

# Representing Reservoir Oil Using Recombination Techniques

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## ABSTRACT

*The approach to reservoir optimization often begins with the appropriate characterization of the reservoir fluid. Deficiencies in sampling methods may lead to erroneous conclusions regarding the fluids in situ and, therefore, the exploitation strategies considered. Moreover, once sampled, the way in which fluids are recombined is many times inadequate. Frequently, bottom-hole samples are also problematic and must be analyzed correctly in order to infer the appropriate information about the reservoir system.*

*This paper discusses sampling and recombination methods that provide the best representation of reservoir fluids. A number of examples are provided where standard approaches to characterization are inadequate*

*and a protocol of recombination is presented. The benefits of the approach are shown. The impact of characterization is also shown relative to allowable production rates and adherence to regulatory edicts.*

## BACKGROUND

Much of the engineering that is involved in the development and exploitation of reservoirs world-wide depends on representative fluid samples. Whether it is the measurement of PVT properties such as density ( $\rho$ ), formation volume factor ( $\beta_o$ ), viscosity ( $\mu$ ), interfacial tension (IFT), gas-oil ratio (GOR) or compressibility ( $c$ ), or the generation of relative permeability relationships or the assessment of enhanced oil recovery (EOR) strategies, each of these endeavors requires a representative reservoir fluid. Although it may seem that

the method for the acquisition of a representative reservoir fluid would be straightforward, it is surprising to see the number of fluid characterizations that are not done correctly. This deficiency then carries through to all of the analyses that are performed and consequently, the results of the engineering may be in error primarily due to the fluid with which the work was commenced; thus the importance in establishing a reliable protocol for the preparation of representative reservoir fluid.

Oil and gas reservoir opportunities are distributed amongst a number of different fluid types (Figure 1). The oils may be heavy oil containing very little gas and very heavy, high-density components, more conventional oils containing components that are easily partitioned into the gas phase, or volatile oils where the difference between the gas phase and the liquid phase is much less pronounced. As one moves to the right of the critical point, the classification of fluid moves to very-rich condensates, retrograde condensates, to wet gas and finally to dry gas. The extremes on either side of the critical point are easy fluids to represent. Heavy oil has almost exclusively methane in the solution gas and  $C_{20+}$  in the liquid. There is very little “gray area”. Heavy oils do not normally have characterization difficulties since the solution gas is almost always at least 93% methane, in which case, recombination methods do not significantly impact the recombined oil properties. Dry gas has only gas-phase components and therefore these gases are easy to sample and to represent. The problems enter with the fluids that contain components that partition easily into both liquid and gas phases. These fluids can then become very sensitive to pressure influences which are ubiquitous in reservoir engineering.

For any well to produce, a pressure gradient must exist. As the pressure decreases from the reservoir pressure down to the bottom-hole flowing pressure, the upper boundary of the phase loop may be breached. Once this occurs, two phases will be present and the potential for different flows of gas and liquid, not consistent with the solution GOR, will be introduced due to the relative difference in mobility of the two phases. Consequently, the gas and liquid flow rates at surface may result in GOR's that are not representative of the fluid in situ; the separator may be producing much more

gas than would be associated with the gas in solution. To some degree, the same response can be observed with a bottom-hole sample (BHS) where a gas-liquid separation may occur, as the fluids flow into the sampler, and the BHS then may have too much gas relative to the oil volume. In both cases, the resulting fluids must be corrected in order to represent correctly the fluids in situ. How this correction is made is the topic of this paper.

### **Deficiencies of Common Correction Techniques**

There are two phenomena contributing to the difficulties encountered with creating a system that represents in situ reservoir fluid. The first is simply related to the rate of production which is directly related to the relative mobility ratio between the gas and oil. Superimposing Figures 1 and 2, as the pressure drops below the bubble-point pressure of the oil, gas will evolve. The gas has a much lower viscosity than the oil and therefore moves much more quickly under an imposed pressure gradient. If that were the only effect, it would be easy to correct for the excessive gas. It would suffice to simply reduce the GOR until the saturation pressure reaches the appropriate value ( $P_{\text{RESERVOIR}}$  for a saturated system or the bubble point that can usually be inferred from field GOR vs pressure history). However, not only is there too much gas but also the gas produced has a different composition than the gas in solution; the composition of the gas evolved may change as a function of pressure. Suffice to analyze the difference between gas cap gas, solution gas and separator gas to appreciate the difference. Table 1 presents the compositions of these gases. It is obvious that the gas cap gas contains more light components than the separator gas which in turn contains more light components than the solution gas. Of course, this is due to the relative volatility of components: nitrogen and methane are much more volatile than the heavier components such as butane and pentane. As the vapor pressure of methane is higher than that of ethane, if the reservoir pressure is between the vapor pressure of methane and the vapor pressure of ethane then, in an idealized system, methane would exist in the gas phase but ethane would not. Thus, if the pressure encountered on the way to the production well is low enough to evolve methane but not low enough to evolve propane, then the evolved gas will be much higher in methane

