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 with 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 (CO₂) (MacDowell et al., 2010). It is accepted that the rise in mean earth temperature must be maintained well below 2°C 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 CO₂ 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 CO₂ by implementing enhanced oil recovery (EOR), before storing it in the subsurface. CO₂ 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 CO₂ in the subsurface (IEA, 2011). CO₂ 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 CO₂ 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 CO₂ EOR. The ensuing report contains the results of the study, along with a literature review, which discusses the industry’s experience with CO₂ 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% OOIP (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 (CO₂) 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 CO₂ into depleted reservoirs to change the properties of immobile hydrocarbons, allowing them to be produced. CO₂ 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, CO₂ EOR can also act as a means of sequestering large volumes of carbon dioxide in the subsurface. Consequently, CO₂ EOR can be considered as the utilisation component of the carbon capture, utilisation, and storage (CCUS) process.

CO₂ 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 CO₂ 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 CO₂ 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 CO₂ EOR process involves three distinct phases, the procurement of CO₂ and transportation to the well site, the injection of CO₂ into the subsurface, and the termination of the project with subsequent storage of CO₂. Each stage presents different economic and technical challenges that must be considered to ensure a successful project.

2.1.1 CO₂ Procurement and Transportation

The success of a CO₂ EOR project is greatly dependent on the feasibility of obtaining CO₂ and transporting it to the field. This is generally the most expensive stage of the CO₂ EOR process, and is a huge factor limiting the expansion of CO₂ EOR to offshore applications (Kang et al., 2016) and to regions in Europe (Hustad and Austell, 2004). The growth of CO₂ EOR activity in the United States during the 1970’s and 1980’s is largely attributed to the abundance of cheap CO₂, however nowadays the depletion of CO₂ sources and rising costs of obtaining CO₂ are hindering further growth, even limiting the progress of existing projects (Melzer, 2012).

CO₂ can be procured from either a geological source or an anthropogenic source. Geological sources refer to large accumulations of naturally occurring CO₂ in the subsurface, whereas anthropogenic sources refer to operations from which CO₂ 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 CO₂ transported in the United States (Whittaker and Perkins, 2013). Alternatively utilising anthropogenic sources of CO₂, such as fertiliser and gas plants, is far more environmentally beneficial, as it results in the sequestration of CO₂ that would otherwise be released into the atmosphere. Anthropogenic sources of CO₂ 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).

CO₂ 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 (Kalidi, 2018). The instalment of pipelines can drastically increase the activity of CO₂ EOR projects in a region, as it significantly reduces the cost of obtaining CO₂. This was experienced in the Permian Basin of West Texas and South Eastern New Mexico, who saw a major boom in CO₂ EOR activity due to the instalment of pipelines connecting three geological sources of CO₂ to the Permian Basin (Figure 2.2) (Hustad and Austell, 2004). A pipeline was also used to connect an anthropogenic source of CO₂ 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 CO₂ per day (NETL, 2010).

![Figure 2.2: CO₂ pipelines in the United States (Moritis, 2009).](image-url)
2.1.2 Injection

CO₂ 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 CO₂ increases to values comparable with oil, while viscosity remains rather low. These conditions are favourable as a high density ensures that the CO₂ 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 CO₂ 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).

Upon injection CO₂ contacts the reservoir fluid, and will begin to mix due its solubility. Interactions between CO₂ 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 CO₂ 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 CO₂. 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 CO₂. 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).

\[
E_R = E_V \times E_D
\]

\[
E_V = E_A \times E_I
\]
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 CO₂ 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 CO₂, however problems can generally be avoided by treating facilities with corrosion protection, using stainless steel, and dehydrating CO₂ (Christensen et al., 2001; Hadlow, 1992).

2.1.3 Storage

As the EOR project matures interactions between CO₂ and oil become less frequent, and the production of residual oil declines. The rate of CO₂ supplied to the well site also tapers off as more CO₂ 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 CO₂ remaining inside the reservoir (Melzer, 2012). Approximately 60% of the CO₂ 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 CO₂ is generally the most expensive stage of a CO₂ EOR project (Melzer, 2012). For this reason the obligation of the operators is to store as little CO₂ as possible, which is unlikely to change without an economic incentive (Hustad and Austell, 2004).
In the subsurface, CO₂ 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 CO₂ storage. Dissolution trapping occurs when CO₂ is dissolved in brine, which increases the density of the CO₂ 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 affects storage potential. Injecting slugs of water alternating with CO₂ have been shown to enhance dissolution trapping, while utilising horizontal wells enhances capillary trapping (Baz et al., 2016). Simulations have also shown that halting CO₂ injection once some pressure limit has been achieved optimises CO₂ storage, whilst injecting deeper into the formation will provide more formation volume in which CO₂ can be stored (Iglauer, 2011). However, the design of a CO₂ flood always considers optimising economic performance as the primary goal, meaning that unless CO₂ 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).

**Equation 2.3:** Zhao-Liao method (Zhao and Liao, 2012)
Estimates storage capacity of highly water-saturated oil fields using material balance and considering three components, CO₂ displacement, CO₂ solution in oil, and CO₂ solution in water.

\[
G_{CO_2} = \rho_{CO_2} Ah \phi S_{CO_2}
\]

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

\[
G_{CO_2} = Ah_n \phi_e (1 - S_{wi}) B \rho_{CO_2, std} F_{oil/gas}
\]

- \(G\) = Sequestration capacity
- \(\rho\) = Density of gas
- \(A\) = Area
- \(h\) = Reservoir depth
- \(\phi\) = Porosity
- \(S_{CO_2}\) = Sequestration factor
- \(B\) = Formation volume factor
- \(F\) = Energy storage efficiency
- \(S_{wi}\) = Irreducible water saturation
2.2 Subsurface Interactions

As discussed in Section 2.12 the efficiency of the CO₂ 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 CO₂ 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)

\[ N_c = \frac{\mu V}{\sigma} \]

The purpose of EOR is to improve the capillary number so that oil can flow under reasonable pressures. This is achieved through CO₂ injection, as CO₂ 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 CO₂ and oil phase (Holm, 1986). The addition of CO₂ 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 CO₂ 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 CO₂ 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 CO₂ phase, whilst CO₂ 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).

