

"DOES MISCIBILITY MATTER IN GAS INJECTION?"

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ABSTRACT

Over the years gas injection design has undergone an evolution in the types of laboratory tests used to design a gas injection project as well as the interpretation of the experimental testing. In the recent past, there has been much written in the area of immiscible and near-miscible gas flooding. Often, some of these applications appear to be very effective and somewhat less expensive than the so-called "miscible" floods.

In this paper the authors discuss some of the considerations which are germane to gas injection and provide evidence that suggests that many of the previously accepted laboratory techniques were not really providing what they were intended to. It is important that one understands the significance of these considerations when designing a gas injection project.

The authors indicate that specific testing can be made to gain insight into the most important features of a gas injection project which concerns the interaction between the level of interfacial tension and the mobility effects. By appropriately quantifying whether a reservoir is going to be

.IFT or mobility-dominated, the operator can concentrate on designing a gas to optimize the factor which is dominant. It is important to know what that dominant factor is so that gas injection processes are the best that they can be. In answer to the question asked in the title of this paper, the authors suggest that most gas injection projects would involve a gas which exhibits properties in the so-called "near-miscible" range. Techniques for determining how miscible one needs to be are provided in this paper.

INTRODUCTION

With the vicissitudes in the oil industry, many times enhanced oil recovery schemes are reviewed with an optimistic or pessimistic attitude. It commonly seems that there is no middle ground. The thought of high initial costs associated with enhanced oil recovery schemes sometimes dissuades some operators from considering what may be their only hope. Whereas, at other times, larger corporations, because of the "charisma" associated with high technology implementation, have spent money needlessly on EOR schemes which from the beginning were not suited to their application.

Take, for example, the winter of 1994-95. Gas prices were low and therefore the production of energy from reservoirs was of much greater value when obtained as a liquid phase rather than as a gas. At times like this, it would be synergistic to have a reservoir where one knows that gas injection would be beneficial and thus have an idea of what is the optimal gas design. Indeed, many companies considered shutting in their gas production and some did reduce gas production due to gas prices. Some of the gas could be used for injection into reservoirs which were declining in productivity. It is important that the research needed to identify good gas injection candidates must be synchronized so that when an opportunity arises, one can apply the principle of serendipity and make these market conditions work for you.

No matter what the history of gas injection has been, which is viewed with different conclusions depending upon to whom you speak, the question still remains of what is the best way to optimize cash flow from a given reservoir. Many of these reservoirs have been under primary and secondary production for a number of years and are in declining stages. At this point, one needs to determine whether any other scheme will be viable or not. It is the contention of the authors that there can be considerable benefit to gas injection into reservoirs which have been classified as lesser contributors to the producing companies bottom line and, that by implementing the appropriate schemes, many of these reservoirs can show a positive return on investment.

In this paper appropriate questions, when evaluating a gas injection design, are discussed along with a commentary on the tools which are presently used to perform the selection. This paper might respond to some of the questions which the reader has had over the years regarding which reservoirs will benefit from gas injection and what type of data is most meaningful in choosing where to apply this technology.

Conventional wisdom as well as some recent developments will be juxtaposed and therefore very little time will be spent detailing the background of gas injection processes. For those who would like to review some of the early developments in the area of miscible gas injection, they are referred to references 1 through 7. An excellent overall summary of low IFT gas injection is provided by Fred Stalkup⁽⁹⁾.

Over the years the authors have met with many groups, domestically and internationally and many of the same questions are asked. Some of these questions will now be addressed and evidence provided in order to clarify the responses provided.

1. For a reservoir which has been waterflooded what are the benefits of gas injection and why does gas injection increase recovery?

Waterflooding is often used as an enhanced oil recovery medium because it is ubiquitous and therefore relatively inexpensive. The inherent flow properties of water are also amenable to pumping operations and the response is normally fairly predictable. Water, however, does have some limitations in enhanced oil recovery processes:

- a) The interfacial tension with typical reservoir crude oils (10 to 20 dyne/cm).
- b) Low viscosity compared to some crude oils.

The reader will note that water design criteria have been purposefully omitted from this discussion wherein for example certain water properties must be evaluated in order to eliminate serious formation damage aspects etc. References 9 through 11 provide a summary of some of the considerations when doing a waterflood but details are beyond the scope of this paper.

