Moonie CO_2 Enhanced Oil Recovery (EOR) Project

Initial Injection Plan 2021

Chapter 7: Hydrogeology

Commercial in Confidence

The Moonie Oil Well 27 (M27)

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7.0 Executive Summary

This chapter examines the Moonie Oil Field Hydrogeology. It includes a discussion of hydrogeological topics and elements such as formation porosity, permeability, hydraulic conductivity, physical pressure and volume concepts, and water pressure gradient analysis that clearly delineate different water qualities in the “Precipice oily water leg”, the overlying Evergreen and the lower main “Precipice water leg”.

To date approximately 60 MM tonnes of water and oil have been extracted from the Moonie Oil Field. This project intends to inject 120,000 tonnes of CO_2 p.a. for 8 years totalling 1 million tonnes or approximately 1.7% of the extracted volume. As such no water will be displaced from outside of the anticline and as no conduit to the surface exists (apart from human intervention) as detailed by the University of Queensland (UQ), there will be no impact to surface or near surface groundwater resources.

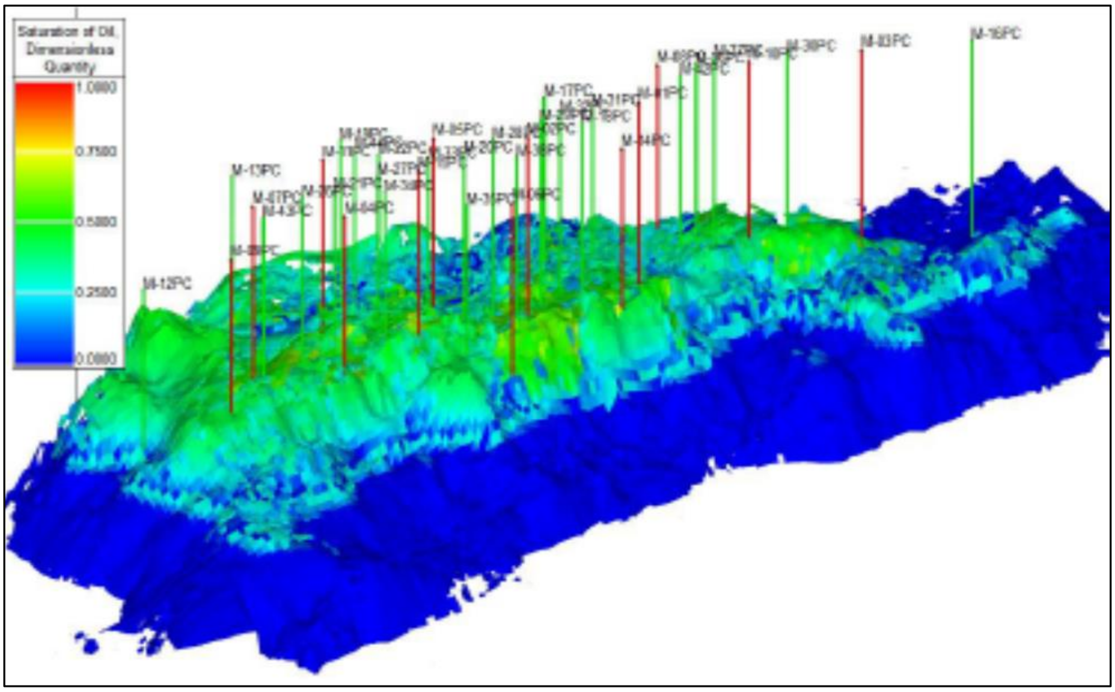
The objective of this section is to discuss the potential and modelled physical impact and aspects of injecting CO_2 into the Precipice oily water leg. Specifically, the formations surrounding the injection point at M27, 1,500m sub surface. Section 7.3 specifies a maximum temperature adjusted upper injection pressure threshold to prevent any impact on the geologic transition zone or sealing barriers.

