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DEPLETION AND RECOVERY BEHAVIOR OF THE GLADYS McCALL GEOPRESSURED GEOTHERMAL RESERVOIR

T. D. Riney

Topical Report

Work Performed for
Center for Energy Studies
The University of Texas at Austin

Under
U. S. Department of Energy
Cooperative Agreement No. DE-FC07-85NV10412

June 1990

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(619) 453-0060

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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

Gladys McCall Well No. 1 produced over 27 million barrels of brine and 675 mm scf gas from the thickest sand (Sand Zone 8; 15,158 to 15,490 feet at the test well) from October 7, 1983 through October 29, 1987 when the well was shutin for a long-term pressure buildup test still underway. The test history may be divided into two major phases: a Depletion Phase of over 3.5 years (October 7, 1983 through April 21, 1987) and a Recovery Phase currently 3.0 years in duration (April 1987 through present). The flow rate during the Depletion Phase was over 30,000 bbls/day part of the time and averaged $q \sim 19,600$ bbls/day. The Recovery Phase consists of a period when the well was held at $q \sim 10,040$ bbls/day (April 21 to October 29, 1987) followed by the ongoing long-term shutin test. Analysis of the available test data at the end of the Depletion Phase resulted in the construction of a conceptual model of the reservoir, which depends on cross-flow from sands overlying/underlying Sand Zone 8 for the observed pressure maintenance and a reservoir simulation model based on the crossflow concept was developed. The present report presents analysis of more complete data now available. Modification of the earlier reservoir simulation model is found necessary to provide a satisfactory match over the integrated data sets of both the Depletion and Recovery Phases of the test history. The results of this DOE long-term testing of the Gladys McCall well have defined an impressively large geopressured reservoir and improved our understanding of the geopressured resource base.

I INTRODUCTION

1.1 BACKGROUND

Many sedimentary basins contain formations with pore fluids at higher than hydrostatic pressures (vertical fluid-pressure gradients greater than about 0.465 psi/ft); these formations are called geopressured. The geopressured strata are comprised of undercompacted clays (or shales) and sandstones with the interstitial fluids bearing most of the overburden pressure. The pore pressure is generally well in excess of hydrostatic and the fluids are saline, hot, and contain dissolved methane. Thus, the fluid contains energy in three forms; thermal energy, hydraulic (or pressure) energy, and chemical energy associated with the methane.

Among geopressured basins in the United States, the northern Gulf of Mexico basin has been most extensively investigated. A review of the estimates of the energy recoverable from the Gulf Coast region has been presented by Garg *et al.* (1985). 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 four deep research wells in the Texas-Louisiana Gulf Coast region:

1. Pleasant Bayou Well No. 2, Brazoria County, Texas.
2. Amoco Fee Well No. 1, Sweet Lake Field, Cameron Parish, Louisiana.
3. L. R. Sweezy Well No. 1, Parcperdue Field, Vermilion Parish, Louisiana.
4. Gladys McCall Well No. 1, Cameron Parish, Louisiana.

Testing of the Amoco Fee and L. R. Sweezy wells has been completed, and the wells have been plugged and abandoned. Long-term production testing of the Pleasant Bayou well is still in progress. Reservoir pressure recovery is currently (May 1990) being monitored in the Gladys McCall well following long-term production testing of the well.

One of the objectives of the DOE program is to investigate the pressure maintenance mechanisms that operate within the reservoirs tested by the design wells. The Parcperdue reservoir was selected because of its well-defined geology and volume so that the testing could be completed within one year. Depletion testing had to be terminated, however, when excessive sand was produced from the unconsolidated formation. The Amoco Fee well exhibited a much larger than anticipated pressure-drawdown during short-term flow testing. Analysis of the downhole pressure data indicated that the well penetrated a zone of relatively high permeability but flow was constrained by either low permeability or geologic structure away from the well.

Selection of the Pleasant Bayou and the Gladys McCall well sites was based on research at the University of Texas at Austin and Louisiana State University that identified localized regions where thick, high-pressure, high-temperature sandstone masses existed as a result of isolation by growth faults, salt movement, facies boundaries or other factors. These geologic studies (Bebout *et al.*, 1978; Bebout, 1982, Brunheld, 1984) successfully identified the Pleasant Bayou and Gladys McCall prospects as large volume aquifers that could be produced for extended periods at high flow rates.

The Gladys McCall geopressured prospect lies at the western edge of the Rockefeller Wildlife Refuge about 55 mi southeast of Lake Charles in Cameron Parish, Louisiana. Preliminary studies of the geology and structure of the area were conducted by D. G. Bebout (1982) and Brunheld (1984) based on well logs from the subject well and five nearby deep wells. The approximate locations of the three major growth faults considered to control the structure of the prospect are shown at 15,500 feet in Figure 1; location of fault III is the most uncertain. The east-west length of the fault block could not be determined from available information.

Recently, John (1988) reviewed the geology of the Gladys McCall prospect. Although no new geological information was available to better establish reservoir boundaries, production flow testing had established that the Gladys McCall test was drawing from a large reservoir. John's model for the depositional origin of the geopressured sand section penetrated by the Gladys McCall test well considers the entire section to be a genetic unit generated within the same channel system, consisting of interconnected channel and point bar sandstones deposited through time. Figure 2 shows a schematic of John's model. When the sand supply was interrupted, shale may have been deposited locally, but the laterally extensive channel and point bar sands may still be interconnected within the genetic system. Consequently, John (1988) suggests that the whole thickness of the sand section, though appearing on the electric log as possibly different and separated sandstones, may behave as a single sand body allowing fluid communication at shale breaks during brine production.

1.2 GLADYS McCALL TEST DATA

Gladys McCall Well No. 1 was spudded on May 27, 1981, drilled to a total depth of 16,510 ft, and plugged back to 15,831 ft. A 7-in diameter casing string was cemented from the surface to 15,958 ft, and the well was completed with 5-in diameter production tubing. Technadril-Fenix and Scisson (1982) managed the drilling, completion and testing of the well until October 1985; Eaton Operating Company took over management of the well for DOE at that time. The stratigraphic section seen in the borehole consists of alternating massive sandstones and thin shales. There are approximately 1,150 ft net of sand in the target Miocene sand within the 14,412 ft to 16,320 ft interval penetrated by the test well. Eleven sequentially numbered sand zones separated by shale breaks at the wellbore were identified from log analysis by Technadril-Fenix and Scisson (1982). Over two-thirds of the net sand is contained in three of the eleven sand zones (nos. 2, 8 and 9). Only Sands 8 and 9 have been perforated.

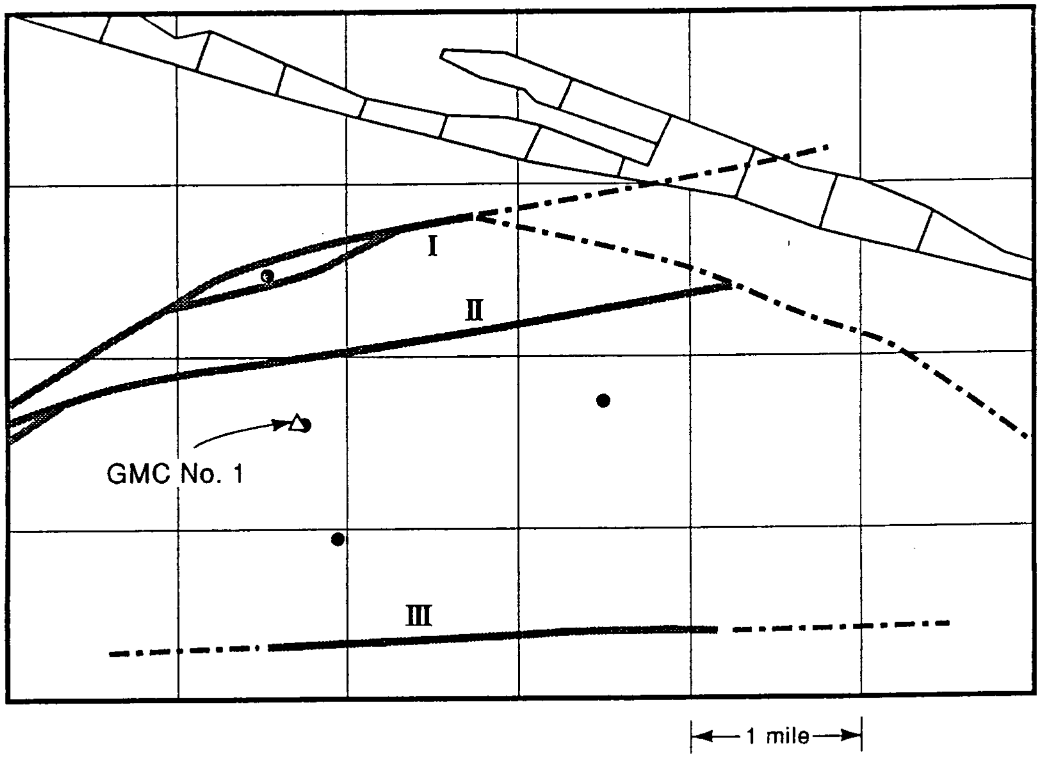

Figure 1. Major growth faults within lower Miocene section at depth (15,500 feet) between Sand Zones 8 and 9 with locations of Gladys McCall No. 1 and nearby deep wells. Geology map adapted from Technadril-Fenix and Scisson (1982).

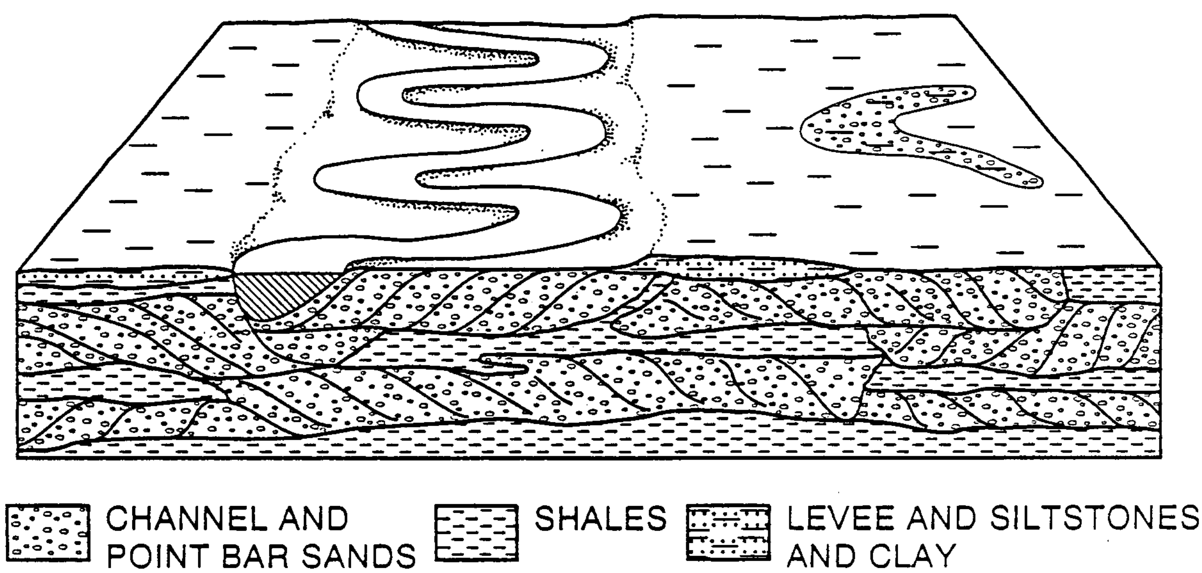

Figure 2. The formation and mechanism for lateral and vertical extension of connected channel and point bar sandstones (John, 1988).

Sand Zone 9, from 15,508 ft to 15,636 ft, was flowed from March 21, 1983 to April 14, 1983. After gas separation, the brine produced was injected into a nearby disposal well. A Panex downhole pressure/temperature gauge positioned at 15,460 ft recorded the pretest reservoir pressure of 12,911 psia and temperature of 298°F. Because of the rapid pressure drawdown in the well, Sand Zone 9 was sealed off with a plug set at $\sim 15,500$ ft in preparation for testing Sand Zone 8.

The 7-in casing was perforated to test Sand Zone 8, from 15,158 ft to 15,490 ft (sand thickness h = 332 ft). A Panex pressure/temperature gauge was fixed at a depth of 15,100 ft to record the initial pressure and temperature: $P_i = 12,784$ psia and $T_i = 289.2$°F. Production started on October 7, 1983, and the test well produced over 27.3×10^6 sep bbl of brine (measured at the brine/gas separator conditions) from October 7, 1983 ($t = 0$) through October 29, 1987 ($t = 1,483$ days) when the well was shutin for a long-term pressure buildup test still underway (May, 1990). The produced fluid was remarkably free of sand and fines over its entire production history.

Laboratory tests (Kelkar *et al.*, 1982) under bench conditions on well-consolidated core samples from the test well gave average values for porosity and permeability of $\phi \sim 0.168$ and $k \sim 83$ md, respectively. Under simulated reservoir conditions they reported permeabilities ($k \sim 1$ to 17 md) that are much smaller than implied by actual field measurements at the test well ($k \sim 133$ md). Kelkar, *et al.* also reported values for the uniaxial compaction coefficient ($C_m \sim 2 \times 10^{-7}$ psi^{-1}) that are very low and inconsistent with values ($C_m \sim 8 \times 10^{-7}$ psi^{-1}) deduced from their measurements for bulk compressibility and Poisson's ratio. The corresponding values for the total formation compressibility would be $C_T = 4.0 \times 10^{-6}$ psi^{-1} and $C_T = 7.7 \times 10^{-6}$ psi^{-1}. Because of these ambiguities, we will use a value of $C_T = 6.27 \times 10^{-6}$ psi^{-1} based on correlations for consolidated sandstone (Earlougher, 1977).

