# UINTA BASIN LENTICULAR SANDSTONE
# RESERVOIR CHARACTERISTICS

C. R. Boardman
C. F. Knutson

January 21, 1980

C. K. GeoEnergy Corporation
5030 Paradise Road, Suite A103
Las Vegas, Nevada 89119

## ABSTRACT

Previous analysis of production curves, from tight gas sand wells in the Uinta Basin of Utah, identified three types of performance - linear, intermediate and near radial. Six wells were selected, covering this distribution, and an attempt was made to determine dynamic reservoir gas volumes, and to compare these "production" volumes with volumes calculated from several different lenticular sand models.

Volumes of the 29 tight gas sandstones present in these six wells were approximated by using long term pressure build-ups to calculate present pressures (and permeabilities). Then, reservoir volumes were calculated using p/z vs cumulative production plots extrapolated to zero pressure. The average reservoir volume interpreted to be about 240,000 cubic feet per foot of net pay (22,300 $M^3M$).

The "production" volumes are compared with the equivalent calculated volumes using four different modeling techniques.

Reservoir Volume $10^6$ cu ft ($10^6 M^3$)

| | Production Volume | Model 1[1] Volume | Model 2[2] Volume | Model 3[3] Volume | Model 4[4] Volume |
|---|---|---|---|---|---|
| Sum of All Wells | 75.3 (2.1) | 60.7 (1.7) | 86.0 (2.4) | - | 136.1 (3.9) |
| Well C | 10.8 (0.31) | - | - | 10.6 (0.30) | - |

The two stoichastic models (2 and 3) seem to provide the best approximation of the "production" data. This approximation may have been better if a more sophisticated pressure build-up analysis would have been used.

Apparent reservoir permeabilities, assuming radial flow, range from .009 to .052 millidarcies and actual sandstone matrix permeabilities are interpreted to range from .06 to .21 millidarcies.


---

(1) Knutson, 1977
(2) Knutson and Ward, 1977
(3) Gidley et al, 1979
(4) Baker, 1980

UINTA BASIN LENTICULAR SANDSTONE
RESERVOIR CHARACTERISTICS

## INTRODUCTION

This study encompasses an analysis of gas production, well log, and pressure buildup data obtained from gas wells in the Uinta Basin, Utah. The objectives were 1) to assess lenticular reservoir volumes and permeabilities, and 2) to test the ability of four tight gas sand reservoir models to predict reservoir volumes. Three of the four models were based on outcrop study data, the other model was based on an evaluation of production data in several western basins containing tight gas sand reservoirs.

Six tight Wasatch gas wells were made available for pressure buildup testing and analysis. They are designated simply as Wells "A,B,C...." to protect the confidentiality of the data.

All six wells have been somewhat continuously on production for 16 to 18 years. The number of months per year each well has been on production and the respective annual production volumes are presented in Table 1. As of June, 1979, cumulative production per well ranged from 447,000 to 1,587,000 MSCF, with an average of about 1,000,000 MSCF.

## GEOLOGY OF THE WASATCH FORMATION IN THE UINTA BASIN

The Wasatch Formation has been assigned to the Paleocene-Eocene of the Tertiary Period. It overlies the Cretaceous Mesaverde Formation and underlies the Tertiary Green River Formation of Eocene age. Its thickness ranges from 850 ft. in the eastern portion of the Basin to more than 3,000 ft. in the central portion. It is composed of fluviatile sandstones and shales. (Murany-1964)

In the general area in which the wells of interest are located, the Wasatch is about 2,500 ft. thick. Most of the producing sands are located in the upper third of the formation.

## BASIC WELL DATA

The six wells tested range in depth from 5,530 to 6,473 ft. Casing diameters range from 4½" to 7" and production tubing from 2" to 2 7/8". Well F only is equipped with a packer in the tubing/casing annulus above the production zone; the other wells have open annuli. The number of perforated zones in each well ranges from two to six.

Diesel fuel and salt water were used as frac fluids. Proppant was primarily 20-40 mesh sand. The size of the jobs ranged from 15,000 gal. frac fluid/15,000 lbs. proppant to 50,000 gal/50,000 lbs. Available injection pressures ranged from 2,500-4,000 psig and available average injection rates from 10.5 BPM to 25.1 BPM. Balls were used for multiple zone treatments.

## RESERVOIR CHARACTERISTICS

Reservoir characteristics were deduced from one or more of the available logs and from pressure measurements.

### Sandstone Fraction

The ratios of gross sandstone thickness to the total thickness of the interval from the top of the uppermost sand to the base of the lowermost sand range from .17 to .35 with an average of .28 (Beds smaller than 5 ft. were not included in this tally.).

### Initial Pressure and Temperature

Measured initial pressures were obtained for Wells A-C, E and F. These values are shown in Table 2. Average gradient for these 5 wells was .437 psi/ft. as indicated in the table. The range was .404 to .478 psi/ft. Since no value was available for Well D, the average was assigned to this well for analytical purposes. As indicated, actual average pressures ranged from about 2,200 to 2,700 psia. The datum for these pressure values is average depth of the midpoints of the perforated zones.

Also shown in Table 2 are calculated values for reservoir temperatures at the same datum depth. These values are based upon the gradient determined from measurements in Wells A, C, D, and E after several weeks of shut-in time. This gradient was approximately $1^{\circ}/100$ ft. depth. As indicated, temperatures ranged from $154^{\circ}$ to $160^{\circ}$ F.

### Net Sand Thickness, Porosity, and Water Saturation

Values for these parameters, determined by analysis of the available logs, are shown in Table 3. Portions of sands with calculated porosities less than 5% and/or water saturations in excess of 70% were excluded from the net pay sand thicknesses.

A total of 28 producing sands were analyzed. Gross sand thicknesses range from 8 to 41 ft. with a median of 22 ft. and net sand thicknesses range up to 31 ft. with a median of 11 ft. Average ratio of net pay sand thickness to gross sand thickness is 0.62.

Calculated net pay sand porosities range from 6% to 14% and water saturations from 25% to the cut off value of 70%. Average values of these two parameters for the 28 sands are 12% and 54% respectively.

Gas Gravity

Available analyses of the gas indicate that its specific gravity is about 0.6.

Reservoir Flow Regimes

The type of flow regime (radial versus linear) was estimated for each well based on production histories. Cumulative annual production volumes shown in Table 1 were plotted versus time on a log-log basis (Figures 1 & 2). Slopes were determined to range from 0.51 to 0.71 and average 0.61. Under conditions of radial flow, slopes are expected to be 1.0 and under conditions of linear flow, 0.5, according to D. O. Cox of Energy Consultants, Inc. of Denver. On this basis, it appears that all six wells exhibit near-linear flow at least after about 5 years of production (Well A appears to exhibit near radial flow during the first 3 to 5 years.).

Permeability

Average permeabilities were calculated by method suggested by D. O. Cox which employes a log-log plot of dimensionless cumulative production versus dimensionless time (Knutson and Boardman-1977). These values are:

| Well | Permeability, md. |
|---|---|
| A | .03 |
| B | .01 |
| C | .02 |
| D | .42 |
| E | .30 |
| F | .19 |

This method assumes that the fracture is infinitely conductive and that it is oriented perpendicular to the long axis of the sand body. After several years of production, Don Montan of Lawrence Livermore Laboratory has found through computer simulation that fractures which make an acute angle with the perpendicular to the long axis result in slopes similar to those for the perpendicular case. Also, Cox has found that fractures which penetrate as much as 1/3 of the width of a sand body yield slopes similar to those for complete penetration (Knutson and Boardman-1978).

## RELATIVE CONTRIBUTION OF INDIVIDUAL SANDS TO FLOW

An attempt was made to determine the relative contribution to flow for individual sands in Well B. Gamma ray, absolute temperature, differential temperature, and noise probes were run to near total depth during production. Production rate was about 100 MSCF/D and flowing tubing pressure at the surface.

In running the noise probe, it was discovered that there was a column of water in the well. Also, the noise generated by gas bubbles moving up through the water column was so great and so variable in intensity that it was impossible to obtain a measure of the relative amount of noise generated by gas movement into the wellbore at each set of perforations.

There were no consistent deflections of the differential temperature curve which might be used to determine relative contribution production. However, there were indications of cooling at all producing sand levels. It appears, therefore, that all completed zones were at least contributing some gas to the observed production.

## FLOW PERIODS UTILIZED IN PRESSURE BUILDUP ANALYSIS

The entire production periods from start-up in the summer of 1978 to final shut-in in the summer of 1979 were used in the pressure buildup analysis. The duration of flow periods, associated prior shut-in times, produced volumes and rates are presented in Table 4. As indicated by this table, the average shut-in time period prior to production was 186 days and the average production time period (including shut-in time) was 246 days. Average shut-in time during the production periods was 51 days.

Blank

$$p_m + p_s + (25 \times 10^{-6} p_s/\text{ft})\ H_g + (.44\ \text{psi/ft})\ H_w$$ (Craft & Hawkins 1959)

where

$p_s$ = surface pressure, psia

$H_g$ = height of gas column above water, ft.

$H_w$ = height of water column above average midpoint depth of the perforated zones, ft.

Surface casing pressures were used for $p_s$ in the case of Wells A, D and E since the water levels determined were those for the casing rather than the tubing and since no early tubing pressures were measured as was the case for the Wells B, C, and F. In the case of these latter wells, values of $H_w$ for the tubing were calculated for use in approximating values for $p_m$ at early times.

Since it was impossible to measure the water level in Well G, an average water column height of 364 ft. was assigned in order to calculate values of $p_m$. The range of water column heights for the other 5 wells was 187-695 ft.

