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PLEASANT BAYOU GEOPRESSURED/GEOTHERMAL TESTING PROJECT BRAZORIA COUNTY, TEXAS

FINAL REPORT

JULY 1985

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PLEASANT BAYOU
GEOPRESSURED/GEOTHERMAL
TESTING PROJECT
BRAZORIA COUNTY, TEXAS

FINAL REPORT

by

P. K. Ortego
FENIX & SCISSON, INC.

for

U. S. DEPARTMENT OF ENERGY

July 1985

TABLE OF CONTENTS

Page

Page

FIGURES

TABLES

1.0 EXECUTIVE SUMMARY

Phase II-B production testing of the Pleasant Bayou No. 2 well began September 22, 1982. The test plan was designed to evaluate the capabilities of the geopressured-geothermal reservoir during an extended flow period. Tests were conducted to determine reservoir areal extent; aquifer fluid properties; fluid property change with production; information on reservoir production drive mechanism; long-term scale and corrosion control methods; and disposal well operations. During this phase of testing, operational aspects of geopressured-geothermal production were also evaluated.

The test was discontinued prematurely in May 1983 because of a production tubing failure. Most of the production tubing was recovered from the well and cause of the failure was determined. Plans for recompletion of the well were prepared. However, the well was not recompleted because of funding constraints and/or program rescheduling. Although the test was not taken to its conclusion, some of the original objectives were satisfied.

In March 1984, the Department of Energy, Nevada Operations Office (DOE/NV) directed that the site be placed in a standby-secured condition. In August 1984, the site was secured. Routine site maintenance and security was provided during the secured period. Effective April 1, 1985, the Geopressured-Geothermal Program was transferred from DOE/NV to the DOE Idaho Operations Office.

Table 1-1 is the chronological sequence of events included in this final report.

TABLE 1-1
PLEASANT BAYOU PROJECT
SEQUENCE OF EVENTS

1.	Continuation of Phase II-B testing	10-24-82	04-13-83
2.	Evaluation of downhole scaling	04-14-83	05-05-83
3.	Preparation for tubing recovery	05-06-83	07-05-83
4.	Tubing recovery operations	07-06-83	08-15-83
5.	Recompletion studies and procurement actions	08-16-83	02-23-84
6.	Restore reserve pit and place site on standby-secured	02-24-84	08-25-84
7.	Monitor and maintain site during secured period	08-26-84	04-01-85

2.0 INTRODUCTION

2.1 Background and Objectives

Phase II-B testing was a redesign of Phase II-A which had been discontinued in July 1981 when the downhole pressure monitoring equipment and wireline were lost in the No. 2 well. Previously in Phase I and Phase II-A, the downhole pressure was monitored while flowing and the pressure loss due to friction for different flow rates had been established.

During Phase II-B testing, the downhole pressures were not measured but were calculated. The primary objective of the first 90 days of Phase II-B was to further evaluate the capabilities and characteristics of the reservoir and compare the results with previous tests results. Beyond the first 90 days, objectives included additional reservoir characterization but also included some operational objectives such as determining the minimum practical manning requirements; establishing performance profiles and maintenance requirements of production equipment; evaluating the economics of gas sales; establishing programs for scale and corrosion control; and ultimately to evaluate and demonstrate electric power generations.

Gruy Petroleum Technology, Inc.'s final report, dated 12-31-82, and titled "Drilling and Completion of Pleasant Bayou No. 2 Brazoria County, Texas," discusses the Pleasant Bayou Project activities from initial drilling activities through the first 31 days of the Phase II-B test. This final report discusses the activities for the remainder of the Phase II-B test and subsequent project activities from termination of the Phase II-B test through transfer of the program to the Department of Energy's Idaho Operations Office.

3.0 CONTINUATION OF PHASE II-B TESTING

3.1 Data Gathering System

3.1.1 Microcomputer. During the first 31 days of the Phase II-B testing (09-22-82 - 10-23-82) Weatherly Engineering Data Systems provided a computerized data gathering system. The system is designed to allow accurate on-stream measurements on geopressured-geothermal wells. Calculations were performed to produce information related to well performance. All measurements and calculations were made at operator-defined intervals and logged on a printer in numeric form so that interpretation of meters or charts was not necessary. The operator could initiate a measurement or calculation on demand, so that activity could be monitored as closely as desired.

The major system components are shown on the information flow block diagram[1], Figure 3-1. The "brain" of the system is the microcomputer module, which performs the major timing, control, and calculation functions. It features a 3-MHz clock, 69 basic instructions, 64K bytes of memory addressing capability, two EIA standard RS232C communications ports, 16 bits of parallel input/output, and 16 levels of prioritized interrupts.

Closely associated with the microcomputer is the memory expansion module, which contains the bulk of the program and holds all the temporary values used in execution and calculation.

The operator interface was provided by an Intertec Data Systems video terminal featuring a typewriter-oriented keyboard. This device is used to enter command functions, date and time, report heading information, and other needed data. It also displays the results of operator-initiated functions.

Data acquisition for the system is handled by three different types of signal interfaces. Wellhead tubing and annulus pressures are gathered by a Panex Model 300 digital indicator featuring special transducers that can handle 10,000 psi at 0.01 percent accuracy. All other analog values are gathered by a Texas Instruments analog-to-digital converter module strapped to take standard 4-20 ma current loops from the transducers wired to it. Accuracy of these transducers is 0.25 percent of full scale. The pulses produced by the three liquid-flow turbines are accepted by Halliburton flow totalizers. These have six-digit liquid-crystal displays that can show whole barrels or tenths of a barrel, switch-selectable,

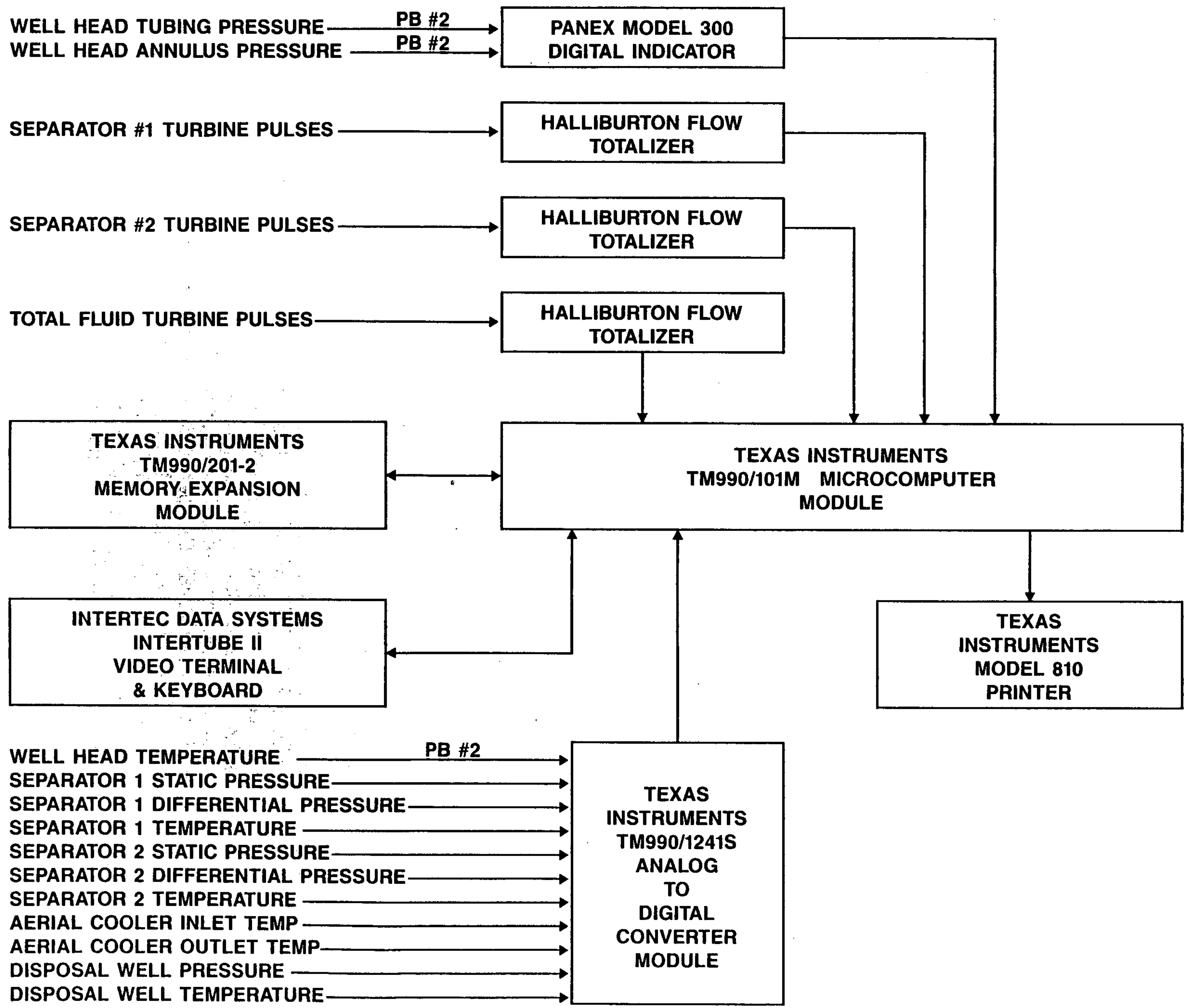


FIGURE 3-1 COMPUTERIZED DATA SYSTEM

and can accommodate different flow turbines by simple switch programming. Figure 3-2 is a schematic showing the location of each data sensor in the system.[1]

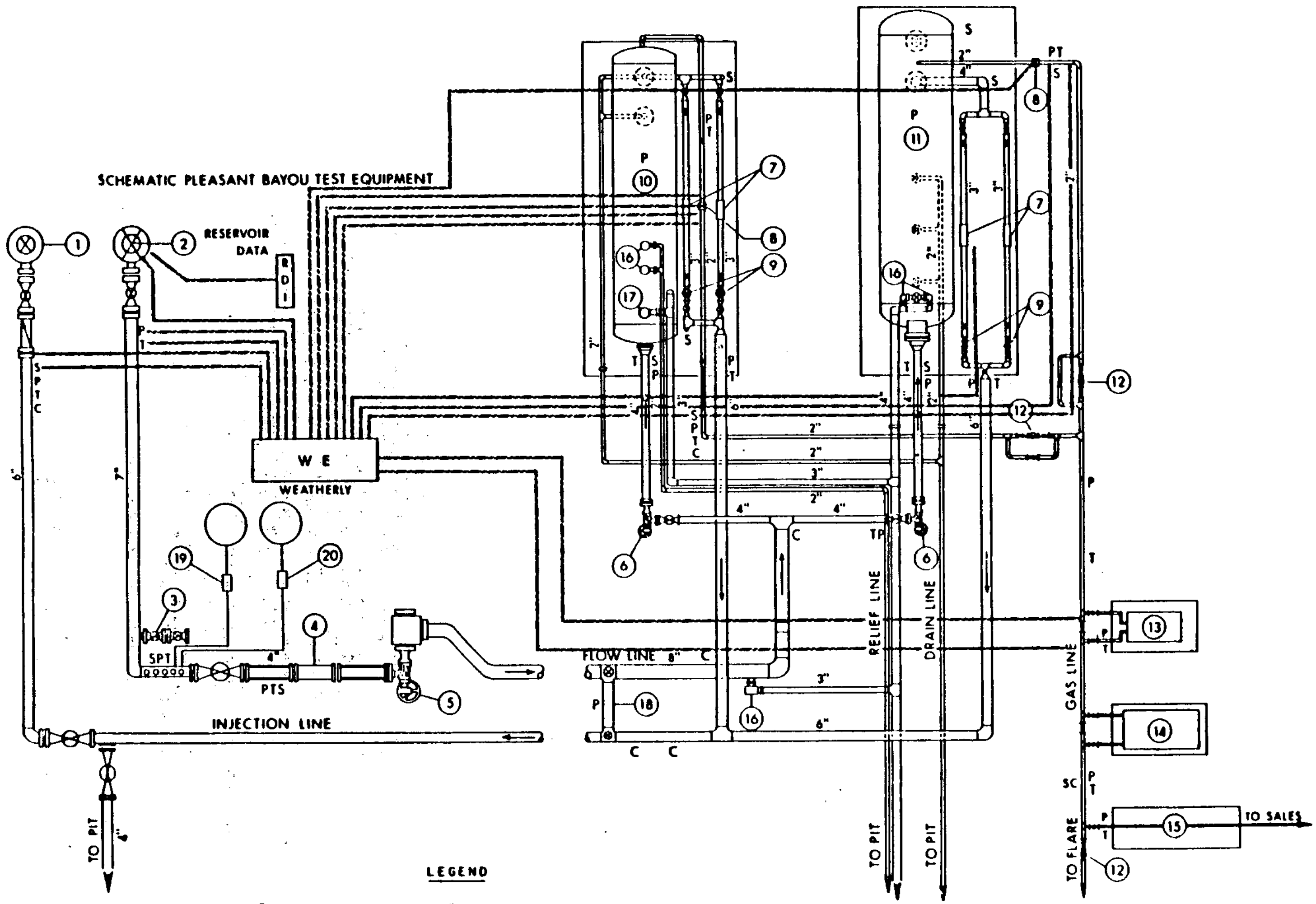
The reports logged by the system are produced on a Texas Instruments Model 810 impact-type printer, which features bidirectional printing at up to 150 characters per second and can print on multiple-part paper. Reports are produced in standard legal-size format. A sample of the data printout is shown in Figure 3-3. Table 3-1 is a glossary of printout item abbreviations. Power is supplied from an external 120-volt AC source. Batteries furnish a minimum of eight hours backup at full load.

This system provided the continuous high accuracy data required to further evaluate the reservoir. Use of the microcomputer system was discontinued at 2400 hours, 10-23-82.

3.1.2 Conventional. Prior to discontinuing use of the microcomputer system, more conventional type instrumentation was installed inside the instrument house, and inside the office trailer. Gas flow rate was measured through orifice meters with seven-day charts; fluid rates were measured with turbine meters. Both at the wellhead and at the separator dump; temperatures and pressures were measured with conventional gauges except for wellhead temperature and pressure which were measured using a Panex pressure/temperature transducer. The Panex display and printer unit was installed inside the office trailer so that these parameters could be monitored continuously. During normal production operations, physical inspection of the production system was conducted hourly. Production data was reported daily at 0800 hours. Figure 3-4 is a sample of the field recorded daily production report. These production reports were used for the remainder of the Phase II-B from 10-24-82 through 4-13-83.

3.2 Production Data

3.2.1 Brine and Gas Production. Table 3-2 is a summary of production data throughout the continuation of the Phase II-B test. During the 171.875 days, from 0001 hours 10-24-82 to 2100 hours 4-13-83, the well was flowing 162.4 days, or 94.5% of the time. During this period, the No. 2 well produced 2,984,653 barrels of brine and 65,727 MCF of gas, for an average gas fluid ratio of 22.02 SCF/barrel, and an average daily production rate of 18,378 barrels brine and 405 MCF gas based on flowing time. The flowing tubing pressure declined 1289 psi from 2789 psia to 1500 psia for an average decline rate of 7.93 psi per day based on flowing time. Figure 3-5 shows the flowing tubing pressure with respect to time during this test interval,



LEGEND

1 - disposal well
2 - test well
3 - ball valve
4 - 4" turbine meter
5 - 2" Willis M3G choke
6 - 2" Willis M6 choke
7 - 3" turbine meter
8 - 2" orifice flanges
9 - 3" dump valve
10 - separator no. 2
11 - separator no. 1
12 - 2" back pressure valve
13 - air cooler
14 - dehydration unit
15 - gas sales meter
16 - relief valve
17 - safety head
18 - bypass line
19 - scale inhibitor pump
20 - corrosion inhibitor pump

FIGURE 3-2 -- DATA SENSOR POINTS

WEATHERLY ENGINEERING DATA SYSTEMS — FIELD TEST DATA — DATE 10/22/1982

TIME	WHTP	WHAP	CSGP	WHT	STAT	DF	TMP	MCFD	TRBN 1	+	STAT	DF	TMP	MCFD	TRBN 2	+	TMCFD	TBOPD	GFR	FTR	FTR	T TRBN	DWP	DWT
1330	2735	-9	222	0	561	34	253	432.945	441053	226	373	0	0	0.000	91138	0	432.945	21696	19.96	271	270	540354	302	239
1345	2735	-9	216	0	562	34	254	433.111	441279	226	369	0	0	0.000	91138	0	433.111	21696	19.96	271	270	540563	298	240
1400	2735	-9	200	0	563	34	255	433.067	441506	227	366	0	0	0.000	91138	0	433.067	21792	19.87	271	270	540773	299	245
1415	2734	-9	193	0	563	34	254	434.008	441733	227	363	0	0	0.000	91138	0	434.008	21792	19.92	272	272	540982	298	240
1430	2734	-9	208	0	564	34	254	433.956	441959	226	360	0	0	0.000	91138	0	433.956	21696	20.00	273	274	541191	296	244
1445	2734	-9	194	0	565	35	255	434.591	442187	228	356	0	0	0.000	91138	0	434.591	21888	19.86	275	274	541400	296	242
1500	2734	-9	215	0	566	34	255	434.873	442415	228	353	0	0	0.000	91138	0	434.873	21888	19.87	275	275	541609	302	243
1515	2733	-9	208	0	566	34	256	433.762	442643	228	350	0	0	0.000	91138	0	433.762	21888	19.82	275	276	541819	296	245
1530	2734	-9	198	0	565	34	256	432.749	442871	228	347	0	0	0.000	91138	0	432.749	21888	19.77	276	276	542028	296	243
1545	2734	-9	202	0	564	34	255	433.513	443098	227	345	0	0	0.000	91138	0	433.513	21792	19.89	278	277	542237	300	243
1600	2733	-9	207	0	564	34	254	434.113	443326	228	343	0	0	0.000	91138	0	434.113	21888	19.83	277	276	542446	295	239
1615	2733	-9	218	0	564	34	254	433.470	443553	227	340	0	0	0.000	91138	0	433.470	21792	19.89	277	276	542655	297	242
1630	2732	-9	189	0	564	34	254	434.188	443781	228	338	0	0	0.000	91138	0	434.188	21888	19.84	278	277	542865	295	241
1645	2732	-9	195	0	564	35	254	434.707	444008	227	336	0	0	0.000	91138	0	434.707	21792	19.95	278	276	543074	297	240
1700	2732	-9	193	0	565	35	256	434.740	444235	227	333	0	0	0.000	91138	0	434.740	21792	19.95	278	277	543283	301	245
1715	2732	-9	209	0	564	35	256	435.698	444463	228	331	0	0	0.000	91138	0	435.698	21888	19.91	278	277	543492	299	245
1730	2732	-9	208	0	566	35	258	435.487	444690	227	329	0	0	0.000	91138	0	435.487	21792	19.98	277	276	543701	301	242
1745	2733	-9	207	0	565	35	257	436.062	444918	228	327	0	0	0.000	91138	0	436.062	21888	19.92	277	275	543910	298	243
1800	2732	-9	215	0	566	35	258	436.724	445145	227	324	0	0	0.000	91138	0	436.724	21792	20.04	276	275	544119	301	247
1815	2732	-9	220	0	569	35	261	434.874	445372	227	322	0	0	0.000	91138	0	434.874	21792	19.96	276	276	544328	298	248
1830	2731	-9	224	0	571	35	262	435.277	445599	227	320	0	0	0.000	91138	0	435.277	21792	19.97	275	274	544537	300	249
1845	2731	-9	214	0	572	35	263	436.789	445826	227	318	0	0	0.000	91138	0	436.789	21792	20.04	274	274	544747	305	252
1900	2731	-9	219	0	572	35	264	437.405	446053	227	316	0	0	0.000	91138	0	437.405	21792	20.07	273	274	544956	301	254
1915	2731	-9	221	0	573	35	263	438.160	446280	227	314	0	0	0.000	91138	0	438.160	21792	20.11	274	273	545165	303	253
1930	2731	-9	218	0	573	35	263	438.426	446507	227	312	0	0	0.000	91138	0	438.426	21792	20.12	274	273	545374	294	254
1945	2731	-9	228	0	574	35	264	437.500	446735	228	310	0	0	0.000	91138	0	437.500	21888	19.99	273	273	545583	301	255
2000	2731	-9	233	0	575	35	264	439.201	446963	228	309	0	0	0.000	91138	0	439.201	21888	20.07	273	272	545792	298	255
2015	2730	-9	236	0	574	35	262	438.668	447191	228	307	0	0	0.000	91138	0	438.668	21888	20.04	274	273	546001	301	249
2030	2730	-9	244	0	572	35	261	440.272	447418	227	305	0	0	0.000	91138	0	440.272	21792	20.20	274	273	546210	299	251
2045	2730	-9	224	0	571	35	262	438.726	447646	228	303	0	0	0.000	91138	0	438.726	21888	20.04	273	272	546419	304	250
2100	2730	-9	246	0	572	35	262	438.214	447873	227	301	0	0	0.000	91138	0	438.214	21792	20.11	273	273	546628	295	250
2115	2730	-9	238	0	572	35	262	438.945	448100	227	299	0	0	0.000	91138	0	438.945	21792	20.14	274	273	546837	299	249
2130	2729	-9	253	0	571	35	261	438.854	448327	227	298	0	0	0.000	91138	0	438.854	21792	20.14	274	273	547046	295	247
2145	2729	-9	229	0	571	35	261	438.113	448554	227	296	0	0	0.000	91138	0	438.113	21792	20.10	274	273	547255	296	247
2200	2729	-9	239	0	572	35	261	437.539	448782	228	295	0	0	0.000	91138	0	437.539	21888	19.99	274	274	547464	299	245
2215	2729	-9	235	0	572	35	260	438.403	449009	227	293	0	0	0.000	91138	0	438.403	21792	20.12	275	274	547673	294	244
2230	2729	-9	239	0	572	35	261	438.445	449236	227	292	0	0	0.000	91138	0	438.445	21792	20.12	274	273	547882	294	246
2245	2728	-9	227	0	573	35	261	438.053	449463	227	290	0	0	0.000	91138	0	438.053	21792	20.10	274	273	548091	297	246
2300	2728	-9	218	0	573	35	261	438.520	449690	227	289	0	0	0.000	91138	0	438.520	21792	20.12	274	274	548300	301	245
2315	2729	-9	220	0	572	35	260	437.754	449918	228	287	0	0	0.000	91138	0	437.754	21888	20.00	274	274	548509	300	244
2330	2728	-9	224	0	572	35	260	438.285	450146	228	286	0	0	0.000	91138	0	438.285	21888	20.02	275	274	548718	293	244
2345	2728	-9	225	0	572	35	259	438.229	450374	228	285	0	0	0.000	91138	0	438.229	21888	20.02	275	274	548927	302	244
0000	2727	-9	230	0	571	35	259	438.014	450603	229	283	0	0	0.000	91138	0	438.014	21984	19.92	274	274	549136	298	243
0015	2727	-9	227	0	570	35	258	436.828	450832	229	282	0	0	0.000	91138	0	436.828	21984	19.87	275	274	549345	303	245
0030	2728	-9	231	0	569	35	257	437.233	451062	230	281	0	0	0.000	91138	0	437.233	22080	19.80	274	274	549554	290	243
0045	2727	-9	217	0	569	35	256	437.127	451291	229	279	0	0	0.000	91138	0	437.127	21984	19.88	274	274	549763	297	243
0100	2726	-9	214	0	569	35	257	436.485	451521	230	278	0	0	0.000	91138	0	436.485	22080	19.77	273	274	549972	299	245
0115	2727	-9	214	0	571	35	258	436.437	451750	229	277	0	0	0.000	91138	0	436.437	21984	19.85	273	274	550181	291	247
0130	2727	-9	211	0	573	35	259	437.878	451980	230	276	0	0	0.000	91138	0	437.878	22080	19.83	274	274	550391	296	247
0145	2727	-9	219	0	573	35	259	437.428	452209	229	274	0	0	0.000	91138	0	437.428	21984	19.90	274	273	550600	295	247
0200	2727	-9	211	0	574	35	259	437.905	452439	230	273	0	0	0.000	91138	0	437.905	22080	19.83	274	273	550808	296	246
0215	2726	-10	208	0	575	35	260	437.764	452667	228	271	0	0	0.000	91138	0	437.764	21888	20.00	273	272	551017	299	247
0230	2725	-10	221	0	575	35	259	437.638	452897	230	270	0	0	0.000	91138	0	437.638	22080	19.82	273	272	551226	298	248
0245	2726	-10	220	0	575	35	259	437.745	453126	229	269	0	0	0.000	91138	0	437.745	21984	19.91	273	272	551435	293	248

FIGURE 3-3

COMPUTERIZED DATA PRINT OUT

TABLE 3-1

GLOSSARY OF
DATA ITEM ABBREVIATIONS

WHTP	=	Wellhead tubing pressure (psia) - at Well No. 2
WHAP	=	Wellhead annulus pressure (psia) at Well No. 2 - (between 9-5/8 inch casing and 5-1/2 inch tubing)
CSGP	=	Casing pressure (psia) at Well No. 2 - (between 9-5/8 inch casing and 13-3/8 inch casing)
WHT	=	Wellhead temperature (°F) - at Well No. 2
STAT	=	Static pressure at orifice meter (psig) - at Sep. #1
DF	=	Differential pressure across the orifice meter (inches of water) - at Sep. #1
TMP	=	Flowing gas temperature at orifice meter (°F) - at Sep. #1
MCFD	=	Measured gas flow rate (MCF/D) - calculated from STAT, DF, and TMP
TRBN 1	=	Cumulative flow of water through first turbine meter total impulses
+	=	Incremental flow of water - number of impulses since previous reading
TRBN 2	=	Cumulative flow of water through second meter total impulses
TMCFD	=	Total gas flow rate (MCF/D) - combination of calculated gas from each separator
TBOPD	=	Total water flow rate (BBL/D) - calculated based on total impulses since last reading from both separators
GFR	=	Gas-fluid ratio (SCF/BBL) - TMCFD/TBOPD
FTR	=	Pressure upstream of filters (psia) - not applicable
T TRBN	=	Cumulative fluid flow through 4-inch turbine at wellhead - turbine impulses
DWP	=	Disposal wellhead pressure (psia) - at Well No. 1
DWT	=	Disposal wellhead temperature (°F) - at Well No. 1

ATTENDANT: RADFORD DATE: 11/29/82

	PLEASANT BAYOU NO.1	PLEASANT BAYOU NO.2
Wellhead pressure - psig	380	1990.44
Wellhead temperature - °F	272	291.68
Casing pressure - psig	0	0 - 0
Adjustable choke		62/64"

TURBINE VOLUMES

	Sep. #1	+	Sep. #2	=	Total	4" Turbine
Accumulative now - Bbl	693,851	+	1,760,259	=		232,908
Accumulative last - Bbl	673,630	+		=		212,650
Daily volume - BPD	19,192	+		=		19,130*

GAS VOLUMES

	Sep. #1	+	Sep. #2	=	Total	Sales
Pressure - psig	570	+				320
Differential in H_2O	38	+				13
Temperature - °F	280	+				60
Volume - Mcf/D	411 *	+	*	=		377 *
Gas fluid ratio - Scf/Bbl	21.48	+		=		
Choke setting	—	+		=		
Hours in service	24					24

FIN COOLER

Pressure in - psig	325
Pressure out - psig	320
Temperature in - °F	235
Temperature out - °F	65

DEHYDRATION UNIT

Boiler temperature - °F	350
Outlet temperature - °F	73
Glycol pump SPM	16
Glycol volume - gal	—

CHEMICAL TREATMENT

	SCALE	CORROSION
Gallons per day	4	20
Parts per million	4	20

ACCUMULATIVE VOLUME

Brine - Bbls	2,290,934
Gas - Mcf	48,874
Average gas fluid ratio	21.33
Cum. flowing time, hrs.	3249.55

PRESSURE DECLINE

Past 24 hrs. - lbs	10.18
Pounds/hr.	.42
Pounds/MMBbls	—

*Corrected volume

FIGURE 3-4

0800 HOURS PRODUCTION REPORT

TABLE 3-2

PLEASANT BAYOU WELL NO. 2
PHASE II-B CONTINUATION

PRODUCTIONS SUMMARY
10-24-82 - 4-13-83

HRS.	PERIOD ENDING 0800	TUBING PRESS. PSIG	ANNULUS PRESS. PSIG	CHOKE SIZE, IN.	WELLHEAD TEMP. °F	GAS PROD. MCF/DAY	BRINE PROD. BBL/DAY	SEP. PRESS. PSIG.	INJECTION PRESS. PSIG	AVG SCF/BBL
8	10-24-82	2776	-0-	56/64"	287	134	6,141	570	350	21.82
24	10-25-82	2753	-0-	56	287	404	17,238	570	360	22.03
24	10-26-82	2453	-0-	60	289	432	19,057	570	395	21.42
24	10-27-82	2432	-0-	60	289	418	19,047	570	405	20.73
24	10-28-82	2410	-0-	60	289	432	19,072	570	405	21.41
22.25	10-29-82	2450.51	-0-	60	288.66	395	20,129	570	410	18.54
24	10-30-82	2332.32	-0-	60	289.05	460	15,627	570	410	27.86
24	10-31-82	2514.95	-0-	56	288.50	409	19,055	565	400	20.28
24	11-01-82	2469.96	-0-	56	288.00	409	17,954	565	405	22.03
24	11-02-82	2431.79	-0-	56	289.10	411	17,926	570	405	21.67
24	11-03-82	2394.58	-0-	56	288.93	405	18,130	570	400	21.11
24	11-04-82	2373.57	-0-	56	289.23	386	17,967	570	400	20.29
24	11-05-82	2362.18	-0-	56	289.38	399	18,182	570	400	20.74
24	11-06-82	2346.91	-0-	56	289.19	405	18,014	570	400	21.22
24	11-07-82	2336.92	-0-	56	289.28	383	18,017	570	400	20.09
24	11-08-82	2318.14	-0-	56	289.38	386	17,971	570	400	20.28
24	11-09-82	2306.97	-0-	56	289.42	368	17,856	570	400	19.45
24	11-10-82	2299.33	-0-	56	289.31	380	17,769	570	405	20.24
24	11-11-82	2289.03	-0-	56	289.44	405	17,562	570	400	21.79
24	11-12-82	2081.11	-0-	60	290.54	409	18,747	570	450	21.81
24	11-13-82	2062.02	-0-	60	290.37	406	18,663	570	450	21.75
24	11-14-82	2054.89	-0-	60	290.64	403	18,662	570	455	21.59
24	11-15-82	2044.43	-0-	60	290.39	411	18,796	570	450	21.87
24	11-16-82	2030.88	-0-	60	290.45	404	18,641	570	450	21.67
24	11-17-82	2019.36	-0-	60	290.73	411	18,559	560	435	22.14
24	11-18-82	1950.89	-0-	62	291.07	417	18,858	575	445	22.11
24	11-19-82	2003.54	-0-	62	291.00	403	18,610	570	440	21.65
24	11-20-82	2003.58	-0-	62	291.25	403	18,882	570	450	21.34

TABLE 3-2
Page 2

24	11-21-82	1994.16	-0-	62/64"	291.31	403	18,869	570	450	21.36
24	11-22-82	1983.78	-0-	62	291.00	403	18,835	570	440	21.40
24	11-23-82	1978.56	-0-	62	291.33	401	18,716	570	450	21.42
24	11-24-82	1966.66	-0-	62	290.92	408	18,786	570	440	21.72
21.8	11-25-82	2035.60	-0-	62	290.71	360	16,662	570	420	21.22
24	11-26-82	2031.29	-0-	62	291.11	399	18,506	570	420	22.88
24	11-27-82	2025.03	-0-	62	291.07	398	18,459	570	410	21.56
21	11-28-82	2000.62	-0-	62	291.46	352	16,058	570	410	21.92
24	11-29-82	1990.44	-0-	62	291.68	411	19,130	570	380	21.48
24	11-30-82	1988.43	-0-	62	291.43	408	19,030	570	380	21.44
24	12-01-82	1978.29	-0-	62	291.29	415	19,020	570	380	21.82
24	12-02-82	1989.75	-0-	62	291.38	405	19,053	570	410	21.26
24	12-03-82	1985.20	-0-	62	291.33	406	19,088	570	380	21.27
24	12-04-82	1981.62	-0-	62	291.73	415	19,005	570	410	21.84
24	12-05-82	1978.77	-0-	62	291.79	404	19,006	570	410	21.26
24	12-06-82	1973.36	-0-	62	291.65	414	19,060	570	405	21.72
24	12-07-82	1972.29	-0-	62	291.60	414	19,037	570	420	21.74
24	12-08-82	1966.54	-0-	62	291.50	418	18,998	570	420	22.00
24	12-09-82	1963.34	-0-	62	291.37	419	18,940	570	422	22.12
24	12-10-82	1954.41	-0-	62	291.20	421	19,123	570	420	22.02
24	12-11-82	1959.45	-0-	62	291.50	409	19,050	570	430	21.46
24	12-12-82	1962.06	-0-	62	291.51	408	19,131	570	430	21.33
24	12-13-82	1956.27	-0-	62	291.58	418	19,071	570	440	21.92
04	12-14-82	1960.20	-0-	62	291.34	70	4,823	570	430	22.00
0	12-15-82	-	-	-	SHUT IN FOR MAINTENANCE		-	-	-	-
20	12-16-82	1987.49	-0-	62	289.44	355	15,123	570	400	23.47
23	12-17-82	1984.39	-0-	62	290.35	402	17,521	585	385	22.94
24	12-18-82	1850.18	-0-	64	291.30	434	18,883	580	400	22.98
24	12-19-82	1843.01	-0-	64	291.43	428	19,054	575	405	22.08
24	12-20-82	1850.18	-0-	64	291.30	434	18,968	580	410	22.91
24	12-21-82	1843.96	-0-	64	291.58	434	18,971	580	422	22.87
24	12-22-82	1852.98	-0-	64	291.54	434	19,049	580	425	22.80
24	12-23-82	1846.59	-0-	64	291.47	425	19,040	578	427	22.32
24	12-24-82	1842.26	-0-	64	291.18	413	19,023	570	422	21.69
22.5	12-25-82	1839.87	-0-	64	291.35	391	17,738	570	425	22.03
22.5	12-26-82	1863.62	-0-	64	291.44	381	18,362	580	410	20.73
24	12-27-82	1857.40	-0-	64	291.32	403	18,757	570	405	21.47

TABLE 3-2
Page 3

24	12-28-82	1853.56	-0-	64/64"	291.58	416	18,760	580	415	22.18
24	12-29-82	1845.39	-0-	64	291.35	403	18,754	570	410	21.53
24	12-30-82	1828.70	-0-	64	291.51	431	18,827	540	422	22.90
24	12-31-82	1860.38	-0-	64	291.20	401	18,569	630	400	21.59
24	01-01-83	1831.24	-0-	64	291.22	425	18,727	550	430	22.68
24	01-02-83	1823.49	-0-	64	291.29	428	18,766	555	432	22.79
24	01-03-83	1771.71	-0-	64	291.61	388	18,689	480	440	20.86
24	01-04-83	1822.69	-0-	64	291.38	417	18,675	560	435	22.32
24	01-05-83	1825.14	-0-	64	291.54	425	18,567	570	445	22.86
24	01-06-83	1875.00	40-0	64	291.00	428	18,652	565	446	22.96
24	01-07-83	1875.00	-0-	64	291.00	421	18,551	570	455	22.69
24	01-08-83	1806.41	-0-	64	291.48	425	18,663	570	450	22.75
24	01-09-83	1900.00	-0-	64	291.00	420	18,570	570	445	22.64
24	01-10-83	1900.00	-0-	64	291.00	420	18,552	570	455	22.66
24	01-11-83	1804.58	-0-	64	290.14	398	18,556	570	455	21.59
24	01-12-83	1798.66	-0-	64	289.83	420	18,531	570	455	22.76
24	01-13-83	1799.39	-0-	64	290.16	422	18,552	570	455	22.74
24	01-14-83	1690.44	-0-	66	290.60	424	18,998	600	468	22.34
24	01-15-83	1683.12	-0-	66	290.28	423	19,050	590	460	22.21
24	01-16-83	1683.26	-0-	66	290.45	425	18,987	600	468	22.40
24	01-17-83	1680.07	-0-	66	290.43	424	18,973	600	460	22.54
24	01-18-83	1674.27	-0-	64	290.22	427	19,012	600	455	22.65
24	01-19-83	1670.23	-0-	66	289.91	418	18,903	600	445	22.08
24	01-20-83	1671.42	-0-	66	290.18	415	18,931	580	460	21.93
24	01-21-83	1671.13	-0-	66	290.40	420	18,958	580	465	22.14
24	01-22-83	1667.84	-0-	66	290.36	419	18,922	580	465	22.12
24	01-23-83	1681.50	-0-	66	290.59	425	18,986	600	472	22.41
24	01-24-83	1675.25	-0-	65	290.52	424	18,941	600	475	22.60
24	01-25-83	1673.90	-0-	66	290.27	430	18,994	600	470	22.83
24	01-26-83	1673.36	-0-	66	290.57	424	18,903	600	475	22.44
24	01-27-83	1677.41	-0-	66	290.38	410	18,834	620	472	21.77
24	01-28-83	1673.67	-0-	66	290.37	409	18,771	620	472	21.78
24	01-29-83	1674.42	-0-	66	290.45	408	18,641	620	470	21.88
24	01-30-83	1677.40	-0-	66	290.36	414	18,776	620	475	22.03
3.75	01-31-83	1677.55	-0-	66	290.09	64	2,958	620	475	21.59
-	2-1/2/3-83	4048.20	-0-	SHUT IN FOR REPAIRS		-	-	-	-	-
17.5	02-04-83	1774.68	-0-	64	286.97	306	13,452	595	455	22.73

TABLE 3-2
Page 4

24	02-05-83	1762.57	-0-	64/64"	288.29	419	18,553	590	450	22.56
24	02-06-83	1751.16	240-0	64	289.16	413	18,354	590	475	22.50
24	02-07-83	1742.62	150-0	64	289.47	411	18,317	585	480	22.48
24	02-08-83	1740.38	180-0	64	289.56	428	18,317	600	480	23.41
24	02-09-83	1744.16	200-0	64	289.66	406	18,226	610	485	22.26
24	02-10-83	1735.15	-0-	64	289.62	403	18,169	620	480	22.18
24	02-11-83	1737.89	100-0	64	289.89	400	18,115	630	482	22.07
24	02-12-83	1730.92	-0-	64	289.84	400	18,098	630	482	22.09
24	02-13-83	1739.43	-0-	64	289.95	400	18,064	630	485	22.14
24	02-14-83	1734.79	-0-	64	290.02	394	18,091	610	485	21.79
24	02-15-83	1736.99	50-0	64	289.82	401	18,100	630	480	22.17
24	02-16-83	1738.66	150-0	64	289.78	395	18,024	630	485	21.91
24	02-17-83	1734.24	140-0	64	290.05	399	18,030	640	490	22.11
24	02-18-83	1732.92	-0-	64	290.09	399	18,111	640	495	22.01
24	02-19-83	1724.55	-0-	64	290.02	401	18,029	640	495	22.21
24	02-20-83	1725.67	-0-	64	289.89	398	17,933	630	500	22.18
24	02-21-83	1728.09	-0-	64	290.07	394	18,053	630	500	21.86
24	02-22-83	1720.61	-0-	64	289.16	394	17,961	630	500	21.96
24	02-23-83	1719.27	-0-	64	290.13	392	17,902	630	515	21.90
24	02-24-83	1719.22	-0-	64	290.23	392	17,886	630	520	21.94
24	02-25-83	1712.25	-0-	64	290.14	397	17,883	635	512	22.20
24	02-26-83	1704.05	-0-	64	289.80	388	17,954	620	505	21.63
24	02-27-83	1715.24	-0-	64	290.02	391	17,886	630	515	21.87
24	02-28-83	1724.65	-0-	64	290.12	380	17,864	630	520	21.28
24	03-01-83	1722.64	-0-	64	290.20	388	17,850	660	520	21.78
24	03-02-83	1724.66	-0-	64	290.64	384	17,822	670	525	21.57
24	03-03-83	1712.74	-0-	64	289.92	387	17,724	660	500	21.81
24	03-04-83	1711.87	-0-	64	289.89	380	17,746	660	518	21.43
24	03-05-83	1710.36	-0-	64	290.13	383	17,665	670	525	21.68
24	03-06-83	1702.82	-0-	64	290.05	382	17,670	670	525	21.62
24	03-07-83	1702.07	-0-	64	290.19	380	17,630	660	530	21.55
24	03-08-83	1700.04	-0-	64	290.21	383	17,596	670	525	21.77
24	03-09-83	1689.46	-0-	64	290.02	378	17,553	660	520	21.60
24	03-10-83	1690.50	-0-	64	290.20	390	17,479	670	528	22.40
24	03-11-83	1682.35	-0-	64	290.02	376	17,450	660	520	21.54
24	03-12-83	1687.08	-0-	64	290.13	377	17,490	670	525	21.58

TABLE 3-2
Page 5

24	03-13-83	1683.12	-0-	64/64"	290.09	378	17,506	670	525	21.59
24	03-14-83	1698.83	-0-	64	290.11	375	17,416	660	525	21.54
24	03-15-83	1712.28	-0-	64	290.10	375	17,451	660	520	21.48
24	03-16-83	1687.55	-0-	64	290.09	376	17,506	660	505	21.46
8.5	03-17-83	1687.63	-0-	64	290.10	133	6,066	670	515	21.89
-	3-18/19-83	-	-0-	SHUT IN FOR REPAIRS		-	-	-	-	-
23.1	03-20-83	1665.97	-0-	64	288.56	383	17,644	600	475	21.69
24	03-21-83	1664.58	120-0	64	289.52	395	17,925	610	480	21.91
24	03-22-83	1655.74	-0-	64	289.97	394	17,935	610	485	21.96
24	03-23-83	1650.85	-0-	64	290.04	390	17,854	615	490	21.85
19.75	03-24-83	1651.52	-0-	64	290.20	317	14,944	620	495	21.21
23.75	03-25-83	1600.17	80-0	65	290.29	381	17,815	610	440	21.40
24	03-26-83	1607.37	-0-	65	290.40	391	17,914	610	435	21.80
24	03-27-83	1574.92	120-0	65	290.60	402	17,932	585	448	22.43
24	03-28-83	1584.68	100-0	65	290.77	403	17,983	590	455	22.45
24	03-29-83	1576.00	100-0	65	290.55	398	18,088	585	455	22.00
24	03-30-83	1577.53	-0-	65	290.60	396	17,988	585	458	22.04
24	03-31-83	1575.82	-0-	65	290.79	400	17,983	600	468	22.26
24	04-01-83	1565.60	-0-	65	290.51	393	17,983	580	458	21.90
24	04-02-83	1561.53	-0-	65	290.52	391	17,993	583	465	21.73
24	04-03-83	1561.10	-0-	65	290.68	398	17,873	600	465	22.29
24	04-04-83	1553.85	-0-	65	290.56	392	17,813	585	465	21.96
24	04-05-83	1555.09	-0-	65	290.57	394	17,768	600	470	22.18
24	04-06-83	1539.02	-0-	65	290.59	388	17,726	588	460	21.80
24	04-07-83	1536.38	100-0	65	290.66	384	17,694	580	470	21.70
24	04-08-83	1530.04	57-0	65	290.72	384	17,638	580	475	21.75
24	04-09-83	1523.53	-0-	65	290.71	386	17,706	585	475	21.78
24	04-10-83	1521.46	-0-	65	290.80	386	17,471	590	475	22.11
24	04-11-83	1510.10	-0-	65	290.66	385	17,371	585	465	22.07
24	04-12-83	1506.96	-0-	65	290.67	385	17,398	585	465	22.04
24	04-13-83	1501.49	-0-	65	290.66	384	17,398	580	468	22.07
13	04-14-83	1499.99	-0-	65	290.50	209	9,248	585	465	20.81
3,898.4						65,727	2,984,653			22.02

FLOWING PRESSURE vs TIME
PHASE II-B

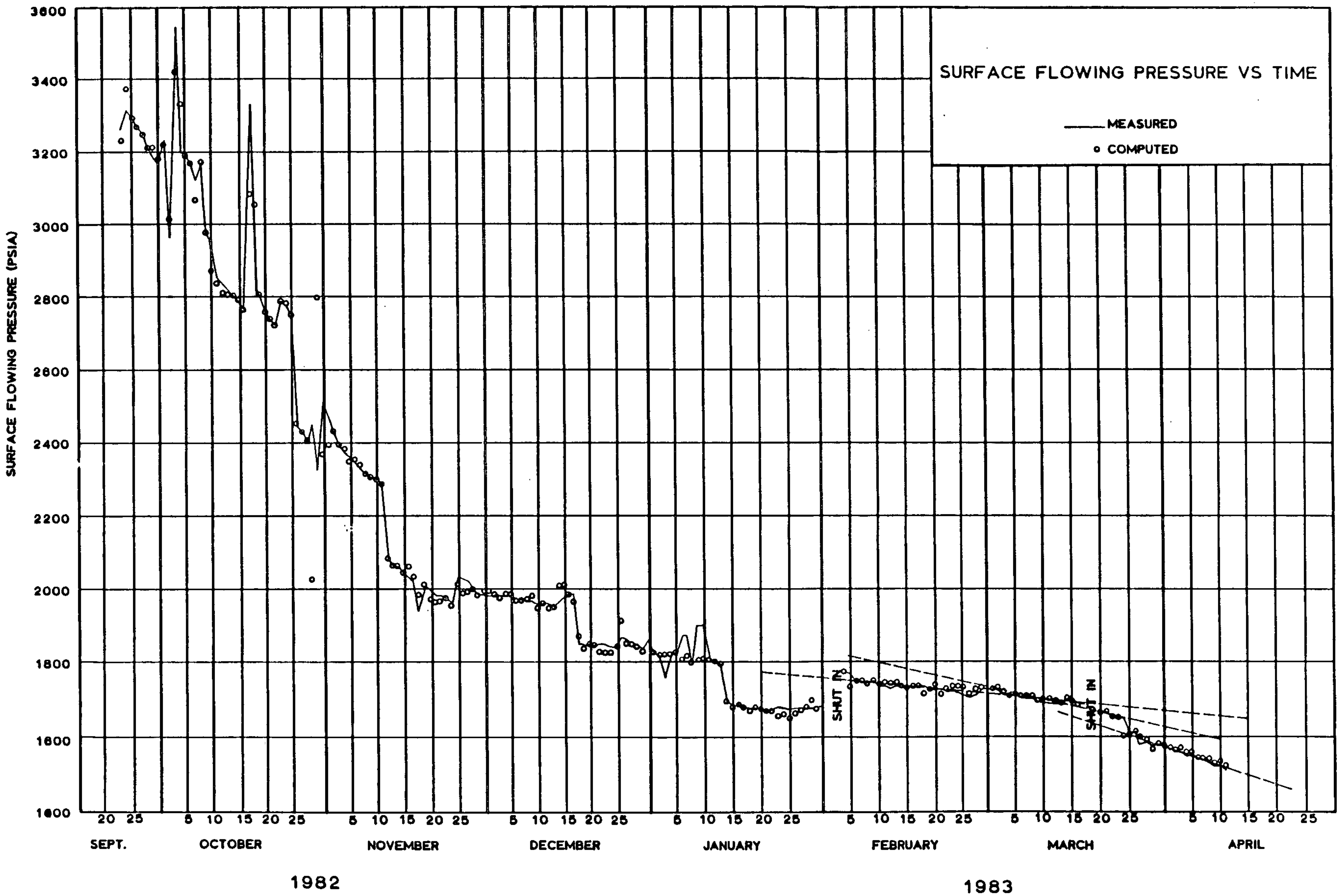


FIGURE 3-5

and for the entire Phase II-B period. The solid line represents the actual measured flowing pressure. The individual points are calculated using a computer reservoir model, which is discussed in Section 11.1, page 53. The increasing in slope, shown by the three dashed lines, indicates that scale build up in the production tubing and wellhead began influencing the wellhead pressures between March 01 and March 15.