Studies by the Rice University brine research group showed that fluids produced from Sand Zones 8 and 9 are essentially identical. Weatherly Laboratories, Inc. reported the following properties of fluid samples recombined to approximate reservoir conditions (Sand Zone 8): brine compressibility $C_w \sim 2.76 \times 10^{-6}$ psi^{-1}, dynamic viscosity $\mu \sim 0.31$ cp, and bubble pressure $\sim 9,200$ psia. The average gas-to-water ratio for the total gas production from the test well is GWR $\sim$ 30.15 SCF/STB (ft^3 bbl^{-1} at 14.67 psia, 60.33°F). Average salinity of the brine is $\sim 97,800$ mg/L.

Although production from Sand Zone No. 8 by Gladys McCall Well No. 1 included numerous rate changes since initiation of the Reservoir Limits Test (RLT) on October 7, 1983 ($t = 0$), the production history may be divided into two major phases. Except for relatively short time intervals (following decreases in the flow rate), the bottomhole pressure generally decreased from the time the RLT was initiated up to April 21, 1987 ($t = 1,292$ days). This period of over 3.5 years will be called the "Depletion Phase" of the reservoir response. The flow rate during the Depletion Phase was over 30,000 sep b/d part of the time and averaged $\sim 19,600$ sep b/d.

Starting on April 21, 1987 the flow rate of the well was lowered in four steps over a four-week period and then held at $q \sim 9,800$ sep b/d until the initiation of the multi-rate flowing portion of the Long Term Test (LTT) on October 24, 1987. The well was shut on October 29 ($t = 1,483$ days) in order to monitor the pressure recovery during the buildup portion of the LTT. The pressure generally increased during the 191 day period of reduced flow rate ($\sim 10,040$ sep b/d from April 21 to October 29, 1987) and has continued to increase since shutin. This total period of about 3.0 years from April 21, 1987 to the present will be called the "Recovery Phase" of the reservoir response.

An earlier paper (Riney, 1988) presented an analysis of the test data available at the end of the Depletion Phase. A conceptual model of the reservoir was constructed which depends on cross-flow at shale breaks from sands overlying Sand Zone No. 8 for the observed pressure maintenance and a reservoir simulation model based on the crossflow concept was developed. The present paper presents analysis of the more complete data now available. This includes reanalysis of the Depletion Phase data in conjunction with the analysis of the new data from the Recovery Phase of the testing of the Gladys McCall Well No. 1. Modification of the reservoir simulation model described in the earlier paper is found necessary to provide a satisfactory match to the integrated data sets comprised of both the Depletion and Recovery Phases of the test history.

II METHOD OF ANALYSIS

The data analysis is complicated by the fact that the well initially experienced severe calcite scaling within the production tubing. Costly and time consuming acid treatments were employed on four occasions to remove the scale. Control of scaling of the well tubulars was then attempted by injecting into the formation a chemical mixture (mostly phosphonate) designed to inhibit the precipitation of calcium carbonate from the brine. The first attempt to inject the phosphonate "pill" into Sand Zone 8 in November 1984 ($t \sim 418$ days) was aborted when the incremental injection pressure exceeded 600 psi. The pill flowback contained solid precipitates and formation plugging was suspected at the time (Durrett, 1985). This appeared to be confirmed when it was not possible to lower the test tool below 15,158 feet when the well was next logged on April 13, 1985. The second attempt to inject a scale inhibitor pill in May 1985 ($t \sim 594$ days) was also aborted. Successful "pill" injections were accomplished during June 1985 ($t \sim 628$ days) and February 1986 ($t \sim 851$ days). The success of the scale inhibitor pills have been crucial to the success of the geopressured test well program (Tomson *et al.*, 1985). Analysis of the Gladys McCall production data has revealed, however, that even successful injections cause an increase in the apparent skin factor, causing an increase in the near-wellbore pressure loss (Riney, 1988).

There have been four periods during the 6.5 years of Sand Zone 8 test history when downhole pressure transient tests have been performed:

1.	October 1983 to December 1983	Reservoir limits test (drawdown/buildup)
2.	April 1985	79-hr test (buildup only)
3.	January 1986	92-hr test (buildup only)
4.	October 1987 to present time	Long-term test (drawdown/buildup).

The first three tests were conducted during the Depletion Phase and the results were described by Riney (1988). The Long-Term Test (LTT) is composed of measurements which were continuously recorded over a multi-rate drawdown and early buildup portion of the test, augmented by measurements made while logging downhole pressure/temperature values, at increasingly longer time intervals between logs, from November 1987 to the present time.

Both the 79-hr and 92-hr tests were found to infer a near-well transmissivity (kh) equal to about half the value measured during the original RLT (Riney, 1988). This reduction in transmissivities was attributed to the presumed plugging of about half the thickness in Sand Zone 8 in combination with a shale stringer (vertical flow barrier) identified from well logs at 15,365 ft to 15,369 ft (Figure 3). At the time of the 92-hr test, however, the well was again logged and the tool reached wellbottom without detecting any obstruction. It was hypothesized that the plugging within the formation remains since there is no flow below the shale stringer to flush the precipitates from the pores. Parametric reservoir simulation studies were performed to estimate the effective distance (ℓ) that the shale stringer extends laterally from the wellbore. It was found that a vertical flow barrier for a distance $\ell \sim 657$ ft (200 m) provided a good match to the downhole pressure transient data recorded before and after the presumed plugging (Riney, 1988).

In preparation for the LTT, a Panex pressure/temperature gauge was lowered in Gladys McCall Well No. 1 on October 24, 1987 ($t = 1,478$ days) and set at a depth of 14,650 feet with the well producing brine at $\sim 9,950$ sep b/d. At 01:17:00 on October 25, the flow rate was increased to $\sim 15,050$ sep b/d. At 13:58:40 on October 25 the rate was decreased to $\sim 12,440$ sep b/d and at 20:05:30 on October 25 the rate was lowered to $\sim 9,950$ sep b/d. On October 26 it became apparent that the measured downhole pressure values were drifting with time. The original ("old") downhole Panex gauge was pulled out and a "new" Panex pressure/temperature was set at 14,650 feet at 22:00:00 on October 26. The flow continued at $\sim 9,950$ sep b/d until the well was shutin at 20:02:10 on October 29, 1987 ($t = 35,598.8$ hrs). The buildup pressure was monitored continuously until 07:00:00 on November 5, 1987 when the new gauge was pulled. The subsequent pressure recovery has been monitored by isolated bottomhole pressure and temperature measurements made with increasing time intervals between logs.

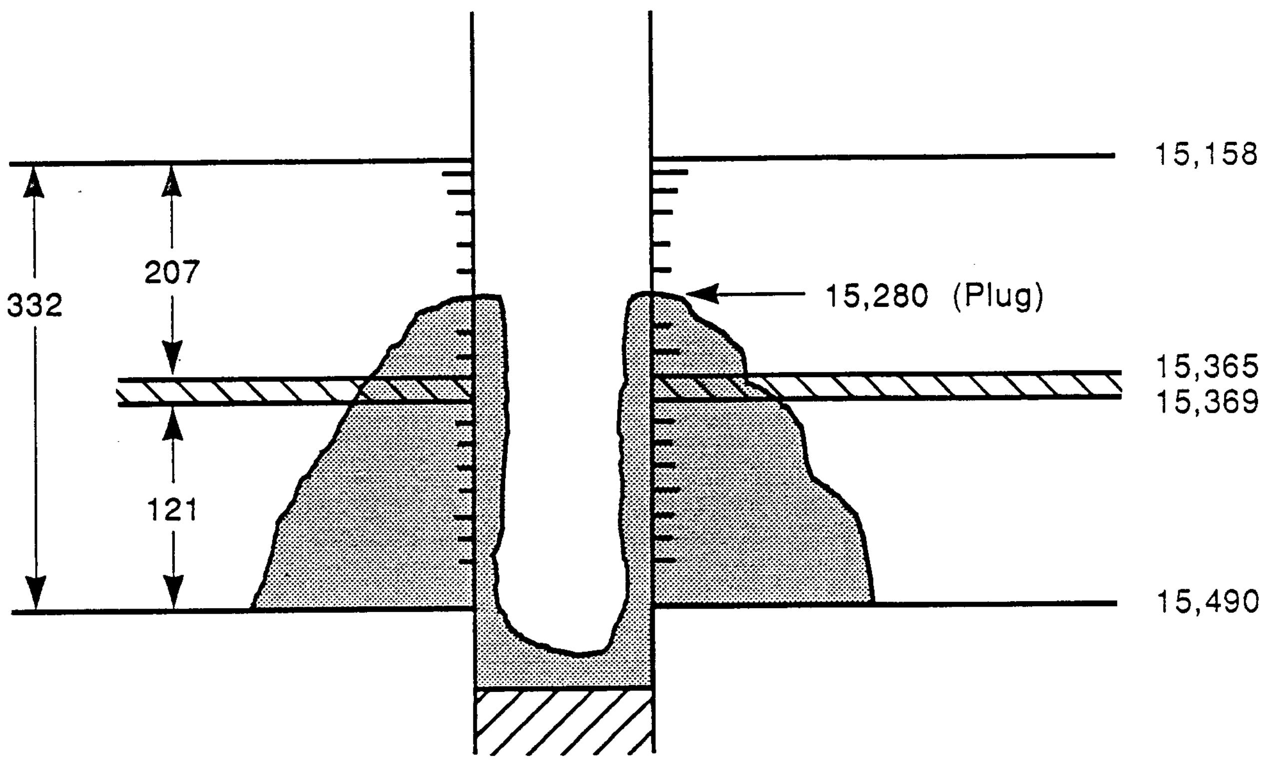

Figure 3. Schematic showing location of the shale stringer in Sand Zone 8 and depth of presumed plug reported at time of 79-hr test.

A wellbore flow model (Pritchett, 1985) was employed to help correct for the drift in the bottomhole pressure values measured with the Old Gauge. Measured values for the wellbore pressure losses (Δp_{wb}) are available from the difference between recordings of the bottomhole and surface Panex gauges during the LTT. Calculated Δp_{wb} values are obtained using flow rate data and the wellbore flow model calibrated using data from early downhole tests. In Figure 4, $\delta(\Delta p_{wb})$ denotes the discrepancy between the measured and calculated values of Δp_{wb}. We note that the discrepancy is zero at about the time the Old Gauge was set at 14,650 feet, t_o = 12:30:00 on October 24. Based on the slopes of the parallel lines approximating the data in Figure 4, the drift in the pressure recorded by the Old Gauge is estimated to be 3.62 psi/hr.

Bottomhole pressure transient data for the three previous tests of the Gladys McCall well were recorded at a depth of 15,100 feet. For analysis purposes it is convenient to use the calibrated wellbore model to correct the LTT data to this depth also. Figure 5 presents a composite plot of the LTT pressure transient data corrected to a depth of 15,100 feet. The reference time of $t_1 = 35,484.04$ hours corresponds to 01:17:00 on October 25.

Except for these four bottomhole pressure transient tests, the Gladys McCall reservoir response must necessarily be inferred from wellhead recordings. The wellhead pressure measurements are related to the reservoir response as follows:

$$\begin{aligned} p_{WH} &= p_{BH} - \Delta p_{wb} \\ &= p_i - \Delta p_{res} - \Delta p_{sk} - \Delta p_{wb} \quad . \end{aligned} \tag{1}$$

Here the pressure drop in the wellbore (i.e. within the production string) is the sum of frictional and hydrostatic pressure losses ($\Delta p_{wb} = \Delta p_{fric} + \Delta p_{hydr}$), p_i the initial reservoir pressure, Δp_{res} the pressure drop in the reservoir in the absence of a skin effect ($s = 0$), and Δp_{sk} the pressure drop due to the skin effect ($s > 0$). Relating the wellhead measurements to the characteristics of the geopressured reservoir involves calculations for subsurface pressure losses ($\Delta p_{wb}, \Delta p_{sk}, \Delta p_{res}$).

During the evaluation of the total available data set from Gladys McCall Well No. 1 we have:

1. Performed simultaneous analysis of the pressure transient data from the four isolated downhole tests. The revised values for the near-well formation properties are used in reservoir simulation computations to calculate Δp_{res}.
2. Evaluated the wellhead pressure data available just prior to and immediately after planned shutin periods during the depletion phase to estimate Δp_{sk}.
3. Recalibrated the wellbore flow model to improve the calculations for Δp_{wb} and, consequently, improve earlier estimates of bottom hole pressures during the Depletion Phase.

