TOWARDS OPTIMIZING GAS CONDENSATE RESERVOIRS

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ABSTRACT

In the last year the authors have fielded many questions from companies, both international and domestic, concerning gas condensate reservoirs. It appears that gas condensates are becoming more important throughout the world. Many international petroleum societies are beginning to have conferences specifically oriented to gas condensate reservoirs and discussing all parameters germane to such systems. In light of this increased interest, the authors have made a short list of questions which are most often asked. Indeed, these questions point to two specific areas which govern the production and future exploitation plans for gas condensate systems. These two areas are characterization and retrograde condensate influences on relative permeability.

It has been found that the characterization of the gas condensate fluids can be strongly influenced by two main factors:

1. Any degree of contamination by a free liquid phase in-situ;
2. Hold-up of the retrograde condensate in the formation resulting in excessive producing GOR's.

Care must be taken when sampling gas condensate wells in order to produce representative recombined fluids. In order to gain an appropriate evaluation of the gas condensate reservoir one must be able to adequately characterize the fluids in-situ. Experimental and theoretical work performed on evaluating retrograde condensate effects has pointed to the fact that the influence of retrograde condensate is much more deleterious in tighter formations and higher interfacial fluids. The ability to identify the influence of retrograde liquid on gas phase production rates is a difficult task and data are provided herein which compare the retrograde condensate effects at two levels of interfacial tension and as a function of rock permeability.

It has been found that in a review of four gas condensate reservoirs, one of which included a fractured system, there was a coupling of a multiplicity of factors including:

1. Interfacial tension effects
2. Viscosity ratio
3. The healing of fractures with its concomitant effect on absolute permeability

In order to adequately forecast such systems, a simulator must incorporate these effects.

SAMPLING CONDENSATE RESERVOIRS

Condensate reservoirs are inherently more difficult to characterize correctly. The literature shows many differences between gas condensate reservoirs and dry gas reservoirs\(^{14}\). One question often asked is during and after sampling. Figure 1 provides a fairly typical GOR versus total flow rate response from a gas condensate reservoir. One sees that, at very low flow rates, one has a high producing GOR and, beyond the certain minimum value in GOR, the trend is again upwards. It is easy to identify why this occurs, but sometimes, when faced with the possibility of having extra sampling runs and spending more time in the field, the generation of a plot such as Figure 1 is not easy.

In the same plot one compares the response which would normally be seen for an oil reservoir. With the oil reservoir, the sampling technique is fairly easy to specify. All one must do is try to produce the well in the domain low enough so that a constant GOR is produced. Since the behaviour is asymptotic as a function of decreasing total flow rate from the well, it is easy to identify what production level one needs to apply for taking the gas and liquid samples. Such is not the case with gas condensate reservoirs however. At low flow rates, as shown in Figure 1, one may be producing enough liquid in the wellbore that, unless the flow rate is high enough, the liquid hold-up will increase and slugging may result. In such a case, the GOR, depending upon at which interval the sample is taken, may fluctuate and result in an excessively high GOR. The increased GOR to the left of the vertical line is due to the low flow rate not providing enough lift to transport the liquids in the wellbore.

By contrast, one may be inducing liquid dropout in the reservoir at high flow rates to the right of the vertical line in Figure 1. In such a case, as the pressure drops below the
dewpoint, the liquid will drop out and begin to collect in the near wellbore region. In so doing, produced hydrocarbons will contain less liquid than they should and therefore the GOR will be high. Thus, when one asks the question, "At what producing rate should a well be sampled?", the only way that one can adequately respond is if one already knows the character of the fluid and the dynamics of the production well. Since this information is not available, sampling gas condensate reservoirs in an optimal manner can sometimes be non-linear and include some trial and error.

