EVALUATING GAS INJECTION PERFORMANCE IN VERY LOW PERMEABILITY, THICK CARBONATE GAS-CONDENSATE RESERVOIRS TO IMPROVE ULTIMATE LIQUID YIELD

by

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A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the Master of Science (Petroleum Engineering).

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ABSTRACT

Gas-condensate reservoirs are thermodynamically complex and require sound reservoir engineering solutions. The main challenge is to recover more condensate because it has a higher market value than that of produced gas. Therefore, in this study we have revisited different gas injection practices to improve the liquid yield and to suggest an optimal gas injection scheme for a thick, low-permeability carbonate reservoir, which also has a compositional variation with depth.

The reservoir model is a 1500 feet thick carbonate reservoir with 5 md permeability in horizontal directions. The vertical permeability of the reservoir is 1 md. The reservoir fluid properties vary with depth, so the liquid-rich zone with 225 STB/MMscf condensate-gas ratio is located at the bottom of the reservoir. Constant volume depletion simulation studies indicated that the maximum liquid dropout of 47 percent occurred near the gas-oil contact. Therefore, a slight pressure reduction below the dewpoint pressure can immediately cause condensation of the liquid. To evaluate the effectiveness of gas cycling in gas-condensate reservoirs, a compositional model was built. We used compositional gradient calculations to generate the reservoir fluid model. This ensured our model matched the measured PVT data, which indicated a composition variation trend with depth. Since the reservoir fluid had non-hydrocarbon gases, such as carbon dioxide, nitrogen, and hydrogen sulfide, this made it possible to re-inject them into the reservoir and analyze their effect on the condensate recovery in comparison with the dry gas.

Results showed that the 50 mol-% CH$_4$/ 50 mol-% N$_2$ gas injection initiated early in the reservoir production lead to higher recovery, 63 percent, which was 36 percent incremental recovery in comparison with the pressure depletion scenario, 27 percent. On the other hand, the lean gas, which in this study was comprised of 95 mol-% CH$_4$ and 5 mol-% C$_2$H$_6$ yielded almost the same cumulative condensate recovery, only 0.5 percent less than that of the 50 mol-% CH$_4$/ 50 mol-% N$_2$ gas mixture. These two alternative options were further studied in gas cycling operations conducted below the dewpoint pressure.

The results of gas injection scenarios operated below the dewpoint pressure demonstrated that the lean gas yielded more condensate, 44.7 percent of condensate initially in-place, than the 50 mol-% CH$_4$/ 50 mol-% N$_2$ gas mixture, 43.7 percent, but this difference was only one percent. Again, the lean gas and the CH$_4$-N$_2$ gas mixture proved their technical feasibility in such reservoirs. An overall condensate recovery during the gas injection below the dewpoint pressure was significantly less than the gas injection initiated in the early stage of production. For instance, the lean gas recovered only 44.7 percent of condensate initially in-place when the gas injection started after 10 years of production. The cumulative recovery for the
same lean gas reached 63 percent if the gas injection started in the beginning of reservoir development.

Additional injection cases studied in this thesis were the pure gases, such as methane, nitrogen, and carbon dioxide, non-acid gases containing hydrocarbon gases and nitrogen only and sour gas injection with some amount of CO$_2$ and H$_2$S. The results of these gases or gas mixtures were close to the lean and CH$_4$-N$_2$ gases. This study further mentioned advantages and disadvantages of using particular gases in the thick, low permeable gas-condensate reservoir case, but to apply these results in the real field scale, thorough economic analysis must be performed in the future and can only provide a better choice for an injection gas.

From the thesis results, we would, however, recommend injecting the 50 mol-% CH$_4$/ 50 mol-% N$_2$ gas mixture into the upper part of the reservoir, starting as early as possible to achieve the greatest condensate recovery.
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<td>Attraction parameter</td>
<td>–</td>
</tr>
<tr>
<td>$b$</td>
<td>Repulsion parameter</td>
<td>–</td>
</tr>
<tr>
<td>$D$</td>
<td>Depth</td>
<td>ft</td>
</tr>
<tr>
<td>$f_L$</td>
<td>Liquid fraction</td>
<td>fraction</td>
</tr>
<tr>
<td>$f_V$</td>
<td>Vapor fraction</td>
<td>fraction</td>
</tr>
<tr>
<td>$k$</td>
<td>Permeability</td>
<td>md</td>
</tr>
<tr>
<td>$k_r$</td>
<td>Relative permeability to phase</td>
<td>–</td>
</tr>
<tr>
<td>$n$</td>
<td>Number of moles</td>
<td>–</td>
</tr>
<tr>
<td>$p$</td>
<td>Pressure of the phase</td>
<td>psi</td>
</tr>
<tr>
<td>$q$</td>
<td>Volumetric flow rate</td>
<td>ft$^3$/day</td>
</tr>
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<td>$R$</td>
<td>Universal gas constant</td>
<td>psi-ft$^3$/lb-mole/°R</td>
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<td>$S$</td>
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<td>fraction</td>
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<tr>
<td>$V$</td>
<td>Volume</td>
<td>ft$^3$</td>
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<tr>
<td>$v$</td>
<td>Superficial (Darcy’s) velocity</td>
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<td>Mole fraction of component in liquid phase</td>
<td>mol-%</td>
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<tr>
<td>$y$</td>
<td>Mole fraction of component in gas phase</td>
<td>mol-%</td>
</tr>
<tr>
<td>$z$</td>
<td>Overall mole fraction</td>
<td>mol-%</td>
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<td>$\zeta$</td>
<td>Molar density</td>
<td>lb-mole/ft$^3$</td>
</tr>
<tr>
<td>$\theta$</td>
<td>Contact angle</td>
<td>°</td>
</tr>
<tr>
<td>$\kappa$</td>
<td>Equation of state parameter</td>
<td>–</td>
</tr>
<tr>
<td>$\lambda$</td>
<td>Mobility of fluid</td>
<td>1/cp</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Fluid viscosity</td>
<td>cp</td>
</tr>
<tr>
<td>$\nu$</td>
<td>Specific molar volume</td>
<td>ft$^3$/lb-mole</td>
</tr>
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<td>$\rho$</td>
<td>Fluid density</td>
<td>lb/ft$^3$</td>
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<td>$\sigma$</td>
<td>Interfacial tension</td>
<td>dynes/cm</td>
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<td>$\phi$</td>
<td>Rock porosity</td>
<td>fraction</td>
</tr>
<tr>
<td>$\omega$</td>
<td>Acentric factor</td>
<td>–</td>
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DISCLAIMER

The author was given some data during an internship with the Karachaganak Petroleum Operating Company (KPO). The views expressed in this thesis are those of the student and do not necessarily express the views of KPO. The conclusions of the thesis are based only on the available data, which, in fact, might not represent the actual field data.
CHAPTER 1
INTRODUCTION

The current economic and social life of humankind is dependent on energy resources, which are mainly represented by oil and natural gas and their products. In the petroleum industry, there is a significant distinction between the two. Oil has more value than a gas and a major effort taken by petroleum companies is to develop fields with the most hydrocarbon liquid yield. Gas-condensate reservoirs are invaluable sources of hydrocarbon liquids, but at the same time, are thermodynamically complex reservoir systems.

One of the main petroleum engineering issues related to the gas-condensate reservoirs is that when the pressure drops below the dew point pressure, condensate dropout occurs within the reservoir. Moreover, high gas production rates cause a great pressure drop near the wellbore region, which in turn causes condensate dropout around the well. This problem is often called a condensate blockage. The condensate dropout both in well and field scales means a considerable loss of revenue coming from selling the condensate liquid. The problem is further complicated by the occurrence of the gas-condensate reservoir in a carbonate formation, where geological uncertainties, reservoir heterogeneity, and the effect of capillary force takes place. As a result, the development of such fields requires thoroughly examined research work.

The widely accepted approach to improve condensate recovery is to keep the reservoir pressure above the dew point pressure, i.e., in the gaseous state, and produce the condensate at the surface. Recycling of the dry gas is the primary pressure maintenance technique that can be implemented in such complex gas-condensate carbonate reservoirs. However, field examples around the world have shown that even during the full gas cycling process, there is a slight pressure decrease and subsequent condensation. This can be ascribed to insufficient compensation of the total hydrocarbon withdrawal from the material balance point of view. Therefore, successful gas cycling processes must be evaluated and designed for both cases: (1) the reservoir pressure above or near to the original dewpoint pressure and (2) the reservoir pressure has dropped substantially below the dewpoint pressure.

The goal of this study is to investigate reservoir pressure, gas and condensate production rate changes during the dry gas cycling, nitrogen injection and mixed injection scenarios applied to the gas-condensate carbonate reservoir. Phase behavior and dynamic reservoir modeling will be studied using compositional numerical software.
1.1 Motivation

Condensate loss in conventional reservoir systems is always challenging, and it requires an extensive reservoir engineering approach. In fact, sound technical knowledge must overcome thermodynamic and geologic complexities that are unique for the gas-condensate carbonate reservoir. Therefore, scientific research must find solutions to better optimize condensate production while benefitting the company economically.

The petroleum industry like other industries aims to make profit from their operations. Thus, optimization of the industrial process to raise money by reducing operational costs is sought. In the gas-condensate carbonate reservoir case, optimization is desirable because the profits mostly come from the condensate. This can be seen in a simple profit calculation example, in which only knowledge of fluid composition and its properties are needed. The following fluid composition is taken from Whitson and Brulé (2000).

<table>
<thead>
<tr>
<th>Component</th>
<th>Composition, mol - %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>2.37</td>
</tr>
<tr>
<td>N₂</td>
<td>0.31</td>
</tr>
<tr>
<td>C₁</td>
<td>73.19</td>
</tr>
<tr>
<td>C₂</td>
<td>7.80</td>
</tr>
<tr>
<td>C₃</td>
<td>3.55</td>
</tr>
<tr>
<td>i-C₄</td>
<td>0.71</td>
</tr>
<tr>
<td>n-C₄</td>
<td>1.45</td>
</tr>
<tr>
<td>i-C₅</td>
<td>0.64</td>
</tr>
<tr>
<td>n-C₅</td>
<td>0.68</td>
</tr>
<tr>
<td>C₆</td>
<td>1.09</td>
</tr>
<tr>
<td>C₇⁺</td>
<td>8.21</td>
</tr>
</tbody>
</table>

This example is worked out on the base of 100 moles total produced and will demonstrate how much of a contribution condensate and gas make to the revenue of the company.

After the surface separation process, this example assumes that gas totally comes from components up to C₅ whereas the condensate contains components C₆⁺. This is not always true and depends on the separation process. Their molar compositions are,

\[ \sum_{i=1}^{5} z_i = z_{C5-} = 73.19 + 7.8 + 3.55 + 0.71 + 1.45 + 0.64 + 0.68 = 88.02 \text{ mol - %} \]
$$\sum_{i=6}^{n_c} = z_{C6^+} = 1.09 + 8.21 = 9.3 \text{ mol} - \%$$

In terms of number of lb-moles these compositions become,

$$n_{C5^-} = 88.02 \text{ lb} - \text{moles}$$

$$n_{C6^+} = 9.3 \text{ lb} - \text{moles}$$

The gas volume produced at standard conditions can be easily calculated,

$$V_g = v \times n_{C5^-} = 379.4 \text{ scf/lb} - \text{moles} \times 88.02 \text{ lb} - \text{moles} = 33.4 \text{ Mscf}$$

The oil volume can be calculated from the following equation,

$$V_o = V_{C6^+} = n_{C6^+} \times \frac{M_{C6^+}}{\rho_{C6^+}}$$

The molecular weight of $C_{6^+}$ can be determined using Kays mixing rule.

$$M_{C6^+} = \frac{z_{C6}M_{C6} + z_{C7^+}M_{C7^+}}{z_{C6} + z_{C6^+}} = \frac{1.09 \times 86 + 8.21 \times 184}{1.09 + 8.21} = 172.5 \text{ lb/lb} - \text{mole}$$

The specific gravity of $C_{6^+}$ is assumed to be less than that of $C_{7^+}$ and close to it.

$$\gamma_{C6^+} \approx 0.8$$

Thus the oil volume becomes,

$$V_o = 9.3 \text{ moles} \times \frac{172.5 \text{ lb/lb} - \text{mole}}{0.8 \times 62.4 \text{ lb/ft}^3} = 32.1 \text{ ft}^3 \text{ or } 5.72 \text{ STB}$$

Current oil and gas prices are around $100/\text{STB}$ and $4.50/\text{Mscf}$, respectively, with the result that,

$$R(\text{oil}) = \frac{$100}{\text{STB}} \times 5.72 \text{ STB} = $572$$

$$R(\text{gas}) = \frac{$4.50}{\text{Mscf}} \times 33.4 \text{ Mscf} = $150.3$$

Therefore, the oil and gas contributions to the total revenue are,

$$R(\text{oil}) = \frac{$572}{$572 + $150.3} \times 100\% = 79\%$$
$$R(gas) = 100\% - 83\% = 21\%$$

Ultimately, the reservoir engineering approach must be directed towards producing condensate. As can be seen from the example above, condensate makes four times more profit than that of gas, which is important to consider. Therefore, understanding of reservoir engineering issues associated with gas-condensate reservoirs and proper solution methods have generated the need to do research on this topic.

1.2 Research Objectives

The objective of this study is to extend the applied theory of gas cycling processes to the case of highly compositional variable gas-condensate reservoirs with low permeability. In particular different gas cycling processes to increase condensate recovery will be evaluated. The research is designed to study:

- Lean gas injection
- Pure nitrogen injection
- Methane and nitrogen injection
- Hydrogen sulfide addition to the lean gas
- \(\text{CO}_2\) injection

Another essential goal is to expand the theoretical considerations of miscibility of these gases with reservoir condensate fluids. This will lead to a better understanding of physical and chemical processes taking place in such reservoirs.

The objectives further can be met by setting clear hypotheses. For instance, the quantitative results are expected to demonstrate higher recovery factors for the gas cycling with partial and full pressure maintenance scenarios. From the qualitative point of view, nitrogen injection might have a similar recovery efficiency as lean gas injection. The mixture of methane and nitrogen is expected to have the highest ultimate recovery of condensate. Hydrogen sulfide is added to injection gases only because of environmental concerns. Its anticipated outcomes to improve the hydrocarbon recovery efficiency have not been well documented. \(\text{CO}_2\), on the other hand, has been proven as a good miscible fluid but mostly in oil reservoirs.
1.3 Methodology

In this research, an analogous reservoir model was built as a representation of the North Caspian basin fields. These reservoirs are characterized by their carbonate structures, a high depositional burial (12,000-19,000 ft), a large hydrocarbon column, low permeability and porosity values, sulfur content and high compositional variation of hydrocarbons (Bedrikovetsky and Basniev, 1994). Reservoir pressure in these formations is very high, which alongside the current temperature makes the reservoir in the near critical region.

The compositional reservoir modeling includes a treatment of a number of fluid components, splitting of C$_7^+$ fraction, tuning the equation of state (EOS) to match experimental data, and pseudoization of the reservoir fluid. These above mentioned procedures require good knowledge of PVT modeling, which will be handled using CMG WinProp software. Moreover, the Peng-Robinson EOS will be applied not only to match the experimental data, but also to run a compositional gradient model to determine the molar compositions of the fluid with depth.

The overall simulation model was built in Eclipse 300, which is the compositional simulation software.

This study is intended to bring clarity regarding techniques that will result in maximum condensate recovery. It has certain limitations. There is a lack of adequate information on the factors that increase the condensate recovery from carbonate reservoirs in the literature. If there is data, reliability of field obtained PVT analysis is also questionable. Another important issue is lack of access to the field information. Most of the time a company operating a field does not publish data available to the general public. Therefore, some properties of the rock and the fluid have to be assumed.

Permeability and porosity obtained in the field cannot provide a full coverage of all simulation grids. Therefore, the first assumption undertaken was to assign uniform permeability and porosity values to the entire simulation model. This approach is justified because the goal of the research was to investigate the impact of injection gases rather than to investigate gas injection sweep efficiency. Another assumption was that the capillary forces between the condensate already dropped out and gas is negligible. This assumption is reasonable for the carbonate reservoir where the rock is preferentially neutral to oil-wet, and thus the liquid phase does not have strong affinity with the gas. Moreover, from a geologic standpoint, it would be better to characterize the carbonate reservoir including vugs and fractures. However, information on their presence, distribution, and frequency is unknown.
1.4 Thesis Outline

This thesis is organized as follows. Chapter 2 provides a general theoretical background regarding carbonate reservoirs and gas-condensate reservoirs PVT. Important compositional fluid flow equations are also presented in this chapter. In order to build a reliable compositional model, fluid characterization constituents, such as EOS tuning, pseudoization, and flash calculations must be taken into account and are discussed in this Chapter. The main purpose of Chapter 2 is to familiarize the reader and the future researcher with these reservoir engineering concepts.

Chapter 3 discusses the literature review, which includes approaches used in the industry to tackle the gas-condensate reservoir problem, current discussions taking place among researchers, and some discrepancies in obtained results.

Chapter 4 explains the fluid modeling procedures and covers some important aspects of the EOS fluid characterization, such as EOS tuning, pseudoization, and PVT data. Some insights into the compositional gradient calculations are also given.

Chapter 5 demonstrates the simulation model used in the research. All parameters and properties needed by the reservoir simulator are explained. Some of these properties are rock data, fluid data, and relative permeability curves. Fluid properties in this chapter are represented by tables.

Chapter 6 discusses the simulation scenarios. Several sensitivity analyses are also presented in this chapter followed by the summary.

Chapter 7 concludes the thesis results, comments on the results, and suggests possible improvements for in the future.
CHAPTER 2
BACKGROUND AND THEORY

This chapter addresses important concepts related to gas-condensate reservoirs to give the reader insight into the development of such fields.

2.1 Carbonate Reservoirs and Their Complexities

Carbonate reservoirs represent a huge amount of oil and gas reserves among conventional petroleum systems. According to Schlumberger, more than 60% of oil and 40% of gas are found in this type of formation (Schlumberger, 2014). Therefore, it is necessary to evaluate geologic challenges properly.

First of all, the marine origin of carbonate reservoirs suggests that the depositional environment creates discrete sedimentary sub-environments (Ahr, 2011). These processes lead to the complex geologic structures that can be categorized as grain dominated areas with preserved primary porosities, reef buildup areas, downslope debris deposits, stratigraphic traps developed in shelf cycles, and chalky-textured areas (Jordan and Wilson, 1994). Consequently, carbonate reservoirs vary in their textures and marine components and have diagenetic alteration traces. The latter is particularly important because diagenesis either improves or hinders a successful reservoir development.

There are several post-sedimentation changes that occur in carbonate reservoirs. Leaching and cementation in early stages modifies the primary porosity on a small scale, and such rock can be found in shelf cycles (Jordan and Wilson, 1994). Reef buildup regions have good preserved initial porosities, and such porosity might have been enhanced by the following leaching and dolomitization. Another diagenetic process found in carbonate reservoirs is fracturing that leads to enhanced permeability regions within the reservoir. These aforementioned processes, i.e., dissolution, dolomitization, and fracturing, and their consequences, such as intraparticle and interparticle pores, vuggy-cavernous pores, and fractures, represent uncertainties encountered in carbonate reservoirs. These irregular reservoir rock porosity and permeability will definitely affect the fluid flow characteristics of gas-condensate systems within carbonate reservoirs.

2.2 Gas-Condensate Phase Behavior

Gas-condensate reservoirs exhibit unique and complex phase behavior relationships. Normal condensation usually occurs when the pressure increases and temperature decreases.
However, in some petroleum reservoirs, gas might condense when reservoir pressure reduces under constant temperature condition (Figure 2.1). Such gas reservoirs were called gas-condensate reservoirs, and such condensation became known as a retrograde condensation phenomena. By definition, the gas-condensate system exists in a region between the critical temperature (Point C) and cricondentherm (Point I) in the phase envelope. When the systems pressure is higher than the dewpoint pressure line, there is only one phase, gas phase, in a reservoir. Figure 2.1 shows the pressure reduction from Point L to D and further to G, which indicates that the single gas phase after passing the dewpoint line condenses into liquid in the reservoir, which is called retrograde condensation (Katz, 1959). This scenario hereafter is considered to be the worst from reservoir engineering and economic standpoints because of the loss of valuable condensate hence revenue loss.

![Phase envelope for a compound system (Katz, 1959).](image)

Figure 2.1: Phase envelope for a compound system (Katz, 1959).

Ideally, most petroleum engineering efforts are intended to prevent the reservoir pressure from decreasing below the dewpoint pressure. In order to achieve that goal, gas injection processes were initiated in early 1940s (Muskat, 1949). However, maximum recovery efficiency is affected mostly by reservoir heterogeneity, such as variations in permeability, faults and fracture locations. Therefore, careful attention must also be paid to the incorporation of appropriate geologic data with sound reservoir engineering solutions.
2.3 Governing Compositional Flow Equations

Since the gas-condensate system occurs near the critical region in the phase envelope, its gas and condensate production rates are not usually constant over time. The traditional black-oil, which assumes a constant gas-oil ratio and formation volume factors, is not applicable in the case of gas-condensate reservoirs. As a result, compositional modeling techniques must be used to simulate the gas-condensate reservoir performance. In this case, the simple continuity equation using Darcy’s law must be rewritten in terms of components of the reservoir fluid.

The general equation (Kazemi, 2013) for the components present in the hydrocarbon phases, i.e., either in liquid or gas phases, is in the following form,

\[-\nabla \cdot \left( x_i \zeta_o \vec{v}_o + y_i \zeta_g \vec{v}_g \right) + (x_i \zeta_o \hat{q}_o + y_i \zeta_g \hat{q}_g) = \frac{\partial}{\partial t} \left[ \phi (x_i \zeta_o S_o + y_i \zeta_g S_g) \right] \] (2.1)

In Eq. 2.1, \( x_i \) and \( y_i \) represent the mole fractions of component \( i \) in the liquid and gas phases, respectively. \( \zeta_o \) and \( \zeta_g \) terms are the molar densities, which are the reciprocals of specific molar volume.

\[ \nu = \frac{V}{n} \] (2.2)

Hence the molar density becomes,

\[ \zeta = \frac{1}{\nu} = \frac{n}{V} \] (2.3)

Further on, in Eq. 2.1, \( \hat{q}_o \) and \( \hat{q}_g \) are oil and gas flow rates; \( \phi \) is porosity, \( S_o \) and \( S_g \) are oil and gas saturations, respectively.

The Darcy’s velocity is expressed for oil and gas phases as follows,

\[ \vec{v}_o = -\frac{k_{ro}}{\mu_o} (\nabla P_o - \gamma_o \nabla D) \] (2.4)

\[ \vec{v}_g = -\frac{k_{rg}}{\mu_g} (\nabla P_g - \gamma_g \nabla D) \] (2.5)

In Equations 2.4 and 2.5, \( \bar{k} \) is the permeability tensor, \( k_{ro} \) and \( k_{rg} \) are relative permeabilities to oil and gas, respectively. \( \mu_o \) and \( \mu_g \) are oil and gas viscosities. The latter term in the parenthesis is important, which is the pressure gradient. \( \nabla P \) with \( o \) and \( g \) subscripts representing oil and gas phase pressure differentials. \( \gamma_o \) and \( \gamma_g \) are oil and gas pressure gradients, and \( \nabla D \) is the depth differences between nodes. A full description of symbols is provided in the list of symbols.

Equations 2.1, 2.4, and 2.5 can be combined and rewritten by including the Darcy’s
velocities,

\[ \nabla \cdot \left[ x_i \zeta_o \hat{k} \frac{k_{x_o}}{\mu_o} (\nabla P_o - \gamma_o \nabla D) + y_i \zeta_g \hat{k} \frac{k_{x_g}}{\mu_g} (\nabla P_g - \gamma_g \nabla D) \right] + (x_i \zeta_o \hat{q}_o + y_i \zeta_g \hat{q}_g) \]

\[ = \frac{\partial}{\partial t} \left[ \phi(x_i \zeta_o S_o + y_i \zeta_g S_g) \right] \quad (2.6) \]

The divergence operator in the Eq. 2.6 must be rewritten in terms of partial derivatives.

\[ \frac{\partial}{\partial x} \left[ x_i \zeta_o \lambda_o k_x \left( \frac{\partial P_o}{\partial x} - \gamma_o \frac{\partial D}{\partial x} \right) + y_i \zeta_g \lambda_g k_x \left( \frac{\partial P_g}{\partial x} - \gamma_g \frac{\partial D}{\partial x} \right) \right] \]

\[ + \frac{\partial}{\partial y} \left[ x_i \zeta_o \lambda_o k_y \left( \frac{\partial P_o}{\partial y} - \gamma_o \frac{\partial D}{\partial y} \right) + y_i \zeta_g \lambda_g k_y \left( \frac{\partial P_g}{\partial y} - \gamma_g \frac{\partial D}{\partial y} \right) \right] \]

\[ + \frac{\partial}{\partial z} \left[ x_i \zeta_o \lambda_o k_z \left( \frac{\partial P_o}{\partial z} - \gamma_o \frac{\partial D}{\partial z} \right) + y_i \zeta_g \lambda_g k_z \left( \frac{\partial P_g}{\partial z} - \gamma_g \frac{\partial D}{\partial z} \right) \right] \]

\[ + (x_i \zeta_o \hat{q}_o + y_i \zeta_g \hat{q}_g) = \frac{\partial}{\partial t} \left[ \phi(x_i \zeta_o S_o + y_i \zeta_g S_g) \right] \quad (2.7) \]

Figure 2.2 represents the geometric depiction of reservoir gridcells and their notation used in the discretization.

Figure 2.2: Reservoir gridcells and their associated subscript coefficients in 3D plane.
The further approximation using the central differences leads to,

\[
\frac{1}{\Delta x_i} \left[ (x_i \zeta_o \lambda_o k_x)_{i+1/2}^n \left( \frac{P_{o,i+1}^{n+1} - P_{o,i}^{n+1}}{\Delta x_{i+1/2}} - \gamma_o \frac{D_{i+1}^n - D_i^n}{\Delta x_{i+1/2}} \right) \right. \\
+ (x_i \zeta_o \lambda_o k_x)_{i-1/2}^n \left( \frac{P_{o,i-1}^{n+1} - P_{o,i+1}^{n+1}}{\Delta x_{i-1/2}} - \gamma_o \frac{D_i^n - D_{i-1}^n}{\Delta x_{i-1/2}} \right) \\
+ (y_i \zeta_g \lambda_g k_y)_{j+1/2}^n \left( \frac{P_{g,i+1}^{n+1} - P_{g,i}^{n+1}}{\Delta y_{j+1/2}} - \gamma_g \frac{D_{j+1}^n - D_j^n}{\Delta y_{j+1/2}} \right) \\
+ (y_i \zeta_g \lambda_g k_y)_{j-1/2}^n \left( \frac{P_{g,i-1}^{n+1} - P_{g,i+1}^{n+1}}{\Delta y_{j-1/2}} - \gamma_g \frac{D_j^n - D_{j-1}^n}{\Delta y_{j-1/2}} \right) \\
+ (y_i \zeta_g \lambda_g k_y)_{j+1/2}^n \left( \frac{P_{g,j+1}^{n+1} - P_{g,j}^{n+1}}{\Delta y_{j+1/2}} - \gamma_g \frac{D_{j+1}^n - D_j^n}{\Delta y_{j+1/2}} \right) \\
+ (y_i \zeta_g \lambda_g k_y)_{j-1/2}^n \left( \frac{P_{g,j-1}^{n+1} - P_{g,j}^{n+1}}{\Delta y_{j-1/2}} - \gamma_g \frac{D_j^n - D_{j-1}^n}{\Delta y_{j-1/2}} \right) \\
+ (z_i \zeta_o \lambda_o k_z)_{k+1/2}^n \left( \frac{P_{o,k+1}^{n+1} - P_{o,k}^{n+1}}{\Delta z_{k+1/2}} - \gamma_o \frac{D_{k+1}^n - D_k^n}{\Delta z_{k+1/2}} \right) \\
+ (z_i \zeta_o \lambda_o k_z)_{k-1/2}^n \left( \frac{P_{o,k-1}^{n+1} - P_{o,k}^{n+1}}{\Delta z_{k-1/2}} - \gamma_o \frac{D_k^n - D_{k-1}^n}{\Delta z_{k-1/2}} \right) \\
+ (y_i \zeta_g \lambda_g k_z)_{k+1/2}^n \left( \frac{P_{g,k+1}^{n+1} - P_{g,k}^{n+1}}{\Delta z_{k+1/2}} - \gamma_g \frac{D_{k+1}^n - D_k^n}{\Delta z_{k+1/2}} \right) \\
+ (y_i \zeta_g \lambda_g k_z)_{k-1/2}^n \left( \frac{P_{g,k-1}^{n+1} - P_{g,k}^{n+1}}{\Delta z_{k-1/2}} - \gamma_g \frac{D_k^n - D_{k-1}^n}{\Delta z_{k-1/2}} \right) \\
+ (x_i \zeta_o \hat{q}_o + y_i \zeta_g \hat{q}_g) = \frac{\partial}{\partial t} \left[ \phi(x_i \zeta_o S_o + y_i \zeta_g S_g) \right] \\
\] (2.8)

2.4 PVT Modeling

The gas-condensate reservoir demonstrates a highly compositional fluid system that must be properly characterized in the simulation models. The proper fluid characterization for the complex PVT modeling process requires knowledge of equations of state (EOS). Generally, these equations describe volumetric and phase behavior of reservoir fluids. It is commonly
known that under high pressure and temperature cases, the ideal gas law does not work, so further improvements are needed. Historically, the Van der Waals EOS proposed in 1873 has been improved, and one of the most used forms of this equation is the Peng-Robinson EOS (1976).

