Demonstration and performance characterization of the Gas Assisted Gravity Drainage (GAGD) process using a visual method

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DEMONSTRATION AND PERFORMANCE CHARACTERIZATION OF THE GAS ASSISTED GRAVITY DRAINAGE (GAGD) PROCESS USING A VISUAL MODEL

A Thesis

Submitted to the Graduate Faculty of the Louisiana State University and Agricultural and Mechanical College in partial fulfillment of the requirements for the degree of Master of Science in Petroleum Engineering

In

The Department of Petroleum Engineering

by

Thaer N N Mahmoud
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Nomenclature

\( g = \) the gravitational acceleration

\( g_c = \) a gravitational acceleration conversion factor

\( h = \) the height of the porous medium

\( K = \) the absolute permeability of the porous medium

\( P = \) the pressure

\( S_{or} = \) the residual oil saturation

\( S_{wi} = \) the initial water saturation

\( t = \) the injection time

\( \phi = \) the porosity of the porous medium

\( \mu = \) the viscosity of the oleic phase

\( \nu = \) the Darcy velocity
Abstract

The Gas Assisted Gravity Drainage (GAGD) process, currently being developed at LSU, is designed to take advantage of gravity to allow vertical segregation between the injected gas and reservoir crude oil due to their density differences. GAGD is recommended for use with CO₂ gas. CO₂ dissolves in oil and causes both swelling and viscosity reduction of oil. The GAGD process uses the existing vertical wells for CO₂ gas injection, and a horizontal well near the bottom of the payzone for oil production. GAGD, as an EOR process, is not restricted to tertiary oil recovery only.

In this research study, a visual glass model has been used to visually discern the mechanisms operative in the GAGD process. The model was also designed to fit different vertical well configurations. The model experiments have proven that GAGD is a viable process for secondary and tertiary oil recovery. Oil recovery in the immiscible secondary mode was as high as 83% IOIP and the oil recovery in the immiscible tertiary mode was 54% ROIP. The model has also shown that the gas injection depth may not have an influence on oil recovery as long as there is vertical communication between reservoir layers. Four different injection depths resulted in oil recovery values between 71% IOIP and 76% IOIP. The visual model experiments have also demonstrated that GAGD is applicable to naturally fractured reservoirs. The oil recovery in the fractured porous media was as high as 76% IOIP, which was higher than the average in homogenous porous media (73% IOIP). Additionally, the GAGD process was found to be viable for higher viscosity oils as well, where secondary immiscible oil recovery was 64% IOIP.

Miscible secondary injection was performed by using naphtha as the oil phase and decane as the miscible gas phase to simulate the miscible GAGD process. The visual model has resulted in a microscopic sweep efficiency close to 100% in the miscible GAGD process. The visual model
experiments have demonstrated three possible mechanisms responsible for high oil recoveries: Darcy-type displacement until gas breakthrough, gravity drainage after breakthrough, and film drainage in the gas invaded regions.
1 Introduction

1.1 Problem Statement

According to the U.S. Department of Energy, most E&P projects could only produce less than 30% of the original oil in place even after primary and secondary recovery techniques (www.DEO.gov). In the U.S. alone, there are still about 377 billion barrels of oil remaining trapped in the ground that is deemed unrecoverable using conventional methods of production. However, with the new emerging technologies and societal demand, the world is very thirsty for energy. The crude oil is the most traded commodity in the world for energy. Therefore, the demand for oil has been increasing constantly in the world. At the same time, it is well known that oil is a finite quantity, and hence the price of the remaining oil keeps on increasing (Figure 1). Conventional gas injection enhanced oil recovery (EOR) practices such as the WAG and CGI, as has been proven in many field projects, are moderately effective with only about 5-10% additional recoveries. Other EOR processes such as chemical techniques are expensive and complex. Hence there is a need to invent a new process that can produce more than 30% of the oil in place to ease the burden of the economy.

![Figure 1: A diagram of the oil price since May 2001 update, (slb.com).](image)
1.2 Research Objective

Since the beginning of the petroleum industry, E&P companies are trying to produce more oil either by maximizing oil recovery or by finding new oil reserves. The age of discovering gigantic reservoirs appears to be over. Therefore, the only available alternative is to maximize the oil recovery from current and previously discovered reservoirs. Enhanced oil recovery technology was born in the early 1980’s with many processes for improved oil recovery such as thermal, chemical and gas injection.

The scope of this research project is focused on gas injection enhanced oil recovery and particularly carbon dioxide injection, is mainly because CO₂ enhanced oil recovery technology has gained increasing popularity. This study therefore investigates a new gas injection process called the Gas Assisted Gravity Drainage (GAGD) process. One of the most important characteristics of the GAGD process is that it works with natural phenomenon of gravity segregation. The basic principle behind the GAGD process can be better explained by considering two fluids with different densities coexisting in a certain medium in which the heavier fluid sinks and the lighter fluid rises to the top due to natural gravity segregation. It is strongly believed that this principle of natural segregation of fluids would apply to crude oil and carbon dioxide in petroleum reservoirs.

Due to the high density difference between carbon dioxide and oil, the carbon dioxide would drain the oil out of the porous media when injected in gravity stable mode. In the GAGD process, gas is injected from the top of the pay zone and the drained oil would be produced from the bottom of the oil zone through a horizontal well. Whether the reservoir is dipping or not, this process is expected improve both the microscopic and the volumetric sweep efficiencies at the same time.
This research study was conducted by using a visual physical model to mimic the GAGD process in the Laboratory. Many different aspects of the GAGD process that can be encountered in field have been investigated including:

- The effect of free gravity flow on ultimate recovery and breakthrough time.
- The effect of injection depth on ultimate recovery and breakthrough time.
- The effect of injection rate on ultimate recovery and breakthrough time.
- The effect of viscosity in the immiscible mode on ultimate recovery and breakthrough time.
- The effect of miscible mode injection on ultimate recovery, and viscous fingering.
- The effect of fracture on ultimate recovery and breakthrough time in immiscible as well as in miscible mode.
- The effect of performing of GAGD in tertiary mode.
- Comparison of continuous gas injection (CGI) performance with GAGD
- The performance of water alternating gas (WAG) injection.
- The feasibility of cyclic injection of carbon dioxide using Huff n’ Puff techniques in GAGD.
- Comparison of Toe to Heel gas injection with normal gravity stable carbon dioxide injection.
- The effect of wettability on ultimate recovery and breakthrough time.
- Visual observation to discern key mechanisms responsible for oil recovery in GAGD

In order to provide better explanation and presentation of this research work the thesis is divided into the three chapters. The second chapter is related Literature Review, the third chapter describes the various visual model techniques that been attempted before the sand pack method.
The fourth chapter describes experimental apparatus fabrication and procedures used; the fifth chapter presents results and discussion. The sixth chapter provides the conclusion and recommendations, and lastly all the needed appendices are attached.
2 Literature Review

In this chapter, literature on the state of enhanced oil recovery and specifically the various processes for CO₂ gas injection EOR are reviewed to bring out the necessity of improving the performance of CO₂ EOR process.

2.1 State of Enhanced Oil Recovery (EOR)

Although EOR been under development for several decades, it lost momentum when the oil prices collapsed in the 1980’s, and so did the interest in research and development on EOR. However, when the price of oil started to pick up in the current decade and the outlook of oil price is still on the rise, E&P companies are showing a great deal of interest in EOR and are planning EOR pilot and full field projects. Literature survey indicates that EOR is mostly limited to three different methods; namely chemical, thermal and gas. Gas, and especially CO₂ injection, is the only method that has been gaining momentum world wide since the late 70’s (Kelly, 2006) (Figure 2). On the other hand, chemical EOR peaked in the mid 80’s, and is almost extinct now. Thermal flooding is generally limited to heavy oil fields only. The recent EOR survey by the oil and gas journal indicates that the gas injection projects have claimed a 54% of the EOR production (Manriqu, 2006).

GAGD using CO₂ gas has dual advantages. The first is the fact that more oil is being recovered to help in quenching the energy thirst with oil that has been deemed unrecoverable before. The second benefit is the sequestration of carbon dioxide (CO₂) (Wood et al, 2006; Manriqu, 2006), which leads to less CO₂ emission into the atmosphere to help fight the global warming. Unfortunately, true CO₂ sequestration is not yet fully practiced, because of the high costs of CO₂ gas separation from flue gases exhausted from power plants. Most of the CO₂ that is used in EOR projects is from natural sources such as the natural CO₂ reservoirs in Colorado, from where
the CO₂ gas is being piped to West Texas. The good news is that with increase of CO₂ demand, new separation technologies are being developed to provide inexpensive CO₂ from industrial sources such as power plants and natural sources such as the separation of CO₂ from produced natural gas. The CO₂ quantities could reach as high as 20% of production from such sources (Schulte, 2005).

Furthermore, CO₂ gas injection can be practiced with relatively low cost (1$/Mscf), plus the transportation cost, and can be applied to many types of reservoirs such as sandstones and naturally fractured carbonates. Moreover, CO₂ gas is readily available through pipe line systems (two CO₂ pipe lines in Louisiana, and one in West Texas) compared to other EOR processes such as chemical injection that require very expensive surfactants at high concentrations. (Manriqu, 2006).

Other injection gases used in gas injection EOR are Nitrogen (N₂), air, flue gas, and hydrocarbon gases. However, it is important to be cautious with the function of these gases because they play two main roles; either to initiate combustion like air or to maintain pressure in the reservoir (Manriqu, 2006). In the case of combustion, precious hydrocarbon could be wasted. But, it might be economical especially for off shore heavy oil assets that are far away from any other alternative source. Additionally, miscible N₂ has been used before in high pressure and light
crude oil reservoirs. However, N₂ gas is mainly used for immiscible pressure maintenance due to its high miscibility pressure. However, the use of N₂ has been on the decline because of the easier availability of CO₂ (Manriqu, 2006). On the other hand, flue gases are still in use because of the low cost associated with immiscible pressure maintenance.

Steam flooding is mostly recommended for heavy oil. It is rarely used in light to medium oil reservoirs (Yates field). Steam injection works by introducing heat energy to the reservoir to increase the temperature of the oil in reservoir, thereby lowering its viscosity to allow an easier flow of the oil to the well and lower the differential pressure that is required (Nasr, 1997). However, steam generation requires large amount of heat to convert water into steam. Therefore, large volumes of natural gas are required. Another problem with steam flooding is that the wells have to be completed with steam flooding in mind instead of conventional completion to serve as primary recovery production wells and later to be converted to steam Huff n’ Puff. Additionally, cyclical Huff n’ Puff has shown to have a diminishing return after a few cycles. In Lengjiaobo heavy oil reservoir in China, steam Huff n’ Puff process has been used. But the recovery was not as well as expected and Huff n’ Puff requires a soaking period for the steam to be effective. Therefore, CO₂ injection has been introduced in three heavy oil pilot projects. It was observed that CO₂ injection was almost suitable for many possible situations. Ultimately, CO₂ associated oil production cost has been significantly lower than steam associated oil production cost, and the ultimate production has increased as well. Cycling gas with hydrocarbon, namely methane is used very often for pressure maintenance. But with the recent increase in natural gas prices, it has been more attractive to sell the natural gas. Hence, to find a different method for enhanced oil recovery is important.
2.2 CO₂ Gas Injection EOR

“CO₂ flooding is the fastest growing enhanced oil recovery in the U.S., and field projects continue to show good incremental oil recovery in response to CO₂ injection” (Martin et al, 1992). In fact many of the field projects have been producing since the middle of 80’s an increment in oil recovery of 7% to 23% IOIP. Field operators have been finding that maximum oil production occurs after breakthrough and production could continue for many years (Martin et al, 1992). CO₂ gas injection is not only valid for light to medium gravity oil but for heavy oil as well CO₂ flooding field applications have been increasing every year. The CO₂ gas injection process is flexible and it could be either miscible or immiscible depending on the existing conditions (pressure, temperature and oil compositions in the reservoir).

It is still a common perception that CO₂ gas injection is geared for light to medium gravity oil only. In fact many pilot tests have been carried out with heavy oil with very encouraging results. In Liaohe oil field in China, with oil viscosity is between 727 cP and 72,700 cP, three CO₂ pilot projects are currently running with very successful results. However, in one of these projects steam of high quality had to be used to break the wax in heavy oil goes to remove the shielding effect to allow CO₂ to come in contact with the oil (Luo et al, 2005).

CO₂ flooding is expected to continue to increase especially as a tertiary method, because of the US government funded research and due to new construction of CO₂ pipelines in West Texas from natural sources. CO₂ gas injection can be used in oil reservoirs for EOR in two different modes, namely immiscible and miscible.

In the immiscible mode, CO₂ gas dissolves in oil causing swelling of oil that could reach up 10% to 22% of the original volume. Furthermore, the viscosity might drop to less than 10% of the original value (Chakravarthy et al, 2006; Luo et al, 2005). Thus, in addition to increasing the
microscopic sweep efficiency, CO₂ gas injection in the immiscible mode further increases the pressure of the reservoir leading to more and easier flow of oil (Martin, 1992). Also, it has been proven that the use of CO₂ gas injection in the immiscible mode instead of steam in heavy oil production would become more economical (Lou et al, 2005).

Miscibility has been defined as that the conditions in which two components are mixed in at all proportions without forming an interface between them (Lake, 1989). Miscibility of CO₂ in oil takes place in one of the two ways. The first method is called first contact, which happens when the CO₂ and oil become completely miscible and create a single phase on their first contact. Furthermore, for the first contact method, minimum miscibility pressure has to be established before the CO₂ comes in contact with the oil, which means that the reservoir should not have been completely depleted. If the reservoir is completely depleted, reservoir pressure has to be increased to reach minimum miscibility pressure before the injection of CO₂ can begins. For Ivanic oil field in Croatia, the reservoir pressure was reported to be 2,030 psia. But the minimum miscible pressure was 2755 psia. Therefore, water injection had to be established first to bring the reservoir pressure up to the minimum miscibility pressure (Novosel, 2005).

The second method is called multiple-contact miscible process, in which miscibility occurs by multiple-contact of gas and oil through condensing/vaporizing mechanisms (mass transfer). The CO₂ gas injection in this process is initiated before establishing the minimum miscibility pressure. However, during the injection process the pressure of the reservoir will increase causing the components in the two fluids to transfer back and forth until the oil filled CO₂ can not distinguish from the CO₂ filled oil (Shedid, 2005).

In the miscible process, CO₂ is very soluble in crude oil at reservoir conditions. Thus, it causes oil swelling, viscosity reduction and pressure increase. Therefore, flow of oil begins long before miscibility has taken place. The increase in CO₂ volume in the crude oil causes a reduction in
the interfacial tension between the crude oil and the injected CO₂ gas increasing the microscopic
sweep efficiency (Martin et al, 1992). Additionally, due to the low formation volume factor of
CO₂ and the low mobility ratio for miscible CO₂ compared to other solvents of crude oil such as
CH₄ or N₂, miscible CO₂ volumetric sweep efficiency is relatively higher (Kulkarni, 2004).

In order to achieve CO₂ miscibility, the CO₂ injection pressure has to be high enough to reach the
minimum miscibility pressure causing enough increase in the density of CO₂ so that it becomes a
good solvent especially for the intermediate hydrocarbons components (C₅-C₁₂) in the crude oil.
Furthermore, in miscible CO₂ flooding, the high solubility of CO₂ in water causes it diffuse to
the previously deemed immobile oil and swell it and reduce the viscosity until the oil becomes
mobile.

It has been shown that the minimum miscibility pressure required is mainly dependent on the
content of C₅ to C₁₂ in the crude oil and in situ temperature; the higher the fraction of C₅ to C₁₂
the lower pressure that is required to achieve miscibility with CO₂ gas (Martin et al, 1992).
Consequently, CO₂ flooding is most efficient in light oil and low temperature reservoirs. None
the less, CO₂ flooding can be used in medium and heavy oil reservoirs as well as practiced in
Liaohe oil field in China. But a higher CO₂ minimum miscibility pressure is required (Figure 3)
for heavy oil. Canadian oil reservoirs appear to be good candidates for CO₂ flooding the low
reservoir temperatures requiring lower minimum miscibility pressures.

Furthermore, when comparing miscible CO₂ injection to miscible hydrocarbon gas injection,
CO₂ gas can be less expensive. Also, CO₂ flooding consumes a green house gas leading to a
better environment and most importantly a higher oil recovery (Martin et al, 1992; Senguel,
2006). However, it is important to mention that CO₂ gas is known to be corrosive to metallic
surfaces in the casings and tubing. CO₂ forms carbonic acid in the presence water, which is
responsible for corrosion (Halvorsen et al, 2006). None the less, there are some ways to protect
metallic surfaces, namely using inhibitors, corrosion resistant alloys, a combination of the two previous technique and composite materials (Havlik et al, 2006), in addition to removal of moisture from the injected CO₂ gas.

**Figure 3**: CO₂ Minimum miscibility pressure with oil, (Martin et al, 1992).

### 2.3 EOR in Naturally Fractured Reservoirs

It is understood that water flooding is most likely to be inefficient for oil recovery in carbonate reservoirs because of low porosity. Naturally fractured reservoirs are most likely to be either oil-wet or mixed-wet. In carbonate rocks, waterflooding is highly inefficient as a secondary recovery method (Adibhtla et al, 2006, Manriqui, 2006), especially when the fracture intensity is relatively high. These facts cannot be ignored as much of the world’s hydrocarbon reservoirs are in
carbonate reservoirs (Manriqu, 2006). Furthermore, it is known that carbonate rocks tend to have a relatively low matrix permeability compared to sandstones, or even that of the fractures within. Low matrix permeability tends to obstruct water flooding recovery, especially if the matrix is oil-wet. One of the suggested methods to solve this problem is chemical flooding by changing the interfacial tension (IFT) as well as the contact angle between the rock and the wetting fluid which represents wettability (Rao et al, 2006). Thereby, lower capillary pressure, leading to higher relative oil permeability and (Adibahtla et al, 2006).