<table>
<thead>
<tr>
<th>Supercritical CO₂</th>
<th>CO₂ volatising light oil components</th>
<th>Miscibility zone</th>
<th>CO₂ condensing into oil</th>
<th>Original oil</th>
</tr>
</thead>
</table>

Figure 2.7: Miscibility stages of supercritical CO₂ and oil (Bossie-Codreanu, 2009).

![Figure 2.7: Miscibility stages of supercritical CO₂ and oil (Bossie-Codreanu, 2009).](image)

*Figure 2.8: Slim tube oil recovery (% at 1.2 HCPV) of CO₂ 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, CO₂ must be injected at a pressure exceeding MMP, however sufficient oil recovery is possible at pressures slightly below MMP (TORP, 2018). As CO₂ is not directly miscible with oil, the process may require approximately ten to twenty metres in order to induce sufficient contact between CO₂ and residual oil (Mungan, 1981a). Once miscibility is achieved a miscible front develops, where CO₂ 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 CO₂ phase and some condensation of CO₂ into the oil phase. Like miscible displacement, the addition of CO₂ to oil acts to swell the oil, reduce its viscosity, and reduce the interfacial tension (Mungan, 1981a). In addition, the extraction of oil into CO₂ 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 CO₂ 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 CO₂ 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 CO₂ slugs will naturally follow in identical paths, meaning that bypassed pore throats will remain unswept (NETL, 2010).

Figure 2.9: Illustration of CO₂ 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 unstable. 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).

\[ M = \frac{k_{r,CO_2}\mu_0}{\mu_{CO_2}k_{ro}} \leq 1 \]  

(For stability)

\[ M - G \leq 1 \]  

k = Absolute permeability  
k_r = Relative permeability  
\( \Delta P \) = Pressure drop across finger  
\( \mu \) = Viscosity  
L = Length of finger  
M = Mobility ratio

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)

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\textsubscript{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).

\[ G = \frac{k_{r,CO_2}}{\mu_{CO_2}} \left( \frac{(\rho_{CO_2} - \rho_o)gsina}{U} \right) \]

Equation 2.9: Gravity parameter (Shapiro, 2016b)

\[ M - G \leq 1 \]

k = Absolute permeability  
k_r = Relative permeability  
\( \rho \) = Density  
\( \mu \) = Viscosity  
U = Dimensionless Velocity  
g = Gravity constant  
a = Incline angle

Equation 2.10: Stability criteria (including gravity) (Shapiro, 2016b)
2.2.2.4 Asphaltene
Contact between CO\textsubscript{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\textsubscript{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\textsubscript{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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ Injection (CGI)

Continuous gas injection (CGI) (Figure 2.12) involves the continuous injection of a predetermined volume of CO₂, generally 20 to 40% hydrocarbon pore volume (HCPV) (Hadlow, 1992), without interruption from another fluid. The injected CO₂ 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 CO₂ 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 CO₂, which has been shown to be worse than all other horizontal displacement methods (Nasir and Demiral, 2012).

![Figure 2.12: Illustration of CO₂ EOR by continuous gas injection (Kansas Geological Survey, 2016)](image)

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 CO₂ slugs followed by the injection of water, which migrate towards production wells in sequential fluid banks.
Water naturally migrates through highly permeable zones, where its presence acts to lower the relative permeability of CO₂ (Nasir and Demiral, 2012). This helps to mitigate viscous fingering and encourages flow into previously unswept areas, resulting in higher ultimate recovery and reduced CO₂ 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).

The injection pattern of the wag technique may follow either a traditional or tapered approach. Traditional WAG techniques use a fixed water to CO₂ 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 CO₂ 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 channeling 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 CO₂ 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 CO₂ 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 CO₂ WAG injection, due to the handling of both water and CO₂. 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 CO₂, 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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).
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 CO₂, 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 CO₂ gave rise to the idea of direct thickeners. This involves the dissolution of some material into CO₂ 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 CO₂ 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 (McCain et al. 1996). Some of these compounds have been shown to mix with CO₂ 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 be found. (Enick and Olsen, 2012)
2.3.7 CO2 Foam

The injection of CO2 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, CO2 foams are generated by mixing gas, surfactant, and water. This creates a series of dispersed CO2 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).](image)

In the reservoir, the foam is inclined to migrate through larger pore spaces, where it encounters drag forces that cause a significant increase in apparent viscosity. As a result, CO2 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 suppress 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 create 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). CO2 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 CO2 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 CO2 foam field applications (Lee and Kam, 2013). The NWE field consists of sands varying from fine siltstone to siltstone, containing various amounts of clay. The reservoir is highly stratified with large variation in vertical permeability (Chou et al., 1992). CO2 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 CO2 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 CO2 daily (one day surfactant, one day CO2). The application of CO2 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 CO₂ EOR well patterns (Li et al., 2014).](image-url)
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 of 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).

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 CO₂ 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 CO₂ EOR mechanisms apply, however certain design considerations must be made when considering CO₂ 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 it 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).

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).

