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ANALYSIS OF SWEET LAKE GEOPRESSURED-GEOTHERMAL AQUIFER

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ABSTRACT

Geopressured-geothermal aquifers are presumed to contain a large resource of natural gas in solution with the native brine. Whether this resource can be produced economically at the present time depends upon the ability of these reservoirs to produce at high rates for extended periods of time.

The Sweet Lake geopressured-geothermal aquifer, located southeast of Lake Charles, Louisiana, is one such aquifer modeled by a two-dimensional geopressured-geothermal simulator. This aquifer is a sandstone within the Frio formation at depths between 15,000 to 15,640 ft with a net porous thickness of 250 ft, a calculated in-situ permeability (from drawdown data) of 17 md, an estimated porosity of 24 percent, a uniaxial compaction coefficient of 4.5×10^{-7} psi^{-1} and a solution gas-water ratio of 11 SCF/STB all at the initial reservoir pressure of 12,060 psi. These parameters are typically pressure sensitive in geopressured-geothermal aquifers and are critically important to aquifer performance. Several simulation experiments are conducted which investigate the effects of varying initial values for these parameters with the experimentally determined values as means. The simulations give both optimistic and pessimistic expectations for aquifer performance. The expected life of the geopressured-geothermal well is reported for each simulation.

INTRODUCTION

The Sweet Lake geopressured-geothermal energy prospect is located approximately 25 miles southeast of Lake Charles, Louisiana. The prospective zone is the Miogypsinoides ("Miogyp") sand of the Frio Formation, which is found at depths between 15,000 and 15,640 ft in the test well, MG-T/DOE AMOCO Fee No. 1.

The prospect is a sedimentary basin developed on the north flank of a salt ridge of east-west trend. The south side of the basin is bounded by a major fault down-thrown to the north. This fault converges eastward with another major east-west fault down-thrown to the south to form a graben. There is a small fault in the west, but it is not known whether this fault extends northeastward and bounds the sands. If this fault is considered as the boundary to the west, the reservoir in this graben has an areal dimension of approximately 9 miles by 3.5 miles. Extension of good quality sand is uncertain at this stage. The dip on the top of the sand sequence is about 20° to the northwest.

Eight sand members were recognized in the 640 foot interval, with 250 ft of net sand thickness. A single zone, fifth from the top, was completed for testing with perforation between 15,387 and 15,414 ft (Durrett and Durham, 1981). The initial reservoir pressure was 12,060 psia at the center of perforation at a depth of 15,400 ft, which is about 4,870 psi above a normal reservoir pressure at this depth. The reservoir temperature at the same depth was 299 °F. Core analysis of the sand yielded air permeability of 3.6 darcys, from which permeability to water is estimated as about 400 md, and porosity of 24 percent. The measured salinity of the brine from the zone was 140,000 ppm. The gas-water ratio observed during the production tests averaged 11 SCF/STB. Compared with solution gas of 34.5 SCF/STB estimated for a saturated brine at the afore-mentioned reservoir condition, this sand had a very undersaturated reservoir fluid. The bubble point pressure for 11 SCF/STB at 299 °F is expected to be about 2,600 psia (Gould et al., 1981).

The first part of this report presents the results of an analysis of the well test data observed over a ten month period. Using the reservoir permeability obtained from this analysis together with the other data acquired at the well, reservoir simulation was conducted and the results are presented.

WELL TEST ANALYSIS

The flow test of the MG-T/DOE AMOCO Fee No. 1 well began on July 1, 1981 and continued more than ten months. During this period, the flow rates were varied step-wise, and also the well was intermittently shut-in to observe pressure build-up. More than 300 chronological data points of bottom hole pressures and flow rates acquired from the test were treated by the multirate test analysis technique (Earlougher, 1977). The result is shown in Figure 1. The slope of the straight line, m, of this figure is 0.147 psi/(STB/day cycle). At the initial reservoir condition, the water formation volume factor, B_w, is estimated to be 1.0575 BBL/STB and the viscosity, μ_w, 0.395 cp (Gould et al., 1981). Employing these data and the net sand thickness, H, of 27 ft, the reservoir permeability is

$$K = \frac{162.6\, B_w \mu_w}{mH} = \frac{(162.6)(1.0575)(0.395)}{(0.147)(27)} = 17.1 \text{ md}$$

