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# An Analysis of Reservoir Production Strategies in Miscible and Immiscible Gas Injection Projects

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## Abstract

Successful design and implementation of a miscible gas injection project depends upon the minimum miscibility pressure (MMP) and other factors such as reservoir and fluid characterization. The experimental methods available for determining MMP are both costly and time consuming. Therefore, the use of correlations that prove to be reliable for a wide range of fluid types would likely be considered acceptable for preliminary screening studies. This work includes a comparative evaluation of MMP correlations and thermodynamic models using an equation of state by PVTsim software (Schlumberger, 2001a). We observed that none of the evaluated MMP correlations studied in this investigation is sufficiently reliable. EOS-based analytical methods seemed to be more conservative in predicting MMP values.

Following an acceptable estimate of MMP, several compositional simulation runs were conducted to determine the sensitivity of the oil recovery to variations in injection pressure (at pressures above, equal to and below the estimated MMP), stratification and mobility ratio parameters in miscible and immiscible gas injection projects. Simulation results indicated that injection pressure was a key parameter that affects oil recovery to a high degree. MMP determined to be the optimum injection pressure. Stratification and mobility ratio could also affect the recovery efficiency of the reservoir in a variety of ways.

**Key words:** Reservoir production; Miscible gas injection; Immiscible gas; Minimum miscibility pressure

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## NOMENCLATURE

*API*= American Petroleum Institute
*CGD*= Condensing Gas Drive
*OOIP*= Originally Oil in Place, STB
*MMP*= Minimum Miscibility Pressure, psi
*T*= Temperature, °F
$T_{pr}$= pseudo reduced temperature of the reservoir Fluid
$T_{pc}$= pseudo critical temperature of the reservoir fluid,° R
$P_{pc}$= pseudo critical pressure of the reservoir fluid, psi
$P_{pr}$= pseudo reduced pressure of the reservoir fluid
$x_{int}$= mole percent of intermediate components ($C_2$ through $C_5$)in the reservoir fluid
$y_{C2+}$ = mole fraction of the ethane plus fraction in the reservoir fluid

## INTRODUCTION

Through the past decades, miscible displacement processes have been developed as a successful oil recovery method in many reservoirs. The successful design and implementation of a gas injection project depends on the favorable fluid and rock properties. The case studies using Eclipse compositional simulator considered the effect of key parameters, such as injection pressure, stratification and mobility ratio on the performance recovery in miscible and immiscible flooding of the reservoir (Schlumberger, 2001b). However, accurate estimation of the minimum miscibility pressure is important in conducting numerous simulation runs. MMP is the minimum miscibility pressure which defines whether the displacement mechanism in the reservoir is miscible or immiscible. Thermodynamic models using an equation of state and appropriate MMP correlations were used in determining the MMP.

Compositional simulation runs determined the sensitivity of the oil recovery to the variations in above mentioned parameters. Significant increase in oil recovery was observed when interfacial tension dependent relative permeability curves were used. These relative permeability curves provide an additional accounting for miscibility by using a weighted average between fully miscible and immiscible relative permeability curves. The local interfacial tension determines the interpolation factor which is used in obtaining a weighted average of immiscible and miscible (straight line) relative permeabilities.

Simulation runs were performed at pressures below, equal to, and greater than estimated MMP for reservoir fluid/ injection gas system. Oil recovery was greatest when miscibility achieved. To investigate the effect of stratification on the performance recovery of the reservoir, the base relative permeability of two layers changed. Location of the high permeable layer (up or bottom layer) in the stratified reservoir greatly influenced the efficiency of the reservoir.

Understanding the effect of interfacial tension and adverse mobility ratio on the efficiency of the gas injection project was the last case study. Injection gas and reservoir fluid compositions differed in such a way to have interfacial tension and mobility dominated mechanism. To investigate the effect of interfacial tension water was considered as a fluid with much higher surface tension values with the oil. Lower surface tension values between rich gas and reservoir fluid (interfacial tension dominated) made gas injection project a more competitive recovery method than waterflooding. In mobility dominated displacement mechanism (lean gas/reservoir fluid system) the viscous instabilities were more important than the interfacial tension effect. For this case, waterflooding with favorable mobility ratio resulted in higher oil recoveries.

## 1. BACKGROUND

### 1.1 Classification of Miscible Displacements

Miscible displacement processes in the oil reservoirs are usually divided into two classes.

#### 1.1.1 First Contact Miscible Processes (FCMP)

Displacements in which the injection fluid and the in-situ reservoir fluid form a single phase mixture for all mixing proportions. Pressure/composition (P-X) diagram is a useful method to illustrate the phase behavior of these mixtures. Pressure/composition diagrams for reservoir fluids are obtained by adding solvent (recycling gas produced in this case) into the reservoir oil and measuring the saturation pressure of the resultant mixture. Initially, as injection gas is added, mixtures will exhibit bubble points as the saturation pressure but as the concentration of the injection gas in the mixture increases, the mixtures formed will exhibit dewpoints. Single-phase mixture exists at pressures above the bubblepoint or dewpoint curves. The highest pressure at which two phases coexist in equilibrium is called the cricondenbar and is equal to FCMP.

#### 1.1.2 Multi-Contact Miscible Processes

Processes in which the injected fluid and the reservoir oil are not miscible in the first contact but miscibility could develop after multiple contacts (dynamic miscibility). These processes are categorized into vaporizing, condensing, and combined vaporizing-condensing drive mechanisms.

The vaporizing-gas drive miscibility is one of the three alternative methods to obtain miscibility at pressures lower than FCM. In vaporizing-gas drive process or high- pressure gas process, lean injection gas vaporizes the intermediate components of the reservoir fluid and creates a miscible transition zone. In this displacement mechanism, miscibility is related to the gas front in the reservoir. As gas moves throughout the reservoir it comes into contact with original reservoir oil and thereby is enriched in intermediate components.

In condensing drive mechanism, injection gas containing low molecular weight hydrocarbon components ($C_2$-$C_6$), condenses in the oil to generate a critical mixture at the displacing front. It is reported that for some reservoir fluids, phase behavior in condensing-gas drives departs substantially from traditional three-component fluid concepts (Zick, 1986; Stalkup, 1987). Experimental observations and equation-of-state analysis indicate existence of combined condensing-vaporizing drive mechanism rather than condensing drive mechanism in the reservoir.

### 1.2 Minimum Miscibility Pressure Correlations

Multiple contact miscible floods have proven to be one of the most effective enhanced oil recovery methods currently available. The available displacement experimental (slim-tube and rising-bubble apparatus) procedures for determining the optimal flood pressure, defined as the minimum miscibility pressure, are both costly and time consuming (Metcalfe et al., 1972). Therefore, use of reliable correlations that were developed from reliable experimental data would be of great interest. The results of these correlations however would only be for the preliminary screening studies that would be conducted over a wide range of conditions. In this study a review of the literature of several MMP correlations of vaporizing gas drive (VGD) and condensing gas drive (CGD) mechanisms is investigated. An early correlation was presented by Benham et al. (1960) where the required gas enrichment for condensing drive mechanism was correlated as a function of temperature, pressure, gas intermediate and heavy fractions of the oil molecular weights.

