

**PRODUCTION ENHANCEMENT USING
CO₂-RICH FLUE GASES**

BY

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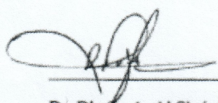
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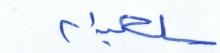
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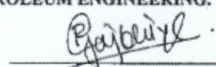
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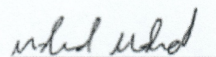
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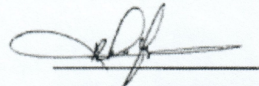
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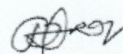
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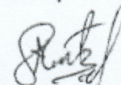
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I humbly and wholeheartedly dedicate this thesis to

*my beloved **parents**, for their endless support throughout my entire life,*

*my **brothers** and **sister**, who I hope I will be part of their future success too,*

*my **friends**, who were the source of joy during this fruitful journey*

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LIST OF ABBREVIATIONSABS

EOR	Enhanced Oil Recovery
CWI	Carbonated Water Injection
GEOR	Gas Enhanced Oil Recovery
CCS	Carbon Capture and Sequestration
IFT	Interfacial Tension
FCM	First Contact Miscible
MCM	Multiple Contact Miscibility
HPAI	High Pressure Air Injection
HTO	High Temperature Oxidation
LTO	Low Temperature Oxidation
WAG	Water Alternating Gas
OOIP	Original Oil in Place
PV	Pore Volume

ABSTRACT

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Gas injection has proven success as one of the most effective enhanced oil recovery processes in which the selection of injected gas largely dependent on economics. The availability of gas is among the crucial elements as far as Gas-EOR project overall costs are concerned. Consequently, the lack of pure CO₂ sources and limited natural reservoirs in Saudi Arabia, made it imperative to focus on other alternative techniques. There are many industries such as power plants, refineries, and cement industries releasing the flue gases in the atmosphere. These flue gases are rich in CO₂ gas, which can substitute the deficit of other gases.

In this study, a flue gas consisting of 11.33 % of CO₂, 70.64% of N₂, and 18.03% of O₂ was tested as a process for well stimulation and EOR. Core flooding experiments are carried out applying two different injection designs: cyclic injection and continuous flooding. Furthermore, two different types of hydrocarbons including crude oil and condensate was used during the experiments. The aim is to analyze the potential application of flue gas to enhance oil recovery in sandstone and carbonate reservoirs.

This study has shown an optimistic outcome of flue gas employment by accompanying the previously mentioned injection designs. The improvement of ultimate recovery has been achieved from both carbonate and sandstone rocks. Cyclic injection produced more oil than with continuous gas injection, however, the experiments followed on stand-alone approach for each process. It has been shown that condensate exhibit a lower interfacial tension relevant to the medium crude oil at the same pressure and temperature conditions, which justifies higher ultimate recovery for condensate in some experiments. Wettability, production rate, and rock properties have a slight effect on the performance of the core-floods tests. In addition, the outcome of IFT measurement shows that condensate and flue gas systems have lower interfacial tension than crude oil with flue gas. The IFT value for the condensate/flue gas at the experiment conditions (pressure and temperature) reached around 15 mN/m, whereas the crude oil with the flue gas was at almost 18 mN/m. This work has led to conclude that flue gas has solid application and potential for mature reservoirs.

ملخص الرسالة

الاسم بالكامل: سالم محسن محمد المري
عنوان الرسالة: تحسين الإنتاج باستخدام غازات المداخل الغنية بثاني أكسيد الكربون
التخصص: هندسة البترول
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تم قبول حقن الغاز كواحد من أكثر عمليات الاستخلاص المعزز للنفط فعالية حيث يعتمد اختيار الغاز المحقون إلى حد كبير على الاقتصاد. يعد توافر الغاز من بين العناصر الحاسمة فيما يتعلق بالتكاليف الإجمالية لمشروعات الاستخلاص المعزز للنفط. وبالتالي، فإن الافتقار إلى مصادر ثاني أكسيد الكربون النقية ومحدودية الخزانات الطبيعية في المملكة العربية السعودية، جعل من الضروري التركيز على التقنيات البديلة الأخرى. هناك العديد من الصناعات مثل محطات الطاقة والمصافي وصناعات الأسمدة التي تطلق غازات المداخل في الغلاف الجوي. غازات المداخل هذه غنية بغاز ثاني أكسيد الكربون، والتي يمكن أن تحل محل النقص في الغازات الأخرى.

في هذه الدراسة، تم اختبار غاز مداخل يتكون من ١١.٣٣٪ من ثاني أكسيد الكربون و ٧٠.٦٪ من N_2 و ١٨.٠٣٪ من O_2 كعملية لتحفيز البئر والاستخلاص المعزز للنفط. يتم إجراء تجارب الغمر الأساسية باستخدام تصميمين مختلفين للحقن: الحقن الدوري والفيضان المستمر. علاوة على ذلك، تم استخدام نوعين مختلفين من الهيدروكربونات بما في ذلك النفط الخام المتكثف والمتوسط في التجارب. الهدف هو تحليل التطبيق المحتمل لغاز المداخل لتحسين استخلاص النفط في مكامن الحجر الرملي والكربونات.

أظهرت هذه الدراسة نتيجة متفائلة لتوظيف غاز المداخل من خلال مرافقة تصاميم الحقن المذكورة سابقاً. تم تحقيق تحسين الاسترداد النهائي من صخور الكربونات والحجر الرملي. أنتج الحقن الدوري زيتاً أكثر من الحقن المستمر للغاز، ومع ذلك، اتبعت التجارب نهجاً قائماً بذاته لكل عملية. لقد تم إثبات أن المكثفات تظهر توتراً بينياً منخفضاً متعلقاً بالنفط الخام المتوسط عند نفس ظروف الضغط ودرجة الحرارة، مما يبرر الاسترداد النهائي الأعلى للمكثفات في بعض التجارب. أدى هذا العمل إلى استنتاج أن غاز المداخل له تطبيقات صلبة وإمكانية لخزانات ناضجة. بالإضافة إلى ذلك، تُظهر نتيجة قياس التوتر السطحي أن

نظام المكثفات وغاز المداخن لهما توتر بيني أقل من النفط الخام مع غاز المداخن. بلغت قيمة التوتر السطحي للغاز المكثف مع غاز المداخن في ظروف التجربة (الضغط ودرجة الحرارة) حوالي 15 مليون نيوتن / م، بينما كان النفط الخام مع غاز المداخن حوالي 18 مليون نيوتن / م. أدى هذا العمل إلى استنتاج أن غاز المداخن له تطبيقات صلبة وإمكانية لخزانات ناضجة.

INTRODUCTION

Gas injection has been acknowledged as one of the best efficient methods under enhanced oil recovery processes. It has been tested in the past few decades throughout the world in many projects in the oil field and proved a success. Recovery of gas injection reaches its optimum when the fluids accommodate a miscible condition with original reservoir fluid, no matter how miscibility was reached and by which process (Whorton & Kieschnick, 1950). However, the choice of gas to use in an EOR is heavily reliant on the availability of the gas, reservoir conditions, and the economic viability of the gas injection process. In Saudi Arabia, the lack of low-cost CO₂ resources draws attention to study rich CO₂ flue gases as an alternative technique that can be economically profitable. The rich CO₂ flue gases possess several characteristics which make them more suitable for gas injection compared to other gases, the most important characteristic being the considerably lower pressure at which CO₂ becomes miscible with crude oil. On top of pressure maintenance and residual oil displacement, the gas injection can also enhance local microscopic sweep efficiency in the swept zones and achieve more oil recovery in contrast with water injection.

When miscibility is reached the interfacial tension (IFT) between gas and oil becomes zero, resulting in an efficient displacement of residual oil. However, due to the very low viscosity of the gas, the mobility become usually very poor. Viscous fingering by injected gas can

happen due to the viscosity difference, mostly in high permeable zones, which leads to an early breakthrough, leading to poor production. Water and chemical flooding among common EOR methods which have proven successful in many cases. However, in tight reservoirs, poor displacement and low injectivity of fluids have been reported. Thus, gas flooding can be a better option in such conditions allowing for a higher injection rate and improving displacement significantly.

1.1 Gases commonly used for GEOR

1.1.1 Flue Gas injection

Flue gas embodies a high percentage of CO₂ which is usually emitted in different industrial processes including cement production, oil, natural gas, and LPG. The composition of the flue gas depends on the fuel used for the combustion process, the fuel used during the combustion process determines the composition of the flue gas, but it commonly includes N₂, CO₂, water vapor, O₂, and SO₂. Sulfur, NO_x, CO, CO₂, and dust. In addition, it may contain some of the air polluting components in flue gases (Bender et al., 2017).

Flue gas produced during cement production can be stored in underground geologic formations such as deep saline aquifers or can be used for pressure maintenance in mature and depleted hydrocarbon reservoirs (Bender, 2011). Flue gas is a mixture of approximately 15 % carbon dioxide and 85 % nitrogen. The flue gas recovers oil by two competing mechanisms, the first mechanism is that the carbon dioxide component dissolves in the oil to reduce oil viscosity, while the second is that the nitrogen component provided the energy for driving the mobilized oil and displaced to the producing well. The

carbon dioxide solubility decreases as the percent of carbon dioxide decrease in the mixture. The producing GOR increased with increasing nitrogen concentration in the mixture. A possible explanation is that nitrogen, being non-condensable, remained as a free gas phase, consequently increasing the relative permeability to the gas phase and increasing the resistance to the diffusion of carbon dioxide into the oil. Flue gas sometimes can be used as gravity drainage, N_2 is a light gas and will stay in the gas cap, while CO_2 at high pressure may be heavier than the gas cap fluid and thus have a tendency to migrate down-dip.

1.1.2 Hydrocarbon gas injection

Hydrocarbon gas has been applied in EOR due to large quantity accessibility in contrast to CO_2 gas. In spite of the fact that CO_2 flooding is said to recover more oil, the main challenge is that in most cases CO_2 not readily available. It has been found that the main mechanisms of oil recovery by gas methods are miscible displacement, viscosity reduction, mobility modification, oil swelling and extraction, and gravity drainage (Koch et al.,1958).

Recycling of produced hydrocarbon gas is an alternative EOR injectant that would be particularly useful for brownfields with marginal economics and tight cost structures. As mentioned in the introduction section above, the availability and low cost of hydrocarbon gas warrants further investigation into its ability to increase oil– field recovery factors compared to CO_2 . In particular, ethane and ethane–based products are becoming widely available and present an opportunity to fields that are unable to utilize CO_2 EOR.

Recycling of produced hydrocarbon gas is another EOR method, which is referred to as the injection of produced hydrocarbon gases back into the oil reservoir.

This gas-injection method is used for reservoir pressure maintenance to improve oil recovery. Considering the hassle with produced gas and difficulties associated with its transportation and selling. For this purpose, it is favored to use gas in the field. The common practice is to implement a continuous hydrocarbon gas injection scheme. It seems this method is more effective than N_2 and CO_2 injection because hydrocarbon gas achieves miscibility with reservoir fluids at considerably lower pressure.

1.1.3 Nitrogen injection

For the reason that nitrogen minimum miscibility pressure is high, N_2 usually displaces oil at pressures below the MMP. In this scenario, the oil does not mix at all with the oil but instead applies external pressure to the reservoir oil pushing it towards the producer. Nitrogen is less expensive compared to other gases and not corrosive.

1.1.4 CO_2 injection

CO_2 is rather attractive because it possesses a low minimum miscibility pressure and has been applied in numerous field cases. It has several favorable effects such as increased sweep of the reservoir, a decrease in fluid viscosity, an increase in the gas-oil ratio, bubble point pressure as well as swelling and formation factors.

The use of carbon dioxide for improving the recovery of crude oil, following primary production, has received considerable attention because of the promising results from the current projects. Both laboratory and field studies have established the capability of carbon

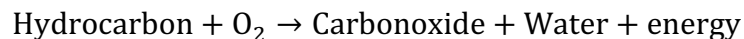
dioxide to displace oil from the reservoir formations with reported recovery efficiencies that approach 100 percent when operating at optimum displacement pressures. Carbon dioxide is injected into the reservoir to dissolve in the crude oil under high pressure to form a single liquid phase, which is much lighter than the original oil. The beneficial effects from the use of carbon dioxide that is responsible for improved recovery efficiencies pertaining to crude oil are promotes swelling, reduce viscosity, increase density, and vaporizes the oil into the CO₂ phase which resulting in high displacement efficiency of the contacted oil.

The lack of mobility control would encourage gas to travels through the path of least resistance, lifting behind oil in low permeability areas. Stable foams restrict flow in high permeability channels, diverting flow to the lower permeability layers. This allows injected fluid to contact oil which would have been unswept by the conventional gas flood. Foam is a dispersion of a large gas volume in a small volume of the continuous liquid phase. Foam can either be introduced into the reservoir through Surfactant Alternating Gas (SAG) floods or co-injection of CO₂ gas and water containing surfactant (preformed foam). The surfactant stabilizes the foam by lowering the surface tension of the liquid film surrounding the gas bubbles (lamella) and reducing the rate of coalescence. Formation of stable foam is only possible with the presence of surfactant in the system. A reaction between the surfactant and injected gas will form a foam which will help in reducing the mobility of carbon dioxide. Khalil & Asghari (2006) in their work proved that the mobility of CO₂ can be reduced dramatically up to 85%.

1.1.5 Air injection

Oil recovery happens naturally when air is injected for the purpose of partial or complete pressure maintenance in an oil reservoir classified as Air Injection Processes (AIP). Temperature and pressure categorize AIP into four main types: Miscible or Immiscible and with or without oxidation during the process. If air and oil become in a miscible state, then the process is often called high-pressure air injection (HPAI). Also, in accordance with the reservoir temperature, the intensity of oxidation varies into low-temperature oxidation (LTO) and high-temperature oxidation (HTO).

The reaction between oxygen and crude oil is an important key to air injection success. There are two principal reaction modes for oil and oxygen that are relevant to the air injection process; namely, 'bond scission' reactions and 'oxygen addition' reactions. Oxygen addition reactions follow the general form of:



In-situ combustion either occurs spontaneously or is initiated by artificial means using the electrical heater or a specified gas. It is essential that oxygen is consumed up to a high degree during the reaction to ensure a safe operation. This will also prevent oil degradation from taking place in the reservoir. Spontaneous ignition can be defined as slow oxidation as a result of a reaction provoked by oxygen in injected gas. For light crude oil temperature usually between 80 to 130 °C, LTO can be effective in consuming all oxygen within injected gas. This led to flue gas generating in the reservoir, this formed gas will contain 10 to 14% of CO₂. The solubility will be directly related to the MMP of N₂ content within the generated flue gas. The mechanisms that aid to oil recovery improvement using air

injection enhanced oil recovery method can be summarized as follows; 1) sweep efficiency improvement due to flue-gas formation; 2) pressure maintenance of the reservoirs; 3) production of light components with NGL; 4) swelling of the oil by the flue-gas; 5) miscibility; 6) microfractures by thermal effect; 7) viscosity reduction.

1.2 Gas Injection Designs

A wide range of gas flooding designs can be implement commonly decided by multiple factors including economics, availability of gas, oil composition, and reservoir characteristics. The gas can be injected in water alternate gas mode (WAG), carbonated water, continuous gas injection, cyclic gas injection, or in other scenarios. Not every reservoir is adequate for gas injection. Therefore, each reservoir must be screened based on specific reservoir rock and fluid properties before any further steps are taken for designing a gas injection project (Taber et al., 1997). Typically, oil reservoirs whose oil has a saturation greater than 20% hydrocarbon pore volume (HCPV), a gravity of greater than 22 °API, and a viscosity of less than 10 cp are considered for gas injection processes (Taber et al., 1997). Gas is much less viscous compared to oil and, as a result, extremely unfavorable mobility ratios of gas to oil are obtained. Gas is less dense than oil which may create a gravity override in the pay zone. Both phenomena may lead to severe consequences like an early gas breakthrough at production wells and poor sweep efficiency. These challenges are controlled by a number of reservoir fluid and rock properties as well as injection design (injection gas composition and rates). One of the engineering solutions to control mobility is the injection of water together with gas alternately or simultaneously (known as WAG or SWAG). Also note that CO₂ becomes supercritical under most of the

reservoir conditions which makes it denser, almost similar to the oleic phase. As a result, the effects of gravity override can be minimized or avoided.

It is crucial to recognize the displacement mechanisms anticipated to take place in situ in design consideration. Analyzing the phase behavior of injected gas and targeted oil reservoir will prevail important information about the flooding condition whether it is miscible, near miscible, or immiscible. For example, in a retrograde gas reservoir, the gas injected can help in the re-vaporization of condensate by raising the reservoir pressure above the dewpoint pressure. This can happen as mass transfer between gas and oil occur

1.2.1 Continuous Gas Injection

Continuous gas injection, which involves injecting the gas continuously without any other fluid. This injection process is very well apprehended from micromodel and coreflood experiments. The effectiveness of this process is higher under miscible conditions. In this technique, CO₂ is injected continuously into the reservoir. Injection rate or pressure and slug size are the design parameters for the continuous CO₂ injection method. It was shown that oil recovery increases with increasing CO₂ slug size. The disadvantage of this methodology, when compared with other CO₂ flooding techniques, is that there is no mobility control in this method. Viscous fingering may occur during CO₂ injection due to the low viscosity of CO₂ and adverse mobility ratio (Nasir and Chong, 2009).

1.2.2 Water Alternating Gas (WAG)

Water Alternating Gas (WAG) injection was initially suggested to improve the volumetric sweep efficiency. This method was first introduced by Caudle and Dyes in 1958 (Caudle

& Dyes, 1958). In this technique, water and CO₂ being injected in cycles as presented in figure 1. The aim is to increase the efficiency of CO₂ flooding and sweep efficiency by reducing CO₂ channeling. The duty of water is to control the mobility to make the front more stable. The other advantage of using water is that it will flow into high permeable channels so that CO₂ may go into the low perm zones. It can be said that CO₂ tackles microscopic displacement and water deals with macroscopic displacement. Water-gas ratio (WAG ratio), slug size, injection rates or pressures, production rates, and cycle timing are the design parameters that have a great impact on the success of WAG (Blackwell et al., 1960).

In this technique, water and gas are injected alternatively to improve the sweep efficiency of gas injected. The predetermined ratio of water/gas is an important factor in the design for this method. In different words, water alternating gas is the recovery mechanism where a slug of gas is injected into the reservoir followed by water which serves as the "chasing fluid". The advantage of using water is that it will flow into high permeable channels so that CO₂ may go into the low perm zones. It can be said that CO₂ tackles microscopic displacement and water deals with macroscopic displacement. Water-gas ratio (WAG ratio), slug size, injection rates or pressures, production rates, and cycle timing are the design parameters that have a great impact on the success of WAG (Christensen et al., 2001).