content. Therefore, as the average pressure of the system decreases, you will tend to see increasing molecular weight of the evolved gas. Consequently, not only do you have to correct for the amount of gas that is present in the samples but also the composition must be corrected; if not, the separator gas will have too much methane to allow for an appropriate characterization of the reservoir fluid.

What are the most common ways to correct for this problem? The first method is to perform a recombination using the GOR at the separator and the gas and liquid streams that have been collected. Figure 3 shows schematically that which happens most of the time, where the separator gas is comprised of separator gas and gas cap gas; the secondary gas cap gas in the separator gas is most commonly due to the drawdown pressure placing the oil at conditions below its bubble point, evolving gas at greater mobility resulting in excess gas at surface. Once it is confirmed that the recombination has too high of bubble point pressure (since the GOR is too high and the gas has too much methane) then the bubble point pressure is often reduced by adding separator liquid. The problem with this approach is that there is too much methane per unit of gas and therefore to arrive at the appropriate bubble point pressure, the GOR will converge to a value that is too low for the appropriate bubble point pressure. A better option, if the target composition is known, from discovery-time sampling of the oil, is to blend a gas on the basis of the composition and properties of the known sample. Equation 1 is used to calculate the appropriate gas composition to blend with the separator liquid to converge to the correct recombination, where  $Z_i$  is the known composition of the reference sample,  $X_i$  is the composition of the separator liquid,  $V$  is the mole fraction gas (based on GOR) and  $Y_i$  is the composition of the gas to blend to synthesize the recombined oil.

$$Z_i = V Y_i + (1-V) X_i \quad (1)$$

The difference between this blending approach (which depends on knowing the target recombination parameters from an initial oil compositional analysis) and the simple approach of adding separator oil to the high-GOR initial recombination, based upon the separator gas, liquid and GOR is shown in Table 2. The recombined oil

using Equation 1 and the synthesized gas resulted in an oil that was close to the original oil (target composition). The GOR of the recombination with synthetic separator gas (460 scf/bbl – 81.9 m<sup>3</sup>/m<sup>3</sup>) was very close to the desired value of 463 scf/bbl (82.5 m<sup>3</sup>/m<sup>3</sup>). However, the recombination achieved by adding the separator gas and liquid, as sampled, and then adding separator oil to bring the bubble point pressure down to the appropriate value reduces the GOR to a value that is excessively low. Note that there is still too much methane in the recombination even after reducing the GOR. As mentioned above, there was initially too much methane in the gas due to secondary gas cap production incident to near-well-bore pressures dropping below the bubble-point pressure. The addition of separator oil only reduces the GOR but it does not correct for the excessive methane.

The above example shows the deficiency of a common technique for trying to correct the problems associated with the influx of too much gas during separator sampling. It shows that a better method is to synthesize a gas to blend with the separator liquid in order to re-create the original oil composition. The only limitation is that the original composition must be known. In some cases this is a very limiting constraint. What if the original composition is not known but the bubble point pressure is? The next example shows the deficiency of another common method.

This well was operating at an oil production rate of 127 m<sup>3</sup>/day. The producing GOR was in excess of 400 m<sup>3</sup>/m<sup>3</sup> and the accepted solution GOR was approximately 100 m<sup>3</sup>/m<sup>3</sup>. This reservoir exhibited unusual character in that the temperature was only 31°C (88°F) and the stock tank oil density was 817 kg/m<sup>3</sup> (42 degrees API). From the hundreds of samples analyzed by the authors over the last twenty years, this example was chosen in order to exhibit clearly the deficiency of the second recombination method. This method involves:

1. Recombine separator gas and liquid at separator GOR
2. Measure the bubble-point pressure. Almost without exception, the bubble-point pressure is higher than it should be.

