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DOE/ET/27081-5 Vol. I

GEOPRESSURED - GEOTHERMAL PROGRAM

MASTER

FINAL REPORT: SALDANA WELL NO. 2 ZAPATA COUNTY, TEXAS

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

DISCLAIMER

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1.0 EXECUTIVE SUMMARY

The Saldana Well No. 2, approximately 35 miles Southeast of the city of Laredo, Texas, was the sixth 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 8, 1980, when Riddle Oil Company abandoned the well as a dry hole at a depth of 11,171 feet.

The well was tested through the annulus between 7-inch casing and 2-3/8 inch tubing. The interval tested was from 9745 to 9820 feet. The geological section was the 1st Hinnant Sand, an upper member of the Wilcox Group. Produced water was injected into the Saldana Well No. 1, which was also acquired from Riddle Oil Company and converted to a disposal well. A Miocene salt water sand was perforated from 3005 to 3100 feet for disposal.

One pressure drawdown flow test and one pressure buildup test were conducted during a 10-day period. A total of 9328 barrels of water was produced. The highest sustained flow rate was 1950 BWPD.

The gas-to-water ratio, measured during testing by adding flare line gas and gas remaining in solution in brine after the separator, ranged from 47 to 54 SCF/BBL. Laboratory recombination studies determined a saturation value of 40.9 SCF/BBL, indicating that gas production was in excess of solubility in the brine at reservoir conditions. Two successful bottom-hole fluid samples indicated a gas-to-water content of 38.8 SCF/BBL, supporting the recombination data. The CO_2 content of the gas was high and ranged from 26.4 to 16.4 mole percent. The H_2S content of the gas was substantially higher than for any previous GEO^2 test. Measured values were between 57 and 93 ppm.

The measured original bottomhole pressure was 6627 psia, with a corresponding original static surface pressure of 2443 psia. The reservoir temperature was 300°F. The highest surface temperature observed during testing was 220°F. The single reservoir drawdown test provided sufficient transient pressure flow information to develop the needed reservoir data. The reservoir appeared to be relatively tight, with a permeability to reservoir fluid of 12.5 millidarcies. Two permeability barriers were found within 265 feet of the wellbore, restricting the drainage area to about 111 degrees (as opposed to 365°).

The total dissolved solids in the produced brine averaged 12,800 mg/l. Light corrosion of the surface test equipment was observed. Scaling was very light at 0.0050 grams per square inch per 1000 barrels of water. Preventive treatment would have been necessary, however, for long-term production.

Approximately 488 pounds of fine solids were produced during testing. About 37% of the solids were drilling mud residue; 34% was formation material; and 29% were products precipitated from the brine.

A one-page summary of test data follows on Page 1-2.

SUMMARY OF TEST RESULTS

SALDANA WELL NO. 2

ZAPATA COUNTY, TEXAS

WELL DATA:

Total Depth of Well	11,171 Feet
Formation	Upper Wilcox, First Hinnant Sand
Gross Sand Interval	90 Feet
Net Sand	79 Feet
Perforations	9745 - 9820 Feet (8 HPF)
Original Reservoir Pressure	6627.2 Psia
Original Reservoir Temperature	300.2°F
Original Shut-In Surface Pressure	2442.9 Psia
Average Porosity	20% (Sidewall Cores)
Average Permeability	20 md (Sidewall Cores)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids	12,800 mg/l
Chlorides	6,630 mg/l
pH	6.5

ANALYSIS OF FLARE LINE GAS:

Methane	70.9	to	78.8	Mole Percent
Carbon Dioxide	26.4	to	16.4	Mole Percent
Heavier Hydrocarbons	2.5	to	4.7	Mole Percent
Other	0.2	to	0.1	Mole Percent
Heating Value	790	to	893	BTU/SCF
H_2S in Gas	57	to	93	ppm

TESTS (From 11-16-80 to 11-25-80):

Flow test	6.0-day reservoir drawdown and flow test during which 9328 barrels of water were produced.
Build-up Test	3.1-day reservoir pressure buid-up test.
Produced Dry Gas-to-Saltwater Ratio	47 to 54 SCF/STB (49.15 average)
Total Water Produced	9328 Barrels
Highest Flow Rate Achieved	1950 BWPD Sustained
Highest Surface Temperature Observed	220°F
Solids Production	High; 50 pounds per 1000 barrels
Corrosion	Light; 0.0046 Grams/1000 BBLS/IN^2
Scaling	Light; 0.0050 Grams/1000 BBLS/IN^2
Lowest Flowing Surface Pressure Observed	424 Psia
Lowest Flowing Bottom-hole Pressure Measured	4237 Psia
Test Well Productivity Index	1.51 BPD per psi
Maximum Explored Volume of Reservoir Water	Approximately 18 Million Barrels
Maximum Distance Explored (BHP Instrument)	2768 Feet
Reservoir	Relatively tight with a permeability to reservoir fluid of 12.5 mds. and a gas saturation in excess of solubility. Two permeability barriers were found within 265 feet of the wellbore, restricting the drainage area to about 111 degrees.
Disposal Well Gross Perforations	3005 to 3100 feet (4 HPF)

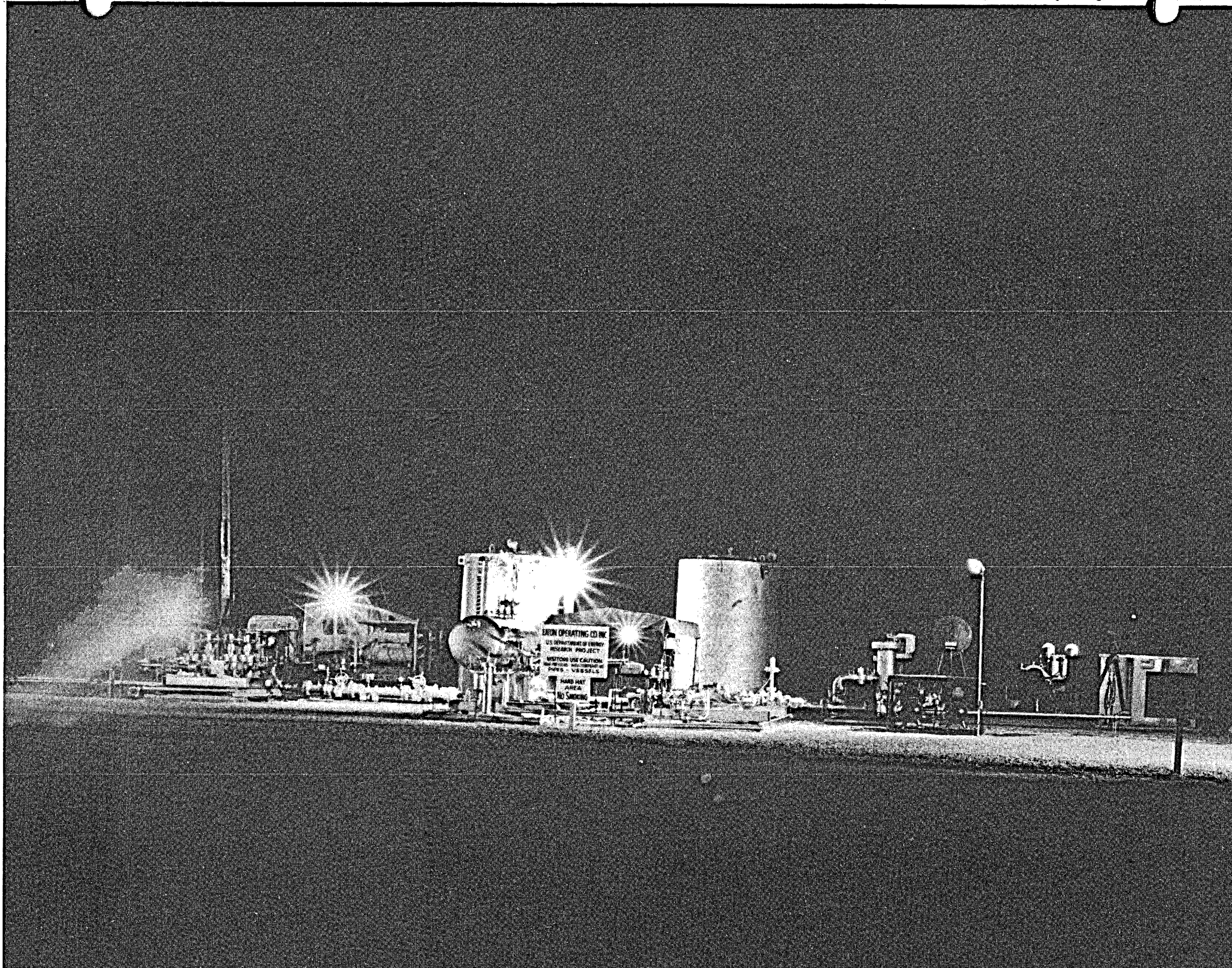


Photo 1-1 Overall view of test equipment

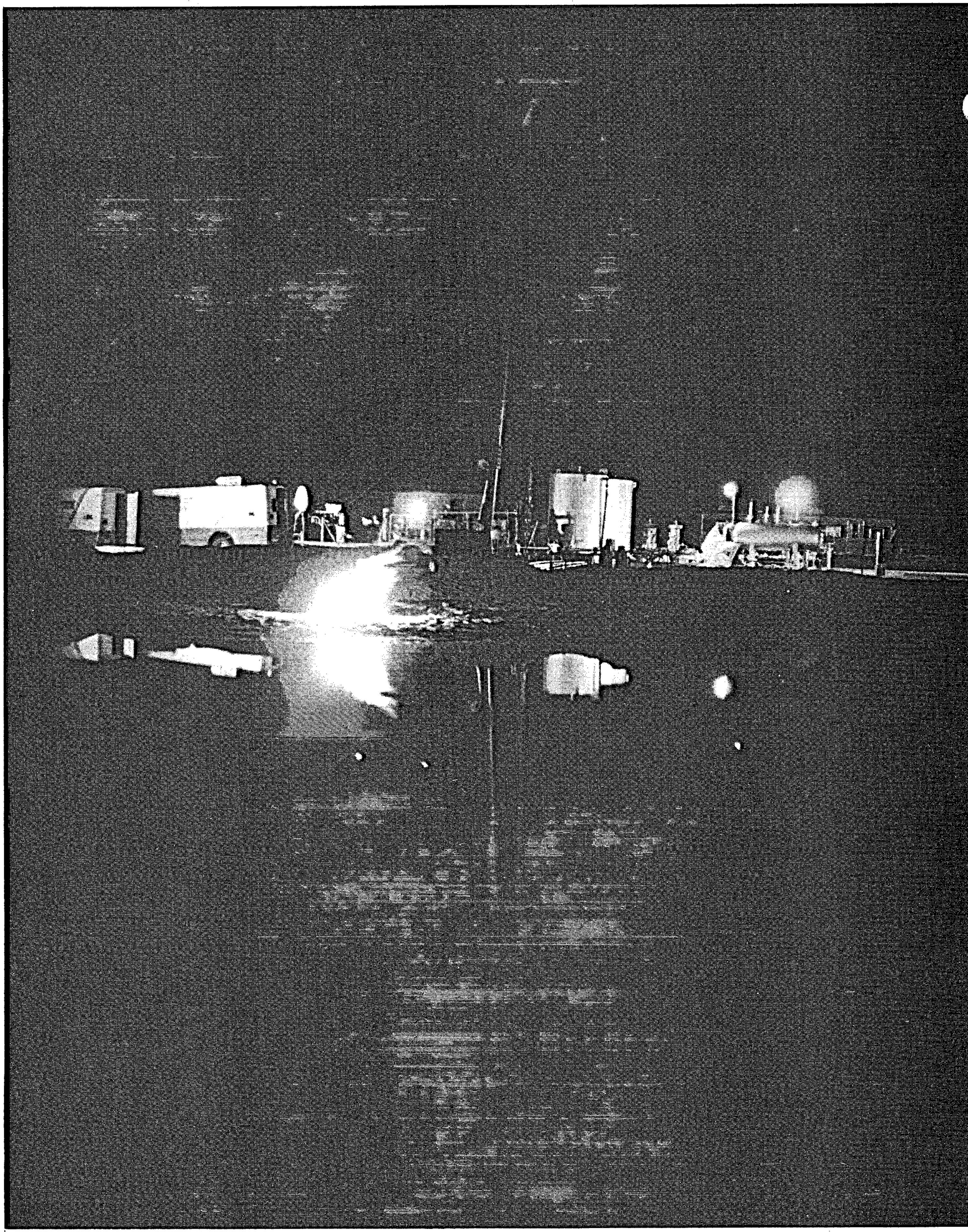


Photo 1-2 Testing in progress. Well is producing approximately 103,000 standard cubic feet of gas per day.

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. The work performed by Eaton is a continuation of the Wells of Opportunity (WOO) Program. The WOO 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 mechanical energy in these aquifers.

The Saldana Well No. 2, acquired for this particular test, was drilled by the Riddle Oil Company (Riddle) in March, 1980, at a cost of approximately $1,035,000. Riddle abandoned the well as a non-commercial producer and offered the well to Eaton for GEO^2 testing. Eaton also acquired the Saldana Well No. 1 from Riddle for use as a disposal well. The Saldana No. 1 Well was drilled by Riddle in December 1979 at a cost of approximately $1,460,000 and also proved to be a non-commercial well.

Contracts were finalized with Riddle Oil Company and the landowner on October 8, 1980, and actual field operations were initiated on October 23, 1980.

2.2 Location and Geography

The Saldana Well No. 2 is located in south Texas approximately 35 miles southeast of the city of Laredo and about 5 miles northeast of Escobas, Texas, in the Martinez Field area, Zapata County. The specific well location is 300 feet from the south line and 2,200 feet from the east line of the A. Stehle Survey, A-497, in the first quadrant of the Tobin township, 24-S, range 9-E grid system. The terrain is hilly, and the location is about 607 feet above sea level. Yearly rainfall is very low, and the land is normally used for game hunting.

Laredo is a major international crossing point along the U.S.-Mexican border. The city, with a population of about 80,000, derives its economy from such diversified sources as feeds and fertilizers, petroleum, smelting of imported ores, apparel manufacture, and brick and tile production.

Exhibit 2-1 indicates the location of the Saldana Well No. 2 in relation to other GEO^2 test wells in Texas. Exhibit 2-2 is a Texas highway map of the location, and Exhibit 2-3 is a Zapata County map of the location. Exhibit 2-4 is a topographic map of the area.

2.3 Operator Contracts and Agreements

Riddle Oil Company was the operator and principal working-interest owner of the two wells. Riddle completed and tested them. Both wells proved to have no commercial hydrocarbon potential, and Riddle agreed to give Eaton the use of the wells for GEO^2 testing. Eaton's legal agreement with Riddle can be found in Appendix "A".

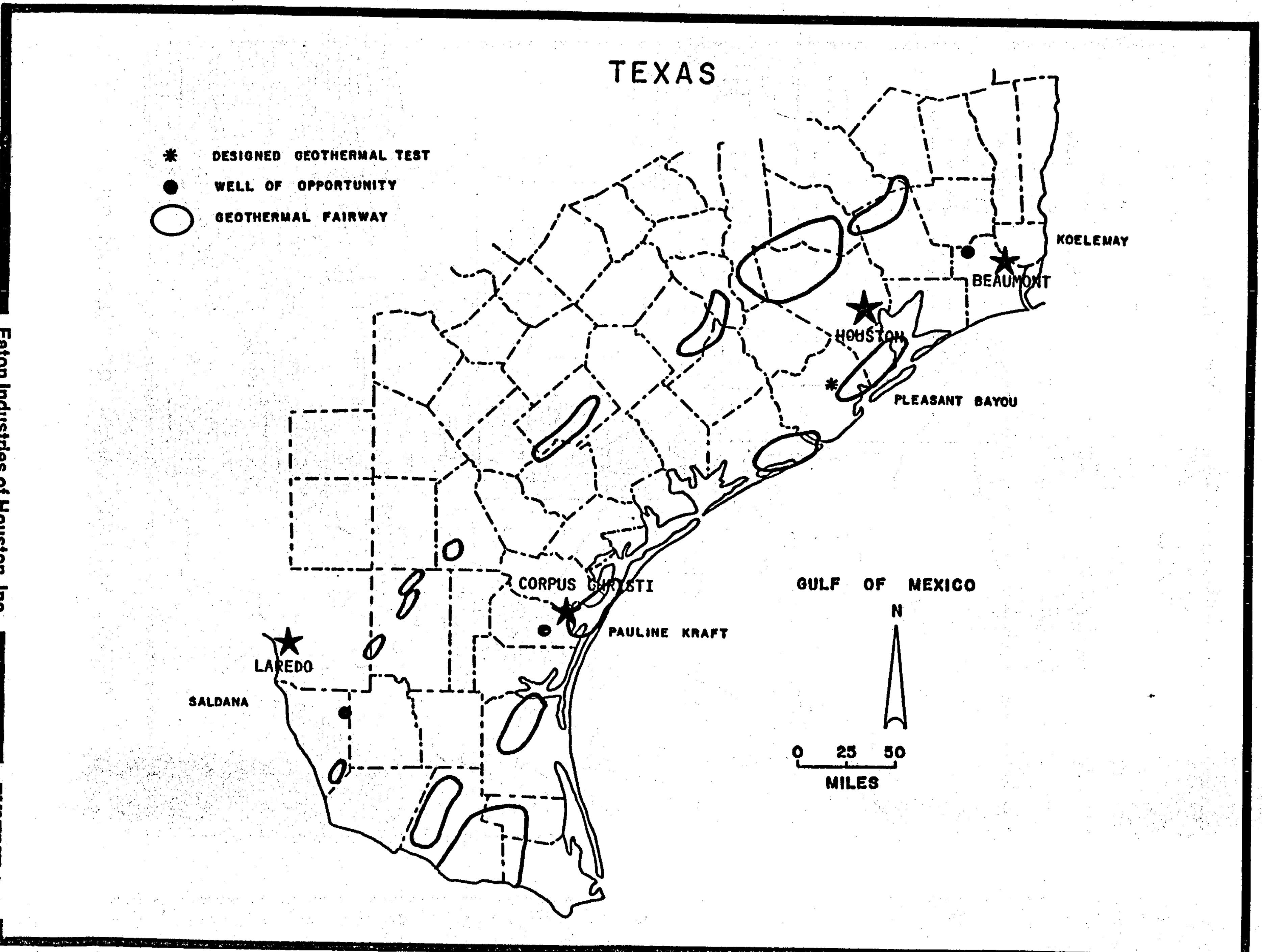
Permission was also obtained from the land and mineral rights owners to conduct the GEO^2 testing. A copy of Eaton's agreement with Saldana family members is in Appendix "A".

2.4 Rig Contractor Agreements

Target Well Service, Inc. was awarded the contract to workover the test well and the disposal well. Target's Rig No. 2 performed the work. The rig was moved on location on October 23, 1980. The rig description and workover contract can be found in Appendix "B".

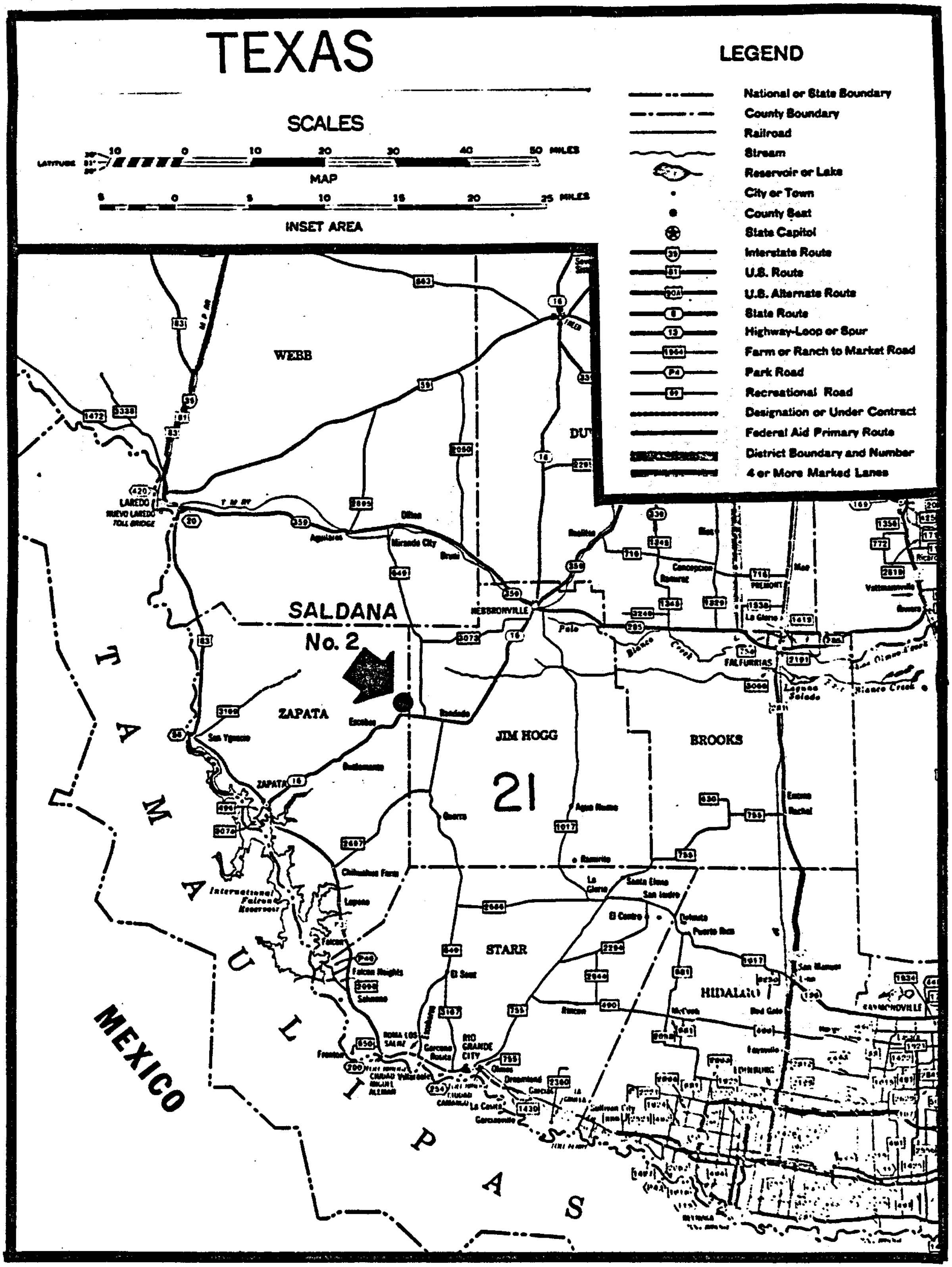
The rig contract for plug and abandonment operations was also awarded to Target Well Service, Inc. Rig operations were completed on December 20, 1980. A description of Target's Rig No. 15 and the contract can be found in Appendix "B".

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



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

EXHIBIT 2-1

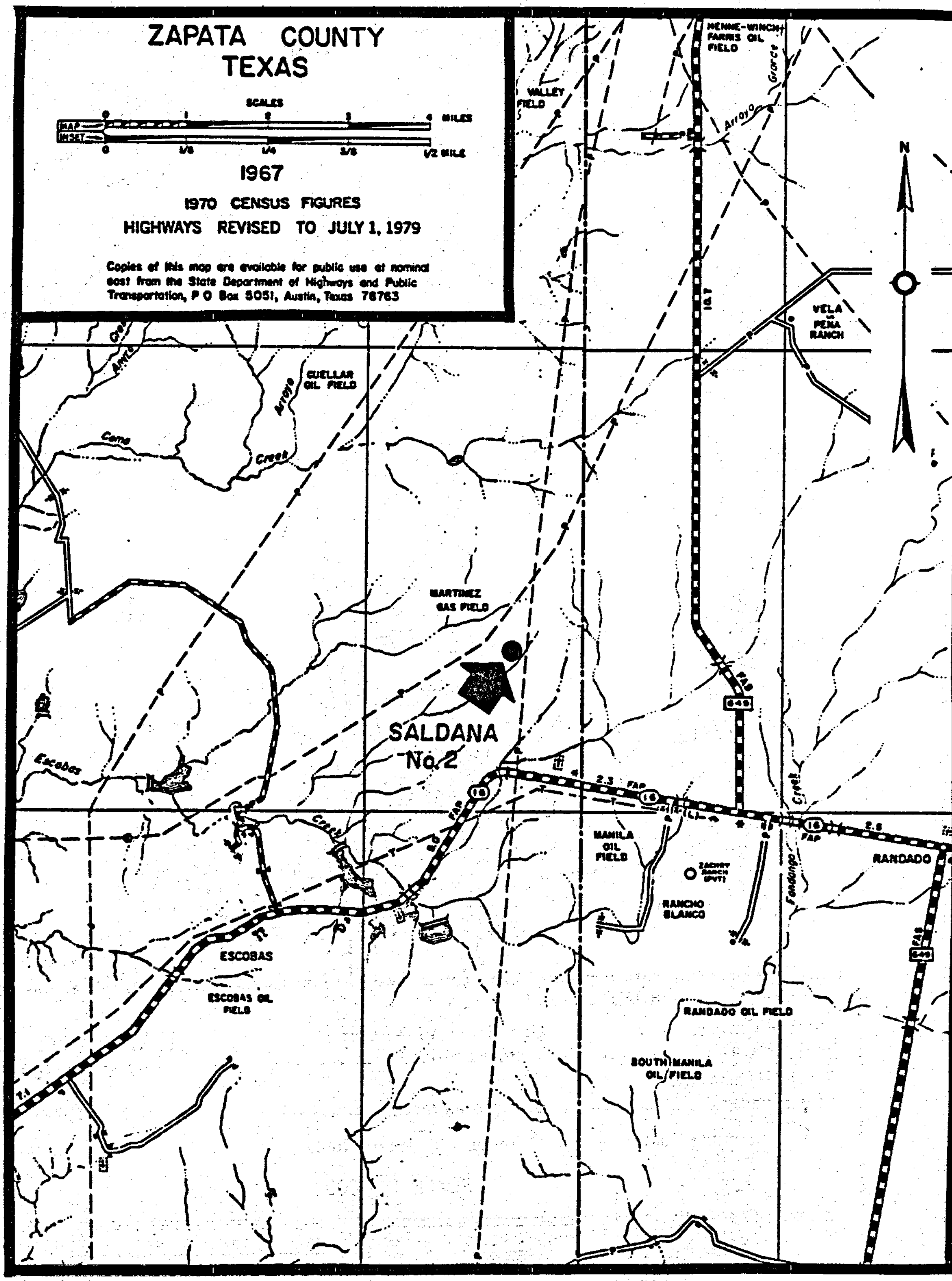


TEXAS HIGHWAY MAP OF LOCATION

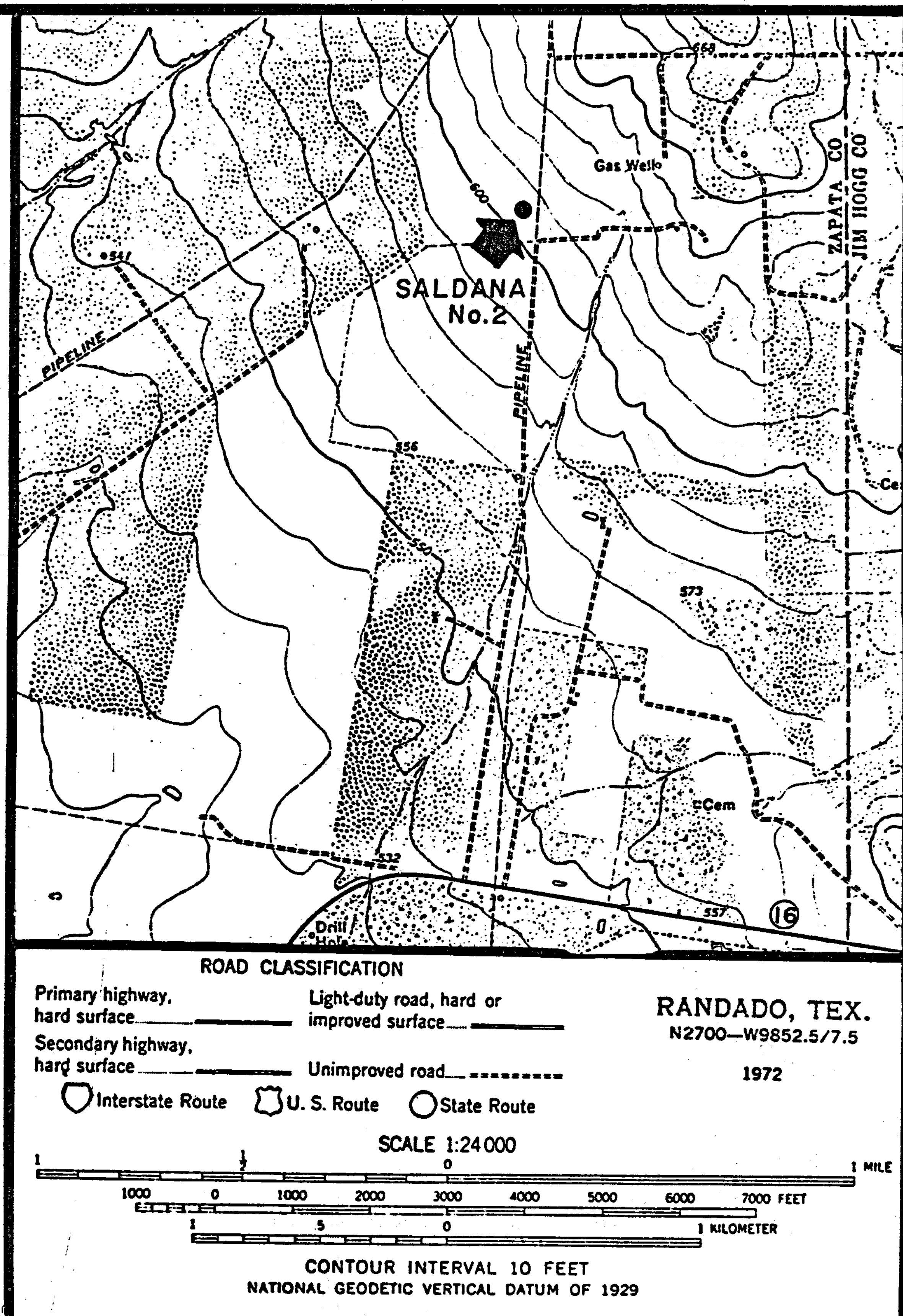
Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

EXHIBIT 2-2

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



ZAPATA COUNTY MAP OF LOCATION



TOPOGRAPHIC MAP OF LOCATION

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

EXHIBIT 2-4

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 Saldana Well No. 2 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 Saldana No. 2 geopressured-geothermal well tested the 1st Hinnant sand. This sand, a unit of the Rockdale formation, is an upper member of the Wilcox Group. These sediments were deposited during the early Eocene/late Paleocene age.

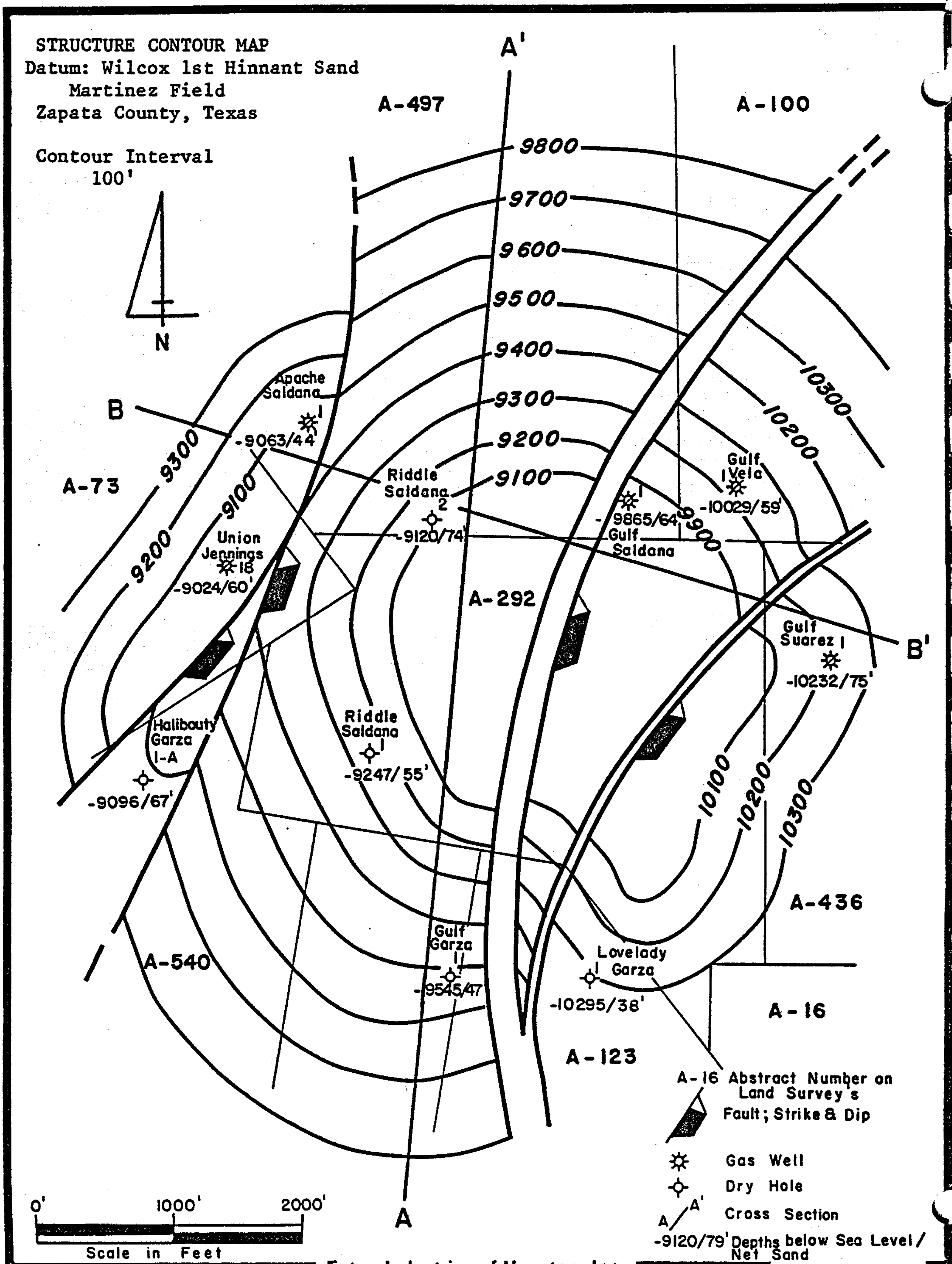
The Wilcox Group consists primarily of a wedge of coarsening upward sandstone and shale sequences, dipping gulfward across a complex growth-fault system. It is the oldest thick sandstone/shale sequence within the Tertiary System of the Gulf Coast. The sediments dip regionally, approximately 1° (100 ft/mile), and thicken abruptly downdip of the Sligo shelf margin (Reference 1).

In South Texas, the upper Wilcox is exhibited by the Rosita delta system. This system is composed of three delta complexes: the Duval, the Zapata, and the Live Oak. The Saldana well lies within the Zapata delta complex, the middle sequence of the upper Wilcox progradation cycle. The depositional patterns of the Rosita delta system are primarily represented by shallow water environments; delta, plain, and delta front sands (Reference 8).

4.2 Local Geology

The 1st Hinnant sand, in the Martinez field, is manifested as a highly faulted domal structure of moderate relief, (Exhibit 4-1). The test well is located within a centralized block, bounded by arcuate north, northeast-south, southwest trending down-to-the-coast faults, (Exhibit 4-2 & 4-3). These faults limit reservoir extent 1600 feet to the east and 1500 feet to the west of the Saldana well, but there are no apparent reservoir limiting barriers either to the north or to the south. The displacement of these faults are 750 feet and 350 feet, respectively.

The depositional environment of the first Hinnant sand appears to be shallow near-shore delta-front sheet sand throughout most of the area. Some thinning and growth faulting can be seen in the western blocks.



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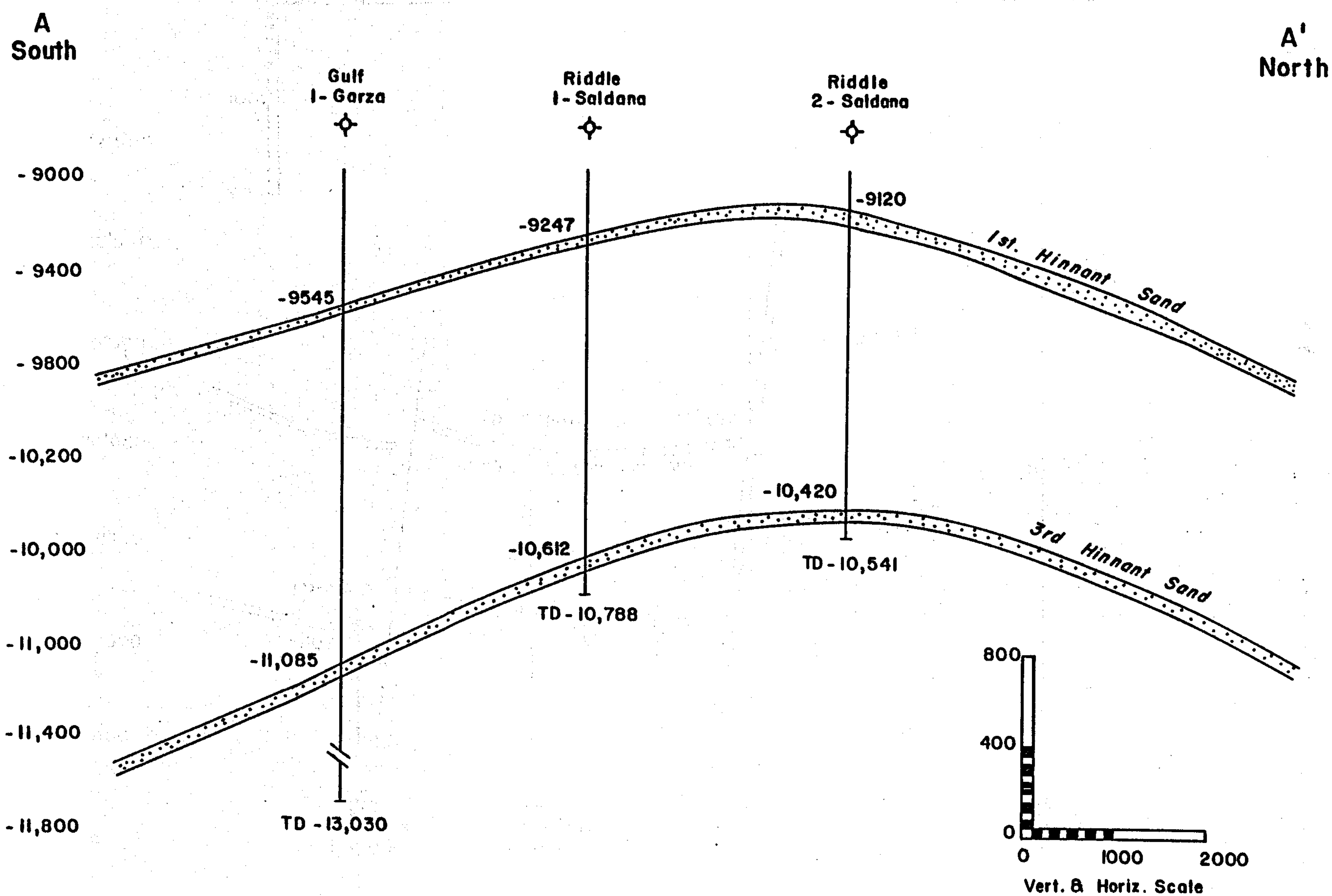
Eaton Operating Co., Inc.

EXHIBIT 4-1

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

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

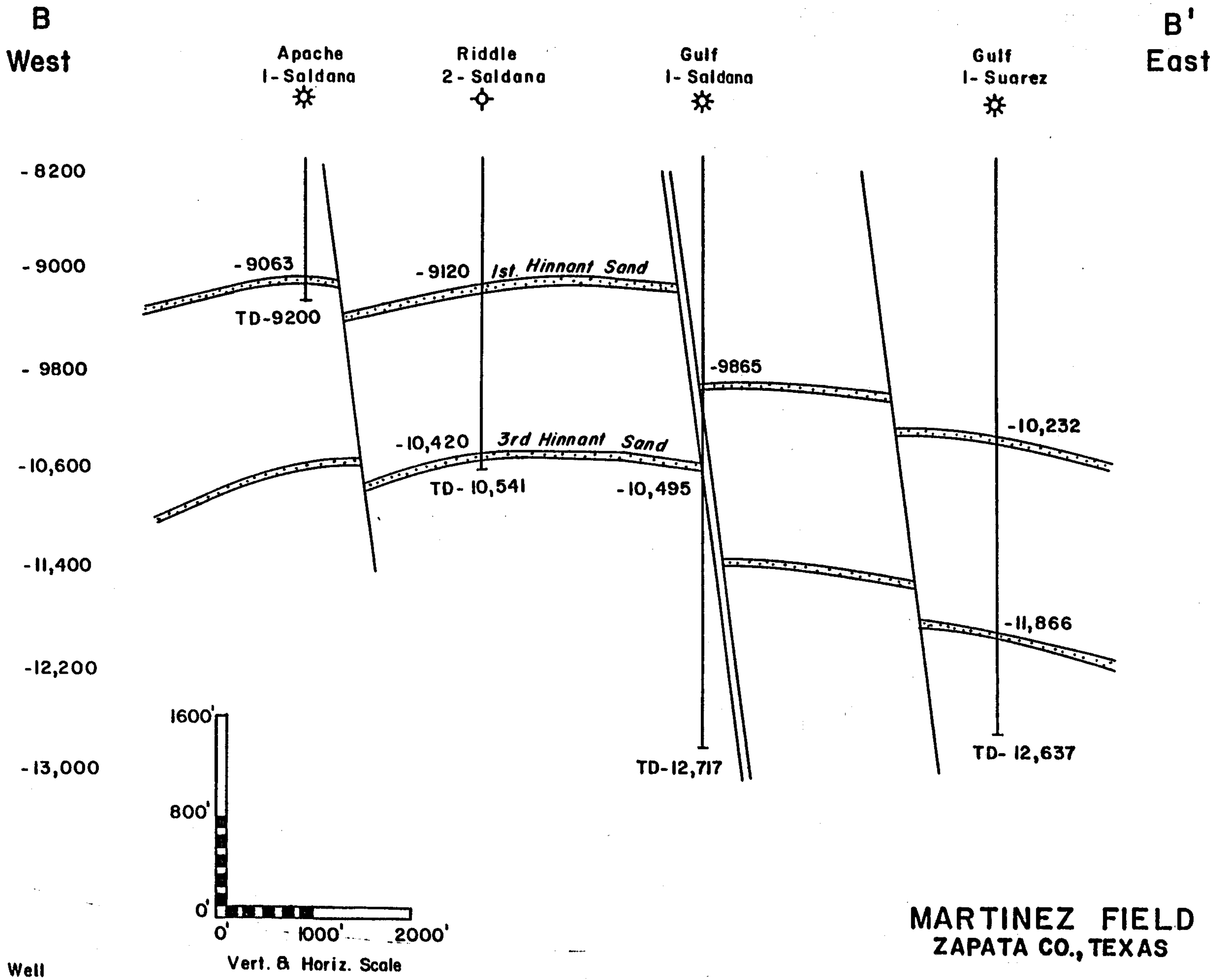


MARTINEZ FIELD
ZAPATA CO., TEXAS
NORTH - SOUTH CROSS-SECTION

- Dry Hole
Depths: Below Sea Level

EXHIBIT 4-2

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



☼ - Gas Well
-◊- - Dry Hole
Depth - Below Sea Level

MARTINEZ FIELD
ZAPATA CO., TEXAS
EAST - WEST CROSS-SECTION

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

EXHIBIT 4-3

5.0 PETROPHYSICS

5.1 Open-Hole Log Analysis - Test Well

Riddle Oil Company conducted several logging surveys for hydrocarbon evaluation during the drilling phase of the Saldana No. 2 Well. When the hole was abandoned, the logs were made available to Eaton for use in reservoir evaluation for the DOE Wells of Opportunity program. The following logs were used in the evaluation of the target reservoir.

1. Dual Induction Log - 1" (Exhibit 5-1)
2. Neutron/Density Log - 5" (Exhibit 5-2)
3. ISF/Sonic Log - 5" (Exhibit 5-3)

Data from the aforementioned logs resulted in the following open-hole measurements:

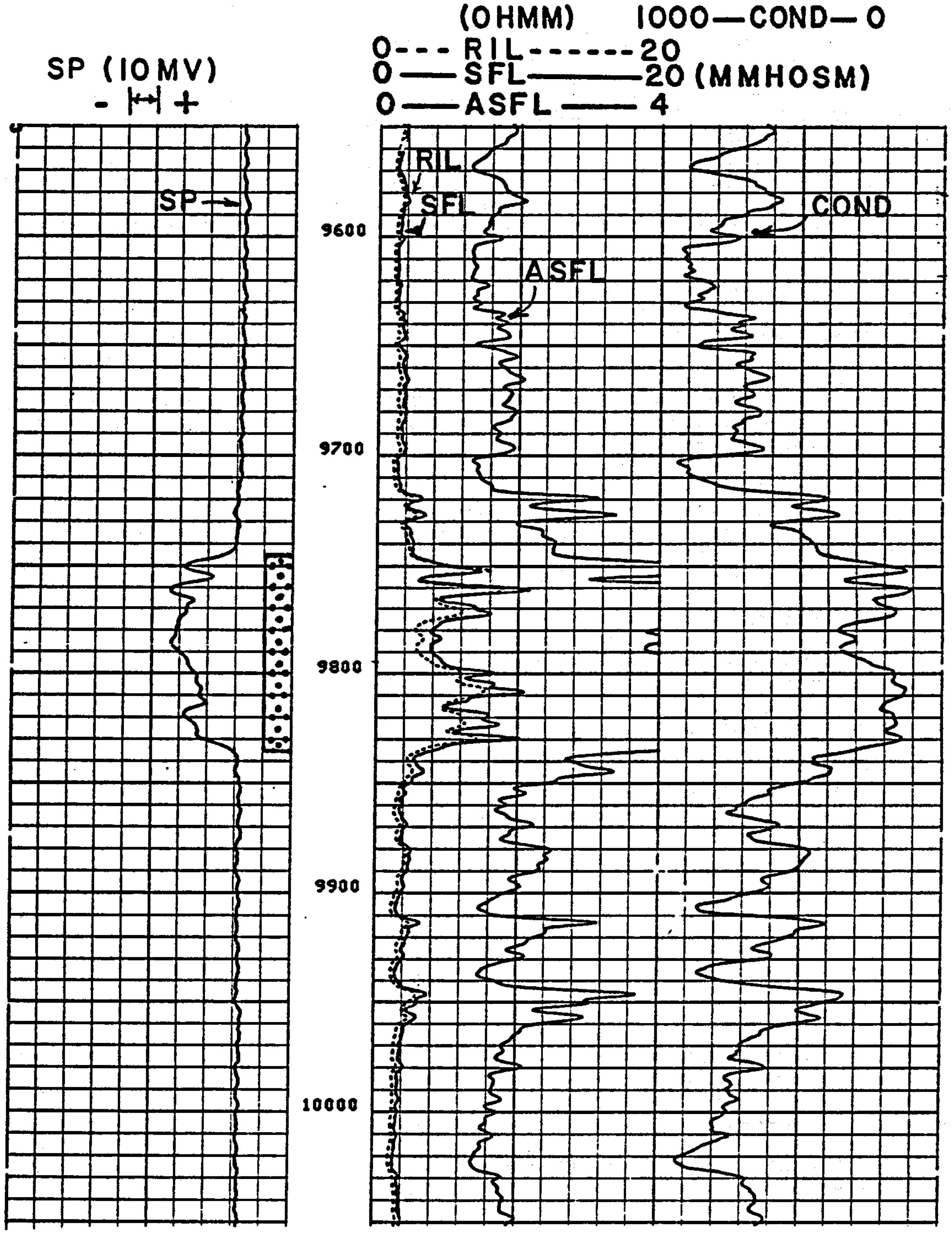
1. Spontaneous potential
2. True formation resistivity
3. Gamma Ray
4. Neutron porosity
5. Density porosity
6. Computed apparent water resistivity
7. Sonic time travel

5.1.1 Porosity

The mean porosity of the net pay sand was 20%, with a range from 18.1% to 22.5%. These values are based on analysis of sidewall cores taken from the 1st Hinnant sand in the Saldana No. 2 Well (Exhibit 5-4).

5.1.2 Sand Thickness

The net sand thickness of the tested zone was 79 feet. This value is based on analysis of both the induction and density log gross interval of 90 feet (Exhibits 5-1 and 5-2). A porosity cutoff of 10% was applied to yield the net value.



DIL LOG 1st HINNANT SAND

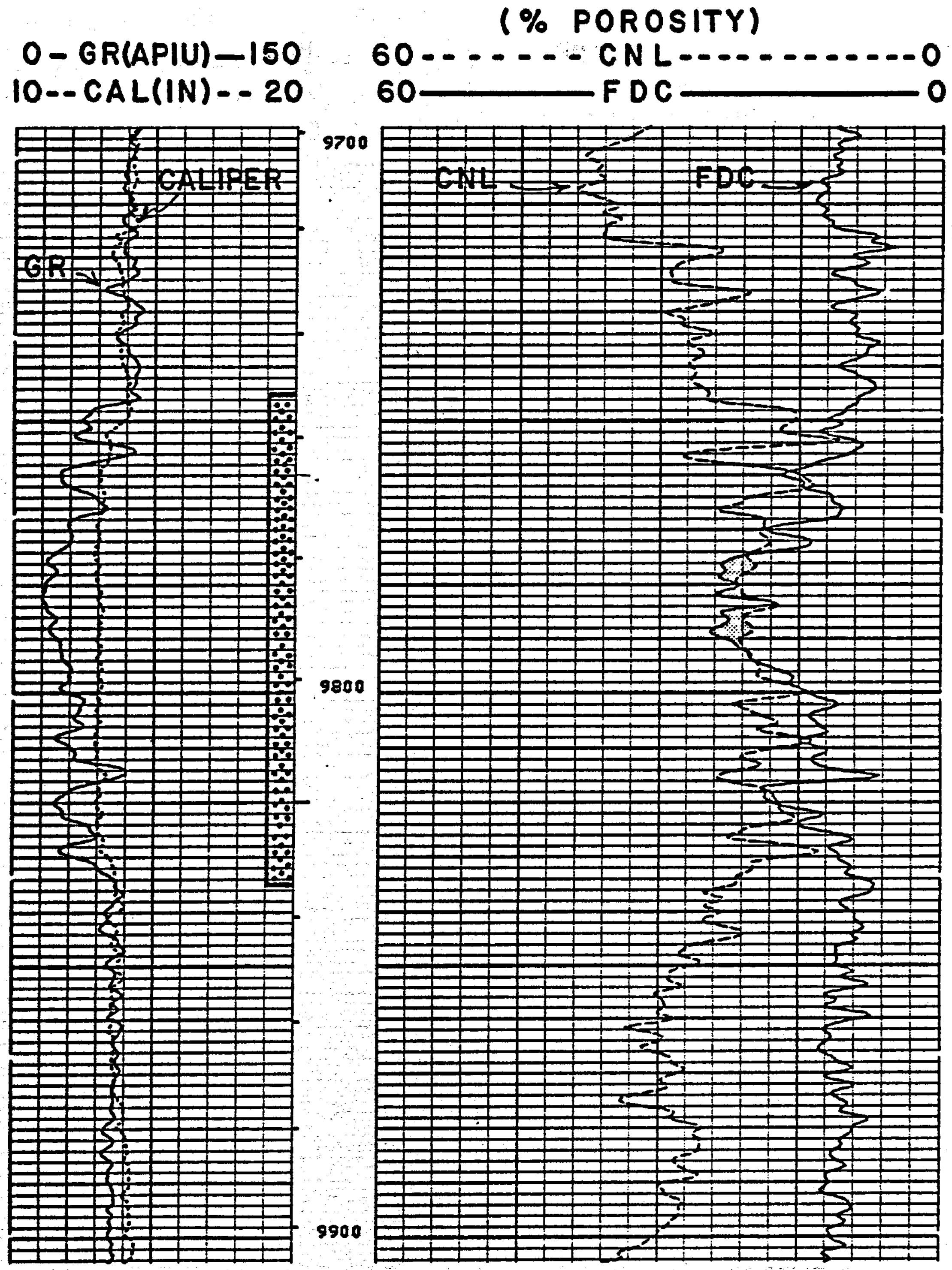
RIDDLE OIL , 2- SALDANA

1-INCH

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

EXHIBIT 5-1

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



NEUTRON/DENSITY LOG 1st HINNANT SAND

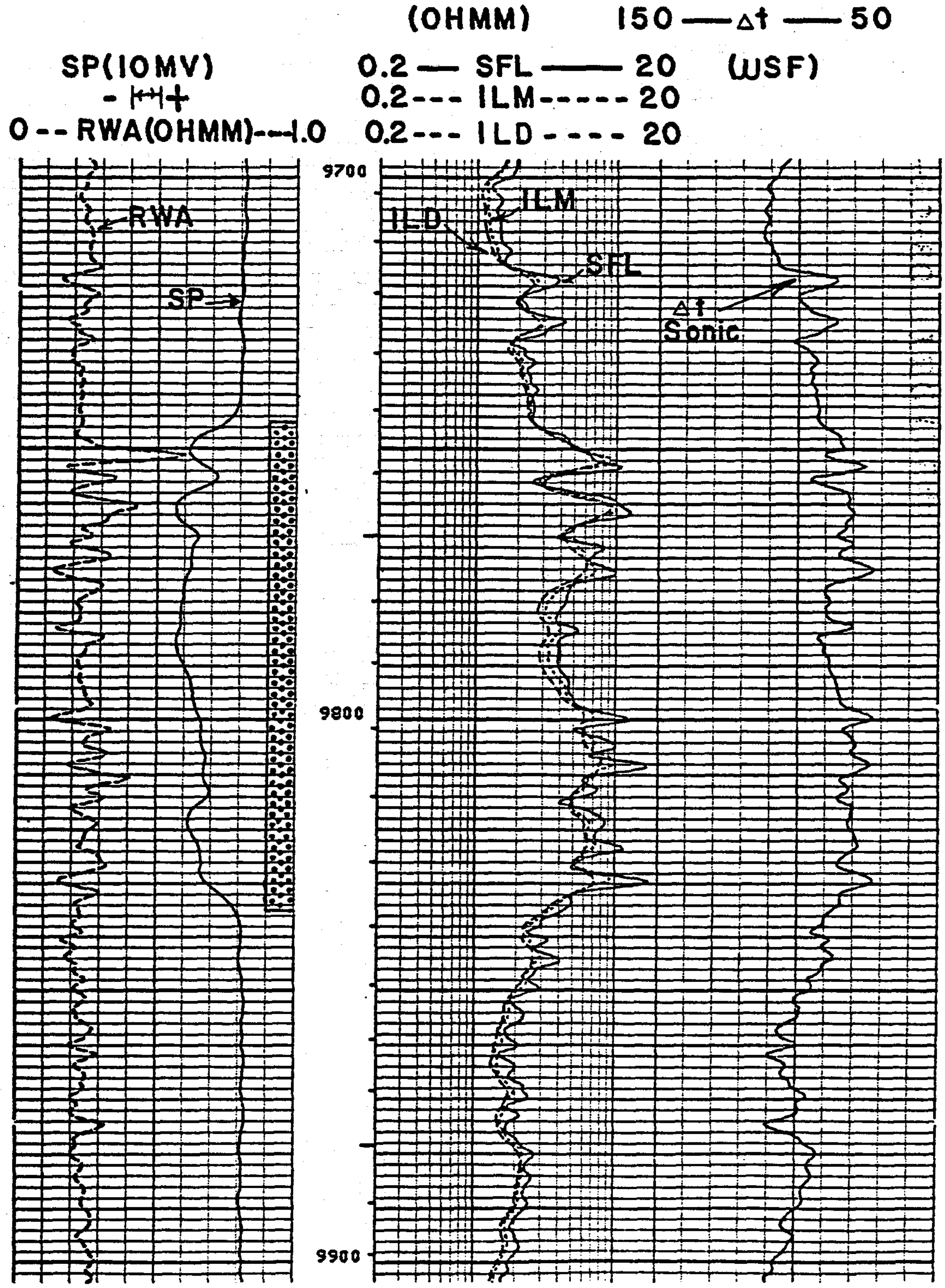
RIDDLE OIL, 2-SALDANA

5-INCH

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

EXHIBIT 5-2

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



ISF SONIC LOG 1st HINNANT SAND

RIDDLE OIL, 2-SALDANA

5-INCH

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

EXHIBIT 5-3

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

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

Sidewall Core Analysis Report

DEPTH FEET	PERM. MD.	POROSITY PERCENT	RESIDUAL SATURATION % BY VOLUME OIL	RESIDUAL SATURATION % BY VOLUME GAS	RESIDUAL SATURATION % PORE SPACE OIL	RESIDUAL SATURATION % PORE SPACE TOTAL WATER	PROBABLE PRODUCTION	°API	GAS UNITS	RECOVERY INCHES	LITHOLOGICAL DESCRIPTION
9760	7.4	18.9	0.0	6.9	0.0	63.4	COND.*		0	¼	Vfg silty shy lmy sd, No flu.
9762	8.8	19.6	0.0	7.4	0.0	62.2	COND.*		0	½	Same as above
9768	25	20.1	0.0	8.0	0.0	60.1	COND.		0	¾	Same as above
9770	19	20.5	0.0	7.7	0.0	62.4	COND.		0	¼	Same as above
9774	41	22.0	0.0	9.6	0.0	56.3	COND.		0	¾	Same as above
9776	37	22.5	0.0	8.2	0.0	63.5	COND.		0	¾	Same as above
9778	12	19.8	0.0	7.4	0.0	62.6	COND.		0	¾	Same as above
9780	23	20.9	0.0	8.4	0.0	59.8	COND.		0	1	Same as above
9782	28	21.9	0.0	9.1	0.0	58.4	COND.		0	¾	Same as above
9784										0	No Recovery
9786	43	22.5	0.0	8.6	0.0	61.7	COND.		0	½	Vfg silty shy sd, No flu.
9788	29	21.3	0.0	8.1	0.0	61.9	COND.		0	¾	Same as above
9790	6.5	18.9	0.0	7.5	0.0	60.3	COND.*		0	1	Same as above
9796	4.4	18.1	0.0	5.2	0.0	71.2	Low Perm		0	½	Same as above
9804	9.2	19.7	0.0	7.6	0.0	61.4	COND.*		0	½	Same as above
9809	12	19.4	0.0	7.2	0.0	62.8	COND.		0	½	Same as above
9817	15	19.6	0.0	7.5	0.0	61.7	COND.		0	1	Same as above
9819	18	19.9	0.0	8.0	0.0	64.8	COND.		0	¾	Same as above

* LOW PERMEABILITY

1st. HINNANT SAND - RIDDLE OIL, 2 - SALDANA

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

EXHIBIT 5-4

5.1.3 Permeability

The mean permeability (air) of the geopressured-geothermal test zone was 20 md. This value was determined from sidewall cores from the 1st Hinnant sand with a range of 4.4 md to 43 md (Exhibit 5-4).

5.1.4 Salinity

An actual formation water sample was obtained from the Saldana No. 2 Well prior to testing. The laboratory analysis yielded a salinity value of 11,121 ppm. This figure was determined from a measured chloride content of 6740 ppm and a chloride-to-salinity constant of 1.65 (Exhibit 5-5).

Estimated water salinity from electric logs ranged from 6000 ppm to 71,000 ppm. These values were determined by the following methods:

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

5.1.4.1 Conventional SP Method: The calculated salinity using the Conventional SP (spontaneous potential) method was 35,000 ppm. This value was determined by solving for the formation fluid resistivity using the maximum SP value from the induction log, and then it was plotted on the Welex Resistivity-Salinity-Temperature chart (Exhibit 5-6). The equations used in determining formation fluid resistivity are as follows:

$$SSP = -(60 + .133T) \log R_{mf}/R_{we} \qquad \text{(Equation 1)}$$

Solving for R_{we}:

$$R_{we} = R_{mf}\left[10^{SSP/(60 + 0.133T)}\right] \qquad \text{(Equation 2)}$$

$$R_w = f\,R_{we} \qquad \text{(Equation 3)}$$

where:

SSP = static spontaneous potential - millivolts

T = formation temperature ^{o}F

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

SOUTHERN PETROLEUM LABORATORIES, INC.

P.O. BOX 20807
HOUSTON, TEXAS 77025
(713) 668-4448

P.O. BOX 52768
LAFAYETTE, LOUISIANA 70501
(318) 984-2374

August 15, 1980

Certificate of Analysis No.29482

Invoice No. 97924

Doug Graham
Eaton Operating
3100 Edlow, Suite 205
Houston, Texas 77027

Sample received 8/15/80

Chloride . . . . 6,740 ppm

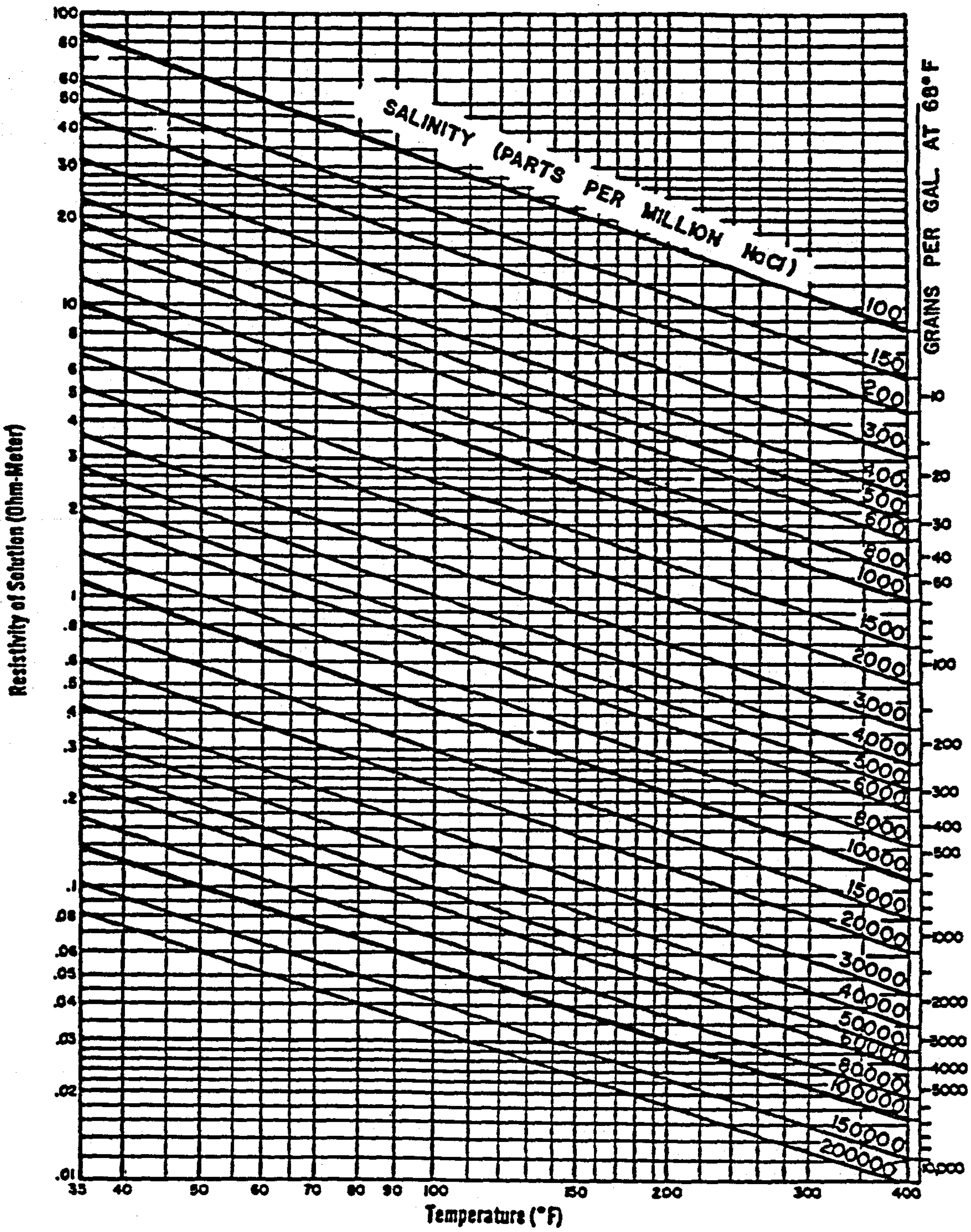
SOUTHERN PETROLEUM LABORATORIES, INC.