The benefit of gas injection is mainly due to the fact that it exhibits a better interfacial tension response than water. There can be major limitations to the injection of gas, which are commonly associated with availability, capital cost and compressor operating costs. Nevertheless, the interfacial tension benefit can often outweigh the extra expense.

$$P_{cap} \propto \frac{IFT}{\text{Pore Throat Radius}} \quad (1)$$

Equation 1 describes the well-accepted end result of the LaPlace equation wherein the capillary pressure is proportional to the interfacial tension and inversely proportional to pore throat radii. Therefore, if at a given injection rate or imposed differential pressure, one is operating at a certain IFT, then, as the IFT is reduced, for that same imposed pressure differential, smaller pore throat radii will be accessed by the injection fluid. The benefit of gas injection can be readily concluded from Equation 1 whereby, if one has a lower IFT using gas than using water, then smaller pore throats will be accessed.

This would indicate that, as long as the gas-oil IFT is lower than the water-oil IFT, gas injection, no matter how immiscible, would be of benefit. This would be a natural conclusion with the only condition being that the spreading co-efficient be positive. The spreading co-efficient is defined as Equation 2.

$$S = \sigma_{G|W} - \sigma_{G|O} - \sigma_{W|O} \quad (2)$$

The best way to think about the spreading co-efficient is as quoted by Oren et al⁽¹²⁾ wherein it is mentioned that, as long as the spreading co-efficient is positive, it will not be possible for the gas and water to establish an interface, but that continuous oil films will exist between the gas and water. This would imply that upon injecting gas, wherein a positive spreading co-efficient is operating, mobilized oil will result and will not simply go to producing water.

This would seem "too good to be true" and that gas would always be better than water. This brings us to the major limitation of gas injection which is associated with an even more adverse mobility ratio than the water. Due to the fact that typical gas viscosities are in the range of 10⁻² cP and that oil viscosities are normally in the range of 1 to 10 cP, one will often see a viscosity ratio of 100 - 1000. The viscosity ratio with water is better. Therefore, one can see how the most important question to answer is how the benefit of reduced IFT using gas interacts with the very adverse viscosity ratio. This question is at the heart of the type of laboratory testing which must be done in order to evaluate the compromise reached between the two effects. Unless that question is answered gas injection remains a risky business.

2. **It seems that one of the criteria which has "always" been used in the design of a gas injection process is a displacement experiment such as a slim tube. What is the validity of using that technique for gas injection design?**

The slim tube has been accepted as a common tool for many years to design the pressure or the composition for gas injection. Whether this convention is truly justified or not has never been very well quantified. Randall and Bennion in 1989 addressed some of these concerns with regards to the slim tube and Thomas et al in 1994 also compared the slim tube with other techniques. Moreover, References 13 through 24 provide other factors which should be considered in the design of gas injection processes. Nevertheless, despite increasing knowledge, the question is often asked about why the slim tube may not be as trustworthy as it was once thought to be.

The best way to respond to that inquiry is to provide some evidence obtained from recent experimental work. Figure 1 suggests the normal recovery vs pressure relationship which one might observe for any typical well-behaved slim tube system. This simply states that, as the pressure is

increased, the recovery increased fairly drastically until one reaches a certain discontinuity at which one encounters the law of diminishing returns. That is, for high pressures much above the discontinuity, there is very little incremental advantage from a recovery perspective. This discontinuity in the past has been accepted as the "MMP". This is at the heart of why slim tubes may not provide a true picture of even phase behavior aspects of gas design.

Figure 2 defines, from a hypothetical standpoint, the slim tube pore size compared to an assumed reservoir rock character. One can see that using Equation 1 at a specified imposed differential pressure, the IFT developed at the discontinuity in Figure 1 may correspond to a pore throat diameter of 15 microns. At 15 microns an arrow is drawn showing that it corresponds to a certain characteristic interfacial tension. Therefore, in that porous media, the IFT asterisk results in a response somewhat similar to Figure 1. As one increases the pressure and the IFT gets lower, there is very little extra pore volume to access and, therefore, very little incremental recovery. This can be seen in Figure 1. If the true pore throat size distribution is as represented in the lower portion of Figure 2, then the IFT asterisk for that same imposed flow rate or differential pressure may correspond to the 15 microns, but it will be in a completely different portion of the pore size distribution than was observed for the slim tube.

Even more specifically, Figure 3 shows the relationship between the pore size distribution of two artificial sand packs. One corresponded to a 200 mesh crushed quartz slim tube whereas the other corresponded to a 325 mesh crushed quartz slim tube. One can see that the pore size distribution is very narrow with approximately 70% of the overall pore sizes being at a 50-75 micron and 75-100 micron diameter for the 325 and 200 mesh sands respectively. Thus, if the logic suggested to this point would apply, one would expect to see a different recovery response on these two systems.

