

IMPERIAL

Evaluation of the Impact of Polymer Thermal Degradation on Polymer flooding Performance in Giant Heterogeneous Carbonate Reservoirs

Abdulaziz Abdullah M Alsaleh

Supervisor:

Prof. Ann Muggeridge

Co-supervisor:

Prof. Martin J. Blunt

October, 2025

Department of Earth Science & Engineering

Imperial College London

Submitted in part fulfilment of the requirements for degree of Doctor of Philosophy in
Petroleum Engineering of Imperial College London and the Diploma of Imperial
College London

Declaration of Originality

I hereby declare that the content of this thesis is the result of my own independent research. Any work that is not my own has been appropriately referenced, and all sources of information and data have been duly acknowledged. This thesis has not been submitted previously for a degree or qualification at any other institution.

Copyright Statement

The copyright of this thesis rests with the author. Unless otherwise indicated, its contents are licensed under a Creative Commons Attribution-Non-Commercial 4.0 International Licence (CC BY-NC). Under this licence, you may copy and redistribute the material in any medium or format. You may also create and distribute modified versions of the work. This is on the condition that: you credit the author and do not use it, or any derivative works, for a commercial purpose. When reusing or sharing this work, ensure you make the licence terms clear to others by naming the licence and linking to the licence text. Where a work has been adapted, you should indicate that the work has been changed and describe those changes. Please seek permission from the copyright holder for uses of this work that are not included in this licence or permitted under UK Copyright Laws.

Dedications

To My

Father: Abdullah Alsaleh

Mother: Muna Alsaleh

Family & Friends

Abstract

This thesis quantifies how polymer thermal degradation and gravity jointly control polymer flooding performance in giant, high-temperature carbonate reservoirs with large injector–producer spacing. An integrated framework was developed combining Buckley–Leverett analysis extended for polymer and gravity effects, validated 1D/2D numerical models, and 3D field-representative sector simulations based on a scaled COSTA carbonate model. A staged Resolution-IV Design of Experiment isolated controlling factors, while a semi-analytical slug-sizing guide supported by statistical screening defined the most probable slug-size window in oil-wet and mixed-wet systems.

Polymer performance was governed primarily by thermal stability. ATBSA sustained viscosity and recovery at 100 °C across injector–producer spacings of 1–5 km, whereas HPAM performance declined rapidly due to degradation. Slug size was a critical parameter: validation of the semi-analytical model confirmed an optimum of approximately 0.34–0.40 PVI, with statistical analysis indicating a most-probable range of 0.31–0.43 PVI. Larger slugs produced diminishing returns once displacement efficiency approached saturation. Gravity interacted with degradation in a time-dependent manner. At early time (≤ 1 PVI), recovery was dominated by polymer stability and slug size. At later time, gravity enhanced recovery in degraded floods (HPAM and waterflooding) but had limited influence when viscosity was preserved by ATBSA due to its favourable mobility ratio.

Field-scale simulations demonstrated ATBSA performance under peripheral line-drive injection schemes typical of Middle Eastern giant carbonates with well spacings of 1–5 km. ATBSA achieved approximately 10% incremental recovery over waterflooding at 3–5 km spacing, closely matching the no-degradation benchmark, while HPAM performance deteriorated under identical conditions. Gains were

attributed primarily to early-time improvements in displacement and sweep efficiency, with gravity contributing marginally at late time.

The thesis provides practical deployment guidelines, including polymer screening by half-life versus exposure time, targeting slug sizes near 0.34 PVI, and accounting for degradation–gravity interactions in wide-spacing field applications.

Publications and Conferences

The research conducted during my Ph.D. has contributed to several academic publications, which form the basis of this thesis. Some of the chapters in this dissertation have been submitted to peer-reviewed journals, while others are prepared for submission following the completion of the thesis. Additionally, parts of this research have been presented at international conferences, showcasing the key findings to the academic and industry communities.

- Alsaleh, A.A., Muggeridge, A.H., and Blunt, M.J. 2024. **Why Gravity Improves Waterflood Recovery in Oil-Wet and Mixed-Wet Reservoirs.** *Geoenergy Science and Engineering* **243** (December): 213375. <https://doi.org/10.1016/j.geoen.2024.213375>.
- Alsaleh, A.A., Muggeridge, A.H., and Blunt, M.J. 2024. **Why Gravity Improves Waterflood Recovery in Oil-Wet and Mixed-Wet Reservoirs.** *Proceedings of InterPore, Edinburgh, Scotland, May 2023*.
- Alsaleh, A.A., Blunt, M.J. and Muggeridge, A.H. 2025. **Thermal Degradation During Polymer Flooding of Giant Oil Fields.** *Proceedings of Offshore Technology Conference, Houston, Texas, USA, May 2025*. doi: <https://doi.org/10.4043/35793-MS>

Acknowledgements

First and foremost, I would like to express my deepest gratitude to my supervisors, Professor Ann Muggeridge and Professor Martin Blunt, for their invaluable guidance, insightful feedback, and unwavering support throughout the course of my PhD journey. Their expertise and encouragement have been instrumental in shaping both the scientific direction and the quality of this work.

I am profoundly grateful to Saudi Aramco for sponsoring my doctoral studies. Special thanks go to my business line management for their vital support during the nomination process and for securing the sponsorship that made this research possible. I would also like to extend my sincere appreciation to the Career Development team at Saudi Aramco for their continuous support and encouragement throughout my PhD journey. A special word of thanks goes to Aggie Cooper, my advisor at Aramco, for her mentorship, insightful discussions, and steadfast guidance.

I wish to acknowledge the excellent support provided by Imperial College London. The facilities, resources, and administrative assistance available to me have been exceptional, allowing me to carry out my research effectively and efficiently.

My heartfelt thanks go to my family and friends for their unwavering love, patience, and encouragement. Their support has been my anchor throughout this challenging and rewarding journey.

I am also grateful to Computer Modelling Group (CMG) for providing access to their advanced simulation software, which was essential for conducting the numerical analyses presented in this thesis.

Finally, I wish to thank all the colleagues, fellow researchers, and staff who, in numerous ways, contributed to making my PhD experience enriching and memorable.

Contents

1	Introduction.....	1
1.1	Background and Overview.....	1
1.2	Motivation and Objectives	5
1.3	Thesis Outline	7
2	Literature Review.....	9
2.1	Fundamentals and Recovery Mechanism	9
2.2	Analytical Microscopic Displacement	14
2.3	Polymer Properties in Solution	18
2.3.1	Viscosity of Polymer Solutions	18
2.3.2	Factors Reducing Polymer Effectiveness	20
2.3.2.1	Polymer Degradation in Solution.....	20
2.3.2.1.1	Thermal Degradation of Polymers.....	21
2.3.2.1.2	Kinetic Modelling of Thermal Degradation	22
2.3.2.2	Other Significant Properties.....	25
2.3.2.2.1	Polymer Rheological Properties	26
2.3.2.2.2	Polymer Flow in Porous Media Physics.....	27
2.3.3	Types of Polymers Used in EOR applications.....	28
2.3.3.1	Partially Hydrolysed Polyacrylamide (HPAM)	28
2.3.3.2	Biopolymers (e.g., Xanthan Gum).....	31

2.3.3.3	Synthetic Copolymers with Functional Monomers.....	32
2.3.3.4	Acrylamide-Tertiary-Butyl Sulfonic Acid Copolymers (ATBS Copolymers).....	33
2.4	Optimization of Polymer Flooding	35
2.4.1	Slug Injection	35
2.5	Field Application Overview	36
2.6	Summary	37
3	Numerical Modelling and Validation of Polymer Flooding in 1D, 2D and a Field Case	39
3.1	Introduction	39
3.2	Numerical Modelling of Polymer Flooding.....	40
3.2.1	Polymer Flooding Including Thermal degradation	40
3.2.1.1	Polymer Transport Equation	40
3.2.1.2	Polymer Viscosity model	41
3.2.1.3	Thermal Degradation Model	42
3.2.1.4	Polymer Mixing Model	42
3.3	One Dimensional (1D) Model and Validation.....	45
3.3.1	Model Initialization.....	46
3.3.1.1	Model Size and Properties.....	46
3.3.1.2	Relative Permeability	47
3.3.1.3	Polymer Model.....	48
3.3.2	Analytical Validation of the Numerical Model.....	54
3.3.3	Grid Refinement Sensitivity.....	55
3.3.4	Displacement Improvement by Mobility	56
3.3.5	Polymer Numerical Performance	58

3.3.5.1	Polymer Performance Benchmarking (No Thermal Degradation)	58
3.3.5.2	Effect of Thermal Degradation	59
3.3.5.2.1	Quantifying Polymer Loss Due to Thermal Degradation.....	59
3.3.5.2.2	Thermal Degradation Model Validation	60
3.3.5.2.3	Impact of Thermal Degradation on Displacement and Recovery	62
3.4	Vertical Two-Dimensional (2D) Model	64
3.4.1	Vertical Grid Resolution Sensitivity	64
3.4.2	Displacement Improvement by Gravity	69
3.5	Field-Scale Heterogeneous Reservoir Model	72
3.5.1	Permeability Scaling	72
3.5.2	Sector Model.....	73
3.5.3	Model Stratigraphy	73
3.5.4	Model Porosity and Permeability Refinement and Upscaling	73
3.6	Summary	74
4	Sensitivity to Thermal Degradation using Design of Experiment (DOE)	76
4.1	Introduction.....	76
4.2	Materials and Methods.....	77
4.2.1	Two-level Fractional Factorial Design	77
4.2.2	Screening Method and Analysis	79
4.2.3	Screening Design	82
4.2.4	Key Design Parameters	82
4.2.4.1	Polymer Type.....	83
4.2.4.2	Polymer Viscosity	83

4.2.4.3	Reservoir Temperature	84
4.2.4.4	Production/Injection Rate	85
4.2.4.5	Todd and Longstaff Mixing Factor	85
4.2.4.6	Slug Size	86
4.2.4.7	Gravitational Cross Flow Factors	86
4.2.5	Screening Design Response	87
4.3	Results and Discussion	88
4.3.1	Initial Parameters Screening (1D Model)	88
4.3.1.1	Statistical Significance of Factors	88
4.3.1.2	1D DOE Main Factors and Interactions	92
4.3.1.2.1	Polymer Type	92
4.3.1.2.2	Slug Size	93
4.3.1.2.3	Mixing Factor	95
4.3.1.2.4	Polymer Type and Rate Interaction	97
4.3.1.2.5	Polymer Viscosity	99
4.3.1.2.6	Reservoir Temperature	100
4.3.2	Secondary Parameters Screening (3D Sector Model)	102
4.3.2.1	Statistical Significance of Factors (DOE) Screening Results	102
4.3.2.2	3D DOE Principal Factors and Interactions	105
4.3.2.2.1	Polymer Type	105
4.3.2.2.2	Slug Size	106
4.3.2.2.3	Stratigraphy	107
4.3.2.2.4	Vertical Anisotropy KvKH	110
4.3.2.2.5	Rate and Stratigraphy	111
4.4	Summary	112

5	Why Gravity Improves Waterflood Recovery in Oil-Wet and Mixed-Wet Reservoirs	114
5.1	Introduction.....	114
5.2	Material and Methods	116
5.2.1	Frontal Displacement Theory	116
5.2.2	Reservoir Wettability	117
5.2.3	Hydrocarbon Recovery Performance.....	118
5.2.4	Gravity Number	118
5.2.5	2D Numerical Simulation Model.....	118
5.2.6	Field-Scale Heterogeneous Reservoir Model	120
5.3	Results and Discussion	122
5.3.1	Analytical Displacement Efficiency	122
5.3.2	2D Numerical Simulation Results	123
5.3.2.1	Overall Recovery Performance.....	123
5.3.2.1.1	Heavy Oil Cases ($\mu_o = 10$ mPa. s)	123
5.3.2.1.2	Light Oil Cases ($\mu_o = 1.4$ mPa. s).....	125
5.3.2.2	Displacement and Sweep Efficiencies	125
5.3.2.2.1	Heavy Oil (Oil-Wet Case).....	126
5.3.2.2.2	Heavy oil (Water-Wet case)	128
5.3.2.2.3	Light Oil (Oil-Wet Case)	129
5.3.3	Field Scale Heterogeneous Model Numerical Simulation Results	131
5.3.3.1	Overall Recovery, Displacement and Sweep.....	131
5.3.3.1.1	Heavy Oil Case ($\mu_o = 10$ mPa. s).....	131
5.3.3.1.2	Light Oil Case ($\mu_o = 1.4$ mPa. s)	133
5.4	Summary	134

6	Thermal Degradation During Polymer Flooding of Giant Oil Fields	136
6.1	Introduction	136
6.2	Estimation of Slug Size and Polymer Selection.....	137
6.2.1	Slug Size.....	137
6.2.2	Exposure Time	142
6.2.3	Screening for Polymer Type	143
6.3	Polymer Flooding Numerical Modelling	144
6.3.1	Polymer Model Setup.....	144
6.3.2	Field-Scale Heterogeneous Reservoir Model.....	144
6.3.3	Performance Measures	146
6.4	Results and Discussion.....	146
6.4.1	Slug Size.....	146
6.4.2	Polymer Selection	148
6.4.2.1	Reservoir Temperature Sensitivity.....	148
6.4.2.2	Exposure Time and Distance Sensitivity	149
6.4.3	Performance Measures	152
6.4.3.1	Slug Size.....	152
6.4.3.2	Exposure Distance.....	152
6.4.3.3	Peripheral Flooding (3 Producers) 5 km COSTA Sector Model	154
6.5	Summary	157
7	Summary and Future Work	158
7.1	Summary	158
7.2	Limitations to be Addressed in Future Work.....	160
8	Bibliography.....	163
9	Appendix	174

A.1 Tertiary Polymer Flooding	174
A.2 Non-Isothermal Model (Low Injection Temperature)	179
A.3 Molecular Weight Validation	182
A.4 CMG STARS Data File Sample	183

List of Figures

Figure 1.1. Schematic figure depicting the improvement in areal sweep produced by polymer flooding is shown in a five-spot system by Sorbie (1991).....	2
Figure 1.2. Half-life forecasts at elevated temperature for stability estimation at 99 °C by Seright et al., (2021).	4
Figure 2.1. Illustration of how local displacement efficiency and sweep efficiency are represented at pore scale (left) and field scale (right) during polymer flooding. The upper part visualizes the spatial distribution of fluids, while the lower part schematically represents the corresponding volumes used to estimate efficiency values. Colour legends: Gray = rock, green = oil, red = displaced oil, magenta = polymer, blue = water.	11
Figure 2.2. Production profiles for polymer food and water flooding demonstrating polymer advances the oil recovery and does not adjust residual oil saturation.	13
Figure 2.3. Fractional flow curves at a) varying endpoint mobility ratios and b) varying gravity numbers (Lake, 1989).	16
Figure 2.4. Waterflooding and secondary polymer flooding fractional flow analysis.	17
Figure 2.5. HPAM polymer instability demonstration through viscosity performance under various levels of temperatures exposure (Seright et al., 2010).	23
Figure 2.6. ATBSA polymer degradation demonstration through viscosity performance under various levels of temperatures exposure (Seright et al., 2021).	24
Figure 2.7. Polymer half-life estimation by Bordeaux Rego et al.(2017) proposed equation of half-life honouring nonlinearity between viscosity and concentration in red, Choi et al. (2014) equation in blue and literature data in black representing almost no major difference between the two approaches.	25
Figure 2.8. Rheology of a shear-thinning fluid. (Firozjahi and Saghafi, 2020; Green and Willhite, 2018).....	26
Figure 2.9. Diagram showing polymer retention in porous media (Sorbie, 1991).....	27
Figure 2.10. Polymer chemical structure of polyacrylamide (PAM) and partially hydrolysed polyacrylamide (HPAM) (Sorbie, 1991).	29
Figure 2.11. Demonstration of HPAM polymer in i) expanded polymer coils in low salinity solution and ii) collapsed polymer coils in high salinity (Sorbie, 1991).....	30

Figure 2.12. Temperature effect on polymer hydrolysis from Moradi-Araghi and Doe (1987).	31
Figure 2.13. Chemical composition of Xanthan. (Sheng, 2011).	32
Figure 2.14. HPAM molecular structure versus Poly(ATBS) molecular structure. (Seright and Wang, 2023).	34
Figure 2.15. Demonstration of slug injection in a reservoir cross section (El-hoshoudy et al., 2017).	35
Figure 3.1. Representation of mixing behaviour at the trailing and leading edges of a polymer slug during polymer flooding, illustrating the impact of the mixing factor ω . (a) Complete mixing $\omega = 1$ at the trailing edge creates a dispersion zone between water and polymer, leading to stable displacement. At the leading edge $\omega = 0$, no mixing occurs, maintaining a sharp interface between polymer and oil. (b) Uniform mixing at both edges $\omega = 1$, results in unrealistic polymer front smearing due to reduced dispersion zone viscosity. (c) No mixing at both edges $\omega = 0$, leads to severe fingering of water into the polymer slug and a sharp polymer front. The ideal scenario applies complete mixing at the trailing edge and no mixing at the leading edge for physically realistic modelling.	44
Figure 3.2. Oil-wet relative permeabilities measured on a carbonate rock from the Middle East (Dakshinamurthy et al., 2014).	48
Figure 3.3. Flory Huggins third order fitting of the viscosity vs concentration experimental data from Choi's.	49
Figure 3.4. Arrhenius plots for HPAM and ATBSA from Seright's experimental data in Table 3.6.	50
Figure 3.5. Polymer flood analytical solution for the designed polymer flood. On the left is the fractional flow shock front analysis. The right side is the solution showing the positions of the shock fronts as a function of dimensionless distance.	54
Figure 3.6. Polymer flood Buckley-Leverett analytical solution compared to the numerical simulation.	54
Figure 3.7. Shock front saturation profiles over distance for multiple cell refinements in the 1D numerical simulation model.	55
Figure 3.8. Pore volume of oil produced at 1 pore volume injected for multiple grid resolutions. At the black circle of grid resolution of 225 cells no major change in the recovery performance is observed.	56
Figure 3.9. Buckley Leverett analytical solution that demonstrate the effect of using different polymer viscosity on polymer fractional flow on the left side, Shock front displacement in the middle and pore volume produced performance in the right side. The legend represents water flooding performance in blue, and different polymer viscosity represented by mobility ratio at shock front. The green line represents the performance expected for polymer viscosity of 10 mPa.s.	57
Figure 3.10. Shock front mobility ratio estimation for different polymer solution viscosities. The blue line represents the mobility ratio at the connate waterfront. The	

magenta line represents the mobility ratio at the polymer front. The circles highlight the viscosity scenarios matching the colours used in Figure 3.9	57
Figure 3.11. Saturation profiles of water flooding and polymer flooding assuming no degradation at 4 years injection and 0.14 Pore volume injected. The model used consists of 220 cells concluded from the cell refinement study work earlier.	58
Figure 3.12. Numerical recovery performance in pore volume of oil produced of ideal polymer flooding assuming no thermal degradation in green benchmarked with water flooding performance in blue. The plot highlights the expected recovery gain from polymer deployment over pore volume injected.....	59
Figure 3.13. Polymer concentration loss due to thermal degradation performance over time for HPAM and ATBSA polymers.	60
Figure 3.14. Flory Huggins third order fitting of the viscosity vs concentration extracted from Figure 3.3 and fitted more precisely to the viscosity range of interest at a maximum of 10 mPa.s.....	61
Figure 3.15. Polymer viscosity thermal degradation performance over time for HPAM and ATBSA polymers. The black line represents the viscosity thermal degradation in the numerical simulation and the circles represent the analytical degradation results.	62
Figure 3.16. Saturation profiles over distance of polymer flooding assuming no thermal degradation in green, ATBSA in magenta, HPAM in red and water flooding in at 4 years injection and 0.14 Pore volumes injected. ATBSA performance was outstanding during that period due to its high half-life of 54 years. HPAM presented much lower performance due to its high thermal instability.	63
Figure 3.17. Numerical recovery performance in pore volumes of oil produced of polymer with ideal no thermal degradation assumed in green, HPAM in red, ATBSA in magenta and water flooding in blue over 2 pore volumes period.	63
Figure 3.18. Water saturation cross section for polymer flood and water flood at water breakthrough time for multiple vertical resolutions. 160 cells demonstrated finer shock front on both floods.	65
Figure 3.19. Oil pore volume produced over pore volume injected for polymer flood with no thermal degradation in 2D for multiple vertical cell resolution. We observe higher recovery performance with higher vertical resolution.	66
Figure 3.20. Oil pore volume produced over pore volume injected for water flood in 2D for different vertical cell resolutions. We observe higher recovery performance with higher vertical resolution.....	66
Figure 3.21. percent incremental recovery gain from 1D model performance at 1 pore volume injected (PVI) for polymer flood in purple and water flood in blue. For the polymer flood minimal recovery gain was observed above 40 cells. For the water flood no recovery gain was seen beyond 20 cells.....	67
Figure 3.22. Oil pore volume produced at 1 pore volume injected over number of cells in the vertical direction for three different production/injection rates for polymer flooding with no thermal degradation scenario.....	68

- Figure 3.23.** Buckley Leverett analytical solution for horizontal and gravity stable 1D displacement. We demonstrate the effect of gravity for different production/injection rates on fractional flow of water flood and polymer flood on the top plot, Shock front displacement in the middle plot and pore volume produced performance in the bottom plot. The legend represents horizontal flow in black, gravity stable flow for multiple production/injection rates in red, blue and green. The dashed lines are for water flood and the solid lines are for polymer flood. At a lower production/injection rate where gravity segregation effect is highest, we observe highest recovery gain for both water flood and polymer flood..... 71
- Figure 3.24.** COSTA model scaling, sector extraction, refinement, and upscaling workflows. a) COSTA model original and 1st stage scaling. b) Sector model and 2nd stage scaling. c) Grid refinement for multiple permeability distribution (coarsening upward, homogeneous and fining upward). d) Vertical upscaled sector models..... 74
- Figure 4.1.** Representation of full factorial design to the left and fractional factorial design to the right. The red spheres represent the runs performance in three-dimensional space..... 78
- Figure 4.2.** Resolutions for the factorial designs that specify the number of runs linked to the number of tested factors. Reprint: State-Ease 360 software. 79
- Figure 4.3.** Half-life performance for HPAM in red and ATBSA in magenta at multiple temperatures with data exponential regression lines..... 84
- Figure 4.4.** Numerical oil pore volume produced as a function of pore volumes of polymer injected for the 1D design of experiment. The performance of 16 runs from **Table 4.6** and waterflood and polymer flood baselines. 89
- Figure 4.5.** Pareto chart for incremental gain/loss of oil pore volume produced from waterflood for the 1D screening DOE. 91
- Figure 4.6.** Half-normal plot for incremental gain/loss of oil pore volume produced from waterflood for the 1D screening DOE..... 92
- Figure 4.7.** Numerical oil pore volume produced as a function of pore volumes of polymer injected with ideal no thermal degradation assumed in green, ATBSA in magenta, HPAM in red, and water flooding in blue over 2 pore volumes period. The plot demonstrates the criticality of polymer type through the contrast in performance of ATBSA and HPAM polymer. ATBSA demonstrate exceptional stability even when there is 1.25 km between wells. 93
- Figure 4.8.** Numerical oil pore volume produced as a function of pore volumes of polymer injected with different slug sizes. No major performance improvement above the optimal analytical slug size of 0.34 PVI. 94
- Figure 4.9.** Water viscosity cross section of polymer bank at the end of polymer injection of slug size of 0.1 PVI and analytical slug size of 0.34 PVI on the left side and at the time of polymer breakthrough. The smaller slug experiences premature breakdown whereas the 0.34 PVI bank front reached the producer before the trailing water breakdown the bank validating the analytical solution. 95

Figure 4.10. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different mixing factors for ATBSA on the left and HPAM on the right. The top and middle plots are rate variant. The bottom plots are smaller slug sizes. Although mixing factor ranked significant in the DOE for ATBSA with the designed slug size of 0.34 PVI mixing factor variations produced minimal effect of recovery. 96

Figure 4.11. Numerical oil pore volume produced as a function pore volume injected for different polymer types and flow rates. The top plot demonstrates the performance of ATBSA and HPAM flowing at 1000 m³/day and the bottom plot at 300 m³/day. ATBSA demonstrated exceptional recovery performance almost matching the performance of polymer with no thermal degradation assumed at both production/injection rates. HPAM demonstrated significant deterioration in performance do to longer exposure imposed by lower production/injection rate and its low half-life. 98

Figure 4.12. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different polymer viscosities..... 99

Figure 4.13. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different reservoir temperatures. ATBSA performance was not affected by the reservoir temperature range in the DOE study 85-100°C and HPAM only showed minimal effect. At higher temperature ATBSA and HPAM showed matching poor performance in line with matching half-life expectance for both at 140°C. 101

Figure 4.14. Numerical oil pore volume produced as a function of pore volumes of polymer injected for the 3D model design of experiment. The performance of 16 runs from **Table 4.8** is shown..... 103

Figure 4.15. Pareto chart for incremental gain/loss of oil pore volume produced from waterflood for the 3D sector model..... 104

Figure 4.16. Half-normal plot for incremental gain/loss of oil pore volume produced from waterflood for the 3D sector model. 105

Figure 4.17. Numerical oil pore volume produced as a function of pore volumes of polymer injected for 3D fine sector model with coarsening upward stratigraphy, slug size of 0.40 PVI, K_{vKH} of 0.50 and rate of 3000 m³/day. The plot shows ideal no thermal degradation assumed in green, ATBSA in magenta, HPAM in red, and water flooding in blue over 2 pore volumes period. ATBSA demonstrate exceptional stability over 1.25 km distance under the influence of heterogeneity. We observe HPAM and waterflooding approaching the performance of the other cases at 2 pore volume due to good sweep efficiency and the influence of gravity. 106

Figure 4.18. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different slug sizes. No major performance improvement above the optimal analytical slug size of 0.34 PVI. Water flooding outperformed the 0.1 PVI slug size beyond 1 PVI related to better gravitational displacement of water compared to mobility displacement of polymer of smaller slugs. 107

Figure 4.19. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different geological models. The colours represent flooding with

ATBSA, HPAM and water. The dashed line represents coarsening upward and fining upward stratigraphies.	108
Figure 4.20. Cross-sections of permeability, water solution viscosity and water saturation of the 3D model at the end of ATBSA polymer injection for coarsening upward and fining upward permeability.	108
Figure 4.21. Numerical oil pore volume produced as a function of pore volume of polymer injected for different vertical anisotropy. The colours represent flooding with ATBSA, HPAM and water. The dashed line represents $KvKH = 0.50$ and $KvKH = 0.10$. Higher vertical permeability introduced incremental gain in recovery that varies with flooding type. ATBSA showed lower incremental gain in comparison to water in line with the analytical analysis of gravitational displacement in Figure 3.23	110
Figure 4.22. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different rates and stratigraphies. The colours represent flooding with ATBSA, HPAM and water. The dashed line represents rates of 3000 m ³ /day and 2000 m ³ /day.....	111
Figure 5.1. Visualization of the displacement process in a) line drive one dimensional model, b) gravity stable drive one dimensional model, c) line drive two-dimensional model that is gravity dominated.....	116
Figure 5.2. Relative permeabilities used in the study to represent a) oil-wet rock, b) mixed-wet rock and c) water-wet rock using the parameters in Table 5.1	117
Figure 5.3. The fractional flow functions for a one-dimensional line drive with no gravity (solid red line) and the one-dimensional gravity stable drive with gravity (dashed red line) for an oil-wet system. The fractional flow can be negative for the gravity stable drive when water moves upwards against gravity causing a reduction in the mobility of water and improved upward oil mobility. The shock from saturation S_{wf} and the average saturation behind the front S_{wbt} are also indicated for the two cases.	122
Figure 5.4. Saturation as a function of dimensionless velocity (fraction of the distance between wells divided by pore volumes injected) for a one-dimensional line drive in an oil wet system with no gravity (solid red line) and the one-dimensional gravity stable drive with gravity (dashed red line). There is an increase in shock front saturation for the gravity stable drive and better displacement behind the front.	122
Figure 5.5. Recovery factor as a function of pore volumes of water injected from numerical simulation (with gravity) at $KvKH = 1$ shown by the dashed lines and at $KvKH = 0$ (no gravity) with solid lines for oil-wet (red), mixed-wet (magenta) and water-wet (blue) models with an unfavourable viscosity ratio. Gravity increases recovery for the oil-wet and mixed-wet cases, whereas the water-wet case experienced a loss in recovery due to gravity.....	124
Figure 5.6. Recovery factor against PV of water injected for numerical simulation (with gravity) at $KvKH = 0.1$, shown by the dashed lines, and at $KvKH = 0$ (no gravity), with solid lines, for oil-wet (red), mixed-wet (magenta) and water-wet (blue) models with an unfavourable viscosity ratio. There is an increase in recovery due to gravity for the oil-	

wet and mixed-wet, whereas the water-wet case has a reduced recovery due to gravity. 124

Figure 5.7. Recovery factor against PV of water injected for numerical simulation (with gravity) at $KvKH = 0.1$, shown by the dashed lines, and at $KvKH = 0$ (no gravity), with solid lines, for oil-wet (red), mixed-wet (magenta) and water-wet (blue) models with an favourable viscosity ratio. There is an increase in recovery due to gravity for the oil-wet before water breakthrough, whereas the water-wet case has no recovery impact due to gravity. 125

Figure 5.8. Water saturation for the oil-wet 1D line drive with no gravity (left) and the 2D line drive with gravity (right) at three depletion stages (breakthrough, 1 PVI and 2 PVI). The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. There is a progressive improvement in displacement by gravity at each depletion stage and poor sweep efficiency prior to water breakthrough which improves at later stages. 127

Figure 5.9. Recovery, displacement and sweep efficiency for the oil-wet 1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). Gravity results in improved ultimate recovery associated from the increased displacement efficiency. $KvKH = 1$ 127

Figure 5.10. Water saturation distributions for the water-wet 1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. There is negligible improvement in displacement efficiency by gravity at each depletion stage due to the high initial displacement efficiency associated with strongly water-wet systems. 128

Figure 5.11. Recovery, displacement and sweep efficiency for the water-wet 1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). Gravity results in a reduced recovery at late times due the poor sweep efficiency and high initial displacement efficiency. 129

Figure 5.12. Water saturation distributions for the oil-wet with light oil viscosity of 1.4 mPa.s in 1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. There is high initial sweep efficiency due to favourable end-point mobility ratio with progressive improvement in displacement. 130

Figure 5.13. Recovery, displacement and sweep efficiency for the oil-wet and light oil viscosity of 1.4 mPa.s (1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). Gravity resulted in the highest improvement in recovery realized at breakthrough due to the increased displacement efficiency and high initial sweep efficiency. 130

Figure 5.14. Sweep efficiency, displacement efficiency, and recovery over PVI for a refined fine grid model (62 layers) in blue with three reservoir characteristics (fining upward-left side, homogeneous-center and coarsening upward-right side). The results

are compared with the upscaled coarse grid model (5 layers) in red for the heavy oil case.....	132
Figure 5.15. Water saturation distributions for the heavy oil coarsening upward and fining upward model at breakthrough, 1 PVI and 2 PVI. C The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. Vertical injector is completed down-dip the structure in blue (right) and the producer is completed up-dip the structure in green. There is high sweep efficiency for the coarsening upward and lower displacement efficiency.	133
Figure 5.16. Sweep efficiency, displacement efficiency, and recovery as a function of PVI for a refined fine grid model (62 layers) in blue with three reservoir characteristics (fining upward-left side, homogeneous-centre and coarsening upward-right side). The results are compared with the upscaled coarse grid model (5 layers) in red for the light oil case.	134
Figure 6.1. The relative permeabilities used for the full factorial design. Oil-wet in red and mixed-wet in magenta.	139
Figure 6.2. Polymer and water fractional flow demonstrating the cloud of shock front saturations of polymer in magenta and water in blue for a total of 44,800 cases.	140
Figure 6.3. Recovery factor at water breakthrough in blue, polymer breakthrough in magenta, at 1 PV displacement in green, and 2 PV displacement in red for a total of 44,800 cases.	140
Figure 6.4. Slug size histogram with blue bars representing the probability density value of slug size bins. The solid red line represents the normal distribution function fit. The black dashed lines represent the 25 th and 75 th percentiles. The red dashed line represents the mean and the green line represents the median.	141
Figure 6.5. Analytical estimation of polymer exposure time for a series of production/injection rates over a range of well spacing (exposure distance).	143
Figure 6.6. Modified COSTA model sectors. a) 1.25 km × 1.25 km sector with one slanted injector in blue and the horizontal producer in green. b) 1.75 km × 5 km sector with one slanted injector in blue and three consecutive horizontal producers in green.	145
Figure 6.7. Recovery performance sensitivity to polymer slug size at multiple depletion stages. The black dashed line represents the optimal slug size proposed by the analytical solution. Polymer thermal degradation is ignored.	147
Figure 6.8. Water volume fraction of polymer at pore volume injected for multiple polymer slug sizes. The black dashed line represents the optimal slug size proposed by the analytical solution.	148
Figure 6.9. Recovery factor performance demonstrating polymer type sensitivity to reservoir temperature at 0.50 PVI and 1.00 PVI for the 1.25 km sector, 0.40 PVI slug and 3000 m ³ /day injection and production rate. Green is polymer with no thermal degradation, Magenta is ATBSA, Red is HPAM and blue is waterflooding with darker shade at 0.5 pore volume injected and lighter shade at 1 pore volume injected.....	149

Figure 6.10. Recovery factor performance demonstrating polymer type sensitivity to exposure distance at 0.50 PVI and 1.00 PVI for the 5 km sector, 0.40 PVI slug and 3000 m³/day injection and production rate. Magenta is ATBSA, Red is HPAM and blue is waterflooding with darker shade at 0.5 pore volume injected and lighter shade at 1 pore volume injected. 150

Figure 6.11. Water saturation distribution at 0.5 PVI and 1 PVI for polymer flooding using ATBSA and HPAM and waterflooding for an injector/producer spacing of 250. The cross-section represents a mid-slice across a 250 m sector from the COSTA model. Water injector in blue and producer in green. The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. 151

Figure 6.12. Water saturation distribution at 0.5 PVI and 1 PVI for polymer flooding using ATBSA and HPAM and waterflooding for an injector/producer spacing of 3 km. The cross-section represents a mid-slice across a 3 km sector from the COSTA model. Water injector in blue and producer in green. The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. 151

Figure 6.13. Slug size sensitivity demonstrated by sweep efficiency, displacement efficiency, and recovery over PVI. Blue is waterflooding, Red is slug size of 0.1 PVI, yellow is slug size of 0.4 PVI and green is slug size of 0.7 PVI. 152

Figure 6.14. Exposure distance effect on polymer performance demonstrated by sweep efficiency, displacement efficiency, and recovery over PVI. Blue is waterflooding, magenta is ATBSA, red is HPAM with circles allocated to a well spacing of 250 m and triangles for a well spacing of 3 km. 153

Figure 6.15. ATBSA and HPAM polymer performance in the 5 km COSTA model with 1 injector and 3 horizontal consecutive producers demonstrated by sweep efficiency, displacement efficiency, and recovery as a function of pore volumes injected. Blue is waterflooding, red is HPAM, magenta is ATBSA and green is polymer with no thermal degradation. 155

Figure 6.16. Water saturation distribution at 0.1, 0.4 and 1 PVI for polymer flooding with no thermal degradation, ATBSA, HPAM and waterflooding that demonstrates the water movement in the layers with time. The cross-section represents a mid-slice across the 5 km COSTA sector model. Water injector in blue and 3 producers in green. The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. 156

Figure 6.17. Water viscosity distribution at 0.1, 0.4 and 1 PVI for polymer flooding with no thermal degradation, ATBSA, HPAM and waterflooding that demonstrates the water movement in the layers with time. The cross-section represents a mid-slice across the 5 km COSTA sector model. Water injector in blue and 3 producers in green. The scale represents water viscosity from 10 mPa.s the initial polymer viscosity in red to 0.40 mPa.s representing the water viscosity. 156

Figure A.1. 2D Micromodel images of displacement process in oil-wet system: a. Image of pre flooding state with high permeability fracture, b. Image at the end of

waterflooding, c. Image at the end of tertiary flooding, d. Image at the end of secondary polymer flooding. Plots represent cumulative recovery comparison of secondary and tertiary. Reprint from Doorwar and Mohanty, 2014) 176

Figure A.2. 2D Micromodel images of displacement process in water-wet system: a. Image of pre flooding state with high permeability fracture, b. Image at the end of waterflooding, c. Image at the end of tertiary flooding, d. Image at the end of secondary polymer flooding. Plots represent cumulative recovery comparison of secondary and tertiary. Reprint from Doorwar and Mohanty (2014). 176

Figure A.3. Numerical oil pore volume produced as a function of pore volumes of polymer injected for secondary versus tertiary flooding at different starting times. These simulations are using ATBS polymer and 0.4 PVI Slugs at a flow rate of 3000 m³/days. The plot demonstrates that delaying the polymer flooding will result in less incremental gain in recovery for the same amount of polymer volume injected..... 177

Figure A.4. Numerical percent water cut as a function of pore volumes of polymer injected for secondary versus tertiary flooding at different starting times. At tertiary recovery the polymer improves the displacement resulting in the formation of an oil bank. This oil bank will result in an intermediate drop in water production. 178

Figure A.5. Water flooding versus secondary polymer flooding visualisation of water station in a core model from Beteta et al. (2022)..... 178

Figure A.6. Water flooding versus tertiary polymer flooding visualisation of water station in a core model from Beteta et al. (2022)..... 179

Figure A.7. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different polymers and injection temperatures. Lower injection temperature demonstrated improvement in HPAM early recovery..... 180

Figure A.8. Cross sections of reservoir temperature, water viscosity and oil viscosity for isothermal and non-isothermal simulations using HPAM polymer at 0.5 PVI. The isothermal case uses injection temperature of 100°C and the non-isothermal uses injection temperature of 25°C. All cases are secondary flooding with a slug size of 0.4 PVI flowing at 3000 m³/day and reservoir temperature of 100°C. 181

Figure A.9. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different polymer molecular weights. Resorting to the scaled down molecular weight of 8 kg/gmole compared to 500 kg/gmole had no effect on polymer recovery..... 182

List of Tables

Table 2.1. Main functions of different developed synthetic polymer monomers (Diab and Al-Shalabi, 2019).....	33
Table 3.1. 1D simulation models base data.	46
Table 3.2. Relative permeability experimental data fitting parameters using Corey correlations.	47
Table 3.3. HPAM polymer viscosity experimental data at different concentrations from Choi et al. (2014).	48
Table 3.4. Polymer viscosity table generated from Flory Huggins model in Figure 3.3.	49
Table 3.5. Polymer solution non-linear viscosity mixing function $fNxp$	50
Table 3.6. Decay constant (τ) experimental data for ATBSA and HPAM at multiple temperatures and half-life projections at 99°C.....	50
Table 3.7. Activation energy and frequency factor coefficients from Arrhenius plot analysis for ATBSA and HPAM.....	51
Table 3.8. CMG STARS molecular weight and density for polymer and water.	52
Table 3.9. Extension of reaction stoichiometry demonstrating how polymer conversation to water volume is materially balanced.	53
Table 3.10. Polymer Reaction stoichiometric data for actual polymer solution molecular weight of 19000 kg/gmole, STARS recommended MW of 8 kg/gmole and testing case of MW of 500 kg/gmole.....	53
Table 3.11. Frontal advance rate and gravity number comparison for the cases plotted in Figure 3.23	69
Table 4.1. Static models properties for the 1D and 3D models included in the DOE study. ...	82
Table 4.2. Projected half-life at the sensitivity temperatures (85 °C and 100 °C), and threshold temperature of 140 °C estimated from Arrhenius fitting in Figure 3.4	83
Table 4.3. Production and injection rate DOE levels for the 1D and 3D field sector models and design depletion rate and frontal advance rate.	85
Table 4.4. Factors and levels used in the 1D screening study.....	87
Table 4.5. Factors and levels used in the 3D sector model screening study.	87
Table 4.6. Experimental design matrix for the 1D model screening study (16 runs).	89
Table 4.7. Oil pore volume production response relative to waterflood at 1 pore volume injected used in the DOE.	90

Table 4.8. Experimental design matrix for the 3D sector model screening study (16 runs)..	102
Table 5.1. Data used to construct the relative permeabilities for the oil-wet, mixed-wet and water-wet rocks.	117
Table 5.2 Simulation cases used to study the effect of gravity on water flooding performance for different rock wettabilities. K_v/K_H is the ratio of the vertical permeability to horizontal permeability. M is the ratio of the endpoint water mobility to the end-point oil mobility for the unfavourable mobility cases with a 10 mPa.s oil and the favourable mobility cases with an oil of viscosity 1.4 mPa.s.	119
Table 5.3. 2D simulation model base data.	119
Table 5.4. 3D COSTA model simulation base data.	121
Table 5.5. Simulation cases used to study the effect of gravity on water flooding performance for different field representative heterogeneous permeability distributions. Vertical resolution represents fine grid model (62 layers) and coarse grid model (5 layers). M is the ratio of the endpoint water mobility to the end-point oil mobility for the unfavourable mobility cases with an oil viscosity of 10 mPa.s and the favourable mobility cases with an oil viscosity of 1.4 mPa.s.	121
Table 6.1. Input parameters ranges and increments for the full factorial slug size statistical analysis.....	138
Table 6.2. 3D COSTA sector models (1.25 and 5 km sectors) simulation base data.....	145
Table A.1. Thermal properties of rock and fluids used in the simulation model.....	180
Table A.2. Oil viscosity as a function of temperature used in the non-isothermal case using Civan, (2006) correlation.	180

Nomenclature

Symbol	Description	Unit
M	Mobility ratio	—
M_{wp}	Mobility of water displacing polymer	—
M_{po}	Mobility of polymer displacing oil	—
M_{sf}	Shock front mobility	—
M^0	End-point water-oil mobility ratio	—
k_{rw}	Relative permeability of water	—
k_{ro}	Relative permeability of oil	—
k_{rw}^0	End-point relative permeability of water	—
k_{ro}^0	End-point relative permeability of oil	—
$k_{rw}(S_w)$	Relative permeability of water	—
$(k_{ro})_{S_{wc}}$	Relative permeability of oil at connate water saturation	—
$(k_{rw})_{S_{orw}}$	Relative permeability of water at residual oil saturation	—
$k_{r,w}(S_{wf})$	Shock front relative permeability of water	—
$k_{r,o}(S_{wf})$	Shock front relative permeability of oil	—
$k_{r,o}(S_{wc})$	Relative permeability of oil at connate water saturation	—
S_w	Water saturation	—
$\bar{S}_w$	Average water saturation	—
S_{wi}	Initial water saturation	—
$\bar{S}_{wi}$	Average initial water saturation	—
S_{wc}	Connate water saturation	—
$S_{w,polymer\ shock}$	Polymer shock front saturation	—
S_{wf}	Shock front saturation	—
S_{or}	Residual oil saturation	—
S_{orw}	Residual oil saturation	—
S	Reduced water saturation	—

f_w	Fractional flow	—
$f_{w,polymer\ shock}$	Fractional flow at polymer shock front saturation	—
λ_d	Mobility of displacing phase	$m^3 \cdot day \cdot kg^{-1}$
λ_o	Mobility of displaced phase	$m^3 \cdot day \cdot kg^{-1}$
λ_w	Mobility of water phase	$m^3 \cdot day \cdot kg^{-1}$
RF	Recovery factor	—
E_S	Sweep efficiency	—
E_D	Local displacement efficiency	—
μ	Apparent viscosity	$mPa \cdot s$
μ_w	Water viscosity	$mPa \cdot s$
μ_o	Oil viscosity	$mPa \cdot s$
μ_p	Polymer viscosity	$mPa \cdot s$
μ_m	Water/polymer mixture viscosity	$mPa \cdot s$
$\mu_{p,max}$	Polymer viscosity at maximum polymer concentration	$mPa \cdot s$
$\mu_{p,eff}$	Polymer effective viscosity	$mPa \cdot s$
$\mu_{w,eff}$	Water effective viscosity	$mPa \cdot s$
μ_{wim}	Incompletely mixed water phase viscosity	$mPa \cdot s$
$\mu_w^{eff}(C_p)$	Effective water viscosity for the water/polymer mixture	$mPa \cdot s$
n_o	Oil Corey exponents	—
n_w	Water Corey exponents	—
K	Permeability	m^2
K_{scaled}	Scaled model permeability	m^2
$K_{average\ target}$	Target geometric average model permeability	m^2
$K_{average}$	Original model geometric average permeability	m^2
$K_{grid\ cell}$	Grid cell permeability	m^2
$\frac{K_v}{K_H}$	Permeability anisotropy	—
K_v	Vertical permeability	m^2
K_H	Horizontal permeability	m^2
ρ_o	Density of oil	$kg \cdot m^{-3}$
ρ_w	Density of water	$kg \cdot m^{-3}$
ρ_r	Density of rock	$kg \cdot m^{-3}$
$\Delta\rho$	Density contrast between fluids	$kg \cdot m^{-3}$
ρ_w^{mole}	Water mole density	$mol \cdot m^{-3}$
M_p	Polymer molecular weight	$kg \cdot mol^{-1}$

M_w	Water molecular weight	$\text{kg}\cdot\text{mol}^{-1}$
$R(C)$	Reaction rate function	$\text{kg}\cdot\text{m}^{-3}\cdot\text{day}^{-1}$
$\left(\frac{dC}{dt}\right)_{deg}$	Concentration change with time	$\text{kg}\cdot\text{m}^{-3}\cdot\text{day}^{-1}$
C	Polymer concentration	$\text{kg}\cdot\text{m}^{-3}$
$C_p(t)$	Polymer concentration as a function of exposure time	$\text{kg}\cdot\text{m}^{-3}$
C_{p0}	Initial polymer concentration	$\text{kg}\cdot\text{m}^{-3}$
C_p	Polymer concentration in the water phase	$\text{kg}\cdot\text{m}^{-3}$
C_{SEP}	Salinity concentration	$\text{kg}\cdot\text{m}^{-3}$
$C_{p,max}$	Polymer concentration at maximum initial viscosity	$\text{kg}\cdot\text{m}^{-3}$
C_{ads}	Adsorbed polymer concentration on the rock surface	$\text{kg}\cdot\text{kg}^{-1}$
r	First order rate constant	day^{-1}
rrf	Frequency factor	day^{-1}
E_a	Activation energy	$\text{J}\cdot\text{mol}^{-1}$
R	Gas constant	$\text{J}\cdot\text{mol}^{-1}\cdot\text{K}^{-1}$
t_D	Dimensionless time	—
x_D	Dimensionless distance	—
g	Acceleration due to gravity	$\text{m}\cdot\text{day}^{-2}$
α	Angle of flow direction	rad
q_t	Total Darcy velocity	$\text{m}\cdot\text{day}^{-1}$
S_p	Flory-Huggins fitting constant	—
A_{p1}, A_{p2}, A_{p3}	Flory-Huggins fitting constants	—
τ	Decay constant	day
$\tau_{1/2}$	Half-life	day
$\tau_{T_{ref}}$	Polymer decay at reference temperature	day
T	Exposure temperature	K
T_R	Reservoir temperature	K
ω	Todd and Longstaff mixing factor	—
u_w	Darcy velocity of the water phase	$\text{m}\cdot\text{day}^{-1}$
D	Dispersion/diffusion coefficient	$\text{m}^2\cdot\text{day}^{-1}$
ϕ	Porosity	—
l	Length	m
w	Width	m
h	Height	m
f	Polymer solution non-linear viscosity mixing function	—

$fN(x_p)$	Polymer solution non-linear viscosity mixing function	—
x_p	Polymer mass fraction	—
α	Effective concentration ration of the polymer solution	—
t_{value_i}	Significant effect factor	—
$Effect_i$	Effect of factors	(unit of response) ²
$MS_{Residual}$	Mean square of residuals	—
n_+	High level number of trials	—
n_-	Low level number of trials	unit of response
Y_+	Responses at high level	unit of response
Y_-	Responses at low level	(unit of response) ²
MS_i	Mean square	unit of response
y_i	Response at point i	unit of response
$\bar{y}$	Average response	—
n	Total number of runs	—
p	Number of factors included in the screening model	—
df	Degree of freedom	—
$t_{value\ limit}$	Factors significance threshold	—
$t_{0.05,df}$	95% confidence limit	—
$Bonferroni_{t_{value\ limit}}$	Bonferroni correction threshold	—
k	Number of factors used in the pareto	—
N_{PD}	Pore volume produced	—
$N_{g/v}$	Gravity number	—
N_g^0	End-point gravity number	—

Chapter 1

Introduction

1.1 Background and Overview

Energy demand across the globe is growing drastically, thus securing reliable, sustainable, and clean energy resources is important (Manrique et al., 2010). Since oil and gas continue to dominate the energy mix, petroleum companies are obliged to deliver affordable and reliable energy supplies with reduced emissions in support of the global energy transition (Shojaeddini et al., 2019). This commitment entails managing the world's increasing energy demand by a parallel growth in proven reserves. However, the pace of replacement of produced reserves by discoveries has been continuously dropping over the previous few decades, and a significant share of current world oil production originates from mature fields (Manrique et al., 2010).

The operation of high maturity level reservoirs using primary and water flooding recovery methods are an environmentally and economically taxing process. Mature fields will typically achieve a global world average recovery factor of 30% - 35% with many of the fields producing at uneconomic water cut of more than 90% (Aadnøy and Looyeh, 2019). Recovery factors are even lower for high oil viscosity reservoirs. High water cut is also wasteful as energy is expended to pump the water to the surface. In most cases this is obtained by burning oil while producing CO₂ in the process. We need to improve recovery factor and reduce water cut in mature fields.

In the case of heavy oil and heterogeneous reservoirs, polymer injection is a proven EOR technology that aims to increase the injection fluid viscosity to overcome viscosity variations between the reservoir oil and injected fluid. This viscosity increase will improve the injection mobility ratio which directly results in enhanced sweep and

displacement efficiency, improved oil recovery, and reduced water production ultimately minimizing carbon footprint as demonstrated in **Figure 1.1** (a & b) (Sorbie, 1991; Swiecinski et al., 2016). It is considered a proven technique with large-scale field applications such as the Daqing field in China (Leung et al., 2010). However, the design complexity of polymer flooding requires a deep understanding of the physics involved to ensure effective deployment (Lohne et al., 2017).

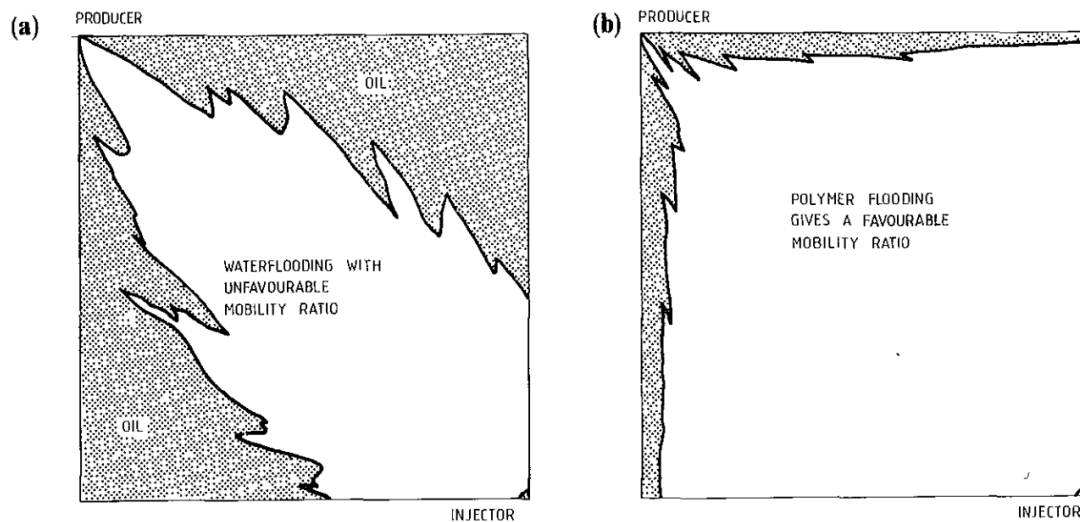


Figure 1.1. Schematic figure depicting the improvement in areal sweep produced by polymer flooding is shown in a five-spot system by Sorbie (1991).

To quantify the uncertainties surrounding polymer flooding projects, essential physics must be included in the modelling tools used to estimate the polymer flood's performance (Lohne et al., 2017). According to Green and Willhite (2018), Sheng et al. (2015) and Sorbie (1991) it is apparent that one of the major limiting physics associated with polymer flooding is polymer instability or degradation. Polymer degradation (the reduction of polymer solution viscosity) has been documented in the literature (Al-Shakry et al., 2018; Clifford and Sorbie, 1985; Dupuis et al., 2013; Knight, 1973; Levitt, 2011; Maurer and Harvey, 1987; Moradi-Araghi, 1987; Muller, 1981; Pielichowski and Njuguna, 2005; Ryles, 1988; Sazali et al., 2020; R. S. Seright et al., 2010; Seright et al., 2021; Shupe, 1981; Vohlidal, 2021; Yang and Treiber, 1985). During polymer solution exposure to hydrocarbon reservoirs it experiences several degradation mechanisms such as mechanical, chemical, thermal or biological degradation (Druetta and Picchioni, 2019).

Both thermal and chemical degradation effects coexist in most high-temperature, high salinity and hardness reservoirs (Choi et al., 2014; Levitt and Pope, 2008; Levitt, 2011). Researchers have shown that in high-temperature reservoirs, polymer flooding

typically performs poorly because the viscosity of the injected polymer reduces over time due to thermally and chemically induced breakup of the polymer molecules (Bordeaux Rego et al., 2017; Choi et al., 2014; Druetta and Picchioni, 2019; Xiang'an Lu et al., 2015; X. Lu et al., 2015; Sharma et al., 2011; Xin et al., 2021, 2018). Polymer structure and the kinetics of viscosification of aqueous solution and the thermal degradation will be described in the following sections.

Until recently, most studies conducted on the most commonly used commercial polymer called hydrolysed polyacrylamide polymer (HPAM) have suggested the infeasibility of its use in harsh reservoir environments. Experiments performed in chemically unstable conditions demonstrated chemical degradation on all the tested polymer samples. Seright et al., (2010) presented findings that suggest polymer stability in temperatures up to 120 °C. His experiments tested thermal degradation in a chemically stable system. He predicted that half of the polymer viscosity can be maintained for more than 8 years at 100 °C and for around 2 years at 120 °C. He also suggested that deploying polymer flooding in elevated temperature reservoirs is possible if the content of divalent cations and oxygen particles' is low.

Although Seright et al., (2010) suggested stability of HPAM for elevated temperature up to 120 °C, the practicality of its use in harsh carbonate reservoir environments is still a challenge due to the nature of high salinity and hardness of reservoir fluids. The good news is that recent developments in polymer technology have expanded polymer flooding applications to these kinds of reservoirs. In a recent work by Seright et al., (2021) a total of 22 thermally and chemically stable polymers were tested under high temperature, high salinity and high divalent ions conditions. His findings suggest thermal and chemical stability of a set of acrylamide-tertiary butyl sulfonic acid (ATBS)-based copolymers. He predicted a viscosity half-life of over 5 years at 120 °C and over 50 years at 99 °C for a copolymer composition non-commercially referred to as ATBSA, consisting of more than 90% ATBS, as demonstrated in **Figure 1.2**, which suggests that polymer injection may be viable in such reservoirs. However, there have been few field applications to date that verify these predictions.

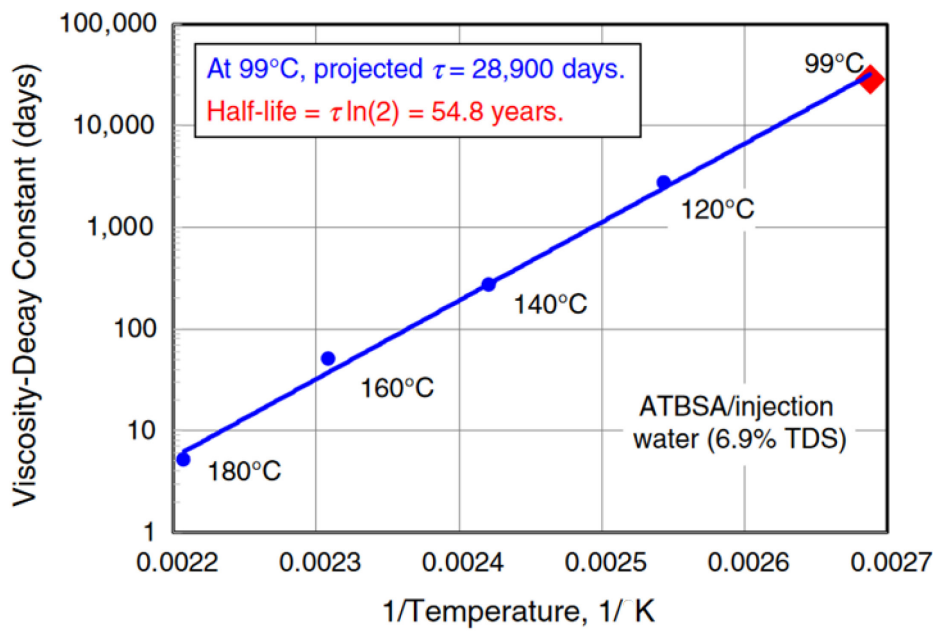


Figure 1.2. Half-life forecasts at elevated temperature for stability estimation at 99 °C by Seright et al., (2021).

Given the unavailability of polymers capable of withstanding extreme reservoir conditions, the lack of field applications is understandable. Nonetheless, with recent advances in polymer technology as discussed earlier in our review, engineers are increasingly evaluating their potential using numerical simulation (Diab and Al-Shalabi, 2019).

This growing interest has been reflected in the Middle East, where ATBS polymers, owing to their demonstrated thermal and chemical robustness, have been taken beyond laboratory screening. In Abu Dhabi, a high ATBS content polymer was successfully piloted through two Polymer Injectivity Tests (PITs) in 2019 and 2021, targeting dual-zone carbonate reservoirs with elevated salinity and temperature (Leon et al., 2024, 2022; Masalmeh et al., 2019). In Northern Kuwait, similar ATBS copolymers were evaluated through core flood experiments under extreme salinity for potential application in extra-heavy oil recovery, showing favourable injectivity and propagation (Akther et al., 2025). Although these results reinforce the viability of ATBS-based formulations, field-scale applications are still limited, and long-term performance validation remains necessary to support broader deployment. Beyond thermal stability, recent work has shown that ATBS polymers also offer a higher viscosity yield and lower dynamic adsorption compared to conventional HPAM, which can improve polymer

propagation and sweep efficiency. Beteta et al., (2025) demonstrated these advantages translate into higher net present value (NPV) in simulation models, even under moderate reservoir conditions, suggesting that the improved economics may justify the higher unit cost of ATBS-based polymers.

As stated earlier to minimize the uncertainty around a polymer flood project, it is important that numerical models capture the relevant polymer physics. Most existing field scale models incorporate the effects of shear thinning and viscoelasticity as well as polymer adsorption, inaccessible pore volume and permeability reduction (Al-Dhuwaih et al., 2018; Aldhuwaih et al., 2015; Alshawaf et al., 2017, 2018; Alzayer and Sohrabi, 2013; Delshad et al., 2008; Slater and Ali, 1970a, 1970b; Tai et al., 2021; Vela et al., 1976; Zhou et al., 2019). However, the impact thermal degradation has rarely been evaluated at the field scale. Large-scale simulation can be accommodated in existing commercial simulators such as CMG-IMEX, CMG-GEM, CMG-STARs, UTCHEM, ECLIPSE100 and EM^{power}. Several publications have investigated the impact of thermal degradation on polymer flooding performance numerically (Beteta et al., 2025; Bordeaux Rego et al., 2017; Choi et al., 2014; Clifford and Sorbie, 1985; Druetta and Picchioni, 2019; Jabbar et al., 2018; Xiang'an Lu et al., 2015; Verma et al., 2009; Xin et al., 2021, 2018). Most of these publications have demonstrated the negative impact of thermal degradation in simple 1D or 2D models.

Bordeaux Rego et al., (2017) extended thermal degradation simulations to a 3D sectoral model in CMG STARs. Their work focused on the development strategy and economics of coupled hot water and polymer injection including the influence of injection temperature on the viscosity of both reservoir fluids and HPAM when using an infill injection scheme with a small well spacing. Their work did not evaluate the use of ATBS in large carbonate reservoirs and it cannot be applied to giant field infrastructure where the well spacing is large (>1 km) and polymer undergoes prolonged exposure to elevated temperature.

1.2 Motivation and Objectives

Heavy oil and carbonate reservoirs remain critical to global energy supplies, accounting for a major portion of the world's conventional oil reserves. Recent estimates suggest that carbonate formations hold approximately 60% of the world's conventional oil reserves (Yao et al., 2021). A large concentration of total reserves of almost one third is located in the Middle East, particularly within the prolific fields of Saudi Arabia, the

United Arab Emirates, and Iraq (Buza, 2008). These reservoirs are often highly heterogeneous and naturally fractured, and they present environmental challenges including elevated temperature, high salinity, and significant water hardness.

Globally, temperatures in carbonate reservoirs often exceed 85 °C, with averages approaching 100 °C in the Middle East and reaching up to 130 °C in the North Sea (Alnarabiji and Husein, 2020; Hassan et al., 2023). These extreme conditions significantly limit the use of conventional polymers such as HPAM, which is known to degrade under thermal and chemical stress, resulting in a loss of viscosity (Choi et al., 2014; Levitt and Pope, 2008; Levitt, 2011). This has historically constrained polymer flooding applications in high-temperature reservoirs.

Recent developments, however, have demonstrated promising avenues for expanding the applicability of polymer EOR. Advanced chemistries such as acrylamide-tertiary butyl sulfonic acid (ATBS)-based copolymers have shown enhanced resistance to thermal and chemical degradation. Laboratory testing and pilot studies in the Middle East have confirmed the viability of these polymers under harsh reservoir conditions (Diab and Al-Shalabi, 2019; Masalmeh et al., 2019; Seright et al., 2021).

Most polymer flooding field applications to date relies on close injector-producer spacing (~250 m) to maintain a stable displacement front and effective mobility control (Seright et al., 2021; Sheng et al., 2015). However, in the Middle East a key constraint remains in the infrastructure of many carbonate fields. These fields were historically developed using peripheral waterflooding, where injectors are placed at the reservoir boundaries and producers are spaced widely—often between 1 and 3 km apart. This spacing mismatch presents a significant operational and design challenge for deploying polymer flooding in such environments.

The aim of this research is to investigate the impact of thermal degradation on polymer flood performance in giant heterogeneous and elevated-temperature reservoirs with large well spacing, utilizing numerical simulation and analytical methods. Polymer applications in carbonate reservoirs have been limited by elevated temperature, high salinity, hardness, and low permeability. However, recent studies have suggested the possibility of polymer deployment in such harsh reservoir environments, expanding its spectrum of applications (Diab and Al-Shalabi, 2019).

Accordingly, the specific objectives of this study are:

1. **To study the effect of thermal degradation on polymer flooding performance** in giant carbonate oil fields with large well spacing, using non-isothermal numerical simulations.
2. **To isolate the effect of thermal degradation and evaluate** its interactions with other significant parameters using Design of Experiment (DOE).
3. **To assess the use of ATBS-based polymers** for EOR applications in high-temperature giant carbonate reservoirs with (1 – 5 km) spacing between the injector and producer.
4. **To evaluate recovery performance** through local displacement efficiency and areal sweep efficiency, and to understand the underlying physical mechanisms contributing to oil recovery including the effect of gravity.
5. **To develop practical guidelines** for polymer deployment that maximize project efficiency in reservoirs with harsh conditions supported by analytical methods.

By integrating numerical modelling, physical understanding of degradation, and analytical assessment, this research aims to provide a comprehensive framework for the successful application of polymer flooding in harsh reservoir environments typical of Middle Eastern oil fields.

1.3 Thesis Outline

The following chapters present the core of this thesis, each addressing a critical component of polymer deployment protocol and the impact of thermal degradation on polymer performance:

- a) **Chapter 3.** The third chapter presents the development of a numerical simulation framework tailored to analyse the effects of polymer degradation. It includes one-dimensional (1D), two-dimensional (2D) vertical cross-sections and field-scale models representing giant heterogeneous carbonate reservoirs with large well spacing. This will cover analytical validation of polymer flooding performance and benchmark it against waterflooding. It will provide initial evaluation of the effect of thermal polymer degradation on performance. It also includes a study of model convergence and cell refinement investigation to enhance the accuracy of the dynamic modelling.

- b) **Chapter 4.** The fourth chapter focuses on the use of Design of Experiment (DOE) to investigate the influence and significance of thermal degradation on polymer flooding. The aim is to evaluate key factors and their interactions, offering a computationally efficient approach to guide field-scale design. In this chapter gravity introduced improvement in recovery and will be discussed further in chapter 5.
- c) **Chapter 5.** The fifth chapter demonstrate the influence of key interactions encapsulated under the gravity term that effect polymer flooding performance. This chapter will focus on waterflooding in oil-wet, mixed-wet and water-wet reservoirs, highlighting the role of gravity in improving recovery. We demonstrate how gravitational segregation enhances vertical displacement efficiency and explore how heterogeneity and reservoir layering interact with gravity-driven flow to influence recovery outcomes. The significance of interactions between gravity and thermal degradation on polymer performance will be discussed in Chapter 6.
- d) **Chapter 6.** The sixth chapter provides guidelines for polymer deployment and confirmation of the validity of deploying polymer in harsh reservoir environments with large well spacings up to 5 km with a line drive peripheral injection scheme. It will provide validation of a published slug size semi-analytical solution through numerical means in heterogeneous reservoirs and extend the solution to determine exposure time as a key baseline for polymer screening. It will provide numerical sensitivity and confirm the feasibility of running ATBS polymer in giant carbonate reservoirs at high temperature. It will demonstrate the source of the gain in recovery by quantifying improvements in displacement and sweep efficiency.
- e) **Chapter 7.** Finally, the concluding chapter summarizes the key findings of the thesis, discusses the limitations of the work, and suggests possible avenues for future research.

Chapter 2

Literature Review

2.1 Fundamentals and Recovery Mechanism

Polymer flooding is a well-established method in chemical enhanced oil recovery (EOR) that has significantly evolved since its conceptualization in the mid-20th century. The method functions by adding water-soluble polymers to the injection water, which increases its viscosity and improves the mobility ratio (M) between water and oil and make it more favourable when $M \leq 1$ (Dyes et al., 1954; Mungan, 1969; Sandiford, 1964; Slater and Ali, 1970b; Sorbie, 1991; Vela et al., 1976).

$$M = \frac{\lambda_d}{\lambda_o} = \frac{(k_{rw}/\mu_w)}{(k_{ro}/\mu_o)}, \quad 2.1$$

where λ_d is the mobility of the displacing phase, λ_o the mobility of the displaced phase (oil), k_{rw}, k_{ro} are the relative permeabilities of water and oil, and μ_w, μ_o are the viscosities of water (or polymer solution) and oil.

The first work on polymer flooding was clear that the process improves oil recovery through a combination of both enhanced sweep and local displacement efficiencies. The recovery factor can be expressed as the product of the two components: sweep efficiency and local displacement efficiency (Lake, 1989):

$$RF = E_S \times E_D = \frac{\text{Volume of oil displaced}}{\text{Volume of original oil in place}} = \frac{\bar{S}_w - \bar{S}_{wi}}{1 - \bar{S}_{wi}}, \quad 2.2$$

where $\bar{S}_w$ is the average water saturation and $\bar{S}_{wi}$ is the average initial water saturation.

Figure 2.1 illustrates the contribution of each of these factors to recovery.

Sweep efficiency is defined as the volume of oil contacted by water over the volume of the original oil in place:

$$E_s = \frac{\text{Volume of oil contacted by water}}{\text{Volume of original oil in place}}, \quad 2.3$$

It characterizes how much of the reservoir is accessed and is primarily influenced by reservoir heterogeneity, mobility ratio, injection pattern, and gravity effect. A higher sweep efficiency indicates broader fluid coverage and reduced bypassed zones, contributing to improved macroscopic recovery.

