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Dr. 1463

DOE/ET/11395-18

GEOPRESSURED-GEOTHERMAL AQUIFERS

DOE/ET/11395--18

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DE84 001145

AUGUST 1983

Prepared for

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NEVADA OPERATIONS OFFICE
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I. EXECUTIVE SUMMARY

On June 26, 1978, a contract (ET-78-C-08-1557) was initiated between the Department of Energy (DOE) and INTERCOMP Resource Development and Engineering, Inc. Per the agreement, INTERCOMP would provide two major tasks:

- Task 1 - Provide petrophysical and reservoir analysis of wells drilled into geopressured-geothermal aquifers containing dissolved methane.
- Task 2 - Perform parametric analysis of massive hydraulic fracturing test data and engineering studies of the Western Gas Sands.

In April 1981, the contract was modified to extend the period of the contract from June 25, 1981 to December 31, 1982. In addition, the contract number was changed to DE-AC08-78ET11395. In December 1982, the contract was extended to June 30, 1983 (modification M002) and later extended to August 31, 1983 (modification M003). These last extensions were necessary to complete and evaluate pressure tests performed on the Gladys McCall Well Number 1.

Under Task 1, two types of wells were analyzed; Wells of Opportunity (WOO) and Design Wells. Wells of Opportunity are wells that had been drilled for oil and gas and were abandoned because of unproductivity. They provided a means to obtain relatively low cost short-term test data on geopressured-geothermal reservoirs. From these data, information such as reservoir performance and characteristics, wellbore characteristics, fluid chemistry and completion techniques were obtained.

Design Wells are wells which were drilled in areas identified as favorable prospects for geopressured-geothermal producers. The tests performed on these wells were normally longer and more detailed. Since these were new wells, well logs and core samples were taken and analyzed to obtain basic reservoir properties.

The Wells of Opportunity and Design Wells analyzed by INTERCOMP are listed in Table 1.1. They are wells located on the Gulf Coast of Texas and Louisiana. Figures 1.1 and 1.2 show their respective locations.

When requested, pretest simulation was performed to estimate reservoir boundaries prior to actual drilling and testing the design wells. Petrophysical analysis was performed by INTERCOMP on available well logs and core data to obtain porosity, permeability, saturation, and salinity data for all zones of interest. Pressure buildup and flow tests performed on each well were analyzed using standard reservoir engineering analysis. In addition, INTERCOMP's reservoir simulation model, BETA II, was used to simulate (i.e. history match) the reported pressure tests. This provided information on formation flow capacity, formation damage, wellbore characteristics, reservoir boundaries and porosity-thickness. When applicable, BETA II was used to project long-term production potential of the reservoirs. This included sensitivity runs on reservoir parameters which were believed to have the greatest influence on production behavior.

TABLE 1.1
ANALYZED WELLS

<u>WELL</u>	<u>TYPE</u>	<u>LOCATION</u>	<u>OPERATOR</u>	<u>ANALYSES</u>
Gladys McCall No. 1	Design	Cameron Parish, LA.	Technadril-Fenix & Scisson	Petrophysical Reservoir Analysis Predictions
Amoco Fee No. 1	Design	Cameron Parish, LA.	Magma Gulf-Technadril	Pretest Petrophysical Reservoir Analysis Predictions
Pleasant Bayou No. 2	Design	Brazoria County, TX.	Fenix & Scisson	Petrophysical Reservoir Analysis Predictions
Fairfax F. Sutter No. 2	WOO	St. Mary Parish, LA.	Gruy Federal, Inc.	Petrophysical Reservoir Analysis
G.M. Koelemay No. 1	WOO	Jefferson County, TX.	Eaton Operating Co., Inc.	Reservoir Analysis Predictions
P.R.Girouard No. 1	WOO	Lafayette Parish, LA.	Eaton Operating Co., Inc.	Reservoir Analysis Predictions
Crown Zellerbach No. 2	WOO	Livingston Parish, LA.	Eaton Operating Co., Inc.	Reservoir Analysis

Texas Geopressured-geothermal Fairways and Test Wells.

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

1-5

FIGURE 1.2

Louisiana Geopressured-geothermal Fairways and Test Wells.

II. INTRODUCTION

Task 1 of the contract is for INTERCOMP to provide petrophysical and reservoir analysis of wells drilled into geopressured-geothermal aquifers containing dissolved methane. The list of Design Wells and Wells of Opportunity analyzed by INTERCOMP under this contract are:

- Fairfax Foster Sutter No. 2 (WOO)
- Pleasant Bayou No. 2 (Design)
- Amoco Fee No. 1 (Design)
- G.M. Koelemay No. 1 (WOO)
- Gladys McCall No. 1 (Design)
- P.R. Girouard No. 1 (WOO)
- Crown Zellerbach No. 2 (WOO)

Petrophysical and reservoir analysis of the above wells were performed based on availability of data. The sections that follow will summarize the analysis performed on each well, the assumptions made during simulation, and conclusions reached.

III. FAIRFAX FOSTER SUTTER NO. 2

The completion and testing reports (Volumes I and II) for Fairfax Foster Sutter No. 2 were received by INTERCOMP in January 1980. The well was tested by Gruy Federal, Inc., under a separate contract to DOE. The well is located in St. Mary Parish, Louisiana, and was the first successful test of a geopressured aquifer under the DOE Wells of Opportunity program.

3.1 PETROPHYSICAL ANALYSIS

Prior to completion of the well, a suite of open hole logs was run from a depth of 13,289 feet to 16,348 feet. The program consisted of the following:

● Spontaneous potential	-	SP
● Gamma Ray	-	GR
● Compensated Formation Density	-	FDC
● Compensated Neutron Porosity	-	CNL
● Spherically Focused Induction	-	ISFL

Paper copies of the field prints were received by INTERCOMP's log analysis section. The digitized data from these curves was input to INTERCOMP's Shaly Sand Analysis. This program is a subset of the log analysis software package known as INTERLOG. Petrophysical properties derived from this analysis include gross sand, net sand, average porosity, average permeability, and water salinity. The calculated results are tabulated versus gross interval (from 15,000 feet to 16,199 feet) in Table 3.1.

The zone of interest was the geopressured lower miocene MA-6 sand which extended from 15,559 feet to 15,933 feet. Average properties calculated for this sand member are also presented in Table 3.1. The logs indicated a gross sand thickness of 374 feet with 346 feet of pay and 7 percent shale. In the text of the DOE report (Volume I), the gross thickness was given as 270 feet and a net of 190 feet, however, the shaded area indicating MA-6 sand on the SP log (p. 33 Volume

1) was in close agreement with INTERCOMP's interpretation. Also, in the petrophysics section of Volume I, the "test interval" was reported to contain 7.5 percent shale. This test interval resulted when the production packer jammed during completion causing all but 58 feet of the perforations (test interval) to become isolated from the production string. Over this 58 feet interval (15,781 feet to 15,839 feet), an average porosity of 16 percent and average permeability of 4.2 to 7.3 md were calculated.

Log calculated salinity of the reservoir water was given in Volume I to be 84K ppm NaCL. A subsequent measurement of a produced water sample yielded 190K ppm total dissolved solids. The Shaly Sand calculations gave salinities over the gross interval ranging from 111K to 157K ppm NaCL (Table 1).

Within reasonable limits, these log derived properties calculated by two independent sources were in good agreement. Some additional properties listed in Volume I and determined by direct measurement included original reservoir pressure (12,200 psi), original reservoir temperature (270°F) and gas solubility (22.8 feet/bbl).

3.2 RESERVOIR ANALYSIS

Following completion, several short flow periods were conducted to clean the wellbore and test the surface facilities. A Hewlett-Packard quartz crystal pressure gauge with surface readout was positioned in the wellbore at 13,865 feet. At the wellhead, a 10,000 psi deadweight tester was installed to measure the surface flowing and shutin tubing pressures. Liquid production from the separator was passed through digital readout turbine meters and the gas was measured with a orifice meter and Barton recorder. Most of these devices performed well throughout the test period. The HP gauge did not function continuously, but good pressures were taken during the second flow and second buildup. Scale deposition was found on the turbine meters and was traced to the high concentration of CO₂ in the produced field. However, during the second flow test, the fluid was treated with scale inhibitor and no further problems occurred.

A sequence of flow and buildup tests was conducted including a 3-day drawdown followed by a 6.5-day buildup, an 11-day drawdown followed by a final 19.8-day buildup. Variable production rates were encountered throughout both flow periods. The actual rates were measured hourly and are presented in Volume II. For our purposes, these data were averaged over time to reduce the number of rate changes. These average rates are shown in Table 3.2.

INTERCOMP's reservoir simulator, BETA II, was initialized with the petrophysical properties previously reported. The reservoir properties used in the study are shown in Table 3.3. Pressure-volume relationships of the produced gas-water mixture were taken from recombination studies of separator gas and liquid as reported in the PVT analysis section of Volume I. Using bubble-point pressure of 11,750 psi at the reservoir temperature of 270°F, the model was set up with no initial free gas in the reservoir. A single layer (58 feet thick) radial computation grid was designed with parallel linear barriers to flow at 850 feet from the well. The flow barriers were imposed to simulate the parallel fault configuration proposed by the given geological interpretation.

The averaged flow rates and the test time schedule were input to BETA II and runs were made to simulate the measured pressure responses at the well. The history match was focused on the second buildup test since the most reliable pressure data was collected during this period. With BETA II initialized as indicated above, the simulated pressures agreed qualitatively with the observed, but not a "history match". This history match resulted when the faults in the computation grid were moved to 650 feet. A plot of log time versus shutin pressure in Figure 3.1 reveals excellent correlation between the actual and simulated pressures.

As can be seen by the figure this modeling proves to be an accurate representation of the reservoir. All of the parameters of the model agree with previously documented information excluding the distance of the fault from the wellbore. This type of data concurrence proves the likeliness that this representation is an accurate one.

TABLE 3.1
PETROPHYSICAL ANALYSIS*
F.F. SUTTER WELL NO. 2
ST. MARY, LOUISIANA

<u>Gross Interval</u>	<u>Net Sand</u>	<u>Average Porosity (%)</u>	<u>Average Permeability (Geom.)</u>	<u>Average Permeability (Arith.)</u>	<u>Perm.-Ft. Darcy-Feet</u>	<u>Salinity PPM NaCL</u>
15000-15099	9	.1502	2.64	3.08	0.024	111,389
15100-15199	24	.1341	1.50	4.19	0.036	132,536
15200-15299	91	.1247	1.08	2.59	0.098	140,605
15300-15399	7	.0936	0.36	1.51	0.003	127,199
15400-15499	19	.0762	0.20	0.27	0.004	157,434
15500-15599	24	.0742	0.18	0.26	0.004	154,694
15600-15699	90	.1289	1.25	4.00	0.113	135,339
15700-15799	100	.1621	4.01	7.42	0.401	131,935
15800-15899	99	.1567	3.32	6.67	0.329	129,246
15900-15999	33	.1614	3.91	5.44	0.129	119,208
16000-16099	0	---	---	---	---	---
16100-16199	0	---	---	---	---	---
-----	--	---	---	---	---	---
15180-15304	111	.1263	1.14	2.89	0.127	135,472
-----	--	---	---	---	---	---
15406-15478	19	.0762	0.20	0.27	0.004	157,434
-----	--	---	---	---	---	---
15559-15933	346	.1457	2.26	5.63	0.782	130,598
15781-15839	58	.1631	4.16	7.33	0.241	129,273

* INTERCOMP's Shaly Sand Analysis

TABLE 3.2

**AVERAGE PRODUCTION RATES USED
IN F.F. SUTTER NO. 2 ANALYSIS**

<u>Day</u>		<u>Production Rate</u>
1		5560
2	FIRST DRAWDOWN	6080
3		5920
3 - 9.5		SHUT-IN
10		6980
11		6400
12	SECOND DRAWDOWN	6000
13 - 14		5780
15 - 20		5220
21		4870

TABLE 3.3

**F.F. SUTTER NO. 2
RESERVOIR PROPERTIES**

Water Density (Standard Conditions)	(GM/CM ³)	1.03
Water Compressibility	(1/PSI)	0.000003
Water Viscosity	(CP)	0.386
Gas Gravity (Density Relative to Air)		0.640
Rock Compressibility	(1/PSI)	0.000007
Reservoir Temperature	(°F)	270.0
Reservoir Thickness	(FT)	58.0
Porosity	(FRACTION)	0.19
Permeability	(MD)	14.0
Reservoir Size	(FT)	20,000

FIGURE 3.1
FAIRFAX FOSTER SUTTER NO 2
BUILDUP ANALYSIS

IV. PLEASANT BAYOU NO. 2

Pleasant Bayou No. 2 is a Design Well located in Brazoria County, Texas. The information provided for INTERCOMP included logs of the well and a report submitted by Mr. Donald Clark entitled "Pleasant Bayou Geopressured/Geothermal Test Wells, Austin Bayou Prospect, Brazoria County, Texas".

This report included all of the recorded drawdown and buildup data based on tests conducted between November 1979 and February 1980. In addition, it contained Mr. Clark's interpretation of the reservoir characteristics. Data from a subsequent test was received in October 1980. The test was a 45 day flow test that occurred in September 1980.

The well logs and the data from the different tests were the bases for the different analyses.

4.1 PETROPHYSICAL ANALYSIS

Prior to completing the well, a series of open hole logs were run covering a depth of 14,262 feet to 16,470 feet. The program consisted of the following:

- Dual Induction Focused
- Compensated Neutron-Formation Density
- Borehole Compensated Sonic

Copies of the field prints were received by INTERCOMP's log analysis section. The digitized data from these curves were input to INTERCOMP's Shaly Sand Analysis. This program is part of the log analysis software package known as INTERLOG. Petrophysical properties derived from this analysis included gross sand, net sand, average porosity, and water salinity.

The zone of interest was the geopressured Frio Sand which extended from 14,262 feet to 14,704 feet. The logs indicated a gross sand thickness of 62 feet with 60 feet of pay and 3 percent shale. With an 11 percent porosity cutoff, the analysis

calculated 54 feet of pay. Over this interval an average porosity of 15.8 percent (16.9 percent with the cutoff) was calculated. The porosity was in good agreement with other estimates reported for the well. Log calculated salinity of the reservoir water was 200,000 ppm. This information is shown in Table 4.1.

4.2 RESERVOIR ANALYSIS

4.2.1 First Analysis

The first analysis of this reservoir was based on a flow test conducted between November 1979 and February 1980.