Another substantial part of the PVT modeling is the verification of fluid properties and parameters used in the model for which laboratory tests are performed. For condensate reservoirs, constant volume depletion (CVD) and constant composition expansion (CCE) experiments are performed (Whitson and Torp, 1983). These experiment data should further be matched by the equations of state.

Modern laboratory tests can give molar compositions of fluids in a great range, sometimes up to \( C_{45+} \). On the other hand, from technical and economical standpoints, the laboratories used to provide the \( C_{7+} \) fraction. The former is expensive, but it gives the reliable PVT information. The latter procedure involving only the \( C_{7+} \) fraction needs an additional splitting procedure, which might lead to some inaccuracies in obtained information. Both expensive and the inexpensive methods describe the reservoir fluid with too many components, which is computationally expensive during numerical reservoir simulations. Therefore, a pseudoization procedure is usually performed beforehand to group several components into a single pseudocomponent.

Coats (1985) defined pseudoization as “the reduction in the number of components used in EOS calculations for reservoir fluids.” Generally, it is grouping of several components into several pseudo-components that afterwards will represent fluid properties as in the original case. These important fluid properties include density, \( z \)-factor, and viscosity of each component. Initially, the lumping procedure starts with splitting \( C_{7+} \) fraction into several heavy pseudo-components. After that, nonlinear regression is performed to match different PVT laboratory data. Once the PVT data is matched, the lumping can be initiated. Important fluid properties extracted to the simulation model include critical pressure, temperature, and volume of pseudo-components, saturation pressure, acentric factors, correction parameters used in EOS, and volume shift parameters (Whitson and Brulé, 2000).

### 2.4.1 Peng-Robinson Equation of State

The petroleum industry often uses the Peng-Robinson EOS for several applications because of its simplicity and consistency at the critical point. For example, in process engineering, design of process equipment, such as heat exchangers, compressors, and fractionating, involves thermodynamic property calculations using the Peng-Robinson EOS. In our case, it is used to describe reservoir fluid behavior during miscible injection processes.
The equation in a general form is,

\[ p = \frac{RT}{\nu - b} - \frac{a}{\nu(\nu + b) + b(\nu - b)} \] (2.9)

where:

\[ a = \Omega_a \frac{R^2T^2_c}{p_c}\alpha \] (2.10)

\[ b = \Omega_b \frac{RT_c}{p_c} \] (2.11)

\[ \alpha = \left[ 1 + \kappa(1 - \sqrt{T_r}) \right]^2 \] (2.12)

\[ \kappa = 0.37464 + 1.54226\omega - 0.26992\omega^2 \quad \text{for } \omega < 0.49 \] (2.13)

\[ \kappa = 0.3796 + 1.485\omega - 0.1644\omega^2 + 0.01667\omega^3 \quad \text{for } \omega > 0.49 \] (2.14)

The \( a \) in equations above is attractive force, and \( b \) is repulsive force. Their multipliers, i.e., \( \Omega_a \) and \( \Omega_b \) are,

\[ \Omega_a = 0.45724 \]
\[ \Omega_b = 0.0778 \]

In discussing the Peng-Robinson EOS or any other EOS, some caveats must be mentioned:

- In some regions, e.g., the near critical region, EOS cannot predict phase behavior and fluid volumes correctly
- It requires a good compositional analysis of fluids in order to input them
- Computation time of the simulation model increases with an increasing number of components

The EOS modeling includes important vapor-liquid equilibrium calculations, which are flash calculation, saturation (bubble point and dew point) pressure calculations, and stability analysis (Whitson and Brulé, 2000). Since the purpose of this research is not the PVT modeling itself, these topics will not be discussed in great detail.

### 2.4.2 Flash Calculation

Flash calculation is performed to determine (1) the number of existing phases, i.e., liquid, gas, or both, (2) the amount of each phase, i.e., \( f_L \) and \( f_V \), and (3) the molar composition of each phase, \( x_i \) and \( y_i \), for given pressure, temperature, and overall composition. Furthermore,
in the literature, it is often called “isothermal flash” since the calculation is performed at a
specified temperature instead of changing temperature.

The derivation of the flash is simple and as follows. Total mole material balance of a
mixture is,

\[ n = n_L + n_V \]  

(2.15)

In a component level, the material balance equations is,

\[ n_i = n_{Li} + n_{Vi} \]  

(2.16)

By definition,

\[ z_i = \frac{n_i}{n} \]  

(2.17)

\[ x_i = \frac{n_{Li}}{n_L} \]  

(2.18)

\[ y_i = \frac{n_{Vi}}{n_V} \]  

(2.19)

The further substitution Eqs. 2.17-2.19 into Eq. 2.16 leads to,

\[ z_i n = x_i n_L + y_i n_V \]  

(2.20)

If both sides of Eq. 2.20 are divided by number of moles, \( n \) and replaced by \( f_L \) and \( f_V \),

\[ z_i = x_i f_L + y_i f_V = x_i (1 - f_V) + y_i f_V \]  

(2.21)

where:

\[ f_V = \frac{n_V}{n} \]

\[ f_L = \frac{n_L}{n} = 1 - f_V \]

The equilibrium ratios, \( K \)-values, for each component are,

\[ K_i = \frac{y_i}{x_i} \]  

(2.22)

A substitution of \( y_i = K_i x_i \) from \( K \)-value relationship into the Eq. 2.21 and a consequent
solution for \( x_i \) and \( y_i \) yield,

\[
x_i = \frac{z_i}{f_V(K_i - 1) + 1} \quad (2.23)
\]

\[
y_i = \frac{z_iK_i}{f_V(K_i - 1) + 1} \quad (2.24)
\]

Also,

\[
\sum_{i=1}^{nc} z_i = \sum_{i=1}^{nc} x_i = \sum_{i=1}^{nc} y_i = 1 \quad (2.25)
\]

Thus,

\[
\sum_{i=1}^{nc} x_i - \sum_{i=1}^{nc} y_i = 0 \quad (2.26)
\]

Thus substituting Eqs. 2.23 and 2.24 into the Eq. 2.26 yields the isothermal flash or the Rachford-Rice equation,

\[
f(f_V) = \sum_{i=1}^{nc} \left[ \frac{z_i(K_i - 1)}{f_V(K_i - 1) + 1} \right] = 0 \quad (2.27)
\]

2.5 Economics of Gas Injection

An important parameter involved in gas cycling operations is the economics of a project. Financial revenues that come from selling condensate must cover the costs required to inject gas into a formation. In this research, several injection gases are studied, so economic costs of each individual injection gas might differ from another. Economics will not be a major aspect of this study. However, some main economic considerations are provided as follows.

**Separation**

First of all, when the hydrocarbon gas is produced to the surface, it goes through multi-stage separation process where valuable hydrocarbons (i.e. condensate) are separated. In this study, three-stage separator is used (See Chapter 5). The separation process is depicted in Figure 2.3.

The separation process is required in any field reservoir development and composed of separators at specific pressure and temperature. In Figure 2.3, \( P \) represents this separation process, overall. The final products that come out of this process are \( V_g \), which is the surface gas, and \( V_o \), which is the surface oil. The latter is the condensate and is sold to a customer. The former, on the other hand, can also be sold, but herein it is re-injected into the reservoir to keep pressure above the dewpoint pressure and to revaporize liquid dropped out in the reservoir (if the pressure drops below the dewpoint).
It should be stated that after the separation process, the surface gas, $V_{\bar{g}}$, still might have some heavy hydrocarbon groups, such as butane, pentane, and higher. Therefore, depending on the nature of injection gas, (e.g., lean gas vs. enriched gas), the surface gas may be further prepared for gas injection purposes in gas processing units.

The separation process is the indispensable part of the field development project, and its costs are always included in economics. Costs of separation are mainly separator units and lines connecting them.

**Gas Processing Unit**

Gas processing units or plants are used to separate some heavy hydrocarbon ends or add them, if they are needed for the gas injection, to the surface gas. Another essential goal is to ensure that impurities, such as $\text{H}_2\text{S}$ and $\text{CO}_2$, are removed from gas. To remove these impurities, amine systems can be used (Thro, 2006).

These two processes, i.e., the gas preparation by controlling the presence of hydrocarbon components and non-hydrocarbon components, mainly dictate economic costs of the gas processing unit. In addition, when a make-up gas is used, it is added to injection gas at this stage.

It should also be mentioned that some intermediate systems, (e.g. cooling and heating units) are used in the gas treatment processes and carry additional costs.

**Gas Compression**

Before the gas injection into the formation, the injected gas must be compressed to high pressures required. This is completed in the gas compression facilities or simply, comprin-
sors. Gas compression facility consists of gas turbines, compressors and other additional equipment.

From an economic point of view, these equipment are expensive and require initial investments. Furthermore, for very high pressure systems, the gas compressor plants will cost more than ordinary ones because high quality, high pressure compressors are needed.

Another essential factor in the gas compression process is energy needed to compress the injection gas. Usually, the gas produced from the reservoir is utilized to burn and create energy. Therefore, the injection cost includes the additional amount of hydrocarbon gas, which can vary from 3 to 10 percent of the gas volume to be injected. In other words, to inject, for example, one million standard cubic feet of gas into the formation, 50,000 scf of gas must be burned to provide compression energy. Miller and Holstein (2006) reports a fuel consumption of 34.4 Mscf per 1 MMscf of gas injected to create compression energy, so it suggests that the gas consumption will depend on a heating value of a gas.

**Nitrogen Generation Plant**

Donohoe and Buchanan (1981) performed a thorough analysis of economic costs associated with the nitrogen injection and their benefits. The main cost with the nitrogen injection is a cryogenic plant to generate N\textsubscript{2} from air. However, these authors contended that it is usually cheaper to buy N\textsubscript{2} from a supplier rather than constructing the plant in the field.

As in the gas compression case, the nitrogen injection also requires some fuel to create energy for compression purposes. Donohoe and Buchanan (1981) provided approximate costs of nitrogen injection in gas-condensate reservoirs in the 1980s. Figure 2.4 shows the expenses of the nitrogen plant, electric power needed to generate nitrogen, and compression. As can be seen from the pie chart, the main cost is energy needed to run the nitrogen generation plant. It must be noted that the cost equivalent of these should be significantly higher today. Nonetheless, Donohoe and Buchanan (1981) concluded that nitrogen injection

![Figure 2.4: Typical costs of nitrogen injection (Donohoe and Buchanan, 1981).](image)
would be effective when the reservoir fluid contained at least 100 barrel of condensate per one million standard cubic feet of gas. Thus, the economic costs of nitrogen generation are covered by the high liquid yield.

**Some Additional Costs**

During the gas injection, there are some other additional costs. First, additional injection wells should be drilled and completed. For very deep reservoirs, the drilling costs might be huge. Even if new injection wells are not drilled but existing production wells are converted into injection wells, it also necessitates additional costs. Injection wells and lines connecting to these wells need technical maintenance, which is another portion of overall injection costs. It was stated the nitrogen injection required the generation plant, so producing wellstream containing nitrogen would also require another plant or additional facility in the separation process to separate these impurities.

In general, gas injection assumes several costly investment projects and their associated risks. Therefore, it is necessary to forecast condensate yield from a reservoir and then perform an economic evaluation of a project. In this research, the economic evaluation was not done, so advantages of a particular gas injection scenario are evaluated only based on a technical point of view.
CHAPTER 3
LITERATURE REVIEW

As stated earlier, gas-condensate reservoirs are complex and need a comprehensive approach to yield the maximum condensate from a given reservoir. The following discussion is aimed at providing an overview of what the industry has done and what has not been implemented yet.

3.1 Gas Cycling Processes

One of the fundamental works dedicated to the gas cycling topic was written by Morris Muskat in 1949, which is the “Condensate Reservoirs” chapter in the “Physical Principles of Oil Production.” In his seminal book, Muskat states several factors that affect recovery efficiency from gas-condensate reservoirs. These factors are cycling efficiency, sweep efficiency, and permeability variation within a formation. In addition, for a tight formation more injection wells are necessary, which will increase the overall project cost. Surface facility costs must also be economically evaluated (Muskat, 1949).

Muskat’s aforementioned statement is still practical for current gas-condensate reservoirs development. In other words, the condensate recovery in such reservoirs depends on what we inject as an injection gas and how we inject into the formation. Furthermore, how injection gases affect the condensate yield is of utmost importance since knowing the latter determines what gas and how it is to be injected into the formation. For tight formations, horizontal wells and horizontal wells with multiple hydraulic fracturing stages are promising engineering techniques nowadays, which reduce substantially the project cost. Surface processes, particularly separation processes, are primarily determined by the condensate yield or condensate-gas ratio (CGR) and a subject to a development strategy of the company.

These three aforementioned questions are to be addressed in this thesis, and the literature review on the gas injection falls into the following general categories.

3.1.1 Traditional Lean Gas Cycling

Lean gas cycling is considered the earliest cycling technique to minimize the amount of condensate dropout. Mostly composed of methane, dry gas has favorable qualities to be miscible with retrograde gas systems (Moses and Donohoe, 1987). To measure the injected dry gas or any other gas effectiveness, two distinctions must be made: gas injection occurring above and gas injection occurring below the dewpoint pressure.
When the gas cycling takes place above the dewpoint pressure, no matter what gas is used, the injected gas will mix with the reservoir gas and lead to 100 percent condensate recovery. Whitson et al. (1999) states that the injected gas might not be fully miscible with the reservoir gas and contends that the miscibility is developed after several contacts. It does not mean, however, that this mixing process will last forever. Since the amount of gas to be injected after the surface separation processes is less than that of the produced gas (without including additional make-up gas), the reservoir pressure undergoes a slight pressure decline. This can simply be explained by material balance, which states that injectant volume must be equal to or more than the produced hydrocarbon volume.

In the second case, i.e., the gas injection below the dewpoint pressure, injected gas should not only displace reservoir gas containing condensate in a solution but also revaporize the condensate formed as the pressure decreases below the dewpoint. Therefore, there are two physical mechanisms happening in the reservoir: (1) the miscible displacement of the reservoir gas and (2) the vaporizing gas drive of condensate. These processes are depicted in Figure 3.1 for a linear porous medium flow system. Aziz (1983) has mentioned these phenomena and further stated that multi-contact miscibility of dry gas with reservoir fluids leads to the vaporization of C\textsubscript{2}-C\textsubscript{6} fraction of liquids and carries these components with the gas. Thus, the produced gas is now richer with liquid components that will be separated at the surface.

![Diagram](image-url)

**Figure 3.1**: Gas condensate system subjected to dry gas injection: (a) initial condition-condensate system below dew point, (b) dry gas injection (Modified after Smith and Yarborough (1968)).
There seems to be general agreement on these two physical phenomena occurring below the dewpoint as was indicated by Aziz (1983), Coats (1985), Kenyon and Behie (1987), and Al-Anazi et al. (2004). Nevertheless, Smith and Yarborough (1968) contended that in addition to a movement of intermediate and heavy components from a liquid phase into the vapor phase, “some light components” move “into the liquid.” This mechanism of vaporizing and condensing drive mechanisms at the same time has been overlooked for a long time in the industry.

Zick (1986) proposed the idea of a condensing/vaporizing mechanism in which intermediate components would be condensed from the injected gas into the oil ahead of the displacing front whereas the intermediate and heavy components would be vaporized from the oil into the injected gas behind the front. Based on that conclusion, Whitson et al. (1999) emphasize that during gas cycling below the dewpoint pressure, the intermediate-rich (C₂-C₅) injection gas can develop the condensing/vaporizing mechanism in the gas-condensate reservoir. Another study by Høier (1997) thoroughly investigated this concept, and the author concluded that the minimum miscibility pressure for the gas-condensate systems could be lower with the enriched injection gas than the dewpoint pressure than was traditionally thought.

Interestingly, the already mentioned study by Smith and Yarborough (1968) reported that a retrograde liquid had been fully recovered when it was contacted by 2.5 PV of dry gas in sand pack experiments. There seems to be opposing findings between Smith and Yarborough (1968) and Whitson et al. (1999), who argues that the lean gas injection rapidly vaporizes some heavy components first, but then its vaporization efficiency declines. The latter authors explain further that not all heavy components of the condensate are revaporized by the lean gas but only some “light” heavy components. Therefore, additional amounts of injected gas will proceed with the reservoir gas leaving the condensate in situ.

In order not to mislead, a clarification must be made regarding the findings by Smith and Yarborough (1968). First of all, the mixture used in their studies consisted of methane and n-pentane, which typically does not represent the reservoir fluid. Moreover, the study was performed in low pressure and temperature conditions. Nonetheless, the authors warned the reader that the condensate revaporization level was also dependent on the presence of the heaviest components in the fluid. A sweep efficiency was also discussed as one of the constraints in a field scale implementation. It should be mentioned that this study was one of the earliest centered on identifying the revaporization character of retrograde condensate even though the following studies adopted the idea as a possibility of producing condensate using only dry gas.

For example, Al-Anazi et al. (2004) performed a similar experiment using pure methane with a synthetic four-component gas-condensate fluid. The authors concluded that methane
revaporized the retrograde liquid from the core and improved the gas permeability. Such general statements may or may not apply in the field scale. Therefore, further investigation is needed to evaluate not only dry gas, but also other gases performance in improving the condensate yield.

These aforementioned findings suggest that there are different options in developing gas-condensate fields: either miscible or immiscible gas injection. For both cases dry gas, nitrogen, carbon dioxide, and a mixture of these gases can be implemented. Although some studies have dismissed some of these options based on experimental results, an unbiased approach would test all of them in this reservoir model. Lastly, it would be of interest to learn how the enriched gas, as Høier (1997) mentioned, contributes to the ultimate liquid yield taking into account that economics must be justified.

3.1.2 Nitrogen Injection Applications

Nitrogen injection had not been used or, in fact, discussed in gas-condensate reservoirs until the 1980s, until natural gas became economically feasible to sell. Early applications of nitrogen in the gas injection processes were rarely documented. Moses and Donohoe (1987) mentioned several fields, such as Elk Basin in Wyoming and Fordoche field in Louisiana, in which nitrogen was utilized as the makeup gas. In these cases, the nitrogen composed approximately 30 percent of a gas mixture. However, Wesley et al. (1981) did not report condensate recovery efficiency results using this mixture.

Vogel and Yarborough (1980) and Moses and Wilson (1981) studied nitrogen injection effects on gas-condensate phase behavior by conducting the PVT cell and slimtube experiments, respectively. These papers concluded that nitrogen caused an increase of the initial dewpoint pressure of the reservoir fluid. Furthermore, these authors stated that the dewpoint pressure was elevated only in the mixing region, so condensate dropout occurred in this region. Interestingly, the latter paper’s authors concluded that the injected gas and in situ fluid had experienced little mixing, which only indicated the true displacement mechanism of the reservoir fluid. The recovery efficiency in Moses and Wilson (1981) studies was 98.4 percent of initial reservoir fluid. Therefore, nitrogen injection was considered to be an immiscible displacement process in the gas-condensate reservoirs.

Some contrasting opinions, however, exist in the literature. Moses and Donohoe (1987) provided an example of Painter field examined by Peterson, which concluded that a high condensate recovery in the field resulted from the multiple-contact miscibility contact of nitrogen with the reservoir fluid. In addition, Sänger and Hagoort (1998) conducted the slim tube experiments to compare methane and nitrogen capabilities in recovering the condensate and pointed out the development of miscible displacement using nitrogen.
Research to date has tended to investigate condensate recoveries experimentally using nitrogen for gas-condensate fluids of North Sea reservoirs. Moreover, a few simulation studies have been performed. For example, Hagoort et al. (1988) reported a double condensate yield increase when nitrogen was compared to pressure depletion in a simulated offshore gas-condensate reservoir. Although these studies have overwhelmingly been devoted to the nitrogen injection benefits in gas-condensate reservoirs, especially in the North Sea, the literature has rarely documented real field cases of nitrogen injection applications and their success.

Recently, Taheri et al. (2013) presented simulation results on condensate recovery from a fractured gas-condensate reservoir in which a 66 percent recovery was achieved by the miscible displacement (i.e., CO$_2$ enrichment), and 43 and 18 percent recoveries were attained in the immiscible and pressure depletion scenarios, respectively. Moreover, the authors expressed that methane, nitrogen, and stock-tank gas were used in the immiscible displacement scenarios.

Thus far, these studies have argued about the condensate recovery mechanism by nitrogen injection: whether it is a miscible or an immiscible mechanism. In this study, our goal was not to focus on the miscibility concepts to elucidate between the two. However, I believe that nitrogen or most of the lean gas injection processes are immiscible rather than miscible, as was mentioned by Whitson et al. (1999) in Section 3.1.1.

These previous works have not only provided an excellent discussion of the complexity of condensate recovery but also showed possibilities for future research. The current study, therefore, is designed to extend these theories beyond the scope of experimental work. Rather, we focused on verifying those results obtained by other researchers and applying effective gas injection scenarios in the low-permeability, thick gas-condensate reservoir case.

To consider nitrogen injection, its qualities, which makes it efficient as the dry gas, must be reviewed. Wu et al. (2013) discussed favorable properties of nitrogen, such as physical and chemical properties, and economic considerations. For example, nitrogen is less dense than the reservoir gas, which makes it stay in the upper part of the reservoir, and is less compressible than other injection gases. The economic aspect includes a low cost of separation, processing, and purifying. Nonetheless, as mentioned earlier, the main disadvantage of nitrogen is the elevation of the dewpoint pressure.

### 3.1.3 CO$_2$ Applications for Gas-Condensate Reservoirs

CO$_2$ injection in the petroleum industry has been widely recognized as an effective method of miscible gas injection processes in oil reservoirs. There are many sources explaining the effectiveness of CO$_2$ injection in oil reservoirs. For example, Holm (1987) summarizes the
miscible displacement processes and mentions properties of CO\textsubscript{2} that significantly assist in lowering residual oil saturation. For this research, CO\textsubscript{2} will be tested purely from a scientific point of view, which is a performance comparison with other gases. It is well-known that CO\textsubscript{2} is costly to implement in a field scale, and it is not available everywhere. Nonetheless, because the reservoir fluid in this study contains about five percent CO\textsubscript{2}, its combination with other gases can alleviate the problem of liquid dropout.

3.1.4 Gas Injection Using the Mixture of Gases

There have been a few studies conducted to investigate the effect of injecting mixtures of gases on condensate recovery. For example, Renner et al. (1989) conducted slim tube experiments with a retrograde gas using both nitrogen and buffer gas. The buffer gas in these experiments consisted of about 40 percent nitrogen and a separator gas with a methane fraction of 49 percent within. The study concluded that the slim tube tests produced a high condensate recovery, 90 percent, using both injection gases and injecting them above the dewpoint pressure. Moreover, at the same pressure, buffer gas had a higher recovery factor than that of nitrogen. It should also be noted that these high recoveries were achieved after 1.2 hydrocarbon pore volume, HCPV, of the gas was injected. In addition, an experiment was done reducing the pressure below the dewpoint that yielded a lower recovery (64 percent) than that of experiments conducted at pressures above the dewpoint.

Renner et al. (1989) also claimed that the physical mechanism of the condensate recovery by the gas mixture depends mostly on the pressure of the system at a time of injection. For pressures higher than the dewpoint pressure, the experimental results indicate the occurrence of multiple-contact vaporizing miscibility. On the other hand, when the pressure is below the dewpoint pressure, nitrogen or gas mixture condensate recovery happens under an immiscible displacement.

As mentioned before, the literature is scarce when looking for results of using gas mixtures in gas-condensate reservoirs. The research has often concentrated on improving oil recoveries using gas mixtures, not condensates. For instance, Shayegi et al. (1996) reported an increase in residual oil recovery after waterflooding using CO\textsubscript{2}-N\textsubscript{2} and CO\textsubscript{2}-CH\textsubscript{4} mixtures during cyclic gas injection. Furthermore, the study conducted pure gases injection to compare performances. Shayegi et al. (1996) concluded that CO\textsubscript{2}-N\textsubscript{2} and CO\textsubscript{2}-CH\textsubscript{4} mixtures with 10 percent of CO\textsubscript{2} yielded 23.8 and 20.9 percent recovery of residual oil, respectively. However, gas utilization was higher for the methane mixture, 4.8 Mscf/STB, than it was for nitrogen, 2.84 Mscf/STB, due to the highest compressibility of the former.

These two studies, again, indicate three possible ways of achieving condensate recovery: (1) miscible displacement above the dewpoint pressure, and (2) immiscible and (3) vaporizing
mechanism below the dewpoint pressure. The first two were discussed in Sections 3.1.1 and 3.1.2. The third one is of particular importance for this study since the reservoir fluid contains almost five percent CO₂. It would also be valuable to check its interaction with other gases in producing condensate from the reservoir.

3.2 Hydrogen Sulfide Addition to Injection Gases

Hydrogen sulfide is also of concern during the field development. Therefore, this study has focused on disposing of this hazardous gas from an environmental standpoint, yet its physical response in gas injection operations must not be overlooked.

From the environmental point of view, Masahiro et al. (2002) provided an excellent review of a step-by-step process implemented by Abu Dhabi National Oil Company, ADNOC, to inject sour gas into oil reservoirs. Although authors did not mention a mole fraction of H₂S in a produced stream, 10 MMscf/day of gas with H₂S and CO₂ had been flaring prior to the sour gas injection project. After the authors discussed all facility and engineering details, they concluded that their aim of reducing toxic emissions into the atmosphere was achieved successfully.

Jamaluddin et al. (1998) also discussed the environmental impact that sour gases had and how air emission standards were rigorous. Therefore, to reduce hazardous impact, the authors mentioned several ways of handling acid/sour gases. Sour gas is a hydrocarbon gas, (i.e., primarily lean gas) which contains hydrogen sulfide and carbon dioxide above a certain level. Acid gas is a mixture of hydrogen sulfide and carbon dioxide only. One of ways of handling acid/sour gases was to inject compressed acid into the formation. Another method was to dispose of acid gases by injecting them together with disposable water into formations. These two aforementioned methods are viable but not technologically attractive from a petroleum engineering standpoint. For that reason, Jamaluddin et al. (1998) considered the pros and cons of dissolving sour gases with light hydrocarbons. For instance, injecting them into the oil reservoir to develop the miscible displacement is a good option.

