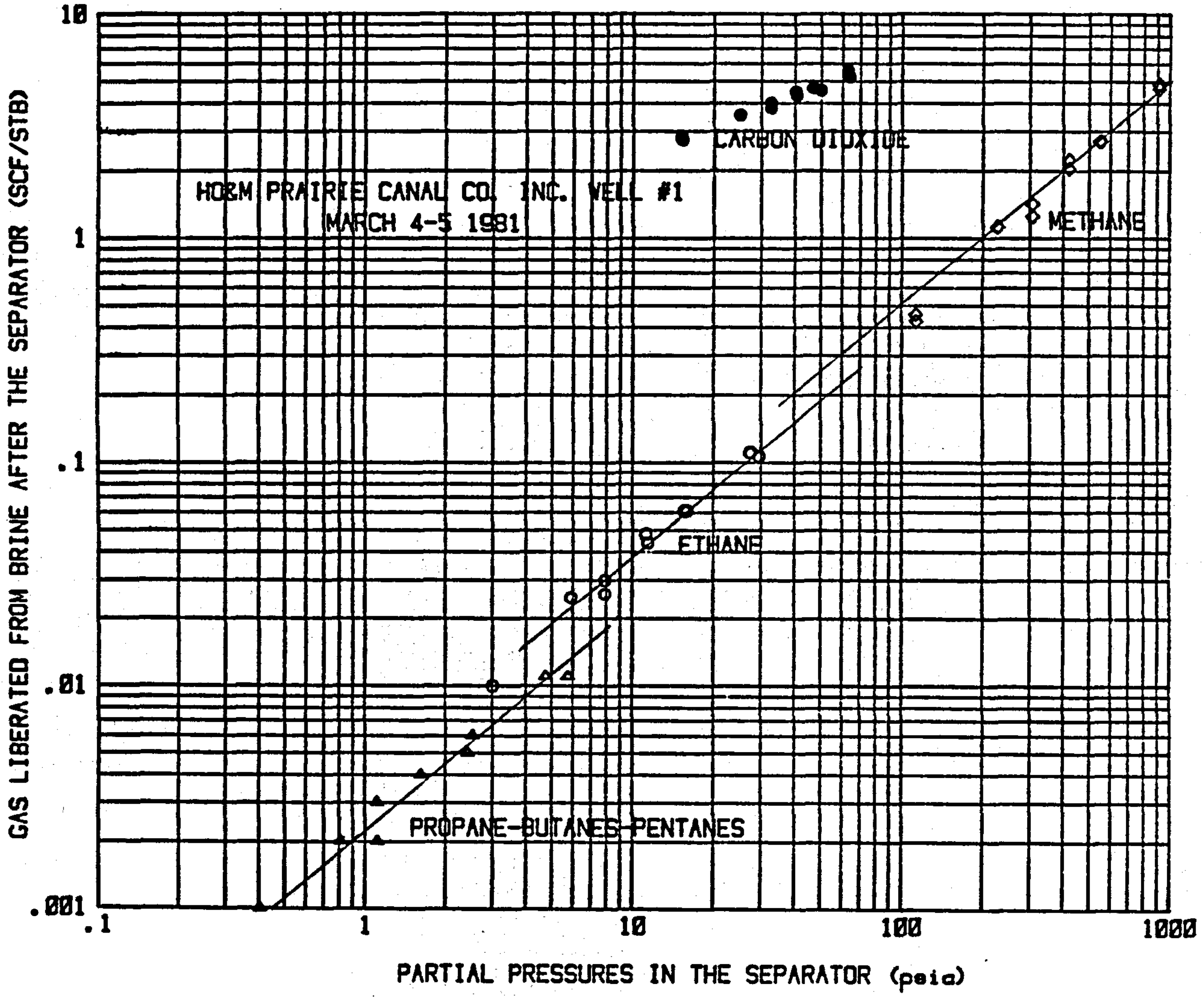
Exhibit 12-43 presents data shown on Exhibit 12-39 thru 12-42 on a single log-log plot. Lines corresponding to Henry's law behavior (slope of 1.0) have also been drawn for each component of the gas. These lines correspond to the slopes of lines from the previous exhibits for gas liberated by pressure reduction after cooling, but they assume Y-axis intercepts of zero. This exhibit reveals only modest differences between hydrocarbon species and clearly reveals the much higher solubility of CO_2.

12.11.3.1 Comparisons to Previously Published Data at Separator Pressures and Temperatures: Interpretation of data from the test of the Wainoco P.R. Girouard Well No. 1 included testing of published algorithms for calculating methane solubility in brines against observed gas content of brine from the separator (Ref. 13). It was concluded that the algorithm developed by S.K. Garg et al. (Ref. 16) for methane solubility in distilled water provided a reasonably accurate estimate of total gas liberated from separator brine by pressure reduction to one atmosphere. Previously discussed Exhibit 12-19b provided comparisons between values calculated with this algorithm and measured values for the 25 analyses of gas from brine during tests of this well. Agreement was within 0.5 SCF/STB for all but three data points. Those three data points were all for samples collected during 3/1/81 and 3/2/81, when free gas was believed entrained in brine to the disposal well due to the combination of high brine rate and sand loading in the separator. The algorithm provided similarly excellent agreement with the small number of data points from the Riddle-Saldana Well No. 2 (Ref. 14) and the Pleasant Bayou Well No. 2 (Ref. 36).



CARBON DIOXIDE PARTITIONING AMONG EXPERIMENTAL STEPS

EXHIBIT 12-42



GAS LIBERATED FROM POST-SEPARATOR BRINE
VS. SEPARATOR PARTIAL PRESSURES

EXHIBIT 12-43

Exhibit 12-44 provides comparisons between data from the controlled study of separator performance and reported laboratory data points on methane solubility in distilled water at 220°F. Actual laboratory data points from the papers by J.E. Davis and J.J. McKetta (Ref. 9) and by O.L. Culberson and J.J. McKetta (Ref. 8) are shown. Lines connecting these points were drawn only to illustrate data trends. The circles on this exhibit again illustrate the excellent agreement between total gas liberated from separator brine by pressure reduction to one atmosphere after cooling and the data published by Culberson and McKetta (Garg algorithm of Ref. 16 was developed to fit the data of Culberson and McKetta).

Total gas content of separator brine, including CO_2 liberated by acid, is greater than laboratory-observed solubility of methane in distilled water. On the other hand, methane content of brine from the separator is only 50 to 80 percent of laboratory-measured methane solubility in distilled water. This reflects a greater depression of methane solubility than could be caused by the modest amount of dissolved solids in brine from this well (43,000 mg/l).

Exhibit 12-45 provides a comparison between measured CO_2 content of brine from the separator and laboratory data points on CO_2 solubility in distilled water at 212°F published by G. Houghton, A.M. McLean, and P.O. Richie (Ref. 18). As previously shown in Exhibit 12-42, the Y-axis intercept of field data is primarily due to HCO_3^- and $CO_3^=$ species in the brine. The difference in slopes of the two lines exceeds reasonable expectation for solubility depression due to dissolved salts. Depression of CO_2 solubility by dissolved hydrocarbons is hypothesized to be a major factor.

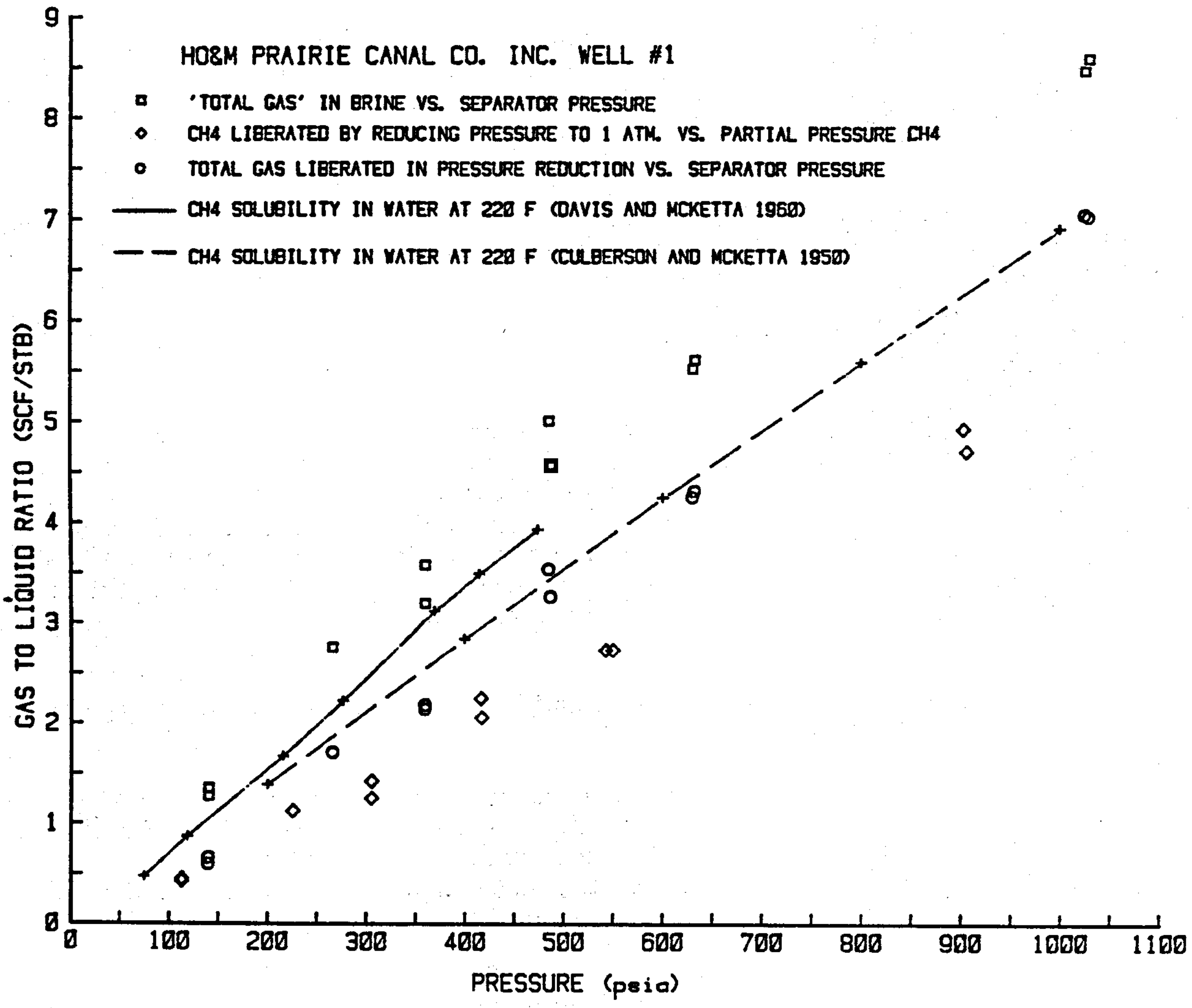
12.11.4 Effect of Separator Pressure and Temperature Upon Quality of Gas from the Separator

Exhibit 12-46 shows CO_2 content of flare line gas versus separator pressure for 44 of the 52 flare line gas samples analyzed in the field during the test of the Prairie Canal well. The other eight samples were collected during times of transient conditions that often cause anomalous gas compositions. A substantial portion of the scatter in the points shown is due to variations of both composition of produced gas and the produced gas/brine ratio.

The symbols for plotted points in Exhibit 12-46 are coded for 25°F ranges in brine temperature. Lines on the graph have been drawn to roughly indicate areas characterized by these temperature ranges. These lines are not isotherms from data interpretation or from theory.

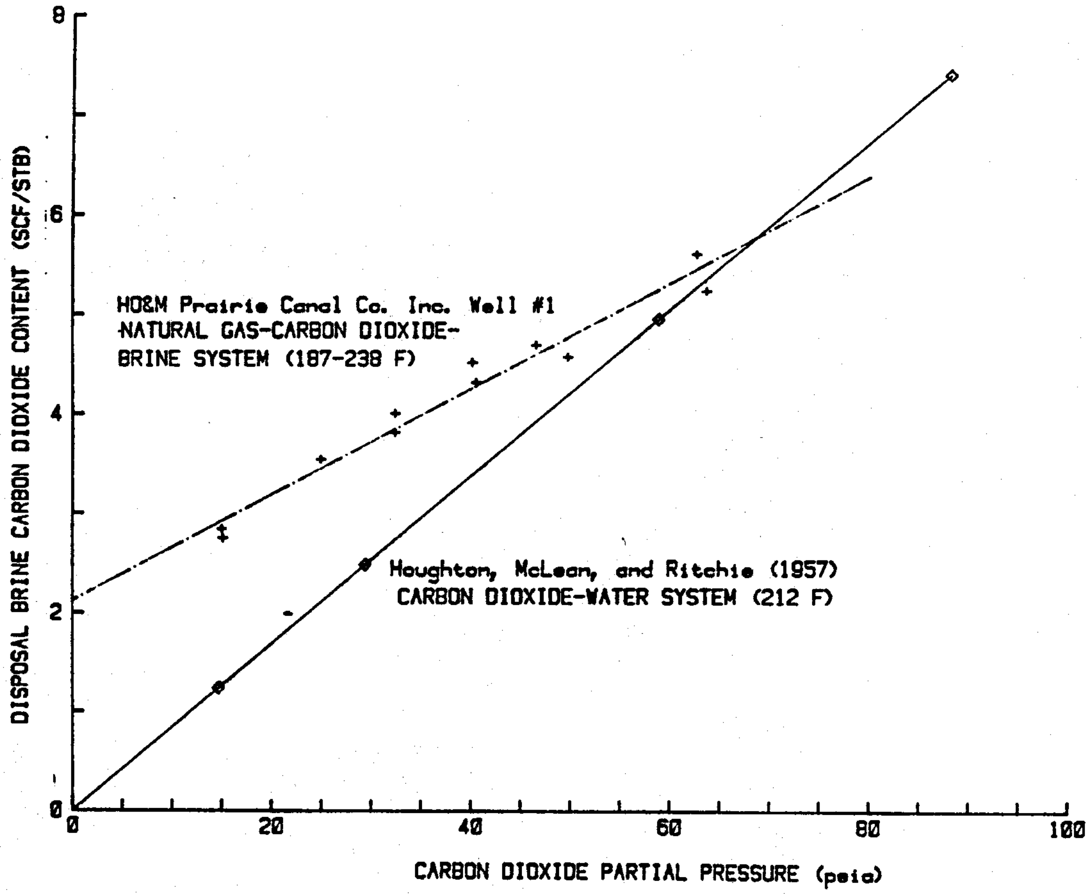
The CO_2 content of separator gas at the highest achieved brine temperatures varied between extremes of 11.6% at a separator pressure of 140 psia and 6.2% at a separator pressure of 1029 psia. For lower temperatures at any specific pressure, CO_2 content of gas was reduced.

Exhibit 12-47 shows the relationship between heating value of gas from the separator and separator pressure for several temperature ranges. As above, lines have been drawn to group data points in selected temperature ranges. The relationships are less clear than for CO_2 content due to the long-term variations in natural gas liquids (NGL) content of produced gas during the series of well tests. The range of NGL content was between 0.70 and 1.05 gallons/MCF. This variation had a greater effect upon the heating value of produced gas than upon its volume.



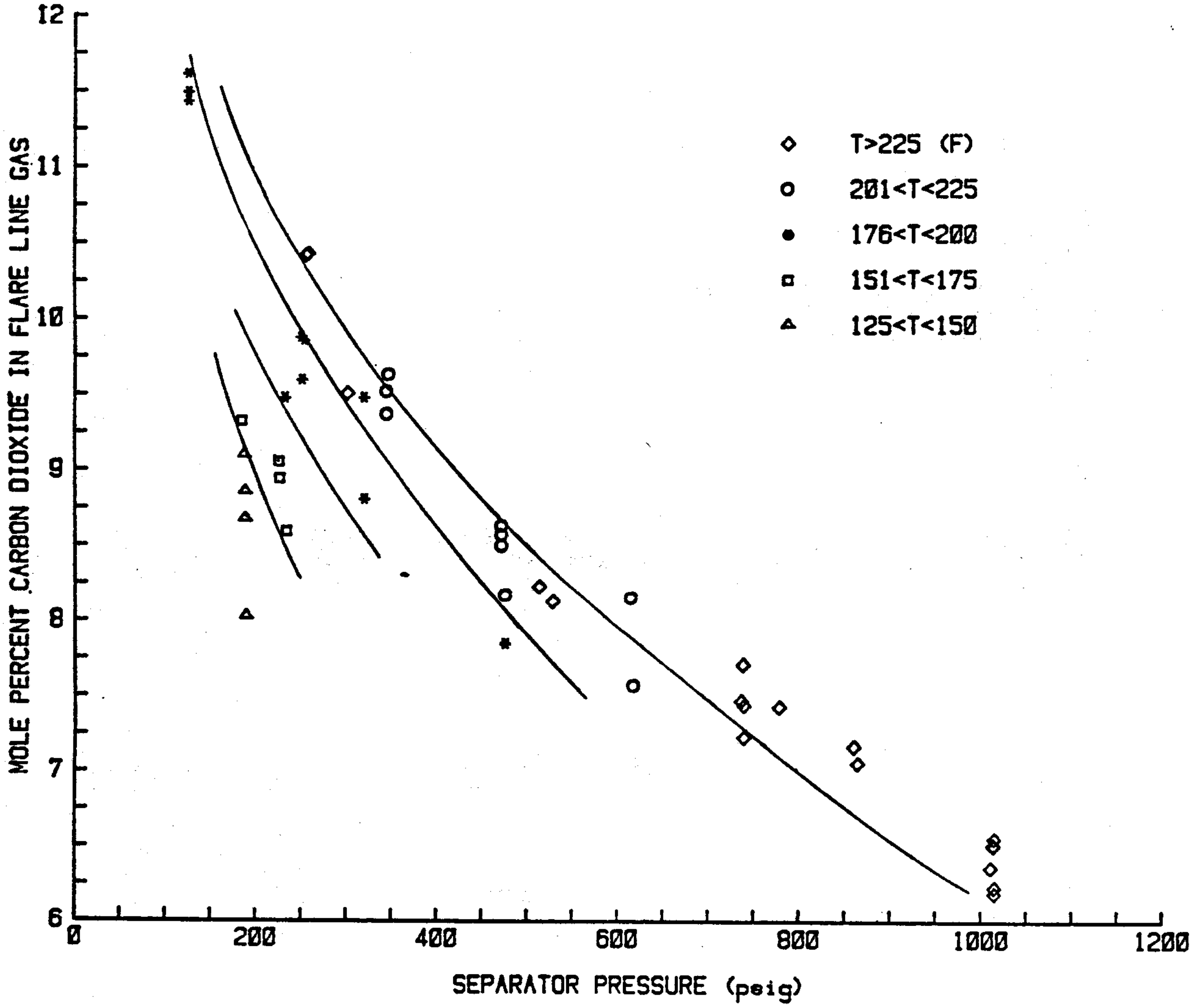
COMPARISON BETWEEN SEPARATOR PERFORMANCE STUDY, AND LABORATORY DATA ON METHANE SOLUBILITY

EXHIBIT 12-44



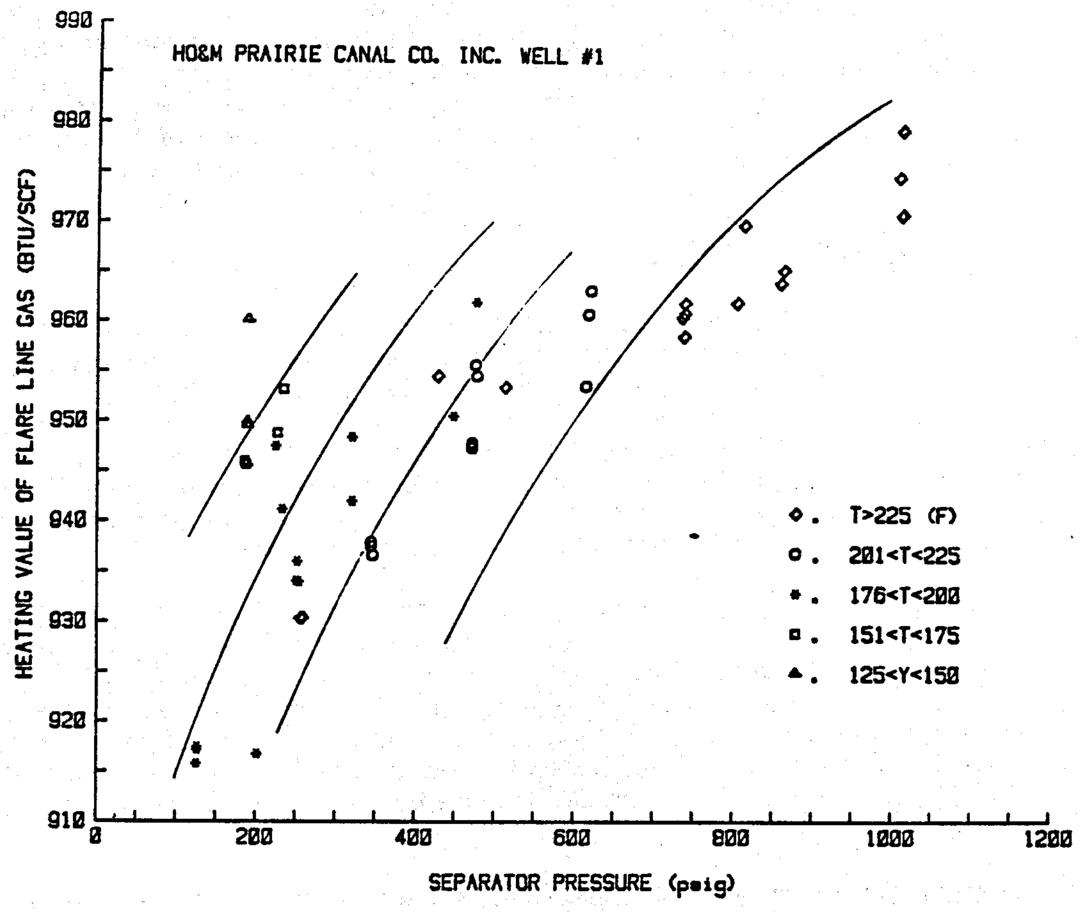
COMPARISON BETWEEN MEASURED CO_2 CONTENT OF POST-SEPARATOR BRINE AND LABORATORY DATA ON CO_2 SOLUBILITY IN WATER

EXHIBIT 12-45



CARBON DIOXIDE CONTENT OF FLARE
LINE GAS VS. SEPARATOR PRESSURE

EXHIBIT 12-46



HEATING VALUE OF FLARE LINE
GAS VS. SEPARATOR PRESSURE

EXHIBIT 12-47

The observed range of heating values of about 920 to 975 BTU/SCF may well be significant in relation to gas sales. If separator pressure had to be as high as 1000 psig to meet CO_2 and heating value requirements of a gas sales contract from a well having the characteristics of Exhibits 12-46 and 12-47, the penalty would be about 5000 BTU of hydrocarbon energy left in each barrel of brine from the separator.

Although quantitative evaluation of various conceivable surface facilities is beyond the scope of this study, it is interesting to note that recovery of thermal energy before separation of gas and brine would improve the quality of gas recovered at any particular separator pressure. Or from a different perspective, prior thermal energy recovery may permit lower separator pressure for gas meeting the quality criteria of a sales contract. Thus quantity of gas marketed per barrel of produced brine could increase.

12.11.5 Separator Efficiency

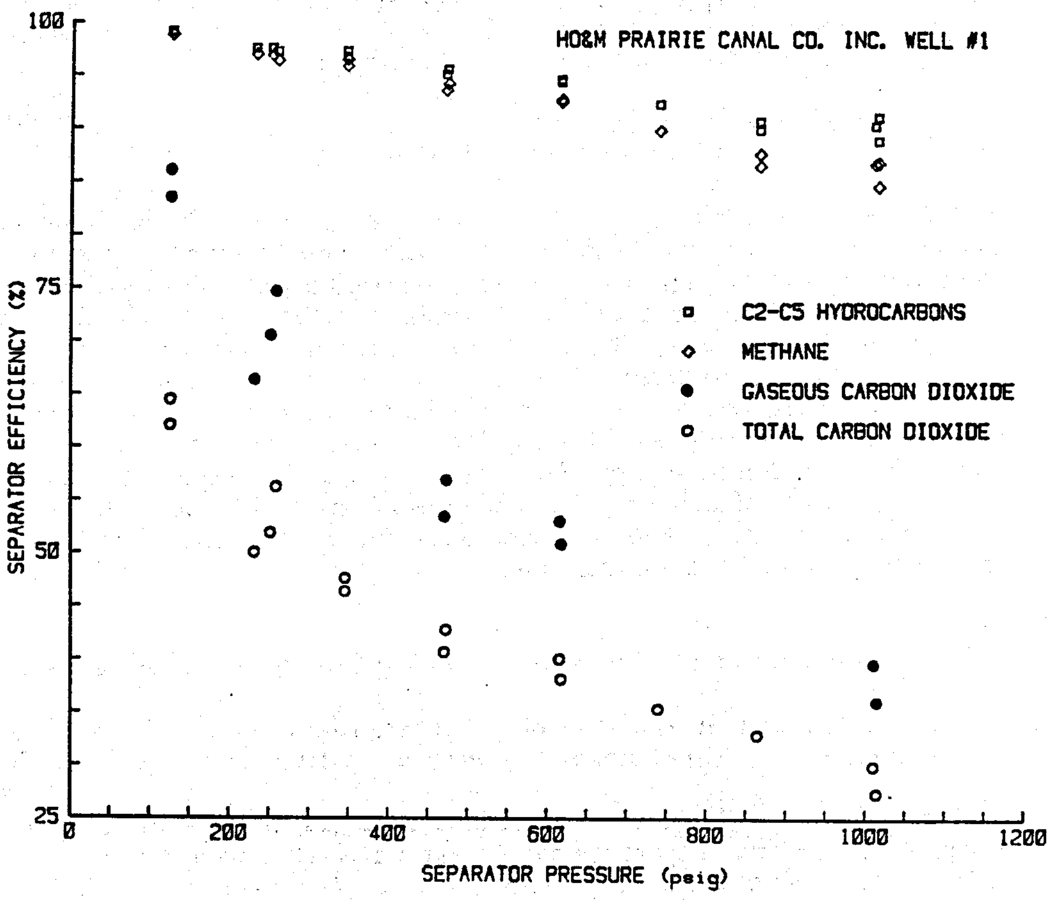
Separator efficiency is defined as the percentage of a specific species, present in the produced brine, that leaves the separator through the gas line. This percentage is useful in relation both to consideration of scaling potential and to examining the tradeoff between gas quality and gas recovery. It is important to note that separator efficiency determined on one test will not be valid for other tests. This is because the absolute amount of each chemical species remaining in separator output brine is dependent upon partial pressure in the separator for that species. This partial pressure is in turn dependent upon composition and quantity of gas produced with the brine.