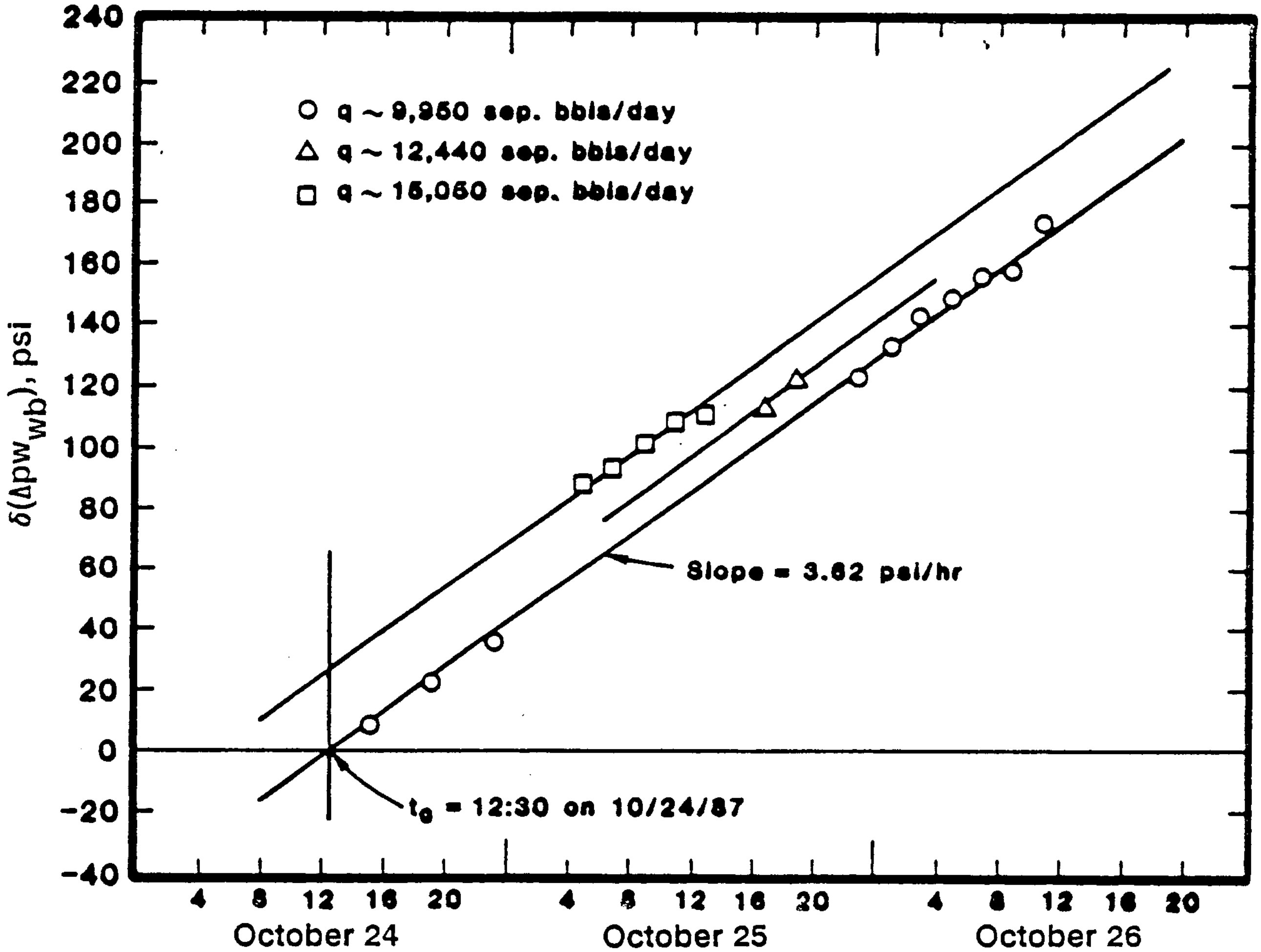

Figure 4. Estimated drift in pressure values recorded by Old Gauge (at 14,650 feet) based on comparison with surface measurements (at 9 feet).

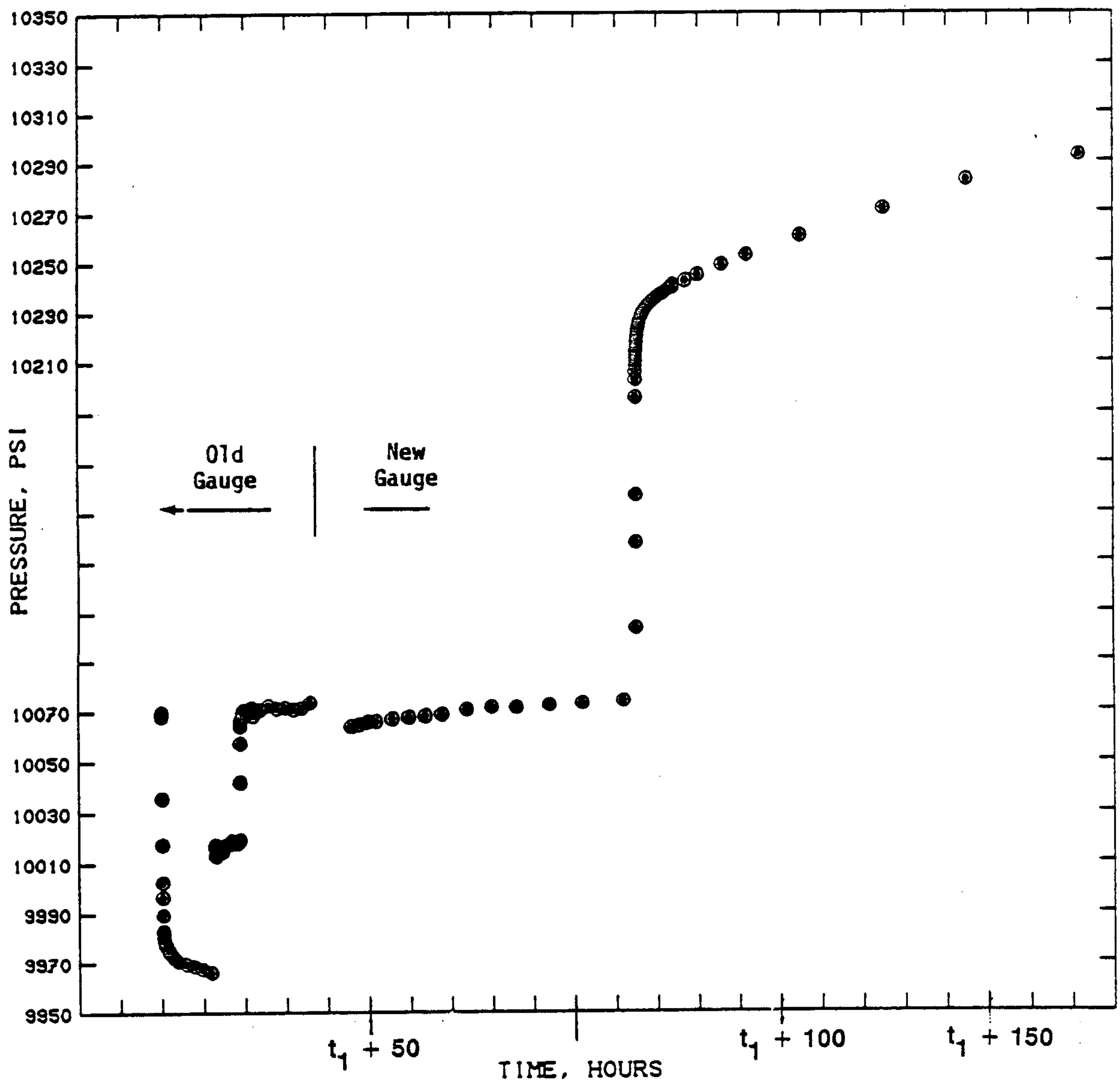

Figure 5. Data points from Long-Term Test of Gladys McCall Sand Zone 8 corrected to 15,100 feet. Old Gauge data also corrected for drift.

These results will be described in the following sections.

III SIMULTANEOUS ANALYSIS OF PRESSURE TEST DATA

The reservoir analysis is simplified by the relatively low gas content. Preliminary parametric simulations were made that maximized the credible effects of any free gas that might evolve within the formation under Gladys McCall conditions; the studies show that the gas in the formation would be confined to a very small zone at the sandface. Parametric simulations assessing the effects of irreversible rock compaction and stress-dependent permeability were also conducted (Riney, 1986). These simulations indicated that any associated nonlinear effects at Gladys McCall would 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 when using linear methods of analysis.

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

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

where $m' = 162.6\mu\, B/kh$. The formation factor (B) is required to convert separator barrels to reservoir barrels. If we assume the fluid viscosity (μ), formation porosity (ϕ) and total compressibility (C_T) are known, a semi-logarithmic plot of pressure transient data can be used to estimate the values of transmissivity (kh) and skin factor (s). The slope m' yield kh and the intercept at $\Delta t = 1$ hr yields s,

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

During the Reservoir Limits Test the well flowed at an average rate of $\sim$ 14,162 sep b/d for 505.5 hours prior to shutin. Figure 6 compares early time plots of $\Delta p / \Delta q$ vs $\log \Delta t$ for the drawdown (October 7–28, 1983) and buildup (October 28–November 30, 1983) portions of the RLT. The slope change at $\Delta t \sim 0.55$ hrs during drawdown is associated with an adjustment in the flow rate. Otherwise, the early drawdown curve is approximated by a straight line of the same slope ($m' = 1.13 \times 10^{-3}$ psi/sep b/d) as the buildup curve.

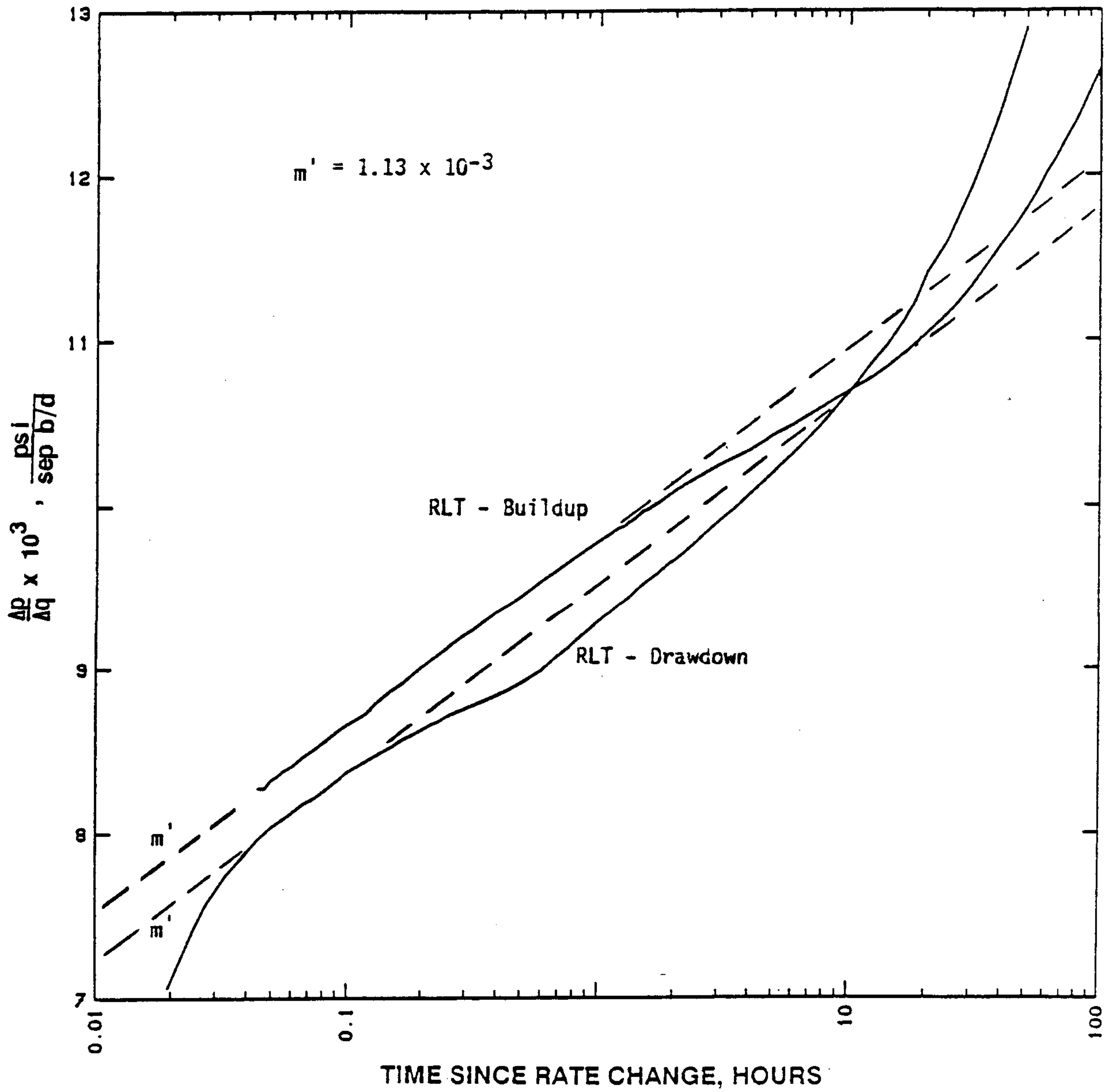

Figure 6. Early-time bottomhole pressure transient data from drawdown and buildup portions of the Reservoir Limits Test of Gladys McCall Sand Zone-No. 8. Datum level is 15,100 ft.

Figure 7 compares plots of $\Delta p/\Delta q$ vs $\log \Delta t$ for the 79-hour (April 9–12, 1985) and 92-hour (January 23–27, 1986) buildup tests with plots for two steps of the LTT (October 24, 1987–present). The plot for the first step (rate change from 9,950 to 15,050 sep b/d) of the multi-rate drawdown portion of the LTT is closely approximated by a line of the same slope ($m' = 1.75 \times 10^{-3}$ psi/sep b/d) as lines approximating the 79-hour and 92-hour tests. The rate was maintained at 15,050 sep b/d for 12.68 hours. The next two step rate changes did not provide useful data for analysis because of the short time (step 2) and a gauge failure (step 3). The plot for the fourth step, the early part of the buildup portion of the LTT (started on October 29, 1987), is also closely approximated by a line of the same slope ($m' = 1.75 \times 10^{-3}$ psi/sep b/d). The slow rise times for the two portions of the LTT shown in Figure 7 appear to be associated with the time taken to complete the flow-rate changes.

In the above simultaneous analysis, the same values for the input parameters were employed as were used in the separate analyses made at the time of each of the downhole pressure transient tests (Riney, 1988): $r_w = 0.2917$ ft, $h = 332$ ft, $\phi = .16$, $\mu = 0.31$ cp, $C_T = 6.27 \times 10^{-6}$ psi^{-1}, $B = 0.984$. The flow rate changes, and the flowing pressures (at 15,100 ft) just prior to the rate changes, are listed in Table 1. The values for the formation transmissivity (kh) calculated from the slopes (m') in the semilog plots are also listed. The drawdown and buildup portions of the initial RLT imply a transmissivity of $\sim 44,090$ md-ft; all subsequent pressure transient tests imply a transmissivity of $\sim 28,340$ md-ft. Assuming $h = 332$ ft, the pressure transient data taken without further information would imply a reduction in near-well permeability from an initial value of $k = 133$ md to $k = 85$ md.

