# PRELIMINARY TEST RESULTS OF THE FIRST GEOPRESSURED-GEOTHERMAL DESIGN WELL, BRAZORIA COUNTY, TEXAS

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## INTRODUCTION

The Pleasant Bayou #2 Geopressured-Geothermal test well was completed in the summer of 1979. The C sand of the Frio formation was selected for completion on the basis of core analysis, well logs, and drillstem tests. The purpose of this paper is to summarize the results of the short term production tests run on the Pleasant Bayou #2 well during 1979 and the Fall of 1980. These tests were analyzed using conventional transient pressure test analysis methods.

The most significant test run during 1979 was a ten day drawdown test from December 3 to December 14 followed by a 20 day buildup period, during which reservoir pressure response was observed. After a hiatus of nine months, a second production test was conducted over a period of 45 days beginning on September 16, 1980. The well was shut in on October 31, 1980. Pressure buildup data continues to be monitered.

Both production tests indicate a formation permeability of 200 millidarcies. The presence of a permeability interruption located approximately 3700 feet from the wellbore is also suggested by these tests.

During the last production test, a producing gas-water ratio of 20 standard cubic feet per barrel of produced water was observed. An additional 9-12 standard cubic feet of gas per barrel was found in the water downstream of the separator. The total gas-water ratio of 29-32 SCF/bbl is in reasonable agreement with laboratory data and correlations for this produced brine.

The major growth fault which forms the reservoir boundary to the northwest of the well is evident from the pressure drawdown data obtained during the last production period. The last production test also indicates an apparent rate dependent skin effect.

## RESERVOIR PARAMETERS

The C sand reservoir is separated from the other sand members of the Frio formation by shale zones. As shown on the isopach map of the C sand after Bebout et al (1), Figure 1, the reservoir is approximately 30 miles long in the southwest-northeast direction along the major growth fault which bounds the reservoir and averages 5 miles in width perpendicular to this major fault. The C sand reservoir body may be fragmented by cross faulting perpendicular to the major fault. However, the effects of this cross faulting on reservoir continuity must await the results of flow testing over extended production periods.

The C sand found in the Pleasant Bayou #2 well is 60 feet thick with a porosity of 17.6% determined from standard core analysis. Compaction coefficients on the order of $5 \times 10^{-7}$ $psi^{-1}$ have been reported by Gray et al (4) for the reservoir sand. However, these investigators have noted that this material exhibits creep behavior and therefore caution must be observed when using these data under the assumption of elastic rock behavior. Water properties have been computed from correlations (3) assuming a gas saturated brine containing 130,000 ppm of dissolved solids. The following table summarizes the data used in the transient pressure test calculations:

| | |
|---|---|
| Reservoir thickness | 60 feet |
| Average porosity | 17.6% |
| Uniaxial compaction coefficients | $5 \times 10^{-7}$ $psi^{-1}$ |
| Pore compressibility | $2.3 \times 10^{-6}$ $psi^{-1}$ |
| Water compressibility | $4 \times 10^{-6}$ $psi^{-1}$ |
| Water viscosity | 0.25 cp |
| Water formation volume factor | 1.05 RB/STB |
| Wellbore radius | 3.5 inches |

## PRODUCTION TEST DATA

Clark (2) has summarized the production test information obtained during the initial period in 1979. The first production from the well occurred on July 9-10, 1979, immediately after the well was perforated. Surface pressure measurements were taken as the pressure gauge would not operate at bottom hole conditions. Clean up of the perforations during this flow period caused interference with the test results.

From November 15 to November 18, 1979, three production periods occurred, the first two of rather short duration. The third flow period lasted over 2 days and provided the first significant test data. Problems with the bottom hole pressure gauge forced the termination of this test. The well was again put on production on November 23, 1979, and was shut-in on November 25 due once again to gauge problems. This testing period served primarily as a check out of the equipment and procedures, as well as providing preliminary reservoir data.

The first substantial flow period for the well occurred from December 3, 1979 to December 14, 1979. During this ten day period, the well produced at an average rate of approximately 13,500 barrels per day. During this test, it was necessary to periodically move the pressure gauge in the well and, thus, the pressure information is somewaht suspect, although later tests have confirmed the general validity of the results obtained from this drawdown period.