The laboratory measurements on the cores by Jogi

et al., (1980) showed the uniaxial compaction coefficient of about 4.5×10^{-7} psi^{-1} for the sand at the in-situ stress, which implies the pore compressibility of 1.5×10^{-6} psi^{-1} for 24 percent porosity. Adding these to the water compressibility, the total compressibility, c_t, is estimated as 5.0×10^{-6} psi^{-1}. The well radius, r_w, is 0.229 ft (the well diameter is 5½ inches). With the intercept value of b = 0.17, the skin factor is calculated as

$$s = 1.1513 \left\{ \frac{b}{m} - \log \left(\frac{K}{\phi \mu_w c_t r_w^2} \right) + 3.2275 \right\}$$

$$= 1.1513 \left\{ \frac{(0.17)}{(0.147)} - \log \left[\frac{(17.1)}{(0.24)(0.395(5\times10^{-6})(0.229)^2} \right] + 3.2275 \right\} = -5.13$$

It is suspected that the tested sand zone has communication with other sand layers. The negative skin factor seems to be ascribed to the layer communication and the formation dip (Earlougher, 1977).

No changes in the line slope are apparent in Figure 1, indicating that no permeability barriers exist in the vicinity of the well. Earlier Gould et al., (1981) reported two barriers, one at a distance of 452 ft from the well and the other at 1,753 ft, based on a preliminary three-day drawdown test. The same authors, however, stated that no such barriers were recognized on pressures measured during the second flow test which followed the three-day test and lasted for 17 days. If these permeability barriers exist, the influence of the nearest barrier may have escaped from detection in our analysis, since approximately one data point per day was used, and with 17.1 md the influence is estimated to appear within 2 days. However, the second barrier should have been reflected in Figure 1.

Gould et al., further postulated that the observed barriers would coincide with the major faults, and hence assumed that only a triangular area of 25° to 48° with the well at its apex would contribute to production. Based on the original geologic interpretation, the two major faults are considered to lie about 1 mile away from the well. With the low permeability resulted from our analysis, the radius of investigation will encompass these faults if the well is flowed for more than 40 days. Furthermore, in order for the boundary effects of the faults to be felt as a slope change of a well pressure drawdown curve, it is necessary to continue the drawdown test for over 6 months. None of the intermediate pressure drawdown tests were as long as these numbers suggest. We, therefore, believe that the original fault locations (Hoffman and Durham, 1981) do not need to be altered.

The large discrepancy of the permeability, 343 md and 17.1 md, is evidently due to the above difference of the assumption on drainage area. The air permeability of 3.6 darcys, from which the water permeability of 400 md has been estimated, is likely to be the results from measurements on unstressed cores. According to the experiments on the Sweet Lake sand cores by Jogi et al., (1981), the permeabilities at the in-situ stress fall in the range between 20 and 110 md. Their measurements were conducted at room temperatures. It is known that sandstone permeability to water substantially decreases when temperature increases (Weinbrandt et al., 1975; Casse and Ramey, 1976). Consequently, 17.1 md appears to be a reasonable estimate for the Sweet Lake reservoir permeability. The observed steep pressure drawdown is considered to have been caused by this low permeability rather than a restricted drainage area.

PARAMETRIC RESERVOIR STUDY

A parametric sensitivity study was initiated in order to define both pessimistic and optimistic aquifer behavior. Our perspective is that the aquifer extends over an area of 17,280 acres (27 mi^2) and is bounded as originally interpreted via seismic and geologic control and that the uncertainties in aquifer behavior result from sparse aquifer data. The present knowledge of this aquifer consists of that data gathered at the location of the MG-T/DOE AMOCO Fee No. 1 well. The initial aquifer pressure (12,060 psia) and initial aquifer temperature (299 °F) at this location when coupled with the geologic structure are sufficient to accurately predict these parameters at other locations in the aquifer, however, measured values for salinity (140,000 ppm), solution gas-water ratio (11 SCF/STB), uniaxial compaction (4.5×10^{-7} psi^{-1}), porosity (24 percent) and absolute permeability (17.1 md) at the well site are not sufficient to predict these parameters at other aquifer locations. Via a parametric study one can obtain the sensitivity of expected well performance to changes in these parameters and thus determine the economic viability of the prospect when faced with a very limited data base.

The focus of the study is the effect that uncertainties in gas-water ratios, porosity, uniaxial compaction and permeability have on the gas production rate at the wellhead. The criteria for comparison is the time that it takes for the gas production rate to decline to 200 MCF/day, which is assumed to be the economic limit for the well completed in the Sweet Lake geopressured aquifer. Here we make the very simplified assumption that if a well will payout before the economic limit is reached then the well may be profitable to drill.

