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ANALYSIS OF PHASE I FLOW DATA FROM PLEASANT BAYOU NO. 2 GEOPRESSURED WELL

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ABSTRACT

Analysis of pressure drawdown/buildup data from the Phase I 45-day production/45-day shutin test indicates (1) the presence of a linear barrier at approximately 3,000 ft and (2) that the skin factor varies widely during the test. The linear barrier appears to correspond to a mapped growth fault. At present, we are unable to identify the physical mechanism responsible for the apparent variation of skin factor. The formation parameters derived from the buildup data have been employed in the MUSHRM simulator to successfully history-match the Phase I pressure and flow data.

INTRODUCTION AND BACKGROUND

Preliminary short-term production and buildup tests of the Pleasant Bayou No. 2 Well were conducted during the second half of 1979. Phase I of the long-term testing of the Pleasant Bayou No. 2 Well was conducted from September 16 to December 15, 1980. The present paper is primarily concerned with the analysis of the pressure/flow data obtained during Phase I.

The Pleasant Bayou No. 2 Well has 7-inch casing set through the Frio sand at 14,644 ft to 14,704 ft (mean depth = 14,674 ft). Bottomhole pressure was measured using the Hewlett-Packard quartz crystal element set at a depth of 14,560 ft. The initial pressure at the 14,560 ft datum was 11,116 psi. Independent temperature sensing capability was also available. Turbine pulse meters, downstream of the separator, were employed to record brine flow rates. Gas flow rates were, however, indirectly calculated.

Assuming a static pressure gradient of 0.46 psi/ft, the initial reservoir pressure (i.e., at 14,674 ft depth) becomes 11,168 psi; this is 72 psi lower than the pressure recorded prior to the "Preliminary Flow Tests" and is 27 psi below the shutin pressure measured on January 3, 1980 at the conclusion of those early tests. Because of the difficulty associated with reproducing downhole pressure measurements with different sensors, no significance is attached to these pressure differences. The bottomhole temperature recorded during Phase I (~306°F) is in reasonable agreement with that obtained earlier (~301°F) in the "Preliminary Flow Tests".

Kharaka, et al. (1979) have reported a salinity of approximately 130,000 ppm for the reservoir brine. With temperature T=306°F and taking salinity by mass S=0.12 (~130,000 ppm at standard conditions), the methane/brine equation-of-state data (Pritchett et al., 1979) yield a methane concentration of 27.2 SCF/STB at saturation. The Gas Water Ratio (GWR) during Phase I flow tests averaged around 23 SCF/STB at separator conditions. This suggests that the reservoir fluids are most probably saturated with gas.

ANALYSIS OF DRAWDOWN/BUILDUP PRESSURE DATA

Pleasant Bayou No. 2 Well was flowed at varying rates from September 16, 1980 to October 31, 1980 for a total of approximately 1085 hours. The flow-rate was kept roughly constant during the following four periods: A. 3.33 hr$<t<$125.67 hr, q_c~6436 STB/D; B. 128.75 hr$<t<$359.5 hr, q_c~10,476 STB/D; C. 363.17 hr$<t<$439.0 hr, q_c~18,184 STB/D; D. 540.5 hr$<t<$1085.03 hr, q_c~12,616 STB/D. In our analysis of the drawdown data, we will consider each of these flow periods separately. Assuming that the reservoir does not initially contain any free gas, it can be shown that the flow stream, at bottom-hole conditions, would contain less than one percent by volume of free gas. Therefore, single-phase analysis methods should be adequate to analyze the pressure data; the buildup of any gas saturation near the wellbore, however, would result in an apparent increase in skin factor.

DRAWDOWN DATA ANALYSIS

The pressure transient analysis methods for multiple-rate flow tests are discussed by Earlougher (1977). A convenient technique is to plot

$$(p_i - p_{wf})/q_n \text{ versus } \sum_{j=1}^{n} (\Delta q_j/q_n) \log (t - t_{j-1}) ,$$

where p_i=initial reservoir pressure; p_{wf}= flowing pressure; q_n=constant flow rate during n^{th} flow period ($t_{n-1} \le t < t_n$); $\Delta q_j = q_j - q_{j-1}$, $2 < j < n$; $\Delta q_1 = q_1$; t_{j-1} = time at end of flow period (j-1); t_0=0. The plot should give us a straight line with slope m'=162.6 μB/kh and intercept

$$b' = m' [\log (k/\phi\mu C_T r_w^2) - 3.23 + 0.87s] .$$

Here μ=reservoir fluid viscosity, cp; B=formation volume factor RB/STB; k=formation permeability, md; h=formation thickness, ft; ϕ=porosity; C_T= total formation compressibility, psi^{-1} $(=[(1-\phi)/\phi]C_m+C_f)$; C_m=uniaxial formation compressibility, psi^{-1}; C_f=fluid compressibility, psi^{-1}; r_w= well radius, ft; and s = skin factor.