3.2.2 Hydrocarbon Production. During the first week of December 1982, hydrocarbons were observed in the effluent water from the glycol dehydrator. A "gun barrel" separator was fabricated to separate and collect the small amount of hydrocarbon. Following the installation of the separator, representatives from the University of Southwest Louisiana collected samples of the liquid hydrocarbon, the wet gas, and effluent water. Test results showed the hydrocarbons to be 30% benzene with the remainder light aromatics, at a concentration of 123 ml per 1000 MCF gas. This equates to approximately 13 gallons per day at a fluid rate of 18,000 barrels brine per day.

An emulsion later developed in the "gun barrel." Champion Chemical Co. attempted to treat and break the emulsion with chemicals. However, the amount of chemical required was cost prohibitive for the recovery of such a small volume. Rather than treat the emulsion with chemicals, a larger excess tank (500 gallon) was converted into a retention tank for the dehydrator effluent. The tank was plumbed so that the hydrocarbon could be collected from the top of the tank and clean water discharged from the bottom. This proved to be an effective method of isolating the hydrocarbons.

3.3 Scale and Corrosion Treatment

3.3.1 Scale. Scale inhibiting chemicals were provided by Champion Chemical Co. The chemical was stored in an enclosed fiberglass tank adjacent to the No. 2 wellhead. The chemical was injected into the flow stream at an autoclave fitting on the bottom turn of the flow loop upstream of the adjustable choke. Injection was from a low volume, high pressure, electric-driven, positive displacement pump through 1/4-inch stainless steel tubing. Champion Chemical Co. worked closely with representatives from Rice University to select the most effective chemicals and determine the most effective treatment rates. The chemical chosen was Champion's Gyptron T-121, which proved to be effective in preventing scale accumulation inside the surface equipment and piping with treatment rates as low as 4 gallons per day at flow rates of 18,000 barrels/day. This is equivalent to approximately four parts per million (PPM) by volume. Gyptron T-121 is an aminomethylene phosphonate.

3.3.2 Corrosion. As for the scale inhibitor, the corrosion inhibitor was also provided by Champion Chemical Co. Selection again was coordinated with Rice University and the chemicals selected were Champion's Cortron RN-97 and RU-22, which are water soluable Quaternary amines. Treatment began at 20 gallons per day (approximately 23 PPM) and was slowly reduced, based on data from corrosion coupons, to 8 gallons per day (approximately 10 PPM). The 10 PPM treatment proved to be effective against corrosion inside production equipment and piping, except for downstream flange faces in high pressure piping. Figure 3-6 shows the location of corrosion coupons within the production system.[2] Table 3-3 is a tabulation of results of corrosion coupon analysis.

As mentioned above, some severe pitting was observed on the downstream side of flanges in some high pressure piping. The pitting appeared to be worst at the internal flange face just inside the ring seal. Regular carbon steel seal rings were also severely pitted in a number of flanges. On 1-31-83, the spool between the 4" Willis choke and target tee had to be removed because the flange and seal were damaged beyond repair. Radian Corporation examined one 4-1/16 inch 15M and one 4-1/16 inch 10M flange and concluded that the localized corrosion was not the result of metallurgical modifications produced by welding but was the result of the inherent lack of corrosion resistance of this cast steel alloy to the geofluid. Additionally, the proprietary corrosion inhibitors were not effective.[3] See Appendix A, which is the report from Radian Corporation titled "Flanges From the High Pressure Geofluid System of the Pleasant Bayou Geopressured Geothermal Well." To remedy this problem, the ring seals were replaced with 316 stainless steel rings and the replacement flanges internally nickel coated.

3.4 Gas Sales

3.4.1 Gas treatment Equipment. Gas from the 3-phase separators was initially cooled using a Fin-X-Line air-cooled heat exchanger rated at 500M BTU/hour, 1000 psi and 300^{o} F. The exchanger was equipped with a 60-inch fan powered by a 5-hp, 220-440V, three-phase electric motor. Typically, gas entering the cooler ranged from 220 to 230^{o} F with an exiting temperature from 60 to 75^{o} F. Downstream of the cooler moisture was removed using a glycol dehydration unit with an 8-5/8 inch absorber rated at 1.4 MMSCF at 600 psi. A 6-inch O.D. x 6-foot long scrubber was installed ahead of the dehydration unit to remove any condensation formed as a result of cooled water vapors from the heat exchanger. Glycol boiler temperatures were maintained at

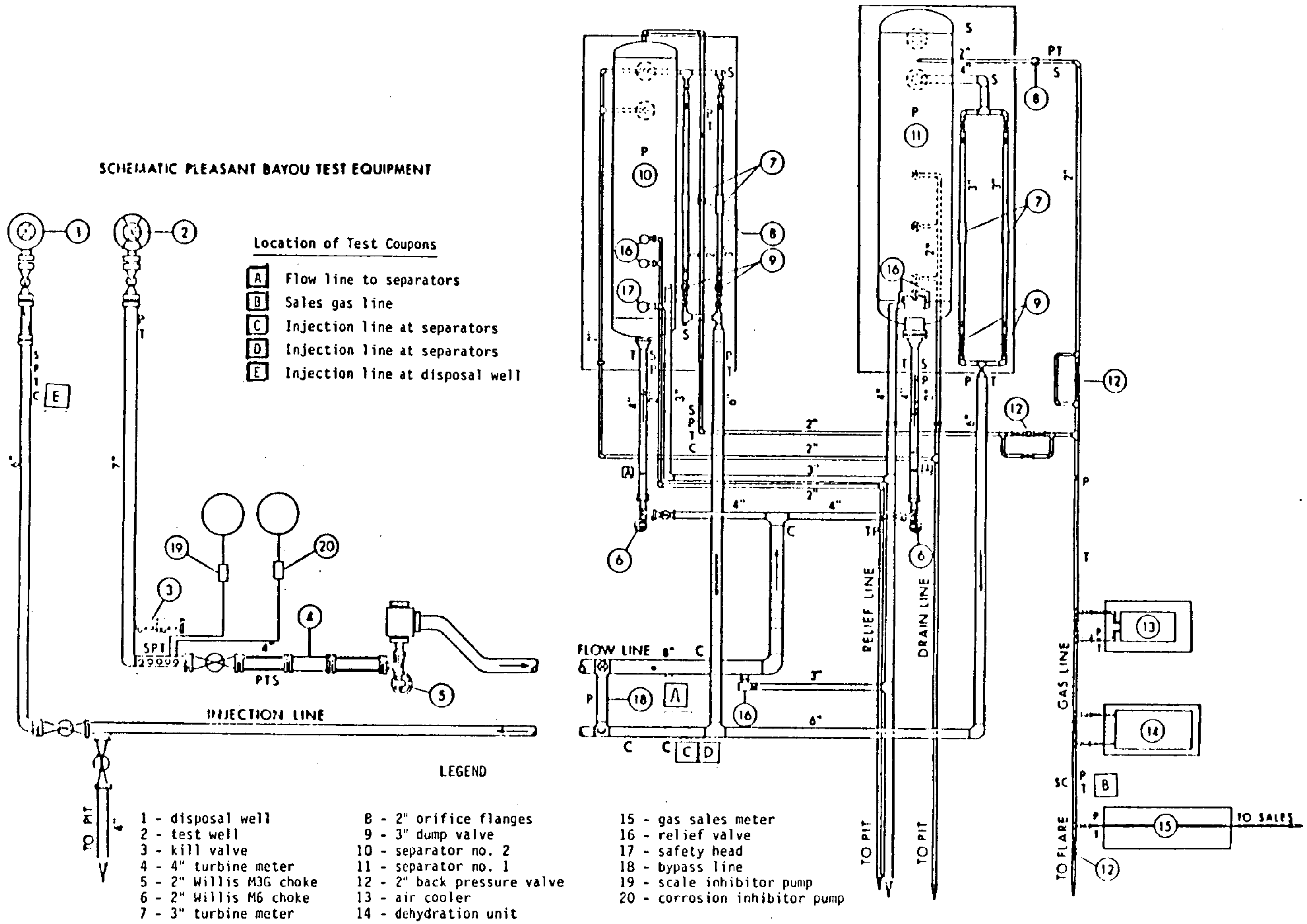


FIGURE 3-6

LOCATION OF CORROSION COUPONS

TABLE 3-3

CORROSION COUPON ANALYSIS

Coupon No.	Location	Date Installed	Date Removed	Wt. Loss mg	Corrosion Rate MPY	Chemical Injection* T-121	RN97/ RU22
E09652	B	10-25-82	11-01-82	388.9	35.8	4-15	0
E0-654	D	"	"	1075.9	99.0	"	0
E0-656	E	"	"	1117.8	102.8	"	0
E09658	A	"	"	1207.5	111.1	"	0
E09661	C	"	"	1087.4	100.0	"	0
A0202	A	11-01-82	11-08-82	599.7	55.2	15	10
A0206	D	"	"	553.2	50.9	"	"
A0203	C	"	"	684.3	62.9	"	"
A0209	E	"	"	554.6	51.0	"	"
A0208	B	"	"	11.6	1.1	"	"
A0210	E	11-01-82	11-15-82	640.4	29.5	15-12	10-15
A0207	B	"	"	9.0	0.4	"	"
A0204	C	"	"	638.5	29.4	"	"
A0201	A	"	"	654.6	30.1	"	"
G04696	B	11-08-82	11-15-82	10.9	1.0	12	15
G04694	D	"	"	286.8	26.4	"	"
G04695	C	"	"	323.5	29.8	"	"
G04679	E	11-15-82	11-22-82	222.9	20.5	12-4	15-20
G04678	D	"	"	293.1	27.0	"	"
G04677	B	"	"	14.6	1.3	"	"
G04675	C	"	"	2441.7	22.2	"	"
G04697	A	11-22-82	11-29-82	282.9	26.0	4	20
G04698	E	"	"	199.2	18.3	"	"
G04699	D	"	"	245.2	22.6	"	"
G04700	B	"	"	18.6	1.7	"	"
G04703	C	"	"	218.6	20.1	"	"
G04657	B	12-13-82	01-11-83	59.0	1.14	4	20
G04658	C	"	"	314.5	5.97	"	"
G04659	D	"	"	304.2	5.77	"	"
G04661	A	"	"	425.8	8.09	"	"

*T-121 - Scale treatment, gal/day
RN97/RU22 - Corrosion treatment, gal/day

approximately 350° F, resulting in outlet temperatures of 60 to 80° F. Moisture content was maintained at 7 pounds per MMSCF of gas or below; effluent from the dehydrator was run through a 500-gallon retention tank with water draining into the separator blowdown pit.

3.4.2 Measurement. Gas was metered through a prefabricated 3-inch meter run per specifications of the purchaser, Houston Pipe Line Co. A scrubber was installed ahead of the orifice flange with an automatic high-level shut-down valve should there be excessive fluid carryover from the dehydrator. A 2-inch back-pressure regulator was installed downstream of the sales meter outlet as a safety valve to release pressure on the line should the automatic valve on the sales scrubber close. This allowed for flaring the produced gas. Additional metering was provided on wet gas from each separator.

3.4.3 Gas Sales Contract. Fenix & Scisson, Inc., entered into a gas sales contract with Houston Pipe Line Co. (Contract No. 12-28131-101) to sell the gas produced by the No. 2 well. In accordance with the contract, the gas sales price was regulated by the price specified for Subpart B of Part 271 in Table I of Section 271.101(a) of the FERC Regulations, which were applicable during each month. Contract terms limited the moisture content of the gas to seven pounds of water vapor per million cubic feet and CO_2 content to a maximum of 10% by volume at a rate of 1000 MCF per day. However, the buyer did accept a higher CO_2 content at volumes less than 1000 MCF per day.

Measurement of the gas was the responsibility of the buyer and metering facilities were provided by the seller. Measurement conformed to the Texas Standard Gas Measurement Act and American Gas Association Gas Measurement Committee Report No. 3.

In accordance with the DOE's lease agreement with IP Farms, Inc., (Lease No. DE-RC08-80NV10085), royalty payments of 25% were paid to the IP Farms, Inc., for all gas sold. Table 3-4 is a tabulation of monthly gas sales during the Phase II-B test. The gross heating values were determined by chromatographic analysis or calorimeter of samples collected by the buyer. A total of 69.6 million cubic feet of gas was sold for the period 10-01-82 through 4-13-83.

3.5 Production Problems

3.5.1 Block Valves. Rockwell 4-inch and 3-inch Model 2345 plug valves were used on brine piping at separator discharges, on the brine bypass, at separator chokes and on the blow down line to the pit. These valves had to be greased,

TABLE 3 - 4

GAS SALES SUMMARY

MONTH	MAX LINE PRESSURE PSIG	MAX TEMP. °F	AVG. BTU/SCF	TOTAL VOLUME MCF	TOTAL MMBTU	CO^2 %	N^2 %	SPECIFIC GRAVITY
10-82	290	89	927	10,675	9,893	12.3	0.52	0.705
11-82	340	76	923	11,795	10,945	12.3	0.52	0.705
12-82	340	67	923	11,328	10,513	12.3	0.52	0.705
1-83	340	60	930	11,175	10,393	12.4	0.52	0.705
2-83	335	67	931	9,611	8,948	12.4	0.52	0.708
3-83	330	71	943	11,359	10,713	12.1	0.50	0.693
4-83	330	73	927	3,693	3,425	12.1	0.50	0.704

SALES PERIOD 10-01-82 - 4-13-83

TOTAL GAS SALES 69,636 64,830

packed and operated frequently in order to keep them functioning properly. When not operated frequently, small amounts of scale or inhibitor residue would build up on or between the plug and valve body. This made it difficult to work the valve or achieve complete fluid shut off when the valve was closed. When not greased or packed frequently, leaks develop through the grease fittings or around the valve stem. Once leaks develop, these areas become more restricted due to the buildup of salt and minerals from the leaking brine. Frequent greasing and packing of the valves proved to be an effective method of preventing leaks around the stems or through the grease fittings. However, while flowing the well continuously, it is not possible to operate the valve (open and close) as often as necessary. Nickel coating the plug and valve body area around the plug allows the valve to be opened and closed easily even after being in service for long periods of time.

Gate valves were used on the gas piping and provided good service with no unusual problems.

3.5.2 Turbine Meters. A total of five turbine meters were used in the production system to measure brine volume. Location of these five meters are shown in Figure 3-7, which is a schematic of the test equipment.[2] Item 4 is the main high pressure turbine which measures the full fluid stream directly off the wellhead flow loop. This is a Camco meter and proved to be very reliable. There is a fluid metering manifold on the fluid discharge of each separator. Each manifold consists of two 3-inch turbine meter runs. Each meter run can be isolated for service while the well is flowing. During the Phase II-B test, all of the fluid was produced through the larger No. 1 separator and the No. 2 separator held in reserve, thus all fluid produced was going through one of the 3-inch turbines. Early on in the test there was a problem with life of the 3-inch turbines. At one point, the turbines were being redressed every four - five days due to turbine bearing failure. The problem was attributed to excess heat on the bearing caused by a combination of the hot brine and frictional heat from the rotor spinning at such high speeds. The meter service company was able to fabricate a bearing from another material which could survive the elevated temperatures. The meters operated well after installation of the redesigned kits.

3.5.3 Control Valves. Fluid dump valves on the separators generally functioned well. However, there was one occasion on 1-30-85, when a roll pin eroded away allowing the valve trim to unscrew. With the trim loose, the separator could not unload and the emergency shut down (ESD) system automatically shut in the well on a separator

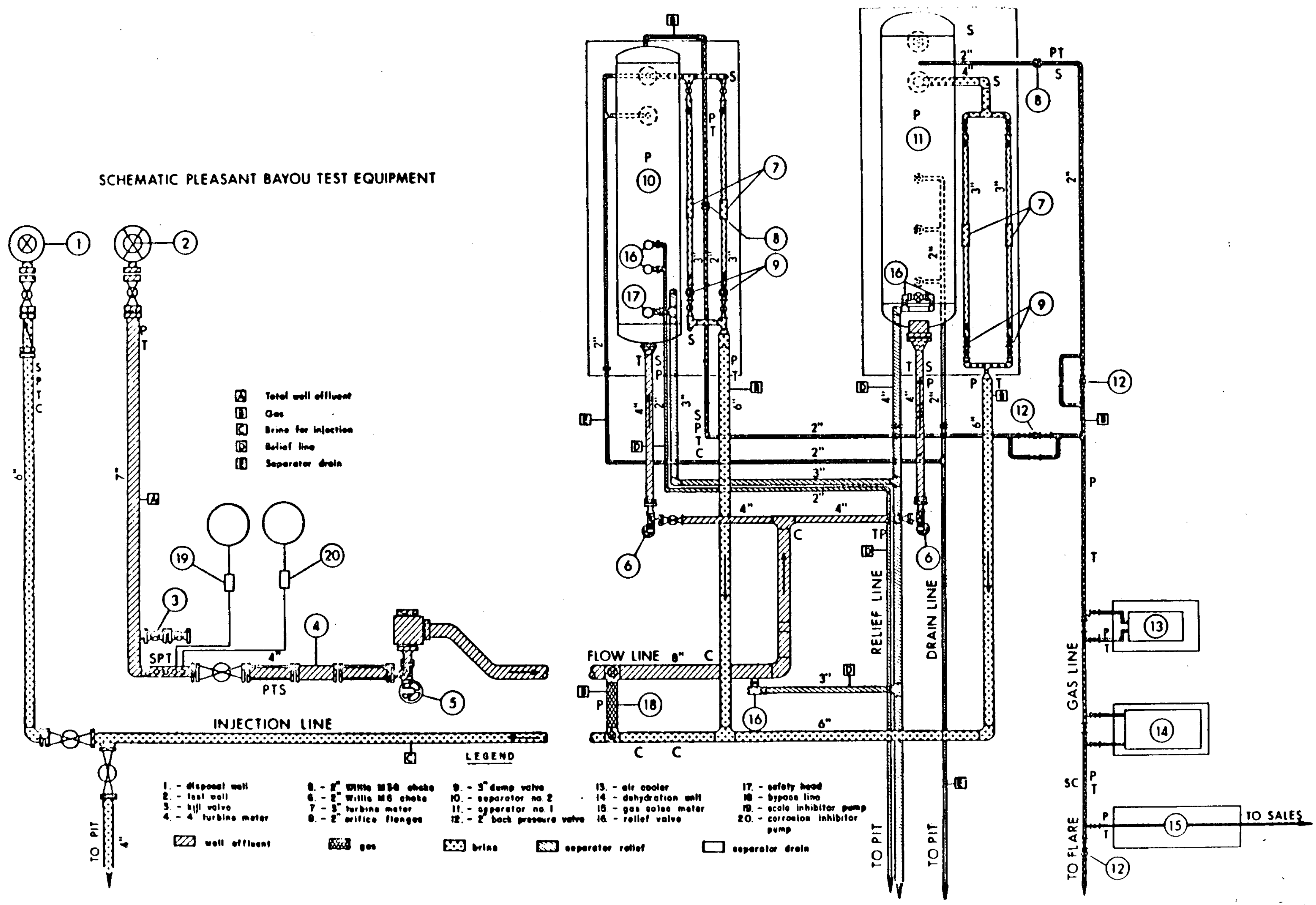


FIGURE 3-7 -- TURBINE METER LOCATIONS

high level. Other than minor adjustments, both liquid dump valves and gas line back pressure regulator valves operated well.

3.5.4 Piping Flanges. Problems with corrosion of piping flanges are discussed in Section 3.3.2, page 18.

3.5.5 Electrical Outages. Site electrical power was obtained commercially from Houston Lighting and Power Co., and was relatively dependable. At times there were short periods of power loss due to damage from thunderstorms or winds. Since both instrument air compressors were electrically powered, a power outage, if longer than four to five minutes, resulted in a well shut in on low instrument air pressure. This problem was corrected by converting one of the standby instrument air compressors to gasoline-driven and by fabricating a much larger instrument air reservoir.

3.5.6 Disposal Well Injection Pressure. The disposal well injection pressure did not have any real effect on continuation of the Phase II-B test, but pressures were higher than expected and would have had some effect had the test been longer. The injection pressures presented in Table 3-2 were taken on the 6-inch injection line near the production separators. Actual wellhead pressures were 40 to 50 psi lower. Figure 3-8 graphically illustrates the injection pressures as the test progressed. At the beginning of this test period, injection pressures were approximately 400 psig with a flow rate of 19,000 barrels per day. At the end of the period, pressures had increased to approximately 475 psig at reduced rates of 17,700 barrels per day. At one period between 2-20-83 and 3-17-83, injection pressures rose above 500 psig to a maximum of 530 psig. During that period, it was necessary to raise the separator operating pressure to 670 psig in order to maintain a steady fluid level.

A minimum of approximately 130 psi pressure differential was needed across the flow control (dump) valve to keep a steady separator fluid level. The increase in the injection pressure could have been caused by an accumulation of materials, such as carbonate scale, at the injection perforations. Plans were to connect a skidded filter unit to the injection line to allow for periodic injection well treatment with acidic acid. The filter pot with filters removed would be used as a container for powdered acidic acid. The acid would be dumped into the filter pot. After the pot's cover had been reinstalled, the injection stream would be diverted through the pot and acid flushed down to the perforations. The filter unit piping, filter pots, and valves were reconditioned and tested but had not yet been installed when the test was terminated. The skid unit and powdered acidic acid were

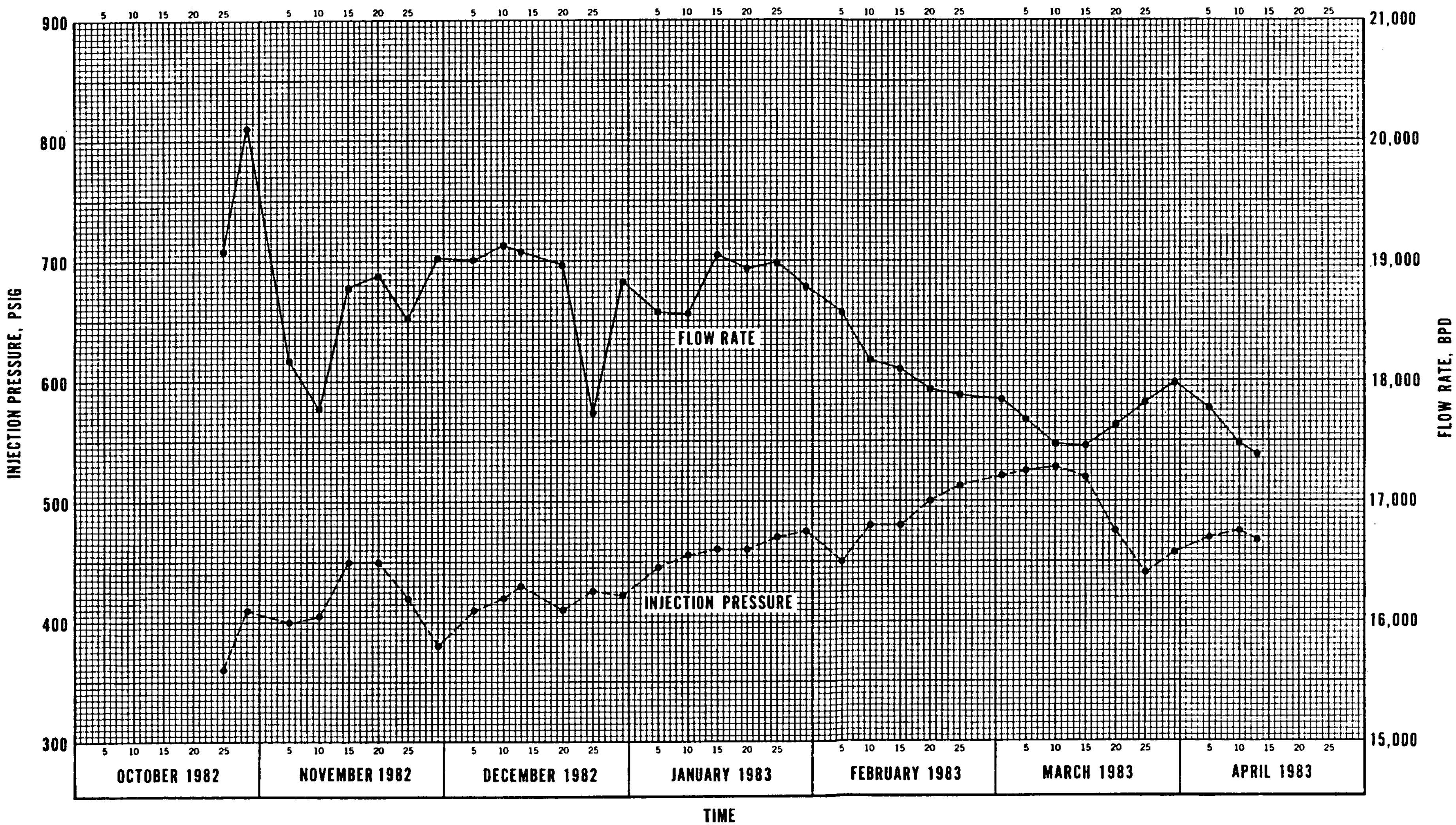

INJECTION PRESSURE, PSIG
900
800
700
600
500
400
300
FLOW RATE, BPD
21,000
20,000
19,000
18,000
17,000
16,000
15,000
FLOW RATE
INJECTION PRESSURE
OCTOBER 1982
NOVEMBER 1982
DECEMBER 1982
JANUARY 1983
FEBRUARY 1983
MARCH 1983
APRIL 1983
TIME

FIGURE 3-8

transferred from the Dow Project where this method was used with limited success.

3.6 Operations and Maintenance Manual

As part of Gruy Petroleum Technology, Inc.'s responsibility under Fenix & Scisson, Inc., Subcontract SC-PB-80-374, operation and maintenance procedures were to be developed during the long-term test. These procedures, in the form of an operation and maintenance manual, were completed and approved and are located in the site office trailer. Table 3-5 is a copy of the manual contents which outlines the subject matter contained.

3.7 Termination of Phase II-B Testing

At 2100 hours, 4-13-83, the well was shut in by the ESD system. The ESD system activated the automatic wing valve apparently due to a low pressure indication from the wellhead pressure sensor. The low pressure was falsely sensed because access to the flow stream had been plugged with an accumulation of carbonate scale. The accumulation of scale was upstream of the scale inhibitor injection point. Following discovery of the scale problem, the Phase II-B test was discontinued until the extend of the problem at the wellhead and downhole could be determined.

TABLE 3-5

OPERATION AND MAINTENANCE MANUAL
CONTENTS

4.0 EVALUATING EXTENT OF SCALE PROBLEMS

4.1 Wellhead and Flow Loop

On 4-15-85, the flow loop was removed for inspection. Inside the upper half of the loop was a uniform accumulation of carbonate scale 1/2 inch thick. Analysis confirmed that the scale was entirely calcium carbonate ($CaCO_3$) mostly in the form of calcite, but with trace amounts of aragonite. The bottom half of the loop also had a 1/2 inch scale deposit with the exception of a 5-foot section near the middle. A short length of wireline had become entangled around a 1/2 inch pipe nipple which was protruding inside the flow stream. Scale had accumulated on and around the snarled wireline nearly plugging the inside of the flow loop. The interior of the tree also had a 1/2 inch deposit of scale effectively reducing the bore through the valves from 5-1/16 inch to 4-1/16 inch. The carbonate scale was very hard and could not be washed or blasted out with high pressure water. To remove this scale from the flow loop it was necessary to circulate acid through the loop of 12-1/2 hours then blast the residue out using a high pressure water jet. After removal of the scale, the loop was reinstalled and pressure tested.

4.2 Well No. 1

A 40-arm casing inspection caliper tool was chosen to evaluate the extent of downhole scale accumulation by measuring the inside diameter of the tubing. Prior to running the caliper tool, a casing collar locator (CCL) and a 4-inch O.D. gauge ring were run to verify that there were no unusual restrictions or obstructions inside the tubing, and check for any fill within the perforated interval. The CCL confirmed that there was fill within the perforated interval. Perforations below 6406 feet were plugged off. Of the total of 150 feet of perforations, 80 feet were plugged. This is illustrated in Figure 4-1.

The caliper survey was then run from a depth of 5810 feet to the surface. The survey showed normal inside diameters for the size and weight of pipe surveyed, with the exception of numerous short erratic intervals indicating restrictions. There was a very thin, soft scale on the inside wall. As the caliper was pulled up the hole this scale was dislodged by the caliper arms. The dislodged scale accumulated above the arms. Continued accumulation of scale above the arms and around the body of the tool eventually caused enough resistance to force the scale past the arms creating the appearance of a restriction. This is why a repeat on the restrictions could not be obtained when running the caliper again through the same interval. The scale collected from the caliper tool was very thin, light green in color, and was not calcium carbonate. Although an analysis of the scale was not performed, it is believed to be a residue from the scale or corrosion inhibitor.

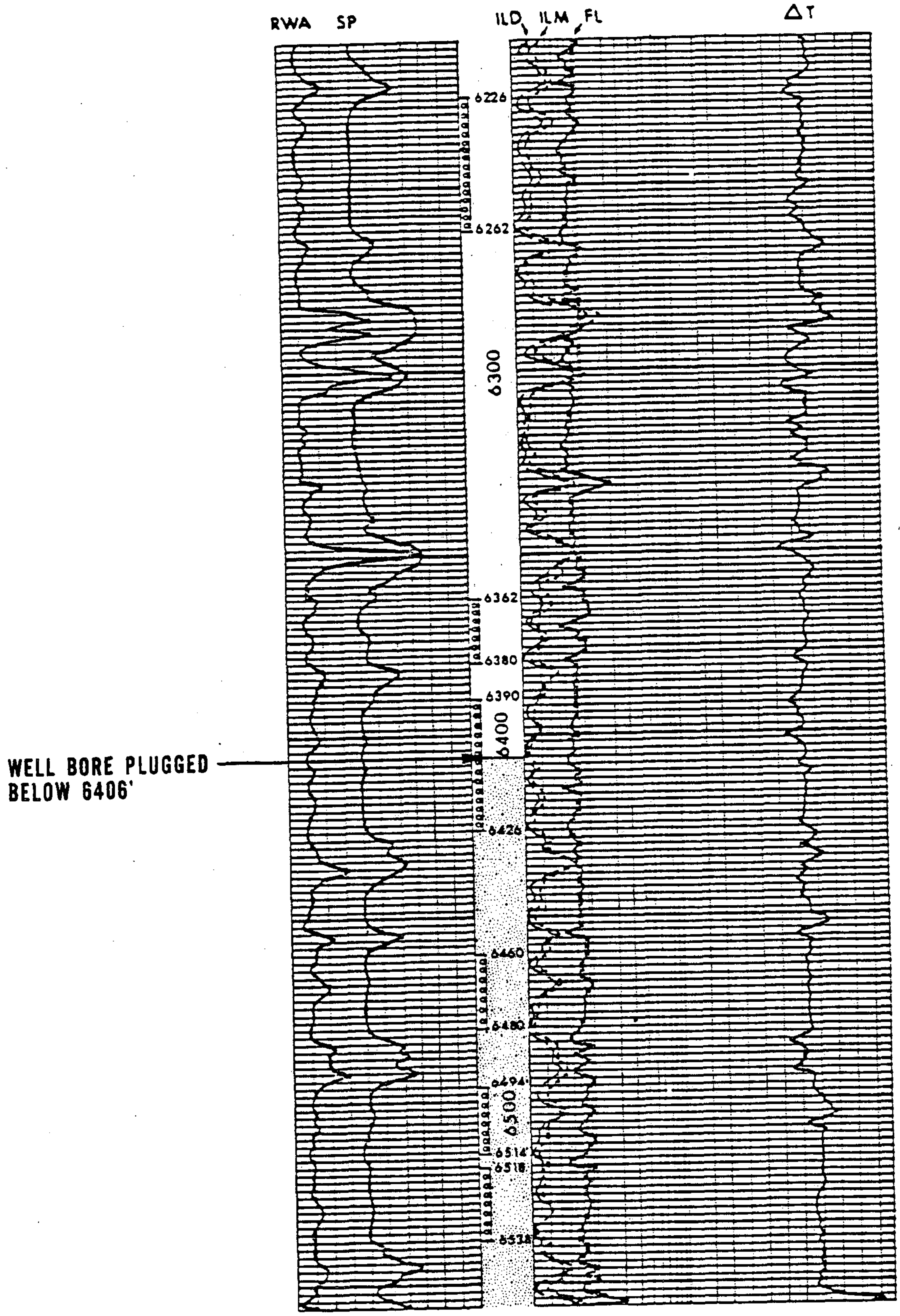


FIGURE 4-1

ELECTRIC LOG PLEASANT BAYOU NO. 1
INJECTION PERFORATIONS

4.3 Well No. 2

As in the No. 1 Well, prior to running the caliper survey, a CCL was run. Fill was tagged at 14,705', just below the bottom of the production perforations as illustrated in Figure 4-2. On 5-04-83, an attempt was made to run the 40-arm caliper in Well No. 2. The log was not run, however, since the restricted I.D. of the tubing hanger did not allow for enough clearance for the caliper tool body. On 5-05-83, a 1-1/16 inch O.D. 3-arm caliper tool was run. The 3-arm caliper tool measured the I.D. at the tubing hanger to be 3.75 inch; from 4.0 to 4.2 inches from surface to 1,000 feet; 4.2 inches at 2,400 feet; 4.3 inches at 3,900 feet; and 4.3 inches at 5,200 feet. The nominal I.D. of 5-1/2 inch O.D., 23 lb/ft. tubing is 4.67 inches. Thus the caliper survey indicated scale thickness from approximately 0.46 inch at the hanger to approximately 0.185 inch at 5,200 feet. Actual measurements when the tubing was later pulled showed scale thickness at the surface to be 0.400 inch and 0.312 inch at 5,200 feet.

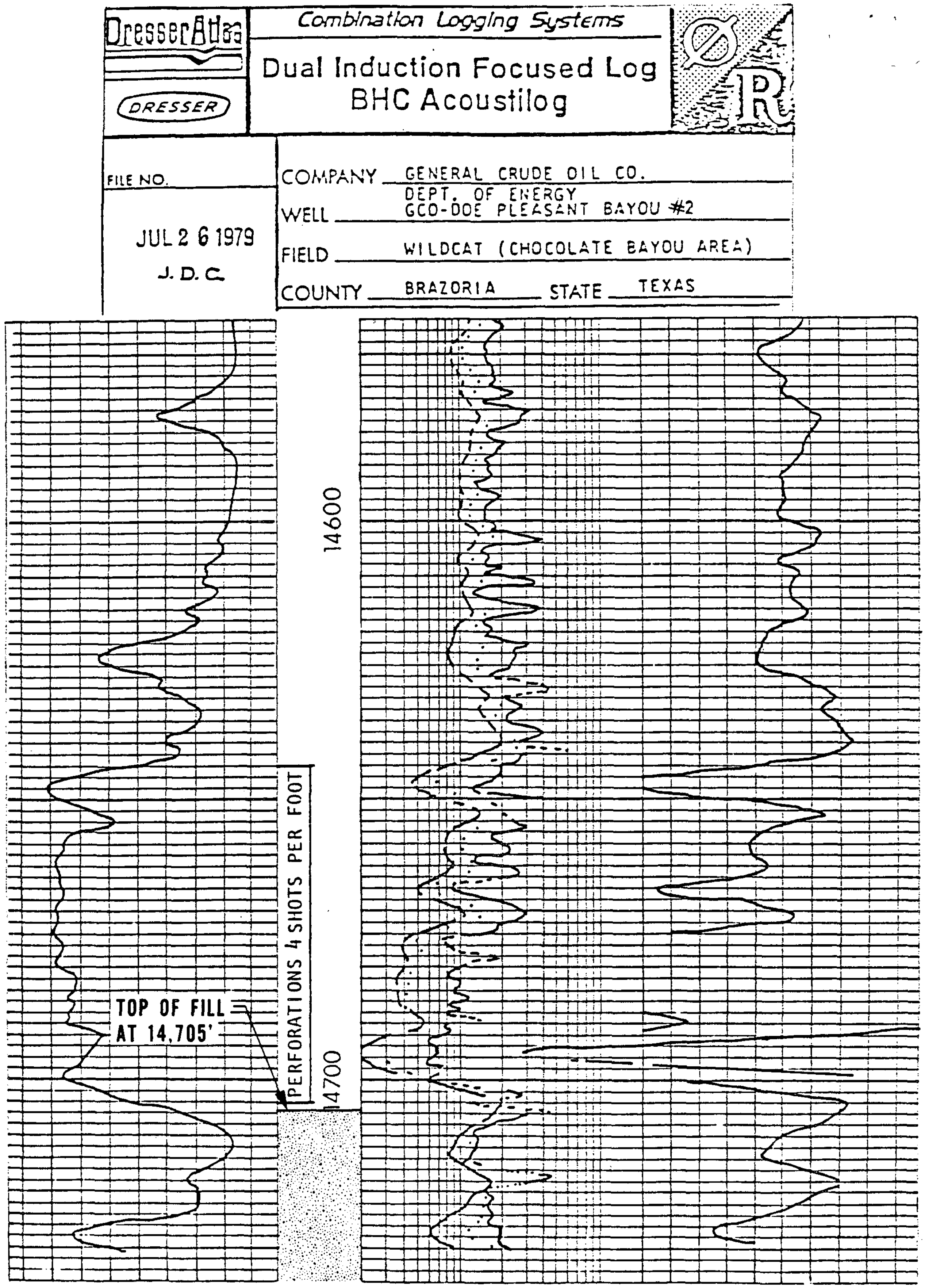


FIGURE 4-2

PB No. 2 INDUCTION LOG, PERFORATED INTERVAL

5.0 RECOVERY OF PARTED TUBING

5.1 Caliper Survey

The 3-arm caliper survey run 5-05-83 indicated the 5-1/2 inch production tubing to be parted at 5225 feet. Subsequent inspection of the 5-1/2 inch x 9-5/8 inch annulus verified that there was communications between the two strings. The tubing parted sometime between the evening of 5-04-83 and the morning of 5-05-83, since there was no pressure on the annulus the afternoon of 5-04-83. This is approximately three weeks after the well was shut in.

5.2 Recovery Operations

5.2.1 "Killing" the No. 2 Well. The first step in the recovery operation was killing the well and relieving the pressure from the annulus. To establish the injection characteristics of the well, an injection test was performed using 9.2 pounds/gallon salt water at rates of 1/2 - 1 barrel/minute. The well was then killed by injecting 250 barrels of 16.5 pounds/gallon XC-polymer mud down the tubing and circulating the annulus from 5225 feet to surface with 272 barrels. The XC-polymer mud was used because of its resistance to contamination by the calcium and zinc bromide fluid in the annulus. Due to migration of the lighter bromide fluid up the hole in the annulus above the tubing part, a differential pressure developed in the annulus. When the pressure reached 980 psig, the annulus was again circulated with 354 barrels of 16.4 pounds/gallon mud.

5.2.2 Installing the Wireline Bridge Plug. As an additional measure of safety to isolate the production perforations from the surface, a wireline set bridge plug was set inside the 5-1/2 inch tubing 19 feet below the top of the bottom section.

5.2.3 Preparation of Site for Rig. In preparation for mobilizing a rig, the area adjacent to the wellhead has to be cleared in a manner such that it could be quickly reinstalled upon recompletion of the well. The flow loop and wellhead above the bottom master valve were disassembled and removed. All equipment, piping, air lines, and electrical lines above ground, between the target tee and the reserve pit, were disassembled and removed.

5.2.4 Rig Mobilization. Between 7-05-83 and 7-14-83, Blanks Drilling Corporation's Rig No. 5 was mobilized and rigged up over the No. 2 well. The rig was a 1,700 HP Skytop-Brewster N95A with a one-million pound hookload capacity.

5.2.5 Rig Operations. Since the annulus was last circulated 5-27-83, further migration of the bromide fluid caused a hydrostatic differential pressure in the annulus of 870 psig. Prior to removing the bottom master valve and installing the blowout preventor (BOP) stack, the annulus was once again circulated. The upper portion (surface to 5225 feet) of the parted tubing was then pulled. The hard scale made it very difficult to break the tubing connections. Torques in excess of 30,000 foot-pounds were required to break connections which would normally break between 10,000 and 12,000 foot-pounds. The tubing parted because of a failed API 8rd. coupling which had split longitudinally over its entire length. Figure 5-1 is a photograph of the failed coupling. The mill pin end had pulled out of the split coupling and lower section of the string dropped downhole. Cause of failure is discussed in Section 6.0, page 40.

The bridge plug inside the 5-1/2 inch tubing was then recovered by making an outside cut just below the first coupling from the top. The 5-1/2 inch tubing was then recovered down to 11,738 feet using an overshot and string-shot back-off, and down to 12,353 feet using an overshot with a reversing tool. From 12,353 to 13,750, it was necessary to wash over the outside of the 5-1/2 inch tubing and again use a string-shot back-off.