General physical effects of sour gases in miscible injection processes are outlined by a number of researchers, Jamaluddin et al. (1998), Van Vark et al. (2004) and Vissers et al. (2012). The important qualities of sour/acid gases are a good miscible characteristic with in situ oils, a favorable mobility ratio, and low interfacial tension between the two fluids. These advantages of sour/acid gases may or may not directly apply in gas-condensate reservoirs since there are few research works done to study the impact of these gases on condensate recovery. As a researcher, my hypothesis is that the sour and acid gases should also perform well in the condensate reservoirs because the latter has the same main physical properties
as the crude oil. Disadvantages of sour/acid gases, on the other hand, are asphaltene precipitation, swelling, and precipitation of salts due to dessication of formation waters during injection.

Lastly, in Sections 3.1.1–3.1.2, it was mentioned that lean gas or methane and nitrogen cause the dewpoint elevation of in situ fluid because of gas injection operations. However, Holm (1987) mentioned that minimum miscibility pressure is lower for $\text{H}_2\text{S}$ than that for methane and nitrogen. Therefore, its presence with lean and other gases can help prevent the quick dewpoint increase which in turn will reduce the amount of liquid dropout.

### 3.3 Compositional Gradient in Gas-Condensate Reservoirs

Historically, thermodynamic laws gave rise to a theory of components segregation due to gravity forces. As early as the 19th century, J.W. Gibbs described the theoretical model of the gravitational compositional gradient (Barrufet and Jaramillo, 2004).

Whitson and Belery (1994) provide an excellent review of the compositional gradient theory and applications. For instance, in the petroleum industry, the concept of the compositional gradient was first described by Muskat and then by Sage and Lacey using simple examples in the 1930s. After that, the industry rarely used this concept until recently. In the 1980s, with discoveries of gas-condensate fields in the North Sea, the possibility of finding oil below it challenged the industry. Therefore, several authors, such as Schulte, Holt, Lindeberg, and Ratje, Hirschberg, and many others performed numerous research projects to investigate the compositional gradient theory (For more details refer to Whitson and Belery (1994)). This paper comprehensively reviews the theory behind the compositional gradient and provides applications known to the industry.

One of the recent practical examples explained by Barrufet and Jaramillo (2004) is the effect of including compositional gradient in a calculation of hydrocarbons initially in-place for the Cusiana Field in Colombia. They concluded that the omission of the compositional gradient would lead to erroneous hydrocarbon reserve estimations, which in turn affects the future field development strategy. Lastly, they suggested using fine grid model for the gas-condensate reservoirs near a wellbore in order to capture the condensate banking effect.

In many cases, the gas-condensate reservoirs exhibit the component segregation due to gravity and thermal forces. Therefore, the compositional gradient use is of utmost importance when dealing with such reservoirs. Some key petroleum engineering areas for which the concept can be used are:

- Determination of condensate initially in-place
• Reservoir development plan: production and injection wells location, perforation intervals

• Surface facilities design

• Miscible displacement processes using gas injection (After Høier (1997))

• A possible need to use compositional modeling rather than the black-oil model.

These practical applications of the compositional gradient are used in this study to evaluate the gas injection process. However, a detailed attention will not be given to the optimization of surface facilities or to the miscible displacement, which was meant to occur in oil reservoirs. The reservoir development plan will be covered in the following sections using the compositional modeling software where one of the main input parameters is fluid properties.
CHAPTER 4

FLUID MODELING FOR RESERVOIR SIMULATION

Since gas-condensate reservoirs represent a unique reservoir system, their pressure – temperature relationships must be defined thoroughly. Furthermore, gas injection processes utilized in such reservoirs involve inter-component mass transfer phenomena for which a component-level characterization is crucial. Therefore, this chapter will describe fluid characterization procedures undertaken to obtain a PVT model and will also discuss some limitations of proper fluid modeling.

4.1 Compositional Gradient Introduction

Because fluid modeling for reservoir simulation is not possible without taking actual fluid samples from a reservoir, the industry has to trust these data all the time. Furthermore, quality of PVT samples is always questionable because of several factors, such as well conditioning prior to the sampling, operating condition changes, a lack of reliable tools, and so on.

Therefore, in this research, the compositional gradient calculations are used to verify the PVT data. The industry actually has techniques (e.g., forward and backward material balance calculations of constant volume depletion test data) to validate the accuracy of fluid samples. Despite that fact, the compositional gradient calculations are intended to elaborate on the current knowledge regarding verifying the data.

4.2 Derivation of Equations for Compositional Gradient

Høier and Whitson (2001) showed the compositional gradient calculation equations using both gravity effect and thermal diffusion as follows,

\[ \sum_{k=1}^{nc-1} \left( \frac{\partial \mu_i}{\partial y_k} \right)_{p,T,y_{j\neq k}} \nabla y_k = F_{G_i} - F_{T_i} \frac{\nabla T}{T} \quad (4.1) \]

and

\[ F_{G_i} = (M_i - \bar{v}_i \rho)g \quad (4.2) \]

Where:
\( \mu_i \) is the chemical potential of component \( i \), \( F_{G_i} \) is the gravity effect, \( F_{T_i} \) is the thermal
diffusion coefficient calculated using the Hasse’s model, $\bar{v}_i$ is the partial molar volume, $M_i$ is the molecular weight of component $i$, $\rho$ is density, $g$ is acceleration due to gravity.

There exist several models to determine thermal diffusion, $F_{Ti}$, such as Hasse, Kempers, and Belery-da Silva models. The Hasse model for an illustration purposes is shown below.

$$F_{Ti} = \frac{1}{M_i}(M_iH_m - M_mH_i) \quad \text{(Hasse model)} \quad (4.3)$$

Where:

$H$ is the partial molar enthalpy.

Nonetheless, all these thermal diffusion models are uncertain to some extent and are rarely used in the existing literature. Therefore, to derive the isothermal compositional gradient case, we need to start with the gradient of chemical potential, which is $f(p, y_k, T)$,

$$\nabla \mu_i = \left( \frac{\partial \mu_i}{\partial p} \right)_{T,y} \nabla p + \sum_{k=1}^{n_c-1} \left( \frac{\partial \mu_i}{\partial x_i} \right)_{p,T,y_k \neq j} \nabla x_k + \left( \frac{\partial \mu_i}{\partial T} \right)_{p,y} \nabla T$$

$$= \bar{v}_i\rho g + \sum_{k=1}^{n_c-1} \left( \frac{\partial \mu_i}{\partial x_i} \right)_{p,T,y_k \neq j} \nabla x_k - S_i \nabla T \quad (4.4)$$

where $S_i$ is the partial molar entropy.

Substituting the Eq. 4.1 into the Eq. 4.4 leads to,

$$\nabla \mu_i = M_i g - S_i \nabla T - F_{Ti} \frac{\nabla T}{T} \quad (4.5)$$

and for the isothermal case when reservoir temperature does not change much over an interval, $\nabla T = 0$,

$$\nabla \mu_i = M_i g \quad (4.6)$$

To solve the Eq. 4.6, the chemical potential must be defined in terms of fugacity,

$$\mu_i = RT \ln f_i \quad (4.7)$$

Thus Eq. 4.6 becomes,

$$RT \nabla (\ln f_i) = M_i g \quad (4.8)$$
Subsequently,

\[
RT \frac{\partial}{\partial D} \ln f_i = M_i g \\
RT \frac{\ln \frac{f_i(D)}{f_i(D_0)}}{D - D_0} = M_i g \\
\ln \frac{f_i(D)}{f_i(D_0)} = \frac{M_i g (D - D_0)}{RT} \\
\frac{f_i(D)}{f_i(D_0)} = \exp \left[ \frac{M_i g (D - D_0)}{RT} \right]
\]

Thus the final form is,

\[
f_i(D) = f_i(D_0) \exp \left[ \frac{M_i g (D - D_0)}{RT} \right] \tag{4.9}
\]

Note that the derivation of the Eq. 4.9 has been based on the depth increasing downwards relative to the reference depth, \(D_0\).

A solution for the Eq. 4.9 involves the fugacity term, which in turn is solved using the PR EOS for multicomponent mixtures. These two terms, i.e., the fugacity and the PR EOS, are presented below.

### 4.2.1 Fugacity

In thermodynamics, fugacity represents the effective pressure of real gases. Due to high pressure and temperature conditions, most of the petroleum reservoirs behave in a non-ideal way. Therefore, the fugacity concept can relate the actual pressure, which is expressed as fugacity, with the ideal gas case. The theory behind the concept is Gibbs molar energy, which states that the chemical potential must be the same for equivalent pressures of ideal and real gases.

Fugacity of component \(m\) in a mixture, \(f_m\), is defined in terms of fugacity coefficient, \(\Phi_m\) as follows,

\[
\Phi_m = \frac{f_m}{x_m p} \quad m = 1, 2, \ldots nc
\tag{4.10}
\]

and

\[
\ln \Phi_m = \frac{b_m}{b} (Z - 1) - \ln(Z - B) - \frac{A}{2\sqrt{2}B} \left\{ \left( \frac{2}{n=1} \sum_{n=1}^{nc} a_{mn} x_n \right) - \frac{b_m}{b} \right\} \ln \left( \frac{Z + (\sqrt{2} + 1)B}{Z - (\sqrt{2} - 1)B} \right) \tag{4.11}
\]
4.2.2 The Peng-Robinson EOS for Mixtures

In section 2.4.1 we discussed the Peng-Robinson equation of state, which has another alternative form in terms of \( Z \)-factor, the gas deviation factor,

\[
Z^3 + Z^2(B - 1) + Z(A - 2B - 3B^2) + (B^3 + B^2 - AB) = 0
\] (4.12)

where:

\[
A = \frac{ap}{R^2T^2}
\] (4.13)
\[
B = \frac{bp}{RT}
\] (4.14)

In Eqs. 4.13 and 4.14, the attraction, \( a \) and the repulsion, \( b \) parameters are defined differently for the mixture in comparison with pure components. Thus,

\[
a = \sum_{m=1}^{nc} \sum_{n=1}^{nc} a_{mn}x_m x_n
\] (4.15)

and

\[
a_{mn} = \sqrt{a_m a_n (1 - \delta_{mn})}
\] (4.16)

In Eq. 4.16, \( \delta_{mn} \) is the binary interaction parameter between two non-similar components, and \( \delta_{mn} = \delta_{nm} \). \( b \) in Eq. 4.14, is defined as follows,

\[
b = \sum_{m=1}^{nc} b_m x_m
\] (4.17)

In the equations above, component parameters are determined the same way as described in section 2.4.1. Note that \( i \equiv m \equiv n = 1, 2, 3, \ldots nc \).

A compositional gradient flowchart is presented in Figure 4.1. Fugacity derivative with respect to pressure is attached in Appendix A which in turn needs the derivatives of \( Z \)-factor with respect to pressure and molar composition. These derivatives of the \( Z \)-factor are presented in Appendix B.
Figure 4.1: Calculation procedure for the isothermal compositional gradient case (Whitson and Brulé, 2000).
4.3 Fluid Samples Analysis

Fluid samples analysis is a preliminary step required to check and obtain reliable fluid samples to use in the EOS modeling. This analysis primarily consists of the compositional gradient calculations and a dewpoint pressure comparison. As mentioned earlier, the industry usually performs laboratory examination of the compositional data and then takes them directly to the EOS tuning procedure. However, because of the unavailability of the full set of laboratory data, this research obtained a reliable fluid composition using the compositional gradient calculations and matched this composition to an available single set of constant-composition expansion experiment.

4.3.1 Compositional Gradient Calculations

In order to properly create the compositional simulation model, the quality of different fluid samples had to be checked and then could be used in the EOS modeling. Fluid samples compositions are given below in Tables 4.1 and 4.2 (KPO, 2009).

Table 4.1: Composition of gas-condensate samples

<table>
<thead>
<tr>
<th>Component</th>
<th>08Y</th>
<th>09Y</th>
<th>10Y</th>
<th>14Y</th>
<th>19Y</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂S</td>
<td>3.94</td>
<td>3.81</td>
<td>4.03</td>
<td>3.86</td>
<td>4.01</td>
</tr>
<tr>
<td>N₂</td>
<td>0.67</td>
<td>0.81</td>
<td>0.67</td>
<td>0.71</td>
<td>0.63</td>
</tr>
<tr>
<td>CO₂</td>
<td>5.38</td>
<td>5.10</td>
<td>5.30</td>
<td>5.27</td>
<td>5.29</td>
</tr>
<tr>
<td>C₁</td>
<td>71.28</td>
<td>71.35</td>
<td>70.26</td>
<td>71.94</td>
<td>71.09</td>
</tr>
<tr>
<td>C₂</td>
<td>5.44</td>
<td>5.32</td>
<td>5.43</td>
<td>5.27</td>
<td>5.33</td>
</tr>
<tr>
<td>C₃</td>
<td>2.79</td>
<td>2.57</td>
<td>2.75</td>
<td>2.64</td>
<td>2.76</td>
</tr>
<tr>
<td>i-C₄</td>
<td>0.53</td>
<td>0.48</td>
<td>0.62</td>
<td>0.55</td>
<td>0.54</td>
</tr>
<tr>
<td>n-C₄</td>
<td>1.14</td>
<td>1.02</td>
<td>1.25</td>
<td>1.15</td>
<td>1.13</td>
</tr>
<tr>
<td>i-C₅</td>
<td>0.54</td>
<td>0.54</td>
<td>0.59</td>
<td>0.56</td>
<td>0.58</td>
</tr>
<tr>
<td>n-C₅</td>
<td>0.57</td>
<td>0.56</td>
<td>0.61</td>
<td>0.61</td>
<td>0.61</td>
</tr>
<tr>
<td>C₆</td>
<td>1.08</td>
<td>1.15</td>
<td>1.21</td>
<td>1.23</td>
<td>1.19</td>
</tr>
<tr>
<td>C₇</td>
<td>0.97</td>
<td>1.08</td>
<td>1.09</td>
<td>1.05</td>
<td>1.00</td>
</tr>
<tr>
<td>C₈</td>
<td>0.92</td>
<td>1.07</td>
<td>1.00</td>
<td>0.96</td>
<td>0.96</td>
</tr>
<tr>
<td>C₉</td>
<td>0.67</td>
<td>0.65</td>
<td>0.71</td>
<td>0.65</td>
<td>0.68</td>
</tr>
<tr>
<td>C₁₀</td>
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<td>0.58</td>
<td>0.60</td>
<td>0.56</td>
<td>0.56</td>
</tr>
<tr>
<td>C₁₁</td>
<td>0.50</td>
<td>0.53</td>
<td>0.55</td>
<td>0.50</td>
<td>0.52</td>
</tr>
<tr>
<td>C₁₂</td>
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<td>0.43</td>
<td>0.44</td>
<td>0.39</td>
<td>0.41</td>
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</table>
Table 4.1: continued.

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<th></th>
<th>C13</th>
<th>C14</th>
<th>C15</th>
<th>C16</th>
<th>C17</th>
<th>C18</th>
<th>C19</th>
<th>C20</th>
<th>C21</th>
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<th>C24</th>
<th>C25</th>
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<th>C27</th>
<th>C28</th>
<th>C29</th>
<th>C30+</th>
</tr>
</thead>
<tbody>
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<td></td>
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<td>0.36</td>
<td>0.39</td>
<td>0.30</td>
<td>0.32</td>
<td>0.28</td>
<td>0.21</td>
<td>0.15</td>
<td>0.11</td>
<td>0.09</td>
<td>0.08</td>
<td>0.07</td>
<td>0.04</td>
<td>0.03</td>
<td>0.02</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>Fluid sample interval, top, ft</td>
<td>15705</td>
<td>15361</td>
<td>15613</td>
<td>15698</td>
<td>15912</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fluid sample interval, bottom, ft</td>
<td>15968</td>
<td>15764</td>
<td>15308</td>
<td>15269</td>
<td>16217</td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reference depth, ft</td>
<td>15837</td>
<td>15587</td>
<td>14961</td>
<td>14984</td>
<td>16066</td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reference pressure, psia</td>
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<td>8236.2</td>
<td>8111</td>
<td>8115.6</td>
<td>8332</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reference temperature, °F</td>
<td>183.34</td>
<td>181.59</td>
<td>177.21</td>
<td>177.37</td>
<td>184.94</td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Date of analysis</td>
<td>5/11/05</td>
<td>10/8/04</td>
<td>8/25/05</td>
<td>8/9/05</td>
<td>6/26/05</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4.1 shows the data from recombined gas-condensate samples. Table 4.2 illustrates oil rim bottomhole samples. At the end of the tables, fluid sampling reference points and their parameters are given because they are necessary for the compositional gradient calculations.
Table 4.2: Composition of oil samples

<table>
<thead>
<tr>
<th>Component</th>
<th>04X (1)</th>
<th>04X (2)</th>
<th>05X</th>
<th>06X</th>
<th>13X (1)</th>
<th>13X (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>H$_2$S</td>
<td>4.13</td>
<td>4.04</td>
<td>4.69</td>
<td>4.09</td>
<td>4.82</td>
<td>4.79</td>
</tr>
<tr>
<td>N$_2$</td>
<td>0.61</td>
<td>0.59</td>
<td>0.60</td>
<td>0.48</td>
<td>0.57</td>
<td>0.66</td>
</tr>
<tr>
<td>CO$_2$</td>
<td>5.79</td>
<td>5.77</td>
<td>5.31</td>
<td>5.33</td>
<td>5.61</td>
<td>5.64</td>
</tr>
<tr>
<td>C$_1$</td>
<td>63.07</td>
<td>63.25</td>
<td>63.42</td>
<td>61.03</td>
<td>61.16</td>
<td>61.27</td>
</tr>
<tr>
<td>C$_2$</td>
<td>6.44</td>
<td>6.41</td>
<td>5.80</td>
<td>5.81</td>
<td>6.22</td>
<td>6.24</td>
</tr>
<tr>
<td>C$_3$</td>
<td>3.90</td>
<td>3.84</td>
<td>3.46</td>
<td>3.57</td>
<td>3.67</td>
<td>3.62</td>
</tr>
<tr>
<td>i-C$_4$</td>
<td>0.75</td>
<td>0.73</td>
<td>0.82</td>
<td>0.68</td>
<td>0.73</td>
<td>0.75</td>
</tr>
<tr>
<td>n-C$_4$</td>
<td>1.69</td>
<td>1.64</td>
<td>1.63</td>
<td>1.54</td>
<td>1.59</td>
<td>1.57</td>
</tr>
<tr>
<td>i-C$_5$</td>
<td>0.83</td>
<td>0.81</td>
<td>0.71</td>
<td>0.76</td>
<td>0.76</td>
<td>0.73</td>
</tr>
<tr>
<td>n-C$_5$</td>
<td>0.92</td>
<td>0.89</td>
<td>0.82</td>
<td>0.82</td>
<td>0.82</td>
<td>0.75</td>
</tr>
<tr>
<td>C$_6$</td>
<td>1.45</td>
<td>1.43</td>
<td>1.36</td>
<td>1.39</td>
<td>1.65</td>
<td>1.51</td>
</tr>
<tr>
<td>C$_7$</td>
<td>1.19</td>
<td>1.19</td>
<td>1.11</td>
<td>1.35</td>
<td>1.26</td>
<td>1.24</td>
</tr>
<tr>
<td>C$_8$</td>
<td>1.14</td>
<td>1.16</td>
<td>1.14</td>
<td>1.31</td>
<td>1.26</td>
<td>1.27</td>
</tr>
<tr>
<td>C$_9$</td>
<td>1.05</td>
<td>1.07</td>
<td>1.16</td>
<td>1.38</td>
<td>1.24</td>
<td>1.25</td>
</tr>
<tr>
<td>C$_{10}$</td>
<td>0.91</td>
<td>0.93</td>
<td>0.96</td>
<td>1.15</td>
<td>1.05</td>
<td>1.08</td>
</tr>
<tr>
<td>C$_{11}$</td>
<td>0.73</td>
<td>0.74</td>
<td>0.76</td>
<td>0.91</td>
<td>0.80</td>
<td>0.82</td>
</tr>
<tr>
<td>C$_{12}$</td>
<td>0.58</td>
<td>0.60</td>
<td>0.61</td>
<td>0.80</td>
<td>0.66</td>
<td>0.68</td>
</tr>
<tr>
<td>C$_{13}$</td>
<td>0.56</td>
<td>0.57</td>
<td>0.60</td>
<td>0.71</td>
<td>0.63</td>
<td>0.65</td>
</tr>
<tr>
<td>C$_{14}$</td>
<td>0.45</td>
<td>0.46</td>
<td>0.50</td>
<td>0.64</td>
<td>0.50</td>
<td>0.51</td>
</tr>
<tr>
<td>C$_{15}$</td>
<td>0.42</td>
<td>0.43</td>
<td>0.44</td>
<td>0.57</td>
<td>0.46</td>
<td>0.47</td>
</tr>
<tr>
<td>C$_{16}$</td>
<td>0.33</td>
<td>0.34</td>
<td>0.35</td>
<td>0.46</td>
<td>0.38</td>
<td>0.39</td>
</tr>
<tr>
<td>C$_{17}$</td>
<td>0.28</td>
<td>0.29</td>
<td>0.31</td>
<td>0.49</td>
<td>0.33</td>
<td>0.34</td>
</tr>
<tr>
<td>C$_{18}$</td>
<td>0.24</td>
<td>0.25</td>
<td>0.28</td>
<td>0.29</td>
<td>0.31</td>
<td>0.32</td>
</tr>
<tr>
<td>C$_{19}$</td>
<td>0.22</td>
<td>0.21</td>
<td>0.29</td>
<td>0.38</td>
<td>0.31</td>
<td>0.32</td>
</tr>
<tr>
<td>C$_{20}$</td>
<td>0.19</td>
<td>0.20</td>
<td>0.23</td>
<td>0.28</td>
<td>0.26</td>
<td>0.27</td>
</tr>
<tr>
<td>C$_{21}$</td>
<td>0.17</td>
<td>0.17</td>
<td>0.21</td>
<td>0.28</td>
<td>0.21</td>
<td>0.21</td>
</tr>
<tr>
<td>C$_{22}$</td>
<td>0.14</td>
<td>0.15</td>
<td>0.19</td>
<td>0.25</td>
<td>0.20</td>
<td>0.21</td>
</tr>
<tr>
<td>C$_{23}$</td>
<td>0.12</td>
<td>0.12</td>
<td>0.17</td>
<td>0.22</td>
<td>0.18</td>
<td>0.18</td>
</tr>
<tr>
<td>C$_{24}$</td>
<td>0.12</td>
<td>0.12</td>
<td>0.15</td>
<td>0.20</td>
<td>0.17</td>
<td>0.18</td>
</tr>
<tr>
<td>C$_{25}$</td>
<td>0.10</td>
<td>0.10</td>
<td>0.14</td>
<td>0.19</td>
<td>0.15</td>
<td>0.15</td>
</tr>
<tr>
<td>C$_{26}$</td>
<td>0.08</td>
<td>0.08</td>
<td>0.12</td>
<td>0.16</td>
<td>0.14</td>
<td>0.14</td>
</tr>
<tr>
<td>C$_{27}$</td>
<td>0.08</td>
<td>0.08</td>
<td>0.10</td>
<td>0.14</td>
<td>0.13</td>
<td>0.13</td>
</tr>
</tbody>
</table>
The fluid samples with their reference parameters, such as depth, pressure, and temperature, were input into the CMG WinProp software, and trends were obtained. We evaluated the trends to determine how similar they were to these results are plotted in the Figures 4.2 and 4.3 for the gas-condensate and oil samples, respectively.

Figure 4.2 illustrates the saturation and reservoir pressures obtained at different depths for the gas-condensate samples. It must be mentioned that the gas-condensate samples of wells 09Y and 14Y were not able to produce the output. This problem was attributed to phase instabilities, yet the exact explanation could be something else. In Figure 4.2, the black lines with the circle marker and with the rhomb marker represent the field accepted saturation and reservoir pressures, respectively (KPO, 2009). The data based upon which these lines were drawn were likely fluid samples taken from different wells. The saturation pressure line in Figure 4.2 suggests that near the gas-oil contact, which is (according to the figure) at 16,400 feet, the reservoir fluid is in a saturated state. Three lines in red, green, and blue colors represent the saturation and the reservoir pressures at different depths based off of 19Y, 08Y, and 10Y wells samples, respectively. As can be seen, two well compositions (08Y and 10Y) are significantly outlying from the field accepted saturation pressure gradient. The first inspection of the 19Y well composition (the red line) seems to be close to the actual field data.

Figure 4.3 shows the reservoir and saturation pressures generated for all depths based on the oil samples. The black line again represents the field accepted saturation and the reservoir pressures. As can be seen, oil well compositions generally follow a similar trend. Moreover, additional samples taken from the same well closely correspond to each other.
Figure 4.2: The reservoir and saturation pressures versus depth for the gas-condensate samples.
Figure 4.3: The reservoir and saturation pressures versus depth for the oil samples.
The reservoir pressure calculations exhibit almost the perfect match with the field accepted pressure gradient model. On the other hand, there is no ideal match in saturation pressures of the samples. These discrepancies in the saturation pressure calculations can be attributed to the fact that it is difficult to measure the saturation pressure while doing bottomhole sampling. The industry usually performs laboratory experiments on collected fluids samples to determine saturation pressures and phase and volumetric properties.

As Figure 4.3 shows, two fluid samples, 06X and 05X, are the closest to the actual field model. On the other hand, none of the oil samples actually indicate the saturated state near the GOC. Therefore, the samples collected earlier or prior to the production could have erroneously indicated the near-saturated state. This problem might be associated with the inaccuracy of samples collected near the gas-oil contact.

### 4.3.2 Dewpoint Comparison

The next step was to check the dewpoint pressure of these samples at a particular depth (15,420 feet) where the dewpoint pressure of the system was 7034 psia, according to the field data (KPO, 2009).

<table>
<thead>
<tr>
<th>Well name</th>
<th>(P_{res}), psia</th>
<th>(P_{dp}), psia</th>
<th>Error, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>06X</td>
<td>8244.83</td>
<td>7084.23</td>
<td>0.71</td>
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<tr>
<td>05X</td>
<td>8265.84</td>
<td>6974.73</td>
<td>0.84</td>
</tr>
<tr>
<td>19Y</td>
<td>8205.35</td>
<td>7184.48</td>
<td>2.14</td>
</tr>
<tr>
<td>13X(2)</td>
<td>8256.84</td>
<td>6844.76</td>
<td>2.69</td>
</tr>
<tr>
<td>13X(1)</td>
<td>8256.60</td>
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<tr>
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<td>6639.30</td>
<td>5.61</td>
</tr>
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<td>10Y</td>
<td>8220.35</td>
<td>7475.30</td>
<td>6.27</td>
</tr>
<tr>
<td>08Y</td>
<td>8204.01</td>
<td>7604.51</td>
<td>8.11</td>
</tr>
</tbody>
</table>

Table 4.3 shows that two oil well samples, 06X and 05X have the least error percentage relative to the reference point. The gas-condensate sample 19Y has had an error of 2.14 percent, which is in an acceptable range of 2-3 percent. Thus, these three well compositions are to be taken for the EOS fluid model characterization.

Interestingly, the dewpoint pressure of the well 19Y has gotten attention since its dewpoint pressure was higher than other gas-condensate samples (08Y and 10Y) exhibited. Usually, gas injection processes lead to the increase in saturation pressures, i.e., bubble point and dewpoint. Therefore, the gas-condensate and oil fluid samples have been checked for
their methane and heptane molar compositions. This scrutiny is justified by the fact that the molar compositions of light and heavy components usually control the bubble point and dewpoint pressure of a system, respectively.

![Methane and Heptane Mole Fractions](image)

Figure 4.4: The mole fractions of methane (top) and heptane (bottom) at the reference point for different fluid samples.

As can be seen from Figure 4.4, the methane content of 19Y and 08Y is higher than average 0.69 mole fraction, 0.739 and 0.735, respectively. Possible explanations for the dewpoint pressure elevation were sought in the data, and it was found that the gas-condensate wells were sampled in 2005 after a start of the gas injection program in 2003.