Glasø (1985) proposed a correlation which was the extension of Benham et al. (1960) study, and gives the MMP for VGD, CGD, $CO_2$, and $N_2$ systems. The input parameters for this correlation are temperature, mole percent of the methane in the injection gas, molecular weight of $C_2$-$C_6$ intermediates in the injection gas and the molecular weight of heptane-plus fraction of the oil. A new parameter called, paraffinicity characterization factor (K), was defined to account for oil composition effect on MMP.

A correlation developed by Sebastian et al. (1985) gives the MMP for $CO_2$-rich gas injection. This study takes into account the effects of impurities (up to 55% mole percent) in the injection gas. The new correlating parameter of this correlation is the pseudocritical molar average temperature of the injection gas. Alston et al. (1985) had investigated the effect of $CO_2$ impurities on MMP with a similar correlation with weight average critical temperature as a correlating parameter.

Firoozabadi and Aziz (1986) modeled the VGD with the Peng-Robinson equation of state and a compositional simulator. They proposed a simple correlation for the estimation of MMP of Nitrogen and lean-gas systems. The MMP was correlated as a function of molecular weights of heavy fractions of the oil, temperature and the molar concentration of intermediates in the oil.

Eakin and Mitch (1988) produced a general equation using 102 rising bubble apparatus (RBA) experiment data. The input parameters are heptane plus fraction, molecular weight, solvent composition and the pseudoreduced temperatures.

Many available MMP correlations in the literature are developed for $CO_2$ or impure $CO_2$ flooding. The evaluated MMP correlations in this study are suitable for hydrocarbon flooding. The reliability of each individual correlation was evaluated by determining, how close the predictive MMPs are to the equation-of-state based results. A comparative evaluation of MMP correlations is one of the objectives of this investigation. The following MMP correlations will be evaluated in the present study.

### 1.3 Glasø Correlation

Glasø (1980) proposed a correlation for predicting minimum miscibility pressure of multicontact miscible displacement of reservoir fluid by hydrocarbon gases, $N_2$ and $CO_2$. These equations are the equation form of the Benham[6] et al. correlation. These equations give the MMP as a function of reservoir temperature, molecular weight of $C_{7+}$, mole percent ethane in the injection gas and the molecular weight of the intermediates ($C_2$ through $C_6$) in the gas.

The proposed equations by Glasø (1980) are as follows:

$$(MMP)_{x=34} = 6{,}329 - 25.410\times y - (46.475 - 0.185\times y)\times z + (1.127\times10^{-12}\times y^{5.258}\times e^{319.8zy^{-1.703}})\times T. \quad (1)$$

$$(MMP)_{x=34} = 6{,}329 - 25.410\times y - (46.475 - 0.185\times y)\times z + (1.127\times10^{-12}\times y^{5.258}\times e^{319.8zy^{-1.703}})\times T. \quad (1)$$

$$(MMP)_{x=44} = 5{,}503 - 19.238\times y - (80.913 - 0.273\times y)\times z + (1.7\times10^{-9}\times y^{3.730}\times e^{13.567zy^{-1.508}})\times T. \quad (2)$$

Where,

$x$= is the molecular weight of $C_2$ through $C_6$ components in injection gas, in lbm/mol,

$y$= is corrected molecular weight of $C_{7+}$ in the stock-tank oil in lbm/mole and is equal to:

$$y = \left(\frac{2.622}{\gamma_{C_{7+}}^{-0.846}}\right)^{6.558}$$

$\gamma_{C7+}$ =specific gravity of heptane-plus fraction, and

$z$ = mole percent methane in injection gas

Prediction of the MMP for $x$ values other than those specified by the mentioned equations should be obtained by interpolation. The accuracy of the MMP predicted from the three mentioned equations is related to the accuracy of the mole percent methane in the injection gas and the molecular weight of $C_{7+}$ in the stock tank oil. The corrected molecular weight of the stock tank oil ($y$) indicates the paraffinicity of the oil which affects the MMP. The paraffinicity of the oil influences the solubility of hydrocarbon gas in the oil (Cook et al., 1969). Oil with paraffinicity characterization factor less than 11.95 represents oil with a relatively high content of aromatic components and consequently has corresponding higher MMPs.

### 1.4 Firoozabadi et al. Correlation

A simple correlation proposed by Firoozabadi et al. (1986) predicts MMP of reservoir fluids using lean natural gas or $N_2$ for injection. Three parameters account the effect of multiple-contact miscibility of a reservoir fluid under $N_2$ or lean gas flooding: The concentration of intermediates, the volatility, and the temperature.

The correlating parameter includes the ratio of the intermediates (mole percent) divided by molecular weight of the $C_{7+}$ fraction. Intermediates contents of a reservoir fluid are usually attributed to the presence of $C_2$ through $C_6$, $CO_2$, and $H_2S$.

Firoozabadi et al. (1986) observed that exclusion of $C_6$ from intermediates improves the correlation of the MMP. Therefore, intermediates in this study are defined by $C_2$ through $C_5$ and $CO_2$ components. The heptane plus molecular weight provides an indication of the oil volatility. The equation is as follow:

$$MMP = 9{,}433 - 188\times10^3 \times \left(\frac{x_{int}}{M_{C7+}T^{0.25}}\right) + 1430\times10^3 \times \left(\frac{x_{int}}{M_{C7+}T^{0.25}}\right)^2 \quad (4)$$

Where: MMP = Minimum Miscibility pressure, psi $x_{int} = x_{co_2} + \sum_{i=2}^{i=5} x_i$ = mole percent intermediates in the oil, and, $M_{C7+}$ = molecular weight of heptane plus.

It should be noted that Peng-Robinson Equation-of-State (PR-EOS) based correlation proposed in this method is primary for estimating MMPs of VGD mechanisms by $N_2$ or lean hydrocarbon gases. The dependency of MMP on reservoir temperature is not well presented in this equation. More data are required to improve this temperature dependency (Firoozabadi et al. 1986).

### 1.5 Eakin and Mitch Correlation

The MMP data of combinations of oils, temperatures and solvents observed by Rising Bubble Apparatus (RBA) were represented by Eakin and Mitch (1988) correlation. Input variables for this equation are solvent composition, $C_{7+}$ molecular weight, and the pseudoreduced temperature of the reservoir fluid. The base solvents used in their study were nitrogen, flue gas, carbon dioxide, and rich and lean natural gases. RBA is an alternative and much quicker apparatus for determining MMP but the obtained MMP is usually higher than the measured MMP by a slim-tube apparatus.

Kay's rules were used to calculate pseudocritical temperature, Tpc, and pseudocritical pressure, Ppc, of the oil (Kay, 1936).The general proposed correlation by Eakin and Mitch is:

$$\begin{aligned}\ln p_{pr} = \ln(MMP/p_{pc}) &= (0.1697 - 0.06912/T_{pr})\times y_{c_1}\times M_{C7+}^{0.5} \\ &+ (2.3865 - 0.005955\frac{M_{C7+}}{T_{pr}})\times y_{C2+} \\ &+ (0.01221 M_{C7+} - 0.0005899\frac{M_{C7+}^{1.5}}{T_{pr}})\times y_{CO_2}\end{aligned} \quad (5)$$

This correlation has a standard deviation factor of 4.8% from the measured MMP values. The measured MMPs are only for two recombined sample of reservoir fluids with API gravities of 36.8 and 25.4, at 180 and 240°F.

