Injection Design for Simultaneous Enhanced Oil Recovery and Carbon Storage in a Heavy Oil Reservoir

by

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Declaration

I declare that this thesis

Injection Design for Simultaneous Enhanced Oil Recovery and Carbon Storage in a Heavy Oil Reservoir

is entirely my own research under the supervision of Professor Martin J. Blunt and Dr. Tara C. LaForce. The research was carried out in the Department of Earth Science and Engineering at Imperial College London. All published and unpublished material used in this thesis has been given full acknowledgement. None of this work has been previously submitted to this or any other academic institution for a degree or diploma, or any other qualification.

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Abstract

We have identified a CO$_2$ and water injection strategy to recover moderately heavy oil and store carbon dioxide (CO$_2$) simultaneously. We propose the use of counter-current injection of gas and water to improve reservoir sweep and trap CO$_2$; water is injected in the upper portion of the reservoir and gas is injected in the lower portion. This process is referred to as water over gas injection or modified simultaneous water alternating gas injection (SWAG). This thesis is based on the results of quasi-validated compositional reservoir simulations in that exact matches were not obtained for the disparate fluids and reservoirs properties but the trends of oil recovery and water cut were accepted as representative of comparative physical mechanisms of displacement. We have compared oil recovery and water cut trends of the compositional simulation model to the displacement experiments conducted by Dyer and Farouq Ali[1] where varying injection rates, number of WAG cycles and size of CO$_2$ slug were investigated. Dyer and Farouq Ali’s displacement experiments used an Aberfeldy crude mixed with liquid petroleum to obtain an oil viscosity of 1055 mPa.s at standard conditions to represent viscosity reservoir conditions. The fluid description used in our compositional simulations are based on PVT-matched properties of oil found in an unconsolidated deltaic, sandstone deposit in the Gulf of Paria, offshore Trinidad. At standard conditions the crude viscosity is 1175 mPa.s and at reservoir conditions (81° C and 27.9 MPa) 8 mPa.s. In this region oil density ranges between 940 and 1010 kg/m$^3$ (9-18 degrees API). The PVT properties were matched by regressing: the 3-parameter Peng-Robinson[2] equation of state to the oil relative volume, total relative volume and; the coefficients of the Lohrenz Bray Clark [3]correlation to the viscosity of the crude between 0 and 20MPa at 81.7 °C.

The reservoir simulation model was scaled to the length to width ratio of the displacement experiment and, the ratio of gravitational to viscous forces of injected water used in
displacement experiments. From this we study we identified the limitations of WAG and the injection parameters favourable to oil recovery, gas trapping and gas storage capacity.

We have then used a synthetic reservoir to represent an unconsolidated sand measuring 1000m × 150m × 100m with average porosity of 26% and initial water saturation of 20% to investigate with representative parameters, determined from the comparison with the displacement experiments, to investigate the efficacy of water over gas injection. The original oil in place (OOIP) is \(3.12 \times 10^6\) m\(^3\) (19 MMbbl). The two water injection rates investigated, 100 and 200 m\(^3\)/day (630 and 1260 bbl/day). These rates correspond to water gravity numbers (dimensionless ratio of viscous to gravity forces) 6.3 to 3.1 for our reservoir properties. The gas injection surface rate was 50 000 sm\(^3\)/day (1.8 Mscf/day) in both instances corresponding to gas gravity numbers ranging between 150 and 200 with varying reservoir flow rates. We have applied this injection strategy using vertical producers with two injection configurations: single vertical injector and a pair of horizontal parallel laterals. The producer was vertical in each case.

The impact of miscibility was investigated by varying the injection gas composition by comparing the effect of using pure CO\(_2\) and a mixture of CO\(_2\) and C\(_2\)-C\(_6\) in a 2:1 ratio, on oil recovery, carbon storage and field performance. Eight simulation runs were conducted varying injection gas composition for miscible and immiscible gas drives, water injection rate and injection well orientation. Our results show that water over gas injection can realize oil recoveries ranging from 17 to 30% of original oil in place (OOIP). In each instance more than 50% of the injected CO\(_2\) remains in the reservoir with less than 15% of retained CO\(_2\) in the mobile phase. The remaining CO\(_2\) is distributed in oil, water and trapped gas phases.

Our reservoir simulations show that water over gas injection can be applied successfully to recover heavy oil and trap CO\(_2\) in an unconsolidated sand. This injection design has also shown immiscible and miscible oil recovery can be improved with horizontal injection. Water injection
over gas injection increases contact between injected CO$_2$ by dispersing the injected gas over a wider volume in the reservoir, hindering gas override and providing reservoir pressure support. Gas storage is inversely proportional to the water gravity number because of the effect the injected water has on gas saturation distribution. In combination with established industry reservoir management techniques such as pressure control and gas cycling, it may be possible to further improve the oil recovery and carbon storage of water over gas injection.
List of Publications


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# Table of Contents

Declaration .......................................................................................................................................................................... 2  
List of Publications ........................................................................................................................................................... 6  
Acknowledgements ......................................................................................................................................................... 7  
Table of Contents .............................................................................................................................................................. 8  
List of Figures .................................................................................................................................................................. 10  
List of Tables .................................................................................................................................................................... 19  
Nomenclature .............................................................................................................................................................. 21  

## Chapter 1

### Introduction

1.1 Motivation ................................................................................................................................................................. 26  
1.1.1 Objectives and Tools ............................................................................................................................................ 33  
1.1.2 Thesis Outline ...................................................................................................................................................... 34  

## Chapter 2

### Literature Review

2.1 Carbon Storage Overview ........................................................................................................................................... 35  
2.2 CO₂ Enhanced Oil Recovery ...................................................................................................................................... 39  
2.2.1 Heavy Oil Characterisation .................................................................................................................................. 41  
2.3 CO₂ Solubility in Heavy oil ........................................................................................................................................... 44  
2.4 Governing equations ..................................................................................................................................................... 47  
2.4.1 Mass conservation ................................................................................................................................................... 47  
2.4.2 Flow through porous media ................................................................................................................................... 49  
2.4.3 Phase Behaviour Prediction ................................................................................................................................... 50  
2.5 Immiscible CO₂ EOR ....................................................................................................................................................... 54  
2.5.1 Sweep Efficiency .................................................................................................................................................... 54  
2.5.2 Gravity dominated displacement .............................................................................................................................. 56  
2.6 Three-phase Relative Permeability ............................................................................................................................ 59  
2.6.1 Relative Permeability Hysteresis ............................................................................................................................ 60  
2.7 Gas Trapping ................................................................................................................................................................. 66  
2.8 CO₂ EOR in Trinidad .................................................................................................................................................... 68  
2.9 Geologic Storage of CO₂ ............................................................................................................................................ 70
List of Figures

Figure 1.1: Geological storage options for CO₂ reproduced from IPCC 2005 after Cook [8, 10]. 27

Figure 1.2: Map showing location of major CO₂ emission sources at Point Lisas and Point Fortin. Reproduced from Mohammed-Singh and Singhal[14]. 29

Figure 1.3: Pie chart showing contribution of major sources of CO₂ emissions in Trinidad and Tobago in 2009, reproduced from Boodlal et al[12]. 30

Figure 1.4: Pie chart showing contribution of processing plants, petrochemical and manufacturing industries at Point Lisas Industrial Estate to CO₂ emissions in Trinidad and Tobago in 2009, reproduced from Boodlal et al.[12]. 31

Figure 2.1: Location of ongoing and planned CO₂ geologic storage projects reproduced from IPCC 2005: Carbon Capture and Storage[23]. 36

Figure 2.2: Reproduction of the CO₂ storage classification system proposed by Cooperative Research Centre for Greenhouse Gas Technologies (CO₂CRC)[28] (modified from the SPE Petroleum Resource Management System[29]). 38

Figure 2.3: CO₂ pressure-temperature phase diagram showing the triple and critical points of pure CO₂ and conditions for solid, liquid, gaseous and supercritical phases reproduced from Bachu, 2003[62]. 40

Figure 2.4: Variation of CO₂ density with temperature and pressure, showing the range of density that would be encountered in sedimentary basins worldwide for various hydrostatic and lithostatic pressure conditions reproduced from Bachu, 2003 [62]. 41

Figure 2.5: Comparison of the Conradson carbon residue, sulphur content and asphaltene content of crude samples as a function of API gravity.[37] 43

Figure 2.6: Semi log plot of the effect of CO₂ on the viscosity of heavy oil of specific gravity 0.953 (17 API) at 24, 60 and 93 °C reproduced from Chung et al [67]. 45

Figure 2.7: Percent error in viscosity prediction of carbon dioxide-heavy oil mixtures using a correlation developed by Chung et al [67] on heavy crude at 24, 60 and 93 °C. 47

Figure 2.8: Semi-log plot of the water gravity number as a function of injection rate for a reservoir measuring 1000m × 150m × 100m with water and oil density of 990 and 890 kg/m³ respectively, water and oil viscosity of 0.001 and 0.008 Pa.s respectively and vertical permeability of 52mD assuming acceleration due to gravity of 9.81m/s². 57

Figure 2.9: Recovery efficiency predicted by the Killough, Carlson and the WAG three-phase hysteresis model compared to the base case where hysteresis is not considered. Relative
permeability was calculated using the Stone I interpolation model. The numerical simulation model was a homogeneous horizontal reservoir with 20% porosity and permeability of 200mD to predict recovery of immiscible WAG injection reproduced from Spiteri and Juanes [100].

Figure 2.10: Recovery efficiency predicted by the Killough two-phase and WAG three-phase hysteresis models compared to the base case with no hysteresis considered using the PUNQ-S3 model to predict recovery of immiscible WAG injection. Relative permeability was calculated using the Stone I method reproduced from Spiteri and Juanes [100].

Figure 2.11: Producing gas-oil ratio predicted by the Stone I, Stone II and Baker models compared to the base case where hysteresis is not considered. The numerical simulation model was a homogeneous horizontal reservoir with 20% porosity and permeability of 200mD in which a quarter five-spot pattern was used to predict recovery of immiscible WAG injection reproduced from Spiteri and Juanes [100].

Figure 2.12: Recovery efficiency predicted by the Stone I model using Land's trapping coefficient, C, of 2.0 and 0.5, compared to the base case where hysteresis is not considered. The numerical simulation model was a homogeneous horizontal reservoir with 20% porosity and permeability of 200mD in which a quarter five-spot pattern was used to predict recovery of immiscible WAG injection reproduced from Spiteri and Juanes [100].

Figure 2.13: Map of the southern peninsula of the island of Trinidad showing the pipeline route between Point Lisas Industrial Estate and the CO$_2$ injection pilot projects in Oropuche and Forest Reserve and the location of the Soldado oil fields in the Gulf of Paria reproduced from Mohammed-Singh et al[14].

Figure 3.1: Schematic showing the length scales of the sandpack used in displacement experiments by Dyer and Farouq Ali[13].

Figure 3.2: Phase envelope of the reservoir fluid showing the line of constant reservoir temperature (81.7 C) intersecting the phase envelope at 22 MPa. The initial reservoir pressure is 27.5 MPa.

Figure 3.3: Semi-log plot of the match of the three-parameter Peng-Robinson EOS regressed to PVT total relative volume measured during differential liberation of the Soldado crude sample at 81.7 °C.

Figure 3.4: Plot of the match of the three-parameter Peng-Robinson EOS regressed to PVT oil relative volume measured during differential liberation of the Soldado crude sample at 81.7 °C.

Figure 3.5: The match of the modified Peng-Robinson equation of state and LBC equation regressed onto PVT data to viscosity measured during constant composition expansion of a moderately heavy oil at a reservoir temperature of 81.7 °C.

Figure 3.6: Swelling factor and viscosity of CO$_2$-Aberfeldy crude mixture used by Dyer and Farouq Ali[1] at 23 °C.
Figure 3.7: Plot of CO\textsubscript{2} solubility as a function of pressure for displacement experiments on a recombined Aberfeldy crude by Dyer and Farouq Ali (observed at 23 °C) swelling test on the Bartlett crude by Chung et al (observed at 93.3 °C) and the relationship used in our reservoir simulations (calculated at 81.7 °C) based on the PVT data regressed 3-parameter Peng-Robinson equation for Soldado live crude oil.

Figure 3.8: Oil-water relative permeability matched to run 1.

Figure 3.9: Gas-oil relative permeability matched to run 6.

Figure 3.10: Simulation results of the effect of WAG ratio and injection rate on (a) oil production rate m\textsuperscript{3}/day; (b) water cut and; (c) gas oil ratio m\textsuperscript{3}/m\textsuperscript{3} for WAG ratios 2:1, 4:1 and 8:1 respectively (left to right) at injection rates 53 rm\textsuperscript{3}/day and 26.5 rm\textsuperscript{3}/day.

Figure 3.11: Oil Saturation profile between injector (left) and producer (right) of WAG injection after injecting with 20% HCPV of carbon dioxide over 10 WAG cycles at 53 rm\textsuperscript{3}/day in (a) 2:1, (b) 4:1 and, (c) 8:1 WAG ratios.

Figure 3.12: Oil recovery factor for 10, 5 and 1 WAG cycles as a function of total pore volumes of water and gas injected at 53rm\textsuperscript{3}/day in 4:1 WAG ratio. Runs were stopped when either total CO\textsubscript{2} injection was 89% HCPV or producing water cut exceeded 95%.

Figure 3.13: Oil recovery factor for 10, 5 and 1 WAG cycles as a function CO\textsubscript{2} injected at 53rm\textsuperscript{3}/day in 4:1 WAG ratio. Runs were stopped when either total CO\textsubscript{2} injection was 89% HCPV or producing water cut exceeded 95%.

Figure 3.14: Producing gas-oil ratio as a function of time for 1, 5 and 10 WAG cycles of 89% HCPV of CO\textsubscript{2} injected at 53rm\textsuperscript{3}/day in a 4:1 WAG ratio.

Figure 3.15: Producing water cut as a function of pore volume injected for 1, 5 and 10 WAG cycles of 89% HCPV of CO\textsubscript{2} injected at 53rm\textsuperscript{3}/day in a 4:1 WAG ratio.

Figure 3.16: Cumulative gas-oil ratio of WAG injection with total CO\textsubscript{2} injection of 179, 89, 40 and 20 of HCPV injected at 53rm\textsuperscript{3}/day in 4:1 WAG ratio over 10 WAG cycles. Runs were stopped after 10 WAG cycles or when producing water cut exceeded 95%.

Figure 3.17: Bar chart showing the distribution of CO\textsubscript{2} retained in the reservoir after injection at WAG ratios 2:1, 4:1 and 8:1 at 26.4 rm\textsuperscript{3}/day for immiscible displacement of a Soldado heavy oil simulation at reservoir conditions with at CO\textsubscript{2} injection totalling of 20% of the HCPV in each case over 10 WAG cycles.

Figure 3.18: Gas saturation profile between the injector (left) and producer (right) after 10 WAG cycles were injected at 53 rm\textsuperscript{3}/day with total CO\textsubscript{2} volume of 20% of the HCPV injected in a 4:1 WAG ratio.
Figure 3.19: Gas saturation profile between the injector (left) and producer (right) after 10 WAG cycles were injected at 26.4 rm³/day with total CO₂ volume of 20% of the HCPV injected in a 4:1 WAG ratio. .................................................................................................................................................................... 106

Figure 3.20: Bar chart showing the distribution of CO₂ retained in the reservoir after injection over 1, 5 and 10 WAG cycles at 53 rm³/day for immiscible displacement of a Soldado heavy oil simulation at reservoir conditions with CO₂ injection totalling of 89% of the HCPV in each case in a 4:1 WAG ratio. ....................................................................................................................................................................... 107

Figure 3.21: Distribution of CO₂ phases dissolved, trapped and mobile during WAG flood in run 4 (8.9% HCPV CO₂ per slug at 53 rm³/day in a 4:1 WAG ratio). Runs were stopped when producing water cut exceeded 95%. ........................................................................................................................................................................ 108

Figure 3.22: Bar chart showing the distribution of CO₂ retained in the reservoir after injection CO₂ slug sizes totalling 10, 20, 40, 89 and 179% of HCPV over 10 WAG cycles at 53 rm³/day in a 4:1 WAG ratio for immiscible displacement of a Soldado heavy oil simulation at reservoir conditions. ...................................................................................................................................................................... 109

Figure 4.1: Schematic of water over gas injection using a single vertical well shown in the x-z plane only (left) and a pair of horizontal wells (right) with a single vertical producer. The dimensions of the grid are the same for both horizontal and vertical injection (not drawn to scale). ................................................................................................................................................................................ 115

Figure 4.2: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 1 - continuous gas injection at 50,000 sm³/day (gas gravity 150-200) along the entire length of a vertical well. The vertical line shows the cut-off point of 5.0 × 10⁶ kg-mole CO₂. ........................................................................................................................ 122

Figure 4.3: Distribution of CO₂ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 1 at 50,000 sm³/day (gas gravity 150-200). Continuous CO₂ injection along the entire length of a vertical well. The vertical line shows the cut-off point of 5.0 × 10⁶ kg-mole CO₂. .................................................................................................................................................. 123

Figure 4.4: Producing gas-oil ratio and oil production profile for Run 1 at 50,000 sm³/day (gas gravity 150-200) - Continuous gas injection along the entire length of a vertical well. The vertical line shows the cut-off point of 5.0 × 10⁶ kg-mole CO₂. ........................................................................................................................................ 124

Figure 4.5: Profile of recovery factor and water cut as a function of pore volume of fluid injected for Run 2 - waterflood with water injection at 200m³/day (gravity number 3.1) along the entire length of a vertical well. ........................................................................................................................................... 125

Figure 4.6: Producing gas-oil ratio and oil production profile for Run 2-waterflood with water injection at 200m³/day (gravity number 3.1) along the entire length of a vertical well. ........................................................................................................................................ 125

Figure 4.7: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 3 - vertical water over gas injection scheme using pure CO₂. Water is injected at 200m³/day (gravity number 3.1) from the top section of the
well and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.8: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 3- vertical water over gas injection scheme using pure CO$_2$. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.9: Producing gas-oil ratio and oil production profile for Run 3- vertical water over gas injection scheme using pure CO$_2$. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.10: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 4- horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.11: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 4- horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.12: Producing gas-oil ratio and oil production profile for Run 4- horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.13: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 5- horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.14: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 5- horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.15: Average reservoir pressure as a function of pore volume of fluid injected for Run 5- horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at
50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The MMP pressure, 22 MPa, is shown in relation to pressure decline.

Figure 4.16: CO$_2$ gas saturation distribution 80 m within the reservoir (in the y-direction) at the end of Run 5- horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The injectors are on the left hand side.

Figure 4.17: Producing gas-oil ratio and oil production profile for Run 5-horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.18: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 6-vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.19: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 6-vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.20: Producing gas-oil ratio and oil production profile for Run 6-vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.21: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 7-vertical water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.22: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 7-vertical water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 
Figure 4.23: Producing gas-oil ratio and oil production profile for Run 7-vertical water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 

Figure 4.24: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 8-vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100m$^3$/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 

Figure 4.25: Distribution of CO$_2$ as in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 8-horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 

Figure 4.26: Producing gas-oil ratio and oil production profile for Run 8-vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100m$^3$/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 

Figure 4.27: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 9-horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 

Figure 4.28: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 9-horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 

Figure 4.29: Producing gas-oil ratio and oil production profile for Run 9-horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 

Figure 4.30: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 10-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and
gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of 5.0 × 10$^6$ kg-mole CO$_2$.

Figure 4.31: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 10-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of 5.0 × 10$^6$ kg-mole CO$_2$.

Figure 4.32: Producing gas-oil ratio and oil production profile for Run 10-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of 5.0 × 10$^6$ kg-mole CO$_2$.

Figure 4.33: Production profile for simulation runs 1, 3, 5, 6 and 9 as a function of the mass of CO$_2$ injected for water injected at 200m$^3$/day (runs 3, 5 and 6) and 100m$^3$/day (run 9) compared to run 1 where no water was injected. The water gravity numbers are 3.1 and 6.3 respectively for both groups.

Figure 4.34: Gas saturation distribution at end of simulation for runs 10 (horizontal low rate), 3 (vertical high rate) and 7 (vertical low rate) (clockwise from top left) showing the top location of the water injector (IW), gas injector (IG) and producer (P). All three simulations are immiscible gas injection.

Figure 4.35: Distribution of CO$_2$ molar density in moles per reservoir volume for vertical miscible gas injection with high rate water injection (Run 6) showing top location of the water injector (IW), gas injector (IG) and producer (P) in 3 dimensions (top) and along the Y-Z plane at the producer (bottom).

Figure 4.36: CO$_2$ gas saturation profile for WAG injection after injecting 5.0 × 10$^6$ kg-mole of CO$_2$ at a rate of 50 000 m$^3$/day (gas gravity 150-200) and water at a rate of 100 m$^3$/day (gravity number 6.3). This cross section is in the plane of the injector seen on the left of the grid.

Figure 4.37: Water saturation profile for WAG injection after injecting 5.0 × 10$^6$ kg-mole of CO$_2$ at a rate of 50 000 m$^3$/day (gas gravity 150-200) and water at a rate of 100 m$^3$/day (gravity number 6.3). This cross section is in the plane of the injector seen on the left of the grid.

Figure 4.38: CO$_2$ gas saturation profile of the vertical water over gas injection scheme after injecting 5.0 × 10$^6$ kg-mole of CO$_2$ at a rate of 50 000 m$^3$/day (gas gravity 150-200) and water at a rate of 100 m$^3$/day (gravity number 6.3). This cross section is in the plane of the injector seen on the left of the grid.

Figure 4.39: Water saturation profile of the vertical water over gas injection scheme after injecting 5.0 × 10$^6$ kg-mole of CO$_2$ at a rate of 50 000 m$^3$/day (gas gravity 150-200) and water at a rate of 100 m$^3$/day (gravity number 6.3). This cross section is in the plane of the injector seen on the left of the grid.
Figure 4.40: Cross section of the reservoir in the (a) Y-Z plane 30 m from the injector in the x-direction, (b) X-Y (top layer), and (c) X-Z (parallel to the injector) planes with block sizes 10m x 5m x 1m; 10m x 5m x 2m (base case) and; 10m x 5m x 4m. The injection parameters are those of run 7 -vertical water over gas injection strategy, pure CO\textsubscript{2} injection at 50 000m\textsuperscript{3}/day (gas gravity 150-200) and water injection at 100m\textsuperscript{3}/day (gravity number 6.3) for four years (3.1 x 10\textsuperscript{6} kg-mole CO\textsubscript{2}). The injector (top left) and producer (bottom right) are shown from top view in (b) and the injector is on the left of (c).

Figure 4.41: Cross section of the reservoir in the (a) Y-Z plane 30 m from the injector in the x-direction, (b) X-Y (top layer), and (c) X-Z (parallel to the injector) planes with block sizes 10m x 2.5m x 2m; 10m x 5m x 2m (base case) and; 10m x 10m x 2m. The injection parameters are those of run 7 -vertical water over gas injection strategy, pure CO\textsubscript{2} injection at 50 000m\textsuperscript{3}/day (gas gravity 150-200) and water injection at 100m\textsuperscript{3}/day (gravity number 6.3) for four years (3.1 x 10\textsuperscript{6} kg-mole CO\textsubscript{2}). The injector (top left) and producer (bottom right) are shown from top view in (b) and the injector is on the left of (c).

Figure 4.42: Producing GOR ratio of vertical water over gas injection strategy for comparing grid resolution. CO\textsubscript{2} was injected at 50 000 m\textsuperscript{3}/day (gas gravity 150-200) and water at 100 m\textsuperscript{3}/day (gravity number 6.3).

Figure 5.1: Schematic of possible injected fluid flow paths for water over gas injection with vertical barriers to flow of varying distances from injectors (left) and varying extent across the reservoir in the direction of flow. Water flow is illustrated as blue arrows pointing downwards and CO\textsubscript{2} is illustrated as black arrows. The dashed arrow in (a) indicates a scenario where CO\textsubscript{2} does not migrate above an extensive shale barrier.
List of Tables

Table 2.1: Experimental design table for 32 regression runs based on the $2^{k-3}$ factorial design for regression of the Peng-Robinson EOS and Lohrenz Bray Clark parameters: $\Omega_1^2$, $\Omega_2^2$, critical pressure, $P_{cr}$, critical temperature, $T_{cr}$, critical volume, $V_{cr}$, critical Z-factor, $Z_{cr}$, volume shift, $V_{sh}$, and acentric factor, $\omega$, of the C$_2$-C$_6$ and C$_7+$ lumped components. The +1 symbol represents the parameter being used and the -1 symbol represents the parameter not being used in the regression to match PVT data. ................................................................................................................................. 53

Table 2.2: Results of displacement experiments conducted by Dyer and Farouq Ali on a recombined Aberfeldy crude at 23 °C and 1 MPa reproduced from Dyer and Farouq Ali[1]....... 74

Table 3.1: Properties of sandpack and reservoir simulations............................................................ 80

Table 3.2: Initial oil composition of a Soldado crude oil sample................................................................. 81

Table 3.3: Comparison of Soldado sample crude properties at different conditions................................. 82

Table 3.4: Summary of component properties and Peng-Robinson equation-of-state parameters used to describe the crude oil sample............................................................ 82

Table 3.5: Water and gas injection rates and corresponding gravity numbers in our simulations and displacement experiments carried out by Dyer and Farouq Ali ................................................................. 89

Table 3.6: Summary of WAG oil recovery for displacement experiments and simulations........... 90

Table 3.7: Summary of impact of WAG ratio and injection rate on oil recovery during WAG....... 91

Table 3.8: Summary of the impact of the number of WAG cycles on oil recovery.......................... 95

Table 3.9: Summary of impact of CO$_2$ slug size on WAG recovery......................................................... 99

Table 3.10: Summary of post-WAG waterflood oil recovery for displacement experiments and simulations..................................................................................................................101

Table 3.11: Summary of WAG carbon storage......................................................................................... 103

Table 3.12: Retained CO$_2$ distribution trends with WAG ratio and gravity number of injected fluids.................................................................................................................................104

Table 3.13: Summary of retained CO$_2$ distribution for the WAG and PWWF stages..........................110

Table 4.1: Parameters used in simulations...............................................................................................116
Table 4.2: Compositional description of crude oil components .................................................................117

Table 4.3: Summary of results .....................................................................................................................120

Table 4.4: Impact of increased water injection rate on performance .......................................................152

Table 4.5: Impact of miscible gas injection on recovery and storage .......................................................154

Table 4.6: Impact of using horizontal injectors .............................................................................................155

Table 4.7: Summary of performance of continuous gas injection, vertical immiscible water over gas and WAG injection after injecting $5.0 \times 10^6$ kg-mole of CO$_2$ at a rate of 50 000 m$^3$/day (gas gravity 150-200). Gas is injected along the entire length of the reservoir in run 1 and WAG but only in the lower 3/5 of the reservoir for run 7. .............................................................................................159

Table 4.8: Grid block dimensions used in the sensitivity study to estimate of CO$_2$ retention and oil recovery after $5 \times 10^6$ kg-moles (2.2 $\times 10^5$ metric tonnes) of CO$_2$ were injected using the injection parameters of Run 7-vertical injection strategy, pure CO$_2$ injection at 50 000 m$^3$/day (gas gravity 150-200) and water injection at 100 m$^3$/day (gravity number 6.3) .................................................................164
Nomenclature

\( \alpha \)  
reduction exponent

\( \xi \)  
viscosity reducing parameter

\( \phi \)  
porosity of porous medium

\( \omega_i \)  
mass fraction of species \( i \)

\( \varphi \)  
a-centric factor

\( \lambda \)  
mobility

\( \mu \)  
viscosity, mPa.s

\( \mu_0 \)  
gas mixture viscosity, mPa.s

\( \rho \)  
density, kg/m\(^3\)

\( \Omega_a^{\omega} \)  
omega A, parameter in the Peng-Robinson EOS

\( \Omega_b^{\omega} \)  
omega B, parameter in the Peng-Robinson EOS

\( a_i \)  
LBC coefficients

\( a \)  
attraction parameter of Peng-Robinson EOS

\( b \)  
repulsion parameter of Peng-Robinson EOS

\( b_r \)  
reduced molar density

\( \ddot{g} \)  
acceleration due to gravity, m/s\(^2\)

\( \vec{k} \)  
phase permeability tensor

\( k_r \)  
relative permeability
p  pressure, MPa
u  superficial velocity
v  molar volume
y_i  mol fraction of component in the i phase
C  Land trapping coefficient
E_v  sweep efficiency
F  correction factors
G  volume of CO_2
H  reservoir thickness, m
K  absolute permeability, mD
L  length of reservoir between injector and producer, m
M  mobility ratio
MW  molecular weight, kg-mole
N_p  number of flowing phases
\vec{N}_i  flux vector of component i across unit volume
N_{gv}  gravity number
P_c  capillary pressure, MPa
R  universal gas constant, 8.314 JK^{-1} mol^{-1}
R_i  rate of production per mass of component i per unit bulk volume
S  fluid saturation
T  temperature, °C
\( T_r \)  reduced temperature, dimensionless

\( W \)  accumulation per unit bulk volume

**subscripts**

\( av \)  average vertical

\( cr \)  critical

\( co \)  connate water

\( d' \)  displaced

\( f \)  free

\( g \)  gas phase

\( hy \)  hysteresis

\( i \)  component or species in a fluid

\( init \)  initial

\( inj \)  injected

\( imb \)  imbibition

\( j \)  phase \( j \)

\( o \)  oil phase

\( or \)  residual oil

\( nw \)  non-wetting phase

\( min \)  minimum

\( max \)  maximum

\( prod \)  produced
\[ s \quad \text{solid phase} \]
\[ t \quad \text{trapped} \]
\[ trap \quad \text{trapped} \]
\[ w \quad \text{aqueous phase} \]
\[ D' \quad \text{displacing} \]
\[ D \quad \text{drainage} \]

**superscripts**

\[ imb \quad \text{imbibition} \]
\[ input \quad \text{input value} \]
\[ start \quad \text{start of imbibition or drainage process} \]
\[ D \quad \text{drainage} \]
Injection Design for Simultaneous Enhanced Oil Recovery and Carbon Storage in a Heavy Oil Reservoir
Chapter 1

Introduction

1.1 Motivation

Global warming is the term used to describe the increasing average global temperatures giving rise to significant changes to the earth’s climate[4]. Anthropogenic carbon dioxide emissions have been identified as the main contributor to increasing atmospheric carbon dioxide concentration and the resulting increase in average global temperatures [4]. The United Nations’ Intergovernmental Panel on Climate Change (IPCC) reports that the impact on human life, resources and the environment will be catastrophic [5]. Caribbean countries such as Trinidad and Tobago will be particularly susceptible to more frequent and powerful hurricanes, rising sea level, flooding and the resulting increase in tropical diseases[5, 6].