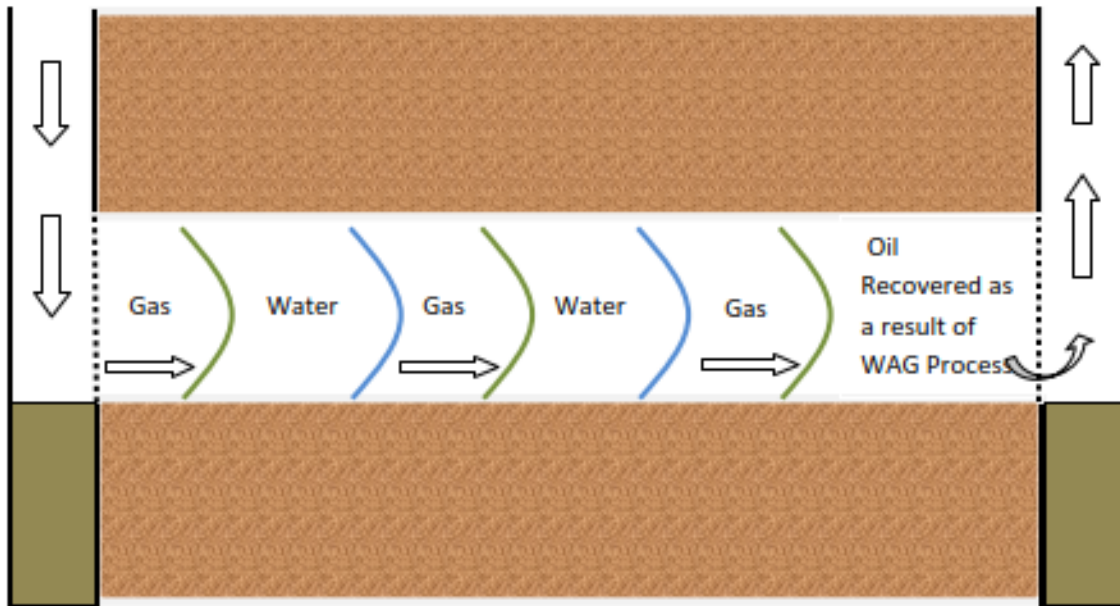


Figure 1: WAG process (Zahoor et al., 2011).

1.2.3 Cyclic Gas Injection

The other method is to utilize one well as a dedicated injector as well as a dedicated producer alternately or it is commonly referred to as huff and puff. Figure 2 shows an illustration of the huff process in which the well only injects gas into the reservoir for a certain duration. The injected gas is expected to be soluble in oil around the stimulated reservoir volume and increase its mobility. Tubing and all fracture networks are used by the gas to flow into the reservoir.

The Huff process is then followed by the oil production process, called puff. In this process, stimulated oil will be produced during the same duration as a huff. Figure 3 shows the illustration of the puff process within the well. In this process, the tubing and the entire fracture networks will be used by oil to flow from the reservoir to the surface.

Implementing, this method doesn't require a certain well-completion design since all perforations have the same function in either huff or puff process. The well acts as an injector as well as a producer well and can be replaced easily because the wellhead flow direction can be modified based on the needs in each process.

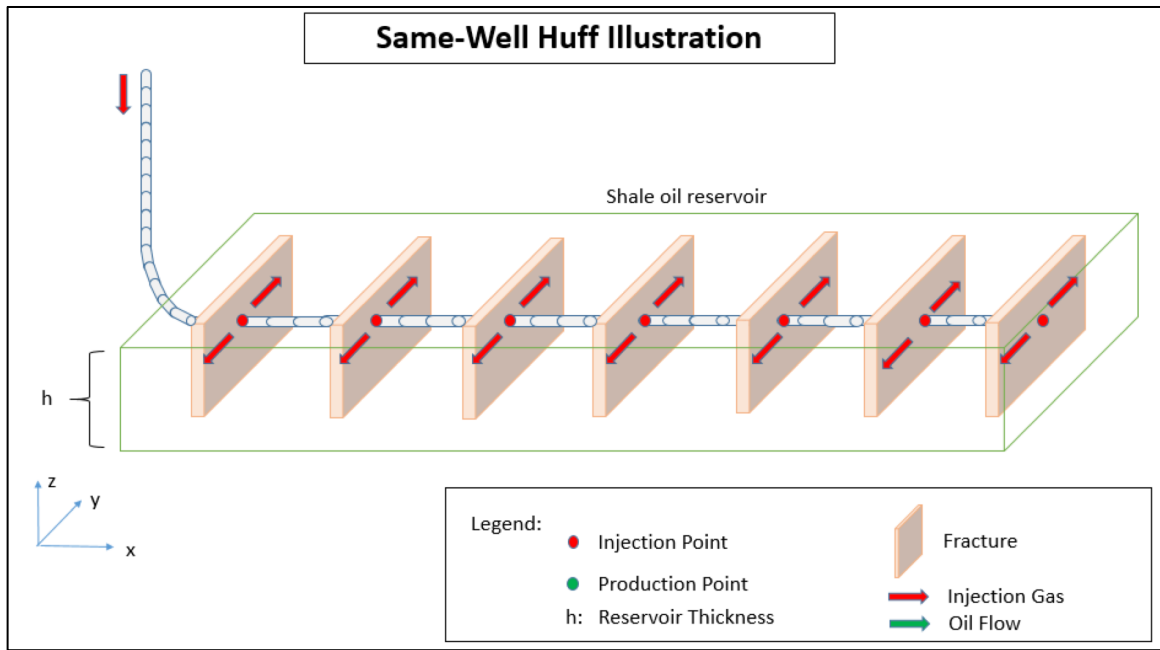


Figure 2: Schematic process of “Huff” in EOR (Du and Nojabaie, 2019).

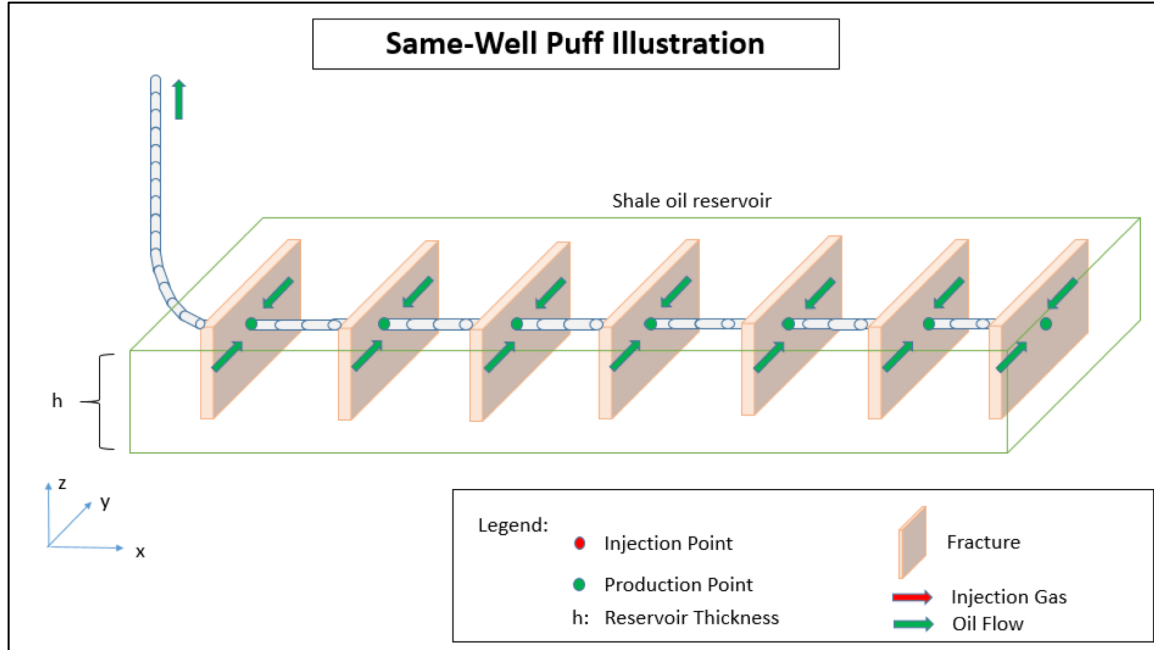


Figure 3: Schematic process of “Puff” in EOR (Du and Nojabaie, 2019).

1.2.4 Carbonated Water Injection (CWI)

Carbonated water injection (CWI) or CO₂ enriched water injection is another CO₂ EOR method. In this method, CO₂ and water are injected simultaneously. They might be mixed at the surface or at the downhole. In this method, CO₂ dissolves in water so that mobility of CO₂ is decreased and sweep efficiency is improved (Sohrabi et al., 2009). When compared with continuous CO₂ injection and WAG, CO₂ breakthrough time will increase during CWI due to decreased mobility. CO₂ has higher solubility in oil than water. Therefore, CO₂ will be transferred into the oil. CO₂ will swell the oil, reduce the viscosity of oil and increase recovery (Mosavat and Torabi 2014).

LITERATURE SURVEY

1.3 History of Gas Injection

Blackwell in 1983 has provided a discussion of the early history from 1950 to 1980 of miscible gas injection and comments on how the initial excitement and optimism of the 1950s turned into pessimism by the 1970s due to poor performance (5–10% OOIP recoveries) in the early field tests caused by viscous fingering and solvent channeling aggravated further by reservoir heterogeneity. To control viscous fingering, methods were developed during the late 1950s and early 1960s to increase the reservoir volume swept by the solvent bank. These developments included the water alternating gas (WAG) process, the use of foaming agents, and polymers. Even after renewed research and field applications in the 1970s, Blackwell concludes that no dramatic breakthroughs occurred and “our ability to control solvent channeling has not changed much since 1960.” He further notes that incremental oil recoveries (over that possible by waterfloods) fell between 6 to 10% OOIP, less frequently in the 10 – 15% range, and rarely exceeded 15%. Much of these data came from the early horizontal CO₂ miscible floods in the US.

Howes in 1988 has provided a review of early EOR activities in Canada up to 1987. The first EOR project was a horizontal hydrocarbon miscible flood by Mobil in the North Pembina Cardium Unit in 1957–1958. It was a success, recovering 72% of OOIP in the

pilot area. Most of the miscible floods were vertical gravity stabilized displacements which yielded incremental recoveries of 15 to 40% OOIP over waterfloods. Several large horizontal miscible floods using the WAG process for conformance yielded smaller incremental recoveries of 5 to 20%, similar to the early miscible flood experience in the US.

The Weyburn CO₂ project exemplifies a trend that can be envisioned for future gas injection EOR in Canada, and perhaps in the world. It aims to sequester large quantities of anthropogenic CO₂ supplied from a coal gasification plant in North Dakota through a 330 km pipeline for the purpose of a profitable commercial-scale gas injection EOR project. It takes advantage of the previous CO₂ flood experiences of the Permian Basin in West Texas and modifies the process with several types of CO₂/water injection schemes in different patterns using combinations of vertical and horizontal injectors and producers (Srivastava et al, 1997).

1.4 CO₂ Capture Processes and Technologies

Carbon dioxide harmful impact on the environment known to be a reason behind climate change has triggered global concerns that led to searching for ways to mitigate its effect. Mitigating the level of CO₂ in the atmosphere through sequestration has been a subject of interest a long time ago. Among the most difficult tasks to achieve this goal is the separation process of CO₂ from its industrial sources as the high cost could stand against such projects. However, stripping CO₂ from a gas mixture with existing technologies is achievable and no longer overlooked in many industries; for example, the production of

hydrogen in the ammonia industry by natural gas reforming, separation of CO₂ from H₂ in its final step. Likewise, in the oil and gas field, methane production with a high impurity of carbon dioxide pushes toward the extraction of CO₂ so that methane can be marketed efficiently. The recent focus on reducing greenhouse gas emissions has at the same time led to increased efforts to store it within the reservoir.

Carbon capture technologies aim to capture CO₂ by separating the CO₂ from the flue gas. Once separated, the purified CO₂ gas is compressed and cooled to the liquid phase to enable transportation, regardless of the final destination. The CO₂ product could potentially be further utilized (CCU) or transported to the final storage site (CCS), however, there is no difference between the capturing strategies. There are today three main combustion processes where carbon capture technologies are applicable; Pre-combustion, Oxy-fuel combustion, and Post-combustion as shown in figure 4. More challenges for the capture of CO₂ confronted in dealing with exhaust gases from cement, petrochemical, power, and other industries. As flue gases composition contain multiple gases differ from case to case depending on combustion fuels. Another CCS handicap is nitrogen dilution of CO₂ lowering its partial pressure. Three major approaches can be envisaged in the capturing of CO₂ resulting from fossil fuels (gas or oil, coal), biomass, or both mixed. In accordance with the power plant application, the option of which process to go with can be determined.

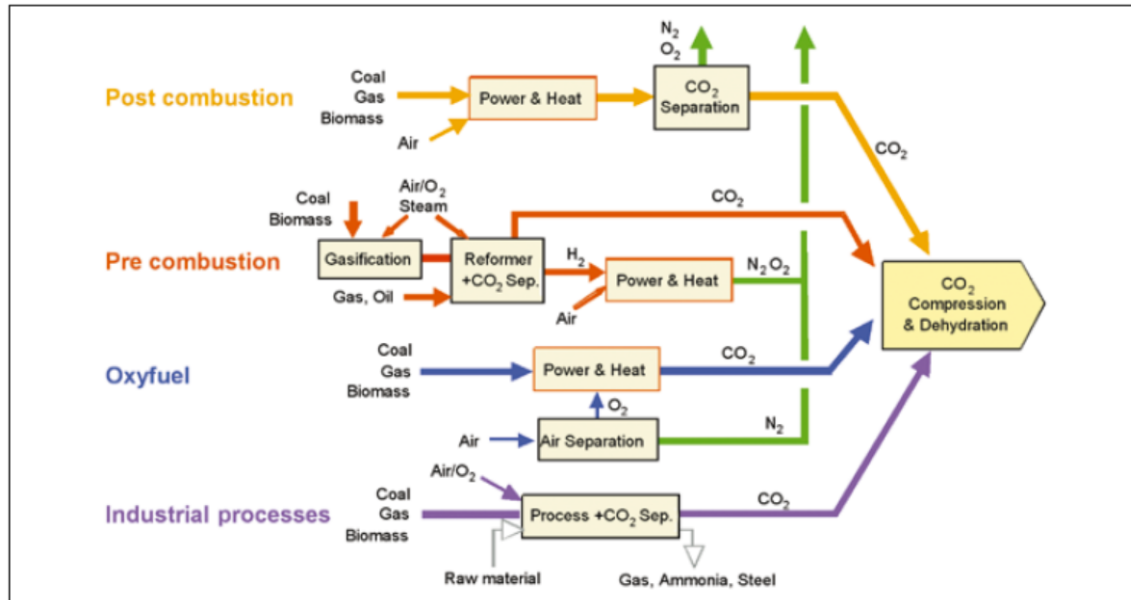


Figure 4: Carbon dioxide capture technologies (Metz et al., 2005).

The most mature post-combustion technologies are absorption processes using amines with Monoethanolamine (MEA) as the technology against which new carbon capture technologies are benchmarked. Absorption technologies are favorable for Sävenäs WTE plant as they are compatible with a low partial pressure of CO₂ (< 15%) in the flue gas (Tsouris et al., 2011).

Separation of CO₂ from flue gases methods, which are generally applied in post-combustion using exhausted gases from burned fossil fuels, as well as in capture from industrial processes, are based on physical and chemical processes, such as cryogenic separation, membranes, absorption, adsorption, and chemical reactions also known as chemical looping (Rivera, 2010). Tsouris et al. (2011) carried out a review on different approaches to separate CO₂ on a large scale from flue gases. In general, this article focused on four main methods for the separation of CO₂ from other gases: membrane purification,

cryogenic distillation, adsorption using solids, and absorption with liquids. However, currently available adsorbents are not efficient to separate pure CO₂ because they also adsorb considerable amounts of N₂. The outcome of this review suggested that monoethanolamide (MEA) is the most suitable technology for the separation of CO₂ with liquid. The schematic process for capturing CO₂ by chemical absorption using amine is shown in figure 5.

Adsorption by physisorption using materials such as activated carbon is a possible solution to capture carbon however further improvements regarding selectivity towards CO₂ is needed for activated carbon as well as scaled-up production. Zeolite is another emerging adsorption technology that could potentially incorporate with amine absorption (Pardakhti et al., 2019) however the technology alone is not considered viable and need further research. Chemisorption technologies using oxides such as lime (CaO) have gained a lot of attention recently especially within the cement industry where exhaust CaO is recycled and utilized for carbon capture.

Cryogenic distillation of CO₂ is associated with a high energy penalty due to the combined temperature and pressure required to operate such processes. Membranes do require high CO₂ partial pressure, thus processing gas with high CO₂ content, such as natural gas, is suitable for such technology (Q.F. Araujo & Maderios, 2017).

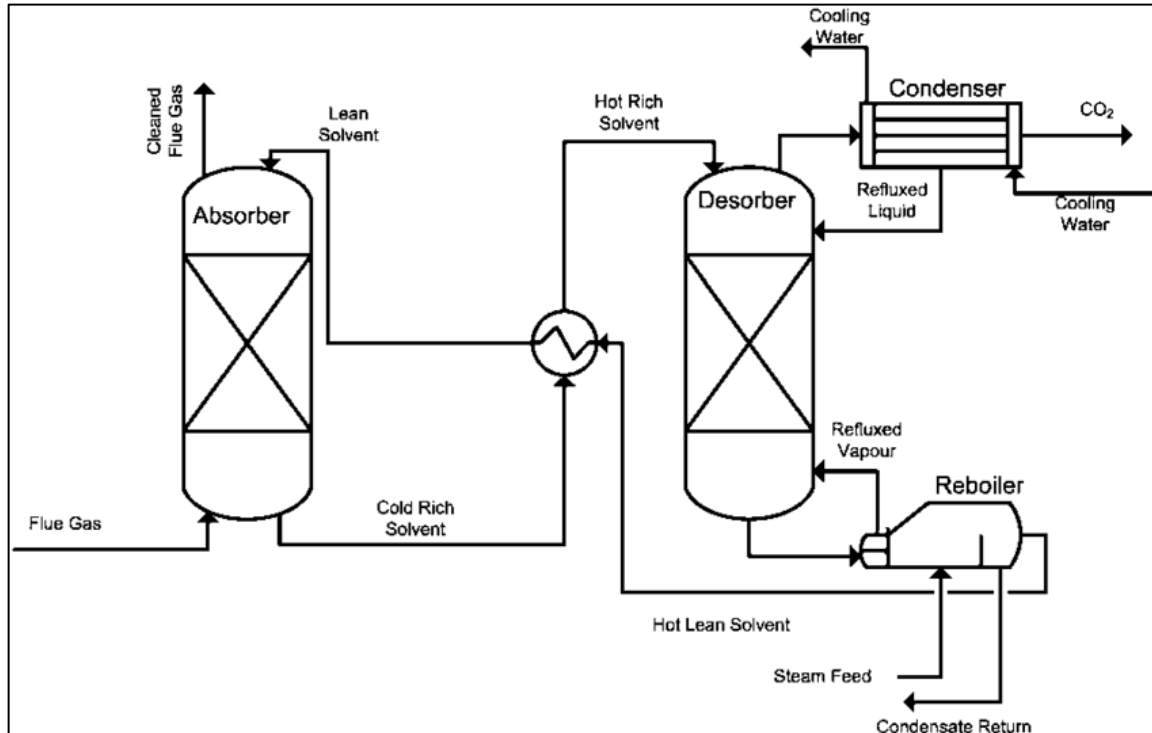


Figure 5: Schematic of chemical absorption process by amine for CO₂ Capture (MacDowell et al., 2010).

