THE MEASUREMENT AND EFFECT OF
THE CRITICAL GAS SATURATION AND RELATIVE PERMEABILITY
ON THE PRODUCTION OF METHANE FROM
GEOPRESSURED AQUIFERS OF SATURATED BRINE

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DIAGRAMS AND PHOTOS FOLLOW TEXT

ABSTRACT

The primary aim of this contractual work was to provide an experimental determination of the critical gas saturation, which contributed to the earlier conclusion that the economic production of methane from geopressured aquifers is probably unachievable.

A subsidiary goal was the theoretical investigation, by mathematical simulation of the effect of a range of critical gas saturations and an assumed suite of relative permeability curves on the production of methane from geopressured methane-bearing aquifers.

A supplementary goal of the effort was to investigate the number of water driven geopressured gas reservoirs that might have a significant residual saturation of trapped gas.

The attempt to measure critical gas saturation at pressures in the range of 5,000 to 10,000 psi. failed. It proved impossible, with the funds and time available, to conclude a successful suite of experiments. The problem was centered on the inability to maintain adequate seals on the end plates of the apparatus.

Numerical simulation confirmed that the level of critical gas saturation required for methane to be produced profitably from geopressured aquifers was unrealistically high.

Most of the water driven geopressured gas reservoirs located through a study of the U.S.G.S. files revealed that there is in general an inadequate level of available data on them. Furthermore, the size of these reservoirs were in general so small that their total gas content would not merit any significant expenditure to win the residual, trapped gas.

I. INTRODUCTION

The primary goal of this contract was to measure the relative permeability of methane and brine in porous media at pressures between 5000 and 10,000 psi.

The need for this information developed following the completion of a prior contract to study the economic and technical feasibility of producing natural gas (methane) from geopressured brines along the (Texas) Gulf Coast.

The results of the earlier study¹ were unequivocal in leading to the conclusion that the probability of technical production of such a resource is quite low. Further, assuming that there may be some locations at which the technical feasibility is present, the probability of achieving economic feasibility is remote. The study with its attendant conclusions was submitted for publication, subjected to technical and editorial review, and then accepted for publication with no changes in the substance of the original report².

Although none of the values of the parameters that control the production of methane gas could be directly measured, the value of only one important parameter could conceivably be outside the range of values assumed for it, viz., the critical saturation of free gas. The critical saturation of the gas is important since it determines at what minimum saturation of gas in the reservoir the gas phase will flow independently of the aqueous phase itself. If the critical saturation of gas is, for example, zero; then the resulting production would have a significantly higher ratio of gas to brine than that corresponding to the solution ratio. This would have a significant beneficial effect on the economics of the production and recovery process.

Experience in oil production operations indicates that the critical gas saturation in crude oil saturated reservoirs is in the range of 1% to 3% p.v. Values of the parameter in this range result in the production of gas and brine in the ratio occurring in the indigenous reservoir solution. In order for any improvement in the producing gas oil ratio to occur, the critical gas saturation would have to be 1 to 2 orders of magnitude less than the assumed range. Whereas there is no evidence or theory to suggest that the critical gas saturation could have so low a value, it was proposed that an attempt be made to determine the critical saturation in a laboratory system that simulated the high pressure production of a geopressured brine. This was the major goal of this contract.

A subsidiary component of the contractual effort was to attempt to determine whether there is a significant number of geopressured natural gas reservoirs that are associated with a natural water drive, and which as a result would be expected to contain significant amounts of trapped, residual gas at the time of abandonment. This objective was somewhat separate and distinct from the primary goal, in that the ultimate use of such a study is to estimate whether there would be any value in a research program dedicated to improving the recovery efficiency of natural gas from such reservoirs.

II. PROJECT ACHIEVEMENTS

At the time of contract termination, the theoretical effect of the critical gas saturation and the relationship between relative gas and fluid permeabilities on the production of methane from geopressured reservoirs had been confirmed by a sophisticated mathematical reservoir simulation study. In addition, the subsidiary effort to examine the occurrence of water driven, geopressured gas reservoirs had been completed. However, the primary effort to study the critical gas saturation in a laboratory simulated geopressured system had not been completed.