How does it influence the overall characterization if one is producing in other than the optimal zone of the production scenario? Figure 2 shows a typical response obtained when recombining separator gas and liquid from a gas condensate well. In this case, the asterisk corresponds to the separator GOR which was observed in the field during the sampling. As is often the case, the relationship in Figure 1 was not scopes during sampling, and therefore Figure 2 may correspond to producing the well in the region to the right of the vertical line in Figure 1. Figure 2 indicates that the saturation pressure is higher than the reservoir pressure and therefore something is wrong. For systems like this where the deviation between the observed saturation pressure of the recombin and the reservoir pressure is less than or equal to 1000 psi, one can normally trust that a manipulation of the GOR will result in satisfying the necessary condition for the recombin. The necessary condition is that the saturation pressure of the recombin sample must be equal to or less than the reservoir pressure at reservoir temperature. By decreasing the GOR by adding additional separator liquid, one will suppress the dewpoint down to a level which meets the reservoir pressure criteria. Should the real dewpoint pressure be lower than the reservoir pressure, one really has no way of knowing that unless the owner was prepared to return to the field and measure the GOR dependency on the flow rate of the system. One may also observe situations where, by increasing the GOR slightly, the saturation pressure may converge quickly to the reservoir pressure. This is an option but, in light of the fact that the gas phase is more mobile than the liquid phase, this is usually not the procedure which is followed.

Nevertheless, with the response as in Figure 2, the modified GOR results in a saturation pressure equal to the reservoir pressure and the recombin fluid properties can then be measured including such things as overall composition, constant composition expansion data as well as constant volume depletion properties.

Figure 2 provides the best case scenario in terms of the credence which can lend to the resulting recombin. The modified GOR fluid still possesses all of the characteristics which are consistent with expectation with a slight modification for GOR which in and of itself is also logical in terms of the higher gas mobility as mentioned earlier. A more difficult case would be that shown in Figure 3 where there is a substantial deviation between the saturation pressure at the separator GOR and the reservoir pressure. In the experience of the authors, often when the saturation pressure of the system shows a positive deviation from the reservoir pressure of more than 1500 psi, it is usually due to the fact that something has occurred in the liquid phase. Work has been performed by the authors in the past, wherein a very slight change in the heavy end character of a gas condensate system can result in significant changes in the saturation pressure. This again is much different than for a conventional oil system. For example, if one has a slight mixing of two different oil zones in the reservoir, the influence of the two may be fairly insignificant on the saturation pressure properties. This is due to the fact that the oil is already a bubblepoint system and, therefore the contaminants which also have a tendency to remain in the liquid phase may modify the bubblepoint behaviour, but the components themselves are both consistent with a bubblepoint response. On the other hand, if one were to have a contamination due to a free oil phase in-situ, which exhibits a bubblepoint response, then the dewpoint behaviour of the dominant gas condensate phase can be radically different. This is consistent since one must increase the pressure of the system to a high enough level in order to change the behaviour of the contaminant components from a natural bubblepoint response to a dewpoint response. This is tantamount to having to vaporize all of the heavier components and in order to do so a significant deviation in pressure from the reservoir pressure is often encountered. This can therefore be used as a criterion by which one can judge if the deviation from the reservoir pressure is due to a liquid phase contaminant or simply a perturbation in the level of producing GOR.

The ways of remedying the deviant behaviour such as that in Figure 3 is also more challenging. Obviously, once the contaminating liquid components have entered into the condensate components, it is extremely difficult, if not totally impossible, to separate the two. Therefore, if that is the only separator liquid obtained, which is a combination of gas condensate components and oil components, then one must either be prepared to re-sample or reduce the GOR to a low enough value to simply meet the necessary condition of the saturation pressure being equal to the reservoir pressure. In so doing however, one will only exacerbate the characterization problems. Two reasons are responsible. The first is that by decreasing the GOR, one will only emphasize the liquid phase, and therefore if the liquid phase is the one which is contaminated, one will be emphasizing the contamination. This will serve to make the subsequent testing with this fluid less representative of the bulk of the reservoir, assuming that the oil phase is only a very small portion of the overall reservoir and...
that the bulk of the reservoir is a gas condensate system. By
decreasing the GOR to a level where the $P_{sat}$ is equal to the
reservoir pressure, the doubt will increase as to whether the data
produced from any studies will then be meaningful.