Table 1. Summary of results of simultaneous analysis of bottomhole pressure transient measurements for Gladys McCall Sand Zone No. 8. Long-Term Test measurements at 14,650 feet were corrected to a common 15,100 feet datum level.

	Reservoir Limits Test		79-Hour	92-Hour	Long-Term Test	
	Drawdown	Buildup	Buildup	Buildup	Drawdown	Buildup
Date of Measurement	Oct 07, '83	Oct 28, '83	April 09, '85	Jan 23, '86	Oct 25, '87	Oct 29, '89
Test Days, d	0	21	550	839	1,479	1,483
Q, 10^3 sep b	0	298	7,788	13,951	27,131	27,182
$[p_{wf}]_{0-}$, psia	12,784	12,418	10,855	10,267	10,068	10,074
Δq, sep b/d	14,162	14,162	15,438	10,470	5,100	9,950
$[\frac{\Delta p}{\Delta q}]_{1\,\mathrm{hr}} \times 10^3$, psi/sep b/d	9.55	9.78	23.9	18.8	18.1	15.5
$m' \times 10^3$, $\frac{\mathrm{psi}}{\sim}/\frac{\mathrm{sep\ b}}{\mathrm{d}}$	1.13	1.13	1.75	1.75	1.75	1.75
kh, md-ft	44,090	44,090	28,340	28,340	28,340	28,340
s	2.28	2.51	8.49	5.11	(4.68)	2.97

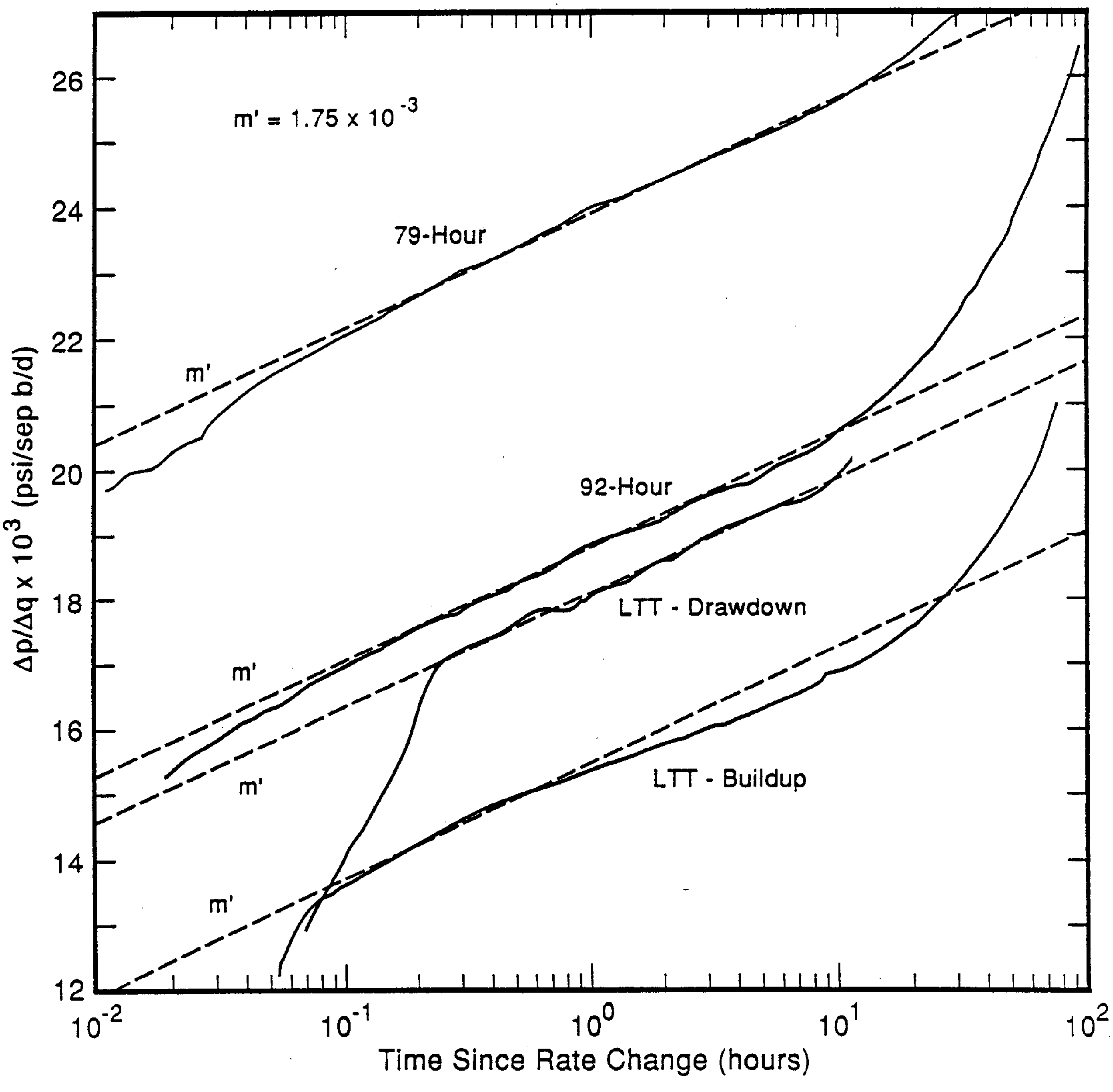

Figure 7. Bottomhole pressure transient data from 79-hour buildup test, 92-hour buildup test, and one step of the multi-rate drawdown, and the early portion of the Long-Term Test of Gladys McCall Sand Zone No. 8. Datum level is 15,100 ft.

Table 1 also lists the values of $[\Delta p/\Delta q]_{1\ \mathrm{hr}}$ read from the straight line approximations to the semilog plots (Figures 6 and 7). Equation (3) yields the corresponding estimates for the skin factor (s) at the time of each of the six downhole pressure transient tests. The estimate for the drawdown portion of the LTT is enclosed in parentheses in Table 1 since any vertical displacement of the $\Delta p/\Delta q$ curve (Figure 7) that might be present after correcting for the linear drift in the old gauge pressure values would affect the estimate for s.

From Equation (2) we see that the pressure drop due to the skin effect changes with Δq according to $\delta p_s = m'(0.87s)\delta q$, or

$$\delta p_s = \frac{141.2\ \delta q \mu B}{kh}\ s \quad . \tag{4}$$

We note that the discrepancy between the skin factor estimates for the two steps of the LTT ($\delta s = 4.68 - 2.97 = 1.71$) would correspond to a constant error in the corrected old gauge pressure values of

$$\delta p_o < \frac{141.2(5100)(0.31)(0.984)(1.71)}{28,340} \sim 13 \text{ psi} \quad .$$

Since an error of this size is possible in our correction for the drift in the pressure values measured with the old gauge, the skin factor based on the early buildup data ($s = 2.97$) is the preferred estimate at the time of the LTT.

IV EVALUATION OF SKIN FACTOR VARIATIONS

There have been numerous times during the depletion testing of Gladys McCall Well No. 1 when the production tubing was free of scaling and the well had flowed at a constant rate for a sustained period prior to a planned shutin. On twenty-one occasions (see Table 2) 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 Δp_{sk} (and thus the apparent value of s) at those times. For this purpose we set $\Delta t = 3$ m $= 0.05$ hr in Equation (2) and solve for s to obtain

$$s = 1.151 \left\{ \frac{1}{m'} \left[\frac{\Delta p}{\Delta q}\right]_{3\,\mathrm{m}} - \log \frac{k(0.05)}{\phi \mu C_T r_w^2} + 3.23 \right\} \quad . \tag{5}$$

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.

When the well is shut $\Delta p_{wb} \rightarrow \Delta p_{hydr}$. The values of Δp_{hydr} have been estimated (at the 15,100 ft datum level) from simultaneous wellhead and bottomhole P/T measurements made at the times of the RLT and 79-hr shutin tests. The sandface shutin pressures $p_{ws}]_{3\,\mathrm{m}}$ listed in Table 2 are calculated based on the approximation $p_{ws}]_{3\,\mathrm{m}} = p_{WH}]_{3\,\mathrm{m}} + \Delta p_{hydr}$. Estimates listed in Table 2 for the sandface flowing pressures just prior to shutin are based on Equation (1), $p_{wf}]_{\Delta t=0-} = p_{WH}]_{\Delta t=0-} + \Delta p_{wb}$, with the values Δp_{wb} calculated using the recalibrated model for wellbore flow (see next section).

Table 2. Estimated values of skin factor (s) at indicated times during depletion testing of Gladys McCall Well No. 1. Listed pressure values (at 15,100 ft datum) are estimated from wellhead recordings just prior to and immediately after shutin.

Date of Recording		Test Days	$[q]_{0-}$ (sep b/d)	$[p_{wf}]_{0-}$ (psia)	$[p_{ws}]_{3\,\mathrm{m}}$ (psia)	$[\Delta p/\Delta q]_{3\,\mathrm{m}} \times 10^3$ (psi/sep b/d)	s
1985	07-22	654	25,728	10,229	10,930	27.25	11.98
	08-05	668	31,080	10,098	10,750	20.98	7.83
	10-06	730	29,388	9,789	10,410	21.13	7.93
	10-28	752	28,644	9,659	10,329	23.39	9.42
1986	01-02	818	23,916	9,689	10,238	22.96	9.13
	01-05	821	22,896	9,764	10,274	22.27	8.68
	02-28	875	30,264	9,605	10,324	23.76	9.66
	04-08	914	28,932	9,414	10,090	23.37	9.40
	06-20	987	27,276	9,207	9,847	23.46	9.47
	06-25	992	27,312	9,205	9,836	23.10	9.23
	07-16	1013	26,916	9,170	9,789	23.00	9.16
	10-05	1094	25,704	9,020	9,627	24.00	9.82
	11-09	1129	25,236	8,967	9,586	24.53	10.17
	11-22	1142	25,092	8,956	9,587	25.15	10.57
	11-26	1146	25,188	8,976	9,603	24.89	10.41
1987	01-01	1182	24,528	8,904	9,561	26.79	11.65
	01-27	1208	24,288	8,872	9,518	26.60	11.53
	02-05	1217	24,324	8,878	9,519	26.35	11.37
	02-15	1227	24,372	8,877	9,518	26.30	11.33
	03-06	1246	24,096	8,834	9,495	27.43	12.08
	04-15	1286	27,040	8,691	9,436	27.55	12.16

Using Equation (5) with $r_w = 0.2917$ ft, $h \rightarrow h' = 207$ ft (see Figure 3), $\phi = 0.16, \mu = 0.31$ cp, $C_T = 6.27 \times 10^{-6}$ psi^{-1} and the values calculated for $\Delta p = p_{ws}]_{3\,\mathrm{m}} - p_{wf}]_{\Delta t=0-}$ (with $m' = 1.75 \times 10^{-3}$ psi/sep b/d from Table 1), the estimates for the skin factor (s) are obtained for the twenty-one shutin times. The results are listed in Table 2 and plotted in Figure 8 against the corresponding values of the bottomhole (15,100 ft datum level) pressure drop from the initial reservoir pressure of 12,784 psi. Also plotted are the estimates for s given in Table 1 from the reevaluation of the downhole pressure transient test data.

The apparent skin factor values displayed in Figure 8 may be related to times at which scale inhibitor pills were injected.

October 1983	At the time of the original RLT the downhole measurement indicate a skin factor of $s = 2.28$ to 2.5.
November 1984	First aborted attempt to inject pill; plugging of part of formation thickness near wellbore by precipitates suspected. Large increase in s value.
April 1985	At the time of the 79-hr buildup test, analysis of downhole measurements indicate a skin factor of $s = 8.49$. Hypothesized skin decrease subsequent to November 1984 pill is indicated by dashed curve approaching the 79-hour data point in Figure 8.
May 1985	Second aborted pill injection causes large increase in skin factor value. Analysis of surface pressure data indicates that the large value of s subsequently decreases with continuous production; decrease attributed to partial flushing of precipitates from pores by flowing brine (see Riney, 1988).
June 1985	First successful pill injection; analysis of surface pressures again indicates an associated large increase in apparent skin factor observed along with subsequent decrease (Riney, 1988). The decrease in the value of s is indicated by the dashed curve approaching trend line A in Figure 8.
July 1985 - January 1986	As bottomhole pressure continues to decrease the apparent skin factor follows trend line A as shown. The skin factor $s = 5.11$ determined at the time of the 92-hr buildup test falls on trend line A.
February 1986	Second successful pill injection; associated increase in apparent skin factor.
February 1986 - October 1987	The apparent skin factor subsequently decreases with flow as indicated by the dashed curve approaching trend line B in Figure 8. As bottom pressure continues to change, the apparent value of s follows trend line B. The value $s = 2.97$ determined at the time of the LTT shutin also falls on trend line B.