The first definitive data with respect to reservoir properties was obtained from the pressure buildup behavior observed after the December 3 - 14 ten day production test. This data is presented in Figure 2 in the form of the conventional Horner plot, in which the logarithm of the time factor

$$\frac{T + \Delta t}{\Delta t} \qquad (1)$$

is plotted against the observed pressures. The flowing time, T, is taken as the cumulative production divided by the last sustained flowrate before closing in the well. The time after shutin, $\Delta t$, corresponds to the measured bottomhole pressure observations. In this case, the cumulative production was taken to be 240,000 barrels, which includes all production from tests since July 1979. The last sustained production rate was 13,650 barrels per day, resulting in an equivalent Horner flow time of 422 hours.

Beginning on September 16, 1980, a 45 day variable rate production test was carried out. The production rate schedule for this test is given below:

| Time Period | $\Delta t$ (Hours) | Production Rate (bbls/day) |
|---|---|---|
| Sept 16 11:30 am | 127 | 6750 |
| Sept 21 7:50 pm | 232 | 10920 |
| Oct 1 11:00 am | 67 | 19102 |
| Oct 4 6:00 am | 103 | 14060 |
| Oct 8 12:45 am | 555 | 13500 |
| Oct 31 5:32 am | to present | well shut in |

The results of this multirate drawdown test are given in Figure 3, in which the data has been reduced by the superposition principle as discussed by Earlougher (3) to a plot of

$$\frac{P_i - P_{wf}}{q_n} \qquad \text{versus} \quad \sum_{1}^{N} \frac{q_j - q_{j-1}}{q_n} \log_{10} (t-t_{j-1}) \qquad (2)$$

If only one flowrate occurred in the test, then this plot would reduce directly to the more familiar plot of pressure drawdown versus the logarithm of the time. The initial pressure for this test was measured as 11116 psig @ 14560 feet.

The well was closed in on October 31, 1980, and the pressure buildup data continues to be monitered. The Horner plot of this information is given in Figure 4 and includes data through November 24, 1980. In reducing this buildup data, it was assumed that the reservoir had stabilized over the 10 month period, since the last production in December 1979, and that only production during the current testing period would affect the pressure buildup results. The Horner flow time, T, was computed to be 1011 hours based on a cumulative production since September 16, 1980, of 568,900 barrels of water and a final sustained rate of 13,505 barrels per day.

The buildup data obtained in December of 1979 and the multirate production test together with the subsequent pressure buildup data form the basis of the analysis presented in this paper.

## FORMATION PERMEABILITY

Formation permeability is computed from the slope of the pressure buildup or drawdown plots shown in Figures 2 - 4 by the relationship (3):

$$k = \frac{162.6\ q\mu B}{mh} \quad \text{or} \quad \frac{162.6\ \mu B}{m'h} \qquad (3)$$

where q - production rate (bbls/day)
μ - viscosity (cp)
B formation volume factor (RB/STB)
h - formation thickness (feet)
m - buildup slope (psi/∿ )
m' - multirate drawdown slope (psi/∿-bbls/day)

It is important to select the slope from pressure data which is no longer affected by wellbore storage effects caused by flowrate changes, but as yet is not affected by reservoir boundaries or lateral changes in formation properties. The permeability computed from the three tests is as follows:

| Buildup Tests | Production Rate (bbls/day) | m (psi/∿) | Permeability (md) |
|---|---|---|---|
| December 1979 (Figure 2) | 13650 | 54.5 | 178 |
| November 1980 (Figure 4) | 13505 | 48.0 | 200 |

| Drawdown Test | m' (psi/∿ - bbls/day) | Permeability (md) |
|---|---|---|
| October 1980 (Figure 3) | 0.0034 | 209 |

The somewhat lower permeability computed from the December 1979 buildup test data may be the result of uncertainties in the measurement of production rates during the preceding drawdown period.

Based upon these results and discounting the December 1979 test, we conclude that the formation permeability in the neighborhood of the well is 200 md.

