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**ANALYSIS OF SWEET LAKE
GEOPRESSURED-GEOTHERMAL AQUIFER**

TOPICAL REPORT

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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 $4.5 \times 10^{-7} \text{ psi}^{-1}$ 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 downthrown to the north (Figure 1, Hoffman and Durham (1981)). This fault converges eastward with another major east-west fault downthrown 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 Phase-III, long term 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 2. 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., (1981) showed the uniaxial compaction coefficient of about $4.5 \times 10^{-7} \text{ psi}^{-1}$ for the sand at the in-situ stress, which implies the pore compressibility of $1.5 \times 10^{-6} \text{ psi}^{-1}$ for 24 percent porosity. Adding these to the water compressibility, the total compressibility, c_t , is estimated as $5.0 \times 10^{-6} \text{ psi}^{-1}$. 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

$$\begin{aligned}
s &= 1.1513 \left\{ \frac{b}{m} - \log \left(\frac{K}{\phi \mu_w c_t r_w^2} \right) + 3.2275 \right\} \\
&= 1.1513 \left\{ \frac{(0.17)}{(0.147)} - \log \left[\frac{(17.1)}{(0.24)(0.395)(5 \times 10^{-6})(0.229)^2} \right] + 3.2275 \right\} \\
&= -5.13
\end{aligned}$$

No changes in the line slope are apparent in Figure 2, suggesting that no permeability barriers exist within the area encompassed by the test.

The above interpretation considerably differs from the earlier one by Gould et al., (1981), which deduced the reservoir permeability of 260 md and recognized two barriers, one at a distance of 452 ft from the well and the other at 1753 ft, based on the Phase-I, three-day, initial flow test at a production rate of about 3,000 BWPD. These barriers correspond to the slope changes at 0.0035 and 0.017 days. The well was, however, filled prior to this test with completion fluids that were heavier than the reservoir brine, and the displacement of the completion fluids was not completed until 0.1 days. This feature is clearly depicted by the increase in well head pressures during this period of the flow test, while the bottom hole pressure decreased. This portion of the bottom hole pressure drawdown curve shows a gradual increase in its slope but is difficult to view as having distinct slope changes. The gradual change in the drawdown curve slope is believed to be the combined effect of the reservoir response and the influence of varying volume of the completion fluids. Gould et al., (1981) also reported that the measured flow rates in the early stage of the test were in error. The results to 0.1 days of the Phase-I test, therefore, seems inadequate for evaluating the reservoir characteristics.

The remaining portion of the Phase-I test drawdown curve contains a drastic slope change at 0.92 days, which Gould et al., interpreted as a result of a flow rate change from 3,000 to 3,750 BWPD. It might have been caused by permeability barriers. Because of rate fluctuations as well as incorrect measurements of flow rates,

however, it is not possible to draw reliable conclusions from the Phase-I test. The Phase-II, 16-day reservoir limit test at a designed rate of 15,000 BWPD was also analyzed by Gould et al. During the first 3.5 days of this test, the adjustments to the surface facilities were made in an attempt to maintain the designed rate. Furthermore, the well was not completely open within the first 4.9 minutes. As a consequence, the first radial flow slope, that is crucial to estimate the intrinsic reservoir permeability without the influence of barriers, was missed and the subsequent drawdown curve was too obscured to confirm the results of the Phase-I test analysis.

Despite the obscurity of the estimates, the slope changes in the drawdown curves observed during the Phase-I and -II tests can not be explained without assuming permeability barriers in the vicinity of the well. The barriers are possibly multiple and are thought to be totally or partially sealing faults which were not detected by the seismic study. Since only one data point a day was used in our analysis of the Phase-III test, Figure 2 failed to show the influence of the faults as slope changes. Considering that no well stimulation was conducted, however, the large negative skin factor is believed to reflect reservoir permeability considerably higher than 17 md and permeability barriers near the well. The log-log plot of bottom hole pressure and time of the Phase-I test data exhibits a nearly unit slope for 1.4 minutes, which is the period of the wellbore storage effect dominance. If the reservoir permeability and skin factor (0.21) by Gould et al., are substituted into a formula (Earlougher, 1977), it is estimated that the data after 0.63 minutes should have been usable for the transient pressure analysis without the wellbore storage effect. The disparity seems to imply that the reservoir permeability will be less than the assessment by Gould et al.

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 by Jogi et al., (1981) on the cores from the perforated interval, the permeabilities at the in-situ stress fall in the range between 25 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). Thus, the core permeabilities at the reservoir conditions are expected to be lower than the above values. However, as only four core samples were used in the measurements, it is difficult to assess from these data a representative permeability value for the entire perforation interval.

Due to the obscured test results, there remains some uncertainty as to the characteristics of the Sweet Lake geopressed reservoir. It would be reasonable to conclude at this stage that multiple sealing or non-sealing faults exist near the well and because of their effects as the permeability barriers, the reservoir is expected to behave for extended production as if it had uniform low permeability of 17 md without faults.