![Figure 2.19: Production history of the Seminole Unit (Melzer, 2013).](image)

<table>
<thead>
<tr>
<th>Property</th>
<th>Porosity (%)</th>
<th>Permeability (mD)</th>
<th>Water Saturation (%)</th>
<th>API Gravity</th>
<th>Oil Viscosity (cP)</th>
<th>Residual oil saturation to miscible CO$_2$ injection (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average</td>
<td>12.8 – 15</td>
<td>15</td>
<td>68</td>
<td>30</td>
<td>1.21</td>
<td>12.3</td>
</tr>
<tr>
<td>Range</td>
<td>2 – 30</td>
<td>0.01 - 400</td>
<td>60 - 80</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 2.1: Rock and fluid parameters of the Seminole Unit ROZ (Honarpour et al., 2010).
A pilot study was commissioned in 1996 to see the response of the ROZ to CO₂ 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 CO₂. 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 CO₂ 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).](image)

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 CO₂ EOR

Identifying candidates for a CO₂ 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 CO₂ 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 CO₂ 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 CO₂, and the cost of capturing, separating and reinjecting CO₂ (ARI, 2006; Johns and Dindoruk, 2013). Neal et al. (2010) provides a detailed report, estimating the costs of CO₂ 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 CO₂ 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 CO₂ EOR project.

Both sandstone and carbonate reservoirs are suitable for CO₂ 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 CO₂ 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 CO₂ flood, as it directly influences whether miscibility can be achieved and if CO₂ 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 CO₂ 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 a criteria to assess the suitability of a reservoir for CO₂ EOR. In general deeper wells are preferable as fracture pressure increases faster with depth than reservoir pressure, meaning MMP and supercritical CO₂ 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 CO₂ to be injected, as the CO₂ 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 C₅ to C₁₂ 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°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°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 CO₂ 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 CO₂ flood they should be considered in the economic analysis, along with other economic factors such as price of oil, government incentives, and cost of CO₂ 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 CO₂ 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

<table>
<thead>
<tr>
<th>Reference</th>
<th>Oil Viscosity (cP)</th>
<th>Oil Gravity API</th>
<th>Oil Composition</th>
<th>Oil Saturation (%PV)</th>
<th>Depth (ft)</th>
<th>Temperature (F)</th>
<th>Porosity (%)</th>
<th>Permeability (mD)</th>
<th>Net Thickness (ft)</th>
<th>Reservoir Pressure (PSI)</th>
<th>Initial Pore Pressure Gradient</th>
<th>Gas Cap</th>
<th>Natural Water Drive Fractures</th>
<th>Already Undergoing EOR</th>
<th>Commingled OIP (MMSTB)</th>
<th>Remaining Oil Fraction (%)</th>
<th>Remaining Oil Fraction (MMSTB)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kang et al. (2016)</td>
<td>&lt;6</td>
<td>0.4 - 6</td>
<td></td>
<td>&gt; 17</td>
<td>&gt; 1600</td>
<td>82 - 260</td>
<td>3 - 37</td>
<td>Homogeneous</td>
<td>Thin unless dipping</td>
<td>&gt; MMP</td>
<td>&lt; Grad(Smin)</td>
<td>None to minor</td>
<td>None to weak</td>
<td>No</td>
<td>No</td>
<td>&gt;20</td>
<td>&gt;5</td>
</tr>
<tr>
<td>Bachu (2016)</td>
<td>0.4 - 6</td>
<td>22 - 45</td>
<td></td>
<td>22 - 40</td>
<td>1600 - 13,365</td>
<td>NC</td>
<td>NC</td>
<td>Homogeneous</td>
<td>Thin unless dipping</td>
<td>&gt; 1500</td>
<td></td>
<td>No</td>
<td>Local or No</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Brashear et al. (1978)</td>
<td>&lt; 12</td>
<td>&gt; 20</td>
<td>High percentage of C5-C12</td>
<td>&gt; 20</td>
<td>1600 - 13,365</td>
<td>NC</td>
<td>NC</td>
<td>Homogeneous</td>
<td>Thin unless dipping</td>
<td>&gt; 2500</td>
<td></td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>&gt;25</td>
<td></td>
</tr>
<tr>
<td>Taber et al. (1997)</td>
<td>&lt; 10</td>
<td>&gt; 25</td>
<td>High percentage of C5-C12</td>
<td>&gt; 25</td>
<td>&gt; 2500</td>
<td>NC</td>
<td>NC</td>
<td>Homogeneous</td>
<td>Thin unless dipping</td>
<td>&gt; 5000</td>
<td></td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alvarado et al. (2002)</td>
<td>&lt; 15</td>
<td>&gt; 5</td>
<td>NC</td>
<td>&gt; 25</td>
<td>&gt; 5000</td>
<td>NC</td>
<td>NC</td>
<td>Homogeneous</td>
<td>Thin unless dipping</td>
<td>&gt; 2500</td>
<td></td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>&gt;25</td>
<td></td>
</tr>
<tr>
<td>Al-Bahar et al. (2004)</td>
<td>&lt;10</td>
<td>&gt;13</td>
<td>NC</td>
<td>&gt;25</td>
<td>&gt;5000</td>
<td>NC</td>
<td>NC</td>
<td>Homogeneous</td>
<td>Thin unless dipping</td>
<td>&gt; 2500</td>
<td></td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 2.3: Previously suggested screening criteria for immiscible CO₂ flooding

<table>
<thead>
<tr>
<th>Reference</th>
<th>Oil Viscosity (cP)</th>
<th>Oil Gravity API</th>
<th>Oil Composition</th>
<th>Oil Saturation (%PV)</th>
<th>Depth (ft)</th>
<th>Gas Cap</th>
<th>Natural Water Drive</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Taber et al., 1997b)</td>
<td>&lt; 600</td>
<td>&gt; 13</td>
<td>NC</td>
<td>&gt; 35%</td>
<td>&gt; 1800</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>(Taber et al., 1997a)</td>
<td>&gt; 13</td>
<td>&gt; 1800</td>
<td>No</td>
<td>&gt; 1800</td>
<td>&gt; 50%</td>
<td>Local or No</td>
<td>No</td>
</tr>
<tr>
<td>(Al-Bahar et al., 2004)</td>
<td>&gt; 13</td>
<td>&gt; 200m</td>
<td>No</td>
<td>&gt; 200m</td>
<td>&gt; 2500</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

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 CO₂ 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 CO₂ per day, in an inverted five spot pattern over forty acres.

