UPSCALING IN POLYMER FLOODED RESERVOIRS

by

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Dedicated to my family

Your inspiration and support has made my study possible
DECLARATION

I declare that this thesis

UPSCALING IN POLYMER FLOODED RESERVOIRS

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 All published and unpublished material used in this thesis has been given full acknowledgement.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

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ABSTRACT

Polymer flooding is one of the most successful techniques in Enhanced Oil Recovery. One of the obstacles to implementing the technique is the understanding of fluid flow in porous media at different length scales. Although many of the microscopic processes, in microns, in the reservoir are well understood, simulating fluid flow in the reservoir at the micron scale is completely impractical. Each project requires numerous simulations to cover a wide range of scenarios. To shorten the run time, the blocks in the reservoir model are generally coarsened from the core scale in centimetres to larger scales in metres or kilometres. This helps reduce the number of gridblocks for simulations from around $10^{13}$ cells to at most $10^5$ or $10^6$ cells. Reservoir rock properties such as porosity and permeability are averaged from the small scales using various methods, known as upscaling. In practice, upscaled permeabilities are calculated using the techniques derived for water flooding. The same upscaled model is then used for studying a variety of fluid displacements and injection schemes. The impact of using upscaled models for simulations of non-Newtonian flow displacement, as in polymer flooding, is not well understood.

This study investigates the effects of upscaling errors on production forecasts in non-Newtonian flow and recommends an approach to be applied in upscaled models for better production predictions. Two permeability distributions: a two-dimensional randomly generated lognormal permeability field and a fluvial system are investigated. These models are flooded by fluids governed by a power law rheological model that represents Newtonian, shear-thinning, and shear-thickening flow behaviour. The errors in production predictions and pressure profiles are analysed. We find considerably high errors in predictions when the properties of fluid displacement are changed. These significant errors can harm economic evaluations of projects. In addition, we prove that upscaled models manipulated for a perfect match to a fine scale model under water flooding should not be used for polymer flooded modelling. Furthermore, we discover that in addition to upscaling permeability, effective viscosity should be parameterised when injecting with non-Newtonian fluid. We recommend adjusting the power law exponent of the displacing fluid model for better results. We verify the new approach and conclude that a good agreement in predictions between fine and coarse scale models can be achieved by a single phase upscaling with an adjustment of the exponent in the power law rheological model.
This chapter of my life would not have completed without the support and guidance of several people.

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<tr>
<td>$A$</td>
<td>Area through which flow occurs</td>
<td>$m^2$</td>
</tr>
<tr>
<td>$B$</td>
<td>Herschel-Bulkley fluid modifier</td>
<td>-</td>
</tr>
<tr>
<td>$B_j$</td>
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<td>fraction</td>
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<td>$C$</td>
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<td>$mPa.s^n$</td>
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<td>Effective saturation for the injected polymer solution within the total aqueous phase</td>
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<tr>
<td>$E_D$</td>
<td>Displacement efficiency</td>
<td>fraction</td>
</tr>
<tr>
<td>$E_{DBT}$</td>
<td>Displacement efficiency at breakthrough</td>
<td>fraction</td>
</tr>
<tr>
<td>$E_V$</td>
<td>Vertical sweep efficiency</td>
<td>fraction</td>
</tr>
<tr>
<td>$E_{VTB}$</td>
<td>Vertical sweep at breakthrough</td>
<td>fraction</td>
</tr>
<tr>
<td>$F$</td>
<td>Force</td>
<td>$kg.m/s^2$</td>
</tr>
<tr>
<td>$F_S$</td>
<td>Fraction of shale in the streamline methods</td>
<td>fraction</td>
</tr>
<tr>
<td>$f$</td>
<td>Frequency of barrier occurrence in the streamline methods</td>
<td>fraction</td>
</tr>
<tr>
<td>$f(k)$</td>
<td>Probability density function of the permeability in the self-consistent approach</td>
<td>fraction</td>
</tr>
<tr>
<td>$f_w(S_w)$</td>
<td>Buckley-Leverett fractional flow function (reservoir water cut)</td>
<td>fraction</td>
</tr>
<tr>
<td>$f_{w2}$</td>
<td>Producing water cut after breakthrough</td>
<td>fraction</td>
</tr>
<tr>
<td>$f_w'(S_w)$</td>
<td>Derivative of Buckley-Leverett fractional flow function</td>
<td>fraction</td>
</tr>
<tr>
<td>$f_0$</td>
<td>Fraction of the medium with $k_0$ permeability tensor in the homogeneous equation approaches</td>
<td>fraction</td>
</tr>
<tr>
<td>$f_1$</td>
<td>Fraction of the medium with $k_1$ permeability tensor in the homogeneous equation approaches</td>
<td>fraction</td>
</tr>
<tr>
<td>$g$</td>
<td>Gravitational acceleration ($= 9.80665$)</td>
<td>$m/s^2$</td>
</tr>
<tr>
<td>$H$</td>
<td>Total thickness</td>
<td>$m$</td>
</tr>
<tr>
<td>$h_i$</td>
<td>Thickness of cell $i$</td>
<td>$m$</td>
</tr>
<tr>
<td>$i_w$</td>
<td>Average water injection</td>
<td>$m^3$</td>
</tr>
</tbody>
</table>
$K$ Rock permeability in a given direction \( \text{mD} \)

$K_j$ Conductivity of block \( j \) in the self-consistent approach \( \text{mD} \)

$K$ Absolute permeability tensor \( \text{mD} \)

$k$ Permeability tensor (symmetric positive definite) \( \text{mD} \)

$k_{\text{eff}}$ Effective permeability \( \text{mD} \)

$k_{\text{el}}$ Effective permeability of streamline \( i \) in the streamline methods \( \text{mD} \)

$k_i$ Permeability of cell \( i \) \( \text{mD} \)

$k_{r,j}$ Relative permeability of phase \( j \) \( \text{mD} \)

$k_{ss}$ Permeability of sandstone \( \text{mD} \)

$k_{sh}$ Permeability of shale \( \text{mD} \)

$k_{ve}$ Effective vertical permeability \( \text{mD} \)

$L$ Total length \( \text{m} \)

$L_S$ Mean of shale lengths in the streamline methods \( \text{m} \)

$L_{S,i}$ Shale length of streamline \( i \) in the streamline methods \( \text{m} \)

$L_x$ Correlation length in \( x \)-direction \( \text{fraction} \)

$L_y$ Correlation length in \( y \)-direction \( \text{fraction} \)

$l_i$ Length of cell \( i \) \( \text{m} \)

$M$ Mobility ratio \( \text{fraction} \)

$m_i$ Mass flow rate \( \text{m/s} \)

$m_{r,j}$ Mass flow rate of phase \( j \) \( \text{m/s} \)

$N_p$ Cumulative oil production \( \text{m}^3 \)

$N_{pBT}$ Cumulative oil production to breakthrough \( \text{m}^3 \)

$N_s$ Initial oil in place at start of the flood \( \text{m}^3 \)

$N_{st}$ Number of stream-tubes in the streamline methods \( - \)

$n$ Power law exponent in the power law rheological model \( - \)