## GAS FILLED RESERVOIR VOID VOLUMES

In order to estimate the gas-filled reservoir void volume from the pressure and gas production data, the average reservoir pressure was approximated for the final shut-in periods. The method used is that recommended by Matthews and Russell (Matthews and Russell 1967), i.e. obtaining p* from Horner plots, obtaining $p^*-\bar{p}$ from type curves, and obtaining $\bar{p}$ by difference. As Matthews and Russell point out, in tight reservoirs the shut-in time required to obtain $\bar{p}$ directly from Horner plots is prohibitive.

The Horner plots for Wells A and B are presented in Figures 3 and 4 as examples. The plot for Well B (also typical Wells C & F) displays at least 2 distinct slopes; one for $\Delta t$ values of 5 to 15 days and another much steeper slope in the 100 + day - $\Delta t$ range. Only the "final" slope was recorded for Wells A, D, and E.

The estimated values of average reservoir pressure are presented in Table 9 along with values of the other parameters required in the computation. Values of these various parameters were approximated for each well as follows:

$\phi_g$ - average for all sands obtained by log computations

$\bar{A}$ - average area for all reservoirs (weighted by net sand thickness). Width is assumed to be 22 x gross sand height and length, 10 x width.

$t_p$ - gas volume produced during flow period divided by rate for last 10 days

$\mu$, $c_g$, $c_w$, $c_f$, - (Erlougher-1977)

$c_t$ - $S_g c_g + S_w c_w + c_f$

$p^*$ - Horner plot extrapolated to $t + \Delta t/\Delta t=1$

$k$ - from final Horner plot slope

$k$

$\frac{p^* - \bar{p}}{m/2.303}$ - (type curve for reservoir with a 5 to 1 length to width ratio - Matthews & Russell-1967)

$m$ - final slope on Horner plots

As indicated in the table, the average pressures obtained are very close to the values of $p^*$. They range from 912 to 1518 psia. In terms of percentage of the initial reservoir pressures, the range is 41% to 67% and the average is 53%.

The initial pressures shown in Table 2, the cumulative gas production volumes in Table 1, and the values of $\bar{p}$ for June 1979 shown in Table 9 were used to develop the plots of $\bar{p}/z$ versus cumulative production (Craft and Hawkins-1959). The initial volumes of gas-in-place were obtained from these curves at the point of intersection with the abscissa ($\bar{p}/z=0$). These values are presented in Table 10 along with the estimated gas filled reservoir volumes and the parameters required for the computation.

As indicated in Table 10, the estimated gas-filled reservoir volumes range from 5.1 to 18.9 million cubic ft. The specific volumes (volume per ft. of net pay) range from 70,000 to 370,000 $ft^3$ and average 240,000 $ft^3$.

A more sophisticated evaluation using the superposition method should have been used if additional pressure data from prior production and shut in periods were available. This type of analysis would have resulted in somewhat higher values of $p^*$ and consequently somewhat higher estimate of reservoir volumes*.

---

* Personal communication, R. D. Carter, Amoco, Tulsa, Oklahoma

## APPARENT OVERALL RESERVOIR PERMEABILITY (RADIAL BASIS)

Apparent reservoir permeabilities were calculated using the final slopes on the Horner plots. It is recognized that these permeabilities are merely apparent values because of the peculiar geometry of these beds. Approximations of the average reservoir matrix permeability *per se* are presented in the following section.

The apparent permeabilities and the parameters used to calculate them are presented in Table 11. The methodology used in the calculations is that described by Matthews and Russell (Matthews and Russell-1967). The calculated values range from .009 to .052 millidarcies and average .025 millidarcies

## RESERVOIR MATRIX PERMEABILITY APPROXMIATIONS

Since the chances are high that at least a number of the producing lenticular reservoirs were penetrated near one side by these 6 wells and since by virtue of the extent of the hydraulic fractures from the wellbore, that particular side should be reflected quite early (in a matter of several days at most) in the pressure buildup response of the reservoir. The pressure buildup from this point on would then be expected to be a function of the flow toward the wellbore from roughly a $180^{\circ}$ sector.

At the point in time when the other side of the reservoir is encountered by the pressure transient, true near-linear flow is assumed to occur with the pressure transient then moving linearly down the long axis of the reservoir. This flow regime is interpreted as being responsible for the "final" slope observed on the Horner Plots.

With this model it can be assumed that the slope of the buildup curve prior to the pressure transients' arrival at the second side of the reservoir would be ½ that of the final slope if it were not for the effect of the linear flow into the frac and linear flow within the frac if it is of finite conductivity (Cinco and Samaniego-1978). Also, the slope of the curve would be expected to be ¼ that of the final slope before the pressure transient arrives at the first side of the reservoir, again if it were not for the effect of the frac. It is with this model and under these assumptions that the average reservoir matrix permeabilities were approximated. These values, which are simply 4 times those shown in Table 11 are:

| Well | Approximations of Matrix Permeability, md. | |
|---|---|---|
| | Modified Horner Plot | Cox's Method |
| A | 0.10 | 0.03 |
| B | 0.06 | 0.01 |
| C | 0.04 | 0.02 |
| D | 0.21 | 0.42 |
| E | 0.14 | 0.30 |
| F | 0.06 | 0.19 |

The foregoing values are those which are comparable to the permeabilities calculated using Cox's methodology which was described previously. This comparison indicates that the Cox permeabilities for Wells A, B, and C are 30%, 17% and 50% of the foregoing values and his values for Wells D, E, and F are 200%, 214%, and 317% of the foregoing values respectively.

## COMPARISON OF OBSERVED RESERVOIR VOLUMES WITH CALCULATED VOLUMES BASED ON KNUTSON'S LENTICULAR RESERVOIR MODEL

Knutson (1977), in a study of fluvial sandstone outcrops on the periphery of the eastern Uinta Basin found that the average width to height ratio for sandstone beds in the Neslen and Farrer facies of the underlying Mesaverde Group is 22 and the average length to width ratio is 10. He reported that the Wasatch beds "exhibited higher length to height ratio's than the Farrer/Neslen population, but the Wasatch sample was too small to make a statistical evaluation meaningful". Because of this lack of statistically significant ratios for the Wasatch, it was assumed that the Farrer/Neslen ratios (W/H=22, L/W=10) were appropriate for the purpose of this analysis.

Knutson (1977) also generated a reservoir model which enabled an estimate of the amount of additional reservoir rock that intersects a given bed and thus possibly has permeable communication with that bed. This model was developed by using the foregoing W/H and L/W ratios and by randomly selecting a number of lenticular bed directions and locations for a multiplicity of sandstone thickness/total interval thickness ratios. The results of his modelling are presented in Figure 8. Specific reservoir area is presented as a function of distance from the wellbore and sandstone/interval thickness ratio. Reservoir volume for a given distance from the wellbore and sandstone fraction is calculated by multiplying the specific reservoir area by total net pay thickness.

Model 1 calculates the gas-filled void volumes of the producing sands for each well using the reservoir parameters described previously and Knutson's ratios of reservoir width to heigth and length to width. These volumes were determined by assuming that the lenticular reservoir beds are elongate rectangular parrelepipeds with heights equal to the net sand thicknesses, widths equal to 22 times the gross sand thicknesses, and lengths equal to 10 times the widths. The effect of reservoir interconnection was not included in these calculations.

Calculated volumes are presented in Table 12. The areas shown in this table were used along with net pay thickness, porosity and water saturation to determine the gas-filled void volumes shown. Calculated individual sand volumes range up to 12.5 million cu. ft. The total volume of $60.7 \times 10^6 ft^3$ compares favorably with the "production" volume of $75.3 \times 10^6 ft^3$.

Model 2 calculates the gas-filled void volume using a stochastic technique to construct a matrix which yields average specific reservoir volume as a function of the sandstone/nonsandstone fraction and effective drainage distance, Figure 8 (Knutson and Ward, 1977). The average sand fraction for the six wells is 0.28, and the average spacing is 640 acres (a "maximum" drainage distance of about 3,000 ft.). Entering Figure 8 at 3,000 feet drainage distance, then proceeding upward to an interprolated sandstone fraction of .28 yields a specific drainage area of about 100 acres. This area can be converted to gas-filled reservoir volume by multiplying it by the sum of the net sand and the average gas filled porosity from the six subject wells. The resulting volume of $86.0 \times 10^6 ft.^3$ compares favorably with "production" volume of $75.3 \times 10^6 ft.^3$.

Model 3 is another stochastic model being used by the NPC Tight Gas Task Group. This model, developed by C. Ovid Baker*, is based on a probability concept presented by Savinskii - (1965) ** and used the outcrop size distribution developed for the Uinta Basin outcrop area by Knutson (1977). Only one well, C, was used for a comparison. The calculated gas filled reservoir volume of $10.6 \times 10^6 ft.^3$ was very close to the "production" volume of $10.8 \times 10^6 ft.^3$, for this well.

Model 4 is a correlation factor developed by Gidley et al (1979) using an analysis of performance data from a number

---

* Personal communication -C.O.Baker, Mobil Research, Dallas,Tx.
** Drew, 1979 presents a similar probability concept.

of wells in the western basins containing appreciable volumes of tight gas sands. The factor predicts the reservoir volume will be 0.25 times the comparable radial volume. This would yield a total gas filled volume of $136.1 \times 10^6$ ft.$^3$ which is comparable to the "production" gas-filled volume of $75.3 \times 10^6 ft^3$.