Sammy Russo

Sammy Russo

WATER SAMPLE ANALYSIS

RIDDLE OIL, 2- SALDANA



RESISTIVITY SALINITY CHART - WELEX

R_{we}	=	equivalent formation fluid resistivity - ohm-m
f	=	water resistivity correction factor -dimensionless

and:

maximum SP (uncorrected)	=	-25 mv	
corrected SSP	=	-25 mv	(Exhibit 5-7)
temperature	=	300°F	
R_{mf}	=	.34 ohm-m @ 75°F	
	=	.09 ohm-m @ 300°F	(Exhibit 5-6)
R_{we}	=	.05	(Equation 2)
f	=	1.04	(Exhibit 5-8)
R_w	=	.052	(Equation 3)
Salinity	=	35,000	(Exhibit 5-6)

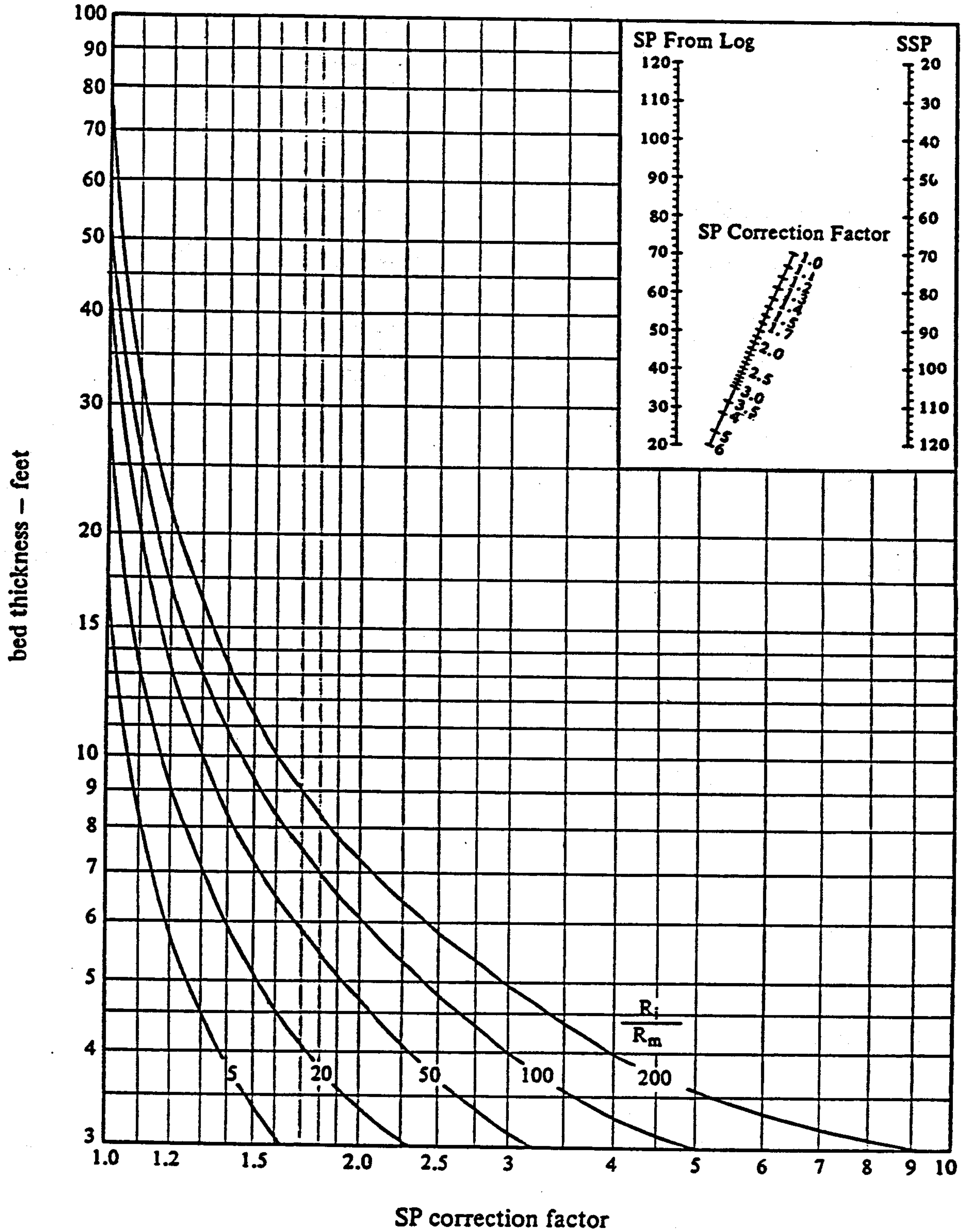
5.1.4.2 **R_{wa} Method:** An estimated salinity of 6000 ppm was calculated using the R_{wa} Method and was determined primarily as a function of porosity and true formation resistivity. The mathematical equation is as follows:

$$F = R_o/R_w \qquad \text{(Equation 4)}$$

$$F = 0.81/\phi^2 \qquad \text{(Equation 5)}$$

$$R_oR_w = 0.81/\phi^2 \qquad \text{(Equation 6)}$$

$$R_w = R_o\phi^2/0.81 \qquad \text{(Equation 7)}$$



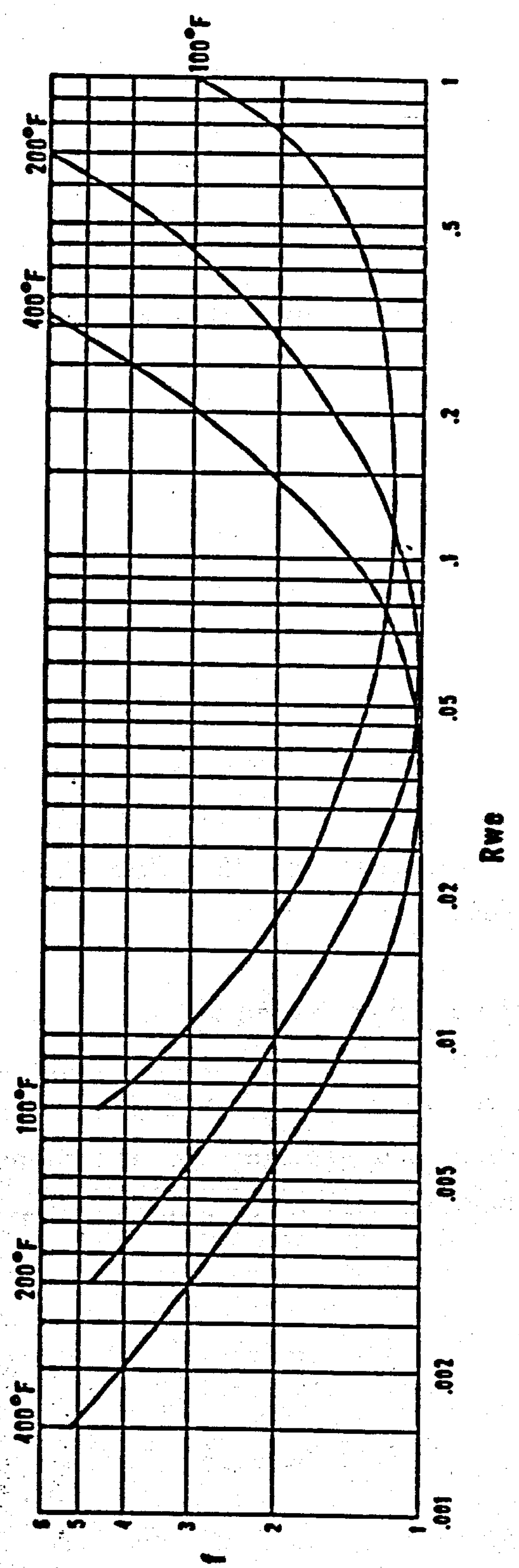
DRESSER - ATLAS

SP CORRECTION CHART

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

EXHIBIT 5-7

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



RWE CORRECTION CHART

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
$\emptyset$	=	porosity - %

and:

R_t	=	4.9 ohm-m
$\emptyset$	=	20%

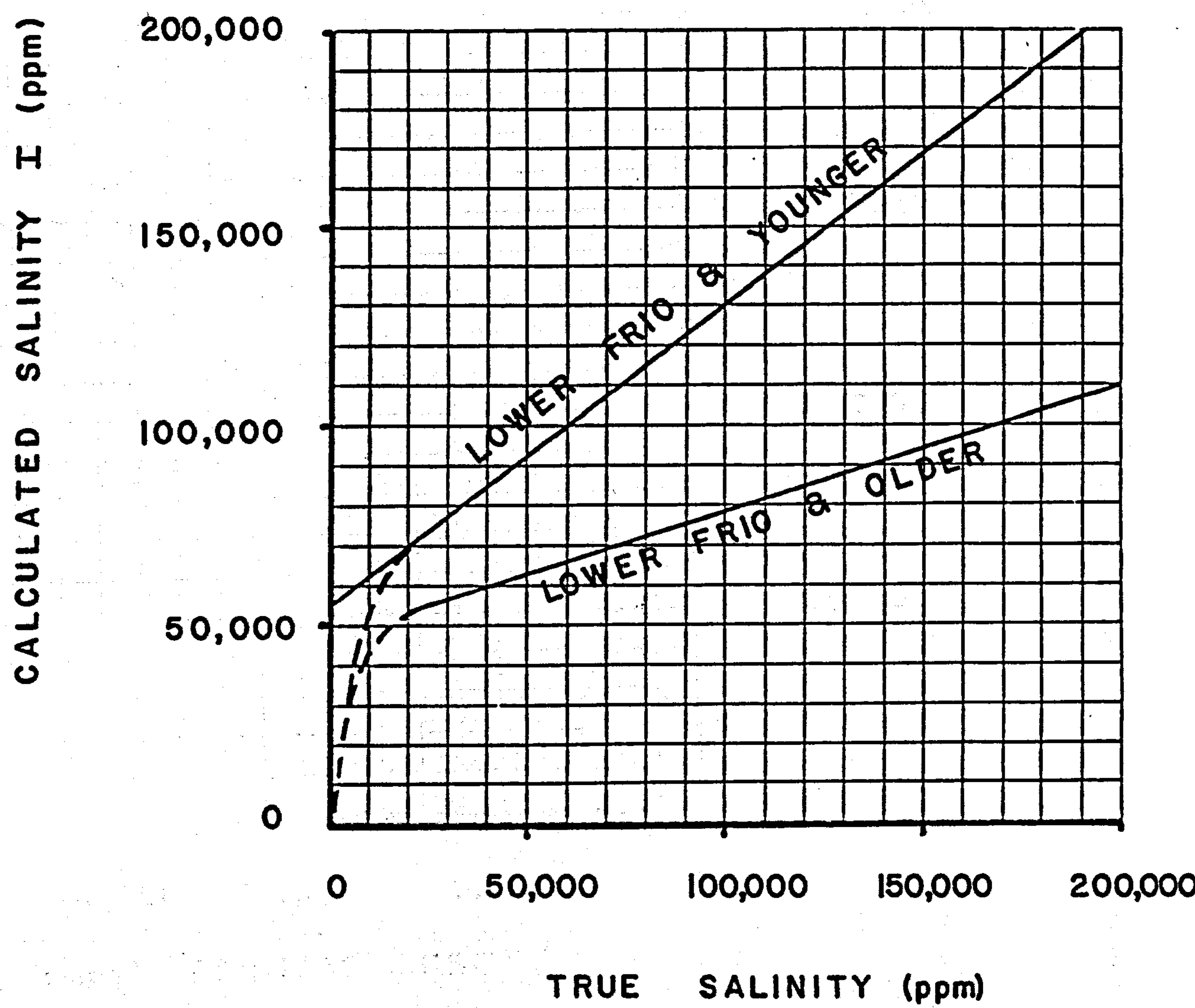
Assuming a 100% water-saturated formation where $R_t = R_o$, (Equation 7), and the previously listed log-derived parameters, a formation water of 0.242 ohm-m is obtained. Plotting the formation water resistivity on the Welex Resistivity Salinity graph (Exhibit 5-6) yields salinity of 6000 ppm.

5.1.4.3 **Dunlap K_f Method:** An estimated salinity of 71,000 was calculated using Henry Dunlap's K_f Method. This value was calculated by obtaining a corrected R_{mf} using Dunlap's $K_f = R_{mf}/R_m$ vs Mud Weight graph (Exhibit 5-7), the Conventional SP Method of salinity determination, and geologic age and salinity correction graphs, (Exhibits 5-9 and 5-10.) The equations used in correcting the R_{mf} are as follows:

$$K_f = R_{mf}/R_m \quad \text{(Equation 8)}$$

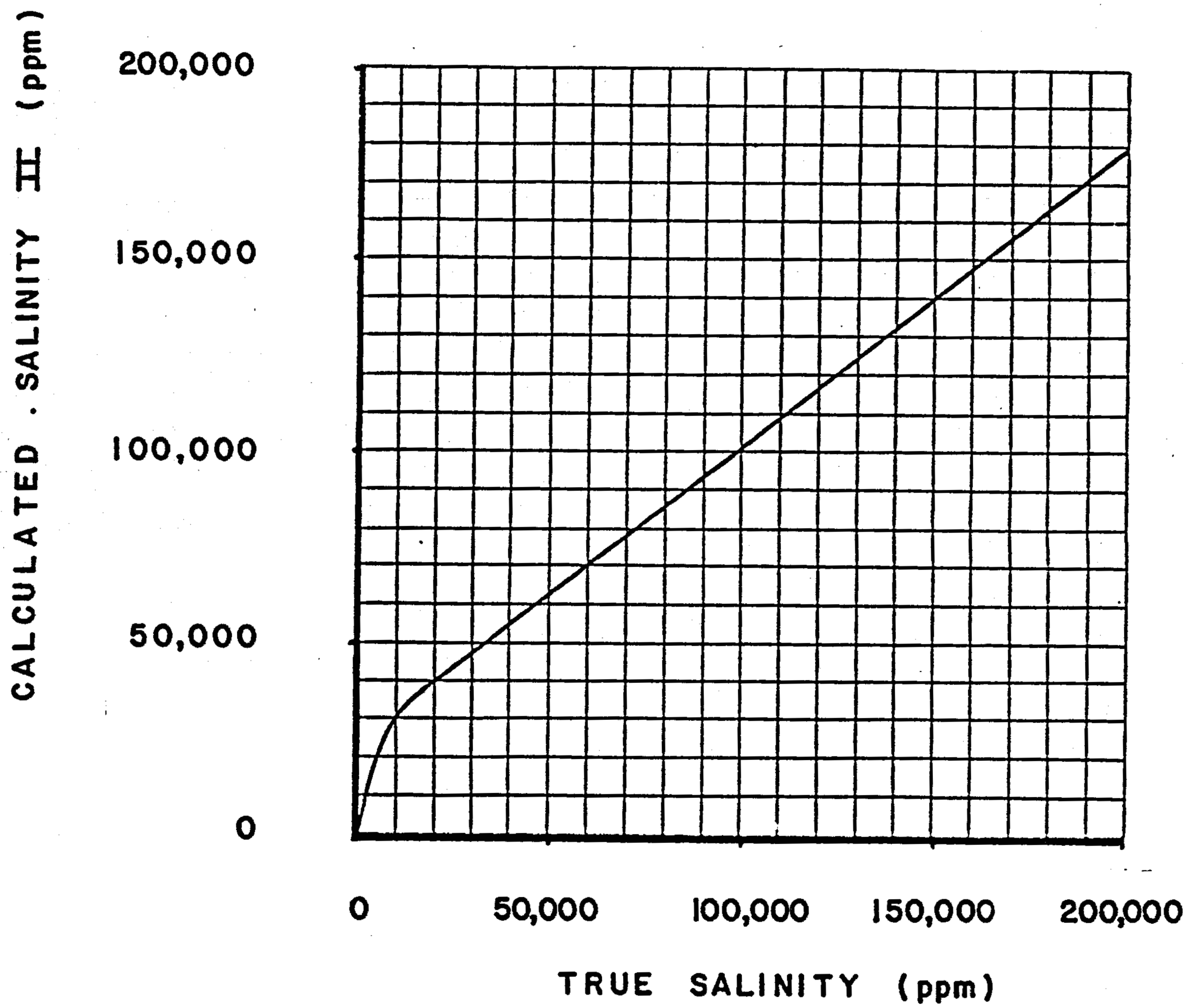
solving for R_{mf}:

$$R_{mf} = K_f R_m \quad \text{(Equation 9)}$$



GEOLOGIC AGE SALINITY CORRECTION

H.F. DUNLAP, FEBRUARY 1981



SALINITY CORRECTION CHART II

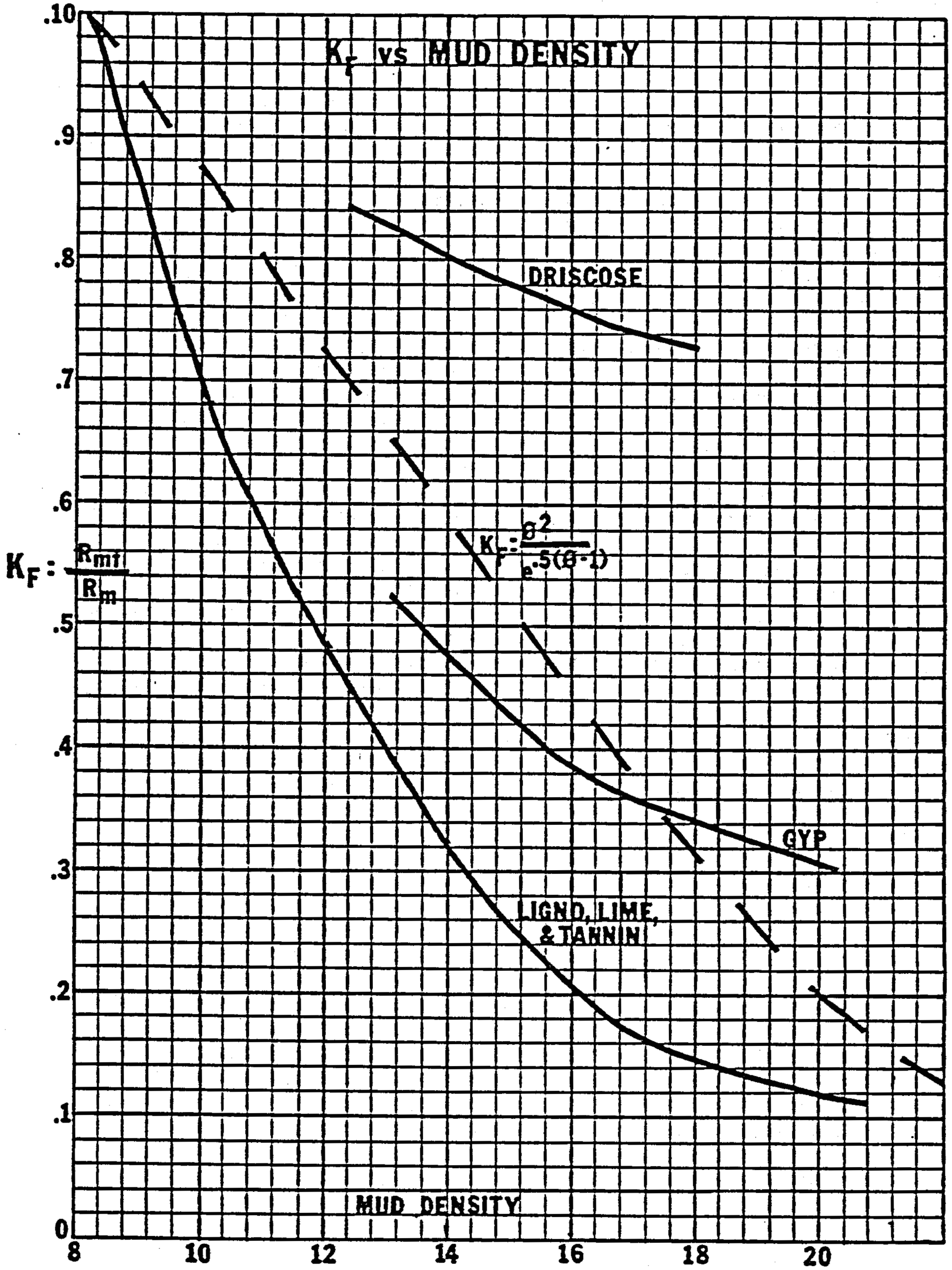
H.F. DUNLAP, MARCH 1981

where:

R_{mf}	=	mud filtrate resistivity - ohm-m
R_m	=	mud resistivity - ohm-m
K_f	=	constant - dimensionless
MD	=	mud density - #/gal.

and:

SP (corrected)	=	-25 mv	
R_m (uncorrected)	=	1.33 ohm-m @ 75°F	
MD	=	16.1 #/gal.	
K_f	=	.2	(Exhibit 5-11)
R_{mf}	=	.266 ohm-m @ 75°F	(Equation 9)
	=	.073 ohm-m @ 300°F	(Exhibit 5-6)
R_{we}	=	.041 ohm-m	(Equation 2)
f	=	1.04	(Exhibit 5-8)
R_w	=	.043 ohm-m	(Equation 3)
Salinity (uncorrected)	=	43,000 ppm	(Exhibit 5-6)
Salinity (corrected I)	=	61,000 ppm	(Exhibit 5-9)
Salinity (corrected II)	=	71,000 ppm	(Exhibit 5-10)



MUD RESISTIVITY CORRECTION CHART
H. F. DUNLAP —— AUGUST 1980

5.1.4.4 **Conductivity Salinity Method:** A salinity of 6600 ppm was calculated using the Conductivity-Salinity method, a variation of the R_{wa} method. In this approach, true formation resistivity is back-calculated by means of using 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:

$$R_t = \frac{1000}{C} \qquad \text{(Equation 9)}$$

where:

R_t = true formation resistivity - ohm-m

C = conductivity - mmhos/m

T_f = formation temperature - ^oF (uncorrected)

and

C = 215 mmhos/m

T_f = 300^oF

$\emptyset$ = 20%

then:

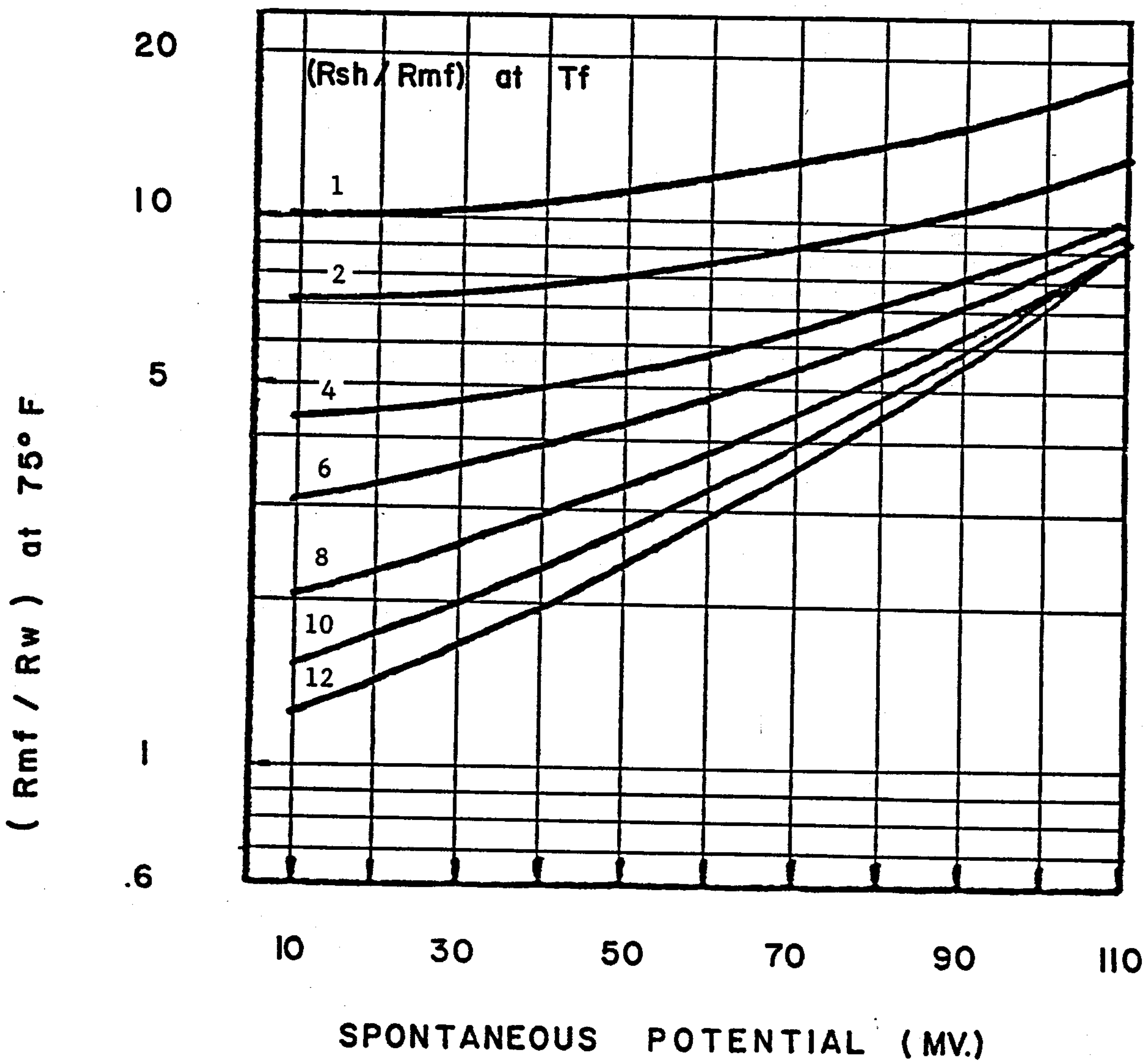
R_t	=	4.65 ohm-m	(Equation 9)
R_w	=	.229 ohm-m	(Equation 6)
Salinity	=	6600 ppm	(Exhibit 5-6)

5.1.4.5 **Shale Resistivity Method:** A salinity measurement of 18,500 was estimated using Dr. K. 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:

$$\left[R_{sh}/R_{mf}\right] @ T_f \qquad \text{(Equation 10)}$$

$$\left[R_{mf}/R_w\right] @ 75^oF \qquad \text{(Equation 11)}$$

(Exhibit 5-12)



NEW SP CHART

SILVA AND BASSIOUNI JUNE 1981

where:

R_{sh} = shale resistivity - ohm-m

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

R_w = formation water resistivity - ohm-m

T_f = formation temperature - ^oF

and:

SP = -25 mv.

R_{sh} = 1.60 ohm-m

T_f = 300^oF

R_{mf} = .34 ohm-m @ 75^oF

.09 ohm-m @ 300^oF (Exhibit 5-6)

$$\left[\frac{1.60}{.09}\right] @ 300^oF = 17.778 \quad \text{(Equation 10)}$$

$$\left[\frac{.34}{R_w}\right] @ 75^oF = 1.05 \quad \text{(Exhibit 5-12)}$$

R_w = .324 @ 75^oF (Equation 11)

Salinity = 18,500 (Exhibit 5-6)

Comparison of the measured versus estimated salinity calculations shows a wide range of salinities. Whereas the R_{wa} and conductivity salinity calculations are short of the measured salinity by factors of 0.54 and 0.59, the shale resistivity, conventional SP, and Dunlap methods exceed the measured salinity by factors of 1.66, 3.15, and 6.38 respectively. These discrepancies may be due to higher than measured sonic porosities for the R_{wa} and conductivity methods, while erroneous log header resistivity readings may have been used in the SP, shale resistivity, and Dunlap methods.

The problem of obtaining correct salinity calculations from electric log information continues to be avidly studied by many institutions in the Gulf Coast Area. At this time an accurate method for determining log-derived salinities continues to be elusive.

5.2 Open Hole Log Analysis - Disposal Well

Saldana No. 1 Well was plugged back for saltwater disposal purposes to a depth of 3335'. Four potential disposal sands were encountered and are identified as follows:

Sand "A"	3005' - 3097'
Sand "B"	2825' - 2885'
Sand "C"	2695' - 2785'
Sand "D"	2475' - 2662'

Sand A had a net thickness of 92', a porosity of 26%, a salinity of 10,000 ppm, and an estimated pressure and temperature of 1708 psi and 115°F, respectively (Exhibit 5-13). It appeared to have the best potential and therefore was completed for saltwater disposal.

5.3 Cased Hole Log Analysis - Test Well

A Variable Density Cement Bond Log was run on the Saldana No. 2 Well after re-entry to total depth. This log served a two-fold purpose:

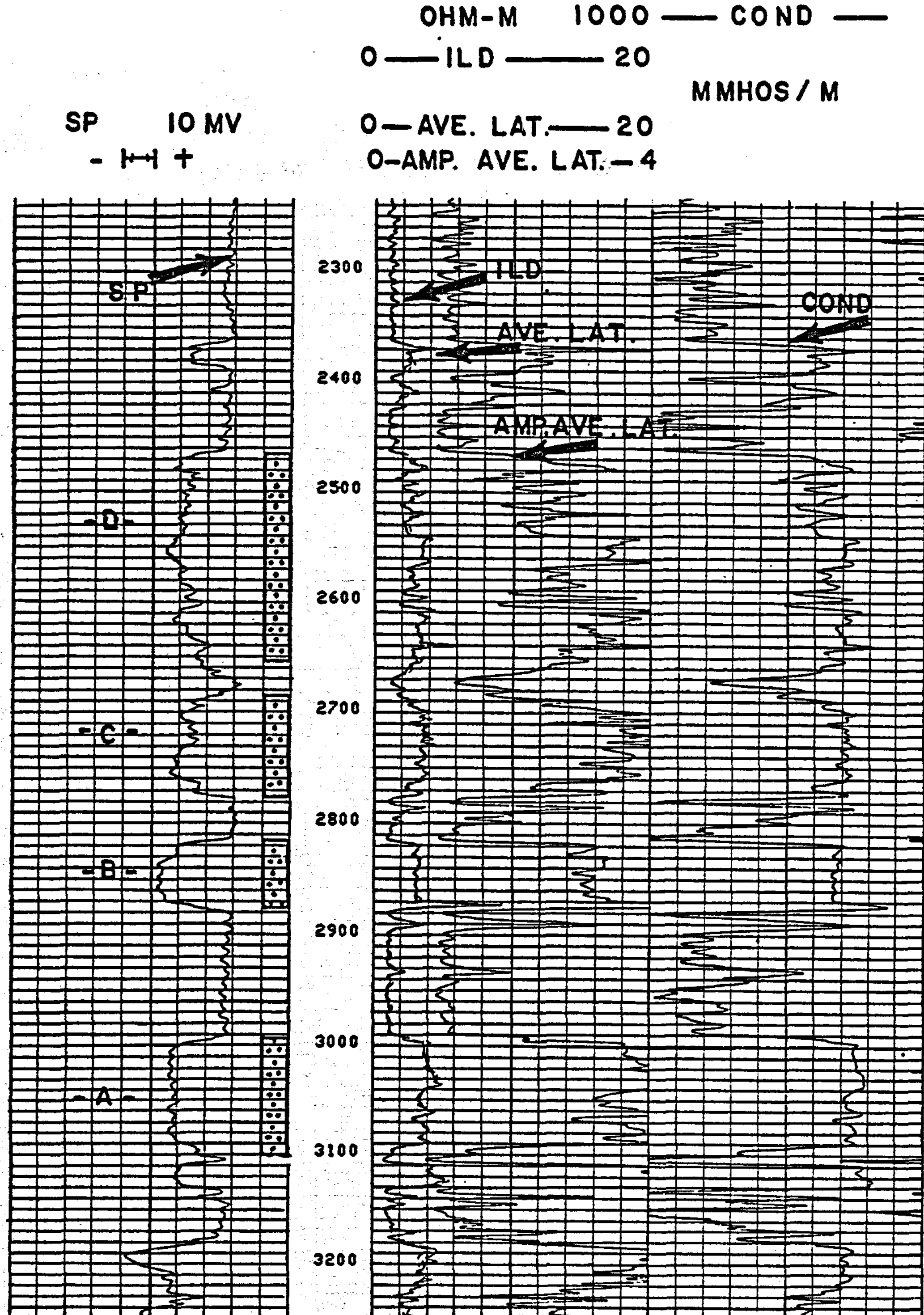
1) To establish an open-hole versus casing-collar correlation.

2) To determine integrity of casing versus cement, and cement versus formation bonding.

Analysis of the test well Variable Density Cement Bond Log, (Exhibit 5-14), indicated that the 1st Hinnant sand (9745' - 9885') was poorly bonded. Sands at the base of the 9-5/8" casing, however, showed excellent cement bonding, thereby isolating the test zone from any overlying sands, (Exhibit 5-14).

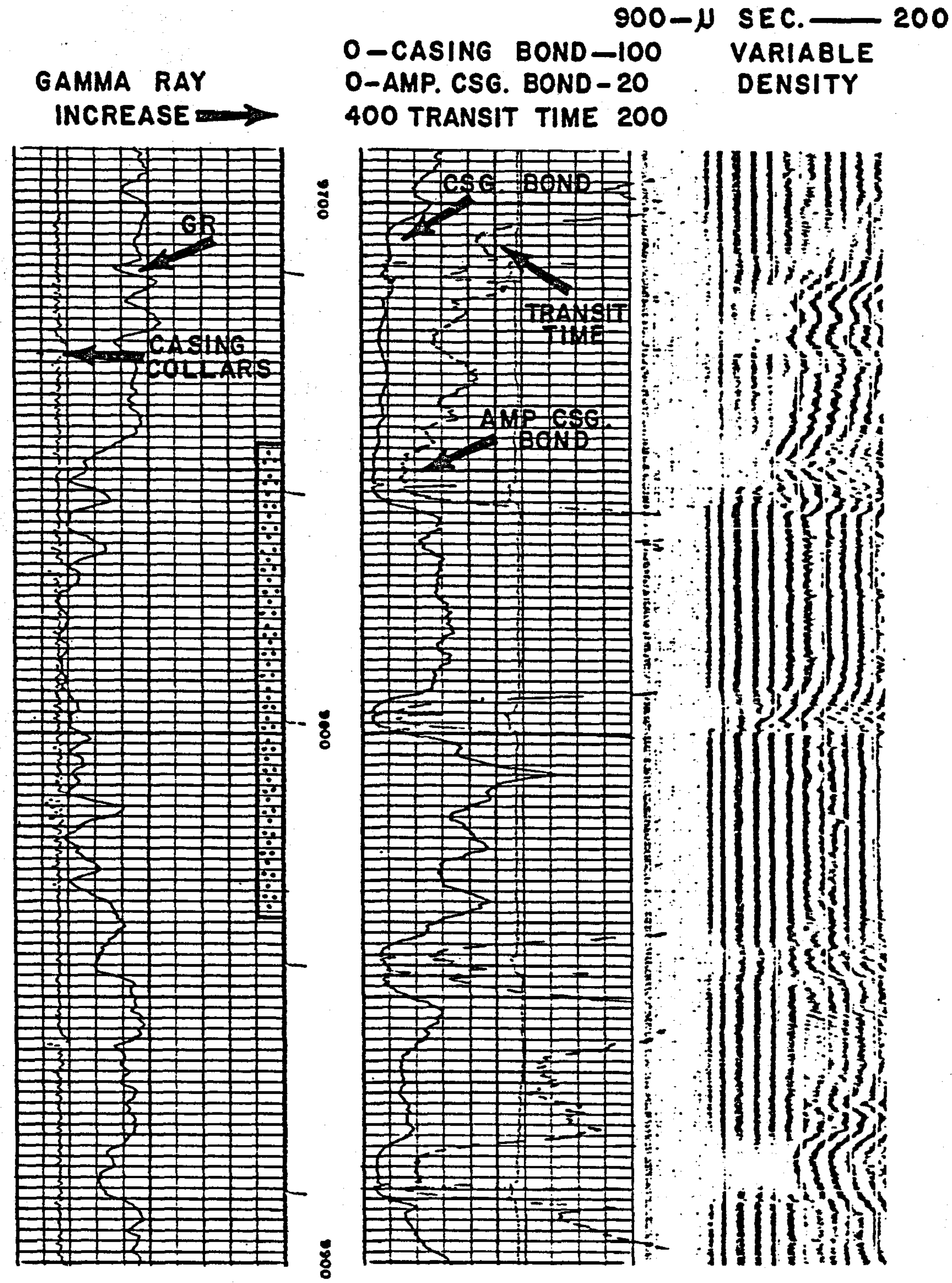
5.4 Cased Hole Log Analysis - Disposal Well

An Acoustic Cement Bond Log was run on the Saldana No. 1 Well for reasons stated in Section 5.3. Analysis of the bond log indicated that the primary disposal zone, Sand "A", was poorly bonded, and that block-squeezing operations were required to isolate the zone, (Exhibit 5-15). These operations are discussed in Section 7.0.



DUAL INDUCTION LATEROLOG - YEGUA SANDS

RIDDLE NO. 1 SALDANA

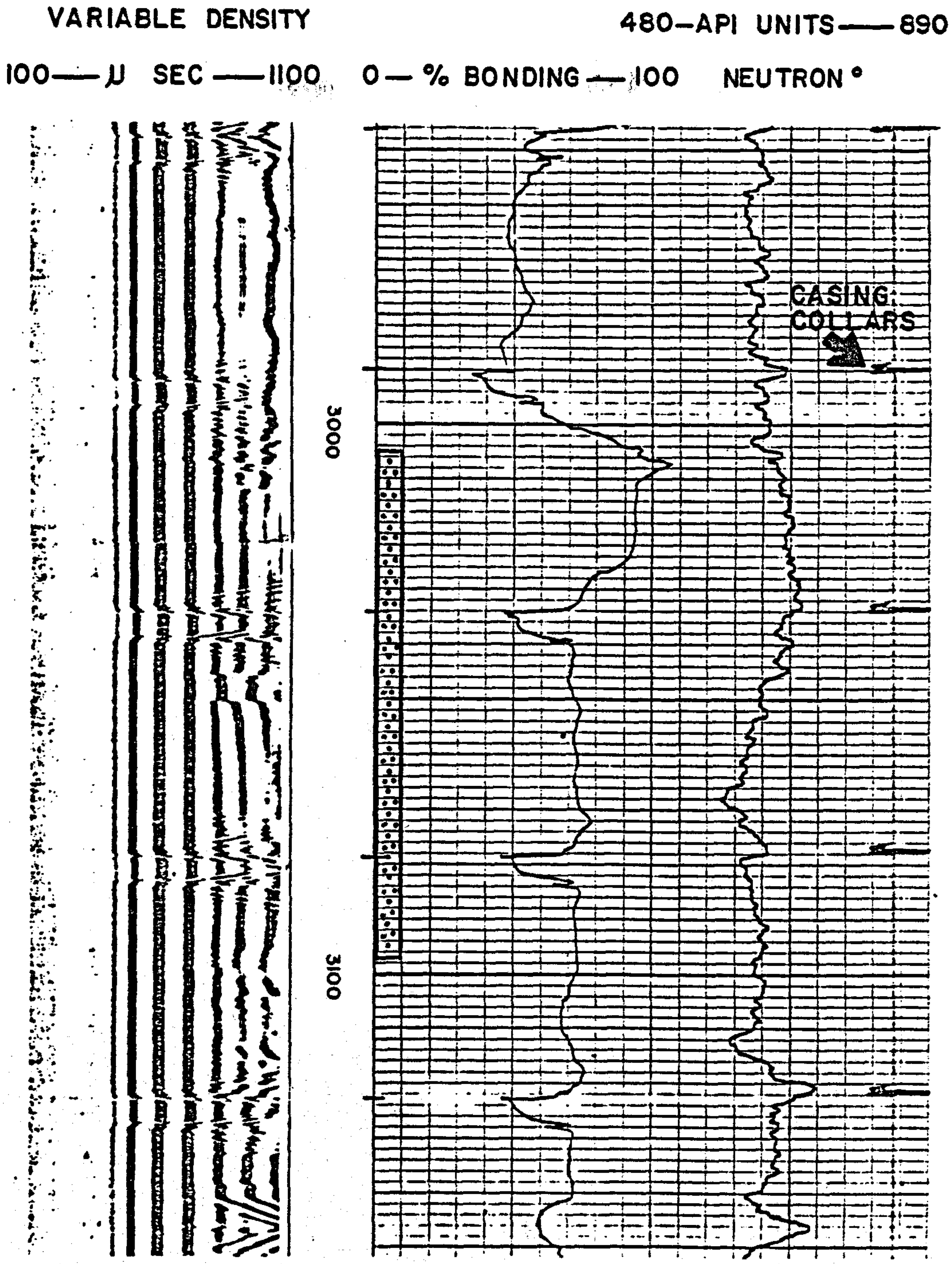


CEMENT BOND LOG - 1st. HINNANT SAND
RIDDLE NO. 2 SALDANA

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

EXHIBIT 5-14

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



ACOUSTIC CEMENT BOND LOG - YEGUA "A" SAND

RIDDLE NO. I SALDANA

6.0 RE-ENTRY AND COMPLETION OPERATIONS - TEST WELL

6.1 Drill Site and Support Facilities

6.1.1 Site Layout

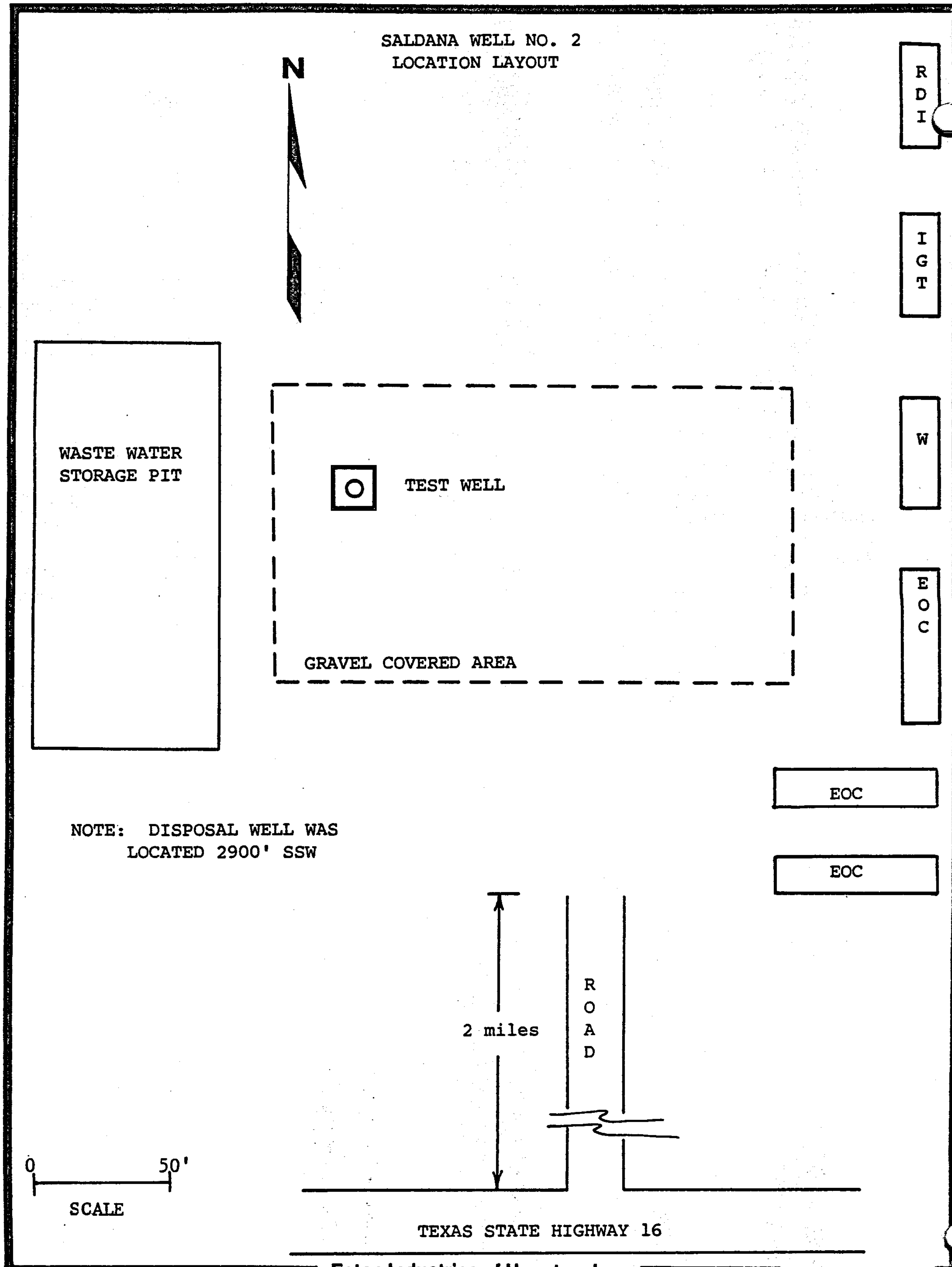
The location layout shown in Exhibit 6-1 accommodated conventional workover equipment used for completion of the test well. The soil is normally hard and dry, and rig operations were performed without any improvements to the location. Prior to moving in the well testing equipment, a portion of the location was covered with a layer of caliche followed by a layer of gravel.

6.1.2 Living Facilities and Utilities

Air-conditioned living facilities were provided for 12 individuals. Target Well Service, Weatherly Engineering, and Reservoir Data, Inc. brought in living trailers for their personnel. Motel accommodations were available in Zapata, Texas.

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. Septic tanks were installed for sanitation.

Radio-telephones were installed in the Eaton house trailers. Rented generators were used to supply electrical power.



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

EXHIBIT 6-1

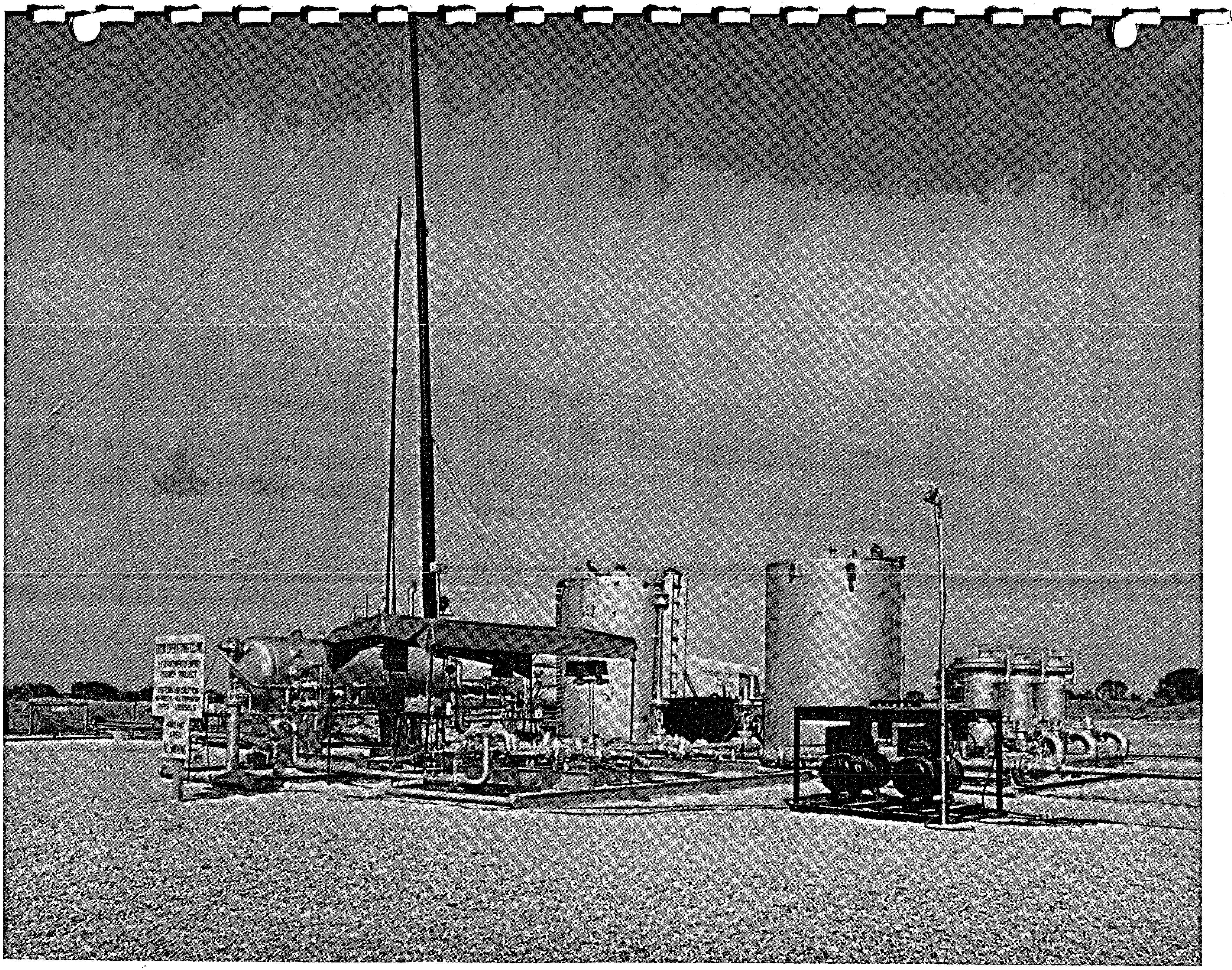


Photo 6-1 A portion of the location covered with gravel

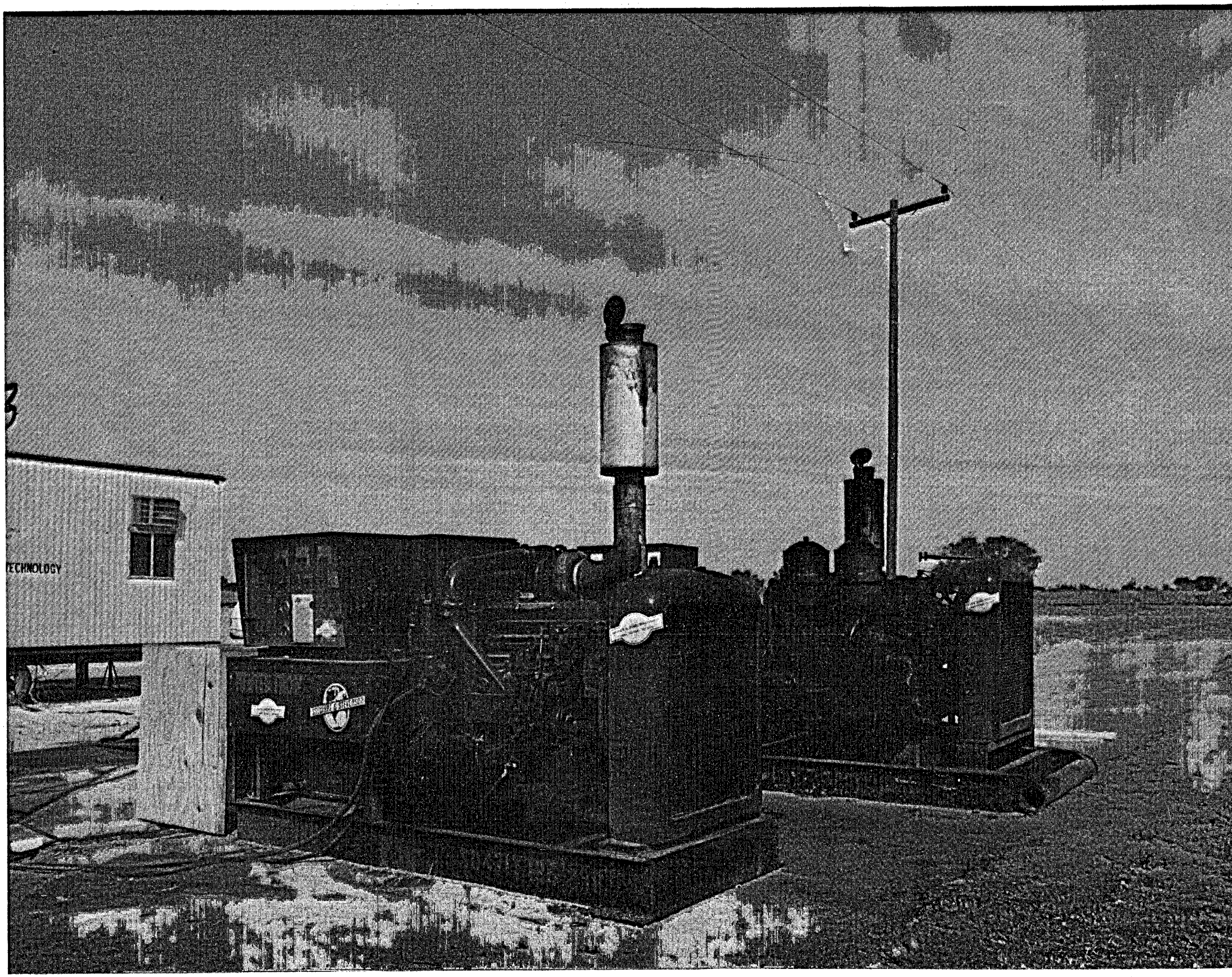


Photo 2. Electric power service to location was unreliable. All electricity was produced by these rental generators.

6.2 Test Well Design

6.2.1 Initial and Actual Well Completion Status

Exhibit 6-2 is a schematic drawing of the test well, illustrating the downhole configuration at the time Eaton took over the well from Riddle. The well had been drilled to a total depth of 11,171 feet. Seven-inch casing was set at 10,655 feet during the drilling operations. The well was "junked" below 9830 feet; however, Riddle did complete the well in the target sand through perforations from 9750 to 9754 feet and from 9760 to 9764 feet. A packer was set with 2-3/8 inch tubing at 9736 feet. The packer seal was not holding, and both the shut-in casing pressure and tubing pressure were 2600 psi.

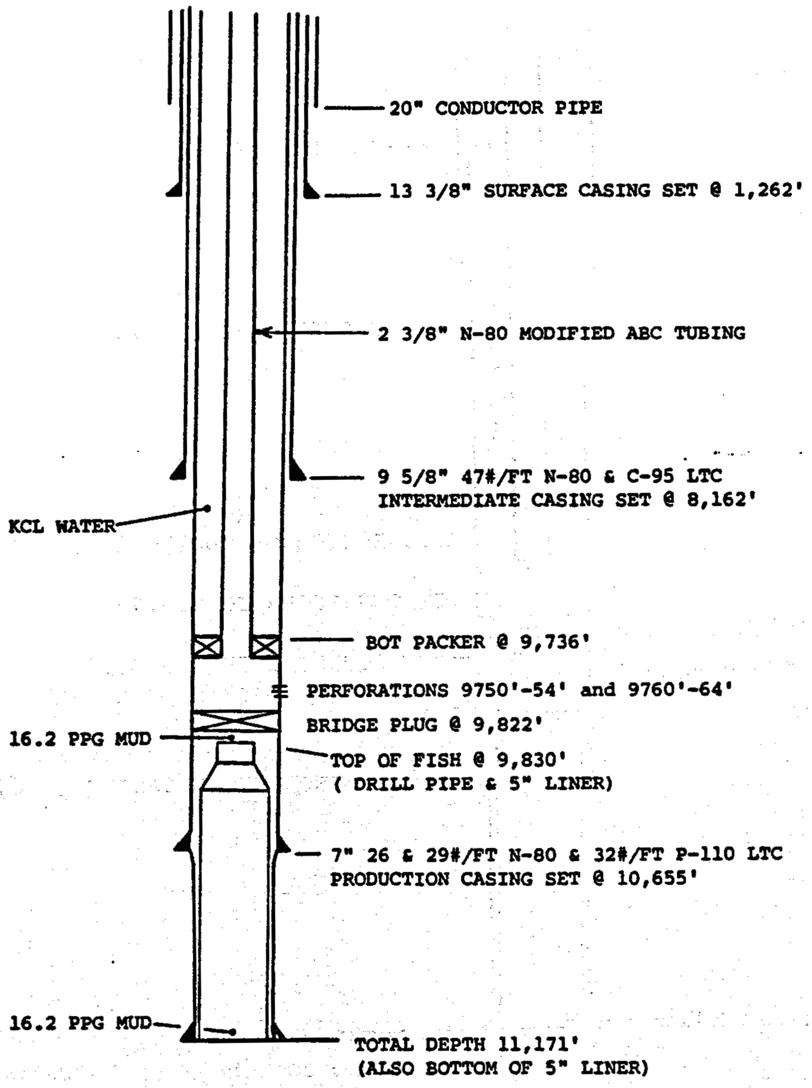


EXHIBIT 6-2: CONDITION AT TIME OF EATON TAKEOVER

Exhibit 6-3 is a schematic diagram illustrating the tubular configuration of the well as completed for testing. Tubing was run open-ended into the well to a depth of 9642 feet. The 13.2 ppg mud was then displaced with 9.0 ppg saltwater, and the target zone was perforated from 9745 to 9820 feet with 8 holes per foot.

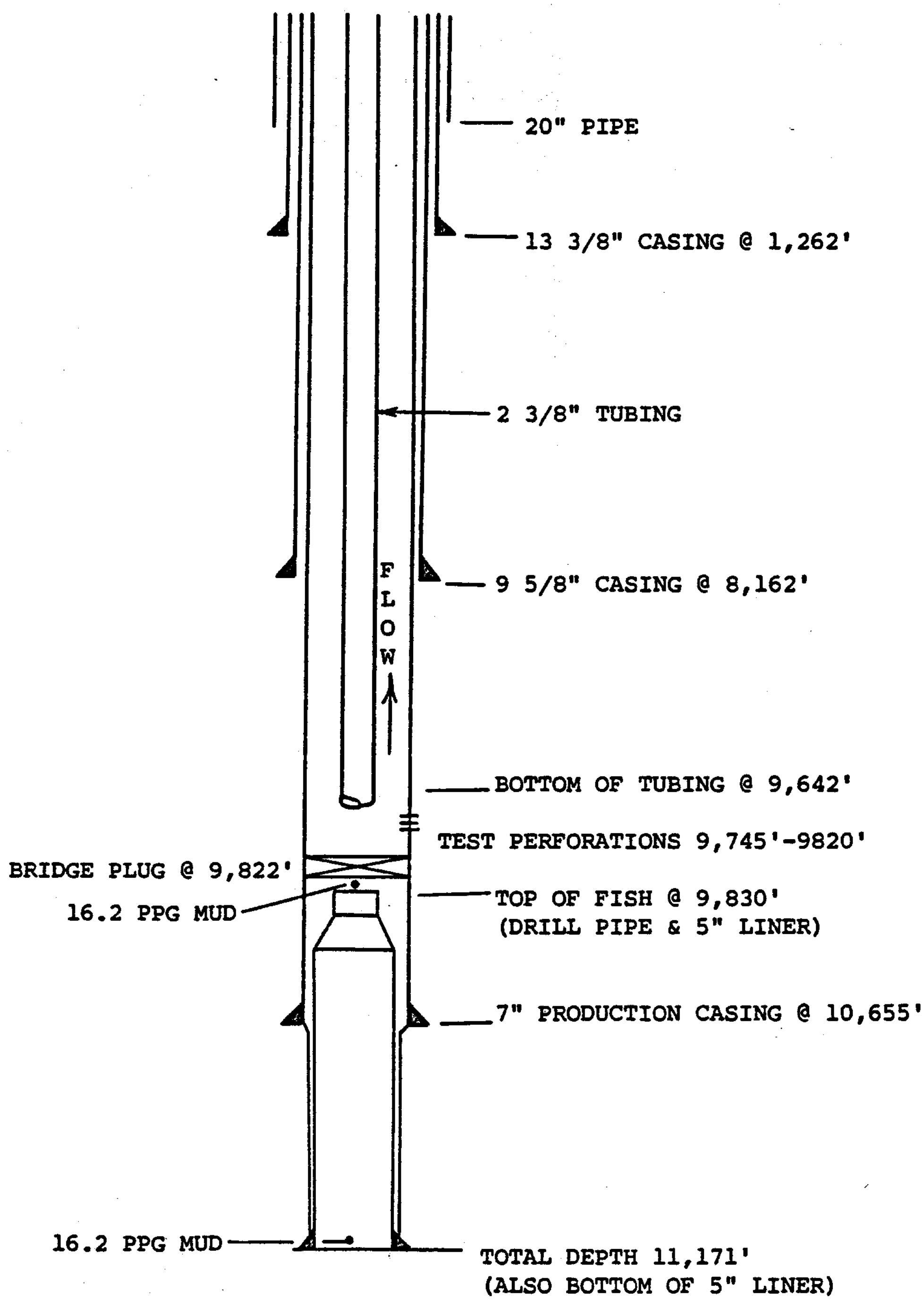


EXHIBIT 6-3: TESTING CONDITION

6.2.2 Tubular Goods Design

Engineering design and safety calculations were performed prior to completion of the well. Exhibit 6-4 summarizes the specifications of the tubular goods installed in the test 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 two 2-inch, 5000-psi working-pressure, hand-operated gate valves and one 2-inch, 5000-psi working-pressure, pneumatic-operated surface safety 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 two 2-inch 5000-psi working-pressure master gate valves, a "tee" with a 2-inch valve for a kill line connection, and a 2-inch "swab" valve for wireline accessibility.

6.2.4 Logging Program

The suite of open-hole logs and sidewall core data obtained by Eaton supplied adequate information for formation evaluation purposes. A gamma-ray acoustic cement bond log run by Riddle was also provided to Eaton. The only log run by Eaton itself was a casing inspection log.

6.3 Re-Entry Operations

The Target Rig No. 2 was moved to the Saldana Well No. 2 location on October 23, 1980, to commence re-entry operations on the test well. The well had 2600 psi of pressure on the tubing and casing. Water in the tubing and casing was displaced by circulating 13.2 ppg mud down the tubing, around the leaking packer, and out of the casing. After the well was dead, the christmas tree was removed, and a blowout preventor stack approved by Eaton was installed and tested to 5000 psi. The 2-3/8 inch tubing and packer were pulled out of the hole. A 6-inch bit was then run in the well to 9688 feet. The 13.2 ppg mud was circulated and conditioned, and the bit was pulled out of the hole.

6.4 Completion Operations

6.4.1 Cased Hole Log

A Dia-Log profile caliper log was run in the 7-inch casing from 9755 feet to the surface. The purpose of the log was to locate casing damage in the area of the packer and to determine the condition of the casing further up the hole. The log indicated that there was severe casing damage from 9740 to 9540 feet. Due to an equipment malfunction, the section from 9170 to 8920 feet was not graded or calipered. There was no indication of wear or any other damage to the rest of the casing. A 40-foot joint at 7740 feet was found to be a lighter joint, probably 29 pounds per foot, instead of the specified 32 pounds per foot.

The condition of the casing was not surprising. The severe damage in the lower section of the well was due to fishing and completion operations conducted by Riddle, and it explains why the packer seal would not hold. Since there were no other salt water sands in the area of the damaged casing, there was no concern about obtaining a proper test of the target sand. The light joint at 7740 feet also did not cause concern, because it was still strong enough to withstand the collapse and burst forces expected to be placed on it during testing.

6.4.2 Production Tubing

The 2-3/8 inch tubing originally pulled out of the well was run back in the hole to serve as a kill string and as a protection string for the bottom-hole pressure instruments. A rotary shoe was placed on the end of the tubing, and the hole was washed from 9760 to 9819 feet. The tubing was pulled back up to 9642 feet and hung in the tubing hanger. The christmas tree was installed and tested to 5000 psi. A wireline was then run in the tubing to 9813 feet to check for possible obstructions. The rig was moved off location on October 29, 1980.

6.4.3 Completion Perforations

The 13.2 ppg mud in the tubing and casing was displaced with 9.0 ppg brine. After displacement the well was allowed to produce about 80 barrels of salt water to the pit. (Riddle's old perforations 9750-54' and 9760-64' were still open). The target sand was then perforated from 9745 to 9820 feet with 8 holes per foot. A Dresser Atlas 1-11/16 inch "Slimkone" zero-phase through-tubing perforating gun was used. The well was opened to flow on October 31, 1980 and produced an estimated 250 barrels of salt water. The shut-in surface pressure was approximately 2450 psi.

RIDDLE SALDANA WELL NO. 2
TUBULAR SUMMARY

Tubular	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	NA	NA	NA	NA	NA	-	-	-
Surface Casing	13-3/8	0	1,262	54.5	12.459	K-55	STC	*	*	*
Intermediate Csg.	9-5/8	0	4,279	47.0	8.525	C-95	LTC	*	*	*
		4,279	4,757	47.0	8.525	N-80	LTC	*	*	*
		4,757	8,162	47.0	8.525	C-95	LTC	*	*	*
Production Csg.	7	0	1,053	29.0	6.059	N-80	LTC	3.33	**	2.6
		1,053	5,168	26.0	6.151	N-80	LTC	**	2.8	**
		5,168	6,736	29.0	6.059	N-80	LTC	**	2.8	**
		6,736	10,655	32.0	5.969	P-110	LTC	**	2.9	**
Liner	5	9,800 Est.	11,171	NA	NA	NA	NA	-	-	-
Tubing	2-3/8	0	9,642	4.7	1.995	N-80	8RD	**	**	2.8

CEMENTING SUMMARY

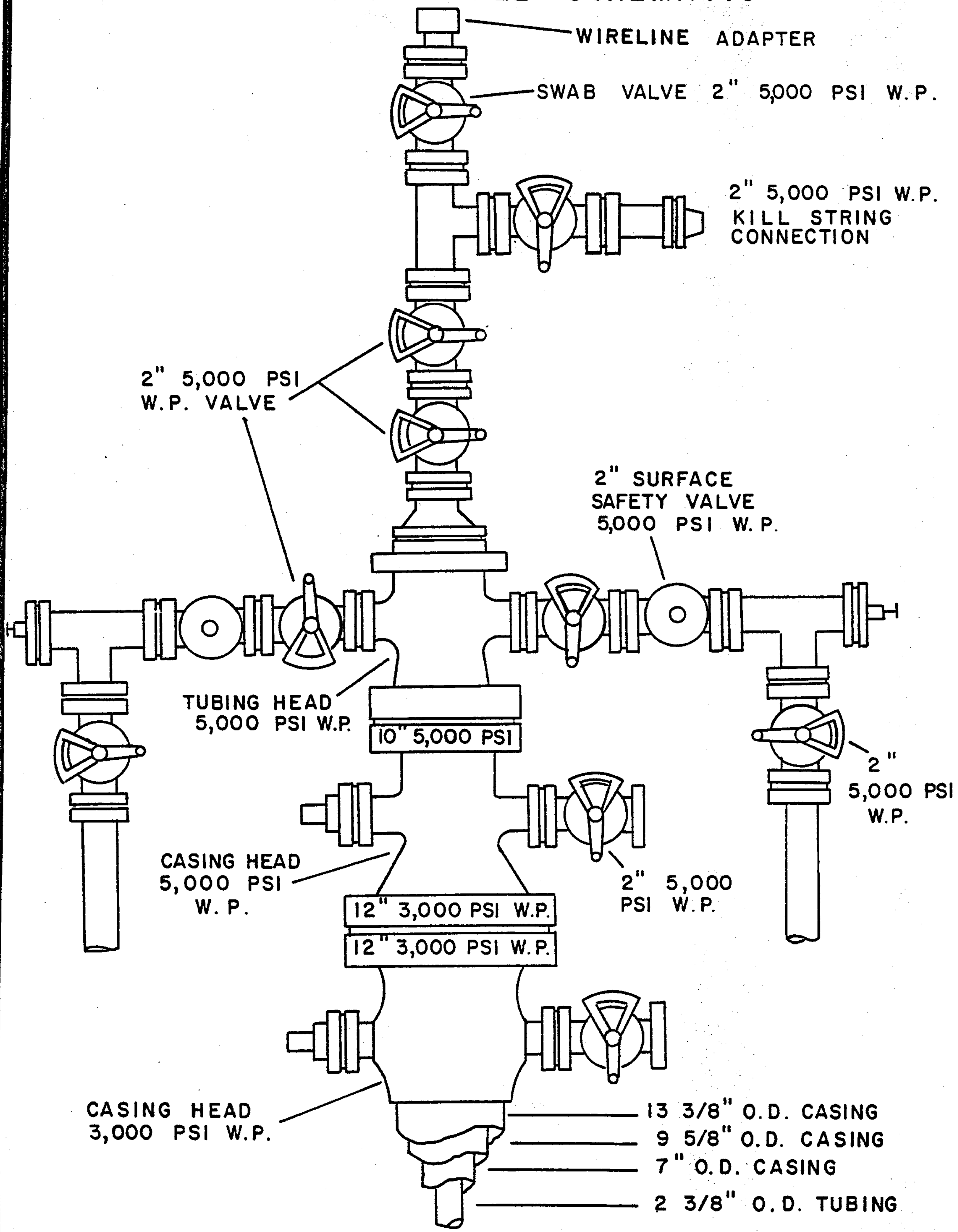
Casing	Size (in.)	Hole Size (in.)	
Surface	13-3/8	17-1/2	Cemented to surface with 675 sacks Halliburton Lite Wate with 5% salt and 500 sacks Class "H" with 2% CaCl.
Intermediate	9-5/8	12-1/4	Cemented with 300 sacks Halliburton Lite Wate with 12% HR-4 and 1/4#/sack Flocele and 400 sacks Class "H" with 18% salt. No returns. Cemented with 700 sacks Lite Wate with 0.2% HR-4 and 1/4#/sack Flocele. No returns.
Production	7	8-1/2	Cemented with 600 sacks Class "H" with 35% Silica Flour, 0.75% CFR-2, 2% KCL, 0.5% Halad 22-A and 0.2% HR-5 with 17#/sack of Disene #2 in last 300 sacks.
Liner	5	6-1/2	Cemented bottom with 175 sacks Class "H". Mixed at 17.0 ppg. Top of liner never cemented.

Note: All casing run, cemented and tested by Riddle.