Exhibit 12-48 shows separator efficiency as a function of separator pressure for CO_2, methane, and natural gas liquids (C_{2+}). The points shown are those for all gas and brine samples that were simultaneously collected from the Prairie Canal well, including during the separator study on March 5, 1981. Efficiencies for CO_2 are shown on two bases. The open circles are on the basis of total CO_2, including that liberated from HCO_3^- or $CO_3^=$ species by acid. The basis for the closed circles is gaseous CO_2, as estimated by subtracting CO_2 in the form of HCO_3^- determined by the alkalinity titration from the total CO_2.

The scatter in points at any particular pressure is due to both variations in temperature and to changes in gas composition during the series of well tests. The effect of composition changes is particulary large for natural gas liquids (C_{2+}).

12.11.6 Effect of Brine Residence Time

IGT's work on Wells of Opportunity indicates that efficiency of the separator used is independent of brine residence time for residence times of two minutes or longer. The separator used consisted of a single ten-foot long horizontal pressure vessel with an inside diameter of 38.5 inches. It had a minimum of internal baffles, so that sand could be readily removed. The upper portion contained brine deflectors near the inlet. The lower half contained a weir, so that three-phase separation was possible in the event of significant oil production. On the Prairie Canal well test, the separator was operated with the brine level at mid-elevation and above the weir. Brine was removed from the "oil" outlet, so that brine residence time was maximized. In the absence of sand, liquid



SEPARATOR EFFICIENCY VS. SEPARATOR PRESSURE
FOR VARIOUS FRACTIONS

EXHIBIT 12-48

volume was about 7.2 barrels, so that a brine rate of 10,400 BPD would have given a one-minute brine residence time.

The only data to date that suggests declining separator efficiency due to short residence time was obtained while producing brine at 6000-6500 STB/D after experiencing heavy sand production. That evidence consisted of the following:

- The calculated total produced gas/brine ratio was about 3 SCF/STB lower than was representative of both earlier and later test data.

- One of five brine samples collected after the separator under those conditions liberated more than 27 SCF/STB of gas upon pressure reduction to one atmosphere after cooling. Three others liberated about 1 SCF/STB of excess gas when pressure was reduced to one atmosphere after cooling the brine samples. Brine residence time when these data were collected was probably less than the 1.7 minutes calculated from brine rate and separator volume. This is because sampling was preceded by heavy sand production, and both ends of the separator were found to contain about 14 inches of sand after the test. Also, at the times of possible degraded separator efficiency, gas from the separator was oscillating between extremes of zero and about one million cubic feet per day, with a period of about one minute. Whether brine rate out of the separator, and therefore residence time, was also varying is not known.

12.11.7 Conclusions and Observations from the Separator Performance Study

Data and analyses support several conclusions of substantial relevance both to conduct of well tests on acquifers and to economics of energy production from aquifers. These are:

- Quantity of each hydrocarbon component of a gas mixture in solution in brine leaving a conventional separator can be estimated at constant temperature using a linear relationship to partial pressure of that component in the separator gas.

- Total gas in solution in brine leaving a separator is consistent with the limited laboratory data on solubility of gases in brine at separator pressure and temperature. Consistency includes the depression by CO_2 of hydrocarbon solubility that has been observed in the laboratory at much higher pressures.

- Carbon dioxide gas in the separator is but one entity in several equilibria between CO_2, HCO_3^-, $CO_3^=$, and carbonate solids. Carbonate solids were absent from surface facilities on the Prairie Canal well test and the total equivalent CO_2 in the species present per barrel of brine was found to be constant. However, the fraction observed as CO_2 gas, and also total produced gas, were found to be dependent upon operating conditions.

- Quality of gas from the separator increased with increasing separator pressure, because solubility of CO_2 increased more rapidly than solubility of methane, and solubility of natural gas liquids does not increase as fast as that of methane.

- Thermal energy recovery from brine before the separator would improve the quality of gas recovered at any specific separator pressure. Or conversely, in the particular case of a gas having the composition observed at the Prairie Canal well, prior cooling of brine may well increase marketable gas from single-stage separation by 2-4 SCF per barrel of brine.

- Separator efficiency for gas recovery from brine is not an inherent characteristic of the separator hardware. This efficiency is a function of brine temperature, gas composition, and produced gas/brine ratio, in addition to operating pressure.

A corollary outcome of this separator performance study is the focusing of attention on the importance and complexity of the $CO_2/HCO_3^-/CO_3^=$ system with respect to evaluating production from aquifers. Observations resulting from consideration of this system are as follows:

- Heating value of hydrocarbons produced with each barrel of brine is a more relevant measure of energy production than standard cubic feet of gas produced.

- Quantitative definition of the CO_2 component of produced gas requires simultaneous sampling of gas and brine streams plus analyses to define CO_2 content as CO_2 gas, HCO_3^-, and $CO_3^=$. These data should be obtained and analyzed at multiple separator pressures to establish validity of results obtained.

- It is questionable whether laboratory studies of the NaCl brine/CH_4/CO_2 system will provide an adequate basis for conclusions regarding saturation of real brines at reservoir pressure and temperature. This is due to the effect of HCO_3^- and $CO_3^=$ observed on real well tests.

- CO_2 content of recovered gas, and therefore total produced gas, may well differ between scaling and non-scaling surface conditions. Also, use of carbonate scale inhibitors that affect the equilibria between CO_2, HCO_3^-, and $CO_3^=$ may well change the CO_2 content of gas through the orifice meter. Sampling and analysis should be scheduled to provide quantitative data on these questions during future well tests.

12.12 Solids Production, Scaling, and Corrosion

Production test data was not obtained from the primary target aquifer for this test (14,976 to 15,024 foot depth) due to excessive solids production during cleanup after perforating. Solids production included chunks of formation material with linear dimensions as great as one inch.

The depth interval actually tested (14,782-14,820 feet) contained an estimated 14 feet of net pay. Thus the flow rates of 1800-7000 BPD translate to rates of 125-500 BPD per foot of pay sand thickness. The production rate per perforation was in the range of 0.01 to 0.045 BPM. This rate was accompanied by substantial production of grains of formation material.

Direct observation of solids production is discussed in Section 12.12.1. Then Sections 12.12.2 through 12.12.4 provide details of analysis of samples of solids. Section 12.12.5 presents additional data on scaling and corrosion.

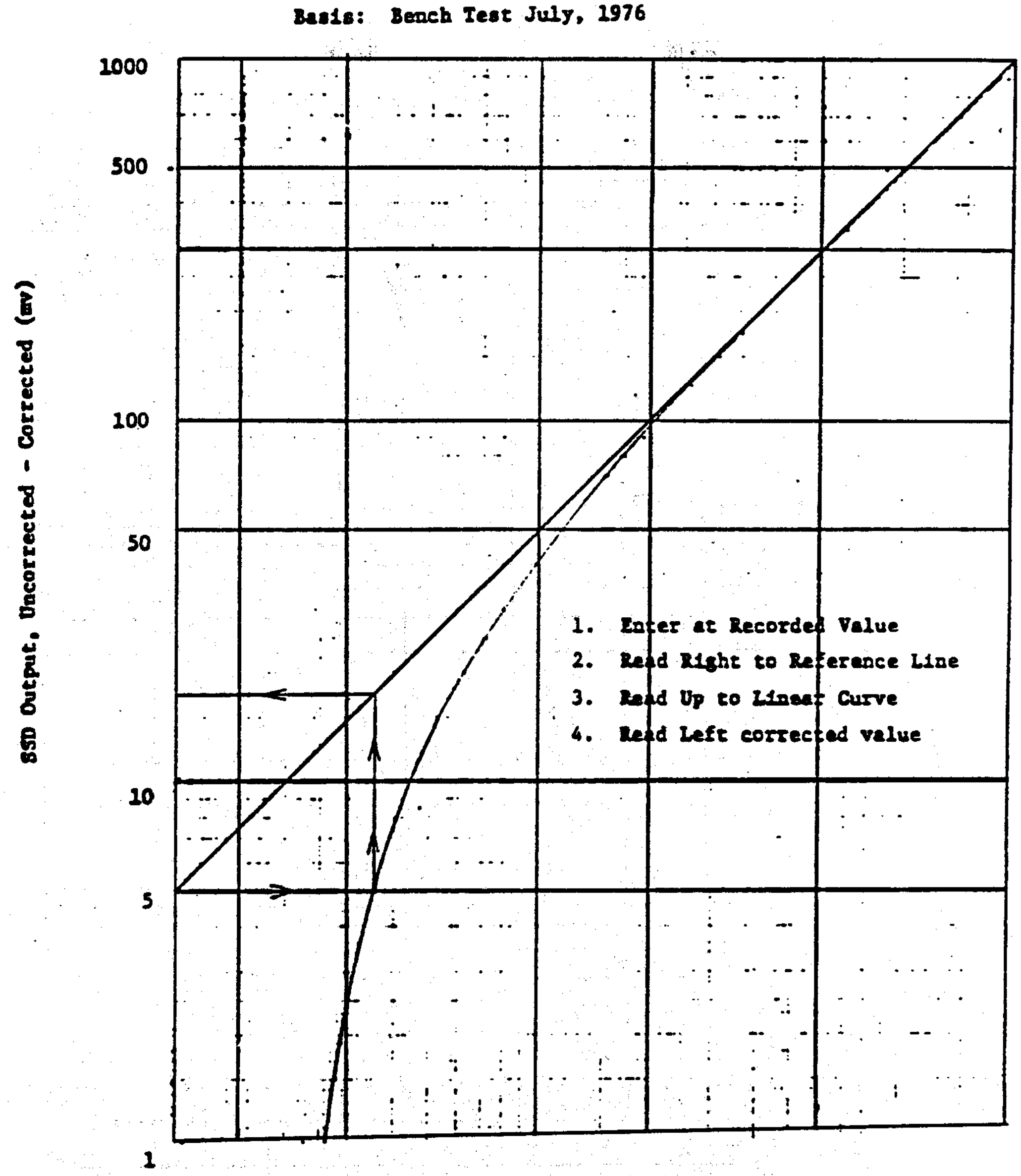
12.12.1 Direct Evidence of Solids Production

Direct evidence of sand production was provided by both electronically recorded data and visual observations. Six categories of such evidence are discussed under the following subheadings:

12.12.1.1 Sonic Sand Detector Data: An Oceanography International Corporation (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 having an inside diameter of 3.862 inches. This installation provided very low sensitivity for the flow rates used in the experiment.

Exhibits 12-49 and 12-50 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 12-49 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, the previous discussion of the recorded sand detector signal (shown graphically in Exhibit 12-13, 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.

Entering Exhibit 12-50 the sand detector probe calibration chart reveals the following minimum detection thresholds for sand:

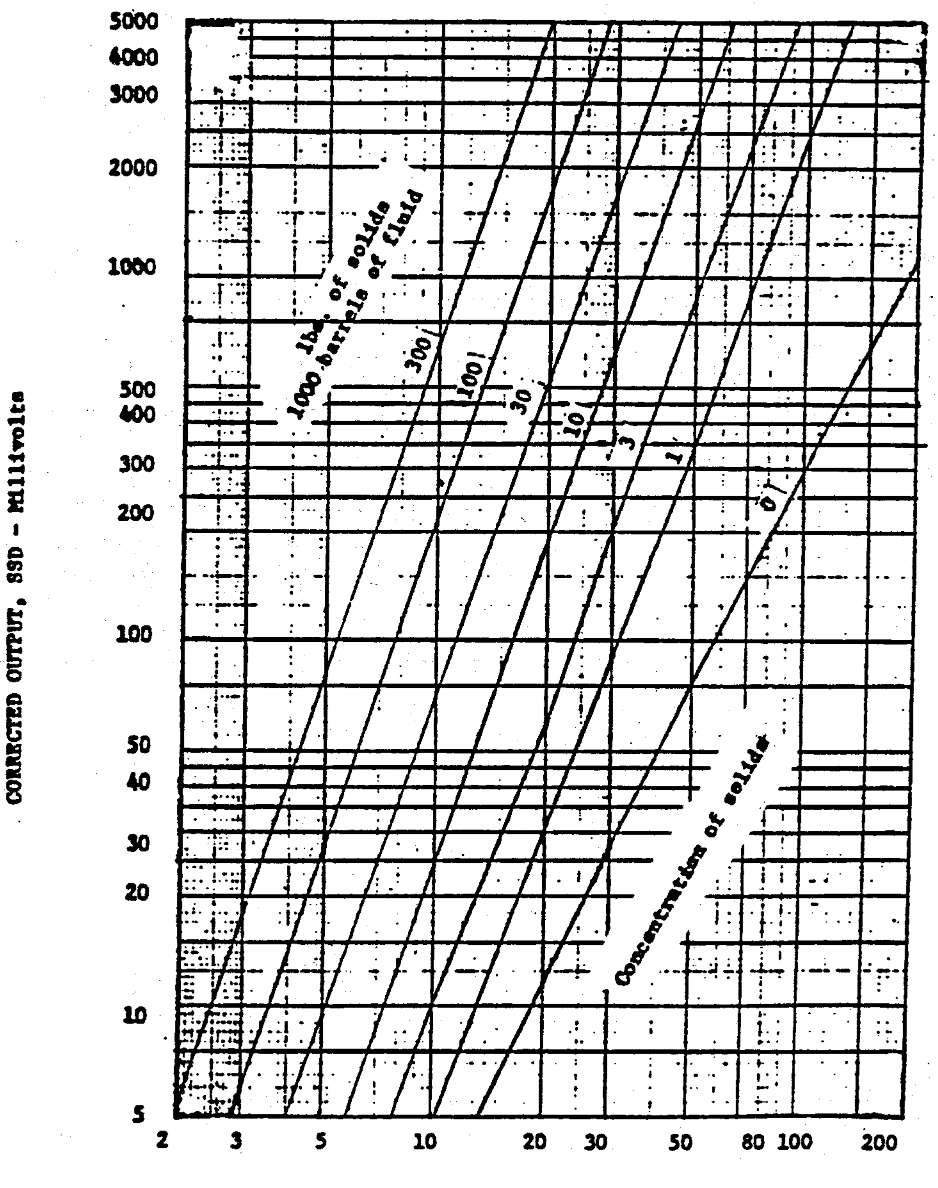


Source: Oceanography International Corporation, "Sonic Sand Detector, Model 582-SSD, Model 563-SSD," Appendix A. College Station, Texas, Revised April 1980.

CORRECTION FOR NONLINEARITY OF AC-DC CONVERTER

EXHIBIT 12-49

Liquid Flow System (GOR = 0)
Basis: Test in 8-inch line using water/Ottawa No. 3 sand)



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

PROBE CALIBRATION

EXHIBIT 12-50

Threshold for Sand Detection

Flow Rate (BPD)	Velocity (ft/sec)	Detectable Sand Concentration* (pounds/1000 bbls)
1800	1.47	>1000
4000	3.26	270
4500	3.66	170
6000	4.88	75
7000	5.70	45

*Based on Ottawa No. 3 sand in an 8-inch line. Validity for the fine sand and silt produced has not been determined.

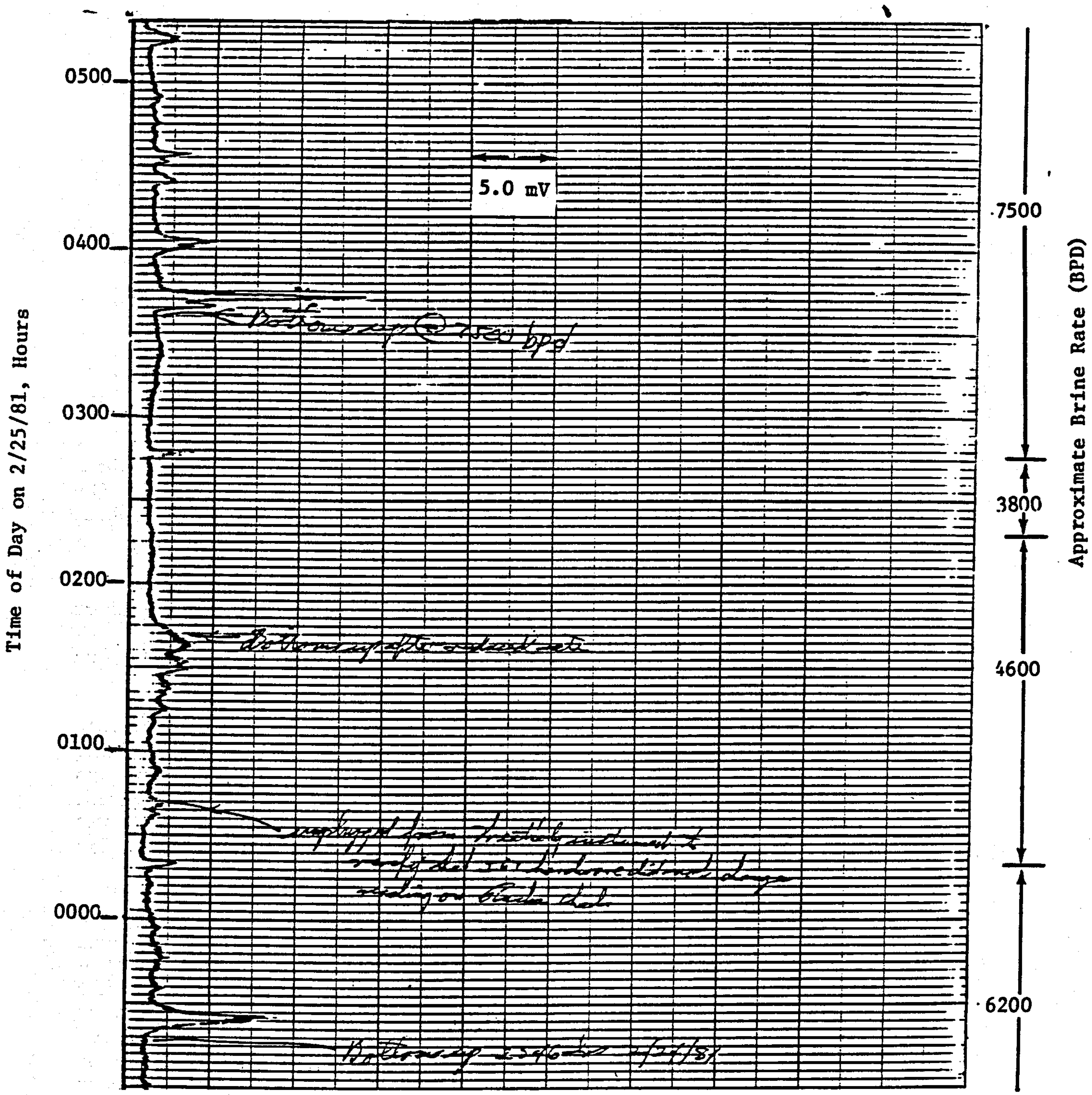
The flow rates tabulated above are values representative of various time intervals during the test sequence. It is apparent that very large amounts of sand could have been produced without detection during the first flow test at 1800 BPD.

The only digitally-recorded sonic sand detector signals that are clearly real were those observed after the brine production rate was increased to 7000 BPD on 2/27/81. The recorded peak values of about 35 millivolts correspond to a sand production rate of about 100 pounds of sand per 1000 barrels.

In practice, detection of "slugs" of sand below the thresholds set forth above was accomplished in the field. Exhibit 12-51 shows a portion of the field strip chart recording of sand detector output on a very expanded scale. This recording reveals several peaks having amplitudes in the range of 2-10 mv and durations as short as a few minutes.

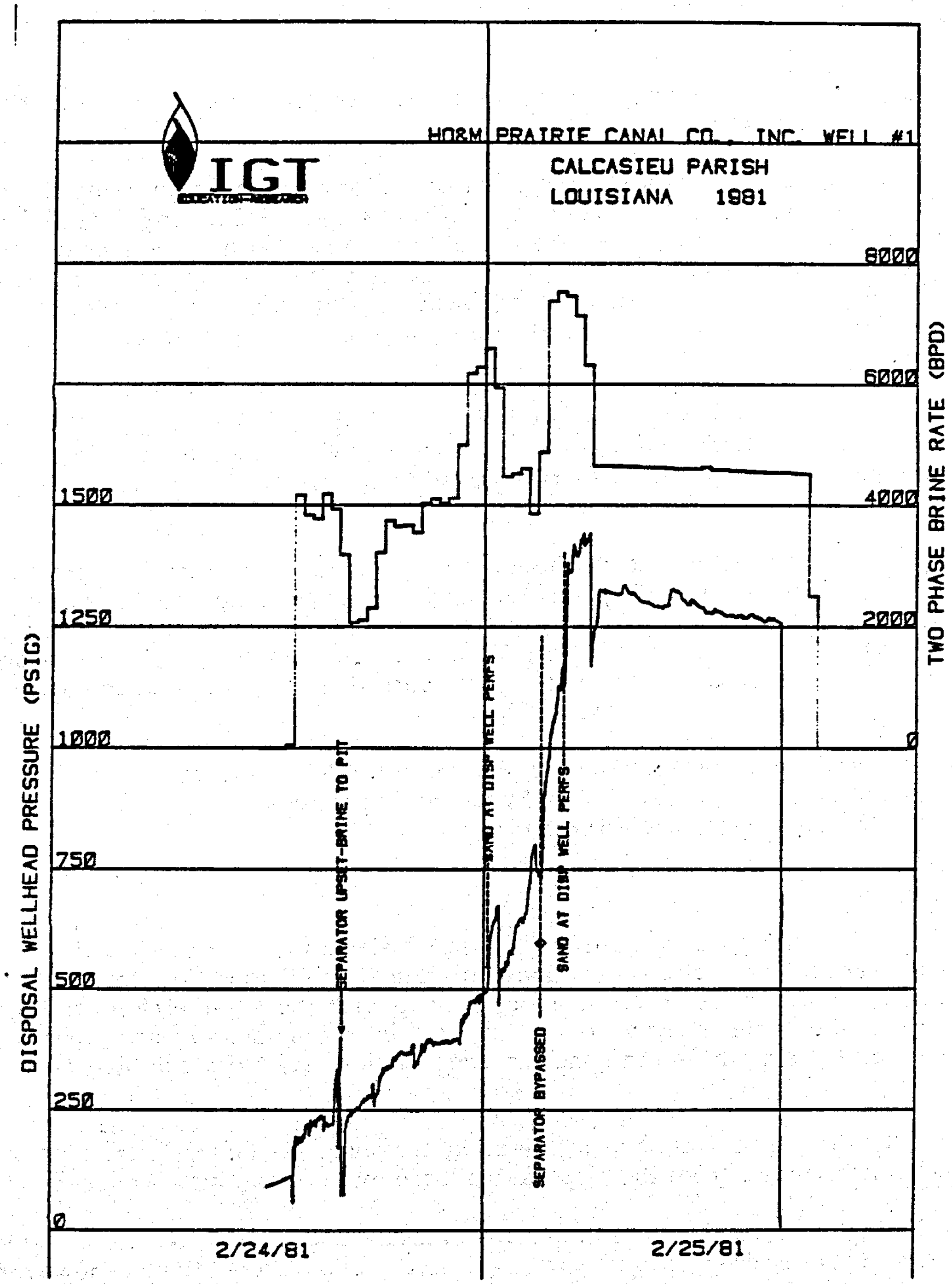
The correlation of these small peaks in sonic sand detector signal with prior brine rate increases and subsequent increases in disposal wellhead pressure provides convincing evidence that these small fast peaks are indeed due to "slugs" of sand. The two handwritten notations of "bottoms-up" on Exhibit 12-51 were made before the subsequent sand detector peaks were actually observed. The basis for these marks was 250 barrels of production (volume of the production well), as indicated by the two-phase wellhead turbine meter, after opening the choke to increase the flow rate.

Exhibit 12-52 shows the jumps in disposal wellhead pressure when these two "slugs" of sand reached the perforations in the disposal well. The times of the dotted lines labeled "SAND AT DISP WELL PERFS" correspond to 130 barrels (disposal wellbore volume) of production after the start of each of the two discussed peaks in sonic sand detector signal. Similar correlations between changes in production well pressure, a sand detector peak 250 barrels later, and a jump in injection pressure 130 barrels later were observed for numerous sand detector signals as small as 2 millivolts. The particular two cited as examples were chosen because all other parameters were constant through the times of interest.