Recovery operations were discontinued with five joints (13,750 - 13,964 feet) of tubing remaining in the hole. Prior to laying down the drill pipe, the polymer mud was conditioned with a biocide and a retrievable bridge plug set inside the 9-5/8 inch casing above the 5-1/2 inch tubing with the plug top at 13,725 feet. Figure 5-2 is a schematic of the wellbore as it existed when the rig was released 8-15-83. Figure 5-3 is a schematic of the bridge plug and retrieving tool, and Figure 5-4 is a drafted version of the original "Otis Packer Installation Report" when the well setting was first run. The top of Item 7 of Figure 5-4, VTR Seal Assembly, was tagged at 13,964 feet, drill pipe measurements, with zero at 25 feet above permanent datum (G.L.).

While recovering the production tubing, scale thickness measurements were obtained. Figure 5-5 shows scale thickness as a function of depth.

FIGURE 5-1
FAILED COUPLING

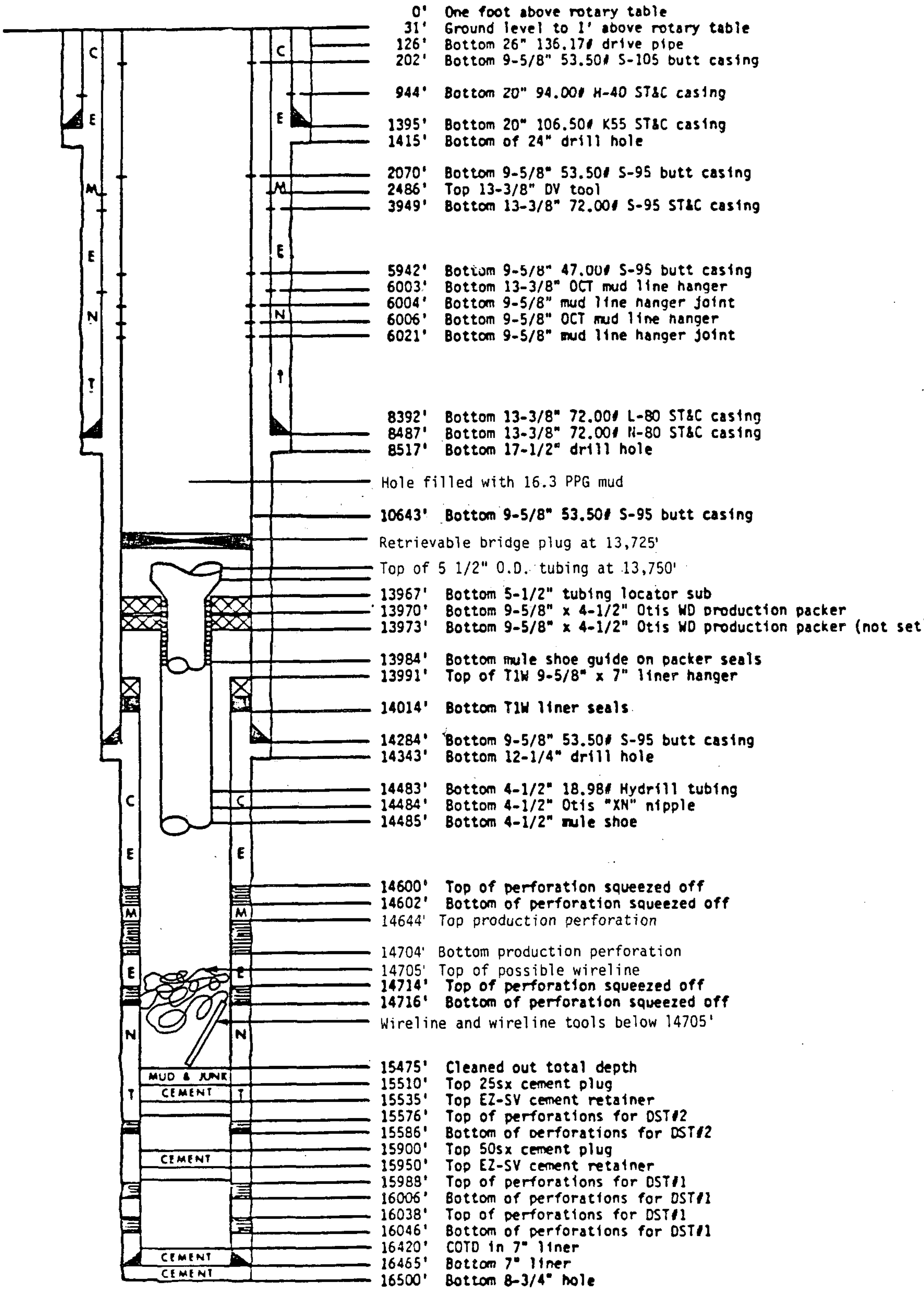
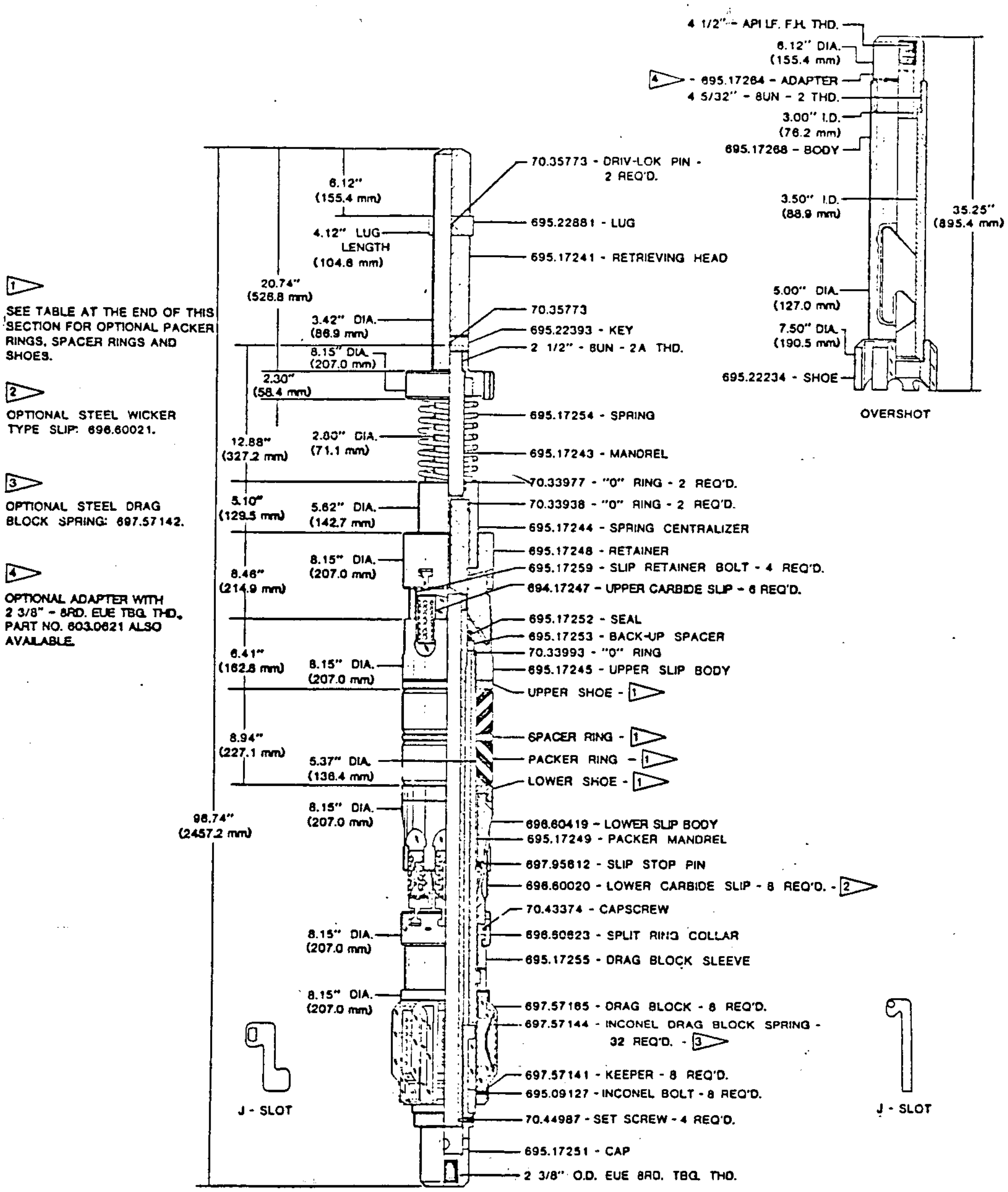


FIGURE 5-2
CONDITION OF No. 2 WELL 8/15/83



MODEL 3 PACKER TYPE
RETRIEVABLE BRIDGE PLUG
9 5/8" - 29.3 - 53.5# - 695.1724
ASSEMBLY NOT AVAILABLE
SPARE PARTS AVAILABLE ON SPECIAL ORDER

4/83
TC013-0002-89

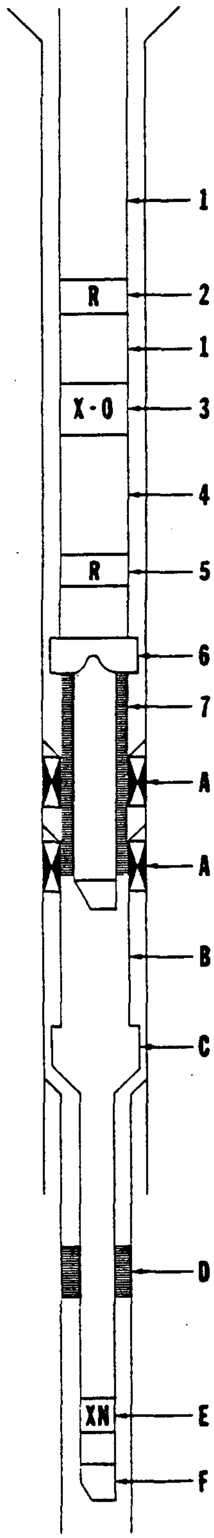
2-57

FIGURE 5-3

BRIDGE PLUG AND RETRIEVING TOOL

COMPANY	FIELD	WELL NAME
General Crude Oil Co.	Chocolate Bayou	Pleasant Bayou #2

COMPANY REP	STATE		SIZE	WEIGHT	GRADE	THREAD				
Arby Trolinger		CASING	9-5/8	53#	S105	Buttress	TYPE COMPLETION FLUID IN CASING			
COUNTY: Brazoria	TX	LINER	7"	38#	P110		TUBING WT. ON	LOWER	MIDDLE	UPPER
		TUBING UPPER	5-1/2	23#	P110	8rdABC	TYPE LATCH	LOWER	MIDDLE	UPPER
		TUBING MIDDLE	5-1/2	23#	P110	FL4S	OPERATOR'S NAME: J. Weatherby, L. Moerbe		MSO: 457775	
		TUBING LOWER	4-1/2	18.98		FJ-Hy	OTIS OFFICE: Friendswood		DATE: 7-3-79	



ITEM	DEPTH	LENGTH	JTS	DESCRIPTION	
	0	25.70		Elevation	
	25.70	1.29		Hanger	
1	26.99	5001.10	128	Tbg. 5½" 8rd ABC	
2	5028.09	1.95		Otis R Nipple 11R43100	4.313
1	5030.04	2006.44	54	Tbg. As Above	
3	7036.48	34.70	1	X-over Jt. 5½ 8rd x 5½ FL4S	
4	7071.18	6843.08	163	Tbg. 5½" FL4S	
5	13914.26	1.29		Otis R Nipple 11R43100	4.313
	13915.55	42.84	1	Tbg. As Above	
	13958.39	.61		X-over 5½ FL4S x 5" 8rd	
6	13959.00	.85		Otis St. Slot Locator 212S9053	5.55 OD 5.00 ID
7	13959.85	23.92		Otis VTR Seal Assem. 212EB9012	4.98 OD
	13983.77	.50		Mule Shoe Guide	
	13984.27			End of Production String	
A	13967.00	3.35		Otis WD Packer 212WD9503	8.06 OD 5.00 ID
A	13970.35	3.35		Otis WD Packer 212WD9503	8.06 OD 5.00 ID
	13973.70	.88		X-over to S.B. Receptacle	8.04 OD 5.00 ID
B	13974.58	22.50		Otis Seal Bore	6.26 OD 5.00 ID
C	13997.08	1.52		Adaptor to TIW	
	13998.60	10.90		TIW Extension	5.01 OD
D	14009.50	4.85		TIW Seals	5.90 OD
	14014.35	469.03		Tbg. 4½" 18.98# Hydril	
	14483.38	.59		X-over	5.00 OD
E	14483.97	.83		Otis "XN" Nipple 11XN3313	4.50 OD 3.313 ID
F	14484.80	.50		Mule Shoe Guide	
	14485.30				

PAGE 1 OF 1

FIGURE 5-4
OTIS PACKER INSTALLATION REPORT

PB No. 2
MEASURED SCALE THICKNESS

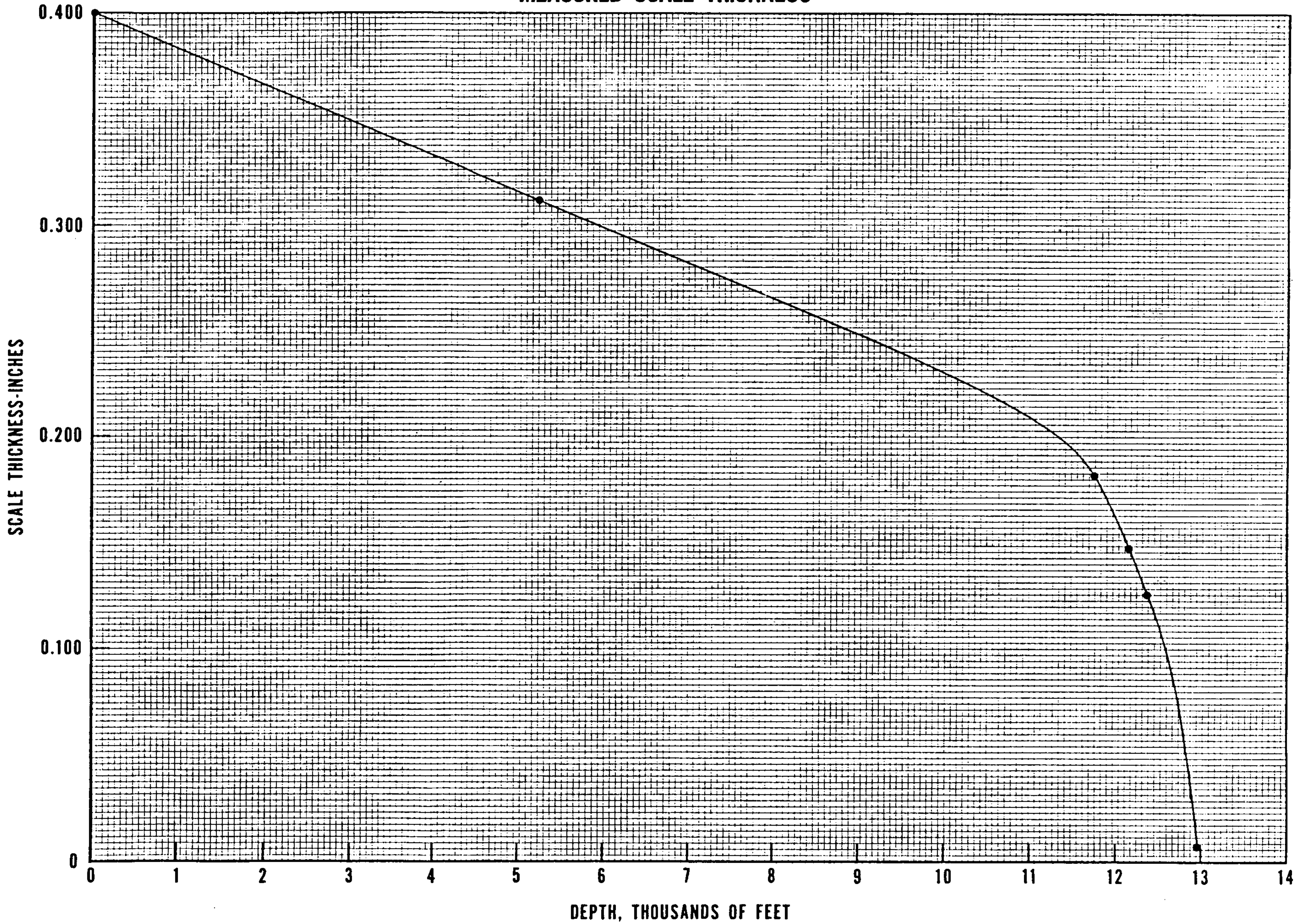


FIGURE 5-5

6.0 TUBING FAILURE ANALYSIS

In planning for recompletion of the No. 2 well, two major determinations had to be made. First, was the recovered tubing suitable for use in recompletion. Second, what was the best method of recompletion to control downhole scale and corrosion.

Analyses of the failed coupling and downhole corrosion were performed by Radian Corporation and Oil Technology Services, Inc., (OTS). Appendix B is an excerpt (pages 3 to 36) from Radian's report titled "Failure Analysis Report Production Tube Components from Three DOE Geopressured-Geothermal Wells on the Texas-Louisiana Gulf Coast." Conclusions and recommendations are found on pages 19 to 21 of the report.

OTS prepared a two-part report titled "Failure Investigation - Pleasant Bayou No. 2." Appendix C is a copy of the conclusion section of each part of that report.

6.1 Summary of Conclusions

The combined analyses and investigations provided by Radian and OTS resulted in the following major conclusions:[4,5]

- Coupling failure initiated a tong gouge which served as a stress concentrator.
- There was no evidence of brittle fracture, cyclic (fatigue) fracture, or corrosion induced fatigue.
- Failure was not a result of a metallurigical defect. Coupling material satisfied all requirements of its specified P-110 grade.
- The teflon ring jump-out during make up appears to have contributed to the failure.
- Problems inherent to the design of both the 8rd. LTC and FL-4S connections make them unsuitable for this application.

7.0 DOWNHOLE CORROSION

Significant corrosion of tubing below ±13,000 feet (point below at which scale deposition stopped) was observed on those interior surfaces where the organic coating had failed. Radian, Appendix B, Pages 16 and 19, attributes this to carbonic acid attack, and calculates the pH of the brine to be 4.3 at a depth of 13,700 feet. The metal loss was most severe on the FL-4S pin lips, see Figure 2-17, Page 33 of Appendix B, probably as a result of increased turbulence at the sharp edges of the FL-4S coupling configuration. Radian also expresses concern that if a downhole scale treatment system were used, the entire string would be subjected to this type of corrosion. Interior surfaces covered with scale suffered very minor corrosion. Radian's recommendations to remedy the corrosion problems are summarized below.

- Consider the use of couplings which do not have sharp-edged lips

- Evaluate use of other organic coating such as "Spincoat"

- Consider use of alternate low allow steels such as 2.25Cr-1Mo with low sulfur content

7.1 Metallurgical Alternatives

OTS studied the metallurgical alternatives and issued a report titled "Reducing Crevice Corrosion - Pleasant Bayou No. 2, Part C, Metallurgical Alternatives to Reduce Crevice Corrosion on 5-1/2 Inch T&C Connections." This report discussed the available options to protect T&C couplings against corrosion. Options discussed included coatings, claddings, vapor deposition, electroless plating, weld cladding, thermoplastics and corrosion resistant alloys. Serviceability, lead time, and costs were also discussed. Details of the discussions are included in Appendix D.

8.0 RECOMPLETION PLANS

8.1 Production Tubing

Based on the analyses, investigations, and studies discussed in Section 7.0, the following plans were developed.

- The existing 5-1/2 inch, 23 pounds/foot, P-110, 8rd. LTC, and FL-4S tubing was not suitable for use in recompleting the No. 2 well. Further, it was not economical to clean and recondition the tube for installation of a new premium type T&C connection.

- New 5-1/2 inch, 23 pounds/foot, P-110 Grade plain end tube and coupling stock would be purchased. A premium type thread would be machined on the new tube and new couplings manufactured with very strict quality control inspection from purchase through downhole installation.

8.2 Scale and Corrosion Control

Recompletion was to include provisions for continuous downhole chemical injection using a specially fabricated chemical injection sub and 1/4 inch tubing on the exterior of the production tubing. This system would allow for injection of scale inhibitors and possibly corrosion inhibitors in the flow stream just above the production packer. Figure 8-1 illustrates this completion method. Chemical injection at the surface is through a specially prepared adapter flange between the upper section of the tree and the tubing head and a ported mandrel type tubing hanger. The 1/4 inch tubing is connected to the bottom of the mandrel hanger body and secured to the outside of the tubing. Figure 8-2 illustrates a typical wellhead system. Just above the packer, the 1/4 inch tubing connects to a specially fabricated sub which allows chemicals pumped from the surface to enter the flow stream.

8.3 Production Packer

Recompletion plans also included removal of the two production packers and tail pipe and installation of a new packer and tail pipe. The existing system was designed for seal assembly travel through the packers and seal bore extension as the tubing string expanded or contracted. The equipment, however, did not function as designed. The seal assembly became lodged inside the seal bore. With this design, it is possible for elevated tensions to develop in the string if the seal assembly becomes stuck in the down position while flowing. When flow is stopped and the string cools, additional tensional stresses are experienced. This could be critical if cooler fluid were injected through the tubing string during acidization or other similar operations. The new equipment would be designed with an adequate seal length to isolate the production tubing from the annulus. A positive latch

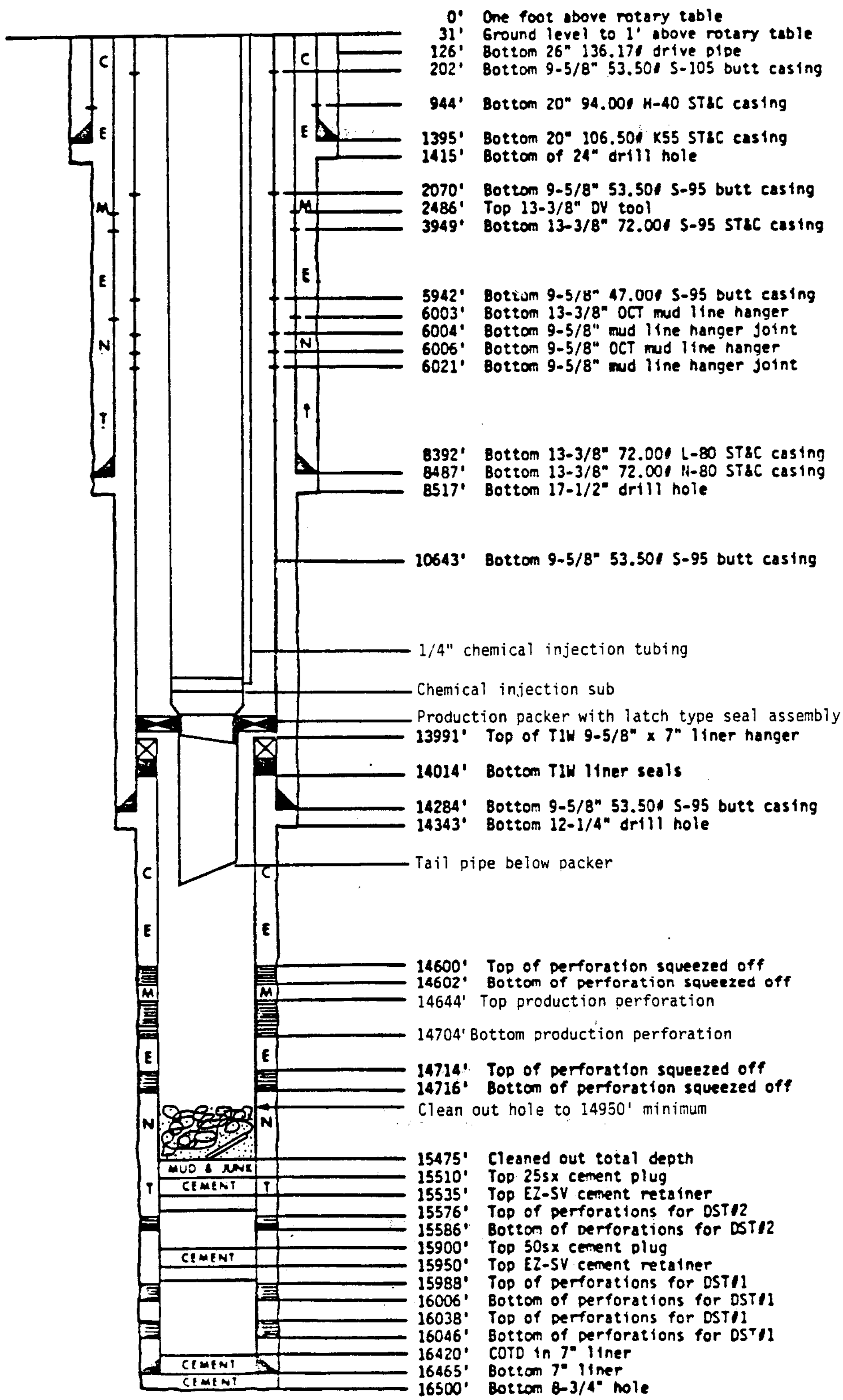
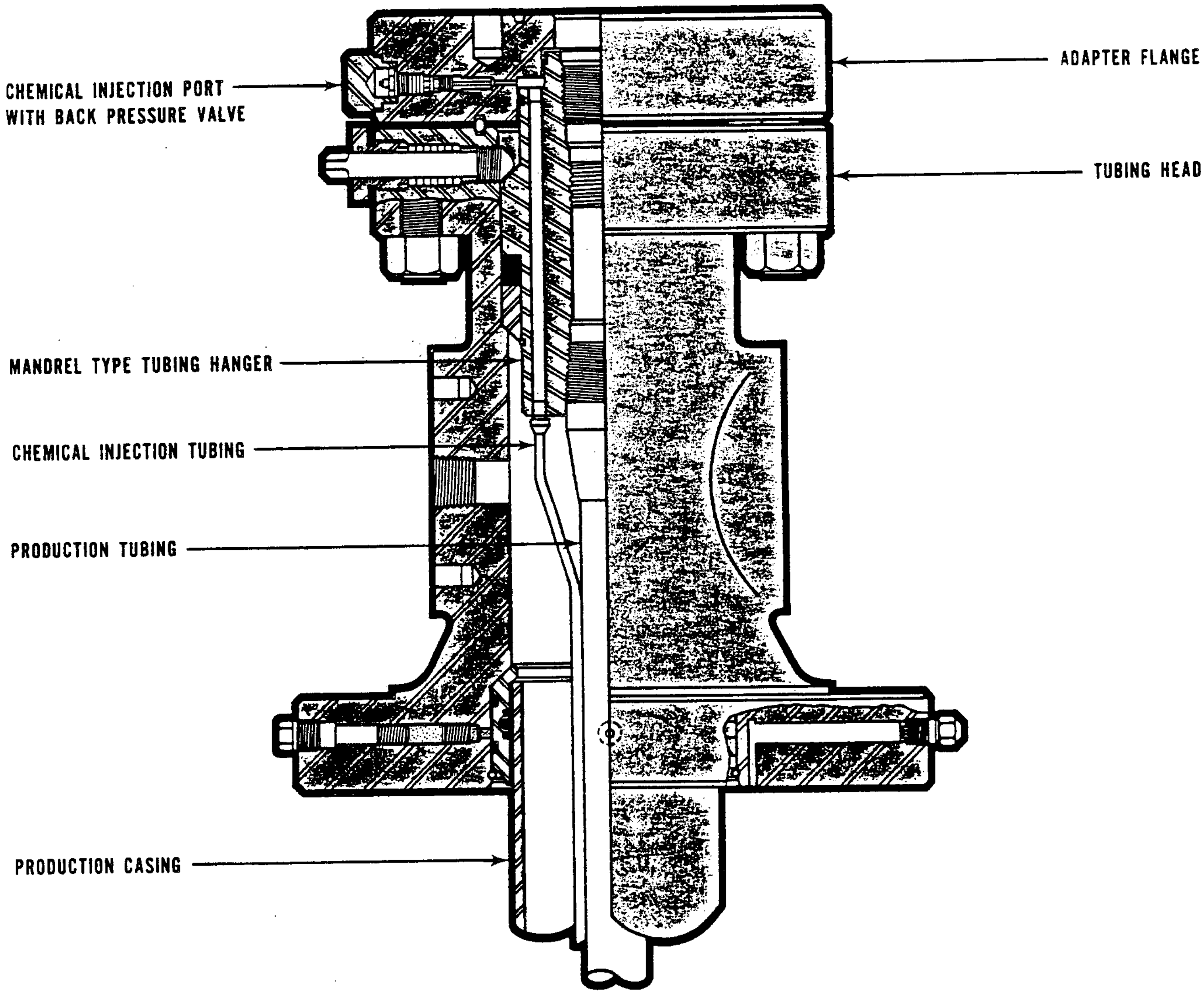


FIGURE 8-1
COMPLETION WITH DOWNHOLE CHEMICAL INJECTION



Type U Tubing Head Spool with Type USS-1 Tubing Hanger

FIGURE 8-2
TYPICAL WELLHEAD ADAPTED
FOR CHEMICAL INJECTION

would hold the seal assembly in place and allow for tensioning the production string to a predetermined amount.

8.4 Procurement Actions

In preparation for recompleting the No. 2 well, procedures and procurement specifications were prepared for the following major items:

- New 5-1/2 inch, 22.54 pounds/foot, P-110 Grade plain end tube
- Machining new threads on tube and manufacturing new connections
- Downhole chemical injection system
- Drill rig and ancillary equipment
- New adapter flange and tubing hanger
- New production packer and hardware

On February 23, 1984, the Department of Energy (DOE) Nevada Operations Office directed that the procurement actions be cancelled "because of insufficient program funding and associated guidance on the availability of near future funding." On March 14, 1984, the DOE issued a stop work order and directed that arrangements be made to place the site in a standby-secured condition.

9.0 PLACING THE SITE ON STANDBY-SECURED

9.1 Plans

Detailed plans were developed for placing the site on standby-secured. The objective was to suspend all field activities and secure the site in a manner which would be cost effective both during the suspended period and upon resumption of site operations. Summary of the planned operations were as follows:

- Remove the Blanks Drilling Corp.'s rig from the location
- Flush the surface piping and production equipment with corrosion inhibitor and maintain on nitrogen purge to protect against corrosion
- Drain, backfill, compact, and reseed the reserve pit area
- Maintain site electrical power, security fence, and floodlights
- Provide for site maintenance during the secured period

All of the above was accomplished with the exception of demobilizing the rig.

9.2 Rig Demobilization.

Blanks Drilling Corp.'s subcontract was modified allowing Blanks to store its rig on location during the secured period.

9.3 Reserve Pit Restoration

For planning purposes, it was necessary to determine the amount of clean fluid and sludge contained in the reserve pit. This was done by obtaining depth measurements of fluid and sludge on a grid pattern across the entire pit area. Using these measurements, the volumes were calculated.

9.3.1 Dewatering. Prior to dewatering, the reserve pit samples of the fluid were analyzed to determine what method of water disposal was most appropriate. Table 9-1 is a tabulation of the results of the analyses.

The water quality did not meet the discharge requirements of the Railroad Commission of Texas (RCC) or the Texas Department of Water Resources. Alternatives were to haul the water by truck to an RRC-approved disposal site or inject it into the No. 1 well. Economics favored injection since there was little risk in formation damage with the elevated chloride level.

TABLE 9-1
RESERVE PIT FLUID ANALYSIS

pH	5.8
Alkalinity mg/l	30
Chlorides x10^3 mg/l	9.8
Conductivity x10^3	22.3
Salinity ppm	13,700
Specific gravity at 60° F	1.01
Sulfates mg/l	15.6
Suspended solids mg/l	49
Dissolved solids mg/l	19,860
Hardness as mg/l $CaCO_3$	6,200
Hydrocarbons mg/l	<0.05

Heavy Metals mg/l

Arsenic	0.21
Boron	0.24
Cadmium	<0.05
Chromium	<0.05
Copper	<0.05
Lead	<0.05
Manganese	4.80
Mercury	<0.05
Zinc	81.60
Barium	3.80
Nickel	<0.05
Selenium	<0.05
Silver	<0.05

The water was removed from the pit with a centrifugal pump and pumped through a 10 micron filter into a storage tank. From the tank, a positive displacement triplex pump was used to inject the water into the No. 1 well. Injection rates varied between 150 and 250 gpm with injection pressures between 350 and 500 psig. All but 500 barrels of pit fluid were disposed of by this method, a total of approximately 30,000 barrels. The remaining 500 barrels were removed by vacuum truck and disposed of at an RRC-approved site.

During fluid injection, communications developed between the 5-1/2 inch tubing and the 9-5/8 inch casing annulus. A maximum of 130 psig was observed on the annulus when the injection pressure was 500 psig. Cause of the communications has not yet been determined.

Seal assembly movement due to tubing string contraction, from injection of cooler water, could have caused seal failure. It is also possible that, after six months of injecting hot brine, the seal assembly became stuck inside the seal bore in the expanded position. The additional stresses from injection of cooler fluids may have caused a connection leak.

9.3.2 Backfilling. Following removal of the water, the remaining sludge was solidified by addition of large quantities of lime and flyash. A combined total of approximately 500 tons of lime and flyash were used. The area was then covered with soil, contoured to approximate the existing terrain, tilled, fertilized, and reseeded. Pit restoration was completed 8-25-84 and the site was secured.

10.0 ACTIVITIES DURING THE SECURED PERIOD

10.1 Rig Storage

Agreements were executed between DOE's Nevada Operations Office and the FDIC and between Fenix & Scisson, Inc., and Blanks Drilling Corp., with allowed Blanks to store its rig at the Pleasant Bayou site. The initial agreement was for the period of June 10, 1984 through October 7, 1984. These agreements were later ammended to extend the storage period and transferred to DOE's Idaho Operations Office.

10.2 Site Maintenance

Routine maintenance was performed at the site during the secured period to ensure that the equipment and overall site could be placed back in operation with minimal rehabilitation.

10.2.1 Weekly Maintenance. A local lease service was employed to perform weekly maintenance in accordance with a pre-established checklist. Weekly maintenance and monitoring included:

- Checking oil levels in air compressors and gasoline engine
- Draining moisture from air compressor tanks
- Running electric motors and gasoline engine
- Operating manual and air actuated valves
- Checking pressures on No. 2 and No. 1 wells
- Checking floodlights and replacing bulbs
- Checking perimeter fence and gates and all buildings
- Maintaining nitrogen purge on surface equipment

10.2.2 Monthly Maintenance. Monthly maintenance included:

- Changing oil and cleaning air filters on compressors and gasoline engine
- Greasing exposed flanges
- Cutting grass inside the fenced area

The Fenix & Scisson maintenance subcontract continued through February 28, 1985. After 2-28-85, continuing maintenance was provided by subcontract through EG&G/Idaho.

10.3 No. 2 Wellhead Pressure

On 7-24-84, pressure began developing on the No. 2 well. At this time, the cause of the pressure is unknown. It is believed to be caused by expansion of the fluid from a gradual temperature stabilization or from rising gases generated by degradation of the polymer mud. Prior to securing the site, the pressure was "bled-off", and it has been monitored since. Figure 10-1 is a plot of the pressure buildup from 8-24-84 through 3-09-85. Average pressure increase has been 4 psi/day.

10.4 Recompletion Study

The option of producing the well through the 9-5/8 inch casing with small kill/treatment string was considered. Figure 10-2 is a schematic of the wellsetting arrangement considered.

OTS was employed to conduct a study of this option specifically calculating adequacy of the 9-5/8 inch to safety function under all possible production situations. OTS used computer modeling, such as its Casing Service Life Analysis Model (C-SLAM), to calculate the stresses in the casing under a variety of service conditions. Appendix E is a copy of the conclusions of OTS' report titled "Engineering Study to Determine the Feasibility of Producing the Pleasant Bayou No. 2 Well Through the 9-5/8 Inch Intermediate/Producing Casing."

PB No. 2 WELL
PLOT OF PRESSURE BUILD UP vs TIME

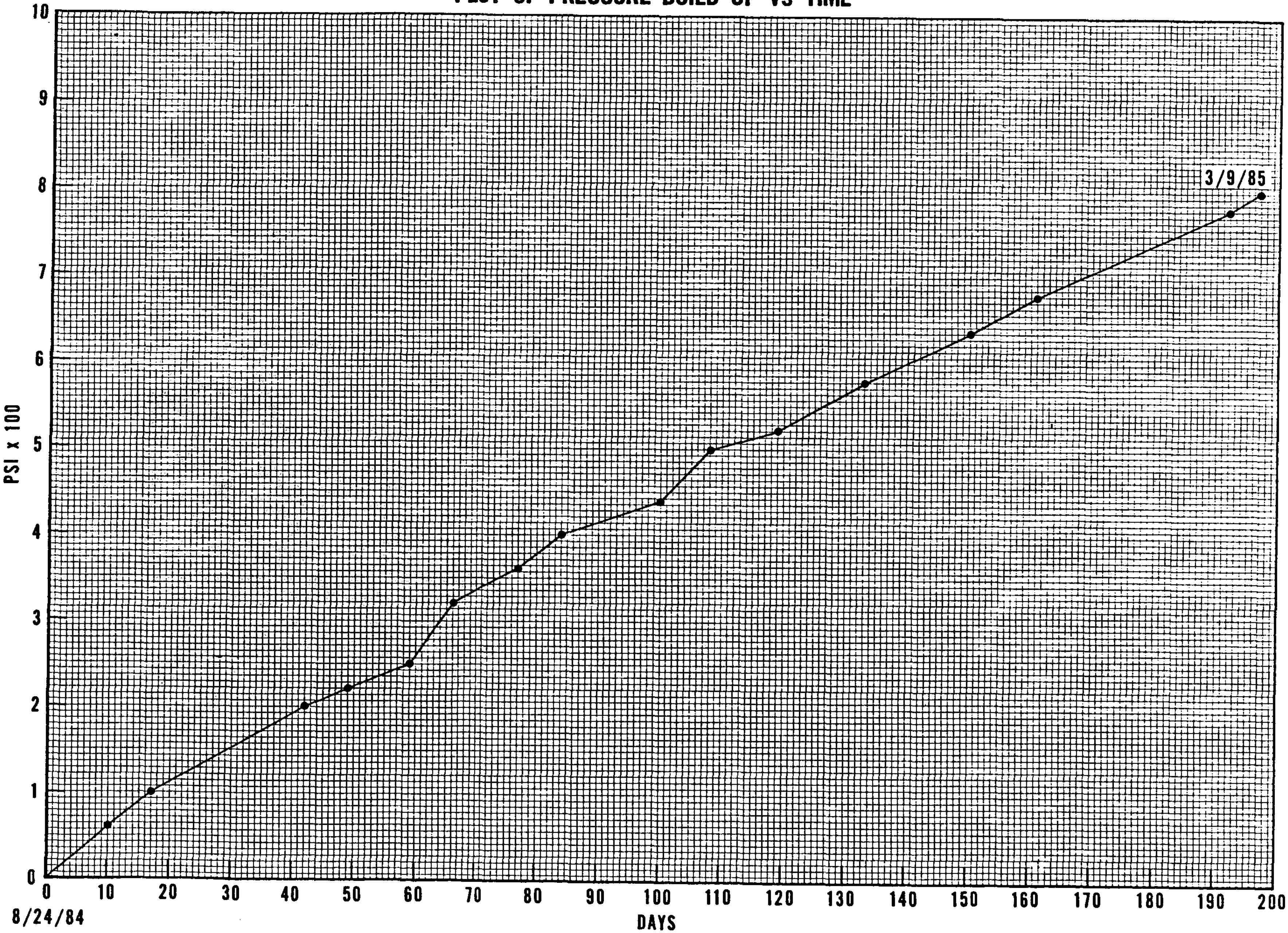


FIGURE 10-1

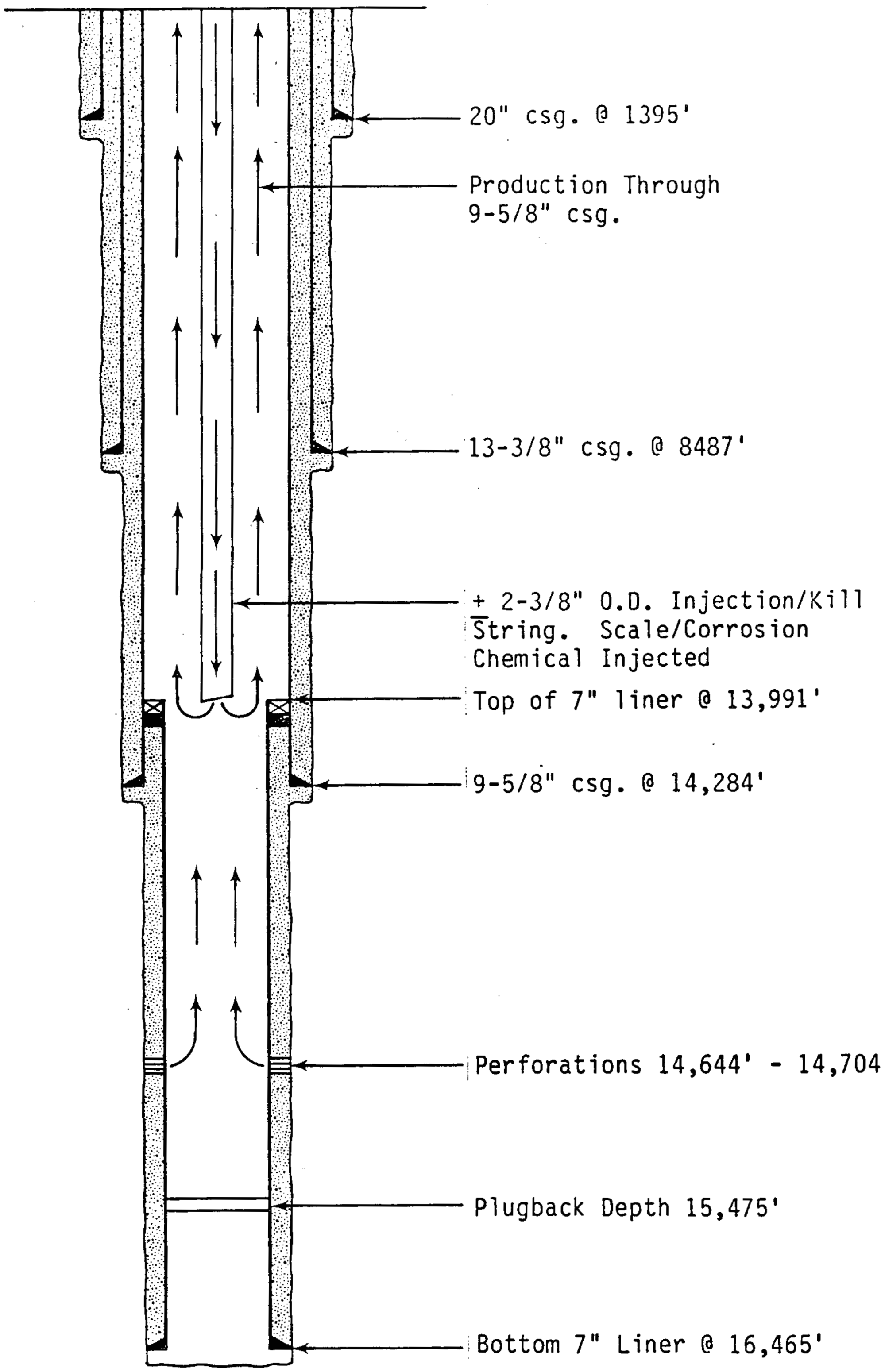


FIGURE 10-2
SCHEMATIC OF PRODUCTION THROUGH CASING

11.0 CONCLUSIONS

Although the Phase II-B test was terminated prematurely, enough data was gathered and experience gained to reach certain conclusions:

11.1 Reservoir Characteristics

Upon termination of the Phase II test, Gruy Petroleum Technology, Inc., utilized its two-dimensional, three-phase, black oil simulator program to simulate performance of the Pleasant Bayou No. 2 Well. The simulator solves the finite-difference behavioral equations using the semi-implicit procedure (SIP). Average block pressures at the end of each time step are converted to flowing bottom-hole pressures using a psuedo-steady state approximation for radial flow in the block, and multiphase flow in the tubing string. Fluid properties were obtained from recombination studies, differential liberation experiments, and viscosity measurements performed by Weatherly Laboratories. The conclusions of the simulation studies are summarized on Page 11 of Appendix F, "Reservoir Simulation study of the Pleasant Bayou No. 2 Well, Brazoria County, Texas."