## FAULTING AND BOUNDARIES

A perceptible change in the initial slope was observed in each of the three tests analyzed in this study. These slope changes are too subtle to be construed as a boundary or a sealing fault. However, they do indicate the presence of a change in formation transmissivity. The presence of a non-sealing fault could produce such an effect. The distance away from the wellbore at which this interruption might be found can be estimated from the relationship given by Earlougher (3):

$$r_{inv} = \sqrt{0.00105 \frac{kt}{\phi \mu c_T r_w^2}}$$

where k - permeability (md)
t - time of investigation (hours)
ϕ - formation porosity
μ - viscosity (cp)

$c_T$ - total effective compressibility ($psi^{-1}$)
$r_w$ - wellbore radius (feet)

The following table summarizes these computations:

| Test | Time at slope change (hours) | Radius (feet) |
|---|---|---|
| Dec. 1979 buildup | 20 | 3672 |
| Oct. 1980 drawdown | 25 | 4449 |
| Nov. 1980 buildup | 18.4 | 3733 |

As observed on the plots, Figures 2 - 4, the time at which the slope changes is open to broad interpretation. Minor changes in the slope will substantially alter this time value. It is felt that the drawdown data is the most tenuous in this respect, and thus it is concluded that the alteration in formation transmissivity occurs at a distance of approximately 3700 feet from the well.

Neither buildup test has indicated as yet any evidence of sealing boundaries. However, the multirate production test data does indicate the presence of a sealing fault, which we interpret to be the major growth fault that bounds the reservoir to the northwest. The slope of the data taken during the last half of the test is 0.0096 psi/(∿ - bbls/day) as compared to a consistent of 0.0053 psi/(∿ - bbls/day)) slope before this time. The virtual doubling of the slope is usually interpreted as indicating a sealing boundary. Determining the precise time at which the change in slope occurs is made difficult by the multirate effect on the generation of the reduced data used in the drawdown analysis. A time value of 530 hours was selected as the best estimate of the time when the slope change occurs. This value corresponds to a distance of investigation of 3.9 miles which agrees reasonably well with the geological interpretation of the growth fault. The buildup data presently being monitered should provide more definitive results in this regard.

SKIN EFFECT

Analysis of the recently concluded multirate production test suggests that apparent near well damage effects (i.e., the skin effects) are dependent on the production rate. The skin effect may be computed from the pressure drawdown equation as documented by Earlougher (3):

$$P_i - P_{wf} = m \left[ \log_{10} \left( \frac{kt}{\phi \mu c_T r_w^2} \right) - 3.23 + 0.87S \right] \qquad (7)$$

It is the usual convention to select the drawdown time as one hour, or

$$b = P_i - P_{wf}\ (1\ \text{hour}) = m \left[ \log_{10} \left( \frac{kt}{\phi \mu c_T r_w^2} \right) - 3.23 + 0.87S \right] \qquad (8)$$

where $P_{wf(1\ hour)}$ is the pressure inferred from the straight line portion of the drawdown plot at a flow time of one hour. In the case of a multirate test, the analysis is similar except that both the slope, m, and the intercept (i.e., t = 1 hour), b, are normalized with respect to the last flowrate

$$m' = \frac{m}{q_n} \qquad b' = \frac{b}{q_n} \tag{5}$$

and the skin factor is computed as

$$S = 1.151 \left[ \frac{b'}{m'} - \log_{10} \left( \frac{k}{\phi \mu c_T r_w^2} \right) + 3.23 \right] \tag{6}$$

As shown in **Figure** 3, the initial flow period of the drawdown test exhibits a slope of 0.0034 psi/(∿ - bbls/day) and an intercept of 0.0316 psi/(bbls/day). The skin effect computed from the above equation for these conditions is 2.96 indicating moderate well damage.