FIELD STRIP CHART RECORDING OF SAND DETECTOR OUTPUT
ON EXPANDED SCALE, 2/25/81

EXHIBIT 12-51



DISPOSAL WELLHEAD PRESSURE AND
TWO-PHASE BRINE RATE, 2/24-25/1981

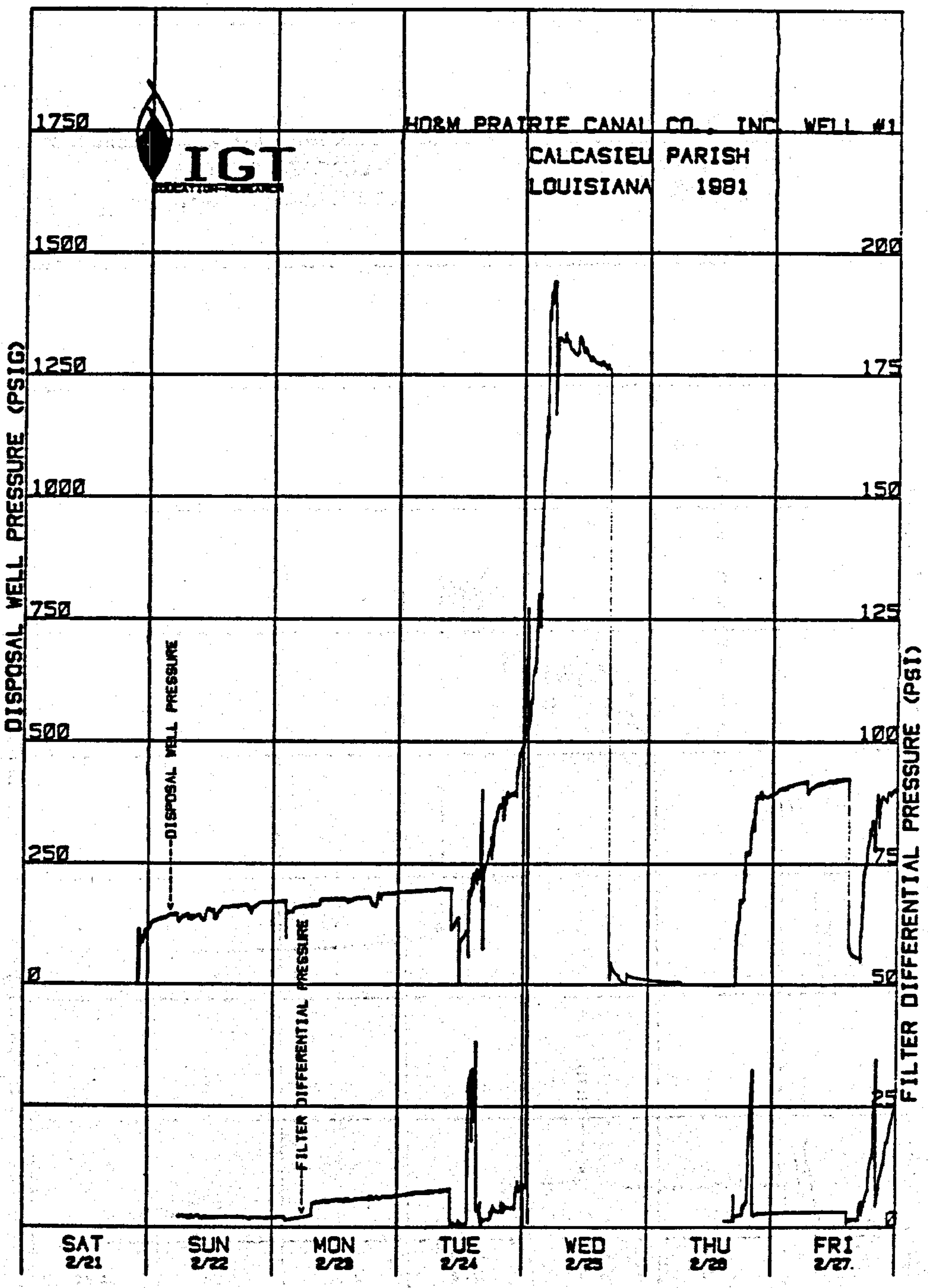
EXHIBIT 12-52

12.12.1.2 Correlation of Disposal Wellhead Pressure with Sand Detector Signal: Exhibit 12-52 shows brine production rate as well as disposal wellhead pressure for the second flow test. The scale for 1/2-hour averages of two-phase wellhead turbine brine rate is on the right side of the chart. Close examination of this exhibit reveals several producing characteristics in addition to the correlation cited above. These include:

- As expected, rapid changes in disposal wellhead pressure occurred at the times of brine rate changes.
- Injection pressure became virtually constant for three hours starting three hours after rate was reduced to about 2000 BPD during 2/24/81. The three-hour delay is the time required for the 480 barrels of production between reduced rate of fluid entering production well perforations and the subsequent passage of that same fluid through disposal well perforations. During the three hours of constant injection pressure, produced sand, if any, was apparently dropping out in surface facilities.
- When the flow rate was increased from 4000 BPD to about 6000 BPD at 2245 hours on 2/24/81, the climb in injection pressure resumed before 480 barrels of fluid had been produced. This is believed to be due to washing of deposited sand from surface facilities.
- The immediate effect of entrained gas upon injection pressure was modest in relation to pressure buildup due to sand. Such gas, due to bypassing of the separator, first hit the disposal perforations while injection pressure was passing 1000 psi. Examination of Exhibit 12-52 reveals roughly 100-150 psi of pressure increase over and above the rate of increase due to entrained sand at the same time.
- Very small sand detector peaks on Exhibit 12-51 correlate with subsequent injection pressure jumps. This correlation is particularly apparent at the times of the highest injection pressures shown.

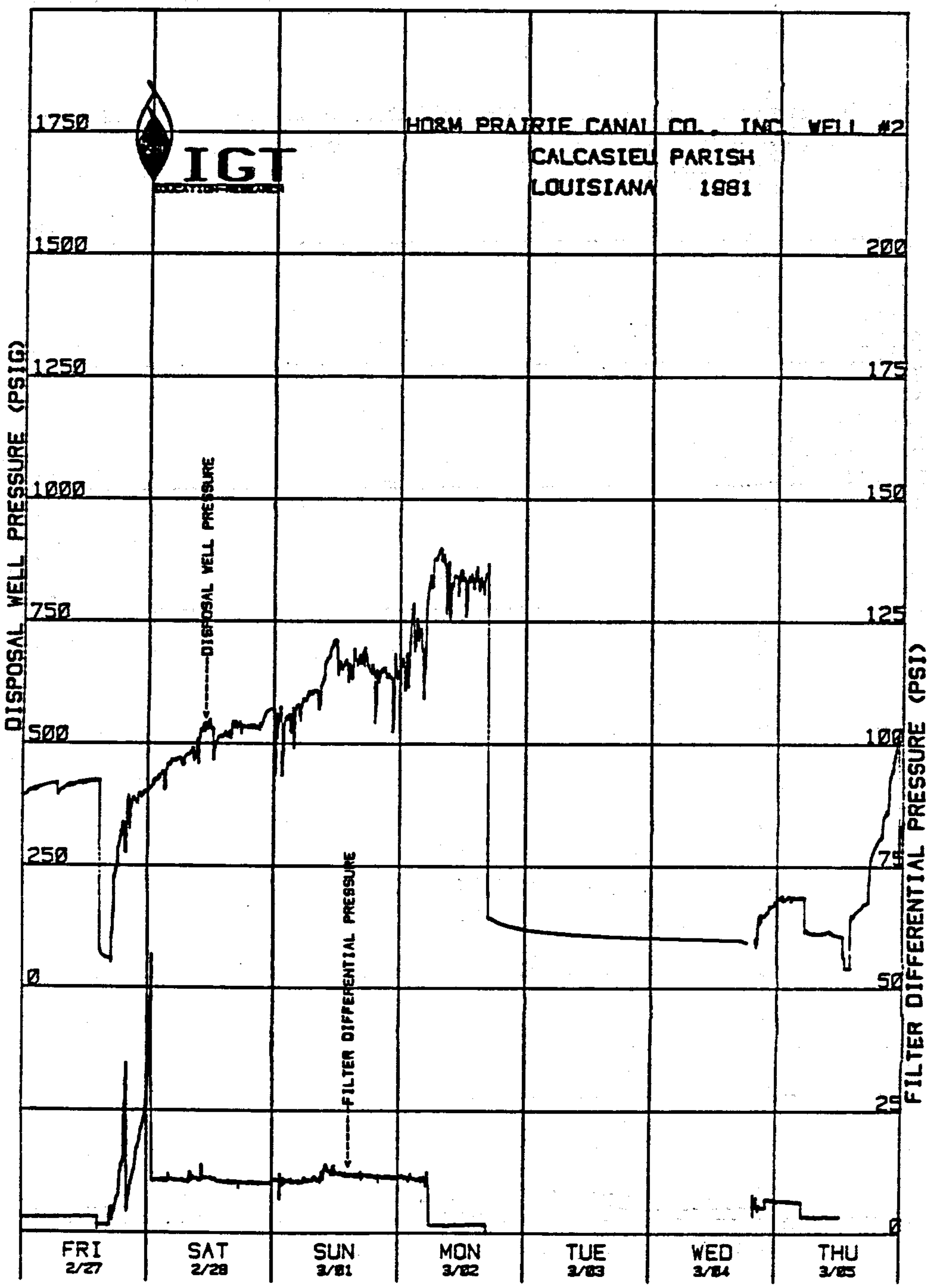
12.12.1.3 Chronological Discussion of Data Relevant to Sand Production: Exhibit 12-53, Parts I and II, shows disposal wellhead pressure for all four flow tests. The scale is on the left and the zero is offset to avoid overlap with the filter differential pressure trace for which the scale is shown on the right. In chronological order, observations regarding correlations of these data and suspended solids data from Exhibit 12-28 to sand production are as follows:

- **2/21/81:** The initial buildup in injection pressure was largely due to flushing of high salinity brine from the disposal wellbore by lower salinity produced brine.
- **2/22/81:** The slow buildup in injection pressure and lack of associated buildup in filter pressure drop suggest little, if any, solids production. However, the suspended solids content of 370 mg/l observed at 1520 hours translates to 0.13 pounds per barrel of brine or production of about 230 pounds of solids in 24 hours



Part 1. DISPOSAL WELLHEAD AND FILTER DIFFERENTIAL PRESSURES

EXHIBIT 12-53



Part 2. DISPOSAL WELLHEAD AND FILTER DIFFERENTIAL PRESSURES

EXHIBIT 12-53
(cont'd)

at a brine production rate of 1800 BPD. Also, the dips in disposal wellhead pressure are provocative in that each has a duration of about the time required to displace one disposal well volume. It is suspected that these dips are initiated by temporary blockage of the separator dump valves or of surface piping by high concentrations of sand or silt in brine from the separator.

- **2/23/81:** A separator upset characterized by brine production out the flare line occurred at 0240 hours. Brine from the separator was diverted to the pit at that time and was observed to be very muddy. At 0310 hours brine flow was switched to a different filter unit. Subsequent inspection of the unit previously used revealed a few pounds of silty mud in the bottom of the filter housing, but the elements appeared clean. Pressure drop across the new filter unit increased throughout the day. The jump in filter pressure drop at 0740 hours and jump in injection pressure 130 barrels later coincided with a transient drop in separator pressure that may well have been associated with a slug of solids from the separator. On the other hand, the trend of increasing filter pressure drop did not change at the times of the two subsequent dips in injection pressure on this date.

- **2/24/81 End of First Flow Test:** A suspended solids sample collected at 0845 hours contained only 35 mg/l (12 pounds/1000 BBLs) of suspended solids. Slow buildup of disposal wellhead pressure and filter differential pressure continued until the well was shut-in at 1013 hours.

- **2/24/81 Shut-in:** The disposal wellhead master valve was closed when the production well was shut in. Thus recorded disposal wellhead pressures have no significance. During this shut-in (1) inspection of the choke revealed minor erosion but not enough to warrant replacement, and (2) the sump below the sand detector and the line to the disposal well were found to contain only small amounts of silty solids. No new scale was observed.

- **2/24/81 Start of Second Flow Test:** Production was resumed using the same filter unit as at the end of the first flow test. In ten minutes, filter pressure drop had increased to more than 25 psi at a brine rate of about 3800 STB/D. Although rate had only been doubled, filter pressure drop had more than tripled. This is presumed to be due to the flushing of solids from the separator by the higher brine rate. At bottoms-up, filter pressure drop increased rapidly to 38 psi, so flow was diverted to a new filter unit. When the brine produced from the formation at this new rate hit the disposal well perforations, injection pressure increased rapidly from 230 psi to 400 psi, causing brine production to the flare line. Blowing to the pit to "backsurge" the disposal well produced muddy water but little reduction in injection pressure. Brine rate from the disposal well was reduced to about 1900 STB/D. A sample of brine that had entered production well perforations at a rate of about 3800 BPD was found to contain 200 mg/l (70 pounds/1000 GPD) of suspended solids. Pressure buildup on the new filter unit was not consistent with the continuing buildup in injection pressure and correlations with sonic sand detector readings previously discussed in Section 12.12.1.2.

- **2/25/81:** Filters were bypassed because of the 600-psi working pressure rating of their housings. At 0315 hours the separator and associated instrumentation were also bypassed. Associated correlations of disposal wellhead pressure with sand detector readings were discussed in Section 12.12.1.2. At 1630 hours separator operation was resumed with brine from the separator flowing to the reserve pit. After 1-3/4 hours of production data had been collected, the production well was shut in. A suspended solids sample collected at 1700 hours contained only 20 mg/l (7 pounds/1000 bbls) of solids from brine produced at 4100 STB/D. Thus a very substantial reduction in solids production had apparently occurred.

- **2/26/81:** Production was resumed at about 2250 STB/D after perforating a new disposal aquifer. At this rate injection pressure leveled out at about 175 psig without prior acidizing. No sand detector signal or pressure jumps were observed when the newly produced brine passed through surface facilities and reached disposal well perforations. Rate was then increased to about 6500 STB/D, giving a filter pressure drop of 5 psi and an injection pressure of 270 psig. Although no sonic sand detector signal was observed, bottoms-up resulted in rapid buildup of filter pressure drop. Flow was switched to a new filter unit after pressure drop reached 33 psi in less than an hour. Similarly 120 barrels later injection pressure increased rapidly from 270 psig to 400 psig. Brine rate was then reduced to about 4500 STB/D. All data suggest that sand production, if any, was minimal at this rate.

- **2/27/81:** Although production was proceeding smoothly at 4500 STB/D, emphasis continued to be upon maximum rate production from the 14 feet of net pay. Therefore at 1440 hours separator output brine was diverted to the pit for acid treatment of the disposal zone. The pump truck operator reported that injection pressure dropped sharply when fresh water reached the disposal well perforations. The operator also stated that little if any further pressure drop occurred as acid was displaced through the perforations. No recorded data is available to support the operator's statements. Brine rate was increased to about 7500 STB/D while flowing to the pit. Bottoms-up was accompanied by sonic sand detector indication of about 100 pounds of sand per 100 bbls of brine. An hour after bottoms-up, separator output brine was switched from the pit to the filters and disposal well. Since filter pressure drop buildup was not consistent with sonic sand detector readings, flow was switched to another filter unit after 1/2-hour. At about this same time disposal wellhead pressure was 170 psig, and sand-laden brine reached disposal well perforations. Less than three hours later the flow was switched to a new filter unit because pressure drop had increased to 35 psi and disposal wellhead pressure had increased to almost 400 psig. Filter loading and buildup of injection pressure continued for the rest of the day at a reduced rate. By the end of the day sand detector readings were at the threshold of about 45 pounds/1000 bbls for detection at a brine rate of 7000 STB/D.

- **2/28/81-3/2/81:** Production continued at 6000-6500 STB/D until the end of the third flow test at 1645 hours on 3/2/81. About two dozen sand detector spikes with amplitudes of 2-5 millivolts appear to be due to slugs of sand with concentrations in the range of 50-75 pounds/1000 bbls. Whether multi-hour changes of this same magnitude in sand detector signal are due to sand or other effects has not been resolved. Lack of buildup of filter pressure drop after switching to a new filter at 0055 hours on 2/28/81 suggests lack of sand production. On the other hand, continuing buildup of disposal wellhead pressure to over 800 psi makes it more probable that produced solids were passing through the filter unit.

A brine sample suite collected at 1230 hours on 2/28/81 contained 30 mg/l (10.5 pounds/100 bbls) of suspended solids.

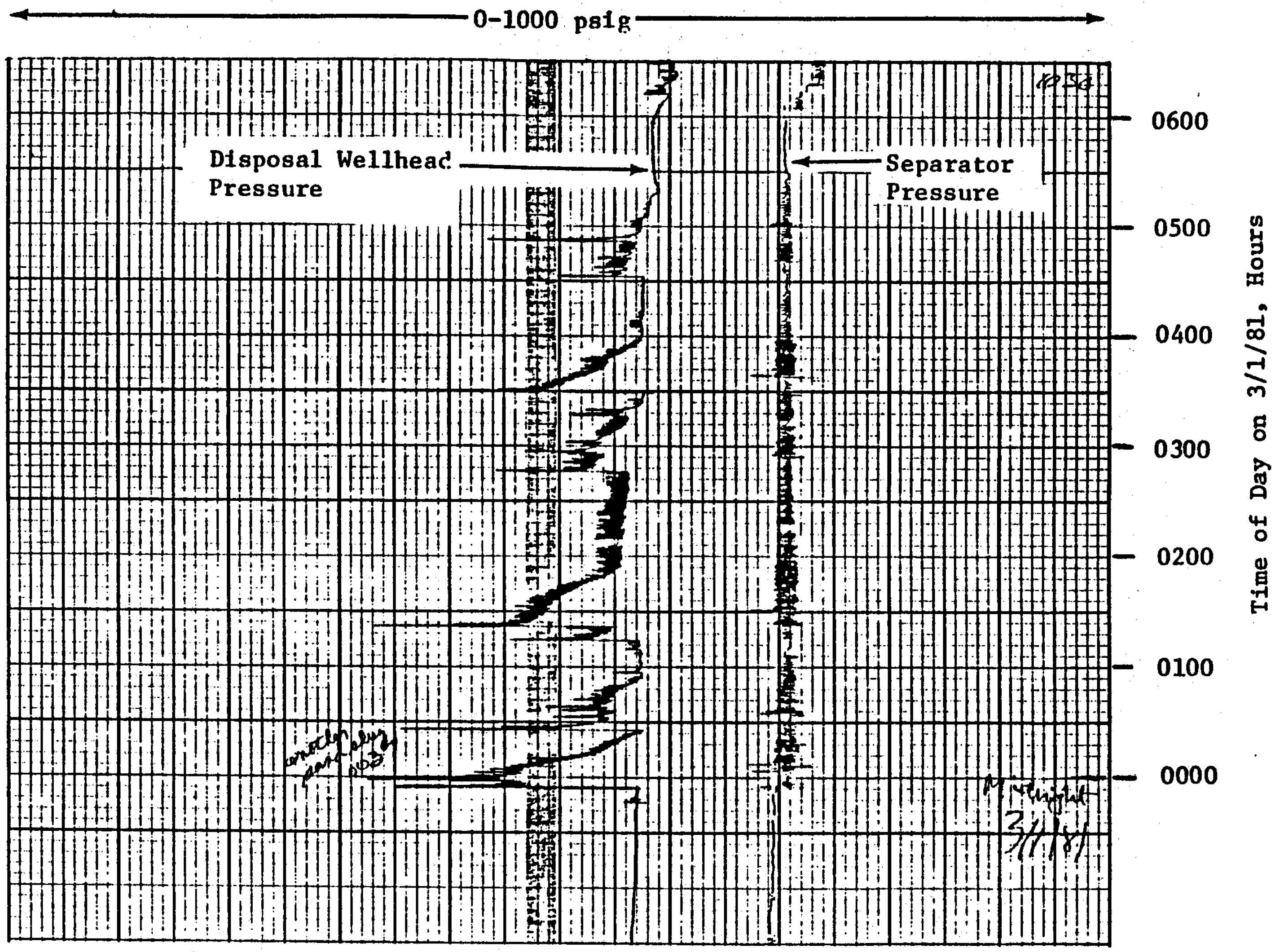
The numerous drops in disposal wellhead pressure may be related to solids injection into the disposal well. However this relationship is not clear. Real-time recording of several such drops is shown in Exhibit 12-54. A striking feature is that the characteristic pressure recovery time of 1/2-hour is the time required for fluid transit from the surface to the disposal well perforations. This makes downhole origin unlikely. These pressure drops are not due solely to sudden unloading of sand from surface facilities to the disposal well. This is because (1) many cubic feet of sand would be required, and (2) a disposal wellhead pressure jump should occur when such sand hits the perforations. It is suspected that gas accumulation in the disposal wellhead may be involved in the observed pressure behavior. However the initial sharp pressure drop is probably due to temporary dump valve or surface piping blockage by sand.

Disposal well pressure shown on Exhibit 12-53, Part II, declining from 145 psig after shut-in of the production well is a valid measurement.

- **3/3/81 and 3/4/81:** At 1400 hours brine was bled from the bottom of the separator using the driving force of gas trapped at 135 psig above the brine. Initial flow contained a high concentration of fine-grained sand. The grain size decreased to silt or clay before breakthrough of brine. The separator clearly contained a large quantity of solids. Shut-in disposal wellhead pressure had declined to 95 psig before the pressure transmitter was isolated from the wellbore at 1800 hours on 3/4/81. Then, at 1915 hours, an injection pump to be used to dispose of brine in the reserve pit was tested by pumping into the disposal well. Injection pressure while pumping reserve pit brine at about 8500 BPD was only 110 psi. In contrast during production at 6000 BPD on 3/2/81 injection pressure had been over 800 psig.

  Production testing resumed at 3800 STB/D at 1940 hours on 3/4/81. There was no indication of sand at bottoms-up, so rate was increased to 4300 STB/D at 2215 hours. At midnight, disposal wellhead pressure had only increased to 180 psig.

- **3/5/81:** Production testing continued at an average rate of 4200 STB/D until 0500 hours. Injection pressure remained constant at only 185 psig and neither the sonic sand detector nor the filter pressure drop gave any indication of sand production. Separator output brine was then diverted to the pit and brine production rate was reduced to 1760 STB/D, so that data could be obtained on separator performance at low separator pressure. The first few minutes of brine flow to the pit was very muddy. After about 1/2-hour the brine appeared clean. However, a brine sample collected at 1008 hours was found to contain 153 mg/l (54 pounds/1000 bbls) of suspended solids.



FIELD STRIP CHART RECORDING OF DISPOSAL WELLHEAD PRESSURE

EXHIBIT 12-54

The initial disposal well shut-in pressure of 120 psig declined to 105 psig in seven hours. Shortly before 1400 hours, pumped injection of reserve pit brine into the disposal well commenced at a rate of about 8500 BPD. The initial injection pressure was only 140 psig. It had increased to 180 psig when a separator output brine rate of 4500 STB/D was added, at 1718 hours. The combined injection rate of about 13,000 BPD caused a jump in injection pressure to 220 psig. When the combined flow reached disposal well perforations, injection pressure jumped to 245 psig and then continued to increase, reaching 310 psig 2-1/2 hours later at 2000 hours. Brine production rate was then increased to 6500 STB/D, increasing combined injection rate into the disposal well to about 16,000 BPD. Disposal wellhead pressure jumped to 350 psig and then continued increasing at about the same rate as that prior to increasing brine rate. When the first brine through production well perforations at 6500 STB/D hit the disposal well perforations, disposal well pressure began to increase more rapidly. Between 2100 hours and shut-in of production at 2305 hours, disposal wellhead pressure increased from 375 psig to 525 psig. One-half hour after shut in of production, disposal wellhead pressure for continuing pump injection of reserve pit brine at about 8500 BPD was 325 psig. Ten hours later it had increased to 425 psig. The only direct evidence for movement of solids during the fourth flow test was (1) visual observation of muddy water when separator output brine was diverted to the reserve pit, (2) suspended solids collected on filter paper at 1008 hours, and (3) the rapid increase in injection pressure while producing 6500 STB/D of brine. No sonic sand detector signals were clearly above the threshold for detection. Filter pressure drop did not increase during times when brine flowed through filters. No dips in disposal wellhead pressure, such as previously illustrated in Exhibit 12-53 were observed.

- **3/6/81:** Surface facilities were examined for evidence of solids production. Inspection of the choke clearly indicated sand production during high rate flow. Although the stem and seat were in excellent shape, the skirt downstream of the seat had been cut through by sand, and appreciable erosion of the choke body had occurred.

  Both ends of the separator were found to contain sand about 14 inches deep. Large amounts of sand and silt had passed over the weir that divides the lower portion of the horizontal separator into two compartments. Assuming a bulk density of 100 pounds/ft^3, the separator is estimated to have contained about 2700 pounds of sand and silt.

12.12.2 Analyses of Formation Material

Plans for the production test of the aquifer between depths of 14,976 and 15,024 feet were abandoned due to production of chunks of formation material during cleanup after perforation. Several such chunks, with linear dimensions in excess of 5 mm, were submitted to Walter C. McCrone Associates, Inc. (McCrone) for electron microscope examination. The complete McCrone report, including 23 photographs, is in Appendix O.

These samples of formation material are from unknown locations within a Hackberry Sandstone 200 feet deeper than the depth interval 14,782 to 14,820 feet actually tested. Nevertheless, the analyses are assumed relevant in relation to mineral species present.

After water washing, the formation chunks were divided into five categories on the basis of visual examination according to grain size, texture, and color. Representative samples from each of the three most abundant categories were than examined with the electron microscope. In summary, results showed that:

- Type 1 sandstone had linear cracks filled with well-crystallized kaolinite. Crystals of pyrite and glauconite (an iron-bearing mineral) were also present.
- Type 2 sandstone contained many feldspar grains, some of which appeared to be dissolving. Kaolinite was again found filling the grain boundaries. Glauconite, barite and pyrite were also detected.
- Type 3 sandstone had chunks of fine-grained feldspar or illite, or both, in a coarse-grained quartz matrix. Calcite and kaolinite were present as well-formed crystals. An unidentified crystal containing sodium, aluminum, and silicon was also observed.