As discussed in the conclusion, scale accumulation materially affected the surface flowing pressures during the later part of the Phase II-B testing. The reservoir model would have been different had the pressures been unaffected.

11.2 Surface Equipment

Major surface equipment components, wellhead, choke, separators, fin cooler, dehydrator, sales meter, and flare functioned properly and reliably during this phase of testing. Problems with other equipment such as valves, flanges, ring seals, and turbine meters have been resolved.

Routine maintenance, proper equipment operation, and scale and corrosion inhibition are essential. The system will not function in this hostile flow environment without them. With scheduled maintenance, proper operating procedures, and scale and corrosion control, equipment reliability should be above 95%.

11.3 Labor Requirements

During typical flowing-injecting-gas sales operations with effective scale and corrosion control, the site could be operated unmanned for short periods.

11.4 Downhole Equipment

11.4.1 Production Well. As discussed in this report, conclusions have been reached regarding certain production well downhole equipment.

- API 8rd., LTC, or FL-4S connections are not suitable for geopressured-geothermal service.
- Slip and seal assemblies are not preferred
- Downhole scale inhibition is necessary for high rate production
- Downhole corrosion inhibition or an effective internal coating is very important
- Restrictions inside the tubing hanger are a disadvantage

11.4.2 Injection Well. Conclusions have also been reached regarding injection well downhole equipment.

- Slip and seal assemblies are likely to become stuck resulting in additional stresses on the injection tubing
- Packer fluid in injection wells should be of minimum density to keep external stresses at a minimum
- Annular pressure caused by heat expansion of fluid in the annulus should be monitored and bled-off to prevent additional external stresses

12.0 PROGRAM TRANSFER

On April 1, 1985, the Geopressured/Geothermal Program was transferred from DOE's Nevada Operations Office to the Idaho Operations Office. Upon issuance of this report, all pertinent files in Fenix & Scisson's Las Vegas Branch offices will be transferred to DOE/Idaho.

13.0 RECOMMENDATIONS

13.1 Production Well Recompletion

13.1.1 Well Clean Out. It is recommended that the following be accomplished during clean out of the No. 2 well:

- Removal of the existing production packers and tail pipe

- Casing scraper run and casing inspection caliper of the 9-5/8 inch casing down to the top of the 7-inch liner

- Clean out hole below existing perforations to a minimum depth of 14,950 feet. This will allow for perforating the zone between 14,844 and 14,920 feet if additional volume is required in the future. Figure 13-1 is a copy of a dual induction focused log in the prospective interval.[2]

Clean out below the existing perforations may be difficult. There is wireline and three sets of wireline tools in the "rathole" below the existing perforations.

13.1.2 Production Tubing. A string of new production tubing should be obtained with premium connections. The new connection should have a smooth internal bore compatable with the tube, have a metal-to-metal pin nose seal, and be free of teflon or other plastic seal rings or grooves.

Both the tube and the connection must undergo a strict quality assurance and quality control program from initial heat treatment to installation. Internal coating should be considered if a reliable, durable type coating is available.

13.1.3 Scale and Corrosion Control. A method of downhole scale control is necessary for efficient long-term production, especially at high rates (20,000 BPD, or above). This can be accomplished by using 1/4 inch capillary tubing external to the production tubing and a downhole chemical injection device just above the production packer. Figure 8-1 illustrates this type of completion.

The tubing should be constructed of Incoloy 825 rather than 316L stainless, since the tube will be exposed to elevated temperatures and a chloride based packer fluid. Consideration should also be given to the use of a two-tube incapsulated system for both scale and corrosion treatment. The second tube could be used as a spare scale treatment tube if the production tubing were protected from corrosion by a coating.

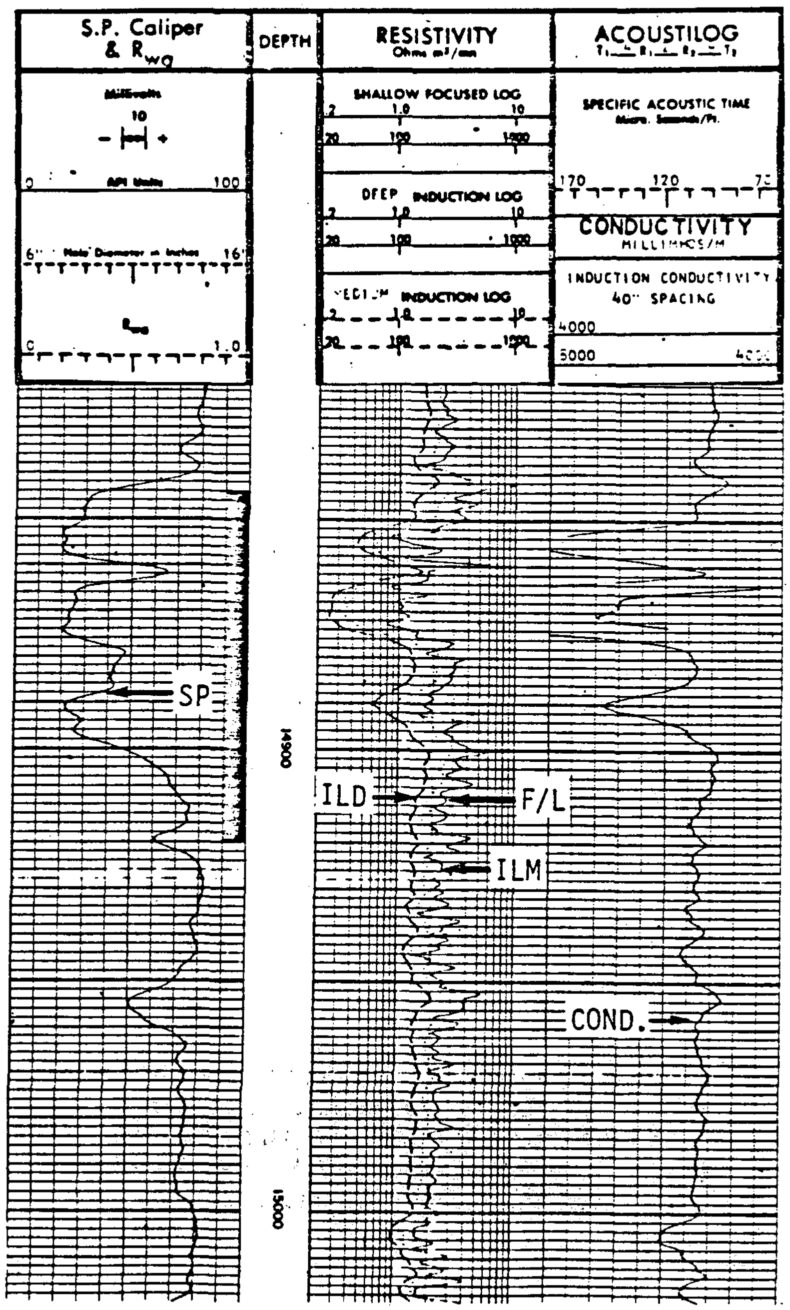


FIGURE 13-1

DUAL INDUCTION FOCUSED LOG OF
PROSPECTIVE PRODUCTION INTERVAL

If a larger tubing string (6-5/8 inch - 7-inch O.D.) is needed for higher production rates, an annular injection completion would be possible. However, there are also problems associated with this type of injection system which must be resolved before its application.

- Even with 7-inch production string, annular volumes between the 7-inch and 9-5/8 inch are still above 300 barrels. The annular fluid would have to be designed for a dual purpose, as a scale inhibitor and as a typical annular fluid.

- The injected fluid must also in itself be non-corrosive. The phosphonate scale chemical used at the surface during the Phase II-B test was very corrosive to alloy steels in its concentrated form. An elevated corrosion rate inside the 9-5/8 inch casing could not be tolerated.

- In conjunction with annular injection, there must be a downhole injection valve. Many similar systems have failed because the small injection valve becomes plugged with fines that remain in the annulus after displacing the annular fluid. Extra precaution would have to be exercised to ensure that the annular fluid is as solid free as possible.

Teneco Oil Co. has had much experience with continuous injection methods and has published reports discussing the advantages and disadvantages of the two methods described above.[8,9,10]

Considering the above discussion and industry experience, the capillary method is favored as long as there is enough annular space for its use.

13.1.4 Perforations. As discussed in Section 13.1.1, above, the wellbore will have to be cleaned out below the existing perforations. It is advisable to clean out the wellbore to a minimum of 14,950 feet so that the zone between 14844 and 14920 feet could easily be perforated in the event higher production rates are desired.

13.2 Injection Well

13.2.1 Determine Source of Communications. As discussed in Section 9.3.1, communications developed between the injection tubing and annulus while injecting the reserve pit fluid. It is unlikely but possible that after injection of the cooler fluid, the tubing string expanded and the seal assembly resealed in the packer seal bore. This can be checked by injecting salt water down the tubing and by pressure testing the annulus.

It is most likely that there is still communications and the tubing string will have to be pulled. The present condition of the No. 1 well is illustrated in Figure 13-2.

13.2.2 Recompletion. Consideration should be given to recompleting the injection well with larger tubing if future production plans are to produce at rates exceeding 35,000 to 40,000 BPD. Larger tubing will lower the frictional losses and help in maintaining lower separator operating pressures. At a flow rate of 30,000 BPD injection, pressures were in the range of 450 psig with the existing 5-1/2 inch tubing and 150 feet of perforations.

Upon recompletion, the wellbore should be cleaned out to ±6780 feet, just above the point where the lost wireline was tagged. The preferred method of cleaning out the wellbore is with nitrogen and foam circulation using continuous tubing.

After cleaning out the wellbore, an injection test using 9.0 to 9.1 pounds/gallons salt water is advisable to determine surface injection pressures at anticipated injection rates. If pressures are excessive, the perforations can be acidized or additional perforations added. Perforations above the 9-5/8 inch casing shoe are not recommended.

No special scale or corrosion treatment is recommended in the injection well if an effective program is used in the production well or surface equipment. Downhole scale and corrosion should be monitored, however, every 3 to 4 months using a multiarm casing inspection caliper.

Occasional acidic acid treatments using the filter unit may prevent the buildup of acid soluable materials at the perforations. If injection pressures become critical, it may be necessary to back flow the perforations using nitrogen and foam.

13.3 Surface Equipment and Facilities

13.3.1 Separators. The No. 2 separator on loan to the Technadrill Fenix & Scisson Gladys McCall Project will have to be reinstalled. Separators No. 1 and No. 2 are rated at 22,000 BPD and 18,000 BPD, respectively. However, separation efficiency and ease of operation decline at these maximum rates. More realistic rates are 20,000 and 15,000 BPD. Additional separation equipment should be considered for rates above 35,000 BPD.

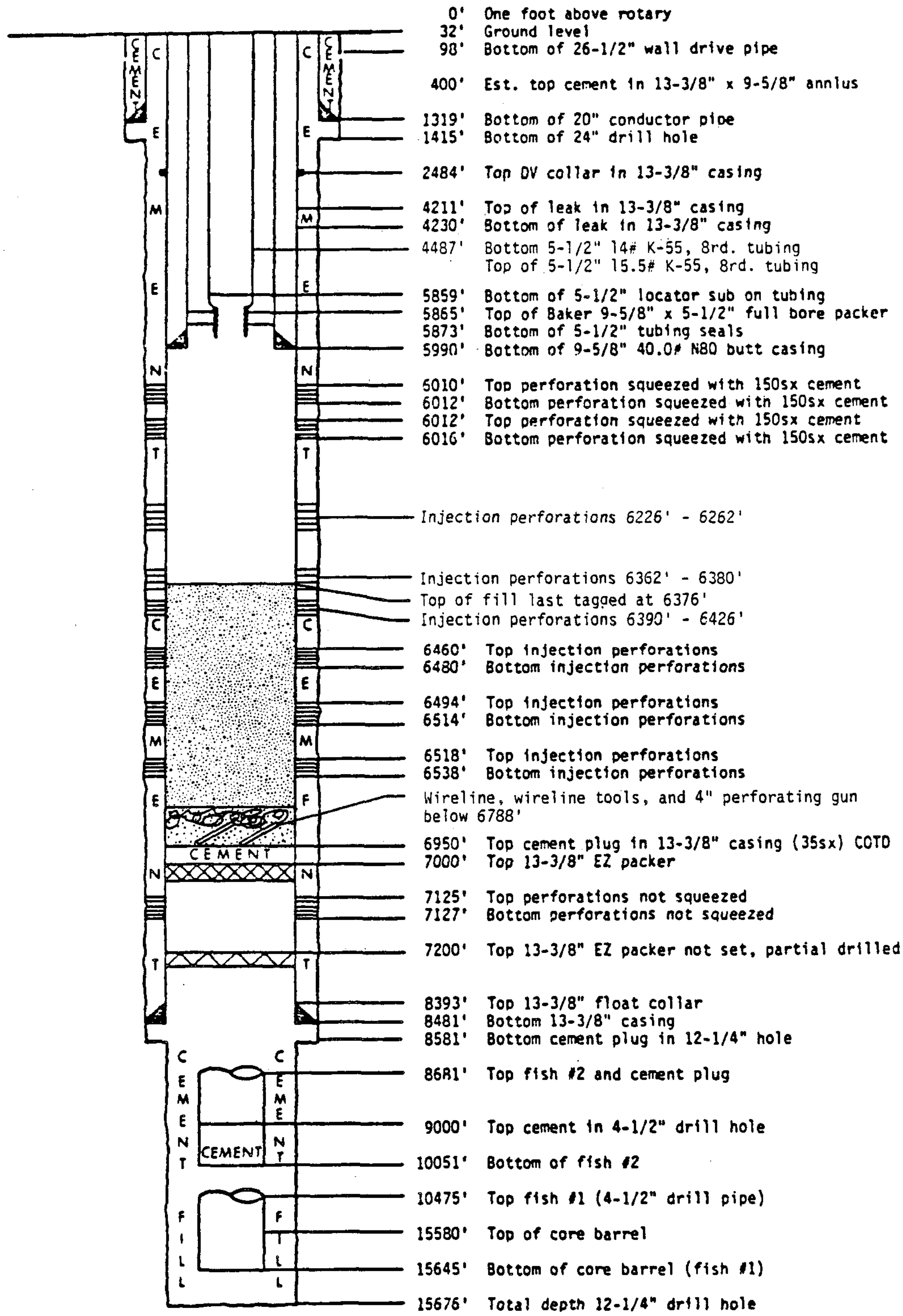


FIGURE 13-2
PB No. 1 PRESENT CONDITIONS

13.3.2 Injection Line. The 6-inch Sch. 80 injection line is sized for 30,000 BPD. Observed pressure loss through the separator dump and 6-inch line was 50 to 60 psi at 30,000 BPD.

If future flow rates over 30,000 BPD are anticipated, a larger line should be considered.

13.3.3 Blowdown Tanks. There is no blowdown system onsite since the reserve pit has been backfilled. Tanks should be provided onsite for diverting the flow while "cleaning-up" the well or other occasions when it is advantageous to divert the flow for short periods. Two thousand barrels of storage should be adequate.

13.3.4 Separator Blowdown Pit. The existing separator blowdown/drain pit originally was lined. The lining has been destroyed and should be replaced.

13.3.5 Filter Unit. The filter unit has been reconditioned and should be installed on the injection line. It can be used for treatments of powdered acidic acid.

13.4 Instrumentation

The Panex pressure/temperature transducer has proven to be an accurate and reliable system for obtaining wellhead pressure and temperature. This instrument must be reinstalled on the wellhead flow loop with the display and printer reinstalled in the office trailer.

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RADIAN
CORPORATION

GEOTHERMAL ANALYTICAL REPORT

Contract No. DE-AC03-81SF11503 **DCN:** 83-212-011-64

Title: Flanges from the High Pressure Geofluid System of the Pleasant Bayou Geopressured Geothermal Well

Report Date: 22 December 1983

Source Contact: Howard Blumhardt

Address: Fenix & Scisson
Route 7, Box 693
Alvin, Texas 77511

Resource: Pleasant Bayou No. 2 Geopressued-Geothermal Well, Brazoria County, Texas

Purpose/Background: To determine if severe internal pitting, observed during site visit, was associated with weldments.

Radian Analyst: Peter F. Ellis II & Dennis M. Anliker

RESULTS

See page 2 for background information and discussion.

Observations: Figures 1 and 2 show cross sections and typical internal views of the two flanges, which have been designated as No. 1 and No. 2 for clarity. No association between the areas of localized corrosion and weldments was evident.

Random measurements of pit depth and width on flange 1 showed a mean pit depth of 0.156 ± 0.202 inches,* and a mean width of 0.580 ± 0.202 inches.* It is unlikely (<1% probability) that any pit exceeded 0.31 inches of depth or 1.27 inches of width. For flange 2, the mean pit depth and width were 0.097 ± 0.017 inches* and 0.756 ± 0.303 inches* respectively. It is unlikely (<1% probability) that any pit exceeded 0.16 inch in depth or 1.50 inch in width.

Flange 1 had a Rockwell B hardness of 78.6 ± 0.2* while flange 2 had a Rockwell B hardness of 92.8 ± 0.8.* Hardness was uniform throughout the metal cross section. Microstructures were also uniform and were typical of cast steel.

As indicated by Figures 1 and 2, the high pressure surface piping was free of the heavy scale buildup which occurred in the well [1].

Conclusions: 1) The severe localized corrosion of the flanges is the result of the inherent lack of corrosion resistance of this alloy to the geofluid. It is not the result of metallurgical modifications produced by welding. 2) The phosphonate scale inhibitor is effective in controlling calcite formation, but the proprietary corrosion inhibitors used were not effective.

*95 percent confidence interval

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RADIAN CORPORATION

BACKGROUND

The 16,500 ft. deep Pleasant Bayou No. 2 geopressured-geothermal well is located in Brazoria County, Texas, near the town of Alvin. This well is currently operated as a natural gas recovery well with about 22 SCF of gas being recovered per barrel of hypersaline geofluid produced.

In a recent 203-day test, geofluid was produced at 20,000 bpd (583 gpm) at a nominal pressure of 2000 psi and nominal temperature of about 300°F. The geofluid passed through high pressure (2000 psi nominal) piping to a train of gas separators, where the natural gas was extracted, and then to a reinjection site for disposal. The flanges which are the subject of this GAR were from the high pressure geofluid system. At the end of the 203-day test, severe localized corrosion was observed on the internal surfaces of these and other flanges.

The Pleasant Bayou geofluid has the following nominal chemistry after the gas is extracted:

> 78,470-78,480 ppm chloride, 0.4 ppm soluble sulfide, 90-94 ppm ammonia, 360-390 ppm alkalinity (as bicarbonate), 9700-9800 ppm calcium, and 311,150-132,150 ppm total dissolved solids. The geofluid contains a significant amount of dissolved carbon dioxide which produces a pH of 4.3 in the reservoir. After production, the pH rises to 5.5-5.6.

Calcite scale formed at a rate of about 0.5 inch/yr. in the upper part of the well [1]. A phosphonate scale inhibitor and proprietary corrosion inhibitors were added at the wellhead to control scale and corrosion in the surface equipment.

DISCUSSION

Dissolved carbon dioxide has long been recognized as a major culprit in "sweet well" corrosion, with severe attack of carbon steels occurring at high temperatures in the absence of protective corrosion products or scales [2], with a strong tendency toward deep pitting in the 212-300°F range [3]. Calcite scale, formed in the upper reaches of the production tube, appears to have been protective [1], but this scale was prevented in the surface equipment as discussed above. In the absence of protective scale, severe localized corrosion problems appear inherent in the selection of carbon steel for this application.

REMEDIAL ACTION

It is understood that the high pressure piping at Pleasant Bayou is being replaced with stainless steel lined piping to control corrosion.

Both above ground [4] and downwell [5] tests at other hypersaline geothermal wells have shown that some low alloy steels have considerable corrosion resistance. Further testing may demonstrate some of these alloys to be useful for geopressured-geothermal systems.

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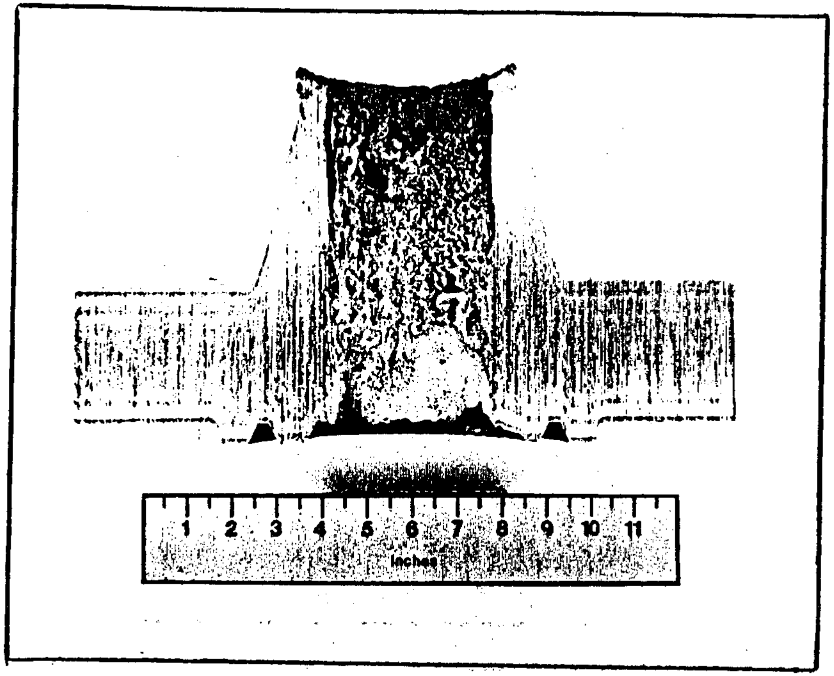
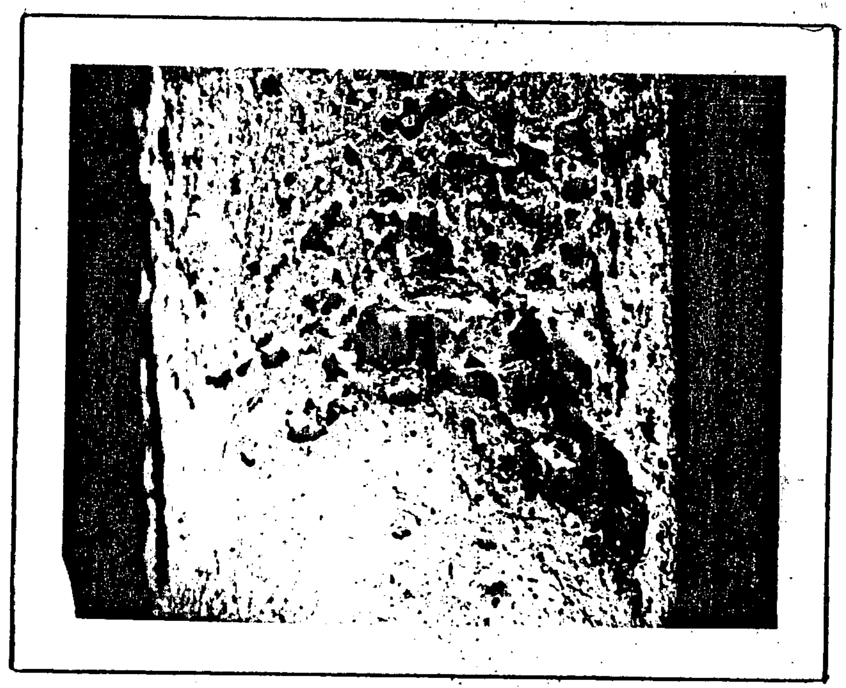
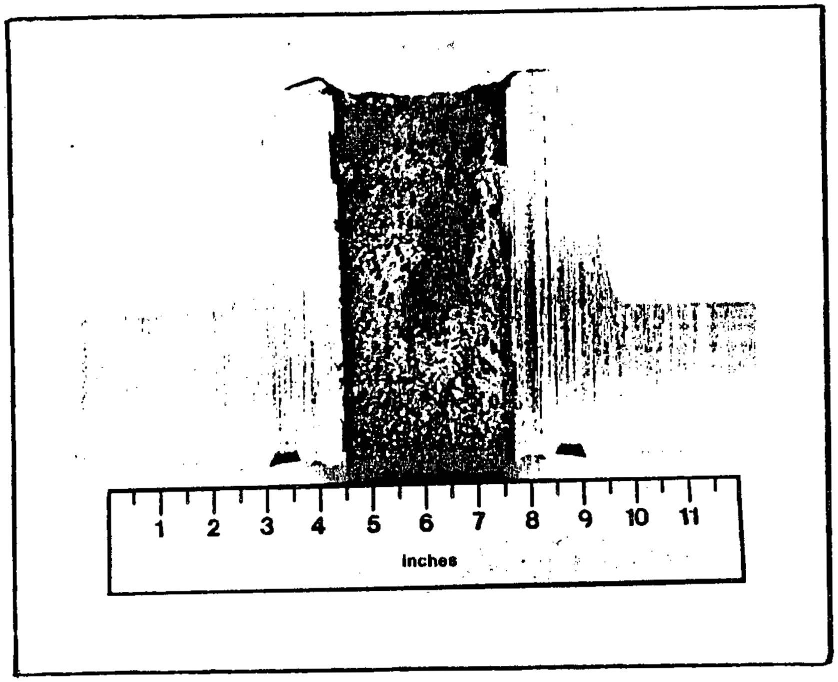


Cross Section

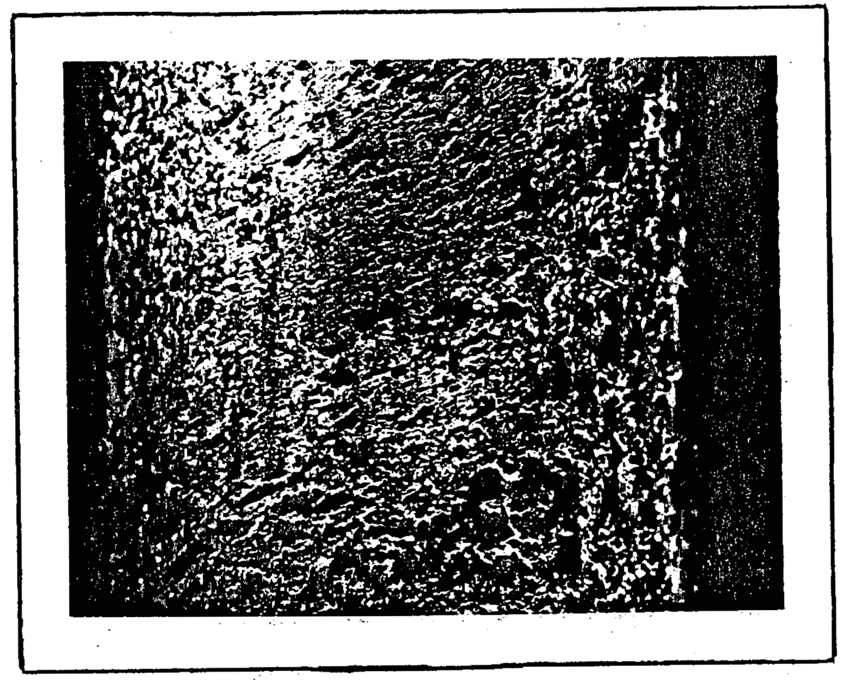


Typical Internal Surface
(approximately actual size)

Figure 1. Cross Section and Typical Internal Surface of Flange No. 1



Cross Section



Typical Internal Surface
(approximately actual size)

Figure 2. Cross Section and Internal Surface of Flange No. 2

RADIAN CORPORATION

DCN 83-212-011-63

FAILURE ANALYSES REPORT

PRODUCTION TUBE COMPONENTS FROM THREE DOE GEOPRESSURED-GEOTHERMAL WELLS ON THE TEXAS-LOUISIANA GULF COAST

Prepared by:

Peter F. Ellis II
Dennis M. Anliker

Prepared for:

UNITED STATES DEPARTMENT OF ENERGY
San Francisco Operations Office
Fossil, Geothermal, and Solar Energy Division
1333 Broadway
Oakland, California 94612

Contract No. DE-AC03-81SF11503

December 1983

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DISCLAIMER

2.0 PLEASANT BAYOU NO. 2

Mission: 1) investigate the cause of failure of the production tube coupling located at 5225 ft, and 2) investigate the "erosion" of production tube pin ends from depths greater than 13,500 ft.

2.1 Background

Pleasant Bayou No. 2 is located in Brazoria County, Texas, near the town of Alvin. The well was initially completed in July 1979. It was the first well drilled exclusively for evaluating geopressured-geothermal resources [Kharaka et al. 1979; Stevens and Clark 1979].

The Pleasant Bayou No. 2 well has a total depth of 16,500 ft. The well is cased with 9 5/8-inch diameter casing from the surface to 14,284 ft with the top 202 ft being 53.50 lb/ft S-105 butt casing and the remainder being 53.50 lb/ft S-95 butt casing. A 7-inch diameter liner is hung from the 13,991-ft level and extends to 16,465 ft. Fluid is produced through perforations in this liner.

Fluid is brought to the surface through a production tube. This production tube consists of 5 1/2-inch, 23.00 lb/ft, P-110 tubing with Atlas-Bradford modified 8-round thread couplings from the surface to 5368 ft. From 5368 ft to a packer at 13,967 ft, the production tube is 5 1/2-inch, 23.00 lb/ft, P-110 casing with FL4S joints. Below the packer is 500 ft of 4-1/2-inch diameter, 18.98 lb/ft, Hydrill pipe.

Chemistry

Table 2-1 summarizes the chemistry of the geofluid produced from Pleasant Bayou No. 2. This fluid is a hypersaline brine with considerable carbon dioxide induced acidity as indicated by the pH of the fluid after the dissolved gases are separated--pH 5.5-5.6--compared to the calculated pH--4.3--when the separated carbon dioxide is "replaced" by thermodynamic equilibrium

TABLE 2-1. CHEMISTRY OF PLEASANT BAYOU NO. 2 GEOFLUID

Parameter	Concentrations
Key Corrosive Species:	
pH (wellhead)	5.5-5.6
(calc. reservoir)	4.3
	ppm
Chloride	78,470-78,480
Sulfate	0
Soluble sulfide	0.4
Ammonia	90-94
Alkalinity (as HCO_3)	360-390
Other Species:	
Silica	90
Calcium	9,700-9,800
Magnesium	690
Sodium	43,000-43,800
Zinc	1.8-1.9
Total dissolved solids	311,150-132,150
Total suspended solids	19

Sources: Clark 1983, Tomson 1983

calculations. This pH shift, from about 4.3 in the formation to 5.5-5.6 at the wellhead, is quite similar to that experienced in hypersaline hydrothermal wells at the Salton Sea, California. The concentrations of chloride and some other key corrosive species are also of comparable magnitude. This suggests that materials experience at Salton Sea may be relevant to the geopressured well design.

Events Preceding Failure

Pleasant Bayou No. 2 is a research well, and the production tube string which is the subject of this failure analysis was the fourth to be installed. Much if not all of the tubing used in the subject string had been used previously in the same well. The subject string was installed in the summer of 1982. In this installation, the production tube was lowered until the locator sub at the bottom of the 5 1/2-inch pipe contacted the packer assembly at 13,967 ft. The production tube was then lifted about 11 ft [Clark 1983; Goldsberry 1983] to allow for thermal expansion of the production tube as the well heated up during production.

A long-term production test, with flow maintained at a constant 20,000 bpd was begun on 22 September 1982 and continued--with a few interruptions--until the well was shut-in on 13 April 1983 (203 days). Twenty-one days after the well was shut-in, the production tube parted at 5225 ft. The lower part of the production string dropped about 11 ft [Goldsberry 1983], bottoming in the polished bore receptacle of the packer assembly.

Repair operations were commenced, and the upper part of the production tube string was retrieved on 19 July 1983. The rest of the production tube string was retrieved over the next few days.

2.2 Field Investigation

On 19 July 1983, Radian visited the Pleasant Bayou site just hours after the upper portion of the production tube string was retrieved. It was observed that the coupling at 5225 ft had split its entire length. In this coupling design, both the field (upwell) and mill (downwell) ends of the tubular are screwed into the coupling. The mill end had disengaged from the split coupling.

The failed coupling had reportedly been made up four or five times previous to its current use. Reportedly each joint was made up with 6300 to 6500 ft-lbs torque when installed, but a torque of 28,000 to 31,000 ft-lbs was required to break the joints [Blumhardt 1983]. This great increase in torque required to break the joints was attributed to the high shear strength of the I.D. scale. This white scale was 5/16-inch thick at the 5225-ft level. The scale was also observed on several racks of tubing that had been pulled from the well.

The failed coupling and some of the field end length of joint 134 were cut off with a torch for shipment as a laboratory specimen. After cutting the tubing with the torch, it was necessary to break the scale with a hammer to complete the parting. In addition to the failed coupling, three feet of the mating pin end (recovered a few days later) and two used but unfailed couplings with pins were requested for laboratory analysis.

Subsequent to Radian's visit, the rest of the production tube was recovered. The white scale was reported to be of fairly uniform thickness down to about 10,000 ft, then tapering to about 0.2 inch thickness at 13,500 ft. FL4S pins from below 13,500 ft were reported to have severe "erosion" of the pin lip. Two pins from the 13,700-ft level were later shipped to Radian for analysis [Ortego 1983].

2.3 Laboratory Analysis and Results

Failed Coupling from the 5225-ft Level

The failed coupling and mating mill (downwell) end were photographed as received, and are shown in Figures 2-1 and 2-2. Deep tong marks were noted on the mill end of the failed coupling near the coupling lip. Close-up photographs of these tong marks on the failed coupling are shown in Figure 2-3. A single crack intersected one of these marks and extended the length of the coupling. The coupling was thoroughly examined with wet fluorescent magnetic particle inspection to detect any other cracks, and none was found. The coupling was then cut lengthwise about 120° away from the fracture surface. Figure 2-4 shows the mating mill-end hand-screwed into the sectioned coupling. No evidence of cross threading was observed, nor was there any difficulty in screwing the mill end into the coupling. The stand-off distance between the two pin ends in the coupling was 0.815 inch. From the remaining scale on the pin ends and failed coupling, the mill end had 21 threads engaged and the field end had 23 threads engaged. Figure 2-4 also shows the elastomer seal improperly seated into the field end as it was observed after sectioning of the coupling.

A portion of the failed coupling and a portion of tubing from the mill end were sectioned for chemical analysis. The results of this analysis are presented in Table 2-2 with the requirements of API Specification 5AX Grade P-110 for comparison.

TABLE 2-2. CHEMICAL ANALYSIS OF TUBING AND COUPLING

Element	Weight Percent		
	Tubing	Coupling	API 5AX Grade P-110
Carbon	0.32	0.33	Not Specified
Manganese	1.52	1.57	Not Specified
Silicon	0.19	0.19	Not Specified
Phosphorus	0.012	0.011	0.040 Max.
Sulfur	0.026	0.022	0.060 Max.
Nickel	0.11	0.16	Not Specified
Chromium	0.23	0.26	Not Specified
Molybdenum	0.18	0.18	Not Specified

Both tubing and coupling met the chemical specifications of API 5AX Grade P-110 material. Even though phosphorus and sulfur are the only elements with specified limits, all the other elements analyzed were present at levels typical of high strength steel. To further verify conformance to API specifications, two tensile samples (A and B) were cut and machined from each of the following: the failed coupling, an unfailed coupling, and the mill-end of tubing that mated into the failed coupling. The results of these tensile tests, with the API requirements, are shown in Table 2-3.

TABLE 2-3. TENSILE TESTS OF TUBING AND COUPLING

Sample	Yield Strength (psi)	Tensile Strength (psi)	Percent Elongation
Failed Coupling A	127,000	139,700	22.3
Failed Coupling B	125,800	137,400	16.5
Unfailed Coupling A	115,700	132,700	17.3
Unfailed Coupling B	116,900	133,100	17.5
Tubing A	124,200	133,300	16.8
Tubing B	124,200	133,600	15.7
API 5AX Grade P-110	110,000-140,000	125,000 Min.	11.0 Min.

The failed coupling, unfailed coupling, and mill-end tubing met all the specifications of API 5AX Grade P-110 material.

Rockwell C hardness readings were taken on a section of the failed coupling and on a section of the mill-end tubing. The failed coupling had very consistent Rockwell C hardness readings of 30 to 31. The hardness readings on the mill-end tubing were similarly consistent from Rockwell C 29 to 30. No evidence of localized hard or soft areas was detected.

Longitudinal cross sections were cut near the fracture and away from the fracture of the coupling. Radial sections were cut from the coupling and from the tubing. All four of these sections were polished and etched for microstructural examination. The microstructures are shown in Figures 2-5, 2-6, 2-7, and 2-8. In each photomicrograph the microstructure consists of a finely divided, tempered martensite that was uniform in all directions.

A longitudinal section was cut through one of the tong deformations adjacent to the fracture in the failed collar. Figure 2-9 shows this section and the 59 percent reduction in wall thickness caused by the tong. Figure 2-10 shows a higher magnification view of the severely deformed grains in the tong mark.

The entire fracture surface was ultrasonically cleaned in an inhibited acid to prepare the surface for examination by low power optical microscopy and with scanning electron microscopy. Figure 2-11 is a composite macrograph of the fracture surface after cleaning. Chevron marks point towards the origin at the tong deformation. The fracture surface appeared to have three vaguely different regions which were the origin of fracture at the tong deformation, the propagation zone covering most of the fracture surface, and a final tensile overload zone toward the field end of the fracture. Fractographic examination with the scanning electron microscope (SEM) showed that all three zones had the predominant features of ductile tensile overload. SEM fractographs of each of the three zones are shown in Figures 2-12, 2-13, and 2-14.

The fracture surfaces in all three zones were indicative of rapid, ductile tensile overload. No evidence of brittle fracture, cyclic fatigue fracture, or corrosion induced fracture was observed.

The white scale on the I.D. surface of the tubing at the 5225-ft level was about 5/16 inch thick as shown in Figure 2-15. This scale was not tenacious at all, but was tightly held in place by compressive forces. This scale was analyzed with energy dispersive X-ray spectroscopy (EDS) to identify the elements present, and with X-ray diffraction (XRD) techniques to determine the compounds present. The EDS analysis (which can detect only elements with an atomic number of 9 or more) showed calcium to be the major elemental constituent. Carbon and oxygen are not detectable by EDS. XRD indicated that the scale was entirely calcium carbonate ($CaCO_3$), mostly in the form of calcite, but with a trace amount of aragonite.

Examination of the steel surface beneath the calcite showed a surface predominantly bright and smooth with no evidence of corrosion. Despite reports that the entire length of the production tube was fluorocarbon lined [Clark 1983], there was no sign of organic lining in any of the parts from the 5225-ft level.

Pins from the 13,700-ft Level

Two pins from the 13,700-ft level were sent to Radian for examination after they were retrieved from the well on 8 August 1983. These pins were reported to be typical of all of the FL4S pins from about 13,500 ft to the bottom of the production tube. This interval is reported to have little scale compared to the upper interval where heavy scaling occurred. Additionally, it is reported that these pins had been in the well for four years [Ortego 1983]. However, the production tube has been pulled on four occasions, and the current installation had been in the well about 203 days when the well was shut-in. Whether or not the tubing at the 13,700-ft level was pulled and inspected prior to installing the current production assembly is not known to Radian.

The pins are the male half of FL4S couplings. The box (female) end is integral to the production tube. As installed, the pin lip is square in cross section or profile and mates to a flat face or lip at the base of the box end of the coupling. The nominal stand-off between the pin lip and box lip is 1/32-1/16 inch [Clark 1983]. The two pins as received are shown in Figure 2-16, while the O.D. surface of the end of one of the pins is shown in more detail in Figure 2-17. This lip shows a rough, jagged surface with considerable metal missing from the lip. This appearance was reported to be typical of all pin lips below 13,500 ft.

The two pins were sectioned longitudinally for examination of the I.D. surface. Figure 2-18 shows the I.D. surface of one of the pins (the other was similar). Originally, the I.D. surface of the tubing was coated with a fluorocarbon material. Figure 2-18 illustrates that about 75 percent of this coating (the dark shiny areas in Figure 2-18) was absent from the pins. Infrared (IR) spectroscopy of some of the remaining coating confirmed that it was a fluorocarbon compound.

Where the organic coating was missing from the walls of the tubing, the surface showed a thin matte gray scale. Where the coating was missing there was also about a 50-80 mil reduction in wall thickness, compared to areas where the coating had remained intact. This metal loss was quite evident in cross section as indicated by Figure 2-19. The corrosion on the pin walls was uniform to the eye.

Figure 2-20 shows a close-up view of the I.D. surface features of a pin from the 13,700-ft level. At the lip where the most severe metal loss occurred, the as-received surface was essentially bare of scale deposits. However, small amounts of deposits were found at a few locations on the pin lip, mostly in the few discrete pits. These deposits were found to be identical to deposits from areas of the I.D. tube wall where the organic coating was absent when examined by EDS. The major detectable elemental constituents were iron, sulfur, and zinc. Calcium and silicon were present in minor amounts, along with traces of potassium, barium, chlorine, and manganese. XRD analysis showed that these deposits consisted of a major amount of calcium carbonate (calcite, $CaCO_3$) and zinc sulfide (sphalerite, ZnS) with a small amount of iron oxide (magnetite, Fe_3O_4). Between these deposits and the steel substrate was a very thin layer not removable by scraping. This layer was removed ultrasonically with inhibited acid to prepare cleaned metal surfaces for SEM visualization.

Figure 2-21 is an SEM micrograph of a pitted area on the pin lip. The surface morphology in this area is indicative of aggressive metal dissolution producing a high degree of microroughness and micropits. No flow related pattern could be discerned, indicating that the corrosion processes dominated the metal-loss mechanism, obscuring any evidence of erosion.

Figure 2-22 is an SEM micrograph--at about twice the magnification of Figure 2-21--typical of the corroded tube wall remote from the lip. This micrograph shows essentially uniform corrosion with some micropitting. The morphology is indicative of slight attack by acids.

2.4 Discussion

Failed Coupling from the 5225-ft Level

The failed coupling and mill end of tubing met the chemical and mechanical requirements of API 5AX Grade P-110 material. The microstructure of the failed coupling in two different planes was a uniform, finely divided, tempered martensite, as expected for this high strength steel. No deficiencies, nonhomogenous areas, or anomalies were discerned in the microstructure near the fracture or away from the fracture in the coupling. The mill-end tubing displayed the same uniform, fine tempered martensitic microstructure. The hardness readings on both the failed coupling and mill-end correlated to the tensile strengths observed in mechanical testing of the components. No evidence of localized hard or soft areas were detected. All laboratory analyses made of the material used for fabrication of the coupling and pin end of tubing ruled out any material defects which would have lead to failure of the coupling.

Visual examination of the threads indicated no evidence of cross threading or other problems in the coupling or mill-end threads. No cracks were found emanating from any of the thread roots.

Fractographic examination of the fracture surface revealed no branching or secondary cracks. The entire fracture surface was indicative of rapid ductile overload as the mode of failure. The origin of the crack was at the tong marks on the mill-end of the coupling. This coupling had reportedly been made up with tubing several times during its service life. At one or more of these joining or breaking apart sequences, deep tong marks were put into the coupling. These tong marks deformed the metal by about a 59 percent reduction in wall thickness, and induced a major stress riser in that area of the coupling. Once the crack initiated, it progressed very rapidly in a ductile overload mode. There was no evidence of brittle fracture, cyclic (fatigue) fracture, or corrosion induced fracture.

An analysis of the stresses acting to fracture the coupling at the 5225-ft level was performed by Radian using a shrink-fit model and a number of simplifying assumptions. The purpose of this analysis was to determine if the applied forces were of adequate order of magnitude to cause the indicated rapid fracture of this coupling (a more detailed analysis was performed and reported separately by Oilfield Technology Services).

A number of assumptions about the well operations were made in order to proceed with the analysis. These assumptions are based on inference from prior reports [Stevens and Clark 1979] and informal communications [Clark 1983; Goldsberry 1983; Tomson 1983]. The accuracy of the analysis is necessarily affected by the accuracy of the data resulting from these inferences and assumptions.