The Aquifer Model. The simulator which was used in this study is a 2-D finite difference simulator specifically designed to solve the mass balance equations for 2-phase, isothermal flow in compacting porous media. Fluid properties (B_w, R_s, μ_w, B_g, μ_g), where the subscripts w and g indicate water phase and gas phase, are treated as functions of pressure at the initial aquifer temperature (Table 1). The water formation volume factor and viscosity in Table 1, both after Gould et al., (1981), are those for the undersaturated water. The gas properties are estimated assuming pure methane. Rock properties (K and ϕ) are likewise treated as functions of pressure. Relative permeability data and capillary

pressure data were not available for the MG-T/DOE AMOCO Fee No. 1 well and experimental data from another geopressured prospect, the Pleasant Bayou field in Brazoria County, Texas, was used (Table 2).

The aquifer was discretized into a 13 x 13 areal point-distributed grid containing 169 blocks each 140 acres in size. The aquifer geometry was duplicated by placing faults in the blocks as indicated by the geological interpretation. The entire Miogyp sand sequence was perforated containing 250 ft of porous sand. In effect we assume that the data obtained from the fifth sand member would be representative of all sand members in the sequence. Each simulation was continued for a period of 10 years. The initial water flow rate, Q_w, is 40,000 STB/day. The aquifer is presumed able to maintain the constant flow rate well condition until the BHP reaches 7,000 psia. At such time the simulator maintains a constant BHP well condition with corresponding declining flow rates.

Effect of Solution Gas on Aquifer Performance. The first study was to determine the effect of variable solution gas-water ratio on the economic life of the well. In these runs the aquifer was presumed homogeneous with K = 17.1 md, ϕ = .24 and $c_m = 4.5 \times 10^{-7}$ psi^{-1}. The data for B_w and μ_w were not altered from those for the undersaturated water shown in Table 1. The solution gas-water ratio was the only variable in these runs.

Log analyses reveal that not all members of the Myogyp sequence yield the same calculated salinity. As was the case in the Pleasant Bayou prospect (Kharaka et al., 1979), water salinity may greatly alter over the areal extent of the Sweet Lake reservoir. Since water can dissolve more gas as its salinity decreases, the suggested salinity variation implies heterogeneity in gas solubility, both vertically and areally. Moreover, gas availability over the geological time span might have varied from place to place, depending on local geologic environments. Therefore, although the brine of the fifth sand at the MG-T/DOE AMOCO Fee No. 1 well is very undersaturated, brines of other sand members and/or those at other locations may contain more hydrocarbon gas. For these reasons, this parameter was included in the investigation.

The available measured data yields 11 SCF/STB for the fifth Miogyp sand member. A saturated brine at the initial conditions would contain dissolved gas in the ratio of 34.5 SCF/STB. We assume that the cummulative effect of production from the Miogyp sequence will display a R_s between these limits. Figure 2 depicts the relative importance of R_s on well performance. The top curve is the case for R_s = 34.5 SCF/STB and the bottom curve is that for R_s = 11 SCF/STB. The reservoir, whether it is saturated or undersaturated, can sustain the desired water rate no more than a month. The well, therefore, produces at declining rates with the bottom hole pressure maintained at 7,000 psi. Figure 2 illustrates this feature. The results are obvious: if R_s approaches 34.5 SCF/STB the well will have an economic life of over 50 years, however with R_s = 11 SCF/STB the economic life of the well will only slightly exceed 10 years.

Viewing the results of these runs as bounds of expected performance, it is clear that the economic life of the well is a strong function of the solution gas-water ratio. This result is not unexpected but does serve to define the minimal life of the well (10 years) when considering R_s as the only variable. We choose the value R_s = 11 SCF/STB as the base case for subsequent simulations and examine the effect that uncertainties in ϕ, c_m, and K will have on the now established minimal time scale of production.

Effects of Porosity Changes. A set of 4 simulations were run to examine the effect that porosity changes have on the established 10 year life of the well. For these simulations R_s = 11 SCF/STB, K = 17.1 md and ϕ took on values of .15, .20, .24 and .30. Porosity was the only variable in these runs. The results are presented in Figure 3. These indicate that if the aquifer behaves as if the effective porosity were .15 the economic limit would be reached in 9 years whereas if the aquifer responds as if the effective porosity were .30 the economic life would extend to 11.25 years. We conclude that the economic life of the well is very slightly affected by large changes in porosity and do not believe that uncertainties in porosity distributions will be critical to the Sweet Lake prospect. It is also pointed out that these simulations reveal that as the economic limit is raised the effect of porosity uncertainty becomes less on the economic life of the well.