Following completion of the well, three flow periods and their subsequent pressure buildups were conducted. The bottomhole pressure was monitored by a Hewlett-Packard pressure element. This was set at different depths throughout the test period due to problems that developed with it. A Panex surface recording gauge was attached to the wellhead to monitor surface pressure. The fluid flow was registered by a liquid turbine flow meter. The first drawdown was run for 2.7 days at which point, electrical contact was lost with the Hewlett-Packard gauge. The buildup following this drawdown lasted 4.9 days and brought the bottomhole pressure up to 11,273 psia. The next drawdown ran for 2.2 days when the signal with the Hewlett-Packard gauge was again lost. It was followed by a 8-day buildup. This brought the BHP up to 11,209 psia at 14,709 feet. At this point the third drawdown was begun. It was continued for 10.3 days and was followed by a 21-day buildup. Because of the problems that developed in the first two tests, they were not used as a basis for the reservoir analysis even though they were included in the simulation. This was done to better reproduce the actual sequence of events involved in the testing.

In order to perform the analysis on Pleasant Bayou No. 2, INTERCOMP's reservoir simulator BETA II was initialized with the petrophysical properties reported above, and the properties shown in Table 4.2. All of the drawdown and buildup test data were supplied with the previously cited report with one additional point being obtained later. The model was

initialized with no initial free gas in the reservoir. The reservoir itself was set up as a single layer (60 feet thick) radial computation grid. One case studied in this analysis had a partial barrier set up at a distance of 1,750 feet from the wellbore. This was used to simulate a inhomogeniety believed to be present in the reservoir. Another case observed combined this partial barrier with a total barrier located 9,000 feet from the well.

The pressure analysis was based on the data from the third drawdown test. The fluid flow rate during the drawdown was not constant. The simulator was given seven different rates to approximate the actual flow.

The pressure buildup following the ten (10) days flow is plotted on Figures 4.1 and 4.2. Figure 4.1 compares it to Case 1 while Figure 4.2 compares it to Case 2.

The reasons for the two cases had to do with the late time buildup pressures. The data is plotted as a "Horner Plot" which, according to ideal pressure buildup theory (Reference 4), should extrapolate to the initial reservoir pressure at the dimensionless time ratio of one if the well is located in an infinite, homogeneous, isotropic reservoir. The buildup pressures were measured at a depth of 14,600 feet. The initial pressure was measured to be 11,275 psia at 14,750 feet. After adjusting for the 15 foot elevation difference, the buildup pressures extrapolated to 11,243 psia at the dimensionless time ratio of one. This extrapolated pressure is 32 psi lower than the initial reported pressure. It is possible that this difference is due to either a calibration different or depth adjustment errors, or a combination of the two.

This was the assumption made in Case 1. Therefore, the 32 psi difference was added to all buildup pressures and the result was the corrected curve shown in Figure 4.1. This buildup curve has two straight line portions which indicates there is a flow barrier in the reservoir. If this barrier was of the linear sealing type, the slopes of the two straight line portions would have a ratio of two. However, this does not prove to be the case, the ratio is less than two. The way this phenomenon was simulated was as a

discontinuity of 1,750 feet from the wellbore with a transmissibility 0.15 times that of the reservoir, or 39 md. This can be physically visualized as a small fault with a throw of less than 60 feet leaving the reservoir rocks on either side continuous.

The pressure match using this method was extremely accurate with all calculated pressures within 3-5 psi of the observed values over 2 1/2 cycles of the time scale.

Several simulator runs were made to test the validity of the assumption for Case 1. From these runs, it is concluded that the pressure difference was not due to pressure depletion.

After Case 1 was completed an additional data point was obtained that measures a pressure of 11,243 psia at 14,750 feet. This indicated that the late portion of the buildup is beginning to curve upward. This trend is shown on Figure 4.2 and is the basis for Case 2.

This additional data point divided the curve into 3 distinct segments indicating that an additional reservoir modification was needed. For this, a sealing radial boundary was added at a distance of 9,000 feet from the well. It covered 180 degrees. The partially sealing fault used in Case 1 was left in-tact. It was found that a reduction in porosity to 15 percent was needed to get the proper pressure buildup. This value is more consistent with the one obtained in the petrophysical analysis.

The main conclusion that can be drawn from this work was that the flow test was not long enough to clearly define any reservoir limits. If the pressures are accurate to $\pm$ psi, a barrier of some type was encountered, but probably only in one direction.

4.2.2 Second Analysis

The analysis for this reservoir was based on a flow test conducted for 45 days beginning in September 1980. At the start of the test the reservoir

had reached an equilibrium pressure of 11,115 psia. The drawdown was conducted for 1,089 hours with the rates varying five times during the test. The well was then shutin allowing for a buildup in excess of 40 days.

The analysis was conducted using BETA II initialized with the petrophysical data previously reported and the reservoir parameters shown in Table 4.2.

These values represented a revision from previous studies in that the total compressibility in the reservoir had been changed from 9×10^{-6} to 4×10^{-6} . This change was in response to a consensus of all investigators (Geopressured Test Analysis Committee, December 1980) in the program.

With this information, the simulator was run according to the test period. The well was flowed for 128 hours at 6,624 BPD, 229 hours at 10,896 BPD, 84 hours at 19,200 BPD, 10 hours at 15,300 BPD, and 638 hours at 13,286 BPD for a total of 1,089 hours. The bottomhole pressures for these drawdowns are shown in Figure 4.3 along with the simulated pressures achieved.

In the process of reproducing these drawdown rates an interesting discovery was made. To get the desired pressures, a variable skin had to be used. It was found that this skin increased linearly with the square of the flow rate. This correlation is shown in Figure 4.4.

At the end of the flow period the well was shutin and the pressure allowed to build for a 40 day plus period. These pressures are shown in Figure 4.5. To make this match it was found that two fault zones existed in the reservoir. The first, which is semi-restrictive to flow, was located 1,750 feet from the wellbore. The second which was sealing was 9,000 feet from the well. The buildup also indicated that there was loss of reservoir transmissibility that increased with distance from the well. Until this characteristic was included in the reservoir, the simulated pressure buildup was consistantly 30 psi higher than the actual data. It was found that this restriction increased gradually to a point where the transmissibility was only 35 percent of the value near the wellbore at 17,000 feet. This could

be due to a reduction of the sand height causing a reduced kh value or some other heterogeneity. There was no pressure data indicating a reservoir limit, had been reached. Once the buildup curve begins to flatten out the limit can be determined. The distance to the edge of the reservoir is at least 40,000 feet.

4.3 PREDICTIONS

Once the history match was completed, a sensitivity analysis was performed to determine the deliverability of the well. All the reservoir characteristics were left unchanged, a tubing head pressure of 1,000 psi was used, and the well was flowed at 40,000 BPD to estimate its capacity. The results of this run are shown in Figure 4.6. The well made the 40,000 barrels for a short time but then dropped off with time. The gas production followed in stride with the water production.

TABLE 4.1
PETROPHYSICAL ANALYSIS*
PLEASANT BAYOU NO. 2
BRAZORIA COUNTY, TEXAS

	<u>INTERVAL</u>	<u>NET POROUS SAND</u>	<u>AVERAGE POROSITY</u>	<u>FM. WATER SALINITY</u>
(1)	14642-14704	60'	.581(.0404-.2358)	200,000 ppm
	Net Porous Sand:	Vshgr < 40%		
		> 0%		
(2)	14642-14704	54'	.1690(.11-.2358)	200,000 ppm
	Net Porous Sand:	Vshgr < 40%		
		> 11%		

* INTERCOMP's Shaly Sand Analysis

TABLE 4.2

**PLEASANT BAYOU NO. 2
RESERVOIR PROPERTIES**

Water Density (Standard Conditions)	(GM/CM ³)	1.03
Water Compressibility	(1/PSI)	0.000003
Water Formation Volume Factor	(RB/STB)	1.035
Water Viscosity	(CP)	.365
Gas Gravity (Density Relative to Air)		0.640
Rock Compressibility	(1/PSI)	0.000007
Reservoir Temperature	(DG F)	300.
Stock Tank Oil Density	(GM/CM ³)	1.000
Standard Pressure	(PSIA)	14.650
Standard Temperature	(DG F)	60.00
Initial Date		November 15, 1979
Reservoir Thickness	(FEET)	60
Porosity	(FRACTION)	.176
Permeability	(MD)	260

FIGURE 4.1

PRESSURE BUILDUP CASE 1

PLEASANT BAYOU NO 2

FIGURE 4.2
PLEASANT BAYOU NO. 2
PRESSURE BUILDUP CASE 2

FIGURE 4.3
PLEASANT BAYOU NO. 2
MULTI RATE DRAWDOWN

FIGURE 4.4
PLEASANT BAYOU NO. 2
FLOW SKIN RELATIONSHIP

FIGURE 4.5
PLEASANT BAYOU NO. 2
BUILDUP ANALYSIS

FIGURE 4.6
PLEASANT BAYOU NO. 2
SENSITIVITY ANALYSIS

V. AMOCO FEE NO. 1

Amoco Fee No. 1 is a Design Well located in Cameron Parish, Louisiana. The operators who drilled, completed, and tested the well were Magma-Gulf/Technadril. Prior to testing the well, sensitivity and pretest simulation runs were made on the well to estimate potential deliverability and reservoir limits. Petrophysical analysis was performed on the logs and core samples taken prior to well completion. Once the tests had been run they were analyzed by hand and simulated using BETA II. Crossflow cases and production scenarios were run to determine the possibility of obtaining uncontaminated samples from other sands and to determine the maximum producibility of the well over a period of time.

5.1 PRETEST ANALYSIS

In September 1980, prior to actually testing the well, a sensitivity analysis was performed on the Magma-Gulf Design Well (Amoco Fee No. 1) to determine potential deliverability. In the first part of this study, INTERCOMP's VFLOW simulator was used to determine the bottomhole flowing pressures that would be required to produce the well at different rates. These results are shown in Figure 5.1. The lower curve is based on 1,000 psia tubing head pressure and 15,700 feet of 5-1/2 inch casing. As can be seen in the graph, a pressure differential of about 9,800 psi is needed to produce 40,000 BPD and 12,000 psi is required for 60,000 BPD.

In the second part of this same pretest study, INTERCOMP reservoir simulator, BETA II, was used to predict a deliverability for the well over a ten day period. The results are shown in Figure 5.2. The major assumption made in this analysis was a low reservoir pressure of 10,000 psia. This and other values used for the study are shown in Table 5.1. Based on these values, 15,700 feet of 5-1/2 inch tubing and a wellhead pressure of 1,000 psia, the well should produce around 36,000 BPD over the ten day period.

In October 1980, another pretest study was performed to determine whether or not the proposed drawdown and buildup test program would accurately define the reservoir and its limits.

Prior to starting this study, INTERCOMP's reservoir simulator, BETA II, was initialized with the basic reservoir properties used in previous studies. Then a grid system for Case 1 was developed. Case 1 was constructed to display the performance of an ideal homogeneous reservoir. The grid was cylindrical in form, surrounded the wellbore and was one dimensional in the radial direction with a thickness of 100 feet. The outer limit of the reservoir was set at 100,000 feet because at that size, the reservoir behaves infinitely. The simulator was run according to the purposed test schedule shown in Table 5.2. An initial flow period of three days was run at 2,400 BPD and the well was shut in for five days to allow the pressure to build back up. The reservoir limit test was then conducted by flowing the well at 20,000 BPD for 60 days and then shutting it in for 120 days. It performed as would be expected for a homogeneous infinite reservoir. Both were straight lines on a semi-log paper with the buildup curve extrapolating back to initial reservoir pressure on a Horner Plot.

It was known, however, that this reservoir probably would not behave homogeneously. In fact, as can be seen in Figure 5.3 the well is located in the vicinity of large fault zones. Some of the facts are known to exist but there are other areas that could possibly be faulted also. In order to simulate these heterogeneities, modifications had to be made to the grid system used in Case 1. Figure 5.4 shows the changes that were made. First, the known fault zones were traced onto the grid system. Then coordinates were added in the angular direction at varying degrees to approximate the faults. Finally, the areas representing the faults were made impermeable to flow. Two cases were run under these conditions. Case 2 approximated the faults known to be present in the reservoir. Case 3 added to those faults the one that could be present.

Both cases were run with the same test periods as Case 1. The results were quite different from Case 1 with the drawdown curving downward at the end and the buildup curving upward defining the faults in close proximity to the well. However, there was no difference between Case 2 and Case 3 indicating that the test was not long enough to define that area of the reservoir. If the buildup was allowed to continue long enough, a small amount of depletion would be noted for Case 3.

Case 2 and Case 3 were then run again extending the second drawdown period to 260 days and then shutting the well in for 300 days. The results of the drawdown are shown in Figure 5.5. As can be seen, the two cases were identical until past 100 days when the pressure in Case 3 began to deplete more rapidly. The buildup portion of this study is shown in Figure 5.6. This Horner Plot shows the most noticeable difference that was seen when the fault is present as in Case 3 or not. If the zone is open ended as in Case 2, and has contact with the rest of the reservoir, the pressure will continue to build and the Horner Plot will extrapolate back to the initial reservoir pressure. If the reservoir is closed off, as in Case 3, there will be no flow to replenish the depleted pressure. Therefore, the region will just reach an equilibrium pressure and will not reach its original level.

Due to the results found in this analysis, it was determined that the length of the reservoir limit test should be extended from the proposed 60 days. It was estimated that the drawdown should be run for at least 200 days or it would never be determined whether there is a fault present or if the well is in contact with the rest of the reservoir.

5.2 PETROPHYSICAL ANALYSIS

Amoco Fee No. 1 was drilled and completed in the Miogypsinoides Sands of the Camerina Zone of the Upper Frio Formation. These sands are found between depths of 15,000 and 15,640 feet in the well.

Prior to perforating the well, a series of logs were run from a depth of 15,062 to 15,735 feet. The logging process consisted of the following:

- Dual Induction - SFL - Sonic
- Gamma Ray
- Compensated Formation Density

In addition, four core samples were tested and results were reported to INTERCOMP. The available data was used to derive petrophysical properties of all sand intervals penetrated by this well. Table 5.3 shows the petrophysical

properties of seven sand zones. Zone 5 has the highest hydraulic capacity of 79,920 md-ft. and average porosity of nineteen percent. This fifty-seven foot sand has a net thickness of twenty-seven feet and an average air permeability of 2,960 md. The attractive characteristics of this zone made it a candidate for the flow tests which was performed in June 1981.

5.3 RESERVOIR ANALYSIS

Following completion of the 5th sand, the initial drawdown test was performed. This test was followed by a buildup and a second drawdown.