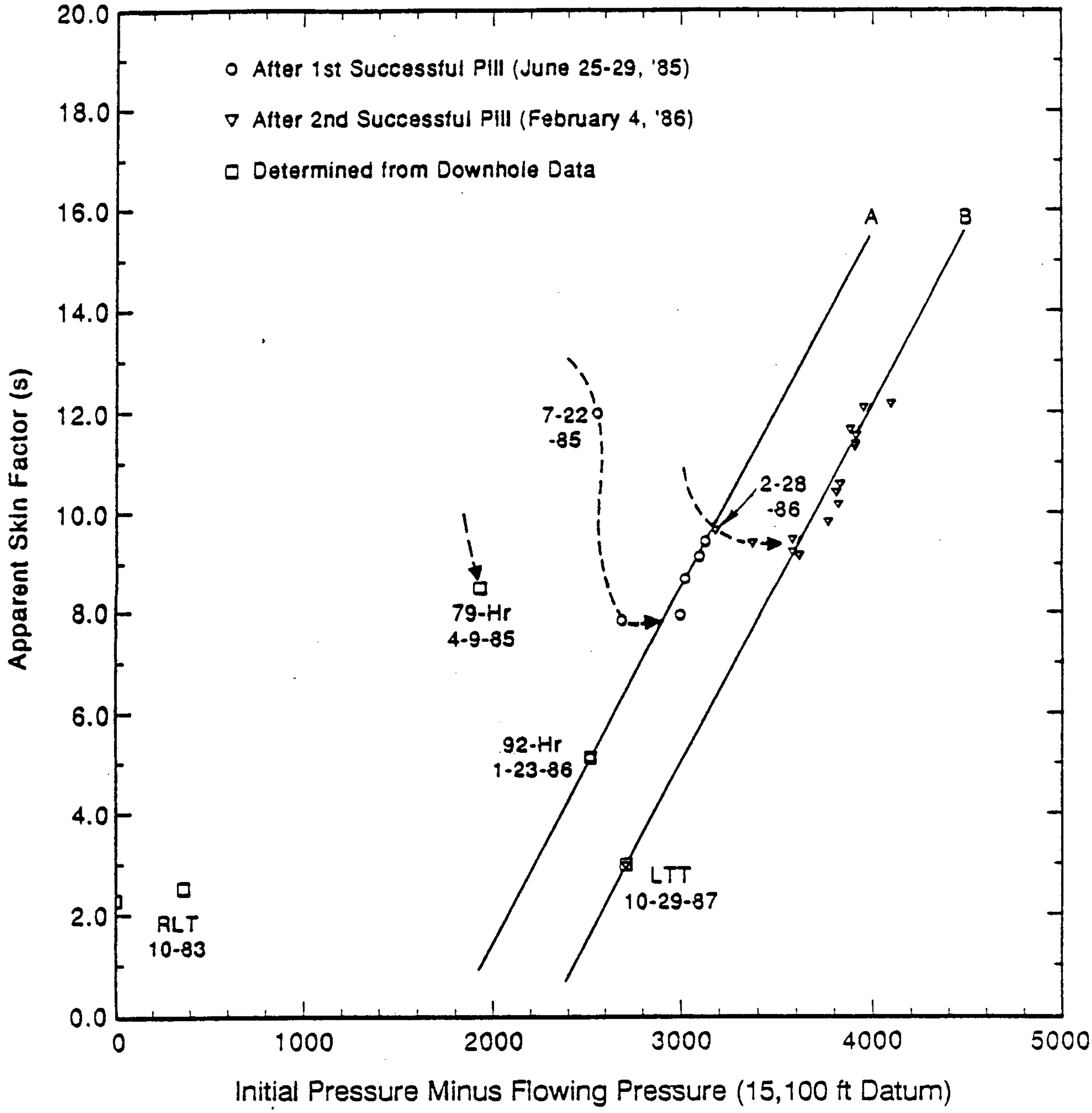

Figure 8. Apparent skin factor (s) values displayed as function of pore pressure decrease (from $P_i = 12,784$ psia) in the neighborhood of the Gladys McCall Well No. 1 wellbore.

The fact that the estimated s values approximate the trend lines A and B in Figure 8 between times that pills were injected implies that the skin factor depends on the bottomhole pressure. Based on parametric calculations performed to examine the possible effects of free gas evolution and nonlinear formation response (preceding section), the latter mechanism seems a more plausible cause for the pressure dependence. The effective stress at the sandface increases as the bottomhole pressure decreases.

In summary, it appears that there are at lease three mechanisms contributing to the variations of the skin factor s:

1. Abrupt increases in s associated with scale inhibitor pill injections, followed by subsequent slow decrease in s by partial removal of precipitates.
2. An apparent increase in s associated with a partial penetration effect caused by reduction of the horizontal communication with the wellbore due to plugging of the formation after November 1984.
3. An increase associated with an increase in the effective stress on the formation adjacent to the wellbore.

V RECALIBRATION OF WELLBORE MODEL

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 by Dukler *et al.* (1964); the effects of tubing roughness are included through a relative roughness parameter (R). Heat loss by combined conduction and convection to a porous water-saturated medium is treated by an approximate analytical solution and its magnitude is controlled by a heat transfer coefficient (U). Both R and U are empirical parameters.

The wellbore model uses an equation-of-state for brine/methane mixtures to calculate the properties of the geopressured fluid as it rises in the production tubing. The equation-of-state incorporates recent data concerning the compressibility of liquid brines (Osif, 1984) and measurements of methane solubility in hot brines reported by Price, *et al.* (1981). The mass fraction composition employed to represent the Gladys McCall brine is as follows:

$$H_2O : 0.904179, \qquad CH_4 : 0.003481, \qquad NaCl : 0.092340 \quad .$$

This choice yields a bubble point of 9,200 psia for a temperature of 289.2°F, in agreement with tests performed on reconstituted Gladys McCall Sand Zone 8 fluids by Weatherly Laboratories, Inc. The selected composition corresponds to GWR = 30.70

SCF/STB which closely approximates the total gas ratio produced from Gladys McCall Well No. 1.

Available stable downhole flowing pressure and temperature measurements in Gladys McCall Well No. 1 since October 7, 1983 (Test Day 0) must be used to calibrate the wellbore model. Unfortunately, the only P/T profile data available (Table 3) were measured on April 18, 1985 (Test Day 549) just prior to the 79-hour shutin test. Since the production tubing was badly scaled at that time the available profile data are corrupted.

Table 3. Pressure and temperature profile data for Gladys McCall Well No. 1.

Date:	10/28/83	4/18/85	1/23/86	10/25/87	10/25/87	10/25/87	10/29/87
Test Day:	21	549	839	1479	1479	1479	1483
Test Name:	RLT	79-Hour	92-Hour	LTT-1	LTT-2	LTT-3	LTT-4
q(sep b/d):	14,160	15,438	10,470	9,950	15,050	12,440	9,950
Depth (ft)	Pressure (psia)						
Tubing	5412	3725	3459	3286	2922[2]	3120[2]	3288
0	5433	–	3433	–	–	–	–
3000	–	5120	–	–	–	–	–
6000	–	6509	–	–	–	–	–
9000	–	7932	–	–	–	–	–
12000	–	9384	–	–	–	–	–
14650	–	–	–	9865[1]	9761[1]	9815[1]	9871[3]
15000	–	10809	–	–	–	–	–
15100	12418	10855	10267	–	–	–	–
15160	–	10880	–	–	–	–	–
Depth (ft)	Temperature (F°)						
0	280[4]	282[5]	275[5]	272[5]	273[5,1]	273[5,1]	273[5]
3000	–	281.7	–	–	–	–	–
6000	–	286.0	–	–	–	–	–
9000	–	289.5	–	–	–	–	–
12000	–	292.0	–	–	–	–	–
14650	–	–	–	295.8	295.7	295.6	293.5[3]
15000	–	293.7	–	–	–	–	–
15100	291.1	293.7	293.7	–	–	–	–
15160	–	293.8	–	–	–	–	–

[1] Unstable wellbore flow; formation temperature changing.

[2] Corrected for gauge drift (Old Gauge).

[3] New Gauge.

[4] Full-stream temperature. Brine out of separator at 275°F.

[5] Estimated by adding 5°F to temperature of brine out of first separator.

During the Reservoir Limits Test (Test Day 21), a stable "full-stream" temperature of 280°F was recorded at the wellhead, while the temperature of the fluid leaving the separator was 275°F. Since full-stream values were not reported after January 1985, wellhead temperatures at the other times (79-hour, 92-hour and LTT) are estimated by adding 5°F to the temperatures recorded for the fluid leaving the first stage separator. The duration of step 2 ($q = 15,050$ sep b/d) and step 3 ($q = 12,440$ sep b/d) of the multi-rate drawdown test prior to the start of the long-term shutin test were too short for stable temperatures to be attained.

Based on the reevaluation of the total pressure/temperature data available, it is apparent that the Sand Zone 8 temperature is higher than the value of 289.2°F measured at the time of the RLT. The P/T data in Table 3 are best matched with the wellbore model recalibrated using the above mass fraction composition, reservoir temperature $T_o = 297.0$°F, and the following values for the empirical parameters: $U = 7.0$ Wm^{-2} °C^{-1}, $R = 0.090$ mm.

Figure 9 compares the calculated pressure profiles with the pressure data in Table 3. The discrepancy for the stable conditions just prior to the 79-hour shutin test (the only pressure profile data) is attributed to the presence of scale on the inner tubing surface.

The new calibration has been used to estimate the pressure drop in the wellbore for a specified flow rate and pressure at the datum level, 15,100 feet. Figure 10 presents the results. The value of 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 value of Δp_{fric}, however, rapidly increases as q increases. The total pressure drop (Δp_{wb}) decreases with increasing q for $q <\sim 3,000$ seb b/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 ~ 125 psi as the datum pressure decreases from 12,000 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 11 compares the results of the recalibrated model predictions for the wellhead temperature with the data available at times of sustained stable flow rate over the production history of the test well. The datum pressure at 15,100 feet was fixed at 10,000 psia. The agreement is quite good. Because of the limited P/T profile data available and lack of downhole pressure data for high flow rates, however, the calibration and associated wellbore model predictions (and consequently the estimated bottomhole pressure data points in Figure 8) are subject to error during periods of the Depletion Phase when flow rates were sustained at $q \sim 20,000$ to 30,000 sep b/d.

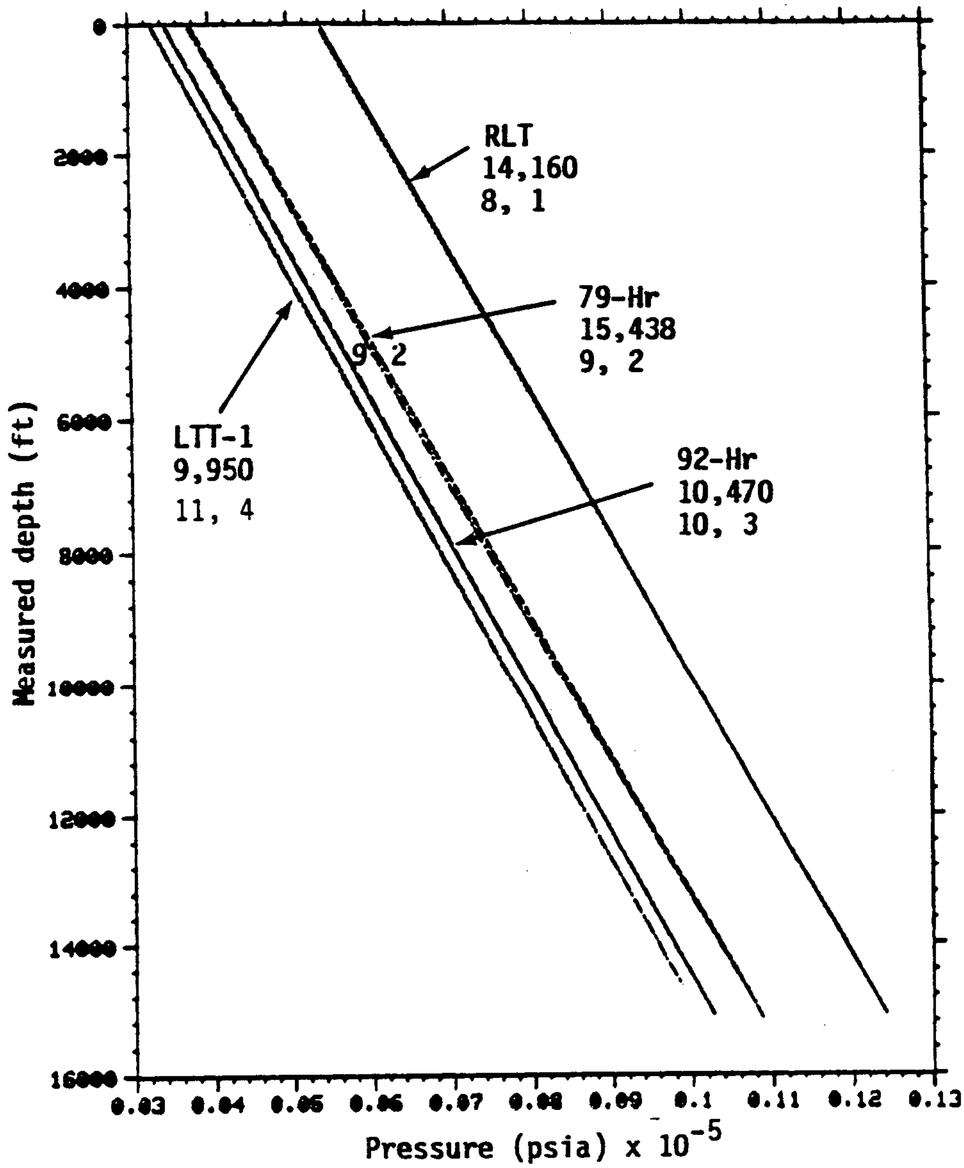

Figure 9. Comparison of recalibrated wellbore model profiles (curves 1,2,3,4) with downhole pressure profile data logged in Gladys McCall Well No. 1 when flowing at 14,160 sep b/d (curve 8), 15,438 sep b/d (curve 9), 10,470 sep b/d (curve 10) and 9,950 sep b/d (curve 11).