Effects of Changes in Uniaxial Compaction. Three simulations were run to examine the effect that uncertainty in uniaxial compaction will have on aquifer performance. Since sedimentary rocks are generally more elastic at higher temperatures, the reported value of c_m resulted from the measurements at room temperatures was regarded as the minimum. For these runs R_s = 11 SCF/STB, K = 17.1 md, = .24 and c_m was given values of 4.5×10^{-7} psi^{-1}, 9.0×10^{-7} psi^{-1} and 18×10^{-7} psi^{-1}. c_m was the only variable in these runs. The results are presented in Figure 4. For $c_m = 9 \times 10^{-7}$ psi^{-1} the economic limit is reached in 14 years while for $c_m = 18 \times 10^{-7}$ psi^{-1} the limit is reached in 18 years. The base case of $c_m = 4.5 \times 10^{-7}$ psi^{-1} yields a life of 10 years. At the economic limit of 200 MCF/day uncertainties in c_m of 1×10^{-7} psi^{-1} yield changes in the life of the well of 1.6 years. These deviations become less significant as the economic limit is raised.

Effects of Changes in Permeability. With the exception of the solution gas-water ratio, this study indicates that permeability is the most important parameter which influences the economic viability of the well. Five simulations were conducted to examine the effect of changes in this parameter. For these runs R_s = 11 SCF/STB, = .24, $c_m = 4.5 \times 10^{-7}$ psi^{-1} and K varied as 17.1 md, 30 md, 50 md, 100 md and 200 md. Permeability was the only variable in these simulations.

Figure 5 is a plot of BHP vs. Time for these runs.

The bottom curve of this figure is the case for K = 17.1 md and corresponds to the Gas Rate vs. Time curves that are presented in Figures 2, 3 and 4. It is obvious from Figures 2, 3 and 4 that the gas rate begins an almost immediate decline. With K = 17.1 md and H = 250 ft, 40,000 STB/day is above the well's capacity to produce so the well always produces with a constant BHP well condition as observed by inspection of the bottom curve in Figure 5.

Figure 6 shows Gas Production Rate vs. Time for these simulations. Comparing Figures 5 and 6 it is observed that as the well produces at a constant Q_w the pressure at the well declines and when the well produces at a constant BHP condition the flow rate declines. These results are also not unexpected and are only presented for continuity.

Figure 6, Gas Rate vs. Time, demonstates the effect that changes in K have on the economic life of the well. As before the base case with K = 17.1 md gives a life of 10 years. For K = 30 md the life of the well is increased to 12 years and when K = 50 md the life is 13 years. We conclude that uncertainties in the permeability do not significantly alter the time scale of production from 10 years established earlier for the base case. The significance of the permeability is in the prolonged period of constant water rate production, which greatly improves cumulative gas recovery.

To investigate the impact on the saturated reservoir, similar runs were repeated with the R_s data shown in Table 1. Figure 7 presents Water Production Rate vs. Time for these simulations. The corresponding gas production behaviors are exhibited in Figure 8. Figure 8 demonstrates that production below the bubble point results in increasing free gas saturation with resulting increased relative gas permeability which gives rise to the positive slope as observed. Comparing Figures 7 and 8, the point at which the slope breaks can be seen to coincide with the well production strategy change from a constant flow rate well condition to a constant BHP well condition. (We assumed zero critical gas saturation.) For the saturated aquifer the effects of uncertainties in absolute permeability are more profound due to the free gas phase flow.

Figure 9 presents the results of a simulation designed to investigate the effects of locating a well in a "high permeability spot". For this run we again consider the undersaturated aquifer with R_s = 11 SCF/STB, = .24 and c_m = 4.5×10^{-7} psi^{-1}. We plot 3 cases; the first is the homogeneous aquifer with K = 17.1 md (our usual base case), the second is a homogeneous aquifer with K = 200 md, and the third is a heterogeneous aquifer in which the well has been placed in a 140 acre section of 200 md permeability while the remaining field acreage has a permeability of only 17.1 md. The effect on economic life is not significant. What is significant, however, is that for high initial rates of recovery (short payout time) a well in a high permeability region of an otherwise low permeability aquifer is economically equivalent to a well in a homogeneous aquifer of the same high permeability. This result suggests that the artificial fracturing of a reservoir, whereby a narrow lenticular permeability "high spot" is created in a low permeability reservoir, will increase the initial rate of recovery to bring the sub-marginal reserves into the marginal category. Alternatively, though the present well may not be productive enough, economical production from the Sweet Lake prospect will be possible from another well located in a high permeability spot, if such spots can be delineated.