The ultimate seal has extremely low permeability (Harfoush et al. 2019a, 2019b, 2019c and Honari et al. 2019a) with core plug measurements of horizontal maximum corrected water permeability ranging from 0.003 to 0.086 mD (arithmetic average of 0.037 mD).

From a physical sciences viewpoint the conclusion from research and modelling indicates that there is no significant physical impact on sealing barriers from the injection pressure, provided the recommended upper injection pressures are not exceeded. The recommended injection pressures are detailed in Table 7-1 and in the general Table from Chapter 1, Table 1-1. This is further discussed in this chapter and also the risk assessment in Chapter 12 and to a lesser extent Chapter 11 and 13.

Figure 7.1 is a 3D model of the Moonie Oil Field, Precipice “Oily Water Leg” (in bright green) sitting over the Precipice Formation water leg (in blue). It illustrates the dome-like anticline structure in which oil, solution gas and water are trapped. It also illustrates the location of the existing Moonie Oil Field wells and shows how the Precipice Sandstone drapes over the pre-Permian structure.

Figure 7.1 The 3D Moonie Anticline



Reservoir static and dynamic models have been created (by Bridgeport and independently by UQ) based on pressure data collected downhole from existing wells over the past 50 years. These models forecast future oil reservoir pressure changes over time and movement of CO_2 within the oil reservoir under various injection regimes.

The models forecast a potential minor local increase of pressure in the water column within 0.5 km of <0.2 m in head, which will be observable from the production-monitoring boreholes surrounding the injection well M27. At the planned injection rate of up to 120,000 tonnes of CO_2 per annum, a relatively small injection volume, the model predicts no change in the water column height of local boreholes within the immediate Moonie Oil Field precinct. Modelling shows that CO_2 injection activities will have no impact on local landholders.

It has been documented that there is substantially more impact from CSG operations, which are active in the shallower formations of the greater regional area. The Condamine Irrigation Alliance reports borehole water column height drops within their boreholes averaging >80 m due to the combination of several factors, including CSG operations and drought. These factors need to be taken into consideration when considering potential impacts to local boreholes.

Due to the small injection volume any thermal effect will occur in the immediate injection zone and will be localised within the upper oily water leg within the anticline, having no effect outside the anticline and not impact the greater Precipice main water leg or the reservoir seal. (see section 7.4).

7.1 Introduction

This initial project proposes injecting scCO_2 into the Precipice “oily water-leg” for the purpose of increasing the ultimate oil recovery from the Moonie oilfield. The potential environmental impacts of injecting CO_2 have been carefully considered within the project area, particularly in relation to the Precipice and other formations (detailed below).