1.5 Mechanisms Involved with Gas-Floods

Shokoya et. al (2005) conducted a study to understand the physical mechanisms of flue gas injection in low viscous oil at low permeability and low porosity formation. They have investigated three types of flue gases: gas A (Pure Nitrogen), gas B (16% CO₂, 1% CO, 83% N₂), and gas C (30% CO₂, 1% CO, 69% N). They have reported that intermediate components of oil transferred into the flue gas until reaching loading limit thereafter condensation of the gas heavier component begins to transfer back into the oil, by a drive mechanism of vaporizing-condensing gas in a process called multi-contact.

Shokoya et al. (2004) inspected the mechanisms by which flue gases obtained by spontaneous ignition support improve oil recovery. This flue gas is produced inside the

reservoir by high pressure air injection (HPAI). Shokoya et al. (2004) executed the experiment at reservoir pressure from 27.63 MPa to 46.06 MPa and 116°C was the reservoir temperature. They come to the conclusion that the main driving mechanism in the process is the interchangeable mass transfer between fluid or what is called forward multi-contact gas drive. The mechanism involves gas light component transfer to oil and intermediate oil component transfer to gas by vaporizing and condensing. They claimed the advantage of this method is more economic than other EOR methods with the benefit of protecting the environment from undesirable gasses.

Srivastava Raj et al. (1999) investigated different gases (flue gas [15 mol% CO₂ with N₂], produced gas [15 mol% CO₂ with CH₄] and 100% CO₂) with low viscosity oil. This study included PVT and core-flooding experiments to assist the effectiveness of mentioned gas in producing heavy oil. Srivastava and his colleagues found pure CO₂ the most suited gas for heavy oil recovery. Solubilization mechanism governed the displacement in the case of pure CO₂ injection, whereas N₂ supported free gas drive and solubilization mechanism partially assisted the oil recovery in produced gas and flue gas. They also concluded that the CO₂ water-altering gas injection scheme for heavy oil could be effective.

Whereas in immiscible displacement, CO₂ and oil will not be miscible and they will not form one phase. Therefore, recovery will be less than a miscible displacement. In immiscible flooding, there are four major mechanisms. The first one is oil swelling; CO₂ dissolves in oil and causes oil swelling. When trapped oil swells, it will come out of the pores. Also, increasing oil saturation with the swelling effect will increase oil relative permeability and so mobility. The second one is the viscosity reduction of oil; when CO₂ dissolves in oil, oil viscosity decreases. With the decrease in oil viscosity, its mobility will

increase (Mosavat and Torabi, 2014). Also, CO₂ will push the oil with the increasing pressure and oil recovery will increase (Ferguson et. al, 2010).

1.6 CO₂-EOR and Miscibility

The CO₂ miscible flooding plays an integral role as it makes CO₂ miscible with available resident oil. This eliminates the capillary pressure which is an impediment to oil recovery. In addition, CO₂ miscible flooding theoretically reduces residual oil saturation to almost zero (Taber et al., 1997). Despite the above advantages of injecting gas under FCM conditions, sometimes it becomes impractical due to required high pressures (Al-Wahaibi et al., 2007). The application of CO₂ injection should be regulated to ensure that injected CO₂ for the purpose of EOR remains at MMP (Lake, 1989). However, another limitation on the pressure is that injected CO₂ should be at a pressure that does not exceed the reservoir fracturing pressure (Torabi et al., 2010). The rationale behind the caution is because diffusion and dispersion increase as the amount of CO₂ injected increases thus a lower EOR efficiency.

Studies over the use of cheap injected gas are dated back to the 19th century. Koch and Hutchinsonl (1958) performed an experimental study to understand miscible displacement of flue gas using the slim tube. They used pure nitrogen and noticed an improvement in vaporizing-gas-drive in the reservoir when high methane concentration exists. They speculated that volatilizing the C₂ to C₆ component of oil into the gas happens in the presence of methane. The authors suggested that this could be applied for certain reservoir cases, as flue gas can be miscible in reservoir conditions. Especially when flue gas injection

will help in stimulating a significant increase in reservoir pressure compared to hydrocarbon gas.

Depending on the condition of the fluid, the gas injection can be either miscible, immiscible, or near-miscible. If there is no interface between two or more fluids and the mixture is distributed uniformly, the phenomenon is called miscible (Green and Willhite, 1998). In theory, with miscible gas injection, the residual oil of a swept area was reduced to zero. This eliminates the interfacial force between oil and carbon dioxide that causes oil preservation in the rock matrix. When miscibility occurs the forces of capillary pressure, which formerly held the oil immobile, disappear and the oil is then free to be carried forward to the producing well and the displacement efficiency approaches 100% in the sweep zone. The miscible gas injection can be divided into first contact miscible (FCM) and multiple contact miscible (MCM). The FCM gas injection means that any amount of injected fluid will be completely soluble in the oil and interfaces between the fluids disappears. The MCM gas injection process is less expensive; however, miscibility occurs after multiple contacts between the injected gas and reservoir oil. The multiple contact miscibility may also be divided into two stages which are vaporizing and condensing as shown in figure 6.

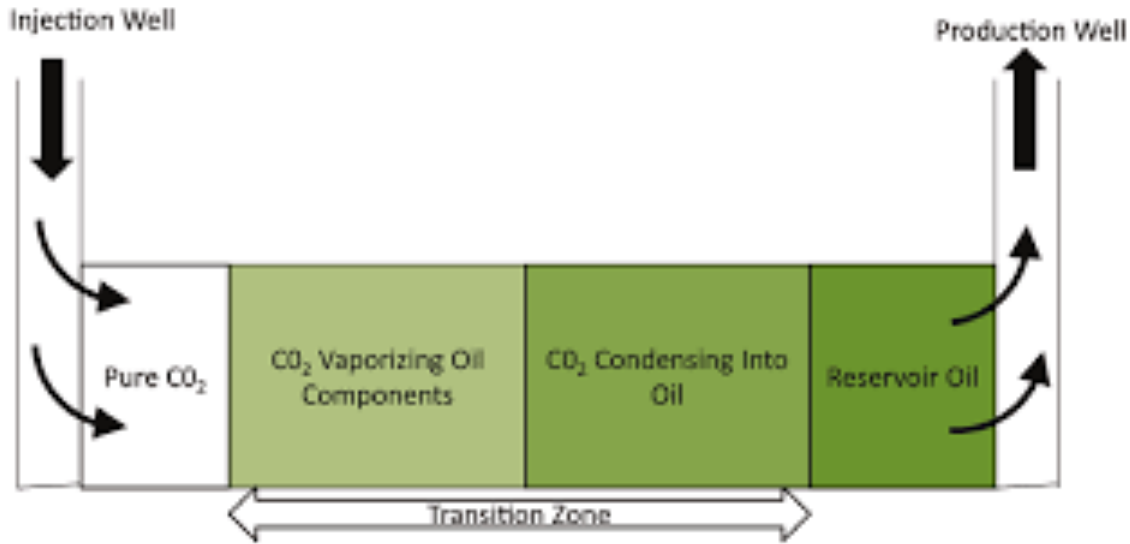


Figure 6: Mechanisms of CO₂ injection (Mohammadian et al., 2010).

1.7 Asphaltene Challenges in GEOR

Many studies have proven that CO₂ flooding can negatively affect the stabilization of asphaltene content within crude oil. In 1997, Srivastava et al. analyzed how CO₂-flood can change asphaltene precipitation using three different crude oil samples from the Weyburn reservoir, the fluid then placed in a high pressure, high volume, and high-temperature cell (PVT). The fluid samples collected from the separator were reconstituted to a different GOR. The onset pressure at which asphaltene begins destabilization occurred for the three samples at 39-46 % of CO₂ concentrations. Later in 2003, Takahashi et al. examined the asphaltene behavior of an oil sample from a carbonate reservoir in the Middle East. Using a light-scattering technique for the crude oil in the PVT cell to examine the onset pressure change with degrading to CO₂ concentration show asphaltene destabilization at CO₂ concentration above 50%.

Verdier et al investigated the change of oil phase behavior in coexistence with CO₂ for two dead oil samples; one from South America and one from the Middle East. In their findings, asphaltene as expected was more stable at higher pressure, however with CO₂ injection asphaltene stability was controlled by lowering the temperature. The crude oil from the middle east also showed similar behavior in a constant CO₂ concentration (18 wt%). At higher temperatures, asphaltene content destabilizes however at high pressure asphaltene was soluble.

1.8 Flue Gas in Application for EOR

The idea of utilizing flue gas (i.e., exhaust gas, inert gas, acid gas) to recover oil from a reservoir is not new. The idea has been tried in various reservoirs a long time ago but with mixed results. With the rise in the synthetic fuels industry., large quantities of flue gases will be produced. These gases will have to be expelled into the atmosphere which will pollute the air.

In 2011 published a case study of a heat carrier fluid injection technology for a heavy oil field in China. This new thermal process is achieved by injection of N₂ and CO₂ simultaneously with steam. Zhong et al. 2013, shared the analysis of the field using software simulation before the pilot test. Their results highlight the efficiency of flue gas in steam stimulation enhancing sweep zone and delaying production decline. Zhong et al. 2013, believed that multiple mechanisms participated in the good results of the pilot test such as; reduction of viscosity induced by heat and gas dissolved, pressure increase, expansion of heat, lowering interfacial tension, and gas assisting gravity drive.

Bender and Akin (2017) performed a 3D composition simulation study of flue gas injection on a depleted reservoir in Turkey. The authors proposed the injection of flue gas to exploit the opportunity of a nearby cement factory. The simulation validated the injection, production, pressure, and saturation history of the reservoir, to compare the effectiveness of injecting flue gas over pure CO₂. They examined the effect of operating parameters on storage and recovery, type of gas injected, and gas solubility. They reported a higher oil recovery with pure CO₂ and storage. They reached the conclusion that injection of flue gas up until reservoir reaches pressurization level followed by CO₂ injection could positively impact the project economics. The proposed pipeline design for the project is shown in figure 7.

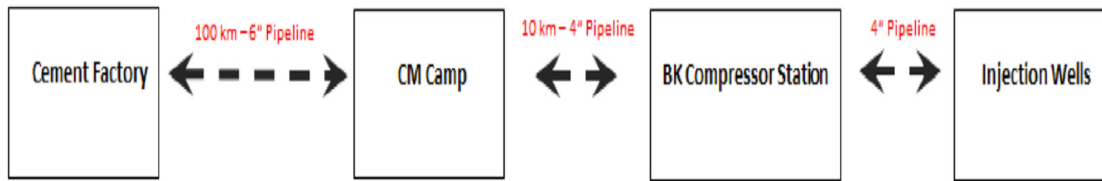


Figure 7: Pipeline design for the cement flue gas EOR-project (Bender and Akin, 2017).

Ossa et al. (2010) presented an evaluation of injecting flue gas into the Llanito oil field supplied from Barrancabermeja Refinery to produce water flooding residual oil. Their work includes experimental analysis of oil-flue gas interaction at in-situ conditions. The study aims to evaluate the best mechanism for flue gas injection into B sandstone formation to ultimately increase the recovery volume factor and flue gas sequestration. In this article, the composition of the flue gas using gas chromatography is found in the following averages: CO₂ 14.98%, N₂ 80.10%, O₂ 3.27%, CH₄ 0.06%, and CO 1.68%.

Al-Hasami et al. (2005) performed a simulation study using a compositional reservoir simulator to assess the displacement effectiveness of CO₂ in gas reservoirs to produce methane. In this research, different parameters were investigated including CO₂ solubility, CO₂ diffusion, and mixing of gas effect. They have stated generally that from a gas reservoir an incremental recovery in the range of 8-11% of gas can be produced if the EOR implementation begins after a primary recovery factor of 85%. An economic analysis using a simple model revealed positive NPVs if the CO₂ purchased for \$20/tonne and total incremental recovery of 10% can be obtained. The list of parameters sensitive in looking at the economics of CO₂-EOR and storage listed in this paper are mixing the injected gas with methane, CO₂ sources, and project time.

Most studies of cyclic gas injection also called (gas huff and puff) were limited to pure CO₂ or with slight impurity, however, increasing interest to evaluate flue gas in this process has clearly shown in recent years. This process is considered a well stimulation technique.

Zhang et al. (2004) analyzed the efficiency of the gas cyclic process in light oil reservoirs through a study focused on phase behavior, core flooding experiments, and simulation utilizing finding results. Zhang et al (2004) employed CO₂ and enriched flue gas (30% CO₂ + 70% N₂) in their work. It was noticed that water flooding residual oil and application schemes are critical for the success of this EOR method. The results presented in this research showed a comparable performance of both CO₂ and enriched oil gas producing 5 IOIP, 9.9 IOIP, and 8.8 IOIP respectively from three runs in each run represent three cycles of displacements. Cyclic gas injection using flue gas has been also applied on a full-field scale. Johnson et al (1990) presented a successful full-field pilot for cyclic flue gas injection by Trotman Oil Company in Kansas. The source of the flue gas is an internal combustion

engine, treated and compressed at 200 psi before injection. The authors described the project as economically feasible at moderate due to the low cost of maintenance and ease of implementation.

The role of oxygen being part of Gas-EOR processes has cast doubt on the type of mechanisms involved. Injection of air containing oxygen will induce in situ combustions resulting in flue gas with a high concentration of CO₂. Montes (2010) research intends to prove that high-pressure air injection (HPAI) strategy into low viscosity oil reservoir doesn't appear like other simple gas floods because thermal positive impact takes place. The author's justification was based on a comparison of wells' performance at Buffalo Check spelling field where HPAI wells recovered more oil than other immiscible floods. His analysis targeted one of the oldest HPAI projects which being implemented at Buffalo Check spelling field. The finding of this paper suggests that HPAI should be looked at as a thermal process.

Ren et al. (2002) described in their paper AIP at light oil reservoir. They figured that in-situ combustion will not be needed for deep light oil reservoirs and heat may not be sustained. Instead, Ren and his team focused on low-temperature oxidization (LTO) which more likely will arise. In this study, the reaction rate, reaction oxygen consumption, and reaction pathways are analyzed. A model was built supplied with data from reaction kinetics of oxygen with light oil. Ren et al. (2002) illustrated the importance of air injection rate in HPAI; unlike (HPAI) which is sensitive to injection rate in LTO the gas injection rate is flexible.

Combustion inside the reservoir by air injection creates a thermal drive that can enhance oil recovery in the heavy oil field. Dong and Hong (2008) carried out a study to investigate the O and CO existence in flue gases role in oil swelling for heavy oil. The experimental work has been done by Hong and Dong comprised of a 2D-physical model and PVT analysis. The 2D-physical model aim is to inspect the effect of flue gas injection rate, injection mode, and slug size. They also have examined the free-gas mechanism. In their finding observed that flue gases perform better in reducing viscosity and oil swelling in live oil rather than dead oil. From the physical model, the authors noticed during multiple contact processes high gas volume remains free proving that in the heavy oil-flue gas method the mechanism of free gas is crucial. They also find out that the most efficient strategy for injection is the vertically downward mode.

1.9 Cyclic Gas Injection

Most experiments that were conducted in the lab came to the same conclusion that CO₂ huff-n-puff outperformed CO₂ continuous injection in unconventional resources. Remarkably, in naturally fractured reservoirs, the injected CO₂ flows easily through a natural fracture network with continuous gas injection (Tovar et al. 2014). This fact will provoke an early CO₂ breakthrough at the producer. Hence, oil recovery efficiency is lessened substantially (Hawthorne et al. 2013).

Muladi et al. (1999) did a simulation study to compare the production efficiency of vertical well with horizontal well in the gas-condensate reservoirs with heterogeneities. A Cartesian 3D model was built using LGR to visualize the vicinity of the wellbore in a better way.

They concluded that the production efficiency of the horizontal well was better for reservoirs whose average permeability is higher than 1 mD, conversely, for reservoirs with average permeability ≤ 1 mD preferable option is vertical well. This is because of the fact that in high average permeability reservoirs fluid has high mobility and can move easily to horizontal well along the vertical direction.

Dehane and co-researchers (2000) studied horizontal wells performance in comparison to vertical wells performance in gas-condensate reservoirs under different depletion schemes. They found that horizontal wells undergo less drawdown pressures than vertical wells and that there is a lower accumulation of liquid nearby wellbore for horizontal wells. They also found that in the case of horizontal wells increasing the drain hole length increases productivity.

Marir et al. (2006) did a simulation study using data from horizontal-wells in Hassi R' Mel field (Algeria) to study water production and recovery of condensate. The results depicted that horizontal wells are useful as they increase the water breakthrough time and also improves the condensate recovery

Miller (2010) using a simulation study inspected the impact of horizontal wells to mitigate condensate banking phenomena in a gas condensate reservoir located in the North field of Qatar. It is one of the largest gas condensate reservoirs in offshore Qatar. For the simulation study two numerical well models were built, one model for horizontal well using Cartesian coordinates and another model for vertical well-using radial coordinates. The results indicated that horizontal well features lower drawdown in comparison to vertical well, leading to lower water conning phenomena and lower condensate accumulation nearby the

wellbore. Moreover, PI for the horizontal wells was also higher. The reason for all this is that horizontal wells have a higher contact area in-between reservoirs and the well, and horizontal wells delay the formation of the condensate bank nearby the wellbore.

Objective

This study aims to investigate the potential use of flue gases released from cement industries for the production enhancement of the hydrocarbon reservoir. The flue gases contain a high concentration of CO₂; CO₂ injection is a well-established technique for enhancing hydrocarbon production. The limited resources of CO₂ restricted its usage in Saudi Arabia. In Saudi Arabia cement industries are located around the mature oil and gas fields offering a great opportunity to decrease project costs by utilizing the high concentration of CO₂ in the flue gases for the production enhancement

The objectives of the study are as follows:

- Investigate the potential application of flue gas for hydrocarbon production enhancement.
- Evaluate the performance of flue gas injection in low permeability carbonate and sandstone reservoirs.
- Evaluate the injection strategy continues or cyclic injection of the flue of gases.