Effects of Permeability Barriers. As a final consideration of the parametric sensitivity analysis a study was conducted to determine the influence of faulting on aquifer behavior. For threse runs R_s = SCF/STB, ϕ = .24, c_m = 4.5×10^{-7} psi^{-1} and K = 17.1 md. We considered 3 cases: the first is our base case with no faulting, the second assumed a continuous fault (K_F = 10^{-3} md) located to the west of the well so as to bisect the aquifer, and the third assumes a similar fault except it has a narrow opening (about 1,500 ft long) that communicates the divided two regions. The results are presented in Figure 10.

We also ran the continuous fault cases in which the leakiness of a fault, K_F, was further reduced. The results were identical to the second case. Therefore, the distant region separated by the fault remained undisturbed in these cases, and the effective drainage area available to the well was decreased to one-half of the base case of no faults. The influence of such faults is very critical, as the well life of 10 years of the base case is shortened to merely 5.5 years. As seen in Figure 10, the narrow communication opening improves the well behavior only slightly.

Recall that if economical, the well will produce at declining rates maintaining the minimum pressure. Therefore, distant faults are detectable only from steeper declines of the gas (or water) rates. If faults are as far as assumed in this study, Figure 10 dipicts that it would take more than half-a-year for their influence to be observed at a well.

CONCLUSION

The results of this study indicate that permeability-thickness and solution gas-water ratio are critical parameters when estimating the economic viability of a geopressured aquifer. The solution gas-water ratio appears to control the economic life of the well and the permeability-thickness controls the rate of recovery.

The permeability of the fifth member of the Miogyp sand sequence is determined to be on the order of 17 md. This value differs significantly from the expected permeability of 400 md but it is supported by the excessive pressure drawdown observed in testing of the MG-T/DOE AMOCO Fee No. 1 well. Further, the measured solution gas-water ratio is 11 SCF/STB and is less than anticipated. This ratio establishes the economic life of the well at close to 10 years. The low permeability limits the capacity of the well to water rates below the design of 40,000 STB/day if this permeability is representative of the entire interval. The rate of recovery may not be

sufficient to payout this well before the economic limit is reached and thus these reserves are believed to be sub-marginal at present gas values.

However, gas production from the Sweet Lake geopressured aquifer may be upgraded to a marginal category, if an extensive fracture system can be created at the existing well or if another well is drilled by delineating a high permeability spot.

ACKNOWLEDGEMENT

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Table 1

Fluid Properties

P psia	B_w BBL/STB	R_s SCF/STB	μ_w cp	B_g BBL/mcf	μ_g cp
5000.	1.0700	18.500	.3700	.819	.02170
5500.	1.0698	21.000	.3710	.765	.02250
6000.	1.0695	21.500	.3720	.717	.02300
6500.	1.0685	23.500	.3725	.674	.02400
7000.	1.0680	24.000	.3750	.637	.02550
7500.	1.0670	25.000	.3765	.615	.02650
8000.	1.0660	26.500	.3780	.588	.02730
8500.	1.0650	27.000	.3800	.567	.02820
9000.	1.0630	29.000	.3835	.548	.02900
9500.	1.0625	30.500	.3850	.532	.03000
10000.	1.0618	31.500	.3860	.517	.03100
10500.	1.0600	33.000	.3880	.500	.03300
11000.	1.0590	34.000	.3900	.494	.03520
11500.	1.0580	35.500	.3920	.482	.03600
12000.	1.0575	37.000	.3950	.475	.03750
12500.	1.0570	38.000	.3970	.467	.03880
13000.	1.0560	39.500	.3990	.456	.03900
13500.	1.0555	40.500	.4050	.451	.03910
14000.	1.0470	41.500	.4200	.443	.03920

Table 2

Capillary Pressure and Relative Permeabilities

S_w frac	P_c psi	k_{rw} frac	k_{rg} frac
1.0	3.20	1.00000	0.0000
0.959	9.25	0.56400	0.0360
0.935	12.27	0.41500	0.0630
0.911	15.20	0.32200	0.1220
0.880	17.72	0.24900	0.2280
0.848	21.35	0.16400	0.3300
0.820	24.98	0.10600	0.4420
0.802	27.39	0.08400	0.5590
0.788	29.82	0.07800	0.6870
0.764	31.76	0.06100	0.8170
0.719	37.21	0.03500	0.9150