Laboratory operations in the desired high pressure range, viz., to 10,000 psi. imposed problems which could not be handled in the time and within the budget prescribed by the contract.

In view of the continued attention given to evaluating the potential of this resource, and the award of multi-million dollar contracts for field studies, despite the negative results of the aforementioned study and its acceptance by the professional technical community, it was decided to continue the effort using funds and services available from other sources. The laboratory problems however continued to be intractable. Re-design and re-construction of the apparatus continued, and industrial and commercial concerns provided the project with significant support in the loan of equipment and consultation on the design of high pressure facilities. It ultimately proved impossible for us to construct and operate an apparatus that would permit us to obtain experimental confirmation of the relative permeability of gas in brine-methane systems at high pressures. The project was therefore abandoned.

*Occidental Research Corporation is to be particularly thanked for their loan to us of high pressure mixing device for preparing the solution of methane in brine.

III. NUMERICAL SIMULATION OF THE EFFECT OF THE CRITICAL GAS SATURATION

The reference geopressured fluid studied in this work is assumed to be a brine saturated with methane at 11,000 psia., and at a temperature of 240°F. The PVT properties of the brine are shown in Figures 1 through 4.

The solubility of methane in pure water is a function of both pressure and temperature³. Over the pressure range anticipated in geopressured reservoirs, the solubility increases with temperature. For the temperature range assumed in this study, the maximum solubility of methane in pure water is 38 SCF/B. The presence of any salt in the water would of course lower this value. For a salinity of 30,000 ppm., the maximum solubility is estimated to be only 34 SCF/B.

The formation volume factor data for water were obtained by extrapolating the data of Dodson and Standing⁴. For the range of pressure considered in this study, B_w varies from 1.037 to 1.045 reservoir barrels per stock tank barrel, see Figures 2 and 3. The water formation volume factor when saturated with gas increases slightly as shown in Figure 3; it is a slight increase because the solubility of gas is quite small.

The viscosity data used in this study are shown in Figure 4⁵. It should be noted that the effects of gas solubility on the viscosity are ignored since the effect is trivial at such low values of solubility.

The reservoir properties of the geopressured aquifer are shown in Table 1. With one significant exception they are those of the most likely, optimistic reservoir described earlier¹. The formation compressibility, however, is now taken as 5×10^{-6} , half the value used in previous studies. This lower value was chosen because, as concluded by Geerstma⁶, the effective value of the compressibility should be of the order of one half that measured in the laboratory under triaxial loading. Although no cores of geopressured aquifers have been subjected to such tests, a value of 10×10^{-6} , which is at the upper end of most laboratory measurements of compressibility of consolidated rocks, was chosen as an optimistic one for the geopressured aquifers. The exact value of the compressibility will of course not alter the relative effects of the various parameters varied in this study.

A. DESCRIPTION OF THE RESERVOIR MODEL

A two dimensional areal model was used to simulate the performance of a typical producing well draining a forty square mile area. The reservoir properties are shown in Table 1. Figure 5 shows the general configuration of the model consisting of uniformly sized grid blocks. For a reservoir thickness of 162 feet and an average permeability of 20 mds., a well was assumed to produce at rates varying from 10,000 STB/D to 40,000 STB/D, and the reservoir pressure decline as a function of time from the initial condition of 11,000 psi. was computed. The simulation runs were made under a constant rate and were terminated when the bottom hole flowing pressure reached a level of 6,000 psi. This is the minimum pressure required for unassisted flow from the well for the

assumed depth of 13,000 feet.

Sensitivity runs were made to study the effect of many variables on methane recovery. Of particular interest were the critical gas saturations and flow rate. Other variables included the overall reservoir permeability as well as zones of higher permeability around the wellbore created by fracturing or acidizing.

The gas water relative permeabilities for the base case represent typical gas water data as shown in published sources^{7,8,9}. In general, indications are that the critical gas saturation for gas water systems ranges from 5 to 10%. In this study, hypothetical runs were made to determine the recovery as a function of critical gas saturation. Figure 6 shows the relative permeabilities used for different cases reported in this study.

