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Potential for Carbon Dioxide EOR in the Cooper and Eromanga Basins

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Executive Summary

Carbon dioxide (CO_2) has been used for enhanced oil recovery (EOR) since the 1960's and is now a relatively established practice in the petroleum industry. The process involves injecting dense CO_2 into the subsurface, where it is able to alter the properties of residual oil, allowing it to flow; this process is optimised if CO_2 is able to achieve miscibility will oil. CO_2 EOR is capable of extending the life of a field by 10 to 20 years, and may recover up to an additional 15% of original oil in place (Hustad and Austell, 2004). In addition to improved recovery, CO_2 EOR results in the storage of large volumes of carbon dioxide in the subsurface, making it a form of carbon sequestration.

CO_2 EOR has been implemented extensively in North America and is gaining popularity in many other regions around the world. This increase in popularity is partly due to the discovery of residual oil zones (ROZs), which are regions of unproduced oil in the subsurface that have undergone extensive natural waterflooding, such that the oil cannot be produced under primary and secondary recovery. This presents an additional target for CO_2 EOR, which has provided a further economic incentive for oil and gas companies. Thus far CO_2 EOR is yet to be implemented in Australia, although the practice is gaining considerable interest in the industry.

The Cooper-Eromanga Basin system provides a seemingly ideal location for CO_2 EOR. Fields in the region are deep and contain light oil, which is favourable for miscible CO_2 flooding. The Cooper Basin also produces a considerable amount of CO_2, which is currently being released into the atmosphere. Implementing CO_2 EOR could provide a means of both improving production in the Cooper and Eromanga Basins and offsetting the emissions footprint of the industry. Despite the increasing interest, there is an absence of literature regarding the feasibility of installing CO_2 EOR in the Cooper-Eromanga Basin system. Few studies have investigated the potential for miscibility in the region, and no basin-wide assessment has been found in the literature.

The objective of this project was to assemble a database of reservoir and hydrocarbon properties in the Cooper-Eromanga Basin system, then to use this database to evaluate the suitability of CO_2 EOR in the region. The suitability of reservoirs to undergo CO_2 EOR was assessed in a screening study, which considered parameters of initial reservoir pressure, reservoir depth, reservoir temperature, oil API gravity, and minimum miscibility pressure (MMP). The MMP was calculated using the Alston *et al.* (1985), Yuan *et al.* (2005), and Emera (2006) correlations, and was expressed as a distribution. The reservoirs were ranked based on their probability of achieving miscibility.

The results of the screening study indicate that there is a high potential for CO_2 EOR to have success in the Cooper and Eromanga Basins. All reservoirs were shown to pass the screening criteria for reservoir depth, reservoir temperature, and oil API gravity. The likelihood of a reservoir achieving miscibility was shown to increase with depth, owing to a decreasing MMP and an increasing reservoir pressure. Hence oil-producing fields in the Cooper Basin and in deeper regions of the Eromanga Basin were identified as having a high likelihood of achieving miscibility with CO_2. The results of this may provide a base from which future work can build upon.

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Chapter 1

Introduction

With an ever-growing rate of energy consumption, Australia's demand for petroleum is expected to rise by 2% per year until 2030 (Senate, 2007). In addition, declining production in regions such as the Cooper-Eromanga Basin system is forcing Australia to import increasing amounts of hydrocarbons, weakening Australia's net trade position (Syed *et al.*, 2010). These issues are compelling Australia's oil and gas industry to improve the current state of reserves by exploring new methods of oil production.

Another issue plaguing the oil and gas industry is the increased pressure on petroleum companies to reduce their carbon footprint. It is well established now that the unprecedented warming of the climate system is largely due to an increase in the atmospheric concentration of greenhouse gasses, such as carbon dioxide (CO_2) (MacDowell *et al.,* 2010). It is accepted that the rise in mean earth temperature must be maintained well below 2^oC until the year 2050 to avoid severe consequences of climate change; this target cannot be achieved if current trends continue (Global CCS Institute, 2017). Fossil fuels are known to be the main cause of the rise in concentration of anthropogenic CO_2 in the atmosphere, through their use in power generation, industrial process, and transportation. This puts added pressure on the fossil industry to explore new methods of reducing emissions (Bachu, 2016).

A solution to the latter the problem is carbon capture and storage (CCS), which involves capturing carbon dioxide that would otherwise be released into the atmosphere and injecting it into the subsurface. CCS is expected to be a major factor in achieving the mean earth temperature target set by the Paris agreement (Global CCS Institute, 2017), however without government intervention there is an insufficient economic incentive for industry to pursue this activity (Melzer, 2012). Need for an economic incentive has given rise to the concept of carbon capture, utilisation, and storage (CCUS), which makes use of the CO_2 by implementing enhanced oil recovery (EOR), before storing it in the subsurface. CO_2 EOR provides a solution for both problems outlined above, as EOR is able to target hydrocarbons that are considered unrecoverable by conventional means, and also has the potential to store large quantities of $C0_2$ in the subsurface (IEA, 2011). CO_2 EOR is yet to be trailed in Australia, but has been implemented with success in North America, South America, Africa, and Europe (Koottungal, 2010).

The purpose of this report is to inform the industry and the public of the potential for CO_2 EOR in Australia. A screening study will be carried out on oil producing reservoirs within the Cooper and Eromanga Basin, in order to loosely assess the suitability for these reservoirs to undergo CO_2 EOR. The ensuing report contains the results of the study, along with a literature review, which discusses the industry's experience with CO_2 EOR.

Chapter 2

Literature Review

During the lifetime of an oil field a reservoir may undergo three stages of oil recovery, primary, secondary, and tertiary. Primary recovery exploits the natural energy of the reservoir, which allows fluid to flow to surface, unassisted by reservoir pressure maintenance. This stage is capable of producing approximately 10% of the original oil in place (OOIP) (Schlumberger Official Glossary, 2018a). As production continues and reservoir pressure declines, production may move into the secondary stage in order to remain economical. This involves the injection of an external fluid into the reservoir, which aids production by providing pressure maintenance and a displacing drive. Common secondary production techniques are waterflooding and gas injection, which may increase total production to 15% to 40% OIIP (Schlumberger Oilfield Glossary, 2018b).

Subsequent to primary and secondary recovery, a great deal of residual oil remains in the reservoir. Accessing and producing this residual oil requires the implementation of a tertiary recovery strategy, also known as enhanced oil recovery (EOR). EOR requires the use of some injection fluid to alter the properties of the residual oil and improve oil mobility, whilst also providing pressure maintenance. Methods of EOR are generally lumped into the following four classifications:

1. Thermal: Injection of heated fluid (steam or water), or in situ combustion. Thermal methods improve mobility by lowering oil viscosity through the addition of heat (Shapiro, 2016c).
2. Chemical: Injection of polymers or surfactants. Chemical injection can improve the mobility of the oil by lowering interfacial tension, or improve sweep efficiency by improving the mobility of the displacing fluid (Shapiro, 2016c).
3. Miscible displacement: Injection of a fluid (carbon dioxide, nitrogen, or hydrocarbon gas) at a pressure sufficient to achieve miscibility with oil. Produces oil by removing the interfacial tension between the oil and the displacing fluid (Shapiro, 2016d).
4. Immiscible displacement: Injection of a fluid (carbon dioxide, nitrogen, or hydrocarbon gas) at pressures insufficient to achieve miscibility. Mobilises residual oil through oil swelling, viscosity reduction, and reduction of interfacial tension (Shapiro, 2016d).

Enhanced oil recovery by carbon dioxide (CO_2) injection is becoming an increasingly popular method of EOR, ever since the practice began in the 1970's (Figure 2.1). The process can be either miscible or immiscible, and involves injecting dense CO_2 into depleted reservoirs to change the properties of immobile hydrocarbons, allowing them to be produced. CO_2 EOR has the potential to produce an additional 5 to 15% OOIP after waterflooding, and extend the field life by 10 to 20 years (Hustad and Austell, 2004). In addition to improved oil recovery, CO_2 EOR can also act as a means of sequestering large volumes of carbon dioxide in the subsurface. Consequently, CO_2 EOR can be considered as the utilisation component of the carbon capture, utilisation, and storage (CCUS) process.

CO_2 EOR has been implemented extensively in the United States since the 1970's, particularly in the Permian Basin of West Texas and South Eastern New Mexico. It is now a well-established practice within the industry, and is gaining interest in other parts of the world (Hustad and Austell, 2004). A study by Koottungal (2010) identified that there were 152 CO_2 EOR projects in progress worldwide, the majority of which were located in the United States, however projects have also been implemented in Canada, Trinidad, Brazil, and Turkey. In addition there has been increasing interest in implementing CO_2 EOR in Australia, East Asia, the North Sea, and the Middle East.

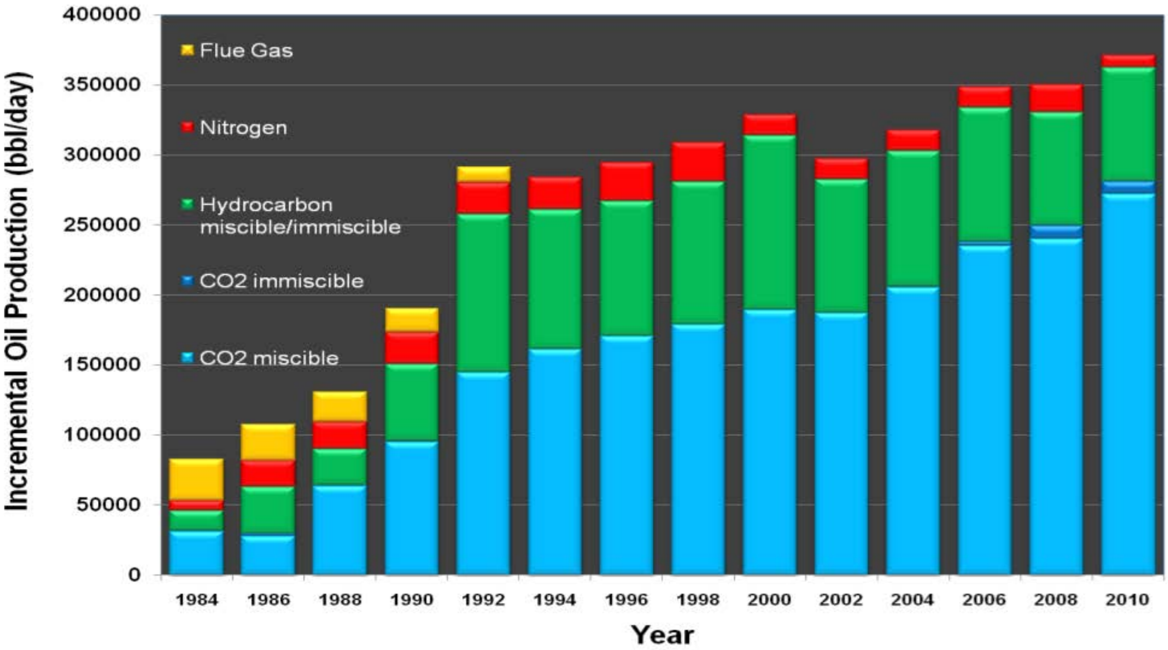

Figure 2.1: Gas flooding activity from 1984 – 2010 (Enick and Olsen, 2012).

2.1 General Process

The CO_2 EOR process involves three distinct phases, the procurement of CO_2 and transportation to the well site, the injection of CO_2 into the subsurface, and the termination of the project with subsequent storage of CO_2. Each stage presents different economic and technical challenges that must be considered to ensure a successful project.

2.1.1 CO_2 Procurement and Transportation

The success of a CO_2 EOR project is greatly dependent on the feasibility of obtaining CO_2 and transporting it to the field. This is generally the most expensive stage of the CO_2 EOR process, and is a huge factor limiting the expansion of CO_2 EOR to offshore applications (Kang *et al.*, 2016) and to regions in Europe (Hustad and Austell, 2004). The growth of CO_2 EOR activity in the United States during the 1970's and 1980's is largely attributed to the abundance of cheap CO_2, however nowadays the depletion of CO_2 sources and rising costs of obtaining CO_2 are hindering further growth, even limiting the progress of existing projects (Melzer, 2012).

CO_2 can be procured from either a geological source or an anthropogenic source. Geological sources refer to large accumulations of naturally occurring CO_2 in the subsurface, whereas anthropogenic sources refer to operations from which CO_2 is produced as a by-product. Geological sources, such as the McElmo and Sheep Mountain Domes in the Colorado, are by far the more economic option, and account for 75% of the total CO_2 transported in the United States (Whittaker and Perkins, 2013). Alternatively utilising anthropogenic sources of CO_2, such as fertiliser and gas plants, is far more environmentally beneficial, as it results in the sequestration of CO_2 that would otherwise be released into the atmosphere. Anthropogenic sources of CO_2 are the more costly and hence less desirable alternative, which will continue to be the industry's view under the current economic conditions (Hustad and Austell, 2004).

CO_2 can be transported to the well site by pipeline, truck, train, or ship (Whittaker and Perkins, 2013). Truck or train may be preferred for smaller projects, whereas larger projects generally utilise pipelines, as they are far more economic for transportation over short distances (Kaldi, 2018). The instalment of pipelines can drastically increase the activity of CO_2 EOR projects in a region, as it significantly reduces the cost of obtaining CO_2. This was experienced in the Permian Basin of West Texas and South Eastern New Mexico, who saw a major boom in CO_2 EOR activity due to the instalment of pipelines connecting three geological sources of CO_2 to the Permian Basin (Figure 2.2) (Hustad and Austell, 2004). A pipeline was also used to connect an anthropogenic source of CO_2 from a synthetic fuels gas plant in North Dakota to the Weyburn oil field of Saskatchewan Canada. This required a 205-mile long pipeline and transports 95 million cubic feet of CO_2 per day (NETL, 2010).

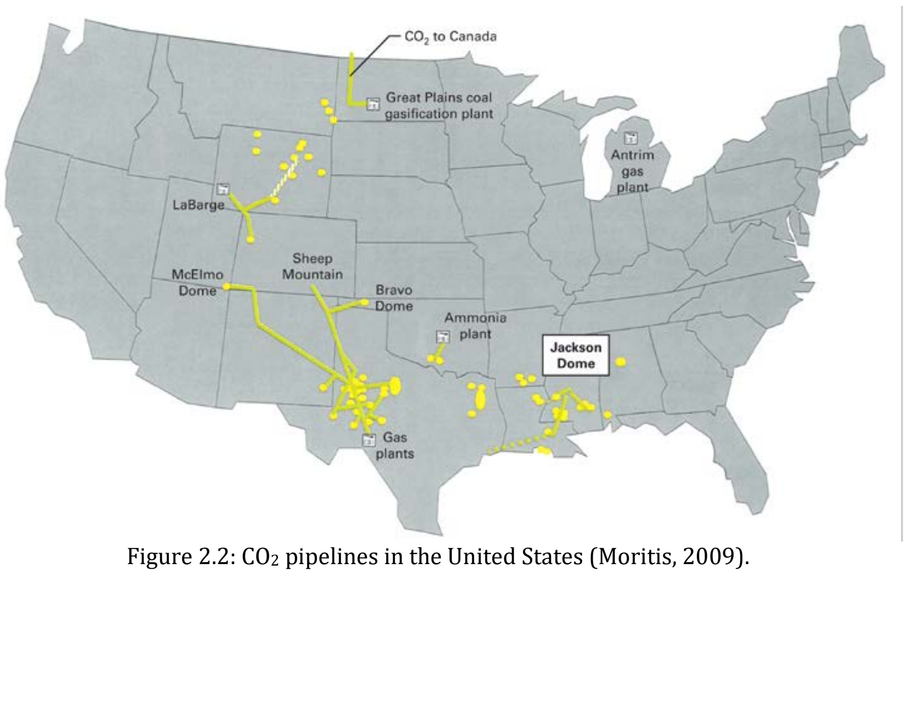

Figure 2.2: CO_2 pipelines in the United States (Moritis, 2009).

2.1.2 Injection

CO_2 is injected into the formation as a liquid or supercritical fluid (Meyer, 2007), restoring reservoir pressure to near original conditions (Figure 2.3) (Marston, 2013). Achieving a supercritical state requires pressures and temperatures in excess of 7.38 MPa and 31.1°C respectively (Aminu *et al*., 2017). In this state, the density of CO_2 increases to values comparable with oil, while viscosity remains rather low. These conditions are favourable as a high density ensures that the CO_2 doesn't instantly rise to the top of the reservoir, while a low viscosity promotes injectivity (Luo *et al.*, 2017). It is generally assumed that CO_2 will remain in its supercritical state in reservoirs of depths exceeding 800 metres (2624 feet) (Aminu *et al*., 2017). Studies by Taber and Martin (1997b), and Alvarado *et al.* (2002) have adopted this as the criteria for the minimum allowable reservoir depth, however miscible floods have been shown to be successful at far shallower depths of 490 metres (1600 feet) (Koottungal, 2012).

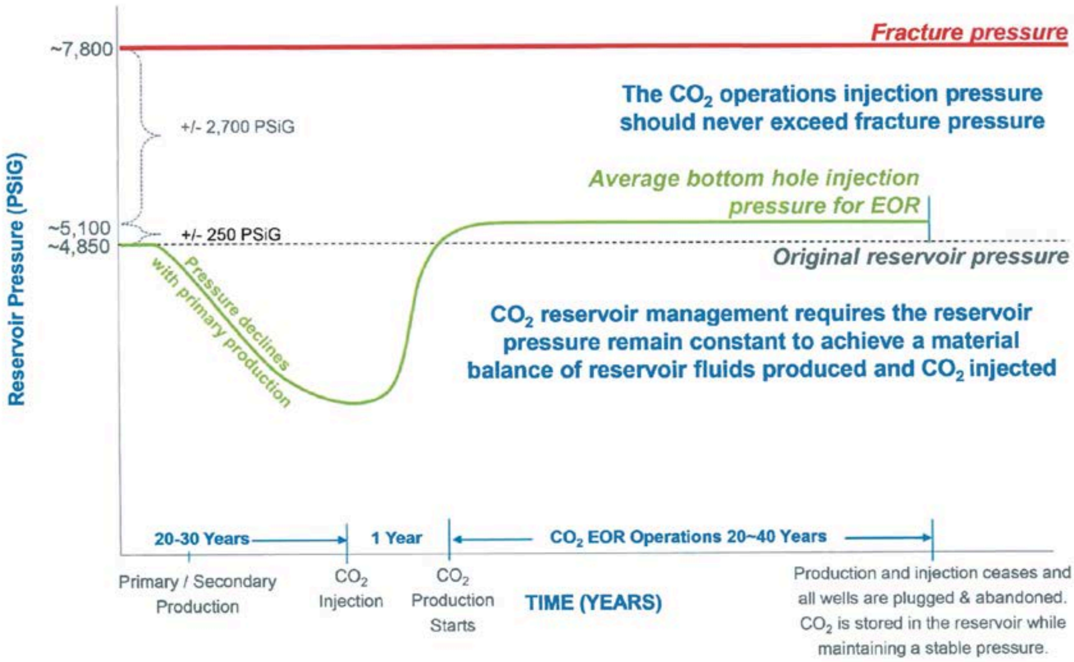

Figure 2.3: Typical average bottom hole pressure during CO_2 EOR (Marston, 2013).

Upon injection CO_2 contacts the reservoir fluid, and will begin to mix due its solubility. Interactions between CO_2 and oil are able to change the properties of the trapped oil, such that it can be mobilised and swept to a producing well (Figure 2.4). The fluid is then produced and the CO_2 is separated, dried, re-pressurised, and reinjected into the formation for further recovery (NETL, 2010). The efficiency of the flood is described by the recovery efficiency (E_R) (Equation 2.1), which is a function of volumetric sweep efficiency (E_V) and displacement efficiency (E_D). Displacement efficiency (E_D) considers oil mobilisation at the pore level, and is defined as the fraction of oil recovered from a region that has been contacted by CO_2. Volumetric sweep efficiency (E_V) describes oil mobilisation beyond the pore level, and relates to the volume of the reservoir that comes into contact with CO_2. Volumetric sweep efficiency can be expressed in terms of the areal sweep efficiency (E_A), and the vertical sweep efficiency (E_I) (Equation 2.2) (Verma, 2015).

Equation 2.1: Sweep efficiency E_R.

$$E_R = E_V * E_D$$

Equation 2.2: Displacement efficiency E_D.

$$E_V = E_A * E_I$$

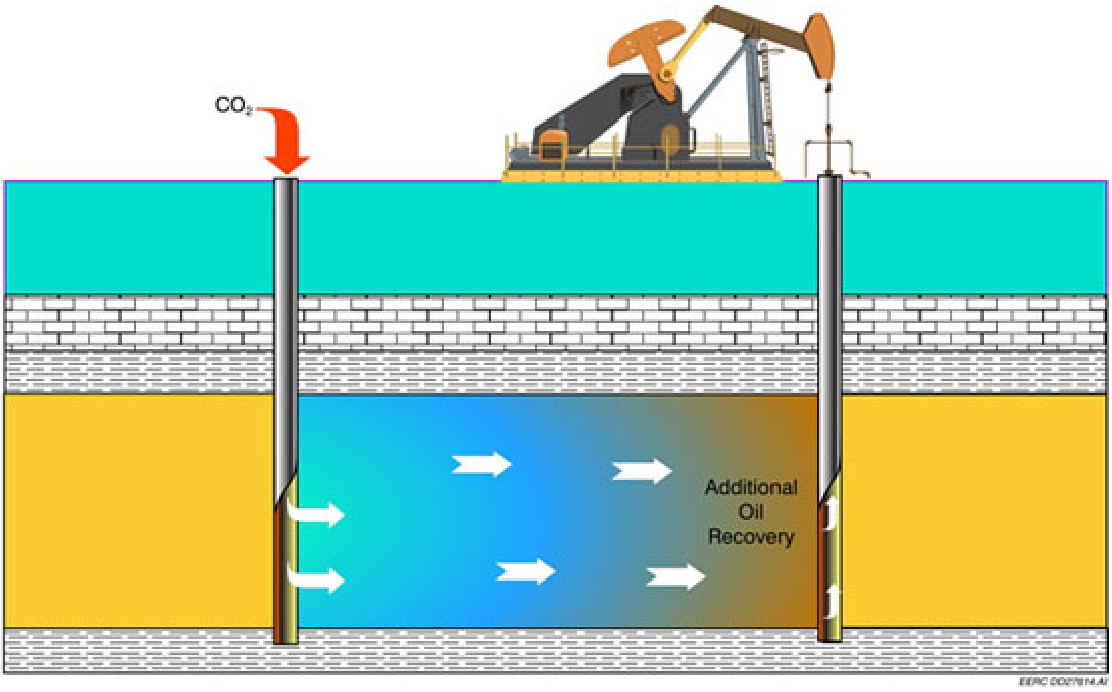

Figure 2.4: Illustration of the CO_2 EOR Process (PCOR, 2018).

The key technical issues that may be experienced at surface during this stage are loss of injectivity, scale formation, and corrosion. Loss of injectivity generally occurs when alternating from CO_2 to water injection, and can lead to a rapid drop in pressure (Christensen *et al.*, 2001). An injectivity loss of around 20% can be expected, although it will likely not seriously affect the project (Hadlow, 1992). Corrosion can be caused by the presence of carbonic acid, and along with scale formation may affect the integrity of the facilities. This is mainly a problem when taking over existing facilities, as they may not have been treated with sufficient corrosion resistance. Problems with corrosion have been experienced in projects such as Lick Creek, where corrosion occurred after the breakthrough of CO_2, however problems can generally be avoided by treating facilities with corrosion protection, using stainless steel, and dehydrating CO_2 (Christensen *et al.*, 2001; Hadlow, 1992).

2.1.3 Storage

As the EOR project matures interactions between CO_2 and oil become less frequent, and the production of residual oil declines. The rate of CO_2 supplied to the well site also tapers off as more CO_2 is recycled back into the subsurface (Figure 2.5). The project will end once recovery is no longer economically viable; the wells are then plugged and abandoned, along with the CO_2 remaining inside the reservoir (Melzer, 2012). Approximately 60% of the CO_2 injected will remain in the formation (Bachu, 2016). Environmentally, this is a great advantage, as it provides the opportunity to sequester large amounts of carbon dioxide and mitigate the emissions footprint of the facility. However, from an economic perspective this is a disadvantage, as acquiring CO_2 is generally the most expensive stage of a CO_2 EOR project (Melzer, 2012). For this reason the obligation of the operators is to store as little CO_2 as possible, which is unlikely to change without an economic incentive (Hustad and Austell, 2004).

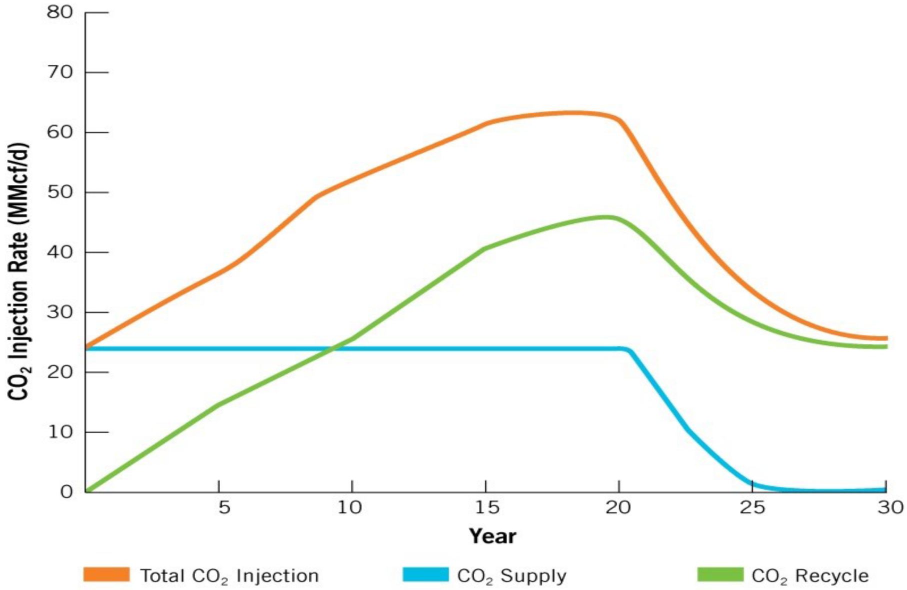

Figure 2.5: Rate of CO_2 injection, recycling, and supply against time (Whittaker and Perkins, 2013).

In the subsurface, CO_2 is subject to the same stratigraphic and capillary trapping as the original oil in place, however additional processes of dissolution and mineral trapping are also attributed to CO_2 storage. Dissolution trapping occurs when CO_2 is dissolved in brine, which increases the density of the CO_2 and allows it to sink into the reservoir. Alternatively, mineral trapping occurs due to the formation of carbonic acid, which goes on to react with the reservoir rock and form solid minerals in the formation (Iglauer, 2011). Despite these trapping mechanisms, migration or leakage may still occur due to improperly plugged wells, cementing issues, or an unsuccessful stratigraphic seal (Whittaker and Perkins, 2013). Constant surveillance is required, which allows problems to be identified quickly and resolved (Aminu *et al.*, 2017; Melzer, 2012; Whittaker and Perkins, 2013). It should however be noted that a report has yet to provide evidence of notable leakage from a storage site (Aminu *et al.*, 2017).

Storage potential is greatly dependent on depositional environment, and is hindered by high formation permeability and irreducible water saturation (Okwen *et al.*, 2014). The injection strategy also effects storage potential. Injecting slugs of water alternating with CO_2 have been shown to enhance dissolution trapping, while utilising horizontal wells enhances capillary trapping (Baz *et al.,* 2016). Simulations have also shown that halting CO_2 injection once some pressure limit has been achieved optimises CO_2 storage, whist injecting deeper into the formation will provide more formation volume in which CO_2 can be stored (Iglauer, 2011). However, the design of a CO_2 flood always considers optimising economic performance as the primary goal, meaning that unless CO_2 storage becomes economically favourable, optimising storage potential will be overlooked (Melzer, 2012). There are several methods that can be used to estimate potential storage in depleted oil and gas fields. Two examples are the US-DOE method (Equation 2.3) and the Zhao-Liao method (Equation 2.4) (Aminu *et al.*, 2017).

<u>Equation 2.3</u>: Zhao-Liao method (Zhao and Liao, 2012)
Estimates storage capacity of highly water-saturated oil fields using material balance and considering three components, CO_2 displacement, CO_2 solution in oil, and CO_2 solution in water.

$$G_{CO_2} = \rho_{CO_2,r} A h \phi S_{CO_2}$$

<u>Equation 2.4</u>: US DOE method (Goodman *et al.*, 2010)
Estimates storage using the same approach as estimating OGIP and OOIP.

$$G_{CO_2} = A h_n \phi_e (1 - S_{wi}) B \rho_{CO_2,std} E_{\left(\frac{oil}{gas}\right)}$$

G = Sequestration capacity
ρ = Density of gas
A = Area
h = Reservoir depth
ϕ = Porosity
S_{CO2} = Sequestration factor
B = Formation volume factor
E = Energy storage efficiency
S_{wi} = Irreducible water saturation

2.2 Subsurface Interactions

As discussed in Section 2.12 the efficiency of the CO_2 flood is dependent on the displacement efficiency and the sweep efficiency. The displacement efficiency describes the ability of the injection fluid to mobilise the residual oil that it comes into contact with, whereas the sweep efficiency describes the volume of the reservoir that comes into contact with the injection fluid. Both parameters are influenced by interactions in the subsurface, which are dependent on reservoir and reservoir fluid properties.