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

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

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

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

### 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 C₅⁺ components of the hydrocarbons. MMP is generally lower for hydrocarbons containing a higher proportion of C₅ – C₁₂ components (Holm and Josendal, 1982), although this is untrue when considering multi ring aromatic compounds, as they do not disperse into the CO₂ 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 (CH₄, N₂) have been shown to hinder miscibility, while intermediate components (C₂, C₃, C₄, CO₂, H₂S) aid miscibility (, 2009). This is an important fact to consider when deciding on the purity of the injection fluid, as although pure CO₂ 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 CO₂ 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 CO₂ 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 CO₂, with the proportion of CO₂ averaging 17% basin-wide. This has resulted in the release of 1.8 million tonnes of CO₂ into the atmosphere through gas production alone (Radke, 2009).

Implementing CO₂ EOR in the Cooper-Eromanga Basin system has been proposed since the 1980s, however, as of yet, it has never materialised. Recently interest into CO₂ 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 CO₂ EOR to recover from residual oil zones, the success of CO₂ EOR seen internationally, and the increasing pressure on the industry to reduce their CO₂ footprint.

![Figure 2.22: Production decline curve of the Cooper-Eromanga Basin System](Image)

**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 fluvial 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°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°API), non-waxy, low sulphur, paraffinic crudes, whereas oils of Jurassic origin are paraffinic and waxy, and are similar to oils originating from 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).
2.6.3 Challenges and Knowledge Gaps

With deep, tight reservoirs containing light oil of low viscosities, and a source of anthropogenic CO₂ as a by-product of gas production, the Cooper-Eromanga Basin system appears perfectly suited to CO₂ EOR. The prospect of implementing CO₂ 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 CO₂ EOR is to be successful in Australia.

The success of CO₂ EOR in the United States during the 1970’s and 1980’s is attributed to the availability of cheap sources of CO₂, 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 CO₂ 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 CO₂ EOR.

Currently there appears to be a gap in the literature regarding the suitability of CO₂ 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 CO₂ EOR. Another issue identified is that there appears to be no cohesive and inclusive database available that will help to assess the region.
A screening study was performed to assess the suitability of oil producing fields in the Cooper and Eromanga Basins to undergo CO₂ EOR. The objective of this study was to identify fields that have a higher potential to be suitable for CO₂ 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 CO₂ 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>
<thead>
<tr>
<th>Property</th>
<th>Condition</th>
<th>Relevance</th>
<th>Sourced from</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (ft)</td>
<td>&gt; 600 m</td>
<td>To achieve supercritical CO₂ and avoid fractures or leaks</td>
<td>Al-Bahar et al. (2004)</td>
</tr>
<tr>
<td>Temperature (F)</td>
<td>&gt; 31.1°C</td>
<td>To achieve supercritical CO₂</td>
<td>Al-Bahar et al. (2004), Bachu (2016)</td>
</tr>
<tr>
<td>Reservoir Pressure (PSI)</td>
<td>&gt; MMP</td>
<td>To achieve miscibility</td>
<td>Al-Bahar et al. (2004)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Property</th>
<th>Condition</th>
<th>Relevance</th>
<th>Justification for dismissing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Viscosity (cP)</td>
<td>&lt; 10</td>
<td>Favourable mobility</td>
<td>Insufficient data. Also Australian oils are known to be of low viscosity</td>
</tr>
<tr>
<td>Oil Saturation (%PV)</td>
<td>&gt; 17</td>
<td>Economic (size of the prize)</td>
<td>Economic consideration and insufficient data</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>3 - 37</td>
<td>Range of current projects</td>
<td>Not critical (Bachu, 2016)</td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>Homogeneous preferred</td>
<td>Prevents channelling</td>
<td>Subjective and high variability (Bachu, 2016)</td>
</tr>
<tr>
<td>Net Thickness</td>
<td>Thin unless dipping</td>
<td>Conformance control</td>
<td>Subjective</td>
</tr>
<tr>
<td>Initial Pore Pressure Gradient</td>
<td>&lt; Grad (5min)</td>
<td>Prevents fracturing the reservoir</td>
<td>More important for CO₂ storage than EOR (Kang, 2016)</td>
</tr>
<tr>
<td>Gas Cap</td>
<td>None to minor</td>
<td>Added complexity</td>
<td>Not critical (Kang, 2016)</td>
</tr>
<tr>
<td>Natural Water Drive</td>
<td>None to weak</td>
<td>Added complexity</td>
<td>Not critical</td>
</tr>
<tr>
<td>Fractures</td>
<td>None to minor</td>
<td>Prevents channelling</td>
<td>Subjective and not critical (Kang, 2016)</td>
</tr>
</tbody>
</table>
## 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).](image)

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

<table>
<thead>
<tr>
<th>Already Undergoing EOR</th>
<th>No</th>
<th>Avoids added complexity</th>
<th>Economic consideration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commingled</td>
<td>No</td>
<td>Prevents channelling</td>
<td>Insufficient evidence</td>
</tr>
<tr>
<td>OIIP (MMSTB)</td>
<td>12.5</td>
<td>Economic (size of the prize)</td>
<td>Economic consideration and insufficient data</td>
</tr>
<tr>
<td>Remaining Oil Fraction (%)</td>
<td>&gt; 20</td>
<td>Economic (size of the prize)</td>
<td>Economic consideration and insufficient data</td>
</tr>
<tr>
<td>Remaining Oil Fraction (MMSTB)</td>
<td>&gt; 5</td>
<td>Economic (size of the prize)</td>
<td>Economic consideration and insufficient data</td>
</tr>
</tbody>
</table>
weight percentage (Appendix E); occasionally the data also included the average molecular weight of C₈⁺ 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 CO₂ was then calculated.
Table 3.3: Composition of typical gas.