PARAMETRIC RESERVOIR STUDY AND DISCUSSION

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 geopressed aquifer. Here we make the very simplified assumption that if a well will recover the initial investment 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 geopressed prospect, the Pleasant Bayou Well in Brazoria County, Texas, were 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 corresponding to the faults in Figure 1. 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. Furthermore, the influence of permeability barriers in the vicinity of the well was assumed to be taken into account by a uniform permeability value. 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, $\phi = .24$ 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 cumulative effect of production from the Miogyp sequence will display a R_s between these limits. Figure 3 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 3 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 4. 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, $\phi = .24$ and c_m was given values of $4.5 \times 10^{-7} \text{ psi}^{-1}$, $9.0 \times 10^{-7} \text{ psi}^{-1}$ and $18 \times 10^{-7} \text{ psi}^{-1}$. c_m was the only variable in these runs. The results are presented in Figure 5. For $c_m = 9 \times 10^{-7} \text{ psi}^{-1}$ the economic limit is reached in 14 years while for $c_m = 18 \times 10^{-7} \text{ psi}^{-1}$ the limit is reached in 18 years. The base case of $c_m = 4.5 \times 10^{-7} \text{ psi}^{-1}$ yields a life of 10 years. At the economic limit of 200 MCF/day uncertainties in c_m of $1 \times 10^{-7} \text{ psi}^{-1}$ 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, $\phi = .24$, $c_m = 4.5 \times 10^{-7}$ 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 6 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 3, 4 and 5. It is obvious from Figures 3, 4 and 5 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 6.

Figure 7 plots Gas Production Rate vs. Time for these simulations. Comparing Figures 6 and 7 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 7, Gas Rate vs. Time, demonstrates 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 8 presents Water Production Rate vs.

Time for these simulations. The corresponding gas production behaviors are exhibited in Figure 9. Figure 9 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 8 and 9, 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 10 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 $R_g = 11$ SCF/STB, $\phi = .24$ and $c_m = 4.5 \times 10^{-7}$ 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 suggests that if the intrinsic reservoir permeability is as low as 17 md, the artificial fracturing, whereby a narrow lenticular permeability "high spot" is created around the well, will increase the initial rate of recovery to bring the submarginal reserves into the marginal category. apparent low permeability of the Sweet Lake reservoir, however, does not seem to be intrinsic but is interpreted as caused by permeability barriers near the well. The above argument, hence, does not apply to this reservoir. 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 of an areal scale of 140 acres or larger 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 these runs $R_s = \text{SCF/STB}$, $\phi = .24$, $c_m = 4.5 \times 10^{-7} \text{ psi}^{-1}$ and $K = 17.1 \text{ md}$. We considered 3 cases: the first is our base case with no faulting, the second assumed a continuous fault ($K_F = 10^{-3} \text{ md}$) 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 11.

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 11, 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 11 depicts 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 fifth member of the Miogyp sand sequence is believed to have multiple sealing or non-sealing faults in the neighborhood of the MG-T/DOE AMOCO Fee No. 1 well. The multi-rate well test analysis of this study indicates that due to their effects as permeability barrier, the reservoir response to a long-term well production will be equivalent to that of a reservoir which has a uniform low permeability of 17 md without near-well faults. The apparent low permeability limits the capacity of the well to water rates below the designed rate of 40,000 STB/day if the other sand layers likewise include faults near the well. The measured solution gas-water ratio is 11 SCF/STB and is considerably less than anticipated. These two critical parameters establishes the economic life of the well at close to 10 years. The rate of recovery may not be sufficient to recover the initial investment from this well before the economic limit is reached, thus these reserves are believed to be submarginal at present gas prices.

However, if the other sand members have larger continuous areal extentions or if another well is drilled by delineating a high permeability spot on an areal scale of 140 acres or more, gas production from the Sweet Lake geopressured aquifer may be upgraded to a marginal category.

Table 1

Fluid Properties

<u>P</u> <u>psia</u>	<u>B_w</u> <u>BBL/STB</u>	<u>R_s</u> <u>SCF/STB</u>	<u>μ_w</u> <u>cp</u>	<u>B_g</u> <u>BBL/mcf</u>	<u>μ_g</u> <u>cp</u>
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	P_c	k_{rw}	k_{rg}
<u>frac</u>	<u>psi</u>	<u>frac</u>	<u>frac</u>
1.000	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 1. Structure Map of Sweet Lake Prospect
Contoured on Top of Miogyp Sand

Figure 2. Multirate Drawdown Test Analysis

Figure 3. Gas Production from Reservoirs Containing Brines Saturated and Undersaturated with Gas

Figure 4. Effects of Porosity Level on Gas Production

Figure 5. Effects of Compaction Coefficient on Gas Production

Figure 6. Influence of Reservoir Permeability Level on Well Pressure Performance

Figure 7. Influence of Reservoir Permeability on Gas Production from Undersaturated Reservoirs

Figure 8. Influence of Reservoir Permeability Level on Water Production from Saturated Reservoirs

Figure 9. Influence of Reservoir Permeability Level on Gas Production from Saturated Reservoirs

Figure 10. Improvement of Gas Production due to High Permeability near a Well

Figure 11. Effects of Minor Faults on Gas Production

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