The Stern Review was a study commissioned by the British Chancellor of the Exchequer to ‘assess the evidence and build understanding of the economics of climate change’ [4]. One of the
main conclusions of this study is the need for all countries to take action on climate change. The cultural, economic, legal and infrastructural diversity worldwide requires a variety of solutions for this to be realized[7-9]. In this thesis we present geological carbon storage, the long term isolation of CO\textsubscript{2} from the atmosphere by injecting CO\textsubscript{2} into the subsurface, combined with enhanced heavy oil recovery as an option for Trinidad and Tobago to sustainably reduce CO\textsubscript{2} emissions. Our objective is to present an injection strategy for water and CO\textsubscript{2} injection into an unconsolidated sand which allows for heavy oil displacement and long term CO\textsubscript{2} storage through gas trapping and CO\textsubscript{2} dissolution in brine and unrecovered crude oil.

The IPCC special report on Carbon Capture and Storage recommends carbon storage in geologic formations such as saline aquifers, depleted hydrocarbon reservoirs and coal methane seams as a means of reducing atmospheric concentrations of CO\textsubscript{2}[8]. A schematic of CO\textsubscript{2} injection for CO\textsubscript{2} enhanced oil recovery (CO\textsubscript{2}EOR) is illustrated as Option 2 in Figure 1.1.

![Geological Storage Options for CO\textsubscript{2}](image)

Figure 1.1: Geological storage options for CO\textsubscript{2} reproduced from IPCC 2005 after Cook [8, 10]
Using CO₂EOR involves injecting CO₂ which can improve oil recovery by reducing oil viscosity and increasing oil volume. However it is possible for injected CO₂ to be produced along with reservoir fluids [11]. By the principle of mass conservation, the volume of CO₂ stored or accumulated in the reservoir is the difference between CO₂ produced (G_{prod}) and CO₂ injected (G_{inj}) plus CO₂ initially (G_{init}) dissolved in oil.

\[ CO_{2\text{stored}} = G_{prod} - (G_{inj} + G_{init}) \]  \hspace{1cm} 1.1

The major sources of Trinidad and Tobago’s CO₂ emissions are [12]:

1. Petrochemical industries where natural gas is used as feedstock and as fuel
2. Natural gas processing to produce liquefied natural gas (LNG) and,
3. Power generation

Each day 3.54 × 10⁶ m³/day (125 MMscf/day; 40 × 10⁶ metric tonnes per year) of CO₂ is produced from the petrochemical industries at the Point Lisas Industrial Estate and the LNG plants at Point Fortin where a total of 1.13 × 10⁸ m³/day (4bcf/d) of natural gas is used as feedstock or fuel [12, 13]. The map below shows the location of the Point Lisas Industrial Estate and LNG plants at Point Fortin.
Trinidad and Tobago is uniquely positioned to capture CO$_2$ because emissions are largely (~70%) generated by stationary sources in these two locations. The carbon emitted by LNG processing accounts for 13% of total emissions and these plants are all located in Point Fortin. Carbon emissions from petrochemical industries account for 56% of total emissions and are all generated at the Point Lisas Industrial Estate[12]. The figure below gives a breakdown of contributing industries and operations to nationwide CO$_2$ emissions.
Figure 1.3: Pie chart showing contribution of major sources of CO$_2$ emissions in Trinidad and Tobago in 2009, reproduced from Boodlal et al.[12].

Figure 1.3 shows that the major contributors to CO$_2$ emissions in Trinidad and Tobago are the petrochemical sector and power generation at Point Lisas and the liquefied natural gas (LNG) plants at Point Fortin.
Figure 1.4: Pie chart showing contribution of processing plants, petrochemical and manufacturing industries at Point Lisas Industrial Estate to CO₂ emissions in Trinidad and Tobago in 2009, reproduced from Boodlal et al. [12].

Ammonia production contributes to 31% (1.10 × 10⁶ m³/day; 39MMscf/d) of CO₂ emissions shown in Figure 1.4. This is the net emissions from the ammonia plant and accounts for CO₂ used as feedstock in the methanol and urea plants within the Point Lisas industrial Estate [12]. Emissions from ammonia production processes are relatively pure streams of CO₂ (90-96% purity) at low pressure [12][14].

The production and processing of crude oil and natural gas accounts for 40% of the national gross domestic product (GDP) [15]. The Kyoto Protocol recognizes the dependence of developing countries on commercial activities that contribute to carbon emissions as a possible obstacle to achieving significant carbon emission reductions [16]. CO₂ EOR will boost oil production by enhancing oil recovery through the mechanisms of oil viscosity reduction, oil swelling and pressure support. CO₂ may also be stored by this process [8] but the efficacy of injection strategies for carbon storage has not been investigated. CO₂EOR in Trinidad and
Tobago is estimated to reduce emissions by 7.5 MtCO\(_2\) and generate an income of US$40/tonne CO\(_2\)[17].

Heavy oil (specific gravity 1.000-0.934; density 1,000 – 934 kg/m\(^3\)) deposits in Trinidad and Tobago have an estimated reserve of 3 billion barrels original oil in place (OOIP)[18]. Heavy oil production in Trinidad and Tobago accounts for 30% of total oil production. However in the past 5 years, total oil production has declined by 9% year on year[13]. CO\(_2\)EOR can reduce Trinidad and Tobago carbon emissions by 40% and recover 31.43 million barrels of oil from acreage under the state oil company, Petroleum Company of Trinidad and Tobago Limited (PETROTRIN)[19].

In Trinidad and Tobago there are conditions conducive to coupled carbon storage and enhanced oil recovery. Firstly, there is supply of carbon dioxide from a central source, the Point Lisas Industrial Estate[12]. Many countries face the challenge of large distances between emitters that can make handling and gathering expensive[20]. Secondly, there are plant processes which emit relatively pure CO\(_2\) such as ammonia and methanol production eliminating the need for major adjustments to facilitate another expensive process, carbon capture[8]. Thirdly, there are relatively short distances (<50km) between sources of emissions and potential heavy oil reservoirs shown in Figure 1.2[14]. This has been a challenge in many instances where there are large distances between sources and sinks which would require extensive time and capital to establish transportation networks[21]. Fourthly, there is the economic need to increase oil production - a major contributor to the nation’s gross domestic product (GDP)[13]. Although our carbon emissions account for less than 1% total carbon emissions worldwide, Trinidad and Tobago ranks as one of the top ten emitters per capita for the past decade[22]. Furthermore, we have signed and ratified international protocols on climate change as a developing nation whose economy is ‘highly dependent on income generated from the production, processing, and export, and/or on consumption of fossil fuels and associated energy-intensive products’
This Kyoto Protocol suggests that for such countries ‘actions related to funding, insurance and the transfer of technology, to meet the specific needs and concerns of developing countries Parties’ will be part of the strategy to reduce worldwide emissions. Considering the confluence of discounts, possibility of international support and the opportunity to demonstrate sustainable development, Trinidad and Tobago is ideally positioned to embark on geologic carbon storage in a manner that satisfy domestic needs while aligning with green and sustainable development policies.

1.1.1 Objectives and Tools

In this thesis we present the application of the water over gas injection strategy to an oilfield in the Gulf of Paria, offshore from Trinidad. Our objectives are to: 1) demonstrate the limitations of water alternating gas injection (WAG) in coupling carbon storage and enhanced oil recovery; 2) validate our simulation model to predict the trend oil recovery and carbon storage; 3) understand the mechanism of carbon trapping and oil recovery with water and CO$_2$ injection and 4) propose an injection strategy which can be optimized for simultaneous carbon storage and enhanced oil recovery.

We have used an equation of state (EOS) package PVTi within the Schlumberger Eclipse reservoir simulation software suite to characterise resident oil phase behaviour by regressing the parameters of the grouped components Peng-Robinson EOS and the Lohrenz-Bray-Clark equation to PVT data obtained from the Ministry of Energy and Energy Affairs, Trinidad and Tobago. We then used this compositional fluid description and the tuned Peng-Robinson EOS and Lohrenz-Bray-Clary correlation within the grid-based Eclipse 300 compositional reservoir simulator, with the carbon storage option, to predict oil recovery, carbon storage and production performance of the WAG and water over gas injection strategies.
1.1.2 Thesis Outline

This dissertation on the topic, Injection Design for Simultaneous Enhanced Oil Recovery and Carbon Storage in a Heavy Oil Reservoir, is divided into three core sections followed by a concluding discussion of findings and future work.

In Chapter 2 we review the state of the reservoir engineering principles pertaining to carbon storage and enhanced oil recovery. The four areas of research and practice relevant to our objectives are carbon dioxide enhanced oil recovery (CO₂EOR); geologic carbon storage; relative permeability and gas trapping mechanisms. In the latter three areas we applied principles determined from experimental work related to carbon storage in aquifers.

In Chapter 3 we review carbon storage using the established practice of water alternating gas (WAG) injection. Our reservoir simulations used the tune EOR and viscosity correlation and we compared the trends to bench scale displacement experiments of a heavy oil. From these results we gain insights into impact and limitations of injection parameters on oil recovery, carbon storage and production performance.

In Chapter 4 we present and investigate our proposed injection strategy for coupled carbon storage and oil recovery. This application of water over gas injection uses gravitational forces to promote CO₂ trapping and economic oil recovery. We also investigate the impact of three injection parameters: water injection rate; injection well orientation and; gas composition, on oil recovery and carbon storage. We found that the injection design increased oil recovery compared to waterflood and continuous gas injection and increased carbon storage compared to WAG injection. There was also improvement in the reservoir performance by reducing water cut, producing GOR and production decline. However the accuracy of our results is limited by the effects of numerical dispersion in predicting carbon storage and oil recovery volumes.

In the Chapter 5 we summarize the findings and conclusions of this study and discuss areas for further research.
Chapter 2

Literature Review

2.1 Carbon Storage Overview

The anthropogenic release of carbon dioxide has been identified as the major contributor to global warming[23]. Since the industrial revolution, the atmospheric concentration of CO$_2$ has increased from an average of 280ppm in the pre-industrial era (before 1790AD) to 360ppm in 2005[24]. There is a worldwide effort of cooperative research and discussion between countries to determine strategies to address this pressing issue[7, 20, 23]. There are also several storage ongoing and planned CO$_2$ storage projects shown in Figure 2.1[8]. Geologic CO$_2$ sequestration or CO$_2$ storage in saline aquifers, depleted or producing hydrocarbon reservoirs and methane coalbed seams[25] is a proposed technical solution to reducing the concentration of CO$_2$ in the atmosphere by collecting CO$_2$ generated at fossil-fuel burning power stations or other industrial sites and injecting it deep underground, rather than allowing its release to the atmosphere.
In this thesis we investigate the process of \( \text{CO}_2 \text{EOR} \) coupled with carbon storage. The weighting attributed to storage or oil recovery will depend on the legal and economic framework in which the activity is undertaken\cite{9}. We present our findings as a comparison between traditional water alternating gas (WAG) injection, continuous gas injection and water over gas injection-where water is injected in the upper portion of the reservoir and gas is injected in the lower portion of the reservoirs- applied to \( \text{CO}_2 \text{EOR} \) with carbon storage that can be applied to moderately heavy oil reservoirs. The four areas of research relevant to our injection design are \( \text{CO}_2 \text{EOR} \); geologic carbon storage; relative permeability and gas trapping mechanisms.

The urgent need for reduction in carbon emissions changes the status of \( \text{CO}_2 \) from costly solvent\cite{26} to abundant waste product. \( \text{CO}_2 \text{ EOR} \) was historically cost and volume constrained with the dual objectives of oil recovery and minimal \( \text{CO}_2 \) injection and retention. On the other
hand, carbon storage requires large volumes of CO$_2$ to be injected and permanently stored underground. Total CO$_2$ emissions are estimated to be 30 Gt per year, the IPCC 2005 report estimates that carbon capture and storage (CCS) can store 10 Gt of CO$_2$ per year ($4.5 \times 10^7$ m$^3$ per day) by 2050[8]. The volume of CO$_2$ to be injected is 3 times global oil production of $1.5 \times 10^7$ m$^3$ per day[27]. The global geologic storage capacity of hydrocarbon reservoirs is estimated to be 675 to 900 Gt CO$_2$, not including undiscovered reservoirs while the storage capacity of saline aquifers may be up to $10^4$ Gt CO$_2$[23].

The data needed for a potential storage site encompasses information on the country or state scale to determine total pore volume; basin scale to determine prospective storage capacity; site characterisation to determine contingent storage capacity and; site deployment to determine operational storage capacity. At each level, particularly for site characterisation and site deployment detailed information is required[28]. Typically oil and gas fields have a much greater volume of data and are better characterised than saline aquifers. The information required to classify the contingent and operational storage capacity of a site is almost routinely available for hydrocarbon reservoirs. The CO$_2$ storage classification system proposed by the Australian-funded Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) is a modification of the system used to classify petroleum reserves [7]. The same information is used to distinguish between prospective, contingent and operational reservoirs.
This information will include detailed geology, structural contour maps, seismic data, well logs, routine and special core analysis, production history, water chemistry, pore pressure data and reservoir characterisation. Although the capacity of hydrocarbon reservoirs may be much less than that of saline reservoirs, these potential geologic sites are closer to being commercial and operational than storage in saline aquifers based on data being more readily available.

Geological carbon storage in hydrocarbon reservoirs can be secured by the structural and stratigraphic trapping which contained hydrocarbon in the reservoir for geologic timescales[8]. Furthermore, CO₂ storage in hydrocarbon reservoirs can potentially return a profit from incremental production[8, 19, 30]. Operators may also have the option of using facilities already in place for the transport, injection and handling of CO₂[8, 21]. The oil and gas industry has

---

**Figure 2.2: Reproduction of the CO₂ storage classification system proposed by Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)[28] (modified from the SPE Petroleum Resource Management System[29])**
experience with CO$_2$ injection and modelling of phase behaviour between CO$_2$ and reservoir fluids to optimize recovery[30-32] and more recently storage in conventional oil reservoirs [30, 33-35]. Heavy oil CO$_2$ EOR injection strategies need to be revisited in order to increase carbon storage realized in current injection strategies and to apply the wealth of information available to the demonstration of commercial and safe CO$_2$ sequestration[30, 36].

2.2 CO$_2$ Enhanced Oil Recovery

Heavy oils are typically undersaturated, less compressible and more viscous than conventional crude oil at standard conditions with specific gravity ranging 934 - 1000 kg/m$^3$[37]. Heavy oil is not produced as easily as conventional crude because of its resistance to flow under natural reservoir energy. EOR methods use heat energy or additives to modify the physical properties situ crude or injected fluids in order to increase recovery[32]. However the volumes injected in EOR operations are limited by the cost of these injected fluids[40, 41]. CO$_2$ has been used in enhanced oil recovery for over 50 years[42-44]. Early investigations focused on the use of CO$_2$ in the liquid and gaseous phase to maximize oil recovery of conventional crude by miscible flooding[45-49]. But by the 1980s immiscible recovery using CO$_2$ was also considered where the main recovery mechanism was dissolution of CO$_2$ into the oil [1, 50-52].

One clear advantage of using CO$_2$ for EOR is the opportunity for cost effective carbon sequestration[9, 17, 35, 53, 54] because storage costs can be offset by incremental oil recovery. CO$_2$ EOR occurs through the mechanisms of crude viscosity reduction, oil swelling and gas drive [55-57] while carbon storage occurs through hydrodynamic trapping, dissolution and precipitation of the CO$_2$[58-61]. The challenge we encounter here is to manipulate operations to the benefit of both objectives. We will now consider the properties of CO$_2$ and heavy oil separately; the interaction between the fluids in equilibrium at reservoir conditions and then in porous media.
The critical pressure and temperature of CO\textsubscript{2} are 7.38 MPa and 31.1°C respectively shown in Figure 2.3 reproduced from Bachu (2003)[62]. In reservoirs deeper than 800m, CO\textsubscript{2} exists as a supercritical fluid, assuming a temperature gradient of 30 °C per km, surface temperature of 15 °C and, a pressure gradient of 10MPa per km.

Figure 2.3: CO\textsubscript{2} pressure- temperature phase diagram showing the triple and critical points of pure CO\textsubscript{2} and conditions for solid, liquid, gaseous and supercritical phases reproduced from Bachu, 2003[62].
Supercritical CO\textsubscript{2} differs from gaseous and liquid CO\textsubscript{2} in that it exists as high density fluid with density ranging 600 to 800 kg/m\textsuperscript{3} at typical reservoir conditions (Figure 2.4). The higher density of the supercritical fluid is advantageous to carbon storage capacity\cite{8}. Although denser than most gases, the density and viscosity of supercritical carbon dioxide presents a challenge for secure storage and enhanced oil recovery, with the tendency of the lighter and less viscous CO\textsubscript{2} to migrate quickly to the top of the reservoir above the denser reservoir fluids-crude oil and water\cite{36, 63, 64}.

### 2.2.1 Heavy Oil Characterisation

Crude oils with specific gravity ranging between 1.000- 0.934 (density 1,000 – 934 kg/m\textsuperscript{3}; API gravity 20-10 degrees) at standard conditions are classified as heavy oils\cite{65}. The cut offs are arbitrary. Crudes with specific gravity outside of these limits are classified as extra heavy oil (>1.000) and conventional oil (< 0.934). Typically the viscosity of such crude oil is in the order...
of a thousand to several thousand mPa.s at standard conditions and may have a sulphur content greater than 2%[37]. These properties all point to the higher viscosity of the crude at reservoir conditions compared to water or less dense oils as a result of having a higher proportion of long hydrocarbon chains and other high-molecular weight compounds[66]. On the basis of three relative distillation characteristics available, Figure 2.5 presents a comparison of the several Soldado crude samples from Trinidad and Tobago to data available in the literature collated by Speight [37] and Chung et al [67]. The Soldado crude has lower than average asphaltene and carbon residue for the range of API gravity. It is unlikely that asphaltene deposits will significantly influence recovery and for this reason we have not accounted for this in our fluid characterization or reservoir simulation.
Figure 2.5: Comparison of the Conradson carbon residue, sulphur content and asphaltene content of crude samples as a function of API gravity.\footnote{The Conradson carbon residue refers to the weight % of residue determined using the Conradson method (ASTM D-189) when distilled at 0.1 MPa. The carbon residue can be correlated to other crude oil parameters such as viscosity, sulfur, nitrogen and asphaltene content.}
2.3 CO₂ Solubility in Heavy oil

Miscible CO₂-crude oil mixtures can occur at certain conditions depending on the composition of the crude oil[68]. Heavy oil and carbon dioxide do not typically achieve miscibility at reservoir conditions. The threshold pressure- the thermodynamic minimum miscibility pressure (MMP)- can be estimated using empirical correlations or EOS to predict phase behaviour[69-71]. For our crude oil sample this pressure is estimated to exceed 80 MPa using the technique developed by Jessen et al[69]. The MMP is a function of temperature and crude oil composition. To lower the MMP, low molecular weight hydrocarbons, C₂-C₅ can be injected with CO₂ to achieve miscibility at reservoir conditions. This has been suggested by several authors to co-optimize carbon storage and EOR [72, 73].

Miscible mixtures are soluble at all proportions above the minimum miscibility pressure for a given temperature. Solubility is the volume of one substance that would dissolve in unit volume of another; it is a function of temperature and pressure. Although not miscible with heavy crude, CO₂ is soluble to a limited degree which allows reduction in oil viscosity, density and increased oil volume[50]. Swelling tests are laboratory experiments carried out over a range of pressures at constant temperature to determine the total volume and viscosity of CO₂-crude oil mixtures.

Miller and Jones [74] conducted laboratory studies using modified PVT equipment to determine the physical characteristics of heavy oil after CO₂ saturation. They investigated crude oil with specific gravities of 1.000, 0.966 and 0.953 (10, 15 and 17°API gravity) for temperatures 24, 60 and 93 °C for pressures ranging from atmospheric pressure to 34.6 MPa. Their results show that CO₂ is soluble in heavy oil for the entire range of pressures indicated at temperatures 60 and 93 °C. The effect of CO₂ on the viscosity of heavy oil with pressure is shown in Figure 2.6; with the addition of CO₂ at constant temperature, the viscosity of crude oil decreased with pressure. The
The largest change in viscosity occurs for crude with the highest initial oil viscosity at 24 °C. As pressure increases, CO₂ solubility in crude and the resulting swelling reduces crude viscosity.

![Figure 2.6: Semi log plot of the effect of CO₂ on the viscosity of heavy oil of specific gravity 0.953 (17 API) at 24, 60 and 93 °C reproduced from Chung et al [67].](image)

Chung et al developed a correlation for the physical properties of heavy oil-CO₂ mixtures based on their experimental work and data available in literature[67]. Their work encompassed a comprehensive range of heavy oil gravities (0.930-1.000 kg/m³) for up to 10 crude oil samples. They defined solubility as the volume of CO₂ which will dissolve in each volume of dead oil, to be mainly dependent on temperature and pressure and slightly on specific gravity.

Dyer and Farouq Ali[1] presented displacement experiments on an Aberfeldy heavy oil at laboratory conditions which was recombined with light oil to 1055 m.Pas representing viscosity
at reservoir conditions. They conducted swelling tests to determine the solubility and physical properties of the CO$_2$-heavy oil mixture at low pressure (<5 MPa) and ambient temperature.

Our available crude oil data does not include swelling test results. In the absence of experimental data, correlations may be considered as representative of actual phase behavior. Swelling tests on crude samples from a heavy oil field to reduce uncertainty in predicting oil recovery and performance. Using correlations is a cheaper and easier option but may have limited temperature and pressure range of applicability[75].

Figure 2.7 shows the range of error in viscosity prediction of a heavy crude using the correlation developed by Chung et al. The error is the difference between actual viscosity and the predicted viscosity as a fraction of actual viscosity. Estimates are poor at low pressure but over 7 MPa the error is within 30%. We have used our tuned 3-parameter Peng Robinson EOS and Lohrenz Bray Clarke correlations predict the phase behaviour determined by swelling tests.
2.4 Governing equations

2.4.1 Mass conservation

The interaction between CO\textsubscript{2} and heavy oil is governed by the principle of mass conservation during mass transfer and while flowing through the porous medium. The three phases present are the CO\textsubscript{2} - rich gaseous phase, oleic and aqueous phase.

In our simulations mass transfer occurs from CO\textsubscript{2} into the oleic and aqueous phases through convection, dispersion and diffusion. When CO\textsubscript{2} is injected in the reservoir, the flow of the gas carries CO\textsubscript{2} through the reservoir by convection of the gas phase. As CO\textsubscript{2} flows through the reservoir, some CO\textsubscript{2} dissolves in oil in quantities that depend on the temperature and pressure.
of the reservoir. The remaining CO$_2$ remains as free gas, trapped gas or dissolved in the aqueous phase. Diffusion and dispersion account for a negligible mass transfer processes. Both these physical mechanisms of transport are due to random motion of molecules which smear sharp concentration gradients [68].

Within the Eclipse compositional simulator, in using the carbon storage option, CO2SOL, we assume there is mass transfer from the CO$_2$ phase into the oil and water phases only, due to dissolution, dispersion and diffusion. The oil phase consists of four components: CO$_2$, methane, C$_2$-C$_6$ and C$_7$. We now present the governing equations for the physical processes simulated as defined by Lake [41] for isothermal multiphase three-dimensional flow through porous media. In the equations below, $j$ represents the phase, (oil, water or gas) and $i$ represents the component within the phase. CO$_2$ can be present in all three phases.

Equation 2.1 represents the conservation of each component (or species) $i$ by considering the mass flux across per unit bulk volume at isothermal conditions. $W_i$ represents accumulation of mass of $i$ in a unit bulk volume and $R_i$ represents the rate of production per mass of $i$ per unit bulk volume. $\vec{N}_i$ is the flux vector of component $i$ across the unit volume.

$$\frac{\partial W_i}{\partial t} + \nabla \cdot \vec{N}_i = R_i$$  \hspace{1cm} (2.1)

Equation 2.2 represents the conservation of component $i$ in the all flowing phases $N_p$ and the stationary phase.

$$W_i = \phi \sum_{j=1}^{N_p} \rho_j S_j \omega_{ij}$$  \hspace{1cm} (2.2)

where $\rho_j$ is the density of the $j$ phase, $S_p$ is the saturation of phase $j$ and, $\omega_{ij}$ is the overall mass fraction of species $i$, in phase $j$, defined as
\[ \omega_i = \frac{W_i}{\sum_{i=1}^{N_p} W_i} \] 2.3

We neglect all components in the solid phase and have not accounted for precipitation. Equation 2.4 represents the mass flux of component \( i \) in all phases accounting for convection in the superficial phase velocity term, \( \vec{u}_j \) and, dispersion in the dispersive tensor term \( \vec{K}_{ij} \).

\[ \vec{N}_i = \sum_{j=1}^{N_p} \rho_j \omega_{ij} \vec{u}_j + \phi \rho_j S_j \vec{K}_{ij} \cdot \nabla \omega_{is} \] 2.4

### 2.4.2 Flow through porous media

Equation 2.6 is an expression of phase superficial velocity in each component, \( i \), in each phase, \( j \).

\[ \vec{u}_{ij} = \lambda_{rj} \vec{k} \cdot (\vec{P}_j + \rho_j \vec{g}) \] 2.5

where \( \vec{P}_j \) is the pressure across each phase in three dimensions, \( \vec{g} \) is the acceleration due to gravity, \( \lambda_{rj} \vec{k} \) the product of the relative mobility in the \( j \) phase and the phase permeability tensor defined as

\[ \lambda_{rj} \vec{k} = \frac{\vec{k}_j}{\mu_j} \] 2.6

where \( \mu_j \) is the viscosity of the phase.