2.2.1 Oil Displacement

Oil displacement refers to the mobilisation of previously trapped hydrocarbons at the pore level; this does not refer to oil that is bypassed by CO_2 as a result of incomplete reservoir sweep. It is necessary to understand the mechanisms by which oil is trapped during imbibition to understand how it can be later liberated by EOR.

In conventional production, hydrocarbons are considered immobile once the relative permeability of the hydrocarbon phase falls to zero and the residual oil saturation is achieved. This implies that the reservoir will only produce water under the existing production strategy, although sufficient volumes of oil may still be remaining in the pore spaces. When viewing this process at the pore level it can be seen that water flows through pore spaces as a continuous fluid, bypassing volumes of hydrocarbons that have either adhered to the rock surface (oil-wet formation) or that exist as isolated droplets (water-wet formation) (Kaldi, 2018). During waterflooding, oil production is greater in water-wet conditions, meaning that oil-wet conditions trap larger volumes of oil in the pore spaces (Rao *et al.,* 1992; Pu *et al.*, 2016). Reservoirs with lower quality are also known to trap larger volumes of oil (Kaldi, 2018).

The process by which oil volumes become dispersed droplets in the pore spaces is called snap-off (Figure 2.6). This occurs during imbibition, when the oil bridge in a pore throat becomes unstable and collapses (Roof, 1970). Capillary forces immobilise the droplet, and will continue to do so until either the interfacial tension between the two phases is reduced, or a pressure gradient is applied that can overcome the capillary forces (Shapiro, 2016b). Equation 2.5 explains this relationship, where ΔP is the required pressure for drop mobilisation and σ is the interfacial tension. The resistance of oil to mobilisation can be related to the capillary number (Equation 2.6), where increasing the capillary number improves oil recovery. The capillary number is a dimensionless value, which relates viscous forces to capillary forces (Donaldson *et al.,* 1985). Notice that capillary number is improved for a higher viscosity of the displacing fluid and a lower interfacial tension.

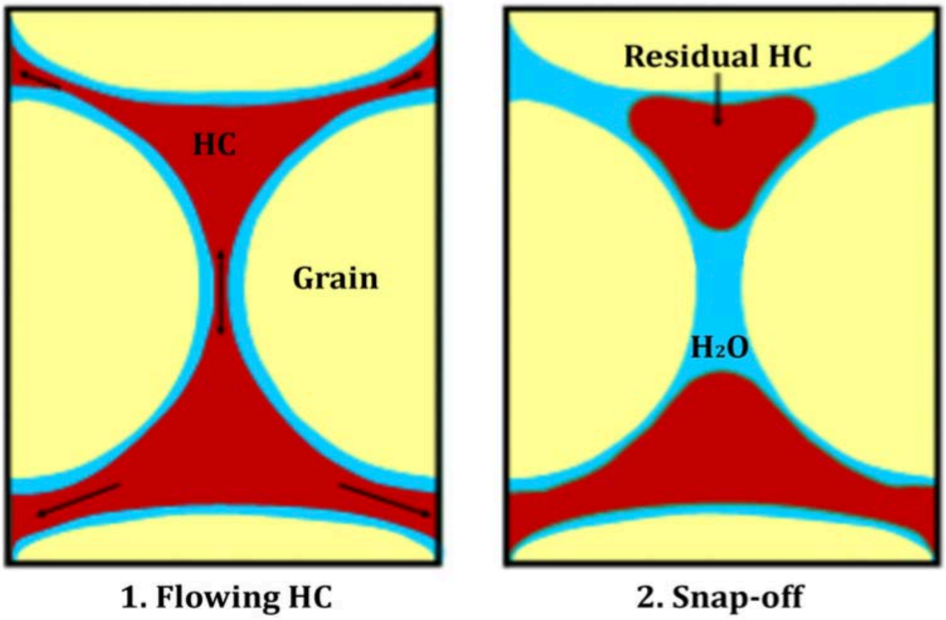

Figure 2.6: Illustration of oil snap-off (Kaldi, 2018).

Equation 2.5: Conditions for drop mobility (Shapiro, 2016b)

$$\Delta P = P_2 - P_1 \geq P_c = \frac{2\sigma\cos(\theta)}{r}$$

Equation 2.6: Capillary number (Donaldson *et al.,* 1985)

$$N_C = \frac{\mu V}{\sigma}$$

ΔP = Pressure across pore
σ = Interfacial tension
P_C = Capillary pressure
θ = Wetting angle
r = Pore radius
N_C = Capillary number
μ = Viscosity of displacing fluid
V = Characteristic velocity

The purpose of EOR is to improve the capillary number so that oil can flow under reasonable pressures. This is achieved through CO_2 injection, as CO_2 is soluble in oil and is therefore able to favourably alter the properties of the oil. The property of solubility means that upon contact there is some amount of mass transfer between the dense CO_2 and oil phase (Holm, 1986). The addition of CO_2 to the oil results in a reduction in interfacial tension, swelling of the oil, and a reduction in viscosity. Reductions in interfacial tension and viscosity act to improve the capillary number, thus improving oil recovery. Simultaneously, the increase in volume due to swelling causes water to be displaced and leads to the subsequent washout of oil (Eremin and Nazarova, 2003); swelling may also improve the relative permeability of the oil phase, increasing the mobility of the oil (Mungan, 1981a). These mechanisms all play a role in both miscible and immiscible displacement, however their influence differs slightly depending on whether CO_2 is able to achieve complete miscibility with oil (Eremin and Nazarova, 2003).

In the context of petroleum engineering, miscibility is defined as the condition in which two fluids can combine in all proportions, without the existence of an interface (Holm, 1986). This is not to be confused with solubility, which is defined by Holm (1986) as the ability of a limited amount of one substance to mix with another substance to form a single homogenous phase. Miscibility between CO_2 and oil is achieved in a dynamic process, involving mass transfer over multiple interactions (Stalkup, 1983). During this process lighter components of the oil are vaporised into the CO_2 phase, whilst CO_2 condenses into the oil phase (Figure 2.7) (Stalkup, 1983; Bossie-Codreanu, 2009; Eremin and Nazarova, 2003). At a sufficiently high pressure this exchange will continue until the properties of the two phases are altered sufficiently to achieve miscibility. The required pressure for miscibility to occur is termed minimum miscibility pressure (MMP), and is a function of temperature and fluid properties (Holm, 1986). Oil recovery is maximised once MMP has been achieved (Figure 2.8) (Yellig and Metcalfe, 1980).

Supercritical CO_2	CO_2 volatising light oil components	Miscibility zone	CO_2 condensing into oil	Original oil

Figure 2.7: Miscibility stages of supercritical CO_2 and oil (Bossie-Codreanu, 2009).

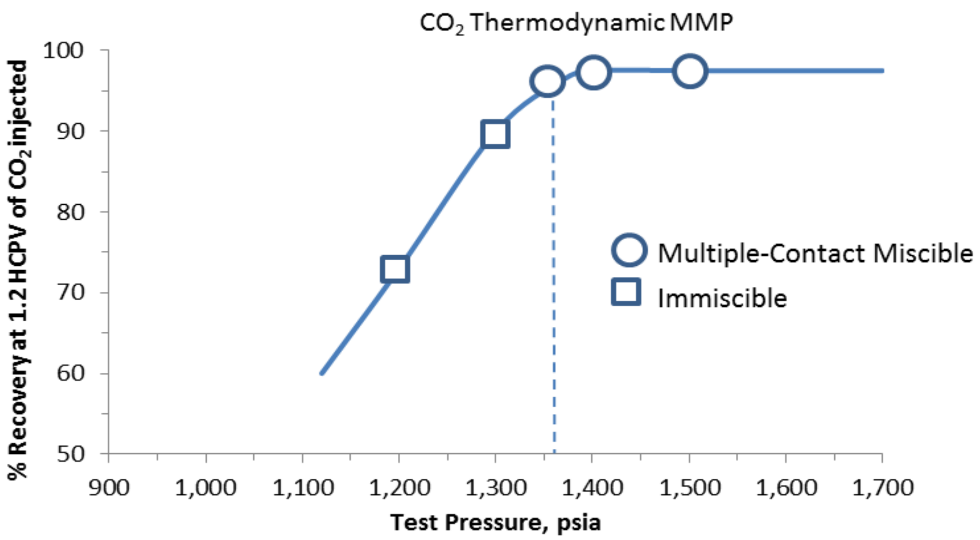

Figure 2.8: Slim tube oil recovery (% at 1.2 HCPV) of CO_2 injected against test pressure (Yellig and Metcalfe, 1980). Note that once miscibility is achieved, oil production does not improve with pressure.

For displacement to be entirely miscible, CO_2 must be injected at a pressure exceeding MMP, however sufficient oil recovery is possible at pressures slightly below MMP (TORP, 2018). As CO_2 is not directly miscible with oil, the process may require approximately ten to twenty metres in order to induce sufficient contact between CO_2 and residual oil (Mungan, 1981a). Once miscibility is achieved a miscible front develops, where CO_2 and oil exist in one homogenous phase (Donaldson *et al.*, 1985); by definition there is now a complete absence of interfacial tension, implying complete mobilisation of contacted residual oil (Holm, 1986). Mobilised oil is subsequently swept to a producing well. Miscible displacement is best suited to deep reservoirs containing light to medium oils (Enick and Olsen, 2012) and has the potential to recover a further 10-20% OOIP upon 80% pore volume injected (PVI) (Meyer, 2007).

If miscibility is not achieved then the two fluids are said to be immiscible, and two phases will be observed. Despite this, solubility effects still allow some amount of vaporisation of light oil components into the CO_2 phase and some condensation of CO_2 into the oil phase. Like miscible displacement, the addition of CO_2 to oil acts to swell the oil, reduce its viscosity, and reduce the interfacial tension (Mungan, 1981a). In addition, the extraction of oil into CO_2 increases the viscosity of the displacing fluid, improving the sweep efficiency (Bossie-Codreanu, 2009). However, immiscible displacement still leaves a considerable amount of oil behind, generally only producing a further 5-10% OOIP (Meyer, 2007). Consequently this is the less favoured method of the two, and is applied considerably less frequently.

2.2.2 Reservoir Sweep

By definition miscible displacement has the ability to almost completely mobilise residual oil at the pore level, resulting in extremely high displacement efficiency (Holm, 1986). Despite this, a large amount of residual oil still remains in formation, implying that the injection fluid does not contact the entire reservoir. This is mainly attributed to channelling due to poor heterogeneity, viscous fingering, or a gravity override, which lead to unconformities in the displacement front (Shapiro, 2016b). Other influences such as corrosion and asphaltene precipitation may also negatively affect sweep efficiency, but to far less of an extent.

2.2.2.1 Channelling

Significant heterogeneity in the formation can cause portions of the CO_2 slug to channel ahead of the displacement front into regions of high permeability known as thief zones (Figure 2.9). This occurs because the injected CO_2 will favour the path of least resistance to flow, *i.e.* paths of higher permeability, meaning paths of low permeability will be bypassed and breakthrough will occur early (Shapiro, 2016b). This is made more unfavourable by the fact that pore throats of low permeability are likely to have also been bypassed during waterflooding, meaning they may still contain significant volumes of oil (Enick and Olsen, 2012). Future CO_2 slugs will naturally follow in identical paths, meaning that bypassed pore throats will remain unswept (NETL, 2010).

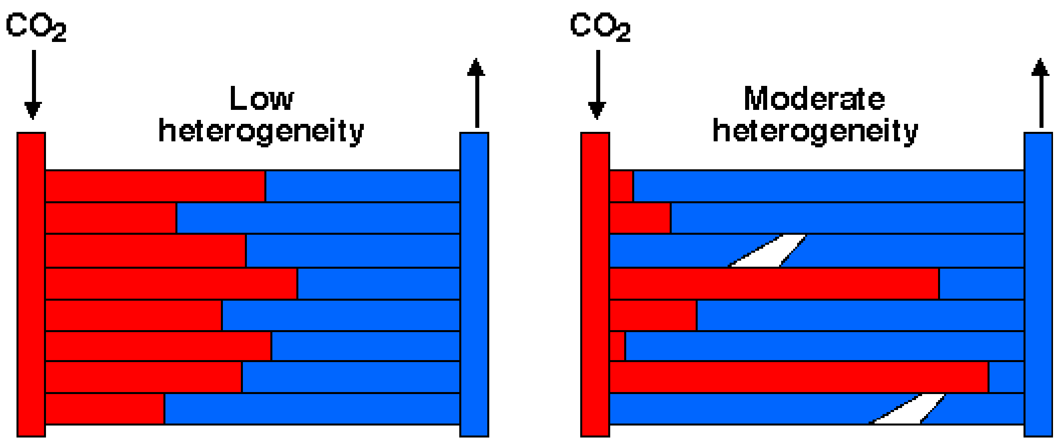

Figure 2.9: Illustration of CO_2 channelling through regions of high permeability (Kansas Geological Survey, 1999)

2.2.2.2 *Viscous Fingering*

Viscous fingering describes the instability of the displacement front due to viscosity differences between the two fluids (Figure 2.10). This occurs if the displacing fluid is of lower viscosity than the reservoir fluid, as the surface between the two phases becomes instable. If this is the case, sections of the injected fluid will 'finger' ahead of the displacement front. The displacement front is considered stable if the mobility of the displacing fluid behind the front is smaller than the mobility of oil ahead of the front. This gives the stability criteria, shown in Equation 2.7. The stability criteria can be rearranged to find the mobility ratio (M), which must be less than or equal to one for stability (Equation 2.8) (Shapiro, 2016b).

Equation 2.7: Stability criteria (Shapiro, 2016b)

$$\frac{kk_{r,CO_2}\Delta P}{\mu_{CO_2} * L} \leq \frac{kk_{ro}\Delta P}{\mu_0 * L}$$

Equation 2.8: Mobility ratio (Shapiro, 2016b)

$$M = \frac{k_{r,CO_2}\mu_0}{\mu_{CO_2}k_{ro}} \leq 1\ (For\ stability)$$

k = Absolute permeability
k_r = Relative permeability
ΔP = Pressure drop across finger
μ = Viscosity
L = Length of finger
M = Mobility ratio

Figure 2.10: Illustration of viscous fingering during CO_2 EOR (Almajid, 2016).

2.2.2.3 *Gravity Override*

A gravity override occurs due to differences in density between the injection fluid and reservoir fluid. This difference in density causes the displacement front to not be uniformly distributed vertically, with heavier components favouring lower regions due to buoyancy (Figure 2.11). In the case of CO_2 EOR, this generally means that oil lower in the formation is bypassed (Shapiro, 2016b). The effect of gravity override can be described by the gravity parameter (G) (Equation 2.9). This can be worked into the stability criteria to give the new stability criteria (Equation 2.10).

Equation 2.9: Gravity parameter (Shapiro, 2016b)

$$G = \frac{kk_{r,CO_2}}{\mu_{CO_2}}\left(\frac{(\rho_{CO_2} - \rho_o)gsin\alpha}{U}\right)$$

Equation 2.10: Stability criteria (including gravity) (Shapiro, 2016b)

$$M - G \leq 1$$

k = Absolute permeability
k_r = Relative permeability
ρ = Density
μ = Viscosity
U = Dimensionless Velocity
g = Gravity constant
a = Incline angle

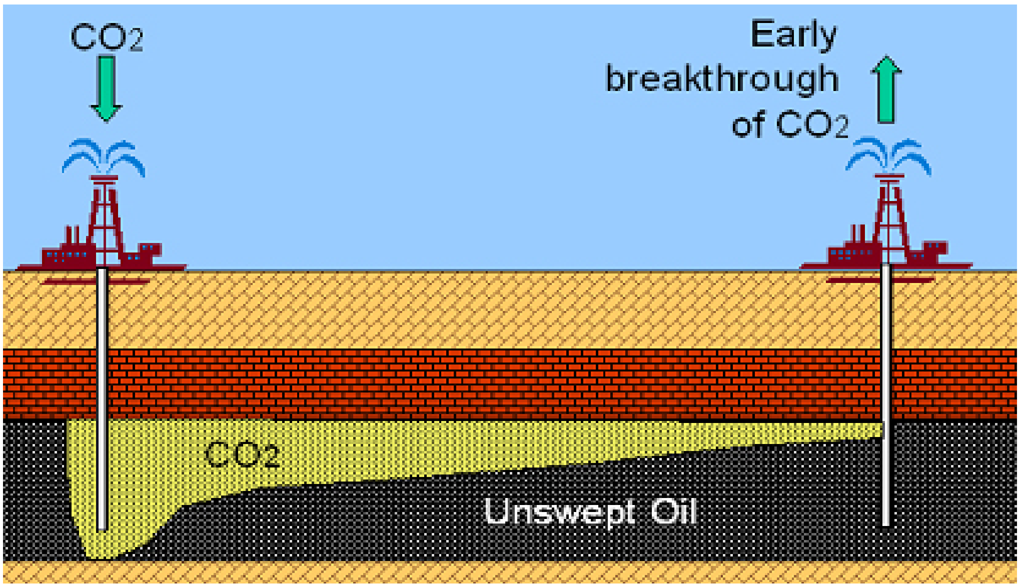

Figure 2.11: Illustration of a gravity override during CO_2 EOR (IFE, 2018).

2.2.2.4 Asphaltene

Contact between CO_2 and reservoir oil may lead to the precipitation of asphaltene, which can severely impede permeability (Mungan, 1981b). Precipitation of asphaltene is mainly dependent on the CO_2 concentration, and displays a positive linear relationship (Srivastava *et al.*, 1999). Although heavy oil contains more asphaltene content, precipitation occurs more easily from light oil. Consideration should be given the amount of resin contained within the oil as the likelihood of precipitation decreases in the presence of high amounts of oil resin (Spiecker *et al.*, 2003; Ghedan, 2009). In addition to reducing permeability, flocks of asphaltene may trap amounts of oil and can alter rock wettability, making the formation more water-wet (Mungan, 1981b).

2.2.2.5 Corrosion

The combination of CO_2 and water forms carbonic acid, which can create a corrosive environment (Mungan, 1981b). In addition to the corrosive problems experienced by drilling and surface equipment, corrosion may also influence the formation, as carbonic acid may act to dissolve calcite or carbonate material (Eremin and Nazarova, 2003). This is likely to be advantageous as connectivity is increased throughout the reservoir, offsetting the effect of asphaltene precipitation (Ghedan, 2009), however increased permeability could lead to conformance issues due to channelling.

2.3 CO_2 Flooding Techniques

In order to mitigate the effects of channelling and improve sweep efficiency, certain mobility and conformance control techniques are implemented. Mobility control reduces the effect of viscous fingering by decreasing the mobility ratio between CO_2 and oil. Conformance control improves the stability of the displacement front, and mitigates channelling and the gravity override. Employing various techniques, along with careful planning and sound reservoir management can drastically improve the performance of the CO_2 flood (Rogers and Grigg, 2001). This section will discuss some of the techniques used in industry to provide mobility and conformance control.

2.3.1 Continuous CO_2 Injection (CGI)

Continuous gas injection (CGI) (Figure 2.12) involves the continuous injection of a predetermined volume of CO_2, generally 20 to 40% hydrocarbon pore volume (HCPV) (Hadlow, 1992), without interruption from another fluid. The injected CO_2 slug may be followed by a second injection fluid, such as water or nitrogen, to drive fluid to the production well (Nasir and Demiral, 2012; Verma, 2015). As one of the earliest CO_2 injection methods implemented by industry, the technique contains some inherent flaws. CGI is generally associated with a poor recovery factor, as it does not supply mobility or conformance control to mitigate channelling (Nasir and Chong, 2009). Ultimate recovery can be somewhat improved by implementing a slower injection rate and a higher injection volume (Shehata *et al.,* 2012), however even with larger injection volumes CGI still does not outperform other similar injection methods (Nasir and Demiral, 2012). Another issue with CGI is the poor utilisation of CO_2, which has been shown to be worse than all other horizontal displacement methods (Nasir and Demiral, 2012).

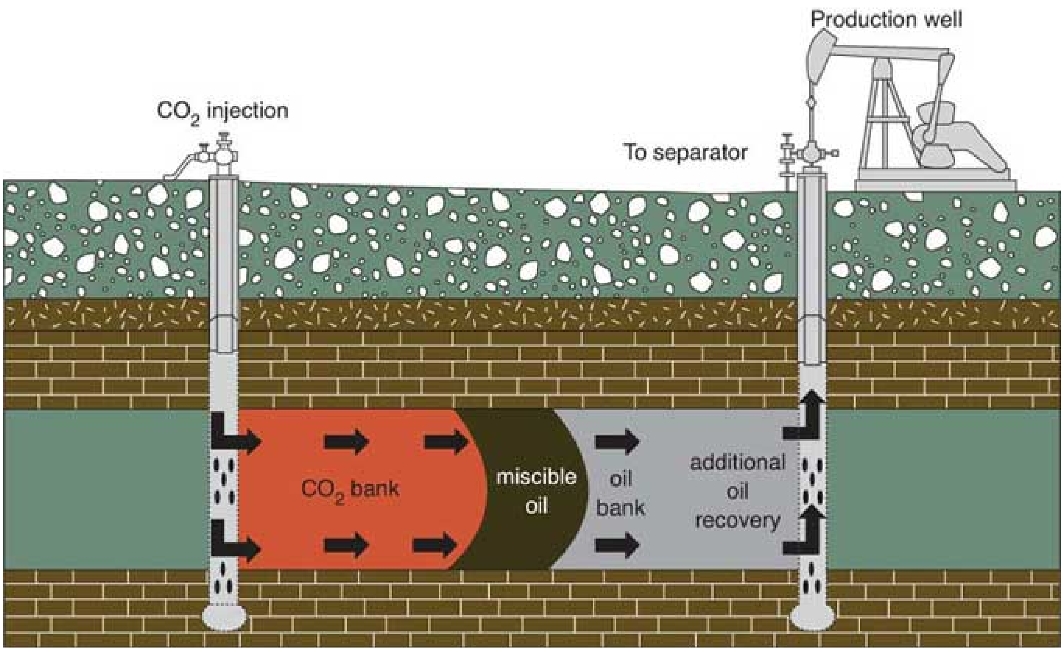

Figure 2.12: Illustration of CO_2 EOR by continuous gas injection (Kansas Geological Survey, 2016)

Despite its issues, continuous injection may be favoured in thinner pay zones, where the effect of gravity override is less significant (Whittaker and Perkins, 2013), and in reservoirs of low transmissibility, where water injection is likely to create oil trapping and injectivity problems (Hernandez *et al.*, 2016). CGI is also associated with an early production response, which may be valued in some cases (Hadlow, 1992).

2.3.2 Water Alternating Gas (WAG)

The Water Alternating Gas (WAG) method is a combination of CGI and waterflooding, designed to overcome the mobility issues associated with CGI. This has since become the most common technique implemented in industry, as it generally yields a greater ultimate recovery than continuous injection (Nasir and Chong, 2009). WAG involves the injection of CO_2 slugs followed by the injection of water, which migrate towards production wells in sequential fluid banks

(Figure 2.13). Water naturally migrates through highly permeable zones, where its presence acts to lower the relative permeability of CO_2 (Nasir and Demiral, 2012). This helps to mitigate viscous fingering and encourages flow into previously unswept areas, resulting in higher ultimate recovery and reduced CO_2 production. Some shortcomings are attributed to the WAG technique, such as gravity segregation, loss of injectivity, slow oil response, corrosion, and oil trapping (Nasir and Chong, 2009; Christensen *et al.*, 1998; Huang and Holm, 1988). Oil trapping is most problematic in water-wet cores, which have been shown to trap 45% of residual oil after WAG injection. This is significantly greater than oil-wet cores, which were shown to trap less than 5% of residual oil in the same study (Huang and Holm, 1988). The WAG technique is also not suitable for tight or water sensitive reservoirs (Enick and Olsen, 2012).

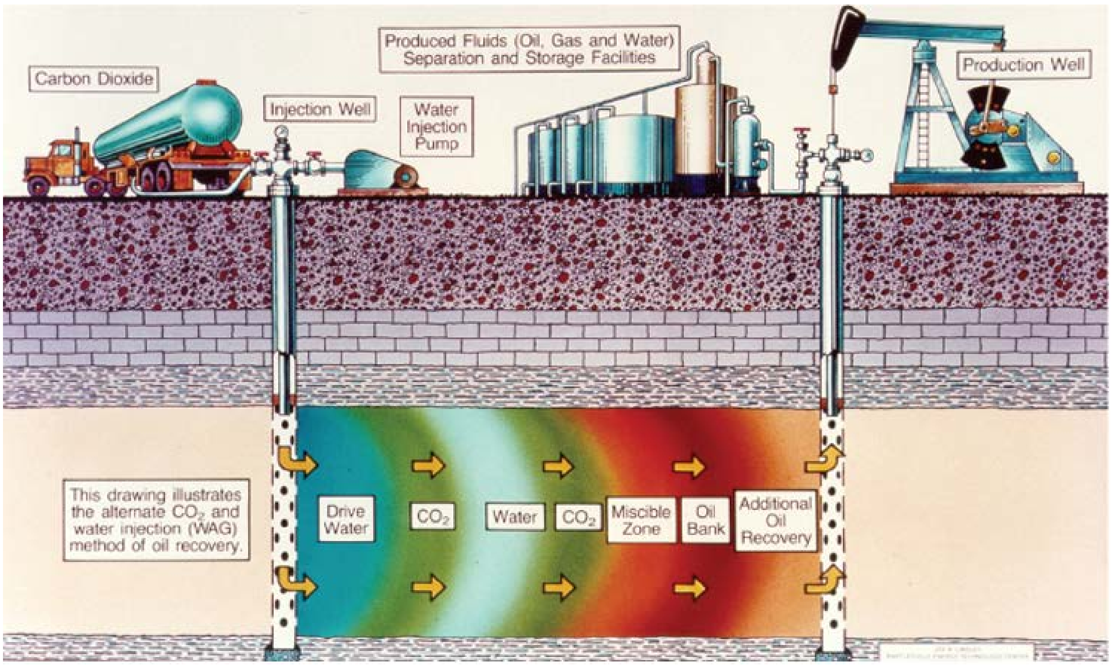

Figure 2.13: Illustration of CO_2 EOR by water alternating gas injection (Grinberg, 2017).

The injection pattern of the wag technique may follow either a traditional or tapered approach. Traditional WAG techniques use a fixed water to CO_2 ratio, commonly 1:1 or 2:1, and slug sizes ranging from 0.1% to 4% HCPV (Enick and Olsen, 2012; Hadlow, 1992). The optimum WAG ratio and slug size has been shown to vary with injection pressure and the mode of displacement (Heidari *et al.*, 2013). Miscible displacement favours low WAG ratios and larger slug sizes, as this promotes contact between CO_2 and oil and will result in less oil trapping. The same is not true for immiscible displacement, as the stability of the front is more important, hence immiscible flooding requires higher WAG ratios and smaller slug sizes to mitigate channelling and early breakthrough (Heidari *et al.*, 2013; Hernandez *et al.*, 2016). Alternatively, tapered WAG does not apply a fixed WAG ratio, but rather decreases the WAG ratio gradually over time (Enick and Olsen, 2012). This approach improves efficiency and prevents early breakthrough, leading to less recycled CO_2 and better oil recoveries; subsequently this approach is the most popular today (Verma, 2015).

A review of WAG field applications by Christensen *et al.* (2001) found that on average the WAG technique improved oil recovery by 10% for CO_2 applications. The majority of these cases were miscible and implemented as tertiary recovery, with few reported unsuccessful. It is also noted that corrosion is a common issue during CO_2 WAG injection, due to the handling of both water and CO_2. This problem is made more difficult by the fact that tertiary floods often take over older facilities, which may have not been designed for such applications (Christensen *et al.*, 2001).

2.3.3 Hybrid Water Alternating Gas (HWAG)

The hybrid WAG (HWAG) technique is a combination of CGI and WAG, aimed at attaining the early production response of CGI and the ultimate recovery of WAG. This is achieved by injecting a predetermined continuous amount of CO_2, followed by intervals of water alternating with gas at some chosen WAG ratio (Hadlow, 1992). Simulation studies confirm that the initial recovery response is better than WAG process (Nasir and Chong, 2009), whilst maintaining a similar

ultimate recovery (Nasir and Demiral, 2012). The initial slug size, which is generally 8-12% HCPV, influences the ultimate recovery, with a smaller initial slug size providing a higher ultimate recovery (Hindi *et al.*, 1992). This technique has been successfully implemented in fields such as the Denver Unit (Shell) and the Dollarhide Unit (Unocal) (Hadlow, 1992).