Local displacement efficiency quantifies the effectiveness of oil removal from the contacted zones and is given by:

$$E_D = \frac{\text{Volume of oil displaced}}{\text{Volume of oil contacted by water}}, \quad 2.4$$

This metric captures pore-scale displacement processes and is governed by wettability, mobility ratio, capillary number, gravity number, residual oil saturation, and polymer rheology.

The older literature demonstrates that polymer flooding improves recovery by increasing both sweep (channelling due to heterogeneity and viscous fingering) and local displacement efficiency (improving fractional flow and oil mobilization) (Green and Willhite, 2018; Needham and Doe, 1987; Pye, 1964; Sandiford, 1964; Slater and Ali, 1970b; Vela et al., 1976). Pope (1980) explicitly stressed the importance of evaluating all three components—areal sweep, vertical sweep, and microscopic displacement—when assessing the effectiveness of a polymer flood. Clifford and Sorbie (1985) further confirmed that polymers can enhance microscopic displacement efficiency, particularly in floods initiated under unfavourable mobility conditions.

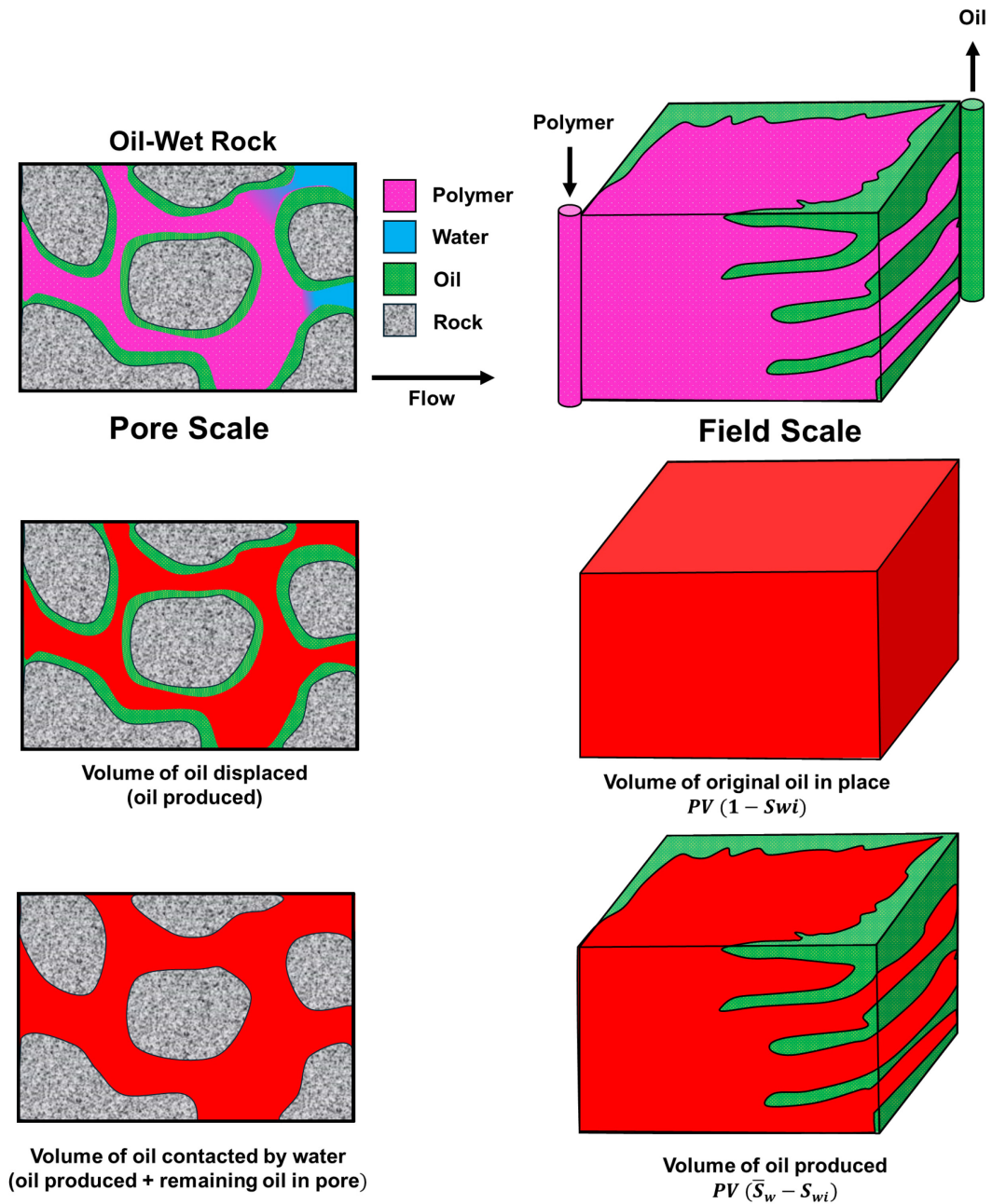


Figure 2.1. Illustration of how local displacement efficiency and sweep efficiency are represented at pore scale (left) and field scale (right) during polymer flooding. The upper part visualizes the spatial distribution of fluids, while the lower part schematically represents the corresponding volumes used to estimate efficiency values. Colour legends: Gray = rock, green = oil, red = displaced oil, magenta = polymer, blue = water.

In contrast, the more recent literature often identifies increased sweep efficiency as the most significant and obvious mechanism of polymer flooding (Sheng et al., 2015) and the contribution of local displacement is often neglected. A wide range of studies (Al-Shakry et al., 2018; Bordeaux Rego et al., 2017; Firozjahi and Saghaei, 2020; Jabbar et al., 2018; Seright et al., 2010; Sheng, 2011; Sheng et al., 2015) consistently present

polymer flooding as a means of reducing the water-oil mobility ratio to achieve better areal and vertical conformance, minimize viscous fingering, and improve the injection profile in heterogeneous formations. These works focus on the capacity of polymers to enhance sweep by redistributing injected fluids across the reservoir, thereby improving contact with previously unswept regions.

Some of these studies further argue that polymer flooding does not improve microscopic displacement efficiency, based on the premise that it does not reduce residual oil saturation (S_{or}) (Sheng, 2011; Sheng et al., 2015). This interpretation equates displacement improvement solely with S_{or} reduction, overlooking the contribution of mobility control and consequent higher shock front saturation. While this interpretation simplifies displacement efficiency to a function of S_{or} reduction, it does not account for the broader definition supported by classical literature and flow theory. These sources indicate that polymers can also enhance local displacement efficiency through dynamic flow modification and front stabilization, even when S_{or} remains unchanged. It is nevertheless acknowledged in the literature that viscoelastic synthetic polymers may, in some cases, contribute to modest reductions in S_{or} by mobilising trapped oil (Sandengen et al., 2017). Additionally, in carbonate reservoirs, adsorption of anionic polymers onto positively charged surfaces can displace surface-bound carboxylic acids, leading to a shift toward more water-wet conditions (Li et al., 2020). Polymer adsorption and its associated wettability effects are therefore recognised as possible mechanisms, but they are system-specific and are not incorporated into the present study.

A more comprehensive understanding, consistent with both experimental evidence and theoretical modelling, suggests that polymer flooding improves both sweep and displacement efficiency. Chapters 4, 5 & 6 will explore this dual role through analytical and numerical investigations and demonstrate both are of equal significance to the recovery process.

While polymer flooding may not always reduce the residual oil saturation, it can accelerate oil recovery by enabling the estimated ultimate recovery (EUR) to be achieved faster than through conventional waterflooding (See **Figure 2.2**). This time advantage can translate into higher net present value (NPV) for oil development projects (Needham and Doe, 1987; Sorbie, 1991). So, in practise the recovery gain is represented by the additional recovery realized at an earlier oil in place (OIP) depletion stage.

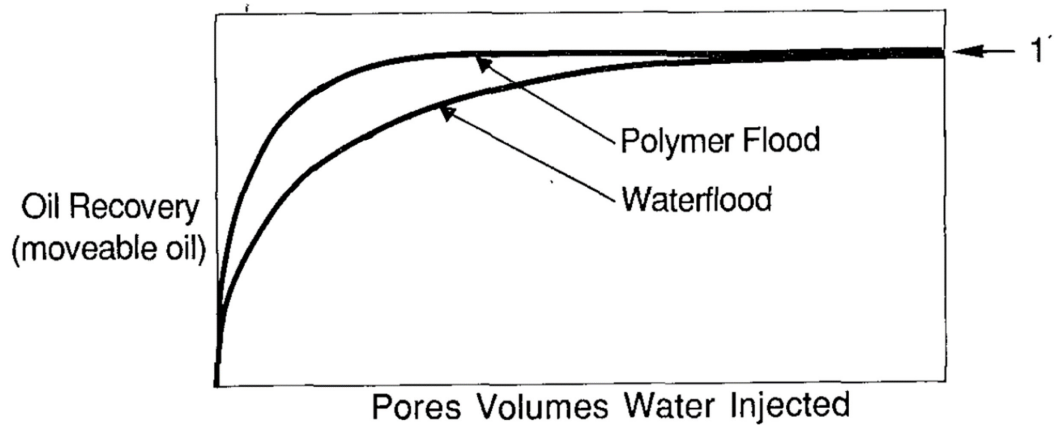


Figure 2.2. Production profiles for polymer food and water flooding demonstrating polymer advances the oil recovery and does not adjust residual oil saturation.

Field experience and documented studies indicate that polymer flooding is more effective when applied as a secondary recovery method rather than as a tertiary process. Secondary polymer floods typically yield higher recovery with lower polymer consumption, as the mobility control begins before water breakthrough and channelling become dominant. As highlighted by Needham and Doe (1987), the average performance of polymer floods initiated after the water–oil ratio (WOR) exceeds 10 is significantly reduced, underscoring the importance of early implementation during the waterflood life. An early injection of polymer improves the sweep efficiency at the pore scale and minimizes the pore volumes (PV) of injected fluid required to achieve maximum oil recovery (Ould Metidji et al., 2023). Juárez-Morejón et al. (2019) demonstrated through core flood experiments that the timing of polymer injection strongly influences oil recovery, with early polymer injection (0 PV waterflood) consistently producing superior sweep and higher final recovery, regardless of the wettability conditions. Similarly, Ould Metidji et al. (2023) reported that polymer injection in secondary mode recovered up to 80% of original oil in place (OOIP), compared to 66% when polymer was injected after waterflooding. These findings collectively support the view that early polymer implementation can enhance recovery efficiency while also reducing operational time and energy consumption.

Nevertheless, this conclusion is not universally supported. Several studies have shown that under specific reservoir conditions, tertiary polymer flooding may outperform secondary application (Bondino et al., 2011; Doorwar and Mohanty, 2014; Fabbri et al., 2014; Skauge et al., 2012). However, the authors of these studies also cautioned that their results should not be over generalised, noting that some of the

apparent advantages of tertiary injection may reflect core-to-core variability rather than a systematic performance benefit. This work will proceed with a primary focus on secondary polymer flooding regardless of these views. We will discuss the literature favouring tertiary over secondary in the appendix A.1 in addition to preliminary simulations sensitivity in tertiary recovery and recommendation to be researched in future work. Collectively, this thesis seeks to demonstrate that classical conclusions regarding effectiveness of water flooding and polymer flooding may not necessarily apply to all reservoir wettability conditions. Given the profound impact of displacement dynamics on flooding performance, this study will further explore how variations in wettability and the influence of gravity can reshape expectations in oil-wet systems revealing potential recovery benefits where traditional literature has often anticipated limitations.

2.2 Analytical Microscopic Displacement

The fundamental description of immiscible displacement in porous media was developed by Buckley and Leverett (1942), who formulated a mathematical model describing how two immiscible fluids (e.g. oil and water) displace each other in one-dimensional, incompressible flow. The core of this analysis is the conservation equation for saturation S for one-dimensional incompressible flow of water, w , and oil, o , is:

$$\frac{\partial S_w}{\partial t_D} + \frac{\partial f_w}{\partial x_D} = 0, \quad 2.5$$

where t_D and x_D are dimensionless time (pore volumes injected where the pore volume is = porosity×bulk volume) and dimensionless distance (fractional distance from injection to production well) respectively. The fractional flow, where at the field scale, the explicit influence of capillary pressure is ignored (Craig et al., 1957) is given by:

$$f_w = \frac{\lambda_w}{\lambda_w + \lambda_o} + \frac{K\lambda_w\lambda_o\Delta\rho g \sin \alpha}{(\lambda_w + \lambda_o)q_t}, \quad 2.6$$

where q_t is the total Darcy velocity (volume injected per unit time per unit area) and λ represent mobilities (relative permeability divided by viscosity). K is the permeability, $\Delta\rho$ is the density contrast between the fluids (the density of the water minus the oil), g is the acceleration due to gravity and α is the angle of the flow direction measured to be positive rotating clockwise relative to the horizontal. Upwards, gravity-stable flow is represented by a negative value of α .

For a one-dimensional line drive with horizontal flow, the gravity term is neglected ($\alpha = 0$) (Hawthorne, 1960). For a gravity stable, vertical upwards displacement, $\sin \alpha = -1$, the water is held back by gravity, leading to a higher local displacement efficiency.

Lake (1989) demonstrated that higher mobility ratios increase the convexity of the fractional flow curve, indicating less efficient displacement as the displacing fluid advances more rapidly relative to the displaced fluid. Conversely, lower mobility ratios decrease the convexity of the curve, producing more gradual saturation changes and improving displacement efficiency. Gravity further affects displacement where favourable gravity forces oppose the movement of the displacing fluid, slowing its advance and enhancing displacement efficiency, while unfavourable gravity accelerates flow, reducing efficiency. These influences are evident in **Figure 2.3**, where variations in mobility ratio and gravity number shift the fractional flow curves, illustrating their combined effect on displacement performance. In his work he re-expressed the fractional flow function in terms of dimensionless groups:

$$f_w = \frac{1 - N_g^0 (1 - S)^{n_o} \sin \alpha}{1 + \frac{(1 - S)^{n_o}}{M^0 S^{n_w}}}, \quad 2.7$$

where n_o and n_w are oil and water Corey exponents, S is the reduced water saturation, α in Lake's work represent by a positive value rotating counterclockwise. For a gravity stable, vertical upwards displacement, $\sin \alpha = +1$:

$$S = \frac{S_w - S_{wi}}{1 - S_{or} - S_{wi}}, \quad 2.8$$

and M^0 is the endpoint water-oil mobility ratio and N_g^0 is end point gravity number:

$$M^0 = \frac{k_{rw}^0 \mu_o}{k_{ro}^0 \mu_w}, \quad 2.9$$

$$N_g^0 = \frac{K k_{ro}^0 \Delta \rho g}{\mu_o q_t}, \quad 2.10$$

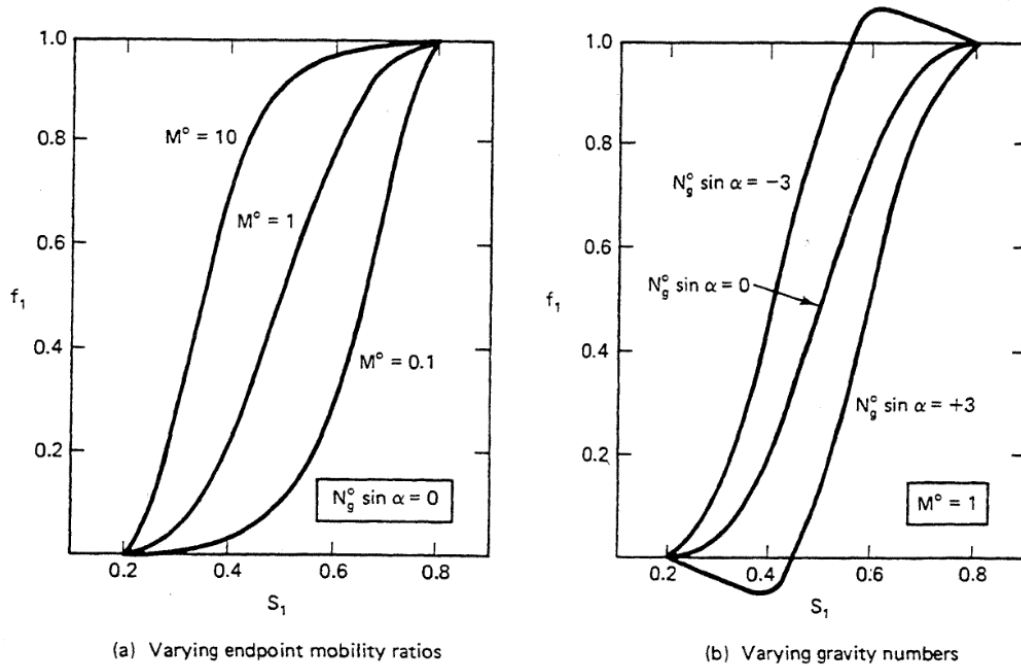
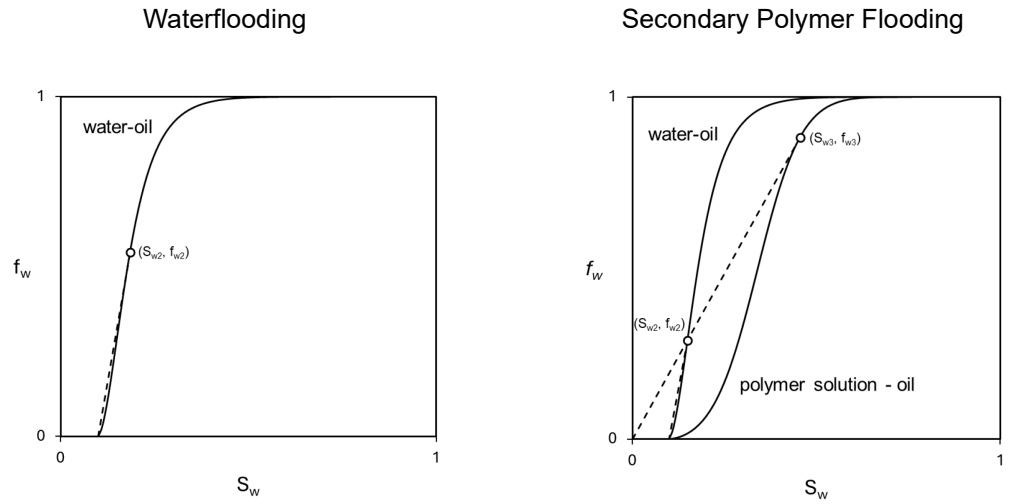
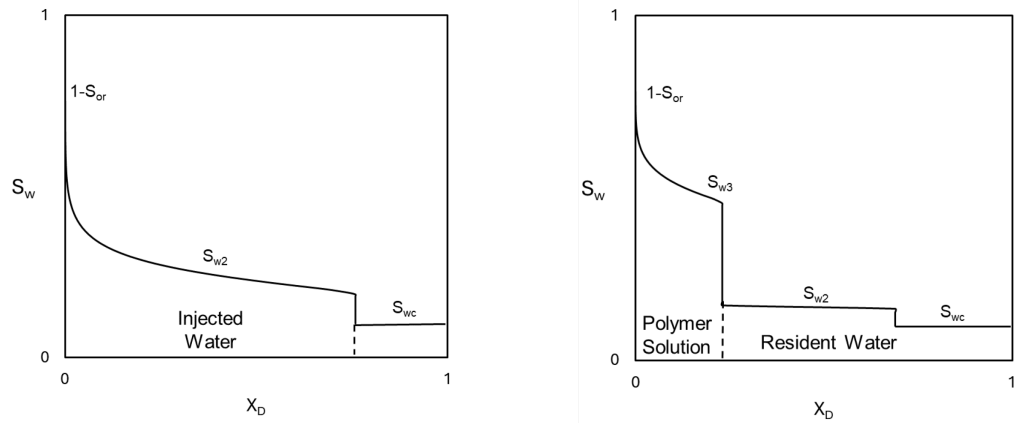


Figure 2.3. Fractional flow curves at a) varying endpoint mobility ratios and b) varying gravity numbers (Lake, 1989).

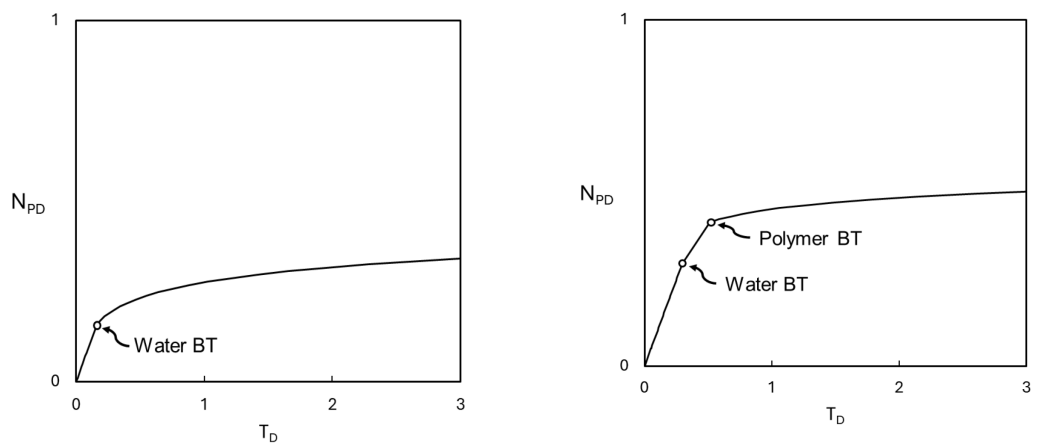
Pope (1980) extended the Buckley-Leverett analysis to model polymer flooding by incorporating the effects of polymer-induced mobility reduction into the fractional flow framework. Unlike waterflooding, where a single shock front typically exists between oil and water, polymer floods in secondary injection scenarios generate two distinct shock fronts. The first front represents the displacement of connate water by the injected polymer solution, while the second marks the displacement of oil by polymer. These fronts travel at different velocities because the fractional flow functions differ for the water-polymer system and the polymer-oil system (See **Figure 2.4**).



a) Fractional Flow Diagram



b) Saturation Profile Before Water Breakthrough (BT)



c) Oil Production Curve

Figure 2.4. Waterflooding and secondary polymer flooding fractional flow analysis.

The polymer front advances more slowly due to its higher viscosity and reduced mobility ratio, resulting in a stepped water production profile often observed in laboratory and field data. Pope's formulation provided a means to predict polymer breakthrough times and estimate oil recovery based on polymer properties and injection conditions. His work significantly advanced the analytical understanding of polymer flooding by demonstrating how polymer solutions improve displacement efficiency through better mobility control and increasing the saturation of the displacement front.

2.3 Polymer Properties in Solution

While the fundamental principles of polymer flooding describe how polymers improve sweep efficiency and displacement in reservoirs, the practical success of such processes depends critically on the chemical nature and physical behaviour of the polymers themselves. Once injected, polymers encounter reservoir conditions that include temperature, formation-water composition, pore structure, rock mineralogy, and wettability. These factors interact with polymer solution properties such as type and concentration, together with operational constraints such as injection rate, to control adsorption, mechanical degradation, retention, and flow resistance during propagation in porous media.

2.3.1 Viscosity of Polymer Solutions

The viscosity of polymer solutions is the primary solution property of interest in polymer flooding applications, as it fundamentally controls the efficiency of the displacement process (Sorbie, 1991). The principal purpose of introducing polymers into the injected water is to increase the viscosity of the displacing phase, thereby reducing the mobility ratio between the injected fluid and the oil, which leads to more stable displacement fronts and improved sweep efficiency. This is especially critical in reservoirs where significant heterogeneity or adverse mobility ratios can lead to viscous fingering and early water breakthrough.

Historically, polymer flooding was considered suitable predominantly for reservoirs containing relatively low-viscosity oils, typically up to about 150 mPa.s (Standnes and Skjevrak, 2014). However, recent experimental studies have demonstrated the potential of polymer flooding even in higher-viscosity oil systems. For instance, Seright et al.

(2010) reported encouraging laboratory results for oil viscosities in the range of 150–1000 mPa.s. Moreover Seright et al. (2018) showed that when displacing a highly viscous 1,610 mPa.s crude oil at 27°C through field cores, oil recovery efficiency increased with polymer solution viscosity up to approximately 25 mPa.s. Beyond this threshold, no significant additional recovery benefit was observed, suggesting that a viscosity of around 25 mPa.s was sufficient to achieve a nearly favourable mobility ratio under these specific reservoir conditions. This finding was attributed to the substantially lower relative permeability to water in the presence of viscous crude oils, enabling lower-viscosity polymer solutions to effectively control mobility. Additionally, the use of horizontal injection and production wells has enabled polymer flooding to be extended to recover oils with viscosities as high as 10,000 mPa.s (Seright and Wang, 2023).

Modelling the viscosity behaviour of polymer solutions is essential for accurately predicting their performance under reservoir conditions. In this work, the relationship between polymer viscosity and concentration has been characterized using experimental data for HPAM from Choi et al. (2014). The viscosity of the polymer solution (μ_p) can be described relative to the base water viscosity (μ_w) through an empirical equation derived from the Flory–Huggins theory, fitted via a third-order polynomial:

$$\mu_p = \mu_w \left[1 + (A_{p1}C_p + A_{p2}C_p^2 + A_{p3}C_p^3)C_{SEP}^{S_p} \right] \quad 2.11$$

where μ_p is the polymer viscosity, μ_w is the water viscosity, C_p is the polymer concentration, C_{SEP} salinity concentration, and $A_{p1}, A_{p2}, A_{p3}, S_p$ are fitting constants. This equation allows for capturing the complex relationship between polymer concentration, salinity, and viscosity—critical factors for designing polymer flooding projects under varying reservoir conditions.

The viscosity-concentration relationship and thermal degradation of polymers are unique to the polymer type and the conditions of testing (temperature, salinity, and hardness) so it is critical to conduct viscosity and decay experiments at actual field condition. In this work we assume, HPAM and ATBS have similar viscosity-concentration relationships due to the unavailability of ATBS viscosity-concentration data. This assumption remains valid, as the initial concentration is not critical in this

context, given that adsorption effects are excluded, and economic performance is beyond the scope of this work.

2.3.2 Factors Reducing Polymer Effectiveness

2.3.2.1 *Polymer Degradation in Solution*

Polymer solutions used in subsurface applications are subject to several degradation mechanisms that can compromise their physical and chemical properties. Such degradation leads primarily to molecular weight reduction, causing loss of viscosity, which is critical for maintaining polymer performance under reservoir conditions (Green and Willhite, 2018; Sorbie, 1991). Understanding the various degradation mechanisms and their kinetics is essential for designing polymer systems that can withstand harsh subsurface conditions over long residence times. Several degradation pathways can act singly or in combination:

Mechanical Degradation: Caused by high shear forces during surface handling or near-wellbore flow through small pore throats, leading to chain scission. Mechanical degradation is usually rapid and can cause an immediate drop in polymer viscosity (Sorbie, 1991).

Biological Degradation: Involves enzymatic attack by bacteria or other microorganisms, more pronounced for biopolymers such as xanthan. While less significant for synthetic polymers like HPAM, biological degradation cannot be entirely neglected (Druetta and Picchioni, 2019; Green and Willhite, 2018).

Chemical Degradation (Hydrolysis and Precipitation): Occurs when amide groups in polyacrylamides convert into carboxylate groups under high temperature or extreme pH, leading initially to increased viscosity but eventually causing polymer precipitation in the presence of divalent cations such as Ca^{2+} and Mg^{2+} (Choi et al., 2014; Clifford and Sorbie, 1985; Moradi-Araghi and Doe, 1987; Sheng, 2011; Sorbie, 1991).

Thermal Degradation: Refers to the cleavage of the polymer backbone due to prolonged exposure to elevated temperatures, resulting in significant loss of molecular weight and viscosity. Thermal degradation becomes the dominant concern in high-temperature reservoirs (Gröllmann and Schnabel, 1982; Levitt and Pope, 2008; Muller, 1981; Sorbie, 1991).

Among these mechanisms, thermal degradation is particularly critical for long-term stability under harsh subsurface conditions and is the focus of this work.

2.3.2.1.1 Thermal Degradation of Polymers

The thermal degradation of synthetic water-soluble polymers, including polyacrylamide (PAM) and its partially hydrolysed variant (HPAM), has been investigated extensively since the late 1970s and early 1980s. Early researchers such as Muller (1981) and Gröllmann and Schnabel (1982) were among the first to distinguish between thermal and chemical degradation pathways in polyacrylamide solutions. While chemical degradation involves hydrolysis and ionic interactions with multivalent cations, thermal degradation specifically refers to the breaking of covalent bonds in the polymer backbone due to heat-induced processes, even under neutral pH and oxygen-free conditions. By the early 1980s, it became clear that polymers could degrade thermally in purely anaerobic conditions—although the rates were much lower than in oxygenated systems. Gröllmann and Schnabel (1982) and Wellington (1983) further explained that free radical formation played a key role in initiating thermal scission of the polymer backbone.

Thermal degradation in acrylamide-based polymers results from scission of the carbon–carbon bonds in the polymer backbone. This process is typically mediated by free radicals, which can form spontaneously at elevated temperatures or be catalysed by:

- Oxygen contamination
- Presence of metal ions such as iron
- Residual initiators from polymer synthesis (Gröllmann and Schnabel, 1982; Levitt and Pope, 2008)

Gröllmann and Schnabel (1982) explained that radicals abstract hydrogen from the backbone, producing carbon-centred radicals that trigger further chain scission, ultimately shortening the polymer chains. This random scission reduces molecular weight, which directly diminishes solution viscosity (Sánchez-Jiménez et al., 2010; Sorbie, 1991).

Muller (1981) conducted fundamental experiments showing that even in distilled water at neutral pH, thermal degradation of polyacrylamide occurs in the absence of oxygen, proving that temperature alone can induce backbone scission. However, the

degradation rate increases significantly when oxygen or metal ions are present. Seright et al. (2010) later quantified these effects, demonstrating that under strict anaerobic conditions, HPAM could maintain half of its initial viscosity for over 8 years at 100°C and about 2 years at 120°C. This highlights that thermal degradation, while inevitable at high temperatures, can be managed to some extent by controlling oxygen and contaminants in the system. (Parker and Lezzi, 1993) found that the degradation followed a first order type kinetic reaction (K. Sandengen et al., 2017).

2.3.2.1.2 Kinetic Modelling of Thermal Degradation

Clifford and Sorbie (1985) used a first-order degradation reaction function to model thermal degradation. The function is a simple characterization of chain scission mechanism of degradation (Xiang'an Lu et al., 2015). Random scission is a degradation mechanism often attributed to the pyrolysis of a wide number of polymers. It assumes fragmentation of the polymer chain by random breakdown of the bonds along the chain producing progressively shorter polymer links until evaporates when the fragments are small enough (Bordeaux Rego et al., 2017; Choi et al., 2014; Clifford and Sorbie, 1985; Sánchez-Jiménez et al., 2010). The polymer thermal degradation is defined in the reaction rate function $R(C)$

$$R(C) = \left(\frac{dC}{dt} \right)_{deg} = -rC \quad 2.12$$

where r is the first order rate constant and C is the polymer concentration that reduces with exposure time. The reaction rate is linked to temperature using the Arrhenius equation.

$$r = rrf \exp \left(\frac{-E_a}{RT} \right) \quad 2.13$$

where rrf is the frequency factor, E_a is the activation energy, R is the gas constant and T is the exposure temperature. The application of the Arrhenius equation to polymer degradation studies commonly relies on decay constant (τ) values determined at various temperatures, as reported for both ATBSA and HPAM in the experimental work of (Seright et al., 2010, 2021). The decay constant, which represents the reciprocal of the

first-order degradation rate constant, is typically derived through regression analysis of viscosity measurements collected over time at each tested temperature (See **Figure 2.5** and **Figure 2.6**)

$$\frac{1}{\tau} = rrf \exp\left(\frac{-E_a}{RT}\right) \quad 2.14$$

Then the concept of half-life ($\tau_{1/2}$) is used to project polymer decay performance at a reference temperature ($\tau_{T_{ref}}$) .

$$\tau_{1/2} = \frac{\ln(2)}{r} = \tau_{T_{ref}} \times \ln(2) \quad 2.15$$

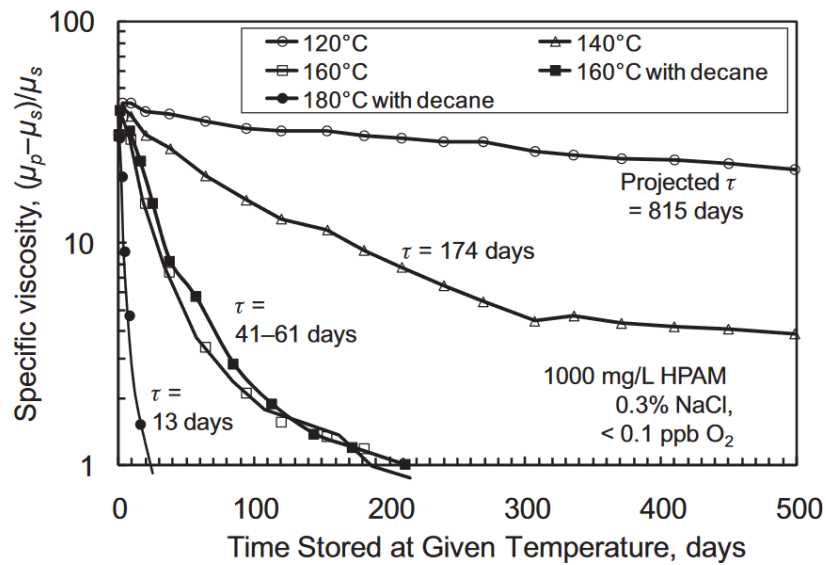


Figure 2.5. HPAM polymer instability demonstration through viscosity performance under various levels of temperatures exposure (Seright et al., 2010).

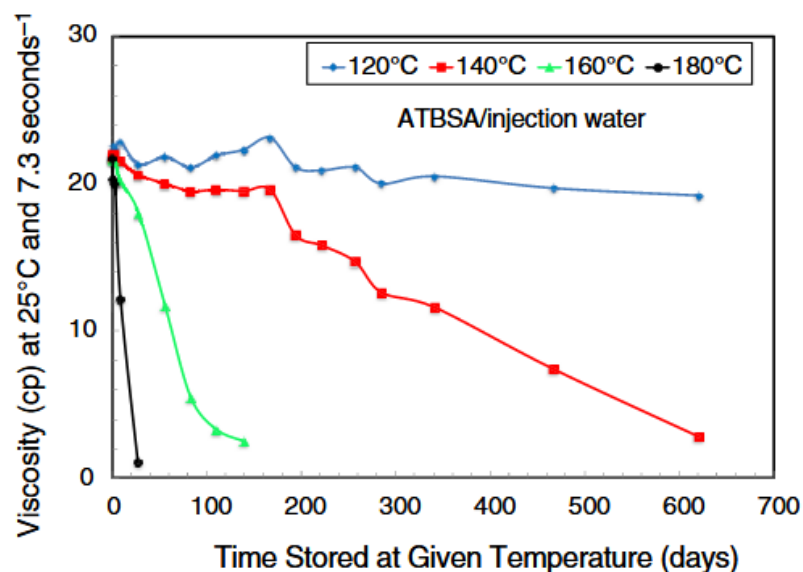


Figure 2.6. ATBSA polymer degradation demonstration through viscosity performance under various levels of temperatures exposure (Seright et al., 2021).

The literature records several definitions of half-life, commonly referring to the time it takes for the polymer to reach half of its original concentration or half of its initial viscosity. A common misconception is the assumption that thermal degradation viscosity reduction is proportional to concentration. The relationship between viscosity and concentration is not linear, assuming this can lead to inaccuracies in degradation modelling (Bordeaux Rego et al., 2017). Although Rego's model prioritizes concentration and Choi's et al. (2014) and Seright's et al (2021) focuses on viscosity, the difference in projected half-life between the interpreted approaches is minimal (see **Figure 2.7**). Therefore, in this work direct application of viscosity will be used in the Arrhenius analysis.

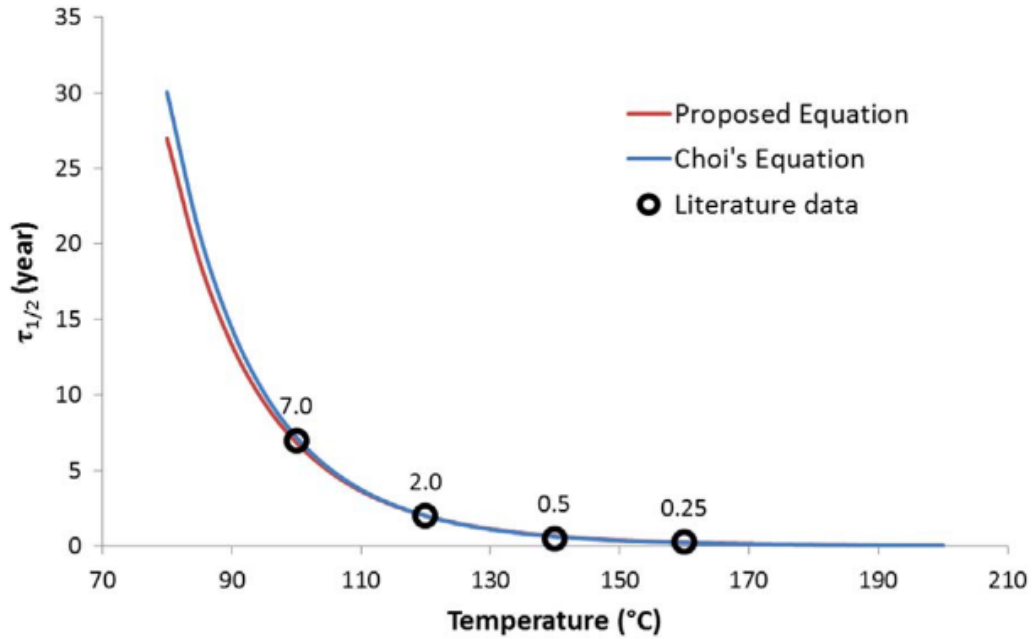


Figure 2.7. Polymer half-life estimation by Bordeaux Rego et al.(2017) proposed equation of half-life honouring nonlinearity between viscosity and concentration in red, Choi et al. (2014) equation in blue and literature data in black representing almost no major difference between the two approaches.

Seright et al. (2010, 2021) applied this kinetic approach to both HPAM and ATBSA polymers, enabling projections of polymer longevity in various reservoir scenarios.

Understanding thermal degradation kinetics is crucial for selecting appropriate polymers and designing flooding strategies in high-temperature environments. The advances in ATBS based polymers provide new opportunities to extend polymer flooding into conditions previously deemed too severe for traditional HPAM formulations.

2.3.2.2 *Other Significant Properties*

Polymer rheological and flow in porous media related properties—including non-Newtonian behaviour, mechanical entrapment, and inaccessible pore volume, permeability reduction are factors that are known to influence polymer flooding performance and reservoir behaviour. In the present study, however, such effects are intentionally excluded to focus specifically on evaluating the impact of thermal degradation on polymer stability and performance, without the added complexity of other interacting mechanisms.

2.3.2.2.1 Polymer Rheological Properties

The rheology of polymer solutions describes how their viscosity changes under applied shear stress and is a fundamental property in polymer flooding applications (Firozjahi and Saghafi, 2020). Unlike water, which behaves as a Newtonian fluid with constant viscosity regardless of shear rate, polymer solutions are non-Newtonian and exhibit viscosity that varies with shear conditions (Green and Willhite, 2018; Sorbie, 1991).

Polymers used in enhanced oil recovery predominantly display shear-thinning behaviour, where viscosity decreases as shear rate increases. This behaviour, often referred to as pseudoplasticity, is well documented in the polymer flooding literature (Green and Willhite, 2018; Sorbie, 1991). Other non-Newtonian behaviours, such as shear thickening, are less common and typically not observed in dilute polymer solutions relevant for EOR (Sorbie, 1991).

Polymer solutions typically exhibit shear-thinning behaviour over an intermediate range of shear rates; however, at very low or extremely high shear rates, they tend to behave as Newtonian fluids with constant viscosity. This pattern is illustrated in **Figure 2.8**, which shows a lower Newtonian region at low shear rates, a shear-thinning region where viscosity decreases with increasing shear, and an upper Newtonian region at high shear rates where viscosity again levels off (Green and Willhite, 2018).

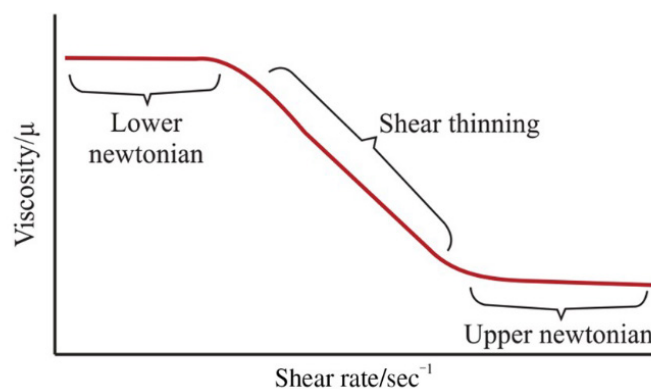


Figure 2.8. Rheology of a shear-thinning fluid. (Firozjahi and Saghafi, 2020; Green and Willhite, 2018).

2.3.2.2.2 Polymer Flow in Porous Media Physics

When polymers flow through porous media, several physical phenomena influence their transport and effectiveness in enhanced oil recovery (EOR) operations. A primary consideration is:

Polymer retention, which encompasses two mechanisms: adsorption and mechanical entrapment. Adsorption occurs when polymer molecules adhere to the surfaces of rock grains, reducing the amount of polymer available for displacement processes. Mechanical entrapment arises when polymer coils become physically trapped in pore throats smaller than the polymer's hydrodynamic size, preventing further propagation through the pore network (See **Figure 2.9**). Together, these processes lead to polymer loss and influence reservoir permeability (Green and Willhite, 2018).

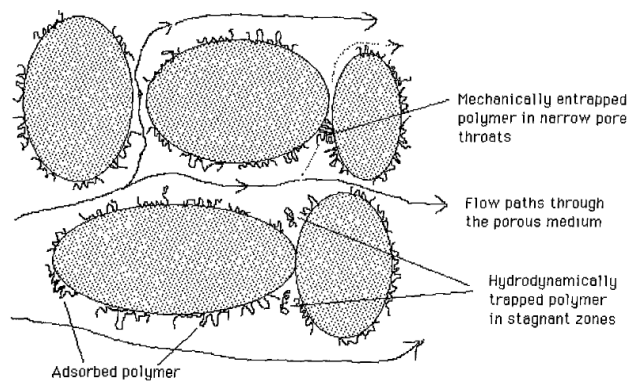


Figure 2.9. Diagram showing polymer retention in porous media (Sorbie, 1991).

An additional concept central to polymer transport is the inaccessible pore volume (IPV). IPV represents the fraction of pore volume that polymer molecules cannot enter due to size exclusion effects. Although water or small solutes can penetrate these narrow pore spaces, polymer molecules are sterically hindered, resulting in a smaller effective pore volume for polymer transport (Mahajan et al., 2021; Sorbie, 1991).

Moreover, polymer solutions can cause permeability reduction in porous media, particularly in the water phase. This occurs due to polymer adsorption layers or mechanical bridging that constrict flow paths, decreasing the effective permeability to water while leaving oil permeability less affected. This property, expressed as the residual resistance factor, is crucial for improving sweep efficiency during polymer flooding (Green and Willhite, 2018; Sorbie, 1991).

It is noteworthy that most polymer flooding applications historically targeted sandstone reservoirs because anionic polymers such as HPAM tend to adsorb significantly on carbonate surfaces, leading to higher retention and reduced efficiency in carbonate formations (Firozjahi and Saghafi, 2020). Recent developments, however, aim to improve polymer performance in carbonate reservoirs through advances in polymer chemistry and surface treatments (Diab and Al-Shalabi, 2019). Beteta et al. (2025) laboratory results have demonstrated lower adsorption levels for ATBS polymer in comparison to HPAM.

2.3.3 Types of Polymers Used in EOR applications

The type of polymer selected, its molecular architecture, and its rheological and stability properties under reservoir conditions are crucial in determining the feasibility and efficiency of polymer flooding operations. Among the various polymers considered for enhanced oil recovery, polyacrylamide in its partially hydrolysed form (HPAM) and the biopolymer xanthan gum have emerged as the most widely used. Their prominence in oilfield applications stems partly from their extensive utilization in other industries making them cheap and readily available in the quantities needed of oilfield applications (Sheng et al., 2015). HPAM has long been applied in processes such as paper manufacturing, drag reduction, and industrial water treatment as a flocculant. Xanthan gum, on the other hand, is well known as a thickening agent in the food industry and is classified as food additive E415 in the UK (Sorbie, 1991):

2.3.3.1 *Partially Hydrolysed Polyacrylamide (HPAM)*

HPAM remains the industry benchmark for polymer flooding because of its affordability, solubility in brine, and effectiveness in mobility control. However, it is susceptible to hydrolysis, precipitation, thermal and mechanical degradation in high-temperature, high-salinity, or high-divalent-cations environments, which limits its application in harsh carbonate reservoirs (Diab and Al-Shalabi, 2019; Green and Willhite, 2018; Seright et al., 2010; Seright and Wang, 2023; Sheng et al., 2015; Sorbie, 1991).

HPAM is synthesized through a two-step chemical process. First, the acrylamide monomers (AM) ($\text{CH}_2=\text{CH}-\text{CONH}_2$) undergoes free-radical polymerization, in which

the carbon-carbon double bonds (C=C) of individual acrylamide molecules open and connect to form a long polymer chain composed of repeating units of $-\text{CH}_2-\text{CH}(\text{CONH}_2)-$. This results in polyacrylamide (PAM), a water-soluble polymer consisting of a carbon-carbon backbone with pendant amide groups ($-\text{CONH}_2$) attached to every other carbon atom. In the second step, a portion of these amide groups along the polymer chain is chemically converted to carboxylate acid groups ($-\text{COOH}$) through a hydrolysis reaction under alkaline conditions or elevated temperature. The carboxylic acid groups can further dissociate or neutralize in water, forming carboxylate anions ($-\text{COO}^-$) and balancing sodium ions (Na^+) as demonstrated in **Figure 2.10** (Choi et al., 2014; Green and Willhite, 2018; Levitt and Pope, 2008; Ma et al., 2015; Sheng, 2011; Sorbie, 1991).

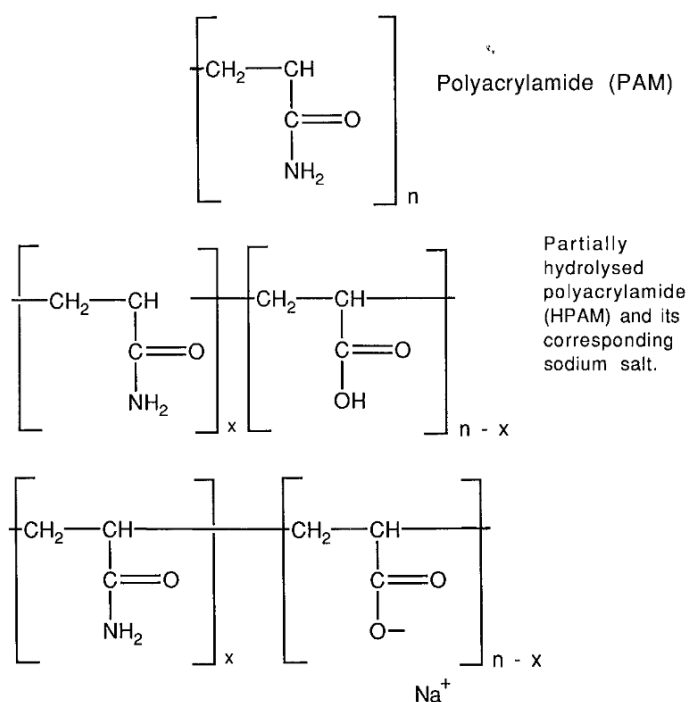


Figure 2.10. Polymer chemical structure of polyacrylamide (PAM) and partially hydrolysed polyacrylamide (HPAM) (Sorbie, 1991).

Typically, 10–30% of the amide groups are hydrolysed to carboxylate groups, introducing negative charges along the polymer chain. These charges create electrostatic repulsion between polymer segments, expanding the polymer coil in aqueous solution and significantly increasing the solution viscosity. This expanded coil structure and high molecular weight make HPAM highly effective at improving mobility control during enhanced oil recovery. However, at high salinity, the acrylate moieties on HPAM become strongly associated with dissolved cations, especially Na^+

and divalent ions like Ca^{2+} and Mg^{2+} . This ionic association shields the negative charges along the polymer backbone, leading the expanded coils to collapse into more compact structures. As shown schematically in **Figure 2.11**, HPAM adopts an extended configuration under low-salt conditions but coils tightly under high-salt conditions. Consequently, the polymer's solution viscosity decreases and approaches that of non-hydrolysed polyacrylamide, limiting its effectiveness under high-salinity reservoir conditions (Levitt and Pope, 2008; Sorbie, 1991).

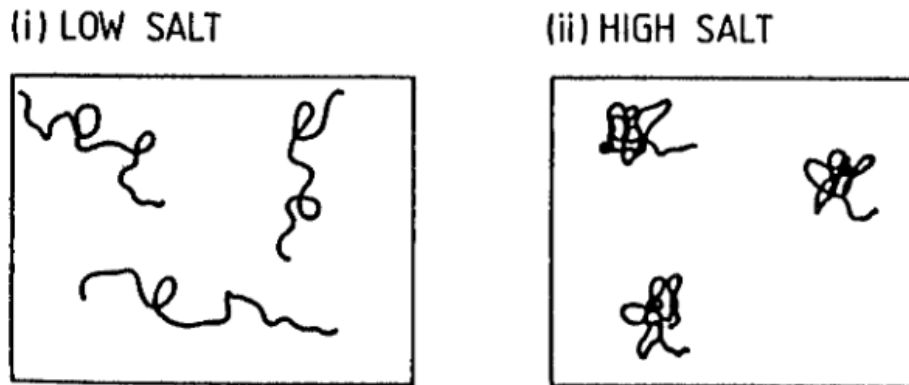


Figure 2.11. Demonstration of HPAM polymer in i) expanded polymer coils in low salinity solution and ii) collapsed polymer coils in high salinity (Sorbie, 1991).

The extent of hydrolysis plays a crucial role in determining key physical properties of HPAM, such as its adsorption behaviour, resistance to shear degradation, and stability under elevated temperatures. Although commercial polymers are manufactured and supplied with a specified degree of hydrolysis, further hydrolysis of the amide groups can continue when the polymer is exposed to high temperatures during reservoir conditions, gradually increasing the carboxylate content of the polymer backbone. Experimental data presented by Moradi-Araghi and Doe (1987), reproduced by Sorbie (1991), illustrate how hydrolysis continues as temperature increases, influencing the polymer's chemical characteristics and performance (see **Figure 2.12**). This ongoing hydrolysis can alter polymer solution properties and interactions with reservoir fluids and rocks, potentially affecting both viscosity and retention behaviour.

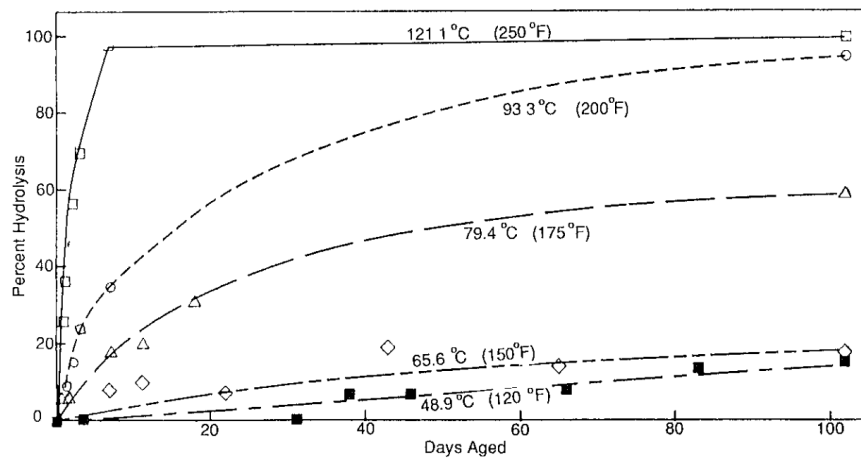


Figure 2.12. Temperature effect on polymer hydrolysis from Moradi-Araghi and Doe (1987).

Moreover, the same carbon-carbon backbone ($-\text{CH}_2-\text{CH}-$) that provides structural integrity in HPAM is also susceptible to chemical and thermal degradation, which can break the polymer chains, leading to viscosity loss under high-temperature reservoir conditions (Choi et al., 2014; Diab and Al-Shalabi, 2019; Green and Willhite, 2018; Levitt and Pope, 2008; Seright et al., 2010; Sorbie, 1991).

2.3.3.2 Biopolymers (e.g., Xanthan Gum)

Biopolymers such as xanthan gum exhibit excellent viscosity-building properties and strong resistance to shear degradation. Their inherent superiority in saline environments arises from their unique molecular architecture (see **Figure 2.13**) and relatively rigid chain structure, which makes them far less sensitive to salinity than synthetic polymers. While they tolerate high salinity well, biopolymers are generally more expensive and can be susceptible to biological degradation under certain reservoir conditions (Diab and Al-Shalabi, 2019; Green and Willhite, 2018; Sorbie, 1991). However, this thesis will not further explore biopolymers in detail, as they fall outside the scope of the polymer types selected for the present study.

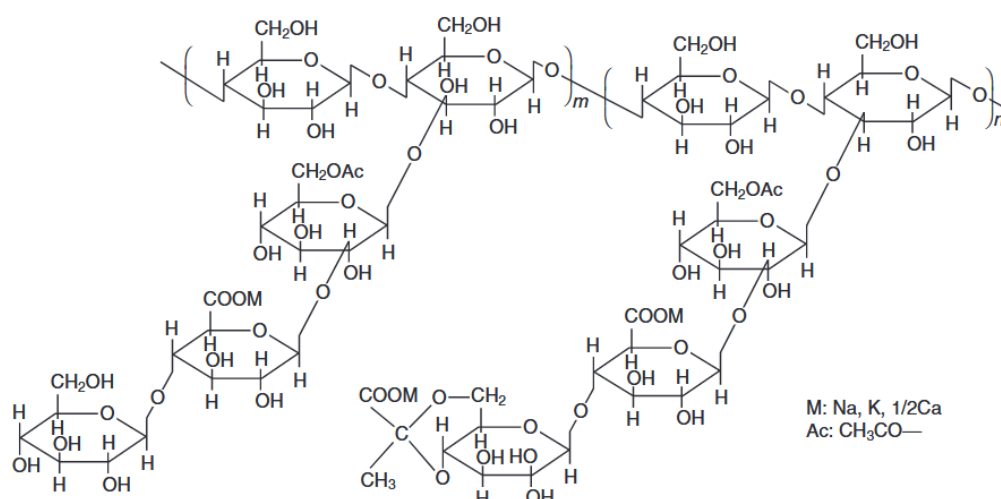


Figure 2.13. Chemical composition of Xanthan. (Sheng, 2011).

2.3.3.3 *Synthetic Copolymers with Functional Monomers*

Seright et al. (2010) demonstrated that HPAM can remain stable at temperatures up to 120 °C under controlled, oxygen-free conditions. However, its practical application in harsh carbonate reservoirs is still limited. This challenge arises due to the high salinity and hardness of reservoir fluids, which can lead to polymer precipitation, viscosity loss, and reduced effectiveness of HPAM under field conditions. To overcome these limitations, recent advances in polymer chemistry have focused on developing new polymer structures and copolymers specifically engineered for extreme reservoir environments. Diab and Al-Shalabi (2019) compiled a detailed overview of synthetic polymer monomers, each designed with specific functionalities to enhance performance under conditions of high temperature, salinity, and brine hardness. These innovations have significantly expanded the operational envelope for polymer flooding, enabling its application in reservoirs previously considered too harsh for conventional polymers (see **Table 2.1**).

Table 2.1. Main functions of different developed synthetic polymer monomers (Diab and Al-Shalabi, 2019).

Monomer	Chemical Name	Charge	Main Function
AM	Acrylamide	Nonionic	The main constituent of synthetic EOR polymers
PAM	Polyacrylamide	Nonionic	Hydrolyzed form of polyacrylamide
HPAM	Partially Hydrolyzed Polyacrylamide	Anionic	The partially hydrolyzed form of polyacrylamide
AA	Acrylic acid	Anionic	Limits hydrolysis and thermal degradation, also a product of AM hydrolysis
AMPS	2-Acrylamido-2-MethylPropane-Sulfonate	Anionic	Increases tolerance to salinity
ATBS	Acrylamide-Tertio-Butyl Sulfonate	Anionic	Limits hydrolysis and thermal degradation
NVP	N-Vinyl-Pyrrolidone	Nonionic	Limits hydrolysis and thermal degradation

Among the various advances described by Diab and Al-Shalabi (2019), particular attention has focused on acrylamide-tertiary-butyl sulfonic acid (ATBS) copolymers as a leading solution for high-temperature, high-salinity environments. Several authors demonstrated that increasing ATBS content in polymer structures significantly improves thermal stability, providing valuable guidance for polymer selection in harsh environment (Beteta et al., 2025; Dupuis et al., 2017; Gaillard et al., 2014; Masalmeh et al., 2019; Rodriguez et al., 2018; Sandengen et al., 2018; Seright et al., 2021).

Notably, Seright et al. (2021) reported that ATBS copolymers can achieve projected half-lives of up to 54 years at 99°C under oxygen-free conditions—performance far surpassing that of conventional HPAM. Such long-term stability positions ATBS-based polymers as strong candidates for giant carbonate reservoirs, where polymers must maintain viscosity and functionality over extended residence times in challenging chemical and thermal conditions.

2.3.3.4 *Acrylamide-Tertiary-Butyl Sulfonic Acid Copolymers (ATBS Copolymers)*

HPAM tolerance to high temperatures and salinity can be significantly enhanced by incorporating additional monomers, such as acrylamide-tertiary-butyl sulfonic acid (ATBS) (Gaillard et al., 2015; Sandengen et al., 2018). ATBS copolymers are specifically engineered to improve thermal and chemical stability, making them more

suitable for deployment in high-salinity and high-temperature reservoirs. Experimental work has demonstrated that ATBS-containing polymers maintain viscosity more effectively under elevated temperatures and salinity conditions (Sandengen et al., 2018). Moreover, Seright et al. (2021) reported projected half-lives of up to 54 years at 99 °C under oxygen-free conditions for ATBS copolymers with over 90% ATBS content, referred to as ATBSA, indicating substantial potential for long-term reservoir applications.

The superior in-reservoir solubility and stability of ATBS copolymers arise from two key chemical mechanisms. First, the ATBS units are structurally more resistant to hydrolysis than acrylamide units, conferring greater inherent thermal stability to the polymer backbone. Second, the sulfonate groups introduced by ATBS are strong acid anions that remain ionized even in high-salinity conditions, unlike the weaker carboxylate groups of acrylate units. This prevents ionic cross-linking and coil collapse, thereby helping to preserve polymer viscosity and avoid precipitation, even in harsh reservoir brines (Sandengen et al., 2017; Swiecinski et al., 2016).

Chemically, ATBS copolymers consist of repeating units of acrylamides, copolymerized with ATBS monomers that introduce a sulfonic acid pendant group (See **Figure 2.14**). Although ATBS has reflected superior stability performance, the specific mechanisms by which sulfonate functionality sustains polymer coil conformation under diverse reservoir conditions remain only partially explored in the current literature and warrant further investigation.

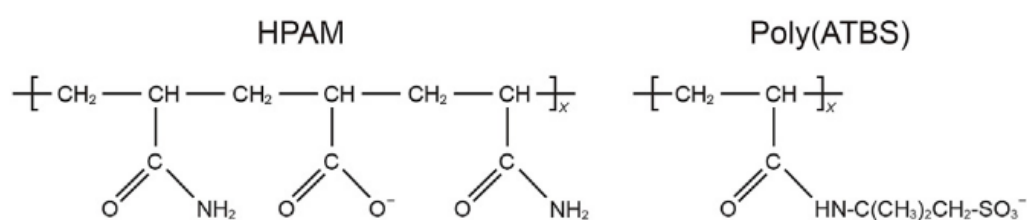


Figure 2.14. HPAM molecular structure versus Poly(ATBS) molecular structure. (Seright and Wang, 2023).

2.4 Optimization of Polymer Flooding

2.4.1 Slug Injection

Mixing polymer with the injected water introduces considerable extra costs, making injecting polymer continuously impractical. In real field applications polymer is injected as a slug followed by drive water (see **Figure 2.15**) (El-hoshoudy et al., 2017). Slug size is a critical design component that aims to provide optimum flood performance and maximum recovery while minimizing cost.

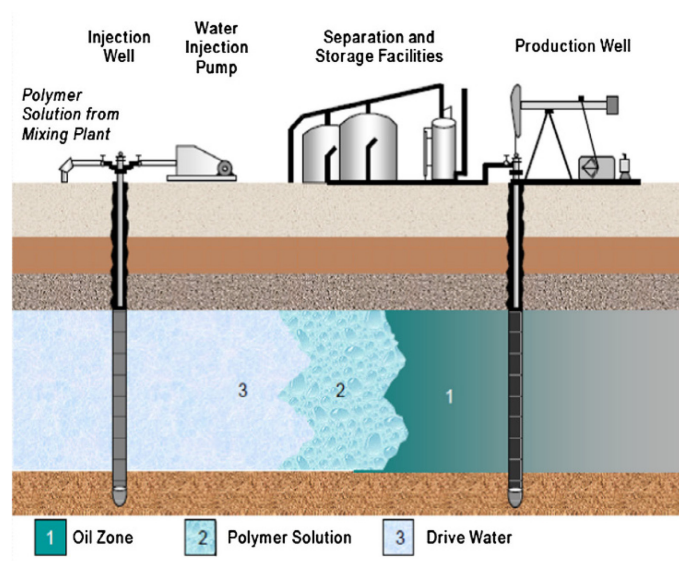


Figure 2.15. Demonstration of slug injection in a reservoir cross section (El-hoshoudy et al., 2017).

Reservoir heterogeneity plays a significant role in determining slug size. Analytical modelling and experiments suggest that heterogeneous reservoirs often require larger slugs, approaching 1 PV, to mitigate channelling effects when the chase water channels through the polymer bank, and ensure stable displacement (Wright et al., 1987). Smaller, high-viscosity slugs are more effective in uniform reservoirs (Wang and Caudle, 1970). Analytical solutions of slug injection accounting for viscous fingering indicate that slugs below 0.52 PV are insufficient due to viscous fingering of the chase water, while 0.52 PV is the minimum size needed to maintain slug integrity and improve recovery efficiency (Abdul Hamid and Muggeridge, 2018). It seems there are inconsistencies in slug volume design in practical field experience and literature findings.

Abdul Hamid and Muggeridge (2018) developed a semi-analytical framework that will be used in this research to optimize polymer slug size by incorporating the Todd and Longstaff mixing factor into the Buckley–Leverett formulation. Their work accounted for a wide range of wettability, mobility ratios, and mixing values to estimate the expected window of slug sizes for oil-wet heavy oil applications. Within this framework, the minimum polymer slug size is defined as the volume required to prevent destruction of the polymer bank by fingering before reaching the producer. The Todd and Longstaff model is used to capture the average effects of mixing and fingering, and the slug size can be expressed in terms of the dimensionless time t_D in the Buckley Leverett solution required to ensure that the leading edge of the polymer slug reaches the production well simultaneously with the trailing water finger.

$$\text{Slug Size } (t_D), \text{ in PV} = \frac{S_{w,polymer\ shock}}{f_{w,polymer\ shock}} \left(1 - \frac{1}{\left(\frac{\mu_p}{\mu_w} \right)^{(1-\omega)}} \right) \quad 2.16$$

where μ_p is the polymer viscosity in mPa.s, μ_w is the water viscosity in mPa.s, ω is the mixing factor, $S_{w,polymer\ shock}$ is the polymer shock front saturation and $f_{w,polymer\ shock}$ is the fractional flow at polymer shock front saturation.

2.5 Field Application Overview

Over roughly five decades of reported pilots and field deployments, polymer flooding has been dominated by HPAM and implemented mainly onshore and in sandstones. A comprehensive compilation by Standnes and Skjevrak (2014) documents that HPAM was used in ~92% of cases, with most projects in North America and a clear majority assessed as technically successful. This dataset remains the standard reference for field experience to date.

In contrast, large-scale applications in carbonate reservoirs are comparatively limited. Reviews consistently attribute this to harsh reservoir conditions high temperature, high salinity and brine hardness which accelerate chemical/thermal degradation and complicate injectivity and near-wellbore performance. These constraints have historically limited polymer applications in carbonates relative to sandstones (Seright and Wang, 2023; Shakeel et al., 2020). Recent work focused on Middle Eastern settings reaches the same conclusion, emphasizing the practical

challenges of polymer flooding in high-temperature, high-salinity carbonate systems (Sebastian et al., 2024).

Accordingly, field activity with sulfonated acrylamide copolymers (ATBS-based systems) in carbonates has so far centred on qualification and injectivity pilots rather than full-field deployments. The pilots were summarized earlier in the introduction chapter of the thesis. On that note, this thesis builds directly on that field record: we evaluate an ATBS-based polymer (ATBSA) under field representative carbonate conditions and large injector–producer spacing, addressing the key gap left by the predominance of HPAM in prior practice and the scarcity of documented, full-scale carbonate deployments.

2.6 Summary

In this chapter we set the analytical and physical basis for the rest of the thesis. We define recovery as the product of displacement and sweep (Eq. 2.1) and use Buckley–Leverett theory to show how mobility ratio and gravity shape the fractional flow function and front behaviour (Eqs. 2.5–2.10). We then extend the framework to polymer flooding, following Pope’s formulation for secondary injection with two shocks, to explain how mobility control can raise the shock front saturation and accelerate oil production without necessarily altering residual oil saturation. We summarise solution and transport properties that govern polymer performance in porous media and focus the discussion on thermal degradation modelled with first order Arrhenius kinetics (Eqs. 2.12–2.15) because high temperature is the dominant field constraint in the target carbonate reservoirs. Finally, we outline practical design elements (e.g., slug injection) and the semi-analytical slug size guidance of Abdul Hamid & Muggeridge (Eq. 2.16) that we will use as a screening tool before full physics simulation. This foundation helps us assess what truly controls performance in the high-temperature, large-spacing carbonate settings of interest and highlights several specific gaps that the thesis addresses:

- a) Quantifying displacement as well as sweep. Much recent literature attributes polymer gains mainly to sweep, often equating “displacement improvement” with a reduction in S_{or} . Here we adopt the broader, classical definition (Eq. 2.4) and show analytically how polymer mobility control and gravity can improve local displacement even when S_{or} is unchanged. Chapters 5 and 6

therefore measure both displacement and sweep explicitly and relate them to the fractional flow physics.

- b) Role of gravity in waterfloods and polymer floods under realistic wettability. Conventional interpretations often treat gravity as detrimental because of poorer sweep. Our analysis (Eqs. 2.6–2.10) shows that gravity also modifies local displacement. We test this rigorously: Chapter 5 isolates gravity in waterfloods across wettability and mobility conditions; Chapter 4 and Chapter 6 examine how gravity interacts with polymer stability and residence time in 3D sectors and field scale patterns.
- c) Thermal degradation over field scale residence times. First order Arrhenius kinetics provide a tractable model, but the impact of long exposure distances (kilometres between injector and producer) on recovery has not been well quantified. Chapters 4 and 6 connect degradation kinetics to performance by using exposure time/distance as a screening baseline and by testing polymers at 1–5 km spacing typical of peripheral line drives.
- d) Slug-size design under mixing and heterogeneity. Published field practice and theory are not always consistent on “optimal” slug volumes. We use the semi-analytical model of Abdul Hamid & Muggeridge (Eq. 2.16) to generate a most-probable window for oil-wet and mixed-wet systems, then validate it numerically in heterogeneous 3D media (Chapters 4 and 6).
- e) Polymer selection for harsh carbonate conditions. Field applications are dominated by HPAM, while carbonate deployments remain limited; ATBS-based polymers show strong laboratory stability but scarce field-scale evidence. Chapter 4 uses DOE to identify when thermal stability is decisive; Chapter 6 provides a field-representative evaluation of ATBSA under peripheral line-drive geometries and large well spacing and formulates a practical selection and deployment guide.

