Simulation Study On WAG-CO_2 Injection Optimization For Less Asphaltene Precipitation In Light Oil

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
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Approved by,

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

PUVENESHWARI A/P NARAYANAN

ABSTRACT

Flow assurance issues due to asphaltene precipitation in light oil reservoirs during water-alternating-carbon dioxide gas (WAG-CO_2) injection are common. The possibility of asphaltene precipitation is often neglected during enhanced oil recovery (EOR) planning phase due to its minute amount in light oils. Another problem is the lack of prior knowledge on the WAG parameters that could possibly enhance the asphaltene precipitation during WAG-CO_2 injection. Based on the severity of the problem, this study was initiated with the aim to determine and suggest the optimum WAG parameters, namely WAG injection rate, WAG injection pressure, WAG cycle sizes, WAG ratio and injected water salinity for lesser asphaltene precipitation. A compositional model was built using compositional simulator for the purpose of this study. The impacts of each WAG parameter were determined by varying the parameters one at a time while keeping others constant in the simulation runs. The results revealed the parameter with profound effects is only the injection pressure. The higher the injection pressure, the lesser the amount of asphaltene precipitated and deposited. WAG ratio of 2:1 gives better oil recovery and lesser asphaltene precipitation due to waterblocking effect. Other parameters have a slight effect or no effect at all on the asphaltene precipitation. Based on this study, it can be deduced that manipulating the injection pressure and WAG ratio will control the amount of asphaltene precipitated and deposited. The outcomes of this study will benefit the operators adopting WAG-CO_2 method in light oil fields through better management of flow assurance problems caused by asphaltene precipitation.

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ABBREVIATIONS & NOMENCLATURE

CGW	Combined Water/Gas Injection
CO_2	Carbon Dioxide
EOR	Enhanced Oil Recovery
FYP	Final Year Project
GOR	Gas-Oil Ratio
HCPV	Hydrocarbon Pore Volume
MMP	Minimum Miscibility Pressure
WAG	Water Alternating Gas
WAG-CO_2	Water Alternating Carbon Dioxide Gas

CHAPTER 1

INTRODUCTION

1.1 Project Background

Enhanced oil recovery using CO_2 gas is capable of increasing oil production beyond typically achievable rates during the final phase of a reservoir life (Andrei *et al.*, 2010). In the recent years water has been injected alongside CO_2 known as the WAG-CO_2 schemes because brine is known to improve the sweep efficiency (Satter *et al.*, 2008; Christensen *et al.*, 1998). In that case, light oil reservoirs are the best candidate for a combination of WAG-CO_2 recovery scheme (Satter *et al.*, 2008).

Although being commercially successful, CO_2 injection poses serious flow assurance problem in the form of asphaltene precipitation (Alian *et al.*, 2011). This issue is mostly unexpected by the operators due to two reasons: (1) light oil has very low (0.1 wt %) content of asphaltene and (2) non-occurrence of asphaltene precipitation phenomenon during primary production (Sarma, 2003; Alta'ee *et al.*, 2010). On-going studies are focused on understanding the complex mechanism of asphaltene precipitation after gas injection. Particularly, the causes of the problem are investigated thoroughly using laboratory research and simulation studies (Alta'ee *et al.*, 2012; Alian *et al.*, 2011; Kokal & Sayegh, 1995).

This study attempts to investigate the optimum condition required during WAG-CO_2 injection scheme for lesser asphaltene precipitation by varying the WAG parameters such as WAG injection rate, WAG injection pressure, WAG cycle sizes, WAG ratio and injected water salinity. In order to represent the production behavior of light oil reservoir under WAG-CO_2 scheme, a compositional model was built using compositional simulator to test a wide variation of values for each WAG parameters, hence concluding the optimal condition.

1.2 Problem Statement

Asphaltene precipitation and deposition causes numerous serious problems in the petroleum industry. Although it is so, the mechanism of asphaltene precipitation is the least understood and the most complex one too. This is because even minor changes in the reservoir properties or reservoir fluids such as temperature, pressure or composition may trigger asphaltene precipitation. The unique behavior of asphaltene is that it precipitates easily in light oil compared to in heavy oils although its amount is very minute in light oils.

The most worrying scenario is that WAG-CO_2 injection, which is very effective in recovering immobile oil, is prone to induce asphaltene precipitation resulting in tremendous economic impacts. Although numerous researches have been done to address the asphaltene problem, yet most of them only focused on the properties of the injected fluids but not on the injection process itself.

In order to overcome the asphaltene precipitation problem, the impact of each WAG parameter namely, WAG injection rate, WAG injection pressure, WAG cycle sizes, WAG ratio and injected water salinity should be determined. This is because a different combination of parameter, will results in different amount of asphaltene precipitation. Some combination may enhance the process, while the others might eliminate the problem at all. Hence, extensive research is required to understand and optimize the WAG-CO_2 scheme for lesser asphaltene precipitation in light oil.

1.2.1 Problem Identification

The problems identified are:

1. The possibility of asphaltene precipitation after WAG-CO_2 gas injection is often neglected during EOR planning phase causing severe problems later on.
2. Lack of references and studies conducted previously to understand the mechanism of asphaltene precipitation in WAG-CO_2 injection scheme caused by the WAG parameters.

1.3 Objectives & Scope of Study

The objectives of the study are:

1. To investigate the impacts of WAG parameters, namely WAG injection rate, WAG injection pressure, WAG cycle sizes, WAG ratio and injected water salinity on asphaltene precipitation;
2. To identify and suggest the optimal conditions required during WAG-CO_2 injection for lesser asphaltene precipitation.

The main aim of the study is to determine the optimum conditions for lesser asphaltene precipitation in light oil reservoirs during WAG-CO_2 injection. The approach is by focusing on the WAG parameters that affect asphaltene precipitation in the presence of water and CO_2.

1.4 Project Relevancy & Feasibility

The project is relevant with the current developments in oil and gas industry. As the demand for oil increases nowadays, the necessity to increase production of oil rises as well. Hence, flooding process and fluid injection methods are vastly employed to recover oil. One of the most common recovery methods in light oil reservoirs is CO_2 injection. Hence, this study, which focuses on the WAG-CO_2 process, is relevant to the current trend in the enhanced oil recovery process. Besides that, this study aims to address the asphaltene precipitation problem faced by many operators during secondary oil recovery in light oil reservoirs. Most of the Malaysian crude is light oil and hence, asphaltene problems are common over here. By suggesting the optimum conditions for lesser asphaltene precipitation, this study will be useful for those operators working on light oil reservoirs in Malaysia and other parts of the world as well. Successful findings from this study will further encourage the utilization of CO_2 gas in oil recovery process rather than being flared conventionally, which will indirectly reduce global warming.

With the execution of the study in two major phases, FYP I and FYP II, the study was completed within the planned timeline. Sufficient reference sources including the availability of previous laboratory work done on asphaltene precipitation during CO_2 injection served as the base to determine the parameters to be tuned. Hence, the study was carried out smoothly. The availability of the required tools and software's at the labs in Universiti Teknologi PETRONAS made it easier to execute the study and finish it on time.

CHAPTER 2

LITERATURE REVIEW

2.1 Enhanced Oil Recovery (EOR)

Rapid rise in the number of EOR projects have been an evident over the last few decades (Andrei *et al*., 2010). The report stated that in the year 2010 only, around 316 EOR projects have been embarked worldwide, producing approximately 1, 627, 000 bpd (2% out of the total oil production today) of enhanced oil production. Enhanced oil recovery (EOR) processes are optimizing the total recovery from reservoirs in terms of volume of hydrocarbon with the objective of maximizing profit. EOR methods enable production of additional oil of 5 – 15% of OOIP for light to medium oil reservoirs when the oilfields are approaching the end of their life (Andrei *et al*., 2010). Satter *et al.* (2008) defines EOR as all methods that use external sources of energy or materials to recover oil that cannot be produced economically by conventional means. Meanwhile, Society of Petroleum Engineers (SPE) summarizes EOR as a process focused on the rock, oil and injectant system as well as on the interplay of capillary and viscous forces to recover oil not produced by means of secondary recovery (Hite *et al*., 2003). EOR is also used for pressure maintenance in the reservoir after primary and secondary recovery (Rehman & Meribout, 2012).

Oil recovery by means of EOR techniques is achieved by altering flow properties and oil interaction with the reservoir rock to increase the oil displacement efficiencies (Satter *et al.*, 2008 & Andrei *et al*., 2010). In order to increase oil displacement efficiency, the capillary forces or interfacial tension are reduced in chemical flooding process while the oil viscosity is decreased in thermal flooding process (Satter *et al.*, 2008). Three major groups of EOR methods are widely used in the industry namely, thermal methods, chemical methods and miscible methods (Satter *et al.*, 2008). The three categories are further divided into several techniques as shown in Figure 2.1.

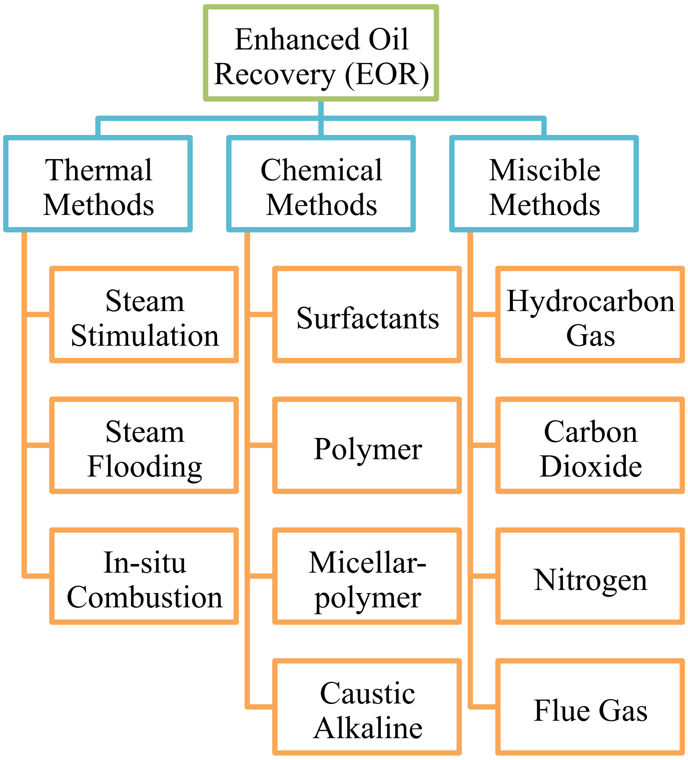


Figure 2.1: Enhanced Oil Recovery Methods (Satter *et al.*, 2008)

2.2 Water-Alternating-Carbon Dioxide (WAG-CO_2) Injection

In light oil reservoirs, WAG injection is commonly practiced for better oil recovery and profile control (Kulkarni & Rao, 2004). Christensen *et al.* (1998) defined WAG as a water slug following a gas slug intermittently injected and also known as combined water/gas injection (CGW). The WAG process is continued until necessary CO_2 slug size is achieved (Andrei *et al.*, 2010). Historically, Mobil was the first company to implement WAG recovery scheme in a sandstone reservoir in the North Pembina field of Alberta around 1957 (Christensen *et al.*, 1998). There are three types of WAG process, namely miscible, immiscible and hybrid WAG injections. The first two processes depend on the type of gas injected and its miscibility with the crude oil. On the other hand, injection of large slug of gas, followed by smaller slugs of water and gas is known as hybrid WAG. In the oil industry, WAG injection is highly on demand compared to pure gas or water injections and is applied to all types of reservoir (Kulkarni & Rao, 2004). The applications and distribution of WAG process is shown in Figure 2.2.

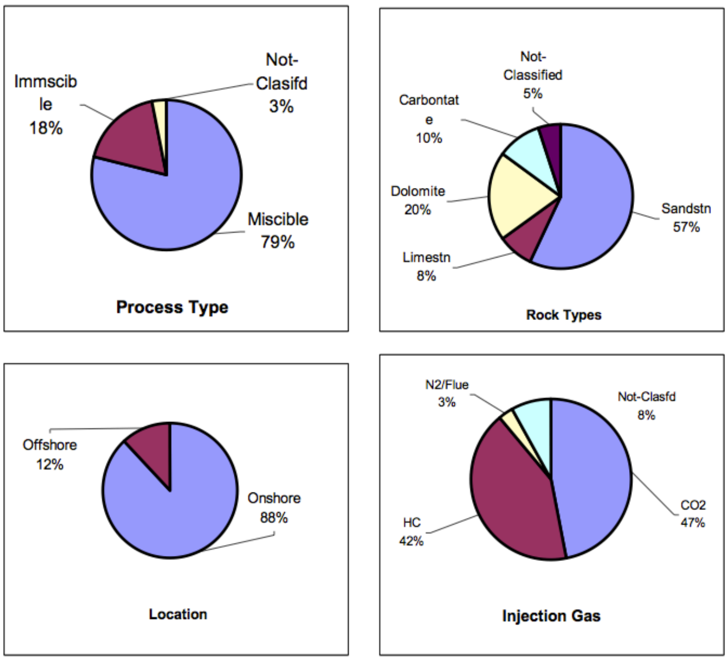


Figure 2.2: The applications and distribution of WAG process (Kulakarni & Rao, 2004)

CO_2 miscible floods applicable to lighter oils have been commercially successful and utilized widely among all the miscible floods (Satter *et al.*, 2008). This is because under supercritical condition, CO_2 is capable of releasing trapped oil by entering into zones not previously invaded by water (Andrei *et al.*, 2010). Comparison between 59 field cases revealed that CO_2 is the commonly used injection gas with 47% of application, followed by hydrocarbon at 42% (Christensen *et al.*, 1998). This clearly indicates the ability of CO_2 gas to increase mobility displacement; hence improving sweep efficiency with up to 40% of recovery compared to all the other EOR methods (Christensen *et al.*, 1998; Para-Ramirez *et al.*, 2001). Water is used to improve sweep of gas injection by means of controlling the mobility of the displacement and stabilizing the front in WAG injection (Christensen *et al.*, 1998). In the presence of water, CO_2 has an acidizing effect on the reservoir (Alta'ee *et al.*, 2010). The deposition of asphaltene can be reduced, though not eliminated all together, when there is presence of brine in contact with oil and CO_2 gas (Sarma, 2003). Figure 2.3 shows the EOR-CO_2 scheme.

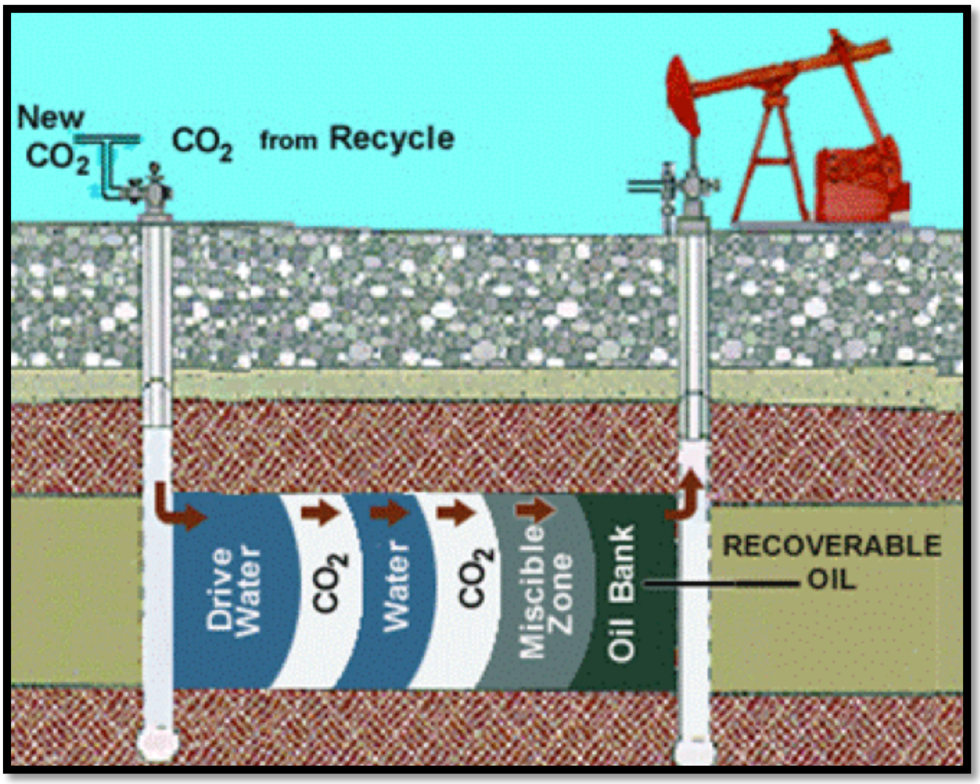


Figure 2.3: CO_2-EOR process in the reservoir (Andrei *et al*., 2010)

The working principle of a WAG process is known as gravity segregation, whereby the gas rise up to the attic while the water settles down into low structure areas, and both displaces the trapped oil in those regions of the reservoir (Sanchez, 1999). The WAG process takes place as the CO_2 gas is injected into the oil-bearing zone under high pressure. When the CO_2 gas eventually reaches the oil-zone, it will decrease the viscosity of the oil as the CO_2 gas and oil mixes together. At the same time, the CO_2 injected will increase the water viscosity and reduce miscibility effects. The oil will then expand and will be able to move along the flow of the reservoir, making way for more oil to be displaced from the reservoir. The smooth flow of oil is possible with reduced interfacial tension and capillary forces due to the miscibility between oil and CO_2 gas. The process of oil displacement by CO_2 gas is clearly indicated in Figure 2.4. Next, when the water slug is introduced into the reservoir, the displaced oil will gain more flow energy to move along the borehole to the surface (Andrei *et al*., 2010; Para-Ramirez *et al*., 2001). Water injection can improve the sweep efficiency by reducing the instability of the gas-oil displacement process and relative permeability effects (Al-Shuraiqi *et al*., 2003). Apart from that, the injected water helps to push the CO_2 further into the oil-rich zones of the reservoir (Rehman &

Meribout, 2012). Kulkarni & Rao (2004) reported that in WAG flooding method, the mechanisms of operations involved includes the following:

a. Gravity segregation in oil/water/gas systems
b. Effect of mobile water saturation
c. Effect of reservoir wettability
d. Effect of spreading coefficient
e. Effect of reservoir heterogeneity
f. Miscibility development

During CO_2 injection, maintaining the reservoir pressure higher than the minimum miscibility pressure (MMP) promises a very good oil recovery (Andrei *et al.*, 2010). MMP is important for achieving miscibility between the CO_2 gas and crude oil (Kulkarni & Rao, 2004). Under specific pressure, temperature and oil composition, CO_2 gas attains miscibility with the oil through multiple contacts (Para-Ramirez *et al.*, 2001). Schlumberger Oilfield Glossary (2013) defines multiple-contact miscibility as the process of components exchange between oil and injected gas until miscibility is reached.

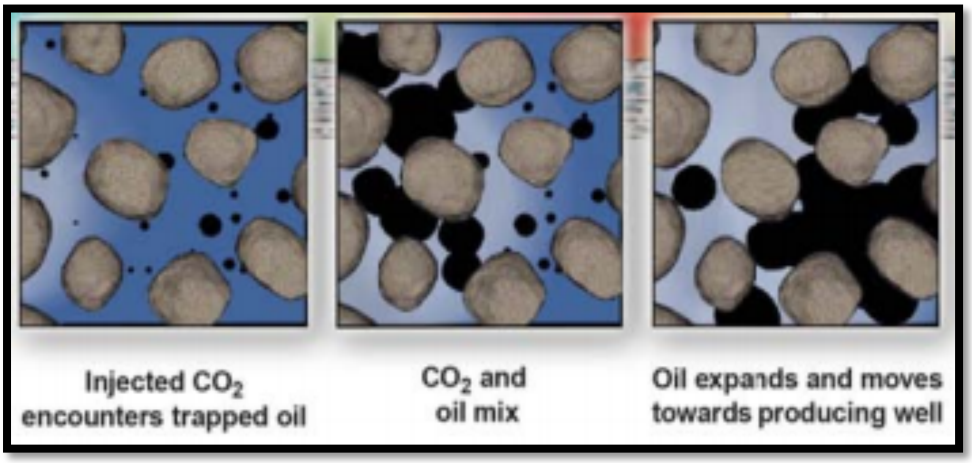


Figure 2.4: Oil displacing mechanism of CO_2 injected gas (Odom, n.d.)

There are two methods of injecting CO_2 gas into the formation, and the selection of the suitable method is highly dependent on the reservoir pressure, temperature and oil characteristics (Andrei *et al.*, 2010). Both the miscible and immiscible displacement methods of CO_2 gas are given in Table 2.1. For fractured reservoirs, miscible injection is suitable while immiscible injection is applied to non-fractured or limited fracture reservoirs (Rehman & Meribout, 2012).

Table 2.1: Comparison between miscible and immiscible CO_2 gas displacement

(Andrei et al., 2010)

Miscible Displament Method	**Comparison Criteria**	**Immiscible Displacement Method**
• Depth < 1200 m • Low oil density (> 22 °API)	Suitable reservoir condition	• Reservoir pressure too low • High oil density
CO_2 gas completely mix with oil within the reservoir	Mixing Properties of CO_2 gas	CO_2 gas does not mix with oil within the reservoir
• Decreases the interfacial tension between two substances to almost zero • Forms a low viscosity fluid that can be easily displaced	Role of CO_2 gas in oil recovery	• Swells the oil by reducing its density • Improves mobility and increases recovery
4 – 12 %	Oil recovery in terms of OIIP	18%

Due to reduced viscous fingering and higher recovery of up to 70% as compared to immiscible flooding, miscible gas flooding is mostly preferred (Kulkarni & Rao, 2004). The incremental oil recovery is achieved in miscible flooding through the mechanisms specified below:

a. Reduce oil viscosity
b. Swell the oil
c. Oil displacement by generating miscibility, that is creating infinite capillary number through zero interfacial tension between oil and solvent

Christensen *et al.* (1998) reported that during miscible WAG injection, 5-spot injection pattern are commonly chose for fairly close well spacing onshore. For reservoirs with low injectivity, the line drive and 5-spot patterns are recommended as it provides better flood front control, however for high injectivity zones, 9-spot pattern will be a good choice (Sanchez, 1999; Kulkarni & Rao, 2004). On the other hand, reducing the injection pattern and increasing the number of wells will yield a higher recovery as detailed by Christensen *et al*. (1998).

Chen *et al.* (2009) found that gas slug size has an impact on the oil recovery by WAG-CO_2 injection. A 0.2 – 0.4 PV slug size is economically recommended although maximum recovery is obtained with a 0.6 PV slug size (Kulkarni & Rao, 2004). It is also said that when the WAG ratio decreases, the oil recovery increases until a threshold value is achieved. Optimum economic recovery in the Rangely field was obtained by injection of a 30% hydrocarbon pore volume (HCPV) slug of CO_2 with a WAG ratio of 1:1 (Attanucci *et al.*, 1993; Al-Shuraiqi *et al*., 2003). In water-wet reservoirs, WAG ratio of 0:1 (CGI) is preferable, whereas WAG ratio of 1:1 is more desired for oil-wet reservoir types (Kulkarni & Rao, 2004). Previously, Kulkarni (2003) has reported that Hybrid WAG with a continuous 0.7 PV gas slug injection followed by 1:1 WAG is able to optimize oil recovery. Al-Shuraiqi *et al.* (2003) accounted that flow rate affects the recovery from WAG and suggested that 3 ml/min is the optimum flow-rate.

Although WAG process yields maximum oil recovery, it also possesses numerous operational problems such as early breakthrough in production wells, reduced injectivity, corrosion, scale formation, asphaltene and hydrate formation as well as temperature difference of injected phases. As reported by Takahashi *et al*. (2003), CO_2 breakthrough is observed to be earlier in carbonate cores than sandstones cores. WAG tapering method could optimize the WAG-CO2 scheme by controlling channeling and breakthrough of gas (Attanucci *et al.*, 1993; Christensen *et al.*, 1998). In this method, CO_2 injection volumes are progressively reduced to make way for more water and less CO_2 are injected during a complete WAG cycle (Kulkarni & Rao, 2004). Another method to optimize WAG as reported by Attanucci et al. (1993) is the reduced half-cycle application that will control fingering of CO_2 gas. Half-cycle refers to the hydrocarbon pore volume of CO_2 gas or water injected before alternating. The advantage of employing this method in any WAG project is that it allows more oil to be in contact with CO_2 gas in the reservoir. Other advantages include increase in efficiency of CO_2 recovery process and CO_2 reserves apart from improving the lift efficiencies.

When employing the WAG technique for improved recovery of oil, there are a number of factors to be considered which includes the reservoir stratigraphy and heterogeneity, rock wettability, fluid properties, miscibility conditions, amount of gas trapped and injection techniques. Other WAG parameters such as cycling frequency, slug size, WAG ratio and injection rate should also be given consideration before employing the WAG technique (Sanchez, 1999).

The advantage of using CO_2 gas for EOR projects is that it can help in reducing the environmental problems in terms of lesser global warming issues. This is because large amount of CO_2 gas can be sequestered from the gas produced, which is normally flared off (Andrei *et al.*, 2010). Kulkarni & Rao (2004) found that CO_2 floods have higher viscosity, thus the injectivity problems that arise are lower compared to other injection methods. It is also an added advantage to use CO_2 gas in highly heterogeneous reservoirs as its physical dispersion causes delays in gas breakthrough and reduces channeling problem as well. However, CO_2 gas is relatively expensive as compared to other injection gases and thus, it is only used for achieving miscible drive and for special cases (Christensen *et al.*, 1998). CO_2 also corrodes the bottom-hole equipments (Rehman & Meribout, 2012).

2.3 Asphaltene

Boussingault identified asphaltene from an ether-insoluble fraction of asphalt in 1837 (Sheu, 2002). Asphaltene can be defined as high molecular hydrocarbons, non-volatile complex molecule and polar fraction of petroleum that is soluble in benzene and insoluble in n-alkanes such as pentane or heptane (Kokal & Sayegh, 1995; Sheu, 2002; Alian *et al.*, 2011). Mousavi-Dehghani *et al.* (2007) reported that asphaltenes are also polyaromatic. According to Nellensteyn, asphaltene generally forms a colloidal system that will be adsorbed by lighter components on the surface (Sheu, 2002).