2.3.4 Simultaneous Water and Gas (SWAG)

Simultaneous water and gas injection is an alternative to WAG, implemented to improve sweep efficiency and reduce operating costs (Nasir and Chong, 2009). This technique requires the simultaneous injection of water and CO_2, such that a two-phase fluid is created is downhole. The mixing itself may be achieved at surface, although mixing downhole is preferred as injectivity is more favourable when injecting one phase at a time (Christensen *et al.*, 2001). Coreflood and simulation studies have shown SWAG injection to be both more efficient and to obtain a higher recovery factor than WAG, HWAG, and CGI (Heidari *et al.*, 2013; Nasir and Chong, 2009; Jaber and Awang, 2017; Nasir and Demiral, 2012). This is accredited to the prior mixing of CO_2 and water, which improves the mobility control of water, and also assists in reducing interfacial tension (Nasir and Demiral, 2012; Heidari *et al.*, 2013). Coreflood studies by Heidari *et al.* (2013) and Nasir and Demiral (2012) report ultimate recoveries of 74.8% and 85% original oil in place respectively. The study by Nasir and Demiral (2012) also showed SWAG injection to reduce residual oil saturation by 0.2 pore volumes, 40% more than WAG.

The SWAG injection technique has been implemented successfully as a miscible flood in Canada's Joffre Viking Pool. Initially program implemented a WAG injection scheme, however the project saw early breakthrough as the WAG technique was unable to effectively control fingering through highly permeable lateral trends. Simultaneous injection of water and CO_2 was shown to stabilise fingering more effectively, however some regions still proved to be beyond control (Pyo *et al.*, 2003).

2.3.5 Gas Assisted Gravity Drainage (GAGD)

Unlike the methods discussed previously, gas assisted gravity drainage (GAGD) is a form of vertical displacement, where gas is injected above the main pay zone and sweeps downwards towards horizontal production wells (Figure 2.14) (Jadhawar and Sarma, 2012). Like CGI, the injected gas plume may be followed by another fluid to assist displacement; alternating fluids are not considered for GAGD (Mungan, 1981b). By implementing a vertical displacement, GAGD takes advantage of the gravity override, which naturally segregates the less dense fluid to the top of the reservoir. The objective is to attain a gravity dominated displacement front, which nullifies the effect of viscous fingering (Hatchell, 2017). This is achieved by injecting CO_2 at a rate lower than the critical rate, which is the rate at which viscous fingering will start to occur (Tiffin and Kremesec, 1988). Through GAGD the displacement front becomes stable, and is able to migrate down the reservoir with maximum sweep efficiency, expanding downwards and sideways as CO_2 is injected (Rao *et al.*, 2004). Aside from improved sweep efficiency, the GAGD technique is advantageous as it eliminates problems such as premature breakthrough and water shielding (Rao *et al.*, 2006), which are associated with the WAG technique. Comparative analysis of GAGD, WAG, and CGI shows that the GAGD technique attains superior tertiary recovery than horizontal methods (Rao *et al.*, 2004).

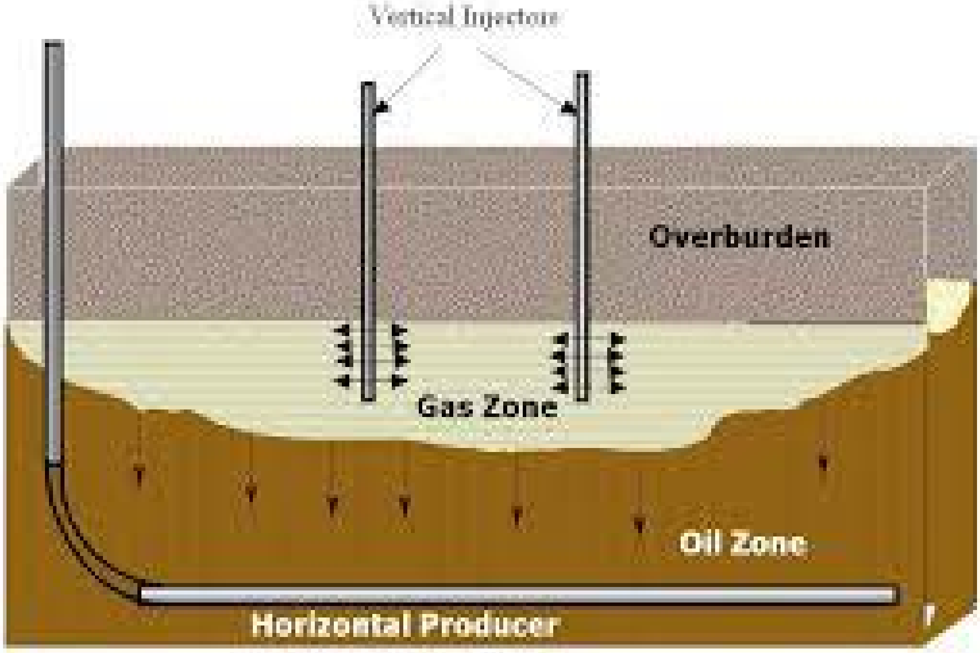

Figure 2.14: Illustration of CO_2 EOR by gas assisted gravity drainage (GAGD) (Dauben International, 2018).

The GAGD technique is best implemented in thick, highly dipping reservoirs, with sufficient vertical permeability (Mungan, 1981b); a steeply dipping reservoir allows the front to remain stable at higher injection rates. Light oil is desirable, preferably above 30°API; excessive channelling has been reported for oils of approximately 20°API (Hatchell, 2017). Immiscible GAGD has also been shown to perform better in oil-wet cores, obtaining 10% higher recovery than their water-wet counterpart. This is attributed to the continuity of oil films in the oil-wet cores, which help create drainage paths (Rao *et al.*, 2006). A trial GAGD flood was implemented in the Bay St. Elaine field in southern Louisiana. The target reservoir was a steeply dipping, fairly homogeneous, 8000-foot sand, with a strong edge water drive (Palmer *et al.*, 1984). The GAGD flood was carried out with two producing wells and one injector well, injecting a solvent of CO_2, methane, and butane at a rate that achieved 70% of the critical velocity. The test proved successful, and was able to achieve an estimated vertical and areal sweep conformance of 75 and 70% respectively. The flood was also able to reduce residual oil saturation to an estimated 5%, down from an original 10 to 20%. For a full review on the GAGD flood of the Bay St. Elaine field see (Palmer *et al.*, 1984).

2.3.6 Direct Thickeners

Early attempts to artificially improve the properties of CO_2 gave rise to the idea of direct thickeners. This involves the dissolution of some material into CO_2 in order to improve mobility by increasing the viscosity of the injection fluid. Ideally the addition of the thickener creates a non-Newtonian fluid, meaning it exhibits shear thinning behaviour such that the viscosity near the wellbore remains low, but increases as the fluid propagates through the reservoir. This will cause the displacing fluid to flow more uniformly into multiple heterogeneous layers, improving the overall sweep efficiency (Enick and Olsen, 2012).

In practice the manufacture of a suitable thickener has proven extremely difficult. The biggest issue is that it is difficult to find a thickening material that will mix with CO_2 under reasonable pressure conditions. This is largely due to the fact that the mechanisms that increase viscosity also hinder dissolution (Enick and Olsen, 2012). Hence mixing requires heat, vigorous stirring, and high pressures, several magnitudes greater than minimum miscibility pressure (Denney, 2013). Some progress has been made, with the application of high molecular weight polymers containing fluorinated compounds (McClain *et al.* 1996). Some of these compounds have been shown to mix with CO_2 under reasonable pressure conditions and increase viscosity up to 500%. However this requires relatively high thickener concentrations, which are not economically feasible. As of 2012 there have been no field tests regarding direct thickeners, as a suitable substance is yet to been found. (Enick and Olsen, 2012)

2.3.7 CO_2 Foam

The injection of CO_2 as a foam was first proposed in the 1960s, and is a method of both conformance and mobility control (Talebian *et al.,* 2014). Similarly to household foams, CO_2 foams are generated by mixing gas, surfactant, and water. This creates a series of dispersed CO_2 droplets, separated by surfactant-stabilised lamellae (Figure 2.15). These components are introduced to the reservoir by alternating injection of surfactant and gas (SAG). The creation and coalescence of the lamellae occurs in situ, due to four main dynamic mechanisms, snap-off, leave behind, mobilisation and division, and gas evolution (Lee and Kam, 2013). These mechanisms rely on the shear created by the tortuosity of the flow path, and are constantly at work to regenerate lamellae as they decay. In order for the process to be effective the rate of generation must exceed the rate of decay (Enick and Olsen, 2012).

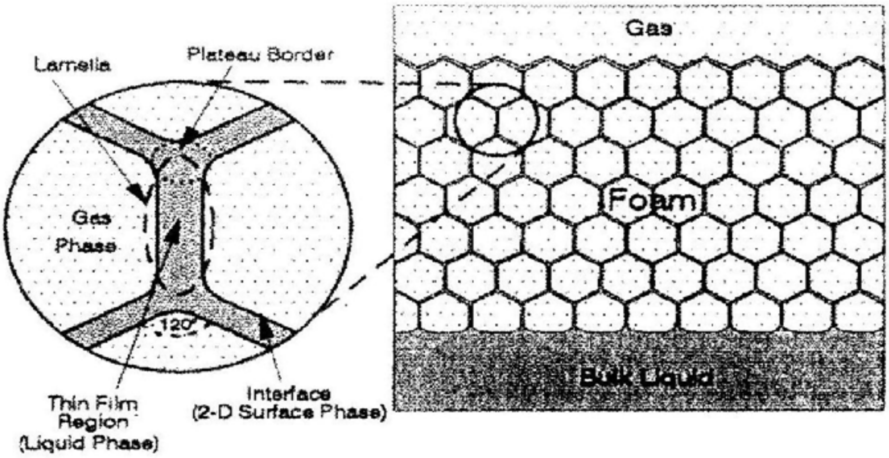

Figure 2.15: Illustration of a generalised foam system (Schramm, 1994).

In the reservoir, the foam is inclined to migrate though larger pore spaces, where it encounters drag forces that cause a significant increase in apparent viscosity. As a result, CO_2 that is not mixed with surfactant will be diverted through smaller pore spaces, improving sweep efficiency. The surfactant can also act to improve oil mobilisation, as the adsorption of the surfactant to the rock surface reduces interfacial tension, thus altering the wettability of the rock (Talebian *et al.,* 2014). The strength of the foam is dictated by whether the intent of the treatment is for conformance or mobility control. If SAG is applied primarily for mobility control, then the goal is to develop weak foam that can be injected for long periods of time and supress viscous fingering. The weak foam is created by using dilute concentrations of surfactant, and is intended to merely match the mobility of the oil, achieving a mobility ratio of unity. If conformance control is the primary objective then the goal is to crate strong foam, of very low mobility, that enters highly permeable thief zones (Enick and Olsen, 2012). This is achieved with higher concentrations of surfactant that can lower mobility by several orders of magnitude (Lee and Kam, 2013). CO_2 foam applied for conformance control is typically intended for short term, near wellbore treatment to divert fluids to regions of lower permeability (Enick and Olsen, 2012).

An example of a field application of CO_2 foam for EOR is the North Ward-Estes (NWE) field, operated by Chevron in Ward and Winkler Counties, Texas; this is known as one of the most successful CO_2 foam field applications (Lee and Kam, 2013). The NWE field consists of sands varying form fine siltstone to siltstone, containing various amounts of clay. The reservoir is highly stratified with large variation in vertical permeability (Chou *et al.*, 1992). CO_2 EOR was initiated in the NWE field in 1989, however the project had issues with poor sweep efficiency since its initiation; this lead to premature breakthrough and low tertiary recovery. Poor sweep efficiency was attributed to poor conformance control, which was evident due to high injectivity and high rate of CO_2 production at specific wells; conformance issues were thought to be due to the unfavourable vertical stratification. SAG injection was employed with the objective of creating a strong foam to provide near wellbore treatment and divert the displacing fluid from thief zones. Surfactant injection was alternated with CO_2 daily (one day surfactant, one day CO_2). The application of CO_2 foam proved highly successful for conformance control, and was able to reduce injectivity by 40 to 85% for up to six months. The results of foam injection were also seen at the producing wells, as the problem well experienced a sharp decline in gas production (Chou *et al.*, 1992).

2.3.8 Well Placement

The location of producing wells relative to surrounding injection wells must be considered in order to improve sweep efficiency. When considering horizontal flooding, the arrangement of wells and the distance between wells must be designed based on geological factors, economic limitations, and oil recovery potential (Verma, 2015, Mungan, 1981a). Common well patterns for horizontal displacement are five, seven, and nine spot wells (Figure 2.16), with five spot patterns shown to provide maximum recovery for various reservoir heterogeneities (Shehata *et al.,* 2012). Some injection schemes may also implement a curtain or line pattern, depending on surrounding geological conditions (Shapiro, 2016b}. Throughout the life of the field well patterns are likely to change, as variations in well placement will be implemented to create new fluid flow paths (Wallace *et al.,* 2013).

In cases of high heterogeneity, horizontal wells may be favoured over vertical wells to increase injectivity and fluid contact (Shehata *et al.,* 2012; Wallace *et al.,* 2013). The effectiveness of horizontal wells is optimised when they are positioned in lower sections of the production zone (Shehata *et al.,* 2012). Horizontal wells are also highly advantageous for vertical displacement, where well placement should encourage the flood to maintain a horizontal front. This is best achieved when wells are regularly placed, in an arrangement such as a line drive (Jadhawar and Sarma, 2012).

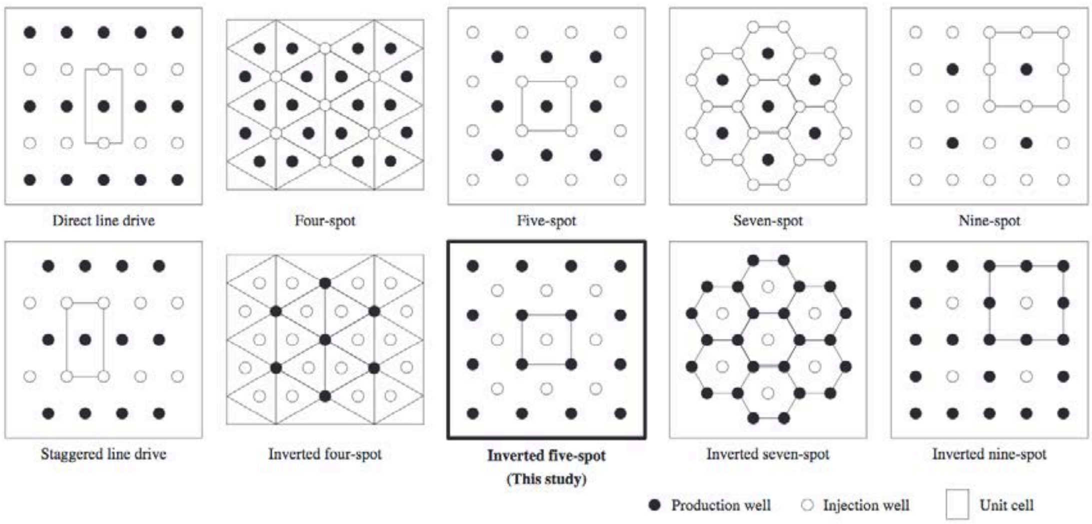

Figure 2.16: Typical CO_2 EOR well patterns (Li *et al.,* 2014).

2.4 The Residual Oil Zone

The residual oil zone (ROZ) describes a naturally occurring section of the reservoir, which cannot be produced by primary or secondary recovery (Aleidan *et al.*, 2017). Traditionally this section of the reservoir was neglected, as the oil was deemed unrecoverable, however, due to the development of EOR, these sections are now being targeted, in some cases as the primary recovery objective. Conventionally the ROZ is located beneath the main pay zone (MPZ) of a reservoir, below oil water contact (OWC) (Melzer *et al.*, 2015). Terminology may permit the ROZ to also include the transition zone (TZ), the thin region below the MPZ where capillary forces allow mobile oil and water to exist together in equilibrium (Melzer *et al.*, 2015) (Figure 2.17). A ROZ zone can also exist by itself, unaccompanied by a MPZ; this is known as a greenfield.

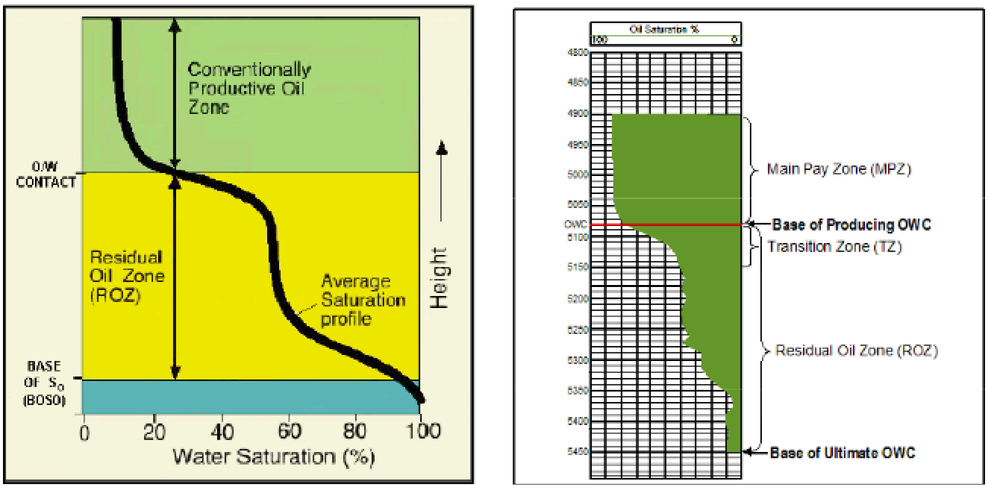

Figure 2.17: Type logs, illustrating the ROZ in the Seminole (left image) and Denver (right image) units (Melzer *et al.*, 2006).

2.4.1 Formation of the ROZ

Residual oil zones are formed following a geological waterflood, in which a natural change in hydrodynamic conditions causes trapped oil to be displaced by water. Changes in hydrodynamic conditions stem from tectonic activity, which may cause uplifts and faults (Melzer *et al.*, 2006). Formation of the ROZ is discussed in depth by Melzer *et al.* (2006), and involves at least one the following three processes; each process considers an initially thermodynamically stable formation, with a water saturation of 100% below the transition zone. Figure 2.18 depicts these processes.

- Regional or local basin tilt (Type 1):
  Regional basin tilt causes displacement of oil to a spill point via a natural water drive. The position of the oil water contact is gravity controlled, hence it is shifted upwards but remains horizontal (Trentham *et al.*, 2012). The resulting ROZ is wedge shaped, and can contain large volumes of oil if tilt is significant or if the initial reservoir is extensive (Melzer *et al.*, 2006).

- Breached and reformed seals (Type 2):
  In this case loss of oil is due to a seal breech, which may occur due to a build-up of fluid pressure or fault reactivation. The seal may or may not reform before significant fluid is lost; the process will leave a zone of residual oil below the oil water contact (Trentham *et al.*, 2012).

- Altered hydrodynamic flow fields (Type 3):
  Displacement of oil due to hydrodynamic flow fields is the most common form of ROZ formation in Texas' Permian basin, where residual oil zones have been investigated extensively. This arises due nearby or distant uplift, generating hydrodynamic forces that allow water to sweep the formation laterally and exit down-dip of the formation; the cross-flow between the MPZ and ROZ creates a tilted oil water contact. The path of water migrating through the subsurface has been termed fairways, which have been mapped

thoroughly in the Permian basin. Research has identified that fairways follow paths of favourable porosity and permeability, which explains why fairways may only sweep lower portions of the reservoir (Trentham *et al.*, 2012).

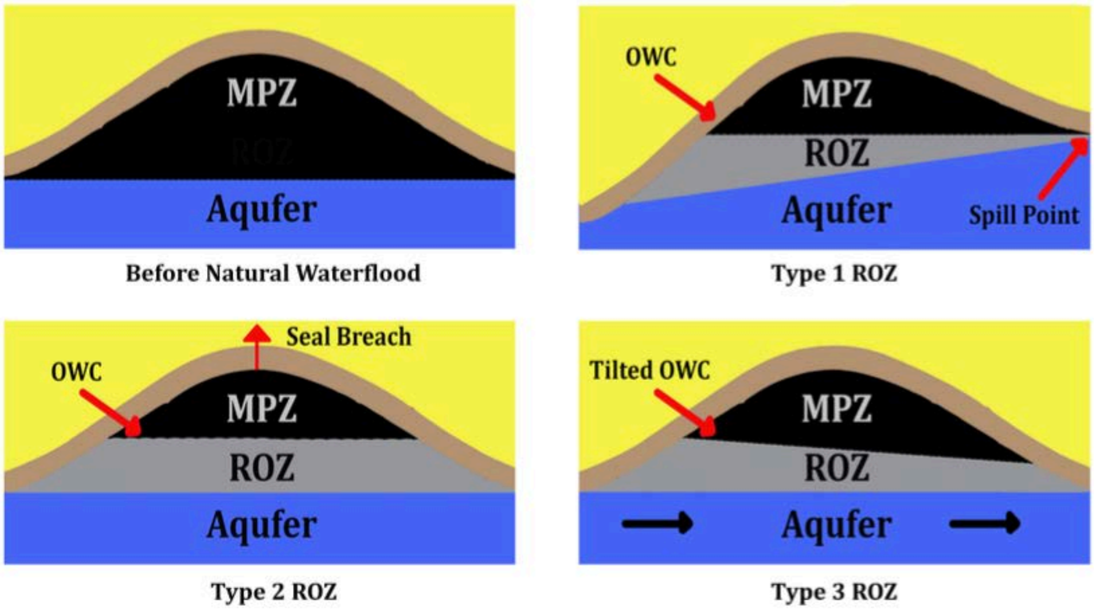

Figure 2.18: Processes of ROZ formation (natural waterflood) (adapted from Melzer *et al.*, 2006).

In many ways a geological waterflood is analogous to a conventional waterflood, however the geological waterflood is generally slower, more efficient, and introduces greater amounts of water (Trentham *et al.*, 2012). After approximately 20 pore volumes of flushing the geological waterflood will have reached maturity and the oil saturation of the swept region will have fallen to the residual oil saturation (Harouaka *et al.*, 2013). At this stage only capillary held oil remains in the swept region of the ROZ and the oil is considered immobile. Intuitively, residual oil saturations in the ROZ and MPZ are very similar (Koperna and Kuuskraa, 2006). Like an artificial waterflood, the conformance of a geological waterflood is imperfect and sweep efficiency can be poor. This results in an erratic oil saturation profile through the ROZ, as it contains both swept and upswept regions (Harouaka *et al.*, 2013). Generally the porosity and permeability are also comparable between the two regions (Melzer *et al.*, 2006), however if the ROZ was formed by meteoric sweep, the quality of the ROZ may be superior to the MPZ. This is in part due to the fact that fairways have a tendency to sweep higher quality reservoirs, but also may be attributed to biogenic processes that follow the geological waterflood (Melzer *et al.*, 2015). With regards to the oil from the MPZ and ROZ, a study by (Aleidan *et al.*, 2017) concluded that the oil in both regions is of the same source and hence has similar properties. The study found no significant difference between the API range, apparent viscosities, types of light volatile components, and abundance of medium and heavy components in either hydrocarbon; however lighter components are in less abundance in the ROZ (Aleidan *et al.*, 2017).

Identifying and characterising potential residual oil zones requires a great deal of data below OWC, which may prove challenging as typically the ROZ zone is not well defined (U.S Geological Survey, 2017). Determining the feasibility of producing from a ROZ requires reliable estimates of oil and water saturation, oil and water properties, and formation properties such as porosity and permeability (Honarpour *et al.*, 2010). A detailed guide can be found in Trentham *et al.* (2015) which discusses the steps required in order to identify potential ROZs; a summary of the process outlined in Trentham *et al.* (2015) can be seen in Appendix A.

2.4.2 Producing from the ROZ

Currently in North America there are several CO_2 EOR projects that are successfully producing from the residual oil zone. These projects are primarily in the Permian Basin of West Texas and South-Eastern New Mexico, however projects in other regions of North America are beginning to gain momentum. As the residual oil zone is comparable to the main pay zone of a maturely waterflooded formation, the same CO_2 EOR mechanisms apply, however certain design considerations must be made when considering CO_2 injection into the ROZ, especially in a

brownfield. For example modeling of the Wasson Denver Unit and the Wasson Bennet Ranch Unit has shown that is beneficial to flood the MPZ and ROZ simultaneously, and to only produce the upper 60% portion of the ROZ. This creates a more uniform distribution of pressure between the two zones and limits out of zone CO_2 flow (Koperna and Kuuskraa, 2006). The remainder of section will discuss two cases where CO_2 injection has been implemented in the residual oil zone, one in a brownfield and the other in a greenfield.

Seminole San Andreas Unit (Hess Corporation)

The Seminole field is located in the Permian Basin of West Texas and is an example of ROZ production in a brownfield. The formation mainly consists of dolomite, with moderate amounts of anhydrite and occasional stylolites (Honarpour *et al.*, 2010). Trapping is structural, with simple broad anticlinal closures (Koperna and Kuuskraa, 2006); the estimated OOIP is one billion barrels of oil. Primary production began in 1936 and continued for 33 years, producing 120 million barrels of oil. Secondary production followed, with a successful waterflooding scheme that produced a further 340 million barrels of oil. Tertiary production was implemented 13 years later, with CO_2 flooding of the main pay zone (Melzer, 2013). Production from the MPZ is predicted to last until 2025, at which time the recovery factor is forecasted to be approximately 65% of the OOIP in the MPZ (Melzer, 2013). The production history of the Seminole Field shows a typical three-peak shape (Figure 2.19), demonstrating a textbook three-stage production strategy (Melzer, 2013).

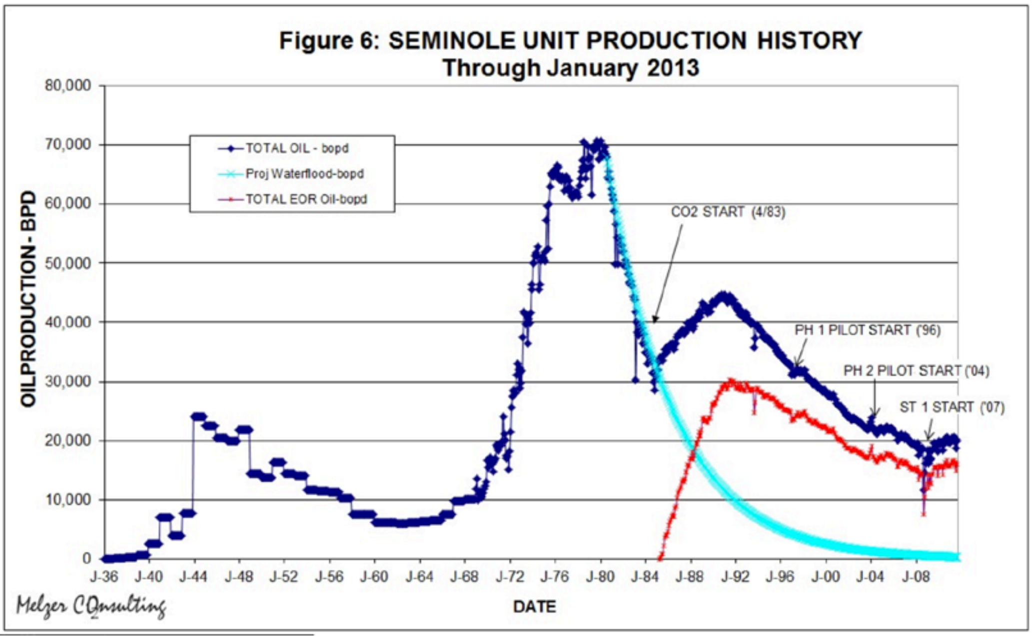

Figure 2.19: Production history of the Seminole Unit (Melzer, 2013).

In the 1980's the operators observed a tilted OWC, and a thick ROZ was discovered (Melzer, 2013). Rock and fluid parameters (Table 2.1) were obtained through coring, testing, and modeling; recovered cores included one pressure core and four sponge cores. Further analysis, including core flood test, slim tube tests, and PVT analysis, was performed to describe the response to CO_2 injection. A full discussion of the processes used and the results obtained can be found in Honarpour *et al.* (2010). The key findings of the study are that cores show significant heterogeneity at the millimeter scale, but less variation at larger scales, with moderate vertical to horizontal permeability in the ROZ (which may help reduce the gravity override). As expected low quality regions contain higher residual saturation than high quality rocks; residual saturation after miscible CO_2 flooding was found to be 12%, recovering an additional 31% of OOIP post waterflood. Lastly the ROZ was found to be mixed wet, with a tendency towards oil wet, and has a water oil relative permeability curve similar to the MPZ (Honarpour *et al.*, 2010).

Table 2.1: Rock and fluid parameters of the Seminole Unit ROZ (Honarpour et al., 2010).