The capillary pressure, \( P_{c,jn} \), between the two phases, is a function of saturation and location within the porous medium, and is defined as

\[ P_j - P_n = P_{c,jn}(S, \vec{x}) \] 2.7
2.4.3 Phase Behaviour Prediction

We have used the Peng-Robinson\[2\] equation of state to predict the phase behaviour of crude oil and injected fluids within the PVTi EOS package. The EOS is as follows

\[ P = \frac{RT}{v-b} - \frac{a}{v(v+b)+b(v-b)} \]  \hspace{1cm} 2.8

where \( P \) represents pressure, \( R \) represents the universal gas constant, \( T \) represents temperature, \( v \) represents the molar volume in SI units. \( a \) represents the attraction parameter and \( b \) represents the repulsion parameter, the units of both parameters depend on the units of \( R \). In this equation the definition of \( a \) and \( b \) are given below\[2\].

\[ a = \Omega_a^0 \frac{R^2 T_{cr}^2}{P_{cr}} A \]  \hspace{1cm} 2.9

where \( \Omega_a^0 \) is constant initially set to 0.457 before regression to PVT data, \( T_{cr} \) and \( P_{cr} \) are the critical temperature and pressures respectively.

\[ A = [1 + m(1 - \sqrt{T_r})]^2 \]  \hspace{1cm} 2.10

and

\[ m = 0.3764 + 1.54226 \varphi - 0.26992 \varphi^2 \]  \hspace{1cm} 2.11

Similarly,

\[ b = \Omega_b^0 \frac{R T_{cr}}{P_{cr}} \]  \hspace{1cm} 2.12

where \( \Omega_b^0 \) is initially set to 0.078 before regression to PVT data, \( T_r \) is the reduced temperature and \( \varphi \) is the Pitzer acentric factor\[76\] defined as

\[ \varphi = -(\log_{10} \varphi + 1) \]  \hspace{1cm} 2.13
where \( p_{vr} \) is the reduced vapour pressure at \( T_r = 0.7 \). For mixtures, the following mixing rules apply to the PR EOS

\[
\begin{align*}
    b &= \sum_j y_j b_j \\
    a_T &= aA \\
    a_T &= \sum_i \sum_j y_i y_j a_{rij}
\end{align*}
\]

where

\[
a_{rij} = (1 - \delta_{ij})(a_{Ti}a_{Tj})^{1/2}
\]

where \( \delta_{ij} \) represents the binary interactive coefficients, independent of pressure and temperature [39].

To predict the viscosity of the crude oil and \( \text{CO}_2 \)-crude oil sample we used the Lohrenz Bray Clark equation [3]. The compositional model of the fluid was based on the regression of the three-parameter Peng-Robinson equation of state and the Lohrenz Bray Clark (LBC) Equation on PVT data of moderately viscous Soldado crude. The viscosity \( \mu \) of each phase is calculated as follows in the LBC correlation:

\[
[(\mu - \mu^0)\xi + 0.0001]^{1/4} = \sum_{i=1}^{5} a_i b_r^{i-1}
\]

where \( a_i \) are the LBC coefficients \( a_1 = 0.1023, a_2 = 0.023364, a_3 = 0.058533, \ a_4 = -0.040758, \ a_5 = -0.0093324 \), \( \mu \) represents the gas mixture viscosity, \( \xi \) the viscosity reducing parameter and \( b_r \) the reduced molar density which is the ratio of the phase volume to the critical molar density. The modified LBC is an extension of the LBC that allows adjustment of the reduced molar density. The modification was included within Eclipse2009.1[77] especially for modelling heavy oil behaviour:

\[
[(\mu - \phi)\xi + 0.0001]^{1/4} = \sum_{i=1}^{5} a_i \exp\left(\frac{b_r}{b_{maxr} - b_r}\right)
\]
In total eight variables ($\Omega_2, \Omega_0$, critical pressure, critical temperature, critical volume and critical Z-factor, acentric factor and volume shift) of the two lumped components $C_2$-$C_6$ and $C_7+$ were regressed to PVT data. The properties coefficients of the pure components CO$_2$ and methane were not regressed to PVT data. The $2^k$-factorial design[78] was used to reduce the number of combinations to be investigated for regression analysis to a manageable 32 runs compared to 256 runs ($2^8$) if each variable was systematically altered for each component. The two levels in this case represent the two lumped components and k represented the 8 variables. The $2^k$-factorial design allowed the impact of eight variables to be assessed using 1/8$^{th}$ the number of runs.
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Table 2.1: Experimental design table for 32 regression runs based on the $2^{k-3}$ factorial design for regression of the Peng-Robinson EOS and Lohrenz Bray Clark parameters: $\Omega^\circ_a$, $\Omega^\circ_b$, critical pressure, $P_{cr}$, critical temperature, $T_{cr}$, critical volume, $V_{cr}$, critical Z-factor, $Z_{cr}$, volume shift, $V_{sh}$, and acentric factor, $\varphi$, of the C$_2$-C$_6$ and C$_7$+ lumped components. The +1 symbol represents the parameter being used and the -1 symbol represents the parameter not being used in the regression to match PVT data.
The accuracy of the regression to the PVT data was tracked by the root mean square error (RSME) between the observed data and Peng-Robinson EOS prediction. Of the 32 combination of variables used the match the PVT data the lowest RMSE was 0.035. This occurred when each variable was regressed for each of the two lumped components, combination 32 shown in Table 2.1.

2.5 Immiscible CO\(_2\) EOR

2.5.1 Sweep Efficiency

Laboratory experiments, correlations and models are based on the premise of CO\(_2\) and heavy oil being in physical contact and in thermodynamic equilibrium. In porous media this does not always occur due to the macroscopic displacement efficiency \(E_V\) being less than unity\[79\]. Also known as the sweep efficiency or conformance factor, \(E_V\) is a measure of the 'effectiveness of the displacing fluid in contacting the reservoir...both areally and vertically, as well as how effectively the displacing fluid moves the displaced oil toward production wells.'\[32\]. As an immiscible gas drive, technique is the main operational challenge to heavy oil CO\(_2\) EOR is low sweep efficiency due to the unfavourable mobility ratio between CO\(_2\) and oil at reservoir conditions. The mobility of a fluid phase, \(\lambda_i\), can also be defined as in Equation 2.6. The mobility ratio of fluids in a displacement process is the ratio of the mobility of the displacing phase, \(\lambda_D\), to that of the displaced fluid phase, \(\lambda_d\).

\[
M = \frac{\lambda_D}{\lambda_d} \quad 2.20
\]

Here we adopt the definition used by Craig \[80\] for immiscible displacement where mobility is measured at the average saturation of the relevant phase. The mobility ratio affects the stability of the displacement front and affects both areal and vertical sweep. If the mobility ratio is greater than 1, flow during displacement becomes unstable resulting in viscous fingering, gas override and water underride. Essentially injected fluid bypasses reservoir oil by flowing
through a preferential path within the reservoir as in viscous fingering or due to buoyancy effect gas flows through the upper layers of the reservoir as in the case of gas override or due to gravity effects water flows through the lower layers as in the case of water underride. The mobility ratio of a moderately viscous crude and CO₂ is unfavorable in that CO₂ will have a much greater Darcy velocity than the oil at the average CO₂ saturation. This means the supercritical fluid will tend to finger through the oil resulting in low sweep efficiency or flow in the upper layers of the reservoir.

The mobility ratio of a moderately viscous crude and water is unfavorable in that water will flow at a higher Darcy velocity than oil at the average water saturation. The challenge of the injection design is to overcome the natural tendency of the injected fluids to bypass oil in the reservoir and flow directly to the producer under the effects of the pressure differential across the reservoir, fluid properties and gravity effects on the fluid. Craig et al [81] reported a decreasing trend for areal sweep efficiency with increasing mobility ratio for an immiscible and miscible oil displacement using water and gas injection in consolidated sandstone. For mobility ratio between 1 and 10, the areal sweep efficiency at breakthrough, ranges between 70 and 50%.

Several approaches have been used to improve the mobility ratio of CO₂ injection processes in order to improve sweep efficiency and oil recovery. Water alternating gas injection has been used to improve macroscopic sweep efficiency by reducing the relatively permeability of the carbon dioxide and providing greater mobility control. Foam and polymers reduce the mobility ratio by changing the viscosity of the injected fluid. Hydrocarbon solvent gas can also be used to decrease crude oil viscosity and effectively reduce the mobility ratio between fluids. The method used in each case depends on oil properties and reservoir characteristics. For miscible gas injection, water injection displaces the miscible oil bank; for immiscible gas displacement, water injection is used to reduce the mobility of injected gas.
In addition to the unfavourable mobility ratio there is the tendency, during immiscible gas injection, for gravity segregation to occur due to the differences in the specific gravity of the injected fluids and crude oil. The vertical sweep efficiency is function of the gravity number and mobility ratio [82]. At reservoir conditions the density of CO\textsubscript{2} ranges between 400 and 700 kg/m\textsuperscript{3}; moderately heavy oil, between 850 and 970 kg/m\textsuperscript{3} and; reservoir brine, between 990 and 1020 kg/m\textsuperscript{3}, assuming molality of 0.51. The density difference results in gas over-ride which leads to poor reservoir sweep by injected fluids. This buoyancy effect has been investigated for CO\textsubscript{2} in aquifers [63, 83, 84]. Injected CO\textsubscript{2} rises to the top of the reservoir until it reaches a low permeability caprock where it spreads out as a mobile plume of dense gas. The amount of trapping is directly related to gas sweep efficiency in porous media [85-87].

2.5.2 Gravity dominated displacement

At the pore scale, buoyancy or gravity forces drive the upward migration of gas but are counteracted by capillary and viscous forces [88]. The scaling groups proposed by Zhou et al [89] were used to identify flow regions in homogeneous or simple heterogeneous models of porous media. The gravity number is a dimensionless ratio of gravity to viscous forces. The gas and water gravity numbers in SI units are defined as:

\[
N_{gv,g} = \frac{(\rho_o - \rho_g)Lk_{av}\hat{g}}{Hu\mu_g} \quad 2.21
\]

\[
N_{gv,w} = \frac{(\rho_w - \rho_o)Lk_{av}\hat{g}}{Hu\mu_w} \quad 2.22
\]

respectively, where \( \rho \) is the fluid density in kg/m\textsuperscript{3}, \( L \) is the length of the rectangular reservoir in m, \( k_{av} \) is the average vertical permeability in m\textsuperscript{2}, \( \hat{g} \) is the acceleration due to gravity in m\textsuperscript{2}/s, \( H \) is the reservoir thickness in m, \( u \) is the flow rate per unit area in m/s, \( \mu \) is the fluid viscosity, o, w and g represent the oil, water and gas phases respectively. We have calculated the gravity numbers based on initial fluid properties.
Equations

\[ N_{gv,g} = \frac{(\rho_o - \rho_g)Lk_{av}\ddot{g}}{\mu u_g} \]  

2.21

\[ N_{gv,w} = \frac{(\rho_w - \rho_o)Lk_{av}\ddot{g}}{\mu u_w} \]  

2.22 shows that for a given system the gravity number can be altered by manipulating the velocity of the injected fluid, crude oil viscosity and density using EOR injection strategies. We will now consider the relationship between fluid injection rates, gravity number and mobility.

Figure 2.8 shows the range of injection rates corresponding to water gravity number. The upper limit of the water injection rate is determined by the fracture pressure limit of the reservoir, which we have estimated to be 30% greater than the initial reservoir pressure. The lower limit of the water injection rate is determined by the range of field operations. Typically the upper limit of the water gravity number is 10 [82].

Figure 2.8: Semi-log plot of the water gravity number as a function of injection rate for a reservoir measuring 1000m × 150m × 100m with water and oil density of 990 and 890 kg/m³ respectively, water and oil viscosity of 0.001 and 0.008 Pa.s respectively and vertical permeability of 52mD assuming acceleration due to gravity of 9.81m/s².
For the system described in Figure 2.8, which we use in Chapter 4, and the limits of field operations, the injection rate to be investigated ranges between the range 60 and 300 m$^3$/day. These rates correspond to the operation limits of water gravity number of 10, and the fracture pressure of 350 bars respectively. Here we assume an initial reservoir pressure of 270 bars for water injection only. With simultaneous gas and water injection, the upper limit of the water injection rate will be lowered to 200 m$^3$/day accommodate the additional pressure support from gas injection remaining within the fracture pressure limit. In Chapter 4 we will discuss the water injection rates used to investigate the efficacy of our injection design within these limits.

In gas injection processes, flow through porous media is gravity-dominated, particularly in heavy oil fields where the density difference is large, capillary forces are in comparison negligible. In gravity dominated flow the gravity number is much greater than the capillary number. Zhou et al.[89] used the relationship between mobilities, gravity and viscous forces, $M N_{gv.g}/(1 + M) \gg 1.0$, to define a system as being dominated by gravity segregation.

In the reservoir described in Figure 2.8, $M N_{gv.g}/(1 + M)$ is 200 assuming the permeability of the displacing fluid and the displaced fluid are equal and the initial viscosity of oil and gas are $8.0 \times 10^{-3}$ and $3.2 \times 10^{-5}$ Pa.s respectively and $N_{gv.g}$ is 200 as in the case of the CO$_2$ storage in Sleipner. Similarly for water injection, assuming the water viscosity is $1.0 \times 10^{-3}$ Pa.s and $N_{gw.w}$ is 3 for a water injection rate of 200 m$^3$/day, in the system described in Figure 2.8, $M N_{gw.g}/(1 + M)$ is 3. As crude viscosity reduces with CO$_2$ dissolution in resident crude $M N_{gw.g}/(1 + M)$ remains greater than 1. For water and gas injection into a reservoir with the properties described in Figure 2.8, which we use in our injection design, the displacement process is dominated by gravity forces. The injection strategy we have applied to carbon storage and enhanced oil recovery uses the gravity forces to improve gas sweep.
2.6 Three-phase Relative Permeability

The principles of conventional three-phase relative permeability applies to immiscible gas drive which we have represented in our simulations with a modified version of Stone’s model\[90, 91\] -Stone I. The three-phase oil relative permeability, $k_{ro}$, is calculated from the input of the relative permeability of water and oil in water as a function of water saturation; and the relative permeability of gas and oil displacing gas in the presence of connate water. In this model the initial oil saturation, $S_{oi}$, is assumed to be constant and an average value is applied to the grid block. Water is at least at the connate water saturation, $S_{wco}$, in each block and in the presence of gas, water and gas are completely segregated.

$$k_{ro} = k_{rocw}S_oF_wF_g$$  \hspace{1cm} 2.23

where $k_{rocw}$ is the oil relative permeability at connate water saturation,

$$\bar{S}_o = (S_o - S_{om})/(1 - S_{wco} - S_{min}) \text{ for } S_o > S_{min}$$  \hspace{1cm} 2.24

$$F_w = k_{row}/(k_{rocw}(1 - \bar{S}_w))$$  \hspace{1cm} 2.25

$$F_g = k_{rog}/(k_{rocw}(1 - \bar{S}_g))$$  \hspace{1cm} 2.26

where

$$\bar{S}_w = (S_w - S_{wco})/(1 - S_{wco} - S_{min}) \text{ for } S_w > S_{wco}$$  \hspace{1cm} 2.27

$$\bar{S}_g = S_g/(1 - S_{wco} - S_{min})$$  \hspace{1cm} 2.28

$k_{rog}$ is the oil relative permeability in the presence of oil, gas and connate water; $k_{row}$ is the oil relative permeability in the presence of oil and water only; $S_o$, $S_w$, and $S_g$ is the average saturation applied to each grid block for oil, water and gas respectively; $S_{om}$ is the minimum of the critical oil-to-water, $S_{owcr}$ and critical oil-to-gas saturation, $S_{ogcr} - min(S_{owcr}, S_{ogcr})$; $F_w$ and $F_g$ are water and gas correction factors respectively.
2.6.1 Relative Permeability Hysteresis

In our simulations we have used Killough's method [92] for relative permeability hysteresis in both the wetting phase and the non-wetting phase to capture the change in effective permeability during cycles of drainage and imbibition. Killough's method is the calculation of a scanning curve to determine the relative permeability when there is a reverse of the imbibition or drainage process between endpoints on the respective curves. We have also used a WAG hysteresis model to account for the dependence of relative permeability on the history of the saturation of the third phase.

In our two phase model, the non-wetting phases may be oil or gas in contact with water. The trapped critical saturation of the non-wetting phase is calculated as a modification of the Land trapping model.

\[ S_{nwcr_t} = S_{nwcr_d} + \frac{s_{hy} - S_{nwcr_D}}{1 + (s_{hy} - S_{nwcr_D})} \]  \hspace{1cm} \text{(2.29)}

where

\[ C = \frac{1}{S_{nwcr_t} - S_{nwcr_d}} - \frac{1}{S_{nw_{max}} - S_{nwcr_D}} \]  \hspace{1cm} \text{(2.30)}

The Land trapping coefficient \( C \) varies with fluid and rock properties [93]. The relative permeability \( k_{nw} (S_{nw}) \) at saturation \( S_{nw} \) on the scanning curve is calculated as a function of the relative permeability values on the bounding imbibition and drainage curves, \( k_{nw_t} \) and \( k_{nw_D} \) respectively.

\[ k_{nw} (S_{nw}) = \frac{k_{nw_t}(S_{norm})k_{nw_D}(s_{hy})}{k_{nw_D}(S_{nw_{max})}} \]  \hspace{1cm} \text{(2.31)}

where

\[ S_{norm} = S_{nwcr_{imb}} + \frac{(S_{nw} - S_{nwcr_t})(S_{nw_{max}} - S_{nwcr_t})}{s_{hy} - S_{nwcr_t}} \]  \hspace{1cm} \text{(2.32)}
Field results have shown that during CO\textsubscript{2} WAG injection, the injectivity of CO\textsubscript{2} decreases after the first WAG cycle due to decreasing water relative permeability. A review of five U.S. WAG floods show an average 20% decline in injectivity after the first cycle\cite{94}. For WAG hysteresis, the fraction of free gas trapped, $S_{g_t}$, in the reservoir is estimated using Land's trapping model\cite{95, 96} expressed as:

$$S_{g_t} = S_{g_{cr}} + \frac{(S_{g_{max}} - S_{g_{cr}})}{(1 + C (S_{g_{max}} - S_{g_{cr}}))} \quad 2.33$$

where $S_{g_{max}}$ is the maximum saturation of gas achieved historically in each grid block, $S_{g_{cr}}$ represents critical gas saturation and $C$ is the Land parameter. Our critical gas saturation was 15% and we have used a Land parameter value of $C = 2$ in our simulation which was estimated in work carried out by Pentland et al on unconsolidated sandpacks\cite{97}. WAG injection hysteresis is calculated to determine secondary drainage curves with each successive WAG cycle. Relative permeability hysteresis describes the change in relative permeability as the process of fluid-rock interaction changes from imbibition (increasing water saturation) to drainage (decreasing water saturation) during WAG injection. Carlson's\cite{98} relationship for a two-phase model determines the relative gas saturation as a function of the free gas saturation:

$$k_{rg}(S_g) = k_{rg}^D (S_{gf}) \quad 2.34$$

where

$$S_{gf} = S_{g_{cr}} + \frac{1}{2}\left\{ (S_g - S_{g_{trap}}) + \sqrt{(S_g - S_{g_{trap}})^2 + \frac{4}{C}(S_g - S_{g_{trap}})} \right\} \quad 2.35$$

In a three-phase model, if drainage begins at a saturation that is less than maximum but more than connate water saturation, the non-wetting phase secondary drainage is derived from the primary drainage curve after Hustad\cite{99}:

$$k_{rg}^D = [k_{rg}^{input} - k_{rg}^{input} (S_{g_{start}})] \cdot \left[ \frac{S_{w_{c}}}{S_{w_{start}}} \right]^\infty + [k_{rg}^{imb} (S_{g_{start}})] \quad 2.36$$
where $k_{rg}^D$ is the secondary drainage gas relative permeability, $k_{rg}^{\text{input}}(S_g^{\text{start}})$ is the primary drainage gas relative permeability at the start of the secondary drainage process, $k_{rg}^{\text{imb}}(S_g^{\text{start}})$ is the gas relative permeability of the imbibition curve at the start of the secondary drainage process, $S_w^{\text{start}}$ is the water saturation at the start of the secondary drainage process, $S_{wco}$ is the connate water saturation and $\alpha$ is the reduction exponent which we have set as 0.1.

Spiteri and Juanes [100] compared the impact of three-phase and two-phase hysteresis models on field scale predictions of oil recovery and producing GOR. The recovery efficiency is the same as fraction of original oil in place that is produced. When the effect of hysteresis is ignored the predicted recovery efficiency is 9% and 5% lower than the prediction from the two-phase models of both Carlson and Killough and, the three-phase model respectively (Figure 2.9).
Figure 2.9: Recovery efficiency predicted by the Killough, Carlson and the WAG three-phase hysteresis model compared to the base case where hysteresis is not considered. Relative permeability was calculated using the Stone I interpolation model. The numerical simulation model was a homogeneous horizontal reservoir with 20% porosity and permeability of 200mD to predict recovery of immiscible WAG injection reproduced from Spiteri and Juanes [100].

The PUNQ-S3 model has slightly different average properties to the homogeneous models used in Figure 2.9 and was used to generate the results of Figure 2.10 to capture the effect of anisotropy in a realistic benchmark model. The porosity, fluid PVT and relative permeability data in PUNQ-S3 the same as the synthetic homogeneous model, but the average horizontal permeability is 100mD and anisotropy ratio is approximately 3. The details of the PUNQ-S3 have been published by Floris et al[101]. The impact of incorporating hysteresis is not as pronounced in the more realistic case (PUNQ-S3) as in the synthetic homogeneous model.

Figure 2.10: Recovery efficiency predicted by the Killough two-phase and WAG three-phase hysteresis models compared to the base case with no hysteresis considered using the PUNQ-S3 model to predict recovery of immiscible WAG injection. Relative permeability was calculated using the Stone I method reproduced from Spiteri and Juanes [100].
Figure 2.11 shows the prediction of producing GOR is much lower when hysteresis is accounted for in the relative permeability models. Hysteresis accounts for greater trapping and so gas production is lower. In our simulations we have used the Stone I model. Spiteri and Juanes also investigated the impact of these models on oil recovery using the PUNQ-S3 reservoir model. The recovery efficiency of the Stone I at the end of 25 years was 58%; for the Stone II and Baker models, recovery efficiency was 54%. Here we see that the method of interpolation had a greater impact on recovery prediction than the type of hysteresis modelling used.
Land's trapping parameter C [96] also had an effect on recovery efficiency as shown in Figure 2.12. The recovery efficiency in the three cases were initially comparable but as the flood progressed and gas saturation increased. We recall Equation 2.20 where the saturation of trapped gas is indirectly proportional to the value of C. For a given maximum and critical gas saturation, a higher value of C yields trapping at a lower saturation- thus reducing contact with reservoir fluids and contribution to oil recovery.

From the preceding review it is evident that the hysteresis model for two-phase and three-phase permeability and the value of the Land's trapping coefficient, C, can have negligible
impact on final recovery estimates. In our reservoir simulations we have used Land's trapping coefficient of two, applied to the Stone I model to a synthetic reservoir representation which a $k_v/k_h$ ratio of 0.1. From the work carried out by Spiteri and Juanes[102], we expect our results to have slightly lower recoveries than similar work which uses three phase permeability hysteresis models but we expect close agreement with the Carlson two-phase model. Having accounted for hysteresis there may possibly be slightly higher recoveries than similar work which do not take this into account. The Land trapping coefficient of 2 which we have used will give relatively conservative recoveries compared to simulations run with a lower Land trapping coefficients. We have chosen this value based on work carried out by Pentland et al to represent CO$_2$ trapping in unconsolidated sand [97].

2.7 Gas Trapping

CO$_2$ trapping can occur as a result of reservoir heterogeneity, mineralization, capillary trapping, and dissolution in reservoir fluids. The influence of reservoir heterogeneity for carbon storage in saline aquifers has been investigated in laboratory experiments, reservoir simulation and well monitoring. Research carried out by Kuo et al [103], Jessen and Kovscek [73], Green et al. [104] and Melick et al [105] agree that heterogeneity increases CO$_2$ storage efficiency by allowing greater access between the injected gas and the reservoir. Numerical simulations have shown that heterogeneity increases the lateral extent of the plume [106], contact with porous media [107], decelerates gas migration [108, 109] and hence increases CO$_2$ dissolution.

Capillary trapping was first modelled by Land [96] relating the trapped gas saturation to the maximum residual saturation of the non-wetting phase and a trapping coefficient. Subsequent work removed the assumption of a monotonic relationship by using a scanning curve [98] and accounting for different rock wettabilities [110] in two-phase flow. Pentland et al [111] investigated the trapping of the non-wetting phase in unconsolidated sand packs for a
liquid/liquid system as a representation of the mechanism of carbon storage in saline aquifers. The results suggest that unconsolidated systems exhibit much lower trapping than consolidated systems and the Land trapping model tends to overestimate trapping of the non-wetting phase.

Mobile \( \text{CO}_2 \) structurally trapped by overlying caprock depends on the integrity and continuity of the caprock to prevent the release of \( \text{CO}_2 \) to the atmosphere [112]. Immobile \( \text{CO}_2 \) trapped as isolated bubbles, dissolved in reservoir fluids or as solid precipitates provide greater storage security [23]. The timescale for mineralization (>100 years) is much greater than the time scale considered in this study and the possible changes to permeability and porosity and can be ignored [113-115]. Qi et al [116] showed that secure storage via capillary trapping can be quickly achieved by injecting chase brine after water and \( \text{CO}_2 \) have been injected into an aquifer. By injecting \( \text{CO}_2 \) and brine into an aquifer and then injecting brine only, \( \text{CO}_2 \) is immobilized as tiny (10 micrometres) isolated droplets within pore spaces [117]. Several researchers have investigated the effect of \( \text{CO}_2 \)-brine precipitates on reservoir characteristics and the resulting relative contribution to total storage [107, 109, 115, 118].

Gas trapping can also be sensitive to gas and water injection rates [119]. Kuo [103] observed gas distribution sensitivity to flowrate on the sub-core scale and concluded that this was an indication of the interplay of viscous, capillary and gravity forces in different flow regimes of the \( \text{CO}_2 \)-brine displacement. Zhou et al [89] studied the relationship between these forces in a two-component, two-phase flow system. The modified gravity number used in their analytical development describes the ratio of gravity to viscous forces for fluid flow in the transverse direction. Simulation studies on carbon storage in aquifers [119, 120] and conventional oil reservoirs [121] have shown gas storage sensitivity to injection rate. In Chapters 3 and 4 we look at the sensitivity of storage to injection rate and by extension the gravity number for WAG and water over gas injection.
2.8 CO₂ EOR in Trinidad

Hydrocarbon deposits are found in the southern half of Trinidad continuing from the Venezuelan Eastern Basin. Whilst heavy oil deposits are found primarily on the south western side of the island, producing natural gas fields are off the north and east coasts. Natural gas is transported by pipeline from the east coast to the Point Lisas Industrial Estate for feedstock in downstream industries such as ammonia and methanol production and, fuel consumption for power generation and to Point Fortin for LNG production and power generation. These operations contribute to the vast majority of the population's anthropogenic carbon dioxide emissions[12]. In 2007, Trinidad and Tobago was ranked 6th in carbon emissions per capita, producing on average 27 metric tonnes per person[22]. The population is quite small (~1.3 million) and production is almost exclusively for export: the majority of CO₂ emissions come from industrial plants, mainly associated with processing oil and gas and account for less than 1% of worldwide emissions [15]. At the Point Lisas Industrial Estate, ammonia plants and methanol produce a waste product of relatively pure stream of carbon dioxide (97-99% CO₂).
Mohammed-Singh et al reports that between 1973 and 1990, several immiscible CO$_2$ floods were conducted as moderately successful pilot projects in the Forest Reserve sand found in the onshore Oropuche and Forest Reserve fields [14]. CO$_2$ was piped 42 km and compressed in four stages, from atmospheric pressure to 68 bar (6.8MPa), between an ammonia plant at Point Lisas and the Forest Reserve oil field. The field had previously undergone primary, secondary and tertiary production with water and natural gas injection. CO$_2$ injection resulted in incremental recovery of 2 to 8% of OOIP. Although preliminary results were encouraging, these projects have been discontinued with no further expansion due to concerns of CO$_2$ escape to surface outcrops in populated areas and other operational issues [122].

Without finding new oil reserves, enhanced oil recovery is needed to boost declining oil production in Trinidad which have been on a steady decline since peaking in 1978[18]. In the last 5 years, annual oil production has declined at a rate of 9% per year[13]. At the same time CO$_2$ emissions continue unchecked and largely unused. Furthermore, given that CO$_2$ EOR
can offset carbon dioxide cost; there is available and unused relatively pure sources of CO$_2$ emissions at the Point Lisas Industrial Estate; heavy oil fields are within a 50km radius of emission sources – coupled CO$_2$EOR and carbon storage should be considered. One obstacle is the location of most heavy oil fields onshore scattered in and around populated areas and which reservoirs may not be structurally sealed[122]. However, carbon dioxide injection in heavy oil fields offshore the western shore of Trinidad (Figure 2.2) can be considered given that the fields are situated away from populated areas and 3D seismic has been acquired over the area to determine locations of faults. Furthermore, in 2003, the first multilateral well was drilled and completed in our area of interest- S759[123].