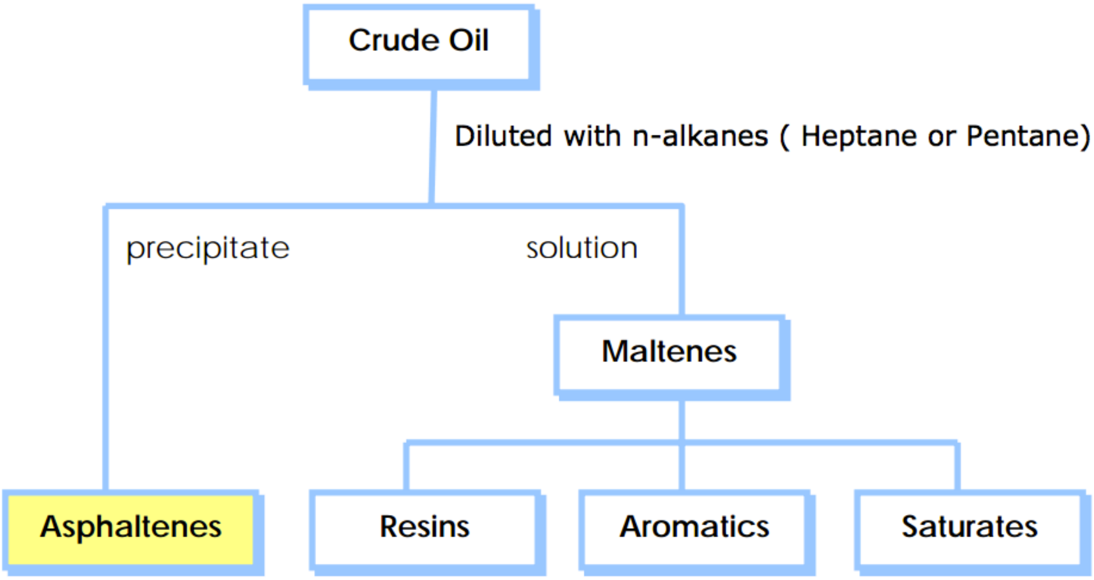


Figure 2.5: SARA fraction of the crude oil (Choiri, 2010)

Asphaltene can be identified as dark brown to black friable solids as shown in Figure 2.6, which decomposes and leaves carbonaceous residue and volatile products upon heating (Kokal & Sayegh, 1995; Sarma, 2003). Asphaltenes will be in their molecular form at high pressures and temperatures (Sheu, 2002). Sheu (2002) also reported that the molecular weight of asphaltene is in the range of 600 to 1000 Daltons and mostly do not exceed 1500 Daltons. At the onset precipitation pressure, the particle size of asphaltenes is 0.5 µm and eventually expands to 1.5 µm at bubble point pressure (Negahban *et al*., 2003; Ashoori, 2005). Asphaltenes are made up of nitrogen, sulphur and oxygen but they can never be broken down into individual components because they do not crystallize (Ashoori, 2005; GH Geochemical Services, n.d.). Based on the asphaltene precipitated by n-pentane and n-heptane from countries around the world, typical elemental compositions of asphaltenes are mainly carbon and hydrogen (Kokal & Sayegh, 1995). Factors that determine the amount of asphaltene in crude oil are the source, depth of burial, API gravity of crude oil and the sulphur and non-sulphur content (Kokal & Sayegh, 1995).

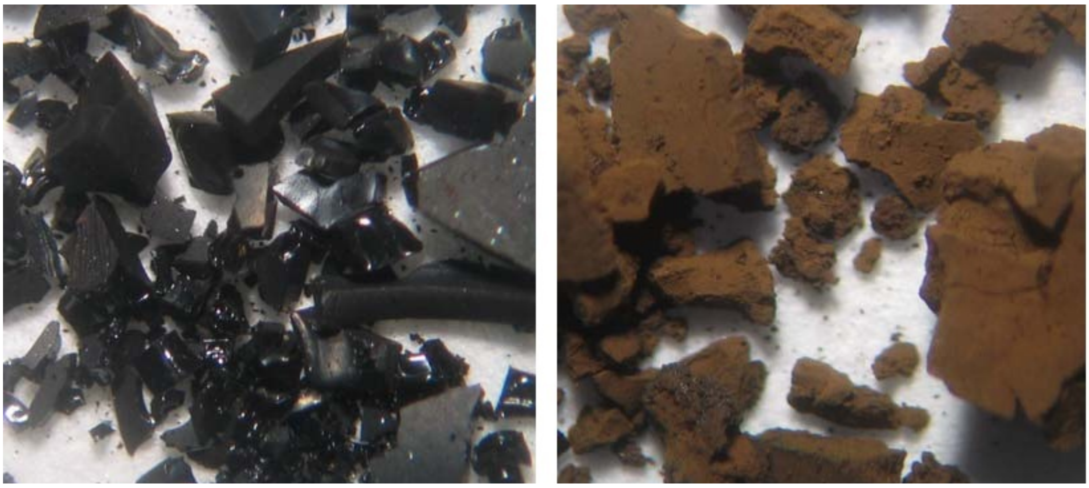


Figure 2.6: Appearance of n-C7 solid asphaltenes (left) and n-C5 solid asphaltenes (right) (New Mexico Technology, n.d.)

According to Ashoori (2005), the nature of asphaltene in solution can be described using two models namely, the solubility model and the colloidal model. In the solubility model, asphaltenes are dissolved in true liquid state. On the other hand, the colloidal model is the one with asphaltenes in the solid phase being suspended in the crude oil and are stabilized by resins. The colloidal system suggested by Nellensteyn as asphaltenes are in colloidal suspensions stabilized by resins is accepted as the physical model for asphaltene (Kokal & Sayegh, 1995). Therefore, the self-association of asphaltene molecules forms asphaltene colloids (Sheu, 2002).

Asphaltenes exist as colloidal dispersions, which are stabilized in solution by highly polar resins and aromatics that act as peptizing agents (Kokal *et al.*, 2005). Buenrostro-Gonzalez (2004) defined resins as the component of deasphalted oil that is strongly adsorbed in surface-active materials such as Fuller's Earth, alumina or silica and can only be desorbed by solvents such as pyridine or a mixture of toluene and methanol. As compared to asphaltenes, resins have lower polarity, lower molar mass and lesser aromatic although they can be converted into asphaltenes by means of oxidation (Khanifar *et al.*, 2011). Resins are insoluble in lower molecular weight alkanes but soluble in alkanes with higher molecular weight. Generally, asphaltenes absorbs resins to form protective layer and together they are present in the crude oil as micelles (Kokal & Sayegh, 1995). These micelles are aromatic hetero-compounds with aliphatic substitutions (Buenrostro-Gonzalez *et al.*, 2004). Sarma (2003) reported that better colloidal stabilization is achieved when the asphaltene-to-resin ratio is low. According to Khanifar *et al.* (2011), high resin content in crude oil preserves the stability of the crude.

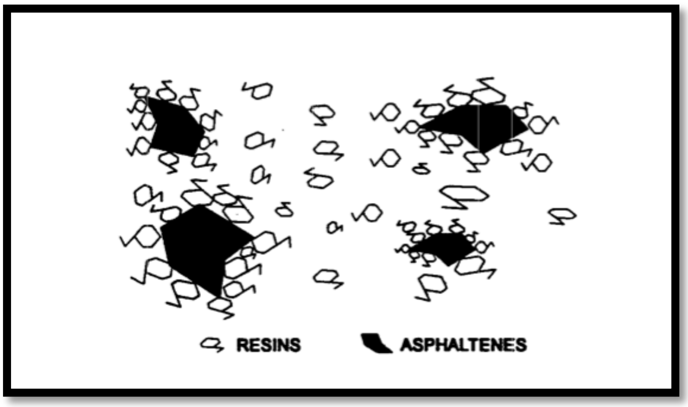


Figure 2.7: Asphaltene and resins peptization (Kokal & Sayegh, 1995)

Asphaltenes are grouped according to the paraffin used to precipitate them from the crude oil. Figure 2.8 indicate that when the precipitating n-alkane molecules get smaller, the amount precipitated increases sharply (Kokal & Sayegh, 1995). Although defining the structure of asphaltene is very complex, a recent study observed that they consist of condensed aromatic nuclei, which carry alkyl and alicyclic systems with heteroatoms scattered throughout (Kokal & Sayegh, 1995). Two chemical structures have been proposed and generally accepted although the exact structure is not fully understood. One of the structures is the continental model and the other one is the archipelago model. In the continental model, asphaltene is thought to be a large central aromatic region with small alkyl chains on the periphery. Meanwhile, asphaltenes are seen as smaller aromatic regions linked by bridging alkanes in the archipelago model (Khanifar *et al.*, 2011).

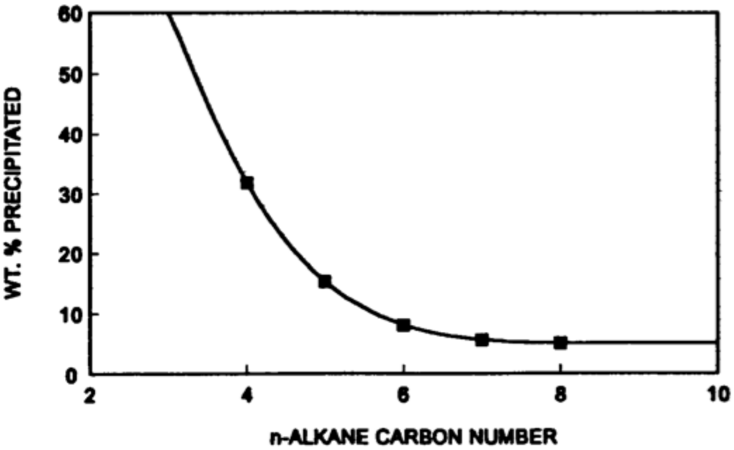


Figure 2.8: Effect of solvent carbon number on insolubles (Kokal & Sayegh, 1995)

2.4 Asphaltene Precipitation in Light Oil Reservoirs

Asphaltene precipitation causes both downstream and midstream problems resulting in lower oil recovery. Some of the downstream problems caused by asphaltene accumulation are catalysts poisoning, delayed coker or coke precursors, and fluidized bed catalytic cracker, deposition in the vessel, entrapment of light components into asphaltene aggregates, formation plugging and wettability reversal towards oil-wetness (Sheu, 2002; Tharanivasan, 2012; Kokal & Sayegh, 1995; Sarma, 2003). Apart from that, asphaltene precipitation will lead to various production and reservoir problems including porosity alteration, permeability reduction, plugging of wellbore and blocking of production system (Alta'ee *et al.*, 2010). Also, it was found that lesser oil saturation is left behind in the reservoirs without asphaltene following a higher oil recovery. The absence of asphaltene particles deposition that will clog the pore spaces in this type of reservoir explains the situation (Lim, 2012). Existing problems in producing wells due to asphaltene precipitation and deposition are dealt by mechanical and chemical cleaning or reservoir condition manipulation, which are not economically viable (Kokal & Sayegh, 1995). After removal of asphaltene, the crude oil is known as "deasphalted oil" or maltenes (Tharanivasan, 2012).

Asphaltene solubility in light oil reservoirs is very low, which disturbs its stability and prompts precipitation (Sarma, 2003; Alian *et al.*, 2011). Studies on the Boscan crude and Mata-Acema crude reveal that the asphaltene content has no significance on its precipitation, whereby the latter crude with much lower asphaltene content caused many problems (Kokal & Sayegh, 1995). The solubility of asphaltene in oil is a function of gas present in the reservoir. Asphaltenes are highly soluble in oil when there is lesser gas present in the reservoir because gas and asphaltene constantly compete for solubility in oil phase.

Khanifar et al. (2011) observed that when the colloidal suspension of asphaltene becomes destabilized due to one of the factors mentioned in the following paragraph, precipitation occurs. This precipitation will cause the asphaltene and resins to come out of the oil and form separate phases with asphaltene as solid phase. The point at which asphaltene first loses its stability and comes out of the crude oil is known as the precipitation onset and the pressure at which this phenomena occurs is called the onset pressure (Kohse & Nghiem, 2004; Khanifar *et al*., 2011). As the API gravity of the crude oil increases, the precipitation onset pressure will increase as well (Hajizadeh *et al*., 2008). Maqbool (2011) reported that generally oil to precipitant volume ratio of 1:40 would be observed when asphaltene precipitates out from oil. Factors that induce asphaltene precipitation include pressure change, temperature change, chemical composition of crude oil, mixing of oil with diluents or other oils, gas lift operations, miscible flooding and during acid stimulation (Kokal & Sayegh, 1995; Tharanivasan, 2012). Apart from these factors, other parameters that can cause asphaltene precipitation inside a reservoir as documented by Mousavi-Dehghani et al. (2004) includes:

- nature of the reservoir fluids,
- saturation and distribution of the reservoir fluids,
- mineralogy and properties of the reservoir rock,
- nature of injection fluids,
- electrokinetic effects due to streaming potential generation as a result of reservoir fluid flow,
- asphaltene and resin contents of the reservoir oil, and
- amount of formation brine and its composition.

As oil is depressurized, the solubility of asphaltene in oil decreases, eventually leading to asphaltene precipitation due to the significant increase in relative molar volume of solution gas and light ends (Sheu, 2002; Tharanivasan, 2012). At high pressures, asphaltene precipitation is relatively low (Buenrostro-Gonzalez *et al*., 2004). Reduction of pressure beyond the onset pressure, especially near bubble point induces asphaltene precipitation except in some cases where the precipitation process takes place at higher pressures (Kohse & Nghiem, 2004; Kokal *et al.*, 2005). This is because of the highest content of dissolved gas in crude oil at bubble point (Tharanivasan, 2012). Para-Ramirez *et al.* (2001) reported that at bubble point pressure, the asphaltene precipitation is the highest. Below bubble point pressure, a reduction in the amount of asphaltene precipitated was observed as the pressure continues to drop (Takahashi *et al*., 2003; Khanifar *et al*., 2011). Chukwudeme & Hamouda found that the injection pressure has no significant effect on the asphaltene precipitation at pressures above the bubble-point. At those pressure conditions, as the pressure continues to drop, the amount of asphaltene precipitated decreases.

Tharanivasan (2012) reported that the effect of temperature on the onset and amount of asphaltene precipitated is not as critical as the effect of pressure. However, Negahban *et al*. (2003) studied that the onset asphaltene precipitation pressure will increase as the temperature decreases. This condition is particularly applicable above the bubble point pressure (Hassanvand *et al*., 2012). The asphaltene precipitation onset time is reportedly shorter and asphaltene solubility is higher at high temperatures (Maqbool, 2011). The asphaltene precipitation is found to be inversely proportional to temperature (Ashoori, 2005). Furthermore, addition of CO_2 at low temperatures will stabilize the asphaltene by dissolving them in the crude (Gonzalez *et al*., 2008). Temperature also may have an impact on the particle size of asphaltene, in which increasing temperature will result in smaller asphaltene particles.

Arab D Reservoir of Ghawar Field, a light oil reservoir experiences asphaltene precipitation and deposition problems after gas injection took place due to gas coning or cresting (Kokal *et al.*, 2005). Kokal *et al.* (2005) accounted that increasing gas-oil ratio (GOR) will result in increase of asphaltene precipitation and deposition. This is because asphaltene precipitation is a function of gas injection. That is why asphaltene precipitation problem is not common in older producing reservoirs. Diminishing GOR in such fields causes asphaltene to be soluble in crude oil, as the lighter-ends have been produced (Sarma, 2003). Addition of gases or paraffinic solvents into the reservoir will make the oil to become less aromatic and causes compositional changes. Such changes in composition will eventually lead to asphaltene precipitation (Tharanivasan, 2012).

Based on SARA analysis data, asphaltene solvency increases when there is higher content of aromatics in the crude, thus the asphaltene is more stable (Sarma, 2003). Increasing temperature may also re-dissolve precipitated asphaltenes (Ashoori, 2005). Crude oil flowing through capillaries and porous media are highly likely to cause asphaltene precipitation because the asphaltene-resin micelles are electrically charged. Hence, the micelles will precipitate if an electrical potential is applied (Kokal & Sayegh, 1995). In the Hassi Messaoud, Lake Maracaibo and Ventura fields, reducing the wellhead pressures had diminished asphaltene deposition problems when the pressure fell below bubble point pressure (Kokal & Sayegh, 1995).

As illustrated in Figure 2.9, asphaltene precipitation could further lead to flocculation and deposition, by which it causes damage to the reservoir (Khanifar *et al.*, 2011). Asphaltene precipitation occurs when the asphaltenes are separated from the stabilized micelles. These asphaltene particles will then lump together to form larger particles as they flow suspended in the reservoir fluid, which is called as flocculation process. As the large lump of asphaltene particles gets heavier, it will eventually sink and settle down on the rock surfaces or bottom-hole equipment surfaces. This process is called the deposition of the asphaltenes (Choiri, 2010). Irreversible flocculation of asphaltene may take place when adequate amount of flocculant such as n-pentane are added into the reservoir, which causes destruction of the asphaltene-resin micelle (Kokal & Sayegh, 1995). The accumulation of asphaltene is higher as the degree of heterogeneities in the reservoir increases (Sarma, 2003; Takahashi *et al.*, 2003).

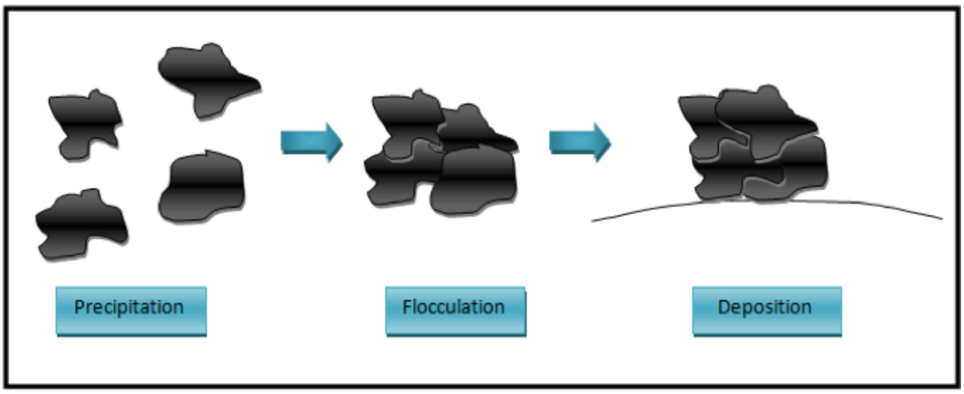


Figure 2.9: The asphaltene precipitation and deposition process (Lim, 2012)

2.5 Effects of Carbon Dioxide (CO_2) on Asphaltene Precipitation

Asphaltene problems may be caused by injection of carbon dioxide (CO_2) in light oil reservoirs. Some of the fields that have undergone problems due to asphaltene precipitation after gas injection are Little Creek Field, Mississippi Field and West Texas Field (Sarma, 2003).

Generally, changes in composition of reservoir fluids, pressure and temperature favor asphaltene precipitation by means of thermodynamic equilibrium alteration of the asphaltene-resin micelles. The mixing of CO_2 and reservoir oil will cause fluid behavior and equilibrium changes as well as alteration to the rock properties resulting in multiple phase equilibria including asphaltene in the form solid (Alta'ee *et al.*, 2010; Kokal & Sayegh, 1995; Negahban *et al.*, 2003). This is due to the alteration of asphaltene resin ratio in reservoir oil, which leads to the precipitation of asphaltene (Alian *et al.*, 2011). Sarma (2003) mentioned that asphaltene destabilization occurs when CO_2 gas is injected due to the pH change that it causes. Destabilized asphaltene-crude mixture caused by the flooding of CO_2 gas will lead to asphaltene precipitation by reducing the carbon-to-hydrogen ratio in the solution (Ashoori, 2005).

CO_2 injection causes destabilization of asphaltene-resin micelles through two mechanisms, as follows (Oilfield Wiki, n.d.):

- Dissolution of CO_2 into crude oil will depeptize the resins
- CO_2 will strip out the lighter hydrocarbons (aromatic components) in which asphaltenes are soluble.

Apart from that, precipitation of asphaltene is highly dependent on the concentration of CO_2 injected. Increasing the CO_2 concentration will also increase the precipitation of asphaltene with the maximum amount at bubble point pressure (Negahban *et al.*, 2003; Sarma, 2003). At low concentration of CO_2 and pressure, asphaltene precipitates in bulk (Sarma, 2003). Alian *et al.* (2011) reported that asphaltene precipitation increases with the increase of pore volume of injection. When the pore volume of injection is high, more CO_2 gas will be in contact with the oil for a longer time and thus, rate of asphaltene precipitation is higher. During CO_2 gas injection, low rate of production can cause asphaltene precipitation as evident in Midale field, which is produced at 100 BPD (Sarma, 2003). Takahashi *et al.* (2003) found that asphaltene precipitation is also dependent on the CO_2 mole percentage. The onset precipitation pressure increases linearly with CO_2 mole percentage. The study showed that at 50% or higher mole of CO_2, the amount of asphaltene precipitated increases.

In addition, the vaporizing drive created by CO_2 gas during injection, will extract resin molecules into the injected gas. When this condition occurs, the asphaltene loses its stability and tend to precipitate. It was also reported that asphaltene precipitation could be reduced during CO_2 flooding by increasing the injection pressure, whereby asphaltene remains dissolved at high pressures. At high pressure, gas will carry away the precipitated and deposited asphaltene leaving the recovered oil to flow through the core. In WAG injection, concentration reduction due to CO_2 gas dissolving in brine decreases asphaltene precipitation (Alta'ee *et al.*, 2012). Increase in CO_2-oil ratio in the reservoir could increase the asphaltene precipitation (Sarma, 2003).

At reservoir temperature, the stability of asphaltene is not affected by CO_2 gas addition but asphaltene became instable when the temperature decreases (Negahban *et al.*, 2003). Asphaltene flocculation is caused by the miscibility of the solvent with the reservoir oil (Alta'ee *et al.*, 2010). The asphaltene problem increases as more miscible solvent dissolves in the crude oil (Kokal & Sayegh, 1995). Para-Ramirez et al. (2001) pointed out that higher amount of asphaltene precipitation is observed during multiple-contact miscibility mixtures such as the oil and CO_2 gas mixture. Multiple contact of CO_2 causes 3-5 times more asphaltene precipitation than first contact of CO_2 (Alta'ee *et al.*, 2010).

2.6 Effects of Water on Asphaltene Precipitation

Tharanivasan (2012) accounted that the presence of water does not affect the solubility of asphaltene in the reservoir. This means that the bulk movement of water will not flush away the highly deformable and sticky asphaltene particles (Ashoori, 2005). Also, above the precipitation onset point, the presence of emulsified water has no significant effect on asphaltene precipitation. However, the pH of the water injected may have some effect on the amount of asphaltene precipitated (Ashoori, 2005). Garshol (2005) reported that asphaltene adsorption process is affected by water, which eventually causes asphaltene deposition. Thus, water mainly has significant impact on the resins that stabilizes the asphaltene, instead of the asphaltene itself (Goual, 2012).

2.7 Summary

CO_2 injection is highly recommended for light oil reservoirs due to its ability to increase the mobility displacement and sweep efficiencies. However CO_2 gas injection causes asphaltene precipitation when it mixes with the reservoir oil and changes the oil composition. Asphaltenes, black solids that are insoluble in n-alkenes can cause serious flow assurance problems during production as well as well as alter the reservoir properties. In order to reduce the asphaltene precipitation, brine is introduced alongside CO_2 injection, which is known as WAG-CO_2 scheme. Previous studies and laboratory works shows that various WAG parameters affect the asphaltene precipitation during WAG-CO_2 scheme implementation. These works serve as a strong base for engineers and researchers to explore and understand the mechanism of asphaltene precipitation in relation to the WAG and CO_2 gas in greater depths.

CHAPTER 3

METHODOLOGY

3.1 Research Methodology

The study was conducted in two major phases under FYP I and FYP II. During the first phase, background studies on previous research works were conducted to gain as much knowledge possible on the subject matter. The information obtained was analyzed and inferred to design the structure of this study. Since the study is based on simulation works, a well-structured simulation process flow was drafted out. The area of interest in this work is to determine how much asphaltene precipitates at different conditions of the WAG-CO_2 injection in light oil reservoirs. FYP II phase was focused on the execution of the planned research to achieve the objectives set forth and hence determine an answer to the problem statement of this study. Based on the objectives, relevant data were collected from various literatures published. The data was then used to build a 3D model and test all the designated parameter to obtain optimum conditions for less asphaltene precipitation. Simplified research methodology chart is shown in Figure 3.1.