- The annular space was filled with 10 lb/gal brine.
- The shut-in pressure just prior to failure was 4000 psia.
- The wellhead was anchored to cemented casing and did not transmit the thrust of the shut-in pressure to the production tubular.
- The annular wellhead pressure prior to failure was 15 psia.
- The geofluid specific gravity is 1.09 at room temperature.
- The average formation temperature between the 5225-ft level and the wellhead was 118°F.

As discussed earlier, the production tubular was installed by lowering until the locator sub at the top of the downwell sealing tool contacted the packer assembly at 13,967 ft, then lifting the locator sub about 11 ft. During normal operation, linear thermal expansion of the production tubular would seat the locator sub and take up some of the elastic elongation due to the tubular weight as well, thus reducing the tensile forces acting upon the production tubular. In addition to the assumptions listed above, it was assumed, for the stress analysis, that thermal contraction as the well cooled to formation temperatures had shortened the production tubular enough so that the locator sub was "picked up." Thus, the entire weight of the production tubular is assumed to be hanging.

Two cases were considered, unscaled tubular and scaled tubular. For the later case, the scale was assumed to be a uniform 5/16-inch thickness from 5225 ft to 10,000 ft, then tapering to essentially nil thickness at 13,500 ft. The calculated volume and weight of calcite scale were 188 cu ft and 31,800 lb, respectively.

Table 2-4 summarizes the results of the analysis in terms of the contribution by a number of factors to the hoop stress operating on the coupling at 5225 ft. Table 2-4 shows that the hoop stresses operating on the 5225-ft coupling are quite close to the measured yield strength of the coupling. The weight of the scale in the tubular added about 4 ksi to the hoop stress on the 5225-ft coupling.

A satisfactory explanation of the cause-of-failure must account for fracture entirely by mechanical overload, failure of the 5225-ft coupling rather than one nearer the surface, the above stress analysis, and the 21-day interval between shut-in and failure. The following scenario is suggested.

At the time of shut-in, the tubular and particularly the coupling at 5225 ft were under reduced stress since the locator sub was resting on the packer assembly, reducing the tensile load on the tubular. After shut-in, the well bore slowly cooled as heat was absorbed by the cooler surrounding geological strata. As cooling progressed, the stresses acting on the 5225-ft coupling increased (as thermal contraction shortened the tubular) toward the limits suggested by the stress analysis.

TABLE 2-4. SUMMARY OF HOOP STRESSES ACTING UPON THE FAILED COUPLING PRIOR TO FRACTURE

	Unscaled Tubular Cooled Until Locator Sub Picks Up	Scaled Tubular Cooled Until Locator Sub Picks Up
	ksi	ksi
Yield Strength	126.4	126.4
Tensile Strength	138.6	138.6
Hoop Stress Due To:		
• Pressure differential between annulus and bore	30	30
• Dependent weight of production tubular	58	58
• Dependent weight of scale	none	8
• Make-up torque	40	40
• Buoyancy	-4	-8
Total hoop stress	124	128

Assumptions:
a) Annular space filled with 10 lb/gal brine
b) Shut-in pressure = 4000 psi at time of failure
c) The pressure difference between the production tube bore and annulus was 3750 psi at 5225 ft at the time of failure.
d) Calculated scale volume ~188 cu ft
e) Geofluid sp gr = 1.09

Note: This table neglects any contribution to hoop stress by axial forces from the thrust of the 4000 psi shut-in pressure on the wellhead. It is assumed that the wellhead is anchored to the cemented casing and that this thrust element is not transmitted to the production tubular.

However, the deep tong marks on the 5225-ft coupling served as stress concentrators, and 21 days after shut-in the mounting stress at the root of the tong marks point exceeded the strength of the coupling, initiating fracture. Once initiated, the fracture itself served as an increasing stress concentrator, causing rapid propagation of the crack through the entire length of the coupling.

During the course of the laboratory analysis, it was observed that the calcite scale was held in place by an apparently large compressive force. In ring shaped specimens of pipe, the scale was tightly held as long as the scale ring was intact, but showed no adherence once the scale ring was cut longitudinally. Measurement (to the nearest mil) of the tube diameter before and after removal of the scale showed a reduction in diameter of 7 mils. This difference in diameter is likely the result of dilation of the tubing bore by the pressure differential across the tube wall during the time the scale was deposited, as well as the differential thermal contraction of the steel and calcite once the tubing was removed from the well.

Pins from the 13,700-ft Level

The pH at this depth, due to dissolved carbon dioxide, was calculated to be 4.3, and it appears that corrosion of the pins is the result of carbonic acid attack. It has long been recognized that at pH's of less than 6, carbonic acid is much more corrosive to steel than mineral acids, such as hydrochloric acid, at equivalent pH [Kirby 1979]. Furthermore, it has been concluded that the increased corrosivity is not explained by the buffering effect of the carbonic acid which retards the rise in pH immediately adjacent to cathodic sites on the steel surface as hydrogen ions are reduced, but there is uncertainty as to the exact role of carbonic acid or dissolved carbon dioxide. deWaard and Milliams [1975] propose a mass-transport--and therefore fluid velocity dependent--mechanism, while Schmitt [1983] argues for a velocity independent catalytic mechanism. The deWaard mechanism appears dominant at velocities of less than about one foot per second, while the Schmitt mechanism is dominant at higher velocity [Ikeda et al, 1983].

These mechanisms apply to bare metal surfaces. In high temperature wells, however, two "extreme conditions" can occur [Dunlop et al 1983]. In the first condition the steel surface is bare of mineral deposition as well as ferrous carbonate and/or magnetite. This surface will corrode at a rapid rate. In the other extreme, the surface is coated with fine grained, tightly adherent ferrous carbonate or magnetite corrosion products. This surface will corrode at a much slower rate.

This last argument accounts well for the observed corrosion of the pins. In areas away from the pin lip, the metal surface was covered with a thin layer of a ferrous product overlain with mineral deposition. Though considerable metal loss (50-80 mils) did occur, these deposits would appear to have given some protection.

At the sharp, square profile of the lip, scale deposition was absent. It is argued that increased turbulence at this point either prevented scale formation or mechanically removed the scale as it formed. Thus, the pin lip approached the first (bare steel) condition while the pin wall approached the second (corrosion product protected) condition. Metal loss from the pin lip was therefore much more rapid. A similar effect was noted in laboratory experiments with rotating cylinder specimens. When the rotation speed exceeded about 6.5 ft/sec, accelerated attack occurred on the sharp edge of the cylinders [Schmitt 1983]. The velocity of the fluid in the Pleasant Bayou production tube was about 10-11 ft/sec.

It is not possible to calculate a definitive corrosion rate for the wall area because it is not known when the organic coating was lost. If these pins were inspected prior to installation of the current production assembly in April 1982--and the coating and pin lips were in good condition at that time--then the calculated tubing wall corrosion rate is 90-143 mpy. The actual rate would have been higher since some time would have elapsed prior to loss of the coating.

If it is assumed that the lower tubing was never removed from the well during workovers (or was not inspected at those times), then the calculated corrosion rate, based on 3.8 yrs service, is 20-30 mpy. Again, the actual rate would have been higher since some time would have elapsed prior to loss of coating.

In autoclave tests using 133,000 ppm chloride synthetic geothermal fluids at 300°F, with sufficient carbon dioxide to produce pH 5, the corrosion rate of carbon steel was about 20-50 mpy [Shannon 1977]. The calculated reservoir pH at Pleasant Bayou was considerably lower (pH 4.3), and this could be expected to significantly increase the corrosion rate. This additional data suggests that the actual corrosion rates of areas not protected by calcite scale tend toward the higher rates.

This issue of metal-loss corrosion is of even more importance for future activities in this well since some form of downhole scale inhibition will most likely be used. Once this is done, then the upper interval of production tube--which was uncoated steel in the case under study--will not be protected by calcite and will likely be subject to the severe attack observed at 13,700 ft.

The accelerated corrosion of the pin lips may possibly be mitigated by use of a different coupling configuration which does not present a sharp edge or corner to the fluid flow. For example in the Amoco Fee No. 1 well (see Section 4), FL4S couplings showed slight lip corrosion while none was observed on Exline pins which have a rounded lip. It is not clear if the Amoco Fee geofluid is inherently less aggressive than at Pleasant Bayou.

A durable organic coating would also be valuable. The Spincoat coating at Amoco Fee appears to have endured much better than the Tuboscope coating used at Pleasant Bayou, and may be useful at the latter location. However, though the chemistry and temperatures are similar at the two wells, the Spincoat has not experienced prolonged high-volume production. It is not clear if the same good performance would occur under such production conditions at Pleasant Bayou.

Another option would be the use of alternative alloys for production tubing. Downwell corrosion studies in Salton Sea geothermal wells have clearly shown that low alloy steel can have considerable potential in hypersaline, high temperature, carbon dioxide-rich environments not too dissimilar to the Pleasant Bayou case. The first significant point of those studies was that composition-controlled steels such as ASTM and AISI grades consistently outperformed property-controlled API casing. This is understandable since microstructure, and particularly inclusion morphology, plays a major role in carbon dioxide corrosion resistance [Ellis et al 1983; Dunlop et al 1983]. In general, composition-controlled alloys, which have restrictions on many impurities, will have more desirable microstructures.

Of all the low alloy steels tested downwell at Salton Sea, 2.25Cr-1Mo had the best performance. This alloy showed an 83-95 percent reduction in corrosion rate compared to carbon steel.

Manganese sulfide stringer inclusions parallel to the steel surface have been identified as the culprit in mesa-type corrosion, a form of localized corrosion common to aqueous carbon dioxide systems [Dunlop et al 1983]. Therefore a specification for 2.25Cr-1Mo with the lowest practical sulfur content might be optimum.

2.5 Conclusions

Failed Coupling From the 5225-ft Level

- Failure initiated at a tong mark which had reduced the coupling wall thickness by 59 percent and served as a stress concentrator. Once the crack initiated it progressed very rapidly in a ductile overload mode. There was no evidence of brittle fracture, cyclic (fatigue) fracture, or of corrosion induced fatigue.

- The coupling material was found to satisfy all requirements of its specified P-110 grade. Failure was <u>not</u> the result of metallurgical defect.

- The production tube at this level was lined with 5/16-inch thick calcite scale. There was no organic coating on the steel. No corrosion of the internal tube surface was noted. The calcite mineral deposition appears to have protected the steel surface.

- A simplified stress analysis indicates that even without the tong damage which precipitated failure, the coupling was operating quite close to its mechanical limits.

<u>Pins from the 13,700-ft Level</u>

- The fluorocarbon coating on the interior surface of the tubing had failed, and about 75 percent of the interior steel surface was exposed to geofluid.

- Significant attack has occurred on surfaces not protected by the organic coating. This metal loss is probably due to carbonic acid corrosion. About 50-80 mils of metal has been uniformly corroded from uncoated areas on the tube wall.

- Even more severe metal loss occurred on the FL4S pin lips, probably as a result of increased turbulence at the sharp edges of this coupling configuration. Corrosion processes dominated the metal loss at this location.

- In future operations, with downwell scale inhibitors to prevent calcite deposition, the severe metal-loss corrosion experienced at the 13,700-ft level can be expected to extend upwards toward the surface.

2.6 Recommendations

- Stronger couplings should be used in the upper portions of the production tube.

- Care should be exercised to avoid mechanical damage to couplings during assembly or disassembly of the production tube string.

- Couplings which do not present sharp-edged lips should be tested to see if this modification will prevent the severe lip corrosion observed at 13,700 ft.

- The Spincoat organic lining which was successful at Amoco Fee No. 1 well should be tested at Pleasant Bayou.

- Selection and use of an alternate low alloy steel for production tubing may become necessary if the above steps are not adequately successful in controlling downwell corrosion. Limited data indicate that a 2.25Cr-1Mo steel with low sulfur content might be promising.

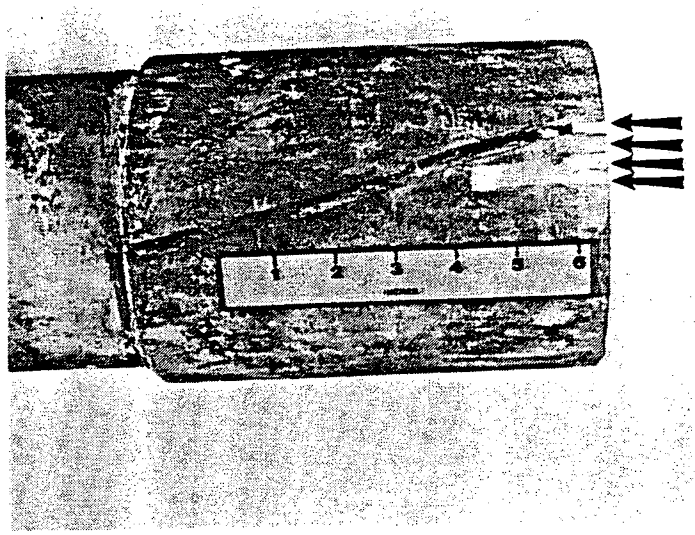


Figure 2-1. The Failed Coupling as Received for Examination. Note the tong marks (arrows) in line with the fracture.

Figure 2-2. The Mating Mill-End of Tubing Which Fell from the Fractured Coupling.

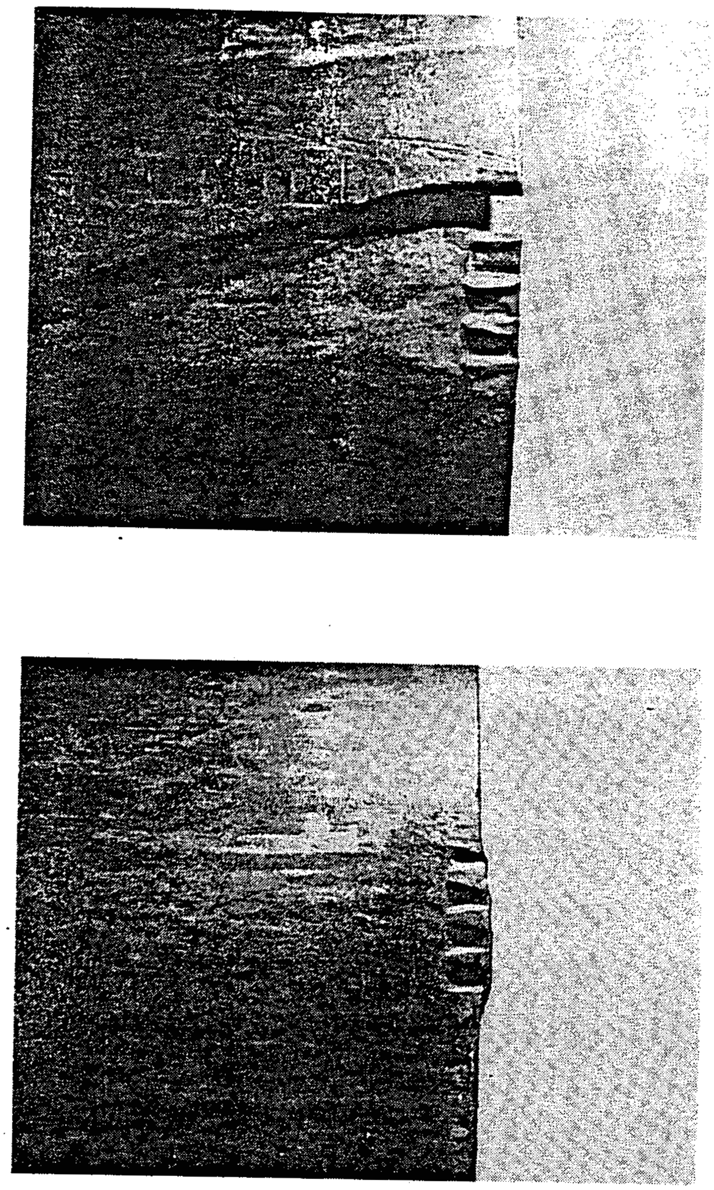


Figure 2-3. Close-up Views of Tong Marks on the End of the Failed Coupling. The top photograph shows deep tong deformations at the fracture, and the lower view shows tong deformations 180° away from the fracture.

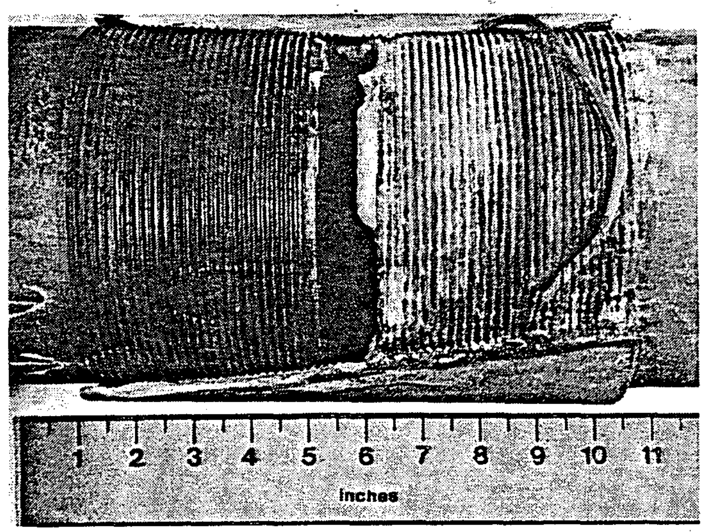
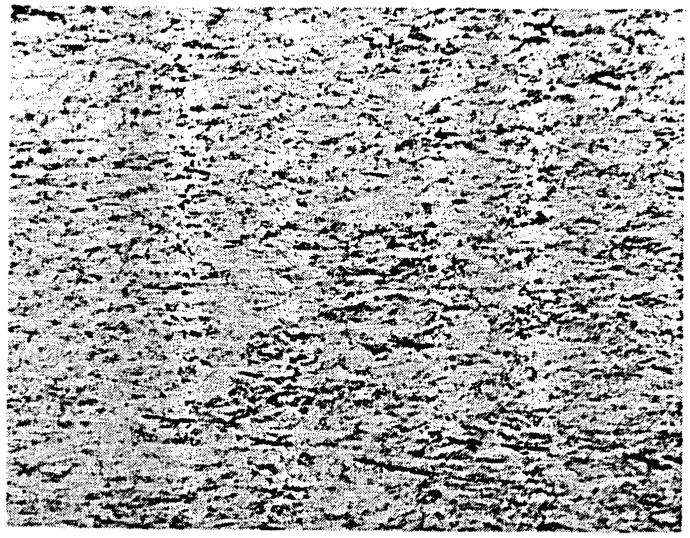
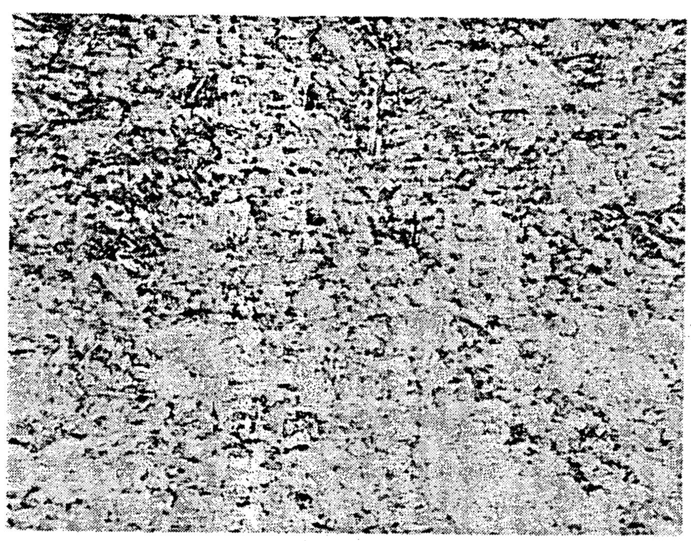


Figure 2-4. Sectioned Coupling with Both Pin Ends Inserted. About 1/3 of the coupling has been cut away. The coupling fracture surface is at the bottom. With the mill-end (on the left) hand-tightened into the coupling the distance between the pin ends is 0.815 inch. Note the displacement of the elastomer seal at the right. This seal was found outside of its field pin seat upon sectioning the coupling.



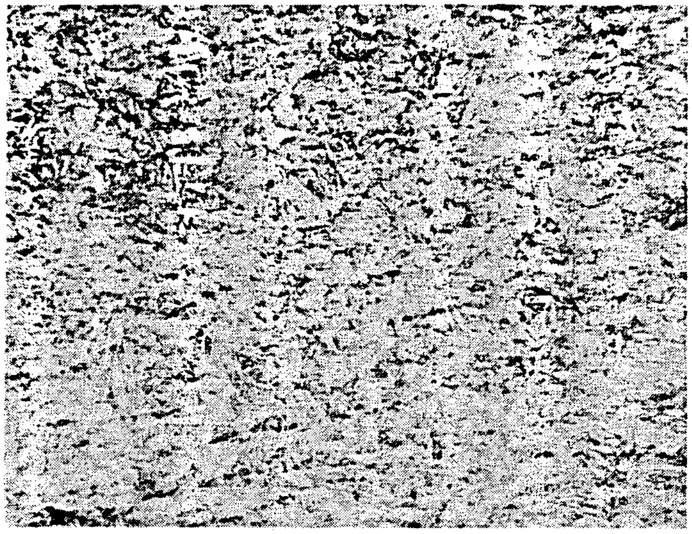
Magnification: 400X
Etch: 2% Nital

Figure 2-5. Photomicrograph from a Longitudinal Section Taken Near the Fracture of the Failed Coupling. The microstructure is finely divided, tempered martensite with some evidence of grain deformation because of the nearby tong mark.



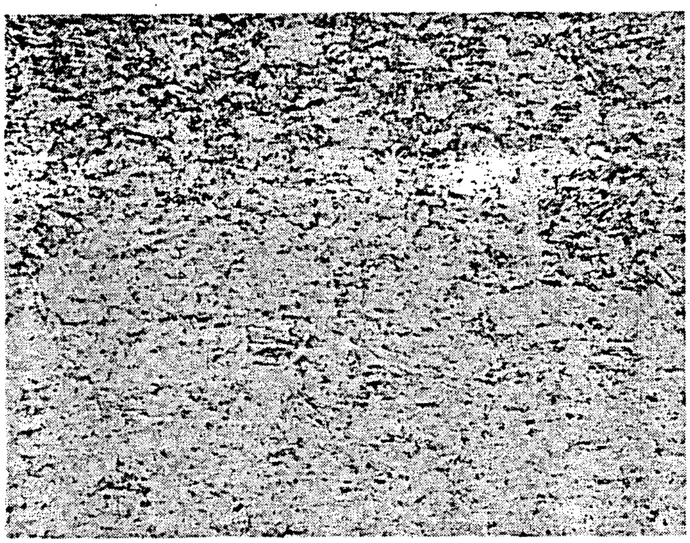
Magnification: 400X
Etch: 2% Nital

Figure 2-6. Photomicrograph from a Longitudinal Section Taken Away from the Fracture of the Failed Coupling. The microstructure is finely divided, tempered martensite.



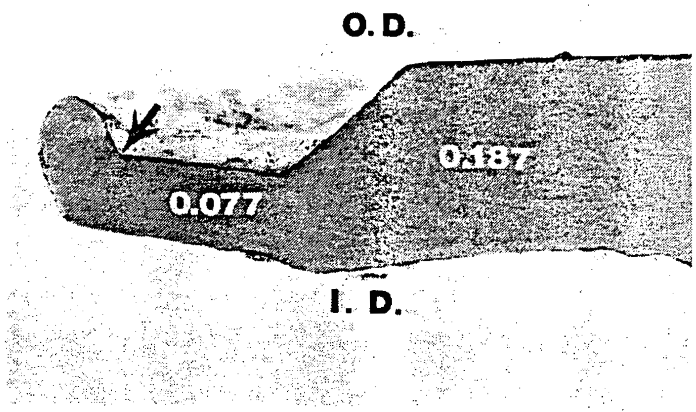
Magnification: 400X
Etch: 2% Nital

Figure 2-7. Photomicrograph from a Radial Section of the Failed Coupling. The microstructure is a finely divided, tempered martensite.



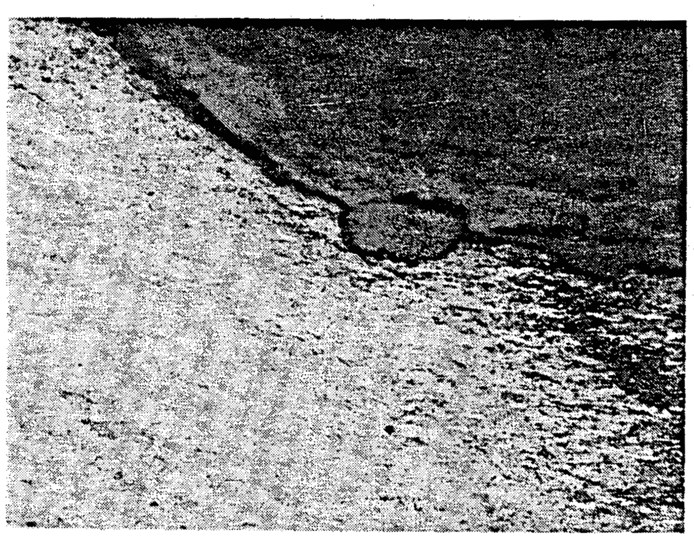
Magnification: 400X
Etch: 2% Nital

Figure 2-8. Photomicrograph from a Radial Section of the Mill-End Tubing. The microstructure consists of finely divided, tempered martensite.



Magnification: 5:67X

Figure 2-9. Longitudinal Cross Section Through a Tong Deformation in the Failed Coupling Adjacent to the Fracture. Numbers indicate nominal wall thickness in inches inside and outside the deformation. The deformation is filled with mounting material. The arrow denotes the location of a higher magnification view shown in Figure 2-10.



Magnification: 200X
Etch: 2% Nital

Figure 2-10. Higher Magnification View of Severely Deformed Grains at the Arrow of Figure 2-9.

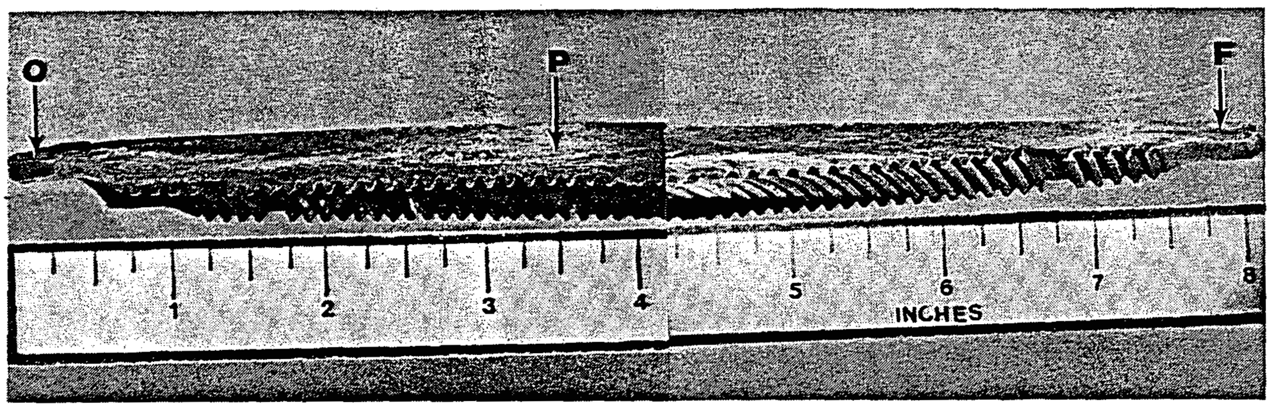
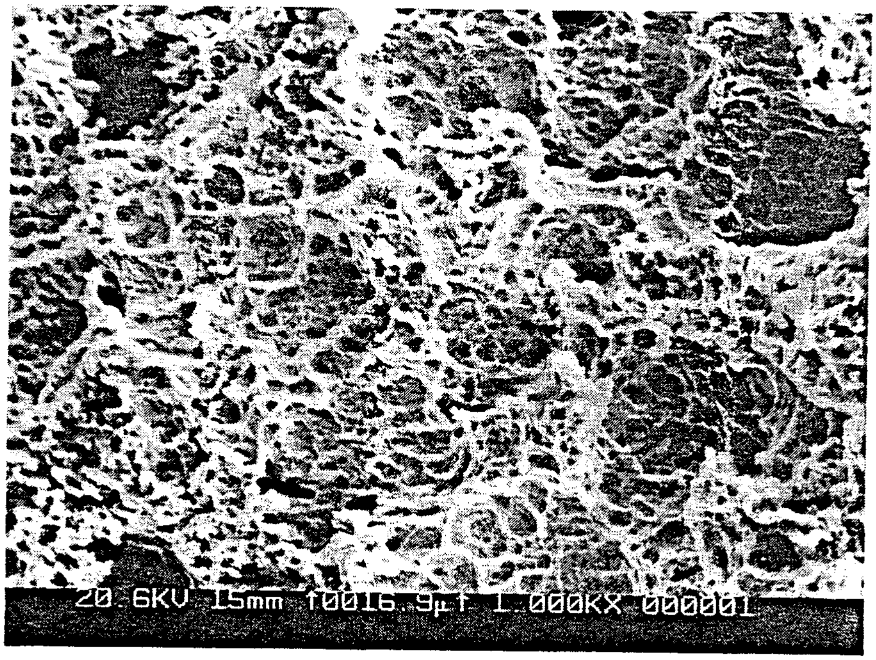
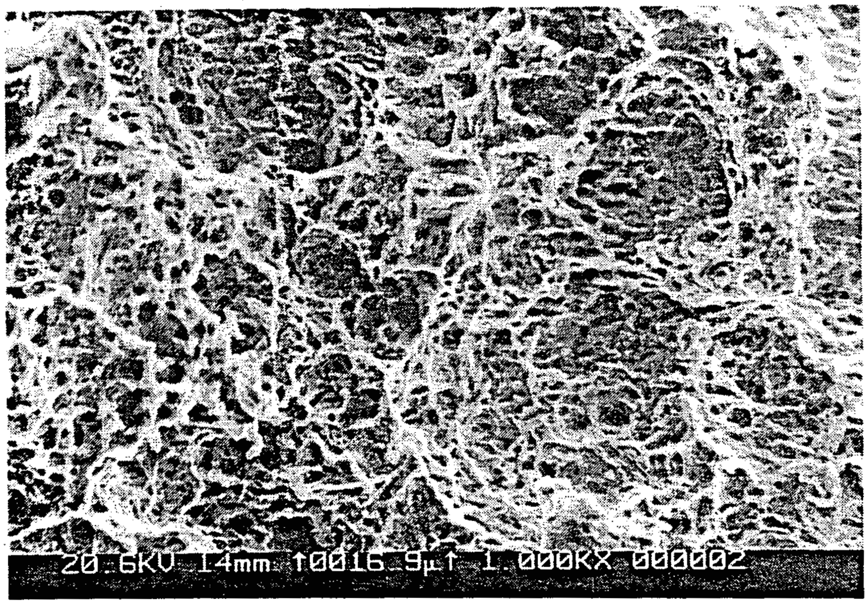


Figure 2-11. The Fracture Surface Removed from the Failed Coupling and Cleaned. The arrow at O indicates the fracture origin at the tong deformation. Fracture moved rapidly to the field end of the coupling at the right. Chevron markings pointing to the origin are evident on approximately the first five and a half inches of the fracture. The final two and a half inches indicates fast final fracture. The arrows at P and F indicate locations of SEM fractographs in Figures 2-13 and 2-14.



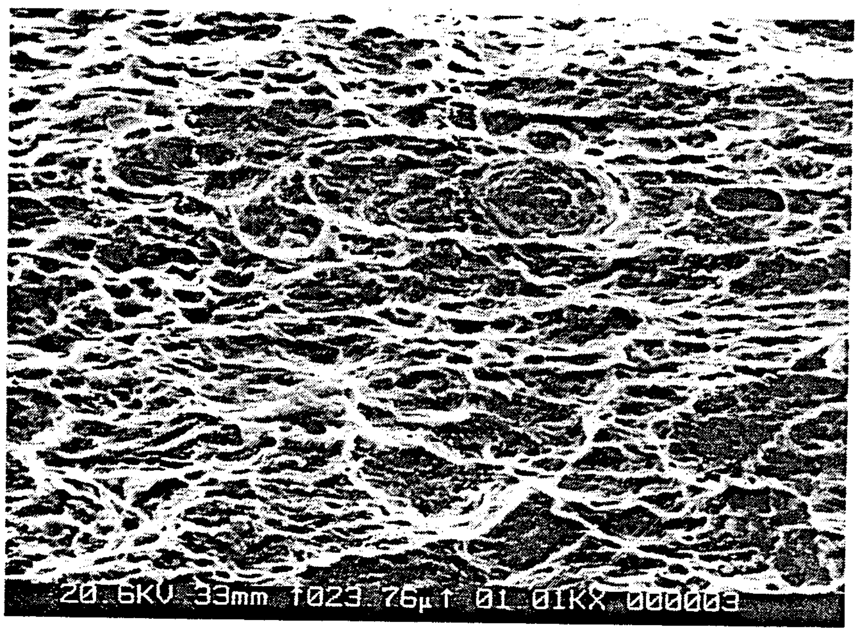
Magnification: 1000X

Figure 2-12. Scanning Electron Fractograph of the Cleaned Fracture Surface at the Origin Area (arrow 0 in Figure 2-11). Ductile dimples are predominant.



Magnification: 1000X

Figure 2-13. Scanning Electron Fractograph of the Cleaned Fracture Surface in the Propagation Zone (arrow P in Figure 2-11). Ductile dimples dominate the entire area.



Magnification: 1010X

Figure 2-14. Scanning Electron Fractograph of the Cleaned Fracture Surface in the Final Fracture Area (arrow F in Figure 2-11). Elongated ductile dimples are the dominant feature.

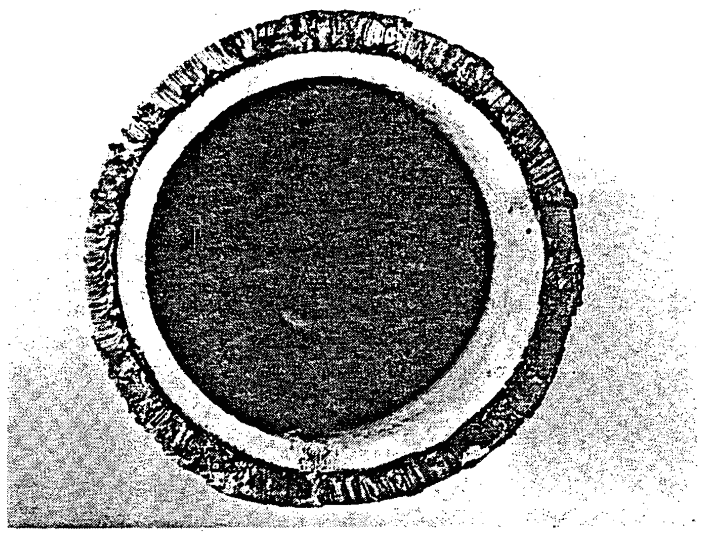


Figure 2-15. White I.D. Scale that was Present on Tubing Pieces from the 5225-ft Level.

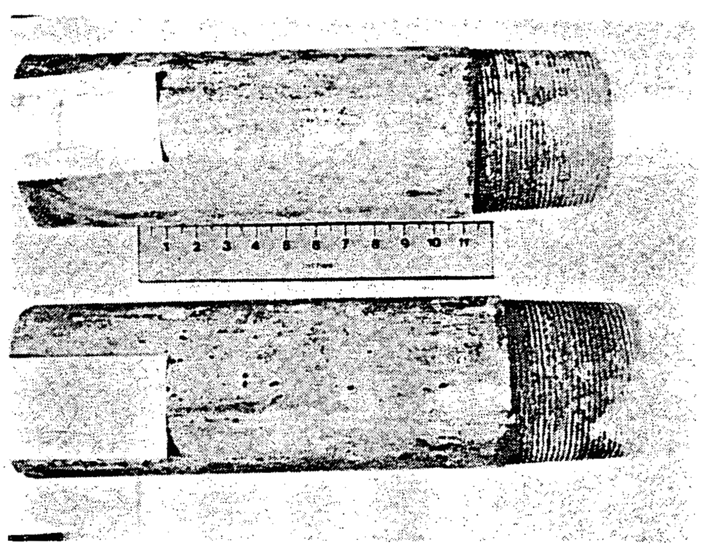


Figure 2-16. Two Pins from the 13,700-ft Level as Received for Analysis.

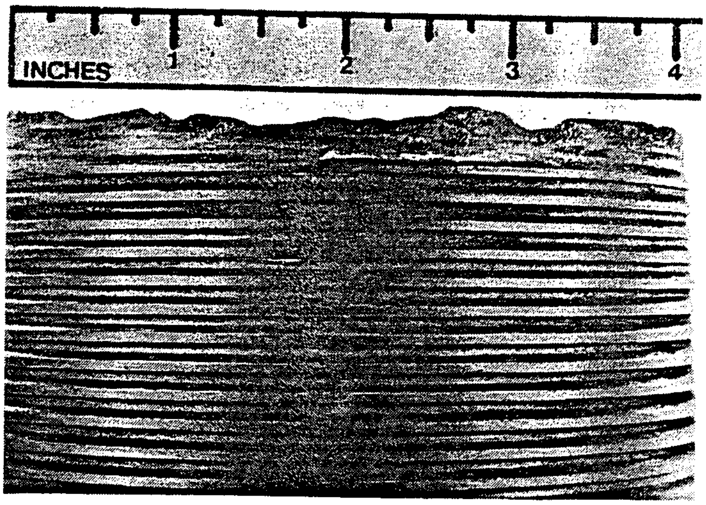


Figure 2-17. O.D. Surface of Pin No. 2 After Cleaning. The end or lip (originally square in cross section or profile) is jagged and rough with considerable metal loss.

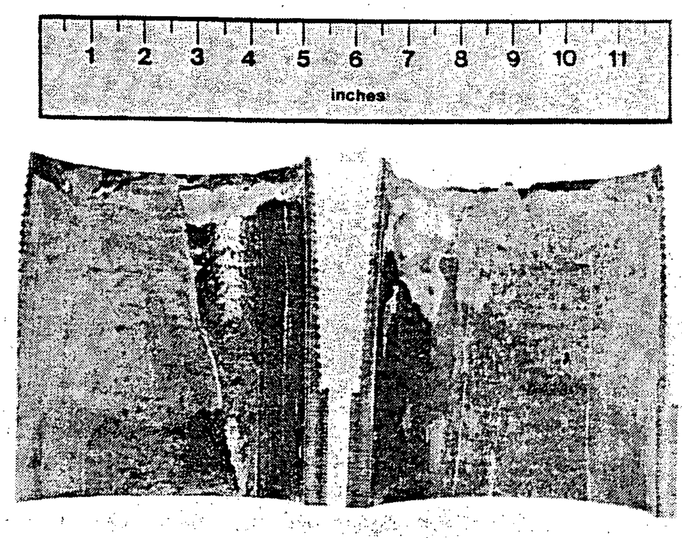
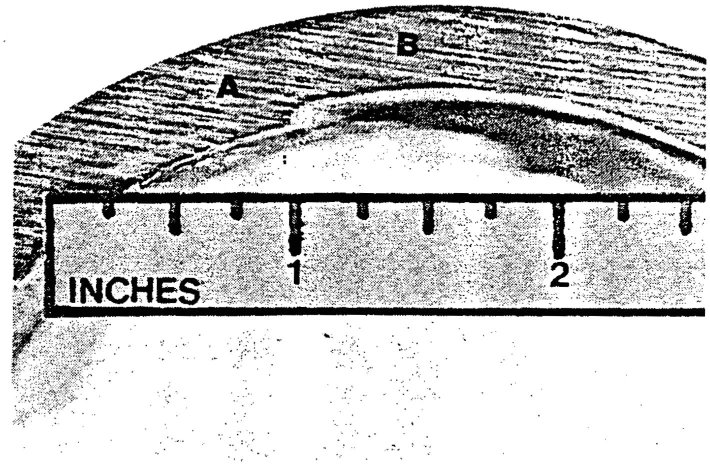


Figure 2-18. I.D. Surface of Pin No. 1 After Sectioning Longitudinally. The organic coating is the dark, shiny material remaining on only about 25 percent of the surface.



Magnification:
~1.25X

Figure 2-19. Cross Section of Pin No. 2 Showing the Reduction in Wall Thickness Where the I.D. Coating was Missing. A is the area where the I.D. coating is still intact and the wall thickness averages 0.410 in. At the area B the I.D. coating is missing and the wall thickness averages 0.334 in.

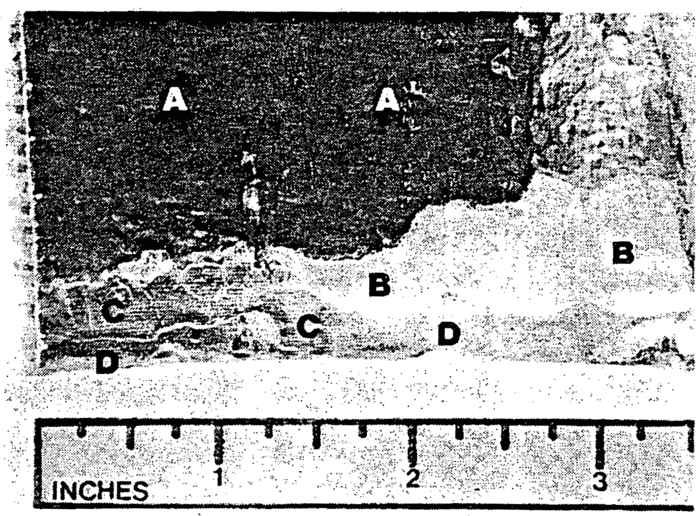
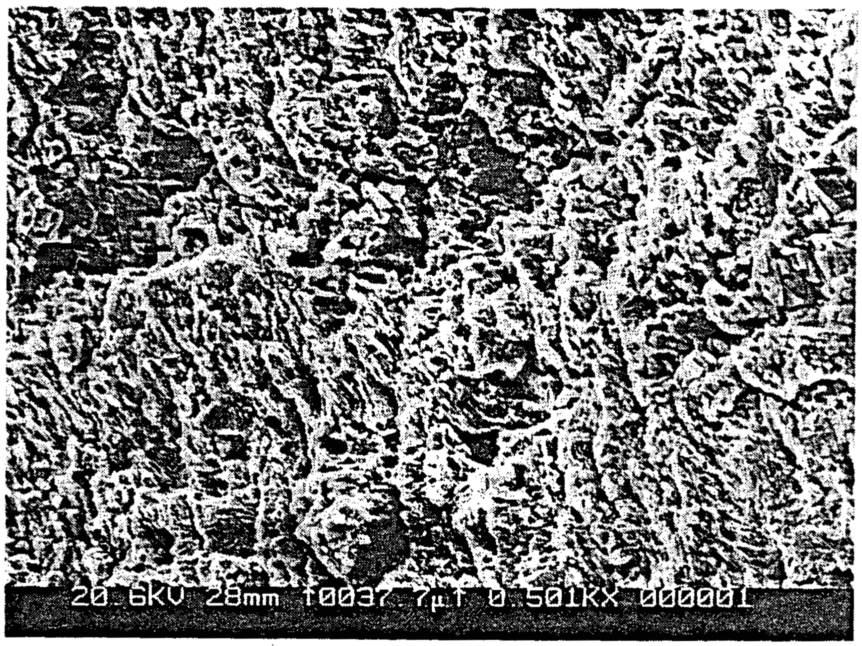
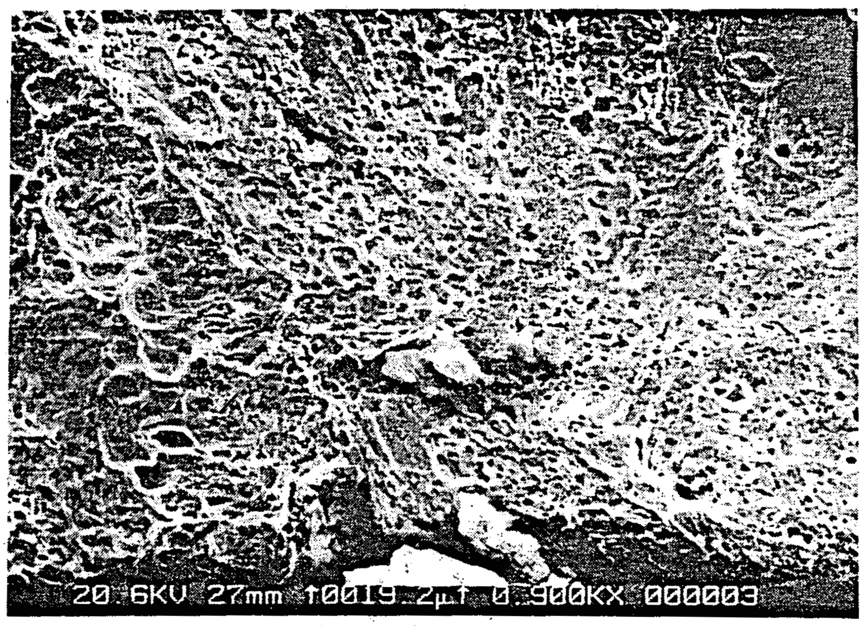


Figure 2-20. Close-up View of I.D. Surface of a Pin From the 13,700-ft Level. The dark coating is still intact at A. The white scale indicated by B is calcite and sphalerite over steel. C indicates bare metal where the coating was recently lost and corrosion has not degraded the original machining marks. D at the lip of the pin is where severe metal loss has occurred.



