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PLEASANT BAYOU GEOPRESSURED–GEOTHERMAL RESERVOIR ANALYSIS—JANUARY 1991

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Topical Report

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DISCLAIMER

FOREWORD

This topical technical report describes work performed by S-CUBED, a Division of Maxwell Laboratories, Inc., under subcontract to the University of Texas at Austin (UTA). The research effort was performed for the U.S. Department of Energy (DOE) under its Cooperative Agreement No. DE-FC07-85NV10412 with UTA. Liaison was maintained between S-CUBED and other researchers under the DOE Geopressured-Geothermal Program throughout this work. Dr. Myron H. Dorfman of UTA was overall Principal Investigator for this DOE/UTA Cooperative Agreement, Ms. Peggy A. M. Brookshier and Mr. Kenneth J. Taylor successively served as the DOE Project Manager.

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ABSTRACT

vary in salinity, temperature, and dissolved methane.

Many sedimentary basins contain formations with pore fluids at pressures higher than hydrostatic value; these formations are called geopressured. The pore pressure is generally well in excess of hydrostatic and the fluids are ~~saline, hot, and contain dissolved methane~~. As part of its program to define the magnitude and recoverability of the geopressured-geothermal energy resource, the U.S. Department of Energy (DOE) has drilled and tested deep wells in geopressured formations in the Texas-Louisiana Gulf Coast region. Geological information for the Pleasant Bayou geopressured geothermal resource is most extensive among the reservoirs tested. Earlier testing of the DOE well (Pleasant Bayou Well No. 2) was conducted in several phases during 1979–1983. Long-term testing was resumed in May 1988 and is currently in progress. This report summarizes the pertinent field and laboratory test data available through December 31, 1990. A numerical reservoir simulator is employed as a tool for synthesizing and integrating the ~~geological~~ reservoir information, formation rock and fluid ~~properties~~ data from laboratory tests, ~~and~~ well data from the earlier testing (1979–1983), and the ongoing long-term production testing (1988–1990) of Pleasant Bayou Well ~~No.~~ 2. A reservoir simulation model has been constructed which provides a detailed match to the well test history to date. The model is constructed within a geologic framework described by the Texas Bureau of Economic Geology and relies heavily on the pressure transient data from the 1980 Reservoir Limits Test in conjunction with the 1988–1990 production testing.

PLEASANT BAYOU GEOPRESSURED-GEOTHERMAL RESERVOIR ANALYSIS—JANUARY 1991

1.0 INTRODUCTION

The Pleasant Bayou fault block ~~lies astride~~ is located at the boundary between Brazoria and Galveston Counties along the Texas Gulf Coast, about 40 miles south of Houston. The fault block was the first prospect selected for testing under the U.S. Department of Energy (DOE) program to evaluate the nation's geopressured-geothermal energy resource. The selection was based on geological work conducted at the University of Texas ~~Texas~~ Bureau of Economic Geology (BEG) by Bebout *et al.* (1978). Pleasant Bayou Well No. 1 was drilled in 1978 and plugged back and completed as a brine disposal well because of hole instability problems. The test well, Pleasant Bayou Well No. 2, was offset 500 feet from the No. 1 well, drilled to a depth of 16,500 feet and completed during 1979.

Pleasant Bayou No. 2 test well has 7-inch casing which is perforated across the thickness of 60 feet comprising the main reservoir sandstone (14,644 to 14,704 feet) within the lower Frio Formation C-zone; the total thickness of the C-zone at the wellbore is composed of 125 feet of sandstone and 109 feet of mudstone. The test well was completed with a 5.5-inch production tubing from 13,952 feet to the surface. After gas separation, the brine produced from the test well is injected into a shallow aquifer using Well No. 1 recompleted as a disposal well.

Preliminary testing (Phase 0) of Well No. 2 took place during 1979, reservoir limits testing during 1980 (Phase I), and long-term testing (Phase II) was conducted during 1981–1983. The test well experienced severe calcite scaling on the inner surface of the production tubing and numerous mechanical problems during Phase II, including wireline and fishing tool loss. Testing was suspended in May 1983 when the 5.5-inch production tubing parted at 5,225 feet (Rodgers, 1982).

Eaton Operating Co. subsequently took over the operation of the Pleasant Bayou facility for DOE; with the Institute of Gas Technology (IGT) responsible for surface production measurements. Both the production well (No. 2) and the injection well (No. 1) were successfully cleaned out and recompleted during 1987. The present completion of the production well is shown in Figure 1. The wireline and tool lost during the initial testing was pushed below the production perforations before recompleting Well No. 2.

The produced brine is principally a sodium chloride solution with substantial concentrations of calcium and ions such as potassium and magnesium; the salinity is ~130,000 ppm total dissolved solids, corresponding to a mass fraction of $S = 0.12$. Solution gases produced are mainly methane ($\sim$ 85%) and heavier hydrocarbons ($\sim$ 5%)

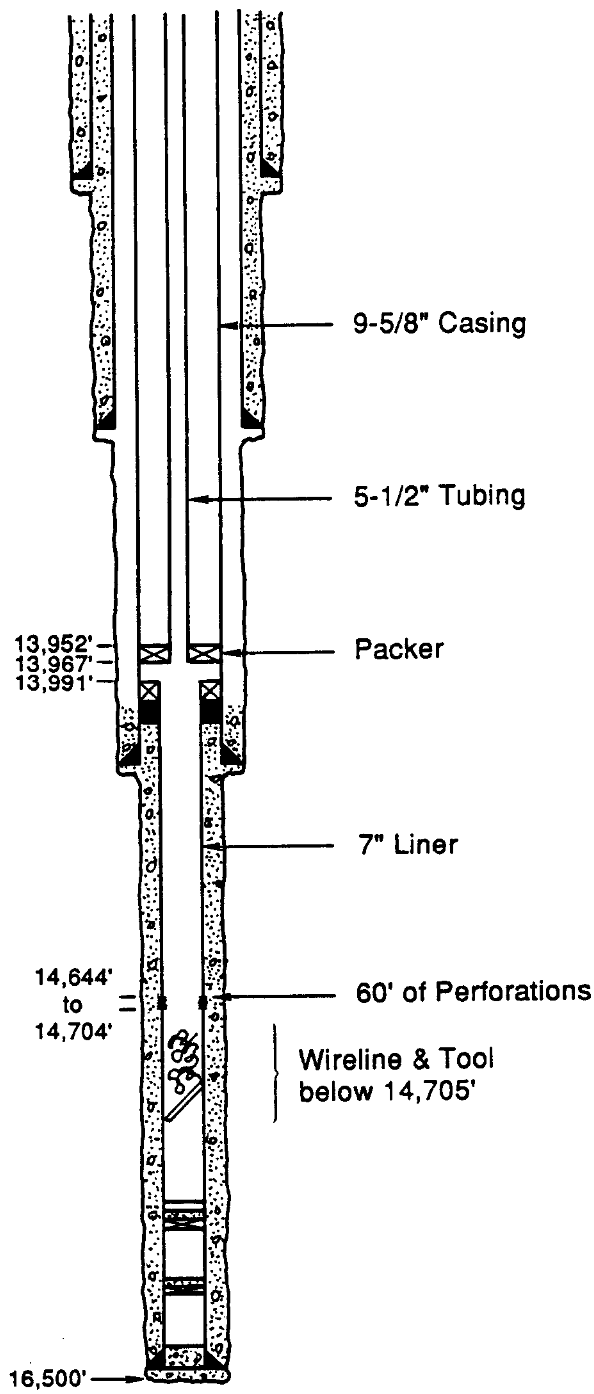

Figure 1. Recompleted Pleasant Bayou test well schematic (Eaton, *et al.*, 1988).

with significant quantities of carbon dioxide (~ 10%). The concentrated brine and presence of carbon dioxide under high temperature and pressure gave rise to problems of scaling in the tubular goods and surface equipment experienced in 1981–1983.

Prior to flow testing the recompleted production well, a phosphonate scale inhibitor "pill" was injected into the formation on April 18, 1988. The design of the phosphonate solution scale-inhibitor pill for Pleasant Bayou was developed by Tomson ~~based on work performed~~ at Rice University (Tomson, *et al.*, 1985). A second inhibitor pill was injected on November 19, 1989 after producing in excess of 7.7×10^6 bbls of brine with no downhole scaling. The success of the scale inhibitor pills ~~have~~ has been crucial to the success of the DOE geopressured geothermal ~~test~~ well program.

In preparation for the new phase of long-term production testing of the No. 2 well that began in May 1988, UTA-BEG (Hamlin and Tyler, 1988) reviewed all the previous geological studies of the Pleasant Bayou area (Bebout *et al.*, 1980; Loucks *et al.*, 1983; Ewing, *et al.*, 1984) and extended the research by focusing on the C-zone reservoir. Configurations were constructed by Hamlin and Tyler that approximate ~~actual~~ estimated reservoir volume, dimensions and pore-space distribution, but that are simple enough to serve as a framework for constructing a reservoir simulation model of the C-zone reservoir. However, data from only the one well are available ~~preventing~~ eliminating the consideration of heterogeneity and shaling laterally in the reservoir model.

The purpose of this paper is to describe the use of a numerical reservoir simulator as a tool for integrating and synthesizing the diverse data sets available for the Pleasant Bayou fault block, each of which describes some aspect of the geopressured-geothermal reservoir and/or its response to fluid production. The data sets available include the geologic interpretations by UTA-BEG, formation rock properties measured on core specimens by the rock mechanics group at the University of Texas (UTA), fluid properties measured in various laboratories (name these involved), data from the new (1988–1990) testing of Pleasant Bayou Well No. ~~2, and our interpretation~~ of the new flow test data in conjunction with pressure measurements made during the 1980 reservoir limits test. The available data sets will never be complete enough to uniquely define the required input parameters in the reservoir simulation model, and are limited to the single well location. The construction of the model requires the performance of a series of parametric calculations in which the input parameters are varied within their ranges of uncertainty in an attempt to match the production history of the test well. Since the data base is continuously being expanded and updated, the model development is a dynamic process and the reservoir simulation model will necessarily evolve as more complete information becomes available from continuing testing of the well. It should be noted that, because of the complexity of the data, several models could be constructed that fit the observed data. This report covers the model selected and developed by S-Cubed.

2.0 UTA-BEG CONFIGURATION

Figure 2 shows the structure map on top of the C-zone as recently revised by Hamlin and Tyler (1988). Locations of deep control wells and the Pleasant Bayou No. 2 test well are also shown. Large growth faults forming major lateral boundaries for the

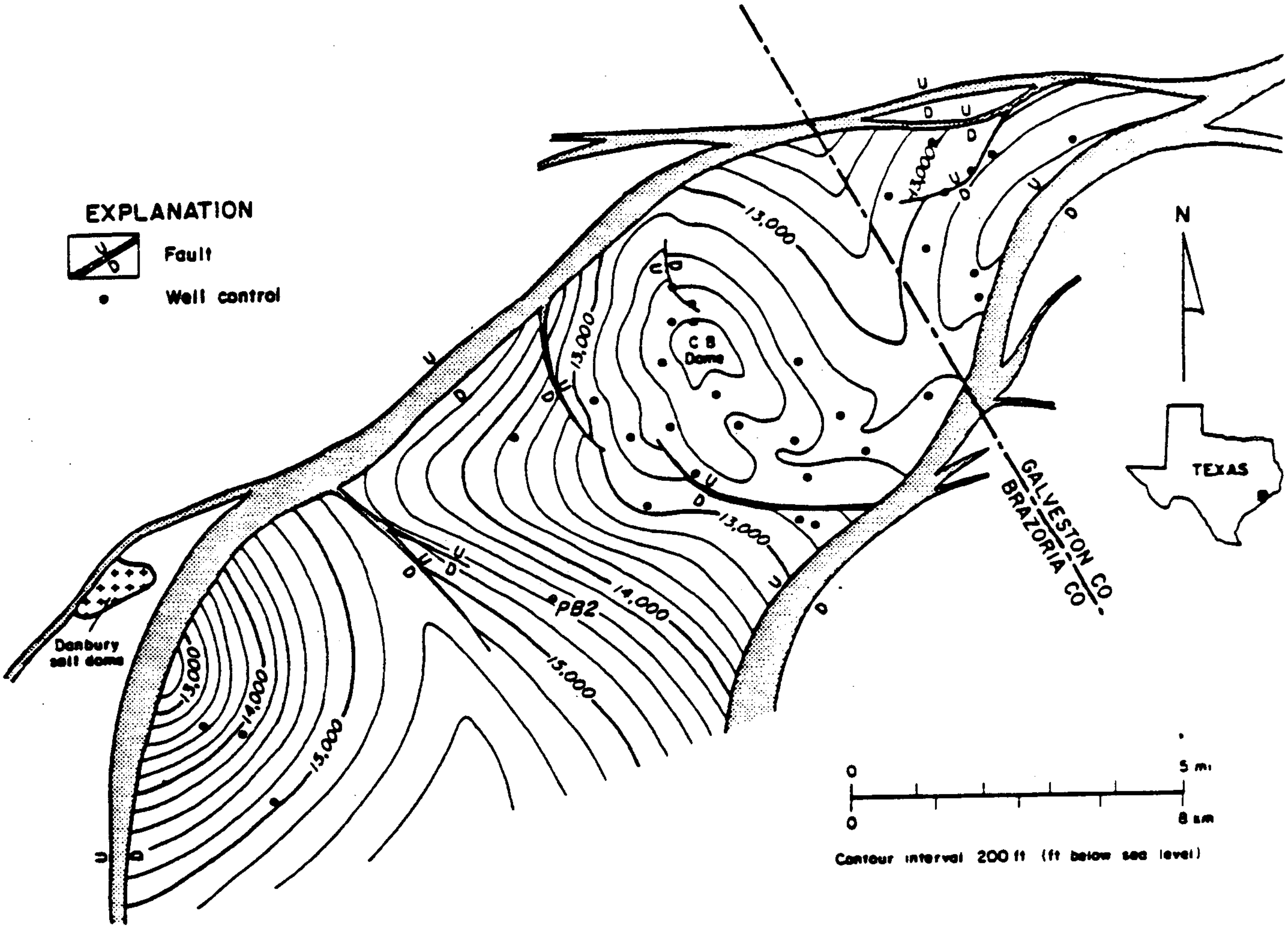

Figure 2. Revised structure map on the top of the C-zone (Hamlin and Tyler, 1988).

Pleasant Bayou fault block are well established except for the southern boundary; no deep control wells penetrate the C-zone in a large area south of the Pleasant Bayou No. 2 well. Numerous smaller faults within the block probably occur, but only those identified with well and seismic data are shown in Figure 2. Porosity pinch-out, possibly in conjunction with smaller internal faults, is considered by Hamlin and Tyler (1988) to form the southern boundary of the fault block, although there is no evidence for a southern boundary. They fix the southern boundary at 3 miles south of the test well for purposes of reservoir volume calculations since the southern area was bypassed by the major sand-depositing channel systems. Since there are no deep wells to the south, this model is conjecture and inferred.

The lateral continuity of the perforated interval of the test well and its communication with the other C-zone sandstones were traced by Hamlin and Tyler (1988) by correlating interbedded mudstones. Figure 3 reproduces a southwest-northeast cross section of the C-zone; Hamlin and Tyler found that only the upper and basal mudstones are continuous throughout the Pleasant Bayou fault block. They form the upper and lower boundaries of the reservoir, which can be subdivided into three units: the lower, middle (main perforated zone) and upper sandstone.

The cross section along the long axis of the fault block (Figure 3) illustrates multiple thick sandstones in the Danbury salt-withdrawal basin, the three sandstone units at the test well, the single massive sandstone at Chocolate Bayou, and thinly interbedded sandstones and mudstones to the northeast. Hamlin and Tyler (1988) conclude that the Chocolate Bayou area is an important region of vertical communication within the reservoir.