The results calculated by using the four models is compared with the "production" volume in the following table:

| | Production | Model 1 | Model 2 | Model 3 | Model 4 |
|---|---|---|---|---|---|
| All Wells | 75.3 | 60.7 | 86.0 | - | 136.1 |
| Well "C" | 10.8 | - | - | 10.6 | - |

## RESERVOIR INTERCONNECTION IMPLICATIONS

The total calculated gas-filled reservoir volume for all 6 wells within a 640 acre circular drainage area based upon log values of porosity and water saturation and outcrop geometries without lens interconnection is $53.4 \times 10^6 ft^3$. (This value excludes those portions of reservoir sand which are estimated to extend beyond 5,960 ft. so as to be consistent with the 640-acre circular drainage area limitation. This excess volume is calculated to be $7.4 \times 10^6 ft^3$.) By comparing this total volume to that deduced from the pressure/production data of $75.3 \times 10^6 ft^3$, it appears that some reservoir interconnection is suggested.

## CONCLUSIONS

- After approximately 18 years of production, the average reservoir pressures in six Wasatch gas wells have declined roughly 50%. The average specific gas-filled reservoir void volume is 240,000 cu. ft. per ft. of net pay thickness and average specific drainage area for these wells is 62 acres.

- The two stochastic models (Models 2 and 3) appear to provide calculated gas-filled reservoir volumes that

---

* 0.25 x 640 ac x 43560 $ft^2$/ac x 355 ft x .055 $\phi g$= $136.1 \times 10^6$ ft.$^3$

compare most favorable with the "production" calculations. In addition these models provide a three dimensional conceptual model of the reservoir sands that is lacking in a "Gidley" type model, which uses a correction factor applied to a radial model.

- Assuming radial flow, the overall apparent reservoir permeabilities range from .009 to .052 millidarcies and the approximations for apparent matrix permeabilities for use in linear flow models range from .06 to .21 millidarcies.

## ACKNOWLEDGEMENTS

This study was funded by the U. S. Department of Energy under contract No. DE-AC08-78ET11399.

Mr. Charles Atkinson of the DOE provided technical direction and made helpful suggestions for the pressure buildup data analysis.

Belco Petroleum Corporation, Gas Producing Enterprises and Diamond Shamrock Oil and Gas Company very generously made their gas wells and well data available for this study.

Colorado Interstate Gas Company shut in a producing well for buildup analysis and recorded the pressure buildups. Mountain Fuel Supply Company recorded pressure buildups and put wells on production specifically for this study during a time of low gas demand.

Mr. Paul Branigan of CER Corporation provided an independent computer check of a number of the determinations from the pressure buildup data and made helpful suggestions regarding analysis techniques. He critically read the manuscript.

The assistance in the field of Leo Jorgenson (Mountain Fuel), Al Maxfield (Belco), Karl Oden (Gas Producing Enterprises), and Bill Swim (Colorado Interstate) is gratefully acknowledged.

## REFERENCES


Agarwal, R. G., R. D. Carter, and C. B. Pollock, "Evaluation and Prediction of Performance of Low Permeability Gas Wells Stimulated by Massive Hydraulic Fracturing", SPE 6838, SPE-AIME Fall Technical Conference, Denver, Colo., Oct. 9-12, 1977.

Cinco, Heber and Fernando Samaniego, "Transient Pressure Analysis for Fractured Wells", SPE 7490, SPE-AIME 53rd Annual Fall Conference, Houston, Tx., October 1-3, 1978.

Craft, B. C. and M. F. Hawkins, Applied Petroleum Reservoir Engineering, Prentice Hall, Inc., Englewood Cliffs, N.J., 1959.

Drew, Lawrence J., "Pattern Drilling Exploration: Optimum Pattern Types and Hole Spacing when Searching for Elliptical Shaped Targets", Mathematical Geology, Vo. II No. 2, 1979.

Erlougher, R. C., Jr. Advances in Well Test Analysis, SPE-AIME Monograph Volume 5, Henry L. Doherty Series, 1977.

Knutson, E. F., "Outcrop Study of Fracture Patterns and Sandstone Geometry, Eastern Uinta Basin, Utah", C. K. GeoEnergy Corporation, Las Vegas, Nevada, September 23, 1977.

Knutson C. F., and C. R. Boardman, "Rock Geometry/Mechanics Study of the Western Tight Gas Reservoirs", Lawrence Livermore Laboratory Report UCRL 13778, September 1977.

Knutson, C. F., and C. R. Boardman, "Continuity and Permeability Development in the Tight Gas Sands of the Eastern Uinta Basin, Utah", DOE Report No. NVO/0011-1, May 1, 1978.

Knutson, C. F. and Don C. Ward, "Implications of Surface Fracture Patterns and Sand Continuity in Relation to Stimulation of Tight Gas Sands, Eastern Uinta Basin, Utah", SPE 6740, Denver, Colorado, Oct. 9-12, 1977.

Matthews, C. S. and D. G. Russell, Pressure Buildup and Flow Tests in Wells, SPE-AIME Monograph Volume 1, Henry L. Doherty Series, 1967.

Murnay, E. E., "Wasatch Formation of the Uinta Basin", Guidebook to the Geology and Mineral Resources of the Uinta Basin, Intermountain Association of Petroleum Geologists, Salt Lake City, Utah, 1964.

Savinskii, Igor D., "Probability Tables for Locating Elliptical Underground Masses with a Rectangular Grid", Consultants Bureau, New York, 1965.

Table 1. GAS PRODUCTION STATISTICS - 6 UINTA BASIN WASATCH WELLS

CUMULATIVE PRODUCTION TIME, MONTHS/CUMULATIVE GAS PRODUCTION, MMCF

| Well | 1961 | 1962 | 1963 | 1964 | 1965 | 1966 | 1967 | 1968 | 1969 | 1970 | 1971 | 1972 | 1973 | 1974 | 1975 | 1976 | 1977 | 1978 | 1979** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | 1/ 17 | 13/ 134 | 23/ 196 | 34/ 262 | 41/ 310 | 51/ 381 | 61/ 437 | 71/ 497 | 82/ 557 | 93/ 613 | 104/ 630 | 114/ 676 | 125/ 723 | 136/ 767 | 147/ 811 | 158/ 851 | 169/ 879 | 175/ 899 | 179/ 915 |
| B | 1/ 5 | 12/ 84 | 22/ 130 | 34/ 175 | 43/ 203 | 52/ 244 | 62/ 278 | 72/ 314 | 83/ 349 | 94/ 384 | 105/ 394 | 115/ 421 | 127/ 450 | 138/ 477 | 149/ 503 | 160/ 527 | 171/ 546 | 176/ 556 | 180/ 566 |
| C | 1/ 16 | 13/ 176 | 24/ 268 | 36/ 346 | 45/ 398. | 55/ 449 | 66/ 508 | 76/ 561 | 87/ 616 | 97/ 665 | 101/ 680 | 110/ 717 | 121/ 757 | 132/ 793 | 143/ 828 | 154/ 860 | 165/ 879 | 171/ 886 | 175/ 892 |
| D | | 10/ 383 | 20/ 532 | 31/ 646 | 40/ 712 | 49/ 792 | 60/ 883 | 71/ 955 | 82/ 1043 | 93/ 1116 | 104/ 1177 | 115/ 1231 | 126/ 1288 | 136/ 1380 | 147/ 1453 | 157/ 1529 | 164/ 1555 | 169/ 1571 | 173/ 1587 |
| E | 1/ 46 | 12/ 293 | 23/ 412 | 33/ 502 | 43/ 596 | 45/ 679 | 56/ 779 | 65/ 864 | 77/ 938 | 88/ 1022 | 99/ 1093 | 109/ 1158 | 120/ 1222 | 131/ 1294 | 142/ 1342 | 153/ 1393 | 164/ 1436 | 170 1463 | 174/ 1479 |
| F | 1/ 15 | 13/ 117 | 24/ 165 | 35/ 216 | 42/ 237 | 47/ 248 | 56/ 269 | 65/ 296 | 73/ 319 | 75/ 328 | 86/ 339 | 94/ 358 | 105/ 378 | 116/ 400 | 127/ 421 | 138/ 438 | 146/ 443 | 149/ 445 | 151/ 447 |

** Through June only.

TABLE 2. INITIAL RESERVOIR PRESSURES AND TEMPERATURES AT AVERAGE DEPTH OF PERFORATIONS

| | WELL | | | | | |
|---|---|---|---|---|---|---|
| | A | B | C | D | E | F |
| Depth of Perforations Midpoint, ft (GL) | 5583 | 5888 | 5640 | 5302 | 5783 | 5508 |
| Initial Pressure, psia | 2254 | 2625 | 2696 | 2317* | 2575 | 2203 |
| Prior Shut-in time, hrs. | - | 1800 | 504 | - | - | 6552 |
| Gradient, psi/ft | .404 | .446 | .478 | .437** | .445 | .400 |
| T, $^oR$ | 617 | 620 | 617 | 614 | 619 | 616 |
| $T_r$ | 1.71 | 1.72 | 1.71 | 1.71 | 1.72 | 1.71 |
| $p_r$ | 3.36 | 3.92 | 4.02 | 3.46 | 3.84 | 3.29 |
| z | .86 | .86 | .86 | .86 | .86 | .86 |
| $p_i/z$, psia | 2621 | 3052 | 3135 | 2694 | 2994 | 2562 |