Recovery in carbonate reservoirs is very dependent on heterogeneity, oil quality, drive mechanism and reservoir management (Adibahtla et al, 2006). Furthermore, enhanced oil recovery processes such as surfactant, gas, and thermal processes can be effective in fractured carbonate reservoirs. However, chemical EOR has many drawbacks such as the high cost of the chemicals for the large quantities due to the high concentration that is needed for flooding and the lack of ability to recycle the surfactants after breakthrough because of the absorption of chemicals on the rock (Manriqu, 2006).

Interestingly, CO₂ flooding in naturally fractured rocks has revealed the ability of CO₂ to interact with in place fluids between the rock and fractures (Darvish et al, 2006), thereby draining the oil out of the low permeability rock matrix into the high permeability fracture and allowing the CO₂ to flood the rock for further drainage. The drainage process is either counter or co-current drainage (Figure 4).

In counter current drainage, the gas is diffused inside in the matrix leading to drainage of the oil into the fractures. On the other hand, co-current drainage is dependent on the viscous displacement of oil in the direction of flow.
2.4 Conventional CO₂ Gas Injection Processes

2.4.1 Continuous Gas Injection (CGI)

Wood et al (2006) described the continuous CO₂ injection (CGI) as a successful process in dipping reservoirs to employ the gravity advantage of CO₂. Furthermore, CO₂ CGI is not likely to be economical unless significant recycling of gas is performed (Charkravarthy et al, 2006). Additionally, accurate reservoir characterization is required before CGI flooding to determine the level of heterogeneity.

In highly heterogeneous reservoirs, CO₂ gas would lose flood front conformance. Consequently, premature breakthrough takes place when the flow of CO₂ is horizontal between two vertical wells (Shedid et al, 2005, Charkravarthy et al, 2006). It has been reported in literature that miscible CO₂ CGI has recovered up to 96% of IOIP in the laboratory at reservoir conditions by swelling the oil, lowering the viscosity and increasing the pressure in the core. However, miscible CGI is not recommended for field application because it requires 1.5 hydrocarbon pore volume of CO₂ gas at miscible pressure to achieve the above high oil recovery. Therefore, it could be cost prohibitive (Shedid et al, 2005).

CGI is conducted by injecting gas (mostly CO₂) in the reservoir continuously without using any other fluids. It is worth mentioning that sometimes some other gases are injected to drive the CO₂ through the reservoir.
2.4.2 Water Alternating Gas (WAG) Process

Water alternating gas (WAG) injection has been one of the standard CO₂ gas injection EOR practices in the field (Kulkarni, 2004). When WAG was developed by Caudle and Dyes in the late 1950’s, it was recommended to use co-injection of water and gas. However, field engineers later changed it to alternate injection because of relative permeability issues. WAG involves alternate injections of small pore volumes (5% or less) of CO₂ and water until the desired volume of CO₂ has been injected from vertical wells to flood horizontally (Chakravarthy et al, 2006) (Figure 5). As has been mentioned, CO₂ microscopic sweep efficiency is higher than that of water. On the other hand, water volumetric sweep efficiency is better than CO₂ in horizontal flooding because of the relatively low density difference between the injected water and reservoir oil in place (Novosel, 2005; Chakravarthy, 2006). However, this is not the case and the difference in density between the injected water and the crude oil would not allow a piston like displacement in the reservoir and the water would sink to the bottom of the reservoir and bypass a much of the oil (Rao et al, 2004) (Figure 6).

Therefore, WAG has not been a very efficient or effective methodology of EOR especially in heterogeneous reservoirs, which constitute the majority (Chakravarthy, 2006). Additionally, WAG is very sensitive to heterogeneity and vertical gravity segregation, which effects are not present in small diameter cores used in laboratories (Novesel, 2005). It had also been stated that WAG has many difficulties to be managed in the field such as water and CO₂ cycling management, heterogeneity, viscous fingering, the need to operate under miscible conditions allowing viscous pressure to dominate the process in the reservoir, and the high number of injection wells required to efficiently and economically flood the reservoir (Kelly, 2006).
Furthermore, some improvements have been made in WAG process in the past decade by adding some polymers to create a gel like fluid in the reservoir to increase the viscosity of the flooding water and to stabilize the front by plugging high permeability streaks in order to prevent viscous fingering effects and premature CO₂ breakthrough (Chakravarthy, 2006). However, it has been noticed that there are some vertical gravity segregation effects taking place in reservoirs and hence measures are being taken to account for such gravity effects such as side tracking from horizontal flooding and essentially to perform a gravity stable CO₂ flooding to sweep the areas that have been bypassed by either miscible CO₂ or water. From the experience of Prudhoe Bay
field it is proven that “Typical MIST (MI Sidetracks) patterns accumulate 3 to 4 times the EOR reserves of conventional vertical well WAG Pattern” (Rathman, 2006). Reservoirs with high vertical permeability to horizontal permeability ratios are inclined to have gravity domination in any form of flooding. In such reservoirs, water flooding will always result in water sinking to the bottom of the reservoir and gas staying at the very top of the reservoir (adverse vertical segregation) defeating the purpose of alternating the flow of fluids to keep the flood front piston like.

2.5 The New Gas Assisted Gravity Drainage (GAGD) Process

The three fluid phases of water, oil and gas co-exist in many reservoirs. However, these three different phases cannot be all mixed together. Gas could be dissolved in water and oil. On the other hand, water and oil do not dissolve in each other. If the oil is saturated with gas and there is still some excess gas present in the reservoir, then a gas cap will form. Three different phases will have different densities at reservoir conditions of temperature and pressure. Gas has the least density, then oil and water has the highest density of the three phases thereby causing vertical segregation of the reservoir fluids. Consequently, gas will always be on top, then oil, then water with some transitional zones. Therefore, the idea behind gravity drainage is to exploit the in situ segregation of fluids by injecting gas in the crest of the zone thus to create pressure maintenance forcing the oil downward the reservoir, which leads to a higher value of ultimate oil recovery (Shreve et al, 1955). Most oil reservoirs fall in two categories namely dipping reservoirs and horizontal or near horizontal reservoirs (Matthews et al, 1956).

In dipping reservoirs, gravity drainage could be used by injecting the gas from up dip, then produce from down dip. However, in order to apply the gravity drainage in dipping reservoirs using vertical wells a few important considerations must be met. These are the conditions that
have to be met first such as low connate water saturation, thick, highly dipping or reef type, light oil with low viscosity, and moderate to high vertical permeability (Rao et al, 2004). Gravity drainage has been practiced in the field for quite sometime, which has been beneficial in increasing the ultimate recovery (Matthews et al, 1956).

Recently, a new gas injection process called Gas Assisted Gravity Drainage (GAGD) has been suggested as a general method of EOR for secondary as well as tertiary recovery processes. This process takes advantage of the gravity segregation effects and horizontal wells for different types of reservoirs. Even though gravity segregation has been understood for a long time, the new GAGD process involves injecting the gas, preferably CO$_2$, from vertical wells at the top of the payzone and producing oil from a horizontal well located at the bottom of payzone (Figure 7) (Rao et al, 2004).

![Figure 7: Conceptual diagram of GAGD, (Rao et al, 2004)](image)

Injecting CO$_2$ in GAGD is beneficial as it combines both high volumetric sweep and high microscopic sweep (Rao et al, 2004), which has been rarely achieved in the past. CO$_2$ swells the
oil and reduces the viscosity in the microscopic level, keeping the CO2 gas chamber above the oil. The oil will be produced through a horizontal well. This will lead to a very high volumetric sweep while holding a stable flood front and delay the CO2 breakthrough. Furthermore, when the CO2 is injected in miscible mode, microscopic sweep will also be very high (Teletzke et al, 2005).

In vertical drainage controlled by gravity in miscible mode, a very short transition zone might form between the miscible CO2 and the oil in place and thereby nearly 100% oil recovery could be achieved (Lacey et al, 1957). Since the gas is being injected in a gravity stable manner, no viscous fingering would take place. Due to the high pressure required to reach the miscibility condition, density of the gas will increase several folds. For example, CO2 density at 14.7 psig and 70 °F is 0.23 lbm/ft³; however CO2 density at 3000 psig and 239 °F approaches 10.3 Lbm/ft³ (Appendix H & I) compared to typical 40 ºAPI oil that has a density of 51.5 lbm/ft³.

Additionally, viscous fingering can take place causing premature breakthrough if injection pressure and production rate not managed appropriately. However, viscous fingering development is related to magnitude of viscous force during the flood, which is directly proportional to the injection rate. If the miscible injection velocity is high, viscous forces would be dominant, thus causing viscous fingering. On the other hand, if the injection rate of the flood is below the critical injection rate, the dominant force would be the gravity force leading to a stable flood front and viscous fingering would not be present (Lacey et al, 1957). Furthermore, in the case of viscous fingering occurrence, if the injection rate slowed down or stopped and time is provided for natural vertical gravity segregation of the reservoir fluids, a stable flood can be resumed below the critical injection rate and without viscous fingering (Kulkarni, 2004). Another advantage of GAGD is that heterogeneity can be neglected when gas flooding is gravity stable.
(Wood et al, 2006), because the flood front will travel down the reservoir in a uniform fashion, thereby draining the oil out of the permeable oil zones.

2.6 Effect of Horizontal Well Technology on Gas Injection EOR

Horizontal well technology in the oil field has been practiced since the 1930’s, which has brought big improvements in oil recovery wherever they are applicable. Horizontal wells have the advantage of having a high productivity index. Furthermore, horizontal wells are ideal for the gravity drainage processes (Rao et al, 2004)

Horizontal wells tend to have a high productivity index, which implies that very little pressure drop across the well-sand face interface is required to have oil flow. The high productivity index is due to the fact that horizontal wells have large contact with the reservoir. Some of the large horizontal wells could extend to 4000 ft from the vertical well bore section, where the entire 4000 ft is a productive zone. On the other hand, regular vertical wells tend to be productive only in the vertical height of the pay zone. It is well known that most reservoirs possess much bigger drainage radius than drainage height.

As has been mentioned previously, gravity drainage can yield high oil recovery. However, conventional vertical wells provide less effective means of recovery especially in none dipping reservoirs than horizontal wells. Therefore, oil production using horizontal wells is becoming much popular in such reservoirs. Morrisson et al (1959) suggested that the creation of horizontal fracture around the vertical well would provide a large drainage sink for the reservoir so that the fluids can be collected in the vertical well and pumped up to the surface. Furthermore, he reported that very little energy is needed to drive the oil into the fracture beside the gravity energy. However, personal communication with experts in this field (Prof. Langlinais, May 18, 2006) suggested that the horizontal fractures are possible only in shallow reservoirs because of
principle stress mechanism. However, Morrisson required the usage of this technique in sand thickness of about 50 ft or more. This idea of horizontal fractures can be improved by horizontal wells that could be better controlled. Furthermore, horizontal wells can be drilled at the bottom of the payzone with much higher precision compared to horizontal fractures. The main advantage of placing the horizontal well at the bottom of the payzone is that when the natural drive of oil such as gas cap or solution drive has been depleted, gravity forces will take over with continued oil production. A second advantage of horizontal wells is that they able to delay gas breakthrough and the encroachment of water (Joshi, 1991).

In the case of heterogeneous reservoirs, vertical injection of steam for heavy oil recovery and horizontal production of oil has been reported to have advantages over horizontal injection and production (Nasr et al, 1997). Vertical wells will be in communication with more than one layer of the reservoir, causing the steam to be distributed throughout the reservoir to maximize oil production in highly heterogeneous reservoirs. This method of steam injection can be applied to gas injection as well.

Another advantage of horizontal wells is the fact horizontal wells could be exploited to operate in different configurations of operations, especially in the case of GAGD. It has been suggested to use the horizontal well as an injector as well as producer in the form of cyclical injection and production (Lim et al, 1996). Because of the low viscosity and density of CO₂, it is believed injecting CO₂ at any depth will cause it to travel to the top of the zone and form a gas cap. Horizontal wells can be suitable and efficient injectors without requiring large pressure drop even at high injection rates. Some previous pilot projects in SAGD have tried to inject from the toe (near the end point in the horizontal well) of the horizontal well and produce from the rest of the well (Figure 8).
2.7 Previous Related Work on GAGD

The investigation of Gas Assisted Gravity Drainage process in the laboratory has been initiated at LSU since 2000. Several researchers (Sharma (2004), Kulkarni (2005) and Paidin (2006)) conducted laboratory studies on this new process, and the results of their works are briefly discussed below.

Sharma (2004) has mainly concentrated on a water-wet physical model to investigate the effect of different dimensionless numbers such as Capillary number (N_c), Bond number (N_B), and Gravity number (N_G) on GAGD performance. He concluded that when injecting at constant pressure in the immiscible mode, the gas type used has no effect on GAGD. Both N_2 and CO_2 recoveries at the same pressure were comparable. Furthermore, the gas was also injected at constant rate to control N_c and N_B, and results indicated that higher the N_B the higher is the GAGD oil recovery.

Kulkarni (2005) has researched the available competing process with GAGD such as WAG and CGI using scaled corefloods. The results have proven that GAGD provides superior recovery compared to WAG and CGI in secondary and tertiary immiscible mode. Additionally, the high pressure coreflood experimentations have proved that injecting in the miscible mode can recover
at or near 100% of IOIP. He further proved that gas breakthrough could be controlled even after it takes place by shutting in the reservoir and providing enough time for vertical segregation to take place. Furthermore, he reported that the higher the gravity number, the higher was the oil recovery. Experimenting with fractured cores, the results have shown an improvement in oil recovery due to presence of the fracture in the core compared to the same core without a fracture. Paidin (2006) conducted important related work to simulate oil-wet reservoirs by using a physical model with altering glass beads wettability from water-wet to oil-wet, in both secondary and tertiary modes. The experimental results confirmed that GAGD oil-wet model recoveries were higher than in the water-wet ones. This is because the oil will always be in a continuous film on the rock and hence it will flow as a continuous film as well. Furthermore, he also reported that increasing the grain size will increase porosity and permeability. Therefore, oil recovery increases with increasing permeability. Furthermore, constant injection pressure experiments resulted in higher oil recoveries than constant injection rate ones, which agreed well with previously reported results of Sharma (2004). Additionally, the effect of vertical fracture on GAGD oil recovery was investigated, the results showed that the presence vertical fracture has positive effects on oil recovery, due to the availability of a path of least resistance for the oil to flow through. The oil found a way out of the matrix through the fracture and the gas found a way into the matrix through the fracture. Thus, in gravity drainage, the fracture has served as an efficient path to cause exchange between the fluids, which agrees with what it is reported by Charkravarthy (2006).

2.8 Dimensional Scaling of GAGD

In order to extend laboratory scale experimental results to field scale, dimensional scaling is required. Many researchers have investigated this dimensional scaling aspect and have identified
several common dimensionless numbers applicable for both the laboratory as well as the field such as Shook et al (1992), Grattoni (2000), and Miguel (2004). The theory of dimensionless numbers was first introduced by Buckingham’s pi theorem (Geertsma et al, 1955). For taking GAGD process from laboratory to field, two dimensionless variables namely dimensionless time and dimensionless gravity number have been identified as being important and are shown in Table 1 below.

Table 1: The two main dimensionless numbers governing gravity stable gas injection, (Sharma, 2005; Paidin, 2006).

<table>
<thead>
<tr>
<th>Dimensionless Number</th>
<th>Formula</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dimensionless Time ($t_D$)</td>
<td>$\frac{KK_{ro}^0 \Delta \rho g / g_c}{h \phi \mu (1 - S_{or} - S_{wi})}$</td>
<td>Miguel et al, 2004</td>
</tr>
<tr>
<td>Gravity Number ($N_G$) or (Gravity force/Viscous force)</td>
<td>$\Delta \rho g \left( \frac{K}{\phi} \right) \mu_o v_d$</td>
<td>Shook et al, 1992</td>
</tr>
</tbody>
</table>

Where:

- $K$ is the absolute permeability of the porous medium (m²);
- $K_{ro}^0$ is the end-point relative oil permeability;
- $\Delta \rho$ is the density contrast between the gas and oleic phase (Kg/m³);
- $g$ is the gravitational acceleration (m/s²);
- $g_c$ is a gravitational acceleration conversion factor (1);
- $h$ is the height of the porous medium (m);
- $\phi$ is the porosity of the porous medium (%);
- $S_{or}$ is the residual oil saturation (%);
- $S_{wi}$ is the initial water saturation (%);
- $t$ is the injection time (min).
3 Various Visual Models Attempted

The objective of these visual models was to mimic the gravity drainage process in natural reservoirs to the extent possible and to provide good visualization of the drainage/displacement process. The oil bearing reservoirs have maximum permeabilities less than 700 m-Darcy and porosities less than 27%. However, it was understood that using a sand pack visual model, which is the most common visualization method, will result in permeability and porosity greater than 3 Darcies and 35%, respectively. Hence, at the beginning of this research study, different types of models were attempted (Appendix N). Different materials and methods that were attempted namely ceramic porous material, Stucco, Portland cement, Epoxy, and Sintered glass beads are described below in detail.