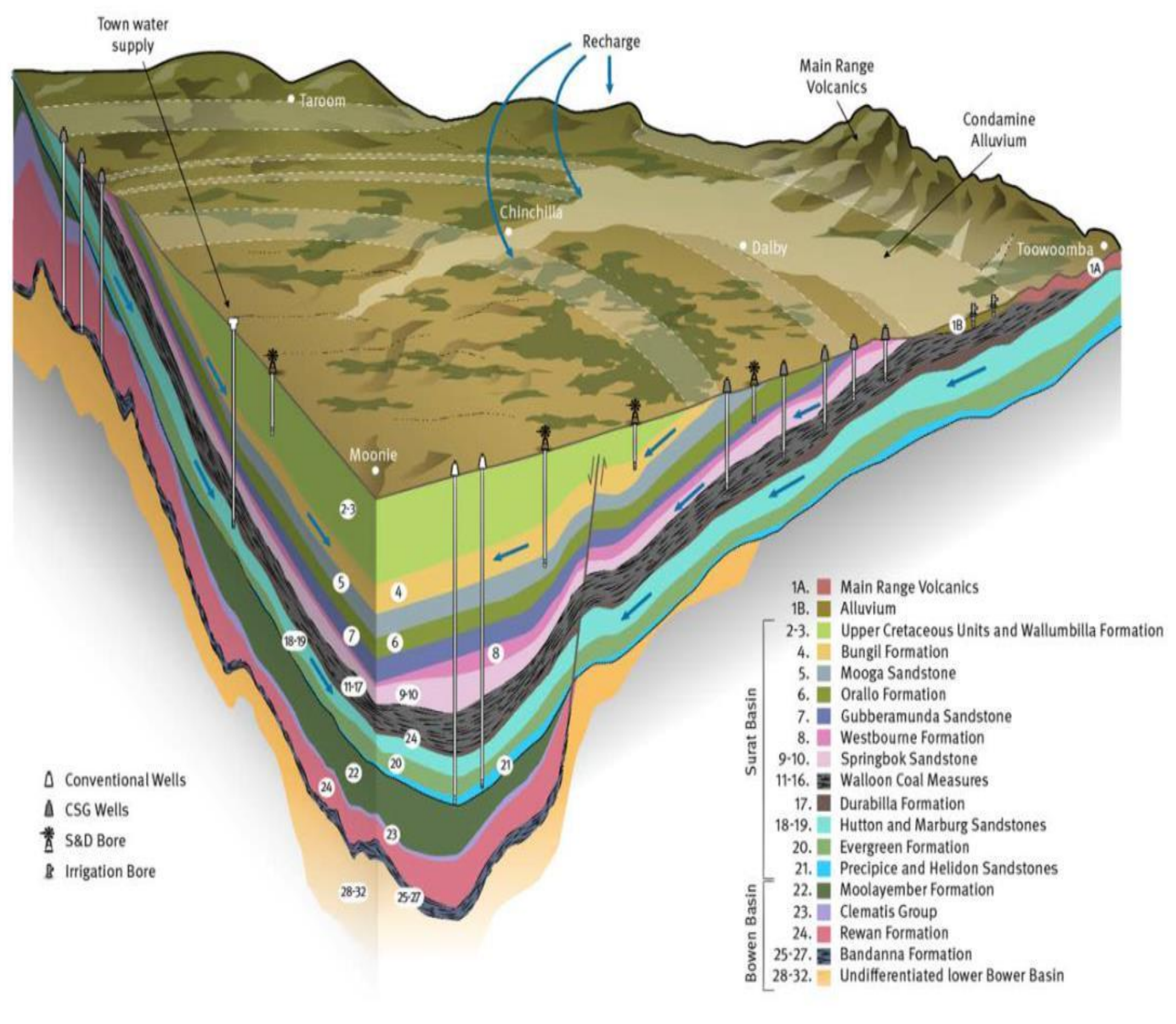
The PL1 Moonie Oil Field is located within the southwestern area of the Surat Cumulative Management Area (CMA) where the Queensland Government Office of Groundwater Impact Assessment (OGIA) has developed a large-scale groundwater hydrostatic model from the collective underground water impact studies submitted from companies and organisations located within this region. The OGIA model predicts and reports on gross aquifer pressure changes across a large area.

From the surface, the geological units present at Moonie and their hydro stratigraphic classification by OGIA (2016) are:

- Springbok Sandstone: a major aquifer,
- Walloon Coal Measures: productive coal seams,
- Eurombah Formation: aquitard,
- Hutton Sandstone: major aquifer,
- Evergreen Formation: aquitard,
- Precipice Sandstone: major aquifer, and
- Moolayember Formation: aquitard/minor aquifer.