$P_c$ Capillary pressure \( \text{Pa} \)

$\Delta P$ Pressure difference between cells \( \text{Pa} \)

$\Delta P_t$ Total pressure difference \( \text{Pa} \)

$p$ Pressure \( \text{Pa} \)

$p_i$ Inlet pressure \( \text{Pa} \)

$p_j$ Pressure of phase \( j \) \( \text{Pa} \)

$p_o$ Outlet pressure \( \text{Pa} \)

$Q_i$ Cumulative water injected in pore volumes \( \text{fraction} \)

$Q_{IBT}$ Pore volume injection at breakthrough \( \text{fraction} \)

$q_i$ Volumetric flow rate in layer \( i \) \( \text{m}^3/\text{s} \)

$q$ Volumetric flow rate \( \text{m}^3/\text{s} \)

$q_{r,j}$ Volumetric flow rate of phase \( j \) \( \text{m}^3/\text{s} \)

$q_t$ Total volumetric flow rate \( \text{m}^3/\text{s} \)
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_k$</td>
<td>Relative permeability reduction factor due to polymer retention fraction</td>
</tr>
<tr>
<td>$R_s$</td>
<td>Solution gas/oil ratio fraction</td>
</tr>
<tr>
<td>$R_v$</td>
<td>Vapor oil/gas ratio fraction</td>
</tr>
<tr>
<td>$r_1, r_2$</td>
<td>Random numbers between 0 and 1 in the streamline methods -</td>
</tr>
<tr>
<td>$S_i$</td>
<td>Length of streamline $i$ in the streamline methods m</td>
</tr>
<tr>
<td>$S_j$</td>
<td>Volumetric saturation of phase $j$ fraction</td>
</tr>
<tr>
<td>$S_{or}$</td>
<td>Residue oil saturation fraction</td>
</tr>
<tr>
<td>$S_{wf}$</td>
<td>Water saturation at the front fraction</td>
</tr>
<tr>
<td>$S_{wi}$</td>
<td>Initial water saturation fraction</td>
</tr>
<tr>
<td>$S_{wBT}$</td>
<td>Average water saturation behind font at breakthrough fraction</td>
</tr>
<tr>
<td>$S_{w2}$</td>
<td>Average water saturation behind font after breakthrough fraction</td>
</tr>
<tr>
<td>$T$</td>
<td>Transmissibility cP.m$^3$/day/Pa</td>
</tr>
<tr>
<td>$t$</td>
<td>Time day</td>
</tr>
<tr>
<td>$t_{BT}$</td>
<td>Exponent in percolation theory -</td>
</tr>
<tr>
<td>$u$</td>
<td>Darcy velocity ($\bar{q}/A$) m/s</td>
</tr>
<tr>
<td>$u$</td>
<td>Face-centred velocity in $x$ -direction in Chapter 5 m/s</td>
</tr>
<tr>
<td>$u_j$</td>
<td>Darcy velocity of phase $j$ m/s</td>
</tr>
<tr>
<td>$V_b$</td>
<td>Bulk volume of the coarse block m$^3$</td>
</tr>
<tr>
<td>$V_{sh}$</td>
<td>Volume fraction of shale fraction</td>
</tr>
<tr>
<td>$V_{shc}$</td>
<td>Critical volume fraction of shale fraction</td>
</tr>
<tr>
<td>$V_{ss}$</td>
<td>Volume fraction of sandstone fraction</td>
</tr>
<tr>
<td>$v$</td>
<td>Face-centred velocity in $y$ -direction in Chapter 5 m/s</td>
</tr>
<tr>
<td>$w$</td>
<td>Total width m</td>
</tr>
<tr>
<td>$w_i$</td>
<td>Width of cell $i$ m</td>
</tr>
<tr>
<td>$w_{Si}$</td>
<td>Shale width of streamline $i$ in the streamline methods m</td>
</tr>
<tr>
<td>$\bar{w}_s$</td>
<td>Mean of shale width in the streamline methods m</td>
</tr>
<tr>
<td>$x$</td>
<td>Distance in $x$-direction m</td>
</tr>
<tr>
<td>$\Delta x$</td>
<td>Cell width m</td>
</tr>
<tr>
<td>$x_D$</td>
<td>Dimensionless distance fraction</td>
</tr>
<tr>
<td>$y$</td>
<td>Distance in $y$-direction m</td>
</tr>
<tr>
<td>$\Delta y$</td>
<td>Cell length m</td>
</tr>
<tr>
<td>$\alpha$</td>
<td>Weighing factor for the yield stress fraction</td>
</tr>
<tr>
<td>$\gamma$</td>
<td>Shear rate 1/s</td>
</tr>
<tr>
<td>$\delta$</td>
<td>Tortuosity fraction</td>
</tr>
<tr>
<td>$\lambda_j$</td>
<td>Mobility of phase $j$ mD/Pa.s</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Viscosity Pa.s</td>
</tr>
<tr>
<td>$\mu_0^j$</td>
<td>Arithmetic mean in $j$-direction -</td>
</tr>
</tbody>
</table>
\( \mu_h \) Harmonic mean in \( j \)-direction

\( \mu_{eff} \) Effective viscosity

\( \mu_i \) Viscosity of fluid in cell \( i \)

\( \mu_j \) Viscosity of phase \( j \)

\( \mu_{j,eff} \) Effective viscosity after mixing of phase \( j \)

\( \rho \) Density

\( \rho_j \) Density of phase \( j \)

\( \rho_r \) Density of rock

\( \tau \) Shear stress

\( \tau_0 \) Yield stress

\( \phi \) Porosity

\( \phi^* \) Porosity available to polymer

\( \phi_{ipv} \) Porosity inaccessible to polymer

\( \Omega \) Sphere flow domain in the self-consistent approach

\( \omega \) Exponent of power averaging methods in Chapter 2

\( \omega \) Todd-Longstaff mixing parameter

**SUBSCRIPTS**

\( b \) Brine

\( D \) Dimensionless

\( g \) Gas

\( o \) Oil

\( p \) Polymer

\( r \) Rock

\( sh \) Shale

\( ss \) Sandstone

\( t \) Total

\( w \) Water

\( x \) \( x \)-direction

\( y \) \( y \)-direction

Pa.s

Pa.s

Pa.s

Pa.s

kg/m\(^3\)

kg/m\(^3\)

kg/m\(^3\)

Pa

Pa

fraction

fraction

fraction

-
### ABBREVIATIONS

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>PVI</td>
<td>Pore volume injection</td>
</tr>
<tr>
<td>RRF</td>
<td>Residual resistance factor</td>
</tr>
<tr>
<td>Q-Q</td>
<td>Quantile-Quantile</td>
</tr>
</tbody>
</table>

### CONVERSION FACTORS

<table>
<thead>
<tr>
<th>Original units</th>
<th>Multiply by (estimated)</th>
<th>Final units</th>
</tr>
</thead>
<tbody>
<tr>
<td>kg/m$^3$</td>
<td>0.3505</td>
<td>lb/bbl</td>
</tr>
<tr>
<td>kg/m$^3$</td>
<td>0.0624</td>
<td>lb/ft$^3$</td>
</tr>
<tr>
<td>kg.m/s$^2$ (N)</td>
<td>0.2248</td>
<td>lbf</td>
</tr>
<tr>
<td>m</td>
<td>3.2808</td>
<td>ft</td>
</tr>
<tr>
<td>m$^3$</td>
<td>6.2898</td>
<td>bbl</td>
</tr>
<tr>
<td>Pa</td>
<td>1.4504x10$^{-4}$</td>
<td>psi</td>
</tr>
<tr>
<td>Pa.s</td>
<td>1000</td>
<td>cP</td>
</tr>
</tbody>
</table>
INTRODUCTION

The world energy demand has continued to increase steadily since 1980. The outlook of world primary energy demand shows an increase of 45% from 2006 to 2030 – an average growth of 1.6% a year. In 2030, eighty percent of the world primary energy mix is predicted to come from fossil fuels. The main energy source is oil for decades to come, though with an increase in coal demand (Figure 1-1).