Property	Porosity (%)	Permeability (mD)	Water Saturation (%)	API Gravity	Oil Viscosity (cP)	Residual oil saturation to miscible CO_2 injection (%)
Average	12.8 – 15	15	68	30	1.21	12.3
Range	2 - 30	0.01 - 400	60 - 80	-	-	-

A pilot study was commissioned in 1996 to see the response of the ROZ to CO_2 injection. Later named Phase I, the pilot study implemented four 80 acre 2:1 line drive patterns, with commingled producers and injectors between the MPZ and the ROZ (Honarpour *et al.*, 2010; Melzer, 2013). The results of Phase I were encouraging, but did present some issues involving injection into the ROZ (Melzer, 2013). A second pilot study (Phase II) was implemented in 2004, this time implementing nine 40 acre inverted 5 spot patterns, with commingled production wells but new injection wells, injecting only into the ROZ (Honarpour *et al.*, 2010; Melzer, 2013). The success of the pilot studies prompted a full field expansion in the Seminole Field, which was implemented in 2007. The project is currently in stage four, with a total of 65 80 acre inverted five spot patterns, with commingled producers and dedicated ROZ injectors. The production decline curve (Figure 2.19) demonstrates the effectiveness of the project, however production is being limited by a shortage of CO_2. Current models predict that production from the ROZ will continue for another 25 years, and is projected to produce 22.5% of the 960 million barrels originally in place in the ROZ (Melzer, 2013).

Tall Cotton Fairway (Kinder Morgan)

Located in Gains County, Texas, the Tall Cotton Project is the industry's first attempt at producing from a greenfield via CO_2 injection. This greenfield, known as the Tall Cotton Fairway, was formed by a type 3 process, and is also part of the San Andreas ROZ fairway (Godec and Kuuskraa, 2017). The field is located at a depth of approximately 5250 feet and extends to approximately 5950 feet. Within this region lies thick dolomite, with a porosity of 12%, and a saturation of between 30% and 50%; net pay is considered to be 450 feet (Kuuskraa, 2017). Development of this field began relatively recently, with the first phase (Phase I) commencing in late 2014. The project is currently in its second phase (Phase II), which began in late of 2016 (Seeking Alpha, 2018). Daily oil production can be seen in Figure 2.20; as of 2017 the Tall Cotton project has produced 1.1 million barrels of oil (Seeking Alpha, 2018).

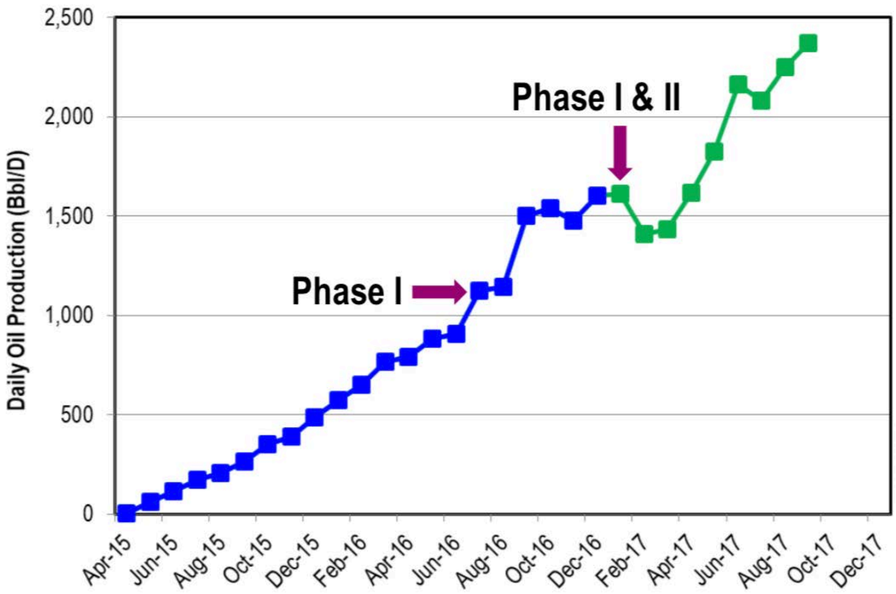

Figure 2.20: Daily oil production in the Tall Cotton Field (Kuuskraa, 2017).

The implementation of Phase I cost 90 million dollars, and required sixteen production wells and fifteen injection wells. This included five water curtain containment wells, and together formed an inverted five spot pattern. Phase I production peaked in January of 2017, at approximately 1600 barrels per day, falling short of the projected 2300 barrels per day. Phase II, implemented in November of 2016, plans on the installing an additional 24 producing wells and 15 injection wells. As of the beginning of 2018, 10 injection wells and 16 production wells have been drilled and completed. Phase II is attempting to implement a staggered line drive, which is thought to be a reaction to the underachievement of Phase I. Phase II is projected to cost a further \$55 USD (Seeking Alpha, 2018). The injection patterns of phase I (P1-P16) and Phase II (P17 – P26) can be seen in Figure 2.21.

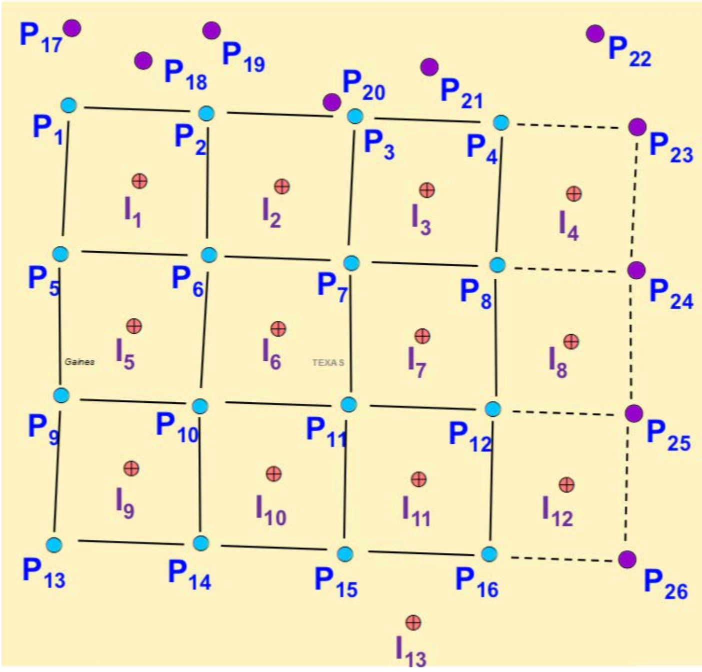

Figure 2.21: Injection patterns of Phase I and Phase II (Kuuskraa, 2017).

2.5 Identifying Candidates for CO_2 EOR

Identifying candidates for a CO_2 flood is an iterative process, which requires a combination of laboratory studies, field tests, modelling/simulation studies, and comparative assessments of similar field cases. In the interest of efficiency the identification process involves initially eliminating candidate reservoirs using vague, inexpensive methods such as screening, before narrowing candidates down via more expensive means, such as field tests, lab tests, and simulation studies. The order and intensity in which the studies are conducted is dependent on the scale of the project, and the readily available data; steps are often revised as more new information is discovered about the field (Johns and Dindoruk, 2013). The general steps of field identification are as follows:

1. Assemble database:
   It is important to first assemble an up to date, consistent, and comprehensive database in order to reliably screen reservoirs, make more accurate predictions, and provide inputs to reservoir models (ARI, 2006). An example of the database inputs used in a study by Advanced Resources International (ARI, 2006) can be seen in Appendix B.

2. Basic technical and economic screening:
   Screening involves loosely assessing the suitability of the field for CO_2 EOR, based on technical and economic criteria established from previous successful projects and laboratory tests. This is an inexpensive process, designed to eliminate obvious fields that are unsuitable to CO_2 EOR. Criteria are kept purposely vague in order to avoid eliminating potential candidates, and to ensure screening remains inexpensive. Generally screening criteria includes properties such as reservoir depth, oil gravity, oil viscosity, minimum miscibility pressure, reservoir pressure, reservoir temperature, and oil saturation.

3. Laboratory studies & reservoir simulation:
   Laboratory studies and reservoir simulation are conducted to gain a better understanding of a specific field, and to obtain data missing from the database. Laboratory studies may include standard PVT analysis, core analysis, swelling tests, slim tube tests and multi contact tests (Johns and Dindoruk, 2013). Pressure cores are usually required to properly assess oil saturation at reservoir conditions. Reservoir simulation is conducted in order to estimate oil recovery and make performance predictions (Johns and Dindoruk, 2013).

4. Economic and risk assessment:
   Economics and risk assessment should consider investment capital and operating costs, which can be calculated by simulation or comparison to analogous projects (Johns and Dindoruk, 2013). Investment costs include purchasing water, gas and surface equipment, installing pipelines, drilling new wells, reworking existing wells, proving surface equipment, and installing recovery plants. Operating costs include regular maintenance, labour, purchasing chemicals, cost of compressing CO_2, and the cost of capturing, separating and reinjecting CO_2 (ARI, 2006; Johns and Dindoruk, 2013). Neal *et al.* (2010) provides a detailed report, estimating the costs of CO_2 transportation and injection in Australia.

5. Pilot study:
   The purpose of a pilot study is to gather information about operational and field problems that laboratory and simulation studies may not be able to anticipate. A pilot study also helps demonstrate applicability the CO_2 flood before investing in a field wide application (Mungan, 1981b).

This report will primarily focus on reservoir screening. Other aspects of the identification process are beyond the scope of the report.

2.5.1 Reservoir Screening Considerations

Reservoir screening considers factors that contribute to achieving miscibility, conformance control, mobility control, and economic success, without the need for reservoir modelling. Some key parameters have been identified, which are known to have a significant effect of the success of a CO_2 EOR project.

Both sandstone and carbonate reservoirs are suitable for CO_2 EOR, provided there is a sufficient volume of oil in place, miscibility can be achieved, and there is not a great deal of fracturing or geological complexity (GHG, 2009; NETL, 2010; Ifeanyichukwu *et al.*, 2014). As discussed in Section 2.3 the wettability and permeability of the formation play major roles in determining the injection strategy. Permeability is generally omitted from screening criteria due to its high variability (Bachu, 2016). It should however remain in consideration, as great variation in permeability generally leads to poor sweep efficiency (Ifeanyichukwu *et al.*, 2014). Natural water drives and gas caps are among other things considered unfavourable, however their absence is not essential to the CO_2 EOR process (Mungan, 1981b). The reservoir must have also demonstrated sufficient sealing and storage capabilities, with consideration given to surrounding wells, as they are likely points of leakage (Whittaker and Perkins, 2013).

Reservoir pressure is an important factor to consider when designing a CO_2 flood, as it directly influences whether miscibility can be achieved and if CO_2 will reach a supercritical state. As current reservoir pressure may be difficult to obtain for numerous reservoirs on a database, screening generally assumes the initial reservoir pressure. Hence, when considering miscible flooding, it is recommended that this initial pressure be greater than the MMP (Kang *et al.*, 2016; Bachu, 2016; Alvarado *et al.*, 2002; Al-Bahar *et al.*, 2004), although significant oil mobilisation may still be achievable at pressures slightly below MMP (TORP, 2018; Shaw and Bachu, 2002). Using initial reservoir pressure is justified by the fact that CO_2 injection is likely restore reservoir pressure close to the initial reservoir pressure (Marston, 2013), and it also ensures that miscibility can be achieved within a realistic pressure range. Injection carried out at a high pressure may cause fracturing of the reservoir, cement or casing failure of nearby wells, early breakthrough, and conformance problems (Mungan, 1981b).

As reservoir pressure and fracture pressure are both functions of depth, depth is also used as criteria to assess the suitability of a reservoir for CO_2 EOR. In general deeper wells are preferable as fracture pressure increases faster with depth than reservoir pressure, meaning MMP and supercritical CO_2 are more likely to be achieved without fracturing the reservoir (Heller and Taber, 1986; Holtz *et al.*, 1999). However operating costs should also be considered as they too increase with depth. Moreover greater depths require more CO_2 to be injected, as the CO_2 volume decreases due to compression (Holtz *et al.*, 1999). Minimum depth is generally considered to be 600-800 metres for miscible flooding (Al-Bahar *et al.*, 2004), however miscible floods have been implemented as shallow as 490 metres (1600 feet) (Koottungal, 2012). For this reason Shaw and Bachu (2002) recommends that depth not be used as a blanket screening criteria for miscible flooding.

The characteristics of the reservoir fluid greatly affect both the sweep efficiency and the ability of the fluid to achieve miscibility. The ideal reservoir fluid is comprised of a high percentage of C_5 to C_{12} components (Holm and Josendal, 1982) and contains little asphaltene content, especially in reservoirs of low permeability (Mungan, 1981b). Oils of high viscosity should be avoided as this amplifies viscous fingering due to an unfavourable mobility ratio (Bachu, 2016; Kang *et al.*, 2016). Miscible flooding is favourable in light-medium oils, preferably greater than 22^{o}API (Kang *et al.*, 2016; Bachu, 2016; Taber *et al.*, 1997b; Al-Bahar *et al.*, 2004), whilst heavy oil, with API gravity ranging 13 to 22^{o}API, may be considered for immiscible flooding (Taber *et al.*, 1997b, Al-Bahar *et al.*, 2004). Shaw and Bachu (2002), and Holtz *et al* (1999) both doubt the suitability of extremely light oils for CO_2 EOR, stating that they may see problems with miscibility and conformance respectively; although insufficient evidence has been found to support either claim.

Factors such as reservoir thickness, residual oil saturation, and original oil in place (OOIP) are all factors to consider when estimating potential recovery, and are included in screening criteria as economic considerations (Bachu, 2016). As these factors do not influence the technical feasibility of installing a CO_2 flood they should be considered in the economic analysis, along with other economic factors such as price of oil, government incentives, and cost of CO_2 procurement, transportation and injection.

2.5.2 Screening and Ranking Criteria

Numerous sets of screening criteria have been developed over time, using data from previous successful CO_2 EOR projects and from reservoir simulation. This should be considered as a preliminary assessment; further testing and analysis is required in order to achieve a successful field application (Mungan, 1981a). Table 2.2 shows previously suggested screening criteria for miscible flooding and Table 2.3 shows previously suggested screening criteria for immiscible flooding. Criteria for immiscible flooding is far less developed, as immiscible flooding occurs less often than miscible flooding.

Table 2.2: Previously suggested screening criteria for miscible CO2 flooding.

Reference	**Kang *et al.* (2016)**	**Bachu (2016)**	**Brashear *et al.* (1978),**	**Taber *et al.* (1997)**	**Alvarado *et al.* (2002)**	**Al-Bahar *et al.* (2004)**
Oil Viscosity (cP)	<6	0.4 - 6	< 12	< 10	< 15	< 10
Oil Gravity API	>22	22 - 45	> 26	> 22	> 25	> 22
Oil Composition				High percentage of C5-C12	High percentage of C5-C12	> 25%
Oil Saturation (%PV)	>17	>26.5		> 20	> 25	
Depth (ft)		1600 - 13,365	NC	> 2500	> 2500	> 600m
Temperature (F)		82 - 260	NC	NC	NC	> 86
Porosity (%)		3 - 37				
Permeability (mD)	Homogeneous preferred		NC	NC	NC	
Net Thickness (ft)	Thin unless dipping		NC	NC	Wide Range	
Reservoir Pressure (PSI)	> MMP	> MMP	> 1500		> MMP	> MMP
Initial Pore Pressure Gradient		< Grad(Smin)				
Gas Cap			None to minor		No	Local or No
Natural Water Drive			None to weak			
Fractures			None to minor			
Already Undergoing EOR	No	No				
Commingled	No	No				
OIIP (MMSTB)		12.5				
Remaining Oil Fraction (%)		>20	>25			
Remaining Oil Fraction (MMSTB)		>5				

Table 2.3: Previously suggested screening criteria for immiscible CO2 flooding

Reference	**(Taber *et al.*, 1997b)**	**(Taber *et al.*, 1997a)**	**(Al-Bahar *et al.*, 2004)**
Oil Viscosity (cP)		< 600	
Oil Gravity API	13 - 21.9	> 13	> 13
Oil Composition		NC	
Oil Saturation (%PV)		> 35%	> 50%
Depth (ft.)	> 1800	> 1800	> 200m
Gas Cap			Local or No
Natural Water Drive			No

Screening criteria should not be taken out of context and it is important to identify the reason for each category and limiting values. As screening criteria are constantly evolving, with newer criteria inheriting values from older criteria, the rationale behind criteria and value selection becomes diluted. The importance of each category is subjective, depending on the goal of the project, be it storage or EOR. Many screening criteria are simply reporting the range of oil and reservoir properties of fields that have undertaken CO_2 EOR, which is not significant justification to rule out potential reservoirs outside of this range. Moreover the ranges themselves are not absolute, and a binary assessment of reservoirs may rule out perfectly suitable fields. To address these shortcomings Rivas *et al.* (1994) performed simulations in order to assess which factors most influence performance. The factors assessed were temperature, pressure, porosity, permeability, dip, API gravity, oil saturation, net oil sand thickness, minimum miscibility pressure, saturation pressure, remaining oil in place, and reservoir depth. The study concluded that the most influential factors were API gravity, oil saturation, and reservoir pressure. It is then proposed that the optimal values of these factors should be used to rank the suitability of reservoirs, where reservoirs with properties closer to optimal values are ranked higher; the results should later be analysed in a subjective manner. The optimal values proposed by Rivas *et*

al. (1994) are displayed in Table 2.4; note that these values were determined by considering a base case of 2000 MSCF of injected CO_2 per day, in an inverted five spot pattern over forty acres.

Table 2.4: Results of Rivas et al. (1994).

Parameter	Optimum	Weight
API gravity	37	0.24
Temperature (°F)	160	0.14
Permeability (mD)	300	0.07
Oil saturation (%)	60	0.20
Pressure/PPM	1.3	0.19
Porosity (%)	20	0.02
Net oil sand thickness (ft.)	50	0.11
Dip (degree)	20	0.03

Dongfeng *et al.* (2014) conducted a similar study to assess the low permeability reservoirs of the Changqing oilfield in China. The study considers reservoir thickness, dip angle, temperature, pressure, depth, porosity, heterogeneity, saturation, fracture development degree, and permeability, using an inverted nine spot pattern (eight production wells surrounding one injection well. The results of the study are displayed in Table 2.5. Table 2.4 and Table 2.5 show effective reservoir thickness to be the most influential factor. The difference in results between Rivas *et al.* (1994) and Dongfeng *et al.* (2014) suggests that the sensitivity of factors varies with field properties.

Table 2.5: Results of Dongfeng et al. (2014).

Parameter	Optimum	Weight
Effective reservoir thickness (m)	1	0.219
Formation pressure (MPa)	25	0.190
Average reservoir permeability (mD)	1.5	0.157
Initial oil saturation (%)	65	0.193
Density of fluid (kg/m³)	700	0.120
Viscosity of fluid (mPa.s)	1	0.120

2.5.3 Calculating Minimum Miscibility Pressure

Minimum miscibility pressure is dependent on the reservoir temperature, composition of the displacing fluid, and composition of oil. The most influential properties that affect miscibility are reservoir temperature and the proportions of the heavier components of oil. Yuan *et al.* (2005) demonstrated a convex relationship between temperature and MMP, where the shape of the curve is dictated by the average molecular weight of C_{5+} components of the hydrocarbons. MMP is generally lower for hydrocarbons containing a higher proportion of C_5 – C_{12} components (Holm and Josendal, 1982), although this is untrue when considering multi ring aromatic compounds, as they do not disperse into the CO_2 phase as easily as other components of comparable size (Hagedorn and Orr, 1994). MMP is also influenced by the proportions of volatile and intermediate compounds in both the displacing fluid and the oil. Volatile components (CH_4, N_2) have been shown to hinder miscibility, while intermediate components (C_2, C_3, C_4, CO_2, H_2S) aid miscibility (, 2009). This is an important fact to consider when deciding on the purity of the injection fluid, as although pure CO_2 may not be necessary, impurities may drastically lower MMP.

Accurate estimates of minimum miscibility pressure can be made through laborious reservoir simulation and laboratory studies, such as slim tube tests, vanishing interfacial tests (VIT), and rising bubble tests. Alternatively, MMP can be predicted, less accurately but far more efficiently with certain correlations, which are based on past laboratory and simulation experience. It is important to note however that applying correlations to regions dissimilar to the source of the correlation introduces significant error to the calculations. This error was noticed by Clark *et al.* (2008), when comparing a variety of correlations to the results of slim tube testing, conducted on hydrocarbons from the Tarrawarra field of Australia's Cooper Basin. The study identified correlations by Alston *et al.* (1985) and Yuan *et al.* (2005) to be the most accurate correlations to predict MMP of Tarrawarra oil, with a percentage error of -17.09% and 10.99% respectively. An alternative MMP correlation was proposed by Emera (2006) in a study at the University of Adelaide. This correlation was created with data from reservoirs including the Cooper and Eromanga Basins (Bon, personal communication); although no studies were found that compared MMP calculated from the Emera (2006) correlation to MMP calculated through slim

tube testing. The Alston *et al.* (1985), Emera (2006), and Yuan *et al.* (2005) correlations can be found in Appendix C.

2.6 CO_2 EOR in the Cooper-Eromanga Basin

The Cooper Basin is Australia's largest onshore oil and gas province, and combined with the overlaying Eromanga Basin, shows high potential for becoming a target for CO_2 EOR. Since production began in the 1960's the region has produced over 5.5 Tcf of gas and 255 million barrels of oil, with an estimated 7 Tcf of proven gas and 320 million barrels of recoverable liquids remaining (Radke, 2009). The combined average primary and secondary recovery factor is expected to be approximately 21% (Alexander, 1999), leaving a significant amount of hydrocarbons to be produced. The Cooper Basin also produces large amounts of CO_2, with the proportion of CO_2 averaging 17% basin-wide. This has resulted in the release of 1.8 million tonnes of CO_2 into the atmosphere through gas production alone (Radke, 2009).

Implementing CO_2 EOR in the Cooper-Eromanga Basin system has been proposed since the 1980s, however, as of yet, it has never materialised. Recently interest into CO_2 EOR in Australia has resurfaced, which is likely due to a combination of declining production in the Cooper-Eromanga Basin system (Figure 2.22) (Core Energy Group, 2016), the potential for CO_2 EOR to recover from residual oil zones, the success of CO_2 EOR seen internationally, and the increasing pressure on the industry to reduce their CO_2 footprint.

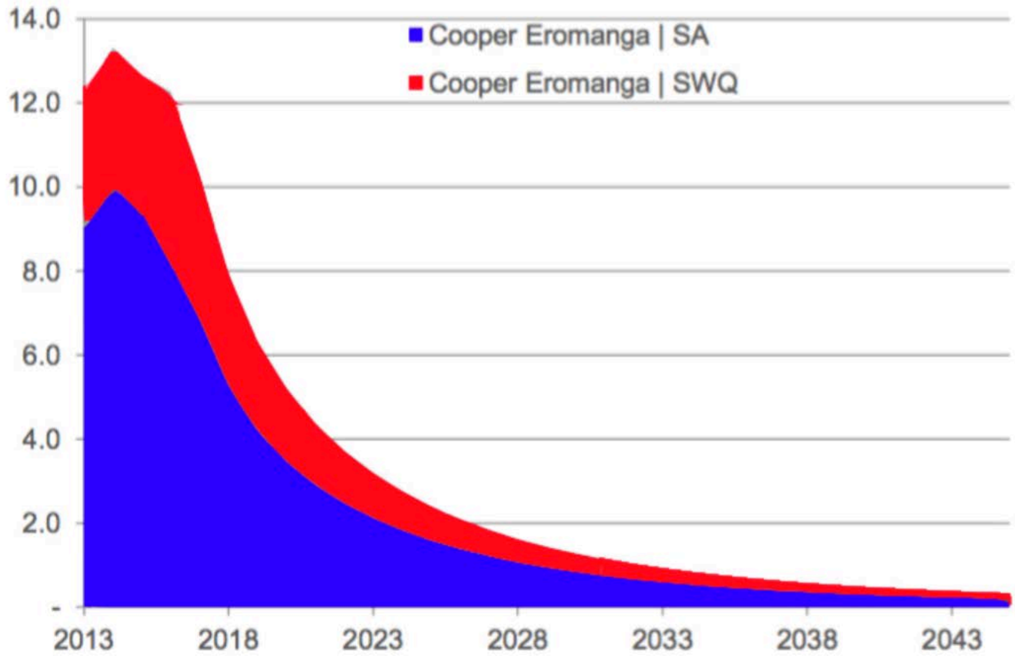

Figure 2.22: Production decline curve of the Cooper-Eromanga Basin System (Core Energy Group, 2016).

2.6.1 Regional Geology

The Cooper Basin is of Late Carboniferous-Triassic origin, with sediments deposited in glacial, fluvial and lacustrine environments (Hall *et al.,* 2016). Key units in the Cooper Basin are, in ascending order, the Merrimellia Formation, the Tirrawarra Sandstone, the Patchawarra Formation, the Toolachee Formation, and the Tinchoo Formation (Appendix D.1). The Tirrawarra Sandstone is the primary oil-producing reservoir, containing 80% of the known oil reserves in the South Australian Region (Alexander, 1999). The Patchawarra and Toolachee Formations contain the main commercial reservoirs in the Cooper Basin (Hall *et al.,* 2015), however these formations primarily produce gas. The Patchawarra, Merrimellia and Tinchoo Formations also contain producible accumulations of oil. Reservoir quality in the Cooper Basin ranges from poor to good, meaning recovery in this region can be difficult. As a result some areas of the Tirrawarra Sandstone have undergone EOR through ethane injection, with some success (Radke, 2009). With regards to seals in the Cooper Basin, exploration generally looks for anticlinal and faulted

anticlinal traps as reservoir seals, but there is high potential for discoveries in stratigraphic and sub-unconformity traps (Alexander, 1999).

The Eromanga basin can be compartmentalised into three sections, the upper non-marine, marine, and lower non-marine (Appendix D.2); hydrocarbon exploration focuses on the lower non-marine section (Alexander, 1999). The lower non-marine section contains Early Jurassic to Early Cretaceous age sediments, deposited in extensive fluviatile and lacustrine environments (Hall *et al.*, 2016). The braided fluvial Hutton and Namur Sandstone are the principal oil reservoirs of the Eromanga Basin, and are of good to excellent quality, with porosities up to 25% and permeability of up to 2500 mD. The McKinlay Member, and the Poolowanna, Birkhead and Murta Formations also produce oil and are considered to have fair to excellent reservoir quality (Alexander, 1999). The trapping mechanisms in the Eromanga basin are primarily structural, with a stratigraphic component. Due to poor sealing characteristics, Eromanga structures are rarely filled to spill point (Alexander, 1999).

Oils and condensates in the Cooper Basin principally originate from Permian age coal and shale, and are considered to be medium to light (30 to 60^{o}API), paraffinic, and have low to high wax contents. Permian oils typically contain significant volumes of dissolved gas, with no evidence of water washing. Oil in the Eromanga Basin originates from either within the Eromanga Basin or within the Cooper Basin, or a mixture of both (Alexander, 1999); although it is widely accepted that vertical migration from the Cooper Basin is the principal source for the majority of oil in the Eromanga Basin. Oils of cretaceous origin are typically light (45^{o}API), non-waxy, low sulphur, paraffinic crudes, whereas oils of Jurassic origin are paraffinic and waxy, and are similar to oils originating form Permian sediments (Alexander, 1999).

2.6.2 Residual Oil Zones

There is a scarcity of literature discussing residual oil zones in Australia, however previous work in the area of seal integrity may allude to the presence of Type 2 residual oil zones. As mentioned above, reservoirs in the Eromanga Basin are rarely filled to spill point (Alexander, 1999), indicating poor trapping characteristics. An extensive study by Boult (1996) investigated the seal integrity of the Hutton, Birkhead, and Namur seals of the Gidgealpa field. The study suggests that vertical migration pathways dominate the Eromanga, due to low capacity regional seals with poor lateral extent. Although there is evidence of meteoric sweep due to uplift in the Great Dividing Range, it is believed that this occurred too late in time for any hydrodynamic regime to have an effect. This meteoric sweep may have skimmed some of the oil from the lower part of previously established columns, however this skimming is not thought to have been sufficient enough to explain the large paleo oil columns seen in Gidgealpa (Boult, 1996).

The study by Boult (1996) has identified that prior to leakage to the Birkhead formation, a paleo oil pool of up to 320 million barrels ($50*10^{6}$ m^{3}) may have existed within the Hutton sandstone. It is also estimated that as much as 300 million barrels ($47*10^{6}$ m^{3}) may have leaked past the Birkhead formation, some of this may have continued to leak up to the Murta formation but this has not yet been identified. The study interpreted that a paleo oil column of 47 m may have existed beneath the Birkhead, indicating a significant portion of residual oil (Figure 2.23).