5.3.1 First Drawdown

The first flow test commenced on June 19 and was stopped on June 22, 1981. The total production was 10,574 barrels of formation brine over a period of 3.03 days. The total gas/water ratio was 10.7 scf/bbl. Sand face pressure was recorded using a Hewlett-Packard downhole pressure gauge. The initial reservoir pressure was 12,062 psia at a reservoir temperature of 299°F. Figure 5.7 shows the early time pressure drawdown plot of the first flow test. From this plot a KH value of 9,161.1 md-ft. was calculated. This KH value determined a 393.3 md permeability for the formation. There were two changes in slope of the curve from 22 psi/cycle to 44 and to 165 psi/cycle. These changes indicated two faults at distances of 452 and 1,753 feet from the wellbore. However, based on calculation of reservoir barrels in place, it was found that the two faults should be closer to the well. It was decided to place these faults at a distance of 250 feet from the wellbore in INTERCOMP's BETA II Simulator. These are shown in Figure 5.8. Other reservoir parameters used in this simulation study are shown in Table 5.4. Figure 5.9 shows the result of the first drawdown history match simulation.

5.3.2 First Buildup

The well was shutin at 7:57 PM on June 22, 1981, and pressure buildup measurements recorded. The final flowing pressure was 11,141 psia. The

fact that the average production rate was below 2,500 BPD and that the pressure was increasing at the time the well was shutin effected the rate of pressure buildup that is plotted on Figure 5.10. The pressure difference from the initial instrument pressure of 12,053 psia, at a datum of 15,337 feet, and the final flowing pressure was 912 psi.

The initial buildup slope was 17.6 psi per cycle, with a final prior flow rate of 2,820 BPD. This slope gave a KH value of 10,764.3 md-ft. and a permeability of 398.7 mds. This was a higher value than that interpreted from the original flow test and was due to the pressure building up during the final flow period, thus reducing the slope expected when shutin.

5.3.3 Second Flow Test

After eight days of shutin, the well was opened to flow on June 30, 1981. The plan for this test was to produce the well at a rate of 15,000 BPD until reservoir limits were detected or twenty days, whichever came first. The period of this test was less than four days. Numerical simulation of the second flow test was performed using the BETA II Simulator. Figure 5.11 shows the second drawdown test and the simulated data. It was found that, using the same reservoir parameters as in the first drawdown simulation, the angle of flow should be reduced. The 60° angle of flow did not provide a match at the later part of the second flow test, therefore, a 26° angle was tried and the match in Figure 5.11 was obtained. The corresponding new reservoir parameters are shown in Table 5.4.

5.4 PREDICTIONS

5.4.1 Crossflow Case - Sands 5 and 6

The undersaturated solution gas ratio in the 5th sand zone made it desirable to test the 6th sand zone and determine the gas content. However, the cost of squeezing the upper zone off prior to perforating the lower zone made that method unacceptable. Therefore, INTERCOMP was asked to determine if it was feasible to deplete the upper zone to a point

where, when perforated, the lower zone would flow long enough for a fluid sample to be taken which would not be mixed with flow from the upper zone. Figure 5.12 shows a schematic of the radial grid system used to evaluate various perforation scenarios.

Prior to perforating the 6th sand zone, the well would flow at a low rate or be shutin in order to modify measurement equipment and set the perforating gun at depth. Then the 5th sand would be drawn down to a low pressure, 8,000 - 9,000 psia, prior to perforation as shown for several cases on Figure 5.13.

The objective of the simulation scenarios, however, was to determine how long flow could be expected exclusively from the lower zone with crossflow into the upper zone given different bottomhole pressures at the time of perforation and different surface flow rates after perforation. To do this, BETA II was run with the same reservoir parameters used to match the second flow test for the 5th sand, and a lower zone was added that was 30 feet thick with a permeability of 26 md. and a porosity of 15 percent. With this reservoir description, the upper zone was drawn down to the desired bottomhole pressure, the lower zone was perforated, and the well was turned on for a specified rate at the surface while crossflow occurred between zones at the bottomhole. The initial bottomhole pressures tested were 7,929 psia, 9,121 psia, and 9,959 psia. For each of these initial pressures, surface flow rates of 500, 1,000, 1,500 and 2,000 BPD were tested. In each case the time required for the upper zone to begin flowing into the wellbore was noted and the results are shown in Figure 5.14. Bottoms-up time at a surface rate of 1,000 BPD was estimated to be about 8 hours.

These results indicated that it will be possible to obtain exclusive flow from the lower zone for a period long enough to get a fluid sample to the surface. The test time was found to be sensitive to surface flow rate due to the expected relative tightness of the lower zone compared to the upper zone. Therefore the lower zone draws down in pressure more quickly with higher rate and allows flow from the upper zone to begin sooner with higher rate.

Another consideration was whether or not the perforating gun would be launched up the hole as a result of the high pressure difference between the wellbore and the virgin 6th sand. Based upon a reservoir KH of 780 md-ft. and a reservoir pressure of 12,200 psia, the initial radial flow was expected to be about 9,300 BPD at a bottomhole pressure of 9,000 psia. This corresponds to a wellbore velocity of about 6 ft/sec. Schlumberger reported that their gun could withstand a velocity of 7.4 ft/sec. without weights and 9.3 ft/sec. with one weight added. Based on this analysis, it appeared feasible to perforate and obtain a suitable sample.

5.4.2 Production Scenarios

In September 1981, Magma-Gulf requested INTERCOMP to predict the maximum producible rate that could be maintained for one year at a fixed tubing head pressure of 750 psia. This simulation study of Amoco Fee No. 1 covered three cases:

- Single sand layer from 15,385' to 15,415'
- Two sand layers from 15,305' to 15,415'
- Five sand layers from 15,080' to 15,415'

The sand layer in Case 1 was the only perforated interval at that present time. This layer was modeled and history matched using INTERCOMP's BETA II Simulator. Table 5.5 summarizes the information for all the layers used in this study.

Listed below are the assumptions that were made during the simulation.

- Interblock vertical transmissibilities were set at zero because there had not been any evidence of vertical communication and because the sand layers were reported to be separated by layers of shale.
- The sand barriers (Faults) modeled for the one-layer case that had been history matched before, were assumed to extend vertically throughout the entire reservoir.

- The permeability values shown in Table 5.5 were originally from logs but were scaled based on a 260 md permeability value for the 5th layer obtained from the history match.

Several runs were made for each case with a fixed tubing head pressure of 750 psia and different production rates for more than a year. The maximum time that each rate could be maintained were defined, and a curve of rate versus maximum time of fixed rate were plotted for each case.

Figures 5.15 through 5.17 show the plots of Qmax versus time for Cases 1 to 3, respectively. The rounded off numbers for production rates are presented in Table 5.6 for the different cases. The degree of reliability of the results for Cases 2 and 3 rested upon the accuracy of the input data and validity of the assumptions made since there was no production history for Layers 1 to 4. However, it should be mentioned that numbers in Table 5.6 are conservative figures representing the results.

5.4.3 Crossflows Case - Sand 4 and 5

The objective of this study was to predict the feasibility of obtaining an uncontaminated sample of the 4th sand at the surface for testing purposes. The 4th sand interval had the highest permeability value after Sand 5, having an estimated hydraulic capacity of 18,750 md-ft. The sand zone was one of the candidates to be perforated and tested next. The following restrictions were made:

- Flow rate from Sand 4 must be greater than 2,000 BPD.
- Sand 5 would not interfere with the production until enough volume of Sand 4 fluid could be produced at the surface.

In order to produce the 4th sand while preventing the flow of the 5th interval, the following relationship must exist:

$$P_4 > P_{BH} > P_5$$

where:

P_4 = The following pressure at the 4th sand zone

P_{BH} = Bottomhole pressure

P_5 = The following pressure at the 5th sand zone

This assumed that P_{BH} can be controlled by controlling the tubing head pressure based on the following relationship:

$$P_W = P_{BH} - (P_f + P_h)$$

where:

P_W = Surface pressure

P_f = Pressure lost due to friction

P_h = Pressure lost due to hydrostatic head

Having the above relationship meant that a portion of the production from the 4th interval will be injected into the 5th sand. The volumes of production and leak off depends on the pressure differences between the bottomhole pressure and the two open sand intervals.

The initial pressure at Zone 4 was 12,000 psi. Therefore, Sand 5 should be produced to a pressure level low enough to allow sufficient time for production of the new zone before pressure equilibrium is reached between the 5th sand and P_{BH} . Needless to say, the greater the pressure difference between P_{BH} and the pressure at Sand Zone 5, the more production time for the top sand (Zone 4) before contamination. Four different cases were simulated to predict the results. They are summarized below:

- Case 1 = Production of 5th sand at 3,000 BPD to stabilize its pressure around 10,500 psi. Perforate Sand 4 and maintain P_{BH} at 11,000 psi.

- Case 2 = Production of 5th sand at 12,000 BPD to stabilize pressure around 8,000 psi. Perforate Sand 4 and maintain P_{BH} at 8,500 psi.
- Case 3 = Same as Case 2 except P_{BH} was set at 9,500 psi.
- Case 4 = Same as Case 2 except P_{BH} was set at 10,500 psi.

Figure 5.18 shows the results from Case 1. Three plots on this figure represent the total production rate from the 4th interval, the leak off rate (from 4th sand into the 5th sand) and the net production rate from Sand Zone 4. The time "t", when the leak off rate equals zero, is the beginning of flow from Sand Zone 5. Therefore, from this point on a mixture of brine was produced from both intervals.

In this case, $t = 4.2$ hours. The net production rate changed from 2,400 to 4,300 BPD. Using an average net production rate of 3,350 BPD for 4 hours resulted in a production of 586 barrels of water from Zone 4 before it was contaminated with the flow from Sand Zone 5.

The 2nd and 3rd cases did not provide enough time to produce Zone 4 alone. The problem here was due to the pressure difference between P_{BH} and P_5 (pressure at Sand Zone 5). In these two cases where the pressure differences are 500 and 1,500 psi, the 5th Zone built up so fast that in a very small time interval it equaled the imposed p_{BH} and therefore, started flowing along with the Sand 4.

The 4th case, yielded a better result. Figure 5.19 shows plots of total production rate from Zone 4, leak off rate into the 5th sand and the net production rate from Zone 4. In this case, $t = .87$ days (when Zone 5 started to flow into the wellbore). The total uncontaminated production at this time was around 2,800 barrels of formation brine. This volume should be large enough to fill the wellbore and be produced at the surface for testing purposes.

It was observed that further increasing of P_{BH} seemed to delay production of the 5th sand; however, it also limited the production rate of the 4th sand and decreased the net volume recovered from this zone.

TABLE 5.1
AMOCO FEE NO. 1
RESERVOIR PROPERTIES

Water Density	(GM/CM ³)	1.03
Water Compressibility	(1/PSI)	.000003
Water Formation Volume Factor	(RB/STB)	1.035
Water Viscosity	(CP)	.386
Gas Gravity (Density Relative to Air)		.640
Rock Compressibility	(1/PSI)	.000007
Reservoir Temperature	(°F)	300.
Reservoir Thickness	(FT)	100
Porosity	(FRACTION)	.22
Permeability	(MD)	260.
Initial Reservoir Pressure	(PSIA)	10,000
Reservoir Depth	(FT)	15,700

TABLE 5.2
AMOCO FEE NO. 1
PROPOSED TEST SCHEDULE

<u>Test Period</u>	<u>Test Duration</u>	<u>Cumulative Test Time</u>	<u>Test Rate (BPD)</u>
Initial Test	3 Days	Day 3	2,400
Shutin	5 Days	Day 8	0
Reservoir Limit Test	60 Days	Day 68	20,000
Shutin	120 Days	Day 188	0

TABLE 5.3
AMOCO FEE NO. 1
PETROPHYSICAL PROPERTIES OF SAND INTERVALS

<u>Sand Depth</u>	<u>Net Sand</u>	<u>Average Porosity</u>	<u>Average Permeability</u>	<u>Hydraulic Capacity md-ft.</u>	<u>Percent Hydraulic Capacity</u>
15080-15144	41'	12.3	175	7,175	4.77
15170-15240	42'	12.1	143	6,006	3.99
15250-15285	27'	15.4	700	18,900	12.57
15305-15355	25'	15.3	750	18,750	12.47
15385-15415	27'	19.0	2960	79,920	53.16
15460-15505	41'	12.2	130	5,330	3.54
15520-15600	51'	12.9	280	14,280	9.50
TOTAL	254'			150,361	100.00

TABLE 5.4
AMOCO FEE NO. 1
RESERVOIR PARAMETERS USED IN BETA II
SIMULATOR TO HISTORY MATCH THE FIRST AND SECOND DRAWDOWN TESTS

	<u>First Test</u>	<u>Second Test</u>
Permeability, md	260	260
Porosity, percent	20	20
Net Thickness, feet	27	27
Graben Angle, degrees	60	26
Initial Pressure, PSI	12,053	11,974
Initial Temperature, degrees	299	299
Bubble Point, PSI	2600	2600
Total Compressibility, 1/PSI	4×10^{-6}	4×10^{-6}

TABLE 5.5
AMOCO FEE NO. 1
PARAMETERS USED IN PRODUCTION SCENARIOS

<u>Sand Layer</u>	<u>Interval</u>	<u>Feet Net Thickness</u>	<u>Average Porosity</u>	<u>Average Permeability</u>
1	15080-15144	41	12.3	15.37 md.
2	15170-15250	42	12.1	12.56 md.
3	15250-15285	27	15.4	61.48 md.
4	15305-15355	25	15.3	65.88 md.
5	15385-15415	27	19.0	260.00 md.

Initial Reservoir Temperature at 15385' = 299°F

Initial Reservoir Pressure at 15385' = 12052 PSI

TABLE 5.6
AMOCO FEE NO. 1
PRODUCTION RATES

<u>Case No.</u>	<u>QMAX</u>
1	6900 BPD
2	9100 BPD
3	12100 BPD

Maximum fixed production rate for one year with 750 PSI THP.