Figure 4 shows the difference between the two responses. Specifically, the 200 mesh sand results in a discontinuity at approximately 31 mole percent LPG enrichment, whereas the 325 mesh sand results in a discontinuity at 47 mole percent LPG enrichment. Thus, even for artificial sand packs, one would see a distinct difference between the two conclusions as to what is an acceptable level of enrichment.

This technology is not new. Mungan 1991⁽¹⁹⁾ concluded that, when he performed a series of recovery vs pressure determinations using slim tubes and actual reservoir rock,

the reservoir rock resulted in an apparent MMP 12.5% higher than the slim tube that he used at that time.

It is the opinion of the authors that this difference between different pore size distributions, included in the slim tube testing which was done in designing field gas injection processes, may differentiate between those floods which have been successful and those which have been found somewhat lacking. Remember, this is only from an IFT perspective and has not, as yet, included the commentary of how the IFT couples to mobility. The interfacial tension must be viewed as a necessary criterion to meet. A clearer portrayal of what should be done in evaluating a gas injection process is to include the IFT vs LPG relationship as seen in Figure 4. By including this IFT vs LPG or IFT vs pressure relationship on different plots, one is able to connect the displacement to at least some absolute criterion. Then, by "judicious" comparison of the pore size distribution of the reservoir to the pore size distribution tested in the lab, one will have a better ability to design a gas for acceptable limits. One can see from the combination of Figures 3 and 5 that, if the recovery was to be linear with IFT change, one would expect to have to get to a level of IFT in the 325 mesh sand pack, approximately 33 - 40% lower than the IFT encountered in the 200 mesh sand pack. On this basis, when the 0.98 dyne/cm IFT was measured at 31 mole % LPG (after a series of reverse contacts resulting in the development of an asymptotic vapor/liquid equilibrium exhibiting 0.98 dyne/cm at reservoir pressure of 26,200 kPa), then for the 325 mesh sand pack, one would expect that a 0.58 dyne/cm IFT would be adequate. In fact, the IFT measured experimentally was 0.21 dyne/cm. The experimental IFT measurements are shown in Figures 6 and 7.

The fact that the IFT corresponding to the discontinuity on the 325 mesh sand pack was much lower than the 0.58 expected could be due to two reasons. The first is that the imaging technique used to identify the pore throat size distribution may be somewhat inaccurate. Petrographic image analysis was used which is a statistical technique derived from the size of the particles. If the actual pore throat sizes were much smaller than the 50 - 75 microns then this would correlate better to the 0.21 dyne/cm IFT required. Indeed, if one reviews the permeability between the two tubes the permeability was lower in the tighter mesh sand pack by a factor of 4. Therefore, rather than having an 8 Darcy permeability, the permeability was on the order of 2 Darcies. This would fit much better with the ratio of IFT.

Another reason would be that for the second tube there may be mobility effects beginning to cause the deviation from a simple IFT ratio/recovery response but such is not thought to be the case.

The fact that this permeability data adhered approximately to the IFT ratio suggests that the response of a slim tube is dominated by IFT effects and, that there is very little influence of viscosity ratio in the slim tube. This is somewhat expected when viewing the rather peaked nature of the pore size distribution.

Things become a little more challenging and non-linear when viscosity ratio effects begin to enter into the fray and cause deviation from this IFT recovery ratio equation. Nevertheless, having this information for a fairly narrow pore size distribution is one way to gain a level of comfort and to be able to extrapolate slim tube data to the real world.

3. There are concerns about a reservoir being mobility vs IFT dominated. What is the best way to make the appropriate conclusion and then to design the optimal gas injection scheme?

That is a difficult question to answer for it contains the requirement that fluid flow must be connected to the phase behavior observed in the system. It is known that fluid flow in the reservoir may be different from fluid flow measured in the laboratory, due to such things as heterogeneities which are difficult to incorporate in lab scale testing, as well as the inherent viscosity instabilities, possibly being scale-dependent, which makes the inclusion of all of these parameters difficult in a laboratory simulation.

These difficulties notwithstanding, significant advances have been made both in laboratory techniques as well as the approach taken by researchers in structuring the laboratory work itself. Take the example shown in Figure 8, wherein the reservoir is characterized by a number of different layers which can be associated with different flow characteristics. These layers are then called flow units. When designing a system for gas injection, will the gas, which has been identified in the previous sections of this paper by slim tube testing and interfacial tension measurements, flow well in these different flow units? Figure 9 shows the slim tube results and the appropriate level of displacement efficiency that was achieved. The IFT's were then measured along with the phase loop and the IFT's were in the range of 1.0 to 2.0 dyne/cm which resulted in the response seen in Figure 10.