<table>
<thead>
<tr>
<th>Component</th>
<th>Weight %</th>
<th>Mol %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen (N₂)</td>
<td>0.01</td>
<td>0.07</td>
</tr>
<tr>
<td>Carbon Dioxide (CO₂)</td>
<td>0.11</td>
<td>0.43</td>
</tr>
<tr>
<td>Methane (CH₄)</td>
<td>0.05</td>
<td>0.95</td>
</tr>
<tr>
<td>C₂⁺</td>
<td>99.83</td>
<td>98.55</td>
</tr>
</tbody>
</table>

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**

\[
\frac{n_\%}{M} = \frac{\sum_{i=2}^{28} \left( \frac{m_\%}{M_i} \right) \times 100\%}{\sum_{i=2}^{28} \left( \frac{m_\%}{M_i} \right)}
\]

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 \( M_W \) is the average molecular weight of C₄⁺ components, \( n \% \) is the molar percentage, and \( M \) is the molar mass. To account for the error associated with gas chromatography, the \( M_{W8+} \) 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 \( M_{W8+} \) was not given, a minimum and maximum possible value of \( M_{W8+} \) was assumed. The minimum and maximum possible values were considered to be the calculated \( M_{W8+} - 10 \) g/mol, and the calculated \( M_{W8+} + 1 \) g/mol respectively. These corrections were decided upon after comparing the measured \( M_{W8+} \) values to the calculated \( M_{W8+} \) values.

**Equation 3.2: Average molecular weight**

\[
M_{W_{C4+}} = \frac{\sum_{i=2}^{28} (n_i \% \times M_i)}{\sum_{i=2}^{28} n_i \%}
\]

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 \( M_{W8+} \) was not given in the completion reports. The maximum and minimum values of MMP were calculated using the maximum and minimum values of \( M_{W8+} \) (see 3.3.2) in the MMP calculation; \( M_{W8+} \) 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 CO₂, 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 CO₂ 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 CO₂ 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 CO₂. 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.](image-url)
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.](image)

The average molecular weight of C₅⁺ components (MW₃⁺) in the oil was plotted against API gravity (Figure 4.3) and depth (Figure 4.4). API gravity and MW₃⁺ exhibit a clear relationship, where MW₃⁺ decreases linearly with API gravity at a rate of approximately 6.6 g/mol. As expected, the relationship between MW₃⁺ and depth strongly resembles the relationship between API and depth, although MW₃⁺ decreases with respect to depth. MW₃⁺ of oils in the Eromanga Basin range from 100 to 280 g/mol, while in the cooper basin the MW₃⁺ of oil ranges from 100 to 220 g/mol.

![Figure 4.3: Relationship between MW₃⁺ and oil API gravity.](image)
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.
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).
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 value

\[
\text{Proportion} = \frac{\text{Maximum Value} - \text{Actual Value}}{\text{Maximum Value} - \text{Minimum Value}}
\]

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.


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).

The calculated probability of a reservoir achieving miscibility is a function of initial reservoir pressure, temperature, and MWC5+. Figures 4.11, 4.12, and 4.13 show the relationship between the probability of a reservoir achieving miscibility with respect to MWC5+, reservoir temperature, initial reservoir pressure, and reservoir depth respectively. 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. Alternatively the likelihood of achieving miscibility displays a clear relationship with MWC5+, and is shown to decrease as the MWC5+ increases, which is expected. Finally the relationship between achieving miscibility and the initial reservoir pressure is shown to be rather strong, whereby the likelihood of achieving miscibility increases as the initial reservoir pressure increases.

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

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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 MWC5+.
A sensitivity analysis was performed to see how the variables of temperature, $\text{MW C}_5^+$, and initial reservoir pressure influence the likelihood that a reservoir will achieve miscibility. 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 $\text{MW C}_5^+$, temperature, 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 $\text{MW C}_5^+$, temperature, and initial reservoir pressure were 180 g/mol, 110°C (230°F), and 17.5 MPa (2538 PSI) respectively. The analysis shows the likelihood of a reservoir achieving miscibility is highly sensitive to values of $\text{MW C}_5^+$ and initial reservoir pressure, demonstrating that the chance of a reservoir achieving miscibility decreases rapidly as $\text{MW C}_5^+$ increases, whilst the contrary is true for initial reservoir pressure. Increasing temperature is shown to decrease the likelihood of a reservoir achieving miscibility, however MMP is far less sensitive to temperature than initial reservoir pressure and $\text{MW C}_5^+$ over the ranges provided.
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 (CO₂). 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 C₅+ components (MW₅⁺). Reservoir temperature is also shown to increase with respect to depth, while MW₅⁺ 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 MW₅⁺ parameter, which lowers MMP.

5.2 Oil Composition

Hydrocarbons with a lower MW₅⁺ were shown to significantly improve the probability of a reservoir achieving miscibility with CO₂. This is because MW₅⁺ was shown to be the most influential parameter in the determination of MMP, where MMP increases steadily with increasing MW₅⁺. MW₅⁺ was also shown to decrease with respect to depth, although this relationship is weak and subject to high variability. The relationship between MW₅⁺ 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 MW₅⁺, 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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>
<thead>
<tr>
<th>Temperature (°C)</th>
<th>MW_{C5+} (g/mol)</th>
<th>MW_{C7+} (g/mol)</th>
<th>Int_{C2-C4} (%)</th>
<th>Int_{C2-C6} (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yuan et al. (2005)</td>
<td>22 – 149</td>
<td>-</td>
<td>139 – 319</td>
<td>-</td>
</tr>
<tr>
<td>Alston et al. (1985)</td>
<td>32 – 117</td>
<td>169 – 302</td>
<td>-</td>
<td>0.2 – 39.4</td>
</tr>
<tr>
<td>Emera (2006)</td>
<td>32 – 137</td>
<td>136 – 248</td>
<td>-</td>
<td>0.2 – 39.4</td>
</tr>
<tr>
<td>C &amp; E Basins</td>
<td>80 – 141</td>
<td>100 – 272</td>
<td>110 – 279</td>
<td>0 – 15.6</td>
</tr>
</tbody>
</table>

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 CO₂ 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 CO₂, 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 CO₂.
- The Cooper-Eromanga Basin system appears to be well suited for CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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


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

- **Drilling:** 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.