FIGURE 51
AMOCO FEE NO. 1
BOTTOM HOLE FLOWING PRESSURE
(WELL HEAD PRESSURE = 1000 PSIA)

FIGURE 5.2

AMOCO FEE NO. 1

WELL DELIVERABILITY AGAINST 1000 PSIA WELLHEAD PRESSURE

FIGURE 5.3
POSSIBLE FAULT ZONE
AMOCO FEE NO. 1

⊙ WELL LOCATION
--- POSSIBLE FAULT

AMOCO FEE NO.1

FIGURE 5.4

--- ACTUAL FAULT ZONE

▨ CASE 2 FAULT APPROXIMATION

▩ CASE 3 ADDITIONAL FAULT ADDED

FIGURE 5.5

PRETEST ANALYSIS - DRAWDOWN
AMOCO FEE NO. 1

FIGURE 5.6

AMOCO FEE 300 DAY BUILDUP

FIGURE 5.7
AMOCO FEE NO. 1
EARLY TIME DRAW-DOWN ANALYSIS

FIGURE 5.8

AMOCO FEE GEOPRESSURED-GEOTHERMAL WELL
FAULT LOCATIONS AND MODEL GRID

FIGURE 5.9
AMOCO FEE NO. 1
FIRST DRAWDOWN ANALYSIS

AMOCO FEE NO. 1
FIGURE 5.10
BUILDUP FOLLOWING FIRST DRAWDOWN

FIGURE 5.11
AMOCO FEE NO. 1 WELL
SECOND DRAW-DOWN TEST

FIGURE 5.12
CROSSFLOW AFTER LOWER
ZONE PERFORATION
AMOCO FEE NO. 1

FIGURE 5.13
SHUT-IN/DRAWDOWN SENARIOS
(FOLLOWING 20 DAY TEST)
AMOCO FEE NO. 1

FIGURE 5.14

CROSSFLOW SENARIOS UPPER ZONE TIME OF PRODUCTION
AMOCO FEE NO. 1

FIGURE 5.15
AMOCO FEE NO.1

FIGURE 5.16
AMOCO FEE NO. 1

FIGURE 5.17
AMOCO FEE NO. 1

AMOCO FEE NO. 1

FIGURE 5.18

TOTAL PRODUCTION RATE, LEAKOFF
AND NET PRODUCTION RATE FOR THE 4TH SAND
UNDER THE FOLLOWING CONDITIONS

- Pressure at Zone 5 Prior to Perforation of Zone 4 10500 PSI
- P_{BH} 11000 PSI

AMOCO FEE NO. 1

FIGURE 5.19

**TOTAL PRODUCTION RATE, LEAKOFF
AND NET PRODUCTION RATE FOR THE 4TH SAND
UNDER THE FOLLOWING CONDITIONS**

- Pressure at Zone 5 Prior to Perforation of Zone 4 8000 PSI
- P_{BH} 10500 PSI

VI. G.M. KOELEMAY NO. 1

Koelemay No. 1 is a Well of Opportunity located about nineteen miles west of Beaumont, Texas in the Doyle Field. The well was drilled and completed on March 19, 1980 by Lear Petroleum, Inc. As the well was recognized a dry hole, Eaton Operating Company took it over under a geopressured contract with DOE. Koelemay No. 1 Well was tested in the Leger Sand of the Yegua Formation of the mid Eocene age. Figures 6.1 and 6.2 show the structural map and a north-south cross section of the formation, respectively.

The tested sand interval was from 11,639 to 11,780 feet on which three drawdown and two buildup tests were performed. It was during the third flow test that significant amounts of oil and gas were produced and the well was returned to Lear Petroleum for commercial production.

The only source of information available to INTERCOMP was two volumes of the final report on Koelemay Well prepared by Eaton Operating Company for DOE, after testing the well and returning it to Lear. Since no logs or core samples analysis were available, no petrophysical evaluation of the formation could be performed by INTERCOMP.

6.1 RESERVOIR ANALYSIS

The first flow test lasted for 1.05 days and it produced 2,243 barrels of formation brine. This test was followed by a pressure buildup test for a period of 3.16 days. The second flow test had a duration of 0.43 days during which 1,638 barrels of brine were produced. The well was then shutin for 1.4 days for the disposal well to be recompleted in another zone. The third flow test lasted 7.27 days and it produced 26,149 barrels of brine. It was during this flow test that a significant amounts of oil and gas started to be produced and it was decided to terminate the test and turn the well back to Lear Petroleum.

The available data on drawdown and buildup tests consisted of pressure and production rates for gas and brine. Using INTERCOMP's BETA II Simulator, it

was decided to match the bottomhole pressures and gas/brine ratios. Reservoir properties used in BETA II are presented in Table 6.1. Table 6.2 shows the PVT properties of the fluids in the formation used in BETA II. The history match period covers 13.46 days from September 12 to September 26, 1980. This period consisted of three drawdown and two buildup tests.

The production rates were supplied to the simulator for different time intervals recorded during the tests. Figure 6.3 shows plots of production rates used in the history match simulation and those measured in the field. Figure 6.4 shows a very good history match for the bottomhole pressure values. The only part of the simulated results that did not follow measured values was at the beginning of the third flow test. These lower observed measurements were probably a resultant of hydrocarbons, up dip in the geologic structure, expanding and reaching the wellbore. It was clear that the simulated points are following a pattern similar to the first two drawdown tests. The simulation results are presenting a two phase system (i.e., water and dissolved gas) and are not reflecting the extra amounts of oil and gas produced. Figures 6.5 and 6.6 show the match obtained for gas/brine ratios and gas production rates respectively. While history matching pressure values, it was noticed that a uniform reservoir permeability could not provide a good match. As a result, further inspection of the pressure test analysis indicated possibility of having a naturally fractured formation near the wellbore. Based on this assumption, a fifty foot radius area around the well gas given a high transmissibility value and it appeared to result in a good match of bottomhole pressure. In matching gas/brine ratios, it was found that a one percent (1%) value of critical gas saturations was needed in order to match the gas breakthrough time.

6.2 PREDICTIONS

The pressure drop due to the first three flow rates of this well shows a lack of potential to produce the well at high rates. In order to obtain more information about the future performance of the well, three different scenario runs were made. In the first case, with a production rate of 3,000 BPD, pressure was sustained for only 45 days after which the well was not able to flow. The short production period of this case eliminated the possibility of any substantial

production of hydrocarbon gases dissolved in water, at/or above 3,000 BPD. In the second case with water production rate of 2,000 BPD, the production period was extended to four years before pressure drop ceased further production. Total gas production at the end of the fourth year was 1,328 MMCF from which about 102.0 MMCF was due to solution gas.

The third scenario has a constant production rate of 1,000 BPD. This case was run up to fifteen years at which time the bottomhole pressure was 4,467 psia. The total gas production of 2,567 MMCF and the cumulative rate production of 5,493 MSTB marked the end of the fifteenth year of production. The cumulative dissolved gas produced in this case was about 192.2 MMCF.

Figures 6.7 through 6.10 visualize performances of bottomhole pressure, gas production rates, gas/brine ratio and cumulative gas production for the last two cases. Results of the history match and prediction cases indicated that: 1) this well does not have the potential to produce at rates higher than 3,000 BPD, 2) the existence of a hydrocarbon zone up dip has increased the oil and gas production significantly, and 3) the amount of dissolved gas produced was a direct function of brine production, at a constant gas brine ratio, and was not high enough to clarify this well as a successful geopressured producer.

TABLE 6.1
G.M. KOELEMAY NO. 1 WELL
RESERVOIR PROPERTIES USED IN BETA II

Thickness, feet	160
Net Thickness, feet	60
Porosity, fraction	.20
Permeability, md	0.35
Initial Reservoir Pressure @ 11,600 feet, PSIA	9420
Initial Reservoir Temperature @ 11,600 feet, °F	260
Rock Compressibility, 1/PSI	3.6×10^{-6}
Reservoir Radius, feet	3000

TABLE 6.2
PVT DATA
G.M. KOELEMAY NO. 1 WELL

<u>Pressure</u> <u>PSIA</u>	<u>Bg</u> <u>RB/MSCF</u>	<u>Gas Viscosity</u> <u>CP</u>	<u>Solution GWR</u> <u>SCF/STB</u>	<u>Water Viscosity</u> <u>CP</u>	<u>Bw</u> <u>RB/STB</u>
2,000	1.578	0.016	30	0.365	1.061
4,000	0.766	0.021	31	0.368	1.055
6,000	0.556	0.025	32	0.372	1.058
8,000	0.448	0.030	33	0.378	1.042
10,000	0.311	0.035	34	0.386	1.036
12,000	0.167	0.041	35	0.395	1.030

The information in this table was obtained from PVT reports for fluid samples of Sweet Lake Amoco Fee No. 1 (geopressured well).

FIGURE 6.1

FIGURE 6.2

FIGURE 6.3
BRINE PRODUCTION RATE FOR G.M.KOELEMAY #1

FIGURE 6.4

PRESSURE HISTORY MATCH FOR G.M.KOELEMAY #1

FIGURE 6.5

GAS-BRINE RATIO HISTORY MATCH FOR G.M.KOELEMAY #1

FIGURE 6.6

GAS PRODUCTION RATE MATCH FOR G.M.KOELEMAY #1

FIGURE 6.7

PREDICTED BOTTOM-HOLE PRESSURE FOR G.M.KOELEMAY #1

FIGURE 6.8

PREDICTED GAS PRODUCTION RATE FOR G.M.KOELEMAY #1

FIGURE 6.9

PREDICTED GAS-BRINE RATIO FOR G.M.KOELEMAY #1

FIGURE 6.10

PREDICTED CUMULATIVE GAS PRODUCTION FOR G.M.KOELEMAY #1

VII. GLADYS McCALL NO. 1

The original Gladys McCall Well No. 1 was drilled in 1969. The well is located in Cameron Parish, Louisiana, at the western edge of the Rockefeller Wildlife Refuge. Being a dry hole, this well was abandoned and was later chosen as a Well of Opportunity. However, in December 1979 a casing failure resulted in abandonment of the well.

Based on the promising reservoir characteristics, DOE initiated a Design Well contract at the same location. This design well was drilled about fifty feet from the original Gladys McCall Well No. 1 (See Figure 7.1). INTERCOMP received copies of the well logs for analysis in October 1981. In February 1982, INTERCOMP was requested to perform a pretest simulation of Sand Zone 9. Although eleven potential production zones were identified from the petrophysical analysis, Zone 9 was felt to be the lower most zone suitable for reservoir limit testing.

In March 1983, drawdown and buildup tests were run on the well to determine the characteristics of the formation. The perforated interval tested was Zone 9 from -15,508 to -15,636 feet. Technadril - Fenix & Scisson (T-F & S) and Reservoir Dynamics, Inc. provided copies of the downhole pressures, rates, and temperature data taken during the reservoir limit tests of Zone 9 in the Gladys McCall No. 1 Well. Also provided were reservoir fluid analyses prepared by Weatherly Laboratories and reservoir calculations and interpretations prepared by J. Donald Clark For T-F & S.

7.1 PETROPHYSICAL ANALYSIS

The available data consisted of a copy of Dual Induction-SFL, Compensated Neutron Formation Density, and Sonic Logs. Petrophysical analysis of the available data resulted in the information reflected in Table 7.1. The 1,448 feet thick sand in this well (14,412-15,860 feet) is broken down to eleven potential production zones. Of these zones, five contain 89 percent of the production sands. The following is a list of these five zones:

<u>ZONE</u>	<u>KH (Water)</u>	<u>% KH</u>
2	3,971	24.0
4	1,462	8.8
8	5,335	32.2
9	3,546	21.5
10	<u>2,219</u>	<u>13.4</u>
	16,533	100.0

Permeability and porosity values, determined through logs analysis, show a fair agreement with the available core data. A semilog plot of porosity versus permeability, Figure 7.2, shows the significant scatter in the core data but the log analysis method (i.e., the solid line) falls through the center of this data.

7.2 PRETEST ANALYSIS

The purpose of the analysis was to perform pretest simulation of Sand Zone 9. This resulted from an agreement among the involved parties to open the massive Zone 9 for the initial flow testing and reservoir limit determination test. The plan was to perforate the top 30 feet and the bottom 30 feet of the 128 foot Zone 9.

INTERCOMP's black oil simulator, BETA II, was used in this study to predict the expected drawdown in 60-day flow tests at rates of 2,000, 5,000, and 10,000 BPD, for the 128 foot sand. In order to initialize the model, the following assumptions were made:

- The reservoir limit was picked as 6,500 feet. This distance is approximately equal to that between the well and a fault located south of the well.
- Homogeneous formation characteristics were assumed.
- A dip angle of 2.8 was calculated, however, it was ignored due to its insignificance.
- The sealing fault north of the well was modeled by excluding from the grid the shaded areas shown in Figure 7.3. The element of

symmetry presented in Figure 7.3 takes advantage of symmetry about a north-south axis intersecting the well. Figure 7.4 shows a 10 x 3 x 3 (R0Z) cylindrical grid used to represent the reservoir.

- The ratio of vertical to horizontal permeability was picked at 1/10.

BETA II was initialized with PVT and relative permeability data obtained from another geopressed well in Cameron Parish, Amoco Fee No. 1. Other reservoir parameters which were used are given in Table 7.2.

Three different production rates of 2,000, 5,000, and 10,000 BPD for a period of 60 days were examined. In addition a lower estimated value of permeability (12.5 md) was tried for each flow rate to determine the sensitivity of the results. Table 7.3 identifies each case.

Figures 7.5 through 7.7 illustrates the results of the different cases for the different values of permeability. The pressure values obtained from simulation under Flow Grid Blocks Pressure (FGBP) reflect the calculated pressure at the producing zone of the top perforated interval. The Average End Block Pressure (AEBP) represents the calculated pressure at the center of the outer most grid block.

Simulation results indicated that pressure transients caused by continued withdrawal reached the assumed boundaries of the reservoir during the testing period.

A plot of pressure versus distance from the wellbore, at the end of 60 days, is shown in Figure 7.8. The low rate case (2,000 BPD) is not plotted here, due to its significant pressure drop at the end of the period. As it is shown in Figure 7.8 the higher the production rate and permeability, the higher is the pressure drop at the boundaries. A maximum drop of 275 psi. was observed for Case 3.1 with $q = 10,000$ BPD and $KW = 27.5$ md.

As in any pretest simulation, the reliability of the noted results depended upon the validity of the assumptions and the input data.

7.3 RESERVOIR ANALYSIS

The reservoir analysis proceeded in two phases. The drawdown and buildup tests taken in March 1983 were analyzed to estimate the permeability of the formation and skin near the wellbore. Secondly, the pressure tests were simulated using INTERCOMP's mathematical reservoir simulator, BETA II, to characterize the reservoir.

Zone 9 was perforated from -15,511 to -15,541 and from -15,567 to -15,627 feet. A three day preliminary flow test indicated a much higher permeability (possibly a K_w of 100-150 md) than estimated from the logs. This was to be substantiated from the planned drawdown and buildup tests.

During the pressure tests there was a small leak existing in the seal assembly at -13,922 feet resulting in communication between the 5-inch production tubing string and the 5 x 7-inch tubing/casing annulus. The pressure in the annulus did change slightly when the well was first put on production; however, it did not decrease substantially during the remaining part of the testing period.