In this constant IFT relative permeability testing, one holds the interfacial tensions constant with a constant viscosity ratio and examines the oil response at these conditions. In performing these experiments, because these parameters are held constant, one can see the influence of interfacial tension and viscosity ratio. For displacements where these are not held constant, these are changing throughout the displacement, and one has difficulty knowing if the differences in recovery are due to viscosity effects, solubility, dynamic IFT changes as well as mixing zone and end effects. By doing these at constant conditions, one can then evaluate whether the benefit of interfacial tension is dominant or whether viscosity ratios appear to be the dominant theme.

This is a very important question to answer because, if there is evidence that the viscosity ratio on a microscale is dominating, then one may not want to pay the price in terms of reducing IFT only to find out that the viscosity ratio is the limiting factor. Conversely, if one finds that the interfacial tension is dominant with very little influence from the viscosity ratio, as in most slim tube studies, then one will be able to concentrate on finding the most efficient agent to reduce IFT, not considering what it may do to the viscosity ratio. This is a common controversy when comparing ethane- vs propane-based hydrocarbon gas injection particularly in Canada. The evidence tends to suggest that ethane-based systems, although satisfying an IFT constraint, may tend to be somewhat viscosity dominated. This dominance will also change from flow unit to flow unit. The conclusion as to which parameter dominates on the microscale is based on how much incremental oil recovery there is between the high and low IFT condition in the constant IFT relative permeability testing. If the oil recovery change is large upon IFT reduction, then the system is not mobility-dominated at the microscale.

4. How does one compare nitrogen, methane and even ethane-or propane-based gases for solvent injection? Is it always true that the propane based solvent is better than the ethane based solvent?

Over the past 20 years, a number of EOR projects have been evaluated using a hydrocarbon gas as an injection fluid. Many times these designs have used the conventional slim tube methodology to identify a correlation, such as shown in Figure 11, where one sees plotted the C_2^+ percentage vs the C_2^+ molecular weight. For systems such as these, this correlation is extremely important since ethane may be readily available but propane may not. Since propane is more expensive and may be harder to find, one needs to know what are the

relative benefits of an ethane-enriched vs a propane-enriched injection gas.

Using standard slim tube criteria, where the slim tube response is dominated more by IFT effects than viscosity ratio, the nature of this correlation may only provide a comparison of IFT values. Indeed, through performing a series of multi-contacts and measuring high pressure interfacial tensions at many of these conditions, one is able to establish the fact that it is an IFT-based correlation. Therefore, the question must be asked in terms of - does the ethane-based solvent, although developing the same IFT level as the propane-based solvent which, by the way, can be quantitatively measured and determined, result in an equally effective displacement as the heavier solvent? In order to answer that question, one needs to determine what is the compromise reached between IFT and mobility on a microscale. In this manner, the constant interfacial tension relative permeability testing can be used as a means of comparing the different responses. Figure 11 showed that type of comparison where the high IFT limit and low IFT limit has been evaluated. In this case, one can see that for the ethane-based system there is a distinct difference between the high IFT and low IFT limit and, therefore, even with the adverse viscosity ratio, significant recovery is achieved. The same thing can then be done using a propane rich system and, if there is little deviation from these curves for the same level of IFT, one can conclude that the microscale displacement is IFT-dominated displacement. Therefore, the conclusion drawn is that the ethane based system will perform equally as well as the propane based system on a microscale and that there will not be any deleterious effects from including the ethane.

One could argue that if the core used in the laboratory is not representative of that in the field then this conclusion may be fallacious. One needs to make certain that, if there are different flow units in the reservoir, which may evoke a different response, that these flow units are scoped at least from the perspective of choosing that which would have the greatest propensity to result in a mobility-dominated system and that type of core which would result in an IFT-dominated core (that is, for mobility-dominated, the pore size distribution is the broadest and for the IFT-dominated system, a very narrow pore size distribution with most the pore throats being smaller). This could answer whether, on a microscale, there is going to be a different response and, if so, these relative permeability curves would take that into account in the simulator.

The one aspect, however, which is not addressed by any of this testing is whether the gravity override effects would be

significant. One can see that a propane-based solvent may indeed have higher density than the ethane-based system, but, if so, one can correct for gravity override simply by increasing the pressure to the point at which the density of the ethane-based solvent equals the density of the propane-based solvent. The only other aspect which would need to be scoped is whether the solubility of the ethane-based is the same as the solubility of the propane-based gas.