B. PREDICTED PERFORMANCE DATA

Effect of Critical Gas Saturation: The performance of the base case is shown in Figure 7 and Table 2. The production is assumed to stay at a level of 20,000 BWD, with a zero initial gas saturation and a critical gas saturation of 5%. The producing gas water ratio data indicate no free gas in being produced. At a minimum bottom hole producing pressure of 6,000 psi., the cumulative recovery is 2.27 BSCF. The average reservoir pressure at the end point ($P_{wf} = 6,000$ psi) has fallen to 8,865 psi.

Following this result, more optimistic values of critical gas saturation were used. Figures 8 and 9 show that for small values of critical gas saturation, as expected, the chances of mobilizing free gas are improved and this is reflected in higher producing gas water ratios and cumulative methane recovery. The results show that the critical gas saturation must drop below 0.5% before any increased gas production is observed. For a significant effect, the critical gas saturation must approach 0.1%.

During the early production life, the producing gas water ratio is 34 SCF/STB for all critical gas saturations. This indicates that the gas produced initially is only the dissolved gas under the cited reservoir and operating conditions. As time progresses, gas will gradually be formed as a free phase. This will at first reduce the producing gas water ratio to some extent until the critical gas saturation is reached when the gas water ratio will begin to increase.

About three years after production has been initiated in the reference case, the average gas saturation in the block around the well reaches a saturation of 0.1%. If the critical gas saturation is 0.1%, then the gas will begin to flow separately from and in parallel with the brine containing gas in solution. In the following three years the gas saturation in other blocks begins to approach or exceed the critical gas saturation. After six years the gas saturation is above critical throughout the reservoir and the producing gas water ratio increases continuously.

A gas saturation of 0.5% is not reached in this reservoir system

after ten years of production. Hence, if the critical saturation is 0.5%, no mobilization of the liberated gas occurs within this time period and there is no further opportunity for it to do so since the bottomhole pressure has already fallen to less than 6,000 psi. (Of course there is some possibility that production could be continued beyond this time as a result of the lightening of the hydrostatic column by the free gas in the tubing stream. However, it occurs too late in the life of the operation to have a meaningful economic impact.)

It should be noted that even at extremely low values of critical gas saturation, the cumulative gas recovery is not a substantial fraction of the original gas in solution in the reservoir: no more than 1.63% of the original gas in place is recovered when the critical gas saturation is as low as 0.1%.

The effect of reservoir permeability: The absolute permeability of the reservoir was varied from 20 to 200 mds. Figure 10 shows that the impact of the increased permeability is substantial only at a very low critical gas saturation. As shown in Figure 11, more gas may be produced at higher permeabilities because the bottom hole pressure will remain higher for the same volume of produced fluid and the economic life is increased. With continued increase in permeability, the effect of cumulative production begins to disappear because of pressure equilibration in the reservoir. The economic limit is increased from 1.63% of the original gas in place at 20 mds. to 3.63% at 40 mds., but only to 5.95% at 200 mds.

Figure 12 shows cumulative gas produced, G_p , in BSCF, as a function of permeability of the homogeneous formation for three different flow rates of 10,000, 20,000, and 40,000 BWD, a critical gas saturation of 0.5% and an abandonment bottom hole pressure of 6000 psi. For the low permeability of 20 mds., a flow rate of 40,000 BWS cannot be maintained for long without the pressure falling below 6000 psi. The cumulative production is much higher for a permeability of 40 mds. The contrast between ultimate production at low and high flow rates decreases with increasing permeability and lower production rates. Figure 12 also shows that the cumulative production increases as the flow rate decreases but the time required for production increases substantially. An economic calculation would be required to determine the optimum flow rate for a set of assumed reservoir and a permissible range of operating conditions.

Effect of Production Rate: The effect of the production rate on the ultimate production is shown in Figure 13. Regardless of the assumed value for the critical gas saturation, a higher withdrawal rate results in the reduction of the cumulative gas recovery because of faster depletion of reservoir energy. The producing life of the well down to the abandonment pressure of 6000 psi. is shown in Figure 14 at the three different flow rates investigated. As shown in Figures 15 and 16, the cumulative production is independent of critical gas saturation when the latter exceeds a value of a few tenths of a percent.

