Early Estimation of Gas Well Reserves Using B H P Buildup and Drawdown Data

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INTRODUCTION

The need for early estimation of gas reserves on deep exploration wells has long been apparent. In an effort to evaluate techniques for early determination of gas reserves, extensive bottom hole pressure and production tests were recently run on 2 new completions. Test Well No. 1 is completed in the Pennsylvanian, and Test Well No. 2 is completed in a lower Permian formation.

Although the subject tests will not result in reliable quantitative reserve estimates in all cases, they should furnish a range of reserves valuable in making decisions concerning the timing of offset development. In addition, other useful data, relating to formation capacity and possible well bore damage, can be determined from the buildup tests. For larger reservoirs, these data can conceivably be of economic importance in indicating the need for and the anticipated results of additional stimulation.

RESERVE DETERMINATION METHODS EMPLOYED

In each test case, it was suspected beforehand that very limited reserves existed; consequently, it was estimated that steady-state flow conditions could be approached within 5 to 6 days. Under such conditions, the methods of determining well reserves as discussed below could be utilized. In addition, with sufficient total withdrawals during the test, a dependable material balance calculation provided a check on the other methods.

Park Jones[1] has presented methods of estimating reserves from gas well reservoir limit tests utilizing drawdown data where either transient or steady-state flow results. Where the test duration is insufficient for transients to effectively reach reservoir boundaries, a minimum reserve value can be established. In the subject tests, apparent steady-state flow was reached; however, data limitations permitted use of drawdown data for only Test Well No. 2. Park Jones's steady-state calculation is, in reality, a differential material balance type calculation as used herein.

Basically, 3 methods of computation have been employed in the subject tests as follows:

1. Material Balance or P/Z Type Calculation - Necessitates a measurable decrease in static reservoir pressure as a result of the total test withdrawals.
2. Differential Material Balance - Necessitates a steady-state condition be reached during the drawdown test, or a linear relationship between flowing BHP and time at constant producing rate.
3. Integral Method[2] - Utilizes buildup curve data. Theoretically applicable only if steady-state conditions are reached during the flow test.

FIELD PROCEDURE

The field or test procedure consisted of the following:

1. Initial static reservoir pressures were determined after a substantial shut-in time. In the subject tests, both test wells had been shut-in in excess of 1 month awaiting pipeline connections.
2. The wells were placed on flow at near constant rate with a bottom hole pressure bomb down hole. The flow test (drawdown) was continued 5 to 6 days. A 180 hr. chart drive clock was used in the bomb during the drawdown test.
3. The wells were shut-in and bottom hole pressure buildups were recorded with both a 3 hr. chart drive and a 72 hr. chart drive.

As mentioned previously, the length of time on flow should be sufficient to allow steady-state conditions to prevail. The required time can be estimated from the following formula:

$$t = \frac{1.69\, \phi\, u c\, r_e^2}{K} \qquad (1)$$

Where: t = producing time, hours
ϕ = porosity, fraction
u = viscosity, cp.
r_e = drainage radius, feet
K = permeability, darcys
c = fluid compressibility, psi^{-1}

RESULTS AND DISCUSSION

General data from the field tests are shown by Tables 1 and 2. Table 3 is a tabulation of results for each well and method of calculation. Step-by-step calculations are shown in the Appendix for Test Well No. 2.

TABLE 1
GENERAL DATA
TEST WELL NO. 1

Drawdown Test Data:

Gas Gravity		0.653
Distillate Gravity		55.1° API
Total Time on Flow		140 Hours 5 Minutes
Total Gas	High Pressure	6,020 MCF
	Low Pressure	186 MCF
Total Distillate		390 Bbls.
Total Water		1 Bbl.
Gas Rate	Maximum	1,130 MCFPD
	Minimum	975 MCFPD
	Average	1,025 MCFPD
	Final 24 Hours	995 MCFPD

Pressure Data:

Pressure Datum	13,007 ft.
Initial Static BHP	5,499 psi
Drawdown Pressures	Erratic
Buildup Pressures	See Fig. 2
Final Static BHP	5044 psi
Reservoir Temperature	180° F

Miscellaneous Data:

Casing	5-1/2 in. set at 13,200 ft. in 8-3/4 in. hole
Tubing	2-7/8 in. to 13,011 ft. (Open-ended)
Packer Setting Depth	12,973 ft.
Perforations	13,004-13,010 ft.
Formation	Pennsylvanian
Stimulation	500 Gallons Acid
Calculated Absolute Open Flow	1420 MCFPD

TABLE 2
GENERAL DATA
TEST WELL NO. 2

Drawdown Test Data:

Gas Gravity		0.676
Distillate Gravity		65.4° API
Total Time on Flow		120 Hours
Total Gas	High Pressure	17,494 MCF
	Low Pressure	417 MCF
Total Distillate		1046 Bbls.
Total Water		44 Bbls.
Gas Rate	Maximum	3619 MCFPD
	Minimim	3242 MCFPD
	Average	3499 MCFPD
	Final 24 Hours	3300 MCFPD

Pressure Data:

Pressure Datum	10,700 ft.
Initial Static BHP	4080 psi
Drawdown Pressures	See Fig. 1
Buildup Pressures	See Fig. 3
Final Static BHP	3368 psi
Reservoir Temperature	150° F

Miscellaneous Data:

Casing	5-1/2 in. set at 13,000 ft. in 6-5/8 in. hole
Tubing	2-7/8 in. to 10,600 ft. (Open-ended)
Packer Setting Depth	10,600 ft.
Perforations	10,690-10,710 ft.
Formation	Lower Permian
Stimulation	200 Gallons Acid
Calculated Absolute Open Flow	10 MMCFPD

TABLE 3
RESERVE SUMMARY

Method	Initial Gas-in-Place MMCF	Ult. Gas Reserves, MMCF	Estimated Ult. Distillate, Bbls.
TEST WELL NO. 1			
Material Balance			
Using C	139	126	5,700
Using Z	154	140	6,400
Differential Material Balance	Drawdown curve erratic due to low flow rate (low capacity)		
Integral			
r_e = 100'	143	130	5,900
1000'	199	182	8,300
2640'	220	200	9,100
TEST WELL NO. 2			
Material Balance			
Using C	145	129	5,400
Using Z	155	138	5,800
Differential Material Balance	179	160	6,700
Integral			
r_e = 100'	208	185	7,800
1000'	291	260	10,900
2640'	324	288	12,200

Material Balance Method

In each of the subject tests, the reserves were of such low magnitude that appreciable decreases were observed in the static reservoir pressures as a result of the test withdrawals. This condition resulted in reliable material balance estimates of reserves by either of the following formulae:

$$G = \frac{W_d}{5.61 \; B_g \; C \Delta P_s} \qquad (2)$$

$$G = \frac{5.03 \; g \; T}{B_g} \; \frac{1}{(P_{si}/Z_i - P_{sf}/Z_f)} \qquad (3)$$

Where: G = Initial gas-in-place, MCF
W_d = reservoir withdrawals at reservoir conditions of temperature and pressure, cf

B_g = gas volume factor, Bbls/MCF
C = average fluid compressibility, psi^{-1}
g = reservoir withdrawals at standard conditions, MCF
T = reservoir absolute temperature, ^oR
P_{si}, P_{sf} = initial and final static pressure, psia
Z_i, Z_f = initial and final gas compressibility factor.

Equation (3) is the more accurate in that it does not involve the average compressibility term, which term introduces error since it is a non-linear function of pressure. Equation (3) is the equation of the straight-line plot of P/Z versus cumulative recovery normally utilized in graphically determining gas reserves and will yield identical results as the plot extrapolated to zero gage pressure.

The initial gas-in-place for Test Wells No. 1 and 2 was 155 MMCF and 154 MMCF, respectively, by material balance calculation. The similarity in the numbers is coincidental.

The material balance method is expected to be the most accurate of the methods employed in analyzing these tests; however, it is pertinent to point out that this method is not applicable to reservoirs where the total withdrawals during the test are not of sufficient quantity to create a measureable difference in the initial and final static pressures. In addition, the shut-in times must be sufficient to give reliable static pressures by extrapolation. Obviously, the closer the initial and final pressures the more chance for percentage error due to bomb limitations and shut-in extrapolation.