To adequately identify the solubility characteristics, one must perform not only the pressure composition diagram experiment but also a multi-contact pressure composition diagram⁽¹⁴⁾ to determine the solubility limit of the multi-contacted upper phase. This multi-contacted upper phase is one which is produced at reservoir pressure but, due to compositional changes, may extract some of the heavier components from the oil into the upper phase. This changes the dynamics of the solubility and swelling of the gas/oil interaction and therefore this would be the only way to judge this phenomena.

5. Does miscibility matter in gas injection?

In answer to that question, one needs to closely define certain elements of that question and use the material presented in this paper. The answer will now be given as a point-by-point summary.

- a) Miscibility, defined as the development of a zero interfacial tension system, does not need to occur in order to have the optimal gas injection scheme. This is due to the fact that, if a system is strongly water-wet and the water adheres more closely to the smaller pore throats, then you do not need or want to enter into the smallest pore throats to recover all of the oil. Therefore, by definition, miscibility is not required in that scenario. For oil-wet systems or where a substantial amount of oil is associated with the smallest pore throats, one will need to approach zero IFT in order to make all of the pore throats accessible to the injection phase. Even for that system, however, one should only be prepared to produce a truly miscible system if it has been shown that the displacement is not going to be viscosity-dominated.
- b) By viscosity-dominated, it is intended that the viscous instabilities are more important than the IFT effect. Otherwise stated, the IFT may be viewed as a necessary condition, but the ability to produce oil effectively from the pore structure is very much a compromise between the IFT and viscosity ratio effects. If a system is viscosity-dominated, the

conclusion may be that the injection gas may be less important from an IFT perspective and, therefore, a broader cross-section of gases may be as applicable as the more expensive one being designed. This means that by identifying which is dominant one can prevent spending money needlessly on a gas flood which would respond the same whether it is methane-based or propane-based.

- c) The most important thing to be gained from this analysis is not necessarily which will be without question the best gas for a specific reservoir unless one is prepared to invest considerable research dollars. However, it is a very effective way to rank reservoirs according to compatibility with one available injection gas stream and the potential of each reservoir to this gas. In other words, why inject gas into one reservoir if another would show more productivity improvement for the same investment.
- d) Often, the interfacial tension effect is the only one which has been determined during the laboratory investigation. This is good reason why many gas injection processes have performed less adequately than others.

CONCLUSIONS

It does not matter whether one is miscible or not as long as one has identified what level of interfacial tension must be reached, what is the compromise reached between interfacial tension and mobility and a safety factor to address issues such as gravity override, solubility and swelling effects is taken into account. By appropriately addressing these parameters one is then prepared to make the best out of each dollar invested in gas injection and to make the best choice of where the dollar should be spent when it concerns the reservoir that most seriously needs enhanced oil recovery.

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FIGURE 1
CONVENTIONAL MMP PLOT