### 1.6 Thermodynamic Method

In this method, selected EOS is calibrated to experimental PVT data including swelling and slim-tube measurements. Using of reliable experimental data in tuning EOS makes EOS (thermodynamic) methods the most reliable prediction methods.

In this method minimum miscibility pressure is explained traditionally by ternary diagrams. The limiting tie line is the extension of the tie line passing through the composition of the original oil and the tie line which passes through the critical point of the ternary diagram is called critical tie line. Monroe et al. (1987) showed three key tie lines which control displacement behavior in the reservoir: The tie lines that extend through injection gas composition, the tie line passing through the oil composition, and the third tie line called "the crossover tie line". Multi contact miscibility occurs if any of these tie lines correspond to the critical tie line. In vaporizing gas drive mechanisms miscibility is controlled only by the limiting tie line passing through the oil composition and is not dependent on injection gas composition. The gas phase composition varies along the dew-point phase boundary expressed at constant pressure and temperature in a pseudoternary diagrams towards the critical point composition. In condensing drive mechanisms the key tie line passing through the injection gas composition controls the development of miscibility. In this displacement mechanism miscibility is obtained at the site of injection. The intermediate components are condensed from the injection gas to the reservoir oil and miscibility develops as the tie line passing through the injection gas composition becomes the critical tie line expressed in ternary diagram model. Orr et al. (1987) and Johns et al. (1993) showed that crossover tie line controls the development of miscibility in combined vaporizing-condensing mechanisms.

### 1.7 Comparative Investigation of MMP Correlations

Multiple contact miscibility achieved by injection of lean hydrocarbon or flue gas into the reservoir is one of the most widely used oil recovery methods in the oil industry. The economic success of gas injection project can be improved by operating at pressures close to MMP. However, this requires accurate experimental measurements of MMP. The current proposed MMP correlations may be good substitute for both costly and time consuming experimental measurements.

Unfortunately, most of the MMP correlations are not flexible to represent a variety of solvent/oil combinations and care must be taken when selecting one of them. Reliable MMP correlations should be used for preliminary screening or feasibility studies, but should not be relied upon. The first part of this study provides an evaluation of the existing lean hydrocarbon or impure $CO_2$-stream MMP correlations published in the literature.

## 1.8 Reservoir Fluid Composition

To investigate the effect of oil composition on estimated minimum miscibility pressure, two different oil samples (reported by Core Laboratories, INC.) with API gravities of 20.8 and 44.5 have been considered. Table 1 provides composition data of these reservoir fluids. Mole percent of heptanes plus fraction (greater than 20%) and high critical point temperature compare to typical reservoir temperature, are indicative of black oil system. The reported simulation results in this chapter are the results of using PVTsim in modeling phase behavior of both reservoir fluids (Schlumberger, 2001).

**Table 1**
**Reservoir Oil Compositions at First Part of the Study (Reported by Core Laboratories, INC.)**

| Component | Oil A, mole% | Oil B, mole% |
|---|---|---|
| $N_2$ | 0.03 | 1.85 |
| $CO_2$ | 0.05 | 0.26 |
| $C_1$ | 28.24 | 38.85 |
| $C_2$ | 0.6 | 10.85 |
| $C_3$ | 1.23 | 7.28 |
| $iC_4$ | 0.47 | 2.81 |
| $nC_4$ | 1.38 | 3.44 |
| $iC_5$ | 0.86 | 2.33 |
| $nC_5$ | 1.06 | 1.52 |
| $C_6$ | 1.39 | 3.29 |
| $C_{7+}$ | 64.69 | 27.52 |
| $C_{7+}$ Properties: | | |
| Molecular Weight | 308 | 175 |
| Oil gravity, °API | 20.8 | 44.5 |

**Table 2**
**Injection Gas Composition**

| Component/Gas | A1 | A2 | A3 | B1 | B2 | B3 |
|---|---|---|---|---|---|---|
| $N_2$ | 0.289 | 0.216 | 0.188 | 7.401 | 5.366 | 4.1 |
| $CO_2$ | 0.079 | 0.101 | 0.115 | 0.307 | 0.35 | 0.355 |
| $C_1$ | 98.038 | 96.482 | 94.211 | 77.582 | 71.203 | 63.337 |
| $C_2$ | 0.556 | 0.779 | 0.938 | 8.763 | 11.163 | 12.321 |
| $C_3$ | 0.457 | 0.805 | 1.131 | 3.128 | 4.99 | 6.43 |
| $iC_4$ | 0.096 | 0.195 | 0.301 | 0.802 | 1.471 | 2.096 |
| $nC_4$ | 0.21 | 0.458 | 0.748 | 0.798 | 1.577 | 2.368 |
| $iC_5$ | 0.069 | 0.176 | 0.321 | 0.349 | 0.803 | 1.347 |
| $nC_5$ | 0.069 | 0.187 | 0.355 | 0.196 | 0.478 | 0.834 |
| $C_6$ | 0.041 | 0.136 | 0.296 | 0.248 | 0.731 | 1.462 |
| $C_7$ | 0.049 | 0.199 | 0.507 | 0.188 | 0.66 | 1.493 |
| $C_8$ | 0.027 | 0.125 | 0.351 | 0.11 | 0.443 | 1.106 |
| $C_9$ | 0.013 | 0.071 | 0.226 | 0.059 | 0.281 | 0.792 |
| $C_{10+}$ | 0.007 | 0.07 | 0.312 | 0.069 | 0.484 | 1.959 |
| $C_{10+}$ Properties: | | | | | | |
| Molecular Weight | 162.71 | 164.74 | 168.43 | 150.16 | 157.29 | 167.66 |
| Density,lb/ft$^3$ | 51.48 | 51.71 | 52.14 | 50.67 | 51.46 | 52.65 |
| Injection Gas Properties: | | | | | | |
| Gas A1:Flash of oil A @ T=100 °F & P=1,200 psi | | | | | | |
| Gas A2:Flash of oil A @ T=200 °F & P=1,500 psi | | | | | | |
| Gas A3:Flash of oil A @ T=300 °F & P=1,800 psi | | | | | | |
| Gas B1:Flash of oil B @ T=100 °F & P=1,900 psi | | | | | | |
| Gas B2:Flash of oil B @ T=200 °F & P=2,400 psi | | | | | | |
| Gas B3:Flash of oil B @ T=300 °F & P=2,800 psi | | | | | | |

### 1.9 Injection Gas Composition

It is most economical to re-inject all or part of the produced dry gas back into the reservoir. Produced gas of the reservoir is an alternative source for gas injection and pressure maintenance processes. To achieve this purpose, the compositions of the injection gases are close to the equilibrium gas with the reservoir fluid. For each reservoir fluid (oil A and oil B), flash calculations at different temperatures (100, 200 and 300 °F) and at pressures, below the corresponding bubble point pressure of the oil at that temperature (Table 2), were made and the separator gas as a result of flash process, has been considered as the injection gas. The higher the temperature of the flash condition, the richer the gas is in intermediate components.

### 1.10 Correlation Results

There are only a few correlations applicable for this investigation. Most of the proposed MMP correlations are presented for $CO_2$ flooding rather than hydrocarbon flooding which is a general case. Among the MMP correlations mentioned above, Firoozabadi et al. (1986) are correlations that are not dependent on injection gas composition. Eakin and Mitch (1988) and Glasø (1985) correlations consider effects of gas and oil compositions in predicting MMPs.