The overall recovery of water is quite low because the reservoir pressure declines so rapidly once production is initiated in the absence of any reinjection or recharge of the reservoir. It can be concluded

that a significant reinjection operation would increase the economic potential of methane production from geopressured aquifers.

The effect of higher permeability in improving the recovery is noteworthy only at high flow rates. Figure 18 shows that for low rates of flow, higher reservoir permeability does not contribute significantly to the enhancement of recovery because a low permeability reservoir can handle low flow rates.

The effect of fracturing: The equivalent effect of massive fracturing and/or acidizing on the performance of these reservoirs was evaluated by inserting a zone of very high permeability around the well bore. The permeability of a radius of $1/9$ that of the drainage radius was increased to as much as 10,000 mds. The results of these calculations are shown in Figure 19. It is obvious that the effect of such stimulation is inversely proportional to the permeability of the reservoir itself; for a permeability of 20 mds. the cumulative production can be increased by a factor of somewhat more than 6 whereas for a reservoir permeability of 50 mds., the stimulation factor is approximately two.

The increase in productivity falls off as the effective radius of the stimulated zone decreases, and it is a moot point as to whether these deep, geopressured reservoirs can be effectively stimulated to secure these desirable increases in production rates and cumulatives.

C. SUMMARY AND CONCLUSIONS OF SIMULATION STUDIES.

The work on numerical simulation of the performance of the described geopressured aquifers demonstrates the importance of several reservoir parameters on the ultimate productivity of the reservoir.

The critical gas saturation is of dominant importance in determining whether producing gas/water ratios will exceed the solution gas ratios of the original brine. If the critical gas saturation in these systems is of the same order of magnitude as believed prevailing in crude oil reservoirs, then it may be concluded that enhancement of the solution gas ratio will not be achieved under any conceivable operating practice.

The effect of the critical gas saturation in controlling the gas production may be qualitatively rationalized in the following way: If all the gas in solution at 34 SCF/B were released, the free gas saturation would only be of the order of 1.5%. Hence, a critical gas saturation above this value would not permit any gas production above the solution gas ratio.

Reservoir permeability has an effect on overall recovery; the effect is significant only at very low critical gas saturation values. The overall permeability of a reservoir is determined by the type of the formation and nature of sedimentation and subsequent burial history. The only factor that is subject to some engineering control is the creation of a zone of high permeability around the well bore by acidizing or fracturing. As shown by the results presented herein, only massive treatments will have any significant effect on the results and it is

moot whether such operations are technically or economically achievable.

Another controlling factor on the recovery efficiency is the withdrawal rate. At low values of the critical gas saturation, lower withdrawal rates result in higher recoveries. However, the resulting longer life of the project has a negative influence on its economic viability.

The assumed minimum bottom hole pressure of 6,000 psi. used in this study certainly has a limiting effect on the total recovery. However, preliminary calculations indicate that any attempt to increase the total withdrawal by artificial lifting techniques results in unfavorable economics.

The major problem which is encountered in attempting to produce methane from geopressured reservoirs is the low recovery at what is believed to be the economic abandonment pressure. Since it does not appear to be economically feasible to improve the recovery by pressure maintenance¹, only truly giant reservoirs appear to be capable of supporting economic production of methane from geopressured reservoirs.

IV. AN EVALUATION OF GEOPRESSURED GAS RESERVOIRS WITH NATURAL WATER INFLUX.

A. INTRODUCTION

There are a large number of geopressured gas reservoirs in the Gulf Coast regions of Louisiana and Texas. Earlier studies have indicated that such depletion reservoirs are relatively small¹⁰. However, should a particular geopressured gas reservoir be associated with an aquifer of any significant size, then it would be anticipated that the expanding water would result in marked influx into the gas column. In reservoirs where this occurred, a residual gas saturation would become trapped by the invading water. It was the purpose of this study to determine whether any evidence could be found for the existence of such trapped, residual gas saturations, and thus recommend the study of means for recovering such trapped gas by novel recovery methods.