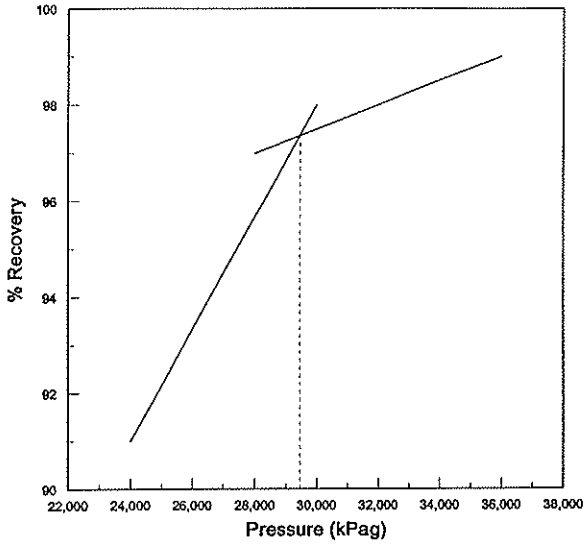


FIGURE 2

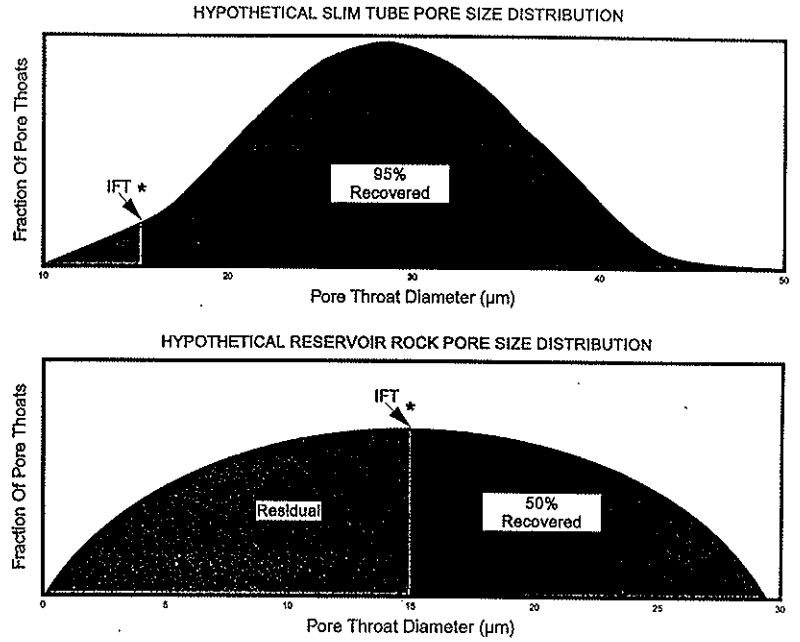


FIGURE 3
PORE TYPE ABUNDANCE BY DIAMETER
(Relative Frequency)