Two different oil samples along with three injection gas compositions for each specific oil gravity cause various combination of gas flooding processes. Tables 3 through Table 5 indicate the predicted MMPs using the three correlations described above. As we know the heavier the reservoir fluid, the higher MMP is required to achieve miscibility. Reservoir fluid with API gravity of 20.8 (oil A) requires the highest MMPs. The injection gas with higher percentage of intermediate components provides lower MMPs for a specified oil reservoir. Therefore, the required MMP to achieve dynamic miscibility for oil A (lower API), is highest for injection gas A1 (leanest) and lowest for injection gas A3 (richest). As mentioned before, the injection gases used in this study are the separator gases which are the result of flash calculations. The separator gas with higher flash temperature contains more intermediate components and is most desirable in gas injection processes.

**Table 3**
**Predicted MMPs Using Eakin and Mitch[11] Correlation**

| Reservoir Temperature, °F | MMP of Oil A (psia) | | | MMP of Oil B (psia) | | |
|---|---|---|---|---|---|---|
| | Gas A1 | Gas A2 | Gas A3 | Gas B1 | Gas B2 | Gas B3 |
| 100 | 6,067 | 5,856 | 5,532 | 3,511 | 3,263 | 2,936 |
| 200 | 6,808 | 6,594 | 6,265 | 3,840 | 3,610 | 3,295 |
| 300 | 7,411 | 7,197 | 6,866 | 4,102 | 3,889 | 3,587 |

Table 3 represents the predicted results using Eakin and Mitch (1988) correlation. Estimated MMP results are provided at reservoir temperatures of 100, 200 and 300 °F. The MMP for oil A and injection gases A1, A2 and A3 is trend consistent.

**Table 4**
**Predicted MMPs by Firoozabadi[10] et al. Correlation (This Correlation like Majority of Lean Gas MMP Correlations Ignores the Effect of Injection Gas Composition)**

| Reservoir Temperature, °F | MMP of Oil A (psia) | MMP of Oil B (psia) |
|---|---|---|
| | Injection gases:A1, A2, A3 | Injection gases:B1, B2, B3 |
| 100 | 8,399 | 3,564 |
| 200 | 8,557 | 4,000 |
| 300 | 8,639 | 4,294 |

The only parameters in Firoozabadi et al. (1986) correlation for vaporizing-drive mechanism are the concentration of intermediates, the oil volatility, and reservoir temperature. This correlation doesn't account for varying injection gas compositions and the estimated MMPs for light oil is relatively not dependent on injection gas composition. Predicted MMP results for reservoir fluids A and B are presented in Table 4.

**Table 5**
**Predicted MMPs Using Glasø[7] Correlation. This Correlation Predicts Unreliable MMPs for Oil A and very Low Values for Injection Gas B2**

| Reservoir Temperature, °F | MMP of Oil A (psia) | | MMP of Oil B (psia) | |
|---|---|---|---|---|
| | Gas A1 | Gas A2 | Gas B1 | Gas B2 |
| 100 | 3,640 | 8,716 | 1,682 | 540 |
| 200 | 6,966 | 18,025 | 3,204 | 1,077 |
| 300 | 10,313 | 27,334 | 4,726 | 1,612 |

Table 5 indicates the correlation results using Glasø (1985) correlation. Unlike the previous correlation this correlation estimates the MMP of fluid with API gravity of 20.8 much higher than the other reservoir fluid but the effect of injection gas composition seems to be negligible. Gas A1 should provide the highest MMPs due to low concentrations of its intermediate components compared to A2 but the results are anomalous. Low estimated MMP values for injection gas B2 seem to be abnormal.

The discrepancy among these correlations makes the selection impossible unless there is evidence that correlation was adequate for an oil/solvent with similar characteristics.

### 1.11 Comparison of Simulation and Correlation Results

Since the reservoir fluid A is heavy the required MMP to achieve miscibility with injection gases A1, A2, and A3 are too high. Therefore, only reservoir fluid B with higher API gravity is appropriate for investigating multi-contact (VGD) miscibility pressures. Table 6 indicates the comparison of estimated MMPs (correlations) and simulation (Schlumberger, 2001b) results for oil B/Gas B1 system in VGD mechanism. Among these correlations Glasø[7] et al. correlation is strongly dependent on reservoir temperature. It can be clearly seen in this correlations that MMP values increase rapidly as temperature increases. Other correlations except for Glasø[7] approach, seems to represent parallel slopes and closer MMP values to each other.

**Table 6**
**Comparison of Simulation[1] (Peng-Robinson EOS-Based Model) and Correlation Results for Fluid B/ Injection Gas B1 System (Vaporizing-Gas Drive Mechanism)**

| T, °F | Simulation | Eakin | Glasø | Firoozabadi |
|---|---|---|---|---|
| 100 | 4,354 | 3,511 | 1,682 | 3,564 |
| 200 | 4,372 | 3,840 | 3,204 | 4,000 |
| 300 | 3,964 | 4,102 | 4,726 | 4,294 |

Evaluation of the accuracy of each MMP correlation illustrates that Firoozabadi et al. (1986) and Eakin and Mitch (1988) methods are found to be the most reliable correlations among the other ones. These correlations are EOS and statistic based models and the good agreement with simulation results could be attributed to this concept. As was mentioned before, simulation approach in calculating MMPs for different injection gas/oil systems is based on equation of state (EOS) model. It should be added that MMP data or other types of PVT data must be used to calibrate the EOS. The advantage of using EOS is that it is a self consistent method and can be easily tuned to available experimental data.

The large discrepancy of the Glasø (1985) correlation in predicting the vaporizing-gas drive MMPs is related to the limited slim tube experiments. This correlation was mostly developed from experimental slim tube MMP data of North Sea gas/oil system and special care should be paid to predict MMPs of other reservoir fluids.

As a general case, the evaluated MMP correlations in this study are not reliable and they should be applied with great care in particular situations even for preliminary MMP calculations and screening processes.

## 2. EVALUATION OF PARAMETERS ON MISCIBLE AND IMMISCIBLE GAS-INJECTION PROCESSES

Injection of cost-effective lean hydrocarbon gas or flue gases could be employed in reservoirs where a favorable combination of pressure, reservoir characteristics and fluid properties make the gas injection project a competitive process compare to other secondary oil recovery methods. However, for a gas injection project, to be competitive several conditions should be satisfied. The incremental oil recovery is largely dependent on injection pressure, reservoir characteristics and fluid properties such as heterogeneity, relative permeability, viscous fingering, fluid mobility, gravity segregation, etc.

In this section, following a reliable estimate of the MMP (based on both simulation and experimental results) a parametric study is done, using a 3D, compositional simulator to analyze the effect of such important parameters in miscible or immiscible performance recovery from the reservoir.

### 2.1 Field Description

The first constructed reservoir grid model is a two-layer homogenous model (9×9×2) with constant porosity (0.13), permeability, and thickness (40 ft). PVT data of the reservoir fluid including the injection gas composition are provided in Table 7.