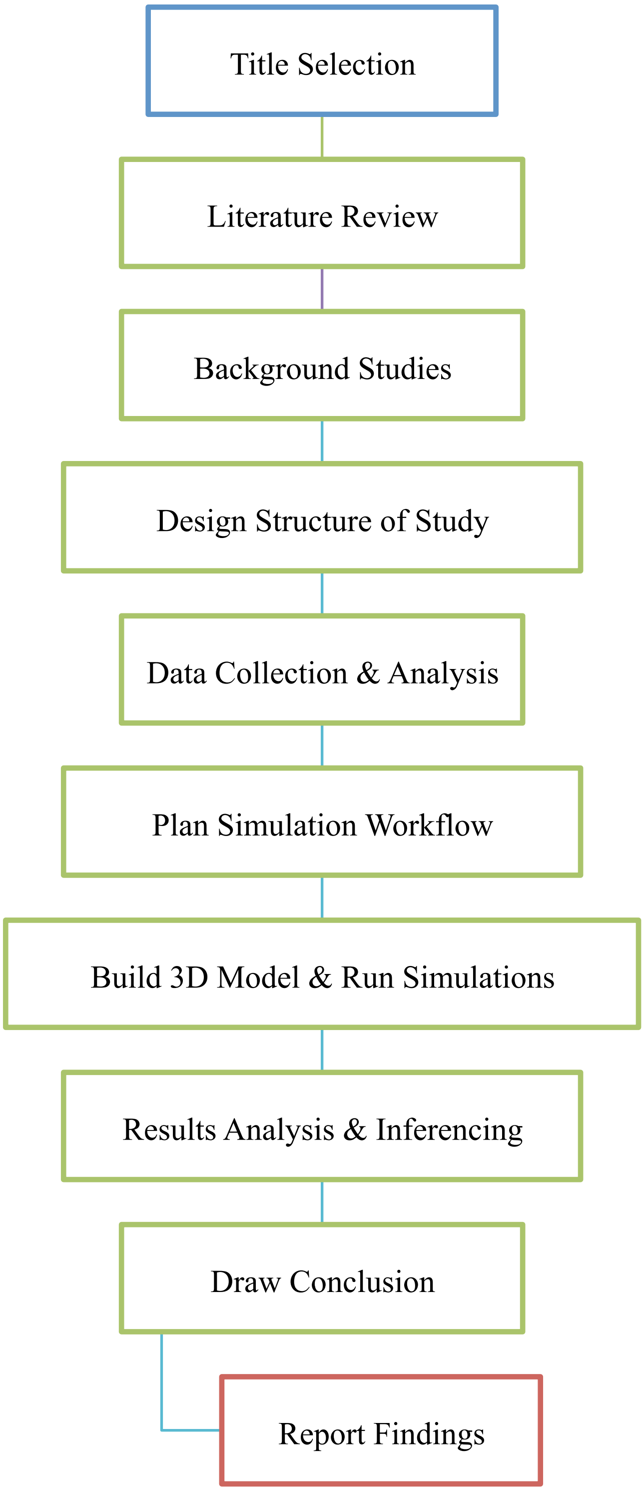


Figure 3.1: Research methodology flowchart

3.2 Project Activities

Table 3.1: Summary of Project Activities

Activity	Tasks
Background Study	• Conduct study on Enhanced Oil Recovery (EOR) mechanisms • Conduct study on mechanisms and limitations of Water-Alternating-Carbon Dioxide (WAG-CO_2) injection • Conduct study on the properties and nature of asphaltene • Conduct study on the problems caused by the precipitation and deposition of asphaltene in light oil reservoirs • Conduct study on the effect of Carbon Dioxide (CO_2) on asphaltene precipitation
Data Collection	• Collect necessary raw data and pre-processed data • Sort and manage data to obtain sufficient information for the study • Data analysis and reservoir characterization
Design Simulation	• Plan workflow for the simulation process • Determine the necessary input data required • Identify the parameters that need to be tuned for testing the objectives of the study • Identify the parameters that need to be held constant
3D Modeling & Simulations	• Build a 3D geological model to represent the integrity of the underlying geology of the reservoir • Incorporate a dynamic reservoir model into the 3D geological model to preserve the fluid flow system of light oil reservoir • Model initialization to validate the 3D reservoir model by comparing volumetric of fluid in-place. • Tuning of various parameters to be tested in order to determine the optimum conditions for less asphaltene precipitation
Results Analysis	• Analyze the results obtained and make inferences • Draw conclusions based on the outcome of the simulation results • Recommend further studies needed to validate the results obtained • Report the findings of the study

3.3 Gantt Chart & Milestones

Activity	Week													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Title Selection	🟩													
Literature Review		🟩	🟩	🟩	🟩									
Background Study				🟩	🟩									
Extended Proposal Submission						🟩🍎								
Design Structure of Study							🟩	🟩						
Proposal Defense								🟩🍎						
Data Collection & Analysis									🟩	🟩	🟩			
Plan Simulation Workflow												🟩		
Draft of Interim Report Submission													🟩🍎	
Interim Report Submission														🟩🍎

Figure 3.2 : Timeline for FYP I

Activity	Week													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
3D Modeling & Simulations	🟩	🟩	🟩	🟩	🟩	🟩	🟩							
Progress Report Submission							🟩🍎							
Results Analysis & Inferencing								🟩	🟩	🟩	🟩	🟩		
Pre-SEDEX										🟩🍎				
Draft Report Submission											🟩			
Dissertation Submission												🟩🍎		
Technical Paper Submission												🟩🍎		
Oral Presentation													🟩🍎	
Finalised Project Dissertation Submission														🟩🍎

Figure 3.3 : Timeline for FYP II

Legend:

Process 🟩 Milestone 🍎

3.4 Tools Required

This project utilized CMG numerical modeling simulation software throughout the execution process. The software serve as an aid to further understand the reservoir and run simulations.

Figure 3.4: CMG logo

1. Builder

Builder is a reservoir simulation model creation, editing and visualization program. It is used for generating input for the other CMG modules. Builder is also useful to quickly generate PVT tables from correlations. Other than that, Builder can be used for well controls, hydraulic fracturing and geomechanics. In this study, Builder was used to build the static model of the reservoir.

2. WinProp

WinProp is used for modeling phase behaviour and properties of reservoir fluids. When used together with the EOS tool, WinProp is able to predict fluid behaviour from lab experiments. This tool can be very useful to study asphaltene precipitation and miscible injections. The asphaltenic oil used in this study was modeled using WinProp.

3. GEM

GEM is able to simulate for multi-component fluids in the reservoir. It was handy for modeling CO_2 and WAG processes in this project. Apart from that, GEM can be used for modeling unconventional gas and liquid reservoirs, hydrocarbon and acid gas injection, gas, gas condensate and volatile oil as well as fractured reservoirs and greenhouse gas.

CHAPTER 4

RESULTS & DISCUSSION

4.1 Data Gathering & Analysis

This research work is based on data collection from various literatures published. Fluid modeling data is the main and crucial data necessary for the purpose of the study. The asphaltenic light oil sample used in the study is Oil Sample 4 (Burke *et al.,* 1990). The oil sample has an API of 38.8, which is a light-oil. The composition data for Oil Sample 4 is given in Table 4.1.

Table 4.1: Composition Data and Their Respective Molecular Weight for Oil Sample 4

Component	**Burke Oil 4**
Nitrogen	0.25
CO_2	2.03
Methane	32.44
Ethane	15.50
Propane	6.54
i-Butane	0.81
n-Butane	3.20
i-Pentane	1.15
n-Pentane	2.13
Hexanes	2.46
Heptanes Plus	33.49
Total	100.00
C_{7+} molecular weight	223
C_{7+} specific gravity	0.8423
Live-oil molecular weight	95.2
API gravity, stock-tank oil	38.8
Asphaltene content in stock-tank oil, wt%	1.7
Reservoir temperature, °F	234
Saturation pressure, psia	2, 492

4.2 Fluid Model

4.2.1 Asphaltene Precipitation Model

The precipitation of asphaltene from reservoir oil due to pressure depletion was modeled using WinProp. This phase behaviour property program uses an enhanced solid thermodynamic model proposed by Nghiem *et al.* (1996) to illustrate the precipitation behaviour of asphaltene and petroleum reservoir fluid. A multiple flash calculation is used to model the precipitation of asphaltene. In this calculation, the fluid phases are described with an equation of state and the fugacities of components in the solid phase are predicted using the solid model described below. The Peng-Robinson EOS (PR EOS) (1976) was used to predict the state of oil and gas phases. The solid phase consist of one or more components, where the precipitated asphaltene is represented as a pure dense phase. The heaviest component can be divided into two parts: a precipitating and a non-precipitating component according to the model used. The precipitating component is the asphaltene and the non-precipitating component is the resins or asphaltene-resin micelles that will not dissociate.

Under isothermal conditions, the precipitating asphaltene component in the solid phase is represented by the following fugacity expression:

$$\ln f_S = \ln f_S^* + v_S (p - p^*) / RT$$

where,

f_s is the reference (asphaltene) fugacity at pressure p and temperature T,

f_s^* is the fugacity at pressure p* and temperature T*,

v_s is the molar volume of the solid (asphaltene), and

R is the universal gas constant.

The equation indicates that the precipitation process is reversible as it is based on the thermodynamic equilibrium conditions. This means the precipitated asphaltene may re-dissolve into the oil when the pressure is extremely low. This is because when the pressure is very low, the system will return to a state outside the asphaltene precipitation behaviour envelope. The reversible process of the precipitated asphaltene will be discussed in the following sections.

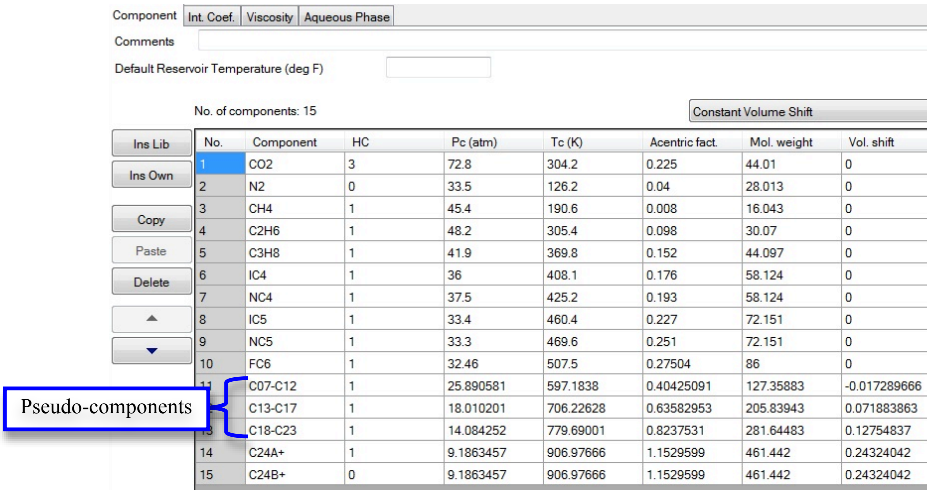
The steps necessary to develop an asphaltene precipitation model are as follows:

- Fluid characterization
- Regression on fluid PVT
- Specification of asphaltene model parameters
- Prediction of asphaltene precipitation behaviour

Fluid Characterization

A dataset to characterize the reservoir fluid was prepared by defining the initial components and their respective compositions up to C_6. The C_{7+} component was also defined to describe the pseudo-components. The characterization of the solid forming components, both in solution and in the solid phase is the crucial step in asphaltene precipitation modeling. Splitting the heaviest component into two components, a non-precipitating component and a precipitating fraction, is necessary to characterize the solid phase. The critical properties and acentric factors for the two components are identical except that they have different interaction coefficients with the light components.

First, the heaviest component C_{7+} is split into a Single Carbon Number (SCN) fraction up to C_{24+} as shown in Figure 4.1. The splitting process was done using a 2-Stage Exponential to describe the molar distribution as a function of molecular weight. This function is an approximation to the gamma function, which is suitable for black oil type fluids. The calculation was done by specifying the C_{7+} molecular weight and specific gravity.



Comments

Default Reservoir Temperature (deg F)

No. of components: 15

Constant Volume Shift

No.	Component	HC	Pc (atm)	Tc (K)	Acentric fact.	Mol. weight	Vol. shift
1	CO2	3	72.8	304.2	0.225	44.01	0
2	N2	0	33.5	126.2	0.04	28.013	0
3	CH4	1	45.4	190.6	0.008	16.043	0
4	C2H6	1	48.2	305.4	0.098	30.07	0
5	C3H8	1	41.9	369.8	0.152	44.097	0
6	IC4	1	36	408.1	0.176	58.124	0
7	NC4	1	37.5	425.2	0.193	58.124	0
8	IC5	1	33.4	460.4	0.227	72.151	0
9	NC5	1	33.3	469.6	0.251	72.151	0
10	FC6	1	32.46	507.5	0.27504	86	0
11	C07-C12	1	25.890581	597.1838	0.40425091	127.35883	-0.017289666
	C13-C17	1	18.010201	706.22628	0.63582953	205.83943	0.071883863
13	C18-C23	1	14.084252	779.69001	0.8237531	281.64483	0.12754837
14	C24A+	1	9.1863457	906.97666	1.1529599	461.442	0.24324042
15	C24B+	0	9.1863457	906.97666	1.1529599	461.442	0.24324042

Figure 4.1: Pseudo-components of Oil Sample 4

After splitting the "plus" fraction, the SCNs were lumped into four pseudo-components and their respective critical properties were calculated via Lee-Kesler (1975) mixing rule correlation. The component specification was then updated to reflect the results of the splitting calculation.

Regression On Fluid PVT

WinProp employs the Agarwal *et al.* (1987) method to regress the EOS model to obtain a good match with the available experimental data. The equation of state used in the fluid characterization was tuned via the regression process to match the reported saturation pressure of 2492 psia. The hydrocarbon interaction coefficient exponent was selected as a regression variable. The regression control was set to convergence tolerance of 0.00001 in order to achieve good match with the experimental data. Based on the regression summary table in the output file, an exact match to the saturation pressure was achieved. The component properties were updated once again and the model is ready for asphaltene precipitation prediction.

Specification of Asphaltene Model Parameters

After splitting and regression has been done, the mole fraction of C_{24+} and asphaltene component was reported as one value in the report file. Therefore, the mole fraction need to be calculated manually and input into WinProp for further modeling process. The calculation for the mole fraction of asphaltene can be done based on the following relation:

$$\text{MW\% of asphaltene} = \text{Weight\% of asphaltene X } (MW_{\text{oil}} / MW_{\text{asphaltene}})$$

Based on the regression output file, the reported average molecular weight of the oil is 94.92 as compared to the reported value of 95.2. The asphaltene content of the stock tank oil is given as 1.7%. From the component table, the molecular weight of C_{24+} component is 0.0559928. Thus, the calculated mole fraction of the precipitating component is as follows:

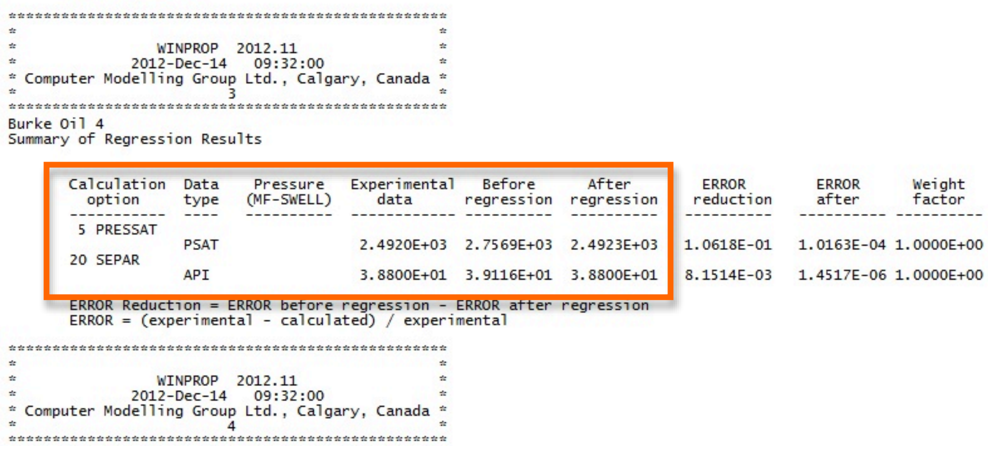
$$\text{Mole\% of asphaltene} = 0.017 \text{ X } (94.92) / (461.442) = 0.00350756$$

$$\text{Mole\% of } C_{24+} = 0.0559928 - 0.00350756 = 0.0524928$$

Table 4.2: Mole % of C_{24+} & asphaltene before and after splitting

Before Splitting			After Splitting	
Asphaltene	0.0559928		Asphaltene	0.00350756
C_{24+}			C_{24+}	0.0524928

Regression was performed again to ensure that the model predicts the correct fluid and solid phase behaviour. The regression parameter set for the run was saturation pressure and stock tank API of oil. The volume shift parameter of the heavy fraction pseudo-components was set as regression variable for the process. The result of the regression run shows an exact match of saturation pressure and stock tank API of oil as shown in Figure 4.2.



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**************************************************
*                                                *
*                WINPROP  2012.11                *
*             2012-Dec-14   09:32:00             *
* Computer Modelling Group Ltd., Calgary, Canada *
*                        3                       *
**************************************************
Burke Oil 4
Summary of Regression Results

       Calculation  Data    Pressure   Experimental   Before      After        ERROR        ERROR      Weight
         option     type   (MF-SWELL)      data     regression  regression   reduction      after      factor
       -----------  ----   ----------  ------------ ----------  ----------   ----------   ---------- ----------
        5 PRESSAT
                    PSAT                2.4920E+03  2.7569E+03  2.4923E+03   1.0618E-01   1.0163E-04 1.0000E+00
       20 SEPAR
                    API                 3.8800E+01  3.9116E+01  3.8800E+01   8.1514E-03   1.4517E-06 1.0000E+00
       ERROR Reduction = ERROR before regression - ERROR after regression
       ERROR = (experimental - calculated) / experimental