2.9 Geologic Storage of CO$_2$

2.9.1 Site selection and risks

CO$_2$ injection does not present a significant technical challenge to the oil industry [44, 56]. However, there remains concerns with the risk of early uncontrolled escape of carbon dioxide should there be fault, fracture or outcrop presenting the opportunity of the carbon dioxide to be release to the atmosphere once it has been injected into the reservoir[124, 125]. Release rates of CO$_2$ from have been measured in a field where more than 100MtCO$_2$ was been injected for CO$_2$ EOR and the results have been used as a prototype for CO$_2$ sequestration- the volume released was roughly 0.005% of the annual injected CO$_2$ volume [126, 127]. Bachu outlined the criteria for selecting a suitable site for geological storage in order to decrease the risk of escape and the potential for devastation[62]. We now consider the geology, data collection and wells in the Soldado field as a potential site for CO$_2$ storage.

**Soldado Field Geology.** The Gulf of Paria pull-apart basin is considered to be a continuation of the Eastern Venezuelan basin[128, 129]. The stratigraphy of the region consists of the three regions 1) a lower fold-and-thrust belt, 2) an upper Northern Transtensional basin fill and 3)
Southern basin successions separated by the NW-SE trending Los Bajos fault. The Soldado field is separated into three compartments: North Field (Northern Basin), Main Field, and East Field (Southern Basin). In the northern basin the Manzanilla and Springvale formations were deposited during the Pliocene age in shallow marine to deltaic environments with sediments sourced from a northwestern emergent high. In the southern Basin the Forest and Cruse formations were also deposited during the Pliocene age with sediments sourced from the Proto-Orinoco river system. The Los Bajos fault system acts as a conduit for hydrocarbons found in both basins sourced from the deeper Upper Cretaceous Naparima Hill formations.

**Soldado Field Data Collection and Development.** The S-759 is in the Soldado North Field. It was discovered in 1998 with drilling of the S-759 well based on seismic data compiled over the area. There was lateral continuity of the unconsolidated Forest sands encountered there which reduced the risk of further developments. This discovery was followed by the drilling of eight vertical wells to delineate the reservoir. In addition to well logs for all wells, there is seismic data and production data. This CO$_2$ storage site may be preferred to potential onshore locations because unlike the land operations there is seismic data available to give information on the reservoir extent and faulting and the field is sufficiently removed from populated areas. Additionally, the wells are relatively new thus reducing the risk of leakage through old well bores[125]. However the risk of seismic activity in the area in relation to CO$_2$ will have to be assessed.

2.10 Coupled Carbon Storage and EOR Applications

The objectives of CO$_2$EOR projects are minimum CO$_2$ utility, maximum CO$_2$ retention and maximum oil recovery. CO$_2$ utility also known as CO$_2$ requirement is the ratio of the total CO$_2$ volume injected to the total volume of oil produced at standard conditions. It is a measure of the economic efficiency of CO$_2$EOR projects and the efficacy of CO$_2$ in mobilizing oil. In the early
stages of a miscible flood CO$_2$ utility is high (> 10 Mscf/bbl) because the oil bank is being formed and mobilized. As the flood progresses CO$_2$ utility decreases as the flood becomes more efficient. CO$_2$ retention is the percentage of CO$_2$ injected which remains in the reservoir at the end of the project[32]. Retention also decreases as the CO$_2$ flood progresses because of gas override.

For coupled carbon storage and CO$_2$ EOR the objectives are slightly different in that high or equivalent CO$_2$ utilization would be favourable along with high retention and oil recovery[58, 130, 131]. Tapered WAG injection, where the water fraction of the WAG ratio is increased stepwise in each cycle, is recommended to overcome high CO$_2$ production, [132]. However if this is applied to coupled carbon storage and CO$_2$ EOR, the additional water injection will reduce the reservoir CO$_2$ storage capacity[72]. Coupled CO$_2$ EOR and carbon storage requires an injection strategy which allows maximum CO$_2$ utility to coincide with favourable oil recovery and carbon storage.

Continuous gas injection. The Weyburn enhanced oil recovery (EOR) project in Canada [133] stands apart from other CO$_2$ EOR projects around the world in that it relies entirely on anthropogenic carbon emissions and operations [134]. The project was preceded by a reservoir simulation investigation into the possibility of co-optimization of carbon storage and oil production from a conventional, light oil field (oil density of 848 kg/m$^3$ and oil viscosity of 4.7 mPa.s)[135]. The project uses a combination of horizontal CO$_2$ injectors, vertical water injectors and vertical producers. Achieving miscibility was argued to be important to achieve co-optimization, along with CO$_2$ injection into bottom waters. Unless light hydrocarbon fractions (C$_2$-C$_6$) are injected with the carbon dioxide stream to reduce the minimum miscibility pressure (MMP) of the crude to reservoir pressure, this does not apply to heavy oil recovery.
**WAG injection.** At present there are 12 immiscible and 8 miscible CO$_2$ EOR projects worldwide - a further 9 immiscible and 2 miscible projects are expected in the next two years [136]. As CO$_2$ sequestration research and efforts continue, CO$_2$ EOR will become a means for sustainable development by generating income while reducing carbon emissions [23]. WAG injection was developed to control cost and improve the sweep efficiency of gas injection processes such as CO$_2$ EOR when gas supplies are expensive and/or limited. In addition to cost constraints the development of this injection strategy can be hampered by fingering, gas override, water underride and loss of injectivity in certain conditions [32]. Under certain conditions WAG injection can be successful at recovery and carbon retention[137]. Dyer and Farouq Ali used material balance calculations to determine oil recovery at each of the four stages used in their displacement experiments[1]. CO$_2$ requirement was defined as the ratio of total CO$_2$ injected to the total volume of oil produced at standard conditions. CO$_2$ retention was defined as the percentage of CO$_2$ injected that was not produced after at the end of experiments reproduced in Table 2.2.
### Experimental Results

#### Experimental Parameters

- **Run Number**
- **Oil Viscosity (mPa.s)**
- **Injection Velocity (m/d)**
- **CO₂ injection (%HCPV)**
- **Number of Slugs**
- **WAG Ratio (H₂O:CO₂)**
- **CO₂ requirement (std m³/m³)**
- **CO₂ retention (% injected)**
- **Initial Water-flood**
- **Post-waterflood**
- **Blow-down**
- **Total**

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<td>15.2</td>
<td>0.9</td>
</tr>
<tr>
<td>13</td>
<td>1055</td>
<td>0.49</td>
<td>20</td>
<td>10</td>
<td>4:1</td>
<td>4.6</td>
<td>53.5</td>
<td>0.0</td>
<td>34.0</td>
<td>10.0</td>
<td>1.0</td>
</tr>
<tr>
<td>14</td>
<td>1055</td>
<td>0.49</td>
<td>20</td>
<td>10</td>
<td>8:1</td>
<td>4.7</td>
<td>57.8</td>
<td>0.0</td>
<td>39.3</td>
<td>4.0</td>
<td>1.6</td>
</tr>
<tr>
<td>15</td>
<td>1055</td>
<td>0.49</td>
<td>20</td>
<td>10</td>
<td>2:1</td>
<td>4.7</td>
<td>23.5</td>
<td>0.0</td>
<td>28.5</td>
<td>14.7</td>
<td>0.8</td>
</tr>
<tr>
<td>22</td>
<td>150</td>
<td>0.98</td>
<td>20</td>
<td>10</td>
<td>4:1</td>
<td>3.4</td>
<td>6.1</td>
<td>0.0</td>
<td>47.8</td>
<td>15.5</td>
<td>1.6</td>
</tr>
<tr>
<td>23</td>
<td>150</td>
<td>0.98</td>
<td>20</td>
<td>10</td>
<td>4:1</td>
<td>13.5</td>
<td>12.5</td>
<td>60.7</td>
<td>2.9</td>
<td>0.1</td>
<td>1.8</td>
</tr>
</tbody>
</table>

Average porosity =0.363± 0.011; average permeability= 12.3± 1.6 µm²; average initial oil saturation=0.897± 0.014; backpressure=1.0MPa

Table 2.2: Results of displacement experiments conducted by Dyer and Farouq Ali on a recombined Aberfeldy crude at 23 °C and 1 MPa reproduced from Dyer and Farouq Ali[1].

Results show that low rate fluid injection (water and gas) were best suited for carbon retention. The effect on carbon storage was reduced as the WAG ratio (H₂O:CO₂) decreased but total oil recovery was essentially the same. The difference in oil recovery during the four stages is directly related to the volume of water injected.

CO₂ retention was much greater when WAG was preceded and followed by a waterflood (runs 7 and 8) but recovery was about 4% lower. The post WAG waterflood is similar to the chase brine used by Qi et al to trap CO₂[116]. Unfortunately there were no runs which can be directly compared to run 8 to determine at which stage, WAG or the post WAG waterflood, CO₂ trapping occurred. However, compared to run 4 where there is no waterflood, the slug size is 4.45 times larger than run 8 and, essentially equal CO₂ requirement there is 45% less carbon retention.
This is in agreement with work done by Qi et al. [116] on miscible displacement of conventional oil and carbon trapping using an optimal WAG ratio (4:1) followed by chase brine to increase CO$_2$ capillary trapping. The oil recovery of run 8 (pre- and post-WAG waterflood) is 12% lower than run 4. However from the results of runs 4 and 5 we can deduce that if more WAG cycles are used recovery and storage will increase. There is greater carbon storage with high oil viscosity than with low. As expected oil recovery is more favourable the lighter oil (22%) but there is a large difference in storage with 43% less CO$_2$ retained. There was a clear increasing trend with CO$_2$ retention and slug size. In Chapter 3 we have duplicated the WAG and post WAG waterflood (PWWF) results to aid in our understanding of coupled CO$_2$ EOR and carbon storage for our development of a suitable injection strategy.

**WAG with miscible gas injection.** Kosvcek and Cakici [72] investigated coupled storage and heavy oil recovery using an enriched gas mixture of CO$_2$ and hydrocarbon gases (ethane, propane and n-butane). On the premise that injecting water reduces carbon storage capacity, the authors simulated a 1:1 ratio of WAG and managed well pressure for mobility control and to minimize production gas-oil ratio (GOR). The optimum time to switch from enriched gas to pure carbon dioxide was also investigated. There was no distinction between mobile and immobile phases of stored CO$_2$. Asghari et al. [138] investigated the effect of operational parameters on CO$_2$ storage in a heterogeneous light oil reservoir. They found storage to be increased with a horizontal producer and miscible gas injection.

**Proposed water over gas injection.** Stone [90] developed an injection strategy of separate but simultaneous gas and water injection to improve gas sweep. Gas is injected at the bottom of the reservoir and water is injected in the same vertical plane in the upper portion of the reservoir. The objective of this strategy was to create a long mixing zone to counteract rapid gravity segregation. Rossen and Shen [139] expanded on Stone’s work and developed analytical solutions based on the fractional flow theory to investigate injection strategies to increase
sweep efficiency by overcoming gravity segregation. They developed a relationship to
determine the point of segregation as a function of fluid injection rate assuming immobile oil. In
this thesis we propose this injection strategy for coupled carbon storage and oil recovery after
reviewing WAG injection.

In Chapter 3 we revisit the work of Dyer and Farouq Ali [140] using compositional reservoir
simulation to gain an understanding of the carbon storage and oil recovery using water and gas
injection. Our results show the impact of varying injection parameters such as rate, water-\text{CO}_2
ratio, number of WAG cycles and, injecting water after WAG injection. We also determine
representative properties for field-scale simulation and verify that we can capture the
displacement processes seen in sandpack experiments.

In Chapter 4 we investigate carbon storage and recovery in heavy oil reservoirs using counter
current injection of water and gas as proposed by Stone[90]. Water over gas injection is
intended to overcome the unfavourable mobility ratio between heavy oil and the injected fluids
as well as promote capillary trapping [141]. We investigate co-optimization of oil recovery and
gas storage using the water over gas injection strategy with a single vertical well and a pair of
parallel horizontal wells in an unconsolidated sand using commercial compositional simulator
ECLIPSE. The results in chapter 4 show the impact of injecting solvent gases, varying injection
well orientation and water injection rates on oil recovery and carbon storage.
Chapter 3

Enhanced Oil Recovery and Carbon Storage using WAG Injection

3.1 Introduction

In this chapter we have used compositional simulation to obtain a better understanding of water alternating gas (WAG) flooding as it relates to EOR and carbon storage in a moderately heavy oil reservoir. We have compared the oil recovery and carbon storage trends of our simulations to the results of Dyer and Farouq Ali’s laboratory experiments [1]. Our simulations were run at reservoir conditions using the properties of the Forest Reserve 4B sand to determine the sensitivity of the trends observed in the displacement experiments. This work is used to find representative properties for field-scale simulation and to verify that we can capture the displacement processes seen in sandpack experiments. Dyer and Farouq Ali’s displacement experiments used an Aberfeldy crude mixed with liquid petroleum to obtain an oil
viscosity of 1055 mPa.s at standard conditions to represent viscosity reservoir conditions. The fluid description used in our compositional simulations are based on PVT-matched properties of oil found in an unconsolidated deltaic, sandstone deposit in the Gulf of Paria, offshore Trinidad. At standard conditions the crude viscosity is 1175 mPa.s and at reservoir conditions (81° C and 27.9 MPa) 8 mPa.s.

3.2 Injection parameters and strategies

Dyer and Farouq Ali [1] used a horizontally mounted sandpack (diameter 98mm and length 415mm) and injected water and CO₂ to displace heavy oil at low pressure (1 MPa) and ambient temperature (23 °C).

![Figure 3.1: Schematic showing the length scales of the sandpack used in displacement experiments by Dyer and Farouq Ali[13].](image)

We have used the same variation of injection parameters: fluid injection rate; CO₂ slug size; number of slugs and; WAG ratio, in our simulations at reservoir conditions shown in Table 3.1 where carbon dioxide is a supercritical fluid as shown in Figure 2.3. We have not attempted to obtain an exact match to the displacement experiments given the difference between the fluid properties, porous media properties, temperature and pressure of the laboratory results and our simulations. The crude composition, dispersion and relative permeability of oil, CO₂ and water were not measured for these displacement experiments.

The four stages considered were an initial waterflood followed by WAG, post WAG waterflood and blowdown. The recovery for each stage, in the relevant runs, is shown in Table 2.2. WAG
injection was conducted in all instances except Run 1, the post WAG waterflood was conducted only if the water cut if the WAG stage did not exceed 95%. Finally the pressure of the system was reduced to atmospheric pressure. Although oil recovery was determined at each stage, only the total gas retained was reported after all stages of recovery including blowdown. To quantify \( \text{CO}_2 \) usage, \( \text{CO}_2 \) requirement and \( \text{CO}_2 \) retention, defined in Chapter 2, were the two metrics calculated. In the displacement experiments WAG injection was followed by a waterflood and finally a blow down, where the producing end is opened to atmospheric pressure. The recovery during the blow down stage occurs through solution-gas drive\[44\]. In two cases, WAG injection was preceded by a waterflood and the post-WAG waterflood (PWWF) was carried out only if after WAG injection, the producing water oil ratio (WOR) was less than 20 (95% water cut). The experiments ended whenever the water cut exceeded 95%. The injection strategy used here was designed for oil recovery and as such a blow down of the sandpack would have been considered beneficial. However with carbon storage as an objective, a blow down would be counterproductive since this will lead to \( \text{CO}_2 \) production. In our simulations we investigate the impact of WAG and post WAG waterflood only. We have also included a simulation run of continuous gas injection for comparison with a gas-oil ratio (GOR) of 500\( \text{m}^3/\text{m}^3 \) used as the economic limit (WOR of 20).

### 3.3 Scaling of the Immiscible \( \text{CO}_2 \) Displacement

The displacement experiments of Dyer and Farouq Ali were based on the scaling groups derived by Rojas [142] for the immiscible displacement of oil by carbon dioxide and water. They satisfied the scaling groups related to geometry of the sandpack, fluid dispersion, fluid injection rates, porosity, ratio of gravitational to viscous forces, ratio of viscous to capillary forces and relative permeability. We have satisfied the scaling of length to width geometry, water injection rates and, ratio of gravitational to viscous forces for water. The ratio of viscous to capillary forces for water and gas is negligible in heavy oil application and was not considered. We have not scaled
our model to the porosity, relative permeability, ratio of gravitational to viscous forces for CO₂, dispersion of CO₂ in oil, or water, gas or oil dispersion of the experiments.

**Reservoir and fluid properties** The field reservoir properties used are summarized in Table 3.1. These properties of the Forest sand are also found in the Soldado Field offshore Trinidad [14]. Our simulations represent a small homogeneous section of unconsolidated sand over a volume of 184m × 30m × 43m (21 × 1 × 21 grid cells) with geometric scaling of Dyer and Farouq Ali’s sandpack such that the ratio of length to width were the same for the hydraulic equivalent of a rectangular reservoir. The grid represents a quarter five-spot between a vertical injector and vertical producer with all layers open to flow. The reservoir represented is clean unconsolidated sand with constant permeability and porosity with no barriers to flow. Migration of fluids outside the grid area is not considered.

<table>
<thead>
<tr>
<th>Component</th>
<th>Mole Fraction</th>
<th>Weight Fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>0.0092</td>
<td>0.0023</td>
</tr>
</tbody>
</table>

Table 3.1: Properties of sandpack and reservoir simulations.
Table 3.2: Initial oil composition of a Soldado crude oil sample.

In Table 3.2 it should be noted that this crude has an uncharacteristically high proportion of methane for heavy oil. However, at initial reservoir conditions (27.5 MPa, 81.7°C) it is above the bubble point as shown in Figure 3.2.

Figure 3.2: Phase envelope of the reservoir fluid showing the line of constant reservoir temperature (81.7°C) intersecting the phase envelope at 22 MPa. The initial reservoir pressure is 27.5 MPa.
Table 3.3: Comparison of Soldado sample crude properties at different conditions.

Table 3.3 shows a comparison of the Soldado crude and CO₂ properties at reservoir and laboratory conditions. At reservoir temperature (81.7°C) and pressure (27.5 MPa), the viscosity and density of CO₂ is less than that of crude and water (1 mPa.s and 986.8 kg/m³ respectively). The composition and properties of the crude oil used in the PVT data match is used to represent the crude oil phase behaviour are shown in Table 3.4.

<table>
<thead>
<tr>
<th>Component</th>
<th>MW</th>
<th>Specific Gravity</th>
<th>p&lt;sub&gt;cr&lt;/sub&gt; (atm)</th>
<th>T&lt;sub&gt;cr&lt;/sub&gt; (K)</th>
<th>z&lt;sub&gt;cr&lt;/sub&gt;</th>
<th>V&lt;sub&gt;cr&lt;/sub&gt; (cc/gm-mole)</th>
<th>Ω&lt;sub&gt;a&lt;/sub&gt;</th>
<th>Ω&lt;sub&gt;b&lt;/sub&gt;</th>
<th>Ω&lt;sub&gt;c&lt;/sub&gt;</th>
<th>φ</th>
<th>Volume Shift</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>44</td>
<td>0.777</td>
<td>33.50</td>
<td>126.2</td>
<td>0.274</td>
<td>90.0</td>
<td>0.457</td>
<td>0.078</td>
<td>0.225</td>
<td>-0.131</td>
<td></td>
</tr>
<tr>
<td>CH₄</td>
<td>16</td>
<td>0.726</td>
<td>45.44</td>
<td>190.6</td>
<td>0.284</td>
<td>98.0</td>
<td>0.457</td>
<td>0.078</td>
<td>0.013</td>
<td>-0.144</td>
<td></td>
</tr>
<tr>
<td>C₂-C₆</td>
<td>53</td>
<td>0.425</td>
<td>51.42</td>
<td>484.9</td>
<td>0.304</td>
<td>235.8</td>
<td>0.578</td>
<td>0.117</td>
<td>0.187</td>
<td>-0.090</td>
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</tr>
<tr>
<td>C₇⁺</td>
<td>388</td>
<td>1.134</td>
<td>15.98</td>
<td>979.4</td>
<td>0.294</td>
<td>1480.4</td>
<td>0.295</td>
<td>0.067</td>
<td>1.049</td>
<td>0.000</td>
<td></td>
</tr>
</tbody>
</table>

Table 3.4: Summary of component properties and Peng-Robinson equation-of-state parameters used to describe the crude oil sample.

Table 3.4 lists the regressed properties of the C₂-C₆ and C₇⁺ grouped components. The compositional model of the fluid was based on the regression of the three-parameter Peng-Robinson equation of state (PR EOS) [2] and the Lohrenz Bray Clark (LBC) viscosity correlation [3] on PVT data of the Soldado crude. z<sub>cr</sub> and V<sub>cr</sub> represent the critical z-factor and critical volume respectively, used in the LBC equation. Regression of the PR EOS parameters critical pressure, p<sub>cr</sub>, critical temperature, T<sub>cr</sub>, acentric factor, Ω<sub>a</sub>, Ω<sub>b</sub>, and Ω<sub>c</sub> and volume shift was carried out on the C₂-C₆ and C₇⁺ grouped components; z<sub>cr</sub> and V<sub>cr</sub> of the were regressed in the LBC correlation. The thermodynamic properties of CO₂ [143] and methane [144] have been
established by published experimental work. The molecular weight and specific of the C7+ fraction were given in the PVT report.

Figures 3.3-3.5 represent the match obtained by regressing the parameters of the PR EOS to total relative volume, oil relative volume and viscosity.

![Graph showing semi-log plot of the match of the three-parameter Peng-Robinson EOS regressed to PVT total relative volume measured during differential liberation of the Soldado crude sample at 81.7 °C.]

Figure 3.3: Semi-log plot of the match of the three-parameter Peng-Robinson EOS regressed to PVT total relative volume measured during differential liberation of the Soldado crude sample at 81.7 °C.
Figure 3.4: Plot of the match of the three-parameter Peng-Robinson EOS regressed to PVT oil relative volume measured during differential liberation of the Soldado crude sample at 81.7 °C.

Figure 3.5: The match of the modified Peng-Robinson equation of state and LBC equation regressed onto PVT data to viscosity measured during constant composition expansion of a moderately heavy oil at a reservoir temperature of 81.7 °C.
**CO₂-crude mixture properties.** Dyer and Farouq Ali published the gas solubility, oil relative volume and, viscosity of the CO₂-Aberfeldy crude mixture shown in Figure 3.6 and Figure 3.7.

**Figure 3.6:** Swelling factor and viscosity of CO₂-Aberfeldy crude mixture used by Dyer and Farouq Ali [1] at 23 °C

**Figure 3.7** is a comparison of CO₂ solubility in the Aberfeldy crude used by Dyer and Farouq Ali, the Bartlett crude used by Chung et al [67] and the predicted solubility for the Soldado crude using the tuned Peng-Robinson EOS and the LBC correlation. We have not attempted to match the solubility of the Soldado crude to the Aberfeldy and Bartlett crudes which are both dead oils. Table 3.2 shows the high (0.42) mol fraction of methane in the Soldado crude; methane has the effect of decreasing the solubility of CO₂ in oil [145]. In our reservoir simulation using the Soldado crude, at initial pressure of 27 MPa, CO₂ solubility is approximately 52 m³/m³ and decreases with decreasing pressure. Figure 3.7 also shows that in depleted or undersaturated
heavy oil crudes such as the Aberfeldy and Bartlett crude, CO$_2$ solubility will comparable to the Soldado crude at a lower reservoir pressures.

![Figure 3.7: Plot of CO$_2$ solubility as a function of pressure for displacement experiments on a recombined Aberfeldy crude by Dyer and Farouq Ali (observed at 23 °C) swelling test on the Bartlett crude by Chung et al (observed at 93.3 °C) and the relationship used in our reservoir simulations (calculated at 81.7 °C) based on the PVT data regressed 3-parameter Peng-Robinson equation for Soldado live crude oil.](image)

**Relative permeability.** Figure 3.8 and Figure 3.9 show the oil and gas relative permeability curves matched to the waterflood (run 1) and single cycle WAG injection of run 6. Dyer assumed the relative permeability determined by Spivak and Chima [55] for heavy oil in unconsolidated porous media[146]. We used the Land’s trapping model with a trapping coefficient of 2 as determined by Pentland et al [97] for unconsolidated sands. The Killough[92] hysteresis model
was applied to the gas and water phase relative permeability. The trapped gas saturation was used in the Stone three-phase oil relative permeability model to alter the residual oil saturation.

Figure 3.8: Oil-water relative permeability matched to run 1.

Figure 3.9: Gas-oil relative permeability matched to run 6

**Fluid Injection rate.** Dyer and Farouq Ali used the same flow rate for water and gas injection.

Based on Equations

\[ N_{g_{v-g}} = \frac{(\rho_o - \rho_g) L k_{av}}{H u \mu_g} \]

2.21 and
2.22 the water and gas gravity numbers used by Dyer and Farouq Ali were 4.27 and \(3.95 \times 10^5\) for the high rate (0.98 m/day) and 8.55 and \(7.90 \times 10^5\) at the low rate (0.49 m/day). In our simulations the equivalent gravity numbers are obtained with water and gas injection rates of 53 and 2 \(\text{rm}^3/\text{day}\) respectively at high rates and; 26.4 and 1 \(\text{rm}^3/\text{day}\) at the low rate. Our water gravity numbers are the approximately those used in the experiments 4.25 and 8.54 for the high and low injection rates respectively.

Dyer and Farouq Ali scaled their displacement experiments to a prototype for sub-critical \(\text{CO}_2\) injection. The equivalent gas injection rates using our simulation parameter conditions are very low but are in keeping with the density of carbon dioxide at supercritical conditions, permeability of the Forest sand and the cost constraint on \(\text{CO}_2\) volumes in \(\text{CO}_2\) EOR processes. These low rates are not practical for carbon storage. Within the fracture pressure limit (30% greater than initial reservoir pressure), we have used injection rates of 53.0 and 26.4 \(\text{rm}^3/\text{day}\) for both water and gas injection and have not attempted to match the gas gravity number of the displacement experiments. At these injection rates, the gas gravity numbers for our reservoir dimensions and properties are \(1.41 \times 10^4\) and \(2.82 \times 10^4\) respectively using Equation

\[
N_{g_v,w} = \frac{\left(\rho_w - \rho_g\right)gL_{av}g}{H \mu_w}
\]

2.21 The ratio of the gas gravity numbers, 2, is the same for the displacement experiments and simulation studies. These are much greater than the gas gravity numbers (150 to 250) used in practice for \(\text{CO}_2\) storage projects and which we use in our field scale model in Chapter 4. The table below summarizes the rates and gravity numbers for displacement and simulation studies.

<table>
<thead>
<tr>
<th>Injection Rate ((\text{rm}^3/\text{day}))</th>
<th>Gravity Number (dimensionless)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water High Rate</td>
<td>0.007</td>
</tr>
<tr>
<td></td>
<td>53.0</td>
</tr>
<tr>
<td></td>
<td>4.3</td>
</tr>
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<td></td>
<td>4.3</td>
</tr>
<tr>
<td></td>
<td>Low Rate</td>
</tr>
<tr>
<td>------------------</td>
<td>----------</td>
</tr>
<tr>
<td><strong>Gas</strong></td>
<td></td>
</tr>
<tr>
<td><strong>High Rate</strong></td>
<td>0.004</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Low Rate</strong></td>
<td>0.004</td>
</tr>
</tbody>
</table>

Table 3.5: Water and gas injection rates and corresponding gravity numbers in our simulations and displacement experiments carried out by Dyer and Farouq Ali

Very high gas gravity numbers translates to the large gravity (buoyancy) forces which dominate the displacement process, resulting in gas override. As the gas gravity number increases the effect of the viscous forces (the product of injection rate and fluid viscosity) diminishes—this translates to a reduced net effect of the viscous forces. The intention of WAG injection is to improve gas sweep by reducing the relative permeability of gas injected after water injection and thus counteracting the buoyancy forces.