The two-year period had substantially increased the amount of dry gas in these sample molar compositions. On the other hand, the methane mole fraction of the 10Y well sample,
which is also the gas-condensate well, have been decreasing remarkably, up to 61 mol-% (See Figure 4.4). Furthermore, the heptane content of 10Y well is approximately five mol-% higher than all other wells. These results imply an interesting phenomenon happening with the 10Y well. One plausible explanation for this effect is the faraway location of 10Y well from the injection wells. One can also notice that this well is depleting naturally, and, in fact, is producing below dewpoint pressure which can be seen from the huge amount of heptant content left in the reservoir. In other words, the huge amount of condensate is remaining in the reservoir, which needs the gas injection to recover that liquid.

These compositional gradient calculations, as shown, can not only generate a fluid compositional model over depth, but also be used as a tool to check the validity of the data, when these data are questionable and sparcely available.

These preliminary calculations showed that gas-condensate samples were not suitable for the following EOS modeling, and the 06X composition has been taken because of its nearness to actual conditions.

4.4 EOS Tuning

The equations of state do not precisely describe reservoir fluids because of two reasons: (1) drawbacks that the equations of state have, and (2) the uniqueness of a specific hydrocarbon fluid. The drawbacks relatively depend on a specific EOS, and the industry performed many modifications to these EOS to improve volumetric and phase equilibria predictions. The second, however, is a subject to a human analysis, which is EOS tuning. Since the given reservoir has a considerable amount of non-hydrocarbon gases, such as hydrogen sulfide, carbon dioxide, and nitrogen, it is unique in comparison with other reservoirs and its volumetric and phase behavior cannot be described by the ordinary EOS. Therefore, the Peng-Robinson (PR) EOS was tuned to match the actual volumetric phase behavior of the reservoir.

The actual tuning process is a trial and error routine that requires changing component parameters to minimize the least square errors. Coats (1985) explained some of the main ideas behind the tuning procedure. In short, by changing several regression parameters individually or together, it is possible is to minimize the difference between the actual and calculated data.

Some of the regression strategies used in this study (after Whitson et al. (1999)) were as follows:

- Variables with the most impact, such as critical properties of heavy components and binary interaction parameters must be chosen first
• The regression on physical properties of light components (< C₆) is not recommended because these components are well defined.

• The use of as few as possible regression parameters is desirable.

It is of utmost importance to know what these regression variables will have an impact on. Otherwise, the tuning procedure will be arduous work. Some effects of regression variables on the volumetric and phase behavior are as follows.

• Critical pressure and temperature will impact the saturation pressure and vapor-liquid equilibrium calculations.

• The critical pressure and temperature of the heaviest components usually controls the dewpoint pressure and hence they impact the dewpoint curve.

• Binary interaction parameters of hydrocarbon pairs will have an impact on the saturation pressure calculation.

• If the reservoir fluid contains a considerable amount of non-hydrocarbon components, the binary interaction parameters between the heavy HC ends and non-HC components can be regressed.

• Volume shift parameter is used only for density corrections.

• Critical Z-factor is used only for viscosity calculations.

Another side of the tuning procedure is to have reliable sets of laboratory data to match with fluid compositions. For most gas-condensate reservoir cases, standard experiment tests are constant-volume depletion (CVD), constant-composition expansion (CCE) experiments, and saturation pressure calculation. Because of the availability of constant-composition expansion experiment results only, the PR EOS was tuned to these data. Most of the former Soviet Union countries still use the old PVT laboratory procedure, and these experiments are not detailed as in some of the Western PVT procedure. For instance, during CVD and CCE experiments, the liquid dropout volume is measured but important parameters, such as Z-factors, produced gas volume, densities, and gas composition can be omitted (Bolotnik et al., 1997). As a result, the EOS characterization might not be as accurate.

Another minor inconsistency between the former Soviet Union and the Western PVT experiments is a demonstration of the liquid dropout volume. For example, in the available data for this study, the liquid volume has been reported as a condensate gas factor (CGF), which is a measure of volume of liquid in the reservoir conditions per volume of gas initially
filled the PVT cell in stock tank conditions in units of \(Rcm^3/Sm^3\). Therefore, to convert data, Bolotnik et al. (1997) suggests,

\[
S_l = \frac{CGF}{C}
\]  

(4.18)

and

\[
C \approx \frac{Z \times T_{dew} \times P_{st} \times 10^6}{T_{st} \times P_{dew}}
\]  

(4.19)

where:

- \(Z\) is the Z-factor of the reservoir fluid at \(T_{dew}\) and \(P_{dew}\); \(T_{dew}\) is the dewpoint temperature in \(^{°R}\); \(P_{st}\) is the pressure at standard conditions, 14.696 psia; \(T_{st}\) is the temperature at standard conditions, 68\(^°F\) or 528\(^°R\); \(P_{dew}\) is the dewpoint pressure in psia.

Table 4.4 shows the data (KPO, 2009) used for the EOS tuning and predicted results after the non-linear regression.

**Table 4.4: Constant composition expansion data at 177.5\(^°F\)**

<table>
<thead>
<tr>
<th>Pressure, psia</th>
<th>Condensate dropout, cm3/m3</th>
<th>Experimental liquid volume, % of cell volume at saturation pressure</th>
<th>Predicted liquid volume, % of cell volume at saturation pressure</th>
<th>Error, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>8267</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>7252</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>7000*</td>
<td>0</td>
<td>0</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>6997.96**</td>
<td>-</td>
<td>-</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>6962</td>
<td>20</td>
<td>0.566</td>
<td>0.565</td>
<td>0.215</td>
</tr>
<tr>
<td>6382</td>
<td>310</td>
<td>8.778</td>
<td>9.595</td>
<td>9.306</td>
</tr>
<tr>
<td>6092</td>
<td>500</td>
<td>14.158</td>
<td>13.969</td>
<td>1.338</td>
</tr>
<tr>
<td>5802</td>
<td>690</td>
<td>19.538</td>
<td>18.082</td>
<td>7.453</td>
</tr>
<tr>
<td>5511</td>
<td>810</td>
<td>22.936</td>
<td>21.790</td>
<td>4.996</td>
</tr>
<tr>
<td>5221</td>
<td>910</td>
<td>25.767</td>
<td>24.954</td>
<td>3.157</td>
</tr>
<tr>
<td>4931</td>
<td>1010</td>
<td>28.599</td>
<td>27.542</td>
<td>3.696</td>
</tr>
<tr>
<td>4641</td>
<td>1070</td>
<td>30.298</td>
<td>29.575</td>
<td>2.387</td>
</tr>
<tr>
<td>4061</td>
<td>1110</td>
<td>31.431</td>
<td>32.200</td>
<td>2.447</td>
</tr>
<tr>
<td>3771</td>
<td>1140</td>
<td>32.280</td>
<td>32.922</td>
<td>1.987</td>
</tr>
<tr>
<td>3191</td>
<td>1200</td>
<td>33.979</td>
<td>33.457</td>
<td>1.538</td>
</tr>
<tr>
<td>2901</td>
<td>1180</td>
<td>33.413</td>
<td>33.354</td>
<td>0.177</td>
</tr>
<tr>
<td><strong>Average error</strong></td>
<td></td>
<td><strong>2.419</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: * is the experimental dewpoint pressure, ** is the predicted dewpoint

Several parameters were changed to match the PR EOS to the experimental data, and they were:

1. \(T_c\) and \(p_c\) of \(C_{30+}\).

2. \(\Omega_A\) and \(\Omega_B\) of \(CH_4\).

The matched liquid dropout curve from the CCE experiment is shown in Figure 4.5. As can be seen, the maximum liquid dropout (with respect to the volume at the saturation pressure) for the reference depth composition, 15,420 ft, is 33 percent at 3000 psia reservoir pressure.

![Figure 4.5: The experimental and predicted liquid volumes from the constant composition expansion experiment.](image)

**4.5 Lumping Procedure**

The next step after the EOS tuning is to use this fluid model in the following numerical simulations. However, the enormous amount of components is computationally expensive, so component lumping (sometimes called “grouping”) is needed. The lumping procedure has been performed based on a stepwise reduction of the number of components suggested by Whitson et al. (1999). The lumped components are shown in Table 4.5. The first column is the original 35 component fluid, whereas the last column is the lumped 12 component fluid.

A general workflow of the lumping procedure is as follows:

1. Matching original number of components to the PVT data, which has been accomplished in Section 4.4.
2. Generating PVT lab experiments using the tuned EOS.

3. Stepwise reducing the number of components of the original fluid composition.

4. Matching this lumped component properties to the originally generated PVT data from Step 2.

5. Repeating Steps 3-4 until the desirable number of components is achieved.

Table 4.5: Lumping procedure of reducing number of components

<table>
<thead>
<tr>
<th>Component</th>
<th>EOS22</th>
<th>EOS16</th>
<th>EOS14</th>
<th>EOS12</th>
</tr>
</thead>
<tbody>
<tr>
<td>N₂</td>
<td>N₂</td>
<td>N₂</td>
<td>N₂</td>
<td>N₂</td>
</tr>
<tr>
<td>CO₂</td>
<td>CO₂</td>
<td>CO₂</td>
<td>CO₂</td>
<td>CO₂</td>
</tr>
<tr>
<td>C₁</td>
<td>C₁</td>
<td>C₁</td>
<td>C₁</td>
<td>C₁</td>
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<tr>
<td>C₂</td>
<td>C₂</td>
<td>C₂</td>
<td>C₂</td>
<td>C₂</td>
</tr>
<tr>
<td>C₃</td>
<td>C₃</td>
<td>C₃</td>
<td>C₃</td>
<td>C₃</td>
</tr>
<tr>
<td>i-C₄</td>
<td>C₄</td>
<td>C₄</td>
<td>C₄</td>
<td>C₄</td>
</tr>
<tr>
<td>n-C₅</td>
<td>C₅</td>
<td>C₅</td>
<td>C₅</td>
<td>C₅C₆</td>
</tr>
<tr>
<td>i-C₆</td>
<td>C₆</td>
<td>C₆</td>
<td>C₆</td>
<td>C₇C₉</td>
</tr>
<tr>
<td>n-C₇</td>
<td>C₇</td>
<td>C₇</td>
<td>C₇</td>
<td>C₁₀C₁₅</td>
</tr>
<tr>
<td>C₈</td>
<td>C₈C₉</td>
<td>C₈C₉</td>
<td>C₈C₉</td>
<td>C₁₆C₂₅</td>
</tr>
<tr>
<td>C₉</td>
<td>C₁₀C₁₁</td>
<td>C₁₀C₁₁</td>
<td>C₁₀C₁₅</td>
<td>C₂₆⁺</td>
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<td>C₁₂C₁₅</td>
<td>C₁₆C₂₅</td>
<td>C₂₆⁺</td>
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<tr>
<td>C₁₁</td>
<td>C₁₈C₁₉</td>
<td>C₁₈C₁₉</td>
<td>C₁₆C₂₉</td>
<td>C₃₀⁺</td>
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<td>C₂₀C₂₁</td>
<td>C₂₀C₂₁</td>
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<td></td>
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<tr>
<td>C₁₃</td>
<td>C₂₂C₂₃</td>
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<td></td>
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<tr>
<td>C₁₄</td>
<td>C₂₄C₂₅</td>
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<tr>
<td>C₁₅</td>
<td>C₂₆C₂₇</td>
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<td>C₁₆</td>
<td>C₂₈C₂₉</td>
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<tr>
<td>C₁₇</td>
<td>C₃₀⁺</td>
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<td>C₂₈</td>
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<tr>
<td>C₂₉</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₃₀⁺</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

It must be noted that in most lumping cases for hydrocarbon reservoirs, it is possible to minimize the number of lumped components to 3-5 components. According to Coats
(1985), however, for the gas-condensate reservoirs practicing the gas cycling processes, the number of heavy components (i.e., heptanes plus) should be in a 3-5 range. This is explained by a need to accurately describe the vaporization mechanism of heavy components during the gas injection. On the other hand, the lightest hydrocarbon gases, such as methane, ethane, propane, and butane were not grouped together, nor were they lumped with non-hydrocarbon gases. The reason not to group these gases is the possibility of injecting them, which requires these components to be separately specified in the flow simulator Eclipse 300. As a consequence, the final number of components in this study was 12, which was reached taking several steps.

4.6 Final Fluid Characterization

The final fluid model obtained from all the fluid characterization steps is presented below. Figure 4.6 illustrates the liquid amount to be condensed for the reservoir fluids at different depths. The highest liquid dropout is expected with the near GOC fluid. This amount from the laboratory experiments is 47 percent. The lowest liquid yield, 20 percent, is expected for the fluid that is in the top of the reservoir.

Tables 4.6 and 4.7 are obtained from the constant volume depletion tests performed using the CMG WinProp package.
Table 4.6: Depletion study at 177.5°F

<table>
<thead>
<tr>
<th>Component</th>
<th>Reservoir Pressure, psia</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>6997.9</td>
</tr>
<tr>
<td>H₂S</td>
<td>3.66</td>
</tr>
<tr>
<td>N₂</td>
<td>0.57</td>
</tr>
<tr>
<td>CO₂</td>
<td>5.31</td>
</tr>
<tr>
<td>C₁</td>
<td>69.89</td>
</tr>
<tr>
<td>C₂</td>
<td>6.06</td>
</tr>
<tr>
<td>C₃</td>
<td>3.47</td>
</tr>
<tr>
<td>C₄</td>
<td>2.02</td>
</tr>
<tr>
<td>C₅C₆</td>
<td>2.43</td>
</tr>
<tr>
<td>C₇C₉</td>
<td>2.75</td>
</tr>
<tr>
<td>C₁₀C₁₅</td>
<td>2.45</td>
</tr>
<tr>
<td>C₁₆C₂₅</td>
<td>0.92</td>
</tr>
<tr>
<td>C₂₆+</td>
<td>0.47</td>
</tr>
</tbody>
</table>

| Equilibrium Gas | Z-factor | 1.1661 | 1.0875 | 1.0147 | 0.8988 | 0.8311 | 0.81 | 0.8325 | 0.8936 |
| Gas Produced, cum. mole % of original fluid | 2.49 | 5.46 | 13.41 | 24.69 | 39.66 | 57.46 | 76.13 |
| Liquid, vol % of original fluid | 7.77 | 15.12 | 26 | 30.21 | 30.04 | 27.78 | 24.64 |
| Molecular weight of C₇+ | 162.5 | 155.4 | 141.1 | 129.2 | 120.3 | 114.3 | 110.8 | 178.8 |

Table 4.7: Cumulative recovery during depletion per MMscf of original fluid

<table>
<thead>
<tr>
<th>Reservoir Pressure, psia</th>
<th>6500</th>
<th>6000</th>
<th>5000</th>
<th>4000</th>
<th>3000</th>
<th>2000</th>
<th>1000</th>
<th>1000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well stream, Mscf</td>
<td>1000</td>
<td>24.9</td>
<td>54.65</td>
<td>134.09</td>
<td>246.88</td>
<td>396.55</td>
<td>574.59</td>
<td>761.31</td>
</tr>
<tr>
<td>Separator recovery</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary separator gas, Mscf</td>
<td>833.993</td>
<td>21.007</td>
<td>46.464</td>
<td>117.071</td>
<td>221.37</td>
<td>364.422</td>
<td>538.332</td>
<td>722.018</td>
</tr>
<tr>
<td>Second-stage gas, Mscf</td>
<td>26.048</td>
<td>0.616</td>
<td>1.298</td>
<td>2.744</td>
<td>4.177</td>
<td>5.332</td>
<td>6.072</td>
<td>6.643</td>
</tr>
<tr>
<td>GOR, Mscf/STB</td>
<td>6.87</td>
<td>7.81</td>
<td>8.50</td>
<td>11.15</td>
<td>14.90</td>
<td>20.22</td>
<td>27.03</td>
<td>34.15</td>
</tr>
<tr>
<td>GOR, m³/m³</td>
<td>1223</td>
<td>1391</td>
<td>1514</td>
<td>1985</td>
<td>2653</td>
<td>3601</td>
<td>4814</td>
<td>6083</td>
</tr>
</tbody>
</table>
Figure 4.7 shows the phase envelope of the system at different depths. As can be seen from figure, initial reservoir pressure at different depths are different: varying from low 8000 psia at 14,600 ft to 8200 psia at 16,100 ft. The dewpoint pressure changes correspondingly with depth.

Figure 4.7: The pressure-temperature diagram of the reservoir fluid at different depths.
CHAPTER 5
SIMULATION MODEL SETUP

An important step in any reservoir simulation study is to correctly build and initialize a reservoir model. The basic properties of this model are described in this chapter. The reservoir model of the carbonate gas-condensate reservoir is an analogous to ones found in the Caspian region.

5.1 Geologic Description of the Model

The analogous field is located in a marginal area of the North Caspian Basin. The basin itself is characterized by thick sedimentary deposits of Late Devonian-Early Permian periods. Kungurian age of Early Permian deposited a thick layer of salts, which is considered the seal of the reservoir.

The carbonate gas-condensate formation (or reservoir) of the field is in the Serpukhovian age of the Carboniferous period. Reservoir thickness is about 1600 feet, and it is represented by a variety of facies. Carbonate layers are described as biohermal, biomorphic-detrital, and organogenic detrital limestones and dolomites. According to Dunham’s classification, their texture can be defined as grainstones and packstones. These complex primary sedimentary processes with secondary diagenetic processes indicate that the reservoir properties are highly heterogeneous and described by vuggy porosity and fractures. However, available literature has not provided a detailed geologic distribution of secondary porosity over the entire field except to indicate that production data are affected by enhanced permeability (Francesconi et al., 2012).

5.2 Reservoir Rock and Fluid Properties

As mentioned, the gas-condensate carbonate reservoir is very thick and complex. The top of the reservoir is at 14,600 ft approximately, and its bottom, which is the gas-oil contact, is at 16,240 ft (O’Hearn et al., 2003). In addition, the reservoir is marked by high initial reservoir pressure, which indicates an abnormal pressure gradient of 0.56 psi/ft. Reservoir temperature, on the other side, can be considered relatively low; at 15240 ft depth, it is 177.5 °F and the geothermal gradient is approximately 0.7 °F per 100 feet (KPO, 2009).

Fluid system of the reservoir is very complex, especially the gas-condensate fluid. For instance, condensate content in the reservoir gas ranges from 400 g/m³ in the upper part of
the reservoir to 900 g/m$^3$ at the gas-oil contact. This might only indicate a high compositional variation of the fluid. These facts have also been verified by gas densities that vary from the top part to the bottom and by the gas compressibility factor, i.e., the gas deviation factor (Francesconi et al., 2012).

5.2.1 Rock Properties

Main rock properties needed for the reservoir simulation are porosity and permeability values. Reservoir porosity was assumed to be 10 percent based on an average of core and log data presented by O’Hearn et al. (2003). Permeability, on the other side, varies significantly even in a small portion of the reservoir. For example, for the given carbonate formation, O’Hearn et al. (2003) reports an arithmetic average permeability of 14.54 md and a geometric average permeability of 0.86 md. Bedrikovetsky and Basniev (1994) however state that permeability is less than 5 md, which is correct because reservoirs have not only uniform permeable zones, but also the least permeable areas or layers. Therefore, the optimistic horizontal permeability for the whole model was assumed to be 5 md, and the vertical permeability was 1 md. The latter was assumed due to the fact that the vertical permeability is not strictly 10 times lower than that of horizontal permeability for the analogous field (KPO, 2009).

5.2.2 Relative Permeability

Relative permeability curves are important parameters which control the fluid flow when several phases are present in the reservoir. However, these phase saturations must exceed a critical value after which the phase starts flowing. For this research case, the reservoir was initially saturated with gas and connate water. The latter is assumed to be static since there is no water injection involved, nor is there any aquifer. Despite that fact, the commercial software Eclipse 300 requires the water-oil relative permeability curves as input. The more significant curves are gas-condensate relative permeability curves, which dictate primarily the gas flow reduction near the wellbore.

Table 5.1 shows the connate and residual phase saturations and the relative permeability endpoints at corresponding saturation values. The connate water saturation was obtained from $S_{hc}$, which is on average 92 percent for the reservoir (O’Hearn et al., 2003). The relative permeability endpoints are from KPO (2009), however, due to the highly heterogeneous character of the reservoir, they might not fully represent the entire field.

Based on these endpoint values, Corey type relative permeability curves were constructed using Eqs. 5.1 and 5.2 for gas-condensate relative permabilities and Eqs. 5.3 and 5.4 for the
Table 5.1: Saturations and relative permeability end points

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connate water saturation, $S_{wc}$</td>
<td>0.08</td>
</tr>
<tr>
<td>Connate gas saturation, $S_{gc}$</td>
<td>0</td>
</tr>
<tr>
<td>Critical gas saturation, $S_{gcr}$</td>
<td>0.10</td>
</tr>
<tr>
<td>Residual oil saturation to water, $S_{orw}$</td>
<td>0.30</td>
</tr>
<tr>
<td>Critical condensate saturation, $S_{cc}$</td>
<td>0.12</td>
</tr>
<tr>
<td>End point of relative permeability to gas in gas-condensate system, $k^*_{rg}$</td>
<td>0.90</td>
</tr>
<tr>
<td>End point of relative permeability to condensate in gas-condensate system, $k^*_{rog}$</td>
<td>0.55</td>
</tr>
<tr>
<td>End point of relative permeability to condensate in oil-water system, $k^*_{row}$</td>
<td>0.55</td>
</tr>
<tr>
<td>End point of relative permeability to water in oil-water system, $k^*_{rw}$</td>
<td>0.20</td>
</tr>
</tbody>
</table>

where:

\[ k_{rg}^* = k_{rg}^* \left( \frac{S_g - S_{gc}}{1 - S_{wr} - S_{gc}} \right)^{ng} \] (5.1)

\[ k_{rog}^* = k_{rog}^* \left( \frac{1 - S_g - S_{wr}}{1 - S_{wr} - S_{gc}} \right)^{nog} \] (5.2)

\[ k_{rw}^* = k_{rw}^* \left( \frac{S_w - S_{wr}}{1 - S_{wr} - S_{orw}} \right)^{nw} \] (5.3)

\[ k_{row}^* = k_{row}^* \left( \frac{1 - S_w - S_{orw}}{1 - S_{wr} - S_{orw}} \right)^{now} \] (5.4)

where:

\[ ng = 3.0 \] and \[ nog = 3.5 \].

The obtained relative permeability curves are presented in Figures 5.1 and 5.2 for the gas-oil and water-oil systems, respectively. As can be observed from Figures 5.1 and 5.2, the rock is preferentially neutral wet. Carbonate reservoirs are considered to be oil-wet, but the field core measurements have showed a mainly neutral to slightly oil-wet character of the rock (KPO, 2009). Another important point is that a carbonate reservoir with a fully saturated gas-condensate fluid is mostly non-wetting at initial conditions. Therefore, consequent liquid dropout has little time to change the wetting characteristics of the rock, which is considered the water-wetting before the drainage cycle (Kazemi, 2014). Based on these premises, Corey’s exponents were chosen to imitate the neutral wet reservoir.
Figure 5.1: The gas-oil relative permeability curves.

Figure 5.2: The water-oil relative permeability curves.
5.2.3 Capillary Pressure

The capillary pressure is an important parameter needed to initialize the reservoir fluid system in the reservoir. Eclipse 300 software uses it (1) to find out the fluid distribution within the hydrocarbon column and also (2) to calculate corresponding pressures of other phases from the capillary pressure curve.

In this research, due to unavailability of data, the water-oil capillary pressure curve was set to zero. This assumption is justified by the fact that the gas-condensate reservoir has a static amount of water (i.e., connate water) and oil is not present in the beginning. The short period of production time theoretically cannot create a strong interfacial tension between the water and condensing liquid.

On the other hand, gas-oil capillary pressure might represent some interfacial forces. In the petroleum industry, because of the complexity of laboratory equipment and procedures required to estimate the gas-oil capillary pressure, it was assumed to be small and usually set to zero. Moreover, O’Hearn et al. (2003) provided a plot in which the interfacial tension for the depth of the current study was low. This low-interfacial tension indirectly implies that there is little gas-oil capillary pressure. Simple calculations using the parachor were performed to check the validity of the zero gas-oil capillary pressure assumption.

Macleod-Sugden correlation to calculate the interfacial tension is,

\[ \sigma_m^{1/4} = \sum_{i=1}^{N_c} [P_i](\rho_{Lm}x_i - \rho_{Vm}y_i) \]  

(5.5)

where:

\( \sigma_m \) = surface tension of mixture, dyne/cm

\( [P_i] \) = parachor of component \( i \)

\( x_i, y_i \) = mole fractions of \( i \) in liquid and vapor phases

\( \rho_{Lm} \) = liquid mixture density, mol/cm\(^3\)

\( \rho_{Vm} \) = vapor mixture density, mol/cm\(^3\)

To obtain the phase density in mol/cm\(^3\),

\[ \rho_L[\text{mol/cm}^3] = 0.016 \frac{\rho_L[\text{lb/ft}^3]}{MW_L[\text{g/mol}]} \]

where:

0.016 is the conversion factor. The conversion is given only for the liquid phase, but it is the same for the vapor phase.

CMG WinProp software was used to flash the reference depth fluid (15,420 feet sample) at several different pressures. The obtained liquid and vapor mole fractions were then entered.
into Eq. 5.5 to calculate the interfacial tensions between the gas and condensate phases. Results are shown in Table 5.2.

### Table 5.2: Interfacial tensions calculated for the reference depth fluid

<table>
<thead>
<tr>
<th>Pressure, psia</th>
<th>$\rho_L$, lb/ft$^3$</th>
<th>$\rho_V$, lb/ft$^3$</th>
<th>$MW_L$, g/mol</th>
<th>$MW_V$, g/mol</th>
<th>$\sigma$, dyne/cm</th>
</tr>
</thead>
<tbody>
<tr>
<td>7000</td>
<td>-</td>
<td>28.54</td>
<td>-</td>
<td>32.52</td>
<td>0</td>
</tr>
<tr>
<td>6000</td>
<td>33.38</td>
<td>25.95</td>
<td>52.76</td>
<td>30.01</td>
<td>0.0007</td>
</tr>
<tr>
<td>5000</td>
<td>33.89</td>
<td>22.12</td>
<td>55.69</td>
<td>27.19</td>
<td>0.0155</td>
</tr>
<tr>
<td>4000</td>
<td>34.83</td>
<td>17.50</td>
<td>61.59</td>
<td>24.85</td>
<td>0.1439</td>
</tr>
<tr>
<td>3000</td>
<td>36.18</td>
<td>12.60</td>
<td>71.08</td>
<td>23.25</td>
<td>0.7305</td>
</tr>
<tr>
<td>2500</td>
<td>36.98</td>
<td>10.19</td>
<td>77.60</td>
<td>22.72</td>
<td>1.3916</td>
</tr>
</tbody>
</table>

Table 5.2 shows that the interfacial tension between gas and condensate and it varies from 0 to 1.4 dyne/cm during the pressure reduction from 7000 to 2000 psia. Since the magnitude of the gas-oil capillary pressure is not clearly known from the literature, it can only be guesstimated.

For example, if a pore throat radius is assumed to be 1 $\mu$m and the contact angle is 0 $^\circ$, then with $\sigma=1$ dyne/cm, the gas-oil capillary pressure is equal to 0.3 psia. This number is small and requires the significant amount of the condensate to drop out the solution. Therefore, the zero assumption of the gas-oil capillary pressure curve is reasonable, yet it is recommended that the industry develop tools to measure it at reservoir conditions.

#### 5.2.4 Fluid Properties

Fluid properties were discussed in Chapter 4, particularly in Section 4.6. This section presents the finalized fluid model that was input in the fluid properties part of the reservoir simulator.

Table 5.3 shows the critical properties of components used in the simulation model. The heavy end parameters were obtained from the PR EOS tuning method.