In order to seek out the required information on such reservoirs, a search was undertaken of the MER files of the U.S. Geological Survey (OCS Office) in Metairie, Louisiana. It was hoped that the data therein might be complete enough, to allow the estimation of S_{gr} , the residual gas saturation, in such reservoirs, and that a correlation of certain reservoir parameters with production data could be developed for extrapolation to other reservoirs and fields.

B. METHOD FOR ESTIMATING RESIDUAL GAS SATURATION

If the original gas saturation, S_{gi} has been reliably estimated and is available, along with an estimate of the original gas in place (OGIP) and a complete pressure and production history, the following method can give a valid estimate of the present average gas saturation, S_{ga} . Further, S_{ga} will approach the value of the residual (to water influx) gas saturation as depletion proceeds.

1. A check of the pressure with the datum depth will indicate whether a gradient of 0.465 psi/ft is exceeded. If so, a geopressured reservoir is indicated.
2. A check of the ratio of pressure decline to the original pressure as a function of the recovery can indicate whether the reservoir is a volumetric one or is subject to water encroachment.
3. The product of one minus the recovery ratio times the original gas saturation will yield the proper value of S_{ga} for the producing reservoir.

C. RESULTS OF THE SEARCH

The study of the U.S.G.S.'s Metairie office's files provided 20 geopressure gas reservoirs which fitted our criterion for having an associated aquifer. The estimated original gas in place in these reservoirs ranged from 1.3 to almost 182 billion standard cubic feet. The estimated original gas saturations in these reservoirs were mostly in the range of 0.60 to 0.75 pore volume %.

The largest reservoir would therefore have a volume of slightly under 50,000 acre feet, and the smallest a volume of only 350 acre feet.*

In keeping with the small reservoir volumes, some 60% of these reservoirs were completed with only one producing well, and in no case were more than four producing and/or abandoned wells shown for any one of these reservoirs. The limited number of wells leads to difficulties in properly evaluating the boundaries and other characteristics of the reservoirs. One of the reporting companies even chose not to reassess their estimates when production proved to be far greater than the original estimate of gas in place, see Table 1.

It should be noted that all of the reservoirs in Table 3 are considered water drive reservoirs due to the geological data that was present in the files, although the overall reservoir size had been underestimated in each case. The possibility exists that for the reservoirs in Table 1 there are interconnected pays which were not revealed by the geological analysis based on the wells that had been drilled.

In order to evaluate any reservoir, the present shut-in well pressure, P_{ws} , is required to calculate the pressure decline ratio, P/P . However, in many instances this piece of data was excluded from the MER application, or was given for the last well test at a previous date so as to be without value for evaluating the current or abandoned conditions. In one case, Company F failed to provide current P_{ws} data for all six reservoirs in a particular field. Without this data it is not possible to determine whether a reservoir may or may not be producing under a water drive.

Where the data was available, it was possible to evaluate the reservoirs for possible drive mechanism based on pressure decline, production, and original gas in place estimates. In some cases, reservoirs that were said to be producing under a water drive appeared not to be so based on the analysis of the pressure decline as a function of the fractional recovery (based on the estimate of original gas in place). The lack of pressure maintenance would suggest that the associated aquifer was not effective in the reservoirs listed in Table 4.

Similarly, the presence of pressure maintenance in reservoirs said to be depletion reservoirs would tend to support the presence of an auxiliary drive mechanism such as a water drive. Some of these reservoirs are listed in Table 5. Incomplete geological data does not allow for an evaluation of an associated aquifer from the geologist's point of view.

As a result of the numerous omissions of necessary data for calculating the residual gas saturation, only a few such calculations could be made, see Table 6. There is no evidence of any uniformity in the calculated values of residual gas saturation, nor is there any apparent correlation with any of the other parameters for the subject reservoirs.

*Compare this range of volumes with the 4 million acre feet reservoir volume of the reference reservoir in the preceding section.

D. DISCUSSION

Most of the geopressured gas reservoirs found in the files of the U.S.G.S. are quite small, in keeping with the results of earlier studies. Therefore, the number of wells penetrating these accumulations are never greater than four, and in many cases comprise only one well. As a result the available data is usually inadequate to carry out the evaluation of the average current or residual gas saturation.