Differential Material Balance or Drawdown Test Method

This method is a solution of the material balance equation differentiated with respect to time, or a solution of

$$G = \frac{Q}{C \; dp/dt} \qquad (4)$$

Where: G = gas-in-place, MCF
Q = withdrawal rate, MCF/day
C = average compressibility, psi^{-1}
dp/dt = slope of pressure versus time curve, psi/day

For application of this method, the flowing bottom hole pressure must reach an approximate linear relationship with time. Such was the case for Test Well No. 2, as shown by Fig. 1. This relationship was not apparent for Test Well No. 1 due to erratic flowing bottom hole pressures believed attributable to the relatively low rate of 1000 MCF per day (low capacity) resulting in apparent liquid accumulation and unloading in the tubing during the test.

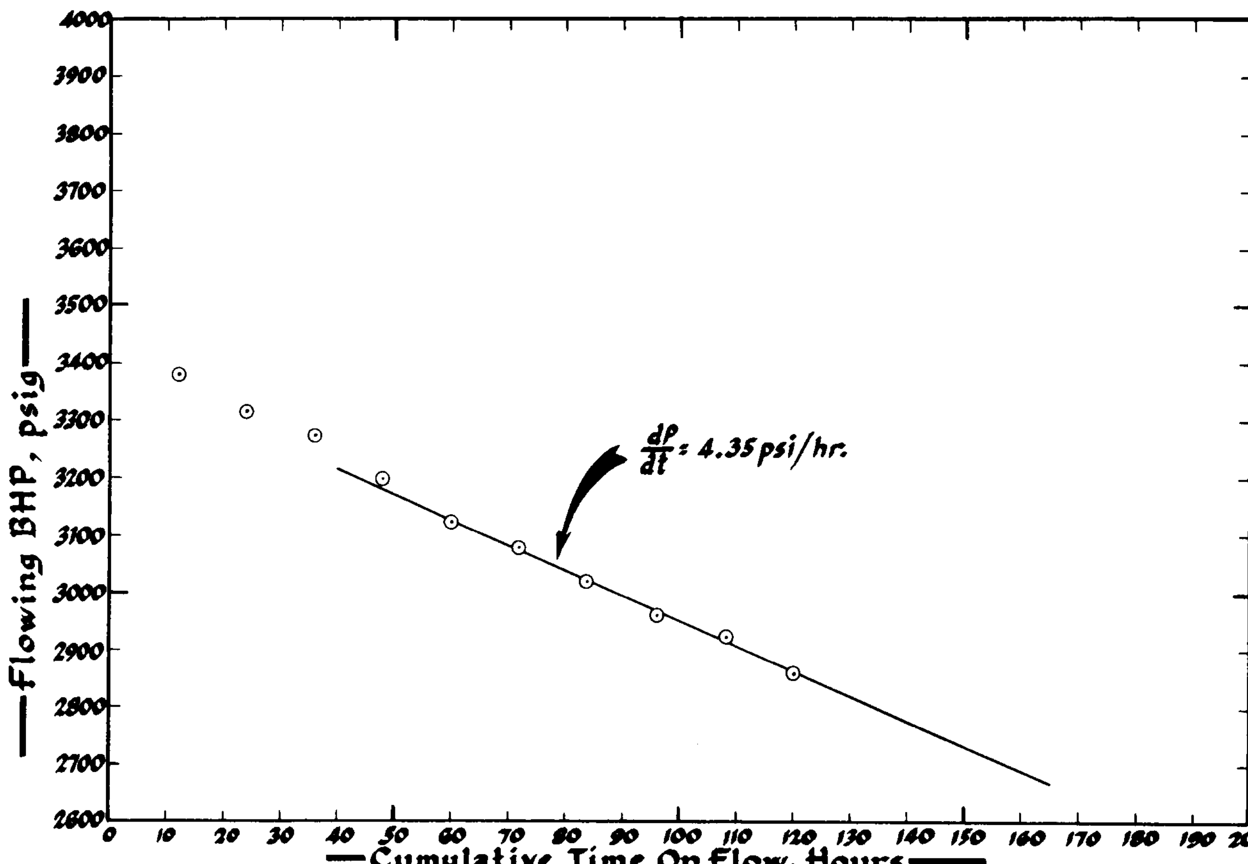

figure 1 - PRESSURE DRAWDOWN CURVE -Test Well no.2

The differential material balance yielded a gas-in-place of 179 MMCF for Test Well No. 2 as compared to 155 MMCF by conventional material balance calculations.