By constructing other cross-sections for the C-zone similar to Figure 3, Hamlin and Tyler delineated the sandstone and mudstone distributions for the entire C-zone reservoir and estimated the total C-zone sandstone volume to be ~ 2.3 mi^3. They assume that thicker sandstones are mostly composed of distributed channel-fill and channel-mouth bar deposits that have porosities similar to the perforated interval in the test well, $\phi_1 \sim 0.18$. Thinner sandstones are considered to have lower porosities, $\phi_2 \sim 0.09$. On the basis of measured sandstone volume and assumed porosity distribution, Hamlin and Tyler (1988) estimate that total C-zone sandstone pore volume is 8.3 billion bbls and that 75 to 80 percent of this is interconnected, i.e., they estimate that the effective pore volume is $V_p = 6.2$ to 6.6 billion bbls.

However porosities can vary widely in a reservoir and a single well value greatly limits the validity of a model.

Figure 4 presents a simple rectangular configuration (BEG1) that Hamlin and Tyler suggest as a reasonable approximation to the geometry, volume and porosity distribution for the C-zone reservoir. The boundaries of the configuration represent average reservoir length, width, thickness and horizontal porosity layers approximate the geometry of the major reservoir sandstones. The model configuration consists of a main high-porosity ($\phi_1 = 0.18$) reservoir sand sandwiched between two low-porosity ($\phi_2 = 0.09$) layers which represent thinner, more isolated sandstones comprising the "remote volume" of its reservoir. In Figure 4 we have superimposed the approximate locations of three internal faults in the main reservoir sand, denoted by F1, F2 and

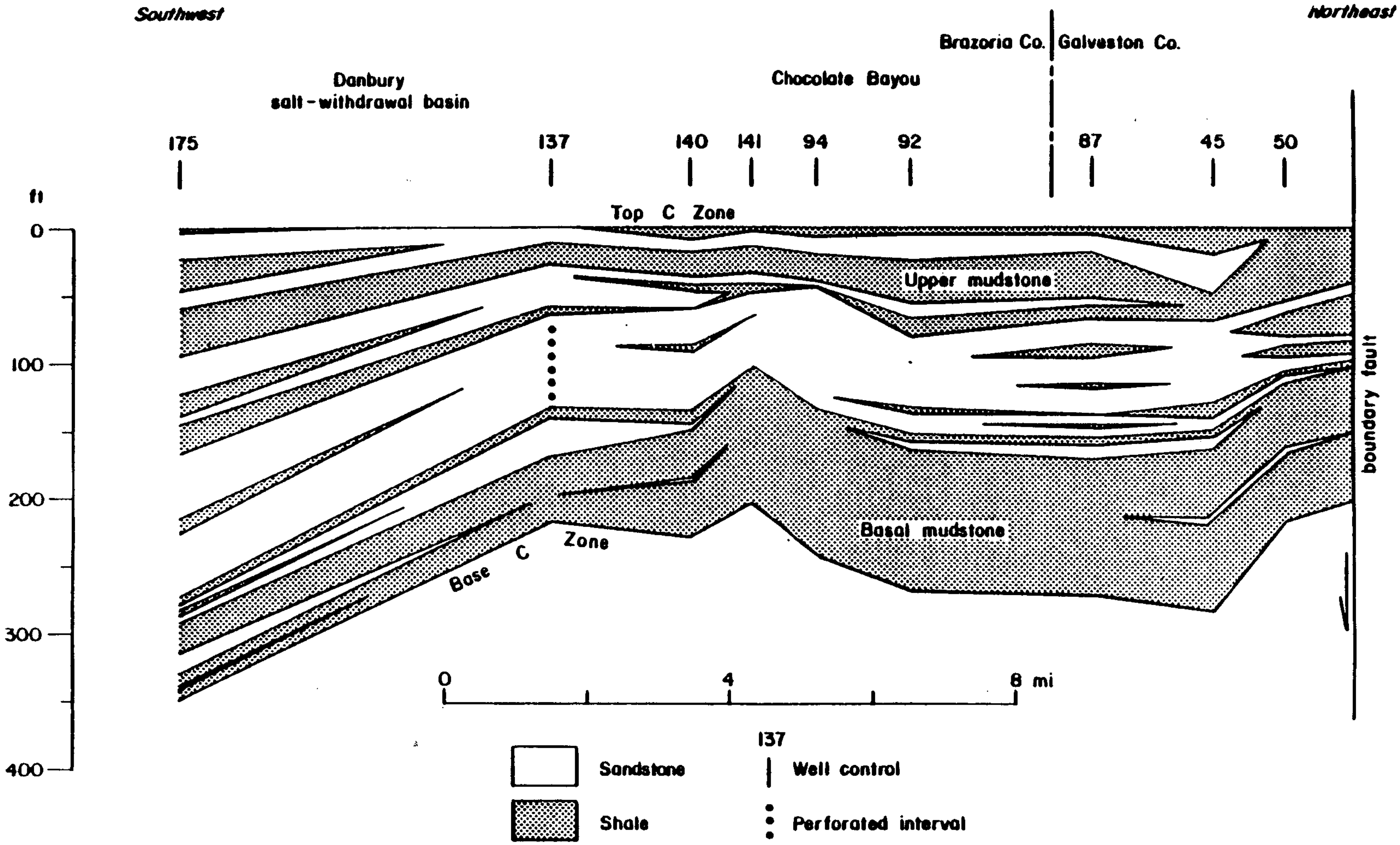

Figure 3. Southwest-northeast cross section showing details of sandstone and mudstone interbedding along strike down the long axis of the fault block (Hamlin and Tyler, 1988).

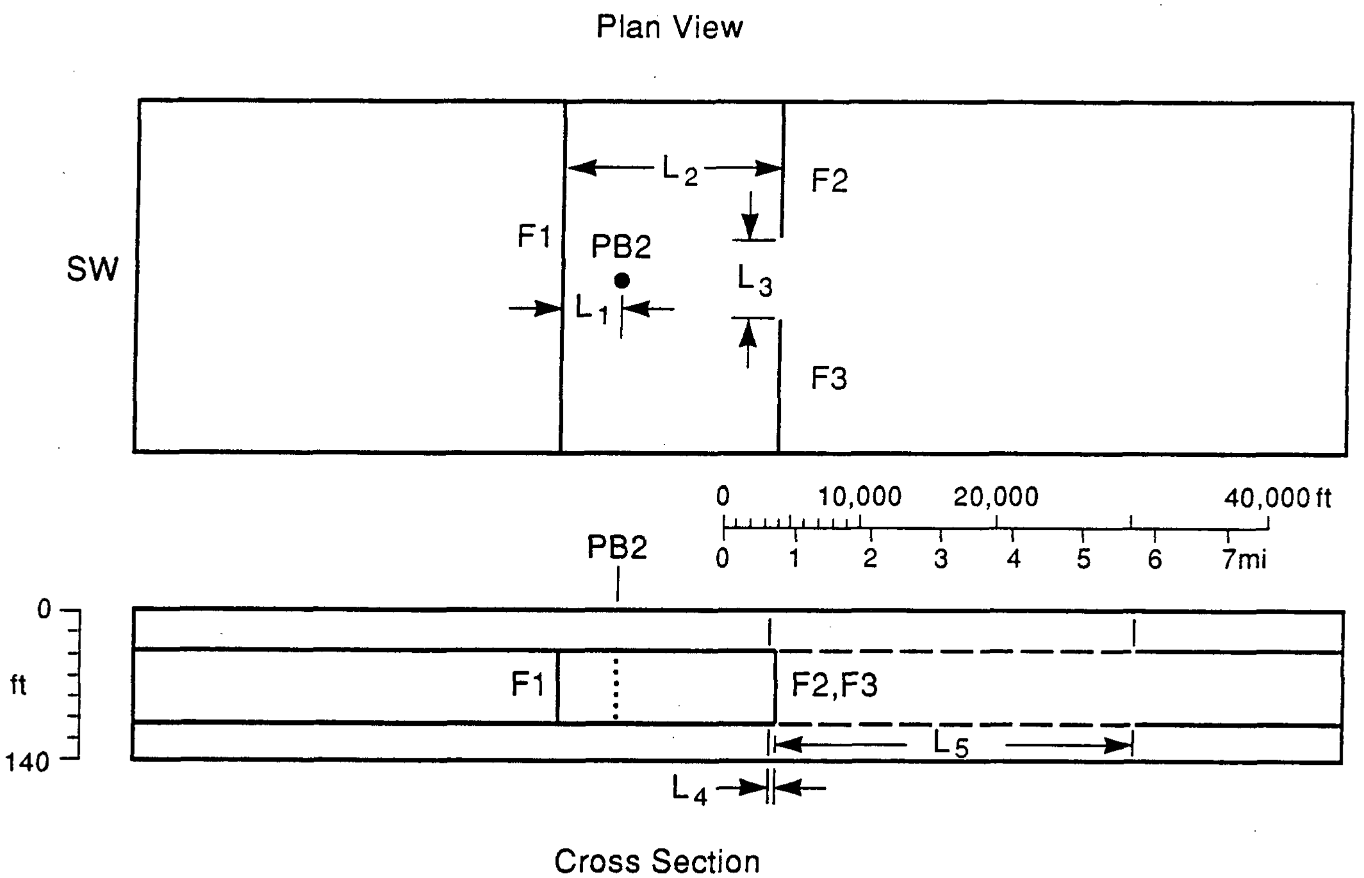

Figure 4. Reservoir simulation model geometry based on BEG1 model.

F3. They represent the internal faults identified in Figure 2 on the basis of seismic and control well data.

The geologically based configuration does not provide information regarding formation compressibility and transmissivity, fluid properties, or the major "effective connection zones" between the remote volume layers and the main reservoir layer. The consolidated geological information presented by Hamlin and Tyler (1988), however, provide a framework within which the reservoir simulation model will be synthesized using the various data sets available.

3.0 PRODUCTION HISTORY

There have been four periods during the history of the Pleasant Bayou test well when downhole pressure/temperature transient measurements have been made. Results from the preliminary short-term (Phase 0) testing were reported by Garg (1980). The three tests to date during long-term testing are as follows:

1.	September 15, 1980 to December 15, 1980	Reservoir limits test (drawdown/buildup)
2.	May 26, 1988 to June 1, 1988	Multi-rate test after recompletion (drawdown/buildup)
3.	May 15, 1989 to May 18, 1989	65-hr test (buildup only)

The 90-day reservoir limits test at the start (Phase I) of the initial long-term testing of the well consisted of a 45-day multi-rate drawdown followed by a 45-day pressure buildup test. These 1980 data are very valuable since this is the only downhole test of sufficient duration to detect the presence of a reservoir boundary (Garg, *et al.*, 1981).

Table 1 lists approximations made to the flow rates reported by Rodgers (1982, Vol. 2) for the 1980 reservoir limits test (RLT). The Panex P/T gauge set at 14,560 feet recorded values of 11,116 psia and 306°F prior to opening the well on September 16, 1980. The well was flowing at a steady rate of $\sim 12,616$ stb/d when shutin at 15:32 on October 31, 1980 for the buildup portion of the RLT. The sandface pressure recorded at 14,560 feet just prior to shutin was 10,388 psia. During November 8-10, the Panex gauge failed and was removed, repaired and reset at 14,560 feet. This resulted in a discontinuity in the buildup pressure data at $t = 54$–46 days as indicated in Figure 5 (corrected to the reference datum of 14,600 feet). The brief transients in the data points are associated with repair of the choke and adjustments in the choke settings at times when the stepped flow-rates were changed. The flow rate approximations in Table 2 do not include the associated overshoots/undershoots in the rate adjustments. On the other hand, the intermediate flow rate changes between 12 to 23 days in Table 1

Table 1. Pleasant Bayou Well No. 2 flow rates during 1980 Reservoir Limits Test.

	Test Day	Date	Time	tp (hrs)	q (STB/D)
	1	9/16/80	11:30	0.0	2,527
	1	9/16/80	12:00	0.5	4,911
	1	9/16/80	12:30	1.0	5,672
A	1	9/16/80	14:50	3.333	6,436
A	6	9/21/80	17:10	125.67	0
	6	9/21/80	19:30	128.00	9,338
B	6	9/21/80	20:15	128.75	10,476
B	16	10/01/80	11:00	359.50	14,556
C	16	10/01/80	14:40	363.17	18,184
C	19	10/04/80	18:30	439.00	17,723
	19	10/04/80	24:00	444.50	14,934
	22	10/07/80	24:00	516.50	13,625
D	23	10/08/80	24:00	540.50	12,616
D	46	10/31/80	15:32	1084.033	0

Table 2. Pleasant Bayou Well No. 2 flow rates during May 1988 Multi-Rate Test.

Step	Date	Time	tp (hrs)	q (stb/d)
1	5/27/88	07:33:36	0.0	4,896
2	5/27/88	19:04:13	11.510	7,398
3	5/28/88	07:03:52	23.504	11,729
4	5/28/88	13:20:00	29.773	11,473
5	5/29/88	13:50:00	54.273	9,433
6	5/30/88	18:07:55	82.572	0

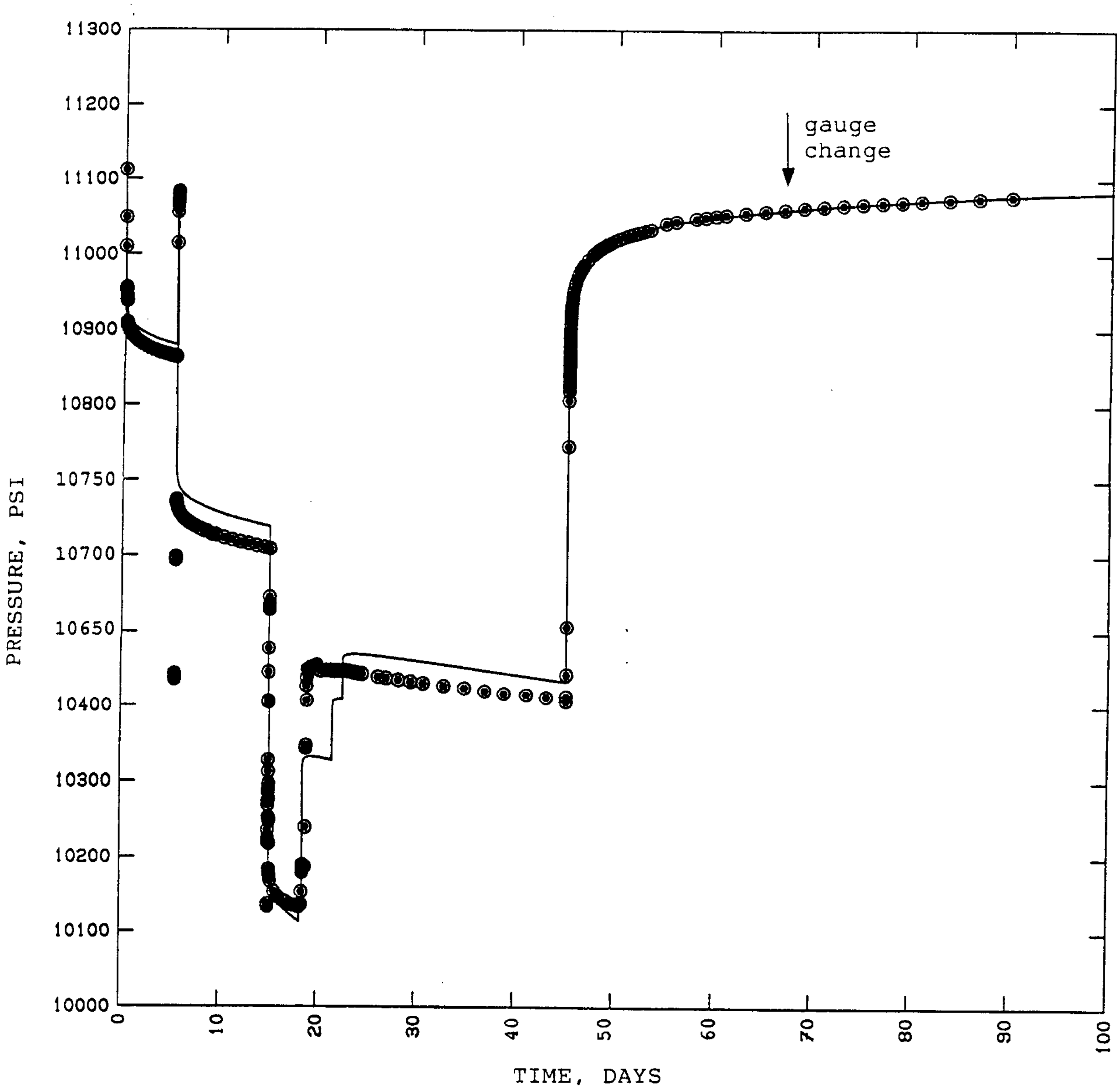

Figure 5. Data points are for 1980 RLT bottomhole measurements corrected to 14,600 ft datum. Curve is the simulated history.

were reported, and they are included in our simulation studies. The fact that the pressure data do not reflect these intermediate rate changes casts some doubt on the accuracy of the Phase I flow rate measurements.