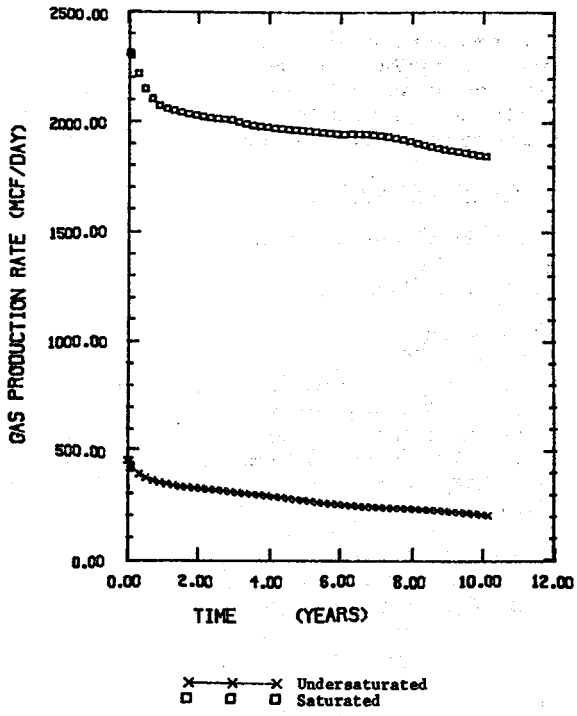

Figure 2. Gas production from reservoirs containing brines saturated and undersaturated with gas.

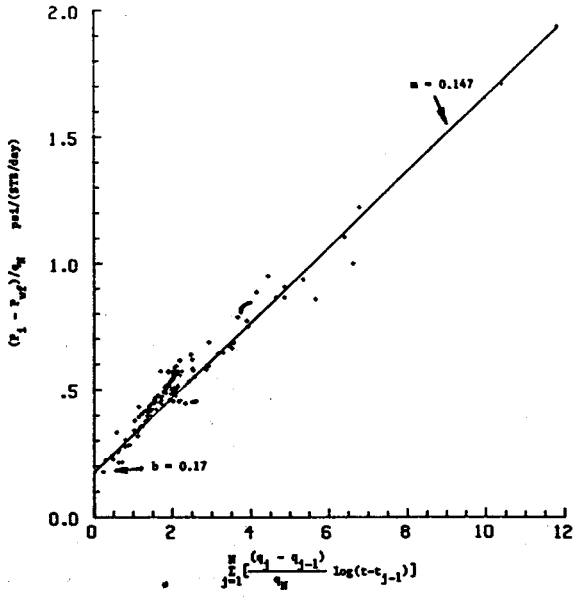

Figure 1. Multirate drawdown test analysis.

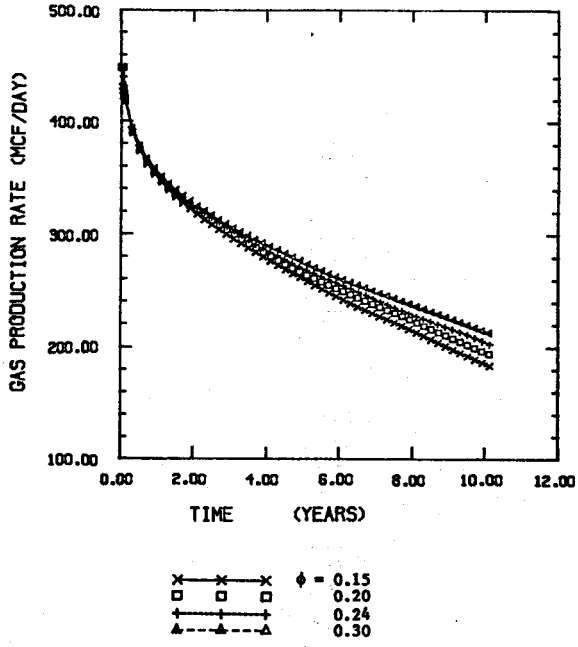

Figure 3. Effects of porosity level on gas production.