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

** Safety factors Very High.

RIDDLE - SALDANA WELL NO. 2
CHRISTMAS TREE SCHEMATIC



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

EXHIBIT 6-5

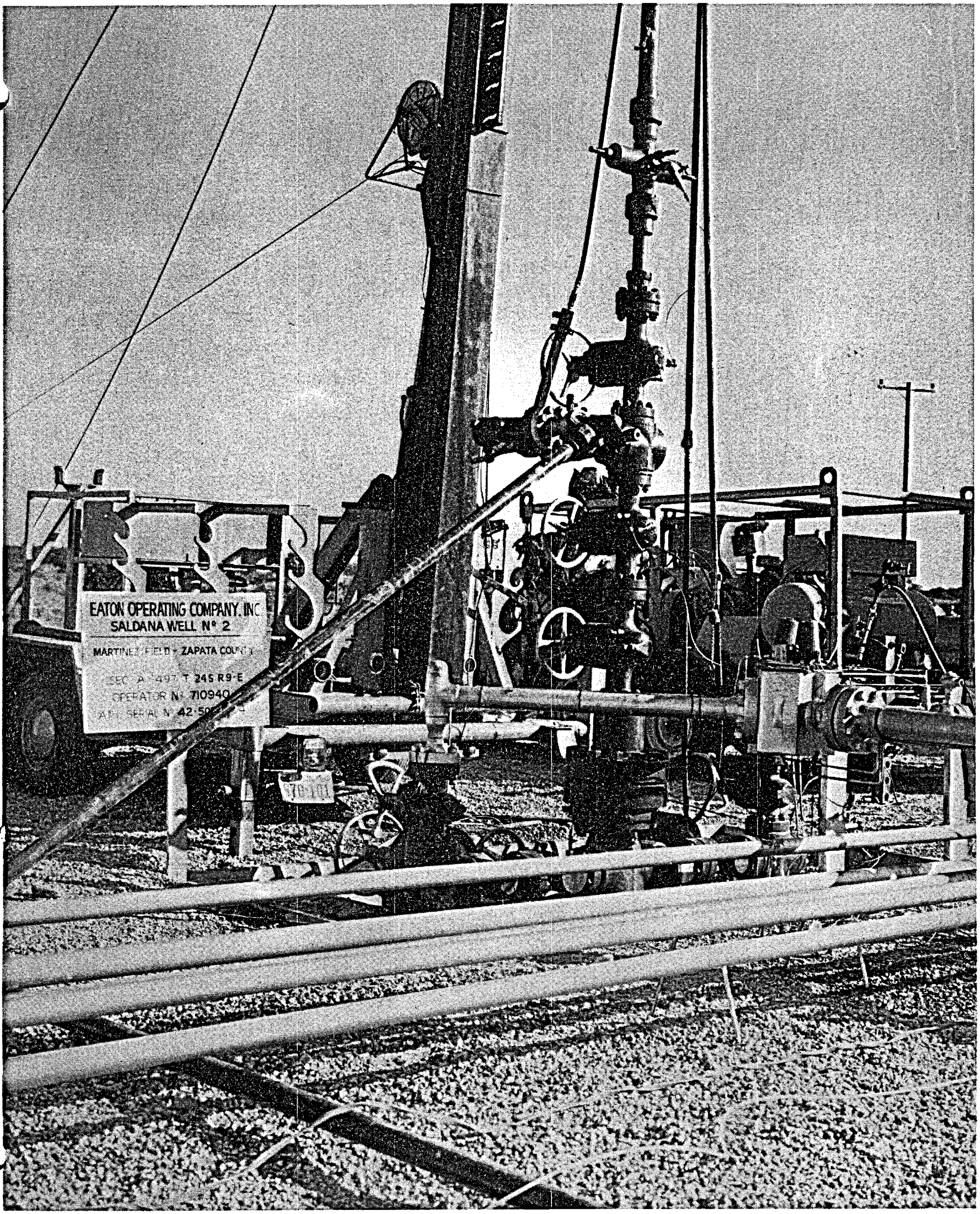


Photo 6-3 Christmas tree and "Y" block connection to flowline

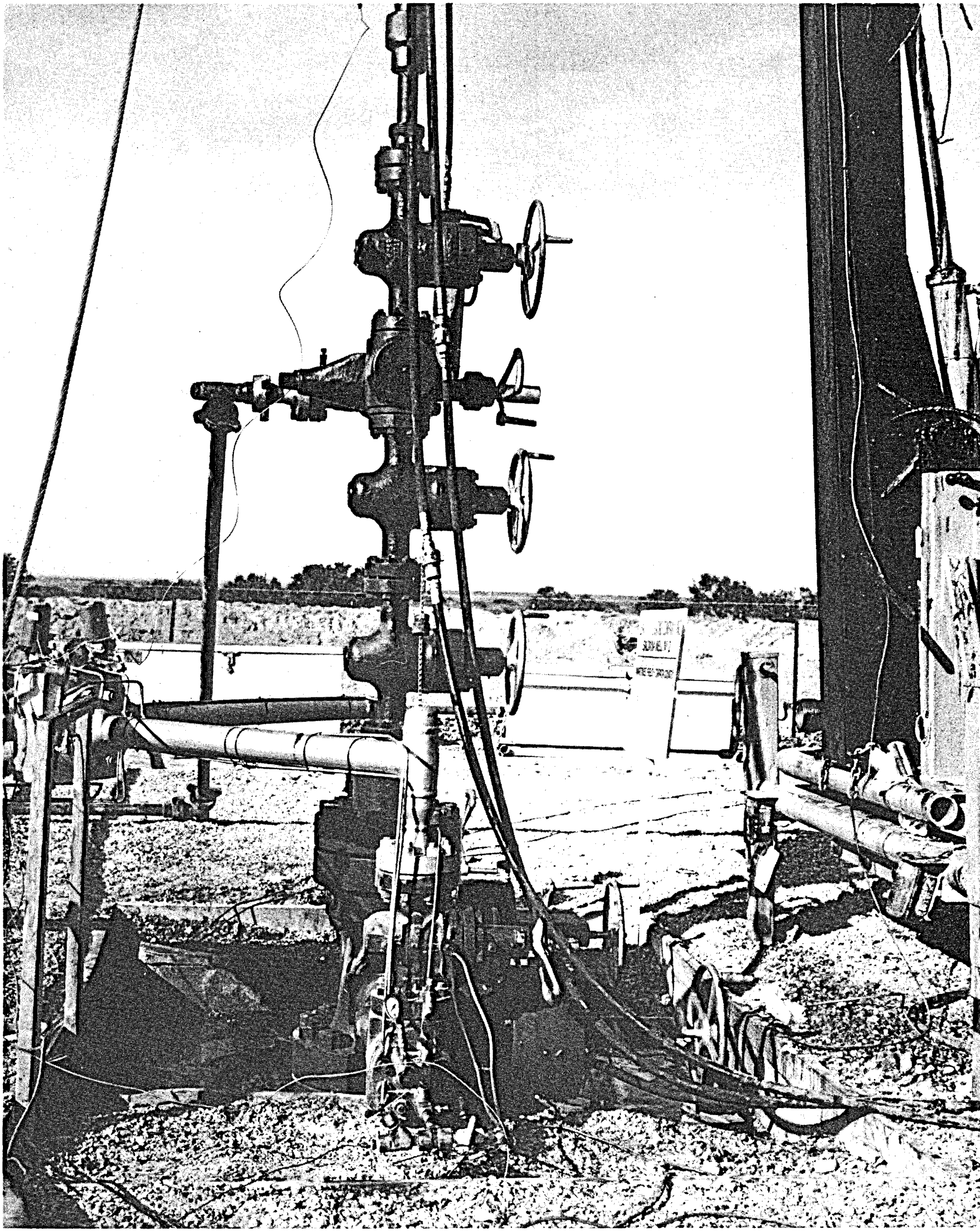


Photo 6-4 Side view of christmas tree with 2-inch 5000-psi working pressure gate valves. Note safety pilot and pressure sensors at bottom center.

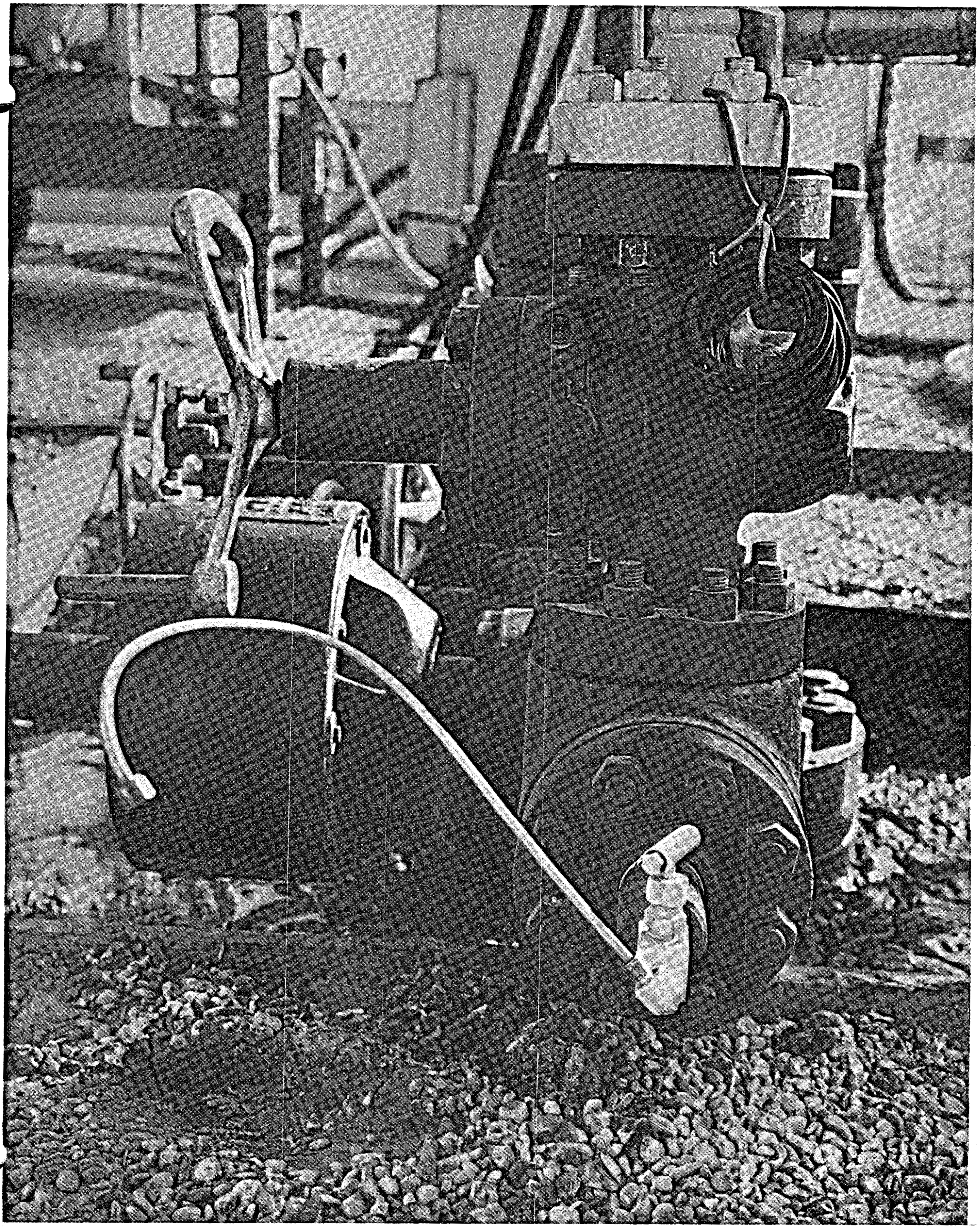


Photo 6-5 A high-pressure fluid sampling point on the wellhead

7.0 RE-ENTRY AND COMPLETION OPERATIONS - DISPOSAL WELL

7.1 Location

The Saldana Well No. 1 was located approximately 2900 feet south-southwest of the test well location. The No. 1 well was also a dry hole which had been abandoned by Riddle Oil Company. The well was in a cleared area where the ground was flat, dry, and hard. No improvements to the location were necessary for rig operations or testing.

7.2 Disposal Well Design

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

- An injection capacity of 8000 barrels of water per day at an injection pressure below 500 psi.
- High temperature capability of up to 300°F.
- A minimum disposal depth of 2450 feet as specified by the Texas Railroad Commission.
- Protection of fresh and brackish water sands by proper completion methods using casing and cement for isolation of sands.

7.2.1 Initial and Actual Well Completion Status

Exhibit 7-1 is a schematic drawing of the disposal well showing the conditions when Eaton took over operations from Riddle. The well contained 2-3/8 inch tubing set on a packer at 9710 feet. The interval from 9831 to 9836 feet had been perforated. The plug back depth was 9842 feet.

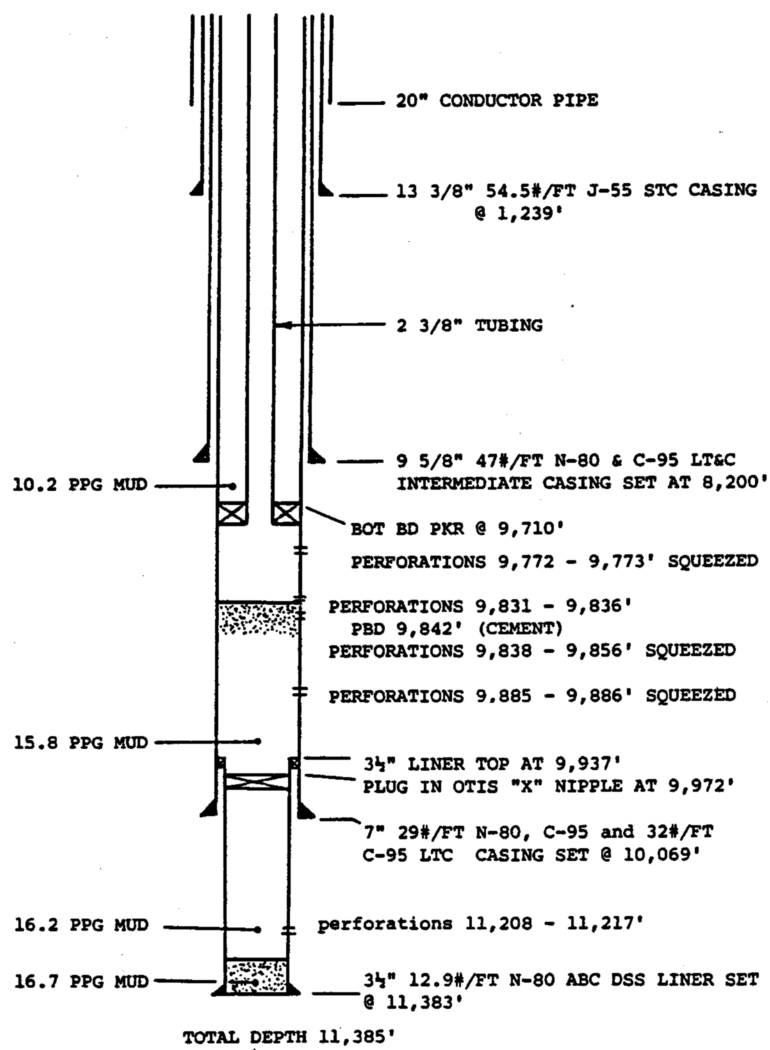


EXHIBIT 7-1: CONDITION AT TIME OF EATON TAKEOVER

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

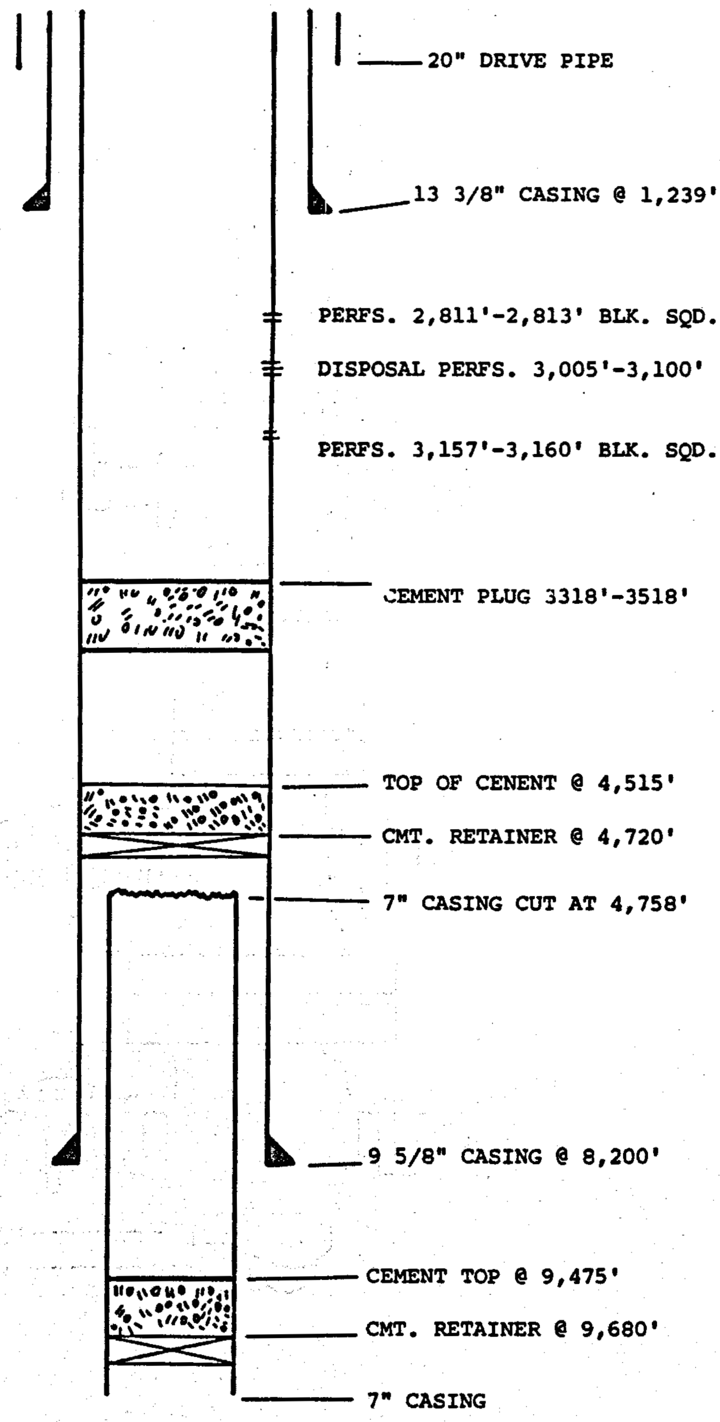


EXHIBIT 7-2: DISPOSAL WELL AS COMPLETED FOR DISPOSAL

7.2.2 Wellhead Design

Exhibit 7-3 is a schematic of the christmas tree installed on the disposal well. The 13-3/8 inch and 9-5/8 inch casing heads, which belonged to Riddle, were not removed. Flanged adapters were added to allow installation of a tubing head and a 3-inch master valve.

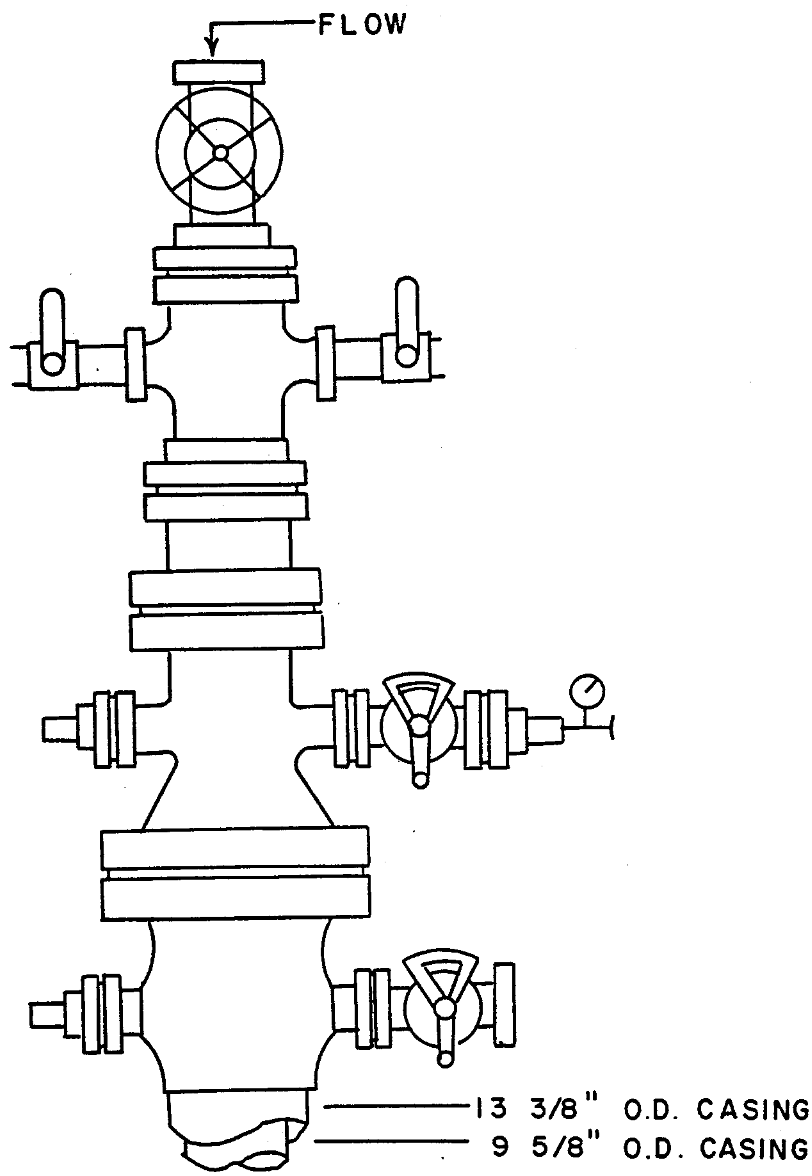


EXHIBIT 7-3: DISPOSAL WELL CHRISTMAS TREE SCHEMATIC

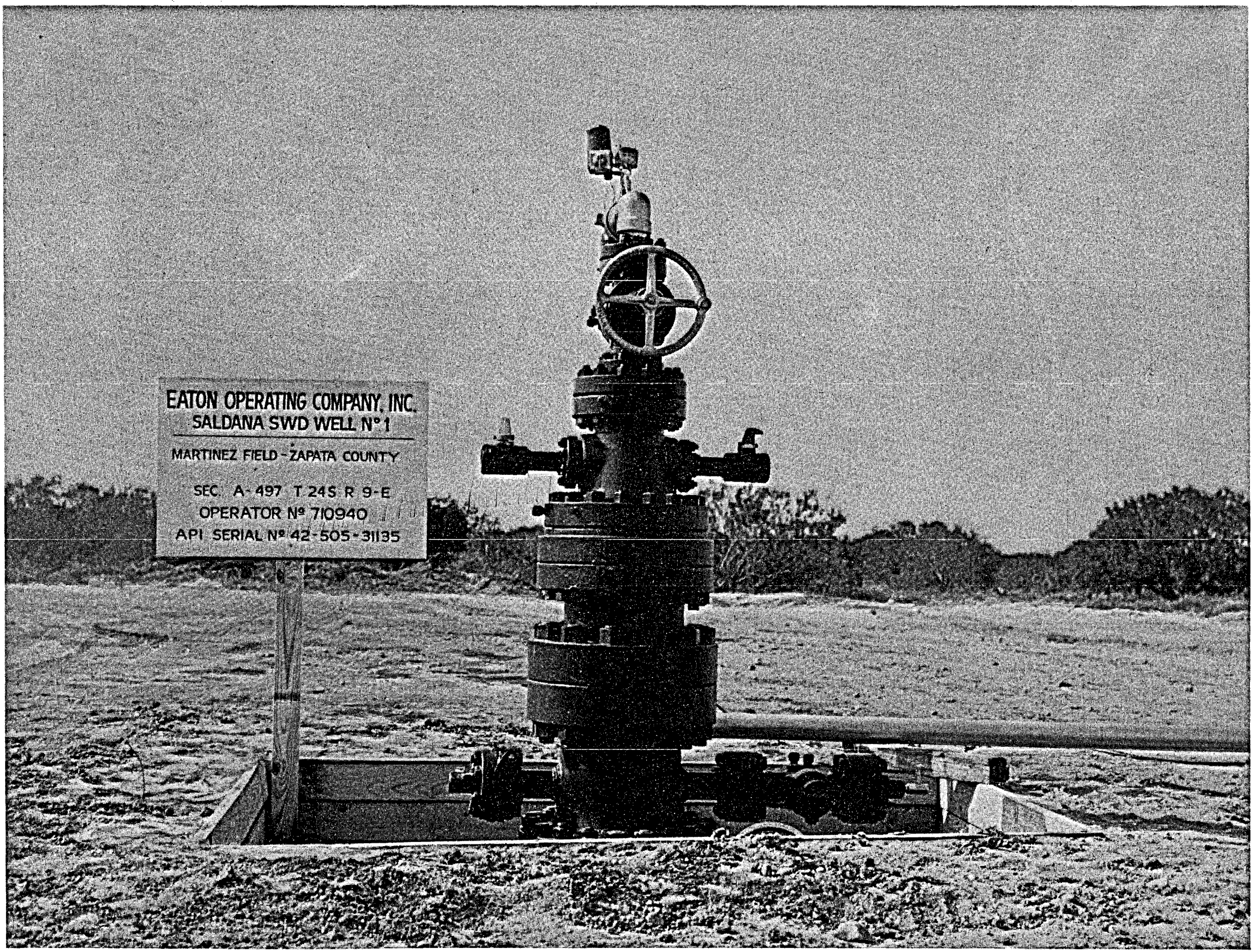


Photo 7-1 **The Saldana Well No. 1 was converted to a salt water disposal well**

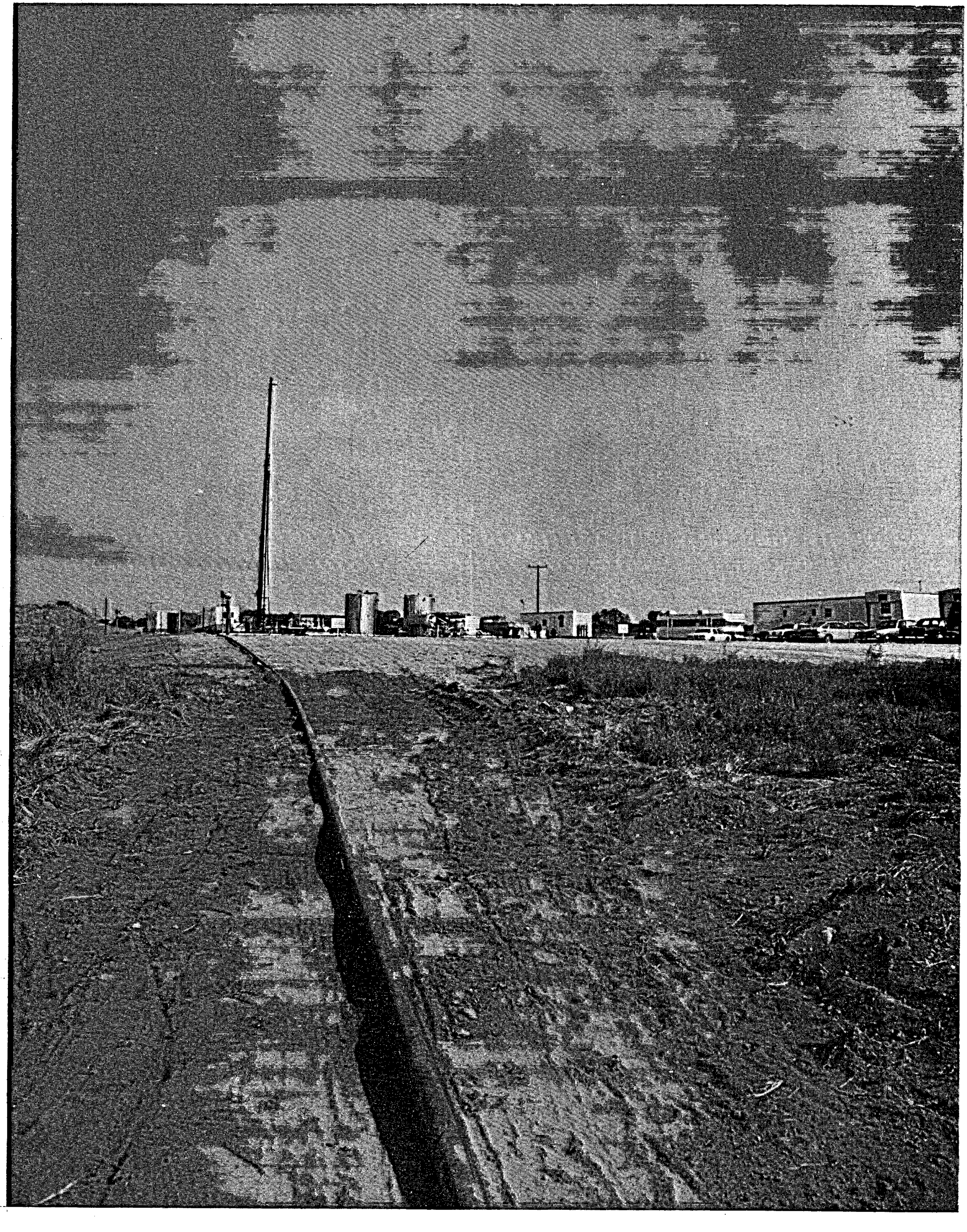


Photo 7-2 A 3-1/2 inch flowline was installed to transport processed water to the disposal well, 2900 feet away.

7.3 Selection of Disposal Zone

The electric log of the Saldana Well No. 1 obtained from Riddle indicated that the following potential disposal sands were available for injection:

Sand	Top	Bottom	Thickness	Average Porosity (%)
A	3005'	3097'	92'	25%
B	2825'	2885'	60'	30%
C	2695'	2785'	90'	26%
D	2475'	2662'	187'	31%

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

7.4 Re-Entry Operations

The Target Rig No. 2 that was used for cleaning out and completing the test well was also selected to perform workover operations on the disposal well.

The rig was moved onto the location on October 28, 1980. The christmas tree was removed, and blowout preventors were installed on the well and pressure-tested to 5000 psi. The tubing and casing fluids were displaced with 13.3 ppg mud, and the 2-3/8 inch tubing and packer were pulled out of the hole. An EZSV cement retainer was then run in the hole with 2-3/8 inch tubing. The retainer was set at 9680 feet. An attempt was made to squeeze off the perforations from 9831 to 9836 feet but injection into the perforations could not be accomplished with 6500 psi surface pump pressure. A cement plug was then spotted from 9675 to 9475 feet, and the tubing was pulled out of the hole.

A free point indicator tool was run in the 7-inch casing, and the casing was found to be stuck at 4781 feet. The casing was cut at 4758 feet and pulled out of the hole. A casing scraper was then run in the 9-5/8 inch casing to 4758 feet. A cement retainer was then set at 4720 feet, and a cement plug was spotted in the 9-5/8 inch casing from 4715 to 4515 feet.

7.5 Completion Operations

A gamma-ray cement bond log was run from 4000 to 2000 feet. The log indicated that the proposed disposal zones were not isolated and that the 9-5/8 inch casing should be squeezed with cement above and below the two disposal sands. A casing inspection log was also run in the 9-5/8 inch casing from 4000 feet to the surface. A cement plug was then spotted from 3518 to 3318 feet. The well was perforated from 3158 to 3160 feet, but fluid could not be pumped into the perforations. The well was perforated from 3157 to 3159 feet, and the interval was squeezed with 230 sacks of cement. The interval from 2811 to 2813 was then perforated and squeezed with 200 sacks of cement. The cement was drilled out from 2736 to 2813 feet. The cemented perforations from 2811 to 2813 feet were pressure-tested and leaked at 700 psi. An attempt was made to re-squeeze the perforations, but no fluid could be pumped into the perforations with 4500 psi. (It is believed that the cement was not completely set during the initial pressure test). The cement was drilled out to 3160 feet, and the lower set of perforations was tested to 1000 psi. Clean saltwater was circulated from 3335 feet to the surface, the 2-3/8 inch tubing was pulled out of the hole, the blowout preventors were removed, and the christmas tree was installed. The rig was released on November 10, 1980.

7.5.1 Perforation and Injectivity Tests

After the rig was moved off location, the well was perforated from 3005 to 3100 feet with 4 holes per foot. Water was injected into the disposal zone at the rate of 21,600 BWPD with 900 psi and 5760 BWPD with 300 psi. From these injectivity tests it was determined that the well was capable of accepting water in excess of 8000 BWPD with a maximum surface injection pressure of 500 psi. (See Exhibit 7-4). No stimulation treatment was necessary for the disposal well.

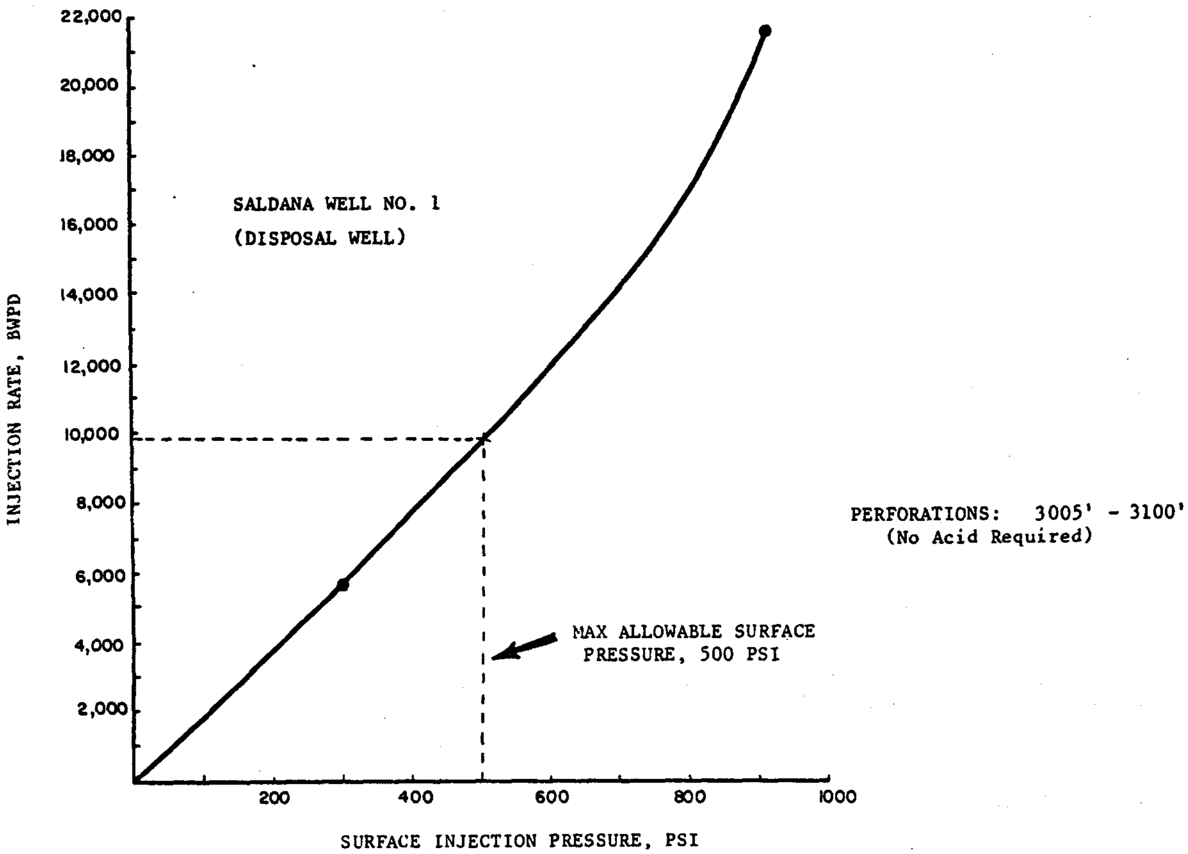


EXHIBIT 7-4: INJECTION RATE VS. SURFACE INJECTION PRESSURE

8.0 TEST OBJECTIVES

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

Specific information desired was the following:

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

9.0 SURFACE TESTING FACILITIES

9.1 Design Requirements

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

• Wellhead Working Pressure	5000	psi
• Flow Line Shut-In Pressure	5000	psi
• Temperature	300°	F
• Brine Flow Rate	20,000	BPD
• Separator Operating Pressure	1200	psi
• Filter Operating Pressure	600	psi

9.2 Main Process Equipment

Exhibit 9-1 is a diagram of the surface test equipment. The well stream entered the flow line at the point where the two flow loops connected. The fluid flow rate, pressure, and temperature were measured ahead of the choke manifold. A fluid sampling port was positioned in the flow stream so that sampling could be performed at flowing wellhead conditions and before the chemical inhibitor injection point. The main flow then passed through a choke manifold and through a data header. The data header incorporated a sonic sand detector and scale/corrosion-measuring coupons. The flow then entered a conventional horizontal well test separator. The gas was measured by an orifice meter and then flared. The separator brine passed through a flow meter manifold. Water samples were obtained at the flow meter manifold. The brine then passed through a 25 micron filter tower manifold before entering a 220-barrel open-top tank. A triplex mud pump was used to move the produced brine through a 3000-foot, 3-1/2 inch O.D. flowline to the disposal well. Pressure and temperature were measured at the disposal wellhead.

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 flowline pressure reached a low of 500 psi, separator pressure reached a high of 1200 psi, or the filter unit pressure reached a high of 600 psi. The pneumatic system could also be activated manually at a safe distance from the test well.

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

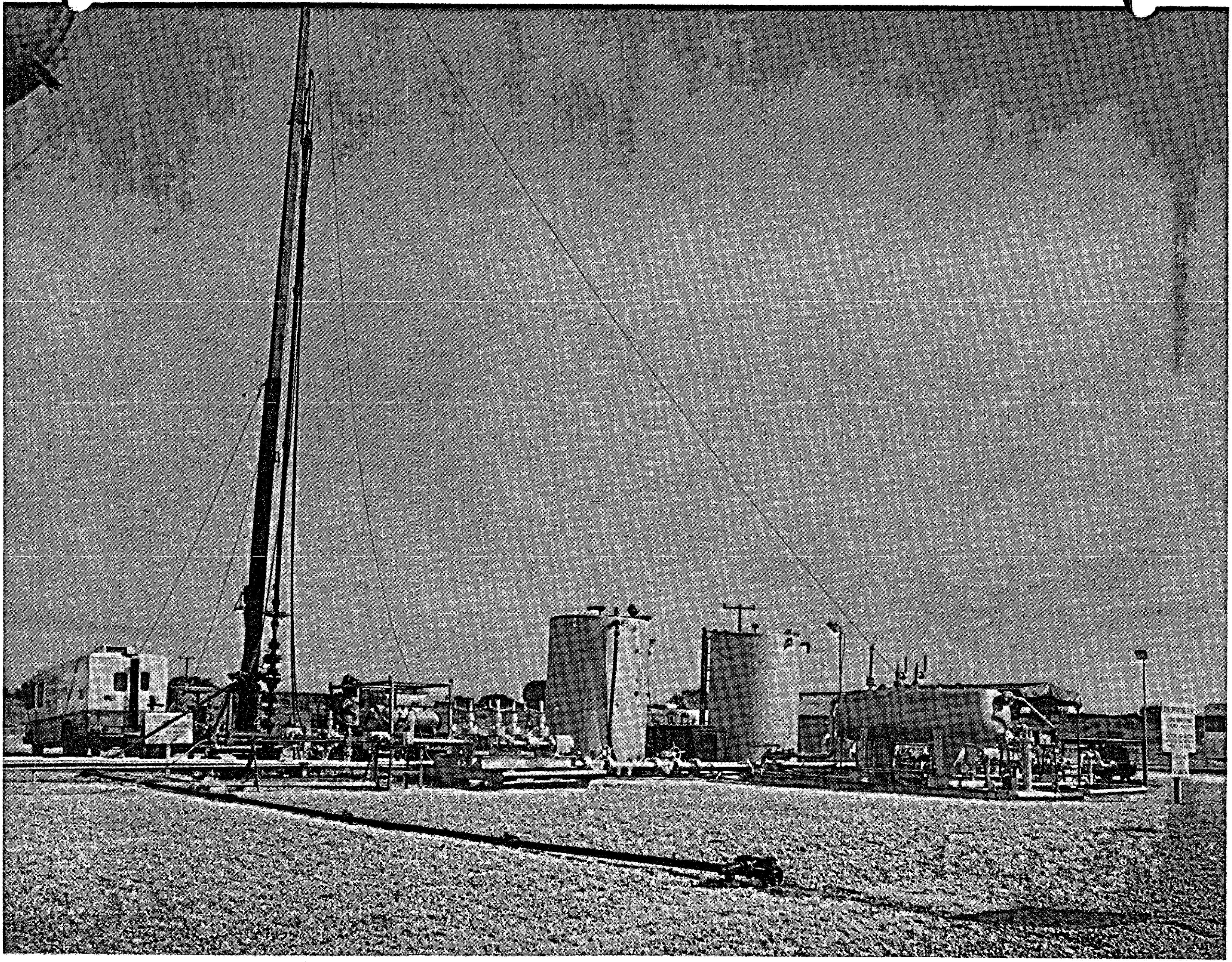


Photo 9-1 Safety "Kill-line" to tubing in foreground

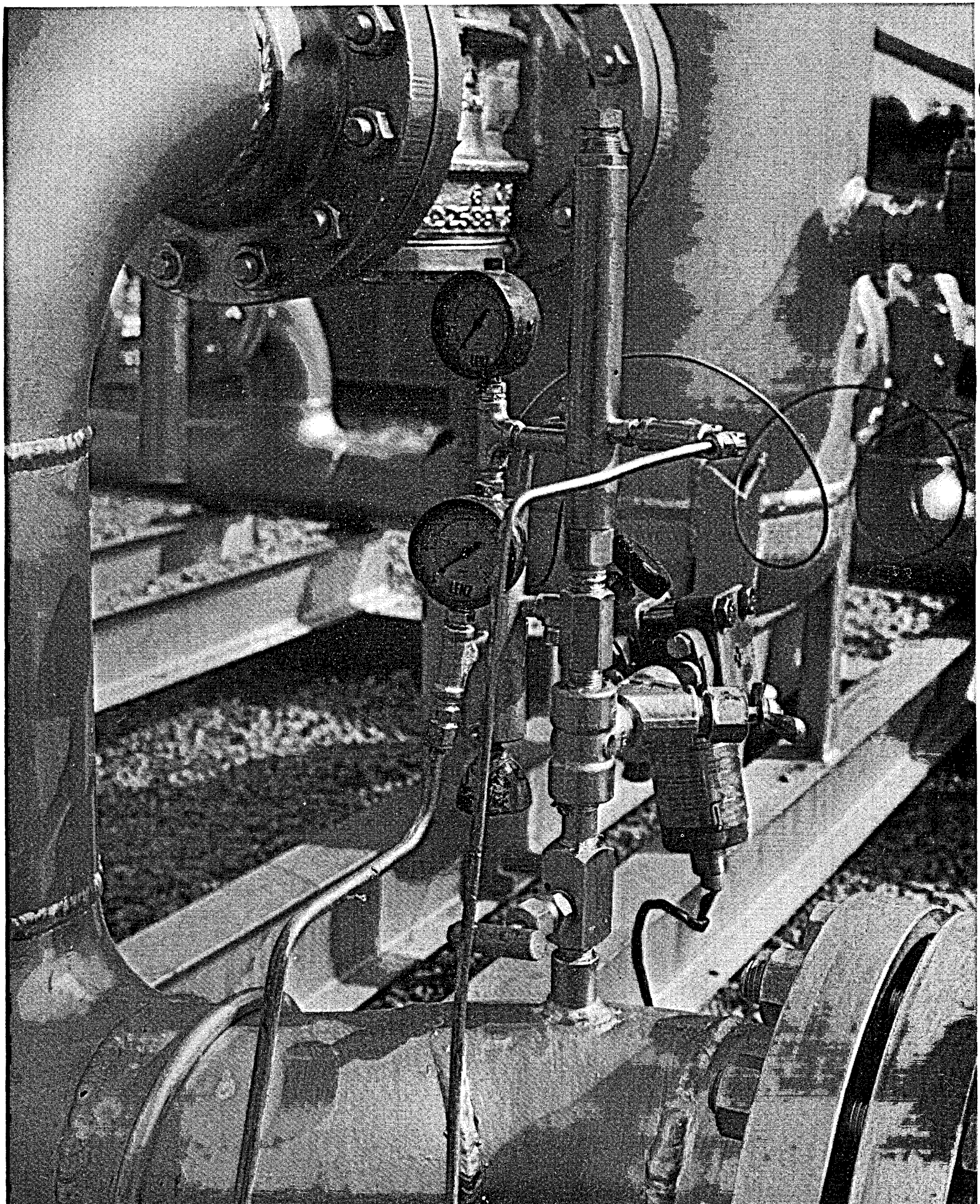


Photo 9-2 Safety shut-in pressure sensor pilot on filter unit

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 raw data for deducing the quantity and properties of produced fluids:

- Institute of Gas Technology (IGT)
- Reservoir Data, Inc. (RDI)
- Weatherly Engineering (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 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° to 400°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 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 to RDI's wellhead lubricator 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 a 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 wellhead.

9.4.1.2 **Data Recording by IGT:** Electrical outputs from 9 of the 10 sensors described above were directly transmitted to the recording location in the IGT trailer using four-conductor shielded cables with Amphenol Series 44 connectors at each end of the outside wiring. Output pulses from the separator brine turbine were amplified and shaped using a Tejas Controls, Inc. "Big Tex II" near the turbine meter. The Big Tex II received 110 volt a-c power from an extension cord. Its output pulses were transmitted to IGT's trailers using the same type field wire and connectors as the other data channels. This method of recording turbine data was developed through cooperation between IGT and RDI during the earlier test of the Lear G.M. Koelemay No. 1 well. Lead time for procurement precluded similar treatment of pulses from the wellhead pressure turbine.

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

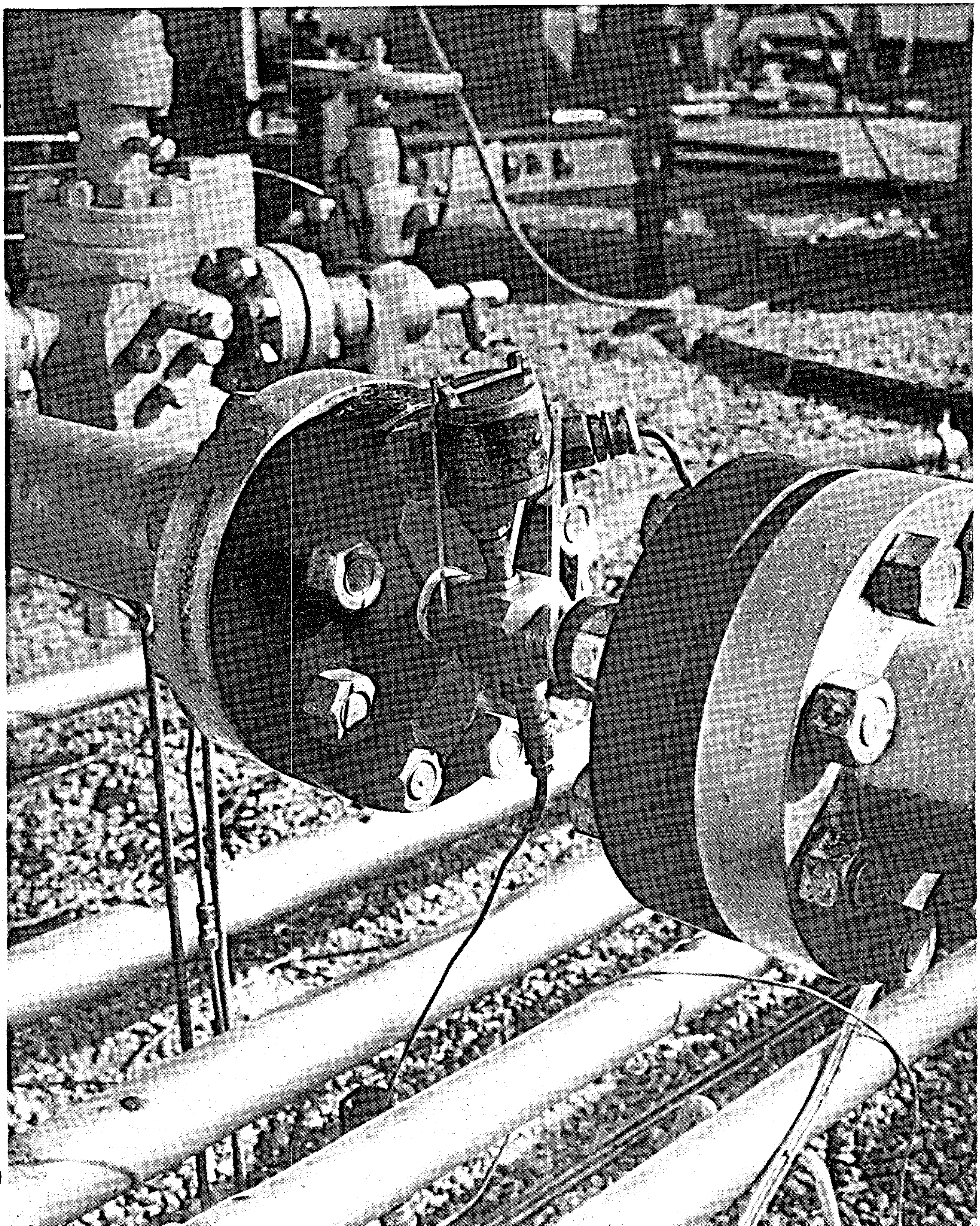


Photo 9-3 Halliburton 1-3/4 inch turbine meter measuring wellhead fluid production rate

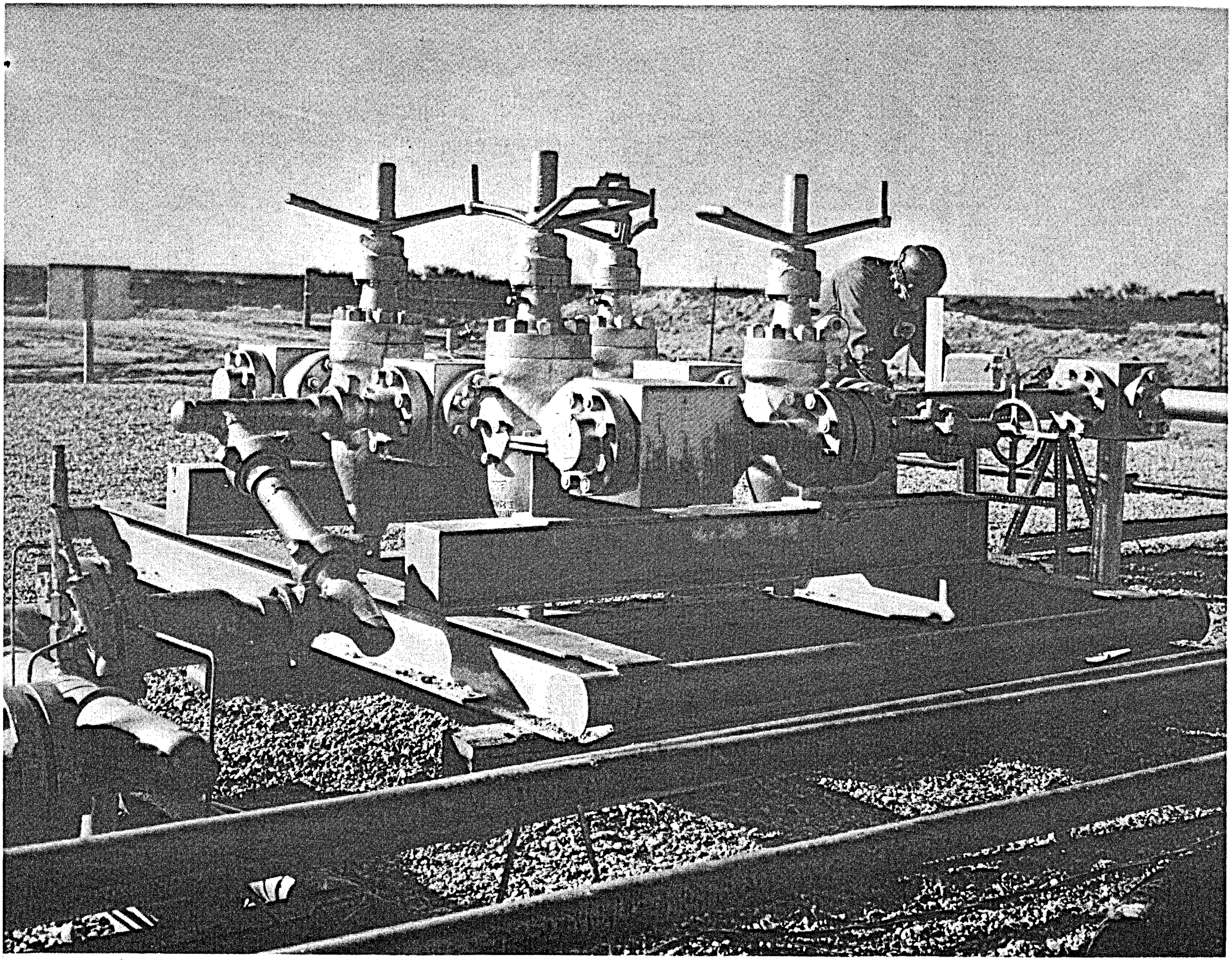


Photo 9-4 Two-inch 10,000-psi working pressure choke manifold

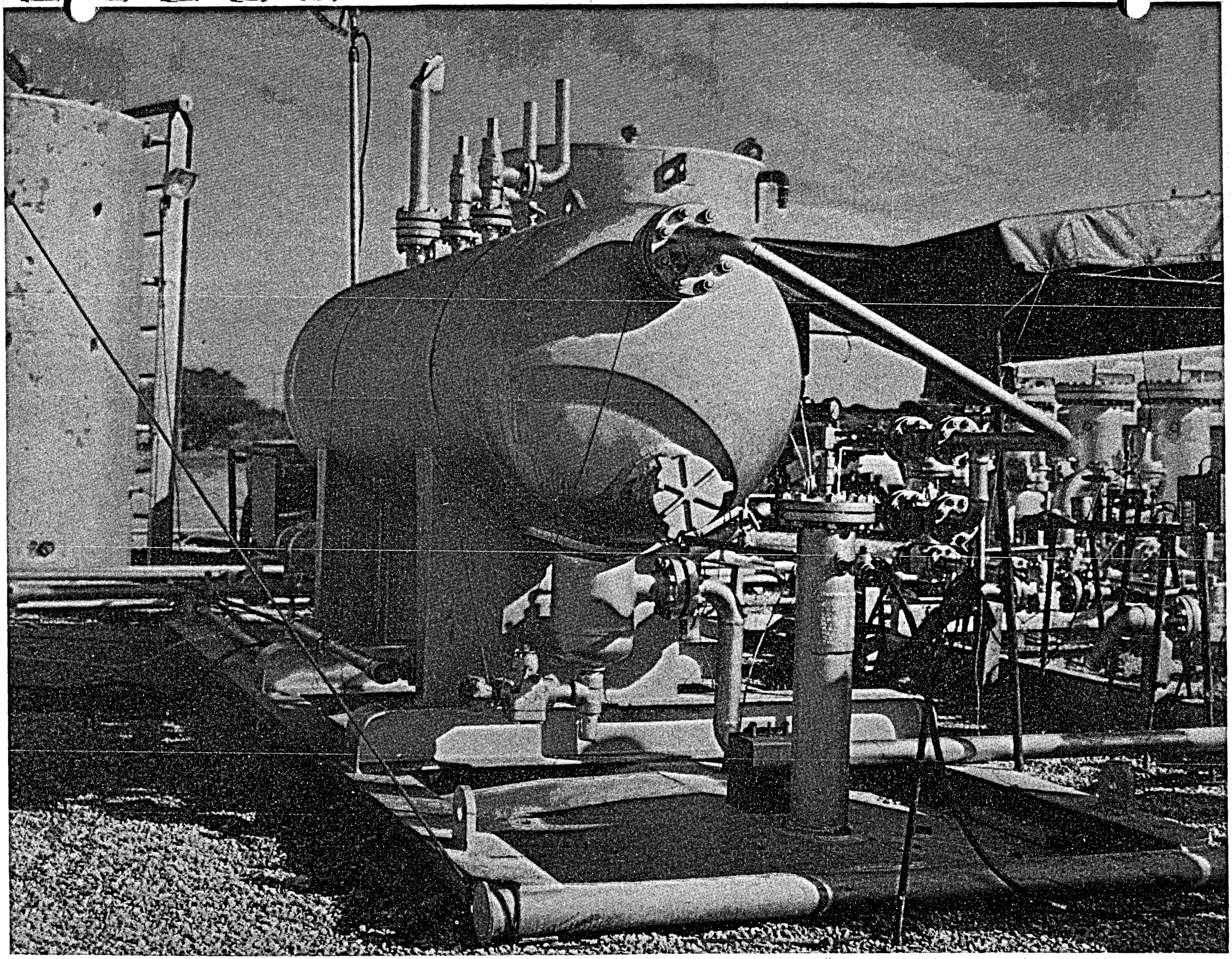


Photo 9-5 Gas leaves the separator at top center through 2-inch line. Brine exits through 3-inch line at lower center.

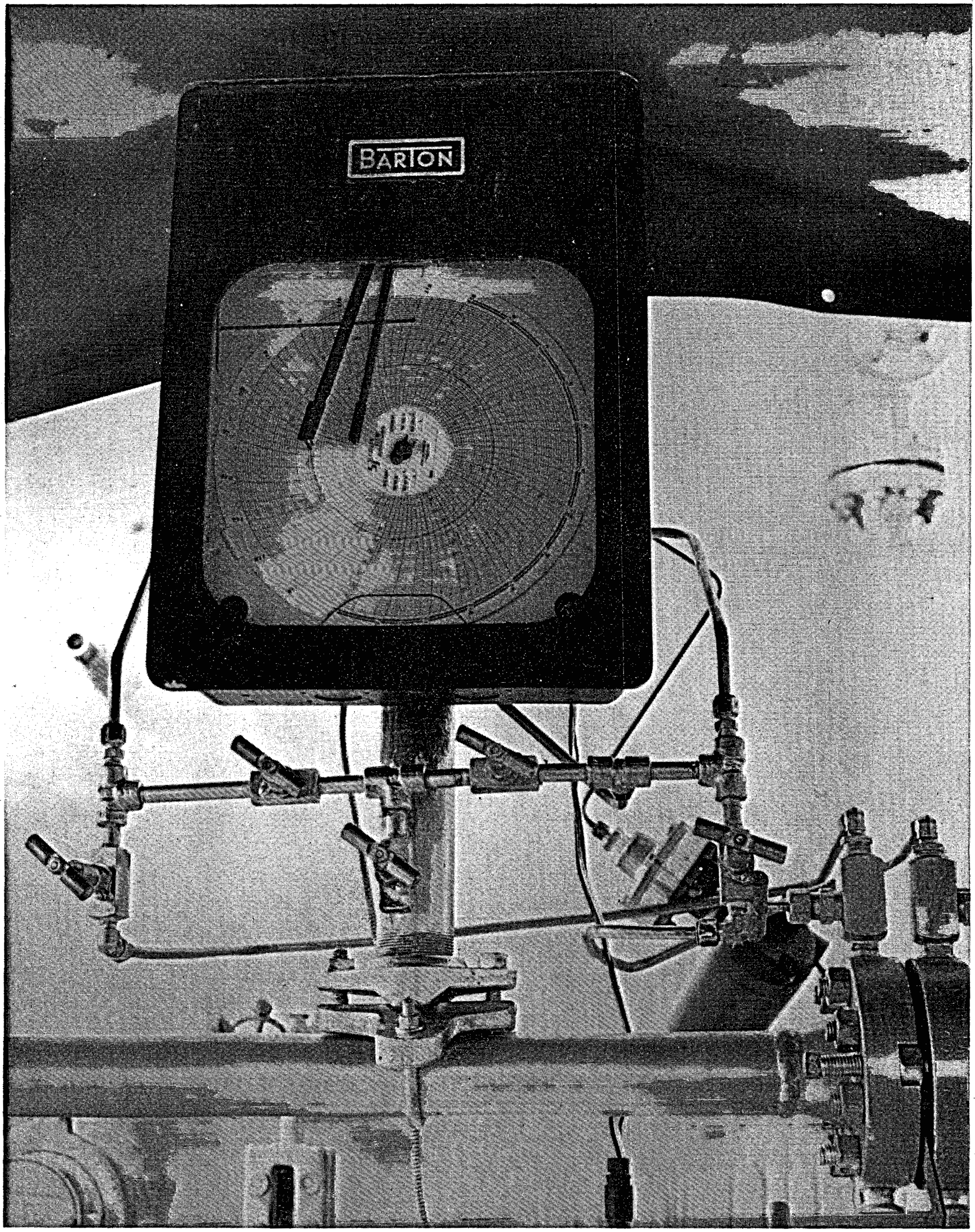


Photo 9-6 Circular 24-hour chart provides record of gas production.

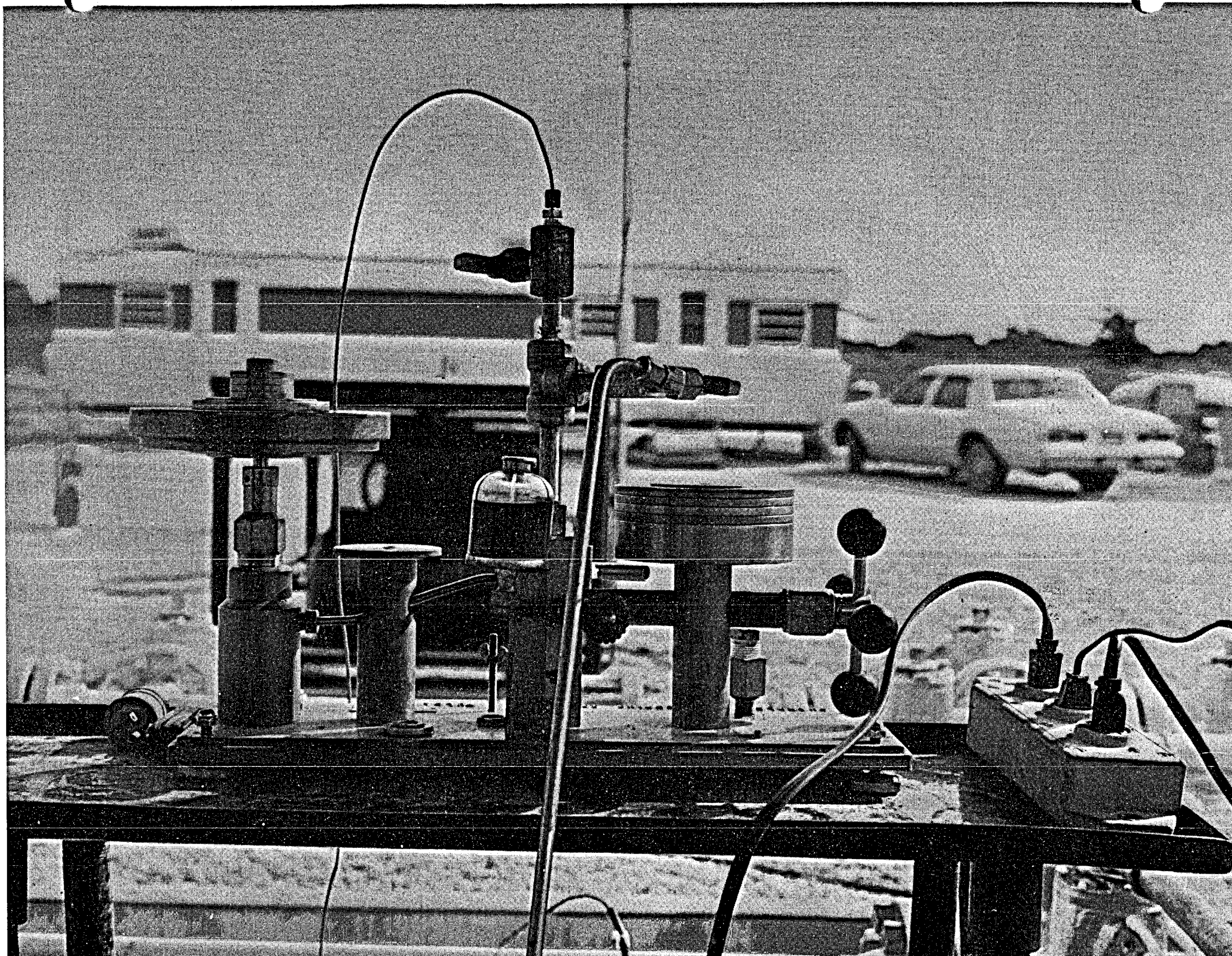


Photo 9-7 Deadweight tester operated by Weatherly to check pressure gauges

Photo 9-8 Two 110-barrel tanks and pump used to calibrate water turbine meters

Photo 9-9 Digital turbine meter recorders on metering skid

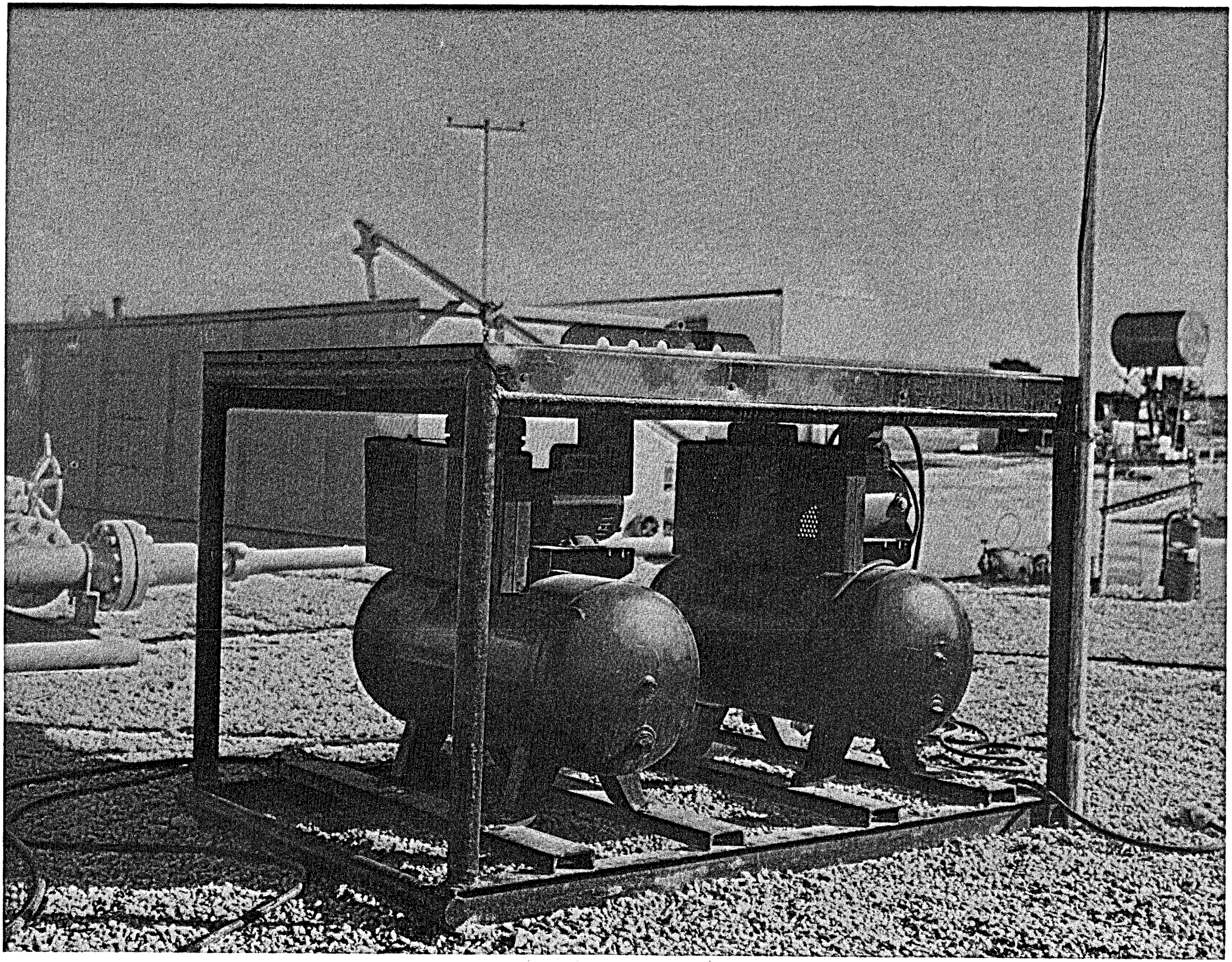


Photo 9-10 Air compressor system used to supply air pressure to operate separator control valves

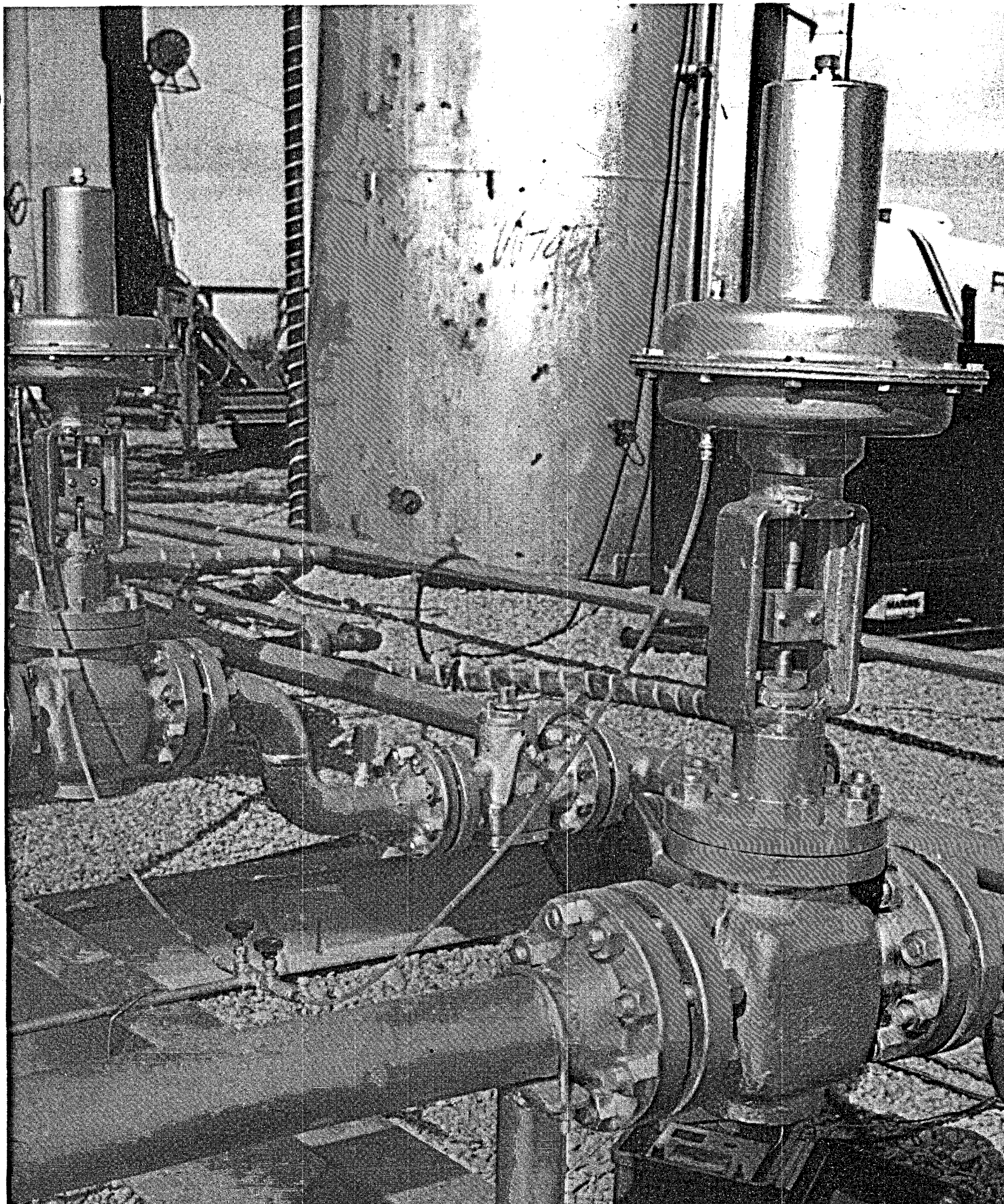


Photo 9-11 Close-up of two balanced piston control valves on water metering skid

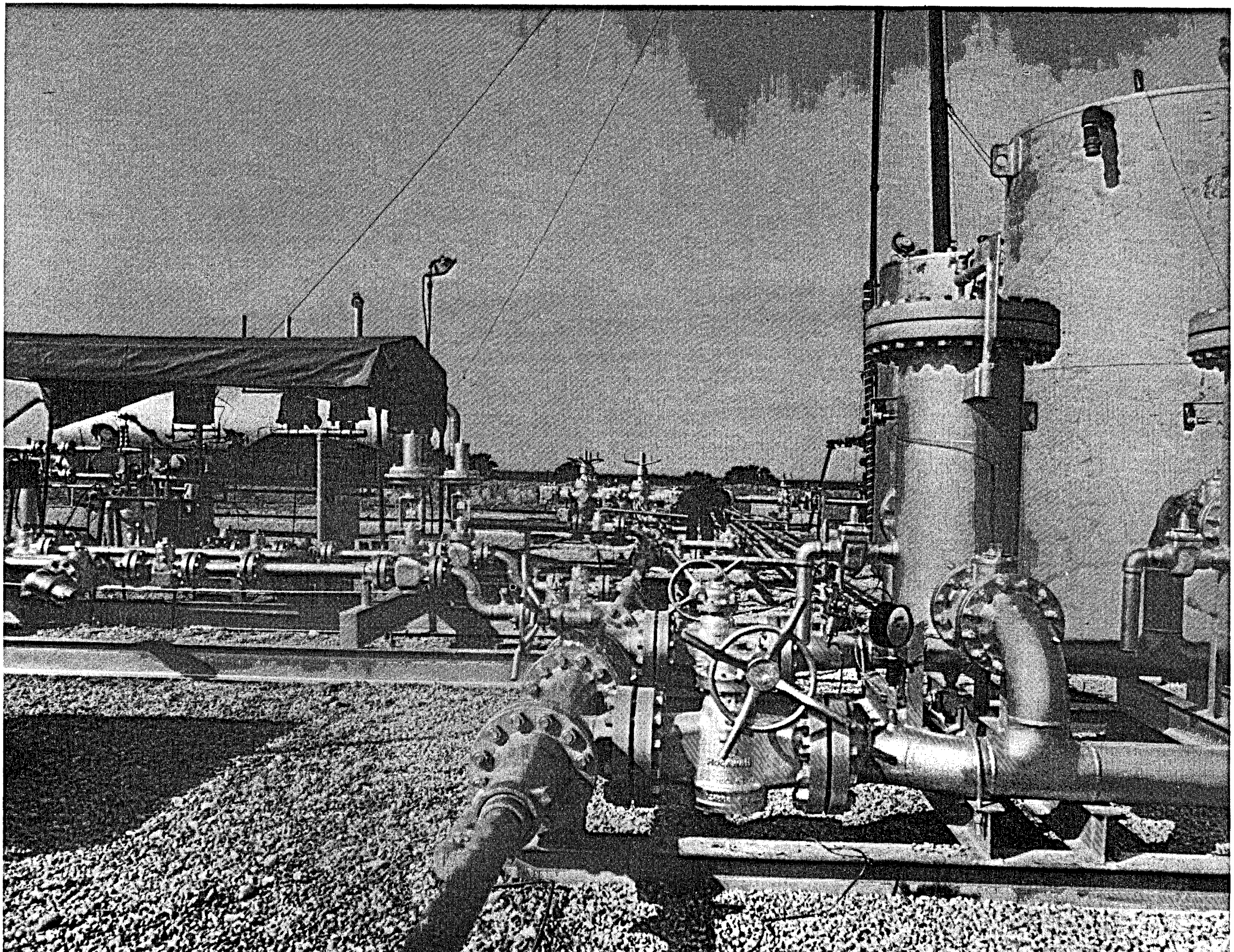


Photo 9-12 Water leaving the metering skid enters the filter unit at right.