**************************************************
*                                                *
*                WINPROP  2012.11                *
*             2012-Dec-14   09:32:00             *
* Computer Modelling Group Ltd., Calgary, Canada *
*                        4                       *
**************************************************
```

Figure 4.2: Regressed values of saturation pressure and oil API

The solid molar volume of the precipitating component should be set to a value higher than the predicted value by the equation of state. Based on the regression result, the solid molar volume is given as 0.50440 L/mol. An initial guess of 0.6 L/mol of solid molar volume was used.

Prediction of Asphaltene Precipitation Behaviour

The predictions of asphaltene precipitation were performed by specifying flash calculation results at every 200 psi from 14.7 to 6000 psia. The precipitation curve obtained was incorrect for the lower pressures, as it did not predict the offset pressure of asphaltene precipitation. The interaction parameter between the precipitating component and the light ends of the oil was adjusted to get a good precipitation curve. Increasing the interaction parameter with the light ends will force the asphaltene to redissolve at lower pressure. Therefore, the interaction parameter was adjusted from 0.2 to 0.4. After several trials with different solid molar volume parameter and interaction parameter, the desired precipitation curve was obtained.

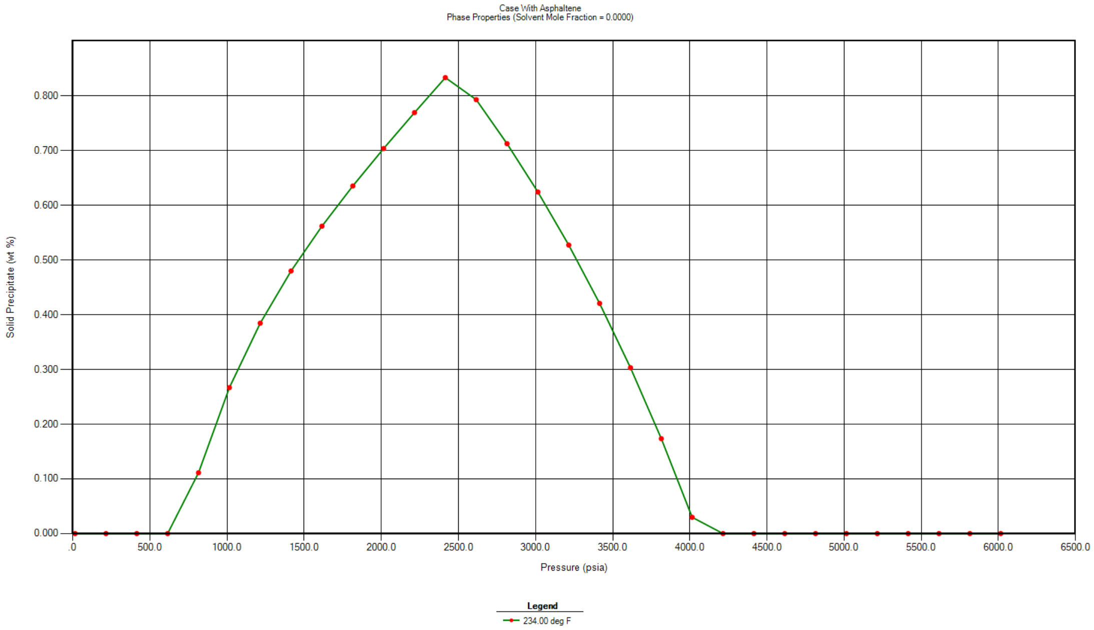

Figure 4.3: Asphaltene precipitation curve at 234 °F

The asphaltene precipitation model shows that the onset pressure is 4200 psia and the offset pressure is 600 psia. Theoretically, maximum asphaltene precipitation in light oil reservoirs should occur at saturation pressure. The results obtained from the precipitation modeling confines to this theory, whereby the maximum precipitation occurs at 2500 psia. Above bubble point pressure, the amount of asphaltene precipitate increases as the pressure decreases. The amount of asphaltene precipitate decreases as the pressure drops below the bubble point. This is due to the evaporation of lighter components from the oil and hence, causing the asphaltene to redissolve into the oil.

4.2.2 Asphaltene Flocculation Model

Irreversibility of solid precipitates is modeled by allowing the asphaltene precipitate (solid s_2) to be transformed into another solid s_1 through a chemical reaction. In other words, the smaller asphaltene particles will flocculate into larger aggregates. The reaction is represented by the following equation:

$$s_1 \leftrightarrow s_2$$

The reaction rate for the formation of solid s_2 is:

$$r = k_{12}\, C_{s_1,o} - k_{21}\, C_{s_2,o}$$

where,

k_{12} is forward rate of formation of solid s_2 from s_1 (day^{-1})

k_{21} is reverse rate of formation of solid s_1 from s_2 (day-1)

r is reaction rate (mol/(m^3 day))

$C_{s1,o}$ is concentration of suspended solid s_1 in oil phase (mol/m^3)

$C_{s2,o}$ is concentration of suspended solid s_2 in oil phase (mol/m^3)

If k_{21} is zero, the reaction is irreversible and s_2 will not redissolve into the solution. If $k_{21} << k_{12}$, the precipitation of s_2 will be reversible. The chemical reaction given above will model the irreversible precipitation or slow redissolution of the precipitated asphaltene.

4.2.3 Asphaltene Deposition Model

In the deposition model, only the flocculated particles (solid s_2) are considered to deposit. The smaller particles of precipitated asphaltene will flow with the oil while the larger and denser flocculates will deposit on the reservoir rocks. The discretized form of the deposition rate equation is:

$$\frac{V_{S_2^d}^{n+1} - V_{S_2^d}^{n}}{\Delta t} - \alpha\, C_{s_2^f}^{n+1}\, \phi^{n+1} + \beta\, V_{S_2^d}^{n+1}\left(v_o^n - v_{cr,o}\right) - \gamma\, u_o^n\, C_{s_2^f}^{n+1} = 0$$

where

$V_{s2,d}$ is volume of deposited solid s_2 per grid block volume

$C_{s2,f}$ is volumetric concentration of flowing solid s_2 per volume of oil

v_o is oil phase interstitial velocity

$v_{cr,o}$ is critical oil phase interstitial velocity

u_o is oil phase Darcy velocity

α is surface deposition rate coefficient

β is entrainment rate coefficient

γ is pore throat plugging rate coefficient

The deposition parameters required are taken from Figuera *et al.* (2010) as shown in Table 4.3.

Table 4.3: Asphaltene Deposition Parameters (Figuera *et al.*, 2010)

Surface deposition rate (α), day^{-1}	1
Entrainment rate (β), ft^{-1}	0.5
Critical interstitial velocity (v_{cr}), ft/day	18
Pore throat plugging rate (γ), ft^{-1}	5
Forward reaction rate (K_{12}), day^{-1}	100
Backward reaction rate (K_{21}), day^{-1}	0

4.3 3D Simulation Model

A synthetic 3D model with dimensions of 2500 ft x 2500 ft x 60 ft was built using Builder with 15000 grid cells. The grid dimensions in the Z direction were divided equally into 6 layers. The reservoir is modeled as homogeneous and hence has a uniform permeability of 300 mD in X and Y directions while permeability in Z-direction is 50 mD. The porosity value assigned for all the grid blocks is 0.25. Other reservoir properties are shown in Table 4.4. Fluid properties employed for the simulation model is given in Table 4.1.

Table 4.4: Reservoir Properties

Reservoir Pressure	3000 psia
Reservoir Temperature	234 °F
Oil saturation	0.8
Connate water saturation	0.2
Initial Condition	Undersaturated (Oil and water only present)