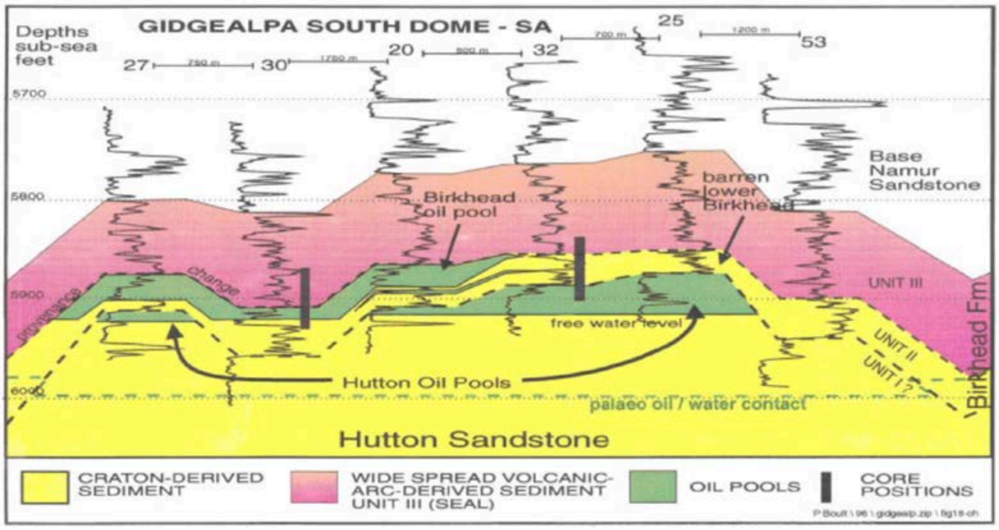

Figure 2.23: Geological interpretation of the Hutton and Birkhead formation in the Gidgealpa South Dome (Boult, 1996).

2.6.3 Challenges and Knowledge Gaps

With deep, tight reservoirs containing light oil of low viscosities, and a source of anthropogenic CO_2 as a by-product of gas production, the Cooper-Eromanga Basin system appears perfectly suited to CO_2 EOR. The prospect of implementing CO_2 EOR in Australia is made more appealing by the fact that projects can take advantage of the wealth of knowledge built up by the industry over the past five decades. However there are still many challenges to overcome and knowledge gaps to fill if CO_2 EOR is to be successful in Australia.

The success of CO_2 EOR in the United States during the 1970's and 1980's is attributed to the availability of cheap sources of CO_2, federal government tax credits and state allowances, and a high oil price. This gave oil companies some financial flexibility, allowing them time to develop experience, refine reservoir screening, improve flood design, build infrastructure, and understand operational problems (Hustad and Austell, 2004). Future CO_2 EOR projects in Australia will not have this luxury, and will have to build up experience through well thought out projects and sound management, all while trying to improve public awareness and the public's perception of CO_2 EOR.

Currently there appears to be a gap in the literature regarding the suitability of CO_2 EOR in the Cooper-Eromanga Basin system. The literature review has failed to uncover any publicly available screening studies of the Cooper and Eromanga Basins, and has only identified a few cases in which miscibility has been investigated in the region through laboratory testing. In addition, little work has been done to identify and characterise residual oil zones, which could become important targets for CO_2 EOR. Another issue identified is that there appears to be no cohesive and inclusive database available that will help to assess the region.

Chapter 3

Methodology

A screening study was performed to assess the suitability of oil producing fields in the Cooper and Eromanga Basins to undergo CO_2 EOR. The objective of this study was to identify fields that have a higher potential to be suitable for CO_2 EOR and therefore should be looked into further, not to define which regions are and are not suitable. This is an important distinction to make as the data and methods used in the calculations contain significant uncertainty, hence do not accurately represent real world scenarios. The following chapter discusses the screening criteria chosen for the study, outlines the methods of data collection and data processing, and identifies the assumptions that were made.

3.1 Selecting Screening Criteria

Screening criteria was selected from previous screening studies, and was also based on the data available. Screening was only conducted for miscible flooding, as fields in the Cooper and Eromanga Basins are deep and contain light oils of low viscosity, hence are not suitable for immiscible flooding. Criteria were only adopted if evidence was found that the property influences the technical feasibility of CO_2 EOR. Criteria based on economic factors, or based on the range of current projects were not considered, as they do not influence the technical feasibility. Table 3.1 lists the criteria that were chosen for screening. Table 3.2 discusses the criteria that were discarded.

Table 3.1: Screening criteria chosen for the study.

Property	Condition	Relevance	Sourced from
Oil API Gravity	> 22	Flood performance	Kang *et al.* (2016), Taber *et al.* (1997a), Bachu (2016), Al-Bahar *et al.* (2004)
Depth (ft)	> 600 m	To achieve supercritical CO_2 and avoid fractures or leaks	Al-Bahar *et al.* (2004)
Temperature (F)	> 31.1°C	To achieve supercritical CO_2	Al-Bahar *et al (*2004), Bachu (2016)
Reservoir Pressure (PSI)	> MMP	To achieve miscibility	Kang *et al.* (2016), Alvaradi *et al. (2002),* Bachu (2016), Al-Bahar *et al.* (2004)

Table 3.2: Screening criteria that were discarded.

Property	Condition	Relevance	Justification for dismissing
Oil Viscosity (cP)	< 10	Favourable mobility	Insufficient data. Also Australian oils are known to be of low viscosity
Oil Saturation (%PV)	> 17	Economic (size of the prize)	Economic consideration and insufficient data
Porosity (%)	3 - 37	Range of current projects	Not critical (Bachu, 2016)
Permeability (mD)	Homogeneous preferred	Prevents channelling	Subjective and high variability (Bachu, 2016)
Net Thickness	Thin unless dipping	Conformance control	Subjective
Initial Pore Pressure Gradient	< Grad (Smin)	Prevents fracturing the reservoir	More important for CO_2 storage than EOR (Kang, 2016)
Gas Cap	None to minor	Added complexity	Not critical (Kang, 2016)
Natural Water Drive	None to weak	Added complexity	Not critical
Fractures	None to minor	Prevents channelling	Subjective and not critical (Kang,

			2016)
Already Undergoing EOR	No	Avoids added complexity	Economic consideration
Commingled	No	Prevents channelling	Insufficient evidence
OIIP (MMSTB)	12.5	Economic (size of the prize)	Economic consideration and insufficient data
Remaining Oil Fraction (%)	> 20	Economic (size of the prize)	Economic consideration and insufficient data
Remaining Oil Fraction (MMSTB)	> 5	Economic (size of the prize)	Economic consideration and insufficient data

3.2 Data Collection

A database was assembled, containing relevant data from all oil producing fields in the Cooper and Eromanga Basins (where available). This data was primarily sourced from publicly available well completion reports, accessed through the South Australian Resources Information Gateway (SARIG). Other data was obtained from the South Australian Petroleum Exploration and Production System (PEPS-SA), however preference was given to the well completion reports when available.

3.2.1 Oil Composition

Oil composition data was found under the hydrocarbon analysis section of the well completion reports. The oil samples were recovered from various locations, such as the manifold, drill string, and bubble hose. Oil composition was calculated by various companies using gas chromatography, whereby the oil sample is heated to vaporisation and injected into a gas chromatograph (Figure 3.1) along with a chase gas. Gas components are carried out of the columns by the inert chase gas, while solid or liquid remains adsorbed to the column. Lighter components transition to the gaseous state more readily, and hence are removed earlier than heavier components; each compound is able to be identified by how long it takes to exit the column. The compounds that exit the system can be identified by a flame ionization detector (FID) or a thermal conductivity detector (TCD) (Freyss *et al*., 1989).

An issue with this method is that it struggles to accurately capture compositions of light components, and heavier components may get stuck in the machine (Bon, personal communication). In addition the data only considers C_2 to C_{27} components, meaning that gas components (CO_2, N_2, CH_4, H_2S) are ignored and heavier components are lumped into a single C_{28+} component. This presents a source of error, which must be recognised.

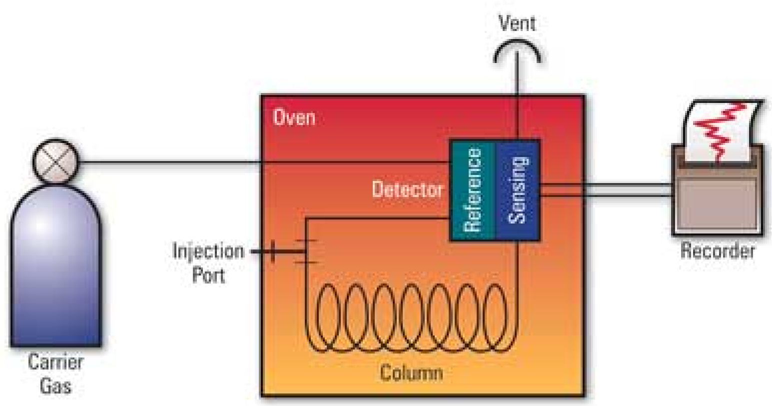

Figure 3.1: Gas Chromatograph (Machinery Lubrication, 2018).

When possible, five sets of oil analysis data were recorded for each formation of each field. Ideally these were obtained from different wells within the field, however in most cases this was not possible due to lack of data. The oil composition was presented in the completion reports as a

weight percentage (Appendix E); occasionally the data also included the average molecular weight of C_{8+} compounds, which was utilised in the calculations when available.

3.2.2 Depth

The depth of the reservoir for each well was found in the completion report, and was taken to be the depth at which the oil sample was obtained from. If this information was not available, the depth was taken to be the middle depth of the formation in that field; this data was obtained from PEPS-SA. If neither sets of data were available, the depth of the reservoir was assumed to be the average depth of the reservoir in surrounding wells.

3.2.3 API gravity

API gravity was obtained from the oil analysis in the completion report, where available. If this could not be found in the completion report API gravity was taken from PEPS-SA.

3.2.4 Reservoir Temperature

Reservoir temperature was taken from measurements in the completion report were available. If not available, temperature was calculated from the temperature gradient given in the completion report, using the depth calculated in section 3.2.2. If no temperature data was found in the completion report, reservoir temperature was taken from PEPS-SA. If none of this data was available, the temperature of the reservoir was assumed to be the average temperature of the reservoir in surrounding wells.

3.2.5 Initial Reservoir Pressure

Initial reservoir pressure was taken from PEPS-SA. If this was not available then the initial reservoir pressure was calculated using a pressure gradient of 0.45 PSI/ft and the depth calculated in section 3.2.2. The assumed pressure gradient was obtained from the available pressure data.

3.2.6 Removing Outliers

Multiple sources of error and inconsistencies in the data resulted in numerous outliers, which needed to be accounted for. Outliers were removed where possible, however considerable restraint was employed to ensure that variability in the data was still taken into consideration. Outliers were only removed if the cause of the discrepancy could be identified beyond a reasonable doubt.

3.3 Calculations

Minimum miscibility pressure (MMP) was calculated using the Alston *et al.* (1985), Yuan *et al.* (2005), and Emera (2006) correlations, which require inputs of reservoir temperature, the average molecular weight of heavy components, and the molar percentage of intermediate components. The Alston *et al.* (1985) and Emera (2006) correlations also require the composition of volatile components in the fluid. As this could not be found in the data, MMP was calculated with and without an assumed 'typical' gas. If the typical gas was not assumed, the proportion of intermediate components and volatile components was assumed to be equal. If the typical gas was assumed, the composition of the typical gas was taken from a high-pressure liquid analysis of the reservoir fluid in Gidgealpa 41 (Table 3.3). The results of each correlation for each reservoir were combined into a distribution in order to capture the relative state of uncertainty; the probability of the reservoir achieving miscibility with CO_2 was then calculated.

Table 3.3: Composition of typical gas.

Component	Weight %	Mol %
Nitrogen (N_2)	0.01	0.07
Carbon Dioxide (CO_2)	0.11	0.43
Methane (CH_4)	0.05	0.95
C_{2+}	99.83	98.55

3.3.1 Molar Percentage

The molar percentage of each component was calculated from Equation 3.1, where $n_{\%}$ is the molar percentage, $m_{\%}$ is the weight percentage, and M is the molar mass. The values for molar mass were either obtained from Engineering ToolBox (2009) or calculated directly.

Equation 3.1: Molar percentage

$$n_{i,\%} = \frac{\left(\frac{m_{i,\%}}{M_i}\right)}{\sum_{i=2}^{28}\left(\frac{m_{i,\%}}{M_i}\right)} * 100\%$$

3.3.2 Average Molecular Weight

Average molecular weight is the weighted average of the molar masses of numerous components in a mixture. This was calculated using Equation 3.2, where MW is the average molecular weight of C_{k+} components, $n_{\%}$ is the molar percentage, and M is the molar mass. To account for the error associated with gas chromatography, the MW_{C8+} value given in the completion report was used, when available. Using this value was found to provide results closer to that of Clark *et al.* (2008).

If the value for MW_{C8+} was not given, a minimum and maximum possible value of MW_{C8+} was assumed. The minimum and maximum possible values were considered to be the calculated MW_{C8+} – 10 g/mol, and the calculated MW_{C8+} + 1 g/mol respectively. These corrections were decided upon after comparing the measured MW_{C8+} values to the calculated MW_{C8+} values.

Equation 3.2: Average molecular weight

$$MW_{CK+} = \frac{\sum_{i=k}^{28}\left(n_{i,\%} * M_i\right)}{\sum_{i=k}^{28}\left(n_{i,\%}\right)}$$

3.3.3 MMP Correlations

The minimum miscibility pressure (MMP) of each set of oil composition data was estimated using the Alston *et al.* (1985), Yuan *et al.* (2005), and Emera (2006) correlations (Appendix C). The Alston *et al.* (1985) and Yuan *et al.* (2004) correlations were chosen based on the study by Clark *et al.* (2008), who identified these correlations as the most suitable to apply to hydrocarbons in the Tirrawarra Field. The Emera (2006) correlation was selected based on the fact that it comes from an Australian study, and was generated in part by using data from the Cooper and Eromanga Basins. This is significant as the aromatics of the hydrocarbons greatly influence the accuracy of the correlation; hence a correlation that was created using data from the region to which it will be applied is favourable. It should however be noted that not all reservoirs fall within the range of data from which these correlations are valid, which is a source of error.

To incorporate the uncertainty in the data a maximum and minimum value of MMP was calculated, if the MW_{C8+} was not given in the completion reports. The maximum and minimum values of MMP were calculated using the maximum and minimum values of MW_{C8+} (see 3.3.2) in the MMP calculation; MW_{C8+} values given in the completion reports were assumed to be correct.

3.3.4 Miscibility

The MMP of each reservoir was estimated by combining the values calculated from the Alston *et al.* (1985), Yuan *et al.* (2005), and Emera (2006) correlations, and expressed as a distribution in order to capture the relative state of uncertainty. The distribution assigned to each MMP calculation was the PERT distribution, a subset of the beta distribution that is defined by the most likely, maximum and minimum value that a variable can take; these values were calculated with algorithms to mitigate a source of bias.

The most likely value of MMP was assumed to be the mean estimated MMP from all correlations. The minimum and maximum values of MMP were assumed to be the lowest minimum, and the highest maximum of all MMP values from all correlations, with a possible further +/- 500 PSI added to account for variability in the data. An additional +/- 750 PSI and +/- 1250 PSI was applied to the maximum and minimum values of the Yuan *et al.* (2005) and Emera (2006) correlations, and the Alston *et al.* (1985) correlation respectively. This was done in order to incorporate the error in the correlations, error in the data, and any unforeseen uncertainty. These values were based on studies by Clark *et al.* (2008) and Bon *et al.* (2005), who compared the correlated MMP values to slim tube tests conducted on oils from the Cooper Basin. Figure 3.2 provides a graphical explanation of how these uncertainties were applied and gives an example of the PERT distribution. Note that the intervals are wide in order to properly capture the relative state of uncertainty. The likelihood of the reservoir achieving miscibility was estimated by considering the probability that the initial reservoir pressure is greater than the estimated MMP. Fields were ranked by their probability of achieving miscibility with CO_2, assuming they passed all other screening criteria.

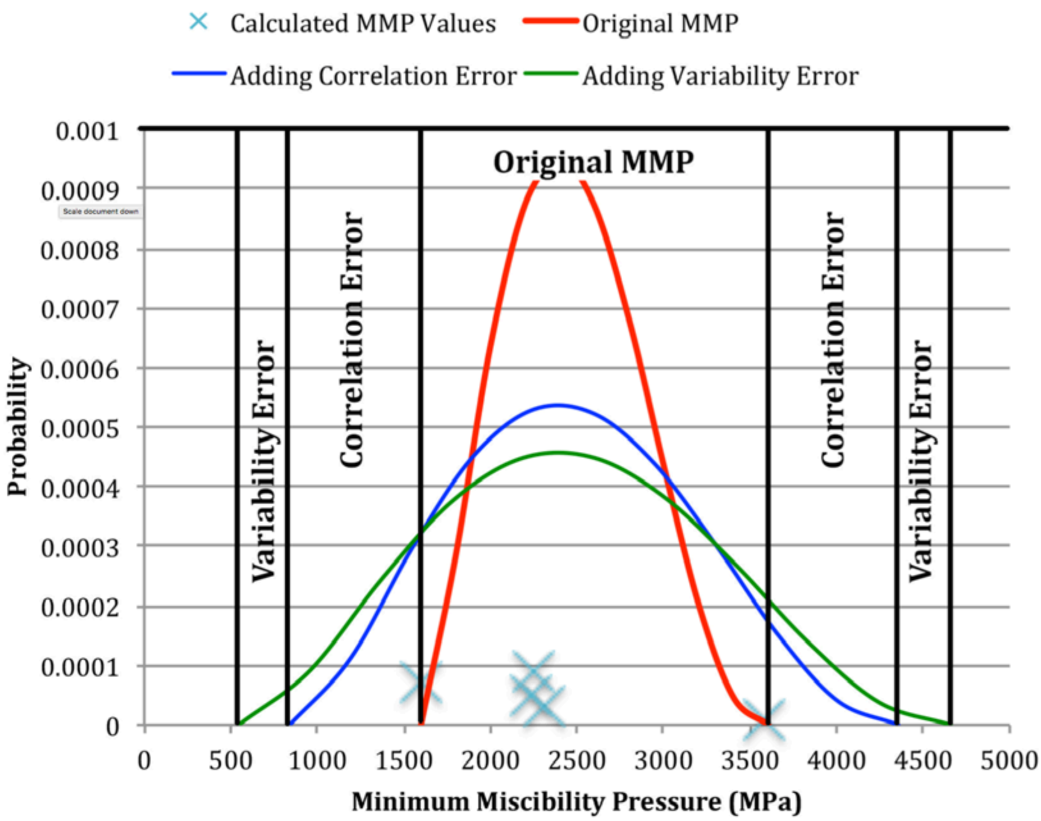

Figure 3.2: Distributions of the MMP of the Fly Lake field, calculated with the Yuan *et al.* (2005) correlation.

Chapter 4

Results

Reservoirs were screened for their suitability of undergoing CO_2 EOR based on their depth, temperature, API, and likelihood of achieving miscibility. The minimum miscibility pressure was calculated using the Alston *et al.* (1985), Emera (2006), and Yuan *et al.* (2005) correlations, which require inputs of temperature and reservoir fluid composition. Uncertainty in the data and in the correlations meant that implementing a binary screening criterion for miscibility, as seen in previous literature, would not accurately represent the system. Consequently the minimum miscibility pressure was expressed as a distribution, where the likelihood of a reservoir achieving miscibility with CO_2 was based on the probability that the initial reservoir pressure exceeds the minimum miscibility pressure. Fields were then ranked based on their likelihood of achieving miscibility with CO_2. The results can be seen in Appendix F. The results show that the investigated fields all pass the depth, temperature, and API criteria, hence only the probability of the field achieving miscibility was used to rank fields.

4.1 Reservoir Characteristics

Figure 4.1 depicts the relationship between reservoir depth, and the initial reservoir pressure and temperature. As expected, both pressure and temperature increase with respect to depth. Initial reservoir pressure and depth show a strong linear relationship, with a pressure gradient of 1.01 MPa/m (0.45 PSI/ft). Reservoir temperature and depth show a reasonably steady linear relationship, with a geothermal gradient of approximately 0.0305°C/m (0.0167°F/ft). Reservoir temperature in the Cooper and Eromanga Basins range from approximately 80 to 140°C.

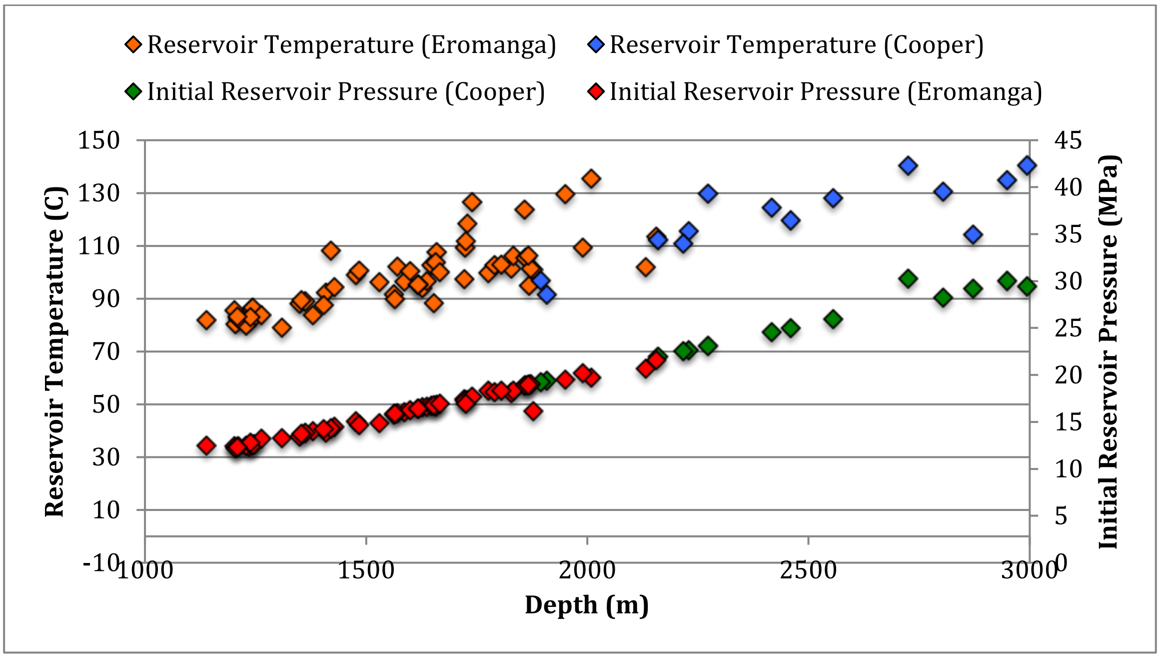

Figure 4.1: Reservoir temperature and initial reservoir pressure verses depth.

4.2 Oil Characteristics

The relationship between oil API gravity and depth can be seen in Figure 4.2. The plot demonstrates a clear distinction between the API gravity of oils in the Cooper and Eromanga Basin. Both sets of data show that API increases with respect to depth; it is unclear whether this relationship is linear as the results are subject to high variability. The figure also shows that shallower regions of the Cooper Basin contain oils with API gravities below 40°API, while deeper regions contain oils with API gravities above 47 °API. Oils in the Eromanga basin range from 40 to 55°API.

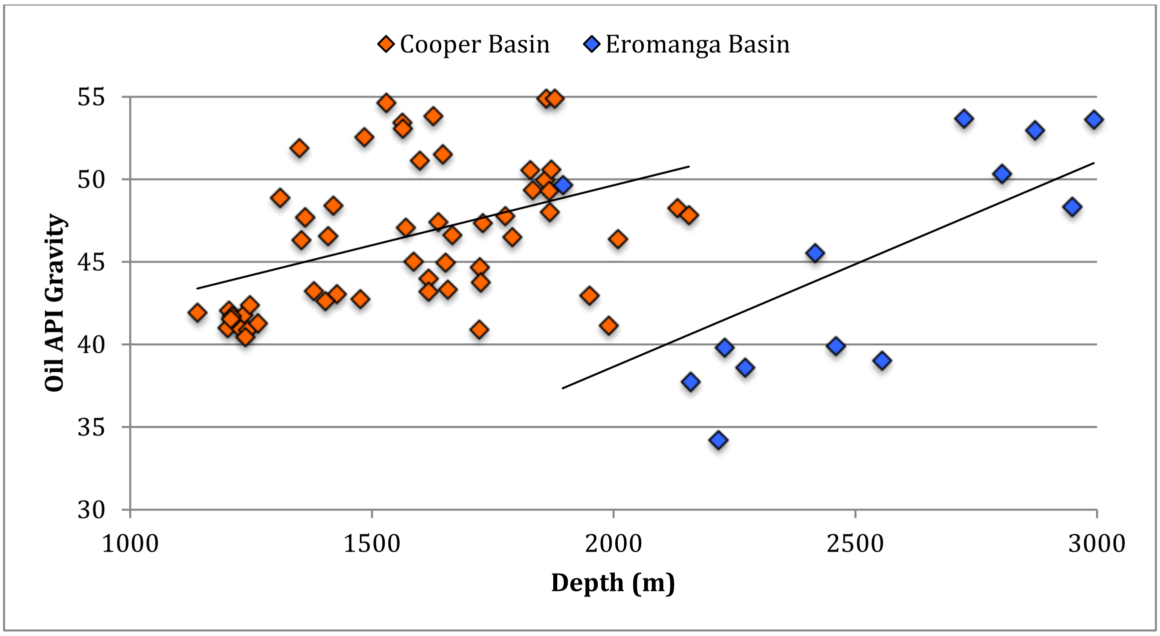

Figure 4.2: API Gravity of hydrocarbons in the Cooper and Eromanga Basin verses depth.

The average molecular weight of C_{5+} components (MW_{C5+}) in the oil was plotted against API gravity (Figure 4.3) and depth (Figure 4.4). API gravity and MW_{C5+} exhibit a clear relationship, where MW_{C5+} decreases linearly with API gravity at a rate of approximately 6.6 g/mol. As expected, the relationship between MW_{C5+} and depth strongly resembles the relationship between API and depth, although MW_{C5+} decreases with respect to depth. MW_{C5+} of oils in the Eromanga Basin range from 100 to 280 g/mol, while in the cooper basin the MW_{C5+} of oil ranges from 100 to 220 g/mol.

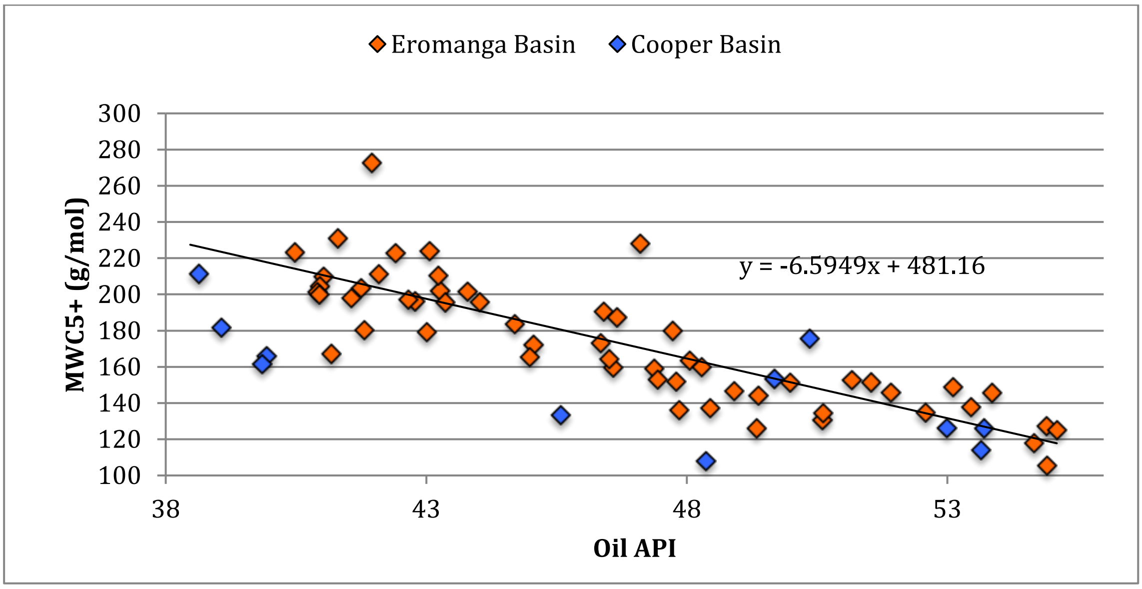

Figure 4.3: Relationship between MW_{C5+} and oil API gravity.