### 3.4 Results and Discussion

#### 3.4.1 Oil Recovery WAG

**Results Overview.** We have compared the WAG oil recovery trends of a laboratory scale displacement experiment and pilot scale simulation. We have not attempted to match oil recovery or carbon storage given the difference in fluid properties, temperature, pressure and reservoir properties. Table 3.6 summarizes results for all fifteen runs. A general comparison of all the runs show WAG recovery to be insensitive to injection rates and most productive with large slug sizes (runs 3, 4, 5, 6 and 10) and high injection WAG ratios (runs 11 and 14). In the sections below recovery and performance (water cut and GOR) are considered in detail with brief discussions.
### Injection Parameters

<table>
<thead>
<tr>
<th>Run No.</th>
<th>Simulation</th>
<th>Experiment</th>
<th>CO₂ injected % HCPV</th>
<th>No. of WAG cycles</th>
<th>WAG Ratio</th>
<th>Experiment at 1MPa</th>
<th>Simulation at 27.5MPa</th>
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<tr>
<td>1</td>
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<td>118</td>
<td>-</td>
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<td>-</td>
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<td>8.0 × 10⁵</td>
<td>8.5</td>
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<td>8:1</td>
<td>39.3</td>
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<tr>
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<td>2.8 × 10⁴</td>
<td>8.0 × 10⁵</td>
<td>8.5</td>
<td>20</td>
<td>10</td>
<td>2:1</td>
<td>28.5</td>
</tr>
</tbody>
</table>

Table 3.6: Summary of WAG oil recovery for displacement experiments and simulations.

**Effect of WAG ratio and injection rate/gravity number.** The impact of WAG ratio was investigated at two injection rates: the lower rate (higher gravity number) in runs 15, 13 and 14 and; the higher rates (lower gravity number) in runs 12, 7 and 11 at 2:1, 4:1 and, 8:1 ratios respectively. The number of WAG cycles (10) and the size of the CO₂ slug size (20% HCPV) were kept constant.
Table 3.7: Summary of impact of WAG ratio and injection rate on oil recovery during WAG.

Both simulation and experimental results show an increasing oil recovery trend with WAG ratio at both injection rates (Table 3.7). In the experiments, waterflood recovery and the 8:1 ratio were essentially equal, 39.1 and 39.3 % respectively; WAG injection used in the absence of a pre- or post waterflood does not significantly improve on waterflood recovery. We can infer that cumulative oil recovery is dominated by water injection rates and is slightly more efficient at lower injection rate. In our simulations, cumulative WAG recovery was basically insensitive to injection rates.

The rate of increase in oil recovery declines for WAG ratio greater than 4:1, indicating the limitation of the sweep efficiency of WAG injection. Water injection is instrumental in mobilizing oil; however, the improvement of combining water and gas injection is limited by gravity segregation. The increase in recovery with increasing WAG ratio represents the sphere of influence of the gas-water mixing zone.

**Performance.** We consider flood performance in our simulations as a function of pore volume injected (PVI) in Figure 3.10. The figures below show producing water cut and gas-oil ratio to be insensitive to injection fluid gravity number. Comparing injection rates, the ultimate recovery differed by less than 5% points, the main benefit of increased injection rate in this context is high oil production rates and oil recovery earlier in the flood Figure 3.10(a). As the WAG ratio
increased, CO$_2$ breakthrough was delayed and gas production is mitigated as shown in Figure 3.10 (c); however, at the same time oil is produced at high (>65%) water cut for an increasing portion of the flood Figure 3.10(b).
Figure 3.10: Simulation results of the effect of WAG ratio and injection rate on (a) oil production rate m³/day; (b) water cut; and (c) gas oil ratio m³/m³ for WAG ratios 2:1, 4:1 and 8:1 respectively (left to right) at injection rates 53 m³/day and 26.5 m³/day.
Figure 3.11: Oil Saturation profile between injector (left) and producer (right) of WAG injection after injecting with 20% HCPV of carbon dioxide over 10 WAG cycles at 53 rm³/day in (a) 2:1, (b) 4:1 and, (c) 8:1 WAG ratios.

Figure 3.11 confirms the hypothesis made earlier that increasing water injection expands the mixing zone. Here we see the effect of WAG ratio on vertical sweep efficiency. The 2:1 WAG
ratio resulted in low oil recovery because of gas over ride and limited contact with the middle of
the reservoir, closer to the producer where high oil saturations are observed indicating oil
bypassing. However the limitation of WAG is that gains to sweep efficiency using increasing
water injection comes at the expense of higher water production Figure 3.10 (b).

**Effect of number of WAG cycles.** A comparison of runs 4, 5 and 6 allows us to investigate
the impact of the number of WAG cycles on oil recovery. The injection rate, 53 and 0.007
rm³/day for simulation and experiments respectively; the total CO₂ injected (20% HCPV); and
the WAG ratio were kept constant. Using constant WAG ratio and total slug size means that per
cycle the CO₂ slug size and volume of water injected decreased with increasing WAG cycles. For
1, 5 and 10 WAG cycles the CO₂ slug size was 20, 4 and 2% HCPV per cycle respectively. In each
of these runs the economic limit of water cut constrained production.

<table>
<thead>
<tr>
<th>Run No.</th>
<th>Simulation CO₂ Slug size</th>
<th>Experiment CO₂ Slug size</th>
<th>No. WAG cycles</th>
<th>WAG ratio</th>
<th>Oil Recovery (%HCPV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>1.4 × 10⁴ 4.3</td>
<td>4.0 × 10⁵ 4.3</td>
<td>89</td>
<td>10</td>
<td>41:1</td>
</tr>
<tr>
<td>5</td>
<td>1.4 × 10⁴ 4.3</td>
<td>4.0 × 10⁵ 4.3</td>
<td>89</td>
<td>5</td>
<td>4:1</td>
</tr>
<tr>
<td>6</td>
<td>1.4 × 10⁴ 4.3</td>
<td>4.0 × 10⁵ 4.3</td>
<td>89</td>
<td>1</td>
<td>4:1</td>
</tr>
</tbody>
</table>

Table 3.8: Summary of the impact of the number of WAG cycles on oil recovery.

A single WAG cycle is essentially continuous gas injection followed by a chase waterflood; water
injection displaces the oil bank but it does not play any role in improving gas sweep efficiency.
For this reason the recovery with a single WAG cycle is the lowest of the three. In simulation and
experiments there is little improvement in oil recovery between 5 and 10 WAG cycles where
incremental recovery is in proportion to the increase of individual slug size- approximately
2%. With 89% HCPV of CO₂ injected with four times the volume of water, these slugs are quite
large and were cut short of the number of WAG cycles (5 and 10) because the water cut limit of
95% was reached after injecting about three PV of fluid.
Figure 3.12 shows that the main difference in oil recovery occurs between 0.2 and 1.0 pore volumes injected when the first water slug is injected. Outside of this range, 0.2 to 1.0 PVI, the oil recovery rate appears equal in all three scenarios, evident as parallel lines.

Figure 3.12: Oil recovery factor for 10, 5 and 1 WAG cycles as a function of total pore volumes of water and gas injected at 53rm³/day in 4:1 WAG ratio. Runs were stopped when either total CO₂ injection was 89% HCPV or producing water cut exceeded 95%.

The rate of recovery in the first pore volume injected effectively controls cumulative recovery. This can be attributed to the timing the oil bank formation (with injection of CO₂) and mobilization (with injection of water).
Figure 3.13: Oil recovery factor for 10, 5 and 1 WAG cycles as a function of CO$_2$ injected at 53rm$^3$/day in 4:1 WAG ratio. Runs were stopped when either total CO$_2$ injection was 89% HCPV or producing water cut exceeded 95%.

Figure 3.13 shows that the timing and size of the first three water slugs are the determinants of oil recovery. The timing of water injection affects the soak time allowed for convection, dispersion and diffusion of CO$_2$ into crude but this must be balanced with gas migration and water production shown in the figures below. As the CO$_2$ slug size in each cycle increases water injection has a lesser effect on mobility control. Prolonged gas injection leads to high producing GOR and early water injection leads to early water breakthrough shown in Figure 3.14 and Figure 3.15 respectively.
Figure 3.14: Producing gas-oil ratio as a function of time for 1, 5 and 10 WAG cycles of 89% HCPV of CO$_2$ injected at 53rm$^3$/day in a 4:1 WAG ratio.
Figure 3.15: Producing water cut as a function of pore volume injected for 1, 5 and 10 WAG cycles of 89% HCPV of CO\textsubscript{2} injected at 53rm\textsuperscript{3}/day in a 4:1 WAG ratio.

**Effect of total slug size.** In runs 3, 4, 10, 7 and 9 the total CO\textsubscript{2} slug sizes injected were 179, 89, 40, 20 and 10% of the hydrocarbon pore volume (HCPV) respectively. The injection rate, 53 and 0.007 rm\textsuperscript{3}/day for simulation and experiments respectively; number of WAG cycles (10) and WAG ratio (4:1) were kept constant.

<table>
<thead>
<tr>
<th>Run No.</th>
<th>Simulation</th>
<th>Experiment</th>
<th>CO\textsubscript{2} Slug size</th>
<th>%HCPV</th>
<th>WAG cycles</th>
<th>H\textsubscript{2}O:CO\textsubscript{2} ratio</th>
<th>Oil Recovery</th>
<th>%HCPV</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>1.4 × 10\textsuperscript{4}</td>
<td>4.0 × 10\textsuperscript{3}</td>
<td>4.3</td>
<td>179</td>
<td>10</td>
<td>4:1</td>
<td>60.0</td>
<td>55.4</td>
</tr>
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<td>4</td>
<td>1.4 × 10\textsuperscript{4}</td>
<td>4.0 × 10\textsuperscript{3}</td>
<td>4.3</td>
<td>89</td>
<td>10</td>
<td>4:1</td>
<td>51.8</td>
<td>55.1</td>
</tr>
<tr>
<td>10</td>
<td>1.4 × 10\textsuperscript{4}</td>
<td>4.0 × 10\textsuperscript{3}</td>
<td>4.3</td>
<td>40</td>
<td>10</td>
<td>4:1</td>
<td>43.3</td>
<td>45.2</td>
</tr>
<tr>
<td>7</td>
<td>1.4 × 10\textsuperscript{4}</td>
<td>4.0 × 10\textsuperscript{3}</td>
<td>4.3</td>
<td>20</td>
<td>10</td>
<td>4:1</td>
<td>33.9</td>
<td>34.4</td>
</tr>
<tr>
<td>9</td>
<td>1.4 × 10\textsuperscript{4}</td>
<td>4.0 × 10\textsuperscript{3}</td>
<td>4.3</td>
<td>10</td>
<td>10</td>
<td>4:1</td>
<td>26.9</td>
<td>22.5</td>
</tr>
</tbody>
</table>

Table 3.9: Summary of impact of CO\textsubscript{2} slug size on WAG recovery.
In the experimental and simulation results, increasing slug size increased oil recovery representing greater contact with the reservoir. The efficacy of large slug sizes however is limited by gravity segregation. In the previous section we saw that oil recovery is dominated by the water portion of WAG recovery in mobilizing oil through the reservoir. As such runs with large water slugs often resulted in higher recovery and water production than comparable runs with lower injection volumes. The large slug sizes however resulted in higher GOR indicating gas override and low sweep efficiency with increasing slug size shown in Figure 3.16. The cumulative GOR of run 9 (10% HCPV) remained constant at 80 m$^3$/m$^3$ for all 10 WAG cycles with 0.35 PVI. Runs 3 and 4 (179 and 89% respectively) reached the economic limit and the run was stopped after less than 10 WAG cycles was injected.

![Figure 3.16: Cumulative gas-oil ratio of WAG injection with total CO$_2$ injection of 179, 89, 40 and 20 of HCPV injected at 53m$^3$/day in 4:1 WAG ratio over 10 WAG cycles. Runs were stopped after 10 WAG cycles or when producing water cut exceeded 95%.](image)

As in previous sections we saw larger slug sizes on a per cycle basis giving rise to earlier gas breakthrough and higher water cut. From these five runs we can conclude that the problem can be attributed to slug size more than WAG ratio.
3.4.2 Oil Recovery post WAG waterflood

In cases where the economic limit of water-oil ratio of 20 (95% water cut) was not exceeded, a post WAG waterflood (PWWF) was conducted. Table 3.10 summarizes results of the post WAG waterflood stage.

<table>
<thead>
<tr>
<th>Run No.</th>
<th>Gravity Number</th>
<th>CO₂ injected % HCPV</th>
<th>No. of WAG cycles</th>
<th>WAG Ratio</th>
<th>PWWF Oil Recovery % HCPV Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>1.4 × 10⁴</td>
<td>4.0 × 10⁵</td>
<td>4.3</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>9</td>
<td>1.4 × 10⁴</td>
<td>4.0 × 10⁵</td>
<td>4.3</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>10</td>
<td>1.4 × 10⁴</td>
<td>4.0 × 10⁵</td>
<td>4.3</td>
<td>40</td>
<td>10</td>
</tr>
<tr>
<td>11</td>
<td>1.4 × 10⁴</td>
<td>4.0 × 10⁵</td>
<td>4.3</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>12</td>
<td>1.4 × 10⁴</td>
<td>4.0 × 10⁵</td>
<td>4.3</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>13</td>
<td>2.8 × 10⁴</td>
<td>8.0 × 10⁵</td>
<td>8.5</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>14</td>
<td>2.8 × 10⁴</td>
<td>8.0 × 10⁵</td>
<td>8.5</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>15</td>
<td>2.8 × 10⁴</td>
<td>8.0 × 10⁵</td>
<td>8.5</td>
<td>20</td>
<td>10</td>
</tr>
</tbody>
</table>

Table 3.10: Summary of post-WAG waterflood oil recovery for displacement experiments and simulations.

Runs 3, 4, 5 and 6 reached the economic limit of 95% water cut during the WAG stage and so the PWWF was conducted only on the runs shown in Table 3.10. The PWWF stage is a scavenging-type flood conducted after it is no longer economically attractive to continue CO₂ injection.

Effect of WAG ratio and injection rate (gravity number). In the PWWF stage, oil recovery decreases with increasing WAG ratio at both injection rates/gravity numbers. This is opposite to the trend observed during the WAG recovery stage and this was observed in both the displacement experiments and simulations. Furthermore, as the slug size decreased in runs 10, 7 and 9, representing CO₂ slug sizes 40, 20 and 10% of HCPV respectively, the oil recovery in the PWWF increased. In terms of oil recovery the PWWF represents the sufficiency of water.
injection during WAG injection. WAG floods with a high PWWF oil recovery would have had higher oil recovery with tapered WAG injection (increasing WAG ratio during flood).

Summary. The results discussed in the sections above show that despite the differences in conditions, rock and fluid properties, there was strong agreement between the simulated and experimental results. The similarity between our simulations and the experiments were homogeneity in porosity and permeability, the scaling of length to width geometry of the sandpack to the reservoir section, ratio of gravitational to viscous forces for water and relative permeability. Our saturation profiles and recovery results show that the efficacy of WAG injection is limited by the extent of the mixing zone and the ability of viscous and capillary forces to overcome gravity segregation as the fluid penetrate the reservoir.

3.4.3 Carbon Storage during WAG

The second objective of this comparison is to determine the sensitivity of carbon storage in heavy oil WAG recovery to injection parameters. Dyer and Farouq Ali have reported the total CO₂ requirement and total CO₂ retention at the end of all stages. Using compositional reservoir simulations we are able to observe the trend of carbon storage for each recovery stage. Table 3.11 summarizes CO₂ storage with varying injection parameters for the runs described in Table 3.6; the continuous gas injection simulation, run 2, is included for reference.
<table>
<thead>
<tr>
<th>Run No.</th>
<th>CO₂ retention (% injected)</th>
<th>% of Retained CO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Mobile</td>
</tr>
<tr>
<td>2</td>
<td>34.7</td>
<td>53.2</td>
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<tr>
<td>3</td>
<td>39.3</td>
<td>26.3</td>
</tr>
<tr>
<td>4</td>
<td>43.8</td>
<td>26.4</td>
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<tr>
<td>5</td>
<td>39.6</td>
<td>24.4</td>
</tr>
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<td>6</td>
<td>18.9</td>
<td>13.9</td>
</tr>
<tr>
<td>7</td>
<td>91.0</td>
<td>20.1</td>
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<td>99.1</td>
<td>15.9</td>
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<td>10</td>
<td>65.9</td>
<td>26.0</td>
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<tr>
<td>11</td>
<td>89.8</td>
<td>9.84</td>
</tr>
<tr>
<td>12</td>
<td>85.2</td>
<td>22.4</td>
</tr>
<tr>
<td>13</td>
<td>82.4</td>
<td>16.8</td>
</tr>
<tr>
<td>14</td>
<td>88.2</td>
<td>12.5</td>
</tr>
<tr>
<td>15</td>
<td>86.0</td>
<td>25.1</td>
</tr>
</tbody>
</table>

Table 3.11: Summary of WAG carbon storage.

**Results Overview.** Continuous gas injection (run 2) resulted in the least efficient carbon retention and the highest fraction of mobile gas with at least 50% more mobile gas than any of the WAG injection processes. Many small (10) WAG slugs (run 9) was the most efficient for carbon retention. Most of the CO₂ retained in the reservoir during WAG was dissolved in oil; 23-33% was trapped at residual saturation and the remainder was mobile.

**Effect of WAG ratio and injection rate (gravity number).** The effect of the WAG ratio was investigated at two injection rates with a total CO₂ volume of 20% of the HCPV injected in each case. Runs 15, 13 and 14 were used to determine the effect of WAG ratios 2:1, 4:1 and 8:1 respectively at the lower injection rate (26.4 rm³/day) or higher dimensionless gravity number for injected gas (8 × 10⁵) and water (8.5). Runs 12, 7 and 11 were used to determine the effect of WAG ratios 2:1, 4:1 and 8:1 respectively at the higher injection rate (53 rm³/day) and lower dimensionless gravity number for injected gas (4 × 10⁵) and water (4.3).
Altering the WAG ratio resulted in opposing retention trends depending on the gravity number. At the high gravity number for water and gas injection the 4:1 ratio retained the smallest fraction and at the low gravity number the opposite occurred as shown in Table 3.12.

<table>
<thead>
<tr>
<th>Run Number</th>
<th>Gravity Number</th>
<th>WAG Ratio</th>
<th>CO₂ Retained</th>
<th>% Retained CO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>15</td>
<td>2:1</td>
<td>88.2</td>
<td>25.1</td>
</tr>
<tr>
<td></td>
<td>13</td>
<td>4:1</td>
<td>82.4</td>
<td>16.8</td>
</tr>
<tr>
<td></td>
<td>14</td>
<td>8:1</td>
<td>86.0</td>
<td>12.5</td>
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<td>12</td>
<td></td>
<td>2:1</td>
<td>85.2</td>
<td>22.4</td>
</tr>
<tr>
<td></td>
<td>7</td>
<td>4:1</td>
<td>91.0</td>
<td>20.1</td>
</tr>
<tr>
<td></td>
<td>11</td>
<td>8:1</td>
<td>89.8</td>
<td>9.8</td>
</tr>
</tbody>
</table>

Table 3.12: Retained CO₂ distribution trends with WAG ratio and gravity number of injected fluids.

As the WAG ratio increased there was greater CO₂ dissolution but less mobile CO₂ and trapped oil at both injection rates. Figure 3.17 shows the distribution of retained CO₂ as a function of WAG ratio at the low injection rate (26.4 rm³/day).

Figure 3.17: Bar chart showing the distribution of CO₂ retained in the reservoir after injection at WAG ratios 2:1, 4:1 and 8:1 at 26.4 rm³/day for immiscible displacement of a Soldado heavy oil simulation at reservoir conditions with at CO₂ injection totalling of 20% of the HCPV in each case over 10 WAG cycles.
At the higher injection rate, lower gravity number, the distribution follows the same trend shown in Figure 3.17 but there is a smaller difference in the distribution of CO$_2$ between the 2:1 and 4:1 ratio. Dissolved CO$_2$ is distributed between the aqueous and oleic phase. With increasing WAG ratio the fraction of CO$_2$ in the aqueous phase increases: 9, 12 and 15% for 2:1, 4:1 and, 8:1 WAG ratios respectively, at the high injection rate and, 10, 13 and 16% at the lower water injection rate, higher gravity number. Increasing the water injection volume (WAG ratio) reduces gas mobility by enabling CO$_2$ dissolution in injected water, dispersion and dissolution in crude oil and trapping.

A comparison of Figure 3.18 and Figure 3.19 shows that at the higher injection rate, lower gravity number, there is a wider distribution of gas in the middle layers of the reservoir, between 1170m and 1150m subsurface, indicating a dampening of buoyancy forces. These gas saturation profiles show the gas override typical of WAG injection with high gas gravity to water gravity number ratios. The wider distribution of gas leads to greater retention, dissolution and trapping.

Figure 3.18: Gas saturation profile between the injector (left) and producer(right) after 10 WAG cycles were injected at 53 m$^3$/day with total CO$_2$ volume of 20% of the HCPV injected in a 4:1 WAG ratio.
Effect of number of WAG cycles. The effect of the number of WAG cycles was investigated by comparing runs 4, 5 and 6 in which 10, 5 and 1 WAG cycle was injected at 53 $\text{rm}^3$/day. In each case the total carbon dioxide slug size, 89% of the HCPV, was injected over the stipulated number of cycles. The fraction of retained CO$_2$ increased with the number of WAG cycles. For 1, 5 and 10 WAG cycles the fraction retained was 18.9, 39.6 and, 43.8% of the total CO$_2$ injected respectively (Table 3.11). Figure 3.20 summarizes the distribution of retained CO$_2$. The fraction of mobile and trapped CO$_2$ increased with the number of WAG cycles while the dissolved fraction decreased.

The distribution of retained CO$_2$ with WAG cycles also reflect the progression of CO$_2$ distribution within a WAG flood (Figure 3.20). Early in the flood dissolution dominates as CO$_2$ comes into contact with fresh oil, residual trapping occurs to a lesser extent and a small fraction of CO$_2$ remains mobile. As the flood progresses, the fraction of mobile and trapped CO$_2$ increases gradually and levels off. In each cycle CO$_2$ injection increases the fraction in the
mobile phase but this is dispersed and dissolved in oil and water and, trapped with water injection.

Figure 3.20: Bar chart showing the distribution of CO$_2$ retained in the reservoir after injection over 1, 5 and 10 WAG cycles at 53 rm$^3$/day for immiscible displacement of a Soldado heavy oil simulation at reservoir conditions with at CO$_2$ injection totalling of 89% of the HCPV in each case in a 4:1 WAG ratio.
Effect of total slug size. The effect of the injected CO$_2$ slug size was investigated by comparing runs 3, 4, 10, 7 and 9. Each slug of 17.9, 8.9, 4.0, 2.0 and 1.0 % of the HCPV respectively, was injected at 53 m$^3$/day for 10 cycles or until the water cut exceeded 95%. In each case a 4:1 WAG ratio was used. The fraction of retained CO$_2$ increased with decreasing slug size from the largest total slug size (179% HCPV) to the smallest (10% HCPV), the fraction of CO$_2$ retained was 39.3, 43.8, 65.9, 91.9, 99.9% of the CO$_2$ injected for decreasing slug size (Table 3.11). Figure 3.22 summarizes the distribution of retained CO$_2$. 

![Figure 3.21: Distribution of CO$_2$ phases dissolved, trapped and mobile during WAG flood in run 4 (8.9% HCPV CO$_2$ per slug at 53 m$^3$/day in a 4:1 WAG ratio). Runs were stopped when producing water cut exceeded 95%.](image)
Figure 3.22: Bar chart showing the distribution of CO$_2$ retained in the reservoir after injection CO$_2$ slug sizes totalling 10, 20, 40, 89 and 179 % of HCPV over 10 WAG cycles at 53 rm$^3$/day in a 4:1 WAG ratio for immiscible displacement of a Soldado heavy oil simulation at reservoir conditions.

There is a general increase in the fraction of mobile CO$_2$ up to slug size 40% HCPV. Figure 3.16 shows the increasing producing GOR with slug size which is reflected in the increasing mobile fraction. As gas flow paths are established between the injector and the producer via the upper layers of the reservoir there is a constant flow of CO$_2$ through the reservoir which allows for little additional trapping, dissolution or retention. For slug sizes greater than 40% HCPV there is not much difference in the fraction of CO$_2$ trapped with increasing slug size as this flow path is established. The smallest total slug size (10% HCPV) represents a short flood life with only 0.35 pore volumes have been injected and a flow path between the injector and producer is not established; whereas the largest total slug size (179% HCPV) represents a much longer flood where 2.5 pore volumes have been injected and gas override in the established flow paths is manifested.
3.4.4 CO₂ Distribution after post-WAG waterflood

A post WAG waterflood was conducted on runs which had a WOR of less than 95% after the stipulated WAG injection parameters. These were runs 7, 9, 10, 11, 12, 13, 14 and 15. Table 3.13 summarizes the distribution of retained CO₂ after the PWWF.

<table>
<thead>
<tr>
<th>Run Number</th>
<th>% CO₂ Retention</th>
<th>% Retained CO₂ after PWWF</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>WAG</td>
<td>PWWF</td>
</tr>
<tr>
<td>7</td>
<td>91.0</td>
<td>63.2</td>
</tr>
<tr>
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<tr>
<td>15</td>
<td>86.0</td>
<td>31.1</td>
</tr>
</tbody>
</table>

Table 3.13: Summary of retained CO₂ distribution for the WAG and PWWF stages.

The PWWF stage ended when the water cut reached the economic limit of 95%. During the PWWF stage, production continued, removing mostly mobile CO₂ and re-mobilizing-trapped from the system (Table 3.11). At the higher injection rates (runs 12, 7 and 7) in 2:1, 4:1 and 8:1 ratios there is a higher fraction of CO₂ retained after PWWF than the lower injection rates 15, 13 and, 14. At higher injection rates, the viscous forces allow injected CO₂ to penetrate further into the reservoir into the trailing plume area beyond the influence of water injected in the PWWF stage. Gas trapped, mobile or dissolved in these regions are not flushed out.

3.5 Discussion

We have examined the oil recovery and carbon storage of WAG and PWWF processes for two different systems: one an experimental sandpack study and one a pilot-scale simulation using properties typical of a moderately heavy oil field offshore Trinidad. There were mostly
similarities in oil recovery except where trends were not clearly increasing or decreasing with injection parameters. However, in these cases the spread in oil recovery factor was less than 5%. This agreement can be expected because we have scaled our simulations to the water injection gravity number of the laboratory displacement experiments and the water injection phase of WAG recovery dominates the recovery process; in addition we suggest that the PVT properties of the two crude oils are not that different.

The main difference between our two systems was the gas gravity number which depends on the density difference between phases and the vertical permeability. With a large density difference buoyancy forces are greater, so where viscous forces are able to counteract this effect with higher gas viscosity, injection rates and lower permeability, gas over ride is mitigated. This was the case with our simulations where the gas gravity number was lower than that used in displacement experiments by an order of magnitude. When gas over ride is mitigated there is greater penetration of gas into the reservoir (Figure 3.18 and Figure 3.19) with greater opportunity for contact with crude oil and trapping of carbon dioxide.

Increasing the number of WAG cycles and decreasing slug size also reduces gas override for a given injection rate because there is better mixing between gas and water causing greater total residual trapping of CO\(_2\). This is evident in the trend of increasing retention with decreasing slug size and increasing WAG cycles. With less mixing between gas and water there is a higher fraction and total volume of mobile gas. The trapping effect of injected water on CO\(_2\) is also evident in the large reduction in mobile gas after the PWWF stage. This is essentially the chase brine proposed by Qi et al [116] for CO\(_2\) trapping in oil fields. The chase brine front moves faster than the mobile CO\(_2\) front and this results in trapping.

WAG recovery can be successful in coupled carbon storage and oil recovery. However, the limitation of gravity segregation excludes this injection strategy as a means of significant storage. The adjustment of injection parameters in traditional WAG cannot facilitate the storage
of large volumes of CO$_2$. The results and discussions above lead to the conclusion that the efficacy of WAG injection for coupled carbon storage and CO$_2$EOR is limited by gravity segregation leading to gas override and water underride. The optimal WAG ratio, slug size and number of WAG cycles are within the limits of the performance of the waterflood and gas flood. By increasing the WAG ratio, the WAG displacement approximates a waterflood and; by increasing the slug size the WAG displacement approximates a gas flood. The optimal WAG scheme cannot simultaneously optimize carbon storage and EOR. However a particular scheme can be chosen to optimize each objective in turn.

We have also learnt that the extending the mixing zone is key to allow penetration of CO$_2$ into the reservoir allowing better oil recovery and carbon storage. We have confirmed the role of water injection in trapping CO$_2$ but recognize that it can limit CO$_2$ storage capacity and field performance. Finally we have found the bench scale experiment and field simulation to be in good agreement despite several major differences in fluid properties, temperature, pressure, porosity and permeability. In the following section we propose a gas injection strategy that uses the gravity forces on injected water and CO$_2$ to extend the mixing zone for coupled oil recovery and carbon storage.
Chapter 4

Injection design for EOR and carbon storage applied to a heavy oil field offshore Trinidad

4.1 Introduction

In this chapter we investigate enhanced recovery and carbon storage in a heavy oil reservoir using counter current injection of water and gas. This injection strategy was developed to improve gas sweep efficiency by Stone[90] and is purported to increase the mixing zone between water and gas compared to other gas injection processes if mixing occurs near the wellbore.