3.1 Ceramic Porous Material

One of the first materials that have been used is the ceramic based porous plates called Glass Bonded Silica, made by Filtros Ceramic Products, NY. The advantage of the Glass Bonded Silica is that it is silica based hence water-wet. Additionally, these are pre-fabricated therefore repeatability with consistent results can be achieved easily.

However, permeability of the plates is above 10 Darcies. Furthermore, the plate size is rather limited to 12” x 12”. For any size bigger than this, they have to be glued creating oil-wet zones in the water-wet model and local disruption of the fluids flow. Furthermore, the delivery time was 3 months with minimum order of about $500. Therefore, the use of ceramic porous material was impractical.
3.2 Stucco

One of the other materials that was attempted is stucco. When stucco is mixed with sand and water, it tends to form a nice homogenous material that can be shaped to any size for use. However, it was observed that the Stucco is a material with very little permeability, hence adding some sand might improve the permeability and porosity as well. Thus, some stucco was mixed with sand and water was poured inside a holding frame.

However, many problems were encountered during the usage of stucco. The most important problems are that the stucco is highly fragile and it is oil wet (Figure 9). Furthermore, stucco requires 28 days to reach 75% of full curing and full curing takes many years (Kosmatka et al, 1988) with a constant source of humidity. If humidity is not present, curing will stop. But curing will restart again as soon some humidity is introduced. Therefore, some of the water used in the tests to saturate the stucco model will be used for the curing of stucco as well. Therefore, no accurate measurement of porous space and hence material balance calculations can be carried out using this model. Thus, stucco was found to be not suitable for use in such applications.

Figure 9: Depiction of attempted visual model using Stucco
3.3 Portland Cement

The lack of limitation on shape and size associated with stucco was desirable. Hence, portland cement was thought to be a good material to be tested since it has higher strength. Some white portland cement was mixed with sand and water for testing. However, some of the stucco problems also showed up with cement, especially the oil-wet nature. Additional problems were one of the surfaces would always have air bubbles because of the trapped gas that is generated during the curing process. Just like stucco, cement requires 28 days to reach 75% of full curing, and full curing may take many years (Kosmatka et al, 1988), during which water will be consumed by the cement. Thereby, accurate material balance cannot be carried out with cement also.

Furthermore, the porosity and permeability of the white cement models turned out to be very low, in the order of 2% porosity and 5 m-Darcy permeability. Therefore, the cement content was lowered to less than 30% (by weight). The porosity and permeability values did not change much, but the model strength was very low. The cement plats started to break up very easily (Figure 4.2). Furthermore, when cement is coated with a thin layer of epoxy to seal the model, the epoxy coating separated due to the low bond strength between the epoxy and the cement model and the low permeability (Figure 10).

3.4 Epoxy

Considering the above options discussed, an oil-wet visual model seemed unavoidable. Therefore, it was proposed that mixing epoxy with glass beads would create good porous media, although that it is oil-wet. Therefore, epoxy resin with curing agent was mixed with glass beads to create a testing plate and then it was allowed to cure. One of the problems with epoxy based plates that the material is strongly oil-wet. Hence, water did not imbibe into the plates under
gravity. Additional pressure was required to force the water into the model. In order to reduce the strong wettability effects, some hand soap with low concentration was mixed with the epoxy (0.5% by weight). The results were encouraging as far as the wettability was concerned and then the water was able to imbibe into the plate under gravity. On the other hand, it seemed that soap had a negative effect on the model overall strength (Figure 11). The small plate could not support its own weight. More importantly, visualizing the process with epoxy based plates was nearly impossible. The color of the glass beads and epoxy mix dominated the red dye color of the decane. Furthermore, it appeared that decane acts like a solvent on the epoxy. Leaks began to appear in the model even in places where it was checked previously for leaks under vacuum.

![Figure 10: Test of white portland cement plates](image)

### 3.5 Sintered Glass Beads

Reviewing the literature, it was discovered that Padhy et al (2005) used sintered glass beads instead of cores for experimental work. Hence, the sintered glass beads technique was applied to the visual model by confining the glass beads inside a glass frame and then sintering the entire system together at high temperature in a furnace. This process was attempted using an electrical furnace to provide the heat necessary at the glass blowing shop of LSU on 6” x 6” model.
The overall permeability is 500 m-Darcy, and the porosity was about 20%. Furthermore, it was completely water-wet.

However, boundary effects were clearly seen at the edges. When the model was flooded with oil from top to bottom, there was clear evidence that the sides have much higher permeability (Figure 12). Furthermore, when the same technique was attempted on a large scale model, the results worsened. The furnace did not provide uniform heat throughout the furnace chamber; hence residual stress caused the glass models (11” x 18”) to break up either during the heating or the cooling process. Additionally, the edge boundary problem had magnified even further. In some instances, oil did not sweep the middle of the model. It was believed that since the heat was applied to the sides of the model, the melted glass would have been forced and accumulated in the middle of the glass model resulting in low porosity and permeability in the middle. Due to the failure of the various models attempted, it was decided to perform the experimental work using the sand pack method described in chapter 4.
Figure 12: Sintered glass beads model
4 Experimental Apparatus and Procedures Used

The experiments were conducted to visualize the gas assisted gravity drainage (GAGD) process of oil recovery by CO$_2$ injection. Miniature visual physical models were initially built to understand the experimental variables and the difficulties that have to be overcome before building a full size model. These include problems such as the most appropriate porous media (sand or glass beads); method of sealing the model, providing of adequate mechanical strength, and injection and production strategies.

Once these problems were resolved, a desired size model was built with optimum parameters. Then the experimental procedure was designed in the simplest possible way keeping in mind accuracy and integrity of the research experiments.

4.1 Construction of the Visual Glass Model

There are several steps to be followed to construct the visual glass model. Some of the steps are needed for structural support, others are needed to provide a sealant for the model, and many serve both the purposes. The construction protocol to be followed precisely to enable the optimum functionality and efficiency of the model is described below.

1. The following list of glass plates need to be cut according to size of the conventional window glass:

   - Two plates of 23” X 13” of 0.25” thick glass.
   - One 23” X 1” of 0.25” thick glass.
   - One 23” X 1” of 0.125” thick glass.
   - Two 10.5” X 1” of 0.25” thick glass.
   - Two 10.5” X 1” of 0.125” thick glass.
• Two 10.75” X 1” of 0.25” thick glass.
• Two 10.75” X 1” of 0.125” thick glass.
• Seven to ten pieces of 1” X 0.5” of 0.25” thick glass.
• Seven to ten pieces of 1” X 0.5” of 0.125” thick glass (this number has to match the previous number).

All the above glass plates will function as spacers except the large glass plates (23” X 13”).

2. It is required to use high strength glue such as epoxy. Two different general types have been used (5 minute epoxy-1500 psi, and the regular -2000 psi) of Devcon®. The 5 minute epoxy has been used most of the times because of the fast curing time. However, the epoxy glue starts to harden very quickly so that the glued parts must be utilized rapidly.

3. Apply the epoxy glue to the glass plates of same sizes of 0.25” and 0.125”. For example, join the 23” X 1” of 0.25” and 0.125” by applying a thin layer of the epoxy glue to one of the plates, and attach the other plate to the first. The same procedure has to be applied to 10.5” X 1”, 10.75” X 1” plates and 1” X 0.5” pieces (0.25” and 0.0125”).

4. It is very important to practice this step before hand to know the appropriate amount of the epoxy glue to be applied to the plates. Too much epoxy glue will spill outside of the plate creating undesirable gluts of glue. Furthermore, it is important not to allow any air between the plates. Leaving the trapped air behind the glue will allow the model fluids to leak out through the plates.

5. Applying some pressure gently at the plates will drive the air out. It could be easily checked visually by seeing the homogeneity of the glue between the plates.
6. The horizontal well was placed by using plastic tubing with an outside diameter of 0.25” with wall thickness of 0.033”. The tubing has to be perforated by using a hand drill with 0.0625” bit. Those perforations will serve the same purpose of regular perforations (to allow fluids to flow in well). It is advised to create as many perforations in the tubing as possible to allow the least pressure drop across the perforation. Next, attach the end fitting to one of the sides. It is important to measure the effective face width of the physical model that it is equivalent to the length of perforated zone of the horizontal well and not perforate beyond that length. For this model, the 0.25” tubing is usually cut to 25.5” length, but the perforated length is only 22” (Figure 13)

7. Next, the glass model was put together by applying a thin layer to 23” X 1” glued parts to the 23” X 13” at the bottom of the long side of the glass plate. Then apply a thin layer of glue to the two sides’ spacers (10.75” plates) on the 23” plates. It is recommended to leave a very small gap between the spacers no larger than 0.25” that will be filled with a sealant later. Attach the perforated tubing to the 23” X 1” plates by applying a thin layer to the bottom side of the tubing and attach it mechanically to the model with C-clamps and allow sufficient time to cure the glue. The 1” X 0.5” spacers have to be distributed throughout the large glass plate to provide the structural support and to provide dimensional stability (glass tends to bulge a little under pressure). The parts that have been assembled together now will be called as model sub assembly below.

8. The next step is to attach the second 23” X 13” plate to the model sub assembly by applying epoxy glue to all the surfaces of the glass spacers that are in contact with the second 23” X 13” glass plate. This process has to be done rather fast before the epoxy glue begins to cure. Once the second glass plate is laid and aligned correctly to the sub
assembly, it is recommended to apply some pressure on the model to drive the air out of the glue; C-clamps were used as a mean of pressure application (Figure 9).

9. Once the glue was cured it can support the model weight, which normally takes up to two hours to complete. Apply Permatex® Clear RTV Silicone to the three sides that have spacers to prevent any leakages from the model.

10. It is recommended to allow a minimum time of eight hours to allow the silicon to cure and stay in place. It is important that not to leave any air pockets between the silicone and the spacers.

11. Two different sand sizes are required for the model to function correctly and provide the flexibility to clean the model once used. The upper 9.5 inches of sand is U.S. Silica Ottawa Sand of mesh size 50/70 (Appendix M). The other sand used is from the same company, but of mesh size 20/30 (Appendix L). The 20/30 sand has to be located near the horizontal to act like gravel packing because the perforation size is much bigger than the 50/70 sand grains diameter, causing sand production. However, applying the 20/30 with 0.5” to 1” height above the bottom of the model will prevent any sand production thereby allowing the fluids to be produced into the horizontal well.

12. Once the model is filled with sand, while keeping enough space on top for the 10.75” X 1” spacers to be glued to the model it is recommended to compact the sand with a rather large piece of the glass. Compacting the sides of the model is crucial because it has been observed that the model would have the highest permeabilities on the sides of the model thereby breaking through from there first (boundary effects). Consequently, over compacting the sand will cause separation of the spacers, bulging in the large plates, or/and fracture in the large plates.

13. The following important points must be considered while gluing the top spacers.
➢ It is important to measure the distance between the two previously glued vertical spacers after assembling the model. Then subtract a half inch and divide the total by two and cut the top spacers to that value. 10.75” is an approximate number that needs to be always adjusted to fit loosely into the model as it is the step in assembly. The inside dimensions of the model tend to change every time a model is built due to human error. Therefore, the human error could be fixed with making the top side spacers fits according to the situation.

➢ Apply a thin layer of glue to both sides of the top spacers and insert them inside the glass model on top. But, a three inch of the 0.25” tubing with an end cap is to be inserted between the two spacers and above the sand top. Leave a gap between the side vertical and horizontal spacers for filling later with silicon. Using the C-clamps, apply some pressure at the large glass plates at the location of the two horizontal spacers that are sandwiched between the two large glass plates as soon as possible to get rid of the air that is trapped with the glue.

13. Allow two hours for the glue to cure while under the C-clamps pressure. Then, remove the C clamps and apply the silicon sealant above the horizontal spacers. It is recommended to allow a minimum of 24 hours for the sealant to cure and to provide an adequate seal.

14. The next step is to perform a visual inspection of the glass model to check if there are any cracks in the glass. If there are areas that are vacant of sealant or may require more sealant, add some silicone sealant.

15. Attach C-clamps to the glass model through out the four sides. It is recommended to attach a clamp approximately every two inches to provide the mechanical binding of the model and to prevent any leaks. The clamps have be cushioned rather than to have a
direct contact with glass. The contact area of the clamps tends to have rough edges. Consequently, when the clamps are applied to the glass, highly concentrated stress points will form which have lead to failures in the glass.

![Image](image_url)

**Figure 13**: A picture of the glass model sub assembly

16. Finally, attach the (1/4” to 1/8”) crossover unions to all the end caps and tighten them carefully without removing any sealant or breaking the glue connection. Attach 1/8” tubing to the model with a valve at the end of each tubing to enable shutting in the model.

### 4.2 Experimental Reagents

Simplicity was followed as much as possible without jeopardizing the integrity and the accuracy of this research. The materials that have been selected to be used in this research study have been used in similar work previously. Materials have been used in this research study are:

- Silica based sand with two mesh sizes (20/30 and 50/70) that have been bought from US Silica at Ottawa plant (Appendices L & M).
- Distilled water
• Decane with purity of 99.99% that has been purchased from Fisher Scientific Company with measured density of 0.7194 gm/CC Appendix D and measured viscosity of (0.966 cP (Appendix C).

• Soltrol 170 Isoparaffin that have been purchased from ChemPoint.com. The soltrol measure density is 0.77 (Appendix E) and the measured viscosity is 2.93 cP (Appendix C).

• Naphtha (VM&P 1% Aromatic) was purchased from Ashland Chemical Company. The measured density of 0.736 gm/CC and viscosity of 0.727 cP (Appendix B).

• CO₂ was purchased from BOC Company in the form large cylinders with purity of 100%.

4.3 Experimental Procedure

The experimental procedure was simplified as much as possible while keeping the procedure as accurate as possible. Gravity feed was used very often; on the other hand, a pump was used when injection rate accuracy was crucial. The experimental procedures can be divided into two subgroups. The first one is focused on preparing the model for first dry run while the second focused on conducting the experiment.

The first subgroup as mentioned above is focused on the preparation for the first experiment; measuring the porosity could be only done at this time, especially when the model is flooded the first time with water. The first subgroup procedure involves the following steps.

1. Prepare a burette that has 1/8” tubing and fittings and fill it up with distilled water. It is important to reduce or even eliminate the dead volume in the connection tubing whenever it is possible. The best way to reduce the dead volume in the tubing is to use the shortest possible tubing that is fixed on the model, and try to fill all other tubing with
water before hand. The burette tubing should be filled with water and have the water level in the burette to be reset to zero before the beginning of any porosity measurement.

2. Next, connect the burette’s tubing to the horizontal well fitting, which is located at the bottom of the physical model and open the burette to flow. The burette usage is more accurate than the pump because the volume could be measured accurately and directly while not the pumping time, the available does not measure fluid volume. The upper vertical well has to remain opened to allow the air to flow out of the model rather than creating pressure inside the model thereby leading failure of the model or trapping of air in the model. The burette might need to be refilled during the course of measurement depending on the pore volume. It is crucial to keep track of the exact volume of water that has imbibed inside the model. In order to know the porosity, the pore volume is divided by the bulk volume of the model. However, it is important to subtract any tubing dead volume from the injected water volume that could not be filled before the porosity measurement as instructed in step 1. Furthermore, if there is any dead volume that could reduce the bulk volume must be accounted for such as the small glass spacers that were used during construction to provide structural strength. Accurate porosity is necessary to obtain accurate dimensionless numbers. To calculate the dead volume of the tubings the following formula has been used:

\[
V_{\text{dead}} = \left( \frac{P_i}{4} (ID)^2 \right) \times 6.4516 \times L \times 2.54
\]

(1)

It should be noted here that the ID of the 1/8” tubing is 0.0625” and the ID of 1/4” tubing is 0.184”, keeping in mind that the units of the above formula are in (CC).

It has been observed that for the first time any of the models is run, the oil saturation in the model tends to be lower than that when the model is cleaned and then re-flooded with oil. The saturation difference could reach 25% and the sand tends to move around the model and
compaction changes as well. Therefore, these changes can lead to a change in permeability. So, it is suggested to perform a dry run (no records need to be taken) on the model first. Then, prepare the model for a regular recorded run. The steps described below are then followed.

4.3.1 Model Preparation

1. Circulate distilled water in the model from top to bottom to clean the sand, stabilize the system and make sure that the entire model is flooded with water.

2. Fill the burette with red dyed decane to flood the physical model from the top to bottom in a gravity stable manner. It is important to open the horizontal well to flow out while collecting the fluids that are flowing out into a large beaker. Large beaker allows long flooding time with a little shut in time. Initially, only water will flow out that is displaced by decane. Later, the decane will breakthrough. In order to have the highest possible oil saturation in the model, pressure is needed to displace the water out of the water wet sand. Therefore, creating as much pressure as possible on the model inlet without exceeding 1.5 psig is useful, by using more than one burette, if possible, that are connected to a tee connection or cross connection and to connect that tee or cross to the model inlet via 1/8” tubing. A second method that is effective in increasing the pressure is to elevate the burette as much as possible above the top of the model. Another way is to open the outlet at maximum. Opening the outlet to maximum creates the least back pressure on the fluids entering the model, thereby leaving the available to pressure to be used to displace the water out.

3. Once the water production ceases to flow out and only decane is flowing out, stop the decane flooding at that time.
4. Next step is to clean the model and finish the dry run. The best and the most efficient method of cleaning the model is to flood the model with CO₂ to drain the decane and water out of the model. CO₂ injection pressure should not exceed more than 1.5 psig. Consequently, a small scale pressure gauge needs to be installed at the injection inlet. The produced decane can be separated from the water easily and reused in the experiments to be followed later.