Together, Chapter 2 establishes the equations, mechanisms, and modelling choices we use to answer the central questions of the thesis: how thermal degradation and gravity jointly influence recovery, what slug sizes are defensible in heterogeneous media, and whether ATBS-based polymers can sustain performance under giant-field conditions.

Chapter 3

Numerical Modelling and Validation of Polymer Flooding in 1D, 2D and a Field Case

3.1 Introduction

In this chapter, we present the development and validation of numerical models used to investigate polymer flooding performance in one-dimensional, two-dimensional, and field-scale systems. The simulations were carried out using the CMG STARS thermal–chemical reservoir simulator. The choice of this simulator is driven by its capability to model polymer thermal degradation through a first-order thermal reaction model, where viscosity reduction is directly linked to polymer concentration decay over time and temperature. This functionality enables a realistic representation of stability differences between polymer types such as HPAM and ATBSA under reservoir-specific thermal conditions.

We begin by initializing the models with the required rock and fluid properties, relative permeability relationships, and polymer parameters, along with the assumptions applied in each case. The numerical results are then validated against analytical solutions from Buckley and Leverett (1942) and Pope (1980) polymer flooding model to ensure the correct representation of displacement behaviour.

A grid refinement study is carried out in both one-dimensional and two-dimensional models to identify an optimal cell resolution that achieves a balance between accuracy and computational efficiency. The study also includes an analytical demonstration of

the improvement in displacement efficiency resulting from mobility control and gravity effects.

Polymer flooding performance is benchmarked against waterflooding, first by assuming no thermal degradation and then by introducing degradation for HPAM and ATBSA polymers. In two-dimensional models, a preliminary sensitivity analysis evaluates the influence of gravity on polymer performance under thermal degradation.

Finally, we establish a permeability scaling workflow for an opensource field-scale heterogeneous reservoir model (COSTA Model) (Costa Gomes et al., 2022), to represent the characteristics of large carbonate reservoirs with wide well spacing from the Middle East. This model serves as the basis for scaling the insights gained from smaller-scale studies to realistic reservoir development cases.

3.2 Numerical Modelling of Polymer Flooding

To model polymer flooding including thermal degradation we use CMG STARS a three-phase, adaptive implicit and multi-component thermal simulator. The reason of use of this simulator is the availability of the first order thermal reaction model that can simulate thermal degradation.

3.2.1 Polymer Flooding Including Thermal degradation

3.2.1.1 *Polymer Transport Equation*

Only the water-phase mass balance equation is modified for polymer flooding, as polymer is transported exclusively in the aqueous phase, while oil and gas phase equations remain unchanged (Alshawaf, 2018). To capture chemical stability under high-temperature conditions, CMG STARS incorporates temperature-dependent polymer degradation by adding a reaction term to the transport equation. This approach allows simulation of irreversible viscosity loss due to hydrolysis or chain scission at elevated temperatures.

$$\phi S_w \frac{\partial C_p}{\partial t} + \frac{(1 - \phi) \rho_r}{\rho_w} \left(\frac{\partial C_{ads}}{\partial t} \right) + u_w \cdot \nabla C_p = \nabla \cdot (D \cdot \nabla C_p) + S_w R(C_p; T) \quad 3.1$$

where ϕ is porosity, S_w is water saturation, ρ_r is the rock density, ρ_w is the water density, C_p is polymer concentration in the water phase, and C_{ads} is the adsorbed polymer concentration on the rock surface (mass polymer/mass rock). The first two terms on the left-hand side represent storage, capturing polymer present in the mobile water phase and polymer adsorbed on the solid matrix. The third term describes advection, where u_w is the Darcy velocity of the water phase:

$$u_w = -\frac{Kk_{rw}(S_w)}{\mu_w^{eff}(C_p)}(\nabla P_w - \rho_w g \nabla z) \quad 3.2$$

where K is the absolute permeability, $k_{rw}(S_w)$ is the relative permeability to water, $\mu_w^{eff}(C_p)$ is the effective water viscosity for the water/polymer mixture, ∇P_w is the water pressure gradient, $\rho_w g \nabla z$ is the gravity term. The fourth term in (Eq. 3.1) accounts for molecular diffusion and mechanical dispersion, where D is the dispersion/diffusion coefficient. The final term, $S_w R(C_p; T)$ represents polymer loss due to thermal degradation, where $R(C_p; T)$ is the first-order reaction described in chapter 2 (Eq. 2.12). This final term CMG STARS to capture irreversible viscosity loss at elevated temperatures, a key factor in polymer flooding design for high-temperature carbonate reservoirs.

3.2.1.2 Polymer Viscosity model

CMG STARS use the Flory Huggins viscosity model described in chapter 2 (Eq. 2.11) to determine the relationship between polymer initial viscosity and concentration by third order fitting on the viscosity and concentration experimental data. A new fitting constant ξ is created by regrouping the original Flory Huggins model.

$$\xi = \mu_w A_p C_{SEP}^{S_p} \quad 3.3$$

$$\mu_p = \mu_w + \xi_1 C_p + \xi_2 C_p^2 + \xi_3 C_p^3 \quad 3.4$$

The viscosity mixing function in CMG STARS employs a non-linear formulation, consistent with the viscosity-concentration relationship proposed by Flory-Huggins theory.

The polymer viscosity is interpreted as a water/polymer mixture viscosity expressed as:

$$\mu_p(C_p) = \mu_{p,max}^f (\mu_w)^{1-f} \quad 3.5$$

where $f(x_p)$ represent the polymer solution non-linear viscosity mixing function, defined as:

$$f(C_p) = \frac{\ln(\mu_p) - \ln(\mu_w)}{\ln(\mu_{p,max}) - \ln(\mu_w)} \quad 3.6$$

where μ_p is polymer viscosity at concentration C_p , $\mu_{p,max}$ is the polymer viscosity at maximum polymer concentration. This concentration-based mixing function is particularly important for simulating thermal degradation, as it accounts for the reduction in polymer concentration caused by polymer chain breakage and its conversion to water.

3.2.1.3 Thermal Degradation Model

CMG STARS adopts the concept of first order reaction that defines the polymer degradation as the exponential drop of polymer concentration in which chains of broken polymer transforms to water to achieve material balance (Bordeaux Rego et al., 2017; Choi et al., 2014; Clifford and Sorbie, 1985). The polymer thermal degradation is defined in the reaction rate function described in chapter 2 (Eq. 2.12). The reaction rate is linked to temperature using the Arrhenius equation described in chapter 2 (Eq. 2.13).

3.2.1.4 Polymer Mixing Model

Todd and Longstaff developed a semi-empirical mixing model for miscible displacement to characterize dispersion at the trailing-edge. This model incorporates a mixing factor to represent viscous fingering and dispersion in coarse grid simulations,

focusing primarily on the miscible displacement of gas into oil. In first-contact miscible displacement with an adverse viscosity ratio, complete mixing results in the formation of a dispersion zone between the displacing and displaced fluids, leading to a stable displacement. Conversely, with no mixing, the displacing fluid fingers through the displaced fluid, causing severe viscous fingering due to the unfavourable mobility ratio (Todd and Longstaff, 1972).

The same model was adapted for polymer flooding to describe the mixing of water into polymer at the trailing edge of a polymer slug (Bondor et al., 1972). The effective viscosities in the polymer-water system are defined as:

$$\mu_{p,eff} = \mu_p^{1-\omega} \mu_m^\omega \quad 3.7$$

$$\mu_{w,eff} = \mu_w^{1-\omega} \mu_m^\omega \quad 3.8$$

where μ_p is the polymer viscosity, μ_w is the water viscosity, μ_m is the viscosity of polymer-water mixture and ω is the mixing factor.

When $\omega = 1$, complete mixing occurs, implying that the dispersion zone extends beyond the grid block, and the viscosity is represented by μ_m . For $0 < \omega < 1$, the dispersion zone is smaller than the grid block, and an adjusted effective viscosity is calculated. If $\omega = 0$, no mixing is assumed, and the viscosities of the pure components are used.

In CMG STARS, however, the simulator does not differentiate between the mixing of injected water and polymer at the trailing edge of the slug and the polymer/connate water mixing at the leading edge. This limitation means that only one mixing factor can be applied to both sides of the polymer slug. Mixing at the leading edge is physically unrealistic and may lead to artificial numerical smearing of the polymer front, even when the mobility ratio is favourable (Aldhuwaihi, 2016; Alshawaf, 2018). Aldhuwaihi's work highlights that adsorption can sharpen the front and minimize dispersion at the polymer slug's leading edge, as polymer mixed with water is rapidly adsorbed. In this study, since no adsorption is assumed for thermal degradation analysis, the mixing effect at the leading edge might underestimate polymer performance.

As a guideline, for displacements with adverse mobility ratios $M_{wp} = \mu_p/\mu_w > 1$, complete mixing $\omega = 1$ yields the best recovery. For favourable mobility ratios with polymer displacing oil $M_{po} = \mu_o/\mu_p = 1$, no mixing $\omega = 0$ provides optimal recovery.

Complete mixing enhances displacement at the trailing edge of the polymer slug, but at the leading edge, it may result in unrealistic fingering due to reduced dispersion zone viscosity (see **Figure 3.1b**). No mixing at the trailing edge leads to severe fingering of water into the polymer slug and maintaining a sharp front at the leading edge (see **Figure 3.1c**). The ideal scenario employs physically realistic mixing factors: high mixing at the miscible, adverse mobility ratio trailing edge and no mixing at the immiscible, uniform mobility ratio leading edge (see **Figure 3.1a**).

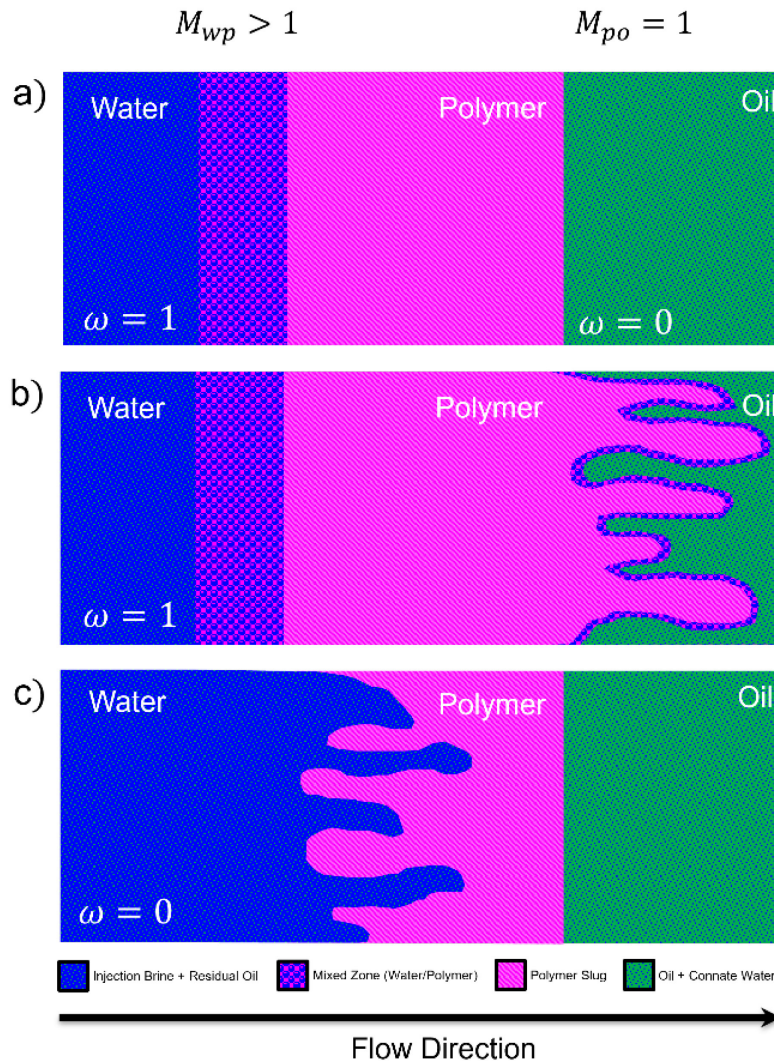


Figure 3.1. Representation of mixing behaviour at the trailing and leading edges of a polymer slug during polymer flooding, illustrating the impact of the mixing factor ω . (a) Complete mixing $\omega = 1$ at the trailing edge creates a dispersion zone between water and polymer, leading to stable displacement. At the leading edge $\omega = 0$, no mixing occurs, maintaining a sharp interface between polymer and oil. (b) Uniform mixing at both edges $\omega = 1$, results in unrealistic polymer front smearing due to reduced dispersion zone viscosity. (c) No mixing at both edges $\omega = 0$, leads to severe fingering of water into the polymer slug and a sharp polymer front. The ideal scenario applies complete mixing at the trailing edge and no mixing at the leading edge for physically realistic modelling.

CMG STARS use polymer effective permeability $\mu_{p,eff}$ in the polymer flow equations (Eq. 3.1) and use the incompletely mixed water phase viscosity μ_{wim} in all other flow equations, defined as:

$$\frac{1}{\mu_{wim}} = \frac{\alpha}{\mu_{p,eff}} + \frac{1 - \alpha}{\mu_{weff}} \quad 3.9$$

where α is the effective concentration ratio of the polymer solution, defined as:

$$\alpha = \frac{C_p}{C_{p,max}} \quad 3.10$$

where C_p is the cell polymer concentration and $C_{p,max}$ is the polymer concentration at maximum initial viscosity. In this chapter we will assume no mixing $\omega = 0$ and continuous polymer injection for validation purposes.

3.3 One Dimensional (1D) Model and Validation

The 1D polymer flooding model represents a simplified analogue of reservoirs with large well spacing, approximately 1.25 km between injectors and producers. This configuration serves as the baseline for subsequent studies that will incorporate field-scale heterogeneity typical of giant carbonate reservoirs. Since polymer thermal degradation is highly sensitive to exposure time at elevated temperatures, we believe large well spacing will impose a stability challenge on polymer performance. The model is designed to be homogeneous to allow isolation of fundamental displacement behaviour and ensures a controlled environment for validation.

The section defines the model dimensions and rock–fluid properties, specifies the relative permeabilities of real oil-wet carbonate reservoirs of the Middle East, and details the polymer properties input in CMG STARS. The model is validated against the analytical Buckley–Leverett solution to confirm the correct implementation of polymer transport and viscosity–concentration relationships. Grid-refinement sensitivity is then assessed to determine the resolution needed to minimise numerical dispersion while maintaining computational efficiency. Finally, preliminary polymer flooding results are presented to establish a performance benchmark for comparison with more complex heterogeneous reservoir cases in later sections.

3.3.1 Model Initialization

3.3.1.1 Model Size and Properties

The base 1D model was designed as a simplified representation of a large well-spacing reservoir with an injector–producer separation of approximately 1.25 km and thin reservoir layer of 10 meters. The model dimensions and properties were selected to provide a consistent baseline for validation against analytical solutions, while representing conditions relevant to large-scale carbonate reservoirs in the Middle East. The reservoir is assumed to be homogeneous, with constant porosity and permeability, to isolate the influence of polymer mobility control and thermal degradation effects from geological complexity. The oil phase represents a heavy oil system (19° API gravity) corresponding to 10 mPa.s at 100°C estimated from the viscosity-temperature API based empirical correlation by Hashim and Hassaballah (2003), to achieve a favourable mobility ratio in line with the relative permeability characteristics described earlier. This low API gravity correlates to a high viscosity of 860 mPa.s at standard conditions consistent with heavy oil classification. The main parameters of the 1D simulation model are summarised in **Table 3.1**, including fluid and rock properties, operational rates, and the Todd–Longstaff mixing parameter, which is set to zero for no mixing conditions in the validation runs.

Table 3.1. 1D simulation models base data.

Parameter	Unit	1D Model (1.25 km)
Model length, l	m	1250
Model width, w	m	1250
Model thickness, h	m	10
Porosity, ϕ	%	20
Permeability, k	mD	500
Residual oil saturation, S_{or}		0.2
Irreducible water saturation, S_{wi}		0.1
Oil viscosity, μ_o	mPa.s	10 (Heavy Oil)
Water viscosity, μ_w	mPa.s	0.41
Polymer solution viscosity, μ_p	mPa.s	10
Oil density, ρ_o	kg/m ³	881
Water density, ρ_w	kg/m ³	1093
Injection and production rate	m ³ /day	300
Reservoir temperature	°C	100
Yearly depletion rate	%OIP/year	3.8
Number of producers		1
Number of injectors		1
Todd-Longstaff mixing, ω		0

We limited the well constraints to a maximum bottom hole flowing pressure (BHFP) of 41368 kPa (fracture pressure), and minimum BHFP of 2000 kPa (bubble point pressure) and ensured they were avoided in studied simulations.

3.3.1.2 Relative Permeability

Relative permeability is a key parameter in determining the mobility ratio and, therefore, the effectiveness of polymer flooding. Its influence extends to selecting the appropriate polymer viscosity to maximise performance under specific reservoir conditions. Seright et al. (2018) demonstrated that in experiments with a rock exhibiting unusually low water relative permeability even a moderate polymer viscosity was sufficient to achieve a near-favourable mobility ratio for a very high oil viscosity reservoir. This highlights the significance of accurately characterising relative permeability when designing polymer flooding projects. Selecting a polymer viscosity without accounting for end point water relative permeability $(k_{rw})_{S_{orw}}$ may result in either under-design, failing to achieve mobility control, or over-design, adding unnecessary cost without recovery benefit.

For this study, an extremely oil-wet case was used based on relative permeability measurements from Middle Eastern carbonate rocks (Dakshinamurthy et al., 2014) (See **Figure 3.2**). We used Corey correlations from Ahmed (2010) to identify the fitting exponents on the measured data to be used to construct the Buckley–Leverett analytical solution for model validation.

$$k_{ro} = (k_{ro})_{S_{wc}} \left[\frac{1 - S_w - S_{orw}}{1 - S_{wc} - S_{orw}} \right]^{n_o} \quad 3.11$$

$$k_{rw} = (k_{rw})_{S_{orw}} \left[\frac{S_w - S_{wc}}{1 - S_{wc} - S_{orw}} \right]^{n_w} \quad 3.12$$

Table 3.2. Relative permeability experimental data fitting parameters using Corey correlations.

Parameter	Value
Water Corey exponent, n_w	1.5
Oil Corey exponent, n_o	5
Residual oil saturation, S_{orw}	0.2
Connate water saturation, S_{wc}	0.1
End point oil relative permeability, $(k_{ro})_{S_{wc}}$	1
End point oil relative permeability, $(k_{rw})_{S_{orw}}$	0.6

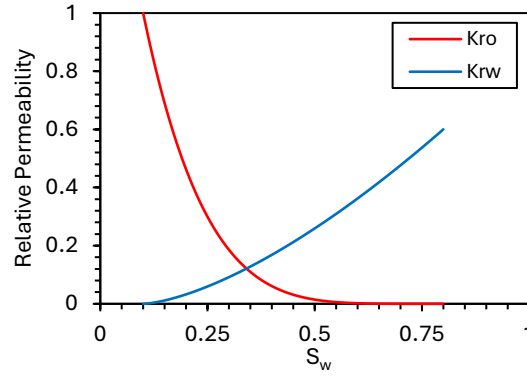


Figure 3.2. Oil-wet relative permeabilities measured on a carbonate rock from the Middle East (Dakshinamurthy et al., 2014).

3.3.1.3 Polymer Model

This section describes the setup of the polymer model in CMG STARS, including viscosity fitting, concentration conversion, non-linear mixing, thermal degradation kinetics, and the treatment of polymer molecular weight. The objective is to ensure that the simulator reproduces the intended polymer rheology and degradation behaviour while maintaining mass and volume consistency.

Viscosity and Concentration Relationship are set using experimental viscosity data from Choi et al. (2014) which were used as the basis for calibration (see **Table 3.3**). Reported polymer concentrations in ppm are converted to weight percent for direct input into CMG STARS. The experimental data is fitted with the simplified third-order Flory–Huggins model (Eq. 3.5), which captures the non-linear viscosity–concentration relationship (See **Figure 3.3**). The fitted curve is then used to generate the viscosity–concentration table (See **Table 3.4**). This table specifies polymer viscosity in terms of mole fraction, mole density, and mass fraction, ensuring that the solution viscosity reaches 10 mPa.s at ~636 ppm.

Table 3.3. HPAM polymer viscosity experimental data at different concentrations from Choi et al. (2014).

Polymer concentration C_p (ppm)	Polymer Concentration C_p (kg/m ³)	Polymer concentration C_p (wt)	Polymer concentration C_p (%wt)	Polymer Viscosity μ_p (mPa.s)
0	0.00	0.000000	0.000000	0.41
300	0.30	0.000275	0.027454	4
500	0.50	0.000458	0.045757	8
1000	1.00	0.000915	0.091515	21
1500	1.50	0.001373	0.137272	55
2000	2.00	0.001830	0.183030	108

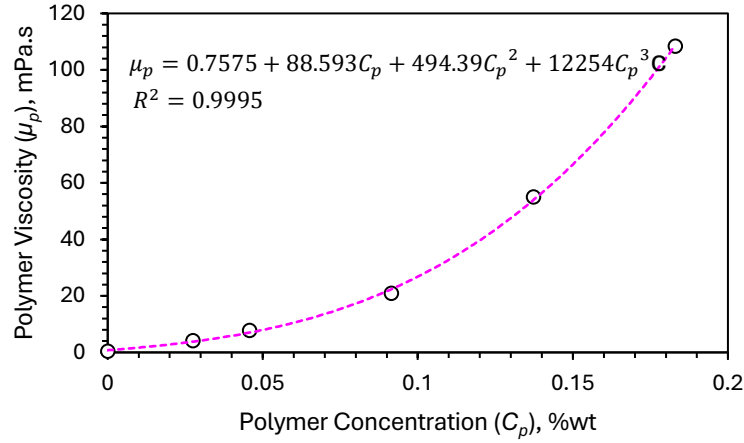


Figure 3.3. Flory Huggins third order fitting of the viscosity vs concentration experimental data from Choi's.

Table 3.4. Polymer viscosity table generated from Flory Huggins model in **Figure 3.3**.

Polymer Concentration C_p (ppm)	Polymer Molar Fraction (wt)	Polymer Mole Density ρ_p^{mole} (gmole/m ³)	Polymer Mass Fraction (wt)	Polymer Mass wt%	Polymer Viscosity μ_p (mPa.s)
0	0	0	0	0.0000	0.41
64	1.309×10^{-7}	0.0079	5.819×10^{-5}	0.0058	1.12
127	2.618×10^{-7}	0.0159	1.164×10^{-4}	0.0116	1.82
191	3.928×10^{-7}	0.0238	1.746×10^{-4}	0.0175	2.52
254	5.237×10^{-7}	0.0318	2.327×10^{-4}	0.0233	3.26
318	6.546×10^{-7}	0.0397	2.909×10^{-4}	0.0291	4.06
381	7.855×10^{-7}	0.0477	3.491×10^{-4}	0.0349	5.00
445	9.164×10^{-7}	0.0556	4.073×10^{-4}	0.0407	5.97
509	1.047×10^{-6}	0.0636	4.655×10^{-4}	0.0465	7.13
572	1.178×10^{-6}	0.0715	5.237×10^{-4}	0.0524	8.46
636	1.309×10^{-6}	0.0795	5.819×10^{-4}	0.0582	10.0

Polymer solution non-linear viscosity mixing function, $fN(x_p)$, is constructed from the fitted data (Table 3.5). This function normalises viscosity against polymer mass fraction and provides CMG STARS with the non-linear interpolation required across the concentration range.

Table 3.5. Polymer solution non-linear viscosity mixing function $fN(x_p)$.

C_p wt%	μ_p (mPa.s)	$\ln(\mu_p)$ (mPa.s)	x_p wt	$fN(x_p)$
0.0000	0.41	-0.90	0	0.000
0.0058	1.12	0.12	5.819×10^{-5}	0.317
0.0116	1.82	0.60	1.164×10^{-4}	0.468
0.0175	2.52	0.93	1.746×10^{-4}	0.570
0.0233	3.26	1.18	2.327×10^{-4}	0.650
0.0291	4.06	1.40	2.909×10^{-4}	0.719
0.0349	5.00	1.61	3.491×10^{-4}	0.784
0.0407	5.97	1.79	4.073×10^{-4}	0.839
0.0465	7.13	1.96	4.655×10^{-4}	0.894
0.0524	8.46	2.14	5.237×10^{-4}	0.948
0.0582	10.0	2.30	5.819×10^{-4}	1.000

Thermal degradation kinetics are incorporate using experimental decay constant data from Seright et al. (2010 & 2021) work in **Table 3.6** for HPAM and ATBSA to determine the activation energy (E_a) and frequency factor (rrf) in Table 2, essential for simulating polymer degradation in CMG STARS.

Table 3.6. Decay constant (τ) experimental data for ATBSA and HPAM at multiple temperatures and half-life projections at 99°C.

Polymer	120°C τ (days)	140°C τ (days)	160°C τ (days)	160°C with oil τ (days)	180°C τ (days)	Projected Half-life at 99°C (years)
ATBSA	2691	266	50	-	5	54.8
HPAM	472	445	155	193	71	3.7

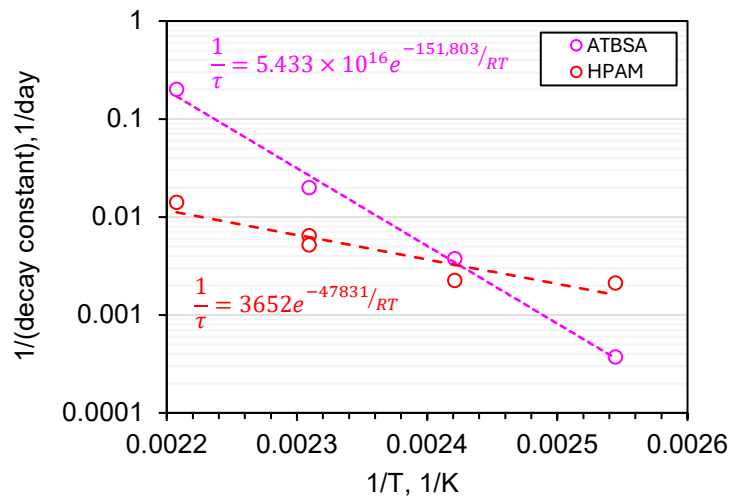
**Figure 3.4.** Arrhenius plots for HPAM and ATBSA from Seright's experimental data in **Table 3.6**.

Table 3.7. Activation energy and frequency factor coefficients from Arrhenius plot analysis for ATBSA and HPAM.

Polymer	Activation Energy (E_a)	Frequency Factor (rrf)
ATBSA	151,803	5.433×10^{16}
HPAM	47,831	3,652

Seright et al. (2021) half-life projections for ATBSA, ATBSB, and ATBST highlighted the sensitivity of polymer stability to solution salinity and hardness. Their study evaluated stability across low-salinity smart water injection (6,900 ppm), saline water injection (69,000 ppm), and connate water salinity (240,000 ppm). In this work, we use ATBSA tested with injected water at 69,000 ppm, assuming no diffusion between the injected and connate water. While diffusion of the injected polymer solution into high-salinity connate water could impact thermal stability, this factor is beyond the current scope and may warrant consideration in future studies.

Reaction Mass and Volume Conservation STARS thermal degradation reaction uses mole units and treat the reaction as a source and a sink. For material balance purposes the first order degradation reaction will convert degraded molecules into water to simplify the process (Bordeaux Rego et al., 2017). Mass balance was achieved by balancing the reaction stoichiometry (See **Table 3.9** and **Table 3.10**). One mole of polymer will produce $1.65 \times 10^5 \frac{m^3}{gmole}$ of water to achieve mass balance. To ensure volume balance from the reaction conversion of polymer to water, we made an adjustment on the polymer density to match the water density of 1092 kg/m^3 . This assumption will ensure that the volume of produced water by the reaction is matching the volume of degraded polymer.

This approach is considered as a key limitation of modelling thermal degradation with a first-order reaction based on polymer concentration—where concentration loss is converted directly to water—is that it may underestimate adsorption effects. It is argued that this approach does not accurately reflect the process, as polymer concentration should ideally remain constant while properties such as molecular weight and viscosity degrades (Druetta and Picchioni, 2019; X. Lu et al., 2015). Preserving polymer mass concentration would result in a more accurate representation of adsorption. In this work adsorption is ignored so the approach is valid; however, for

actual field implementation studies involving adsorption and preserving polymer mass concentration should be considered.

Polymer Molecular Weight The treatment of polymer molecular weight in CMG STARS requires careful consideration. Polymers such as HPAM typically have molecular weights in the range of 8,000–20,000 kg/gmol (Moshtaghi et al., 2023; Yang et al., 2024), while ATBS-based copolymers are generally lower, often around 8,000 kg/gmol (Ahmed et al., 2023). These values are several orders of magnitude higher than the numerical limits tolerated by the simulator. Using such realistic molecular weights directly in STARS produces mole fractions that fall below solver tolerances, causing severe numerical instability.

To address this, CMG strongly recommends assigning molecular weights below 10 kg/gmol (CMG, 2022). This value is not physical, but a numerical scaling factor designed to keep polymer mole fractions within stable limits for the solver. In this work, the simulator default of 8 kg/gmol is used for both HPAM and ATBS (See **Table 3.8**). Sensitivity test on a higher molecular weight of 500 kg/gmole confirm that consistent scaling of the reaction stoichiometric coefficients will ensure a recovery performance that is not impacted by molecular weight (See **Figure A.9**).

The reason is that STARS tracks polymer in mole units but enforces material balance through reaction stoichiometry. One “pseudo-mole” of polymer degrades into the correct equivalent volume of water, preserving mass and volume balance regardless of the absolute molecular weight assigned. This means the chosen molecular weight does not influence polymer viscosity, transport, or degradation behaviour. Lowering it simply avoids convergence issues while ensuring physical consistency.

This numerical strategy is therefore a practical requirement rather than a limitation. By applying the default 8 kg/gmol, the model achieves stable simulations of polymer flooding and thermal degradation while maintaining fidelity to the physical processes observed in real HPAM and ATBS systems.

Table 3.8. CMG STARS molecular weight and density for polymer and water.

Parameter	Unit	Value
Polymer molecular weight, M_p	kg/mol	8
Water molecular weight, M_w	kg/mol	0.018
Polymer density, ρ_p	kg/m ³	1093
Water density, ρ_w	kg/m ³	1093
Water mole density, ρ_w^{mole}	gmole/m ³	60707

Table 3.10. Polymer Reaction stoichiometric data for actual polymer solution molecular weight of 19000 kg/gmole. STARS recommended MW of 8 kg/gmole and testing case of MW of 500 kg/gmole.

CASE	Component	Molecular Weight kg/gmole	Moles gmole	Mole %
HPAM Actual MW	Water	0.018	105555.56	0.9999905263
	Polymer	19000	1	9.474×10^{-7}
	Dead Oil	0.214	0	
STARS Recommended Research Used	Water	0.018	444.44	0.99775505113
	Polymer	8	1	2.245×10^{-3}
	Dead Oil	0.214	0	
Testing Case	Water	0.018	27777.78	0.99996400130
	Polymer	500	1	3.600×10^{-5}
	Dead Oil	0.214	0	

Table 3.9. Extension of reaction stoichiometry demonstrating how polymer conversation to water volume is materially balanced.

CASE	Component	Concentration kg/m ³	Concentration ppm	Concentration wt	Concentration %wt	Mole Density gmole/m ³	%wt	Mass Density kg/m ³	m ³ /gmole	Volume m ³
HPAM Actual MW	Water	1092.72	1092720	1	100	60707	0.9999999945	1093	1.65×10^{-5}	17
	Polymer	0.636	636	0.000582	0.058	0.0000	5.512×10^{-10}	1093	17	17
	Dead Oil		0	0	0			881	0.00024	0
STARS Recommended Research Used	Water	1092.72	1092720	1	100	60707	0.9999869083	1093	1.65×10^{-5}	0.00732
	Polymer	0.636	636	0.000582	0.058	0.0795	1.309×10^{-6}	1093	0.007	0.00732
	Dead Oil		0	0	0			881	0.00024	0
Testing Case	Water	1092.72	1092720	1	100	60707	0.9999997905	1093	1.65×10^{-5}	0.46
	Polymer	0.636	636	0.000582	0.058	0.0013	2.095×10^{-8}	1093	0.458	0.46
	Dead Oil		0	0	0			881	0.00024	0.00

3.3.2 Analytical Validation of the Numerical Model

The validation process of the polymer flood for a one-dimensional simple numerical simulation was based on the Buckley-Leverett theory for waterflooding which was expanded to polymer flooding applications by Pope (1980). In a polymer flood two shock fronts are formed as illustrated by **Figure 3.5**. An initial breakthrough of connate water with constant water cut followed by the polymer breakthrough due to different front speeds. The theory was used to build an analytical solution to validate the numerical simulation model as seen in **Figure 3.6**.

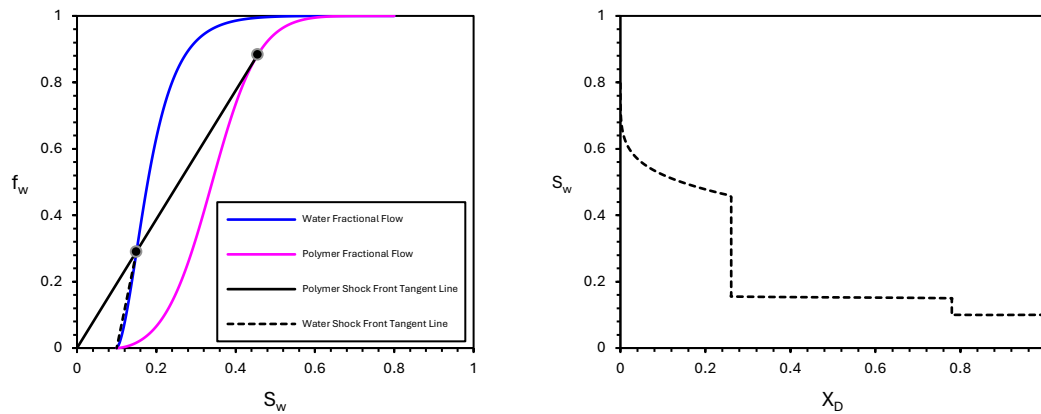


Figure 3.5. Polymer flood analytical solution for the designed polymer flood. On the left is the fractional flow shock front analysis. The right side is the solution showing the positions of the shock fronts as a function of dimensionless distance.

The numerical simulation saturation profile had a close match with Buckley-Leverett polymer shock front analytical solution as demonstrated in **Figure 3.6**. This provided confidence on the polymer flood setup in CMG-STARS and set the stage for thermal degradation evaluation. The numerical simulation results are based on 1800 grid cells over 1250 meters distance.

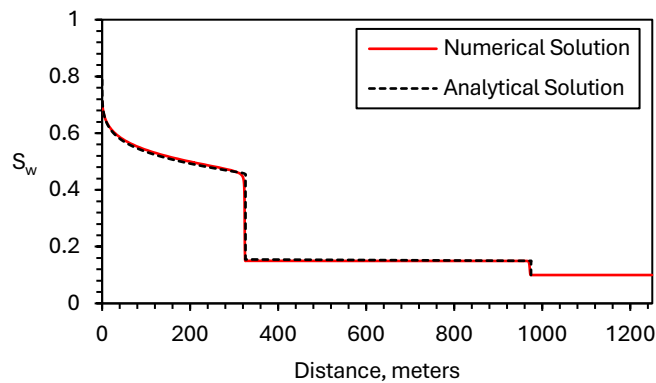


Figure 3.6. Polymer flood Buckley-Leverett analytical solution compared to the numerical simulation.

3.3.3 Grid Refinement Sensitivity

In a field scale the luxury of having fine grid resolution is computationally costly. The best grid size for simulating the polymer flood was established through a grid refinement experiment. Various 1D models with grid blocks ranging from 23 cells to 1800 cells were assessed to evaluate grid resolution impact on polymer flood performance. The purpose of doing this refinement investigation is to identify the minimum grid blocks required to represent accurate simulation results.

In field scale dynamic models low model resolution are implemented to reduce computing time. According to the cell refinement investigation done on the one-dimensional numerical simulation model, coarser grids have demonstrated smearing of the shock front of both connate water and injected polymer. This smearing caused early water breakthrough and unrepresentative recovery estimation (see **Figure 3.7**). The 112 and 220 grid cells shock fronts demonstrate accurate match with the analytical solution at polymer shock front. However, at the connate water, smearing is observed but it is over ~20 to 30 meters and anticipated to not impact the flooding performance especially at this low shock front saturation.

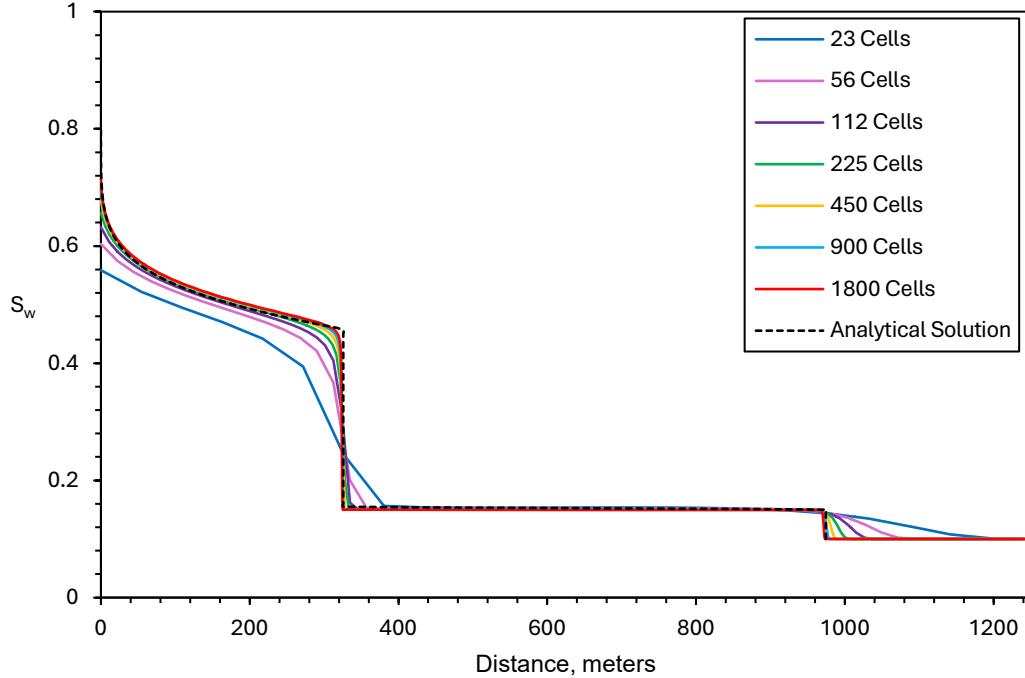


Figure 3.7. Shock front saturation profiles over distance for multiple cell refinements in the 1D numerical simulation model.

In terms of recovery, at 220 grid cells the numerical pore volume recovered started to plateau at ~ 0.444 (see **Figure 3.8**). This indicates that any further refinement will only introduce waste in computational time and will introduce minimal improvement in simulation accuracy. We will proceed with the 220 grid cells for the numerical simulation in 1D and 2D work of this thesis.

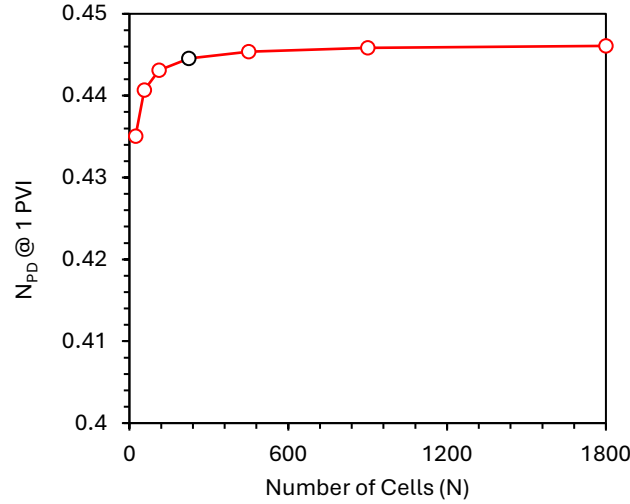


Figure 3.8. Pore volume of oil produced at 1 pore volume injected for multiple grid resolutions. At the black circle of grid resolution of 225 cells no major change in the recovery performance is observed.

3.3.4 Displacement Improvement by Mobility

Polymer flooding improves displacement efficiency by reducing the mobility ratio between the injected and displaced fluids. The analytical framework for evaluating stability in immiscible displacements is based on the mobility ratio at the displacement front. The relevant measure is the shock front mobility ratio, M_{sf} , expressed as:

$$M_{sf} = \frac{\frac{k_{r,w}(S_{wf})}{\mu_w} + \frac{k_{r,o}(S_{wf})}{\mu_o}}{\frac{k_{r,o}(S_{wc})}{\mu_o}} \quad 3.13$$

where $k_{r,w}(S_{wf})$ and $k_{r,o}(S_{wf})$ are the water and oil relative permeabilities at the shock-front water saturation S_{wf} , and $k_{r,o}(S_{wc})$ is the oil relative permeability at connate water saturation. A displacement is considered favourable if $M_{sf} \leq 1$.

Here we demonstrate analytically using the Buckley–Leverett solution that displacement recovery improves significantly when polymer viscosity increases up to

around 10 mPa.s. Above this point, additional viscosity provides diminishing improvements in recovery (See **Figure 3.9**), also the polymer shock front mobility ratio improvement after 10 mPa.s does not reduce much further (See **Figure 3.10**). It is important to emphasize that this threshold does not represent an economic optimum, as economic considerations such as polymer cost are not addressed in this thesis. Instead, 10 mPa.s is highlighted as a technically reasonable target that delivers a high incremental recovery gain while demonstrating the role of mobility ratio in stabilizing displacement.

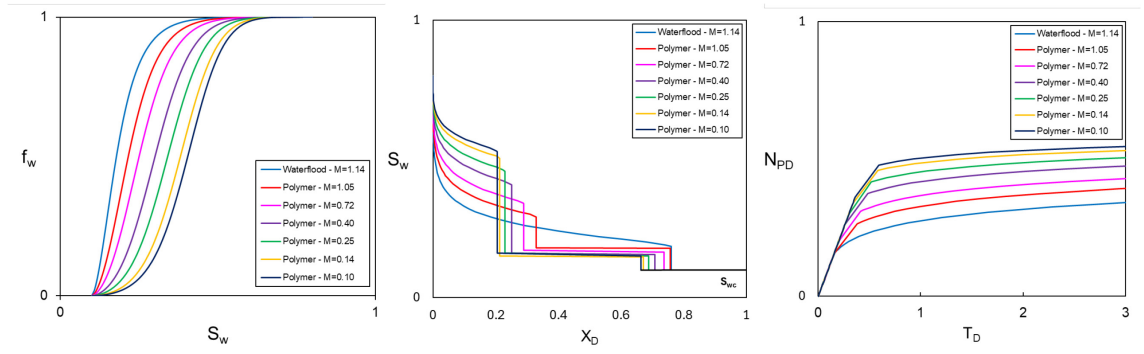


Figure 3.9. Buckley Leverett analytical solution that demonstrate the effect of using different polymer viscosity on polymer fractional flow on the left side, Shock front displacement in the middle and pore volume produced performance in the right side. The legend represents water flooding performance in blue, and different polymer viscosity represented by mobility ratio at shock front. The green line represents the performance expected for polymer viscosity of 10 mPa.s.

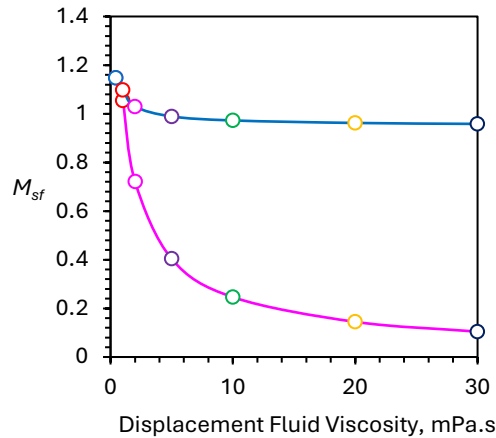


Figure 3.10. Shock front mobility ratio estimation for different polymer solution viscosities. The blue line represents the mobility ratio at the connate waterfront. The magenta line represents the mobility ratio at the polymer front. The circles highlight the viscosity scenarios matching the colours used in **Figure 3.9**.

3.3.5 Polymer Numerical Performance

3.3.5.1 *Polymer Performance Benchmarking (No Thermal Degradation)*

We set up a water flooding case for a one-dimensional model to be used as a benchmark to evaluate the polymer flood performance. Polymer should introduce improved displacement performance. We overlapped the saturation profiles of the water flood and polymer flood for the same time step to evaluate improvement in displacement (see **Figure 3.11**). Polymer has slowed down the shock front and achieved an improved displacement efficiency when compared to the water flood performance.

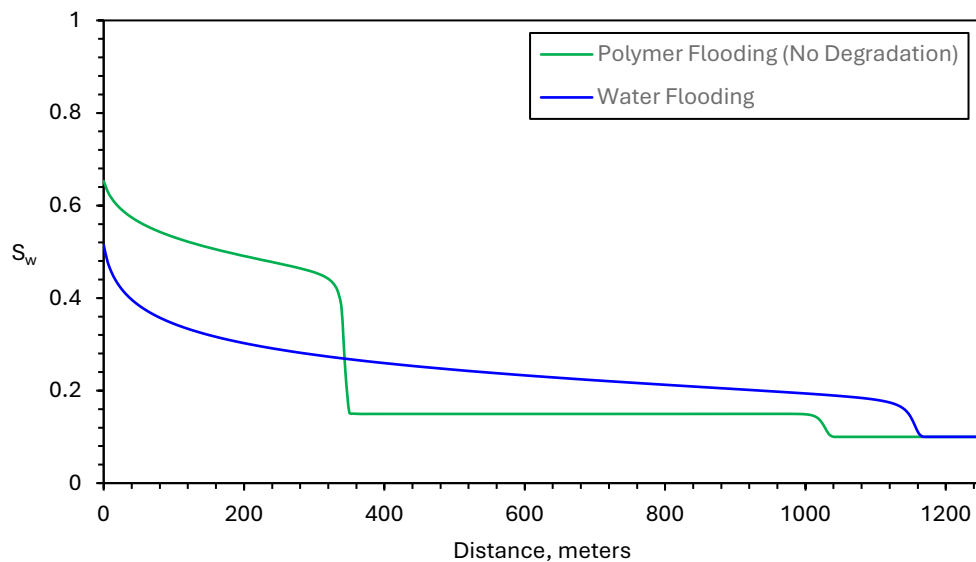


Figure 3.11. Saturation profiles of water flooding and polymer flooding assuming no degradation at 4 years injection and 0.14 Pore volume injected. The model used consists of 220 cells concluded from the cell refinement study work earlier.

Polymer flood simulation results suggested a 17% incremental recovery gain in comparison with water flood (see **Figure 3.12**). This enhancement in oil recovery is driven by the improvement in mobility ratio by the increase of displacing fluid viscosity with polymer addition. These are preliminary data assuming continuous polymer flooding scheme which is impractical for field application. So as part of the sensitivities slug injection of varied sizes will be evaluated to mimic field application.

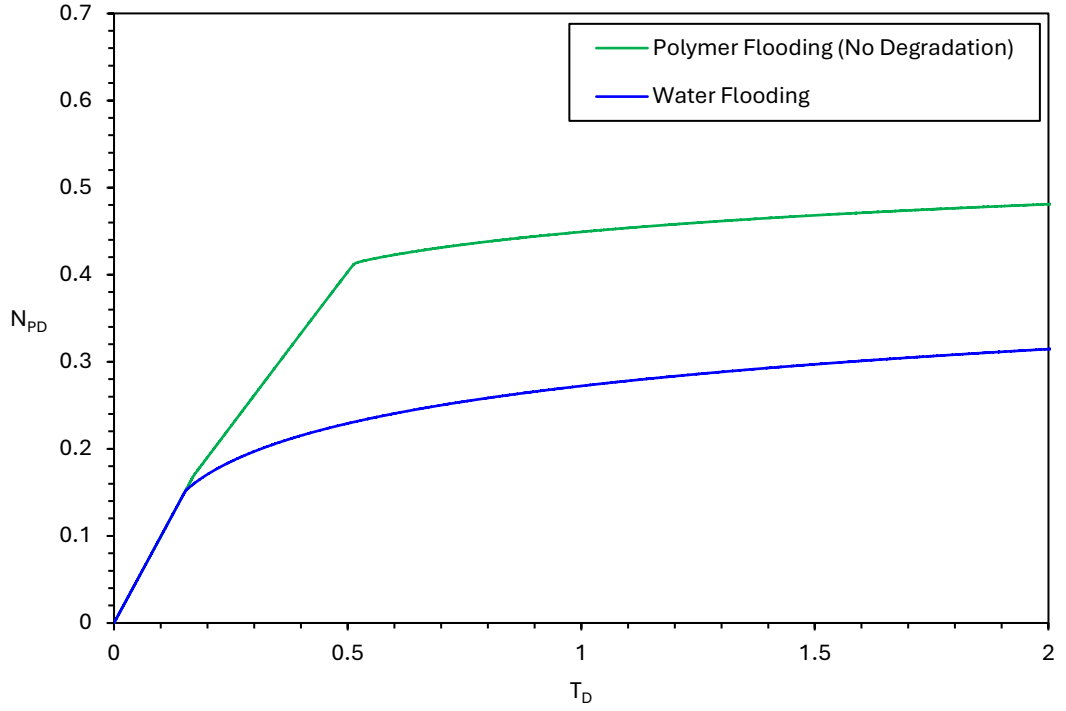


Figure 3.12. Numerical recovery performance in pore volume of oil produced of ideal polymer flooding assuming no thermal degradation in green benchmarked with water flooding performance in blue. The plot highlights the expected recovery gain from polymer deployment over pore volume injected.

3.3.5.2 *Effect of Thermal Degradation*

3.3.5.2.1 **Quantifying Polymer Loss Due to Thermal Degradation**

Thermal degradation leads to a progressive reduction in polymer concentration during reservoir exposure, which in turn reduces solution viscosity and mobility control. Thermally degraded polymer is expected to exhibit a better displacement and sweep performance than water flood and worse performance when compared to a stable polymer flood. Here we compare polymer to water flooding by using the two types of polymers proposed previously, HPAM suggested to be unstable for this application, and ATBSA proposed as a stable alternative. To quantify the extent of polymer loss due to thermal degradation, we integrate the analytical first-order degradation kinetics reaction rate function (Eq. 2.12) to estimate the reduction in polymer concentration as a function of exposure time:

$$C_p(t) = C_{p0}e^{-rt} \quad 3.14$$

where r is the first order rate constant and C_{p0} is the initial polymer concentration that reduces with t the exposure time. This formulation provides a direct and quantitative measure of polymer loss due to thermal degradation under static reservoir conditions.

The predicted polymer concentration decay over time for HPAM and ATBSA polymers at a reservoir temperature of 100 °C is shown in **Figure 3.13**. HPAM exhibits a rapid loss of polymer concentration, indicating severe thermal instability under these conditions. In contrast, ATBSA shows a much slower concentration decline, retaining a significant fraction of its initial concentration over several decades of exposure. This highlights the strong dependence of polymer retention on chemical structure in high-temperature reservoirs.

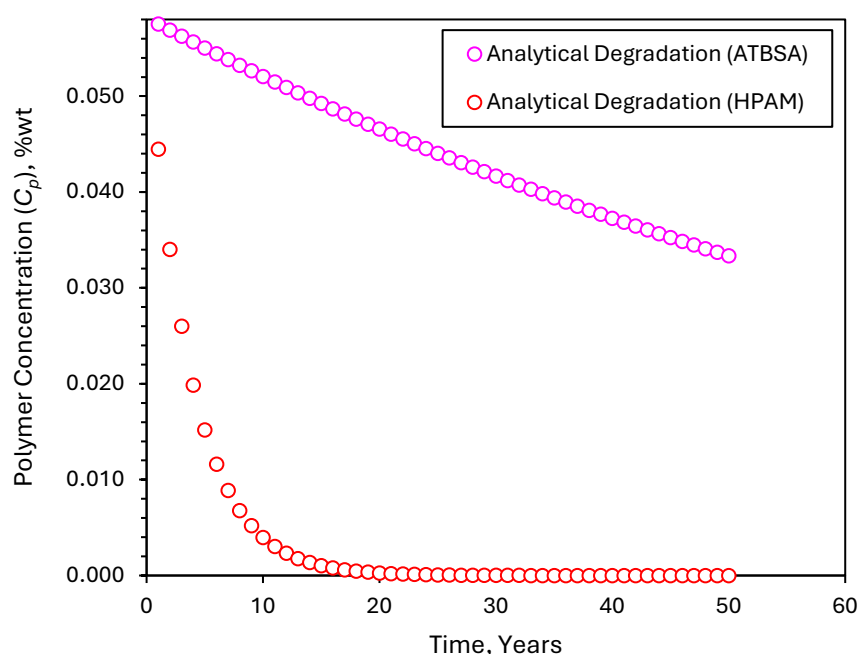


Figure 3.13. Polymer concentration loss due to thermal degradation performance over time for HPAM and ATBSA polymers.

3.3.5.2.2 Thermal Degradation Model Validation

To express the analytically predicted concentration loss in terms of viscosity for validation purposes, the degraded polymer concentration is converted to solution viscosity using the Flory–Huggins-based third-order viscosity–concentration correlation shown in **Figure 3.14**. This correlation was extracted from the viscosity data presented in **Figure 3.3** and fitted over the viscosity range of interest up to 10 mPa·s.

The fitted relationship is used solely to translate concentration decay into an equivalent viscosity decay, enabling consistency between analytical predictions and numerical simulation outputs.

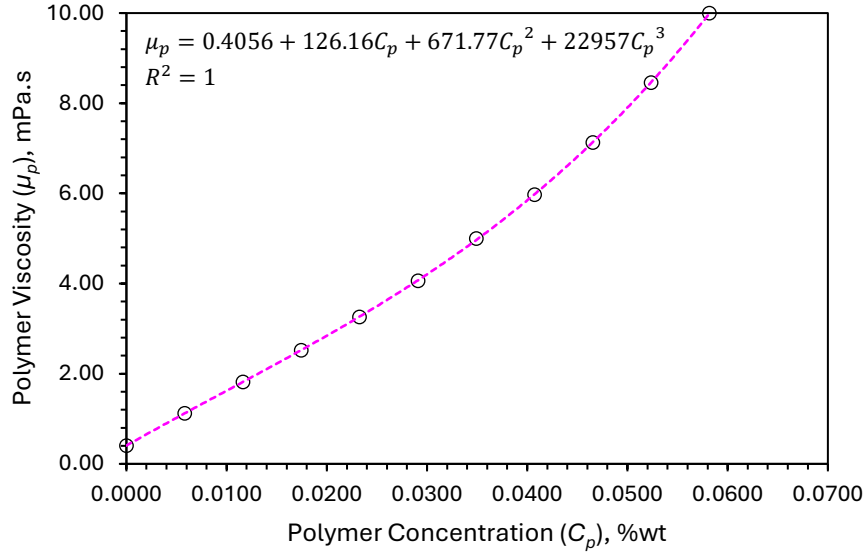


Figure 3.14. Flory Huggins third order fitting of the viscosity vs concentration extracted from **Figure 3.3** and fitted more precisely to the viscosity range of interest at a maximum of 10 mPa.s.

Before evaluating polymer flooding performance under the influence of thermal degradation, the numerical degradation model is validated against the analytical first-order degradation kinetics described above. To eliminate the challenges of tracking the thermal degradation at the shock front we followed an alternative approach where we replaced the connate water in the static model with the polymer mixture of initial concentration of 0.058 %wt and solution viscosity of 10 mPa.s. We run a 60-year case with no flow at a reservoir temperature of 100°C. The numerical simulation demonstrated a perfect match with the analytical solution which confirms the validity of the polymer thermal degradation performance simulations seen in **Figure 3.15**.

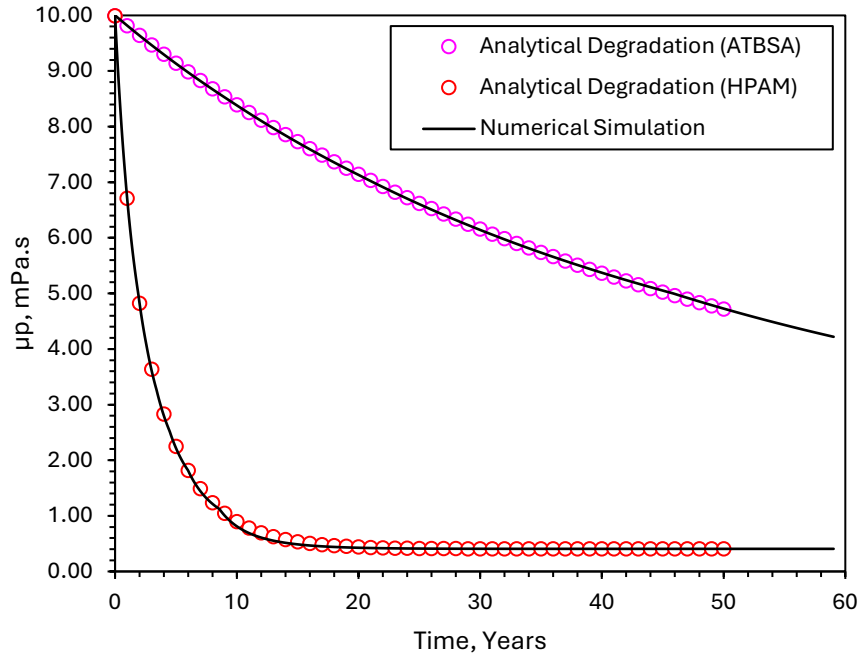


Figure 3.15. Polymer viscosity thermal degradation performance over time for HPAM and ATBSA polymers. The black line represents the viscosity thermal degradation in the numerical simulation and the circles represent the analytical degradation results.

3.3.5.2.3 Impact of Thermal Degradation on Displacement and Recovery

We present the comparison in shock front displacement at the same time step and identical injection volume. As shown in **Figure 3.16**, HPAM shows only marginal improvement over waterflooding due to its thermal breakdown, while ATBSA maintains front sharpness and approaches the performance of the stable polymer case. This highlights the critical role of thermal stability in sustaining mobility control, with ATBSA offering significantly better displacement under high-temperature conditions and large spacing.

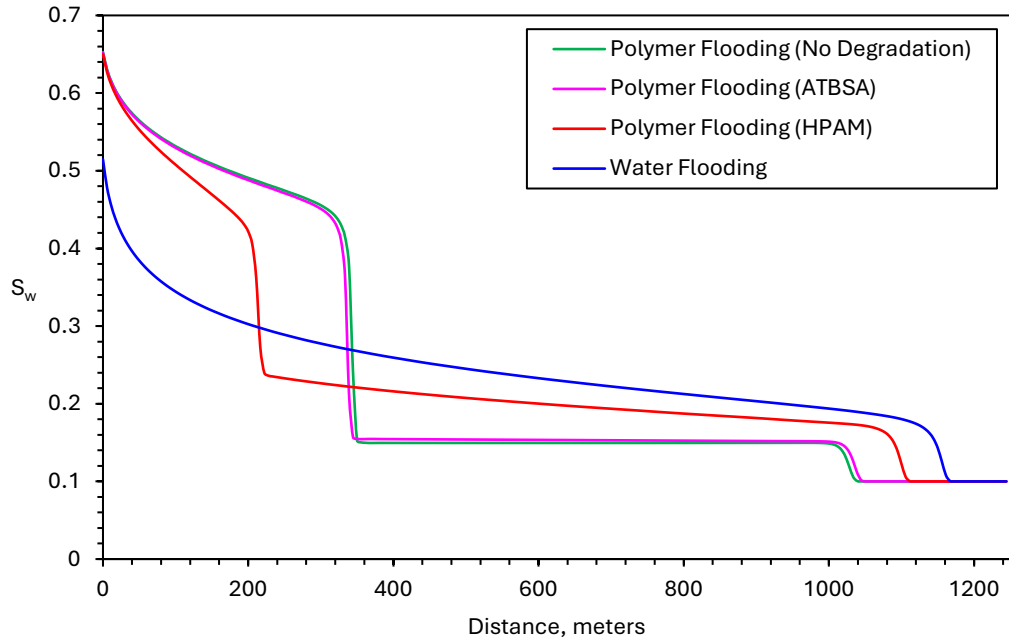


Figure 3.16. Saturation profiles over distance of polymer flooding assuming no thermal degradation in green, ATBSA in magenta, HPAM in red and water flooding in at 4 years injection and 0.14 Pore volumes injected. ATBSA performance was outstanding during that period due to its high half-life of 54 years. HPAM presented much lower performance due to its high thermal instability.

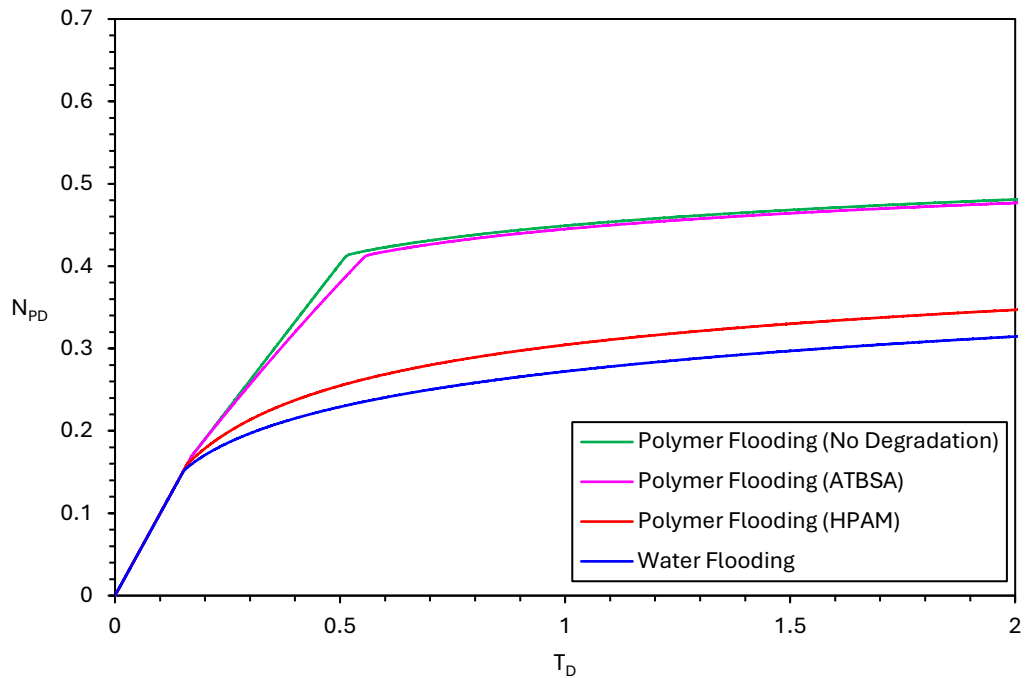


Figure 3.17. Numerical recovery performance in pore volumes of oil produced of polymer with ideal no thermal degradation assumed in green, HPAM in red, ATBSA in magenta and water flooding in blue over 2 pore volumes period.

This displacement behaviour is further confirmed when evaluating recovery performance over time. As shown in **Figure 3.17**, both ATBSA and the no-degradation polymer case maintain superior oil recovery, reaching over 0.47 pore volumes recovered at 2 injected pore volumes. In contrast, HPAM, due to thermal degradation, levels off significantly earlier, achieving only ~ 0.34 , while waterflooding trails even further at ~ 0.31 . These results highlight that while thermally degraded polymers still outperform water, their effectiveness diminishes over time. ATBSA's thermal stability enables it to sustain high recovery rates and closely match the ideal polymer case, reinforcing its suitability for high-temperature applications. These 1D results demonstrate that polymer loss due to thermal degradation can be quantified analytically and validated numerically, and that thermal stability plays a decisive role in maintaining polymer flooding performance. This motivates further investigation of thermal degradation effects at field scale.

3.4 Vertical Two-Dimensional (2D) Model

The one-dimensional (1D) model was extended into a vertical two-dimensional (2D) configuration by introducing grid refinement in the vertical direction. This allows a more representative assessment of crossflow between layers and provides a better approximation of fluid sweep and displacement behaviour. The objective is to evaluate whether vertical resolution, production/injection rate, or anisotropy influence recovery performance during water and polymer floods, and to assess the added impact of polymer thermal degradation under these conditions.

3.4.1 Vertical Grid Resolution Sensitivity

The current study incorporates relative permeabilities obtained from experiments on a carbonate rock sample (see **Figure 3.2**). All simulations adopt a base model with 1250 m spacing and 225 horizontal cells. However, the 2D vertical resolution sensitivity analysis was performed using 1000 m spacing and 180-cell base case. A vertical grid refinement study was conducted by introducing up to 160 cells over a 10 m gross thickness. Rock, fluid, and polymer properties were kept consistent with the previous section to ensure that observed changes in performance are attributed solely to vertical resolution. The model was configured with a production/injection rate of $300 \text{ m}^3/\text{day}$

and a vertical-to-horizontal permeability ratio of 1.0, using a uniform permeability of 500 mD. The injector and producer were both completed across the full vertical thickness of the reservoir, allowing unrestricted vertical flow and crossflow throughout the formation. This well configuration was adopted to isolate the impact of vertical grid discretization on displacement behaviour, independent of completion effects. For the present chapter, a 160 cells resolution was adopted to demonstrate the influence of grid refinement on flood-front development, as illustrated in **Figure 3.18**. In all other simulations, a minimum of 10 cells in the vertical direction was used consistently, as this level of refinement was found sufficient to capture vertical flow behaviour concluded from the following results.

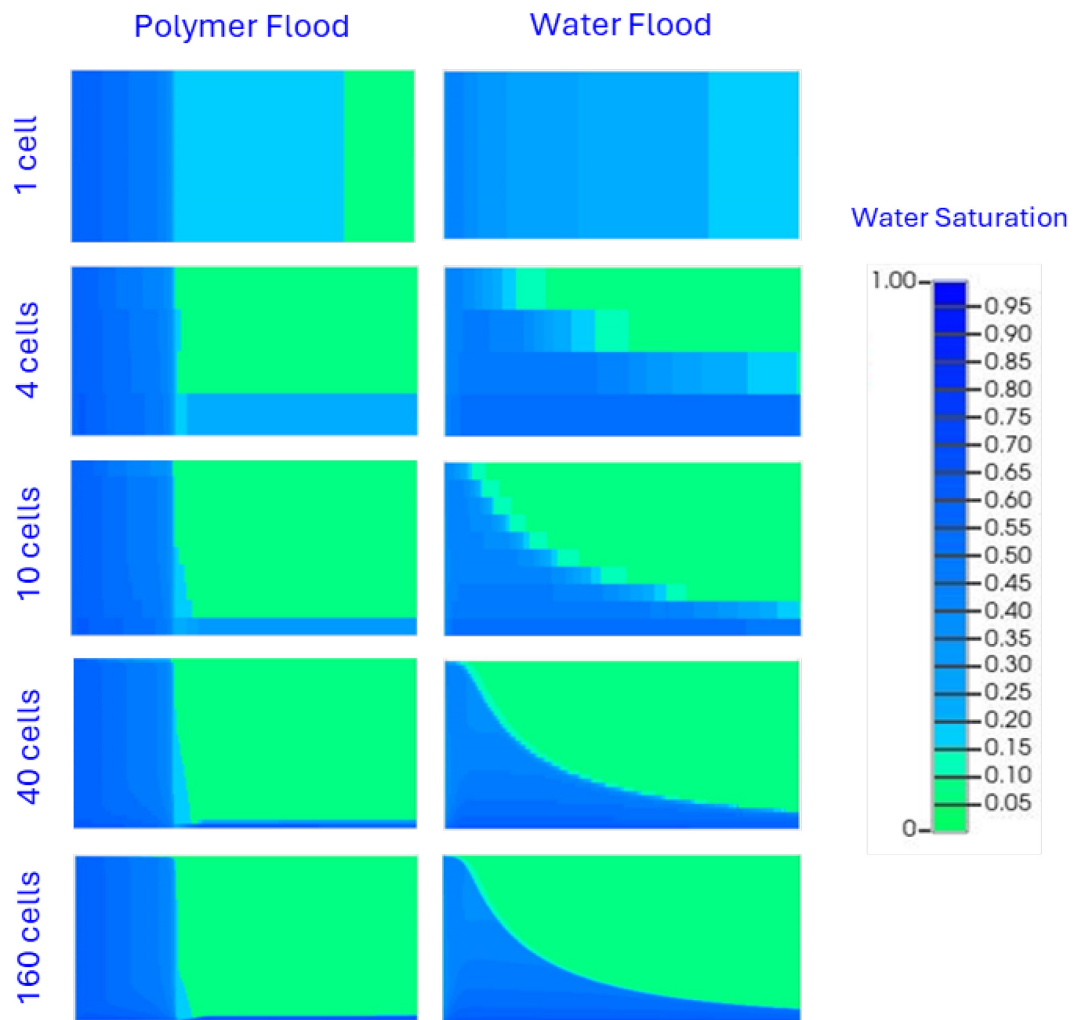


Figure 3.18. Water saturation cross section for polymer flood and water flood at water breakthrough time for multiple vertical resolutions. 160 cells demonstrated finer shock front on both floods.