The uniaxial formation compressibility (C_m) for the Pleasant Bayou sands is of the order of 10^{-6} psi^{-1} (see Gray, et al. (1979)). Assuming that C_f ~3×10^{-6} psi^{-1} and ϕ=0.176, we obtain C_T~7.7×10^{-6} psi.

The drawdown data for flow period A, shown in Figure 1, can be approximated by two straight lines with slopes (m') of 0.00469 psi-D/bbl-cycle and 0.005575 psi-D/bbl-cycle. With q_n=6436 STB/D, μ= 0.267 cp, B=1.050, h=60 ft, we obtain for formation mobility kh/μ and permeability k: (i) Near Well Bore: kh/μ≃36,400 md-ft/cp, k= 162 md; (ii) Far Field: kh/μ≃30,600 md-ft/cp, k =136 md. The two straight line segments in Fig. 1 intersect at approximately t~48 hours. The transition from near well permeability to far field permeability occurs approximately at: r_{trans} = $(0.00105\ kt/\phi\mu C_T)^{0.5}$ ≃4750 ft. This value for the transition is only an order of magnitude estimate.

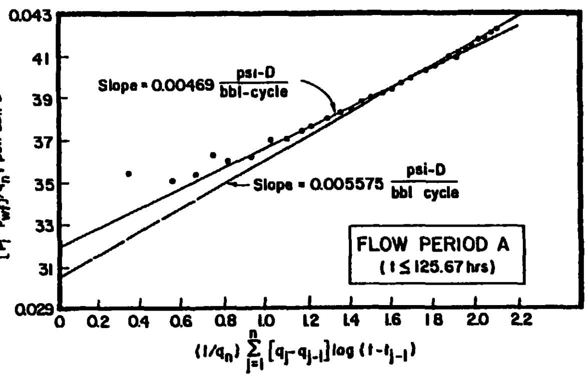

Figure 1. Drawdown data for t ≤ 125.7 hours.

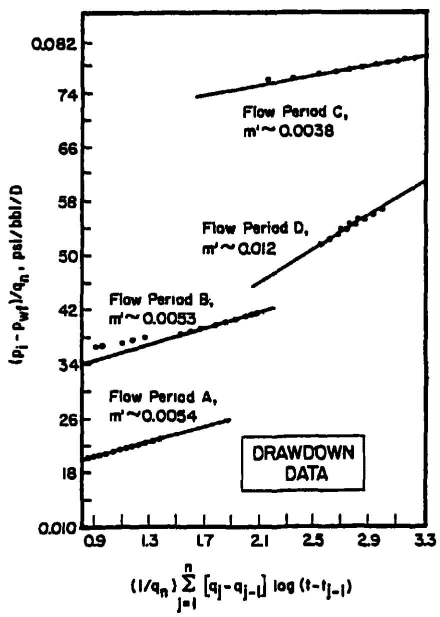

Figure 2. Drawdown data for the various flow periods.

Finally, the near well data yield a skin factor of s≃0.35.

A similar plot for flow period B, yields kh/μ=32,000 md-ft/cp, k=143 md and s≃0.51. The drawdown data for flow period C give kh/μ=44,300 md-ft/cp, k=197 md and s≃6.3.

Fig. 2 shows the drawdown data for flow periods A, B, C and D. The slope of the straight line corresponding to flow period D is approximately twice that of straight lines for the earlier flow periods; this indicates the presence of a linear barrier to flow. Variations in the flow rate of the well during the interval between the flow periods C and D, however, make it impossible to estimate the distance to the barrier.

BUILDUP DATA ANALYSIS

For buildup tests with widely varying flow rates before shutin, shutin pressure plotted against reduced time (Earlougher, 1977),

$$p_{ws} \text{ versus } \sum_{j=1}^{N} (q_j/q_N) \log \left(\frac{t_N - t_{j-1} + \Delta t}{t_N - t_j + \Delta t}\right) ,$$

should yield a straight line with slope m. Here q denotes the final flow rate prior to shutin, t_N is the shutin time, and Δt is the buildup time. Formation mobility and skin factor are given by:

$$kh/\mu = 162.6\ q_N\ B/m$$

$$s = 1.151\ [(p_{1hr}-p_{wf})/m - \log (k/\phi\ \mu C_T r_w)^2 + 3.23]$$

where p_{wf} is the final flowing pressure before shutin, and p_{1hr} is the shutin pressure at Δt~1 hour extrapolated from the straight line.