A Panex downhole pressure gauge was used in the drawdown and buildup tests. It was positioned at a depth of -15,460 feet in the 7-inch casing or about 50 feet above the top perforation.

7.3.1 Drawdown Test

The flow test started at 6:15 p.m. on March 21, 1983 and lasted for 23.776 days. During this period, 99,416 barrels of brine were produced. Production rates were recorded on the inlet and outlet sides of the separator and averaged 4,181 BWPD. The initial bottomhole pressure and temperature measured at a depth of -15,460 feet were 12,910 psia and 298°F. The wet gas/water ratio recorded during the drawdown period ranged from 28-33 SCF/STB.

Figures 7.9 through 7.12 illustrate the bottomhole pressure response of the well during the drawdown test. Figure 7.9 is a plot of pressure versus time

in hours. Figure 7.10 is a log-log plot of the initial bottomhole pressure minus the flowing pressure versus elapsed time. A semi-log plot of pressure versus time is shown in Figure 7.11 and a plot of pressure change per cycle versus time is shown in Figure 7.12.

Figure 7.11 shows two possible straight line segments. The first occurred between .2 and 8 hours and has a slope of 28 psi/cycle, and the second occurred at 100 hours and has a slope of 287 psi/cycle. It was assumed that the first straight line (28 psi/cycle) represented pseudosteady-state flow. This slope was used to calculate the production capacity and skin factor. The detail calculations are shown on Figure 7.13 and resulted in a permeability-thickness product of 9543.6 md-ft. Using a 128 ft. net sand thickness yielded a permeability value of 74.56 md, and a skin factor of -.74.

To verify that the first straight line did represent pseudosteady-state flow, the following empirical equations (Reference 4) were used to calculate the expected end of wellbore storage distortion:

$$\begin{aligned}
 (1) \quad C_s &= \frac{25.65 A_{wb}}{\rho} \\
 &= \frac{25.65 (.0997)}{65.24} \\
 &= .0392 \text{ bbl/psi}
 \end{aligned}$$

where C_s = Wellbore Storage Constant, bbl/psi
 A_{wb} = Wellbore Area, sq. ft.
 ρ = Density of Wellbore Liquid, lbm/cu. ft.

$$\begin{aligned}
 (2) \quad t_{wbs} &= \frac{[200,000 + 12,000 S] C_s}{kh/\mu} \\
 &= \frac{[200,000 + 12,000 (-.74)] .0392}{5943.6/.388} \\
 &= .30 \text{ hours}
 \end{aligned}$$

where t_{wbs} = Wellbore Storage Duration, hours
 S = Skin Factor
 kh = Permeability-thickness, md-ft.
 μ = Viscosity, cp

The calculated end of well storage distortion of .3 hours indicated that the first straight line did represent pseudosteady state flow.

The second straight line (287 psi/cycle) possibly represents the pressure behavior influenced by boundary effects. From the radius of investigation equation (Reference 4),

$$r_i = \left(\frac{k(t) 24}{948 \theta \mu C_t} \right)^{\frac{1}{2}}$$

where r_i = Radius of Investigation, feet
 t = Time, days
 θ = Porosity, fraction
 μ = Viscosity, cp
 C_t = Total Compressibility, 1/psi

the pressure transients were calculated to have traveled approximately 12,221 feet into the formation by the end of the drawdown period, $t = 23.776$ days.

As shown on the drawdown figures, the pressure after 60 hours continued to drop significantly with time. This indicates that the reservoir was bounded and was not acting as an infinite reservoir.

7.3.2 Buildup Test

The buildup test followed the initial drawdown. Bottomhole pressures were reported for approximately 2.5 days at which time the pressure gauge was removed.

Figures 7.14 through 7.17 illustrate the pressure response of the well during the buildup test. Figure 7.16 presents the Horner plot and Figure 7.17 is the slope of the Horner plot. The effective production life, T , used in generating the Horner plot was 590.3 hours.

As shown in Figure 7.16, a single straight line was identified with a slope of 25 psi/cycle. This slope was used to calculate the formation properties shown in Figure 7.18. For 128 feet of net thickness and a calculated capacity of 10,688.8 md-ft., a permeability of 83.5 md was calculated. A resultant skin factor of .17 was calculated.

According to ideal pressure buildup theory (Reference 4) which assumes an infinite, homogeneous, isotropic reservoir, extrapolating the straight line segment on a Horner plot to infinite shut-in time $[(T + DT)/DT = 1]$ will give the original formation pressure, P_i . This is true only for tests in which the radius of investigation does not encounter any reservoir boundary during production. For a well in a reservoir in which there has been some pressure depletion, extrapolating the straight line on a Horner plot to infinite shut-in time provides an estimate of P^* which is related to, but is not equal to current average drainage-area pressure. As shown in Figure 7.16 the average pressure, $P^* = 12,600$ psig, is 310 psi below the initial pressure 12,910 psig reported prior to the drawdown. This possibly indicates that reservoir boundaries were reached during production. The change of slope of the pressures reported near the end of the buildup test further support flow boundaries (faults) and/or formation pinchout.

The simulation phase consisted of history matching the two pressure tests using INTERCOMP's BETA II program. Basic reservoir properties used in BETA II are presented in Table 2.4. Table 7.5 presents the PVT properties of the reservoir fluid. The values found in these tables were provided by T-F & S and were also obtained from laboratory analysis of fluid samples taken from the Gladys McCall well.

The radial computation grid used in history matching is shown in Figure 7.19. The grid was a half element of symmetry comprised of 15 radial

rings, 5 theta angles, and 3 layers. The radial rings varied from .49 feet to 12,000 feet from the wellbore. It was estimated from the drawdown analysis that approximately 12,000 feet would be sufficient to include any significant pressure disturbances in the reservoir. The areas in the grid that are shown as shaded areas were initialized with zero net pay. The dash lines are the approximate location of the faults at -15,500 feet, slightly above the tested Zone 9.

Figure 7.20 illustrates the layering scheme used in the model. It was assumed that the gross sand thickness equal the net sand thickness for each layer and that the top of Sand A was flat (i.e. dip angle = 0). The initial pressure entered was 12,910 psi at a datum depth of -15,460 feet. The production data supplied to the model came from the daily testing reports supplied by T-F & S. The model was initialized with a uniform porosity of .2405 and a uniform horizontal permeability of 80 md.

The results of history matching the two pressures tests are shown in Figures 7.21 through 7.28. The different plots are similar to the ones previously described in the flow test section. The pressures calculated by the model were reported at a depth of -15,524.5 feet. These were corrected to the datum depth (-15,460 feet) using a .4287 psi/ft. gradient.

History matching the drawdown and buildup tests proved not to be difficult and as shown in Figures 7.21 through 7.28, the match is good. As shown in Figure 7.23, the calculated and observed pressures started to decline around 60 hours into the drawdown and continued to decline to the end of the test.

To simulate this phenomenon, the permeability thickness of the outer radial rings, rings 12-15, were reduced. This indicated formation barriers of some form approximately 3,500 to 4,000 feet from the wellbore. This modification also reduced the barrels of brine in place from the initial 1,054 million barrels to 135 million barrels.

7.4 PREDICTIONS

A prediction run was made to determine how long the well could flow at a rate of 20,000 BWPD while maintaining a flowing bottomhole pressure greater than 6,500 psia. This pressure was chosen because it approximates the hydrostatic head required at the datum depth of -15,460 feet. The prediction run continued from the end of the buildup test. The well was shut in for an additional 4 days before it was opened for flow. Figure 7.29 illustrates the results. As shown, the well succeeded in making the specified rate for approximately 104 days (2496 hours) before falling below the flowing bottomhole pressure of 6,500 psia. This resulted in a cumulative production of 2.098 million barrels of brine.

From the analysis of the two pressure tests and from the simulation, there are indications that the reservoir is bounded. To the North and South of the well are known faults, no-flow boundaries. However, as was observed during simulation, there are other forms of sand barriers limiting the reservoir: i.e. reduction of sand height or other forms of heterogeneity. These barriers appear to be dominant in limiting the flow capacity of the reservoir.

TABLE 7.1

PERMEABILITY AND HYDRAULIC CAPACITY DATA

GLADYS McCALL NO. 1

	Sand Zone No.	Interval	Net Thickness	Preliminary Estimate, Ka	Preliminary Estimate, Kw	Preliminary Kwh	Preliminary % Kwh	Intercomp Kw	Intercomp Kwh	Intercomp % Kwh
7-10	1	14,412-14,465	54'	--	--	--	--	7.30	394.2	2.12
	2	14,550-14,772	223'	178	34.0	7,582.0	37.33	17.81	3,971.0	21.35
	3	14,782-14,800	19'	--	--	--	--	24.96	474.0	2.55
	4	14,920-14,969	50'	113	24.0	1,200.0	5.91	29.25	1,462.0	7.86
	5	15,031-15,066	36'	--	--	--	--	2.11	76.0	0.41
	6	15,098-15,108	11'	--	--	--	--	7.85	86.0	0.46
	7	15,120-15,137	18'	--	--	--	--	12.96	233.0	1.25
	8	15,158-15,490	333'	109	23.0	7,659.0	37.71	16.02	5,335.0	28.68
	9	15,508-15,636	129'	49	12.5	1,612.5	7.94	27.49	3,546.0	19.06
	10	15,642-15,783	142'	44	11.0	1,562.0	7.69	15.63	2,219.0	11.93
	11	15,784-15,860	<u>77'</u>	35	9.0	<u>693.0</u>	<u>3.41</u>	10.46	<u>805.0</u>	<u>4.33</u>
TOTAL			<u>1,092'</u>			<u>20,308.5</u>	<u>99.99</u>		<u>18,601.0</u>	<u>100.00</u>

TABLE 7.2
RESERVOIR PARAMETERS
GLADYS McCALL NO. 1
(PRETEST SIMULATION OF SAND ZONE 9)

Top of Sand	15508 Feet
Net Sand Thickness	128 Feet
Permeability to Water	27.5 md
Porosity Fraction	.17
Rock Compressibility	2×10^{-6} 1/psi
Initial Reservoir Temperature	290°F
Initial Pressure @ 15508'	12800 Psia
Completion Interval	
- Top 30 ft.	15508-15538'
- Bottom 30 ft.	15606-15636'

TABLE 7.3
IDENTIFICATION OF CASES
GLADYS McCALL
(PRETEST SIMULATION OF SAND ZONE 9)

<u>Case No.</u>	<u>BWPD Production Rate</u>	<u>KW md.</u>
1.1	2,000	27.5
1.2	2,000	12.5
2.1	5,000	27.5
2.2	5,000	12.5
3.1	10,000	27.5
3.2	10,000	12.5

TABLE 7.4

GLADYS McCALL NO. 1

RESERVOIR PROPERTIES

Water Density (standard conditions)	1.045 gm/cm ³
Water Compressibility	2.75 x 10 ⁻⁶ 1/psi
Water Formation Volume Factor	1.0479 RB/STB
Water Viscosity	.388 cp
Gas Gravity	.6775
Rock Compressibility	.475 x 10 ⁻⁶ 1/psi
*Reservoir Temperature @ 15,460 feet	298°F
*Reservoir Pressure @ 15,460 feet	12,910 psi
Standard Pressure	15.025 psia
Standard Temperature	60°F
Reservoir Thickness	128 feet
Porosity	24.05 percent

* Note: Pressure and temperature were measured on March 21, 1983 prior to the drawdown.

TABLE 7.5

GLADYS McCALL NO. 1

PVT PROPERTIES

PRESSURE	SOLUTION GAS	VISCOSITY	FORMATION VOLUME FACTOR
PSIA	SCF/STB	CP	RB/STB
2000.	16.5	.480	1.0755
4000.	24.0	.390	1.0720
6000.	28.5	.388	1.0680
8000.	31.3	.380	1.0625
*10030.	32.9	.375	1.0567
12000.	33.7	.370	1.0510
13000.	33.8	.365	1.0480
14000.	33.9	.360	1.0445

* Reported saturation pressure at 298°F.

FIGURE 7.1
 LOCATION OF GEOPRESSURED-GEOTHERMAL TEST WELL
 GLADYS McCALL PROSPECT NEAR GRAND CHENIER, LOUISIANA

FIGURE 7.2

GLADYS McCALL WELL NO. 1

LOGARITHM OF PERMEABILITY vs. POROSITY

GLADYS MCCALL NO. 1
(PRETEST SIMULATION OF
SAND ZONE 9)

FIGURE 7.3
GRID TOP VIEW
SHADED AREA IS EXCLUDED FROM
THE RESERVOIR TO REPRESENT
THE FAULT

GLADYS McCALL NO.1
THE ELEMENT OF SYMMETRY FOR A CYLINDRICAL GRID

*The shaded area is excluded from the reservoir to represent the fault

FIGURE 7.4

FIGURE 7.5
FLOWING GRID BLOCK AND AVERAGE END
BLOCK PRESSURE FOR
CASES 1.1 and 1.2

GLADYS McCALL NO. 1

FGBP ▲ CASE 1.1 ($q = 2000$, $KW = 27.5$)
 ■ CASE 1.2 ($q = 2000$, $KW = 12.5$)

AEBP ● CASE 1.1 ($q = 2000$, $KW = 27.5$)
 ○ CASE 1.2 ($q = 2000$, $KW = 12.5$)

FIGURE 7.6
FLOWING GRID BLOCK AND AVERAGE END
BLOCK PRESSURE FOR
CASES 2.1 and 2.2

GLADYS McCALL NO. 1

FIGURE 7.7
 FLOWING GRID BLOCK AND AVERAGE
 END BLOCK PRESSURE FOR
 CASES 3.1 and 3.2
 GLADYS McCALL NO. 1

FGBP ▲ CASE 3.1 ($q = 10,000$, $KW = 27.5$)
 ■ CASE 3.2 ($q = 10,000$, $KW = 12.5$)

AEBP ● CASE 3.1 ($q = 10,000$, $KW = 27.5$)
 ○ CASE 3.2 ($q = 10,000$, $KW = 12.5$)

PRESSURE vs. DISTANCE FROM
WELL AT 60 DAYS

FIGURE 7.8

GLADYS McCALL NO. 1

FIGURE 7.9

GLADYS MCCALL WELL #1 - DRAWDOWN 3/21-4/14/83

FIGURE 7.10

GLADYS MCCALL WELL #1 - DRAWDOWN 3/21-4/14/83

FIGURE 7.11

GLADYS MCCALL WELL #1 - DRAWDOWN 3/21-4/14/83

FIGURE 7.12

GLADYS MCCALL WELL #1 - DRAWDOWN 3/21-4/14/83

DRAWDOWN ANALYSIS

Test Date 3/21 - 4/14/83
 Producing Formation Sand A - Zone 9
 Hole Size (inches) 4.276" ID Tubing; 5.920" ID Casing
 Cum. Prod. NP (bbl) 99416
 Stabilized Daily Prod. q (bbl) 4042 Bbls/D
 Effective Prod. Life t (hr) = $24 N_p / q$ 590.3