Table 5.4 shows the composition of the gas-condensate fluid at the reference depth and Peng-Robinson EOS parameters that are/are not affected by the tuning procedure. As can be seen from the table, $\Omega_a$ and $\Omega_b$ multipliers and the volume shift parameter for methane were changed. A primary reason to change these parameters, especially for methane, was that the PR EOS does not predict methane density (i.e., volumetric properties) accurately.

Table 5.5 represents the binary interaction parameters for the reservoir fluid system. The upper right of the table is diagonally symmetric to the lower left part but not shown here. Zeros state that there is no interaction with the same molecule in the fluid. In most of petroleum literature, binary interaction parameters of heavy hydrocarbons ($C_7+$) with
Table 5.3: Critical properties of the 12-component gas-condensate fluid

<table>
<thead>
<tr>
<th>Component</th>
<th>Mol. Weight, lb/lb-mole</th>
<th>$p_c$, psia</th>
<th>$T_c$, °R</th>
<th>$v_c$, ft³/lb-mole</th>
<th>$Z_c$</th>
<th>$T_b$, °R</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂S</td>
<td>34.0800</td>
<td>1296.1872</td>
<td>671.7600</td>
<td>1.5778</td>
<td>0.2837</td>
<td>383.0400</td>
</tr>
<tr>
<td>N₂</td>
<td>28.0130</td>
<td>492.3160</td>
<td>227.1600</td>
<td>1.4337</td>
<td>0.2895</td>
<td>139.3200</td>
</tr>
<tr>
<td>CO₂</td>
<td>44.0100</td>
<td>1069.8688</td>
<td>547.5600</td>
<td>1.5057</td>
<td>0.2741</td>
<td>350.4600</td>
</tr>
<tr>
<td>C₁</td>
<td>16.0430</td>
<td>667.1984</td>
<td>343.0800</td>
<td>1.5858</td>
<td>0.2874</td>
<td>201.0600</td>
</tr>
<tr>
<td>C₂</td>
<td>30.0700</td>
<td>708.3472</td>
<td>549.7200</td>
<td>2.3707</td>
<td>0.2846</td>
<td>332.1000</td>
</tr>
<tr>
<td>C₃</td>
<td>44.0970</td>
<td>615.7624</td>
<td>665.6400</td>
<td>3.2518</td>
<td>0.2803</td>
<td>415.9800</td>
</tr>
<tr>
<td>C₄</td>
<td>58.1240</td>
<td>544.1358</td>
<td>755.6304</td>
<td>4.1244</td>
<td>0.2767</td>
<td>484.2616</td>
</tr>
<tr>
<td>C₅₋₆</td>
<td>78.3534</td>
<td>484.5211</td>
<td>872.1158</td>
<td>5.1620</td>
<td>0.2672</td>
<td>580.2886</td>
</tr>
<tr>
<td>C₇₋₉</td>
<td>107.5239</td>
<td>436.9514</td>
<td>1013.7811</td>
<td>6.7611</td>
<td>0.2715</td>
<td>704.4889</td>
</tr>
<tr>
<td>C₁₀₋₁₅</td>
<td>160.2032</td>
<td>314.3237</td>
<td>1204.4733</td>
<td>9.8758</td>
<td>0.2401</td>
<td>866.5702</td>
</tr>
<tr>
<td>C₁₆₋₂₅</td>
<td>264.3673</td>
<td>226.2934</td>
<td>1396.1513</td>
<td>15.6628</td>
<td>0.2366</td>
<td>1084.1403</td>
</tr>
<tr>
<td>C₂₆₊</td>
<td>387.0740</td>
<td>122.1977</td>
<td>1690.6463</td>
<td>22.0706</td>
<td>0.1486</td>
<td>1284.2150</td>
</tr>
</tbody>
</table>

Table 5.4: Composition of reservoir fluid at reference depth of 15,420 feet and PR EOS parameters used in reservoir simulation

<table>
<thead>
<tr>
<th>Component</th>
<th>Composition, mol-%</th>
<th>Acentric factor</th>
<th>$\Omega_a$</th>
<th>$\Omega_b$</th>
<th>Volume shift parameter</th>
<th>Parachor</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂S</td>
<td>3.6605</td>
<td>0.1000</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>80.1000</td>
</tr>
<tr>
<td>N₂</td>
<td>0.5728</td>
<td>0.0400</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>41.0000</td>
</tr>
<tr>
<td>CO₂</td>
<td>5.3102</td>
<td>0.2250</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>78.0000</td>
</tr>
<tr>
<td>C₁</td>
<td>69.8931</td>
<td>0.0080</td>
<td>0.36886746</td>
<td>0.06223600</td>
<td>-0.1925</td>
<td>77.0000</td>
</tr>
<tr>
<td>C₂</td>
<td>6.0598</td>
<td>0.0980</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>108.0000</td>
</tr>
<tr>
<td>C₃</td>
<td>3.4688</td>
<td>0.1520</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>150.3000</td>
</tr>
<tr>
<td>C₄</td>
<td>2.0166</td>
<td>0.1877</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>187.2912</td>
</tr>
<tr>
<td>C₅₋₆</td>
<td>2.4255</td>
<td>0.2554</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>238.0973</td>
</tr>
<tr>
<td>C₇₋₉</td>
<td>2.7530</td>
<td>0.3485</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>310.2356</td>
</tr>
<tr>
<td>C₁₀₋₁₅</td>
<td>2.4472</td>
<td>0.5183</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>448.3654</td>
</tr>
<tr>
<td>C₁₆₋₂₅</td>
<td>0.9240</td>
<td>0.7920</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>686.1024</td>
</tr>
<tr>
<td>C₂₆₊</td>
<td>0.4685</td>
<td>1.0690</td>
<td>0.45723553</td>
<td>0.07779607</td>
<td>0</td>
<td>908.7982</td>
</tr>
</tbody>
</table>
light hydrocarbons are ignored. In this study, binary interaction parameters are given for all components by CMG WinProp, which internally uses a Chueh and Prausnitz equation to calculate hydrocarbon pair interactions. It is essential to know how reservoir simulation software calculates or determines property since an output of any reservoir simulation model would be questionable without the right input and the right treatment.

Table 5.5: Binary interaction parameters for the 12-component system

<table>
<thead>
<tr>
<th></th>
<th>H₂S</th>
<th>N₂</th>
<th>CO₂</th>
<th>C₁</th>
<th>C₂</th>
<th>C₃</th>
<th>C₄</th>
<th>C₅C₆</th>
<th>C₇C₉</th>
<th>C₁₀C₁₅</th>
<th>C₁₆C₂₅</th>
<th>C₂₆+</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂S</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>N₂</td>
<td></td>
<td>0.1300</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂</td>
<td></td>
<td>0.1350</td>
<td>0.0000</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₁</td>
<td></td>
<td>0.0700</td>
<td>0.0250</td>
<td>0.1050</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₂</td>
<td></td>
<td>0.0850</td>
<td>0.0100</td>
<td>0.1300</td>
<td>0.0027</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₃</td>
<td></td>
<td>0.0800</td>
<td>0.0900</td>
<td>0.1250</td>
<td>0.0085</td>
<td>0.0017</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₄</td>
<td></td>
<td>0.0750</td>
<td>0.0950</td>
<td>0.1166</td>
<td>0.0151</td>
<td>0.0051</td>
<td>0.0009</td>
<td>0</td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>C₅C₆</td>
<td></td>
<td>0.0610</td>
<td>0.1073</td>
<td>0.1150</td>
<td>0.0228</td>
<td>0.0100</td>
<td>0.0036</td>
<td>0.0008</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C₇C₉</td>
<td></td>
<td>0.0495</td>
<td>0.1100</td>
<td>0.0984</td>
<td>0.0341</td>
<td>0.0181</td>
<td>0.0089</td>
<td>0.0041</td>
<td>0.0012</td>
<td>0</td>
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<td></td>
</tr>
<tr>
<td>C₁₀C₁₅</td>
<td></td>
<td>0.0369</td>
<td>0.1566</td>
<td>0.0731</td>
<td>0.0534</td>
<td>0.0331</td>
<td>0.0202</td>
<td>0.0126</td>
<td>0.0070</td>
<td>0.0024</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>C₁₆C₂₅</td>
<td></td>
<td>0.0644</td>
<td>0.2000</td>
<td>0.2000</td>
<td>0.0818</td>
<td>0.0568</td>
<td>0.0399</td>
<td>0.0290</td>
<td>0.0202</td>
<td>0.0117</td>
<td>0.0035</td>
<td>0</td>
</tr>
<tr>
<td>C₂₆+</td>
<td></td>
<td>0.0297</td>
<td>0.0848</td>
<td>0.1828</td>
<td>0.1060</td>
<td>0.0779</td>
<td>0.0583</td>
<td>0.0452</td>
<td>0.0342</td>
<td>0.0229</td>
<td>0.0107</td>
<td>0.0020</td>
</tr>
</tbody>
</table>

5.3 Separator Conditions

Separator conditions (i.e., pressure and temperature) are important because they determine the initial hydrocarbon reserves in the reservoir. Traditionally, many reservoir simulator programs define static and dynamic quantities (e.g., gas initially in-place, oil initially in-place, producing flow rates, gas-oil ratios) in terms of stock-tank conditions. Therefore, setting proper separator conditions not only determines these quantities but also dictates the maximum recoverable amount of liquid and gas.

Table 5.6: Three-stage separation process

<table>
<thead>
<tr>
<th>Stage</th>
<th>Pressure, psia</th>
<th>Temperature, °F</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1000</td>
<td>95</td>
</tr>
<tr>
<td>2</td>
<td>500</td>
<td>77</td>
</tr>
<tr>
<td>3*</td>
<td>14.7</td>
<td>68</td>
</tr>
</tbody>
</table>

* - Stock tank

Table 5.6 presents the three-stage separation process used in this study. Gas-condensate reservoirs yield different liquid amounts depending on separator conditions used. In this research, a separator optimization process was not aimed, so the selected separator stages
and their conditions might differ from an optimal separator process for this specific fluid. Nonetheless, the first and second stage separation pressures and temperatures were set high for this study because there might be a loss of valuable condensate due to a sudden change of reservoir conditions. One should also note that accepted stock-tank temperature is 68°F or 20°C.

5.4 Simulation Model

The simulation model built in Eclipse 300 (Schlumberger, 2013) is depicted in Figure 5.3. The model is a rectangular-shaped box with dimensions of 3000 feet in x-direction, 1500 feet in y-direction, and 1500 feet in z-direction. The depth to the top of the reservoir as mentioned before is 14,600 feet, so the bottom of the reservoir is at 16,100 feet.

![Figure 5.3: 3D description of the simulation model.](image)

A simulation grid cell has 100x100x15 feet dimensions in x-, y-, and z-directions, respectively. Therefore, the number of grid cells in x-direction is 30, in y-direction - 15, and in z-direction - 100. The total number of simulation cells is 45,000.

Production wells are located on the boundaries of the reservoir model. Injection wells are located in the center, particularly in the centers of two five-spot patterns (See Figure 5.3).
5.3. Detailed information about production and injection well locations are provided in Table 5.7.

Table 5.7: Production and injection well locations

<table>
<thead>
<tr>
<th>Well</th>
<th>Mode</th>
<th>$i$-location</th>
<th>$j$-location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well5</td>
<td>Injection</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Well10</td>
<td>Injection</td>
<td>23</td>
<td>8</td>
</tr>
<tr>
<td>Well20</td>
<td>Production</td>
<td>15</td>
<td>1</td>
</tr>
<tr>
<td>Well21</td>
<td>Production</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Well22</td>
<td>Production</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Well23</td>
<td>Production</td>
<td>1</td>
<td>15</td>
</tr>
<tr>
<td>Well24</td>
<td>Production</td>
<td>30</td>
<td>1</td>
</tr>
<tr>
<td>Well25</td>
<td>Production</td>
<td>30</td>
<td>15</td>
</tr>
</tbody>
</table>

5.5 Well Completion

The overall reservoir development strategy was intended to utilize gravity drainage forces. As a consequence, the production wells were completed and perforated in the liquid-rich
bottom of the reservoir, whereas the injection wells were completed in the upper part of the reservoir.

Figure 5.4 shows the locations of six wells with perforated depths. A blue plane divides the reservoir model in half vertically, which is the end of 50th layer at 15,350 feet.

This chapter described all parameters required for the proper reservoir simulation, and results obtained based on these input parameters will be presented in the following chapter. It must be mentioned that the output of the model strongly depends on the input files, and the future researchers can take these inputs as an example to build their own Eclipse model and improve for their use.
CHAPTER 6
RESERVOIR SIMULATION RESULTS

The simulation model described in the previous chapter has been run for 40 years. The pressure depletion case is used to estimate the amount of condensate loss. Other cases involved the gas injection, and it was started after one year of gas production.

6.1 Pressure Depletion

Natural depletion of the reservoir is simulated to observe a long-term productivity, which in turn determines economic profits. A reservoir pressure response versus time is depicted in Figure 6.1. Since six production wells produce at a constant rate of 12,000 Mscf of gas per day, the pressure steadily declines with time. The first five years of production can be described as a transient period followed by a pseudosteady-state regime. From Figure 6.1, the dewpoint pressure of the model cannot be determined. Since the production wells were constrained to bottomhole pressure of 2200 psia, there was no gas production after 27 years, and the reservoir pressure was at 2200 psia.

![Figure 6.1: Reservoir pressure during depletion.](image)
Figure 6.2 tells us when the dewpoint pressure has been reached which is two years after the start of production. Before this time, condensate production was high and equaled 2090 STB/day. However, when the reservoir pressure dropped below the dewpoint, the condensate production rate experienced the sudden drop. This indicated that some heavier components condensed in the reservoir, so the producing gas content was not rich with the liquefiable components. In addition, the cumulative recovery of condensate was achieved 7.8 million STB at 27 years of production with no significant increase afterward because there was no gas production.

![Graph showing condensate production rate and cumulative condensate production](image)

Figure 6.2: Condensate production rate and cumulative condensate production during pressure depletion.

Importantly, the condensate left behind is enormous during the pressure depletion. Figure 6.3 shows that as soon as the reservoir pressure dropped below the dewpoint, condensate has started accumulating in the whole reservoir reaching 68 percent in 25 years. On the other hand, the condensate remaining in free gas sharply declines after the dewpoint and ends up at only four percent.

Figure 6.3 does not reveal how much sellable condensate is left behind. To obtain the tangible amount of the liquid, the condensed liquid percentage, 68 percent, must be multiplied by 2.93x10^7 STB, the condensate initially in-place in terms of free gas. One can calculate that almost 20 million STB of condensate has been left in the reservoir after 20-25 years.
Figure 6.3: Fraction of condensate remained in free gas and dropped out as liquid during pressure depletion as regards the initial condensate in-place.

Figure 6.4: Fraction of liquid dropout vs. reservoir pressure during pressure depletion.
Figure 6.4 shows the fraction of liquid dropped out during the pressure depletion. As one can observe, the figure closely resembles the constant volume depletion experiment (See Figure 4.6). The figure shows that the apparent dewpoint pressure of the reservoir fluid is slightly higher than 7000 psia, which should not be taken as a single value. Rather it represents the dewpoint pressure of the producing interval, which has the dewpoint pressure varying from 6970 to 7190 psia.

6.1.1 Discussion on Pressure Depletion

First examination of Figure 6.4 implies that the traditional CVD experiment mimics the gas-condensate reservoir behavior but does not fully represent the actual performance. The reservoir model has reached almost the 70 percent of liquid at the end of the reservoir life. The CVD experiment, on the other hand, showed that the maximum liquid dropout for the liquid-rich bottom part of the reservoir is 47 percent at 5000 psia. Figure 6.4 is in accordance with the liquid dropout curve depicted in Figure 4.6. However, the extra condensate volume from 5000 psia to the constraining bottomhole pressure of 2200 psia (See Figure 6.4) might be attributed to the liquid formed in the upper part of the reservoir due to the pressure reduction, but the exact explanation remains unclear.

The overall performance of the reservoir in terms of the recovered condensate is poor, as can be seen from Figures 6.2 and 6.3. 7.9 million barrels of cumulative condensate after 40 years is roughly 27 percent of recovery. Another way to look at it is by examining the Figure 6.3, which indicates the condensate remaining in free gas, which was almost four percent, and the condensate left behind as liquid, 69 percent, with a total of 73 percent.

Hence these figures suggest that the condensate recovery must be restored by applying gas injection schemes that will be discussed in the following sections.

6.2 Pure Gases

This section focuses on the comparison of pure gas injection scenarios, such as methane, nitrogen, and carbon dioxide. The injection started after a year of production for three cases. Table 6.1 shows production and injection rates assigned to wells. Because Well20 and Well21 are located in the middle of the reservoir model, they produce half of wells capacity of 6000 Mscf/day. Wells on corners (i.e., Wells 22-25) produce a quarter of 6000 Mscf/day. Furthermore, injection wells are injecting a full amount of produced gas.

Before discussing results obtained during the gas injection scenarios, pressure maintenance, especially, in such gas-condensate reservoirs, must be explained. A primary goal from the pressure maintenance is to fill a voidage space left after the gas production. Since the
Table 6.1: Production and injection well rates

<table>
<thead>
<tr>
<th>Well</th>
<th>Mode</th>
<th>Rate, Mscf/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well20</td>
<td>Production</td>
<td>3000</td>
</tr>
<tr>
<td>Well21</td>
<td>Production</td>
<td>3000</td>
</tr>
<tr>
<td>Well22</td>
<td>Production</td>
<td>1500</td>
</tr>
<tr>
<td>Well23</td>
<td>Production</td>
<td>1500</td>
</tr>
<tr>
<td>Well24</td>
<td>Production</td>
<td>1500</td>
</tr>
<tr>
<td>Well25</td>
<td>Production</td>
<td>1500</td>
</tr>
<tr>
<td>Well5</td>
<td>Injection</td>
<td>6000</td>
</tr>
<tr>
<td>Well10</td>
<td>Injection</td>
<td>6000</td>
</tr>
</tbody>
</table>

Initial reservoir gas-condensate has the heavy components, its compressibility under reservoir conditions is fixed. However, after the production and the separation process, these heavy ends are removed as condensate, and the light gas, e.g., lean gas, is injected back, which is more compressible than the initial gas at reservoir conditions.

As can be seen from Figure 6.5, three gases act differently in maintaining reservoir pressure. Because CH\textsubscript{4} and CO\textsubscript{2} are highly compressible, 12,000 Mscf of gas is not enough to keep the pressure above the dewpoint. Moreover, a comparison between two shows that CO\textsubscript{2}
is more compressible than CH₄. On the other hand, N₂ exhibits better capability in maintaining the pressure. This can be associated with the less compressible property of nitrogen than two other gases which in turn results in a full voidage replacement of produced reservoir fluid.

Figure 6.6 shows the condensate production rates versus time. As in the natural depletion case, the condensate production starts at 2090 STB per day and then declines slightly. At the beginning of the gas injection process, there is a sudden rate drop that can be attributed to the pressure response from injection wells. As was indicated from Figure 6.5, pressure maintenance capability is the highest for nitrogen and the lowest for carbon dioxide. Therefore, in the Figure 6.6, the condensate production rate sharply declined for the CO₂ injection case because the latter reached the dewpoint pressure at five years of production. The nitrogen injection case, on the other side, has the potential of producing at high rates for the first 13 years because it keeps the reservoir pressure high enough, around 7400 psia. However, a quick decline in condensate production rate, which is, in fact, steeper than that of two other cases, implies that something happened in the reservoir.

![Condensate Production Rate](image)

**Figure 6.6:** Condensate production rate response during injection of pure methane, nitrogen, and carbon dioxide.

The possible explanation for this sudden drop during the nitrogen injection is as follows. Nitrogen breakthrough took place in production wells that resulted in immediate production decline. It is well-known that when an injection fluid breakthroughs in a production well,
the producing content of the well is no longer one hundred percent hydrocarbon fluid. In other words, nitrogen breakthrough will increase nitrogen content of a producing wellstream. Figure 6.7 clearly indicates that, at 11 years, the nitrogen content had started increasing rapidly and had reached 0.53 or 53 mole-% at 40 years.

![Figure 6.7: Concentrations in mole fractions of methane (blue), nitrogen (black), and carbon dioxide (green) from producing wellstream of Well20 during pure gas injection scenarios.](image)

Figure 6.8 shows that, upon the nitrogen injection, the liquid starts dropping out in the reservoir. For example, neither CH$_4$ nor CO$_2$ have the effect of immediate liquid dropout. Both of them maintain the reservoir pressure (it would be better to say that these gases keep the pressure in a slight decline mode) until it hits the dewpoint of the reservoir fluid when the condensate comes out of the gas.

Figure 6.8 also tells how much condensate remains in the reservoir gas and the liquid form. Even though nitrogen has such a notorious physical effect, it has left only 13.5 percent of the condensate initially in-place, 2.93x10$^7$ STB, which is about 4 million STB. Methane and carbon dioxide injection scenarios left 16 and 25 percent of the condensate initially in-place as the liquid phase, respectively. From this perspective, the nitrogen injection initiated at the beginning of production seems to alleviate greatly the problem of condensate loss, yet its final recovery factor and accompanying financial costs must be evaluated.

Figure 6.9 shows the liquid dropout curve from a pressure perspective. Again, the nitro-
Figure 6.8: Fraction of condensate (with respects to the condensate initially in-place) remained in free gas and dropped out as liquid during pure gas injection scenarios.

The nitrogen injection exhibits the immediate liquid formation in the reservoir, which can be seen from the $N_2$ curve in Figure 6.9. In comparison with the two other curves, the nitrogen injection curve is completely dissimilar to them. The physical explanation for the nitrogen effect is that, during the first 15 years of the injection, the injected nitrogen mixed with the reservoir gas and kept the pressure high enough at approximately 7400 psia. As it was mentioned before, however, upon contact with \textit{in situ} gas, the dewpoint of this mixing front increased significantly followed by the immediate liquid dropout. After the first breakthrough, at 7400 psia and 0.07 liquid volume of the condensate (See Figure 6.9), nitrogen injected does not further contact with the pure reservoir gas but does with the previously adulterated gas. Moreover, the liquid dropout seen in Figure 6.8 means that after the first cycle, the 7 percent of condensate formed in pores. These two effects, i.e., the increasing amount of nitrogen in the reservoir gas and the poor miscibility of nitrogen with condensate, led to the increase in the reservoir pressure.

Another important sign that can be seen from Figure 6.9 is a displacement characteristic of pure injection gases. The nitrogen injection not only increased the reservoir pressure, but it also increased the liquid volume. This fact suggests that instead of vaporizing the condensate, nitrogen causes an additional condensate to form. Therefore, the nitrogen injection is the
Figure 6.9: Fraction of liquid dropout vs. reservoir pressure during pure gas injection scenarios.

slightly-miscible-to-immiscible process when contacting the liquid condensate in the reservoir but not the vaporizing process. CO$_2$ and CH$_4$, on the other hand, express a better vaporizing mechanism than N$_2$, which can be seen from their liquid fraction decrease (curves going downwards in Figure 6.9).

The results of pure gas injection scenarios suggest nitrogen, methane, and carbon dioxide injected alone cannot provide both full pressure maintenance and high flowrates at the same time. Each of these gases has its advantages and disadvantages. Table 6.2 summarizes some of these advantages and disadvantages that effect cumulative condensate recovery. In the table, emphasis was made on technical aspects of injected gases, yet some economic aspects are also given. Therefore, based on the technical aspects exclusively, overall gas injection performances can be estimated.

Results of recovery factors are given in Figure 6.10. CO$_2$, as expected, has a lower recovery factor than that of two other gases, which is almost 56 percent. CH$_4$ and N$_2$ recovered more than 60 percent of the condensate initially in-place with 62.8 and 61.43 percents, respectively. The difference in recovery factors between two is not significant - only 1.37 percent. Therefore, a trade-off between technical and economic aspects of using either of these gases is needed for full field implementation.

Some of the earlier stated observations are also seen in the recovery factor plot. For
Table 6.2: Advantages and disadvantages of pure injection gases (Adopted from Kleinsteiber et al. (1983))

<table>
<thead>
<tr>
<th>Injected fluid</th>
<th>Advantage</th>
<th>Disadvantage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>Revaporization quality of liquid condensed by multiple contacts</td>
<td>Highly compressible, i.e., high surface volume of methane is needed</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Partial pressure maintenance</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Late gas sales</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>Less compressible</td>
<td>Immediate liquid dropout</td>
</tr>
<tr>
<td></td>
<td>High pressure support</td>
<td>Cost of plants for generation</td>
</tr>
<tr>
<td></td>
<td>Early gas sales</td>
<td>Impured production stream that requires separation facilities</td>
</tr>
<tr>
<td>Carbon dioxide</td>
<td>Better revaporization quality</td>
<td>Partial pressure maintenance</td>
</tr>
<tr>
<td></td>
<td>Early gas sales</td>
<td>High cost</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Unavailable everywhere</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Corrosion</td>
</tr>
</tbody>
</table>

Figure 6.10: Fractions of condensate recovered during pure gas injection scenarios.
example, the nitrogen injection due to its high pressure maintenance in the early production stage (i.e., up to 20 years) produced more condensate than methane. However, after the breakthrough the condensate production rate began declining so did the cumulative condensate recovery.

These observations from pure gas injection scenarios lead the current research to the logical question of whether these gases would function differently if they were mixed or some mole fraction of other gases was added. Therefore, the following gas injection schemes are also considered.

6.3 Non-Acid Gas Mixtures Injection

In discussing this section, attention is paid to the pragmatic side of gas injection processes applied in the real field situations. In the previous section, the performance of pure gases was studied, and was discovered that the injection of pure gases alone may not be optimal.

Therefore, from a practical viewpoint, the industry has been using a produced hydrocarbon gas either lean or mixed with non-hydrocarbon gases. Their possible effects on condensate recovery efficiency have been outlined in the literature review.

The most used gas for gas cycling in the gas-condensate fields is lean gas. In this research, it was used as a base case to compare other gas injection mixtures with the lean gas performance. Table 6.3 provides a composition of the lean gas.

<table>
<thead>
<tr>
<th>Component</th>
<th>Composition, mole-%</th>
</tr>
</thead>
<tbody>
<tr>
<td>C₁</td>
<td>95</td>
</tr>
<tr>
<td>C₂</td>
<td>5</td>
</tr>
<tr>
<td>Total</td>
<td>100</td>
</tr>
</tbody>
</table>

In addition to the lean gas, different molar compositions of methane and nitrogen were used to form mixtures. These molar composition ratios were 90 mol-% CH₄/10 mol-% N₂, 75 mol-% CH₄/25 mol-% N₂, and 50 mol-% CH₄/50 mol-% N₂ with increasing nitrogen content in the mixtures. In fact, the petroleum industry has already utilized injection gases with nitrogen content as mentioned in Chapter 3. Furthermore, an increase of nitrogen content in the presence of other gases to more than 50 mol-% has been found to be impractical. Therefore, the abovementioned ratios were used in this study.

Another possibility is to use a separator gas for the gas cycling. Composition of the separator gas is given in Table 6.4. This composition was obtained from the three-stage separation process used in the reservoir model. It should be noted that, after each stage, a
different molar composition of a component is separated, so the final injected composition is approximated. The separator gas contains some light components up to hexane, and this amount of butane-hexane is 2 mol-%. However, these heavier hydrocarbon groups are valuable and can be sold. One idea behind the injection of the separator gas with some content of valuable hydrocarbons is to examine the concept brought by Whitson et al. (1999), which states that enriched gas can efficiently produce more condensate than the lean gas.