* Estimated value

** Average - Wells A, C, E, &F

## TABLE 3. COMPLETED RESERVOIR SAND PROPERTIES CALCULATED FROM LOG DATA

| Well | Gross Sand Depth, ft. | Sand thickness, ft. Gross | Net* | | Net Sand Porosity/ Water Saturation, % |
|---|---|---|---|---|---|
| A | 5460-86 | 26 | 8 | | 14/51 |
| | 5576-5608 | 32 | 17 | | 13/49 |
| | 5709-36 | 27 | 22 | | 12/46 |
| | All Zones | 85 | 47 | | 13/48 |
| B | 5495-5510 | 15 | 15 | | 13/50 |
| | 5652-63 | 11 | 11 | | 13/44 |
| | 5674-98 | 24 | 6 | | 12/25 |
| | 5825-54 | 29 | 29 | | 14/60 |
| | 5898-5935 | 37 | 31 | | 13/53 |
| | 6285-96 | 11 | 11 | | 9/30 |
| | All Zones | 127 | 103 | | 13/50 |
| C | 5410-40 | 30 | 30 | | 13/52 |
| | 5472-94 | 22 | 10 | | 14/58 |
| | 5543-54 | 11 | 5 | | 14/54 |
| | 5758-76 | 18 | 6 | | 9/65 |
| | 5796-5806 | 10 | 4 | | 10/58 |
| | 5858-80 | 22 | 8 | | 6/69 |
| | All Zones | 113 | 63 | | 12/56 |
| D | 5096-5108 | 12 | 2 | ** | 9/70 |
| | 5116-33 | 17 | 15 | | 13/60 |
| | 5234-62 | 28 | 18 | | 11/65 |
| | 5396-5412 | 16 | 13 | | 12/69 |
| | 5474-84 | 10 | 2 | ** | 11/70 |
| | 5504-18 | 14 | 8 | | 11/70 |
| | All Zones | 97 | 58 | | 12/65 |
| E | 5474-5500 | 26 | 11 | | 10/50 |
| | 5540-60 | 20 | 10 | | 7/70 |
| | 5726-39 | 13 | 12 | | 12/39 |
| | 5936-63 | 27 | 13 | | 8/45 |
| | 6344-52 | 8 | 8 | | 13/35 |
| | All Zones | 94 | 54 | | 10/46 |
| F | 5425-66 | 41 | 9 | | 14/70 |
| | 5596-5618 | 22 | 22 | | 14/67 |
| | All Zones | 63 | 31 | | 14/68 |

* Porosity cutoff of 5% and water saturation cut off of 70% were used in net sand thickness approximations.

** Assumed values (calculated water saturation for entire sand thickness was more than 70%).

TABLE 4. FLOW TEST DATA

| Well | Prior Shut in Time, days | Production Start Date | Production Stop Date | Production Period Days Produced/ Days Shut in | Calculated Flow Period, $t_p$* days | Latest Average Flow Rate, q**, MCF/day | Volume Produced, $V_p$, MCF |
|---|---|---|---|---|---|---|---|
| A | 170 | 9/18/78 | 5/14/79 | 213/42 | 209 | 138 | 28,903 |
| B | 192 | 9/16/78 | 6/21/79 | 208/41 | 180 | 103 | 18,554 |
| C | 169 | 9/17/78 | 6/22/79 | 212/65 | 104 | 110 | 11,457 |
| D | 170 | 9/17/78 | 5/14/78 | 206/33 | 267 | 103 | 27,474 |
| E | 166 | 9/14/78 | 5/14/79 | 230/14 | 251 | 142 | 25,639 |
| F | 249 | 11/21/78 | 6/21/79 | 99/112 | 67 | 50 | 3,348 |

* $t_p = V_p/q$

** Latest 10 days of actual production.

TABLE 5. MONTHLY PRODUCTION PERIOD STATISTICS

| Month | | Well A | Well B | Well C | Well D | Well E | Well F |
|---|---|---|---|---|---|---|---|
| Sept. | 1978 | 2115/ 12 | 851/ 14 | 994/ 13 | 2145/ 13 | 4027/ 16 | - - |
| Oct. | 1978 | 2716/ 21 | 2834 31 | 1376/ 31 | 3139/ 22 | 5013/ 31 | - - |
| Nov. | 1978 | 4041/ 26 | 1079/ 28 | 919/ 27 | 2940/ 24 | 3274/ 28 | 437/ 9 |
| Dec. | 1978 | 3684/ 28 | 2641/ 28 | 733/ 21 | 2814/ 23 | 3998/ 28 | 988/ 27 |
| Jan. | 1979 | 4271/ 31 | 2778/ 31 | 977/ 18 | 4050/ 31 | 4682/ 31 | 572/ 21 |
| Feb. | 1979 | 3118/ 28 | 2089/ 28 | 1346/ 24 | 3830/ 27 | 3554/ 25 | 325/ 12 |
| Mar. | 1979 | 3256/ 27 | 2080/ 28 | 1448/ 29 | 3148/ 26 | 3308/ 29 | 200/ 12 |
| Apr. | 1979 | 4357/ 30 | 2482/ 30 | 2015/ 30 | 4377/ 30 | 4443/ 30 | 146/ 3 |
| May | 1979 | 1345/ 10 | 810/ 10 | 626/ 10 | 1031/ 10 | 1340/ 10 | 290/ 7 |
| June | 1979 | - - | 912/ 8 | 1023/ 9 | - - | - - | 390/ 8 |

* Data not available

TABLE 6. PRESSURE BUILDUP DATA-WELLS B,C,F

| $\Delta t$, days | Measured Tubing Pressure, psia | | | Calculated Pressure at Perforations' Midpoint, psia | | |
|---|---|---|---|---|---|---|
| | Well B | Well C | Well F | Well B | Well C | Well F |
| 1 | 655 | 700 | 512 | 975 | 1093 | 738 |
| 2 | 700 | 805 | 525 | 1026 | 1210 | 753 |
| 3 | 723 | 864 | 528 | 1052 | 1277 | 756 |
| 4 | 782 | 870 | 533 | 1119 | 1284 | 762 |
| 5 | 805 | 876 | 535 | 1145 | 1290 | 764 |
| 6 | 809 | 881 | 536 | 1149 | 1296 | 765 |
| 7 | 819 | 888 | 538 | 1161 | 1304 | 767 |
| 8 | 825 | - | 539 | 1168 | - | 768 |
| 10 | 833 | 893 | - | 1177 | 1309 | - |
| 11 | 837 | - | - | 1181 | - | - |
| 12 | 843 | 900 | - | 1188 | 1317 | - |
| 13 | 845 | 903 | - | 1190 | 1321 | - |
| 14 | - | 905 | - | - | 1323 | - |
| 15 | 853 | - | - | 1199 | - | - |
| 16 | 854 | 910 | - | 1200 | 1328 | - |
| 17 | 857 | 914 | - | 1204 | 1331 | - |
| 105 | 943 | 983 | 623 | 1300 | 1409 | 863 |
| 121 | 953 | 994 | 630 | 1311 | 1421 | 871 |

Notes: Well B: Water level in the casing was measured at 5,615 ft. on June 30, 1979 ($\Delta t$=11) and at 5,611 ft. on October 2, 1979 ($\Delta t$=105). Tubing water level was calculated to have been 5,362 ft. and 5,366 ft. respectively on these dates. $t_p$ = 180 days.

Well C: Casing water level was measured at 4,945 ft. on June 30, 1979 ($\Delta t$,11days) and at 4,949 ft. October 2, 1979 ($\Delta t$=105 days). The June 30th level was assumed to hold from $\Delta t$=1 through $\Delta t$-17. $t_p$s=104 days.

Well F: 1- Well was worked on at $\Delta t$=8 days.

2- Average water column height of 363 ft. for Wells A-E was assumed throughout entire buildup. $\Delta t_p$= 67 days.

TABLE 7. PRESSURE BUILD-UP DATA - WELLS A,D,E

| Well | $t_p$, days [(1)] | $\Delta t$, days | Measured Surface Casing Pressure, psia | Calculated Pressure at Perforations Midpoint, psia |
|---|---|---|---|---|
| A | 209 | 98 | 1069 | 1303 |
| | | 141 | 1120 | 1361 |
| | | 157 | 1131 | 1373 |
| D | 267 | 98 | 810 | 996 |
| | | 141 | 836 | 1025 |
| | | 157 | 843 | 1033 |
| E | 251 | 98 | 816 | 1090 |
| | | 141 | 848 | 1127 |
| | | 157 | 859 | 1139 |

Note: (1) Total volume produced divided by latest rate (latest 10 days)

TABLE 8. WATER LEVEL DEPTHS AND SURFACE GAS PRESSURES MEASURED IN 1979 BY DEAD WEIGHT TESTER AND ECHOMETER.

| Well | Date | Tubing Pressure, psia | Casing Pressure, psia | Depth of Water Level In Casing, ft. |
|---|---|---|---|---|
| A | 8/20/79 | 1069 | 1069 | 5379 |
| | 10/2/79 | 1118 | 1120 | 5379 |
| | 10/18/79 | 1112 | 1131 | * |
| B | 6/30/79 | * | * | 5615 |
| | 10/2/79 | 943 | 1035 | 5611 |
| | 10/18/79 | 953 | 1050 | * |
| C | 6/30/79 | * | * | 4945 |
| | 10/2/79 | 983 | 986 | 4949 |
| | 10/18/79 | 994 | 996 | * |
| D | 8/20/79 | 561 | 810 | 5115 |
| | 10/2/79 | 550 | 836 | 5115 |
| | 10/18/79 | 541 | 843 | * |
| E | 8/20/79 | 816 | 816 | 5410 |
| | 10/2/79 | 851 | 848 | 5410 |
| | 10/18/79 | 859 | 859 | * |
| F | 10/2/79 | 623 | * | * |
| | 10/18/79 | 630 | * | * |