Saturation Pressure	2492 psia
Net-to-Gross (NTG)	0.8
Reservoir Depth	1000 ft
Oil-Water Contact (OWC)	1500 ft
Asphaltene content, % (weight)	1.7
Unit Used	Field

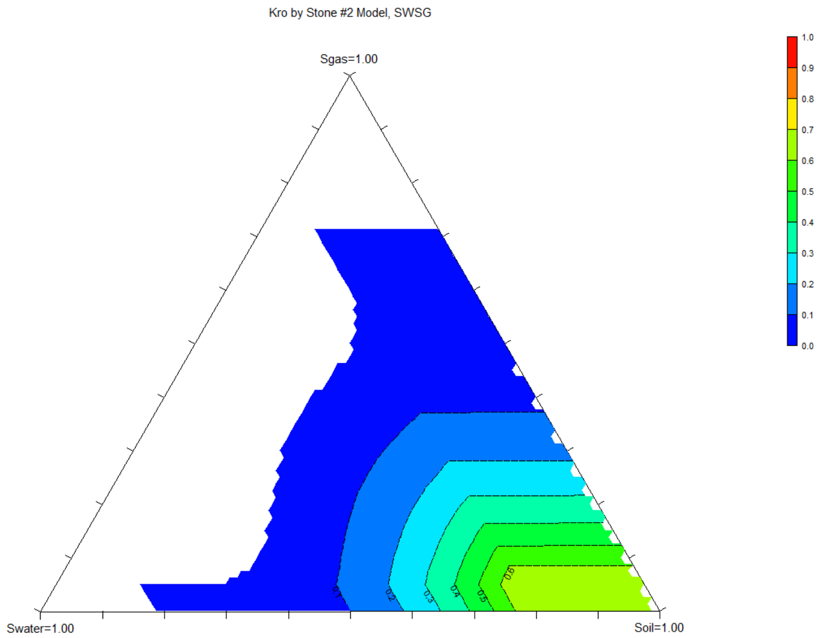

Figure 4.4: Saturation diagram

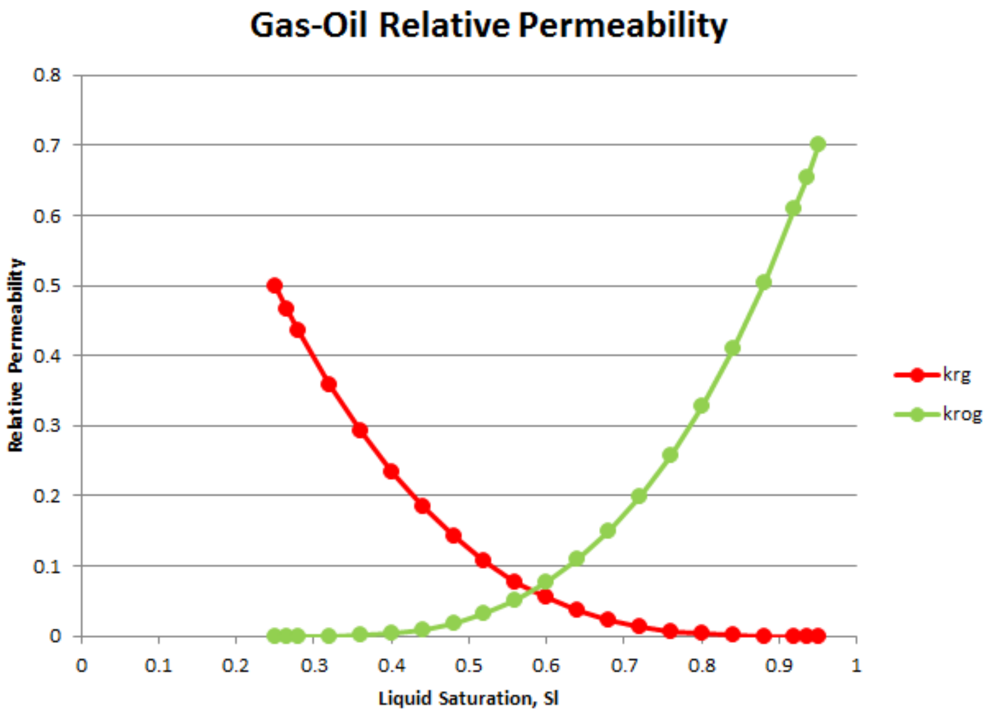

Figure 4.5: Gas-oil relative permeablity curve

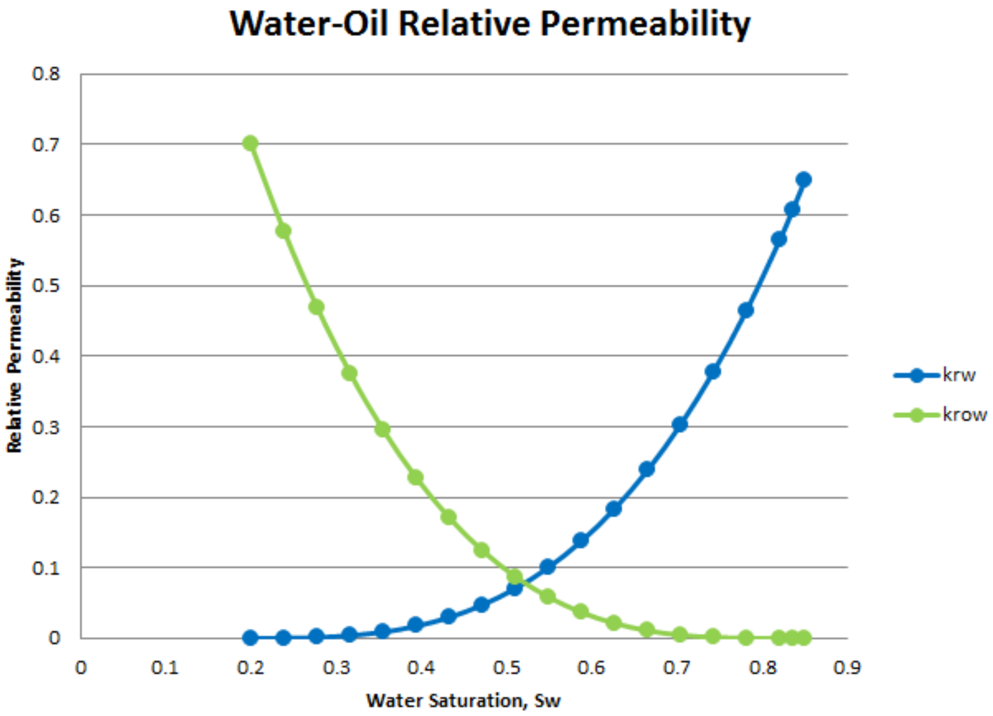

Figure 4.6: Water-oil relative permeability curve

The reservoir has an OIIP of 8.85 MMstb, and OWIP of 3.224 MMstb. For the simulation purpose, the producer well is located in grid block 50, 50 and was operated under a constant bottomhole pressure of 1000 psia. Meanwhile, the injector is located in grid block 1, 1. GEM compositional simulator was used to run the simulation for all the cases as defined in the following sections. The reservoir was put under depletion drive for 2 years, waterflooding for 5 years and water-alternating-gas (WAG-CO_2) injection for 7 years. The 3D simulation model is shown in Figure 4.7 with the producer and injector wells locations. Two separate fluid models were created to test for cases with and without asphaltene precipitation. These fluid models were then incorporated into the static model built.

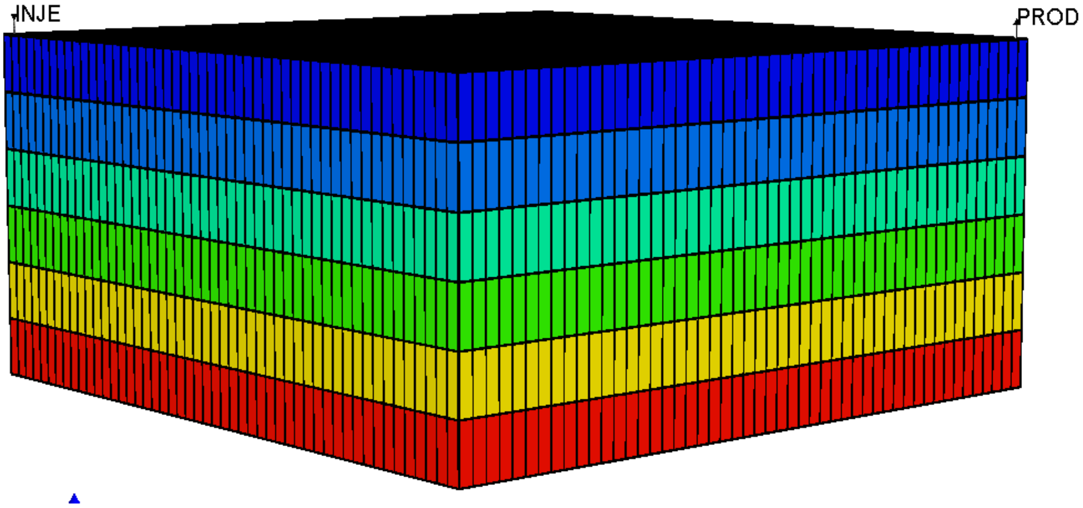

Figure 4.7: 3D simulation model with the producer and injector locations

4.4 Effect of Injection Pressure on Asphaltene Precipitation

The effect of injection pressure on asphaltene precipitation during WAG-CO_2 process was tested by varying the pressures while other parameters were fixed. Three injection pressures were chosen as shown in Table 4.5. Case 1 was designed to investigate the effect of injection pressure lesser than bubble point pressure. Case 2 was used to check the effect of injection pressure equivalent to bubble point pressure and Case 3 higher than bubble point pressure. Two runs were performed, one considering the asphaltene option and the other one without asphaltene precipitation.

Table 4.5: Test Cases for Injection Pressure Variable

Fixed Parameters	
Water Injection Rate	2000 stb/day
Gas Injection Rate	10 MMscf/day
WAG Cycle Size	1 month
WAG Ratio	1:1
Variable Parameter: WAG Injection Pressure	
Case 1	2000 psi
Case 2	2500 psi
Case 3	3000 psi

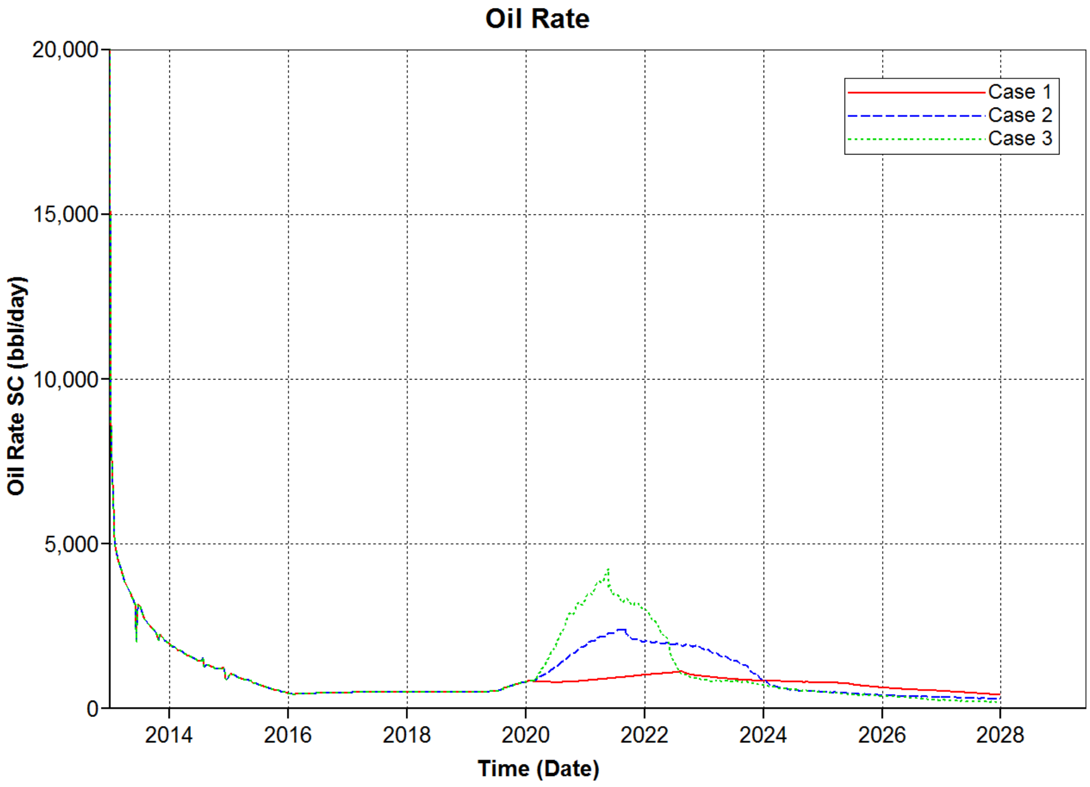

Figure 4.8: Comparison of Oil Rate for Different Injection Pressure Cases

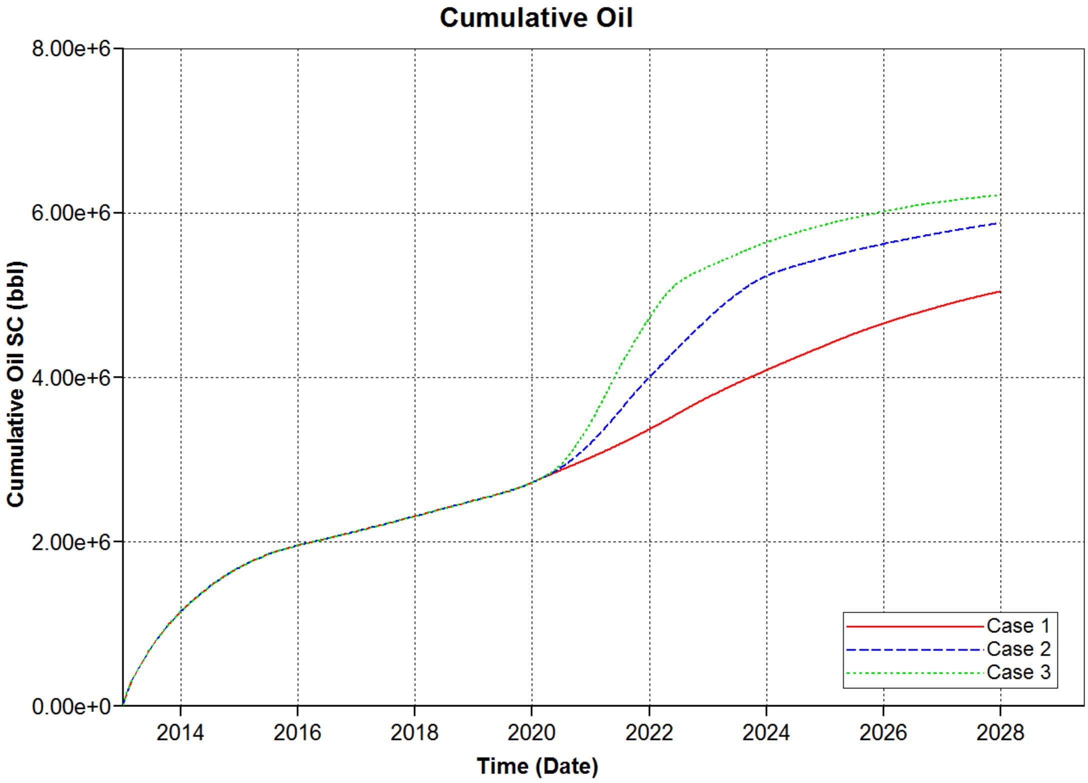

Figure 4.9: Comparison of Cumulative Oil for Different Injection Pressure Cases

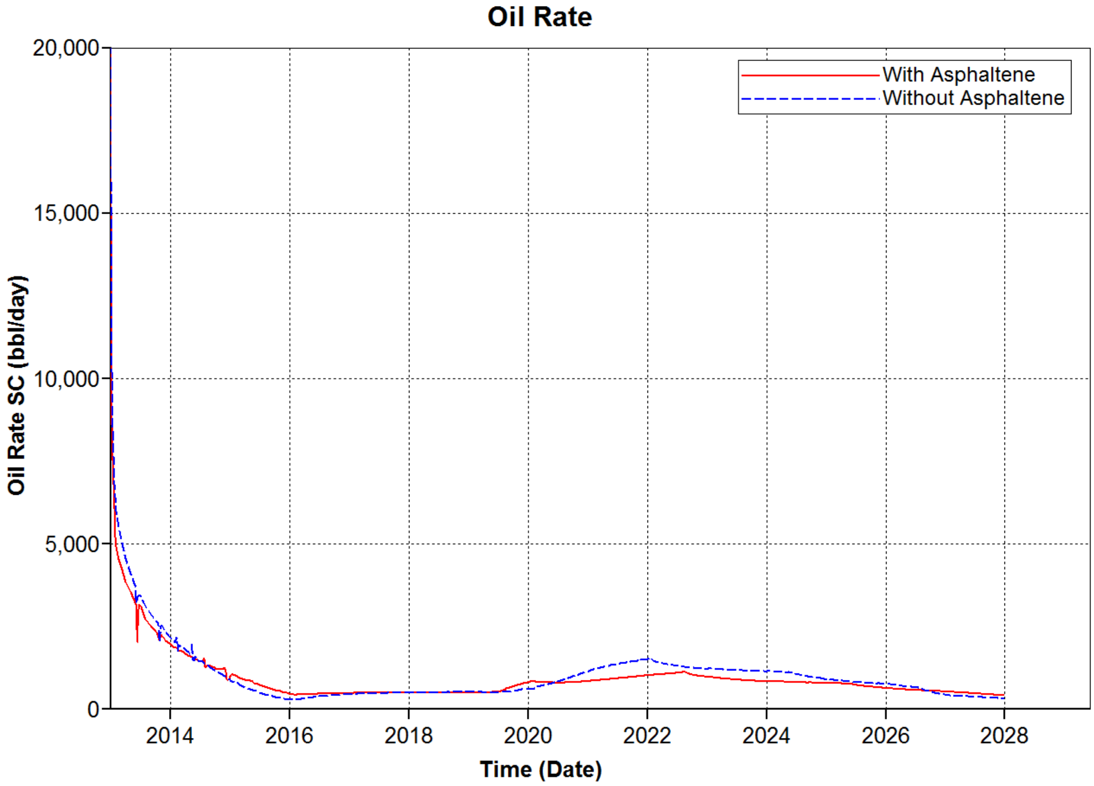

Figure 4.10: Comparison of Oil Rate for Case 1 With and Without Asphaltene Option

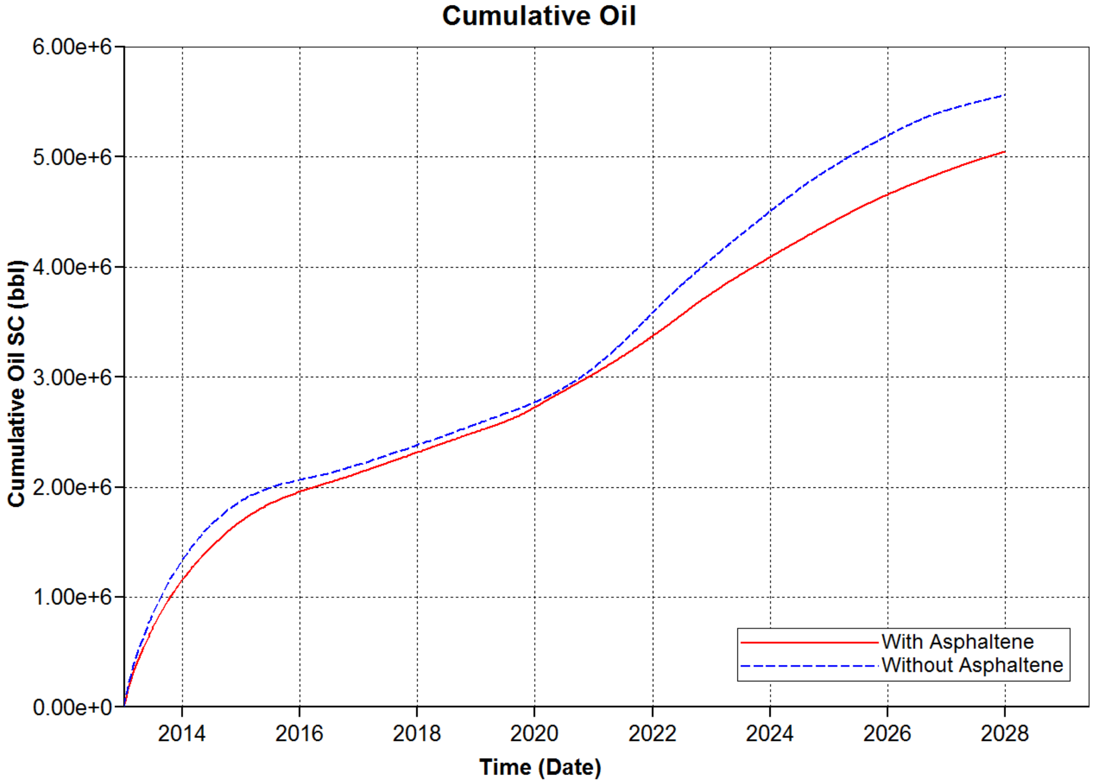

Figure 4.11: Comparison of Cumulative Oil for Case 1 With and Without Asphaltene Option

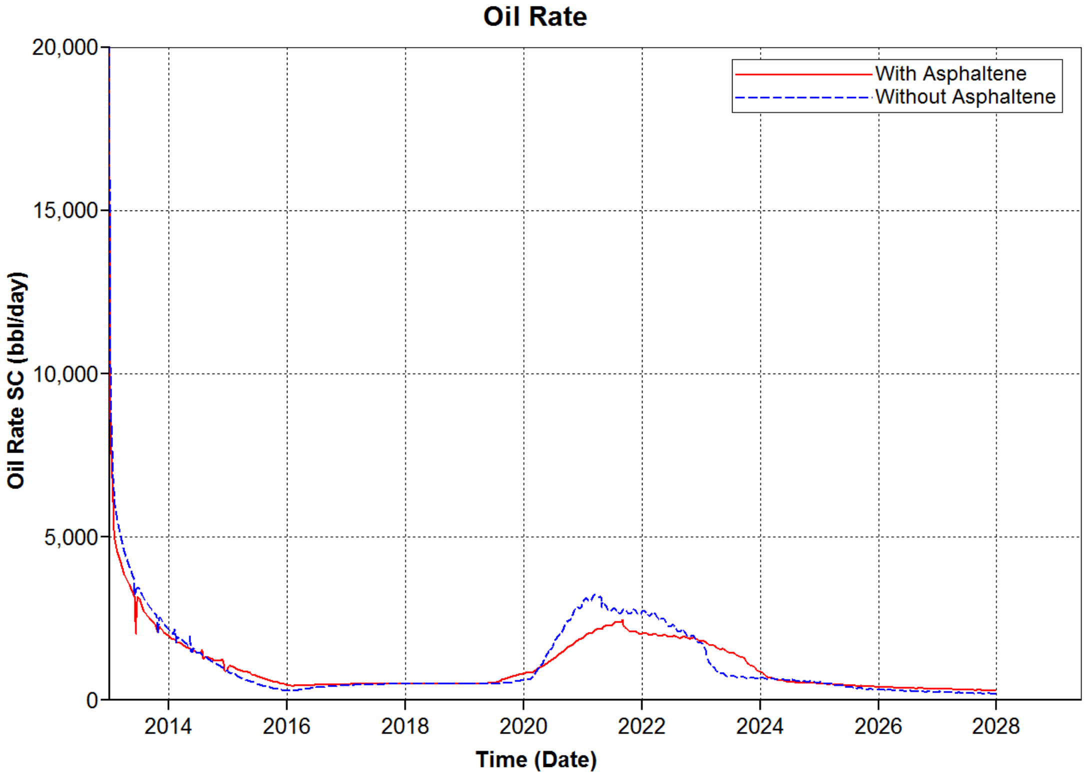

Figure 4.12: Comparison of Oil Rate for Case 2 With and Without Asphaltene Option

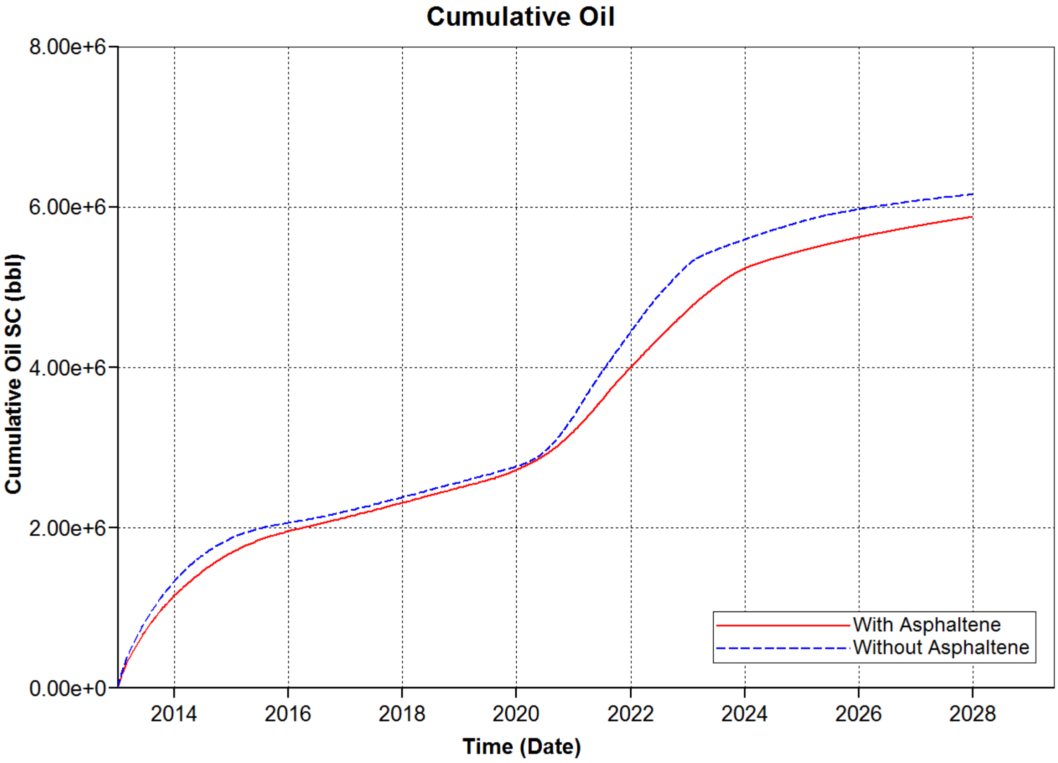

Figure 4.13: Comparison of Cumulative Oil for Case 2 With and Without Asphaltene Option

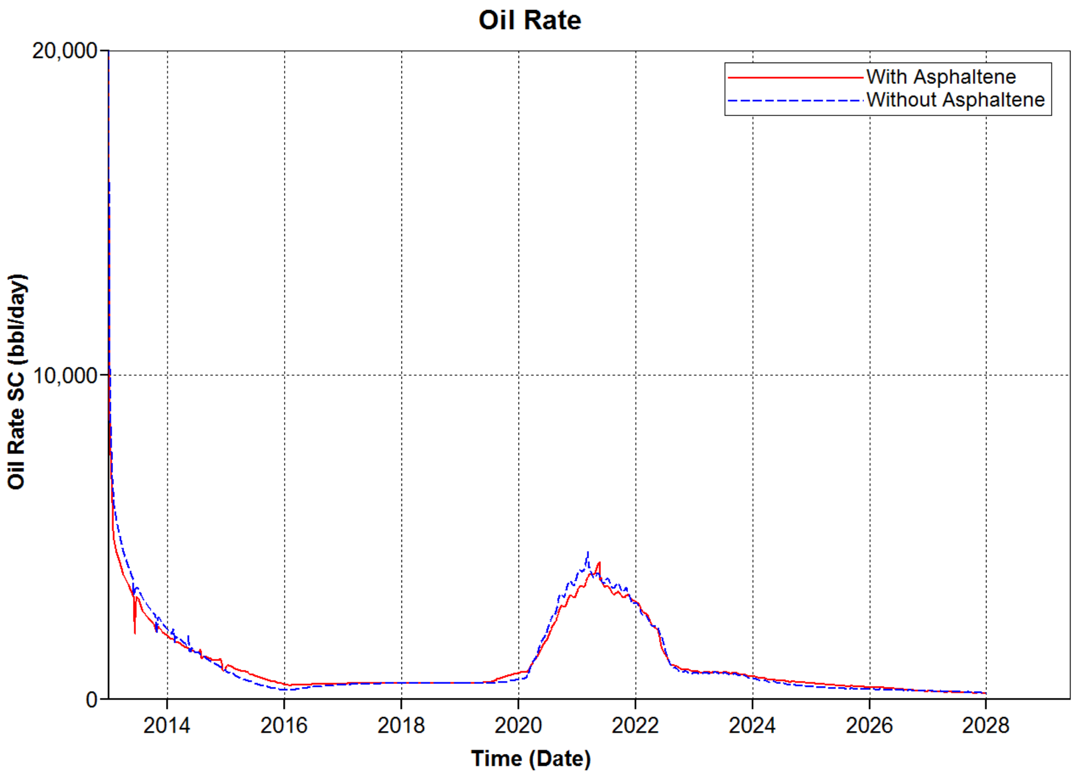

Figure 4.14: Comparison of Oil Rate for Case 3 With and Without Asphaltene Option

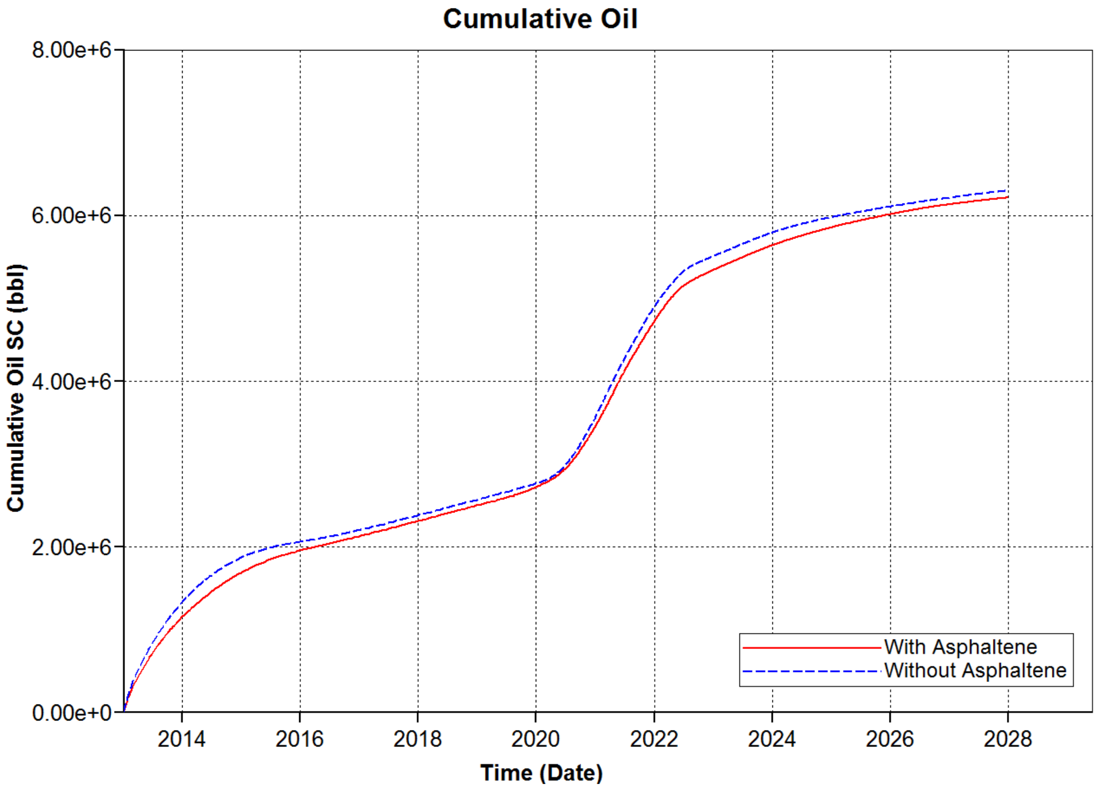

Figure 4.15: Comparison of Cumulative Oil for Case 3 With and Without Asphaltene Option

Table 4.6: Comparison of oil recovery at different injection pressures

	Oil Recovery (MM stb)			
Period (years)	Primary Recovery	Waterflooding	WAG-CO_2 Injection (With Asphaltene)	WAG-CO_2 Injection (Without Asphaltene)
	2	5	7	7
Case 1	1.906 (21.54%)	2.7186 (30.72%)	4.9165 (55.56%)	5.5575 (62.58%)
Case 2	1.906 (21.54%)	2.7186 (30.72%)	5.787 (65.40%)	6.1571 (69.34%)
Case 3	1.906 (21.54%)	2.7186 (30.72%)	6.1636 (69.66%)	6.3013 (70.96%)

Figure 4.8 and Figure 4.9 show the resulting oil rate versus time and cumulative oil versus time plots for all the three cases run with asphaltene option throughout the primary oil recovery, waterflooding and WAG-CO_2 injection phases. Based on the plot, the higher the injection pressure is, the higher the oil recovered. This indicates that the asphaltene precipitation reduces as the injection pressure is increased. When the injection pressure is high, the CO_2 gas flows at high velocity during injection. Therefore, the gas surpasses the oil with very less reactions. Since there is less contact between the oil and the injected gas, the lighter components, which stabilize the asphaltene-resin micelles, were retained in the oil. Hence, lesser asphaltene precipitates when the injection pressure is high due to micelle stability. In contrary, when the injection pressure is low, the gas will move with low velocity, thus reacting with the oil along the way to release lighter components of the oil. So, the asphaltene precipitation occurs rapidly under this condition. The results are deemed to be correct as it has been experimentally proved by Alta'ee *et. al*. (2010) that higher injection pressure lead to lesser asphaltene precipitation. Comparisons between all the cases with and without asphaltene option were made. Based on the plots, it can be deduced that the runs with asphaltene option gives lesser oil recovery compared to the runs without asphaltene option, regardless of the injection pressure applied. When asphaltene precipitation and deposition occurs, the permeability and porosity of the reservoir will be reduced due to plugging of the pore spaces. This reduction will restrict the oil flow from the reservoir, and hence reduce the amount of oil recovered.