This method is identical to that presented by Park Jones[1] for steady-state or bounded reservoir conditions.

Integral Method

The integral method involves solution of the following equation:

$$V_p = \frac{0.829 \times 10^{-3}\ kh}{F u c} \int_{\Theta = 0}^{\Theta = \infty} \frac{(P_s^2 - P_w^2)\ d\Theta}{(P_s^2 - P_o^2)} \qquad (5)$$

Where: V_p = gas pore volume, cu. ft.
kh = interwell capacity, md-ft
P_s = final static pressure, psi
P_w = shut-in bottom hole pressure, psi
P_o = final flowing BHP, psi
Θ = build-up time
F = function of drainage and well radii, dimensionless
u, c = as previously defined

Numerical values for each of the above terms are available from the drawdown and buildup test data, except for the function F. For non-fractured systems, such as the subject cases,

$$F \cong \frac{1}{4 \ln r_e / r_w} \qquad (6)$$

It is necessary to assign values to the drainage radius, r_e, and the effective well bore radius, r_w, for use in the integral method. Since these values appear as a log function, they are not seriously critical in a non-fractured system, as shown by the tabulation of results, Table 3. The results of the integral method are shown on this tabulation to be higher than, but comparable with, the previously discussed reserve calculations

The integral method has a number of limitations, primarily related to the necessity of reaching steady-state flow during the drawdown test. In cases where the integral method is applicable, the first 2 methods might also be applicable; however, in situations such as with Test Well No. 1, where 1 of the first methods fails, 2 methods remain for comparison.