3. Slowly deplete the pressure to target bubble-point pressure by bleeding off gas.
4. Compare resulting composition for relative properties. This in many reservoirs is more of a “feel” since there may be no previous analysis for comparison.

Starting at a GOR of about 100 m<sup>3</sup>/m<sup>3</sup>, the separator oil and gas are recombined. They are equilibrated and the bubble point pressure was measured. The pressure is then reduced slowly during which time the gas is released; the gas can actually be removed from the system differentially or the gas can be retained in contact with liquid phase (the authors have observed that for the large majority of systems this is not a parameter to which the recombination is sensitive). Once the target pressure is achieved, the equilibrium oil is isolated and analyzed. To be reliable, this method should yield the same results whether the separator GOR is 100 or 200 or 300 or higher, since many times the separator GOR may change from well to well and the recombination should not be a function of which well is sampled. Unfortunately, Figure 4 shows the changing solution GOR depending on the separator GOR with which one begins the analysis. As the initial separator GOR increases (abscissa), the solution GOR (ordinate) also increases. As the separator GOR increases, more of the gas is from the gas cap (only a specific amount of solution gas). As the methane content increases, if technique 1 is used (adding separator liquid), the ultimate GOR will decrease due to the decreasing solubility of the gas (increasing methane content). Figure 4 shows the relationship between Method 1 and Method 2.

The response of Method 1 was described previously. However, Method 2 appears not to be acceptable. The reason is obvious when examining the vapor pressures of the different components (Figure 5). As the GOR at separator increases and is forced into solution by increasing the pressure, all of the gas, methane included, dissolves. Then, as the pressure of the recombined oil is reduced and the gas is evolved, the lighter components are the ones that are liberated. In the case shown here, virtually all of the gas liberated would be methane with little ethane liberated due to real-gas effects (chemical

potential effects). In this ideal case, if the bottom hole flowing pressure is higher than the vapor pressure of ethane at reservoir temperature, the separator GOR could be increased and the corresponding solution GOR would increase. This effect is shown schematically as Figure 6; thus the relationship between separator GOR and solution GOR in Figure 4 for Method 2; Method 2 may result in a continual concentrating effect of C<sub>2+</sub> in the liquid phase. In light of this response, the first two most-common techniques for recombination are shown to be deficient.

### Proposed Better Technique: Method 3

As was stated earlier, the reason for excess gas at the separator is usually due to the higher mobility of the gas phase. The exacerbation occurs due to the extraneous gas having more methane in it than it should; using a depletion strategy, it has been shown that the separator GOR will determine the solution GOR and that it therefore, in some cases, is not an acceptable approach. The assumption used in Method 2 is that the gas evolving above the bubble-point pressure is the same composition as the gas evolving below the bubble-point pressure (the source of the extraneous gas in the field is necessarily below P<sub>sat</sub>). It was suggested that the recombination had to be corrected for GOR and gas composition and therefore the best method would include both of these corrections. The following algorithm was developed to allow for these two contributions to be corrected.

The material balance on the separator gas is as follows:

$$GC Y_{iGC} + (1-GC) Y_{iSG} = Y_{iSEP} \quad (2)$$

The separator gas composition is known but the gas cap gas (Y<sub>iGC</sub>) and the solution gas composition (Y<sub>iSG</sub>) are unknown. Therefore, the solution will involve iteration since there are more unknowns than equations. The steps of the algorithm are:

1. Assume the mole fraction of the gas cap gas.
2. Assume the fraction of the separator gas that is gas cap gas.
3. Calculate Y<sub>iSG</sub> from Equation 2.
4. Perform a theoretical recombination and a bubble-point pressure computation using an EOS tuned to the preliminary recombination. If the P<sub>b</sub> (EOS) is

high then increase the GC fraction assumed in step 2. If the Pb is low then decrease the GC fraction assumed in step 2.

5. Once converged to the correct bubble-point pressure, compare the  $Y_{iGC}$ . If the  $Y_{iGC}$  calculated in step 5 is different (within a tolerance specified) from that assumed in step 1 then replace the assumption in step 1 with the value calculated in step 5 and repeat the iteration. If  $Y_{iGC}$  is the same as in step 1 then end calculations.