EXPERIMENTAL PROCEDURE AND METHODOLOGY

1.10 Materials

Cement flue gas was prepared at the lab by the injection of CO₂ and air at different partial pressure. The composition of the gas prepared at the lab presented in table 4.2 is almost identical to that of the cement factory in table 4.1. The cyclic gas injection was performed by first saturating the core with the condensate. A dry core was used to simulate the skin formation damage positioned next to the saturated core. N₂ flooding is performed to imitate the natural depletion behavior of the reservoir. Then the injection flue gas takes place and is allowed to soak for 4 hrs.

Table 1: Gas Composition from the Cement Factory

Parameter	Unit	Kiln Main stack
O_2	%	18.01
CO_2	%	11.33
N_2	%	70.66
CO	ppm	11.727
SO_2	mg/Nm ³	0.336
NO_x	mg/Nm ³	111.29
H_2S	mg/Nm ³	0
PM_{10}	mg/Nm ³	8.947
$PM_{2.5}$	mg/Nm ³	4.474

Table 2: Gas Prepared in the Lab

<i>Parameter</i>	Unit	Gas Prepared
<i>O₂</i>	%	18.01
<i>CO₂</i>	%	11.33
<i>N₂</i>	ppm	70.66

1.10.1 Core Samples

Four Bandera Gray Sandstone samples and four Indiana limestone cores of 5-inch length and 1.5 inches diameter used in the core-floods experiments. The Amott Harvey wettability index for Indiana with the Arabia medium oil was -0.15 which is neutral wet. For the same oil, the index with Bandera gray was +0.35 which is slightly water wet with the same oil.

Table 3: The Physical Properties of the Cores

<i>Core#</i>	Rock Type	Length (in)	Width (in)	Pore Volume (ml)	Bulk Volume (cm)³	Ø %	Average Permeability (md)
1	Indiana Limestone	5	1.5	19.1	144.2	13.4	60
2	Bandera Gray Sandstone	5	1.5	20.6	144.2	14.5	10
3	Indiana Limestone	5	1.5	22.9	144.2	15.9	32
4	Bandera Gray Sandstone	5	1.5	20.5	144.2	14.2	7
5	Indiana Limestone	5	1.5	22.1	144.2	15.3	19

6	Bandera	5		25.2	144.2	17.5	10
	Gray						
	Sandstone		1.5				
7	Indiana	5		24.5	144.2	16.6	9
	Limestone		1.5				
8	Bandera	5		31.9	144.2	21.6	19
	Gray						
	Sandstone						

1.10.2 Oil Type

Crude oil and condensate samples are obtained from Saudi Arabian oil reservoirs. A crude oil sample with measured viscosity of 15 cP and API gravity of 40°. The condensate sample measured viscosity was 2 cP and the API gravity was 30°. All measurement of viscosity and gravity was taken at atmospheric conditions.

Table 4: Oil Viscosity Table at Different Temperature

<i>Liquid</i>	<i>Temperature</i>	<i>Density</i>	<i>Viscosity</i>
		<i>g/cm3</i>	<i>mPa.s</i>
<i>Sample-A</i>	20	0.86844	15
	40	0.85424	7.7984
	60	0.83859	4.5257
	80	0.69576	2.9380
<i>Sample-B</i>	20	0.79672	2
	40	0.78135	1.41
	60	0.73782	1.04
	80	0.68278	0.797

1.10.3 Toluene

Toluene also called as toluol is an aromatic hydrocarbon. It is a colorless, water-insoluble liquid and it smells like paint thinners. This pure solvent was used during this experiment to clean the tubes and the core flooding system after each experiment.

1.10.4 Methanol

Methanol is a type of alcohol used in the experiments to clean the apparatus after the Toluene.

1.10.5 Deionized Water

Deionized water was used to supply the pumps. It was also used to clean the lines, tubes, and IFT equipment to prevent any impurity inside the cell.

1.10.6 Gas Cylinders

CO₂ gas cylinder of 700 psi pressure and zero air cylinder of 2000 psi was used to prepare the flue gases mixture in the lab.

1.11 Measurement of Core Properties

Measurement of porosity and permeability is important, especially for core flooding experiments. To perform these measurements, the dimensions of the core, dry weight, and wet weight of all cores should be known. After the core was saturated with oil the porosity and the pore volume were calculated.

Oil absolute permeability was determined by measuring the pressure differential across the core, the fluid viscosity, and flow rate. Darcy's Law was brought about by Henry Darcy, who derived an equation to relate the flow of a fluid through a medium as a function of length, cross-sectional area, pressure difference, the viscosity of fluid, and permeability of the medium. The equation for this is as follows:

$$Q = \frac{-KA\Delta P}{\mu L}$$

Where:

Q- flow rate in cc/sec

μ- viscosity in cp

L- length in cm

K-permeability

A-Area in cm²

ΔP- pressure difference in atm All of the above gives us the gas permeability value in Darcy.

1.11.1 Pore Volume Measurement

The calculation of the pore volume is carried out by measuring the dry core sample, and then 1 PV of crude oil is injected in the core at the pressure of 2000 psi. Next, this saturated core is weighted. Pore volume is then calculated by subtracting the dry weight from the wet weight. The density of the crude oil and condensate is measured using the viscometer.

1.11.2 Core Saturation

After the core was loaded into the core holder and the lines attached, the entire setup was subject to a vacuum, via the laboratory vacuum line, for approximately 12 hours. Then oil was allowed to enter the pores. Each core was saturated for 48 hours in a cell at 2000 psi and 80 C.

1.11.3 Core Loading

The core sample is placed carefully inside the core holder so that it doesn't break. Then, the confining pressure of 2000 psi is applied using the syringe pump. After ensuring that there is no leakage all lines inside the oven are fitted into the core holder.

1.11.4 Pressure Build-up

Initially, almost 1.5 PV was injected into the core at a different rate to measure the absolute permeability of the oil as well as saturating the core. The pressure builds up slowly up till it reaches 1000 psi because the backpressure was set at 1000 psi. The overburden pressure was increased to 2500 psi.

1.11.5 Heating

The temperature of the core flooding was set at 80 °C. It usually takes three hours for the core to reach that temperature and for the oil expansion effect to stop.

1.12 Equipment

1.12.1 Core-flooding experiment setup

The core holder used in this study to house cylindrical cores of up to 1.5-in diameter and approximately 14-in length. An annulus space existed between the casing and the sleeve and was used to apply a radial confining pressure using mineral oil. End-piece spacers were necessary to allow the 5-inch composite core to fit within the 12-inch core holder. Two spacers of 2-in each were placed at the front and back of the core, respectively. The end-caps and sleeve ensured complete isolation of the core from the confining mineral oil. The coreholder was placed in a vertical position. Pressure transducers were used to record the inlet and outlet pressures of the coreholder.

The injection system consisted of two ISCO syringe pumps, three accumulators and a variety of valves, and 1/8-inch diameter tubing. The higher capacity injection pump (260 mL) was used for the injection of the coreflooding fluids (oil, nitrogen, carbon dioxide) and connected to the accumulators. Three piston accumulators contain oil, nitrogen, and carbon dioxide. Two separate inlet lines were connected to the core holder, one for the nitrogen and carbon dioxide showing in the red line in the schematic in figure 8. The other line is set for the oil and connected as well to the core holder. The outlet is connected to the backpressure which is controlled by an ISCO pump. Pressure sensors are connected to a computer system.

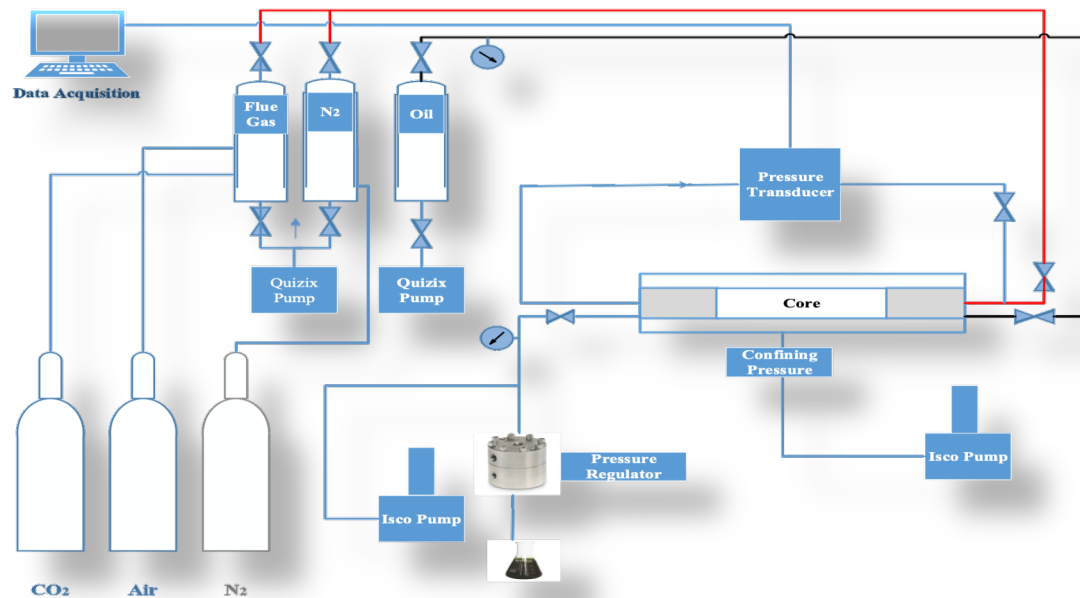


Figure 8: The schematic of the core-flood equipment used in the KFUPM petroleum laboratory.

1.12.2 SVM 3001 Viscometer

This equipment provides an accurate measurement of multiple parameters, including kinematic viscosity, viscosity index, density, dynamic viscosity, and more with a small sample volume. It was used to quantify the viscosity of oils used at different temperatures and atmospheric pressure. The viscometer was used is shown in figure 9.



Figure 9: SVM 3001 Viscometer Measures Viscosity at Different Temperature and Atmospheric Pressure.

1.12.3 Gas Chromatograph

Gas Chromatograph (GC Varian 3600) was used to ensure the accuracy of the composition of the prepared flue gas mixture. The Gas Chromatograph which analyzed the composition of the gas is shown in figure 10.



Figure 10: Gas Chromatograph.

1.12.4 Drop Shape Analyzer

Initially, this equipment should be cleaned very carefully to ensure accurate measurement of IFT. The U-shaped needle and the syringe were cleaned with toluene followed by methanol and water. Next, we should test the accuracy of the pendant drop equipment by calibrating with the measurement of the IFT of the deionized pure water /air system to verify that the value of 70.26 mN/m is obtained. The crude oil sample is then loaded into the IFT equipment. The volume of the droplet has to be large enough to measure an accurate IFT value, but the volume of the drop should be controlled carefully by the motor

control so that it keeps hanging in the tip of the needle. The drop shape analyzer equipment is shown in figure 11.



Figure 11: Drop shape analyzer.

1.12.5 Quizix Pump

This pump was utilized to inject the liquids inside the core sample in the core-flooding experiments. It has the capability to inject fluid at different rates ranging between 0.001 cm³/min to 60 cm³/min at various injection pressures that can reach to 7000 psi (48.26 MPa). This pump contains two barrels that can either operate individually or as a pair to provide a continuous flow. This pump work using software called “Pump Works” and can be adjusted by connecting it to a computer using a USB port. Based on the required

injection mode, the proper mode can be loaded. The Quizix Pump used in the experiment is shown in figure 12.



Figure 12: Quizix Pump.

1.12.6 Syringe Pump

Different series of TELEDYNE ISCO syringe pumps with different pressure and injection limits were used during the experiments. It was used to apply the confining pressure on the core holder as well as the pore pressure. The pump uses deionized water for the confining pressure. Figure 13 shows a TELEDYNE ISCO syringe pump and controller used in the experiments.



Figure 13: TELEDYNE ISCO Syringe Pump and Controller.

1.12.7 Back Pressure Regulator

As shown in figure 14, a Back Pressure Regulator (BPR) system was used to maintain the pressure at the outlet of the core holder and was set at 1000 psi for all the experiments.

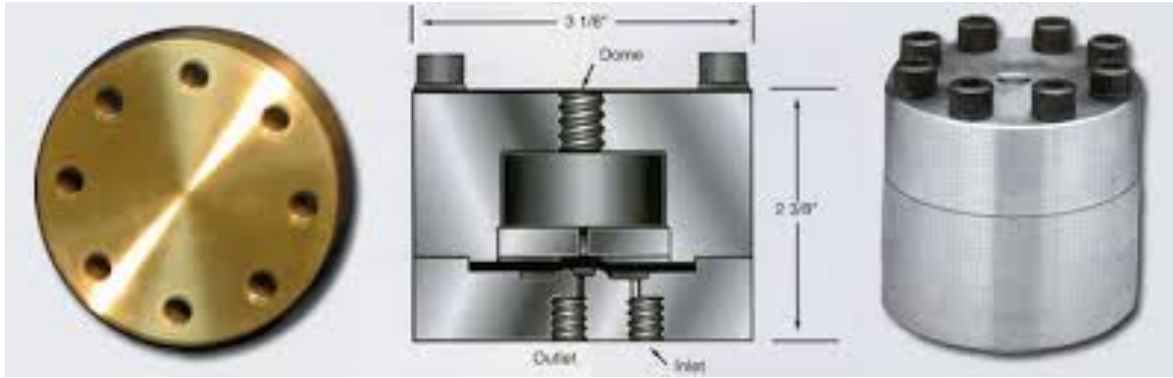


Figure 13: Backpressure Regulator.

1.13 Methodology

1.13.1 Experimental Process

A total of 8 core flooding experiments were carried out as shown in Table 4. For the comparison of the cyclic gas injection process efficiency, experiments with continuous gas injection–CGI and cyclic gas injection were performed. The studies were conducted at a reservoir temperature of 80 °C and a reservoir pressure of 1000 psi.

Table 4: Experiment process

<i>Experiment #</i>	<i>1</i>	<i>2</i>	<i>3</i>	<i>4</i>	<i>5</i>	<i>6</i>	<i>7</i>	<i>8</i>
<i>EOR Process</i>	Continuous injection (1-4)				Cyclic injection (5-8)			
<i>Injection Rate (ml/min)</i>	1	1	0.3	0.3	0.3	0.3	0.3	0.3
<i>Rock Type</i>	IL	BG	IL	BG	IL	BG	IL	BG
<i>Hydrocarbon Sample</i>	A	A	A	A	A	A	B	B

1.13.2 Flue Gas Preparation

Flue gas used was typical of the cement industry. The mass of CO₂ and nitrogen to give the desired composition of flue gas given the volume (of the transfer vessel) and target pressure was determined. The determined mass of CO₂ was transferred first into the transfer vessel at 100 psi, then nitrogen was transferred next and pressurized to the target pressure which is 1000 psi. The prepared mixture was then analyzed using a Gas Chromatograph (GC Varian 3600) to ensure the accuracy of the composition of the prepared flue gas mixture. The gas samples collected from the test cell were analyzed for composition using a GC Varian 3600. The carrier gas is Helium, and the detector type is TCD (Thermal Conductivity Detector). The TCD measures the variations in the thermal conductivity of the effluent gas from the column of the GC and compares it to that of the reference flow of carrier gas (helium). The column temperature was set constant at 323 K for 10 minutes during which 3 injections were made and thereafter ramped up to 378 K for one minute at the rate of 323 K/min to vaporize the content of the column. To accurately quantify the proportion of each component of the vapor phase of the test cell at any instant, the GC was calibrated. Known volumes (100 μ L, 200 μ L, 300 μ L, 400 μ L), and consequently the moles of pure components (nitrogen, carbon dioxide, and methane) were injected into the GC. This gave their signature chromatograms, retention times, and their corresponding peak areas. The moles of each component at the different volumes were then plotted against their corresponding peak areas to obtain their calibration curves and equations as shown in figure 14. The equations are then used to estimate the relative amount of their corresponding components in the vapor phase. When summed together, the proportion of

each component of the vapor phase in relation to the total of all the components can be estimated.

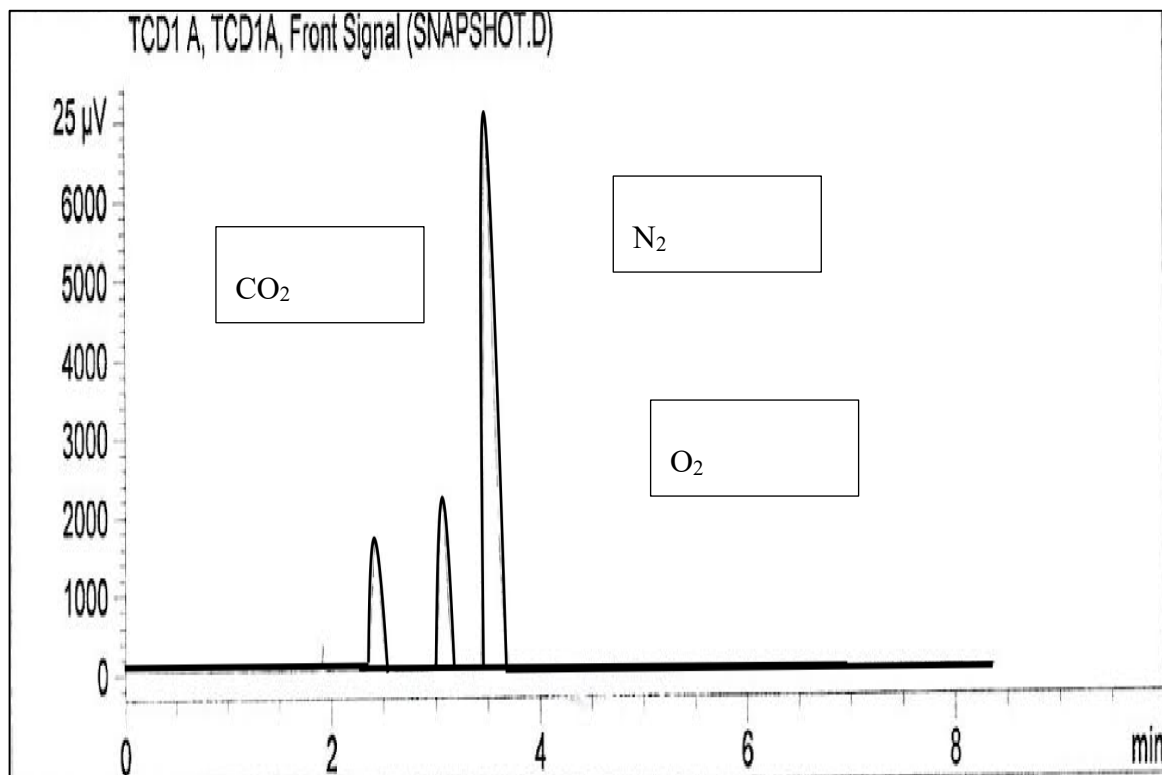


Figure 14: Chromatogram of a gas mixture containing nitrogen, methane, and carbon dioxide.