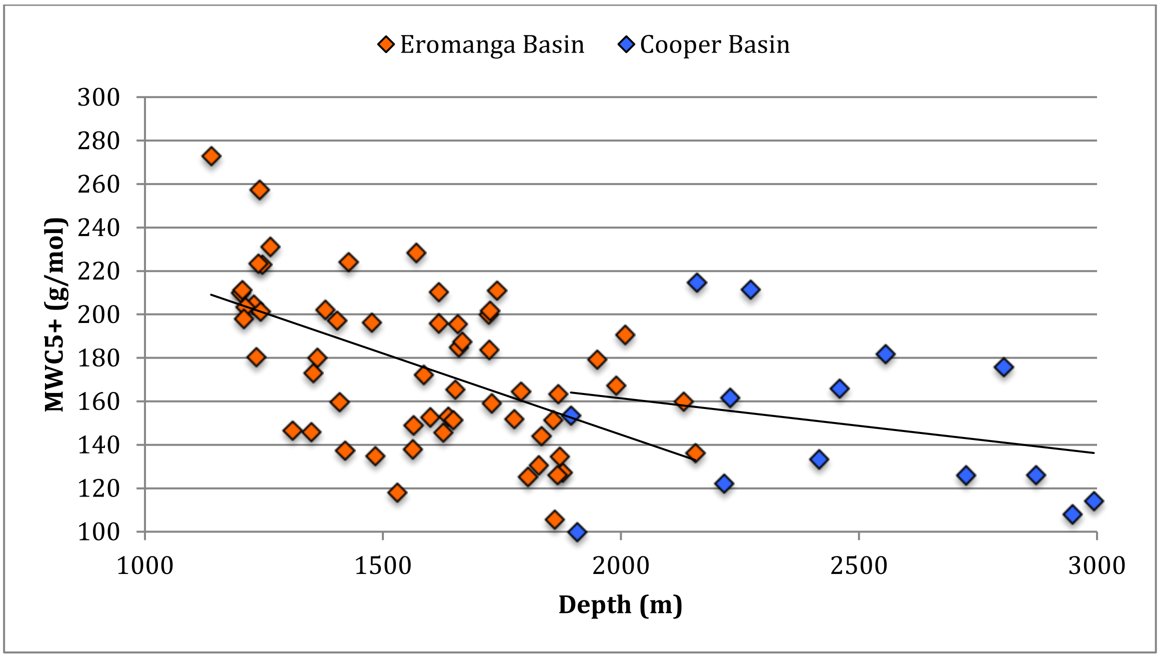

Figure 4.4: MW_{C5+} of hydrocarbons in the Cooper and Eromanga Basin verses depth

4.3 MMP Correlations

The most likely values of MMP, which were calculated by correlations, were plotted against reservoir temperature (Figure 4.5), MW_{C5+} (Figure 4.6), and depth (Figure 4.7). It can be seen in Figure 4.5 that the relationship between MMP and reservoir temperature is rather weak, although a slight positive trend can be seen. Figure 4.6 shows the relationship between MMP and MW_{C5+}. This figure displays a clear correlation between MMP and MW_{C5+}, where MMP is shown to increase with MW_{C5+}. No clear distinction can be made between oils of the Cooper and Eromanga Basin. Figure 4.7 shows that MMP decreases with depth, although the relationship is not strong and subject to significant variability. The figure also shows that there is no clear difference between the MMP of the shallower Eromanga Basin compared to the deeper Cooper Basin.

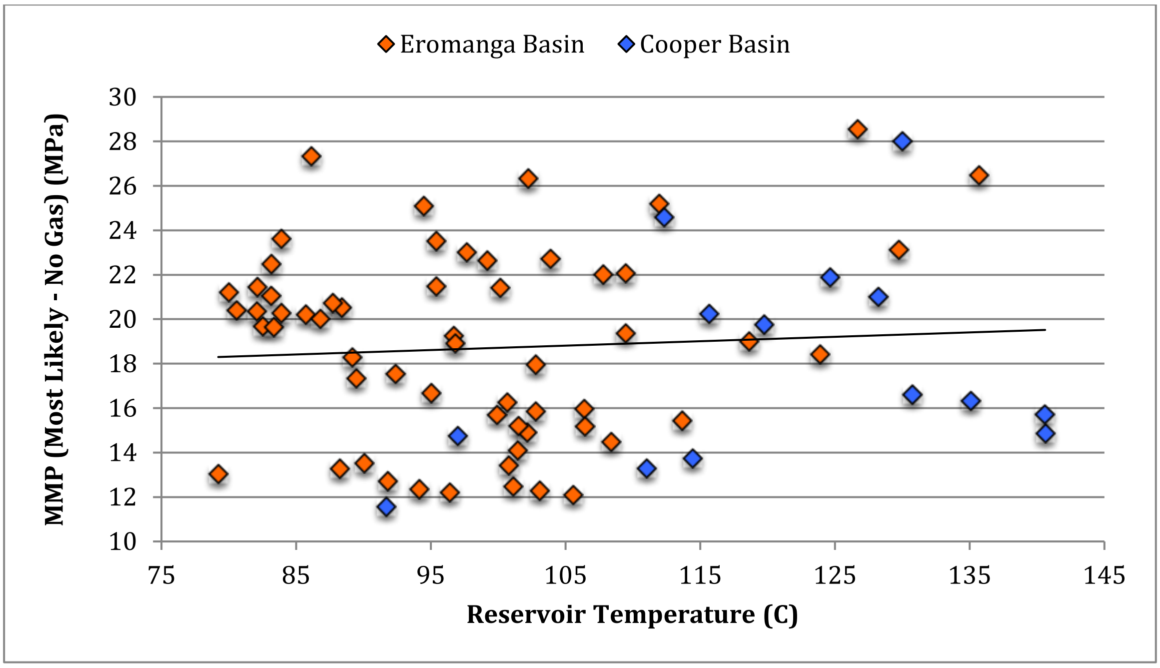

Figure 4.5: Dependency of most likely MMP with respect to reservoir temperature.

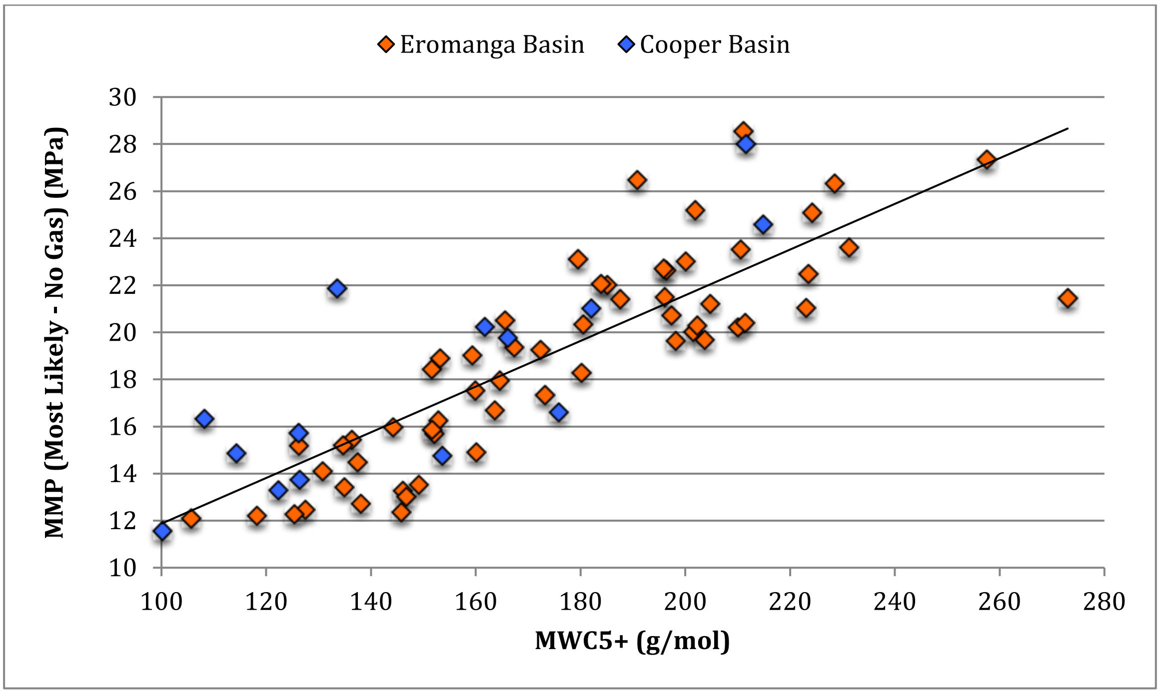

Figure 4.6: Dependency of most likely MMP with respect to reservoir MW_{C5+}.

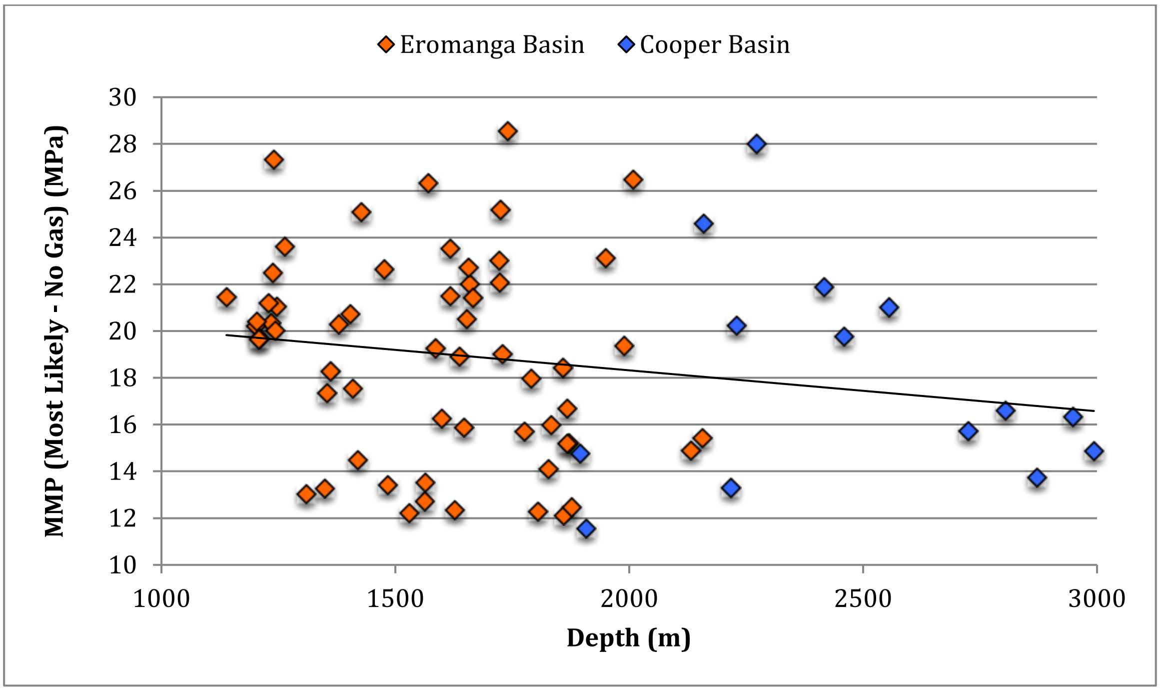

Figure 4.7: Most likely MMP verses depth.

The MMP was calculated both with and without the assumption of a 'typical' gas. Figure 4.8 shows the relationship between MMP calculated with and without the assumed gas. This relationship appears to be linear, but is slightly offset by 2 MPa in the x direction. This demonstrates that the presence of the typical gas decreases the MMP by approximately 2 MPa (290 psi).

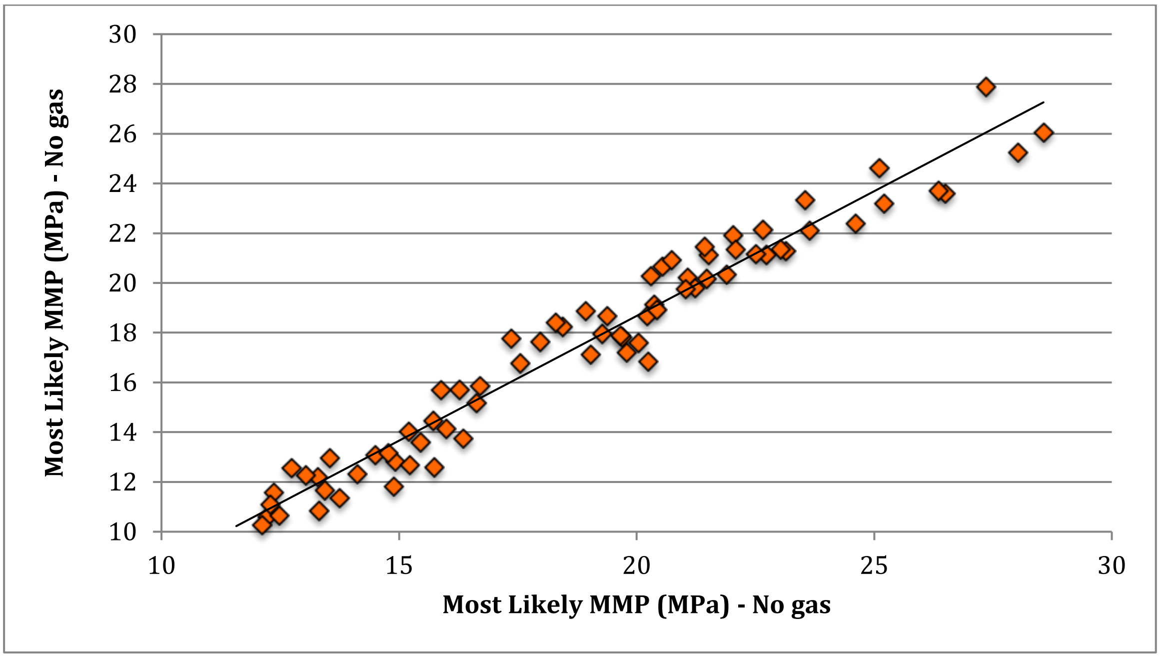

Figure 4.8: Relationship between MMP with and without the assumed typical gas.

A sensitivity analysis was performed on MMP to see the effect that temperature and MW_{C5+} have on MMP. The MW_{C5+} curve was calculated by varying MW_{C5+} from the minimum to the maximum value found in the Cooper and Eromanga Basins (100 to 280 g/mol), while temperature remained constant at 110°C (230°F). Likewise the temperature curve was calculated by varying temperature from the minimum to the maximum value found in the Cooper and Eromanga Basins (80 to 140°C or 175 to 285°F), while MW_{C5+} remained constant at 180 g/mol. The resulting plot can be seen in Figure 4.9, where the MMP is on the Y-axis and the X-axis shows the proportion of the temperature or MW_{C5+} value to the respective maximum ($Proportion = \frac{Maximum\ Value - Actual\ Value}{Maximum\ Value - Minimum\ Value}$). The plot shows that MMP is more sensitive to MW_{C5+} than reservoir temperature, meaning that MMP changes more rapidly with respect to MW_{C5+} than with respect to reservoir temperature over the given ranges. The plot also shows that the relationship between MMP and MW_{C5+} is convex, meaning MMP is less sensitive to changes in MW_{C5+} at higher values.

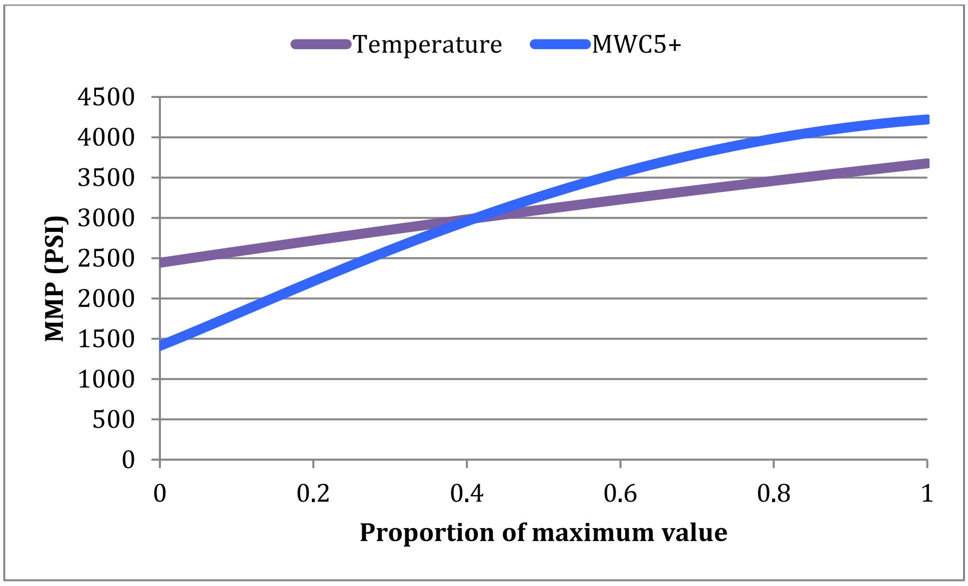

Figure 4.9: Sensitivity analysis of most likely MMP with respect to temperature and MW_{C5+}.

4.4 Achieving Miscibility

The MMP of each formation in each field was expressed by the PERT distribution, a subset of the Beta distribution. The probability of the reservoir achieving miscibility was calculated to be the probability of MMP being less than the initial reservoir pressure. An example of an MMP distribution can be seen in Figure 4.10, which shows the MMP distribution of hydrocarbons in the Tirrawarra Field. The plot also shows the slim tube MMP of hydrocarbons in the Tirrawarra field, as calculated by Clark *et al.* (2008).

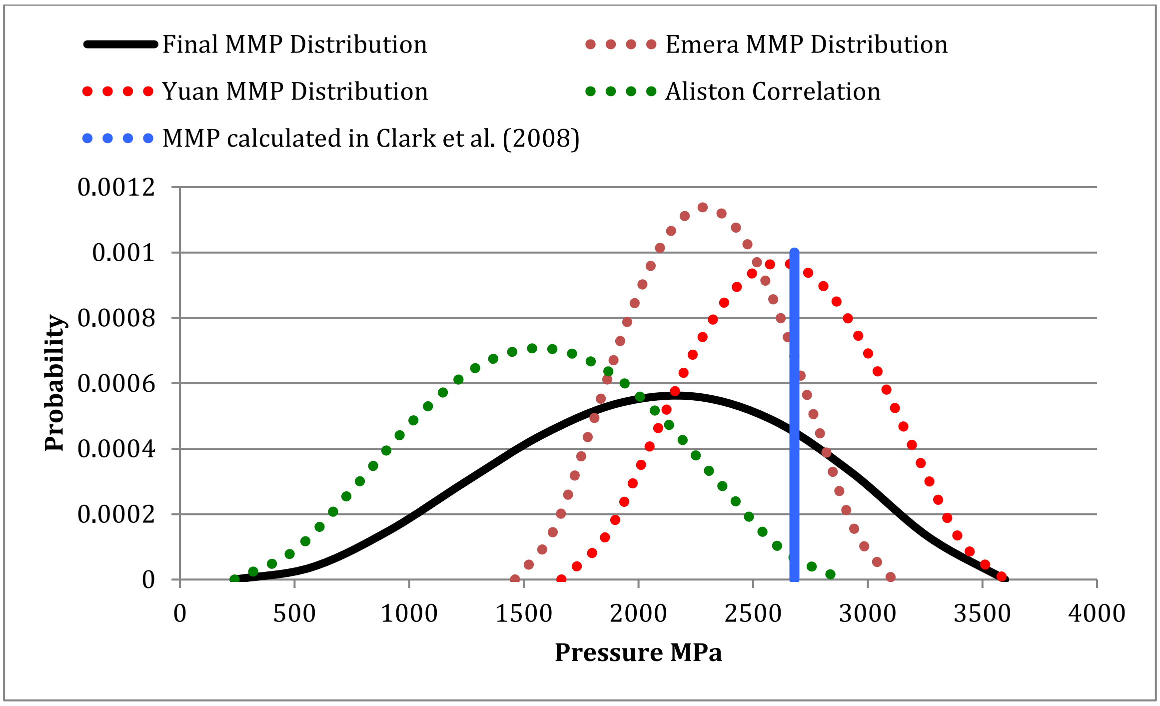

Figure 4.10: MMP distributions of the Tirrawarra field, accompanied by the slim tube MMP measured by slim tube tests (Clark *et al.*, 2008).

The calculated probability of a reservoir achieving miscibility is a function of initial reservoir pressure, temperature, and MW_{C5+}. Figures 4.11, 4.12, and 4.13 show the relationship between the probaility of a reservoir achieving miscibility with respect to MW_{C5+}, reservoir temperature, initial reservoir pressure, and reservoir depth respectivly. The likelihood of achieving miscibility appears to increase with reservoir temperature, which is rather counter intuitive as MMP is shown to increase with temperature. However this relationship is rather weak and is subject to significant variability. Alternativly the likelihood of achieving miscibility displays a clear relationship with MW_{C5+}, and is shown to decrease as the MW_{C5+} increases, which is expected. Finally the relationship between achieving miscibility and the initial reservoir pressure is shown to be rather strong, whereby the likelihhod of achieving miscibility increases as the initial reservoir pressure increases.

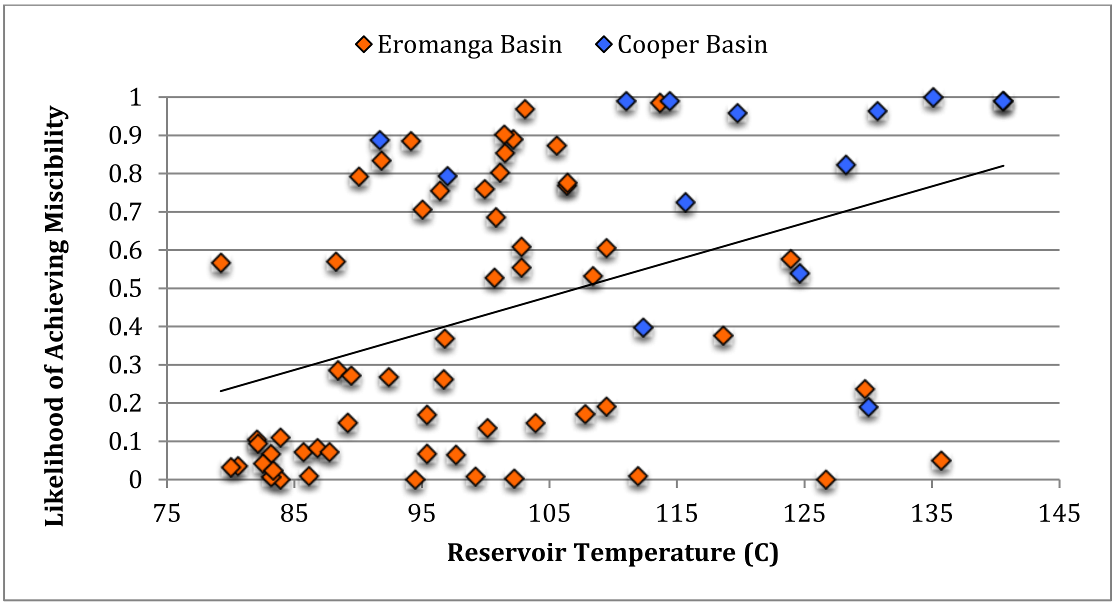

Figure 4.11: Relationship between the likelihood of a reservoir achieving miscibility and reservoir temperature.

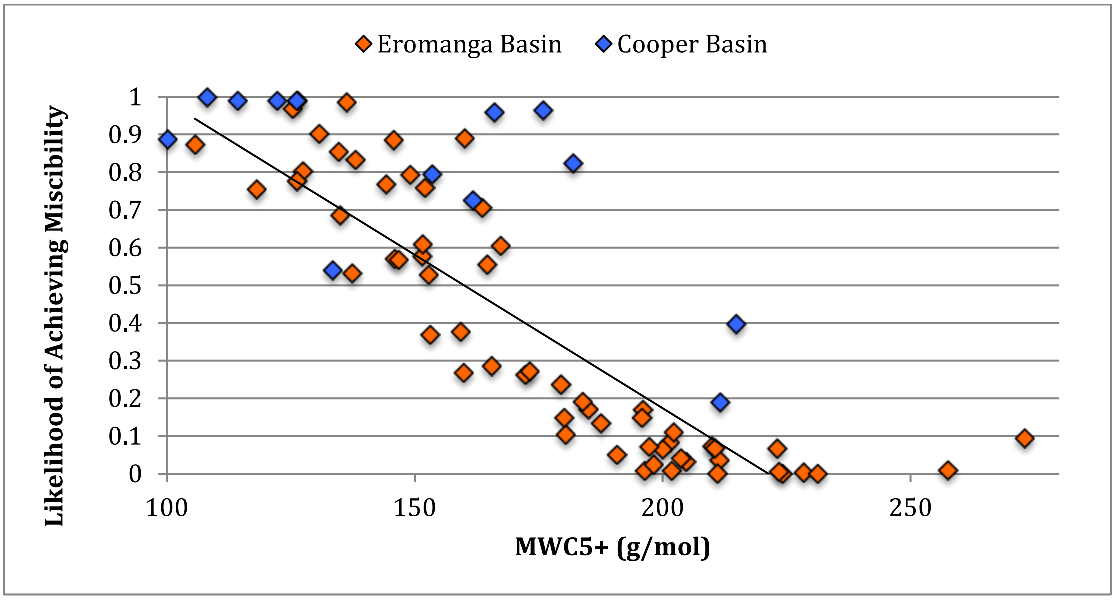

Figure 4.12: Relationship between the likelihood of a reservoir achieving miscibility and MW_{C5+}.

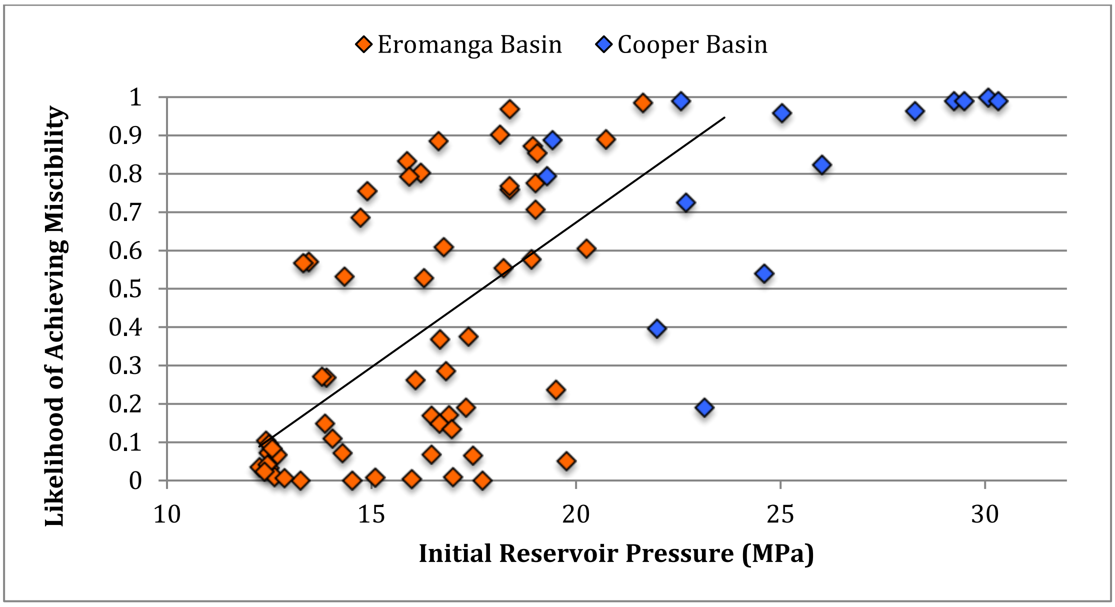

Figure 4.13: Relationship between the likelihood of a reservoir achieving miscibility and initial reservoir pressure.

A sensitivity analysis was performed to see how the variables of temperature, MW_{C5+}, and initial reservoir pressure influence the likelihood that a reservoir will achieve miscibiliy. As with the sensitivity analysis for MMP, each curve was calculated by changing each variable between the maximum and the minimum value seen in the data, while the other variables were held constant. The ranges of MW_{C5+}, temperatre, and initial reservoir pressure were 100 to 280 g/mol, 80 to 140°C (175 to 285°F), and 12.25 to 25.68 MPa (1775 to 3725 PSI) respectively. The constant values of MW_{C5+}, temperatre, and initial reservoir pressure were 180 g/mol, 110°C (230°F), and 17.5 MPa (2538 PSI) respectivly. The analysis shows the liklihood of a reservoir achieving miscibility is highly sensitive to values of MW_{C5+} and initial reservoir pressure, demonstrating that that the chance of a reservoir achieving miscibility decreases rapidly as MW_{C5+} increases, whilst the contrary is true for initaial reservoir pressure. Increasing temperature is shown to decrease the liklihood of a reservoir achieving miscibilitity, however MMP is far less sensitive to temperature than initial reservoir pressure and MW_{C5+} over the ranges provided.