It should be emphasized at this point that the  $Y_{iGC}$  calculated in step 5 is the micro-flash gas determined as the equilibrium gas at the bubble-point pressure. Once converged, the gas that is first released from the oil as it drops below its bubble-point pressure is the theoretical gas computed from the EOS which should be the main constituent of the gas cap gas.

Using this approach, Figure 7 shows the results of the calculations compared to Methods 1 and 2. This approach results in a unique characterization of the reservoir fluid that is independent of the separator GOR used to create the recombined oil. It has been assembled into a computer program called “Separator Wizard”. It is better than the most common techniques in use since it corrects for both gas cap gas volume and compositional effects.

### **Application**

The above technique was tested on a reservoir that was sampled for the first time. The operating company suggested that since the well was recently drilled, and since there had been no noticeable depletion, the separator gas and oil could be used directly to create a reservoir fluid. The producing GOR was 214 m<sup>3</sup>/m<sup>3</sup> and the bubble point was recommended, by the operator, as 8274 kPa (1200 psia) at a reservoir temperature of 50°C (122°F). The reservoir pressure was 11721 kPa (1700 psi). The fluids were obtained and the separator gas and liquid were recombined at separator GOR and reservoir temperature. The observed bubble-point pressure was 26,200 kPa (3800 psi), 2100 psi higher than the original reservoir pressure. Obviously, there was a gas contamination problem.

The algorithm described above was used to correct the recombination parameters. Table 3 presents the difference between the separator, calculated gas cap and solution gas that would be used to synthesize the recombined oil to represent the reservoir. The resulting recombination had the appropriate bubble point pressure and its properties were consistent with other analogous pools. The GOR change is significant using this method compared to other common techniques. Using oil based on Method 3 recombinations, as much as 400 psi difference in MMP has been observed using this technique compared to the two other recombination methodologies that have been described.

### **SUMMARY**

Although separator samples are often obtained and routinely used to create reservoir fluids thought to represent fluids in situ there can be significant error introduced by the method used for the recombination. Three approaches have been described in this paper. Method 1 often introduces much error and always is a conservative method resulting in low GOR, higher density, viscosity and IFT. However, it does result in lower formation volume factors than should be (lower GOR and therefore less shrinkage). Method 2 may be adequate as long as the bottom hole flowing pressure (or bubble point – whichever is lower) is high compared to the vapor pressure of ethane at reservoir temperature. If the bottom hole flowing pressure is less than the vapor pressure of ethane at reservoir temperature, Method 2 is probably not adequate and Method 3 should be used. Method 3, which takes a material balance view of the gas cap and solution gas contributions to separator gas can always be used since it does at least as much as simple depletion (Method 2).

Component	Gas Cap Gas Mole Fraction	Separator Gas Mole Fraction	Solution Gas Mole Fraction
N2	0.0815	0.0481	0.0275
CO2	0.0124	0.0111	0.0101
C1	0.6468	0.5305	0.4586
C2	0.1174	0.1381	0.1510
C3	0.0731	0.1271	0.1605
iC4	0.0099	0.0249	0.0342
nC4	0.0285	0.0888	0.1261
iC5	0.0071	0.0125	0.0158
nC5	0.0233	0.0189	0.0162