Magnification: 501X

Figure 2-21. Scanning Electron Micrograph Typical of the Pitted I.D. Surface at the Lip of a Pin (area D in Figure 2-20) After Cleaning. The dissolution process produced numerous micropits with little evidence of erosion or flow induced corrosion. Flow was from top to bottom.



Magnification: 900X

Figure 2-22. Scanning Electron Micrograph of Cleaned I.D. Surface Away From the Lip of a Pin (area B in Figure 2-20). No coating remained, but scale covered this surface. Uniform corrosion and mild micropitting are evident.

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FAILURE INVESTIGATION
PLEASANT BAYOU NO. 2
PART A

FAILURE ANALYSIS OF A 5-1/2" 23# P-110 LTC MOD MILL END CONNECTION

PREPARED FOR
FENIX AND SCISSON

BY
OIL TECHNOLOGY SERVICES, INC.

Michael J. Jellison 9/16/83
Michael J. Jellison Date
Engineer

Erich F. Klementich 9/16/83
Erich F. Klementich, P.E. Date
President

FS-301

TELEPHONE: 713-462-8298 TELEX: 795134

4.0 CONCLUSION

The failure of the LTC Mod coupling at 5,400' was due to high stresses in the connection. The stresses resulted from a combination of the shut-in service conditions and the stresses incurred during make-up. The crack probably initiated at the O.D. surface on the mill end. The crack was associated with a stress riser created by tong gouges. Although the LTC Mod connections were made up and broken out at least two(2) times, the failed connection and LTC Mod connections examined at the rig site did not show signs of extensive galling; therefore, it does not appear that wear contributed to the failure. Corrosion apparently did not contribute to the failure.

The fact that the failed coupling had deep tong gouge marks and that the teflon seal ring jumped out during make-up can account for why the failure occurred at approximately 5,400' and not closer to the surface where the stresses created by the shut-in condition were higher. A teflon seal ring jump-out appears to be a significant factor because couplings with deeper gouges marks were observed and these did not split.

Although the pipe was apparently made up to API recommended torque values, field experience has shown that teflon rings lower the torque required to obtain a nominal make-up. Consequently, all connections were highly stressed. Moreover, the tolerances of the API LTC connector do not lend themselves to a precision make-up required for a high load service condition or a geopressured brine completion.

Since failure is likely if the 5-1/2" LTC Mod connections are run again in the Pleasant Bayou No. 2, a design change is definitely required. OTS is currently working on a recommendation for recompleting the well, and a report will be issued when the work is completed.

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FAILURE INVESTIGATION
PLEASANT BAYOU NO. 2
PART B

ANALYSIS OF A 5-1/2" 23# P-110 LTC MOD X FL-4S TUBING SYSTEM

Prepared For

FENIX AND SCISSON

by

OIL TECHNOLOGY SERVICES, INC.

10/10/83
Michael J. Jellison Date
Engineer

10-10-83
Erich F. Klementich, P.E. Date
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3.0 CONCLUSION

The Failure Investigation shows that neither the 5-1/2" 23# P-110 LTC Mod or the FL-4S connections can be used to recomplete the Pleasant Bayou No. 2. Problems inherent to the design of the connections make them unsuitable for this application. Furthermore, workover and fishing operations and previous service in the well has damaged the pipe body sufficiently to require extensive repairs.

A higher efficiency, non-recessed premium connector better suited for use as production tubing can provide a stronger, safer design. An appropriate connector along with a means for preventing crevice corrosion and erosion/corrosion in the tubing string is definitely required. Part C of this report, which was previously submitted, offers a number of tubing string design alternatives suitable for recompleting the well.

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REDUCING CREVICE CORROSION

PLEASANT BAYOU NO. 2

PART C

METALLURGICAL ALTERNATIVES TO REDUCE CREVICE CORROSION ON 5-1/2" T & C CONNECTIONS

PREPARED FOR

FENIX AND SCISSON

BY

OIL TECHNOLOGY SERVICES, INC.

Gregory P. Fehr 9/16/83

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TABLE OF CONTENTS

1.0 PROJECT

1.1 Identify metallurgical alternatives to reduce crevice corrosion on 5-1/2" T&C connections for Pleasant Bayou No. 2 well. All reasonable alternatives (including marginal) are to be considered with an analysis of expected serviceability, producibility, relative cost and lead times.

2.0 BACKGROUND

2.1 On August 11, 1983, Dr. Fred Goldsberry requested an analysis of various alternatives ranging from the basic API Spec 5AX P110 to P110 connection, various cladding/coating systems on Pin ID, coupling ID, complete coating of the coupling, and corrosion resistant alloy (CRA) combinations. Advantages and disadvantages of the various combinations relative difficulty of producing the different designs are to be included.

3.0 INVESTIGATION

3.1 The following alternatives have been considered:

A. API Spec 5AX P110 pin and coupling
B. P110 pin with coupling electroless nickel coated (ENC)
    1. 100% coating on coupling
    2. Coating on coupling ID only
C. ENC coating on pin end ID and coupling ID between shoulders only
D. ENC pin ID and clad coupling ID between shoulders
E. ENC pin ID and OD and coupling ID and OD
F. P110 pin with coupling clad between shoulders only
G. Clad pin ID and coupling ID between shoulders only
H. Clad or ENC coated pin ID and Controlled Nucleation Thermal Deposition (CNTD) on coupling ID between shoulders only
I. P110 pin with Corrosion Resistant Alloy (CRA) coupling
J. Clad on pin ID with CRA coupling
K. ENC coated pin with CRA coupling
L. CRA casing with CRA couplings

Sketches of these configurations appear in Appendix A

3.2 All of the options with the exception of the CRA casing and couplings still exhibit a corrosion cell at the interface of the P110 material

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and protected surface. Since local corrosion at this interface is of concern, the following general comments are included for awareness.

3.2.1 In an iron-water system, the reaction is cathodically controlled because hydrogen ions are available in small quantity. In other words, cathodic polarization limits the rate of reaction. Here both electrodes polarize, however, the cathode polarizes to a greater degree. The point at which these rates meet indicates the maximum current available for corrosion. A substance such as oxygen is a depolarizer because it decreases the slope of one of the reactions, thereby increasing the corrosion current and the amount of corrosion.

3.2.2 In examining a similar case for a passive metal anode, it is seen that it does not polarize along straight lines, but follows an S-shaped curve. The electrochemical behavior of most chemicals exhibiting active-passive transitions is exhibited by such curves. As the potential of the anode becomes increasingly noble, the current per unit area and the corrosion rate increase until a critical current density is reached. This value corresponds to the maximum corrosion rate. At more noble potentials, the current density drops by orders of magnitude and passivity is established. In the iron-water system, increases in oxygen content allow more current to flow until the critical density is reached. Further increases cause passivity. Many alloys passivate even in nonoxidizing media.

3.2.3 In general corrosion, the anode areas on the metal surface shift to different positions until the entire metal surface has been anodic at some time. It is possible that at a given point, corrosion occurs on a group of readily dissolved atoms until this group is depleted and then the point of attack moves to some other point. In this way the metal suffers a general thinning.

3.2.4 As with all types of corrosion, many factors influence the rate of attack. The corrosive media is the most important factor governing corrosion. The acidity, temperature, concentration, motion relative to metal surface, degree of oxidizing power and aeration, and presence or absence of inhibitors or accelerators should always be considered. Most of these factors interact and often this interaction is very complex. For instance, in the discussion of the corrosion of iron in water, aeration was seen to play two roles. Oxygen can behave as a depolarizer and increase the rate of corrosion by speeding up the cathodic reaction. It also can act as a passivator because it promotes the formation of a stable, passive film. As a general rule, increases in temperature increase reaction rates, but increasing temperature also tends to drive dissolved gases out of solution so that a reaction that requires dissolved oxygen can often be slowed down by heating.

3.2.5 By a similar argument, concentration can be seen to play two roles. Most chemical reaction rates are increased by increasing the concentration of reactants; however, increasing the concentration of a salt in solution usually decreases the solubility of the solution for dissolved gases. Again, oxygen concentration is decreased, and depending upon which role oxygen was taking in the reaction corrosion could be increased or decreased.

3.2.6 The motion of the solution relative to the metal can bring sufficient oxygen to the metal surface to provide protection or it can sweep away protective corrosion products. Even some inhibitors show two actions. The anodic inhibitors (that behave to decrease the extent of anodic areas), if present in only small amounts, can actually accelerate corrosion or shift the form from general attack to pitting. In down-hole applications, we generally know only the approximate fluid velocities and the chemistry, if known, is only approximate.

This rather elementary discussion of corrosion principles leads one to the realization that the subject is complex. One can only reach the conclusion that, in applications where so little is known about the detailed environment, the safest thing to do is take the most conservative approach and design for the "worst case" condition since there is little or nothing that can be done to alter the environment.

3.3 Discussion of the various protective systems is itemized individually

3.3.1 Coatings in general: The approach in the use of coatings is to provide the less noble areas in question with a protective coating that will, in effect, render the remainder of the system to be approximately uniform and without areas of high corrosion susceptibility. Relatively thin coatings of metallic and inorganic materials may, in many cases, provide a satisfactory barrier between metal and its environment. The primary function of such coatings is (aside from sacrificial coatings such as zinc) to provide an effective barrier. Metal coatings are applied by electrodeposition, flame spraying, electroless deposition, cladding, hot dipping, and vapor deposition. We will discuss three of these methods in this analysis. Inorganics are applied or formed by spraying, diffusion, or chemical conversion and will not be addressed herein. Metal coatings usually exhibit some formability, whereas the inorganics are brittle. In any case, a complete barrier must be provided. Porosity or other defects may result in accelerated localized attack on the base metal and be the cause of early failure.

3.3.2 Cladding: This involves a surface layer of metal which can be applied by numerous methods. The clad material behaves as the more noble of the system and, depending on the surface area, spreads the corrosion over a larger area. For example, in the tubing systems under consideration, the coupling area between the ends of the pipe, if clad with a material such as nickel, would cause the large surface area of the tubing to corrode (albeit a small amount) rather than the coupling itself corroding extensively and giving rise to early failure. Several methods for cladding are Ceracon

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process, HIP process, and weld overlay, each of which will be discussed in the process section.

3.3.3 Vapor Deposition: This is accomplished in a vacuum chamber. The coating material is vaporized by heating electrically, and the vapor deposits on the parts to be coated. This method is generally more expensive than others and is limited to the so-called "critical" parts. We will discuss a new process called "Controlled Nucleation Thermal Deposition" or CNTD for short that has been developed by San Fernando Laboratories for high erosion and corrosion applications.

3.3.4 Electroless Plating: Unlike electroplated coatings, electroless coatings are applied without electric current; the coating is produced by autocatalytic chemical reduction. The electroless metal is plated onto a surface by reducing metal ions to metallics with sodium hypophosphite. Among the particularly useful metals that have been demonstrated to be practical are nickel, cobalt, palladium, copper, platinum, gold, silver, and miscellaneous alloys involving at least one of the above metals. A wide variety of reducing agents are an integral part of the chemical plating solution make-up. Typical reducing agents which have been reported include hypophosphite, formaldehyde, hydrazine, borohydrides, amine boranes, and derivatives thereof. The substrate to be metallized must be of a catalytic nature. In circumstances where the substrate does not possess a suitable catalytic surface, a preactivation in an effective catalyst may be employed.

3.3.5 Welding: Weld cladding must be carefully controlled on any quenched and tempered material. The energy field has been slow to appreciate the many problems that may be solved through the expeditious use of this method. The nuclear energy field has used it successfully for decades in applications where the corrosion problems are as severe or more severe than is experienced in this industry. There is no reason that a clad surface cannot be produced having all the chemical and physical properties specified

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in the referenced specifications. In many cases the final cost would be minimized and the overall quality maximized. However, if existing P110 pipe is welded, the chemical composition of the casing must be known, and a special welding procedure must be qualified per ASME Boiler and Pressure Vessel Code Section IX to insure the base metal Q&T properties are not degraded.

3.3.6 Thermoplastics: The production and utilization of plastics has increased tremendously over the past 25 years. Fluorocarbons, or Teflon, Kel F and other fluorocarbons are the "noble metals" of the plastics in that they are corrosion resistant to practically all environments up to 550 degrees Fahrenheit. These materials have been developed for a wide variety of uses and can be bonded or deposited directly onto the metallic surface. In addition to excellent corrosion protection, the low coefficient of friction of these materials is the basis for a very successful application in valves where a confined Teflon sleeve separates the plug and body and acts as a lubricant thereby prevent sticking or freezing of the metal parts. The difficulties of all possible applications of these materials including use as corrosion barrier rings surpass their potential as a solution.

3.4 Processes

3.4.1 Cladding: The Ceracon Process

3.4.1.1 This emerging technology is capable of producing full density parts containing either one or more materials, thus, it appears to be ideal for the production of what we will refer to as "compound" material parts. A suitable powdered metal preform is first prepared by any suitable pressing technique such as cold die compaction, cold isostatic pressing (CIP), injection molding, slip casting, etc. The company density and degree of sintering, if any, need only be sufficient to accommodate handling of the preform for the consolidation step.

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3.4.1.2 Figure 1 shows the process route in the Ceracon process. Ceramic grain is heated in a fluidized bed while the preforms are heated to the same temperature in an induction susceptor with a controlled atmosphere. The induction furnace and fluidize act to assure that both parts are of the correct temperatures -- not necessarily the same -- when they are mated for consolidation. A robotized system charges hot grain into a tray and places the preform within the grain. They tray assembly is transferred to the press die cavity and axial motion of the press ram pressurizes the grain which acts as a hydrostatic media and causes the metal to densify. The part is then ejected and the part and grain separate freely. The grain is recycled and the parts are cooled for finishing treatments. The system is highly controlled with sensors feeding process information to a computer for on-line monitoring and control of all stages of the process.

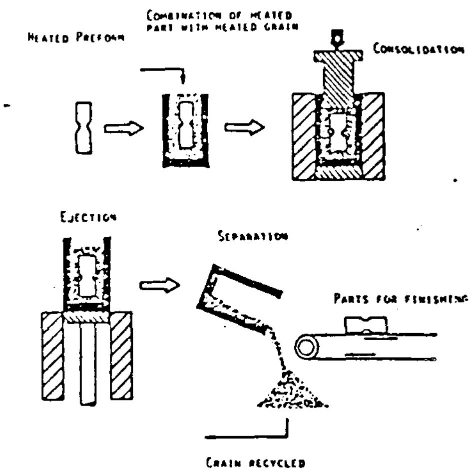

FIG. 1 Ceracon process stages

3.4.1.3 This process is currently being used for a wide variety of complex parts and utilizing a wide range of materials. A project is presently being negotiated with a major oil company to develop pipe and tubing with the characteristics necessary for both the tube and coupling under consideration here. This application entails the manufacture of a full density piping preform necessary for drawing in a conventional tube mill. The inside of the preform will be of a corrosion resistant material such as Inconel or Stainless and the outside conventional low carbon steel. This appears to be a cost effective method of producing a product that would resolve many of the existing problems in sour gas wells. It is capable of producing the piping or tubing and there appears to be little doubt about the coupling. From a metallurgical consideration, it appears that the chemistry, heat treatment and corrosion problem could be resolved using this process.

3.4.1.4 Ceracon is an economical alternative to standard Hot Isostatic Pressing (HIP) for the consolidation of powders to full density, near-net-shapes. The physical properties developed with this process are competitive with wrought or forged materials and, in many cases, produce fine grained materials that cannot be produced using standard technologies available today. Accuracy of the final shape depends on proper preform design. Part-to-part variations are a function of control of the preform density, grain characteristics, positioning within the grain and consolidation temperature and pressure. Computerization is an integral part of the Ceracon process and is necessary. Good surface finish is obtained and detail maintained during consolidation. Capabilities of forming a wide range of materials into complex shapes having thin sections, transverse holes and reverse corners opens up the process to a variety of applications where material costs are high.

3.4.1.5 Contact Information: Oliver D. Smith, President, The Ceracon Corporation, First City Tower, Suite 4350, Houston, Texas 77002.

3.4.2 Cladding: Standard Hot Isostatic Pressing (HIP)

3.4.2.1 Standard HIP is similar to the Ceracon process in some respects, but is more complex. Here, a powder preform is pressed to a specific density and then is "canned" by encasing the part in a nonporous metal material. This is necessary because the pressing media is a gas and the preform is porous. After the part is encased, it is introduced into a high temperature, high pressure furnace and pressure applied. This process has a relatively low ceiling pressure (30,000 psi or 200 MPa) and relies on creep as the dominant mechanism of densification, therefore, long dwell times (typically one to three hours) are necessary. After the batch is consolidated, the "canning" material is stripped away and the part is ready for further processing.

3.4.2.2 This process is capable of producing the coupling from one or more materials. Its ability to produce full density, high quality materials is excellent, however, it is more costly than other approaches owing to it being a batch process and the intermediate steps of canning and canning removal. It is, however, unlikely that tubing could be produced by this method because of the long lengths involved. No furnace system exists that could do this.

3.4.2.3 Contact Information: Charles Smith, Autoclave Engineers, Inc., 2930 W. 22nd St., Erie, PA 16506

3.4.3 Cladding: Welding

3.4.3.1 As mentioned elsewhere in this report, weld cladding should be evaluated as a possible means of applying the clad to the pin ID's. This has been done for many years in the nuclear pressure vessel business where corrosion is of prime consideration and the pressures and temperatures are very high.

3.4.4 Vapor Deposition: Controlled Nucleation Thermal Deposition (CNTD)

3.4.4.1 CNTD is similar to standard chemical vapor deposition in that it is done in a vacuum or partial vacuum chamber. At this point, the similarity disappears. Figure 2 shows how the furnace is configured. The chamber is heated indirectly by induction. The graphite block internal to the furnace provides the heat to the part. The system operates at a partial vacuum. Where normal CVD systems depend upon vaporized material for the deposition source, the CNTD process uses mixtures of gases which "plate out" on the part. The thickness of the as-deposited material may be controlled

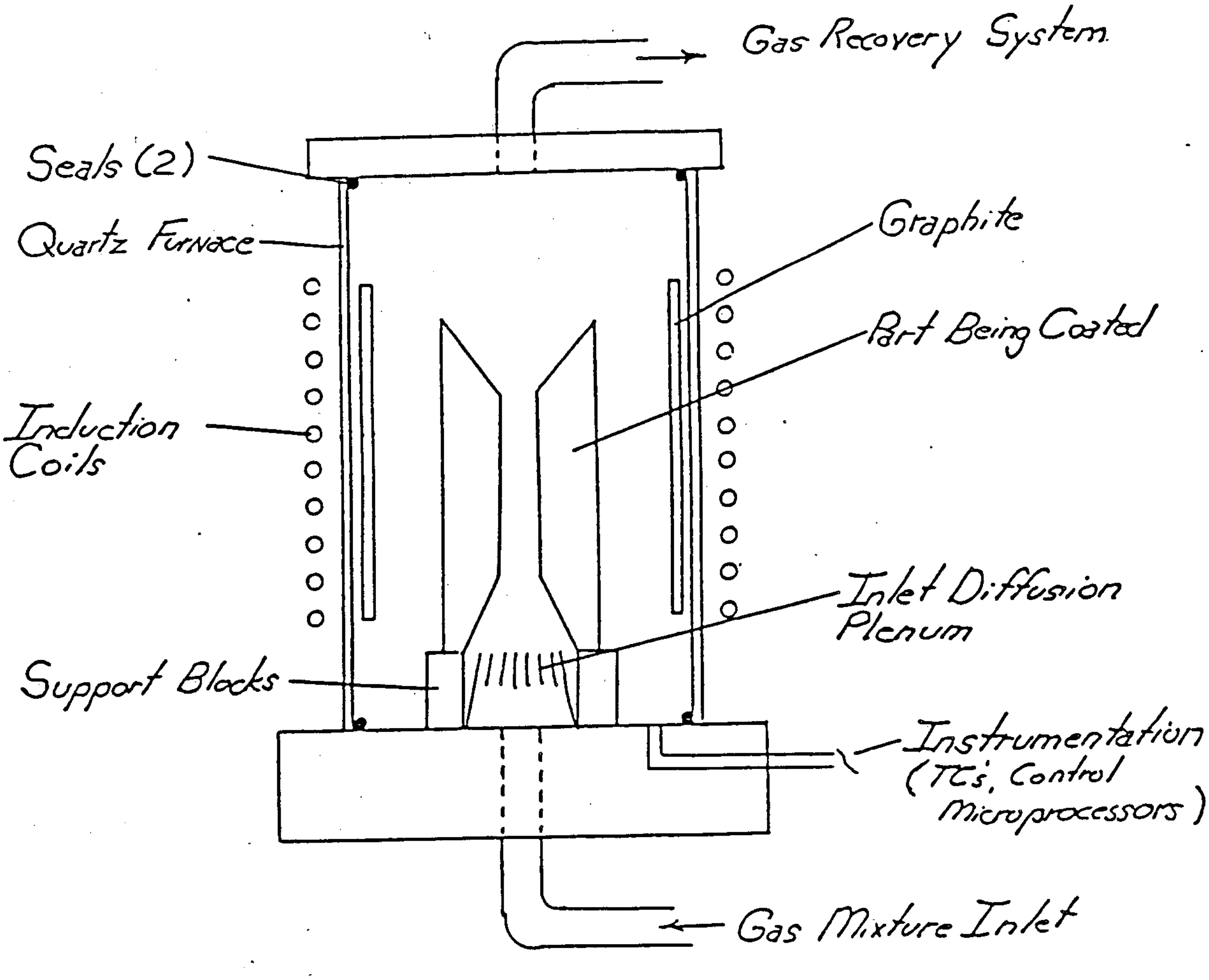

FIG 2.

Schematic Configuration of CNTD System.

from very thin (0.1 micron) upward to approximately 10 mils (0.010 inches), however, most materials deposited become dendritic when thick deposits are conducted.

3.4.4.2 Another interesting characteristic of this process is that the deposited material has extremely small grain sizes -- generally on the order of 0.05 to 1 micron and are equiaxial in morphology. Materials currently used include tungsten carbide, silicon nitride and titanium diboride. The hardness of these materials ranges from about 1500 V_{500} upwards to 7000 V_{500}.

3.4.4.3 Materials deposited by the CNTD process are, by their nature, very corrosion resistant, however, there are some design considerations that must be addressed. The coating deposited on the inside of round parts is deposited in residual compression which is an excellent feature. However, when deposited on the exterior surface, the deposit is in residual tension. The ultimate strength of the material is around 400,000 psi and the yield strength about the same, so any probability of flexure for a deposit on the external surface of a round part is very risky. When the deposit is made the process inside the chamber requires near laminar flow of the gases. This would probably require a development program to deposit the material on machined, internal threads. This is particularly true since the threads could not be machined after the material was deposited.

3.4.4.4 There is little question that the materials deposited by the CNTD process would be ideal where corrosion and erosion protection is required. There are several difficulties that would have to be addressed by development efforts. The coupling is probably all that could be done because of the length of a standard tube unless the industry is willing to do short pieces which could subsequently be welded to make up a joint.

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3.4.4.5 Contact Information: Mr. Bob Holzl, President, San Fernando Laboratories (a Division of Dart & Kraft, Inc., Pacoima, California).

3.4.5 Electroless Plating: Of the many candidate materials to be used, electroless nickel (ENC) is probably the best. The industry has considerable experience with it and the corrosion properties are well documented. As with other processes, ENC of the tube run would probably be extremely difficult. This is because most plating operations are not equipped to plate such an item vertically, and, if it were so equipped, the flow time would make production very expensive.

3.4.5.1 The thickness of electroless nickel can be controlled to meet most applications and it has excellent strength and ductility. Its high hardness and natural lubricity provides very good resistance to abrasion and galling. This is important when subjected to the rigors of the field handling.

3.4.5.2 ENC is deposited with an amorphous structure and provides corrosion protection by functioning as a barrier coating. The part to be coated is cleaned and immersed in the solution of sodium hypophosphite, water, and liquid nickel sulfate. Both acid and alkaline processes are available, however, the acid type solutions provide phosphorous contents of 7-12% by weight with the remainder dominated by nickel. Alkaline nickel solutions operate at lower temperatures and result in significantly lower phosphorous contents (typically 5% by weight). These coatings, due to their lower phosphorous content, are not as hard as those obtained from acid type baths, nor do they produce equivalent corrosion protection. Deposits from acid baths are more suitable for engineering applications owing to the high hardness values, superior wear and corrosion resistance when compared to coatings of unalloyed electrodeposited nickel.

3.4.5.3 Contact Information: There are many companies providing technology. Examples are Allied-Kelite, Enthone Incorporated, Technic, Inc. and WearCote International;

American Plating, Mr. Bill Turner, Houston; Schumacher Co., Inc., Mr. John Babcock, Houston.

3.5 Corrosion resistant alloy for the entire string can easily be engineered, and cost is the only key consideration.

3.6 Considerations for shouldering connections

3.6.1 Of all the available technology, ENC coating of the entire inside diameter of the coupling appears to be easily accomplished. The manufacturing capacity is readily available and, from the technical viewpoint, there appears near 100% probability of success in the application. Assuming that the average coating was specified to be 3 mils (0.003 inches), handling problems may arise. Very small abrasions or nicks in the coating could possibly cause serious problems owing to the "two metals" whereby a cell is formed at the penetration in the coating and accelerated corrosion could take place. The application of ENC would affect the torque values necessary to provide hand-tight and power-tight, however, this is not considered to be a significant difficulty.

3.6.2 The use of ENC coating on the shoulders of the coupling alone would be reasonably easy to accomplish. The center portion of the coupling could be coated and final machined thus assuring that only the shoulder was coated. Some degree of testing would be required to assure that, although the shoulder is well protected, the gap between the coupling and the tube may still experience a marked degree of corrosion. This may occur because of the probability of a stagnant area developing at this point or irregular flow caused by the "trap."

3.6.3 The application of CNTD materials on the coupling threads and shoulder would require significant amount of development work and testing. It may be difficult or impossible to assure an even coating of the chosen material over all areas owing to the requirement for laminar flow during the deposition process. Application of the material over the shoulder, however, is 95% probable to be successful. This would ensure a very corrosion resistant and nearly completely erosion proof arrangement. The gap between the coupling and the tubing would still likely be a problem for the same reasons listed in 2. A combination of CNTD material with a one inch interface between the CNTD material and the coupling threads may provide an even better solution.

3.6.4 The Ceracon process provides the greatest probability of success from all technical aspects compared to HIPing or welding, whether a barrier coating is applied to the full length of the coupling or just to the shoulder. The process can be used best to apply a protective material to the full length of the coupling and would probably be done in that manner regardless. Where the deposit is required on the shoulder alone, the area where the threads are to be would be machined away. Some development work would be required to arrive at the best combination of materials with candidates such as 22Cr-5.5Ni-3Mo (SAF-2205), 27Cr-31Ni-3.5Mo-1.0Cu (Sanicro 28), 22Cr-47Ni-6.5Mo-2Cu (Hastelloy G-3), or 16Cr-59Ni-16Mo-4W (Hastelloy C-276) being given initial consideration. The base material should be chosen as to meet P-110 requirements.

3.6.4.1 Perhaps the best aspect to this approach is the possibility of fabricating the entire tubing length from a corrosion resisting material as the inside clad. If this can be accomplished at a reasonable cost, the improved "up-time" should be improved by a minimum of 50%.

3.6.4.2 As with the other processes, it is considered impossible to apply the Ceracon process to the end of a finished tube/pipe because of the nature of the process. It is recommended that the Ceracon process be given major consideration.

3.7 Considerations of non-shouldering connections has been limited to one option that is not recommended as explained earlier. If nonmetallic or teflon "washers" could be developed which would function as flow straighteners in this area. This would provide additional insurance by partially sealing off the coupling from the corrosion media and minimizing the trap volume. See Figure 3. However the development time required to design a thread and manufacturing tolerances to properly shoulder against a bonded insert is currently prohibitive.

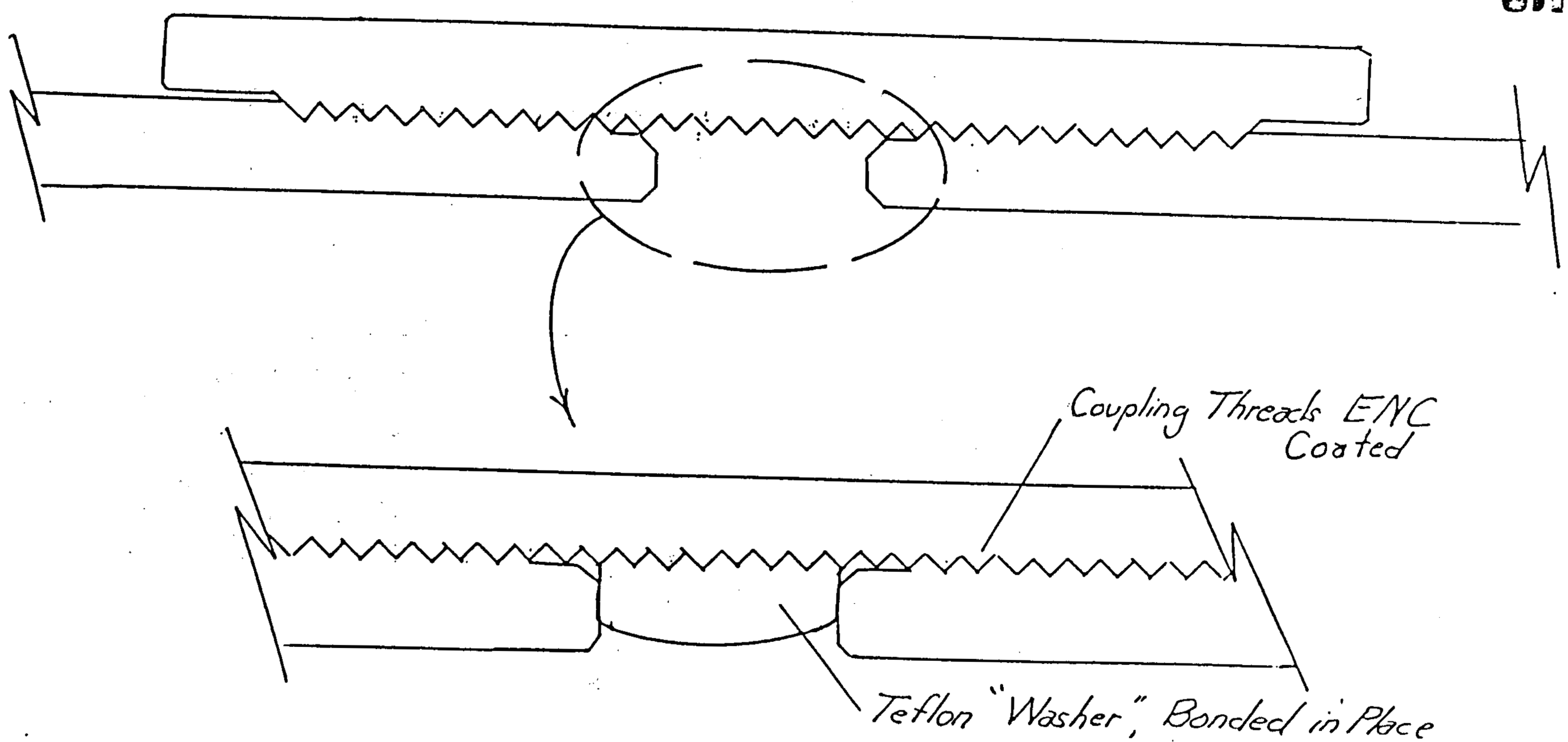


FIG. 3

Teflon "Washer" to function as Corrosion Barrier and Flow Straightener.

3.8 SERVICEABILITY CONSIDERATIONS

3.8.1 Performance in operations should be satisfactory with either ENC or cladding with the Ceracon process. Considerable experimentation with CNTD would be required to evaluate its performance although there is no technical reason it shouldn't. It is likely that the combination of CNTD applied materials in conjunction with ENC would be superior to either, but it is equally likely that the CNTD material would be subject to damage in the field because of its extremely high hardness. The bond strength of either would not be a problem and flaking or chafing should not occur. Of the three processes, the Ceracon materials would rank best in serviceability because the corrosion resistant material could be made to consist of half or more of the thickness of the coupling if desired. Damage in handling and installation would not effect its ability to function in use. Its ability to form tubes and couplings must rank it highest in potential application. ENC is likely to be the least expensive and fastest solution to resolve the problem, if only on a temporary basis. CNTD is expensive and will require considerable development work, but would produce a highly corrosion and erosion resistant material. This may be even more useful in valves where the need for erosion protection is equally or more important that corrosion resistance.

3.9 LEAD TIME

3.9.1 The technologies under consideration are ranked as follows - number one being the most available:

3.9.2 Electroless Nickel Coatings (ENC) is available now. All that would have to be done is write specifications governing the purchase and/or technical requirements.

3.9.3 The Ceracon process has been in development for two years and is presently available for many products. Work is under way to produce corrosion resistance cladding over other materials. This is probably the only process that can resolve all the problems and has the capability to clad with materials such as titanium. We believe that it would require six months to a year of development by Ceracon plus a serious interest by one of the equipment manufacturers to expedite this effort.

3.9.4 CNTD is available now, however, deposition on surfaces such as coupldding threads is believed to be extremely difficult. We expect that a year to eighteen months of development work would be necessary.

3.9.5 HIP clad requires specific commitment for special set up for cladding only the shoulder area.

3.10 COST CONSIDERATIONS

3.10.1 Costs necessary to implement the use of these manufacturing processes range from very high to relatively inexpensive. The long range cost savings for most of them is excellent. The rankings so far as development costs necessary to use the materials and/or technologies are as follow:

3.10.2 Electroless nickel is ranked first and is available in Houston.

3.10.3 Welding/HIPing operation falls into the next range, but special configurations can increase cost; full length cladding of coupling uses material that will be machined away except for the space between shoulders.

3.10.4 CRA material will probably be less than the next two options, especially if only the coupling is CRA and the pin is coated.

3.10.5 The ceracon process is still in the development stage and would require an investment on the order of $150,000 and $500,000 for the development effort. In addition, the support and participation of a manufacturer capable of drawing tubing would be required if bi-metallic tubing is to be pursued. A manufacturer of couplings could pursue the technology with a reasonable investment. The long range cost savings potential is greatest with this process.

3.10.6 The CNTD technology is reasonably perfected for smooth surfaces, but is problematical for coupling threads. A good estimate isn't available for cost, but an educated guess is around $700,000 to $1,500,000. This estimate is based on an intimate knowledge of progress of a development effort toward implementing this technology for use in mud pump liners. This effort progressed very slowly and was finally dropped.

4.0 ANALYSIS

4.1 All of the options that leave a crevice where the shouldering surfaces are anodic will still cause problems.

4.2 The type and amount of corrosion at the P-110 - noble material interface cannot be predicted with 100% accuracy.

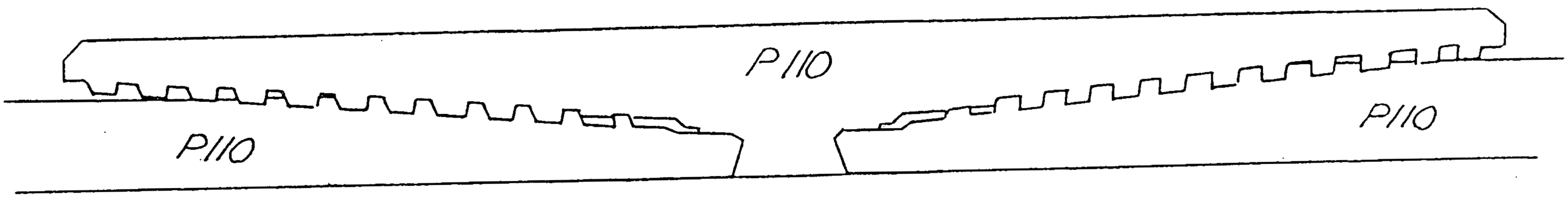
4.3 One of the systems using ENC with 0.5 mil coating thickness where the P-110 does not remain uncoated in the crevice appears to be the most promising with the exception of using CRA for the string. NL/Atlas Bradford and OTIS PTS can machine their standard threads and plate with ENC at 0.5 mils. Therefore, an ENC coated pin in a CRA coupling should withstand the corrosion.

5.0 SUMMARY

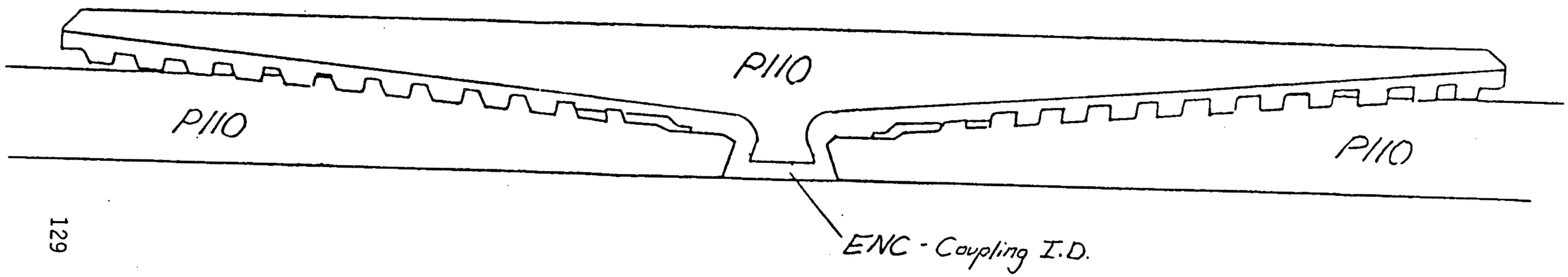
5.1 If the ENC coaters can coat the ID and OD of the pin and (which two have already indicated they can), 100% coating of the pin and couplings, 100% coating of the pin and ID coating of the coupling, or 100% coating of the pin with a CRA coupling will probably be the fastest, most cost effective alternative other than a CRA string.