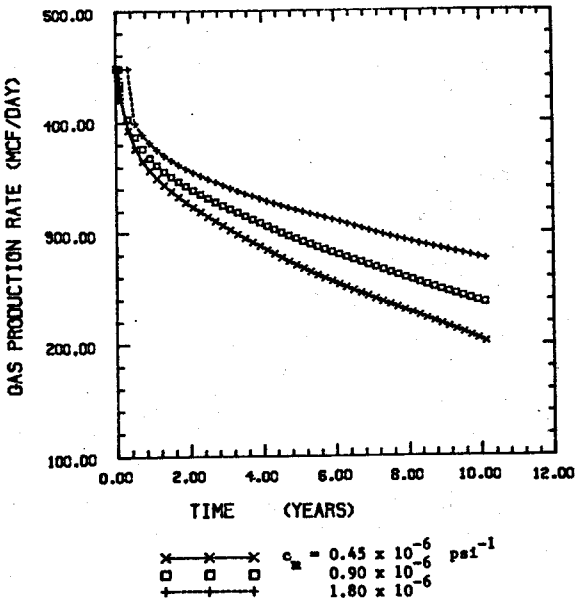

Figure 4. Effects of compaction coefficient on gas production.

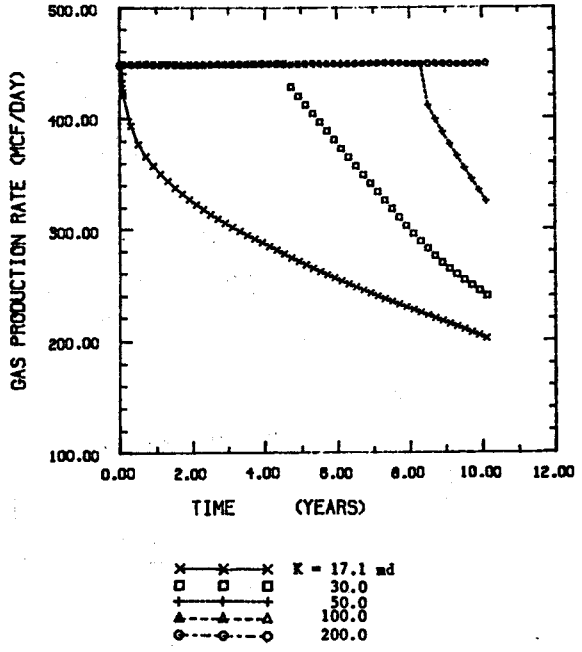

Figure 6. Influence of reservoir permeability on gas production from undersaturated reservoirs.

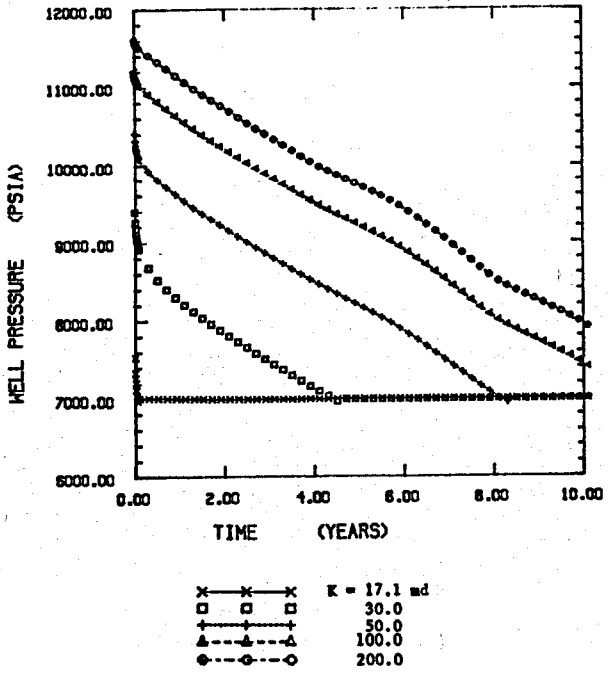

Figure 5. Influence of reservoir permeability level on well pressure performance.

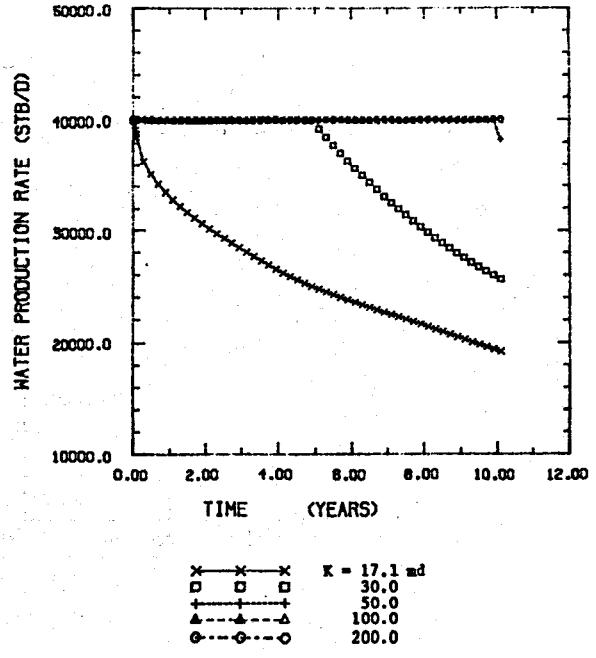

Figure 7. Influence of reservoir permeability level on water production from saturated reservoirs.