Fig. 3 shows that the buildup data may be approximated by three straight line segments with slopes (m) of 49.8, 64.2 and 90 psi/cycle respectively. The slope of the third straight line segment is almost twice of the first straight line segment.

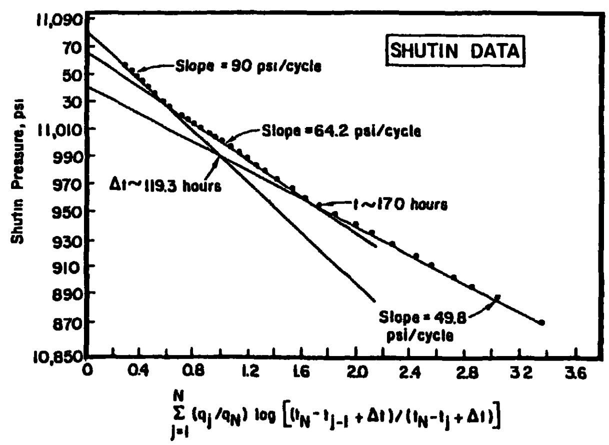

Figure 3. Shutin pressure versus reduced time.

The first straight line segment yields for near wellbore permeability: $kh/\mu \simeq 43,300$ md ft/cp, $k = 192$ md. With $p_{1hr}=10,891$ psi and $p_{wf}=10,386$ psi, a skin factor of $s=4.12$ is obtained. The pressure buildup data start deviating from this straight line segment at approximately $\Delta t \simeq 17.0$ hours. The radius investigated by the buildup test at this point in time is approximately given by: $r_{inv} = (0.00105\ k\Delta t/\phi\mu C)^{0.5} \simeq 3080$ ft.

The near doubling of slope at late buildup times indicates the presence of a linear barrier. The distance L to the linear barrier is approximately given by $L= 0.01217\ (k\Delta t_x/\phi\mu C_T)^{0.5}$ ft, where Δt_x=shutin time corresponding to the intersection of the two straight line segements. With Δt_x=119.3 hours (see Fig. 3), we obtain $L \simeq 3060$ ft. The distance to the linear barrier is essentially the same as the radial distance within which the formation permeability is 192 md.

The question now arises as to whether the middle straight line segment merely represents the nonlinear effects of the linear barrier at 3000 ft or whether it reflects a mobility change. At present, it is not possible to answer this question conclusively. The reservoir simulation calculations presented in the next section, however, indicate that the pressure drawdown/buildup can be satisfactorily matched by assuming a homogeneous reservoir with a permeability of 192 md, and a linear barrier at 3000 ft.

DISCUSSION

The principal results of the preceding analysis can be summarized as follows:

(i) Analysis of buildup data yields a value of $kh/\mu \simeq 43,300$ md-ft/cp which is in good agreement with that obtained from the drawdown period C. Analyses of drawdown periods A and B however, give somewhat lower values for kh/μ.

(ii) The pressure buildup data indicate the presence of a linear barrier at approximately 3,000 ft.

(iii) Analyses of different flow periods and buildup data lead to widely differing values for skin factor s.

Bebout, et al. (1979) have mapped several growth faults that traverse the prospect area (Fig. 4). At the depth of ~14,000 ft the nearest mapped fault lies approximately 0.5 mile to the southeast of the Pleasant Bayou No. 2 test well; this fact provides some geological basis for the linear barrier identified from an analysis of pressure data.

The following are three of the possible mechanisms that could lead to a change in skin factor: 1. Buildup of free gas near the wellbore during drawdown; 2. Formation compaction and hence a reduction in formation permeability; and 3. Non-Darcian flow near the wellbore. Detailed

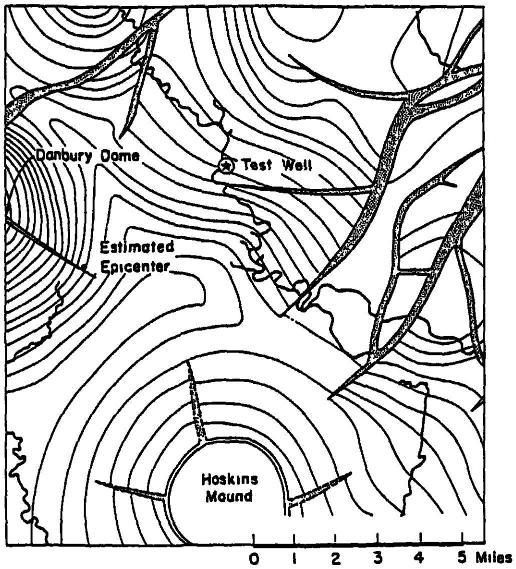

Figure 4. Location of Pleasant Bayou No. 2 well relative to growth faults.

analysis (Garg, et al., 1981), however, indicates that these mechanisms cannot account for the rather large variations in skin factor inferred from the Phase I test data.