Figure 7-2 represents a hydro stratigraphic model of the Surat Basin groundwater illustrating the layered sequence of aquifers (sandstone reservoirs) and aquitards (shaly silty seals) with the surface location of Moonie indicated in the lower left-hand corner (OGIA 2016)

Figure 7-2, A 3D Hydro-stratigraphic model of the Surat Basin (OGIA 2016)



7.1.1 Local well borehole water column heights.

The existing production wells in the Moonie Oil Field are sub-artesian, meaning that the oil and water cannot flow naturally to surface due to lack of reservoir pressure, so artificial lift (pumping) is utilised. The original oil reservoir pressure within the Moonie field has diminished slightly over the six decades of production. At the proposed CO_2 injection volume and rates, the model predicts that the oil reservoir pressure in the field will increase, but insufficiently to reach original reservoir pressure. However, once production ceases then the model predicts the oil reservoir pressure will over time approach the original reservoir pressure.

The Moonie Oil Field anticlinal structure has trapped the existing gases (including existing 5% CO_2), oil and water within the structure for an estimated 60 Ma proving the efficacy of the seals.
The Hydrogeological studies collectively completed by Bridgeport and UQ include:

- the regional and local geological structure and formation properties (see Chapter 6),
- the groundwater systems inside the oil reservoir and in the layers above and below the oil reservoir,
- the chemistry and water pressure gradients of the groundwater (see Chapter 8), and
- the potential impact on the groundwater receiving environment (see Chapter 13).

7.2 “Precipice Oily Water Leg” Permeability and Hydraulic Conductivity

Average horizontal permeability of the upper Precipice oily water leg is approximately 580 mD (millidarcy) and vertical permeability 127 mD with an average porosity of 16.8%. This is based on core analysis (permeability tests conducted by University of Queensland), production well testing and drill stem tests of the discovery wells and is further discussed in Chapter 9 Predictive Reservoir Models and Petrophysics.

The Evergreen Formation and Moolayember Formation (see Figure 7-2), which overlie and underlie the Precipice Sandstone respectively, are typically one to two orders of magnitude lower permeability than the Precipice (OGIA 2016) and include impermeable aquitard layers. Digital core analysis and mercury injection capillary pressure data for the Evergreen Formation (as reported in Chapter 9, Petrophysics) support this conclusion and demonstrate that the Evergreen has a lower permeability in the Moonie field.

7.3 Injection Pressures

Fracture pressures, thermal effects, and fault reactivation pressures as constraints to maximum bottomhole injection pressures and minimum temperature have been examined. Some conclusions are:

- Injection pressures (flowing bottom hole pressures) will need to be constrained (reduced) to remain below a thermally adjusted estimate of the fracture gradient (see specification in Table 7-1 below),
- Reservoir fracture pressure can be reduced due to thermal effects (cooling) from CO_2 injection, particularly at high injection rates. This is factored into the calculation of the maximum allowable fracture pressure detailed below on the assumption such a condition is realised,
- The recommended pressures are detailed in Table 7-1 below as estimated by UQ,

Table 7-1, Recommended Bottom Hole Pressures (BHPs)

Item	Bottom Hole Pressures	
	(kPa)	(psi)
Maximum Allowable Injection Pressure (thermally adjusted - 14.5% from the fracture pressure of the overlying seal)	39,388	5,712
Casing Yield Pressure * depends on type and design,	26,500	3,844
Miscibility * depends on temperature and pressure of $scCO_2$	>11,380	>1,605
Estimated Injection pressure range, depends on temperature, mass, density	11,380 to 39,388 Depending on yield pressures	1,605 to 5,712 Depending on yield pressures

7.3.1 Co2 Miscibility Effect

The CO_2 miscibility effect is highly dependent on a range of factors such as temperature, pressure, pore throat size and geochemistry of the receiving formation water. The recommended bottomhole pressure conditions listed above have been modelled and the injection pressure will be substantially below the temperature adjusted fracture pressure of the receiving formation and overlying seal. Injection pressure is subject to trial, but the upper injection pressure will be limited b the thermally adjusted pressure, which is significantly lower than the formation fracture initiation pressure estimated by UQ.