Figure 1-1: World primary energy demand by fuel based on the International Energy Agency’s reference scenario, unit in one million tonne of oil equivalent (Mtoe) - reprinted from International Energy Agency (2008).
Global primary oil demand is predicted to rise by an average of one percent per year from $85 \times 10^6$ STB/day in 2007 to $106 \times 10^6$ STB/day in 2030. This projected figure is based on the reference scenario described in chapter one of “World Energy Outlook 2008” by International Energy Agency (2008). The increase in world oil demand in this projection is highly dependent on growth in the global economy and government policies related to energy. The fastest growth is projected to be in India at approximately four percent per year over the outlook period. Although a number of new government policies in several countries such as promoting fuel-efficient vehicles and encouraging biofuels supply in the United States and Europe may contribute to the reduction of oil demand, the projected demand still progressively grows over the outlook period. Oil fields under or awaiting development can only compensate for the decline in crude oil production of existing fields. In order to meet the world energy demand, the contributions of natural gas liquids (NGLs), non conventional oil, and additional oil recovered by enhanced oil recovery (EOR) are necessary. These contributions are projected to bring the world oil production up from $82.3 \times 10^6$ STB/day in 2007 to $103.8 \times 10^6$ STB/day in 2030 (Figure 1-2), which is just slightly lower than the world demand.

Figure 1-2: World oil production by source - reprinted from International Energy Agency (2008).
The world proven crude oil reserves are estimated to 1.47 trillion barrels in 2010 (OPEC, 2011). These reserves have doubled since 1980 because of advances in technology, enhanced recovery, and new reservoir development. Based on worldwide data from IHS Energy, the average recovery factor in oil fields is estimated at 34% (Schulte, 2005). Improving recovery factors of oil fields could make a huge difference to recoverable reserves. The production life of existing fields can be increased through secondary and tertiary (enhanced) oil recovery techniques. These can help postpone the peak of conventional oil production. Based on an estimate from the International Energy Agency, a one percent increase of the average recovery factor at producing fields would add over 80 billion barrels to the world's proven oil reserves (i.e. 5-6% of 1.47 trillion barrels). The increase could come from a number of advances in technology that potentially improve oil recovery factors. Examples of technologies are improvements in the efficiency of secondary and tertiary recovery, better imaging of reservoirs, and real time production management. More details can be found in chapter nine of “World Energy Outlook 2008” by International Energy Agency (2008). Schulte (2005) stated that with present practices, EOR processes can generally increase ultimate recovery by 7-15%. With IEA’s estimation of 80 billion barrels per one percent increase of the recovery factor, the EOR processes can potentially increase the world proven reserves by 560-1200 billion barrels.

1.1 Enhanced Oil Recovery

Augmentation in reservoir productivity by injecting of fluids other than natural gas and water have been designated “improved”, “tertiary”, and “enhanced” oil recovery processes. Production of a reservoir normally begins by the natural energy of the reservoir or with help of artificial lift. This primary recovery is typically less than thirty percent (Kokal & Al-Kaabi, 2010). When natural energy is depleted or no longer economical to produce, extra energy must be applied to the reservoir to maintain oil production. This secondary recovery can be conducted by water flooding or by injected water of dry hydrocarbon gas for pressure maintenance. The second stage of production is estimated to increase recovery to 30-50% of oil in place (Kokal & Al-Kaabi, 2010). EOR processes may be divided into four categories: thermal, miscible (gas), chemical, and other. These techniques aim to alter the properties of the reservoir fluids and improving fluids flow from reservoirs to wellbores. This recovery stage is applied to increase the amount of oil recovered beyond the range that conventional primary and secondary recovery can achieve. Advanced EOR technologies can lift the ultimate recovery to over 50% and up to 80+% in extreme cases (Kokal & Al-Kaabi, 2010). Typical recovery mechanisms and their recovery stages
are summarized in Figure 1-3. Additionally, improved oil recovery (IOR) is defined as any practice used to increase oil recovery including secondary recovery and EOR processes. IOR also includes practices to augment sweep efficiency such as infill drilling, horizontal well and polymers for mobility control or improved conformance (Stosur et al., 2003).

![Diagram of Oil Recovery Mechanisms](image)

**Figure 1-3: Recovery mechanisms - reprinted from Kokal and Al-Kaabi (2010).**

The inefficiency of oil recovery has stimulated research and development of new EOR technologies for almost a hundred years. The potential applicability of EOR processes depends upon technological, economic, material and institutional constraints. Tremendous interest in EOR generated in the 1970s and early 1980s after an oil price increase. However, the collapse in oil price in the 1990s and early 2000s led to a significant loss of expertise amongst oil companies and technology providers.

Oil prices are affected by supply and demand. From the “World Energy Outlook 2008” (IEA, 2008), demand continues to rise throughout the projected period, whereas supply is falling. The decline of supply is mainly due to depletion of existing fields and lack of recent discoveries of large fields. In order to boost supply and meet demand, EOR is necessary. The increase in oil prices, which are driven by the difference between supply and demand, enables EOR projects to be economic. The interest in EOR
technologies has returned as the price of oil has escalated during the past couple of years. The deployment of EOR will contribute significantly to future reserves growth and help increase in oil supply.

According to IEA, the total world oil production from EOR accounts for about $3 \times 10^6$ STB/day, roughly 3.5% of the world daily production. Thermal recovery and miscible gas injection are the two most preferred EOR methods because of mature technologies associated with them. Polymer injection has been widely applied. Chemical EOR contributes for approximately $4 \times 10^5$ STB/day to the total world oil production nowadays. Polymer flooding has been implemented very successfully, especially in China. The main purpose of adding water-soluble polymers is to reduce the water/oil mobility ratio by increasing the viscosity of water. Based on the recent rise in oil price and the success in China, the interest in chemical EOR is renewed. According to Kokal and Al-Kaabi (2010), several field trials and pilots are ongoing or pending in many countries such as Oman, Canada, the United States, India, Argentina, Brazil, and Austria (Kokal & Al-Kaabi, 2010).