Some of the so-called "water drive" reservoirs do not appear to be so in view of the reported pressure decline accompanying the production of gas. Similarly, some designated "gas expansion" reservoirs appear to have an auxiliary drive mechanism, which may or may not be due to water encroachment.

In summary, the data available in the U.S.G.S. files is hopelessly inadequate to prepare an estimate of residual gas saturation in water driven, geopressured gas reservoirs. It would be necessary to seek the data present in the operator's files on the reservoirs in question for any serious attempt to determine the residual gas saturation. Even at that however, informal contacts with operator's engineering personnel suggest that even their data is frequently insufficient for the goal of this work.

The basic problem here is the fact that these reservoirs are indeed small, and, individually, contribute little to the overall reserve or profitability of the operator. These geopressured reservoirs are in production because they happened to be discovered and were not, for the most part, a purposeful target for the exploration program. Thus, there is little economic reward or other incentive for the operator to invest funds and engineering effort in determining and assembling a great deal of information on these reservoirs.

E. RECOMMENDATIONS

It is recommended that further study of water driven geopressured gas reservoirs by the D.O.E. be halted. The original amount of gas in these reservoirs is relatively small (from a national point of view), and the recovery of the residual, trapped gas does not present a resource that would have any national significance.

From a technical point of view, the problem of recovering the trapped gas, say by pressure depletion, or by the injection of low surface tension fluids is not likely to result in efficient production of the gas. Pressure depletion will be a lengthy operation, if at all feasible, for where the aquifer has been strong enough to encroach into the gas column it will be necessary to increase the withdrawal rate of the water to very high rates to draw down the reservoir pressure. The injection of low surface tension fluids to aid in the reduction of the trapped gas saturation will be a relatively expensive operation because of the high injection pressures that will be required to inject such fluids against the high reservoir pressure being maintained by the encroaching water. Further, the experience with chemical flooding for the recovery of crude oil does not permit one to be sanguine about the possibility of achieving sufficiently low surface tensions within a

reservoir to affect any significant reduction in trapped, non-wetting phase saturations. There may well be specific circumstances where the recovery of residual, trapped gas may represent a significant profitability target for a particular operator and the future may well see private development work undertaken to recover such resources.

V. EXPERIMENTAL DETERMINATION OF THE CRITICAL SATURATION OF METHANE IN HIGH PRESSURE SYSTEMS OF METHANE SATURATED BRINE.

A. METHODOLOGY

The method chosen for the experimental determination of the critical gas saturation of methane gas in high pressure systems of methane saturated brine is similar to that described by Handy¹¹ for the determination of the critical gas saturation in methane saturated crude oil systems.

A synopsis of the basic methodology is as follows: A porous medium of known volume is saturated with the saturated solution of the gas in brine at the saturation pressure. The pressure is then permitted to decrease at a controlled rate, and the fluid production - gas and brine separately - is measured for each step-wise decrease in pressure. With this data in hand, the free gas saturation in the pack can be calculated, and both a critical gas saturation and a relationship between the relative gas and relative liquid permeabilities can be calculated subsequent to reaching the critical gas saturation.

B. EXPERIMENTAL APPARATUS AND OPERATION.

A schematic drawing of the experimental apparatus is shown in Figure 20. The experimental apparatus is set up and run as follows: Bottled methane (Grade 2 - purified) is compressed by the gas booster pump that raises it to a working pressure of 10,000 psig. The methane is displaced by the gas booster into the high pressure autoclave that has been previously filled with a 2% brine solution. The volume of the autoclave is 1 liter. The autoclave unit is equipped with a "MagneDrive" dispersion unit that is capable of equilibrating the gas in solution in a relatively short time.

After the system has been equilibrated at the desired pressure, the solution of gas in brine is displaced from the autoclave (with additional volumes of high pressure methane supplied by the booster) into an accumulator. The latter has a working volume of 2.5 liters and is made of 316 stainless steel with 2 inch thick walls, 1 inch thick end-plates, and 3 inch thick back-up plates. The accumulator is equipped with a stainless steel piston with double O-Ring seals. Before the methane saturated brine is displaced into the accumulator, one side is filled and pressured up to the test pressure with the brine solution.