4.5 Effect of Injection Rate on Asphaltene Precipitation

Different injection rates were applied as specified in Table 4.7 to investigate the effect of injection rate on asphaltene precipitation during WAG-CO_2 injection. The results of the runs are shown in the following plots.

Table 4.7: Test Cases for Injection Rates Variable

<table>
<tr><th colspan="3">Fixed Parameters</th></tr>
<tr><td>Injection Pressure</td><td colspan="2">3000 psi</td></tr>
<tr><td>WAG Cycle Size</td><td colspan="2">1 month</td></tr>
<tr><td>WAG Ratio</td><td colspan="2">1:1</td></tr>
<tr><td colspan="3">Variable Parameter: WAG Injection Rate</td></tr>
<tr><td></td><td>Water Injection Rate</td><td>Gas Injection Rate</td></tr>
<tr><td>Case 1</td><td>2000 stb/day</td><td>10 MMscf/day</td></tr>
<tr><td>Case 2</td><td>4000 stb/day</td><td>20 MMscf/day</td></tr>
<tr><td>Case 3</td><td>6000 stb/day</td><td>30 MMscf/day</td></tr>
</table>

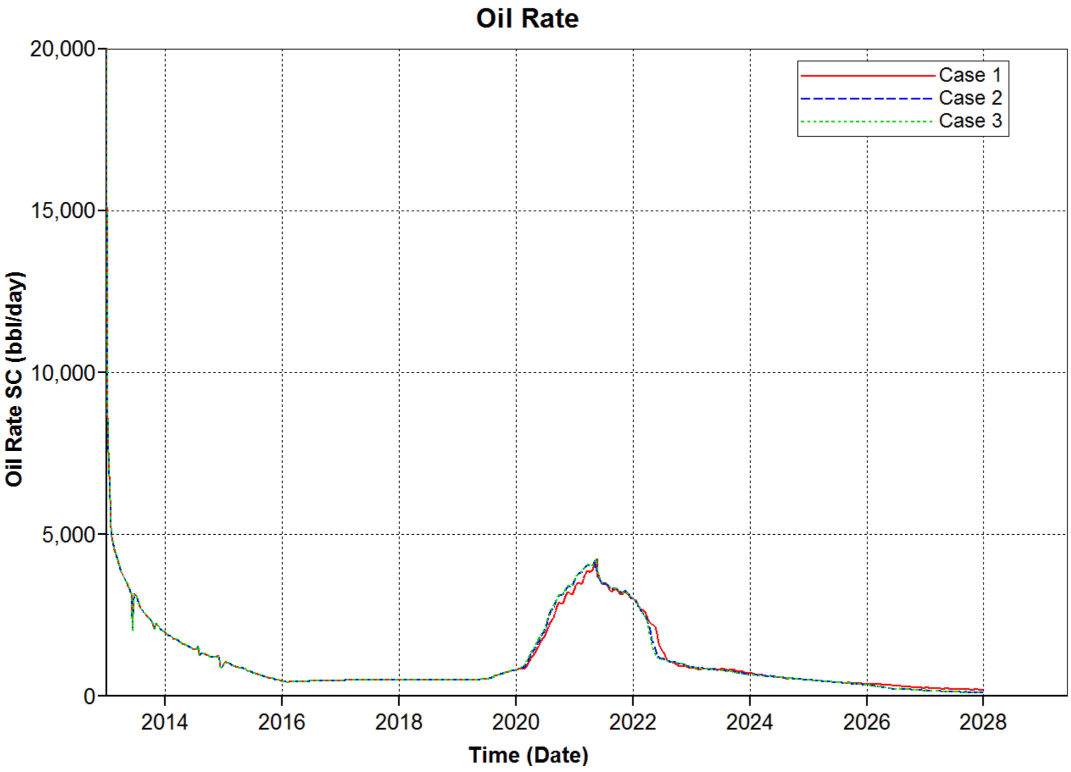

Figure 4.16: Comparion of Oil Rate for Different Injection Rates

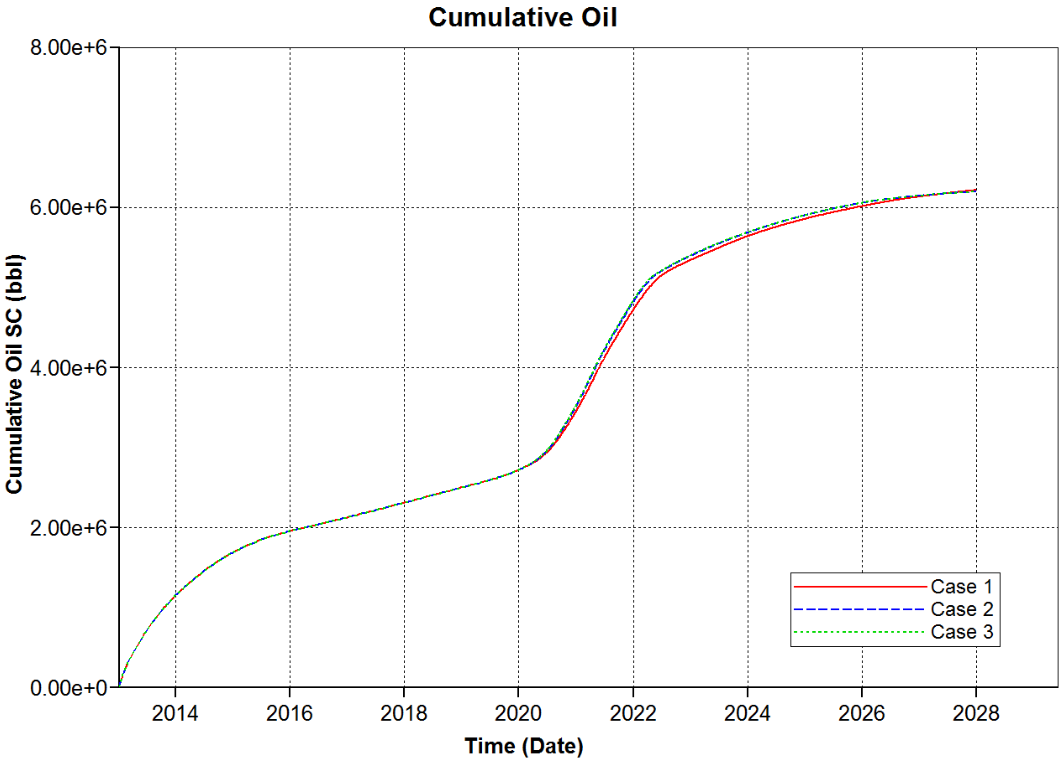

Figure 4.17: Comparison of Cumulative Oil for Different Injection Rates

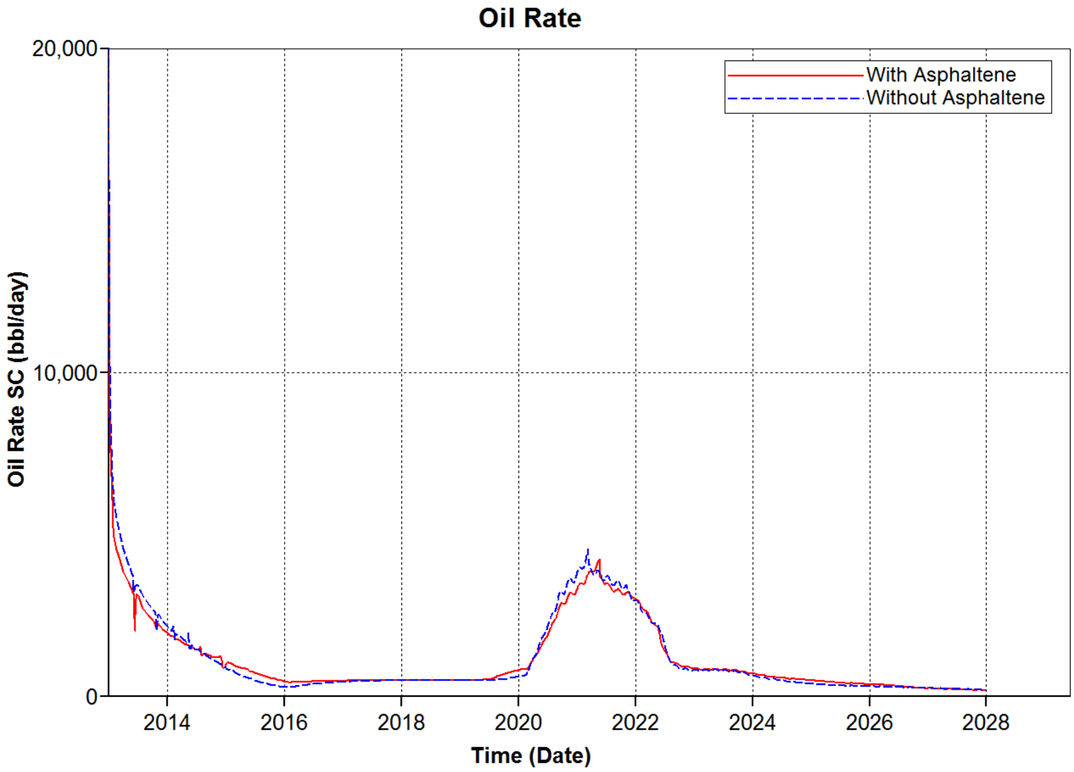

Figure 4.18: Comparison of Oil Rate for Case 1 With and Without Asphaltene Option

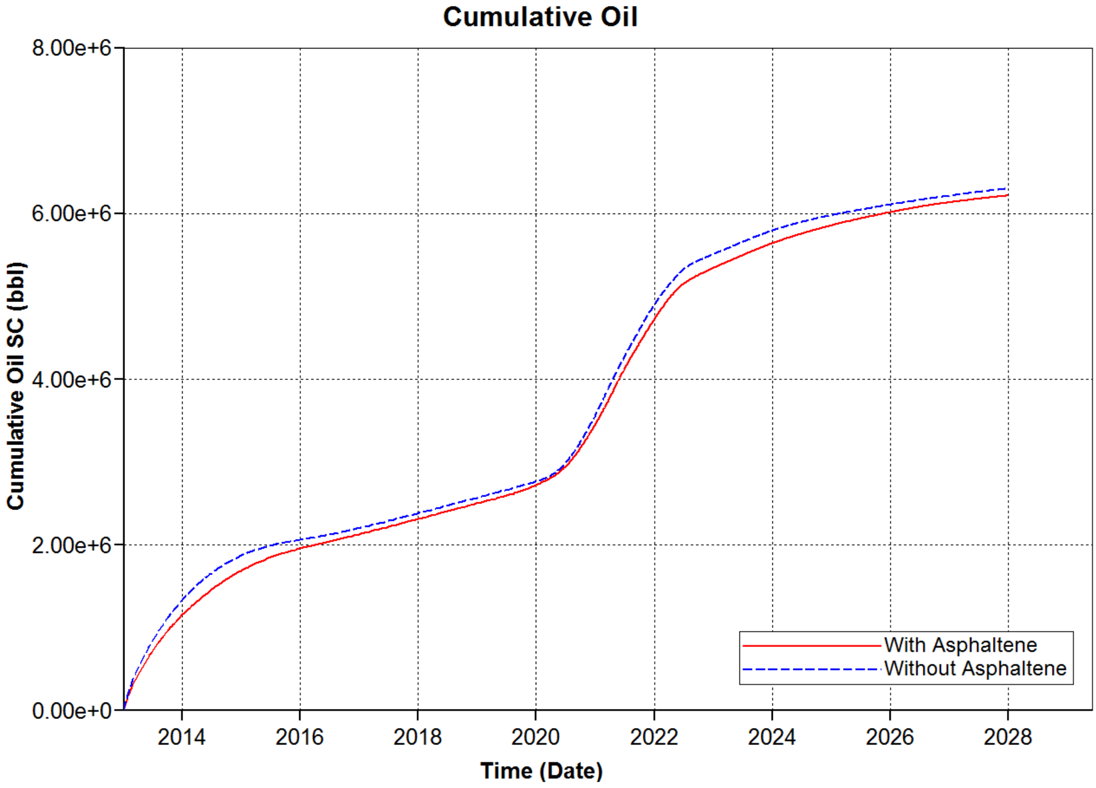

Figure 4.19: Comparison of Cumulative Oil for Case 1 With and Without Asphaltene Option

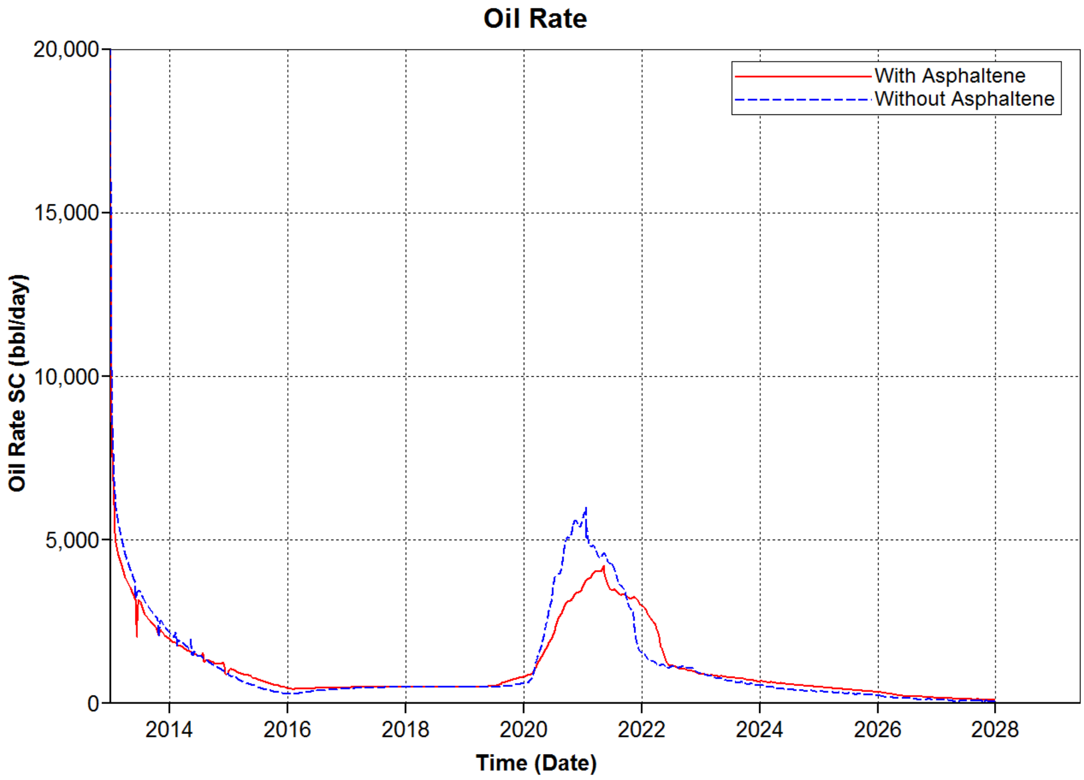

Figure 4.20: Comparison of Oil Rate for Case 2 With and Without Asphaltene Option

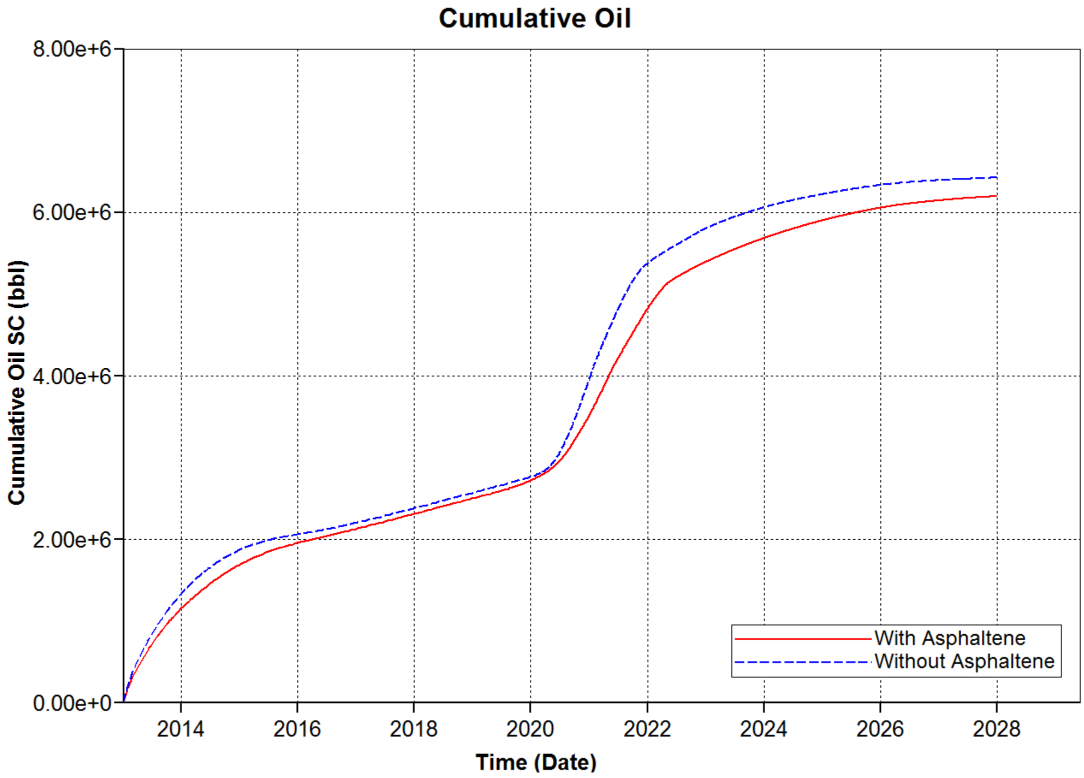

Figure 4.21: Comparison of Cumulative Oil for Case 2 With and Without Asphaltene Option

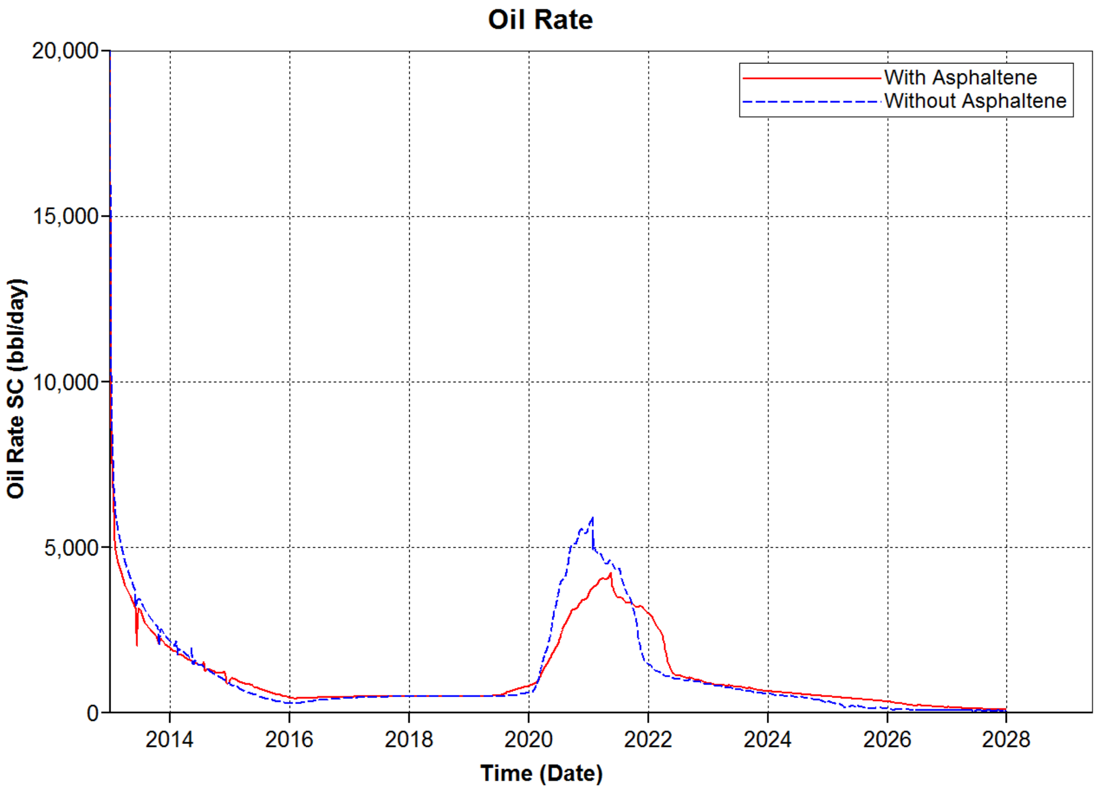

Figure 4.22: Comparison of Oil Rate for Case 3 With and Without Asphaltene Option

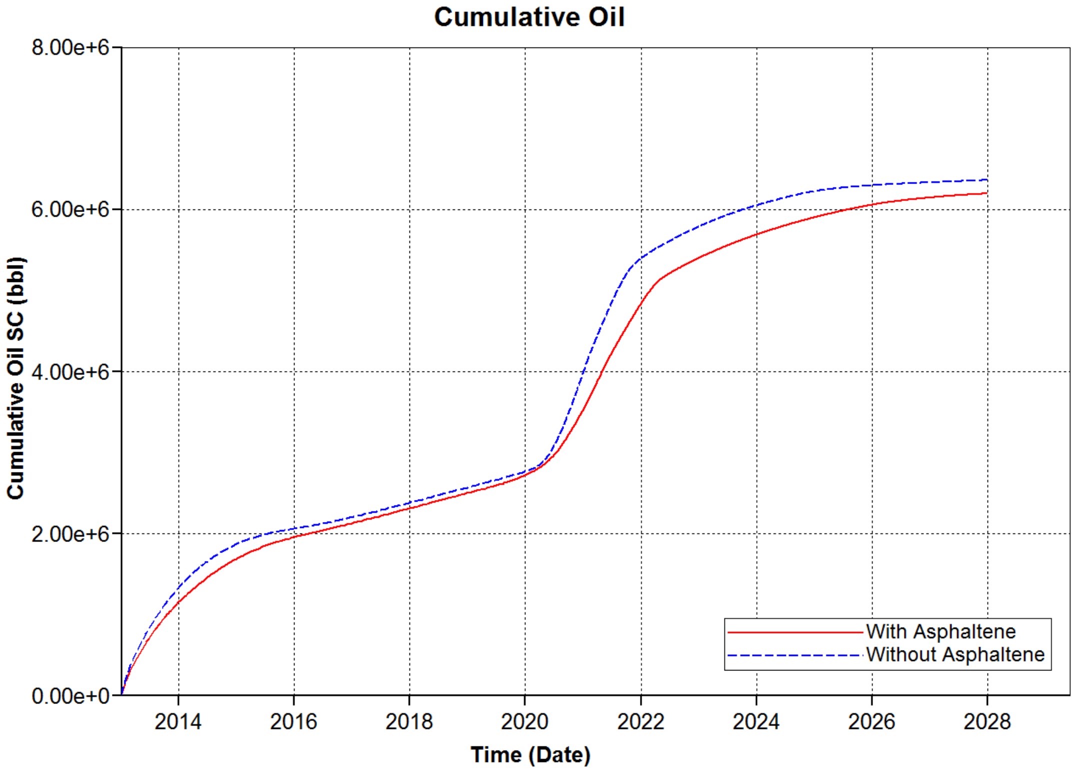

Figure 4.23: Comparison of Cumulative Oil for Case 3 With and Without Asphaltene Option

Table 4.8: Comparison of oil recovery at different injection rates

	Oil Recovery (MM stb)			
Period (years)	Primary Recovery	Waterflooding	WAG-CO_2 Injection (With Asphaltene)	WAG-CO_2 Injection (Without Asphaltene)
	2	5	7	7
Case 1	1.906 (21.54%)	2.7186 (30.72%)	6.1636 (69.66%)	6.3013 (70.96%)
Case 2	1.906 (21.54%)	2.7186 (30.72%)	6.114 (69.10%)	6.4259 (72.36%)
Case 3	1.906 (21.54%)	2.7186 (30.72%)	6.1208 (69.17%)	6.3629 (71.65%)

Figure 4.16 and Figure 4.17 show the resulting oil rate versus time and cumulative oil versus time plots for all the three cases run with asphaltene option throughout the primary oil recovery, waterflooding and WAG-CO_2 injection phases. Based on the plots, the injection rates have very small impact on the amount of oil recovered as evident in all the three cases. This indicates that the asphaltene precipitation rate is affected by the injection rate to a minimal extent. Although the change is small, from the plots the trend observed is oil recovery increases with increasing injection rate. When the injection rate increases, the pressure in the reservoir will increase as well. So, the injected gas will flow quickly pass the oil with less reactions. Hence, this explains the change in amount of asphaltene precipitated during the increment of injection rates. This confines to the experimental results by Alian et al. (2011), whereby the asphaltene precipitation reduces with increasing injection rate. However, comparing the runs with same injection rate but without asphaltene option indicates that the asphaltene precipitation reduces the amount of oil recovered. This is due to the pore throat plugging of the deposited asphaltene, which will restrict the oil flow.

4.6 Effect of WAG Cycle Size on Asphaltene Precipitation

The effect of WAG cycle size on asphaltene precipitation during WAG-CO_2 process was tested by varying the sizes with other parameters being fixed. Three cycle sizes were chosen as shown in Table 4.9. Two runs were performed, one considering the asphaltene option and the other one without asphaltene precipitation.

Table 4.9: Test Cases for WAG Cycle Size Variable

Fixed Parameters	
Injection Pressure	3000 psi
Water Injection Rate	6000 stb/day
Gas Injection Rate	30 MMscf/day
WAG Ratio	1:1
Variable Parameter: WAG Cycle Size	
Case 1	1 month
Case 2	3 months
Case 3	6 months

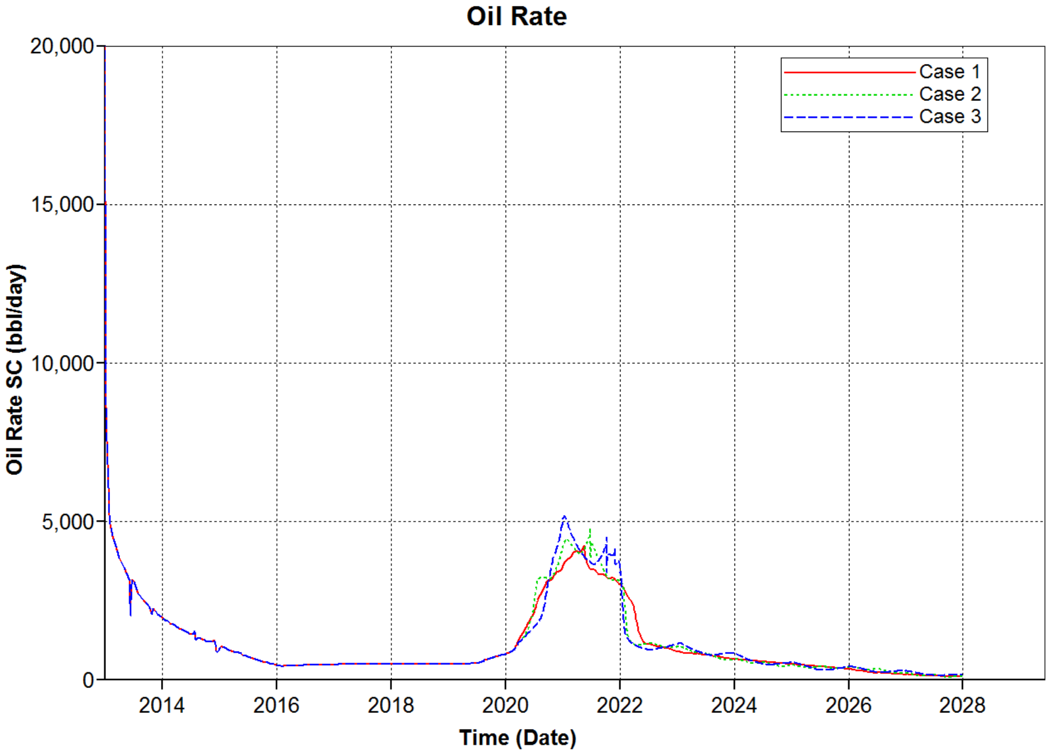

Figure 4.24: Comparison of Oil Rate for Different WAG Cycle Sizes

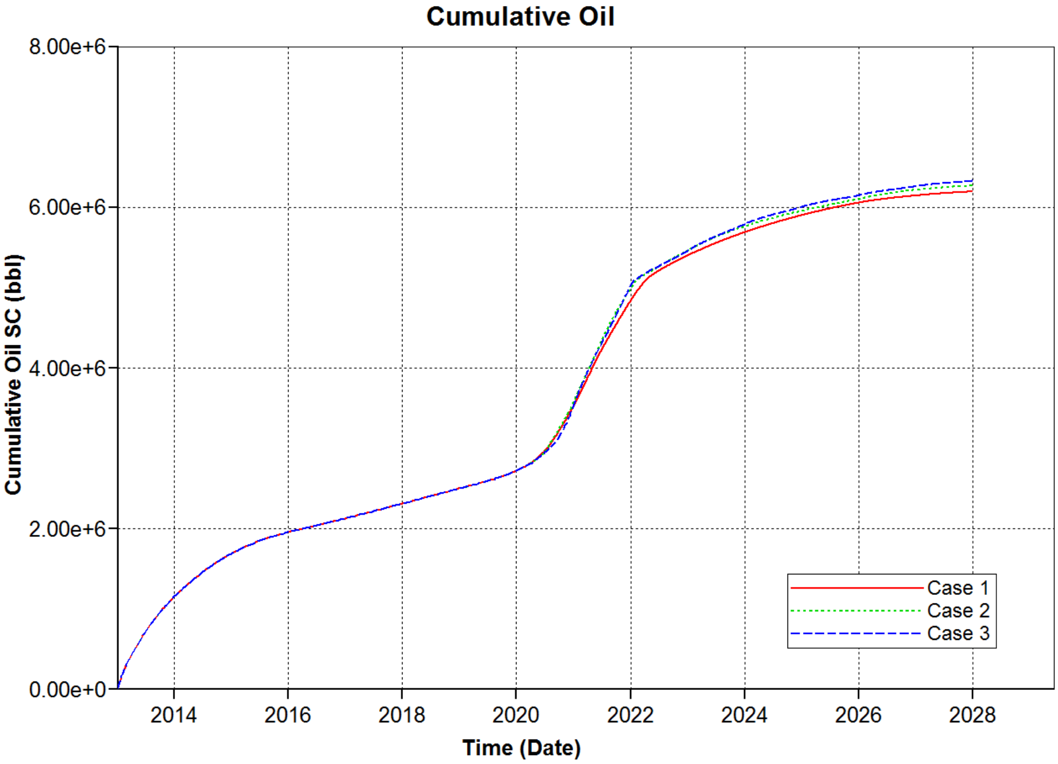

Figure 4.25: Comparison of Cumulative Oil for Different WAG Cycle Sizes

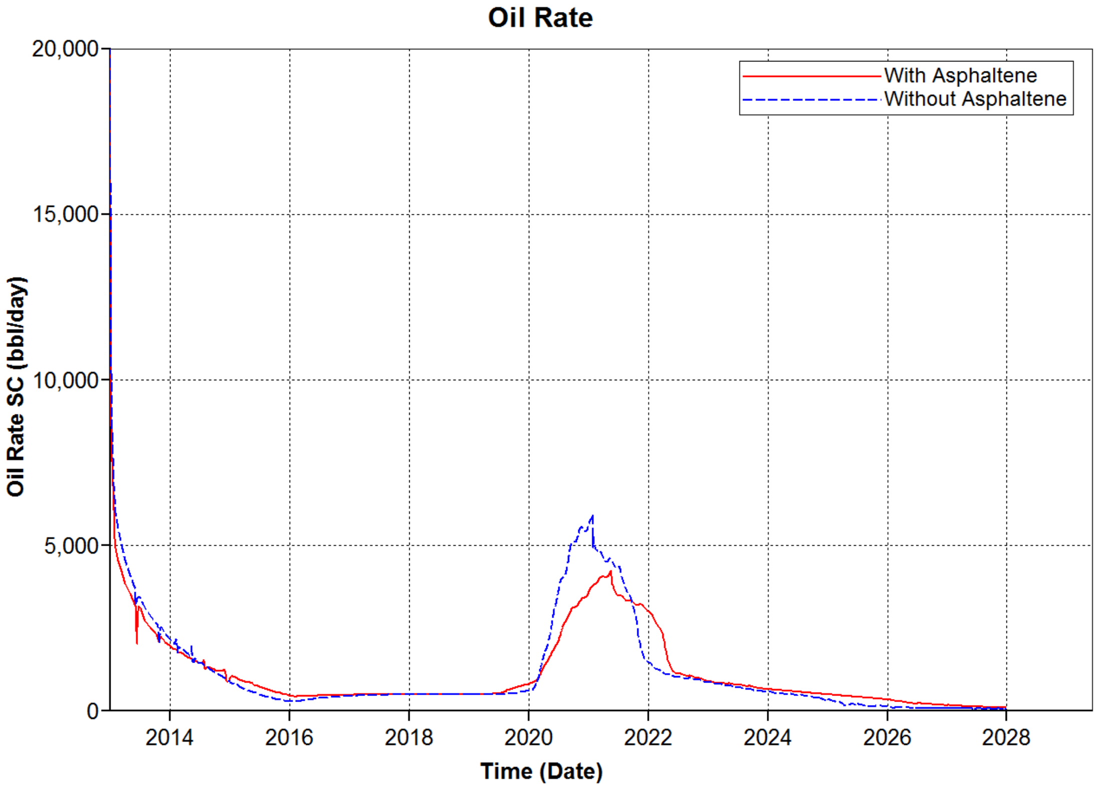

Figure 4.26: Comparison of Oil Rate for Case 1 With and Without Asphaltene Option

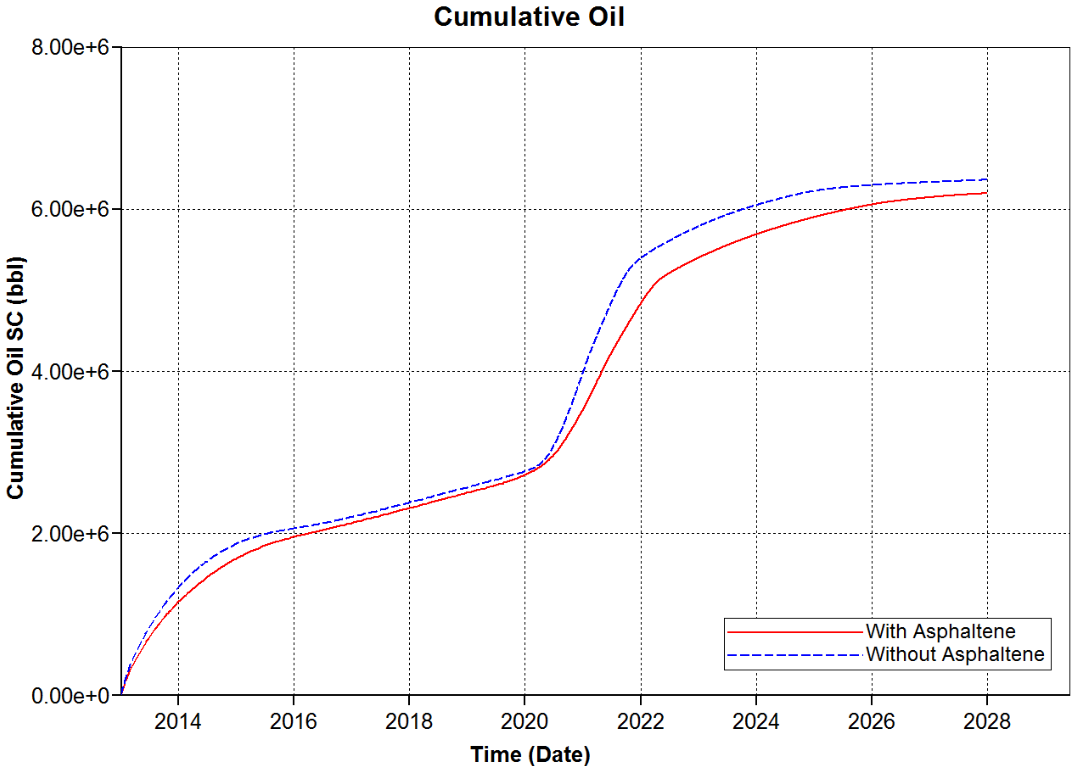

Figure 4.27: Comparison of Cumulative Oil for Case 1 With and Without Asphaltene Option

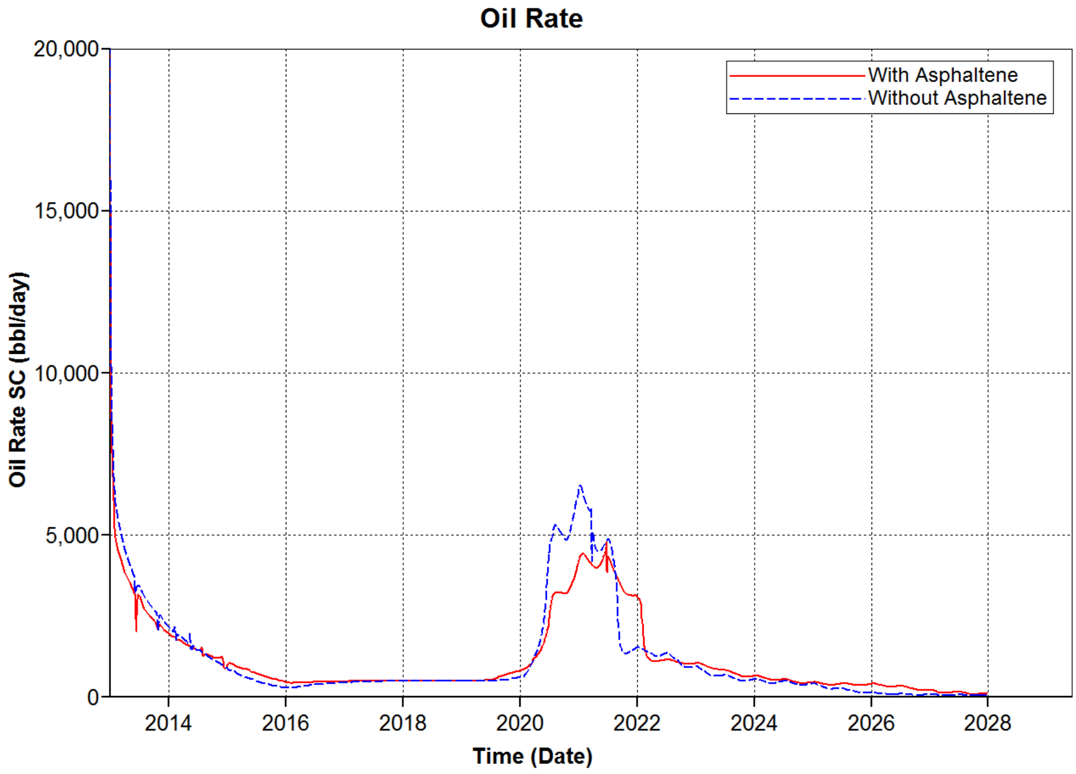

Figure 4.28: Comparison of Oil Rate for Case 2 With and Without Asphaltene Option

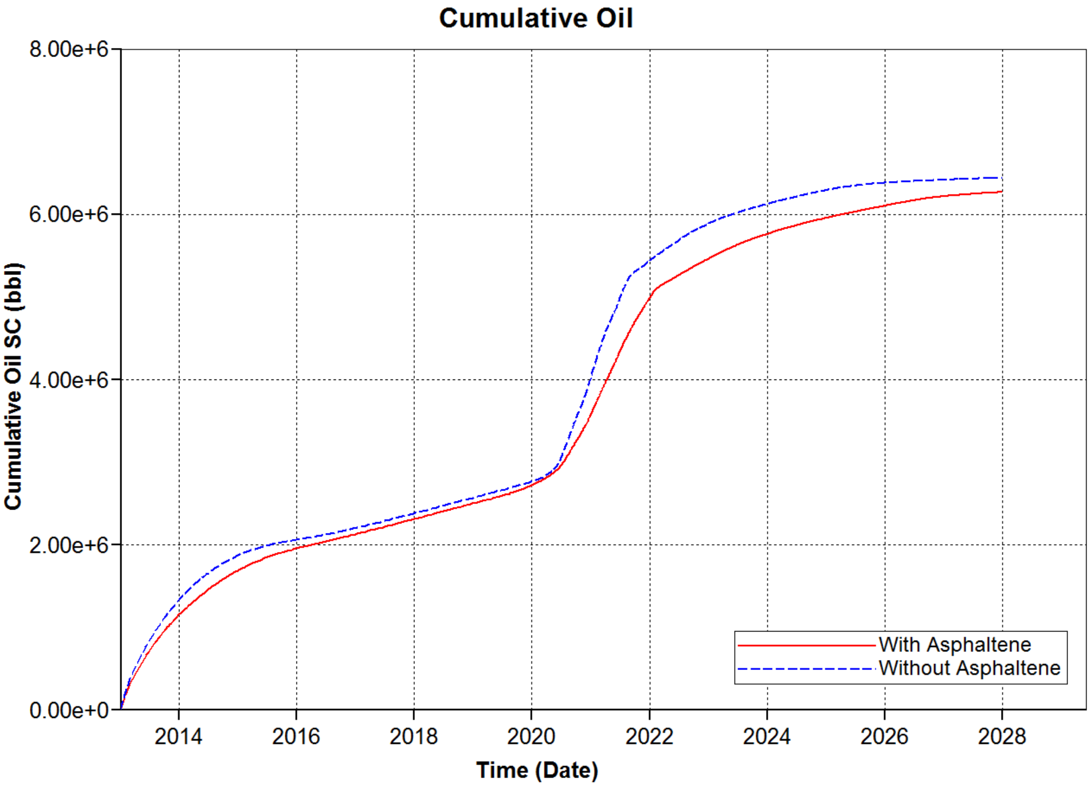

Figure 4.29: Comparison of Cumulative Oil for Case 2 With and Without Asphaltene Option

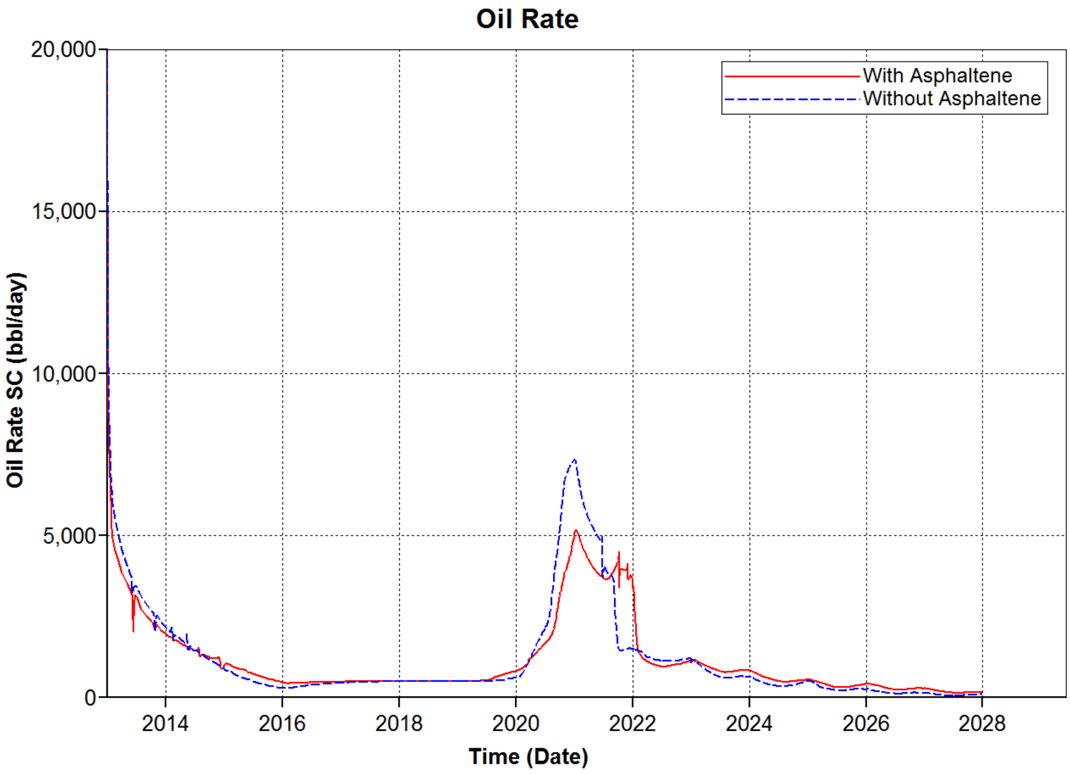

Figure 4.30: Comparison of Oil Rate for Case 3 With and Without Asphaltene Option

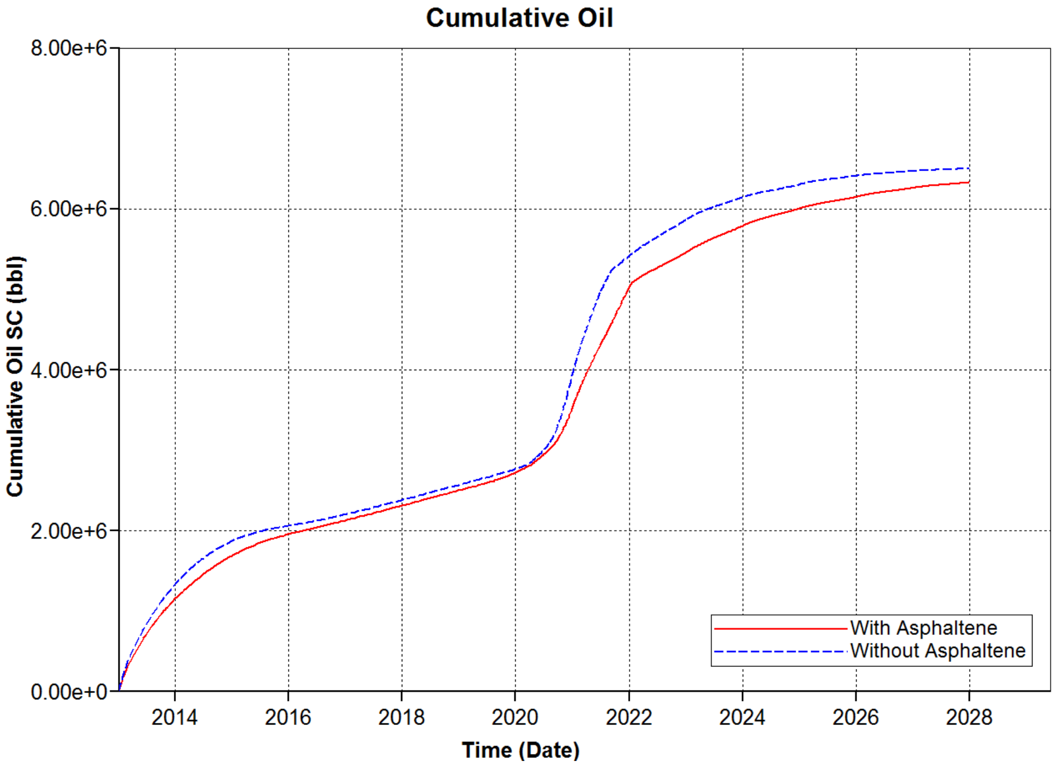

Figure 4.31: Comparison of Cumulative Oil for Case 3 With and Without Asphaltene Option

Table 4.10: Comparison of oil recovery at different WAG cycles

	Oil Recovery (MM stb)			
Period (years)	Primary Recovery	Waterflooding	WAG-CO_2 Injection (With Asphaltene)	WAG-CO_2 Injection (Without Asphaltene)
	2	5	7	7