5.2 Details of the preferable options can be pursued at Fenix and Scisson's direction.

APPENDIX A



A



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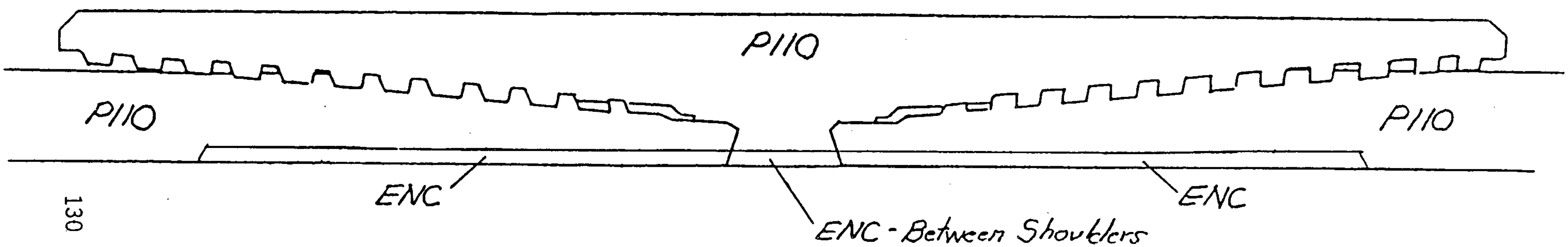
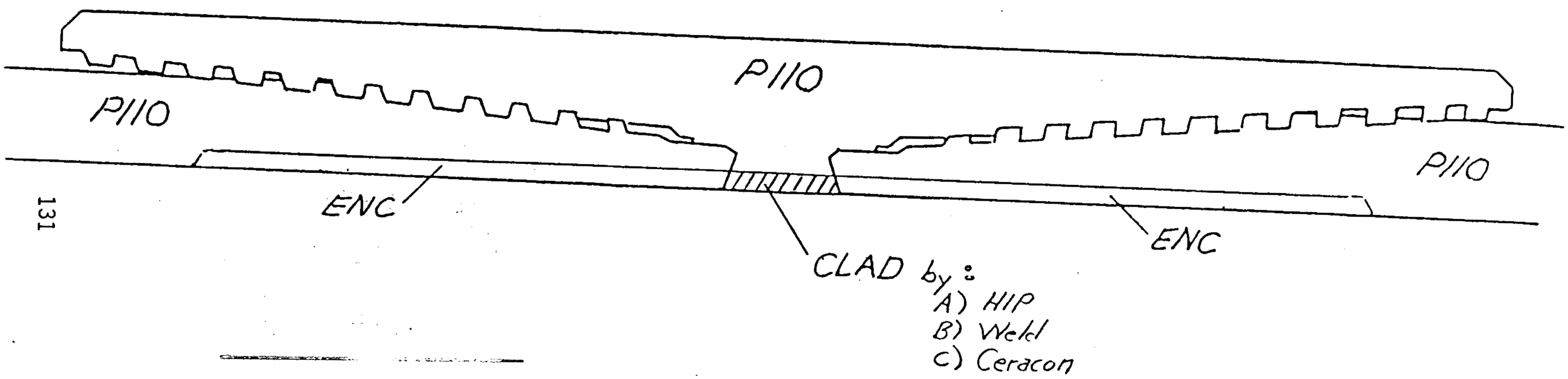
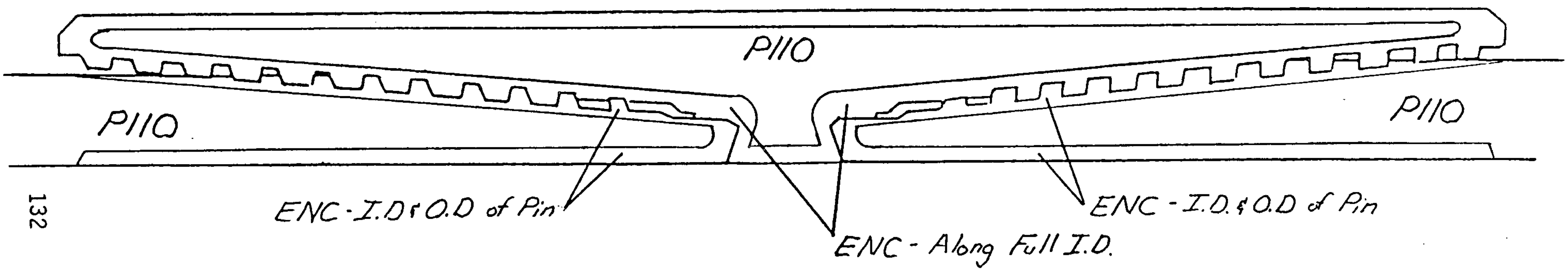
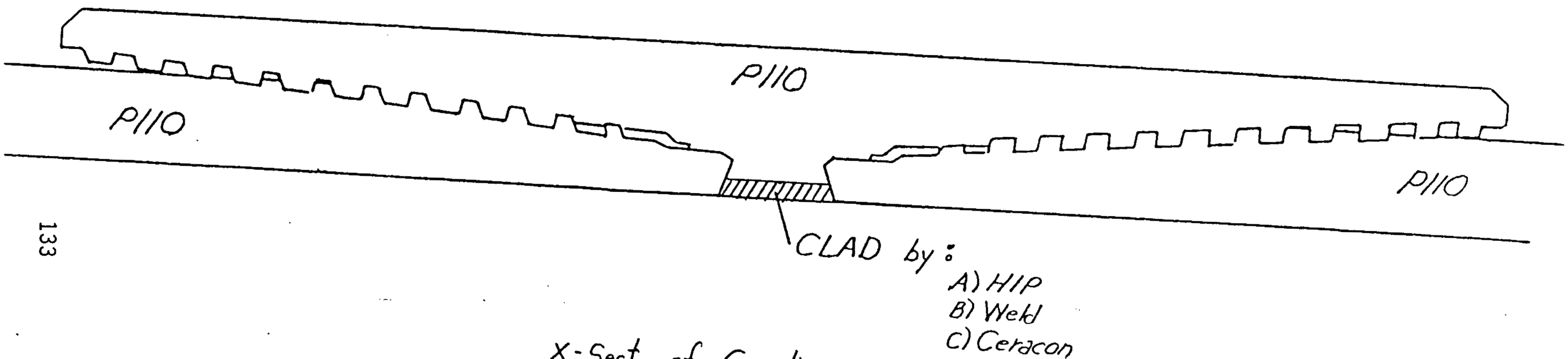
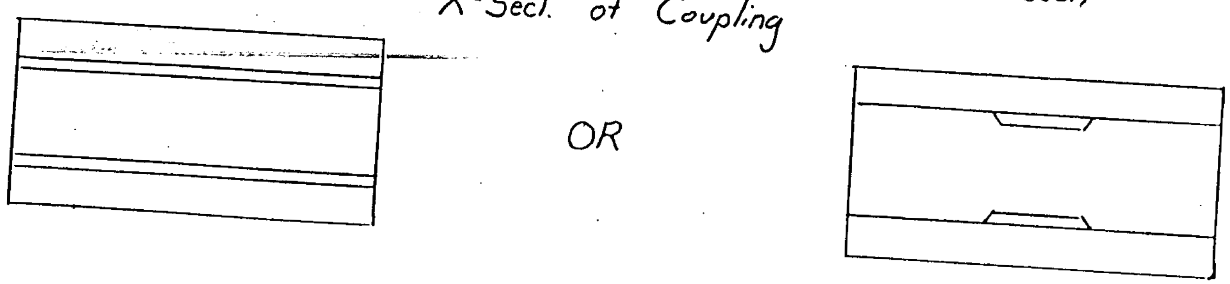

P110
P110
P110
ENC
ENC
ENC - Between Shoulders


P110
P110
P110
ENC
ENC
CLAD by:
A) HIP
B) Weld
C) Ceracon


P110
P110
P110
ENC - I.D & O.D of Pin
ENC - Along Full I.D.
ENC - I.D. & O.D of Pin



X-Sect. of Coupling



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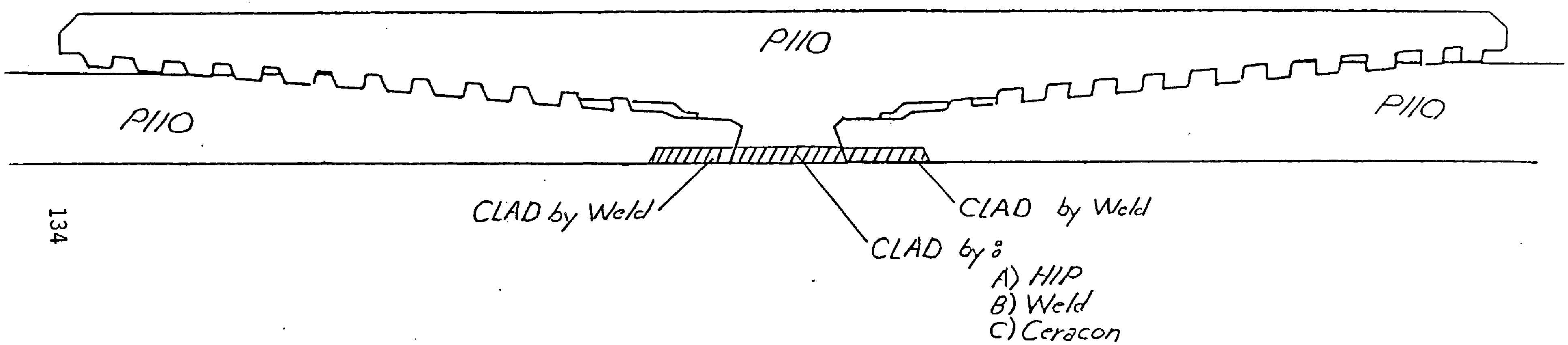
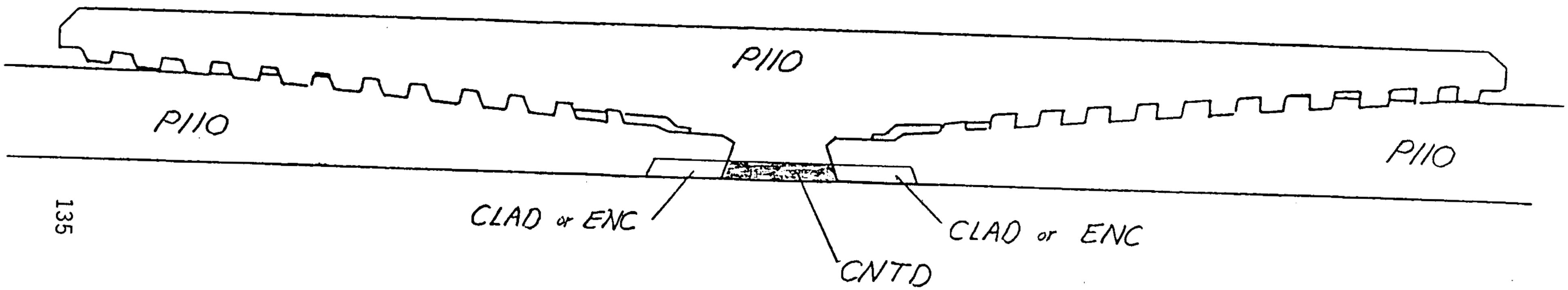
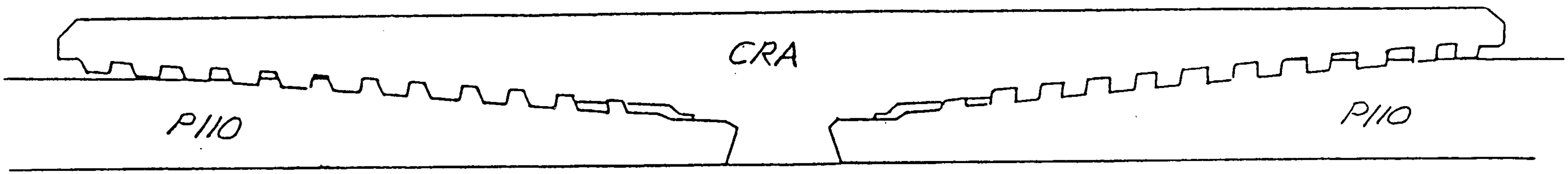
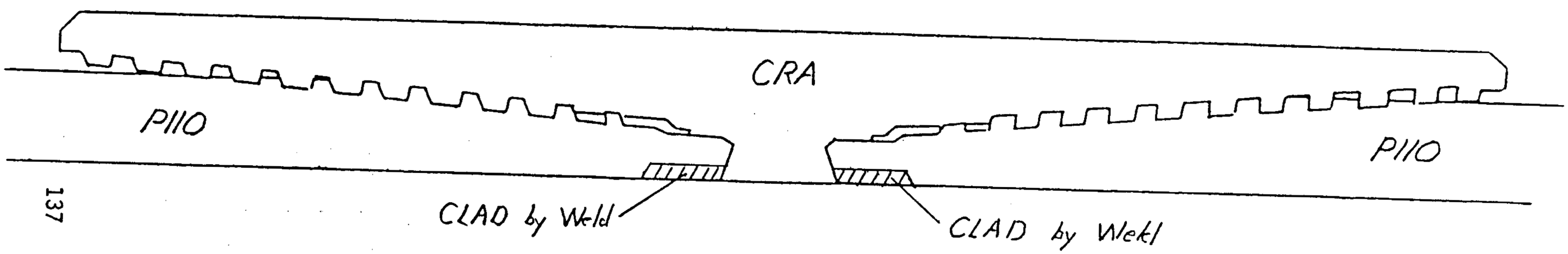
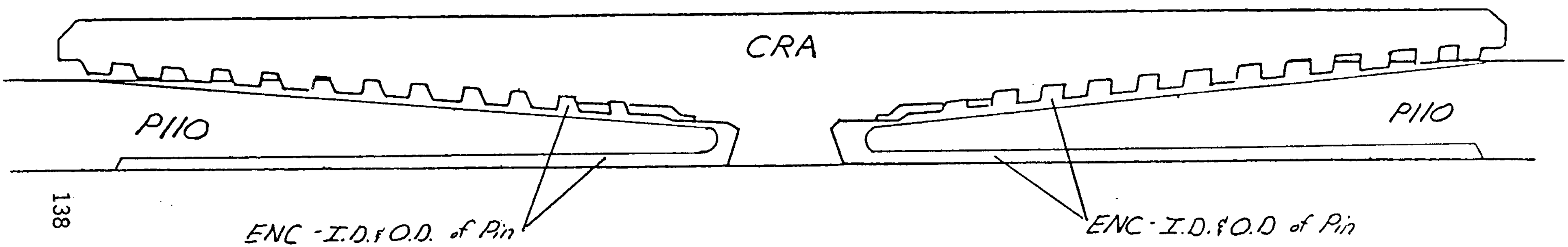

P110
P110
P110
CLAD by Weld
CLAD by Weld
CLAD by:
A) HIP
B) Weld
C) Ceracon


P110
P110
P110
CLAD or ENC
CNTD
CLAD or ENC


CRA
P110
P110


CRA
P110
P110
CLAD by Weld
CLAD by Weld



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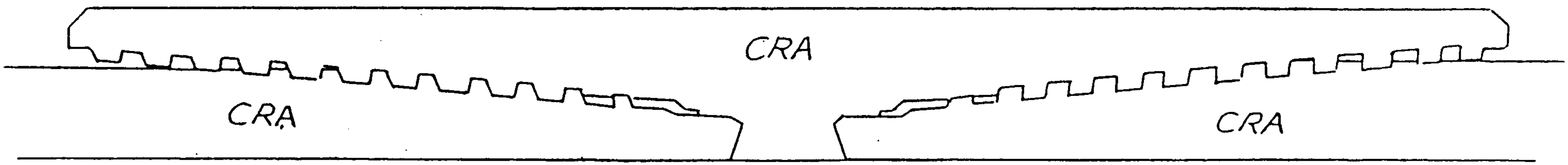


7

OIL SERVICES, INC.
7701 WILSHIRE PLACE, SUITE 200
HOUSTON, TEXAS 77040

Engineering Study to Determine The Feasibility of Producing the Pleasant Bayou No. 2 Well Through the 9-5/8" Intermediate/Producing Casing

Prepared By

Oil Technology Services, Inc.

For

Fenix & Scisson, Inc.

Michael J. Jellison 9/15/84
Michael J. Jellison — Date
Engineer

Gregory P. Fehr 9/15/84
Gregory P. Fehr, P.E. — Date
Vice President

TELEPHONE: 713-462-8298 TELEX: 795134

OTS

4.0 CONCLUSION

The Pleasant Bayou No. 2 can be safely produced through the 9-5/8" intermediate/production casing string provided that the casing is not excessively worn or corroded. Some type of casing inspection log capable of accurately measuring remaining wall thickness must be performed prior to recompleting the well. An acid stimulation treatment cannot be performed if the remaining wall thickness in the upper portion of the string (above 5,000') is less than nominal wall thickness. If the casing inspection log reveals wear or corrosion resulting in a decrease of wall thickness in portions of the string of more than 0.035" from nominal wall thickness, additional work is required to determine the feasibility of producing through the 9-5/8" string safely.

Special precautions are required to avoid overloading the 9-5/8" casing in service. The 9-5/8" casing should not be evacuated below 5,000'. Furthermore, an effort should be made to limit cool down of the casing as much as possible since unacceptably high axial tension loads can be generated in the casing from cool down.

Based on the circulation computer runs and C-SLAM runs, an emergency bullhead kill down the annulus can be accomplished safely with 16.0 PPG kill mud.

Stresses in the 9-5/8" 53.5# and 9-5/8" 47# buttress connections are acceptable for the conditions analyzed. The Joint Analysis Model indicated adequate sealing of internal pressure for both connections.

The 2-7/8" 6.5# P-105 CS design is recommended for the treatment/kill tubing string. However, 2-3/8" 4.7# P-105 CS can be used. The 2-7/8" string design allows for faster unloading of the well than the 2-3/8" design and the reduction in flow rate during production should not be excessive with 2-7/8" tubing as compared to 2-3/8" tubing. Reverse circulation, circulation down the annulus and up the tubing, is not recommended for the unloading operation due to excessive time requirements.

The present wellhead requires a metal-to-metal seal on the 9-5/8" casing stub looking up. If there is insufficient height of the casing stub to machine a metal-to-metal seal an extension of the casing stub looking up can be welded on.

A live annulus completion with 7" or 6-5/8" buttress casing used as tubing is definitely worth considering. A live annulus completion will prevent corrosive fluids from coming in contact with the 9-5/8" intermediate/production casing. Anti-scaling corrosion inhibitor fluid can be pumped down the casing/tubing annulus. Furthermore, no wellhead changeout is required for a live annulus completion provided that the tubing selected can be hung from the same tubing spool previously used for the 5-1/2" casing.

G

RESERVOIR SIMULATION STUDY

of the

PLEASANT BAYOU NO. 2 WELL

BRAZORIA COUNTY, TEXAS

by

James H. Hartsock
Susan R. Clemmons

July 25, 1983

GRUY PETROLEUM TECHNOLOGY, INC.
Consultants in Energy Systems

CONTENTS

FIGURES

1.0 INTRODUCTION

The Pleasant Bayou No. 2 well represented the first full-scale production test of a geopressured-geothermal aquifer in the United States. Consequently, considerable planning was involved in designing the flow tests and collecting data. The production tests were divided into three phases. The first phase was conducted to measure both the surface and bottomhole pressures as the well was flowed at various flow rates between 5,000 and 20,000 barrels per day. The second phase was intended, initially, to measure both the bottomhole and surface pressures while the well flowed at its maximum deliverability. Shortly after this test began, the bottomhole gauge and nearly all of the wireline were lost in the hole. After remedial operations to push the wireline to bottom and clean up the well, the phase-two test was resumed without a bottomhole-pressure measuring device. The phase-three test was merely an extension of phase-two with continuous recording devices so that the well could produce in an operational mode without continuous surveillance.

The results of the analysis of the pressure-production history are the subject of this addendum.

2.0 SIMULATION MODEL

2.1 Model Description

The computer program utilized to simulate the performance of the Pleasant Bayou No. 2 well is a two-dimensional, three-phase, black oil simulator that is the sole property of H. J. Gruy and Associates. The simulator solves the finite-difference behavorial equations using the semi-implicit procedure (SIP). Average block pressures at the end of each time step are converted to flowing bottomhole pressures using a pseudo-steady state approximation for radial flow in the block, and multiphase flow in the tubing string is computed using the method published by Orkiszewski(1). Model geometry can be controlled by designating those blocks included within the boundary of the reservoir, thus limiting calculations to those blocks containing active fluid. The model accounts for fluid-porous medium effects such as gravity, viscous, and capillary forces and permits spatial variation in fluid properties. Heterogeneous rock properties are entered as individual block properties. Computed results are printed at specified time intervals and automatic-restart capability exists in the model.

2.2 Fluid Properties

On October 14, 1982, a representative of Weatherly Laboratories collected several surface separator samples from the Pleasant Bayou No. 2 well. At the time, the flowing gas-water ratio was 20.11 cubic feet of gas per barrel of separator liquid. Using this as a basis for recombination, the reservoir fluid exhibited a bubble-point pressure of 7,460 psia at the reservoir temperature of 308°F. A differential liberation experiment and viscosity measurements were performed using the recombined fluid and the results are shown in Appendix A. These data were used as fluid property data in the aquifer simulator.

3.0 HISTORY MATCH

The history match was accomplished in what was considered to be three phases. In the first phase, from September 16 through October 31, 1981, both bottomhole and surface flowing pressures were recorded with quartz crystal gauges accurate to 0.01 psi. Phase two extended from September 23 to December 22, 1982, in which only the surface flowing pressures were measured with a quartz crystal gauge. The third phase recorded only the surface flowing pressures with a less-accurate continuously-recording meter.

The objective of the history-match procedure was to derive unique aquifer geometry and aquifer properties that would provide an adequate pressure match of the recorded pressures in all three phases. Since the production rate during phase two remained essentially constant for a considerable period of time, the pressure-time relationship provided some clues as to the basic geometry of the aquifer.

The phase-two pressure data exhibit an early, fairly rapid decline from September 23 to November 15, suggesting that the aquifer is limited in areal extent. After mid-November, however, the rate of change of pressure with respect to time dropped significantly, suggesting that, at some distance from the well, there is an aquifer with larger storage and flow capacities. Using this rationale as a basis for the aquifer description, numerous combinations of aquifer geometries and aquifer properties were attempted in order to match simultaneously the phase-one and phase-two pressure data. Although several different geometries and properties computed adequate history matches of phase one, no single set of data could be found which adequately matched the pressure data from both phases.

In working with the data and attempting the history matches, it became evident that the pressure performance of the phase-two test was influenced by either a wellbore phenomenon or some near-wellbore effects within the reservoir. These effects were manifested in a "skin effect" which appeared to increase as a function of time. When the skin effect at the wellbore was increased as a function of time, a satisfactory history match of all three phases was achieved using the aquifer description as shown in Figure 1. The measured and computed histories as a function of time are shown in Figure 2 through 5, inclusive.

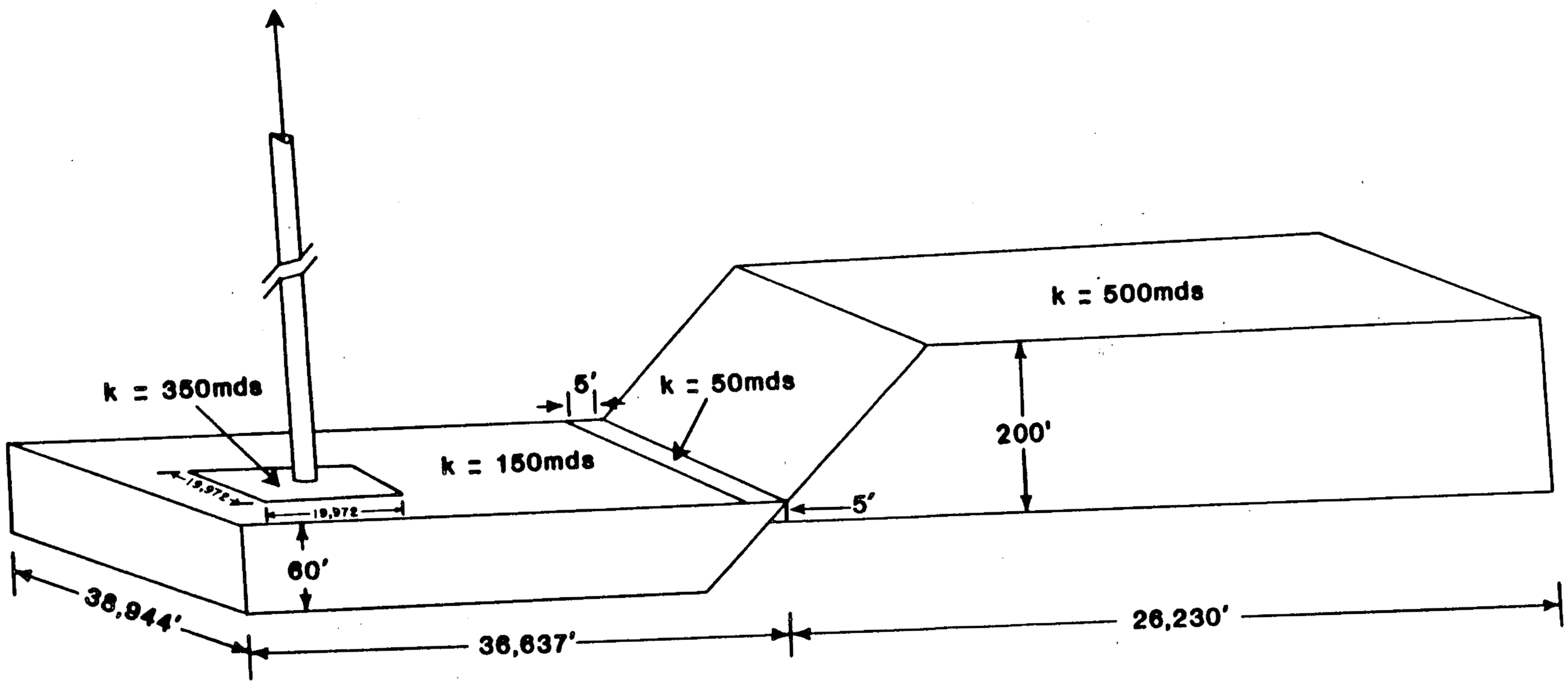


FIGURE 1

AQUIFER DESCRIPTION, PLEASANT BAYOU NO. 2 WELL

Figure 1. Aquifer description, Pleasant Bayou No. 2 well.

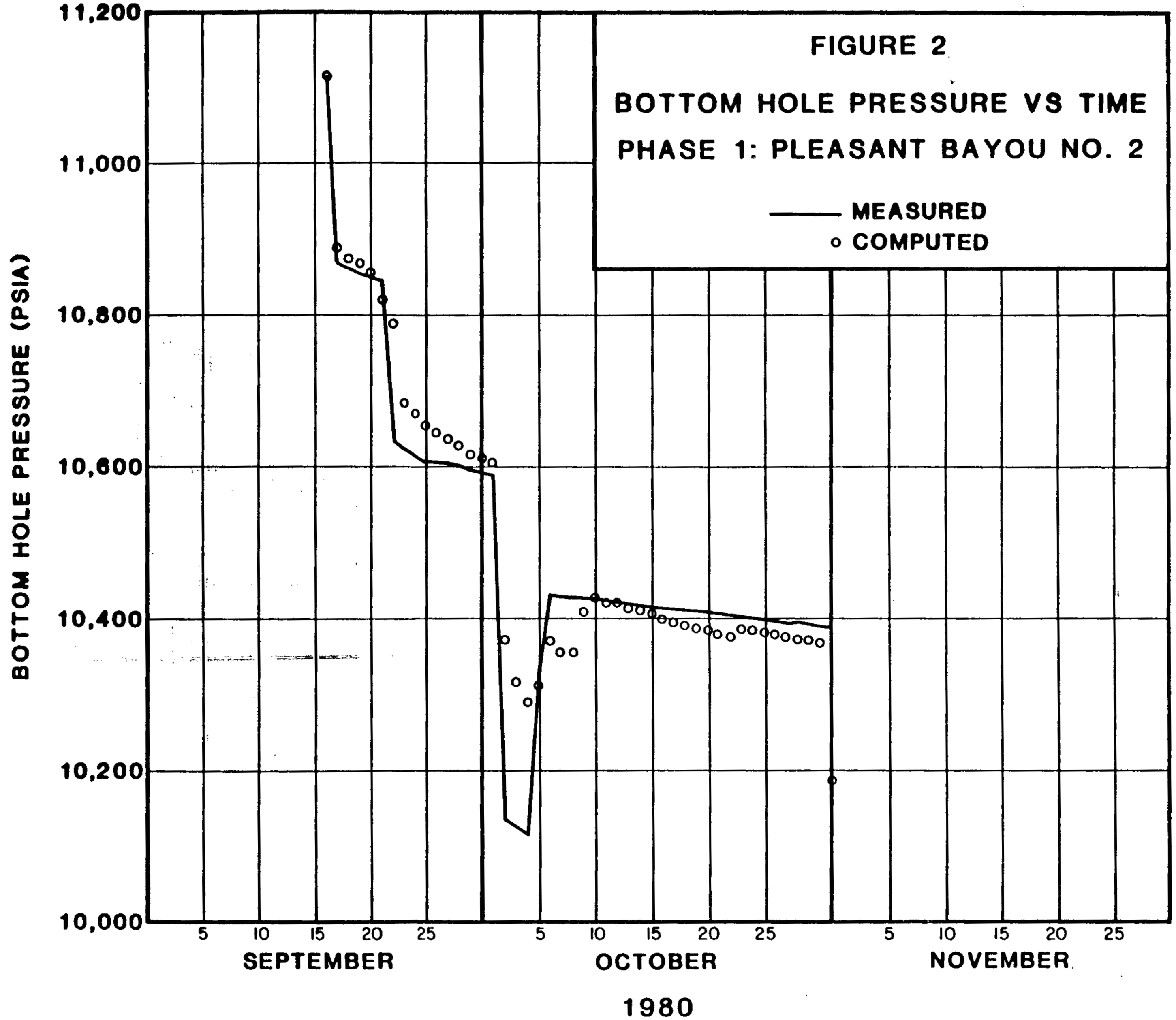


Figure 2. Bottomhole pressure vs time, Phase 1: Pleasant Bayou No. 2.

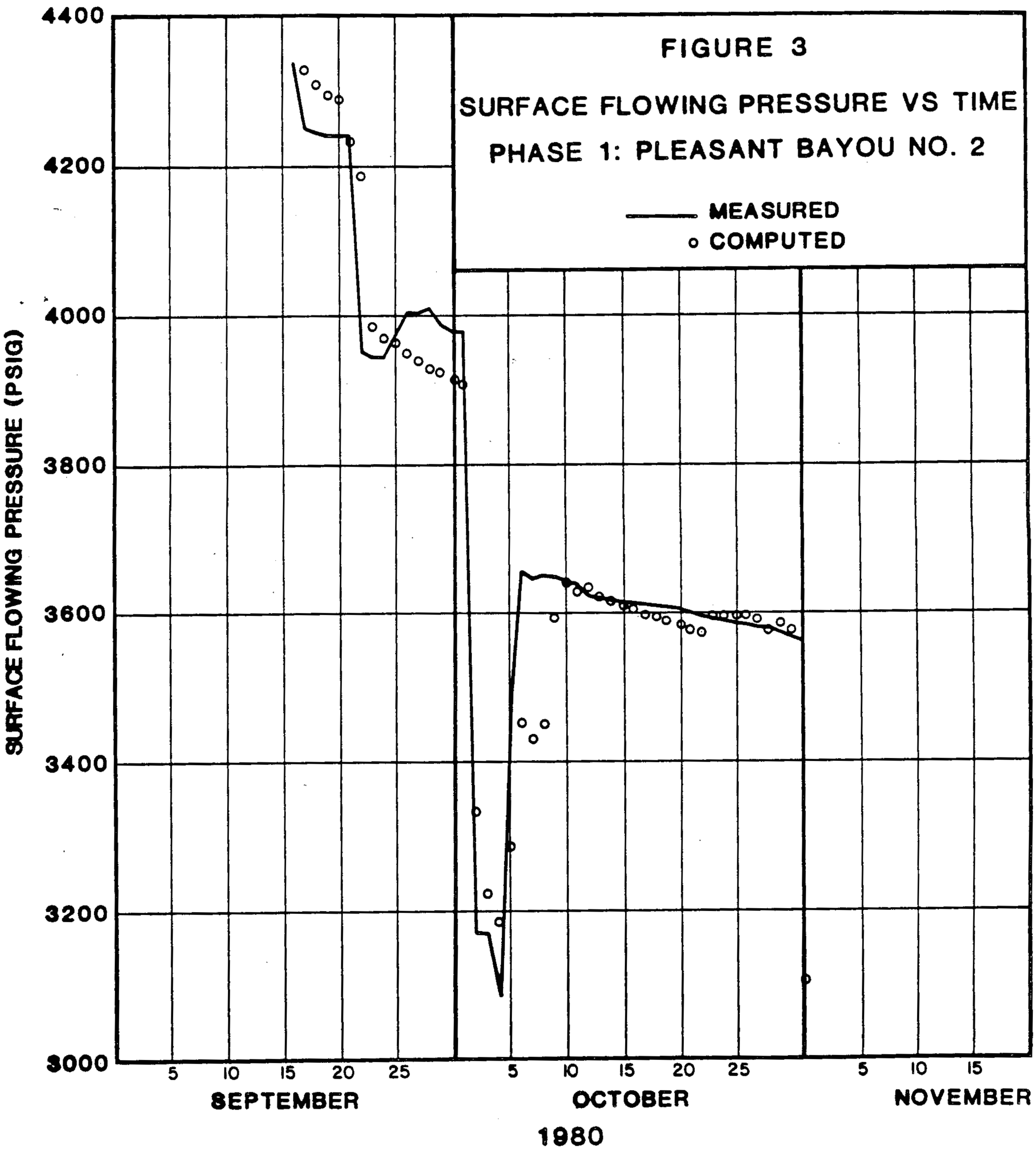


Figure 3. Surface flowing pressure vs time, Phase 1: Pleasant Bayou No. 2.

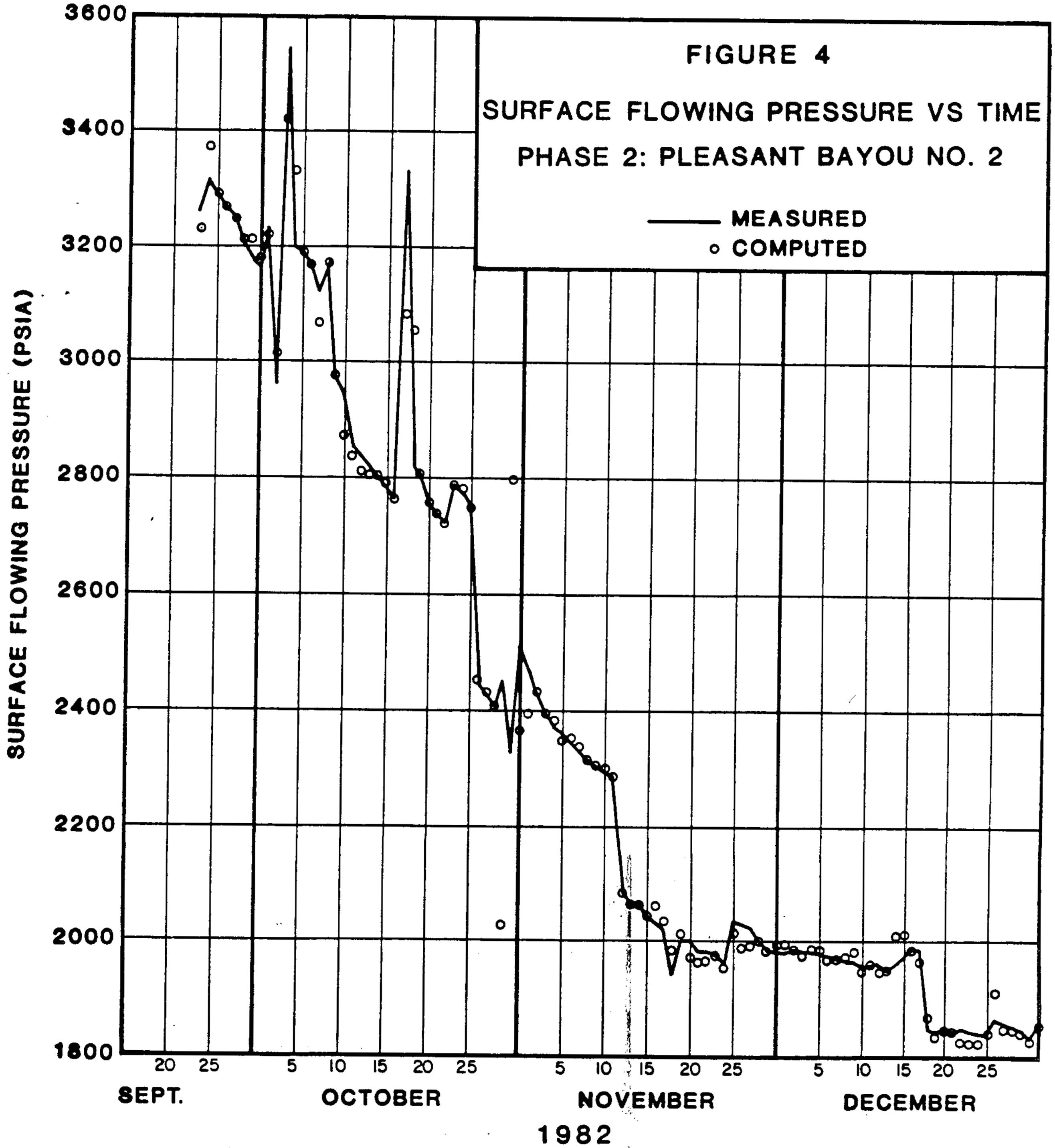


Figure 4. Surface flowing pressure vs time, Phase 2: Pleasant Bayou No. 2.

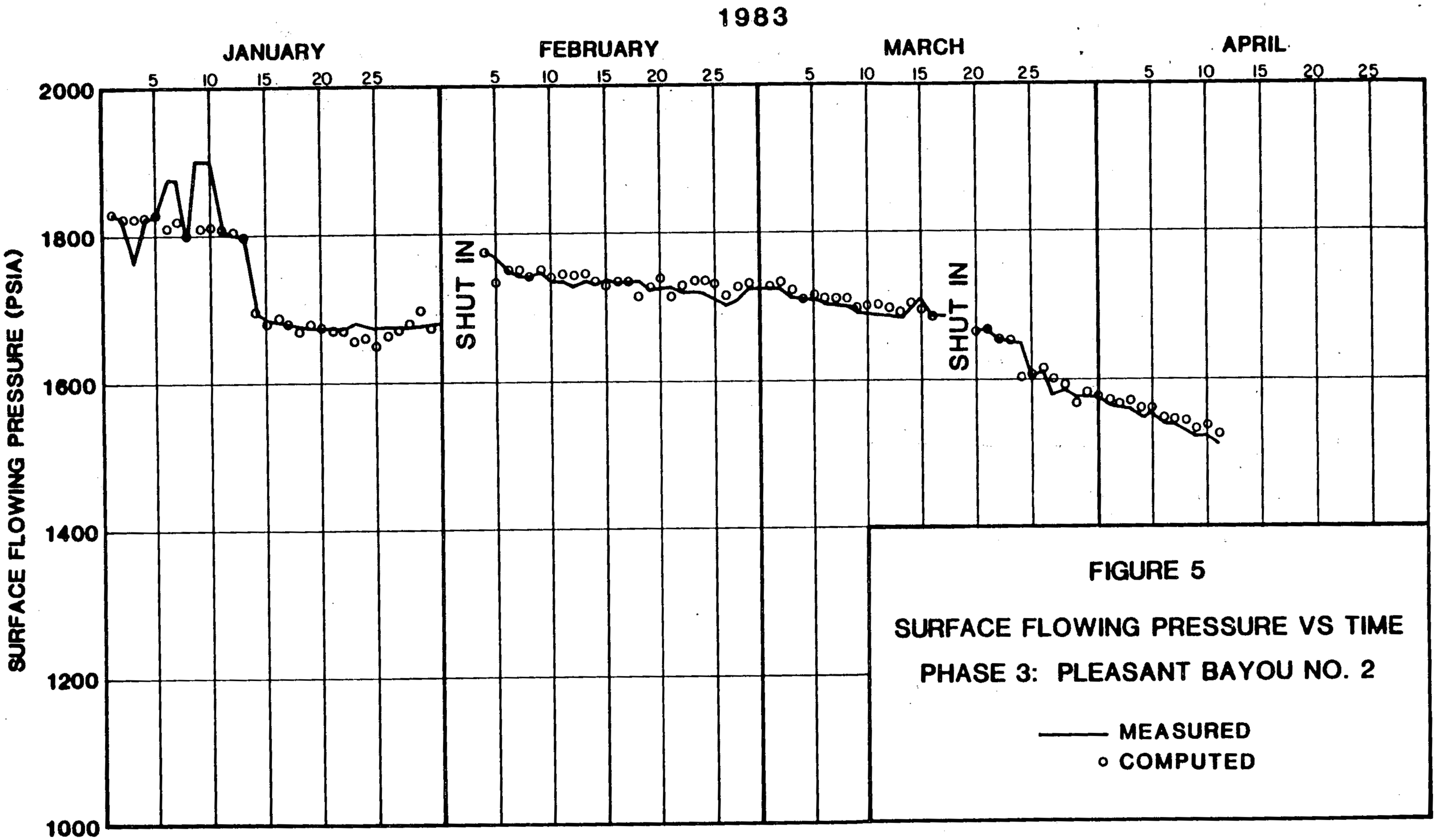


Figure 5. Surface flowing pressure vs time, Phase 3: Pleasant Bayou No. 2.

Since it is possible to history match nearly any single well pressure performance if the skin effect is allowed to be a dynamic rather than a static variable, the cause of this behavior was sought. Initially, we postulated that as the flowing wellbore pressure declined and the net overburden pressure increased in the vicinity of the wellbore, the porosity and, hence, permeability decreased as a consequence of differential compaction. Also, owing to the high total dissolved-solids concentration of the produced brine, scaling within the tubing string probably increased the frictional pressure loss, not only because of the reduction in the pipe diameter but also by an increase in the relative roughness. Lastly, and undoubtedly the most critical factor adding to the pressure drop, was the presence of wireline in the tubing. At the beginning of the phase-two test, the wireline lost at the aborted beginning of the phase-two test was believed to be below the lowest perforations. When the wellhead was disassembled in April 1983, large amounts of wireline were found lodged in the flowloop with significant scale buildup upstream of the pressure sensing device. Apparently, during the phase-two test, the wireline gradually moved up the tubing, causing an added pressure drop which distorted the surface flowing pressures. A plot of the skin effect imposed in the model to achieve a history match of the phase-two and -three data is shown in Figure 6.

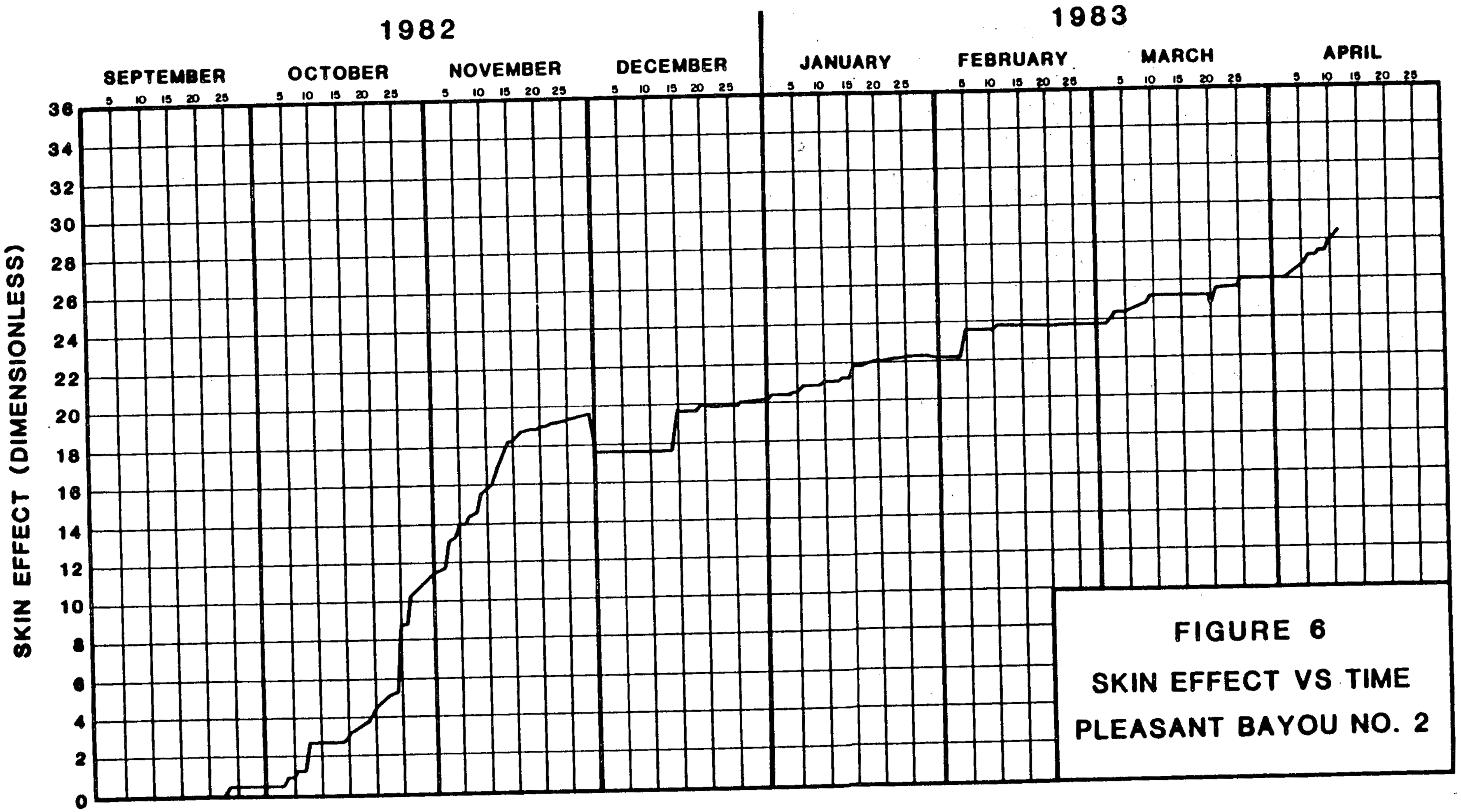


Figure 6. Skin effect vs time, Pleasant Bayou No. 2

4.0 CONCLUSIONS

Based on the analysis of the pressure history of the Pleasant Bayou No. 2 well, the following conclusions were reached:

1. The aquifer in which the well is completed has a large areal extent. The results of the simulation indicate that the aquifer could be as large as 56,000 acres.

2. The presence of the wireline in the hole and the gradual scale buildup materially affected the surface flowing pressures during the phase-two and phase-three periods. These factors cast some doubt as to the validity and uniqueness of the aquifer geometry derived by the simulation.

3. The permeability of the aquifer is relatively high for a geopressured sand. An area of 9,000 acres surrounding the well has a permeability of 350 md which reduces to 150 md beyond this area.

4. The aquifer was modeled as two units with poor communication between them. This was interpreted as a non-sealing fault in which only five feet of each sand were in contact and the permeability of this zone was reduced to 50 md.

REFERENCES

1. Orkiszewski, J: "Predicting Two-Phase Pressure Drops in Vertical Pipes," Journal of Petroleum Technology, June (1967).

APPENDIX A

Weatherly Laboratories' Reservoir Fluid
Analysis Report for Pleasant Bayou No. 2

WEATHERLY LABORATORIES, INC.

E. WEATHERLY, JR.
CHAIRMAN

223 GEORGETTE LAFAYETTE, LA 70506
PHONE (318) 232-4877

JOHN D. NEAL
PRESIDENT
BRYAN SONNIER
VICE PRESIDENT

FEBRUARY 11, 1983

THE GRUY COMPANIES
2500 TANGLE WILD, SUITE 150
HOUSTON, TEXAS 77063

ATTENTION: DR. J. HARTSOCK

RE: RESERVOIR FLUID STUDY
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD
BRAZORIA COUNTY, TEXAS

GENTLEMEN:

ATTACHED ARE THE RESULTS OF THE ANALYSES OF THE CHEMICAL AND PHYSICAL CHARACTERISTICS OF A RECOMBINED RESERVOIR FLUID SAMPLE FROM THE SUBJECT WELL. SURFACE SEPARATOR SAMPLES WERE COLLECTED FROM THIS WELL BY A REPRESENTATIVE OF WEATHERLY LABORATORIES, INC. ON OCTOBER 14, 1982. THE GAS-WATER RATIO (GWR) MEASURED ON THIS TEST, 20.11 CUBIC FEET OF SEPARATOR GAS PER BARREL OF SEPARATOR LIQUID, WAS USED AS THE BASIS FOR ONE RECOMBINATION. THE RESULTANT RESERVOIR FLUID EXHIBITED A BUBBLE POINT OF 7460 PSIA AT THE RESERVOIR TEMPERATURE 308 DEGREES FAHRENHEIT.

OTHER RECOMBINATIONS WERE DONE TO DETERMINE A BUBBLE POINT -VS- GWR RELATIONSHIP. A DIFFERENTIAL LIBERATION AND VISCOSITY MEASUREMENTS WERE PERFORMED USING RESERVOIR FLUID RECOMBINED TO THE PRODUCED GWR AT THE TIME OF SAMPLING.

WE WISH TO THANK YOU FOR THIS OPPORTUNITY OF SERVING YOU. SHOULD THERE BE ANY QUESTIONS CONCERNING THIS REPORT, PLEASE CONTACT US.