As the saturated brine is pumped into the accumulator, the unsaturated brine is pumped into the test core, which has previously been evacuated. The pressure in the core is brought up to the desired pressure, say 10,000 psi., by the use of a back pressure regulator that restricts the flow of effluent from the core. When the accumulator has been fully charged with methane saturated brine, approximately 3.5 pore volumes of unsaturated brine will have been flowed through the test core. At this point, the unsaturated brine will begin to be displaced by the saturated test brine.

The experimental core-holder assembly consists of the following: A Berea sandstone core, two inches in diameter and 70 inches long is

"epoxied" into a thin walled stainless steel tube that is in turn placed inside a high pressure cylinder. It is suspended on its ends by slip-in joints on the end-plates that are equipped with O-ring seals. The annular space is filled with a heat transfer fluid that serves the dual purpose of transmitting uniform heat from the outer cylinder wall, which is heated with heating tape, to the core itself, and of maintaining an overburden pressure on the inner system that can in itself be regulated by another back pressure regulator and appropriate pumping and fluid delivery system.

The effluent fluids from the core are run through a separator after passing through the back pressure regulator and a micro-metering valve. The separated gas is run through a wet-test meter and the brine is collected in appropriate receivers for measurement.

The core is initially evacuated for an extended length of time and then saturated with nitrogen. The pore volume of the system is determined using Boyle's Law, and then nitrogen is flowed through the core at different rates to determine the absolute permeability of the core. The core is evacuated again, saturated with carbon dioxide and evacuated a third time.

The 2% brine solution is then used to saturate the core. After saturation is achieved, the brine is flowed through the core in order to determine the specific permeability to the liquid. The core is then shut in and the rest of the system, including the accumulator and the autoclave, is evacuated and filled with brine.

The MagneDrive unit is then activated as methane is pumped into the autoclave through the booster. Each saturated charge is displaced into the accumulator and this process in turn pumps more brine through the core system. After the accumulator is fully charged with the gas saturated brine, the next charge will reverse the direction of the piston and start to displace the saturated brine into the core. The actual depletion experiment can now be initiated.

C. EXPERIMENTAL RESULTS

The results to date must be seriously qualified because of a series of mechanical failures that have developed while conducting experiments. It appears from the results obtained to date that the critical gas saturation in the system described above is in excess of 5%. However, because of the consistent failures encountered, there is question concerning the validity of the observations made to date.

The failures have arisen in the seals, and most recently in yielding of the end plates (see Figure 21). The 3 inch back-up plates (see description of experimental apparatus) were added to the accumulator, but failure of the seals continued to plague efforts to complete a sufficient number of duplicate runs.

The work had to be abandoned for lack of funds to pursue further design changes and reconstruction of the apparatus.

NOMENCLATURE

- A = Area of field
- B/D = Barrels per day
- Bg, Bw = Formation volume factor of gas and water, respectively
- BHP = Bottomhole pressure, psia
- Bscf = Billion standard cubic feet, 10^9 scf
- Ce = Effective compressibility, $C_e = C_f + S_w C_w$, psi^{-1}
- D = Depth of well from mid pay zone to surface, ft
- ft = Feet
- G_p = Produced gas, Mcf
- GWR = Gas-water ratio, Mcf/STB
- h = Net sand thickness, ft
- K = Single-phase permeability, md
- Krg, Krw = Relative permeabilities to gas and water, respectively
- Mcf = Thousand cubic feet
- P = Pressure, psia
- P_i = Initial pressure, psia
- P_{wh} = Wellhead pressure, psia
- q_w = Water production rate
- R_e = Drainage radius, ft
- R_p = Instantaneous producing gas-water ratio
- R_w = Wellbore radius, ft
- S = Salinity of salt, PPM
- S_g, S_w = Gas and water saturations, respectively
- S_{gi} = Initial gas saturation
- S_{ger} = Critical or maximum immobile gas saturation
- STB = Stock tank barrel
- T_r = Reservoir temperature, °F
- t = Time, years
- φ = Porosity
- μ_g, μ_w = Viscosity of gas and water, respectively, CP
- ρ_g, ρ_w = Density of gas and water, respectively, lb/Mcf, lb/ft³