Well No. Gladys McCall #1
 Field East Crab Lake Field
 State Cameron Parish, Louisiana

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

$$kh = \frac{162.6 q \mu B}{m}; \quad k = \frac{kh}{h}$$

h 128 ft

μ .388 cp

B 1.0479

q 4042 B/D

m 28 psi/cycle

$$kh = \frac{162.6 (4042) (.388) (1.0479)}{28} = 9543.6 \text{ md-ft}; \quad k = \frac{9543.6}{128} = 74.56 \text{ md}$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, ΔP_{skin} (Psi):

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

$$\Delta P_{\text{skin}} = (m) X 0.87 (s).$$

k 74.56 md

r_w .2467 ft

ϕ .2405

P_i 12910 psig

μ .388 cp

P_{1hr} 12752 psig

c 3.22×10^{-6} psi^{-1}

m 28 psi/cycle

$$s = 1.151 \left[\frac{12910 - 12752}{28} - \log \frac{(74.56) 10^6}{.2405 (.388) (3.22) (.2467)^2} + 3.23 \right] = -.74$$

$$\Delta P_{\text{skin}} = 28 (.87) (-.74) = -18 \text{ psi.}$$

FIGURE 7.13

FIGURE 7.14

GLADYS MCCALL WELL #1 - BUILDUP 4/14-4/17/83

FIGURE 7.15

GLADYS MCCALL WELL #1 - BUILDUP 4/14-4/17/83

FIGURE 7.16

GLADYS MCCALL WELL #1 - BUILDUP 4/14-4/17/83

FIGURE 7.17

GLADYS MCCALL WELL #1 - BUILDUP 4/14-4/17/83

BUILDUP ANALYSIS

Test Date 4/14 - 4/17/83
 Producing Formation Sand A - Zone 9
 Hole Size (inches) 4.276" ID Tubing; 5.920" ID Casing
 Cum. Prod.NP (bbl) 99,416
 Stabilized Daily Prod. q (bbl) *4042 bbls/D
 Effective Prod. Life t (hr) = $24 N_p/q$ 590.3

Well No. Gladys McCall #1
 Field East Crab Lake Field
 State Cameron, Parish, Louisiana

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

$$kh = \frac{162.6 q \mu B}{m}; \quad k = \frac{kh}{h}$$

h 128 ft

μ .388 cp

B 1.0479

q 4042 B/D

m 25 psi/cycle

$$kh = \frac{162.6 (4042) (.388) (1.0479)}{25} = \underline{10688.8} \text{ md-ft}; \quad k = \frac{10688.8}{128} = \underline{83.5} \text{ md}$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, Δp_{skin} (Psi):

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

$$\Delta P_{\text{skin}} = (m) \times 0.87 (s).$$

k 83.5 md

r_w .2467 ft

ϕ .2405

P_{1hr} 12525 psig

μ .388 cp

P_{wf} 12360 psig

c 3.22×10^{-6} psi⁻¹

m 25 psi/cycle

$$s = 1.151 \left[\frac{12525 - 12360}{25} - \log \frac{(83.5) 10^6}{.2405 (.388) (3.22) (.2467)^2} + 3.23 \right] = \underline{.17}$$

$$\Delta P_{\text{skin}} = 25 (.87) (.17) = \underline{3.7} \text{ psi.}$$

* Cumulative production reported at outlet to separator between 15:00 on 4-7-83 and 12:56 on 4-14-83 was:

- 99416-71450 = 27966 Bbls.
- 27966 Bbls./6.92 Days = 4042 Bbls./Day

FIGURE 7.18

FIGURE 7.19

GLADYS McCALL WELL NO. 1
SIMULATION GRID

FIGURE 7.20

GLADYS McCALL WELL NO. 1
MODEL LAYERS

FIGURE 7.21

GLADYS MCCALL WELL #1 - DRAWDOWN 3/21-4/14/83

FIGURE 7.22

GLADYS MCCALL WELL #1 - DRAWDOWN 3/21-4/14/83

FIGURE 7.23

GLADYS MCCALL WELL #1 - DRAWDOWN 3/21-4/14/83

FIGURE 7.24

GLADYS MCCALL WELL #1 - DRAWDOWN 3/21-4/14/83

FIGURE 7.25

GLADYS MCCALL WELL #1 - BUILDUP 4/14-4/17/83

FIGURE 7.26

GLADYS MCCALL WELL #1 - BUILDUP 4/14-4/17/83

FIGURE 7.27

GLADYS MCCALL WELL #1 - BUILDUP 4/14-4/17/83

FIGURE 7.28

GLADYS MCCALL WELL #1 - BUILDUP 4/14-4/17/83

FIGURE 7.29

GLADYS MCCALL WELL #1 - PREDICTION

VIII. P. R. GIROUARD NO. 1

The P.R. Girouard Well No. 1 is one of the wells included in the Wells of Opportunity (WOO) Program. It is located about 10 miles southeast of Lafayette, Louisiana, in the Cade Field. Figure 8.1 shows the location of the well. The terrain is flat and is about 29 feet above sea level. The sand formation penetrated by this well is the Oligocene Marginulina Texana No. 1 Sand (Marg. Tex. 1) of Upper Frio age. The perforated interval tested was from -14,744 to -14,819 feet.

This study proceeded in two phases. The drawdown and buildup tests were analyzed to estimate the permeability of the formation and skin near the wellbore. Secondly, the pressure tests were simulated using INTERCOMP's mathematical reservoir simulator, BETA II. This resulted in information concerning formation flow capacity, near wellbore stimulation, and reservoir characteristics.

The only source of information available to INTERCOMP was two volumes of a final report of the Girouard Well. These volumes were prepared by Eaton Operating Company, Inc. for DOE under a separate contract.

8.1 PETROPHYSICAL ANALYSIS

The test well is located in the Cade Field. The field lies at the apex of a highly faulted low relief domal structure. Figure 8.2 is the structure map showing the well location and the faults in the area. The well is located approximately 1,200 feet from the north bounding fault. There is also a shaley zone to the north of the well where there is pinch out of net sand.

During the drilling phase of the Girouard Well, several logging surveys were conducted for hydrocarbon evaluation. The following logs were made available to Eaton for use in reservoir description:

1. ISF Induction Log
2. Acoustic Velocity Log

Table 8.1 summarizes the formation properties reported by Eaton. Permeability estimates of the geopressure-geothermal test zone were not available prior to the flow test. Also no core samples were taken from the sand interval. Therefore, the buildup and drawdown test analysis was the only good means to estimate formation permeability.

8.2 RESERVOIR ANALYSIS

Prior to the first drawdown test, the well was perforated from -14,744 to -14,819 feet. Preliminary flow periods were used to clean the hole and test the surface facilities. A total of 1,625 barrels of fluid was produced prior to the first test. A Hewlett-Packard surface recording bottomhole pressure guage was used in each pressure test. The pressure element each time was set at -14,644 feet in the 7 5/8 inch casing 100 feet above the top of the perforations. The Time-Pressure recordings are reported in Eaton's report Volume II.

8.2.1 First Drawdown Test

The intital flow test started on July 22, 1980 and lasted for 1.01 days. During the flow period 4,117 barrels of water were produced to give a cumulative production of 5,742 barrels at the end of the test. The production rate increased uniformly from 3,866.4 BPD to a final rate of 4,344 BPD. The initial bottomhole pressure was 13,141.67 psia at the guage depth of -14,644 feet. The gas in solution measured approximately 40 cubic feet of gas per barrel of water.

Figures 8.3 through 8.4 illustrate the bottomhole pressure response of the well during the first drawdown test. Figure 8.3 is a log-log plot of the initial pressure minus the flowing pressure versus time. A semi-log plot of pressure versus time is shown in Figure 8.4. Figure 8.4 shows that there exists two possible straight line segments. The first occurred between .2 and .8 hours and has a slope around 164 psi/cycle, and the second occurred between 10 and 24 hours and has a slope of 1,200 psi/cycle. In order to choose which slope would be used to estimate the formation properties, a type-curve analysis was performed. The results of this analysis is shown on

Figure 8.3. The circles represent the Ramey curve that closest matched the solid line of observed pressures. This type curve corresponded to a skin of -5 and a dimensionless wellbore storage value of 1×10^5 .

The first drawdown test did not last long enough to begin psuedo steady-state flow, however, from the type curve analysis, it was approaching steady-state. For this reason, the second straight line segment (slope = 1,200 psi/cycle) was used to calculate the production capacity, and skin factor. As shown on Figure 8.5, a permeability-thickness of 129 md-ft. was calculated for the pay zone. Using a 91 foot net sand thickness yielded a permeability value of 1.4 md. The calculated skin factor of -5.6 indicated a significant near wellbore improvement.

The dash line shown on Figure 8.3 equates to a half slope normally observed when there is linear flow. As illustrated, the observed pressure line had a slope slightly less than the half slope. Another observation was that the general curvature of the pressure line during the early hours of the drawdown is greater than one would expect from a radial flow regime. Both of these observations indicate that there is some type of improvement near the wellbore.

8.2.2 First Buildup Test

The first buildup test followed the initial drawdown and lasted for 2.18 days. At this time the pressure element was removed for bottomhole sampling. About 5 barrels of water was produced during the sampling. At about 6.1 days from the beginning of the buildup test, the pressure element was reset close to -14,644 feet and recorded a pressure of 13,111 psia.

Figures 8.6 through 8.7 illustrate the pressure response of the well during the buildup test. Figure 8.7 represents the Horner plot. The effective production life, T, used in generating the Horner plot was 31.72 hours.

Two straight lines were identified. One had a slope of 140 psi/cycle and the second has a slope of 900 psi/cycle. Similar to the first drawdown, a

type-curve matching analysis was employed. The results are shown on Figure 8.6. The type-curve that best matched the observed pressures had a slope of -5 and a wellbore storage of 1×10^5 . The general curvature of the observed pressure line when compared to the half slope line indicated again that there is some wellbore improvement.

Pseudo steady-state flow was estimated to have begun 28 hours ($\log \frac{T + DT}{DT} = 2.13$) after the well was shutin. For this reason, the slope of the second straight line was used to calculate the formation properties. The calculations are shown on Figure 8.8. For 91 feet of net thickness and a calculated capacity of 173 md-ft., a permeability of 1.9 md was estimated. Again a skin factor of -5.6 was calculated.

8.2.3 Second Drawdown Test

The well was again opened to flow on July 29, 1980, and lasted for 1.36 days. The initial bottomhole pressure was 13,111 psia. The flow rate observed during the test was not very stable; ranging from 6,988.8 BPD to 8,459.6 BPD. In addition, there was a sudden pressure increase from 11,860 to 11,898 psia 6.1 hours after the start of the test. The sand detector recorded passing of some debris about the same time. This was interpreted by Eaton as cleaning of some plugged perforation. After this time, the pressures recorded were erratic. The following bottomhole pressure at the end of the test was 11,241 psia.

Figures 8.9 through 8.10 illustrate the pressure response of the well during the second drawdown. Figure 8.11 shows the analytical results. As before two straight lines were identified.

The type-curve analysis was again used to determine which slope would be used in the calculations. This analysis is shown on Figure 8.9. As illustrated, steady-state flow was estimated to have begun 21 hours after the start of the test which indicated that the slope of 1,155 psi/cycle should be used to calculate formation properties. Using a net thickness of

91 feet, and a capacity of 241 md-ft., an effective permeability of 2.7 md, and a skin factor of -5.5 were calculated. The general shape of the observed pressure line shown in Figure 8.9 again indicated that there was near wellbore improvement.

The results obtained from analysis of the three tests are summarized in Table 8.2. The tests indicate there is an improvement near the wellbore either due to stimulation or natural fractures. Since no cores were taken and the well was not stimulated, there is no definitive explanation for this phenomenon. This observation was investigated further during the reservoir simulation portion of the study.

The simulation phase consisted of history matching the three pressure tests using INTERCOMP's BETA II program. Basic reservoir properties used in BETA II are presented in Table 8.3. Table 8.4 has the PVT properties of the fluid supplied to the model. The values found in these tables were provided in Eaton's report and were obtained from laboratory analysis of fluid samples taken from the Girouard Well.

The radial grid and layering scheme used in history matching are shown in Figures 8.12 and 8.13. The grid was comprised of 17 radial rings, 3 theta angles, and 4 layers. The radial rings varied from 0.6 feet to 8,000 feet from the wellbore. It was estimated that 8,000 feet would be sufficient to include any significant pressure disturbance in the reservoir. In setting up the grid, it was also assumed that there was zero net pay to the north of the well. The initial pressure entered was 13,198 psi at a datum depth of -14,644 feet. This pressure is slightly higher than reported because of pretest production.

The results of history matching the three pressure tests are shown in Figures 8.14 through 8.16. The number of observed pressure points per test were reduced to aid in history matching. The pressures calculated by the model were reported at a depth of -14,762.75 feet. These were corrected to the datum depth (-14,644 feet) using a 0.4202 psi/ft. gradient.

History matching the first drawdown and buildup proved to be relatively simple and as shown in Figures 8.14 and 8.15, the match is good. The second drawdown, proved to be more complex, especially simulating the cleaning of the perforations 6 hours into the drawdown. To simulate this phenomenon, a vertical permeability barrier was placed in the model between the perforated Layers 2 and 3. During the first drawdown Layer 2 was producing at 70 percent of the production rate specified and Layer 3 at 30 percent. The ratio was changed to 65 and 35 percent at the beginning of the second drawdown. After six hours into the second drawdown, Layer 3 was opened to 50 percent of the production rate. This caused an increase in pressure of about the same magnitude as was measured in the field. This is shown clearly in Figure 8.16.

A formation permeability of 4.6 md and an effective skin of -6 had to be used to match the pressures observed during the drawdown and buildup tests. This permeability is approximately two times larger than the average permeability, 2 md, calculated analytically. This was expected since the pressure analysis assumed a radial flow of 360 degrees and a 180 degree radius was numerically simulated.