Table 6.4: Composition of injected separator gas

<table>
<thead>
<tr>
<th>Component</th>
<th>Composition, mole-%</th>
</tr>
</thead>
<tbody>
<tr>
<td>H$_2$S</td>
<td>5</td>
</tr>
<tr>
<td>N$_2$</td>
<td>-</td>
</tr>
<tr>
<td>CO$_2$</td>
<td>7</td>
</tr>
<tr>
<td>C$_1$</td>
<td>77</td>
</tr>
<tr>
<td>C$_2$</td>
<td>6</td>
</tr>
<tr>
<td>C$_3$</td>
<td>3</td>
</tr>
<tr>
<td>C$_4$</td>
<td>1</td>
</tr>
<tr>
<td>C$_5$C$_6$</td>
<td>1</td>
</tr>
<tr>
<td>C$_7$C$_9$</td>
<td>-</td>
</tr>
<tr>
<td>C$<em>{10}$C$</em>{15}$</td>
<td>-</td>
</tr>
<tr>
<td>C$<em>{16}$C$</em>{25}$</td>
<td>-</td>
</tr>
<tr>
<td>C$_{26+}$</td>
<td>-</td>
</tr>
<tr>
<td>Total</td>
<td>100</td>
</tr>
</tbody>
</table>

Figure 6.11 describes a reservoir pressure change during injection operations. As seen from the figure, increasing nitrogen content in a methane-nitrogen mixture keeps the pressure high. For example, an increase of N$_2$ from 10 mol-% to 25 mol-% increases the reservoir pressure by 200 psia, from 6446 to 6648 psia at the end of production. In the early stage of the reservoir development, this difference is not huge even though the tendency is clear: nitrogen replaces a voidage space efficiently. An efficient mixture seems to be the 50 mol-% CH$_4$/50 mol-% N$_2$ mixture, which allows recycling of gas in the near vicinity of the initial dewpoint pressure.

The other two gases, i.e., lean gas and separator gas perform poorly in supporting the reservoir pressure at a high level. These results can be seen from the green and brown lines in Figure 6.11 which stand for the lean gas and the separator gas, respectively. For example, the lean gas could keep the reservoir pressure at 6300 psia at the end of production while the nearest mixture with the 10 mol-% N$_2$ maintained pressure 200 psia more than the lean gas. When the lean and separator gases are compared, it seems that adding heavier components to methane-ethane mixture, such as propane, butane, and pentane-hexane, reduces the pressure faster than the lean gas.
Field condensate production rate is depicted in Figure 6.12. In the beginning of production, condensate production rates decline gradually for all injection mixtures. After the reservoir pressure reached the dewpoint, the rates started declining rapidly. The earliest dewpoint reach happened to the separator gas, 7 years, and the longest period of being above the true dewpoint pressure was in the 50 mol-% CH_4/50 mol-% N_2 mixture case, 14 years. As seen from Figure 6.12, in the early reservoir life, increasing nitrogen content helps produce at high production rate for a longer period than the mixture without nitrogen. Interestingly, the mixture with 50 mol-% of N_2 exhibits the similar behavior as pure nitrogen described in the Section 6.2.

Figure 6.12 also shows that the lean gas and the 90 mol-% CH_4/10 mol-% N_2 mixture demonstrate similar condensate production rates over time. It does not, however, imply that 10 mol-% of N_2 has the same quality of revaporizing the liquid condensed in the reservoir as that of 5 mol-% ethane. Rather it can only indicate that the reservoir pressure can be higher with such an amount of nitrogen than with 5 mol-% ethane. The separator gas, on the other hand, shows a dissimilar rate performance than other mixtures. Although it does not have strong capability of maintaining the reservoir pressure, the separator gas case has a much more gradual decline of condensate production rate than the other gases. Moreover, at the end of field production, the separator gas has the highest condensate flowrates.
Figure 6.12: Condensate production rates during the injection of non-acid mixtures.

Producing gas-oil ratios can be seen in Figure 6.13. The separator gas curve has a less steep slope, which means that the condensate produced from the wellstream is higher than from other mixtures. Figure 6.13 also points out that the 50 mol-% CH$_4$/50 mol-% N$_2$ mixture could retain a more or less constant gas-oil ratio for the initial 15 years of production. Other mixtures containing nitrogen have gas-oil ratios jumping earlier depending on the reduction of nitrogen content.

Figure 6.14 indicates the effectiveness of these mixtures in preventing liquid formation as well as the likelihood of reducing the condensate already formed in the reservoir by revaporizing it.

From Figure 6.14, it is seen that the separator gas is the only mixture that does not cause the immediate liquid drop when injected into the reservoir. Other injected mixtures to some extent cause the condensate to drop from the reservoir gas. The severest initial liquid dropout is associated with the 50 mol-% CH$_4$/50 mol-% N$_2$ mixture, which is 4 percent until the true dewpoint of the reservoir fluid has been reached. Other mixtures have had the liquid condensing upon the injection into the reservoir, and this initial liquid amount strongly increases with increasing nitrogen content in mixtures.

The main issue here, however, is to what extent these mixtures are efficient in recovering the condensate. As mentioned before, there are two things involved in the recovery efficiency
Figure 6.13: Gas-oil ratios during injection of non-acid mixtures.

Figure 6.14: Fraction of condensate left behind with respect to condensate initially in-place during the injection of non-acid mixtures.
from which conclusions can be made. First, if the gas injection started in the early stage of production, it must prevent the condensate formation due to the pressure reduction. Second, it should revaporize the condensate dropped if the pressure falls below the dewpoint. Figure 6.14 clearly shows that none of the mixtures have both qualities in the condensate recovery process. Moreover, the pressure maintenance criterion is not met for any of the gases including the CH\textsubscript{4}-N\textsubscript{2} mixture, or any other mixture with N\textsubscript{2}. None of the injected gases could keep pressure near the original dewpoint pressure without make-up gas. However, the revaporization characteristic can be seen from several mixtures.

The separator gas has a high magnitude of the curvature at 6000 psia, which possibly indicates its superiority over other gases for revaporization. Furthermore, the revaporization characteristics of injected mixtures diminish with reducing methane content. Finally, in the 50 mol-% CH\textsubscript{4}/50 mol-% N\textsubscript{2} mixture this quality completely disappears.

Another important observation that can be deduced from Figure 6.14 is that by selecting the injection gas with better vaporizing characteristics, one might cause the liquid condensation instead. In other words, increasing methane content, which is better for revaporization of condensate, also causes more condensate to drop out from the reservoir gas. For example, the 90 mol-% CH\textsubscript{4}/10 mol-% N\textsubscript{2} mixture caused the 15 percent of liquid condensation when compared to the 75 mol-% CH\textsubscript{4}/25 mol-% N\textsubscript{2} mixture that caused only the 13 percent of liquid formed in the reservoir. The lean gas resulted in even more liquid dropout, 16.7 percent, than that of 10 mol-% and 25 mol-% N\textsubscript{2} containing mixtures. In the lean gas case, more liquid is dropped not only because of the high methane content in the mixture but also because of the presence of ethane rather than nitrogen. The separator gas that has 77 mol-% CH\textsubscript{4}, which is same as in the 75 mol-% CH\textsubscript{4}/25 mol-% N\textsubscript{2} mixture, however, performs differently in comparison with other gases. In fact, these effects of liquid condensation are attributed to the pressure reduction that is mainly controlled by the composition of the injection gases. As discussed before, the addition of hydrocarbons with increasing carbon number makes the injection gas to be more compressible at reservoir conditions which in turn causes the rapid pressure drop.

Figure 6.14 demonstrates that the separator gas has engendered more liquid dropout than that of other gas mixtures and has substantially deteriorated the situation at the end of field life. This result proves that the argument mentioned by Whitson et al. (1999) on the condensate recovery improvement using the enriched gas is valid only for revaporization purposes but is disadvantageous for maintaining reservoir pressure. Disadvantages of the separator gas are two: (1) the injected separator gas condenses with the \textit{in situ} gas below the dewpoint (See Figure 6.14) and (2) it is economically expensive to inject the C\textsubscript{3}-C\textsubscript{6} content.
Figure 6.15: A comparison of condensate recovery factors for all non-acid injection gases.

Figure 6.15 presents recovery factors for all these cases (line colors are the same as in the previous figures), and they range from 62.8 percent for the separator gas to 63.5 percent for the 90 mol-% CH$_4$/10 mol-% N$_2$ mixture. Overall, their ultimate recovery performance was in a range of 1 percent cumulative condensate production. The results of these gas mixtures will be compared against injected gases presented in other sections later on in the summary section.

Gas injection in the field scale poses both technical and economic questions, such as what gas to use, how much gas is needed, and what it will cost. The gas injection scenarios used in this section have replicated the most common injection methods implemented in real fields, and the research results have met those expectations. An operating company must answer the question: “What is the ultimate goal from gas cycling operations?” What is obvious here is that none of the gases are leading, so their performances are more or less at the same range.

From the technical point of view, it became clear that neither methane nor nitrogen provides a sufficient level of miscibility to revaporize the condensate formed in the reservoir. Moreover, nitrogen causes the reverse: the liquid condensation upon the injection. Therefore, a logical question arises: “If a partial miscibility is created by mixing CO$_2$ with either methane or nitrogen, how will it affect the results?”
6.4 CO₂ Performance When Injected with Methane and Nitrogen

An addition of CO₂ to injection gases has rarely been studied in the development of gas-condensate reservoirs. Therefore, one of the primary purposes of including CO₂ in an injected mixture is to investigate its effect on the condensate recovery. Its capability in gas injection processes was mentioned in Section 6.2 in comparison with other gases. However, due to economic costs, the industry has not injected CO₂ by itself. It was always mixed and injected with other gases (Shayegi et al., 1996).

Another reason to implement CO₂ with methane and nitrogen is the presence of CO₂ in the reservoir fluid. As shown in Table 5.4, the amount of CO₂ is more than 5 mol-%. Hence it is favorable to inject it into the reservoir. Ratios of injected CO₂ over CH₄ and over N₂ are:

- 10 mol-% CO₂ / 90 mol-% CH₄
- 20 mol-% CO₂ / 80 mol-% CH₄
- 10 mol-% CO₂ / 90 mol-% N₂
- 20 mol-% CO₂ / 80 mol-% N₂

Lastly, the physical theory behind the revaporization of liquid condensate can be elaborated with CH₄-CO₂ and N₂-CO₂ mixture injections. In some cases, the efficiency of main injected gas can either be improved or worsened by adding some amount of different gas. Moreover, when injected together, the gas mixture is also involved in physical and chemical interactions with each other. Therefore, these processes can yield unpredicted results.

Reservoir pressure response during CH₄-CO₂ and N₂-CO₂ mixtures injection is shown in Figure 6.16, and the results are anticipated. Nitrogen content with the highest molar percentage shows the maximum reservoir pressure of 7200-7300 psia. The same is seen for methane, but the result when compared to the nitrogen gas is poor.

Figures 6.17 and 6.18 represent the producing gas-oil ratios and condensate production rates, respectively, for the aforementioned mixtures. The tendencies seen in the pure methane and nitrogen injection cases are also observed in the CO₂ inclusion cases. Nitrogen, for instance, keeps the GOR longer and at more or less a constant amount for the first 15 years than that of methane. From Figure 6.18, the condensate production rate for methane-carbon dioxide mixtures is significantly higher than that of pure methane (See Figure 6.6) and lower than that of the lean gas (See Figure 6.12). This difference raises a question regarding whether the small amount of ethane (i.e., 5 mol-% in the lean gas) performs better with methane than that of carbon dioxide, which is 10 and 20 mol-% in these cases.
Figure 6.16: Reservoir pressure during the injection of mixtures with CO$_2$.

Figure 6.17: Gas-oil ratios during injection of gas mixtures containing CO$_2$. 
Figure 6.18: Condensate production rates during the injection of mixtures with CO\(_2\).

On the other hand, both the lean gas and the methane-carbon dioxide mixtures yield the same recovery in the end, but these small peculiarities of C\(_2\)H\(_6\) over CO\(_2\) should be further studied from the fundamental physical and chemical perspectives.

Figure 6.19 shows the liquid dropout curves versus the reservoir pressure for the CO\(_2\) containing mixtures. The maximum liquid dropout was observed for methane-carbon dioxide mixtures. For example, the 20 mol-% CO\(_2\)/ 80 mol-% CH\(_4\) injected gas experienced almost 19 percent liquid dropout of the condensate initially in-place whereas 10 mol-% CO\(_2\) less mixture with CH\(_4\) caused 17.7 percent of condensate to form. The lean gas exhibited one percent less, or 16.7 percent condensate drop (See Figure 6.14) in the reservoir. It must be noted that the reservoir pressure change during the lean gas and the 10 mol-% CO\(_2\)/ 90 mol-% CH\(_4\) mixture injection was almost identical, which is reasonable because both C\(_2\)H\(_6\) and CO\(_2\) have critical properties close to each other. Nevertheless, the difference in the liquid dropout between the two can be attributed to different molecular interactions with methane even though it has not been proved.

The nitrogen and carbon dioxide mixtures have also expressed slightly different behavior than pure gases. It was clear that nitrogen would cause the immediate liquid dropout that has occurred as seen in Figure 6.19. However, the true dewpoint of the reservoir fluid seems shifted when it contacted the 10 mol-% CO\(_2\)/ 90 mol-% N\(_2\) mixture. This phenomenon might
be associated with mass transfer occurring with the injection and in situ gases that resulted in a phase behavior change.

On the other hand, the explanation given for the pure nitrogen stated that the reservoir pressure just did not go below the 7250 psia and after the breakthrough nitrogen started increasing the pressure. Clearly, the same phenomena happened with the N₂-CO₂ mixture where N₂ prevails and imitates the pure N₂ behavior.

6.5 Discussion on the Phase Behavior of Reservoir Gas Above the Dewpoint Pressure

Figures 6.9, 6.14, and 6.19, the liquid dropout curves vs. pressure, indicate that gases or gas mixtures cause liquid dropout in the reservoir. Moses and Wilson (1981), Vogel and Yarborough (1980) stated that the main reason for this is the dewpoint elevation of the original gas-condensate fluid. In gas injection, this is true at the mixing zone between injection and in situ gas. In other words, because of component mixing, the front will have a higher dewpoint pressure than the original dewpoint pressure, which, in turn, will cause liquid dropout.

On the other hand, the statement by Whitson et al. (1999) claiming that the injection
and *in situ* gases are fully “miscible” above the dewpoint pressure remains unclear. A clarification may be useful: Accordingly, “miscible” and “miscibility” terms are generally related to liquid-liquid and gas-liquid systems. In these cases, an injected gas, for example, reduces interfacial tension between gas and oil to zero, thereby promoting miscible displacement. Therefore, miscible displacement necessitates vanishing fluid-fluid interface and interfacial tension. However, Amin et al. (2010) showed that interfacial tension between two supercritical gases (fluids) could exist at high pressure and temperature systems. The authors experimentally measured the interface between CO$_2$ and CH$_4$ for a very small droplet formed at the end of a needle, and reported interfacial tension of 0.012 dyne/cm at 23.167 Mpa and 368.15 K. This paper, therefore, qualifies the gas-gas “non-mixing” as the gas-gas immiscibility, which was previously mentioned in thermodynamics literature by Prausnitz et al. (1998). On the other hand, from the equation of state point of view, the mixture containing CO$_2$ and CH$_4$ at different proportions, does not show the two-phase behavior when the mixture is flashed at the pressure and temperature conditions reported by Amin et al. (2010).

Figure 6.20 shows the vapor pressure curve for pure methane and nitrogen and denotes the regions where these gases will stay as single solid, liquid, and gas phases. The $x$- and $y$-axes represent temperature in Celsius and pressure in Mpa, respectively.

![Figure 6.20: Pressure-temperature diagram for pure methane and pure nitrogen (WolframAlpha, 2014).](image)

Figure 6.20 suggests that the injected methane and nitrogen will be in the supercritical region for reservoir applications (Figure 4.7). Therefore, both *injection* and *in situ* gases exist as the supercritical phases, which could be considered as dense fluids resembling very light liquids.
6.6 Summary of Early Injection Scenarios

The gas injection scenarios described in this section, which were started in the early life of the reservoir, demonstrated some similarities and peculiarities, as well. Even though economics usually dictates the likelihood of using a specific gas or gas mixtures, from the reservoir engineering point of view, most of the gases tested in this research performed in the same range.

Table 6.5 is given to sum up technical performances of these injected fluids. The total number of cases was 12, and they are presented in the order they were mentioned. They start from a pure gas injection and end with the mixtures containing CO₂.

Table 6.5: Summary of engineering aspects of injection gases

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Injection Gas</th>
<th>Phase Vol-%</th>
<th>Average Pressure Drop, psia/year</th>
<th>Average Liquid Dropout, %/year</th>
<th>Recovery Factor, %</th>
<th>Gas Utilization, Mscf/STB</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CH₄</td>
<td>100</td>
<td>47.09</td>
<td>0.41</td>
<td>62.80</td>
<td>16.25</td>
</tr>
<tr>
<td>2</td>
<td>N₂</td>
<td>100</td>
<td>17.78</td>
<td>0.34</td>
<td>61.43</td>
<td>16.89</td>
</tr>
<tr>
<td>3</td>
<td>CO₂</td>
<td>100</td>
<td>89.40</td>
<td>0.63</td>
<td>55.97</td>
<td>20.06</td>
</tr>
<tr>
<td>4</td>
<td>CH₄, C₂H₆</td>
<td>95, 5</td>
<td>48.63</td>
<td>0.41</td>
<td>63.14</td>
<td>15.29, 0.80</td>
</tr>
<tr>
<td>5</td>
<td>CH₄, N₂</td>
<td>90, 10</td>
<td>43.48</td>
<td>0.37</td>
<td>63.14</td>
<td>14.49, 1.61</td>
</tr>
<tr>
<td>6</td>
<td>CH₄, N₂</td>
<td>75, 25</td>
<td>38.42</td>
<td>0.33</td>
<td>63.48</td>
<td>11.96, 3.99</td>
</tr>
<tr>
<td>7</td>
<td>CH₄, N₂</td>
<td>50, 50</td>
<td>30.89</td>
<td>0.26</td>
<td>63.48</td>
<td>7.97, 7.97</td>
</tr>
<tr>
<td>8</td>
<td>Separator gas</td>
<td>100</td>
<td>56.60</td>
<td>0.45</td>
<td>62.80</td>
<td>16.25</td>
</tr>
<tr>
<td>9</td>
<td>CO₂, CH₄</td>
<td>10, 90</td>
<td>50.22</td>
<td>0.44</td>
<td>62.46</td>
<td>1.64, 14.76</td>
</tr>
<tr>
<td>10</td>
<td>CO₂, CH₄</td>
<td>20, 80</td>
<td>53.45</td>
<td>0.47</td>
<td>61.09</td>
<td>3.41, 13.65</td>
</tr>
<tr>
<td>11</td>
<td>CO₂, N₂</td>
<td>10, 90</td>
<td>23.83</td>
<td>0.33</td>
<td>61.77</td>
<td>1.67, 15.05</td>
</tr>
<tr>
<td>12</td>
<td>CO₂, N₂</td>
<td>20, 80</td>
<td>29.91</td>
<td>0.35</td>
<td>61.43</td>
<td>3.38, 13.51</td>
</tr>
</tbody>
</table>

Some general observations from Table 6.5 are:
1. The average reservoir pressure drop is high for non-nitrogen containing gases.
2. The average liquid dropout increases with increasing methane content.
3. Recovery factors for all cases except the pure CO$_2$ are in a 61-63.5 percent range. Recovery factor using the pure CO$_2$ reached only 55.97 percent.

4. Gas utilization ranged from 9.2 Mscf/STB (for the 50 mol-% CH$_4$/ 50 mol-% N$_2$ mixture) to 10.43 Mscf/STB for the pure CO$_2$ case.

Analysis shows that the mixture containing nitrogen attained the highest recovery of the condensate initially in-place. Moreover, the recovery factor of the CH$_4$-N$_2$ mixture did not change if the nitrogen content was reduced from 50 mol-% to 25 mol-%. However, two other parameters, the average pressure drop and liquid dropout, did change in these two cases. For example, the average reservoir pressure in the 25 mol-% N$_2$ case decreased 7 psia more per year than the 50 mol-% N$_2$ mixture, so it results in leaving 0.07 percent more condensate per year.

The lean gas and the 90 mol-% CH$_4$/ 10 mol-% N$_2$ mixture also accomplished the same recovery of condensate, 63.14 percent, at the end of the reservoir life. In their case, nitrogen due to less gas compressibility than ethane could sustain the lower pressure drop and hence leave less liquid in the reservoir.

Comparisons of injected gases have clearly shown that commonly used gases in the petroleum industry are capable of doubling the condensate produced over that from the natural depletion. The economics of the cases will ultimately determine what case is the best, but the economic evaluation was not the focus of this study. Without delving into the economics, however, one might observe from Table 6.5 tells some possible and impossible scenarios.

One of the very likely scenarios is to use the 50 mol-% CH$_4$/ 50 mol-% N$_2$ mixture. It gives the higher recovery, and it leaves the least condensate at the end of the field life. In addition to that, the reservoir pressure in the end is high - 6950 psia, which also creates the possibility of depleting the reservoir afterwards. In this CH$_4$-N$_2$ mixture case, the economic costs of nitrogen generation plants, surface cleaning and separation facilities, and injection wells must be justified by the high gas price. In other words, gas sales revenues must cover nitrogen injection costs. From a purely technical standpoint, the injection of the 50 mol-% CH$_4$/ 50 mol-% N$_2$ gas mixture is very attractive.

The lean gas is also competitive with the 50 mol-% CH$_4$/ 50 mol-% N$_2$ gas mixture, yet some of its technical qualities are not as good as the nitrogen containing mixture. However, it possesses the partial miscibility quality with the condensate and hence can vaporize it to some degree. A drawback of the lean gas is that profits coming from selling condensate as soon as it was produced will be delayed. Overall, the recovery factor with the lean gas is high and close to the 50 mol-% CH$_4$/ 50 mol-% N$_2$ mixture. Therefore, the lean gas injection
is also a viable option.

CO$_2$ containing gas mixtures worked out poorly, especially since using CO$_2$ to vaporize condensing liquid has rarely been seen. Moreover, it became apparent that 10 mol-% of CO$_2$ with methane has given less recovery than that of 5 mol-% C$_2$H$_6$ with the same gas. It is clear that these two components (i.e., CO$_2$ and C$_2$H$_6$) will behave differently if they are injected with CH$_4$. One must also reflect on the CO$_2$ use, which is usually carried out in enhanced oil recovery projects and has proved its feasibility. Therefore, it must be emphasized that successful CO$_2$ operations occur only when it is utilized to be dissolved in oil and then by swelling and reducing oil viscosity to make oil movement easy. On the other hand, the gas-condensate reservoir does not contain oil or condensate at the beginning of production. Therefore, the impact of injected gases is seen in maintaining the reservoir pressure rather than revaporizing condensate forming in the reservoir.

To examine the revaporization effect, particularly the possible miscibility mechanism, these three (i.e., the lean gas, the 50 mol-% CH$_4$ / 50 mol-% N$_2$ gas, and the 10 mol-% CO$_2$ / 90 mol-% CH$_4$ gas) mixtures are taken into sensitivity analyses.

### 6.7 Sensitivity Analysis

The first goal of the sensitivity analyses was to investigate how much gas is needed to maintain the reservoir pressure above the dewpoint pressure so that maximum condensate recovery can be achieved. Another sensitivity is to check if these gases would perform the same way if the condensate already formed in the reservoir. To recover this liquid, the vaporizing miscibility mechanism must come into play to revaporize the condensate. However, some gases, like nitrogen and methane, have already showed that they are rather more immiscible than they are miscible with the reservoir liquid. In this case, the immiscible displacement development might be observed.

Another thing mentioned in the literature review, is the addition of H$_2$S into the lean gas. The aim here is to dispose of the hazardous gas, but its effect on the physical mechanism of condensate recovery is also interesting. It must be mentioned the H$_2$S addition is not considered with other two gases because it could cloud the research and might not give plausible results.

The last goal in the sensitivity analysis was to test whether these gases would increase the condensate recovery by injecting through horizontal wells.
6.7.1 An Effect of Adding Make-up Gas

In the gas injection scenarios discussed before, the gas injection rate was 12,000 Mscf/day, which was the same as the total production rate from production wells. However, this injection amount did not satisfy the pressure maintenance requirement, and reservoir pressure dropped below the dewpoint pressure. In this sensitivity analysis case, an additional amount of gas was added to the injection gas so that the reservoir pressure would stay above the original dewpoint pressure and prevent the liquid condensation in the reservoir.

Figure 6.21: The reservoir pressure vs. time when the make-up gas added to the injection gas.

Figure 6.21 represents the reservoir pressure versus time during the gas injection with the make-up gas. As can be seen from this figure, the make-up gas maintains the reservoir pressure around 7600 psia by efficiently replacing the total produced voidage space.

Figure 6.22 shows the make-up gas injection rates versus time for the lean gas, the 50 mol-% CH$_4$/50 mol-% N$_2$, and the 10 mol-% CO$_2$/90 mol-% CH$_4$ gas mixtures. The nitrogen containing mixture required the least amount of the make-up gas, approximately 1800 Mscf. When the lean gas and the CH$_4$-CO$_2$ gas mixture are compared, it seems that the latter needs more make-up gas in the overall gas injection period. This effect is attributed to the highly compressible quality of this gas, (i.e., the CH$_4$-CO$_2$ gas).

Figure 6.22 also demonstrates the declining make-up gas injection requirement for all
injection gases. For instance, in the first 15 years of gas injection, the need for the make-up gas declined steadily. However, after 15 years, this decline rate was even steeper. This sudden drop in the make-up gas requirement can be associated with the gas breakthrough after which the reservoir gas is not more pure but rather contaminated with the previously injected gas. Therefore, the make-up gas can be reduced significantly. In addition, Figure 6.22 suggests that the make-up gas injection rate might flatten at the end of field development, as seen in the 50 mol-% CH$_4$/50 mol-% N$_2$ gas injection case.

Figure 6.23 shows the condensate production rates for the make-up gas case injected above the dewpoint pressure. In comparison with no make-up gas case, the overall production rate decline with the make-up gas injection is less sharp than without the make-up gas.

The earlier mentioned breakthrough time is also seen in Figure 6.23, which was after 15 years for all injection gases. Furthermore, a period of time from 15 years to 30 years is characterized by the sharp decline in production. For instance, during this time, the production rate for all three gases decreased by half, from 1600 STB/day to 800 STB/day. The condensate production rates appear to start to plateau at the end of the reservoir life. It might be true that because the injection gas produces hydrocarbon gas containing the condensate more and more, these valuable hydrocarbon gas is replaced by nitrogen. Therefore, a producing wellstream content has the least amount of condensate yield. It
Figure 6.23: Condensate production rates versus time when three gases injected with the make-up gas.

might also indicate that the need in make-up gas for the CH$_4$-N$_2$ gas mixture diminishes because the reservoir gas already has some content of nitrogen, which makes it easy to maintain the reservoir pressure.

Figures 6.24 and 6.25 show the condensate dropout in the reservoir during the lean gas, the 50 mol-% CH$_4$/50 mol-% N$_2$, and the 10 mol-% CO$_2$/90 mol-% CH$_4$ gas injection cases from time and pressure perspectives, respectively.

As seen from Figures 6.24, three gases started the immediate liquid dropout in the reservoir upon gas injection. Even though the nitrogen containing mixture showed the better pressure maintaining quality in this sensitivity case, it also demonstrated a higher level of liquid dropout rather than the two other gases. For example, at the end of the reservoir life, the 50 mol-% CH$_4$/50 mol-% N$_2$ gas mixture caused more than six percent of condensate initially-in-place to drop out from the reservoir gas, whereas the two other mixtures caused slightly more than one percent of liquid dropout in the reservoir.

Figure 6.25 shows that three gases maintain the reservoir pressure above the original dewpoint pressure of 7000 psia. However, as was said, three gases demonstrate the immediate liquid dropout in the reservoir, which can be attributed to partial mixing of these injected gases with in situ gas. As can be seen from Figure 6.25, because pressure did not drop below
the dewpoint, these three gases, especially the lean and the CH₄-CO₂ gas did not indicate any vaporizing quality of condensate.

![Graph of Volume of Condensate Left Behind vs. Time](image)

Figure 6.24: Fraction of condensate remained as liquid in the reservoir vs. time for three injection gas mixtures.