Although the well was produced at $q \sim 20,000$ bbl/d for a total production of $\sim 3.7 \times 10^6$ bbl during 1981-1983 (Phase II), no successful downhole measurements were made and the available wellhead recordings are of no diagnostic value because of severe scaling in the production tubing and surface equipment. Total production during the initial 1979-1983 testing (Phases 0, I and II) was $Q_1 \sim 4.5 \times 10^6$ bbl.

A Panex pressure/temperature gauge was lowered in the recompleted Pleasant Bayou Well No. 2 on May 26, 1988 (test day 0) and set at a depth of 13,950 feet in preparation for the multi-rate test (MRT). After equilibriating overnight, stable P/T values of 10,685 psia and 293.7°F were recorded; the well was opened at 07:33:36 on May 27, 1988 ($t = 0.0$ hours). Some adjustments in flow rate were required before a steady value was attained; an average rate $\sim 4,896$ stb/d was produced during the initial step of the MRT. This flow rate and the other averaged rates for the MRT shown in Table 2 are based on orifice values reported by IGT. On May 28 ($t = 30$ hours) the pressure readings of the original ("Old") downhole gauge began to drift; on May 29 ($t \sim 52$ hours) it failed completely. It was pulled out the hole and replaced by a "New" Panex gauge also set at 13,950 feet. The test well was flowing at a steady rate of $\sim 9,433$ stb/d when shutin at 18:07:55 on May 30, 1988 ($t = 82.572$ hours) for the buildup portion of the MRT. The flowing P/T values recorded at 13,950 feet just prior to shutin were 10,281 psia and 300.3°F. Figure 6 shows the MRT data corrected to the reference datum level of 14,600 feet.

On June 20-21, 1988 (test day 25–26) there was production of a large amount of sand when the flow rate was increased stepwise to flow rates up to $\sim 25,000$ stb/d. There was a dramatic drop in the surface pressure after the sand production. The rate was subsequently held below $\sim 20,000$ stb/d with no further significant sand production. The flow rate generally declined to $\sim 17,400$ stb/d when it was reduced to a stable rate of $q \sim 12,205$ stb/d on April 27, 1989, in preparation for the 65-hour shutin test.

On May 15, 1989 (test day 354) a Panex P/T gauge was lowered in the well flowing at $q \sim 12,205$ stb/d and set at 14,600 feet. Equilibriated values of 10,085 psia and 307.7°F were recorded just prior to shutting the well at 08:07:44 on May 15, 1989 ($t = 8,472.0$ hours) for the 65-hour buildup test.

Subsequent to the 65-hour pressure buildup test (May 15–18, 1989), the test well was produced at $\sim 16,000$ stb/d until it was shutin on November 16, 1989 in preparation for the second scale inhibitor pill injection. Production resumed on November 24 and continued to May 30, 1990 when the well was shutin to evaluate the mechanical integrity of the disposal well. The flow rate had gradually declined to $\sim 15,400$ stb/d at that time.

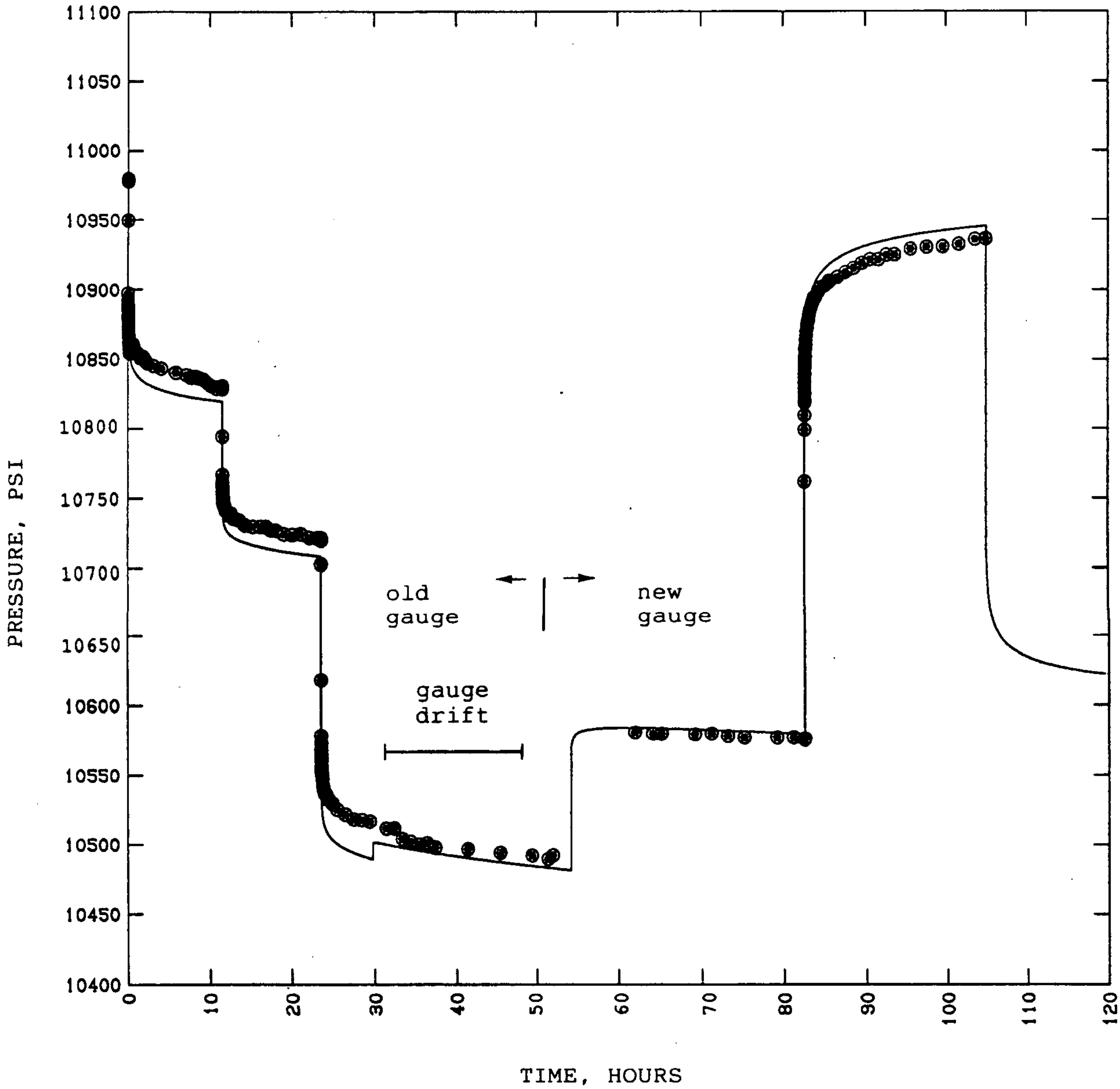

Figure 6. Data points are for 1988 MRT bottomhole measurements corrected to 14,600 ft datum. Curve is the simulated history.

During the June 1989–May 1990 period the rate was maintained at $\sim$ 16,000 stb/d to provide the brine inlet pressure needed for flow operation of the Hybrid Power System (HPS). Once the HPS experiment and workover of the disposal well was completed, production was resumed on July 27, 1990 (test day 792). The rate was increased from $\sim$ 16,000 stb/d in four stages until a flow rate of $q \sim$ 24,000 stb/d was attained on October 16, 1990 (test day 873). A slug of about ten gallons of sand was produced on October 28 (test day 885); the production rate was subsequently reduced to $\sim$ 12,000 stb/d. Sand detection equipment will be installed in the production system prior to further testing at high flow rates.

During the 1988–1990 production testing to date (May 27, 1989–December 31, 1990), Pleasant Bayou Well No. 2 has produced an additional volume of $Q \sim 13.3 \times 10^6$ bbls.

Since the production tubing has been free of scale during the 1988–1990 production testing, bottomhole pressures can be inferred from wellhead recordings during periods of stable flow. A wellbore flow simulator calibrated against pressure/temperature logs performed in the recompleted test well will be employed for this purpose. Before presenting the analysis of the pressure transient and production testing data, available information on the reservoir properties and the wellbore calculations will be described.

4.0 RESERVOIR PROPERTIES AND WELLBORE CALCULATIONS

4.1 Fluid Properties

An equation-of-state package for water/sodium chloride/methane mixtures (Pritchett, 1985) is used to calculate the properties of the reservoir fluid as it moves from the formation to the surface. The package is similar to one developed earlier (Pritchett *et al.*, 1979) but incorporates additional brine compressibility data (Osif, 1984) and methane solubility data (Price, *et al.* 1981). For reservoir conditions measured at 14,560 feet at the start of the 1980 reservoir limits test (11,116 psia, 306°F), the mass fractions corresponding to a fully saturated liquid brine, according to the equation-of-state, would yield a gas-to-water ratio of 31.7 SCF/STB (ft^3 bbl^{-1} at 14.67 psia, 60.33 °F). Since the actual measured value is GWR $\sim$ 24 SCF/STB, the reservoir is assumed to be initially undersaturated.

The mass fraction composition employed to represent the Pleasant Bayou brine in the equation-of-state calculations is as follows:

H_2O: 0.87733 CH_4: 0.00267   NaCl: 0.12000

This choice yields GWR = 24.0 SCF/STB. We choose to use a common datum level of 14,600 feet hereafter. The reservoir conditions measured at the start of the 1980 reservoir limits test become (at 14,600 feet datum):

$$P_o = 11,134 \text{ psia} \qquad T_o = 306°\text{F}$$

The pressure would need to be reduced to $\sim$ 6400 psia for free methane gas to evolve from the reservoir brine. However, carbon-dioxide and other gas components present in the brine might cause free gas to evolve at higher pressures.

Prior to the 1988 multi-rate test, after recompleting the well, a stable pressure of 10,685 psia was measured at 13,950 feet; the temperature measurements were in error (see later section). Flowing temperature measured at 14,600 feet prior to the 1989 65-hr shutin test was 306°F, in agreement with the 1980 measurement. The pressures recorded at 13,950 feet are corrected to the datum depth by adding 292.7 psi. The reservoir conditions at the start of the testing of the Pleasant Bayou Well No. 2 after recompletion are therefore assumed to be (at 14,600 feet datum):

$$P_i = 10,978 \text{ psia} \quad T_i = 306°\text{F}$$

The corresponding calculated equation-of-state values for the dynamic viscosity (μ), formation factor (B_o) and compressibility (C_w) of the reservoir fluid are as follows:

$$\mu = 0.270 \text{ cp} \quad B_o = 1.049 \text{ res bbl/std bbl} \quad C_w = 2.55 \times 10^{-6} \text{ psi}^{-1}$$

4.2 Formation Properties

The total compressibility of the reservoir formation is computed from the sum of the uniaxial pore volume compressibility (C_{pm}) and fluid compressibility (C_w) in accordance with the relation $C_T = C_{pm} + C_w = \phi^{-1}C_m + C_w$. Here $C_m = \phi C_{pm}$ is the uniaxial formation compressibility. A representative value for the coefficient C_m has been estimated from UTA rock mechanics tests on Pleasant Bayou reservoir cores (Fahrenthold and Gray, 1985) to be $C_m \sim 3$ to 6×10^{-7} psi^{-1}. Using $C_w = 2.55 \times 10^{-6}$ psi^{-1} and $\phi = 0.18$, these values for C_m imply $C_T = 4.2 - 5.9 \times 10^{-6}$ psi^{-1} for the BEG1 main reservoir sand. We assume a value of $C_T = 4.83 \times 10^{-6}$ psi^{-1}.

Earlier analysis and history-matching calculations (Garg, *et al.*, 1981) for the 1980 Phase I data employed the following estimates for formation properties: $\phi_o = 0.176$ and $C_T = 7.7 \times 10^{-6}$ psi^{-1}. The analysis detected a single hydrologic boundary at a distance of $L \sim 3,000$ feet, a near-well transmissivity of kh = 11,520 md-ft, and a variable skin factor. If the present estimates for formation properties ($\phi = 0.18$ and

$C_T = 4.83 \times 10^{-6}$ psi^{-1}) had been used, the corresponding results of the earlier analysis would have been

$$
\begin{aligned}
L &= 3000\sqrt{\frac{7.7}{4.83}\,\frac{0.176}{0.18}} \sim 3740 \text{ ft} \\
s &= s_{orig} + 1.151 \log\left(\frac{4.83}{7.7}\,\frac{0.18}{0.176}\right) = s_{orig} - 0.22 \quad .
\end{aligned}
$$

With the latter adjustment, the multi-rate analysis by Garg, *et al.* (1981) gave the following estimates for the skin factor (s) for three steps (A, B and C in Table 1) of the drawdown portion and the buildup portion of the 1980 RLT: A ($s = 0.13$), B ($s = 0.29$), C ($s = 6.08$), buildup ($s = 3.90$).

In addition to pressure transient data interpretation, formation permeability can also be estimated from log/core analysis. Two common methods employ the following two relations:

$$
\text{(Schlumberger)} \qquad k = \left[\frac{100(\phi_e)^{2.25}}{S_{w,irr}}\right]^2
$$

$$
\text{(Dresser Atlas)} \qquad k = \frac{0.136(100\phi_e)^{4.4}}{100\, S_{w,irr}} \quad ,
$$

where

$$
\begin{aligned}
k &= \text{permeability (md)} \\
\phi_e &= \text{effective porosity} \\
S_{w,irr} &= \text{irreducible water saturation} \quad .
\end{aligned}
$$

Using $S_{w,irr} = 0.14$ (Rodgers, 1982, Vol. 1) we compute for the following estimates for the two BEG1 sands:

Main Reservoir Sand ($\phi = 0.18$)

(Schlumberger)	$k \sim 227$ md
(Dresser Atlas)	$k \sim 214$ md

Remote Volume ($\phi = 0.09$)

(Schlumberger)	$k \sim 10$ md
(Dresser Atlas)	$k \sim 11$ md

The estimates based on ϕ_2 are considered less reliable since the remote volume is comprised of a large number of thin sandstone layers with varying properties.

4.3 Wellbore Calculations

The wellbore flow model (Pritchett, 1985) calculates the steady flow in a geothermal well producing under stable conditions. Starting with specified bottomhole conditions, the program integrates up the well to predict the wellhead conditions. The frictional effects in the wellbore are treated using a correlation due to (Duckler, *et al.* 1964); the effects of tubing roughness are included through a relative roughness parameter (R) which occurs as a model input parameter. Heat loss by combined conduction and convection from a porous water-saturated medium is treated by an approximate analytical solution; its magnitude is controlled by the well geometry and the effective formation conductivity (K). The wellbore model uses the equation-of-state for the Pleasant Bayou brine, described above, to calculate the properties of the geopressured fluid as it rises in the production tubing. The far-field temperature gradient is assumed to be 1.2 °F/100 ft above 10,000 feet, 2.33 °F/100 ft depths 10,000–14,600 feet, and 1.25 °F/100 ft below 14,600 feet.