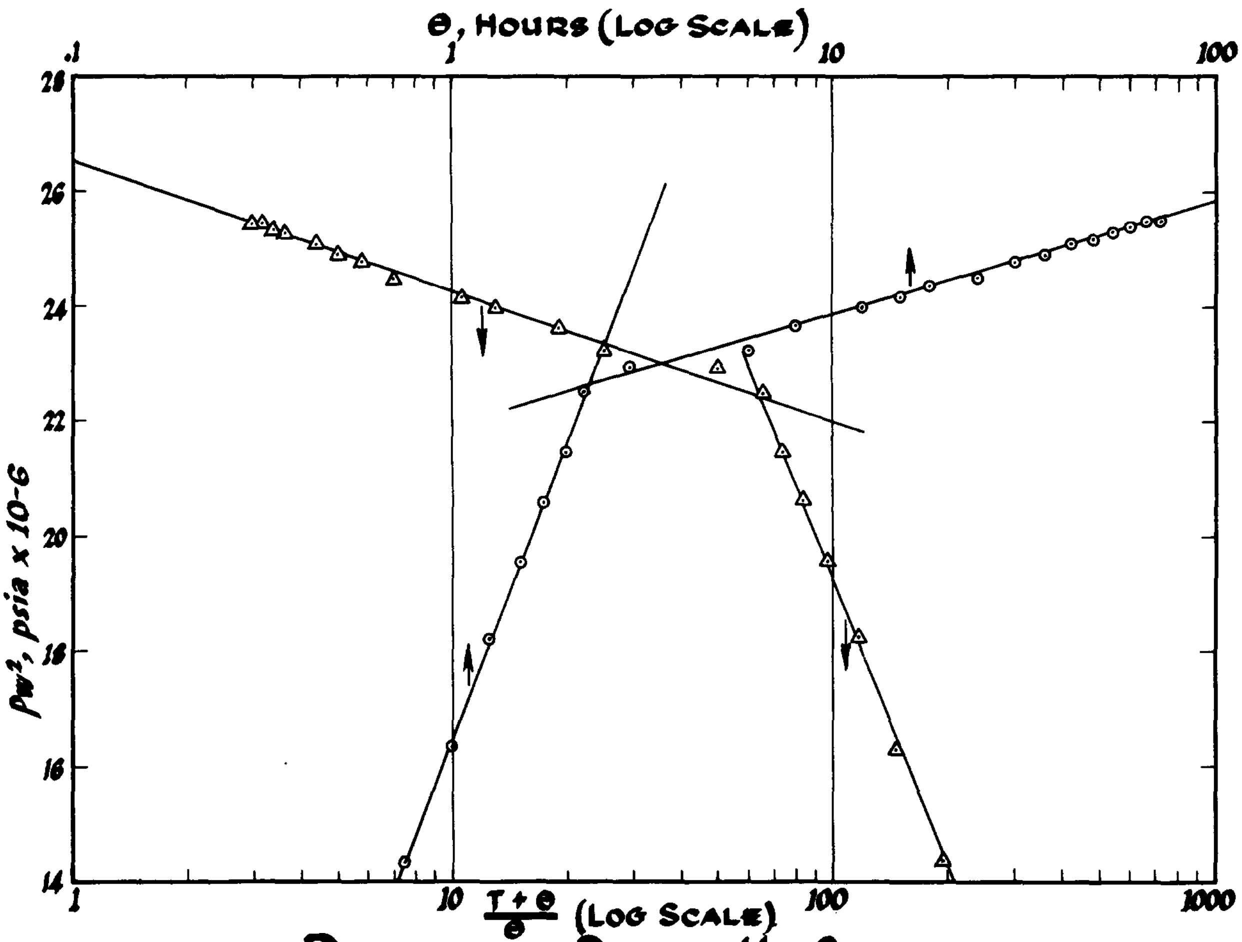

figure 2 -PRESSURE BUILD-UP CURVE- Test well no.1

Test Results

Table 3 is a tabulation of results for each well and method of calculation. Ultimate gas reserves as reflected in this table are those reserves recoverable to an abandonment pressure of 500 psia. The reserves of each of the test wells are extremely low, being in the order of 150 to 200 MMCF, certainly far below those reserves required for additional development. By comparing the ultimate gas reserves as calculated by the various methods, it is apparent that reasonable agreement was achieved between the methods.

In reporting results of the integral method, 3 values of drainage radius are shown with ultimate gas reserves calculated for drainage radii of 100 ft., 1000 ft. and 2640 ft., with the ultimate gas reserves ranging from 185 MMCF to 288 MMCF, a less than 2 fold increase for a 26-fold increase in the value of drainage radius. It is not recommended that drainage radius be determined by comparing reserves calculated by the integral method to reserves calculated by other methods.

Actual Performance As Verification of Test Results

Actual performance of the 2 test wells in the form of bottom hole pressure versus cumulative production is shown by Fig. 4. Extrapolation of the pressure performance of Test Well No. 1 indicates an ultimate gas recovery of 148 MMCF to an abandonment pressure of 500 psia. After producing approximately 80 MMCF from this well, additional intervals were perforated in the formation not in communication with the initial zones perforated.

An extrapolation of BHP/z versus cumulative gas recovery for Test Well No. 2 indicates an ultimate recovery of 124 MMCF to an abandonment pressure of 500 psia. For both test wells, subsequent performance has verified the range of results obtained from the initial pressure and production tests.

As a matter of interest, the pore volume reserves as calculated from log derived parameters exceeded 4 billion cu. ft. for each of these wells based on drainage areas of 640 acres, resulting in favorable offset economics in the absence of the pressure and production tests or subsequent producing performance.

A third test similar to those reported herein was run on another Pennsylvanian gas well; however, equipment failures after approximately 22 hr. on flow required discontinuation of the test. Nevertheless, the data obtained were utilized in calculations to arrive at an estimate of the ultimate gas reserves. The results of the test data indicated reserves of approximately 900