We have applied the water over gas injection scheme to improve oil recovery and gas trapping for a model of a heavy oil reservoir in offshore Trinidad. Water injection at the top of the reservoir prevents rapid channelling of injected gas in the upper layers of the reservoir and forces injected gas to penetrate deeper into the reservoir as it rises upwards, thus promoting gas residual and capillary trapping.
4.2 Grid and Fluid Description

Stone and Jenkins\cite{90, 147} derived equations assuming residual oil saturation to determine the distance that the water and gas flow together in a rectangular reservoir before complete segregation:

\[ L_g = \frac{Q}{k_z(\rho_w - \rho_g)gH\lambda^m_t} \]  

where \( Q \) is the total volumetric injection rate of fluids, \( k_z \) vertical permeability, \( \rho_w \) and \( \rho_g \) densities of water and gas respectively, \( H \) is thickness of the reservoir perpendicular to flow and \( \lambda^m_t \) is the total mobility in the mixed zone. Rossen and van Duijin \cite{148} refuted the theoretical justifications presented by Stone and Jenkins \cite{90, 147} based on a quasi-steady state displacement but determined that Equation 4.1 can be derived with the only assumptions reproduced below:

1. Homogenous anisotropic porous medium.
2. Reservoir is either open or cylindrical with an open outer boundary confined by no-flow barriers above and below.
3. System is in steady-state with steady state injection at volumetric rate \( Q \). Oil is at its residual saturation and is immobile.
4. Incompressible phases.
5. No mass transfer between phases.
6. No dispersive processes, including fingering, and negligible capillary-pressure gradients.
7. Newtonian mobilities in all phases.
8. Immediate attainment of local steady-state mobilities which depend only on local saturations. Gas mobility $\lambda_g$ decreases monotonically with water saturation and $\lambda_w$ is monotonically increasing with water saturation.

Our reservoir simulations have satisfied assumptions 2, 7 and 8 only. We have accounted for heterogeneity, incompressible phases, mass transfer between phases, dispersion and unsteady state injection. The initial oil saturation (80%) is much greater than residual oil saturation.

Our simulation grid represents a $89,000 \text{ m}^2$ (22-acre) spacing between injector and producer within the S-759 area of the Soldado field (Figure 2.13). Oil recovery occurs through the processes of water and immiscible gas drive. The horizontal and vertical water over gas injection schemes are shown schematically in Figure 4.1. In the vertical injection scheme the injector was completed over the entire reservoir interval; gas was injected in the lower 60m, water was injected in the upper 40m of the formation.

![Figure 4.1: Schematic of water over gas injection using a single vertical well shown in the x-z plane only (left) and a pair of horizontal wells (right) with a single vertical producer. The dimensions of the grid are the same for both horizontal and vertical injection (not drawn to scale).](image)

In our reservoir description we have randomly assigned a single porosity and single permeabilities in the i-, j- and k-direction to each cell to represent a laterally continuous unconsolidated sand. The values of these parameters are within 20% of the average properties
of porosity and permeability i-, j- and k-directions (Table 4.1) to represent heterogeneity with no spatial correlation. Al-Ghanim et al [121] used this injection strategy to optimize oil recovery using a black oil simulator and they concluded that heterogeneity and viscous forces had a greater effect on oil recovery and gas sweep than gravity segregation. Each grid block measures 10m × 5m × 2m over the entire grid (100 × 30 × 50).

<table>
<thead>
<tr>
<th>Reservoir Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference Pressure</td>
</tr>
<tr>
<td>Temperature</td>
</tr>
<tr>
<td>Average porosity</td>
</tr>
<tr>
<td>Average permeability</td>
</tr>
<tr>
<td>Average water saturation</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Properties at reservoir conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Density</td>
</tr>
<tr>
<td>Brine Density</td>
</tr>
<tr>
<td>CO₂ Density</td>
</tr>
<tr>
<td>CO₂ Compressibility factor</td>
</tr>
<tr>
<td>CO₂ Solubility in crude</td>
</tr>
<tr>
<td>CO₂ Solubility in brine</td>
</tr>
<tr>
<td>CO₂ Injection rate</td>
</tr>
<tr>
<td>CO₂ viscosity</td>
</tr>
<tr>
<td>Brine viscosity</td>
</tr>
<tr>
<td>Oil viscosity</td>
</tr>
</tbody>
</table>

Table 4.1: Parameters used in simulations.

The fluid properties were determined by the 3-parameter Peng-Robinson EOS[149] and Lohrenz Bray Clark (LBC) correlation[3][77]parameters to the viscosity, relative and total volume of PVT data for the sample. The compositional analysis and regressed equation of state (EOS) and LBC parameters of Equations 2.8 to 2.12 of the sample are shown in Table 4.2 and are explained fully in Chapter 2. These were used to estimate the phase behaviour of the crude oil and CO₂-crude solubility.
Table 4.2: Compositional description of crude oil components

<table>
<thead>
<tr>
<th>Components</th>
<th>Mole %</th>
<th>Weight %</th>
<th>M kg·mole</th>
<th>Pcr(MPa)</th>
<th>Tcr(K)</th>
<th>Ω⁰ₐ</th>
<th>Ω⁰₅</th>
<th>φ</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>0.92</td>
<td>0.23</td>
<td>44</td>
<td>7.4</td>
<td>304.7</td>
<td>0.457</td>
<td>0.078</td>
<td>0.225</td>
</tr>
<tr>
<td>CH₄</td>
<td>42.80</td>
<td>3.90</td>
<td>16</td>
<td>4.6</td>
<td>190.6</td>
<td>0.457</td>
<td>0.078</td>
<td>0.013</td>
</tr>
<tr>
<td>C₂-C₆</td>
<td>14.82</td>
<td>4.47</td>
<td>53</td>
<td>5.1</td>
<td>495.7</td>
<td>0.528</td>
<td>0.117</td>
<td>0.182</td>
</tr>
<tr>
<td>C₇⁺</td>
<td>41.46</td>
<td>91.39</td>
<td>388</td>
<td>1.5</td>
<td>1196.3</td>
<td>0.391</td>
<td>0.084</td>
<td>0.805</td>
</tr>
</tbody>
</table>

4.3 Reservoir simulation

There are several factors that can affect oil recovery and carbon storage. Based on work carried out by Dyer and Farouq Ali [140] and Sobers et al [36], we investigate the effect of three variables: injection well orientation; water injection rate and injection gas composition on CO₂ storage and oil recovery. A 2³ factorial experimental design has been used to systematically investigate the effect of each of the three aforementioned variables and combinations of these variables. Each variable was varied such that two options were considered: low and high injection rate, pure and mixed gas stream; vertical and horizontal injectors. The composition of the mixed gas by mol fraction was 0.667 and 0.333 for CO₂ and the C₂-C₆ fraction respectively. This was determined so that the minimum miscibility pressure, 23 MPa, was below the initial reservoir pressure and all injected gas will dissolve in crude oil.

For our field scale model, we kept the gas surface injection rate constant at 50 000 m³/day (1765 Mcf/day). As the gas reservoir volume changed with reservoir pressure the gas reservoir rate varied between 185 and 240 m³/day, the gas gravity number ranged between 200 and 150. For comparison the gas gravity number (N_{gv-g}), defined in Equation

\[ N_{gv-g} = \frac{(\rho_o - \rho_g)LK_{av}g}{Hu\mu_g} \]

2.21, for injection at Sleipner ranges between 20 and 200 [119].
The water gravity numbers were 3.1 to 6.3 for injection rates of 200 and 100 \( \text{m}^3/\text{day} \) respectively. The producer was constrained to an upper limit of fluid production of 400 \( \text{rm}^3/\text{day} \). In each instance we injected \( 2.2 \times 10^5 \) metric tonnes of \( \text{CO}_2 \). We have compared the recovery and storage of the simulations to traditional methods, waterflood for oil recovery only and continuous \( \text{CO}_2 \) injection for oil recovery and gas storage. The retained \( \text{CO}_2 \) is defined as the difference between injected and produced \( \text{CO}_2 \). The percentage of dissolved, mobile and trapped gas is a fraction of the retained \( \text{CO}_2 \) in the liquid, mobile gas and trapped gas phase respectively.

The producing gas-oil ratio (GOR) is the ratio of gas to the volume of oil produced at standard conditions. The water cut is the ratio of the volume of water produced to the total volume of liquid produced at standard conditions.

### 4.4 Results Overview

Eight simulations were conducted to investigate the impact of three injection design elements: water injection rate, injection gas composition and, injector well orientation using water over gas injection. Two injection design factors, water injection rate and injection gas composition, affected the total pore volume of fluids injected into the reservoir; therefore to normalize results we have evaluated oil recovery, storage and performance by the mass of \( \text{CO}_2 \) injected. Table 4.3 summarizes these results after \( 5 \times 10^6 \) kg-moles (\( 2.2 \times 10^5 \) metric tonnes) of \( \text{CO}_2 \) were injected. We have used a continuous gas flood (run 1) and a waterflood up to 95% water cut (run 2) to compare the reservoir performance to pure water or gas injection.

The results shown in Table 4.3 are the results of compositional simulation using a PVT-matched fluid description and simulation parameters which were discussed in Chapter 2 which captured the trend of oil recovery observed in scaled displacement experiments carried out by Dyer and Farouq Ali[140].
Table 4.3 : Summary of results.

Water over gas injection design is intended to mitigate water under-ride, gas over-ride and improve gas sweep efficiency. With the exception of the low gravity number (high water injection rate) vertical injection scheme (runs 3 and 6), water cut was modest – less than 50%, with recovery greater than the estimated recovery factor for the S-759 area under either the water flood (run 2) or continuous gas injection simulations (run 1). Although the vertical injection scheme was not as severely affected as the water flood case by water under-ride, the GOR in these cases were among the highest. All of the water injection designs were also successful in recovering more oil and trapping more CO₂ as a residual phase compared to the continuous gas injection base case. Continuous gas injection successfully retained 94% of the CO₂ at the limit but it had the highest proportion (34%) of the retained mobile gas in the upper layers of the reservoir.

There is neither experimental data nor compositional reservoir simulations of water over gas injection in a heavy oil reservoir available in the literature. However, the results presented here represent a comparison of injection parameters, injection rate, injection gas composition and injector orientation, where the same reservoir simulation parameters: two-phase and three-
phase relative permeability; relative permeability hysteresis; trapping coefficient and; fluid description have been used to match the oil recovery trends in CO$_2$ and water displacement experiments carried out by Dyer and Farouq Ali [140]. The fluid description has been validated by matching with PVT data- the RMS of actual and predicted data was 0.035 for viscosity, total and relative oil volume data. These results represent a quantitative comparison of the oil recovery and carbon storage of water over gas injection when the water injection rate, gas composition and injector well orientation is varied. We first review the production and storage profile of each injection design and we use this to infer a recovery and storage mechanism for water over gas injection based on the mass transfer between CO$_2$ and the aqueous and oleic phase, CO$_2$ trapping mechanisms, mobility ratio and balance of viscous and gravity forces of injected fluids discussed in Chapter 2.

We have investigated the impact of two water injection rates on oil recovery and carbon storage. Based on the limitations of fracture pressure and operational range of water gravity number and scoping studies, the two injection rates (below and above the water gravity number of 5) explore the operational range of water injection in our reservoir. We expect significant differences in oil recovery and carbon storage as a result of water injection rate to captured with these two rates given the narrow range of water gravity number and injection rates shown in Figure 2.8. The results in Tables 4.5 to 4.7 in Section 4.7 and 4.8 highlight the impact of each injection parameter on carbon storage and oil recovery and underscore the mechanism proposed. Finally, the proposed mechanism for oil recovery and carbon storage in water over gas injection is illustrated in the context of the final gas saturation distribution in Section 4.9.

4.5 Production and Storage Profiles

The discussion and figures below detail the carbon storage, oil recovery and performance (producing gas oil ratio and water cut) of each run. At this stage we focus mainly on the trends
and mainly qualitative comparisons between runs with respect to the displacement mechanism. In the section 4.6, a more quantitative discussion is undertaken.

**Run 1-** We have included this simulation run with continuous gas injection for comparison to the water over gas injection schemes and to isolate the effects of gas injection and water injection. As expected there is a low but relatively steady water cut (Figure 4.2).

![Graph of oil recovery factor, water cut, and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 1- continuous gas injection at 50,000 sm³/day (gas gravity 150-200) along the entire length of a vertical well. The vertical line shows the cut-off point of 5.0 x 10⁶ kg-mole CO₂.](image)

Figure 4.2: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 1- continuous gas injection at 50,000 sm³/day (gas gravity 150-200) along the entire length of a vertical well. The vertical line shows the cut-off point of 5.0 x 10⁶ kg-mole CO₂.

Figure 4.3 shows rapid trapping of CO₂ that remains relatively constant through the flood. With production, the dissolved fraction steadily declined as the fraction of mobile CO₂ increased. At the cut off, and for much of the CO₂ flood, there is an almost even distribution of CO₂. With only CO₂ injection, gas override becomes increasingly dominant as the flow path between the injector and producer is established and the solubility of CO₂ in surrounding crude approaches its limit for the given conditions of temperature and pressure.
Figure 4.3: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 1 at 50,000 sm$^3$/day (gas gravity 150-200). Continuous CO$_2$ injection along the entire length of a vertical well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.4 shows the production profile and producing GOR of continuous gas injection. The noisy response in GOR can be attributed in part to the proximity of the bubble point pressure (23 MPa) to the bottom-hole pressure at the producer and CO$_2$ coming out of solution as pressure declines from reservoir pressure to the producing pressure. Another reason for variation in producing GOR is the effect of numerical dispersion on estimates of GOR. The scatter in data is due to truncation errors for Newton iterations used for simulation to determine pressure and fluid saturation with time. Nevertheless the baseline indicates a gradual increase in GOR with time.

At the cut-off point shown the majority of injected gas is being produced (oil production rate~100 m$^3$/day and GOR ~300-400). This supports the conclusion of flow paths being
established between the injector and producer. Oil production rates are driven by pressure support of the injected gas.

![Gas Oil Ratio vs Oil Production Rate](image)

**Figure 4.4:** Producing gas-oil ratio and oil production profile for Run 1 at 50,000 sm³/day (gas gravity 150-200). Continuous gas injection along the entire length of a vertical well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO₂.

**Run 2** - This water flood simulation was included to provide a base case comparison to the water over gas injection scheme, the performance is shown in Figure 4.5 and Figure 4.6. As is typical of waterflooding in heavy oil fields, water breakthrough occurs early in the flood and the oil production rate declines rapidly thereafter. The cut-off in this instance coincided with the end of the flood at 95% watercut. On a PVI basis this flood performed worse than continuous gas injection shown in Figure 4.2.
Figure 4.5: Profile of recovery factor and water cut as a function of pore volume of fluid injected for Run 2-waterflood with water injection at 200m³/day (gravity number 3.1) along the entire length of a vertical well.

Figure 4.6: Producing gas-oil ratio and oil production profile for Run 2-waterflood with water injection at 200m³/day (gravity number 3.1) along the entire length of a vertical well.
Run3-This simulation represents high rate (200 m³/day) water injection and low gravity number (3.1) of the vertical water over gas injection scheme using pure CO₂. The gas gravity number ranges between 200 and 150. The water cut and producing GOR is lower than the waterflood and continuous gas injection schemes respectively. Figure 4.7 shows the water cut initially increasing as in the waterflooding case (Figure 4.5) but then decreases sharply at 0.05 PVI. Figure 4.8 shows that at this stage, the oil production rate has not increased significantly but about 50% of injected CO₂ is dissolved in oil. Simultaneously only 10% of injected CO₂ is in the mobile phase but in Figure 4.9 we see the producing GOR has not increased. After gas breakthrough at 0.1 PVI, the oil production rate declines steadily.

When CO₂ is first injected it quickly dissolves in undersaturated crude oil and connate water, but mainly oil. While this is occurring injected water flows through the reservoir relatively unhindered by gas injection as in the case of the water flood. However as oil near the wellbore becomes saturated with CO₂, the injected gas migrates longer distance, in the mobile phase, in the reservoir before being dissolved in oil as a flow path between the injector and the producer is established. During this time water percolating downwards contacts gas migrating upwards and results in gas trapping and dispersion. The mixing of gas and water retards the downward percolation of water resulting in a drop in the producing water cut. At the same time, the crude oil with dissolved CO₂ flows toward the producer with a lower viscosity, lower density and slightly larger volume because of the swelling effect.

Under gravity segregation, mobile gas, injected water, CO₂-saturated crude and undersaturated crude separate according to relative densities as they are displaced through the reservoir. The result is displacement of crude oil above, within and below the mixing zone due to mobile CO₂, a mixture of low viscosity mobile crude, water and CO₂ water displacement respectively. This stage of displacement results in a levelling off of oil production rate similar to piston like displacement. Eventually with complete gravity segregation the mixed zone collapses. Ensuing
gas override and water underride results in increasing producing GOR and water cut respectively along with the production of low viscosity crude.

Effectively the water over gas injection scheme retards gas breakthrough and water production. As the flood progresses there is a slow but steady decline in the fraction of mobile gas and a corresponding increase in the fraction of dissolved CO$_2$ in mainly oil. Whereas the mobile fraction increases with continuous CO$_2$ injection, here we see the opposite with the vertical water over gas injection scheme.

Figure 4.7: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 3- vertical water over gas injection scheme using pure CO$_2$. Water is injected at 200m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 
Figure 4.8: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 3-vertical water over gas injection scheme using pure CO$_2$. Water is injected at 200m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of 5.0 x 10$^6$ kg-mole CO$_2$.

Figure 4.9: Producing gas-oil ratio and oil production profile for Run 3-vertical water over gas injection scheme using pure CO$_2$. Water is injected at 200m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of 5.0 x 10$^6$ kg-mole CO$_2$. 
Run 4 - This simulation represents high rate water (200m³/day) injection and low gravity number (3.1) of the horizontal water over gas injection scheme using pure CO₂. The production trends shown in the figure below are similar to those discussed for run 3. Figure 4.10 shows the decline of the rate of increasing water cut at 0.7 PVI, compared to the vertical injection scheme in Figure 4.7, the water cut is retarded later in the flood. After injection of 0.35PVI the storage rate is relatively constant as shown by the straight line relationship in Figure 4.10. There is a steady increase in oil recovery and carbon storage after the cut-off point. The delayed increase in GOR shows that gas override is not as pronounced as in the vertical injection scheme and the flow of CO₂ between the injection and producer is not as quickly established. The wider distribution of injected fluids, compared to the vertical injection scheme, can account for greater reservoir contact and contact between injected fluids resulting in a large mixing zone. There is a sharp decline in oil production as seen with the conventional waterflood, but this levels off to near constant oil production rates between 0.12 PVI and 0.25 PVI. Also the average GOR is lower than the vertical injection scheme and continuous gas injection.
Figure 4.10: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 4-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 200 m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Despite this being an immiscible gas flood with reservoir pressure below the MMP, the fraction of mobile CO$_2$ in the reservoir is less than 5% for most of the flood. Figure 4.11 shows the distribution of CO$_2$ in the reservoir. We see here as in previous cases that CO$_2$ trapping occurs very quickly and remains relatively constant throughout the flood. However, as the flood progresses, mobile CO$_2$ becomes dissolved in oil and the fraction of mobile CO$_2$ rapidly decreases with the first 0.1 PVI and then levels off to about 3% as the flood progresses. The first 0.1 PVI corresponds to the dissolution of the CO$_2$ with undersaturated crude near the wellbore and within the reservoir. Subsequent CO$_2$ injection represents dissolution along the edges of the CO$_2$ plume which we will discuss more fully later. After the first decline in oil production, Figure 4.12 shows relatively steady oil production from 0.13 PVI to 0.33 PVI, which is symptomatic of piston-like displacement.
Figure 4.11: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 4-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 200m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 

![Graph showing the distribution of CO$_2$ phases as a function of PVI](image-url)
Figure 4.12: Producing gas-oil ratio and oil production profile for Run 4-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 200m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

**Run 5** - This simulation represents high rate water (200m$^3$/day) injection and low gravity number (3.1) of the horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. As in previous runs the increase in water cut is reduced at about 0.05 PV. However, in this instance the decline represents a 50% decrease in water cut (Figure 4.13). The downward percolation of injected water is hindered by the upward migration of low viscosity crude which has a lower density than water and CO$_2$-undersaturated crude. When this oil bank arrives at the producer there is an increase in oil production coinciding with an increase in GOR ratio which represents CO$_2$ coming out of solution at surface conditions. The mixed zone in this case consists of water and CO$_2$-crude oil mixture.
Figure 4.13: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 5-horizontal water over gas injection scheme using a 2:1 mixture of CO₂ and the C₂-C₆ fraction. Water is injected at 200 m³/day (gravity number 3.1) from the top lateral and gas is injected at 50,000 m³/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of 5.0 x 10⁶ kg-mole CO₂.

Figure 4.14 shows the distribution of CO₂ in the gaseous (trapped and mobile) and liquid phases (dissolved) for the duration of miscible gas injection. Towards the end of the flood the reservoir pressure declines below the minimum miscibility pressure of 23 MPa shown in Figure 4.15. This results in CO₂ evolving from the crude oil and being trapped in the reservoir. A very small fraction of the evolved CO₂ is mobile because of low saturations and the disconnected distribution of CO₂ in the reservoir as shown in Figure 4.16.
Figure 4.14: Distribution of CO₂ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 5- horizontal water over gas injection scheme using a 2:1 mixture of CO₂ and the C₂-C₆ fraction. Water is injected at 200m³/day (gravity number 3.1) from the top lateral and gas is injected at 50,000m³/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of 5.0 × 10⁶ kg-mole CO₂.
Figure 4.15: Average reservoir pressure as a function of pore volume of fluid injected for Run 5-
horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is
injected at 200m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000m$^3$/day (gas
gravity 150-200) in the bottom lateral in the same plane. The MMP pressure, 22 MPa, is shown in relation
to pressure decline.
Figure 4.16: CO$_2$ gas saturation distribution 80 m within the reservoir (in the y-direction) at the end of Run 5- horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The injectors are on the left hand side.

Similar to the horizontal immiscible CO$_2$ injection the oil production and GOR levels off between for a period, in this case between 0.22 and 0.42 PVI shown in Figure 4.17. The subsequent increase in producing GOR which coincided with a slight decline in oil production rate, does not coincide with loss of miscibility. The increase in GOR is represents a higher proportion of CO$_2$ in the production stream. As in previous cases this can be attributed to the arrival of the CO$_2$ 'plume' (CO$_2$– crude oil mixture) at the producer. We discuss this further when we take a closer look at CO$_2$ distribution in the reservoir.
Figure 4.17: Producing gas-oil ratio and oil production profile for Run 5-horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200m$^3$/day (gravity number 3.1) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

**Run 6** - This simulation represents high rate water (200m$^3$/day) injection and low gravity number (3.1) of the vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. The results shown below are show the effects of vertical and immiscible gas injection discussed earlier. The increasing water cut is curtailed as several banks of low viscosity crude are produced (Figure 4.18). This reduction of water cut coincides with increases in oil production. The increase in producing GOR seen in Figure 4.20, represent higher CO$_2$ production as the extent the CO$_2$ plume arrives at the producer. Unlike previous cases however, there is a noticeable decline in the rate of CO$_2$ storage as oil is produced with an increasing volume of CO$_2$. Toward the end of the flood as the pressure declines, miscibility is lost and evolved CO$_2$ is trapped within the reservoir as in run5.
Figure 4.18: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 6-vertical water over gas injection scheme using a 2:1 mixture of CO\(_2\) and the C\(_2\)-C\(_6\) fraction. Water is injected at 200 m\(^3\)/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000 m\(^3\)/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of 5.0 \(\times\) 10\(^6\) kg-mole CO\(_2\).
Figure 4.19: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 6 - vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 200m$^3$/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of 5.0 x 10$^6$ kg-mole CO$_2$. 
Figure 4.20: Producing gas-oil ratio and oil production profile for Run 6-vertical water over gas injection scheme using a 2:1 mixture of CO\textsubscript{2} and the C\textsubscript{2}-C\textsubscript{6} fraction. Water is injected at 200m\textsuperscript{3}/day (gravity number 3.1) from the top section of the well and gas is injected at 50,000m\textsuperscript{3}/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of 5.0 × 10\textsuperscript{6} kg-mole CO\textsubscript{2}.

Run 7-This simulation represents low rate (100m\textsuperscript{3}/day) water injection and high gravity number (6.3) of the vertical water over gas injection scheme using pure CO\textsubscript{2}. The water cut and producing GOR is lower than the waterflood and continuous gas injection schemes. Figure 4.21 shows the water cut initially increasing up to approximated 30%, but then levels off at about 0.24 PVI. This decline in water production with respect to water production comes shortly after a slight increase in oil production rate shown in Figure 4.23. Figure 4.22 shows that at this stage, about 45% of injected CO\textsubscript{2} is dissolved in oil, reducing the oil viscosity. The distribution trend of CO\textsubscript{2} is markedly different from the high rate (200m\textsuperscript{3}/day)/ low gravity number (3.1) injection trend in run 3 (Figure 4.11). Whereas in the high rate injection case the mobile fraction declines and the dissolved fraction increases, with low injection rate the dissolved fraction decreases and the trapped and mobile fraction increases.
The fraction of dissolved CO\textsubscript{2} is less than the higher water injection rate case because the lower injection velocity increases the ratio of gravity to viscous forces. We recall the gravity number for the low water injection rates and high water injection rate at 6.3 and 3.1 respectively. The higher gravity force of injected water allows better gas trapping. As a result lateral gas migration is hindered.

Figure 4.21: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 7-vertical water over gas injection scheme using pure CO\textsubscript{2}. Water is injected at 100 m\textsuperscript{3}/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000 m\textsuperscript{3}/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of 5.0 \times 10\textsuperscript{6} kg-mole CO\textsubscript{2}.

When the GOR increases (Figure 4.23) there is no sharp decline in the oil production rate as seen with the high injection rate. Here we see the production profile of the vertical injection scheme having greater similarity to the horizontal injection scheme than the high rate vertical injection scheme. This indicates greater contact between the injected fluids and crude oil at the lower injection rate.
Figure 4.22: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 7-vertical water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of 5.0 × 10$^6$ kg-mole CO$_2$.

Figure 4.23: Producing gas-oil ratio and oil production profile for Run 7-vertical water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of 5.0 × 10$^6$ kg-mole CO$_2$. 
As in previous cases, the water over gas injection scheme retards gas breakthrough and water production but there are no drastic changes in oil, water or gas production as seen in previous immiscible and vertical gas injection runs. Between 0.4 and 0.12 PVI the production profile is similar to piston like displacement.

**Run 8**-This simulation represents low rate water (100m$^3$/day) injection and high gravity number (6.3) of the vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. The results shown in the figures below represent the effects of vertical and immiscible gas injection discussed earlier. The increasing water cut is curtailed as shown in Figure 4.24 as several banks of low viscosity crude are produced. This reduction of water cut coincides with increases in oil production (Figure 4.26). The increase in producing GOR seen in Figure 4.26, represent higher CO$_2$ production as the extent the CO$_2$ plume arrives at the producer. There is a noticeable decline in the rate of CO$_2$ storage as oil is produced with an increasing volume of CO$_2$. Toward the end of the flood as the pressure declines, miscibility is lost and evolved CO$_2$ is trapped within the reservoir as in runs 5 and 6. However this occurs earlier than those cases because the lower volume of water injected provided less pressure support.
Figure 4.24: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 8-vertical water over gas injection scheme using a 2:1 mixture of CO₂ and the C₂-C₆ fraction. Water is injected at 100m³/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000m³/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO₂.