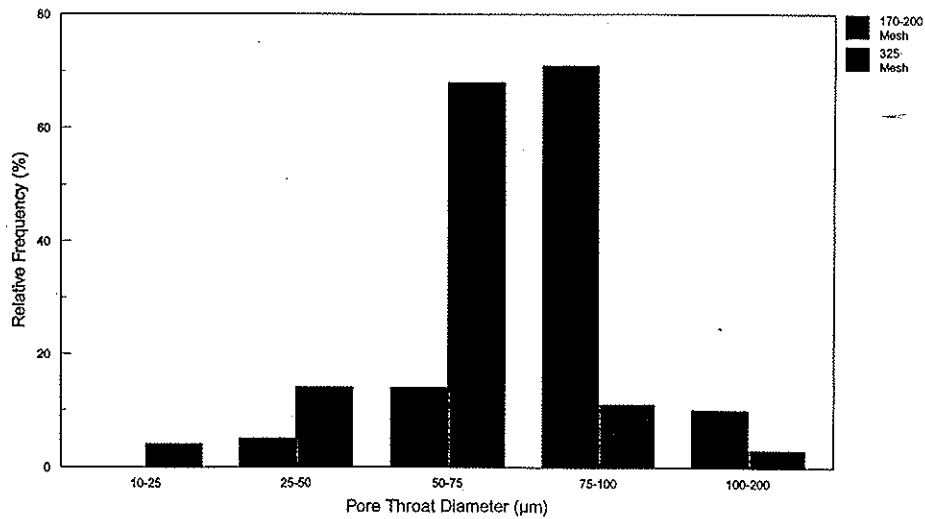


FIGURE 4
STANDARD RECOVERY vs ENRICHMENT RELATIONSHIP

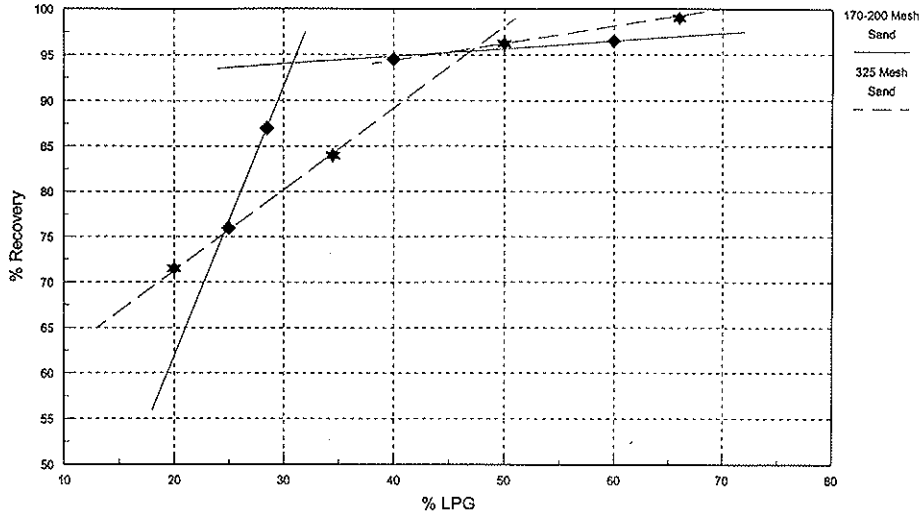


FIGURE 5
STANDARD RECOVERY vs ENRICHMENT RELATIONSHIP
IFT vs ENRICHMENT

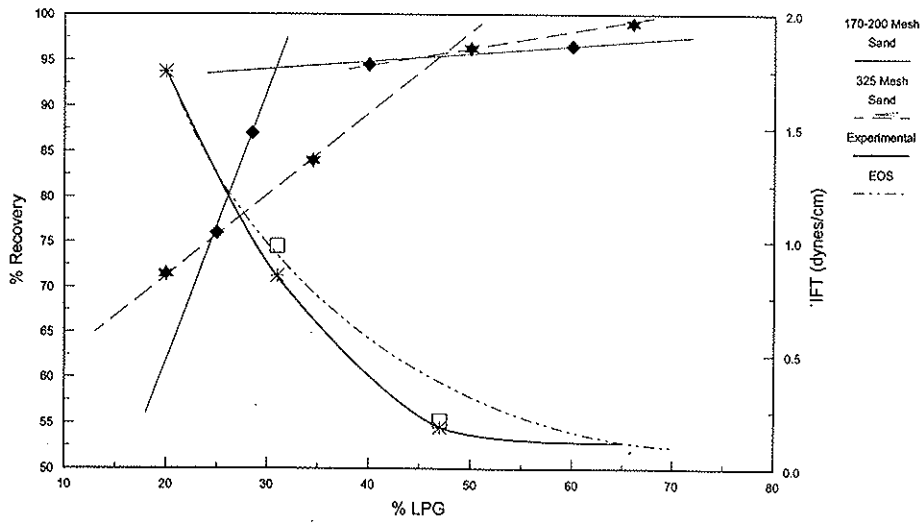
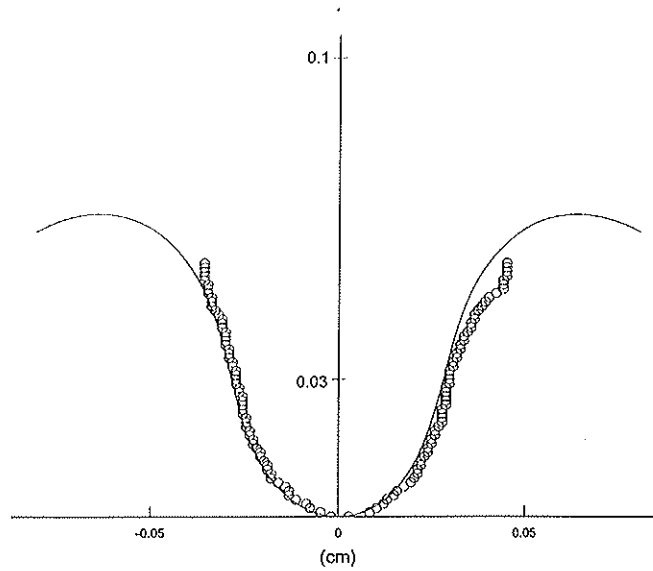
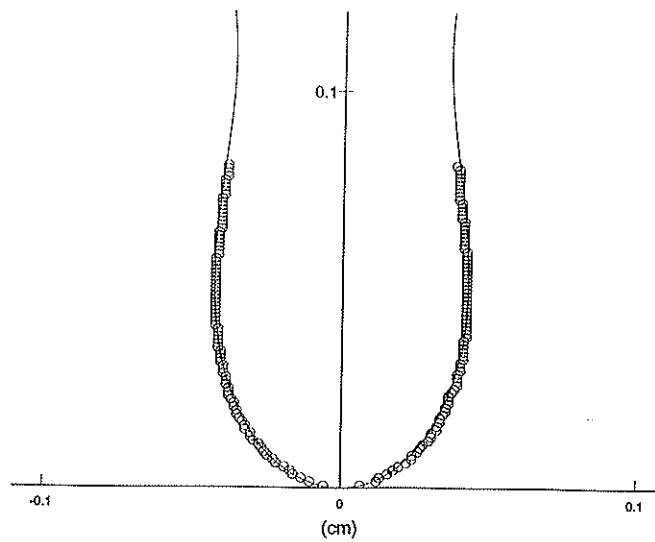


FIGURE 6
47% LPG
ASYMPTOTIC IFT @ 96°C & 26200 kPa



Simulation of IFT (dynes/cm): 0.208
Total Error: 3.6715e-04
Density Difference (kg/m³) = 228

FIGURE 7
31% LPG
ASYMPTOTIC IFT @ 96°C & 26200 kPa



Simulation of IFT (dynes/cm): 0.980
Total Error: 1.1133e-00
Density Difference (kg/m³) = 336