Secondly, as one sees some liquid phase contamination
which requires a distinct drop in the GOR for the
recombination, one will often see a response where the
behaviour will change from a dewpoint to a bubblepoint.
Therefore, the implications of this decrease in GOR are very
serious. Moreover, the approach to be taken for the
exploitation of such a reservoir may also become obscured in
that, rather than being a gas condensate system, it may become
a light oil system, thereby bringing other questions into the fray
such as, "Would this be a better candidate for a gas injection
process or waterflooding instead of primary depletion or
possibly a gas cycling project?".

One other behaviour often associated with a gas
condensate system which shows liquid phase contamination
problems is that there may be some solid phase instability.
Typically, there are very few solids which will precipitate from
a gas condensate system. Rarely one sees diamondoid
precipitation and, although more frequently the precipitation of
sulphur-containing compounds might be a problem, one can
usually trace those to the composition and the conditions of the
production string. The situations, however, showing dark high
molecular weight solids being produced in the production wells
are usually representative of solid phase components being
precipitated from the phase which is contaminating the gas
condensate components and is not an inherent problem with the
light gas condensate components themselves. It is usually a rule
of thumb that if the molecular weight of the produced solids is
greater than 500 - 700 and the solubility of those solids is high
in an aromatic solvent, such as toluene, then there is a good
chance that the solids originate with a separate oil phase in-situ,
and not only is there a problem with the characterization of the
gas condensate phase but the oil is also causing production
problems due to solid components incompatibilities.

In the last two years, the authors have encountered two
gas condensate systems which exhibited solid precipitation
problems. One had the response shown in Figure 4 where
solids precipitated at high temperature as long as the pressure
was high whereas at lower pressures no solids were formed,
even at low temperatures. A response such as this would
usually be representative of a liquid phase contamination of the
gas condensate since the solids in this case were pressure-
dominated and therefore corresponded to an asphaltene type of
deposit. Since the vapour pressures of asphaltene are extremely
low, it is highly unlikely that these components are produced
from the gas phase in-situ and therefore this is a telltale sign
that the incompatibility was caused by a contaminating oil phase
in-situ. Remember that, although the reservoir was almost
totally dominated by the gas condensate phase, the production
of the oil phase was enough to result in approximately 100 kg
of solids produced per 1000 barrels of liquid phase recovered.
Although in a laboratory perspective this mass percentage is
extremely small, from an operating perspective it was more than an
annoyance.

Another system recently analyzed showed a very waxy
condensate phase containing components as high as $C_{50}$. Because of the very high temperature and pressure of this
reservoir, these components could actually exist in the gas phase
at reservoir conditions and, upon depletion and liquid phase
dropout, the system exhibited vapour liquid solid behaviour. In
this case, the cloud point temperature was exactly the same as
the melting point of the solid components which were
centrifuged out of the liquid phase at the cloud point
temperature. In other words, it was a totally reversible
phenomenon normally associated with nothing but a pure wax
system. That was a fairly unique fluid but, in that case, there
was vapour liquid solid equilibrium with a system which
exhibited a dewpoint pressure 200 psi less than the reservoir
pressure and no signs of contamination. The differentiating
feature in that case was that the molecular weight of the solid
phase was on the order of 450 and the solid was reversible.
For these reasons it is more credible that it was associated with
a gas condensate system with no free oil contamination effects.