The method of superposition is used to analyze the effects of the multiple production rates on the drawdown behavior. As such, the plot of,

$$\frac{P_i - P_{wf}}{q_n} \quad \text{versus} \quad \sum_{1}^{N} \frac{q_j - q_{j-1}}{q_n} \log_{10} (t - t_{j-1}) \tag{2}$$

should be a continuous progression of points. However, as observed in Figure 3 there is a noticeable upward discontinuous shift in the data as the production rate is stepwise increased. The slope of each curve does remain the same. We have interpreted this behavior as an indication of a rate dependent skin effect.

The skin factor for each flowrate has been computed from equation 8 by extrapolating a value for the intercept b', taking into account the change in slope observed during the initial flow period. The skin factors computed are:

| Flowrate (bbls/day) | Skin Factor |
|---|---|
| 6750 | 2.96 |
| 10920 | 4.96 |
| 19100 | 6.98 |

These skin factors are plotted versus production rate in Figure 5. Also shown on Figure 5 are the skin factors computed from each of **the** buildup tests. The buildup test skin factors fall below the multirate drawdown trend, but are greater than the initial low flowrate skin factor.

The most plausible explanation for this behavior is the possibility that particle fines loosened in the formation near the wellbore during drilling and completion are pushed into pore throats at high production rates, thus reducing the permeability near the well.

An alternative explanation may be that non-darcy or 'turbulent' flow occurs near the well at higher flowrates. For this to occur, only a relatively small portion of the perforated interval could be open to flow inorder to generate localized fluid velocities high enough to cause the non-darcy effect. Furthermore, if it were postulated that only a few feet of perforations were open to flow, then the skin effect caused by limited entry alone would be substantially higher than that observed.

The effects of gas evolution about the wellbore, should it occur, would not explain the observed behavior since the accumulation process is a gradual one rather than an abrupt transition as indicated by the test data.

## FUTURE TESTING

In the short term, the pressure buildup following the last 45 day production test will continue to be monitered. It is hoped that a buildup period of at least 90 days will be observed before recommencement of production, so that the maximum amount of reservoir information such as the presence of boundaries and potential reservoir depletion can be extracted. Although the sensitivity of the pressure measurements are excellent, the degree of accuracy in the measurements necessary to detect depletion at the current cumulative production level is questionable. Note the pressure discontinuity shown in Figure 4 at the late time buildup due to pulling and rerunning the pressure gauge in the hole for necessary maintenance.

The most crucial reservoir data to be obtained will require an extended production period. Specifically, the continuity of the reservoir laterally along the growth fault and the overall areal extent of the reservoir must be detected by depletion. The contribution of water from the contiguous shale zones and the accessibility of other sands through the shale zones will require extended production and reservoir pressure monitoring.

Finally the in situ effects of reservoir compaction on reservoir production may only become evident after a substantial pressure drawdown is obtained in the reservoir.

The analysis of long term production behavior and the effects described above will require the use of reservoir simulation models.

## CONCLUSIONS

Analysis of test data from the Pleasant Bayou #2 well completed in the Frio C sand indicates:

(1) The reservoir permeability is approximately 200 md.
(2) The producing gas-water ratio is 20 SCF/Barrel and the total gas-water ratio is 29 to 32 SCF/Barrel.
(3) A permeability alteration due to a change in sand characteristics or, alternatively, a non-sealing fault is located about 3700 feet from the well.
(4) The major growth fault that bounds the reservoir to the north is evident in the last multirate pressure drawdown test data.
(5) An apparent rate sensitive skin effect has been interpreted from the multirate production test data.
(6) Moderate skin damage in the well has been determined from each of the pressure transient tests.

## NOMENCLATURE

$B$ - formation value factor (RB/STB)
$b$ - intercept of drawdown test (psi)
$b'$ - intercept of multirate drawdown test (psi/(bbls/day)
$c_T$ - total effective compressibility (1/psi)
$h$ - formation thickness (feet)
$k$ - formation permeability (md)
$m$ - buildup or drawdown slope (psi/∿)
$m'$ - multirate drawdown slope (psi/(∿ - bbls/day))
$P_i$ - initial static reservoir pressure (psig)
$P_{wf}$ - flowing bottomhole well pressure (psig)
$q$ - flowrate (bbls/day)
$r_{inv}$ - radius of investigation (feet)
$r_w$ - radius of the wellbore (feet)
$S$ - skin factor
$T$ - Horner flow time (hours)
$t$ - time since start of flow (hours)
$\Delta t$ - time since shut-in (hours)
$\mu$ - viscosity

subscripts j, N - indicate time periods

## REFERENCES

(1) Clark, J.D.,"Summary of Production Tests, Reservoir Engineering Interpretations of Pleasant Bayou Wells No. 1 and 2, Geopressured Geothermal Project, Brazoria County, Texas", Report submitted to Department of Energy, January 29, 1980.