Table 3 lists the available downhole flowing pressure and temperature measurements in Pleasant Bayou Well No. 2 since it was recompleted. The temperature profile recordings of June 1, 1988 are suspect; the surface gauge recorded a value 6.5°F higher than the recording at a depth of 20 feet during the logging. The May 14–15, 1989 data are preferred for calibrating the wellbore flow model since both the pressure and temperature profile measurements are considered reliable, the measurements extend to 14,600 ft rather than 13,950 ft as was the case for June 1, 1988 measurements, and the higher flow rate (12,205 stb/d) ensures that the frictional pressure drop is more significant than for the earlier case (8,726 stb/d). The P/T data are best matched (for the assumed fluid composition and reservoir temperature T_o = 306°F), with the following values for the empirical parameters: $K = 1.05$ Wm^{-2} °C^{-1}, $R = 0.12$ mm.

Figures 7 and 8 compare the measured P/T profile data with calculations using the calibrated wellbore model. The calculated temperature profile for $q = 12,205$ stb/d falls (curve 7) between the two measured profiles of May 14–15, 1989 (curves 5 and 6 in Figure 8); the corresponding pressure profiles (Figure 7) are also in good agreement. The calculated and measured pressure profiles for $q = 8,872$ stb/d (curves 2 and 3) are also in agreement. Although no reliable surface temperature data for June 1, 1988 are available, the wellhead recordings on July 21, 1988 when the well had flowed at $q \sim 19,200$ stb/d for a sustained period are comparable to the calculated value (curve 4, Figure 8).

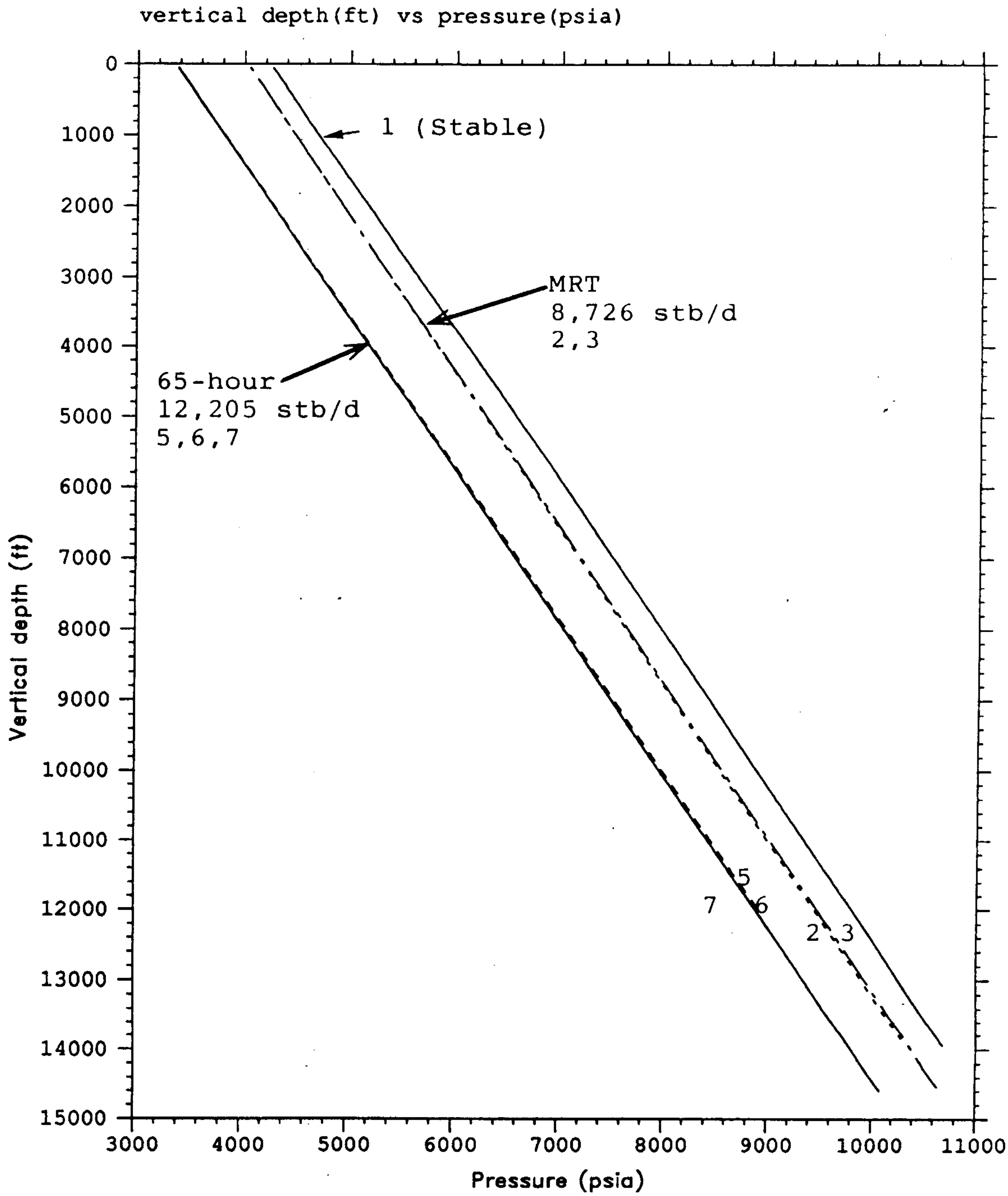

Figure 7. Calculated pressure-depth profiles (curves 3,7) compared with downhole values logged in Pleasant Bayou Well No. 2 when flowing at 8,726 stb/d (curve 2) and 12,205 stb/d (curves 5,6). A stable profile logged prior to the MRT test is also shown (curve 1).

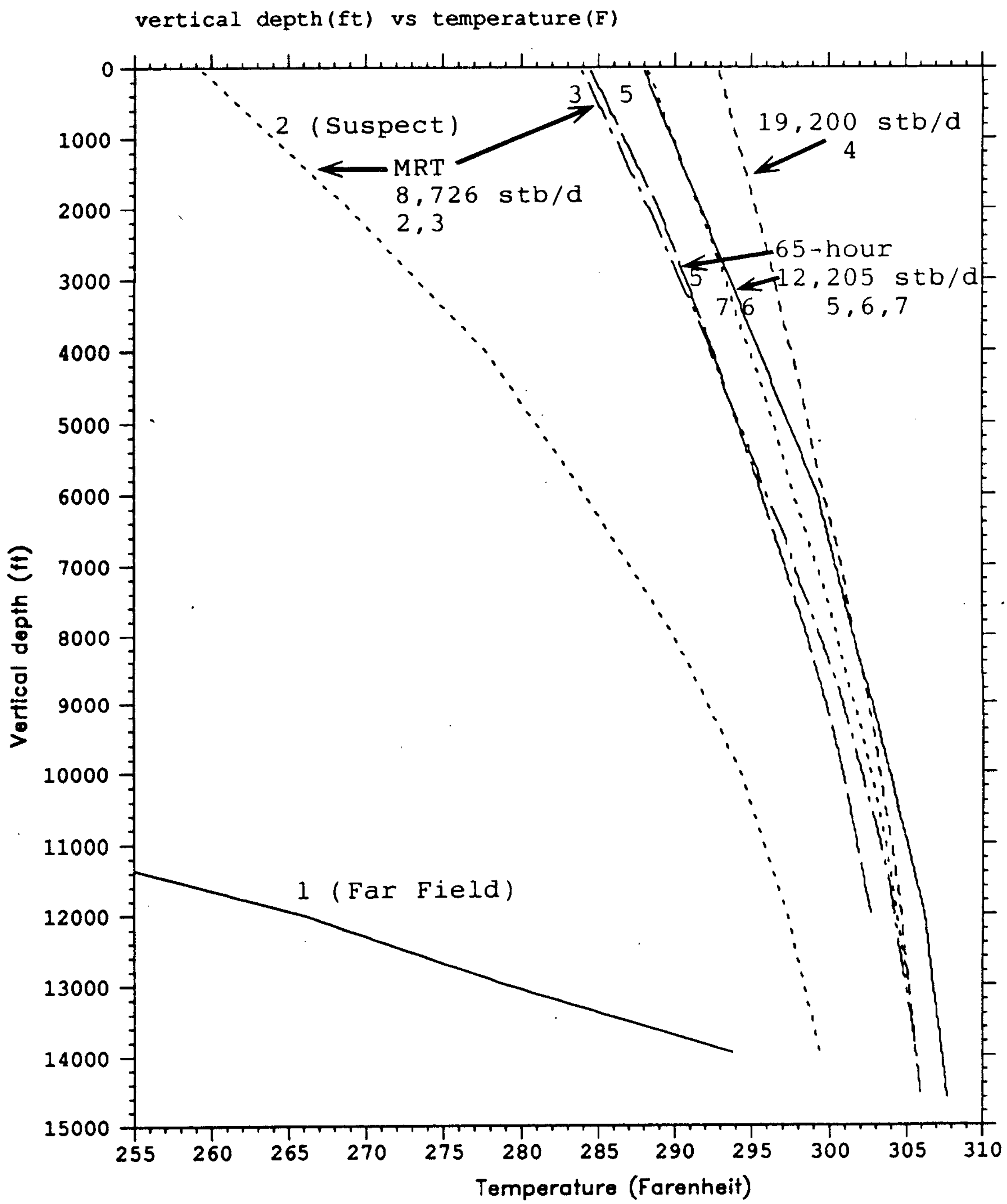

Figure 8. Calculated temperature-depth profiles (curves 3,7) compared with downhole values logged in Pleasant Bayou Well No. 2 when flowing at 8,726 stb/d (curve 2) and 12,205 stb/d (curves 5,6). Calculation for 19,200 stb/d (curve 4) and the far-field geothermal gradient are also shown (curve 1).

Table 3. Pressure and temperature profile data for recompleted Pleasant Bayou Well No. 2.

Date	June 1, 1988		May 14, 1989		May 14–15, 1989	
Test Day	6		353		354	
Test Name	MRT		65–Hour		65–Hour	
q (stb/d)	8,726		12,205		12,205	
Depth (ft)	p (psia)	T* (°F)	p (psia)	T (°F)	p (psia)	T (°F)
15	—	—	3,364	284.4	3,357	287.9
20	4,037	259.3	—	—	—	—
2,000	4,934	268.9	4,281	288.9	—	—
4,000	5,831	277.7	5,209	292.5	—	—
6,000	6,731	284.1	6,136	295.7	6,118	299.3
8,000	7,640	289.9	7,064	298.7	—	—
10,000	8,545	294.3	7,990	300.9	—	—
12,000	9,450	297.3	8,919	302.7	8,889	306.1
13,950	10,334	299.4	—	—	—	—
14,600	—	—	—	—	10,085	307.7

* Temperature data suspect

The calibrated wellbore model has been used to estimate the pressure drop ($\Delta p_{wb} = \Delta p_{hydr} + \Delta p_{fric}$) in the wellbore for a specified flow rate and pressure at the datum level, 14,600 feet. Figure 9 presents the results. The hydrostatic component (Δp_{hydr}) decreases with increasing q since the fluid is less dense as it has less time to cool in the wellbore at higher rates; the frictional component (Δp_{fric}), however, rapidly increases as q increases. The total pressure drop (Δp_{wb}) decreases with increasing q for $q <\sim$ 3,500 stb/d and then increases rapidly with q. For a fixed value of q, Δp_{wb} decreases with a decreasing value for the datum pressure; since more gas evolves in the wellbore at the lower datum pressure the wellbore fluid is less dense. The decrease is $\sim$ 100 psi as the datum pressure decreases from 11,500 to 8,000 psia.

The change in datum pressures has negligible effect on the wellhead temperatures predicted by the wellbore model; the flow rate does have a significant effect. Figure 10 compares the results of the calibrated model calculations with the wellhead temperatures recorded at times of sustained flow at a stable rate. The datum pressure at 14,600 feet was fixed at 10,000 psia. The agreement is quite good.

Because of the limited downhole P/T profile data available, however, the calibration and associated wellbore model predictions (and consequently the bottomhole pressure values estimated from wellhead recordings) are subject to error during periods

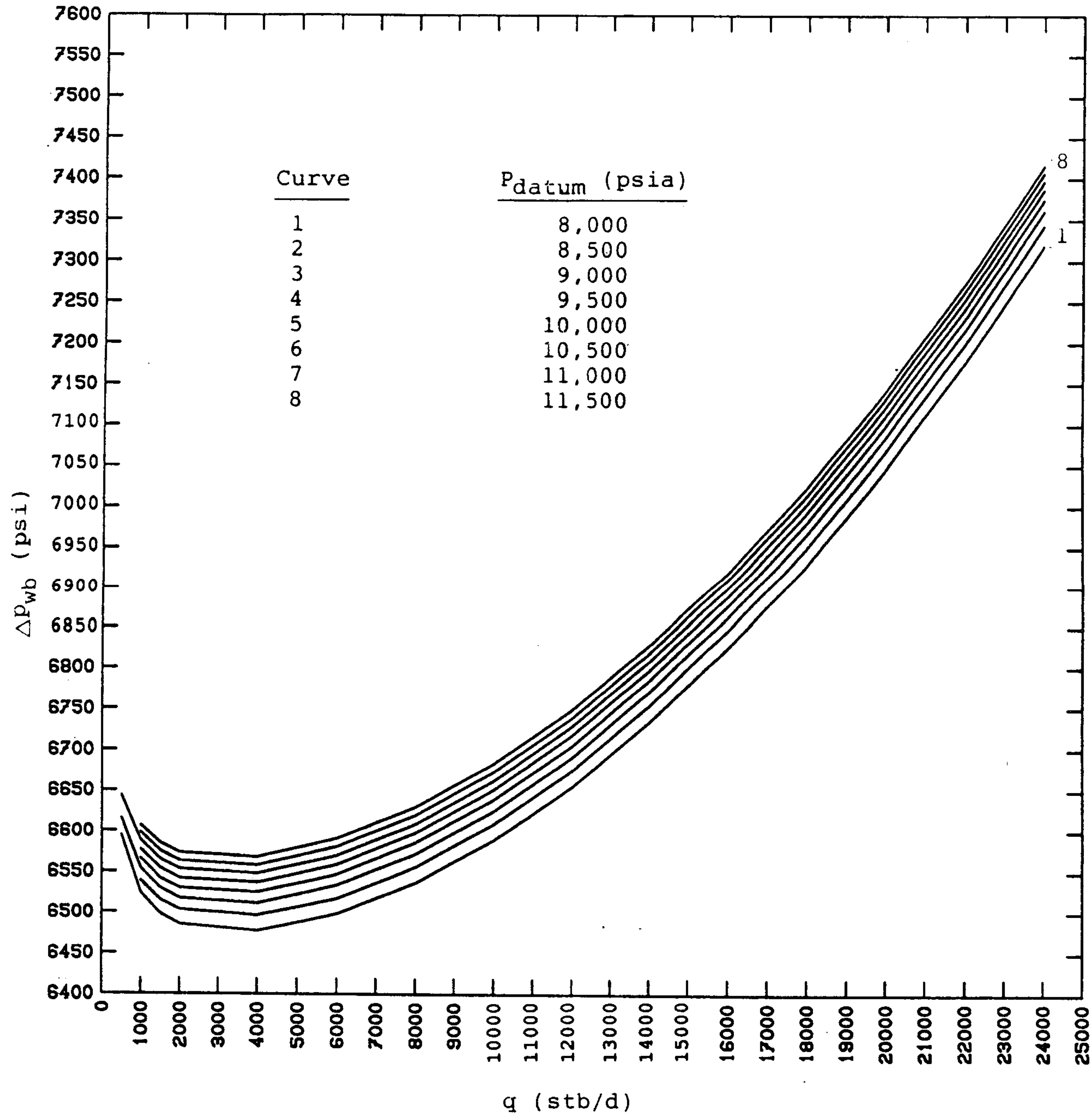

Figure 9. Wellbore pressure drop variations with flow rates for Pleasant Bayou Well No. 2 (calculated with calibrated wellbore flow model: $K = 1.05\ \mathrm{W/m^2{-}^\circ C}$, $R = 0.12$ mm, $T_{datum} = 306°F$). Datum pressure at 14,600 feet set at values indicated on curves.