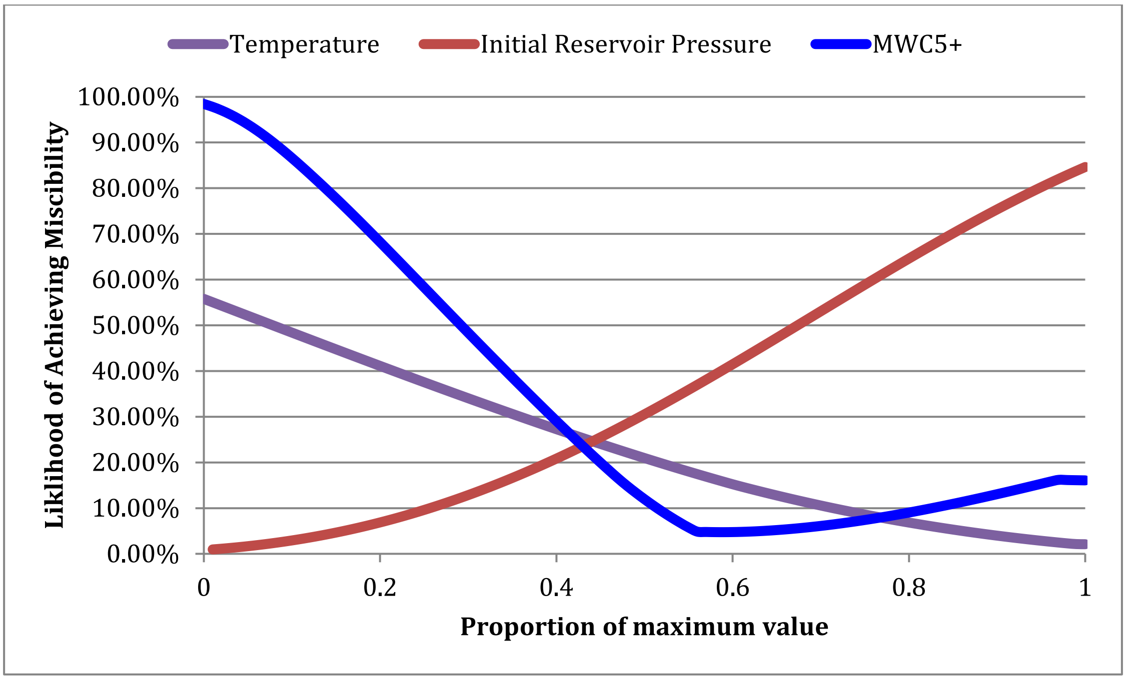

Figure 4.14: Sensitivity analysis of the likelihood of a reservoir achieving miscibility with respect to temperature and MWC5+.

Chapter 5

Discussion

The key variables in the screening study were reservoir temperature, oil composition, and initial reservoir pressure. Reservoir temperature and oil composition were used to calculate the minimum miscibility pressure (MMP) distribution. The initial reservoir pressure was used with the MMP distribution to determine the likelihood of the reservoir achieving miscibility with carbon dioxide (CO_2). The following section discusses how the reservoir temperature, oil composition, and initial reservoir pressure influenced the likelihood of the reservoir achieving miscibility; the section also discusses the potential sources of error involved in the study.

5.1 Reservoir Temperature

The likelihood of a reservoir achieving miscibility was shown to increase with increasing reservoir temperature. This is a rather counterintuitive result as the minimum miscibility pressure should increase with temperature, and the chance of a reservoir achieving miscibility should reduce as MMP increases. However the results show that the relationship between MMP and temperature is rather weak. This is reflected in the sensitivity analysis of MMP, which shows that temperature is not as influential on MMP as the average molecular weight of C_{5+} components (MW_{C5+}). Reservoir temperature is also shown to increase with respect to depth, while MW_{C5+} is shown to decrease. This result means that although an increasing reservoir temperature may act to slightly increase MMP, it is being offset by a decreasing MW_{C5+} parameter, which lowers MMP.

5.2 Oil Composition

Hydrocarbons with a lower MW_{C5+} were shown to significantly improve the probability of a reservoir achieving miscibility with CO_2. This is because MW_{C5+} was shown to be the most influential parameter in the determination of MMP, where MMP increases steadily with increasing MW_{C5+}. MW_{C5+} was also shown to decrease with respect to depth, although this relationship is weak and subject to high variability. The relationship between MW_{C5+} and depth can be explained by the relationship between API gravity and depth. Oil API gravity is known to generally increase with respect to depth due to the higher degree of thermal alteration experienced in greater depths (Hunt, 1996). Oil API gravity was also shown to have an inversely proportional relationship to MW_{C5+}, which is expected as oils with a higher API gravity contain higher proportions of lighter fluid. This is significant as it means that MMP decreases with depth, which contradicts the trend stated in Heller and Taber (1986) (Appendix D.3). This finding also implies that regions of high API, such as those in the deeper areas of the Cooper Basin, are shown to have low values of MMP, and hence have a high likelihood of achieving miscibility.

The presence of the typical gas was shown to significantly improve MMP. This was expected, as there was a considerable proportion of carbon dioxide in the gas, which added to the intermediate components of the reservoir fluid. In most cases the proportion of intermediate components was greater than the proportion of the volatile components (methane and nitrogen), hence MMP was lowered. It should be noted that without the presence of volatile components, the intermediate components of the reservoir fluid are not accounted for in the Alston *et al.* (1985) and Emera (2006) correlations. This means that the significant decrease in MMP is likely due the inclusion of the intermediate components rather than the inclusion of the gas components. Assuming a typical gas presents an obvious source of error, as this does not represent the actual reservoir fluid composition. Both the gas-oil ratio and proportions of gas vary from field to field, meaning in some cases MMP may be negatively affected due to higher proportions of volatiles.

5.3 Initial Reservoir Pressure

The potential for a reservoir to achieve miscibility with CO_2 was shown to increase with the initial pressure of the reservoir. This result is explained by the relationship between initial reservoir pressure and depth, and MMP and depth. MMP is shown to slightly decrease with depth, which is a result of MW_{C5+} decreasing with depth. Alternatively, the initial reservoir pressure increases significantly with depth. The criterion for miscibility is that the initial reservoir pressure must be higher than the minimum miscibility pressure, therefore the likelihood of this condition being met increases at greater depths, when the initial reservoir pressure is higher and the MMP is lower. This implies that deeper formations, such as the Poolowanna, Tirrawarra, and Patchawarra, generally have a higher likelihood of achieving miscibility than shallower formations, such as the Murta, and McKinlay Unit.

5.4 Regions of Interest

Screening has identified numerous reservoirs in the Cooper and Eromanga Basin to be suitable for CO_2 EOR. The results of the screening study can be found in Appendix F; regions of high to low potential for achieving miscibility have been identified. Regions identified as having a high potential of achieving miscibility should be investigated further, while regions of low potential should not be ignored if the state of information changes. Two regions of interest are discussed below.

A key finding of the screening process is that reservoirs in the Tirrawarra Sandstone show a high potential for being suitable for CO_2 EOR, as the probability that they will achieve miscibility is extremely high. This is reinforced by studies from Clark *et al.* (2008), who proved the potential for miscibility through slim tube testing, and Bon *et al.* (2004; 2005), who identified similar nearby regions in the Cooper Basin to show high potential for being suitable to CO_2 EOR. This result is significant because the Tirrawarra Sandstone contains large accumulations of oil and regions of relatively low reservoir quality (Razaee, 1997), meaning that the volume of oil attainable through CO_2 EOR may be substantial.

The Gidgealpa field, which extends through the Namur, Birkhead, Hutton, Poolowanna, and Tirrawarra formations, shows a high potential of achieving miscibility in multiple formations. The Gidgealpa field has been a major hydrocarbon play since its discovery in 1967, however the field is now seeing declining production. For example, the Hutton and Birkhead formations of the Gidgealpa South dome had recovered a combined 7.7 MMSTB by the late 1990s, with predicted initial oil in place of 12 MMSTB and 7 MMSTB respectively (Lanzilli, 1999); this presents a large target to be produced by CO_2 EOR. In addition to residual oil in the main pay zone, Boult (1996) has identified that a large residual oil zone may exist in the Hutton and Birkhead Formations. This presents an opportunity for CO_2 EOR to recover a significant amount of remaining oil in the region.

5.5 Sources of Error

There were numerous sources of significant error in this study, including error due to the MMP correlations, error in the data, and error due to assumptions. This error was incorporated into the results by expressing MMP as a distribution that attempts to capture the state of information. It can be seen in Figure 4.10 that the distributions of the MMP are very wide, which reflects the magnitude of the uncertainty involved in these calculations.

5.5.1 Correlations

A significant source of error in the study comes from the correlations that were used to calculate MMP. These correlations are notorious for being inaccurate, however this is justified by the fact that they are a far more efficient method of calculating MMP than laboratory testing. Further error is introduced when these correlations are applied to regions with different oil properties than the region in which the correlations were validated (Clark *et al.,* 2008). The validated ranges

of parameters are shown in Table 5.1, along with the range of values seen in the Cooper and Eromanga Basin.

Table 5.1: Table of valid parameter ranges for the correlations used in the analysis.

	Temperature (°C)	MW_{C5+} (g/mol)	MW_{C7+} (g/mol)	Int_{C2-C4} (%)	Int_{C2-C6} (%)
Yuan *et al.* (2005)	22 – 149	-	139 – 319	-	2 - 40.03
Alston *et al.* (1985)	32 – 117	169 – 302	-	-	-
Emera (2006)	32 – 137	136 – 248	-	0.2 – 39.4	-
C & E Basins	80 – 141	100 - 272	110 - 279	0 – 15.6	0 – 40.6

Table 5.1 shows that the range of reservoir temperatures in the dataset are contained within the ranges provided by the Yuan *et al.* (2005) correlation, and are close to that of the Emera (2006) correlation. However many reservoirs in the data set, especially those of the Cooper Basin, are hotter than the reservoirs used to validate the Alston *et al.* (1985) correlation; this results in a high potential for error in the MMP for hot reservoirs calculated using the Alston *et al.* (1985) correlation. The MW_{C5+} range of the dataset is shown to exceed both limits of the range provided in the Emera (2006) correlation, while the lower values of MW_{C5+} and MW_{C7+} in the data set are below the limits provided in the Alston *et al.* (1985) and Yuan *et al.* (2005) correlations respectively. However the majority of reservoirs lie within the ranges provided by the Emera (2006) and Yuan *et al.* (2005) correlations, meaning that the error in the MMP calculations for these correlations is not overly significant. Lastly the proportions of intermediate components are mostly contained in the ranges provided by the correlations.

The justification for using the Alston *et al.* (1985) and Yuan *et al.* (2005) correlations is that they were identified by Clark *et al.* (2008) as the best suited correlations to calculate MMP in the Tirrawarra field. The Tirrawarra field is the hottest reservoir in the dataset, and has a MW_{C5+} and MW_{C7+} value lower than the ranges proposed by the correlations. Clark *et al.* (2008) found that the Alston *et al.* (1985) and Yuan *et al.* (2005) correlations calculated MMP with a percentage error of -17.09% and 10.99% respectively, when compared to slim tube tests. A similar study by Bon *et al.* (2005) on a nearby undisclosed reservoir found that the MMP calculated by the Alston *et al.* (1985) and Yuan *et al.* (2005) correlations had a percentage errors of -27.83% and 6.58% respectively. This error was incorporated into the MMP distribution. Justification for using the Emera (2006) correlation is that it was validated using data collected from oils in the Cooper and Eromanga Basin (Bon, personal communication), hence the correlation is likely to be suited to the region.

5.5.2 Data

Due to the lack of a consistent and cohesive database, there are many sources of error stemming from the collected data. The impact of this error was minimised by attempting to collect data from consistent sources, and giving preference to well completion reports as they contain direct measurements from the field. However the methods of data collection used in the well completion reports were rarely explained, and the uncertainty in the data was seldom discussed. Error in the data was most noticeable in the measurements of oil composition, which, as discussed in Section 3.2.1, were calculated using gas chromatography. This presented a significant source of error as gas chromatography fails to capture accurate measurements for light and heavy oil components, hence fails to accurately characterise the oil. In order to avoid this error, the MW_{C8+} measurements, given in the completion reports, were used where possible. If no MW_{C8+} measurement could be found, a calculated most likely, maximum, and minimum value of MW_{C8+} was used to capture the uncertainty.

5.5.3 Assumptions

Due to the lack of gas characterisation in the fluid composition data the MMP was calculated two ways; first assuming the proportion of volatile components was the same as the proportion of intermediate components, and second assuming a typical gas was present. As stated in (Radke, 2009) there are different regions in the Cooper-Eromanga Basin system that have extremely high proportions of methane, carbon dioxide, and Nitrogen gas. These gasses don't exist in a consistent proportion, so assuming any proportion of volatile or intermediate components will provide a source of error, as it misrepresents the fluid composition. The consequence of using the typical gas is that it favoured the intermediate components, and hence lowered the MMP.

5.5.4 Distributions

To account for the sources of error discussed above, distributions were assigned to the calculated MMP values of each correlation, which were then carried through to the calculation of a final MMP distribution. The MMP was expressed as a PERT distribution, a subset of the Beta distribution, which requires inputs of a minimum, maximum, and most likely value. As discussed in Section 3.3.4, each correlation was assigned a minimum and a maximum possible value based on the accumulated uncertainty that was allocated due to the variability in the data, the error of the correlations, and the error in the data. The magnitude of the uncertainty meant that the ranges of the distribution are wide, however these ranges were necessary to capture the perceived state of uncertainty.

As seen in Figure 4.10, the calculated MMP distributions of the Tirrawarra Formation (assuming no gas) all contained the slim-tube MMP calculated by Clark *et al.* (2008). Moreover the most likely values of the Alston *et al.* (1985) and Yuan *et al.* (2005) correlations were relatively close to the MMP calculated by Clark *et al.* (2008) when using the same correlations. Unfortunately the study by Clark *et al.* (2008) was the only miscibility study found in the literature that considered a known reservoir in the Cooper-Eromanga Basin system, hence it is the only metric to base the validity of the MMP distributions on. This should not be taken to mean that the MMP distributions are valid, rather that more work is required in order to improve the state of information. With regards to the MMP distributions calculated using the typical gas, the Alston *et al.* (1985) and Emera (2006) distributions both failed to capture the MMP of the Tirrawarra field, as calculated by Clark *et al.* (2008). Consequently there is no justification for considering these values to be correct, and they were not considered in the discussion.

5.6 Conclusion

The objective of this study was to assess the suitability of reservoirs in the Cooper-Eromanga Basin system to undergo CO_2 EOR. This was achieved by building up a database and applying screening criteria to oil producing reservoirs within the Cooper and Eromanga Basins. The screening criteria consisted of reservoir depth, reservoir temperature, oil API gravity, and the likelihood of the reservoir achieving miscibility. Reservoir screening was able to identify fields with a high potential of achieving miscibility with CO_2, such as the Tirrawarra and Gidgealpa fields.

The key conclusions of the study are as follows:

- All reservoirs in the Cooper-Eromanga Basin system passed the screening criteria of reservoir depth, reservoir temperature, and oil API gravity, established in previous literature.
- Minimum miscibility pressure (MMP) is more sensitive to oil composition than reservoir temperature (over the ranges found in the Cooper and Eromanga Basin). Consequently the results showed that MMP decreases with respect to depth.
- As the initial reservoir pressure increases with respect to depth, the likelihood of a reservoir achieving miscibility generally improves with depth. This implies that deeper reservoirs have a greater chance of achieving miscibility with CO_2.
- The Cooper-Eromanga Basin system appears to be well suited for CO_2 EOR.
- There is a significant amount of uncertainty associated with the current data. More accurate screening would require improved methods of data collection and analysis.
- Further work must be done in order to validate these results with laboratory studies.

Chapter 6

Future Work and Recommendations

There is still much work to be done to fill the knowledge gaps in the literature. This study has identified regions that show promise for being suitable for CO_2 EOR; these regions should be investigated further with more advanced methods of analysis. This report may also play a small role in improving industry awareness, and it is hoped that this work will be expanded upon as the state of information improves. The following points should be considered for areas of future work.

1. Investigating regions of interest:
   This study has identified numerous regions that may be suitable for CO_2 EOR. Future work should look at investigating these regions further, with laboratory and simulation studies, economic and risk analysis, and pilot studies.

2. Improving the database:
   It was found that there was no coherent and complete database available that contained easily accessible information on numerous fields. This made gathering data for the screening study difficult, at it required data to be obtained from individual completion reports. Creating an integrated, cohesive and complete database would improve the efficiency of future screening studies.

3. Improving the minimum miscibility pressure (MMP) correlations:
   The MMP correlations used in this study were not valid for the entire range of properties seen in the Cooper and Eromanga Basins. This led to error in the results, and also casts some doubts on the validity of the results. The only way to reduce the uncertainty in this area is by conducting more miscibility studies in the region and developing regional MMP correlations, with known error. This would improve the quality of future screening studies.

4. Identifying and characterising residual oil zones:
   There was a noticeable absence of literature on residual oil zones in the Cooper and Eromanga Basins. This knowledge gap should be filled as residual oil zones could provide a substantial target for future CO_2 EOR projects. Identifying residual oil zones would more require routine analysis below the oil water contact,

5. Improving industry experience:
   Improving the overall industry experience would allow CO_2 EOR to become a common industry practice in Australia, as it currently is in the United States. There appears to be some tentativeness in oil and gas companies and in the general public about bringing this technology to Australia, largely due to the perceived state of uncertainty. This issue will only be resolved if industry gains experience in the practice, which can only be done through further research and field studies.

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Appendix A

Summary of the step-by-step guide to identify residual oil zones (ROZs) proposed by Trentham *et al.,* (2015).

A basin-wide study requires basin-wide structural maps in order to reconstruct the tectonic history, post hydrocarbon entrapment. Analysis should aim to identify any evidence of sweep, which would signify a geological waterflood; Table A.1 shows the identifiable characteristics for each type of ROZ. This data should be combined with available field seismic data and stratigraphic cross sections to further investigate sweep below OWC and allow for preliminary modeling. In the case of a type 3 ROZ, modeling may include fairway mapping, which has been done extensively in the Permian basin.

Once a potential ROZ is identified, specific field data that extends past OWC should be reviewed. This includes drill stem tests, water chemistry analysis, mud logs, wireline logs, core sample analysis, and additional seismic data; any anecdotal information from the field is also valuable. Raw data should also be revisited, as analysis below OWC may have been assumed pointless, and hence glanced over. Any differences in water chemistry, mineralogy, fluid composition, and pore geometry between MPZ and ROZ should be noted, as these may indicate the presence of a ROZ. Finally an attempt should be made to calculate oil saturation from available logs and core samples. This data will likely prove inconclusive, due to the nature of log data and general core sample analysis, however any evidence of oil saturations above 25% should be considered for future testing. At this stage, any regions that show no evidence of a ROZ should be eliminated from consideration.

Once potential ROZs have been identified and mapped, further exploration into the subsurface is required to gather new data. It is advised that the

The following signs show presence of a ROZ

- <u>Drilling</u>: Oil in the pits is expected when drilling in the MPZ and is likely to occur when drilling through the ROZ; this is due to many ROZs being oil wet and having relatively high saturations. A drilling break may also be noticed when drilling through a ROZ. As stated above, type 3 ROZs may be of considerably higher reservoir quality than the MPZ, meaning they are easier to drill through.

- <u>Logging</u>: Interpreting log data may prove difficult when considering a ROZ, as changes in water chemistry and the presence of sulfur can impede analysis. The presence of sulfur may interfere with calculations using the Archie's equation, to determine water resistivity. Meanwhile meteoric sweep of water through the ROZ means that water chemistry may be altered; hence water resistivity cannot be assumed equal to that of the MPZ. Consequently, attempts to calculate water resistivity in the ROZ are often inconsistent with each other and with core data. Logging may however be used to identify areas of improved porosity as a result of secondary dolomization.

- <u>Mud Logging</u>: When drilling below OWC mud logs may report some form of odor or yellow hue. This is a sign that some amount of oil is being produced, hence may indicate the presence of a ROZ. In addition the presence of sulfur in the mud logs shows evidence of biogeochemical reactions during meteoric sweep, and hence may also be an indication of a potential residual oil zone.

- <u>Core Samples:</u> Core samples taken in ROZs of carbonate reservoirs tend to reveal a mixed-wet to oil-wet region, due to secondary dolomization. Core samples of the lower portion of a ROZ may also show some precipitation of bitumen. Bitumen generally precipitates at OWC however if the OWC has migrated upwards, bitumen precipitate may still reside in the ROZ. Other indicators of a ROZ in the core sample are higher porosity and permeability, presence of free sulfur crystals, and spotty oil, which have been discussed previously.

TABLE 5.1 - Summary of "Classic" Observations of ROZ's and the ROZ-based Revised Interpretation of the Observations

ACTIVITY	EVIDENCE	CLASSIC INTERPRETATION	ROZ INTERPRETATION	ROZ EXPLAINATION
Drilling	Oil on pits	Transition zone/MP remnant oil	Presence of ROZ highly likely	Oil wet reservoir. Oil is released during drilling. Often seen in Roz's
	Drilling Break	Aquifer / No Significance	Good Reservoir	Open marine environment. Good cycles and flow units.
Mud Logging	Cut in samples	Transition Zone / MP Remnant	Oil saturation present	Residual Oil Saturation is present
	Dull gold Fluorescence in samples	Transition Zone / MP Remnant	"Water washed" oil	Indicative of Mother Nature's Waterflood. Reduced Saturation of oil.
	Odor in samples	Transition Zone / MP Remnant	Oil saturation present	Indicative of Mother Nature's Waterflood. Reduced Saturation of oil.
	Gas show	Not expected. From Oil Zone above if present.	Oil saturation present	Indicative of Mother Nature's Waterflood. Reduced Saturation of oil.
	"Free" Sulfur crystals	Suggest at or below O/W contact	Mother Natures Waterflood	Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.
	Sulfur and Anhydrite	No significance	Mother Natures Waterflood	Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.
	Sulfur and Calcite	No significance	Mother Natures Waterflood	Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.
DST	Sulfur or Black Sulfur water	Not unusual / No significance	To be Expected.	Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.
	Salty Sulfur water	Not unusual / No significance	To be Expected	Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.
	Lower Salinity than expected	Not unusual / No significance	Meteoric Derived Flushing	Indicative of Mother Nature's Waterflood. Meteoric Derived Flushing.
	"Skim" of Oil	Not unusual / No significance	To be Expected. Never significant oil	Oil Wet reservoir. Small amounts of Oil is released during pressure drop.
	Good to Excellent Pressure	Not unusual / No significance	To be Expected	ROZ is not in pressure cmmunicationwith a Main Pay
Logging	Rw different than MP	Not unusual / No significance	ROZ water chemistry different than MP	Rw is different because the meteoric derived sweep is composed of lower salinity water
	So > 30% in calculations	Might be productive	ROZ. Residual to waterflood and MNW	Rw is different because the meteoric derived sweep is composed of lower salinity water
	Different M an N than MP needed	Not unusual / No significance	fabric destructive dolomitization in ROZ only	Rocks have undergone a second diagenetic event
	Excellent Porosity in dolomite	Not unusual / No significance	Open Marine + Sweep associated dolomitization	Thicker open marine cycles and Secondary dolomitization in ROZ during sweep
	"Looks like a *Winner*"	set casing	ROZ can have appearance of producable on completion	ROZ thicker cycles, secondary dolomitization, salinity differences make calculations difficu
Core Analysis	5 - 40% oil saturation	Zones with higher water saturation non-productive	Saturations expected following MNW	Expected. So after Mdeteoric Derived Sweep
	Oil Wet Core	Consider log analysis	Sweep related fabric destructive dolomitization >> Oil wettin	Expected after Sweep related fabric destructive dolomitization
	Open marine facies	Not unusual / No significance	Good Quality reservoir, thick cycles and flow units	ROZ's tend to be found in more open marine settings
	SHR near base and/or top	Suspect oil/water contact(s)/water washing	Water Washing from Meteoric Derived Flushing	Multiple SHR Zone suggest Multiple O/W contact, both Paleo and recent
	Better Porosity and Perm than main pay	Not unusual / No significance	Good Quality reservoir, thick cycles and flow units	ROZ's tend to be found in more open marine settings
	Sulfur Crystals	Diagenesis - no interpretation	Free sulfur often found in ROZ	Converrsion by Sulfate reducing bacteria results in free sulfur
	Sulfur and Anhydrite	Diagenesis - no interpretation	Free sulfur often found in ROZ	Converrsion by Sulfate reducing bacteria results in free sulfur
	Sulfur and Calcite	Diagenesis - no interpretation	Free sulfur often found in ROZ	Converrsion by Sulfate reducing bacteria results in free sulfur
	Spotty Oil Stain	Consider Log Analysis	Intervals with low perm in ROZ	Intervals with low perm in ROZ can have remnat high saturations
	Leached molds	Not unusual / No significance	Leaching during MNW	Leaching during MNW
	Leached Fracture	Not unusual / No significance	Leaching during MNW	Leaching during MNW
	Fabric Destructive dolomite	Not unusual / No significance	Secondary dolomitization in ROZ during sweep	Secondary dolomitization in ROZ during sweep
	Limestone below oil stained interval	Not unusual / No significance	Zone is below Swept ROZ	Zone is below Swept ROZ
Completion	large volumes of fluid (sulfur water)	expect a decrease in water production over time	Large volumes of water cut on IP indicates an ROZ	Swept down to residual to waterflood, good porosity and perm in open marine
	Less than 5% oil	expect an increase in oil production over time	>85% water cut on IP indicateds an ROZ	Swept down to residual to waterflood
	Good Pressure	Not unusual / No significance	ROZ not drained, to be expected	Thinner cycles in MP don't reduce pressure in ROZ
	Lower Salinity than expected	Suspect water flow	Meteoric Derived water	Meteoric Derived water has lower salinity
	Different Scale than in Main Pay	Suspect water flow	Different water chemistry	MNW changes water chemistry significantly

Table A.1: Summary of the classic observations of residual oil zones (Trentham *et al.*, 2015).

Appendix B

Example of the database spread sheet used in ARI (2016).

Basin Name	Pemian West Texas 8A
Field Name	SEMINOLE
Reservoir	SAN ANDRES

Reservoir Parameters:	MPZ	ROZ
Area (A)	15,700	15,700
Net Pay (ft)	135	100
Depth (ft)	5,100	5,262
Oil-Water Contact Dip	N/A	20
Porosity	13.0%	13.0%
Reservoir Temp (deg F)	157	157
Initial Pressure (psi)	2020	2020
Pressure (psi)	1360	1360
B_{oi}	1.387	1.387
B_o @ S_o, swept	1.050	1.387
S_{oi}	0.880	0.320
Swept Zone S_o	0.320	0.320
S_{wi}	0.120	0.680
API Gravity	35	35
Viscosity (cp)	2.20	2.20
Dykstra-Parsons	0.75	0.75

Oil Production	MPZ	ROZ
Producing Wells (active)	358	15
Producing Wells (shut-in)	250	-
Cum Oil (MMbbl)	620.5	3.0
2002 Production (MMbbl)	8.6	0.5
CO2-EOR Cum (MMbbl)	141.0	3.0
2002 CO2-EOR (MMbbl)	8.3	0.5
02 CO2-EOR Reserves (MMbbl)	126.0	7.8

Water Production	MPZ	ROZ
2002 Water Production (Mbbl)	0	0
Daily Water (Mbbl/d)	0	0.0

Injection	MPZ	ROZ
Injection Wells (active)	184	0
Injection Wells (shut-in)	0	0
2002 Water Injection (MMbbl)	0	0.0
Daily Injection - Field (Mbbl/d)	0	0.0
Cum Injection (MMbbl)	0	0.0
Daily Inj per Well (Bbl/d)	0	0.0

Volumes	MPZ	ROZ
OOIP (MMbl)	1,353.0	365.3
Cum P/S Oil (MMbl)	479.5	-
2002 P/S Reserves (MMbl)	5.5	-
Ult P/S Recovery (MMbl)	485.0	-
Remaining (MMbl)	868.0	365.3
Recovery Efficiency (%)	36%	0%

OOIP Volume Check	MPZ	ROZ
Reservoir Volume (AF)	2,119,500	1,570,000
Bbl/AF	639.9	232.7
OOIP Check (MMbl)	1,356.2	365.3

SROIP Volume Check	MPZ	ROZ
Reservoir Volume (AF)	2,119,500	1,570,000
Swept Zone Bbl/AF	307.4	232.7
SROIP Check (MMbl)	651.5	365.3

ROIP Volume Check	MPZ	ROZ
ROIP Check (MMbl)	868.0	365.3

Appendix C

MMP correlations proposed by Alston *et al.* (1985), Yuan *et al.* (2005), and Emera (2006).