(2) Earlougher, Robert C., Jr. "Advances in Well Test Analysis", Monograph Volume 5, Society of Petroleum Engineers of AIME, Dallas, Texas, 1977.

(3) Gray, K.E., Jogi, P.N., Morita, N., and Thompson, T.W., "The Deformation Behavior of Rocks from the Pleasant Bayou Wells", Proceedings - Fourth United States Gulf Coast Geopressured-Geothermal Energy Conference: Research and Development, Austin, Texas, October 29-31, 1979.

(4) Bebout, D.G., Loucks, R.G., and Gregory, A.R. "Frio Sandstone Reservoirs," Bureau of Economic Geology, The University of Texas at Austin, Austin, Texas, 1978.

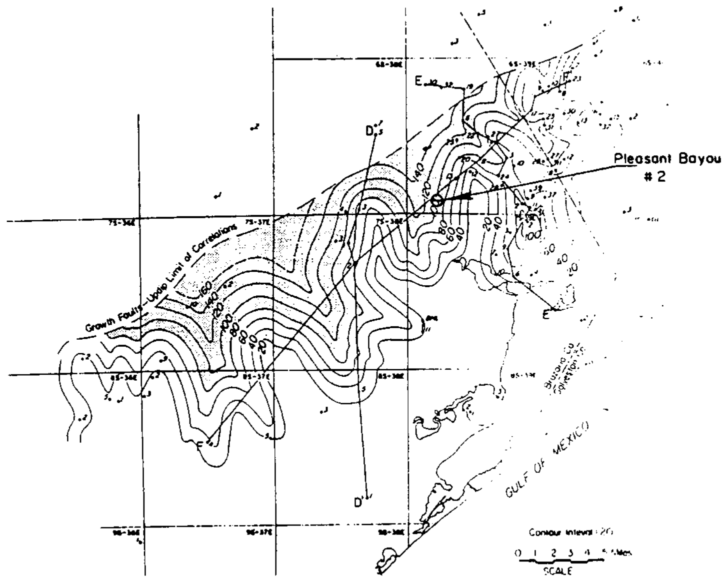


Figure 1

NET SAND THICKNESS
C-SAND FRIO FORMATION
BRAZORIA COUNTY

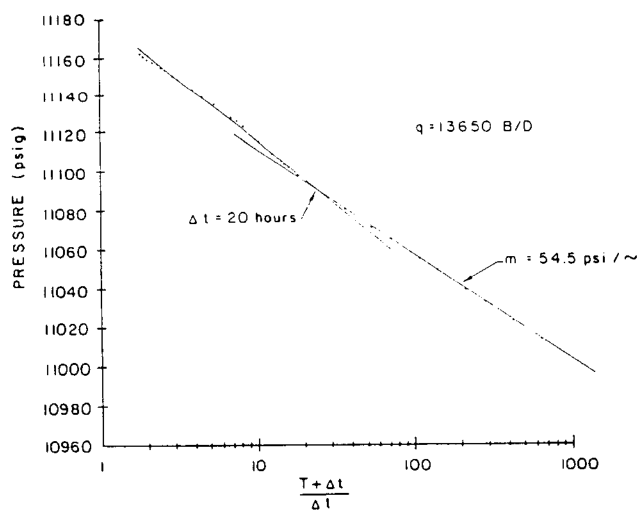


Figure 2

PLEASANT BAYOU #2
DECEMBER 1979 BUILDUP TEST
q = 13650 B/D

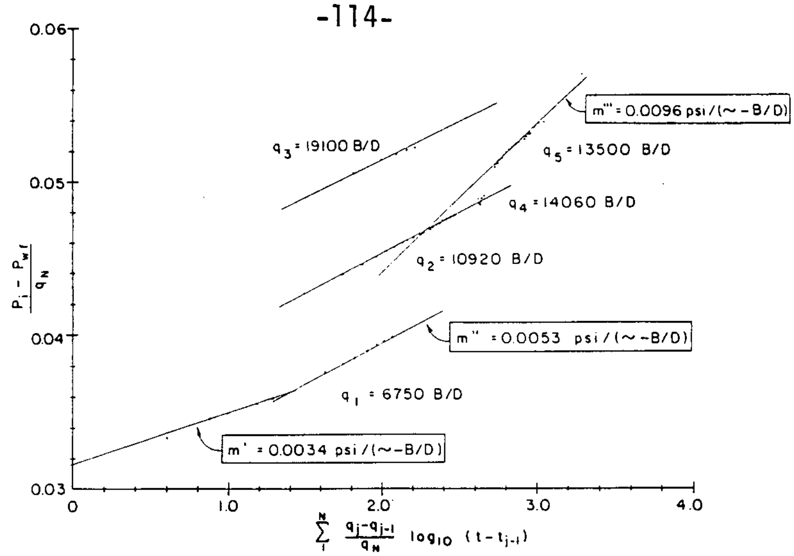


Figure 3

PLEASANT BAYOU #2
OCTOBER 1980 DRAWDOWN TEST
$q_3$ = 19100 B/D

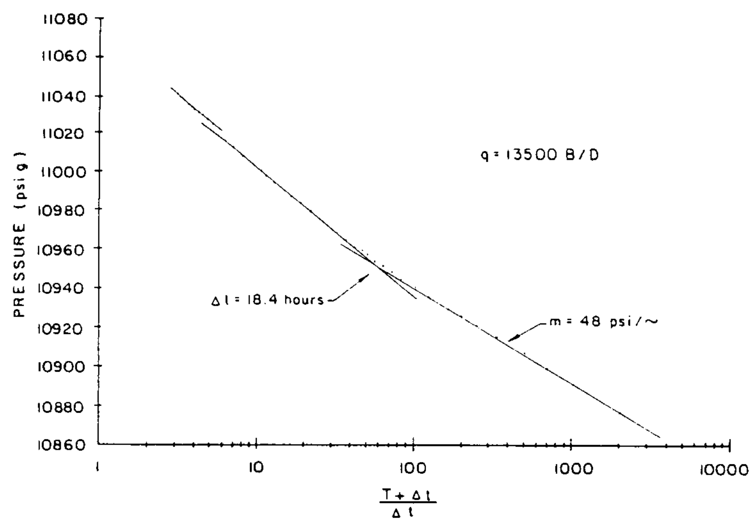


Figure 4

PLEASANT BAYOU #2
NOVEMBER 1980 BUILDUP TEST
q = 13500 B/D

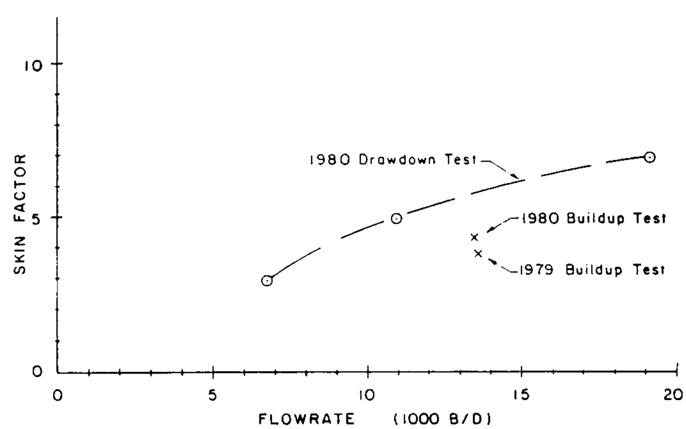


Figure 5

PLEASANT BAYOU #2
RATE SENSITIVE SKIN FACTORS