**Table 7**
**Reservoir Fluid and Injection Gas Composition**

| Component | Reservoir Fluid, mole % | Injection Gas, mole % |
|---|---|---|
| $N_2$ | 0.92 | 0 |
| $CO_2$ | 0.32 | 0.877 |
| $C_1$ | 41.25 | 87.526 |
| $C_2$ | 8.68 | 6.36 |
| $C_3$ | 7.27 | 3.906 |
| $C_4$ | 4.9 | 1.331 |
| $C_5$ | 2.89 | 0 |
| $C_6$ | 4.29 | 0 |
| $C_{7+}$ | 29.48 | 0 |
| Heptanes Plus Properties: | | |
| Molecular Weight | | 202 |
| Specific Gravity | | 0.86 |

Reservoir fluid is initially undersaturated. The initial reservoir pressure is 4,300 psi and the saturation pressure of the reservoir fluid at 217 °F is 2,931 psi. Low water viscosity in the reservoir, 0.3 cp, giving rise to the low gas to oil mobility ratio. Setting the initial condition for the location of water/oil contact to 8,500 ft (80 ft below the oil zone), and setting the oil/water capillary pressure to zero could eliminate the transition zone between oil and water phases. The very small compressibility and volume of the water; however, makes water rather insignificant in this problem. Initial oil and water saturations are 0.78 and 0.22.

Injection well is perforated in the first layer whereas the production well is completed in the second layer and produced on deliverability against a 1,000 psi flowing bottomhole pressure. Lean gas with similar composition of the vapor phase in equilibrium with the reservoir fluid at reservoir temperature and at pressure slightly below the bubble point, is injected continuously into the first layer of the reservoir with average thickness of 40 ft. Constant injection pressure (4,800 psia) for the injection well is the only constraint applied to the injection well.

### 2.2 Relative Permeability Effect

The term miscible recovery is defined as any oil recovery displacement mechanism, where the phase boundary or interfacial tension between the displaced and displacing fluids is negligible. In this situation the capillary number becomes infinite and the residual oil saturation can be reduced to the lowest possible value because there is no interfacial tension (IFT) between the fluids. Setting the reference surface tension defines the interpolation factor as:

$$F = \left(\frac{\sigma}{\sigma_0}\right)^N$$

Consequently the appropriate relative permeability curve dependent on dominant flow will be used by the following equation:

$$K_{ro} = FK_{ro}^{imm} + (1-F)K_{ro}^{mis} \qquad (6)$$

In this section, miscibility option is imposed by setting an arbitary high reference surface tension ($\sigma_0$). The immiscibility factor approaches to zero for gridblocks containing two phases become fully miscible ($\sigma \approx 0$) and form a single phase. Simulation runs conducted at injection pressure of 4,800 psi (This is the estimated MMP value determined for injection gas/reservoir fluid system at reservoir temperature of 217 °F) for two cases of miscible (straight line $k_r$) and immiscible (input saturation data) option.

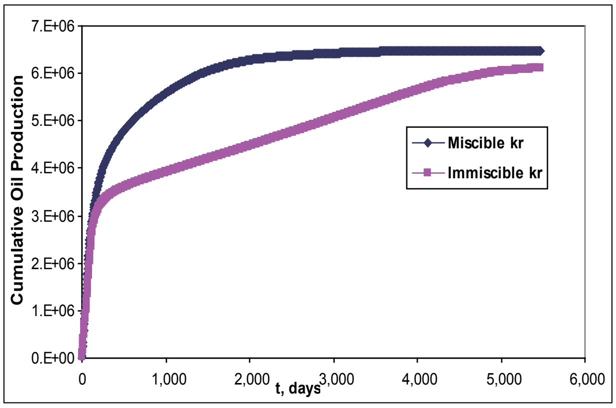



**Figure 1**
**Comparison of Cumulative Oil Production for Miscible and Immiscible Relative Permeabilities (Injection Pressure of 4,800 psi)**

Cumulative oil production and predicted recovery vs. pore volume of injection gas is provided in Fig. 1. Distinct recovery trends are estimated for different miscible and immiscible relative permeabilities. The calculated oil recoveries at 1.2 pore volume of injected gas for miscible $k_r$ and immiscible $k_r$ are 73.5% and 55.4% of OOIP. In other word, 18.1% OOIP is the incremental oil recovery using miscible $k_r$ for the same injection pressure and pore volumes of injection gas as those of immiscible ones. Moreover, the revenue from additional oil recovery is concentrated in the early life of the project and the rate of return of investment using miscible $k_r$ is higher compare with that of immiscible $k_r$. Considerable amount of recoverable oil is produces up to nearly seven years of gas injection for miscible $k_r$. Therefore it is most beneficial to stop flooding at this time, since only a maximum of 0.1% OOIP incremental oil recovery is predicted at the end of the project which is at 15 years of injection.

It should be noted that for highly undersaturated reservoirs with high-gravity crude oils, which is this case study, recovery increases significantly by initiating gas injection project at the highest pressure possible, even though miscibility is not developed. The improvement in recovery efficiency is mainly the result of reduction in oil viscosity, oil swelling, and vaporization of the residual oil. Recovery in miscible displacement is strongly sensitive to changes in fluid properties and reduction in interfacial tension, resulting in variation of the relative permeability endpoints.

### 2.3 Injection Pressure Effect

In this part of the study, the effect of injection pressure on the oil recovery from the entire symmetrical grid model has been investigated. Injection and production wells are completed in the first and second layer, respectively. Estimated MMP based on equation of state analytical method is approximately 4,800 psi. Simulation runs have been conducted at pressures below, equal to and greater than this pressure (4400, 5000, 5600 and 6200 psi). Since in vaporizing drive mechanisms, the pressure at miscible front should be greater than the predicted miscible pressure, injection of gas at 5,000 psi will raise the average reservoir pressure from initial pressure to the miscibility pressure of 4,800 psi. Therefore, the injection pressure of 5,000 psi seems to be the best candidate for representing MMP in simulation model. Estimated recoveries at 1.2 pore volume of injected gas are about 50.9, 75.2, 79.6, and 82.6% OOIP which are attainable after 677, 537, 486, and 444 days of continuous gas injection, respectively.