5. Once most of the oil and water are produced by CO₂ injection and the only production is gas, then stop CO₂ flooding.

6. The best fluid that was identified to clean the model was acetone. Acetone is strong enough to dissolve the decane but it does not act that much on the epoxy glue so that it is not dissolved in the process. Since the density of acetone is equal to 0.7851 gm/cc while the decane density is equal to 0.71 gm/cc, bottom flooding is recommended for the cleaning cycle in gravity stable manner. Continue injecting acetone from the burette until no red dye is seen in the model.

7. Then, inject water from the horizontal well in the gravity stable manner as well. Bottom water injection was found to be effective in removing the acetone out of the model after three to four pour volumes of water injection.

The last step is to measure the permeability. Permeability is measured indirectly using Darcy’s law by measuring the flow rate, the pressure drop between the injection and the production points, the width of the cross sectional area of the sand and the height of the sand.

8. The first step is to allow water circulation inside the model from top to bottom for a while, using two to three pore volumes to stabilize the system.

9. Fill the burette while the system is flowing and have a stop watch ready. The stop watch should be started at the moment when the top of water is at the zero mark, and then stop it
at the 10 cc mark. Calculate the flow rate by dividing the injected volume (10 cc) by the
time and the result should be in cc/sec. Since the pressure exerted in the permeability test
is based on hydrostatic head, changes in the hydrostatic head will change the pressure
exerted on the porous media inlet. Hence the least amount of water that leads to the least
hydrostatic pressure drop should be used (10 cc).

10. Measure the height in inches of the water in the burette from the top of the sand and not
from the floor level. Convert this measurement to pressure by using the following
formula:

\[ P_{(Atm)} = (0.052 \times \text{height}/12) \times 8.33)/14.7 \]  

(2)

The unit of pressure will be in atmospheres for application in Darcy’s equation. It is
assumed that \( \Delta P \) is equal to the value of the pressure that is calculated above since the
outlet pressure is atmospheric.

11. Measure the face width, thickness and height of the porous media as well. The units of
these measurements should be in \( \text{cm} \) to be used later in Darcy’s equation. The cross
sectional area of the porous media is calculated by multiplying the thickness by the face
width.

12. The viscosity of the distilled water is taken as 1 cP. Finally, Darcy’s law is used to
calculate the permeability of the porous media and is given below

\[ K = \frac{q \times \mu \times L}{A \times \Delta P} \]  

(3)

The unit of permeability in this form of Darcy’s equation is in Darcy (0.9869 \( \mu \text{m}^2 \)).

The main objective of all the above steps is to prepare the physical model for use in the
experiments. Furthermore, it was observed that the failure of the visual model after previous
steps is rare. All the previous steps are simply used for testing the model durability. Now the
model is ready for GAGD Experiments. The procedure followed in the next phase is as described below.

13. Flood the physical model with the red dyed decane again, as before (top to bottom) in gravity stable manner, as in step 2 above. The produced water is collected carefully because it is the best indication of the amount of the oil in physical model. Therefore it is recommended to use a beaker with precise reading increments, not higher than 5 cc/increment, at the beginning of the flooding until most of the oil is produced. Then switch to a bigger beaker to keep the flow continuous as long as possible. It is recommended to flood the visual model with three to four pore volumes of decane to ensure that all the mobile water has been drained.

14. The next step is to collect all the water that has been produced in the previous step and calculate the amount of oil in place. Knowing the amount of oil in place is essential for material balance and recovery calculations later on.

15. Prepare the time lapse camera by first starting the Logitech Image Studio® software. Then set the time interval according to the length of the run and injection rate. The shorter the time interval, the longer is the play time and the larger the stored file on the computer. For instance, when the flow rate was set at 2 cc/min, the flood front velocity is relatively low hence the time interval can be set at 30 seconds (Figure 14). If the injection rate is set around 8 cc/min, where the flood front will move much faster and the picture time interval should be shorter (say 10 seconds).

16. Once the camera is set up correctly, set the time display clock to the desired starting time. Three different types of experiments were conducted, namely immiscible CO₂ injection, miscible liquid solvent injection and water flooding. The overall configuration of the experimental apparatus should like Figure 16 and Figure 17.
Figure 14: Time lapse setup menu on the Logitech Image Studio
Figure 15: Schematics of the experimental apparatus setup
4.4 Immiscible CO₂ Injection

1. Connect the CO₂ rotameter via the appropriate tubing to the desired injection location. It is important to have back pressure on the rotameter by about 10 to 15 psig from the CO₂ source to guarantee continuous flow without any pulsation.

2. Connect the horizontal well to the separator. It is recommended to have more than one separator. When one separator is full, then switch to the second separator without interrupting the experiment. The separator is connected to a second CO₂ rotameter to measure the produced gas flow rate at ambient pressure and temperature.

3. Start the time lapse camera, then open CO₂ rotameter to desired flow rate, start the stop watch and finally open the horizontal well to flow out to the separator.
4. Readings such the oil level in the separator, water level, injection pressure, and CO₂ injection rate should be taken frequently. The rotameter might have small variation of injection rate due to variation of injection pressure. Hence, it is important to monitor the rotameter and adjust the flow accordingly. Furthermore, it is important to observe the progress of the experiment and record the important events such as breakthrough time, heterogeneity effects and discoloration.

5. The average experimental run time was about 5 hours. The time lapse camera could be shut down before the end of the 5 hours upon discretion to save disk space and video playing time, especially if there are no major changes in the porous media are taking place.

6. Shut in the physical model by closing the CO₂ injection, and the horizontal well valves. Deplete the pressure inside the model, especially when the pressure inside the model is above 1 psig. Even though the model appears to be strong, little pressure for a long time may lead to undetectable leaks, especially in the presence of solvent such as decane.

For the visual model to be used again for conducting similar type of experiment such as injecting CO₂ at a different rate there is no need to clean the model for removing the red dyed decane. Simply flood the model with decane again and then same amount of decane in place can be assumed as the previous experiment unless some water production took place (very rare). In the case of any water production due to CO₂ interfacial tension changes, account for the water produced and add it to the previously recorded amount. The decane re-flooding should be done from bottom to top of the model.
4.5 Miscible Liquid Solvent

The miscible experimentation was designed to mimic miscible gravity drainage of CO₂. In the miscible case, a minimum miscibility pressure has to be established for the miscibility to take place. Increasing the pressure on CO₂ will cause the density of the gas to become much higher than that under the immiscible situation. In fact, CO₂ density will approach the oil density and the density difference will be very little. Furthermore, the two fluids have to be miscible with each other just like miscible CO₂ gas and oil.

In order to simulate the low density difference, two fluids of close densities have to be used. Naphtha and decane are chosen for use in these experiments. The density of naphtha is 0.736 gm/cc (appendix B), and the density of decane is 0.719 gm/cc (appendix D). The densities of the two fluids have been measured. Furthermore, naphtha and decane are miscible (Figure 17). Therefore, it has been decided to use red dyed naphtha for oil and clear decane to represent miscible CO₂ gas. The miscible liquid solvent experimental protocol was very much the same except in few steps as described below.

![Figure 17: Testing miscibility of decane and naphtha](image)

1. Flood the physical model with red dyed naphtha in similar manner as discussed in step 13.

2. Fill the transfer vessel with fresh uncolored decane. Drive the air out of the decane section of the vessel. Shaking the vessel slightly would help to drive the air out. Once the decane is the only fluid that is coming out of the vessel, then connect the vessel to the
physical model via 1/8” tubing. A pressure gauge should be connected to the tubing to measure the injection pressure for later calculation and it is important not to exert high pressure on the physical model that leads to a failure. It is recommended to always maintain the pressure below 2 psig.

3. Just like the immiscible CO₂ run, perform steps 2 through 5 as mentioned in immiscible CO₂ injection.

After the completion of each of the miscible runs, the physical model has to be cleaned by injecting acetone and follow the steps 7 and 8 mentioned in model preparation.

4.5.1 Waterflooding

Waterflooding is a standard secondary recovery technique that has been widely practiced in the field. The following experimental procedure was designed to investigate the effect of prior waterflooding on GAGD performance:

1. Prepare the model as described in steps 13 through 16 of model preparation procedure.

2. Connect the pump directly to physical model without any connection to the transfer vessel because the injection fluid is distilled water which can be fed to the pump directly.

3. Just like the immiscible CO₂ run, perform steps 2 through 5 as discussed in immiscible CO₂ injection.

Waterflooded models need to be cleaned to remove any residual oil saturation. Follow steps 7 and 8 from model preparation procedure to clean the model.
5 Results and Discussion

This research project was aimed at evaluating and characterizing the GAGD process using a glass model for visualization in addition to matching measurements for quantifying the performance. This visual model has been found to be very useful in studying the GAGD process in the laboratory. The use of a visual model in laboratory experiments has many advantages and disadvantages. Advantages provided by the model are the flexibility of testing various configurations such as injection depth variation, injection location, and the ability to insert a horizontal well. The main disadvantage is that such a glass model can only be operated at ambient conditions of pressure and temperature. The visual approach also provides the flexibility of visualizing the results as they take place rather than just imagining or speculating the mechanisms. The visual model results are discussed in terms of the gravity number and dimensionless time in order to scale the model findings to the field. Visual experiments have been conducted to compare between GAGD processes with presently used conventional processes. The visual experiments are divided into two sub groups: the secondary recovery mode and the tertiary recovery mode.

In the secondary recovery mode, it is has been assumed that the primary depletion drive, whether it is gas cap, gas in solution or water drive has been completed. Therefore, the secondary recovery process in this case was selected to be CO$_2$ GAGD process. In other cases, waterflooding was selected to be the secondary recovery, and then CO$_2$ GAGD was applied as the tertiary recovery method.
5.1 Secondary GAGD Experiments

The definition of secondary recovery is nothing but an external fluid such as water or gas injected in the reservoir (Slb.com, 2006). Almost all reservoirs will go through the secondary recovery phase because the primary depletion rarely recovers more than 20% of IOIP without water drive. However, in water drive reservoirs, primary recovery could be as high as 40% IOIP.

The purpose of this group of experiments is to seek answers to the following questions:

- Is GAGD valid as a secondary recovery method?
- How can the gravity force be the dominant force in place?
- What are the possible configurations that GAGD process can use? Does it always have to be top injection?
- Would injecting miscible gas have a better recovery than immiscible gas injection?
- What is the effect of injection rate on oil recovery and breakthrough time?
- Can GAGD be an effective means of oil recovery for naturally fractured reservoir in miscible and immiscible modes?
- Is GAGD applicable for heavy oils as a non-thermal attractive?

In order to answer the above questions, the secondary recovery experiments were further subdivided into several groups namely injection depth, injection rate, injection method and fractured models. Furthermore, each one of the above groups has been investigated in the miscible and immiscible mode as well. However, one experiment was conducted to establish a base case that will validate the effect of the GAGD in visual glass models.

5.1.1 Base Case Experiment

This base case experiment was simply done by allowing only free gravity to facilitate oil recovery under atmospheric pressure without any interference or the presence of CO₂. This
experiment was performed in the same manner as all the other immiscible experiments with the exception of opening the model at the top for air entrainment. The importance of this experiment is to understand the effect of free gravity drainage, the influence of the hydrostatic head of fluid in place and to make sure that capillary pressure exists in this visual model just like real reservoirs. The oil recovery lasted for a relatively short time with a recovery of less than 43% IOIP. Visual observations indicated still higher residual oil saturation (Figure 18), while the oil production seized in a very short time after gas breakthrough (Figure 19).

This experiment thus served as a proof of the general validity of all the experiments to be followed and also shows the effectiveness of CO₂ when present in the process in the GAGD recovery process.

5.1.2 Visual GAGD Performance

The first set of experiments was aimed toward investigating the general functioning of GAGD. It was hypothesized that are large reservoir scale, once the injection of CO₂ begins; a gas cap will form in a semi circular shape that is centered on the injection point (Figure 7).

This semi circular gas cap will grow up thereby draining the oil out of the sand. However, laboratory experiments using the small visual models have shown otherwise especially in the
immiscible mode. As the CO₂ gas being injected into the visual model, the oil started to drain out of the model from the top to bottom but with a near horizontally flood front (Figure 20) rather than semi circular like with little viscous fingering. The near horizontal flood front proves that the density contrast between CO₂ gas and oil is allowing the gravity force to dominate the flooding process. Since CO₂ viscosity is near insignificant (0.01477 cP) (Appendix J) compared to decane in place (0.92 cP) (Appendix C). The mobility ratio will have an adverse effect. Hence the viscous force and viscous fingering will have some effects on process but are limited under gravity stable flood.

![Figure 19: Oil recovery in free gravity drainage experiment](image)

One of the most important advantages of the GAGD process is that using CO₂, the volumetric sweep efficiency (Ev) in the immiscible mode at or near 100% in the visual model (Figure 21).

The volumetric sweep efficiency is defined (Lake, 1989) as

$$E_v = \frac{\text{Volume Of Oil Contacted By Displacing Agent}}{\text{Volume Of Oil Originally In Place}}$$  \hspace{1cm} (4)

The overall recovery efficiency is defined as (Lake, 1989):

$$E_r = E_d \times E_v$$  \hspace{1cm} (5)
where $E_D$ is the microscopic sweep efficiency.

The high volumetric sweep efficiency is due to the domination of gravity forces (Martin, 1992), which is a direct result of the large difference in density between the two fluids. CO$_2$ has flooded the model almost completely from top to bottom. Furthermore, CO$_2$ did not bypass the heterogeneous zones when flooded under gravity domination.

![Figure 20: CO$_2$ gas is draining the model](image1)

There are two main factors that control gravity domination in GAGD Process. They are the density contrast between fluids and the low injection rate to minimize viscous forces and improve the gravity number. However, the presence of viscous force is also important in the GAGD process for pressure maintenance and to displace the oil out of the porous media. However it is much more important to maintain the domination of the gravity force in the process.

![Figure 21: Two pictures of the same model, before and after the CO$_2$ flooding](image2)
Further experimental observations have shown that the injection pressure tends to start near zero at the beginning of the experiment. However then it starts to rise slowly as the experiment progresses. The sharp and relatively faster increase in pressure indicates gas breakthrough initiation (Figure 22). After personal communication with experts in this research field (Prof. Langlinais, LSU, April, 2006), it is confirmed that the gas injection pressure climbs very fast just near breakthrough because of oil flow near the horizontal well changes from continuous to droplets that are accumulating in the pore space. The visual model pressure has to exceed the interfacial tension of the droplets so as to force them out of the pore space into the perforations of the horizontal well. For a high injection rate the pressure will be maintained relatively high enough to overcome the surface tension of droplets. On the contrary, if the injection rate is relatively low, the pressure will have to build up enough to overcome the surface tension in order to facilitate the oil to flow out. However, when the pressure inside the model drops below the surface tension, the flow in the horizontal well stops and the pressure build up cycle begins again. From Figure 22, it can be seen that the 2 cc/min pressure line has many swings of up and down pressure build up and loss. On the other hand, the 8 cc/min pressure line has only one pressure swing. Furthermore, it was observed consistently that the first injection pressure peak is an indication of gas breakthrough near taking place. However, this peak is not the highest value over the life of the run, but the first.

5.1.3 Effect of Injection Depth on GAGD

It has been hypothesized before the beginning of the experiments that if the CO₂ gas is injected near the horizontal well, production will begin at a sooner time. It was believed sooner production time is due to the forming of a gas balloon near the injection point thereby draining the oil from the gas balloon zone. If the balloon is close to the horizontal well, production will
begin with very little time delay after injection. However, this CO\textsubscript{2} gas balloon will have to rise to the top of the pay zone and form a semi-circular shaped gas cap that will eventually drain the oil from top to bottom in the entire pay zone.

![First Pressure Peak](image)

**Figure 22:** Pressure fluctuations in visual model

Therefore, four injection depths were chosen for examination namely the very top of the pay zone, 2.5”, 5” and 7.5” from the top of the pay zone. These depths represent 0%, 25%, 50% and 75% of the physical model height, respectively. In order to eliminate or minimize any external effects on recovery other than injection depth, all four injection locations were fitted inside one visual model.

However, the formation of a CO\textsubscript{2} gas balloon was not observed in the experiment. The CO\textsubscript{2} gas has always traveled to the top directly without forming a gas balloon around the injection point (Figure 23). The relatively loose packing of the sand around the outside periphery of the injection tube appears to be the reason for the gas to rise to the top immediately upon entering the model. However, it is believed that the vertical and horizontal permeabilities are near equal in
the visual model, which is rarely true in real reservoirs. Therefore, the absences of this phenomenon could be attributed to permeabilities issues.

However, it was observed that there were no real variations in oil recovery among the three the injection depths of 0”, 2.5” and 7.5” from the top of the pay zone (Figure 24). However, 5” injection depth recovered a little less oil than the other three injection depths. But it is believed that the injection well was somehow filled with sand creating a restriction on the injection rate in the case of 5” injection depth. The 5” depth injection pressure has researched 0.9 psig, while the highest recorded injection pressure with the other three were only 0.4 psig. This observation clearly indicates that relatively low oil recovery obtained in 5” injection depth case is due to well related effect and consequent restriction on flow.

Furthermore, the gas cap formation has been observed as a near horizontal front rather than a convex shape. The horizontal front of the CO₂ gas suggests that the dominant force in place is the gravity force compared to capillary and viscous forces and that the flood front is stable as well.