- **Logging:** 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 dolomitization.

- **Mud Logging:** 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.

- **Core Samples:** Core samples taken in ROZs of carbonate reservoirs tend to reveal a mixed-wet to oil-wet region, due to secondary dolomitization. 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

<table>
<thead>
<tr>
<th>ACTIVITY</th>
<th>EVIDENCE</th>
<th>CLASSIC INTERPRETATION</th>
<th>ROZ INTERPRETATION</th>
<th>ROZ EXPLANATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling</td>
<td>Oil on pits</td>
<td>Transition zone/MP remnant oil</td>
<td>Presence of ROZ highly likely</td>
<td>Oil wet reservoir. Oil is released during drilling. Often seen in ROZ's</td>
</tr>
<tr>
<td>Drilling Break</td>
<td>Aquifer / No Significance</td>
<td>Good Reservoir</td>
<td>Open marine environment. Good cycles and flow units.</td>
<td></td>
</tr>
<tr>
<td>Mud Logging</td>
<td>Cut in samples</td>
<td>Transition Zone / MP Remnant</td>
<td>Oil saturation present</td>
<td>Residual Oil Saturation is present</td>
</tr>
<tr>
<td></td>
<td>Dull gold Fluorescence in samples</td>
<td>Transition Zone / MP Remnant</td>
<td>&quot;Water washed&quot; oil</td>
<td>Indicative of Mother Nature's Waterflood. Reduced Saturation of oil.</td>
</tr>
<tr>
<td></td>
<td>Odor in samples</td>
<td>Transition Zone / MP Remnant</td>
<td>Oil saturation present</td>
<td>Indicative of Mother Nature's Waterflood. Reduced Saturation of oil.</td>
</tr>
<tr>
<td></td>
<td>Gas show</td>
<td>Not expected. From Oil Zone above if present</td>
<td>Oil saturation present</td>
<td>Indicative of Mother Nature's Waterflood. Reduced Saturation of oil.</td>
</tr>
<tr>
<td></td>
<td>&quot;Free&quot; Sulfur crystals</td>
<td>Suggest at or below O/W contact</td>
<td>Mother Natures Waterflood</td>
<td>Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.</td>
</tr>
<tr>
<td></td>
<td>Sulfur and Anhydrite</td>
<td>No significance</td>
<td>Mother Natures Waterflood</td>
<td>Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.</td>
</tr>
<tr>
<td></td>
<td>Sulfur and Calcite</td>
<td>No significance</td>
<td>Mother Natures Waterflood</td>
<td>Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>ROZ is not in pressure communication with a Main Pay</td>
</tr>
<tr>
<td>DST</td>
<td>Sulfur or Black Sulfur water</td>
<td>Not unusual / No significance</td>
<td>To be Expected</td>
<td>Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.</td>
</tr>
<tr>
<td></td>
<td>Salty Sulfur water</td>
<td>Not unusual / No significance</td>
<td>To be Expected</td>
<td>Result of activity of Sulfate Reducing Bacteria. Indicates Meteoric Derived Flushing.</td>
</tr>
<tr>
<td></td>
<td>Lower Salinity than expected</td>
<td>Not unusual / No significance</td>
<td>Meteoric Derived Flushing</td>
<td>Indicative of Mother Nature's Waterflood. Meteoric Derived Flushing.</td>
</tr>
<tr>
<td></td>
<td>&quot;Skim&quot; of Oil</td>
<td>Not unusual / No significance</td>
<td>To be Expected</td>
<td>Oil Wet reservoir. Small amounts of Oil is released during pressure drop.</td>
</tr>
<tr>
<td></td>
<td>Good to Excellent Pressure</td>
<td>Not unusual / No significance</td>
<td>To be Expected</td>
<td>ROZ is not in pressure communication with a Main Pay</td>
</tr>
<tr>
<td>Logging</td>
<td>RW different than MP</td>
<td>Not unusual / No significance</td>
<td>ROZ water chemistry different than MP</td>
<td>RW is different because the meteoric derived sweep is composed of lower salinity water.</td>
</tr>
<tr>
<td></td>
<td>So &gt; 30% in calculations</td>
<td>Might be productive</td>
<td>ROZ. Residual to waterflood and MNW</td>
<td>RW is different because the meteoric derived sweep is composed of lower salinity water.</td>
</tr>
<tr>
<td></td>
<td>Different flow than MP needed</td>
<td>Not unusual / No significance</td>
<td>Rocks have undergone a second diagenetic event</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Excellent Parity in dolomite</td>
<td>Not unusual / No significance</td>
<td>Open Marine + Sweep associated dolomitization</td>
<td>Thicker open marine cycles and Secondary dolomitization in ROZ during sweep.</td>
</tr>
<tr>
<td></td>
<td>&quot;Looks like a Winner&quot;</td>
<td>set casing</td>
<td>ROZ can have appearance attributable to production on completion</td>
<td>ROZ thicker cycles. secondary dolomitization. salinity differences make calculations difficult</td>
</tr>
<tr>
<td>Core Analysis</td>
<td>5-40% oil saturation</td>
<td>Zones with higher water saturation non-productive</td>
<td>Saturations expected following MNW</td>
<td>Expected. So after Meteoric Derived Sweep</td>
</tr>
<tr>
<td></td>
<td>Oil Wet Core</td>
<td>Consider log analysis</td>
<td>Sweep related fabric destructive dolomitization &gt;&gt; Oil water</td>
<td>Expected after Sweep related fabric destructive dolomitization</td>
</tr>
<tr>
<td></td>
<td>Open marine facies</td>
<td>Good Quality reservoir. thick cycles and flow units</td>
<td>ROZ's tend to be found in more open marine settings</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SHR near base and/ or top</td>
<td>Suspect oilwater contact(s)/water washing</td>
<td>Water Washing from Meteoric Derived Flushing</td>
<td>Multiple SHR Zone suggest Multiple O/W contact. Both Paleo and Recent.</td>
</tr>
<tr>
<td></td>
<td>Better Porosity and Perm than main pay</td>
<td>Not unusual / No significance</td>
<td>Good Quality reservoir. thick cycles and flow units</td>
<td>ROZ's tend to be found in more open marine settings</td>
</tr>
<tr>
<td></td>
<td>Sulfur Crystals</td>
<td>Diagnosis - no interpretation</td>
<td>Free sulfur often found in ROZ</td>
<td>Conversion by Sulfate reducing bacteria results in free sulfur.</td>
</tr>
<tr>
<td></td>
<td>Sulfur and Anhydrite</td>
<td>Diagnosis - no interpretation</td>
<td>Free sulfur often found in ROZ</td>
<td>Conversion by Sulfate reducing bacteria results in free sulfur.</td>
</tr>
<tr>
<td></td>
<td>Sulfur and Calcite</td>
<td>Diagnosis - no interpretation</td>
<td>Free sulfur often found in ROZ</td>
<td>Conversion by Sulfate reducing bacteria results in free sulfur.</td>
</tr>
<tr>
<td></td>
<td>Specity Oil Stain</td>
<td>Consider Log Analysis</td>
<td>Intervals with low perm in ROZ</td>
<td>Intervals with low perm in ROZ can have remnant high saturations.</td>
</tr>
<tr>
<td></td>
<td>Leached molds</td>
<td>Not unusual / No significance</td>
<td>Leaching during MNW</td>
<td>Leaching during MNW.</td>
</tr>
<tr>
<td></td>
<td>Leached Fractures</td>
<td>Not unusual / No significance</td>
<td>Leaching during MNW</td>
<td>Leaching during MNW.</td>
</tr>
<tr>
<td></td>
<td>Fabric Destructive dolomite</td>
<td>Not unusual / No significance</td>
<td>Secondary dolomitization in ROZ during sweep</td>
<td>Secondary dolomitization in ROZ during sweep.</td>
</tr>
<tr>
<td></td>
<td>Limestone below oil stained interval</td>
<td>Not unusual / No significance</td>
<td>Zone is below Sweep ROZ</td>
<td>Zone is below Sweep ROZ.</td>
</tr>
<tr>
<td>Completion</td>
<td>large volumes of fluid (sulfur water)</td>
<td>expect a decrease in water production over time</td>
<td>Large volumes of water cut on IP indicates an ROZ</td>
<td>Swept down to residual to waterflood. good porosity and perm in open marine.</td>
</tr>
<tr>
<td></td>
<td>Less than 5% oil</td>
<td>expect an increase in oil production over time</td>
<td>&gt;85% water cut on IP indicates an ROZ</td>
<td>Swept down to residual to waterflood.</td>
</tr>
<tr>
<td></td>
<td>Good Pressure</td>
<td>Not unusual / No significance</td>
<td>ROZ not drained. to be expected</td>
<td>Thinner cycles in MP don't reduce pressure in ROZ.</td>
</tr>
<tr>
<td></td>
<td>Lower Salinity than expected</td>
<td>Suspect water flow</td>
<td>Meteoric Derived water</td>
<td>Meteoric Derived water has lower salinity.</td>
</tr>
<tr>
<td></td>
<td>Different Scale than in Main Pay</td>
<td>Suspect water flow</td>
<td>Different water chemistry</td>
<td>MNW changes water chemistry significantly.</td>
</tr>
</tbody>
</table>