In summary, therefore, when characterizing the fluid
obtained from sampling a gas condensate reservoir, one needs
to be aware of the following practices:

There will be an optimal producing flow rate for the
well in question. There is little possibility of being
able to predict a priori what the appropriate flow rate
is for sampling the well. This is due to the fact that
the separator response will be a function of the
interfacial tension, the viscosity ratio, the reservoir
rock characteristics, the tubing size and type as well
the depletion parameters of the gas condensate itself.
The best possible thing to do if one needs to obtain a
representative characterization without having to
repeatedly return to the well, if the fluids are not
representative, is to perform a GOR versus flow rate
sequence while sampling so that the best possible
samples can be taken.

2 In recombining the separator gas and liquid to achieve
a representative reservoir fluid one must be very
cautious about how the GOR is being adjusted. The
approach taken by the authors is that as long as the
downward adjustment in the GOR does not change the
behaviour of the fluid from a dewpoint to a
The saturation pressure deviation from reservoir pressure should not usually be in excess of 1000 psi. If it is, then one may expect to see some liquid phase contamination and therefore the resulting recombination may bear no resemblance to the actual fluid which is in-situ in the reservoir. Many times with a system which exhibits liquid phase contamination, a change from dewpoint to bubblepoint is evoked by decreasing the GOR to meet the necessary condition of $P_{eq}$ equalling reservoir pressure. One needs to be very vigilant and careful in systems that are like this.

If there are solid instabilities then this is usually a strong indicator that a liquid phase contamination is occurring in-situ, particularly if the molecular weight of the solid components is high and the solid phase response is more sensitive to pressure than to temperature and is irreversible.

**RETROGRADE CONDENSATE EFFECTS ON RELATIVE PERMEABILITY**

Retrograde condensation results in a number of problems. The most obvious and serious of these is lost productive capacity due to accumulation of liquid in the reservoir. This has two facets: the first is associated with not being able to produce the higher value liquid components and secondly, the increased liquid saturation results in reduced gas flow rates. These factors work in concert and the more serious the liquid dropout, the greater the reduction in gas relative permeability.

For a system which is single phase initially, relative permeability effects are absent. Relative permeability should be viewed as a dependent variable determined by three other parameters or influences. These general influences are associated with:

1. interfacial tension effects
2. viscosity ratio
3. pore size distribution

By definition, IFT effects are only involved when two phases are present. The interfacial tension is important because of the capillary pressure equation, which can be viewed intuitively as equation 1, wherein in order to sweep through a pore in a two phase scenario, the differential pressure must be equal to or exceed the capillary pressure.

$$\Delta P \geq P_{cap} \propto \frac{\text{Interfacial Tension}}{\text{radius}}$$

One can observe from Equation 1 that as the interfacial tension decreases, the capillary pressure decreases. Conversely as the radius of the pore throat which contains the retrograde liquid decreases, the capillary pressure holding the liquid in the pore increases. Therefore, to be able to produce retrograde liquid from small pore throats, one must have either a very high differential pressure driving force or low interfacial tension.

Extrapolations of this thinking would indicate, therefore, that for gas condensate systems which exhibit high interfacial tensions where the pore throats are very small, which may correspond either to low permeability rock or higher permeability rocks but with very large coordination number, the success of flowing the liquid from the rock, once it has condensed, will be limited. In such cases vaporization (lean gas cycling) or injection of IFT reducing agents (CO₂) may be the only option to enhance the performance. On the other hand if the equilibrium gas and liquid exhibit low interfacial tension, then the liquid may flow freely from most of the pore throats in the rock and very little retrograde condensate relative permeability reduction will be observed.

Conversely, where the pore throat diameters are much larger, even though the interfacial tension may be high, it may be easy to overcome the capillary forces which are keeping the liquid in those pore throats. Therefore, for larger pore throat systems which may correspond to higher permeability rocks and/or small coordination numbers, the interfacial tension effect may not be very important.