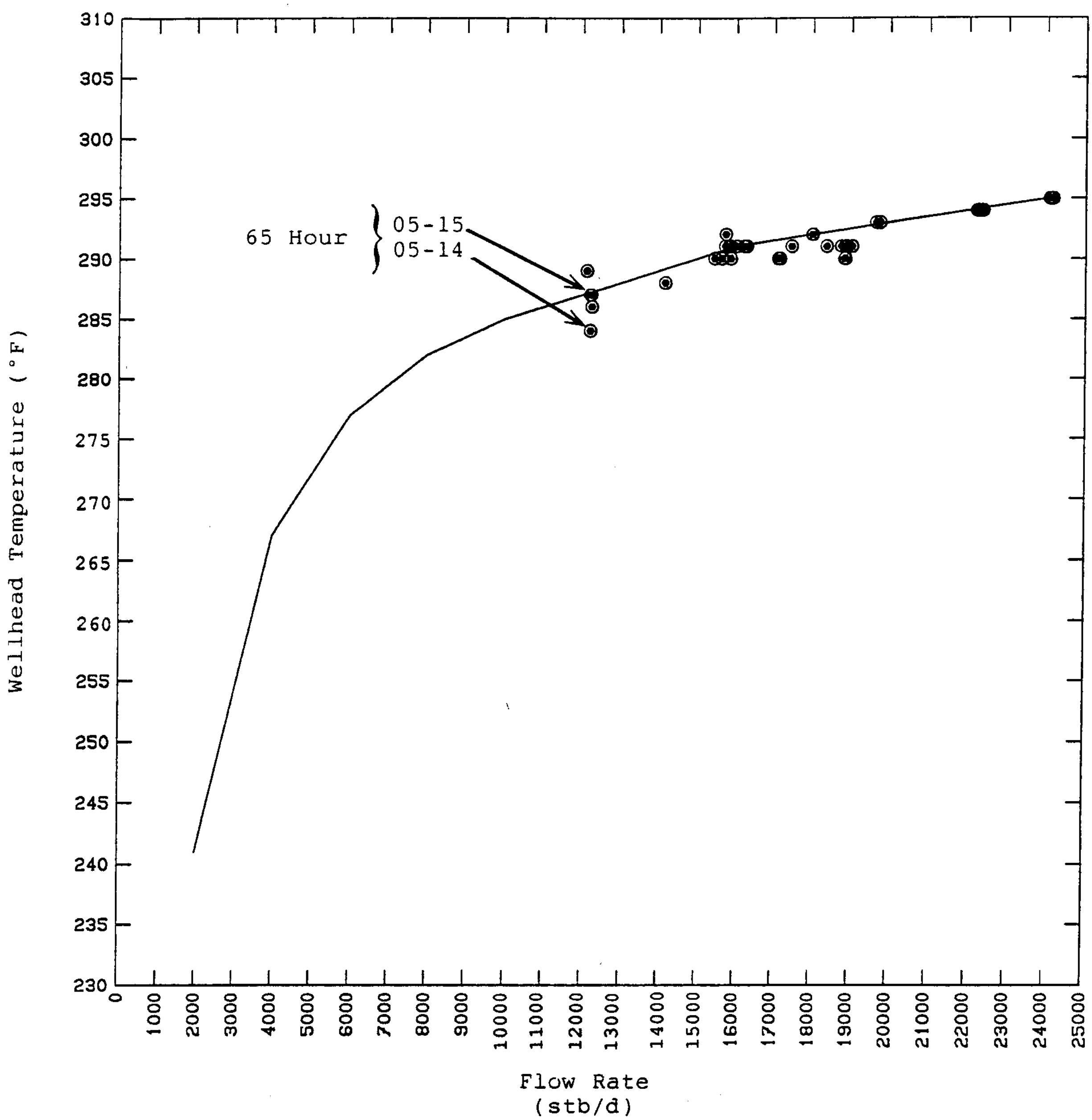

Figure 10. Stable wellhead temperatures recorded at Pleasant Bayou Well No. 2 during 1988–1990 (data points) at indicated flow rates compared with wellbore model calculations (curve).

of high flow rates. This is illustrated by Figure 11 which presents the calculated wellbore pressure drop variations using different values for the relative roughness parameter (R). An increase from the selected calibration value of $R = 0.12$ mm to $R = 0.21$ mm would increase the calculated value of Δp_{wb} by less than $\sim$ 50 psi at the calibration flow rate (12,205 stb/d) but would predict a value $\sim$ 160 psi higher at $q = 24,000$ stb/d. The estimated value of the flowing bottomhole pressure based on wellhead recordings would be correspondingly higher.

5.0 ANALYSIS OF PRESSURE DATA

5.1 Pressure Transient Data

The reservoir analysis is simplified by the relatively low gas content; the effects of any free gas that might evolve within the Pleasant Bayou reservoir formation would be confined to a very small zone at the sandface. The relative permeability of the formation to the liquid brine would in such a two-phase region be reduced somewhat. Parametric simulations assessing the effects of irreversible rock compaction and stress-dependent permeability (Riney, 1986) indicated that any associated nonlinear effects at Pleasant Bayou would also likely occur only in the neighborhood of the wellbore. Such local effects would be reflected as variations in the apparent value of the skin factor.

Consider a well flowing under semi-steady state conditions at rate q for an equivalent production period t_p. If there is a step rate change at time t_p, the shutin sandface pressure change ($\Delta p = p_{ws}]_{t_p+\Delta t} - p_{wf}]_{t_p}$) is approximated by (in oilfield units; see Earlougher, 1977)

$$\frac{\Delta p}{\Delta q} = m'(\log \Delta t + \log \frac{k}{\phi \mu C_T r_w^2} - 3.23 + 0.87\, s) \quad , \tag{1}$$

where $m' = 162.6\mu\, B_o/kh$. Set $\Delta t = 1$ hr and solve for s to obtain

$$s = 1.151 \left\{ \frac{1}{m'} \left[\frac{\Delta p}{\Delta q}\right]_{1\,\mathrm{hr}} - \log \frac{k}{\phi \mu C_T r_w^2} + 3.23 \right\} \quad . \tag{2}$$

Figure 12 compares plots of $\Delta p/\Delta q$ vs $\log \Delta t$ for the buildup portion of the RLT (rate change from 12,616 to 0 stb/d on October 31, 1980) and the 65-hour buildup test (rate change from 12,205 to 0 stb/d on May 15, 1989) with plots for two steps of the MRT. The plot for the first step (rate change from 0 to 4,896 stb/d on May 27, 1988) of the drawdown portion of the MRT reflects adjustments made to establish a stable flow rate but thereafter is closely approximated by a line of the same slope ($m' = 3.83 \times 10^{-3}$ psi/stb/d) as lines approximating the RLT and 65-hour buildup tests. The plot for the

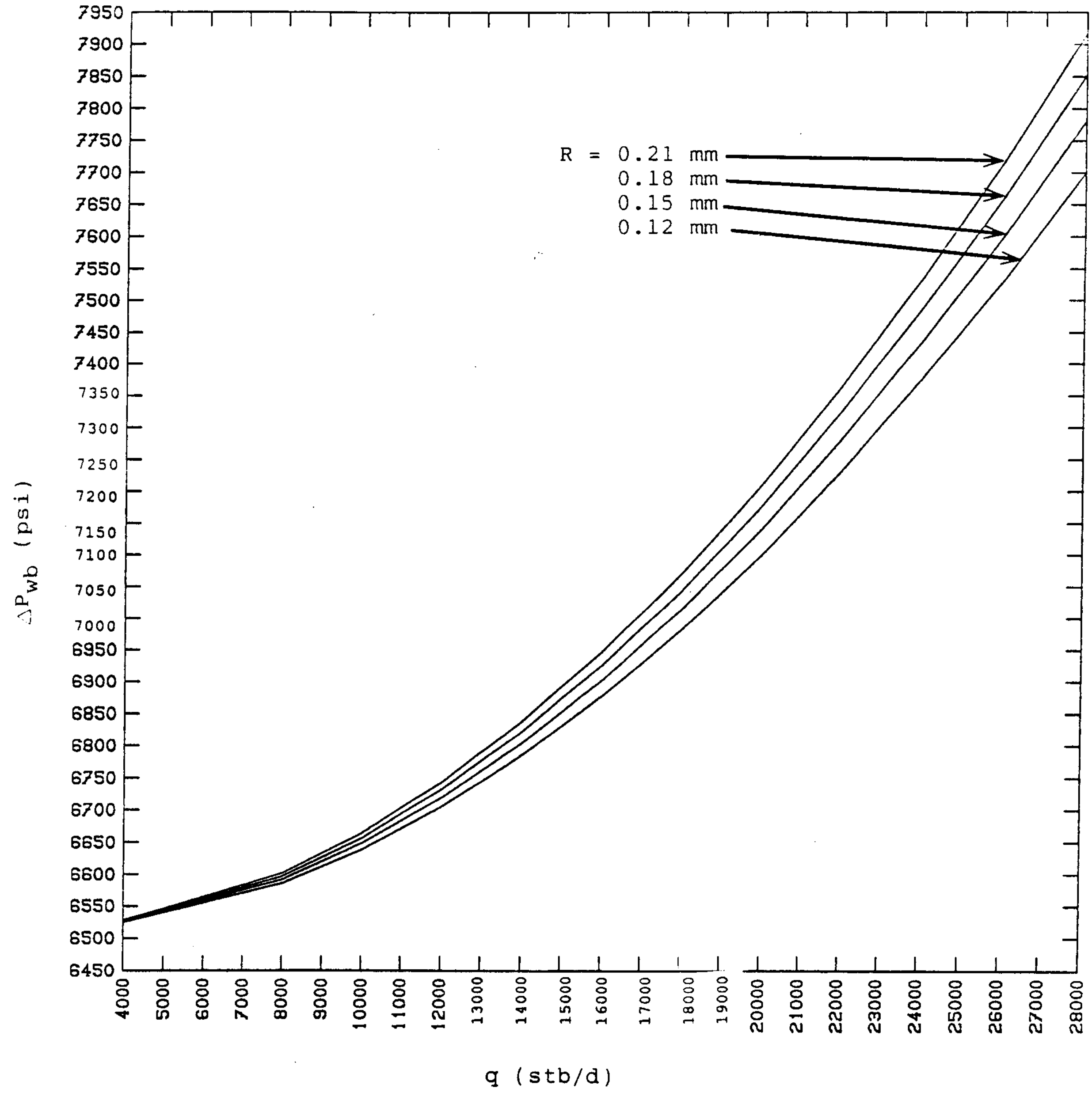

Figure 11. Effect of roughness factor (R) on wellbore pressure drop variation with flow rate (calculated with $K = 1.05$ W/m^2–°C, $T_{datum} = 306$°F and indicated values of R). Datum pressure at 14,600 feet set at 9,500 psia.

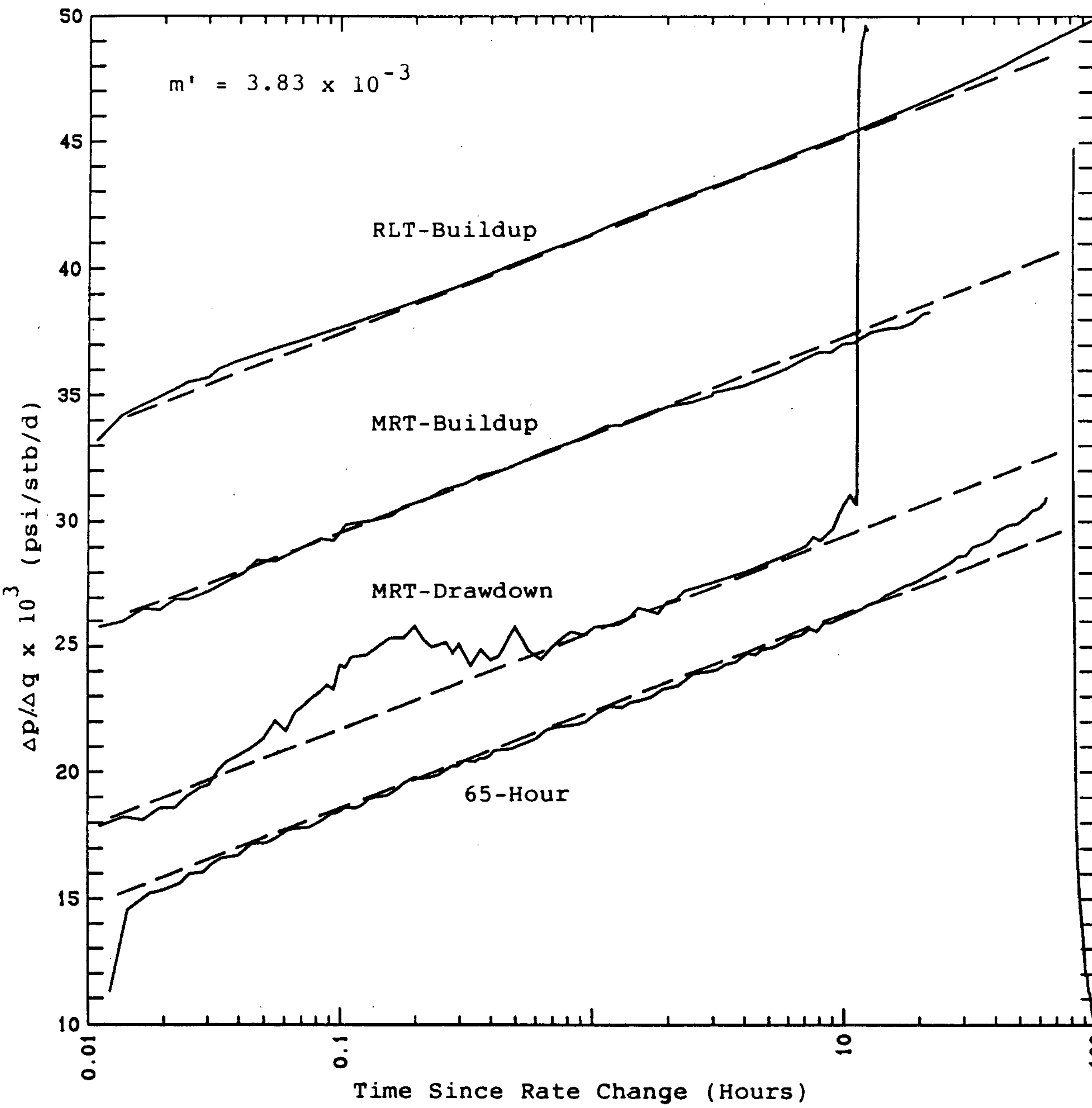

Figure 12. Bottomhole pressure transient data from buildup portion of 1980 Reservoir Limits Test, the 65-hour buildup, one step of the multi-rate drawdown, and the buildup after the multi-rate test of Pleasant Bayou Well No. 2. Datum level is 14,600 feet.

early part of the buildup portion of the MRT (rate change from 9,433 to 0 stb/d on May 30, 1988), is also closely approximated by a line of the same slope.

In the above simultaneous analysis, the input parameters employed were: $r_w = 0.2917$ ft, $h = 60$ ft, $\phi = .18$, $\mu = 0.27$ cp, $C_T = 4.83 \times 10^{-6}$ psi^{-1}, $B_o = 1.049$. The value for the formation transmissivity corresponding to m' is given by

$$kh = \frac{162.6\mu B_o}{m'} = 12,024 \text{ md} - \text{ft} \quad .$$

These values for the input parameters were also used in Equation (2) to calculate the values of the skin factor listed in Table 4.

Table 4. Summary of simultaneous analysis of bottomhole pressure transient measurements for Pleasant Bayou Well No. 2. Multi-rate and reservoir limits data were corrected to common 14,600 feet datum level.