Since only one Big Tex II pulse amplifier and shaper could be obtained in time for the test, automatic digital recording was provided only for the separator brine turbine. The signal from the wellhead turbine was displayed in the IGT trailer in units of barrels using a Halliburton LCD-1 Flow Totalizer. Readings were recorded manually.

Control software provided for scanning of all analog channels every 5 seconds. Values measured for separator pressure and orifice differential pressure each 5 seconds were then squareroot-averaged over operator-selected time intervals for data recording. Linear averaging was performed for other analog channels. Time intervals for permanent records varied from 30 seconds at the beginning of each test up to as long as 5 minutes during long-term stable production or shut-in periods. Cumulative counts from the brine turbines were recorded at the time of each permanent record. Permanent records were produced both by real time printouts and by storing of digital data on magnetic cartridge tapes. Backup strip-chart recording of eight analog channels was provided.

9.4.2 Wireline Company Recording (Reservoir Data, Inc.)(RDI)

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 at the midpoint of 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 at the midpoint of the zone tested.

- **Bottomhole Pressure:** During flow and buildup tests, pressure at the 9580-foot gauge datum, 62 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 1-3/4 inch Halliburton 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 Panex thermister-type temperature sensor was installed in a thermal well in the high-pressure flowline from the wellhead. The sensor extended approximately 2" into the flowline.

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

- Manual recording of depth indicated by the wireline odometer.

- Observation of visual display of temperature until the value stabilized. Then manual recording of temperature and setting that value into the HP computer on the HP bottomhole pressure gauge.

- Switching of the downhole tool to pressure recording and then manual logging of 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. The analog signal from the wellhead brine temperature sensor was digitized. Pulses from the wellhead turbine were converted to an analog signal by using the rate meter in a Halliburton Model LO-II Flow Totalizer. This analog signal was then digitized at the time of each permanent record in the same manner as the temperature data.

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 to 5 minutes during stable flow or low rate of pressure buildup. Permanent records were produced by both real-time printing and digital recording on magnetic tape.

All RDI raw data are 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° to 400°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,
- Gas temperature downstream from the orifice,
- 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 due to including gas temperature and composition in orifice interpretation and correcting brine flow rate to reflect brine volume at a temperature of 60°F.

10.0 PRE-TEST OPERATIONS

10.1 Completion and Well Bore Cleaning

Before the target sand was perforated for testing, the well was allowed to produce about 80 barrels of salt water through Riddle Oil Company's old perforations, 9750-9754 feet and 9760-9764 feet. These perforations were open during all of Eaton's completion operations. The well was perforated with 8 holes per foot from 9745 to 9820 feet on October 31, 1980. The well was then allowed to produce approximately 250 barrels of salt water to allow removal of perforating debris and completion fluids. During this flow period the well did not appear to be capable of sustaining production at rates in excess of 2000 BWPD, and it was decided to perform the initial reservoir pressure drawdown test at a flow rate of 1500 BWPD.

10.2 Downhole Sampling of Fluids

Two bottomhole samples were successfully collected on 11/13/80, using Gearhart Owen samplers that incorporated the modifications developed after the Lear G.M. Koelemay well test. During the trip in with each sampler, 5 to 10 barrels of brine were produced to ensure fresh formation brine at the sample collection depth of 9743 feet (2 feet above the top perforation.) During the first sampler run, gas blew for 23 minutes before the annulus brine level reached the wellhead. Drawdown was minimized by producing brine at only 5 to 10 gal/min (175 to 350 bbl/day). After brine reached the surface, the wellhead pressure was 2200 psi during production and 2300 psi with the well shut in.

10.3 Preliminary Wellbore Pressure and Temperature Recordings

Static wellbore pressure and temperature readings were obtained by Reservoir Data, Inc. on November 14, 1980.

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 than 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.

Exhibits 10-1 and 10-2 are the measured wellbore pressures and temperatures tabulated and graphically plotted as a function of depth.

The midpoint of the perforations was 9780 feet, and the pressure measured at this depth was 6627.18 psia. The temperature at the same depth was 300.2^{o}F. There was significant difference between this temperature and the predicted reservoir temperature of 258^{o}F.

The pressure element was then raised to 9580 feet. This position placed the gauge within the protective tubing string. The pressure calibration temperature was programmed for 300^{o}F, since this would be the approximate temperature of the fluids at the measurement depth during production.

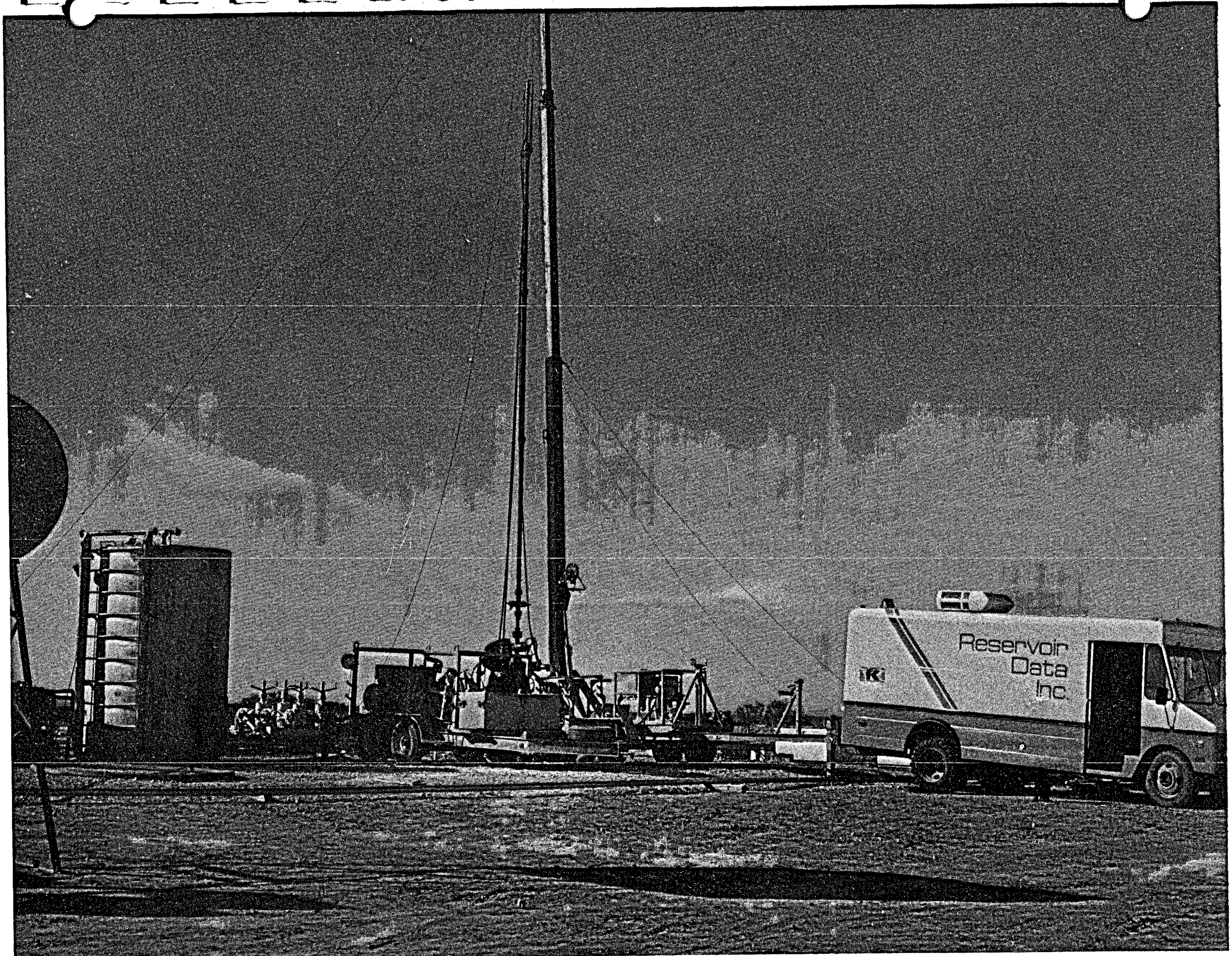


Photo 10-1 RDI wireline unit. Libricator and pressure control system at center.

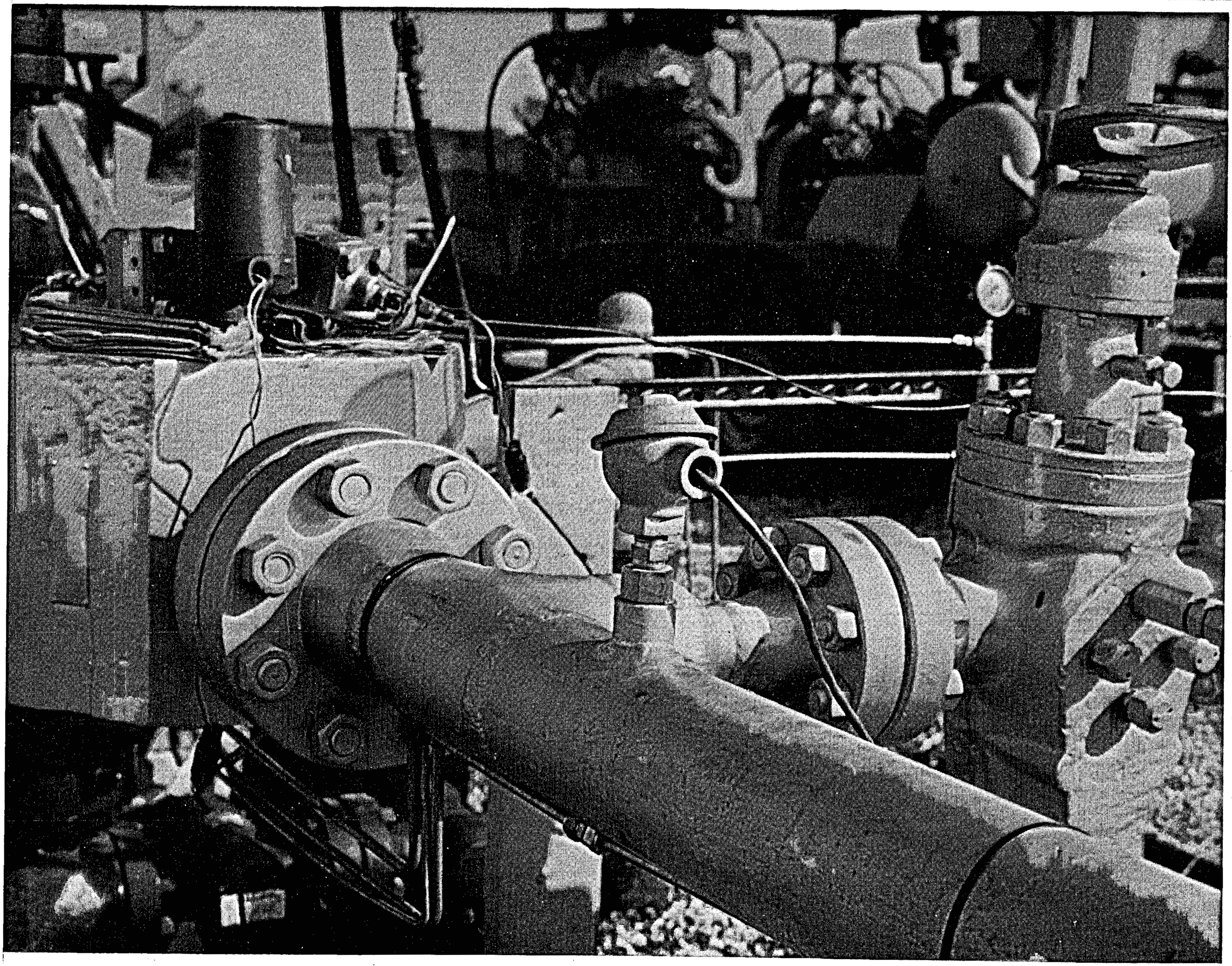


Photo 10-2 RDI temperature probe in main flowline at wellhead. Bypass line control valve at right.

Saldana Well No. 2

Static Pressure and Temperature Depth Measurements

Depth (feet)	Pressure (psia)	Temperature (°F)
0	2442.91	58.0
1,000	2875.90	106.9
2,000	3312.04	129.3
3,000	3746.36	151.3
4,000	4179.11	170.9
5,000	4608.62	197.9
6,000	5035.60	216.0
7,000	5460.58	234.5
8,000	5882.76	257.2
9,000	6302.73	279.7
9,780	6627.18	300.2

Data Obtained on November 14, 1980.

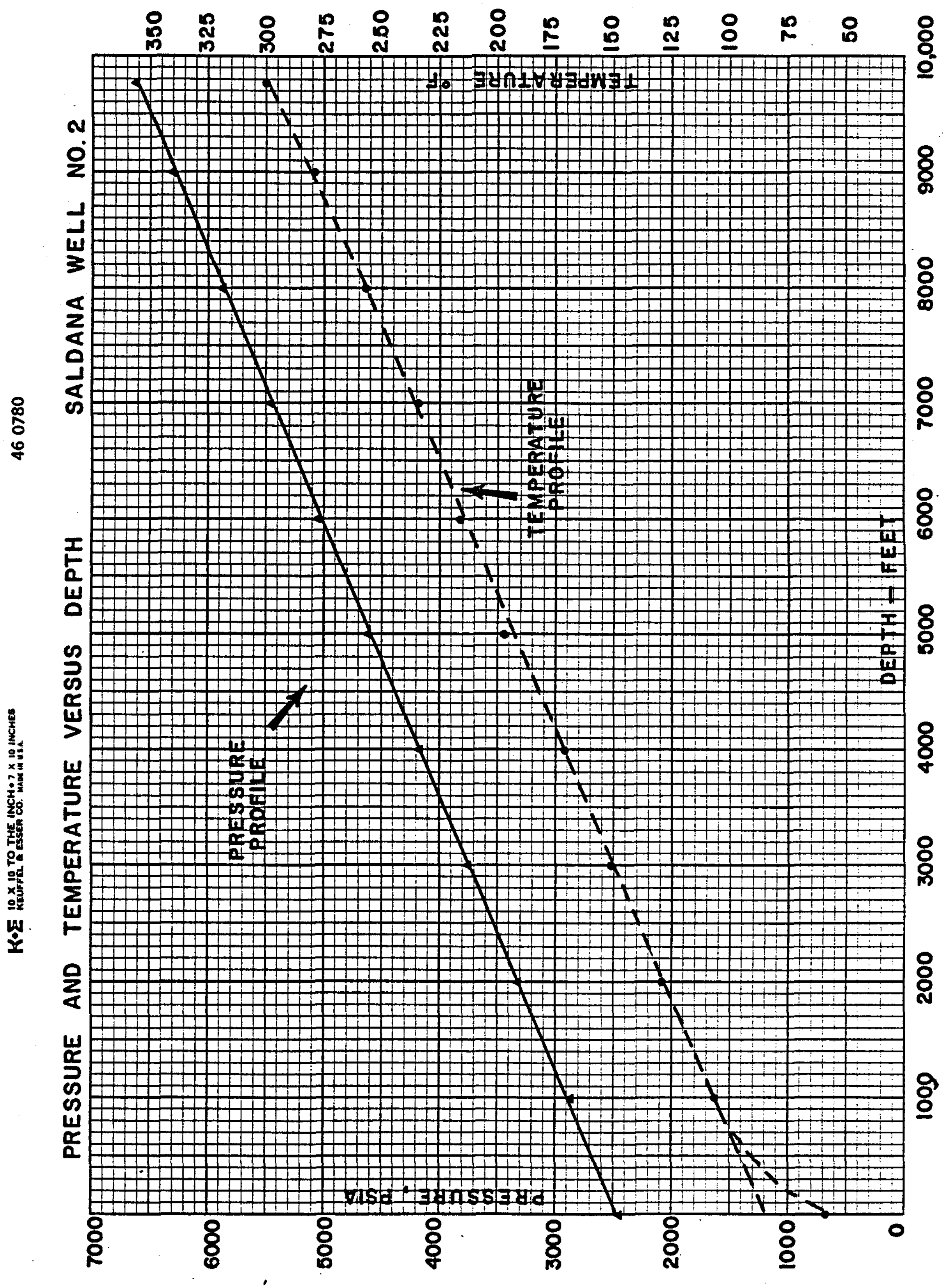


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EXHIBIT 10-2

11.0 TEST SEQUENCE

The test sequence for the Saldana No. 2 well included two preliminary flow periods to clean the hole and check the producing ability of the well. A total of 330 barrels of salt water was produced during these tests. After these preliminary flow periods, one flow test and one buildup test were carried out to evaluate reservoir parameters, produced fluids, and flow characteristics.

11.1 Flow Test

The reservoir pressure drawdown flow test lasted 6 days, during which 9328 barrels of water were produced. The test was initially planned to last only 24 hours; however it was decided to continue the flow because of the nature of the data being obtained.

11.2 Buildup Test

The flow test was followed by a 3.1-day reservoir pressure buildup test. At the end of the buildup test, it was decided that all desired short-term data had been obtained, and testing operations were terminated.

12.0 TEST RESULTS AND ANALYSIS

12.1 Initial Pressure Drawdown Flow Test

The downhole datum (9580') pressure just prior to opening the choke on November 16, 1981 was stable at 6545.13 psia. The surface pressure reading was 2444.19 psia.

The adjustable production choke was to be opened very slowly to a metered rate of 1500 BWPD. The recording instruments were programmed for 10-second readouts. The choke opening started at 1515:50 hours. The first flow meter recording was 2024 BWPD at 1516:30 with BHP at 6469.57 psia. The next 10-second reading was 5882 BWPD and 6235.95 psia. The rate at 1517:40 was 6615 BWPD with BHP of 4905 psia. (See RDI Raw Data, Appendix G, Volume II.) It was obvious at this time that the choke opening was too large and pressure was dropping too rapidly. The well was flowing faster than the reservoir fluid was entering the wellbore. Therefore the readings were of wellbore pressure and not of the desired reservoir sandface pressure. It was necessary to cut this flow rate back, if reasonable engineering data was to be obtained.

It required very minor adjustments of the choke and some time to get the rate back to about 1500 BWPD. At 1522:50 the rate was 1647 BWPD, and the datum pressure had risen to 5152.31 psia. Exhibit 12-1 is the semilog plot of this early pressure versus the logarithm of flow time. After about 16.56 minutes (0.0115 days) on flow, the rate was relatively constant, and the straight-line radial flow decline was apparent at a slope of about 80 psi per cycle. The peak flow rate thereafter was 1614 BWPD, with a gradual decrease to 1592 BWPD during the next 30 minutes or to 0.032 days on the graphical plot.

The question arose whether to abort the test, allow the pressure to build back to original pressure, and then restart the drawdown test. This discussion resulted from the extreme drop in wellbore pressure recorded in this early portion of the test. Once the choke opening size was known for the 1500 BWPD rate, the test could have been restarted to eliminate the undesired early wellbore flowing pressure. The test was continued, however, leaving this as an example to be presented for discussion.

The slope change at 0.019 days to 160 psi per cycle, a 2-to-1 change, supported the first permeability barrier. This was a good example of what happens when the choke is opened too fast, and the well flows faster than the reservoir. There were sufficient data to project straight line radial flow conditions that would allow proper calculation of productivity and skin effect. A short-time buildup test could be run at the end of the production test to allow a recheck on the early-time drawdown plot.

Exhibit 12-1 plots a complete set of the well flowing data needed for reservoir evaluation. These data are "Bottom-Hole Flowing Pressure;" "Wellhead Flowing Pressure," "Wellhead Flowing Temperature," and "Barrels of Fluid per Day." They are computer-plotted every 10 seconds during the first 2 hours of the flow period and every minute for the remainder of the flow test. They are sampled at the same time intervals and tape recorded, giving the reservoir engineer the total effective production history for the well and reservoir.

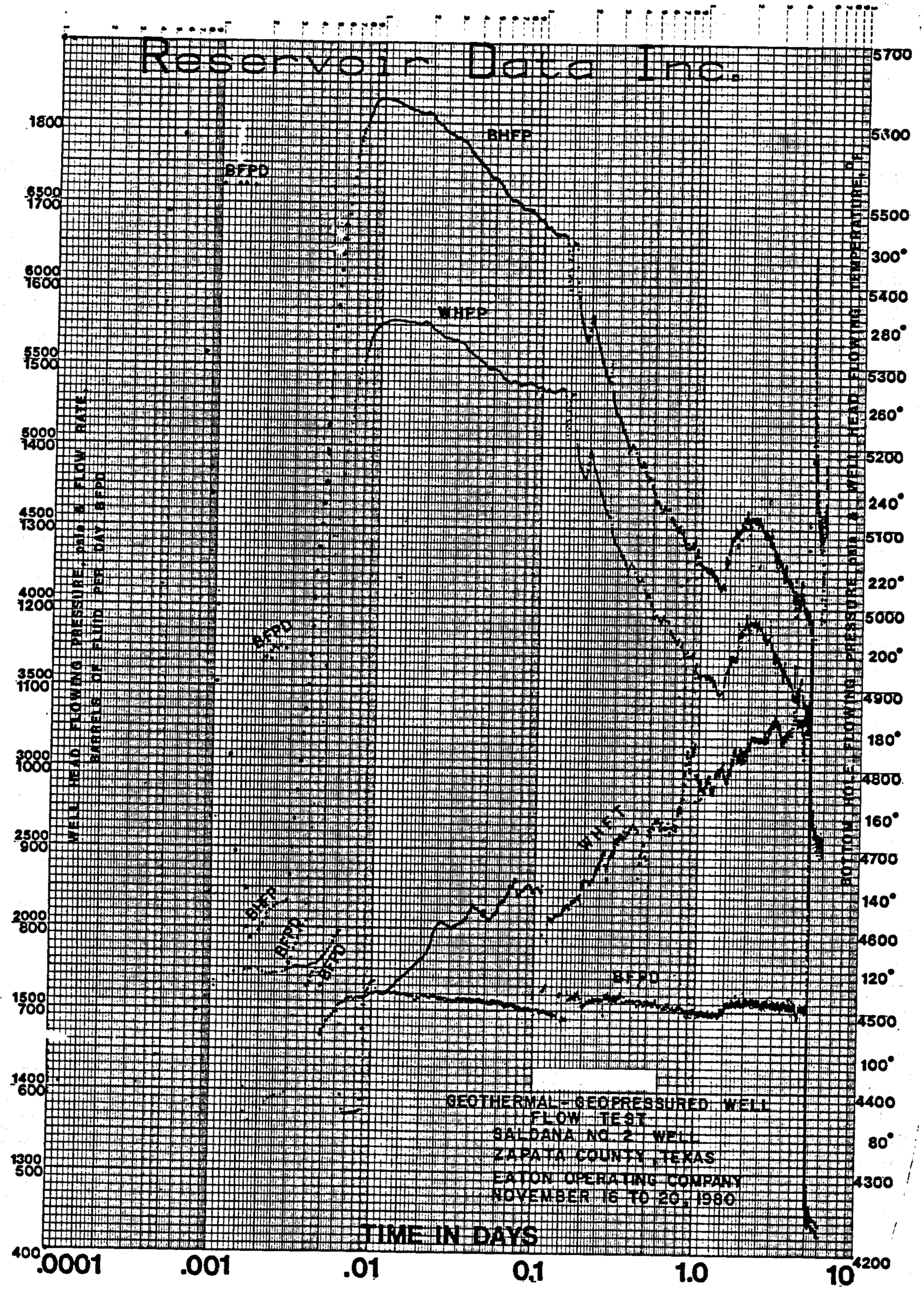

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EXHIBIT 12-1

Exhibit 12-2 is the same graphical plot of data depicted in Exhibit 12-1. The drawdown slopes used for engineering analyses are depicted. The bottom-hole pressure scale and time are the only labels used on this graph. The scale of the pressure plot is selected for interpretation and does not show the original pressure of 6545.13 psia. The rapid decline in pressure from 6545 to 5700 psia is not depicted.

The initial slope chosen was 80 psi per log cycle between 0.01 and 0.019 days (14.4 and 27.4 minutes). This initial slope allows a calculation of 985.26 md.-ft. as the productivity of the reservoir to the produced brine. This is detailed on a data form, Exhibit 12-7.

The estimated net sand from electric logs was about 79 feet, which would give a permeability of 12.47 mds. The skin factor was +7.47 and, when converted to true value, would account for a 520-psi pressure loss caused by the skin factor and/or partial penetration. The permeability determined gave a hydraulic diffusivity of 319,882 square feet per day. The productivity index (P.I.) was 1.5132 bbls per day per psi, and the completion efficiency was 46 percent. The viscosity of 0.310 cps used in this calculation was laboratory-measured by Weatherly Laboratories on recombined reservoir fluid samples from the well.

12.1.1 First Drawdown Slope

The first change in drawdown slope was depicted at 0.019 days or a distance of 156 feet from the wellbore. This slope change was by a factor of 2 or to 160 psi per cycle. This supports the calculation that the first slope is 80 psi per cycle, and the change to 160 psi per cycle represents the first permeability barrier.

The pre-choke flow meter recorded uncorrected flow rates of between 1603 and 1581 barrels of reservoir fluid per day (BFPD). This converts to an average of 1457.2 standard barrels of brine per day.

The volume of aquifer explored to 0.019 days was estimated from the drawdown slope and the "Y" function as 225,000 barrels of reservoir brine. The barrels of brine in place can also be estimated using a porosity of 20.3 percent. This is an average value taken from analysis of 17 sidewall cores. The formation volume factor of 1.0731 for the brine and its originally dissolved gases was obtained from Weatherly Laboratories' PVT study of the recombined reservoir fluid. These factors give 1467.6 standard barrels of brine per acre-foot. The radial distance of 156 feet supports a total of 1.76 acres, and, using 79 net feet of pay, would allow a total volumetric calculation of 204,000 barrels of brine. This is approximately the same order of magnitude as the 225,000 barrels calculated from the brine compressibility and the drawdown slope.

12.1.2 Second Drawdown Slope

The second drawdown slope occurred from 0.019 to 0.033 days (27.4 to 47.5 minutes). The metered rate of production was between 1586 and 1581 BFPD, an average of 1447.2 standard barrels of brine per day. The drawdown slope of 160 psi per cycle occurs after the first permeability barrier or possible sealing fault. The flow angle is reduced to 180 degrees radially around the wellbore. The barrier occurs at a radial distance of 156 feet from the well bore.

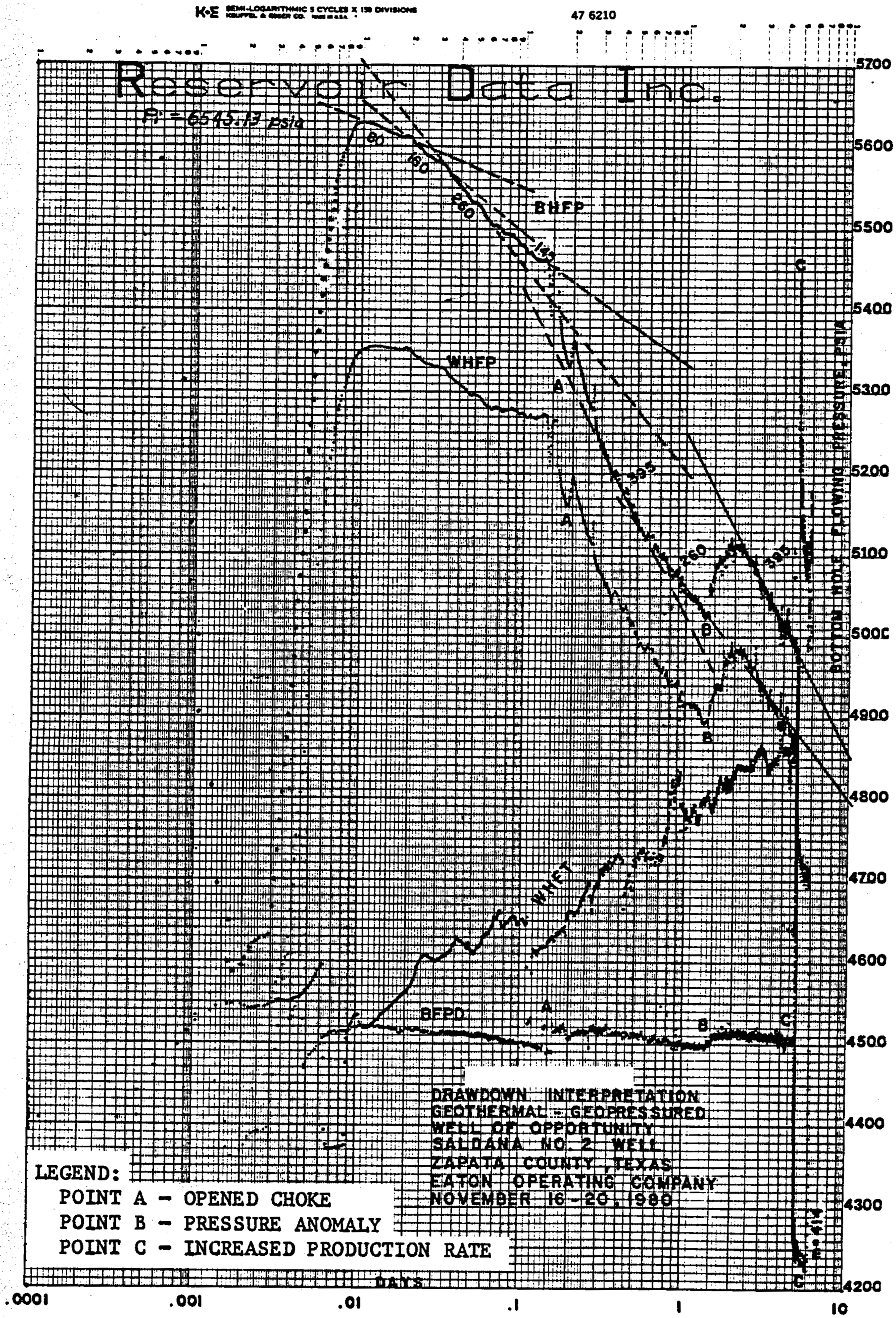

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EXHIBIT 12-2

(The distance explored to 0.033 days is 205 feet). This radial distance would support 3.03 acres, but the permeability barrier cuts this value in half, or to 1.52 acres. This would give a volumetric value of 176,000 barrels of brine. The slope of 160 psi per cycle depicts 194,000 barrels of brine at 0.033 days.

12.1.3 Third Drawdown Slope

The third change in drawdown slope occurs between 0.033 and 0.055 days and depicts an increase to 260 psi per cycle. This would reduce the flow angle around the well to 111 degrees with this additional permeability barrier. The distance explored at 0.055 days is 265 feet. This puts the closure to flow close to the well. The slope of the drawdown supports an explored volume of brine of 197,000 barrels. This additional reduction in flow angle or area supports about 1.56 acres or about 181,000 barrels. Note the pore volume calculations are slightly less than those calculated from the drawdown slope. An increase in porosity from 20.3 percent to 22.09 percent would give equivalent values.

12.1.4 Fourth Drawdown Slope

The fourth change in drawdown slope occurred between 0.055 and 0.140 days, with a slope of 145 psi per cycle. Two conditions were responsible for this decrease in drawdown slope. One was a change in metered flow rate from 1570 to 1455 BFPD. The second was improved productivity in the reservoir. This improved productivity was in the kh value. The probable major effect would be in the net sand, "h," or increase in net pay. The explored water seen at 0.14 days was 867,000 barrels.

12.1.5 Choke Adjustment

The slow decrease in producing rate was very recognizable from the recorded flow meter and plotted data. After about 3 hours and 50 minutes on flow, the metered flow rate had dropped to about 1450 barrels of fluid per day. It was obvious that to maintain a rate at or above 1500 BFPD the size of the flow choke would have to be continuously increased. The choke was adjusted to a higher flow rate at 1907 hours (0.140 days on flow) to a rate of 1630 BFPD. Exhibit 12-2 has this time on the graph designated by the letter "A". The distinct increase in rate is seen on the flow plot. The surface and bottom-hole pressure graphs depict a quick drop in pressure and the sharp rise caused by the reservoir flow rate catching up with the sudden increase in the well flow rate at the opening of the choke.

Some time was required for the adjusted flow rate to become stabilized at the sandface. Therefore no additional interpretation was attempted until about 0.28 days, or until after about 6 hours and 43 minutes of cumulative flow time.

12.1.6 Fifth Drawdown Slope

The fifth drawdown interpretive slope change occurred between 0.28 and 0.60 days. This was caused by additional restrictions in area flow parameters. The increased flow rate between 1608 and 1537 BFPD is a part of the increase, with restricted flow area comprising the majority of the change. The explored volume of water at the end of this slope, or at 0.60 days, is 1.418 million barrels. The maximum radial distance explored is 876 feet.

12.1.7 Sixth Drawdown Slope

The next drawdown slope change occurred between 0.60 and 1.40 days, and an additional decrease in production rate was observed. This rate dropped from 1537 to 1500 BFPD. The radial distance tested to 1.4 days was 1338 feet. The volume of fluid explored, to this time, was 4.855 million barrels of brine.

12.1.8 Pressure Anomaly

An anomaly in pressure and rate of production increase occurred at about 1.384 days. This is labeled as point "B" on Exhibit 12-2. This anomaly occurred without a change in the production choke. Note the difference depicted between point "B" and point "A," where the choke was opened for additional production. This was interpreted as a plugged perforation that suddenly unplugged allowing flow to occur from an untapped sand zone, possibly an unproduced sand lense within the original perforated interval. This caused a rise in production rate from about 1477 BFPD to a peak of just under 1600 BFPD. The datum flowing pressure rose from 5025 psia to as high as 5123 psia as a direct result.

This additional sand flow furnished the majority of production at this time, which in turn reduced the rate of the previous intervals being produced and allowed an increase in pressure around the wellbore in these zones. The pressure and production equalized in about 20 hours, and a new drawdown slope of about 395 psi per cycle occurred between 2.2 and 4.9 days. A slight trace of sand was seen on the sand indicator at the time the "bottoms-up" was expected at the surface from this anomaly.

The drawdown slope of 395 psi per cycle gave an explored brine volume of 5.126 million barrels at 2.2 days and 11.417 million barrels at 4.9 days. The radial distances explored were 1678 and 2504 feet respectively.

12.1.9 Final Drawdown Rate

To evaluate the maximum flow capabilities of the well and reservoir, a flow rate of between 2500 and 3000 barrels per day of metered fluid was planned. This would allow the surface flowing pressure to remain above the 400 psia needed for disposal of the produced fluids. Computer-plotted production and pressure meter readouts were changed from 5-minute to 10-second recordings to insure control of data during rate change. The production choke was opened very slowly to a maximum rate of 3452.3 BFPD at 1309:10 hours. The bottom-hole pressure dropped from 4985 psia to 4568 psia during this opening period. The surface pressure dropped from 1069 psia to 859 psia. The flowing wellhead temperature increased from 189° to 192°F and continued to increase with time. This period of change is designated by the letter "C" on Exhibit 12-2.

The production choke was regularly opened in an attempt to maintain this higher rate. When surface pressure diminished to 500 psia, the choke was completely opened, and the rate was regulated by maintaining a separator pressure between 500 and 424 psia. The final metered rate dropped to about 2500 BFPD, or about 1899 standard barrels of brine per day, prior to being shut in at the end of 6 total days on flow. The final explored volume of aquifer was 18.01 million barrels with a maximum explored distance of 2768 feet. This is a reservoir volume of about 12,272 acre feet. If we assume a net pay average of 79 feet, this would require 155.3 acres of productive area. A radial explored distance of 2768 feet, 79 feet of net sand, and 155.3 acres of productive area would require a restricted angle of flow of approximately 101.2 degrees. This is approximately the same restricted flow angle that was detected after the second barrier. This would suggest that all permeability barriers were seen during the first 80 minutes of the flow period. The other slope changes were mostly reservoir heterogeneities and production rate variations.

12.2 Graphical Analysis of Explored Reservoir Volume

Exhibit 12-3 is a log-log plot of the Jones "Y" drawdown and the explored volume of brine "W" versus the logarithm of time. The fluid pressure drawdown, at the sandface of the reservoir, is directly proportional to the volume of reservoir explored to that particular time. This drawdown is referred to in psi per day per reservoir barrel of fluid produced. The data obtained should plot a 45-degree straight line, as long as transient flow exists. The shift to the right or left will occur when permeability barriers are reached or change in reservoir fluid viscosity is detected. This "Y" function becomes constant when steady state flow occurs. A steady state condition occurs when all productive limits of the reservoir have been reached. The "Y" function, or drawdown, is plotted from the log scale on the left side of the graph.

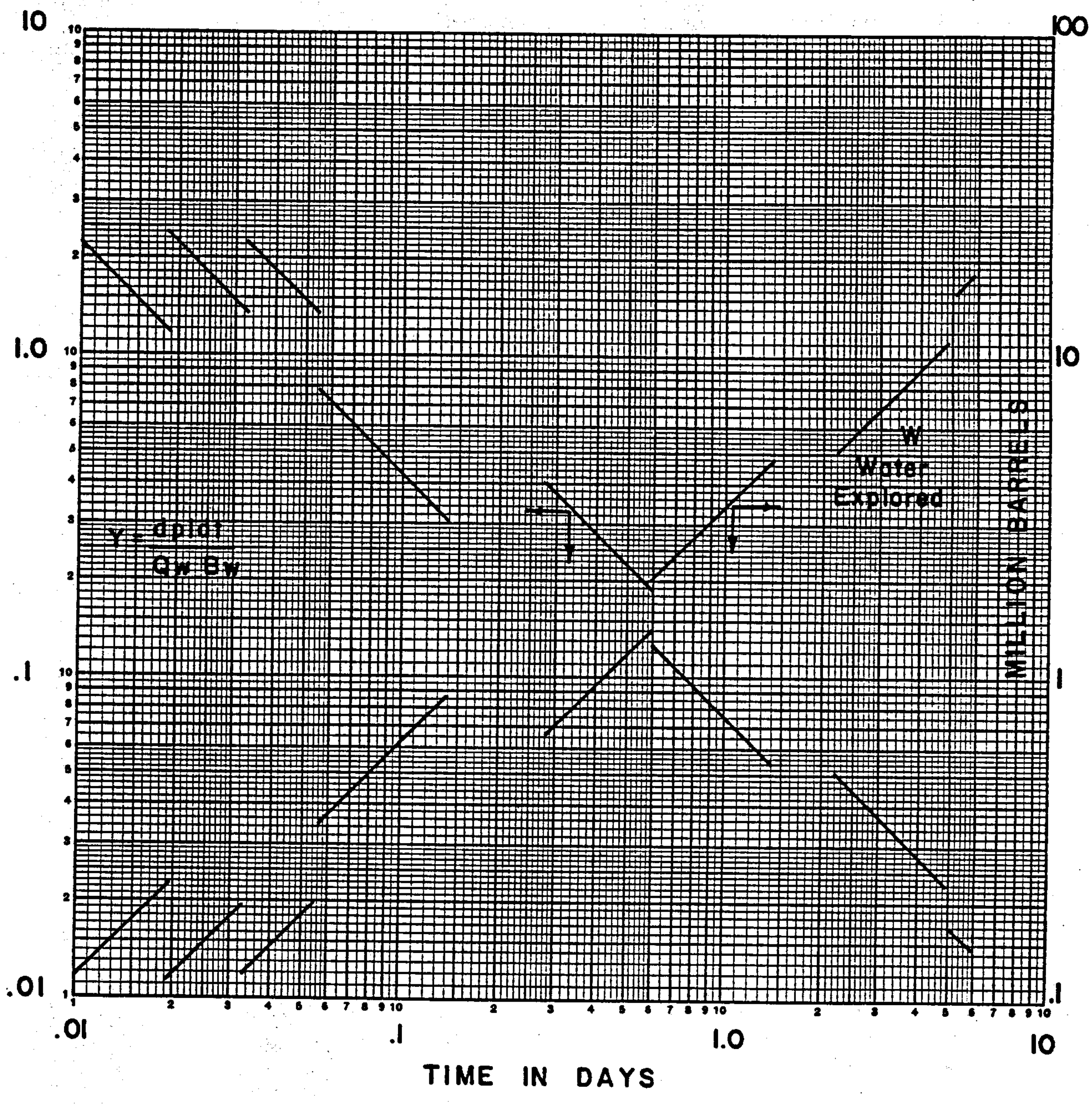
The right side of the graph has the log scale for the volume of fluid in standard barrels explored as a function of time. The water explored becomes a 45-degree line plot that is perpendicular to the "Y" plot. When steady state flow occurs, "Y" becomes a constant value, and the total volume of "W" is constant. It is this condition that depicts the total reservoir volume. These plots are one of the more positive methods of determining whether steady state flow is occurring and whether total reservoir limits have been found.

12.3 The Pressure Buildup Test

The pressure buildup test has been given less importance in this test. The value of buildup tests as a reservoir tool is limited. Exhibit No. 12-4 is the three-day pressure buildup plot that followed the six days of continuous flow. On this graph the slope of 258 psi per cycle occurs between 0.08 and 0.5 days. There is also a slight increase in slope starting at 0.5 days thru 3.0 days. The change in slope from 258 to 280 psi per cycle is by a factor of 1.085 or about 8.5 percent.

The drawdown slope of 260 psi per cycle between 0.60 and 1.40 days is probably the only slope correlation between the two types of plot. Anything after 1.5 days of shut-in time could be considered to be within the area of time effect of a short flow period.

SALDANA NO. 2 WELL
EXPLORATION DRAWDOWN TEST
AQUIFER EXPLORED
6 - DAY FLOW TEST
November 16 thru 22, 1981



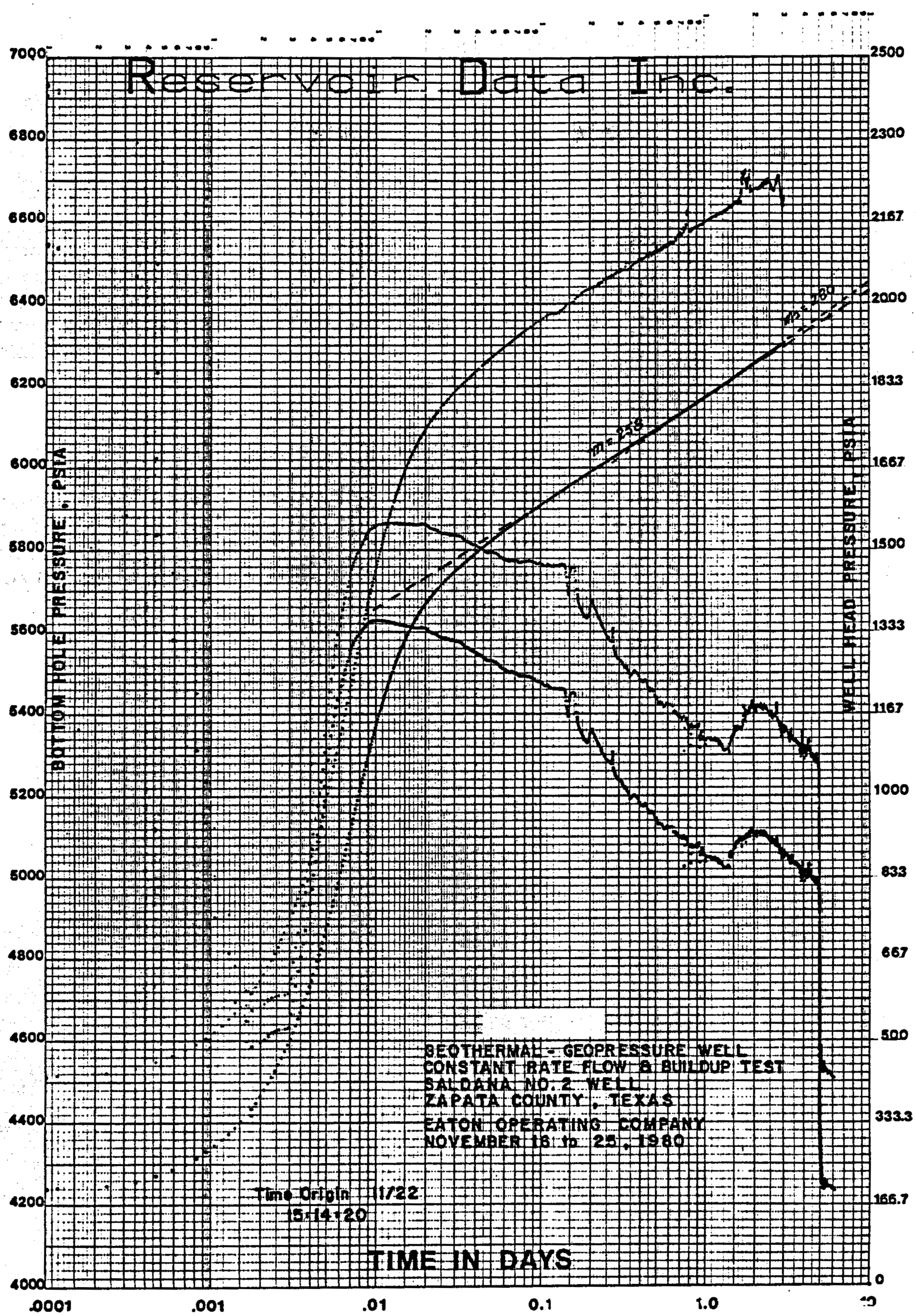


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EXHIBIT 12-4

12.4 The Horner-type Buildup Plot

The total flow time for the well was 5.9987 days, and the final buildup pressure was read at 6308.58 psia after 3.0875 days of shut-in time. This graph, Exhibit 12-5, plots the pseudo-time of total flow time plus shut-in time divided by shut-in time. The first slope was 272 psi per cycle with an intercept of the second slope of 436 psi per cycle at a pseudo-time of about 4.8 days. The pseudo-time of 4.8 is equivalent to about 1.58 days of real shut-in time. The extrapolation of the Horner plot to a pseudo log time of one gave a buildup pressure of 6512 psia. This is only about 33 psi below the original measured pressure of about 6545 psia. Since the original reservoir pressure was measured, the value of this time graph for extrapolation to an expected original pressure has little value. The original reason for developing this type of graphical plot was an attempt to gain a reasonable original reservoir pressure when it was not available by measurement.

12.5 Summary of Reservoir Engineering Data

Certain measured and calculated data are given below to recap the above discussion. Exhibit No. 12-6 is a graphical plot of the total well test, depicting wellhead flowing pressure, bottom-hole flowing pressure, wellhead flowing temperature, and barrels of reservoir fluid produced per day plotted versus time in days. Exhibits 7a, 7b, and 7c are the calculation data sheets for the reservoir drawdown test.

- Production Test Start : 1730:50 on 11-16-80
- Well Shut in : 1514:00 on 11-22-80
- Initial Reservoir Pressure : 6627.18 psia measured at 9780 ft.
- Reservoir Temperature : 300.2^{o}F measured at 9780 ft.
- Initial Surface Pressure : 2442.91 psia measured in lubricator.
- Porosity : 16 percent estimated from log data, 20.3 percent average of 17 sidewall cores.
- PVT Data by Weatherly Laboratories:

  Cw = 3.54×10^{-6} Vol/Vol. per psi saturated @ 300^{o}F and 6633 psia.

  Bw = 1.0731 Vol/Vol. @ 6633 psia, 300^{o}F, and saturated with 42.3 ft^3 of dry gas.

  Viscosity of Reservoir Fluid : 0.310 cps @ 6633 psia, 300^{o}F, and saturated with 42.3 ft^3 of dry gas.

- Calculated Reservoir Data:

kh = 985.26 md.-ft.

k = 12.47 mds., using 79 feet of net effective pay.

s = +7.47 skin and/or partial penetration

Δ P(skin) = 520 psi

P.I. = 1.5132 Bbls per day per psi

Completion Efficiency : 46 percent

Maximum Volume of Water Explored : 18.01 million bbls.

Maximum Area Explored : 155.3 acres

Maximum Radial Distance Explored : 2768 feet.

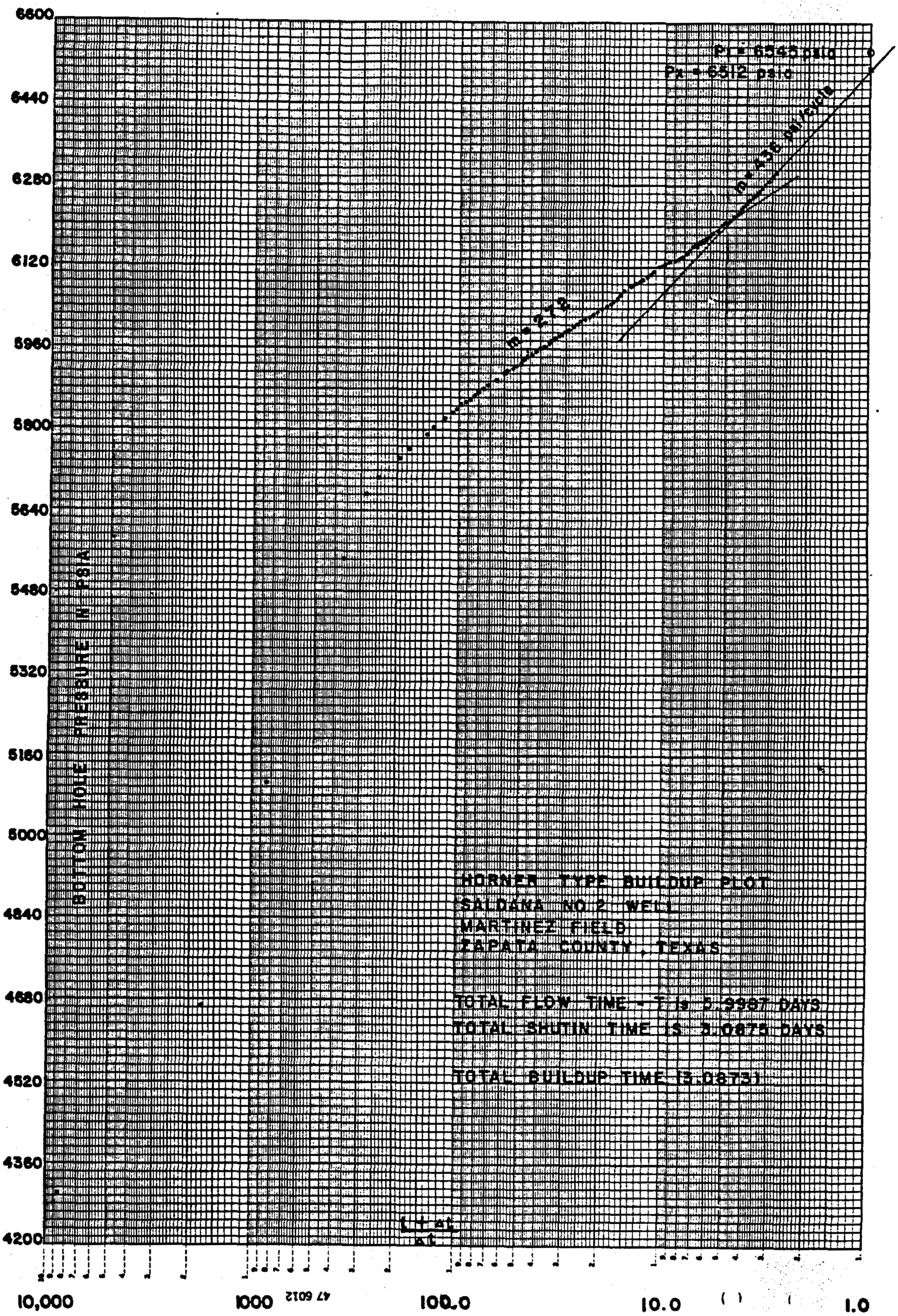

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EXHIBIT 12-5

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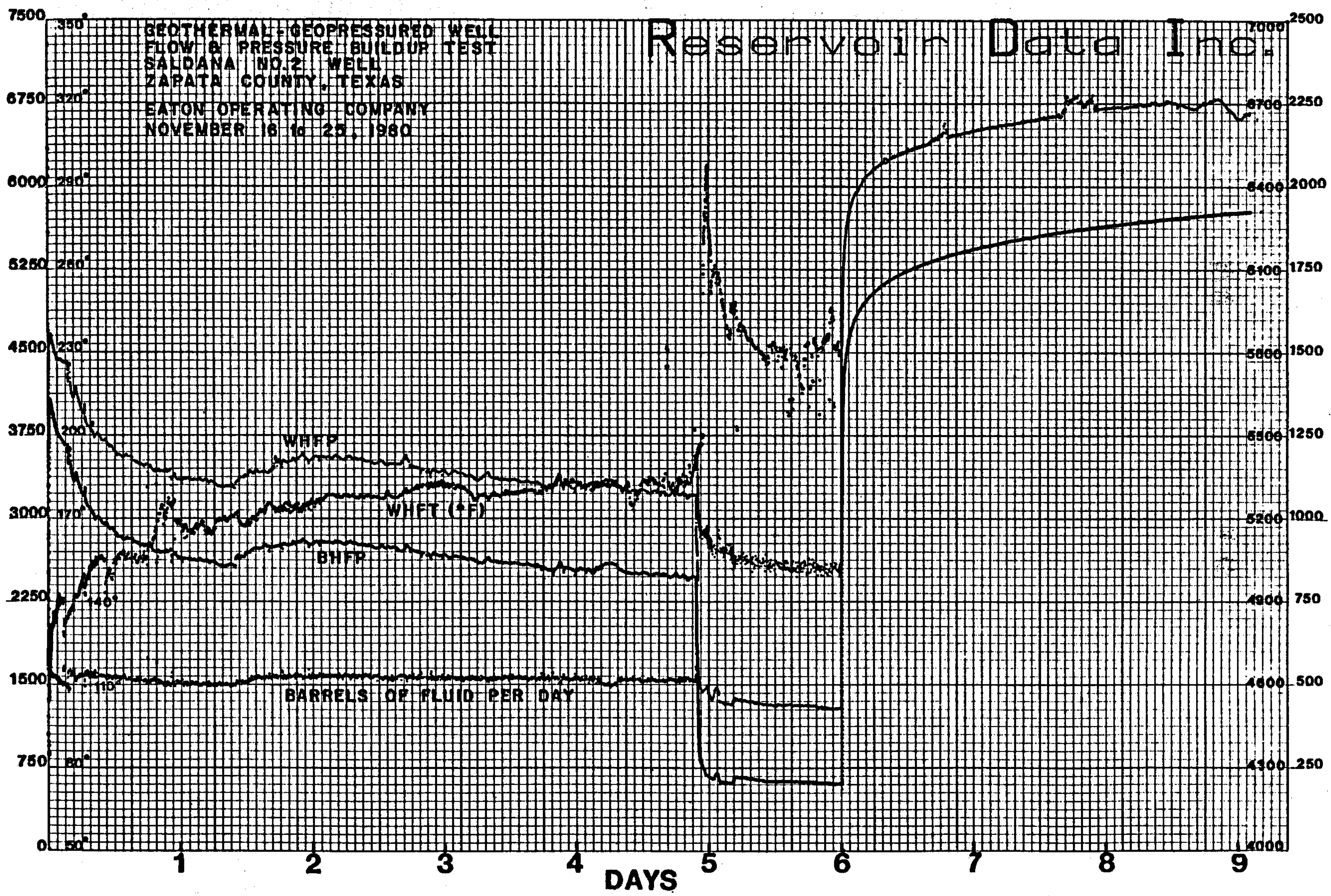

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EXHIBIT 12-6

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST
FOR
GEOTHERMAL-GEOPRESSURED WELL

Test date: 16-21 Nov. 1980 Type Test: Drawdown Lease and Well No. Saldana No. 2
Producing Formation: First Hinnant (Upper Wilcox) Sand Field: Martinez (Zapata County)
Hole size: ______ Casing Size: 7" Tubing Size: 2-3/8" State: Texas
Cumulative Production: 93,911 Bbls W Gas Gravity: .8024 Z: ______
Constant Rate Production: 1457.2 (bbls/day) Water Salinity: 13,000 PPM Total Solids
Total Production Life: 6.0 days Porosity, ϕ: .203 Gas-Water Ratio: 44.5 ft^3/bbl
Reservoir Temperature: 300 °F Net Pay: ±79 ft. Perforations: 9745-9820 ft
μg ______ cps μw 0.310 cps Bw 1.0731 R.B./B. Bg – R.B./MCF
C_T 3.92 $X10^{-6}$ Cg – $X10^{-6}$ Cw 3.54 $X10^{-6}$ C_r 1.5 $X10^{-6}$
m 80 psi/cycle P at 1 hour: 5582 Sg – Sw 1.00 Pi 6627.18 psia @9780'
Pf 4238.36 psia
Pi = 6545 psia @9580'

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

$kh = 162.6\ (Q)(B)(\mu)/(m)$

$kh = 162.6\ (1457.2)\ (1.0731)\ (0.310)\ /\ (80) =$ 985.26 md-ft

$k = (985.26)$ md-ft / (79) ft = 12.47 mds

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

$Bg = (\quad)(\quad)(\quad)\ .34279/(\quad) =$ ______ Res. bbl/ MCF

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

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

$$s = 1.151\left[\left(\frac{(6545)-(5582)}{(80)}\right) - \log\left(\frac{(12.47)\ 10^6}{(0.203)(0.310)(3.92)(0.085)}\right) + 3.23\right] = +7.47$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)(7.47)(80) = 520 psi

IV. Diffusivity, η

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

$\eta = .006328\ (12.47)\ /\ (0.203)(0.310)(3.92)10^{-6} =$ 319,882 ft^2/day

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RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: 16-21 Nov. 1980 Type Test: Drawdown Lease and Well No. Saldana No. 2

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

$$J\ (\text{actual}) = \frac{Qw}{P_i - P_f} = \frac{(1457.2\ )}{(6545\ - 5582\ )} = \underline{1.5132}\ \text{bbls/D-psi}$$

$$J\ (\text{ideal}) = \frac{Qw}{(P_i - P_f) - \Delta P\ \text{skin}} = \frac{(1457.2\ )}{(6545\ - 5582\ ) - (520\ )} = \underline{3.2894}\ \text{bbls/D-psi}$$

$$CE = \frac{J\ (\text{actual})}{J\ (\text{ideal})} = \frac{(1.5132\ )}{(3.2894\ )} = \underline{.4600} \quad \text{or} \quad \underline{46}\ \%$$

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

$$d = 2\sqrt{(319{,}882\ )} \times \sqrt{t} = (\ 1131\ )\sqrt{t}$$

time, days	$\sqrt{t}$	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
.019	.1378	156	80	360°	1.17071	0.225×10^6
.033	.1817	205	160	180°	1.35741	0.194×10^6
.055	.2345	265	260	111°	1.33958	0.197×10^6
.140	.3742	423	145	Choke Change	0.303578	0.867×10^6
.60	.7746	876	395		0.1856054	1.418×10^6
1.40	1.1832	1338	260	Increased Productivity	0.542189	4.855×10^6
4.9	2.2136	2504	395	After Anomaly	0.0230577	11.417×10^6
5.9889	2.4472	2768	414*	Rate	0.0146165	18.010×10^6

*Calculated slope using data between 5.1972 and 5.9889 days of flow period. Rates for Y function corrected for each calculation above.

Y = (80)/(2.3)(1.0731)(1457.2)(0.019) = 1.17071 psi per day per reservoir barrel.

W = (1)/(1.0731)(3.54×10^{-6})(1.17071)= 224,857 Bbls of aquifer explored

(7758)(0.203)/(1.0731) = 1467.6 Bbls of water per acre-foot

$(156)^2\ \pi\ /(43{,}560) = 1.76$ acres

(1.76 Acres)(79 ft)(1467.6 Bbl/Ac-ft) = 204,055 Bbls.

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

EXHIBIT 12-7b

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

RESERVOIR LIMIT TEST (Continued)

Saldana No. 2 Well

Production Drawdown Test Drta

Cum. Flow Time, Days	Slope, m psi/cycle	RDI Meter BFPD	Corrected STBWPD	Y dp/dt QwBw	Aquifer Explored, Million Barrels
0.010	80	1603		2.22435	0.118
0.019	80	1586	1457.2	1.17071	0.225
0.019	160	1586		2.35760	0.112
0.033	160	1581	1447.2	1.35741	0.194
0.033	260	1581		2.23263	0.118
0.055	260	1548	1429.8	1.33958	0.197
0.056	145	1570		0.75894	0.347
0.140	145	1455	1382.3	0.303578	0.867
		Choke Adjustment			
0.28	395	1608		0.397726	0.662
0.60	395	1537	1437.1	0.1856054	1.418
0.60	260	1537		0.1265107	2.081
1.40	260	1500	1387.8	0.0542189	4.855
		Anomaly			
2.2	395	1580		0.0513558	5.126
4.9	395	1520	1416.5	0.0230577	11.417
		Increased Production Rate			
5.1972	414*	2616.92	1987.3	0.0162405	16.209
5.9889	414*	2523.37	1916.2	0.0146165	18.010

*Calculated slope for final 19 hours on flow test:

4262.98 psia @ 20:00:00, 11/21/80   Log of 5.197222 days = 0.7157712868

4237.49 psia @ 15:00:00, 11/22/80   Log of 5.988889 Days = 0.7773862555

25.49 psi in 19 hours   0.0615749687

(25.49 psi)/(0.0615749687) = 414 psi per log cycle.

Qw-RDI Meter = 2523.37 BFPD average of 10 readings @ 15:00 on 11/22/80

Qw-RDI Meter = 2616.92 BFPD average of 10 readings @ 20:00 on 11/21/80

Conversion factor to standard barrels: 0.7594.

12.6 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 of specific topics has been chosen to provide an orderly development of the results obtained. Discussions of the test sequence and real-time test data obtained provide background for the discussion of hydrocarbon production. Conclusions regarding hydrocarbon chemistry are then reflected in the calculation of gas production rates as well as the ratio of produced gas to produced brine. Details of brine chemistry are then presented as background for the next section, "Solids Production, Scaling, and Corrosion."

12.6.1 The Test Sequence

The following chronological summary provides an overview of test activities most relevant to interpretation of well performance in terms of quantities and properties of produced fluids. Prior to the beginning of the test, the well had produced about 850 barrels of reservoir fluids. This estimate allows for production of 500 barrels by the original operator, 80 barrels while displacing mud with 9-ppg brine, 250 barrels during cleanup after perforating, and 20 barrels during bottom-hole sampling.

- **11/15/80 0600-2400 hours:** The temperature and pressure gradients inside the tubing were measured by RDI.
- **11/16/80 1516 hours:** Opening of the choke for the first flow rate began. After 2 minutes, the flow rate was about 6600 bbl/day, which was much greater than desired. The choke opening was then reduced. A third choke adjustment was made starting at about 1523 hours (7 minutes after first start of flow). A final adjustment at 1908 hours provided the desired brine production rate of about 1500 bbl/day.
- **11/20/80 1030-1330 hours:** Samples of separator gas and brine were collected for laboratory recombination and differential liberation studies.
- **11/21/80 1249-1253 hours:** The choke opening was adjusted in steps to increase the brine production rate from about 1500 to about 2400 bbl/day.
- **11/22/80 1514 hours:** The well was shut in for recording pressure buildup.
- **11/25/80 1720 hours:** Real-time data recording ended.
- **12/3/80:** Samples of scale and separator sludge were collected in conjunction with disassembling the surface test equipment.

12.6.2 Real Time Production Data

Overall, the quality of both the electronically-recorded and manually-logged real time data is substantially lower for this test than for the two previous well tests by the Eaton team. The reason for this is very bad weather which occurred during the 7 days of production testing.

Both preparation of the location and preparation for field work by individuals anticipated reasonably normal weather conditions at the location during November. However, an unusual winter cold front stalled in the vicinity of the test for a full week. Temperatures were in the 30's and 40's, wind velocities were consistently high, and precipitation was continuous and very heavy at times. Total precipitation for the week of testing alone was near the normal annual precipitation of about 7 inches. These weather conditions, plus the resulting mud, took a toll both in terms of electrical malfunctions and in terms of timely and accurate manual logging of data. Fortunately, the program contains sufficient redundancy in data collection for careful evaluation of all real-time data to provide accurate description of fluid production. Such description required several actions which had not been performed on data from previous well tests. The most significant of these actions were the following:

- Manual digitizing of Weatherly temperature, annulus pressure, and brine production data, to facilitate computer plotting as a step in data evaluation

- Development of the hardware and software required for manipulation of RDI data collected with a Hewlett-Packard 9825 computer, using IGT's Hewlett-Packard 85 computers

- Developing software for calculating single-phase separator brine rate from two-phase wellhead turbine data

- Developing software for integration of RDI data into the format required by IGT computational procedures and for calculating weighted moving averages of digital data.

The most difficult of these was transcription of RDI data into a form usable by IGT. Hewlett-Packard models 9825 and 85 computers have differences in language and operational characteristics such that it is impossible for one to read data recorded on magnetic tape by the other. However, both can communicate with the Hewlett-Packard model 9875A cartridge tape unit. RDI's cooperation in providing the computer statements used to record its data on magnetic tape made it possible for IGT to read the serial data on those tapes into the cartridge tape unit using a borrowed HP 9825B computer. After transcribing the serial data from this intermediate tape to tape generated by the HP 85 computer, two HP 85 computers were linked to convert RDI's serial data format into the random access data format required by IGT processing.

Once the RDI data were in the random access form required, additional software development for data manipulation was required to perform the following actions:

- Place the data files in proper chronological sequence. Blocks of data of durations up to several hours were out of sequence in the data tape provided to IGT.