Unfortunately, other factors cloud the issue. One of the factors which complicates this development is the mobility effect. If one were to analyze the viscosity ratio between most equilibrium gas and condensate systems, the viscosity of the gas would normally be at least 10 - 20 times lower than that of the condensate phase. Due to the inherent nature of the less viscous phase to flow more readily, it will tend to take the path of least resistance and will preferentially flow through the larger pore throats. Gardner⁷ has shown correlations wherein for gas/liquid flows, exponential viscous finger growth is often seen. Therefore in light of the IFT criterion (equation 1), one may automatically conclude that the larger pore throat sizes will contribute to much easier production from a reservoir which exhibits liquid condensate effects. This is usually true. However, even though the fluids may have the capacity to flow...
through most of the rock where the pore throats are larger, the gas may preferentially "choose" only the largest pore throats and may bypass the rest. Therefore even though the gas may have a low enough IFT to potentially sweep all pore throats, it may, due to mobility effects, only contact those of larger dimension. Therefore a compromise will be reached between interfacial tension and mobility. If the system is mobility-dominated, then the only way to effectively reduce the liquid saturation may be to vaporize components from the liquid into the flowing gas phase. Whether the free liquid will flow or improved recovery will have to rely on extraction effects depends on the compromise reached between IFT and mobility in the presence of the actual porous media.

In order to assess the optimal way to produce a gas condensate, one must be prepared to perform the testing in the presence of the porous media. If the actual reservoir rock is not used, one may have the appropriate viscosity ratio and interfacial tension, but the conclusions drawn may be inappropriate in light of the fact that the compromise between mobility and IFT is not the one which would be consistent with the reservoir rock.

It should be noted at this point that in light of the coupled nature of interfacial tension, mobility and the pore size distribution of the porous media that laboratory testing must adequately represent each of these three factors. If any portion of laboratory analysis does not adequately represent these parameters, then the credence which one can lend to the conclusions drawn from a more routine laboratory study may be minimal. That is, if viscosity ratio is used as a reference for atmospheric relative permeability testing, but the interfacial tension of the fluids is not matched, then one has a priori biased the conclusions in favour of the system being mobility dominated.

One of the standard tests which is often applied to determine the response of a gas condensate system is the constant volume depletion test wherein the liquid phase as a function of pressure is measured. On this basis one can determine if the liquid is of high enough volumetric proportion to cause a problem. Usually, those fluids which exhibit less than 1% retrograde condensation show very little tendency to reduce gas $k_w$'s. However, in some cases, even at low liquid dropouts, the liquid tends to migrate into the production wellbore and result in reductions in gas permeability. The evaluation via CVD, however, introduces one to how serious the problem may be and initiates the overall evaluation on a laboratory scale.

Following the performance of a constant volume depletion test one often will quantify the influence of the retrograde condensate on the gas relative permeability. Figure 5 provides an example of some data obtained by the authors.

In this case one sees the expected effect of a reduction in gas relative permeability very severe for the lowest permeability system and least severe for the highest permeability core. The techniques for measuring retrograde condensate themselves are very difficult from a laboratory perspective since all of the influences which were mentioned earlier are at play.

Figure 6 shows an example of the influence of liquid saturation on the relative permeability. In this test which was performed by the authors for a very extreme condition reservoir fluid one sees the drastic impact of small liquid saturations on the gas productivity as well as the influence of the interfacial tension. In this case, the interfacial tensions of the fluids were measured using the machine vision pendant drop technique as shown in Figure 6. This technique has been described by Rotenberg(9). Using this technique, interfacial tensions down to $10^{-2}$ dyne/cm can be measured quickly and consistently.

With the interfacial tension at a level of 0.2 dyne/cm, one sees a slightly lower critical condensate saturation than at the 2 dyne/cm system. Moreover, the influence of the IFT on the endpoint saturations and relative permeabilities is also as intuitively expected. The influence of the critical condensate saturation may be very important depending upon the degree of retrograde condensation effect. For example, if the maximum retrograde condensation effect is lower than the critical condensate saturation then the only way in which the gas productivity can be remedied is by extracting the components. Thomas et al(10) defined extraction effects for systems such as this. For retrograde condensate levels higher than the critical condensate saturation one may be able to consistently mobilize and produce the condensate saturation above the critical saturation. This therefore points to the importance of being able to accurately define the liquid dropout as well as the critical condensate saturation.