Figure 4.25: Distribution of CO₂ as in the gaseous (trapped and mobile) and liquid phases (dissolved) a function of pore volume of fluid injected for Run 8-vertical water over gas injection scheme using a 2:1 mixture of CO₂ and the C₂-C₆ fraction. Water is injected at 100m³/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000m³/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO₂.
Figure 4.26: Producing gas-oil ratio and oil production profile for Run 8-vertical water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100m$^3$/day (gravity number 6.3) from the top section of the well and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom 3/5 of the well. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

**Run 9**—This simulation represents low rate water (100m$^3$/day) injection and high gravity number (6.3) of the horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. As in previous runs the increase in water cut is reduced at about 0.5 PVI. The decline represents a 50% decrease in water cut. This corresponds to an increase in oil production which represents the arrival of the oil bank of reduced-viscosity crude. The increase in oil production coincides with an increase in GOR ratio which represents CO$_2$ coming out of solution at surface conditions. Unlike the CO$_2$ immiscible gas drive the volume this oil bank is slightly larger and contains a greater fraction of dissolved CO$_2$. 
Figure 4.27: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 9- horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100 m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

Figure 4.28 shows the distribution of CO$_2$ for the duration of miscible gas injection. After 0.14 PVI the reservoir pressure declines below the minimum miscibility pressure of 23 MPa. This results in CO$_2$ coming out of solution and most is trapped in the reservoir but an increasing fraction becomes mobile as the flood switches from a miscible to immiscible gas flood. As the pressure declines injected gas does not form a miscible solution with crude and previously dissolved CO$_2$ enter the trapped or free gas phase. This results in significant decline in the fraction of dissolved CO$_2$. This coincides with declining oil production and increasing GOR as expected.
Figure 4.28: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 9 — horizontal water over gas injection scheme using a 2:1 mixture of CO$_2$ and the C$_2$-C$_6$ fraction. Water is injected at 100 m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000 m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 
Figure 4.29: Producing gas-oil ratio and oil production profile for Run 9-horizontal water over gas injection scheme using a 2:1 mixture of CO₂ and the C₂-C₆ fraction. Water is injected at 100 m³/day (gravity number 6.3) from the top lateral and gas is injected at 50,000 m³/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of 5.0 × 10⁶ kg-mole CO₂.

**Run 10**—This simulation represents low rate water (100 m³/day) injection and high gravity number (6.3) of the horizontal water over gas injection scheme using pure CO₂. Here we see the characteristic reduction of water cut of water over gas injection (Figure 4.30) as in previous runs corresponding to a slight increase in oil production between 0.02 and 0.04 PVI (Figure 4.32). There is a straight line relationship between the oil recovery, carbon storage and PVI. Along with the stable water cut, steady oil production rate and gas oil ratio, it is apparent that after injecting 0.1 PVI of pure CO₂, the CO₂ has not arrived at the injector. The fluids injected are being widely distributed in the reservoir resulting in even oil displacement. This indicates high vertical and areal sweep efficiency. Within the first 0.08 PVI there is a decline in mobile CO₂ followed by a relatively constant and low fraction of mobile oil (Figure 4.31) in the reservoir as in run 7. The results for run 10 are very similar to those of run 4.
Figure 4.30: Profile of oil recovery factor, water cut and mass of carbon dioxide stored as a function of pore volume of fluid injected for Run 10-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$. 


Figure 4.31: Distribution of CO$_2$ in the gaseous (trapped and mobile) and liquid phases (dissolved) as a function of pore volume of fluid injected for Run 10-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of 5.0 $\times$ 10$^6$ kg-mole CO$_2$. 
Figure 4.32: Producing gas-oil ratio and oil production profile for Run 10-horizontal water over gas injection scheme using pure CO$_2$. Water is injected at 100m$^3$/day (gravity number 6.3) from the top lateral and gas is injected at 50,000m$^3$/day (gas gravity 150-200) in the bottom lateral in the same plane. The vertical line shows the cut-off point of $5.0 \times 10^6$ kg-mole CO$_2$.

In the following sections we shall consider quantitative comparisons of the simulation runs at the cut-off point ($5.0 \times 10^6$ kg-mole CO$_2$ injected) with respect to injection parameters.

### 4.6 Water injection rate

Four pairs of simulation runs were used to determine the impact of the water injection rate on oil recovery and carbon storage. These were runs 3 and 7 (immiscible gas, vertical injector); runs 4 and 10 (immiscible gas, horizontal injectors); runs 5 and 9 (miscible gas, horizontal injectors) and; runs 6 and 8 (miscible gas, vertical injectors). Table 4.4 summarizes the impact of the higher water injection rate on oil recovery, carbon storage and water cut.
### Table 4.4: Impact of increased water injection rate on performance.

<table>
<thead>
<tr>
<th>Comparative Runs</th>
<th>Injector Type</th>
<th>Injection Gas Type</th>
<th>Difference in Recovery Factor</th>
<th>% Incremental carbon storage</th>
<th>% Incremental producing GOR</th>
<th>% Water cut increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 7</td>
<td>Vertical</td>
<td>Immiscible</td>
<td>0.00</td>
<td>-10</td>
<td>-20</td>
<td>29</td>
</tr>
<tr>
<td>4 10</td>
<td>Horizontal</td>
<td>Immiscible</td>
<td>0.02</td>
<td>0</td>
<td>0</td>
<td>11</td>
</tr>
<tr>
<td>5 9</td>
<td>Horizontal</td>
<td>Miscible</td>
<td>-0.03</td>
<td>-9</td>
<td>-24</td>
<td>23</td>
</tr>
<tr>
<td>6 8</td>
<td>Vertical</td>
<td>Miscible</td>
<td>0.03</td>
<td>-15</td>
<td>-18</td>
<td>19</td>
</tr>
</tbody>
</table>

**Oil Recovery.** In the vertical immiscible gas injection scheme, oil recovery was not sensitive to water injection rate. The high water injection rate (low water gravity number) resulted in higher oil production in the early stages of the flood but then declined rapidly, as shown for run 3 in Figure 4.33. In the horizontal immiscible gas injection scheme oil recovery was slightly (2%) lower with the lower injection rate (higher gravity number). For miscible gas injection, oil recovery with low rate water injection yielded similar oil recoveries with both types of injector wells but for horizontal injection the high water rate resulted in slightly lower oil recovery. For the vertical injector, high water rate injection improved recovery. As shown in Figure 4.33, in the case of horizontal wells the high water rate recovered oil at a higher rate early in the flood, then declined, while the low water rate flood oil production rate increased later in the flood and stayed relatively high.
Figure 4.33: Production profile for simulation runs 1, 3, 5, 6, and 9 as a function of the mass of CO$_2$ injected for water injected at 200 m$^3$/day (runs 3, 5, and 6) and 100 m$^3$/day (run 9) compared to run 1 where no water was injected. The water gravity numbers are 3.1 and 6.3 respectively for both groups.

**Carbon Storage** The vertical immiscible gas injection scheme stored 10% more CO$_2$ with the lower water injection rate while the horizontal immiscible gas injection scheme there was identical carbon storage at both rates. At the lower injection water injection rate, the higher gravity to viscous forces allow for better CO$_2$ trapping. With low rate water injection (high gravity number) however there was a greater fraction of mobile gas. The horizontal injection schemes all resulted in more dissolved CO$_2$ because of the higher reservoir pressure and better distribution of injected gas.

**Performance** Higher producing GOR was observed in almost all low water rate injection schemes. However the low water injection rates mitigated water cut.
4.7 Injection gas composition

Four pairs of simulation runs were used to determine the impact of the injection gas composition on oil recovery and carbon storage. These were runs 3 and 6 (high water rate injection, vertical injector); runs 4 and 5 (high water rate injection, horizontal injectors); runs 7 and 8 (low water rate injection, vertical injector) and; runs 9 and 10 (low water rate injection, horizontal injectors). Miscible gas was used in runs 5, 6, 8 and 9.

**Oil Recovery** For a given fluid injection volume, oil recovery was higher and faster using a mixture of \( \text{CO}_2 \) and light hydrocarbons for all variations of water injection rate and well orientation. The difference in recovery was not proportional to the fraction of miscible gas injected. Miscible gas injection has the greatest impact on oil recovery for the horizontal low water rate injection scheme. Table 4.5 gives a summary of the impact of miscible gas injection.

<table>
<thead>
<tr>
<th>Comparative Runs</th>
<th>Injector Type</th>
<th>Water gravity number [dimensionless]</th>
<th>Difference in Recovery Factor</th>
<th>% Incremental carbon storage</th>
<th>% Incremental producing GOR</th>
<th>% Water cut increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 6</td>
<td>Vertical</td>
<td>3.1</td>
<td>0.07</td>
<td>-40</td>
<td>-25</td>
<td>-15</td>
</tr>
<tr>
<td>4 5</td>
<td>Horizontal</td>
<td>3.1</td>
<td>0.09</td>
<td>-32</td>
<td>246</td>
<td>0</td>
</tr>
<tr>
<td>7 8</td>
<td>Vertical</td>
<td>6.3</td>
<td>0.04</td>
<td>-36</td>
<td>-24</td>
<td>0</td>
</tr>
<tr>
<td>9 10</td>
<td>Horizontal</td>
<td>6.3</td>
<td>0.14</td>
<td>-25</td>
<td>178</td>
<td>-50</td>
</tr>
</tbody>
</table>

Table 4.5: Impact of miscible gas injection on recovery and storage.

**Carbon Storage** In all cases using pure \( \text{CO}_2 \) was better for carbon storage rather than \( \text{CO}_2 \)-lean gas mixture. In run 9, miscibility was lost when the reservoir pressure fell below the MMP. The dissolved gas came out of solution and was either trapped or mobile with a greater portion of evolved gas becoming trapped. Figure 4.31 shows the fraction mobile, trapped and dissolved gas as the average reservoir pressure declines for run 9. Despite is change in displacement
mechanism run 9 had the highest oil recovery as well as the largest change as compared to immiscible gas injection with the same well configuration and rates as run 10.

**Performance** The horizontal immiscible injection schemes yielded higher producing GOR. Miscible injection resulted in equal or lower water cut than immiscible gas injection; there is no clear trend in incremental oil recovery with injector well orientation or water injection rate.

### 4.8 Effect of Injector type

Four pairs of simulation runs were used to determine the impact of the injection well orientation on oil recovery and carbon storage. These were runs 3 and 4 (immiscible gas, high water rate injection); runs 5 and 6 (miscible gas, high water rate injection); runs 7 and 10 (immiscible gas, low water rate injection) and; runs 8 and 9 (miscible gas, low water rate injection). Runs 4, 5, 9 and 10 used horizontal injectors. Table 4.6 summarizes the impact of using horizontal injectors on oil recovery and carbon storage.

<table>
<thead>
<tr>
<th>Comparative Runs</th>
<th>Injection Gas Type</th>
<th>Water gravity number [dimensionless]</th>
<th>Difference in Recovery Factor</th>
<th>% Incremental carbon storage</th>
<th>% Incremental producing GOR</th>
<th>% Water cut increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 4</td>
<td>Immiscible</td>
<td>3.1</td>
<td>0.01</td>
<td>16</td>
<td>-87</td>
<td>-29</td>
</tr>
<tr>
<td>5 6</td>
<td>Miscible</td>
<td>3.1</td>
<td>0.03</td>
<td>31</td>
<td>-40</td>
<td>-27</td>
</tr>
<tr>
<td>7 10</td>
<td>Immiscible</td>
<td>6.3</td>
<td>-0.01</td>
<td>5</td>
<td>-84</td>
<td>-3</td>
</tr>
<tr>
<td>8 9</td>
<td>Miscible</td>
<td>6.3</td>
<td>0.09</td>
<td>22</td>
<td>-43</td>
<td>-51</td>
</tr>
</tbody>
</table>

Table 4.6: Impact of using horizontal injectors.

In three of the four scenarios horizontal wells performed better with higher oil recovery. Horizontal injectors were better than vertical injectors for CO$_2$ storage for all water injection rates and injection gas compositions. Using horizontal injectors also reduced water cut and
producing GOR. A comparison of the production profile of runs 5 and 6 in Figure 4.33 show the typical delay in the second peak in oil production using horizontal injectors.

Figure 4.34: Gas saturation distribution at end of simulation for runs 10 (horizontal low rate), 3 (vertical high rate) and 7 (vertical low rate) (clockwise from top left) showing the top location of the water injector (IW), gas injector (IG) and producer (P). All three simulations are immiscible gas injection.

4.9 Saturation Profiles

The gas saturation distribution profiles shown in Figure 4.34 give a qualitative indication of the extent of the CO₂ plume. The vertical injection scheme allows gas to migrate toward the top
layers of the reservoir rapidly. There is good vertical sweep along the edge of the reservoir but areal sweep is poor. The difference between the low rate and high rate water injection is the expanse of the CO$_2$ plume in the upper layer. High rate injection limits the expanse of the plume in the uppermost layers by forcing the main plume an extra 80m along the reservoir (relative to the x-axis). The vertical migration of the CO$_2$ plume in the horizontal injection scheme is less than the vertical injection scheme because there is greater areal sweep. At this stage low gas saturation dominates the plume. The large plume in run 7 has high gas saturation at the point of injection and at the top of the reservoir but this is smaller than the area covered by lower gas saturations. Although the horizontal injection scheme in run 10 has free gas at higher saturations, these high saturations are not near the producer or at the top of the reservoir so a high GOR is not realized.

For the miscible gas drives almost all of the CO$_2$ is dissolved in oil so it is not possible to show a gaseous CO$_2$ distribution. Figure 4.35 shows the distribution of CO$_2$ in run 6 as the molar density of the CO$_2$ per reservoir volume which is analogous to the gas plume extent for immiscible gas. The extent of the area contacted by injected CO$_2$ is smaller in the vertical direction than the comparable gas plume of the immiscible drive in run 7. However there is better areal sweep.
Figure 4.35: Distribution of CO$_2$ molar density in moles per reservoir volume for vertical miscible gas injection with high rate water injection (Run 6) showing top location of the water injector (IW), gas injector (IG) and producer (P) in 3 dimensions (top) and along the Y-Z plane at the producer (bottom).
4.10 Comparison of Injection Strategies

We have also compared the oil recovery and carbon storage of continuous gas injection, vertical WAG in a 1:1 ratio with water injected at 100m³/day and vertical water over immiscible gas injection (run 7). The table below represents performance, early in the flood life, after injecting $5.0 \times 10^6$ kg-mole of CO₂ at a surface rate of 50 000 m³/day.

<table>
<thead>
<tr>
<th>Run</th>
<th>Water gravity number [dimensionless]</th>
<th>Injector type</th>
<th>Injection Fluid ratio CO₂:H₂O</th>
<th>R.F.</th>
<th>Carbon Retention $\times 10^6$ kg-mole</th>
<th>% Mobile Phase</th>
<th>% Residual Phase</th>
<th>% Dissolved in oil and water</th>
<th>GOR</th>
<th>Water Cut</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-</td>
<td>Vertical</td>
<td>1:0</td>
<td>0.11</td>
<td>4.69</td>
<td>33</td>
<td>34</td>
<td>33</td>
<td>380</td>
<td>0.02</td>
</tr>
<tr>
<td>7</td>
<td>6.3</td>
<td>Vertical</td>
<td>3:2</td>
<td>0.17</td>
<td>4.71</td>
<td>14</td>
<td>38</td>
<td>48</td>
<td>79</td>
<td>0.37</td>
</tr>
<tr>
<td>WAG</td>
<td>6.3</td>
<td>Vertical</td>
<td>3:2</td>
<td>0.18</td>
<td>2.34</td>
<td>38</td>
<td>35</td>
<td>27</td>
<td>500</td>
<td>0.57</td>
</tr>
</tbody>
</table>

Table 4.7: Summary of performance of continuous gas injection, vertical immiscible water over gas and WAG injection after injecting $5.0 \times 10^6$ kg-mole of CO₂ at a rate of 50 000 m³/day (gas gravity 150-200). Gas is injected along the entire length of the reservoir in run 1 and WAG but only in the lower 3/5 of the reservoir for run 7.

Table 4.7 shows a comparison of CO₂ WAG, water over gas and continuous injection using a single vertical injector. It should be noted that in the case of continuous gas injection and WAG, the injector was open along the entire length of the reservoir while in WAG injection, gas was injected over a length of reservoir which was 40% shorter. Water over gas injection is clearly more efficient in CO₂ storage than WAG injection. Although there is no significant difference in oil recovery (1%) twice the carbon storage is realized.

Figure 4.36 and Figure 4.37 show the CO₂ and water saturation distribution in the reservoir in the plane of the injector for the WAG injection scheme. The CO₂ flow path between the injector and producer in Figure 4.36 are mainly along the length of the upper layers of the reservoir. In contrast, there is greater penetration of CO₂ in the middle layers of the reservoir at lower saturations using water over gas injection (Figure 4.38).
Figure 4.36: CO₂ gas saturation profile for WAG injection after injecting $5.0 \times 10^6$ kg-mole of CO₂ at a rate of 50 000 m³/day (gas gravity 150-200) and water at a rate of 100 m³/day (gravity number 6.3). This cross section is in the plane of the injector seen on the left of the grid.
Figure 4.37: Water saturation profile for WAG injection after injecting $5.0 \times 10^6$ kg-mole of CO$_2$ at a rate of 50 000 m$^3$/day (gas gravity 150-200) and water at a rate of 100 m$^3$/day (gravity number 6.3). This cross section is in the plane of the injector seen on the left of the grid.

The highest water saturation is seen along the lower layers of the reservoir in Figure 4.37 which explains the higher producing water cut in WAG injection. In the water over gas injection scheme there is no distinct water underride, high water saturation is seen in the upper left corner of Figure 4.39 and decreases moving away from the injector.

These results show the impact of water injection above gas allows greater contact of CO$_2$ with the reservoir at lower concentrations. This results in much greater storage, trapping and dissolution of CO$_2$ in crude oil. Water over gas injection significantly reduces the producing GOR and water cut compared to WAG.
Figure 4.38: CO$_2$ gas saturation profile of the vertical water over gas injection scheme after injecting $5.0 \times 10^6$ kg-mole of CO$_2$ at a rate of 50,000 m$^3$/day (gas gravity 150-200) and water at a rate of 100 m$^3$/day (gravity number 6.3). This cross section is in the plane of the injector seen on the left of the grid.
Figure 4.39: Water saturation profile of the vertical water over gas injection scheme after injecting $5.0 \times 10^6$ kg-mole of CO$_2$ at a rate of 50 000 m$^3$/day (gas gravity 150-200) and water at a rate of 100 m$^3$/day (gravity number 6.3). This cross section is in the plane of the injector seen on the left of the grid.

The upper right hand of Figure 4.38 is not contacted by injected CO$_2$ throughout the flood. The sweep efficiency of the flood can be increased by temporarily shutting off water injection while CO$_2$ injection continues, to allow recovery of oil and gas trapping in that area.

### 4.11 Sensitivity to Numerical Dispersion

From the inception of water over gas injection numerical dispersion in reservoir simulation has been identified as the main source of error. The extent of dispersion is proportional to the grid spacing used to apply the finite difference equations in approximating the convection term of the mass transfer equations. The result of this is smearing of fluid saturation profiles [90] and could over estimate the trailing area of the plume. In this section we vary the grid resolution in
the y (Δy) and z (Δz) directions to determine the extent of sensitivity and the possible impact on our results by reviewing the results of run 7 (vertical injection strategy, immiscible gas injection at 50 000 m³/day and water injection at 100 m³/day).

4.11.1 Grid Resolution

Our original grid blocks measured 10 m × 5 m × 2 m over the entire grid. The absolute permeability and porosity were randomly assigned within 20% of the average properties listed in Table 4.1. There is no correlation between permeability and porosity and no variation of facies. We have determined the sensitivity to our results by varying Δy and Δz by ± 50% of the original grid block dimensions. The total grid dimensions and Δx were kept constant. In changing the grid block dimensions the number of grid cells varied as shown in Table 4.8.

<table>
<thead>
<tr>
<th>Grid block dimensions</th>
<th>Number of Grid blocks</th>
<th>Retained CO₂ (% injected)</th>
<th>% Retained</th>
<th>Oil recovery (% OOIP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base 10m × 5m × 2m</td>
<td>150 000</td>
<td>94</td>
<td>14</td>
<td>16.5</td>
</tr>
<tr>
<td>Δy 10m × 2.5m × 2m</td>
<td>300 000</td>
<td>78</td>
<td>15</td>
<td>16.0</td>
</tr>
<tr>
<td>10m × 10m × 2m</td>
<td>75 000</td>
<td>98</td>
<td>16</td>
<td>17.0</td>
</tr>
<tr>
<td>Δz 10m × 5m × 4m</td>
<td>75 000</td>
<td>96</td>
<td>22</td>
<td>14.0</td>
</tr>
<tr>
<td>10m × 5m × 1m</td>
<td>300 000</td>
<td>84</td>
<td>15</td>
<td>19.0</td>
</tr>
</tbody>
</table>

Table 4.8: Grid block dimensions used in the sensitivity study to estimate of CO₂ retention and oil recovery after 5 × 10⁶ kg-moles (2.2 × 10⁵ metric tonnes) of CO₂ were injected using the injection parameters of Run 7-vertical injection strategy, pure CO₂ injection at 50 000 m³/day (gas gravity 150-200) and water injection at 100 m³/day (gravity number 6.3).

From Table 4.8 we can conclude that carbon retention and oil recovery are sensitive to grid refinement in the y- and z-directions. With decreasing Δy, CO₂ storage and oil recovery predictions are more conservative. Figure 4.34 gives an indication of the flow path of injected CO₂. Injected gas flows laterally (x- and y-direction) near the wellbore and as the viscous force weakens, buoyancy forces become dominate and there is upward flow. Figure 4.35 shows that migration in the y-direction also strongly influences the flow path to the producer. Near the
wellbore the viscous force, gas saturation are convection are greater than further into the reservoir. With larger grid blocks in the y-direction, the averaging of velocity, gas saturation, convection, dispersion and diffusion results in large differences of values between grid leading to truncation errors during simulation. The differences in CO$_2$ distribution with grid spacing is extent of convection and the point at which fluid flow becomes dominated by gravity forces. Fine grids show lower storage because they allow the effects of buoyancy forces to be realized early in the flood with greater override and the development of a large plume.

With increasing $\Delta z$, the CO$_2$ storage prediction is more optimistic and oil recovery is more conservative. However for the largest grid block size there is a greater fraction of mobile CO$_2$ and much less dissolved CO$_2$ compared to other runs. The higher storage represents a plume with higher gas saturation and a greater fraction mobile CO$_2$. Figure 4.40 and Figure 4.41 shows the gas saturation profile in three planes for varying $\Delta z$ and $\Delta z$. The finest grid shows greatest override in Figure 4.40 (b) and Figure 4.41(b) and the greatest lateral extent of the CO$_2$ plume in the y-direction in Figure 4.40 (c) and Figure 4.41(c).
Figure 4.40: Cross section of the reservoir in the (a) Y-Z plane 30 m from the injector in the x-direction, (b) X-Y (top layer), and (c) X-Z (parallel to the injector) planes with block sizes 10m × 5m × 1m; 10m × 5m × 2m (base case) and; 10m × 5m × 4m. The injection parameters are those of run 7 - vertical water over gas injection strategy, pure CO₂ injection at 50 000m³/day (gas gravity 150-200) and water injection at 100m³/day (gravity number 6.3) for four years (3.1 × 10⁶ kg-mole CO₂). The injector (top left) and producer (bottom right) are shown from top view in (b) and the injector is on the left of (c).
Figure 4.41: Cross section of the reservoir in the (a) Y-Z plane 30 m from the injector in the x-direction, (b) X-Y (top layer), and (c) X-Z (parallel to the injector) planes with block sizes 10 m × 2.5 m × 2 m; 10 m × 5 m × 2 m (base case) and; 10 m × 10 m × 2 m. The injection parameters are those of run 7 - vertical water over gas injection strategy, pure CO\textsubscript{2} injection at 50 000 m\textsuperscript{3}/day (gas gravity 150-200) and water injection at 100 m\textsuperscript{3}/day (gravity number 6.3) for four years (3.1 × 10\textsuperscript{6} kg-mole CO\textsubscript{2}). The injector (top left) and producer (bottom right) are shown from top view in (b) and the injector is on the left of (c).
The underestimation of the gravity override of the plume in coarse grids were also observed by Yamamoto and Doughty[150] when applied to carbon storage in saline aquifers. The variation in carbon retention is also reflected in the producing GOR shown in Figure 4.42. The scatter of data in these graphs is due to truncation errors when the set number of Newton iterations do not satisfy set tolerance of changes in grid properties. Nevertheless, the baseline of the data can be indicative of a satisfactory difference tolerance. Retention was lower in instances where CO$_2$ breakthrough occurs earlier (increase in average GOR) in the simulations shown in Figure 4.42 (c), (d) and (e). The increased retention, trapping and dissolution is a manifestation of the overestimation the trailing area of the plume[90].
Figure 4.42 Producing GOR ratio of vertical water over gas injection strategy for comparing grid resolution. CO\textsubscript{2} was injected at 50 000 m\textsuperscript{3}/day (gas gravity 150-200) and water at 100 m\textsuperscript{3}/day (gravity number 6.3).
The grid refinement study has shown oil recovery to be sensitive to $\Delta z$ grid refinement with higher recovery predicted for the finer grid. On the other hand $\text{CO}_2$ storage is most sensitive to $\Delta y$ grid refinement with lower storage for the finer grid. Generally computed $\text{CO}_2$ storage decreases with increased grid refinement while the oil recovery trend depends on the direction of grid refinement. This analysis indicates that the simulation results in this work may tend to over-estimate $\text{CO}_2$ storage because of numerical dispersive effects but that the main characteristics of the displacement (relative size and location of $\text{CO}_2$ plume, distribution of $\text{CO}_2$ phases) and the comparative performance of injection strategies have been captured.

4.12 Discussion

$\text{CO}_2$ injected into the reservoir moves toward the top of the reservoir and along the reservoir pressure gradient toward the producer. As the gas plume progresses through the reservoir, $\text{CO}_2$ may dissolve in undersaturated oil near the wellbore or farther away; remain mobile throughout or become trapped near the wellbore or farther away. Water injection rate, injection gas composition and injector well orientation affect the size and shape of the $\text{CO}_2$ plume.

Vertical injection gives rise to an extensive plume along the edge of the reservoir and in the uppermost layers. There is limited penetration into the reservoir and gas over-ride is dominant. This results in early oil production and gas trapping. However having established a flow path between the injector and producer, the effect of the low sweep efficiency is evident in the high GOR and decrease in oil production after the low viscosity oil bank arrives at the producer. Unlike the vertical injection scheme, horizontal injection produces a plume that penetrates the centre of the reservoir and delays gas over-ride. The advantage of this is low producing GOR and a greater capacity for efficient gas storage; the disadvantage is delayed oil production (Figure 4.33).
Water injection in the upper layer of the reservoir forces the migrating CO$_2$ plume further into the reservoir. This can improve areal sweep and mitigate gas over-ride; however, as expected, increasing the water injection rate increases water cut. Where there is contact between injected fluids, the downward percolation of water interrupts gas flow paths within the plume and can effectively leave gas stranded. The greater the contact between gas and water, the more likely that gas capillary trapping can occur. Horizontal injection improves water and gas contact at low gas saturation. At an increased water injection rate gravity forces are less dominant and the movement of injected water is more influenced by the horizontal pressure gradient than by the vertical gravitational forces.

Water gravity number is the ratio of gravity forces to viscous forces and is inversely proportional to injection rate. Low water injection rates (higher water gravity number) are consistently more efficient at carbon storage than high water injection rate because at lower water injection rate a larger CO$_2$ plume was allowed to form. A larger CO$_2$ plume is beneficial to gas trapping because there is greater contact with the reservoir at low gas saturation.

Immiscible gas injection produces a large plume that does not penetrate deeply into the reservoir. In addition to limited dissolution, oil bypassing and gas over-ride contribute to lower oil recovery. Gas over-ride is less pronounced with miscible gas injection (Figure 4.34 and Figure 4.35). For this reason the miscible gas floods showed lower GOR at our cut-off in vertical injection schemes (Table 4.5). However the CO$_2$ dissolved in miscible gas injection is produced with the low viscosity oil bank and so this injection scheme can be less efficient at CO$_2$ storage and it is reflected in the much higher GOR of the horizontal miscible gas injection scheme where miscible gas drive and horizontal injection both act to improve areal sweep towards the producer.

The water cut trend with respect to miscible gas injection is not immediately apparent. Vertical and high rate water injection generally increase water cut while horizontal and low rate water
injection has the opposite effect. In Table 4.5 the combination of opposite effects appears to cancel out so that there is no change in water cut. Miscible gas injection reduces the water cut by the formation of an oil bank with lower viscosity and over a larger area of the reservoir than immiscible gas injection. We are able to see this effect for vertical high water rate injection and horizontal low water rate injection where the reduction in water cut was 15 and 50% respectively.

The difference between the fraction of mobile gas in the continuous gas injection case and water over gas injection schemes cannot be attributed only to increased capillary trapping but mainly increased dissolution. Given that the average reservoir pressure for the continuous gas injection was comparable to the water over gas injection schemes, the greater fraction of dissolved CO$_2$ can only be attributed to dispersion leading to increased dissolution of CO$_2$ and undersaturated oil.