Case 1	1.906 (21.54%)	2.7186 (30.72%)	6.1636 (69.66%)	6.3013 (70.96%)
Case 2	1.906 (21.54%)	2.7186 (30.72%)	6.1929 (69.99%)	6.4434 (72.56%)
Case 3	1.906 (21.54%)	2.7186 (30.72%)	6.2087 (70.17%)	6.5047 (73.25%)

Figure 4.24 and Figure 4.25 show the resulting oil rate versus time and cumulative oil versus time plots for all the three cases run with asphaltene option throughout the primary oil recovery, waterflooding and WAG-CO_2 injection phases. Based on the plots, the cycle size has only a slight impact on the amount of oil recovered. This indicates that the asphaltene precipitation rate is slightly affected by the cycle size. The reservoir was first put under waterflood before the WAG-CO_2 injection took place. Therefore, the water saturation in the reservoir is higher at the beginning of the gas injection process. The high water saturation makes part of the oil inaccessible for the injected CO_2 gas. The presence of water will trigger the CO_2 gas to dissolve in the water before contacting the oil in the reservoir. When the WAG cycle size is bigger, more water will be retained in the reservoir prior to gas injection. Hence, more gas will dissolve into the water to swell the reservoir oil. Since the gas has to pass through the water film before reaching the oil, lesser reaction is expected between the oil and gas phases. This explains the higher oil recovery during larger cycle sizes, which indicates lesser asphaltene precipitation. The results obtained confines to the laboratory works conducted by Ong (2012), whereby the larger WAG cycles provided higher oil recovery. However, comparing the run with the highest oil recovery with the run with same cycle size but without asphaltene option indicates that the asphaltene precipitation reduces the amount of oil recovered. The oil rate versus time and cumulative oil versus time plots for the comparison case between with and without asphaltene option for all the WAG cycle sizes are shown in Figure 4.26 to Figure 4.31.

4.7 Effect of Injected Water Salinity on Asphaltene Precipitation

Three cases with different salinity of injected water as shown in Table 4.11 were tested to determine the effect of salinity on asphaltene precipitation during WAG-CO_2 injection. Two runs were performed, one considering the asphaltene option and the other one without asphaltene precipitation.

Table 4.11: Test Cases for Injected Water Salinity Variable

Fixed Parameters	
Injection Pressure	3000 psi
Water Injection Rate	6000 stb/day
Gas Injection Rate	30 MMscf/day
Cycle Size	1 month
WAG Ratio	1:1
Variable Parameter: Injected Water Salinity	
Case 1	10000 ppm
Case 2	20000 ppm
Case 3	35000 ppm

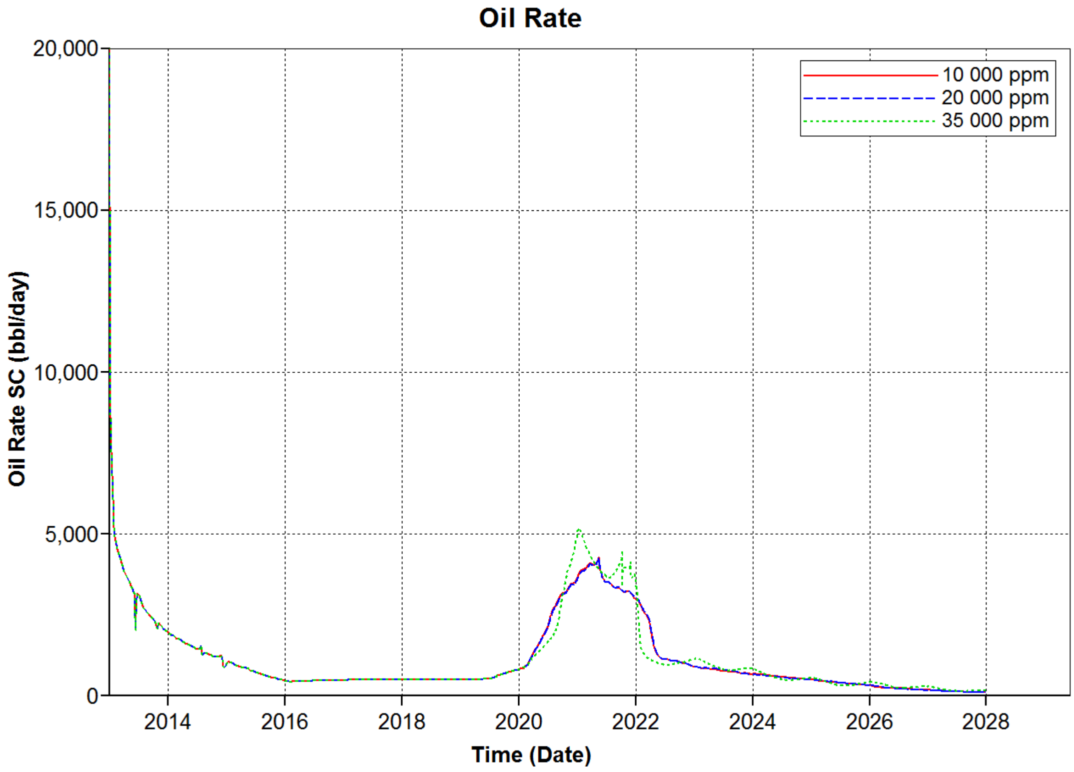

Figure 4.32: Comparison of Oil Rate for Different Injected Water Salinity

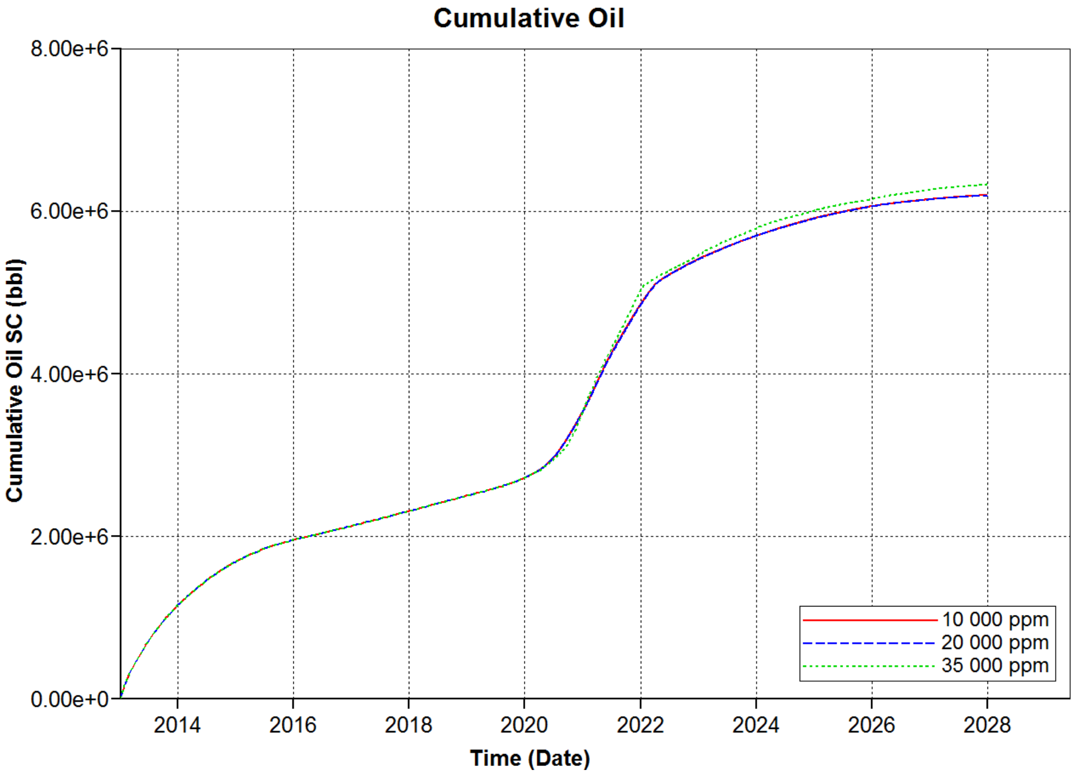

Figure 4.33: Comparison of Cumulative Oil for Different Injected Water Salinity

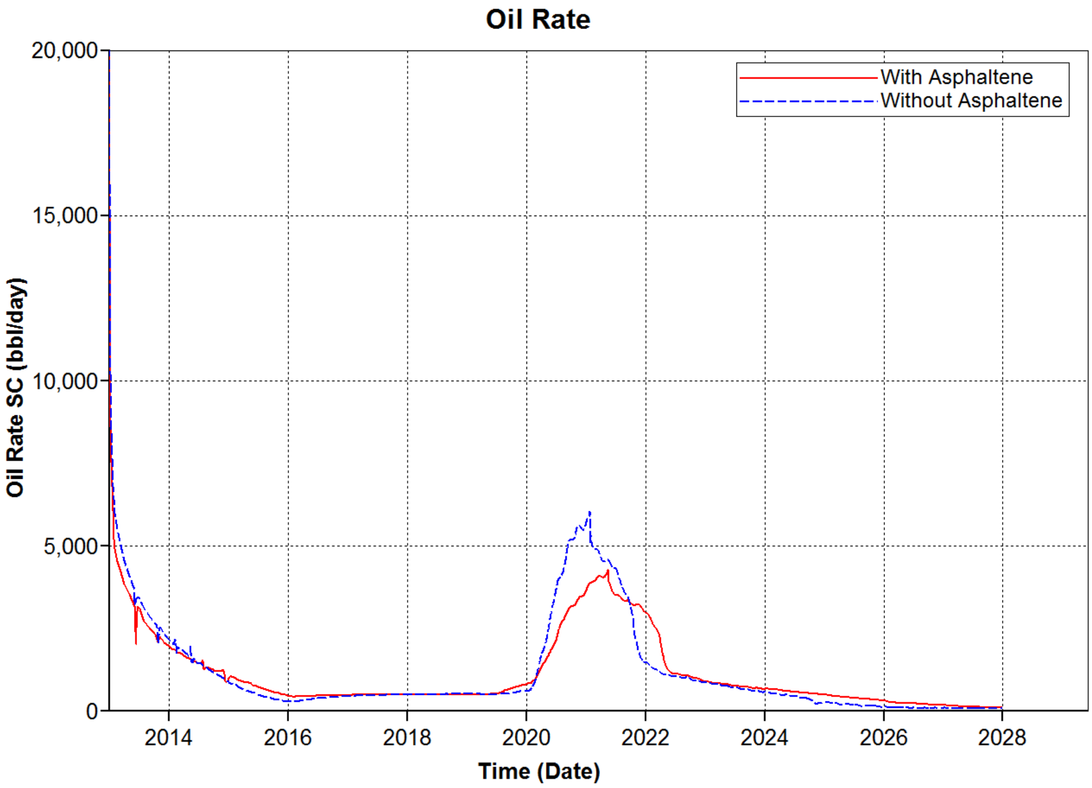

Figure 4.34: Comparison of Oil Rate for Case 1 With and Without Asphaltene Option

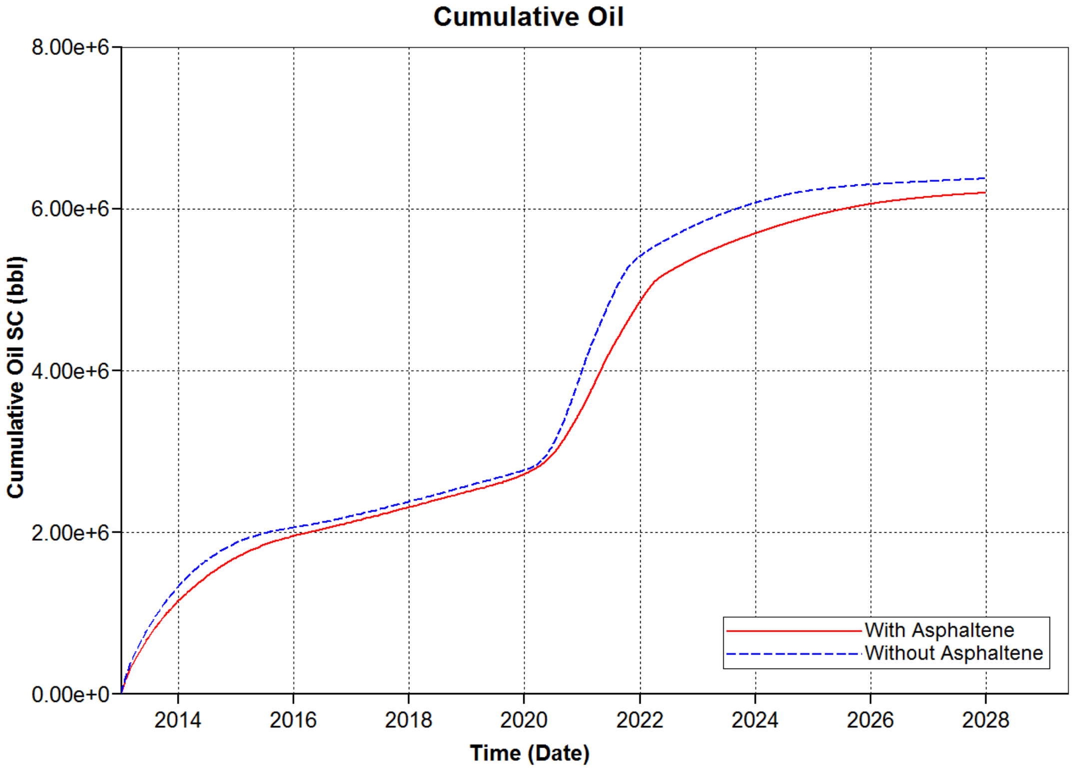

Figure 4.35: Comparison of Cumulative Oil for Case 1 With and Without Asphaltene Option

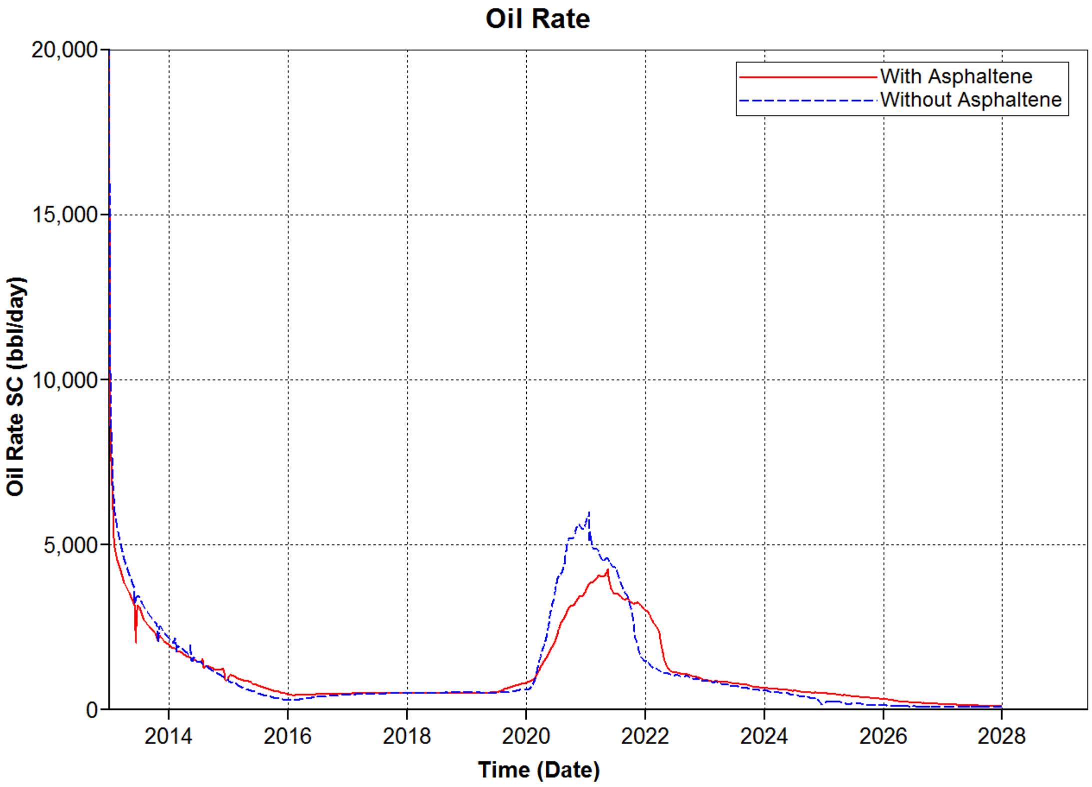

Figure 4.36: Comparison of Oil Rate for Case 2 With and Without Asphaltene Option

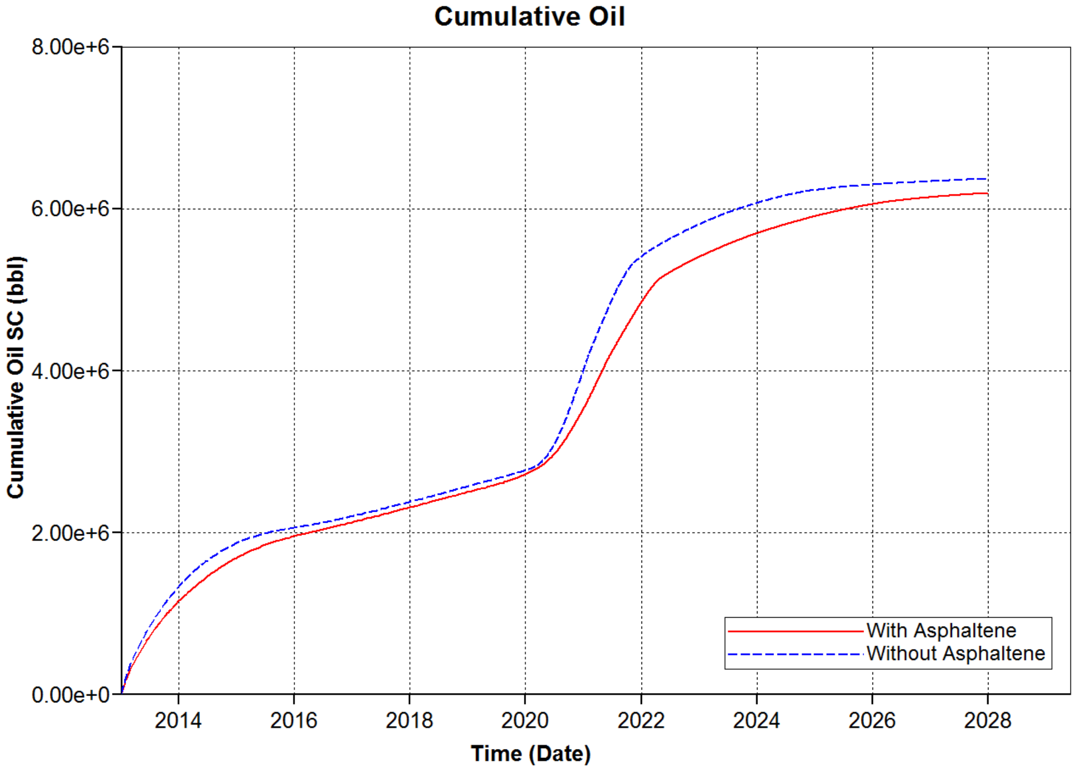

Figure 4.37: Comparison of Cumulative Oil for Case 2 With and Without Asphaltene Option

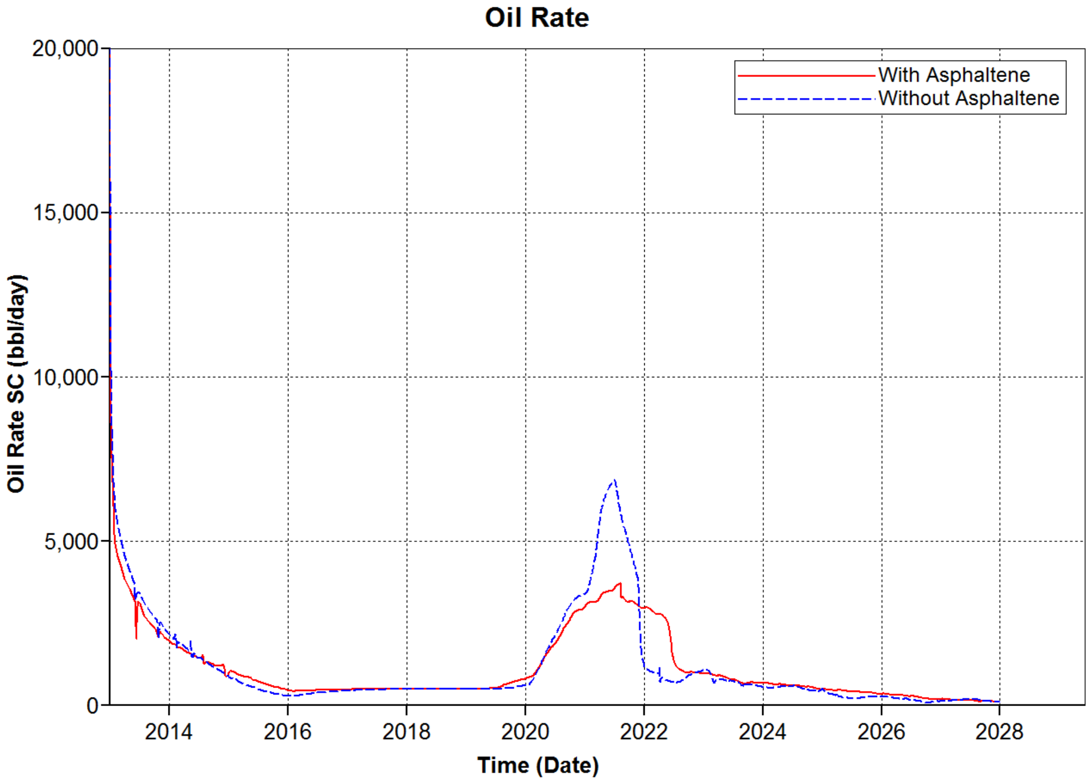

Figure 4.38: Comparison of Oil Rate for Case 3 With and Without Asphaltene Option

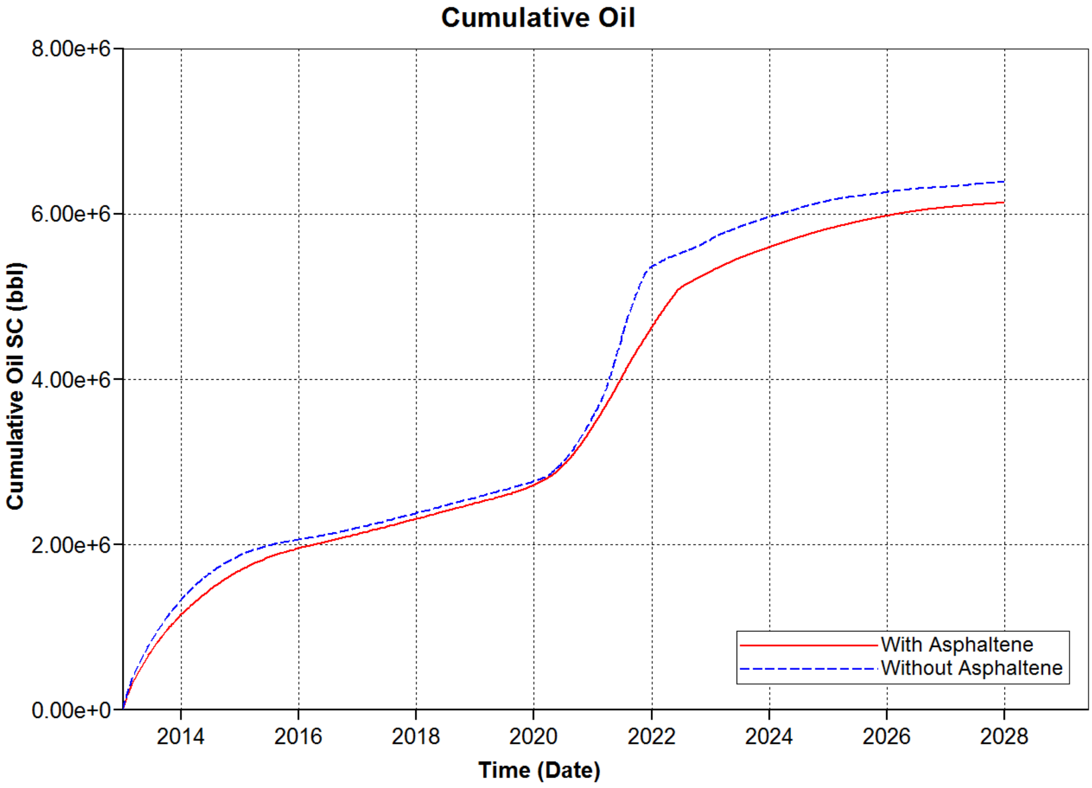

Figure 4.39: Comparison of Cumulative Oil for Case 3 With and Without Asphaltene Option

Table 4.12: Comparison of oil recovery at different injected water salinity

	Oil Recovery (MM stb)			
Period (years)	Primary Recovery	Waterflooding	WAG-CO_2 Injection (With Asphaltene)	WAG-CO_2 Injection (Without Asphaltene)
	2	5	7	7
Case 1	1.906 (21.54%)	2.7186 (30.72%)	6.2087 (70.17%)	6.5047 (73.25%)
Case 2	1.906 (21.54%)	2.7186 (30.72%)	6.2087 (70.17%)	6.5047 (73.25%)
Case 3	1.906 (21.54%)	2.7186 (30.72%)	6.2087 (72.33%)	6.5047 (74.44%)

Figure 4.32 and Figure 4.33 show the resulting oil rate versus time and cumulative oil versus time plots for all the three cases run with asphaltene option throughout the primary oil recovery, waterflooding and WAG-CO_2 injection phases. Based on the plots, the injected water salinity of 35 000 ppm gives higher recovery, indicating least asphaltene precipitation. This is because higher concentration of salt ions in the water will inhibit the asphaltene precipitation on the rock. However, comparing the run with the highest oil recovery with the run with same cycle size but without asphaltene option indicates that the asphaltene precipitation reduces the amount of oil recovered. The oil rate versus time and cumulative oil versus time plots for the comparison case between with and without asphaltene option for the salinity cases are shown in Figure 4.34 to Figure 4.39.

4.8 Effect of WAG Ratio on Asphaltene Precipitation

Three WAG ratios were chosen as shown in Table 4.13 to determine the effect of WAG ratio on asphaltene precipitation during WAG-CO_2 injection. Two runs were performed, one considering the asphaltene option and the other one without asphaltene precipitation.

Table 4.13: Test Cases for WAG Ratio Variable

Fixed Parameters	
Injection Pressure	3000 psi
Water Injection Rate	6000 stb/day
Gas Injection Rate	30 MMscf/day
Cycle Size	1 month
Variable Parameter: WAG Ratio (Water:Gas)	