The liquid dropout is fairly easy to do since it is a routine phase behaviour experiment. However, to determine the critical condensate saturation is much more difficult. The critical condensate saturation is defined as the condensate saturation below which the condensate will not be able to move or be moved and above which the condensate will be mobile. Therefore, to measure the critical condensate saturation strictly one must deplete the dewpoint fluid in the representative reservoir rock and then subsequently flow equilibrium vapour through the specimen. Depending upon the pore volume of the system, the dead volumes of the experimental apparatus and inherent nature of the liquid phase being dropped out, this can be an extremely difficult procedure. If the condensate is mobile but is trapped in the accessories of the experimental apparatus, one may have too high of critical condensate saturation. One may then possibly get involved in a gas cycling scheme when, in fact, the critical condensate saturation is lower and would not
necessitate a cycling operation. Because of the inherent difficulties in measuring this, some laboratories have judged the residual condensate saturation to be the same as the critical condensate saturation. This, however, is not the case.

By a residual condensate saturation, one defines this value by filling the specimen completely with a bubblepoint equilibrium phase produced from the depletion experiment. By filling the core completely with that phase, one has filled all of the pore throats and pores with the liquid. Upon injecting the gas, even though it is an equilibrium gas, the pore throats, which are so small that the IFT between the gas and the liquid preclude entry, will still be filled with the condensate. In other words, it will only be a judge of which pores the equilibrium gas has been able to sweep. For the pore size distribution given in Figure 7 at a level of IFT which corresponds to 20 microns and the obviously artificial pore size distribution contained in Figure 7 (for explanation purposes), the residual condensate saturation will be associated with all of the pores lower than 20 microns. In such a case, the critical condensate saturation, if measured as a residual condensate saturation, could be very high; the residual condensate saturation will be an indication of the saturation of the condensate remaining in the core that could not be swept.

If one compares that to the critical condensate saturation, when the condensate saturation builds up to a certain value, then the first sign of production of that condensate would be called the critical condensate saturation. This does not mean that all of the condensate will move from the core but only represents the saturation at which the condensate has become mobile. Necessarily, therefore, the critical condensate saturation is going to be governed by the gas condensate response in the largest pore throats whereas the residual condensate saturation is going to be governed by the gas liquid interaction in the smallest pore throats. The critical condensate saturation will be the most optimistic value and the residual condensate saturation will be the most pessimistic value. Otherwise stated, the critical condensate saturation will indicate the lowest saturation that needs to be built up before the condensate in the largest pore throats will be mobilized. This, however, does not mean that the condensate in the lower pore throats will be mobilized and, in fact, will not be. Indeed, as the condensate phase begins to migrate throughout the rock one may result in the net effect associated with the residual condensate saturation being more representative than the so-called critical condensate saturation.

At a level of IFT the smaller pore throats will have the possibility of imbibing the liquid phase and therefore once the smaller pore throats are filled with the condensate there may be no possibility other than through gas cycling or through IFT manipulation of accessing those pore throats and mitigating the influence of retrograde condensation on the relative permeabilities.