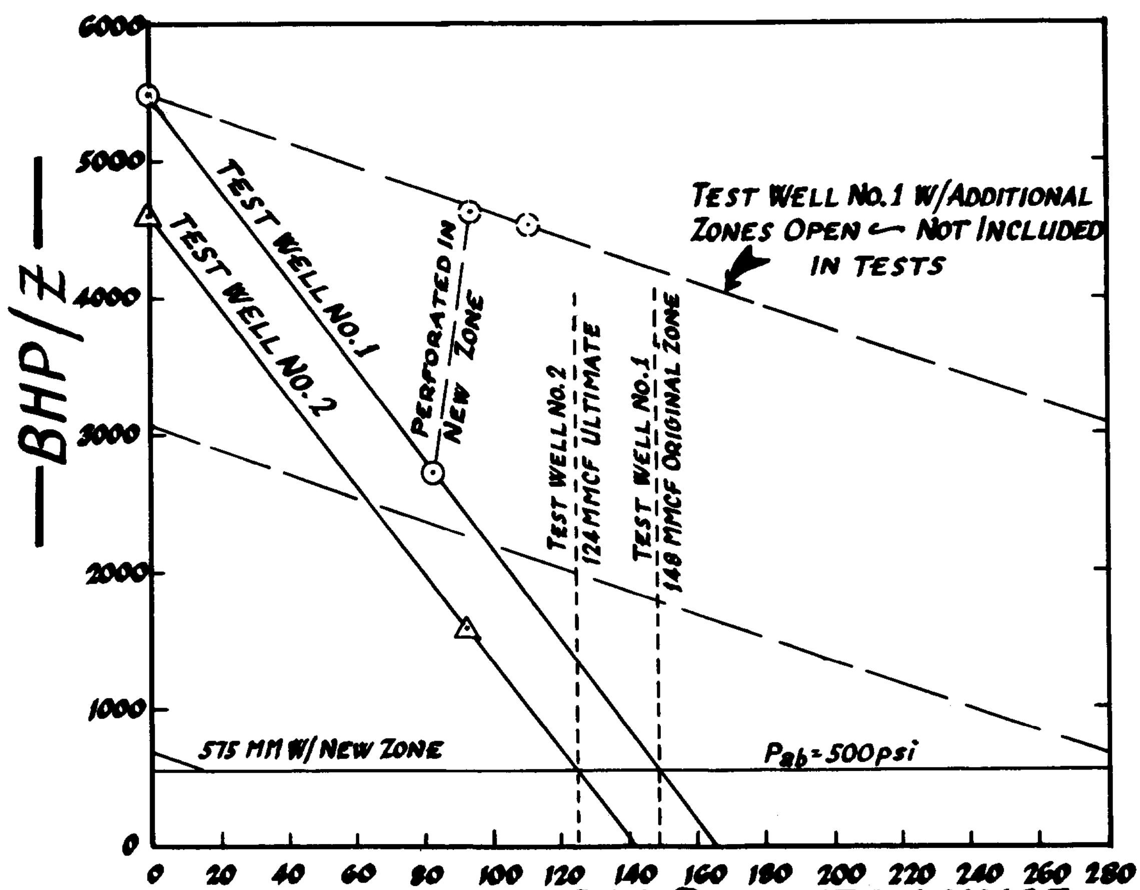

Figure 4 - BHP/Z vs. CUMULATIVE PROD. - Test Wells No.1 & 2 ACTUAL PERFORMANCE

MMCF. Subsequent pressure-cumulative data on this well, extrapolated to an abandonment pressure of 500 psi, indicate an ultimate recovery of 650 MMCF.

Conclusion

In limited reservoirs, early pressure-production testing can be valuable in efforts to postpone decisions concerning offset development until sufficient performance data are obtained to verify the test results.

APPROXIMATE COST OF TEST

The subject tests required approximately 9 days of field testing. Depending on the location of the well, considerable engineering time or field personnel time can be involved. In addition, 1 or 2 days of engineering office time are required to accumulate data and make the necessary calculations. Wire line service costs and equipment rental charges for each test are approximately \$250, exclusive of the bottom hole pressure bomb. An Amerada Type RPG-3 bomb was used on all surveys.

ACKNOWLEDGEMENT

Appreciation is expressed to Pan American Petroleum Corporation for permission to present these tests and results, and to engineering and production personnel contributing to these tests, particularly Mr. Ed Snook, who gathered most of the field data and aided with interpretation.