	Multi-rate Test		65-Hour	Reservoir Limits Test
	Drawdown	Buildup	Buildup	Buildup
Date of Measurement	May 27, '88	May 30, '88	May 15, '89	Oct 31, '80
Test Days, d	1	4	354	(46)
Q, 10^3 stb	0	31.94	5,913	($\sim$ 542)
$[p_{wf}]_{0-}$, psia	10,978	10,574	10,085	10,406
Δq,stb/d	4,896	9,433	12,205	12,616
$[\frac{\Delta p}{\Delta q}]_{1\text{ hr}} \times 10^3$, psi/stb/d	25.5	33.4	22.3	41.2
m' x 10^3, $\frac{\text{psi}}{\sim}/\frac{\text{stb}}{\text{d}}$	3.83	3.83	3.83	3.83
kh, md-ft	12,024	12,024	12,024	12,024
s	-0.13	+2.24	-1.09	+4.59

5.2 Skin Factor Variations

There have been times during the 1988–1990 testing when Pleasant Bayou Well No. 2 had flowed at a constant rate for a sustained period prior to a planned shutin. On the eight occasions listed in Table 5, recordings of the wellhead pressure were made on a continuous basis just prior to and immediately after shutin. These data can be evaluated to estimate the value of the skin factor at those times. For this purpose we set $\Delta t = 3$ m $= 0.05$ hr in Equation (1) and solve for s to obtain

$$s = 1.151 \left\{ \frac{1}{m'} \left[\frac{\Delta p}{\Delta q} \right]_{3\,\mathrm{m}} - \log \frac{k(0.05)}{\phi \mu C_T r_w^2} + 3.23 \right\} \quad . \tag{3}$$

The choice of $\Delta t = 3$m is made since it has been found to be long enough for wellbore storage effects to be small, and short enough for thermal changes to be negligible.

Table 5. Estimated values of skin factor (s_{est}) at indicated times during testing of Pleasant Bayou Well No. 2. Listed pressure values (at 14,600 ft datum) are estimated from wellhead recordings just prior to and immediately after shutin.

Date of Recording		Test Day	$[q]_{0-}$ (stb/d)	$[p_{wf}]_{0-}$ (psia)	$[p_{ws}]_{3\mathrm{m}}$ (psia)	$[\Delta p/\Delta q]_{3\mathrm{m}} \times 10^3$ psi/stb/d	s_{est}
1988	08-31	97	19,244	10,094	10,434	17.67	−0.99(±0.78)
	10-17	144	19,006	10,044	10,408	19.15	−0.54(±0.79)
1989	05-15	354	12,143	10,078	10,304	18.61	−0.70(±1.24)
	05-31	370	14,463	10,050	10,338	19.91	−0.31(±1.04)
	07-20	420	15,864	9,897	10,240	21.62	+0.20(±0.95)
	09-08	470	15,756	9,912	10,264	22.34	+0.42(±0.95)
	11-16	539	15,819	9,920	10,293	23.58	+0.79(±0.95)
1990	05-30	734	15,400	9,775	10,159	24.94	+1.20(±0.98)

When the well is shut $\Delta p_{wb} \rightarrow \Delta p_{hydr}$. The value of $\Delta p_{hydr}(\sim 6,460$ psi) has been estimated (at the 14,600 ft datum level) from simultaneous wellhead and bottomhole pressure measurements made at the times of the MRT and 65-hr shutin tests. The sandface shutin pressures $[p_{ws}]_{3\,\mathrm{m}}$, listed in Table 5, are calculated based on the approximation $[p_{ws}]_{3\,\mathrm{m}} = [p_{WH}]_{3\,\mathrm{m}} + \Delta p_{hydr}$. Estimates for the sandface flowing pressures just prior to shutin are given by $[p_{wf}]_{\Delta t=0-} = [p_{WH}]_{\Delta t=0-} + \Delta p_{wb}$, with the values Δp_{wb} calculated using the calibrated model for wellbore flow, are also listed in Table 5.

Using Equation (3) with $r_w = 0.2917$ ft, $h = 60$ ft, $\phi = 0.18, \mu = 0.27$ cp, $C_T = 4.83 \times 10^{-6}$ psi^{-1} and the values calculated $\Delta p = p_{ws}]_{3\,\mathrm{m}} - p_{wf}]_{\Delta t=0-}$ (with $m' = 3.83 \times 10^{-3}$ psi/stb/d and kh = 12,024 md-ft from Table 4), the estimates listed in Table 5 for the skin factor (s_{est}) are obtained for the eight shutin times.

Estimations for Δp at 14,600 feet from the wellhead recordings are subject to error. Estimates of $[p_{ws}]_{3\mathrm{m}}$ are believed to be accurate within $<\sim$ 50 psi. Since estimates for $[p_{wf}]_{0-}$ use calculated Δp_{wb} values, errors probably increase at higher flow rates. As discussed above, use of too small a value of R in the calibrated wellbore model would underestimate the calculated value of Δp_{wb}; the estimate for $[p_{wf}]_{0-}$ would be underestimated by a corresponding amount. The associated estimate for the skin-factor using Equation (3) would consequently tend to be overestimated at higher flow rates.

To illustrate the effect of an error of $\sim \pm 50$ psi in our estimations for Δp at 14,600 feet, we note from Equation (3) that the corresponding margin of error in the skin factor estimate is $\delta s \sim 1.151[\Delta p/\Delta q]_{3\mathrm{m}}/m'] \sim 15/\Delta q \times 10^{-3}$. The associated errors in s_{est} are included in Table 5. We note from Table 4 that the value of s determined from the downhole data at the time of the 65-hour shutin test ($s = -1.09$) falls within the range of uncertainty for the corresponding value estimated from wellhead recordings ($s = -0.70 \pm 1.24$).

The estimates for the skin factor obtained from the simultaneous analysis of the downhole pressure data (Table 4) and the analysis of the surface data (Table 5) are plotted in Figure 13 against the corresponding values of the bottomhole (14,600 ft datum) pressure drop from the original reservoir pressure of $P_o = 11,134$ psia. Also plotted are estimates for s based on the multi-rate analysis of the 1980 RLT downhole (Garg, *et al.*, 1981).

The estimated skin factors from the 1980 RLT data (drawdown steps A, B, C and buildup values) and the 1988 MRT data are approximated by a single trend line. The apparent drop in the estimated s value between May 30 (MRT buildup) and August 31, 1988 is believed to be associated with the sand production on June 20–21, 1988 discussed earlier. Subsequent to the sand production, the estimated values of s are approximated by a second line parallel to the earlier trend line (Figure 13).

The fact that the estimated s values approximate the trend lines might indicate that the skin factor depends on bottomhole pressure. Based on parametric calculations performed to examine the possible effects of free gas evolution and nonlinear formation response (earlier section), the latter mechanism would be a more plausible cause for the pressure dependence. The effective stress at the sandface increases as the bottomhole pressure decreases. The dependence of s on the bottomhole pressure must be considered tenuous, however, since its evaluation from surface data is subject to significant error.

In summary, there are possibly three mechanisms contributing to the apparent variations of the skin-factor s:

1. An increase associated with an increase in the effective stress on the formation in the neighborhood of the wellbore.
2. An abrupt decrease in s associated with sand production on June 20–21, 1988.
3. Possible creation of a very small gas bubble within the near-wellbore formation composed of carbon-dioxide and minor gas species in the brine.

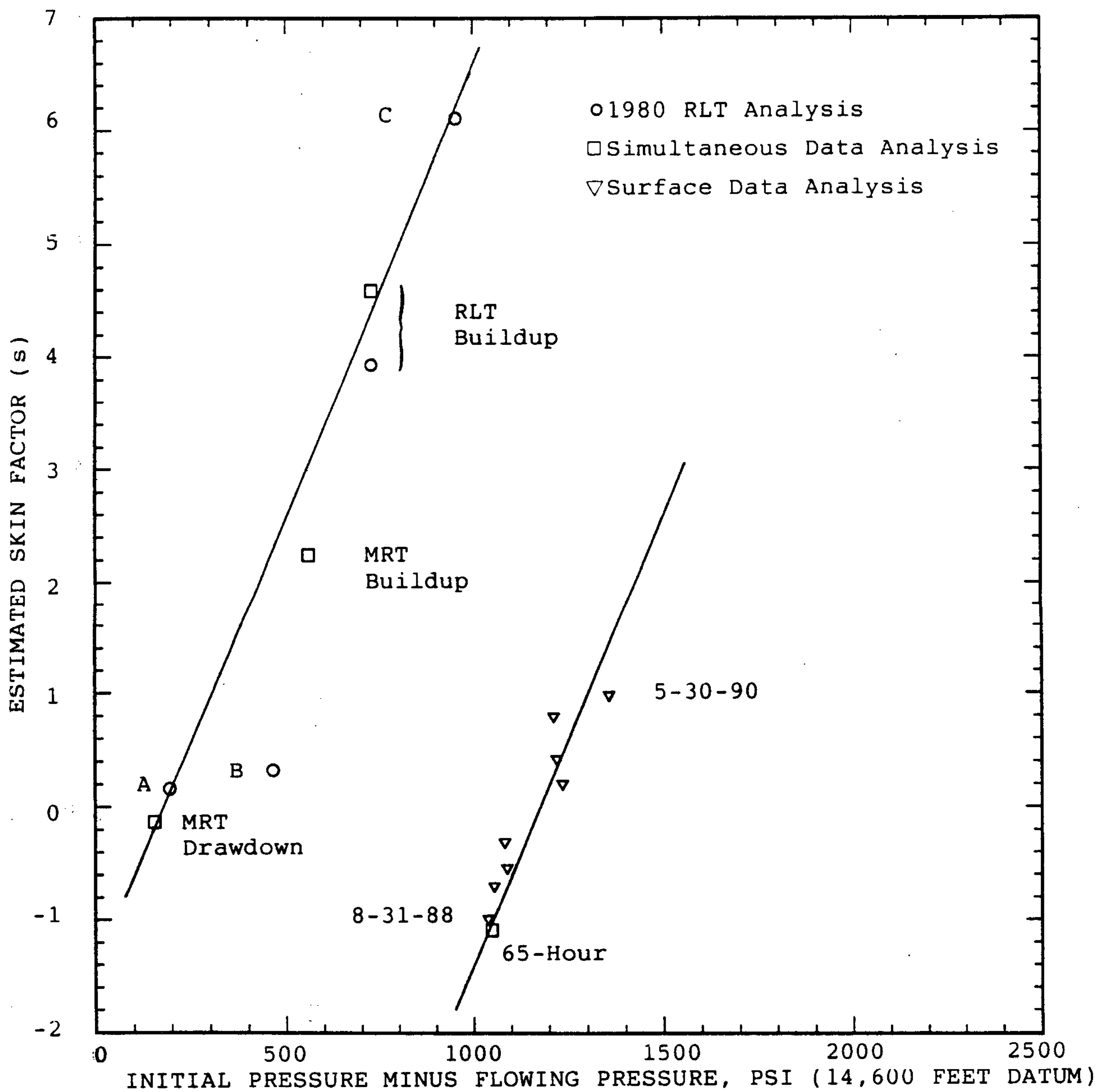

Figure 13. Estimated skin factor (s) values displayed as function of pore pressure decrease (from $P_o = 11,134$ psia) in neighborhood of the Pleasant Bayou Well No. 2 wellbore.

There is no evidence of an increase in the skin-factor associated with the injection of phosphonate scale inhibitor pills on April 18, 1988 and November 19, 1989. This is contrary to the experience at the Gladys McCall geopressured test well (Riney, 1990).

5.3 Reservoir Volume Estimate

The measured drop in the stable reservoir pressure (at 14,600 feet datum) between September 16, 1980 and May 27, 1988 was

$$\Delta P = P_o - P_i \tag{4}$$

$$= 11,134 - 10,978 = 156\text{psi} \tag{5}$$

This value and the formation properties assumed for the Pleasant Bayou reservoir can be used to estimate the connected pore volume drained by the test well,

$$V_p = \frac{QB}{C_T \Delta p} \tag{6}$$

$$\sim \frac{(4.5 \times 10^6)(1.049)}{(4.83 \times 10^{-6})(156)} = 6.26 \times 10^9\text{bbl} \tag{7}$$

This value is remarkably close to the estimate of $V_p = 6.2$ to 6.6 billion bbls based on the geological studies of Hamlin and Tyler (1988). The agreement is to some extent fortuitous given the inherent errors in downhole pressure measurements.

6.0 RESERVOIR SIMULATION MODEL

6.1 Preliminary Simulations

The BEG1 reservoir configuration (Figure 4) has a pore volume of 8.0 billion bbls comprised of the main reservoir sand (5.3 billion bbls) and the remote volume (2.7 billion bbls). Since both the stable pressure data and the geological studies imply a total connected pore volume of 6.2 to 6.6 billion bbls, portions of the reservoir configuration are presumably not hydrologically connected to the test well. The report by Hamlin and Tyler (1988) does not delineate regions of isolated and interconnected porosity within the reservoir configuration.

Fluid flow within the interconnected reservoir pore volume is controlled by internal hydrological barriers and major permeable zones. The locations, lengths and orientation of these heterogeneities cannot be completely defined with existing well and seismic data (Hamlin and Tyler, 1988). Dimensional parameters L1 through L5 have been introduced into the BEG1 configuration (Figure 4) to correspond to these uncertainties and preliminary reservoir simulation calculations have been performed to estimate their effective values. The simulations were performed for both the 1980 RLT and the 1988–1990 production histories.

Since the thickness of the main reservoir sand of BEG1 is h = 70 feet, we take $k_1 = 12,024/70 = 172$ md to preserve the near-well horizontal transmissivity determined from the pressure transient data analysis. The vertical permeability and far-field horizontal permeabilities were varied in the preliminary reservoir simulations. The total formation compressibility ($C_T = 4.83 \times 10^{-6}$ psi^{-1}) and brine properties ($\mu = 0.27$ cp, $\rho = 1036.8$ kg/m^3) were the same throughout the reservoir volume.

The 1980 RLT and the early stages of the 1988–1990 test histories of the well primarily reflect the properties of the main reservoir sand. The remote volume parameters begin to affect the calculated test history only during longer production periods. Preliminary simulations were made which verified the presence of a hydrologic barrier at approximately 3,000 to 4,000 feet (L1) from the test well as detected from an earlier analysis of the 1980 RLT data (Garg *et al.*, 1981). The calculations implied that the barrier (represented by F1 in Figure 4) effectively seals off direct communication with the southwest portion of the main reservoir sand. Models that included gaps or significant leakage across this barrier gave simulated 1988–1990 pressure decline rates that were too small. Presumably, the mapped internal fault to the southwest of the test well (see Figure 2) either extends across the width of the main reservoir sand or acts in combination with porosity pinch-out zones to form the barrier represented by F1 in Figure 4.

The distance (L2) between the barrier F1 and the other two major mapped internal faults (F2 and F3) was also varied in the preliminary simulations as was the gap (L3) between F2 and F3. Comparison of the simulations with the 1988–1990 test history implied that faults F2 and F3 do not effectively block off communication to the northeast portion of the reservoir. Apparently, permeable flow paths exist that circumvent these faults. The massive sandstone in the Chocolate Bayou region (Figure 3) is presumed to provide vertical communication between the main reservoir sand and the overlying/underlying units as suggested by Hamlin and Tyler (1988). In the reservoir model (Figure 4) the corresponding zones of vertical communication to the southeast and northwest of F2/F3 are represented, respectively, by the lengths L4 and L5.