**Table 1: Comparison of Gas Cap, Separator and Solution Gases**

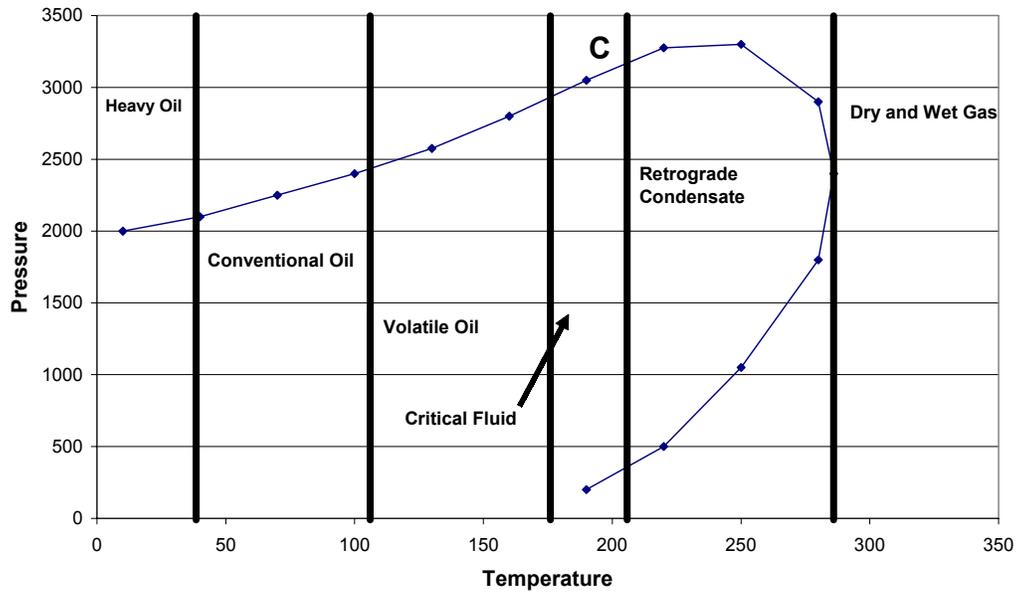
Component	Oil Compositions - Mole Fractions		
	Original Oil Sample	Synthetic Separator Gas	Sampled Separator Gas
Nitrogen	0.0032	0.0044	0.0089
Carbon Dioxide	0.0289	0.0275	0.0219
Hydrogen Sulphide	0.0038	0.0039	0.0009
Methane	0.3501	0.3522	0.3643
Ethane	0.0780	0.0747	0.0699
Propane	0.0576	0.0622	0.0456
iso-Butane	0.0142	0.0175	0.0103
n-Butane	0.0295	0.0348	0.0204
iso-Pentane	0.0134	0.0112	0.0076
n-Pentane	0.0137	0.0124	0.0095
Hexanes Plus	0.4076	0.3992	0.4407
GOR - scf/bbl	463.0	460.0	382.0

**Table 2: Comparison of Recombined Oil Compositions and Original Time-of-Discovery Oil Composition**

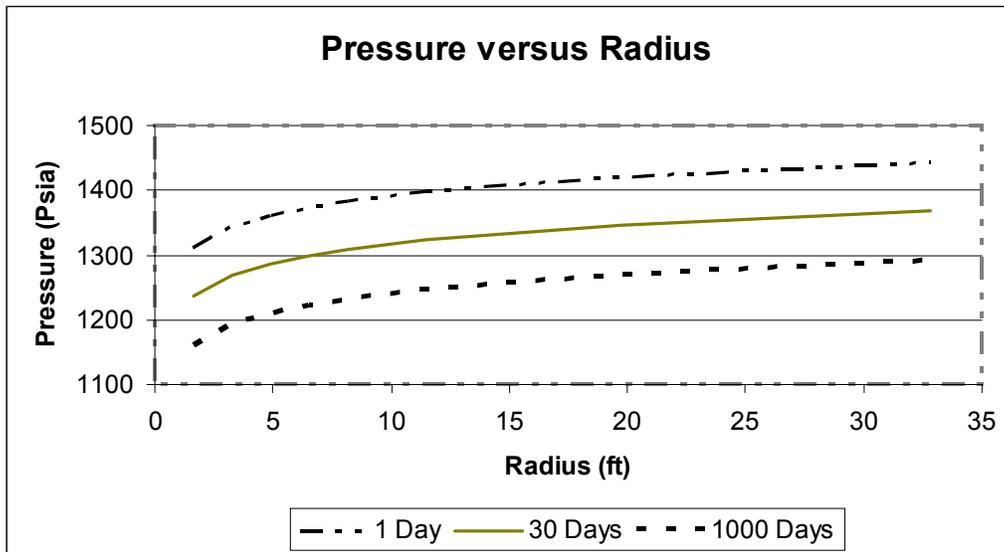
Component	Compositions - Mole Fractions		
	Separator Gas Sample	Calculated Gas Cap Gas	Calculated Solution Gas
Nitrogen	0.0102	0.0448	0.0000
Carbon Dioxide	0.0191	0.0145	0.0269
Hydrogen Sulphide	0.0053	0.0028	0.0099
Methane	0.6948	0.7837	0.4819
Ethane	0.1038	0.0819	0.1404
Propane	0.0828	0.0401	0.1610
iso-Butane	0.0159	0.0055	0.0352
n-Butane	0.0371	0.0148	0.0783
iso-Pentane	0.0127	0.0045	0.0279
n-Pentane	0.0115	0.0042	0.0250
Hexanes Plus	0.0068	0.0032	0.0134