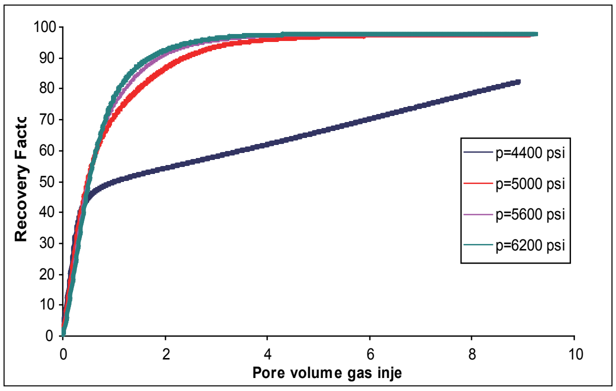
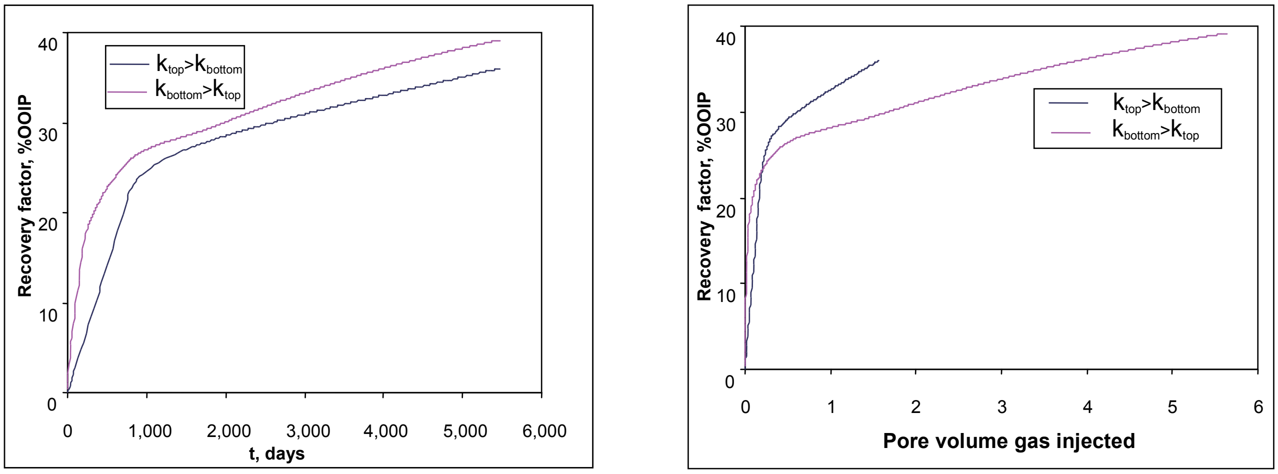



**Figure 2**
**Incremental Oil Recovery After Around 4 Pore Volume of Injected Gas is Marginal at Pressures Above MMP**

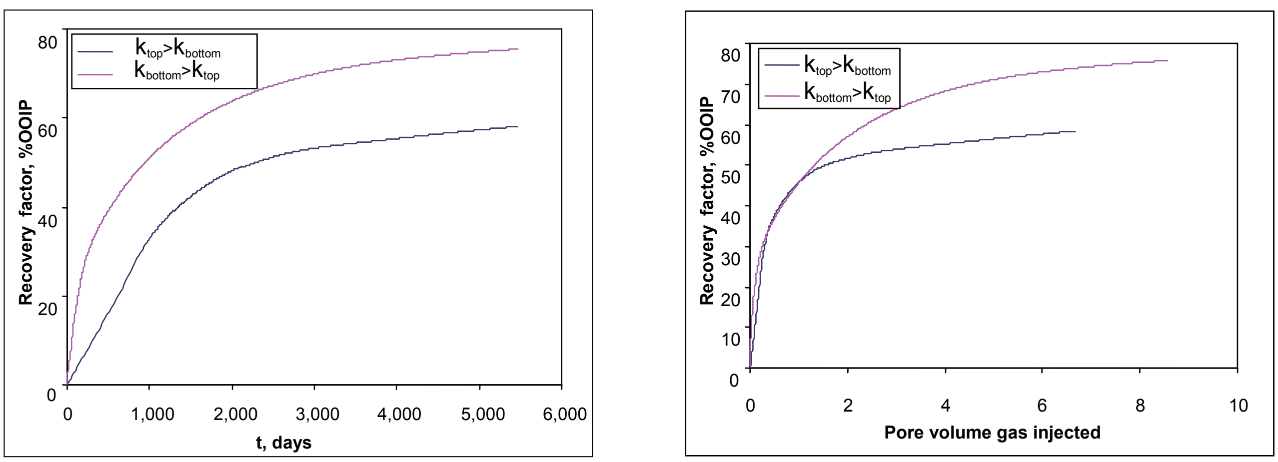
It is clearly seen in Fig. 2 that incremental oil recovery due to miscible injection is paramount; however the marginal increase in oil recovery as the result of injection at pressures higher than MMP may not compensate for additional equipment and operating costs at greater pressures. Oil recoveries are usually greatest when the gas injection process is operated under miscible conditions. Miscibility can be achieved by managing the reservoir pressure. Under appropriate condition of achieving miscibility, MMP will be the optimum injection pressure.

**Table 8**
**Reservoir Grid Data (Stratified Reservoir) and Water Properties**

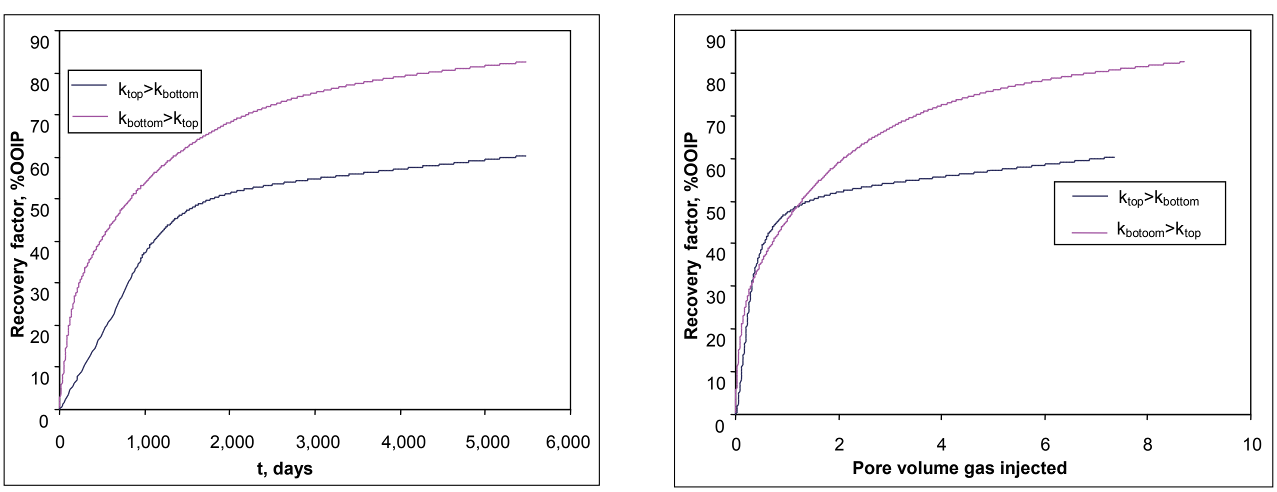
| Reservoir Grid Data | | | | |
|---|---|---|---|---|
| NX=NY=9, NZ=2 | | | | |
| DX=DY=293.3 ft | | | | |
| Porosity | | | | 0.13 |
| Datum (subsurface), ft | | | | 8,420 |
| Oil/water contact, ft | | | | 8,500 |
| Capillary pressure at contact, psi | | | | 0 |
| Initial pressure, psi | | | | 4,300 |
| Reservoir temperature, °F | | | | 217 |
| Layer | Horizontal permeability | Vertical Permeability | Thickness, ft | Depth to top (ft) |
| 1 | 90 (3) | 9 (0.3) | 40 | 8,340 |
| 2 | 3 (90) | 0.3 (9) | 40 | 8,380 |
| Water properties | | | | |
| Compressibility, $psi^{-1}$ | | | | $3 \times 10^{-6}$ |
| Density, $lbm/ft^3$ | | | | 63 |
| Rock compressibility, $psi^{-1}$ | | | | $4 \times 10^{-6}$ |
| Viscosity, cp | | | | 0.3 |




**a) Estimated Oil Recovery at Injection Pressure of 4,400 psi**




**b) Estimated Oil Recovery at Minimum Miscibility Pressure of 5,000 psi**




**c) Estimated Oil Recovery at Injection Pressure of 5,600 psi**

**Figure 3**
**Stratification Effect on Oil Recovery at Different Injection Pressures**

### 2.4 Stratification Effect

Conformance efficiency is one of the determinant factors that control maximum oil recovery from a reservoir. Conformance efficiency is defined as the fraction of the total pore volume within the pattern area that is contacted by the displacing fluid. The dominating factors that control conformance area are the gross sand heterogeneity and size distribution of the rock interstices, which usually are defined in terms of permeability variation or stratification.