* not measured

TABLE 9 AVERAGE RESERVOIR PRESSURES, JUNE 1979

| | WELL | | | | | |
|---|---|---|---|---|---|---|
| | A | B | C | D | E | F |
| $\phi_g$, fraction | .066 | .064 | .052 | .050 | .053 | .045 |
| $\bar{A}$, million $ft^2$ | 4.0 | 3.6 | 2.5 | 1.8 | 2.3 | 6.1 |
| $t_p$, hrs | 5016 | 4320 | 2496 | 6408 | 6024 | 1608 |
| $\mu$, cp | .0155 | .0152 | .0155 | .0145 | .0151 | .0144 |
| $c_g$, $psi^{-1} x 10^{-6}$ | 723 | 776 | 776 | 970 | 806 | 1090 |
| $c_w$, $psi^{-1} x 10^{-6}$ | 3 | 3 | 3 | 3 | 3 | 3 |
| $c_f$, $psi^{-1} x 10^{-6}$ | 5 | 5 | 5 | 5 | 5 | 5 |
| $c_t$, $psi^{-1} x 10^{-6}$ | 340 | 364 | 364 | 453 | 378 | 508 |
| $p^*$, psia | 1572 | 1427 | 1525 | 1146 | 1288 | 925 |
| k, md | .025 | .021 | .009 | .055 | .036 | .012 |
| $\frac{.000264\, k\, t_p}{\phi g \mu c_t \bar{A}}$ | .023 | .020 | .008 | .157 | .082 | .002 |
| $\frac{p^* - \bar{p}}{m/2.303}$ | .23 | .23 | .10 | 0 | .10 | .10 |
| m, psi/cycle | 542 | 293 | 393 | 262 | 352 | 295 |
| m/2.303 | 235 | 127 | 171 | 114 | 153 | 128 |
| $p^* - \bar{p}$, psi | 54 | 30 | 17 | 0 | 15 | 13 |
| $\bar{p}$, psia | 1518 | 1397 | 1508 | 1146 | 1273 | 912 |

TABLE 10 RESERVOIR GAS FILLED VOID VOLUMES BASED ON PRESSURE/PRODUCTION VOLUME ANALYSES

| | Well | | | | | |
|---|---|---|---|---|---|---|
| | A | B | C | D | E | F |
| Reservoir Gas Volume, BSCF | 2.64 | 1.17 | 1.95 | 2.95 | 2.80 | 0.75 |
| Initial Reservoir Pressure, psia | 2254 | 2625 | 2696 | 2317 | 2575 | 2203 |
| Initial z | .86 | .86 | .86 | .86 | .86 | .86 |
| Reservoir Temperature, $^{o}R$ | 617 | 620 | 617 | 614 | 619 | 616 |
| Calculated Gas-Filled Reservoir Volume, $10^6$ ft.$^3$ | 17.5 | 6.7 | 10.8 | 18.9 | 16.3 | 5.1 |

TABLE 11. APPARENT RESERVOIR PERMEABILITIES

| | Well A | Well B | Well C | Well D | Well E | Well F |
|---|---|---|---|---|---|---|
| T, °R | 617 | 620 | 617 | 614 | 619 | 616 |
| p*, psia | 1572 | 1427 | 1525 | 1146 | 1288 | 925 |
| $p_{wf}$, psia | 898 | 923 | 980 | 808 | 852 | 725 |
| p*, $p_{wf}$/2, psia | 1235 | 1175 | 1253 | 977 | 1070 | 825 |
| $T_r$ | 1.71 | 1.72 | 1.71 | 1.71 | 1.72 | 1.71 |
| $p_r$ | 1.84 | 1.75 | 1.87 | 1.46 | 1.60 | 1.23 |
| z | .90 | .90 | .90 | .92 | .91 | .93 |
| $B_g$ | .0127 | .0134 | .0125 | .0163 | .0148 | .0196 |
| q, mcf/d | 113 | 75 | 41 | 115 | 105 | 16 |
| $\mu$, cp | .0155 | .0152 | .0155 | .0145 | .0151 | .0144 |
| m, psi/cycle | 542 | 293 | 393 | 262 | 352 | 295 |
| kh, md.ft. | 1.19 | 1.51 | .59 | 3.01 | 1.94 | .44 |
| h, ft | 47 | 103 | 63 | 58 | 54 | 31 |
| k, md | .025 | .015 | .009 | .052 | .036 | .014 |

TABLE 12. RESERVOIR GAS FILLED VOID VOLUMES* BASED ON LOG LOG VALUES OF NET SAND THICKNESS, POROSITY, AND WATER SATURATION AND GEOMETRY DETERMINED FROM OUTCROPS

| Well | Sand No. | Estimated Area $10^6 ft^2$ | Net Sand Volume $10^6 ft^3$ | Gas Filled Pore Volume $10^6 ft^3$ |
|---|---|---|---|---|
| A | 1 | 3.27 | 26.16 | 1.81 |
| | 2 | 4.96 | 84.32 | 5.57 |
| | 3 | 3.53 | 77.66 | 5.05 |
| Total | | | 188.14 | 12.43 |
| B | 1 | 1.09 | 16.35 | 1.06 |
| | 2 | 0.59 | 6.49 | .47 |
| | 3 | 2.79 | 16.74 | 1.51 |
| | 4 | 4.07 | 118.03 | 6.61 |
| | 5 | 6.63 | 205.53 | 12.54 |
| | 6 | 0.59 | 6.49 | .41 |
| Total | | | 369.63 | 22.60 |
| C | 1 | 4.36 | 130.80 | 8.11 |
| | 2 | 2.34 | 23.40 | 1.38 |
| | 3 | 0.59 | 2.95 | .19 |
| | 4 | 1.57 | 9.42 | .30 |
| | 5 | 0.48 | 1.92 | .08 |
| | 6 | 2.34 | 18.72 | .36 |
| Total | | | 187.21 | 10.42 |
| D | 1 | 0.70 | 1.40 | .04 |
| | 2 | 1.40 | 21 | 1.09 |
| | 3 | 3.79 | 68.22 | 2.66 |
| | 4 | 1.24 | 16.12 | .60 |
| | 5 | 0.48 | 0.96 | .03 |
| | 6 | 0.95 | 7.60 | .25 |
| Total | | | 115.30 | 4.67 |
| E | 1 | 3.27 | 35.97 | 1.80 |
| | 2 | 1.94 | 19.40 | .41 |
| | 3 | 0.82 | 9.84 | .72 |
| | 4 | 3.53 | 45.89 | 2.02 |
| | 5 | .31 | 2.48 | .21 |
| Total | | | 113.58 | 5.16 |
| F | 1 | 8.14 | 73.26 | 3.08 |
| | 2 | 2.34 | 51.48 | 2.37 |
| Total | | | 124.74 | 5.45 |

* Excludes effect of reservoir interconnection.

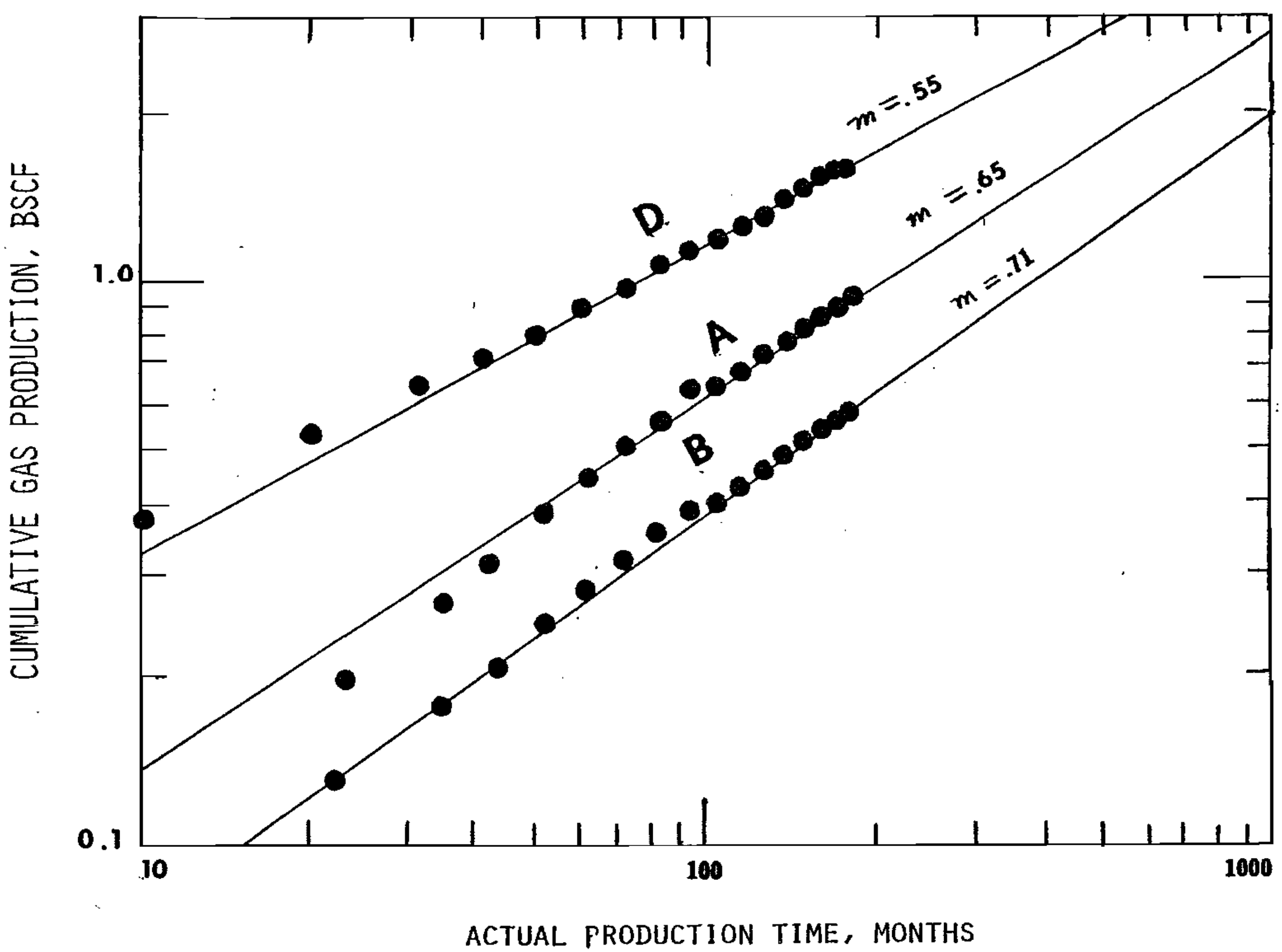


FIG. 1 Cumulative Gas Production versus Actual Production Time Wells A, B and D.