Figure 6.26 shows how condensate recovery factor varies with time for the three injection gas cases. When the make-up gas was used, Figure 6.26 suggests that the 50 mol-% CH₄-50 mol-% N₂ mixture performs worse than the two other gases, but the condensate recovery difference is not huge, only 2-3 percent. The nitrogen containing mixture recovered 64.5 percent of condensate initially in-place while the lean gas recovered 66.5 percent.

Table 6.6 shows that these gases, as some other gas injection mixtures tested in this study, recovered maximum 63.5 percent of condensate initially in-place, so the difference with the use of make-up gas is only four percent at most (the 10 mol-% CO₂/90 mol-% CH₄ case).

<table>
<thead>
<tr>
<th>Case</th>
<th>RF no make-up gas, %</th>
<th>RF with make-up gas, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lean gas</td>
<td>63.14</td>
<td>66.55</td>
</tr>
<tr>
<td>50 mol-% CH₄-50 mol-% N₂</td>
<td>63.48</td>
<td>64.51</td>
</tr>
<tr>
<td>10 mol-% CO₂/90 mol-% CH₄</td>
<td>62.46</td>
<td>66.89</td>
</tr>
</tbody>
</table>
Figure 6.25: Fraction of liquid dropout in the reservoir vs. pressure for three injection gas mixtures.

Figure 6.26: Condensate recovery factor vs. time for make-up gas use cases.
Figure 6.26 also implies that condensate recovery did not increase significantly when the make-up gas was added to the injection gas.

These results suggest that the make-up gas cannot provide a significant increase in condensate production, except the better pressure maintenance and, consequently, the least amount of the liquid dropout in the reservoir. Therefore, the additional 1-4 percent of condensate will not likely justify the costs of the make-up gas.

6.7.2 An Effect of Delaying Gas Injection

As early as in 1948, Standing presented results of cycling operations below the dewpoint pressure. Standing et al. (1948) concluded that the condensate recovery was the largest when the gas cycling was operated at low pressures. Even though these or similar results from other researchers infer that the condensed liquid can better be revaporized at low pressures, some physical effects have not been mentioned or clarified. For reservoir systems, like the one presented in Figure 2.1, the gas-condensate fluid experiences the retrograde phenomenon in which after reaching the maximum liquid dropout, the condensate starts revaporizing according to thermodynamic laws.

The reservoir fluid system in this research, however, is notably different from the conventional one (See Figure 4.7). The critical point was not detected using CMG WinProp. Moreover, even if the critical point was presumed to be at the left of the reservoir temperature lines, the retrograde region stretches until the cricondentherm point at 1000 psia. This large retrograde area might or might not experience the retrograde phenomenon.

The injection was initiated after 10 years of natural depletion. By this time, the reservoir pressure had declined to 4775 psia. Figure 6.27 presents the reservoir pressure versus time when the lean, the 50 mol-% CH\textsubscript{4}/50 mol-% N\textsubscript{2}, and the 10 mol-% CO\textsubscript{2}/90 mol-% CH\textsubscript{4} gas mixtures are injected. When the injection started the reservoir pressure remained at that level or increased. For example, the blue and green lines represent the lean gas and CO\textsubscript{2}-CH\textsubscript{4} mixtures, respectively. The reservoir pressure change during these gas injections varied in a 20-60 psia range. The mixture with half methane and half nitrogen, on the other hand, demonstrated higher increasing pressure than the other two gases. It increased the pressure by almost 700 psia.

Figure 6.28 shows the condensate production rate during the injection of the mixtures. The methane-nitrogen mixture created high pressure which increased the production rate in comparison with other two gases, in the first 10 years of the injection. However, after the breakthrough its decline rate was much steeper than the two other gases. Overall, at the end of the field life the lean gas and the CO\textsubscript{2}-CH\textsubscript{4} mixture both were producing the same - roughly 460 STB/day. The nitrogen containing mixture yielded only 395 barrels a day.
Figure 6.27: The reservoir pressure change during the injection of the lean, the 50 mol-% CH$_4$/50 mol-% N$_2$, and the 10 mol-% CO$_2$/90 mol-% CH$_4$ gas mixtures started after some liquid condensation.

Figure 6.28: The condensate production rates for the lean, the three injection gas mixtures started after some liquid condensation.
Figures 6.27 and 6.28 suggest that partially-miscible-to-immiscible characteristics of injected gases prevail in the condensate existing reservoir. One typical attribute of the nitrogen immiscibility is a steadily increasing reservoir pressure. Due to the pressure increase, the condensate rate raised an extra 100 barrels per day. However, after the breakthrough, which occurred 9 years after the start of the injection, the condensate rate declined sharply. It must be noted that the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} gas had a longer breakthrough time, 13 years (See Figure 6.12) when injected at the beginning of the field development in comparison with this case. One of possible explanations is that the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} mixture does not achieve the good miscibility with the reservoir condensate. This further means that the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} mixture displaces condensate immiscibly to some extent. However, due to the high gas mobility which in turn results in the high mobility ratio, the gas breakthrough time is soon.

The other two gases, i.e., the lean gas and the 10 mol-% CO\textsubscript{2}/ 90 mol-% CH\textsubscript{4} mixture have manifested longer breakthrough times than if they started in the early period of production. For example, here their breakthrough times are approximately 12 years after the gas injection started, whereas in Section 6.3, the breakthrough time observed for the lean gas was approximately 10 years. The CO\textsubscript{2}-CH\textsubscript{4} mixture behaved in the same way as the lean gas. The reservoir pressure and condensate rates show the long plateaus, and this evidence indicate that two gases might have had the miscibility with the \textit{in situ} condensate.

Figure 6.29 demonstrates effects of injection gases on reducing the liquid condensed in the reservoir. The upper left Figure 6.29(a) is the reservoir oil saturation after depleting the reservoir for 10 years. The upper right Figure 6.29(b) is an oil saturation at the end of the lean gas injection. The bottom right and left Figures 6.29(c)-6.29(d) are the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} and the 10 mol-% CO\textsubscript{2}/ 90 mol-% CH\textsubscript{4} mixture injection cases, respectively. The color bar range in Figure 6.29 is from 0 to 1.

One can observe the complete similarity between the ethane and carbon dioxide containing mixtures immediately. Therefore, it can be inferred that 5 mol-% C\textsubscript{2}H\textsubscript{6} and 10 mol-% CO\textsubscript{2} gases perform in the same way in the presence of CH\textsubscript{4}. Figure 6.29(c) shows that CH\textsubscript{4}-N\textsubscript{2} mixture leaves more liquid than two other gases. For example, the light turquoise colors, 0.3, around the production wells are more pronounced in the methane-nitrogen injection case while other two other gases have the small spots in the light sea green background, 0.25.

Figure 6.29(c) also suggests that the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} gas has uniform movement downwards under a gravity drainage. This effect can be attributed to the injected gas density, which is slightly higher than the reservoir gas due to the nitrogen presence. On the other hand, the two methane mixtures with ethane and carbon dioxide within demonstrate their vulnerability to the fastest breakthrough which in turn implies poor sweep efficiency
during the gravity drainage. Gravity drainage is not always the case so it will have an impact only in thick reservoir cases.

The actual amount of the condensate remaining in the field scale is shown in Figure 6.30. Allowing the reservoir pressure to drop in the first 10 years precipitates more than half of the condensate initially in-place to condense. Upon the gas injection, it is seen that all injected mixtures reduce liquid content to a certain extent. On average, the residual liquid volume was reduced by 0.1 or 2.9 million barrels in terms of condensate.

Figure 6.31 show a liquid saturation in a $i = 8$ vertical slice in 10 years and a propagation of injected lean gas at different times. Oil saturation has reached 0.7 in the bottom part of the reservoir. After the start of the injection, an injection front slowly sweeps the condensate towards the bottom. The lean gas front moves laterally rather than vertically.
Figure 6.30: Fraction of liquid dropout in the reservoir vs. time after gas injection.

Figure 6.31: Oil saturation cross-section through the injection well at different times during the lean gas injection initiated at 10 years.
Figures 6.32 and 6.33 demonstrate the gas injection sweep efficiency with the 50 mol-% CH$_4$/ 50 mol-% N$_2$ and 10 mol-% CO$_2$/ 90 mol-% CH$_4$ gases, respectively. As in the lean gas case, the oil saturation is shown as the vertical slice through the injection well (Well5) located in $i = 8$.

It can be seen from Figures 6.32(b)-6.32(d) that the CH$_4$-N$_2$ mixture has a funnel-like sweeping characteristic over two other gases. This effect can be attributed to a more stable front than that of two other gases. On the other hand, as the oil saturation color bar shows, the near vicinity of the injection well seems unswept because light blue colors represent 0.1-0.2 oil saturation.

It is reasonable to consider that the 50 mol-% CH$_4$/ 50 mol-% N$_2$ performs in the immiscible displacement manner. For example, when the mixture is injected for the first 10 years (See Figure 6.32(b)), only grids in which the injection well is located show the full gas saturation. However, grids that are adjacent to the well nodes express the oil saturation of point 0.1. If the methane-nitrogen injection had been fully miscible with the in situ condensate, 10 years of injection would have been enough to completely revaporize the near vicinity of the wellbore. It is also difficult to state that the CH$_4$-N$_2$ mixture can develop the multiple-contact miscibility with the condensate, as some of the researchers in the past
The partially-immiscible characteristic of the 50 mol-% CH$_4$/ 50 mol-% N$_2$ gas is also seen in Figure 6.34. The $x$-axis of the plot is the reservoir pressure during the gas injection, and it varies from 4,500 to 7,500 psia. The black line represents the CH$_4$-N$_2$ mixture. Once the injection has started, the reservoir pressure in the CH$_4$-N$_2$ case began increasing and repeating its way back. As a result, the liquid volume decreased accordingly by 10 percent.

The way the CH$_4$-N$_2$ gas functions in the gas-condensate reservoir is due to the reservoir pressure increase, the slight gravity forces affecting it from the top, and the subsequent sweep of the condensate. It has not been mentioned yet that the high reservoir pressure produced by the gas mixture can also expel some gas trapped within the pores and push them towards production wells. However, this effect can be minor.

The lean gas and the CO$_2$-CH$_4$ mixture, on the other hand, show the vaporizing quality of the reservoir condensate. When Figures 6.32(a) and 6.33(a) are compared, it is clear that the CO$_2$-CH$_4$ mixture could better revaporize the vicinity of the wellbore than that of the CH$_4$-N$_2$ mixture. Moreover, the slow spreading front of the former strengthens its miscibility quality. Therefore, it is necessary to design the gas injection processes so that injection gases can achieve the miscibility with the reservoir liquid.
Figure 6.34: Fraction of liquid dropout vs. pressure during the lean, the 50 mol-% CH₄/50 mol-% N₂, and the 10 mol-% CO₂/90 mol-% CH₄ gas injection.

Figure 6.35: Recovery factor of condensate vs. time for the lean, the 50 mol-% CH₄/50 mol-% N₂, and the 10 mol-% CO₂/90 mol-% CH₄ gas injection cases.
Figure 6.35 presents the recovery factors obtained by injecting these three mixtures. Remarkably, the overall recovery was more than 15 percent less than when gases were injected in the early life of the reservoir. It seems that early declining production rates have considerably reduced the cumulative condensate production. The recoveries for the lean, the 50 mol-% CH$_4$/50 mol-% N$_2$, and the 10 mol-% CO$_2$/90 mol-% CH$_4$ gases reached 44.7, 43.7, and 44.37 percent, respectively.

### 6.7.2.1 An Effect of Adding Make-up Gas

The recoveries achieved during the injection of the lean gas, the 50 mol-% CH$_4$/50 mol-% N$_2$ gas, and the 10 mol-% CO$_2$/90 mol-% CH$_4$ gas below the dewpoint pressure proved that such small amounts of condensate produced would not give grounds for the successful economic implementation of the project. In other words, approximately 45 percent of condensate recovered can rarely cover costs required for gas cycling. As a result, it might be reasonable to consider the plan to achieve the maximum possible condensate recovery by adding the make-up gas.

It was assumed that an operating company could purchase the make-up gas needed to increase the reservoir pressure above the original dewpoint pressure. These amounts of the make-up gas will vary depending on the current reservoir pressure and will also vary with a type of injected gas.

Figure 6.36 shows the reservoir pressure change vs. time. The gas injection started after 10 years of primary production. As can be seen from this figure, the increase in the injection rate slowly increased the reservoir pressure to 7400 psia after 20 years. After this time, the reservoir pressure was more or less at the same level.

Figure 6.37 shows how much gas was needed to restore the reservoir pressure back to the original state and keep it at that level.

As can be seen from Figure 6.37, the three make-up gas rates steadily increased for the first 20 years of gas injection. After this time, (i.e., 20 years of injection) the make-up gas rate fluctuated for all gases, and this is attributed to a need to stabilize the reservoir pressure at the constant level. When three injection gases are compared in terms of voidage space replacement, the nitrogen containing mixture again shows the better voidage replacement than the two other gases. Another important thing seen from Figure 6.37 is that the make-up gas requirement doubled for the delayed gas injection case in comparison with the gas injection initiated in the early period of the reservoir life. For instance, the make-up gas requirement for the lean gas and the 10 mol-% CO$_2$/90 mol-% CH$_4$ gas was 3000-3500 Mscf/day in the early stage of gas injection when gas cycling was initiated above the dewpoint. However, in this case, the initial make-up gas requirement started from almost 6000 Mscf/day. This
Figure 6.36: The reservoir pressure vs. time when the make-up gas added to the injection gas.

Figure 6.37: Make-up gas injection rate vs. time for the three injected gas mixtures.
is necessary to raise the reservoir pressure, which dropped to 4800 psia after 10 years of primary production. In addition, the need for make-up gas increased steadily for the whole period of the reservoir pressure build-up.

Figure 6.38 shows condensate production rates varying with time during the gas injection with the make-up gas to build the reservoir pressure to the original value.

Figure 6.38: Condensate production rates vs. time for the lean gas, the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} gas, and the 10 mol-% CO\textsubscript{2}/ 90 mol-% CH\textsubscript{4} gas mixture injection cases.

As can be seen from Figure 6.38, increasing pressure support helped to produce more condensate in the early periods than without the make-up gas. However, this constant, high condensate production rate dropped after certain time. This effect can be attributed to the gas breakthrough time. For example, the CH\textsubscript{4}-N\textsubscript{2} gas injection caused the breakthrough to happen earlier than the two other gas injection cases. Particularly, the gas breakthrough with the CH\textsubscript{4}-N\textsubscript{2} gas occurred after 10 years of gas injection, whereas the lean and the CO\textsubscript{2}-CH\textsubscript{4} gas mixtures demonstrated the breakthrough time 20 years after the start of gas injection. These results possibly indicate that these two gases not only raised the reservoir pressure but also involved in some miscible type of displacement. On the other hand, this effect was not seen in the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} gas injection case, which could infer that its miscibility characteristic with the condensate dropout was poor.

Figure 6.39 manifests how much of the liquid liquid dropped out in the reservoir was
revaporized with time. This figure shows that there was 55 percent of liquid dropped out in the reservoir at the beginning of the gas injection. Then this fraction of liquid dropout started reducing as soon as the reservoir pressure increased. By 20 years of gas injection (or 30 years of the field development), the amount of liquid dropout in the reservoir was reduced to 10 and 20 percent for the CH$_4$-N$_2$ and the lean gas (also the CO$_2$-CH$_4$ gas) injection cases, respectively. After 20 years of gas injection, all three gases demonstrate no reduction of the condensate liquid left behind. This, first of all, might be associated with no pressure increase after this time. Figure 6.36 showed the reservoir pressure was kept at constant level of 7400 psia. Another possibility is that during the gas injection, the injected and \textit{in situ} gases exchanged with components, so the \textit{in situ} gas was no longer the gas at initial conditions. In other words, the component mass transfer altered the initial phase behavior of the reservoir gas. Therefore, the dewpoint pressure was shifted upwards, and pressure must be increased above that level to achieve the revaporation.

Figure 6.40 shows how much gas is needed at the end of the reservoir life to achieve the condensate recovery depicted in Figure 6.41. As seen in Figure 6.40, the cumulative gas injection increases gradually. As expected, the make-up gas requirement for the CH$_4$-N$_2$ gas mixture is less than for the two other gases because of the low compressibility of nitrogen.
Figure 6.40: Total gas injection volume vs. time for the three gas injection cases.

Figure 6.41: Condensate recovery factor vs. time for the lean gas, the 50 mol-% CH₄/50 mol-% N₂ gas, and the 10 mol-% CO₂/90 mol-% CH₄ gas mixture injection cases.
Nevertheless, the make-up gas needed at the end was almost 40 Bscf in comparison with the no make-up gas case. The lean and CO₂-CH₄ gas mixtures, on the other hand, requires up to 60 Bscf of additional gas to recovery more condensate.

These ultimate recoveries of condensate are depicted in Figure 6.41. The lean gas and the 10 mol-% CO₂/ 90 mol-% CH₄ gas mixture cases performed in the same manner and reached 58 percent recovery of condensate initially in-place. This is 14 percent incremental recovery with respect to no make-up gas injection scenario. Nitrogen containing mixture, on the other hand, recovered less condensate than the two other gases, only 54 percent.

### 6.7.3 An Effect of Adding Hydrogen Sulfide into The Lean Gas

Traditionally, the lean gas is used in gas cycling operations to maintain the reservoir pressure and to produce the condensate. Therefore, an enormous amount of research addressed the lean gas efficiency in such reservoirs. The results found in this study also indicate that condensate recovery can be doubled in comparison with the natural depletion scenario. On the other hand, the literature has rarely presented the impact of H₂S on the cumulative condensate recovery.

Sections 6.3 and 6.7.2 have reported the lean gas injection results for the gas cycling initiated after one year and after 10 years of the production, respectively. The results indicated that the early gas injection start is a better option for recovering more condensate. Therefore, this sensitivity analysis has focused only on adding H₂S to the lean gas for the gas injection started in the beginning of the reservoir life.

Table 6.7 presents four molar compositions of CH₄, C₂H₆, and H₂S used in the sensitivity study. Note that after adding the 5, 10, 15, and 20 mol-% of H₂S the overall mixture composition changes.

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Amount of H₂S added, mol-%</th>
<th>CH₄, mol-%</th>
<th>C₂H₆, mol-%</th>
<th>H₂S, mol-%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lean gas</td>
<td>-</td>
<td>95</td>
<td>5</td>
<td>0</td>
</tr>
<tr>
<td>1</td>
<td>5</td>
<td>90.48</td>
<td>4.76</td>
<td>4.76</td>
</tr>
<tr>
<td>2</td>
<td>10</td>
<td>86.36</td>
<td>4.55</td>
<td>9.09</td>
</tr>
<tr>
<td>3</td>
<td>15</td>
<td>82.61</td>
<td>4.35</td>
<td>13.04</td>
</tr>
<tr>
<td>4</td>
<td>20</td>
<td>79.17</td>
<td>4.16</td>
<td>16.67</td>
</tr>
</tbody>
</table>

Another important thing to note is that the addition of more than 5 mol-% of H₂S is practically impossible in the real field situation because reservoir fluid contains up to 5 mol-% of H₂S (See Table 5.4). However, several other gas-condensate and oil fields located in
the Caspian Sea region have a H$_2$S content up to 20 mol-%. Consequently, results of these studies can be applicable to those reservoirs to some extent, if conditions are met. It will be easier to see the effects of adding H$_2$S with multiple cases. In other words, increasing H$_2$S content can show a pattern towards which it follows.

Figure 6.42 illustrates the reservoir pressures during the lean gas and the H$_2$S mixed gas injection cases. All gases exhibited declining reservoir pressure, which is a clear indication that H$_2$S is more compressible than nitrogen. Moreover, increasing H$_2$S content demonstrated a dramatic decline in the reservoir pressure. For example, the first 5 mol-% of H$_2$S added into the lean gas caused the reservoir pressure to drop from 6240 psia to 6112 psia or by 128 psia. Subsequent addition of H$_2$S decreased each previous gas injection pressure by 100-120 psia.

![Figure 6.42: The reservoir pressure comparison between different H$_2$S mole fractions in the injected lean gas.](image)

Figure 6.43 describes the trend of condensate production rates for H$_2$S containing mixtures. The black markered line represents the lean gas injection. As can be seen, all production rates steadily decline by the end of production. The lean gas, for instance, had the higher condensate production rate in the first 33 years of production than the four other gases. However, in the last seven years its production rate was substantially lower than the other four gases. The reservoir pressure shown in Figure 6.42 seems to provide an insight
into the early portion of the curve, which is due to the relatively high reservoir pressure. The lean gas could produce more condensate.

Four H₂S containing gases experienced a higher condensate production drop than that of the lean gas. In addition, they manifested the same behavior as in the pressure case: the higher the H₂S content in the gas meant the higher the condensate production rate drop. Regardless of this disadvantage, the highest H₂S containing mixture exhibited a higher condensate production rate than that of other gases in the last seven years. These results might indicate that an additional mechanism took place.

![Figure 6.43: Condensate production rates vs. time during the lean gas injection with a H₂S content.](image)

It is clear that the physical miscibility started at 33 years of production. Even though the Figure 6.43 does not indicate but simply implies that phenomenon, Figure 6.44 shows the slight reduction of the liquid condensed in the reservoir. As expected, increasing H₂S content of the gas caused more condensate to form than that of the lean gas. For example, in 30 years, the gas with the 20 mol-% H₂S addition reached 20.37 percent of the condensate being left behind.

From Figure 6.44, it is difficult to see the amount of condensate revaporized by the gases. Nevertheless, the numbers say the 20 mol-% H₂S gas reduced the amount of liquid from 20.47 to 19.97 percent whereas the 5 mol-% H₂S gas contributed to the reduction from 17.86 to 17.72 percent. These results may indicate that 20 mol-% H₂S with the lean gas can better
revaporize the condensate left in the reservoir than the lean gas with less amount of H$_2$S. In order to estimate this dominance, the initial liquid fraction, however, should be the same for both mixtures.

Figure 6.44: Fraction of liquid dropout vs. pressure for all H$_2$S containing lean gas cases.

One of the key findings of this study is the liquid dropout behavior upon the gas injection. For example, Figure 6.44 demonstrates the additional amount of H$_2$S in the lean gas minimizes the immediate liquid condensation (i.e., greater than 7000 psia). It is probable that the better miscibility is achieved by the extra amount of H$_2$S rather than by the lean gas alone. This finding agrees with the theory mentioned by Holm (1987) that states the low minimum miscibility pressure of H$_2$S.

Figure 6.45 summarizes the cumulative recovery factors for all H$_2$S cases. The highest condensate recovery was observed in the pure lean gas case while other H$_2$S containing gases performed in descending order with increasing H$_2$S content. The reason for the slightly poor recovery is, in fact, mainly due to the pressure maintenance capabilities of these gases. The revaporization mechanism started affecting the dropped condensate at the end of the reservoir life, and it could not alleviate the liquid dropout problem.
Figure 6.45: Cumulative recovery factor for the lean gas injection cases with a H$_2$S content.

6.7.4 Horizontal Wells

Horizontal wells have become popular since the 1970s in the oil and gas industry. Nowadays, their advantages have been proven in many tight reservoirs in which a large drainage area is needed. Currently, the industry is drilling such wells in unconventional reservoirs and fracturing them.

In this research, horizontal wells are utilized to investigate sweep efficiency performance during gas injection operations. In the gas-condensate reservoir case, unusual well configurations, such as horizontal wells, vertical hydraulically fractured wells, and horizontal wells with hydraulic fracture stages, are generally used to study a condensate blockage effect, which occurs near the wellbore. Since objectives of this research were not studying the blockage problem, the study examined only the horizontal wells to employ gravity forces.

Two horizontal wells, i.e., one production and one injection well are drilled exactly on top of each other. Figure 6.46 shows these two wells with their locations and perforation intervals. Vertical sections of these wells are located in $i = 6$ and $j = 8$ and $i = 25$ and $j = 8$ gridcells. In addition, the production well is horizontally drilled near the gas-oil contact, approximately 200 feet above the GOC. The injection well is drilled 150 feet below the reservoir top (14,600 feet). Both production and injection wells are 1600 feet long.

Figure 6.47 shows the reservoir pressure over time during the horizontal wells use. As
Figure 6.46: Horizontal well location and configuration.

Figure 6.47: The reservoir pressure change vs. time for the lean, the 50 mol-% CH$_4$/ 50 mol-% N$_2$, and the 10 mol-% CO$_2$/ 90 mol-% CH$_4$ gas injection cases using horizontal wells.
expected, the methane-nitrogen mixture had the highest reservoir pressure during the whole reservoir production. After the gas injection start at year one, the methane-nitrogen gas mixture could maintain the reservoir pressure in a slightly declining fashion, and this period lasted for 25 years. After that the reservoir pressure remained more or less at a 6700 psia range. The intersection of these decline and plateau periods may indicate the breakthrough time of the the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} mixture.

The lean gas and the 10 mol-% CO\textsubscript{2}/ 90 mol-% CH\textsubscript{4} mixture manifested almost the same pressure results. Their reservoir pressure decline rate was much higher than the methane-nitrogen injection case. They both ended up with around 6000 psia.

Interestingly, the reservoir pressure decline using horizontal wells was significantly higher than that of vertical wells. Figures 6.11 and 6.16 reported the average reservoir pressures for the same mixtures using vertical wells in which the highest pressure was 7000 psia for the CH\textsubscript{4}-N\textsubscript{2} mixture and the lowest pressure was 6200 psia for the 10 mol-% CO\textsubscript{2}/ 90 mol-% CH\textsubscript{4} mixture. These results can be attributed to the fact that the horizontal injection well is perforated in the upper part of the reservoir where the initial reservoir pressure is lower than the average. Thus, the calculated reservoir pressure during simulation studies is lower than in the former case.

Figure 6.48: Condensate production rate vs. time during the gas injection through the horizontal wells.
Figure 6.48 illustrates the condensate production rate over time. The production started with a high rate, above 2500 STB/day, and then declined slowly for all cases. The lean gas and the 10 mol-% CO₂/90 mol-% CH₄ mixture experienced a sudden rate drop at five years, which is due to reaching the dewpoint of the system. For the next 20 years (i.e., 5-25) the rate decline of all injection scenarios was 700-800 psia. The next sudden rate drop was observed at 25 years, which was due to the breakthrough from the production well. At the end of production the rates for the three mixtures were approximately at 600 STB/day level.

The results found in this sensitivity analysis indicate that the horizontal wells perform much better than vertical wells. The initial condensate production rate was 2090 STB a day for the vertical wells whereas the horizontal well produced 400 STB extra when compared to the former. Theoretically, the same reservoir fluid system must produce at the same rate. One likely explanation is that the horizontal production well was drilled near the GOC, which is liquid-rich. The vertical wells, however, produced from the 750 feet interval, which gave the average rate for the producing interval. Therefore, discrepancies in producing condensate rates will exist.

The results from Figures 6.47-6.48 also suggest that placing horizontal production and injection wells far away delays the breakthrough time. This is crucial because after the breakthrough the reservoir behaves in an inefficient manner.

Figure 6.49: Gas saturations at the end of the reservoir life for three mixtures.

Figure 6.50: Oil saturations at the end of the reservoir life for three mixtures.
Figures 6.49-6.50 show the 3D gas and oil saturation maps, respectively. 6.49(a) and 6.49(c) indicate that the lean gas and CO₂-CH₄ gases are very similar in their properties. Both of these gases express high gas saturation, 0.92, at the top of the reservoir and around 0.7 gas saturation in the bottom layers. On the other hand, the 50 mol-% CH₄/ 50 mol-% N₂ mixture (See 6.49(b)) demonstrates a dissimilar result when compared to the previous two. It shows more uniform gas saturation distribution from the top towards the bottom.