Two new stratified reservoir models were constructed to ascertain the effect of stratification on the miscible and immiscible oil recovery processes. The new constructed model (Table 8) is a two-layer stratified reservoir. The layers have horizontal permeability values of 90 and 3 mD, and vertical permeabilities of 9 and 0.3 mD, respectively. The ratio of horizontal to vertical permeabilities of each layer is 10. In all of the simulation models the injection and production wells are completed in the first and second layers of the reservoir, respectively (one reservoir has $k_{top}$= 90, $k_{bottom}$=3 mD and anther one has $k_{top}$= 3, $k_{bottom}$=90 mD).

**Table 9**
**Comparison of Oil Recovery at 1.2 Pore Volume of Injected Gas (Injection is Always in the Top Layer and Production from the Bottom of the Reservoir)**

| Injection Pressure, psi | Predicted Oil Recovery and GOR at 1.2 Pore Volume of Injected Gas | | | |
|---|---|---|---|---|
| | $k_{top}$> $k_{bottom}$ ( $k_{top}$ =90 mD ; $k_{bottom}$ =3 mD) | | $k_{bottom}$ > $k_{top}$ ( $k_{top}$ =3 mD ; $k_{bottom}$ =90 mD) | |
| | t, days | Rec., %OOIP | t, days | Rec., %OOIP |
| 4,400 | 4,378 | 33.8 | 1,546 | 28.6 |
| 5,000 | 1,955 | 47.7 | 854 | 48.4 |
| 5,600 | 1,633 | 48.7 | 784 | 48.8 |

Table 9 summarizes the simulation results regarding recovery performance of the stratified reservoir under miscible and immiscible gas injection. The calculated oil recoveries are provided at 1.2 pore volume of gas injected and for the cases where the higher permeable layer is located in the upper or lower part of the reservoir. The injection and production wells are completed in the first and second layers of the reservoir, respectively. Recovery performance of the stratified reservoir during 15 years of miscible or immiscible gas injection of the reservoir is presented in Fig. 3. The predicted recoveries are presented as function of time and volume of injected gas at the same time. Comparison of the simulation results leads to the following conclusions:

(1) Significant increase in oil recovery is observed for a miscible displacement mechanism. Incremental oil recovery between injection pressures of 5,000 and 5,600 psi indicates minimum miscibility pressure (5,000 psi) as the optimum injection pressure from economic point of view.

(2) Comparison of the estimated recovery values for two different cases, $k_{top}$ > $k_{bottom}$ ($k_{top}$ =90 mD and $k_{bottom}$ =3 mD) and $k_{bottom}$ > $k_{top}$ ($k_{top}$ =3 mD and $k_{bottom}$ =90 mD), indicate the key factor that determines the effect of layering on oil recovery at a particular injection pressure, is the vertical location of the high-permeability streak in the stratified reservoir. If the high permeability layer is located in the lower half of the reservoir ($k_{bottom}$ > $k_{top}$), the oil recovery improves since the combination of the stratification and gravity effects retard the segregation of the gas into the top portion of the reservoir cross-section. This effect is more evident in miscible displacement mechanism where the gas is injected at pressures equal to or above MMP value. It should be noted that in making this comparison, the determinant time factor in evaluating the incremental oil recovery or project economics should be taken into account. Reported recovery values for the second case, where the more permeable layer is located on the lower half of the reservoir ($k_{bottom}$ > $k_{top}$), are in earlier times of project life compare with those of the first case.

(3) High potential of gas injectivity (smaller times required to inject 1.2 pore volume of gas) when $k_{bottom}$ > $k_{top}$ makes this case advantageous in comparison for the other case where $k_{top}$> $k_{bottom}$.

### 2.5 Interface Tension and Mobility Ratio Effects

Oil recovery by miscible flooding has not been applicable as widely as waterflooding. Unlike the case for miscible flooding, waterflooding can be employed successfully from both technical and economic point of view in most oil recovery projects. In this part of the study, appropriate questions, when evaluating a gas injection design are discussed with more details.

The benefit of gas injection is mostly because of the fact that it exhibits better surface tension effect than water. High cost includes operating and equipment costs, solvent availability, and pressure/composition requirements for miscibility are the major limiting factors in miscible flooding. Nevertheless, the interfacial tension benefit can often outweigh the extra expense.

The benefit of gas injection can be easily concluded from the relation of capillary pressure as a function of interfacial tension and pore throat radius. Capillary pressure is proportional to the interfacial tension and inversely proportional to the pore throat radius. This indicates that as long as the water-oil interfacial tension is greater than the gas-oil interfacial tension, gas injection, no matter how immiscible, would be of benefit since the smaller pore throats will be accessed during gas injection. However, adverse mobility ratio which originates from large oil/gas viscosity ratio (range of oil viscosity, 0.23-0.31 cp), associated in most gas injection projects makes this recovery method risky. Therefore, understanding the interaction between interfacial tension and adverse mobility ratio is subject of great importance for a gas injection project. Next section is the simulation approach that is followed to investigate the effect of mobility ratio and interfacial tension on the recovery of the reservoir.

An 18×18×3 cross-section model is used in this simulation to make a quarter of a five-spot pattern (Table 10). The three layers of the reservoir are homogeneous with constant porosity, permeability and thickness values. It should be noted that miscible gas recoveries are not sensitive to the shape of the relative permeability curves. As miscibility develops, the saturation curve approaches to the straight line with different endpoints relative permeabilities.

**Table 10**
**Reservoir Data and Water Properties**

| Reservoir Grid Data | | | | |
|---|---|---|---|---|
| NX=NY=18, | | | | |
| NZ=3 | | | | |
| DX=DY=293.3 ft, DZ=27 ft | | | | |
| Porosity | | | | 0.13 |
| Datum (subsurface), ft | | | | 8,421 |
| Oil/water contact, ft | | | | 8,600 |
| Capillary pressure at contact, psi | | | | 0 |
| Initial pressure, psi | | | | 4,300 |
| Water Properties | | | | |
| Compressibility, $psi^{-1}$ | | | | $3\times10^{-6}$ |
| Density, $lbm/ft^3$ | | | | 63 |
| Rock compressibility, $psi^{-1}$ | | | | $4*10^{-6}$ |
| Layer | Horizontal Permeability | Vertical Permeability | Thickness, ft | Depth to Top (ft) |
| 1 | 90 | 0.9 | 27 | 8,340 |
| 2 | 90 | 0.9 | 27 | 8,367 |
| 3 | 90 | 0.9 | 27 | 8,394 |

The average water viscosity 0.31 cp, which is close to the reservoir oil viscosity, gives rise to an exceptionally low and favorable mobility ratio for water-oil displacement. The varied fluid composition and injection gases are provided in Table 11.