- Remove redundant data files.

- Interpolate data to provide estimated values where data files corresponding to the precise 1/2-hour intervals employed in IGT's interpretation were missing.

- Integrate the brine production rates recorded on each RDI file and then calculate average brine production rates for each 1/2-hour time increment.

- Calculate the average RDI wellhead pressure for each 1/2-hour time increment for use in the procedure developed for estimating separator brine rate from two-phase wellhead turbine rate data.

Use of these computational tools, judgments rendered in the minimal manual data editing performed, and the resulting data set, believed truly representative of well performance, are described under subheadings which follow.

A complete listing of data used for interpretation (edited as discussed in subsequent subsections) is provided as Appendix F.

12.6.2.1 **Production Well Pressures:** Producing annulus pressure was electronically recorded by both RDI and IGT. In addition, dead weight measurements of that pressure were periodically performed by Weatherly Engineering. Prior to the start of production, all three measurements were in excellent agreement. However, substantial departures were observed, beginning about 24 hours after onset of production. Exhibit 12-8 portrays annulus pressure data recorded by all three parties for the 48 hours of November 17 and 18. The pressure excursions in IGT and Weatherly data are believed to have been caused by the plugging of the 1/8-inch stainless steel tubing between the producing annulus and the pressure sensors, possibly by hydrate formation.

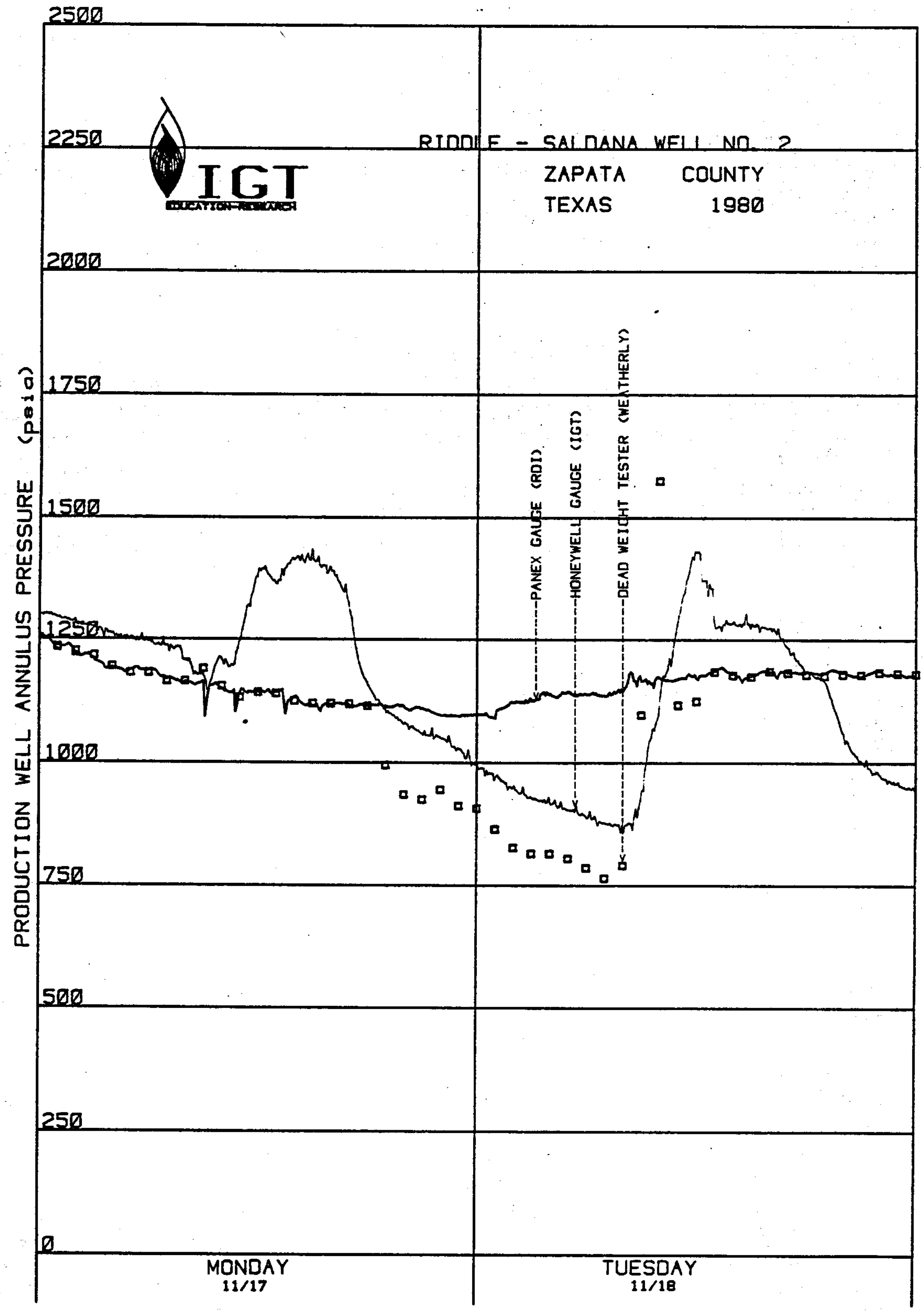
All three pressure measurements were made from the same path into the wellhead annulus. Beyond that point, the RDI Panex gauge was connected with about 2 feet of 5/16-inch stainless steel tubing. The tubing and gauge were close enough to the wellhead to be warmed by flowing brine. In contrast, both IGT's pressure transmitter and the Weatherly-operated deadweight tester were connected to the tap by more than 10 feet of 1/8-inch stainless steel tubing. A substantial portion of that tubing was sufficiently distant from the producing wellhead to be at local ambient temperature. None of the gauge lines had been prefilled with fluid prior to the start of testing. Thus, initial pressurizing of these lines was with the brine and gas present in the wellhead.

The possible role of hydrates in plugging a length of small stainless steel tubing was identified during data interpretation. Factors contributing to that hypothesis are the following:

- Hydrates were unequivocally identified during the subsequent test of the HO&M Prairie Canal Co., Inc., Well No. 1

- At a pressure of 1000 psi, pure methane forms hydrates in water at temperatures up to 48°F. Formation at even higher temperatures occurs with true natural gases.

- The pressure increases recorded near mid-day are hypothesized to be the result of daytime warming. This is supported by temperature recorded at the disposal well. Injection into that well was first initiated after 1500 hours on November 17. Wellhead temperature recorded prior to that time is believed representative of ambient temperature as discussed in Section 12.6.2.2. Recorded disposal wellhead temperature reached a minimum of 43.8°F at 0720 hours on 11/17/80. At the start of the increase in Weatherly and IGT annulus pressure data, at about



PRODUCTION WELL ANNULUS PRESSURE

EXHIBIT 12-8

1045 hours on 11/17/80, recorded disposal wellhead temperature had increased to 58.1°F.

The real time data believed representative of production well pressures throughout the production test are shown in Exhibit 12-9. Bottomhole and annulus pressures are data recorded by RDI. Tubing pressure was recorded by IGT. All data points are shown in this exhibit. None of these data points were manually edited.

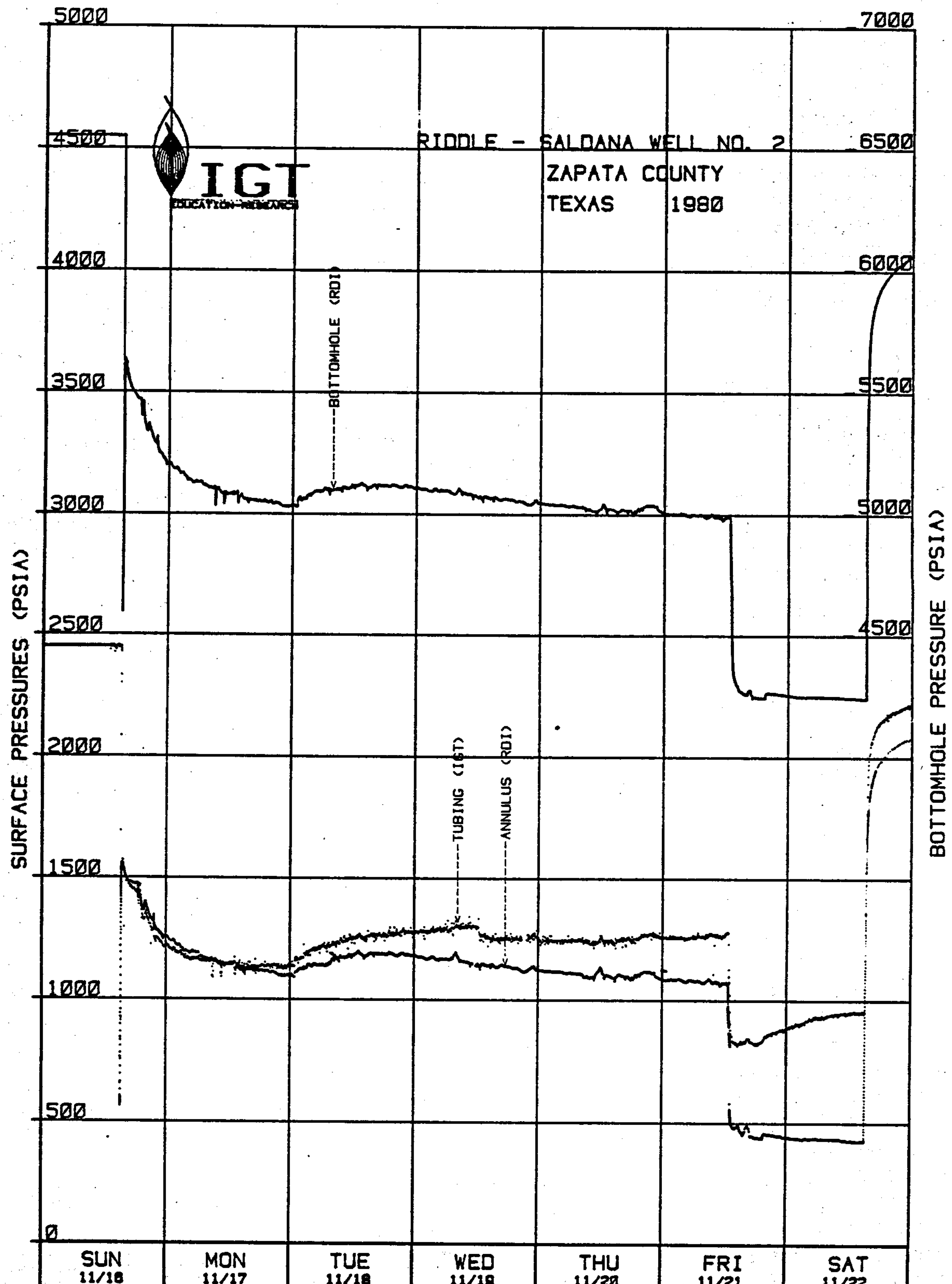
The departure between tubing and annulus pressure during the first 12 hours of production is believed caused by decreased density of the fluid column in the annulus as a result of gas production. The subsequent slow increase in tubing pressure, relative to annulus pressure, reflects development of a gas head in the shut-in tubing due to small bubbles of gas entering the bottom of the tubing. The decrease in tubing pressure at mid-day on 11/19/80 is the result of a small, short-duration lubricator leak.

12.6.2.2 Temperature Data: All recorded temperature data are presented in Exhibit 12-10. About two dozen of the roughly 2000 IGT data points for each curve have been manually edited to remove grossly erroneous values resulting from electrical shorting. In addition, IGT's separator temperature data were manually edited during three different time intervals to provide a more realistic estimate of true well performance. Two of these intervals were 0810 to 0840 hours on 11/19/80 and 2255 to 2325 hours on 11/19/80. The reason is that brine flow to the flare line (separator upset) provided higher values than would have occurred in the absence of the separator upset. The third interval was when massive brine production through the flare line occurred as a result of control air failure during the time interval of 1225 to 1245 on 11/21/80. No editing of either RDI or Weatherly Data has been performed.

The RDI temperature spike before start of testing on 11/16/80 is consistent with RDI's printed real-time recording. The departure between gas temperature measurements by Weatherly and IGT before 1400 hours on 11/17/80 is not understood. However, since IGT and Weatherly data are in agreement after the first change of charts by Weatherly, values recorded by IGT have been used for data interpretation.

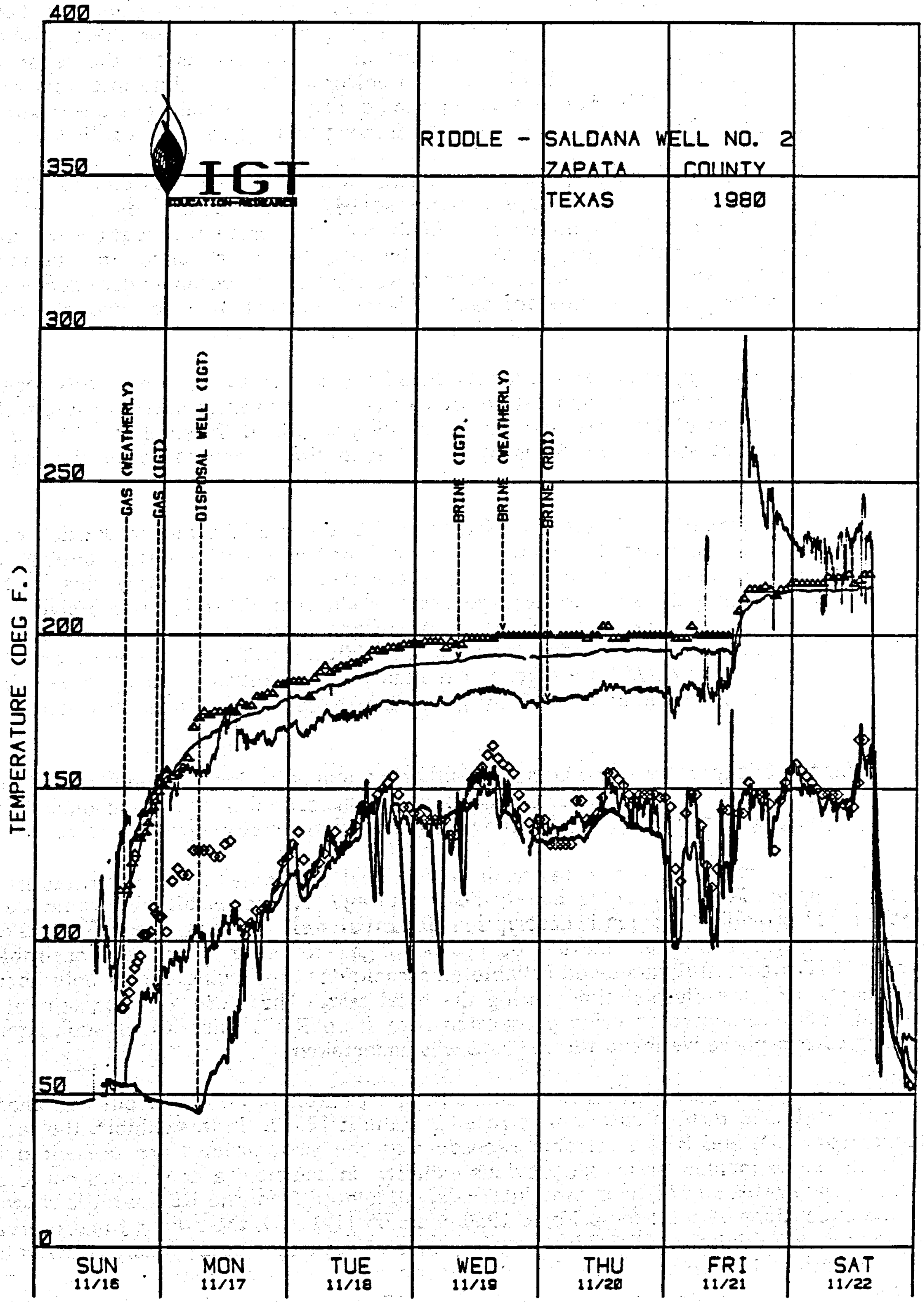
The discrepancy between wellhead brine temperature recorded by IGT and data manifold brine temperature recorded by Weatherly has been consistent on all three tests jointly instrumented. IGT's temperatures are low due to air cooling of the IGT temperature well, which was mounted on a tee outside the flowing brine stream. Because the difference is small, IGT values have been used, without correction, to calculate brine volumes and thermal energy production.

The close agreement between disposal wellhead temperature during times of brine disposal and gas temperature downstream from the orifice meter is coincidental. The disposal well brine was cooled by residence time in an open 200-barrel tank on the production well location, plus additional cooling while moving through the 1/2-mile surface line between the injection pump and the disposal wellhead. In contrast, the gas experienced air-cooling in approximately 15 feet of 2-inch line between the separator vessel and the point of temperature measurement. The fact that the two recorded data channels are truly independent is apparent from the low values of disposal wellhead temperature before start of injection on 11/17/81 and by the disposal wellhead cooling during interruptions of injection between noon on 11/18/80 and noon of 11/19/80. The minimum temperatures of the disposal wellhead and the gas through the orifice meter correlate well with intensity of rainfall.



PRODUCTION WELL PRESSURES

EXHIBIT 12-9



RECORDED TEMPERATURE DATA

EXHIBIT 12-10

12.6.2.3 **Brine Production Rate:** All recorded data on brine production are shown graphically in Exhibit 12-11. The top pair of overlying data sets is for the two-phase flow through the wellhead turbine. The bottom pair of data sets is for the separator brine turbine. In each case, the data displayed in uniform 1/2-hour time intervals were electronically recorded. The data sets with periodic longer time steps are the result of manual data logging. Data manipulation prior to drawing this figure was as follows:

- **RDI Production Wellhead Turbine:** The raw data tape copy provided to IGT by RDI was processed to produce random access files readable by the HP 85 computer, as previously discussed. RDI's recorded brine rate data were then integrated by multiplying each rate by elapsed time since the previous permanent record, and then summing these products in chronological sequence. The average production rate for each 1/2-hour interval was then deduced from this calculated cumulative production as a function of time.

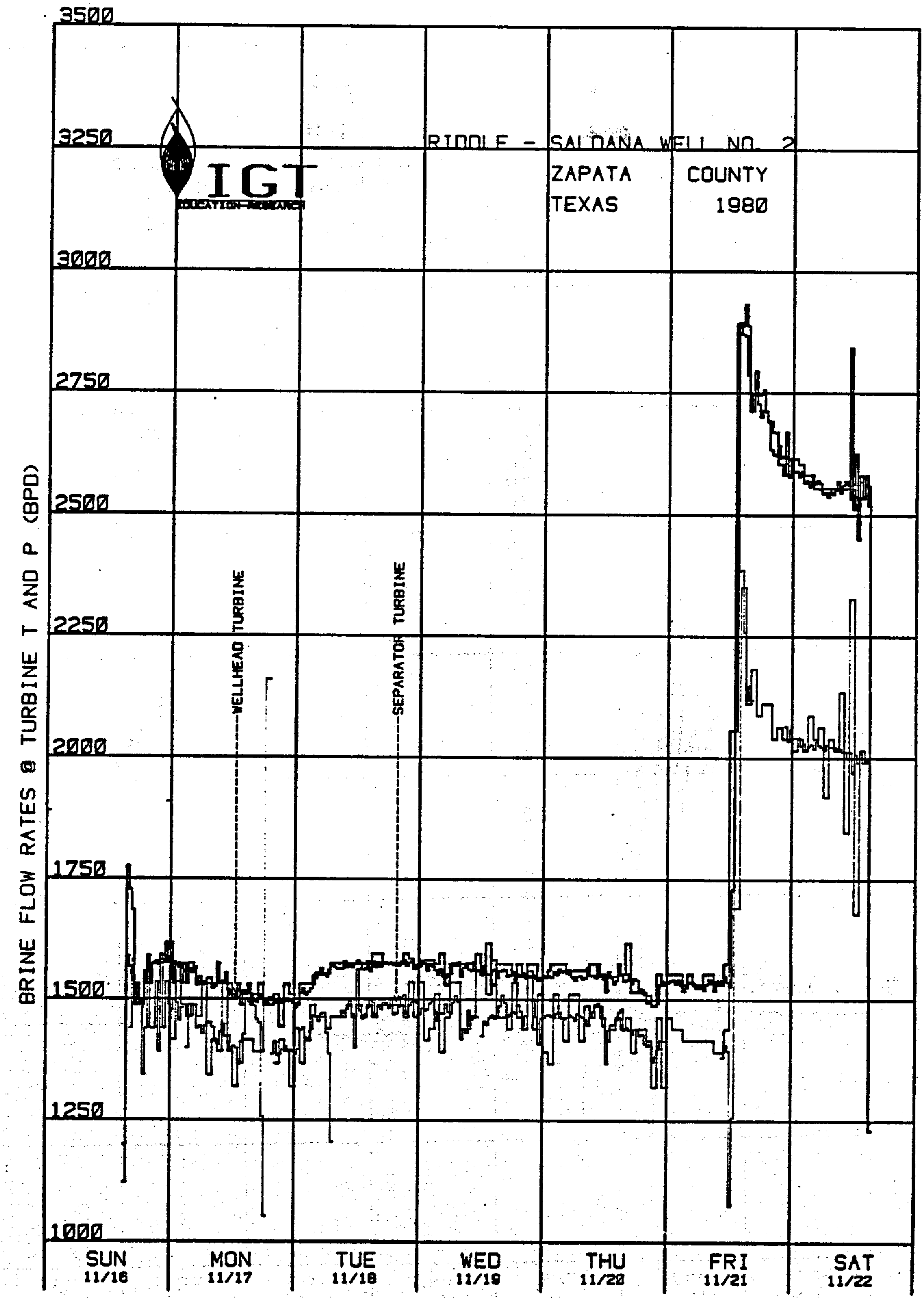
- **IGT Manual Logging of Production Wellhead Turbine Data:** Each manually logged data point represented cumulative production to the nearest barrel at a specific time. Values plotted are the result of dividing the difference in cumulative production at successive times by the elasped time since the prior logging of data.

- **IGT Recording of Separator Brine Rate:** IGT's electronic brine production data consisted of recording the cumulative number of brine turbine output pulses as a function of time. Computer software was then used to multiply this by the meter factor and calculate average brine production rates for successive 1/2-hour intervals. The gaps in the data reflect intervals of data loss due to electrical shorts or other malfunctions. In addition, IGT measurements prior to 2000 hours on 11/17/80 are erroneously high due to electronic noise pulses. This electronic noise was eliminated by grounding of cable shields at 1930 hours on 11/17/80.

- **Weatherly Separator Brine Data:** Weatherly's manually logged cumulative brine production data were manually digitized and processed in the same manner as previuusly described for production wellhead data manually logged by IGT.

For each turbine, comparison of rates from electronically recorded data with rates from manually logged data clearly revealed the advantage of successful electronic data collection for providing a smooth description of actual well performance. This makes use of such data for determination of produced gas to brine ratio very desirable. However, IGT successfully achieved reliable electronic data recording during only about three quarters of the elasped time during the total test. Therefore, development of a means to estimate separator brine production rate from RDI's impressively consistent recording of two-phase wellhead turbine rate was undertaken.

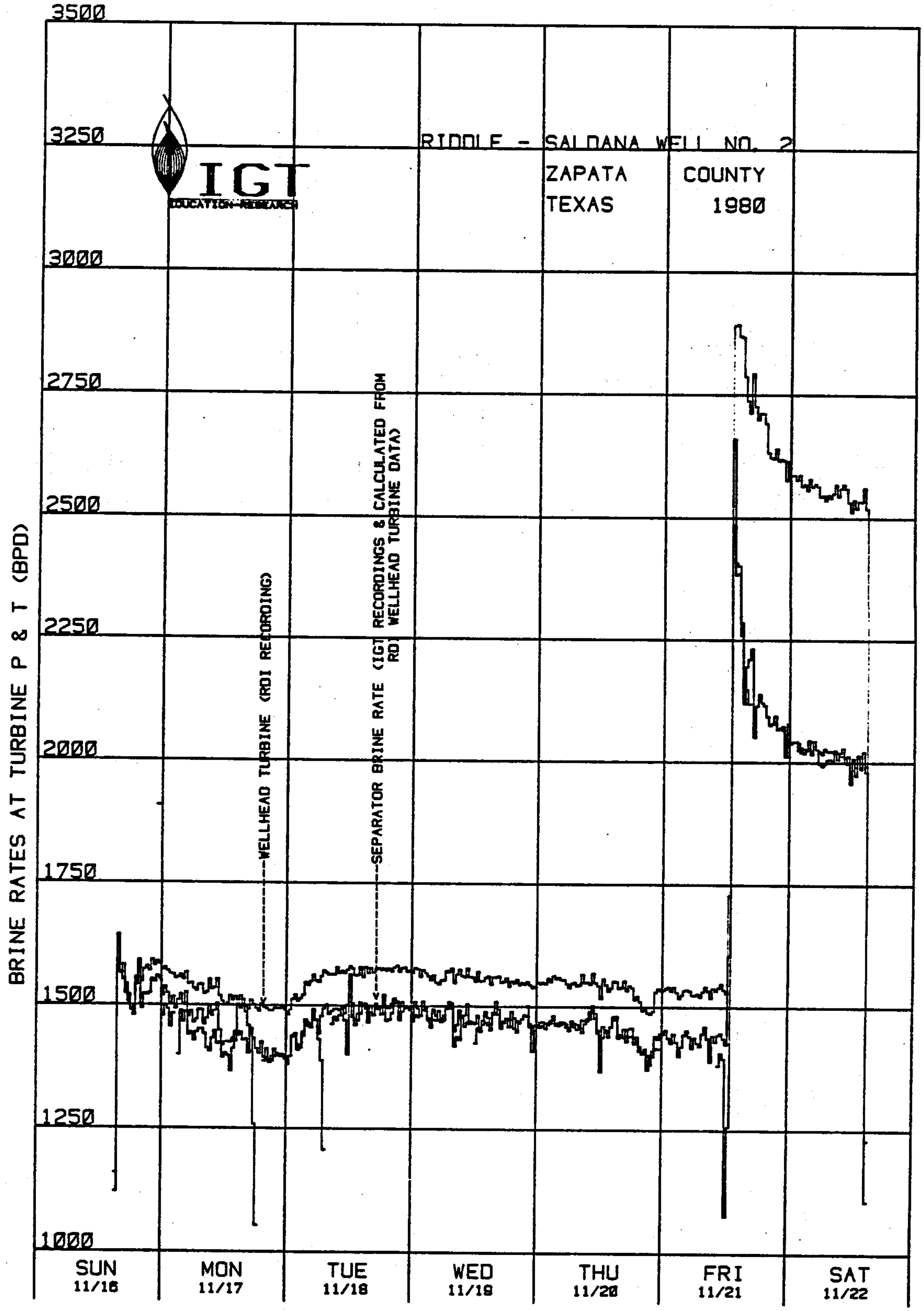
The high degree of success achieved in calculating separator brine rate from two-phase production wellhead turbine data is illustrated in Exhibit 12-12. In this exhibit, the rates deduced from RDI and IGT electronic recording of the two turbines are presented in exactly the same manner as in the previous exhibit. In addition, a continuous curve of separator brine rates on 1/2-hour time intervals, calculated from the RDI data, is shown. With the exceptions of the time prior to 1930 hours on 11/17/80, the 3-hour time interval before the rate increase on 11/21/80, and the times of separator upsets characterized by brine production through the flare line, discrepancies between calculated and measured separator brine rates are much less than the scatter in brine rates calculated from manually logged data and portrayed in Exhibit 12-11.



Note: This Exhibit shows manually logged and electronically recorded raw data for both the two-phase wellhead turbine and the separator turbine. (See also Exhibit 12-12).

RECORDED BRINE PRODUCTION DATA

EXHIBIT 12-11



Note: This Exhibit is a comparison of brine rates calculated from two-phase turbine data with electronically recorded rates from the separator turbine. (See also Exhibit 12-11).

COMPARATIVE BRINE RATES

EXHIBIT 12-12

The procedure for successfully calculating separator brine rate from the rate of two-phase flow through the wellhead brine turbine started with the following equation:

$$Q_w = Q_s \left[1 + \left(\frac{Q_g}{Q_s} + GWR_s - GWR_w \right) \frac{1}{5.6146} \frac{14.73}{P_w} \frac{T_w + 460}{520} \right] \qquad \text{(Eq. 1)}$$

where -

Q_w	=	wellhead turbine rate, bbl/day
Q_s	=	separator turbine rate, bbl/day
Q_g	=	flare line gas rate, SCF/day
GWR_w	=	gas/water ratio in brine leaving the separator, SCF/bbl
GWR_s	=	gas/water ratio for gas in solution at wellhead temperature and pressure, SCF/bbl
P_w	=	pressure in the wellhead turbine, psia
T_w	=	temperature in the wellhead turbine, ^oF

This equation simply states that the volume through the wellhead turbine should equal the volume of brine through the separator turbine plus the volume occupied by free gas at wellhead turbine temperature and pressure. If no free gas is present in the turbine, that is, if -

$$\left(\frac{Q_g}{Q_s} + GWR_s - GWR_w \right) \leq 0 \qquad \text{(Eq. 2)}$$

then Equation 1 should be $Q_w = Qs$.

This starting point for calculating separator brine rate does not include the effect of temperature upon brine volume, because data from previous tests reveal that the brine temperature drop between the turbines is less than 5^oF.

Solving Equation 1 was accomplished as a modification to IGT's software for calculating gas production and gas-to-water ratio. For each 1/2-hour time interval, Q_g is the gas rate to the flare line from orifice meter data interpretation. Values for GWR_s and GWR_w for each 1/2-hour time interval are calculated using the algorithm developed by S. K. Garg, of Systems Science and Software (Ref. 10) to duplicate methane solubility data of Culberson and McKetta (Ref. 6). Selection of this algorithm resulted from comparison with brine flash data from the WOO test of the P. R. Girouard Well No. 1 (Ref. 9).

Solving Equation 1 with this procedure and the boundary condition on existence of free gas in the wellhead turbine did not provide an adequate fit with recorded separator turbine data. Therefore, the solution of Equation 1 for Q_s was modified by adding two empirical constants as follows:

$$Q_s = \frac{AQ_w - 5.045 \times 10^{-3} B \dfrac{(T_w + 460)}{P_w} Q_g}{1 + 5.045 \times 10^{-3} B \dfrac{(T_w + 460)}{P_w} (GWR_s - GWR_w)} \qquad \text{(Eq. 3)}$$

where A and B are empirical constants. (Other parameters were defined previously.) The physical reasoning behind the selection of these particular constants is as follows:

"A" represents the calibration discrepancy between outputs of the two turbines under conditions of identical fluid flow.

"B" is a multiplicative departure from calculated gas volume in the wellhead turbine. It is expected to be less than 1 due to effects such as residence time required for gas to come out of solution or decreased mole fraction of CO_2 in the gaseous phase at wellhead pressure.

Values for A and B were determined by solving the simultaneous equations resulting from the use of values for all other parameters at two times of very different and stable operating conditions. The times chosen were 0300 hours on 11/20/80 and 0100 hours on 11/22/80. This calculation revealed the following reasonable answers:

A = 1.03373, implying a 3.3% discrepancy in turbine calibrations

B = 0.81664, implying a free gas content in the wellhead turbine equal to 82% of the value calculated with the rather simplistic assumptions used.

Solving Equation 3 with these values yielded the excellent fit between calculated and measured separator brine rates that is shown in Exhibit 12-12. The fit is particularly pleasing when one observes the discrepancies at times of known separator upsets characterized by brine production to the flare line. These times are 0810 to 0840 hours on 11/19/80, 2255 to 2325 hours on 11/19/80, 1200 to 1230 hours on 11/20/80, and 1225 to 1245 hours on 11/21/80. In each case, the calculated brine rate is higher than the measured separator turbine rate, which did not include brine lost to the flare line.

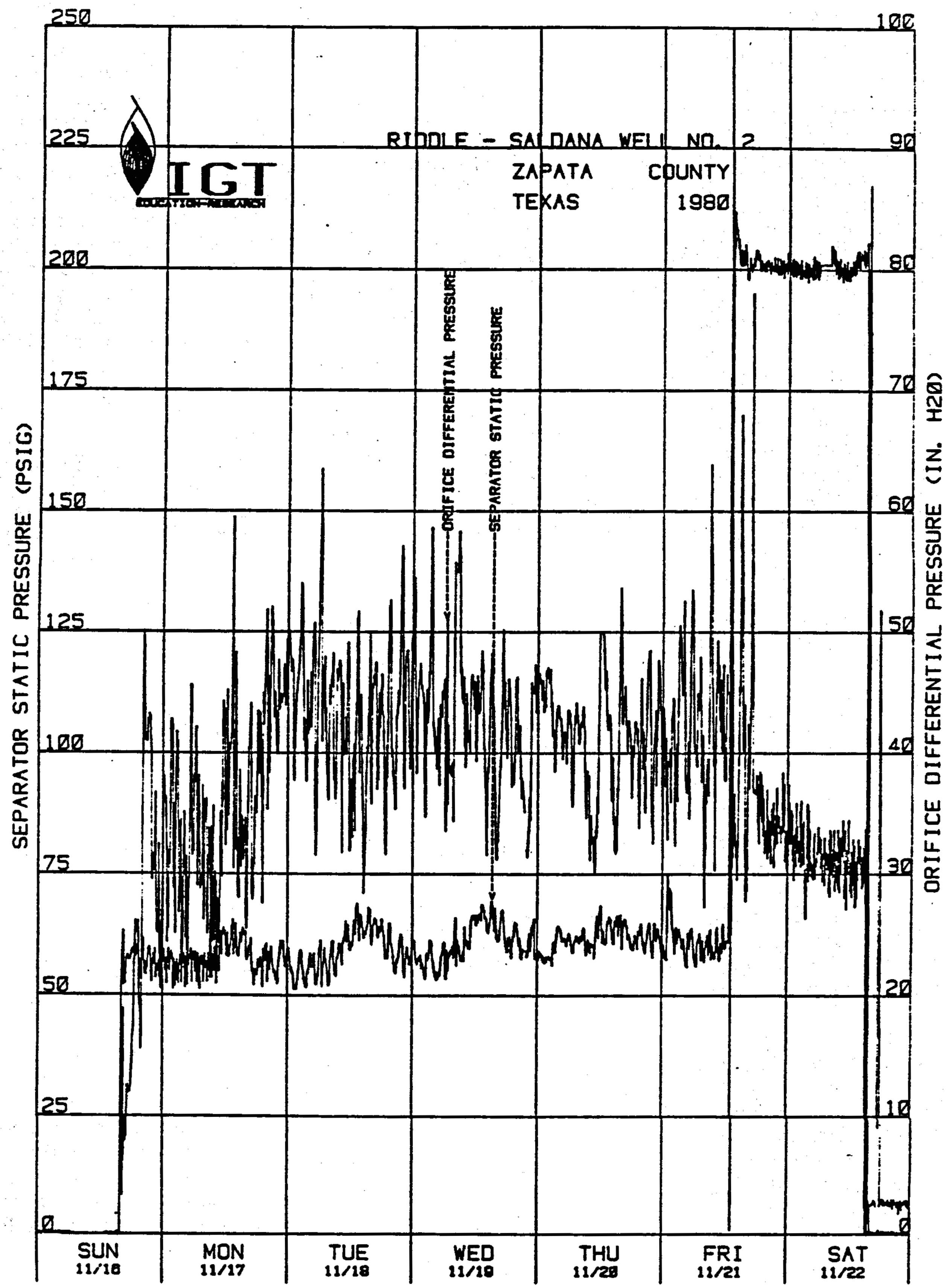
12.6.2.4 Separator Pressure and Orifice Differential: IGT data for these two parameters are presented graphically in Exhibit 12-13. The amount of hand-editing due to electrical shorting in wet connectors was less than for other channels, because the transmitters and connectors were under a canvas canopy. Only about 6 individual points for each of these channels were hand-edited to remove erroneous zero values due to electrical shorting. In addition, the raw separator data exhibited a transient excursion to a peak of 233 psig between 0600 and 0800 hours on 11/22/80. In contrast, separator pressures recorded by Weatherly remained constant at about 200 psig during the same time interval. Since no other recorded data exhibited a transient consistent with a buildup and decline in separator pressure at that time, all recorded values were hand-edited to the average of 201 psig characteristic of IGT's recorded values before and after the transient. Both separator pressure and orifice differential pressure were hand-edited to correct recorded values during times of separator upset characterized by brine production to the flare line. Such editing was performed for the time intervals 0810 to 0840 hours on 11/19/80, 2255 to 2325 hours on 11/19/80, 1200 to 1230 hours on 11/20/80, and 1225 to 1245 hours on 11/21/80. In each case, the hand-editing substituted the average of values recorded before and after the separator upsets.

The low separator pressure of about 60 psig was used during production at about 1500 bbl/day to minimize error in gas production rate due to zero variations in the output of the differential pressure transmitter. By operating at this pressure and using the smallest orifice plate on location (0.50-in. opening), differential pressure was maintained in excess of 30 inches of water. Both experience on prior tests and periodic zero checks during this test have revealed unexplained variations of ± 1.0 inch of water in the zero baseline for orifice differential pressure. Since gas production rate is a function of the square root of orifice differential pressure, the uncertainty in gas production due to a ± 1 inch of water uncertainty in a recorded value of 30 inches of water results in an uncertainty of less than ± 2% in calculated gas production rate to the flare line.

When flow rate was increased at mid-day on 11/21/80, separator pressure was increased as required to maintain a recorded orifice differential pressure of 30 to 40 inches of water without the loss of data that would have resulted from changing to an orifice plate of different size.

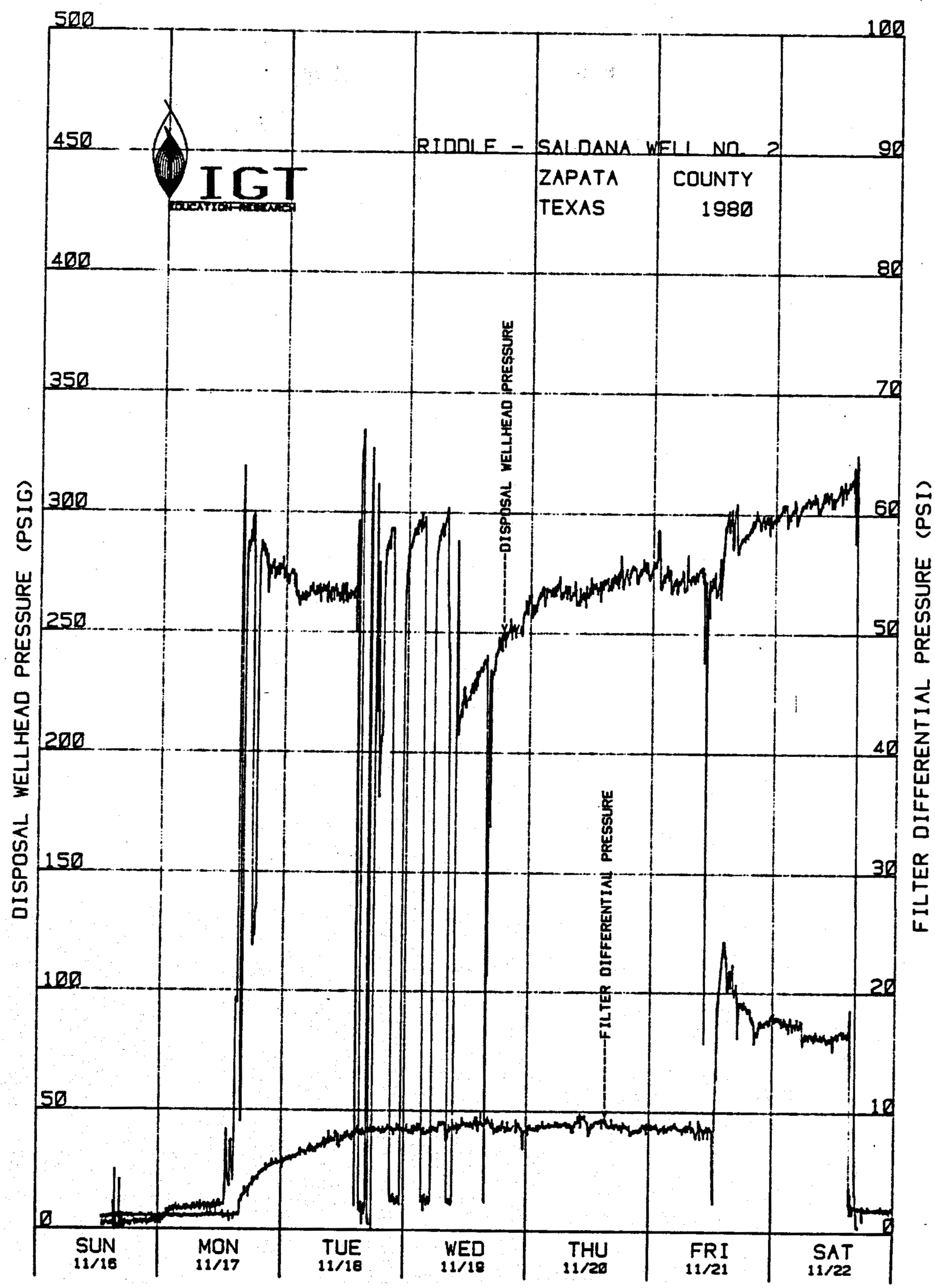
12.6.2.5 Filter Differential Pressure and Disposal Wellhead Pressure: Recorded data for these two parameters are presented in Exhibit 12-14. The only manual editing of filter differential pressure data was at about a half-dozen individual points where zero or negative values were recorded due to electrical shorting. About two dozen disposal wellhead pressure points were similarly edited. This larger number was due to the necessity for several Amphenol Series 44 connectors in the 1/2-mile of wire to the disposal wellhead plus occasional damage to the cable by grazing cattle.

Flow rates to the disposal well differ from brine production rates because of use of a 200-barrel settling tank on the production well location plus an injection pump to transfer liquid from that tank to the disposal well. The majority of fluid produced during the first 24 hours was produced to the reserve pit on the production well location, due to problems with the injection pump. The cyclic injection on the afternoon of 11/18/80 and morning of 11/19/80 resulted from problems with speed control on the injection pump. During periods of injection, the 200-barrel tank was pumped down until termination of injection was dictated by air entering the pump suction. Each time the settling tank filled, the injection pump was restarted.



SEPARATOR AND ORIFICE DIFFERENTIAL PRESSURES

EXHIBIT 12-13



DISPOSAL WELLHEAD AND FILTER DIFFERENTIAL PRESSURES

EXHIBIT 12-14

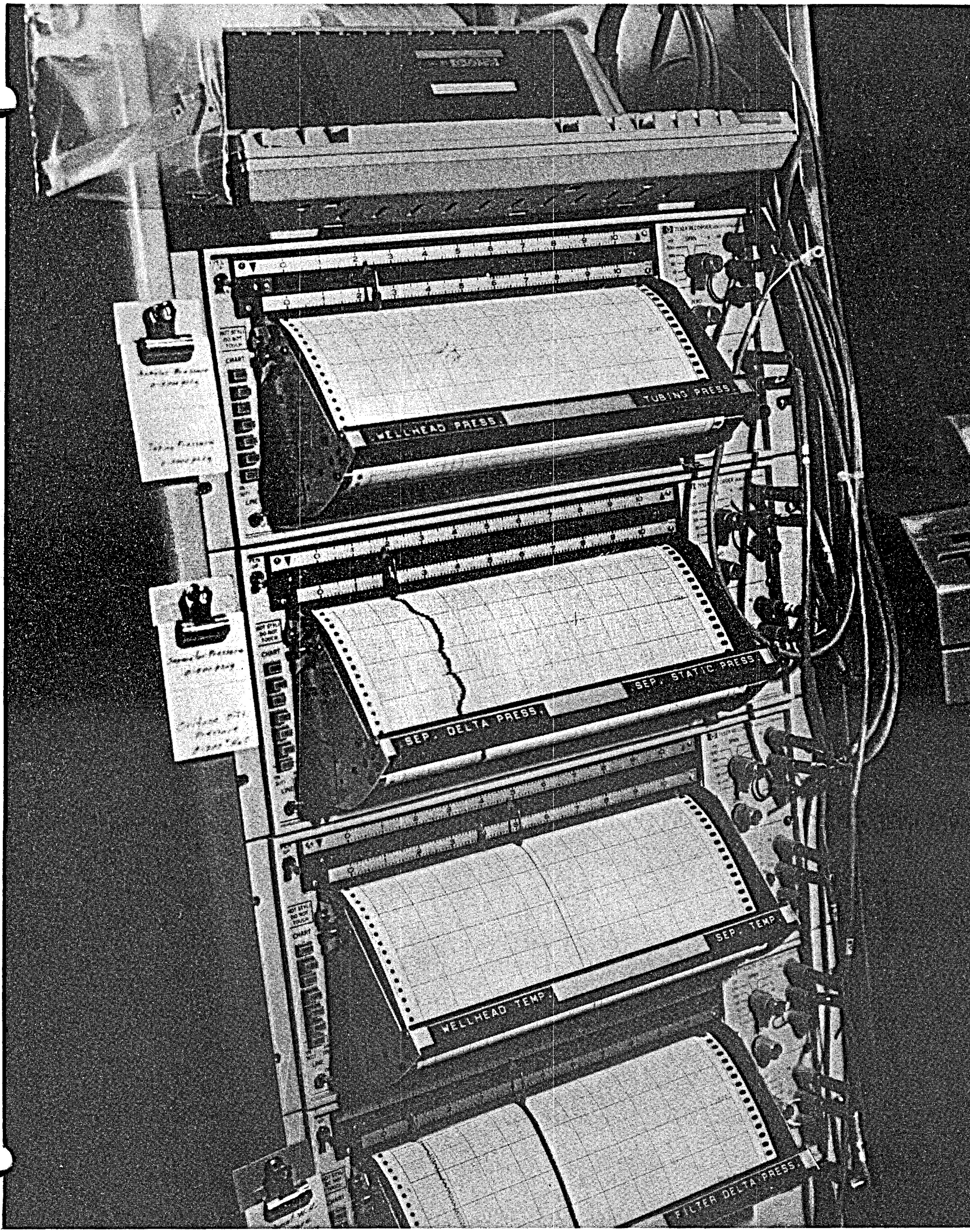


Photo 12-1 IGT strip chart data recording panel

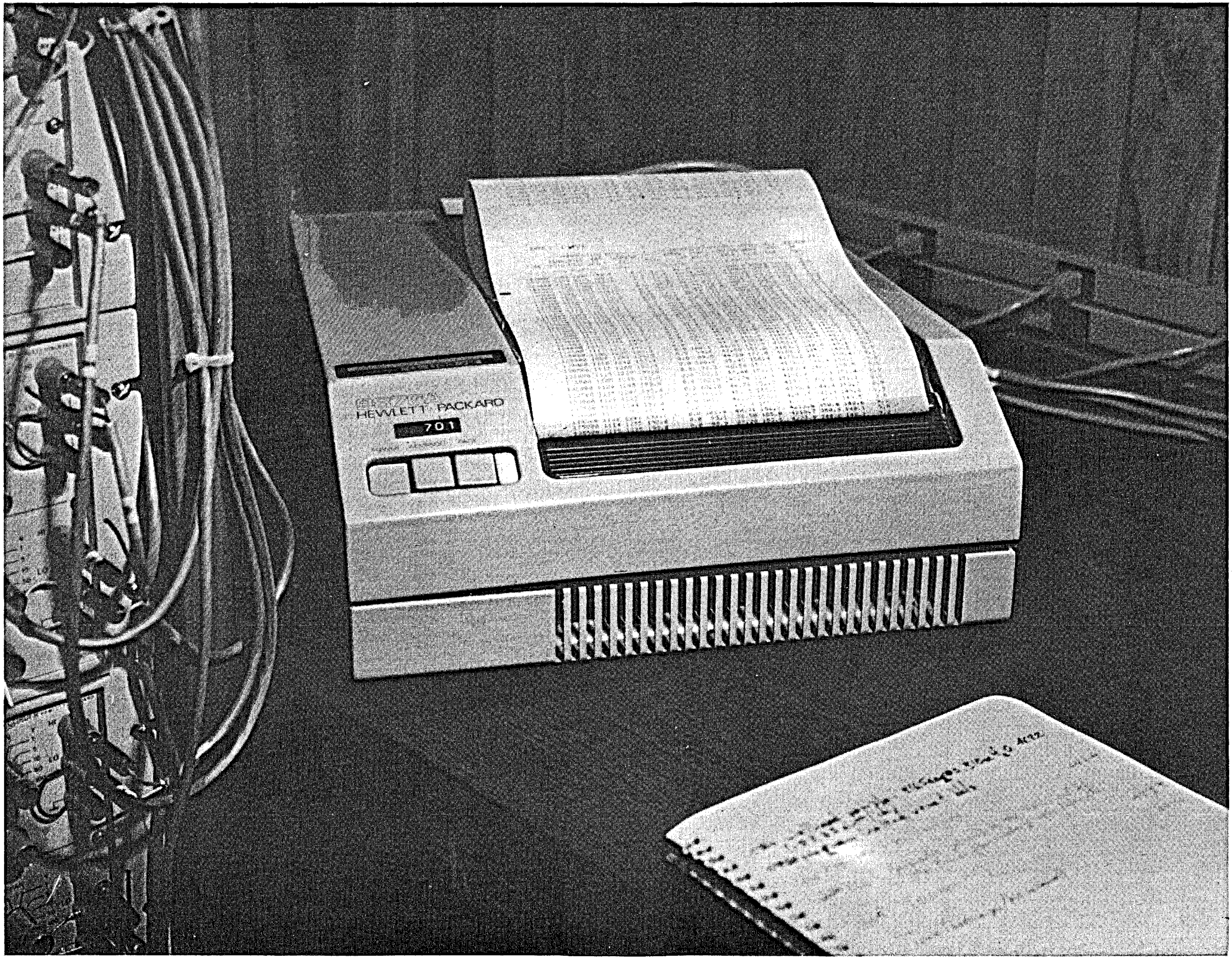


Photo 12-2 IGT computer printing module

The problem with the injection pump speed control was solved at midday on 11/19/80. For the remaining 3 days of the test, the injection rate approximated the brine production rate. The effect of increasing brine production rate, and injection rate, was apparent at mid-day on 11/21/80.

12.6.3 Characteristics of Produced Gases

Sections 12.6.3.1 through 12.6.3.4 provide details of gas sample collection and analysis for all gas composition data obtained. Section 12.6.3.5 describes the interpretation of these data, which suggests the presence of gas in the reservoir in excess of solubility in brine. Section 12.6.3.6 discusses judgments made in selecting gas compositions for interpretation of orifice meter data to determine time-dependent gas production to the flare line.

12.6.3.1 Bottom-hole Samples: Two bottom-hole samples were successfully obtained from a depth of 9743 feet (2 feet above the shallowest perforation) at 1518 hours and 1711 hours on 11/13/80. A few barrels of brine were produced before each filling of the sampler to ensure sampling of fresh reservoir brine. Pressure drawdown during this production was only about 100 psi.

The two filled samplers were transported to Chicago for analysis of contents under the GRI contract "Gas Saturation in Formation Waters." On 11/20/80 and 11/21/80, they were flashed to an evacuated manifold that included a flexible bag, which permitted flashing to 1 atm pressure. After each flashing, gas from the flexible bag was compressed into 300-cc stainless steel cylinders. Two cylinders were required for the gas from each bottom-hole sampler.

Gas from all four stainless steel cylinders was analyzed by mass spectrometry on 11/26/80, 13 days after bottom-hole sampling. Results of the flashings and of these analyses are shown in Exhibit 12-15. For each bottom-hole sample, the fractional compositions shown were calculated from the analyses and contents of the two laboratory cylinders used. The small reported hydrogen content of the gas is generated by reactions between the brine and metallic components of the sampler.

12.6.3.2 Flare Line Gas Samples: Flare 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.

Procedures used for i) sample collection, ii) gas chromatography analyses in the field, iii) Draeger apparatus analysis, and iv) mass spectrometry analysis in IGT's Chicago laboratories are described in the following subsections:

- **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. A temperature greater than 100°C was used, 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 Swagelok caps.

EXHIBIT 12-15

QUANTITY AND COMPOSITION OF GAS FROM BOTTOMHOLE SAMPLES

	Sample No. 1	Sample No. 2
Collection Time	1518 hours; 11/13/80	1711 hours; 11/13/80
Date of Flashing	11/20/80	11/21/80
Flash Gas Brine Ratio	38.7 SCF/bbl	38.8 SCF/STB
Date of Mass Spectrometric Analysis	11/26/80	11/26/80

Gas Composition	Sample No. 1 Mol %	Sample No. 1 SCF/bbl	Sample No. 1 gal/MCF	Sample No. 2 Mol %	Sample No. 2 SCF/bbl	Sample No. 2 gal/MCF
H_2	0.60	.232		0.10	0.039	
CO_2	17.92	6.935		19.85	7.702	
Methane	79.06	30.596		77.58	30.101	
Ethane	2.10	0.813	0.5600	2.11	0.819	0.5627
Propane	0.24	0.93	0.0659	0.28	0.109	0.0769
n-Butane	0.02	0.008	0.0063	0.02	0.008	0.0063
i-Butane	0.03	0.012	0.0098	0.02	0.008	0.0065
Benzene	0.02	0.008	0.0056	0.03	0.012	0.0084
Toluene	0.01	0.004	0.0033	0.01	0.004	0.0033
Other Gases *	<0.01	<0.004		<0.01	<0.004	
Total			0.6509			0.6641

* Content of each of the following gases was less than 0.01 mol % and assumed zero for normalizing: nitrogen, pentanes, hexanes, heptanes, octanes, nonanes, xylene, helium, and argon.

- **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 C6+ 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 with an on-line Perkin Elmer integrater. The area of each peak was then multiplied by the response factor of that component from a standard and the composition normalized to 100%.

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

  Results of the field gas chromatograph analyses are given in Exhibit 12-16. With the exception of C_{6+}, the uncertainties in reported values are estimated to be as follows:

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

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

  Natural gas liquids (NGL) content for ethane through pentane has been calculated for each gas analysis using values for SCF per gallon of liquid from Figure 16-1 of the 1974 revised edition of the Engineering Data Book published by the Gas Processors Suppliers Association in cooperation with the Gas Processors Association (Ref. 4). The quantity of ethane through pentane NGL per MCF of total gas is also shown in Exhibit 12-16. The C_{6+} components are not included because of the large uncertainty in gas chromatograph results for these components.

- **Draeger Apparatus Analyses:** Hydrogen sulfide concentrations shown in Exhibit 12-16 were 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. Mercury and ammonia were looked for only in the sample taken at 1920 hours on 11/16/80. The results were below minimum detectable limits - less than 3 ppm ammonia and less than 0.05 mg/m^3 mercury. Results for CO_2 were consistent with those from gas chromatograph analysis and are not reported.

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

  Immediately prior to 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. Analysis results are presented in Exhibit 12-17 for all components detected with concentrations greater than 0.01 mole percent. Gases that would have been detected and reported if concentrations had exceeded this value include hydrogen, helium, oxygen, nitrogen, argon, octanes, nonanes, and xylene.

  The NGL content calculated for each analysis is also shown in Exhibit 12-17. This calculation is reported for ethane through pentane only, as well as for all hydrocarbons above the detection threshold. This breakdown facilitates the combining of gas chromatograph and mass spectrometer analyses to be discussed in Section 12.6.3.6.

Photo 12-3 IGT chemistry lab with gas chromatograph

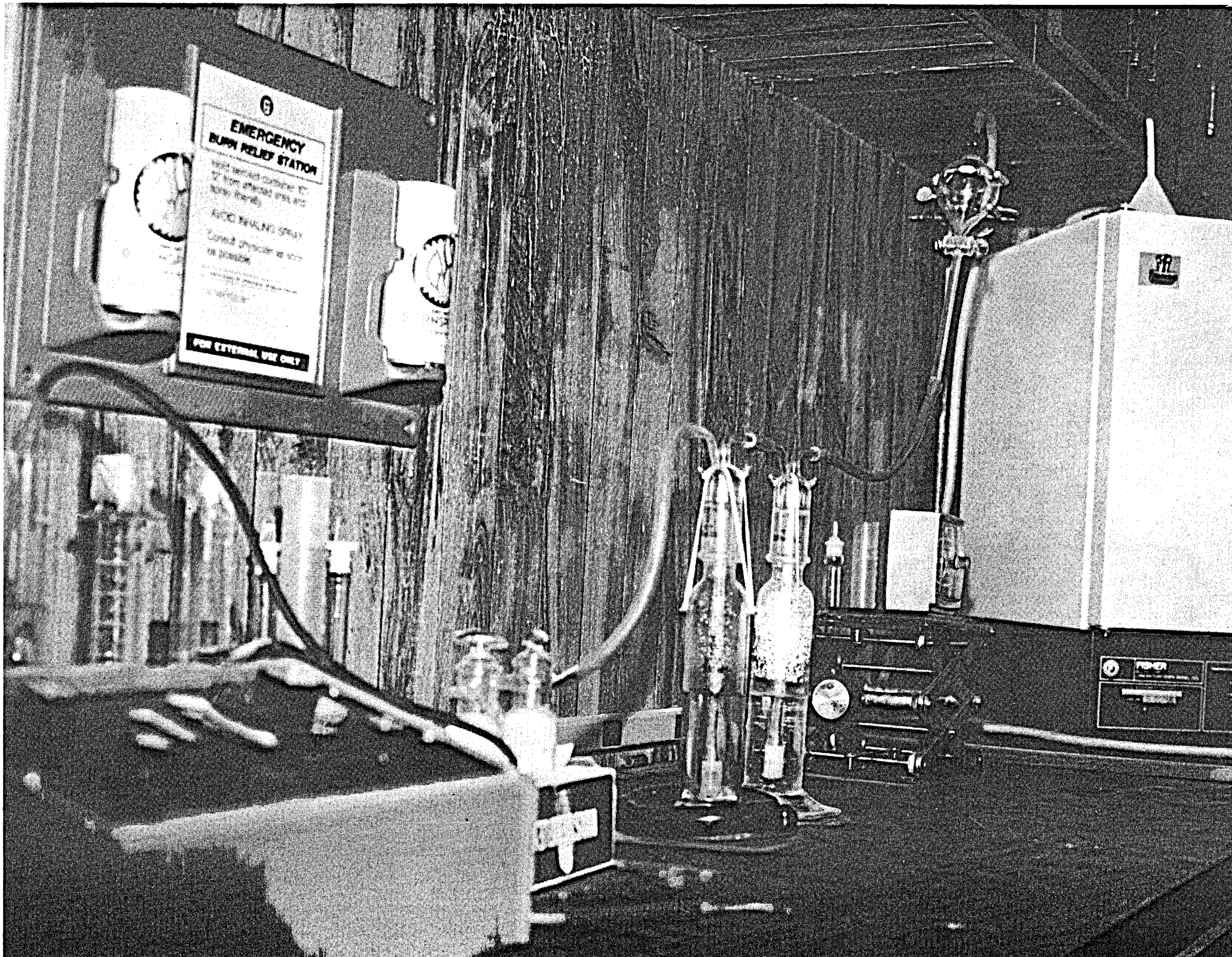


Photo 12-4 A section of the IGT field chemistry lab

RIDDLE-SALDANA WELL #2 — FLARE LINE GAS FIELD GAS CHROMATOGRAPHY (Part I)

Sample Date	11/16/80			11/17/80		11/18/80			11/19/80		
Sample Time	1800	2000	2045	0745	1900	0930	1030	1635	1030	1530	2030
Component, mol %											
Methane	74.72	70.88	76.14	72.06	72.88	73.36	72.78	73.50	72.80	73.83	73.78
Ethane	2.14	2.06	2.49	2.39	2.51	2.53	2.55	2.60	2.65	2.68	2.66
Propane	0.29	0.32	0.43	0.42	0.44	0.45	0.45	0.47	0.49	0.50	0.51
n-Butane	0.02	0.04	0.04	0.04	0.04	0.05	0.08	0.04	0.06	0.05	0.05
i-Butane	0.02	0.03	0.04	0.03	0.04	0.04	0.04	0.05	0.04	0.05	0.05
Pentanes	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.02	0.03	0.02
C_6+	0.03	0.03	0.06	0.09	0.14	0.03	0.03	0.04	0.08	0.00	0.04
Nitrogen	0.19	0.22	0.19	0.38	0.26	0.24	0.28	0.06	0.20	0.21	0.14
Carbon Dioxide	22.57	26.41	20.60	24.57	23.67	23.28	23.78	23.22	23.65	22.66	22.75
H_2S ppm*	35	60	57	93	75		83		73	70	
Separator Pressure, psig	59.2	60.6	54.3	52.8	56.1	57.9	58.8	65.6	61.2	65.8	61.8
Separator Temperature °F	120	133	135	167	176	184	184	188	193	194	193
Sample Point Temperature °F	63	74	81	103	109	130	131	143	150	155	137
C2-C5 NGL, gal/MCF	0.6667	0.6632	0.8113	0.7786	0.8230	0.8306	0.8454	0.8549	0.8803	0.8948	0.8886

* H_2S content was determined using length of stain tubes (Draeger Apparatus)

EXHIBIT 12-16, Part I

RIDDLE-SALDANA WELL #2 — FLARE LINE GAS FIELD GAS CHROMATOGRAPHY
(Continued Part II)

Sample Date	11/20/80			11/21/80				11/22/80			
Sample Time	1000	1420	1920	0930	1220	1508	2120	0908	1113	1245	1442
Component, mol %											
Methane	71.25	72.68	73.17	74.57	73.87	78.75	77.63	77.36	77.19	76.96	77.38
Ethane	2.47	2.65	2.62	2.86	2.75	3.57	3.33	3.25	3.24	3.25	3.23
Propane	0.44	0.49	0.50	0.58	0.54	0.87	0.79	0.76	0.74	0.74	0.76
n-Butane	0.05	0.05	0.05	0.07	0.06	0.10	0.09	0.09	0.09	0.09	0.09
i-Butane	0.04	0.05	0.05	0.06	0.05	0.10	0.11	0.09	0.09	0.09	0.09
Pentanes	0.01	0.03	0.02	0.02	0.02	0.04	0.04	0.03	0.03	0.04	0.04
C_6+	0.09	0.04	0.02	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Nitrogen	0.12	0.29	0.11	0.09	0.07	0.09	0.09	0.06	0.11	0.08	0.06
Carbon Dioxide	25.53	23.73	23.47	21.71	22.62	16.45	17.90	18.34	18.50	18.74	18.33
H_2S ppm*		68				34			32		
Separator Pressure, psig	59.2	62.7	63.1	59.5	61.3	203	200	202	199	200	202
Separator Temperature °F	195	196	195	195	195	209	214	215	215	216	216
Sample Point Temperature °F	140	151	145	101	118	149	140	144	142	156	158
C2-C5 NGL, gal/MCF	0.8118	0.8841	0.8752	0.9707	0.9240	1.2694	1.1836	1.1438	1.1357	1.1420	1.1421

* H_2S content was determined using length of stain tubes (Draeger Apparatus)

Exhibit 12-17. ANALYSES OF RIDDLE-SALDANA WELL No. 2 FLARE LINE GAS BY MASS SPECTROSCOPY

Sample Collection Date	11/18/80	11/21/80	11/22/80
Sample Collection Time	1040	1600	1345
Sample Analysis Date	12/11/80	12/11/80	12/11/80
Separator Pressure, psig	61.1	201	203
Separator Temperature, ^{o}F	185	210	216
Component, mol %			
Methane	72.44	77.56	78.75
Ethane	2.38	3.30	2.97
Propane	0.41	0.73	0.66
n-Butane	0.05	0.13	0.10
i-Butane	0.02	0.08	0.07
Pentanes	0.02	0.10	0.07
Hexanes	0.01	0.08	0.04
Heptanes	0.01	0.04	0.02
Benzene	0.05	0.10	0.07
Toluene	0.04	0.07	0.06
Xylene	0.00	0.00	0.01
Carbon Dioxide	24.57	17.81	17.18
C2 - C5 NGL, gal/MCF	0.7767	1.1837	1.0529
All NGL, gal/MCF	0.8127	1.2862	1.2075

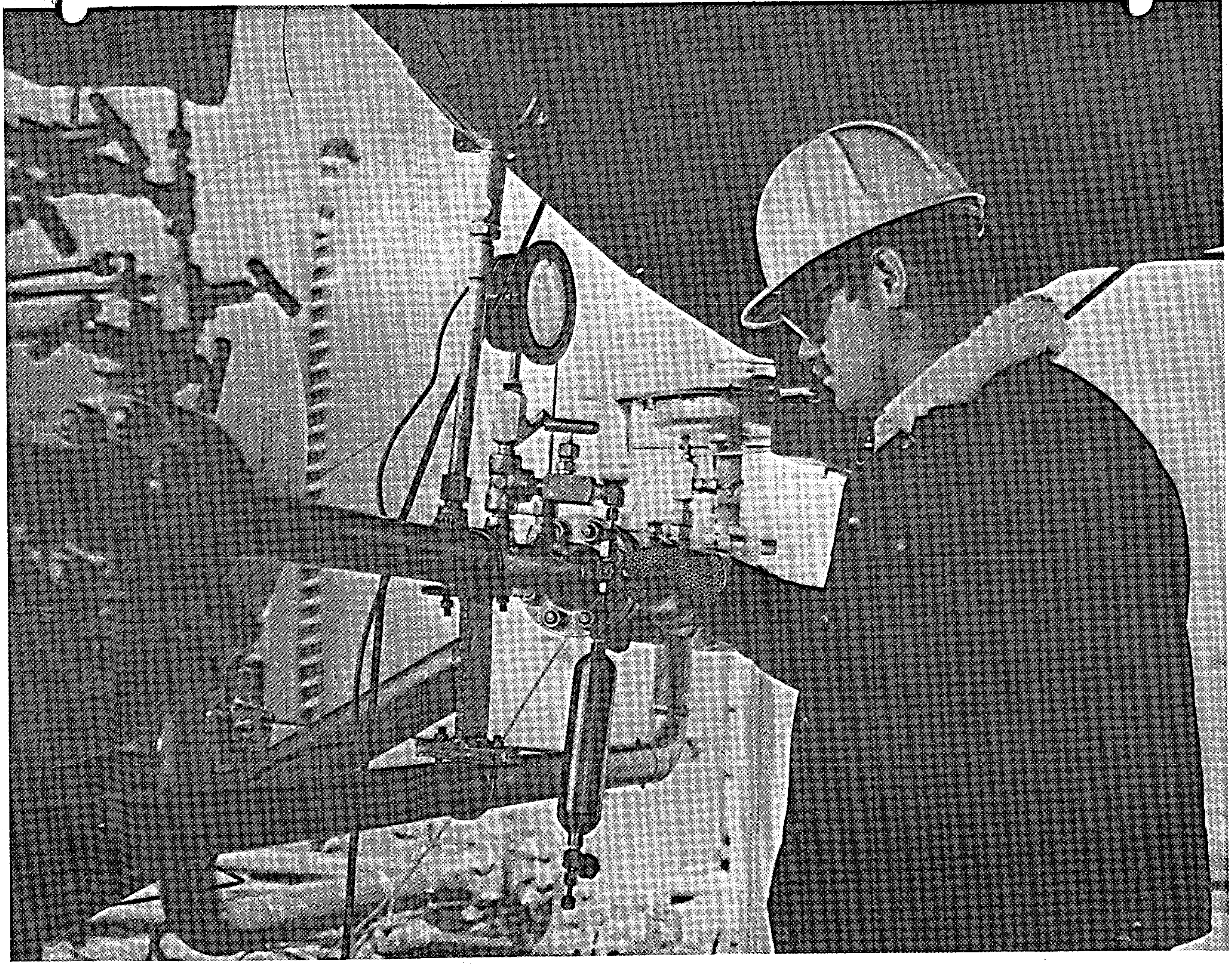


Photo 12-5 IGT chemist obtaining gas sample at separator

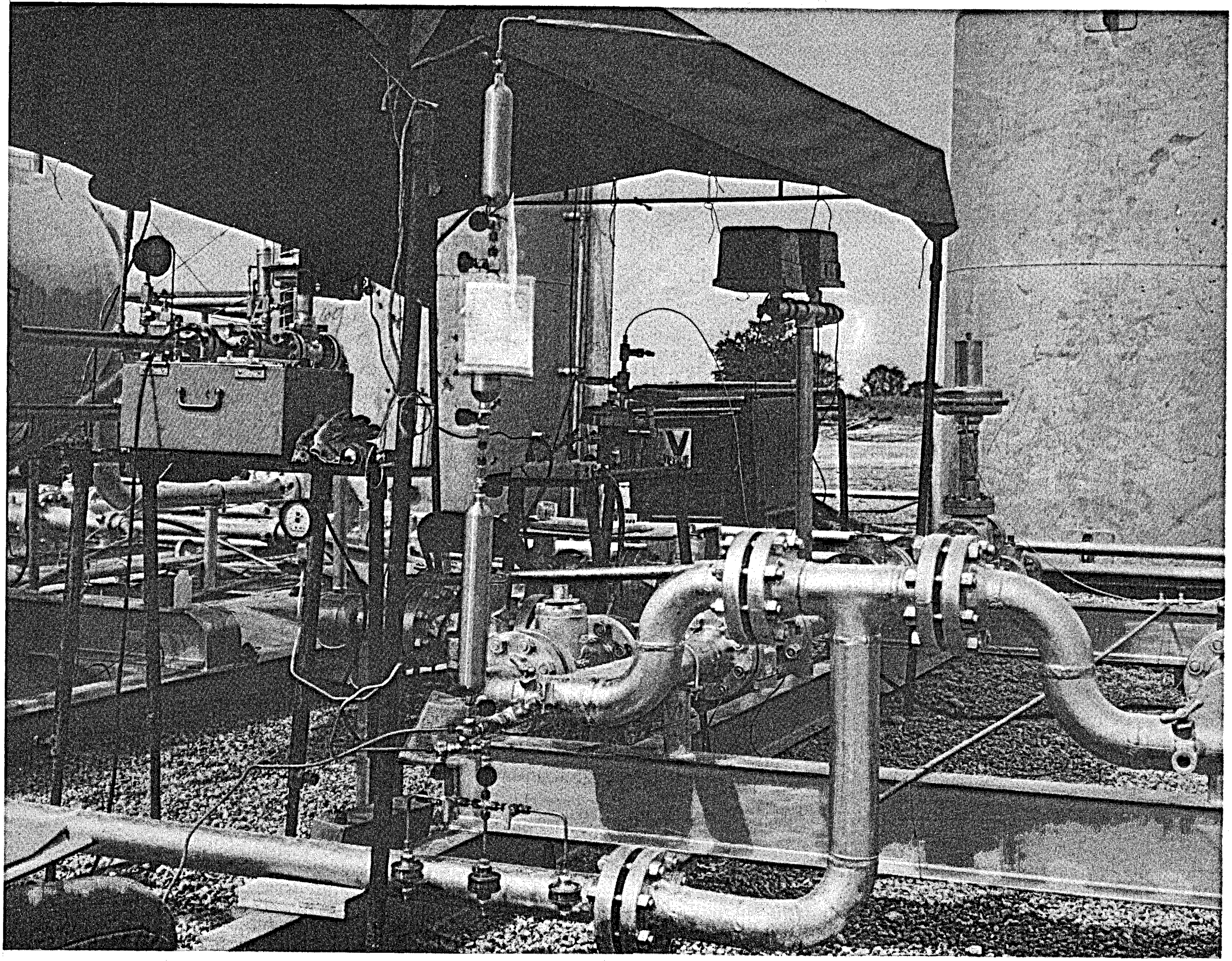


Photo 12-6 IGT disposal brine sampling point at center front

12.6.3.3 **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 of three right-angle changes in flow direction. The sampling point was at separator pressure. Sample collection and the 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 was hot to the touch.
- Closing the sample vessel outlet valve.
- Closing the sample vessel inlet valve.
- Closing the sample port valve.
- Disconnecting the sample vessel from the sampling point and immersing it in water until it was cooled to the field laboratory ambient temperature (about 25°C). Cooling by water immersion provided the advantage that any sample vessel exhibiting leakage by bubble formation could be rejected.
- After cooling, connecting the sample vessel to a 500-cc syringe, with less than 5 cc of air-filled dead volume in connecting tubing, fittings, and the syringe itself.
- Opening the sample vessel to allow gas flashed from brine in the pressure vessel to move vertically into the large syringe.
- Striking the cylinder repeatedly to ensure that the carbon dioxide had 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 12-18. Note that flashing and analysis for the sample collected at 1345 hours on 11/22/80 were performed in IGT's Chicago laboratories 7-1/2 weeks later.