### 1.2 Upscaling for Reservoir Simulation

Geological models are created based on the geological structure and the petrophysics of the reservoir. The grids are populated geostatistically using a variety of data sources. Advances in geological modelling and modern reservoir imaging techniques leads to more detailed reservoir descriptions. These result in very fine scale geological models. The length scales of geological models are generally the same as those of the data acquisition and are not related to production data. A typical geostatistical model might contain $10^7$–$10^8$ cells with cell sizes in the areal direction of 15-30 metres and thickness of 0.30 metre (Durlofsky, 2003). Reservoir simulators use reservoir properties from geological models to predict reservoir performance under different operating conditions for given production periods. Reservoir simulation models can also use production data from history matching to perform production forecasts. In the reservoir performance predictions, uncertainty factors must be taken into account for sensitivity analysis. This includes numerous geological realizations and production scenarios that can require thousands of simulations. Reservoir simulators can generally handle on the order of $10^5$ – $10^6$ simulation cells depending on the simulation model. A black oil model can typically be run in a shorter time than a compositional model and consequently can be run with more gridblocks. In many models, simulations of over $10^6$ grid cells may be too expensive to run routinely. A high level of upscaling may be
necessary if a detailed assessment of project risk and uncertainty is required. However, the higher the upscaling level is, the more the fine scale detail may be lost.

The main objective of upscaling is to make the reservoir models more practical to simulate, mainly by reducing computational time, for uncertainty analysis and risk assessment. An upscaled model should preserve the most important flow characteristics of a geological model, especially in regions with high fluxes (Durlofsky, 2003). Over the last few decades, various upscaling techniques have been presented to determine rock properties on a coarser scale. Porosity and saturation at the coarse scale can simply be calculated by a volume weighted averaging of the values at the fine scale. However, a flux in a geological model is a complex function of permeabilities and the relative permeabilities. These values at a coarse scale need to reproduce the average flux as close to that obtained from the fine model as possible. Several upscaling methods have been developed to minimize errors in predictions. The upscaling techniques can be divided into single-phase upscaling and two-phase upscaling based on the parameters being upscaled. Single-phase upscaling is faster but may be less reliable; while two-phase upscaling may require full field simulation, which may not be possible in many models due to CPU time and memory. The main advantage of the single-phase upscaling is that upscaled models can easily be rebuilt if an initial conceptual model has been changed. On the other hand, the rerun of a fine scale model may be required when using some methods of two-phase upscaling. The main issue in upscaling is how to optimise the processing time while minimising the information loss, which may reduce errors. Using a coarser grid introduces errors in predictions of production recovered. A total error in upscaling is a combination of a discretisation error and loss of reservoir heterogeneity. These two errors have different effects on predictions. The discretisation error accelerates a water breakthrough time; whereas the loss of heterogeneity can usually delay the water breakthrough time (Muggeridge, 1991).

1.3 Thesis Overview

1.3.1 Motivation

Each EOR project faces considerable capital investment and financial risks. One of the most important parameters in an economic evaluation is incremental production from the EOR process. These production predictions are obtained from reservoir simulation. Upscaling of geological data to reservoir models is a common practice in reservoir simulation to make models more practical to simulate.
Reducing the number of gridblocks introduces errors in the simulation that leads to errors in production forecasts. This eventually effects decision making in implementing EOR process. Many upscaling studies have been conducted on water flooded or immiscible gas injected reservoirs. The tenth SPE Comparative Solution Project or SPE 10 (Christie & Blunt, 2001) is a good resource for understanding the effects of upscaling on production forecasts; however, the project only investigated immiscible gas injection on a two-dimensional model and water flooding on a three-dimensional model. In water flooding, all associated fluids are Newtonian, which means that the viscosity is constant regardless of shear rate. Polymer flooding, on the other hand, involves the displacement of Newtonian fluid by non-Newtonian fluid. The effective viscosity of displacing fluid, which depends upon the average shear rate, has an impact on flow velocity. Ignoring the effect of non-Newtonian flow behaviour may result in errors in production predictions (Savins, 1969). Thus far, a study in the effect of non-Newtonian fluid displacement at various scales has not yet been found in literature.

Polymer flooding, as one method for Enhanced Oil Recovery, is expected to contribute to future reserves growth. Reserves estimates depend strongly on the recovery factor, which is found from reservoir simulation. In general, simulation models are upscaled from geological models using water flooding by matching fluxes. The same models have then been applied different scenarios of polymer flooding for uncertainty assessment. The different in predictions between simulation and geological models under polymer flooding has not been considered. Questions when using these upscaled models in predictions are:

- What errors in predictions should we expect?
- Should water breakthrough be expected earlier or later and by how much?
- Is oil recovery under or overestimated and by how much?

An assessment of upscaling errors in reservoir simulation for polymer flooding process is not available. These errors in predictions not only impact field development and decision making but also have significant effects on the estimation of the world’s potential reserves growth.
1.3.2 Objectives

The main objective of this research project is to investigate upscaling techniques for reservoirs under polymer flooding. The major criterion is to minimise the errors in predictions. The second purpose is to find a method that provides simulation results in good agreement with fine scale models while saving considerable computational processing time and cost. The aim is to develop fast, accurate upscaling algorithms.

1.3.3 Methodology

An investigation of errors in upscaling on a variety of reservoir scales will be conducted on heterogeneous two-dimensional models under water flooding and polymer flooding. Several fast upscaling algorithms such as power law averaging and renormalization methods will be examined at selected length scales. A selected method that offers the closest results to fine scale models is verified in three-dimensional models. The Schlumberger simulation software - ECLIPSE version 2010.1 with the polymer flooding option is the main simulator in this study.

1.3.4 Thesis Outline

This thesis is divided into four core sections followed by the discussion of main findings and recommended future work.

Chapter 2: we review the relevant literature in upscaling techniques and non-Newtonian fluid flow behaviour in porous media.

Chapter 3: we identify equations for polymer flooded modelling. We validate the use of ECLIPSE reservoir simulator with polymer flooding option.

Chapter 4: we investigate the impact of upscaling in two-dimensional heterogeneous models under non-Newtonian fluid flooding.
Chapter 5: we identify the best approach to use upscaled models for shear-thickening polymer flooding study.

Chapter 6: we summarise our findings and suggest areas for future research.
LITERATURE REVIEW

2.1 Flow through Porous Media

The equations of single-phase and multiphase flow through porous media in the absence of gravity and capillary pressure are described in this section. More details can be found in Dake (1978).