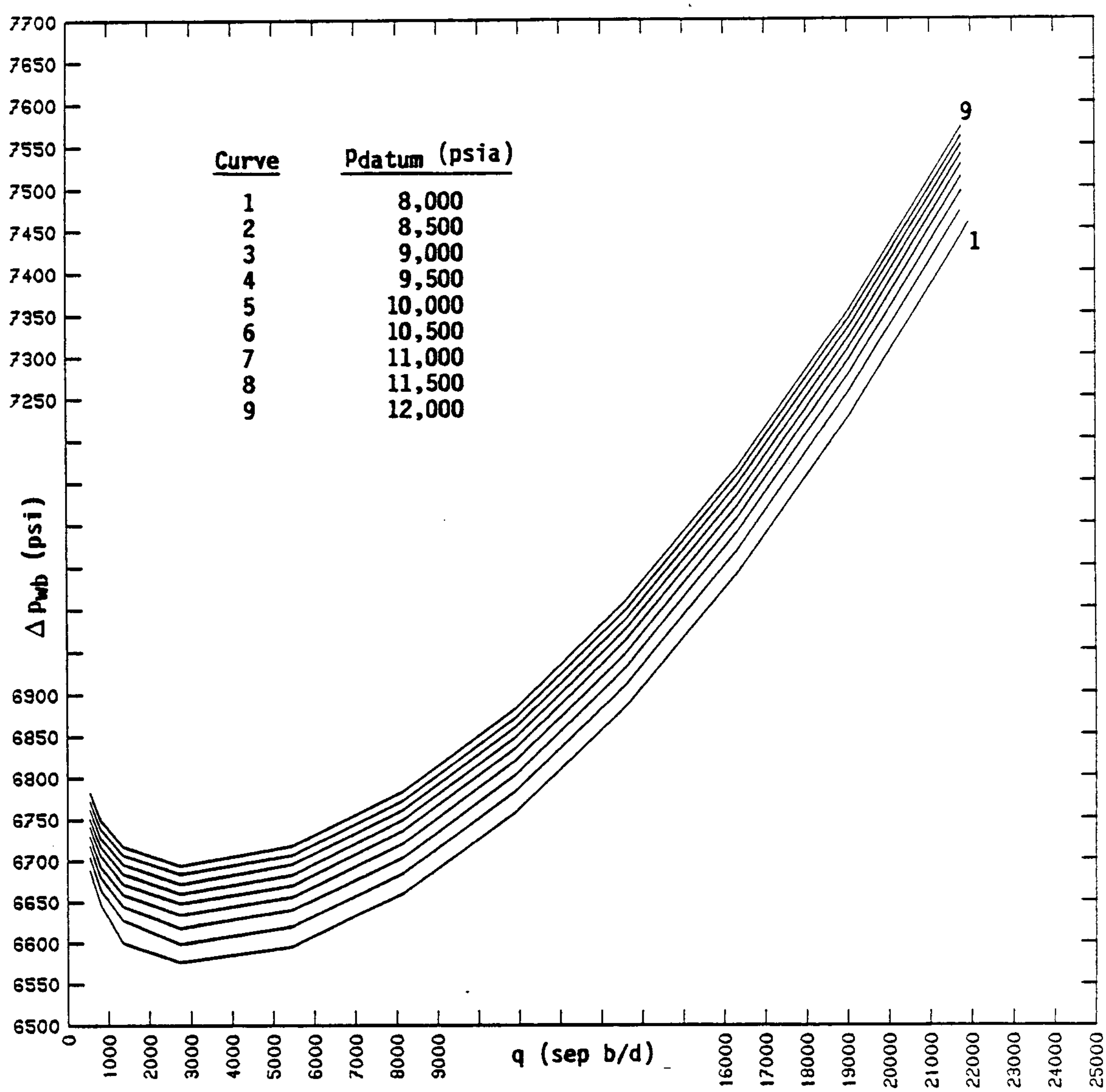

Figure 10. Wellbore pressure drop variations with flow rates for Gladys McCall Well No. 1. (Calculated with recalibrated wellbore flow model: $U = 7.0, R = 0.09$ mm, $T_{datum} = 297°F$). Datum pressure at 15,100 feet fixed at values indicated on curves.

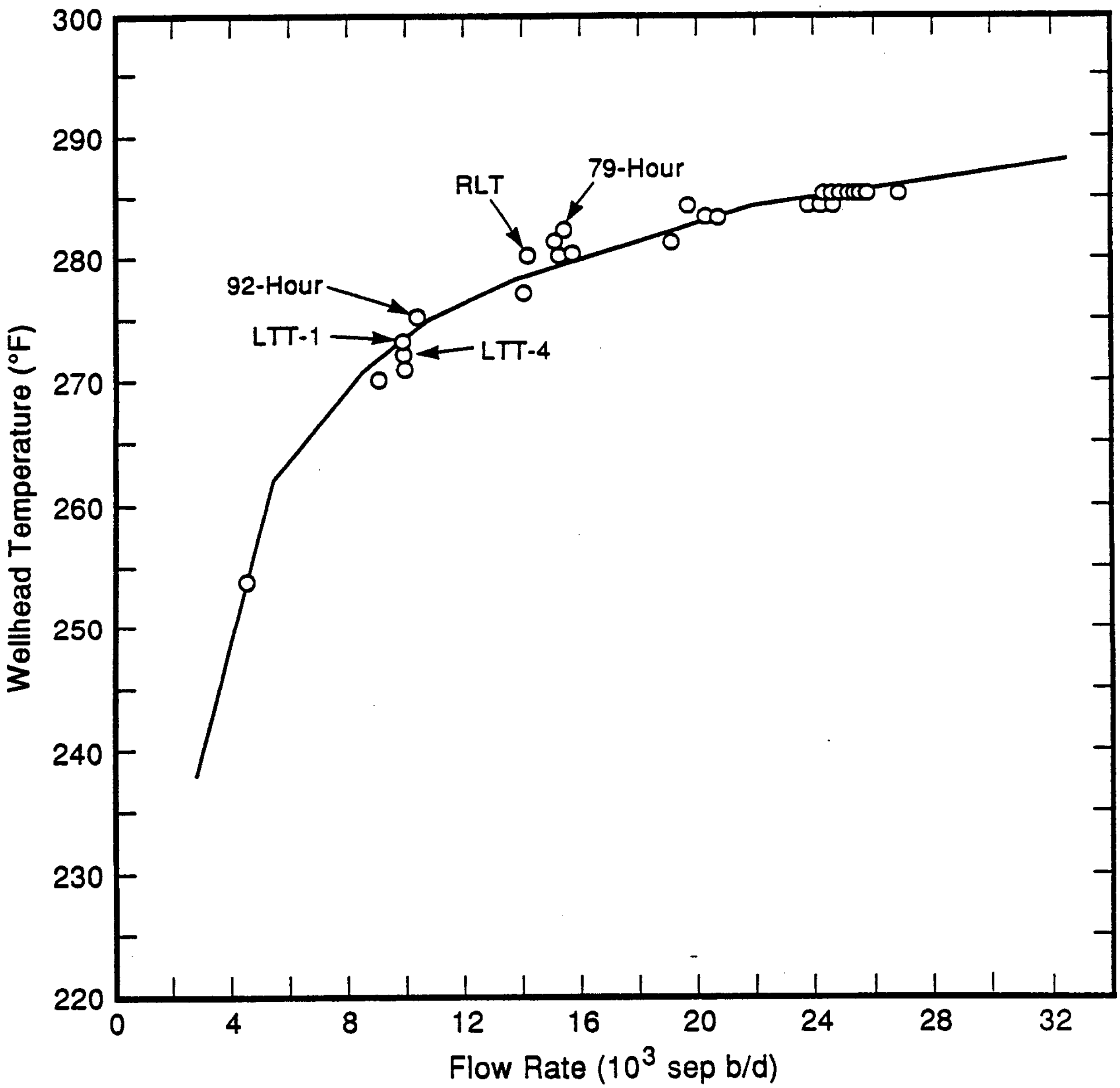

Figure 11. Stable Gladys McCall wellhead temperatures recorded during 1983–1987 (data points) at indicated flow rates compared with recalibrated wellbore model calculations (curve).

VI IMPLICATIONS OF INTEGRATED ANALYSIS

The significant implication of the simultaneous analysis of the four pressure transient tests is the fact that the LTT infers a near-well formation transmissivity unchanged from the values inferred by the 79-hour and 92-hour data. It is interesting to note that the reduction in the kh product from the RLT value ($28,340/44,090 = 0.64$) is close to the hypothesized reduction in the sand thickness in horizontal communication with the wellbore ($207/332 = 0.62$) at the time of the 79-hour test (Figure 3).

Actual obstruction within the borehole has not been observed in later downhole probes at Gladys McCall. It is plausible that brine flow cleaned out the borehole obstruction observed on April 13, 1985; scouring action appears to have occurred subsequent to each of the four pill injections (two successful and two unsuccessful attempts). After each pill injection there was a large increase in the apparent skin factor but the magnitude of the skin effect subsequently decreased, presumably from the cleansing action of the flowing fluid. This effect might not occur in a completely plugged horizon as there is no flow; horizontal communication with the wellbore apparently has remained reduced to $\sim$ 64 percent of its original value.

The variations in kh in Table 1 would be difficult to explain in terms of nonlinear rock formation behavior. Any decrease in kh would likely start at the sandface (lowest pressure/highest effective stress) and move outward as the reservoir depleted. The radial propagation of the nonlinear effect would imply a monotonically increasing apparent skin factor in association with a decreasing value for the apparent kh product (Riney, 1986). It is difficult to envision a decrease in kh to 64 percent of the original value after producing 7.8×10^6 sep b and then no further change upon producing an additional 19.4×10^6 sep b. The only significant nonlinear formation response apparent from the Gladys McCall test well data is in the immediate vicinity of the wellbore as reflected in the dependence of the skin factor on the change in the effective stress (Figure 8).

Since all other downhole pressure transient measurements are consistent, it is reasonable to question the measurements made at the time of the RLT. Were the actual flow rates only $\sim$ 62 percent of the values reported? This is not credible since the stable full-stream temperature (280°F) recorded at the surface during RLT drawdown is consistent with the flow rate reported (Figure 11). Also, the pressure drop measured in the wellbore from 15,100 ft to the surface is consistent with the reported flow rate (Figure 9).

Since nonlinear formation response and measurement error do not seem plausible, the pressure transient data available from the Gladys McCall Well No. 1 are best explained by the presumed partial plugging of the sand formation in conjunction with the presence of a thin shale stringer in Sand Zone No. 8.

VII RESERVOIR SIMULATION MODEL

Figure 12 shows a schematic of the geopressured reservoir simulation model (which employs SI metric units) used to match the integrated data sets comprised of the full test history of Sand Zone 8. The configuration, symmetrical across a north-south plane through the test well, is basically the same as employed in the earlier paper (Riney, 1988) except the total volume is enlarged by removing the earlier assumption that the flow barriers F1 and F2 form the southern and northern boundaries of the reservoir. The distances of F1 (240 m) and F2 (400 m) from the test well are based on the analysis of the downhole pressure data from the RLT (Riney, 1988). The distance (ℓ = 200 m) which the shale stringer near the middle of Sand Zone 8 extends from the well is based on reservoir simulation parametric calculations described in an earlier section. The present model assumes 62 percent of the thickness of Sand Zone 8 is above the shale stringer (Figure 3); the earlier model used 50 percent.

In the new model, F1 and F2 are assumed to be internal sealing faults that do not extend as far as the east-west boundaries of the reservoir. They are assumed to form horizontal flow barriers for the same distance from the test well as the major shale break at the top of Sand Zone 8 forms a vertical flow barrier. The north-south dimensions of the reservoir drained by the test well is assumed to extend for 2,440 m as shown. The east-west dimensions and the upper and lower boundaries in Figure 12, however, are unchanged from the earlier model. The thickness of 390 m approximates the net sand in the Miocene sand/shale sequence penetrated by the test well. The north-south and east-west dimensions roughly approximate the fault block dimensions mapped in Figure 1.

The thickness of Sand Zone 8 is approximated by 100 m as in the earlier model. The near-well horizontal permeability is chosen to be $k_1 = 134$ md (1.33×10^{-13} m^2) to preserve the value of $kh = 44,090$ md-ft estimated from the RLT data. The more distant horizontal permeability in Sand Zone 8 is assumed to be $k_2 = 2 \times 10^{-14}$ m^2 as in the earlier model; this permeability value is also used for the reservoir southern and northern extensions beyond faults F1 and F2 (i.e., $k_4 = 2 \times 10^{-14}$ m^2). The effective horizontal permeability in the regions of the reservoir beyond the east and west ends of the faults was varied in a series of simulations; the best history match was obtained using $k_3 = 5 \times 10^{-15}$ m^2. The total compressibility ($C_T = 9.1 \times 10^{-4}$ MPa^{-1}(6.27×10^{-6} psi^{-1})) and porosity (ϕ = 0.16) throughout the extended Sand Zone 8 volume are the same as in the earlier model. The reservoir brine properties were also unchanged: $\mu = 0.31 \times 10^{-4}$ Pa$-s$(0.31 cp), $\rho = 1030.5$ kg/m^3.