Result and Discussion

Flue gas injection application is expected to improve oil recovery by reducing oil viscosity and other enhancement mechanisms. Different mechanisms can be involved depending on the degree of miscibility between the displacing fluid and displaced fluid. Generally, the gas-oil capillary forces reduce with increasing pressure, and only when it is reduced to zero, miscibility is reached. It is ought to be a feasible and environmentally friendly technique.

1.14 Results of Continuous Flue Gas Injection

Each experiment was conducted by injecting N_2 to depict the natural depletion followed by the flue gas as a tertiary recovery process. The N_2 immiscible flooding was performed to examine the effectiveness of flue gas by relatively comparing pressure profile and recovery. The incremental increase in oil recovery by the flue gas, support the attribution for other mechanisms of displacement such as IFT decrease and wettability alteration. Different rock and fluids parameters effect were investigated such as permeability, wettability, IFT, and oil type.

In the first experiment, the continuous core flooding method was performed on an Indiana limestone core with a constant injection rate of 1 cc/min and the permeability is 60 md.

Figure 15 present the oil recovery of the original oil in place with the pressure profile across the core. The breakthrough for the N₂ delayed after 0.7 PV was injected, this is attributed to the wettability of the limestone rock (neutral-wet). The pressure difference increased in the early stage of flooding, then stabilized at 4.5 psi. The total recovery reached around 27 % OOIP.

The injection of flue gas slightly increased the recovery up to 4% of OOIP. An early breakthrough was observed after 0.3 PV was injected; this implies that a high mobility ratio results in an early breakthrough of injected gas. The pressure stabilized at a lower pressure than the primary recovery showing an indication that the flue gas achieved some degree of success in mobilizing residual oil. This also could prove viscosity reduction of oil which in return caused a slight decrease in the pressure stabilization. Figure 16 depicts multiple increases in the pressure, we speculate that this might be due to viscous fingering in the porous media.

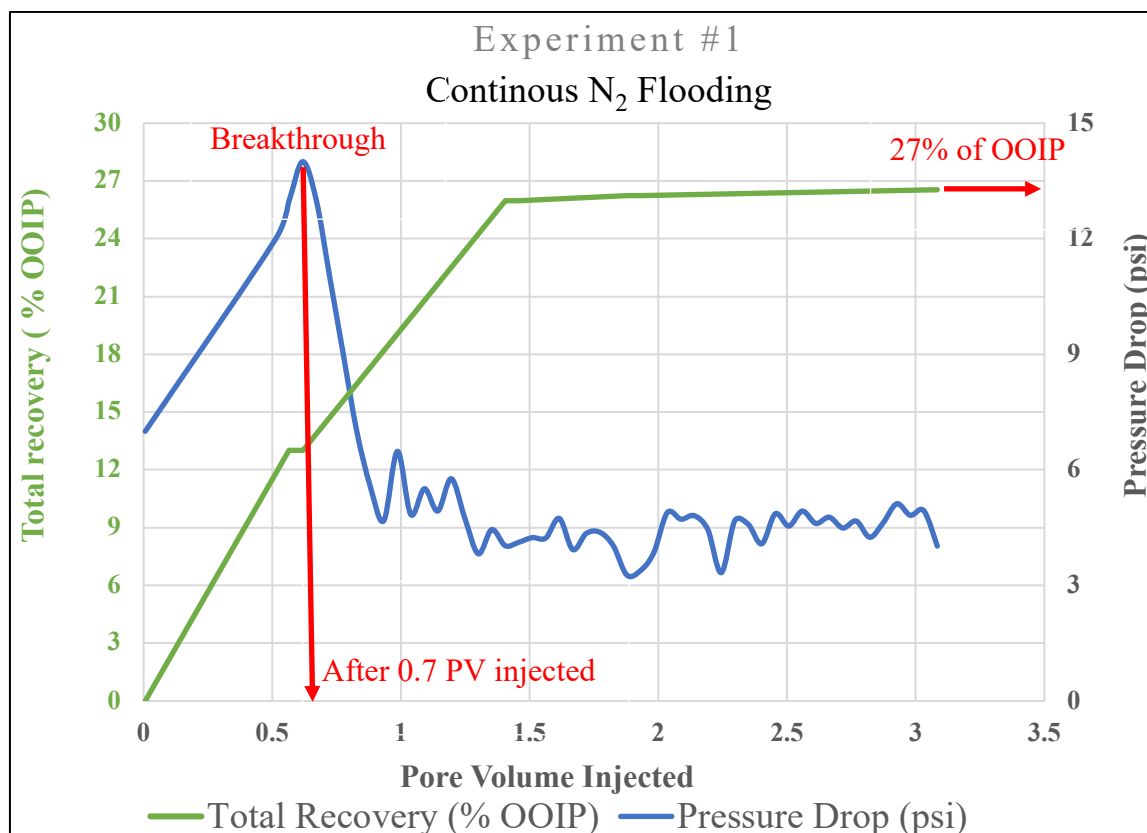


Figure 15: Profiles of oil recovery, inlet and outlet pressures for N₂ flooding Indiana Limestone core (Permeability: 60 md).

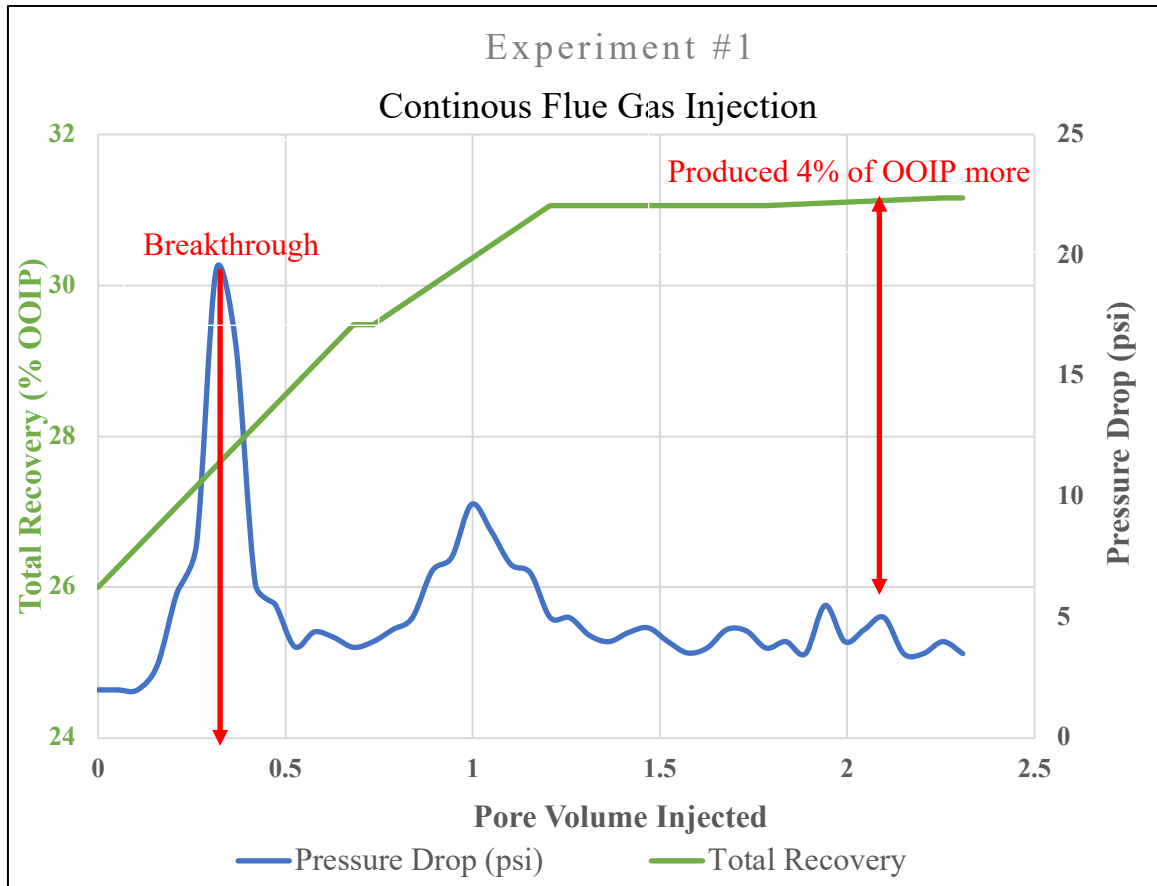


Figure 16: Profiles of oil recovery, inlet and outlet pressures for Flue gas flooding Indiana Limestone core (Permeability: 60 md).

In experiment-2 coreflood with continuous injection mode was performed on Bandera Gray sandstone with a constant injection rate at 1 cc/min. The permeability of the core sample is 10 md. The total recovery from the N₂ flooding reached around 25% (of OOIP) as shown in figure 17. In addition, it can observe that an early breakthrough occurred after only 0.3 PV injected. We propose that this might be due to the large capillary pressure which lowered the oil density and encouraged the early breakthrough. It is worth mentioning that, unlike, what happened in the limestone rock the recovery continued after breakthrough and eventually reached stabilization at 15 psi.

The recovery from the flue gas flooding for the same rock is 8% of OOIP. It is notable that this good performance was due to two reasons. First, this type of rock is known to exhibit slightly water-wet behavior, thus, more favorable wettability condition as to Indiana limestone. Second, the low permeability allowed for a longer time for the displaced fluid and displacing fluid to interact together. Figure 18 presents the oil recovery with the pressure profile across the core. For the flue gas, the differential pressure stabilized at a lower value around 10 psi, this can only be attributable to the fact that partial miscibility between the flue gas and the oil was reached. Figure 18 also shows the multiple increases of the pressure drop confirming the viscous fingering that is caused by the low relative permeability between the two fluids.

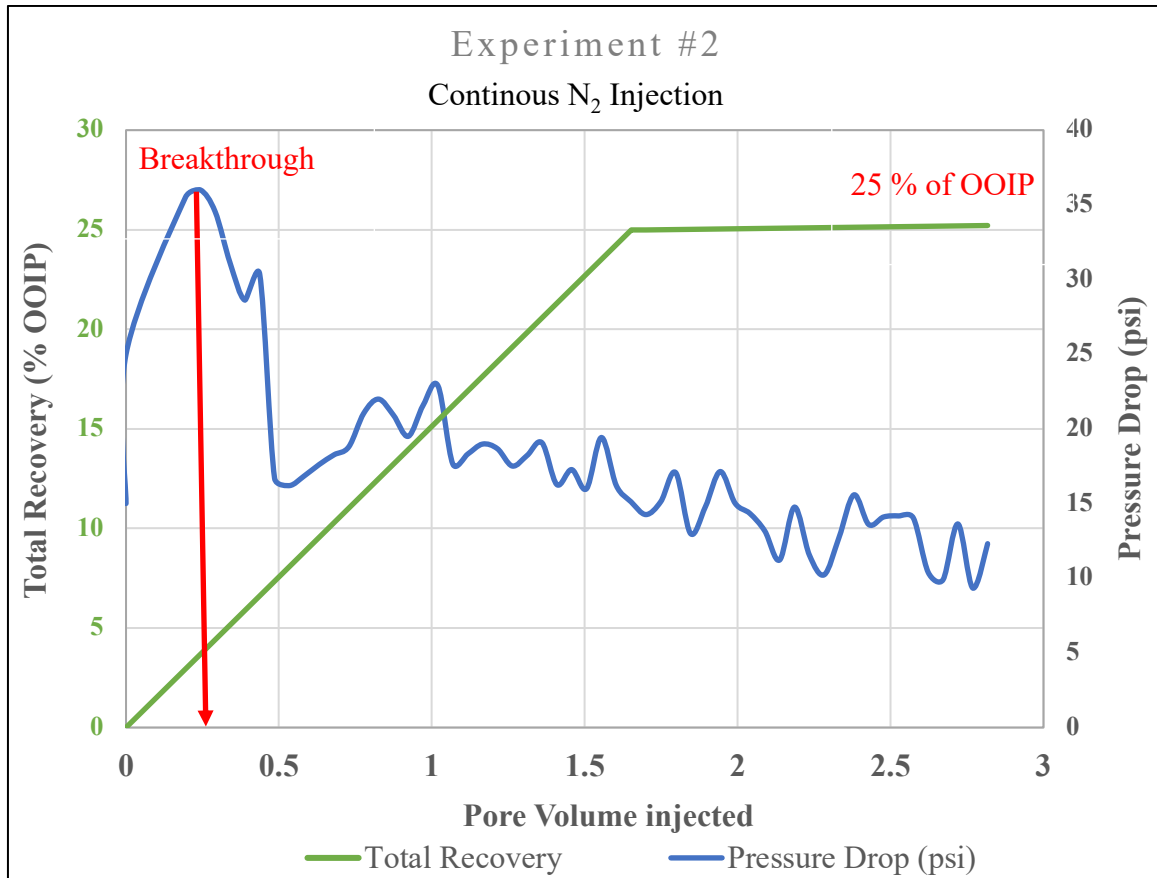


Figure 17: Profiles of oil recovery, inlet and outlet pressures for N₂ flooding sandstone (Permeability: 10 md).

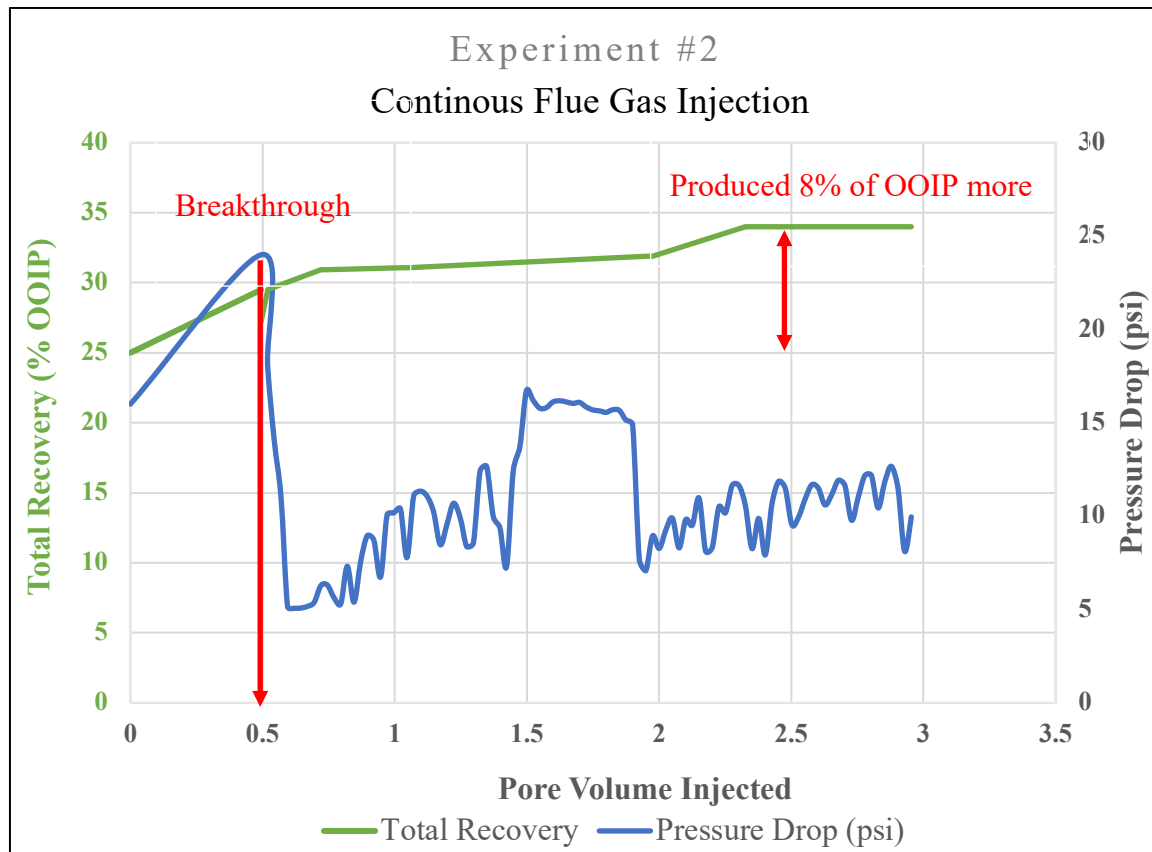


Figure 18: Profiles of oil recovery, inlet and outlet pressures for Flue gas flooding sandstone core (Permeability: 10 md).

Experiment-3 of continuous flue gas injection is done on an Indiana limestone core with a lower permeability (19 md) and lower injection rate at 0.3 cc/min. The injection of N_2 yielded a lower recovery and the sweep efficiency was considerably poor when compared with the same rock type at higher permeability and injection rate as shown in Figure 19. This could be explained by the very early breakthrough encountered and the gas override. This is also consistent with the concept of capillary forces which increases in lower permeability.

Comparing the pressure profile of flue gas injection shows that when the permeability is low due to high capillary forces the gas finds a way out. Figure 20 shows a very low oil

recovery contribution of around 1% of OOIP. The total recovery is less than what we produced from the same rock type at a higher rate and permeability. This shows that the Indiana rock favors higher permeability and injection rate to delay breakthrough.

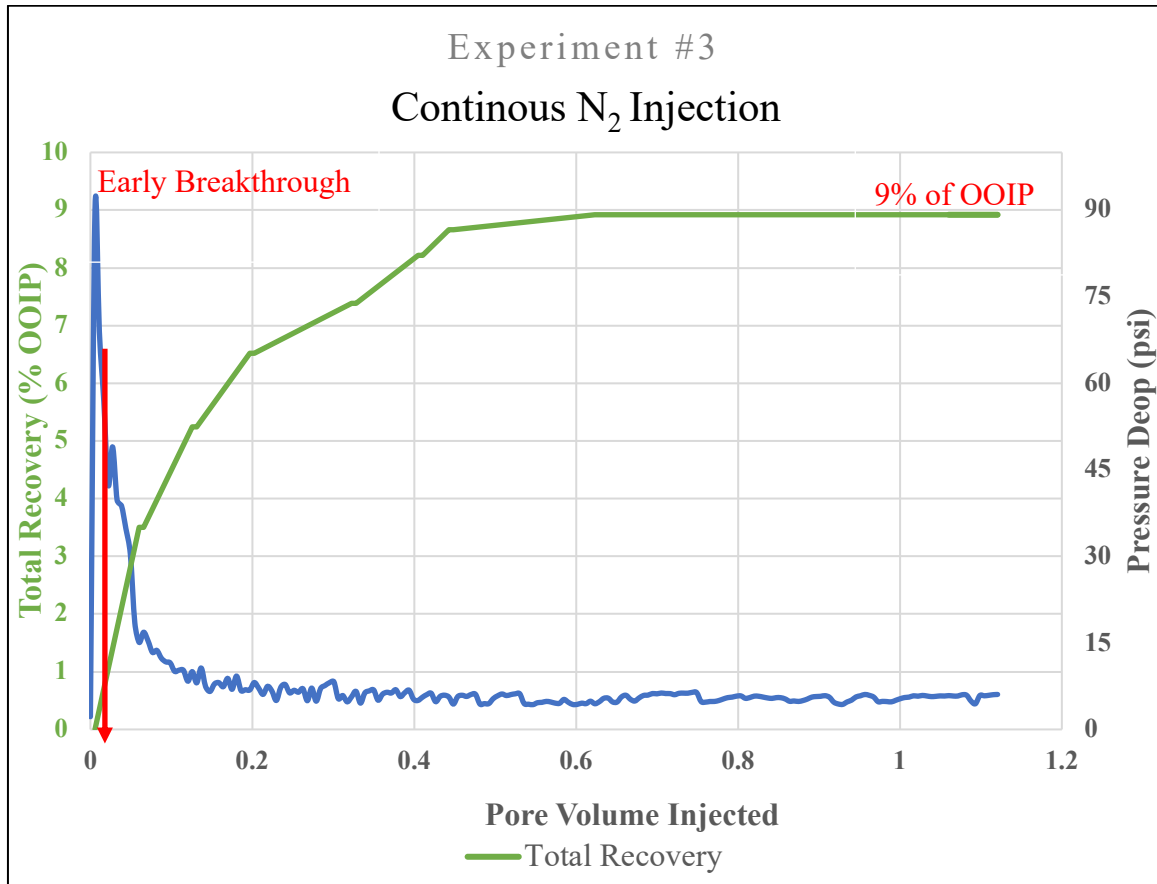


Figure 19: Profiles of oil recovery, inlet and outlet pressures for N₂ flooding Indiana Limestone core (Permeability: 32 md).