8.3 PREDICTIONS

A prediction run was made to determine how long the well could flow at a rate of 10,000 BPD and maintain a flowing bottomhole pressure greater than 6,000 psia. This pressure was chosen because it approximates the hydrostatic head required at the datum depth of -14,644 feet. The run continued from the end of the second drawdown using the calculated pressure of 11,036.9 at the beginning pressure. It assumed that the formation was supplying the only support to the well; i.e. the reservoir did not extend beyond the limits of the simulation grid. Figure 8.17 illustrates the results. As shown, the well succeeded in making the specified rate for 33.21 days (797 hours) before falling below the flowing bottomhole pressure of 6,000 psia.

From the analysis of the three pressure tests and from the simulation, there was an indication that there exists some natural stimulation near the wellbore. One

possible theory, is that the northern bound fault is somehow supplying support to the well through natural fractures; which appears, analytically, as a negative skin. The pressures observed early in each test is not a result of pure linear flow nor radial flow to the wellbore but somewhere between.

The results from the prediction run indicate the well is restricted by the low formation permeability. For this reason, it is unlikely that the well could produce for a lengthy period of time at a high production rate.

TABLE 8.1
P.R. GIROUARD WELL NO. 1
FORMATION PROPERTIES

Top of Marg. Tex. 1 Sand	-14,720 feet
Gross Thickness	107 feet
Net Thickness	91 feet
Mean Porosity	26% (Sonic Travel Time Log)
Water Salinity	33,500 ppm
*Reservoir Pressure @ 14,644 feet	13,142 psia
*Reservoir Temperature @ 14,644 feet	272 ^o F
Rock Compressibility	.53 x 10 ⁻⁶ 1/psi

*Note: Pressure and temperature were measured on July 22, 1980 prior to first drawdown test.

TABLE 8.2

P.R. GIROUARD WELL NO. 1

COMPARISON OF THREE PRESSURE TESTS

	<u>m</u> <u>PSI/CYCLE</u>	<u>kh</u> <u>md.-ft.</u>	<u>k</u> <u>md</u>	<u>S</u> <u>—</u>	ΔP_s <u>PSI</u>
First Drawdown	1,200	129	1.4	-5.6	-5,846
First Buildup	900	173	1.9	-5.6	-4,385
Second Drawdown	1,155	241	2.7	-5.5	-5,527

TABLE 8.3

P.R. GIROUARD WELL NO. 1

RESERVOIR PROPERTIES

Water Density (Standard Conditions)	1.0151 gm/cm ³
Water Compressibility	3.1 x 10 ⁻⁶ 1/psi
Water Formation Volume Factor	1.0468 RB/STB
Water Viscosity	.21 cp
Gas Gravity	.7311
Rock Compressibility	.53 x 10 ⁻⁶ 1/psi
Reservoir Temperature	274°F
Standard Pressure	15.025 psia
Standard Temperature	60°F
Reservoir Thickness	107 feet
Porosity	26 percent

TABLE 8.4
P.R. GIROUARD WELL NO. 1
PVT PROPERTIES

<u>Pressure</u> <u>PSIA</u>	<u>Solution Gas</u> <u>SCF/STB</u>	<u>Viscosity</u> <u>CP</u>	<u>Formation Volume Factor</u> <u>RB/STB</u>
2,000.	18.5	.28	1.0725
6,000.	30.3	.24	1.0642
10,000.	41.0	.22	1.0550
12,000.	44.0	.21	1.0497
*13,142.	45.6	.20	1.0468
13,500.	45.7	.19	1.0456
14,000.	45.8	.18	1.0448

* Reported saturation pressure at 274°F.

FIGURE 8.1 Geopressured-Geothermal Test Wells In Louisiana

P.R. GIROUARD WELL NO. 1

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

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
3100 Edloe
Houston, Texas 77027
(713) 627-9764

FIGURE 8.2

FIGURE 8.3

FIGURE 8.4

DRAWDOWN ANALYSIS

Test Date First Drawdown 7/22-23/80 (1.01 Days)
 Producing Formation Marg. Tex. No. 1
 Hole Size (inches) 7 5/8
 Cum. Prod.NP (bbl) 5742
 Stabilized Daily Prod. q (bbl) 4344
 Effective Prod. Life t (hr) = $24 N_p/q$ _____

Well No. P.R. Girouard No. 1
 Field Cade
 State Louisiana

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

$$kh = \frac{162.6 q \mu B}{m}; \quad k = \frac{kh}{h}$$

h 91 ft

μ .21 cp

B 1.0468

q 4344 B/D

m 1200 psi/cycle

$$kh = \frac{162.6 (4344)(.21)(1.0468)}{1200} = \underline{129} \text{ md-ft}; \quad k = \frac{129}{91} = \underline{1.4} \text{ md}$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, ΔP_{skin} (Psi):

$$s = 1.151 \left[\frac{P_i - P_{10hr}}{m} - \log \left(\frac{k}{\phi \mu c r_w^2} \right) + 2.23 \right]$$

$$\Delta P_{\text{skin}} = (m) X 0.87 (s).$$

k 1.4 md

r_w .3177 ft

ϕ .26

P_i 13142 psia

μ .21 cp

P_{10hr} 12240 psia

c 3.732×10^{-6} psi^{-1}

m 1200 psi/cycle

$$s = 1.151 \left[\frac{13142 - 12240}{1200} - \log \frac{1.4}{.26(.21)(3.732 \times 10^{-6})(.3177)^2} + 2.23 \right] = \underline{-5.6}$$

$$\Delta P_{\text{skin}} = 1200(.87)(-5.6) = \underline{-5846} \text{ psi.}$$

FIGURE 8.5

P.R. GIROUARD WELL #1 - BUILDUP ANALYSIS

FIGURE 8.6

FIGURE 8.7

BUILDUP ANALYSIS

Test Date First Buildup 7/23-26/80 (2.18 Days)
 Producing Formation Marg. Tex. No. 1
 Hole Size (inches) 7 5/8
 Cum. Prod.NP (bbl) 5742
 Stabilized Daily Prod. q (bbl) 4344
 Effective Prod. Life t (hr) = 24 N_p/q 31.72

Well No. P.R. Girouard No. 1
 Field Cade
 State Louisiana

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

$$kh = \frac{162.6 q \mu B}{m}; \quad k = \frac{kh}{h}$$

h 91 ft

μ .21 cp

B 1.0468

q 4344 B/D

m 900 psi/cycle

$$kh = \frac{162.6(4344)(.21)(1.0468)}{900} = \frac{173}{91} \text{ md-ft}; \quad k = \frac{173}{91} = \frac{1.9}{91} \text{ md}$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, Δp_{skin} (Psi):

$$s = 1.151 \left[\frac{P_{10hr} - P_{wf}}{m} - \log \left(\frac{k}{\phi \mu c r_w^2} \right) + 2.23 \right]$$

$$\Delta P_{skin} = (m) X 0.87 (s).$$

k 1.9 md

r_w .3177 ft

φ .26

P_{10hr} 12640 psia

μ .21 cp

P_{wf} 11848 psia

c 3.732x10⁻⁶ psi⁻¹

m 900 psi/cycle

$$s = 1.151 \left[\frac{12640 - 11848}{900} - \log \frac{1.9}{.26(.21)(3.732 \times 10^{-6})(.3177)^2} + 2.23 \right] = \frac{-5.6}{900}$$

$$\Delta P_{skin} = 900(.87)(-5.6) = \frac{-4385}{900} \text{ psi.}$$

FIGURE 8.8

P.R. GIROUARD WELL #1 - SECOND DRAWDOWN ANALYSIS

FIGURE 8.9

FIGURE 8.10

DRAWDOWN ANALYSIS

Test Date Second Drawdown 7/29-31/80 (1.36 Days)
 Producing Formation Marg. Tex. No. 1
 Hole Size (inches) 7 5/8
 Cum. Prod. NP (bbl) 16346
 Stabilized Daily Prod. q (bbl) 7800
 Effective Prod. Life t (hr) = $24 N_p/q$ _____

Well No. P.R. Girouard No. 1
 Field Cade
 State Louisiana

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

$$kh = \frac{162.6 q \mu B}{m}; \quad k = \frac{kh}{h}$$

h 91 ft

μ .21 cp

B 1.0468

q 7800 B/D

m 1155 psi/cycle

$$kh = \frac{162.6(7800)(.21)(1.0468)}{1155} = \underline{241} \text{ md-ft}; \quad k = \frac{241}{91} = \underline{2.7} \text{ md}$$

II. Calculation of Skin Effect, s; and Pressure Loss Due to Skin, Δp_{skin} (Psi):

$$s = 1.151 \left[\frac{P_i - P_{10hr}}{m} - \log \left(\frac{k}{\phi \mu c r_w^2} \right) + 2.23 \right]$$

$$\Delta p_{\text{skin}} = (m) X 0.87 (s).$$

k 2.7 md

r_w .3177 ft

ϕ .26

P_i 13111 psia

μ .21 cp

P_{10hr} 11850 psia

c 3.732×10^{-6} psi⁻¹

m 1155 psi/cycle

$$s = 1.151 \left[\frac{13111 - 11850}{1155} - \log \frac{2.7}{.26(.21)(3.732 \times 10^{-6})(.3177)^2} + 2.23 \right] = \underline{-5.5}$$

$$\Delta p_{\text{skin}} = 1155(.87)(-5.5) = \underline{-5527} \text{ psi.}$$

FIGURE 8.11

P. R. GIROUARD WELL NO. 1
SIMULATION GRID

FIGURE 8.12

P. R. GIROUARD WELL NO. 1 MODEL LAYERS

FIGURE 8.13

P.R. GIROUARD WELL #1 - FIRST DRAWDOWN

FIGURE 8.14

P.R. GIROUARD WELL #1 - FIRST BUILDUP

FIGURE 8.15

P.R. GIROUARD WELL #1 - SECOND DRAWDOWN

FIGURE 8.16

P.R. GIROUARD WELL #1 - PREDICTION

FIGURE 8.17

IX. CROWN ZELLERBACH NO. 2

The Crown Zellerbach Well No. 2 is in DOE's Wells of Opportunity program. As shown in Figure 9.1, it is located in Livingston Parish, Louisiana. The sand formation (Sand A) penetrated by this well is a Tuscaloosa Sand. The perforated interval tested was from -16,720 to -16,750 feet.

This study proceeded in two phases. The drawdown and buildup data was analyzed to define reservoir properties such as permeability, pay thickness, reservoir limit and wellbore skin factor. Secondly, the drawdown and buildup tests were simulated using INTERCOMP's reservoir simulator, BETA II.

The only source of well information available to INTERCOMP was two volumes of a final report on the Crown Zellerbach No. 2 Well prepared by Eaton Operating Company, Inc. for DOE.

9.1 PETROPHYSICAL ANALYSIS

The Sand A studied is composed of alternating sands and shales. The top of the sand structure is shown in Figure 9.2. The Crown Zellerbach No. 2 is located on an anticlinal fold between two faults. In the northwest direction, the dip angle was estimated to be 2.4 degrees with the northernmost fault existing some 2,300 feet from the well.

Table 9.1 summarizes the formation properties reported by Eaton. Sidewall core samples were not available; therefore, the buildup and drawdown tests were used to estimate formation permeabilities.

9.2 RESERVOIR ANALYSIS

Two tests were performed on the Crown Zellerbach Well No. 2; a 4.6-day drawdown test and a subsequent 1.6-day buildup test. A Hewlett-Packard pressure element was used in each test. It was set at a depth of 16,536 feet within the 2 3/8 inch tubing.

9.2.1 Drawdown Test

The measured drawdown pressure data were corrected to a datum level of 16,736 feet which was the center of the perforated interval of Sand A. The data were plotted on a semi-log plot shown on Figure 9.3. The average flow rate during the 4.6 days was 2,229 BWPD.

As shown on Figure 9.3, five linear segments were drawn corresponding to times of 0.02-0.40, 0.40-1.10, 1.10-1.20, 1.20-1.80 and 4.10-4.60 days. These same time intervals are also shown in the Jones plot of Y-factor versus drawdown time, Figure 9.4. Using the slope of 328 psi/cycle, an estimation of the formation permeability thickness, permeability, and wellbore skin factor were calculated to be 366.2 md.-ft., 10.46 md., and -1.67 respectively. The detail computations are shown on Figure 9.5.

Table 9.2 gives the slopes (psi/cycle), the ratios between the slope m_1 and the other slopes m_i , and the distance to each possible formation barrier. The change of $m_3 = 323$ psi/cycle to $m_4 = 410$ psi/cycle is strictly due the significant increase of flow rate to about 2,800 BWPD at 1.70 days. Pressure readings were missing from $t = 1.80$ to $t = 4.10$ days due to a short in the wire between the pressure probe and the surface. Thus, only the breaks at 0.02 and 0.40 days occurred as a result of the change in formation characteristics and they represented the corresponding distances to formation discontinuities at 120 and 537 feet from the wellbore. The available geology did not indicate a fault at 120 feet. The ratio $m_1/m_2 = 0.699$ is not exactly or close to 0.500. The discontinuity at 120 feet was interpreted as a change in the formation permeability k from 10.46 md to 7.31 md. Also, the ratio $m_2/m_3 = 1.452$ and the down shift of the 45-degree slope in the Jones plot, Figure 9.4, would indicate a permeability thickness increase at 537 feet and this was interpreted as an increase in the formation net pay thickness from 35 feet to 51 feet. However, it was not possible to locate the physical orientation of the two formation property changes.

As shown in Table 9.2, the distance to the farthest barrier obtained from the drawdown plot was 1,821 feet. From the Jones plot, Figure 9.4, the Y-factor (psi/bbl) seemed to reach a constant pressure decline at the end of the 4.6-day drawdown period and stabilized at 0.01 psi/bbl. The initial water in place was computed to be 13,218 MSTB by using the following equation.

$$N = \frac{1}{c Y_s B_w}$$

where N = water in place, STB
 c = total effective compressibility, psi^{-1}
 Y_s = constant Y-factor, psi/bbl
 B_w = water formation volume factor, bbl/STB

In this case, $c_w = 3.12 \times 10^{-6} \text{ psi}^{-1}$, $c_r = 3.90 \times 10^{-6} \text{ psi}^{-1}$, $c = S_w c_w + c_r = 7.02 \times 10^{-6} \text{ psi}^{-1}$, $B_w = 1.0777 \text{ bbl/STB}$ (mean value from 7,008 to 10,150 psi, Table 9.3), and $Y_s = 0.01 \text{ psi/bbl}$. This water in place of 13,218 MSTB corresponds to a drainage area of some 309 acres.