Increasing the number of vertical cells led to improved recovery for both water and polymer flooding, with higher vertical resolution yielding greater incremental oil

recovery at 1.0 PVI compared to the 1D base case. This trend is illustrated in **Figure 3.19** for polymer flooding and in **Figure 3.20** for water flooding. In both cases, models with finer vertical grids exhibited earlier breakthrough, reflecting enhanced vertical flow and crossflow representation. These results highlight the sensitivity of displacement efficiency to vertical discretization, even in a homogeneous system.

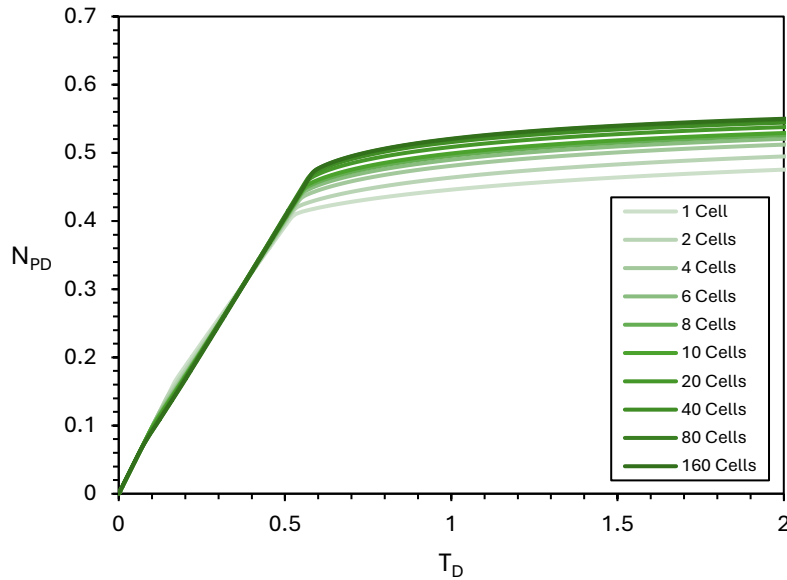


Figure 3.19. Oil pore volume produced over pore volume injected for polymer flood with no thermal degradation in 2D for multiple vertical cell resolution. We observe higher recovery performance with higher vertical resolution.

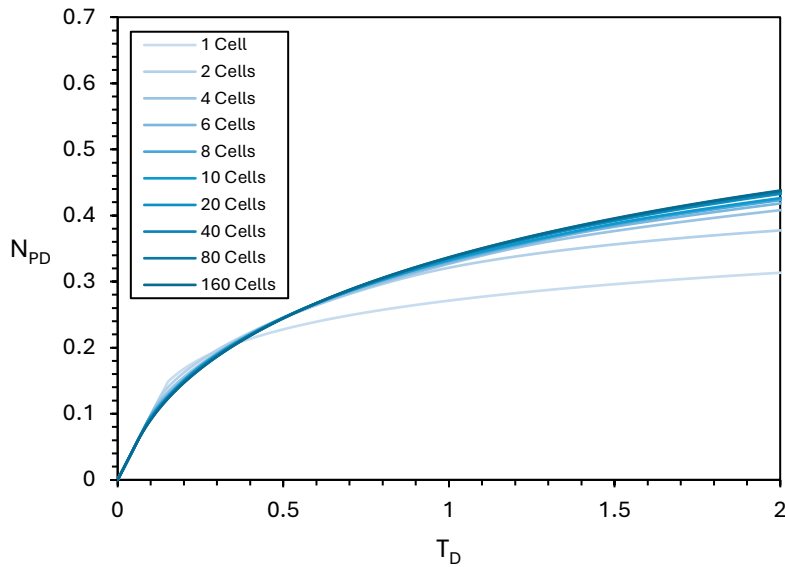


Figure 3.20. Oil pore volume produced over pore volume injected for water flood in 2D for different vertical cell resolutions. We observe higher recovery performance with higher vertical resolution.

The incremental improvement in oil recovery is quantified in **Figure 3.21**, which compares recovery at 1 PVI to the base 1D model. For waterflooding, recovery increased sharply by approximately 5–6% when moving from a single cell to just 2–20 cells, after which no further gains were observed. In contrast, polymer flooding exhibited a more gradual increase, reaching up to ~7% incremental recovery at 40 cells, with diminishing improvements thereafter. This suggests that waterflood performance is less sensitive to very fine vertical resolution, while polymer flooding benefits more from detailed representation of flow paths, consistent with its reduced mobility and more stable displacement front.

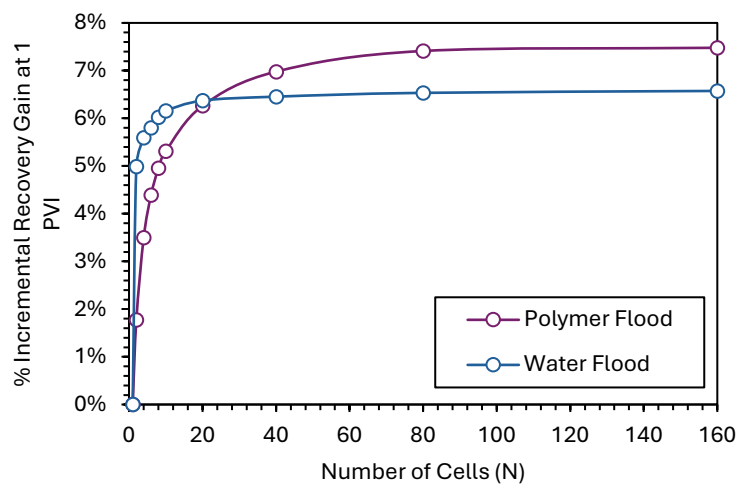


Figure 3.21. percent incremental recovery gain from 1D model performance at 1 pore volume injected (PVI) for polymer flood in purple and water flood in blue. For the polymer flood minimal recovery gain was observed above 40 cells. For the water flood no recovery gain was seen beyond 20 cells.

We extended the sensitivity analysis to multiple production/injection rates (see **Figure 3.22**) and observed that at higher rates ($>1000 \text{ m}^3/\text{day}$), polymer flooding became less sensitive to vertical resolution. Another key observation is the ~10% difference in incremental recovery between the $1000 \text{ m}^3/\text{day}$ and $100 \text{ m}^3/\text{day}$ cases. This improvement appears to be driven by gravity acting in the vertical direction. Interestingly, this outcome is counterintuitive when compared with the classical interpretation that gravity segregation reduces sweep efficiency, a point that will be revisited in later discussion.

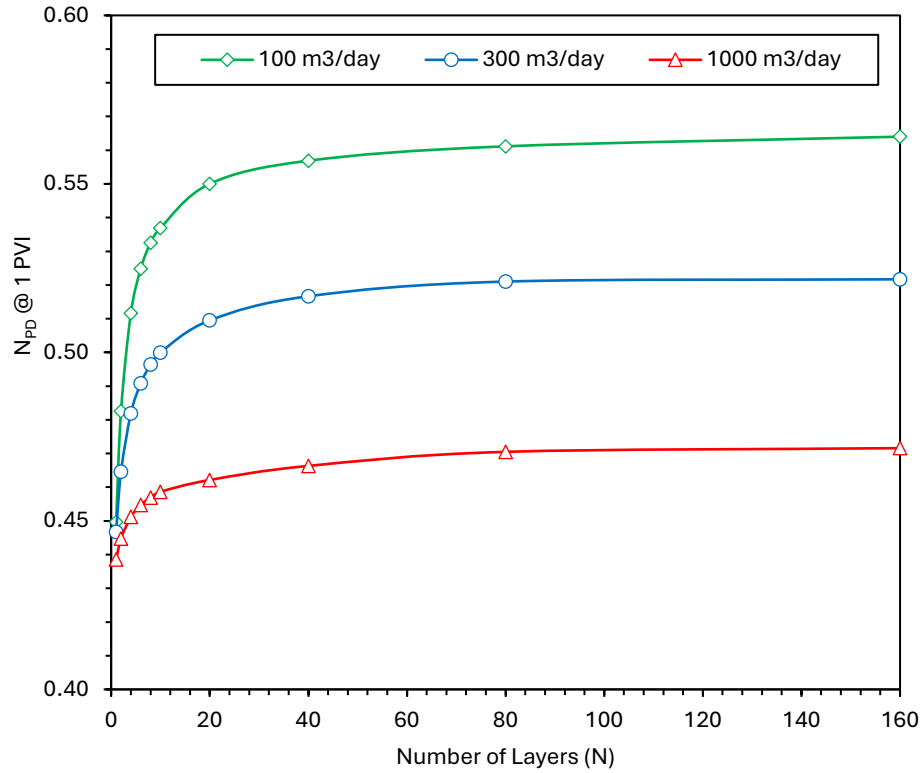


Figure 3.22. Oil pore volume produced at 1 pore volume injected over number of cells in the vertical direction for three different production/injection rates for polymer flooding with no thermal degradation scenario.

In Chapter 5, a detailed analysis of the sources of recovery gain will be carried out using a vertical resolution of 160 cells, which provides an accurate visual representation of displacement and sweep and allows quantification of the dominant contributing mechanisms.

3.4.2 Displacement Improvement by Gravity

In addition to mobility control demonstrated in section 3.3.4, gravity can also improve displacement efficiency. When density differences exist between the injected and displaced fluids, gravity segregation can slow down the flood front by reducing the displacing fluid mobility. The effect of gravity can be incorporated into the Buckley–Leverett formulation by modifying the fractional flow function to include a gravity term. Here we will use (Eq. 2.6) to incorporate the effect of gravity on the fractional flow in a 1D model using the model initialization data in section 3.3.1. We will also use Lake (1989) interpretation of the Buckley–Leverett solution to demonstrate the influencing of gravity of polymer and water flooding performance.

We will run a series of cases to examine the combined influence of gravity and mobility control on frontal advance rate for both water and polymer flooding under horizontal and gravity-stable flow configurations. The resulting frontal advance rates and gravity numbers are summarised in **Table 3.11** for the cases shown in **Figure 3.23**.

Table 3.11. Frontal advance rate and gravity number comparison for the cases plotted in Figure 3.23

Case	Flow Type	Flood Type	Rate (m ³ /day)	Frontal Advance Rate (m/day)	Gravity Number
1	Horizontal	Water Flood	1000	3.20	0.09
2	Horizontal	Polymer Flood	1000	0.97	0.09
3	Gravity-Stable	Water Flood	100	0.09	88
4	Gravity-Stable	Polymer Flood	100	0.09	88
5	Gravity-Stable	Water Flood	300	0.28	29
6	Gravity-Stable	Polymer Flood	300	0.28	29
7	Gravity-Stable	Water Flood	1000	1.09	9
8	Gravity-Stable	Polymer Flood	1000	0.85	9

For the horizontal cases, the gravity number remains small, indicating viscous-dominated flow, and polymer injection substantially reduces the frontal advance rate compared to water flooding due to improved mobility control. In contrast, under gravity-stable conditions, the gravity number increases significantly as injection rate decreases, reflecting the increasing dominance of buoyancy forces. In this regime, the frontal advance rate is primarily governed by gravity effects, and the difference between water and polymer flooding becomes less pronounced at low injection rates. At higher rates within the gravity-stable configuration, viscous forces regain importance as the gravity number decreases, leading to higher frontal advance rates and a renewed

influence of polymer mobility control. Overall, these cases illustrate the transition from viscous-dominated to gravity-dominated displacement and highlight the role of gravity in slowing the flood front and improving displacement efficiency.

The effect of gravity is demonstrated in **Figure 3.23**, where fractional flow, shock-front development, and oil recovery performance are compared for water and polymer floods analytically under horizontal (dip angle is zero) and gravity-stable conditions (negative dip angle $\sin \alpha = -1$). The influence of gravity is more pronounced in water floods, with fractional flow behaviour showing greater sensitivity to production/injection rate. At lower production/injection rates, the impact of gravity on fractional flow is maximized, producing sharper transitions and more stable displacement fronts compared to the horizontal case.

The middle plot of **Figure 3.21** illustrates the shock-front profiles. S_w is the shock front displacement saturation representing the saturation at a given position in the model. For polymer floods at low production/injection rates, a single dominant shock front is formed, while at higher rates (1000 m³/day) a secondary shock associated with connate water becomes more evident at high water saturation. This confirms that lower production/injection rates improve displacement stability through gravity segregation, whereas higher rates diminish its effect as viscous forces dominate.

The bottom plot of **Figure 3.21** presents the cumulative recovery performance. At low production/injection rates (100 m³/day), both water and polymer floods achieve nearly identical recovery, with polymer injection providing no additional displacement improvement. This observation highlights an important economic implication: under gravity-dominated conditions, polymer flooding may not yield incremental recovery beyond that of conventional waterflooding. Therefore, for any designed production/injection rate, gravity effects must be carefully evaluated to assess the true baseline performance of waterflooding before considering the additional cost and complexity of polymer flooding.

These findings indicate that, contrary to the classical view that gravity segregation reduces sweep efficiency, in vertical displacement systems gravity can enhance displacement by stabilizing the flood front. The magnitude of this effect depends strongly on production/injection rate, with the greatest benefit observed at low rates. For polymer floods, the combination of gravity segregation and mobility control produces the highest incremental recovery when viscous instabilities are significant, but offers little additional advantage when gravity dominates.

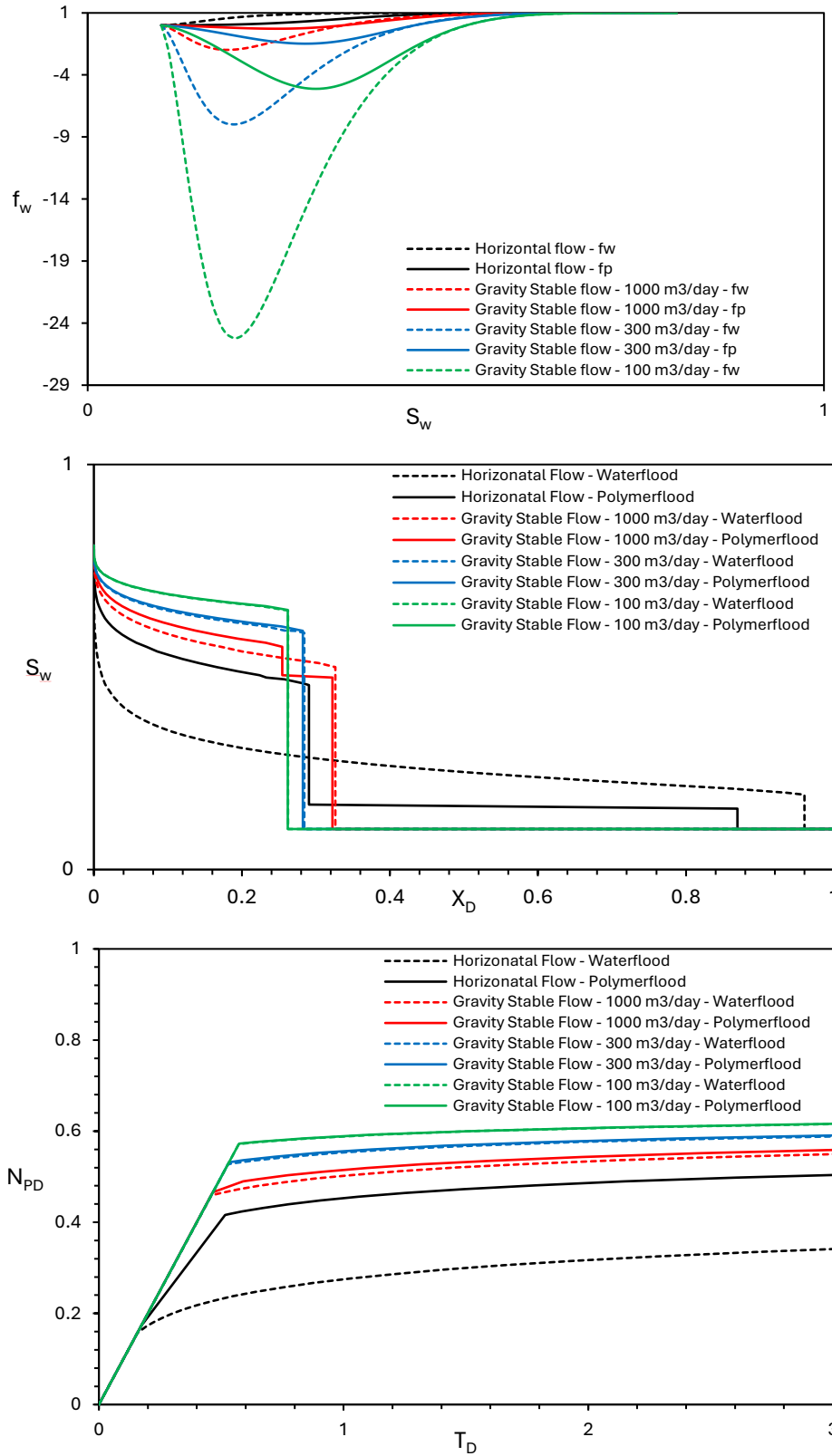


Figure 3.23. Buckley Leverett analytical solution for horizontal and gravity stable 1D displacement. We demonstrate the effect of gravity for different production/injection rates on fractional flow of water flood and polymer flood on the top plot, Shock front displacement in the middle plot and pore volume produced performance in the bottom plot. The legend represents horizontal flow in black, gravity stable flow for multiple production/injection rates in red, blue and green. The dashed lines are for water flood and the solid lines are for polymer flood. At a lower production/injection rate where gravity segregation effect is highest, we observe highest recovery gain for both water flood and polymer flood.

3.5 Field-Scale Heterogeneous Reservoir Model

Giant carbonate reservoirs with high permeability of the Middle East (Saudi Arabia, Kuwait, Iraq, Iran) possess huge reserves and contribute to nearly one third of global oil production (Alavi, 2004; Ebrahimi et al., 2016; Gulick and Jr, 1998; Powers et al., 1966; Qi and Liu, 2024). We investigated the impact of gravity on a sector model that simulates a heterogeneous carbonate reservoir, using the COSTA Model as a reference point for the geological and petrophysical complexity common in Middle Eastern reservoirs. The COSTA Model is a partially synthetic, geologically representative, dataset developed to closely reflect the properties of carbonate reservoirs. It is built using anonymous data collected from 43 wells located in the northeastern region of the Rub Al Khali basin (Costa Gomes et al., 2022). However, the model has limitations, featuring extreme heterogeneity in the permeability with a low effective permeability (geometric average of 17 mD), with just 18% of the net gross contributing significantly to fluid flow. Recognizing that this model does not represent typical Middle Eastern reservoir characteristics, we implemented a permeability scaling approach. This scaling was necessary to align the model more closely with the permeability distribution observed in the vast carbonate reservoirs of Saudi Arabia, allowing us to better capture their geological and fluid flow behaviour.

3.5.1 Permeability Scaling

We used a power-law scaling method to modify the permeability distribution of the COSTA Model, while maintaining a representative level of heterogeneity. We adjusted the permeability average from 17 mD to 300 mD and capped the maximum value to 1.5 Darcy, see **Figure 3.24a**; an increase guided by the expected high permeability in Saudi fields (such as the Hanifa Reservoir) (Alsharhan and Magara, 1995).

$$K_{scaled} = K_{average\ target} \cdot K_{average}^{-\alpha} \cdot K_{grid\ cell}^{\alpha} \quad 3.15$$

where K_{scaled} is the scaled model permeability, $K_{average\ target}$ is the targeted geometric average model permeability, $K_{grid\ cell}$ is the original model permeability, $K_{average}$ is the original model geometric average permeability and α is the distribution factor where the model is made more heterogeneous for $\alpha > 1$, and more homogeneous for $\alpha < 1$.

3.5.2 Sector Model

The COSTA Model covers an area of 60 km in length and 26 km in width and would require massive computational power to run using the fine grid resolution needed to investigate the influence of gravity. We extracted a 1.25×1.25 km sector from the southeastern side of the anticline, dipping down at 1° . We defined an open hole up-dip vertical producer, and a down-dip vertical injector completed across the full reservoir thickness to represent the line drive mechanism usually adopted in Middle Eastern reservoirs, see **Figure 3.22b**. We performed two stages scaling by direct scaling at field level using distribution factor of $\alpha = 1$. The scaling at field level produced unrealistic high permeability values exceeding 100,000 mD, so we applied a second stage of scaling on the extracted sector to cap the permeability to 1.5 Darcy while maintaining an average permeability of 300 mD. To apply the cap on the scaling function, we applied iterative scaling method by restricting K_{scaled} to the cap permeability and adjusting the $K_{average\ target}$ value until the targeted overall geometric average of K_{scaled} is achieved. Another approach was used by iterating the distribution factor α but it resulted in very homogeneous model that is not suitable for our analysis, see **Figure 3.24b**

3.5.3 Model Stratigraphy

The COSTA Model vertical permeability distribution is coarsening upward characterized by high permeability at the top of the reservoir and lower permeability on the bottom layers. We did a synthetic flipping of the extracted sector to establish a fining upward reservoir and extend our evaluation on the impact of gravity on recovery performance. We also applied a global homogenous permeability distribution to the same sector to evaluate the impact of heterogeneity, see **Figure 3.24c**.

3.5.4 Model Porosity and Permeability Refinement and Upscaling

The COSTA model is constructed with lateral dimensions of 250×250 m for broad spatial coverage and a vertically refined structure comprising 62 layers, each roughly 0.8 m thick. This design choice aims to capture the diverse geological features present within the target zone. To address the issue of numerical dispersion, a finer lateral mesh of 75×75 grid blocks of size 17×17 m was employed. In the initial phase of our study,

involving a 2D homogeneous model, we used a very fine grid to resolve the gravity segregation. The modified COSTA model also has a very fine resolution, much finer than would necessarily be used in field scale simulations. To examine the effect of upscaling in a heterogeneous model we applied vertical upscaling to achieve a coarser resolution of 5 layers, each with an average thickness of approximately 10 m, as seen in **Figure 3.22d**. Preserving the essential characteristics of vertical heterogeneity within the model, while simultaneously exploring the critical role of vertical resolution in accurately simulating the effects of gravity in field-scale models will be discussed in chapter 5.

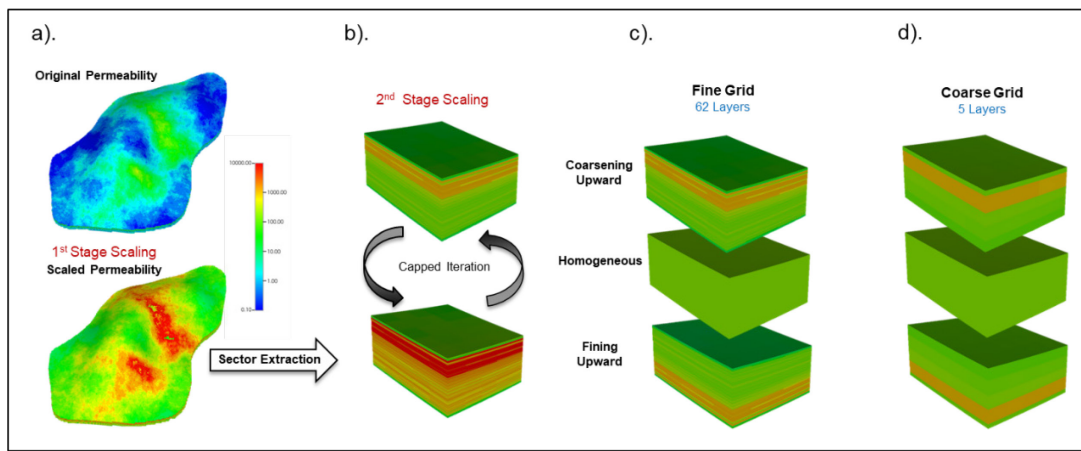


Figure 3.24. COSTA model scaling, sector extraction, refinement, and upscaling workflows. a) COSTA model original and 1st stage scaling. b) Sector model and 2nd stage scaling. c) Grid refinement for multiple permeability distribution (coarsening upward, homogeneous and fining upward). d) Vertical upscaled sector models.

3.6 Summary

In this chapter, we constructed and validated numerical models to investigate the fundamental behaviour of polymer flooding under a range of conditions and scales. The CMG STARS simulator was employed due to its capability to represent polymer transport and thermal degradation through a first-order reaction model, allowing reliable evaluation of stability differences between polymer types such as HPAM and ATBSA. The modelling framework incorporated experimentally derived relative permeability and viscosity–concentration relationships to ensure physical consistency with carbonate reservoir conditions.

The 1D base model was first established and benchmarked against the Buckley–Leverett analytical solution and Pope’s extension for polymer flooding. This validation

confirmed the correct representation of polymer transport, viscosity functions, and thermal degradation. A grid refinement sensitivity demonstrated the minimum resolution required to capture polymer shock-front dynamics without unnecessary computational cost, leading to the adoption of ~220 cells as an efficient and accurate discretization for 1D modelling.

Polymer flooding was shown to significantly improve displacement efficiency compared to waterflooding, with an incremental recovery gain of ~17% under no-degradation conditions. When thermal degradation was introduced, HPAM performance degraded rapidly at reservoir temperature, achieving only marginal improvement over waterflooding, whereas ATBSA retained stability and achieved recoveries close to the ideal no-degradation case. This highlighted the critical importance of polymer thermal stability for high-temperature carbonate applications.

The 1D model was then extended to a vertical 2D configuration to investigate the impact of vertical resolution, production/injection rate, and gravity. The results showed that finer vertical grids improved recovery by more accurately capturing crossflow and gravity segregation effects. Waterflooding exhibited recovery gains of 5–6% with as few as 2–20 vertical cells, while polymer flooding required finer resolution (up to ~40 cells) to fully capture displacement stability. At high production/injection rates (>1000 m³/day), polymer floods showed minimal sensitivity to resolution beyond 1 m per cell thickness, whereas at low rates (100 m³/day), incremental recovery improved by ~10% due to gravity segregation. Importantly, under gravity-dominated conditions, polymer flooding offered no additional benefit over waterflooding, underscoring the need to evaluate gravity effects before justifying polymer deployment.

Finally, analytical Buckley–Leverett solutions incorporating both mobility control and gravity confirmed the dual mechanisms through which polymer improves displacement. Mobility control reduces viscous fingering, while gravity segregation stabilizes the displacement front at low production rates. Together, these analyses demonstrate that polymer recovery gains are highly rate-dependent, and that gravity can enhance rather than hinder recovery.

The chapter concluded with the preparation of a scaled sector model from the COSTA carbonate dataset, modified through permeability scaling and vertical refinement. This provides a geologically representative basis for field-scale studies in subsequent chapters, where the combined effects of polymer stability, mobility control, and gravity segregation will be examined under heterogeneous reservoir conditions.

Chapter 4

Sensitivity to Thermal Degradation using Design of Experiment (DOE)

4.1 Introduction

As described in previous chapters, polymer degradation can be a key component in determining the success of polymer projects. In this chapter we study the significance of polymer thermal stability on recovery in a heterogeneous reservoir sector representative of carbonate reservoirs in the Middle East with large well spacing. The analysis also incorporates the interaction between thermal degradation and gravity to capture their combined influence on recovery. This work will set the design basis to formulate guidelines and prove feasibility of polymer deployment in peripheral large well spacing field applications.

The design of polymer flooding requires an in-depth understanding of the complex physics involved in the displacement process. However, running all possible scenarios to assess the effects of various parameters is computationally expensive and time-consuming. To overcome this challenge, we employ the Design of Experiment (DOE) method, which allows for the systematic optimization of the process by efficiently reducing the number of required simulations while still capturing the most critical factors. Through this approach, we aim to validate the importance of thermal degradation and isolate the effects of other parameters interactions, ensuring that the influence of each factor is accurately evaluated.

The concept of experimental design has its roots in the 19th century, where early statisticians began exploring how different factors influenced outcomes in various

scientific experiments. However, it was Sir Ronald Fisher in the early 20th century who laid the foundation for the modern methods of design and analysis of experiments. Fisher's work revolutionized experimental methodology by introducing key principles such as randomization, replication, and blocking, which helped researchers minimize bias and increase the accuracy of their findings. One of his most significant contributions was the development of the full factorial design, where all possible combinations of factors are studied, allowing for a detailed understanding of both the main effects and interactions between variables (Fisher, 1935; Yates, 1964).

Building on Fisher's work, Finney (1943) introduced the concept of fractional factorial designs, demonstrating that only a carefully chosen fraction of a full factorial is sufficient to estimate the most important effects. This innovation made experimental design more efficient by reducing the number of experimental runs while still preserving interpretability. Box and Hunter (1961) later extended and popularized fractional factorials for industrial and engineering applications, embedding them within a broader framework of response surface methodology and sequential experimentation.

This chapter employs these principles, making use of fractional factorial design to evaluate the effects of multiple variables on polymer flooding performance while maintaining a manageable number of experiments.

4.2 Materials and Methods

4.2.1 Two-level Fractional Factorial Design

Factorial designs are central to experiments that investigate the effects of multiple factors simultaneously. In a two-level factorial design, each factor in the experiment is assigned two levels, typically denoted as low and high. A full factorial design includes every possible combination of factor levels, and for k factors, the total number of experimental runs required is 2^k . While this approach allows the researcher to independently estimate the effects of each factor and all possible interactions, it becomes increasingly impractical as the number of factors grows due to the exponential increase in required runs.

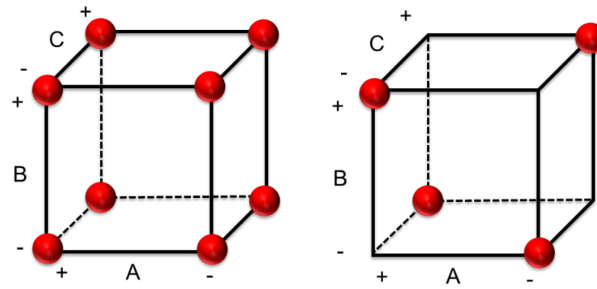


Figure 4.1. Representation of full factorial design to the left and fractional factorial design to the right. The red spheres represent the runs performance in three-dimensional space.

To manage this complexity, the two-level fractional factorial design is used. Rather than testing all possible combinations of factor levels, fractional factorial designs strategically select a subset of these combinations (see **Figure 4.1**). The trade-off is that some effects will be aliased or confounded, meaning the experiment cannot distinguish between certain effects due to the reduced number of runs. For example, if a main effect is aliased with a two-factor interaction, the researcher cannot tell whether the observed outcome is due to the change in the main factor or the interaction between two other factors. Confounding in fractional factorial designs arises naturally from running only a fraction of the full set of experiments. This overlap of effects is not arbitrarily chosen but is instead a property of the design resolution. Researchers accept this confounding by assuming that higher-order interactions (involving three or more factors) are negligible, which allows those interactions to be confounded with lower-order effects or main effects. This assumption enables a reduction in the number of runs while still providing reliable estimates of the more important main effects and two-factor interactions.

A key feature of fractional factorial designs is the resolution of the design, which indicates the extent of aliasing between effects. The resolution defines how confounded the effects are within the design and determines which effects can be independently estimated (see **Figure 4.2**):

- **Resolution III:** No main effects are aliased with other main effects. However, main effects may be aliased with two-factor interactions, meaning that changes in individual factors cannot always be distinguished from interactions between pairs of factors.
- **Resolution IV:** Main effects are not aliased with other main effects or with two-factor interactions. However, some two-factor interactions may be aliased with

each other, and main effects may be confounded with higher-order interactions, such as three-factor interactions.

- **Resolution V:** In designs of this resolution, no main effects or two-factor interactions are aliased with each other. However, two-factor interactions may still be aliased with three-factor interactions, and main effects may be confounded with interactions involving four factors.

		Number of Factors																				
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	
Runs	4	2 ²	2 ³⁻¹ _{IV}																			
	8		2 ³	2 ⁴⁻¹ _{IV}	2 ⁵⁻² _{IV}	2 ⁶⁻³ _{IV}	2 ⁷⁻⁴ _{IV}															
	16			2 ⁴	2 ⁵⁻¹ _{IV}	2 ⁶⁻² _{IV}	2 ⁷⁻³ _{IV}	2 ⁸⁻⁴ _{IV}	2 ⁹⁻⁵ _{IV}	2 ¹⁰⁻⁶ _{IV}	2 ¹¹⁻⁷ _{IV}	2 ¹²⁻⁸ _{IV}	2 ¹³⁻⁹ _{IV}	2 ¹⁴⁻¹⁰ _{IV}	2 ¹⁵⁻¹¹ _{IV}							
	32				2 ⁵	2 ⁶⁻¹ _{IV}	2 ⁷⁻² _{IV}	2 ⁸⁻³ _{IV}	2 ⁹⁻⁴ _{IV}	2 ¹⁰⁻⁵ _{IV}	2 ¹¹⁻⁶ _{IV}	2 ¹²⁻⁷ _{IV}	2 ¹³⁻⁸ _{IV}	2 ¹⁴⁻⁹ _{IV}	2 ¹⁵⁻¹⁰ _{IV}	2 ¹⁶⁻¹¹ _{IV}	2 ¹⁷⁻¹² _{IV}	2 ¹⁸⁻¹³ _{IV}	2 ¹⁹⁻¹⁴ _{IV}	2 ²⁰⁻¹⁵ _{IV}	2 ²¹⁻¹⁶ _{IV}	
	64					2 ⁶	2 ⁷⁻¹ _{IV}	2 ⁸⁻² _{IV}	2 ⁹⁻³ _{IV}	2 ¹⁰⁻⁴ _{IV}	2 ¹¹⁻⁵ _{IV}	2 ¹²⁻⁶ _{IV}	2 ¹³⁻⁷ _{IV}	2 ¹⁴⁻⁸ _{IV}	2 ¹⁵⁻⁹ _{IV}	2 ¹⁶⁻¹⁰ _{IV}	2 ¹⁷⁻¹¹ _{IV}	2 ¹⁸⁻¹² _{IV}	2 ¹⁹⁻¹³ _{IV}	2 ²⁰⁻¹⁴ _{IV}	2 ²¹⁻¹⁵ _{IV}	
	128						2 ⁷	2 ⁸⁻¹ _{IV}	2 ⁹⁻² _{IV}	2 ¹⁰⁻³ _{IV}	2 ¹¹⁻⁴ _{IV}	2 ¹²⁻⁵ _{IV}	2 ¹³⁻⁶ _{IV}	2 ¹⁴⁻⁷ _{IV}	2 ¹⁵⁻⁸ _{IV}	2 ¹⁶⁻⁹ _{IV}	2 ¹⁷⁻¹⁰ _{IV}	2 ¹⁸⁻¹¹ _{IV}	2 ¹⁹⁻¹² _{IV}	2 ²⁰⁻¹³ _{IV}	2 ²¹⁻¹⁴ _{IV}	
	256							2 ⁸	2 ⁹⁻¹ _{IV}	2 ¹⁰⁻² _{IV}	2 ¹¹⁻³ _{IV}	2 ¹²⁻⁴ _{IV}	2 ¹³⁻⁵ _{IV}	2 ¹⁴⁻⁶ _{IV}	2 ¹⁵⁻⁷ _{IV}	2 ¹⁶⁻⁸ _{IV}	2 ¹⁷⁻⁹ _{IV}	2 ¹⁸⁻¹⁰ _{IV}	2 ¹⁹⁻¹¹ _{IV}	2 ²⁰⁻¹² _{IV}	2 ²¹⁻¹³ _{IV}	
	512								2 ⁹	2 ¹⁰⁻¹ _{IV}	2 ¹¹⁻² _{IV}	2 ¹²⁻³ _{IV}	2 ¹³⁻⁴ _{IV}	2 ¹⁴⁻⁵ _{IV}	2 ¹⁵⁻⁶ _{IV}	2 ¹⁶⁻⁷ _{IV}	2 ¹⁷⁻⁸ _{IV}	2 ¹⁸⁻⁹ _{IV}	2 ¹⁹⁻¹⁰ _{IV}	2 ²⁰⁻¹¹ _{IV}	2 ²¹⁻¹² _{IV}	

Figure 4.2. Resolutions for the factorial designs that specify the number of runs linked to the number of tested factors. Reprint: State-Ease 360 software.

Choosing the appropriate resolution depends on the goals of the experiment and available resources. For our screening purposes, we will be using a Resolution IV design. This design allows us to estimate main effects and two-factor interactions without aliasing them with each other, while accepting that some two-factor interactions may be aliased with higher-order effects. Resolution IV strikes a balance between experimental efficiency and clarity of results, making it suitable for the objectives of our study.

4.2.2 Screening Method and Analysis

The screening process for significant factors in the experimental design is detailed. We used the Stat-Ease 360[®] software to perform the analysis. To determine the significance of factors, the half-normal probability plot and the Pareto chart are used. The half-normal probability plot displays the absolute values of factor effects along a straight line. Insignificant effects typically follow this line, as they represent random noise, while significant effects deviate from it. This plot is useful in highlighting important factors that contribute meaningfully to the response. The Pareto chart ranks factor effects by magnitude, from largest to smallest, with bars representing factors that exceed

the significance thresholds. These thresholds, including the t_{value} and the Bonferroni limit, are calculated to identify the most significant effects.

The t_{value} is calculated to assess each factor's significance:

$$t_{value_i} = \frac{|Effect_i|}{\sqrt{MS_{Residual} \left(\frac{1}{n_+} + \frac{1}{n_-} \right)}} \quad 4.1$$

where n_+ and n_- represent the number of trials at the high and low levels of a factor, respectively, and $MS_{Residual}$ is the mean square of residuals. The t_{value} is used to determine whether the effect of a factor significantly deviates from random error.

The effect of a factor is calculated as follows:

$$Effect_i = \frac{\sum Y_+}{n_+} - \frac{\sum Y_-}{n_-} \quad 4.2$$

where $\sum Y_+$ sums the responses over n_+ all runs at the high level and $\sum Y_-$ sums over n_- all runs at the low level. This calculation quantifies the factor's influence on the response by measuring the difference between its high and low levels.

In the context of analysis of variance (ANOVA), the mean square (MS_i) is obtained by:

$$MS_i = \frac{\sum_{i=1}^n (y_i - \bar{y})^2}{n - p} \quad 4.3$$

where MS_i the mean square is the sum of squares $\sum_{i=1}^n (y_i - \bar{y})^2$ divided by the corresponding degrees of freedom $df = n - p$. Here, p represents the number of factors included in the screening model, when applied to an individual effect, the number of parameters considered in the mean square calculation and n is the total number of runs ($n_+ + n_-$). For residuals, the degrees of freedom account for all factors that are treated as insignificant for a given response. In two-level factorial designs, where each factor is represented by a high and a low value, the degree of freedom for each effect is equal to one. The calculated mean square values are then used in the estimation of t_{values} for the individual effects according to (Eq. 4.1).

To evaluate the statistical significance of these effects, the student t -distribution is employed to determine confidence intervals, particularly when the variance or standard deviation of the parameters is unknown. As originally discussed by Lenth (1989), the t -distribution provides a standardized framework that resembles the normal distribution but incorporates higher probability in the tails, thereby offering a more robust estimate of uncertainty. This property allows definition of a t_{value} limit based on the degrees of freedom and chosen confidence interval. For this study, a 5% error margin (95% confidence) is applied, leading to the t -value limit expressed as:

$$t_{value} \text{ limit} = t_{0.05, df} \quad 4.4$$

This threshold provides the statistical boundary above which an effect can be considered significant. To control for multiple comparisons, we applied the Bonferroni correction, which adjusts the significance threshold based on the number of factors. The Bonferroni limit is calculated by:

$$Bonferroni_{t_{value} \text{ limit}} = t_{0.05/k, df} \quad 4.5$$

where k is the number of factors used in the pareto at once. This correction ensures a more conservative threshold, reducing the likelihood of false positives when many factors are under investigation.

Factors are classified based on their significance relative to these thresholds. Main effects and interactions that exceed the Bonferroni limit are prioritized for further analysis, as they are considered the most significant. For Resolution IV designs, however, two-way interactions may be confounded with other two-way interactions, making it difficult to isolate their true effects. The analysis may still include interactions that exceed the t_{value} limit if necessary, although any factor or interaction that does not meet the t_{value} threshold is discarded as insignificant.

In fractional factorial designs, particularly Resolution IV designs, confounding is an inherent issue. While this confounding may lead to uncertainty in determining which interactions are significant, interactions that are physically or theoretically reasonable are still included in the analysis. Their combined effect can still influence the results and help identify key factors, even if they are aliased with other interactions.

4.2.3 Screening Design

The initial sensitivity analysis was conducted on the one-dimensional model to exclude the effect of gravity, focusing on identifying the parameters with the highest sensitivity responses. The most sensitive parameters from this analysis were then carried over to the second stage of sensitivity, which was performed on a 3D heterogeneous field sector model. This model captures stratigraphic layering, vertical anisotropy, and crossflow representative of Middle Eastern carbonate reservoirs, allowing us to evaluate polymer thermal degradation under conditions where gravity and heterogeneity are active. This extension was particularly important because it allowed us to investigate the interplay between degradation and gravity, two opposing mechanisms that strongly influence recovery efficiency. Chapter 3 demonstrated that while thermal degradation reduces polymer viscosity with longer residence times, promoting gravity segregation by reducing production/injection rate can improve recovery. The purpose here was therefore not only to confirm whether the factors identified as significant in the 1D analysis remain dominant, but also to establish whether the benefits of gravity can offset, or even outweigh, the penalties imposed by degradation.

4.2.4 Key Design Parameters

This section outlines the design parameters employed in the screening study. The factors selected have been demonstrated, both experimentally and numerically in existing literature, to influence polymer flooding performance. The primary objective is to identify thermal degradation as a key factor and investigate the interactions that amplify its impact on polymer thermal stability. The static models' parameters are included in **Table 4.1**.

Table 4.1. Static models properties for the 1D and 3D models included in the DOE study.

Parameter	Unit	1D Model	3D Model
Grid blocks		225×1×1	75×75×62
Grid block size	m	5.55×1250×10	16.67×16.67×0.80
Reservoir length, l	m	1250	1250
Reservoir width, w	m	1250	1250
Reservoir thickness, h	m	10	49.5
Porosity, ϕ	%	20	21
Permeability, K	mD	500	300

4.2.4.1 Polymer Type

Two polymer types, HPAM and ATBSA, were included in the DOE. Their thermal and chemical degradation behaviour was introduced in Chapter 3 (see **Table 3.6** and **Table 3.7**) and summarised in terms of half-life performance at relevant reservoir temperatures in **Table 4.2**. HPAM was carried forward as the conventional baseline polymer, while ATBSA was chosen as a representative of the newer ATBS-based polymers designed for thermal stability. Together, they allow the sensitivity analysis to capture the contrast between a polymer that is technically challenged at reservoir conditions and one that is designed to remain stable under high temperature and salinity.

Table 4.2. Projected half-life at the sensitivity temperatures (85 °C and 100 °C), and threshold temperature of 140 °C estimated from Arrhenius fitting in **Figure 3.4** .

Polymer	Half-life at 85 °C (years)	Half-life at 100 °C (years)	Half-life at 140 °C (years)
ATBSA	200	50	0.5
HPAM	4	2.5	0.8

4.2.4.2 Polymer Viscosity

Polymer viscosity is a key factor in determining the effectiveness of mobility control during displacement. As discussed in Chapter 3, analytical evaluation using the Buckley–Leverett framework indicated that displacement recovery improves significantly with increasing polymer viscosity up to around 10 mPa·s, beyond which incremental gains become marginal. For this reason, 10 mPa·s was selected as the high-level viscosity in the DOE, representing a technically reasonable upper limit for the targeted field application.

To provide contrast, the low-level viscosity was set at 5 mPa·s, corresponding to approximately half of the reference value. This choice reflects two important considerations: first, it captures the practical scenario where field operators may prefer to work with lower polymer concentrations to reduce chemical costs; second, it enables the DOE to test the sensitivity of recovery to viscosity reduction, thereby indicating whether stable displacement can still be achieved at more economical concentrations. The viscosity–concentration relationship described in Chapter 3 (Eq. 3.5) was used to calibrate these levels, where a third-order Flory–Huggins fitting provided the basis for translating viscosity into polymer concentration. At the selected viscosities, the required polymer concentrations fall in the range of 0.03–0.06 wt%. Including both levels

therefore ensures that the DOE captures the interplay between viscosity, polymer degradation, and recovery, while also reflecting operational and economic realities.

4.2.4.3 *Reservoir Temperature*

Identifying the appropriate temperature range for the fractional factorial DOE is essential. Globally, temperatures in carbonate reservoirs often exceed 85°C, with averages around 100°C in the Middle East and reaching up to 130°C in the North Sea (Alnarabiji and Husein, 2020; Hassan et al., 2023). In this study, sensitivity analysis is carried out at 85 °C and 100 °C, representing the most relevant conditions for Middle Eastern reservoirs.

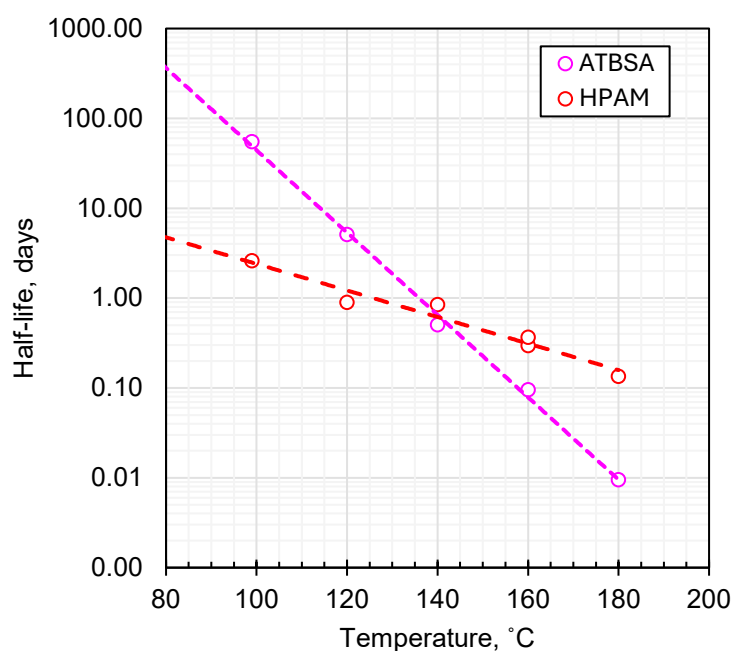


Figure 4.3. Half-life performance for HPAM in red and ATBSA in magenta at multiple temperatures with data exponential regression lines.

Polymer thermal stability is inherently a function of temperature, and the ability of a polymer to sustain its viscosity depends strongly on the reservoir thermal environment. To express this relationship more intuitively, the Arrhenius degradation trends presented in Chapter 3 (**Figure 3.4**) were converted into half-life versus temperature relationships. **Figure 4.3** presents the outcome of this conversion, providing a direct measure of polymer stability across a wide temperature range. The results confirm that while ATBSA can be considered stable at 100 °C, it rapidly loses this advantage at higher temperatures, with a crossover above ~140 °C where HPAM becomes comparatively

more resistant. This demonstrates that polymer stability cannot be defined in absolute terms but must always be evaluated relative to reservoir temperature. For this reason, temperature is a critical factor to incorporate into the DOE design criteria, as it directly governs polymer longevity and influences the feasibility of polymer flooding in high-temperature reservoirs.

4.2.4.4 *Production/Injection Rate*

Polymer exposure time is a function of distance between the injector and producer wells and the speed of displacement. Field operators can influence surface rates and the percentage of reservoir oil depletion (OIP), which serves as the basis for rate selection for the DOE sensitivity analysis. The fractional factorial design is conducted in two stages: a one-dimensional model and a three-dimensional field sector model with varying net pay thicknesses. For each stage, the DOE low-level depletion rate is set to represent typical field operation conditions in the Middle East, ranging from 2.5% to 3.5% OIP per year (Alsaleh et al., 2024). The high-level depletion rate is designed to simulate more aggressive conditions, ranging from 4% to 12% OIP per year (see **Table 4.3**).

Table 4.3. Production and injection rate DOE levels for the 1D and 3D field sector models and design depletion rate and frontal advance rate.

Case	DOE Level	Rate (m ³ /day)	Depletion Rate (%OIP/year)	Frontal Advance Rate (m/day)
1D	Low	300	3.5%	0.23
	High	1000	11.7%	0.75
3D Field Sector	Low	2000	2.8%	0.21
	High	3000	4.1%	0.37

4.2.4.5 *Todd and Longstaff Mixing Factor*

The Todd and Longstaff model was introduced in Chapter 3; here we justify our choice of ω . Todd and Longstaff (1972) proposed the semi-empirical mixing formulation and calibrated ω against laboratory and field displacement data, recommending a range of 0.33–0.67—with lower values (~ 0.33) reflecting sharper, field-scale fronts and higher values (~ 0.67) matching the stronger mixing seen in sand-pack experiments. For the 1D screening DOE, we set $\omega = 0$ and $\omega = 1$ to bracket the extremes (no mixing vs. complete mixing) and keep the focus on thermal degradation sensitivities without imposing an uncalibrated intermediate value.

For the 3D DOE and subsequent simulations, which use a heterogeneous carbonate reservoir sector, we adopt $\omega = 0.67$ to represent the expected fingering/sub-grid dispersion. This is consistent with calibration to experimental fingering and common simulation practice (Abdul Hamid and Muggeridge, 2018; Blackwell et al., 1959). While Abdul Hamid and Muggeridge (2018) note that heterogeneous reservoirs may warrant a case-specific mixing study, our thesis centres on thermal degradation; an additional ω sensitivity could be performed if desired, but is not required for the present objectives.

4.2.4.6 *Slug Size*

The slug size represents a key economic design parameter, as it controls polymer volume and cost while also influencing front integrity. Using the initialised data of relative permeability, together with a polymer viscosity of 10 mPa·s and a Todd and Longstaff mixing factor of $\omega = 0.67$, the semi-analytical framework of Abdul Hamid and Muggeridge (2018) (extended Buckley–Leverett with Todd–Longstaff mixing) predicts a near-optimal slug size of ~ 0.34 PV. The full workflow and validation of this approach will be presented in Chapter 6. Because the DOE in this chapter involves different viscosities and mixing assumptions, a fractional-factorial statistical screening was carried out (see Chapter 6). 0.40 PV was chosen as high level, while 0.10 PV was set as the low, economical level to test sensitivity to reduced polymer volume and its interaction with thermal degradation.

4.2.4.7 *Gravitational Cross Flow Factors*

To capture the role of gravity and crossflow in polymer flooding performance, we extend the DOE to include parameters derived from the COSTA sector model introduced in Chapter 3, Section 3.5. Three factors are considered:

Vertical anisotropy $\frac{K_v}{K_H}$: varied between 0.1 (low level, representing restricted vertical communication) and 0.5 (high level, representing enhanced crossflow and gravity influence).

Stratigraphy: tested in two distributions, coarsening-upward and fining-upward permeability profiles, as previously defined in **Figure 3.24**.

Vertical resolution: fine grid (62 layers) versus coarse grid (5 layers), representing the impact of upscaling on vertical flow and segregation (see **Figure 3.24**).

These gravitational crossflow factors were selected to evaluate how reservoir architecture and model resolution interact with thermal degradation, with levels chosen to bracket realistic conditions for Middle Eastern carbonate reservoirs.

Listed in **Table 4.4** and **Table 4.5** are key design factors that will be used in the DOE to screen the main factors and interactions to be researched further in following chapters.

Table 4.4. Factors and levels used in the 1D screening study.

Factors	Low	High
Polymer viscosity, μ_p	5 mPa.s	10 mPa.s
Reservoir temperature, T_R	85 °C	100 °C
Rate, $Q_{inj/prod}$	300 m ³ /day	1000 m ³ /day
Polymer type	HPAM	ATBSA
Slug size	0.1 PV	0.4 PV
Mixing factor, ω	0	1

Table 4.5. Factors and levels used in the 3D sector model screening study.

Factors	Low	High
Rate, $Q_{inj/prod}$	2000 m ³ /day	3000 m ³ /day
Polymer type	HPAM	ATBSA
Slug size	0.1 PV	0.4 PV
Vertical anisotropy $\frac{K_v}{K_H}$	0.1	0.5
Stratigraphy	Fining Upward	Coarsening Upward
Vertical resolution	Coarse	Fine

4.2.5 Screening Design Response

The response factor selected for the 1D DOE analysis is the incremental oil pore volume produced at 1 pore volume injected, calculated relative to the waterflood baseline representing the gain in recovery. The water flood baseline corresponds to the recovery without any chemical enhancement. This metric provides a clear measure of polymer flooding performance under thermal degradation and is used to construct the Pareto and half-normal probability charts. In the 3D DOE analysis, the oil pore volume produced at one pore volume injected was selected as the response factor in absolute value,

replacing the incremental gain from the waterflood baseline used in 1D. This adjustment was necessary because waterflood performance in 3D is influenced by heterogeneity and gravity and cannot be treated as a consistent reference.

4.3 Results and Discussion

4.3.1 Initial Parameters Screening (1D Model)

We used the 1D line-drive model introduced in Chapter 3 (model setup and grid refinement; see Chapter 3, Section 3.3) to establish a gravitational crossflow free baseline. The six factors and their levels are exactly those listed in **Table 4.4**. The DOE setup and significance testing follow the workflow already described in this chapter's Materials and Methods (Two-level fractional factorial design and Screening method and analysis; (Eqs. 4.1–4.5), using a Resolution IV quarter-fraction generated in Stat-Ease 360[®]. All following simulation will adopt polymer flooding as a secondary recovery.

4.3.1.1 *Statistical Significance of Factors*

The design generated a total of 16 runs, shown in **Table 4.6**, which formed the experimental matrix for the 1D simulations. The grid resolution was fixed at 225 cells, as established in Chapter 3, to minimise numerical artefacts and ensure that observed performance changes were attributable to the design factors. The results of this initial screening are expected to highlight the most significant parameters influencing polymer flooding performance when degradation is present and to provide the foundation for the more complex 3D heterogeneous sector model analysis presented later.

Figure 4.4 illustrates the recovery responses from the 16 DOE runs compared against the waterflood and polymer flood baselines. Polymer flood base line corresponds to continuous polymer flooding assuming no mixing and flowing at 1000 m³/day. The ensemble of runs forms a window of deviation, with incremental gains and losses of more than ~3 to 16% observed relative to the waterflood baseline (See **Table 4.7**). This spread highlights the combined influence of the design factors, even though not all six contribute equally to the observed variation.

Table 4.6. Experimental design matrix for the 1D model screening study (16 runs).

STD	Run	Polymer Viscosity (mPa.s)	Reservoir Temperature °C	Rate (m3/day)	Polymer Type	Slug Size (PV)	Mixing factor
5	1	5	85	300	ATBS	0.4	1
4	2	10	100	300	HPAM	0.1	1
7	3	5	100	300	ATBS	0.1	0
6	4	10	85	300	ATBS	0.1	1
9	5	5	85	1000	HPAM	0.1	1
12	6	10	100	1000	HPAM	0.1	0
10	7	10	85	1000	HPAM	0.4	1
8	8	10	100	300	ATBS	0.4	0
15	9	5	100	1000	ATBS	0.1	1
13	10	5	85	1000	ATBS	0.4	0
14	11	10	85	1000	ATBS	0.1	0
2	12	10	85	300	HPAM	0.4	0
11	13	5	100	1000	HPAM	0.4	0
1	14	5	85	300	HPAM	0.1	0
3	15	5	100	300	HPAM	0.4	1
16	16	10	100	1000	ATBS	0.4	1

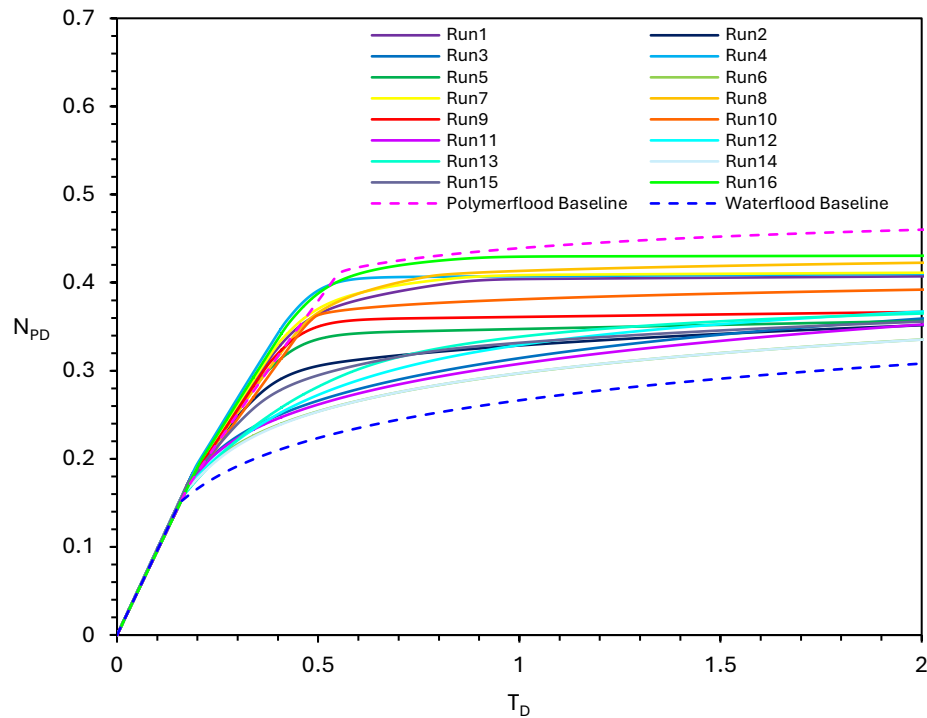


Figure 4.4. Numerical oil pore volume produced as a function of pore volumes of polymer injected for the 1D design of experiment. The performance of 16 runs from **Table 4.6** and waterflood and polymer flood baselines.

Table 4.7. Oil pore volume production response relative to waterflood at 1 pore volume injected used in the DOE.

Run	N _{PD} @ 1PVI (Waterflood Baseline)	N _{PD} @ 1PVI (DOE Runs)	Incremental Gain/Loss @ 1PVI (Response)
1	0.27	0.40	0.14
2	0.27	0.33	0.06
3	0.27	0.31	0.05
4	0.27	0.41	0.14
5	0.27	0.35	0.08
6	0.27	0.30	0.03
7	0.27	0.41	0.14
8	0.27	0.41	0.15
9	0.27	0.36	0.09
10	0.27	0.38	0.11
11	0.27	0.31	0.04
12	0.27	0.33	0.06
13	0.27	0.34	0.07
14	0.27	0.30	0.03
15	0.27	0.33	0.07
16	0.27	0.43	0.16

The statistical significance of each factor and interaction was then evaluated using the Pareto chart of standardized effects (see **Figure 4.5**). In this chart, the t_{value} limit provides the threshold for statistical significance at the 95% confidence level, while the more conservative Bonferroni limit acts as an additional safeguard against false positives when multiple factors are tested simultaneously. Slug size (E), polymer type (C), and mixing factor (F) clearly exceed both thresholds, confirming their dominant role in determining polymer flooding performance under thermal degradation.

Polymer type is especially critical in this context, as it encapsulates the influence of thermal degradation: ATBSA maintains viscosity over longer exposure times compared to HPAM, which rapidly loses effectiveness. The strong significance of polymer type confirms that stability under reservoir conditions is central to sustaining recovery gains.

The polymer type–rate interaction (CD) and polymer viscosity (A) lies between the t_{value} and Bonferroni limits, indicating partial significance. The interaction between polymer type and rate reflects the dependence of degradation on exposure time: at lower injection rates, polymers reside longer in the reservoir, amplifying differences in thermal stability between HPAM and ATBSA; at higher rates, shorter residence times reduce this contrast.

By contrast, reservoir temperature (B) lies below the t_{value} threshold, suggesting that within the relatively narrow range of 85–100 °C tested, temperature does not directly appear as a dominant effect. Its role is expressed indirectly through polymer type and its interaction with rate, a point explored further in the next section.

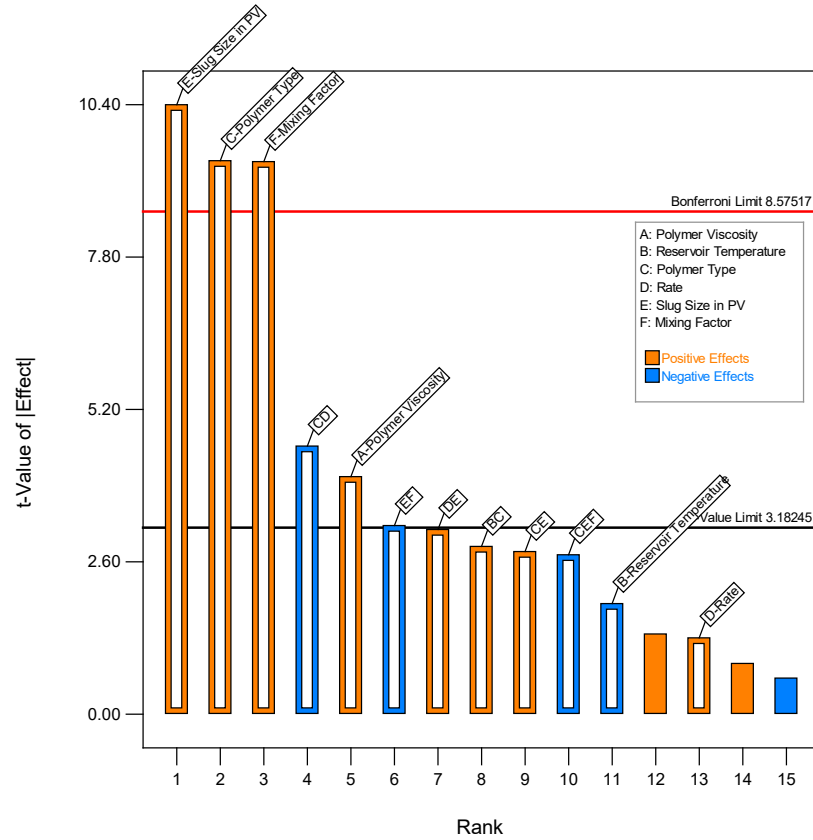


Figure 4.5. Pareto chart for incremental gain/loss of oil pore volume produced from waterflood for the 1D screening DOE.

The half-normal probability plot (see **Figure 4.6**) supports these findings. Slug size (E), polymer type (C), and mixing factor (F) deviate strongly from the reference line, confirming high significance, while polymer type–rate interaction (CD) and polymer viscosity (A) shows moderate deviation (partial significance). Reservoir temperature and the remaining factors cluster close to the line, indicating weak or negligible effects in this screening. Overall, the 1D screening highlights slug size, polymer type, and mixing factor as the key drivers of polymer flooding performance under thermal degradation, with the polymer type–rate interaction providing an additional insight into the importance of exposure time. Reservoir temperature, though less visible here, remains an underlying factor to be revisited in broader sensitivity studies.

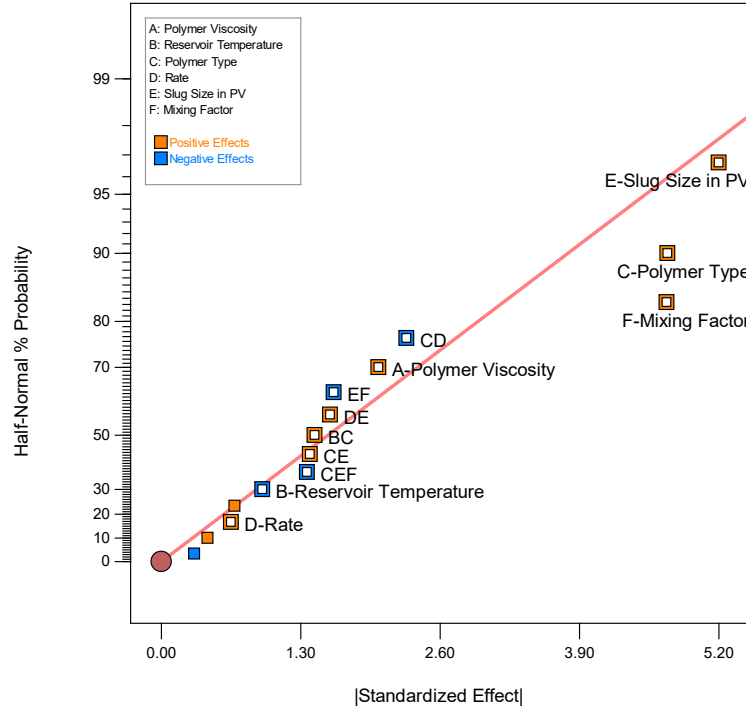


Figure 4.6. Half-normal plot for incremental gain/loss of oil pore volume produced from waterflood for the 1D screening DOE.

4.3.1.2 1D DOE Main Factors and Interactions

The Pareto and half-normal probability charts provide a structured assessment of which factors most strongly influence polymer flooding performance under thermal degradation in the 1D screening model. Slug size, polymer type, and the mixing factor clearly exceed both the t_{value} and Bonferroni thresholds, confirming their dominant importance. Polymer viscosity and the polymer type–rate interaction rank between the two thresholds, classifying them as partially significant. Reservoir temperature falls below the t_{value} threshold, appearing statistically insignificant in this initial screening. These results establish which parameters warrant prioritization in the subsequent 3D sector analysis, where heterogeneity and gravity effects will also be present. In line with the base-case design data discussed earlier, subsequent analyses will honour a rate of 1000 m³/day, a slug size of 0.34 PVI, and a mixing factor of 0.67, except in cases where these parameters are themselves the subject of sensitivity testing.

4.3.1.2.1 Polymer Type

Polymer type emerged as a dominant factor, encapsulating the role of thermal stability in governing recovery. The strong influence of this parameter reflects the sharp contrast between HPAM, which rapidly degrades at elevated temperatures, and ATBSA, which

sustains its viscosity over much longer exposure periods. The outcome here confirms that degradation resistance is central to polymer performance and reinforces polymer type as a critical factor to be carried into sector and field scale studies (See **Figure 4.7**).