This brings us to another point wherein the measurement of retrograde condensate effects can be very sensitive. This is mainly the case where the differential pressure of the system is fairly high. For a large differential pressure, the thermodynamic behaviour may be coupled in with the fluid flow behaviour. Figure 9 shows a comparison between an equilibrium assumption versus a non-equilibrium assumption. For the equilibrium assumption following each saturation level using the analog methane binary, the core was depressurized. The gas was collected and the gas composition was used to interpolate the gas phase saturation. The pressure effect, however, resulted in a compression of that gas phase over what would normally be present if there had not been a substantial differential pressure. It should be noted that in this case the differential pressure was as high as 30% of the backpressure setting. Therefore, by including a compression effect of the vapour phase only, the non-equilibrium values were generated in Figure 9. Compared to that, are the values calculated from the equation of state based on the produced gas composition upon depressurizing the core. One can see that although they are different there is a reasonable comparison between the two. Knowing this may be particularly important for some of the gas condensate relative permeability testing that may have to be done very close to the saturation pressure corresponding to very low interfacial tensions. For example, if an IFT required was in the order of 0.1 dyne/cm which meant that the operating pressure had to be within 50 psi of the saturation pressure, then the differential pressure would result in a pressure higher than the saturation pressure. Therefore, knowing the comparison and the reasonable response between the equation of state calculated values and the non-equilibrium assumption is an important parameter to note for those performing the experimentation.

**SIMULATION APPLICATIONS**

The ability to produce representative experimental data is inherently important. Nevertheless, this importance would be diminished significantly if there was no ability to couple these data into making forecast estimates for gas condensate reservoir performance. The constant volume depletion data are normally readily imported into a simulation model. The ability, however, to couple the fluid phase behaviour with the fluid flow characteristics is more challenging from a simulation perspective and one must be very aware of some of the factors which need to be present in a simulator. A quick review of these parameters, as mentioned earlier, are:

1. Influence of interfacial tension on relative permeabilities.
2. The inclusion of viscosity/IFT compromise in the relative permeabilities.
3. An adequate means of representing the liquid dropout.
4. The influence of pore volume compressibility as a function of pressure.

5. For fractured systems, the mechanism whereby fractures heal as the reservoir is depleted and the net overburden pressure increases.

The authors have worked in the last year with a system which required all of these parameters. For instance, upon discovery and initial depletion, the behaviour was above the dewpoint and corresponded mainly to a simple gas decompression problem. Once the dewpoint pressure was reached and liquid phase dropout commenced then this had an influence, based upon the retrograde condensate effect. Not only did that occur but simultaneously with the decrease in pressure the IFT began to increase. This increasing IFT resulted in more drastic relative permeability decreases. In a reverse synergistic effect, the decreasing pressure and increasing IFT also resulted in decreasing absolute permeability due to the fractured nature of some of the systems which the authors have modelled. This calls into play, therefore, an influence in the absolute permeability of the model along with an ability to interpolate between relative permeabilities corresponding to high and low IFT regimes. The authors found it necessary to have the simulator used (Computer Modelling Group compositional simulator GEM) modified to include all of these effects and every one of these effects was required in order to get an adequate response of the field data.

Only in using a simulator with this much detail and based upon detailed experimental data can one hope to close the gap between the initial characterization and the initial hopes associated with discovery and the ultimate dollar value which can be realized from such reservoirs.

CONCLUSIONS

Characterization of the gas condensate is often a very challenging endeavour. Many times the separator GOR's will be too high depending upon whether the well is being produced at too high or too low a flow rate.

2 Techniques for modifying GOR difficulties are routine whereas if there is any contamination of the produced liquid phase these problems require resampling. A rule of thumb for saturation pressure deviation from reservoir pressure is defined. Usually, if a GOR manipulation is required the saturation pressure is normally less than 1000 psi higher than the reservoir pressure. If there is greater than 1000 psi deviation from reservoir pressure then normally this is associated with a liquid phase contamination problem.

3 Retrograde condensate effects on relative permeability have been shown. These effects become more serious with increasing interfacial tension and decreasing rock permeability. This effect is determined by the interplay of interfacial tension, pore size distribution, viscosity ratio and, to some degree, connate water saturation.

4. Determination of retrograde condensation effects on relative permeability is a challenging measurement to make experimentally and some procedural concerns are identified with possible solutions.

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