Most of the simulations were performed assuming the presence of vertical communication between the main reservoir sand and remote layers towards the northeastern end of the reservoir (over lengths L4 and/or L5) but assuming that the pore volume of the main reservoir sand southwest of F1 (Figure 4) is isolated from hydrologic communication with the test well; this corresponds to a connected pore volume of $V_p = 6.1$ billion bbls. In some cases the calculations were repeated with vertical communication between the layers permitted to the southwest of F1 (along with vertical communication over L4 and/or L5). This allowed the entire pore volume of the BEG1 configuration to be in communication with the test well (i.e., $V_p = 8.0$ billion bbls). The effect on the simulated history through October 1990 was small. It will likely be necessary to refine the assumed distribution of the connected pore volume as the depletion testing continues.

6.2 History Matching Calculations

Iterative parametric history-matching simulations established the following estimates for the dimensional parameters L1 through L6 illustrated in Figure 4:

$$\begin{aligned} L1 &= 990 \text{ m } (3{,}248 \text{ feet}) \\ L2 &= 5380 \text{ m } (3.34 \text{ miles}) \\ L3 &= 1420 \text{ m } (0.88 \text{ miles}) \\ L4 &= 100 \text{ m } (328 \text{ feet}) \\ L5 &= 7154 \text{ m } (4.45 \text{ miles}) \end{aligned}$$

(The reservoir simulator employs SI metric units). As discussed above, the distance L1 from the test well to the sealing fault F1 is based primarily on analysis of the 1980 RLT pressure transient data. L2 approximates the distance from F1 to the mapped faults F2 and F3 shown in Figure 2; L3 approximates the gap between the ends of faults F2 and F3 in the main reservoir sand. L4 and L5 approximate the distances from F2/F3, to the southwest and northeast, respectively, of the 13,000 feet contour on the structure map (Figure 2). Vertical communication between the three sandstone units is permitted in this region which represents the single massive sandstone at Chocolate Bayou.

The reservoir simulation model used to match the test well history to date uses a horizontal permeability of $k_1 = 1.70 \times 10^{-13}$ m^2 (172 md) for the main reservoir sand lying between sealing fault F1 and faults F2/F3. As discussed above, this preserves the near-well transmissivity determined from the pressure transient data. The horizontal permeability in the region of the main reservoir sand southwest of F1 was set to $k_1/4 = 4.24 \times 10^{-14}$ m^2 (43 md), but the calculations are insensitive to its value. To the northeast of F2/F3 simulations were made for several choices of the horizontal permeability. Table 6 lists values for six cases in which the value ranged from $k_1/4$ to $2k_1$.

Table 6. Horizontal permeabilities employed for reservoir simulation parametric calculations based on BEG1 configuration (k_1 = 172 md). The vertical permeability in each of the indicated regions for each case equals one-tenth the listed horizontal permeability value.

Case No.	V_p (10^9 bbls)	Main Reservoir Sandstone SW of F1	F1 to F2/F3	NE of F2/F3	Remote Volume
1	6.1	$k_1/4$	k_1	k_1	$k_1/7$
2	6.1	$k_1/4$	k_1	k_1	$k_1/10$
3	6.1	$k_1/4$	k_1	k_1	$k_1/8$
4	6.1	$k_1/4$	k_1	$k_1/2$	$k_1/7$
5	6.1	$k_1/4$	k_1	$k_1/4$	$k_1/4$
6	6.1	$k_1/4$	k_1	$2k_1$	$k_1/7$
7	8.0	$k_1/4$	k_1	k_1	$k_1/7$
8	8.0	$k_1/4$	k_1	k_1	$k_1/8$

The horizontal permeability in the two low-porosity layers (remote volume) of the model was also varied. Simulations in which its value varied between $k_1/4$ to $k_1/10$ are listed in Table 6.

The vertical permeability in each of the three layers was set at one-tenth of its value for the horizontal permeability ($k_V = k_H/10$). Since vertical communication in the Chocolate Bayou area is allowed over a very large area (L4 and L5 in Figure 4), the simulated results are not sensitive to the k_V values. The simulated results, however, are sensitive to the distance (L2–L4) from the test well to the area of vertical communication through the otherwise impermeable shales separating the main reservoir sand from the overlying/underlying low-porosity layers.

In simulating the detailed test history of the 1980 RLT and the 1988 MRT, the skin factor (s) at each step was varied according to the downhole pressure transient analysis (first trend line in Figure 13). This relation was assumed to hold up to the time of the abrupt decrease in s associated with sand production on June 20–21, 1988. Subsequent to that time, its value was held constant at $s = +0.56$ for the remainder of the 1988–1990 simulated production of the Pleasant Bayou test well.

The curves in Figures 5 and 6 show the simulated test histories compared with the downhole measurements for the 1980 RLT and 1988 MRT, respectively. The simulations are for the case 1 permeability distribution (Table 6), but essentially identical results for these relatively short test periods are calculated using the other permeability distributions in Table 6.

To distinguish between the models for the permeability distributions in Table 6, it is necessary to consider longer production periods.

Parametric calculations to evaluate the effect of permeability variations on the reservoir depletion behavior during the 1988–1990 production testing employed averaged flow rate values to conserve computational time. The skin factor was set at $s = +0.56$ throughout these parametric calculations. Figure 14 compares the simulated sandface pressure histories (at 14,600 feet datum) for the first six cases listed in Table 6. It was found that the depletion response of the reservoir model is primarily controlled by the dimensional parameters (L1 through L5) and the permeability of the main reservoir sand in the region from F1 to F2/F3. The calculated sandface pressure for the six cases varies less than $\sim$ 60 psi over the simulated time history.

Figure 15 compares the results for two pairs of calculations (cases 1 and 7; cases 3 and 8) in which the permeability distributions in the model were the same but communication from the remote layers to the main reservoir sand southwest of F1 was either allowed (V_p = 6.1 billion bbls) or not allowed (V_p = 8.0 billion bbls). The reservoir volume difference is seen to change the calculated sandface pressure for each model pair by less than $\sim$ 20 psi over the simulated production history.

The case 1 permeability distribution was chosen for a detailed history matching simulation of the Pleasant Bayou test well. Detailed comparisons for the 1980 RLT and 1988 MRT have already been given for this simulation (Figures 5 and 6). Figure 16 presents a more detailed comparison with the downhole data during the buildup portion of the 1980 RLT. The semi-log plot in Figure 17 compares the detailed simulation of the 1988–1990 test history with the available data. The data points in Figure 17 include the downhole measurements from the 1988 MRT and 1989 65-hour test and the pressure values estimated from surface recordings. Figure 18 presents a more detailed comparison with the 1989 65-hour test. The linear plot in Figure 19 presents a more detailed comparison of the simulated test history with the pressure values estimated from the wellhead recordings.

7.0 DISCUSSION

The good agreement between the estimates for the connected pore volume given by the geological studies and the stable pressurements has provided a sound basis for modeling the Pleasant Bayou reservoir. The BEG1 geological configuration in conjunction with the well test data has permitted the construction of the reservoir simulation model to proceed in a logical sequence as the well test history evolved. This is in sharp constrast to the situation at Glady McCall where no geological information is available for determining the reservoir connected pore volume or for locating reservoir boundaries (Riney, 1990).

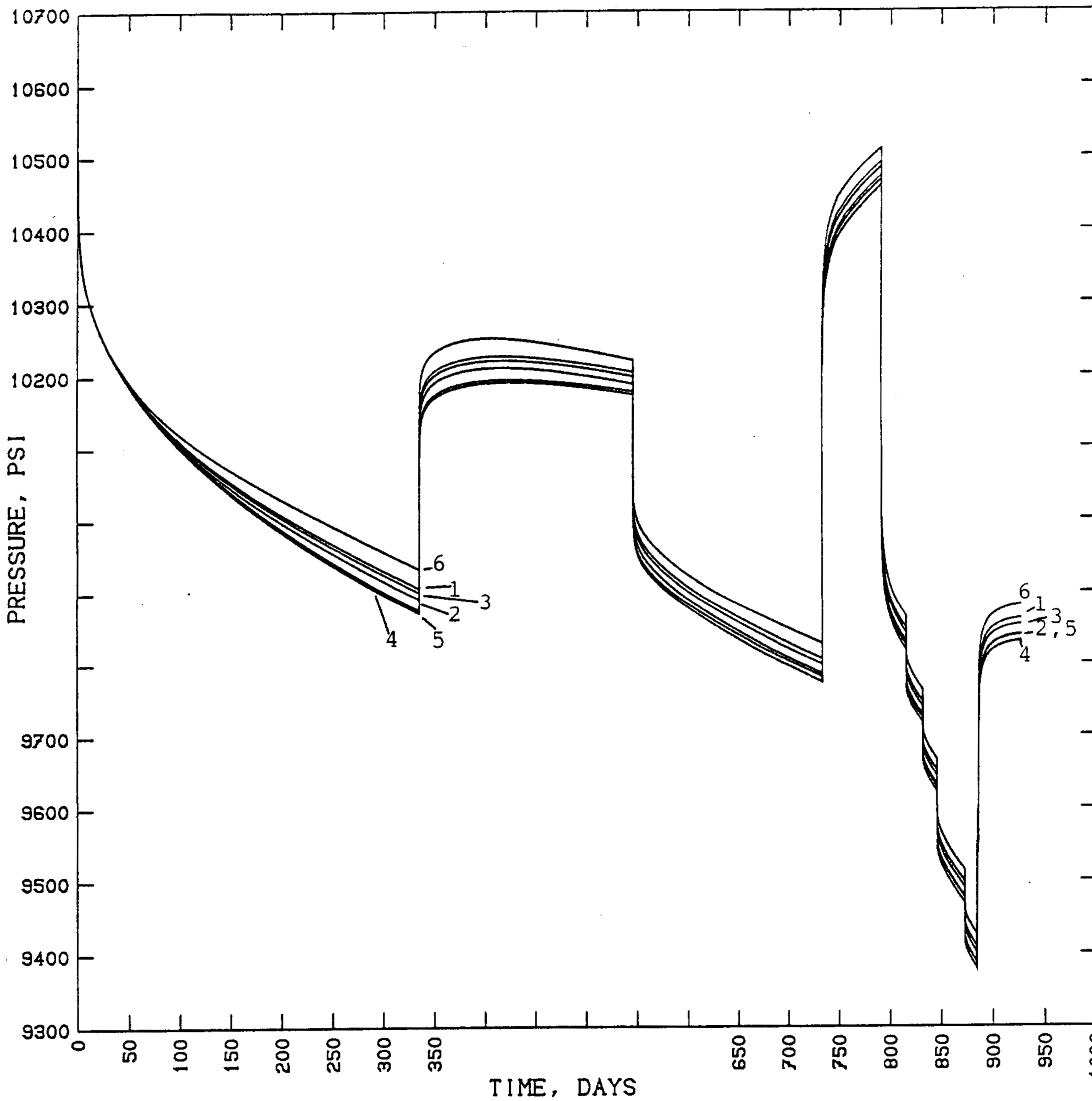

Figure 14. Parametric simulations to evaluate effect of permeability distributions on the depletion behavior of the model. Numbers refer to distributions in Table 6. Datum level is 14,600 feet.

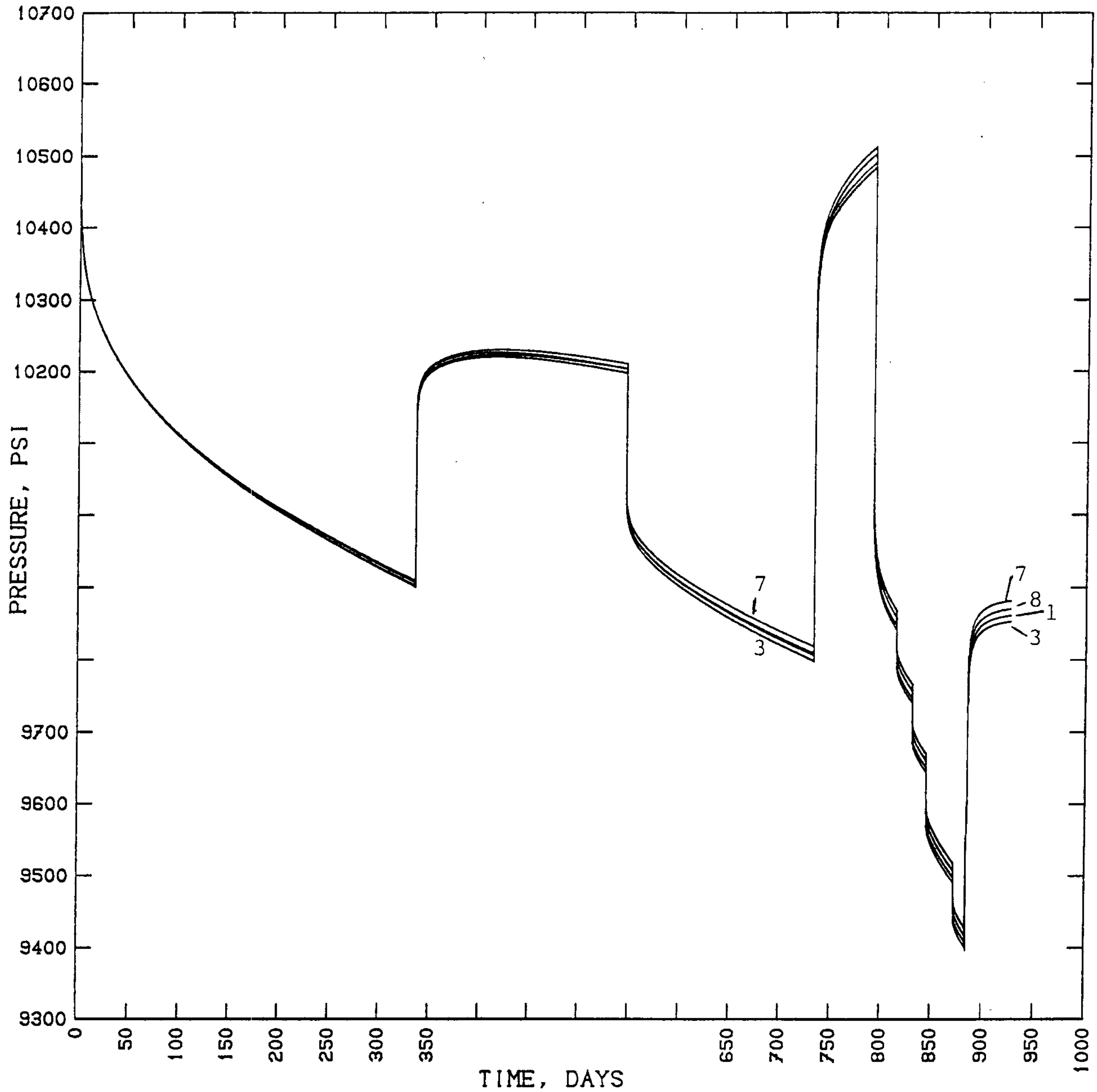

Figure 15. Parametric simulations to evaluate effect of assumed value of connected pore volume on depletion behavior of model. Numbers refer to distributions in Table 6. Datum level is 14,600 feet.