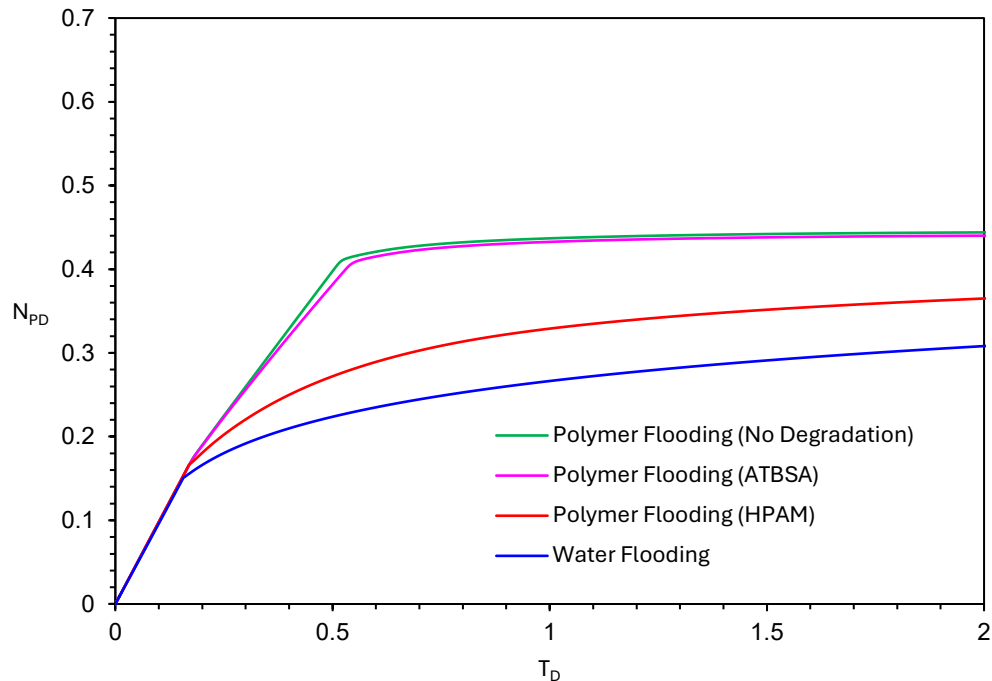


Figure 4.7. Numerical oil pore volume produced as a function of pore volumes of polymer injected with ideal no thermal degradation assumed in green, ATBSA in magenta, HPAM in red, and water flooding in blue over 2 pore volumes period. The plot demonstrates the criticality of polymer type through the contrast in performance of ATBSA and HPAM polymer. ATBSA demonstrate exceptional stability even when there is 1.25 km between wells.

4.3.1.2.2 Slug Size

Slug size emerged as one of the most significant factors in the 1D DOE, confirming its strong influence on recovery performance. The DOE results demonstrate that slug size governs both the extent of mobility control and the integrity of the polymer bank, making it one of the most critical parameters in polymer flood design. **Figure 4.8** shows the recovery response for a range of slug sizes of ATBSA polymer flowing at 1000 m³/day. Larger slugs above 0.4 PV did not provide any major performance improvement, while smaller slugs such as 0.1 PV underperformed relative to the optimum but still offered noticeable incremental recovery compared to waterflooding. This suggests that even sub-optimal slug sizes can contribute significantly to recovery and may present a more economical option for field operators in certain cases.

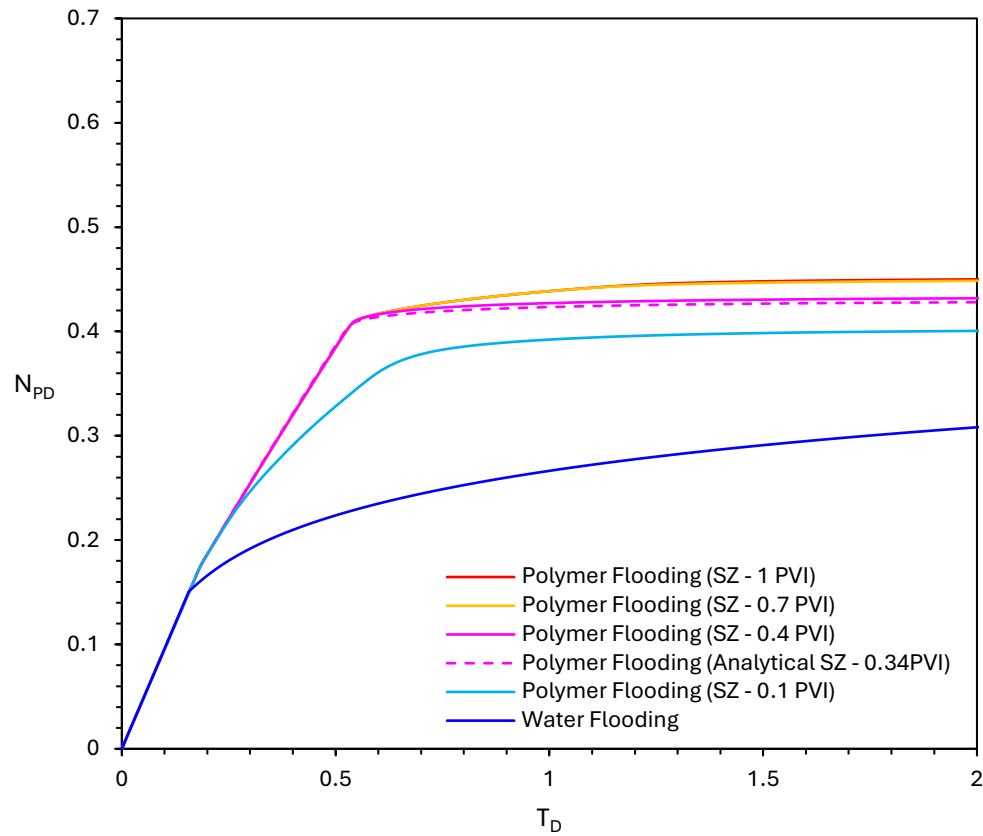


Figure 4.8. Numerical oil pore volume produced as a function of pore volumes of polymer injected with different slug sizes. No major performance improvement above the optimal analytical slug size of 0.34 PVI.

The cross-sectional profiles in **Figure 4.9** help explain this behaviour. For the 0.1 PV case, the polymer bank loses integrity through premature breakdown, as the trailing water overtakes the slug before polymer breakthrough. By contrast, the 0.34 PV slug maintains a stable polymer bank, with the polymer front reaching the producer ahead of the chase water. This confirms that the slug size predicted for our reservoir design parameters (~ 0.34 PV) is sufficient to ensure displacement stability and aligns with the analytical/statistical work presented in Chapter 6.

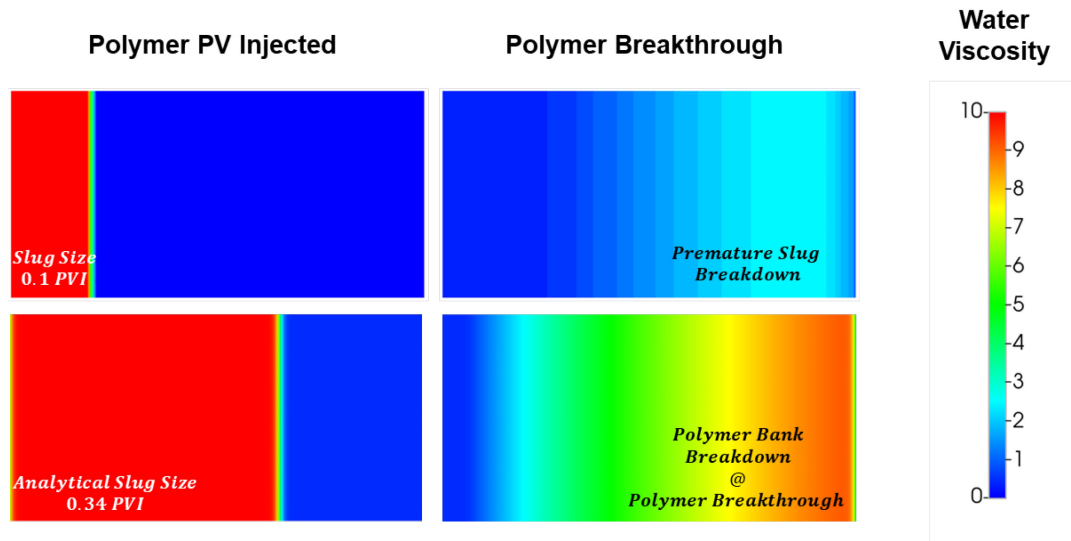


Figure 4.9. Water viscosity cross section of polymer bank at the end of polymer injection of slug size of 0.1 PVI and analytical slug size of 0.34 PVI on the left side and at the time of polymer breakthrough. The smaller slug experiences premature breakdown whereas the 0.34 PVI bank front reached the producer before the trailing water breakdown the bank validating the analytical solution.

It should be stressed, however, that these observations are based on a 1D analysis, where the effects of crossflow, gravity, and reservoir heterogeneity are absent. While the trends are clear, validation in more realistic 3D heterogeneous models is required to confirm the practical feasibility of both optimal and sub-optimal slug sizes. This is explored in the following section of the DOE.

4.3.1.2.3 Mixing Factor

The mixing factor ranked as statistically significant in the Pareto analysis, highlighting its role in controlling dispersion and fingering. In the 1D simulations (see **Figure 4.10**), however, its effect varied depending on polymer type and slug size. For ATBSA at the designed slug size of 0.34 PV, variations in ω between 0 and 1 produced only minimal changes in recovery, indicating that a stable polymer bank is largely insensitive to dispersion effects. For HPAM under the same slug size, recovery improved noticeably with higher ω values, as greater mixing helped stabilize the degraded polymer bank and limit premature fingering.

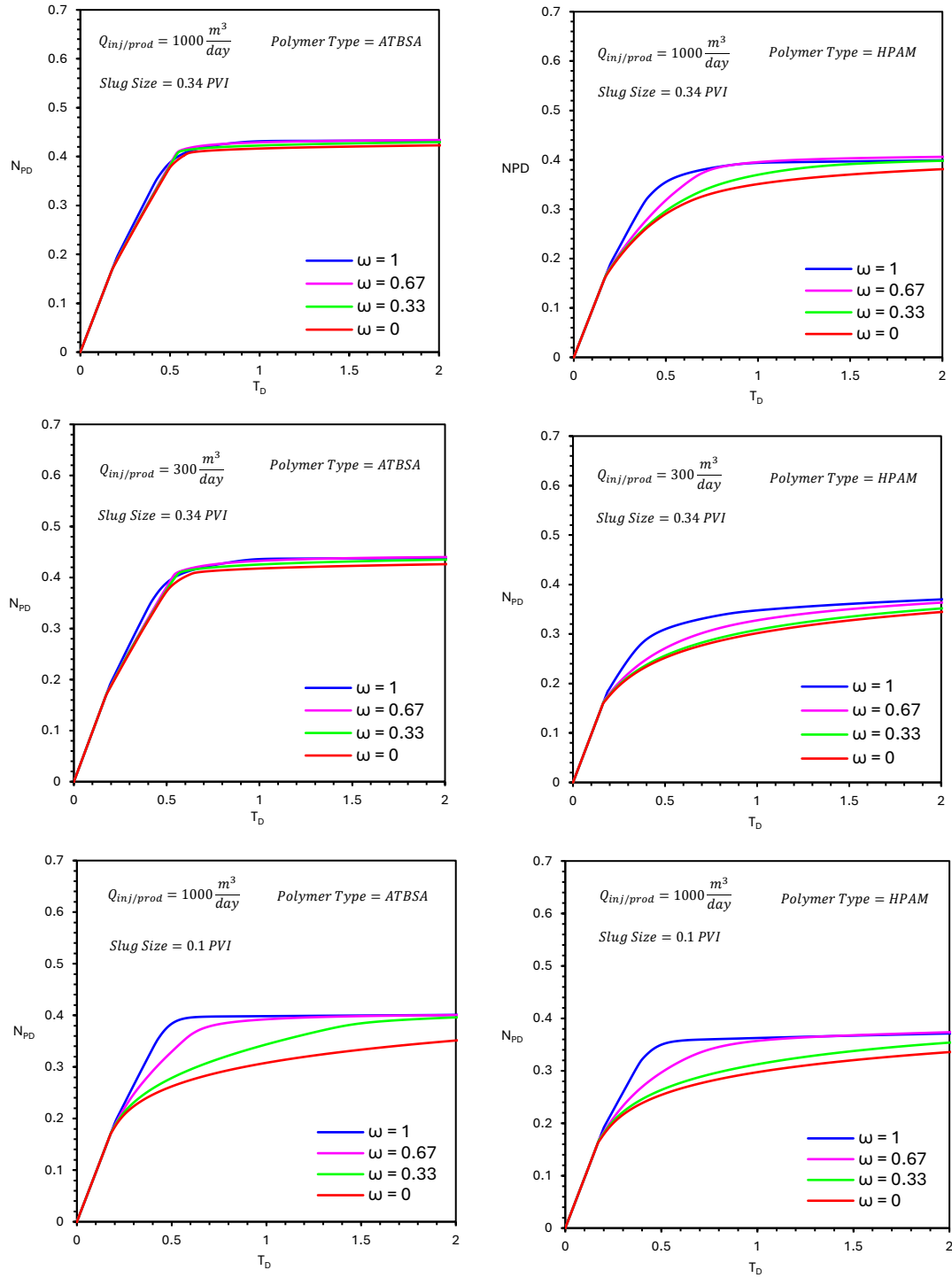


Figure 4.10. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different mixing factors for ATBSA on the left and HPAM on the right. The top and middle plots are rate variant. The bottom plots are smaller slug sizes. Although mixing factor ranked significant in the DOE for ATBSA with the designed slug size of 0.34 PVI mixing factor variations produced minimal effect of recovery.

The influence of the mixing factor became far more pronounced for smaller slugs (0.1 PVI). In these cases, both ATBSA and HPAM showed strong sensitivity to ω , with low values leading to rapid slug breakdown and early chase water override. At higher ω values, however, dispersion acted to preserve slug integrity and sustain displacement efficiency, allowing smaller slugs to perform remarkably well compared to their low-mixing counterparts. This highlights that while larger, stable polymer banks are less affected by mixing, smaller slugs are impacted heavily by ω to maintain effectiveness magnifying the significance of detailed study to incorporate the most representative ω value. Given these observations, no further sensitivity to ω will be carried forward into the 3D DOE. Instead, a fixed value of 0.67 will be adopted, consistent with prior studies (Abdulhamid & Muggeridge, 2018; Blackwell et al., 1959).

4.3.1.2.4 Polymer Type and Rate Interaction

The interaction between polymer type and injection/production rate was identified as partially significant in the Pareto analysis, underlining the role of residence time in determining the extent of thermal degradation. This is clearly illustrated in **Figure 4.11**, where the performance of ATBSA and HPAM is compared at high (1000 m³/day) and low (300 m³/day) production/injection rates.

ATBSA demonstrated robust stability, with recovery levels almost indistinguishable from the no-degradation case across both rates. Within the scope of this DOE design, production/injection rate therefore appears to have little effect on ATBSA. However, it is important to note that these results are based on the specific limits tested in the 1D model. At the field scale, with much larger well spacing and longer polymer residence times, exposure will be extended significantly. Under such conditions, even ATBSA can be expected to exhibit stronger sensitivity to production/injection rate through the combined effects of thermal degradation and gravity segregation.

For HPAM, the impact of rate was more immediate. At 1000 m³/day, reduced exposure time partially mitigated thermal degradation, leading to better performance compared to the 300 m³/day case. At the lower rate, prolonged residence time amplified viscosity loss and caused marked deterioration in recovery relative to ATBSA. This amplified the importance of understanding thermal stability in relation to production/injection rate, which directly translates to polymer residence or exposure time in the reservoir.

It is also important to highlight that rate on its own ranked as statistically insignificant in the 1D DOE. This is expected, since in one-dimensional systems the injection/production rate has no direct impact on displacement efficiency. Its significance only emerges through its interaction with polymer type, where the combined effects of degradation and exposure time alter recovery outcomes.

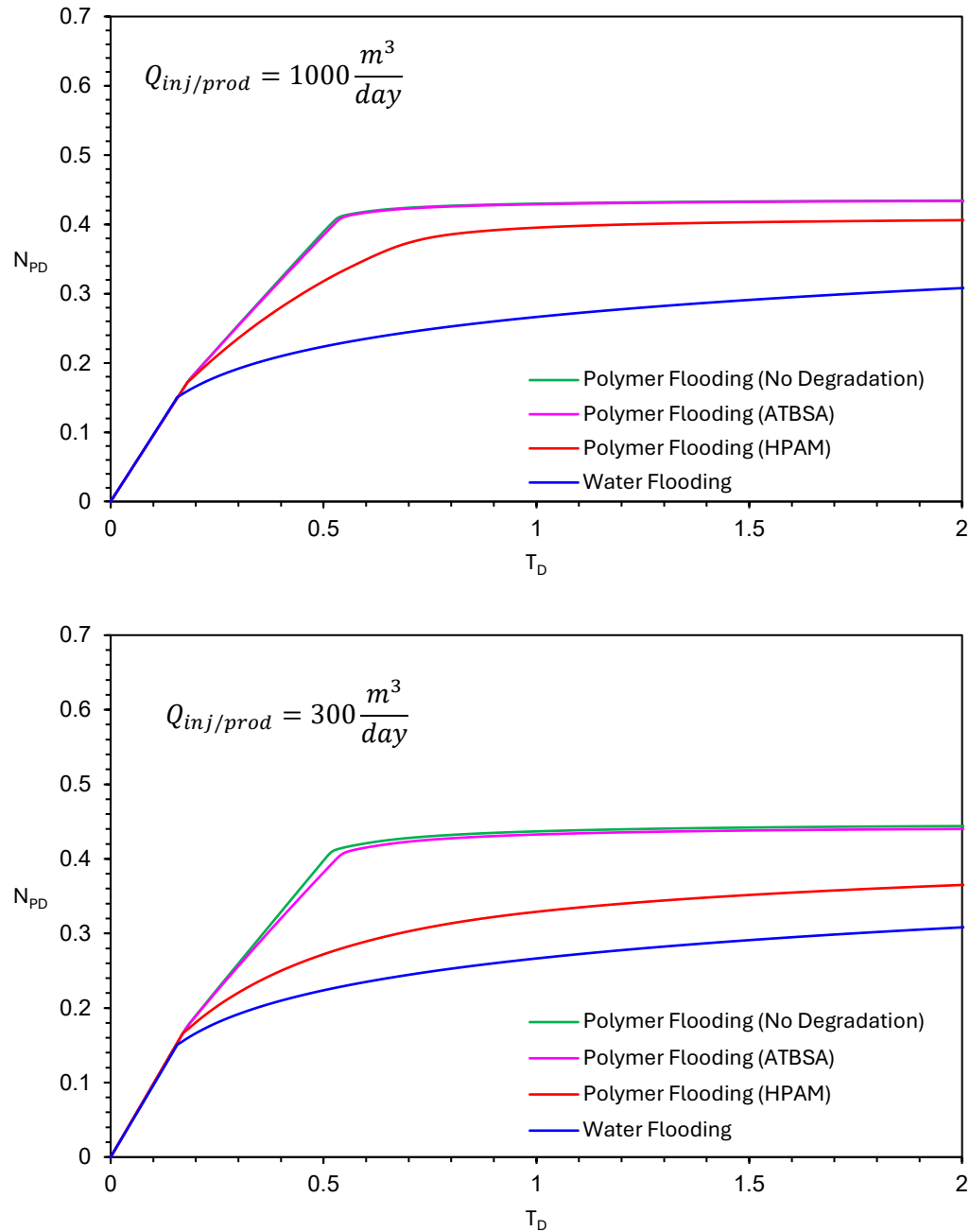


Figure 4.11. Numerical oil pore volume produced as a function pore volume injected for different polymer types and flow rates. The top plot demonstrates the performance of ATBSA and HPAM flowing at $1000 \text{ m}^3/\text{day}$ and the bottom plot at $300 \text{ m}^3/\text{day}$. ATBSA demonstrated exceptional recovery performance almost matching the performance of polymer with no thermal degradation assumed at both production/injection rates. HPAM demonstrated significant deterioration in performance do to longer exposure imposed by lower production/injection rate and its low half-life.

Overall, this analysis demonstrates that polymer type and rate cannot be considered in isolation. While ATBSA appears exceptionally stable, its use may represent an overdesign and excessive cost in some applications. Conversely, even HPAM if deployed with careful consideration of exposure time and properly matched to field OIP depletion conditions, could deliver outstanding performance at significantly lower cost.

4.3.1.2.5 Polymer Viscosity

Polymer viscosity ranked as partially significant in the DOE analysis, falling between the t_{value} and Bonferroni thresholds. Although it did not exert as strong an influence as slug size or polymer type, its impact on recovery is still evident within the 5–10 mPa·s window explored in this study. **Figure 4.12** illustrates how higher viscosities consistently improve displacement efficiency relative to waterflooding, with incremental recovery gains diminishing as viscosity increases.

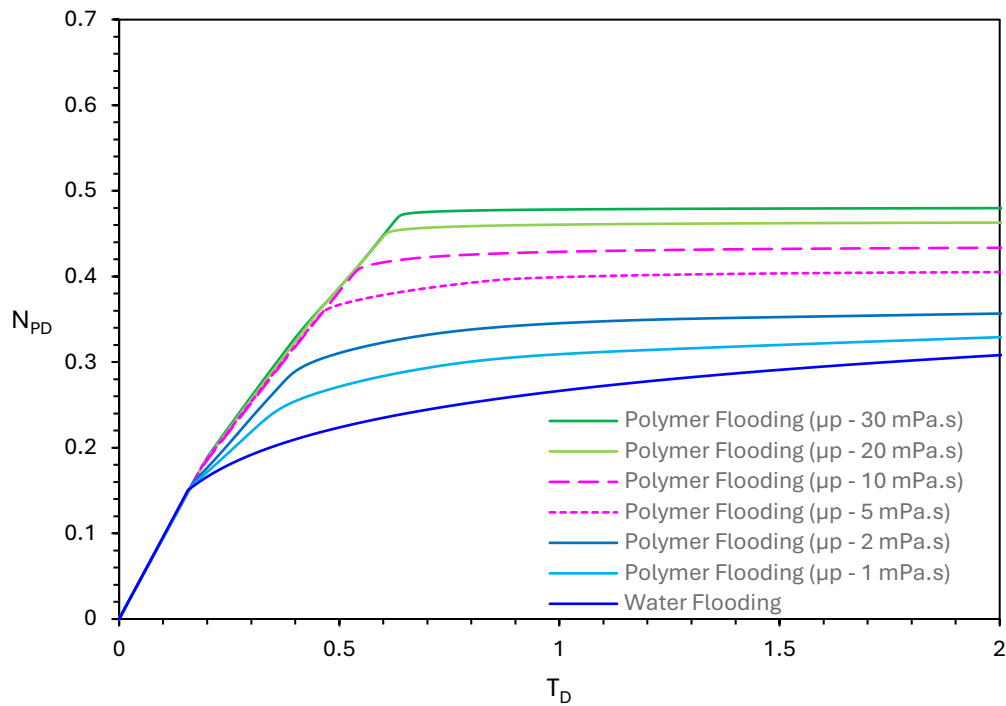


Figure 4.12. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different polymer viscosities.

This outcome is consistent with the analytical evaluation presented in Chapter 3 (**Figure 3.9**), where the Buckley–Leverett framework showed that displacement recovery improves sharply as polymer viscosity increases up to ~ 10 mPa·s, after which further gains become marginal. The partial statistical significance observed here can be attributed to the relatively narrow viscosity range adopted in the DOE (5–10 mPa·s).

When broader viscosity ranges are considered, as demonstrated in **Figure 4.12**, the role of viscosity is clearly more pronounced.

Overall, viscosity should be regarded as a primary design parameter, particularly in relation to thermal degradation where polymer stability can alter the effective viscosity delivered in the reservoir. For subsequent 3D DOE and field-scale studies, we will carry forward the use of 10 mPa·s, as this value has been established analytically and numerically to represent a technically robust choice, balancing performance with diminishing returns at higher viscosities.

4.3.1.2.6 Reservoir Temperature

Reservoir temperature was expected to rank as a significant parameter due to its direct role in accelerating polymer thermal degradation through the Arrhenius relationship. However, in the 1D DOE it ranked below the t_{value} threshold, reflecting limited statistical significance within the design scope. This outcome is largely explained by the short exposure times inherent to the 1D model and the thermal stability of the polymer types considered.

As shown in **Figure 4.13**, ATBSA maintained a performance that was nearly identical to the no-degradation case across the tested range of 85–100 °C. This aligns with its design as a thermally stable polymer at 100 °C, where no substantial decline in viscosity or recovery is expected. HPAM, by contrast, exhibited modest deterioration in recovery, consistent with its shorter half-life under the same conditions. At 140 °C, which was outside the DOE design limits but included here for comparison, both polymers showed significant performance losses and converged toward similar outcomes, reflecting their matching half-life expectations under extreme thermal stress.

Although temperature did not emerge as a statistically significant factor in this screening, it remains a critical consideration for field application, as exposure times in real reservoirs are much longer and higher temperatures can accelerate degradation beyond what is captured here. For the purposes of this thesis, however, reservoir temperature will not be carried forward into the 3D DOE. Instead, a reservoir temperature of 100 °C will be adopted as the representative operating condition for all subsequent studies and sensitivity analyses.

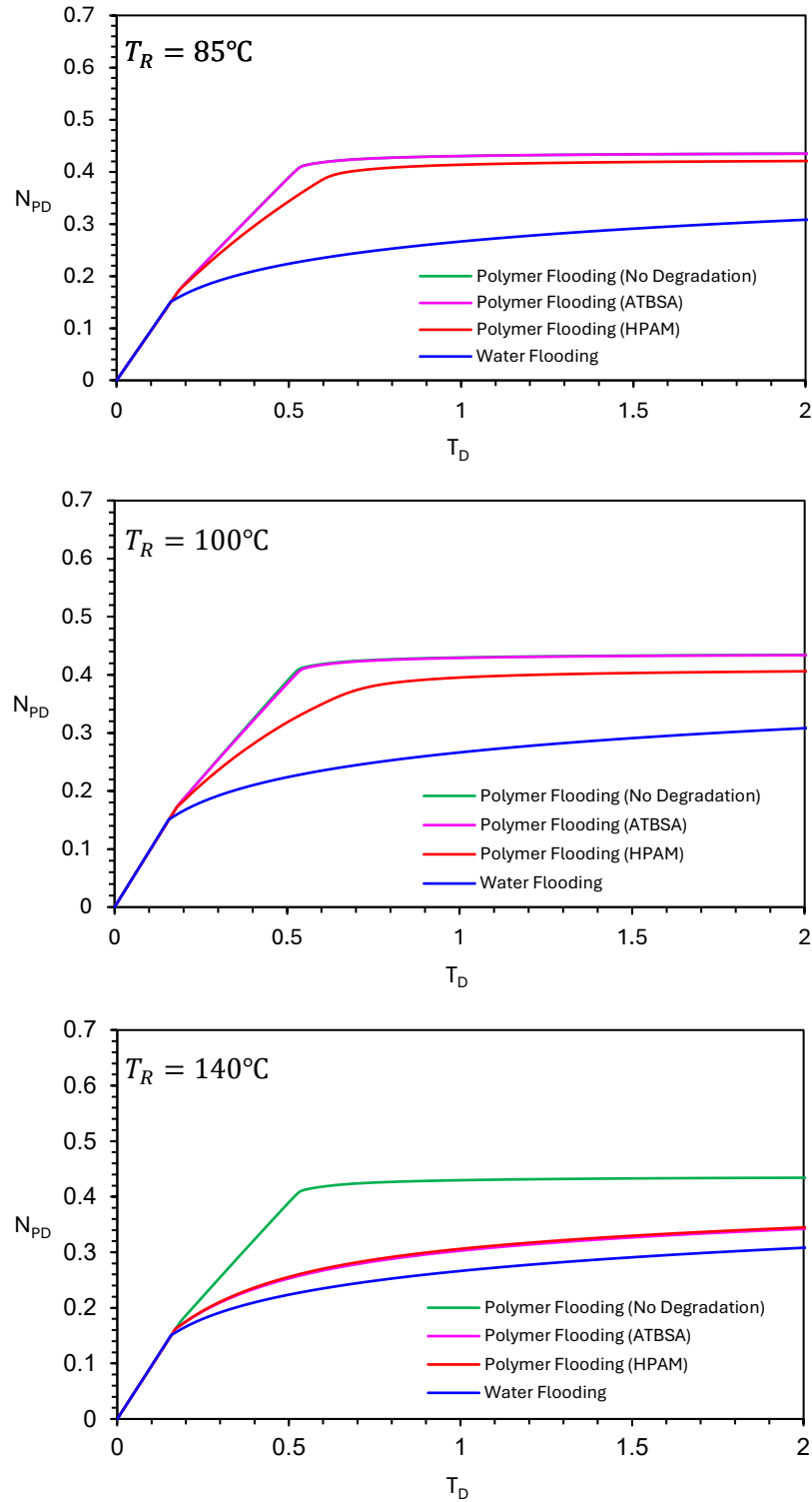


Figure 4.13. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different reservoir temperatures. ATBSA performance was not affected by the reservoir temperature range in the DOE study 85-100°C and HPAM only showed minimal effect. At higher temperature ATBSA and HPAM showed matching poor performance in line with matching half-life expectation for both at 140°C.

4.3.2 Secondary Parameters Screening (3D Sector Model)

In the second stage, we extended the screening to the COSTA 3D sector model by adding 3 new factors introduced earlier in section 4.2.4.7 that will incorporate gravity and heterogeneity. A line-drive configuration was adopted, with an up-dip producer and a down-dip injector. The producer was modelled as a horizontal well placed at the top of the reservoir, while the injector was represented by a slanted well intersecting the full pay zone. From the 1D DOE, we carried forward polymer type, slug size, and injection/production rate, as these ranked among the most influential parameters. Reservoir temperature and the mixing factor were excluded at this stage: the reservoir temperature was fixed at 100 °C as the representative operating condition for all subsequent studies, while the mixing factor was set at 0.67 based on earlier calibration. Polymer viscosity was also fixed at 10 mPa·s, consistent with the design value established in the analytical and 1D studies. with the parameters carried forward from 1D, these formed the experimental design summarised in **Table 4.5**.

4.3.2.1 *Statistical Significance of Factors (DOE) Screening Results*

The 3D DOE was constructed using the same Resolution IV fractional factorial design, resulting in 16 runs as summarised in **Table 4.8**. As stated earlier in the screening design response here we used the absolute value of oil pore volume produced at one pore volume injected.

Table 4.8. Experimental design matrix for the 3D sector model screening study (16 runs).

STD	Run	Rate (m3/day)	Polymer Type	Slug Size (PV)	$\frac{K_v}{K_H}$	Stratigraphy	Vertical Resolution	N _{PD} @ 1PVI (Response)
9	1	2000	HPAM	0.1	0.5	Fining Upward	Fine	0.26
6	2	3000	HPAM	0.4	0.1	Fining Upward	Fine	0.31
13	3	2000	HPAM	0.4	0.5	Coarsening Upward	Coarse	0.35
11	4	2000	ATBS	0.1	0.5	Coarsening Upward	Coarse	0.35
7	5	2000	ATBS	0.4	0.1	Fining Upward	Coarse	0.39
8	6	3000	ATBS	0.4	0.1	Coarsening Upward	Coarse	0.38
15	7	2000	ATBS	0.4	0.5	Fining Upward	Fine	0.41
4	8	3000	ATBS	0.1	0.1	Fining Upward	Fine	0.30
10	9	3000	HPAM	0.1	0.5	Coarsening Upward	Fine	0.33
14	10	3000	HPAM	0.4	0.5	Fining Upward	Coarse	0.32
3	11	2000	ATBS	0.1	0.1	Coarsening Upward	Fine	0.30
16	12	3000	ATBS	0.4	0.5	Coarsening Upward	Fine	0.40
12	13	3000	ATBS	0.1	0.5	Fining Upward	Coarse	0.31
2	14	3000	HPAM	0.1	0.1	Coarsening Upward	Coarse	0.28
1	15	2000	HPAM	0.1	0.1	Fining Upward	Coarse	0.27
5	16	2000	HPAM	0.4	0.1	Coarsening Upward	Fine	0.30

Figure 4.14 presents the oil pore volume responses for all runs, which form the basis for the Pareto and half-normal probability analysis.

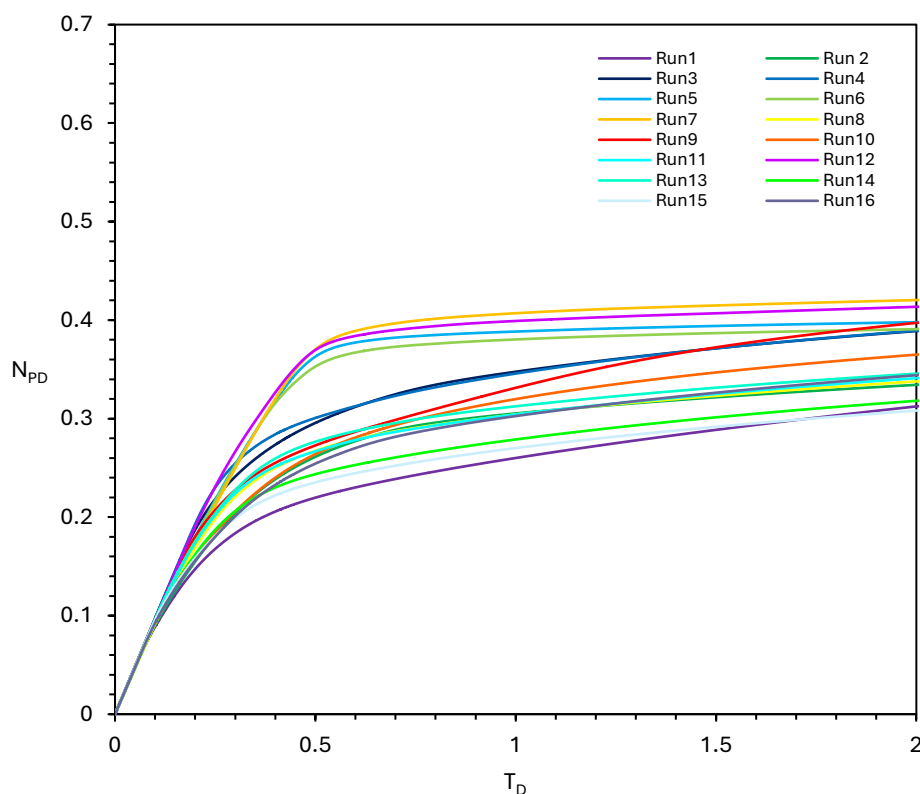


Figure 4.14. Numerical oil pore volume produced as a function of pore volumes of polymer injected for the 3D model design of experiment. The performance of 16 runs from **Table 4.8** is shown.

The statistical significance of the 3D factors was evaluated using the Pareto chart of standardized effects (**Figure 4.15**). Slug size (C) and polymer type (B) exceed both the t_{value} and Bonferroni limits, confirming them as the dominant parameters. This is consistent with the 1D results, demonstrating that polymer stability and bank size remain the primary controls on recovery even when gravity and heterogeneity are introduced. Stratigraphy (E) and vertical anisotropy (D) lie above the t_{value} threshold, indicating that reservoir heterogeneity becomes increasingly important in 3D as expected. Stratigraphy dictates how the polymer bank interacts with vertical permeability trends, while anisotropy governs the degree of gravity segregation and crossflow between layers. Their significance shows that the balance between viscous displacement and gravity-driven redistribution is a critical mechanism once heterogeneity is represented.

The interaction between rate and stratigraphy (AE) also emerges above the significance threshold, underscoring that operating rate cannot be considered in isolation. In coarsening-upward systems, low production/injection rates enhance the gravitational displacement in the bottom low permeability layers and improve vertical sweep conformance. In fining-upward systems the low rates will force the displacement to the bottom high permeability layers which causes bypassing of the top layers and poor sweep. This interaction illustrates how polymer degradation competes with gravity: slower rates increase exposure time and thus degradation, but at the same time they allow gravity to improve sweep and displacement.

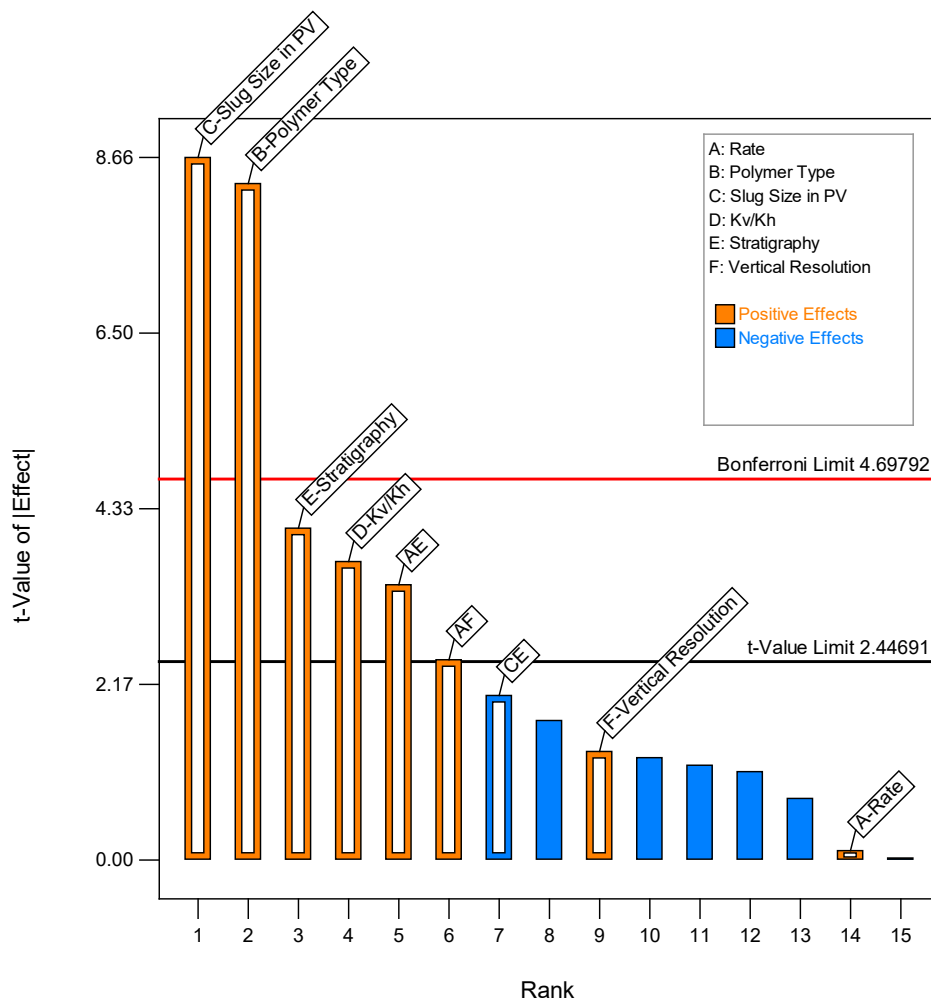


Figure 4.15. Pareto chart for incremental gain/loss of oil pore volume produced from waterflood for the 3D sector model.

The half-normal probability plot (**Figure 4.16**) supports the Pareto analysis. Slug size and polymer type deviate clearly from the reference line, confirming their dominant role, while stratigraphy, anisotropy, and the rate–stratigraphy interaction

also show noticeable departures consistent with partial significance. Vertical resolution and rate remain close to the line, reinforcing their weaker influence at 1 PVI. Overall, the half-normal plot confirms that polymer type and slug size remain the key controls in 3D, with geological architecture and gravity effects emerging as additional contributors.

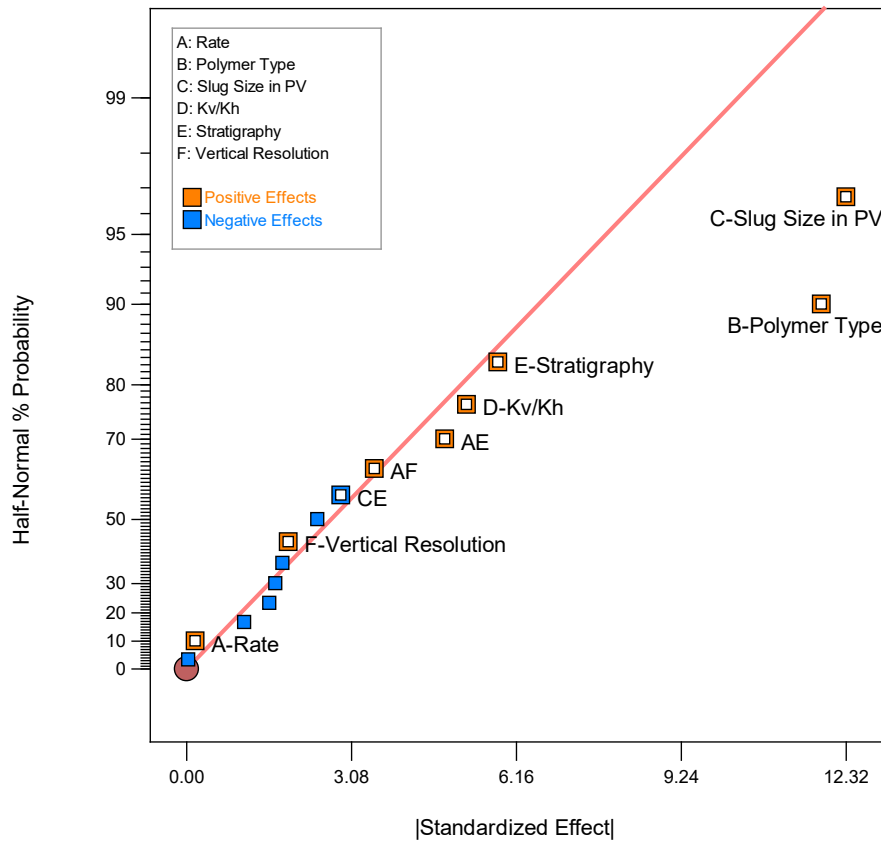


Figure 4.16. Half-normal plot for incremental gain/loss of oil pore volume produced from waterflood for the 3D sector model.

4.3.2.2 3D DOE Principal Factors and Interactions

4.3.2.2.1 Polymer Type

Polymer type continues to dominate performance in 3D, as shown in **Figure 4.17**. ATBSA closely tracks the ideal no-degradation case over the first pore volume injected, confirming its thermal stability under reservoir conditions. HPAM, by contrast, shows a gradual loss of viscosity and weaker displacement, though its performance begins to converge with waterflood at later times. The late-time pickup of HPAM and waterflood beyond 1.5–2 PVI indicates the increasing role of gravity in redistributing fluids across layers. These results confirm that degradation resistance is the primary driver of early

recovery, but that gravity mechanisms can partially compensate for polymer instability at later stages

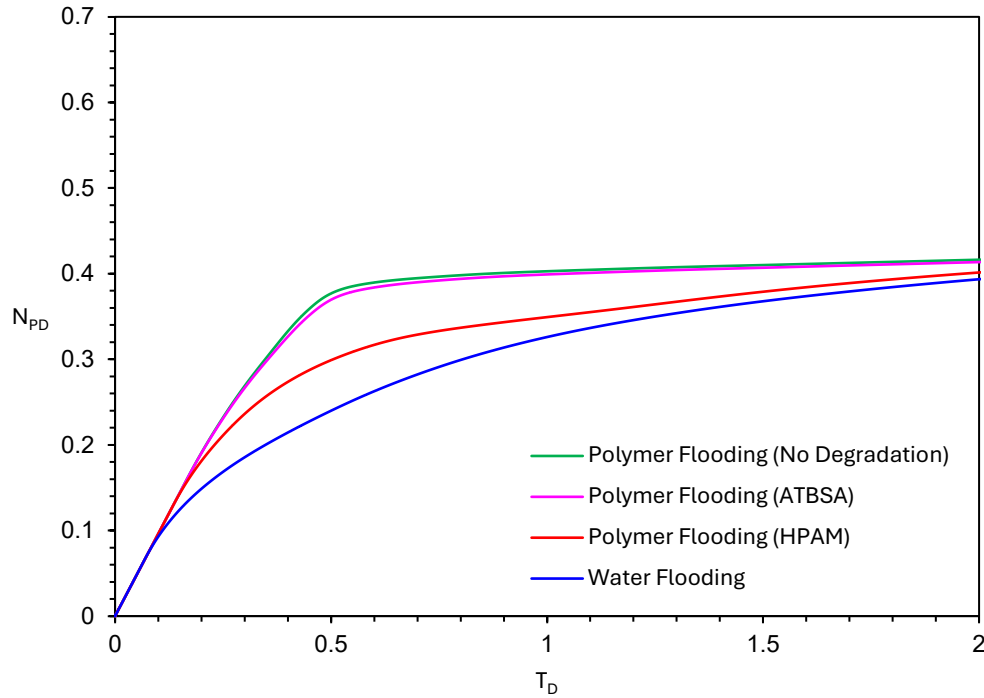


Figure 4.17. Numerical oil pore volume produced as a function of pore volumes of polymer injected for 3D fine sector model with coarsening upward stratigraphy, slug size of 0.40 PVI, $\frac{K_v}{K_H}$ of 0.50 and rate of 3000 m³/day. The plot shows ideal no thermal degradation assumed in green, ATBSA in magenta, HPAM in red, and water flooding in blue over 2 pore volumes period. ATBSA demonstrate exceptional stability over 1.25 km distance under the influence of heterogeneity. We observe HPAM and waterflooding approaching the performance of the other cases at 2 pore volume due to good sweep efficiency and the influence of gravity.

4.3.2.2.2 Slug Size

Figure 4.18 demonstrates that increasing slug size improves recovery up to the analytical optimum of ~ 0.34 PV similar to the results in 1D from **Figure 4.8**, beyond which no further gains are achieved. Smaller slugs, such as 0.1 PV, underperform and are eventually overtaken by waterflood after 1 PVI. This crossover highlights the competing roles of viscous control and gravity: a small polymer bank is quickly diluted and displaced by chase water, while water benefiting from gravity segregation achieves superior sweep. Larger slugs maintain bank integrity long enough to delay this effect, underscoring the importance of matching slug volume to both degradation resistance and reservoir stratigraphy. Importantly, the results confirm that the semi-analytical prediction of an optimum slug size of ~ 0.34 PV remains valid even in the presence of

heterogeneity, demonstrating the robustness of the analytical framework when extended to realistic 3D sector conditions.

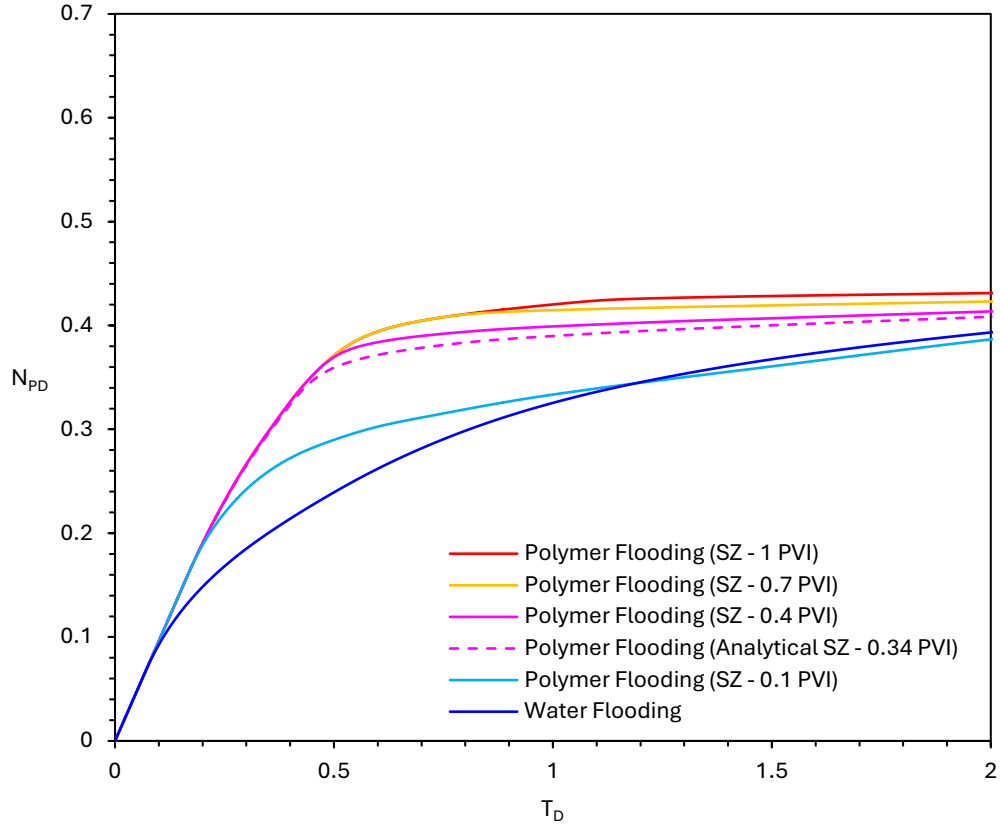


Figure 4.18. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different slug sizes. No major performance improvement above the optimal analytical slug size of 0.34 PVI. Water flooding outperformed the 0.1 PVI slug size beyond 1 PVI related to better gravitational displacement of water compared to mobility displacement of polymer of smaller slugs.

4.3.2.2.3 Stratigraphy

The influence of stratigraphy is illustrated in **Figure 4.19**, with supporting cross-sections in **Figure 4.20**. Here we use a customized discrete colour scale, transitioning from blue at residual oil saturation $S_w = 0.8$ to green at connate water saturation $S_w = 0.1$. This scale incorporates a broader spectrum of colours to capture subtle variations in water saturation, enhancing the visualization of displacement and the effect of gravity on the vertical cross section. Using the standard colour scale did not visually capture the subtle changes in water saturation.

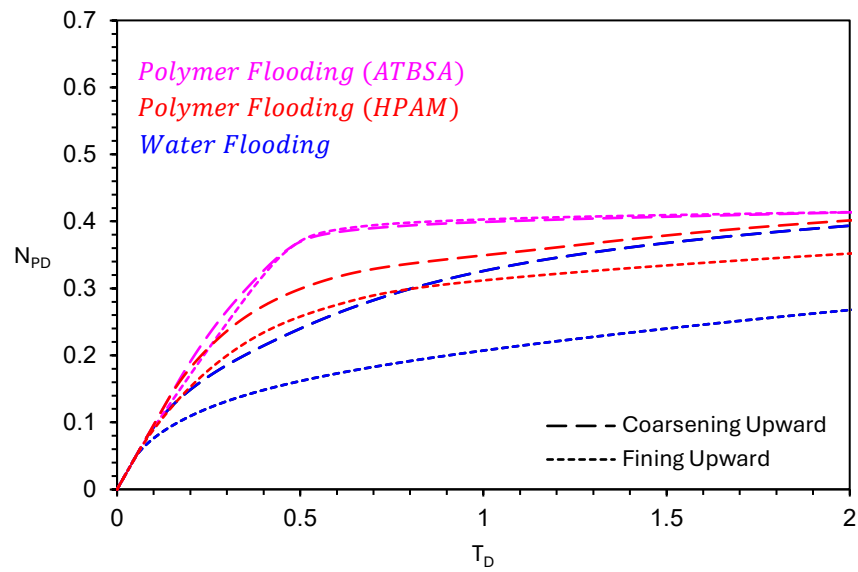


Figure 4.19. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different geological models. The colours represent flooding with ATBSA, HPAM and water. The dashed line represents coarsening upward and fining upward stratigraphies.

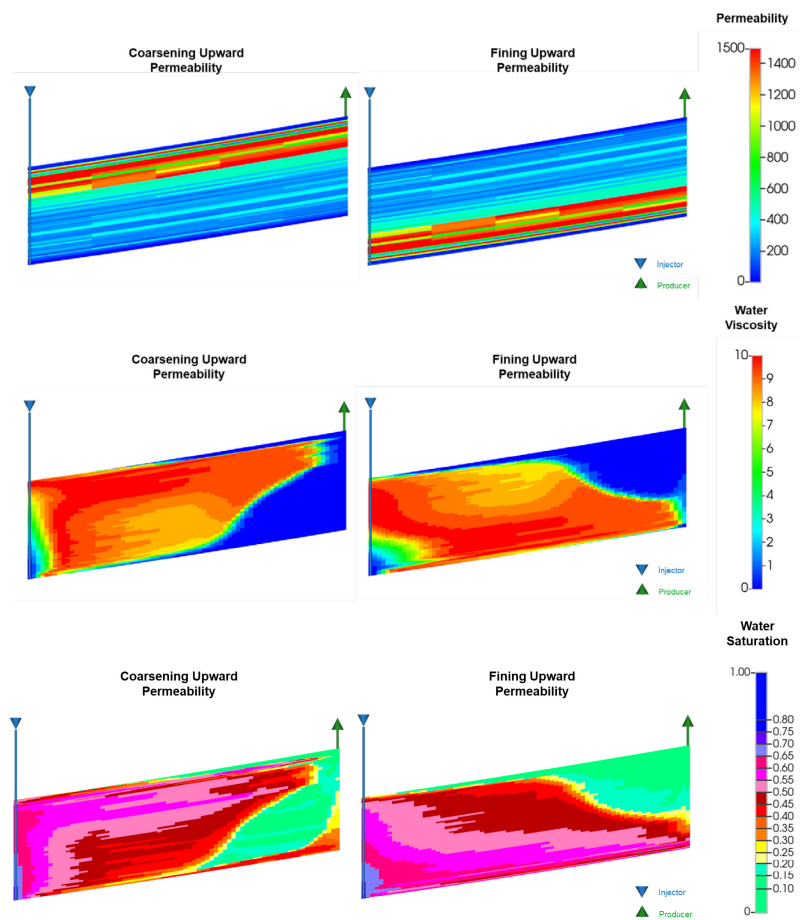


Figure 4.20. Cross-sections of permeability, water solution viscosity and water saturation of the 3D model at the end of ATBSA polymer injection for coarsening upward and fining upward permeability.

At 1 PVI, ATBSA shows little sensitivity to layering order, maintaining performance under both coarsening-upward and fining-upward settings. However, HPAM and waterflood outcomes differ strongly. In the fining-upward case, breakthrough occurs earlier, leading to lower recovery. The coarsening-upward configuration benefits from gravity redistribution, with injected fluids sweeping efficiently into lower-permeability zones. The cross-sections confirm that in fining-upward systems the bank is confined to high-permeability layers, while in coarsening-upward cases gravity promotes better vertical conformance. These results show that stratigraphy governs how degradation interacts with gravity, amplifying performance differences once polymer stability is compromised.

The impact of stratigraphy is tied to how thermal degradation develops along vertical permeability contrasts. In coarsening-upward systems, the upper high-permeability layers carry the front rapidly with short residence times, limiting degradation at the leading edge. Degraded polymer accumulates mainly in the tighter lower layers where flow is slower, and exposure is longer. In fining-upward systems, the basal high-permeability conduit draws the polymer quickly to the producer with less degradation, while the upper tight units experience delayed displacement.

Figure 4.20 makes this distribution–displacement link clear. The viscosity cross-sections show where degraded polymer resides reduced viscosity in the lower units for coarsening-upward, and a higher-viscosity channel along the basal high-permeability zone for fining-upward. The water saturation cross-sections then demonstrate displacement efficiency. For the coarsening-upward case, the high-water saturation region extends more evenly across the vertical profile, indicating effective displacement in the upper layers with gravity-assisted advance into the tight base. In the fining-upward model, displacement is concentrated in a narrow basal channel leading to early breakthrough, while the upper layers retain lower water saturation at the end of polymer injection. These observations confirm that stratigraphy governs both the distribution of thermally degraded polymer at the front and the overall displacement efficiency, with gravity either mitigating or amplifying the penalties associated with longer exposure depending on the layering order.

4.3.2.2.4 Vertical Anisotropy $\frac{K_v}{K_H}$

Figure 4.21 shows that higher vertical permeability $\frac{K_v}{K_H} = 0.50$ enhances recovery for both HPAM and ATBSA relative to the high-anisotropy case. This improvement reflects stronger gravity-driven crossflow, which redistributes polymer across layers and delays fingering. The gain is most evident for HPAM and water, where lower displacement viscosities increase the rate of gravity segregation. In these cases, gravity partially compensates for viscosity loss by driving fluids into zones that would otherwise remain unswept, leading to a visible improvement in displacement efficiency. ATBSA, on the other hand, maintains low mobility and a much lower segregation rate due to its thermal stability at 100 °C. This explains why the incremental gain from gravity is smaller for ATBSA: the polymer bank already advances recovery efficiently without relying heavily on gravity redistribution.

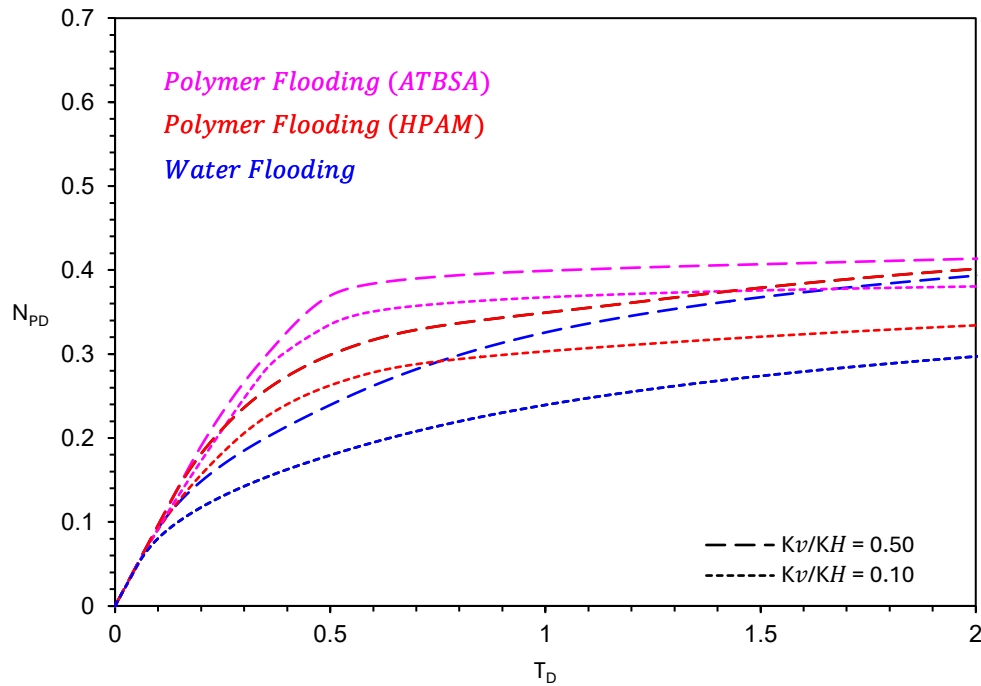


Figure 4.21. Numerical oil pore volume produced as a function of pore volume of polymer injected for different vertical anisotropy. The colours represent flooding with ATBSA, HPAM and water. The dashed line represents $\frac{K_v}{K_H} = 0.50$ and $\frac{K_v}{K_H} = 0.10$. Higher vertical permeability introduced incremental gain in recovery that varies with flooding type. ATBSA showed lower incremental gain in comparison to water in line with the analytical analysis of gravitational displacement in **Figure 3.23**.

These results highlight the dual role of vertical anisotropy. It amplifies gravity effects that can mitigate the consequences of thermal degradation in unstable polymers, while for a thermally stable polymer like ATBSA, it acts only as a secondary enabler.

Importantly, the contribution of gravity becomes more pronounced beyond 1 PVI, where crossflow and vertical segregation have more time to redistribute fluids. At earlier stages, recovery is governed primarily by polymer stability and slug size, whereas at later stages gravity-driven mechanisms play a stronger role. This confirms that thermal stability is the more critical factor in advancing recovery, as it sustains polymer effectiveness during the period when incremental barrels have the highest economic value.

4.3.2.2.5 Rate and Stratigraphy

Figure 4.22 presents the effect of injection rate in the coarsening-upward case. In this stratigraphy, the upper high permeability layers dominate the flow and promote override. At lower rates, gravity has more time to act, and for low viscosity displacing fluids such as water or degraded HPAM, segregation becomes stronger. However, in this case gravity also improves vertical displacement by redistributing fluids into the lower permeability layers, partly offsetting the negative effect of polymer degradation. This leads to higher late time recovery at the lower rate. At higher rates, the stronger viscous drive reduces the opportunity for gravity segregation, keeping the polymer bank more uniformly distributed but limiting the gravity contribution to vertical displacement.

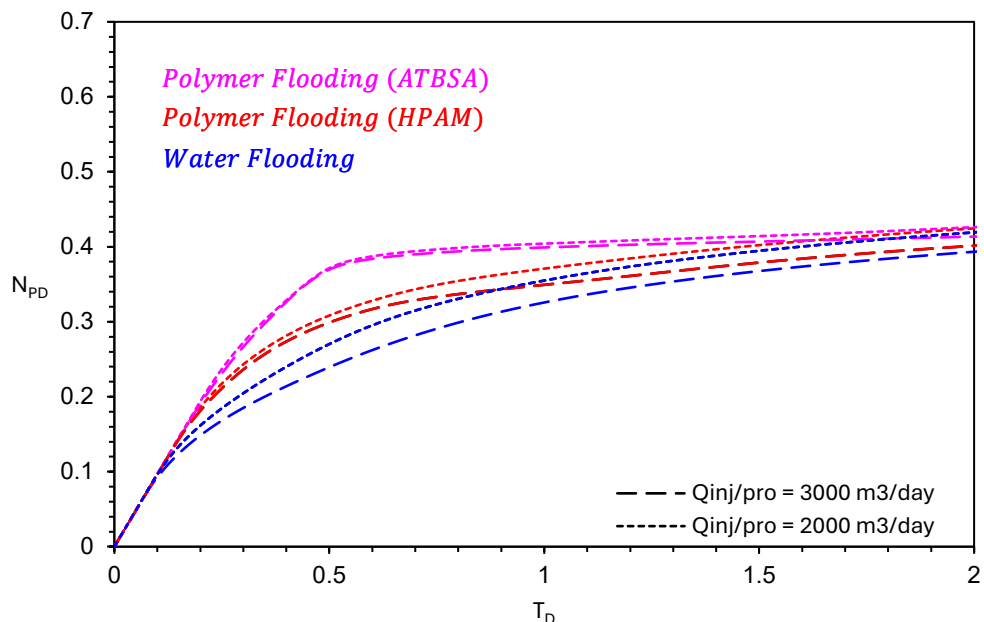


Figure 4.22. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different rates and stratigraphies. The colours represent flooding with ATBSA, HPAM and water. The dashed line represents rates of 3000 m³/day and 2000 m³/day.

The contrasting behaviour between polymers reflects the interplay between degradation and gravity. HPAM shows sensitivity to rate: at 2000 m³/day, longer residence time increases degradation, but gravity segregation improves vertical displacement enough to raise recovery relative to the higher-rate case. At 3000 m³/day, shorter exposure reduces degradation, yet the weaker gravity contribution limits incremental gains. ATBSA, by contrast, is largely unaffected by rate. Its stability preserves viscosity even at longer residence times, and because the mobility remains low, the segregation rate is minimal. As a result, ATBSA curves overlap, showing stable performance independent of rate, while HPAM and waterflood are more rate dependent.

This confirms that in coarsening-upward systems, rate governs the trade-off between degradation and gravity segregation. For thermally stable polymers such as ATBSA, recovery is stable across rates, as viscosity is preserved, and the bank remains intact. For polymers prone to degradation such as HPAM, gravity can partially compensate for viscosity loss at lower rates, making rate selection a critical variable in balancing early-time degradation against late-time displacement improvement.

4.4 Summary

This chapter applied a Resolution IV DOE to evaluate the role of thermal degradation and its interaction with gravity in polymer flooding. The 1D screening isolated degradation effects, while the 3D COSTA sector introduced stratigraphy, vertical anisotropy, and crossflow. Performance in 3D was measured as oil pore volume produced at 1 PVI. The results show that polymer thermal stability is the most critical factor. ATBSA, stable at 100 °C, maintains viscosity and mobility control, and its recovery is largely unaffected by stratigraphy, anisotropy, or rate within the ranges tested. HPAM, by contrast, loses viscosity with exposure time, making its performance strongly dependent on geological architecture and operating conditions.

The analysis also highlights the interplay between degradation and gravity. Gravity segregation provides greater benefit when viscosity is reduced, which explains why water and degraded HPAM show stronger improvements in displacement when gravity is active. At early times (to 1 PVI), recovery is controlled mainly by polymer type and slug size. At later times, beyond 1–1.5 PVI, gravity becomes more influential, redistributing degraded polymer and water into previously unswept zones. Rate plays an important role in this process: for low-viscosity floods such as HPAM and

waterflood, lower rates enhance gravitational displacement and improve recovery despite the longer residence time. For ATBSA, recovery is largely independent of rate because viscosity is preserved, and segregation is minimal.

Across both 1D and 3D, polymer type and slug size emerged as the key parameters. The semi-analytical optimum slug size of about 0.34–0.40 PV remains valid in 3D, even with heterogeneity included, while smaller slugs such as 0.1 PV are quickly diluted and eventually outperformed by waterflood. These findings support ATBSA as a robust option for large-spacing, high-temperature carbonate reservoirs. Its thermal stability ensures recovery is advanced early and reduces dependence on gravity or operating conditions, unlike HPAM, which relies more heavily on gravitational displacement to offset degradation losses.

In the next chapter (Chapter 5), we examine the physics of how gravity improves recovery in waterfloods and the importance of capturing this accurately in simulations. Chapter 6 then extends the analysis to field applications, evaluating polymer flooding with peripheral injector–producer spacing of approximately 5 km.

Chapter 5

Why Gravity Improves Waterflood Recovery in Oil-Wet and Mixed-Wet Reservoirs

5.1 Introduction

As discussed in Chapter 4, gravity effects were shown to be significant for waterfloods and for polymers that degrade under reservoir conditions. Here, we focus on waterflooding and examine in detail the physics of displacement under the influence of gravity. Does gravity help or hinder recovery and storage? Water is often injected into oil reservoirs to displace the hydrocarbon; in storage applications gas (carbon dioxide, natural gas or hydrogen) is injected, which displaces the resident brine. Buoyancy moves the less dense fluid to the top of the formation, while the denser phase slumps to the bottom. The balance between viscous forces (which push the fluids through the reservoir) and buoyancy can be controlled by adjusting the injection rate. Does buoyancy lead to an improvement in recovery or storage efficiency, or does it result in poorer performance?

Existing experimental and numerical research on two-phase flow during water flooding has demonstrated a reduction in oil recovery upon water breakthrough when gravity dominates flow (Craig et al., 1957; Hu and Li, 2021; Richardson and Perkins, 1957; Spivak, 1974; Talash and Crawford, 1966). The reason for this is that the water falls to the bottom of the reservoir leaving oil in the upper parts of the formation. The sweep efficiency – the fraction of the reservoir contacted by water – decreases as

buoyancy becomes more important. Some of these studies have also concluded that gravity has no significant impact on the ultimate oil recovery (i.e., after the injection of one to two pore volumes of water) (Richardson and Perkins, 1957; Talash and Crawford, 1966).

Most experiments to date have used simple, benchmark systems, such as sand or bead packs which were strongly water-wet. In these cases the water shock front saturation is high and there is almost no rarefaction; where the water has contacted the rock, it is locally immediately at the residual oil saturation (Lebedeva and Fogden, 2011). In such conditions, gravity will lead to a reduction in recovery upon breakthrough due to poor vertical sweep. Eventually, as more water is injected, the water does contact most of the reservoir, leading to a final recovery governed by the residual oil saturation, regardless of gravity.

However, few, if any, reservoirs are strongly water-wet. In mixed-wet and oil-wet rocks, recovery continues after breakthrough, behind the waterfront, due to the drainage of thin oil layers and the slow displacement from smaller regions of the pore space. The residual saturation is rarely, if ever, reached for economically sensible amounts of water injected, usually 0.5-2 pore volumes (Blunt, 2017). Hence, recovery is not determined solely by the residual saturation; indeed, the assumption in this case is misleading. To evaluate the overall recovery, we need to consider both the sweep and the local displacement efficiency. Gravity affects the local displacement: a gravity unstable displacement (the denser fluid above a lighter fluid, both moving downwards) gives a lower frontal saturation and a slower recovery after breakthrough; in contrast a gravity-stable flood (denser fluid below the lighter fluid, both moving upwards) leads to more favourable local recovery since gravity holds back the water and favours upwards flow of the oil.