Gas breakthrough times in these four experiments have been between 39 and 45 minutes. Near equal gas breakthrough times once again suggest that all four runs were gravity stable and the
dominant force is the gravity. The similar gas breakthrough times also suggest that the gas will always travel to the top of the zone immediately upon injection due to the density contrast. Furthermore, the breakthrough time is governed by the gas cap and not by the injection depth. Additionally, the initial overlap of oil recoveries at all the for injection depths as shown in Figure 24 suggests that the initial process involving drainage and displacement is the same for all the four depths.

![Figure 24: Effect of injection depth variation on ultimate recovery](image)

**Figure 24**: Effect of injection depth variation on ultimate recovery

### 5.1.4 Effect of Injection Rate on GAGD

Gas injection rate is one of the most important factors that need to be optimized for the success of the GAGD process. Injection flow rate controls the flood front velocity and hence dictates whether the gravity force is the dominating the process or not. If the injection rate is too high, two negative factors will be generated adversely affecting the GAGD process. The pressure will increase rapidly causing the viscous force to gain more domination. Another disadvantage of
high pressure is the increase of in situ CO₂ density that leads to less gravity domination in the process. However, higher injection rate tends to decrease the time required to complete the process and makes the GAGD process more attractive economically. Furthermore, increasing the CO₂ gas pressure in the reservoir is beneficial due to increased CO₂ solubility in the oil. Higher CO₂ gas in the solution lowers the interfacial tension, hence improved E_D, and lowers the viscosity of the oil. Therefore, a balance between gravity domination, gas in solution and economics needs to be maintained for successful GAGD field implementation.

A set of GAGD experiments at three different injection rates were performed. The three injection rates used were 2 cc/min, 4 cc/min and 8 cc/min to simulate low, intermediate and high injection rates. Interestingly, it was observed that the higher the injection rate, the higher the ultimate GAGD oil recovery in the visual model (Figures 25).

![Figure 25: Effects of injection rate on GAGD oil recovery](image)

5.1.5 Mechanism of GAGD Oil Recovery

It is believed that the oil recovery in the GAGD process is initially dominated by displacement mechanism. The liquid oil hydrostatic pressure is assisting the CO₂ gas to displace the oil out of
the porous medium. However, the displacement mechanism loses domination after breakthrough because the displacement process requires pressure drop as the driving force, which is present as the first peak in the injection pressure profile shown in Figure 26. Once the breakthrough takes place, the gas pressure drop tends to decrease. However it does not become zero because of other causes such as relative permeabilities, capillary trapping and horizontal well effects.

The gravity drainage mechanism starts to gain domination after gas breakthrough, and vertical segregation starts to take place draining the fluids from top to bottom to be produced in the horizontal well.

It was observed that when the physical model was shut in for a period of time, the model seems to segregate the denser phase (oil) from the lighter phase (CO₂ gas) causing vertical gravity segregation, which has been observed by Rathman (2006). Furthermore, the oil in the gas zone would have more time to drain out of the pore space and accumulate at the bottom of the model causing vertical segregation (Figure 27). This vertical segregation is highly advantageous to optimize the ultimate recovery especially when most of the production is CO₂ gas, the visual model was shut in for a period of time. However, when CO₂ gas injection resumed, an increase in the oil recovery has been observed. The increase in production could be as high as 5% when the production is reinitiated. Figure 26 shows an increase in oil recovery by 5.3% in a relatively short time in GAGD visual model experiments.

### 5.1.6 Effect of Miscible CO₂ Gas Injection on GAGD

Miscible CO₂ gas injection has been practiced in field extensively in different forms namely Continuous Gas Injection, and Water Alternating Gas injection. According to literature, it has been hypothesized that the microscopic displacement efficiency of miscible gas injection is at or
near 100% (Shedid et al, 2005; Charkravarthy et al, 2006). Miscible experimentation was necessary to validate these hypotheses. However, due to the glass visual model limitations and the necessary high pressure required to achieve miscibility, it was not possible to simulate the miscibility conditions in the physical model using CO₂ gas. Hence two different miscible liquids were used instead to simulate the miscible GAGD tests. The fluids that were chosen for miscibility simulation are red dyed naphtha for oil and clear decane for miscible CO₂ gas.

![Figure 26: Effect of gas injection rate on oil recovery](image)

This experiment proved that \( E_D \) is indeed approaching 100% in miscible flooding. It has been visually verified by observing the complete disappearance of the red dye from the flooded area of the visual model. However, as evident from Figure (33), the volumetric sweep efficiency \( E_V \) is less than 100%. In fact initially, \( E_V \) was considerably less than the immiscible \( E_V \). But, two
different ways have been identified to increase $E_V$. The first one is to allow enough time for miscible injection, which would eventually flood the whole model providing an $E_V$ of 100%. However, this may require large volume of the miscible CO$_2$ gas injection. The second way is to inject the miscible CO$_2$ gas at a very low rate. Also, control the production to be at minimum so as to optimize the gravity force and minimize the viscous force at the same time. Extensive economic studies are required on both these scenarios before going for any field implementation because of time and cost impact on the project economics.

**Figure 27**: Vertical distribution of oil saturation

Furthermore, it appears that the miscible injection in the visual model is quite sensitive to the injection rate. This can be attributed to low density difference between the two liquids used (0.01655 gm/cc, Appendices B and D). This density difference is negligible compared to the immiscible case density difference of (0.7176 gm/cc, Appendices D and J). Therefore, any increase in rate will allow more viscous force domination which might lead to viscous fingering and premature gas breakthrough (Figure 28), which leads to be recycled thereby raising the operational costs.

It is crucial to mention that the gravity domination on the process of the field miscible GAGD is expected to be better than the laboratory gravity domination. In the laboratory, the fluids density
difference was negligible as been mentioned. But in the field, the density difference will be much larger. The CO\textsubscript{2} gas density under 4000 psig and 239 is 0.2111 gm/cc (Appendix K). The density value will result in density difference of 0.67 gm/cc for typical 30 API Gravity oil. Therefore, gravity force will be much bigger than the laboratory gravity force which leads to better GAGD oil recovery.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{miscible.png}
\caption{Miscible drainage simulations (8 cc/min).}
\end{figure}

In the laboratory experiment, reliable recovery data was not obtained from miscible injection because the two liquids are miscible with each other even in the separator. Unlike two miscible liquids, miscible CO\textsubscript{2} gas would evolve in the separator as soon as the pressure drops down. Therefore, the naphtha volume measurements in the separator were not recorded after decane breakthrough. Furthermore, the breakthrough time could not be observed accurately for the same reason. However, measurements of recoveries due to miscible fluid injection have been made with some reliability up to the breakthrough time. Although limited quantitative results were obtained from this experiment, the data could be useful in providing the conceptual understanding of miscible injection (Figure 28).

It seems that the higher the injection rate, the lesser is the recovery at the breakthrough, which is obvious because the higher the injection rate the stronger the viscous force and the lower the
gravity number. However, with higher injection rates, the oil recovery was also much faster (Figure 5.14) and this might be attractive economically as well. It is cautioned that the miscible experimental results reported in this study are unreliable after breakthrough point. Therefore, it is suggested to look in to other reports that contain more accurate miscibility results on GAGD (Kulkarni, 2005).

![Figure 29: Miscible recoveries in GAGD](image)

5.1.7 Effect of Vertical Fracture on GAGD

The literature review has revealed that much of the oil in the world is in carbonate reservoirs. Furthermore, the literature review suggested that most carbonate reservoirs are naturally fractured. Therefore, fractured carbonate reservoirs need to be considered for any EOR processes. Generally naturally fractured reservoirs have not been considered as good candidates for gas EOR process. This is mainly because theses processes perform horizontal flooding between two vertical wells, and the great density contrast between the two fluids (CO₂ gas and
oil), particularly in the immiscible mode, will cause the gas to find an easy path of low resistance through the fracture to the production well; thereby causing premature gas breakthrough and low oil recoveries. However, gravity drainage has been hypothesized to be an effective method of EOR in naturally fractured reservoirs.

Therefore, a set of experiments was conducted to investigate the impact of vertical fractures on GAGD. One of the visual models was built to simulate the naturally fractured reservoirs by inserting two cylindrical shaped fine wire meshes inside the model. The results were as expected; immiscible GAGD was proven to be a successful method of EOR even in the presence of fractures. The fractures did not show detrimental effects on GAGD oil recovery. The observations in are in good agreement with the finding of Wood et al (2006). In fact, this laboratory study as shown in Figure 30 indicated clearly suggested that natural fractures would improve GAGD oil recoveries when compared to un-fractured ones (Figure 30) as explained below.

When CO₂ gas is applied in a gravity stable manner, the gas will naturally try to stay on the top of the pay zone and then slowly expand. If the gravity force is maintained to be the dominant force in place, then the natural fractures will work as an effective additional exchange path between the CO₂ bearing fractures and the matrix containing the oil (Figure 31).

However, if the gravity force looses its domination to viscous force, then adverse effects are expected. These adverse effects include premature gas breakthrough, viscous fingering and lower volumetric sweep efficiency as shown in the miscible GAGD run in the fractured model (Figure 32). It is believed that due to the very low density contrast existing because the model fluids used (naphtha and decane) is only 0.01655, which is far from field realities.
5.1.8 Application of Huff-n-Puff in GAGD

Steam Huff-n-Puff is one of the standard heavy oil EOR practices that have been effective in the field. The process consists of injecting a slug of steam from vertical wells, and then shutting the well in to provide a soaking period in order for the steam to increase the reservoir temperature and lower the viscosity of the heavy oil, then putting the injection wells on production. Huff-n-Puff can also be used with a limited number of cycles until the area surrounding the vertical well has very low oil saturation. Then it will be difficult for the oil to flow into the well because of relative permeability effects.

![Figure 30: Effect of the natural fractures on GAGD oil recoveries for the immiscible case](image)

![Figure 31: Vertically fractured porous media in immiscible CO₂ gas flooding](image)
Figure 32: Miscible injection in vertically fractured porous media

It has been visually observed the CO₂ gas always migrates to the top of the pay zone regardless of the injection depth as was discussed in section 5.1.2 (Figure 33). Hence, it has been proposed that GAGD could be conducted in a similar Huff-n-Puff fashion, but using a horizontal well instead. It was believed that injecting CO₂ gas and producing oil from the same horizontal well may be economically attractive as well. Economic savings can be achieved by not drilling additional vertical wells for gas injection in the filed. Therefore, one of the visual models was modified to have the horizontal well that can handle both the injection and production as well. The results turned out to be interesting. The ultimate production was near 71% (Figure 34). This oil recovery was almost similar to the ultimate recoveries of 65% to 74% obtained in the same visual model for various other GAGD experiments. In this test, oil was produced in every individual cycle unlike steam Huff n’ Puff process where relative permeability effects have showed adverse effects on oil recovery. However, CO₂ gas recycling will be required since every time the oil was open to flow out, CO₂ gas was produced as well from the model and leaving very little CO₂ gas left behind.

Another disadvantage of the GAGD Huff-n-Puff that has been observed is that relatively high injection pressures may be required to force the CO₂ gas through the horizontal well into the sand body and to the top of the pay zone. The other disadvantage is that when the horizontal
well is allowed to flow oil out, the production of oil was rather large and quick in relatively a short period of time. Translating this huge production of oil in a short period to the field would require the need for surface equipments that will be able to handle such high flow volumes of oil for a short period. Such equipment may be very expensive and hence extensive economical studies are required before field implementation. Furthermore, this experiment is not scaled for field applications. The purpose of this experiment is to demonstrate the viability of Huff-n-Puff in GAGD oil recoveries.

![Huff-n-Puff](image)

**Figure 33: Huff-n-Puff**

### 5.1.9 Effects of Oil Viscosity on GAGD

Thermal methods and especially steam injection has been used as the primary method for heavy oil EOR to reduce the oil viscosity. However, the literature review has revealed that the thermal EOR is not effective in all cases. On the other hand, CO₂ gas injection has been gaining ground even in the heavy oil EOR (Luo et al, 2005). Hence, this particular set of experiment was conducted to simulate the application of GAGD for higher viscosity oil.

Soltrol was selected for oil due to its relative high viscosity (2.93 cP) compared to decane viscosity of 0.966 cP (Appendix C). Higher viscosity experiments were conducted in both miscible and in immiscible modes.
The immiscible recovery of Soltrol was lower compared to the experiments where decane was used for the oil phase under similar experimental conditions. The recovery of Soltrol was around 65% for the best case (Figure 35). Higher injection rates seem to have a positive influence on the process similar to low viscosity experiments.

In contrast to lower viscosity runs immiscible CO₂ volumetric sweep efficiency is significantly lower than 100% because of the adverse mobility ratio effect. The difference between the gas phase and liquid phase viscosities has increased by many folds in this case. Viscous fingering was observed very clearly as can be seen in Figure 36, which lead to premature gas breakthrough. Gas viscous fingering would lead loose of gas pressure ending the displacement phase prematurely (Figure 36).
The miscible Soltrol experiment was conducted using red dyed Soltrol for oil and clear decane to represent miscible CO$_2$ gas. The miscible recovery of Soltrol did not seem to be the ideal solution for the situation. Severe viscous fingering was observed even more clearly than the immiscible case (Figure 37) because of losing the gravity advantage of the gas. The density difference between fluid phases was 0.0509 gm/cc, which is relatively very low (appendixes D & E). Consequently, the viscous force was dominant. Furthermore, the adverse mobility ratio effects were present as well. However, it is expected that the gravity force will have more
domination in field application due to higher density difference between the fluids than the laboratory density difference.

![Figure 37: Miscible GAGD process with high viscosity oil](image)

**Figure 37:** Miscible GAGD process with high viscosity oil

### 5.1.10 Effect of Wettability on GAGD

The majority of carbonates reservoirs is naturally fractured and is oil wet or mixed wet. Paidin (2006) studied wettability effects on GAGD oil recoveries in oil-wet porous media using a physical model. Hence, it was suggested to build a model for visualizing the GAGD behavior in oil wet porous media. As expected, the recovery was high in oil-wet porous media compared to water-wet porous media (Figure 38).

One advantage of oil-wet reservoirs is that they can utilize the beneficial effects of the thin film oil flow. Thin film of oil flows on the reservoir matrix rather than droplets that has to be pushed through the pore throats. Since the simulated case represents light oil with relatively low viscosity, $E_V$ will be at or near 100% as proven before. Additionally, the thin film flow of oil facilitates better $E_D$ for the rock, which is evident from the very light color of the model after the GAGD flood (Figure 39 and Figure 40).
Figure 38: Oil wet model recovery graph vs. water wet model

Figure 39: Oil-wet porous media before GAGD

Figure 40: Oil wet physical model after performing immiscible GAGD
5.1.11 Toe to Heel Gas Injection in GAGD

It was hypothesized that performing Toe to Heel gas injection using a single horizontal well would be successful since the CO$_2$ gas would raise to the top of the pay zone. Toe to Heel is simply performing dual completions on the horizontal well. One completion is for conventional horizontal well production (Heel) and the other completion is for CO$_2$ gas injection (Toe).

A visual model was constructed to conduct this experiment. The visual model had two horizontal wells in contact with the porous media. The first well is for CO$_2$ gas injection and it was a very short plastic tubing. At the same depth, the production horizontal well was located two inches away. The experimental results were found to be less than encouraging. The gas was found to break-through in less than one minute. Shortly after that decane production is seized and only the CO$_2$ gas was produced. The CO$_2$ gas has thus found a path of least resistance (Figure 41) through the porous media into the production perforations of the horizontal well.

![Figure 41: Toe to Heal](image)

Therefore, it was postulated that increasing the distance between the injection wells and the production well will permit the CO$_2$ gas to travel to the top and thereby allowing gravity domination. Hence, the distance between the two wells was increased from 2 inches to 12 inches. After re-conducting some of the experiment, the similar phenomenon was observed again. In an attempt to mitigate the early CO$_2$ gas breakthrough, the gas injection rate was reduced from 8
cc/min to 2 cc/min to further enable the gravity force to take over. However, all these efforts failed resulting in poor oil recovery of only 7% IOIP (Figure 42).

It is observed that the CO₂ gas did not travel to the top of the pay zone since the hydrostatic pressure of decane was apparently higher than the gravity force on the gas. In addition, the horizontal well has provided an exhaust path for the CO₂ gas to exit the model thru the production perforations. The test appears not to leverage the gravity force to come into play in the production process.

![Figure 42: Toe to Heel GAGD oil recovery curve](image)

5.1.12 Single Point Horizontal Well Contact Effects on GAGD

All the experiments in this research study utilized the horizontal well that was placed flat at the bottom through out the visual model and representing the line contact with the porous media for GAGD oil recovery. Therefore, it was thought that this configuration might be having an advantage for oil production due to the provision of large contact area (line contact) within the porous media as in the visual model. However, in field practice, the horizontal well does not have as much contact with porous media. Therefore, the horizontal well was placed as a point
contact near the bottom of the visual model to test the influence of the horizontal well placement on the GAGD oil recoveries.

A visual model was constructed for the purpose of placing the horizontal well as a point contact within the porous media (Figure 43). It was decided to perform this experiment by injecting CO$_2$ gas at a rate of 8 cc/min at the very top of the pay zone so as to compare the results with the other 8 cc/min injection rate experiments.

![Figure 43: Diagram demonstrating the difference between single point and conventional horizontal well](image)

At the beginning of the experiment the CO$_2$ gas swept the model with a stable front. Furthermore, the gas flood front went down through the model in a horizontal manner indicating a linear flow. However, when the CO$_2$ gas flood front approached the location of the production point, a semi circular shaped swept pattern was observed with a radial flow (Figure 44).