7.3.2 Fault Slip Analysis

Fault slip analysis using Monte Carlo simulation (to account for uncertainties in stresses and fault orientations/geometries in the deeper part of the Surat Basin) suggests the pressure at which fault slip would occur (P90 = 53,150 kPa, mean = 57,250 kPa) is substantially higher than the BHP limit of any injection well, as determined by other operational constrains. It is thus not a significant risk to this injection project

7.3.3 Subsurface pressure constraints on injection

Injecting $scCO_2$ (or any other fluid) will increase the pressure in the immediate injection zone. This increase in pressure, will be largest around the perforated interval of the injection well and decreases with distance (both horizontal and vertical) away from the well (this is predicted by the model in Chapter 9). A pressure threshold at surface will limit the injection pressure of the $scCO_2$. to maintain safe operations.

7.3.4 Fracture pressure

If the pressure at the injection well reaches a certain level it is possible to mechanically fracture the rock. The pressure at which this occurs is the fracture pressure of the formation. Exceeding the fracture pressure will cause fractures to propagate into or through the receiving formation and/or the overlying sealing formation. Therefore, the bottom hole pressure (BHP) of the injection well should not be allowed to increase above the fracture pressure. A safety margin should be employed to ensure this does not occur, with BHP limited to 90% of the fracture pressure as the maximum limit of injection wells, a value used in Canadian EOR operations (Bachu and Gunter 2005).

An additional consideration when assessing the actual fracture pressure as a limit for the injection well BHP, is a further reduction in fracture pressure due to possible thermal effects of injecting relatively cool $scCO_2$ into a relatively warm reservoir.

Vilarrasa et al (2015) determined that the thermal effects were only evident in the injection zone and “lowest tens of metres” of caprock in their injection models in Salah, Algeria. This suggests if the caprock is thick enough, the thermal effects of CO_2 injection are unlikely to jeopardize the top seal capacity.

The Precipice “Blocky Sandstone Reservoir” in the Surat Basin is overlain by a Transition Zone, which is typically 20-80m thick. The Transition Zone is geologically complicated with significantly lower permeability than the underlying Blocky Sandstone Reservoir, however, it is not being considered as the main seal for containment of $scCO_2$. Simple UQ-SDAAP project models of notional $scCO_2$ injection in the including thermal effects showed that the cooling effect of the $scCO_2$ is focused on the injection well completion area or zone.

7.4 Thermal effected injection zone

UQ constructed a simulation model of a well completion at the base of the Blocky Sandstone Reservoir. In the model, injected $scCO_2$ was 30°C cooler than the initial reservoir temperature and it was estimated that the lowest 5m of the (geologic) Transition Zone was cooled by 20°C after 30 years of injection at a rate 10 times greater than this initial project injection rate (Rodger et al. 2019c). This initial project considers a much smaller injection volume and period, significantly diminishing the potential effect described by Rodgers above.

While much larger than the proposed initial project, the full-scale Moonie injection model is similar in scale to simulations by Vilarrasa et al (2015) which suggests that while the lower part of the geologic Transition Zone will experience some cooling, there will be no thermal effect propagating up to the overlying Ultimate Seal. Nonetheless, 90% of the ‘thermally adjusted’ fracture pressure will serve as a bottomhole pressure limit for notional injection wells.

With improved understanding of the geomechanics (i.e., the stress profile) of the Transition Zone, it may be possible to safely inject above the fracture pressure of the reservoir. These properties will be examined during this initial injection project.

7.5 Slip Tendency

Since pressure during injection diffuses radially, and rapidly decreases with distance from the injection well, potential injection sites should be located away from significantly faulted areas to eliminate the risk of $scCO_2$ leakage through the MG fault. Reservoir modelling has shown that the CO_2 does not approach the MG fault over the initial 8-year project and that the original reservoir pressure will not be reached. Given the small injection volume and the proposed operational BHP limits, the risk of fault slip is remote to nil.