12.12.3 Analyses of Suspended Solids

Six samples of suspended solids trapped on a 0.45-micron membrane filter were obtained concurrently with the collection of filtered brine samples downstream from the separator. The amounts of solids collected varied between 20 and 370 mg/l, as previously shown in Exhibit 12-28 (Section 12.10.5.1) and discussed in Section 12.12.1.3. Three of the samples were selected for x-ray diffraction (XRD) and x-ray fluorescence (XRF) analyses. Results of these analyses are shown in Exhibit 12-55.

The major difference in analytical results was a decrease in the amount of barite detected between the first day sampled and the latter two days. This decrease in barite would be consistent with the assumption that the barite produced was not formation material but was material injected into the well as drilling mud, that was being flushed out as the well flowed. However, this decrease in barite is not supported by a corresponding decrease in barium in the filtered brine. The barium in the three analyzed brine samples increased with time (Exhibit 12-28, Section 12.10.5.1). Although iron was found by XRF to be a major component in two of the three samples of suspended solids, no iron compounds were detected by XRD. The peaks in the iron compounds diffraction pattern were probably masked by the peaks in the patterns of other crystalline compounds present.

Sample Date and Time	Compounds Identified (XRD)		Elements Found (XRF)		
	Major	Minor	Major	Minor	Trace
22 Feb 1981 1030 370 mg/ℓ	$BaSO_4$ (Barite) NaCl α-SiO_2	$CaCO_3$ (Aragonite)	Ba,S,Al,Fe Cl,Si,K	Ca,Ti, Sr,P Ni,Zn	As,Cu
25 Feb 1981 1700 20 mg/ℓ	NaCl α-SiO_2	$CaCO_3$ (Aragonite) $BaSO_4$ (Barite)	Cl, Al, Si	Fe,Ca,K P,Zn,S,Ba,Ti,Ni	Sr,Cu
5 March 1981 1008 153 mg/ℓ	NaCl α-SiO_2	$CaCO_3$ (Aragonite) $BaSO_4$ (Barite)	Cl Al,Si,Fe K,Ca	P,S,Ba,Ti Zn,Ni,Sr	Cu

COMPOSITION OF SUSPENDED SOLIDS SAMPLES FROM THE HO&M PRAIRIE CANAL CO., INC. WELL NO. 1

EXHIBIT 12-55

12.12.4 Analyses of Solids Samples From Surface Hardware

Solids produced by the well are of three types. These are (1) materials introduced into the well by man (i.e., drilling mud), (2) formation material (sand and clays), and (3) solids resulting from the precipitation of species that were in solution in the brine at reservoir temperature and pressure. Scaling in surface facilities results from a portion of the precipitated solids becoming bonded to the steel walls of the surface piping and vessels. The sample collection and analysis procedures used were designed to provide estimates of portions of solids in each of these types.

Section 12.12.4.1 describes collection of samples of filter housing solids, solids in the separator, and a scale sample. Analytical procedures used and results of most analyses for these samples are described in Section 12.12.4.2. Section 12.12.4.3 through 12.12.4.5 contain discussions and the remaining analytical results for each of the three samples of solids analyzed by IGT.

12.12.4.1 **Collection of Samples of Produced Solids:** Field observations at the time of sample collection, plus details of sample collection and compositing for each of the three samples analyzed in detail in the laboratory, are described below.

- **Solids from Filter Holders:** Filter units in use were switched several times during the test, due to development of excess pressure drop. When filter elements were replaced, samples were collected from the sludge in the bottom of the pressure vessel containing 20 individual filter elements. In all cases, the filter elements were found to be loaded with gray clay-like material. The sludge from the bottom of the vessels was similar in color and texture. Total quantity of solids on the filter elements and of the sludge was roughly five pounds in each case.

  Samples of sludge from the bottom of the pressure vessel, rather than solids on the filter elements themselves were selected, to minimize laboratory problems caused by filter fibers in the sample.

  Equivalent amounts of sludge collected at three different times were combined into a single composite sample for laboratory analysis. The samples in the composite were from filters that developed high pressure drops on 2/24/81, 2/26/81, and 2/27/81. Thus, the analysis is representative of material caught by filters during the early high-rate production.

- **Solids From the Separator:** Samples from the separator were collected only after the third flow test and after the fourth flow test. Neither suite of samples is considered a valid representation of the overall average distribution of solids inside the separator. On 3/4/81, after the third flow test, three one-liter bottles of solids-laden brine were collected about a minute apart while draining brine from the bottom of the separator. The solids settled to 1/3 to 2/3 of the height of each bottle. The first sample was primarily gray fine-grained sand, whereas almost half the solids in the last bottle were a black clay-like material. The appearance of the solids in the second bottle was between these two.

On 3/6/81 after the fourth flow test, samples were collected from inspection ports on the ends of the separator, after dirty brine had been bled off the bottom. The top of the solids in both ends of the separator was above the 4-inch ID ports. Sand was scraped out of each port by hand to form near-vertical surfaces about a foot into the sand bank. Handfuls of sand from various exposed layers with differing visual appearances were then placed in sample bottles. Although layers of varying appearance and texture were observed at both ends of the separator, outlet end material (from the "oil dump" side of the weir) generally had smaller grain size and darker color than solids at the inlet end.

The sample selected for laboratory analysis was a stirred composite of roughly equal amounts of material taken from the two ends of the separator on 3/6/81. Samples collected on 3/4/81 are in storage but no analyses have been performed.

- **Scale Sample:** On 2/26/81, the thin buildup of scale from three prior well tests was chipped from a few square inches of interior surface of pipe between the filters and the disposal well. Then, on 3/6/81, scale was again chipped from a portion of this same area for analysis. This latter scale was less than 0.01 inches thick, including rust that adhered to the pipe side of the scale samples. The largest chip contained rust-free spots as large as 1/8-inch across. These were colorless and translucent to daylight.

12.12.4.2 **Analytical Procedure for Samples of Solids:** Chemical and physical analyses of each of the three samples by IGT consisted of (1) x-ray diffraction analysis, (2) chemical analysis for selected cations plus carbonates, (3) particle size distribution measurements, and (4) microscopic examination. Methods used and results from the first three of these are described in the rest of this section. Results of microscopic examination are provided in the three subsequent sections, which provide discussions of each sample.

- **X-ray Diffraction Analyses:** These analyses were performed for portions of each sample to identify minerals present after three pretreatment procedures. The pretreatment procedures were (1) deionized water wash to remove water-soluble precipitates that formed due to brine evaporation, (2) cold <u>1N</u> hydrochloric acid wash to break up particles bonded by carbonate precipitation from produced brine, and (3) refluxing in boiling <u>6N</u> hydrochloric acid to dissolve all carbonate species present. Results of these analyses are tabulated in Exhibit 12-56.

- **Chemical Analysis for Selected Cations plus Carbonates:** The primary objective of the multi-step analytical procedure described below was estimation of the relative amount of carbonate precipitate in each sample. Steps in analysis and results are:

  1. <u>Determination of Initial Weight</u>

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

Water Washed	Scale	Solids From Filter Holders	Solids From Separator
Major (1-100%)	Calcite	Barite α-Quartz	α-Quartz Barite
Minor (0.01-1%)	Barite	Calcite Aragonite NaCl	Albite
1N HCl Washed			
Major	Barite	Barite α-Quartz	α-Quartz Barite
Minor	—	—	Albite
6N HCl Washed			
Major	Barite	Barite α-Quartz	α-Quartz Barite
Minor	—	—	Albite

Ref. No. 45328, 33-35, 39-40

X-RAY DIFFRACTION ANALYSIS OF SOLIDS COLLECTED FROM THE HO&M PRAIRIE CANAL CO., INC. WELL NO. 1

EXHIBIT 12-56

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 12-57(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 12-57(A).

The previously described x-ray diffraction analysis was then performed to identify compounds in crystalline form in the samples. The only remaining crystalline species identified from the scale sample was barite. Acid insoluble residue from the filter housings contained both barite and quartz. Quartz was the predominate mineral species remaining in residue from the separator. Barite and a small amount of albite ($NaAl\ Si_3O_8$) were also identified in this sample.

5. Analysis of Acid Solution

The volume of the acid solution from Step 3 was measured. The solution was then analyzed 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 12-57(A).

6. Balance Cations with Observed CO_2

Step 5 above defined the weight percent of the initial sample for seven species that were cations of molecules in that sample. The first calculation performed to deduce probable associated anions was calculation of CO_2 that would have been liberated in Step 2 above, if all of the calcium and magnesium were in carbonate form in the initial sample. Results of this calculation are shown in Exhibit 12-57(B). This calculation provided close agreement with measurement of acid-liberated CO_2 for the samples from the filter holders and separator. However, for the scale sample the weight percents of calcium and magnesium were not sufficient to account for all the acid liberated CO_2. Further, the only identified cation with sufficient abundance to account for the "missing" CO_2 from solids on the filters was iron. It was therefore assumed that iron carbonate (siderite) was a component of the solids. The sample weight percent of iron

A. Analysis of Samples

Sample Description	Wt % 6N HCl Soluble Solids								Wt % 6N HCl Insoluble Residue
	CO_2	Na	K	Ca	Mg	Sr	Ba	Fe	
Scale	39.5	0.12	0.013	27.3	0.49	0.89	1.9	12.5	0.3
Solids from Filter Holder	4.3	0.87	0.097	3.5	0.17	0.11	1.6	3.4	77.0
Solids from Separator	0.9	0.50	0.11	0.52	0.12	0.02	1.2	1.9	89.7

B. Sources of Acid Liberated CO_2

Sample Description	CO_2 (wt %) Measured	CO_2 (wt %) Calculated for Mg + Ca as Carbonates	Fe (wt %) Required for $FeCO_3$ to Provide Missing CO_2
Scale	39.5	30.9	10.9
Solids from Filter Holder	4.3	4.2	0.13
Solids from Separator	0.9	0.8	0.13

C. Calculated Mass Balance

Sample Description	Wt % Calculated for (Na, K)Cl	$(Ca,Mg)CO_3$	$BaSO_4$	$SrSO_4$	$FeCO_3$	Fe_3O_4	Measured Residue	Total
Scale	0.33	69.90	3.23	1.87	23.17	1.54	0.3	100.3
Solids from Filter Holder	2.39	9.33	2.72	0.23	0.46	4.40	77.0	96.5
Solids from Separator	1.48	1.72	2.04	0.04	0.23	2.47	89.7	97.7

ESTIMATED COMPOSITION OF ACID SOLUBLE SOLIDS
FROM THE HO&M PRAIRIE CANAL CO., INC. WELL NO. 1

EXHIBIT 12-57

required in siderite is tabulated in the last column of Exhibit 12-57(B). This assumed siderite was not confirmed by x-ray diffraction analysis.

7. Calculation of Mass Balance as a Test of Validity of Conclusions

For calculation purposes it was assumed that dissolved solids for the cations remaining after balancing observed CO_2 were (1) chlorides for Na and K, (2) sulphates for Ba and Sr, and (3) magnetite (F_3O_4) for Fe. The presence of magnetite is based on x-ray diffraction identification of a small amount of magnetic material which adhered to the stirring bar used to stir the separator solids during washing with water. Calculated percentages for each assumed species are tabulated in Exhibit 12-57(C). As shown, adding measured percentage acid-insoluble residue for each sample provides mass balances in the range of 96.5 to 100.3 percent.

- **Particle Size Distribution Measurements:** Particle size analyses were performed to determine the sizes of the particles or grains present and the percentage of particles in each size fraction. This is to estimate the size and size fraction of particles produced by the well (both natural and man-introduced particles), produced by scaling, and produced by carbonate agglomeration in the well's plumbing, and to estimate the size and amount of particles being injected into the disposal well.

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 break up any carbonate-bound particles. The procedure used for each particle size distribution measurement was as follows:

1) Pretreat the sample portion by stirring in a beaker of deionized water or 1N HCl.

2) Pour the slurry through a 75-micron opening (200-mesh) nylon screen and chase with deionized water. Material passing through the screen was caught on a preweighed Whatman 40 (8-micron) filter paper.

3) Dry both fractions and weigh to determine fraction smaller than 75 microns.

4) Determine distribution of sizes larger than 75 microns by dry screening.

5) Determine size distribution of material from the filter paper using a Coulter Counter identifying twelve steps in the range of less than 4.0 microns to less than 50.8 microns.

6) Appropriately normalize the results of Steps 4 and 5 above using weights determined in Step 3 to provide percentages in each column tabulated in Exhibit 12-58.

Particle Size Distribution*	Scale		Solids From Filter Holders		Solids From Separator	
	As Rec'd	HCl Insol.	As Rec'd	HCl Insol.	As Rec'd	HCl Insol.
A > 1180µm	99.6%	13%	8.3%	1.3%	1.5%	1.1%
1180µm > A > 600µm	0.4	13	1.7	0.9	5.2	5.3
600µm > A > 300µm	<0.1	20	1.0	0.8	18.3	18.0
300µm > A > 150µm	<0.1	13	1.8	1.7	21.0	23.9
150µ > A > 75µm	<0.1	7	5.9	7.0	16.0	19.8
75µm > A > 32µm	<0.1†	34†	3.8	11.1	2.4	3.2
32µm > A > 16µm	—	—	21.0	27.7	10.7	8.4
16µm > A > 8µm	—	—	37.0	32.3	15.8	11.6
8µm > A > 4µm	—	—	19.5	17.2	9.1	8.7
Insoluble Residue						
1N HCl, wt. %	1.9	—	79.9	—	94.4	—

* Amounts, A, in weight percent, between the effective diameters listed. Fractions less than 75µm in size were determined with a Coulter Counter.

† Insufficient sample was left for particle sizing below 75µm by Coulter Counter. This number is the total amount of material with particle sizes less than 75µm.

PARTICLE SIZE DISTRIBUTIONS FOR SOLIDS FROM THE HO&M PRAIRIE CANAL CO., INC. WELL NO. 1

EXHIBIT 12-58

Results from applying this procedure to portions of each of the three samples are shown in Exhibit 12-58. In preparing this table, some size steps from the Coulter Counter have been combined so that each reported step corresponds to approximately a factor of two in effective particle diameters. It is noted that the procedure used provides questionable results for the size range of 32-75 microns and does not account for particles with diameters less than 4-8 microns.

Each size distribution listed in Exhibit 12-58 is normalized to 100 weight percent. For the "as received" samples, these are also percentages of the total sample. However, tabulated values in the "HCl Insol." columns must be multiplied by the fraction of the sample that is insoluble in 1N HCl to determine percentage of total sample. To make this possible, a separate third portion of each sample was dried and leached with 1N hydrochloric acid to determine the percent of the sample insoluble in acid. Results of this analysis are listed in the bottom line of Exhibit 12-58.

12.12.4.3 Discussion of Solids from the Filter Holder: The solids from the filter holder showed evidence of carbonate precipitation. More than 20% of the sample was acid-soluble with carbonate content of about 12% (Exhibits 12-57 and 12-58). Fragments of the light reddish-brown scale were visible under low magnification in water-washed particle size fractions down to at least 300 microns. These fragments were missing from the same size acid-washed fractions, as would be expected for acid-soluble precipitate.

Also visible under low magnification in both the water-washed and acid-washed size fractions were filter fibers and what appeared to be sand-packed balls of a clear gel. The filter fibers were visible down to the 75-micron size fraction and made up a proportionally larger percentage of the larger size fractions. The balls of gel were visible down to the 600-micron size fraction. The gel was clear and very soft. As it only appeared in the filter solids, it may be a grease used in surface hardware.

Fifty percent by weight of the water-washed and acid-washed materials were less than 16 microns (Exhibit 12-58). Except for the largest (greater than 1180 microns) fraction, there was little difference between the two washed samples. The difference in the largest fraction was probably due to dissolution of precipitates or scale.

The CO_2 produced by the filter solids and the mass balance calculations are shown in Exhibit 12-57(C). The calculated composition accounts for approximately 97% of the sample. Exhibit 12-56 shows the crystalline compounds determined by x-ray diffraction analysis of the water-washed and two acid-washed portions of the filter solids. The water-washed material is basically barite and quartz with minor amounts of calcite, aragonite, and sodium chloride salt. The sodium chloride may have been occluded in the gel mentioned above and not completely dissolved during the water washing. The acid-washed filter solids are basically barite and quartz.

12.12.4.4. Discussion of Solids from the Separator: The solids from the separator showed little evidence of precipitation. The material had a low solubility in acid and a low carbonate content (Exhibits 12-57 and 12-58). Examination of the water-washed and acid-washed materials under a low-power microscope detected little difference between the two portions of the composite sample. No evidence of scaling was visible.

Particle size distribution data is shown in Exhibit 12-58. These show little difference between the water-washed and acid-washed samples. In both cases, 50% of the material by weight was smaller than 150 microns.

Carbonate content of the separator solids was only about 2% and the acid-insoluble residue was almost 90% of the sample weight. Exhibit 12-57(C) gives an estimated composition of the solids. For these mass balance calculations it was assumed that the iron was present as iron (II) carbonate ($FeCO_3$) and magnetite (Fe_3O_4). Iron (II) carbonate is assumed to be present to account for the carbonate not accountable as calcium and magnesium carbonates and to partially provide cations required by the mass balance calculations. The presence of magnetite is based on x-ray diffraction identification of a small amount of magnetic material which adhered to the stirring bar used to stir the separator solids during washing with water. This iron compound is used to supply the remainder of the iron shown to be present by elemental analysis. Approximately 98% of the material can be accounted for using the percentage of the insoluble material and the calculated compounds present.

Exhibit 12-56 shows the crystalline compounds determined by x-ray diffraction analysis of the water, 1N HCl, and 6N HCl-washed sample material. All three indicate that the solids are basically quartz, barite, and a minor amount of albite.

12.12.4.5 **Discussion of Scale Sample:** The scale sample was removed from a previously cleaned area on the piping between the filter holders and the disposal well. The sample was in the form of flakes with diameters greater than 600 microns before acid washing. With 1N HCl treatment, 98% by weight of the sample dissolved (Exhibit 12-58). The particles remaining after the 1N HCl leach were distributed evenly among the reported size fractions. However, under microscopic examination, the fractions larger than 150 microns contained fewer visible sand grains. This would be expected if the filter were operating properly. The particles in this size range were black flakes, possibly a corrosion of the pipe rather than a precipitation product from the brine. There was insufficient sample for x-ray identification.

The 150 to 75-microns size fraction consisted of approximately equal amounts of black flakes and sand grains. The fraction greater than 75 microns was all black. Sand may have been present, but it could not be detected visually.

The scale material was almost totally soluble in 6N HCl. The CO_2 produced was about 40% of the sample weight. Exhibit 12-57(C) presents the mass balance calculations. Using the same assumptions as for the previous samples, 100% of the sample could be accounted for. It appears that 93% of the scale was calcium-magnesium-iron carbonates.

Exhibit 12-56 presents the results of x-ray diffraction analysis of the three washed samples. Although the scale contained 12.5% iron and almost 25% calculated iron carbonate, no iron compounds were detected in the diffraction pattern. Only calcite and a minor amount of barite were detected in the original material. Since only a small amount of material remained after acid leaching, only barite could be detected.

12.12.5 Scale and Corrosion Evaluation

Rice University Department of Environmental Science and Engineering performed on-site tests for scaling and corrosion during the first and second flow tests. Their full report is contained in Appendix N. They reported that scale was not a serious problem during the test due to relatively cool surface temperatures (about 220°F compared to a reservoir temperature of 294°F), low flow rates (5000-7000 BPD), and the short duration of the test. The scale that did form on test coupons was found by scanning electron microscope examination to be calcium carbonate with iron possibly substituted for the calcium. This agrees with IGT's scale analyses.

Coupons exposed to brine flow early in the test lost weight. Microprobe analyses indicated only a trace amount of iron sulfide formation. The small loss in weight may have been due to the abrasive action of sand produced by the well. Coupons exposed to the well later in the test did gain weight; $CaCO_3$ crystals were observed on these coupons. This indicated that scale might be a long-term problem.

Both aminomethylene phosphoric acid (AMP) and phosphate ester (PE-22) were tested as scale inhibitors while the separator and filters were bypassed on 2/25/81. The pH, alkalinity, and calcium levels in the brine were monitored to test the effectiveness of the scale inhibitors.

Addition of 5 ppm AMP brought about a greater change in these values than 5 ppm PE-22. This indicates that AMP is a better scale inhibitor than PE-22. The addition of 0.5 ppm AMP had little effect on the pH, calcium, and alkalinity values.

Inhibitors were not injected during the third and fourth flow tests. During the third flow test, surface brine temperature averaged about 245°F for almost three days. This is about 20°F higher than when inhibitor evaluations were performed. Also, surface pressure was lower than the roughly 1300 psig during inhibitor evaluations. With this recognition, the carbonates identified by IGT, and observed on the corrosion coupon in the brine stream between 1620 hours on 2/25/81 and 1100 hours on 3/1/81, are consistent with expectations from the inhibitor evaluation.

12.13 Test Equipment Performance

12.13.1 Gas Chromatography

The Carle Model 111-H Gas Chromatograph used in the field eluted a water vapor peak, making quantification of hydrocarbons heavier than pentane difficult. A baseline upset which occurred with valve switching within the instrument resulted in uncertain nitrogen values. Additional discussion on this subject can be found in Section 12.10.3.1.

12.13.2 Separator Efficiency

Separator effectiveness is believed to have been affected by the buildup of solids within the vessel during testing. At times the gas rate from the separator would oscillate between extremes of zero and about one million cubic feet per day within a period of about one minute. If large separator oscillations occur on future tests, it is recommended that the vessel be checked for solids buildup as soon as possible.

12.13.3 Disposal Brine Filter System

It is believed that a large amount of fine solids passed through the 25-micron filter elements used in the Nowata (Model No. 6FH60C-600) filter system. Smaller-micron filter elements can be used in the Nowata filter system; however, frequent replacement of small-micron fiber filter cartridges during long-term production periods would be expensive and impractical. Evaluation of a Ronningen-Petter 5-micron, self-cleaning pressure filtration system is planned on a forthcoming WOO test.

12.13.4 Sonic Sand Detector

Quantitative analysis of the OIC Sand Systems, Inc., sonic sand detector data is suspect because of inconsistency with producing characteristics. The very small grain size of some of the produced solids casts further doubt on the validity of the sand detector record. Calibration by the manufacturer is performed with sand of much larger grain size. Also, the sand detection signal is rate-sensitive, and fluid velocities in the data header were low in relation to optimal detection operation. Additional discussion on this subject can be found in Section 12.12.1.1.

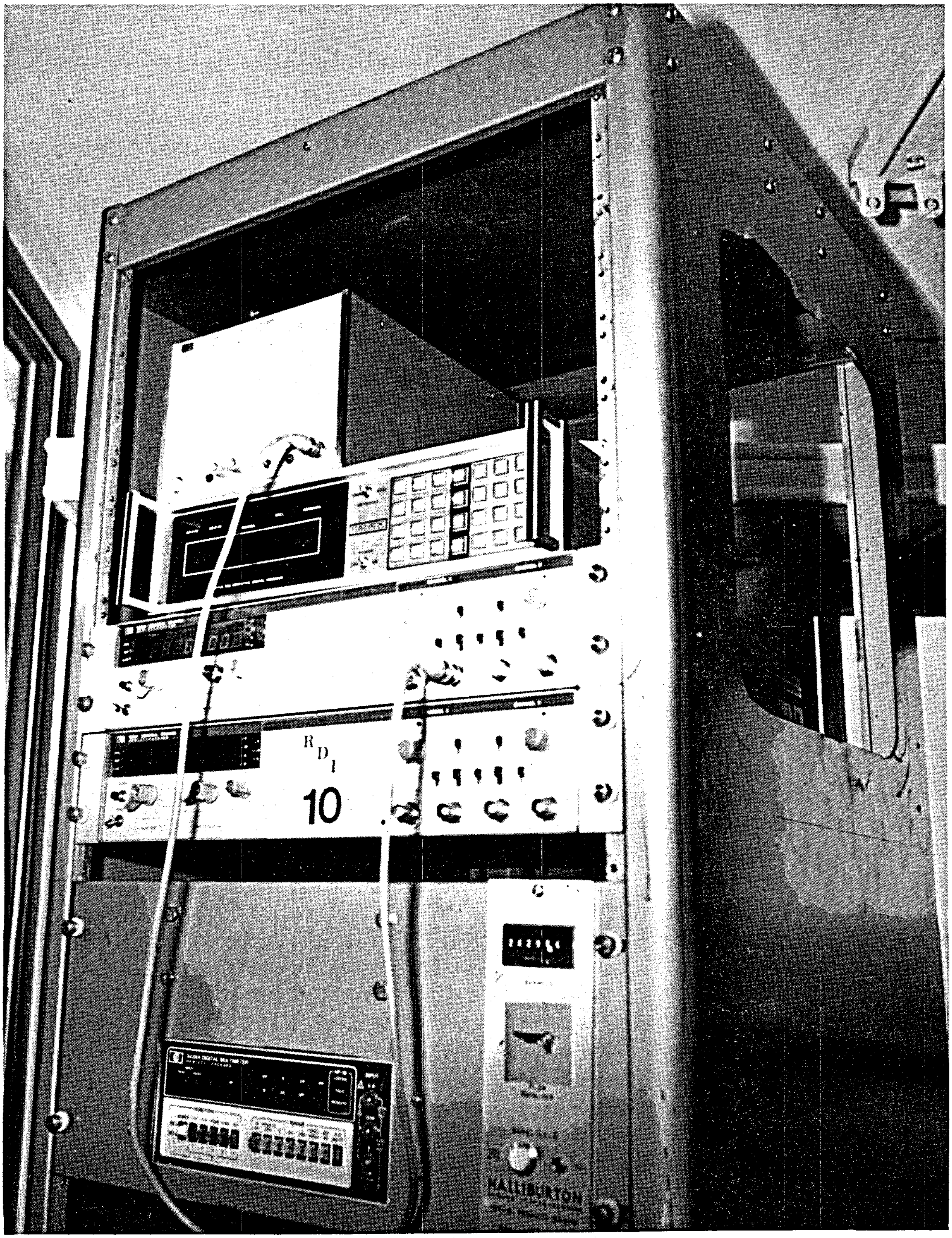


Photo 12-2 Strip chart recorders in IGT's test trailer.