Case 1	1:1
Case 2	2:1
Case 3	1:2

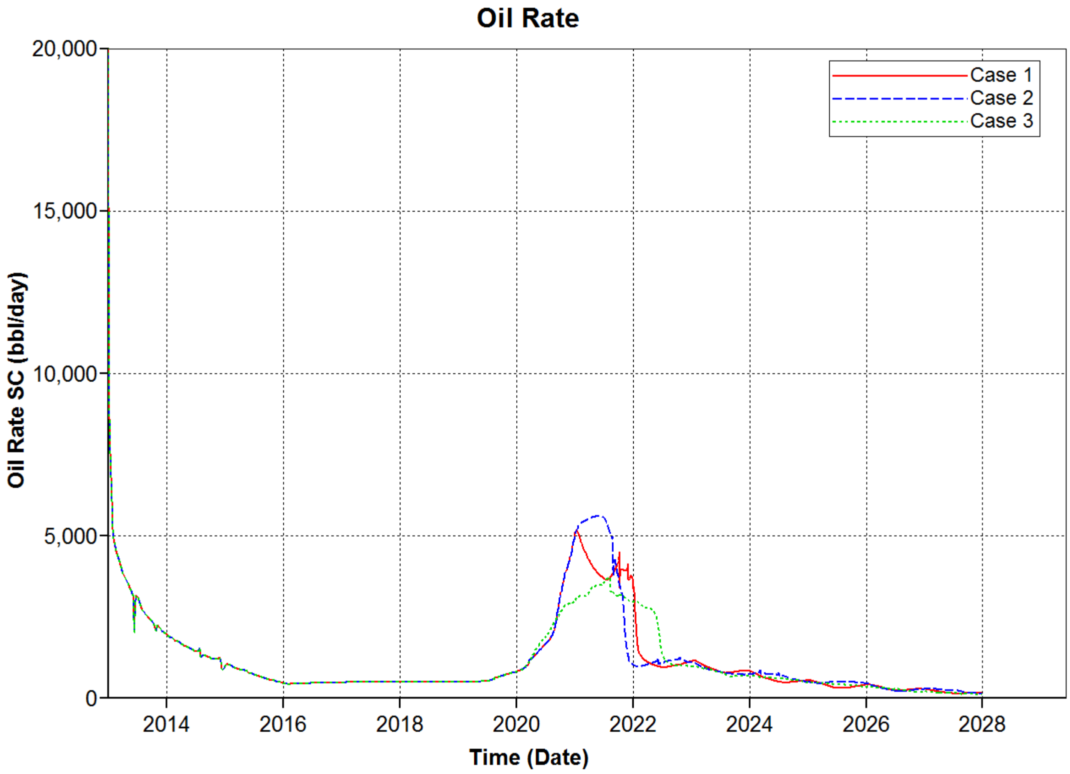

Figure 4.40: Comparison of Oil Rate for Different WAG Ratios

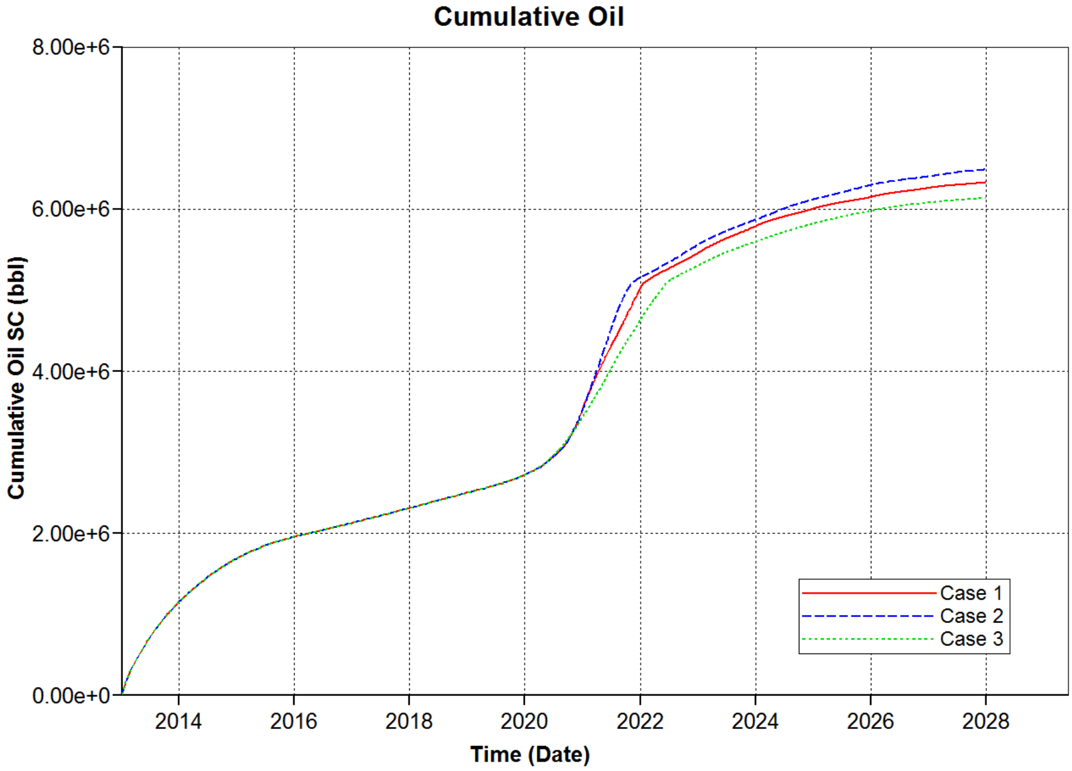

Figure 4.41: Comparison of Cumulative Oil for Different WAG Ratios

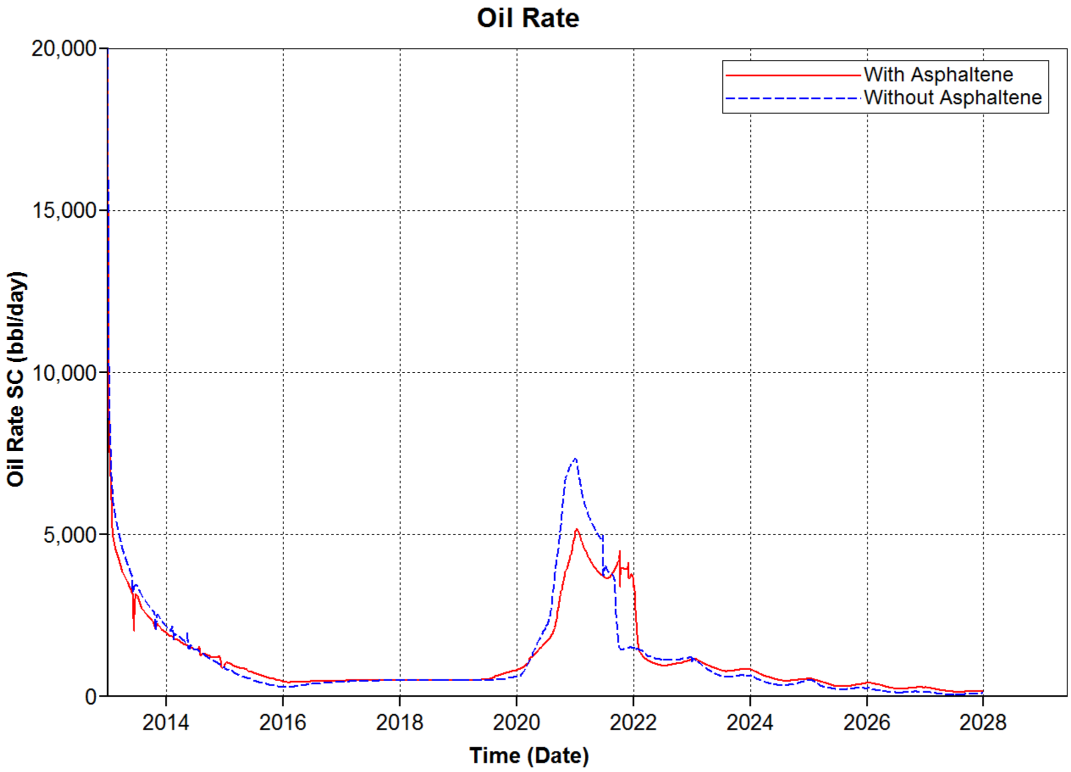

Figure 4.42: Comparison of Oil Rate for Case 1 With and Without Asphaltene Option

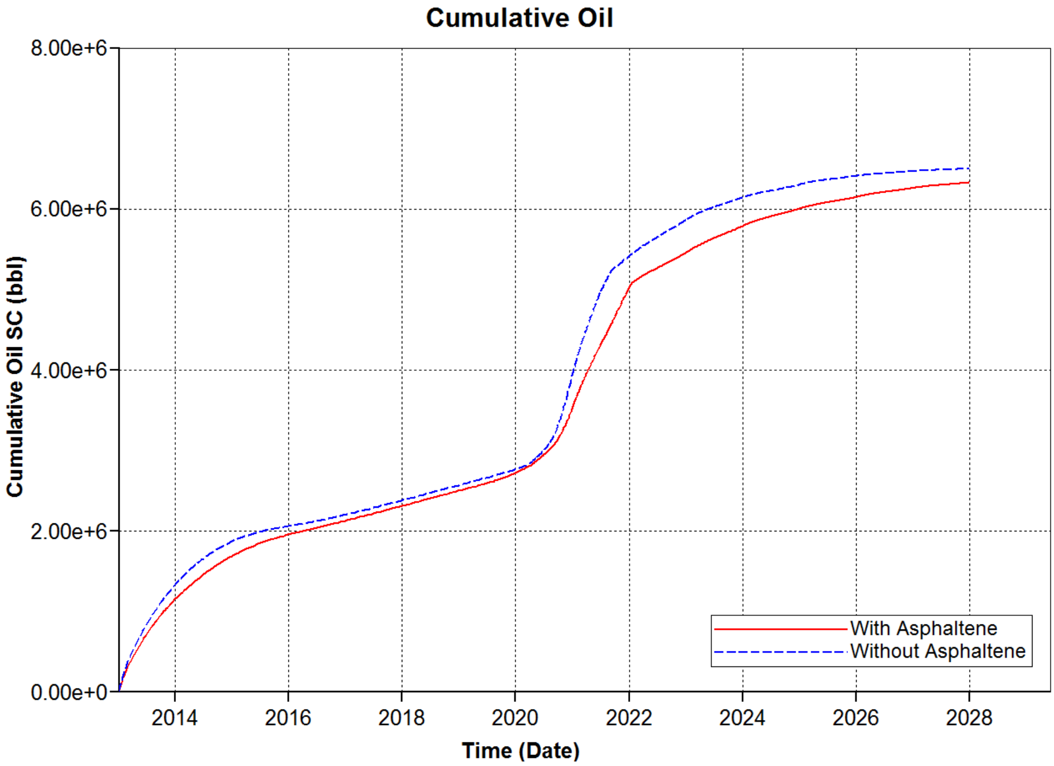

Figure 4.43: Comparison of Cumulative Oil for Case 1 With and Without Asphaltene Option

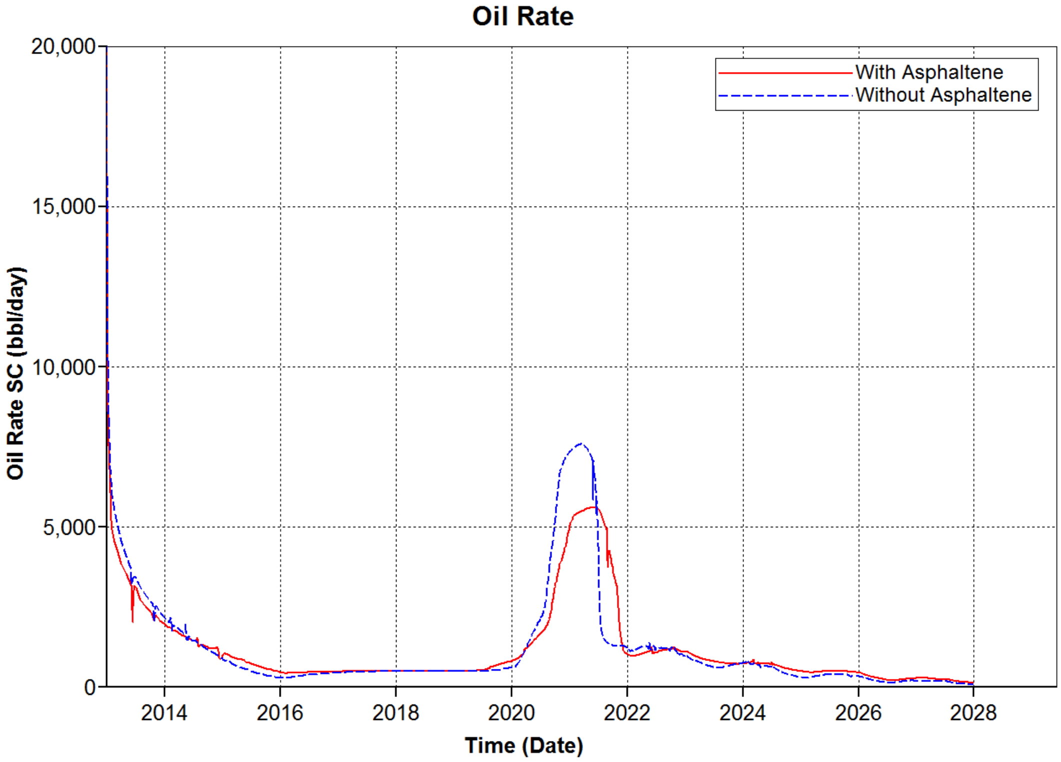

Figure 4.44: Comparison of Oil Rate for Case 2 With and Without Asphaltene Option

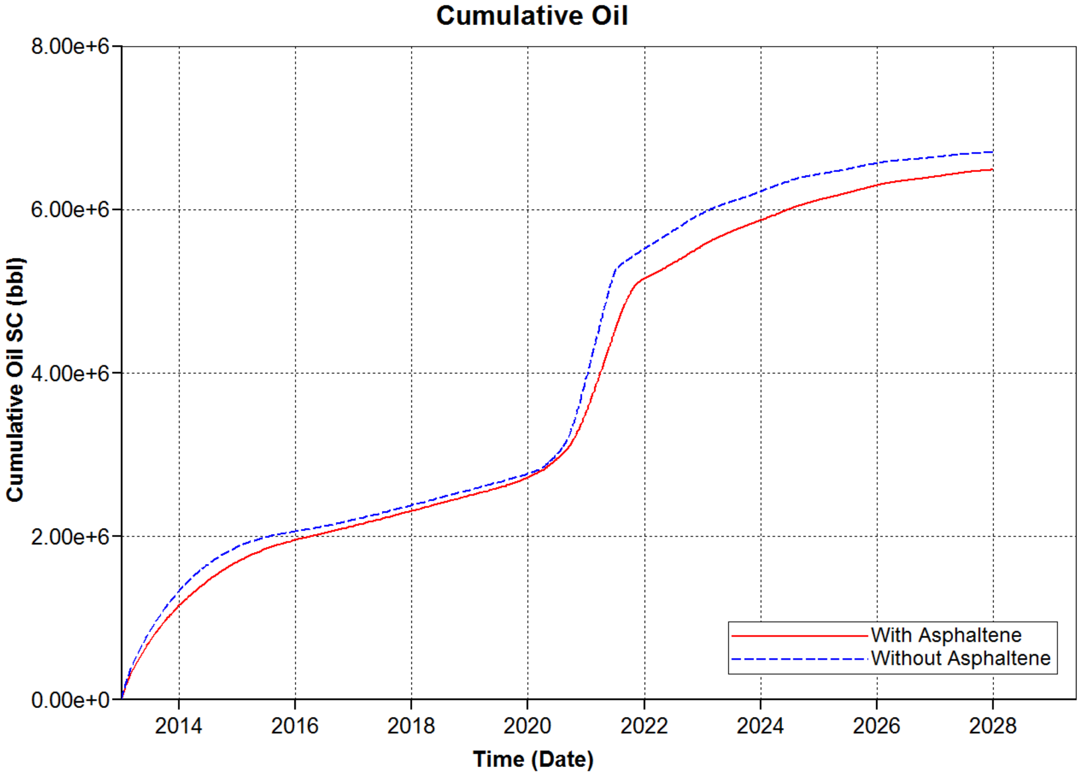

Figure 4.45: Comparison of Cumulative Oil for Case 2 With and Without Asphaltene Option

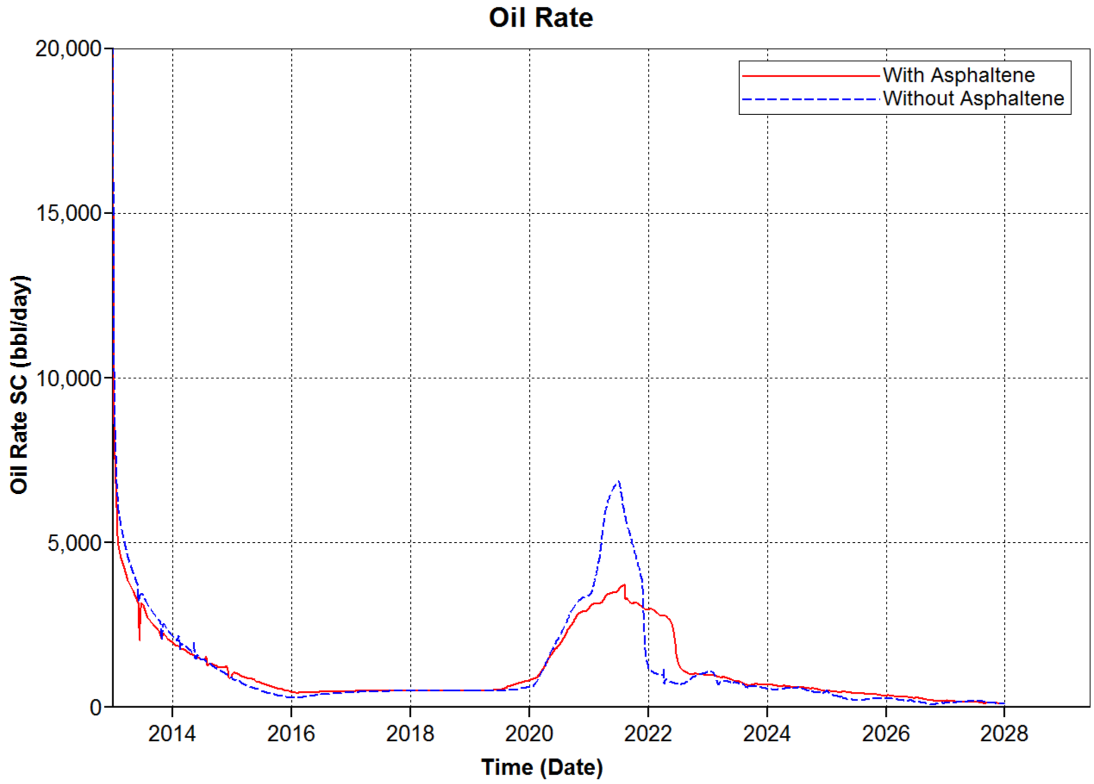

Figure 4.46: Comparison of Oil Rate for Case 3 With and Without Asphaltene Option

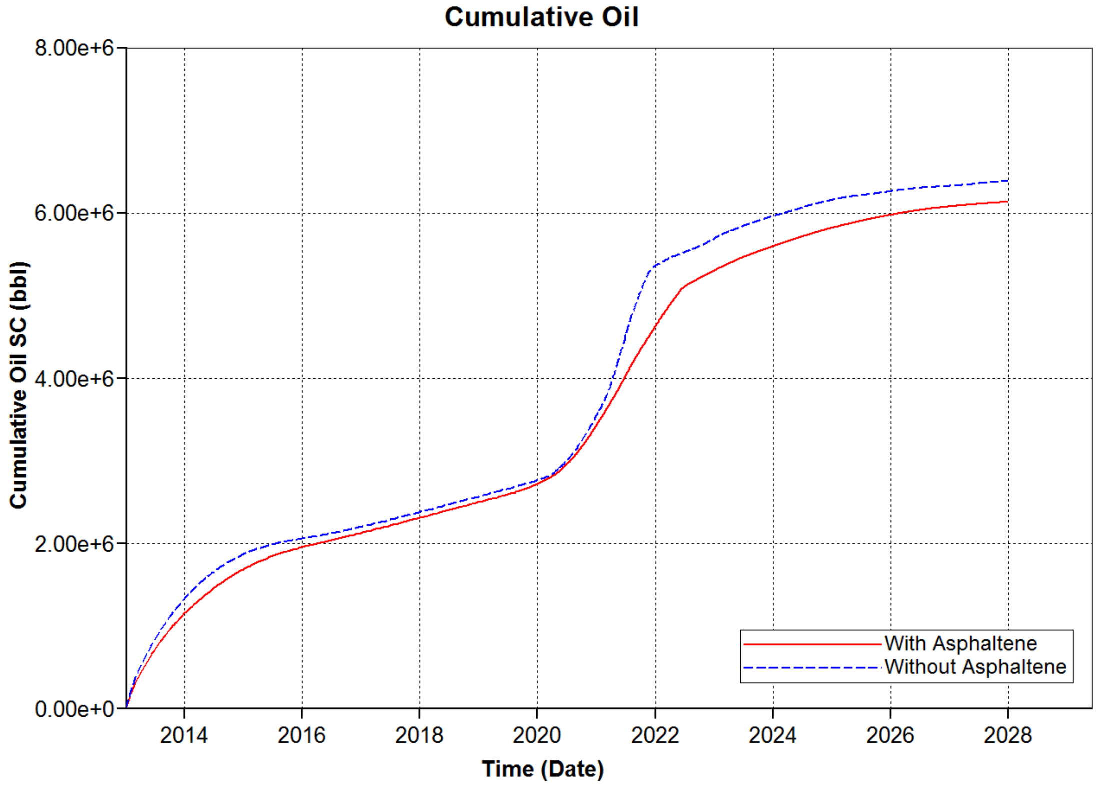

Figure 4.47: Comparison of Cumulative Oil for Case 3 With and Without Asphaltene Option

Table 4.14: Comparison of oil recovery at different WAG ratios

	Oil Recovery (MM stb)			
Period (years)	Primary Recovery	Waterflooding	WAG-CO_2 Injection (With Asphaltene)	WAG-CO_2 Injection (Without Asphaltene)
	2	5	7	7
Case 1	1.906 (21.54%)	2.7186 (30.72%)	6.2087 (70.17%)	6.5047 (73.25%)
Case 2	1.906 (21.54%)	2.7186 (30.72%)	6.4882 (73.33%)	6.7021 (75.47%)
Case 3	1.906 (21.54%)	2.7186 (30.72%)	6.0002 (67.81%)	6.3876 (71.93%)

Figure 4.40 and Figure 4.41 show the resulting oil rate versus time and cumulative oil versus time plots for all the three cases run with asphaltene option throughout the primary oil recovery, waterflooding and WAG-CO_2 injection phases. Based on the plots, the ratio size has a significant impact on the amount of oil recovered but the oil recovery is different for different ratio. This indicates that the asphaltene precipitation rate is affected variably by the WAG ratio. WAG ratio of 2:1 gives the highest oil recovery, indicating lowest amount of asphaltene precipitation. During WAG injection with ratio of 2:1, the amount of water injected is double the amount of CO_2 gas injected. Hence, there will be higher water saturation present at the oil displacement front. This water will shield the gas from contacting the oil in a phenomenon known as waterblocking. Waterblocking weakens the effectiveness of CO_2 gas, as the gas has to dissolve in the water and diffuse through it to displace the oil. Therefore, lesser contact occurs between the gas and the oil, hence explaining the low amount of asphaltene precipitated. The results obtained in this study confines to the laboratory work findings conducted by Todd *et. al.* (1981). However, comparing the run with the highest oil recovery with the run with same cycle size but without asphaltene option indicates that the asphaltene precipitation reduces the amount of oil recovered. The oil rate versus time and cumulative oil versus time plots for the comparison case between with and without asphaltene option for the entire WAG ratios are shown in Figure 4.42 to Figure 4.47.

CHAPTER 5

CONCLUSION & RECOMMENDATION

5.1 Conclusions

Based on the study conducted, the following conclusions can be drawn:

- The higher the injection pressure, the lesser the amount of asphaltene precipitated and deposited.
- Injection rates have minimal impact on the amount of asphaltene precipitation.
- WAG cycle sizes slightly affect the amount of asphaltene precipitation. Hence, choosing small cycle size will be economic in optimizing the WAG-CO_2 injection.
- Higher injected water salinity gives lesser amount of asphaltene precipitation. In this study, 35 000 ppm is recommended.
- WAG ratio size has a significant impact on the amount of oil recovered but the oil recovery is different for different ratio. WAG ratio of 2:1 gives the highest oil recovery, indicating lowest amount of asphaltene precipitation

In conclusion, the project achieved all the objectives set forward within the given timeline. The results from this study can contribute to the better understanding of the mechanism of asphaltene precipitation with the thorough study on the impact of WAG parameters. With the understanding about these conditions, a well-planned approach to implement WAG-CO_2 schemes in light oil reservoirs is achievable in the future projects. These outcomes of the study will benefit the operators and the industry in providing a good insight about the impacts of the WAG injection rate, WAG injection pressure, WAG cycle sizes, WAG ratio and injected water salinity on triggering asphaltene precipitation in light oils.

5.2 Recommendations

A few recommendations are intended for further study purposes. The recommendations are:

- The impact of other parameters such as injected gas pore volume should be investigated to optimize the WAG-CO_2 injection.
- Heterogeneous reservoir should be used to compare the impacts of different parameters on the oil recovery as only homogeneous reservoir was used in this study.
- Datasets from existing reservoirs should be used in the study to obtain valuable information about asphaltene precipitation in different reservoir types.
- Longer project timeline should be designated to the students so that adequate research can be conducted.
- Tutorial on how to use CMG software is highly recommended to avoid waste of time on trial-and-error exercises during the project phase.

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