We will show that in the presence of gravity, water slumps to the bottom of the reservoir during the displacement, where it accumulates and then pushes upwards. The result is similar to a gravity-stable, vertical upwards displacement with a more favourable local displacement efficiency (for 1-2 pore volumes of water injected) than an equivalent flood with density-matched fluids. This effect is particularly significant in oil-wet and mixed-wet reservoirs. The motivation of this work is to aid injection design and to highlight the importance of vertical resolution in simulation models to accurately capture the impact of gravity. We will also study a model of a heterogeneous carbonate reservoir with upward coarsening and upward fining to evaluate the

significance of gravity on recovery performance in field applications. This analysis will demonstrate that it is incorrect to assume that gravitational effects (which can be controlled by varying the injection rate) will always lead to poorer recovery.

In gas storage operations, we expect the same behaviour, but in reverse. Here the injected gas, which is generally the non-wetting phase, is less dense and less viscous than the water it displaces. Again, the local displacement efficiency (gas displacing water) is enhanced by having rapid segregation of fluids. The gas rises to the top of the formation where it accumulates under the cap rock, and then pushes the water down in a gravity-stable manner, potentially increasing storage efficiency compared to an equivalent displacement in the absence of buoyancy.

5.2 Material and Methods

5.2.1 Frontal Displacement Theory

The analysis is based on the Buckley–Leverett framework for immiscible displacement (Buckley and Leverett, 1942) that includes the influence of gravity on local displacement as presented in Chapter 2 (see Section 2.2, Eqs. 2.5 and 2.6). Here we extend that analysis to consider the implications for two-dimensional line drive displacements where both viscous forces and gravity act simultaneously. In this case, horizontal and vertical flows occur together, and gravity segregation gives rise to a gravity tongue that reduces the overall areal and vertical sweep (see **Figure 5.1**). The central question for this chapter is how gravity modifies local displacement efficiency and what that implies for macroscopic recovery.

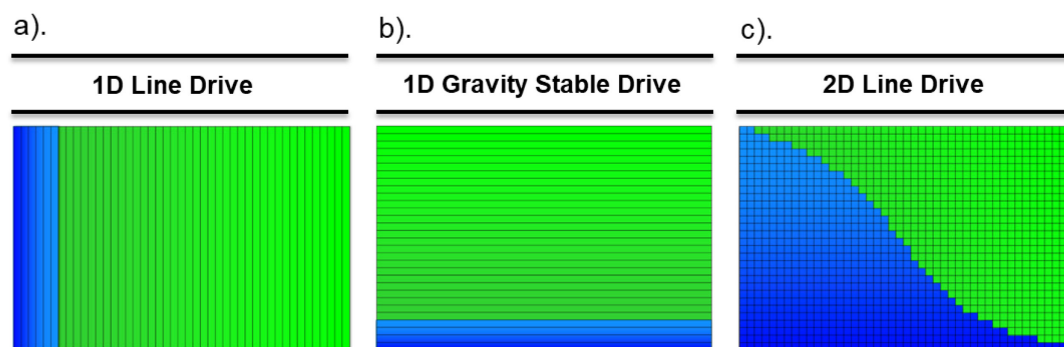


Figure 5.1. Visualization of the displacement process in a) line drive one dimensional model, b) gravity stable drive one dimensional model, c) line drive two-dimensional model that is gravity dominated.

5.2.2 Reservoir Wettability

The oil-wet relative permeabilities applied in this section are described in Chapter 3 (see **Table 3.2**). Here, in addition to the oil-wet case measured on a Middle Eastern carbonate rock (Dakshinamurthy et al., 2014), we include mixed-wet and water-wet cases constructed using power-law functions to extend the analysis to these types of rocks (see **Table 5.1** and **Figure 5.2**). Although residual oil saturation varies with wettability in reality, we keep the residual oil saturation constant across all wettability cases in this chapter to maintain a consistent initial oil in place and to isolate the impact of wettability-dependent relative permeability shape on displacement behaviour and recovery trends, ensuring that differences in recovery arise from changes in flow functions rather than from prescribed endpoint saturation values.

Table 5.1. Data used to construct the relative permeabilities for the oil-wet, mixed-wet and water-wet rocks.

Rock Wettability		Oil-Wet (Carbonate Rock Sample)	Mixed-Wet	Water-Wet
Parameter	Unit	Value	Value	Value
Oil Corey exponent, n_o	-	5	3	1
Water Corey exponent, n_w	-	1.5	3	3
Oil endpoint relative permeability, k_{ro}^0	-	1	1	1
Water endpoint relative permeability, k_{rw}^0	-	0.6	0.5	0.3
Residual oil saturation, S_{or}	-	0.2	0.2	0.2
Irreducible water saturation, S_{wi}	-	0.1	0.1	0.1

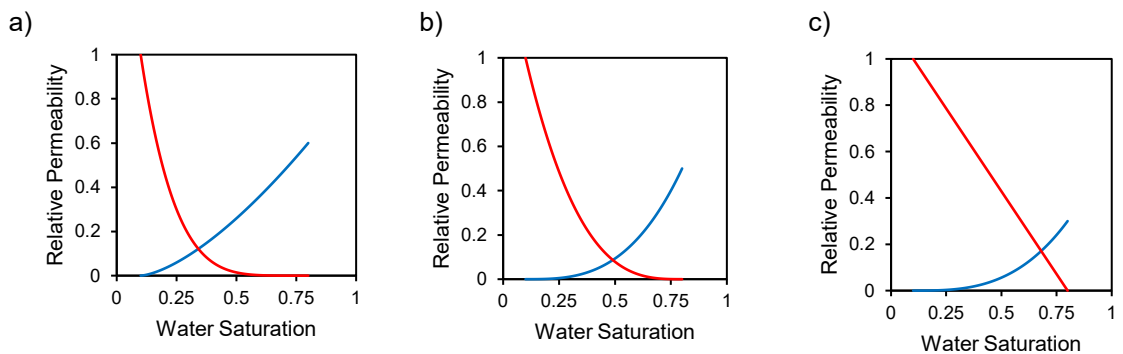


Figure 5.2. Relative permeabilities used in the study to represent a) oil-wet rock, b) mixed-wet rock and c) water-wet rock using the parameters in **Table 5.1**.

5.2.3 Hydrocarbon Recovery Performance

The performance of a waterflood or polymer flood is commonly expressed as the product of sweep efficiency and local displacement efficiency (Lake, 1989). A detailed formulation of these terms is already presented in Chapter 2 (Eqs. 2.2–2.4). In brief, sweep efficiency describes the volumetric extent of the reservoir contacted by the injected fluid, while local displacement efficiency reflects the effectiveness of oil removal from the contacted regions. Together, they determine the overall recovery factor and provide the framework for analysing how gravity, mobility ratio, and heterogeneity influence hydrocarbon recovery.

5.2.4 Gravity Number

As discussed earlier, gravity influences the displacement in two ways. The first, which has been well studied, is its impact on sweep efficiency which is a function of a gravity number defined as the ratio of the time taken for the injected water to move vertically from the top to the bottom of the reservoir, to the time taken for horizontal flow between wells (Shook et al., 1993; Sorbie et al., 1990). The second influence is on local displacement efficiency, as quantified by Buckley-Leverett analysis. Here the relevant gravity number is instead a ratio of speeds and independent of the reservoir size and shape: it is the ratio of the speed of vertical flow under gravity to horizontal flow between wells discussed in chapter 2 (Eq. 2.10) (Lake, 1989). Since this effect will be the emphasis of our study, we use this definition.

5.2.5 2D Numerical Simulation Model

The two-dimensional fine-grid vertical cross-sectional model used in this study was constructed as described earlier in Chapter 3, Section 3.4, where a vertical refinement study was carried out with 160 cells in the vertical direction. A constant-rate line drive was then simulated with CMG's adaptive implicit isothermal simulator IMEX™. The cases investigated are listed in **Table 5.2** and were designed to evaluate recovery performance in oil-wet, water-wet, and mixed-wet systems under both unfavourable and favourable mobility conditions in a gravity-dominated system. The fluid and rock

properties are given in **Table 5.3**. Capillary pressure was neglected, consistent with Craig (1957), as its impact on field-scale displacement is minor compared to mobility and gravity effects. Oil density is assumed to be constant in the heavy oil and light oil case. Oil density does change between light and heavy oil but the difference is usually within 5 to 10% in comparison to the viscosity difference of almost 7 folds so we decided to neglect the density difference during the gravity effect evaluation.

Table 5.2 Simulation cases used to study the effect of gravity on water flooding performance for different rock wettabilities. K_v/K_H is the ratio of the vertical permeability to horizontal permeability. M is the ratio of the endpoint water mobility to the end-point oil mobility for the unfavourable mobility cases with a 10 mPa.s oil and the favourable mobility cases with an oil of viscosity 1.4 mPa.s.

Cases	Rate	Wettability	μ_o	K_v/K_H	M	$N_{g/v}$
1	1000 m ³ /day	Oil-wet	10 mPa.s	1	15	0.09
2	1000 m ³ /day	Mixed-wet		1	12	0.09
3	1000 m ³ /day	Water-wet		1	7	0.09
4	1000 m ³ /day	Oil-wet		0.1	15	0.01
5	1000 m ³ /day	Mixed-wet		0.1	12	0.01
6	1000 m ³ /day	Water-wet		0.1	7	0.01
7	1000 m ³ /day	Oil-wet		0	15	0.00
8	1000 m ³ /day	Mixed-wet	1.4 mPa.s	0	12	0.00
9	1000 m ³ /day	Water-wet		0	7	0.00
10	100 m ³ /day	Oil-wet		1	15	0.88
11	1000 m ³ /day	Oil-wet		1	2	0.63
12	1000 m ³ /day	Water-wet		1	1	0.63
13	1000 m ³ /day	Oil-wet		0	2	0.00
14	1000 m ³ /day	Water-wet		0	1	0.00

Table 5.3. 2D simulation model base data.

Parameter	Unit	Value
Grid blocks		180×1×160
Grid block size	M	5.55×1000×0.063
Reservoir length, l	M	1000
Reservoir width, w	M	1000
Reservoir thickness, h	M	10
Porosity, ϕ	%	20
Permeability, K	mD	500
Residual oil saturation, S_{or}		0.2
Irreducible water saturation, S_{wi}		0.1
Oil viscosity, μ_o	mPa.s	10 (Heavy Oil)
Oil viscosity, μ_o	mPa.s	1.4 (Light Oil)
Water viscosity, μ_w	mPa.s	0.41
Oil density, ρ_o	kg/m ³	881
Water density, ρ_w	kg/m ³	1093

We compared the overall recovery, local displacement efficiency and sweep efficiency results of the two-dimensional simulation with a 1D simulation that ignored gravity:

this is equivalent to $K_v/K_H = 0$ and $N_{g/v} = 0$. We studied recovery at breakthrough and ultimate recovery to determine the significance of gravity segregation for all cases. The overall recovery is directly outputted by the simulator, whereas both displacement and sweep efficiency were calculated by exporting the water saturation grid into a MATLAB code to calculate the fraction of the reservoir contacted by water at multiple depletion stages. For practicality the yearly OIP depletion rate was designed to be 18% OIP per year at a water shock frontal advance rate of 3.2 m/day, achieving 1 PV displacement at approximately 5.5 years. Note that many fields in the Middle East adopt a more restrictive depletion policy not exceeding 3% per year to maintain healthier reservoir performance.

5.2.6 Field-Scale Heterogeneous Reservoir Model

The field-scale sector model used in this chapter is the same COSTA-based heterogeneous carbonate model introduced and prepared in Chapter 3 (see Section 3.5). The permeability scaling, sector extraction, stratigraphic variations, and vertical refinement/upscaling procedures have already been described in detail there (**Figure 3.24**). In brief, the model was adapted from the COSTA dataset (Costa Gomes et al., 2022) and scaled to a representative Middle Eastern carbonate reservoir with a geometric average permeability of 300 mD, capped at 1.5 Darcy. The sector extracted measures 1.25×1.25 km and was configured as a line drive with a down-dip injector and an up-dip producer. Stratigraphic variations included coarsening-upward, fining-upward, and homogeneous permeability distributions, and both fine and vertically upscaled grids were employed.

The 3D sector model used the basic reservoir data provided in **Table 5.4**. The model's pore volume is 13 times that of the initial 2D synthetic model, so the injection and production rates were set to 2000 m³/day to match a 2.8% OIP per year depletion rate at a water shock frontal advance rate of 1.2 m/day which seems high at this low depletion rate due to uncontrolled water acceleration in high permeability paths in the COSTA model. This depletion rate was selected in alignment with Middle Eastern oil field practices. We designed several simulation scenarios to assess gravity's impact on overall recovery when including different field-representative heterogeneities, using both unfavourable and favourable mobility conditions, see **Table 5.5**. For each mobility and permeability mix, we analysed both refined and coarse grids. We limited the well

constraints to a maximum liquid rate of 2000 m³/day, maximum bottom hole flowing pressure (BHFP) of 41368 kPa (fracture pressure), and minimum BHFP of 2000 kPa (bubble point pressure). Usually, producers are shut-in and recompleted at 90% water cut however, in this study water cut is not constrained to ensure all cases are operated with voidage replacement.

Table 5.4. 3D COSTA model simulation base data.

Parameter	Unit	Value
Grid blocks (Refined)		75×75×62
Grid block size (Refined)	m	16.67×16.67×0.80
Reservoir length, l	m	1250
Reservoir width, w	m	1250
Reservoir thickness, h	m	49.5
Porosity, ϕ	%	21
Average permeability, K	mD	300
Residual oil saturation, S_{or}		0.2
Irreducible water saturation, S_{wi}		0.1
Oil viscosity, μ_o	mPa.s	10 (Heavy Oil)
Oil viscosity, μ_o	mPa.s	1.4 (Light Oil)
Water viscosity, μ_w	mPa.s	0.41
Oil density, ρ_o	kg/m ³	881
Water density, ρ_w	kg/m ³	1093
Injection and production rate	m ³ /day	2000
Depletion rate	%OIP/year	2.8
K_v/K_H		0.5

Table 5.5. Simulation cases used to study the effect of gravity on water flooding performance for different field representative heterogeneous permeability distributions. Vertical resolution represents fine grid model (62 layers) and coarse grid model (5 layers). M is the ratio of the endpoint water mobility to the end-point oil mobility for the unfavourable mobility cases with an oil viscosity of 10 mPa.s and the favourable mobility cases with an oil viscosity of 1.4 mPa.s.

Cases	Permeability Distribution	Characterization	μ_o	M	Vertical Resolution
1	Heterogeneous	Coarsening upward	10 mPa.s	15	Fine Grid
2	Heterogeneous	Coarsening upward			Coarse Grid
3	Heterogeneous	Fining upward			Fine Grid
4	Heterogeneous	Fining upward			Coarse Grid
5	Homogeneous	-	1.4 mPa.s	2	Fine Grid
6	Homogeneous	-			Coarse Grid
7	Heterogeneous	Coarsening upward			Fine Grid
8	Heterogeneous	Coarsening upward			Coarse Grid
9	Heterogeneous	Fining upward			Fine Grid
10	Heterogeneous	Fining upward			Coarse Grid
11	Homogeneous	-			Fine Grid
12	Homogeneous	-			Coarse Grid

5.3 Results and Discussion

5.3.1 Analytical Displacement Efficiency

We previously demonstrated in Chapter 3 (Section 3.4.2) that gravity can significantly enhance displacement efficiency by modifying the Buckley–Leverett fractional flow solution to include a gravity term (Eq. 2.6). There, we compared fractional flow behaviour, shock-front development, and recovery for water and polymer floods under horizontal and gravity-stable conditions (**Figure 3.23**).

To set the stage for this work, we illustrate here case 1 from **Table 5.2**, focusing on the oil-wet system with similar dip angle setup for horizontal and gravity stable displacement noted in section 3.4.2. The Buckley–Leverett analysis shows the poor displacement efficiency of a horizontal 1D flood compared with the same system under gravity-stable vertical displacement (see **Figure 5.3** and **Figure 5.4**). Without gravity, the large viscosity contrast between oil and water, combined with oil-wet relative permeability, results in early water breakthrough. In contrast, under gravity-stable conditions $N_{g/v} = 0.09$, the shock front is higher and advances more slowly, leading to most recovery occurring before breakthrough. We expect the same influence of gravity for the mixed-wet and water-wet cases but with an even higher overall recovery.

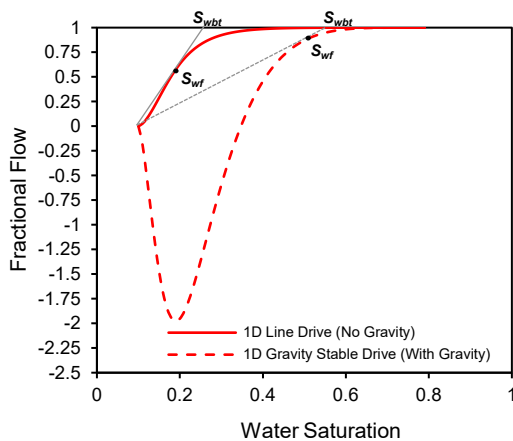


Figure 5.3. The fractional flow functions for a one-dimensional line drive with no gravity (solid red line) and the one-dimensional gravity stable drive with gravity (dashed red line) for an oil-wet system. The fractional flow can be negative for the gravity stable drive when water moves upwards against gravity causing a reduction in the mobility of water and improved upward oil mobility. The shock from saturation S_{wf} and the average saturation behind the front S_{wbt} are also indicated for the two cases.

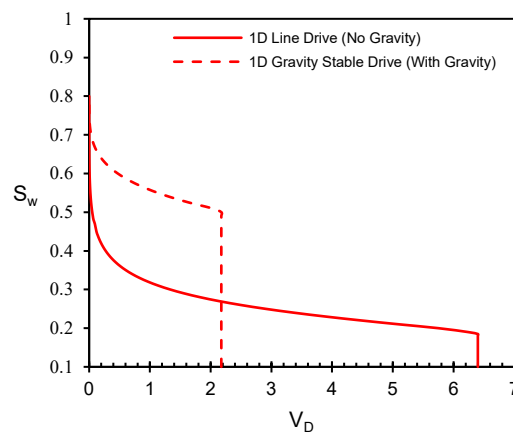


Figure 5.4. Saturation as a function of dimensionless velocity (fraction of the distance between wells divided by pore volumes injected) for a one-dimensional line drive in an oil wet system with no gravity (solid red line) and the one-dimensional gravity stable drive with gravity (dashed red line). There is an increase in shock front saturation for the gravity stable drive and better displacement behind the front.

5.3.2 2D Numerical Simulation Results

5.3.2.1 Overall Recovery Performance

We plotted the recovery performance over 5 pore volumes of water injected (PVI) for the three wettability cases (oil-wet, mixed-wet and water-wet) (see **Figure 5.5** to **Figure 5.7**). The cases 1 – 9 in **Table 5.2** used in this section were setup to represent heavy oil displacement with a permeability anisotropy K_v/K_H of 1, 0.1 and 0. They are designed to represent flow with a high, moderate and zero gravity numbers. Cases 11 – 14 represent light oil displacement with higher gravity number. The results show the change in recovery from the introduction of gravity to a horizontal 2D displacement.

5.3.2.1.1 Heavy Oil Cases ($\mu_o = 10 \text{ mPa.s}$)

In all cases with a high $N_{g/v}$ (**Figure 5.5**) gravity leads to an earlier water breakthrough (where the recovery curve first deviates from a straight line of unit slope) as a result of gravity segregation and a reduction in sweep efficiency. For the oil-wet case, gravity improves recovery after ~ 0.3 PVI due to the improvement in local displacement efficiency, as the water pushes upwards through the reservoir after segregating to the base, as quantified by the analytical solution for vertical flow shown in **Figure 5.3** and **Figure 5.4**. For the mixed-wet case recovery exceeds that obtained from the no gravity case after ~ 1.2 PVI; however, for the water-wet case the recoveries with and without gravity only cross after 5 PVI, which is beyond most economic limits. Here the improvement in local displacement due to gravity is modest, as most recovery is achieved anyway at or near breakthrough.

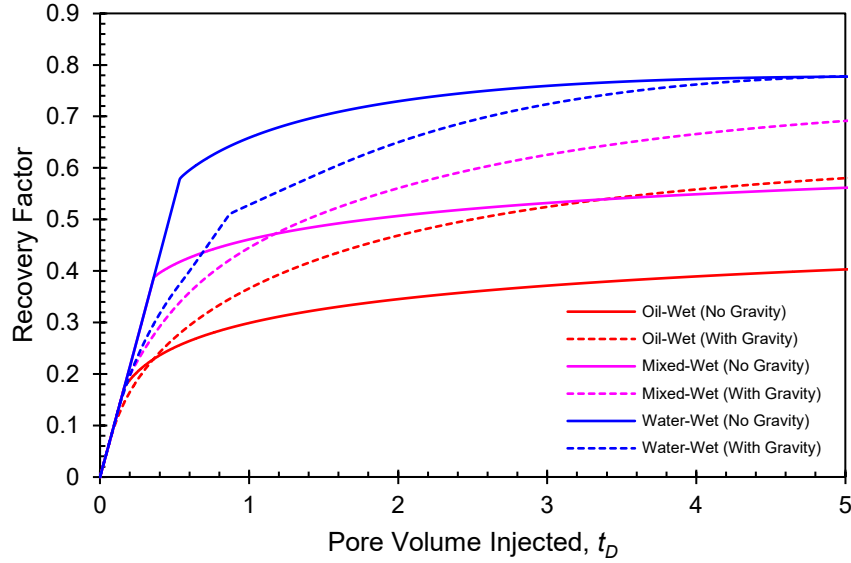


Figure 5.5. Recovery factor as a function of pore volumes of water injected from numerical simulation (with gravity) at $K_v/K_H = 1$ shown by the dashed lines and at $K_v/K_H = 0$ (no gravity) with solid lines for oil-wet (red), mixed-wet (magenta) and water-wet (blue) models with an unfavourable viscosity ratio. Gravity increases recovery for the oil-wet and mixed-wet cases, whereas the water-wet case experienced a loss in recovery due to gravity.

A lower ratio of vertical to horizontal permeability of 0.1 associated with low $N_{g/v}$ (see **Figure 5.6**), results in a more modest improved recovery with gravity, since its effect is smaller. However, in the oil-wet and mixed-wet cases this improvement is seen more quickly because gravity is weaker and hence the deterioration in sweep efficiency is more modest.

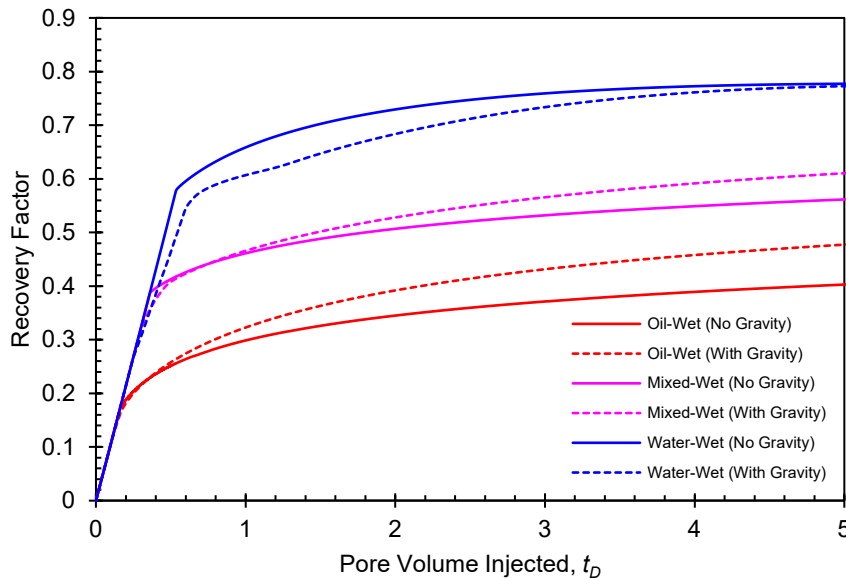


Figure 5.6. Recovery factor against PV of water injected for numerical simulation (with gravity) at $K_v/K_H = 0.1$, shown by the dashed lines, and at $K_v/K_H = 0$ (no gravity), with solid lines, for oil-wet (red), mixed-wet (magenta) and water-wet (blue) models with an unfavourable viscosity ratio. There is an increase in recovery due to gravity for the oil-wet and mixed-wet, whereas the water-wet case has a reduced recovery due to gravity.

5.3.2.1.2 Light Oil Cases ($\mu_o = 1.4 \text{ mPa.s}$)

In the oil-wet case gravity leads to recovery improvement even before water breakthrough: this is a result of high sweep efficiency from the favourable mobility ratio and the improvement of local displacement imposed by gravity segregation. For the water-wet case in a favourable mobility ratio flood, it is a piston like displacement and gravity will add no further improvement on displacement (See **Figure 5.7**).

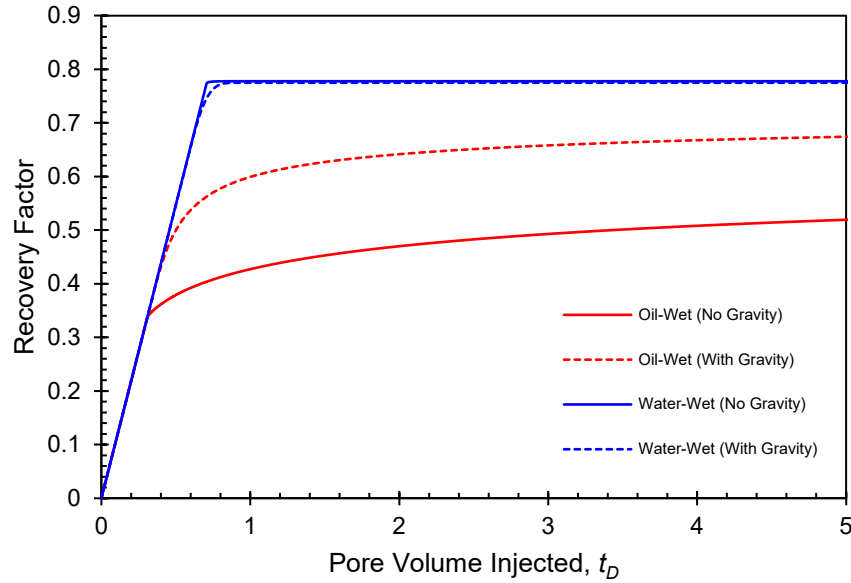


Figure 5.7. Recovery factor against PV of water injected for numerical simulation (with gravity) at $K_v/K_H = 0.1$, shown by the dashed lines, and at $K_v/K_H = 0$ (no gravity), with solid lines, for oil-wet (red), mixed-wet (magenta) and water-wet (blue) models with an favourable viscosity ratio. There is an increase in recovery due to gravity for the oil-wet before water breakthrough, whereas the water-wet case has no recovery impact due to gravity.

Saturation plots are presented in the following displacement and sweep efficiencies section, comparing the oil-wet and water-wet performance for heavy oil, and oil-wet performance for light oil.

5.3.2.2 Displacement and Sweep Efficiencies

To further investigate the cause of recovery gain or loss by gravity for the three wettabilities we compared snapshots of the water saturation distribution for the 1D (no gravity) and 2D (significant gravity effects) line drive simulations at breakthrough, 1 PVI and 2 PVI (see **Figure 5.8**, **Figure 5.10** and **Figure 5.12**). The corresponding displacement and sweep efficiencies are shown in (**Figure 5.9**, **Figure 5.11** and **Figure 5.13**). We focused the evaluation on the oil-wet and water-wet cases as they represent

the limiting cases. we used a customized discrete colour scale, transitioning from blue at residual oil saturation $S_w = 0.8$ to green at connate water saturation $S_w = 0.1$. This scale incorporates a broader spectrum of colours to capture subtle variations in water saturation, enhancing the visualization of displacement and the effect of gravity on the vertical cross section.

5.3.2.2.1 Heavy Oil (Oil-Wet Case)

The comparison between the 1-D and 2-D line-drive simulations highlights the contrasting roles of viscous-dominated and gravity-dominated flow on recovery behaviour. In the 1-D case, where gravity is absent, displacement is purely viscous and results in a relatively uniform saturation front and a gradual increase in recovery with injected pore volume. In contrast, inclusion of gravity in the 2-D model leads to early water breakthrough and a lower overall recovery of 8% at breakthrough (see **Figure 5.9**), caused by the formation of a gravity tongue. At this stage, sweep efficiency in the 2-D model remains limited to 23%; however, displacement efficiency in the lower part of the reservoir reaches 36%, compared with only 18% for the corresponding 1-D case. The saturation distributions in **Figure 5.8** show that this improvement arises from downward segregation of water, which preferentially displaces oil in the lower layers while bypassing the upper zones at early time. As injection proceeds beyond breakthrough, continued gravity segregation progressively improves cross-sectional sweep and mobilises oil from previously unswept regions. Consequently, both sweep and displacement efficiencies increase in the 2-D model, and the overall recovery eventually exceeds that of the 1-D displacement. After 2 PVI, the 2-D line drive achieves a 23% incremental increase in displacement efficiency and a 13% incremental gain in recovery relative to the 1-D case, demonstrating the dominant contribution of gravity to late-time recovery.

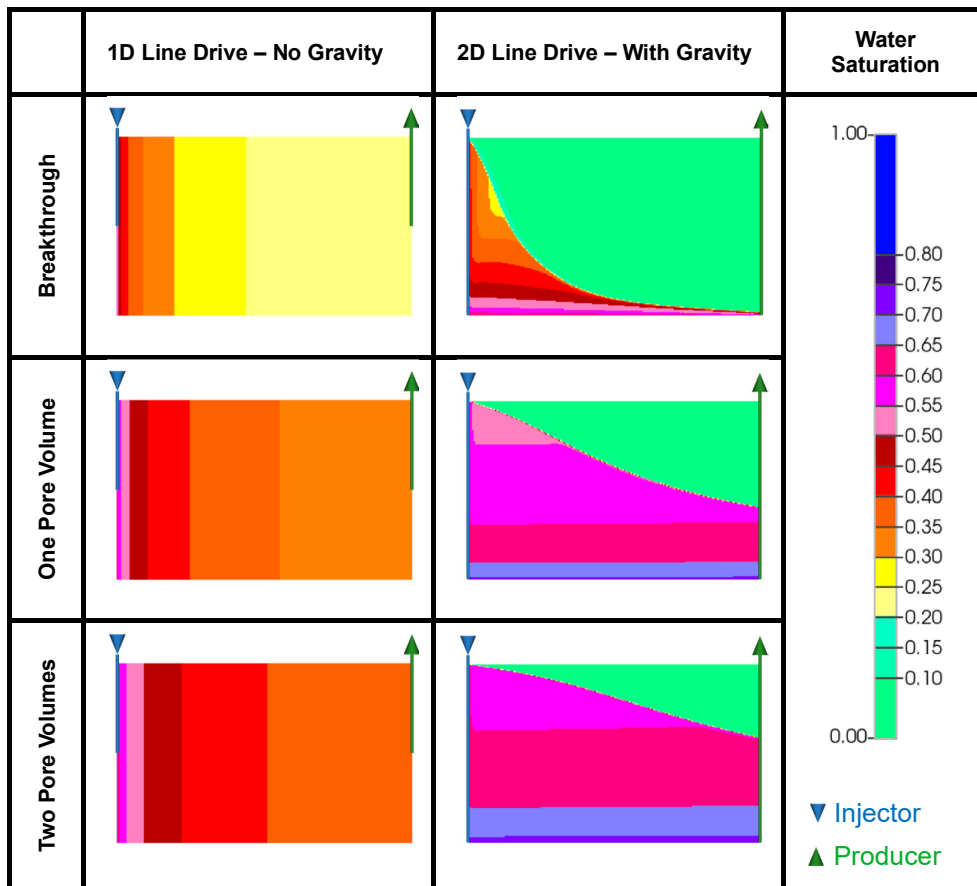


Figure 5.8. Water saturation for the oil-wet 1D line drive with no gravity (left) and the 2D line drive with gravity (right) at three depletion stages (breakthrough, 1 PVI and 2 PVI). The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. There is a progressive improvement in displacement by gravity at each depletion stage and poor sweep efficiency prior to water breakthrough which improves at later stages.

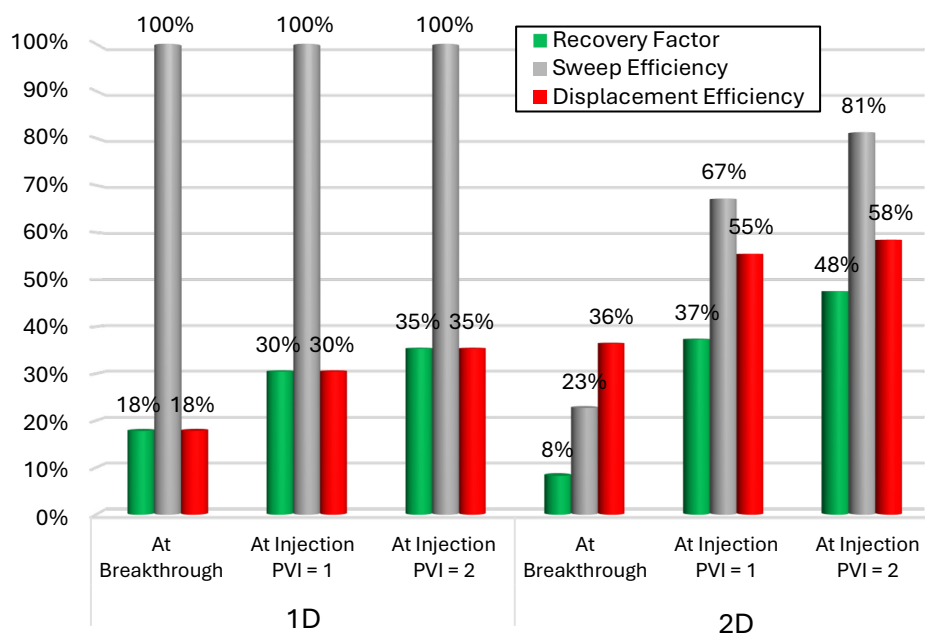


Figure 5.9. Recovery, displacement and sweep efficiency for the oil-wet 1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). Gravity results in improved ultimate recovery associated from the increased displacement efficiency. $K_v/K_H = 1$.

5.3.2.2.2 Heavy Oil (Water-Wet case)

Strongly water-wet rocks tend to have high displacement efficiency and the mobile oil behind the flood front is minimal. Although gravity contributed to minor improvement in the displacement efficiency as seen in **Figure 5.10** and calculated in **Figure 5.11**, this made no significant contribution to overall recovery. The overall recovery is always impacted negatively by gravity in this type of wettability due to the poor sweep efficiency resulting from gravitational segregation.

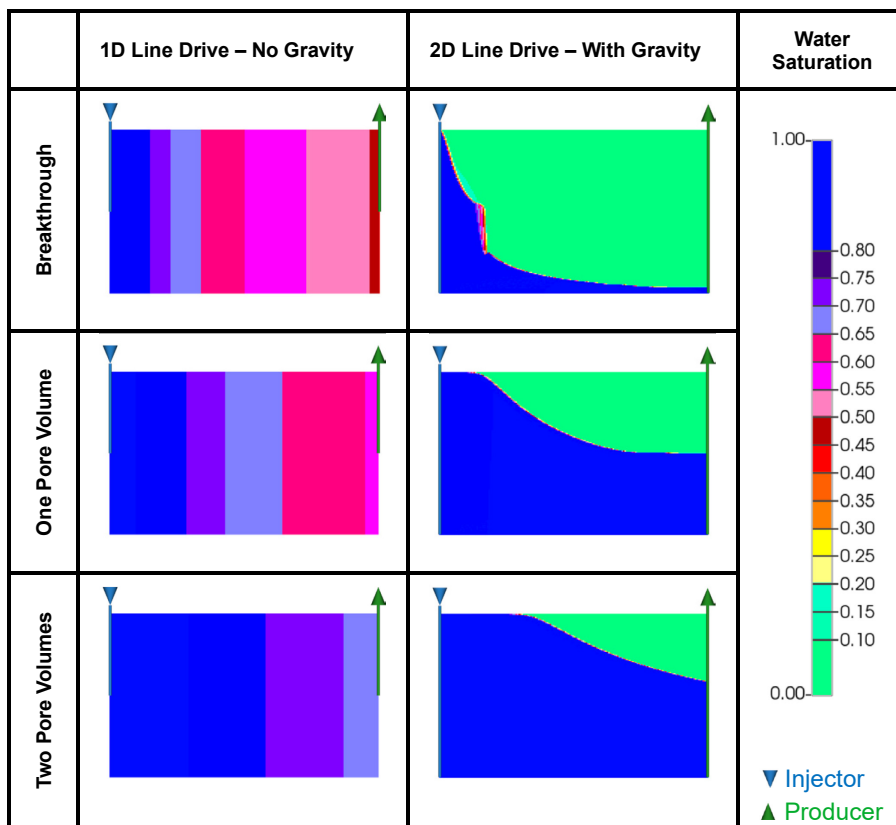


Figure 5.10. Water saturation distributions for the water-wet 1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. There is negligible improvement in displacement efficiency by gravity at each depletion stage due to the high initial displacement efficiency associated with strongly water-wet systems.

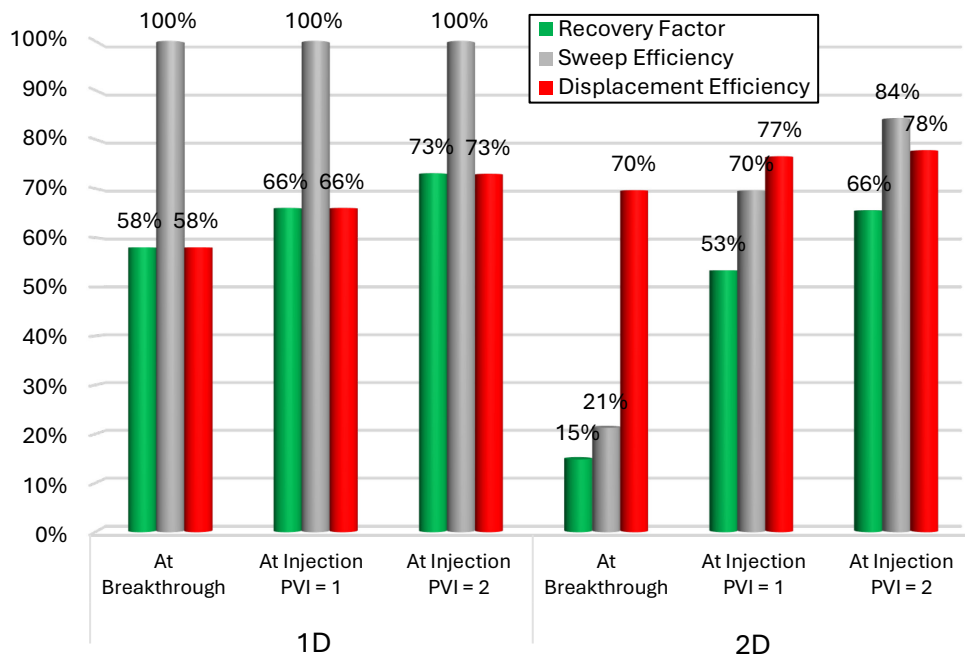


Figure 5.11. Recovery, displacement and sweep efficiency for the water-wet 1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). Gravity results in a reduced recovery at late times due the poor sweep efficiency and high initial displacement efficiency.

5.3.2.2.3 Light Oil (Oil-Wet Case)

Here we test an oil-wet case with a favourable end-point mobility ratio. The favourable mobility ratio improves the initial sweep efficiency by minimizing the negative gravity effect (see **Figure 5.12**). The combined effect of high initial sweep and local displacement efficiencies resulted in better recovery before water breakthrough. The 2D line drive simulation with gravity resulted in 3% higher incremental recovery than the no gravity case at breakthrough in **Figure 5.13**. When we compare the displacement efficiency gain by gravity at two PVI between the heavy oil case in **Figure 5.9** and the light oil case in **Figure 5.13**, 23% and 19%, respectively, we observe that gravity improves the displacement efficiency more in the heavy oil case. However, at the same PVI the recovery gain by gravity is higher for the light oil case at 17% compared to 13% in the heavy oil case. These results demonstrate that gravity consistently enhances local displacement efficiency and reduces sweep, and the combined effect of both factors are of equal importance to the final recovery performance.

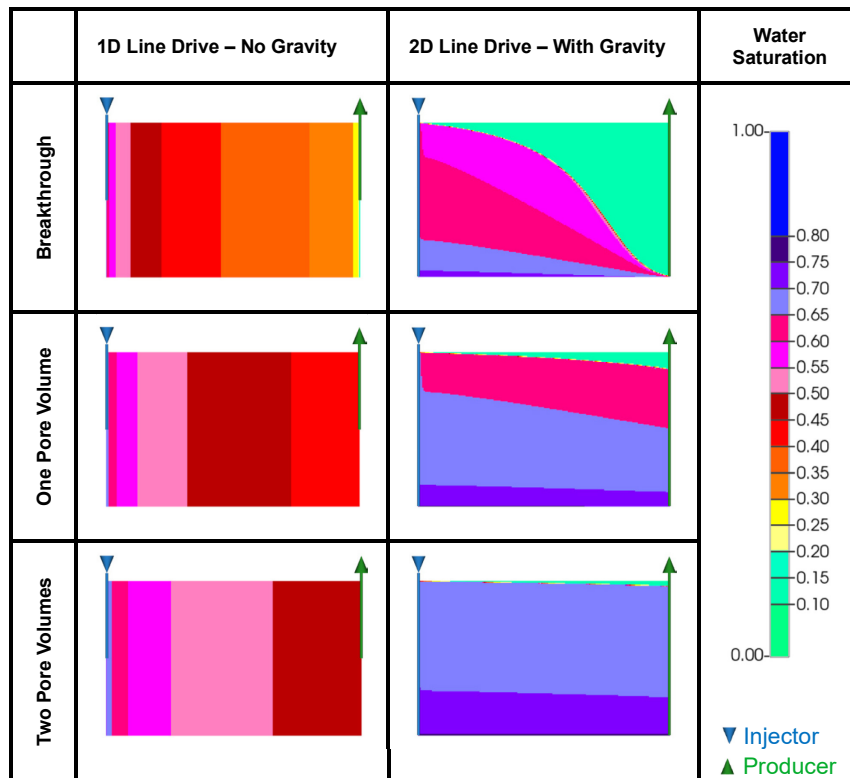


Figure 5.12. Water saturation distributions for the oil-wet with light oil viscosity of 1.4 mPa.s in 1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. There is high initial sweep efficiency due to favourable end-point mobility ratio with progressive improvement in displacement.

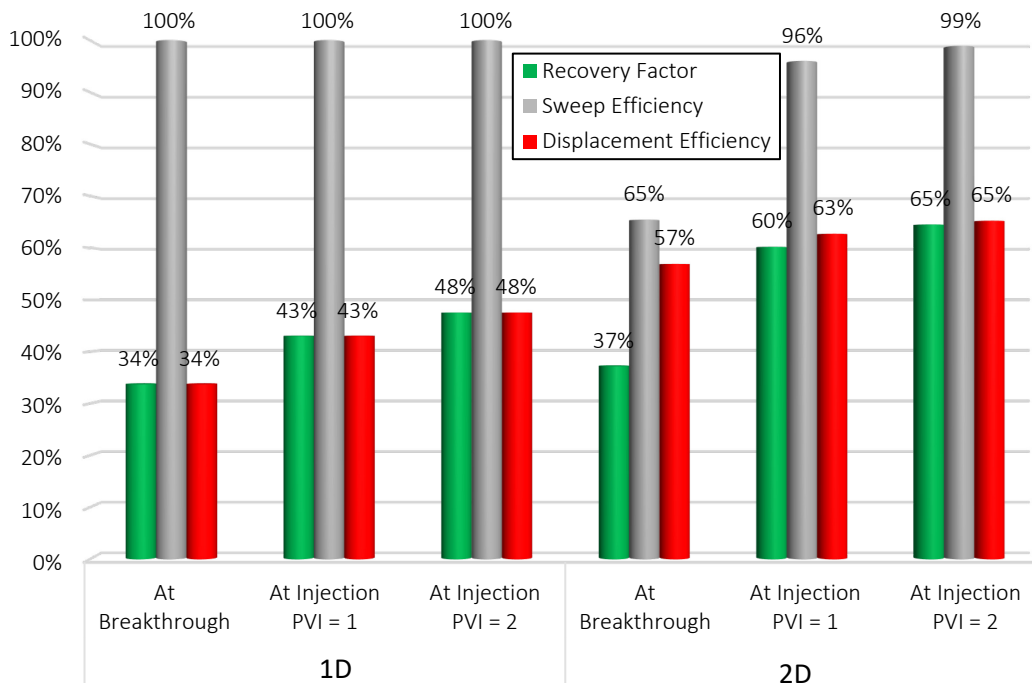


Figure 5.13. Recovery, displacement and sweep efficiency for the oil-wet and light oil viscosity of 1.4 mPa.s (1D line drive with no gravity and the 2D line drive with gravity at three depletion stages (breakthrough, 1 PVI and 2 PVI). Gravity resulted in the highest improvement in recovery realized at breakthrough due to the increased displacement efficiency and high initial sweep efficiency.

It is incorrect to solely associate gravity with poor sweep when evaluating flooding projects. These results demonstrate the significant role of gravity in flooding performance, its interactions with rock wettability, and with end-point mobility ratio. Gravity improves local displacement efficiency most in oil-wet reservoirs. A favourable end-point mobility ratio further enhances recovery by reducing the negative impact of gravity on sweep.

5.3.3 Field Scale Heterogeneous Model Numerical Simulation Results

5.3.3.1 *Overall Recovery, Displacement and Sweep*

We extended the analysis to a sector from the scaled COSTA model to examine the impact of gravity on realistic field applications, **Table 5.5**. We plotted sweep efficiency, displacement efficiency, and recovery against PVI for a fine grid model (62 layers) with three reservoir characteristics (fining upward, homogeneous and coarsening upward). The results are compared with the upscaled model (5 layers). These show how the recovery gain or loss by gravity changes with time in field scale heterogeneous reservoirs. The grid coarsening increases numerical diffusion and reduces the rate of segregation due to gravity (see **Figure 5.14** and **Figure 5.15**).

5.3.3.1.1 **Heavy Oil Case ($\mu_o = 10 \text{ mPa} \cdot \text{s}$)**

Among the three reservoir characteristics studied, the coarsening-upward reservoir resulted in the highest recovery because of the better sweep efficiency. This is due to the permeability distribution counteracting gravitational segregation (see **Figure 5.14**). The injected fluid moves faster in the top layers of the reservoir due to the high permeability there resulting in improved vertical conformance. However, displacement efficiency was the lowest due to the downward segregation of the water (see **Figure 5.15**). Conversely the fining upward stratigraphy had the lowest recovery although the best displacement efficiency is achieved. This is due to the poor sweep efficiency caused by the combined effects of gravitational segregation and the injected water flowing preferentially in the lower high-permeability part of the reservoir.

Better recovery was seen in the fine grid coarsening upward and homogeneous models due to the influence of gravity, whereas no improvement was seen in the fine grid, fining upward model. We deduce this because in the coarse grid, coarsening upward stratigraphy, vertical sweep was improved due to the reducing influence of gravity on sweep as time increases, whilst the improvement in displacement efficiency remains constant with time after breakthrough. This latter effect is seen in all cases.

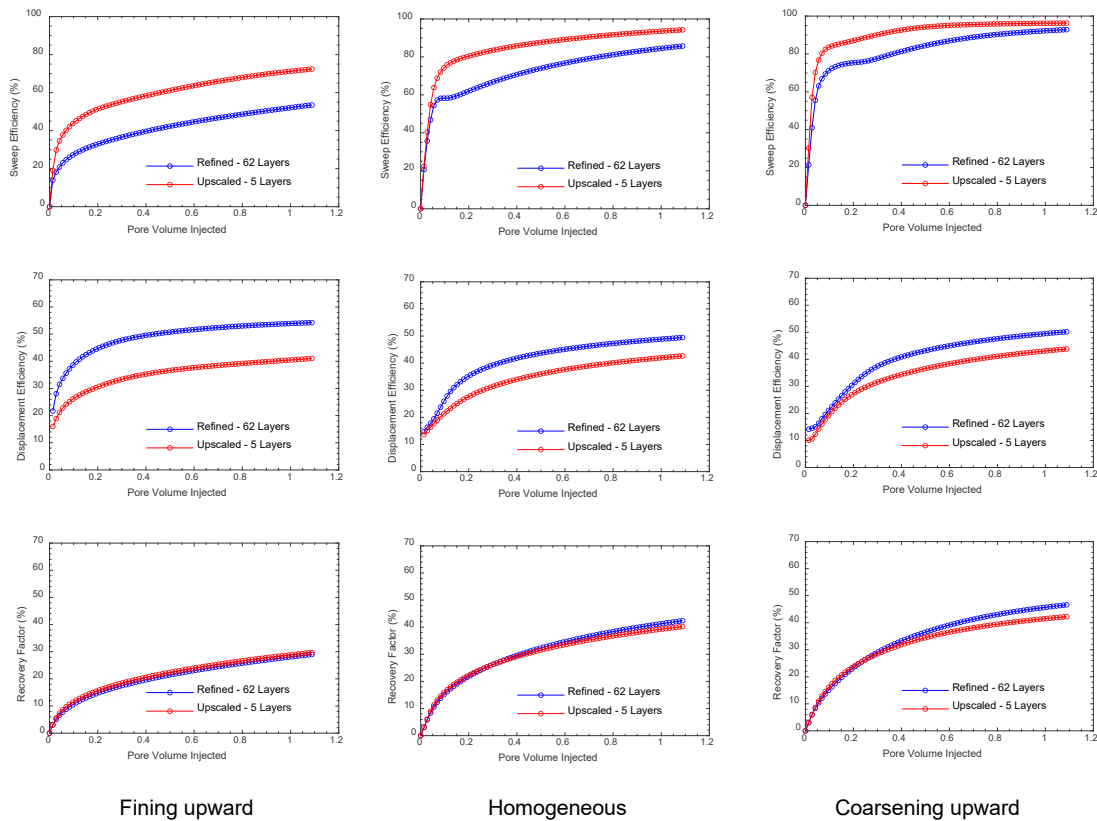


Figure 5.14. Sweep efficiency, displacement efficiency, and recovery over PVI for a refined fine grid model (62 layers) in blue with three reservoir characteristics (fining upward-left side, homogeneous-center and coarsening upward-right side). The results are compared with the upscaled coarse grid model (5 layers) in red for the heavy oil case.

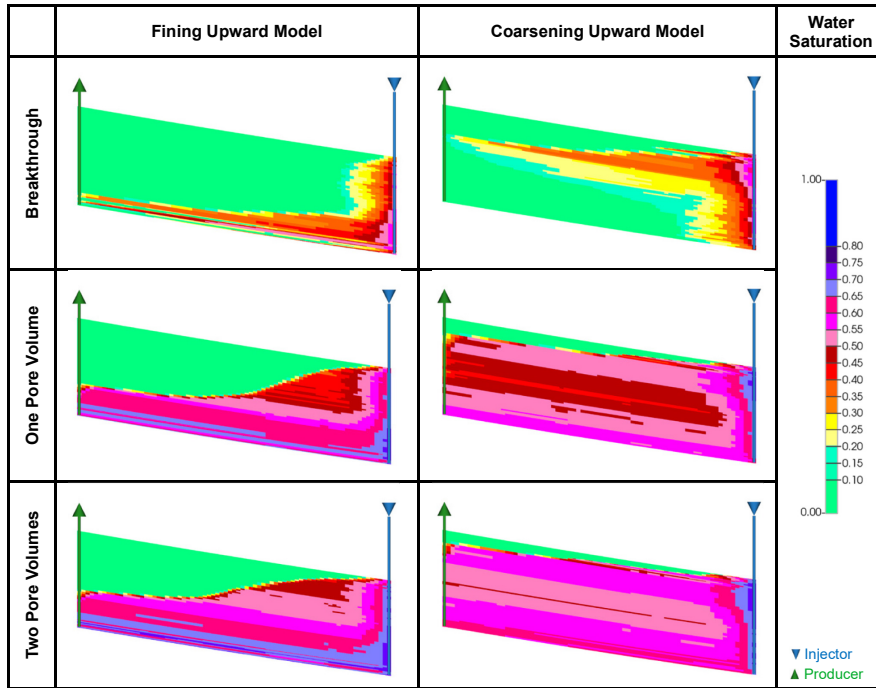


Figure 5.15. Water saturation distributions for the heavy oil coarsening upward and fining upward model at breakthrough, 1 PVI and 2 PVI. C The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green. Vertical injector is completed down-dip the structure in blue (right) and the producer is completed up-dip the structure in green. There is high sweep efficiency for the coarsening upward and lower displacement efficiency.

5.3.3.1.2 Light Oil Case ($\mu_o = 1.4 \text{ mPa.s}$)

An improved recovery was seen in the finer grid models for all three reservoir types (see **Figure 5.16**). The coarsening upward and homogeneous cases broke through later than the heavy oil case, whereas the breakthrough occurred at a similar PVI in the fining upward case to the heavy oil case. This is due to the good sweep introduced by the favourable end-point mobility ratio in light oil reservoirs. There was also a small improvement in displacement efficiency in the light oil case.

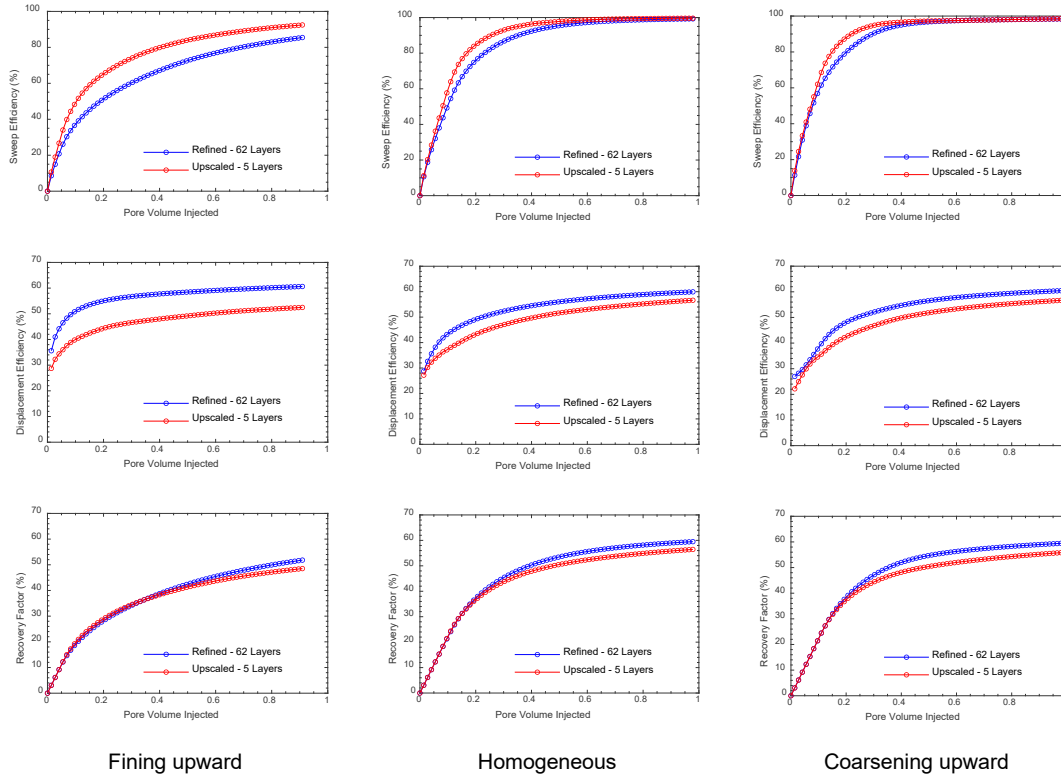


Figure 5.16. Sweep efficiency, displacement efficiency, and recovery as a function of PVI for a refined fine grid model (62 layers) in blue with three reservoir characteristics (fining upward-left side, homogeneous-centre and coarsening upward-right side). The results are compared with the upscaled coarse grid model (5 layers) in red for the light oil case.

5.4 Summary

In this chapter we investigated the combined impact of gravity, wettability, and end-point mobility ratio on recovery performance for horizontal line drives in both homogeneous and field-scale heterogeneous reservoirs. The purpose was to develop a detailed understanding of how gravity influences displacement and sweep efficiency, complementing the earlier screening in Chapter 4 where gravity was shown to affect waterfloods and polymer flooding, but was far less significant for thermally stable ATBSA.

In heavy oil homogeneous reservoirs with unfavourable mobility ratios, gravity improved recovery in oil-wet and mixed-wet systems after 1–2 PVI. Initially both displacement efficiency and sweep were poor, but later gravitational segregation of the fluids resulted in improved displacement efficiency, with the effect most marked in oil-wet reservoirs. In light oil homogeneous reservoirs with favourable mobility ratios, gravity also improved recovery in oil-wet and mixed-wet systems, and here the improvement occurred even before water breakthrough due to a combination of favourable mobility ratio and segregation. In contrast, in water-wet systems

displacement efficiency was already high, so gravity provided little benefit; instead, segregation reduced sweep efficiency and lowered overall recovery.

A consistent outcome across all wettability states was that breakthrough recovery was always reduced by gravity under unfavourable mobility conditions. This reduction arose from poorer sweep efficiency caused by segregation, even though later-time recovery was improved by enhanced displacement. Reservoir heterogeneity further influenced recovery. In coarsening-upward permeability distributions, sweep efficiency was improved, which counteracted the negative effect of segregation; in such cases, gravitational segregation consistently improved recovery, with displacement gains outweighing sweep losses. In fining-upward permeability distributions, sweep efficiency was further reduced, cancelling the displacement improvement and leading to negligible overall gain. For light oil in fining-upward settings, the incremental effect of gravity was minimal.

These results confirm that gravity influences recovery by enhancing displacement efficiency but reducing sweep efficiency, and that both effects must be carefully considered for specific reservoir conditions. At present, conventional wisdom suggests that rapid injection, forcing a viscous-dominated displacement, is desirable because it leads to higher recovery at breakthrough. However, this work demonstrates that lower injection rates can allow gravity segregation to improve displacement efficiency after breakthrough, particularly in oil-wet and mixed-wet systems. This has direct implications for field operations, where the potential late-time benefits of gravity may be overlooked if injection is optimised only for breakthrough recovery. The study also highlighted the importance of vertical resolution in simulation, as coarse grids reduce the apparent effects of gravity segregation and misrepresent flow dynamics.

While the influence of gravity in waterflooding is well established, this chapter quantifies and clarifies how gravity modifies displacement and sweep under different wettability, mobility ratios, and stratigraphic conditions, highlighting effects that are often under-appreciated. Building on these insights, the next chapter shifts focus to polymer flooding in giant carbonate reservoirs at field scale. Chapter 6 will examine thermal degradation during polymer floods under injector–producer spacings of about 5 km, where gravity segregation may again become significant. It will also validate the use of ATBSA under these conditions and provide a detailed evaluation of the displacement and sweep processes that control recovery in real field applications.

Chapter 6

Thermal Degradation During Polymer Flooding of Giant Oil Fields

6.1 Introduction

This chapter evaluates the feasibility of polymer flooding in giant carbonate reservoirs with well spacings of 1–2 km across 5–10 km patterns, conditions typical of field deployment in the Middle East. At such scales, the longer residence time of injected polymer means prolonged exposure to high temperature and salinity, increasing the impact of thermal degradation and providing more scope for gravity segregation to influence recovery. The objective is to test the performance of ATBSA, a thermally stable polymer, under these demanding conditions and to provide deployment guidelines that address both feasibility and the role of gravity at field scale.

Economic considerations and optimization of polymer flooding designs often focus on the size of the injected polymer slug. The typical deployment of polymer flooding projects in the Middle East involves peripheral injection at reservoir boundaries and horizontal producers with large well spacing. This combined with the high temperature, salinity, and hardness of these reservoirs presents difficulties for deploying HPAM polymers. The extended exposure of polymers to reservoir conditions can degrade their effectiveness. Large polymer banks may also be needed to mitigate the adverse effects of water fingering behind the polymer front, which can severely impact the success of the project. In addition, the heterogeneous nature of carbonate reservoirs leads to

uneven polymer propagation, with high-permeability layers dominating the flow, further complicating the recovery process.

In this work, we present guidelines for the successful deployment of polymer flooding in giant carbonate reservoirs with high temperatures and large well spacings. These are developed using a combination of analytical solutions and field-scale simulations. We apply a modified Buckley–Leverett analytical solution for polymer flooding to provide an initial screening of optimal slug size and polymer type. We then use reservoir simulations to validate the slug size proposed by the analytical solution and to confirm the benefits of using ATBSA to improve recovery performance at large well spacings. Performance is assessed in terms of recovery, displacement, and sweep efficiency, with further insights drawn from changes in saturation and viscosity distributions over time.

We will focus on modelling polymer thermal stability and will assume that other factors such as polymer adsorption, shear thinning and well injectivity are insignificant to minimize the design complexity. We will compare the performance of two polymers, HPAM and ATBSA, with very different thermal stabilities in the COSTA models representing giant carbonate reservoir.

6.2 Estimation of Slug Size and Polymer Selection

We will first evaluate the minimum slug size that will maintain its integrity, in the absence of thermal degradation using Buckley Leverett frontal advancement theory and validate it numerically. We will then estimate the expected exposure time of polymer at different well spacing and production/injection rates using the same theory and use it as a selection guide for the polymer type. Finally, we will include the effects of thermal degradation and test the feasibility of HPAM and ATBSA at different reservoir temperatures and well spacing.

6.2.1 Slug Size

To optimize slug size selection, we use a semi-analytical solution for slug size incorporating Todd and Longstaff's mixing factor for a broad range of wettability, mobility ratios, and mixing factors to estimate the expected range of slug size used in oil-wet heavy oil applications. Here, we apply the semi-analytical solution for slug size

introduced in Chapter 2 (Eq. 2.16) to approximate the minimum polymer slug size required to prevent destruction by fingering before reaching the production well. This formulation, based on the Todd and Longstaff model, represents the average effects of fingering as demonstrated by Abdul Hamid and Muggeridge (2018), and ensures that the leading edge of the polymer slug arrives at the producer simultaneously with the trailing water finger.

We conducted a full factorial design across a range of input parameters summarized in **Table 6.1**, to represent the spectrum of possible slug sizes. This numerical analysis covered conditions ranging from oil-wet to mixed-wet relative permeability, mobility ratios, and mixing factors. Using a statistical approach, we identified the most representative slug sizes for the fractional factorial sensitivity analysis. The input parameters produced relative permeabilities grouped as oil-wet (red) and mixed-wet (magenta), both practical for polymer flooding (see **Figure 6.1**). The end-point mobility ratio was controlled to values between 1 and 2 to represent practical applications limited to moderate heavy oil reservoirs of viscosity ranging from 5 to 30 mPa.s. We defined mixing factors as 0 (no mixing), 0.33 (typical for reservoir applications), 0.50, and 0.67 (used in laboratory experiments).

Table 6.1. Input parameters ranges and increments for the full factorial slug size statistical analysis.

Parameters	Unit	Increment	Range
Initial water saturation, S_{wi}			0.1, 0.15
Residual oil saturation, S_{or}		0.05	0.05 : 0.05 : 0.2
Corey exponent oil, n_o		1	5 : 1 : 8
Corey exponent water, n_w		0.5	1 : 0.5 : 3
Water viscosity, μ_w	mPa.s	0.1	0.4 : 0.1 : 1
Oil viscosity, μ_o	mPa.s	5	5 : 5 : 30
Polymer viscosity, μ_p	mPa.s	5	5 : 5 : 30
Water end-point relative permeability, k_{rw}^0		0.1	0.2 : 0.1 : 0.8
Oil end-point relative permeability, k_{ro}^0			1
Mixing factor, ω			0, 0.33, 0.50, 0.67

Using power law functions, we generated relative permeabilities that cover most possible wettability realizations that represent oil-wet and mixed-wet reservoirs (see **Figure 6.1**). We constructed 1120 relative permeabilities to use for the fractional flow analysis for secondary polymer flooding.

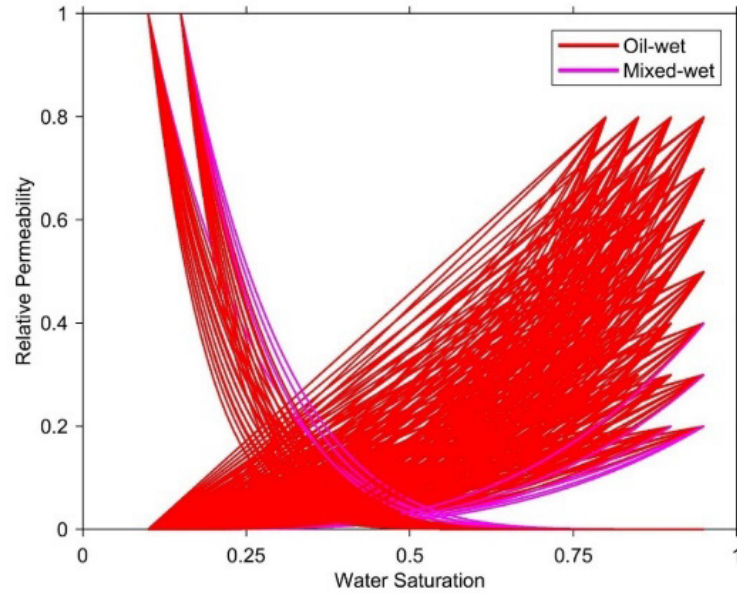


Figure 6.1. The relative permeabilities used for the full factorial design. Oil-wet in red and mixed-wet in magenta.

To identify the polymer shock fractional flow and saturations for the cases tested we used the extended solution of the Buckley-Leverett to secondary immiscible flooding derived by Pope (1980) discussed in chapter 2. In a polymer flood two shock fronts are formed, with an initial breakthrough of connate water with constant water cut followed by the polymer breakthrough due to different front speeds. In this work we neglect adsorption so the tangent line will start from the water saturation value of zero and connects to the polymer fractional flow curve at the tangent point to get the polymer shock front saturation and intersect the water fractional flow to get the water shock front saturation (see **Figure 6.2**). We focused on the cases where the shock front mobility ratio is expected to be between 1 (a favourable mobility ratio) and 2 (a slightly unfavourable mobility ratio). The sensitivity study considers around 45,000 cases that satisfy these mobility conditions for all possible wettability scenarios and used range of viscosities. **Figure 6.3** demonstrates that most of the recovery occurs prior to polymer breakthrough, indicating that basing the optimal slug size on the timing of polymer breakthrough is sound. This approach ensures efficient utilization of the polymer while minimizing costs and maximizing recovery, providing a practical framework for optimizing polymer flooding operations.

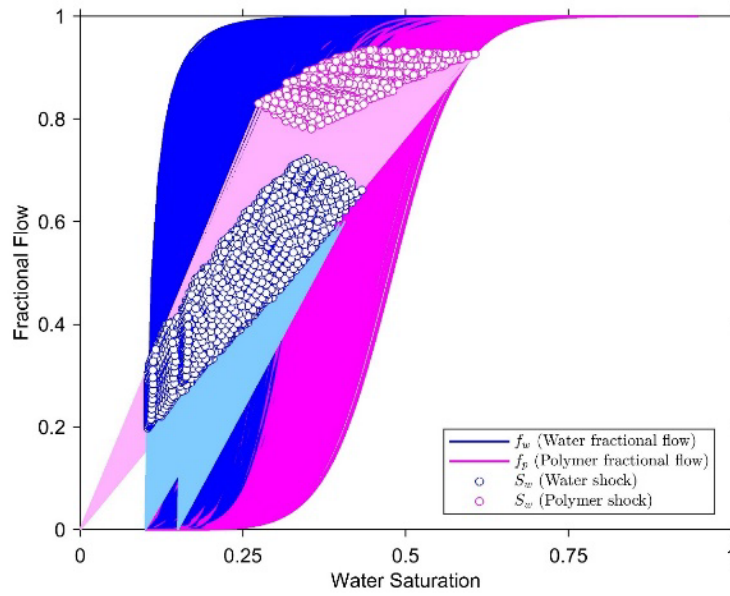


Figure 6.2. Polymer and water fractional flow demonstrating the cloud of shock front saturations of polymer in magenta and water in blue for a total of 44,800 cases.