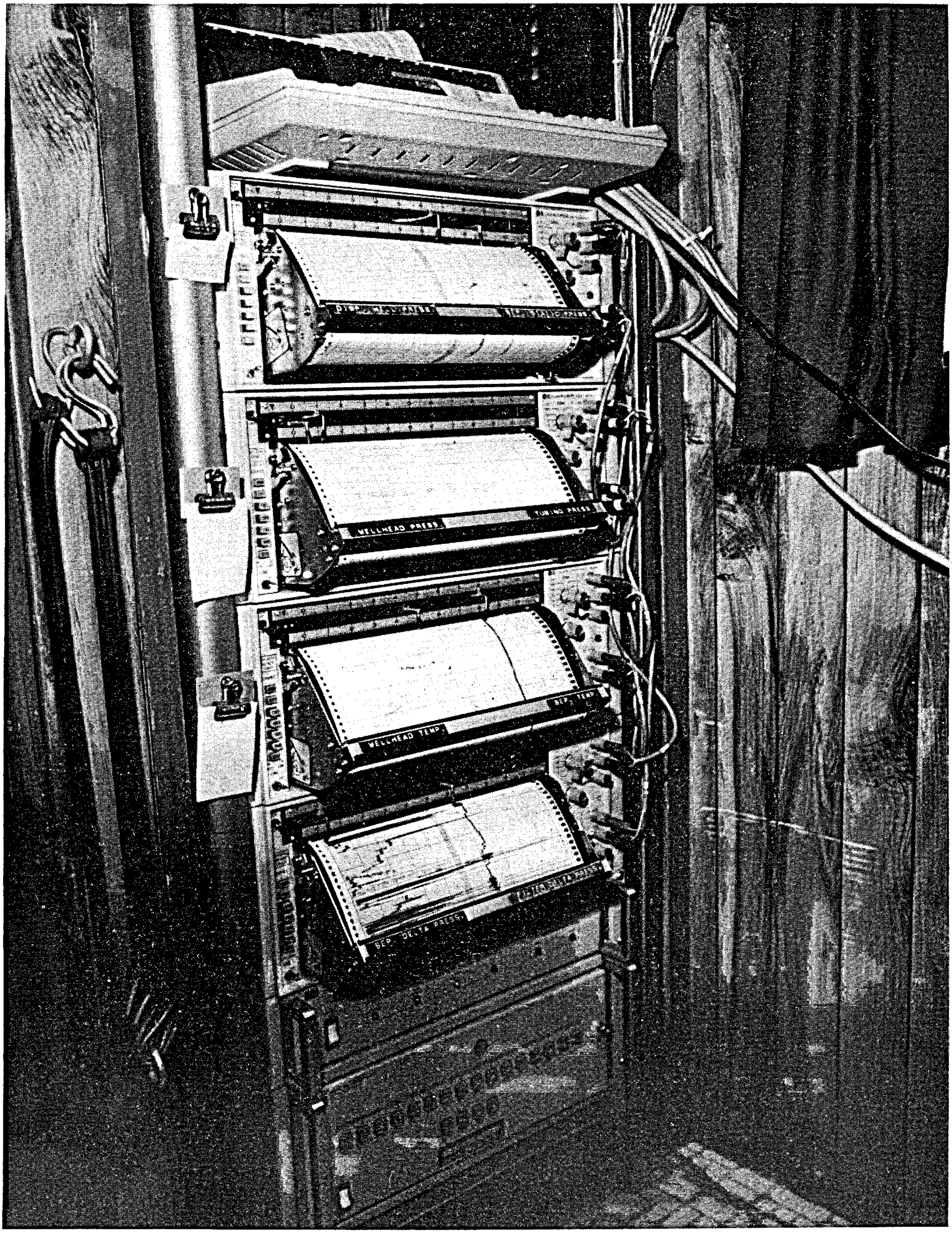


Photo 12-1 RDI's turbine meter and Panex meter digital data modules.

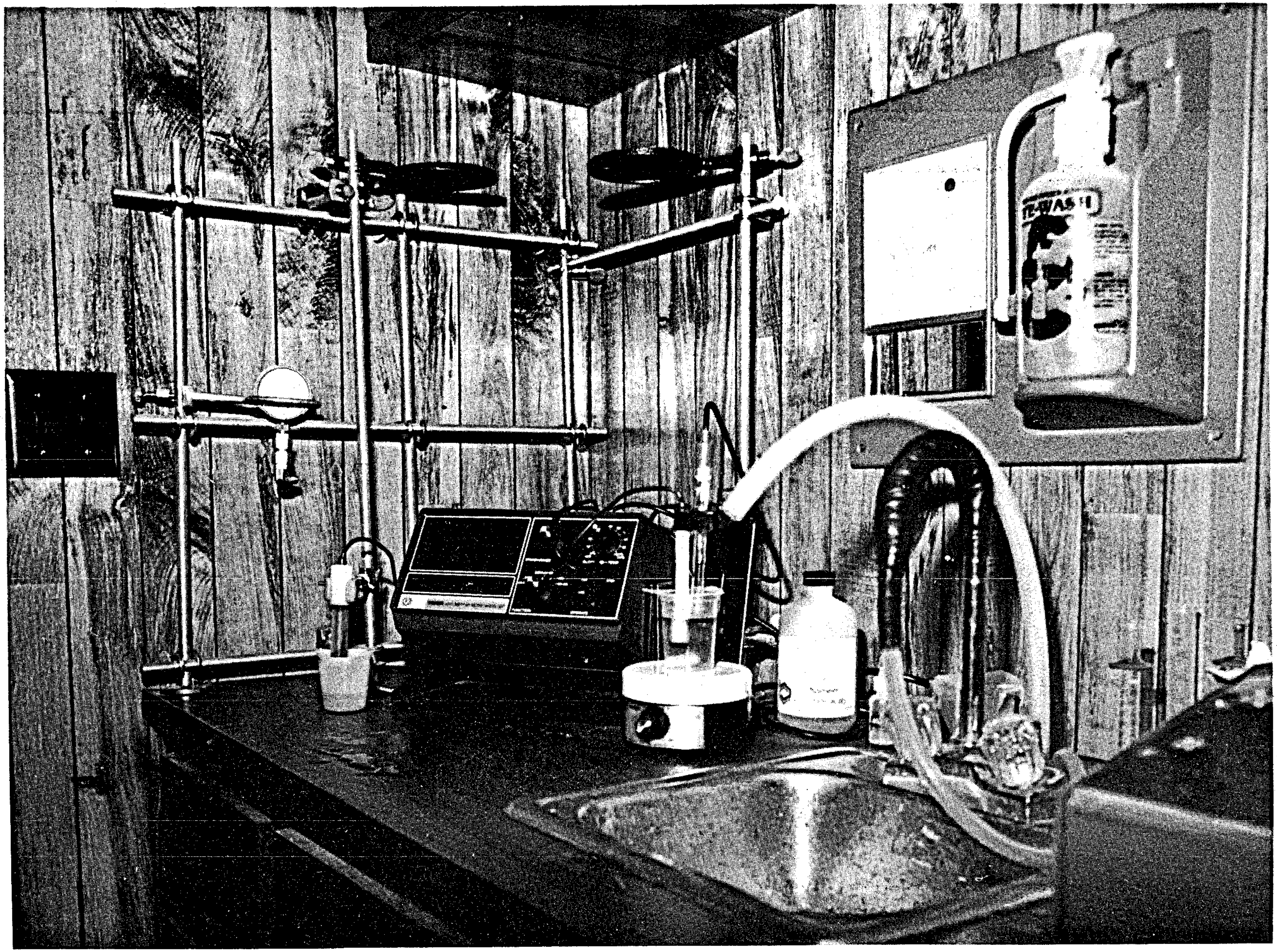


Photo 12-3 A section of the IGT chemistry lab in the on-site test trailer.

Photo 12-4 IGT's chemistry lab with gas chromatograph.

Photo 12-5 Pressure is being bled off of the data header so that a scale/corrosion coupon can be inspected.

Photo 12-6 Disposal brine being flushed through sampling bomb. System is at 10,000-psi operating pressure.

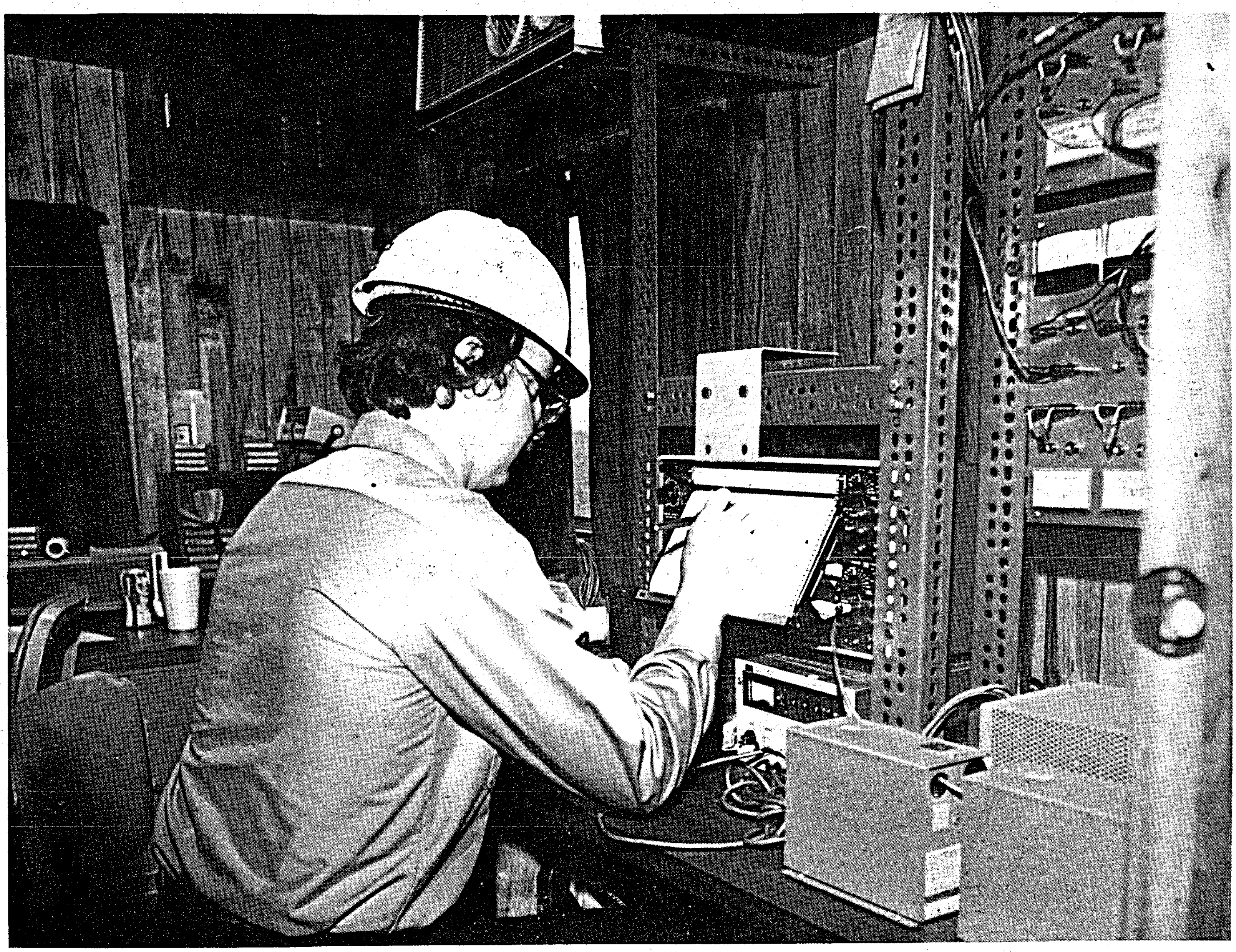


Photo 12-7 IGT's site testing supervisor making notes on sand detector strip chart.

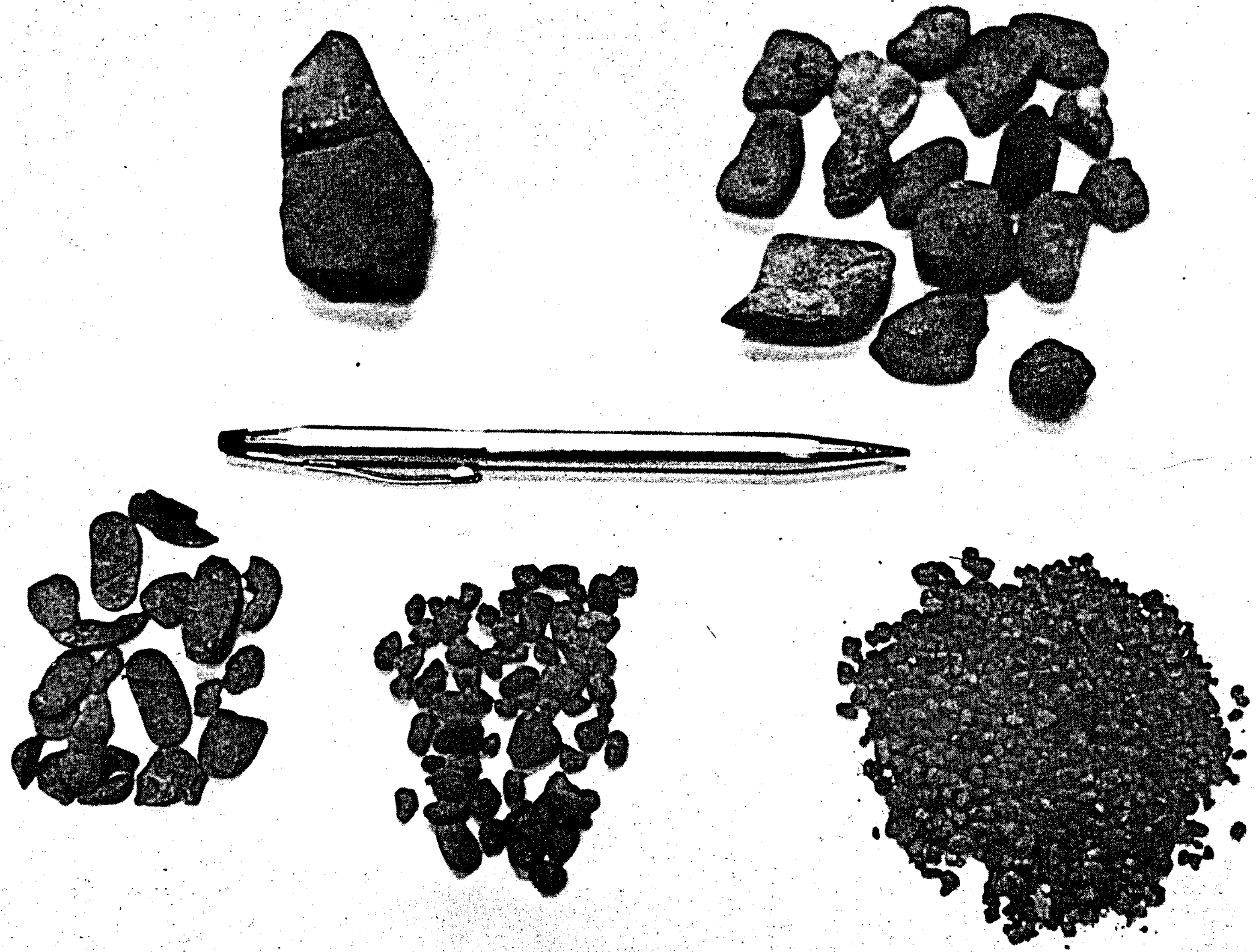


Photo 12-8 Samples of rocks and formation material produced from primary test zone.

13.0 PLUG AND ABANDONMENT OPERATIONS

13.1 Plugging of Test Well

The test well was killed on March 6, 1981 by pumping 57 barrels of 17.4 ppg mud down the tubing and 290 barrels of mud down the casing-tubing annulus.

The WellTech Rig No. 31 was moved to the location on March 16, 1981. 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 in the 5-1/2 inch casing at 14,660 feet. The perforations from 14,782 to 14,820 feet were then squeezed through the retainer with 150 sacks of cement. Final squeeze pressure was 4800 psi. Twenty-five sacks of cement were then spotted on top of the retainer.

A bridge plug was then set at 11,700 feet, and the 5-1/2 inch casing was jet cut at 11,500 feet. The casing could not be pulled free, and it was then cut at 23 feet so the slips could be removed. After the slips and 23 feet of casing were removed, a freepoint survey indicated that the casing was free from 7323 feet to the surface. The pipe was cut at 7342 feet but could not be pulled loose. The casing was then cut at 6344 and pulled out of the hole.

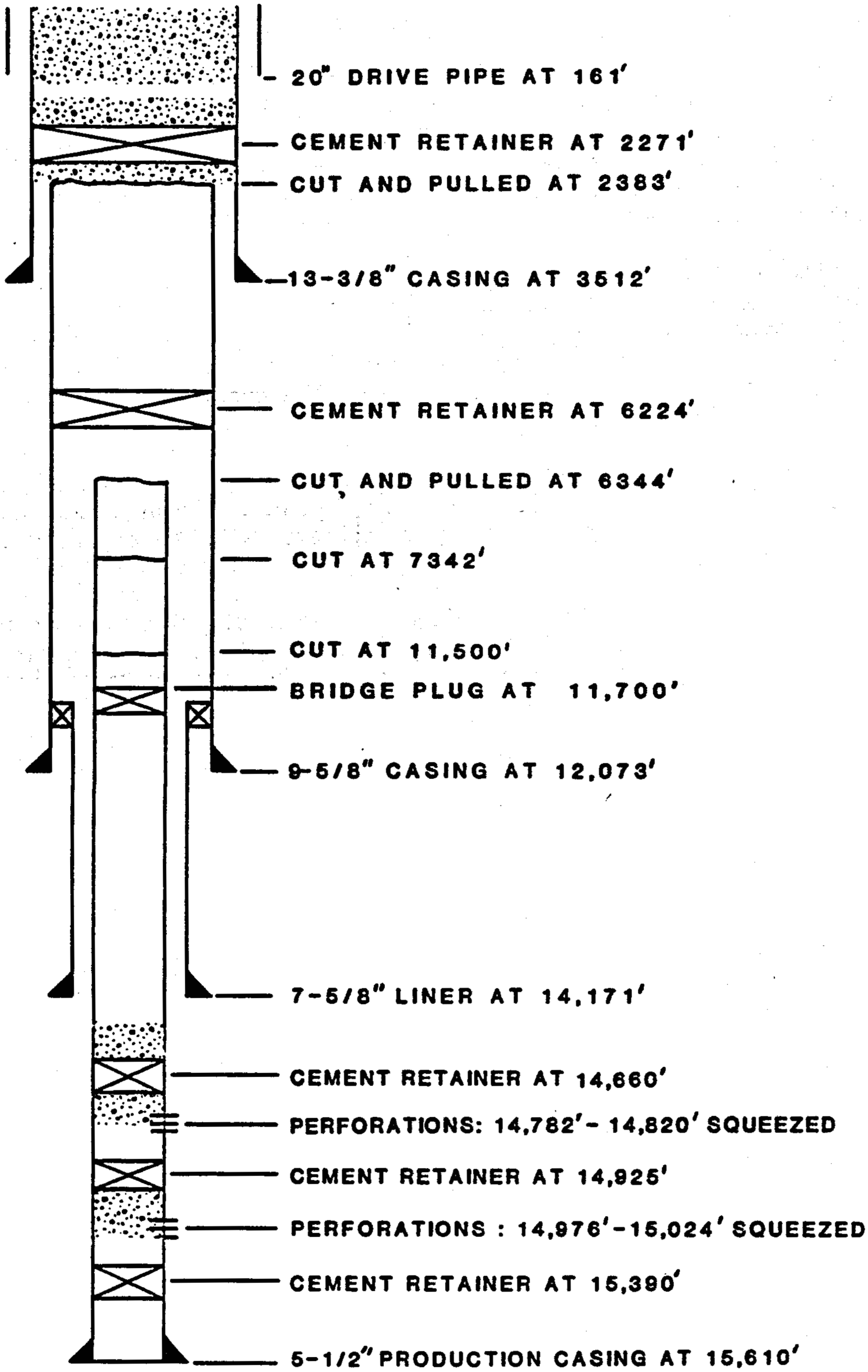
Next, a cement retainer was set in the 9-5/8 inch casing at 6224 feet. The casing was cut at 23 feet, and the slips were removed. A freepoint survey indicated that the casing was free at 2416 feet. The casing was then separated at 2383 feet using a string shot. The pipe was removed from the well, and a cement retainer was set in the 13-3/8 inch casing at 2271 feet. Two hundred sacks of cement were pumped below the retainer, and 50 sacks were spotted on top of the retainer. A cement plug was then spotted from 100 feet to the surface. The 13-3/8 inch casing and 20-inch drive pipe were cut 4 feet below ground level and removed. Exhibit 13-1 is a schematic diagram illustrating the configuration of the plugged and abandoned well.

The rig was released on March 24, 1981.

13.2 Plugging of Disposal Well

A workover rig was not required to plug the disposal well, since a tubing string was not in the hole, and all casing was cemented in place. The plugging procedure consisted of pumping 390 sacks of cement in the well. The drive pipe, surface casing, and 5-1/2 inch casing were cut off 4 feet below ground level. The abandonment work on the disposal well was completed on March 22, 1981.

PRAIRIE CANAL COMPANY, INC. WELL NO. 1
PLUGGED AND ABANDONED CONDITION



Eaton Industries of Houston, Inc. EXHIBIT 13-1
Eaton Operating Co., Inc.

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

14.0 CONCLUSIONS

- The solubility value of gas was found to vary from a low of 44.9 SCF/BBL for theoretical calculations to a high of 49.7 SCF/BBL for extrapolated laboratory recombination data. The IGT solubility value, "deduced from field data," is 43.3 SCF/BBL. These values, when compared to actual produced average gas/water ratios of 41 to 50 SCF/BBL, explain why there is strong disagreement among the contributors to this report as to whether or not the reservoir contained gas in excess of brine solubility.

- This well produced more solids than any previous WOO test well. The large amount of solids was produced at an estimated rate of 100 to 200 pounds per 1000 barrels and would preclude long-term operation of the well unless sand control was accomplished at the perforations.

- The separator's efficiency was independent of brine residence time, for residence times of two minutes or longer. The efficiency is not necessarily an inherent characteristic of the separator hardware; it is mainly a function of brine temperature, gas composition, produced gas/brine ratio, and separator operating pressure.

- Thermal energy recovery from brine before the separator would improve the quality of gas recovered at any specific separator pressure. Or conversely, in the particular case of gas having the composition observed at the Prairie Canal well, prior cooling of brine may well increase marketable gas from single-stage separation by 2-4 SCF per barrel of brine.

- Scaling and corrosion were considered very light. However, preventive treatment for calcium carbonate scaling would be necessary if long-term production were desired.

- Pressure transient analysis indicated that the reservoir was not capable of the high sustained production rates needed for commercial considerations.

- To gain the most accurate reservoir data from pressure transient analysis, the pressure at the sand face at the start of a flow test should be the original reservoir pressure. The closer the starting flow pressure is to the original, the more accurate are the resulting calculations.

- Concentrations of mercury in the produced brine averaged 0.79 micrograms per liter. This value is above the 0.10 micrograms per liter upper limit recommended by the U.S. Environmental Protection Agency for protection of aquatic organisms and for human consumption. Concentrations of boron averaged 55 milligrams per liter. This concentration is extremely toxic to plant life. Long-term surface disposal of the produced brine would be precluded because of the mercury and boron concentrations.

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APPENDIX A

Operator Contracts and Agreements

Agreement with Houston Oil and Minerals Corporation

HOUSTON OIL & MINERALS CORPORATION

October 7, 1980

Eaton Operating Company, Inc.
3100 Edloe, Suite 205
Houston, Texas 77027
Attn: Mr. J. T. Walker

Re: Prairie Canal Company Well No. 1, Prairie Canal Company Lease, South Lake Charles Field, Calcasieu Parish, Louisiana

Gentlemen:

This letter confirms a new agreement between Houston Oil & Minerals Corporation ("HOM") and Eaton Operating Company, Inc. ("Eaton") regarding Eaton's request to: (i) review HOM's logs and geological information (collectively "geological information") to evaluate the above referenced well ("Well") for geothermal-geopressure testing and (ii) conduct research, field testing and evaluation (collectively "field test" or "field testing") of the geopressured, geothermal acquifers penetrated by the Well and underlying the tract of land described in that certain Oil & Gas Lease, dated August 20, 1979 from Prairie Canal Co., Inc., as lessor and HOM as lessee and recorded in Conveyance Book 1530, Page 41, under Entry No. 1583396 as supplemented by a certain letter agreement dated August 20, 1979 and executed between those same parties (collectively "Lease") ~~on behalf of the United States Department of Energy ("DOE") Division of Geothermal Energy~~, a copy of which Lease is attached hereto as Exhibit "A" and incorporated herein by reference for all purposes. cgl JAE

Except for Eaton's reimbursement of HOM's drilling costs during the seventy-two (72) hour geological evaluation period, this letter agreement supercedes a previous letter agreement ("the September 11, 1980 agreement"), dated September 11, 1980 and executed between the parties, under which HOM had determined at 8:00 p.m. on October 3, 1980 that the Well was not capable of producing oil and/or gas in commercial quantities and was not necessary to HOM's exploratory activities and had tendered the Well or Well bore to Eaton in accordance with the September 11, 1980 agreement; however, Eaton was unable to conclude drilling negotiations within the seventy-two (72) hour period and returned the Well and Well bore to HOM without field testing it.