Exhibit 12-18. ANALYSIS OF GAS FLASHED OFF BRINE AFTER SEPARATOR FROM THE RIDDLE-SALDANA WELL NO. 2

Sample Collection Date	11/17/80[1]	11/18/80[1]	11/21/80	11/22/80[2]	11/22/80[3]
Sample Collection Time	1140	1235	1615	1154	1345
Separator Pressure, psig	63.9	62.6	201	199	203
Brine Temperature, °F	171	187	210	215	216
Gas/Brine Ratio, SCF/bbl	0.32	0.31	2.04	0.73	1.59
Component, mol %					
Methane			50.8	52.2	58.6
Ethane			1.9	1.9	2.1
Propane			0.3	0.3	0.3
n-Butane			0.03	0.04	0.04
i-Butane			0.02	0.04	0.02
Pentanes			0.00	0.00	0.02
C_{6+}			0.02	0.02	0.24
Nitrogen			0.4	0.5	2.9
Carbon Dioxide			46.6	45.1	35.8

1 Insufficient gas sample; no analyses performed.

2 Cylinder leaked. (Pressure under Swagelok Cap.)

3 Cylinder flashed at IGT Chicago on 1/14/81; gas analyzed by mass spectrometry that same date.

Note: All samples analyzed on 1/14/81

12.6.3.4 **Gas Samples by Other Parties:** Several parties other than IGT collected and/or analyzed gas samples. Representatives of the following organizations collected their own samples on location.

- Weatherly Laboratories, Inc.
  Lafayette, La.
- McNeese State University
  Lake Charles, La.
- U.S. Geological Survey
  NSTL Station, Miss.
- U.S. Geological Survey
  Menlo Park, Calif.

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.

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

- **USGS Gulf Coast HydroScience Center:** Preliminary results from analyses of gas samples for radon 222 were provided in a letter from Mr. Thomas F. Kraemer dated January 22, 1981. A second letter, dated 4/22/81 provided final results of radioactivity analyses plus results of gas chromatograph and carbon isotope ratio analysis for one of these samples by Dr. George Claypool of the USGS, Denver. Results of these analyses are presented in Exhibit 12-19.

  Mr. Kraemer observed that the radon content of the samples analyzed is only about 10% of that from other geopressured-geothermal well tests. He has hypothesized that this low value may be associated with the existence of a free gas phase in the reservoir.

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

Exhibit 12-19. GAS ANALYSIS RESULTS REPORTED BY THE USGS HYDROSCIENCE CENTER

Date	Time	^{222}Rn Content (dpm/l at time of sampling)
11/20/70	17:20	17.3
11/21/80	12:22	20.9
11/21/80	16:00	18.2
11/22/80	10:00	17.4

Date	Time	Gas Composition: Component	Vol %
11/22/80	10:00	N_2	0.1
		CO_2	16.54
		Methane	79.23
		Ethane	3.91
		Propane	0.66
		n-Butane	0.11
		i-Butane	0.11
		n-Pentane	0.02
		i-Pentane	0.03

Carbon Isotope Ratio	
Methane $^{13}C/^{12}C$	-42.4 per mil

- **Reservoir Fluid Studies: Weatherly Laboratories (Mr. John Neal):** Weatherly Laboratories, Inc., collected samples of separator gas and brine between 1030 and 1330 hours on 11/20/80. Weatherly's complete report of analyses performed is provided in Appendix J. Only portions of that report most relevant to defining the quantity and composition of produced gases are discussed in the paragraphs below.

  Several samples of separator brine were flashed to 1 atm and 78°F. The average gas/brine ratio for samples collected at a separator pressure of 60 psig was found to be 0.8 SCF/bbl. Although the quantity of gas from each flash was too small for complete analysis, CO_2 content was estimated to be about 49%.

  Gas chromatograph analysis of a separator gas sample by Weatherly Laboratories provided results consistent with the average of IGT's field analyses of samples collected before and after sample collection by Weatherly. The most notable difference was in reported mole percents of ethane and propane in dry gas. IGT's values averaged 2.56 and 0.46 mole percent, respectively, whereas the Weatherly values were 2.33 and 0.36 mole percent. The reported values for CO_2 content were very close. Two IGT samples averaged 24.63 mole percent, whereas the Weatherly analysis yielded 24.00 mole percent.

  A total of 9 recombinations (two of which were discarded) were performed by Weatherly Laboratories at the reservoir temperature of 300°F reported by RDI. In units of standard cubic feet of separator gas at 14.65 psia and 60°F per barrel of separator brine at 60 psig and 145°F, observed bubble points ranged between extremes of 19.99 SCF/bbl at 2330 psia and 45.05 SCF/bbl at 8850 psia. With these units, the bubbles point at reservoir conditions was 39.45 SCF/bbl at 6633 ± 20 psia.

  Using Weatherly Laboratories, Inc. values for relevant brine volumes and gas content of separator brine, plus converting both gas and brine volumes to the pressure base of 14.73 psia and temperature base of 60°F used in this report, results in a total gas solubility of 40.86 SCF/STB.

  The sample recombined to a total gas content of 40.86 SCF/STB was used for a four-step differential liberation experiment. The composition and amount of gas liberated at each step are shown in Exhibit 12-20.

12.6.3.5 **Indications of Free Gas in the Reservoir:** The analytical results presented in the preceeding portions of Section 12.6.3 strongly suggest that production of gas in excess of solubility in reservoir brine began early in the test and increased stepwise when the production rate was increased on 11/21/80. Observations leading to this hypothesis are discussed below:

- **Comparison of Bottom-hole Sample Analysis and Recombination Studies:** The solubility 40.86 ± 0.5 SCF/STB found in recombination to reservoir temperature and pressure is 2.1 SCF/STB higher than that observed from flashing bottom-hole samples. However, this difference is due primarily to the different CO_2 contents measured. Exhibit 12-20a compares the amount of each gaseous species

Exhibit 12-20. GAS COMPOSITIONS DURING DIFFERENTIAL LIBERATION

Pressure Step, psia	6632-4000	4000-2500	2500-1000	1000-15
Total Gas, SCF/STB	6.8	7.7	10.8	17.0
Gas Composition, mol %				
CO_2	1.80	3.05	8.76	18.64
Methane	92.24	92.74	88.46	79.18
Ethane	4.43	3.44	2.44	1.85
Propane	0.96	0.54	0.26	0.10
n-Butane	0.19	0.07	0.02	0.01
i-Butane	0.18	0.07	0.02	0.03
n-Pentane	0.08	0.02	0.01	<0.01
i-Pentane	0.05	0.01	0.01	<0.01
Hexanes	0.03	0.01	0.01	<0.01
Heptanes+	0.04	0.05	0.02	0.19

for the bottom-hole samples and the recombination study. For this exhibit, the analyses of the two bottom-hole samples described in Exhibit 12-15 (Section 12.6.3.1) have been averaged and then normalized on a hydrogen- and nitrogen-free basis to be consistent with the normalization by Weatherly Laboratories, Inc. The comparison reveals that the hydrocarbon content of bottom-hole samples was actually slightly greater than at the bubble point during the recombination studies (31.4 SCF/STB vs. 31.1 SCF/STB). Agreement is within the limits of experimental accuracy for both measurements. It is therefore suggested that the apparent difference in gas solubility may be due primarily to loss of CO_2 by reactions inside the sample vessel.

EXHIBIT 12-20a. COMPARISON OF BOTTOM-HOLE SAMPLE AND RECOMBINATION GAS/BRINE RATIOS

	IGT		Weatherly Laboratories, Inc.	
	Bottom-hole		Recombination	
Gas Component	mol %	SCF/STB	mol %	SCF/STB
Total Gas	100	38.75	100	40.86
CO_2	18.95	7.343	24.00	9.806
Methane	78.60	30.458	73.06	29.852
Ethane	2.11	0.818	2.33	0.952
Propane	0.26	0.101	0.36	0.147
n-Butane	0.02	0.008	0.05	0.020
i-Butane	0.02	0.008	0.05	0.020
C5+	0.03	0.012	0.15	0.061
Hydrocarbon Gases	81.05	31.41	76.00	31.05

- **Increase in NGL Content:** The bottom-hole sample and the gas samples caught before producing a brine volume equal to the volume of the wellbore ("bottoms-up") contained only about 0.66 gallons of NGL per MCF of toal gas produced. However, gas samples caught during the 24 hours after bottoms-up contained 0.80 ± 0.03 gallons of ethane through pentane liquids per MCF. The content of these species had increased to more than 0.90 gallons per MCF before the production rate was increased on 11/21/80. All seven gas samples collected and analyzed after the rate increase on 11/21/80 contained more than 1.1 gallons of NGL per MCF.

Comparison of this increasing NGL content with analyses performed after each step in differential liberation reveals that the increase would be expected from production of free gas that had accumulated in the reservoir because of differential liberation in the tested reservoir of saturated brines migrating upward from much greater depth. For successive steps in differential liberation, the content of ethane through pentane liquids in liberated gas varied as follows:

Pressure Step, psia	Ethane Through Pentane NGL Content of Total Liberated Gas, gal/MCF
6632-4000	1.61
4000-2500	1.12
2500-1000	0.74
1000-15	0.54

The higher NGL content of free gas is considered in greater detail in Section 12.6.4.4.

- **Radon 222 Content of Produced Gas:** As previously observed, the radon 222 content of gas produced on 11/20/80 to 11/22/80 was in the range of 17.3 to 20.9 dpm/l at the time of sampling. This is only about one-tenth the concentration observed for prior geopressured-geothermal well tests. Mr. Thomas F. Kraemer of USGS has hypothesized that this low concentration may be due to radon exsolving from reservoir brine into an adjacent free-gas phase in the reservoir.

12.6.3.6 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. The data presented in Section 12.6.3 reveal modest day-to-day variations in composition, plus substantial changes in composition at "bottoms up" on the first day of production (11/16/80) as well as at the time of production rate and separator pressure increase on 11/21/80. Therefore, for calculations of production, separate compositions were selected for each of nine different time intervals, as shown in Exhibit 12-21.

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. For all times prior to the increase in production rate and separator pressure during 11/21/80, the value of 0.11 mole percent for C_{6+} was used on the basis of mass spectrometric analysis of the sample collected at 1040 hours on 11/18/80. The value of 0.24 mole percent used after the production rate and separator pressure increase is the average of values from mass spectrometric analyses of samples collected at 1600 hours on 11/21/80 and 1345 hours on 11/22/80.

EXHIBIT 12-21. GAS COMPOSITIONS FOR PRODUCTION CALCULATIONS

Date	11/16	11/16	11/17	11/18	11/19	11/20	11/21	11/21	11/22
Time	<2000	<2000					<1400	>1400	
Gas Composition, mol %									
N_2	0.20	0.19	0.32	0.19	0.18	0.18	0.08	0.09	0.08
CO_2	24.47	20.59	24.12	23.41	23.00	23.57	22.15	17.14	18.44
Methane	72.75	76.10	72.47	73.16	73.43	72.96	74.16	78.02	77.04
Ethane	2.10	2.49	2.45	2.56	2.66	2.58	2.80	3.44	3.23
Propane	0.31	0.43	0.43	0.46	0.50	0.48	0.56	0.83	0.75
n-Butane	0.03	0.04	0.04	0.06	0.05	0.05	0.06	0.10	0.09
i-Butane	0.02	0.04	0.04	0.04	0.05	0.05	0.06	0.10	0.09
Pentanes	0.01	0.01	0.02	0.01	0.02	0.02	0.02	0.04	0.04
C6+	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.24	0.24
NGL,gal/MCF	0.7099	0.8565	0.8495	0.8897	0.9311	0.9043	0.9913	1.3225	1.2381
Specific Gravity									
(Air = 1.0)	0.8094	0.7753	0.8108	0.8036	0.8006	0.8056	0.7936	0.7556	0.7660
Heating Value, Btu/SCF	790.5	835.4	798.4	808.3	814.3	807.6	826.3	893.3	877.0

12.6.4 Produced Gas and Gas/Brine Ratio

Sections 12.6.4.1 through 12.6.4.3 provide details of raw data interpretation to deduce flare line gas production, brine production, and the total produced gas/brine ratio. Values from a number of these intermediate steps are tabulated under the appropriate columns in Appendix K. Specific columns will be referred to in the detailed discussions in these first three sections. Sections 12.6.4.4 and 12.6.4.5 examine changes in gas/brine ratio in relation to producing conditions. Section 12.6.4.6 then presents the comparison of produced gas/brine ratio to laboratory data on gas solubility which concludes that hydrocarbon gas production was in excess of solubility in reservoir brine. In Section 12.6.4.7, the NGL content of free gas in the reservoir is deduced. Finally, Sections 12.6.4.8 and 12.6.4.9 examine the observed fluctuations in gas/brine ratio on a time scale of hours and conclude that these fluctuations are due to "pockets" of free gas within the reservoir.

12.6.4.1 Flare Line Gas Production: Flare line gas compositions representative of various time intervals during the test were selected as discussed in Section 12.6.3.6 and tabulated in Exhibit 12-21. The steps used to calculate the time dependence of gas production to the flare line, with those gas compositions, are as follows:

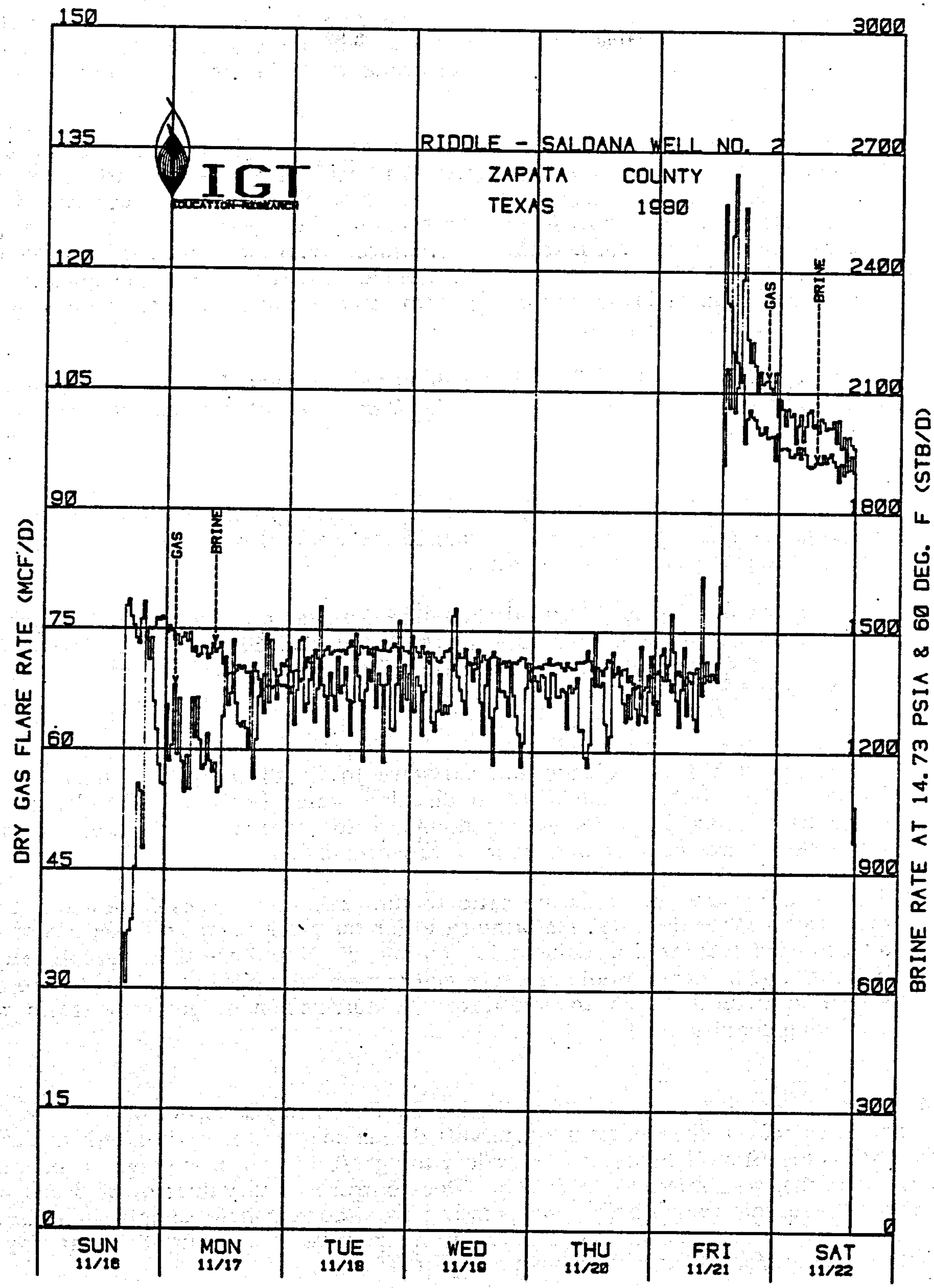
- Calculating the specific gravity and heating value for the average gas composition for each time interval, using methods prescribed in ANSI/ASTM D 3588-77. This ANSI/ASTM procedure assigns the physical properties of normal hexane to all C6+ hydrocarbons. The resulting calculated values are shown in Exhibit 12-21 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 methods prescribed in A.G.A. Gas Committee Measurement Report No. 3. Implementing this methodology requires values for super-compressibility ($F_{pv} = \sqrt{1/z}$). The values of z used for interpretation were calculated for various separator pressures and temperatures, using a computer program developed by IGT for a different project. Results of this calculation, 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 12-22.

- 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 AND BRINE PRODUCTION RATE

EXHIBIT 12-22

12.6.4.2 Brine Production Rate: Section 12.6.2.3 provided a comparison of all raw data on brine rates and described the successful development of a procedure for estimating brine production rate at separator pressure and temperature from two-phase wellhead turbine data. The brine production rate so estimated is believed to be a more accurate representation of actual well performance than the data recorded from the separator brine turbine.

For each 1/2 hour, the calculation of brine rate at separator pressure and temperature was performed by the same computer program that performed the gas production rate calculations described in the preceeding section. Inputs to each 1/2-hour calculation include dry gas flare rate as well as 1/2-hour averages for two-phase wellhead turbine rate, production wellhead pressure, separator pressure, and brine temperature. The half-hourly observed value for two-phase wellhead turbine rate is shown in the third column of Appendix K. Calculated brine rate at separator pressure and temperature is shown in the ninth column of that Appendix.

Brine rate at 14.73 psia and 60°F is then calculated for each 1/2-hour time interval. Results are tabulated in column 10 of Appendix K and presented graphically in Exhibit 12-22.

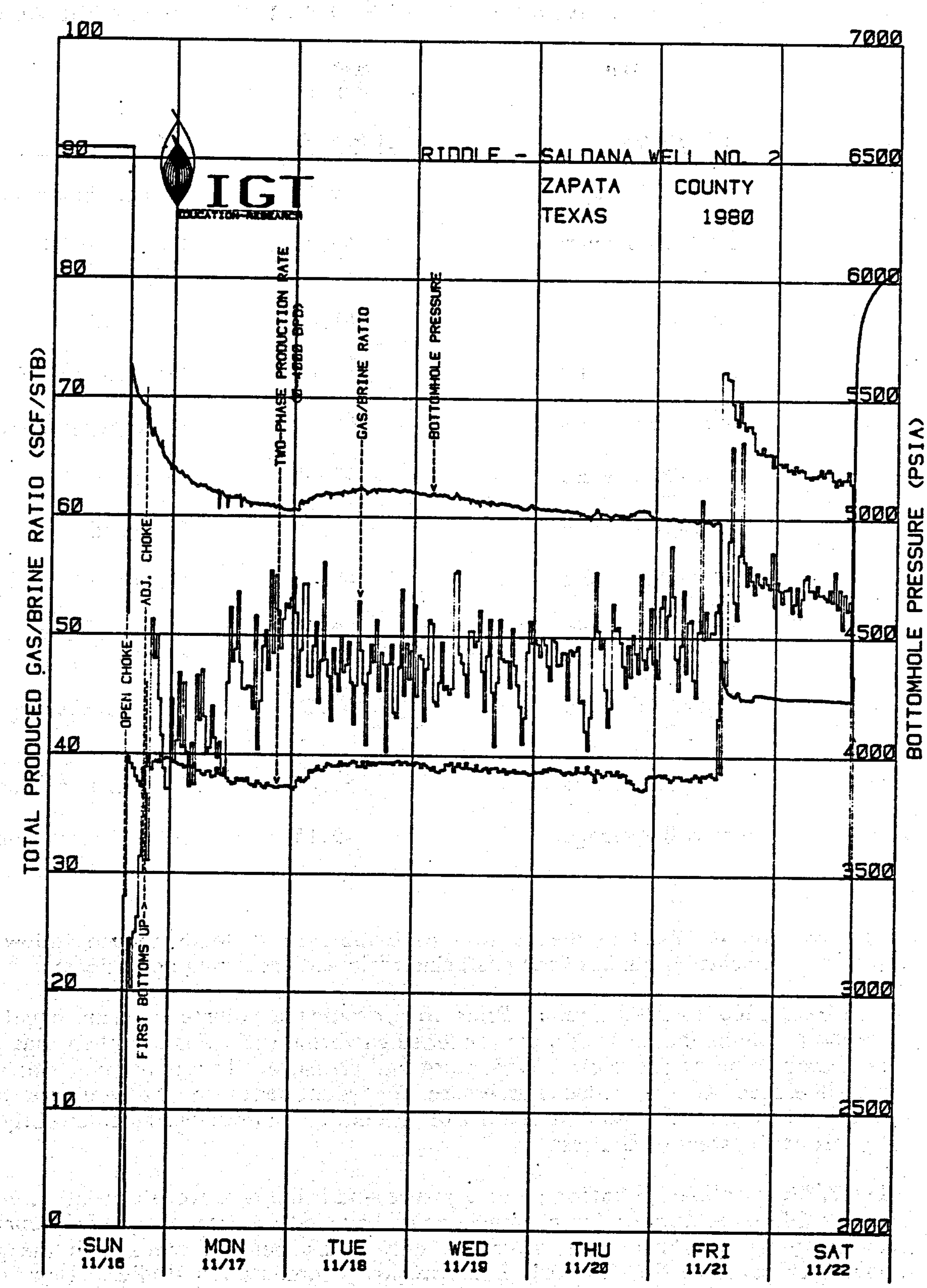
12.6.4.3 Produced Gas/Brine Ratio: Total produced gas is the sum of gas to the flare line plus gas remaining in solution in brine to the disposal well. Total produced gas has been estimated using the following steps:

- Dividing the previously discussed flare line dry gas production rate for each 1/2 hour by the 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 System Science and Software to fit the data of Culbertson and McKetta for methane solubility in distilled water (Ref. 6). Results of this calculation using 1/2-hour averaged values for separator pressure and brine temperature are reported in column 12 of Appendix K.

- 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 12-23. Bottom-hole pressure and two-phase wellhead flow rate are also shown in Exhibit 12-23 to facilitate the correlation of gas/brine ratio with producing conditions.

12.6.4.4 Correlation of Gas/Brine Ratio with Producing Conditions: Average gas/brine ratios for 11 different time intervals during the test are tabulated in Exhibit 12-24. After the first 21 hours of production, the gas/brine ratio, averaged over short-term fluctuations, was above 47 SCF/STB. This contrasts with values of 38.8 and 40.9 SCF/STB at reservoir temperature and pressure from bottom-hole sample analysis and Weatherly Laboratories recombination studies, respectively. During the last day of production, the gas/brine ratio was above 53 SCF/STB.



CORRELATION OF TOTAL PRODUCED GAS/BRINE RATIO
WITH BOTTOMHOLE PRESSURE AND TWO-PHASE FLOW RATE

EXHIBIT 12-23

Exhibit 12-24. AVERAGE GAS/BRINE RATIO FOR VARIOUS TIME INTERVALS

Date	Time Interval	Gas/Brine Ratio, SCF/STB	Comment
11/16/80	1600-2000 hours	29.14	Before "bottoms up"
11/16/80	2000-2400 hours	43.50	GWR peak after "bottoms up"
11/17/80	0000-1100 hours	41.69	No trend
11/17/80	1100-2400 hours	49.02	Increasing GWR
11/18/80	0000-1200 hours	48.74	Decreasing GWR
11/18/80	1200-2400 hours	47.04	No trend
11/19/80	0000-2400 hours	47.74	No trend
11/20/80	0000-2400 hours	48.25	No trend
11/21/80	0000-1400 hours	50.88	Before increasing rate
11/21/80	1400-2400 hours	54.24	After increasing rate
11/22/80	0000-1500 hours	53.66	Rest of flow test
	Overall Average	49.15	After bottoms up

Examination of Exhibit 12-23 in the context of Exhibit 12-24 leads to the following observations on the relationship between gas/brine ratio and producing conditions:

- **11/16/80,** 1600 to 2000 hours: Prior to producing a volume of brine equal to wellbore volume (bottoms up), the produced gas/brine ratio was less than that for saturated brine at reservoir temperature and pressure. This is normal, because gas liberated at the reduced pressure for each depth in the wellbore had migrated to the wellhead before start of production and was produced directly to the pit at the start of the test.

- **11/17/80:** Declines in bottom-hole pressure and brine rate were consistent with reasonable expectations for a homogenous, bounded sandstone aquifer. During the morning, gas/brine ratio averaged only a few percent more than the gas solubility revealed by Weatherly Laboratories recombination studies. However, for the latter half of this calendar date the overall trend in gas/brine ratio was an increase to about 52 SCF/STB. Allowing time for displacing of the wellbore, the increase in gas/brine ratio started when bottom-hole pressure was about 5200 psia. Whether the recorded small midday fluctuations in pressure and rate have any relationship with increased gas production is conjectural. However, the increased gas production did correlate with the largest sand detector reading observed during the test (about 1/3 the most sensitive scale for 1-1/2 hours with a decline to zero in about 5 more hours).

- **11/18/80 and 11/19/80:** At about 0100 hours on 11/18/80, both bottom-hole pressure and brine rate increased with no manual adjustments of surface conditions. These increases were accompanied by reversal in the trend of gas/brine ratio. The average of fluctuations, of 0.5 and 2 hours duration, dropped from about 52 to about 47 SCF/STB in 8 hours. One plausible explanation for this behavior is the beginning of flow of brine from previously plugged perforations.

  With the exception of roughly doubling the duration of fluctuations, gas/brine ratio remained about 47 to 48 SCF/STB through midnight of 11/19/80. Over a dozen 15-to-45-minute sand detector peaks to 15% to 30% of the most sensitive scale occurred on 11/19/80 but do not correlate with production fluctuations.

- **11/20/80 and AM of 11/21/80:** During the morning of 11/20/80 bottom-hole pressure dropped below its previous minimum of 5060 psia and increase of gas/brine ratio resumed. Overall gas/brine ratio for 11/20/80 had increased to 48.25 SCF/STB from the low of 47.07 recorded 2 days earlier. The next morning (11/21/80), the average was up to 50.88 SCF/STB.

  During the evening of 11/20/80, a 3-hour fluctuation in bottom-hole pressure and brine rate due to reservoir phenomena was observed. With allowance for time for travel up the wellbore, the pressure drop and brine rate increase correlate with the 3 hours of gas/brine ratio in excess of 50 SCF/STB early on 11/21/80. In contrast, most of the shorter-term positive spikes in bottom-hole pressure appear to correlate with peaks in gas/brine ratio at the wellhead. Thus, these may be caused by the response of the choke to increased gas content.

- **11/21/80 PM and 11/22/80:** At about 1300 hours on 11/21/80, the choke was opened wider to increase flow rate. The resultant drop in bottom-hole pressure to about 4250 psi was accompanied by an increase in produced gas/brine ratio to an average of 54.24 SCF/STB for the remainder of that calendar date. For the 15-1/4 hours of production before the well was shut in on 11/22/80, the gas/brine ratio was dropping slowly but still averaged 53.66 SCF/STB.

The overall average gas/brine ratio, between "bottoms up" after first opening the choke on 11/16/80 and shut-in of the test on 11/22/80, was 49.15 SCF/STB. This is 8.3 SCF/STB greater than the solubility at reservoir conditions determined by recombination studies. During that time, 8886 STB of brine were produced. Thus the produced volume of gas in excess of solubility in the volume of produced brine was about 74 MCF.

Since no dry gas production had ever occurred from any depth in this well, and since less than 1000 barrels of total brine had been produced in both prior testing by Riddle Oil Company and during well cleanup after perforating, a gas volume of 74,000 SCF could not possibly have accumulated in the vicinity of the wellbore due to such activities. We are therefore forced to conclude that gas in excess of that soluble in reservoir brine, free gas, exists in the reservoir.

12.6.4.5 Total Produced Gas/Brine Ratio from Flashing of Wellhead Samples: The Gas Research Institute-funded IGT program "Gas Saturation in Formation Waters" includes development of an "isokinetic sampling" technique for representative sampling of multiphase flow at wellhead pressure. The intent is to withdraw a small fraction of the wellhead flow stream using a concentric sampling tube in a region of highly turbulent flow.

Although operation was outside design criteria for the low flow rate and low wellhead pressure at the Saldana well test, 23 samples were caught and flashed to 1 atmosphere while flowing at about 1500 bbl/day. Resultant gas/brine ratios are shown in relation to the produced gas/brine ratio from the test data in Exhibit 12-25. Nine of the flashes of wellhead samples revealed gas/brine ratios in close agreement with the previously discussed analysis. However, a comparable number revealed ratios about 20% higher. The remaining flash results were all high and between these extremes.

Meaningful conclusions about well performance from these data are not possible due to lack of understanding of the reason for the 20% variation. However, the results are encouraging with respect to further refinement of hardware for matching of flow rates into and around the sampling probe, elimination of the small high-pressure valve before the sample collection chamber, and the future use of the equipment on wells capable of flowing at rates high enough to provide the required turbulence at the sampling point.

12.6.4.6 Comparison of Laboratory and Field Data on Hydrocarbon Solubility: The following paragraphs present comparisons of previously presented bottom-hole sample and recombination study results with solubility estimates based upon laboratory work on solubility of pure methane in sodium chloride brine. Flared hydrocarbon production is then discussed in relation to this comparison.

Exhibit 12-26 provides a tabulation of results from bottom-hole sample flashing and recombination of separator fluids plus values calculated from three procedures developed to fit laboratory data on methane solubility in sodium chloride brine. Note that the new Blount equation (Ref. 29), based upon his 1981 re-evaluation of his data, has been used.

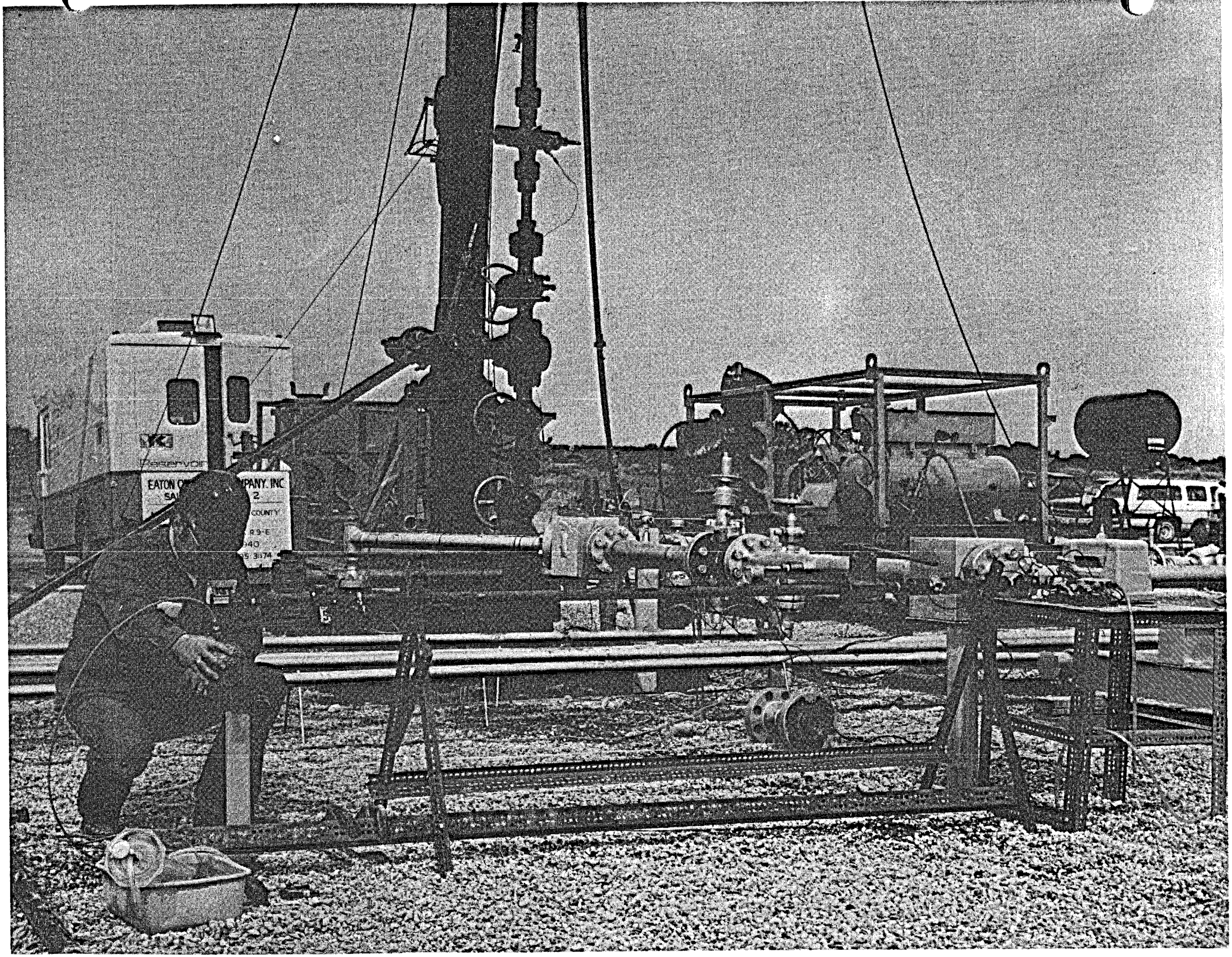
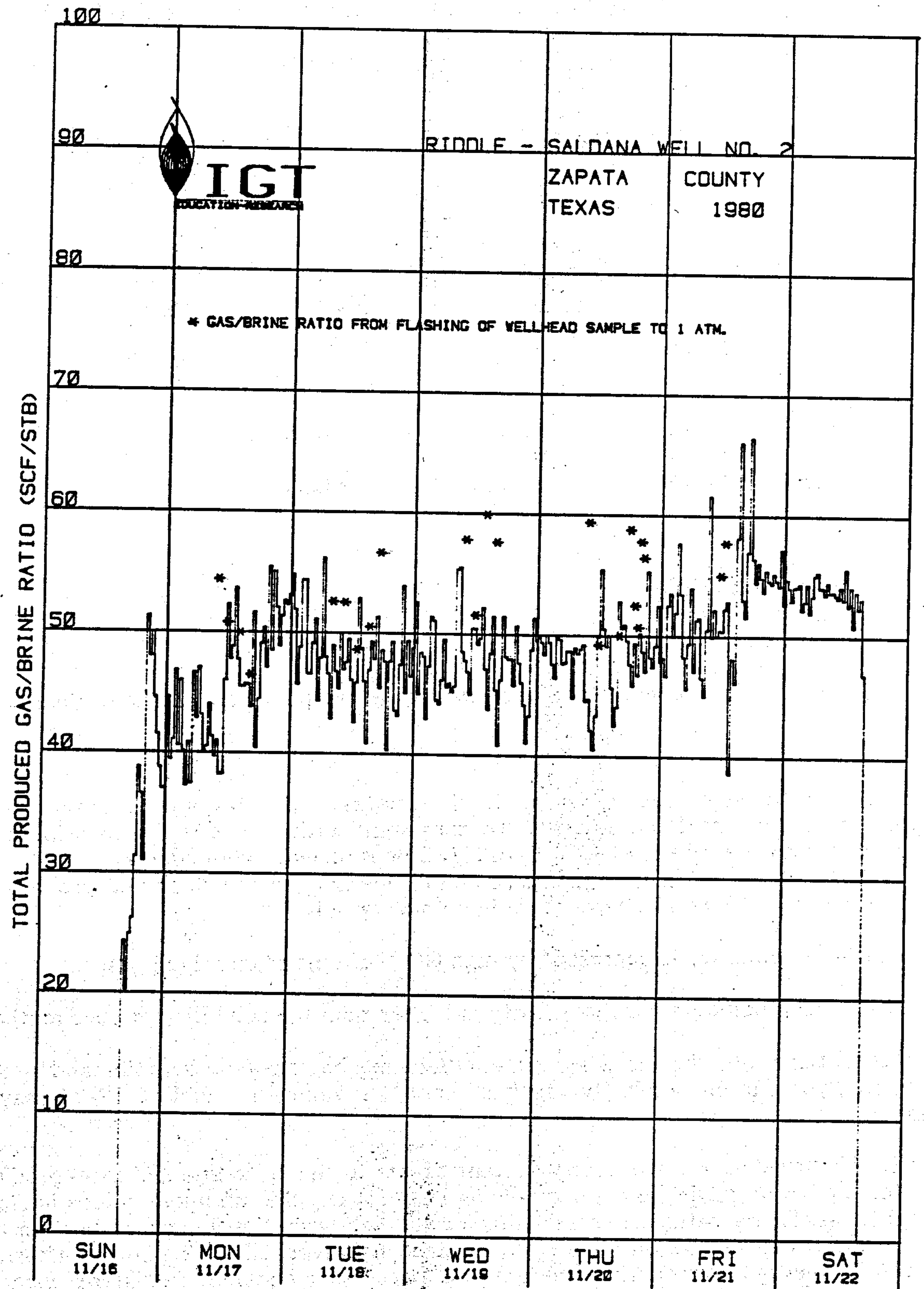


Photo 12-7 Experiment in progress with "Isokinetic sampling" apparatus



COMPARISON OF PRODUCED GAS/BRINE RATIO WITH RATIO OBTAINED FROM FLASHING WELLHEAD SAMPLES TO 1 ATMOSPHERE

EXHIBIT 12-25

Exhibit 12-26. GAS SOLUBILITY AT RIDDLE-SALDANA WELL No. 2

RESERVOIR CONDITIONS*

	Riddle-Saldana Brine and Gas		Laboratory H_2O, NaCl, CH_4 System		
	Bottom-hole Samples	Recombination Studies	S^3 Algorithm	Haas Procedure	Blount 1981 Equation
All Components	38.75 **	40.86	33.58	34.84	37.97
Hydrocarbon Portion	31.41	31.05	33.58	34.84	37.97
Methane Content	30.46	29.85	33.58	34.84	37.97

* Salinity = 12,800 mg/l
Pressure = 6630 psia
Temperature = 300°F.

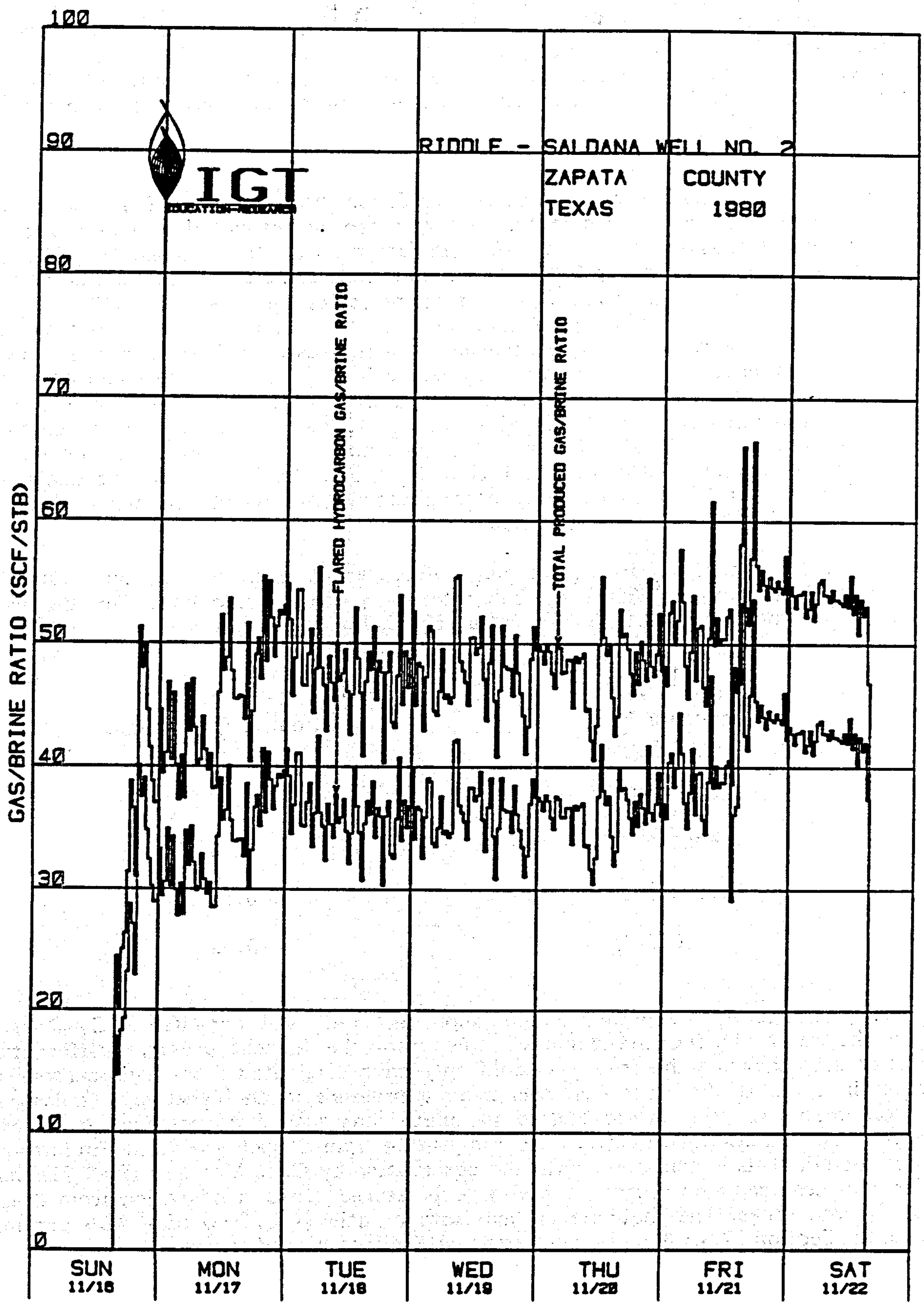
** Additional CO_2 stayed in the brine when the samples were flashed. (See Section 12.6.5.5).

The departures between results from field samples and all computational fits to laboratory studies on idealized systems are consistent with trends shown in preliminary laboratory work on the effect of CO_2 by C. W. Blount (private communication). At 5000 psi and 302°F, he has observed that more than 20% CO_2 in the dissolved gas has the following effects in a 5 weight percent sodium chloride solution:

- Methane solubility is depressed by high CO_2 content of dissolved gas.
- Total gas, including CO_2, solubility is higher than the solubility of pure methane.

These observations plus the close agreement between bottom-hole samples and recombination on hydrocarbon solubility, suggest that all values in Exhibit 12-27 may be reasonable.

Exhibit 12-27 shows both hydrocarbon content of gas to the flare line and total produced gas. After a peak in gas/brine ratio following bottoms up, the minimum values in flared hydrocarbon gas/brine ratio are reasonably consistent with the values of bottom-hole sample flash and recombination results for 1/2 day. However, beginning on the afternoon of 11/17/80, average hydrocarbon content of flared gas became consistent with the higher values from laboratory studies of pure methane solubility. During



TOTAL PRODUCED AND FLARED HYDROCARBON GAS/BRINE RATIOS

EXHIBIT 12-27

the 24 hours of production after bottoms-up following the rate increase on 11/21/80, the flared hydrocarbon gas/brine ratio remained consistently above the highest values tabulated in Exhibit 12-26. It is highly unlikely that errors in lab or field work are large enough for flared hydrocarbons to be consistent with production of only solution gas. Thus we conclude that the free gas phase in the reservoir was clearly evident in the last 24 hours of production.

12.6.4.7 NGL Content and Source of Free Gas in the Reservoir: The C_2-C_5 NGL content of free hydrocarbon gas in the reservoir can be estimated by comparing the results of the bottom-hole sample analysis with data from the four gas samples collected and analyzed in the field on 11/22/80. The bottom-hole samples contained 0.80 gallons C_2-C_5 per MCF of C_1-C_5. Their C_1-C_5 gas/brine ratios averaged 31.3 SCF of C_1-C_5 per barrel. Thus each barrel of brine contained 31.3 SCF of C_1-C_5 gas, which in turn contained 0.025 gallons of C_2-C_5 hydrocarbons. In contrast, the four flare line samples on 11/22/80 contained 1.40 gallons of C_2-C_5 per MCF of C_1-C_5 and contained 43.4 SCF of C_1-C_5 per barrel of brine. Thus, each barrel of produced brine contained 43.4 SCF of C_1-C_5, which in turn contained 0.061 gallons of C_2-C_5 NGL. Assuming the incremental C_1-C_5 gas and included C_2-C_5 NGL are a free gas phase in the reservoir, each barrel of brine produced on 11/22/80 contained 12.1 SCF of such gas, which in turn contained 0.036 gallons of such NGL. Thus, the free gas phase appears to contain 3.0 gallons of C_2-C_5 NGL per MCF of C_1-C_5 hydrocarbons.

The C_2-C_5 NGL content of C_1-C_5 gases liberated in each of the four steps of differential liberation by Weatherly Laboratories has been calculated for the data previously presented in Exhibit 12-20 (Section 12.6.3.4). The results are:

Pressure Step, psia	C_2-C_5 NGL Content of C_1-C_5 Gas, gal/MCF
6632-4000	1.64
4000-2500	1.16
2500-1000	0.81
1000-15	0.66

The difference between the estimated 3.0 gallons of C_2-C_5 NGL per MCF of C_1-C_5 free gas in the reservoir and the value of 1.64 from the highest pressure differential liberation step suggests the free gas could only have originated from hydrocarbons in solution in brine if the liberation was from a pressure much higher than measured reservoir pressure. It is interesting to speculate that such a phenomenon may have occurred in conjunction with upward brine migration from a much greater depth into the aquifer tested. This is consistent with the observation by C. S. Mathews (Ref. 21) that by far the most common source of gas in geopressured zones is migration from deep-seated source rocks. The methane carbon isotope ratio ($^{13}C/^{12}C$) of - 42.4 per mil reported in Section 12.6.3.4 is also consistent with a deep-seated source.

12.6.4.8 **Fluctuations in Gas/Brine Ratio:** The ±10% fluctuations in gas/brine ratio on a time scale from tens of minutes to a few hours is a surprising characteristic of this well. Prior use of the same test equipment, instrumentation, and data processing on the P. R. Girouard and G. M. Koelemay well tests did not reveal such fluctuations. The following paragraphs describe evaluations that strongly suggest that the fluctuations are not caused by phenomena occurring in the surface test equipment.

One obvious question is whether the fluctuations are caused by operation of the back-pressure regulator and dump valve on the separator. Exhibit 12-28, Parts 1 and 2, are from a strip chart recording of separator pressure and orifice differential pressure. Part 1 covers the time interval between 0700 and 1100 hours on 11/21/80. At this time, separator pressure was about 60 psig, and brine rate was about 1400 STB/day. Part 2 covers 1400 to 1800 hours on that same date. This time interval is after increasing production rate and separator pressure to about 2200 STB/day and 200 psig. Both time intervals include fluctuation in gas/brine ratio that exceed 10 SCF/STB. It is apparent from both of these figures that multiple changes in separator control valve settings occurred during the excursion in differential pressure due to increased gas production.

The apparent control operation in Exhibit 12-28 is that of the back-pressure control on the flare line. It is doubtful whether brine dump-valve throttling has clear signature on these data traces. One means of examining whether brine level changes in the separator caused fluctuations in gas/brine ratio is the following:

- At the normal brine level in the separator, a level change of 1 inch would change gas volume at separator temperature and pressure by 2.9 ft^3. Observation of the sight glass on the separator revealed that brine-level fluctuations were generally less than this amount. At 60 psig, only 14.5 SCF of gas would be displaced from the separator by a 1-inch increase in brine level. At 200 psig, as much as 52 SCF could be displaced by such a level change. However, the gas volume required to increase the GWR by 10 SCF/STB for 1/2 hour is about 310 SCF for a brine rate of 1500 STB/day and 450 SCF for a brine rate of 2200 STB/day. Since these volumes are roughly 10 times the gas displaced from the separator by a 1-inch increase in brine level, such level changes cannot be the reason for observed fluctuations in gas/brine ratio.

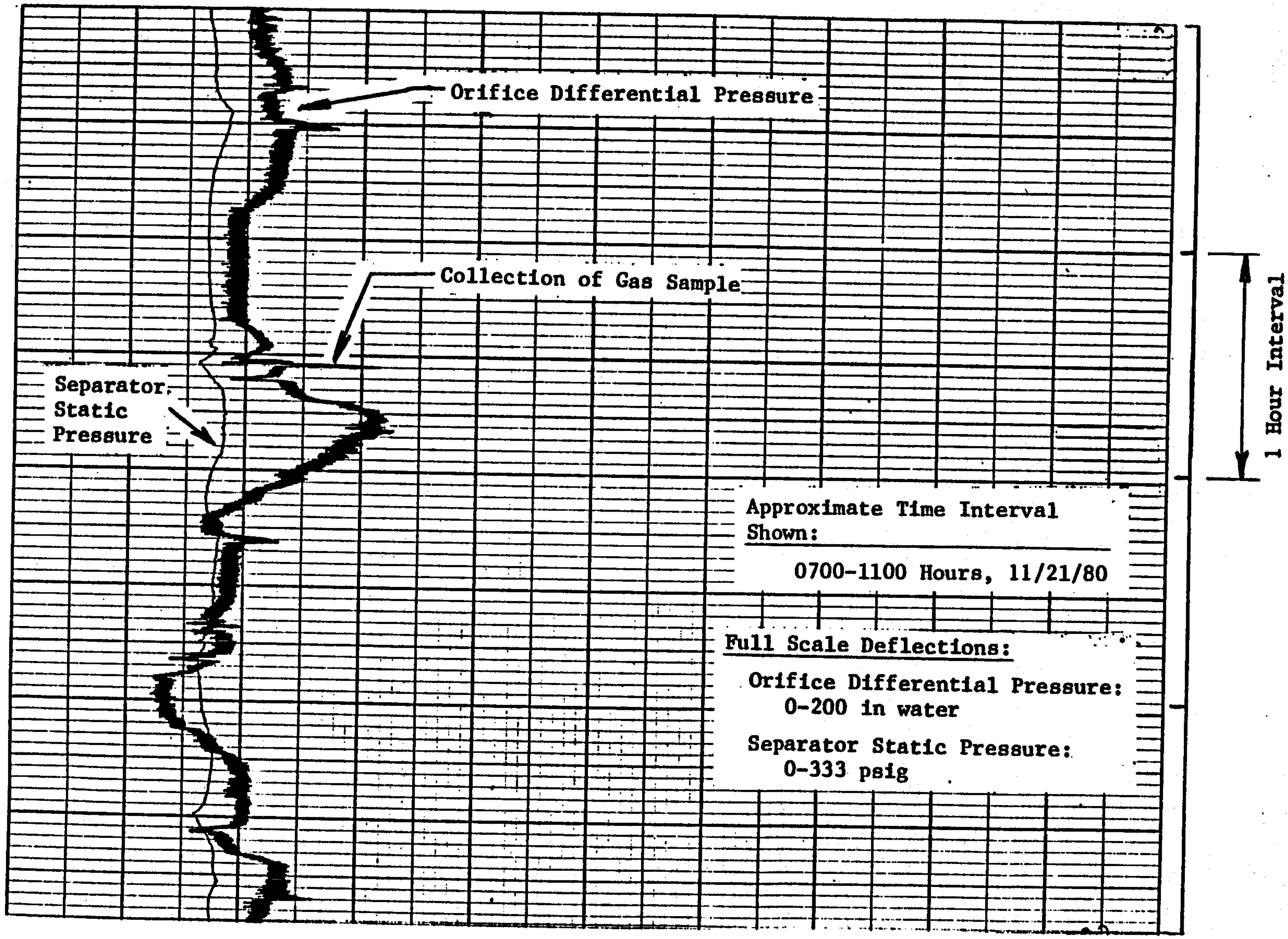
Additional examination of fluctuations in gas/brine ratio was performed by use of weighted moving averages to smooth the fluctuations in calculated 1/2-hour averages. Two smoothing functions were used. Using R to denote gas/brine ratio and the subscript "i" to denote the time interval in question, the functions were the following:

- Smoothed $R_i = \frac{1}{2}(0.5R_{i-1} + R_i + 0.5R_{i+1})$ and

- Smoothed $R_i = \frac{1}{3}(0.25\,R_{i-2} + 0.75R_{i-1} + R_i + 0.75R_{i+1} + 0.25R_{i+2})$

Values calculated for each 1/2 hour of production using these smoothing functions are tabulated in Appendix L.

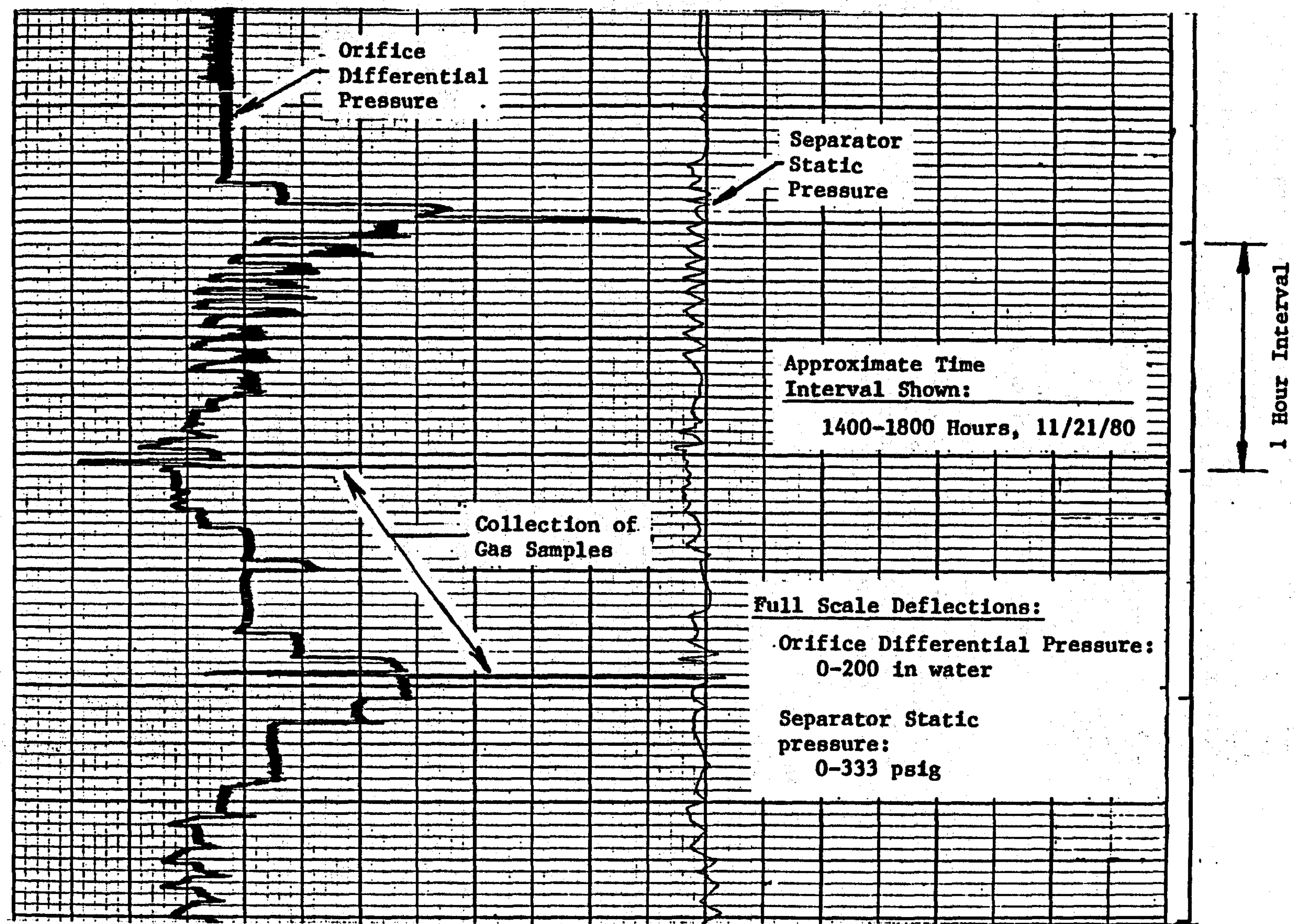
EXHIBIT 12-28, Part I



FIELD STRIP CHART RECORDING OF SEPARATOR PRESSURE AND ORIFICE DIFFERENTIAL PRESSURE

Part I: 0700 to 1100 hours, 11/21/80

EXHIBIT 12-28, Part II



FIELD STRIP CHART RECORDING OF SEPARATOR PRESSURE AND ORIFICE DIFFERENTIAL PRESSURE

Part II: 1400 to 1800 hours, 11/21/80

Exhibit 12-29 shows the effect of the second (5 time interval) smoothing function in comparison with calculated 1/2-hour values of gas/brine ratio and the electronically digitized raw data values of orifice differential pressure. The 2-day interval selected for this graphical presentation includes the rate change on 11/21/80. Examination of this figure leaves little doubt that the 1/2-hour fluctuations in gas/brine ratio are a reasonable representation of gas flow through the orifice meter. Smoothing with weighted moving averages eliminates sharp fluctuations that are probably real.

12.6.4.9 Correlation of Gas/Brine Ratio Fluctuations with Gas Composition: Whether or not the fluctuations in gas/brine ratio originated in the reservoir has been addressed by examining the composition of individual gas samples. Emphasis has been placed upon the most reliable data by considering only the methane through pentane components of samples analyzed using the field gas chromatograph.

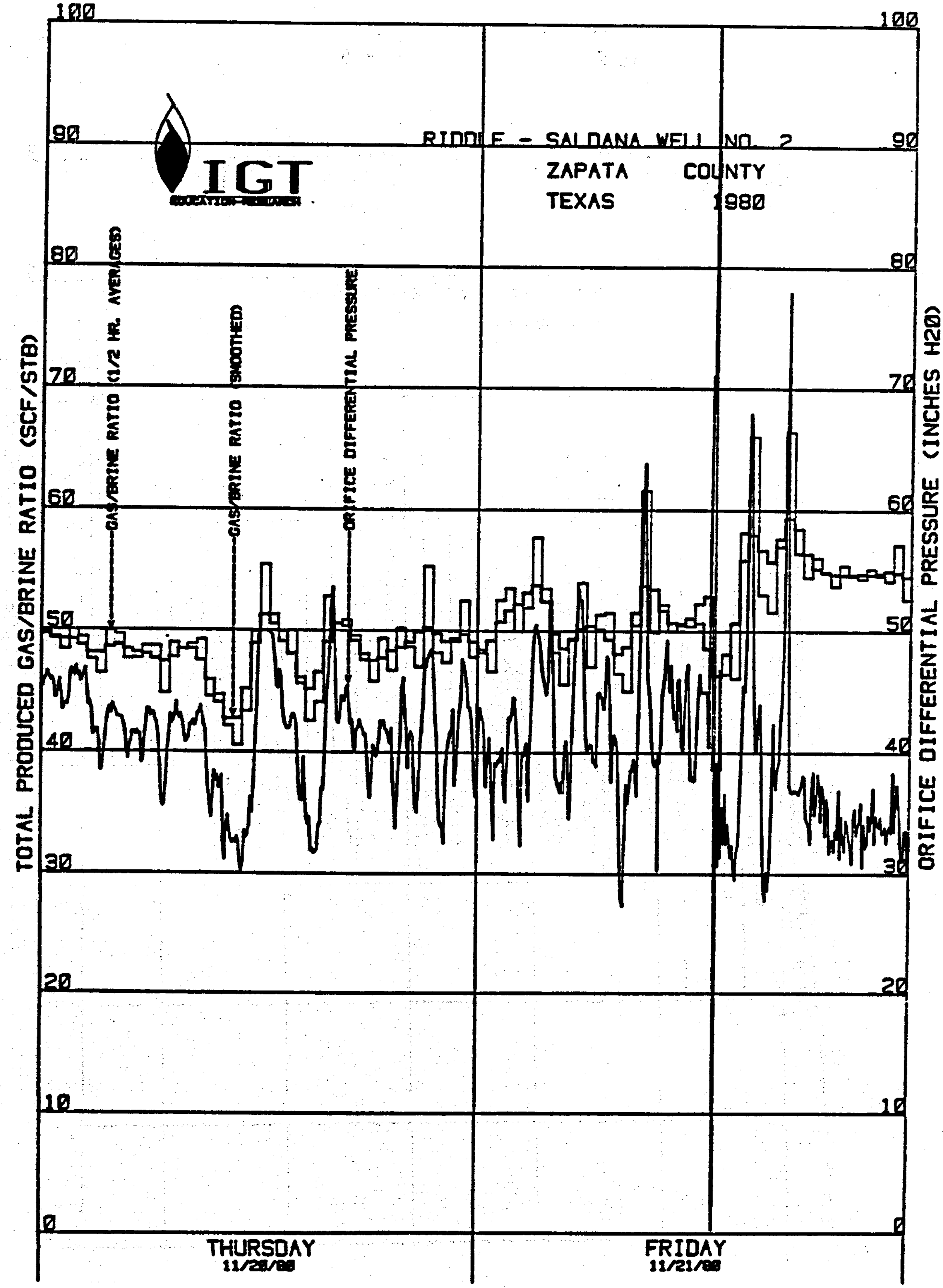
Exhibit 12-30 shows flared hydrocarbon gas/brine ratio plus the ethane through pentane NGL content of all samples presented in Section 12.6.3.2. The larger NGL content for each sample is due to renormalizing the field gas chromatograph analyses on Exhibit 12-16, (Section 12.6.3), such that only the hydrocarbon gases from methane through pentane are considered (i.e., the points in Exhibit 12-30 are normalized on a CO_2, N_2, C_{6+} free basis).

On this same basis, the NGL content of the two bottom-hole samples averaged 0.80 gallons/MCF. The flare line sample collected before bottoms-up (1800 hours on 11/16/80) had an NGL content of 0.864 gal/MCF. This is reasonably close to the values for the bottom-hole samples. However, gas samples caught during the 12 hours after bottoms-up contained 1.03 gallons of ethane through pentane (C_2-C_5) liquids per MCF of methane through pentane (C_1-C_5) hydrocarbons in the sample. The content of these species had increased to more than 1.20 gallons of C_2-C_5 per MCF of C_1-C_5 before the production rate was increased on 11/21/80. All seven gas samples collected and analyzed after the rate increase on 11/21/80 contained more than 1.4 gallons of C_2-C_5 NGL per MCF of C_1-C_5 hydrocarbons. Thus, the higher the gas/brine ratio, the higher the NGL content.

Close examination of Exhibit 12-30 reveals this generalization to be true for gas/brine ratio fluctuations during each day as well as for the overall trend. It therefore appears likely that the fluctuations in gas/brine ratio actually originated in the reservoir.

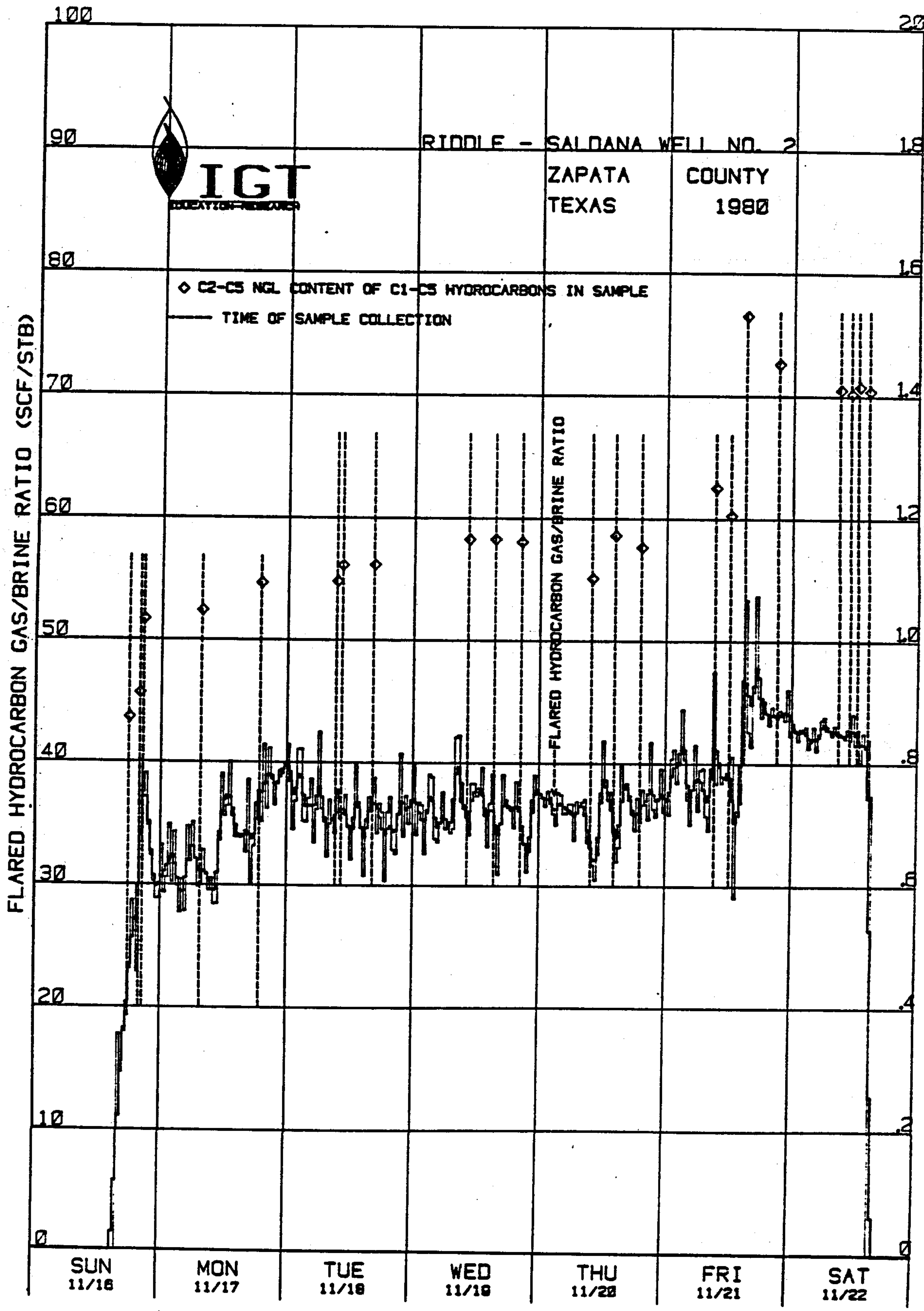
One possible mechanism for the fluctuations to originate in the reservoir is gas accumulation in small "pockets" characterized by lower capillary pressure (i.e., larger pore throats) than surrounding reservoir rock. The size of such "pockets" can be estimated from the surplus gas in a single positive fluctuation in gas/brine ratio.