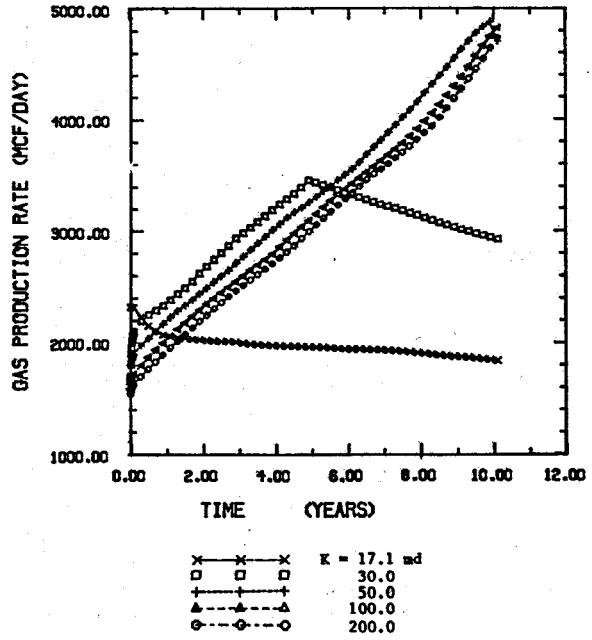

Figure 8. Influence of reservoir permeability level on gas production from saturated reservoirs.

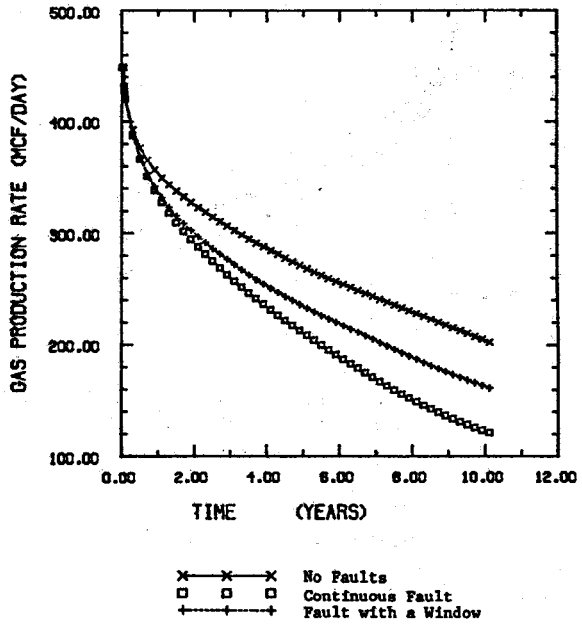

Figure 10. Effects of minor faults on gas production.

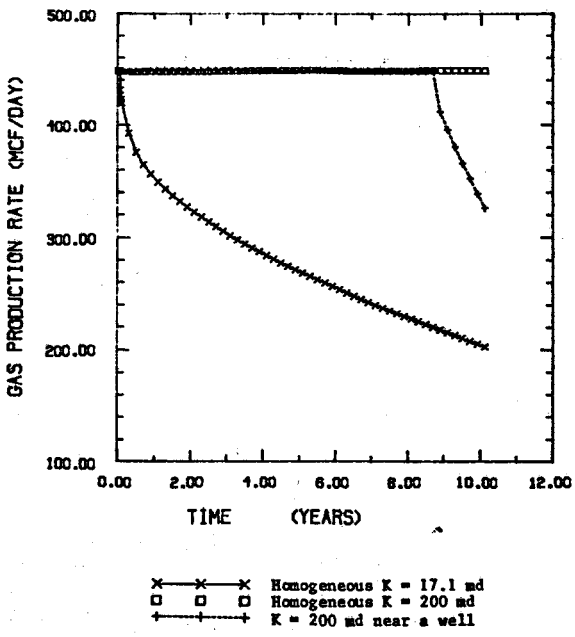

Figure 9. Improvement of gas production due to high permeability near a well.