HOM now agrees to plug and abandon the Well temporarily, to remove and release HOM's current drilling contractor, and to deliver the Well and Well bore to Eaton for the consideration described in Section 3 hereof and Eaton hereby agrees to accept the Well and Well bore for its field testing operations, subject to the following provisions:

Section 1. Delivery of Well and Well Bore.

(a) HOM has retaken control of the Well and Well bore as of 8:00 p.m. on October 6, 1980 under the September 11, 1980 agreement. Upon execution of this letter agreement, HOM, at its sole cost and expense, will conduct such operations as it deems necessary and desirable to plug and abandon the Well temporarily in accordance with the rules and regulations of the Department of Conservation of the State of Louisiana, and, atthe conclusion of those operations, will release and remove the drilling rig and its drilling contractor (Cliffs Drilling Company) from the Well site location.

(b) As soon as the operations described in subsection 1(a) have been concluded, HOM shall immediately notify Eaton and shall tender and deliver the Well and Well bore to Eaton's full and complete supervision and control for its field testing in accordance with the provisions of this agreement.

Section 2. HOM Representations.

HOM represents to Eaton that:

(i) HOM is the present owner and lessee of all exclusive rights to explore, develop, and produce oil and gas only on the Lease, except as provided otherwise in the Lease;

(ii) HOM does not own the surface of any of the tracts of land covered by the Lease nor does it own or claim title to the right to explore, develop, and produce minerals other than oil and gas, except to the extent provided in that Lease;

(iii) HOM does not have the authority to approve the drilling of a salt water disposal well on the Lease by Eaton to dispose of salt brines produced from the field test of the Well;

(iv) HOM shall be solely responsible and liable to Eaton to distribute the consideration described in Section 3 fairly and equitably to any other Leasehold working interest owners, if any, and HOM shall indemnify and hold Eaton harmless from any such distribution by HOM;

(v) HOM shall furnish the complete name (or names) and address (or addresses) of the owner or owners of the surface and/or mineral estates of the tract of land covered by the Lease; and

(vi) HOM is in compliance with and accepts all of the applicable provisions of Exhibit "B" which is attached hereto and incorporated herein by reference for all purposes.

Section 3. Consideration and Eaton's Representations, Warranties and Covenants.

(a) Upon HOM's tender and delivery of the Well and Well bore for Eaton's field testing under subsection 1(b), Eaton shall immediately deliver (1) a cashier's check payable to HOM in the total sum of Ninety-Five Thousand Dollars ($95,000.00) for HOM's permission to utilize the Well bore for its field testing, and (2) a cashier's check payable to HOM in the total sum of Forty-Three Thousand Five Hundred Dollars ($43,500.00) already due and payable for HOM's direct drilling costs incurred under subsection 1(c) of the September 11, 1980 agreement.

(b) As further inducement to HOM to grant Eaton permission to review the geological information and conduct field testing on the Well, Eaton represents, warrants, and covenants to HOM that:

(1) Prior to any operations on the Lease or the Well, Eaton shall (i) obtain all necessary and appropriate consents from the surface and mineral owners and their tenants for any of its above described activities on the Lease or the Well, (ii) secure lawful access and egress from those owners and tenants, and all necessary federal, state, and local government permits required for its field test operations on the Well, and (iii) acquire from the Lessor under the Lease and deliver to HOM an executed waiver or extension of HOM's 90-day obligation to clean up and restore the Well site under paragraph 12 of the Lease.

(2) Eaton shall not conduct any activities on the Well bore or Lease other than its field testing of geothermal acquifers in the Well without HOM's prior written consent;

(3) Eaton will not interfere with any other well or Lease operations conducted by HOM or any subsidiary thereof;

(4) In the event any Eaton activity on the Lease indicates the presence of commercial quantities of any mineral, including uranium or petroleum, Eaton will immediately notify HOM of its discovery and furnish HOM within a reasonable time with a copy of the log or logs and all other geological or geophysical data in Eaton's possession covering such discovery indicating minerals in commercial quantities;

(5) Eaton shall supply HOM with a full and complete copy of all field testing information and test reports on the Well and Lease at the conclusion of the field testing on the Well;

(6) In the conduct of all Eaton's activities on the Lease, it shall comply at all times with any order, ruling, or regulation of the Department of Natural Resources of the State of Louisiana, any other state or local subdivision or agency and any federal or state laws; and

(7) At the conclusion of its field testing operations hereunder, Eaton shall properly plug and abandon the Well, remove all of its drilling equipment materials and supplies, and restore and clean up the Well site location in accordance with the provisions of the Lease and any waiver or extension of HOM's clean-up and restoration obligations thereunder.

(c) If any of the foregoing representations or warranties in subsection 3(b) be or shall become false or if Eaton shall violate any of the above covenants during the term of this agreement, HOM may terminate this agreement immediately without notice to Eaton, take all necessary actions or remedies to recover any damages to its Well or Lease and/or to remove Eaton from the Well and Lease, and retain as liquidated damages the $95,000 payment made under subsection 3(a).

(d) At the conclusion of its field testing, Eaton, at its sole cost and expense, shall properly plug and abandon the Well in accordance with applicable federal, state and local laws and all rules and regulations issued thereunder and with any Lease provisions. Eaton shall also notify HOM at least three (3) days in advance of any plugging operations and provide HOM with written plans for such plugging operations, so that HOM may review and approve those plans prior to the commencement of plugging operations.

(e) Eaton shall complete its field testing on the Well, its plugging of the Well and its clean-up activities within one hundred and eighty (180) days from the execution of this agreement by Eaton. Eaton shall notify HOM prior to releasing its clean-up contractor so that HOM may inspect and determine if Eaton's clean-up operations are in accordance with the Lease provisions. If those clean-up operations are not in accordance with the Lease provisions in HOM's opinion, Eaton shall undertake such additional clean-up operations as are reasonably necessary to comply with those Lease provisions.

Section 4. No Mineral Ownership Conveyed.

This agreement does not convey to Eaton any ownership interest in the Lease or lands covered thereby nor does Eaton have any vested interest in any mineral or energy resources produced during the field testing of the Well; and it is expressly agreed between Eaton and HOM that no mineral or energy resource will be saved and sold without HOM's prior written consent.

Section 5. Insurance.

At all times during the term hereof, Eaton, its agents, representatives and contractors, shall carry and maintain the insurance coverages described on Exhibit "C" (which is attached hereto and incorporated herein by reference for all purposes) with insurance companies satisfactory to HOM and comply with all requirements stated in Exhibit "C". All of the insurance policies described in Exhibit "C" shall contain provisions that the insurance companies will have no right of recovery or subrogation against HOM or its joint lessees, their employees, subcontractors or agents for injuries, death, losses or damages covered by those policies.

Before conducting any of those activities under this agreement, Eaton shall complete and return to HOM a Certificate of Insurance form which is attached hereto as Exhibit "D" evidencing coverage required by the provisions of this letter and the unequivocal agreement on the part of each insurance company to notify HOM of cancellation of or any material change in insurance coverage at least thirty (30) days before the effective date of such cancellation or change.

Section 6. Indemnities.

(a) Eaton (for and on behalf of itself, its contractors, agent, or representatives, collectively "Eaton") hereby indemnifies, defends, and saves HOM and its joint lessees, their employees, contractors, agents, and invitees harmless from and against all losses, damages, injuries, or causes of action, judgments, or costs (including attorneys' fees and other expenses incurred in the defense of any claim or lawsuit) thereof, including but not limited to, claims for (1) defects or unfitness of equipment or any building or structure (2) pollution or environmental damages of whatsoever kind or nature to the land and waters covered by the Lease and the land and waters adjacent thereto and (3) injury, death, or damage, of or to (i) employees or property of Eaton, (ii) employees or property of HOM and its joint lessees, their agents, contractors, or invitees, or (iii) any third party or its property (including but not limited to, any trespass or any reduction of the fair market value of any property covered by the Lease), resulting from, arising out of, or related in any way to, any of Eaton's operations or activities on the Lease or the Well, including all of Eaton's field testing operations or Eaton's transportation to or from that Well or Lease, even though such loss, damage, injury, or cause of action results from, or arises out of, the joing or concurrent negligent act or omission of HOM and its joint lessees, their employees, agents, contractors, or invitees. However, Eaton's indemnity obligations under this subsection 6(a) shall not extend to any loss, damage, injury or cause of action resulting from, or arising out of the sole negligent act or omission of HOM and its joint lessees, their employees, agents, contractors or invitees and shall be limited to the maximum limits specified for the insurance required in Exhibit "C".

(b) Eaton indemnifies, defends, and saves HOM and its joint lessees, their employees, agents, contractors or invitees harmless from and against any claims, damages, penalties or fines asserted or levied by any federal, state, or local governmental agency for violations of any statute, rule, ordinance or regulation, including the failure to plug and abandon the Well properly and environmental damages and any costs of cleaning up such damages, resulting from, arising out of, or related in any way to Eaton's operations or activities on the Lease or the Well or any transportation to and from that Lease.

Section 7. Termination of Agreement.

Except as otherwise provided herein, this agreement shall be effective as of the execution of this letter by Eaton and shall terminate one hundred and eighty (180) days from that date; provided, however, that the provisions of subsections 3(b), (c), (d), and (e) and Sections 6 and 8 shall survive any termination of this agreement and shall be continuing obligations.

Section 8. Confidentiality.

Except for any geological information released by HOM to Eaton under the September 11, 1980 agreement, all other HOM geological information, including Well logs, seismic data, maps and reports reviewed and discussed with Eaton Eaton shall not disclose, release, or in any other manner, divulge to any third party any portion of that confidential geological information (except as may be released to it by HOM under the September 11, 1980 agreement) without HOM's prior written consent and shall take all necessary and reasonable steps to prevent any such disclosure or release by its employees or agents.

Section 9. Notices.

(a) Except for Section 10, all notices required hereunder shall be in writing marked to the attention of the party's designated representative shown below and shall be mailed by United States mail, registered mail, return receipt requested, postage prepaid or hand delivered to the following addresses of the parties:

If to HOM	Houston Oil & Minerals Corporation Houston Oil & Minerals Tower 1100 Louisiana Houston, Texas 77002 Attention: General Manager, Eastern Division Telephone: 713/658-3000
If to Eaton:	Eaton Operating Company, Inc. 3100 Edloe, Suite 205 Houston, Texas 77027 Attention: Mr. Ben Eaton Telephone: 713/627-9764

At any time during the term of this agreement, either party may change its address and/or designated representative by notifying the other party as provided above.

(b) Eaton shall also provide HOM with the name, home address, and telephone number of a representative to notify Eaton when the operations described in subsection 1(a) have been concluded and HOM is ready to tender and deliver the Well and Well bore to Eaton.

Section 10. Accident Notification.

In the event Eaton or its contractors, their employees, agents, subcontractors, or invitees are involved in any accident on the Lease or if any accident involves HOM's property, equipment, or personnel, or if any accident involves any third party in any manner whatsoever while Eaton or its contractors, their employees, agents or contractors are performing any activities on the Lease, Eaton shall immediately report the accident to the attention of:

Safety Department
Houston Oil & Minerals Corporation
Houston Oil & Minerals Tower
1100 Louisiana
Houston, Texas 77002
Telephone Number: 713/658-3000

If the accident involves loss of life, serious injury, or substantial property loss or damage (in excess of $100,000), this report shall be made by collect telephone call. If the accident is of a less serious nature, notification may be made by the notice provisions of this letter agreement. All accidents must be reported. The reporting of any accident will not imply any admission of liability on the part of HOM or Eaton or its contractors, their employees, agents or subcontractors.

Section 11. Assignment of Agreement.

Eaton shall not assign this letter agreement without HOM's prior written consent. The provisions of this letter agreement shall be binding upon and shall inure to the benefit of the parties hereto, their affiliates, subsidiaries, successors and permitted asssigns.

Section 12. Governing Law.

All interpretations of this agreement shall be governed by the laws of the State of Louisiana, excluding any conflicts of laws, statutes, or provisions which, if applicable, would apply the laws of another state to the interpretation of this agreement.

If the foregoing terms and conditions are satisfactory to Eaton, please indicate Eaton's acceptance and approval thereof by executing the enclosed duplicate originals of this agreement in the space provided below and return this letter agreement to HOM, marked to the attention of the undersigned.

Sincerely yours,

HOUSTON OIL & MINERALS CORPORATION

By: Charles J. Swize
Charles J. Swize
General Manager
of the Eastern Division

ACCEPTED AND APPROVED this
10 day of October, 1980.

EATON OPERATING COMPANY, INC.

By: B A Eaton

Agreement with Prairie Canal Company, Inc.

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

EATON OPERATING COMPANY, INC.

October 17, 1980

Prairie Land Company, ~~Inc~~.
P. O. Box 1048
Lake Charles, Louisiana 70601

Re: Prairie Canal Co., Inc. Well No. 1
Prairie Canal Co., Inc. Lease
South Lake Charles Field
Calcasieu Parish, Louisiana

Gentlemen:

This letter, if accepted by you and two signed copies thereof are returned to us by October 20, 1980, shall constitute the basis of an agreement between "Prairie Land Company, ~~Inc~~. (Prairie) and Eaton Operating Company, Inc. (Eaton) as to the following matters.

I.

Eaton is a party to a written contract with the United States government represented by the Division of Geothermal Energy, Department of Energy (D.O.E.), to carry out research, field testing and evaluation of well sites in Texas - Louisiana Frio-Miocene trend where reservoir and production data can be obtained to assess the energy potential (dissolved gas and heat) of Gulf Coast geopressured geothermal aquifers.

Houston Oil & Minerals Corporation has drilled the above referenced well to a projected total depth of approximately Sixteen Thousand Five Hundred Feet (16,500 ft.) and has elected to plug the well as non-commercial.

II.

Eaton is of the opinion that the subject well qualifies as a well of opportunity candidate within the definition of the Eaton-D.O.E. contract, and Eaton recommends a production test of one or more aquifers within the well bore for D.O.E. approval, sponsorship and sole financial support.

III.

Eaton shall be responsible for:

1. Obtaining all federal, state and local governmental permits required for such operations.

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

2. Providing insurance coverage through the length of testing and research, at limits of $80,000,000.00 liability and $25,000,000.00 cost of well control (land).

3. Providing well test data to Prairie at the conclusion of the test.

4. Assumption of all liabilities associated with further operations of the test.

5. Eaton will drill a saltwater disposal well near the Prairie Canal Co., Inc. Well No. 1, to dispose of all brines, flare the gas, if any, and plug the wells on completion of the test. All of this shall be accomplished by methods approved by the appropriate regulatory agency.

6. Eaton would agree to complete the testing and research in approximately 180 days.

7. Assumption of the well bore site ownership during the full time period of testing.

8. Eaton shall, at the request and urging of the landowner, with the express approval of the operator Houston Oil & Minerals Corporation, extend the following option to landowner, Prairie, to-wit:

(a) Eaton shall notify Prairie fourteen (14) days prior to plugging the <u>test</u> well, and;

(b) Prairie shall notify Eaton by return mail, that Prairie <u>shall</u> <u>exercise</u> Prairie's option as follows:

(c) Eaton shall set an E.Z.S.V. retainer above the test perforations, squeeze cement below the retainer with a minimum of Five Thousand (5,000) pounds of surface pressure.

(d) A detailed list of materials which Eaton will release to Prairie, subject to conditions herein set out, shall be approved and agreed to by Eaton and Prairie. (It is expressly understood and agreed the materials are owned by the United States of America and cannot by law be sold to Prairie, by Eaton). Eaton shall demand that Prairie send a cashiers check to the supplier, whose name, address and copies of the invoices shall be furnished to Prairie, to pay for the five and one half inch (5-1/2") casing and any other materials so agreed upon. The supplier shall issue Eaton credit for said materials, to allow Eaton to purchase replacement material. Prairie has an option to replace said material in kind.

(e) When Eaton, assuming Prairie has elected to exercise said option, has completed the work as set out in (c) above and has removed the tubing and surface equipment. Prairie shall release Eaton of all liability in writing, shall so notify the proper government authorities they are the operator and Eaton shall quit the premises and any obligation Eaton may have had to either Prairie or Houston Oil & Minerals, shall cease.

(f) As compensation for use of government equipment, Prairie will provide Eaton with all their test data.

(g) In the event Prairie does not elect to exercise said option as herein set out, then this agreement as written, shall control and the option shall be void.

IV.

Prairie shall be responsible for:

1. Allowing Eaton to conduct geothermal-geopressured testing at the well site and in the aquifers below same.

2. Allowing Eaton the authority to drill a saltwater disposal well on Prairie's land near the site of the Prairie Canal Co., Inc. Well No. 1, as herein described.

3. Allowing Eaton to produce, explore and develop geothermal test data.

4. Allowing Eaton a reasonable use of the surface rights surrounding the well bore and disposal well location site.

V.

This agreement does <u>not</u> convey to Eaton any ownership interest in the land, nor does Eaton have any vested interest in any minerals or energy resources produced during any of the tests, and it is expressly agreed between Eaton and Prairie that no energy resources will be saved or sold.

VI.

Eaton further expressly states that any and all portions of this agreement shall be subject to the approval of the D.O.E. and should said agency disapprove any of this agreement in whole or in part, then this agreement shall be null and void.

VII.

Whenever notice is required or permitted under the terms of this agreement, same 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 Prairie:

Prairie Land Company, ~~Inc.~~
P. O. Box 1048
Lake Charles, Louisiana 70601

Attention: Mr. Carl Patton
Telephone: 318/439-8836

If to Eaton:

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

Attention: Mr. B. A. Eaton
Telephone: 713/627-9764

VIII.

This agreement shall be binding on the legal representatives, successors and assigns of the parties hereto.

IX.

Attached hereto are the following documents incorporated by reference herein as set out and marked as Exhibit I and Exhibit II.

If the above conforms to your understanding of this agreement between us, please sign and return two copies to us in the time specified above.

Sincerely,

EATON OPERATING COMPANY, INC.

By B A Eaton
B. A. Eaton
President and Project Manager

ACCEPTED AND AGREED TO THIS 17th DAY OF October, 1980.

PRAIRIE LAND COMPANY, ~~INC~~.

By [signature]

ACCEPTED AND AGREED TO THIS 20th DAY OF October, 1980.

APPENDIX B

Rig Contractor Agreements

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

WellTech Rig #5

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

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

Subcontract No. 0453-80

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
[signature]	1-29-81
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. 0453-80

AWARD

Amount $93,600.00

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	W. E. Rose
Name	Signature
Purchasing Manager	January 29, 1981
Title	Award Date

UNIT PRICE SCHEDULE

Item No.	Description	Estimated Quantity	Unit	Unit Price	Estimated Price
1.	Mobilization	36	Hrs.	$195.00	$7020.00
2.	Contractor-Directed Operations	408	Hrs.	$195.00	$79,560.0
3.	Standby Ready		Hrs.	$195.00	N/A
4.	Demobilization	36	Hrs.	$195.00	$7020.00
		ESTIMATED TOTAL COST			$93,600.0

* An additional charge of $10.00/hr. will be billed to contractor if drill pipe is used.

* Fluid end parts for pumps will be rebilled to contractor at cost.

WellTech, Inc.

Louisiana Division
Post Office Box 51933. O.C.S.
Lafayette, Louisiana 70505
318/232-3413

RIG #5

Wilson Mogul Model "42", self-propelled back-in Winchmobile, power 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 twin-disc torque converters. The unit is equipped 1-1/8" drill line, water-circulating brakes, rotary drive, one V-8 Parkersburg hydrotarder. The mast is 110' angular, with hook load 300,000#, hydraulically raised and telescoped. Racking capacity i doubles: 20,000 2-7/8" drill pipe or 28,000 2-3/8" tubing. The Cr consists of five (5) sheaves allowing 8-line string up. Installed one hydraulically operated breakout cylinder.

2	Gardner Denver 310 HP PA-8Triplex with 4" liners, Pump powe by 8V-71N Series GM Diesel engine, 10,000 Series Torque convertors-8542 Spicer transmissions.
1	Mission 5' x 6" mud-mixing pump powered by 3-71 GM Diesel engine.
1	Gardner Denver 2-1/2 x 2-1/2 centrifugal fresh water transfer pump powered by Lister Diesel engine.
1	18' high x 20 x 17 hydraulically raised substructure equipp with 17-1/2" Ideco rotary.
1	Baash Ross 4-sheave, 150-ton Shorty Traveling Block.
1	PC-150 Oil Well Swivel.
1	3" x 40' Rotary Hose, 3000# working pressure.
1	6" Series 1500 Cameron Type QRC 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" Preventer.
1 set	Koomey Accumulators with 20-gallon capacity and 3000# working pressure.
1	Advance Model "C" spider with 2-3/8" or 2-7/8" slips.

WellTech, Inc.

Louisiana Division
Post Office Box 51933, O.C.S.
Lafayette, Louisiana 70505
318/232-3413

RIG #5 - Continued

1		180,000# Martin Decker Weight Indicator.
2		60KW light plant, powered by 6-71 GM Diesel Engine.
1		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 with 2-3/8" and 2-7/8" jaws.
1		Baash Ross 3" x 38' Kelly with 2-7/8" I.F. 4-1/2" API L. H. box connection.
2	sets	Pipe racks, ramp and catwalk.
1		Air-conditioned living quarters.
1	set	2-3/8" and 2-7/8" Tubing elevators.

All necessary mud lines and hand tools.

Big rigs for big jobs.

In Louisiana, we operate a number of 24-hour rigs which are among the largest in the world. We operate these rigs from South Louisiana through Mississippi and Alabama to the Florida Panhandle. They come equipped with high pressure mud pumps, substructures, hydraulic blowout preventers, pipe racks and mud tanks and are capable of operating to 25,000 feet. In addition, we have conventional double derrick rigs for daylight operations.

But rigs are only half the story. Our Louisiana people are among the most professional, interested and competent groups you'll encounter. They understand and can handle the special needs of the deep, high pressure wells in this area.

The Louisiana Division has a hard-won reputation for excellence. We intend to maintain it.

LOUISIANA DIVISION

Well Servicing Rigs

Rig Types Available	Derrick Height	Capacity (Pounds)	Line Rating	Engine	Horse Power	Rated Depth
Double Derrick	96'	180,000	Six	8V-71	304	18,000'
Double Derrick	96'	250,000	Six	12V-71	456	28,000'

Workover and Completion Rigs (24 Hour) — Houma, Louisiana

	Rig 31	Rig 32	Rig 34
Derrick	110' Double	110' Double	112' Double
Capacity (Pounds)/ Line Rating	354,000/ Ten	354,000/ Ten	358,000/ Ten
Engines	(2) 12V-71 900 H.P.	(2) 12V-71 900 H.P.	(2) 12V-71 900 H.P.
Substructure	18'	18'	18'
Rotary	17½"	17½"	17½"

Workover and Completion Rigs (24 Hour) — Lafayette, Louisiana

	Rig 2	Rig 3	Rig 4	Rig 5	Rig 8	Rig 10
Derrick	110' Double	104' Double	110' Double	110' Double	110' Double	110' Double
Capacity (Pounds)/ Line Rating	300,000/ Eight	300,000/ Eight	300,000/ Eight	300,000/ Eight	300,000/ Eight	358,000/ Ten
Engines	(2) 6V-71 456 H.P.	(2) 8V-71 608 H.P.	(2) 12V-71 900 H.P.	(2) 12V-71 900 H.P.	(2) 8V-92 700 H.P.	(2) 12V-71 900 H.P.
Substructure	16'	15'	18'	18'	18'	18'
Rotary	17½"	17½"	17½"	17½"	17½"	17½"

Workover and Completion Rigs (24 Hour) — Laurel, Mississippi

	Rig 61	Rig 62	Rig 63	Rig 64	Rig 65	Rig 66	Rig 67
Derrick	116' Double	116' Double	116' Double	110' Double	110' Double	110' Double	112' Double
Capacity (Pounds)/ Line Rating	369,000/ Ten	369,000/ Ten	369,000/ Ten	354,000/ Ten	354,000/ Ten	354,000/ Ten	300,000/ Eight
Engines	(2) V-12 900 H.P.	(2) V-12 900 H.P.	(2) V-12 900 H.P.	(2) V-12 900 H.P.	(2) V-12 900 H.P.	(2) V-8 900 H.P.	(2) V-8 608 H.P.
Substructure	27'	27'	27'	18'	18'	18'	23'
Rotary	17½"	17½"	17½"	17½"	17½"	17½"	17½"

Other Equipment Available

Mud pumps, BOP's, [illegible]

WellTech, Inc.

700 Rusk Avenue
Houston, Texas 77002
713/225-5555
TLX 774386
(WELLTECH HOU)

FACT SHEET

WellTech, Inc. is a privately held oil and gas well servicing contractor with over 260 rigs involved in the completion, servicing and workover of oil and gas wells, operating in the Central, Southwestern, Southeastern and Rocky Mountain regions of the United States. WellTech is jointly owned by subsidiaries of Bechtel Corporation and Hanna Mining Company.