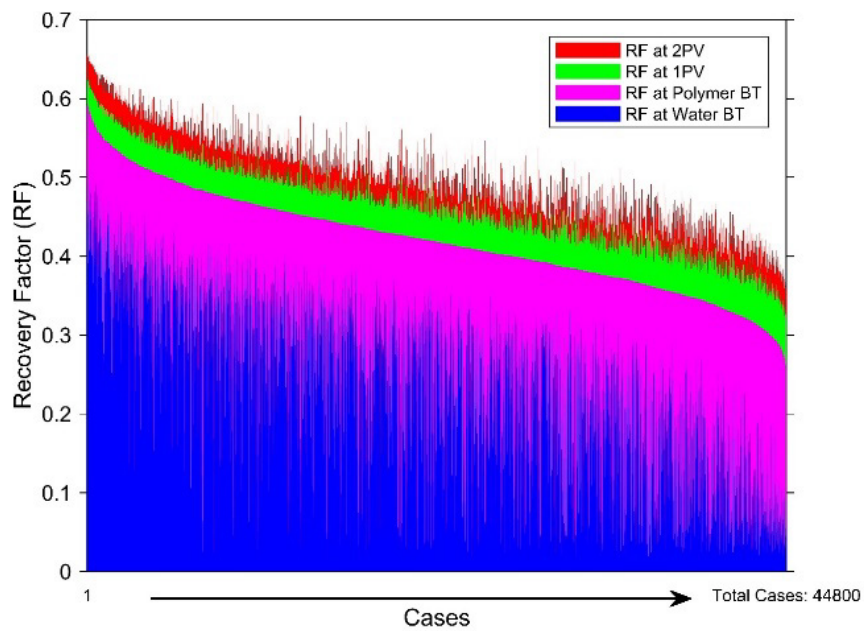


Figure 6.3. Recovery factor at water breakthrough in blue, polymer breakthrough in magenta, at 1 PV displacement in green, and 2 PV displacement in red for a total of 44,800 cases.

We used this analytical interpretation of the polymer shock front saturation to estimate the slug size required for optimal recovery performance using the input parameters in **Table 6.1**. We generated a histogram of the estimated slug size data and fit a normal distribution function to determine the most probable slug size. This approach provides a practical guide for estimating slug sizes tailored to specific applications, accounting for unique reservoir characteristics such as wettability, mobility ratio, and mixing to maximize recovery efficiency. Based on the probability distribution function and histogram statistical analysis the expected slug size would usually be between 0.31 and 0.43 PVI with mean and median of approximately 0.37 PVI (See **Figure 6.4**).

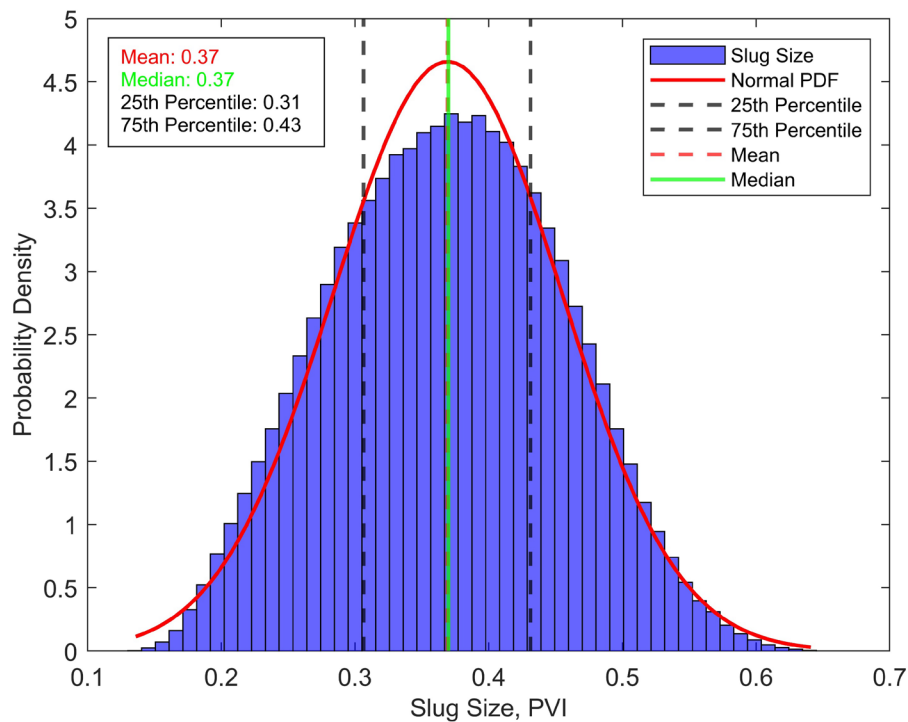


Figure 6.4. Slug size histogram with blue bars representing the probability density value of slug size bins. The solid red line represents the normal distribution function fit. The black dashed lines represent the 25th and 75th percentiles. The red dashed line represents the mean and the green line represents the median.

The above represent the spectrum of expected optimal slug size in carbonate reservoir with various tested conditions summarized in **Table 6.1**. However, here we estimate the slug size specific to the reservoir condition of interest stated in the model initialization section 3.3.1. We constructed the analytical Buckley—Leverett solution using data from (**Table 3.2** and **Table 6.2**) and applied polymer viscosity of 10 mPa.s and mixing factor of 0.67 to the slug size semi-analytical equation (Eq. 2.16) to estimate a slug size of 0.34 PVI. We will simulate this slug size in the results sections to confirm the

reliability of this solution and what is the expected deviation caused by reservoir heterogeneity and vertical crossflow.

6.2.2 Exposure Time

Polymer exposure time, an extension of the analytical work used to estimate slug size, represents the duration required for the injected polymer to travel through the reservoir and reach the production well.

$$\text{Exposure Time } (t), \text{ in years} = \frac{\text{Slug Size } (t_D) \times \text{Reservoir PV}}{Q_{inj}} \quad 6.1$$

It is calculated based on slug size in PVI, reservoir pore volume in m^3 , and Q_{inj} injection rate in $\frac{m^3}{day}$. The selected polymer must have a half-life that exceeds the expected exposure time, accounting for factors such as exposure distance and designed production/injection rate. By aligning the polymer's stability with the calculated exposure time, we can prevent premature degradation, maintain viscosity, and optimize polymer recovery performance. **Figure 6.5** is a guide that represents the exposure time as a function of distance for different flow rates. These exposure time calculations are based on the pore volume of the 3D COSTA model (5 km sector) from **Table 6.2** used in the simulations.

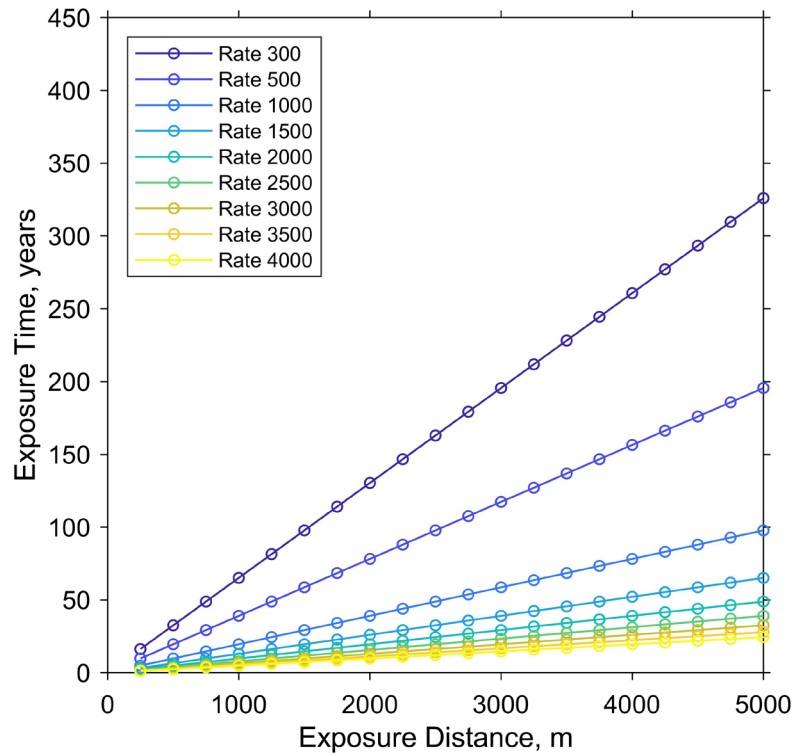


Figure 6.5. Analytical estimation of polymer exposure time for a series of production/injection rates over a range of well spacing (exposure distance).

6.2.3 Screening for Polymer Type

The half-life concept discussed first in chapter 2 (Eq. 2.15) is used as a comparative measure to assess polymer stability at specific temperatures (see **Figure 4.3**). For example, HPAM polymer retains half of its initial viscosity after 2.5 years at 100°C and 4 years at 85°C, whereas ATBSA can maintain its viscosity for up to 50 years at 100°C and 200 years at 85°C (**Table 4.2**). It is vital to correlate these durations with the time required for the polymer solution to cross the reservoir. The exposure time depends on the speed of the polymer shock front, production/injection rate and the distance between the injector and producer. Selecting a polymer with a half-life significantly exceeding the exposure time is essential to ensure sustained polymer performance. Identifying the range of reservoir temperatures for the targeted applications is essential.

6.3 Polymer Flooding Numerical Modelling

6.3.1 Polymer Model Setup

We use the same polymer viscosity calibration established earlier: a third order Flory–Huggins fit to the concentration data (see **Figure 3.3**), with the simulator viscosity table taken from **Table 3.4** and the underlying experimental measurements in **Table 3.3**. Thermal degradation follows the first order Arrhenius formulation introduced previously, using the decay constants and activation parameters in (**Table 3.6** and **Table 3.7**), with half-life projections summarised in **Table 4.2** and trends shown in (**Figure 3.4** and **Figure 4.3**). Mixing is represented with the Todd–Longstaff model using a fixed $\omega = 0.67$, as adopted and justified in Chapter 4 under the discussion on the Todd–Longstaff mixing factor.

6.3.2 Field-Scale Heterogeneous Reservoir Model

We use the COSTA based workflow already established in Chapter 3 (see **Figure 3.24** and Section 3.5 for refinement/upscaling), with the vertical stratigraphy (coarsening-upward and fining-upward). The $1.25 \text{ km} \times 1.25 \text{ km}$ sector employed in Chapter 4 and Chapter 5 is retained unchanged as the large-spacing reference for polymer screening. In this chapter we introduce a larger field-representative sector of $1.75 \text{ km} \times 5 \text{ km}$ with peripheral injection and three horizontal producers spaced at 1 km, the first producer located 3 km from the injector (See **Figure 6.6**); this layout is consistent with the deployment context discussed earlier. All static rock properties and base grid specifications are listed in (**Table 6.2**). Fluid and rock properties inputs are the same as in earlier chapters: heavy oil with an oil-wet system, using the carbonate relative permeability set from Dakshinamurthy et al. (2014) compiled in Chapter 3 (**Table 3.2** and its associated figure). The producers are designed to keep producing with no water-cut shut-in constraint to ensure consistent material balance and avoid pressurizing the reservoir.

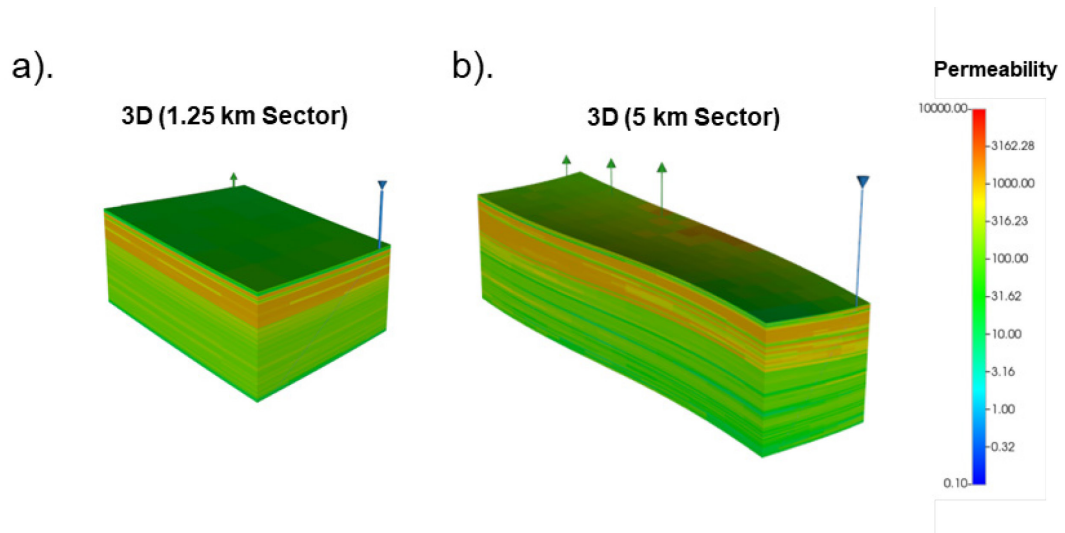


Figure 6.6. Modified COSTA model sectors. a) 1.25 km $\times$ 1.25 km sector with one slanted injector in blue and the horizontal producer in green. b) 1.75 km $\times$ 5 km sector with one slanted injector in blue and three consecutive horizontal producers in green.

Table 6.2. 3D COSTA sector models (1.25 and 5 km sectors) simulation base data.

Parameter	Unit	3D (1.25 km sector)	3D (5 km sector)
		Value	Value
Grid blocks (Refined)		75 $\times$ 75 $\times$ 62	300 $\times$ 105 $\times$ 62
Grid block size (Refined)	M	16.67 $\times$ 16.67 $\times$ 0.80	16.67 $\times$ 16.67 $\times$ 0.80
Reservoir length, l	M		1250
Reservoir width, w	M		1250
Reservoir thickness, h	M		49.5
Porosity, ϕ	%		21
Average permeability, K	mD		300
Residual oil saturation, S_{or}			0.2
Irreducible water saturation, S_{wi}			0.1
Oil viscosity, μ_o	mPa.s	10 (Heavy Oil)	10 (Heavy Oil)
Water viscosity, μ_w	mPa.s		0.41
Oil density, ρ_o	kg/m ³		881
Water density, ρ_w	kg/m ³		1093
Injection and production rate	m ³ /day		3000
Number of producers			1
Depletion rate	%OIP/year		4.1
$\frac{K_v}{K_H}$			0.5

6.3.3 Performance Measures

While polymer flooding does not significantly alter the water breakthrough time, it does reduce the rate at which the water cut increases. As discussed in Chapter 2, this improvement in recovery efficiency can be attributed to enhanced sweep efficiency and improved local displacement. In analysing the simulation results, performance comparisons will focus on recovery, local displacement efficiency, and sweep effectiveness using equations (Eqs. 2.2–2.4). We present the results using the same MATLAB code used in Chapter 5

6.4 Results and Discussion

6.4.1 Slug Size

This section determines whether the analytical estimation of 0.34 PVI as the optimal slug size for polymer flooding also applies in the heterogeneous reservoirs. This is evaluated through a numerical sensitivity analysis. We ran a slug size sensitivity in the commercial numerical simulator on the 1.25 km COSTA sector model. We used slug sizes ranging from 0.1 PVI to 1.0 PVI as shown in in **Figure 6.7**. We observe that recovery increases with slug size at early stages of depletion, but the increase diminishes beyond 0.34 PVI. We also observe that even in the presence of reservoir heterogeneity polymer breakthrough remains consistent at 0.38 PVI for all slug sizes bigger than 0.34 PVI, as illustrated in **Figure 6.8**. The relationship between recovery factor and slug size remained consistent, with 0.34 PVI providing near-maximal recovery efficiency. These results confirm the applicability of the analytical solution in optimizing slug sizes for heterogeneous reservoirs while accounting for the minor impact of heterogeneity on breakthrough timing.

In practice, field experience shows that polymer slug sizing is often chosen pragmatically based on the observation that polymer efficiency can deteriorate once polymer injection stops and is followed by water; therefore, extending slug size is not automatically optimal and is frequently judged on an economic basis (Sagyndikov et al., 2025). Although degradation could motivate larger injected polymer volumes, the COSTA sector results still show only marginal incremental recovery beyond 0.34 PVI. Hence, 0.34 PVI is interpreted as the technical “capture most of the benefit” slug size,

while larger slugs may remain economically attractive for some operators depending on polymer cost, injectivity, and the value of incremental oil. In this work, degradation did not materially shift the slug-size optimum because the ATBS-based polymer formulation considered remains stable over the simulated timeframe; however, degradation should be further assessed and incorporated into the analytical workflow alongside polymer adsorption/retention, which is not represented in the current analytical model and can lead to an underestimation of the required injected slug.

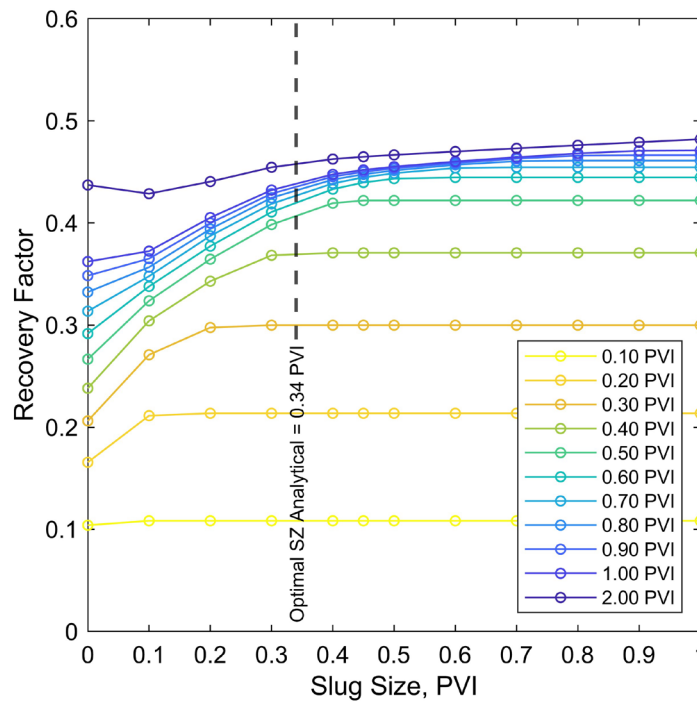


Figure 6.7. Recovery performance sensitivity to polymer slug size at multiple depletion stages. The black dashed line represents the optimal slug size proposed by the analytical solution. Polymer thermal degradation is ignored.

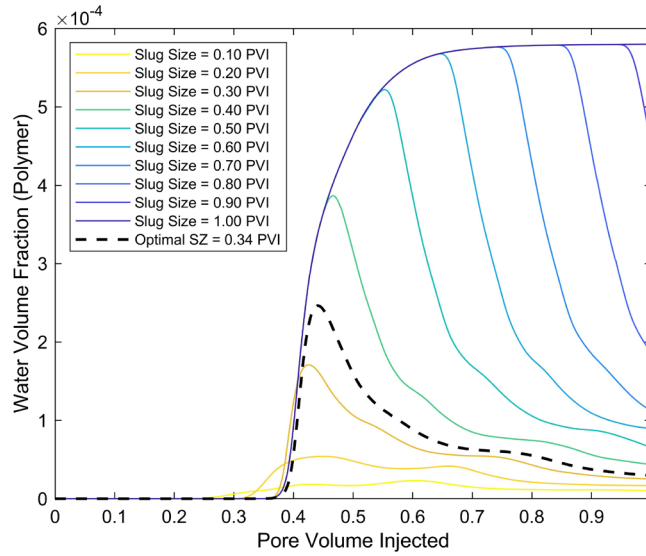


Figure 6.8. Water volume fraction of polymer at pore volume injected for multiple polymer slug sizes. The black dashed line represents the optimal slug size proposed by the analytical solution.

6.4.2 Polymer Selection

Here we present evidence that ATBSA is a viable polymer for giant harsh reservoirs with large well spacing of 1 to 5 km and why HPAM may fail in these kinds of reservoir. First, we share recovery performance of these two polymers under low, moderate and high reservoir temperatures. Then, we study the effect of exposure time and distance on recovery for both polymers.

6.4.2.1 Reservoir Temperature Sensitivity

The Arrhenius analysis revealed that polymers achieve better half-life performance at lower temperatures (85°C) but experience significant degradation at elevated temperatures (140°C), as shown in **Table 4.2**. To evaluate recovery performance, simulations assessed HPAM and ATBSA polymers on the 1.25 km COSTA model sector, a polymer slug of 0.40 PVI and injection and production rate of 3000 m³/day for various reservoir temperatures (**Figure 6.9**). Below 100°C, ATBSA polymers exhibited exceptional recovery improvements, closely matching the performance of polymers without thermal degradation effects. In contrast, HPAM polymers achieved moderate recovery improvements, limited by their shorter half-life (2.5 to 4 years) and the large well spacing (1.25 km), which resulted in reduced recovery gains. At 140°C, both

polymers failed to deliver effective recovery enhancements, rendering them unstable under high-temperature conditions. These findings underscore the detrimental impact of elevated reservoir temperatures on polymer performance and highlight the importance of ensuring a relatively high estimated half-life at the target reservoir temperature.

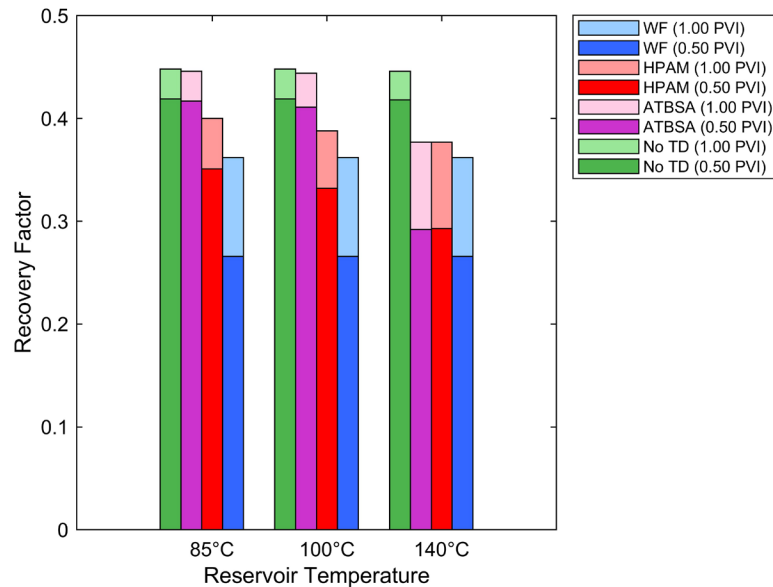


Figure 6.9. Recovery factor performance demonstrating polymer type sensitivity to reservoir temperature at 0.50 PVI and 1.00 PVI for the 1.25 km sector, 0.40 PVI slug and 3000 m³/day injection and production rate. Green is polymer with no thermal degradation, Magenta is ATBSA, Red is HPAM and blue is waterflooding with darker shade at 0.5 pore volume injected and lighter shade at 1 pore volume injected.

6.4.2.2 Exposure Time and Distance Sensitivity

This study examines how exposure time and distance impact the recovery performance of HPAM and ATBSA polymers. We completed an injector and a producer at spacings of 250 m, 1 km, 2 km, and 3 km within the 5 km COSTA model sector. The simulations used a polymer slug size of 0.40 PVI and maintained an injection and production rate of 3000 m³/day. Recovery performance was compared at 0.50 PVI, recognizing that polymers typically accelerate hydrocarbon recovery during early depletion stages but do not significantly enhance ultimate recovery (1 to 2 PVI). In **Figure 6.10**, at a small well spacing of 250 m, both HPAM and ATBSA showed similar incremental recovery gains of approximately 14% over waterflooding at 0.50 PVI. This is also demonstrated with an almost identical saturation profile of HPAM and ATBSA in **Figure 6.11**. This result highlights the effectiveness of HPAM in short-distance applications with minimal exposure time. However, as exposure distance increased, the incremental recovery gains

declined for both polymers. ATBSA maintained a 10% improvement, while HPAM achieved only 2.5% in reference to waterflooding performance, demonstrating ATBSA's superior stability over larger well spacings and highlighting HPAM's limitations for similar applications. This is also demonstrated by a more saturated profile of ATBSA in comparison to HPAM in **Figure 6.12**. This is in line with polymer selection guided by exposure time estimation from **Figure 6.5** where the expected exposure over a distance of 3 km is ~25 years which is half of ATBSA half-life and almost 10 times longer than the HPAM half-life. Interestingly, overall recovery showed an increasing trend with greater exposure distance, despite the expectation that prolonged exposure to high reservoir temperatures would reduce polymer performance. This trend aligns with the findings of Alsaleh et al. (2024) and demonstrated in Chapter 5, which suggest that gravity enhances oil recovery in oil-wet reservoirs. For instance, at 250 m spacing, depletion rates are more viscosity-dominated at 20% per year, whereas at 3 km spacing, depletion rates are more gravity-dominated at 1.6% per year. Although the previous conclusion in Chapter 4 showed an insignificant influence of gravity on ATBSA performance, here we see gains in recovery due to gravity.

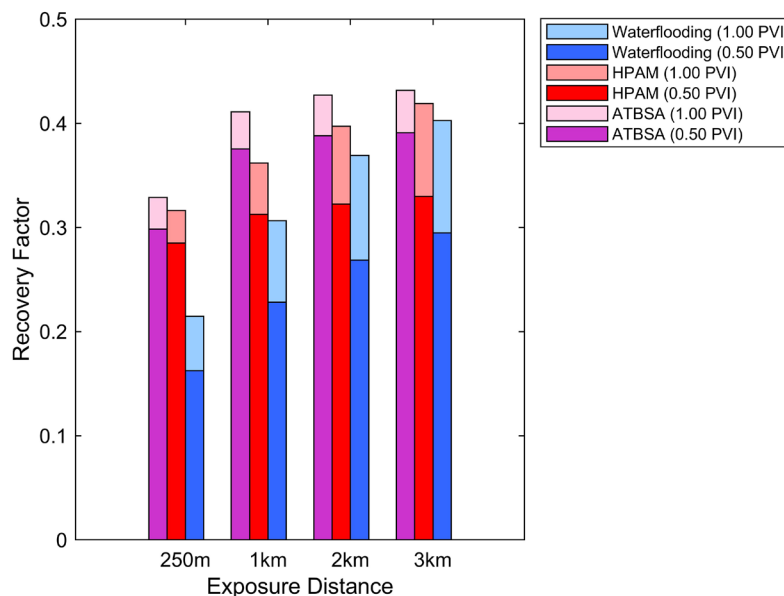


Figure 6.10. Recovery factor performance demonstrating polymer type sensitivity to exposure distance at 0.50 PVI and 1.00 PVI for the 5 km sector, 0.40 PVI slug and 3000 m³/day injection and production rate. Magenta is ATBSA, Red is HPAM and blue is waterflooding with darker shade at 0.5 pore volume injected and lighter shade at 1 pore volume injected.

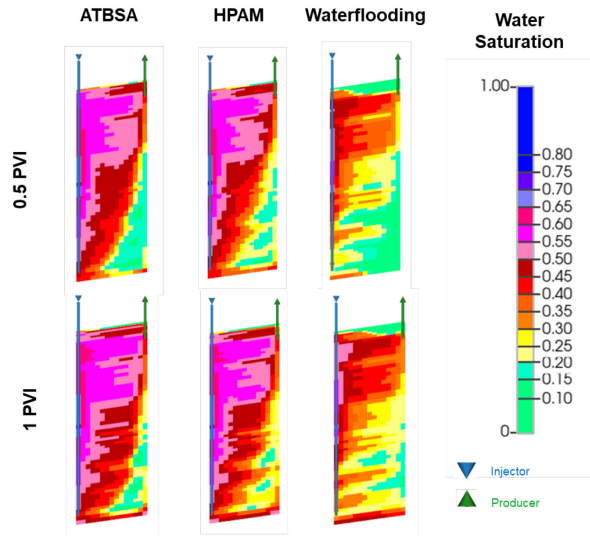


Figure 6.11. Water saturation distribution at 0.5 PVI and 1 PVI for polymer flooding using ATBSA and HPAM and waterflooding for an injector/producer spacing of 250. The cross-section represents a mid-slice across a 250 m sector from the COSTA model. Water injector in blue and producer in green. The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green.

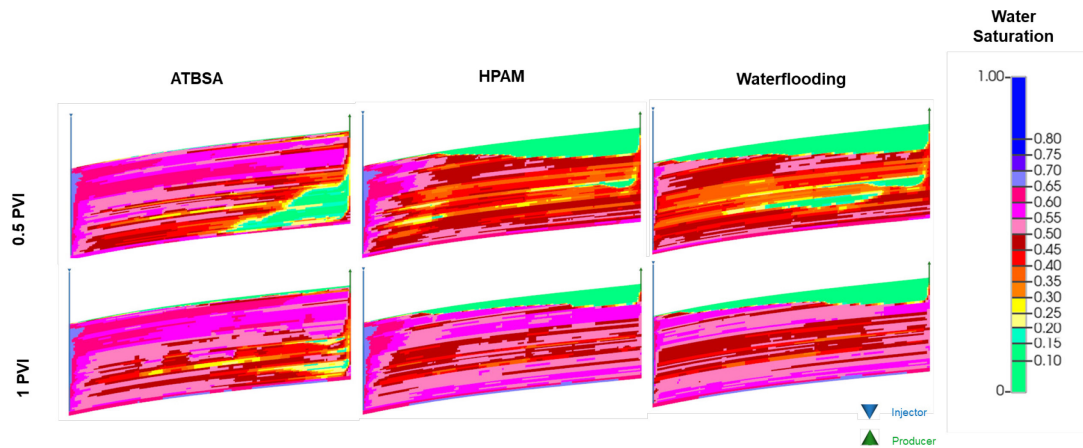


Figure 6.12. Water saturation distribution at 0.5 PVI and 1 PVI for polymer flooding using ATBSA and HPAM and waterflooding for an injector/producer spacing of 3 km. The cross-section represents a mid-slice across a 3 km sector from the COSTA model. Water injector in blue and producer in green. The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green.

6.4.3 Performance Measures

6.4.3.1 *Slug Size*

Recovery performance showed little improvement for slug sizes above 0.40 PVI validating the analytical solution. The reason is that the local displacement efficiency almost maximizes at 0.40 PVI (See **Figure 6.13**) and any additional polymer pumped in the reservoir will just be passing through the reservoir causing no further recovery.

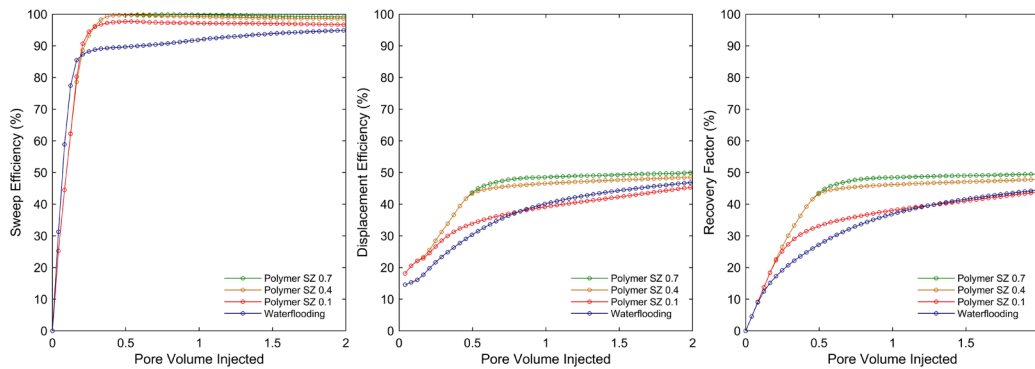


Figure 6.13. Slug size sensitivity demonstrated by sweep efficiency, displacement efficiency, and recovery over PVI. Blue is waterflooding, Red is slug size of 0.1 PVI, yellow is slug size of 0.4 PVI and green is slug size of 0.7 PVI.

6.4.3.2 *Exposure Distance*

In **Figure 6.14**, ATBSA and HPAM achieved the highest recovery gain from waterflooding at a well spacing of 250 m, but the overall recovery was lower than at 3 km well spacing. Injecting at 3000 m³/day across all cases meant that flow was viscous dominated at shorter well spacings, leading to poor sweep efficiency due to the reservoir's upward coarsening. However, significant displacement improvement by polymer was observed. At 3 km well spacing, flow was gravity-dominated, enhancing sweep and displacement efficiency through gravity-stable displacement, resulting in better recovery. ATBSA exhibited the highest sweep efficiency at 3 km well spacing and demonstrated improvement in displacement efficiency, but it is incomparable to waterflooding in magnitude. This indicates that the low mobility of the polymer reduces segregation rates, limiting recovery improvement due to gravity. At large well spacing, recovery gains from stable polymer injection are attributed to enhanced sweep efficiency at early time and improvement in displacement efficiency by gravity at later time.

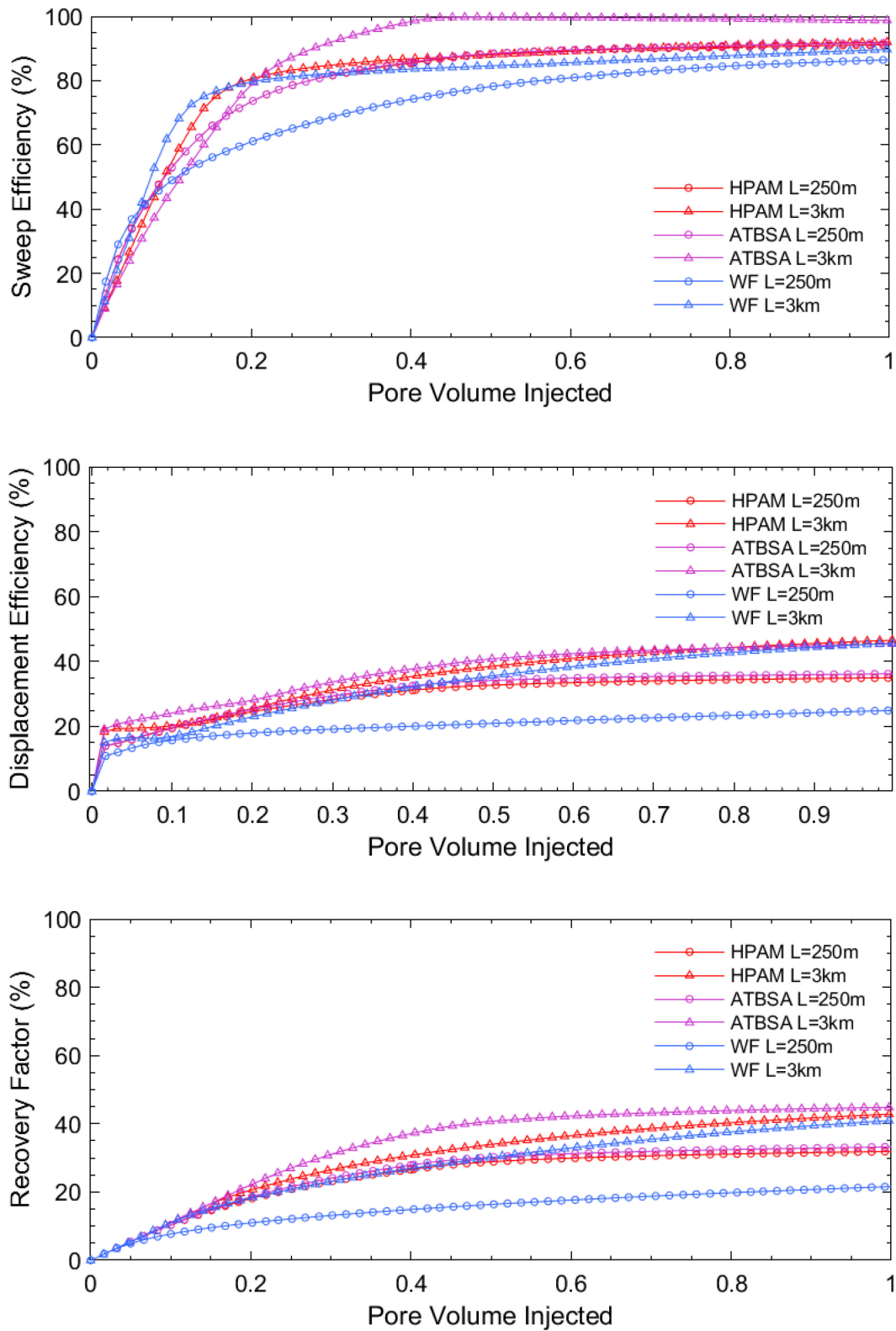


Figure 6.14. Exposure distance effect on polymer performance demonstrated by sweep efficiency, displacement efficiency, and recovery over PVI. Blue is waterflooding, magenta is ATBSA, red is HPAM with circles allocated to a well spacing of 250 m and triangles for a well spacing of 3 km.

6.4.3.3 *Peripheral Flooding (3 Producers) 5 km COSTA Sector Model*

The 5 km COSTA sector model incorporates a slanted peripheral injector, and three horizontal producers located in the top layer of a reservoir with upward-increasing permeability (see **Figure 6.6b**), designed to replicate the infrastructure of giant Middle Eastern reservoirs. In **Figure 6.15**, ATBSA demonstrates an incremental recovery gain of approximately 10% compared to waterflooding. Its performance closely matches that of polymer flooding when thermal degradation is excluded, reinforcing the feasibility of ATBSA in large-scale reservoir applications. Most of the recovery gain stems from improved sweep efficiency, aligning with earlier conclusions on exposure distance effects. Notably, after 0.40 PVI, the displacement improvement plateaus, while waterflooding and HPAM flooding continue to deliver incremental gains in displacement efficiency. By 1 PVI, the recovery performance of polymer flooding and waterflooding ultimately converge.

The observed recovery trends highlight the role of displacement efficiency in the overall performance of the various flooding scenarios. This behaviour can be further analysed through the water saturation cross-sections of the four flooding strategies, as illustrated in **Figure 6.16**. ATBSA demonstrated excellent sweep and displacement at 0.4 PVI, with the formation of an oil bank ahead of the flood front. In contrast, waterflooding showed inferior sweep efficiency, lower displacement performance, and a gravity-stable displacement. At 1 PVI, waterflooding exhibited improved displacement efficiency with a more uniform saturation distribution. However, ATBSA's displacement performance was less uniform, with better displacement observed in the upper reservoir layers, while the lower layers experienced notable inefficiency and retention of trapped oil. **Figure 6.17** reveals that the trailing water slug creates preferential flow paths in high-permeability zones, bypassing the polymer slug and leaving remaining oil and polymer in the bottom layers. This limitation underscores the need for optimized well placement to improve displacement efficiency in the lower layers and minimize polymer retention, despite ATBSA's significant 10% incremental recovery gain.

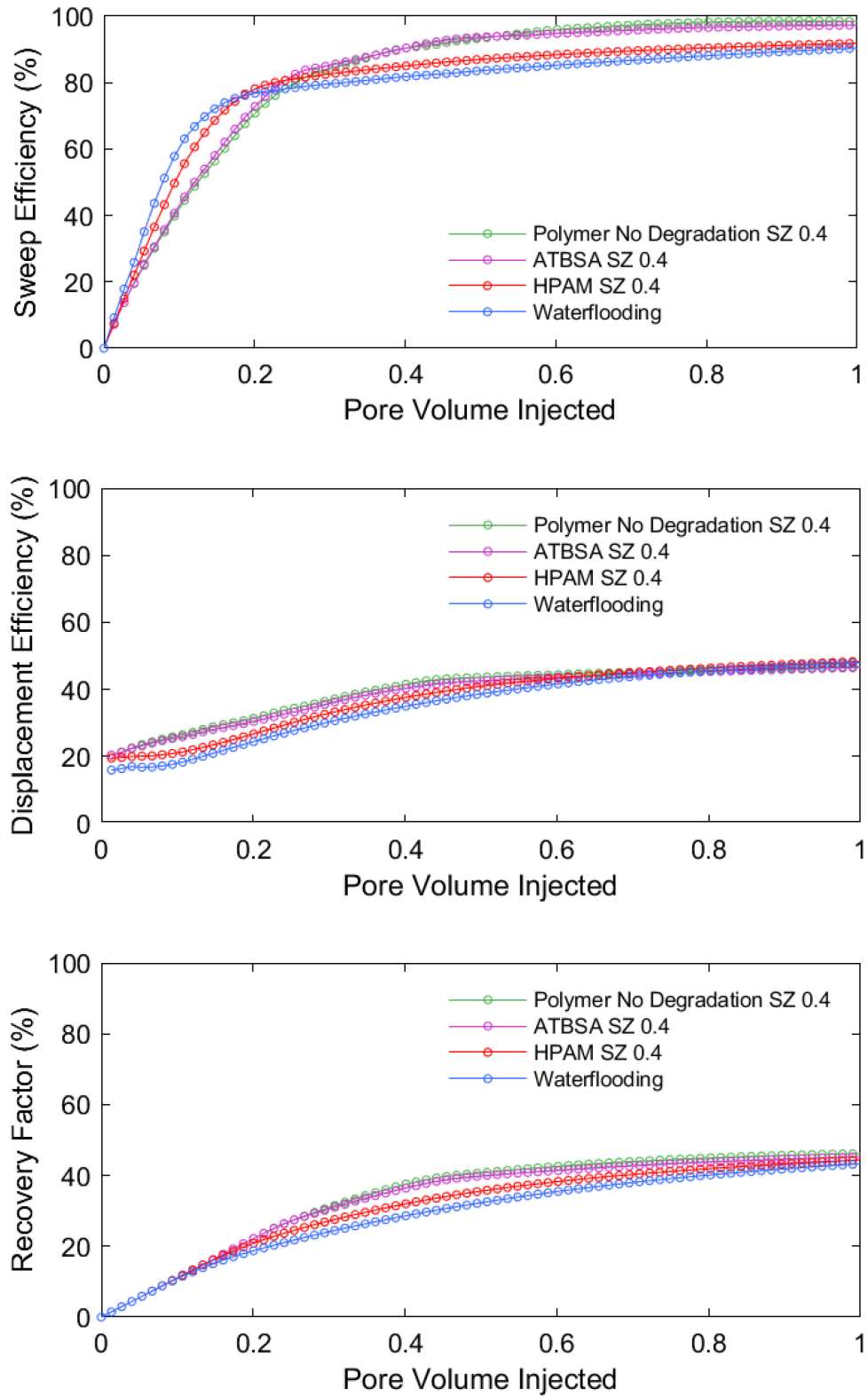


Figure 6.15. ATBSA and HPAM polymer performance in the 5 km COSTA model with 1 injector and 3 horizontal consecutive producers demonstrated by sweep efficiency, displacement efficiency, and recovery as a function of pore volumes injected. Blue is waterflooding, red is HPAM, magenta is ATBSA and green is polymer with no thermal degradation.

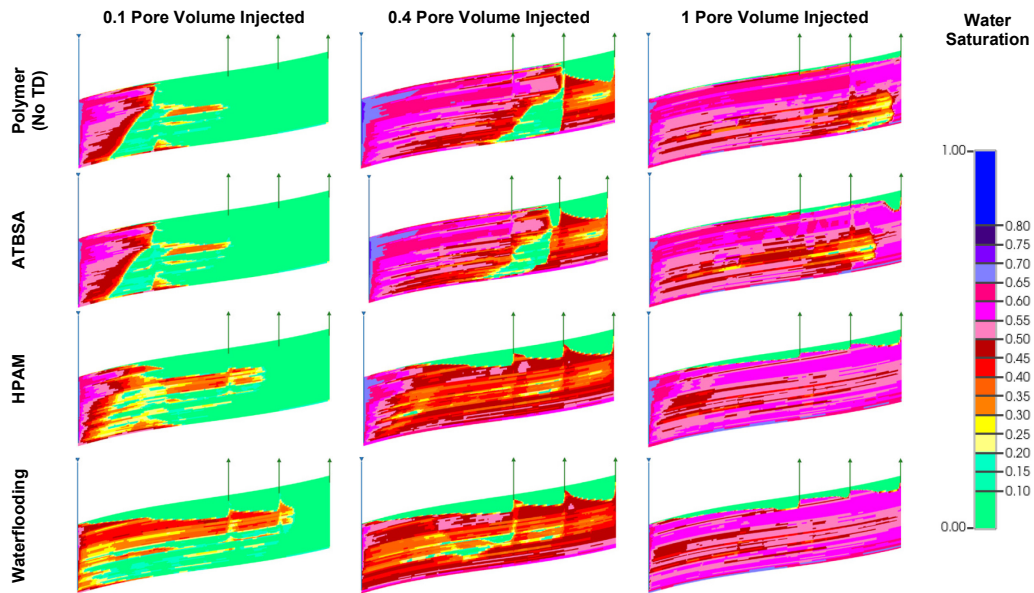


Figure 6.16. Water saturation distribution at 0.1, 0.4 and 1 PVI for polymer flooding with no thermal degradation, ATBSA, HPAM and waterflooding that demonstrates the water movement in the layers with time. The cross-section represents a mid-slice across the 5 km COSTA sector model. Water injector in blue and 3 producers in green. The scale represents water saturation from 80% water saturation at residual oil in blue to 10% connate water saturation in green.

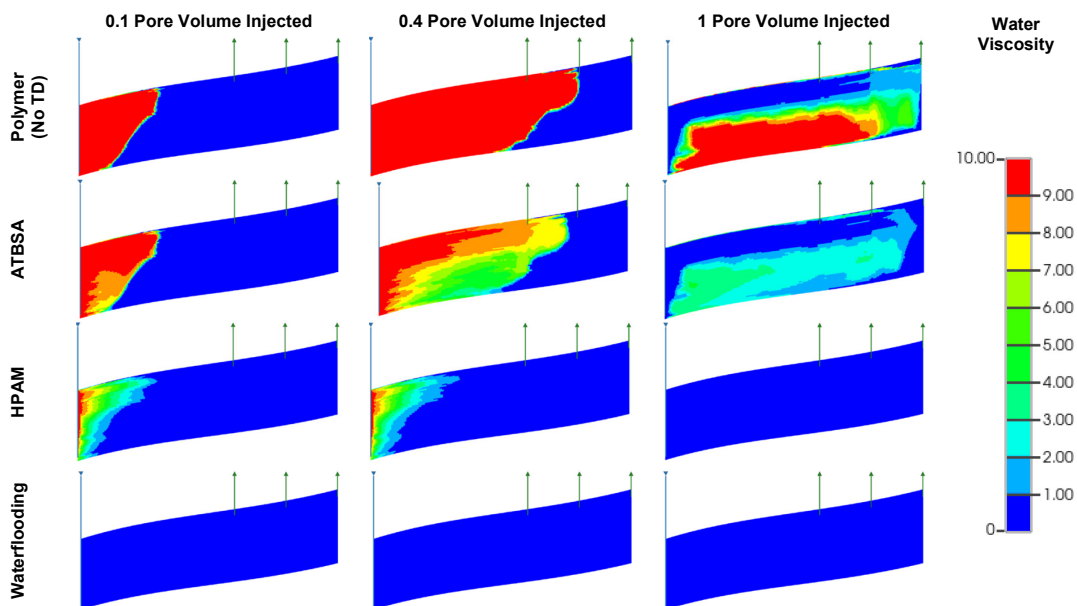


Figure 6.17. Water viscosity distribution at 0.1, 0.4 and 1 PVI for polymer flooding with no thermal degradation, ATBSA, HPAM and waterflooding that demonstrates the water movement in the layers with time. The cross-section represents a mid-slice across the 5 km COSTA sector model. Water injector in blue and 3 producers in green. The scale represents water viscosity from 10 mPa.s the initial polymer viscosity in red to 0.40 mPa.s representing the water viscosity.

6.5 Summary

This work determines the significance of thermal degradation on polymer flooding performance and demonstrates the successful implementation of ATBSA polymer in heterogeneous reservoirs with large well spacing when using a finite sized slug of polymer. Numerical simulation has confirmed that the analytical solution for optimal slug size (0.34 PVI) is applicable even in heterogeneous reservoirs, where slug sizes exceeding 0.34 PVI provide diminishing returns in recovery due to the saturation of local displacement efficiency. The ATBSA polymer demonstrated exceptional stability and recovery performance in harsh environments with well spacings ranging from 1 to 5 km, as its extended half-life at high temperatures (e.g., 50 years at 100°C) makes it suitable for prolonged reservoir exposure. By contrast, HPAM polymers, while effective at smaller well spacings (e.g., 250 m), showed significant performance deterioration at larger spacings due to their lower thermal stability and shorter half-life. Recovery gains were driven by improvements in both sweep and displacement efficiencies, with ATBSA maintaining the highest sweep and displacement efficiency at large well spacings. Although recovery performance declined with increasing well spacing for both polymers, ATBSA consistently outperformed HPAM, retaining up to 10% incremental recovery gains over waterflooding at 3 km spacing. The superior stability of ATBSA therefore supports its application in giant reservoirs with extensive well configurations. At larger spacings, gravity effects enhanced recovery even for ATBSA promoting stable displacement and counteracting the adverse impact of thermal degradation. Finally, ATBSA demonstrated a 10% incremental recovery gain in the peripheral flooding setup used in this study, but optimizing well placement could further improve displacement inefficiencies in lower-permeability layers and minimize polymer bypassing.

Chapter 7

Summary and Future Work

7.1 Summary

This thesis set out to determine when, how, and to what extent thermal degradation limits polymer-flooding performance in high-temperature carbonate reservoirs with large well spacing, and how gravity modifies both displacement and sweep as spacing increases. We built and validated a modelling framework, screened the controlling variables with a staged DOE, isolated the physics of gravity in waterfloods, and then tested field-scale feasibility of thermally stable polymers focusing on ATBSA under injector–producer spacings up to 5 km. Across the work, the central theme is the interplay between polymer thermal stability and gravity: stability governs early displacement gains; gravity increasingly governs late-time behaviour and becomes more influential as spacing grows.

Chapter 3 developed and validated the numerical models and provided the first quantitative indications of stability-driven performance differences. The 1D models were benchmarked against Buckley–Leverett and polymer extensions, and the thermal-degradation kinetics implemented in the simulator were cross-checked against the analytical first-order solution, confirming correct viscosity decay for HPAM and ATBSA at 100 °C. Grid-refinement studies then set the minimum resolution to capture fronts and segregation reliably, and the 2D vertical cross-section established how gravity and resolution alter displacement and sweep. These foundations showed ATBSA tracking the no-degradation case closely while HPAM rapidly lost effectiveness, motivating the field-scale investigations that follow.

Chapter 4 used a Resolution-IV fractional factorial DOE to identify which variables matter most once degradation is active. In 1D screening, slug size and polymer type dominated, with mixing significant and viscosity and the polymer-type–rate interaction partially significant; temperature effects were weak within 85–100 °C because residence times were short. These results guided the 3D COSTA sector screening, where we added stratigraphy and vertical anisotropy. In 3D, slug size and polymer type remained primary, while stratigraphy and anisotropy became significant, indicating that geological architecture and gravity start to condition outcomes once crossflow is present. The rate-stratigraphy interaction also emerged, foreshadowing Chapter 5’s gravity results and Chapter 6’s spacing study.

Chapter 5 focused on gravity in waterfloods to separate displacement mechanisms from chemistry. We showed that gravity improves displacement efficiency but reduces sweep; the net effect depends on wettability, mobility, and layering. In oil-wet and mixed-wet systems, gravity improved recovery after breakthrough; in water-wet settings it offered little benefit and could lower overall recovery through poorer sweep. Breakthrough recovery was always reduced by gravity under unfavourable mobility ratios because of sweep loss. Coarsening-upward layering counteracted segregation losses and delivered net recovery gains; fining-upward layering amplified sweep loss so gains were negligible. Conventional wisdom states that high rates for viscous-dominated flow maximise recovery at breakthrough, but this thesis shows that lower rates can enable gravity to improve displacement after breakthrough. This effect may be missed if insufficient vertical resolution is used in simulation.

Chapter 6 translated these insights to giant-field conditions. We validated, numerically, the semi-analytical solution by Abdul Hamid and Muggeridge (2018) of slug-size optimum of ~ 0.34 PVI in heterogeneous media; gains diminished above this size because local displacement efficiency had already saturated. This observation held even as heterogeneity advanced breakthrough slightly earlier than the analytical prediction. We then compared HPAM and ATBSA at spacings from 250 m to 3–5 km. As spacing increased, gravity became more important and overall recovery improved, but thermal degradation penalised HPAM while ATBSA retained performance; at 3 km ATBSA delivered $\sim 10\%$ incremental oil over waterflood by 0.5–1 PVI, while HPAM’s gain collapsed to a few percent. Displacement gains for ATBSA plateaued beyond ~ 0.4 PVI, and by ~ 1 PVI waterflood and polymer curves converged as gravity continued to reorganise fluids. Cross-sections in the 5 km sector showed trailing water bypass

along high-permeability paths and polymer retention in tight layers, pointing to well-placement and conformance opportunities. Overall, ATBSA's thermal stability, combined with appropriate slug sizing, advanced recovery early without needing gravity; gravity then added incrementally at late time, especially in oil-wet systems.

7.2 Limitations to be Addressed in Future Work

This study made various simplifying assumptions that should be examined in future work. These include modelling thermal degradation with a first order reaction, a polymer solution salinity concentration of 69,000ppm, neglecting diffusion and ignoring additional polymer behaviours including polymer adsorption, inaccessible pore volume, shear thinning and well injectivity.

The simulator uses a first order reaction for thermal degradation which results in polymer decaying directly to water. It could be argued that this approach does not accurately reflect the process, as in reality the polymer molecules gradually break down into shorter molecules resulting in a reducing viscosity and continuing adsorption of the shorter chain molecules (Druetta and Picchioni 2019; Lu et al. 2015). In this work adsorption is ignored so this simplified degradation model is unlikely to affect our results; however, for actual field implementation studies involving adsorption a more sophisticated reaction model should be considered.

Studies by Seright et al. (2021) estimated the half-lives of different types of ATBS (ATBSA, ATBSB, and ATBST) and evaluated their stability across low-salinity smart water injection (6,900 ppm), saline water injection (69,000 ppm), and connate water salinity (240,000 ppm). In this work, we use ATBSA dissolved in low salinity injected water at a concentration of 69,000 ppm and assumed no diffusion between the injected and connate water. In practice diffusion of the injected polymer solution into high-salinity connate water could further impact thermal stability and may warrant consideration in future studies.

This study has focused specifically on the impacts of polymer thermal stability on recovery performance and so has neglected other factors that influence polymer flooding performance such as polymer adsorption, inaccessible pore volume, shear thinning and well injectivity. Further work should evaluate the relative importance of these factors when designing for actual field implementations.

As explained in the methodology our simulations included Todd and Longstaff mixing at both the polymer front and the trailing edge of the polymer slug, due to the limitations of the simulator implementation. This caused more spreading of the polymer slug because we also neglected adsorption to focus on the impacts of thermal degradation. Including adsorption of the polymer would reduce this spreading at the polymer front however it would reduce the slug size over the course of the displacement due to loss of polymer to the rock. Further work into slug size should evaluate the relative importance of spreading versus adsorption.

Another limitation is the treatment of injection temperature. As discussed by De Leon Ismael Bento (2015), HPAM viscosity at concentrations above 1000 ppm is sensitive to temperature. In this work, we assumed constant initial viscosity since the injected polymer concentration is below this threshold and therefore not expected to be affected by the difference between surface injection temperature ($\sim 25^{\circ}\text{C}$) and reservoir temperature ($\sim 100^{\circ}\text{C}$). However, in practice, injecting cold water can reduce injectivity by temporarily increasing the oil viscosity in the near-wellbore region, which could impact early flood performance. At higher polymer concentrations, designing the polymer viscosity under a dual-temperature system (surface injection versus reservoir conditions) becomes more complex and requires further investigation to ensure accurate representation of polymer rheology in the simulation model. Preliminary results are included in the appendix A.2.

In addition, this study has not examined the potential of polymer flooding as a tertiary recovery process. Field experience generally indicates that polymer injection is more effective when applied as a secondary recovery method immediately after primary depletion. However, several studies have shown that under certain reservoir conditions, tertiary polymer flooding may outperform secondary application (Bondino et al., 2011; Doorwar and Mohanty, 2014; Fabbri et al., 2014; Skauge et al., 2012). An additional argument for tertiary deployment is economic: waterflooding is cheaper to implement and conducting a waterflood first provides valuable information on reservoir heterogeneity that can inform the design of a subsequent polymer project. These considerations suggest that further work should include a systematic evaluation of ATBSA performance in tertiary mode to determine its feasibility under harsh reservoir conditions. Discussions on tertiary recovery and preliminary results are included in the appendix A.1.

The study of polymer thermal degradation on the field scale requires extremely long simulation times (Sharma et al., 2011). Polymer upscaling methods were established recently and targeted various polymer physical features (Al-Dhuwaih et al., 2018; Al-Ibadi et al., 2021; Sharma et al., 2011; Tai et al., 2021; Verma et al., 2009). The impact of thermal and chemical degradation on polymer viscosity has not been upscaled previously and is a vital feature that need to be included in full field simulators. An upscaling workflow and methods should be constructed to upscale polymer thermal and chemical degradation features in a heterogenous field scale model.

Bibliography

- Aadnøy, B.S., Looyeh, R., 2019. Shale Oil, Shale Gas, and Hydraulic Fracturing, in: Petroleum Rock Mechanics. Elsevier, pp. 357–389.
<https://doi.org/10.1016/B978-0-12-815903-3.00016-9>
- Abdul Hamid, S.A., Muggeridge, A.H., 2018. Analytical solution of polymer slug injection with viscous fingering. *Comput Geosci* 22, 711–723.
<https://doi.org/10.1007/s10596-018-9721-0>
- Ahmed, M.E., Sultan, A.S., Al-Sofi, A., Al-Hashim, H.S., 2023. Optimization of surfactant-polymer flooding for enhanced oil recovery. *J Petrol Explor Prod Technol* 13, 2109–2123. <https://doi.org/10.1007/s13202-023-01651-0>
- Ahmed, T., 2010. Relative Permeability Concepts, in: Reservoir Engineering Handbook. Elsevier, pp. 288–330. <https://doi.org/10.1016/B978-1-85617-803-7.50013-4>
- Akther, S., Baroon, B.A., Al-Ghadhour, A.D.M., Al-Otaibi, A.E., Delamaide, E., Soltani, A., Bekri, S., Rousseau, D., 2025. Polymer Flooding to Unlock Extra-Heavy Oil from a Deep Northern Kuwait Clastic Field: Feasibility Investigation. Proceedings of the IOR+ 2025 - 23rd European Symposium on IOR, European Association of Geoscientists & Engineers, Edinburgh, Scotland, United Kingdom, pp. 1–25. <https://doi.org/10.3997/2214-4609.202531028>
- Alavi, M., 2004. Regional stratigraphy of the Zagros fold-thrust belt of Iran and its proforeland evolution. *American Journal of Science* 304, 1–20.
<https://doi.org/10.2475/ajs.304.1.1>
- Aldhuwaih, A., 2016. Upscaling Polymer Flooding to Model Sub-gridblock Geological Heterogeneity and Compensate for Numerical Dispersion (Thesis). Imperial College London.
- Al-Dhuwaih, A., King, P., Muggeridge, A., 2018. Upscaling for Polymer Flooding. Proceedings of the SPE EOR Conference at Oil and Gas West Asia, SPE, Muscat, Oman. <https://doi.org/10.2118/190335-MS>
- Aldhuwaih, A., King, P., Muggeridge, A.H., 2015. Upscaling Polymer Flooding to Model Sub-gridblock Geological Heterogeneity and Compensate for Numerical Dispersion. Dresden, Germany. <https://doi.org/10.3997/2214-4609.201412149>
- Al-Ibadi, H., Stephen, K., Mackay, E., 2021. Fast Upscaling of Polymer Flood Simulations Using Fractional Flow and Scaled Mobilities. Proceedings of the

- SPE Europec featured at 82nd EAGE Conference and Exhibition, SPE, Amsterdam, The Netherlands. <https://doi.org/10.2118/205182-MS>
- Alnarabiji, M.S., Husein, M.M., 2020. Application of bare nanoparticle-based nanofluids in enhanced oil recovery. *Fuel* 267, 117262. <https://doi.org/10.1016/j.fuel.2020.117262>
- Alsaleh, A.A., Muggeridge, A.H., Blunt, M.J., 2024. Why gravity improves waterflood recovery in oil-wet and mixed-wet reservoirs. *Geoenergy Science and Engineering* 243, 213375. <https://doi.org/10.1016/j.geoen.2024.213375>
- Al-Shakry, B., Skauge, T., Shaker Shiran, B., Skauge, A., 2018. Polymer Injectivity: Investigation of Mechanical Degradation of Enhanced Oil Recovery Polymers Using In-Situ Rheology. *Energies* 12. <https://doi.org/10.3390/en12010049>
- Alsharhan, A.S., Magara, K., 1995. Nature and distribution of porosity and permeability in jurassic carbonate reservoirs of the Arabian Gulf basin. *Facies* 32, 237–253. <https://doi.org/10.1007/BF02536872>
- Alshawaf, M., Krevor, S., Muggeridge, A., 2017. Analysis of Viscous Crossflow in Polymer Flooding. Presented at the IOR 2017 - 19th European Symposium on Improved Oil Recovery, Stavanger, Norway. <https://doi.org/10.3997/2214-4609.201700331>
- Alshawaf, M.H., 2018. Experimental, Numerical and Economical Analysis of Polymer Floods in Stratified Reservoirs (Thesis). Imperial College London.
- Alshawaf, M.H., Muggeridge, A., Krevor, S., 2018. Experimental Investigation of Cross-Flow in Stratified Reservoirs During Polymer Flooding. Proceedings of the SPE Improved Oil Recovery Conference, SPE, Tulsa, Oklahoma, USA. <https://doi.org/10.2118/190328-MS>
- Alzayer, H., Sohrabi, M., 2013. Numerical Simulation of Improved Heavy Oil Recovery by Low-Salinity Water Injection and Polymer Flooding. Proceedings of the SPE Saudi Arabia Section Technical Symposium and Exhibition, SPE, Al-Khobar, Saudi Arabia. <https://doi.org/10.2118/165287-MS>
- Beteta, A., McIver, K., Silva, C., Sorbie, K., Farthing, D., Johnson, G., 2025. Is there Value in using ATBS Type Polymers in Lower Temperature and Salinity Reservoirs? Proceedings of the IOR+ 2025 - 23rd European Symposium on IOR. European Association of Geoscientists & Engineers, Edinburgh, Scotland, United Kingdom, pp. 1–16. <https://doi.org/10.3997/2214-4609.202531007>
- Beteta, A., Sorbie, K.S., McIver, K., Johnson, G., Gasimov, R., Van Zeil, W., 2022. The Role of Immiscible Fingering on the Mechanism of Secondary and Tertiary Polymer Flooding of Viscous Oil. *Transp Porous Med* 143, 343–372. <https://doi.org/10.1007/s11242-022-01774-8>
- Blackwell, R.J., Rayne, J.R., Terry, W.M., 1959. Factors Influencing the Efficiency of Miscible Displacement. *Transactions of the AIME* 217, 1–8. <https://doi.org/10.2118/1131-G>
- Blunt, M.J., 2017. Multiphase Flow in Permeable Media: A Pore-Scale Perspective. Cambridge University Press, United Kingdom.

- Bondino, I., Nguyen, R., Hamon, G., Ormehaug, P.A., Skauge, A., Jouenne, S., 2011. Tertiary Polymer Flooding in Extra-Heavy Oil: an Investigation using 1D and 2D Experiments, Core Scale Simulation and Pore Scale Network Models. Presented at the International Symposium of the Society of Core Analysts, Austin, Texas, USA.
- Bondor, P.L., Hirasaki, G.J., Tham, M.J., 1972. Mathematical Simulation of Polymer Flooding in Complex Reservoirs. *Society of Petroleum Engineers Journal* 12, 369–382. <https://doi.org/10.2118/3524-PA>
- Bordeaux Rego, F., Botechia, V.E., Schiozer, D.J., 2017. Heavy oil recovery by polymer flooding and hot water injection using numerical simulation. *Journal of Petroleum Science and Engineering* 153, 187–196. <https://doi.org/10.1016/j.petrol.2017.03.033>
- Box, G.E.P., Hunter, J.S., 1961. The 2 k-p Fractional Factorial Designs Part I. *Technometrics* 3, 311. <https://doi.org/10.2307/1266725>
- Buckley, S.E., Leverett, M.C., 1942. Mechanism of Fluid Displacement in Sands. *Transactions of the AIME* 146, 107–116. <https://doi.org/10.2118/942107-G>
- Buza, J.W., 2008. An Overview of Heavy and Extra Heavy Oil Carbonate Reservoirs in the Middle East, in: *All Days*. Presented at the International Petroleum Technology Conference, IPTC, Kuala Lumpur, Malaysia, p. IPTC-12426-MS. <https://doi.org/10.2523/IPTC-12426-MS>
- Choi, B., Jeong, M.S., Lee, K.S., 2014. Temperature-dependent viscosity model of HPAM polymer through high-temperature reservoirs. *Polymer Degradation and Stability* 110, 225–231. <https://doi.org/10.1016/j.polymdegradstab.2014.09.006>
- Civan, F., 2006. Viscosity–Temperature Correlation for Crude Oils Using an Arrhenius-Type Asymptotic Exponential Function. *Petroleum Science and Technology* 24, 699–706. <https://doi.org/10.1081/LFT-200041178>
- Clifford, P.J., Sorbie, K.S., 1985. The Effects of Chemical Degradation on Polymer Flooding, in: *SPE Oilfield and Geothermal Chemistry Symposium*. Presented at the SPE Oilfield and Geothermal Chemistry Symposium, SPE, Phoenix, Arizona, p. SPE-13586-MS. <https://doi.org/10.2118/13586-MS>
- Costa Gomes, J., Geiger, S., Arnold, D., 2022. The design of an open-source carbonate reservoir model. *PG* 28, petgeo2021-067. <https://doi.org/10.1144/petgeo2021-067>
- Craig, F.F., Sanderlin, J.L., Moore, D.W., Geffen, T.M., 1957. A Laboratory Study of Gravity Segregation in Frontal Drives. *Transactions of the AIME* 210, 275–282. <https://doi.org/10.2118/676-G>
- Dakshinamurthy, N., Verma, N.K., Abdul Salam, T., Al-Sammak, I., Koronfol, S., Dernaika, M., Teh, W.J., 2014. Computation of Relative Permeability Curves in Middle Eastern Carbonates Using Digital Rock Physics. *Proceedings of the International Petroleum Technology Conference, IPTC, Kuala Lumpur, Malaysia*, p. IPTC-18211-MS. <https://doi.org/10.2523/IPTC-18211-MS>
- Delshad, M., Kim, D.H., Magbagbeola, O.A., Huh, C., Pope, G.A., Tarahhom, F., 2008. Mechanistic Interpretation and Utilization of Viscoelastic Behavior of Polymer Solutions for Improved Polymer-Flood Efficiency. *Proceedings of the*

- SPE Symposium on Improved Oil Recovery, SPE, Tulsa, Oklahoma, USA.
<https://doi.org/10.2118/113620-MS>
- Diab, W.N., Al-Shalabi, E.W., 2019. Recent Developments in Polymer Flooding for Carbonate Reservoirs under Harsh Conditions. Proceedings of the Offshore Technology Conference Brasil, OTC, Rio de Janeiro, Brazil, p. D031S033R008. <https://doi.org/10.4043/29739-MS>
- Doorwar, S., Mohanty, K.K., 2014. Polymer Flood of Viscous Oils in Complex Carbonates. Proceedings of the SPE Improved Oil Recovery Symposium, SPE, Tulsa, Oklahoma, USA, p. SPE-169162-MS. <https://doi.org/10.2118/169162-MS>
- Druetta, P., Picchioni, F., 2019. Influence of the polymer degradation on enhanced oil recovery processes. Applied Mathematical Modelling 69, 142–163. <https://doi.org/10.1016/j.apm.2018.11.051>
- Dupuis, G., Al-Maamari, R.S., Al-Hashmi, A.R., Al-Sharji, H.H., Zaitoun, A., 2013. Mechanical and Thermal Stability of Polyacrylamide-based Microgel Products for EOR. Proceedings of the SPE International Symposium on Oilfield Chemistry, SPE, The Woodlands, Texas, USA. <https://doi.org/10.2118/164135-MS>
- Dupuis, G., Antignard, S., Giovannetti, B., Gaillard, N., Jouenne, S., Bourdarot, G., Morel, D., Zaitoun, A., 2017. A New Thermally Stable Synthetic Polymer for Harsh Conditions of Middle East Reservoirs. Part I. Thermal Stability and Injection in Carbonate Cores. Proceedings of the Abu Dhabi International Petroleum Exhibition & Conference, SPE, Abu Dhabi, UAE, p. D021S044R003. <https://doi.org/10.2118/188479-MS>
- Dyes, A.B., Caudle, B.H., Erickson, R.A., 1954. Oil Production After Breakthrough as Influenced by Mobility Ratio. Journal of Petroleum Technology 6, 27–32. <https://doi.org/10.2118/309-G>
- Ebrahimi, D., Amini, A., Solgi, A., Hajikazemi, E., 2016. An Integrated Appraisal of Burgan Reservoir in Soroosh Oil Field, Using Petrographic and Petrophysical Approaches. OJG 06, 1014–1031. <https://doi.org/10.4236/ojg.2016.69076>
- El-hoshoudy, A.N., Desouky, S.E.M., Elkady, M.Y., Al-Sabagh, A.M., Betiha, M.A., Mahmoud, S., 2017. Hydrophobically associated polymers for wettability alteration and enhanced oil recovery – Article review. Egyptian Journal of Petroleum 26, 757–762. <https://doi.org/10.1016/j.ejpe.2016.10.008>
- Fabbri, C., Cottin, C., Jimenez, J., Nguyen, M., Hourcq, S., Bourgeois, M., Hamon, G., 2014. Secondary and Tertiary Polymer Flooding in Extra-Heavy Oil: Reservoir Conditions Measurements - Performance Comparison. Proceedings of the International Petroleum Technology Conference, IPTC, Doha, Qatar, p. IPTC-17703-MS. <https://doi.org/10.2523/IPTC-17703-MS>
- Finney, D.J., 1943. The Fractional Replication of Factorial Arrangements. Annals of Eugenics 12, 291–301. <https://doi.org/10.1111/j.1469-1809.1943.tb02333.x>
- Firozjaili, A.M., Saghaei, H.R., 2020. Review on chemical enhanced oil recovery using polymer flooding: Fundamentals, experimental and numerical simulation. Petroleum 6, 115–122. <https://doi.org/10.1016/j.petlm.2019.09.003>
- Fisher, R.A., 1935. The design of experiments. Oliver & Boyd.