Figure 45 also indicates that the configuration of the horizontal well placement in the visual model does not influence the GAGD oil recovery. Furthermore, it provides an additional proof that GAGD is a very effective process when gravity forces are predominant in the porous media and when the horizontal well is located at the bottom of the pay zone (Figure 44). Since two different visual models were used, Figure 45 shows some difference between the two oil
recoveries. Of course, each model has its own unique characteristics, affecting the recovery to the extent seen in Figure 45.

Figure 44: Point contact of the horizontal producer with porous media instead of line contact

Figure 45: Point contact production vs. line contact
5.2 EOR in Tertiary Mode

One of the most common practices in the industry is to perform waterflooding on the reservoir after the completion of primary depletion the reservoir. However, waterflooding may not always be the most efficient means of oil recovery for all reservoirs. Thus, the residual oil saturation may still be high in the reservoir even after the waterflood. The next stage of oil recovery involves tertiary recovery or enhanced oil recovery that includes gas, chemical and steam injection.

Natural bottom water drive in reservoirs is considered to be an efficient means of oil recovery in medium and light oil reservoirs, when the water drive is gravity stable. However, waterflooding is not very efficient especially when the water is flowing horizontally between two vertical wells. Water has higher density than oil and lower viscosity as well. Higher density of water will cause the water to sink to the bottom of the reservoir on its way from the injector to the producer leading to oil bypassing. Furthermore, the lower viscosity of water results in an adverse mobility ratio leading to viscous fingering and premature breakthrough of water. In all cases, secondary waterflooding increases the mobile water saturation in the reservoir which becomes an important parameter for consideration of process applications.

5.2.1 GAGD after Waterflooding

After the secondary waterflooding in oil reservoirs, the residual oil could be as high as 70% of IOIP (DOE.gov). Therefore, some means of EOR will be required to recover the trapped oil from the reservoirs. Furthermore, allowing the reservoir to be shut in for long periods will cause vertical gravity segregation. It is to be expected that the lower density fluids (oil and gas) would travel to the top of the pay zone and the heavier density fluid (water) will sink to the bottom of the pay zone. Therefore, a horizontal well can be placed at the bottom of oil zone and perform
GAGD even if there is water in place that might shield the oil from coming in contact with CO\textsubscript{2} gas. Water shielding is not believed to be a big issue in this case because the CO\textsubscript{2} gas is very soluble in water (Martin, 1992). Therefore, the CO\textsubscript{2} gas could contact the oil even after waterflooding.

A visual model was built to provide appropriate vertical wells to perform horizontal waterflooding first and then to conduct CO\textsubscript{2} GAGD flood. It is important to keep in mind that viscosity of decane is 0.96 cP (Appendix C) and the viscosity of water is equal to 1 cP. Thus, the favorable mobility ratio provided stable flood front during the waterflooding. Furthermore, the low density difference between the fluids (0.2809 gm/CC) and the relatively small model size yielded a good waterflood performance. Therefore, the waterflooding at high injection rate (8 cc/min) from the vertical well was dominated by viscous force. The viscous force has allowed the water to be suspended in matrix for a relatively long time thereby combating the weak gravity force in place. This was further aided by the relatively small size of the visual model, the waterflooding was relatively very efficient with an oil recovery of 85.1%. Over all, the gravity force still forced the water to sink slightly to the bottom. Figure 45 shows that the oil height (red color) in the physical model is increasing as the distance increases from the injector. If the model was long enough the water height will eventually become very small.

Gas injection from top was performed on the waterflooded model afterwards. Because of 85 % oil recovery in the waterflood, only about 15% IOIP was available for CO\textsubscript{2} flooding in this case. The GAGD recovery was an incremental 54.5% ROIP over the waterflooding, which is in good agreement with the literature (Martin et al, 1992). The volumetric sweep efficiency ($E_V$) was near 100% again (Figure 47), but $E_D$ was relatively low because the injection pressure was very low in the immiscible GAGD test. Thus, the CO\textsubscript{2} solubility in water was very low leading to less contact of CO\textsubscript{2} gas and oil in place that has resulted in low $E_D$ (Figure 47).
It is important to mention that water production was observed to be high due to GAGD after waterflood. The horizontal well was placed at the bottom of the model, not just below the high residual oil saturation zone as it has been proposed previously. Thus, in order to produce the oil, the water has to be produced first. The horizontal well was not set just below the high residual oil saturation because the model was already built up and there was no prior precise knowledge of the location of the high residual oil saturation zone. However in the field well, logs and reservoir simulations will allow the appropriate placement of the horizontal well to minimize the water production in tertiary GAGD floods.
5.2.2 Effect of Wettability on Waterflooding Oil Recovery

As mentioned before, waterflooding is a very common practice for secondary oil recovery in the field. However, waterflooding is known to be an ineffective oil recovery method, especially in oil-wet reservoirs. Therefore, there is a need to test the effectiveness of waterflooding in both water-wet and oil-wet porous media and to compare the results with secondary GAGD oil recovery.

A visual model was constructed to perform secondary mode waterflooding in oil-wet porous media. The sand grains were treated with Dimethyldichlorosilane and Methylene Chloride to render them oil-wet. The final waterflood oil recovery was 35.6% IOIP (Figure 48). Figure 48 further compares the effectiveness of waterflooding in water-wet and oil-wet porous media. The waterflood oil recovery in oil-wet porous media is very poor. Furthermore, secondary GAGD is more efficient for oil recovery when compared with secondary waterflooding in oil-wet porous media.

The waterflooding was stopped in the oil-wet visual model after 90 minutes since the produced fluids contained 100% water. Furthermore, Figure 49, compared to Figure 46 (water-wet), suggests that the oil-wet porous media has strongly resisted water to flow through the porous media. Hence, viscous force has lost its domination and as a result gravity force has dominated the process. Therefore, water has sunk to the bottom of the porous media and thereby only the oil at the bottom of the visual model was displaced.

It was also aimed to confirm the wettability of the presumed oil wet porous media. In order to substantiate this, fractional water flow curves were generated for both oil-wet and water-wet porous media and are shown in Figure 50. There is a clear difference in the performance of both the porous media. As expected, the oil-wet fractional water flow lies to the left of water-wet fractional water flow curve. Furthermore, the water-wet porous media had much higher
waterflood oil recovery than the oil-wet porous media, which is clearly evident from the end point water saturations.

Figure 48: Comparison of waterflood in oil-wet and water-wet oil recoveries

Figure 49: Oil-wet porous medium after waterflooding.
5.3 Comparison of GAGD with Conventional Gas Injected EOR

There are many EOR methods that are being practiced by the industry namely gas, thermal, and chemical EOR. Each EOR method has its own applications, advantages, and disadvantages. Thermal EOR methods are applied for heavy gravity oils, especially with high viscosity. The advantages such as lowering the viscosity and disadvantages are complexity and long term planning. In the gas injection EOR, there are several conventional methods. These methods are water alternating gas, continuous gas injection, and gravity drainage in dipping reservoirs. The gravity drainage is similar to GAGD, but GAGD is a further improvement and it incorporates horizontal well technology with the gravity drainage mechanism.

5.3.1 Continuous Gas Injection (CGI) Process

The purpose of CGI is to obtain high oil recovery from waterflooded reservoirs using CO₂ gas. CO₂ is known for its advantages in improving the E_D by swelling and reducing the viscosity of oil (Shedid et al, 2005). However, flowing CO₂ between two vertical wells in CGI extenuates the
disadvantages of CO₂. CO₂ gas density (0.656 gm/cc @ 239 °F and 5000 psig) (Appendix K) would be less than the oil density (0.87 gm/cc for 30 API gravity) even in miscible injection. Therefore, the gas will elevate to the top of the pay zone, and bypass most of the oil with low volumetric sweep efficiencies.

A visual model was constructed to model the CGI process in the immiscible mode with a vertical gas injector and a vertical oil producer well. The results were as expected. It has been observed that the CO₂ gas traveled to the top of the pay zone bypassing the majority of the oil. The gas recovered the oil only from very top of the pay zone. Therefore, the benefit of using the CO₂ in CGI was mitigated by the large density difference between the fluids. Figure 51 show unambiguously the oil recovery difference between secondary GAGD oil recovery of 76% IOIP and CGI 10% IOIP.

![Figure 51: Comparing CGI with GAGD with keeping everything else constant.](image-url)
5.3.2 Water Alternating Gas (WAG) Process

WAG was first developed primarily to solve the problem of density difference and oil bypassing in CGI. It was thought that the density of the light CO₂ gas could be increased by alternating the injection slugs of CO₂ gas with water. Furthermore, water has higher Eᵥ value than CO₂ (Novosel, 2005). WAG could be performed with both miscible and immiscible gas injection, followed by water injection. The CO₂ gas will always rise to the top of the pay zone. In contrast, water will always drain to the bottom of the zone. Therefore, opposite slugs of gas and water were believed to homogenize the injected fluids in order to stabilize the flood front. However, WAG field results did not turn out as good as expected (Chakravarthy, 2006). The front did not conform as well as it was expected, because of vertical fluid gravity segregation effects. Adverse mobility ratio was strong in the process, thereby developing severe viscous fingering. Over all, the premature CO₂ gas and water breakthrough took place, with recovery less than expected (Kelly, 2006).

It was proposed to perform WAG in the laboratory experiments to visualize the process and verify its drawbacks. Thus, one of the visual models was developed to perform the WAG. The CO₂ gas and water slugs had a ratio of 1:1 by volume.

The gas as expected traveled to the top of zone immediately, bypassing most of the oil behind. On the other hand, water injection had the same characteristics of waterflooding. The ultimate recovery was 71.9%. However, it is important to remember that this physical model has performed equally well in waterflooding. Even though, WAG recovery was 71.9%, it was slightly lower than GAGD (74% IOIP) in the same visual model. In Addition, WAG recovery rate was much slower than GAGD recovery rate (Figure 52). The slower WAG recovery rate can be attributed to the time period of CO₂ gas injection where CO₂ gas has just traveled to the top without any contribution to production.
Comparing Figure 53 and Figure 54, it was visually verified visually that $E_V$ of WAG was considerably less than that of GAGD. During the experimentation with WAG, co-injection of CO₂ gas and water took place inadvertently. Therefore, it is believed that $E_V$ would have been less than that shown in Figure 53. When WAG process is applied to the field, the volumetric sweep efficiencies will be much lower resulting in the lack of front conformity with the consequences of viscous fingering and premature gas breakthrough.

Figure 52: Comparison between WAG and GAGD

Figure 53: Demonstration of WAG process
5.4 Time Scaling

The second important scaling calculations done in this research study for meaningful field interpretation is the time scaling. Time scaling will simply scale a minute in the laboratory test to the corresponding time in the field. Most of the experiments conducted in the lab were run for almost 300 minutes. It is important to note that some of the properties of the visual model are very high compared to the field such as the visual model permeability, which has varied in between 1.7 and 4 Darcies. These permeability values are very high when compared to the field.

Time scaling equation used was (Sharma, 2005):

\[
t_d = \frac{KK_{ro}^{0} \Delta \rho g / g_c}{h \phi \mu(1 - S_{or} - S_{wi})}
\]  

Where:

- \( t_d \) is the dimensionless time
- \( K \) is the absolute permeability of the porous medium (m²);
- \( K_{ro}^{0} \) is the end-point relative oil permeability;
- \( \Delta \rho \) is the density contrast between the gas and oleic phase (Kg/m³);
- \( g \) is the gravitational force (m/sec²);
g_c is a gravitational force conversion factor (1);

\( \mu \) is the oil viscosity (Pa.s);

h is the height of the porous medium (m);

\( \phi \) is the porosity of the porous medium (%);

S_{or} is the residual oil saturation (%);

S_{wi} is the initial water saturation (%);

GAGD process is currently being designed for field application in a Louisiana depleted oil reservoir. Hence, the time scaling was chosen to be applied for the same oil. The oil field properties are listed in Table 2. GAGD is highly dependent on vertical flow of oil, and the vertical permeability is needed to be used for most calculations such as the time scaling and gravity number. Furthermore, it is well known that the vertical permeability is most likely to be less than the horizontal permeability. Hence, the vertical permeability was assumed to be equal to one tenth of the horizontal permeability value and used in the time scaling calculations.

**Table 2**: Reservoir field properties that have been used in time scaling

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability (K)</td>
<td>210 m-Darcy</td>
</tr>
<tr>
<td>Vertical Permeability (K_v)</td>
<td>21 m-Darcy</td>
</tr>
<tr>
<td>K_ro</td>
<td>0.48</td>
</tr>
<tr>
<td>Porosity</td>
<td>24%</td>
</tr>
<tr>
<td>Height</td>
<td>30 ft</td>
</tr>
<tr>
<td>Oil density</td>
<td>40.272 lb/ft^3</td>
</tr>
<tr>
<td>Proposed GAGD Pressure</td>
<td>2500 psig</td>
</tr>
<tr>
<td>CO_2 Density</td>
<td>8.73 lb/ft^3</td>
</tr>
<tr>
<td>S_{wi}</td>
<td>38.8%</td>
</tr>
<tr>
<td>S_{or}</td>
<td>20%</td>
</tr>
<tr>
<td>( \mu )_{oil}</td>
<td>0.763 cP</td>
</tr>
</tbody>
</table>

Using equation 6, the time has been calculated in minutes by creating a Visual Basic program to output into an Excel Spreadsheet (Appendices H and I). The spreadsheet provides comparison between each laboratory minute to the corresponding field time.
Table 3: Time scaling from lab to Buckhorn field for secondary immiscible recovery.

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>1 Minute in lab equivalent to days in field</th>
<th>Projected field days to recover 65% IOIP using CO₂ in secondary immiscible recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>3.2</td>
<td>869</td>
</tr>
<tr>
<td>3</td>
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<td>3.6</td>
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<tr>
<td>6</td>
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<tr>
<td>7</td>
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</tr>
<tr>
<td>32</td>
<td>2.5</td>
<td>114</td>
</tr>
</tbody>
</table>

Thus, depending on the particulars of the laboratory test, a minute of laboratory time means anywhere from 0.9 days to 5.3 days in the field.

5.5 Gravity Number

Gravity number is one of the important dimensionless numbers that is usually used to characterize the gravity drainage process. Gravity number represents the ratio of gravity force to viscous force.
In this study, gravity number was calculated except for some cases, where the gas injection was not performed from top to bottom such as horizontal waterflooding and when there is no control over the injection rate. The gravity number is given by (Sharma, 2005):

\[ N_g = \frac{\Delta \rho g K}{\Delta \mu v_d} \]  

(7)

Where:

- \( K \) is the absolute permeability of the porous medium (m\(^2\));
- \( K_{ro}^0 \) is the end-point oil relative oil permeability;
- \( \Delta \mu \) is the viscosity difference between oil and gas (Pa.s);
- \( v_d \) is the Darcy velocity, given by (injection rate/(cross sectional area * porosity)) (m/s);
- \( \Delta \rho \) is the density contrast between the oil and gas phase (Kg/m\(^3\));
- \( g \) is the gravitational acceleration in (m/sec\(^2\));

A Visual Basic program (Appendix F) was prepared to calculate the gravity number using the spreadsheet (Appendix G) to compare the calculated gravity numbers for the visual model with the reported values by Kulkarni (2005) from field projects and corefloods. It has been found that visual model gravity numbers were reasonable close to the field range of gravity number (Figure 55). Furthermore, interestingly some of the gravity numbers from the visual models were overlapping with field gravity numbers. This clearly indicates that the gravity drainage mechanism occurring in the field projects is reasonably well represented in the visual model experiments. While in the range of \( N_g \) was from 0.2 to 1 for the visual model experiments, it varied from 3 to 9 for the high pressure corefloods and from 1-30 in the field projects.

Analyzing the relationship between the gravity number and oil recoveries (Figure 56), it seems that there is no apparent relationship between the gravity number and oil recoveries. It is
believed that the experimental range was not wide enough to be able to establish a relationship that is clear.

Figure 55: Comparison of Gravity Number for fields, corefloods and visual models

Figure 56: Gravity number vs. recovery
6 Conclusions and Recommendations

6.1 Conclusions

With today’s high demand on energy, especially oil, settling for 30-40% IOIP recovery after primary depletion and secondary waterflood seems to be illogical. Hence, a new gas injection process called GAGD was investigated in this study for improved oil recovery. GAGD employs the advantage of density difference between two fluids and uses the gravity to force the oil down into a horizontal well. Using CO₂ in this process will perform the task of enhanced oil recovery as well as sequestrating CO₂ to minimize the greenhouse gases.

This research study was focused on building visual models that are flexible for use in the laboratory to test the GAGD process and to answer some optimization and configuration questions that will be useful in field applications. The visual model was kept as simple as possible to allow better understanding of the process. Hence, the visual model was built using conventional window glass for framing and filled with silica-based Ottawa sand, which silica based. Perforated plastic tubing was used to simulate a horizontal well laid down at the bottom of the visual model. The visual models have provided excellent visualization and reliable results as well. Distilled water was used to mimic the brine in the model. Additionally, decane, soltrol and naphtha were used in the visual model to simulate different conditions of oil in the reservoir. All the experimental work was performed under ambient conditions due to the limitations of the visual model capability.

The visual model experimentation has provided confirmatory support for the GAGD theory and the important conclusions are summarized blow:

- GAGD process is viable for both secondary and tertiary oil recovery.
• The visual model experiments have demonstrated three possible mechanisms responsible for high oil recoveries: Darcy-type displacement until gas breakthrough, gravity drainage after breakthrough, and film drainage in the gas invaded regions.