**Table 3: Compositions of Separator, Calculated Gas-Cap and Solution Gas**

## Typical Pressure - Temperature Diagram



**Figure 1: Classification of Fluid Types**



**Figure 2: Calculated Pressure Profile**

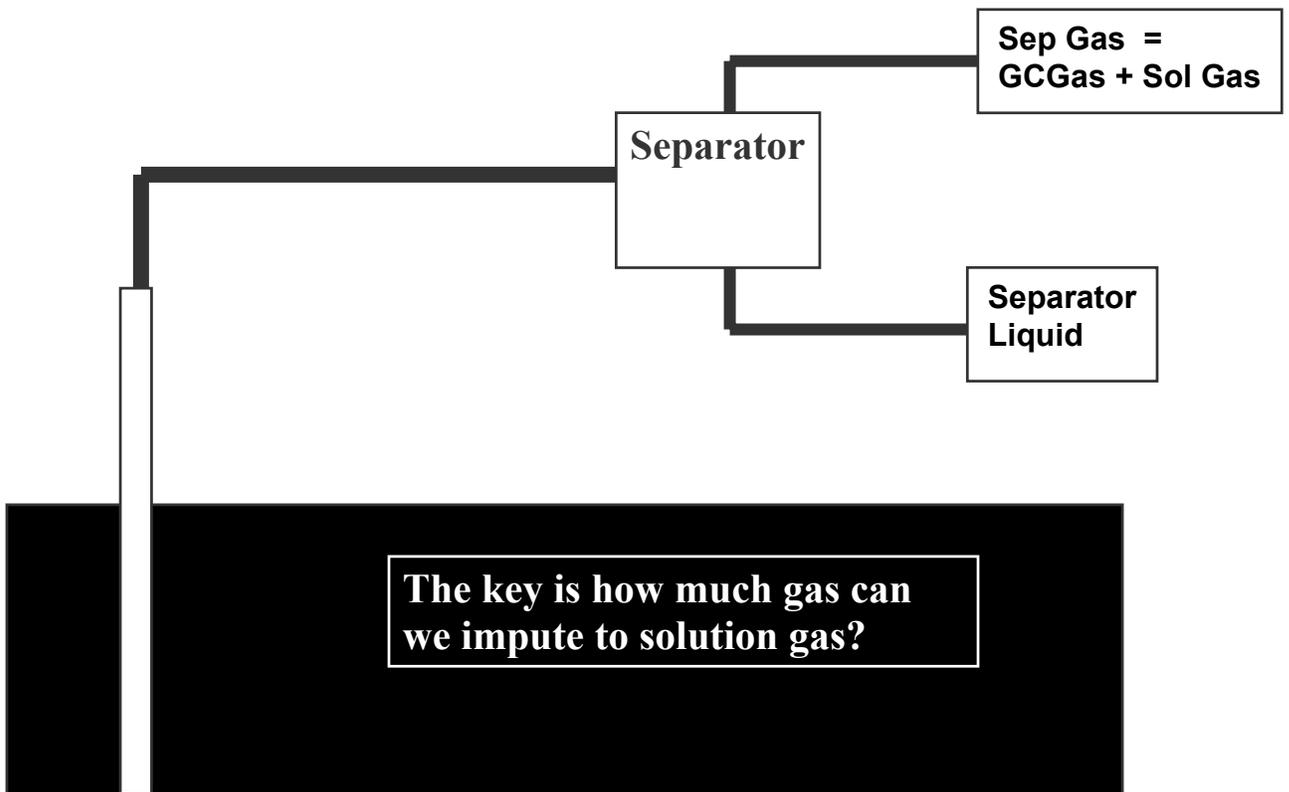


Figure 3: Typical Separator Situation

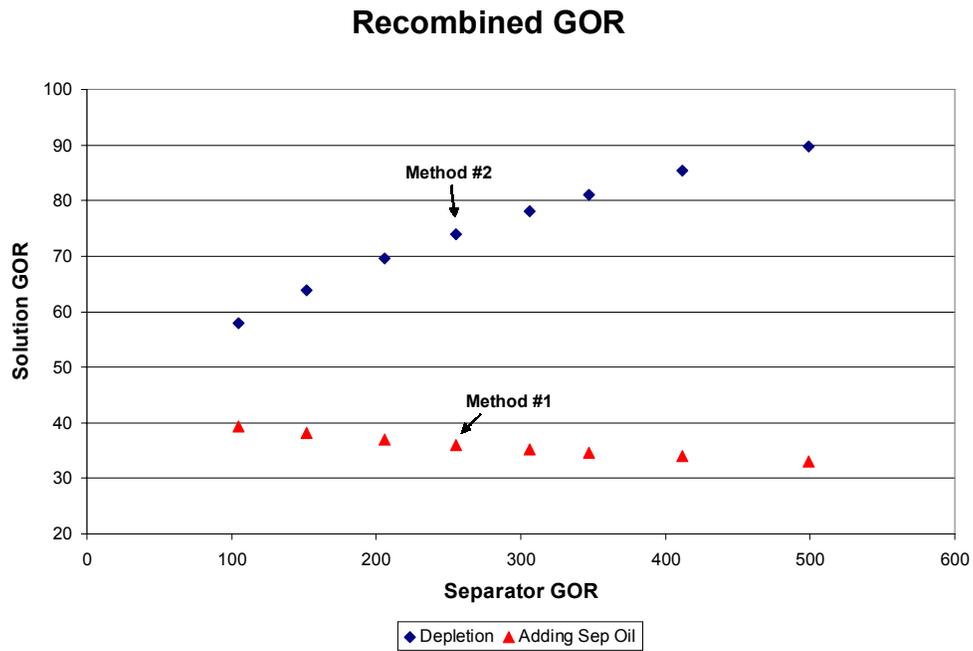
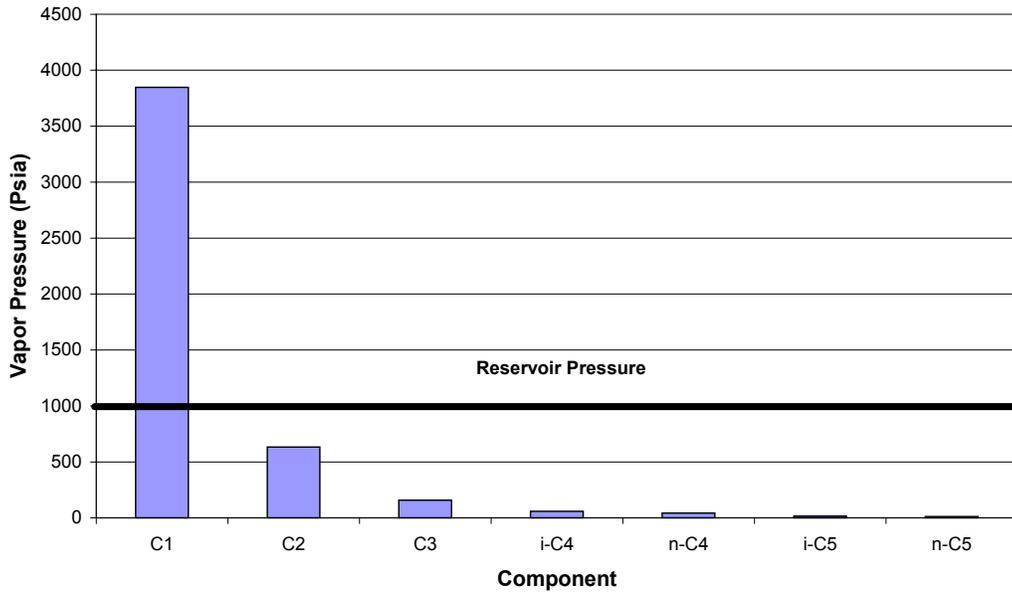
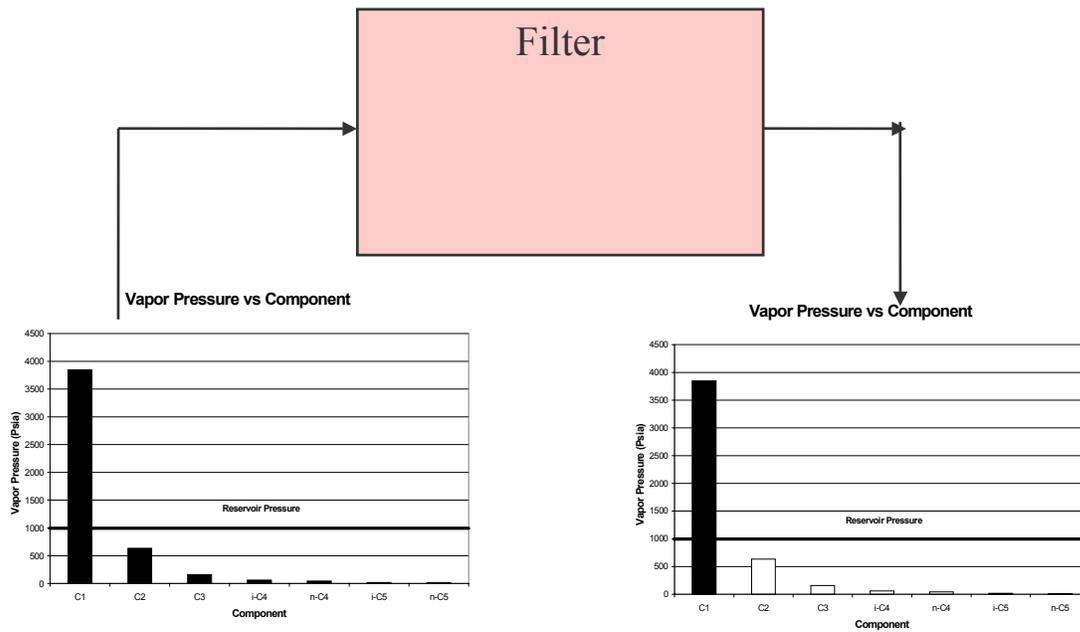