Using $t = \frac{\phi \mu c r_e^2}{0.0008 k}$
 where t = time semi-steady state begins, hours
 ϕ = porosity, fraction
 μ = viscosity, cp
 c = total effective compressibility, psi^{-1}
 r_e = radius of drainage, feet
 k = permeability, md

The time semi-steady state flow would begin in 148.50 hours or 6.19 days, $\phi = 0.17$, $\mu = 0.314 \text{ cp}$, $c = 7.02 \times 10^{-6} \text{ psi}^{-1}$, $r_e = 1,821 \text{ feet}$, and $k = 10.46 \text{ md}$. Thus, the 4.6-day drawdown had not quite reach the semi-steady flow condition.

9.2.2 Buildup Test

Similar to the drawdown data, the measured shutin pressure data were first corrected to a datum level of 16,736 feet prior to constructing a Horner plot. This plot is shown in Figure 9.6. Using the slope of 420 psi/cycle, the formation permeability thickness, permeability and wellbore skin factor were calculated to be 256 md-ft., 7.31 md, and -3.77 respectively. The detail computations are shown on Figure 9.7

The buildup analysis gave a lower permeability thickness and a more negative skin factor than the drawdown analysis. Also, the initial reservoir pressure (P^*) extrapolated from the Horner plot was estimated to be 9,450 psia. This was different from the reported initial pressure of 10,113 psia; a difference of 663 psia.

Odeh and Nabor indicated in a paper, "The Effect of Production History on Determination of Formation Characteristics from Flow Tests", (JPT, 1966), that the magnitude of the stabilized rate of flow could affect the computations of permeability thickness as well as the extrapolated initial reservoir pressure. Such computations would be too low if the stabilized rate of flow was less than the last rate of flow prior to stabilization.

Prior to the beginning of the buildup test the well was producing at a relatively constant rate of 2,019 BWPD during the final 12 hours of flow test and the flow rate in the last hour was 1,987 BWPD. As recommended by Odeh and Nabor, the buildup test should last at least 1 1/2 times the production flow test for the purpose of calculating permeability thickness and initial reservoir pressure. In this case, the buildup period (1.6 days) is only 0.35 times that of the drawdown period (4.6 days). Also concerning, was the interruption of the flowing pressure recordings due to equipment failure from $t = 1.80$ days to $t = 4.10$ days during the flow test; and, that the pressure bomb was reported to be operating above its rated temperature. For the reasons stated above, the pressure buildup data reported was believed to be subject to error. During the simulation phase of the pressure tests, more emphasis was placed on history matching the drawdown test than on the buildup test.

A horizontal 9 x 2 x 1 cylindrical grid shown in Figure 9.8 was used to simulate the drawdown and buildup tests. The radial grid blocks were logarithmically spaced from the center with the reservoir limit set at 1,821 feet. The PVT data used in simulation is shown in Table 9.3. The other initial basic reservoir data needed were either obtained from the Eaton's reports or estimated from well-known correlations. These are shown in Table 9.4.

A constant value of 17 percent for porosity was used for the entire reservoir. The absolute permeability of all the grid blocks was 10.46 md (from drawdown analysis) except those blocks enclosed by $I_1 = 6$, $I_2 = 9$, $J_1 = 2$, $J_2 = 2$, $K_1 = 1$, and $K_2 = 1$; where I_1 , I_2 , J_1 , J_2 , K_1 , and K_2 are the lower and upper limits inclusively on the r , θ , z coordinates of the cylindrical grid. These blocks covered the area 120 feet for the wellbore to the grid boundary. The formation pay thickness was 35 feet for all the grid blocks except those enclosed by $I_1 = 8$, $I_2 = 9$, $J_1 = 1$, $J_2 = 1$, $K_1 = 1$, and $K_2 = 1$, which represented the area 537 feet from the wellbore to the grid limit. The thickness in this region was initially 51 feet. The average reservoir pressure before the first drawdown began was estimated to be 9,850 psia.

During the history match the following variables were to be adjusted judiciously: porosity (ϕ), absolute permeability (k), skin factor (S), flow rates (q_w), and reservoir grid limit. The skin factor S was incorporated in the well index WI which was the data required by the BETA II simulator for computing the well bottomhole pressures. The WI equation for this study was

$$WI = \frac{0.00708}{0.73763 + S}$$

Tables 9.5 and 9.6 shows the initial and the final adjusted values of these variables, most of which were the same as their starting values. Figure 9.9 and Table 9.7 give the history match results of the drawdown and buildup pressure data respectively. The match on the flowing bottomhole pressure

in the drawdown test was very good. However, the simulated buildup pressures could be obtained simply by decreasing the initial reservoir pressure from 9,850 psia to 9,450 psia, which would be the extrapolated value in the Horner plot. Since the buildup data were believed to be erroneous, a match on these data was felt to be meaningless.

TABLE 9.1
CROWN ZELLERBACH WELL NO. 2
FORMATION PROPERTIES

Top of Sand A	-16,718 feet
Gross Thickness	36 feet
Net Thickness	35 feet
Mean Porosity	17% (Density/Neutron Log)
Water Salinity	31,700 ppm
*Reservoir Pressure @ 16,736 feet	10,114 psia
*Reservoir Temperature @ 16,736 feet	330°F

* Note: Pressure and temperature were measured on June 3, 1981 prior to the drawdown test.

TABLE 9.2
CROWN ZELLERBACH WELL NO. 2
SAND A
RESERVOIR LIMIT ANALYSIS

DETECTION TIME, t_b DAYS	i	SLOPE m_i psi/cycle	m_1/m_i	m_{i-1}/m_i	DISTANCE TO DISCONTINUITY* r_e , ft
0.02	1	328	1	--	120
0.40	2	469	0.699	0.699	537
1.10	3	323	1.015	1.452	890
1.20	4	410	1.250	0.788	930
1.80	4	410	1.250	0.788	1139
4.10	5	390	1.189	1.051	1719
4.60	5	390	1.189	1.051	1821

* Distance to discontinuity was calculated by

$$r_e = 2 \sqrt{\eta t_b}$$

with

$$\eta = \frac{6.33 \times 10^{-3} k}{\phi \mu_w c}$$

With $k = 10.46$ md, $\phi = 0.17$, $\mu_w = 0.308$ cp, and $c = 7.02 \times 10^{-6}$, $\eta = 180,135 \text{ ft}^2/\text{day}$
and $r_e = 849 \sqrt{t_b}$.

TABLE 9.3
CROWN ZELLERBACH WELL NO. 2
SAND A
RESERVOIR BRINE PVT DATA

<u>Pressure</u> psia	<u>Viscosity</u> cp	Water Formation Volume Factor <u>RB/STB</u>
5584*	0.298	1.0880
6000	0.299	1.0864
7008	0.301	1.0828
8005	0.304	1.0794
9000	0.308	1.0760
10150	0.314	1.0724

* Bubble point pressure

Solution gas-oil ratio = 38.0 SCF/STB.

TABLE 9.4
CROWN ZELLERBACH WELL NO. 2
SAND A
INITIAL RESERVOIR DATA

Initial Reservoir Temperature	327°F
Bubble Point Pressure	5,584 psia
Rock Compressibility	$3.90 \times 10^{-6} \text{ psi}^{-1}$
Water Compressibility	$3.12 \times 10^{-6} \text{ psi}^{-1}$
Initial Water Formation Volume Factor	1.0724 bbl/STB
Specific Gravity of Reservoir Water	1.0214
Gas Gravity	0.8034

TABLE 9.5

**CROWN ZELLERBACH WELL NO. 2
SAND A
INITIAL AND FINAL ADJUSTED DATA
IN HISTORY MATCHING**

<u>VARIABLE</u>	<u>INITIAL</u>	<u>FINAL</u>
Porosity, %	17	17
Permeability md	k = 10.46 in all grid blocks except: I1 = 6, I2 = 9, J1 = 2, J2 = 2, K1 = 1, K2 = 1, k = 7.31	k = 10.46 in all grid blocks except: I1 = 6, I2 = 9, J1 = 2, J2 = 2, K1 = 1, K2 = 1, k = 3.00
Pay Thickness feet	h = 35 in all grid blocks except: I1 = 8, I2 = 9, J1 = 1, J2 = 1, K1 = 1, K2 = 1, h = 51	h = 35 in all grid blocks except: I1 = 8, I2 = 9, J1 = 1, J2 = 1, K1 = 1, K2 = 1, h = 60
Average reservoir pressure before 1st drawdown, psia	9,850	9,850
Skin factor	0.000	-0.266
Well index	0.010	0.015
Reservoir grid limit feet	1,821	1,821

TABLE 9.6

CROWN ZELLERBACH WELL NO. 2
SAND A
INITIAL AND FINAL ADJUSTED FLOW RATES
IN HISTORY MATCHING

<u>TIME DAYS</u>	<u>INITIAL BWPD</u>	<u>FINAL BWPD</u>
0 to 0.0002	2,779 (actual)	2,799
0.0002 to 1.10	2,229 (average)	2,229
1.10 to 1.80	2,600 (actual)	2,600
1.80 to 4.60	2,229 (average)	2,450

TABLE 9.7

CROWN ZELLERBACH WELL NO. 2

SAND A

HISTORY MATCH - BUILDUP PRESSURE

<u>TIME HOURS</u>	<u>SHUT-IN PRESSURE, psia</u>	
	<u>OBSERVED</u>	<u>SIMULATED</u>
0.10	7798	8391
1.00	8280	8757
5.00	8749	9142
10.00	8913	9290
20.00	9043	9432
30.00	9113	9506
39.30	9161	9547

Mapped, edited, and published by the Geological Survey

TOPOGRAPHIC MAP

SCALE 1:24 000

ROAD CLASSIFICATION

- Primary highway, hard surface ——— Light-duty road, hard or improved surface ———
- Secondary highway, hard surface ——— Unimproved road - - - - -
- Interstate Route U. S. Route State Route

INTERCOMP

CROWN ZELLERBACH WELL NO. 2

SAND A

LOCATION MAP

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

● Oil Well
 ☼ Gas Well
 ○ Dry Well
 ⊕ Location

9-15

INTERCOMP

CROWN ZELLERBACH WELL NO. 2

SAND A

STRUCTURE CONTOUR MAP

FIGURE: 9.2

INTERCOMP

CROWN ZELLERBACH WELL NO. 2

SAND A

DRAWDOWN PLOT

INTERCOMP

CROWN ZELLERBACH WELL NO. 2

SAND A

JONES PLOT

DRAWDOWN ANALYSIS

Test Date June 5 - 9, 1981
 Producing Formation Tuscaloosa - Sand A
 Hole Size (inches) 6.094
 Cum. Prod. N_p (bbl) _____
 Stabilized Daily Prod. q (bbl) 2,229 RWPD
 Effective Prod. Life t (hr) = $24 N_p / q$ _____

Well No. Crown Zellerbach No. 2
 Field Livingston Parish
 State Louisiana

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

$$kh = \frac{162.6 q \mu B}{m}; \quad k = \frac{kh}{h}$$

h 35 ft

μ 0.308 cp

B 1.0760

q 2,229 B/D

m 328 psi/cycle

$$kh = \frac{(162.6)(2,229)(0.308)(1.0760)}{(328)} = \underline{366.2} \text{ md-ft}; \quad k = \frac{366.2}{35} = \underline{10.46} \text{ md}$$

II. Calculation of Skin Effect, s ; and Pressure Loss Due to Skin, Δp_{skin} (Psi):

$$s = 1.151 \left[\frac{P_i - P_{1hr}}{m} - \log \frac{k}{\phi \mu c r_w^2} + 3.23 \right]$$

$$\Delta P_{\text{skin}} = (m) X 0.87 (s).$$

k 10.46 md

r_w 0.254 ft

ϕ 0.17

P_i 9,835 psig

μ 0.308 cp

P_{1hr} 8,535 psig

c 7.02×10^{-6} psi⁻¹

m 328 psi/cycle

$$s = 1.151 \left[\frac{9,835 - 8,535}{328} - \log \frac{10.46}{(0.17)(0.308)(7.02 \times 10^{-6})(0.254)^2} + 3.23 \right] = \underline{-1.67}$$

$$\Delta P_{\text{skin}} = (328)(0.87)(-1.67) = \underline{-477} \text{ psi.}$$

INTERCOMP

CROWN ZELLERBACH WELL NO. 2

SAND A

DRAWDOWN ANALYSIS

INTERCOMP

CROWN ZELLERBACH WELL NO. 2

SAND A

HORNER PLOT

BUILDUP ANALYSIS

Test Date June 1 - 11, 1981
 Producing Formation Tuscaloosa, Sand A
 Hole Size (inches) 6.094
 Cum. Prod. N_p (bbl) 10,109
 Stabilized Daily Prod. q (bbl) 2,019 BWPD
 Effective Prod. Life t (hr) = $24 N_p / q$ 120.17

Well No. Crown Zellerbach No. 2
 Field Livingston Parish
 State Louisiana

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

$$kh = \frac{162.6 q \mu B}{m}; \quad k = \frac{kh}{h}$$

h 35 ft

μ 0.304 cp

B 1.0777

q 2,019 B/D

m 420 psi/cycle

$$kh = \frac{(162.6)(2,019)(0.304)(1.0777)}{420} = \frac{256}{420} \text{ md-ft}; \quad k = \frac{256}{35} = \frac{7.31}{35} \text{ md}$$

II. Calculation of Skin Effect, s ; and Pressure Loss Due to Skin, Δp_{skin} (Psi):

$$s = 1.151 \left[\frac{P_{1hr} - P_{wf}}{m} - \log \frac{k}{\phi \mu c r_w^2} + 3.23 \right]$$

$$\Delta P_{\text{skin}} = (m) X 0.87 (s).$$

k 7.31 md

r_w 0.254 ft

ϕ 0.17

P_{1hr} 8,195 psig

μ 0.304 cp

P_{wf} 7,361 psig

c 7.02×10^{-6} psi⁻¹

m 420 psi/cycle

$$s = 1.151 \left[\frac{(8,195) - (7,361)}{420} - \log \frac{7.31}{(0.17)(0.304)(7.02 \times 10^{-6})(0.254)^2} + 3.23 \right] = -3.77$$

$$\Delta P_{\text{skin}} = (420)(0.87)(-3.77) = -1.378 \text{ psi.}$$

INTERCOMP

CROWN ZELLERBACH WELL NO. 2

SAND A

BUILDUP ANALYSIS

INTERCOMP

CROWN ZELLERBACH WELL NO. 2

SAND A

RESERVOIR GRID

CROWN ZELLERBACH NO. 2 WELL (SAND A) DRAWDOWN

INTERCOMP
CROWN ZELLERBACH WELL NO. 2
SAND A
HISTORY MATCH DRAWDOWN PRESSURE
FIGURE: 9.9

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