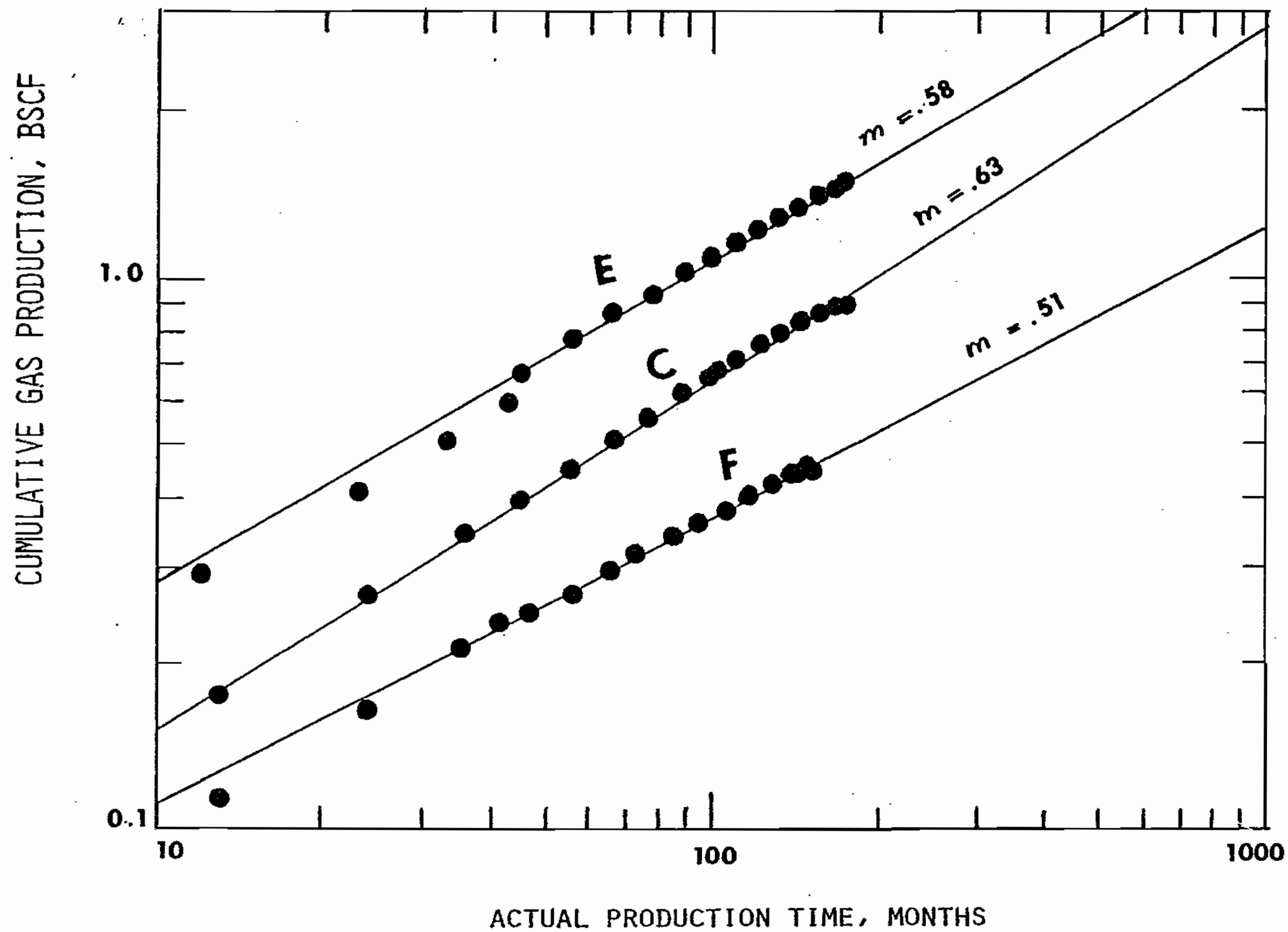


FIG. 2 Cumulative Gas Production versus Actual Production Time Wells C, E and F.