REFERENCES

1. Park Jones, "Reservoir Limit Test on Gas Wells", Journal of Petroleum Technology, p. 613, June, 1962.
2. Scott, P. H.: "An Integral Method For Determining Reservoir Pore Volume From Pressure Buildup Data", Private Communication from Pan American Petroleum Corporation Research Department.

APPENDIX

RESERVE CALCULATIONS
TEST WELL NO. 2

I. Material Balance:

P_{si} = 4080 psi

P_{sf} = 3368 psi

The final static pressure was chosen as an approximate average on Part III of the buildup curve, Fig. 3. The deviation of all points adjacent to the horizontal line is less than 8 psi which is within the accuracy of the bomb and interpretation; therefore, it is believed that the pressure had stabilized at an average value.

Using Equation (2): (Compressibility)

$$G = \frac{W_d}{5.61\, B_g\, C\, \Delta P_s} \quad (2)$$

$$B_g = 5.04\ \frac{Tz}{P}\ \frac{\text{bbls}}{\text{MCF}} = \frac{5.04\ (610)\ 0.869}{4080}$$

$$B_g = 0.653\ \frac{\text{bbls}}{\text{MCF}}$$

$$C = \frac{1}{P} - \frac{1}{z}\frac{dz}{dp} \qquad P_{ave} = 3724$$

$$C = \frac{1}{3724} - \frac{1}{.84}(78 \times 10^{-6}) = 176 \times 10^{-6} \text{ per psi}$$

dz/dp is the slope of pressure versus z at the average pressure.

W_d = 17,911 x .653 x 5.61 = 65,700 cu. ft.

ΔP_s = 4080 - 3368 - 712

$$G = \frac{65{,}700}{5.61(.653)\ 176(712)}\ 10^6 = 145 \text{ MMSCF}$$

At an abandonment pressure of P_a, the ultimate gas recovery is given by the following:

$$\text{Ult. Gas} = G\left(1-0.1985\ \frac{P_a\ B_{gi}}{z_a T}\right)$$

$$= 145\left[1-0.1985\ \frac{500(.653)}{.93(610)}\right]$$

$$= 145\ (.89)$$

Ult. Gas = 129 MMCF @ P_a = 500 psi

Using Equation (3): (Compressibility Factor)

$$G = \frac{5.03\ g\ T}{B_g}\left(\frac{1}{P_{si}/Z_i - P_{sf}/Z_f}\right)$$

$$G = \frac{5.03\ (17{,}911)(610)}{.653}\left(\frac{1}{\frac{4080}{.869} - \frac{3368}{.812}}\right)$$

G = 155 MMCF

Ultimate Gas Recovery = 155 x .89 = 138 MMCF

A P/Z versus cumulative plot yields the same values.

II. Differential Material Balance:

Using Equation (4)

$$G = \frac{Q}{C\ dp/dt}$$

The near straight line portion of Fig. 1 yields a slope of 4.35 psi/hr, therefore,

$$G = \frac{3300}{176 \times 4.35 \times 24}$$

G = 179 MMCF

III. Integral Method:

The integral method pore volume is expressed by Equation (5)

$$V_p = \frac{0.829 \times 10^{-3}\ kh}{F\,u\,c}\int_{\Theta=0}^{\Theta=\infty}\frac{(P_s^2 - P_w^2)\ d\Theta}{(P_s^2 - P_o^2)}$$

The value of the integral, 0.845, was determined by planimetering the area under a plot of $(P_s^2 - P_w^2)$ versus Θ.

The capacity, kh, is determined by

$$kh = \frac{1637\ Q\ u\ T\ z}{m}$$

where m is the slope in psi ^{2}/cycle of the interwell, Part II, portion of the buildup curve shown on Figure 3. $m = 0.356 \times 10^6$ psi^2/cycle.