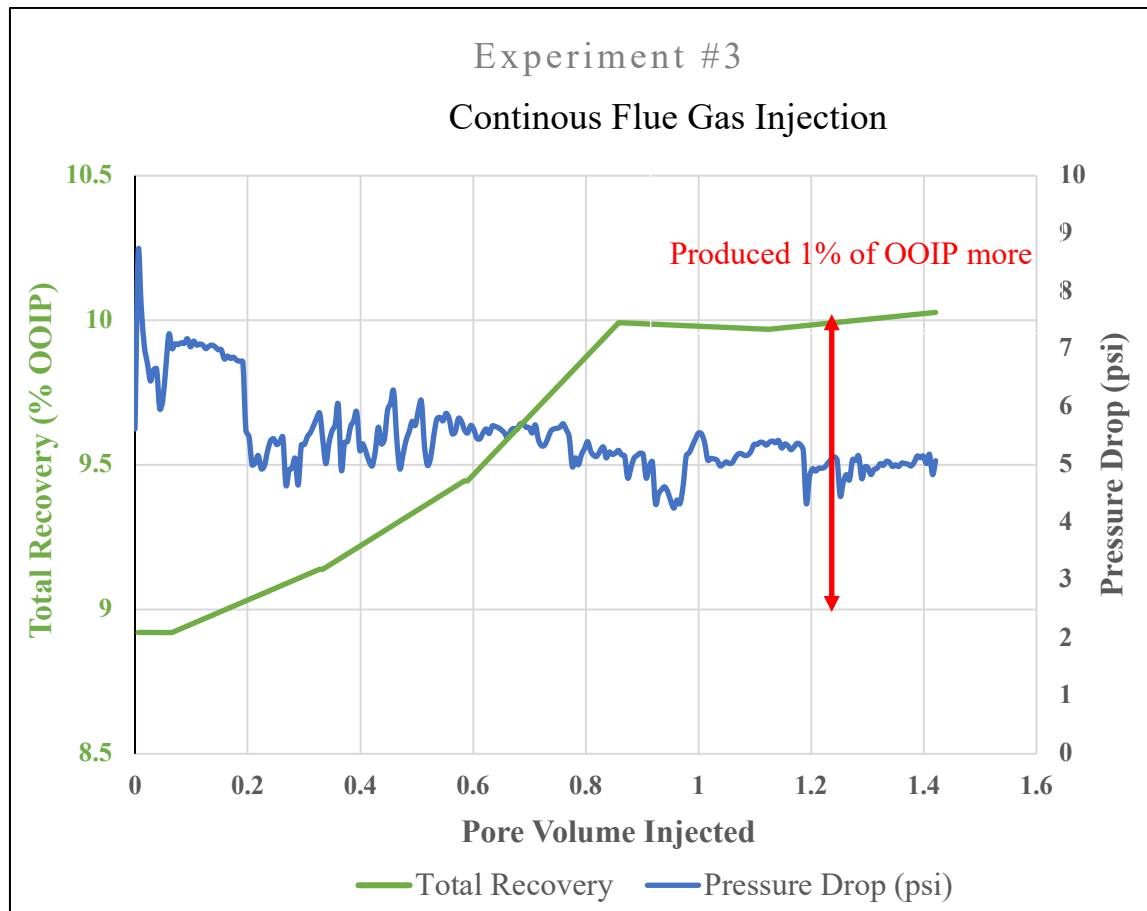


Figure 20: Profiles of oil recovery, inlet and outlet pressures for Flue Gas flooding Indiana Limestone core (Permeability: 32 md).

Experiment-4 was performed on Bandera gray sandstone rock with the permeability of 7 md. The result shows more oil recovery for the N_2 immiscible displacement and this can be explained by the lower injection rate which results in lowering the mobility ratio. It shows that N_2 flooding performs better with lower permeability for the sandstone as shown in figure 21.

This type of sandstone is slightly water wet and performs better when the permeability and injection rate is lowered with N_2 . From the N_2 injection we produced almost 28% of OOIP and 5% of OOIP came out from the flue gas injection as shown in figure 22. These results

support the conclusion that the rock wettability has a significant effect on the optimization of the continuous flue gas injection rate as well as the permeability.

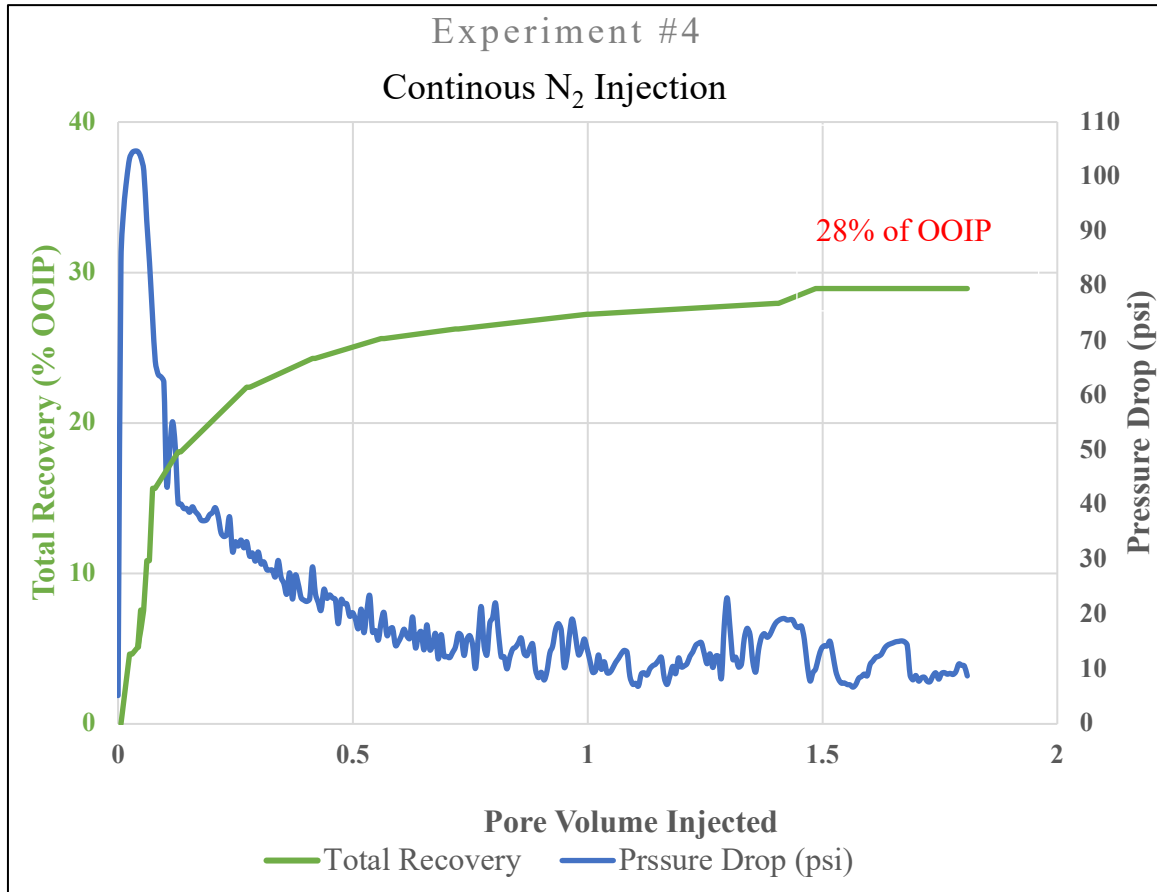


Figure 21: Profiles of oil recovery, inlet and outlet pressures for N₂ flooding sandstone core (Permeability: 7 md).

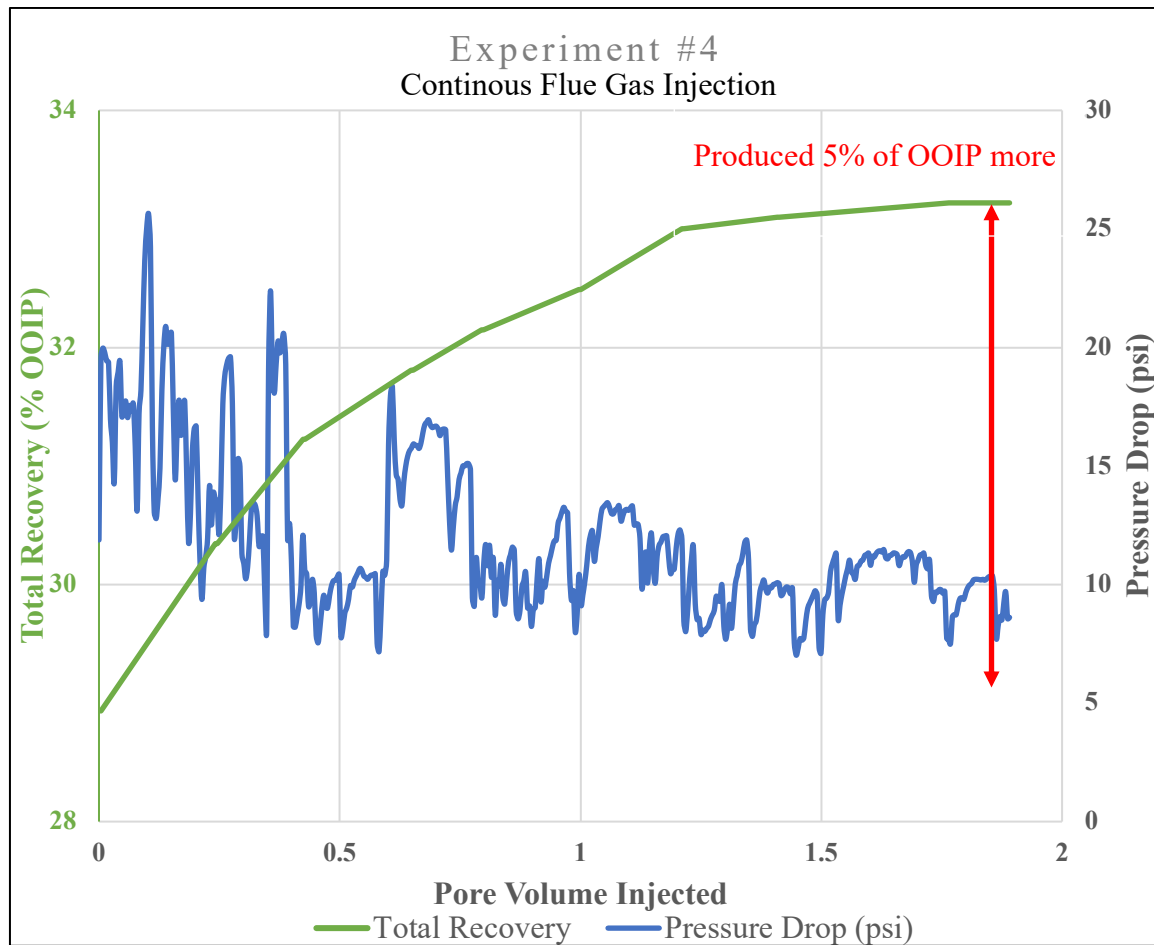


Figure 22: Profiles of oil recovery, inlet and outlet pressures for Flue gas flooding sandstone core (Permeability: 7 md).

1.15 Results of Cyclic Flue Gas Injection

As compared to continuous flooding, Huff and Puff is the recommended method, as this method has several advantages and removes the problems associated with continuous flooding. Firstly, continuous flooding has the issues of conformance control whereby the gas can break through the producer well as this is obviated by the Huff and Puff injection. Secondly, there is a lot of operational flexibility which this method of huff and puff renders and hence this makes this technique successful.

Figure 23 presents oil recovery, inlet pressure, and outlet pressure as a function of time for the fifth experiment. The core is Indiana limestone the permeability is 19 md. In this case, the oil being used is a medium viscosity oil (15 cp @ 20 C). It can be seen from this figure that, the ultimate recovery is 33% of OOIP which is distributed as follows: 20% of OOIP produced from the first cycle, 9% of OOIP produced from the second cycle, and 4% of OOIP from the third cycle. However, the soaking period for each cycle was four hours with the increase in the total amount of Gas injected, as well as the number of cycles, the recovery factor is seen to increase. the amount of oil recovered increases significantly during the initial cycles and thereby the increase in the total oil recovered rate gradually decreases over time with increasing cycles. The injected gas in each cycle substitute for the pressure loss due to volume decrease. The Huff 'n' Puff mode proved to be an outstanding process to produce oil.

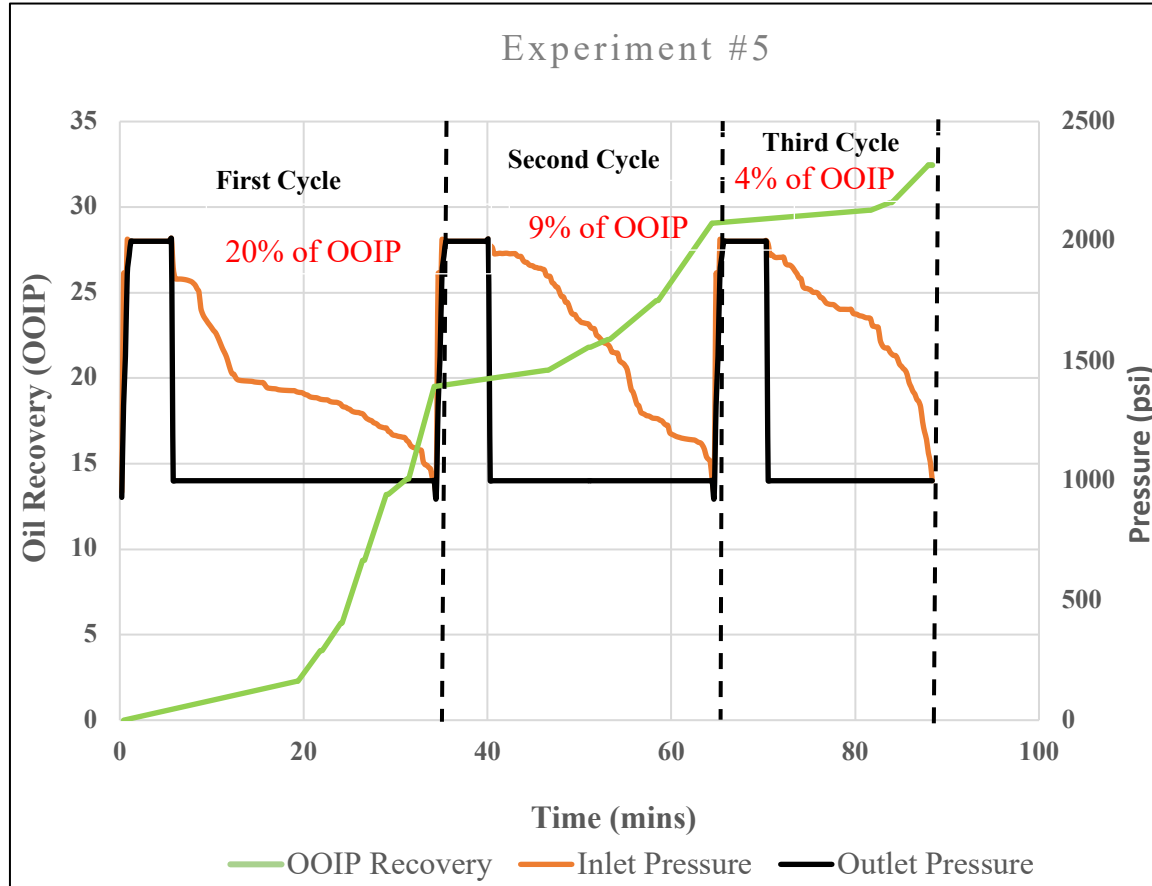


Figure 23: Profiles of oil recovery, inlet and outlet pressures for huff and puff mode.

In figure 24 the oil recovery, inlet pressure, and outlet pressure presented as a function of time for the sixth experiment. In this case, the same medium oil viscosity is used but the core is a lower permeability 10 md sandstone. It can be seen from this figure that, the ultimate recovery is 45% of OOIP which is distributed as follows: 38% of OOIP produced from the first cycle, 6% of OOIP produced from the second cycle, and 1% of OOIP from the third cycle. It performed better than the Indiana Limestone, because of the lower permeability which allowed better interaction between the flue gas and the oil.