Figure 4: Comparison of Method 1 and Method 2 for Recombination

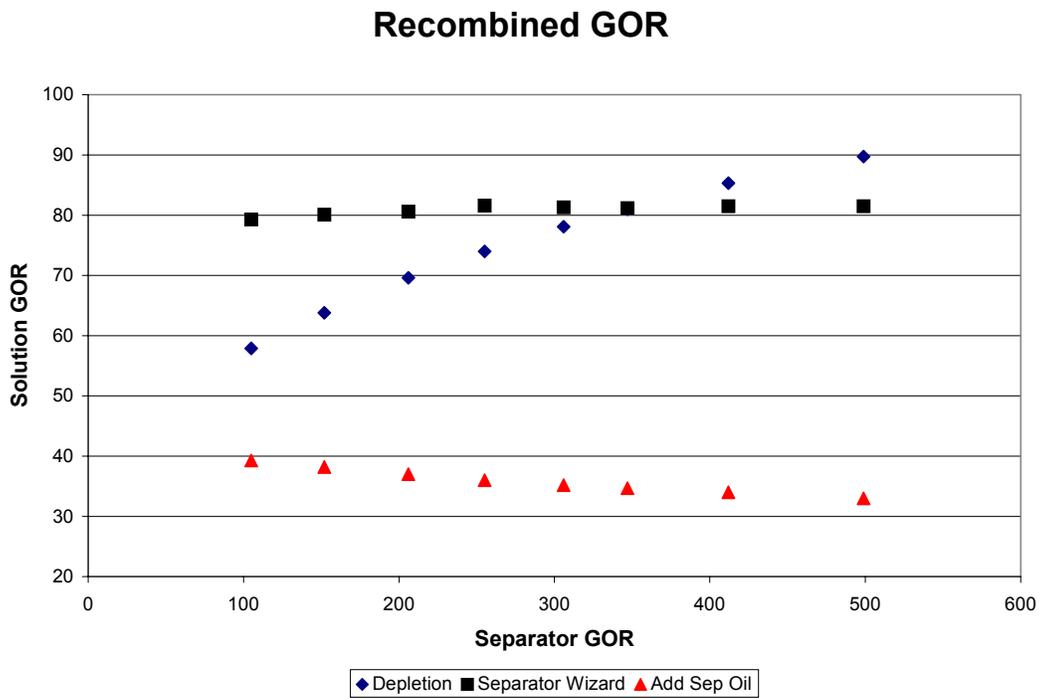
## Vapor Pressure vs Component



**Figure 5: Component Vapor Pressures at 31°C**



**Figure 6: Oil Behaving as a Filter for Lower Vapor Pressure Components**



**Figure 7: Comparison of Methods 1 through 3**

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