The 290 m thick upper layer in the model represents overlying/underlying sands that contribute to the pressure support of Sand Zone 8 by fluid crossflow at shale breaks. Both the horizontal and vertical effective permeabilities in this layer and the vertical permeability in Sand Zone 8 are all assumed to be 2×10^{-16} m^2. The total

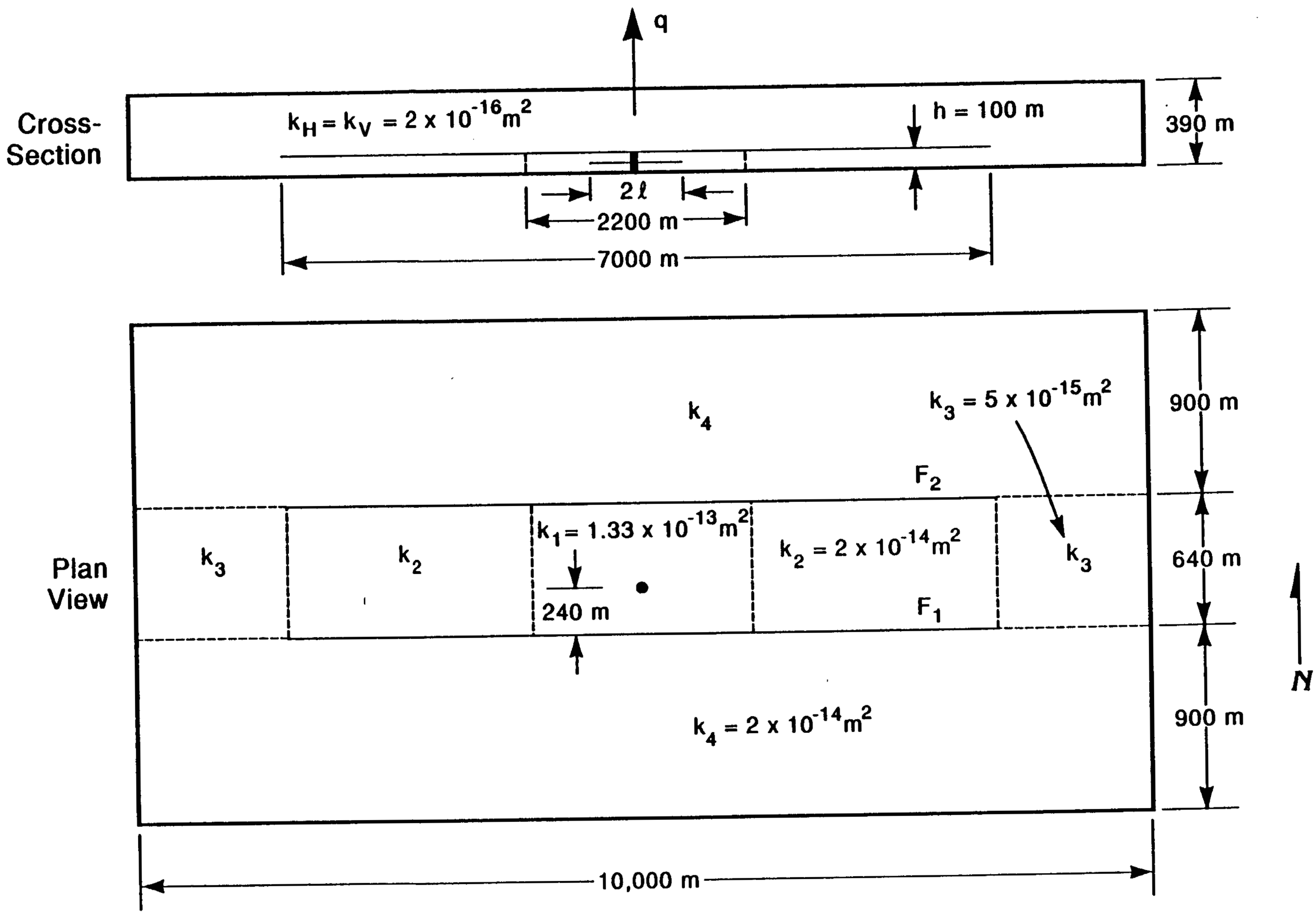

Figure 12. Vertical section (upper) and planar (lower) views of model for Gladys McCall reservoir based on concept that crossflow from overlying/underlying sands sustain pressure in sand zone 8 (k_i = horizontal permeabilities in Sand Zone 8; ℓ = 200 m).

compressibility is the same as in Sand Zone 8 but the porosity was reduced to $\phi = 0.12$ in this "remote volume" to provide the best history match.

It should be emphasized that the actual reservoir properties away from the test well are not known and our choices represent "effective values" that provide a good match to the integrated Depletion and Recovery Phases of Gladys McCall Well No. 1.

In simulating the production history of the well, the numerous rate changes were closely approximated. The values of the skin factor (s) determined from the wellhead pressures in (Figure 8) were employed in the simulation. The variations in the value of s is treated in the usual way in the numerical calculations by varying the values of the "equivalent well radius", i.e. $r_w^* = r_w \exp(-s)$. At $t \sim 418$ days (November 28, 1984), plugging by the first aborted pill injection of the portion of Sand Zone No. 8 below the shale stringer is assumed; flow into the wellbore thereafter is restricted to the upper 207 ft (Figure 3) so that the near-well apparent transmissivity is reduced to $kh = 28,340$ md-ft. Figure 13 compares the simulated sandface pressure at the datum level (15,100 feet) with bottomhole values estimated from wellhead recordings during periods of stable production. As shown in Figure 14, the simulated sandface pressure agrees equally well with bottomhole values estimated from wellhead recordings just after planned shutins ($[p_{ws}]_{3\,\mathrm{m}}$). There is also good agreement through the simulated transition from the Depletion Phase to the Recovery Phase during the four week period starting on April 21, 1987 (Figure 15). The simulated sandface pressure during the multi-rate flowing portion of the LTT and the shutin portion of the LTT are compared with the bottomhole data (corrected to the datum level) in Figures 16 and 17, respectively. The differences between the simulated and measured bottomhole pressures are within the accuracy of the measurements.

VIII DISCUSSION

Nonlinear reservoir response mechanisms have not been detected at Gladys McCall except possibly as a skin effect in the vicinity of the wellbore. Nevertheless, nonlinear processes (e.g., irreversible formation compaction, shale water influx, leaky boundaries, formation creep, etc.) might be present and have affected long-term pressure maintenance, but be too subtle to be apparent in the test data from a single well in a poorly defined reservoir. This would be in contrast with the experience at the Parcperdue geopressured reservoir where robust nonlinear effects were manifested from the early short-term testing of the L. R. Sweezy well.

A simple reservoir configuration (Figure 12) has been used as a framework for constructing a linear model to match the integrated data base available for Gladys McCall. The reservoir boundaries were chosen such that total fault block volume roughly approximates the dimensions suggested by the limited geological information and the near-field reservoir properties are based on data from the test well. The configuration

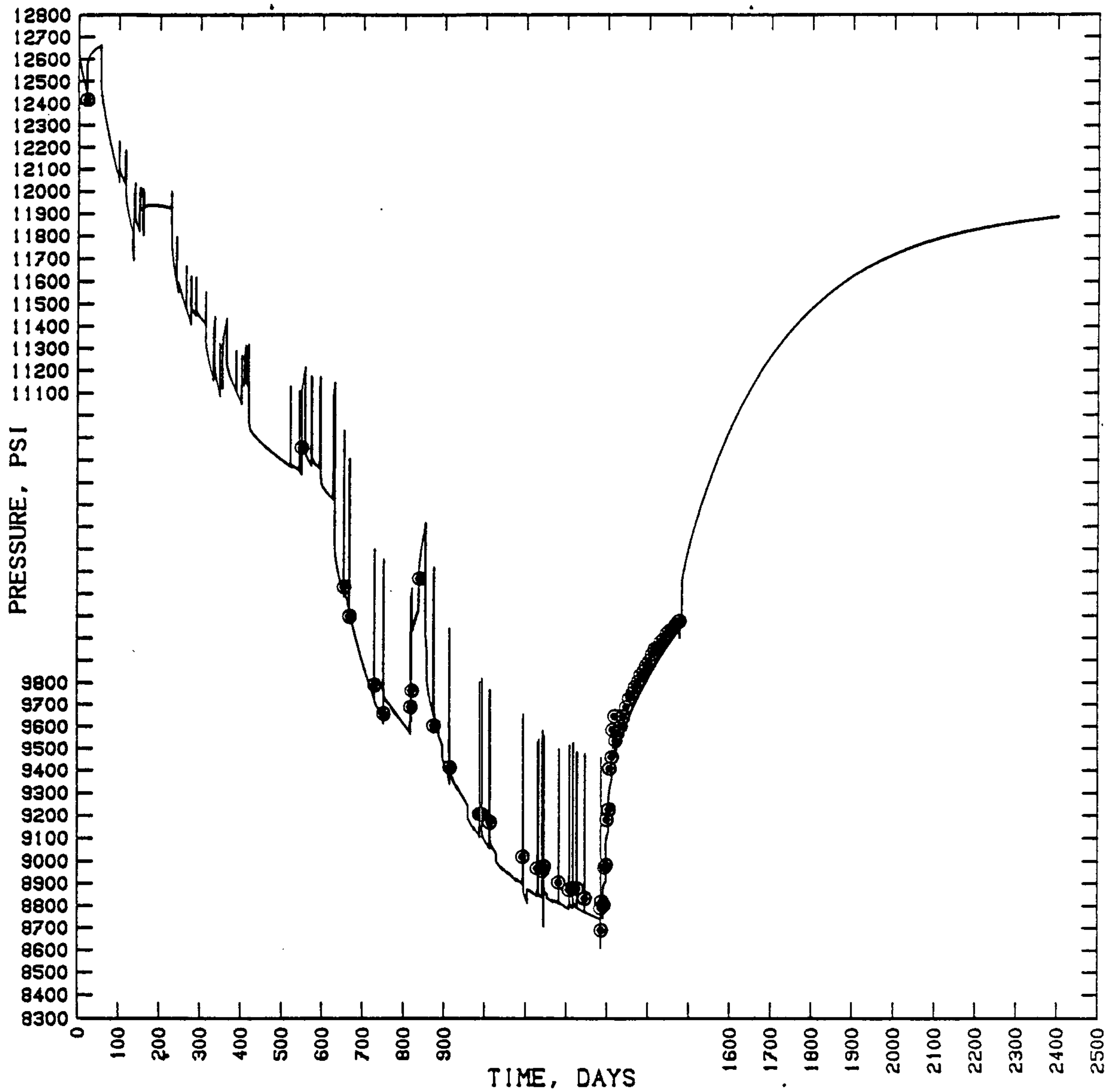

Figure 13. Simulated sandface pressure history (curve) compared with values (points) estimated from flowing wellhead recordings of Gladys McCall Well No. 1. Datum level is 15,100 ft.

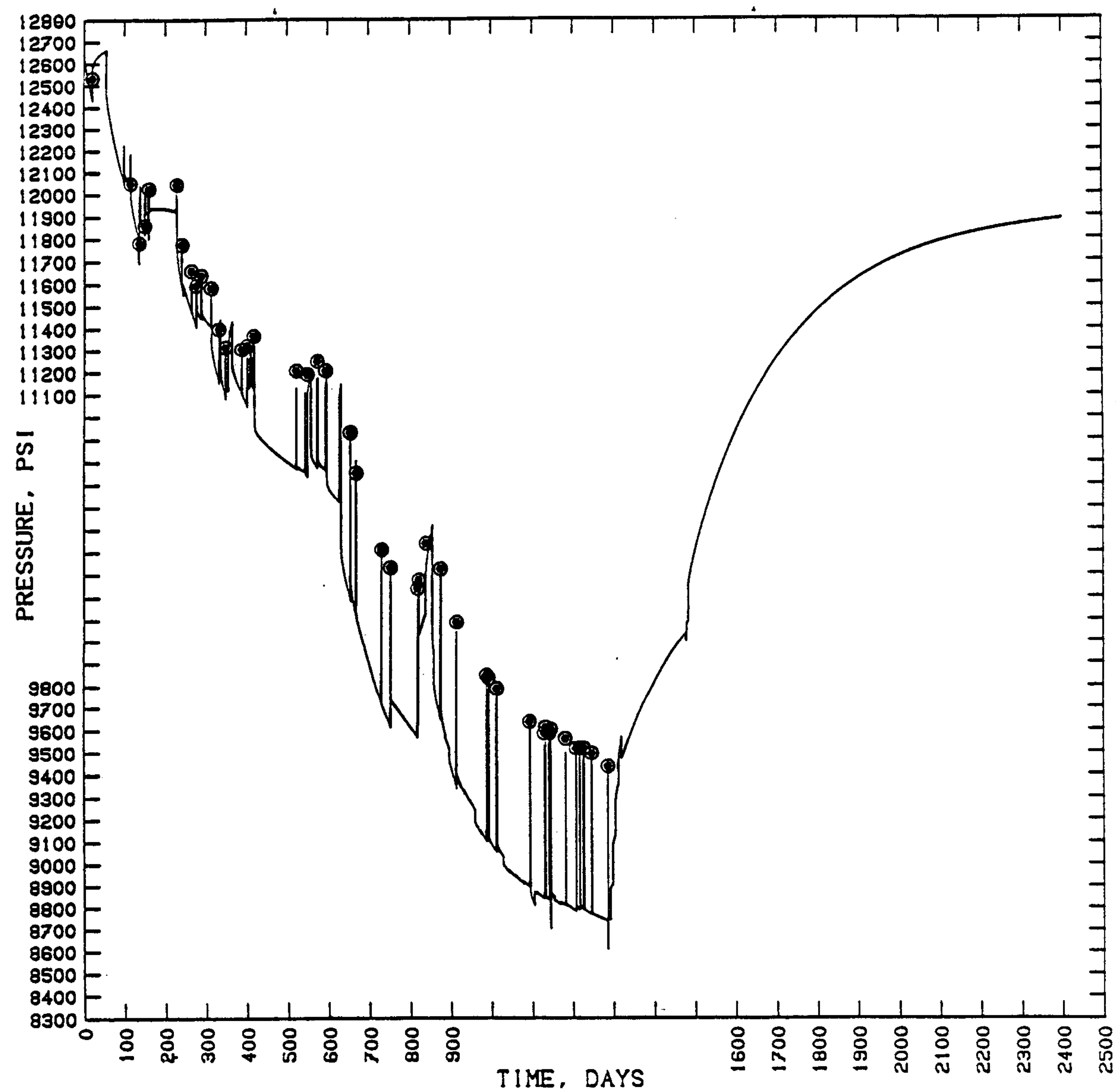

Figure 14. Simulated sandface pressure history (curve) compared with values (points) estimated from instantaneous ($t = 0.05$ hr) wellhead shutin pressure recordings. Datum is 15,100 ft.