2.1.1 Single-phase Flow Equations

In the absence of gravity, Darcy’s law is

\[ u = -\frac{k}{\mu} \cdot \nabla p \]  \hspace{1cm} (2-1)

Where:

- \( u \) \hspace{1cm} \text{Darcy velocity (}q/A\text{)}
- \( k \) \hspace{1cm} \text{Permeability tensor (symmetric positive definite)}
- \( \mu \) \hspace{1cm} \text{Viscosity}
- \( p \) \hspace{1cm} \text{Pressure}

The statement of mass conservation
\[
\frac{\partial}{\partial t} (\phi \rho) + \nabla \cdot (\rho \mathbf{u}) + \bar{m} = 0
\]  \hspace{1cm} (2-2)

Where:
\[
\begin{align*}
\phi & \quad \text{Porosity} \\
\rho & \quad \text{Density} \\
u & \quad \text{Darcy velocity} \ (q / A) \\
\bar{m} & \quad \text{Mass flow rate per unit volume (positive for production)}
\end{align*}
\]

By substituting Darcy’s Law into the statement of mass conservation, the single-phase flow equation neglecting gravity is

\[
\frac{\partial}{\partial t} (\phi \rho) - \nabla \cdot \left( \frac{\rho}{\mu} k \cdot \nabla p \right) + \bar{m} = 0
\]  \hspace{1cm} (2-3)

Assuming the fluid and rock are incompressible, then \(\frac{\partial \rho}{\partial t} = 0\), the simplified pressure equation is

\[
\nabla \cdot \left( \frac{1}{\mu} k \cdot \nabla p \right) = \bar{q}, \quad \text{where } \bar{q} = \frac{\bar{m}}{\rho}
\]  \hspace{1cm} (2-4)

Equation (2-4) is also known as the single-phase pressure equation. In general, upscaling procedures are developed based on Equation (2-4).

### 2.1.2 Multiphase Flow Equations

In the absence of gravity, Darcy’s law is

\[
u_j = -\frac{k_{rj}}{\mu_j} k \cdot \nabla p_j, \quad j \text{ refers to a phase (oil/water)}
\]  \hspace{1cm} (2-5)

Where:
\[
\begin{align*}
u_j & \quad \text{Darcy velocity of phase } j \\
k_{rj} & \quad \text{Relative permeability of phase } j \\
k & \quad \text{Permeability tensor} \\
\mu_j & \quad \text{Viscosity of phase } j \\
p & \quad \text{Pressure}
\end{align*}
\]

The statement of mass conservation

\[
\frac{\partial}{\partial t} (\phi \rho_j s_j) + \nabla \cdot (\rho_j \mathbf{u}_j) + \bar{m}_j = 0
\]  \hspace{1cm} (2-6)
Where:

- \( \phi \) Porosity
- \( \rho_j \) Mass density of phase \( j \)
- \( S_j \) Volumetric saturation of phase \( j \)
- \( u_j \) Darcy velocity of phase \( j \)
- \( \bar{m}_j \) Mass flow rate per unit volume of phase \( j \) (positive for production)

Assuming \( \frac{\partial \phi}{\partial t} = 0 \), \( \rho_j \) does not vary with time or space, and capillary pressure is negligible, \( p_c(S_w) = p_o - p_w = 0 \), Equation (2-6) is reduced to

\[
\nabla \cdot u_t = -\bar{q}_t
\]  
(2-7)

Where:

- \( u_t \) Total velocity
- \( \bar{q}_t \) Total volumetric flow rate, \( \bar{q}_t = \bar{q}_w + \bar{q}_o \)
- \( \bar{q}_j \) Volumetric flow rate of phase \( j \), \( \bar{q}_j = \frac{\bar{m}_j}{\rho_j} \)

The total Darcy velocity is given by

\[
u_t = u_w + u_o = -k \left( \frac{k_{rw}}{\mu_w} + \frac{k_{ro}}{\mu_o} \right) \cdot \nabla p
\]  
(2-8)

Where:

- \( u_t \) Total velocity
- \( u_w \) Water velocity
- \( u_o \) Oil velocity
- \( k \) Permeability tensor
- \( k_{rw} \) Relative permeability of water
- \( k_{ro} \) Relative permeability of oil
- \( \mu_w \) Water viscosity
- \( \mu_o \) Oil viscosity
- \( p \) Pressure

Since \( u_w = f(S_w)u_t \), where \( f(S_w) \) is Buckley-Leverett fractional flow function, substituting in Equation (2-6) results in the water saturation equation

\[
\phi \frac{\partial S_w}{\partial t} + \nabla \cdot [u_t f(S_w)] = -\bar{q}_w
\]  
(2-9)

Replacing Equation (2-8) in Equation (2-7) gives
\[ \nabla \cdot \left[ k \left( \frac{k_{RW}}{\mu_w} + \frac{k_{RO}}{\mu_o} \right) \nabla p \right] = \bar{q}_t \] (2-10)

Introduce the total mobility, \( \lambda_t \)

\[ \lambda_t = \lambda_w + \lambda_o = \frac{k_{RW}}{\mu_w} + \frac{k_{RO}}{\mu_o} \] (2-11)

Equation (2-10) then reduces to

\[ \nabla \cdot \left[ k \lambda_t (S_w) \nabla p \right] = \bar{q}_t \] (2-12)

The pressure equation (2-12) and the saturation equation (2-9) are for two immiscible fluids. If the fluids have identical properties and do not interfere, the two-phase pressure equation (2-12) is the same as the single-phase pressure equation (2-4).

For modelling of reservoir flows, the continuum differential equations are discretised on to a series of gridblocks. The two most common numerical methods for finding approximate solutions to partial differential equations (PDE) and their systems are the finite difference method (FDM) and the finite element method (FEM). The FDM is based on the application of a local Taylor expansion to approximate the PDE. A topologically square network of lines is used in the discretisation of the PDE. The FEM uses an integral form of the PDE in discretisation processes. More detailed understanding of the approaches are in “Finite Difference, Finite Element and Finite Volume Methods for Partial Differential Equations” by Peiró and Sherwin (2005). The FEM is believed to be superior compared to other methods because the method can accurately follow material interfaces. In geosciences, FEM has yet to work with gravity and two-phase flow in reservoirs.

Geological models created by any numerical methods might contain \( 10^7 \)–\( 10^8 \) cells, whereas reservoir simulators can generally handle on the order of \( 10^5 \) – \( 10^6 \) simulation cells. Therefore upscaling processes are required. Many upscaling techniques, especially two-phase upscaling, compute upscaled transmissibility rather than permeability (Durlofsky, 2005). Transmissibility is an interblock quantity that relates the flow from one block to an adjacent block in terms of the pressure difference between the blocks. Considering only the \( x \)-direction, the relationship can be expressed as Equation (2-13), where \( q \) is flow rate, \( T_{x,i} \) is transmissibility in the \( x \)-direction, the subscripts \( i \) and \( i + 1 \) denote the gridblocks, the subscript \( i + 1/2 \) is for the interface between them. The transmissibility in the \( x \)-direction between
block $i$ and block $i + 1$ can be calculated by Equation (2-14). The $\Delta x, \Delta y, \Delta z$ are the sizes of gridblock. The $(k_x)_{i+1/2}$ is the weighted harmonic average of $x$ component of permeability in block $i$ and $i + 1$ that can be determined by Equation (2-15).

$$q_{i+1/2} = (T_x)_{i+1/2}(p_i - p_{i+1})$$

(2-13)

Where

$$(T_x)_{i+1/2} = \frac{2(k_x)_{i+1/2}\Delta y\Delta z}{\Delta x_{i+1} + \Delta x_i}$$

(2-14)

and

$$(k_x)_{i+1/2} = \frac{[\Delta x_{i+1} + \Delta x_i](k_x)_i(k_x)_{i+1}}{[\Delta x_{i+1}(k_x)_i] + [\Delta x_i(k_x)_{i+1}]}$$

(2-15)

### 2.2 Upscaling Classifications

Upscaling techniques can be classified in several different ways. Durlofsky (2003) classified the upscaling methods based on the type of parameters being upscaled and the way in which the parameters are computed.