Insert Figure 3

$$kh = \frac{1637(3300)(.025)(610)(.87)}{.356 \times 10^6}$$

$$kh = 201 \text{ md - ft.}$$

Gas viscosity can be estimated from various handbooks, expressed as a function of temperature, pressure and gravity. As discussed previously, the F function for unfractured well systems is approximately

$$F = \frac{1}{4 \ln r_e/r_w}$$

Therefore,

$$V_p = \frac{0.829 \times 10^{-3}(201)\ \ 0.845}{F(.025)(176 \times 10^{-6})}$$

$$V_p = 32{,}000/F$$

For various values of r_e

r_e	F	V_p	G	Ult. Reserves
100'	.042	762,000	208	185
1000'	.030	1,067,000	291	260
2640'	.027	1,185,000	324	288
				MMSCF

Where

$$G = \frac{Vp}{5.615 \times B_g} = \frac{Vp}{3.66}$$

Ult. Gas Reserves = 0.89 G for P_a = 500 psi.

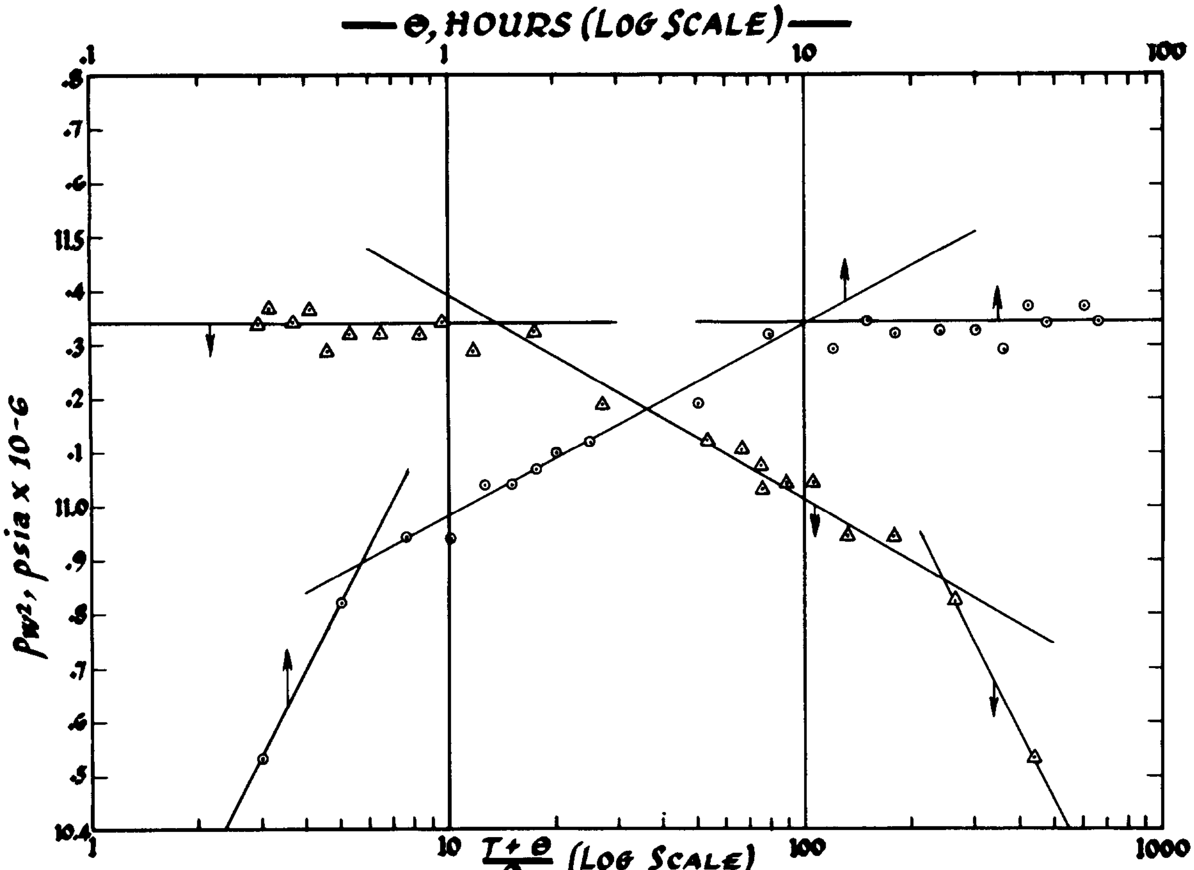

figure 3 -PRESSURE BUILD-UP CURVE- Test Well no. 2