FIGURE 8
CROSS-SECTION SHOWING ROCK TYPE DISTRIBUTION

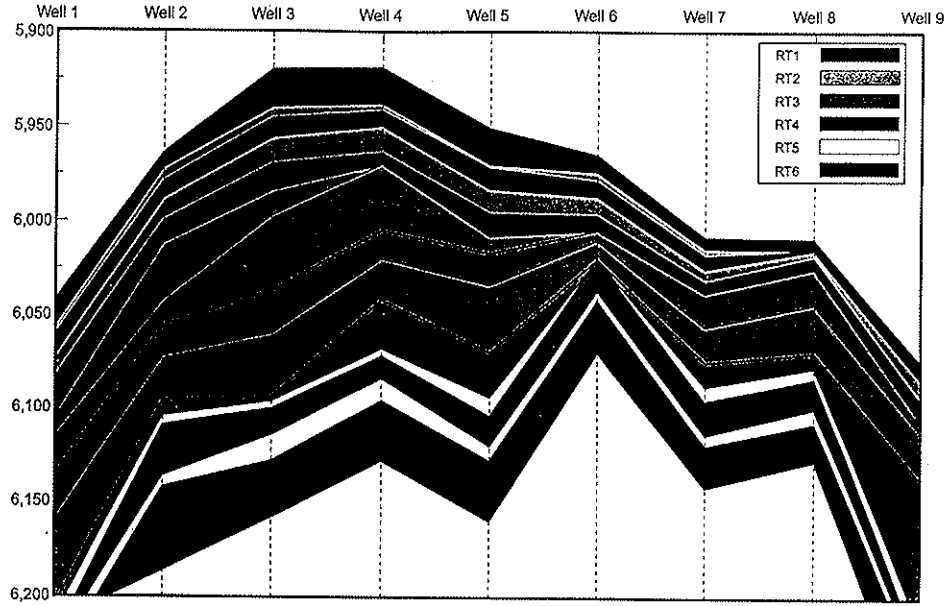


FIGURE 9

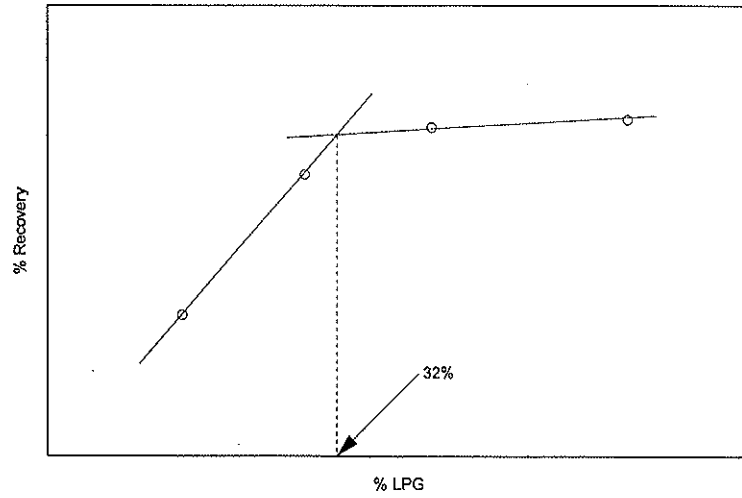


FIGURE 10
 RELATIVE PERMEABILITY - RT2
 RELATIVE PERMEABILITY vs INJECTION GAS SATURATION

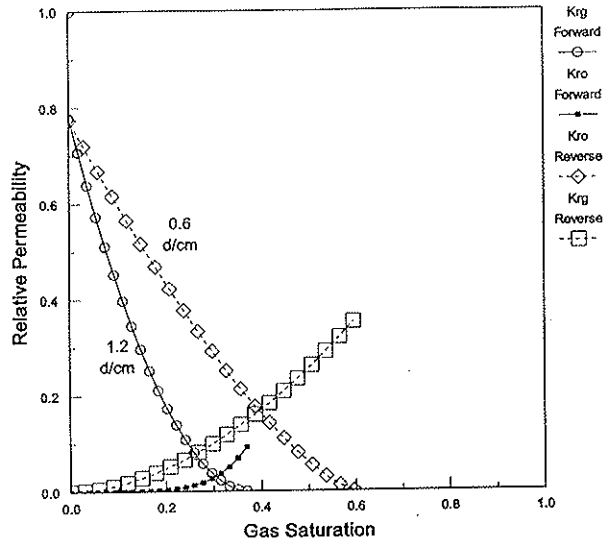


FIGURE 11
 ENRICHMENT CORRELATION