#### 2.2.1 Classification Based on Type of Parameters Being Upscaled

Following the pressure equations described in Section 2.1, the upscaling methods can be divided into two categories: single-phase and two-phase upscaling. In single-phase upscaling, only the absolute permeability and porosity are coarsened using selected computation methods. The relative permeability is used directly from the geological model without any manipulation. Two-phase upscaling, on the other hand, considers the upscaling of the absolute permeability, the relative permeability and sometimes the capillary pressure. Single-phase upscaling considers only the flow problem, whereas multiphase upscaling takes into account both flow and transport problems.
Single-phase Upscaling Techniques

Single-phase upscaling refers to any methods where only absolute permeability (or transmissibility) and porosity are upscaled. In single-phase upscaling, the pressure equation is modified but the saturation equation remains the same. In many cases, reservoir models for multiphase systems are generated by only upscaling the absolute permeability and porosity.

Analytical Approaches

Averaging Techniques

The easiest upscaling method is to average values from fine scale models in the same regions. This average can be calculated using various algorithms as follows:

Arithmetic

\[ k_{\text{arithmetic}} = \frac{\sum_{i=1}^{n} k_i h_i}{\sum_{i=1}^{n} h_i} \]  

(2-16)

Harmonic

\[ k_{\text{harmonic}} = H \left( \frac{\sum_{i=1}^{n} h_i}{\sum_{i=1}^{n} k_i} \right)^{-1} \]  

(2-17)

Geometric

\[ k_{\text{geometric}} = \left( \prod_{i=1}^{n} k_i \right)^{1/n} \]  

(2-18)

If a reservoir consists of several layers and the permeability in each layer is homogeneous and isotropic, the arithmetic average is an exact solution when fluid flows parallel to reservoir layers. For series flow in linear beds, the average permeability is calculated by the harmonic average (Warren & Price, 1961).

Warren and Price (1961) investigated the effect of permeability variation on three-dimensional flow in porous media. The continuous distribution functions including lognormal, exponential, skewed lognormal, linear and discontinuous distributions that were used to generate random permeability fields using Monte Carlo simulation were examined. Computational experiments were conducted using single-phase flow approach. The results showed that among the three averaging methods, regardless of
distribution types, the homogeneous system with the geometric permeability gives the most probable flow behaviour of the heterogeneous system.

Matheron (1967) studied the two-dimensional flow through infinite blocks with a heterogeneous permeability field that had an isotropic spatial correlation and followed a lognormal distribution. Matheron proved analytically that the block permeability, under these conditions, is equal to the geometric mean. Comparing the three averaging methods, the harmonic average gives the lowest value while the arithmetic mean provides the highest mean i.e. \( k_{\text{harmonic}} < k_{\text{geometric}} < k_{\text{arithmetic}} \).

**Combined Averaging Techniques**

The harmonic average gives the exact effective permeability when flow direction is along a series of connected cells. The arithmetic average is used to calculate the exact effective permeability across a 1-cell-thick plane. Combining these two rules yields arithmetic-harmonic and harmonic-arithmetic permeability upscaling methods. In the arithmetic-harmonic average (Equation (2-19)), the permeabilities of the cells in perpendicular plane to the flow direction are averaged by the arithmetic average; then are harmonically averaged the results along the flow direction to determine the upscaled permeability (Figure 2-1(a)). The harmonic-arithmetic averaging method (Equation (2-20)), is similar to the arithmetic-harmonic average except the lines of cells along the flow direction are harmonically averaged first. Then the arithmetic average is applied to obtain the effective permeability (Figure 2-1(b)). Cardwell and Parsons (1945) proved that the arithmetic-harmonic averaging method offers an upper bound of the effective permeability. They named this averaging method Cardwell maximum, \( c_{\text{max}} \). They found that the harmonic-arithmetic averaging method gives the lower bound and called this average Cardwell minimum, \( c_{\text{min}} \).
Le Loc’h (1987) proposed using the geometric average of the arithmetic-harmonic and the harmonic-arithmetic averaging methods to calculate the effective permeability (Equation (2-21)). This approach is called Cardwell-Parsons in Petrel (Schlumberger, 2009).

For the flow in x-direction, the three combined averaging methods are summarised as follows:

Arithmetic-harmonic

\[
k_{a-h} = c_{max} = \frac{n_x}{n_yn_z} \left[ \sum_{i=1}^{n_x} \sum_{j=1}^{n_y} \sum_{k=1}^{n_z} k_{i,j,k} \right]^{-1}
\] (2-19)

Harmonic-arithmetic

\[
k_{h-a} = c_{min} = \frac{n_x}{n_yn_z} \sum_{j=1}^{n_y} \sum_{k=1}^{n_z} \left[ \sum_{i=1}^{n_x} (k_{i,j,k})^{-1} \right]^{-1}
\] (2-20)

Cardwell-Parsons

\[
k_{c-p} = \sqrt{k_{h-a}k_{a-h}} = \sqrt{c_{min}c_{max}}
\] (2-21)

The inequality of the effective permeability by various averaging methods can be written as follows:
Grindheim (1990) and Durlofsky (1992) investigated the use of various averaging methods including arithmetic, harmonic, geometric, harmonic-arithmetic, and arithmetic-harmonic in computing the effective conductivities of two-dimensional blocks. Several spatial distributions of the cell conductivities, including uncorrelated and correlated, statistically isotropic and anisotropic, and sand-shale binary, were studies. The flow results from upscaled cases compared against the fine grid model revealed that none of simple averaging methods is valid for all heterogeneous formations.

Maschio and Schiozer (2003) modified Equation (2-21) by replacing the exponent \( \frac{1}{2} \) with the Dykstra-Parsons coefficient, \( DP \) (Dykstra & Parsons, 1950). The \( DP \) calculation is described in their paper. Their proposed averaging method, \( k_{eff} = (c_{max})^{DP} (c_{min})^{(1-DP)} \), was investigated in three models: model A from 36×36×6 cells to 9×9×2 cells, model B from 60×220×85 cells (SPE 10 Model 2) to 20×73×28 cells and 12×44×17 cells, model C from 240×120×96 cells to 40×20×16 cells. The ranges of permeabilities were 5-2,000 mD in model A, 0-20,000 mD in model B, and 0.5-800 mD in model C. Their method was benchmarked against a pressure solver method and the Cardwell-Parsons average (Equation (2-21)). Simulations of the fine scale models were conducted by a streamline simulator. The results from their method are closer to the results from the fine scale simulation compared to the Cardwell-Parsons average. In addition, the results from their method is similar to the pressure solver method but with much better computational performance (about 250 times faster in model B). Although this method is better than the Cardwell-Parsons average and faster than the pressure solver method, the results from this method are not exactly matched to those from the fine scale simulations.