The volume of gas produced during a 2-hour, positive, 5 SCF/STB fluctuation in gas/brine ratio, while producing at a 1500-bbl/day rate, is 625 SCF. Assuming this gas comes from 1500 psi drawdown of a gas-filled porosity of 8%, the 625 SCF of produced gas would have originated from a "pocket" having a volume of about 100 cubic feet of reservoir rock.



CORRELATION OF 1/2-HOUR AND WEIGHTED MOVING AVERAGES FOR PRODUCED GAS/BRINE RATIO WITH ORIFICE DIFFERENTIAL PRESSURE

EXHIBIT 12-29



CORRELATION OF C2-C5 NGL CONTENT OF C1-C5 HYDROCARBONS IN FLARE LINE GAS SAMPLES WITH FLARED HYDROCARBON GAS/BRINE RATIO

EXHIBIT 12-30

When such "pockets" are combined with previous observations and conclusions, the emerging reservoir model exhibits the following characteristics:

- Produced gas is thermogenically mature and probably originated at much greater depth.
- The estimated NGL content of free gas (3.0 gal C_2-C_5/MCF C_1-C_5) may be that for differential liberation from saturated brine from much greater depth.
- Multiple small accumulations (a few MCF each) of free gas existed in the vicinity of the wellbore prior to start of brine production.

At the same time, many questions cannot be resolved with the limited data and ancillary investigation possible within the cost constraints on this test. Among these are:

- Whether continuing drawdown would have ultimately provided commercially interesting production rates (as occurred on the test of the Lear G. M. Koelemay No. 1 Well).
- Whether the "pockets" of gas reflect only critical gas saturation or contain regions of higher gas content.
- Whether reservoir heterogeneity in pore throat sizes over distances of 10's of feet can indeed result in capillary pressure drive of diffusion to create gas "pockets" that are stable over geologic time.
- Whether shale stringers or CO_2 have a role in controlling producing characteristics.

12.6.5 Brine Sample Collection and Analysis

Sections 12.6.5.1 through 12.6.5.3 provide details of bottom-hole brine samples, post-separator brine sampling by IGT, and brine samples collected and analyzed by other parties. Section 12.6.5.4 provides an overview discussion of analytical results. Finally, unique characteristics of this well related to carbon dioxide and sulfur are discussed in Sections 12.6.5.5 and 12.6.5.6.

12.6.5.1 Bottom-hole Samples: Two samples were successfully collected from a depth of 9743 feet (2 feet above the top perforation) on 11/13/80, before the start of production testing. After transport to IGT, the samples were flashed to separate gas from brine on 11/20/80 and 11/21/80, as previously described in Section 12.6.3.1. In this report the word "flash" refers to reducing pressure to ambient atmospheric pressure, without regard to temperature.

The brine from both samplers was found to be dark and murky because of a black precipitate, but the second was less dark than the first. The precipitate was still present after the pH was lowered to about 0.5 and raised to about 10 by adding nitric acid and sodium hydroxide, respectively. All of the brine analyses on the downhole samples were done on portions acidified with nitric acid and then filtered, except for the analysis of acid-liberated CO_2. The CO_2 analysis was done on an unfiltered portion made basic with sodium hydroxide to avoid CO_2 loss prior to acid liberation. Laboratory analysis procedures were as set forth in Appendix M. Results of these analyses are tabulated in Exhibit 12-31.

Exhibit 12-31. BRINE ANALYSIS RESULTS FOR BOTTOMHOLE SAMPLES COLLECTED 11/13/80 AND FLASHED 11/20/80 AND 11/21/80

Component	Sample No. 1	Sample No.2	Component	Sample No. 1	Sample No. 2
Suspended Solids, mg/l	112	118	Cr, µg/l	250	250
Acid-Liberated CO_2, mg HCO_3^-/l	3270	3090	Cu, µg/l	110	126
SiO_2, mg/l	150	190	Fe, mg/l	166	55
Cl^-, mg/l	6500	6400	Hg, µg/l	3.8	2.1
F^-, mg/l	1.9	1.6	K, mg/l	26	26
$SO_4^=$, mg/l	36	36	Mg,mg/l	7.8	7.6
As, µg/l	6.0	3.1	Mn, mg/l	1.04	0.58
B, mg/l	38	89	Na, mg/l	4600	4700
Ba, mg/l	15.9	3.6	Pb, µg/l	260	450
Ca, mg/l	55	58	Sr, mg/l	7.6	6.8
Cd µg/l	3.4	20.2	Zn, mg/l	0.82	1.14

12.6.5.2 **Separator Output Sampling:** Surface samples for brine analysis were collected from a tap off the inlet to the brine metering skid. This tap was downstream from the separator vessel, by about 15 feet of 3-inch piping, and upstream of the separator dump valves. The sampling point was at the same pressure and temperature as the separator.

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.

Complete laboratory analyses were performed on three samples selected from the beginning, midpoint, and end of the test sequence. Results from daily field analyses beginning 14 hours after bottoms-up, plus the three complete laboratory analyses, are shown in Exhibit 12-32.

RESULTS OF ANALYSIS OF POST-SEPARATOR BRINE FROM THE RIDDLE-SALDANA WELL #2

	Units	17 Nov 80 1025	18 Nov 80* 1135	19 Nov 80* 1256	20 Nov 80 1116	21 Nov 80* 1603	22 Nov 80 1137	Estimated Analytical Accuracy	Mean	Standard Deviation
Temperature	°C	75	83	85	86	95	95	1	86.5	7.0
pH	-	6.5	6.6	6.7	6.6	6.3	6.3	0.1	6.5	0.2
Specific Conductance	µmhos/cm @ 25°C	18,300	18,300	18,400	18,000	18,200	18,200	100	18,200	125
Suspended Solids	mg/ℓ	135	139	117	71	82	82	1	104	27
Dissolved Solids	mg/ℓ	13,100	12,500	13,300	12,700	12,700	12,400	100	12,800	320
Alkalinity	mgHCO_3^-/ℓ	1,730	1,660	1,650	1,660	1,600	1,610	10	1,650	40
Total CO_2	mgHCO_3^-/ℓ	2,080	2,140	2,160	2,120	2,440	2,470	10	2,240	160
NH_3	mg/ℓ	12	12	12	11	11	11	1	11.5	0.5
SiO_2	mg/ℓ	120	140	130	130	130	120	10	128	7
Cl^-	mg/ℓ	6,700	6,600	6,800	6,700	6,500	6,500	100	6,630	110
F^-	mg/ℓ	1.6			1.6		1.7	0.1	1.6	
S^{2-}	mg/ℓ	<0.5	<0.2	<0.2	<0.2	<0.2	<0.2	0.2	<0.2	
SO_4^{2-}	mg/ℓ	35			32		31	1	33	
As	µg/ℓ	<1.6			<1.6		<1.6	2	<1.6	
B	mg/ℓ	90			86		88	1	88	
Ba	mg/ℓ	8.0			8.1		7.8	0.5	8.0	
Ca	mg/ℓ	50			48		48	1	49	
Cd	µg/ℓ	2.9			0.3		0.9	0.1	1.4	
Cr	µg/ℓ	41			< 5		46	5	<31	
Cu	µg/ℓ	13			< 1		2	1	< 5	
Fe	mg/ℓ	21			6.7		3.4	0.1	10.4	
Hg	µg/ℓ	1.1			1.6		3.4	0.1	2.0	
K	mg/ℓ	24			25		24	1	24	
Mg	mg/ℓ	7.0			7.4		6.7	0.1	7.0	
Mn	mg/ℓ	0.33			0.19		0.11	0.01	0.21	
Na	mg/ℓ	4,620			4,620		4,630	10	4,620	
Pb	µg/ℓ	11.8			5.9		0.9	0.2	6.2	
Sr	mg/ℓ	6.4			6.2		6.4	0.1	6.3	
Zn	mg/ℓ	0.31			0.5		<0.03	0.01	<0.13	

*Field Analyses only.

12.6.5.3 **Brine Samples by Other Parties:** Representatives of the following organizations collected brine samples on location:

- Weatherly Laboratories
  Lafayette, La.
- McNeese State University
  Lake Charles, La.
- U.S. Geological Survey
  Menlo Park, Calif.
- U.S. Geological Survey
  NSTL Station, Miss.
- Matson and Associates
  Houston, Texas

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 in Appendix I.

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

- **USGS Gulf Coast HydroScience Center:** Letters from Thomas F. Kraemer dated January 22, 1981, and April 22, 1981, provided the following results from measurements of radium 226 and the uranium content of produced brine:

Date	Time	^{226}Ra, dpm/l	U, μg/l	$^{234}U/^{238}U$ Activity Ratio
11/17/80	11:35	65.8 ± 2.81		
11/18/80	11:12	70.9 ± 0.93		
11/19/80	13:05	68.9 ± 1.58		
11/20/80	--		0.044	1.347
11/20/80	11:29	77.5 ± 1.76		
11/21/80	16:33	62.6 ± 2.35		
11/22/80	11:43	66.2 ± 0.42		

In his letters, Mr. Kraemer advised that the radium 226 concentrations were "somewhat surprisingly high for the salinity" and that the 0.44 mg/l uranium content should be considered a maximum due to filtering problems caused by the high concentration of suspended matter in the sample. He observed that this maximum for uranium content is very low, but consistent with values he has found for other geopressured wells.

- **Matson and Associates (Matson):** The complete report of results of analyses performed on-site by Matson is provided as Appendix N. Analyses of both brine and solids are included in this report.

For direct comparison with IGT values, Exhibit 12-33 provides the Matson brine analysis data expressed in the same units used by IGT. Most of the values measured by both parties are in good agreement. Exceptions have been discussed by IGT and Matson with the following conclusion:

- **Fe (Matson, 0.09-11 mg/l; IGT, 3.4-21 mg/l):** The differences may largely be due to differences in sampling points and times. The only samples where consistent results should be expected were collected after the separator at 1116 hours (IGT) and 1230 hours (Matson) on 11/20/80. Reported Fe concentrations for these samples are 6.7 mg/l (IGT) and 0.09 mg/l (Matson). The difference may be because IGT's sample was filtered during collection, whereas the Matson sample was filtered roughly 10 to 15 minutes after collection in an open vessel but before analysis for Fe. A large portion of Fe in the Matson sample was assumed by both parties to have been precipitated due to loss of CO_2 and to contact with air. The precipitate would then have been trapped on the filter before analysis. Both parties will use on-line filtering at sample point temperature and pressure on future tests.

- **Weatherly Laboratories, Inc.:** Brine samples collected by Weatherly Laboratories, Inc. were for physical properties measurements. No chemical analyses of brine were performed.

12.6.5.4 Discussion of Analytical Results: All reported concentrations for several species were consistent. The average concentrations in Exhibit 12-32 are probably representative of brine in the reservoir for the following:

- NH_3
- CL^-
- F^-
- K
- Mg
- Na
- Sr
- $SO_4^{=}$
- $S^{=}$

RESULTS OF BRINE ON-SITE ANALYSES REPORTED BY MATSON & ASSOCIATES FOR THE RIDDLE-SALDANA WELL #2

	Units	16 Nov 80 2330	16 Nov 80 2330	17 Nov 80 1400	17 Nov 80 1400	18 Nov 80 1255	18 Nov 80 1315	19 Nov 80 1230	20 Nov 80 1230
Temperature	°C	65.5	65.5	79.4	79.4	90.6	90.6	95.0	95.0
pH	—	6.49	7.09	6.42	6.54	6.95	7.05	7.20	7.23
Conductivity	μmho/cm	17,500	20,760	22,300	24,000	23,000	18,900	25,000	23,900
Alkalinity *	mg HCO_3^-/ℓ (to pH 3.5)	1,776	1,788	1,854	1,976	1,820	1,781	1,795	1,854
SiO_2	mg/ℓ	114	108	117	112	125	130	134	120
Cl^-	mg/ℓ	6,380	6,550	6,480	6,360	6,420	6,430	6,400	6,610
S^{2-}	mg/ℓ	0	0	0.2	trace	0	0.1	0	0.24
SO_4^{2-}	mg/ℓ	0	0	0	0	0	0	0	0
Ca	mg/ℓ	58.5	57.7	53.7	52.1	59.3	60.9	51.3	48.1
Fe	mg/ℓ	4.4	3.65	5.0	1.7	11.0	1.0	7.5 (non-filtered)	0.09 (filtered)
Hardness	mg $CaCO_3$/ℓ	212	174	178	176	168	188	164	144
Univ. Of Houston ID		RS1116802330A After Separator	RS1116802330C After Choke	RS1117801410C From Tree	RS1117801410A Pump Tank	RS1118801255A After Separator	RS1118801315B Before Separator	RS1119801230A After Separator	RS1120801230A After Separator

* Mason Tomson of Rice University has verbally related that a sample collected shortly after bottoms up on 11/16/80 had the high value of 2245 mg HCO_3^-/ℓ. He has recommended sampling for alkalinity analysis at a similar time on future wells.

EXHIBIT 12-33

Several other species exhibited a reasonably consistent decrease with time. These are the following:

- Total suspended solids
- Fe
- Mn
- Pb
- Zn

The metals, Fe, Mn, Pb, and Zn are probably of anthropogenic origin. Their decrease is the result of the purging action of the brine flowing through the wellbore and plumbing. The lowest values are probably an upper limit for their true concentrations in the reservoir brine. The decrease in the production of total suspended solids is probably a clean-up of material either introduced during drilling or broken loose from the reservoir formation during perforation and initial flow. The analysis of the total suspended solids will be discussed in Section 12.6.7.

Additional species exhibited concentrations in bottom-hole samples that were not consistent with trends from surface sample analyses. These were the following:

- Ca
- SiO_2
- As
- B
- Ba
- Cd
- Cu
- CO_2

The variations in As, Cd, and Ca concentrations are probably due to differing amounts of these materials in the sampler versus materials introduced with the casing. The lowest reported values are probably upper limits for brine in the reservoir.

The 30%$\pm$15% higher values for SiO_2 in the bottom-hole samples are not understood. The 10% to 20% higher Ca content of bottom-hole samples may result from formation of carbonate precipitates before surface sampling. The variation in total CO_2 values will be discussed in Section 12.6.5.5. The difference in barium between bottom-hole samples and the consistent surface sample values may be due to residence time in the bottom-hole sampler before filtering and subsequent analysis.

Two of the measured constituents have concentrations that should be noted because of their environmental significance.

- B: One bottom-hole sample had anomalously low concentration. Nevertheless, the concentrations found preclude surface disposal of the brine due to its phytotoxicity.

- Hg: The variations in concentration are not understood. Nevertheless, the lowest measured concentration is well above the 0.10 g/l limit recommended by the U.S. EPA for the protection of fresh and marine aquatic organisms and for drinking water standards. This will preclude surface disposal of the brine.

The chromium concentrations for the brine on 11/17/80 and 11/22/80 are essentially the same, about 44 µg/l. The anomalously low value, <5 µgCr/l, for the 11/20/80 sample is not understood. The much higher values for the bottom-hole samples (about 250 µg/l) is assumed to be due to reactions of brine with sampler components during the week before flashing.

12.6.5.5 **Total Produced CO_2:** Portions of the CO_2 produced from the reservoir were determined in four different steps of sample collection and analysis during production testing. These steps were the following:

- CO_2 in the gaseous phase at separator temperature and pressure was quantized as a part of flare line gas sample analysis.
- CO_2 that was liberated as a gas when separator brine samples were flashed to one atmosphere at room temperature, was quantized in conjunction with that flashing.
- CO_2 in solution at room temperature, in bicarbonate form, or in dissolved carbonates, was determined by acid liberation as a part of brine analysis.
- CO_2 that precipitated as magnesium or calcium carbonate before brine sample collection was quantized only as a part of solids analysis.

Exhibit 12-34 provides a comparison of CO_2 content, except for that in precipitates, for the bottom-hole samples and for the produced fluids at times of collection of surface brine samples for acid liberation analysis. At each of these times, CO_2 content of flare line gas has been estimated from dry gas production, and the gas composition has been used to calculate flare gas rate at that time. Exhibit 12-34 reveals that total CO_2 content in the bottom-hole samples was about the same as estimated for the times of collection of three of the surface brine samples. Ten to twenty percent more CO_2 per barrel of brine is estimated at the times of collection of the other three surface samples. Whether this greater amount of CO_2 was actually produced is questionable, because gas samples were not collected at the same times as brine samples. Specifically, the flare gas CO_2 content of 3925 mg CO_2/l of brine tabulated for 1256 hours on 11/19/80 is probably erroneously high. This is because produced gas/brine ratios averaged only 46.5 SCF/STB at times of collection of the three gas samples on that date. In contrast, the produced gas/brine ratio was 51.6 SCF/STB at the time of collection of the brine samples (1256 hours). If the absolute amount of CO_2, rather than mole percent, in produced gas was constant, flare gas CO_2 content would have been 3540 SCF CO_2/STB. Calculated total CO_2 at 1256 hours on 11/19 would have been 5200 SCF CO_2/l of brine rather than 5585 SCF CO_2/l.

Exhibit 12-34. TOTAL CO_2 CONTENT OF GAS AND BRINE

Brine Sample Collection		CO_2, mg/l			
Date	Time	To Flare	Flashed	Acid Liberation	Total
Bottomhole Samples					
11/13/80	1518	N.A.	2290	2360	4650
11/13/80	1711	N.A.	2540	2230	4770
Surface Samples					
11/17/80	1025	3010	100*	1500	4610
11/18/80	1135	3520	100*	1540	5160
11/19/80	1256	3925	100*	1560	5585
11/20/80	1116	3340	100*	1530	4970
11/21/80	1603	2890	300*	1760	4950
11/22/80	1137	3170	300*	1780	5250

N.A. = Not applicable.

*Estimated values assuming 0.3 SCF CO_2/STB at a separator pressure of 60 psig and assuming 0.9 SCF CO_2/STB at a separator pressure of 200 psig.

12.6.5.6 **Sulfur Content of Produced Fluids:** The hydrogen sulfide content of produced gas was substantially higher than for any previous test of a geopressured aquifer. Seven Length of Stain Tube (Draeger Apparatus) measurements, at a separator pressure of about 60 psig and after bottoms-up, averaged 74 ppm. Measured values were between limits of 57 and 93 ppm.

After increasing separator pressure to about 200 psig, two measurements yielded values of 34 and 32 ppm H_2S in flare line gas. Assuming total sulfur content of produced fluids to be constant per barrel of brine, the expected increase in $S^=$ concentration in brine due to the 40 ppm decrease in H_2S content of gas is 0.4 mg $S^=$/l.

Both measurements of $S^=$ in brine after increasing separator pressure to 200 psig gave concentrations of approximately 0.2 ± 0.2 mg/l. In contrast, a value greater than 0.4 mg/l is required for consistency with the measured H_2S content of flared gas.

The analyses performed have been carefully reviewed. Significant points from that review are the following:

- Use of Teflon-lined stainless steel sample vessels with stainless steel valves does not eliminate the well-known loss of H_2S from gas samples due to reaction with steel. A gas sample that should have contained about 75 ppm of H_2S was transported to IGT's Chicago Laboratory by Federal Express. It was analyzed 48 hours after collection using a Perkin-Elmer Sigma 1 gas chromatograph with a flame photometric detector. This instrument has exceptionally high sensitivity to sulfur compounds. Several small peaks due to sulfur compounds, including H_2S, were observed, all below 5 ppm. The total of all peaks was substantially below the 75 ppm from field measurements.

- Volatile sulfur-bearing species may have been lost from brine to the atmosphere during the minutes required to collect each brine sample in an open container and carry it to the field laboratory for $S^=$ analysis.

12.7 Solids Production, Scaling and Corrosion

These topics are inextricably interconnected. Produced solids are of three types, materials introduced into the well by man (i.e., drilling mud), formation material (sand and clays), and solids resulting from precipitation of species that are in solution in brine at reservoir temperature and pressure. Scaling of surface facilities results from some of the precipitated solids becoming bonded to the steel walls of surface piping and vessels. The test of the P. R. Girouard Well No. 1 revealed that as little as two percent of carbonate precipitate was bonded to the surface facilities. The vast majority (about 3000 pounds) was injected into the disposal well. From the perspective of brine disposal, corrosion may be a source of produced solids.

The order of presentation in subsections which follow has been selected to provide understanding of results from the experiment. Section 12.7.1 presents data concerning time dependence of production of solids with grain sizes large enough to be seen on the sonic sand detector or to develop filter backpressure. Section 12.7.2 presents the data from X-ray analysis of samples of suspended solids collected during the test and reveals complexities in interpretation of X-ray results. Section 12.7.3 describes scale coupon observations, combines these with X-ray analyses of scale samples collected from surface piping after the production test, and develops an estimate of how scaling conditions changed during the test. Section 12.7.4 describes collection and analyses of samples from the particular solids resulting from the test. Finally, Section 12.7.5 combines the information from 12.7.1 through 12.7.4 into a reasonable scenario for solids production, scaling, and corrosion.

12.7.1 Sand Detector Signals and Pressure Drop Across Filters

Recorded data from these sources has been examined for clues regarding times of sand production and correlations with producing characteristics. A copy of the strip chart record from the OIC Sonic Sand Detector is provided in Appendix P. Filter differential pressures recorded by IGT are tabulated in Appendix F and portrayed graphically in Exhibit 12-14 in Section 12.6.2.5. Filter differential pressures manually logged by Weatherly are tabulated in Appendix E.

The sand detector was located between the choke and the separator. It was exposed to all produced sand after start of production through the separator at 1600 hours on 11/16/80.

For roughly the first 24 hours of production, produced brine was diverted to the reserve pit without flowing through the filters because of problems with the injection pump. Although the time of start of flow through the filters was not documented, it is presumed to have been 1700 hours on 11/17/80, because IGT's digital recording of filter pressure drop exhibited a 1.4 psi jump from a previously stable base line value of 1.1 psi at that time. Also, Weatherly began manual logging of filter pressure drop at 1700 hours, the time of their first reading after 1600 hours.

From presumed start of flow through filters until the rate increase on 11/21/80, a discrepancy exists between data recorded electronically from IGT's differential pressure transmitter and values logged manually by Weatherly from a dial-type differential pressure gauge. IGT's recorded values (see Exhibit 12-14 in Section 12.6.2.5) increased from 2.4 psi at 1700 hours on 11/17/80 to about 5.7 psi at midnight. During 11/18/80 the value increased further to about 8.5 psi. For the next 2-1/2 days until increasing rate, only minor fluctuations, in the range of 8 to 9 psi, were observed.

In contrast, Weatherly logged the value zero until 1300 hours on 11/19/80 and then 2 psi until the rate increase during 11/21/80.

After the rate increased during 11/21/80, IGT and Weatherly data became reasonably consistent. Discrepancies are less than 20 percent and values are in the range of 15-25 psi.

The data discrepancy is frustrating in its effect on correlation of pressure buildup, sand detector signals, and producing characteristics. Various possible correlations are the following:

- After a few minor sand detector signals, the largest signal of the entire test commenced at 0930 hours on 11/17/80. This signal averaged roughly 1/3 of the most sensitive scale for 1-1/2 hours and then declined to zero during the next 3-5 hours. This sand detector signal correlates with the jump in gas/brine ratio from about 40 SCF/STB to about 50 SCF/STB after 1100 hours.

- It is conceivable that the filter differential pressure buildup recorded by IGT the evening of 11/17/80 reflects washing of previously produced sand from the separator to the filters. However, no such buildup was logged by Weatherly.

- During the early morning of 11/18/80, the increased buildup in filter differential pressure correlates with a very low level of sand detector signal and with the increases in both bottom-hole pressure and brine production rate. Again, no such buildup was logged by Weatherly.

- A series of over a dozen substantial sand detector signals were recorded between 1000 hours and midnight on 11/19/80. No correlating filter differential pressure response was recorded by IGT. However, the change from zero to 2 psi in values logged by Weatherly occurred during the second of the signals of this series.

The jump to roughly 20 psi for filter differential pressure during 11/21/80 was recorded by both IGT and Weatherly. This jump correlates with the flow rate increase from about 1500 bpd to about 2500 bpd. The sand detector showed no significant signal at this or any later time. The jump in filter differential pressure is therefore believed to be due to brine rate increase through partially plugged filters.

Exhibit 12-35 provides an estimate of sand production during the larger observed peaks. Although the detailed corrections for non-linearity in the AC-DC convertor in the sand detector and for two-phase flow have not been made, this exhibit delineates the times of greatest sand production. The calculated total of 979.4 pounds is greater than the weight of produced solids found after the test, as will be described in Section 12.7.4.

The only clear correlation of sand detector signal with producing characteristics is production of roughly 150 pounds of sand just before the jump in gas/brine ratio from near saturation to about 15% above saturation on 11/17/80. The other correlations previously discussed are speculative.

12.7.2 Suspended Solids

12.7.2.1 **IGT Analyses:** Samples of suspended solids caught on 0.45 micron filter paper were obtained concurrently with collection of brine samples for analyses. Results of X-ray diffraction (XRD) and X-ray fluorescence (XRF) analyses of three such samples of suspended solids are tabulated in Exhibit 12-36. These three samples were collected at the same time as the fully analyzed brine samples (Section 12.6.5.2).

No significant differences were observed between the second, fourth, and sixth days of the test. Barium sulfate, assumed to be from the drilling mud, is the major crystalline component in all three samples analyzed, with lesser amounts of sodium chloride, quartz, and calcium carbonate. Iron was found by XRF to be a minor component in the suspended solids samples; however, no crystalline iron compounds were identified in the XRD patterns.

12.7.2.2 **Analysis by Matson and Associates (Matson):** Matson also collected suspended solids by filtering brine samples with 0.45 micron filters. The solid filtered material was analyzed using the SEM-EDAX system. Chloride, aluminum, silica, titanium and iron were reported to be present (See Appendix N).

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

SONIC SAND DETECTOR DATA AND CALCULATIONS

SALDANA WELL NO. 2

Date	Time	Flow Rate (Q) BWPD	Fluid Velocity Ft/Sec	Average Sonic Sand Detector Reading	Sand Production Lbs./Day	Duration of Sand Production (hrs)	Actual Sand Production Lbs.
11-17-80	0930-1130	1,515	1.236	14	1887.8	2.0	157.3
11-17-80	1130-1300	1,510	1.232	3	407.2	1.5	25.4
11-18-80	1215-1315	1,581	1.290	4	495.2	1.0	20.6
11-18-80	1015-1115	1,570	1.281	12	1506.4	1.0	62.8
11-19-80	1140-1210	1,559	1.272	26	3310.3	0.5	69.0
11-19-80	1235-1315	1,566	1.278	26	3279.3	0.67	91.5
11-19-80	1335-1415	1,553	1.267	24	3079.8	0.67	86.0
11-19-80	1435-1450	1,558	1.271	20	2550.4	0.25	26.6
11-19-80	1500-1515	1,548	1.263	26	3357.6	0.25	35.0
11-19-80	1525-1540	1,551	1.266	20	2570.6	0.17	18.2
11-19-80	1550-1605	1,562	1.275	20	2534.4	0.25	26.4
11-19-80	1615-1640	1,560	1.273	17	2161.0	0.42	37.8
11-19-80	1700-1740	1,555	1.269	17	2174.7	0.67	60.7
11-19-80	1810-1840	1,550	1.265	10	1287.3	0.50	26.8
11-19-80	1915-1940	1,552	1.266	12	1542.3	0.42	27.0
11-19-80	2020-2040	1,552	1.266	12	1542.3	0.33	21.2
11-19-80	2125-2155	1,551	1.266	16	2570.6	0.50	53.6
11-19-80	2200-2235	1,549	1.264	19	2449.8	0.58	59.2
11-19-80	2255-2320	1,530	1.248	8	1058.1	0.42	18.5
11-19-80	0015-0030	1,551	1.266	12	1542.3	0.25	16.1
11-19-80	0205-0215	1,562	1.275	13	1647.4	0.17	11.7
11-19-80	0225-0245	1,560	1.273	16	2033.9	0.33	28.0
							TOTAL 979.4

Sample Calculation:
(For Data on 11-17-80)

$$\text{Sand Production Lbs/Day} = \frac{206 \times \text{SSD Reading}}{\text{Velocity}^2}$$

$$= \frac{206 \times 14}{(1.236)^2} = 1887.8 \text{ Lbs/Day}$$

EXHIBIT 12-35

Exhibit 12-36. COMPOSITION OF SUSPENDED SOLIDS SAMPLES FROM THE RIDDLE-SALDANA WELL #2

Sample Date and Time	Component Identified (XRD)		Element Found (XRF)		
	Major	Minor	Major	Minor	Trace
17 Nov. 1980	$BaSO_4$	NaCl	Ba,S	Cl	K,Sr,Zn
1115		SiO_2		Si	P
		$CaCO_3$		Ca,Fe	Cd,I
20 Nov. 1980	$BaSO_4$	NaCl	Ba,S	Cl	K,Sr,Zn
1142		SiO_2		Si	P
		$CaCO_3$		Ca,Fe	Cd,I
22 Nov. 1980	$BaSO_4$	NaCl	Ba,S	Cl	K,Sr,Zn
1154		SiO_2		Si	P
		$CaCO_3$		Ca,Fe	Cd,I

Major 1-100%; Minor 0.01-1%; Trace 0.01%

Entries on the same line are approximately equal.

All constituents listed in probable order of decreasing abundance.

12.7.2.3 Discussion of X-Ray Analyses: Notable differences between IGT and Matson X-ray fluorescence results are:

- Barium and sulfur are reported as major components by IGT but were not identified by Matson.
- Titanium and aluminum are reported by Matson, but they are not identified by IGT.
- Minor amounts of calcium are reported by IGT, but it is not identified by Matson.

Possible reasons have been identified for these differences. One is that Matson apparently used gold to make the sample surface electrically conductive, as is required by SEM-EDAX analysis. As a result, the sulfur K X-ray is probably masked by gold M series X-rays having essentially the same wavelength. Also, the K series X-ray wavelengths for titanium are very close to the L series X-ray wavelengths for barium. The aluminum identified may be due to the mount for the sample. Since IGT identified barium sulfate by X-ray diffraction, it is possible that the titanium reported by Matson is in fact barium. Finally, the peaks in Figure 14 of the Matson report (Appendix N) are quite small for all reported species, due to the very large peak for the gold M series X-rays. The peak corresponding to the minor amount of calcium reported by IGT may be lost in noise in the Matson analysis.

12.7.3 Scaling and Corrosion

Matson closely monitored surface equipment for scaling and corrosion during the entire test. Their work included use of corrosion coupons, as will be discussed in Sections 12.7.3.1 and 12.7.3.2, and the on-site brine analyses previously discussed in Section 12.6.5.3. The complete report by these investigators is provided in Appendix N.

No scale inhibitors were tested, due to lack of serious scaling.

12.7.3.1 Corrosion Coupon and Scaling of Piping: Corrosion coupons were installed in the data header between the choke and the separator. Two long-term and ten short-term mild steel coupons were exposed to brine flow. The coupons were affected by both mild deposition of a black substance and by mild corrosion.

Short-term coupons revealed negligible deposits or corrosion at the start of flow. During the remainder of brine production at a rate at about 1500 bpd, mild deposition of a black substance plus mild corrosion pitting was observed on all coupons. The coupon which was in place only after increasing the flow rate and separator pressure during 11/21/80 exhibited mild corrosion and no deposition.

While surface facilities were being dissassembled for transport on 12/2/80, they were examined for scale deposition. All surface piping between the choke and the settling tank was covered with a thin veneer of shiny black scale. Between the choke and the separator, this scale was tightly bonded to the pipe. Scoring of the scale followed by multiple heavy blows on the outside of the pipe with a hammer loosened small flakes. Scale was not as tightly bonded downstream from the separator. One or two hammer blows provided flakes without pre-scoring. A few samples of about 1 cm^2 each were collected from both upstream and downstream of the separator.

Piping in the flowstream contained no solids other than the scale. Minor amounts of solids had collected in "dead-ends" in the piping but samples were not taken due to much larger amounts in the separators, filter, and settling tank, as will be discussed in Section 12.7.4.

12.7.3.2 Analyses of Scale Samples: Scale samples were analyzed using scanning electron microscopes equipped for energy dispersive X-ray analysis. Analysis of scale on corrosion coupons was reported by Matson. In addition, analysis of the scale samples recovered from piping upstream from the separator and downstream from the filters was made by Walter C. McCrone Associates, Inc. under a GRI-funded subcontract from IGT.

Reports by both organizations are in Appendices N and O. Exhibit 12-37 summarizes findings reported by both. A phenomenological interpretation to be set forth below is plausible if the following assumptions are correct:

- that the Matson report text does not mention sulfur due to sulfur K X-ray masking by the large gold M series X-ray peak due to the gold coating. Sulfur is identified in Figures 7 and 12 of the Matson report in Appendix N for coupon 3666 and for the deposit from coupon 3622. The sulfur peak on the right side of the gold peak is discernable in these figures. Further, the relationship to the very large iron peak height is consistent with that in Figure 4 of the McCrone report in Appendix O. (The McCrone sulfur peak is not masked, because carbon, rather than gold, was used to make the samples conductive).

- that the titanium identified by Matson is actually barium (Ti K wavelengths are very close to Ba L wavelengths).

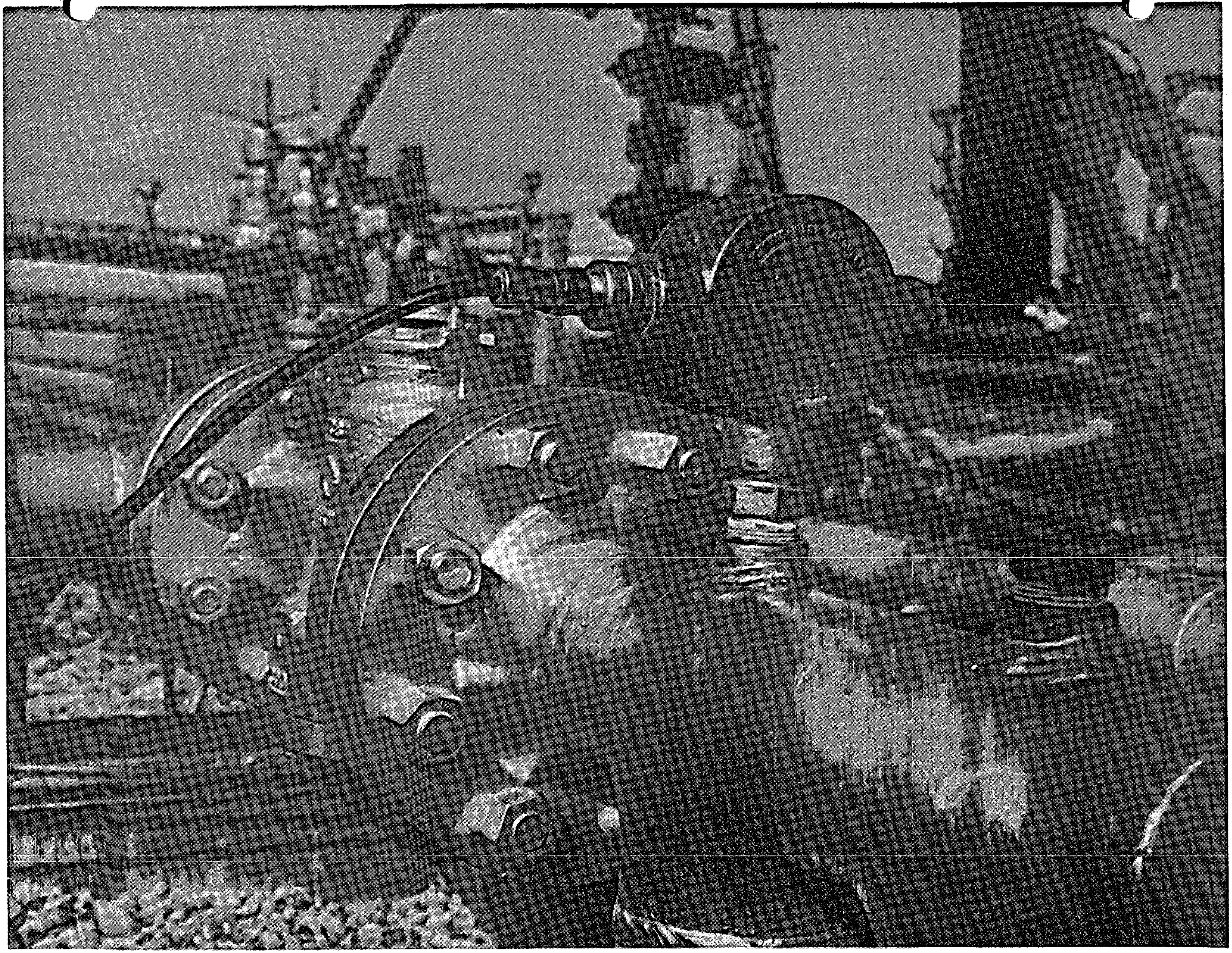

Photo 12-8 Sand detector probe on data header, upstream of separator

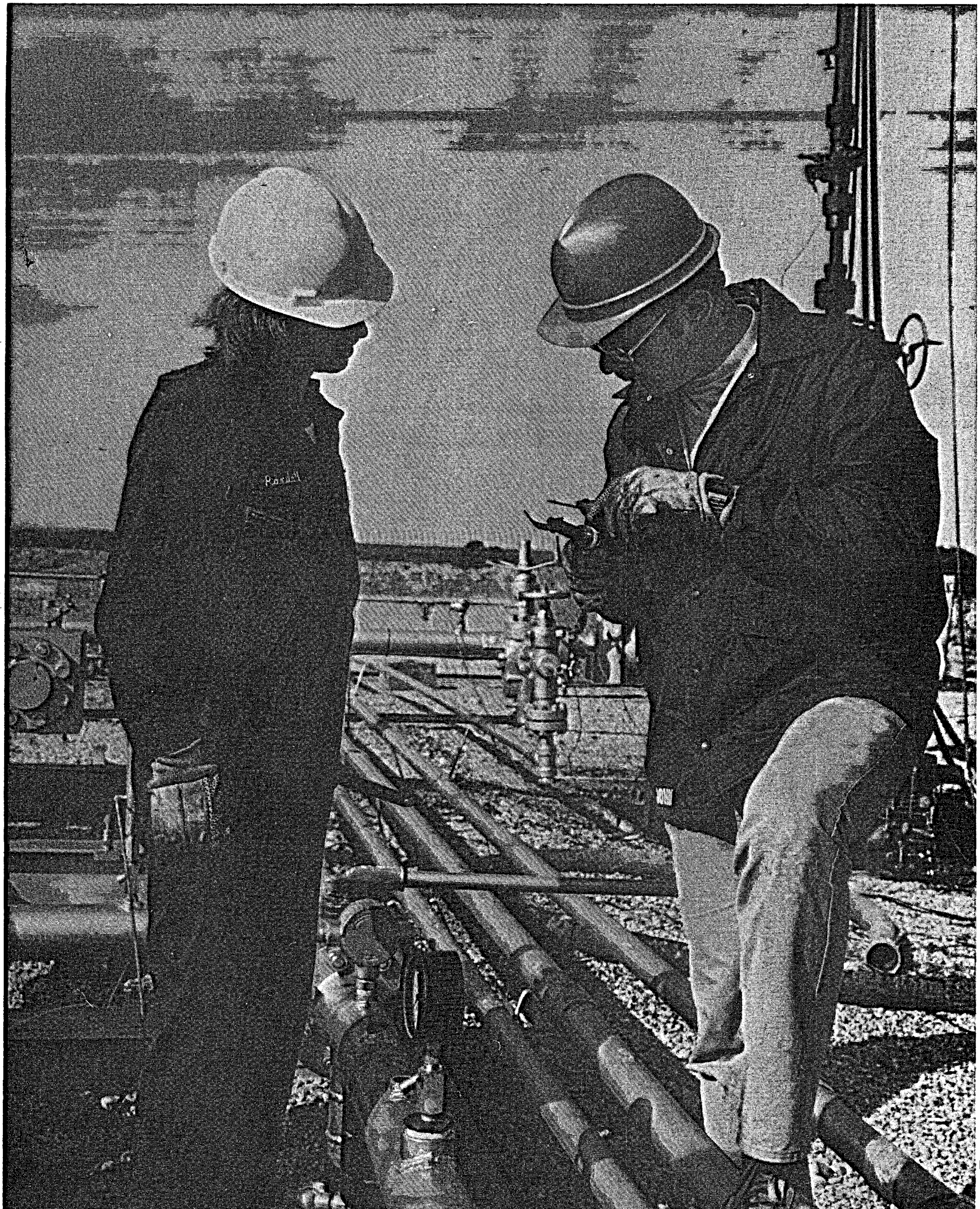

Photo 12-9 Scale/Corrosion coupons being checked by a member of the Matson and Associates team

Exhibit 12-37. ANALYSES OF SCALE

Matson and Associates Coupon Analyses:

Coupon Number	Time In	Time Out	Description	Species Identified*
3675	1515 hrs 11/16/80	0915 hrs 11/20/80	Black Scale and Corrosion	Fe, Ca, Si, Al, Cl
3666	1125 hrs 11/18/80	1015 hrs 11/19/80	Black Scale and Highest Weight Gain	Fe, S, Si, Ca, Al, Mg, Ti
3622	0900 hrs 11/21/80	0600 hrs 11/22/80	Colorless Deposit Scraped Off Coupon	Fe, Si, S, Al, Cl Ca, Mg, Ti

McCrone Pipe Scale Analyses:

Sample Source	Side of Beam Incidence	Species Identified*
Between Choke and Separator	Side Nearest Pipe	Major: Ca, Fe Minor: Na, Cl, Al, Si, S
Between Choke and Separator	Side Farthest From Pipe	Major: Fe, S, Cl, Ca Trace: Na, Al, Si
Between Filters and Settling tank	Side Nearest Pipe	Major: Fe, S Minor: Na, Si, Cl, Ca
Between Filters and Settling Tank	Side Farthest From Pipe	Major: Ca Minor: Al, Si, S, Cl, Fe

*Approximate order of abundance.

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A first and important step in phenomenological interpretation is to recognize the dichotomy between the two pipe scale samples studied by McCrone. Examination of the edge of the scale chip from upstream of the separator revealed a calcite layer bonded to the pipe and then overlain by a layer of an iron sulfide such as pyrite or pyrrhotite. Similar examination of the scale chip from between the filters and separating tank revealed the same layers but in opposite order. The iron sulfide was bonded to the pipe and then overlain by calcite.

If the assumptions previously stated are true, the black color of deposits on both pipe and coupons was due to an iron sulfide. Further, the large amount of iron in relation to calcium for the coupons that were only in the flowing stream before the 11/21/80 rate and separator increase suggest that the calcium bonded to pipe was residue from a previous test. It therefore appears that scale formed early in the test was predominately iron sulfide.

After the rate, separator pressure, and temperature increase during 11/21/80, scale-forming characteristics changed dramatically. The iron sulfide component on coupon No. 3622 may well have been laid down only during the 3-1/2 hours that the coupon was in place before the increases. This would bring weight gain into line with the previous short-term coupon (No. 3612). Lack of color in the deposit on coupon No. 3622 would have been due to the very small amount of iron sulfide and possible overlayering with SiO_2. Such overlaying is hypothesized due to the large Si peak in Figure 12 of the Matson report and the similar peak in Figure 3 of the McCrone report.

In contrast, at the pressure of near one atmosphere in the line between the filters and settling tank, the rate increase appears to have triggered calcite scale deposition. A substantial amount of such scale overlays the iron sulfide at that point. However, the amount was not large enough to obscure the black color.

12.7.4 Additional Produced Solids

Substantial quantities of particulate solids were deposited in the separator and settling tank during this test. Collection and analysis of samples from these sources, plus the modest amount of material caught by the filters, are discussed in Section 12.7.4.1 and 12.7.4.2.

12.7.4.1 Sampling of Separator Sludge, Solids from the Filter, and Settling Tank Solids: A unique characteristic of this test was use of a horizontal, rectangular, open-top, 220-barrel settling tank between the filters and the disposal well. The tank was divided into two compartments by a vertical wall about 40% of the distance from one end to the other. Fluid was injected into the smaller compartment from the top. Flow between compartments was through a 6-inch diameter hole at the bottom of the wall and in the center of the tank. The outlet from the tank to the injection pump suction was a 6-inch diameter opening at a bottom corner on the end of the large compartment farthest from the fluid injection point and dividing wall.

After the test, fluid was pumped to the injection well until air entered the pump suction. The tank was then allowed to cool overnight to eliminate the visibility problem due to water vapor. The next morning, a solids/water interface was clearly visible in the smaller compartment. Thickness of the layer of solids varied with position between zero and four inches. However, very fine dispersed solids remained suspended in the second compartment and were uniformly distributed over the bottom.

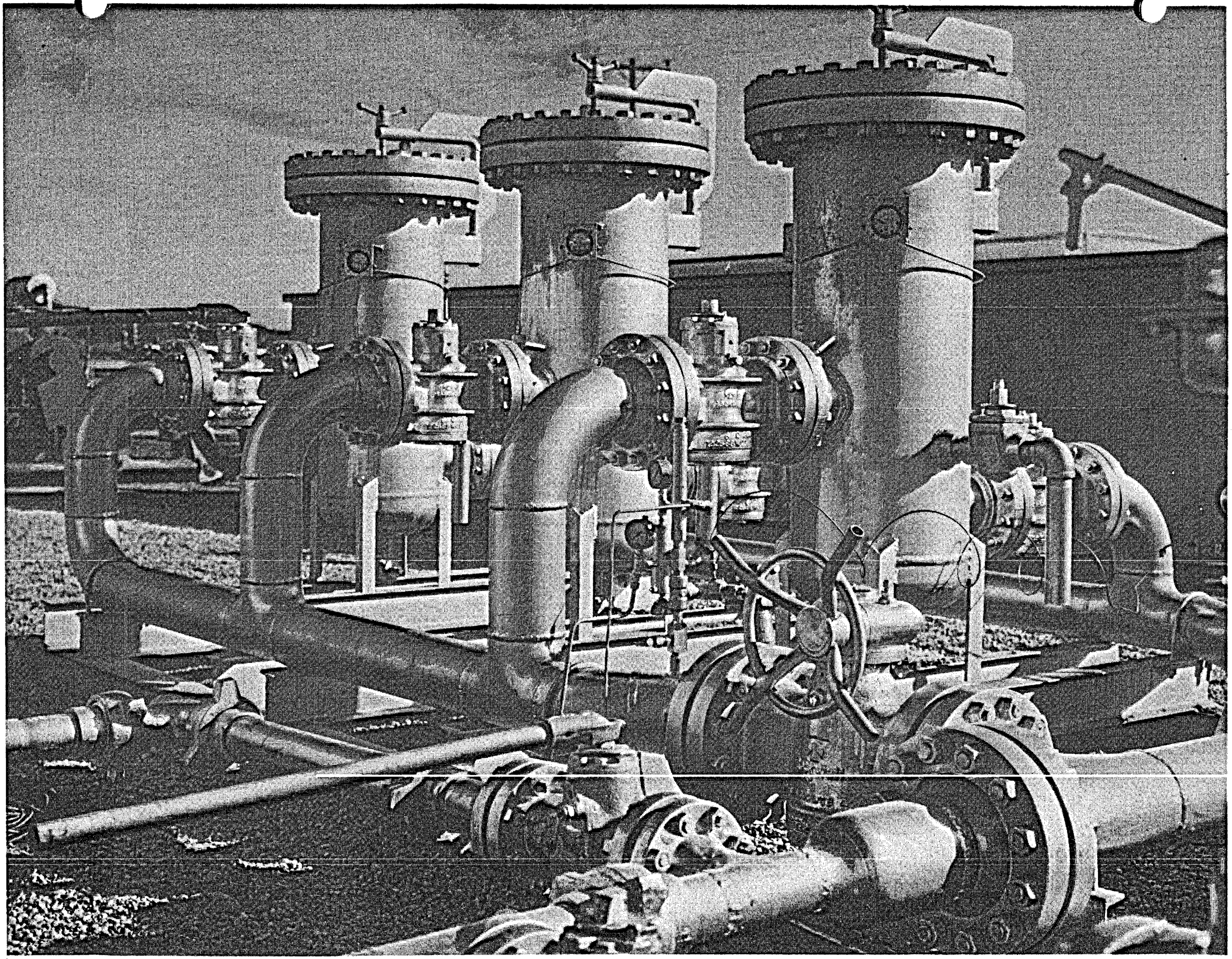

Photo 12-10 Three-tower water filter unit, using fiber cartridge-type filter elements

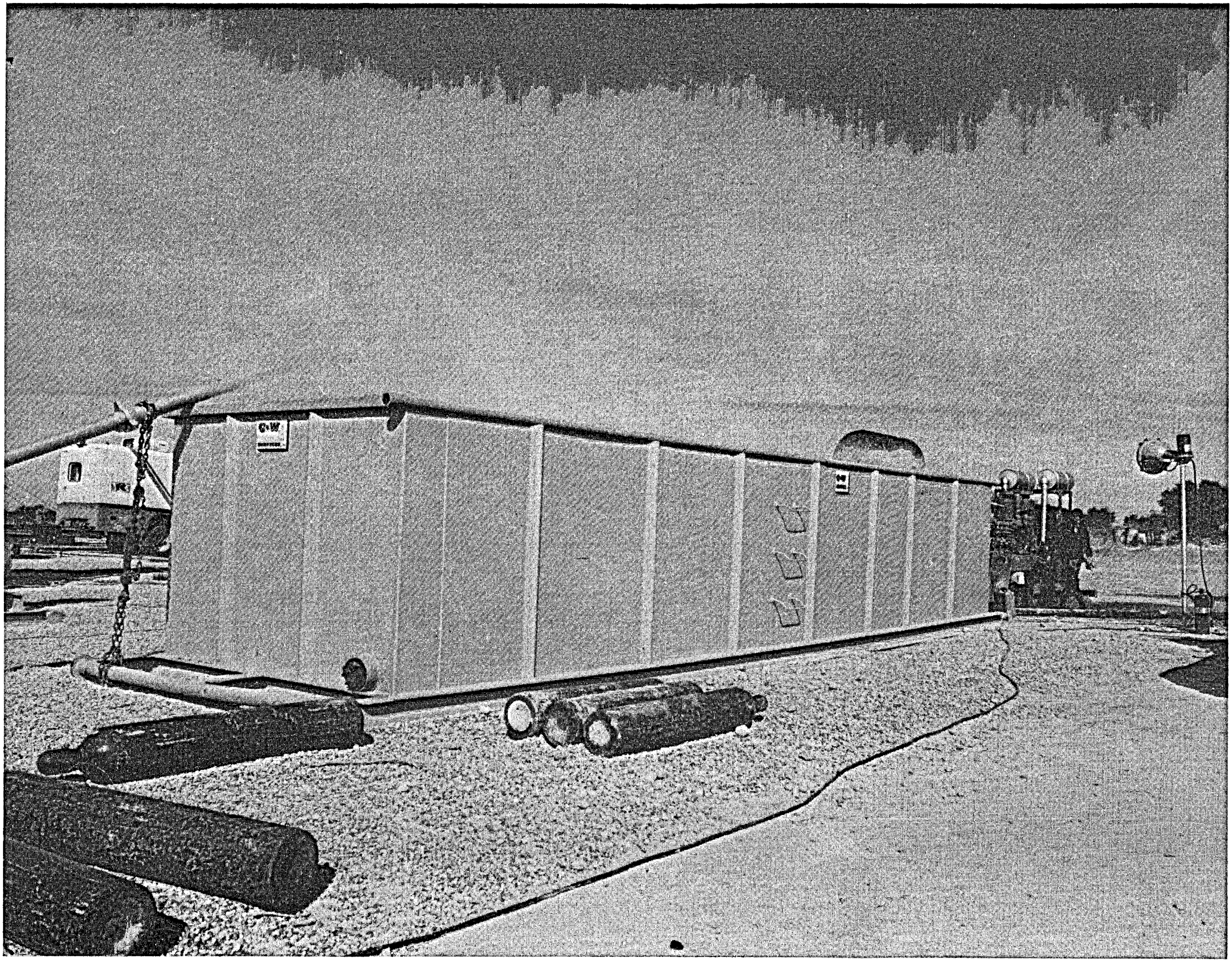

Photo 12-11 Processed water from the filter unit enters a 220-barrel tank and is pumped to disposal.

Photo 12-12 Triplex fluid pump, used to pump the processed brine to the disposal well

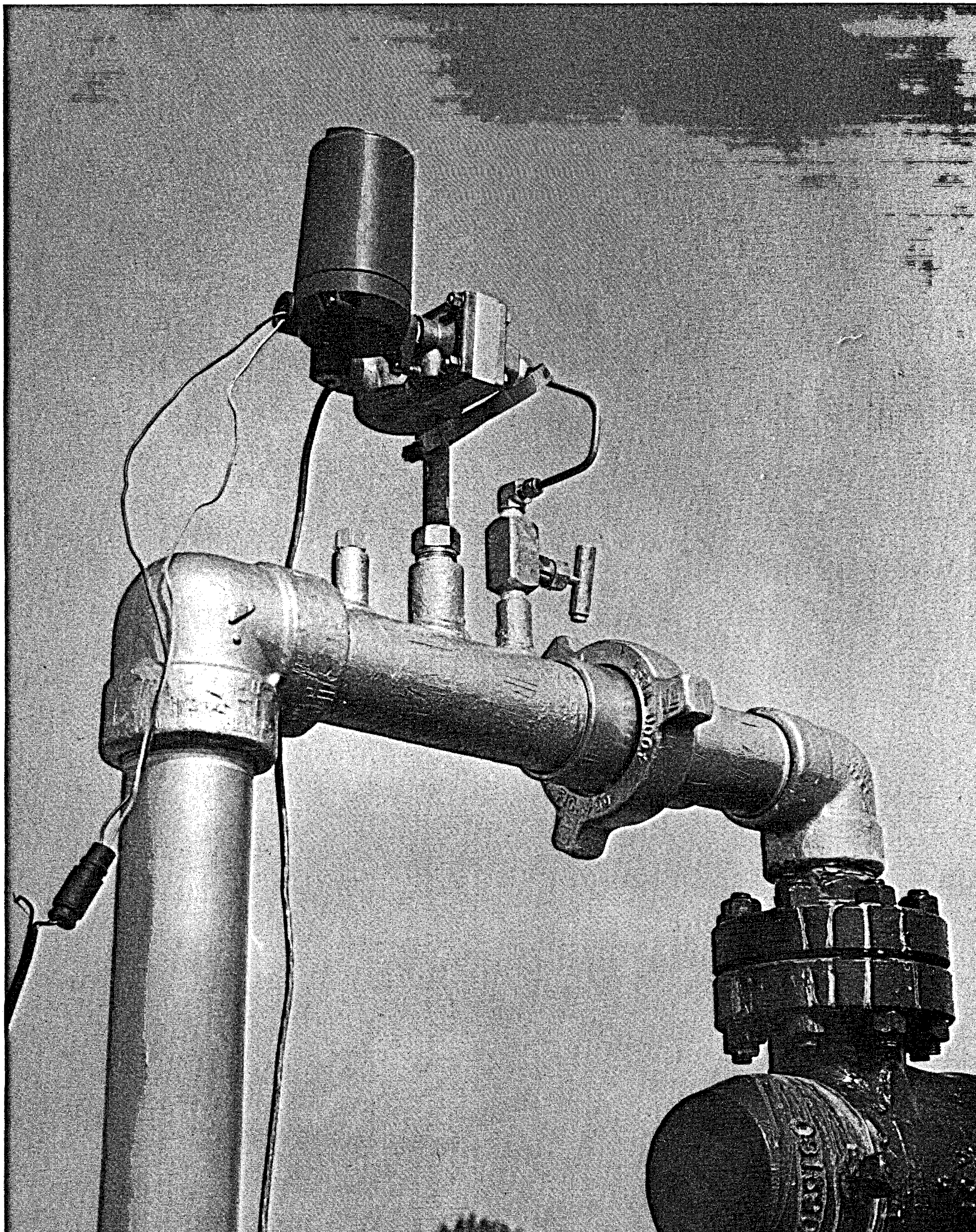

Photo 12-13 Close-up of IGT temperature and pressure transducers on disposal well

A substantial portion of remaining water was removed from the tank over the next 24 hours by using small hydraulic jacks to slowly elevate the inlet end of the tank in increments. This slow drainage was nevertheless accompanied by washing roughly five percent of very fine solids from the large compartment onto the ground. Most of this was from a trench through the solids due to water flow from the small compartment.

Six slurry samples were then collected from each compartment in the tank. In addition, a large number of measurements of slurry depth were made and total slurry volume in each compartment was calculated. Slurry volumes were 11.5 ft^3 in the inlet compartment and 27.9 ft^3 in the outlet compartment.

Analysis of the twelve samples to determine solids content of the slurry consisted of the following steps.

1. Centrifuge each sample to concentrate the slurry.

2. Decant water off each sample and measure water volume, concentrated slurry volume and concentrated slurry weight.

3. Calculate the average value for each tank compartment for concentrated slurry density and pounds of concentrated slurry per cubic foot of initial slurry. Results were 31.5 pounds/ft^3 plus a concentrated slurry density of 1.236 g/cc for the inlet compartment and 20.4 lbs/ft^3 plus a concentrated slurry density of 1.208 g/cc for the outlet compartment.

4. Average grain density for each compartment was measured on a dried portion after samples from that compartment had been composited. Results were 3.44 g/cc for the grain density in the inlet compartment and 3.28 g/cc in the outlet compartment.

5. The portion of concentrated slurry weight per cubic foot of water in each compartment due to solids was then calculated from the slurry density and grain density. Results were 37.5% for the inlet compartment and 33.8% for the outlet compartment.

Pounds of solids in each compartment were then calculated by multiplying the slurry volume in each by results of Steps 3 and 5 above. Results are:

Solids in Inlet Compartment	=	136 pounds
Solids in Outlet Compartment	=	192 pounds
Total Solids in Settling Tank	=	328 pounds

An independent estimate of produced solids passing out of the separator is provided by the suspended solids measured on 0.45 micron filter paper during collection of suites of brine samples. Average suspended solids reported (Exhibit 12-32) for the five daily brine samplings after start of flow to the settling tank was 98 mg/l or 0.0343 pounds per barrel. Thus, the 7260 barrels produced after 1700 hours on 11/17/80 would have carried 250 pounds of solids to the filters and settling tanks.

While the surface facilities were being dissassembled for transport on 12/2/80, quantities of contained solids were estimated and samples were collected as follows:

- **Surface Piping:** Piping in the flowstream contained no solids other than the side previously discussed. Samples were not collected from the small amounts of solids at dead ends in the surface piping.

- **Separator:** The separator was designed for three-phase operation. However, it was used as a two-phase separator with brine exiting from the "oil dump." A layer of about 6 inches of solids was found at the inlet end of the separator. A small amount of solids was also recovered from the "water dump" fitting. However, the smaller amount suggests that the layer of solids in the separator did not extend to that position (about 5-6 feet from the inlet end). Assuming a density of 100 pounds per cubic foot, the quantity of solids in the separator after the test is estimated to be about 50 pounds. A sample was collected for laboratory analysis.

- **Filter Unit:** One filter tower was used for the entire test. Pressure drop across filters was a maximum of 25 psi vs. a rating of 50 psi.

  When the unit was opened after the test the only solids were those on the individual filter elements. Total amount was only about 10 pounds. A single sample, consisting of solids scraped from multiple filter elements, was collected for analysis.

12.7.4.2 Analysis of Separator Sludge, Solids from the Filter, and Settling Tank Solids: A total of four samples of solids, collected after the production test, have been analyzed. These samples are:

- Sludge from the Separator

- Solids from Filters

- A composite of the six samples from the inlet compartment of the settling tank

- A composite of six samples from the outlet compartment of the settling tank.

These samples were collected as previously described in Section 12.7.4.1. Several analyses were performed on portions of each sample. These analyses, plus calculations performed to estimate composition of the solids, are as follows:

1. <u>Determine Initial Weight</u>

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

2. Perform 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 wt % CO_2 of the total sample. Results are tabulated in Exhibit 12-38.

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. Analyze the 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 Exhibit 12-38.

X-ray diffraction analysis was then performed to identify compounds in crystalline form in the samples. The only crystalline species identified were barite and quartz.

Finally, the percent barite in three of the samples was estimated by measuring the density of the solid residue and assuming that the only constituents were barite (density = 4.5 g/cc) and quartz (density = 2.66 g/cc). Again, results are tabulated in Exhibit 12-38.

5. Analyze the 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, Fe and Ba. Weight of each of these species was calculated by multiplying the concentration of each species (expressed in mg/l) by 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 Exhibit 12-38.

6. Perform Calculation to Estimate the Composition of Acid Soluble Solids

Step 5 above defined the weight percent of initial sample for six species that were cations of molecules in that sample. The first calculation performed to deduce probable associated anions is calculation of CO_2 that would have been liberated in Step 3 above if all of the calcium and magnesium were in carbonate form in the initial sample. Results of this calculation are shown in Exhibit 12-39, Part A. This calculation provided excellent agreement with measurement of acid liberated CO_2 for the two composites from the settling tank. However, for the samples from the separator and filter, the weight percents of calcium

ANALYSIS OF SOLIDS COLLECTED AFTER THE PRODUCTION TEST

Sample Description	CO_2 liberated by boiling 6<u>N</u>HCℓ (wt %)	------- Residue --------- Total wt%	Barite* wt%	Quartz* wt%	-- Cations in Acid Solution (wt %) -- Na	K	Ca	Mg	Fe	Ba
Sludge from Separator	1.6	89.6	58.2	31.4	0.54	0.038	0.83	0.104	2.4	0.022
Solids from Filter	10.9	69.	ND+	ND+	0.77	0.052	4.7	0.23	9.0	0.008
Settling Tank Inlet Compartment	2.7	77	42.4	34.6	1.4	0.10	2.2	0.21	5.7	0.23
Settling Tank Outlet Compartment	3.2	67.6	31.8	35.8	1.8	0.21	2.6	0.23	8.0	0.56

* Calculated from residue density <u>assuming</u> that the residue is composed <u>only</u> of barite and quartz.

\+ N.D. = not determined

EXHIBIT 12-38

ESTIMATED COMPOSITION OF ACID SOLUBLE SOLIDS

(A) Sources of Acid Liberated CO_2

Sample Description	CO_2 (wt %) Measured	CO_2 (wt %) Calculated for Ca + Mg as Carbonates	Fe(wt %) Required for $FeCO_3$ to Provide Missing CO_2
Sludge from Separator	1.60	1.10	0.63
Solids from Filters	10.9	5.6	6.7
Settling Tank Solids - Composite A	2.7	2.8	-0-
Settling Tank Solids - Composite B	3.2	3.3	-0-

(B) Calculated Mass Balance

	wt. % of Component						
	Calculated for						
Sample Description	(N,K)Cl	$(Ca,Mg)CO_3$	$FeCl_2$	$FeCO_3$	$BaCl_2$	Measured Residue	Total
Sludge from Separator	1.45	2.43	4.02	1.31	0.03	89.6	98.8
Solids from Filters	2.06	12.53	5.22	13.90	0.01	69.	102.7
Settling Tank Solids - Composite A	3.76	6.21	12.94	-0-	0.35	77.	100.3
Settling Tank Solids - Composite B	5.02	7.28	18.16	-0-	0.85	67.6	98.9

EXHIBIT 12-39

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 required in siderite is tabulated in Exhibit 12-39, Part A.

Finally it was hypothesized that the remaining acid-soluble species were chlorides. Credibility of this hypothesis was tested by calculating a mass balance. Results are shown in Exhibit 12-39. The calculated total solids accounted for with these assumptions ranges between 98.8 and 102.7 percent of original sample. This agreement is within the range of experimental error for the analyses performed.

X-ray diffraction analysis of solids from the filter did not confirm the hypothesized siderite ($FeCO_3$). The diffraction patterns for barite ($BaSO_4$), quartz (SiO_2) and aragonite ($CaCO_3$) were clearly identified. Also, ankerite ($Ca(Fe_{.33}Mg_{.67})CO_3$) appeared to be present. However, this compound cannot both account for the acid liberated CO_2 and provide an adequate mass balance.

12.7.4.3 Grain Size Distribution: Grain size distributions were determined for two separate portions from each sample analyzed, as discussed above in Section 12.7.4.2. Pre-treatments of the separate portions of each sample before each pair of grain size distribution measurements were the following:

- Wash one portion with de-ionized water to dissolve salts from evaporation of reservoir brine.
- Wash the separate portions with room temperature 1N HCl to dissolve salts and to decompose carbonates.

Thus the difference between size distributions in each pair is that the first distribution is representative of total solids, whereas the second describes only the portion that is not acid-soluble. Subtracting the second distribution from the first would provide an estimate of the size distribution for carbonates precipitated from the brine. The procedure used for each grain size distribution measurement was as follows:

1. Pre-treat the sample portion by stirring in a beaker of de-ionized water or 1N HCl.
2. Pour the slurry through a 75-micron opening (200 mesh) nylon screen and chase with de-ionized water. Material passing through the screen was caught on a pre-weighed 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 that identifies twelve steps in the range of less than 4.0 microns to less than 50.8 microns.

6. Appropriately normalize results of 4 and 5 above, using weights determined in Step 3, to provide each column tabulated in Exhibit 12-40.

It is noted that this procedure did not quantitatively account for either the size step between 50.8 and 75 microns or for particles less than 4-8 micron diameter in the original sample.

Examination of Exhibit 12-40 reveals that, with the exception of solids from filter, 90% of solids in each sample were smaller than 20-25 microns (25 microns = 0.001 inches). Visual examination of sizes greater than 75 microns from the filters revealed that (i) all particles greater than 1180 microns were filter fiber, (ii) filter fibers were visible in all size fractions down to 75 microns, and (iii) other particles larger than 75 microns appeared to be lumps of agglomerated, very fine grain material, rather than individual grains, such as sand.

12.7.5 Scenario for Production and Precipitation of Solids

Several aspects of the data and analyses previously presented require that subjective judgement and speculation be used to develop any consistent scenario for production and precipitation of solids. Nevertheless, most elements of such a scenario are set forth in sections which follow. Section 12.7.5.1 addresses total quantity of produced solids. Section 12.7.5.2 examines the amounts of various species. Finally, Section 12.7.5.3 addresses time dependence of solids production and scaling.

12.7.5.1 Quantity of Produced Solids: Examinations of surface test facilities after the test identified an estimated 380 pounds of particulate solids. The majority of this, an estimated 320 pounds, was in the settling tank.

Total production of solids was probably greater than the above estimate. Two reasons for this belief are:

- Fluids were produced through the separator to the pit for about the first 22 hours after bottoms-up. The filters and settling tank were bypassed until successful operation of the injection pump commenced at about 1700 hours on 11/17/80.
- It is probable that a substantial amount of ultra-fine-grained material was transported through the settling tank and injected into the disposal well.

A crude estimate of solids production during the first 22 hours can be derived from the quantities of suspended solids determined in conjunction with daily collection of suites of brine samples. Exhibit 12-32 reveals that suspended solids were 135 mg/l at 1025 hours on 11/17/80. Between bottoms-up and 1700 hours on 11/17/80, 1330 barrels of brine were produced. Using this concentration and brine volume provides an estimate of about 65 pounds for solids production to the reserve pit.