The success of water over gas injection design depends on reservoir contact. Water over gas injection is particularly successful in gas trapping and dispersion. The injection of water almost always maintained reservoir pressures to allow CO$_2$ solubility in oil. In addition to isolating gas bubbles, water injection also dispersed injected CO$_2$, allowing contact with undersaturated oil.

Our numerical dispersion study showed that carbon storage may be overestimated by up to 12% in some instances while oil recovery are reasonably well predicted within 3%.
Chapter 5

5.1 Summary of Results and Conclusions

5.1.1 Overview

In this thesis we have presented the application of the water over gas injection strategy to an oilfield offshore Trinidad for simultaneous carbon storage and oil recovery. This injection strategy was proposed by Stone and Jenkins to improve gas sweep efficiency. We demonstrated the limitations of water alternating gas injection (WAG) in coupling carbon storage and enhanced heavy oil recovery using a validated simulation model. In Chapter 3 we presented our understanding of the mechanism of carbon trapping and oil recovery with water and CO$_2$ injection. Based on this we proposed the water over gas injection strategy in Chapter 4; water is injected in the upper portion of the reservoir and gas was injected in the lower portion of the reservoir. We investigated the effect of different injection well orientation, injection gas composition and water injection rates, which can be optimized for simultaneous carbon storage and enhanced oil recovery for specific reservoir and fluid compositions.
5.1.2 Injection strategies

**WAG Injection.** We found that traditional WAG recovery can be successful in coupled carbon storage and oil recovery. However, the limitation of gravity segregation limits this injection strategy as a means for significant carbon storage. The adjustment of injection parameters alone is insufficient to facilitate the storage of large volumes of CO$_2$ because of low CO$_2$ utilisation of the process. By observing the gas and water saturation distribution, we concluded that extending the mixing zone from the injector is the crux of increasing oil recovery and carbon storage. We have confirmed the role of water injection in trapping CO$_2$ from post-water flood injection but recognize that it can limit CO$_2$ storage capacity and field performance. Finally, we have found the bench scale experiment and field simulation to be in good agreement despite differences in fluid properties.

**Water over gas injection.** We have applied the water over gas injection strategy using vertical producers with two injection configurations: single vertical injector and a pair of horizontal parallel laterals. Our results show that water over gas injection can realize oil recoveries ranging from 17 to 30% of the original oil in place. More than 50% of injected CO$_2$ remains in the reservoir, only 15% of which in the mobile phase.

Our reservoir simulations show that water over gas injection can be applied successfully to recover heavy oil and trap CO$_2$ in an unconsolidated sand. For immiscible and miscible gas injection, the process can be storage and recovery can be increased by using horizontal injection wells. Water injection over gas injection increases contact between injected CO$_2$ by dispersing the injected gas over a wider area in the reservoir, hindering gas over-ride and providing reservoir pressure support. The rate of water injection has a greater impact on gas storage than oil recovery. In combination with established industry reservoir management techniques such as pressure control and gas cycling, it is possible to have efficient oil recovery and carbon storage using water over gas injection. However, fluid and reservoir properties and the
weighting assigned to oil recovery and carbon storage with the cost of miscible gas, water and gas handling taken into account will determine the injection parameters used.

The injection of water in the upper layers almost always maintained reservoir pressures to allow CO\textsubscript{2} solubility in oil. In addition to isolating gas bubbles, water injection also dispersed injected CO\textsubscript{2}, allowing contact with undersaturated oil. Effectively water injection and be used to control the size of the CO\textsubscript{2} plume and the CO\textsubscript{2} saturation distribution. The overall effects of water over gas injection are gas trapping and improved gas sweep.

The success of water over gas injection design for coupled carbon storage and oil recovery is hinged on contact between injected fluids. We have considered the case of a unconsolidated sand with no barriers to flow such as shale beds with \(k_v/k_h < 0.1\). From our investigation we can hypothesize that the location and extent of a barrier to vertical flow, in particular, can affect the sweep efficiency of the water over gas injection scheme. For example the schematic in Figure 5.1 show horizontal shale barriers within the mixing zone which would hinder the gas migration to the upper portion of the reservoir and affect the size of the water-CO\textsubscript{2} mixing zone.

![Figure 5.1: Schematic of possible injected fluid flow paths for water over gas injection with vertical barriers to flow of varying distances from injectors (left) and varying extent across the reservoir in the direction of flow. Water flow is illustrated as blue arrows pointing downwards and CO\textsubscript{2} is illustrated as black arrows. The dashed arrow in (a) indicates a scenario where CO\textsubscript{2} does not migrate above an extensive shale barrier.](image-url)
5.2 Limitations and Future Work

In this thesis we investigated the mechanism of two injection strategies for coupled oil recovery and carbon storage. Our work was based on the PVT data of a moderately heavy oil. Our investigation with miscible gas injection may allow for the extension of our conclusions to lighter oils. However we have not conducted simulations to investigate the mechanism and phase behaviour of using crudes heavier than what we have used.

A second limitation of our work is the representation of the reservoir. Our synthetic reservoir represents a single unconsolidated sand body where there is no vertical or horizontal barriers to flow or variation of facies between the injector and the producer. Barriers to flow can mitigate CO$_2$ migration to the top of the reservoir but the effect on storage and oil recovery cannot be definitely inferred from the work presented here. Of particular interest would be barriers to flow and variation of facies within the mixing zone or near injectors. The success of water over gas injection depends on counter current contact between water and gas however if this is disrupted carbon storage, oil recovery and performance may be affected.

Another limitation of our results and conclusion is the effect of numerical dispersion in the grid-based simulations which underestimated gas override thus overestimating carbon storage. On the other hand our estimation of oil recovery may be considered slightly conservative. Using fine grid extends run-times, even for the quarter-five spot section, simulations can last over one week.

The main areas of this thesis needing further work are the absolute estimates of storage and oil recovery, the representation of the reservoir and reducing simulation run-time. Reducing the effect of numerical dispersion on the grid based simulation would not only improve prediction of the metrics considered but will also allow more complex reservoirs to be considered. A simple improvement would be to investigate where local grid refinement can be used to
improve predictions. Our simulations suggest that near the well bore and within the mixing zone are likely areas which need finer gridding. Alternatively grid refinement can be used along the flow path of the CO₂ plume. Streamline simulation is not appropriate mainly because of the cross flow of counter current fluid injection. A secondary area of improvement will be optimizing the vertical and lateral distance between horizontal injectors. We have conducted all horizontal simulations with the water and gas injector in the same plane. An offset between laterals may affect mixing of the injected fluids.
APPENDIX
An example of the input data deck for ECLIPSE simulations of water over gas injection

The example input deck shown here is for run 7. This file refers to but does not include porosity, permeability and fluid data which are not shown here. The PVT data has been presented in Chapter 2. The data shown below include relative permeability, capillary pressure, well schedule and constraints.

**Main Data File**

```plaintext
RUNSPEC

---NOSIM

METRIC

---NORSSPEC

OIL
WATER
GAS

COMPS
4 /

UDQDIMS
16 16 1* 8 /

TABDIMS
2 1 40 40 /

CO2SOL

EQLDIMS
```
1 20 /

WELLDIMS
4 100 5/

--FULLIMP

START
1 Jan 2000 /

NSTACK
200/

SATOPTS
HYSTER /

--HWELLS

UNIFOUT

DIMENS
100 30 50/

GRID  ---------------------------------------------------------------

INIT

DX
150000*10/

DY
150000*5/

DZ
150000*2 /

TOPS
3000*1135/
--BOX
-1 100 1 30 1 50/

INCLUDE
PORO_150.INC/

INCLUDE
PERM_150_1.INC/

INCLUDE
PERM_150_2.INC/

INCLUDE
PERMZ_52.INC/

EDIT

PROPS

SALINITY
0.51/

ROCK
1135 3*/

--Sw krw krow Pcow
SWOF
0.20 0.00 1.0 0.483
0.27 0.02 1* 1*
0.30 1* 0.35 0.345
0.31 0.04 1* 1*
0.34 0.05 1* 1*
0.38 0.06 1* 0.207
0.42 0.07 0.17 1*
0.46 0.08 1* 0.103
0.50 0.09 1* 1*
0.54 0.10 1* 0.069
0.58 0.12 1* 1*
0.62 0.13 1* 1*
0.65 1* 0.02 1*
0.66 0.14 1* 1*
0.69 0.15 1* 1*
0.73 0.16 0 1*
0.75 0.20 0 0 /TABLE 1

SGOF
--Sg  Krg  Krog  P cog
0   0   0.37  0
0.1 0   0.37  0.103
0.15 0   0.35  0.131
0.2 0.05 0.33  0.134
0.25 1* 0.3  0.138
0.3 1* 0.25  0.152
0.5 0.07 0.12  0.200
0.52 0.078 0.1  1*
0.57 0.11 0.07  1*
0.6 0.13 0.03  0.221
0.7 0.2  0   0.228
0.78 0.3  0   0.269
0.79 0.38 0   0.324
0.80 0.55 0   0.345 /TABLE 1

EHYSTR
0.1 4 1* /

STONE1

WAGHYSTR
2.0 0.1/
2.0 0.1/

--Water PVT functions
--Pref FVF compress. visc.

PVTW
1135 3*/

--Specify initial liquid composition

ZMFVD
1135 0.0092 0.428 0.1482 0.4146 /

--Surface densities : only the water value is used

DENSITY
1* 998.4 1* /

--***************regions section**************--

REGIONS

SATNUM
150000*1
/
IMBNUM
150000*2
/

SOLUTION =-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=-=

--Request initial state solution output

RPTSOL
PRESSURE SOIL SWAT SGAS /

SWAT
150000*0.2/

PRESSURE
150000*275.8/
SGAS
150000*0.0/

PBUB
150000*260/

XMF
150000*0.0092
150000*0.428
150000*0.1482
150000*0.4146 /

YMF
150000*0.0
150000*0.0
150000*0.0
150000*0.0 /

ZMF
150000*0.0092
150000*0.428
150000*0.1482
150000*0.4146 /

RSW
150000*0.0 /

--EQUIL
--2560 275.8 3048 0 2134 /

SUMMARY

---
--Request field GOR, water cut oil rate and total, gas rate

INCLUDE
SUML.INC/

SCHEDULE

RPTSTR
BASIC=5 FREQ=6 /

AIMCON
6* -1 /

SAVEEND

--RPTPRINT
--0 1 0 1 1 0 1 0 0 /

UDQ
DEFINE FURETD FCMIT_1-FCMPT_1 /
UNITS FURETD KG-M /

DEFINE FUTRPD FCGMI_1/FURETD /
UNITS FUTRPD PERCENT /

DEFINE FUMOBLE FCGMM_1/FURETD /
UNITS FUMOBLE PERCENT/

DEFINE FUDISS (FCWM_1+FCOM_1)/FURETD /
UNITS FUDISS PERCENT/

/
--Specify solution maps of pressure and saturations

RPTSCHED
PRESSURE SOIL SWAT SGAS /
--One stage separator conditions

SEPCOND
Sep Field 1 15.6 1.014 /
/

--Define injection and production wells
WELSPC
P FIELD 100 30 1140 OIL /
/

--2000a uses WELSEPC to associate separator with wells
WSEPCOND
P SEP /
/

COMPDAT
P 100 30 1 50 'OPEN' 1* 1 /
/

WCONPROD
P OPEN RESV 400 3* 400 1*/
/

TUNING
--1 30 0.5 0.25 5.0 0.5 0.3 1* 1E10 0.1 /
/
/
/

GECON
FIELD 2* 0.95 1* 1* All N /
/

--Define injection well

WELLSTRE
Solvent 1.0/
/
WELSPECS
IW WINJ 1 1 1140 WATER/
IG GINJ 1 1 1140 GAS /
/

COMPDAT
IW 1 1 1 19 OPEN 1 1* 0.15 /
IG 1 1 20 50 OPEN 1 1* 0.15 /
/

WCONINJE
--WELL INJ STATUS CRTL RATE RESV BHP THP
--NAME TYPE
   IG GAS OPEN RATE 50000 1* 350 1*/
   IW WATER OPEN RATE 100 1* 350 1*/
/

WINJGAS
IG Stream Solvent /
/

WELTARG
IW WRAT 100 /
IG GRAT 50000/
--P ORAT /
/

TSTEP
10*0.01 990*3/

END
An example of the input data deck for ECLIPSE simulations of WAG injection

The example input deck shown here is for WAG injection (run WAG). This file refers to but does not include porosity, permeability and fluid data which are not shown here. The PVT data has been presented in Chapter 2. The data shown below include relative permeability, capillary pressure, well schedule and constraints.

**Main Data File**

```
RUNSPEC  ==================================================================================
--NOSIM

METRIC
--NORSSPEC

OIL
WATER
GAS

COMPS
4 /

UDQDIMS
16 16 1* 8 /

TABDIMS
2 1 40 40 /

CO2SOL

EQLDIMS
1 20 /

WELLDIMS
4 100 5/
--FULLIMP

START
1 Jan 2000 /

NSTACK
200/

SATOPTS
```
HYSTER /
--HWELLS
UNIFOUT

DIMENS
100 30 50/

GRID

INIT

DX
150000*10/

DY
150000*5/

DZ
150000*2 /

TOPS
3000*1135/

--BOX
--1 100 1 30 1 50/

INCLUDE
PORO_150.INC/

INCLUDE
PERM_150_1.INC/

INCLUDE
PERM_150_2.INC/

INCLUDE
PERMZ_52.INC/

EDIT

PROPS

INCLUDE
SwellnoN2.INC/

SALINITY
0.51/

ROCK
1135 3*/

--Sw krw krow Pcow
SWOF
0.20 0.00 1.0 0.483
0.27 0.02 1* 1*
0.30 1* 0.35 0.345
0.31 0.04 1* 1*
0.34 0.05 1* 1*
0.38 0.06 1* 0.207
0.42 0.07 0.17 1*
0.46 0.08 1* 0.103
0.50 0.09 1* 1*
0.54 0.10 1* 0.069
0.58 0.12 1* 1*
0.62 0.13 1* 1*
0.65 1* 0.02 1*
0.66 0.14 1* 1*
0.69 0.15 1* 1*
0.73 0.16 0 1*
0.75 0.20 0 0 /TABLE 1

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</tr>
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</tr>
<tr>
<td>0.6</td>
<td>0.13                0.03</td>
</tr>
<tr>
<td>0.7</td>
<td>0.2                 0</td>
</tr>
<tr>
<td>0.78</td>
<td>0.3                 0</td>
</tr>
<tr>
<td>0.79</td>
<td>0.38                0</td>
</tr>
<tr>
<td>0.80</td>
<td>0.55                0</td>
</tr>
</tbody>
</table>

| EHYSTR | 0.1 4 1* / |

**STONE1**

<table>
<thead>
<tr>
<th>WAGHYSTR</th>
<th>2.0 0.1/</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.0</td>
<td>0.1/</td>
</tr>
</tbody>
</table>

---Water PVT functions
---Pref FVF compress. visc.
PVTW
1135 3*/

--Specify initial liquid composition

| ZMFVDD | 1135 0.0092 0.428 0.1482 0.4146 / |
--Surface densities: only the water value is used

DENSITY
1* 998.4 1* /

--****************regions section*************--

REGIONS

SATNUM
150000*1
/

IMBNUM
150000*2
/

SOLUTION

--Request initial state solution output

RPT SOL
PRESSURE  SOIL  SWAT  SGAS /

SWAT
150000*0.2/

PRESSURE
150000*275.8/

SGAS
150000*0.0/

PBUB
150000*260/

XMF
150000*0.0092
150000*0.428
150000*0.1482
150000*0.4146 /

YMF
150000*0.0
150000*0.0
150000*0.0
150000*0.0 /

ZMF
150000*0.0092
150000*0.428
150000*0.1482
150000*0.4146 /
RSW
150000*0.0 /

--EQUIL
--2560 275.8 3048 0 2134 /

SUMMARY
---------------------------------------------------------------

--Request field GOR, water cut oil rate and total, gas rate

INCLUDE
SUML.INC/

FURETD
FUTRPD
FUMOBLE
FUDISS
FUSTORE

FCMW
1/

SEPARATE

--RPTONLY

SCHEDULE

RPTRST
BASIC=5 FREQ=3 /

AIMCON
6* -1 /

SAVEEND

--RPTPRINT
--0 1 0 1 1 0 1 0 0 /

UDQ
DEFINE FURETD FCMIT_1-FCMPT_1 /
UNITS FURETD KG-M /

DEFINE FUTRPD FCGMI_1/FURETD /
UNITS FUTRPD PERCENT /

DEFINE FUSTORE (FURETD/FCMIT_1)*100 /
UNITS FUSTORE PERCENT /

DEFINE FUMOBLE FCGMM_1/FURETD /
UNITS FUMOBLE PERCENT/
DEFINE FUDISS (FCWM_1+FCOM_1)/FURETD /
UNITS FUDISS PERCENT/
/
--Specify solution maps of pressure and saturations

RPTSCHEd
PRESSURE SOIL SWAT SGAS /

--One stage separator conditions

SEPcond
Sep Field 1 15.6 1.014 /
/

--Define injection and production wells
WELSpECS
P FIELD 100 30 1140 OIL /
/

--2000a uses WELSEPC to associate separator with wells
WSEPcond
P SEP /
/

CPMDAT
P 100 30 1 50 'OPEN' 1* 1 /
/

WCONPROD
P OPEN RESV 400 3* 400 1*/
/

TUNING
--1 30 0.5 0.25 5.0 0.5 0.3 1* 1E10 0.1 /
/
/

GECON
FIELD 2* 0.95 1* 1* All N /
/

--Define injection well

WELLSTRE
Solvent 1.0/
/

WELSpECS
--IW WINJ 1 1 1140 WATER/
IG GINJ 1 1 1140 GAS /
/

CPMDAT
--IW 1 1 1 19 OPEN 1 1* 0.15 /
IG 1 1 1 50 OPEN 1 1* 0.15 /
/
WCONINJE
--WELL INJ STATUS CRTL RATE RESV BHP THP
--NAME TYPE
   IG GAS OPEN RATE 50000 1* 350 1*/
slightly Higher injection pressure at top of reservoir
-- IW WATER OPEN RATE 100 1* 350 1*/
/
WINJGAS
IG Stream Solvent /
/
WELTARG
--IW WRAT 100 /
IG WRAT 100/
--P ORAT /
/
WELLWAG
IG T G 50 W 70/
/
TSTEP
10*0.01 990*2.5/
END
An example of the input data deck for ECLIPSE simulations of horizontal water over gas injection

The example input deck shown here is for horizontal water over gas injection (run 9). This file refers to but does not include porosity, permeability and fluid data which are not shown here. The PVT data has been presented in Chapter 2. The data shown below include relative permeability, capillary pressure, well schedule and constraints.

Main Data File

```
RUNSPEC  ==================================================================================
        --NOSIM
METRIC
        --NORSSPEC
        OIL
        WATER
        GAS
        COMPS
        4 /
        UDQDIMS
         16 16 1* 8 /
        TABDIMS
         2 1 40 40 /
        CO2SOL
        EQLDIMS
         1 20 /
        WELLDIMS
         4 100 5 /
        --FULLIMP
        START
         1 Jan 2000 /
        NSTACK
         200/
        SATOPTS
        HYSTER /
```
HWELLS
UNIFOUT
DIMENS
100 30 50/
GRID
INIT
DX
150000*10/
DY
150000*5/
DZ
150000*2 /
TOPS
3000*1135/
--BOX
--1 100 1 30 1 50/
INCLUDE
PORO_150.INC/
INCLUDE
PERM_150_1.INC/
INCLUDE
PERM_150_2.INC/
INCLUDE
PERMZ_52.INC/

EDIT
PROPS
INCLUDE
SwellnoN2.INC/
SALINITY
0.51/
ROCK
1135 3*/
--Sw krw  krow  Pcow
SWOF
0.20 0.00 1.0 0.483
0.27 0.02 1* 1*
0.30 1* 0.35 0.345
0.31 0.04 1* 1*
0.34 0.05 1* 1*
0.38 0.06 1* 0.207
0.42 0.07 0.17 1*
0.46 0.08 1* 0.103
0.50 0.09 1* 1*
0.54 0.10 1* 0.069
0.58 0.12 1* 1*
0.62 0.13 1* 1*
0.65 1* 0.02 1*
0.66 0.14 1* 1*
0.69 0.15 1* 1*
0.73 0.16 0 1*
0.75 0.20 0 0 /TABLE 1

SGOF
--Sg Krg Krog P cog
0 0 0.37 0
0.1 0 0.37 0.103
0.15 0 0.35 0.131
0.2 0.05 0.33 0.134
0.25 1* 0.3 0.138
0.3 1* 0.25 0.152
0.5 0.07 0.12 0.200
0.52 0.078 0.1 1*
0.57 0.11 0.07 1*
0.6 0.13 0.03 0.221
0.7 0.2 0 0.228
0.78 0.3 0 0.269
0.79 0.38 0 0.324
0.80 0.55 0 0.345 /TABLE 1

EHYSTR
0.1 4 1* /

STONE1

WAGHYSTR
2.0 0.1/
2.0 0.1/

--Water PVT functions
--Pref FVF compress. visc.
PVTW
1135 3*/

--Specify initial liquid composition

ZMFVD
1135 0.0092 0.428 0.1482 0.4146 /

--Surface densities : only the water value is used

DENSITY
1* 998.4 1* /
--***************regions section*************--

REGIONS

SATNUM
150000*1
/
IMBNUM
150000*2
/

SOLUTION  ---------------------------------------------------------------------

--Request initial state solution output

RPTSOI
PRESSURE SOIL SWAT SGAS /

SWAT
150000*0.2/

PRESSURE
150000*275.8/

SGAS
150000*0.0/

PBUB
150000*260/

XMF
150000*0.0092
150000*0.428
150000*0.1482
150000*0.4146 /

YMF
150000*0.0
150000*0.0
150000*0.0
150000*0.0 /

ZMF
150000*0.0092
150000*0.428
150000*0.1482
150000*0.4146 /

RSW
150000*0.0 /


--EQUIL
--2560 275.8 3048 0 2134 /

SUMMARY

--Request field GOR, water cut oil rate and total, gas rate

INCLUDE
SUML.INC/

FURETD
FUTRPD
FUMOBLE
FUDISS

SEPARATE

--RPTONLY

SCHEDULE

RPTRST
'BASIC=5' FREQ=6 SOIL SWAT SGAS PRESSURE /

AIMCON
6* -1 /

SAVEEND

--RPTPRINT
--0 1 0 1 1 1 0 1 0 0 /

UDQ
DEFINE FURETD FCMI1_1-FCMPT_1 /
UNITS FURETD KG-M /

DEFINE FUTRPD FCMG1_1/FURETD /
UNITS FUTRPD PERCENT /

DEFINE FUMOBLE FCMGMM_1/FURETD /
UNITS FUMOBLE PERCENT /

DEFINE FUDISS (FCW1_1+FCOM_1)/FURETD /
UNITS FUDISS PERCENT /

/ --Specify solution maps of pressure and saturations

RPTSCHE
PRESSURE SOIL SWAT SGAS /

--One stage separator conditions

SEPCOND
Sep Field 1 15.6 1.014 /
--Define injection and production wells
WELSPECS
P FIELD 100 30 1140 OIL /

--2000a uses WELSEPC to associate separator with wells
WSEPCOND
P SEP /

COMPDAT
P 100 30 1 50 'OPEN' 1* 1 /

WCONPROD
P OPEN RESV 400 3* 400 1*/

TUNING
--1 30 0.5 0.25 5.0 0.5 0.3 1* 1E10 0.1 /

GECON
FIELD 2* 0.95 1* 1* All N /

--Define injection well
WELLSTRE
Solvent 0.667 0.0 0.333 /

WELSPECS
IW WINJ 1 1 1140 WATER/
IG GINJ 1 1 1140 GAS /

COMPDAT
IW 1 1 1 1 OPEN 1 1* 0.15 /
IW 1 2 1 1 OPEN 1 1* 0.15 /
IW 1 3 1 1 OPEN 1 1* 0.15 /
IW 1 4 1 1 OPEN 1 1* 0.15 /
IW 1 5 1 1 OPEN 1 1* 0.15 /
IW 1 6 1 1 OPEN 1 1* 0.15 /
IW 1 7 1 1 OPEN 1 1* 0.15 /
IW 1 8 1 1 OPEN 1 1* 0.15 /
IW 1 9 1 1 OPEN 1 1* 0.15 /
IW 1 10 1 1 OPEN 1 1* 0.15 /
IW 1 11 1 1 OPEN 1 1* 0.15 /
IW 1 12 1 1 OPEN 1 1* 0.15 /
IW 1 13 1 1 OPEN 1 1* 0.15 /
IW 1 14 1 1 OPEN 1 1* 0.15 /
IW 1 15 1 1 OPEN 1 1* 0.15 /
IW 1 16 1 1 OPEN 1 1* 0.15 /
IW 1 17 1 1 OPEN 1 1* 0.15 /
IW 1  18  1 1 OPEN 1 1* 0.15 / 
IW 1  19  1 1 OPEN 1 1* 0.15 / 
IW 1  20  1 1 OPEN 1 1* 0.15 / 
IW 1  21  1 1 OPEN 1 1* 0.15 / 
IW 1  22  1 1 OPEN 1 1* 0.15 / 
IW 1  23  1 1 OPEN 1 1* 0.15 / 
IW 1  24  1 1 OPEN 1 1* 0.15 / 
IW 1  25  1 1 OPEN 1 1* 0.15 / 
IW 1  26  1 1 OPEN 1 1* 0.15 / 
IW 1  27  1 1 OPEN 1 1* 0.15 / 
IW 1  28  1 1 OPEN 1 1* 0.15 / 
IW 1  29  1 1 OPEN 1 1* 0.15 / 
IW 1  30  1 1 OPEN 1 1* 0.15 / 

IG 1  1  50  50 OPEN 1 1* 0.15 / 
IG 1  2  50  50 OPEN 1 1* 0.15 / 
IG 1  3  50  50 OPEN 1 1* 0.15 / 
IG 1  4  50  50 OPEN 1 1* 0.15 / 
IG 1  5  50  50 OPEN 1 1* 0.15 / 
IG 1  6  50  50 OPEN 1 1* 0.15 / 
IG 1  7  50  50 OPEN 1 1* 0.15 / 
IG 1  8  50  50 OPEN 1 1* 0.15 / 
IG 1  9  50  50 OPEN 1 1* 0.15 / 
IG 1  10  50  50 OPEN 1 1* 0.15 / 
IG 1  11  50  50 OPEN 1 1* 0.15 / 
IG 1  12  50  50 OPEN 1 1* 0.15 / 
IG 1  13  50  50 OPEN 1 1* 0.15 / 
IG 1  14  50  50 OPEN 1 1* 0.15 / 
IG 1  15  50  50 OPEN 1 1* 0.15 / 
IG 1  16  50  50 OPEN 1 1* 0.15 / 
IG 1  17  50  50 OPEN 1 1* 0.15 / 
IG 1  18  50  50 OPEN 1 1* 0.15 / 
IG 1  19  50  50 OPEN 1 1* 0.15 / 
IG 1  20  50  50 OPEN 1 1* 0.15 / 
IG 1  21  50  50 OPEN 1 1* 0.15 / 
IG 1  22  50  50 OPEN 1 1* 0.15 / 
IG 1  23  50  50 OPEN 1 1* 0.15 / 
IG 1  24  50  50 OPEN 1 1* 0.15 / 
IG 1  25  50  50 OPEN 1 1* 0.15 / 
IG 1  26  50  50 OPEN 1 1* 0.15 / 
IG 1  27  50  50 OPEN 1 1* 0.15 / 
IG 1  28  50  50 OPEN 1 1* 0.15 / 
IG 1  29  50  50 OPEN 1 1* 0.15 / 
IG 1  30  50  50 OPEN 1 1* 0.15 / 

/ 

WCONINJE 
--WELL INJ STATUS CRTL RATE RESV BHP THP 
--NAME TYPE 
   IG  GAS  OPEN  RATE 50000 1* 350 1*/ 
   IW  WATER  OPEN  RATE 100 1* 350 1*/ 

/ 

WINJGAS 
IG Stream Solvent / 

/ 

WELTARG 
IW WRAT 100 /
IG GRAT 50000/
--P ORAT /
/

WELOPEN
IW OPEN/
/

TSTEP
10*0.01 990*2/

SAVE

TSTEP
200*1 500*2/

SAVE

END
Bibliography