**Power Averaging Methods**

Journel *et al.* (1986) used a binary type permeability distribution with a spatial autocorrelation to study the transition between shale and sandstone. The total gridblocks were 432 cells: 12×6×6 for the horizontal flow and 6×6×12 for the vertical flow. Each gridblock was assigned a diagonal isotropic permeability tensor of 0.01 mD for shale and 1,000 mD for sandstone. The effective permeability was determined empirically by dividing the total volumetric flux across a section perpendicular to the flow.
direction by the imposed pressure gradient. Then, the results were compared with the power averaging method calculated by

\[ k_{eff}^\omega = V_{sh}k_{sh}^\omega + (1 - V_{sh})k_{ss}^\omega \]  \hspace{1cm} (2-23)

Where \( V_{sh} \) is the shale volume in fraction, \( k_{sh} \) is the shale permeability, \( k_{ss} \) is the sandstone permeability, and \( \omega \) is the averaging power. Since the effective permeability lies between the harmonic average \((\omega = -1)\) and the arithmetic average \((\omega = 1)\) (Cardwell & Parsons, 1945), the power averaging exponent is constrained to the value between -1 and 1. When \( \omega \to 0 \), the \( k_{eff}^\omega, k_{sh}^\omega, k_{ss}^\omega \) are replaced by \( \ln(k_{eff}), \ln(k_{sh}), \ln(k_{ss}) \) which corresponds to the geometric average. They concluded that the power averaging exponents of 0.57 for horizontal flow and 0.12 for vertical flow provided the closest results to the fine scale simulation when the shale proportion is less than 0.5. Deutsch (1985) continued the research and modified Equation (2-23) to

\[ k_{eff} = \left\{ \sum_{j=1}^{n} p_j k_j^\omega \right\}^{1/\omega} \]  \hspace{1cm} (2-24)

Where \( k_{eff} \) is the effective permeability, \( n \) is the number of classes, \( p_j \) is the volume fraction of class \( j \) in the block, \( k_j \) is the arithmetic averaged permeability of class \( j \), and \( \omega \) is the power averaging exponent.

This power averaging approach can also be used for diagonal permeability tensor calculation as follows:

\[ k_{eff,i} = \left\{ \frac{1}{V_b} \int_{V_b} (k_i)^\omega dV \right\}^{1/\omega_i} \text{ when } \omega_i \neq 0 \]  \hspace{1cm} (2-25)

and

\[ k_{eff,i} = \exp\left\{ \frac{1}{V_b} \int_{V_b} \log(k_i) dV \right\} \text{ when } \omega_i \to 0 \]  \hspace{1cm} (2-26)
The fine scale permeability, $k_i$, and the upscaled permeability, $k_{eff,i}$, are diagonal tensors with $i$ designating the diagonal component. $V_b$ is the bulk volume of the coarse block. If two different values of $\omega_i$ are applied, the calculation becomes a combined averaging approach. For example, if $k_{eff}$ for the horizontal flow in $x-z$ coordinate is calculated by applying $\omega_i = -1$ (the harmonic average) along each layer and then applying $\omega_i = 1$ (the arithmetic average) to average these layers, this is the harmonic-arithmetic averaging method. Noetinger (1994) studied the use of Green’s functions to calculate the effective permeability. One of his conclusions was that the power averaging method with the exponent of one third can be used as a simple estimation for the effective permeability of three-dimensional lognormal medium.

**Percolation Theory**

Percolation theory was introduced in the mathematics literature by Broadbent and Hammersley (1957) to study fluid flow through some random properties of a medium. Kirkpatrick (1973) conducted numerical studies in the normalised electrical conductance of random resistivity networks. Deutsch (1989) applied the Kirkpatrick’s relationship (1973) to flow through porous medium. For binary medium, the effective permeability can be determined by Equation (2-27)

$$\frac{k_{eff}}{k_{ss}} = c(V_{shc} - V_{sh})^t$$

(2-27)

Where $V_{shc}$ is the critical volume fraction of shale, $t$ is an exponent (between 1.5 to 2.0), and $c$ is a proportional constant (between 1.5 to 2.0). The critical shale fraction is the maximum amount of shale for percolative flows. If the medium contains more shale than the critical shale fraction, the flow rate will drop dramatically. Deutsch (1989) investigated the relationship between the effective permeability and the volume fraction of shale. The power averaged model and the percolation model from Kirkpatrick’s relationship (1973) were compared against experimental results. Both models offered good matches to the experimental results. The percolation model gives the lower mean squared error when the experimental data are fitted as well as allows the estimation of permeability for very shaly sequences. However, the percolation theory relies on three parameters: $V_{shc}, c, t$, whereas the power averaged model only needed one input parameter, $\omega$. He concluded that for sandstone/shale sequences, the power averaging method is recommended because of its simplicity and effectiveness.
However, his suggestion may not be suitable for models with the net to gross close to the percolation threshold as the power average may not give a good result.

**Self-consistent Approach**

The self-consistent model can be classified as an effective medium approximation and an embedded matrix method. The effective medium theory was originated by Bruggeman (1935) to calculate effective macroscopic properties of a medium based on the properties and the fraction of each component. Dagan (1979, 1981) applied this theory to evaluate the effective hydraulic conductivity of heterogeneous and isotropic formations and later extended to anisotropic formations (Dagan, 1989). The method considers a collection of $N$ blocks in a sphere flow domain, $\Omega$, as presented in Figure 2-2(a). Each block has a conductivity of $K_j$. The diameter of the sphere domain tends to infinity. The shape, size, and location of the centroid ($\bar{x}_I$) of each block are characterised. Considering only a fixed block - $K_j$, the surroundings are replaced by a medium with the conductivity - $K_0$. The matrix then becomes a homogeneous medium with a submerged block - $K_j$ as shown in Figure 2-2(b). As the diameter of the sphere domain tends to infinity, which implies a very far boundary, the flow can be assumed uniform. A block of conductivity - $K$ can be represented by a spheroid in an unbounded domain as demonstrated in Figure 2-2(c).

![Figure 2-2: The model of formation serving for the self-consistent approach - reprinted from Dagan (1989).](image)
In isotropic formations, using spherical inclusions, the effective permeability is calculated by

\[
 k_{\text{eff}} = \frac{1}{D} \left[ \int_0^{\infty} \frac{f(k)dk}{k(D-1)+k_{\text{eff}}} \right]^{-1}
\]

(2-28)

Where \( f(k) \) is the probability density function of the permeability and \( D \) is the space dimension (1, 2, 3). The effective permeability can be determined by numerically calculating Equation (2-28) until the equality is obtained. This approach assumes a completely random medium. The blocks in the medium are randomly set with no correlation of the size and properties between two different blocks. Therefore, it prohibits the modelling of formations with high order spatial correlations of permeability.

In addition, Desbarats (1987) conducted numerical simulations for binary permeability distribution in a three-dimensional system and found that the results were satisfied only when the shale fraction is less than 0.6. In other words, the effective medium theory doesn’t work near the percolation threshold.