7.6 Fault Reactivation Pressure

As well as assessing fracture pressure as a limit to well BHP, fault reactivation pressure was assessed probabilistically by UQ using a Monte-Carlo approach and Mohr Coulomb failure analysis. It suggested that the pressure at which fault slip would occur is likely to be significantly higher than the BHP limit (avoiding inducing fractures in the blocky sandstone reservoir) of any injection well. Injection wells need to be located away from any faulted areas (to mitigate the risk of CO_2 leakage through faults). Pressure quickly decreases with distance from the injection well due to radial diffusion of the relatively minute volume in an extremely large container and it is extremely unlikely that fault slip would occur due to injection operations.

7.6.1 Conclusions

If 90% of the mid-case fracture pressure is used as the operating maximum bottomhole pressure (BHP) for injection wells, the BHP limit would be 39,750 kPa at 2,300m. If injection wellhead pressure (WHP) is controlled at surface, then this BHP limit would not be reached during the $scCO_2$ injection project.

7.7 Groundwater Chemistry

The groundwater chemistry of the oil reservoir is unique and naturally contains crude oil, other associated chemical compounds (e.g., BTEX) and formation water. These characteristics are entirely different to the Evergreen Aquifer and the Precipice Main Water Leg and is further discussed in the section on Groundwater Geochemistry (see Chapter 8).

7.7.1 Impact of CO_2 on water quality and seals

Core from the Moonie field was analysed by UQSDAAP for porosity and mineral content to build geochemical models and predict chemical reactions between the formation water of injected $scCO_2$. The current base line formation water quality is listed in Chapter 2, Table 2-5: Average Moonie Water Quality Readings, this data is gathered quarterly.

The Precipice sandstone in the Moonie Oil Field has been found to have different mineral and pore characteristics than studied well core samples in the northern regions of the Surat Basin.

The analysis of the $scCO_2$-formation water-rock minerals behaviour model indicates a general formation water pH decrease can be expected in the Moonie Precipice Sandstone (‘58 sands’) buffered by higher dissolved bicarbonate content (than in the northern Surat Basin) and by minor mineral dissolution to a pH of 4.8-5.3 over time.

In the laboratory experiments and in modelling by UQ, the addition of $scCO_{2,}$ resulted in the water pH being buffered to 5-5.6. (Rodgers etal 2019) Ankerite and minor kaolinite was precipitated in cleaner sandstones, and smectite in clay-rich sandstones and shales samples of the Moonie core. Precipitation of smectite may maintain or improve sealing capacities of clay rich seals and may adsorb CO_2.

The formation water in the Precipice ”58-10” sands is carbonate rich solute which has an inherently high buffering capacity. The reaction of these formation waters with carbonic acid (when CO_2 forms an acid in the presence of water) and the 3 chemical methods of chemical entrapment are discussed in Chapter 8 Groundwater Chemistry. The predicted alteration of carbonates and feldspar is consistent with observations from experiments using relative permeability reactions performed as part of the UQSDAAP & CTSCo projects. Precipitation of kaolinite, ankerite, smectite has been observed where there has been natural CO_2 alteration.

Evidence of previous natural thermogenetic CO_2 and hydrothermal fluid alteration, fractured quartz grains, and fracture fills has been observed to occur with mineral trapping as carbonates in core samples throughout the Surat Basin. Similar reactions will occur with the mild acid produced from the CO_2 and water as explained in Chapter 8.

An analysis of the Precipice oily water leg indicates the water within the oil reservoir is:

- of very low surface beneficial water quality, due to the oily water characteristics (Table 2-5), and other factors discussed below. When it arrives at the surface it is directed to evaporation dams and BEL has no beneficial reuse arrangements with the landowners nearby,
- being of a “disturbed” nature brought about by constant pumping over several decades, and
- without treatment is unfit for any commercial-beneficial use.

Being in an anticlinal structure, the Precipice oily water leg is not directly connected to the surface or sub-surface hydrological systems (aquifers) used by landowners in the area.