HISTORY-MATCH CALCULATIONS

The formation properties derived from the buildup data have been employed in the reservoir simulator MUSHRM to match the observed drawdown/buildup pressures and flow rates. For simulation purposes, the reservoir was assumed to be a rectangular volume with the following dimensions: length, l=42,000 ft; width, w=24,000 ft; and height, h=60 ft. A two-dimensional areal grid was employed with the production well located at 3,000 ft from one boundary and 21,000 ft from the other three. All four boundaries are impermeable and insulated.

The reservoir rock is assumed to be a sandstone with the following properties: porosity, $\phi=0.176$; permeability, k=192 md; uniaxial compressibility, $C_m=10^{-6}$ psi^{-1}; and skin factor, s=3.24. The skin factor is somewhat less than that inferred from buildup data. The skin factor derived from shutin data consists of two components i.e., (1) skin due to well damage and (2) apparent skin resulting from the gas buildup near the wellbore. Several preliminary simulations indicated that the apparent skin due to gas buildup is of the order $\Delta s \sim 0.9$; thus the skin factor attributable to well damage is $s \simeq 3.24$.

The relative permeabilities used in the present simulation (Garg et al. 1981) are based on laboratory measurements reported by Roberts (1980). These data indicate that the gas phase remains essentially immobile for $S_g<0.235$ and the liquid phase relative permeability declines dramatically with small amounts of free gas in the pores. The production history imposed in the simulation consists of 13 distinct constant rate segments to reflect the observed changes in flow rate during the Phase I production test. All pressures are referred to the 14,560 ft datum.

Fig. 5 compares the calculated bottom-hole pressures with observed drawdown pressures. There is good agreement between the observed and simulated pressures for flow periods B and D. The calculated flowing pressures are lower by approximately 50 psi than the measured pressures for flow period A. The measured pressure drop for flow period C is some 40-50 psi greater than the computed value. The measured and calculated pressure drops for flow periods A and C could be made to coincide by using a variable skin factor. We are, however, unable at this time to provide any justification for a variable skin factor.

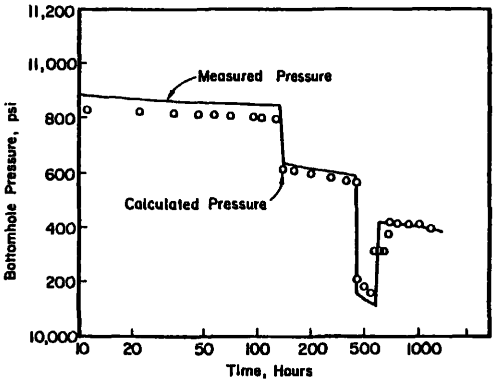

Figure 5. Calculated and measured pressure data (drawdown).

Fig. 6 compares the observed and calculated buildup pressures. Note that 19 psi were subtracted from all computed pressure values to match observed and calculated pressures at the end of the flow period. In general, there is good agreement between the observed and simulated buildup pressures.

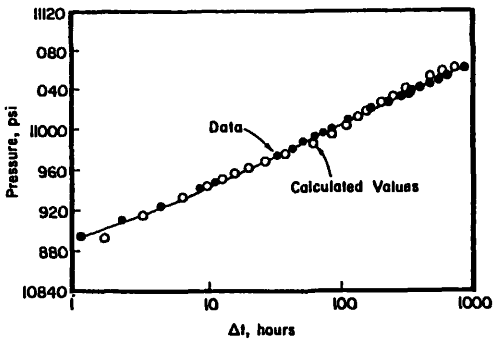

Figure 6. Calculated and measured pressure data (buildup).

The calculated methane content of the produced brine is 26.9 SCF/STB and compares favorably with the observed average GWR of 23 SCF/STB corrected for the gas left in the brine as it exists the separator (Preliminary calculations indicate that the observed GWR should be increased by 10-15 percent.

CONCLUSION

In summary, the formation parameters inferred from the buildup data were successfully employed in the reservoir simulator MUSHRM to history match the Phase I pressure and flow data. Current DOE plans call for further long term testing (Phase II, producing up to 40,000 bbl/D for six months) of the Pleasant Bayou geopressured reservoir; the data from this test should be helpful in identifying additional reservoir boundaries, and further refining the estimates for formation parameters.

ACKNOWLEDGEMENT

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