• GAGD process is largely dependent on the domination of the gravity force. When the gravity force is dominating the process, no viscous fingering will be present thereby eliminating premature gas breakthrough. Furthermore, gravity force domination will overcome any permeability heterogeneity in the system and hence better ultimate oil recovery.

• Varying the gas injection depth in the pay zone did not have much effect on the ultimate GAGD oil recovery. The difference between the oil and CO$_2$ gas densities was so high that the gas always traveled to the top of the visual model and formed a gas cap, thereby effectively draining the oil to the bottom.

• It was observed consistently that increasing the CO$_2$ injection rate tends to increase the ultimate GAGD oil recovery and with a faster recovery rate at late time. However, increasing the injection rate indefinitely is believed to have negative effects. Too high as injection rate, may cause the gravity force to lose its domination and thereby allowing viscous force to become stronger. Viscous force domination may lead to oil bypassing and premature gas breakthrough, thereby creating the need for gas recycling and operational cost increase.

• Immiscible CO$_2$ gas injection in GAGD has resulted in oil recoveries between 65% and 87% IOIP with volumetric sweep efficiencies almost equal to 100%.

• Miscible injection in GAGD would provide a nearly perfect (100%) microscopic sweep efficiency. However, due to the low density difference and high CO$_2$ gas injection
pressure, viscous force has to be controlled. By maintaining the front velocity at low speeds, viscous fingering and oil bypassing can be avoided.

- Huff-n-Puff process can be applied to GAGD using the horizontal well. Huff n’ Puff is found to be an effective oil recovery technique because the CO₂ gas will always travel to the top of the pay zone no matter where it is injected. This process will help in saving the cost of drilling extra vertical gas injection wells. However, the draw back of Huff n’ Puff GAGD is that there will be time periods of no oil production, but just gas injection. During the oil production period, oil production will be of great quantity in short time period which therefore requires special surface equipments. Furthermore, great deal of gas recycling will be required.

- Toe to Heel in GAGD oil recovery did not perform as expected. The CO₂ gas didn’t rise to the top of the pay zone; instead it found a path of least resistance to the horizontal well. It is believed that the viscous force and the hydrostatic pressure of decane over powered the gravity force.

- Wettability effects on GAGD were tested using the visual model. Oil wet reservoirs are expected to have a continuous oil film flow on the matrix rather than droplets in between the pore space. The oil recovery in oil-wet porous media during the immiscible GAGD model was 83%, which was 10% higher than the corresponding water-wet porous media.

- Performing waterflooding on oil-wet porous media resulted in very low oil recovery especially if it is strongly oil-wet. It was observed that the gravity force has dominated the process. Secondary GAGD oil recovery is much more efficient than the secondary waterflooding in oil-wet porous media.

- Naturally fractured carbonate reservoirs appear to be good candidates for the GAGD process. The presence of the fracture can be exploited in the process as an effective gas-
fluid exchange path between the fracture and the matrix. It is recommended to operate in the immiscible mode rather than the miscible mode to maintain gravity force domination. GAGD oil recoveries in fractured porous media were consistently higher than the non-fractured porous media recoveries by an average of 5%.

- GAGD process can also be used recover even higher viscosity oils. The visual model has provided evidence that CO₂ in miscible and immiscible injections are applicable for heavy oil recovery. The most important consideration is to maintain the domination of the gravity force. Since the mobility ratio in highly adverse, viscous fingering could take place during the gas injection drainage of heavy oil if critical rates for gravity stable displacement are exceeded.

- GAGD was performed in the tertiary mode after conducting the waterflood. The oil recovery was 54.5% ROIP. It is believed that oil recovery would be better in field application since the horizontal well can placed just above the oil-water contact thereby reducing the water production significantly.

- The gravity force has strong influence on WAG and CGI. The visual model tests showed that the CO₂ gas in both processes always traveled to the top of the pay zone bypassing large amounts of oil. Additionally, the water always sank to the bottom of the pay zone as expected, because the water is most likely to be of higher density than the oil. These tests clearly indicate gravity segregation to the main cause of poor performance of WAG in the field.

### 6.2 Recommendations

Further GAGD visualization is recommended to explore some unanswered questions. The important recommendations are:
• Higher strength glass based visual model to be constructed that is capable of handling real reservoir pressures and temperatures by using stronger glass, such as carbon fiber or steel reinforced glass, and rigid steel framing. Real reservoir condition would be advantageous for understanding the GAGD process and its components. In order to simulate real miscibility, CO₂ gas has to be used to take advantage of the large value of the gravity difference unlike using chemical solvents with very little gravity difference. Furthermore, using reservoir conditions will help in further understanding GAGD mechanism such as drainage and displacement.

• Investigate the optimum injection while keeping the gravity force dominating the GAGD process.

• Study the optimum injection method, study the optimum injection configuration. Would a combination of injection depths be more beneficial.

• Study carbonate porous medium with and without fracture by obtaining carbonate porous medium such as chalk.

• Study the effect of layered permeabilities in reservoirs on GAGD process since most reservoirs are layered.
References


52. US DoE’s Improved Oil Recovery Web site.


## Appendix A: List of Experiments

<table>
<thead>
<tr>
<th>Experiment #</th>
<th>Injection depth from top of model (inch)</th>
<th>Rate (CC/min)</th>
<th>Recovery (% IOIP)</th>
<th>Porosity (%)</th>
<th>K (D)</th>
<th>Sw</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>10</td>
<td>N/A</td>
<td>43</td>
<td>43.0</td>
<td>3.096</td>
<td>30.0</td>
<td>Free gravity flow was allowed to establish a base case.</td>
</tr>
<tr>
<td>2</td>
<td>7.5</td>
<td>2</td>
<td>67</td>
<td>43.0</td>
<td>3.096</td>
<td>30.0</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>7.5</td>
<td>4</td>
<td>72</td>
<td>43.0</td>
<td>3.096</td>
<td>30.0</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>7.5</td>
<td>8</td>
<td>83</td>
<td>43.0</td>
<td>3.096</td>
<td>30.0</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>5</td>
<td>2</td>
<td>71</td>
<td>37.6</td>
<td>4.040</td>
<td>23.2</td>
<td>The permeability of the visual model was relatively low in this experiment, then it has changed to a higher value after. Low permeability has shown to have a positive effect on recovery.</td>
</tr>
<tr>
<td>6</td>
<td>5</td>
<td>4</td>
<td>88</td>
<td>37.6</td>
<td>1.730</td>
<td>30.0</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>2.5</td>
<td>2</td>
<td>65</td>
<td>41.2</td>
<td>3.629</td>
<td>55.0</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>2.5</td>
<td>4</td>
<td>71</td>
<td>41.2</td>
<td>3.629</td>
<td>55.0</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>2.5</td>
<td>8</td>
<td>74</td>
<td>41.2</td>
<td>3.629</td>
<td>55.0</td>
<td>The model for shut-in near the end of exp, then restarted at later time with a jump of production due to phase segregation</td>
</tr>
<tr>
<td>10</td>
<td>0</td>
<td>4</td>
<td>73</td>
<td>41.2</td>
<td>3.629</td>
<td>54.0</td>
<td>The model for shut-in near the end of exp, then restarted at later time with a jump of production due to phase segregation.</td>
</tr>
<tr>
<td>11</td>
<td>0</td>
<td>8</td>
<td>69</td>
<td>41.2</td>
<td>3.629</td>
<td>53.0</td>
<td>No shut-in was practiced to demonstrate the effect of shut-in time.</td>
</tr>
<tr>
<td>12</td>
<td>0</td>
<td>N/A</td>
<td>65</td>
<td>41.2</td>
<td>3.629</td>
<td>53.0</td>
<td>Water was used for oil, and red dyed n-decane was used for gas to simulate low difference in densities between the fluids</td>
</tr>
<tr>
<td>13</td>
<td>0</td>
<td>2</td>
<td>94</td>
<td>41.2</td>
<td>2.787</td>
<td>30.0</td>
<td>Naphtha was used for oil and decane for CO₂ in the miscible mode. 100% microscopic sweep efficiency, and with less than 100% vertical sweep efficiency.</td>
</tr>
</tbody>
</table>
Naphtha was used for oil and decane for CO₂ in the miscible mode. Vertical sweep efficiency tends to improve with the lower injection rate.

Naphtha was used for oil and decane for CO₂ in the miscible mode. 100% microscopic sweep efficiency, and with less than 100% vertical sweep efficiency. This experiment is a proof that recovery is dependent on injection rate in the miscible mode.

Intermittent injection of CO₂ in the horizontal well was tested here.

2 fractures have been introduced in the model

2 fractures have been introduced in the model

2 fractures have been introduced in the model. It seems that in order to have a positive effect of the fractures on the overall recovery, injection rate has to be on the high.

2 Fractures were used in the model, Miscible flooding the model (Naphtha for oil, and Decane for miscible CO₂)

Soltrol was used for oil. Soltrol has a higher viscosity (2.93 Cp) compared to Decane (0.92 Cp).

Soltrol was used for oil. The higher viscosity of oil seems to be independent of CO₂ injection rate

Soltrol used for oil and Decane for Miscible CO₂ condition. It has been observed that just like in any miscible case, microscopic sweep was 100%, but volumetric sweep was less 100%. Furthermore, the above one mobility ratio had an adverse effect, however, if the miscible
<table>
<thead>
<tr>
<th>Experiment</th>
<th>Injection Rate</th>
<th>Permeability</th>
<th>Mobility Ratio</th>
<th>Recovery</th>
<th>Mobility Ratio</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>24, 25</td>
<td>0, 2.5&quot;</td>
<td>3600 m-Darcy</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>26, 27, 28</td>
<td>5, 7.5&quot;</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The purpose of this model was to run all four configurations (0", 2.5", 5", and 7.5") from top in the same model to have a better comparison.

This experiment has been repeated. The previous run had a permeability of 3600 m-Darcy, with a recovery of 69%. It seems that the permeability has an adverse effect to a point.

This experiment has been repeated, the previous run had a permeability of 3600 m-Darcy, with a recovery of 74.1%. It seems that the permeability has an adverse effect to a point.

Continues gas injection was done by a vertical well, and the oil was produced from another well.
The gas rose to the top immediately, and produced only from the top perforations. Very little recovery.

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td>Vertical Well</td>
<td>8</td>
<td>85.1</td>
<td>45.7</td>
<td>2.500</td>
</tr>
</tbody>
</table>

The injection rate is believed to be rather too high to allow the gravity effect to take place, viscous effect was the dominate effect in the process.

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>31</td>
<td>0</td>
<td>8</td>
<td>8.2</td>
<td>45.7</td>
<td>2.500</td>
</tr>
</tbody>
</table>

GAGD was performed after the horizontal water flooding. The water flooding was very efficient; it produced more 85.1% of IOIP.

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>32</td>
<td>0</td>
<td>8</td>
<td>83.7</td>
<td>45.7</td>
<td>4.000</td>
</tr>
</tbody>
</table>

This model is oil wet. It was film flow of oil.

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>33</td>
<td>Vertical Well</td>
<td>2</td>
<td>71</td>
<td>45.7</td>
<td>4.000</td>
</tr>
</tbody>
</table>

WAG. The waterflooding part has out performed the gas flooding part. CO2 gas flooding was not effective because the gas traveled to the top immediately and bypassed the oil. Water injection performed just like waterflooding pattern.

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>34</td>
<td>10 and 2</td>
<td>8</td>
<td>7.2</td>
<td>42.6</td>
<td>3.846</td>
</tr>
</tbody>
</table>

Toe to Heal. In this experiment the CO2 gas injection was at the same height of production to simulate the Toe to Heal process. The outcome is not encouraging; it seems that due to the close proximity of injection to the production did not allow the gravity force to dominate the process. It is believed that the dominant force in place is the viscous. The horizontal production well acted like a vacuum to attract the CO2. No gas cap formed.

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>35</td>
<td>0</td>
<td>8</td>
<td>82.2</td>
<td>44.7</td>
<td>1.365</td>
</tr>
</tbody>
</table>

Single point production. In this experiment the horizontal production well is simulated by a point contact outward instead of a horizontal well line contact with porous media.

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>36</td>
<td>Vertical</td>
<td>8</td>
<td>35.3</td>
<td>35.5</td>
<td>4.000</td>
</tr>
</tbody>
</table>

This model is oil-wet. The need for oil- wet fractional flow curve aroused. Therefore, this test was
performed. The water sank to the bottom of the visual model (gravity force domination in this case)
Appendix B: Density and Viscosity of Naphtha with Red Dye

Density

Weight empty Pycnometer and Stopper = 33.74 gm
Pycnometer with distilled water = 61.58 gm
Weight water in Pycnometer (61.58-3.74) = 27.84 gm
Temperature of distilled water = 25 C
Volume of water = 27.84/0.997 g/ml = 27.923 ml
Re-weight empty Pycnometer and stopper = 33.73 gm
Weight Pycnometer filled with naphtha = 54.28 gm
Weight (naphtha) in Pycnometer = 54.28-33.73 =20.55 gm
Naphtha density with the red dye = 20.55/27.923 = 0.73595 gm/mL

Viscosity

Temperature 25 deg C
Viscometer 200 (K 671)
Factor @ 25 deg C = 0.0988 cSt/Sec
Time = 10 Sec
Viscosity = 10 Sec x 0.0988 cSt/Sec x 0.73595 = 0.727 cP

Fenelon Nunes
Academic Coordinator
May 24, 2006
Appendix C: Viscosity Measurement of Soltrol and Decane

Soltrol with Red Dye

101 sec $\times 0.03765$ cSt/s $\times 0.77$ g/cc = 2.928 cP (Temp= 21.5°C)

Manufacture informs: 2.45 cSt (38°C-100°F)

Decane’s Viscosity

38 sec $\times 0.03533$ cSt/s $\times 0.7194$ g/cc = 0.966 cP (Temp=21.5°C)

Fenelon Nunes
Academic Coordinator
May 24, 2006
Appendix D: Decane Density Measurement

<table>
<thead>
<tr>
<th>nC7</th>
<th>Density</th>
<th>Temperature</th>
<th>Period of Oscillation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>p1 °F</td>
<td>P1</td>
<td>(P1)^2</td>
</tr>
<tr>
<td>0.6801</td>
<td>75</td>
<td>4.4008</td>
<td>19.3670</td>
</tr>
</tbody>
</table>

Constant A = 0.4089

Constant B = 7.2400

<table>
<thead>
<tr>
<th>Sample - Decane</th>
<th>Temp.(°F)</th>
<th>Expected</th>
<th>Deviation %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density gms/cc</td>
<td>0.7194</td>
<td>75</td>
<td>0.8676</td>
</tr>
</tbody>
</table>

Note:
1. Use Density values provided at 15.6°C from properties & constants and correct to measured or desired temperature using density correction (VCF)

Blue Enter Values

Density measurements was performed on March 10, 2006 by Daryl Sequeira using a pre-calibrated Anton Paar Densitometer (Model No. DMA 45/512)
Appendix E: Density Measurement of Soltrol

<table>
<thead>
<tr>
<th>nC7</th>
<th>Density</th>
<th>Temperature</th>
<th>Period of Oscillation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>p1</td>
<td>°F</td>
<td>P1</td>
</tr>
<tr>
<td></td>
<td>0.6801</td>
<td>75</td>
<td>4.4008</td>
</tr>
</tbody>
</table>

Constant A = 0.4089

Constant B

<table>
<thead>
<tr>
<th>Sample - soltrol</th>
<th>Temp.(°F)</th>
<th>Expected</th>
<th>Deviation %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density gms/cc</td>
<td>0.7703</td>
<td>75</td>
<td>0.8676</td>
</tr>
</tbody>
</table>

Note:

1. Use Density values provided at 15.6°C from properties & constants and correct to measured or desired temperature using density correction (VCF)

Density measurements was performed on March 10, 2006 by Daryl Sequeira using a pre-calibrated Anton Paar Densitometer (Model No. DMA 45/512)
Appendix F: Gravity Number Calculation Using Visual Basic

Private Sub CommandButton1_Click()
    'Gravity Number Program
    Dim obExcelApp As Object
    Set obExcelApp = GetObject(, "Excel.Application")
    Dim t, Mu1, Mu2, K, Den1, Den2, g, Porosity, A, q As Double
    Dim Delta_Den, Delta_Mu, u, Ng As Double
    A = (22 * 0.3308) * 0.00064516 'This area represents the cross sectional area of the
    'pours media that will be used in Darcy velocity calculation later in m^2
    g = 9.81 'm/sec^2 which represents the acceleration due to gravity
    For x = 1 To 27
        Mu1 = Sheet1.Cells(x + 4, 5) ' This viscosity represents the oil viscosity
        Mu1 = Mu1 * 0.001 'converting the viscosity from cP to Pa.sec
        Mu2 = Sheet1.Cells(x + 4, 6) ' This viscosity represents the carbon dioxide viscosity
        Mu2 = Mu2 * 0.001 'converting the viscosity from cP to Pa.sec
        Delta_Mu = Abs(Mu2 - Mu1) ' finding Delta viscosity
        K = Sheet1.Cells(x + 4, 4) 'This is the perm of the physical model
        K = K * 9.869233E-13 ' Converting Perm from Darcy to M^2
        Porosity = Sheet1.Cells(x + 4, 3) 'This is the porosity of the model
        Porosity = Porosity / 100 'Converting the porosity from percent to fraction
        Den1 = Sheet1.Cells(x + 4, 7) 'This density represents the density of oil in place
        Den2 = Sheet1.Cells(x + 4, 8) 'This density represents the density of the injected
        carbon dioxide
    Next x
End Sub
Delta_Den = Abs(Den2 - Den1) * 1000 'Finding the density difference between the two fluids then convert the value to Kg/m^3 units

q = Sheet1.Cells(x + 4, 9) ' This is the injection rate of carbon dioxide

q = q * 0.000001 'Converting flow rate from mL/sec to m^3/sec

u = q / (A * Porosity*60) 'Darcy velocity

Ng = (Delta_Den * g * K) / (Delta_Mu * u)