- Gaillard, N., Giovannetti, B., Favero, C., Caritey, J.-P., Dupuis, G., Zaitoun, A., 2014. New Water Soluble Anionic NVP Acrylamide Terpolymers for Use in Harsh EOR Conditions. Proceedings of the SPE Improved Oil Recovery Symposium, SPE, Tulsa, Oklahoma, USA. <https://doi.org/10.2118/169108-ms>
- Green, D.W., Willhite, G.P., 2018. Enhanced oil recovery, Second edition. ed, SPE International textbook series. Society of Petroleum Engineers, Richardson, Texas, USA.
- Gröllmann, U., Schnabel, W., 1982. Free radical-induced oxidative degradation of polyacrylamide in aqueous solution. *Polymer Degradation and Stability* 4, 203–212. [https://doi.org/10.1016/0141-3910\(82\)90027-1](https://doi.org/10.1016/0141-3910(82)90027-1)
- Gulick, K.E., Jr, W.D.M., 1998. Waterflooding Heterogeneous Reservoirs: An Overview of Industry Experiences and Practices. Society of Petroleum Engineers.
- Hashim, E.T., Hassaballah, A.A., 2003. An Improved Viscosity-Temperature Correlation for Crude Oils. *Petroleum Science and Technology* 21, 1625–1630. <https://doi.org/10.1081/LFT-120024378>
- Hassan, A.M., Al-Shalabi, E.W., Alameri, W., Kamal, M.S., Patil, S., Shakil Hussain, S.M., 2023. Manifestations of surfactant-polymer flooding for successful field applications in carbonates under harsh conditions: A comprehensive review. *Journal of Petroleum Science and Engineering* 220, 111243. <https://doi.org/10.1016/j.petrol.2022.111243>
- Hawthorne, R.G., 1960. Two-Phase Flow in Two-Dimensional Systems - Effects of Rate, Viscosity and Density on Fluid Displacement in Porous Media. *Transactions of the AIME* 219, 81–87. <https://doi.org/10.2118/1323-G>
- Hu, J., Li, A., 2021. Experimental Investigation of Factors Influencing Remaining Oil Distribution under Water Flooding in a 2-D Visualized Cross-Section Model. *ACS Omega* 6, 15572–15579. <https://doi.org/10.1021/acsomega.0c05534>
- Jabbar, M., Xiao, R., Teletzke, G.F., Willingham, T., Al Obeidli, A., Al Sowaidi, A., Britton, C., Delshad, M., Li, Z., 2018. Polymer EOR Assessment Through Integrated Laboratory and Simulation Evaluation for an Offshore Middle East Carbonate Reservoir. Proceedings of the Abu Dhabi International Petroleum Exhibition & Conference, SPE, Abu Dhabi, UAE. <https://doi.org/10.2118/193274-MS>
- Juárez-Morejón, J.L., Bertin, H., Omari, A., Hamon, G., Cottin, C., Morel, D., Romero, C., Bourdarot, G., 2019. A New Approach to Polymer Flooding: Effects of Early Polymer Injection and Wettability on Final Oil Recovery. *SPE Journal* 24, 129–139. <https://doi.org/10.2118/190817-PA>
- Knight, B.L., 1973. Reservoir Stability of Polymer Solutions. *Journal of Petroleum Technology* 25, 618–626. <https://doi.org/10.2118/4167-PA>
- Lake, L.W., 1989. Enhanced Oil Recovery. Prentice Hall, United Kingdom.
- Lebedeva, E.V., Fogden, A., 2011. Micro-CT and Wettability Analysis of Oil Recovery from Sand Packs and the Effect of Waterflood Salinity and Kaolinite. *Energy Fuels* 25, 5683–5694. <https://doi.org/10.1021/ef201242s>

- Lenth, R.V., 1989. Quick and Easy Analysis of Unreplicated Factorials. *Technometrics* 31, 469–473. <https://doi.org/10.1080/00401706.1989.10488595>
- Leon, J.M., Masalmeh, S.K., AlSumaiti, A.M., Baslaib, M., 2024. Assessment of World's First Two Polymer Injectivity Tests Performed in Two Giant High-Temperature/High-Salinity Carbonate Reservoirs Using Single-Well Simulation Models and Pressure Falloff Tests Analysis. *SPE Journal* 29, 2686–2702. <https://doi.org/10.2118/211451-PA>
- Leon, J.M., Masalmeh, S.K., AlSumaiti, A.M., Baslaib, M., 2022. Assessment of World First Two Polymer Injectivity Tests Performed in Two Giant High Temperature/High Salinity Carbonate Reservoirs Using Single Well Simulation Models and PFO's Analysis. *Proceedings of the ADIPEC, SPE, Abu Dhabi, UAE*, p. D031S111R001. <https://doi.org/10.2118/211451-MS>
- Leung, J., Srinivasan, S., Huh, C., 2010. Accounting for Heterogeneity in Scale-Up of Apparent Polymer Viscosity for Field Scale Application. *Proceedings of the SPE Improved Oil Recovery Symposium, SPE, Tulsa, Oklahoma, USA*, p. SPE-129798-MS. <https://doi.org/10.2118/129798-MS>
- Levitt, D., Pope, G.A., 2008. Selection and Screening of Polymers for Enhanced-Oil Recovery, in: *All Days. Presented at the SPE Symposium on Improved Oil Recovery, SPE, Tulsa, Oklahoma, USA*, p. SPE-113845-MS. <https://doi.org/10.2118/113845-MS>
- Levitt, D.B., 2011. Chemical Degradation of Polyacrylamide Polymers Under Alkaline Conditions.
- Li, Z., Ayirala, S., Mariath, R., AlSofi, A., Xu, Z., Yousef, A., 2020. Microscale Effects of Polymer on Wettability Alteration in Carbonates. *SPE Journal* 25, 1884–1894. <https://doi.org/10.2118/200251-PA>
- Lohne, A., Nødland, O., Stavland, A., Hiorth, A., 2017. A model for non-Newtonian flow in porous media at different flow regimes. *Comput Geosci* 21, 1289–1312. <https://doi.org/10.1007/s10596-017-9692-6>
- Lu, X., Jiang, H., Li, J., Zhao, L., Pei, Y., Zhao, Y., Liu, G., Fang, W., 2015. Polymer Thermal Degradation in High-Temperature Reservoirs. *Petroleum Science and Technology* 33, 1571–1579. <https://doi.org/10.1080/10916466.2015.1072561>
- Lu, Xiang'an, Jiang, H., Smørgrav, E., Li, J., Ding, S., Li, C., Liu, G., 2015. A New Thermal Degradation Model of Polymer in High-Temperature Reservoirs. *Proceedings of the SPE/IATMI Asia Pacific Oil & Gas Conference and Exhibition, SPE, Nusa Dua, Bali, Indonesia*. <https://doi.org/10.2118/176460-MS>
- Ma, Q., Shuler, P.J., Aften, C.W., Tang, Y., 2015. Theoretical studies of hydrolysis and stability of polyacrylamide polymers. *Polymer Degradation and Stability* 121, 69–77. <https://doi.org/10.1016/j.polymdegradstab.2015.08.012>
- Mahajan, S., Yadav, H., Rellegadla, S., Agrawal, A., 2021. Polymers for enhanced oil recovery: fundamentals and selection criteria revisited. *Appl Microbiol Biotechnol* 105, 8073–8090. <https://doi.org/10.1007/s00253-021-11618-y>
- Manrique, E., Thomas, C., Ravikiran, R., Izadi, M., Lantz, M., Romero, J., Alvarado, V., 2010. EOR: Current Status and Opportunities. *Proceedings of*

- the SPE Improved Oil Recovery Symposium, SPE, Tulsa, Oklahoma, USA.
<https://doi.org/10.2118/130113-MS>
- Masalmeh, S., AlSumaiti, A., Gaillard, N., Daguerre, F., Skauge, T., Skuage, A., 2019. Extending Polymer Flooding Towards High-Temperature and High-Salinity Carbonate Reservoirs, in: Day 3 Wed, November 13, 2019. Presented at the Abu Dhabi International Petroleum Exhibition & Conference, SPE, Abu Dhabi, UAE, p. D031S068R002. <https://doi.org/10.2118/197647-MS>
- Maurer, J.J., Harvey, G.D., 1987. Thermal degradation characteristics of poly(acrylamide-co-acrylic acid) and poly(acrylamide-co-sodium acrylate) copolymers. *Thermochimica Acta* 121, 295–306. [https://doi.org/10.1016/0040-6031\(87\)80180-6](https://doi.org/10.1016/0040-6031(87)80180-6)
- Moradi-Araghi, A., 1987. Hydrolysis and Precipitation of Polyacrylamides in Hard Brines at Elevated Temperatures. *SPE Reservoir Engineering*.
- Moradi-Araghi, A., Doe, P.H., 1987. Hydrolysis and Precipitation of Polyacrylamides in Hard Brines at Elevated Temperatures. *SPE Reservoir Engineering* 2, 189–198. <https://doi.org/10.2118/13033-PA>
- Moshtaghi, M., Eškinja, M., Mori, G., Griesser, T., Safyari, M., Cole, I., 2023. The effect of HPAM polymer for enhanced oil recovery on corrosion behaviour of a carbon steel and interaction with the inhibitor under simulated brine conditions. *Corrosion Science* 217, 111118. <https://doi.org/10.1016/j.corsci.2023.111118>
- Muller, G., 1981. Thermal stability of high-molecular-weight polyacrylamide aqueous solutions. *Polymer Bulletin* 5. <https://doi.org/10.1007/BF00255084>
- Mungan, N., 1969. Rheology and Adsorption of Aqueous Polymer Solutions. *Journal of Canadian Petroleum Technology* 8, 45–50. <https://doi.org/10.2118/69-02-01>
- Needham, R.B., Doe, P.H., 1987. Polymer Flooding Review. *Journal of Petroleum Technology* 39, 1503–1507. <https://doi.org/10.2118/17140-PA>
- Ould Metidji, M., Juarez Morejon, J.L., Garcia Mayoral, M.F., Rodriguez Pardo, M.R., Montes Ruiz, J., Lereau, D., Monzon Vazquez, J., Dupuis, G., 2023. Secondary Versus Tertiary Polymer Flooding: A Laboratory Evaluation in Low Permeability HT/HS Carbonate Reservoir Conditions. *Proceedings of the International Petroleum Technology Conference, IPTC, Bangkok, Thailand*, p. D031S028R001. <https://doi.org/10.2523/IPTC-22908-MS>
- Parker, W.O., Lezzi, A., 1993. Hydrolysis of sodium-2-acrylamido-2-methylpropanesulfonate copolymers at elevated temperature in aqueous solution via ¹³C n.m.r. spectroscopy. *Polymer* 34, 4913–4918. [https://doi.org/10.1016/0032-3861\(93\)90018-6](https://doi.org/10.1016/0032-3861(93)90018-6)
- Pielichowski, K., Njuguna, J., 2005. Thermal degradation of polymeric materials. *Rapra Technology*, Shawbury.
- Pope, G.A., 1980. The Application of Fractional Flow Theory to Enhanced Oil Recovery. *Society of Petroleum Engineers Journal* 20, 191–205. <https://doi.org/10.2118/7660-PA>

- Powers, R.W., Ramirez, L.F., Redmond, C.D., Elberg, E.L.Jr., 1966. Geology of the Arabian Peninsula: Sedimentary Geology of Saudi Arabia. (U.S. Geological Survey Professional Paper No. 560- D), <https://doi.org/10.3133/pp560D>.
- Pye, D.J., 1964. Improved Secondary Recovery by Control of Water Mobility. *Journal of Petroleum Technology* 16, 911–916. <https://doi.org/10.2118/845-PA>
- Qi, G., Liu, B., 2024. Production Feature Analysis of Global Onshore Carbonate Oil Reservoirs Based on XGBoost Classifier. *Processes* 12, 1137. <https://doi.org/10.3390/pr12061137>
- Richardson, J.G., Perkins, F.M., 1957. A Laboratory Investigation of the Effect of Rate on Recovery of Oil by Water Flooding. *Transactions of the AIME* 210, 114–121. <https://doi.org/10.2118/693-G>
- Rodriguez, L., Antignard, S., Giovannetti, B., Dupuis, G., Gaillard, N., Jouenne, S., Bourdarot, G., Morel, D., Zaitoun, A., Grassl, B., 2018. A new thermally stable synthetic polymer for harsh conditions Of Middle East reservoirs. *Proceedings of the RDPETRO 2018: Research and Development Petroleum Conference and Exhibition, Abu Dhabi, UAE, 9-10 May 2018, American Association of Petroleum Geologists, Society of Exploration Geophysicists, European Association of Geoscientists and Engineers, and Society of Petroleum Engineers, Abu Dhabi, UAE, pp. 16–19.* <https://doi.org/10.1190/rdp2018-41754597.1>
- Ryles, R.G., 1988. Chemical Stability Limits of Water-Soluble Polymers Used in Oil Recovery Processes. *SPE Reservoir Engineering* 3, 23–34. <https://doi.org/10.2118/13585-PA>
- Sagyndikov, M., Dupuis, G., Seright, R., Thomas, A., Wilton, R., 2025. Revisiting Water Injection Post-Polymer Flooding: A Global Perspective on Project Performance. *Proceedings of the IOR+ 2025 - 23rd European Symposium on IOR, European Association of Geoscientists & Engineers, Edinburgh, Scotland, United Kingdom, pp. 1–25.* <https://doi.org/10.3997/2214-4609.202531004>
- Sánchez-Jiménez, P.E., Pérez-Maqueda, L.A., Perejón, A., Criado, J.M., 2010. A new model for the kinetic analysis of thermal degradation of polymers driven by random scission. *Polymer Degradation and Stability* 95, 733–739. <https://doi.org/10.1016/j.polymdegradstab.2010.02.017>
- Sandengen, K., Meldahl, M.M., Gjersvold, B., Molesworth, P., Gaillard, N., Braun, O., Antignard, S., 2018. Long term stability of ATBS type polymers for enhanced oil recovery. *Journal of Petroleum Science and Engineering* 169, 532–545. <https://doi.org/10.1016/j.petrol.2018.06.001>
- Sandengen, Kristian, Melhuus, K., Kristoffersen, A., 2017. Polymer “viscoelastic effect”; does it reduce residual oil saturation*. *Journal of Petroleum Science and Engineering* 153, 355–363. <https://doi.org/10.1016/j.petrol.2017.03.029>
- Sandengen, K., Widerøe, H.C., Nurmi, L., Hanski, S., 2017. Hydrolysis kinetics of ATBS polymers at elevated temperature, via ¹³C NMR spectroscopy, as basis for accelerated aging tests. *Journal of Petroleum Science and Engineering* 158, 680–692. <https://doi.org/10.1016/j.petrol.2017.09.013>

- Sandiford, B.B., 1964. Laboratory and Field Studies of Water Floods Using Polymer Solutions to Increase Oil Recoveries. *Journal of Petroleum Technology* 16, 917–922. <https://doi.org/10.2118/844-PA>
- Sazali, N., Ibrahim, H., Jamaludin, A.S., Mohamed, M.A., Salleh, W.N.W., Abidin, M.N.Z., 2020. Degradation and stability of polymer: A mini review. *IOP Conf. Ser.: Mater. Sci. Eng.* 788. <https://doi.org/10.1088/1757-899X/788/1/012048>
- Sebastian, A., Mushtaq, M., Al-Shalabi, E.W., AlAmeri, W., Mohanty, K., Masalmeh, S., AlSumaiti, A.M., 2024. Investigating the effects of make-up water dilution and oil presence on polymer retention in carbonate reservoirs. *Sci Rep* 14, 27924. <https://doi.org/10.1038/s41598-024-78743-2>
- Seright, Campbell, A.R., Mozley, P.S., Han, P., 2010. Stability of Partially Hydrolyzed Polyacrylamides at Elevated Temperatures in the Absence of Divalent Cations. *SPE Journal* 15, 341–348. <https://doi.org/10.2118/121460-PA>
- Seright, R.S., Campbell, A.R., Mozley, P.S., Han, P., 2010. Stability of Partially Hydrolyzed Polyacrylamides at Elevated Temperatures in the Absence of Divalent Cations. *SPE Journal*.
- Seright, R.S., Wang, D., 2023. Polymer flooding: Current status and future directions. *Petroleum Science* 20, 910–921. <https://doi.org/10.1016/j.petsci.2023.02.002>
- Seright, R.S., Wang, D., Lerner, N., Nguyen, A., Sabid, J., Tochor, R., 2018. Can 25-cp Polymer Solution Efficiently Displace 1,600-cp Oil During Polymer Flooding? *SPE Journal* 23, 2260–2278. <https://doi.org/10.2118/190321-PA>
- Seright, R.S., Wavrik, K.E., Zhang, G., AlSofi, A.M., 2021. Stability and Behavior in Carbonate Cores for New Enhanced-Oil-Recovery Polymers at Elevated Temperatures in Hard Saline Brines. *SPE Reservoir Evaluation & Engineering* 24, 1–18. <https://doi.org/10.2118/200324-PA>
- Shakeel, M., Pourafshary, P., Rehan Hashmet, M., 2020. Hybrid Engineered Water–Polymer Flooding in Carbonates: A Review of Mechanisms and Case Studies. *Applied Sciences* 10, 6087. <https://doi.org/10.3390/app10176087>
- Sharma, A., Delshad, M., Huh, C., Pope, G.A., 2011. A Practical Method to Calculate Polymer Viscosity Accurately in Numerical Reservoir Simulators. *Proceedings of the SPE Annual Technical Conference and Exhibition, SPE, Denver, Colorado, USA*. <https://doi.org/10.2118/147239-MS>
- Sheng, J., 2011. *Modern chemical enhanced oil recovery: theory and practice*. Gulf Professional Pub, Amsterdam ; Boston, MA.
- Sheng, J.J., Leonhardt, B., Azri, N., 2015. Status of Polymer-Flooding Technology. *Journal of Canadian Petroleum Technology* 54, 116–126. <https://doi.org/10.2118/174541-PA>
- Shojaeddini, E., Naimoli, S., Ladislav, S., Bazilian, M., 2019. Oil and gas company strategies regarding the energy transition. *Prog. Energy* 1. <https://doi.org/10.1088/2516-1083/ab2503>
- Shook, M., Li, D., Lake, L.W., 1993. Scaling immiscible flow through permeable media by inspectional analysis. *International Journal of Rock Mechanics and*

- Mining Sciences & Geomechanics Abstracts 30, A223.
[https://doi.org/10.1016/0148-9062\(93\)91860-L](https://doi.org/10.1016/0148-9062(93)91860-L)
- Shupe, R.D., 1981. Chemical Stability of Polyacrylamide Polymers. *Journal of Petroleum Technology* 33, 1513–1529. <https://doi.org/10.2118/9299-PA>
- Skauge, A., Ormehaug, P.A., Gurholt, T., Vik, B., Bondino, I., Hamon, G., 2012. 2-D Visualisation of Unstable Waterflood and Polymer Flood for Displacement of Heavy Oil. *Proceedings of the SPE Improved Oil Recovery Symposium*, SPE, Tulsa, Oklahoma, USA, p. SPE-154292-MS. <https://doi.org/10.2118/154292-MS>
- Slater, G.E., Ali, S.M.F., 1970a. Two-Dimensional Polymer Flood Simulation. *Proceedings of the Fall Meeting of the Society of Petroleum Engineers of AIME, SPE, Houston, Texas*, p. SPE-3003-MS. <https://doi.org/10.2118/3003-MS>
- Slater, G.E., Ali, S.M.F., 1970b. Simulation of Oil Recovery By Polymer Flooding. *Journal of Canadian Petroleum Technology* 9. <https://doi.org/10.2118/70-04-05>
- Sorbie, K.S., 1991. *Polymer-improved oil recovery*. Blackie ; CRC Press, Glasgow : Boca Raton, Fla.
- Sorbie, K.S., Sheb, M., Hosseini, A., Wat, R.M.S., 1990. Scaled Miscible Floods in Layered Beadpacks Investigating Viscous Crossflow, the Effects of Gravity, and the Dynamics of Viscous Slug Breakdown.
- Spivak, A., 1974. Gravity Segregation in Two-Phase Displacement Processes. *Society of Petroleum Engineers Journal* 14, 619–632. <https://doi.org/10.2118/4630-PA>
- Standnes, D.C., Skjevrak, I., 2014. Literature review of implemented polymer field projects. *Journal of Petroleum Science and Engineering* 122, 761–775. <https://doi.org/10.1016/j.petrol.2014.08.024>
- Swiecinski, F., Reed, P., Andrews, W., 2016. The Thermal Stability of Polyacrylamides in EOR Applications. *Proceedings of the SPE Improved Oil Recovery Conference*, SPE, Tulsa, Oklahoma, USA. <https://doi.org/10.2118/179558-MS>
- Tai, I., Giddins, M.A., Muggeridge, A., 2021. Improved Calculation of Wellblock Pressures for Numerical Simulation of Non-Newtonian Polymer Injection. *SPE Journal* 26, 2352–2363. <https://doi.org/10.2118/205339-PA>
- Talash, A., Crawford, P., 1966. A Study of the Effect of Gravity on Oil Recovery by Water Flooding. *Proceedings of the the Fall Meeting of the Society of Petroleum Engineers of AIME, Dallas. Texas*.
- Todd, M.R., Longstaff, W.J., 1972. The Development, Testing, and Application Of a Numerical Simulator for Predicting Miscible Flood Performance. *Journal of Petroleum Technology* 24, 874–882. <https://doi.org/10.2118/3484-PA>
- Vela, S., Peaceman, D.W., Sandvik, E.I., 1976. Evaluation of Polymer Flooding in a Layered Reservoir With Crossflow, Retention, and Degradation. *Society of Petroleum Engineers Journal* 16, 82–96. <https://doi.org/10.2118/5102-PA>
- Verma, S.K., Adibhatla, B., Kaminsky, R.D., Wattenbarger, R.C., Davidson, J.E., 2009. Modeling Polymer Flood in an Unstructured Grid Simulator.

- Proceedings of the SPE Reservoir Simulation Symposium, SPE, The Woodlands, Texas. <https://doi.org/10.2118/118985-MS>
- Vohlídal, J., 2021. Polymer degradation: a short review. *Chemistry Teacher International* 3, 213–220. <https://doi.org/10.1515/cti-2020-0015>
- Wang, G.C., Caudle, B.H., 1970. Effects of Polymer Concentrations, Slug Size And Permeability Stratification in Viscous Waterfloods. Proceedings of the Fall Meeting of the Society of Petroleum Engineers of AIME, SPE, Houston, Texas, p. SPE-2927-MS. <https://doi.org/10.2118/2927-MS>
- Wellington, S.L., 1983. Biopolymer Solution Viscosity Stabilization—Polymer Degradation and Antioxidant Use. *Society of Petroleum Engineers Journal* 23, 901–912. <https://doi.org/10.2118/9296-PA>
- Wright, R.J., Wheat, M.R., Dawe, R.A., 1987. Slug Size and Mobility Requirements for Chemically Enhanced Oil Recovery Within Heterogeneous Reservoirs. *SPE Reservoir Engineering* 2, 92–102. <https://doi.org/10.2118/13704-PA>
- Xin, X., Yu, G., Chen, Z., Wu, K., Dong, X., Zhu, Z., 2018. Effect of Polymer Degradation on Polymer Flooding in Heterogeneous Reservoirs. *Polymers* 10. <https://doi.org/10.3390/polym10080857>
- Xin, X., Yu, G., Wu, K., Dong, X., Chen, Z., 2021. Polymer Flooding in Heterogeneous Heavy Oil Reservoirs: Experimental and Simulation Studies. *Polymers* 13. <https://doi.org/10.3390/polym13162636>
- Yang, S.H., Treiber, L.E., 1985. Chemical Stability of Polyacrylamide Under Simulated Field Conditions. *Society of Petroleum Engineers Journal*.
- Yang, Y., Wang, Y., Liu, Y., Liu, P., 2024. Enhancing Oil Recovery in Low-Permeability Reservoirs Using a Low-Molecular Weight Amphiphilic Polymer. *Polymers* 16, 1036. <https://doi.org/10.3390/polym16081036>
- Yao, Y., Wei, M., Kang, W., 2021. A review of wettability alteration using surfactants in carbonate reservoirs. *Advances in Colloid and Interface Science* 294, 102477. <https://doi.org/10.1016/j.cis.2021.102477>
- Yates, F., 1964. Sir Ronald Fisher and the Design of Experiments. *Biometrics* 20, 307. <https://doi.org/10.2307/2528399>
- Zhou, Y., Muggerridge, A.H., Berg, C.F., King, P., 2019. Effect of Layering on Incremental Oil Recovery From Tertiary Polymer Flooding. *SPE Reservoir Evaluation & Engineering* 22, 941–951. <https://doi.org/10.2118/194492-PA>

Appendix

A.1 Tertiary Polymer Flooding

This section reviews the conclusions of the research that demonstrated tertiary polymer flooding has better performance than secondary flooding. Also, it includes initial simulations on the COSTA sector model. Fabbri et al. (2014) reported that a tertiary polymer flood achieved a higher ultimate recovery (77%) compared to a secondary polymer flood (58%). However, the incremental oil attributed solely to the polymer was greater in the secondary case (58%) than in the tertiary (47%), highlighting the importance of how recovery is defined and measured. These values are in line with earlier observations in similar oils (Bondino et al., 2011; Skauge et al., 2012), suggesting that while final recovery may be higher in tertiary mode, the efficiency and impact of polymer injection are often more substantial when applied earlier.

In further analysis, Beteta et al. (2022) conducted a direct comparison between secondary and tertiary polymer floods using analogue core systems. While their results showed that tertiary injection outperformed secondary by approximately 5% OOIP, the authors were cautious in interpreting this outcome. They explicitly stated that such a result could be due to core-to-core variability and refrained from generalizing the superiority of tertiary injection. Their visual flood front observations attributed the rapid oil recovery in tertiary mode to the formation of strong oil banks and viscous crossflow, though they maintained that no definitive performance hierarchy could be established between the two approaches.

The complexity of this debate becomes particularly evident when considering wettability and reservoir heterogeneity and demonstrating the physical mechanics at pore scale in the work of Doorwar and Mohanty (2014). Their study included both core flood experiments and micromodel visualizations to compare secondary and tertiary polymer flooding performance under various wettability and heterogeneity conditions.

In the core flood experiments, tertiary polymer floods recovered more oil than secondary floods across multiple cores, including Berea and Silurian dolomite. This outcome was attributed to the ability of the tertiary polymer to access oil that was bypassed during the initial waterflood. The difference was more apparent in oil-wet dolomite cores, where secondary injection was less effective due to the nature of flow pathways and limited early sweep.

To better understand the flow mechanisms, the authors conducted micromodel experiments in both oil-wet and water-wet systems featuring connected heterogeneity. In the oil-wet micromodel (see **Figure A.1**), they observed that although tertiary polymer flooding recovered oil more slowly, the final cumulative oil recovery was comparable to that of the secondary flood. The secondary flood recovered oil faster, but a significant portion remained bypassed. The tertiary flood, applied after a waterflood, was able to mobilize this remaining oil. The authors concluded that in these settings, the timing of polymer injection was not critical, as both modes ultimately recovered similar volumes of oil. In contrast, the water-wet micromodel (see **Figure A.2**) demonstrated a more favourable response to secondary polymer flooding. The authors noted that spontaneous imbibition in water-wet media contributed to a more uniform polymer sweep, allowing secondary injection to access tighter pore regions earlier in the displacement process. Consequently, in water-wet systems, secondary polymer flooding was more efficient than tertiary.

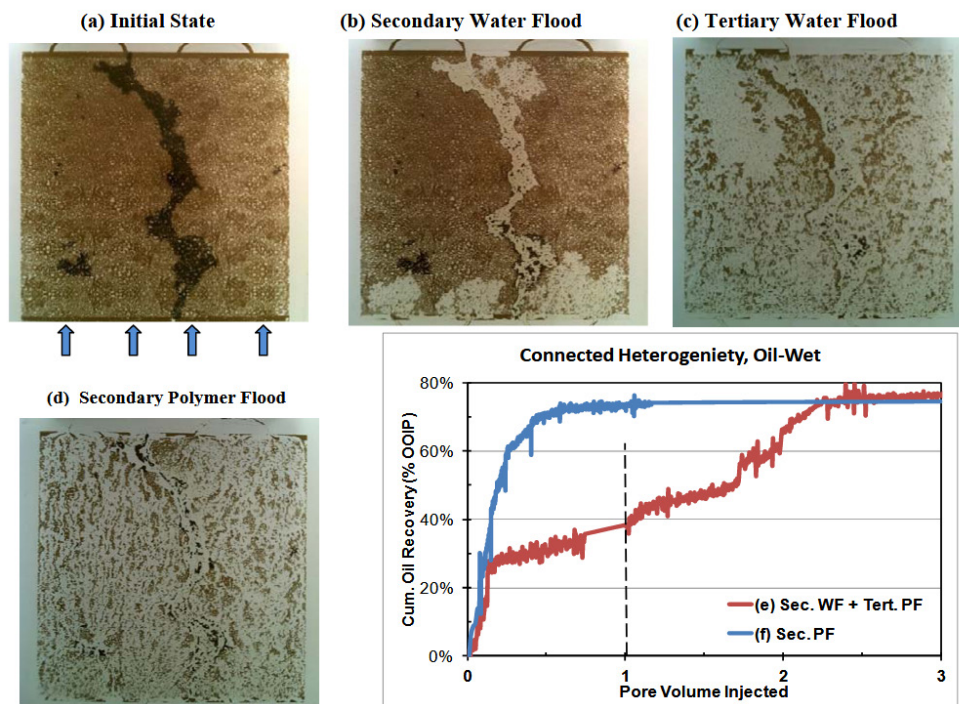


Figure A.1. 2D Micromodel images of displacement process in oil-wet system: a. Image of pre flooding state with high permeability fracture, b. Image at the end of waterflooding, c. Image at the end of tertiary flooding, d. Image at the end of secondary polymer flooding. Plots represent cumulative recovery comparison of secondary and tertiary. Reprint from Doorwar and Mohanty, 2014)

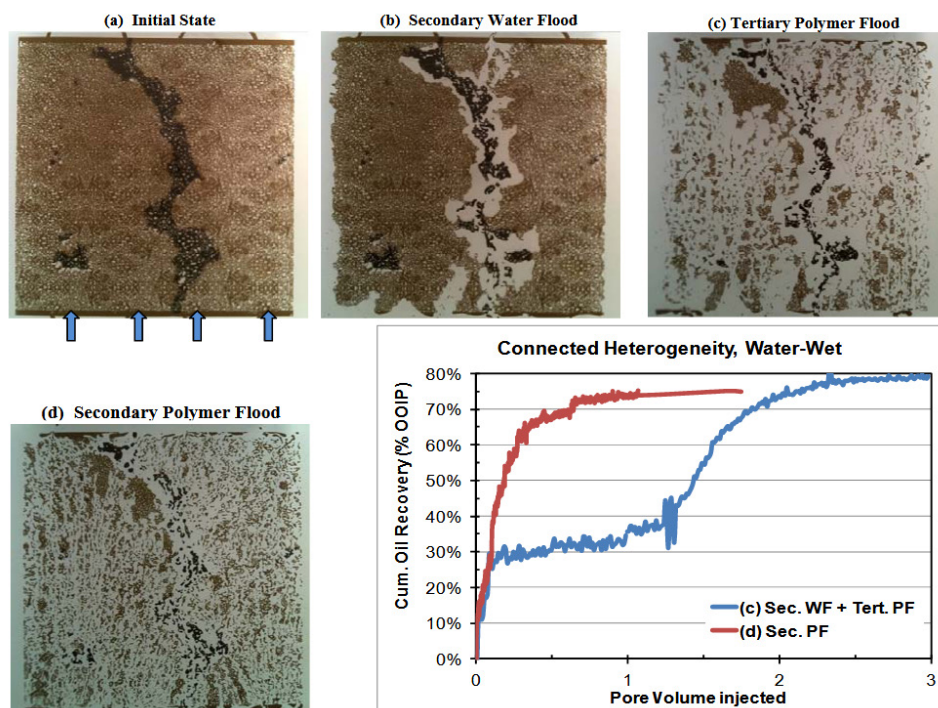


Figure A.2. 2D Micromodel images of displacement process in water-wet system: a. Image of pre flooding state with high permeability fracture, b. Image at the end of waterflooding, c. Image at the end of tertiary flooding, d. Image at the end of secondary polymer flooding. Plots represent cumulative recovery comparison of secondary and tertiary. Reprint from Doorwar and Mohanty (2014).

These findings underscore the critical influence of wettability on the displacement process. In water-wet systems, polymer floods benefit from capillary-driven mechanisms that enhance early sweep and reduce bypassing. However, in oil-wet heterogeneous media, these benefits are diminished, and flow becomes more sensitive to the reservoir's pressure and saturation history. As such, polymer injected in tertiary mode may leverage the altered saturation profile from a prior waterflood to reach previously unswept oil.

Most of the opposing views on secondary versus tertiary performance have been demonstrated at the microscopic or core scale, where outcomes are highly sensitive to wettability, pore structure, and initial conditions. Several authors have cautioned that discrepancies in recovery could partly reflect variability between cores or differences in experimental setups rather than an inherent advantage of one injection mode (Beteta et al., 2022). Our preliminary simulations on the COSTA sector model indicate that polymer applied as a secondary flood yields better performance, showing earlier recovery gains and larger incremental oil for the same polymer slug volume (see **Figure A.3** and **Figure A.4**).

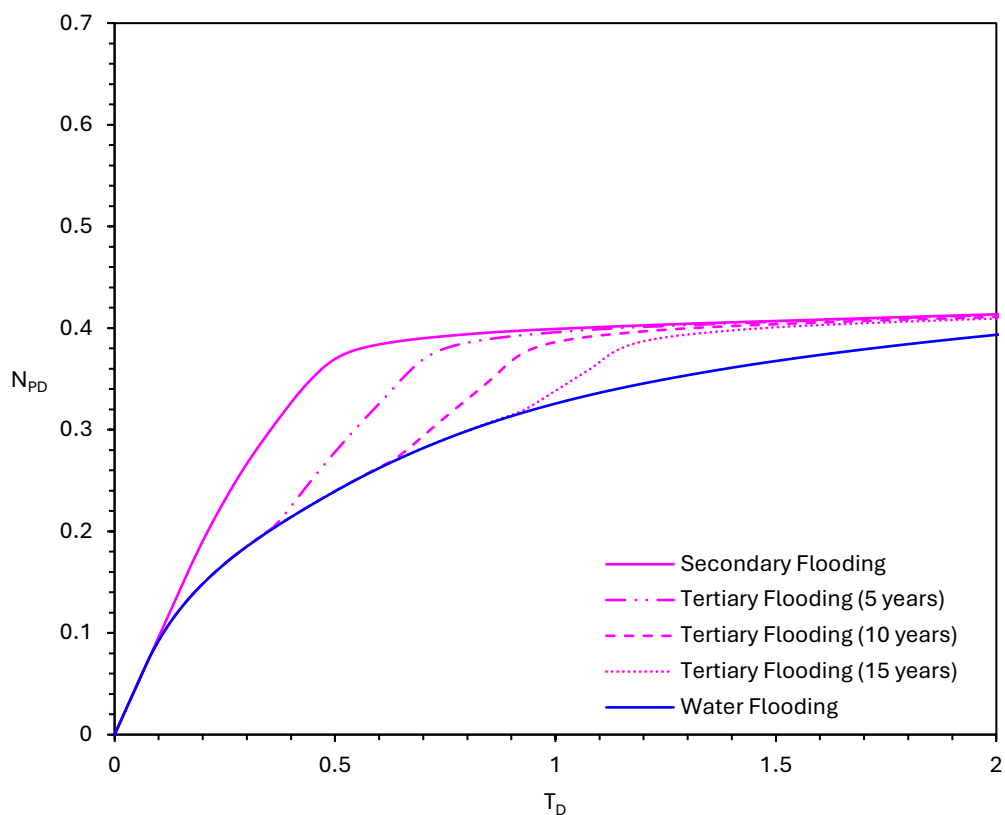


Figure A.3. Numerical oil pore volume produced as a function of pore volumes of polymer injected for secondary versus tertiary flooding at different starting times. These simulations are using ATBS polymer and 0.4 PVI Slugs at a flow rate of 3000 m³/days. The plot demonstrates that delaying the polymer flooding will result in less incremental gain in recovery for the same amount of polymer volume injected.

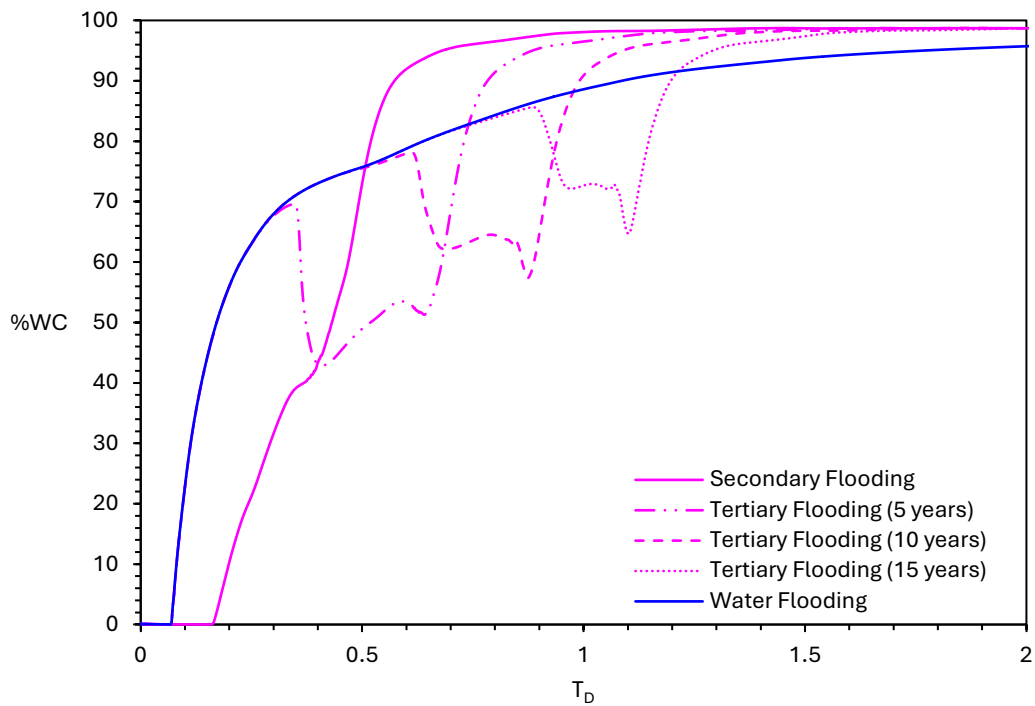


Figure A.4. Numerical percent water cut as a function of pore volumes of polymer injected for secondary versus tertiary flooding at different starting times. At tertiary recovery the polymer improves the displacement resulting in the formation of an oil bank. This oil bank will result in an intermediate drop in water production.

These results align with the interpretation that secondary polymer banks improve displacement earlier and across a larger contacted volume, whereas tertiary floods must overcome waterflood-altered pathways. Beteta et al. (2022) visually confirmed the formation of strong oil banks during tertiary polymer injection, attributing this to viscous crossflow effects, which is consistent with the water cut and flood front behaviour observed in our simulations (see **Figure A.5** and **Figure A.6**) and with prior experimental observations (Bondino et al., 2011; Skauge et al., 2012).

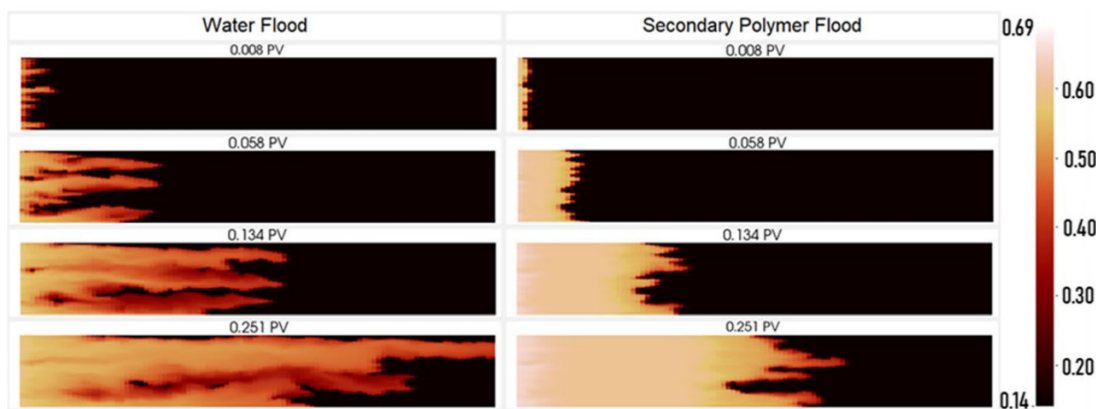


Figure A.5. Water flooding versus secondary polymer flooding visualisation of water station in a core model from Beteta et al. (2022).

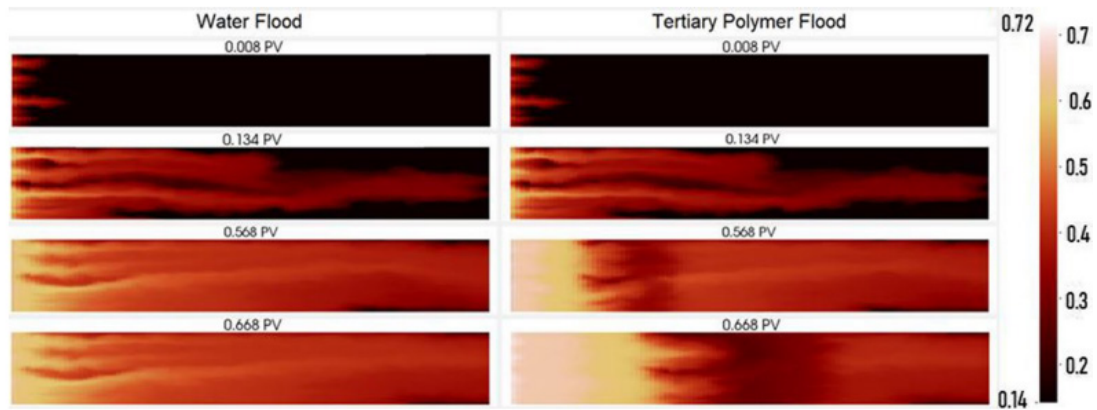


Figure A.6. Water flooding versus tertiary polymer flooding visualisation of water station in a core model from Beteta et al. (2022).

The hypothesis advanced by Doorwar and Mohanty (2014) that the relative effectiveness of secondary versus tertiary polymer flooding depends on wettability and saturation history remains unresolved at larger scales. Our preliminary COSTA sector simulations point to a clear advantage for secondary floods, yet they cannot fully test the late-time benefits that tertiary floods may offer in oil-wet systems. This gap highlights the need for further study, to determine whether the pore-scale mechanisms proposed can be validated under reservoir conditions and incorporated into reliable design guidelines for giant carbonate fields.

A.2 Non-Isothermal Model (Low Injection Temperature)

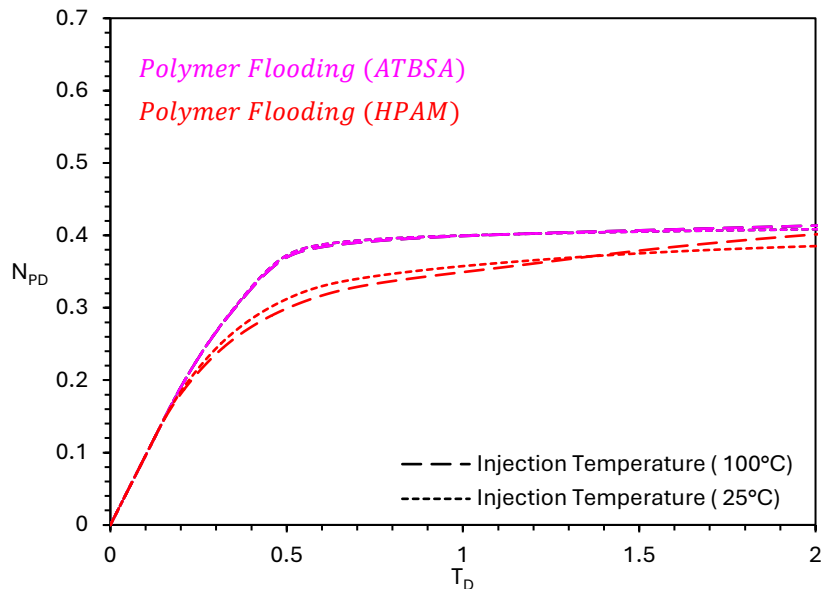
We ran a preliminary non-isothermal variant that couples heat transport to the flow model using representative carbonate rock and shale over/underburden thermal properties (see **Table A.1**) and temperature-dependent oil viscosity from (Civan, 2006) (see **Table A.2**). We compared an isothermal case (injection at reservoir temperature 100°C) with a cooled injection case (surface temperature 25°C). **Figure A.7** and **Figure A.8** show two clear effects: cooling slows HPAM thermal degradation and lifts early recovery, but the same cooling raises near-wellbore oil viscosity, threatening injectivity and reducing recovery gains at later time. ATBSA is largely insensitive over the tested window because its viscosity is preserved at reservoir temperature.

Table A.1. Thermal properties of rock and fluids used in the simulation model.

Parameters	Unit	Value
Rock thermal conductivity	J/(m.day.°C)	2.74×10^5
Water thermal conductivity	J/(m.day.°C)	1.15×10^4
Oil thermal conductivity	J/(m.day.°C)	6.05×10^4
Over/underburned initial temperature	°C	100
Overburden volumetric heat capacity		2.347×10^6
Overburden thermal conductivity		1.5×10^5
Underburden volumetric heat capacity		2.347×10^6
Underburden thermal conductivity		1.5×10^5

Table A.2. Oil viscosity as a function of temperature used in the non-isothermal case using Civan, (2006) correlation.

Temperature, °C	$\mu_o, mPa \cdot s$
25	861
35	228
45	92
55	48
65	29
75	20
85	14
95	11
100	10

**Figure A.7.** Numerical oil pore volume produced as a function of pore volumes of polymer injected for different polymers and injection temperatures. Lower injection temperature demonstrated improvement in HPAM early recovery.

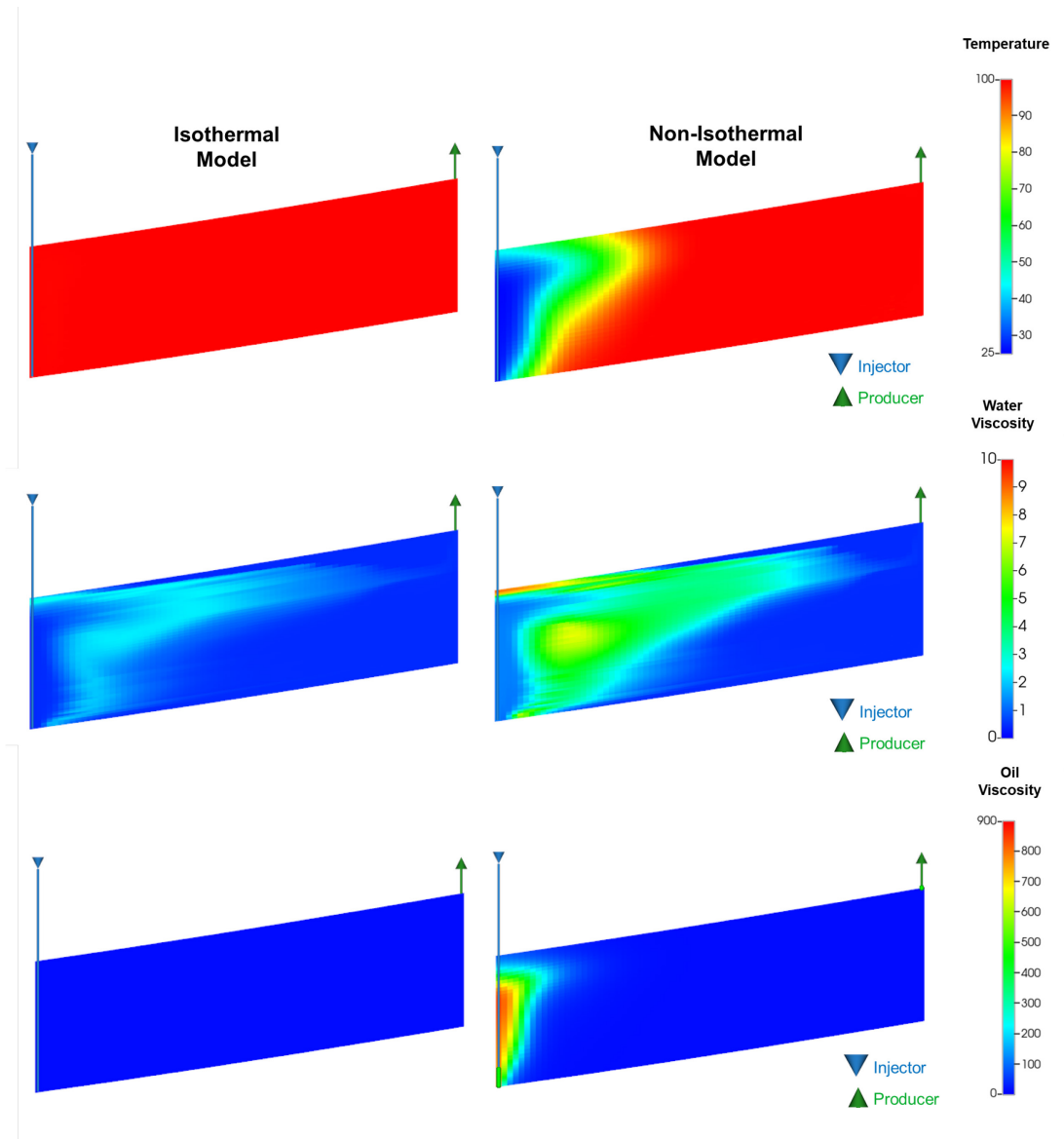


Figure A.8. Cross sections of reservoir temperature, water viscosity and oil viscosity for isothermal and non-isothermal simulations using HPAM polymer at 0.5 PVI. The isothermal case uses injection temperature of 100°C and the non-isothermal uses injection temperature of 25°C. All cases are secondary flooding with a slug size of 0.4 PVI flowing at 3000 m³/day and reservoir temperature of 100°C.

These trials were run with a high, fixed injectivity index and without explicit wellbore heat transfer or pressure constraints, so near-wellbore increase in viscosity effect on injectivity is minimized; Chapter 7 already lists this treatment of injection temperature as a limitation. The results therefore indicate potential upside for HPAM longevity under cooled injection, but also a practical risk of injectivity loss that our simplified setup could not fully capture.

Future work should first, couple temperature to well constraints and wellbore heat transfer. Second, model injectivity limits and evaluate mitigation (e.g., moderated injection temperature, staged heating, or controlled fracturing). Third, include explicit

temperature–rheology coupling for higher polymer concentrations, and last re-evaluate polymer decay using local temperature histories rather than a single reference temperature.

A.3 Molecular Weight Validation

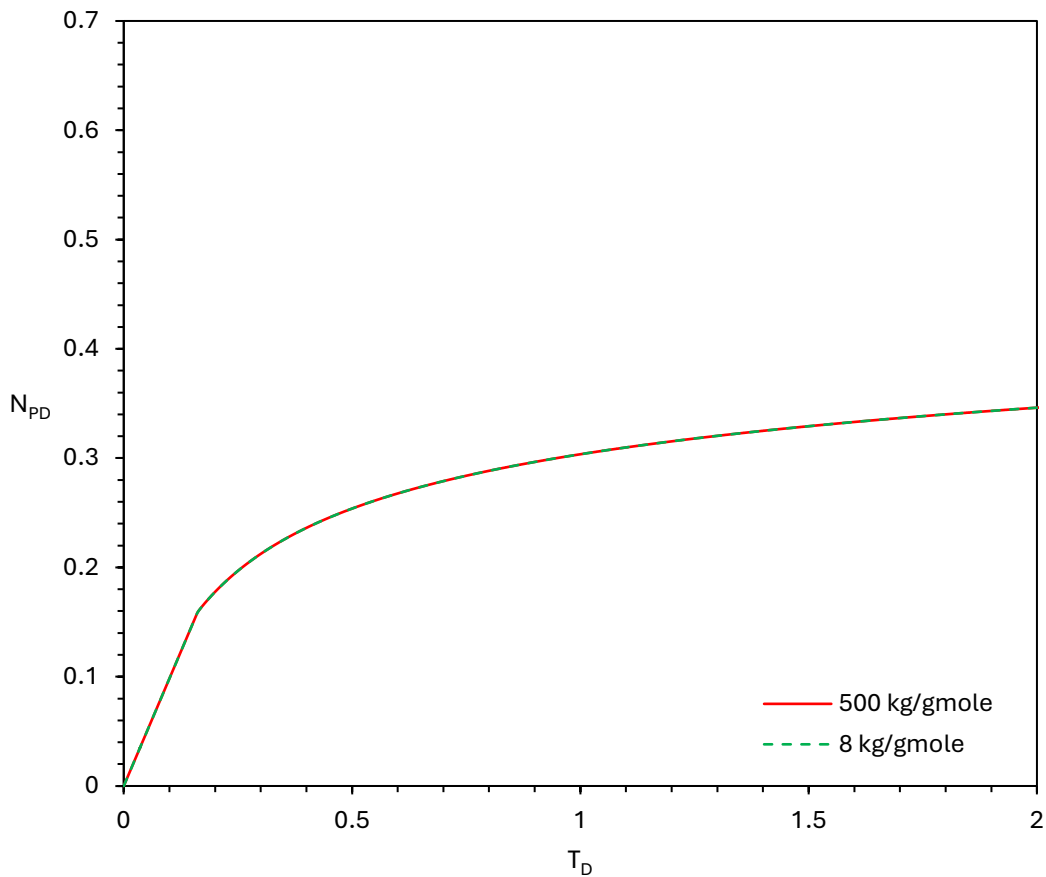


Figure A.9. Numerical oil pore volume produced as a function of pore volumes of polymer injected for different polymer molecular weights. Resorting to the scaled down molecular weight of 8 kg/gmole compared to 500 kg/gmole had no effect on polymer recovery.

A.4 CMG STARS Data File Sample

```
** 2022-03-08, 17:00:35, aaa421
** 2022-03-08, 17:44:08, aaa421
** 2022-03-09, 21:33:12, aaa421
** 2022-03-11, 14:38:15, aaa421
** 2022-03-16, 19:35:39, aaa421
** 2022-05-05, 21:44:03, aaa421
** 2022-09-08, 10:41:52, aaa421
** 2022-09-09, 12:11:57, aaa421
** 2022-09-13, 17:37:51, aaa421
** 2022-09-15, 14:18:22, aaa421
** 2022-09-15, 14:22:19, aaa421
** 2022-09-23, 11:05:13, aaa421
** 2022-09-30, 08:40:43, aaa421
** 2022-10-07, 12:02:34, aaa421
** 2022-10-11, 21:36:51, aaa421
** 2022-10-11, 21:51:35, aaa421
** 2022-10-24, 15:09:30, aaa421
** 2022-11-16, 17:49:13, aaa421
RESULTS SIMULATOR STARS 202110
```

```
WSRF WELL 1
WSRF GRID TIME
WSRF SECTOR TIME
OUTPRN GRID NONE
OUTPRN RES NONE
OUTSRF WELL LAYER ALL
OUTSRF GRID ALL
OUTSRF WELL DOWNHOLE
INUNIT SI
WPRN GRID 0
** *****
** Definition of fundamental cartesian grid
** *****
GRID VARI 225 1 1
KDIR DOWN
DI IVAR
225*5.555555
DJ JVAR
1*1250
DK ALL
225*10

DTOP
225*2380
** 0 = null block, 1 = active block
NULL CON      1

PVCUTOFF 0
```

POR CON 0.2
 PERMI CON 500
 PERMJ CON 500
 PERMK CON 500
 ** 0 = pinched block, 1 = active block
 PINCHOUTARRAY CON 1
 END-GRID

 ROCKTYPE 1
 CPOR 4E-7
 ROCKCP 2.347e6 0
 THCONR 2.74E5
 THCONW 6.05E4
 THCONO 1.15E4
 HLOSST 100
 HLOSSPROP
 OVERBUR 2.347e6 1.5e5
 UNDERBUR 2.347e6 1.5e5
 ** Model and number of components
 MODEL 3 3 3 2
 COMPNAME 'Water' 'Polymer' 'Dead_Oil'
 CMM
 0.0180153 8 0.213827
 PCRIT
 0 0 0
 TCRIT
 0 0 0
 MASSDEN
 1092.72 1092.72 881.472
 CP
 4.68571e-07 4.68571e-07 2.3106e-06
 CT1
 1.83146e-09 1.83146e-09 0.00086092
 AVG
 0 0 0
 BVG
 0 0 0
 GVISCOR
 VISCTABLE
 ** temp

5	2.18753	10	431402.2336
15	1.63462	10	7392.7887
25	1.28347	10	860.8267
35	1.03714	10	227.5981
45	0.861168	10	92.1436
55	0.730806	10	47.8825
65	0.623861	10	29.1644
75	0.54699	10	19.7749
85	0.484118	10	14.4650
95	0.431185	10	11.1860
100	0.406572	10	9.9996

110	0.367864	10	8.2047
125	0.329517	10	6.4239
150	0.265606	10	4.7098
190	0.210647	10	3.3489
230	0.174062	10	2.6588
270	0.147767	10	2.2509
310	0.126934	10	1.9848
350	0.111318	10	1.7987
390	0.098995	10	1.6618
430	0.0888547	10	1.5573
470	0.0803775	10	1.4750
510	0.0731853	10	1.4086
550	0.0670065	10	1.3539
590	0.0616409	10	1.3082
630	0.0569381	10	1.2694
670	0.0527822	10	1.2360
710	0.0490831	10	1.2071
750	0.0457695	10	1.1818
790	0.0427841	10	1.1594
830	0.0400804	10	1.1395

VSMIXCOMP 'Polymer'

VSMIXENDP 0 1.31105e-06

VSMIXFUNC 0 0.317034 0.467712 0.569904 0.650198 0.718907 0.783566 0.838971
0.894338 0.947828 1

PRSR 101

TEMR 100

PSURF 101

TSURF 16.85

** Reaction specification

STOREAC

0 1 0

STOPROD

444.444 0 0

RPHASE

0 1 0

RORDER

0 1 0

EACT 151803.26

FREQFAC 54330146823867000

OMEGA_PW *LEGACY 'Polymer' 0.67

PTYPE CON 1

ROCKFLUID

RPT 1

** Sw krw krow

SWT

0.1 0 1

0.11 0.001024482 0.930583298

0.12 0.002897672 0.865076199

0.13 0.005323363 0.803311184

0.14 0.008195853 0.745125588
 0.15 0.011454053 0.690361531
 0.16 0.015056744 0.638865844
 0.17 0.018973666 0.59049
 0.18 0.023181374 0.545090041
 0.19 0.027661005 0.502526507
 0.2 0.032396955 0.462664366
 0.21 0.037376034 0.425372939
 0.22 0.042586903 0.390525833
 0.23 0.048019675 0.358000867
 0.24 0.053665631 0.32768
 0.25 0.059517006 0.299449262
 0.26 0.065566827 0.273198682
 0.27 0.071808784 0.248822213
 0.28 0.078237137 0.226217666
 0.29 0.084846629 0.205286637
 0.3 0.091632426 0.185934432
 0.31 0.09859006 0.16807
 0.32 0.105715389 0.151605859
 0.33 0.113004554 0.136458028
 0.34 0.120453952 0.122545949
 0.35 0.128060208 0.109792423
 0.36 0.135820152 0.098123534
 0.37 0.143730798 0.08746858
 0.38 0.151789328 0.07776
 0.39 0.159993076 0.068933302
 0.4 0.168339515 0.060926995
 0.41 0.176826248 0.053682513
 0.42 0.185450991 0.047144147
 0.43 0.19421157 0.041258974
 0.44 0.203105912 0.035976781
 0.45 0.212132034 0.03125
 0.46 0.22128804 0.027033631
 0.47 0.230572111 0.023285175
 0.48 0.239982507 0.019964558
 0.49 0.249517552 0.017034064
 0.5 0.259175639 0.014458261
 0.51 0.268955219 0.012203932
 0.52 0.278854801 0.01024
 0.53 0.288872948 0.008537459
 0.54 0.299008273 0.007069302
 0.55 0.309259437 0.005810451
 0.56 0.319625145 0.004737683
 0.57 0.330104145 0.003829561
 0.58 0.340695225 0.00306636
 0.59 0.351397211 0.00243
 0.6 0.362208966 0.001903969
 0.61 0.373129387 0.001473255
 0.62 0.384157402 0.001124274
 0.63 0.395291972 0.000844801
 0.64 0.406532088 0.000623892

0.65	0.417876766	0.000451821
0.66	0.429325052	0.00032
0.67	0.440876016	0.000220916
0.68	0.452528755	0.000148053
0.69	0.464282386	9.58238E-05
0.7	0.476136051	5.9499E-05
0.71	0.488088913	3.51336E-05
0.72	0.500140155	1.94966E-05
0.73	0.512288981	0.00001
0.74	0.524534613	4.62664E-06
0.75	0.536876291	1.85934E-06
0.76	0.549313274	6.0927E-07
0.77	0.561844837	1.44583E-07
0.78	0.574470272	1.90397E-08
0.79	0.587188885	5.9499E-10
0.8	0.6	0

** Sl krg krog

SLT

0.3	0.6	0
0.33125	0.527344	3.72529e-09
0.3625	0.459375	4.76837e-07
0.39375	0.396094	8.14721e-06
0.425	0.3375	6.10352e-05
0.45625	0.283594	0.000291038
0.4875	0.234375	0.00104284
0.51875	0.189844	0.00306794
0.55	0.15	0.0078125
0.58125	0.114844	0.0178179
0.6125	0.084375	0.0372529
0.64375	0.0585938	0.0725954
0.675	0.0375	0.133484
0.70625	0.0210938	0.233756
0.7375	0.009375	0.392696
0.76875	0.00234375	0.636501
0.8	0	1

INITIAL

VERTICAL DEPTH_AVE NOEQUIL

REFPRES 26200

REFDEPTH 2380

DWOC 2390

INTYPE CON 1

MFRAC_WAT 'Water' CON 1

MFRAC_OIL 'Dead_Oil' CON 1

NUMERICAL

RUN

DATE 2021 1 1.00000

**

**

```

**
**
WELL 'WINJ-1'
INJECTOR MOBWEIGHT EXPLICIT 'WINJ-1'
INCOMP WATER 0.999998689 1.31104541e-06 0.0
TINJW 100.0
OPERATE MAX BHW 1000.0 CONT
**      rad geofac wfrac skin
GEOMETRY K 0.0762 0.37 1.0 0.0
      PERF GEOA 'WINJ-1'
** UBA      ff      Status Connection
      1 1 1      1.0 OPEN FLOW-FROM 'SURFACE'
LAYERXYZ 'WINJ-1'
** perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length
      1 1 1 2.777777 625.000000 2380.000000 2.777777 625.000000 2390.000000
10.000000

```

```

**
**
**
WELL 'WPRO-1'
PRODUCER 'WPRO-1'
OPERATE MAX BHF 1000.0 CONT
OPERATE MIN BHP 101.325 CONT
**      rad geofac wfrac skin
GEOMETRY K 0.0762 0.37 1.0 0.0
      PERF GEOA 'WPRO-1'
** UBA      ff      Status Connection
      225 1 1      1.0 OPEN FLOW-TO 'SURFACE'
LAYERXYZ 'WPRO-1'
** perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length
      225 1 1 1247.222068 625.000000 2380.000000 1247.222068 625.000000
2390.000000 10.000000

```

```

SETPI MULT 'WINJ-1'
      100.0
SETPI MULT 'WPRO-1'
      100.0

```

```

DTWELL 0.001
AUTOTUNE
DATE 2021 2 1.00000
DATE 2021 3 1.00000
DATE 2021 4 1.00000
DATE 2021 5 1.00000
DATE 2021 6 1.00000
DATE 2021 7 1.00000
DATE 2021 8 1.00000
DATE 2021 9 1.00000
DATE 2021 10 1.00000

```


DATE 2021 11 1.00000
DATE 2021 11 9.00000
DATE 2021 12 1.00000
DATE 2022 1 1.00000
DATE 2022 2 1.00000
DATE 2022 3 1.00000
DATE 2022 4 1.00000
DATE 2022 5 1.00000
DATE 2022 6 1.00000
DATE 2022 7 1.00000
DATE 2022 8 1.00000
DATE 2022 9 1.00000
DATE 2022 10 1.00000
DATE 2022 11 1.00000
DATE 2022 12 1.00000
DATE 2023 1 1.00000
DATE 2023 2 1.00000
DATE 2023 3 1.00000
DATE 2023 4 1.00000
DATE 2023 5 1.00000
DATE 2023 6 1.00000
DATE 2023 7 1.00000
DATE 2023 8 1.00000
DATE 2023 9 1.00000
DATE 2023 10 1.00000
DATE 2023 11 1.00000
DATE 2023 12 1.00000
DATE 2024 1 1.00000
DATE 2024 2 1.00000
DATE 2024 3 1.00000
DATE 2024 4 1.00000
DATE 2024 5 1.00000
DATE 2024 6 1.00000
DATE 2024 7 1.00000
DATE 2024 8 1.00000
DATE 2024 9 1.00000
DATE 2024 10 1.00000
DATE 2024 11 1.00000
DATE 2024 11 7.00000
INJECTOR MOBWEIGHT EXPLICIT 'WINJ-1'
INCOMP WATER 1.0 0.0 0.0
TINJW 100.0
OPERATE MAX BHW 1000.0 CONT
DATE 2024 12 1.00000