YOURS VERY TRULY

JOHN NEAL

LAB. NO. N1814-10046

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

GEOPRESSURE/GEOTHERMAL PROJECT SAMPLING AND LABORATORY PROCEDURE

1) WATER VAPOR CONTENT OF SEPARATOR GAS WAS DETERMINED BY FLOWING GAS FROM A METERING VALVE ON THE SEPARATOR GAS METER RUN THROUGH A WEIGHING TUBE (INDICATOR DRIERITE ($CaSO_4$) WEIGHED TO 0.1 MILLIGRAM) TO A G.C.A./PRECISION SCIENTIFIC WET TEST METER. SEPARATOR GAS SAMPLES WERE TAKEN FROM THE SAME PLACE INTO EVACUATED 1 GALLON STAINLESS STEEL (S.S.) CYLINDERS AFTER THOROUGH PURGING OF TRANSFER LINE AT SEPARATOR PRESSURE. SEPARATOR LIQUID SAMPLE CYLINDERS (500 ML. S.S.) WERE FIRST CHARGED WITH SEPARATOR GAS TO FULL SEPARATOR PRESSURE. THE LIQUID CYLINDERS WERE THEN CONNECTED TO THE SEPARATOR WATER SAMPLING POINT BY A S.S. TUBE LONG ENOUGH TO LOOP THROUGH A COOLING BATH. THE WATER TRANSFER LINE WAS THEN SLOWLY AND THOROUGHLY PURGED AT THE CYLINDER. SEPARATOR WATER WAS LET INTO THE CYLINDER BY SLOWLY BLEEDING GAS FROM THE TOP VALVE. AT NO TIME WAS THE WATER CAUGHT IN THE CYLINDER ALLOWED TO DROP BELOW SEPARATOR PRESSURE.

2) FLASH LIBERATION OF GAS FROM SEPARATOR WATER WAS ACCOMPLISHED BY USING A WEIGHED SEPARATOR FLASK. THIS SEPARATOR FLASK WAS CONNECTED TO THE OUTLET OF A SEPARATOR WATER CYLINDER BY A SHORT CAPILLARY LINE. GAS FROM THE SEPARATOR FLASK PASSED THROUGH A WEIGHED DRYING TUBE THROUGH A GLASS CYLINDER (~ 300 ML.) TO A RUSKA GASOMETER. A VACUUM VALVE AND A MERCURY MANOMETER WAS CONNECTED TO THE GAS MANIFOLD BETWEEN THE DRYING TUBE AND THE GASOMETER. BEFORE COMMENCING THE FLASH, THE ENTIRE FLASH GAS MANIFOLD WAS EVACUATED AND THEN FILLED WITH HELIUM TO ATMOSPHERIC PRESSURE. A KNOWN VOLUME OF SEPARATOR WATER WAS PUSHED OUT OF THE SAMPLE CYLINDER AT A PRESSURE SLIGHTLY ABOVE FIELD SEPARATOR PRESSURE BY USE OF A CALIBRATED MERCURY PUMP. THE VOLUME OF STOCK TANK WATER PRODUCED WAS DETERMINED BY ITS WEIGHT AND DENSITY. THE VOLUME OF DRY GAS EVOLVED WAS DETERMINED WITH THE GASOMETER. THIS GAS VOLUME WAS SUBJECT TO $\pm$ 2 % ERROR DUE TO THE VERY SMALL AMOUNTS MEASURED. THE GAS WAS CHARGED TO A CHROMOTOGRAPH FOR ANALYSIS FROM THE GLASS CYLINDER.

3) PHYSICAL RECOMBINATION OF SEPARATOR EFFLUENTS:
DRY SEPARATOR GAS WAS CHARGED INTO A TEMPERATURE CONTROLLED CELL. THE VOLUME OF THIS WINDOWED CELL IS KNOWN FOR ANY PRESSURE AND TEMPERATURE. THE PRESSURE OF THE GAS IN THE CELL WAS MEASURED WITH A MERCURY MANOMETER AND A BAROMETER. THIS CALCULATED GAS VOLUME WAS SUBJECT TO A $\pm$ 1 % ERROR DUE TO THE SMALL AMOUNT CHARGED TO THE CELL. A VOLUME OF SEPARATOR WATER WAS CHARGED INTO THE WINDOWED CELL BY USE OF A CALIBRATED MERCURY PUMP. THE WATER WAS METERED AND MEASURED AT A PRESSURE SLIGHTLY ABOVE FIELD SEPARATOR PRESSURE. FOUR RECOMBINATIONS WERE DONE IN ORDER TO PRODUCE A SATURATION PRESSURE-VS-GAS WATER RATIO CURVE. RESERVOIR FLUID RESULTING FROM RECOMBINATION OF THE PRODUCED GWR WAS USED TO PERFORM A DIFFERENTIAL LIBERATION AND VISCOSITY MEASUREMENT.

4) PRESSURE-VOLUME RELATIONS OF RECOMBINED RESERVOIR FLUID AT RESERVOIR TEMPERATURE:
EACH DATUM OF PRESSURE-VOLUME RELATIONS WAS CORRECTED FOR MERCURY PUMP CALIBRATION, MANIFOLD EXPANSION, CELL EXPANSION, MERCURY COMPRESSIBILITY AND MERCURY THERMAL EXPANSION. LIQUID VOLUME PERCENT WAS DETERMINED BY CALIBRATED CATHETOMETER AND BY DATA INTERPRETATION.

5) DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT RESERVOIR TEMPERATURE:
GAS FROM EACH PRESSURE DECREMENT OF THE DIFFERENTIAL LIBERATION WAS ANALYZED IN THE SAME MANNER AS DESCRIBED IN 2), (FLASH LIBERATION). DIFFERENTIAL LIQUID CHANGES WERE NOTED.

6) VISCOSITY OF RESERVOIR FLUID WAS MEASURED BY MR. J. R. COMEAU OF WEATHERLY LABORATORIES. A DESCRIPTION OF MR. COMEAU'S EXPERIMENTAL PROCEDURES IS GIVEN BELOW:
GEOTHERMAL WATER VISCOSITIES WERE MEASURED USING AN E.L.I. ROLLING BALL VISCOMETER WITH AN ELECTRONIC DETECTION SYSTEM TO PREVENT ELECTROLYSIS. THE DETECTION SYSTEM CONSISTS OF A SENSITIVE AUDIO AMPLIFIER WITH POSITIVE FEEDBACK ADJUSTED JUST BELOW OSCILLATION. FEEDBACK WAS TURNED ON BY AN AUTOMATIC SWITCH AS THE VISCOMETER WAS INVERTED AT THE BEGINNING OF THE CYCLE AND TURNED OFF WHEN THE BALL MADE CONTACT. PART OF THE SIGNAL WAS USED TO TURN THE DIGITAL TIMER ON AND OFF. TIMES WERE MEASURED TO 1/100TH OF A SECOND AND AVERAGED. THE VISCOMETER WAS CALIBRATED AT EACH OF THREE ANGLES USING SEVERAL KNOWN VISCOSITY STANDARDS WHICH WERE CHECKED AGAINST CANNON-FENSKE VISCOMETERS AND THE RESULTS ($t\Delta\rho$ vs. μ) PLOTTED. THE VISCOMETER WAS RECALIBRATED USING DISTILLED WATER AT SEVERAL TEMPERATURES. THESE RESULTS WERE USED ALONG WITH PREVIOUS RESULTS TO OBTAIN NEW CALIBRATION CURVES.

t = ROLL TIME, (SECONDS)

$\Delta\rho$ = DENSITY DIFFERENCE BETWEEN BALL AND RESERVOIR FLUID, (gm./ml.)

μ = VISCOSITY, (CENTIPOISE)

THE VISCOMETER WAS CHARGED WITH RESERVOIR FLUID AND RUN AT 308°F AT 1000 LB. INTERVALS. THE VISCOSITIES HAD A PROBABLE ERROR OF $\pm$ 0.007 CENTIPOISE.

FIELD DATA FOR WEATHERLY LABORATORY INVESTIGATION

WELL RECORD

COMPANY	THE GRUY COMPANIES
WELL	PLEASANT BAYOU NO. 2
FIELD	PLEASANT BAYOU
COUNTY AND STATE	BRAZORIA, TEXAS

FIELD CHARACTERISTICS

FORMATION NAME			
SAND NAME AND DESIGNATION			
DATE COMPLETED			
ORIGINAL RESERVOIR PRESSURE	(@ 14,750 FT.)	11,275	PSIA

WELL CHARACTERISTICS

ORIGINAL PRODUCED GAS-LIQUID RATIO			
PERFORATIONS		14,467-14,707	FT
ELEVATIONS			
TOTAL DEPTH			
LAST RESERVOIR PRESSURE	(@ 14,560 FT.)	11,162	PSIA
RESERVOIR TEMPERATURE		308	DEGREES F

SAMPLING CONDITIONS

DATE SAMPLED		10-14-82	
TUBING PRESSURE, FLOWING		2818	PSIG
PRIMARY SEPARATOR TEMPERATURE	(METER RUN)	260	DEGREES F
PRIMARY SEPARATOR PRESSURE		560	PSIG
PRIMARY SEPARATOR GAS RATE	(WET GAS)	427.2	MCF/DAY
SEPARATOR LIQUID RATE		21,247	BBLS./DAY
GAS-LIQUID RATIO (SEPARATOR)		20.11	SCF/BBL.SEP.WATER
SHRINKAGE FACTOR (VOL.S.T.WATER @ 60'F/VOL.SEP.WATER)		0.9468	
GAS-LIQUID RATIO (STOCK TANK)		21.24	SCF/BBL.S.T.WATER
PRESSURE BASE		14.65	PSIA @ 60 DEGREES F

NOTE: FOR DRY GAS, 20.10 SCF/BBL. SEP. WATER @ SEP. CONDITIONS.
21.23 SCF/BBL. S.T. WATER @ 60'F.

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

CALCULATION OF GAS RATE, 10-14-82 TEST

(Factors from GPSA Engineering Data Book)

$\sqrt{Hw\ Pf}$	=	149.7498	Hw	=	39 "H2O ,	Pf	=	575 psia
Fb	=	115.6168	D	=	1.939 " ,	d	=	0.750 "
FpB	=	1.0055			14.65 psia			
Fr	=	1.0003	b	=	0.0485			
Y2	=	1.0004	Hw/Pf	=	0.068 ,	d/D	=	0.387
Fg	=	1.1844	Gravity	=	0.7129 ,	Fg	=	$\sqrt{1 / 0.7129}$
Ftf	=	0.8498	Temp.	=	260 degrees F ,	Ftf	=	$\sqrt{520 / 720}$
Fpv	=	1.0152	pTr	=	1.973 ,	pPr	=	0.835
			Z	=	0.9702 ,	Fpv	=	$\sqrt{1 / Z}$

$$Q = \sqrt{Hw\ Pf} \times Fb \times Fpb \times Fr \times Y2 \times Fg \times Ftf \times Fpv \times 24$$

Q = 427.2 MCF/day @ 14.65 PSIA @ 60 Degrees F

RESERVOIR FLUID SUMMARY

Reservoir Temperature, Degrees F		308
Saturation Pressure at 308 Degrees, Psia		7460
Compressibility of Reservoir Oil at 308 Degrees F		
Vol. per Vol. per Psi x 10 6		
From 7460 Psia to 9000 Psia		2.92
From 9000 Psia to 11275 Psia		2.87
		DIFF. LIB.
Saturated Oil at 7460 Psia, 308 Degrees F		
Density, Gms. per Ml.		1.0264
Lbs. per Bbl.		359.8
Specific Volume, Cu.Ft. per Lb.		0.015606
Viscosity, Centipoise		0.363
Formation Volume Factor, Bbls. per Bbl.		
"Equivalent Stock Tank Oil" at 60 Degrees F	1.0603 *,	1.0621
Solution Gas-Oil Ratio, Cu.Ft. per Bbl.	25.03 *,	25.78 WET
"Equivalent Stock Tank Oil" at 60 Degrees F	24.45 *,	24.50 DRY
Reservoir Oil at 11275 Psia 308 Degrees F		
Density, Gms. per Ml.		1.0379
Lbs. per Bbl.		363.8
Specfic Volume, Cu.Ft. per Lb.		0.015434
Viscosity, Centipoise		0.379
Formation Volume Factor, Bbl. per Bbl.		
"Equivalent Stock Tank Oil" at 60 Degrees F		1.0504
Thermal Expansion at Psia, % per Degrees F		

NOTE: REFERENCES TO 'OIL' ABOVE SHOULD READ 'WATER'.

* BASED ON SEPARATOR WATER FLASH.

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

COMPOSITE LABORATORY DATA 308 DEGREES F

RECOMBINATION (1) 25.00 SCF SEP. GAS @ 14.65 PSIA & 60'F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE PSIA	PRESSURE VOLUME RELATIONS		LIQUID VOLUME PERCENT	OIL VISCOSITY CENTIPOISES	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/Vsat Bt	SPECIFIC VOLUME cu. ft. per Pound			FORMATION VOLUME FACTOR Bo **	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO PER BARREL STOCK TANK OIL AT 60'F DRY **	WET **
11275 RES.	0.9962	0.015435	100.00		1.0494		29.62	30.20
9950 B.P.	1.0000	0.015493	100.00		1.0534		29.62	30.20
9000	1.0028	0.015537	BUBBLE					
8000	1.0062	0.015589	99.95					
7000	1.0101	0.015650	99.85					
6000	1.0141	0.015712	99.74					
5000	1.0189	0.015786	99.56					
4000	1.0250	0.015881	99.25					
3000	1.0341	0.016022	98.66					
2000	1.0519	0.016297	97.26					
1000	1.1088	0.017179	92.28					
500	1.2306	0.019066	83.73					
141	2.4943	0.038645	43.99					
100	3.9418	0.061071	27.59					
89	5.1137	0.079227	20.41					

NOMENCLATURE:

V/VSAT. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 14.65 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

COMPOSITE LABORATORY DATA 308 DEGREES F

RECOMBINATION (4) 10.00 SCF SEP. GAS @ 14.65 PSIA & 60'F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE PSIA	PRESSURE VOLUME RELATIONS		LIQUID VOLUME PERCENT	OIL VISCOSITY CENTIPOISES	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/Vsat Bt	SPECIFIC VOLUME cu. ft. per Pound			FORMATION VOLUME FACTOR Bo **	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO PER BARREL STOCK TANK OIL AT 60'F DRY **	WET **
11275 RES.	0.9764	0.015437	100.00		1.0473		13.78	14.35
10000	0.9799	0.015493	100.00		1.0510		13.78	14.35
8000	0.9855	0.015581	100.00		1.0570		13.78	14.35
6000	0.9912	0.015671	100.00		1.0632		13.78	14.35
4000	0.9970	0.015763	100.00		1.0694		13.78	14.35
3000 B.P.	1.0000	0.015810	100.00		1.0726		13.78	14.35
2000	1.0075	0.015929	99.56					
1452	1.0162	0.016067	98.88					

NOMENCLATURE:

V/VSAT. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 14.65 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

COMPOSITE LABORATORY DATA 308 DEGREES F

RECOMBINATION (2) PRODUCED 20.10 SCF SEP. GAS @ 14.65 PSIA & 60'F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE PSIA	PRESSURE VOLUME RELATIONS: RELATIVE VOLUME V/Vsat Bt	PRESSURE VOLUME RELATIONS: SPECIFIC VOLUME cu. ft. per Pound	LIQUID VOLUME PERCENT	OIL VISCOSITY CENTIPOISES	FORMATION VOLUME FACTOR Bo **	DIFFERENTIAL LIBERATION: FORMATION VOLUME FACTOR Bo	DIFFERENTIAL LIBERATION: SOLUTION GAS-OIL RATIO PER BARREL STOCK TANK OIL AT 60'F DRY **	DIFFERENTIAL LIBERATION: SOLUTION GAS-OIL RATIO PER BARREL STOCK TANK OIL AT 60'F WET **
11275 RES.	0.9890	0.015434	100.00	0.379	1.0486	1.0504	24.50	25.78
10000	0.9926	0.015491	100.00	0.373	1.0525	1.0542	24.50	25.78
9000	0.9955	0.015535	100.00	0.369	1.0555	1.0573	24.50	25.78
8000	0.9984	0.015581	100.00	0.365	1.0586	1.0604	24.50	25.78
7460 B.P.	1.0000	0.015606	100.00	0.363	1.0603	1.0621	24.50	25.78
7400	1.0002	0.015610	BUBBLE					
7000	1.0015	0.015630	99.99	0.361				
6000	1.0054	0.015691	99.90	0.357				
5000	1.0096	0.015756	99.78	0.354		1.0691	19.77	20.92
4000	1.0148	0.015837	99.58	0.353				
3000	1.0224	0.015956	99.13	0.353		1.0737	14.35	15.34
2000	1.0370	0.016184	98.02	0.356				
1000	1.0825	0.016894	94.17	0.361		1.0784	6.30	7.04
500	1.1907	0.018582	86.45					
150	2.0653	0.032231	51.96					
102	3.2622	0.050910	31.75					
15								
15*						1.0000	0.00	0.00

NOMENCLATURE:

V/VSAT. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 14.65 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH. ALSO BASED ON SEP. WATER FLASH: SOLUTION GAS IN RESERVOIR FLUID IS 24.45 SCF DRY GAS/BBL. S.T. WATER @ 60'F. REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

COMPOSITE LABORATORY DATA 308 DEGREES F

RECOMBINATION (3) 15.00 SCF SEP. GAS @ 14.65 PSIA & 60°F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE PSIA	PRESSURE VOLUME RELATIONS: RELATIVE VOLUME V/Vsat Bt	PRESSURE VOLUME RELATIONS: SPECIFIC VOLUME cu. ft. per Pound	LIQUID VOLUME PERCENT	OIL VISCOSITY CENTIPOISES	DIFFERENTIAL LIBERATION: FORMATION VOLUME FACTOR Bo **	DIFFERENTIAL LIBERATION: RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO PER BARREL STOCK TANK OIL AT 60°F: DRY **	SOLUTION GAS-OIL RATIO PER BARREL STOCK TANK OIL AT 60°F: WET **
11275 RES.	0.9821	0.015436	100.00		1.0480		19.06	19.64
9000	0.9857	0.015493	100.00		1.0518		19.06	19.64
8000	0.9914	0.015582	100.00		1.0579		19.06	19.64
6000	0.9972	0.015673	100.00		1.0641		19.06	19.64
5050 B.P.	1.0000	0.015717	100.00		1.0671		19.06	19.64
5000	1.0001	0.015719	BUBBLE					
4000	1.0043	0.015785	99.90					
3000	1.0099	0.015873	99.66					
2000	1.0210	0.016047	98.89					
1000	1.0555	0.016590	95.96					
500	1.1459	0.018011	88.52					
193	1.5309	0.024062	69.19					

NOMENCLATURE:

V/VSAT. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 14.65 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

EFFECT OF GAS-WATER RATIO UPON BUBBLE POINT PRESSURES @ 308'F

GAS-WATER RATIO (SCF DRY SEP. GAS @ 14.65 PSIA & 60'F) / (BBL. SEP. WATER @ 560 PSIG & 287'F)	BUBBLE POINT (PSIA)
27.4 EXTRAPOLATED	~ 11275 RESERVOIR PRESSURE
25.00	9950
20.10	7460
15.00	5050
10.00	3000

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SEPARATOR WATER FLASH TO 0 PSIG & 76°F

SOLUTION GAS-WATER RATIO, DRY = 3.22

, WET = 3.79 $\dfrac{\text{SCF GAS @ 14.65 PSIA \& 60°F}}{\text{BBL. WATER @ 0 PSIG \& 60°F}}$

SHRINKAGE = 0.9468 $\dfrac{\text{VOL. S.T. WATER @ 60°F}}{\text{VOL. SEP. H2O @ 560 PSIG \& 287°F}}$

STOCK TANK WATER DENSITY = 1.0845 Gm/ML. @ 60°F

GAS GRAVITY , DRY = 0.9061 (SEE ANALYSIS)

, WET = 0.8616

PRODUCED OCTOBER 14, 1982:

GWR = 21.23 + 3.22 = 24.45 $\dfrac{\text{SCF TOTAL DRY GAS @ 14.65 PSIA \& 60°F}}{\text{BBL. STOCK TANK WATER @ 60°F}}$

GWR = 21.24 + 3.79 = 25.03 $\dfrac{\text{SCF TOTAL WET GAS @ 14.65 PSIA \& 60°F}}{\text{BBL. STOCK TANK WATER @ 60°F}}$

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SEPARATOR GAS SAMPLED:
OCTOBER 14, 1982 @
560 PSIG & 260°F

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	
WATER		0.045 + .004
CARBON DIOXIDE	12.497	12.491
NITROGEN	0.552	0.552
METHANE	82.598	82.560
ETHANE	2.895	2.894
PROPANE	0.923	0.923
ISO-BUTANE	0.141	0.141
N-BUTANE	0.131	0.131
ISO-PENTANE	0.036	0.036
N-PENTANE	0.020	0.020
HEXANES	0.028	0.028
HEPTANES PLUS	0.179	0.179
TOTAL	100.000	100.000
GRAVITY (AIR = 1.00)	0.7129	0.7129

NOTE: WATER MEASURED ON SITE, AVERAGE 3 RUNS.

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
SEPARATOR WATER FLASH
@ 0 PSIG & 76°F
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY (MOLE %)	WET (MOLE %)
WATER		15.04
CARBON DIOXIDE	35.03	29.76
NITROGEN	-----	-----
METHANE	62.95	53.48
ETHANE	1.64	1.39
PROPANE	0.33	0.28
ISO-BUTANE	0.02	0.02
N-BUTANE	0.03	0.03
ISO-PENTANE	0.00	0.00
N-PENTANE	0.00	0.00
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.9061	0.8616

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
5000 PSIA SAMPLE -
DIFFERENTIAL LIBERATION
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY (MOLE %)	WET (MOLE %)
WATER		2.60
CARBON DIOXIDE	5.19	5.06
NITROGEN	-----	----
METHANE	88.13	85.84
ETHANE	4.11	4.00
PROPANE	1.82	1.77
ISO-BUTANE	0.31	0.30
N-BUTANE	0.30	0.29
ISO-PENTANE	0.09	0.09
N-PENTANE	0.05	0.05
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6545	0.6536

GAS DEVIATION FACTOR (Z) = 1.0434 @ 5000 PSIA & 308'F

BBLS. GAS IN RES./MMSCF (Bg) = 804 @ 5000 PSIA & 308'F

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
3000 PSIA SAMPLE -
DIFFERENTIAL LIBERATION
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY (MOLE %)	WET (MOLE %)
WATER		2.82
CARBON DIOXIDE	2.75	2.67
NITROGEN	-----	-----
METHANE	91.86	89.28
ETHANE	3.55	3.45
PROPANE	1.35	1.31
ISO-BUTANE	0.22	0.21
N-BUTANE	0.21	0.20
ISO-PENTANE	0.04	0.04
N-PENTANE	0.02	0.02
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6193	0.6182

GAS DEVIATION FACTOR (Z) = 0.9724 @ 3000 PSIA & 308'F

BBLS. GAS IN RES./MMSCF (Bg) = 1,249 @ 3000 PSIA & 308'F

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
1000 PSIA SAMPLE -
DIFFERENTIAL LIBERATION
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY (MOLE %)	WET (MOLE %)
WATER		3.00
CARBON DIOXIDE	7.17	6.95
NITROGEN	-----	----
METHANE	89.54	86.86
ETHANE	2.51	2.43
PROPANE	0.62	0.60
ISO-BUTANE	0.07	0.07
N-BUTANE	0.06	0.06
ISO-PENTANE	0.02	0.02
N-PENTANE	0.01	0.01
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6449	0.6431

GAS DEVIATION FACTOR (Z) = 0.9682 @ 1000 PSIA & 308'F

BBLS. GAS IN RES./MMSCF (Bg) = 3732 @ 1000 PSIA & 308'F

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
15 PSIA SAMPLE -
DIFFERENTIAL LIBERATION
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

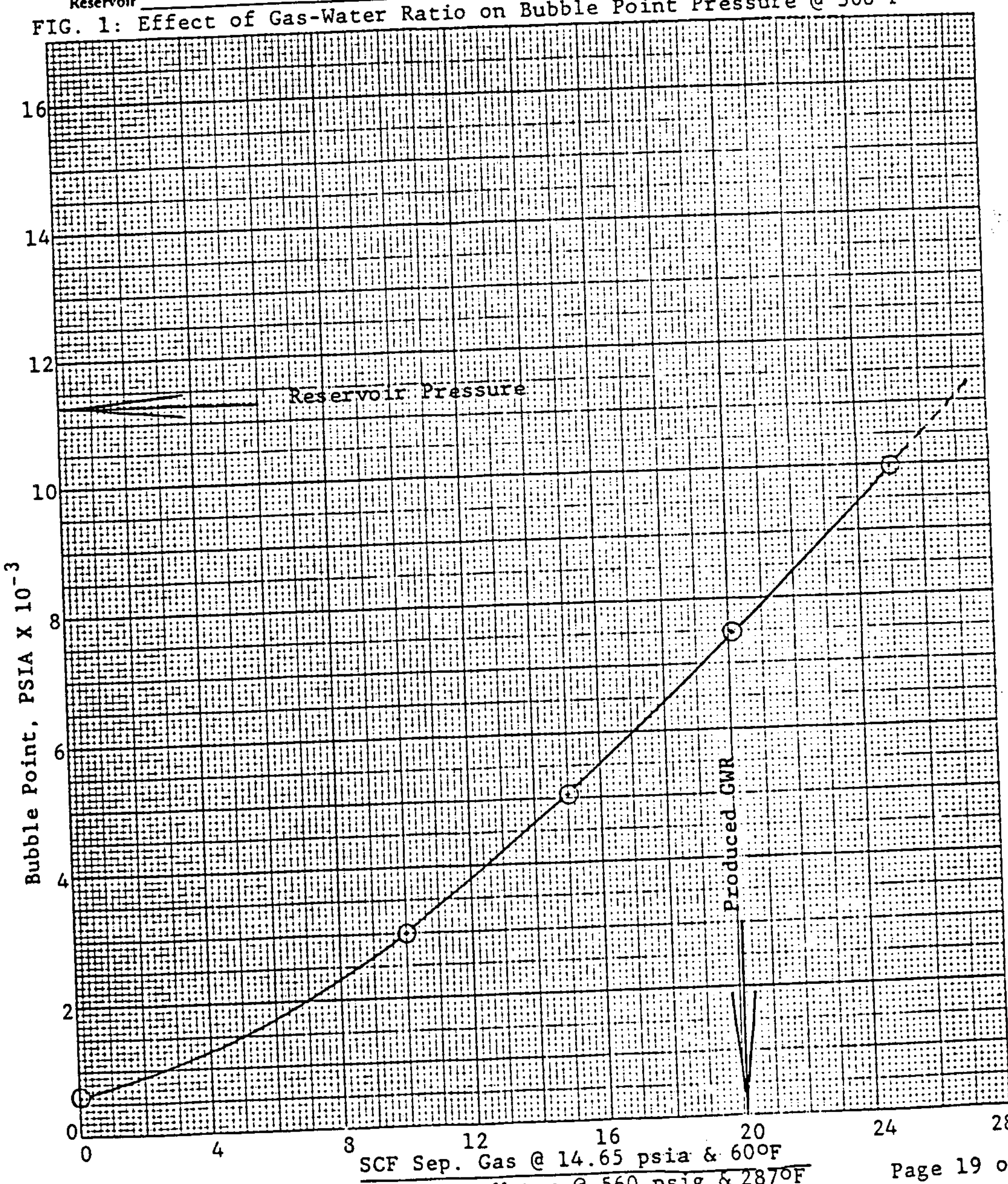
	DRY	WET
	MOLE %	
WATER		10.45
CARBON DIOXIDE	33.43	29.94
NITROGEN	-----	----
METHANE	64.15	57.44
ETHANE	2.00	1.79
PROPANE	0.30	0.27
ISO-BUTANE	0.05	0.04
N-BUTANE	0.04	0.04
ISO-PENTANE	0.02	0.02
N-PENTANE	0.01	0.01
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.8932	0.8630

GAS DEVIATION FACTOR (Z) = 1.000 @ 15 PSIA & 308'F

BBLS. GAS IN RES./MMSCF (Bg) = 263,081 @ 14.65 PSIA & 308'F

Company The Gruy Companies
Well Pleasant Bayou No. 2
Reservoir
Field Pleasant Bayou

FIG. 1: Effect of Gas-Water Ratio on Bubble Point Pressure @ 308°F

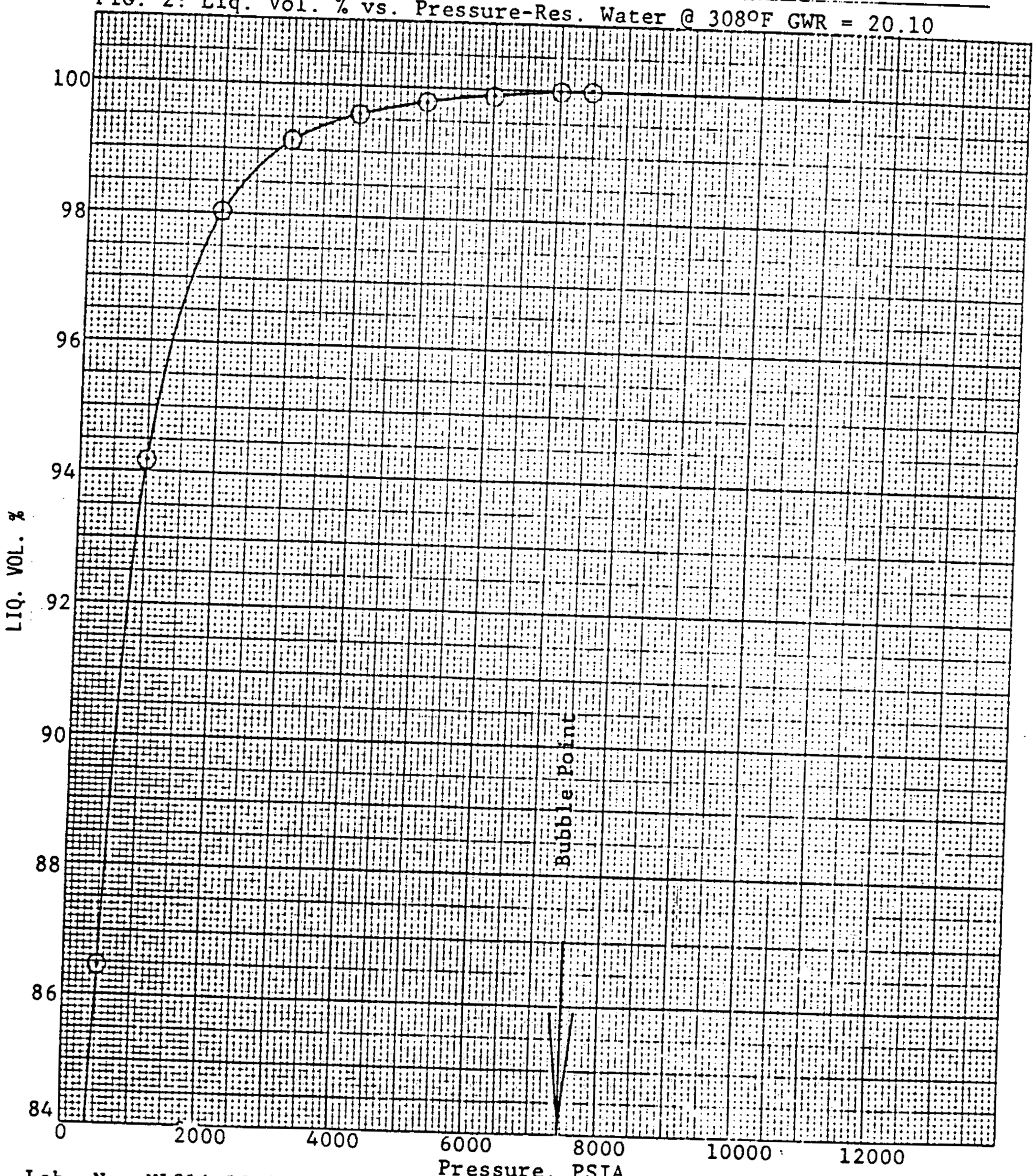


Page 19 of 24

LAB NO. N1814-10046

Company The Gruy Companies
Reservoir
Well Pleasant Bayou No. 2
Field Pleasant Bayou

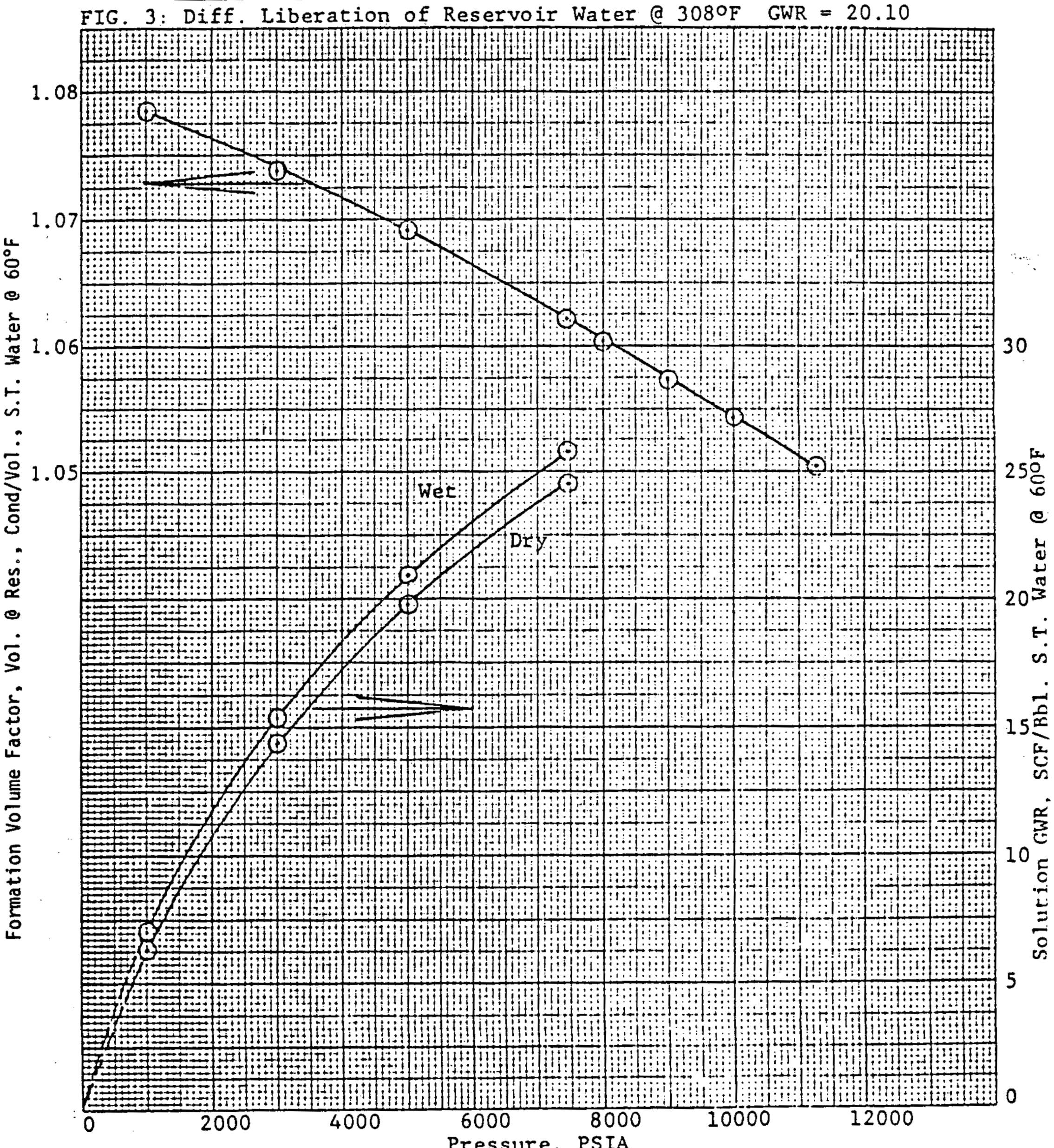
FIG. 2: Liq. Vol. % vs. Pressure-Res. Water @ 308°F GWR = 20.10



Lab. No. N1814-10046

Company The Gruy Companies Well Pleasant Bayou No. 2
Reservoir Field Pleasant Bayou

FIG. 3: Diff. Liberation of Reservoir Water @ 308°F GWR = 20.10

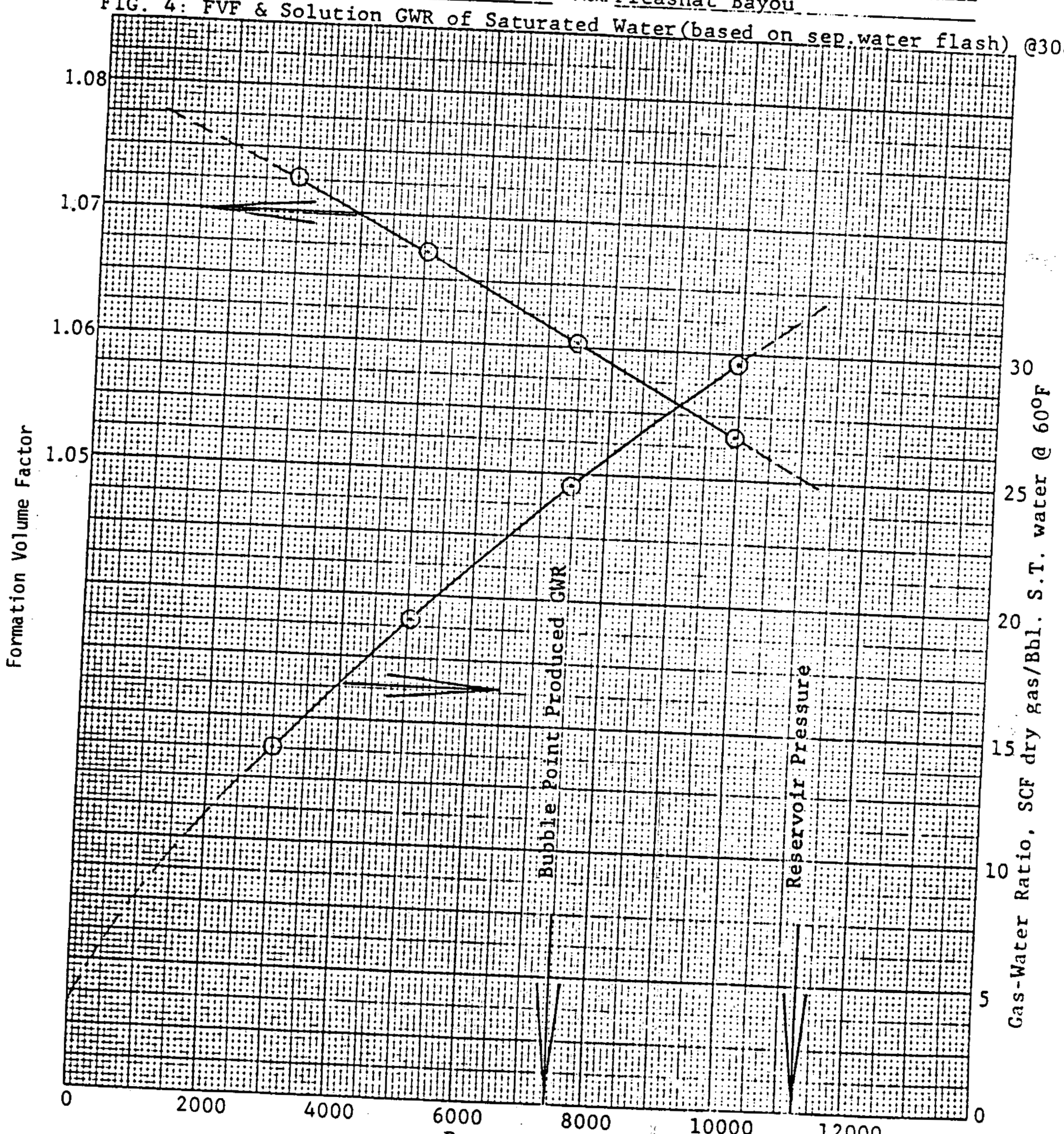


Lab. No. N1814-10046

Page 21 of 24

Company The Gruy Companies
Reservoir
Well Pleasant Bayou No. 2
Field Pleasnat Bayou

FIG. 4: FVF & Solution GWR of Saturated Water (based on sep.water flash) @308



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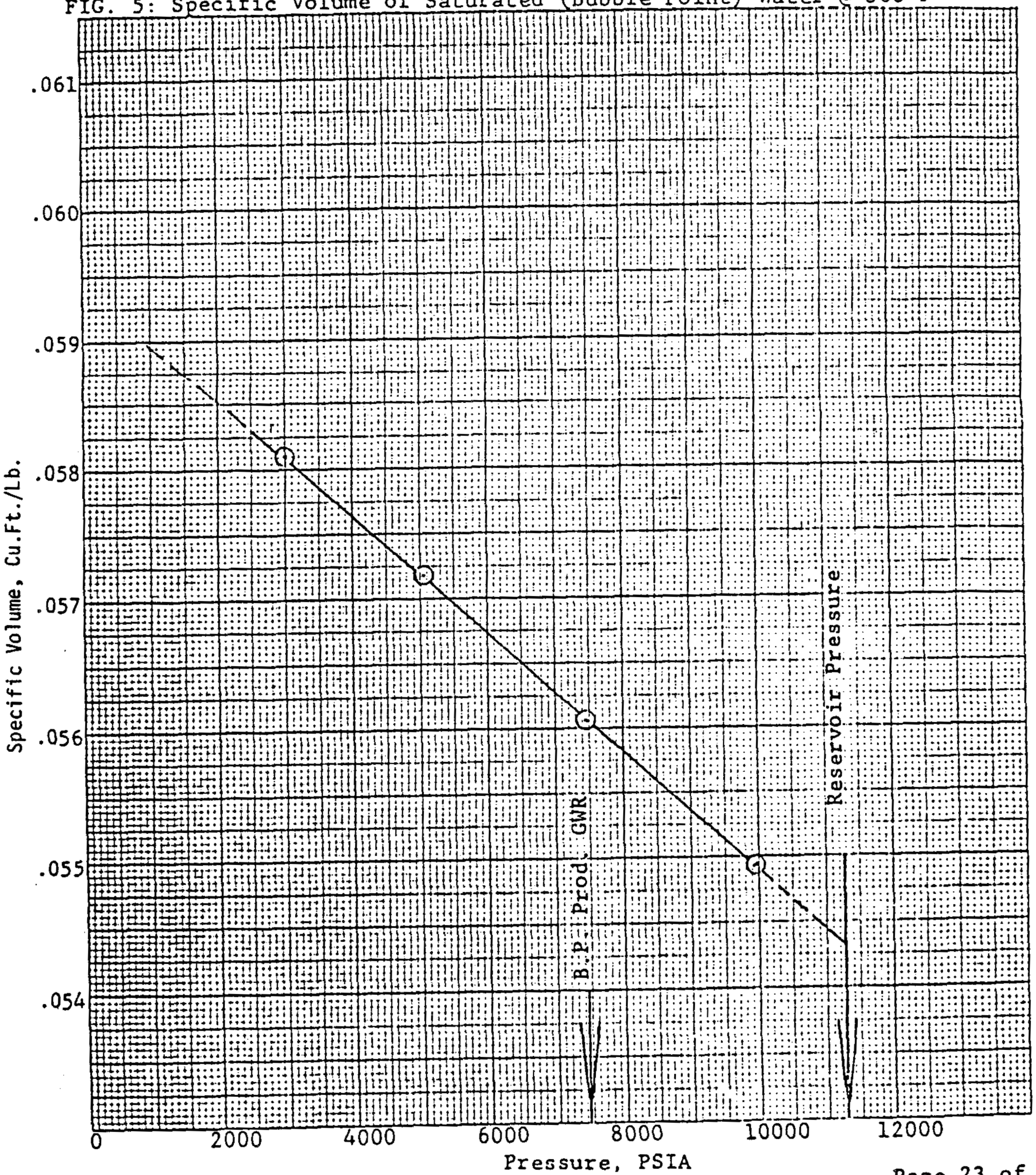
Company The Gruy Companies
Reservoir
Well Pleasant Bayou No. 2
Field Pleasant Bayou

FIG. 5: Specific Volume of Saturated (Bubble Point) Water @ 308°F



LAB NO. N1814-10046

Page 23 of 24