FINANCIAL DATA:

1979 Revenues:	$ 72 million
1979 Net Worth:	$138 million
1979 Working Capital:	$ 12 million

CORPORATE OFFICERS:

David M. Carmichael Chairman of the Board and Chief Executive Officer	Christian N. Seger Vice President-Marketing
James S. LeVoy President and Chief Operating Officer	John D. McLain Vice President-Operations
Steven C. Grant Vice President-Finance and Treasurer	Nelson R. Jones Controller
Elizabeth A. Sauer Corporate Secretary	W. Leo Payne Assistant Treasurer

BANKING REFERENCES:

First City Natl. Bank of Houston 1001 Main St. Houston, Texas 77001 Mr. William J. Rovere, Jr. 713/658-6564	Bankers Trust Company 280 Park Ave. 15th Floor New York, New York 10017 Mr. Ned Benedict 212/692-3490	Canadian Imperial Bank of Commerce One Main Place, Suite 818 Dallas, Texas 75250 Mr. R. Randy Brintnell 214/748-5187

VENDOR REFERENCES:

IDECO Division of Dresser Dresser Tower Houston, Texas 77001 713/972-3669	Cabot Corporation Box 1101 Pampa, Texas 79005 806/669-2581	Cooper Manufacturing 3306 Chas. Page Blvd. Tulsa, Oklahoma 74101 918/582-2194

CUSTOMER REFERENCES:

Wainoco Oil & Gas Co. 1100 Milam Bldg., Suite 600 Houston, Texas 77002 Mr. Ed Pharis Production Manager 713/656-9900	Atlantic Richfield Co. Box 1346 Houston, Texas 77001 Mr. Frank Brown Drilling Superintendent 713/965-6001	Phillips Petroleum Co. Box 1967 Houston, Texas 77001 Mr. Bill McMillian Production Superintendent 713/797-0066

WELLTECH RIG #5

Name	Position	Time Worked
Larry N. Broussard	Driller	6 yrs.
Cecil M. Miller	Derrickman	8 mths.
Alphuis Mathews	Floorhand	1 yr. 10 mths.
Conrad Hanks	Floorhand	5 mths.
Bobby L. Guidry	Driller	5 yrs. 10 mths.
Lovelace J. Landry	Derrickman	2 yrs. 5 mths.
Eddie J. Simon	Floorhand	5 mths.
Onephor Mathews, Jr.	Floorhand	6 mths.
Rex Faust	Driller	9 yrs. 5 mths.
James E. Fontenot	Derrickman	5 mths.
Byron D. Paul	Floorhand	5 mths.
John T. Ferris	Floorhand	5 mths.
Wilton Duhon	Driller	13 yrs. 9 mths.
Percy D. Hardy, Jr.	Derrickman	2 mths.
Raywood Duhon	Floorhand	3 yrs. 3 mths.
Will R. Begnaud	Floorhand	4 yrs. 4 mths.
Lee West	Pusher	8 yrs. 10 mths.
Nathan C. McManus	Pusher	7 yrs. 5 mths.

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number Prairie Canal #1 County Calcasieu Pa: State Louisiana Field Name South Lake Charles Field Well Location and Land Description 2200 FEL & 2300 F&L Section 21, Township 11S & Range 8W.

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. 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

		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	~~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 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

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 personn 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 time 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.

WellTech Rigs #31 & 61

Subcontract No. 0511-80

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
[signature]	3/10/81
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. 0511-80

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 May 81 — Award Date

UNIT PRICE SCHEDULE

Item No.	Description	Estimated Quantity	Unit	Unit Price	Estimated Price
1.	Mobilization	36	hrs.	$ 195.00	$ 7020.00
2.	Contractor-Directed Operations	240	hrs.	$ 195.00	$ 46,800.00
3.	Standby Ready			$ 195.00	$ N/A
4.	Demobilization	36	hrs.	$ 195.00	$ 7020.00
			ESTIMATED TOTAL COST		$ 60,840.00

#An additional charge of $10.00/hr. will be billed to contractor if drill pipe is used.

#Fluid end parts for pumps will be rebilled to contractor at cost.

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.

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 substructure 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.

Big rigs for big jobs.

In Louisiana, we operate a number of 24-hour rigs which are among the largest in the world. We operate these rigs from South Louisiana through Mississippi and Alabama to the Florida Panhandle. They come equipped with high pressure mud pumps, substructures, hydraulic blowout preventers, pipe racks and mud tanks and are capable of operating to 25,000 feet. In addition, we have conventional double derrick rigs for daylight operations.

But rigs are only half the story: Our Louisiana people are among the most professional, interested and competent groups you'll encounter. They understand and can handle the special needs of the deep, high pressure wells in this area.

The Louisiana Division has a hard-won reputation for excellence. We intend to maintain it.

LOUISIANA DIVISION
Well Servicing Rigs

Rig Types Available	Derrick Height	Capacity (Pounds)	Line Rating	Engine	Horse Power	Rated Depth
Double Derrick	96′	180,000	Six	8V-71	304	18,000′
Double Derrick	96′	250,000	Six	12V-71	456	28,000′

Workover and Completion Rigs (24 Hour) — Houma, Louisiana

	Rig 31	Rig 32	Rig 34
Derrick	110′ Double	110′ Double	112′ Double
Capacity (Pounds)/ Line Rating	354,000/ Ten	354,000/ Ten	358,000/ Ten
Engines	(2) 12V-71 900 H.P.	(2) 12V-71 900 H.P.	(2) 12V-71 900 H.P.
Substructure	18′	18′	18′
Rotary	17½″	17½″	17½″

Workover and Completion Rigs (24 Hour) — Lafayette, Louisiana

	Rig 2	Rig 3	Rig 4	Rig 5	Rig 8	Rig 10
Derrick	110′ Double	104′ Double	110′ Double	110′ Double	110′ Double	110′ Double
Capacity (Pounds)/ Line Rating	300,000/ Eight	300,000/ Eight	300,000/ Eight	300,000/ Eight	300,000/ Eight	358,000/ Ten
Engines	(2) 6V-71 456 H.P.	(2) 8V-71 608 H.P.	(2) 12V-71 900 H.P.	(2) 12V-71 900 H.P.	(2) 8V-92 700 H.P.	(2) 12V-71 900 H.P.
Substructure	16′	15′	18′	18′	18′	18′
Rotary	17½″	17½″	17½″	17½″	17½″	17½″

Workover and Completion Rigs (24 Hour) — Laurel, Mississippi

	Rig 61	Rig 62	Rig 63	Rig 64	Rig 65	Rig 66	Rig 67
Derrick	116′ Double	116′ Double	116′ Double	110′ Double	110′ Double	110′ Double	112′ Double
Capacity (Pounds)/ Line Rating	369,000/ Ten	369,000/ Ten	369,000/ Ten	354,000/ Ten	354,000/ Ten	354,000/ Ten	300,000/ Eight
Engines	(2) V-12 900 H.P.	(2) V-12 900 H.P.	(2) V-12 900 H.P.	(2) V-12 900 H.P.	(2) V-12 900 H.P.	(2) V-8 900 H.P.	(2) V-8 608 H.P.
Substructure	27′	27′	27′	18′	18′	18′	23′
Rotary	17½″	17½″	17½″	17½″	17½″	17½″	17½″

Other Equipment Available

Mud pumps, BOP's, power swivels, tanks, pipe racks

WellTech, Inc.

700 Rusk Avenue
Houston, Texas 77002
713/225-5555
TLX 774386
(WELLTECH HOU)

FACT SHEET

WellTech, Inc. is a privately held oil and gas well servicing contractor with over 200 rigs involved in the completion, servicing and workover of oil and gas wells, operating in the Central, Southwestern, Southeastern and Rocky Mountain regions of the United States. WellTech is jointly owned by subsidiaries of Bechtel Corporation and Hanna Mining Company.

FINANCIAL DATA:

1979 Revenues:	$ 72 million
1979 Net Worth:	$138 million
1979 Working Capital:	$ 12 million

CORPORATE OFFICERS:

David M. Carmichael
Chairman of the Board and
Chief Executive Officer

Christian N. Seger
Vice President-Marketing

James S. LeVoy
President and
Chief Operating Officer

John D. McLain
Vice President-Operations

Steven C. Grant
Vice President-Finance
and Treasurer

Nelson R. Jones
Controller

Elizabeth A. Sauer
Corporate Secretary

W. Leo Payne
Assistant Treasurer

BANKING REFERENCES:

First City Natl. Bank of Houston
1001 Main St.
Houston, Texas 77001
Mr. William J. Rovere, Jr.
713/658-6564

Bankers Trust Company
280 Park Ave.
15th Floor
New York, New York 10017
Mr. Ned Benedict
212/692-3490

Canadian Imperial Bank
of Commerce
One Main Place, Suite 818
Dallas, Texas 75250
Mr. R. Randy Brintnell
214/748-5187

VENDOR REFERENCES:

IDECO Division of Dresser
Dresser Tower
Houston, Texas 77001
713/972-3669

Cabot Corporation
Box 1101
Pampa, Texas 79005
806/669-2581

Cooper Manufacturing
3306 Chas. Page Blvd.
Tulsa, Oklahoma 74101
918/582-2194

CUSTOMER REFERENCES:

Wainoco Oil & Gas Co.
1100 Milam Bldg., Suite 600
Houston, Texas 77002
Mr. Ed Pharis
Production Manager
713/658-9900

Atlantic Richfield Co.
Box 1346
Houston, Texas 77001
Mr. Frank Brown
Drilling Superintendent
713/965-6001

Phillips Petroleum Co.
Box 1967
Houston, Texas 77001
Mr. Bill McMillian
Production Superintendent
713/797-0066

WellTech, Inc. Personnel Rig #31

Name	Title	Years of Experience
Danny Hunter	Rig Supervisor	6 Years
John Sandusky	Rig Supervisor	8 Years
Ronald Mansfield	Rig Operator	6 Years
James Harris	Rig Operator	12 Years
Davis Lawrence	Derrick Man	4 Years
Michael Klingman	Derrick Man	4 Years
Roy Bundrick	Floor Hand	8 Years
Robert Penton	Floor Hand	10 Years
William Reliford	Floor Hand	7 Months
William Callihan	Floor Hand	2 Years
Charlie Morris	Floor Hand	3 Years
Oskie Wilson	Floor Hand	1½ Years
Peter Swarthout	Rig Operator	3 Years
Ralph Kountz	Derrick Man	2 Years
Alan Lufcy	Floor Hand	4 Years
David Hofer	Rig Operator	4 Years
Louis Jefferson	Derrick Man	2 Years
John Caves	Floor Hand	2 Years

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number Prairie Canal #1 County Calcasieu
State Louisiana Field Name South Lake Charles Fld Well Location Parish
Land Description 2200 FEL & 2300 F&L Section 21, Township 11S & Range 8W.

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. <u>General Description of Work</u>. 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. <u>Minimum Equipment and Services</u>. 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. <u>Workweek and Personnel Requirement.</u> 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. 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

		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 Furnished 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	N/A
49. Materials for "boxing in" rig and derrick.	N/A	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 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 stoppe 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 campsite relics, and artifacts. The Subcontractor shall control the movements of his person 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 antiquitie 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 tim 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 damag 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 specificatior whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structure
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.

EATON OPERATING COMPANY, INC.

October 20, 1980

United States Department of Energy
P. O. Box 14100
Las Vegas, Nevada 89114

Attention: Mr. James B. Cotter, Director

Re: Contract No. DE-AC08-80ET27081
RFA #0035 Subcontract No. 0252-80

Gentlemen:

Please refer to our letter dated October 14, 1980, above subject.

WellTech, Inc. inadvertently gave Rig #31 to Getty Oil Company and assigned Rig #61 to us.

Please insert the attached pages as applicable in our proposed Subcontract #0252-80.

Yours very truly,

W. E. Rose

W. E. Rose
Purchasing Manager

WER:mt
Attachments

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WellTech, Inc.

Louisiana Division
Post Office Box 51933, O.C.S.
Lafayette, Louisiana 70505
318/232-3413

RIG #61

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 Hydro-tarder. 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. 3-1/2" 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 engines, CLT-5860 Allison Transmissions.

1 5" X 6" centrifugal mud mixing pump powered by Detroit 4-71N diesel engine.

1 2-1/2" X 2" centrifugal fresh water transfer pump powered by single cylinder Lister 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 Oilwell 17-1/2" rotary table, 300 ton capacity.

1 McKissick 250 ton, 5 sheave traveling block grooved for 1-1/8" line with Web Wilson 250 ton Hydra Hook.

1 IDECO Swivel, 200 ton capacity.

1 3" X 45' rotary hose, 5,000# working pressure.

2 Shaffer "LWS" ram blowout preventers, 6" - 1500 series, flanged top and bottom, H_2S trim.

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R I G #61 - Continued

1 Hydril "GK" annular blowout preventer, 6" - 1500 Series, studded top, flanged bottom, H_2S trim.

1 Drilling spool 6" 1500 series, studded top and bottom, (1) 2" flanged outlet, (1) 3" flanged outlet, 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 Cavins type "F" air operated spider slips with inserts for 2-3/8", 2-7/8" and 3-1/2" tubing.

1 Martin Decker type "FS" weight indicator with Hercules Model 118 anchor.

2 125 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 gal. Diesel fuel tank.

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R I G #61 - Continued

1 Set Foster 58-93-R Hydraulic tongs with jaws for 2-3/8", 2-7/8", and 3-1/2" O. D. tubing.

1 3-1/2" O. D. Square Kelly Baash Ross.

1 Baash Ross Kelly Drive Bushing for 3-1/2" O.D. Square Kelly.

1 Set each 175 ton center latch elevators for 2-3/8", 2-7/8" and 3-1/2" tubing.

1 40 ft. long catwalk.

4 28 ft. long pipe racks.

1 Air Conditioned skid mounted house. Accommodations for WellTech Pusher and two others.

2 Hydraulically operated breakout and make-up cylinders installed in mast.

WellTech, Inc.

700 Rusk Avenue
Houston, Texas 77002
713/225-5555
TLX 774386
(WELLTECH HOU)

WELLTECH PERSONNEL
RIG #61

Rig Supervisors

Bert Riley- previously worked for offshore company from 1950-1968 (roughneck, driller, and pusher). He worked from 1968-1975 as a driller and pusher. Riley has been with WellTech for 1½ years.

James Johnson - previously employed as a driller. He has been working with WellTech for 1 year.

Drillers

Clovis W. Creel - previously worked as a floorhand and derrickman. He has been drilling for WellTech for 5 months.

Willie L. Johnson - previously worked as a roughneck. He has been employed by WellTech 1½ months.

Ronald E. Copeland - previously worked as a motorman and derrickman. He has been drilling for WellTech for 8 months.

John D. Emmons - has been employed by WellTech for one year.

APPENDIX "C"
SUMMARY OF RIG OPERATIONS
H.O.&M. - PRAIRIE CANAL WELL NO. 1
RE-ENTRY OF TEST WELL

Daily Drilling Report Date	Day No.	Operation
10-24-80	1	Rigging up. Made arrangements for blowout preventer stack, choke system, and mud tanks.
10-25-80	2	Continued to rig up. Offloaded drill pipe, drill collars, blowout preventers, tongs, and elevators. Rig-up of equipment approximately 60% complete.
10-26-80	3	Continued to rig up. Finished rigging up mud pumps, charging unit, and extra mud tank. Nippled up blowout preventers and drilling nipple. Installed degasser, choke manifold, pit level indicator, and flow-monitoring equipment. Picked up tongs and kelly. Approximately 80% rigged up.
10-27-80	4	Rigged up and set rathole and mousehole. Finished rigging up choke manifold. Tested blowout preventers and casing to 1360 psi, choke manifold and SWACO choke to 5000 psi. Leveled rig and rigged up flare line. Installed flange on blowout preventer valve and extra kill line. Rigged up power tongs, rotary guard, Martin Decker torque gauge, and Martin Decker four-pin recorder.
10-28-80	5	Rigged up Dia-log and attempted to run 9-5/8 inch O.D. casing inspection tool; it would not go through blowout preventers. Attempted to run 7-5/8 inch O.D. casing inspection tool, but mud was too heavy, and it failed to go. Cleaned mud tank and rigged down Dia-log. Picked up bottom-hole assembly (mill, junk basket, 4-3/4 inch O.D. drill collars) and 3-1/2 inch O.D. drill pipe and ran in hole. Picked up kelly and attempted to break circulation, but pumps did not work - repaired same and circulated out at approximately 5000 feet.
10-29-80	6	Picked up 3-1/2 inch drill pipe, using lay-down equipment. Attempted to repair Benton rental tongs without success. Rigged up Specialty, Inc. power tongs. Picked up kelly and circulated out at 11,235 feet. Ran in hole to 13,141 feet. While attempting to circulate at 13,141 feet, pipe became stuck. Pulled 40,000 lb over the weight of the pipe and was able to free same. Continued to work pipe and attempting to

Daily Drilling Report Date	Day No.	Operation
		circulate, but pumps were losing pressure. Switched back and forth between pumps until they lost pressure completely.
10-30-80	7	Pumps failed again. Called vacuum trucks and pumped out mud pits. WellTech, Inc. changed out mixing pump and repaired both mud pumps.
10-31-80	8	Finished cleaning mud tanks and repairing mud mixing pump. Replaced flapper valve on water pump. Mixed and conditioned mud in pits, but hopper plugged. Repaired same and switched suction hoses. Broke circulation with No. 1 pump and pumped for half an hour. Swab went out; changed to No. 2 pump and continued to circulate while repairing pump No. 1. Serviced rig and replaced shaker screen. Ran 5 stands in hole. Picked up kelly and broke circulation at 1500 psi. Milled from 13,141 feet to 13,150 feet. Lost mud weight and gained viscosity in mud tanks. Mixing pump would not work. Replaced mixing pump and mixed mud in pits to bring up weight.
11-01-80	9	Moved water pump and primed same for rig water. Reamed from 13,156 to 13,181 feet. Lost pressure on No. 1 pump, switched to pump No. 2. Lost pressure on No. 2 pump, both pumps down, called Halliburton. Worked on pumps and mixed mud while waiting for Halliburton pumps. Rigged up Halliburton. Washed and reamed from 13,181 to 13,643 feet.
11-02-80	10	Washed and reamed 13,643 to 13,782 feet. Drilled cement from 13,782 to 14,006 feet. WellTech brought out another pump and rigged up same. Kept Halliburton on standby. Tagged retainer at 14,006 feet and milled same to 14,008 feet. Drilled cement from 14,008 to 14,149 feet and hole to 14,171 feet. Circulated and cleaned the hole, conditioned the mud, and checked for flow every hour. Had slow flow back.
11-03-80	11	Finished circulating and conditioning mud to clean the hole. Pulled out of the hole, pulling first 40 stands very slowly. Power tongs would not grip metal on grade "E" drill pipe. Finished coming out of the hole with manual tongs and rotary. Tested blowout preventers and rigged up Schlumberger. Ran electromagnetic thickness tool in 9-5/8 inch O.D. casing from 11,700 to 3500 feet and in 7-5/8 inch O.D. casing from 14,122 to 12,700 feet.

Daily Drilling Report Date	Day No.	Operation
11-04-80	12	Rigged down Schlumberger. Picked up bottom-hole assembly and began to run in the hole. Slipped and cut 180 feet of drill line. While continuing to run in hole, power tongs failed. Worked on power tongs (replaced guide pins) and continued to run in hole. Circulated and conditioned mud before going into open hole. Began to wash and ream from 14,171 feet.
11-05-80	13	Washed and reamed from 14,171 to 15,438 feet. Had approximately 200 units of gas at 15,000 feet for two minutes.
11-06-80	14	Washed and reamed from 15,438 to 15,534 feet. Drill pipe stuck when rig was shut down for 10 minutes for repairs to the control system. Circulated, worked and jarred on stuck drill pipe. Spotted 100 barrels of 17.3 ppg oil base mud with 52 barrels outside bottom-hole assembly. Worked stuck pipe while pumping 2 barrels of oil-base mud each hour.
11-07-80	15	Continued to work stuck drill pipe and pumping 1.5 to 2 barrels of oil-base mud every hour. Unable to work stuck drill pipe; shaft in drawworks broken. Continued to pump oil-base mud, reduced rate to 1 barrel every 2 hours.
11-08-80	16	While repairing the rig (replacing high-low clutch shaft), continued to pump oil-base mud, reducing the rate from 1 barrel every 2 hours to 1 barrel every 4 hours.
11-09-80	17	Completed rig repairs and jarred fish loose. Pulled bit up into protection casing. Could not circulate after jarring loose. Pulled 6 more stands and circulated. Pulled 7 more stands and began to circulate out oil-base mud.
11-10-80	18	Circulated out but did not recover any oil-base mud. Washed and reamed to a total depth of 15,684 feet. Circulated and conditioned mud in hole. Mud was cut to 16.0 ppg from 17.3 ppg with 300 units of gas.
11-11-80	19	Circulated and conditioned mud until mud was stablized at 17.4 ppg going in and coming out. Made 6-stand short trip and circulated 17.4 ppg mud with one complete circulation. Began to pull out of the hole laying down 3-1/2 inch O.D. drill pipe.

Daily Drilling Report Date	Day No.	Operation
11-12-80	20	Continued to pull out of the hole, laying down 3-1/2 inch O.D. drill pipe.
11-13-80	21	Finished pulling out of the hole and laying down bottom-hole assembly. Rigged up to run 5-1/2 inch O.D. casing. Started to run 5-1/2 inch O.D. casing.
11-14-80	22	Continued to run 5-1/2 inch O.D. casing while testing same as it was being run in the hole. Testing unit stuck on collared pipe and had to be taken apart to get it loose. Continued to run 5-1/2 inch O.D. casing, putting mud in each joint and stopping every 5 joints to fill up.
11-15-80	23	Broke circulation at bottom on 7-5/8 inch O.D. liner and checked for flow. Finished running 5-1/2 inch O.D. casing with shoe at 15,610 feet. Rigged up cementing head and lines. Cemented casing with a slurry of 750 sacks class "H" cement with 35% Silica, 1% CFR-2, 0.6% Halad-22A, 0.4% HR-5, and 3 lb Hi-dense with 81 barrels of fresh water. Displaced with 345 barrels of 17.4 ppg mud and bumped plug with 1500 psi. A 15-barrel SAM-5 spacer was placed ahead of the cement, and a 5 barrel SAM-5 spacer was placed behind the cement. Waited on cement for approximately 6 hours.
11-16-80	24	Continued to wait on cement for approximately 18 more hours. Tested casing to 1500 psi and nippled down blowout preventers. Installed casing hanger and nippled up tubing spool.
11-17-80	25	Nippled up blowout preventers and tested same to 1500 psi. Rigged up Schlumberger. Ran cement bond log to 15,140 feet, but tool failed. Pulled out of the hole and changed tool. Ran back in hole to 15,478 feet, and tool failed again. Pulled out of the hole and changed tool. Ran back in hole to 15,478 feet and completed logging.
11-18-80	26	Rigged down Schlumberger. Rigged up to run 2-3/8 inch O.D. tubing. Picked up 2-3/8 inch O.D. tubing and started running in hole. Plans were changed; began to pull out of the hole. Worked with Halliburton on a cement squeeze program and waited on RTTS tool. Started to run RTTS tool, but plans were changed. Rigged down bell nipple and installed companion flange for lubricator on hydril. Rigged up Schlumberger and prepared to run cement bond log under pressure.

Daily Drilling Report Date	Day No.	Operation
11-19-80	27	Waited on cross-over sub for lubricator; upon arrival rigged up same. Attempted to run cement bond log under a pressure of 1500 psi. Ran in hole with 5 tools (5th tool worked). Logged from 15,482 to 11,000 feet. Rigged down Schlumberger. Nippled up bell nipple and flow line and started to run back in hole with 2-3/8 inch O.D. tubing.
11-20-80	28	Finished running back in hole with 2-3/8 inch O.D. tubing to 15,526 feet. Displaced 17.3 ppg mud with 9.0 ppg brine water. Pulled out of the hole to 14,850 feet laying down excess tubing. Nippled down blowout preventers.
11-21-80	29	Set off blowout preventers and nippled up production tree. Began to rig down and released rig at 1800 hours on 11/21/80. Tested production tree to 7500 psi for 30 minutes - no leaks. Returned 250 joints of S-135 drill pipe, 80 joints of "E" drill pipe, and 24 joints of 4-1/2 inch O.D. drill collars.
11-22-80	30	Rigging down.
11-23-80	31	While rigging down substructure, it was discovered that there was pressure on the production tree. It was attempted to bleed off the pressure over a 20-minute period, with no noticeable drop in pressure. A 10,000-psi gauge and a flange were ordered, to flow air and fluid through an adjustable choke. After installing the equipment, a pressure of 1530 psi was noted on the gauge. The pressure was bled to 0 psi over a 1-1/2 hour period.
11-24-80	32	Continued rigging down. Checked well for pressure. Removed valves from production tree, skidded substructure off well, and rigged down same. Rigged down derrick and cleaned up location.