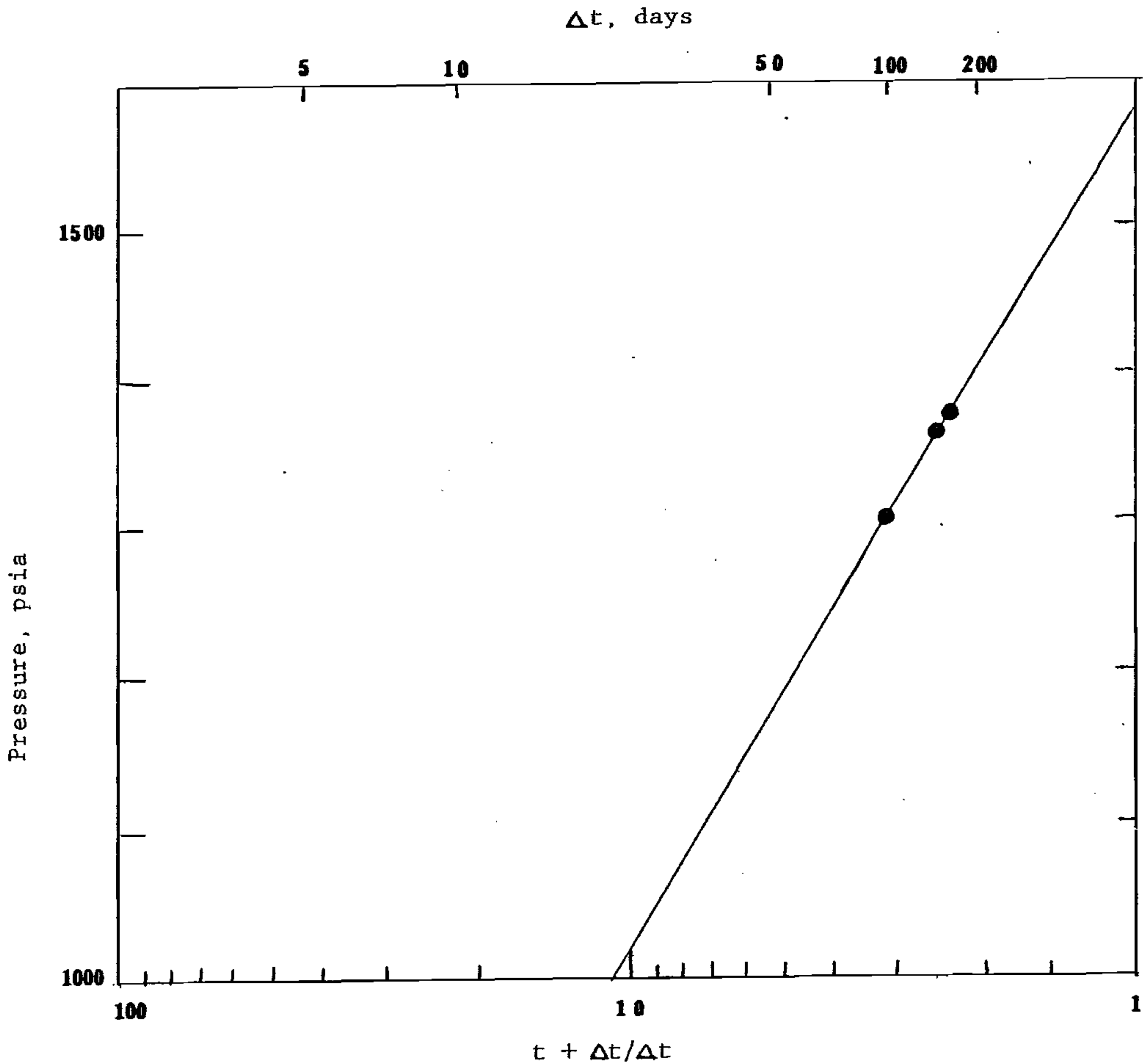


FIG. 3 Pressure Buildup - Well A

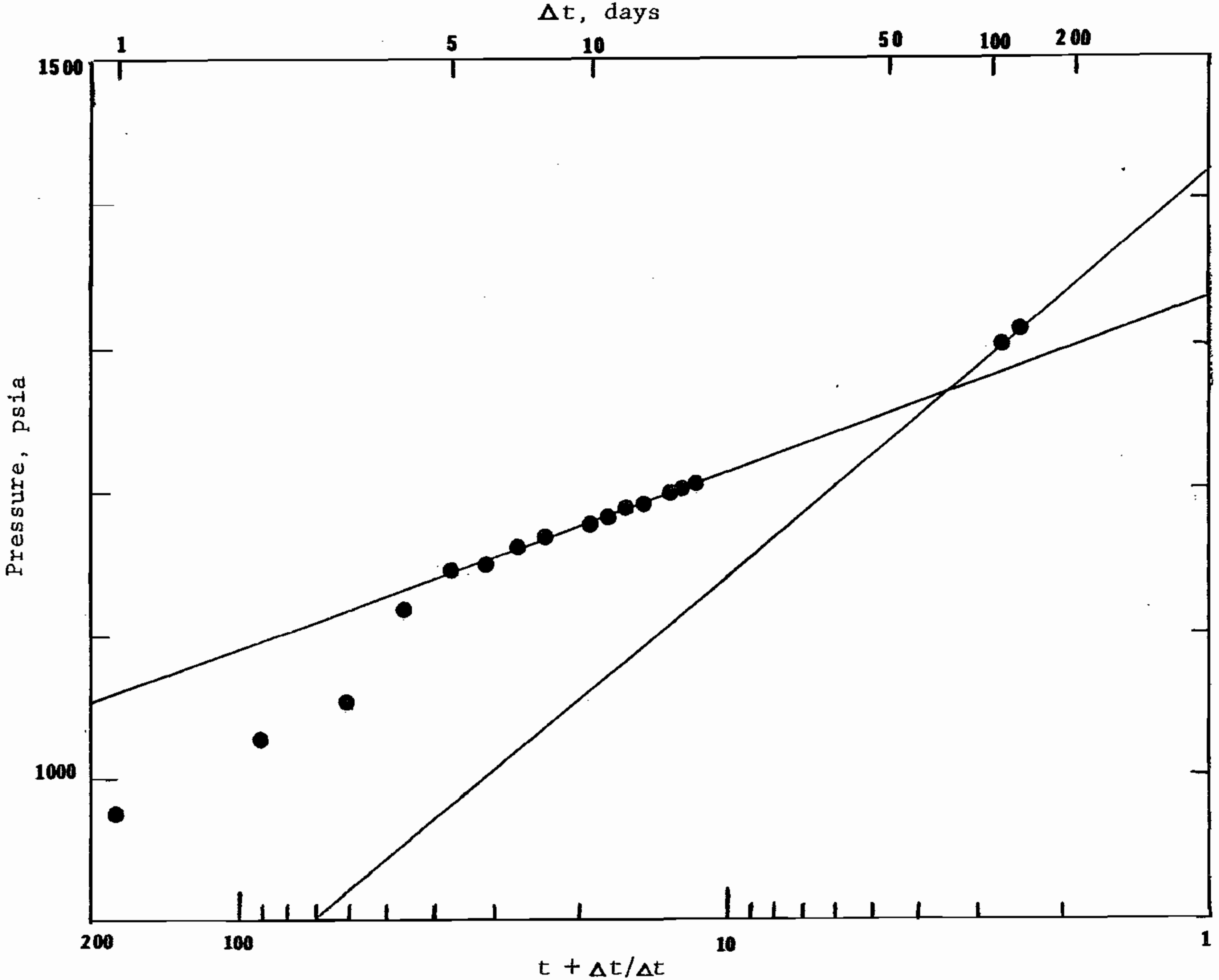


FIG. 4 Pressure Buildup - Well B

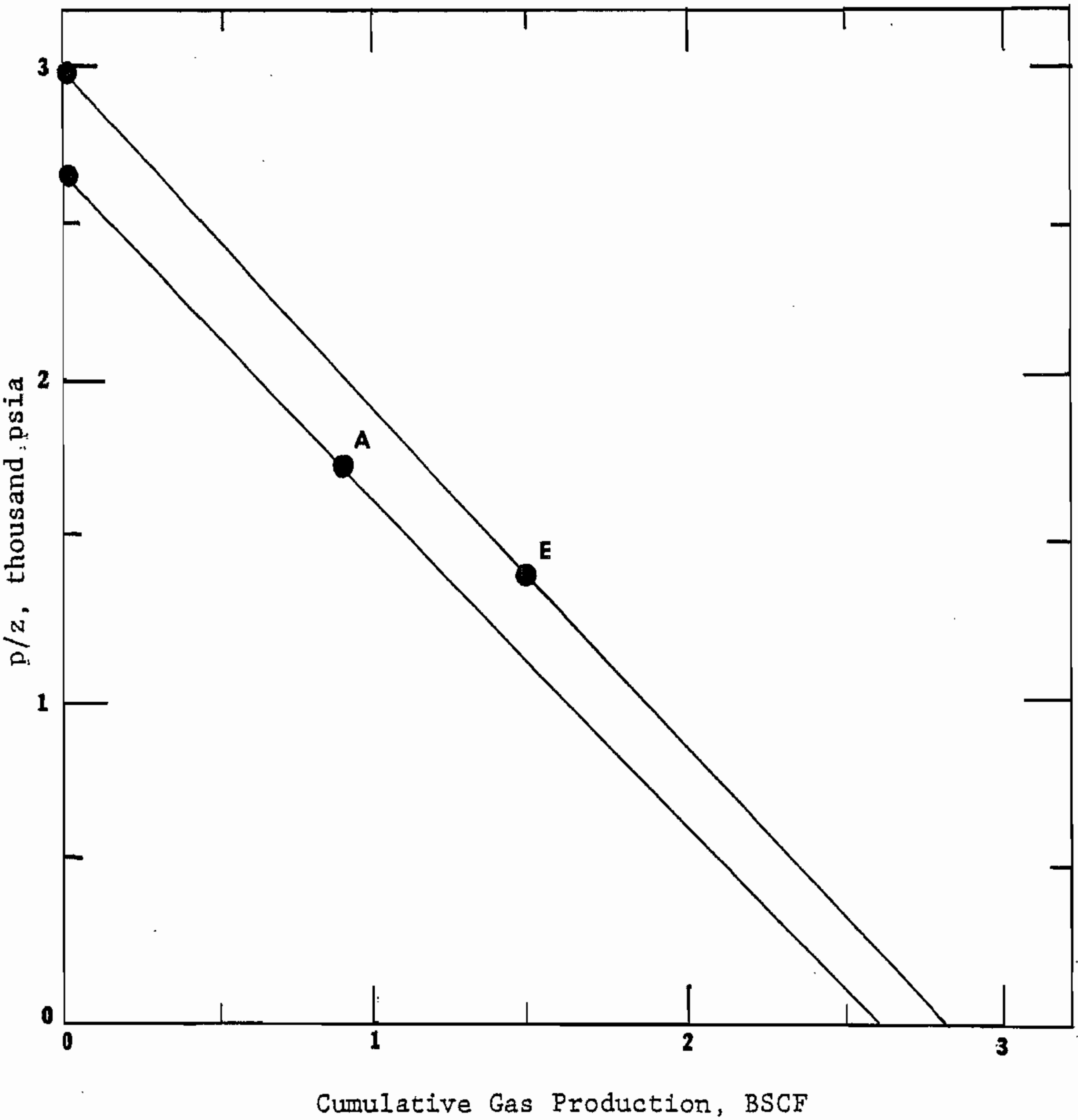


FIG. 5 p/z versus Gas Production - Well A & E

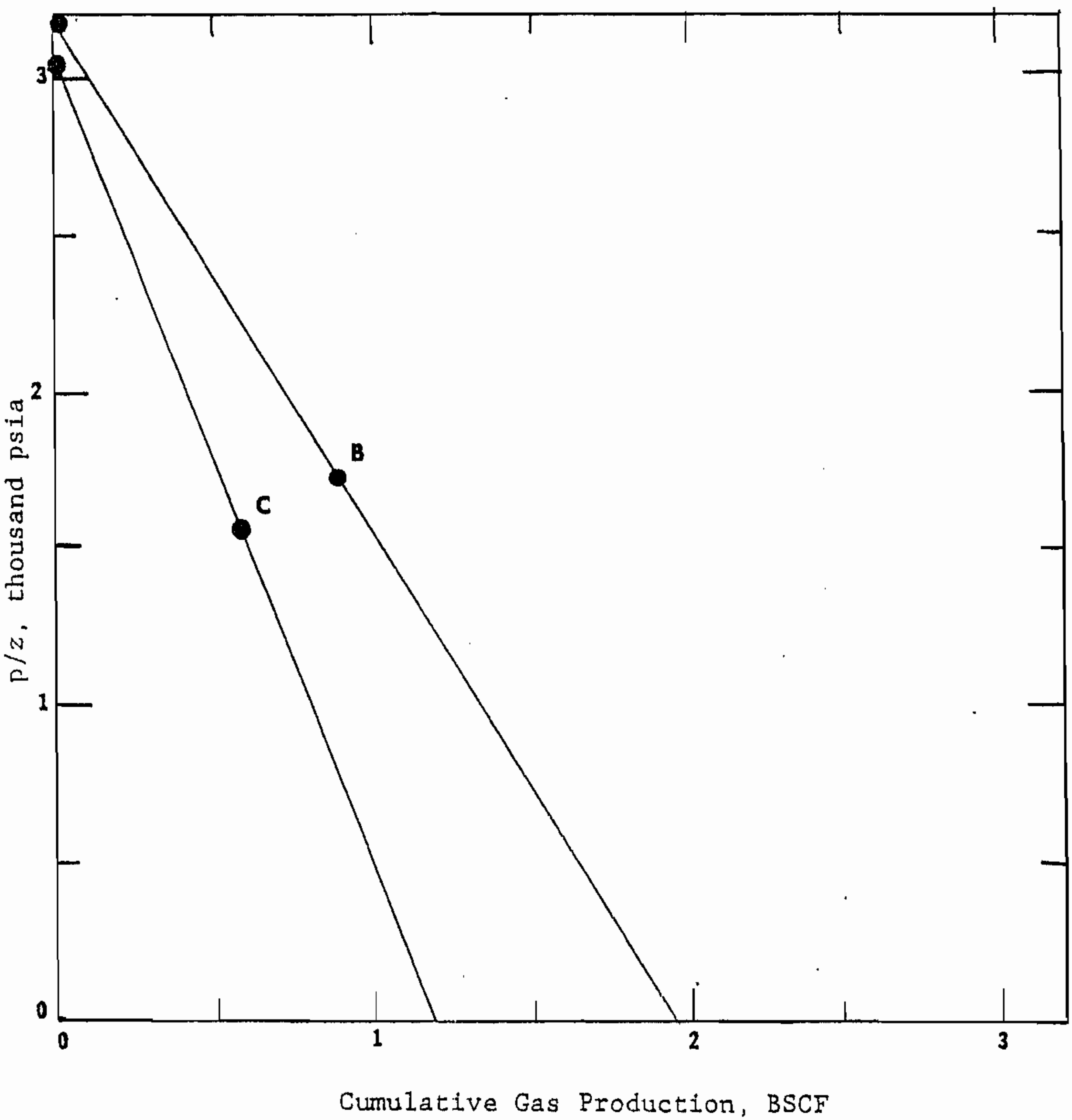


FIG. 6 p/z versus Gas Production - Well B & C