C.1: Alston *et al.* (1985) Correlation

1. Stock Tank Oil (small or zero quantities of volatile and intermediate components)

$$MMP_{CO_2} = 8.78 * 10^{-4} * (T)^{1.06} * (M_{C5+})^{1.78} * \left(\frac{x_{vol}}{x_{int}}\right)^{0.136}$$

2. Oil with bubble point pressure (P_b) < 0.35 MPa

$$MMP_{CO_2} = 8.78 * 10^{-4} * (T)^{1.06} * (M_{C5+})^{1.78}$$

Alston *et al.* (1985) – MMP (PSI)

T = Reservoir Temperature (F)
M_{C5+} = Average molecular weight of C_{5+} components (g/mol)
x_{vol} = Proportion of volatiles
x_{int} = Proportion of intermediates (C_2-C_4)

C.2: Yuan *et al.* (2005) Correlation

Equation 2.12: Yuan *et al.* (2005) MMP correlation

$$MMP_{CO_2} = a_1 + a_2 M_{C7+} + a_2 P_{C2-C6} + \left(a_4 + a_5 M_{C7+} + a_6 \frac{P_{C2-C6}}{(M_{C7+})^2}\right)T + (a_7 + a_8 M_{C7+} + a_9 (M_{C7+})^2 + a_{10} P_{C2-C6})T^2$$

Yuan *et al.* (2005) – MMP (PSI)

T = Reservoir Temperature (F)
M_{C5+} = Average molecular weight of C_{5+} components (g/mol)
x_{vol} = Proportion of volatiles (%)
x_{int} = Proportion of intermediates (C_2-C_4)

$a_1 = -1463.4$	$a_2 = 6.61$	$a_3 = -44.979$	$a_4 = 2.139$	$a_5 = 0.1167$
$a_6 = 8166.1$	$a_7 = -0.12258$	$a_8 = 1.2283 * 10^3$	$a_9 = -4.0152 * 10^{-6}$	$a_{10} = -9.2577 * 10^{-4}$

C.3: Emera (2006) Correlation

1. Oil with bubble point pressure (P_b) > 0.345 MPa

$$MMP_{CO_2} = 7.43497 * 10^5 * (T)^{1.1669} * (M_{C5+})^{1.201} * \left(\frac{x_{vol}}{x_{int}}\right)^{0.109}$$

2. Stock tank oil (P_b) ≤ 0.345 MPa (zero volatile fraction and non-zero intermediate fraction)

$$MMP_{CO_2} = 7.43497 * 10^5 * (T)^{1.1669} * (M_{C5+})^{1.201} * \left(\frac{1}{x_{int}}\right)^{0.023}$$

3. Stock tank oil (P_b) ≤ 0.345 MPa (zero volatile fraction and zero intermediate fraction)

$$MMP_{CO_2} = 7.43497 * 10^5 * (T)^{1.1669} * (M_{C5+})^{1.201}$$

Emera (2006) – MMP (MPa)

T = Reservoir Temperature (F)
M_{C5+} = Average molecular weight of C_{5+} components (g/mol)
x_{vol} = Proportion of volatiles (%)
x_{int} = Proportion of intermediates (C_2-C_4)

Appendix D

Figures.

D.1: Cooper Basin Stratigraphy

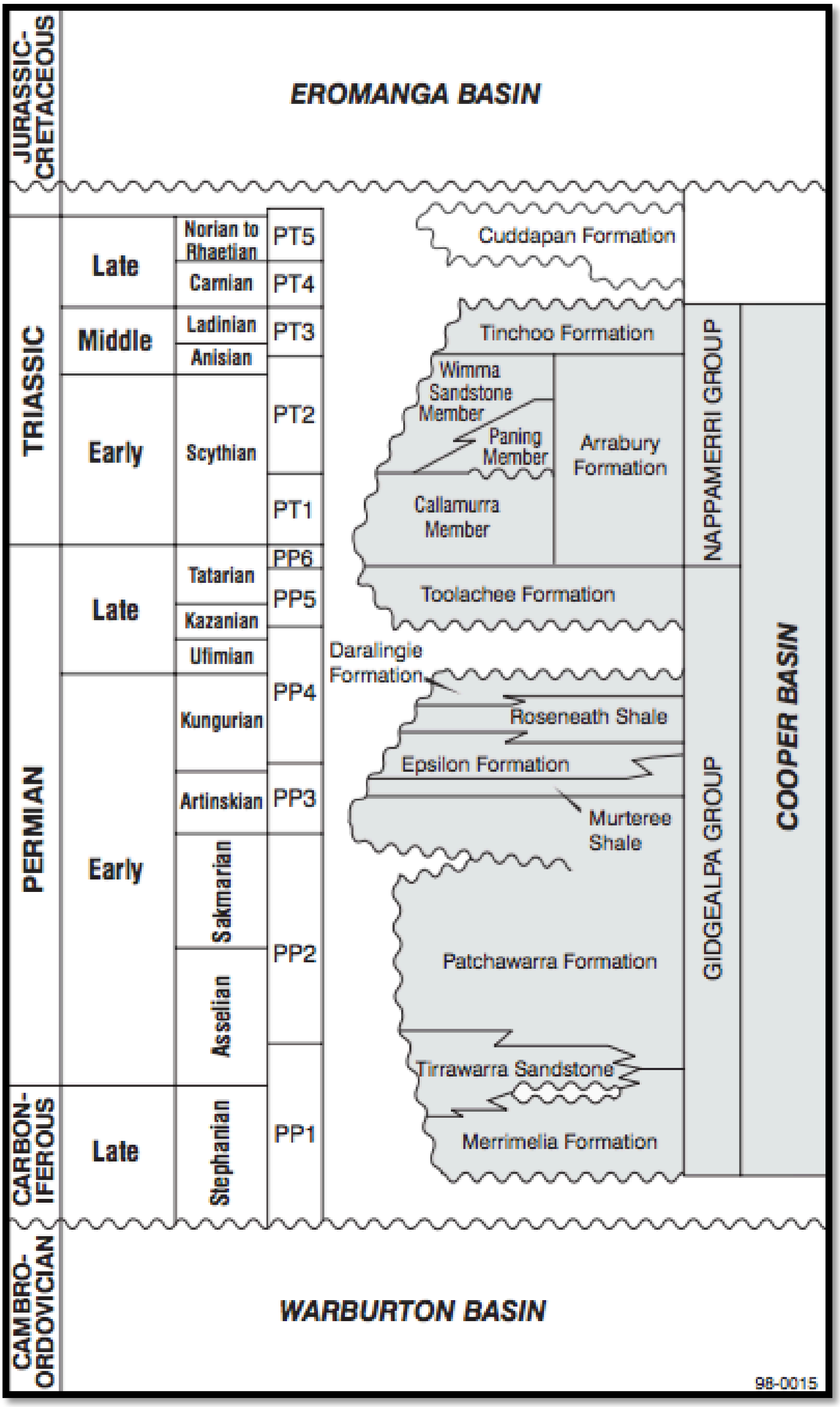

Figure D.1: Stratigraphy of the Cooper Basin (Alexander, 1999).

D.2: Eromanga Basin Stratigraphy

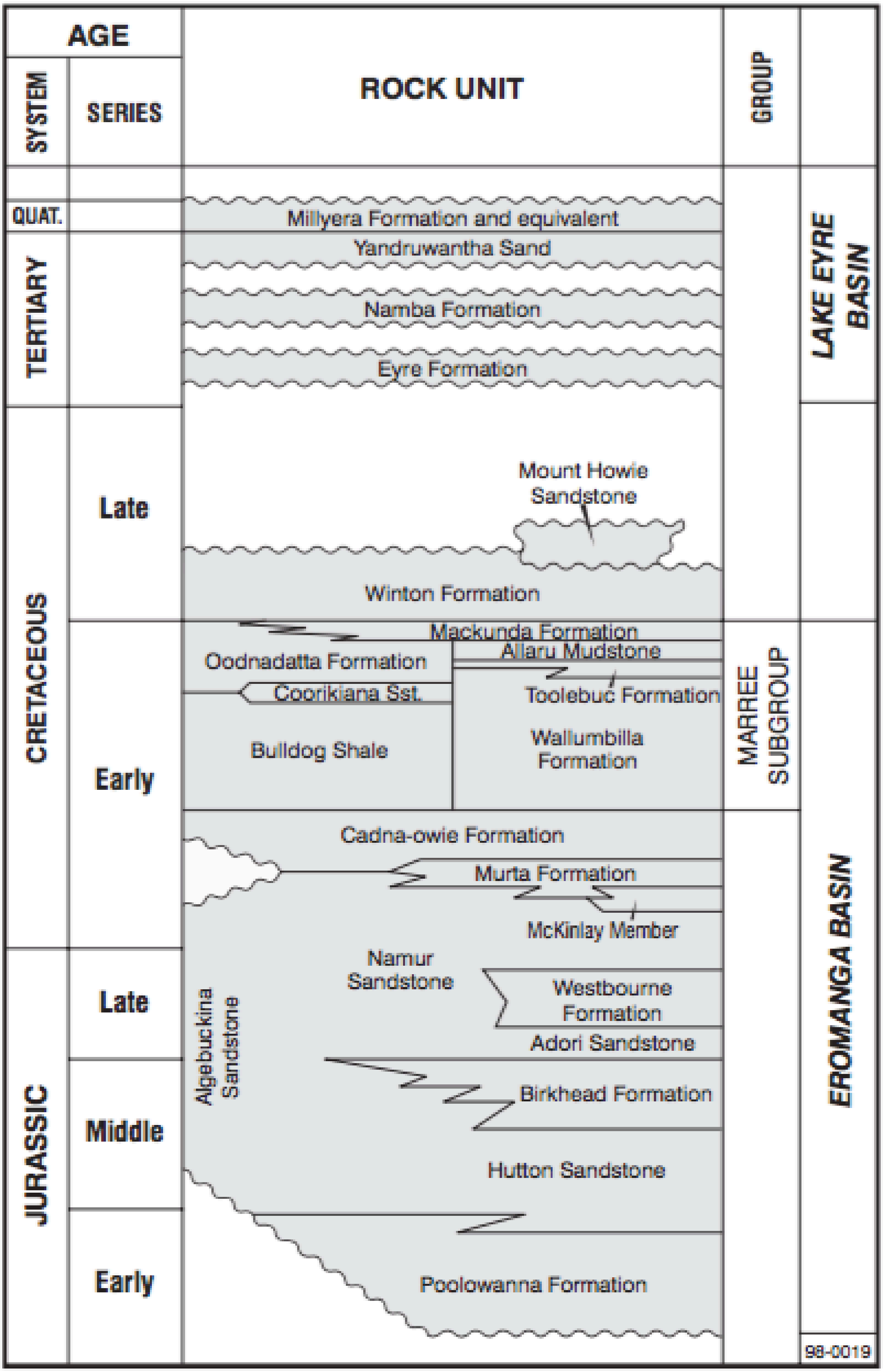

Figure D.2: Stratigraphy of the Eromanga Basin (Alexander, 1999)

D.3: MMP verses Depth

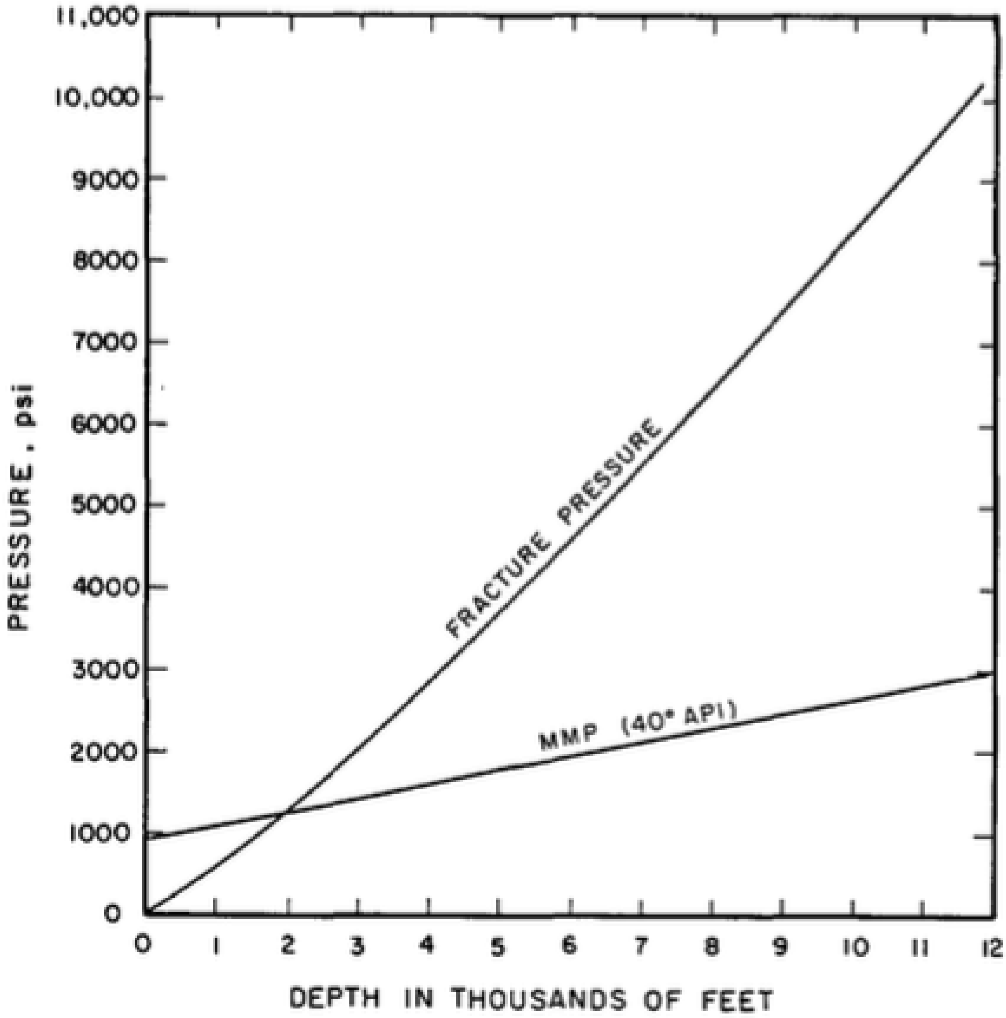

Figure D.3: Depth verses MMO (Heller and Taber, 1986)

Appendix E

Example of oil composition data.

[redacted]

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Amdel Limited
(Incorporated in S.A.)
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AMDEL LIQUID ANALYSIS SERVICE   Method R2.1

Client: SANTOS LTD   Report # F5296/89

Sample: ALWYN 3
DST 2, 4/9/89
Mooga Murta MBR, 3910-3942ft

Boiling Point Range (Deg.C)	Component	Weight%	Mol%
-88.6	ETHANE	0.03	0.20
-42.1	PROPANE	0.06	0.27
-11.7	I-BUTANE	0.13	0.45
-0.5	N-BUTANE	0.19	0.65
27.9	I-PENTANE	0.40	1.11
36.1	N-PENTANE	0.41	1.14
36.1-68.9	C-6	1.52	3.53
80.0	BENZENE	0.00	0.00
68.9-98.3	C-7	2.86	5.71
100.9	METHYLCYCHX	1.68	3.42
110.6	TOLUENE	0.00	0.00
98.3-125.6	C-8	3.29	5.76
136.1-144.4	ETHYLBZ+XYL	0.46	0.87
125.6-150.6	C-9	2.78	4.30
150.6-173.9	C-10	3.53	4.96
173.9-196.1	C-11	3.34	4.27
196.1-215.0	C-12	3.56	4.18
215.0-235.0	C-13	4.63	5.02
235.0-252.2	C-14	5.65	5.70
252.2-270.6	C-15	6.57	6.19
270.6-287.8	C-16	6.48	5.72
287.8-302.8	C-17	6.38	5.31
302.8-317.2	C-18	7.96	6.26
317.2-330.0	C-19	7.73	5.76
330.0-344.4	C-20	6.00	4.25
344.4-357.2	C-21	5.75	3.88
357.2-369.4	C-22	5.36	3.45
369.4-380.0	C-23	4.05	2.50
380.0-391.1	C-24	3.00	1.77
391.1-401.7	C-25	2.45	1.39
401.7-412.2	C-26	1.22	0.67
412.2-422.2	C-27	1.02	0.54
>422.2	C-28+	1.51	0.77
	Total	100.00	100.00

(0.00 = LESS THAN 0.01%)

The above boiling point ranges refer to the normal paraffin hydrocarbon boiling in that range. Aromatics, branched hydrocarbons, naphthenes and olefins may have higher or lower carbon numbers but are grouped and reported according to their boiling points.

Average molecular weight of C-8 plus   222 g/mol

This report relates specifically to the sample tested; it also relates to the batch insofar as the sample is representative of the Batch.

Approved Signatory

Date   05-Oct-89

This laboratory is registered by the National Association of Testing Authorities Australia. The test(s) reported herein have been performed in accordance with its terms of registration. This document shall not be reproduced except in full.

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Figure E: Example of oil composition data, taken from Alwyn 03.0.1

Appendix F

Results of the screening study.

Very Low Potential	Low potential	Potential	High Potential	Very High Potential

1	2	3	4	5	6	7
Field	**Formation**	**Depth** (m)	**Temperature** (°C)	**API gravity**	**MW**$_{c5+}$ (g/mol)	**Initial Reservoir Pressure** (MPa)

8	9	10	11	12
MMP (MPa) (Alston *et al.,* 1985) – $x_{Vol}/x_{Int} = 1$	**MMP** (MPa) (Yuan *et al.,* 2005) – $x_{Vol}/x_{Int} = 1$	**MMP** (MPa) (Emera, 2006) – $x_{Vol}/x_{Int} = 1$	**Most likely MMP** (MPa) - $x_{Vol}/x_{Int} = 1$	**Likelihood of achieving miscibility** - $x_{Vol}/x_{Int} = 1$
MMP (MPa) (Alston *et al.,* 1985) – Typical gas	**MMP** (MPa) (Yuan *et al.,* 2005) – Typical gas	**MMP** (MPa) (Emera, 2006) – Typical gas	**Most Likely MMP** (MPa) – Typical gas	**Likelihood of achieving miscibility** – Typical gas

1	2	3	4	5	6	7	8	9	10	11	12
Alwyn	Mckinlay	1234	82	42	180	12.4	21.8	19.9	19.3	20.4	10.46%
							21.7	18.0	17.8	19.1	16.52%
Alwyn	Murta	1201	86	1	210	12.5	21.5	19.6	19.5	20.2	7.31%
							21.4	17.2	17.5	18.7	13.03%
Alwyn	Namur	1246	83	42	223	12.7	22.5	20.7	20.0	21.1	6.75%
							22.4	19.4	18.9	20.2	8.47%
Arrakis	Birkhead	1867	95	48	164	19.0	18.7	14.7	16.7	16.7	70.69%
							18.6	13.5	15.5	15.9	74.91%
Big Lake	Birkhead	1950	130	43	179	19.5	23.2	21.7	24.5	23.1	23.72%
							23.1	18.9	21.9	21.3	40.34%
Big Lake	Hutton	2008	136	46	191	19.8	24.6	26.4	28.5	26.5	5.08%
							24.4	21.9	24.5	23.6	22.81%
Big Lake	Namur	1728	119	47	159	17.4	19.8	17.1	20.1	19.0	37.71%
							19.8	14.2	17.4	17.1	57.48%
Bookabourdie	Birkhead/ Hutton	2132	102	48	160	20.7	16.3	12.8	15.6	14.9	89.08%
							16.3	9.7	12.5	12.8	94.91%
Brolga	Patchawarra	2872	114	53	126	29.2	15.5	11.0	14.7	13.7	99.00%
							15.5	7.6	11.0	11.4	99.00%
Calamia West	Hutton	1476	99	43	196	15.1	24.1	21.7	22.1	22.7	0.85%
							24.0	21.0	21.4	22.1	1.82%
Calamia West	Murta	1204	81	42	211	12.3	21.8	20.1	19.4	20.4	3.62%
							21.7	17.7	17.5	18.9	9.76%
Callabonna	Birkhead	1857	124	50	152	18.9	19.1	16.4	19.9	18.4	57.77%
							19.0	16.1	19.6	18.2	59.39%
Charo	Birkhead	1775	100	48	152	18.4	17.2	13.8	16.2	15.7	75.97%
							17.1	11.9	14.4	14.5	83.16%
Daralingie	Patchawarra	2272	130	39	212	23.1	23.9	29.9	30.3	28.0	19.04%
							23.7	25.4	26.6	25.3	39.05%
Deparanie	Tirrawarra	2459	120	40	166	25.0	20.0	18.2	21.1	19.8	95.95%
							20.0	14.3	17.3	17.2	99.85%
Dirkala	Birkhead	1626	94	54	146	16.6	14.2	10.1	12.8	12.4	88.58%
							14.2	8.9	11.6	11.6	91.50%
Dullingari	Murta	1483	101	53	135	14.7	15.0	11.2	14.2	13.4	68.68%
							15.0	8.6	11.5	11.7	78.58%
Dullingari	Namur	1529	96	55	118	14.9	14.2	9.8	12.7	12.2	75.55%
							14.2	7.4	10.2	10.6	83.32%
Fly Lake	Patchawarra / Tirrawarra	2804	131	50	176	28.3	16.5	14.7	18.7	16.6	96.47%
							16.5	12.6	16.5	15.2	98.32%
Gidgealpa	Birkhead	1827	101	51	131	18.1	15.7	11.9	14.8	14.1	90.31%
							15.7	9.2	12.1	12.3	94.50%
Gidgealpa	Hutton	1832	106	49	144	18.4	17.3	13.9	16.8	16.0	76.90%
							17.3	11.1	14.0	14.1	85.35%
Gidgealpa	Namur	1585	97	45	172	16.1	21.0	17.7	19.0	19.3	26.30%
							21.0	15.7	17.2	18.0	39.67%
Gidgealpa	Poolowanna	1989	109	41	167	20.2	21.0	17.4	19.7	19.4	60.57%
							20.9	16.4	18.8	18.7	64.98%
Gidgealpa	Tirrawarra	2229	116	40	162	22.7	19.6	19.4	21.7	20.2	72.59%
							19.6	14.1	16.8	16.8	93.11%

Jena	Mckinlay	1228	80	41	205	12.5	22.4	21.2	20.0	21.2	3.31%
							22.3	18.9	18.2	19.8	9.27%
Jena	Murta	1139	82	42	273	12.5	21.8	22.0	20.6	21.5	9.51%
							21.6	19.9	19.0	20.2	14.96%
Keleary	Tinchoo	2416	125	46	133	24.6	18.1	23.4	24.2	21.9	54.00%
							18.0	21.3	21.8	20.3	57.92%
Kerinna	Hutton	1570	102	47	228	16.0	23.7	28.5	26.8	26.3	0.41%
							23.5	24.1	23.5	23.7	6.68%
Limestone Creek	Mckinlay	1240	86	-	258	12.6	25.6	30.3	26.2	27.4	1.00%
							25.4	31.4	26.9	27.9	1.00%
Limestone Creek	Murta	1210	83	42	204	12.4	21.0	19.2	18.9	19.7	4.19%
							20.8	16.2	16.5	17.8	13.57%
Malgoona	Merrimelia	2217	111	34	122	22.6	15.8	10.3	13.9	13.3	99.00%
							15.8	6.8	10.0	10.9	99.00%
Mckinlay	Namur	1243	87	41	201	12.6	20.8	19.7	19.6	20.0	8.34%
							20.7	15.7	16.4	17.6	20.99%
Meranji	Namur	1721	98	41	200	17.5	23.4	22.9	22.7	23.0	6.56%
							23.3	20.2	20.6	21.4	19.12%
Merrimelia	Birkhead	1860	106	55	106	18.9	18.6	7.1	10.6	12.1	87.35%
							18.6	4.7	7.6	10.3	91.58%
Merrimelia	Namur	1877	101	55	127	16.2	14.3	10.0	13.1	12.5	80.33%
							14.3	7.4	10.3	10.7	87.15%
Merrimelia	Nappamerri	2159	112	38	215	22.0	22.7	25.5	25.6	24.6	39.80%
							22.6	21.9	22.7	22.4	50.73%
Moorari	Birkhead	2156	114	48	136	21.6	16.5	13.2	16.6	15.4	98.62%
							16.5	10.5	13.8	13.6	99.39%
Moorari	Tirrawarra	2948	135	48	108	30.1	18.1	13.2	17.7	16.3	99.98%
							18.1	9.7	13.6	13.8	99.00%
Muteroo	Birkhead	1659	108	-	185	16.9	23.6	20.6	21.9	22.0	17.18%
							23.5	20.5	21.9	21.9	17.64%
Muteroo	Hutton	1723	109	45	184	17.3	23.5	20.6	22.1	22.1	19.17%
							23.4	19.5	21.2	21.4	24.18%
Muteroo	Patchawarra	1908	92	-	100	19.4	19.8	6.0	8.9	11.6	88.85%
							19.8	3.7	6.0	9.8	92.40%
Narcoonowie	Birkhead	1599	101	51	153	16.3	17.9	14.3	16.6	16.3	52.84%
							17.8	13.5	15.8	15.7	56.09%
Narcoonowie	Murta	1349	88	52	146	13.5	15.0	11.3	13.6	13.3	57.12%
							14.9	9.7	12.0	12.2	64.58%
Narcoonowie	Namur	1409	92	47	160	13.9	19.6	15.8	17.3	17.5	26.90%
							19.5	14.6	16.2	16.8	34.88%
Nungeroo	Namur	1263	84	41	231	13.3	24.0	24.5	22.4	23.6	0.07%
							23.9	21.9	20.6	22.1	2.06%
Pelican	Namur	1739	127	-	211	17.7	25.3	30.1	30.3	28.6	0.10%
							25.1	26.1	27.0	26.1	2.80%
Pelican	Patchawarra	2555	128	39	182	26.0	21.3	19.4	22.5	21.0	82.40%
							21.2	17.5	20.6	19.8	84.64%
Pintari North	Namur	1379	84	43	202	14.0	22.5	19.3	19.1	20.3	11.06%
							22.4	19.3	19.1	20.3	11.03%
Spencer North	Birkhead	1637	97	47	153	16.7	19.8	18.0	19.0	18.9	36.92%
							19.7	18.0	18.9	18.9	36.83%
Spencer North	Hutton	1647	103	52	152	16.8	17.3	13.8	16.5	15.9	60.95%
							17.3	13.6	16.2	15.7	62.13%
Spencer North	Namur	1427	94	43	224	14.5	25.4	25.7	24.2	25.1	0.07%
							25.2	25.0	23.7	24.6	0.32%
Spencer West	Birkhead	1617	95	44	196	16.5	23.3	20.4	20.8	21.5	17.06%
							23.2	19.9	20.4	21.1	19.43%
Spencer West	Namur	1617	95	43	210	16.5	24.8	23.2	22.7	23.5	6.86%
							24.6	22.9	22.5	23.3	7.60%
Strzelecki	Birkhead	1656	104	43	196	16.7	23.2	22.2	22.8	22.7	14.87%
							23.1	19.7	20.7	21.1	25.52%
Strzelecki	Hutton	1724	112	44	202	17.0	24.4	25.5	25.7	25.2	0.93%
							24.3	22.2	23.1	23.2	7.14%
Strzelecki	Namur	1420	108	48	137	14.3	15.8	12.2	15.5	14.5	53.25%
							15.8	10.2	13.4	13.1	64.82%

Sturt	Birkhead	1652	88	45	166	16.8	22.4	19.6	19.6	20.5	28.69%
							22.3	19.9	19.8	20.7	28.10%
Sturt	Patchawarra	1895	97	50	154	19.3	16.6	12.6	15.0	14.8	79.46%
							16.6	10.3	12.6	13.2	83.21%
Sturt	Poolowanna	1871	101	51	135	19.0	16.4	13.3	16.0	15.2	85.49%
							16.3	9.5	12.2	12.7	93.09%
Taloola	Hutton	1790	103	47	165	18.2	19.8	16.0	18.2	18.0	55.54%
							19.7	15.5	17.7	17.6	57.76%
Taloola	Namur	1403	88	43	197	14.3	22.9	19.6	19.7	20.7	7.22%
							22.8	20.0	20.0	20.9	4.77%
Taloola	Poolowanna	1866	106	49	126	19.0	16.9	12.8	15.8	15.2	77.68%
							16.9	11.2	14.1	14.0	82.60%
Tantanna	Hutton	1666	100	47	188	17.0	23.3	20.0	20.9	21.4	13.48%
							23.2	20.2	21.1	21.5	14.66%
Tantanna	Mckinlay	1361	89	48	180	13.9	20.7	16.5	17.6	18.3	14.94%
							20.6	16.8	17.8	18.4	14.53%
Tantanna	Namur	1353	89	46	173	13.8	19.8	15.5	16.9	17.4	27.23%
							19.7	16.2	17.5	17.8	24.09%
Tantanna	Poolowanna	1805	103	55	125	18.4	14.2	9.7	13.0	12.3	96.93%
							14.2	8.0	11.1	11.1	98.09%
Tirrawarra	Tirrawarra	2993	141	54	114	29.5	18.1	10.8	15.8	14.9	99.00%
							18.1	6.7	10.7	11.8	99.00%
Ulandi	Mckinlay	1238	83	40	223	12.9	23.4	22.8	21.3	22.5	0.67%
							23.2	20.6	19.7	21.2	3.57%
Ulandi	Murta	1208	83	42	198	12.4	20.5	19.4	19.1	19.7	2.49%
							20.3	16.5	16.8	17.9	11.92%
Wancoocha	Birkhead	1562	92	53	138	15.9	14.1	10.8	13.4	12.7	83.42%
							14.1	10.6	13.1	12.6	82.72%
Wancoocha	Hutton	1564	90	53	149	15.9	15.1	11.6	13.9	13.5	79.30%
							15.1	10.7	13.1	13.0	82.27%
Wancoocha	Murta	1309	79	49	147	13.3	15.0	11.2	12.9	13.0	56.80%
							15.0	10.0	11.9	12.3	61.61%
Woolkina	Tirrawarra	2724	141	54	126	30.3	15.8	13.3	18.2	15.7	99.00%
							15.8	8.9	13.2	12.6	99.00%