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Table 1
PARAMETERS USED IN CALCULATIONS

A	40 mile ² = 25,600 acres
C _e	1.1 x 10 ⁻⁵ psi ⁻¹
D	13,000 ft
h	162 ft
P _i = P _b	11,000 psi
P _{wh}	500 psi
R _w	0.2 ft
S	30,000 PPM
S _{gi}	0.0
T _r	240°F
φ	0.18

Table 2
BASE CASE PARAMETERS

A	40 mile ² = 25,600 acres
C _e	1.1 x 10 ⁻⁵ psi ⁻¹
D	13,000 ft
h	162 ft
K	20 md.
P _i = P _b	11,000 psi
P _{wh}	500 psi
q _w	20,000 B/D
R _w	0.2 ft
S	30,000 PPM
S _{gi}	0.0
S _{gcr}	5%
T _r	240°F
φ	0.18

Table 3 - Reservoirs with Erroneous OGIP Estimates

Reservoir	Company	$\Delta P/P$	Recovery Ratio	OGIP Est. Billion SCF
D-1	E	.20	3.5	4.80
D-2	E	.12	2.4	13.20
D-3	E	.05	.92	8.73
B-3	B	.24	1.00	42.05

Table 4 - Non-Supported Designated Water Drive Reservoirs

Reservoir	Comp.	P_i	P_{ws}	$\Delta P/P$	Recov.	OGIP Billion SCF	Grad	Depth Feet
F-2	D	8770	2720	.69	.46	181.9	.69	13100
F-3	D	8303	6153	.26	.17	24.90	.68	12138
G-1	G	7850	3570	.55	.44	42.1	.64	12270
G-2	G	6520	2500	.62	.57	3.44	.62	10474
H-2	B	7290	2217	.70	.75	1.28	.55	13277
H-4	B	5465	4469	.18	.19	13.36	.48	11416
H-9	B	6271	4807	.23	.25	81.59	.51	12404

Table 5 - Designated Gas Expansion Drive Reservoirs with Possible
Auxiliary (Water) Drive

Reservoir	Comp.	P_i	P_{ws}	$\Delta P/P$	Recov.	OGIP Billion SCF	Grad	Depth Feet
D-4	E	8763	6211	.29	.67	46.20	.66	13250
D-5	E	8763	5495	.37	.41	80.60	.67	13164
D-6	E	8753	5334	.39	.56	90.00	.68	12837
D-7	E	8678	6366	.27	.93	16.01	.61	14150

Fig. 1 - Methane solubility in water.

Fig. 2 - Effect of temperature and pressure on B_w .

Fig. 3 - Effect of gas solubility on B_g .

Fig. 4 - Variation of brine viscosity with pressure.

Fig. 5 - Representation of the numerical grid system.

Fig. 6 - Gas-water relative permeability data.

Fig. 7 - Predicted performance of the base case.

Fig. 9 - Effect of S_{gcr} on cumulative gas recovery (base case).

Fig. 10 - Effect of S_{gcr} on cumulative gas recovery as a function of permeability.

Fig. 11 - Effect of reservoir permeability on cumulative gas recovery at $S_{gr} = 0.1$.

Fig. 12 - Effect of production rate on cumulative gas recovery as a function of reservoir permeability.

Fig. 13 - Effect of S_{gcr} on cumulative gas recovery as a function of production rate.

Fig. 14 - Effect of production rate of cumulative gas recovery ($S_{gcr} = 0.5\%$, $K = 20 \text{ md}$).

Fig. 15 - Effect of production rate on cumulative gas recovery as a function of S_{gcr} .

Fig. 16 - Effect of permeability on cumulative gas recovery as a function of S_{gcr} .

Fig. 17- Average reservoir pressure as a function of fractional recovery.

Fig. 18 - Effect of reservoir permeability on cumulative gas recovery as a function of production rate.

Fig. 19 - Effect of S_{gfr} on cumulative gas recovery as affected by the high permeability zone.

Fig. 20 - Schematic of Apparatus

Fig. 21--Photograph showing deformation of end plate