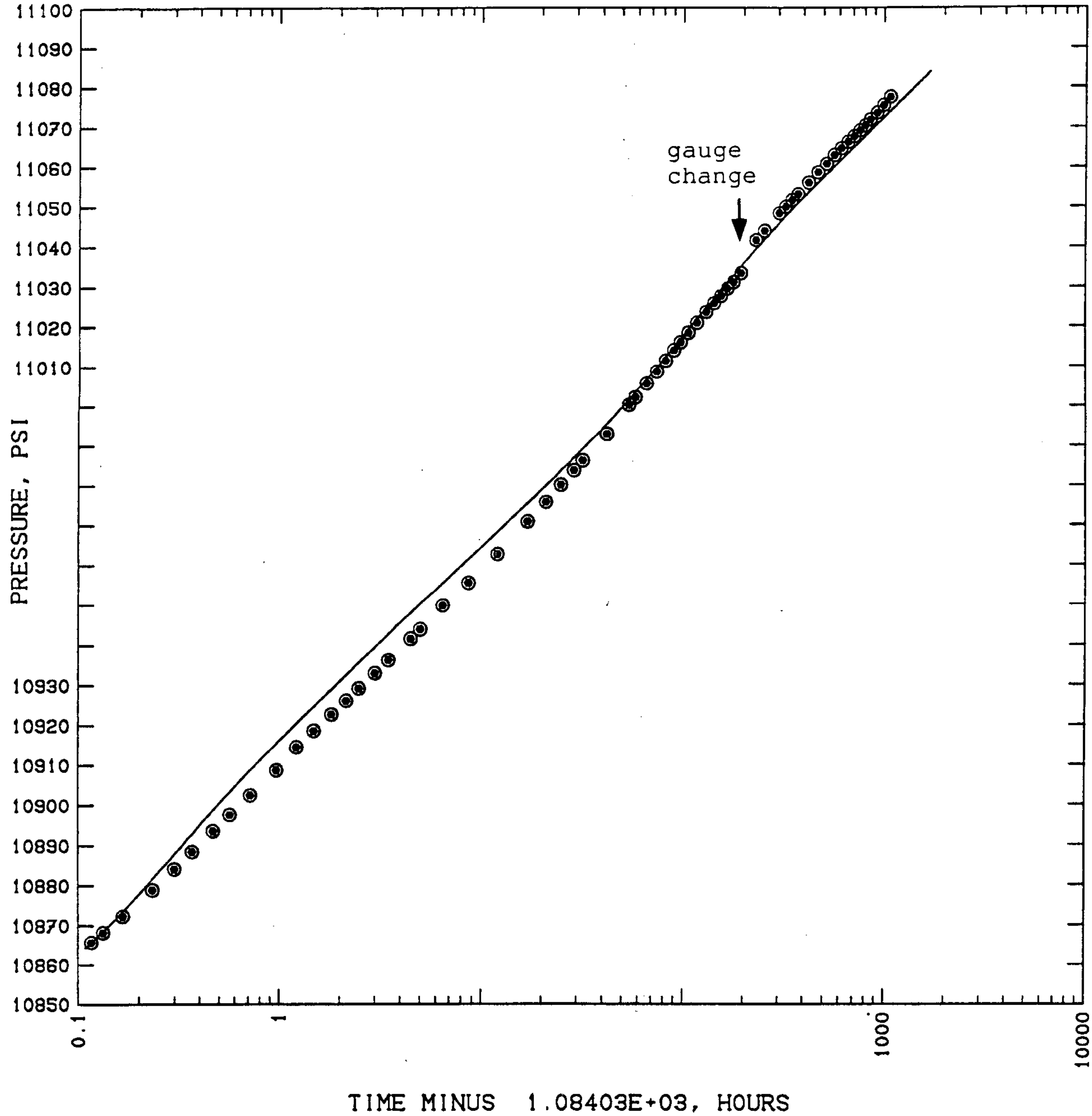

Figure 16. Detailed comparison of simulated 1980 RLT pressure history (curve, case 1) with bottomhole pressure buildup test data (points) for Pleasant Bayou Well No. 2. Datum level is 14,600 feet.

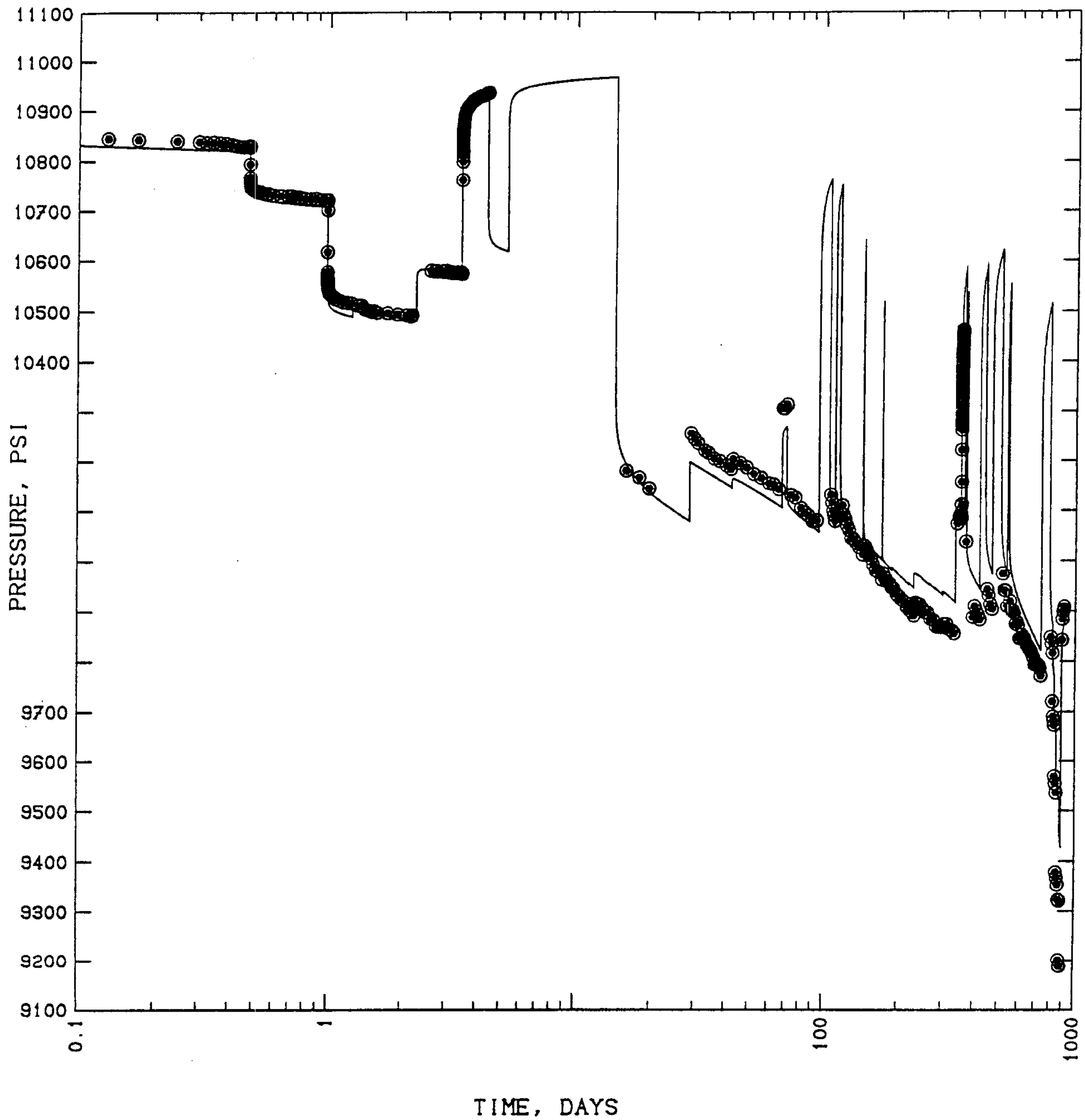

Figure 17. Comparison of simulated 1988–1990 production history (curve, case 1) with composite bottomhole pressure data (points) from test history of Pleasant Bayou Well No. 2. Datum level is 14,600 feet.

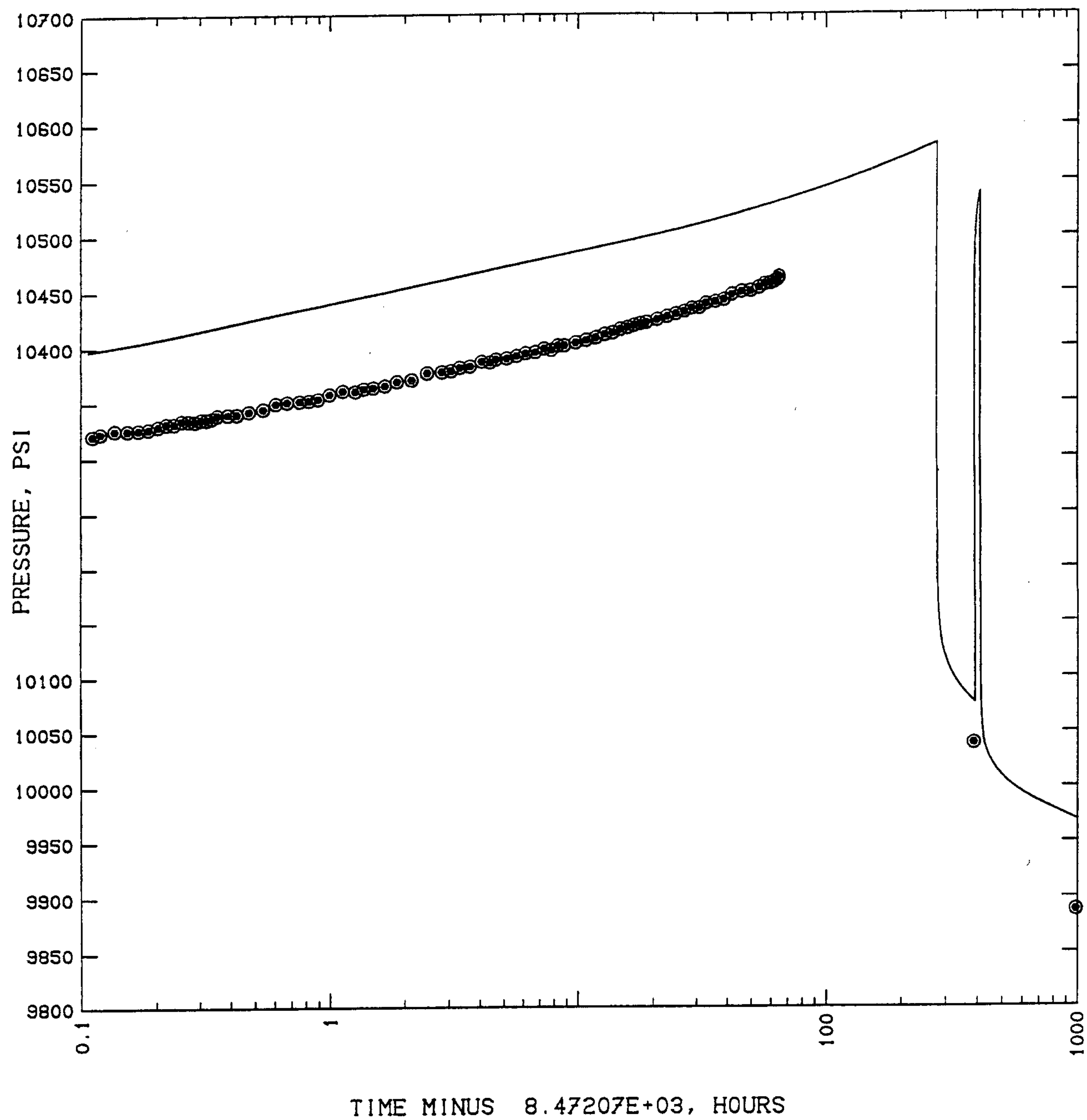

Figure 18. Detailed comparison of simulated 1988–1990 production history (curve, case 1) with May 1989 65-hour buildup test data (points) for Pleasant Bayou Well No. 2. Datum level is 14,600 feet.

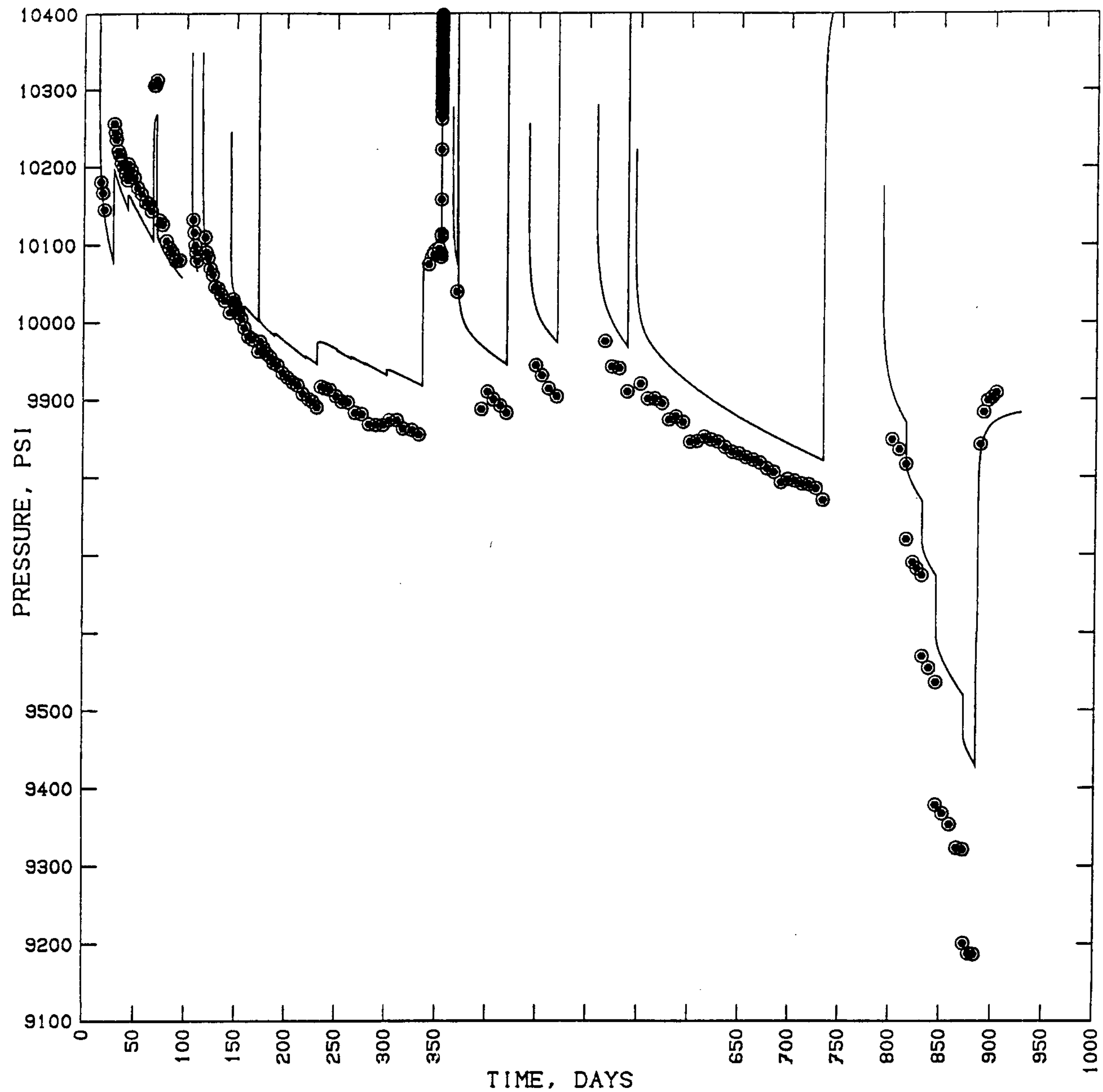

Figure 19. Detailed comparison of simulated 1988–1990 production history (curve, case 1) with flowing bottomhole pressure values (points) estimated from wellhead recordings of Pleasant Bayou Well No. 2. Datum level is 14,600 feet.

At the present time it has been about twenty months since the last downhole pressure/temperature measurements. A downhole test is planned for early in 1991. Flowing pressure and temperature profiles will be made (to augment the data in Table 3); this will allow recalibration of the wellbore model used to estimate bottomhole flowing pressures from wellhead values. The well then be shut with the gauge set at the datum level to measure the pressure buildup response and to estimate the current skin factor value. Comparison with earlier test data (Table 4 and Figure 13) should permit the isolation of the cause of the apparent discrepancy, at low pore pressures, between the simulated bottomhole pressure and the values estimated from wellhead recordings.

With continued long-term production testing it should be possible to distinguish between the reservoir models (Table 6) which equally well match the test history through December, 1990. It is anticipated that revisions in the permeability distributions assumed in the remote regions of the reservoir model may be required and that a more definite determination of the reservoir connected pore volume will be realized. It remains to be seen if the Pleasant Bayou geopressured reservoir will exhibit nonlinear formation response as the pore pressure decreases (and the effective stress on the formation rock increases).

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