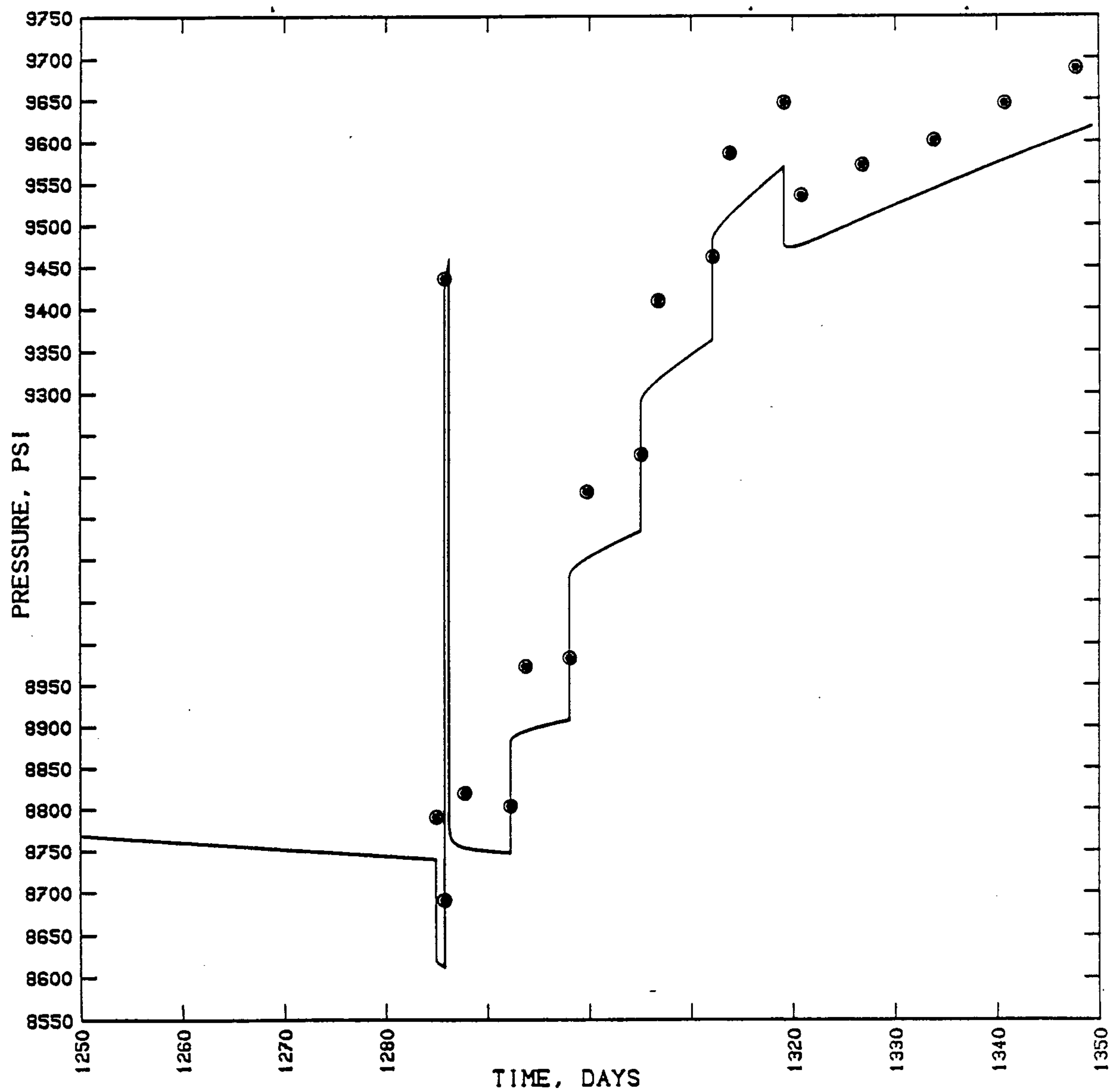

Figure 15. Simulated sandface pressure history (curve) compared with estimated values (points) during transition from Depletion Phase to Recovery Phase. Datum is 15,100 ft.

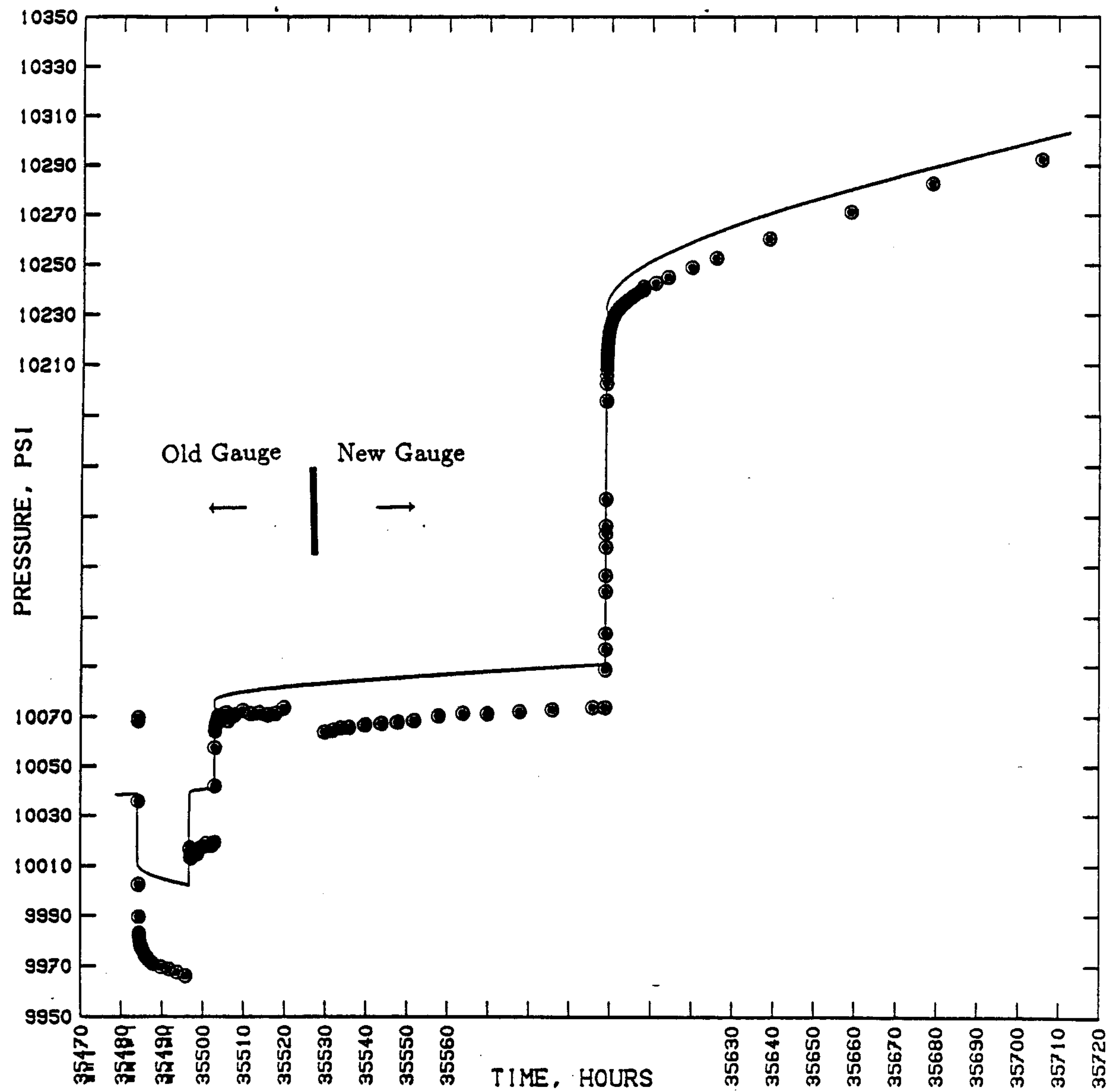

Figure 16. Simulated sandface pressure history (curve) compared with measured bottomhole data (points) during LTT. Datum is 15,100 ft.

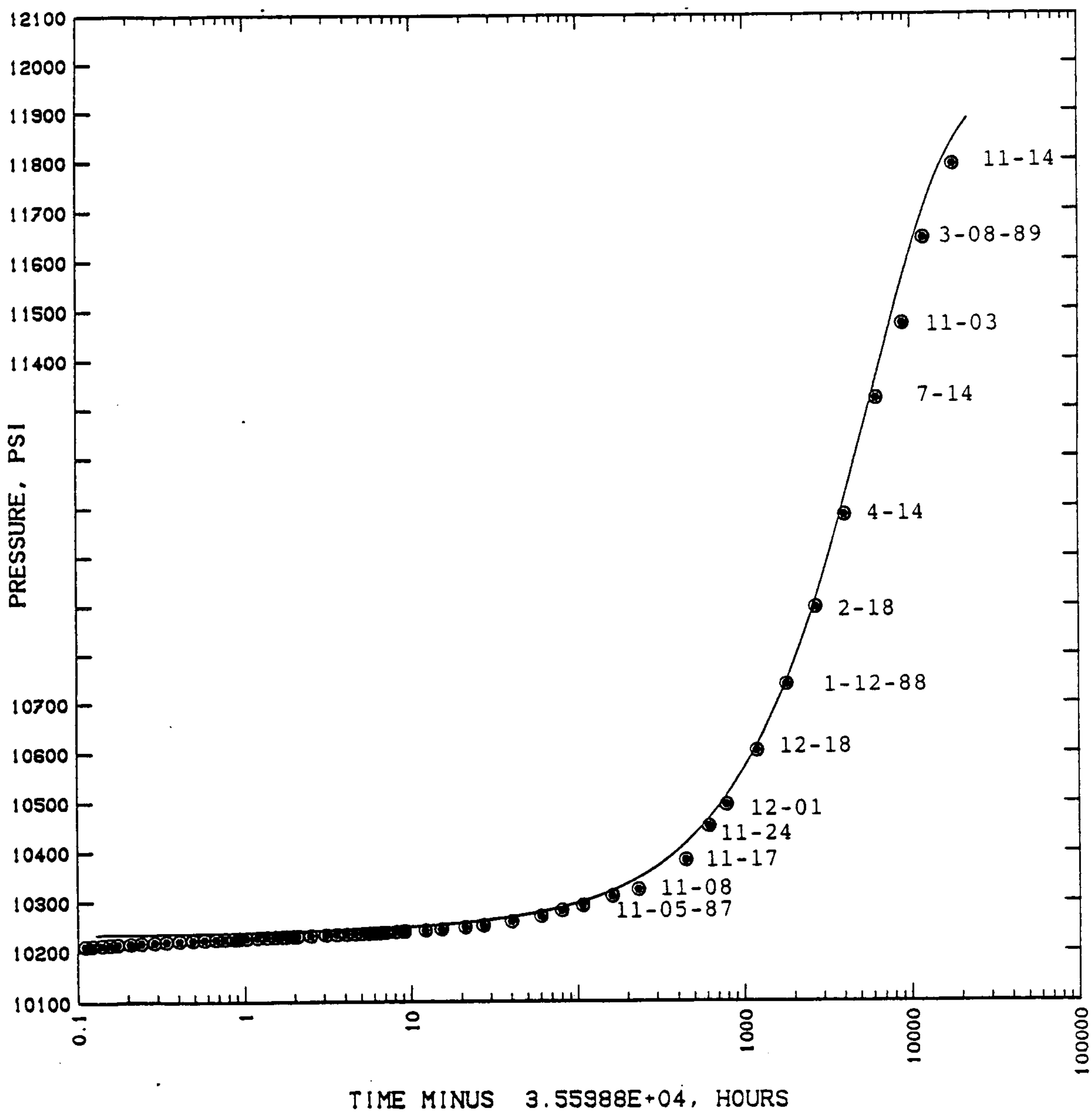

Figure 17. Simulated pressure buildup history (curve) compared with bottomhole pressure data (points) measured during the long-term shutin test still underway at Gladys McCall Well No. 1. Datum level is 15,100 feet.

used is only one of many alternatives, however, and is not particularly constrained by the geological data. The unknown far-field reservoir properties were varied in a series of parametric calculations to arrive at values that provide a good match to the available test data. The quality of the history match obtained during the transition from the Depletion to the Recovery Phase was sensitive to the parameters that control the hydrologic connection to the remote volumes of the reservoir. The value chosen for the effective porosity in the reservoir volume representing the overlying/underlying sands affects the quality of the history match during the Recovery Phase.

The good match that the simulation model provides with the integrated data base does not imply that the selected configuration approximates the actual reservoir geology or that the far-field reservoir properties approximate the actual values. It only suggests that the depletion and recovery behavior of the real system is similar to that of the model selected. This non-uniqueness problem cannot be resolved in the absence of more definitive information defining the geology and reservoir properties away from the Gladys McCall test well.

The connected pore volume of the linear (but heterogeneous) reservoir model used to match the integrated Gladys McCall data is

$$V_p = 10,000(2,440)[(0.16)(100) + (0.12)(290)] = 1.24 \times 10^9 \text{ m}^3(7.8 \times 10^9 \text{ bbl}) \quad .$$

Since estimates for distances made from well test analysis depend on the square root of C_T, all lateral dimensions employed in the model would need to be increased by $\sim$ 20 percent if $C_T = 4.0 \times 10^{-6}$ psi^{-1} were used, or decreased by $\sim$ 10 percent if $C_T = 7.7 \times 10^{-6}$ psi^{-1} were used, rather than $C_T = 6.27 \times 10^{-6}$ psi^{-1}. These dimensions would also lie within the uncertainty of the known geology of the Gladys McCall fault block.

The pore volume in the new reservoir model is triple the volume of the model used in the earlier reservoir simulation for only the Depletion Phase of the Gladys McCall test well history. The increase results from removing the earlier assumption that the two flow barriers (F1 and F2 in Figure 12) represent the north and south reservoir boundaries. The barriers are now treated as internal flow barriers that allow hydrologic connection to regions of the fault block to the north and south of F1 and F2.

In contrast with the situation at Gladys McCall, the geological information for the geopressured C-zone being tested by the Pleasant Bayou research well is extensive. Considerable deep-well data and broad-based geological work has defined the boundaries and internal structure of the reservoir and estimated the connected pore volume to be between 6.2 and 6.6 $\times$ 10 bbl (Hamlin and Tyler, 1988). Long-term production testing of the Pleasant Bayou well, now in progress, will provide a basis for comparing geopressured reservoir volume estimates based on extensive geological data as opposed with estimates based on actual depletion behavior of the reservoir. These results may provide further insight for interpreting the Gladys McCall test data.

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