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

2. Oil with bubble point pressure (P_b) < 0.35 MPa
   \[ MMP_{CO_2} = 8.78 \times 10^{-4} \times (T)^{1.06} \times (M_{C5+})^{1.78} \]

---

Alston et al. (1985) – MMP (PSI)

\[ T = \text{Reservoir Temperature (F)} \]
\[ M_{C5+} = \text{Average molecular weight of C}_5^+ \text{ components (g/mol)} \]
\[ x_{vol} = \text{Proportion of volatiles} \]
\[ x_{int} = \text{Proportion of volatiles (C}_2^{-}\text{C}_4) \]

---

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

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

\[ MMP_{CO_2} = a_1 + a_2 M_{C7+} + a_3 P_{C2-C6} + a_4 M_{C7+} + a_5 P_{C2-C6} + a_6 (M_{C7+})^2 T \]
\[ + (a_7 + a_8 M_{C7+} + a_9 (M_{C7+})^2 + a_{10} P_{C2-C6}) T^2 \]

---

Yuan et al. (2005) – MMP (PSI)

\[ T = \text{Reservoir Temperature (F)} \]
\[ M_{C5+} = \text{Average molecular weight of C}_5^+ \text{ components (g/mol)} \]
\[ x_{vol} = \text{Proportion of volatiles (g/mol)} \]
\[ x_{int} = \text{Proportion of volatiles (C}_2^{-}\text{C}_4) \]

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1. Oil with bubble point pressure (P_b) > 0.345 MPa
   \[ MMP_{CO_2} = 7.43497 \times 10^5 \times (T)^{1.1669} \times (M_{C5+})^{1.201} \times \left(\frac{x_{vol}}{x_{int}}\right)^{0.109} \]

2. Stock tank oil (P_b) ≤ 0.345 MPa (zero volatile fraction and non-zero intermediate fraction)
   \[ MMP_{CO_2} = 7.43497 \times 10^5 \times (T)^{1.1669} \times (M_{C5+})^{1.201} \times \left(\frac{1}{x_{int}}\right)^{0.023} \]

3. Stock tank oil (P_b) ≤ 0.345 MPa (zero volatile fraction and zero intermediate fraction)
   \[ MMP_{CO_2} = 7.43497 \times 10^5 \times (T)^{1.1669} \times (M_{C5+})^{1.201} \]

---

Emera (2006) – MMP (MPa)

\[ T = \text{Reservoir Temperature (F)} \]
\[ M_{C5+} = \text{Average molecular weight of C}_5^+ \text{ components (g/mol)} \]
\[ x_{vol} = \text{Proportion of volatiles (g/mol)} \]
\[ x_{int} = \text{Proportion of volatiles (C}_2^{-}\text{C}_4) \]
Appendix D

Figures.