Sheet1.Cells(x + 4, 10).Value = ""
Sheet1.Cells(x + 4, 10).Value = ""
Sheet1.Cells(x + 4, 10).Value = Ng

Next x

End Sub
## Appendix G: Gravity Number Calculation Spread Sheet

<table>
<thead>
<tr>
<th>Exp #</th>
<th>Porosity (%)</th>
<th>$K$ (Darcy)</th>
<th>$\mu_{\text{oil}}$ (cP)</th>
<th>$\mu_{\text{injection}}$ (cP)</th>
<th>$\rho_{\text{oil}}$ gm/cc</th>
<th>$\rho_{\text{CO2}}$ gm/cc</th>
<th>Injection Rate (CC/min)</th>
<th>Gravity Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>43.0</td>
<td>3.0960</td>
<td>0.96</td>
<td>0.01474</td>
<td>0.71940</td>
<td>1.83E-03</td>
<td>2</td>
<td>0.998014</td>
</tr>
<tr>
<td>3</td>
<td>43.0</td>
<td>3.0960</td>
<td>0.96</td>
<td>0.01474</td>
<td>0.71940</td>
<td>1.83E-03</td>
<td>4</td>
<td>0.499007</td>
</tr>
<tr>
<td>4</td>
<td>43.0</td>
<td>3.0960</td>
<td>0.96</td>
<td>0.01474</td>
<td>0.71940</td>
<td>1.83E-03</td>
<td>8</td>
<td>0.249504</td>
</tr>
<tr>
<td>5</td>
<td>37.6</td>
<td>4.0400</td>
<td>0.96</td>
<td>0.01474</td>
<td>0.71940</td>
<td>1.83E-03</td>
<td>2</td>
<td>1.138771</td>
</tr>
<tr>
<td>6</td>
<td>37.6</td>
<td>1.7300</td>
<td>0.96</td>
<td>0.01474</td>
<td>0.71940</td>
<td>1.83E-03</td>
<td>4</td>
<td>0.243821</td>
</tr>
<tr>
<td>7</td>
<td>41.2</td>
<td>3.6290</td>
<td>0.96</td>
<td>0.01474</td>
<td>0.71940</td>
<td>1.83E-03</td>
<td>2</td>
<td>1.120860</td>
</tr>
<tr>
<td>8</td>
<td>41.2</td>
<td>3.6290</td>
<td>0.96</td>
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<td>0.71940</td>
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<td>3.6290</td>
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<td>0.71940</td>
<td>1.83E-03</td>
<td>8</td>
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</table>
Appendix H: Visual Basic Time Scaling Program

Private Sub CommandButton1_Click()

'Time Scaling Program

Dim obExcelApp As Object

Set obExcelApp = GetObject(, "Excel.Application")

Dim t, Mu_o, K, Kro, Den1, Den2, g, gc, Porosity As Double

Dim h, Sor, Swi, Td, t1, Td1 As Double

Dim t_BH, Mu_o_BH, K_BH, Kro_BH, Den1_BH, Den2_BH, Porosity_BH As Double

Dim h_BH, Sor_BH, Swi_BH, Td_BH As Double

Kro = 0.66 ' End point relative oil perm

h = 10 'in inches

h = h * 2.54 / 100 'converted to meters

gc = 1

g = 9.81 'm/sec^2

For X = 1 To 28

Mu_o = Sheet2.Cells(X + 7, 8) ' This viscosity represents the oil viscosity

Mu_o = Mu_o * 0.001 'converting the viscosity from cP to Pa.sec

K = Sheet2.Cells(X + 7, 7) ' Kabs of the physical model

K = (K) * 9.869233E-13 ' Converting Perm from Darcy to M^2

Keff = K * Kro 'Effective Perm of the model

Den1 = Sheet2.Cells(X + 7, 10) 'Density of oil

Den2 = Sheet2.Cells(X + 7, 11) 'Density of the flooding fluid

Delta_Den = Abs(Den2 - Den1) * 1000 'Finding the density difference
Porosity = Sheet2.Cells(X + 7, 6) 'Porosity of the model

Porosity = (Porosity) / 100 'Porosity in fraction

Sor = Sheet2.Cells(X + 7, 5) 'Residual oil saturation

Sor = Sor / 100 'Residual Oil saturation in fraction

Swi = Sheet2.Cells(X + 7, 4) 'Initial water saturation

Swi = Swi / 100 'Initial water saturation in fraction

Td = (Keff * Delta_Den * (g / gc)) / (h * Porosity * Mu_o * (1 - Sor - Swi))

Td = Td * 60 'Calculating the experimental dimensionless time in sec

'Buckhorn field data

K_BH = 210 * 0.1 'm-Darcy

K_BH = (K_BH / 1000) * 9.869233E-13 ' Converting Perm from Darcy to M^2

Kro_BH = 0.48

Keff_BH = K_BH * Kro_BH

Den1_BH = 40.727 'lb/ft^3

Den1_BH = Den1_BH * 16.01846 'Kg/m^3

Den2_BH = 139.97 'Kg/m^3 taken from NITS website

'http://webbook.nist.gov/chemistry/fluid/

Delta_Den_BH = Abs(Den2_BH - Den1_BH) 'Finding the density difference

Swi_BH = 0.388 'Initial water saturation

Sor_BH = 0.2 'Residual oil saturation

Porosity_BH = 0.24 'Field Porosity

Mu_o_BH = 0.763 'cP (Live oil viscosity)

Mu_o_BH = Mu_o_BH * 0.001 'Converting cP to Pa.s
h_BH = 30 'in ft (Pay zone height)

h_BH = h_BH * 0.3048 'Convert pay zone from ft to m

Td_BH = (Keff_BH * Delta_Den_BH * (g / gc)) / (h_BH * Porosity_BH * Mu_o_BH * (1 - Sor_BH - Swi_BH))

Td_BH = Td_BH * 3600 * 24 'Convert field dimensionless time into sec

t = Td / Td_BH

Sheet2.Cells(X + 7, 12).Value = ""

Sheet2.Cells(X + 7, 12).Value = t

Next X

End Sub
## Appendix I: Time Scaling Spread Sheet

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<th>$S_{or}$</th>
<th>$\phi$ (%)</th>
<th>$K$ (D)</th>
<th>$\mu_{oil}$ (cp)</th>
<th>$\mu_{injection}$ (cp)</th>
<th>$\rho_{oil}$ gm/cc</th>
<th>$\rho_{CO2}$ gm/cc</th>
<th>1 minute in lab equivalent to days in field</th>
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Appendix J: CO₂ Properties at Ambient Temperature (71 °F) and Different Pressures

Isothermal Properties for Carbon dioxide

- Fluid Data
- Auxiliary Data
- References
- Additional Information
- Notes
- Other Data Available:
  - View data in HTML table.
  - Download data as a tab-delimited text file.
  - Main NIST Chemistry WebBook page for this species.
  - Recommended citation for data from this page.
  - Fluid data for other species

Fluid Data

Isothermal Data for T = 71.000 °F

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<thead>
<tr>
<th>Phases</th>
<th>Pressure [psia]</th>
<th>Density [g/ml]</th>
<th>Viscosity [cP]</th>
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National Institute of Standards and Technology (NIST)
http://webbook.nist.gov/chemistry/fluid/
Appendix K: CO₂ Properties at Typical Reservoir Temperature (239°F) and Different Pressures

Isothermal Properties for Carbon monoxide

- Fluid Data
- Auxiliary Data
- References
- Additional Information
- Notes
- Other Data Available:
  - View data in HTML table.
  - Download data as a tab-delimited text file.
  - Main NIST Chemistry WebBook page for this species.
  - Recommended citation for data from this page.
  - Fluid data for other species

Fluid Data

Isothermal Data for T = 239.00°F

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<th>Viscosity [cP]</th>
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National Institute of Standards and Technology (NIST)
http://webbook.nist.gov/chemistry/fluid/
Appendix L: 20/30 Sand Technical Information

U.S. SILICA

ASTM® 20/30
UNGROUNDED SILICA
PLANT: OTTAWA, ILLINOIS
(1) AMERICAN FOUNDERS' SOCIETY

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TYPICAL PROPERTIES

COLOR .................................................. WHITE
GRAIN SHAPE ....................................... ROUND
HARDNESS (Mohs) .............................. 7
MELTING POINT (Degrees F) .................. 3100

MINERAL ............................................ QUARTZ
pH .................................................... 7
SPECIFIC GRAVITY ................................ 2.65

TYPICAL CHEMICAL ANALYSIS, %

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<td>Al₂O₃ (Aluminum Oxide)</td>
<td>0.05</td>
<td>K₂O (Potassium Oxide)</td>
<td>&lt;0.01</td>
</tr>
<tr>
<td>TiO₂ (Titanium Dioxide)</td>
<td>0.01</td>
<td>LOI (Loss On Ignition)</td>
<td>0.1</td>
</tr>
<tr>
<td>CaO (Calcium Oxide)</td>
<td>&lt;0.01</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

CONFORMS TO ASTM C778

December 15, 1997

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WARNING: The product contains crystalline silica - quartz, which can cause silicosis (an occupational lung disease) and lung cancer. For detailed information on the potential health effect of crystalline silica - quartz, see the U.S. Silica Company Material Safety Data Sheet.

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(304) 258-2500

Appendix M: 50/70 Sand Technical Information

AFS (1) 50/70
UNGROUND SILICA
PLANT: OTTAWA, ILLINOIS

(1) AMERICAN FOUNDRYMEN'S SOCIETY

<table>
<thead>
<tr>
<th>USA STD SIEVE SIZE</th>
<th>TYPICAL VALUES</th>
<th>% RETAINED</th>
<th>% PASSING</th>
</tr>
</thead>
<tbody>
<tr>
<td>MESH</td>
<td>MILLIMETERS</td>
<td>INDIVIDUAL</td>
<td>CUMULATIVE</td>
</tr>
<tr>
<td>40</td>
<td>0.425</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>50</td>
<td>0.300</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>70</td>
<td>0.212</td>
<td>97.0</td>
<td>98.0</td>
</tr>
<tr>
<td>PAN</td>
<td>2.0</td>
<td>2.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

TYPICAL PROPERTIES

AFS ACID DEMAND (@pH 7) .................................................. <1
AFS GRAIN FINENESS ..................................................... 50
COLOR ................................................................. WHITE
GRAIN SHAPE ......................................................... ROUND
HARDNESS (Mohs) ...................................................... 7

MELTING POINT (Degrees F) ........................................ 3100
MINERAL ................................................................. QUARTZ
MOISTURE CONTENT (%) .............................................. <0.05
pH ................................................................. 7
SPECIFIC GRAVITY .................................................. 2.65

TYPICAL CHEMICAL ANALYSIS, %

SiO₂ (Silicon Dioxide) ............................................. 96.7
Fe₂O₃ (Iron Oxide) .................................................. 0.020
Al₂O₃ (Aluminum Oxide) ......................................... 0.06
TiO₂ (Titanium Dioxide) ......................................... 0.01
CaO (Calcium Oxide) ............................................. 0.01
MgO (Magnesium Oxide) ......................................... <0.01
Na₂O (Sodium Oxide) ............................................ <0.01
K₂O (Potassium Oxide) .......................................... <0.01
LOI (Loss On Ignition) .......................................... 0.1

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http://www.u-s-silica.com/PDS/Ottawa/OttAFS50702000.PDF
## Appendix N: List of the Various Models Attempted

<table>
<thead>
<tr>
<th>Model number</th>
<th>Purpose</th>
<th>Bonding material and ratio</th>
<th>Glass beads size range (mm)</th>
<th>Horz or Vertic Pouring</th>
<th>Out come</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>First test</td>
<td>Stucco 65% by volume</td>
<td>0.1-0.2</td>
<td>Vertic</td>
<td>Rigid, Rough, Heterogeneous</td>
</tr>
<tr>
<td>2</td>
<td>Improve homogeneity, rigidness and roughness</td>
<td>Stucco 65% by volume</td>
<td>0.1-0.2</td>
<td>Vertic</td>
<td>Oil wet</td>
</tr>
<tr>
<td>3</td>
<td>Testing class 1 white cement</td>
<td>Cement 65% by volume</td>
<td>0.1-0.2</td>
<td>Horz</td>
<td>One near impermeable surface.</td>
</tr>
<tr>
<td>4</td>
<td>Trying to create four impermeable surfaces</td>
<td>Cement 65% by volume</td>
<td>0.1-0.2</td>
<td>Horz</td>
<td>Crater like shapes at one side</td>
</tr>
<tr>
<td>5</td>
<td>Trying to remove the crater like shapes</td>
<td>Cement 65% by volume</td>
<td>0.1-0.2</td>
<td>Vertic</td>
<td>Irregular top surface</td>
</tr>
<tr>
<td>6</td>
<td>Removing the irregularities at the top surface</td>
<td>Cement 65% by volume</td>
<td>0.1-0.2</td>
<td>Vertic</td>
<td>Crater like shapes exist at the top surface</td>
</tr>
<tr>
<td>7</td>
<td>Removing the irregularities at the top surface</td>
<td>Cement 65% by volume</td>
<td>0.1-0.2</td>
<td>Vertic, then laid Horz and flipped</td>
<td>Crater like shapes exist at the one surface</td>
</tr>
<tr>
<td>8</td>
<td>Removing the irregularities at the top surface</td>
<td>Cement 65% by volume</td>
<td>0.1-0.2</td>
<td>Horz</td>
<td>Crater like shapes exist at the top surface</td>
</tr>
<tr>
<td>9</td>
<td>Trying to remove the crater like shapes</td>
<td>Cement 65% by volume</td>
<td>0.1-0.2</td>
<td>Horz</td>
<td>Air bubbles shape, increased in size, the air is completely trapped</td>
</tr>
<tr>
<td>10</td>
<td>Removal of air bubbles shapes</td>
<td>Cement 65% by volume</td>
<td>0.1-0.2</td>
<td>Horz</td>
<td>Nearly impermeable bottom surface, less air bubbles. Oil wet.</td>
</tr>
<tr>
<td>11</td>
<td>Change the wettability to water wet</td>
<td>Cement 16% by volume</td>
<td>0.04-0.075</td>
<td>Horz</td>
<td>Low structural strength</td>
</tr>
<tr>
<td>12</td>
<td>Improve the structural</td>
<td>Cement 25% by Volume</td>
<td>0.04-0.075</td>
<td>Horz</td>
<td>Stronger than previous model,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>strength</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>13</td>
<td>Change or lower the wettability to water wet, or neutral. Very small scale</td>
<td>Cement 20% by volume</td>
<td>0.04-0.075</td>
<td>Horz</td>
<td>Very low strength, weakly oil wet.</td>
</tr>
<tr>
<td>14</td>
<td>Larger scale. Papering to run the first test</td>
<td>Cement 31.3% by volume</td>
<td>0.04-0.075</td>
<td>Horz</td>
<td>Acceptable strength, very low permeability. But it broke later before running the test.</td>
</tr>
<tr>
<td>15</td>
<td>Papering to run the first test.</td>
<td>Cement 30% by volume</td>
<td>0.4-0.6</td>
<td>Horz</td>
<td>Acceptable strength, very low permeability.</td>
</tr>
<tr>
<td>16</td>
<td>Papering to run the first test.</td>
<td>Cement 30% by volume</td>
<td>0.4-0.6</td>
<td>Horz</td>
<td>It seems that increasing the glass beads size requires higher cement ratio, it broke again while trying to prepare the model for testing.</td>
</tr>
<tr>
<td>17</td>
<td>Testing the epoxy as a bonding material</td>
<td>Epoxy 30% by weight</td>
<td>0.4-0.6</td>
<td>Horz</td>
<td>Very strong matrix, strongly oil wet, and repel water.</td>
</tr>
<tr>
<td>18</td>
<td>Anticipation of usage.</td>
<td>Epoxy 15% by weight</td>
<td>0.4-0.6</td>
<td>Horz</td>
<td>Acceptable strength, strongly oil wet, and repel water.</td>
</tr>
<tr>
<td>19</td>
<td>Allow the water to go inside the matrix</td>
<td>Epoxy 15% by weight. Surfactant 2.67% by weight</td>
<td>0.4</td>
<td>Horz</td>
<td>Attract water; but matrix seemed weak at first glance maybe because of the introduction of surfactant.</td>
</tr>
<tr>
<td>20</td>
<td>Increase the matrix strength</td>
<td>Epoxy 15% by weight. Surfactant 0.5% by weight</td>
<td>0.4</td>
<td>Horz</td>
<td>Stronger matrix, but does not attract water as much</td>
</tr>
</tbody>
</table>
Vita

Thaer Mahmoud is the son of Najieb Mahmoud and Wasfiah Mussa, where he was born in Kuwait. He received his high school in 1995 from Zarka Highschool, Jordan. He joined the University of Wisconsin-Madison, after he migrated to the U.S. He received his Bachelor of Science in Mechanical Engineering in 2003. In 2004 he joined the graduate school at Louisiana State University, Baton Rouge. He received a Masters of Science in Petroleum Engineering in August 2006. He will be Joining ConocoPhillips soon after his graduation.