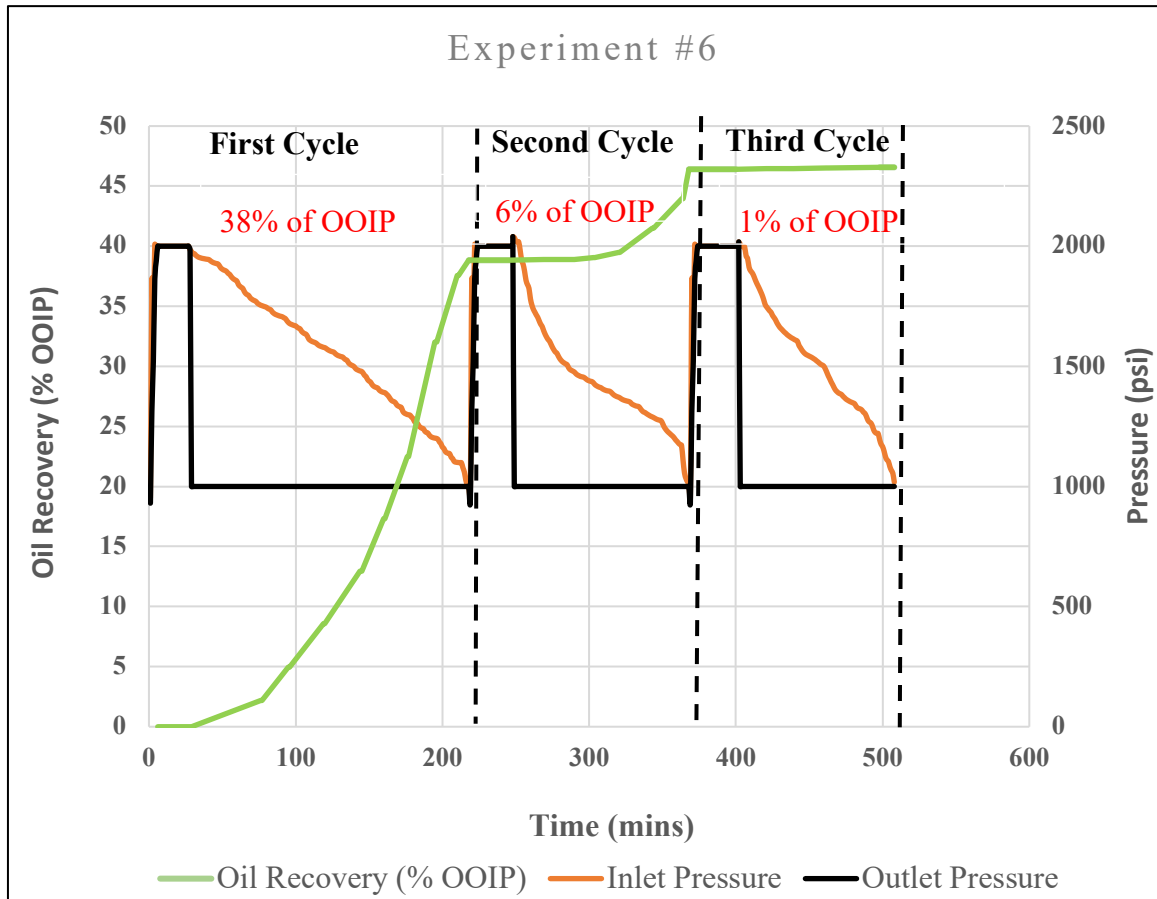


Figure 24: Profiles of oil recovery, inlet and outlet pressures for huff and puff mode.

Figure 25 shows that with the condensate, the cyclic method works very great especially with Indiana limestone. The total recovery is 80% of OOIP which is distributed as follows: 60% of OOIP produced from the first cycle, 17% of OOIP produced from the second cycle, and 3% of OOIP from the third cycle. It is presumed the good performance was a result of the low permeability and the lower viscosity of condensate which may have led to some degree of miscibility. This could be also due to the miscibility effect as the pressure

reached 2000 psi, we expect miscible fluid or near miscible. The total recovery is 80 % OOIP which proves the effectiveness of flue gas in this method.

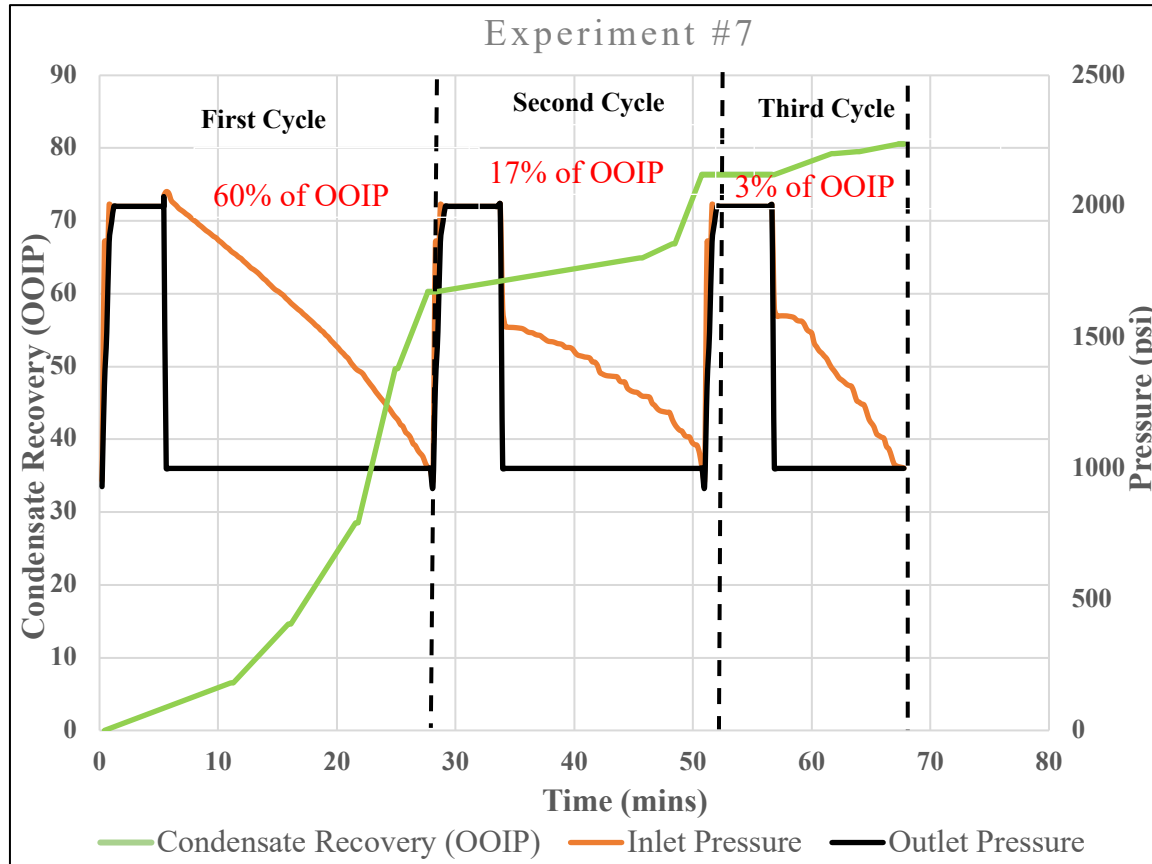


Figure 25: Profiles of oil recovery, inlet and outlet pressures for huff and puff mode.

Figure 26 shows that with the condensate, the cyclic method works very great especially with Indiana limestone. The total recovery is 70% of OOIP which is distributed as follows: 48% of OOIP produced from the first cycle, 19% of OOIP produced from the second cycle, and 3% of OOIP from the third cycle. The recovery was lower than the previous experiment, this may be due to the higher permeability of this core. It can be also observed that the pressure drop behavior for each cycle, it drops faster in each cycle. This is because of lower residual oil after each cycle

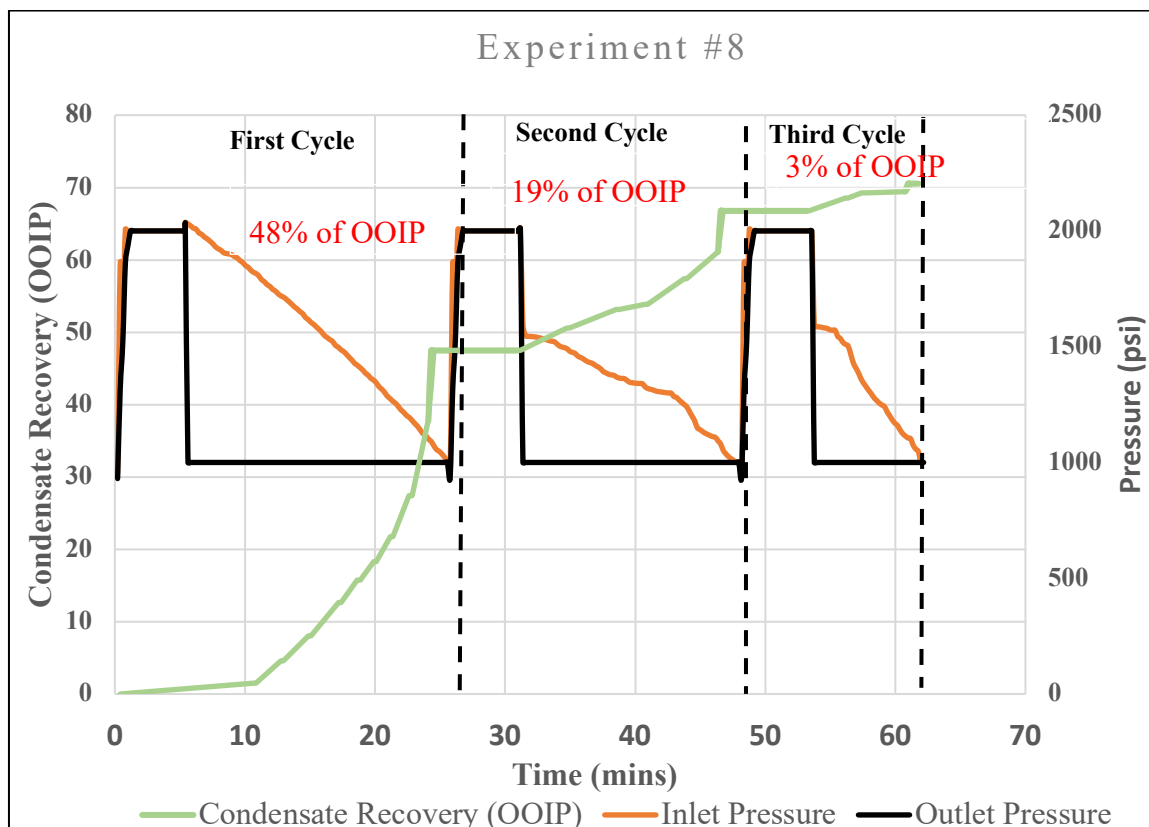


Figure 26: Profiles of oil recovery, inlet and outlet pressures for huff and puff mode.

1.16 IFT of the Oil and the Flue gas

The flue gas/oil IFT measurements were investigated at different pressures and temperatures for the two oil samples (crude oil: 30° API, condensate: 40° API). The IFT measurement was done to assess the interaction of the flue gas with crude oil and condensate. The pendant drop method was chosen to measure the gas-oil interfacial tension at high pressures and high temperatures.

For the measurement of IFT, it is required to have the densities of the phases under condition. In this work, the densities of the crude oil and condensate are obtained using the densitometer as shown in the table below. Even though oil density (dead oil) does not change much as a function of pressure, the densities for different values of pressure were determined. Tables 5 & 6 show the oil density as a function of temperature and pressure. For oil density determination, the Standing–Katz method was used.

Table 5: Crude oil density as a function of temperature/pressure

TEMPERATURE (°F (°C))	PRESSURE (PSI)	ΔP_P	ΔP_T	OIL DENSITY (LB/FT ³)	OIL DENSITY (G/CM3)
(86 °F (30 °C))	14.7	0	0.31	53.75	0.861
	200	0.04	0.31	53.79	0.862
	400	0.05	0.31	53.84	0.862
	600	0.1	0.31	53.94	0.864
	800	0.15	0.31	54.09	0.866
	1000	0.2	0.31	54.29	0.870

	1200	0.25	0.31	54.54	0.874
	1400	0.3	0.31	54.84	0.878
	1600	0.35	0.31	55.19	0.884
	1800	0.4	0.31	55.59	0.890

Table 6: Condensate density as a function of temperature/pressure:

TEMPERATURE (°F (°C))	PRESSURE (PSI)	ΔP_P	ΔP_T	OIL DENSITY (LB/FT³)	OIL DENSITY (G/CM3)
(86 °F (30 °C))	14.7	0	0.52	49.26	0.789
	200	0.06	0.52	49.27	0.789
	400	0.08	0.52	49.35	0.790

600	0.15	0.52	49.5	0.793
800	0.2	0.52	49.7	0.796
1000	0.23	0.52	49.93	0.799
1200	0.28	0.52	50.21	0.804
1400	0.35	0.52	50.56	0.809
1600	0.4	0.52	50.96	0.816
1800	0.45	0.52	51.41	0.823

The density of the flue gas is determined using correlation. The compressibility factor was calculated by Brill and Beggs' correlation at respective pressure and temperature for the density of the flue gas as shown in Table 5. Taking into account that oil density (dead oil) does not change much as a function of pressure, the oil density at atmospheric pressure was used.

Table 7: Flue Gas (11.33% CO₂, 70.66% N₂ and 18.01% O₂) Density as a Function of
Pressure at 86 °F (30 °C)

PRESSURE (PSI)	P_{PR}	T_{PR}	Z	GAS MIXTURE DENSITY (LB/FT³)	GAS MIXTURE DENSITY (G/CM³)
14.7	0.02446165	2.00116463	0.999033	0.05187764	0.000831
200	0.33281162	2.00116463	0.989809	0.71249	0.011413
400	0.66562323	2.00116463	0.981357	1.437279	0.023023
600	0.99843485	2.00116463	0.973655	2.172992	0.034808
800	1.33124646	2.00116463	0.9666	2.918445	0.046749
1000	1.66405808	2.00116463	0.96023	3.672262	0.058824
1200	1.99686969	2.00116463	0.954624	4.432572	0.071003
1400	2.32968131	2.00116463	0.949877	5.19719	0.083251

1600	2.66249292	2.00116463	0.946079	5.963493	0.095526
1800	2.99530454	2.00116463	0.943315	6.72861	0.107782

The interfacial tension between the system of either crude oil or condensate with flue gases at a different range of temperature was determined using the pendant drop method. To determine the IFT the flue gas (lighter phase) is introduced in the visual cell as a bulk phase and a drop of the oil (denser phase) is introduced in the bulk phase through a needle using a syringe pump. The pressure and temperature of the system are kept constant at specific conditions during the measurement. The procedure adopted in the experiment is to inject the flue gas into the visual cell at a specific pressure and then the temperature of the system is raised to the desired value. Once the system temperature is reached to desired value the pendant drop (oil drop) was introduced in the system. The system is allowed to have sufficient time for the equilibrium and then IFT data was recorded using the inbuilt set of software instruction. The system is capable of recording the pressure, temperature, the density of phases, the video of the drop, and the corresponding IFT value. Then the temperature is raised to the desired value and then drop was introduced in the system and the IFT value is acquired. The procedure is repeated for all the measurements for the range of temperature and pressure for the crude oil and condensate sample.

The shape and size of the liquid droplet for both oil samples are captured by the digital video camera. Figure 27 shows the drop shape analysis of the crude oil and flue gas system

at different pressure and temperature conditions. It can be seen in figure 28 the drop shape changes as a function of pressure and temperature. The size of the drop becomes smaller in size as system pressure increases however there is a slight decrease in the drop size with an increase in the system temperature. The results in the shape of the drop size as a function of temperature and pressure are reflected in terms of IFT. At constant temperature, the IFT of the system decreases with an increase in pressure. On the other hand, at constant pressure, the IFT value of the system slightly decreases with an increase in temperature. Similar, effects were observed for the condensate and flue gas as shown in figure 30. However, the shape and size of the condensate appear to be relatively small as compared to the crude oil suggesting that IFT for the condensate and flue gas is comparatively smaller in magnitude with crude oil and flue gas system.

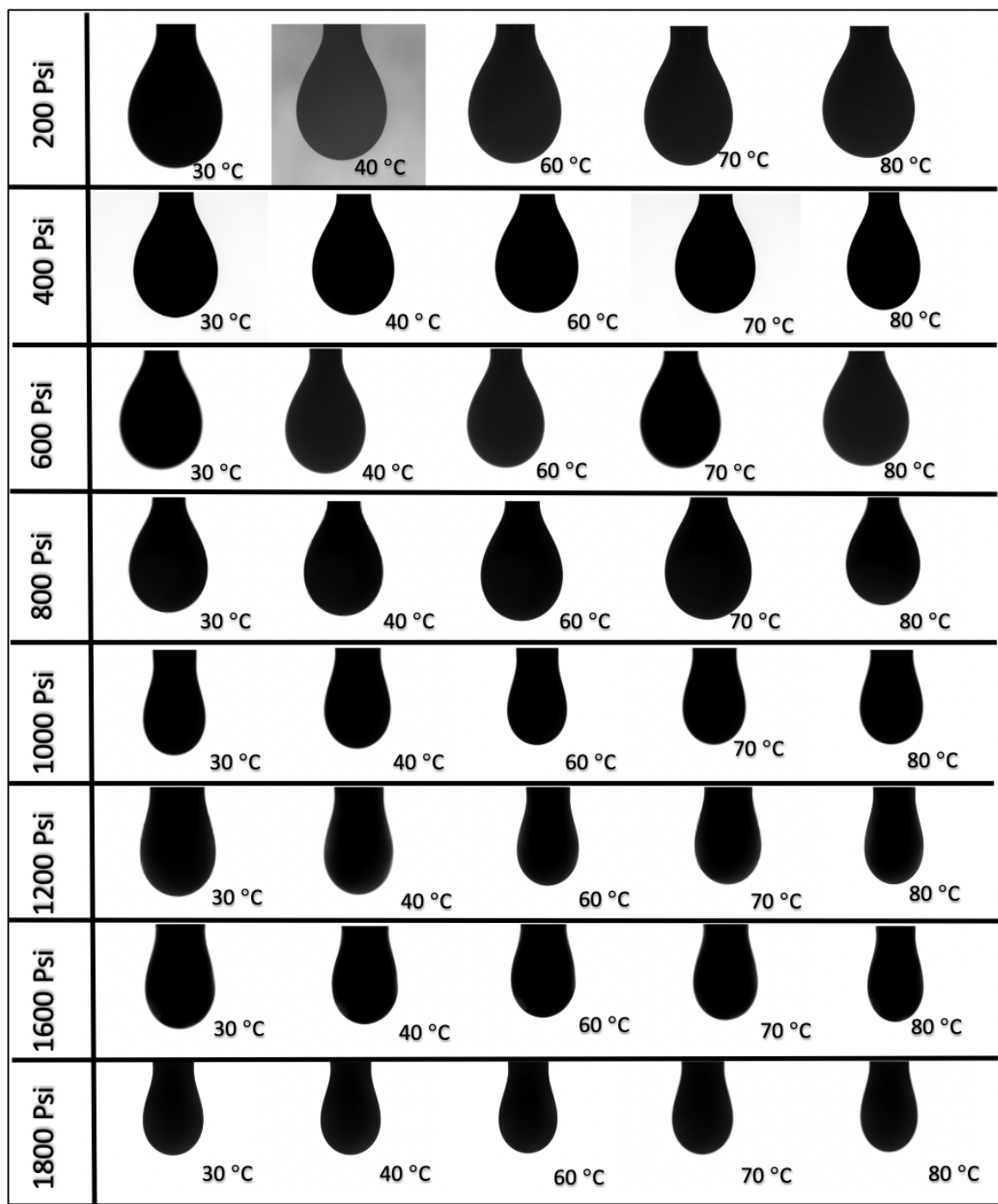


Figure 27: Pendant drop shape at various pressure and temperature for the flue gas and the crude oil.