D.1: Cooper Basin Stratigraphy

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

Figure E: Example of oil composition data, taken from Alwyn 03.0.1
Appendix F
Results of the screening study.

### Appendix F

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**Note:** Results of the screening study.
<p>| Jena      | Mckinlay  | 1228 | 80 | 41 | 205 | 12.5 | 22.4 | 21.2 | 20.0 | 21.2 | 3.31% |
| Jena      | Murta     | 1139 | 82 | 42 | 273 | 12.5 | 21.8 | 22.0 | 20.6 | 21.5 | 9.51% |
| Keleary   | Tinchoo   | 2416 | 125| 46 | 133 | 24.6 | 18.1 | 23.4 | 24.2 | 21.9 | 54.00%|
| Kerinna   | Hutton    | 1570 | 102| 47 | 228 | 16.0 | 23.7 | 28.5 | 26.8 | 26.3 | 0.41% |
| Limestone Creek | Mckinlay  | 1240 | 86 | -  | 258 | 12.6 | 25.6 | 30.3 | 26.2 | 27.4 | 1.00% |
| Limestone Creek | Murta     | 1210 | 83 | 42 | 204 | 12.4 | 21.0 | 19.2 | 18.9 | 19.7 | 4.19% |
| Malgoona  | Merrimelia| 2217 | 111| 34 | 122 | 22.6 | 15.8 | 10.3 | 13.9 | 13.3 | 99.00%|
| Mckinlay  | Namur     | 1243 | 87 | 41 | 201 | 12.6 | 20.8 | 19.7 | 19.6 | 20.0 | 0.34% |
| Meranji   | Namur     | 1721 | 98 | 41 | 200 | 17.5 | 23.4 | 22.9 | 22.7 | 23.0 | 6.56% |
| Merrimelia| Birkhead  | 1860 | 106| 55 | 106 | 18.9 | 18.6 | 7.1  | 10.6 | 12.1 | 97.35%|
| Merrimelia| Namur     | 1877 | 101| 55 | 127 | 16.2 | 14.3 | 10.0 | 13.1 | 12.5 | 80.33%|
| Merrimelia| Nappanerri| 2159 | 112| 38 | 215 | 22.0 | 22.7 | 25.5 | 25.6 | 24.6 | 39.80%|
| Moorari   | Birkhead  | 2156 | 114| 48 | 136 | 21.6 | 16.5 | 13.2 | 16.6 | 15.4 | 98.62%|
| Moorari   | Tirrawarra| 2948 | 135| 48 | 108 | 30.1 | 18.1 | 13.2 | 17.7 | 16.3 | 99.14%|
| Muteroo   | Birkhead  | 1659 | 108 | -  | 185 | 16.9 | 23.6 | 20.6 | 21.9 | 22.0 | 17.39%|
| Muteroo   | Hutton    | 1723 | 109 | 45 | 184 | 17.3 | 23.5 | 20.6 | 22.1 | 22.1 | 19.17%|
| Muteroo   | Patchawarra| 1908 | 92 | -  | 100 | 19.4 | 19.8 | 6.0  | 8.9  | 11.6 | 88.85%|
| Narcooowie| Birkhead  | 1599 | 101| 51 | 153 | 16.3 | 17.9 | 14.3 | 16.6 | 16.3 | 52.84%|
| Narcooowie| Murta     | 1349 | 88 | 52 | 146 | 13.5 | 15.0 | 11.3 | 13.6 | 13.3 | 57.12%|
| Narcooowie| Namur     | 1409 | 92 | 47 | 160 | 13.9 | 19.6 | 15.8 | 17.3 | 17.5 | 26.90%|
| Ningeroo  | Namur     | 1263 | 84 | 41 | 231 | 13.3 | 24.0 | 24.5 | 22.4 | 23.6 | 0.07% |
| Pelican   | Namur     | 1739 | 127 | -  | 211 | 17.7 | 25.3 | 30.1 | 30.3 | 28.6 | 0.10% |
| Pelican   | Patchawarra| 2555 | 128| 39 | 182 | 26.0 | 21.3 | 19.4 | 22.5 | 21.0 | 82.40%|
| Pintari North | Namur    | 1379 | 84 | 43 | 202 | 14.0 | 22.5 | 19.3 | 19.1 | 20.3 | 11.06%|
| Spencer North | Birkhead | 1637 | 97 | 47 | 153 | 16.7 | 19.8 | 18.0 | 19.0 | 18.9 | 36.92%|
| Spencer North | Hutton  | 1647 | 103| 52 | 152 | 16.8 | 17.3 | 13.8 | 16.5 | 15.9 | 60.95%|
| Spencer North | Namur   | 1427 | 94 | 43 | 224 | 14.5 | 25.4 | 25.7 | 24.2 | 25.1 | 0.01% |
| Spencer West | Birkhead| 1617 | 95 | 44 | 196 | 16.5 | 23.3 | 20.4 | 20.8 | 21.5 | 17.06%|
| Spencer West | Namur   | 1617 | 95 | 43 | 210 | 16.5 | 23.2 | 22.2 | 22.8 | 22.7 | 14.87%|
| Strzelecki | Birkhead  | 1656 | 104| 43 | 196 | 16.7 | 23.2 | 22.2 | 22.8 | 22.7 | 14.87%|
| Strzelecki | Hutton    | 1724 | 112| 44 | 202 | 17.0 | 24.4 | 25.5 | 25.7 | 25.2 | 0.93% |
| Strzelecki | Namur     | 1420 | 108| 48 | 137 | 14.3 | 15.8 | 12.2 | 15.5 | 14.5 | 54.25%|</p>
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