APPENDIX "C"
SUMMARY OF RIG OPERATIONS
H.O.&M. - PRAIRIE CANAL WELL NO. 1
WORKOVER NO. 1 TEST WELL

Daily Drilling Report Date	Day No.	Operation
1-07-81	1	Positioning WellTech Rig No. 9 on location.
1-08-81	2	Rigged up. Received 100 barrels of 9.5 ppg brine.
1-09-81	3	Rigged up floor. Pulled out of hole with 2-3/8 inch tubing. Found parted coiled tubing after pulling 91 stands. Rigged up coiled tubing unit and latched onto parted coiled tubing. Pulled out of hole with coiled tubing and Dyna Drill assembly. Rigged down coiled tubing unit, closed rams, and installed TIW valve.
1-10-81	4	Pulled out of hole with 2-3/8 inch tubing to 2200 feet. Started flowing. Reversed out rubber and cement particles. Changed set in pump. Reverse circulated. Pulled out of hole. Drawworks engine had cracked head. Changed head on 8V71 engine.
1-11-81	5	Pulled out of hole with 2-3/8 inch tubing. Re-entry guide badly damaged by junk. Layed down 3 bad joints of tubing. Ran in hole with bit and 6 stands of tubing. Pipe stopped going in hole. Pulled out of hole. Picked up 4-5/8 inch mill. Ran in hole with mill. Layed down 4 bad joints of tubing. Ran 6060 feet of pipe in the hole. Recovered several pieces of rubber from flow line.
1-12-81	6	Shut down for weekend.
1-13-81	7	Ran in hole with 2-7/8 inch tubing and 4-5/8 inch mill. Stopped at 14,227 feet. Washed down from 14,227 to 14,910 feet. Circulated 11.1 ppg mud out with rubber, cement, and shale cuttings. Used the tongs to rotate string. Circulated 50 barrrels of mud. Tubing pressure was 0 psi.
1-14-81	8	Picked up tubing and washed from 14,910 to 15,494 feet and stopped. Circulated out red and black rubber and cement. Rigged up power swivel. Could not rotate, except when moving pipe. Pulled 8 stands out of hole. Could not rotate. Ran 2 stands in hole. Pumped 500 barrels at 40 barrels per minute. Shut in well.

Daily Drilling Report Date	Day No.	Operation
		Weatherly rigged up choke line from casing valve to sump hole.
1-15-81	9	Pulled out of hole measuring tubing. Total length 15,464 feet. Rigged up Schlumberger and ran junk basket and gauge ring on wireline to 15,466 feet. Pulled out of hole and recovered several pieces of heavy black rubber. Ran junk basket back in hole to 15,415 feet. Pulled out and found no junk in basket. Set 5-1/2 inch EZSV cement retainer at 15,390 feet.
1-16-81	10	Went in hole with tubing and wireline guide. Tagged plug at 15,390 feet. Reverse circulated out of tubing. Fluid returns were clean. Pulled tubing up 14,860 feet. Nippled down blowout preventers and nippled up christmas tree.
1-17-81	11	Cleaning mud tank. Made 1-27/32 inch gauge run on wireline to 15,300 feet. Rigged down and moved out WellTech Rig No. 9.

APPENDIX "C"
SUMMARY OF RIG OPERATIONS
H.O.&M. - PRAIRIE CANAL WELL NO. 1
WORKOVER NO. 2 TEST WELL

Daily Drilling Report Date	Day No.	Operation
1-31-81	1	Moving in WellTech Rig No. 5 and spotting equipment.
2-01-81	2	Rigging up.
2-02-81	3	Installed back-pressure valve. Nippled down christmas tree and set slips. Broke out tree, and bushing stayed in tree. Waited on TIW valve. Removed tree and installed TIW valve. Nippled up 6-inch 1500 Series blowout preventers with 2-3/8 inch rams on bottom and blind rams on top. Nippled up 6-inch 1500 Series G.K. hydril. Moved structure over well. Raised and rigged up floor. Put up stairs and rigged up choke manifold, bell nipple, and flow line. Hooked up HCR valve and SWACO choke. Hooked up fill-up line. Hung power tongs, put up kelly slide and picked up kelly. Drilled rathole and dressed out kelly. Tested blind rams and choke manifold to 4000 psi and hydril to 3500 psi. Backed out hold-down screws, pulled and layed down pack-off. Put on kelly and raised mud weight in tank from 17.1 ppg to 17.4 ppg. Filled casing with 10 barrels and tubing with 2-1/2 barrels. Circulating and conditioning light mud from 17.3 ppg in and 16.8 ppg out to 17.4 ppg in and out. Slugged pipe, broke circulation slowly with 2800 psi. Formation took 2 to 3 barrels of mud. Started pulling out of hole.
2-03-81	4	Pulled out of hole measuring pipe, and filling hole every 5 stands. Picking up and making up bottom-hole assembly. Went in hole. Rigged up reversing line to shaker. Carried and measured 14 joints of tubing to catwalk. Circulated and washed from 14,959 to 14,990 feet, unplugging tubing by pumping long way. Lost 4 barrels of mud in hole. Started pumping long way. Hole stayed full but no flow in flow line. Started pulling out of hole. Pipe was wet. Mixed and pumped slug of mud.
2-04-81	5	Finished pulling out of hole. Broke down bottom-hole assembly. Layed down wash pipe. No recovery. Picked up new bottom-hole assembly of 4-1/16 inch overshot dressed with 1-11/16 inch grapples and started in hole to 7400 feet, drifting pipe. Circulated and conditioned

Daily Drilling Report Date	Day No.	Operation
		mud, cutting mud weight back to 17.3 ppg. Finished in hole 14,750 feet, drifting pipe. Circulated and conditioned mud. Cutting mud weight back to 17.3 ppg.
2-05-81	6	Circulated and conditioning mud at 14,790 feet. Washed from 14,790 to 15,022 feet. Hit obstruction at 15,022 feet. Circulated to clean hole while installing rotary chain. Attempting to get over bottom-hole sampler tool. Circulating and attempting to get over tool. Mixed and pumped slug of mud. Started to pull out of hole and slips broke. Waited on new slips. Cut joint of 2-3/8 inch tubing into muleshoe. Finished pulling out of hole. Broke out and layed down fishing tools. No recovery. Made up muleshoe joint and went in hole. Washed 15,022 to 15,081 feet.
2-06-81	7	Washed from 15,081 to 15,155 feet. Circulated and conditioned mud. Worked on pumps. Pump suction had approximately 3 inches of barite settlement. Raised viscosity in mud from 47 to 60. Washed from 15,155 to 15,240 feet. Hit obstruction. Attempted to get through, got stuck, and pulled loose. Circulated and conditioned mud with 1000 psi at 2 barrels per minute. Pressure went up to 1200 psi. Started losing returns. Circulated and conditioned mud. Working pipe constantly. Gained returns. Working approximately a 50-foot stroke. Pulled 5 stands to get above perforations. Finished circulating out. Ran 5 stands back to bottom. Had 8 feet of fill. Pulling out of hole. Recovered approximately 2 barrels sandstone from shale shaker.
2-07-81	8	Finished pulling out of hole with muleshoe joint. Rigged up McCullough. Ran 4.51-inch gauge ring, junk basket, and two sinker bars to 4000 feet. Pulled out of hole and cleaned sandstone from junk basket. Ran 4.51-inch gauge, junk basket, and two sinker bars to 4,728 feet and pulled out of hole - nothing in junk basket. Ran gauge ring, four sinker bars, and junk basket to 5,076 feet and stopped going in hole. Pulled out of hole. Made trip in hole with two sinker bars to 14,656 feet, pulled out of hole, and rigged down McCullough. Made up bottom-hole assembly. Went in hole to 7,405 feet. Attempted to reverse circulate; pipe plugged. Pumped down tubing and unplugged pipe. Tried to reverse circulate and lost 6 barrels of mud at 1000 psi. Pulled 40 stands of pipe out of hole to 5054 feet. Attempted to reverse circulate and plugged pipe. Pumped down pipe to unplug. Reversed circulated and lost 30 barrels of mud at 1000 psi. Mixed and pumped slug of mud. Pulling out of hole.

Daily Drilling Report Date	Day No.	Operation
2-08-81	9	Finished pulling out of hole. Layed down wash pipe. Went in hole to 5000 feet with muleshoe joint. Hooked up lines to reverse circulate. Reverse circulated at 5000 feet. Cut off 90 feet of drill line. Going in hole to 10,000 feet. Reverse circulated at 10,000 feet with 800 psi. Finished going in hole to 15,240 feet. Attempted to reverse circulate, failed. Pumped down tubing with 2000 psi. Pipe plugged. Pulled one stand to 15,160 feet. Pumped down tubing and broke circulation with 1800 psi. Circulated and conditioned mud at 15,180 feet. Pump rate 1 barrel per minute at 1700 psi. Lost 4-1/2 barrels of mud. Pulled up 10 stands to 14,567 feet. Swabbed for 6 stands and had drag for 6 stands (10,000 lb). Circulated with 1700 psi.
2-09-81	10	Pulled 10 stands to 13,960 feet. Attempted to circulate while working on rig pumps. Rigged up Halliburton. Circulated and conditioned mud at 2 barrels per minute at 2400 psi. Reverse circulated. Pressure went from 1900 psi to 1500 psi. Loosing returns. Circulated down tubing. Pressure increased from 1800 to 2400 psi at 2 barrels per minute. Ran 10 stands in hole to 14,567 feet. Circulated and conditioned mud at 2400 psi, 2 barrels per minute. Ran 5 stands to 14,867 feet. Circulated and conditioned mud at 2400 psi, 2 barrels per minute. Mud weight circulating out at 13.2 ppg. Circulated and conditioned mud to 17.1 ppg in and out. Ran 6 stands in hole to 15,240 feet. Circulated and conditioned mud at 2400 psi, 2 barrels per minute. Hit something 9 feet off bottom. Approximately 1-1/2 barrels of sandstone and shale recovered from shale shaker.
2-10-81	11	Started out of hole. Pipe pulling wet. Mixed and pumped slug. Changed slip inserts. Finished pulling out of hole. Layed down muleshoe. Made up bottom-hole assembly consisting of bit and scraper. Changed tong dies and adjusted tongs. Finished going in hole to 14,940 feet. Laid down 9 joints of tubing. Ran 5 stands in hole to 14,970 feet. Washed from 14,970 to 15,210 feet with 2 barrels per minute at 2400 psi. Circulated and conditioned hole for logging.
2-11-81	12	Mixed and pumped slug. Pulled out of hole with bit and scraper. Broke down bit, scraper, and jars. Rigged up Dia-log. Started in hole and found tight spot in 5-1/2 inch casing at 3800 feet. Ran casing caliper log from 15,167 feet to the surface. Rigged down Dia-log.

Daily Drilling Report Date	Day No.	Operation
		Waited on McCullough. Rigged up McCullough. Started in hole and tool stopped at 4060 feet.
2-12-81	13	Unable to get below 4060 feet with caliper inspection. Pulled out of hole. Rigged down McCullough. Picked up bottom-hole assembly of wash pipe with globe catchers and went in hole to 15,232 feet. Picked up kelly. Pumped 40 barrels 17.3-ppg mud with Halliburton. No returns. Pulled 20 stands to 14,006 feet. Picked up kelly. Working pipe constantly. Circulated out 300 barrels of 17.3-ppg mud. Ran in 10 stands and circulated at 14,630 feet for 1-1/2 hours. Ran in 5 stands and circulated at 14,941 feet for 1 hour.
2-13-81	14	Finished circulating at 14,941 feet. Ran 5 stands. Picked up kelly and circulated at 15,232 feet. Washed and reamed from 15,232 to 15,390 feet. Circulated to clean hole. Mixed and pumped slug. Pulled out of hole with wash pipe. Globe catchers broken. No recovery. Approximately two barrels of sandstone over shale shaker.
2-14-81	15	Broke down bottom-hole assembly. Cleaned and loaded out fishing tools. Picked up and started in hole with EZSV cement retainer. Rigged up Halliburton and set EZSV cement retainer at 14,925 feet. Tested annulus and EZSV to 1000 psi. Broke down formation with 3000 psi at 2 barrels per minute. Mixed and pumped 250 sacks of class "H" cement with 35% Silica flour, 1% CF R-2, 0.6% Halad 22-R, 0.7% HR-12, 7 lb per sack High Dense No. 3. Mixed with 27 barrels of fresh water. Total slurry 58 barrels at 17.5 ppg. Final pressure 4400 psi. Had 3 barrels return. Pumped 55 barrels under retainer. Reversed out 5 barrels ahead and 5 barrels behind cement. Pulled 5 stands. Flowing back. Rigged up and reversed out. Conditioned mud from 16.0 ppg to 17.3 ppg. Slugged pipe. Pulled out of hole.
2-15-81	16	Pulled out of hole. Layed down setting tool. Rigged up SWACO choke. Tested blowout preventers with 4000 psi and tested hydril to 3000 psi for 30 minutes. Went in hole with wireline re-entry guide on 2-3/8 inch tubing. Washed down and tagged plug at 14,920 feet. Rigged up Halliburton and test lines to 10,000 psi. Displaced 17.3-ppg mud with 9.0-ppg saltwater.
2-16-81	17	Finished displacing and washing well with saltwater. Layed down 9 joints of tubing and hung tubing at 14,648 feet. Rig down floor and substructure. Installed christmas tree and tested to 8000 psi. Rig released at 2100 hours. Washing tanks, pumps, and rigging down.

APPENDIX "C"
SUMMARY OF RIG OPERATIONS
H.O.&M. - PRAIRIE CANAL WELL NO. 1
PLUGGING AND ABANDONMENT TEST WELL

Daily Drilling Report Date	Day No.	Operation
3-17-81	1	Move in rig and start rigging up. 50% complete.
3-18-81	2	Finished rigging up. Broke circulation. Circulating pressure 2200 psi. Final circulating pressure was 1600 psi at 1.5 barrels per minute. Nippled down christmas tree and nippled up 7-1/16 inch Cameron-Type U double blowout preventers. Rigging up rig floor. Started out of hole with 2-3/8 inch tubing.
3-19-81	3	Finished pulling out of hole with 2-3/8 inch tubing. Totalled 14,654.83 feet. Rigged up pressure-testing unit to test blowout preventers. Tested pipe rams to 6000 psi for 30 minutes. Tested valves on spool to 6000 psi for 30 minutes. Tested valves on choke manifold to 4000 psi for 10 minutes. Made up EZSV and setting tool. Waited on adapter for bell nipple. Nippled up bell nipple and flow line. Went in hole with EZSV on 2-3/8 inch tubing to 14,660 feet. Rigged up Halliburton. Broke circulation and conditioned mud.
3-20-81	4	Circulated and conditioned mud. Stung into retainer and established pumping rate at 2300 psi at 1 barrel per minute and 4500 psi at 2 barrels per minute. Pumped 200 sacks, class "H" with 0.5% CFR-2, 1.5% HR-12. Final squeeze pressure 4800 psi. Pulled out of retainer and spotted 25 sacks on top of retainer, 343 feet of cement, or 32.75 cubic feet. Pulled out of hole with setting tool and layed down 90 joints of tubing. Went in hole with McCullough wireline and set bridge plug at 11,700 feet. Rigged up 5-1/2 inch casing jet cutter and went in hole to 11,600 feet. Tested 5-1/2 inch pipe rams to 3000 psi for 15 minutes. Cut 5-1/2 inch casing at 11,500 feet. Picked up 5-1/2 inch casing spear and attempted to pull casing. Nippled down blowout preventers to check 5-1/2 inch casing slips. Slips would not pass through blowout preventers.
3-21-81	5	Pulled 5-1/2 inch casing to 300,000 pounds. Casing weight 190,000 pounds. Rigged up McCullough and went in hole and cut casing at 23 feet. Picked up 5-1/2 inch casing spear and pulled out of hole with 23 feet of 5-1/2

Daily Drilling Report Date	Day No.	Operation
		inch casing and slips. Worked 5-1/2 inch casing with stretch of 118". Held 2000 psi on casing while working with no returns. Unable to release spear. Rigged up 4-1/2 inch power tongs, released spear, changed grapples and stripped wireline through spear. Reheaded wireline. Went in hole with McCullough free point tool. Free-point found 5-1/2 inch casing 100% stuck at 7550 feet and 100% free from 7323 feet to surface. Started to pull out of hole with free-point tool; became stuck at 1428 feet. Pulled out of rope socket. Waited for fishing tools. Made up 1-3/8 inch grapple with 4-11/16 inch guide on 2-3/8 inch tubing and started in hole. Unable to get past 450 feet. Pulled out of hole. Went in hole with 1-3/8 inch grapple and 3-5/8 inch guide. Tagged fish at 1434 feet. Pulled out of hole with no recovery. Went in hole to push fish to bottom and attempt to recover.
3-22-81	6	Went in hole with overshot and tagged fish at 6200 feet. Pushed fish to 7600 feet. Pulled out of hole and layed down 2-3/8 inch tubing. No recovery of fish. Nippled up blowout preventers and tested to 3000 psi with rig pump. Went in hole with casing cutter and cut casing at 7342 feet and pulled out of hole with wireline. Worked casing and attempted to establish circulation. Had 2 feet of movement. Went in hole with casing cutter, cut casing at 6344 feet and pulled out of hole with wireline. Pulled out of hole with 4-1/2 inch pup joints, spear, and top joint of 5-1/2 inch casing. Rigged up lay-down equipment.
3-23-81	7	Laid down 5-1/2 inch casing using cat line. Rigged up lay-down machine. Finished laying down 5-1/2 inch casing. Total casing recovered was 6330 feet, consisting of 151 joints and 2 cut joints. Rigged down casing equipment and finished strapping casing. Nippled down blowout preventers and rigged up McCullough to run 9-5/8 inch EZSV cement retainer. Went in hole with EZSV and set at 6224 feet. Nippled down 9-5/8 inch casing spool. Went in hole with 9-5/8 inch casing spear and attempted to pull 9-5/8 inch slips, but unable to move them. Rigged up McCullough and stripped wireline through 9-5/8 inch spear. Cut 9-5/8 inch casing at 23 feet. Laid down cut casing joint and made up 1 joint of 4-1/2 inch drill pipe on spear. Went in hole with free-point tool; had short in surface equipment. Waited for replacement truck. Rigged up McCullough and went in hole with 9-5/8 inch casing free-point tool. Casing 100% free at 2416 feet. Made 3 attempts with casing cutter but could not get past 9-5/8 inch stub. Made up string shot.

Daily Drilling Report Date	Day No.	Operation
3-24-81	8	Finished making up string shot. Went in hole with string shot and disconnected 9-5/8 inch casing at 2383 feet. Rigged up lay-down machine. Broke out 33 joints of 9-5/8 inch casing while waiting for high torque tongs. Laid down tongs and rigged up high torque tongs. Finished laying down 2387 feet of 9-5/8 inch casing consisting of 61 joints. Went in hole with 2-3/8 inch tubing and pulled out of hole laying down same. Made up EZSV cement retainer on 2-3/8 inch tubing, went in hole and set at 2271 feet.
3-25-81	9	Rigged up Halliburton and pumped 220 sacks of cement below EZSV retainer and spotted 50-sack plug on top of retainer. Pulled out of hole to 100 feet and spotted a 50-sack plug from 100 feet to surface. Pulled out of hole and rigged down Halliburton. Rigged down substructure and cut pipe 4 feet below ground. Washed out mud tanks and rigged down.

APPENDIX "D"
SUMMARY OF RIG OPERATIONS
H.O.&M. - PRAIRIE CANAL WELL NO. 1
DISPOSAL WELL DRILLING

Daily Drilling Report Date	Day No.	Operation
11-22-80		Drove 14-inch conductor pipe to 115 feet. Final blow count was 165 blows per foot.
11-24-80	1	Filled in part of fresh water pit and built turn-around pad extension on west side of location. Completed rig pad. Rigging up.
11-25-80	2	Continued rigging up - approximately 65% complete.
11-26-80	3	Continued rigging up. Tied mud tanks together and rigged up Koomey Unit. Installed flare line and hooked up air lines. Installed "V" door and catwalk. Set up tubing racks and moved 3-1/2 inch O.D. drill pipe. Hooked up rotary chain and unloaded 9-5/8 inch O.D. casing.
11-27-80	4	Nippling up double-studded flange and hydril. Installed drilling nipple, laid water line and rigged tongs. Picked up kelly and installed rathole and mousehole.
11-28-80	5	Spudded well and drilled to 693 feet. Plugged the drilling bit, attempted to unplug it, failed. Pulled out of the hole, cleaned the bit, ran back in the hole, and drilled to 753 feet.
11-29-80	6	Drilled from 753 to 1003 feet. Ran gyroscopic survey at 1003 feet, indicating a 1° deviation from vertical. Drilled from 1003 to 1528 feet and circulated and conditioned mud. Ran gyroscopic survey at 1497 feet indicating a 1° deviation from vertical. Pulled out of the hole and rigged up Superior casing equipment. Ran 38 joints of 9-5/8 inch O.D. casing with the shoe at 1528 feet. Circulated and conditioned mud and rigged down Superior casing equipment. Rigged up Halliburton cementing equipment and pumped a lead slurry of 600 sacks of light weight cement with 3% NaCl mixed in 142 barrels of fresh water. It was followed by a tail slurry of 300 sacks class "H" cement, with 1% CaCl, mixed in 32 barrels of fresh water.

Daily Drilling Report Date	Day No.	Operation
11-30-80	7	Waited for cement to set for 23 hours and began to nipple down.
12-01-80	8	Nippled down hydril and cut off landing joint. Installed 9-5/8 inch O.D. wellhead rated for 3000 psi. Tested wellhead to 1500 psi and nippled up blowout preventers.
12-02-80	9	Serviced rig and tested the following items: casing (to 1500 psi), pipe rams, HCR valve, hydril (to 1500 psi), blind rams, choke, and valves. Ran in hole with 3-1/2 inch O.D. drill pipe and tagged float collar at 1435 feet. Tagged shoe at 1519 feet and drilled through shoe. Circulated and conditioned mud while drilling cement and formation to 1555 feet.
12-03-80	10	Drilled from 1555 to 1626 feet and pulled out of the hole. Changed bottom-hole assemblies and ran back in the hole. Drilled from 1626 to 1814 feet and serviced rig. Drilled from 1814 to 2389 feet and took survey at 2205 feet, indicating a 1/4^{o} deviation from vertical.
12-04-80	11	Drilled from 2388 to 2710 feet. Took short trip (22 stands). Drilled from 2710 to 3255 feet and pulled out of the hole for new bit.
12-05-80	12	Finished pulling out of the hole to change bits and ran back in the hole. Drilled from 3265 to 3723 feet and ran gyroscopic survey, indicating a 1^{o} deviation from vertical at 3722 feet. Drilled from 3722 to 4047 feet.
12-06-80	13	Unballing bit at 4007 feet. Drilling from 4007 to 4187 feet and attempted survey - clock not working. Drilled from 4187 to 4283 feet and ran gyroscopic survey indicating a 1/4^{o} deviation from vertical at 4377 feet. Drilled from 4283 to 4377 feet and proceeded to service the rig. Drilled from 4377 to 4553 feet.
12-07-80	14	Drilled from 4553 to 4645 feet. Pulled out of the hole to change bit and bottom-hole assembly. Picked up bottom-hole assembly and ran in the hole inspecting each connection; found all drill collars and stabilizers over-torqued. Layed down 8 drill collars and 2 stabilizers and picked up new ones. Ran in hole with new bottom-hole assembly and 3-1/2 inch O.D. drill pipe.

Daily Drilling Report Date	Day No.	Operation
12-08-80	15	Finished running in the hole and broke circulation. Drilled from 4645 to 5220 feet. Pulled out of the hole and rigged up logging equipment. Ran ISF/PGT (Density), SGTE (Gamma-ray), and caliper.
12-09-80	16	Finished running log from 5281 to 1524 feet and rigged down logging equipment. Ran in hole measuring pipe to the total depth of 5282 feet. Circulated and conditioned hole. Ran gyroscopic survey at 5242 feet, indicating a 1/4° deviation from vertical. Pulled out of the hole laying down 3-1/2 inch drill pipe and bottom-hole assembly. Rigged up Superior casing equipment and began to run 5-1/2 inch O.D. casing.
12-10-80	17	Finished running 122 joints of 5-1/2 inch O.D. casing with shoe at 5260 feet. Rigged down Superior casing crew's equipment and rigged up Halliburton's cementing equipment. Cemented the casing with a lead slurry of 805 sacks of light weight cement mixed in 192 barrels of fresh water and weighing 12.7 ppg, followed by a tail slurry of 500 sacks class "H" cement mixed in 62 barrels of fresh water, displaced with 118 barrels of 9.5 ppg saltwater. Picked up blowout preventers and set casing with 92,000 lb on slips. Cut casing and nippled down blowout preventers. Nippled up head on well and tested same to 2000 psi.
12-11-80	18	Rigging down - approximately 80% complete.
12-12-80	19	Finished rigging down and moving rig off location.
12-13-80	20	Crew cleaning location.
12-14-80	21	Crew cleaning location.
12-15-80	22	Cleaned up location. Rigged up logging equipment and ran cement bond log from 5070 to 3050 feet. Rigged down logging equipment and waited for daylight to perforate. Cement bond log showed good bond.
12-16-80	23	Perforated interval from 4570 to 4600 feet with 122 shots in two runs, pumping in after each run. Perforated interval from 4490 to 4560 feet with 283 shots in 3 runs, pumping in after each run. Cleaned up and repaired location.

Daily Drilling Report Date	Day No.	Operation
12-17-80	24	Continued cleaning up and repairing location.
12-18-80	25	Continued cleaning up and repairing location.
12-19-80	26	Continued cleaning up and repairing location.
12-20-80	27	Rigged up Halliburton and filled tubing with acid, establishing a pump rate of 1 barrel per minute at 1050 psi. Pumped 5000 gallons of 15% FE acid, 0.15% PEN-5, 0.2% HAI-55, and 250 gallons matriseal OWG. Started pumping 10,000 gallons regular HFD acid with 0.15% PEN-5 and 0.2% HAI-55. Followed acid with 2000 gallons of "Clayfix" solution and displaced all treatment fluid with saltwater.
2-26-81		Pumped into formation at 2 BPM with 600 psi. Preceded cement with 50 barrels of water. Pumped 35 sacks of "light" cement, 12.8 ppg, and displaced same with 100 barrels saltwater at 4 BPM and 600 psi. Slowed pump to 1 BPM for last 8 barrels. Final pressure was 50 psi. Waited on cement (WOC).
2-27-81		WOC. Perforated well 3350 to 3410 feet and 3070 to 3130 feet with 4 holes per foot.
2-28-81		Acidized well with 5000 gallons "FE" acid and 10,000 gallons of HF acid. Followed acid with 2000 gallons of 2% "Clayfix" solution.