PARTICLE SIZE DISTRIBUTION OF SOLID MATERIAL FROM THE RIDDLE-SALDANA WELL #2 BEFORE AND AFTER TREATMENT WITH DILUTE HYDROCHLORIC ACID

Effective Screen Diameter, Microns	Fraction Larger than Effective Screen Diameter, Weight Percent							
	Sludge from Separator		Solids Upstream of Filter		Settling Tank Solids - A		Settling Tank Solids - B	
	As Rec'd	HCl Insol.	As Rec'd	HCl Insol.	As Rec'd	HCl Insol.	As Rec'd	HCl Insol.
1180	0.0	0.0	9.1	2.1	0.0	0.0	0.0	0.0
600	0.2	<0.1	15.0	2.1	0.0	0.0	0.0	0.0
300	0.2	<0.1	17.4	4.7	<0.1	0.0	<0.1	<0.1
150	0.1	<0.1	11.8	12.6	0.1	<0.1	0.2	<0.1
75	0.2	<0.1	6.7	18.8	1.9	<0.1	2.1	0.1
51	<0.1	<0.1	0.3	0.4	2.0	0.7	1.4	0.4
40	0.7	0.8	0.8	1.2	1.7	1.4	1.1	0.9
32	1.3	1.9	1.6	3.5	4.4	3.8	1.9	3.1
25	2.1	3.9	2.1	3.6	6.4	4.5	3.5	6.2
20	5.4	8.4	2.7	5.1	8.9	8.0	6.8	9.1
16	9.2	13.4	3.0	6.2	10.7	11.2	9.5	11.1
13	14.0	17.0	3.6	7.5	12.7	13.6	11.8	12.0
10	16.4	17.1	4.5	8.1	13.2	14.8	14.2	13.4
8	16.4	14.9	5.7	8.1	13.1	14.4	15.8	13.7
6	14.6	11.4	6.2	7.2	11.6	12.5	14.6	13.0
5	11.1	7.1	5.4	5.2	7.8	9.1	10.5	9.8
4	8.1	4.1	4.1	3.6	5.5	6.0	6.6	7.2
Amount insoluble in 1 N HCl	91.2		65.6		80.2		79.2	

Since no basis exists for estimating quantity of solids entering the injection pump, estimated total solids production consists of the following major elements:

Solids Disposition	Amount
Scale	20 pounds
Reserve Pit	65 pounds
Separator	50 pounds
Filter and Piping	25 pounds
Settling Tank	328 pounds
Disposal Well	<0 pounds
Total	<488 pounds

Since only about 9000 barrels of brine were produced from the reservoir, solids production averaged roughly 0.05 pounds per barrel of brine for the entire test.

12.7.5.2 Amounts of Various Solid Species: Exhibit 12-40 is a tabulation of results previously discussed in terms of pounds of various solids identified or hypothesized to have been produced. The estimates for scale are based upon the McCrone analyses, with the assumption that the pyrite is about 0.002 inches thick and the calcite is about 0.004 inches thick. Total area of scale deposition is estimated to be about 200 ft^2. Most other entries are calculated from Exhibit 12-39 plus estimated total solids at each location. Estimates for material to the reserve pit assume the same composition as for the sum of the two compartments in the settling tank.

It is emphasized that values tabulated in Exhibit 12-41 are estimates. Errors as large as a factor of two are possible in any or all of the values. Further, substantial amounts of $FeCO_3$ and $FeCl_2$ have been assumed with no direct evidence that these species actually existed in the produced solids.

12.7.5.3 Time Dependence of Solids Production: Data from the sonic sand detector was previously discussed in Section 12.7.1. An estimate of 980 pounds of produced sand was developed. Of this total, 800 pounds was estimated to have been produced after start of production to the settling tank. Only the first 150 pounds of estimated sand production was found to correlate with any other data. That correlation was before onset of a gas/brine ratio in excess of gas solubility in reservoir brine.

Lack of correlation with other producing characteristics on 11/19/80 is particularly puzzling, because lower bottom-hole pressure and a greater pore pressure gradient had been experienced two days earlier.

ESTIMATED AMOUNTS AND DISPOSITION OF SOLIDS

Solid Composition:	FeS_2	$FeCO_3$	$(Ca, Mg)CO_3$	Chlorides	$BaSO_4$	Sand & Shale	Total Pounds
Probable Source:	---------precipitation from brine------------				Drilling Mud	Reservoir	
Disposition (pounds)							
Scale	10	—	10.	—	—	—	20
Reserve Pit	—	—	4.4	14	24	23	65
Separator	—	.7	1.2	2.8	29	16	50
Filter and Piping	—	2.7	3.0	1.7	9	9	25
Settling Tank Inlet	—	—	8.0	23	58	47	136
Settling Tank Outlet	—	—	14.0	47	62	70	192
Disposal Well	—	—	>0	>0	>0	>0	>0
TOTAL (pounds)	10	3.4	>41	>88	>182	>165	>488

EXHIBIT 12-41

The ultrafine grain size of produced solids casts further doubt on the validity of the sand detector record. Calibration data from the manufacturer is for Ottawa No. 3 sand. Although the effect of grain size is not mentioned in the manufacturer's literature, it is questionable whether the device could respond to the grain sizes smaller than 25 microns that were characteristic of more than 90 percent of produced solids. The sand detector may have responded to lumps of agglomerated material which subsequently broke down to individual grains.

In contrast to the sonic sand detector, suspended solids collected on 0.45 micron filters each day exhibited a monotonic decline from 140 to 80 mg/l over the last six days of the test. Further, most of these samples were collected at times when the sand detector was quiescent. Also, the total of cumulative solids to the settling tank, estimated from suspended solids, is reasonably consistent with the measured amount, (250 pounds vs. 330 pounds). It is therefore considered most probable that solids production was virtually continuous, rather than only at the times of sonic sand detector response.

The time dependence of scale deposition is particularly intriguing. Coupon observations revealed that little, if any, scale formed from the start of flow, at 1500 bpd and separator pressure of 60 psig, until brine temperature exceeded 160°F. For brine temperatures in the range of 175°F to 200°F, a black deposition of iron sulfide occurred at both 60 psig and near atmospheric pressure. After the increase in flow rate on 11/21/80, and the resultant temperature increase to 220°F, coupon observations suggest that iron sulfide scaling stopped. However, at the near-atmospheric pressure between the filter and settling tank, predominately calcite scale was deposited over the previously deposited iron sulfide.

12.8 Test Equipment Performance

12.8.1 Malfunctions of Sensing and Transmitting Equipment

The quality of data is substantially lower for this test than for the two previous well tests by Eaton because of bad weather which occurred during the testing period. An unusually severe winter cold front produced a large amount of rain, along with near freezing temperatures and high winds. The weather took a toll both in terms of electrical malfunctions and in terms of timely and accurate manual logging of data. Fortunately, the testing program contained sufficient redundancy in data collection. Additional discussion of this subject can be found in Section 12.6.2.

12.8.2 Disposal Pump

As a result of low test well production pressures, it was necessary to use a pump to move the produced brine through the 3000-foot, 3-1/2 inch flowline to the disposal well. A Gardner-Denver Model PA-8 Triplex Mud Pump was rented for this purpose. The pump was powered by a GM V-8 diesel engine. During production, the pump and engine required almost daily maintenance service and 24-hour observation by test personnel. A production operation utilizing disposal pumps versus separator pressure energy for injection would obviously be less practical.

12.8.3 Bottom-hole Fluid Sampler

The newly redesigned Gearhart Industries sampler operated properly, and two bottom-hole fluid samples were successfully obtained from a depth of 9743 feet. The explosively driven cutter and rupture disc assembly, which failed to operate properly during past WOO tests, has apparently been successfully redesigned.

12.8.4 Gas Chromatography

The Carle Model 111-H Gas Chromatograph used in the field developed a water vapor leak 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 on page 12-38.

12.8.5 Disposal Brine Filter System

It is estimated that more than 328 pounds of fine solids passed through the 25-micron filter elements used in the Nowata (Model No. 6FH60C-600) filter system. The individual filter elements trapped only about 10 pounds of solids. 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 on a well such as the Saldana Well No. 2 would be expensive and impractical. Evaluation of a Ronningen-Petter 5-micron, self-cleaning pressure filtration system is planned on a forthcoming WOO test.

12.8.6 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 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.

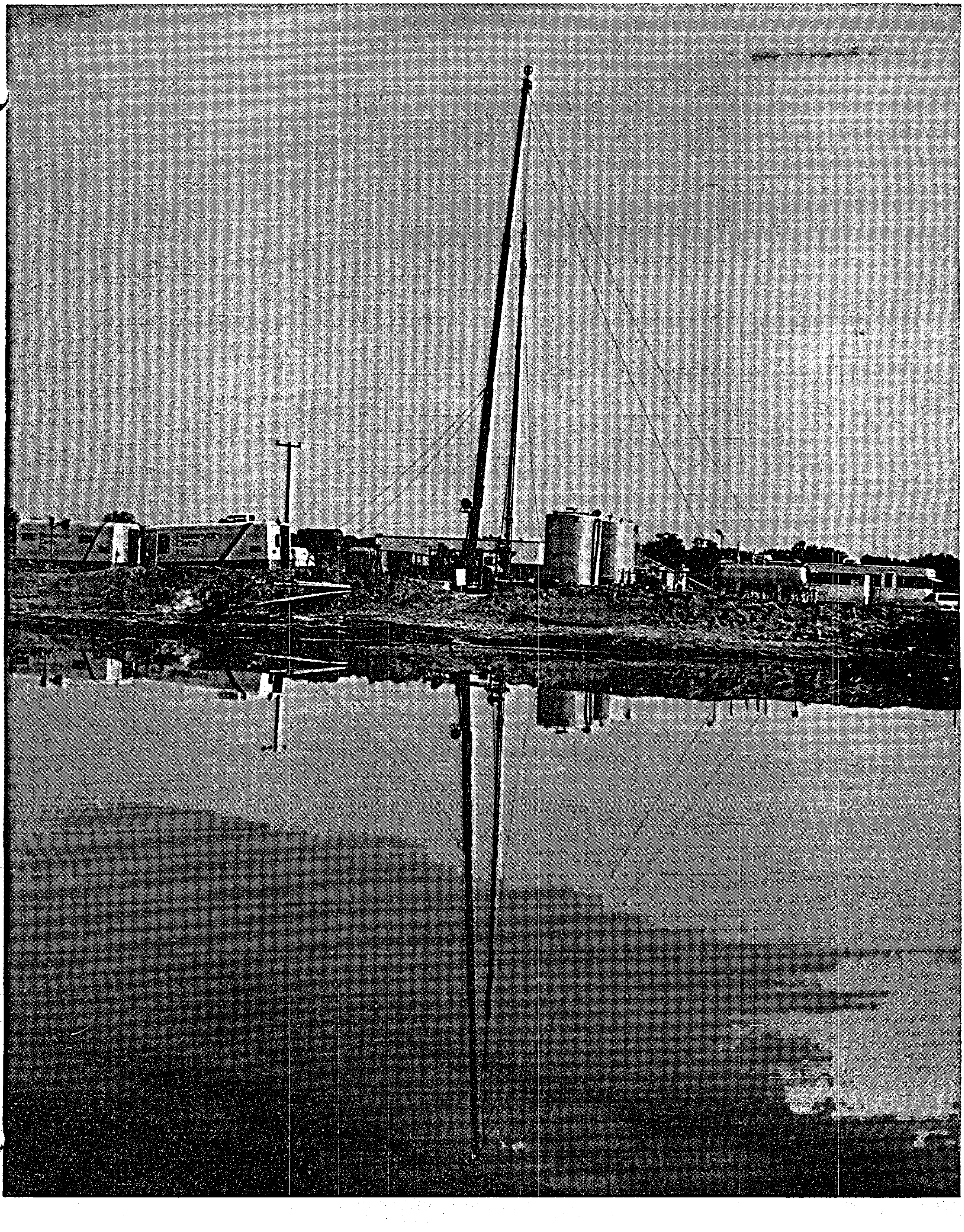

Photo 12-14 View of the test equipment from the far side of the reserve pit

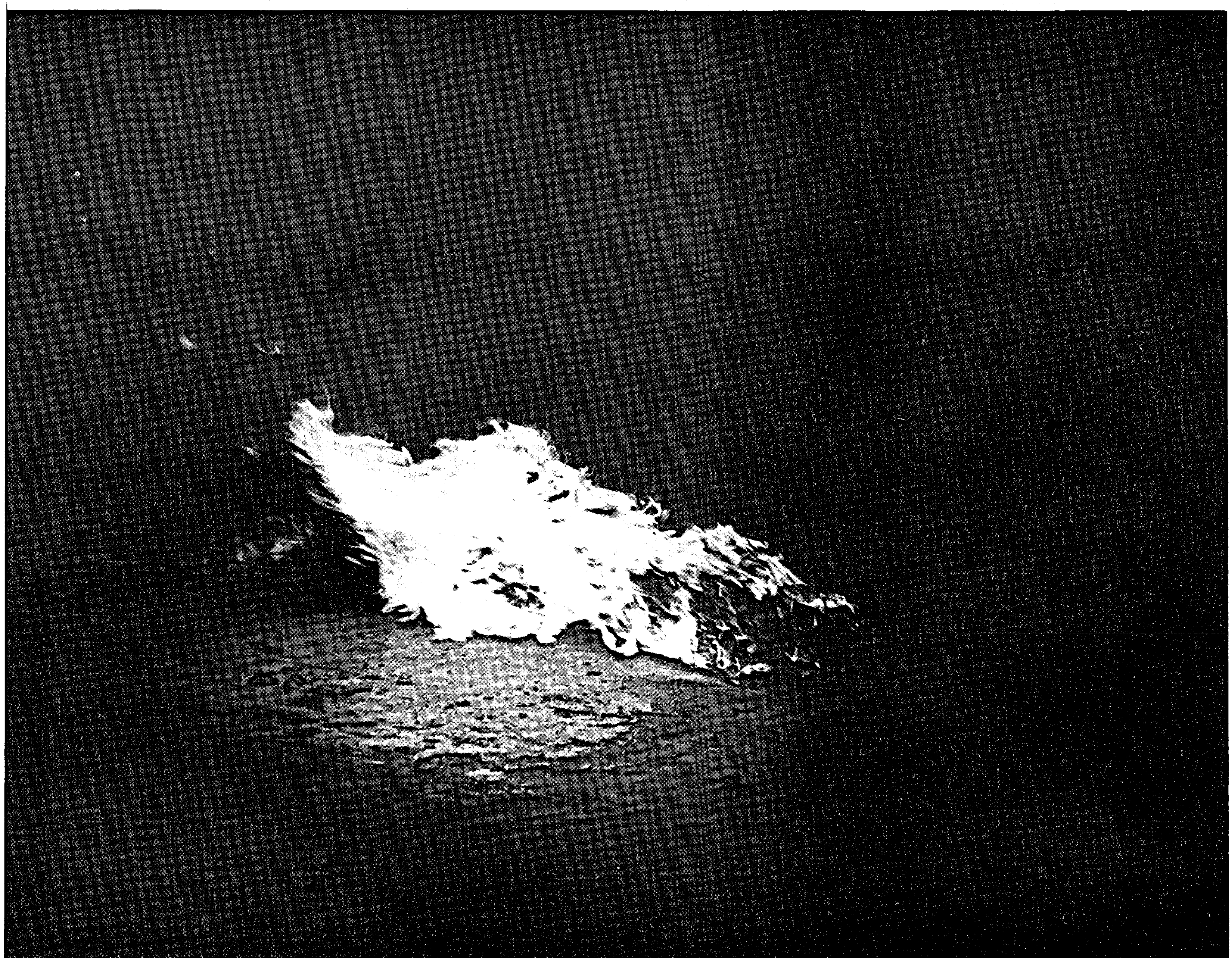

Photo 12-15 Approximately 1070 BTU of heat energy being generated every second

13.0 PLUG AND ABANDONMENT

13.1 Plugging of the Test Well

Target's Rig No. 15 was moved onto the location on December 4, 1980. The salt water in the tubing and casing was displaced with 13.5 ppg mud, the christmas tree was removed, and blowout preventers were installed and tested. The 2-3/8 inch tubing was pulled out of the hole. A cement retainer was set at 9547 feet and the test perforations were squeezed with 190 sacks of cement. Ten sacks of cement were spotted on top of the retainer. A bridge plug was then set at 9386 feet in the 7-inch casing.

A free point indicator, run in the 7-inch casing, indicated that the casing was partially free at 6100 feet. The casing was cut at 6061 feet and removed from the well. A cement retainer was then set at 6027 feet in the 9-5/8 inch casing. A cement plug was spotted from 6027 to 5782 feet.

The blowout preventers were removed, and the 9-5/8 inch casing was cut at 400 feet and pulled out of the well. A cement retainer was set in the 13-3/8 inch casing at 352 feet, and cement was spotted from 352 feet to the surface. The surface casing and drive pipe were cut off 3 feet below ground level.

The rig operations were completed on December 17, 1980, and the rig was moved to the disposal well.

13.2 Plugging of Disposal Well

The Target Rig No. 15 was rigged up on the Saldana No. 1 Well on the same day it was moved from the test well. The wellhead was removed, and blowout preventers were installed and tested. A cement retainer was set in the 9-5/8 inch casing at 2906 feet. The perforations were squeezed with 225 sacks of cement, and 50 sacks of cement were spotted on top of the retainer.

The interval from 400 to 399 feet was then perforated. A total of 375 sacks of cement were pumped into the 9-5/8 inch casing to isolate the fresh water sands above 400 feet. The drive pipe, surface casing, and 9-5/8 inch casing were cut off 3 feet below ground level.

The rig was released on December 20, 1980.

14.0 CONCLUSIONS

The gas-to-water ratio measured during testing ranged from 47 to 54 SCF/BBL and was greater than the gas solubility of 41 SCF/BBL at reservoir conditions. Free gas in the reservoir was evident during testing operations. Produced hydrocarbon gas was in excess of the amount that could have been in solution in the produced reservoir brine. The natural gas liquids content of the gas plus the atomic carbon ratio of the methane fraction suggest that the free gas probably originated at a depth greater than the reservoir depth.

The measured reservoir temperature of 300.2°F was much higher than the corrected electric log temperature of 258°F. Although there is no other verification of the 300.2°F temperature reading, it is believed to be correct. The implication here is that log temperatures and correction methods can be subject to large errors.

Scaling and corrosion were considered light; however, preventive treatment would be necessary if long-term production were desired.

The large amount of solids production is significant because of the potential problems associated with long-term solids processing. No abrasion of the production equipment occurred because of the relatively low flowing pressures.

The test separator was a very effective device for removing produced gas from the brine. The processed water contained less than 2 SCF/BBL of gas, at a separator operating pressure of 200 psi. The gas associated with the disposal brine leaving the separator was composed of 42.50% methane and 53.87% CO_2. This type of gas is not marketable. Additional refinement of the present gas separation method is therefore not considered essential.

Concentrations of mercury in the produced brine averaged 2.0 micrograms per liter. This value is well 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 88 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.

The reservoir has a limited flow capacity of about 985 millidarcy-feet, which is well within the economical range for petroleum hydrocarbons, but much too low for GEO^2 aquifer economics.

15.0 REFERENCES

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APPENDIX A

Operator Contracts and Agreements

Agreement with Riddle Oil Company

riddle oil company

September 4, 1980

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

Attn: Mr. B. A. Eaton

Re: Saldana #1 and #2
Zapata Co., Texas

Dear Mr. Eaton:

Enclosed are two copies of our agreement dated August 12, 1980 which have been executed by Melvin Close, the Executor of Mr. Riddle's Estate.

This letter will also confirm our telephone conversation of this date wherein we authorized you to offer the landowner $20,000.00 for his consent to your testing the captioned wells. Such $20,000.00 will be deducted from the $95,000.00 you are to pay us under the agreement.

Yours very truly,

W. H. King

W. H. King

WHK/ps

Encl.

1804 N.E. Loop 410, Suite 100
San Antonio, Texas 78217
Telephone: Area Code 512 824-9627

EATON OPERATING COMPANY, INC.

August 12, 1980

Riddle Oil Company
1804 N. E. Loop 410
Suite 100
San Antonio, Texas 78217

Attention: Mr. W. H. King

Re: Saldana Well #2 and Well #1
Zapata County, Texas

Gentlemen:

This letter, if accepted by you and two signed copies thereof are returned to us by August 26, 1980, shall constitute the basis of an agreement between Riddle Oil Company (Riddle) and Eaton Operating Company, Inc. (Eaton) as to the following matters.

I.

A. Eaton is a party to a contract with the United States government represented by the Division of Geothermal Energy, Department of Energy, 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.

B. Riddle has drilled the above referenced wells to total depth and proposes to plug the wells as non-commercial.

II.

Eaton is of the opinion that the subject wells qualify as well of opportunity candidates 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.

A. Eaton shall be responsible for:

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

1. Obtaining all federal, state and local governmental permits required for such operations.

2. Providing insurance coverage through the length of the 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 information to Riddle at the conclusion of test.

4. Assumption of all liabilities associated with further operations of the wells through plugging and the final clean up of the locations.

5. Eaton will pay Riddle the sum of $95,000 in cash, as a fee for use of the well bores. In addition, Eaton agrees to make its best efforts, consistent with good oil field practices, to recover as much 7" casing as practicable. The recovered 7" casing and the 2-3/8" tubing now in the wells will be laid on racks adjacent to the wells for Riddle's account.

6. Riddle has drilled the Saldana #1 approximately 2900' south of the Saldana #2 well. Eaton proposes to utilize the Saldana #1 well bore to dispose of produced fluids. As compensation for use of this well bore, Eaton will plug the well and make every attempt, consistent with good oil field practices, to recover as much 7" casing as practicable. This recovered 7" casing and 2-3/8" tubing presently in the well will be laid on racks adjacent to the well for Riddle's account.

7. Eaton would agree to complete the testing and research in approximately 180 days.

B. Riddle shall be responsible for:

1. Riddle shall be ~~the sole corporation~~ [illegible] liable to fairly and equitably distribute the payment to any other working interest partners, if any, and Eaton shall be held harmless from such distribution if any, by Riddle.

IV.

This letter agreement does not convey to Eaton any ownership interest in the land, nor does Eaton have any vested interest in any mineral or energy resources produced during any of the tests, and it is expressly agreed between Eaton and Riddle that no mineral or energy resource will be saved or sold.

V.

Eaton shall be furnished the complete name (or names) and address (or addresses) of the fee owner and mineral owner, if not the same, and it is agreed that this agreement shall be of no force and effect without the informed written consent of said owner.

VI.

Eaton hereby agrees to indemnify and hold Riddle et al harmless from any and all claims for injury or damages the cause of which may occur in connection with Eaton's operation of the saidwells, limited to $80,000,000.00 liability and $25,000,000.00 well control as described in Section III-A-2.

VII.

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.

VIII.

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 Riddle:

Riddle Oil Company
1804 N. E. Loop 410
Suite 100
San Antonio, Texas 78217

Attention: Mr. W. H. King
Telephone: 512/824-9627

If to Eaton:

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

Attention: Mr. B. A. Eaton
Telephone: 713/627-9764

IX.

This agreement shall be binding on the legal representatives, successors, and assigns of the parties hereto.

X.

Attached hereto are the following documents incorporated by reference herein as set out and marked as Exhibit I, Exhibit II.

If the above conforms to your understanding of the agreement between us, please sign and return two copies to us in the time specified above.

Sincerely yours,

EATON OPERATING COMPANY, INC.

By B A Eaton
B. A. Eaton, President and Project Manager

ACCEPTED AND AGREED TO THIS 19 DAY OF August, 1980.

RIDDLE OIL COMPANY

By: [signature]

EXECUTOR OF THE ESTATE
OF MAJOR A. RIDDLE

Agreement with Saldana Family Members

LAW OFFICES OF
MANN, CRONFEL, DICKINSON & SALDAÑA
VILLA CASTILE BUILDING
1616 FLORES AVE. - P. O. DRAWER [illegible]
LAREDO, TEXAS 78040
TEL. AC [illegible]

ED MANN
LAWRENCE A. MANN
A. CRONFEL MEURER
CHARLES R. DICKINSON, JR.
FRANCISCO J. SALDAÑA, JR.

CHARLES R. DICKINSON, JR.
Certified Specialist
Estate Planning and Probate Law
Texas Board of Legal Specialization

October 3, 1980

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

ATTN: Mr. Sid Walker.

RE: Geopressure testing of Saldana No. 1 and No. 2 Wells, Zapata County, Texas.

Dear Mr. Walker:

Enclosed please find proposed form of landowner's consent to geopressure testing to be conducted under agreement with Riddle Oil Company for your comments.

Please get back to me as soon as possible in order to discuss this matter further.

Very truly yours,

FRANK J. SALDANA, JR.

FJSJr:sfc
Enclosure

cc: EL PEYOTE MINERAL TRUST
1619 Reynolds
Laredo, Texas 78040

October 2, 1980

Eaton Operating, Inc.

Re: Geothermal and geopressure testing of the Riddle-Saldana Nos. 1 and 2 Wells

Dear Sirs:

This will evidence the consent of El Peyote Mineral Trust on behalf of all persons owning an interest in the minerals underlying the tract on which above two wells were drilled, for the testing of said two wells by you under agreement with Riddle Oil Company with respect to geothermal and geopressure testing in accordance with agreement between Eaton Operating, Inc. and Riddle Oil Company, dated   , a copy of which is hereto attached as Exhibit "A", upon the following terms and conditions:

1. All operations, including the plugging of said two wells and clean-up operations shall be completed within one hundred eighty (180) days from the date of this consent agreement.

2. It is understood and agreed that the Riddle Oil Company lease under which said two wells were drilled from El Peyote Mineral Trust as Lessor dated July 28, 1978 has terminated under its own terms and provisions, and nothing herein shall operate to enlarge the rights of Lessee thereunder except to the extent that additional time is granted in which to plug said wells as herein set out and to the extent that the testing operations are permitted under this agreement. Operations conducted by you shall not be deemed to be operations for drilling or reworking of any well under the provisions of said lease, or under any other lease covering the premises, and any incidental production obtained by you as a result of your operations shall not be considered as production from any lease covering said premises, or any part thereof.

3. You acquire no ownership interest in the oil, gas and/or other mineral underlying the premises, or the lands on which said wells are bottomed and upon the expiration of one hundred eighty (180) days from this date, all of your rights hereunder shall terminate or upon completion of plugging and clean-up operations, whichever occurs first.

4. You shall assume the responsibility for plugging each of said wells in accordance with all relevant rules, regulations and statutes of the State of Texas or the Railroad Commission of the State of Texas though nothing contained in this agreement shall relieve Riddle Oil Company of its obligation to plug such wells as required insofar as El Peyote Mineral Trust is concerned.

5. In connection with its operations hereunder, Eaton agrees that in the subsurface disposal of salt water it will not inject any salt water into any fresh water bearing sands and shall take all necessary measures to prevent the intrusion into fresh water sands of salt water resulting from its operations.

6. Eaton agrees to pay the owner of the surface estate for all damage to any existing roads, fences or other improvements, or to livestock, to the land itself, and all growing crops thereon resulting from any of its operations, or from any salt water, chemicals, oil or other substance being permitted to flow on the above land.

7. Eaton agrees to use reasonable care in preventing any salt water, oil or poisonous substances which are dangerous to livestock from being available to grazing livestock on said land as a result of its operations, and also from escaping on the land covered by this lease. In exercising such standard of reasonable care, Eaton agrees to erect adequate fences to prevent livestock from being exposed to any facilities or substances which might be considered a hazard or danger to such livestock. Eaton agrees to pay the owner of the surface or any grazing tenant, as the case may be, reasonable compensation for all damages to fences, water wells and reservoirs and all improvements now or hereafter situated on the surface of the premises, caused by Eaton's operations, unless such damage is repaired by Eaton to the satisfaction of the owner of the surface estate.

8. Eaton agrees, upon cessation of any testing or exploratory operations hereunder, to restore the land, other than roads presently in existance, used in connection with this operation to as near its original state as is practical, including discing and planting said land with four (4 lbs.) pounds of buffel grass seed per acre. No compensatory payment paid by Eaton to the owner of the surface estate shall relieve Eaton of such obligation.

9. Eaton agrees that before plugging any well, it will notify the owner of the surface estate in person or by telephone of its intention to do so, and will allow the owner of the surface estate a reasonable time, not exceeding seventy-two (72) hours thereafter, within which to elect to take over the hole for the purposes of attempting to make and complete a water well. Upon the owner of the surface estate's election, within the specified time, to attempt to complete the well as a water well, and complying with all rules and regulations of the Railroad Commission of the State of Texas and applicable statutes, Eaton will, at its expense set all plugs as may be required by the Railroad Commission at the base of the fresh water bearing sand designated by the owner of the surface estate, or her representative, and thereafter deliver the well to said owner of the surface estate, leaving in such well all surface casing and such production casing as may have been run and set to at least the depth of the designated water sand and thereafter the owner of the surface estate shall own the well and shall be responsible for all subsequent matters in connection with the well and for compliance with applicable statutes and regulations of all regulatory agencies having jurisdiction. Eaton shall have no liability to El Peyote Mineral Trust in connection with any of the operations which may be conducted by the owner of the surface estate after delivery of any such water well to said owner of the surface estate who shall thereafter bear all responsibility and liability with respect thereto.

10. El Peyote Mineral Trust reserves the right to execute oil, gas and/or mineral leases covering said property, or any part thereof.

11. In the event that, in the course of its operations, Eaton perforates sands capable of producing oil and/or gas in paying or commercial quantities it shall immediately notify El Peyote Mineral Trust to that effect, and notwithstanding anything herein contained to the contrary, El Peyote Mineral Trust reserves the right to takeover any such well for production of oil and/or gas upon the expiration of Eaton's operations hereunder, agreeing, in that event, to assume all obligations for plugging any such wells in accordance with all pertinent rules and regulations of the Railroad Commission of the State of Texas.

12. Upon delivery of this agreement, Eaton shall furnish to El Peyote Mineral Trust the following:

(a) Copies of any and all agreements between Riddle Oil Company or the Estate of M. A. Riddle and Eaton Operating Inc., and thereafter with true and correct copies of any subsequent agreements between such parties.

(b) A copy of any and all proposals submitted to the Department of Energy in connection with Eaton's proposed operations relative to said two wells, and thereafter any and all reports to the Department of Energy, or any other person whatsoever, containing the results of such testing of Eaton.

13. Eaton agrees to conduct its operations in a reasonable manner with due regards to the rights of El Peyote Mineral Trust, the surface estate owner and other lessees or grazing tenants and agrees that in conducting its operations it shall keep all gates closed except while actually passing through same and shall limit traffic and operations to the minimum requirements for the purposes of this agreement. Eaton agrees to use extreme care and caution in conducting its operations so as not to disturb hunters on said property during the deer and quail season in Zapata County, Texas, though some disruption is inevitable and anticipated by the parties.

14. Eaton agrees to pay to El Peyote Mineral Trust on behalf of all persons owning an interest in the oil, gas and/or other minerals underlying said property as compensation for possible damage to existing formations underlying said property in the immediate vicinity of said two wells, or resulting from the inevitable consumption of escape of natural gas, condensate or oil from said wells, the sum of $50,000.00. El Peyote Mineral Trust represents that it is authorized to negotiate such agreement on behalf of all persons owning an interest in the oil, gas and/or other minerals underlying said property and agrees to make timely and proper distribution of such compensatory damages.

15. This agreement is performably wholly in Zapata County, Texas, but any and all payments called for or provided for herein shall be payable to El Peyote Mineral Trust in Webb County, Texas.

16. This agreement is subject to approval of the Department of Energy and in the event that the Department of Energy does not approve this agreement in whole or in part this agreement shall be null and void and all rights hereunder shall immediately cease.

17. Eaton represents that it has sufficient experience in conducting the contemplated tests so as to carry out such operation in a prudent manner and that its operations will not endanger further or subsequent operations or production from other wells drilled or to be drilled on the above described property; and that any formation damage which will be caused will not be such so as extend to or affect the prospects of producing oil and/or gas from future wells drilled on said property.

18. Attached hereto are the following documents incorporated by reference herein as set out and marked as Exhibit I and Exhibit II.

This agreement is binding upon the parties hereto, their heirs, successors and assigns of the parties hereto.

Very truly yours,

EL PEYOTE MINERAL TRUST

By: F. J. Saldana
F. J. Saldana

By: Irene Saldana
Irene Saldana

By: Oscar M. Saldana
Oscar M. Saldana

ACCEPTED October 8, 1980

EATON OPERATING, INC.

BY: B A Eaton
B. A. Eaton, President and
Project Manager

APPENDIX B

Rig Contractor Agreements

Target Rig No. 2

Workover

Subcontract No. 0251-80

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)

Target Well Servicing
1000 One Allen Center
Houston TX 77002

NAME AND TITLE OF PERSON AUTHORIZED TO SIGN OFFER (Type or Print)

Gordon A. Griffith,	Vice-President
Typed Name	Title
G. A. G[illegible]	October 10, 1980
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):

____

Target Well Servicing

Company

DATA ON EQUIPMENT TO BE USED ON THE JOB

October 7, 1980

Date

Rig and equipment to be furnished by Subcontractor. (To be completed by prospective bidder. Award of Subcontract is subject to rig inspection.)

Subcontractor's Rig Number: SEE ATTACHED PAGE

Drawworks:

Engines-Number, Make, Model and HP:

Slush Pumps-Make, Model, and Size:

Auxiliary Pump and Power:

Derrick or Mast-Make, Size and Capacity:

Substructure-Height and Capacity:

Drill Pipe-Sizes and Amounts:

Drill Collars-Sizes and Numbers:

Mud Pump-GPM and PSI:

Centrifugal Pump for Water Transfer-Size, etc.:

Blowout Preventers-Power Actuated:

TARGET
WELL
SERVICING
CORPUS CHRISTI TEX.

RATE SCHEDULE

EFFECTIVE OCTOBER 1ST, 1980

TARGET WELL SERVICING

CORPUS CHRISTI, TEXAS
(A DIVISION OF ATCO LTD.)
P. O. BOX 9548 • 7454 LEOPARD ST. • CORPUS CHRISTI, TEXAS 78408
PHONE 512-883-6363

HOUSTON SALES OFFICE:
713-757-1046

Rig rates for location generally within 75 miles of Corpus Christi, San Diego or Kingsville.

Rig #1 as inventoried	$144/hour	Rig #6 as inventoried	$142/hour
Rig #2 as inventoried	$143/hour	Rig #7 thru #12 as inventoried	$142/hour
Rig #3 as inventoried	$142/hour	Rig #14 as inventoried	$200/hour (24 hour)
Rig #4 as inventoried	$142/hour		
Rig #5 as inventoried	$169/hour (24 hour)		

1) Full time tool pusher required on all rigs - $125/day. ($185/day-24 hour)
2) Mileage charges for crew cab .55¢ per mile.
3) Rig fuel extra and as inventoried. (Customer pays for what he uses — not a flat rate per hour!)
4) Material, consumables or rentals if furnished by Target at cost plus 10% to customers account.
5) Ram rubbers charged back to customer in cases of abnormal or unusual use.
6) Minimum charge of 10 hour day, 5 day week on all rigs (excluding 24 hour) including rig travel time, rig up, rig down, testing and stand by, excluding statutory holidays.
7) Trucking to and from well site of regular and additional equipment furnished by customer.
8) Separate hydraulic prime mover C/W 453 diesel for Bowen power swivel when required $285/day. (daylight operation)
9) Separate 200 barrel mud plant C/W 471 diesel $260/day. (daylight operation)
10) Swabbing after acid and/or sour gas $200/day.
11) For locations too distant for daily travel, generally in excess of 75 miles, the following rate changes apply: Out of town expenses for rig crew (excluding local labor) $150/day for a four man crew, plus round trip crew cab mileage charges from job site to crew's domicile one time per week and return (normally one round trip per week for daylite rig and one round trip every 4 days for 24 hour rig) at 55¢ per mile.
12) Pump substitution (subject to availability) National 165 or Oilwell 346D for Oilwell 640A (8000) or National 300 (8000) - Add $250/day ($350/day - 24 hour).
13) Trailer substitution - toolpusher trailer for mobile home - Add $15/day.
14) 12 foot substructure adaptable to Franks 300 Rig - Add $250/day.
15) 11 foot keel to deck workover barge 16 foot clearance work floor. Utilizing our normal equipment (subject to availability)
16) Eckols Model ULTRA 5½ tongs suitable for drill pipe up to 4½" $300/day (subject to availability)

Day Lite Rigs

Rig #1

Cooper LTO 550 Double Drum Back-In Oilwell Servicing and Workover Unit with 104', 240,000 lb. capacity derrick. Mounted on a Cooper C5 self propelled carrier with GMC 12V71N diesel engine and Allison CLBT 5860 torque converter transmission and 22' hydrotarder on brake system unit with 12.5 KW diesel electric power plant and derrick lights, rod hangers, tubing racks and Koomey separately powered 20 gallon capacity 3 valved closing unit.
Work Platform - 7' x 8' adjustable expanded metal with slide out sections.
Mud Pump - National JWS 5L Triplex C/W 671 Detroit Diesel C/W choke manifold.
Mud Tank - Size as required up to 200 barrels.
Blowout Preventor - Shaffer 6" x 1500 series dual hydraulic.
Tubing Tongs - Foster catheads, model 58-93.
Slips - Advance model "C" Air Spider.
Free use of Bowen Power Swivel HDS - 2 or Bowen Power Sub-PS-60. Off rig hydraulics.
Oil Saver - Guiberson Model H.
Block McKissick - 100 ton.
Elevator and Links - B.J. or King.
Tool Pushers trailer and crew dog house trailer. (Combined office trailer-Dog house Rig #1)
Misc. - Necessary tools and inserts to handle 2⅜" and 2⅞" regular tubing, ½" to ⅞" rods.

Rig #2

Cooper LTO 350 Back-In Workover and Servicing rig powered by GM 8V71 engine and Allison CLBT-750 torque converter transmission, double drum hoist, Cooper 104 foot clearance 240,000 lb. capacity derrick, equipped with hydrotarder, brakes, self contained 12.5 KW diesel electric plant and derrick lights, rod hangers, tubing racks and Koomey separately powered 20 gallon capacity 3 valved closing unit.
Accessories - Same as Rig #1

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number Saldana No. 2 County Zapata
State Texas Field Name Martinez Well Location and
Land Description A. Stehle Survey; Abstract 497; 300' FSL & 2200' FEL

CTP-02. COMMENCEMENT AND COMPLETION

The Subcontractor shall complete mobilization within five (5) calendar days after the date of receipt of Notice to Proceed and shall complete the entire work under the Unit Price Schedule ________________ days after the date of receipt of Notice to Proceed. The contract completion date will be extended by the amount of time spent on Contractor-Directed Operations and Standby, to the extent that is deemed necessary.

CTP-03. STATEMENT OF WORK

A. General Description of Work. The Subcontractor's work consists of furnishing all personnel, equipment, materials and services, and supplies as specified herein, for conducting the following work: See Tentative Drilling Program, Attachment ____

B. Minimum Equipment and Services. The minimum equipment, facilities, services, and items required to complete the work is specified in CTP-07. All contractor-furnished items will be delivered to and picked up from the drill site by others. The minimum equipment and services designated to be furnished and operated by the Subcontractor will be at no additional cost to the Contractor.

C. Workweek and Personnel Requirement. The Subcontractor shall furnish minimum three man qualified drilling crew, including toolpusher, to maintain a 24-hour day, 7-day week operation.

CTP-04. MUD PROGRAM

Contractor agrees to furnish all mud additives and chemicals and will arrange to purchase all necessary engineering services. Mud program will be designed as dictated by hole conditions.

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

CTP-07. MINIMUM EQUIPMENT AND SERVICES

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
1. Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location.		XX
2. Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3. Fishing tool services and fishing tool rental.	XX	
4. Derrick timbers.		XX
5. Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)		XX
6. Conventional drift indicator.		XX (?)
7. Earthen mud pits and reserve pits.	XX	
8. Steel mud tanks if required.		XX
9. Necessary pipe racks and rigging up material.		XX
10. Normal storage for mud and chemicals.		XX
11. Necessary spools, flanges and fittings to connect blowout preventers.		XX

	To Be Provided By And At Expense of	
	Contractor	Subcontractor
12. Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	XX	
13. Staked, levelled and compacted location, including earth pits.	XX	
14. Rat and mouse holes to meet subcontractor's requirement.		XX
15. Test tanks with pipe and fittings.	XX	
16. Separator with pipe and fittings.	XX	
17. Labor to connect and disconnect Subcontractor's mud tank.		XX
18. Labor to disconnect and clean test tanks and separator.	XX	
19. Drilling mud, chemicals, lost circulation materials and other additives.	XX	
20. All tubular goods, miscellaneous line pipe and fittings.	XX	
21. All testing tools including inflatable and retrievable packers.	XX	
22. Special tools, casing scraper, etc.	XX	
23. Special mud pump capacity in excess of rig requirements.	XX	
24. Wireline split and conventional core barrels and wireline core catchers: two each ten-feet long split core barrel; one each twenty-feet long conventional barrel.	N/A	
25. Conventional core bits, barrels and catchers.	XX	
26. Diamond wireline core bits.	N/A	
27. Cement and cementing service.	XX	
28. Logging services.	XX	

		To Be Provided By And At Expense Of	
		Contractor	Subcontractor
29.	Directional, caliper, or other special services.	XX	
30.	Gun or jet perforating services.	XX	
31.	Core boxes, wrapping supplies, and storage facilities.	XX	
32.	Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33.	Equipment for drill stem testing.	XX	
34.	Mud Logging Services.	XX	
35.	Sidewall Coring Services.	XX	
36.	Welding Service (Except for Subcontractor's equipment).	XX	
37.	Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38.	Casing scratchers and centralizers.	XX	
39.	Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40.	Water at Source and Water Hauling Service.	XX	
41.	Water storage tanks 1000 gallon capacity.		XX
42.	Fuel and lubricants for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel in excess of ______ per gallon.		XX
43	Drill pipe. ________________		
44.	Drill collars. ________________		
45.	Handling tools, clamps, etc., for each drilling assembly.		
46.	Weight indicator.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
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.

	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

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.

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The Subcontractor will be required to make his own arrangements with his employees for housing and feeding. The Subcontractor may locate toolpusher's house trailer near the drilling location, as designated by the Contractor.

CTP-12. DERRICK MISALIGHMENT

If, at any time, the Subcontractor's derrick becomes misaligned over a hole, the Subcontractor shall be required to commence realignment operations within eight hours of the misalignment. If such misalignment occurs as the result of fault or negligence on the part of the Subcontractor, the Subcontractor shall receive no compensation for the time or cost spent in realignment. If the misalignment is not the fault of, or caused by, Subcontractor negligence, the Subcontractor shall be compensated under Item 2. of the Unit Price Schedule.

CTP-13. LOSS OF HOLE

A hole shall be termed "lost" if the Contractor determines that the condition of the hole will prevent its successful completion, or if for any reason the Contractor deems it impractical to continue drilling. If the Contractor determines that a hole has been lost before required depth has been attained, and that further attempts to complete it will be impractical, he shall order work on the hole stopped, shall investigate the circumstances in contributing to its loss, and shall notify the Subcontractor of his decision in writing. The Contractor may, at his option, order the commencement of work at an alternate location.

Contractor shall assume liability, while work is being performed under Contractor-directed operations, for loss of, damage to, or destruction of the hole, Subcontractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, subs, stabilizers, and bits, unless such loss, damage, or destruction shall be caused by the Subcontractor's fault or negligence.

CTP-14. ABANDONMENT

In the event that, prior to completion of the work required, a hole covered by this Subcontract is abandoned, upon direction of the Contractor, the Subcontractor will be paid for work performed under the applicable items of the Unit Price Schedule.

The term "abandonment" as used in this paragraph shall mean abandonment to suit the convenience of the Contractor, as directed by the Contractor, under conditions which do not come within the scope of the paragraph entitled "Loss of Hole" of these specifications.

CTP-15. STANDARD FOR PRESSURE VESSELS

All Subcontractor's compressed air equipment and accessories shall be designed, fabricated, inspected, and certified in accordance with the SAME Boiler and

Pressure Vessel Code, Section VIII. For equipment fabricated under the 1968 Code, either Division I or Division II (but not both) of the Code may be used.

CTP-16. PRESERVATION OF ANTIQUITIES, WILDLIFE, AND LAND AREAS

Federal law provides for the protection of antiquities located on land owned or controlled by the U. S. Government. Antiquities include Indian graves, or campsites, relics, and artifacts. The Subcontractor shall control the movements of his personnel and his Subcontractor's personnel at the jobsite to ensure that any existing antiquities discovered thereon will not be disturbed or destroyed by such personnel. It shall be the duty of the Subcontractor to report the existence of any antiquities so discovered. The Subcontractor shall also preserve all vegetation except where such vegetation must be removed for survey or construction purposes. Further, all wildlife shall be protected.

CTP-17. RESPONSIBILITY FOR LOSS OF OR DAMAGE TO EQUIPMENT

1. Subcontractor's Surface Equipment. Subcontractor shall be liable at all times for damage to or destruction of Subcontractor's surface equipment including all drilling tools, machinery, and appliances for use above the surface and for any other type of equipment including in-hole equipment when such in-hole equipment is above the surface, regardless of when or how such damage or destruction occurs. The Contractor shall be under no liability to compensate the Subcontractor for any such loss except loss of damage thereto caused by negligence of the Contractor, its agents, or employees.

2. Loss of Tools in the Hole

   a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.

      i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.

      ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

b. Contractor-Furnished Equipment. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor.

CTP-18. CONTRACTOR MINIMUM EQUIPMENT REQUIREMENTS AND STANDARDS

The following American Petroleum Institute Standards and Recommended Practices of the latest issue, as of the date of bid opening, are a part of these specifications whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structures
3.	API Std. 7	Specification for Rotary Drilling Equipment
4.	API Std. 8A	Specification for Hoisting Equipment
5.	API Std. 9A	Specification for Wire Rope
6.	API RP-5C1	Recommended Practice for Care and Use of Casing, Drill Pipe and Tubing
7.	API RP-9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service
8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

Target Rig No. 15

Plugging and Abandonment

Subcontract No. 0251-80

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)

Target Well Servicing
1000 One Allen Center
Houston TX 77002

NAME AND TITLE OF PERSON AUTHORIZED TO SIGN OFFER (Type or Print)

Gordon A. Griffith,	Vice-President
Typed Name	Title
G. A. Griffith	December 2, 1980
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):

Target Well Servicing

Company

DATA ON EQUIPMENT TO BE USED ON THE JOB

December 2, 1980

Date

Rig and equipment to be furnished by Subcontractor. (To be completed by prospective bidder. Award of Subcontract is subject to rig inspection.)

Subcontractor's Rig Number: (SEE ATTACHED PAGE)

Drawworks:

Engines-Number, Make, Model and HP:

Slush Pumps-Make, Model, and Size:

Auxiliary Pump and Power:

Derrick or Mast-Make, Size and Capacity:

Substructure-Height and Capacity:

Drill Pipe-Sizes and Amounts:

Drill Collars-Sizes and Numbers:

Mud Pump-GPM and PSI:

Centrifugal Pump for Water Transfer-Size, etc.:

Blowout Preventers-Power Actuated:

Target Well Servicing
1000 One Allen Center
Houston, Texas 77002

December 2, 1980

Rig #15

Cooper 4210 Back-In Workover Servicing rig powered by GM 8V71 engine and torque converter transmission, double drum hoist, Cooper 96 foot 205,000 lb., capacity derrick, equipped with hydrotarder, brakes, self contained 12.5 kw diesel electric plant and derrick lights, rod hangers, tubing racks and komey, separately powered 20 gallon capacity 3 valved colsing unit.

Work Platform - 7'x 8 adjustable.
Mud Pump - Oilwell 346P-ST Tripley C/W 671 Detroit Diesel
Mud Tank - 200 barrels
Blowout Preventor - Shaffer 6" x 1500 series dual hydraulic
Tubing Tongs - Foster catheads, Model 58-93
Slips - Guiberson F-1 spider
Free use of Bowen Power Swivel HDS
Oil Saver - Guiberson Model H
Block McKissick
Elevator and Lings - B.J. or King
Mis. - Necessary tools and inserter to handle
2 3/8" and 2 7/8" regular tubing 1/2" to 7/" rods.

(GM 8V71 engine) 273 H.P. @ 1800 RPM
(671 Detroit) 205 H.P. @ 1800 RPM

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well.Name and Number Saldana No. 2 County Zapata
State Texas Field Name Martinez Well Location and
Land Description A. Stehle Survey; Abstract 497: 300' FSL & 2200' FEL

CTP-02. COMMENCEMENT AND COMPLETION

The Subcontractor shall complete mobilization within five (5) calendar days after the date of receipt of Notice to Proceed and shall complete the entire work under the Unit Price Schedule _______________ days after the date of receipt of Notice to Proceed. The contract completion date will be extended by the amount of time spent on Contractor-Directed Operations and Standby, to the extent that is deemed necessary.

CTP-03. STATEMENT OF WORK

A. General Description of Work. The Subcontractor's work consists of furnishing all personnel, equipment, materials and services, and supplies as specified herein, for conducting the following work: See Tentative Drilling Program, Attachment ____

B. Minimum Equipment and Services. The minimum equipment, facilities, services, and items required to complete the work is specified in CTP-07. All contractor-furnished items will be delivered to and picked up from the drill site by others. The minimum equipment and services designated to be furnished and operated by the Subcontractor will be at no additional cost to the Contractor.

C. Workweek and Personnel Requirement. The Subcontractor shall furnish minimum three man qualified drilling crew, including toolpusher, to maintain a 24-hour day, 7-day week operation.

CTP-04. MUD PROGRAM

Contractor agrees to furnish all mud additives and chemicals and will arrange to purchase all necessary engineering services. Mud program will be designed as dictated by hole conditions.

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

CTP-07. MINIMUM EQUIPMENT AND SERVICES

		To Be Provided By And At Expense Of	
		Contractor	Subcontractor
1.	Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location.		XX
2.	Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3.	Fishing tool services and fishing tool rental.	XX	
4.	Derrick timbers.		XX
5.	Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)		XX
6.	Conventional drift indicator.		XX
7.	Earthen mud pits and reserve pits.	XX	
8.	Steel mud tanks if required.		XX
9.	Necessary pipe racks and rigging up material.		XX
10.	Normal storage for mud and chemicals.		XX
11.	Necessary spools, flanges and fittings to connect blowout preventers.		XX

	To Be Provided By And At Expense of	
	Contractor	Subcontractor
12. Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	XX	
13. Staked, levelled and compacted location, including earth pits.	XX	
14. Rat and mouse holes to meet subcontractor's requirement.		XX
15. Test tanks with pipe and fittings.	XX	
16. Separator with pipe and fittings.	XX	
17. Labor to connect and disconnect Subcontractor's mud tank.		XX
18. Labor to disconnect and clean test tanks and separator.	XX	
19. Drilling mud, chemicals, lost circulation materials and other additives.	XX	
20. All tubular goods, miscellaneous line pipe and fittings.	XX	
21. All testing tools including inflatable and retrievable packers.	XX	
22. Special tools, casing scraper, etc.	XX	
23. Special mud pump capacity in excess of rig requirements.	XX	
24. Wireline split and conventional core barrels and wireline core catchers: two each ten-feet long split core barrel; one each twenty-feet long conventional barrel.	N/A	
25. Conventional core bits, barrels and catchers.	XX	
26. Diamond wireline core bits.	N/A	
27. Cement and cementing service.	XX	
28. Logging services.	XX	

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
29. Directional, caliper, or other special services.	XX	
30. Gun or jet perforating services.	XX	
31. Core boxes, wrapping supplies, and storage facilities.	XX	
32. Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33. Equipment for drill stem testing.	XX	
34. Mud Logging Services.	XX	
35. Sidewall Coring Services.	XX	
36. Welding Service (Except for Subcontractor's equipment).	XX	
37. Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38. Casing scratchers and centralizers.	XX	
39. Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40. Water at Source and Water Hauling Service.	XX	
41. Water storage tanks 1000 gallon capacity.		XX
42. Fuel and lubricants for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel in excess of ______ per gallon.		XX
43 Drill pipe. ______		
44. Drill collars. ______		
45. Handling tools, clamps, etc., for each drilling assembly.		
46. Weight indicator.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
47. If applicable, drill pipe protectors for Kelly joint and each joint of drill pipe running inside of casing for use with normal strings of drill pipe.	XX	
48. Automatic driller (Optional).	N/A	
49. Materials for "boxing in" rig and derrick.	N/A	
50. Conventional core barrel.	XX	
51. Drilling recorder-minimum 2-pin.	XX	
52. Extra labor for running and cementing casing.	XX	
53. Casing tools.	XX	
54. Running of casing-conductor.	XX	
55. Running of casing-surface.	XX	
56. Running of casing protection, if applicable.	XX	
57. Running of casing production, if applicable.	XX	
58. Running of casing liner, if applicable.	XX	
59. Power casing tongs.	XX	
60. Tubing tools.	XX	
61. Power tubing tong.	XX	
62. Swabbing unit with swabbing line	XX	
63. Swab.	XX	
64. Swab lubricator.	XX	
65. Swab rubbers.	XX	
66. Light plant-adequate capacity for night-time operations, Subcontractor requirements.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
67. Drill rig-minimum failing 1500 rotary rig or approved equal for continuous wireline coring and drilling to ± 1500 feet.	N/A	
68. Two adequate circulating pumps and adequate mud mixing pumps.		XX
69. 1000 gallon water truck with driver for hauling water within two miles of work sites.	N/A	
70. Minimum of one two-way communications system.	N/A	
71. IADC Daily Drilling Report, Bit Record and Tally Forms.		XX

The above Subcontractor designated items are the minimum acceptable requirements for the Subcontractor drilling equipment. This is not intended to be a complete list of items to be furnished by the Subcontractor. The Subcontractor is required to furnish all drilling maintenance tools, materials, and equipment not herein designated, but which are normal components for a complete drilling rig required for drilling and testing operations described in these specifications.

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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.

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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.

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2. Loss of Tools in the Hole

   a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.

      i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.

      ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

b. Contractor-Furnished Equipment. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor.

CTP-18. CONTRACTOR MINIMUM EQUIPMENT REQUIREMENTS AND STANDARDS

The following American Petroleum Institute Standards and Recommended Practices of the latest issue, as of the date of bid opening, are a part of these specifications whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structures
3.	API Std. 7	Specification for Rotary Drilling Equipment
4.	API Std. 8A	Specification for Hoisting Equipment
5.	API Std. 9A	Specification for Wire Rope
6.	API RP-5C1	Recommended Practice for Care and Use of Casing, Drill Pipe and Tubing
7.	API RP-9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service
8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

APPENDIX "C"
SUMMARY OF RIG OPERATIONS
RIDDLE - SALDANA No. 2
RE-ENTRY OF TEST WELL

Daily Drilling Report Date	Day No.	Operations
10-23-80	1	Loaded rig and equipment and moved to location.
10-24-80	2	Arrived on location and began to rig up. Checked pressure on well. Shut-in tubing pressure and shut-in casing pressure were 2600 psi.
10-25-80	3	Rigged up Swaco choke and flow lines. Started displacing water with 13.2 ppg mud. Had 400 psi on the casing and 700 psi on the tubing. Continued displacing water with 13.2 ppg mud.
10-26-80	4	Circulated and conditioned mud until well was dead. Rigged up rig floor and tongs. Tested blowout preventers to 5000 psi and hydril to 3500 psi. Pulled 2-3/8" O.D. tubing out of the hole (total 258 joints). Laid down packer and picked up 6" O.D. bit and ran in hole to 9688'. Circulated and conditioned mud prior to logging.
10-27-80	5	Rigged up Dialog. Ran casing inspection log from 9755' to surface. Rigged down Dialog. Nippled down blowout preventer stack and removed old tubing hanger. Nippled up new tubing hanger, but seal failed.
10-28-80	6	Installed new seal in tubing hanger, nippled up tubing head, and tested same to 5000 psi. Nippled up blowout preventer stack and tested same to 5000 psi (hydril to 3500 psi). Rigged up floor and tongs. Ran in hole with collar made into a rotary shoe at the bottom, tagged fill at 9760' and worked same to 9819'. Circulated and conditioned mud. Replaced packing in mud pump. Pulled and layed down 6 joints of tubing (bottom at 9642'). Rigged down floor and tongs. Nippled down blowout preventer stack and nippled up christmas tree. Tested same to 5000 psi. Rigged up Dialog and ran in hole. Tagged bottom at 9813'.
10-29-80	7	Rigged down Dialog. Rigged down equipment and rig. Moved rig off location.

10-30-80	8	Rigged up Halliburton and displaced 13.2 ppg mud with 9.0 ppg completion brine. Rigged down and released Halliburton. Had a shut-in tubing pressure of 1950 psi. Opened well to pit on open choke and had a flowing tubing pressure of 250 psi and a shut-in casing pressure of 2045 psi. Shut-in well for pressure build up.
10-31-80	9	Rigged up Dresser Atlas and perforated interval from 9745' to 9820' with 8 holes per foot. Well had a shut-in tubing pressure of 2450 psi and produced a total of 250 barrels of water.
11-01-80	10	No activity. Shut-in tubing pressure was 2450 psi.

APPENDIX "C"
SUMMARY OF RIG OPERATIONS
RIDDLE - SALDANA No. 2
PLUGGING AND ABANDONMENT OF TEST WELL

Daily Drilling Report Date	Day No.	Operations
12-04-80	1	Moving in rig. Set tank and pump. Changed rams in blowout preventers and loaded up all test equipment, preparing to move same to Lafayette. Finished moving in rig.
12-05-80	2	Moved in and rigged up cementing equipment and tied in vacuum trucks. Displaced salt water with 13.5 ppg mud and changed out lines. Nippled up blowout preventors and pulled out of the hole, laying down 720' of 2-3/8" O.D. tubing.
12-06-80	3	Pulled 2-3/8" O.D. tubing out of hole. Ran in hole with gauge ring/junk basket to 9640'. Collar locator indicating rough pipe. Ran in hole with EZSV cement retainer and set same at 9547'. Pulled out of the hole with setting tool. Ran in hole with stinger for cement retainer.
12-07-80	4	Finished running in the hole to 9534'. Pumped 13.0 ppg mud, breaking formation with 4100 psi at 1 barrel per minute. Mixed and pumped 200 sacks of cement (190 sacks into formation and 10 sacks above retainer). Circulated and pulled out of the hole, laying down 24 joints of pipe. Rigged up and ran a cast iron bridge-plug and set same at 9386'.
12-08-80	5	Nippled down blowout preventer stack, double ring adapter, and double string tubing hanger. Rigged up casing jacks and welded 7-inch casing pump to casing stub. Pulled 280,000 lbs. to clear slips from bradenhead. Stretch indicated pipe stuck at 5800'. Rigged up free-point indicator.
12-09-80	6	Working 7-inch casing with jacks. Ran in hole with free point indicator, but it was not working properly. Pulled out of hole and replaced arms. Ran in hole with tool - deepest point at 6100' was partially free. Pulled out of the hole with free point indicator and ran in hole with chemical casing cutter. Cut casing at 6061'. Pulled out of the hole with landing joint and 3 full joints. Pulling between 120,000 and 130,000 lbs. Rigged-down jacks, stripped off bowls, and loaded out jacks. Rigged up 13-3/8" O.D. blowout preventers.

12-10-80	7	Finished changing to 7-inch O.D. rams. Replaced rig floor. Rigged up casing crew and lay-down unit. While laying down 7-inch, casing tongs failed. Rigged-up replacement tongs and layed down 53 joints.
12-11-80	8	Opened well and tied in hydraulic tong unit. Continued laying down 7-inch casing. Rigged down and loaded out casing tools and lay-down machine. Changed rams. Picked up and ran in hole with EZSV cement retainer on 2-3/8" O.D. tubing.
12-12-80	9	Ran in hole with 9-5/8" O.D. cement retainer and set same at 6027'. Rigged up cementing unit and tested tubing. Rebuilt casing connections. Leak developed on tubing-hanger flange. Picked up BOP stack and made tie-ins. Mixed and pumped 80 sacks of class "H" cement with a slurry weight of 15.6 ppg. Top of plug at 5782', bottom of plug at 6027'. Pulled out of the hole 420' and reversed out.
12-13-80	10	Layed down 2-3/8" O.D. tubing. Started digging out casing hanger and bradenhead.
12-14-80	11	Continued digging out cellar. Nippled down BOP stack. Rigged up CRC and ran in hole to 400' with casing cutter. Tool failed. Replaced 9-5/8" casing cutter, ran in hole and cut 9-5/8" O.D. casing at 400'. Pulled out of the hole and picked up 9-5/8" spear; pulled casing free with 51,000 lbs.
12-15-80	12	No operations. Shut down for Sunday.
12-16-80	13	Rigged up casing crew and lay-down machine. Layed down 9 joints of 9-5/8" O.D. 47.0-lbs/ft casing. Rigged down and loaded out casing crew equipment and lay-down machine. Picked up 13-3/8" O.D. EZSV cement retainer and ran in hole and set same at 352'. Rigged up cementing equipment. Attempted to break down formation without success. Spotted a 250-sack class "H", 15.0 ppg slurry, cement plug from 0' to 352'. Layed down 2-3/8" O.D. tubing. Washed cement out of blowout preventors and top of pipe.
12-17-80	14	Finished rigging down and moving out. Cut off 20" O.D. and 13-3/8" O.D. casing. Welded steel plate on stub 3' below ground level.

APPENDIX "D"
SUMMARY OF RIG OPERATIONS
RIDDLE - SALDANA No. 1
COMPLETION OF DISPOSAL WELL

Daily Drilling Report Date	Day No.	Operations
10-28-80		Finished moving in rig.
10-30-80	1	Rigged up and nippled down bottom of the tree and master valve. Nippled up and tested blow-out preventer stack to 5000 psi. Tested hydril to 3500 psi. Rigged up floor and tongs. Displaced water and 13.3 ppg mud. Circulated and conditioned mud. Pulled out of the hole.
10-31-80	2	Finished pulling out of the hole. Made up setting tool and cement retainer. Ran in hole with cement retainer. Circulated and set EZSV at 9680'. Attempted to break formation down with 6500 psi -unable to break it down. Set cement plug from 9475' to 9675'. Reversed out and pulled 5 stands. Pulled out of the hole, laying down 2-3/8" O.D. tubing. Nippled down stack and welded on 7-inch O.D. casing.
11-01-80	3	Removed 7-inch O.D. casing slips and seal. Rigged up 7-inch O.D. casing slips. Rigged up Dialog and ran free point indicator. Casing was found to be stuck solid at 4781', (free at 4750'). Nippled up blowout preventers and Hydril annular preventer. Rigged up Dialog to cut 7-inch O.D. casing. Ran in hole and cut 7-inch O.D. casing at 4758', at which point the cutting tool became stuck, but it was possible to work it free. Began to pull cutting tool out of the hole, but tool again became stuck at the top of a joint and could not be worked free. Tied tool with block and pulled off jet shoe body. Rigged down Dialog and rigged up casing crew. Began pulling 7-inch O.D. casing out of the hole and laying down same. Experienced problems with the tongs; they would not hold onto collars. Ordered back up tongs.
11-02-80	4	Finished rigging up back-up tongs and continued laying down 7-inch O.D. casing - very tight connections. A hydraulic line ruptured, causing the hydraulic unit to fail. Replaced the hydraulic unit. Finished laying down 7-inch O.D. casing and loaded out the casing crew. Changed the blowout preventer rams and picked up 9-5/8" O.D. casing scraper. Ran in hole.
11-03-80	5	Washed down with 9-5/8" O.D. casing scraper. Circulated and conditioned mud at 4758'. Pulled out of the hole, but

pin backed out of bottom of collar. Ran in hole with collar down and engaged fish. Pulled out of the hole with fish and layed down same. Picked up Baker cement retainer and ran in hole to 4720'. Tested tubing to 4500 psi and rigged up Halliburton.

11-04-80	6	Set a cement retainer at 4720' and put 1200 psi on casing; unable to break down formation at 4000 psi. Spotted a 200' cement plug in the 9-5/8" O.D. casing between 4515' and 4715'. Circulated in reverse and pulled out of the hole. Laid down setting tool and rigged up Dresser-Atlas. Ran a cement bond log which had very poor resolution. Rigged down Dresser-Atlas. Rigged up McCullough to run casing inspection log. Achieved very poor resolution. Rigged up Dresser-Atlas again and ran cement bond log. Picked up and ran in hole with Halliburton bridge-plug on wireline. It failed to set. Pulled out of the hole to repair collar locator. Ran back in the hole with Halliburton bridge-plug and it again failed to set. Attempted to come up the hole, but the bridge plug kept hanging up. Worked bridge plug back down to 4019' and worked on it approximately 20 minutes, pulling up to 4000 lbs. Pulled out of rope socket and pulled out of the hole with wireline. Picked up overshot and skirt guide. Ran in hole and tagged fish at 4536'. Worked over fish pulling 4000 lbs over weight of string until overshot came loose. Could not get another hold on the fish. Pulled out of the hole and broke down overshot for inspection.
11-05-80	7	Rigged up McCullough and ran casing inspection log from 4000' to surface. Made up Baker bridge-plug. Ran in hole with bridge-plug on 2-3/8" O.D. tubing and attempted to set same. Unable to set. Pulled out of the hole with bridge-plug. Ran back in hole open-ended to 3518'. Rigged up Halliburton and set a 200' cement plug from 3318' to 3518'. Pulled out of the hole. Ran in hole with Baker full bore packer on 2-3/8" O.D. tubing to 2950' and tested annulus to 500 psi. Rigged up Dresser-Atlas and perforated interval from 3158' to 3160'. Attempted to run cement squeeze but could not pump into perforations.

11-06-80	8	Perforated interval from 3157' to 3159' with 4 shots per foot and squeezed with 230 sacks of Class H cement pumped at 3 barrels per minute and 2400 psi. Waited for cement to set for 6.5 hours and tested squeeze to 1000 psi. Re-set retrievable cementing tool at 2602'. Perforated interval between 2811' and 2813' and squeezed with 200 sacks of Class H cement, pumped at 2.5 barrels per minute and 1400 psi. Waited for cement to set for approximately 8 hours.
11-07-80	9	Pulled out of the hole after testing cement squeeze to 1350 psi. Ran in hole with 8½-inch O.D. bit and tagged cement top at 2736'. Drilled cement from 2736' to 2813'. Tested squeeze perforations from 2811' to 2813'; took fluid at 700 psi. Pulled out of the hole.
11-08-80	10	Ran in hole with 2-3/8" O.D. tubing and retrievable cementing tool. Set same at 2601' and attempted to break down perforations. They held 4500 psi. Pulled out of the hole with 2-3/8" O.D. tubing and retrievable cementing tool. Washed down from 2835' to 3113'. Drilled cement from 3113' to 3132'.
11-09-80	11	Continued drilling cement to 3160'. Tested casing to 1000 psi. Ran in hole to 3335' and displaced mud with saltwater. Pulled out of the hole, laying down tubing and collars. Nippled down blowout preventers and nippled up wellhead. Began to rig down.
11-10-80	12	Moved rig off location.
11-11-80	13	Rigged up Dresser-Atlas and perforated interval from 3005' to 3100' with 4 holes per foot (held 500 psi on casing while perforating tubing). Rigged down Dresser-Atlas. Broke down perforations with 1300 psi. Pumped in 86 barrels of brine at 15 barrels per minute and 900 psi. Loaded produced water from test well (90 barrels) and pumped it into the disposal well at approximately 4 barrels per minute at a maximum of 300 psi. Had an instant initial shut-in of 100 psi, which was reduced to 0 psi approximately 5 minutes after the initial shut-in.

APPENDIX "D"
SUMMARY OF RIG OPERATIONS
RIDDLE SALDANA No. 1
PLUGGING AND ABANDONMENT OF DISPOSAL WELL

Daily Drilling Report Date	Day No.	Operations
12-17-80	1	Moved in rig and rigged up. Removed christmas tree and installed blowout preventors. Picked up 9-5/8" O.D. EZSV cement retainer and started going in hole with 2-3/8" O.D. tubing.
12-18-80	2	Ran in hole with 9-5/8" O.D. EZSV cement retainer to 2906' and set same. Rigged-up and displaced salt water with 11.0 ppg mud. Pumped 225 sacks of cement below retainer and 50 sacks above. Used class "H" cement at 15.5 ppg. Pulled out of the hole laying down 2-3/8" tubing. Dug out cellar to bradenhead valve and bled off trapped air. Rigged up 1-inch perforating gun with 4 shots per foot and ran in hole. Gun misfired. Pulled out of the hole. Replaced gun and perforated interval 400-399'. Pulled out of the hole and layed down gun. Pumped 31 barrels of mud down annulus.
12-19-80	3	Circulated both ways with a pressure of 900 psi at 2.5 barrels per minute. Mixed and pumped 160 sacks class "H" cement at 15.5 ppg. Lost returns - approximately 105 sacks of cement. Cleared perforations. Waited for cement to set for 5 hours. Displaced mud from hole with salt water. Mixed and pumped 270 sacks of class "H" cement, at 15.5 ppg, down the annulus with continuous returns. Rigged down cementing equipment and nippled down the blowout preventer stack.
12-20-80	4	Continued to rig down rig. Cut 20", 13-3/8", and 9-5/8" casing. Welded steel plate on to pipe stub.