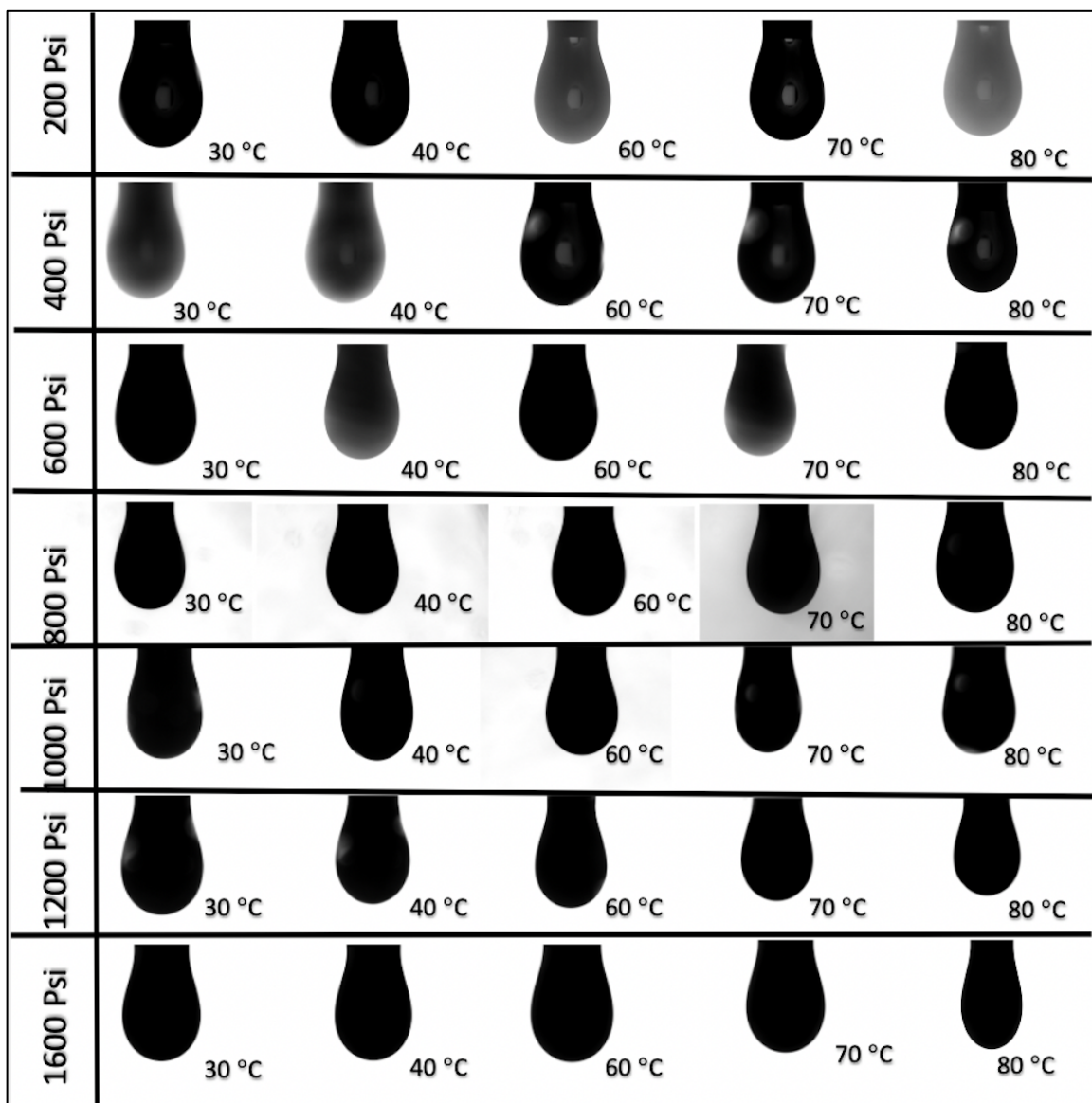


Figure 28: Pendant drop shape at various pressure and temperature for the flue gas and the condensate.

The results of the IFT measurements are plotted as a function of temperature and pressure. As shown in figure 29 five curves are representing the IFT of the crude oil as a function of pressure for a temperature of $T = 20\text{ }^{\circ}\text{C}$, $T = 40\text{ }^{\circ}\text{C}$, $T = 60\text{ }^{\circ}\text{C}$, $T = 70\text{ }^{\circ}\text{C}$ and $T = 80\text{ }^{\circ}\text{C}$ respectively.

Despite the fact that IFT trends concerning pressure for both crude oil and condensate samples, the rate of IFT variation at each specific pressure, $[(IFT_{P2} - IFT_{P1}) / (P_2 - P_1)]$, is not the same. It is observed the rate of IFT variation decreases at higher pressure. In other words, the effects of pressure on IFT are less profound at higher pressure. To address the effects of temperature figures 27 and figure 28 provide clues by comparing the droplet shape and size. The IFT decreases slightly with increases in temperature, which might be due to gas evolution from the liquid phase; however, the temperature effect is not significant.

Similar trends were observed for the condensate and flue gas system as shown in figure 30. Even though the magnitude of the IFT is comparatively less compared to the crude oil and flue gas system indicating the mutual solubility of the condensate and flue gas is more favorable in comparison to the crude oil considered in this study. The IFT values of the crude oil and flue gas and condensate and flue gas are shown in Figures 29 and 30 respectively.

Table 8: IFT values for the crude oil at different pressure and temperature

Temperature (°C)	Pressure (psi)	Gas Density (g/cm ³)	IFT [mN/m]
30	200.1	0.85858681	23.5148055
	387.15	0.84697702	22
	598.85	0.83519233	21.2017755
	803.3	0.82325106	20
	977.3	0.81117615	19.8826836
	1203.5	0.79899689	19.5
	1394.9	0.78674901	19
	1677.65	0.76221849	18.8
40	210.25	0.85896452	23.3274599
	401.65	0.84777196	21.7259857

	598.85	0.83644964	21.1855657
	800.4	0.82501782	20.051066
	975.85	0.81349817	19.3685583
	1220.9	0.80191577	18.9
	1423.9	0.79029963	18.8
	1667.5	0.76710016	18.7
60	217.5	0.85964814	23
	413.25	0.84919578	21.4888552
	616.25	0.83867641	21.2323142
	806.2	0.82811321	19.6117028
	1029.5	0.81752688	19.0035016
	1290.5	0.8069379	18.6180724

	1493.5	0.79636736	18.4
	1696.5	0.77537048	18.3
70	229.1	0.85995887	22.0679894
	424.85	0.84983674	20.9574239
	620.6	0.83966746	20.2331837
	804.025	0.82947472	19.2048692
	1051.25	0.81927897	18.8
	1329.65	0.80909944	18.1093029
	1329.65	0.80909944	18.1093029
	1551.5	0.79895506	18
	1692.15	0.77884763	17.9
80	234.9	0.86025157	21.7785207

	439.35	0.8504371	20.6492783
	630.75	0.84058867	19.8587864
	797.5	0.83072942	19
	1080.25	0.82087915	18.7
	1363	0.81105596	17.8357647
	1573.25	0.80127713	17.5
	1684.9	0.7819192	17.5

Table 9: IFT values for the condensate at different pressure and temperature

Temperature	Pressure (psi)	Gas Density (g/cm ³)	IFT [m/Nm]
30	200	0.78858681	22
	400	0.78896452	21.2
	600	0.78964814	21
	800	0.78995887	19.9
	1000	0.79025157	18.5
	1200	0.78858681	17.5
	1600	0.78896452	17.6
40	205	0.01103548	21.8
	405	0.02222804	21
	605	0.03355036	20.8

60	805	0.04498218	19.5
	1005	0.05650183	17.3
	1205	0.06808423	17.1
	1605	0.09131754	16.8
	210	0.01035186	20.8
	410	0.02080422	20.2
	610	0.03132359	19.5
	810	0.04188679	19
	1010	0.05247312	17.2
	1210	0.0630621	17.2
	1610	0.08416274	16.4
70	215	0.01004113	20

	415	0.02016326	19.5
	615	0.03033254	18.2
	815	0.04052528	18
	1020	0.05072103	16.6
	1220	0.06090056	16.2
	1615	0.08113526	15.5
80	220	0.00974843	19.5
	420	0.0195629	19
	620	0.02941133	18.7
	820	0.03927058	17.8
	1025	0.04912085	16.5
	1225	0.05894404	16

	1620	0.07844061	15.4
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The results show that hydrocarbon gas-oil interfacial tension decreases as the pressure rises due to lowering density contrast and increasing mutual solubility of gas composition into the crude oil. The reduction is more significant at reduced pressure in the range of 200 psi to 1000 psi. In contrast, the temperature does not have significant effects on IFT. Furthermore, oil composition can change density contrast and also the mutual solubility which causes IFT variation for various samples at identical pressure-temperature conditions. It can be seen that the flue gas with the condensate sample gives a lower value of IFT [15 mN/m at 1600 psi] as shown in figure 30 whereas, the IFT for the medium viscosity crude oil is around 17 mN/m at 1600 psi.

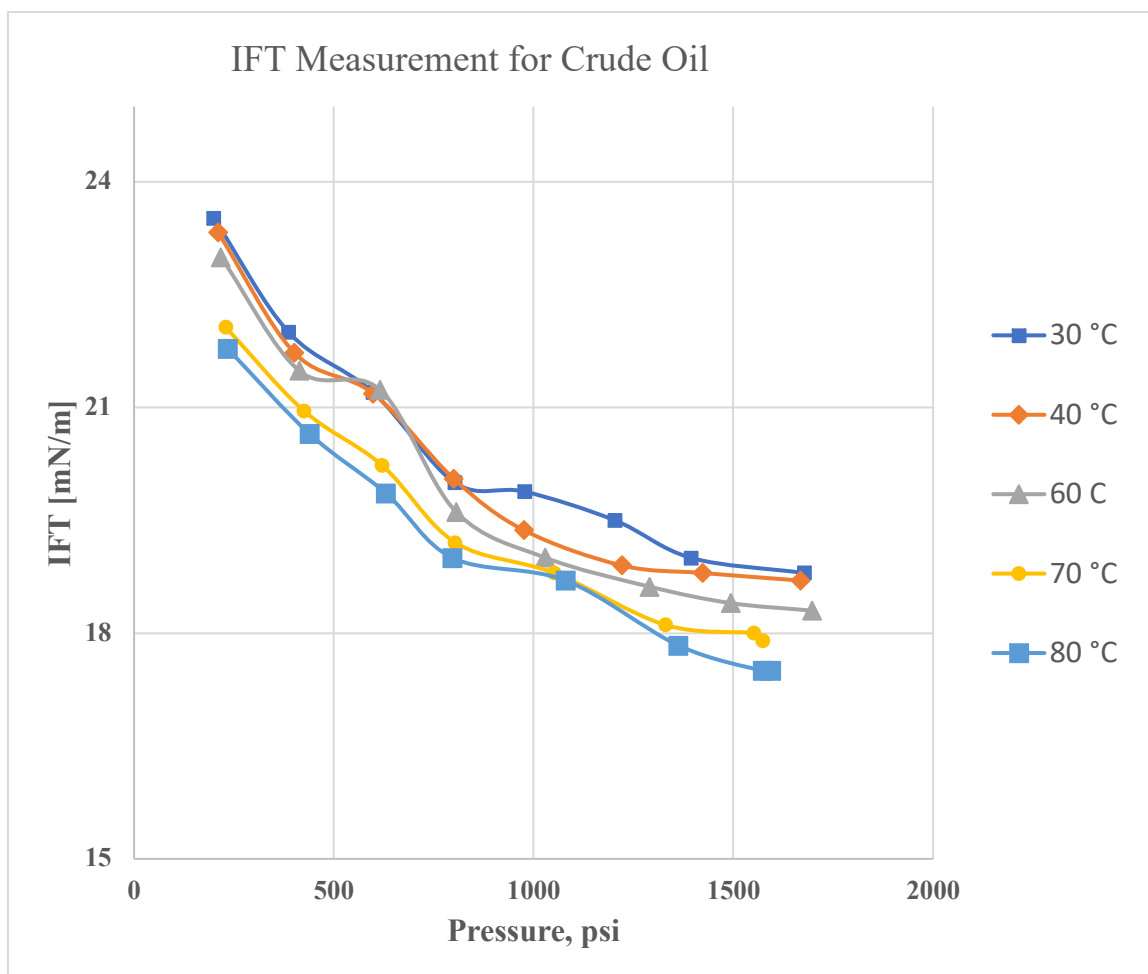


Figure 29: IFT measurement for the crude oil.

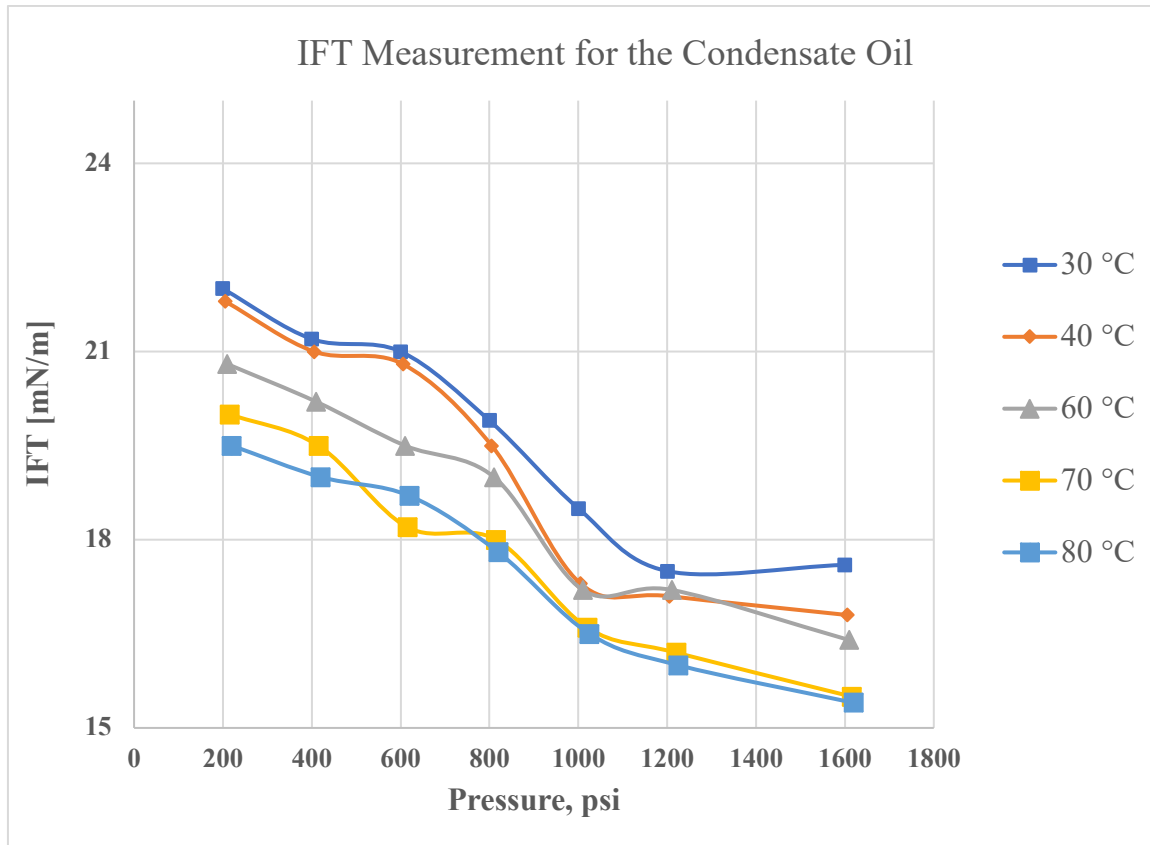


Figure 30: IFT measurement for the crude oil.

1.17 Summary of Results

Table 10: Results summary of flue gas continuous flooding

Continuous Gas Injection	Experiment	Permeability	Rock	Recovery	Recovery	Total
	#			after N₂	after	Recovery
					Flue Gas	%
						(OOIP)
	1	60	IL	27 %	4 %	31 %
	2	10	BG	25 %	8 %	33 %
	3	32	IL	9 %	1 %	10 %
	4	7	BG	28 %	5 %	33 %

Table 11: Summary of flue gas cyclic injection

CYCLIC GAS INJECTION	EXPERI MENT #	PERMEA BILITY	ROC K	RECOV ERY (% OOIP)	RECOV ERY (% OOIP)	RECOV ERY (% OOIP)	TOTAL RECOV ERY (% OOIP)
				First Cycle	Second Cycle	Third Cycle	
	5	19	IL	20 %	9 %	4 %	33 %
	6	10	BG	38 %	6 %	1 %	45 %
	7	9	IL	60 %	17 %	3 %	80 %
	8	19	BG	48 %	19 %	3 %	70 %

Conclusion and Recommendation

For the continuous gas injection, it can be inferred from the results that the rock wettability has a significant effect on the optimization of the continuous flue gas injection rate. In Indiana limestone better performance with higher permeability and flow rate was noticed and the opposite is true for the Bandera Gray Sandstone.

For the cyclic gas injection for the condensate, high recovery of the condensate was obtained indicating the effectiveness of cyclic gas injection with condensate recovery. For core experiments, the amount of oil recovered increases significantly during the initial cycles, and thereby the increase in the total oil recovered rate gradually decreases over time with increasing cycles. For huff and puff experiments it has been found that there exists an optimum soaking time. An increase beyond the optimum soaking time does not increase in the total amount recovered with the increase in the total amount of gas injected, as well as the number of cycles, the recovery factor is seen to increase. However, after reaching a maximum RF point, further increases in the number of cycles or the total amount of gas injected becomes irrelevant.

The outcome of IFT measurement shows that condensate and flue gas systems have lower interfacial tension than crude oil with the flue gas. The IFT value for the condensate/flue gas at the experiment conditions (pressure and temperature) reached around 15 mN/m,

whereas the crude oil with the flue gas was at almost 18 mN/m indicating the application of flue gas are more prevalent in the condensate reservoir.

In this work adequate range of temperature and pressure is not considered also the interaction of the flue gas and oil composition is not evaluated. This is very important to understand the mechanism as well as the application of the flue gas for EOR and production enhancement of the condensate reservoir. The following recommendation can be considered to further explore the mechanism and application of flue gases.

It is recommended further investigation of the IFT with different oil samples and different flue gas compositions. Also, the recovery mechanism requires further understanding by evaluating the effect of flue gas interaction with oil in relation to the PVT properties. The understanding of the effect of the different parameters (pressure, temperature, etc.) on the interaction of flue gases with oil and condensate can provide insight into the process optimization.

Also, the WAG process could overcome the high mobility of flue gas and increase the volumetric sweep efficiency. The combined gas and injected water can significantly enlarge the swept volume and adjust the fluid injection profile. It can improve sweep effectively and should be investigated.

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