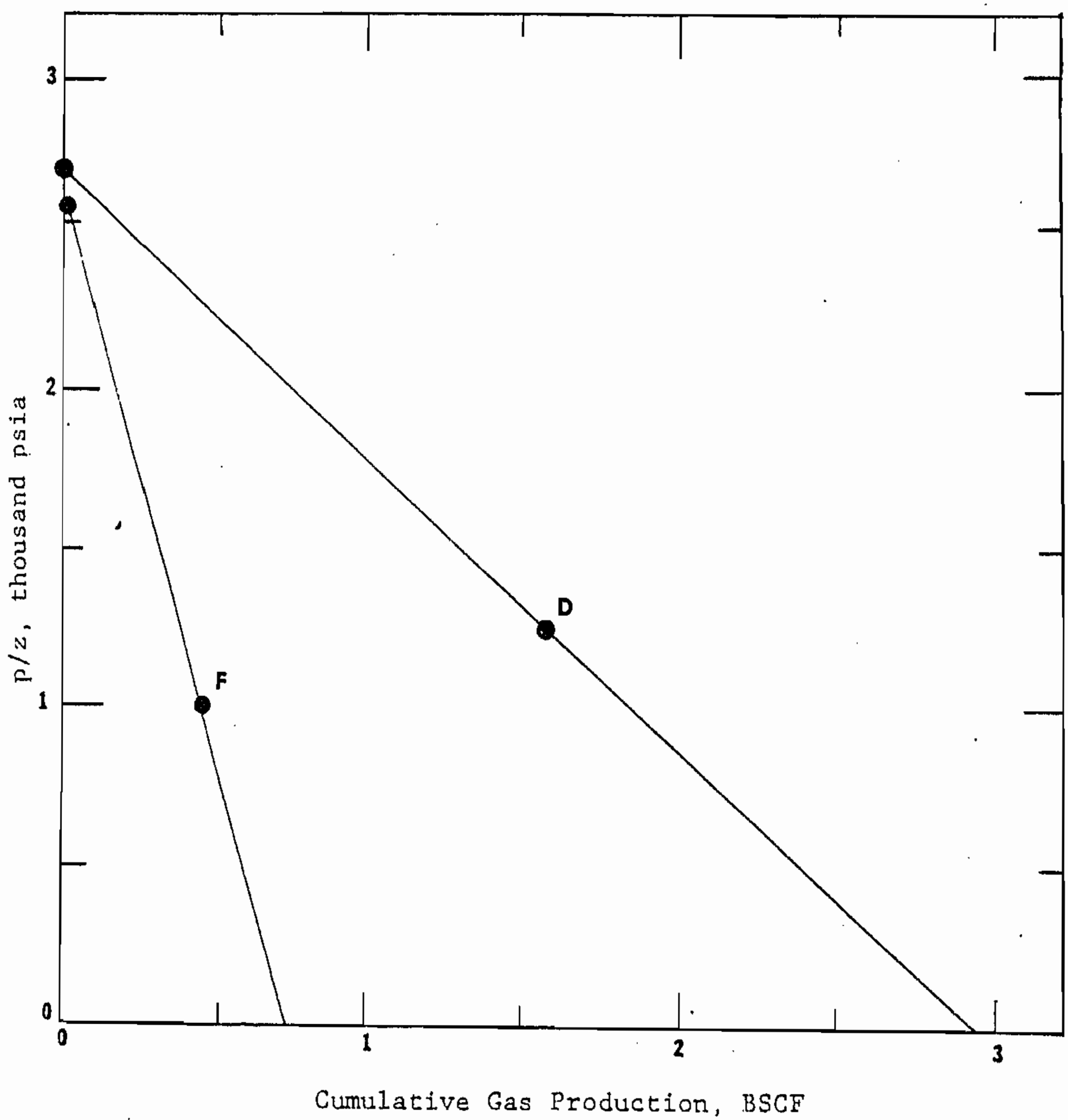


FIG. 7 p/z versus Gas Production - Well D & F

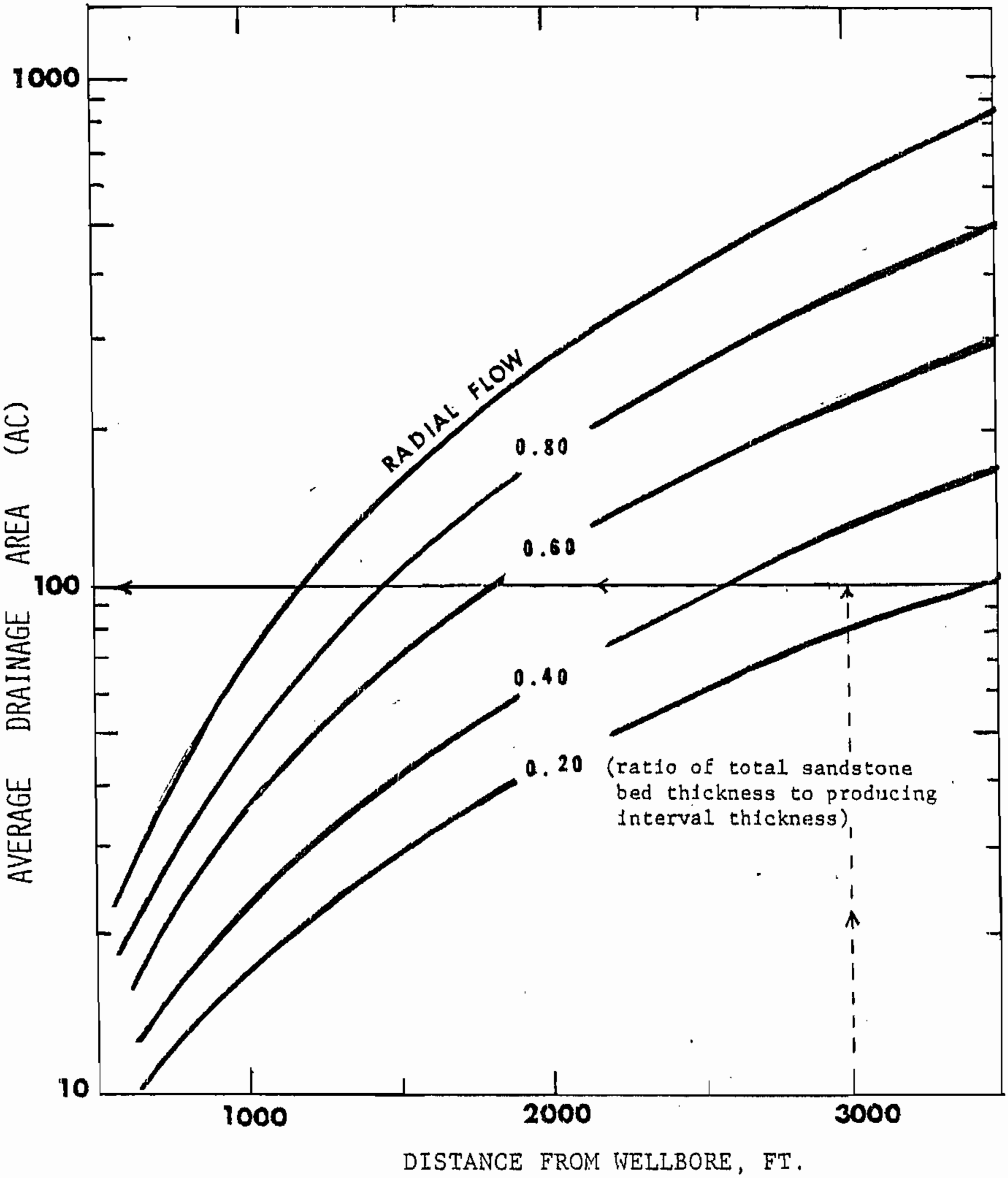


FIG. 8. Reservoir Drainage Area versus Distance from Wellbore as a Function of the Ratio of Total Sandstone Bed Thickness to Total Producing Interval Thickness (after Knutson- 1977)