The first dry injection gas A is intended to represent a dominated mobility ratio displacement, whereas the rich injection gas B represents an interfacial tension dominated factor occurring in the reservoir. The initial reservoir pressure is 4,300 psi and the saturation pressure of the reservoir fluid with API gravity of 33 is 2,255 psi.

Injection and production wells are located on the corners of the grid model to make a five-spot pattern. Gas injection well is perforated in the first and second layers of the reservoir, whereas, water injection and production wells are completed in the second and third layers. Constant injection pressure and reservoir volume water injection rate are the injection well constrains. The water injection rate is determined in such a way that same order of injected water and injected gas pore volumes at the end of the project would be injected. Minimum flowing bottomhole pressure of 1,000 psi is the production-well constrain especially at the early times of production where pressure declines dramatically.

The injection gas composition varies in such a case to have interfacial tension and mobility ratio dominated

**Table 11**
**Reservoir Fluid and Injection Gas Compositions**

| Gas Component | Reservoir Fluid | Injection Gas A | Injection Gas B |
|---|---|---|---|
| $N_2$ | 0.139 | 0.461 | 0.67 |
| $CO_2$ | 0.049 | 0.266 | 5.03 |
| $C_1$ | 34.279 | 78.923 | 60.95 |
| $C_2$ | 4.364 | 18.34 | 23.76 |
| $C_3$ | 3.486 | 2.01 | 9.59 |
| $iC_4$ | 2.633 | 0 | 0 |
| $iC_5$ | 4.875 | 0 | 0 |
| $C_6$ | 3.771 | 0 | 0 |
| $C_{7+}$ | 46.464 | 0 | 0 |
| Heptanes plus properties: | | | |
| Molecular weight: 202 | | | |
| Specific gravity: 0.86 | | | |
| Oil viscosity: 0.31 cp | | | |
| Injection-gas A viscosity:0.02 cp | | | |
| Injection-gas B viscosity:0.04 cp | | | |

displacement mechanisms of the particular reservoir fluid. Mobility ratio of the lean injection-gas A (viscosity of 0.02 cp) and the reservoir fluid is around 15.6, whereas the calculated mobility ratio of the oil and the intermediate injection-gas B equals 7.8.

Recovery comparison is based on the differences between the estimated recovery for the gas and water injection projects. Unit mobility ratio is employed in simulating waterflooding project. Figs. 4 and 5 provide the oil recovery comparison results in mobility and interfacial surface tension dominated displacement mechanisms. The calculated recoveries at 1.2 pore volume of gas or water injection are 41.98 and 49.95 % OOIP for mobility dominated mechanism, and 75.46 and 50.32 % OOIP for interfacial tension dominated mechanism, respectively. As results indicate, for a mobility dominated displacement mechanism the viscous instabilities are more important than the interfacial tension effect and the injection gas composition is less important from an interfacial surface tension point of view. In these cases waterflooding with favorable mobility ratio yields higher oil recovery values (Fig. 4).

Absence of unfavorable mobility ratio in miscible flooding results in significant oil recovery due to the low interfacial tension between the injection gas and reservoir fluid (Fig. 5).

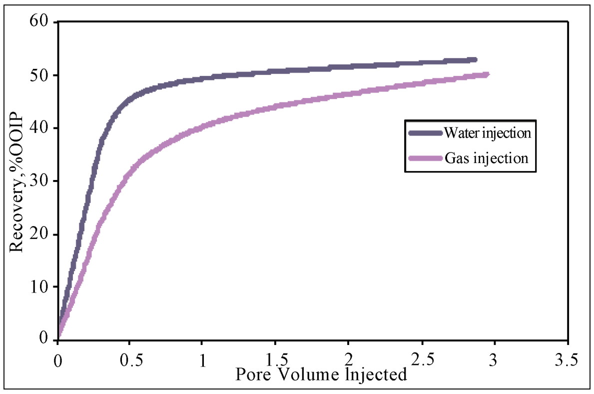



**Figure 4**
**High Mobility Ratio in Gas Injection Project Decreases the Oil Recovery from the Reservoir (Njection with Lean Gas A, Mobility Ratio=15.6)**

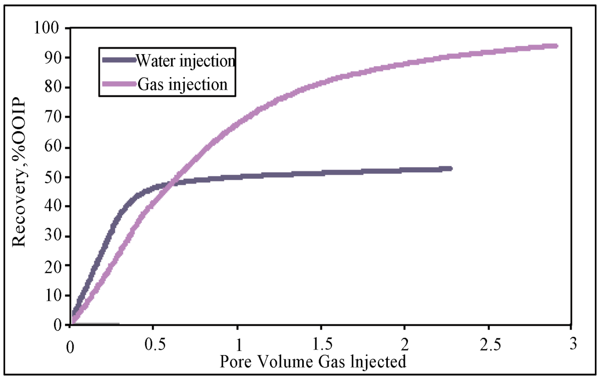



**Figure 5**
**Absence of Unfavorable Mobility Ratio in Miscible Flooding Improves the Oil Recovery to a High Degree (Injection with Rich Gas B, Mobility Ratio=7.8)**

## CONCLUSIONS

The first part of this study presented an evaluation of the existing MMP correlations published in the literature for lean hydrocarbon gases. The reliability of individual correlations was evaluated by determining, on average, how close the appropriate MMPs and EOS-based analytical calculations are. As a general observation, the evaluated MMP correlations studied in this investigation were not sufficient for preliminary MMP-calculation purposes. Many of these correlations have proven not to honor the effect of fluid composition properly. The methods of Firoozabadi[10] et al. and Eakin and Mitch were found to be the most reliable of the correlations tested. In most cases EOS-based analytical methods seemed to be more conservative in predicting MMP values. Hence, experimental MMP measurements would also be required for the design of gas-injection projects and calibration of fluid model.

Following a reliable estimate of MMP, numerous compositional simulation models were used to investigate the effect of key parameters in miscible or immiscible recovery performance of the reservoir. Distinct recovery trends were observed using different miscible and immiscible relative permeabilities. For the same injection pressure and pore volumes of injection gas as those of immiscible relative permeability curve, the incremental oil recovery using miscible $k_r$, was substantial.

Incremental oil recovery was determined by injection pressure. Pressure was the key parameter in determining whether or not the injection gas will be miscible with the in-situ oil. A multiple-contact miscible process was proven viable to increase the oil recovery to a high degree. Oil recoveries were usually greater when the gas-injection process was operated under miscible conditions. Miscibility can be achieved by injecting gas at pressures equal to or greater than MMP. At pressures higher than the MMP, the incremental recovery obtained was not substantial.

Comparison of estimated oil recoveries illustrated that stratification can affect oil recovery substantially. The major factor on the stratification effects was the vertical location of the higher-permeability layer. A high-permeability layer located in the lower half of the reservoir may improve the oil recovery potential. The maximization of oil recovery for this case may be the result of a combination of vertical displacement caused by gravity override and horizontal displacement of the oil by the high-permeability layer.

If a system is viscosity-dominated, the injection-gas composition may not be important from an interfacial tension perspective. In this situation, an alternative waterflooding recovery method may show more productivity improvement even with less investment. Therefore, understanding the effect of adverse mobility ratio and interfacial tension on the recovery of the reservoir is of great importance for a gas injection project to be implemented successfully.

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