From Figure 6.49(a) and 6.49(c), one should observe that the gas saturation at the top reached the maximum gas saturation of 0.92. Figure 6.49(b), on the other hand, indicates only some areas, particularly around the horizontal injection well, have reached almost the maximum gas saturation. These gas saturation results suggest that the CH₄-N₂ mixture is different from two other gases. There is a strong possibility that the high gas density of the CH₄-N₂ mixture acts as it does in a gravity override model. In other words, the lean and CO₂-CH₄ gases tend to stay in the upper part of the reservoir, which explains their highest gas saturations at the top.

Figures 6.50(a)-6.50(c) therefore indicate the reason for high oil saturation in two cases excluding the CH₄-N₂ gas. These results are due to the gravity forces acting heavily in the CH₄-N₂ case while being poor in the two other cases. Figure 6.50, however, does not inform the amount of the condensate left behind in the reservoir.

![Figure 6.51: Fraction of condensate (with respect to the condensate initially in-place) left behind during the use of horizontal wells.](image-url)
Figure 6.51 shows the liquid fraction change over time. Almost 14 and 13 percent liquid amounts were observed in the 10 mol-% CO$_2$/ 90 mol-% CH$_4$ (the green line) and the lean gas (the blue line) cases, respectively. On average, the CH$_4$-N$_2$ mixture (the black line) caused the less amount of liquid to condense than the two other gases. For example, in 25 years, the condensed liquid volume for the CO$_2$-CH$_4$ mixture was 13.5 percent, while the CH$_4$-N$_2$ mixture caused only the half of that amount, 6.5 percent. The sudden jump in the liquid fraction at 9 years for the methane-nitrogen mixture was also observed in the Figure 6.48 but was not distinguished at the first look. Figure 6.51 certainly suggests that this sudden jump occurred due to reaching the true dewpoint pressure.

The results of the lean and CO$_2$-CH$_4$ gases seem to provide insights into the miscibility mechanism. After the breakthrough took place at 25 years, the fraction of condensed liquid volume by injecting the lean and CO$_2$-CH$_4$ gases started decreasing (See Figure 6.51). However, it is not clear to what extent the miscibility occurs.

Figure 6.52: Fraction of cumulative condensate recovered vs. time during the use horizontal wells.

Figure 6.52 shows the cumulative condensate recovery using the the lean, the 50 mol-% CH$_4$/ 50 mol-% N$_2$, and the 10 mol-% CO$_2$/ 90 mol-% CH$_4$ gas mixtures. The condensate recoveries for all three gas injection cases were more than 45 percent incremental condensate recovery over the natural depletion of the reservoir using the single horizontal production well. In addition, the CH$_4$-N$_2$ gas mixture yielded an enormous amount of condensate initially.
in-place. The recovery factor for this mixture was 78.15 percent. That is almost 15 percent more than when the mixture is injected through the vertical wells. The lean gas and CO$_2$-CH$_4$ mixture recoveries were also higher when they were injected using the vertical wells. For example, the lean gas achieved 75.08 percent of recovery while the CO$_2$-CH$_4$ mixture produced 73.38 percent of the condensate initially in-place. Such a high recovery can be explained by the proper employment of gravity forces. However, this effect can be observed only in the thick gas-condensate reservoirs.

6.8 Summary

Chapter 6 shows the engineering aspects of the gas cycling processes in the industry. It is concluded that considerable loss of the condensate with the natural depletion scenario is not favorable.

To solve the condensate loss problem, the gas injection scenarios were initiated in these reservoir simulation studies. The main focus was the examination of gas effects on condensate recovery.

The main injection gases were the pure gases, such as methane, nitrogen, and carbon dioxide, the non-acid gases, such as the lean gas and the methane-nitrogen mixture, and acid gases, such as hydrogen sulfide and carbon dioxide containing mixtures.

Recovery factors using these gases reached more than 60 percent of the condensate initially in-place. Only the pure CO$_2$ case had the 55 percent recovery. It should be noted that this study examined only the injection gas effects, and the economic sides of some gases were not evaluated. However, it is well-known that CO$_2$ is expensive which prohibits its use in such a huge amount.

Many gases exhibited the same physical behavior even when they were mixed with other gases. For example, nitrogen is the best pressure maintaining gas, and it proved so in the mixtures with other gases. Methane has a poorer results in maintaining reservoir pressure than that of nitrogen but better than other gases.

Some disadvantages of nitrogen and methane were also observed. For instance, both of them cause the dewpoint increase of the original reservoir fluid which in turn drops the condensate even above the original dewpoint pressure. Moreover, CO$_2$, C$_2$H$_6$, and H$_2$S addition to injection gases can reduce the liquid dropout effect to some extent.

These gases, i.e., CO$_2$, C$_2$H$_6$, and H$_2$S showed that they better revaporize the liquid condensed in the reservoir. However, this was not observed in the full scale. A possible explanation is that the gas injection aimed to employ gravity forces, so the injection wells were perforated in the upper part of the reservoir. In other words, the reservoir pressure
prevailed in determining how much condensate would be produced.

To investigate physical revaporization mechanism, three gases, the lean, the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} and the 10 mol-% CO\textsubscript{2}/ 90 mol-% CH\textsubscript{4} gases, were used in the sensitivity analysis. Their results suggested the CH\textsubscript{4}-N\textsubscript{2} mixture immiscibly displaced the condensate liquid. The lean gas and the CO\textsubscript{2}-CH\textsubscript{4} mixture demonstrated slightly miscible behavior. The recoveries for all three cases reached less than 45 percent.

The revaporization can also be achieved by H\textsubscript{2}S containing mixtures. Even though these mixtures cannot hold the reservoir pressure high enough, they can develop full miscible displacement.

The last part of the chapter discussed the horizontal wells use in the development of the gas-condensate reservoirs. It was shown that gravity forces can play a huge role in recovering liquid from such reservoirs.
CHAPTER 7
CONCLUSIONS AND RECOMMENDATIONS

The research results and also methods used to achieve those results successfully met the initial hypotheses and expectations. Based on those results, the research conclusions were drawn and divided into the following categories:

7.1 General Conclusions

Petroleum research dedicated to the gas-condensate reservoirs is significant and vast. Nevertheless, some answers regarding the mechanisms of condensate recovery remain unclear. This research elaborated on current technical knowledge and provided some possible explanations for the physical phenomena taking place in the reservoir. The way the fluid modeling procedure was incorporated with the reservoir simulation model was also shown. More detailed conclusions of both procedures are presented in the following sections.

7.1.1 Fluid Modeling Procedure

Conclusions drawn from the fluid modeling procedure are as follows:

• The fluid modeling process in the petroleum industry requires good knowledge of petroleum thermodynamics. Even though many such theories and laws are well described, there are still some gaps in knowledge. For example, during the compositional gradient calculations two wells did not generate any results. This problem was attributed to the phase instabilities. Therefore, petroleum engineering research should consider some improvements on understanding chemical processes involved in oil and gas operations.

• The compositional gradient calculations may be used to obtain the fluid composition when PVT data are unavailable. The results of such calculations showed that the compositional gradient can be used as one of the tools to verify the PVT data. Nonetheless, it must be stated that the verification of PVT data can only be performed on fluid samples that do not have lateral variations.

• The gas-oil contact output from CMG WinProp cannot indicate the exact GOC location. Thus, further research is required to determine accurately the thermodynamics for petroleum reservoirs. There is a similar problem with the critical point of the reservoir fluid, which could not be detected using this advanced software package.
7.1.2 Gas Injection Models

Gas injection models studied in this research covered the gas cycling operation in the gas-condensate reservoirs from different perspectives. One of these aspects was to examine the effect of individual gas or gas mixtures on the cumulative condensate recovery. Emphasis was also given to examining how these positive or negative effects took place. Furthermore, the research also studied factors that can cause an alteration of these results, particularly, the gas injection below the dewpoint pressure and the horizontal wells applications. Based on the evaluation of obtained results, the study comments on the physical effects of gas injection processes and concludes:

- The natural depletion case showed that the actual amount of condensate formed in the reservoir is substantially higher than that from the constant-volume depletion experiment. This high condensate recovery can become mobile in the reservoir.

- Upon the first contact with the reservoir gas, methane and nitrogen caused immediate liquid dropout. The results of this study confirmed the theory of the dewpoint pressure elevation, which is the main cause of the liquid dropout.

- Pure nitrogen injection is an entirely immiscible displacement process with the liquid condensed in the reservoir. Some mixtures containing nitrogen also showed the immiscible displacement characteristic with the reservoir condensate.

- Nitrogen immiscible displacement performance in the reservoir scale indicate that some statements regarding its ability to vaporize the condensate might not be true. It must be noted that these statements were based on experimental work.

- The dewpoint elevation phenomena and the subsequent liquid dropout suggest that above the original dewpoint pressure, some gases do not mix at all proportions with the reservoir gas. This phenomenon has rarely been studied in petroleum reservoirs even though in thermodynamics it is known as the gas-gas immiscibility, which can be called as the supercritical fluid partial miscibility occurring in gas-condensate reservoirs.

- In petroleum reservoir engineering two miscible fluids mix in all proportions; otherwise, for limited mixing, they are partially miscible. In practice, when two fluids are miscible there is no fluid interface between the phases. In other words, the interfacial tension is zero. There are situations, as in low-temperature CO$_2$-oil mixing, where one may have two liquid phases and one vapor at a given temperature and pressure. Typically, the interfacial tension between the two liquid phases are small for this particular case. No practical three-phase vapor-vapor-liquid system have been reported, however, recently
Amin et al. (2010) reported a vapor-vapor system with an interface, which had a very low interfacial tension. Such situations cannot be reproduced by the equation of state used in commercial or current in-house simulators.

- The physical explanation for the supercritical fluid (i.e., gas-gas) partial miscibility is as follows. Under the high reservoir pressure, which was 8200 psia in this research, the reservoir fluid was in the supercritical state. The supercritical fluid means that the phase density of the fluid is not distinguishable which in turn implies that the reservoir fluid, i.e., gas, behaves like liquid at the high pressures. Thus, the gas injected at these pressures will not fully mix with the reservoir gas upon injection.

- The supercritical fluid partial miscibility was seen in several gas injection scenarios, such as nitrogen and methane containing mixture injections. The exceptions were only the pure CO$_2$, the separator, and the 20 mol-% H$_2$S containing lean gas injection cases, which indicate that these gases possess the same qualities as the reservoir gas at elevated pressures.

- Methane gas shows slight miscibility but only after multiple contacts with the reservoir condensate.

- Nitrogen, due to its less compressible quality can replace the huge voidage space. Other gases studied in this research do not share this property.

- Hydrogen sulfide addition to the lean gas improves the miscibility characteristic of the overall mixture which in turn shows the better revaporizing mechanism than that of the pure lean gas. However, the drawback of this mixture is the higher declining reservoir pressure and, hence, more liquid dropout in the reservoir.

- The better revaporization quality of the lean gas can also be achieved with either ethane or carbon dioxide. Moreover, their performance with a high content of methane was almost the same.

These theoretical aspects of the gas injection processes have been thoroughly discussed in the context of appropriate figures. Meanwhile, the research also questioned some practical sides of the gas injection. Therefore, some practical conclusions of the research are:

- The lean gas and the 50 mol-% CH$_4$/ 50 mol-% N$_2$ mixture yielded nearly the same recovery at the end of the reservoir life. Their feasibility in the field scale can only be determined after the economic evaluation is done.
• One might consider using the 50 mol-% CH\textsubscript{4}/ 50 mol-% N\textsubscript{2} mixture to employ the gravity forces and keep the reservoir pressure steady for a long time, once the economic evaluation of the project is done.

• In a case of introducing the gas injection in the reservoir with already condensed liquid, one should consider lean gas because of its revaporization quality due to the miscible contacts.

• The simulation results also suggest that, in the case of similar recovery efficiencies with hydrocarbon gases, one should consider using the leanest gas. Moreover, if non-hydrocarbon gases (e.g., CO\textsubscript{2} and H\textsubscript{2}S) are present in the reservoir fluid, they might be reinjected with methane instead of other sellable gases.

• The separator gas and, similarly, the enriched gas injections are not recommended in gas cycling operations. Instead of vaporizing the liquid already condensed, these gases start condensing, so their benefits can mutually be diminished by the condensation effect. Additionally, these intermediate hydrocarbons can be sold.

• The option of full gas cycling in the very low permeable reservoirs must be evaluated thoroughly. The research results suggest that cumulative condensate recovery achieve a maximum of 63 percent in the homogeneous model example. However, in the actual reservoir this number can be significantly lower due to geologic heterogeneities.

• The make-up gas utilized in the early gas injection cases did not contribute significantly to the ultimate condensate recovery. The difference between with and without make-up gas injection scenarios was only up to four percent. Therefore, this tiny amount of additional condensate can hardly justify economic costs of the make-up gas purchase.

• The effect of delaying gas injection can negatively impact the condensate recovery. First of all, the retrograde condensation phenomena for a particular fluid must be studied carefully. Then the question of feasibility of gas injection at low pressures will be answered. In this research, the deferral of the gas injection did not contribute to increase in production. This result was attributed to the highly complex nature of the reservoir fluid.

• The make-up gas used with the delayed gas injection scenario showed the significant increase in the cumulative condensate production. Therefore, the economic evaluation should be performed to evaluate whether the make-up gas is economically beneficial.
• One might consider the application of horizontal wells in the thick gas-condensate formation. However, in this case, it would be more beneficial to use the CH_2-N_2 mixture or any other mixture that contains nitrogen in order to utilize gravity forces.

7.2 Future Work

The current research, as other research studies similarly did, oversimplified and in some cases assumed the reservoir model properties. Therefore, these study results are directly derived from parameters used and might not apply in other gas-condensate reservoir cases. However, one can improve the methods and their consequences by minimizing assumptions and taking into account the following recommendations:

For the Methods:

• The first assumption of the model was the uniform porosity and permeability values, so the model can be improved by including contrasting rock values, especially, the permeability value.

• It would be worth paying attention to the gas-oil capillary pressure curve because the condensate accumulation can reach a very high value in which capillary forces start playing a significant role. Since the gas-oil interfacial tension was calculated from the correlation, its accuracy is questionable. Therefore, some experimental work must also be designed to measure the capillary pressure in gas and oil systems.

• Another recommendation for future work is that there is an indirect relationship between the interfacial tension and relative permeability curves. In this study, the relative permeability curves did not depend on the interfacial tension. However, it would be better to check and apply suitable relations between the interfacial tension and relative permeability curves.

• The capillary pressure and relative permeability curves are also somewhat interconnected to a pore size distribution. Therefore, it is recommended that those interrelations be established and examine for their effects during the gas injection.

• Investigating the gas-gas immiscibility phenomena in petroleum reservoirs is also recommended since it provides an insight into gas injection processes operated at high pressures.

• Because this research did not focus on investigating the condensate blockage effect, this study can be extended to future work in which the productivity of vertical, horizontal, and hydraulically fractured horizontal wells can be analyzed.
For the Development Strategies:

- Since the reservoir fluid contained some amount of CO₂ and H₂S, it would be an alternative to inject them into the oil rim zone, below the GOC.

- Future research can investigate the effect of injected CO₂ and H₂S on enhancing oil recovery from the oil rim.

- Another possible way of developing the gas-condensate reservoir with the oil rim is to develop two units together. For example, there is a possibility of sweeping the condensate towards the oil rim so that they will mix and flow more easily towards production wells.

- Since waterflooding provides better sweep efficiency and maintains reservoir pressure, it is recommended to inject water below the oil rim and to examine its effect on condensate recovery. In this case, the water injection might not show an immediate effect, but as soon as water moves upwards, condensate recovery change can be seen. In this case, it is probably recommended not to develop the gas-condensate unit until the oil rim is depleted.

- Another possibility is to develop two units together with combined gas and water injection scenarios. Both injection fluids should provide a better pressure support, which is essential to prevent liquid dropout from the gas-condensate fluid.
REFERENCES CITED


APPENDIX A

FUGACITY DERIVATIVE WITH RESPECT TO PRESSURE

The Eq. 4.10 in terms of fugacity is,

\[ f_m = x_m p \Phi_m \]

The pressure derivative of fugacity can be evaluated as shown,

\[
\frac{\partial f_m}{\partial p} = \frac{\partial}{\partial p} [x_m p \Phi_m] \\
= x_m \left\{ \frac{\partial}{\partial p} [p \Phi_m] \right\} \\
= x_m \left\{ \frac{\partial p}{\partial p} \Phi_m + p \frac{\partial \Phi_m}{\partial p} \right\} \\
= x_m \left\{ \Phi_m + p \frac{\partial \Phi_m}{\partial p} \right\}
\]

The final form can be rearranged as follows,

\[
\frac{\partial f_m}{\partial p} = x_m \left\{ \Phi_m + p \frac{\partial \Phi_m}{\partial p} \right\} \\
= \frac{x_m p \Phi_m}{p} + x_m p \frac{\Phi_m}{\Phi_m} \frac{\partial \Phi_m}{\partial p} \\
= \frac{f_m}{p} + f_m \frac{\partial (\ln \Phi_m)}{\partial p}
\]

Hence,

\[
\frac{\partial f_m}{\partial p} = f_m \left\{ \frac{1}{p} + \frac{\partial (\ln \Phi_m)}{\partial p} \right\} \quad (A.1)
\]

In the equation above, the derivative of fugacity coefficient with respect to pressure, \( \frac{\partial (\ln \Phi_m)}{\partial p} \) must be determined.

Recall the Eq. 4.11:

\[
\ln \Phi_m = \frac{b_m}{b} (Z - 1) - \ln (Z - B) - \frac{A}{2 \sqrt{2B}} \left\{ \left( \sum_{n=1}^{N_c} a_{nm} x_n \right) - \frac{b_m}{b} \right\} \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right)
\]
\[
\frac{\partial (\ln \Phi_m)}{\partial p} = \frac{\partial}{\partial p} \left( \frac{b_m}{b} (Z - 1) - \ln (Z - B) - \frac{A}{\sqrt{2B}} \left\{ \left( \sum_{n=1}^{N_c} a_{nm} x_n \right) \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right) \right\} \right) 
\]
\[
= b_m \frac{\partial Z}{\partial p} - \frac{1}{(Z - B)} \left( \frac{\partial Z}{\partial p} - \frac{\partial B}{\partial p} \right) - \frac{1}{2\sqrt{2}} \left( \sum_{n=1}^{N_c} a_{nm} x_n \right) \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right) 
\]
\[
\frac{\partial}{\partial p} \left\{ \frac{A}{B} \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right) \right\} \
\text{term is calculated using the product and chain rules,} 
\]
\[
\frac{\partial}{\partial p} \left\{ \frac{A}{B} \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right) \right\} = \frac{\partial}{\partial p} \left( \frac{A}{B} \right) \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right) + \frac{A}{B} \frac{\partial}{\partial p} \left( \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right) \right) 
\]
\[
= \frac{\partial A}{\partial p} B - \frac{A \partial B}{B^2} \left( \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right) \right) 
\]
\[
+ \frac{A}{B} \left\{ \frac{Z - (\sqrt{2} - 1) B}{(Z + (\sqrt{2} + 1) B)} \left( \frac{\partial Z}{\partial p} - (\sqrt{2} + 1) \frac{\partial B}{\partial p} \right) \left( \frac{Z - (\sqrt{2} - 1) B}{Z + (\sqrt{2} + 1) B} \right) \right\} 
\]
\[
= \frac{b_m}{b} \ln \left( \frac{Z + (\sqrt{2} + 1) B}{Z - (\sqrt{2} - 1) B} \right) - \frac{1}{(Z - B)} \left( \frac{\partial Z}{\partial p} - \frac{\partial B}{\partial p} \right) 
\]
\[
\text{Hence,} 
\]
\[
\frac{\partial (\ln \Phi_m)}{\partial p} = b_m \frac{\partial Z}{\partial p} - \frac{1}{(Z - B)} \left( \frac{\partial Z}{\partial p} - \frac{\partial B}{\partial p} \right) 
\]
\[
- \frac{A}{2\sqrt{2}B} \left( \sum_{n=1}^{N_c} a_{nm} x_n \right) \left( \frac{\partial Z}{\partial p} + (\sqrt{2} + 1) \frac{\partial B}{\partial p} \right) - \frac{A}{2\sqrt{2}B} \left( \sum_{n=1}^{N_c} a_{nm} x_n \right) \left( \frac{\partial Z}{\partial p} - (\sqrt{2} - 1) \frac{\partial B}{\partial p} \right) 
\]
\[
\text{Thus, the Eq. A.1 finally becomes,} 
\]
\[
\frac{\partial f_m}{\partial p} = f_m \left\{ \frac{1}{p} + \frac{b_m}{b} \frac{\partial Z}{\partial p} - \frac{1}{(Z - B)} \left( \frac{\partial Z}{\partial p} - \frac{\partial B}{\partial p} \right) \right\} 
\]
\[
- \frac{A}{2\sqrt{2}B} \left( \sum_{n=1}^{N_c} a_{nm} x_n \right) \left( \frac{\partial Z}{\partial p} + (\sqrt{2} + 1) \frac{\partial B}{\partial p} \right) - \frac{A}{2\sqrt{2}B} \left( \sum_{n=1}^{N_c} a_{nm} x_n \right) \left( \frac{\partial Z}{\partial p} - (\sqrt{2} - 1) \frac{\partial B}{\partial p} \right) 
\] 
(A.2)
APPENDIX B

DERIVATIVES OF Z-FACTOR

B.1 Derivative of Z-factor with respect to $p$

The Eq. 4.12 is a function of,

$$f(Z, A, B) = Z^3 + Z^2(B - 1) + Z(A - 2B - 3B^2) + (B^3 + B^2 - AB) = 0$$

In this equation, all variables are pressure dependent. Thus the derivative of function $f$ with respect to pressure is,

$$\frac{\partial f}{\partial p} = \left( \frac{\partial f}{\partial Z} \right)_{A,B} \frac{\partial Z}{\partial p} + \left( \frac{\partial f}{\partial A} \right)_{Z,B} \frac{\partial A}{\partial p} + \left( \frac{\partial f}{\partial B} \right)_{Z,A} \frac{\partial B}{\partial p}$$

where:

$$\frac{\partial A}{\partial p} = \frac{\partial}{\partial p} \left( \frac{\alpha p}{R^2T^2} \right) = \frac{\alpha}{R^2T^2} \quad \text{(B.1)}$$

$$\frac{\partial B}{\partial p} = \frac{\partial}{\partial p} \left( \frac{\beta p}{RT} \right) = \frac{\beta}{RT} \quad \text{(B.2)}$$

Thus,

$$\frac{\partial f}{\partial p} = [Z^2 + 2Z(B - 1) + (A - 2B - 3B^2)] \frac{\partial Z}{\partial p}$$

$$+ [Z - B] \frac{\alpha}{R^2T^2}$$

$$+ [Z^2 + Z(-2 - 6B) + (3B^2 + 2B - A)] \frac{\beta}{RT} = 0$$

Hence,

$$\frac{\partial Z}{\partial p} = \frac{(B - Z) \frac{\alpha}{R^2T^2} - [Z^2 - 2Z(1 + 3B + (3B^2 + 2B - A)] \frac{\beta}{RT}}{[3Z^2 + 2Z(B - 1) + (A - 2B - 3B^2)]}$$ \quad \text{(B.3)}$$

B.2 Derivative of Z-factor with respect to $x_m$

Similarly, the Z-factor and its variables are dependent on the composition of the mixture.

$$\frac{\partial f}{\partial x_m} = \left( \frac{\partial f}{\partial Z} \right)_{A,B} \frac{\partial Z}{\partial x_m} + \left( \frac{\partial f}{\partial A} \right)_{Z,B} \frac{\partial A}{\partial x_m} + \left( \frac{\partial f}{\partial B} \right)_{Z,A} \frac{\partial B}{\partial x_m}$$
Since,

\[ A = \frac{p}{R^2T^2} \sum_{m=1}^{N_c} \sum_{n=1}^{N_c} a_{mn}x_m x_n \]

In order to take the derivative of \( A \), \( \frac{\partial A}{\partial x_m} \), it is better to expand the mixing term into several components. Let’s say, \( N_c = 3 \). Thus,

\[
\frac{\partial A}{\partial x_m} = \frac{p}{R^2T^2} \frac{\partial}{\partial x_m} \left\{ \sum_{m=1}^{3} \sum_{n=1}^{3} a_{mn}x_m x_n \right\}
\]

\[
= \frac{p}{R^2T^2} \frac{\partial}{\partial x_m} \left\{ \begin{array}{c} a_{11}x_1 x_1 + a_{12}x_1 x_2 + a_{13}x_1 x_3 \\ a_{21}x_2 x_1 + a_{22}x_2 x_2 + a_{23}x_2 x_3 \\ a_{31}x_3 x_1 + a_{32}x_3 x_2 + a_{33}x_3 x_3 \end{array} \right\}
\]

Let us take the derivative with respect to component 3, \( m = 3 \)

\[
\frac{\partial A}{\partial x_3} = \frac{p}{R^2T^2} \frac{\partial}{\partial x_3} \left\{ \begin{array}{c} a_{11}x_1 x_1 + a_{12}x_1 x_2 + a_{13}x_1 x_3 \\ a_{21}x_2 x_1 + a_{22}x_2 x_2 + a_{23}x_2 x_3 \\ a_{31}x_3 x_1 + a_{32}x_3 x_2 + a_{33}x_3 x_3 \end{array} \right\}
\]

\[
= \frac{p}{R^2T^2} \left\{ \begin{array}{c} a_{13}x_1 + a_{23}x_2 + \\ a_{31}x_3 + a_{32}x_2 + 2a_{33}x_3 \end{array} \right\}
\]

\[
= \frac{p}{R^2T^2} \left\{ \begin{array}{c} a_{31}x_3 + a_{32}x_2 + a_{33}x_3 + \\ a_{13}x_1 + a_{23}x_2 + a_{33}x_3 \end{array} \right\}
\]

\[
= \frac{p}{R^2T^2} \left\{ \begin{array}{c} 3a_{3n}x_n + \\ 3a_{n3}x_n \end{array} \right\}
\]

Thus the general form of the derivative \( \frac{\partial A}{\partial x_m} \) can be written as,

\[
\frac{\partial A}{\partial x_m} = \frac{p}{R^2T^2} \left\{ \sum_{m=1}^{N_c} (a_{mn} + a_{nm})x_n \right\} \quad \text{(B.4)}
\]

Similarly,

\[
\frac{\partial B}{\partial x_m} = \frac{\partial}{\partial x_m} \left( \sum_{m=1}^{N_c} b_m x_m \frac{p}{RT} \right) = b_m \frac{p}{RT} \quad \text{(B.5)}
\]
Then,

\[
\frac{\partial f}{\partial x_m} = \left[3Z^2 + 2Z(B - 1) + (A - 2B - 3B^2)\right] \frac{\partial Z}{\partial x_m} + [Z - B] \frac{p}{R^2T^2} \left\{ \sum_{m=1}^{N_c} (a_{mn} + a_{nm})x_n \right\} \\
+ [Z^2 + Z(-2 - 6B) + (3B^2 + 2B - A)] \frac{b_m p}{RT} = 0
\]

A further rearrangement of the equation above leads to,

\[
\left[3Z^2 + 2Z(B - 1) + (A - 2B - 3B^2)\right] \frac{\partial Z}{\partial x_m} = \\
- [Z - B] \frac{p}{R^2T^2} \left\{ \sum_{m=1}^{N_c} (a_{mn} + a_{nm})x_n \right\} \\
- [Z^2 + Z(-2 - 6B) + (3B^2 + 2B - A)] \frac{b_m p}{RT}
\]

Thus the final form of the \( \frac{\partial Z}{\partial x_m} \) is,

\[
\frac{\partial Z}{\partial x_m} = \frac{-1}{\left[3Z^2 + 2Z(B - 1) + (A - 2B - 3B^2)\right]} \left\{ [Z - B] \frac{p}{R^2T^2} \left\{ \sum_{m=1}^{N_c} (a_{mn} + a_{nm})x_n \right\} \\
- [Z^2 + Z(-2 - 6B) + (3B^2 + 2B - A)] \frac{b_m p}{RT} \right\}
\]

(B.6)