Homogeneous Equation Approaches

Wen and Gómez-Hernández (1996) classified the homogenisation theory (Bensoussan et al., 1978), the method of spatial averaging with closure (Crapiste et al., 1986) and the method of moments (Kitanidis, 1990) in this category. These three techniques consider the problem of scale change in mathematical terms and determine the equations and parameters on a larger scale from equations at a given scale. The first hypothesis is that the medium has spatial periodicity to allow the study of the whole domain to be replaced by a basic cell subjected to periodic boundary conditions (replacing the medium in Figure 2-3(a) with the medium in Figure 2-3(b)). The second hypothesis is that the period is very small compared to the domain size. This is to ensure that the large scale equation emerges. The effective permeability can then be solved numerically.
Quintard and Whitaker (1988) derived an analytical solution for the effective permeability tensor in a stratified binary system as follows:

\[ k_{\text{eff}} = f_0 k_0 + f_1 k_1 + \frac{f_0 f_2 (k_0 - k_1)(1_{0,1} - 0_{0,1})(k_1 - k_0)}{(1_{0,1})(f_0 k_1 - f_1 k_0)(1_{0,1})} \]  

(2-29)

Where \( f_0 = \frac{V_0}{V_{\text{total}}} \) is the fraction of the medium with \( k_0 \) permeability tensor and \( f_1 = \frac{V_1}{V_{\text{total}}} \) is the fraction of the medium with \( k_1 \) permeability tensor. Kasap and Lake (1990) proposed the calculation of the effective permeability as a full tensor. If only two blocks with known permeabilities presented, the result of the full tensor method is the same as the result from Equation (2-29).

Renormalization Techniques

The real space renormalization technique was developed primarily for the study of critical phenomena in physics. King (1989) applied this technique to calculate the effective permeability. The effective permeability of a new coarser grid is calculated by the series of successive aggregations on elementary groups of four cells in two dimensions and eight cells in three dimensions following an electrical analogy. The algorithm starts with \( 2^D \) cells, when \( D \) is the space dimension (1, 2, 3). The number of gridblocks is then reduced to \( 2^{(n-1)D} \) cells. The effective permeability of each new renormalized block is calculated by an equation derived from the electrical analogy (e.g. Equation (2-30), (2-31), or (2-34)). The process is repeated until the desired number of cells, ultimately one single cell, is reached as shown in Figure 2-4.
Several upscaling algorithms have been derived from renormalization method including directional, Migdal-Kadanoff, and simplified approaches as follows:

**Directional approach**

King (1988) derived an equation to calculate the effective permeability of isotropic media in the two-dimensional system. The flow occurs either in the horizontal direction (Figure 2-5(a)) or the vertical direction (Figure 2-5(b)). No flow boundary is assumed in the direction perpendicular to the flow. Figure 2-5(bottom) shows the equivalent resistor networks used to calculate the horizontal and vertical permeabilities. The networks are simplified by the use of the star-triangle (or Y-Δ) transformation. This transformation results in simple series and parallel circuits. The circuits can then be reduced to a single resistance and converted to a conductance. For two-dimensional systems, the effective permeability in each direction is calculated based on the flow in that direction by

\[
 k_{eff} = \frac{4(K_1+K_2)(K_2+K_4)(K_2K_4(K_1+K_2)+K_1K_3(K_2+K_4))}{[(K_2K_4(K_1+K_3)+K_1K_3(K_2+K_4))(K_1+K_2+K_3+K_4)]+(3(K_1+K_2)(K_3+K_4)(K_1+K_3)(K_2+K_4))} 
\]  

(2-30)

The location of \(K_1, K_2, K_3, K_4\) are shown in Figure 2-5(top): (a) for the horizontal flow and (b) for the vertical flow. The detailed derivation that results in Equation (2-30) and the three-dimensional renormalization procedure are described in King (1988, 1989). If the permeability field of the fine scale model is anisotropic, Equation (2-30) must be modified by taking into account both \(k_x\) and \(k_y\) of each cell.
**Migdal-Kadanoff approach**

An alternative scheme is a Migdal-Kadanoff renormalization. More details are explained in Burkhardt and Van Leeuwen (1982). Figure 2-6 shows the process to determine the effective permeability of a coarser grid when the flow occurs in the horizontal direction with no flow boundary. The group of four cells is broken into two one-dimensional systems (two sets of 2×1 cells). The effective permeability of two cells is calculated using the series circuit analogy. Then the two sets are combined to a single cell by parallel circuit analogy. The effective permeability when the flow is in the horizontal direction can be presented by Equation (2-31):

$$ k_{eff} = \frac{k_1k_2(k_3+k_4)+k_3k_4(k_1+k_2)}{(k_1+k_2)(k_3+k_4)} $$(2-31)

The cell index for permeabilities: $k_1, k_2, k_3, k_4$, in Equation (2-31) is also shown in Figure 2-6. This approach can be extended to three-dimensional systems relatively straightforward compared to the directional approach. This method is exactly the same as the harmonic-arithmetic average (Equation (2-20)) from two-by-two cells to a single cell; then repeat through the hierarchy of scales.
Figure 2-6: Migdal-Kadanoff renormalization scheme for horizontal flow - reprinted from Williams (1992).

Simplified renormalization

Le Loc’h (1987) proposed this method by following the Migdal-Kadanoff renormalization scheme. Firstly, two cells are grouped alternatively in parallel and series with respect to the flow direction. The permeabilities of the coarser cells are calculated by the harmonic mean, $\mu_h = 2k_1k_2/(k_1 + k_2)$, for series and the arithmetic mean, $\mu_a = (k_1 + k_2)/2$, for parallel groupings. The alternated groupings and the averaging processes continue until the desired cell size is reached with the unique value. This approach is only for isotropic permeability fields.
Figure 2-7 is an example of this upscaling procedure when the flow is only in the horizontal direction. The exponents \( x \) and \( y \) denote to the grouping directions. Start by grouping two cells in series along \( x \)-direction; then, merge two rectangular cells along \( y \)-direction, the final result yields a minimum value \( c_{\min} \) (Equation (2-32)). Another grouping begins by combining two cells in parallel first; then, join two rectangular cells in series. This second grouping results in a maximum value \( c_{\max} \) (Equation (2-33)). The effective permeability is calculated by the geometric mean of the minimum and maximum values (Equation (2-34)).

\[
c_{\min} = \mu_x (\ldots \mu_x (\mu_h) \ldots)
\]

\[
c_{\max} = \mu_y (\ldots \mu_y (\mu_h) \ldots)
\]

\[
k_{eff} = \sqrt{(c_{\max})(c_{\min})}
\]

For anisotropic permeabilities, Renard et al. (2000) replaced the exponent \( \frac{1}{2} \) in Equation (2-24) by exponents, \( \alpha \) and \( (1 - \alpha) \), \( k_{eff} = (c_{\max})^\alpha (c_{\min})^{(1-\alpha)} \). The calculation of \( \alpha \) can be found in their paper. The permeability in each direction is directionally calculated.
CHAPTER 2: LITERATURE REVIEW

Tensorial renormalization

Gautier and Noetinger (1997) proposed a new renormalization algorithm by calculating the full tensor permeability with periodic boundary conditions for pressure gradient and direct analogue network. Details of the periodic boundary conditions can be found in Durlofsky (1991). They concluded that further research is needed to improve the algorithm accuracy and implement in three-dimensional systems.

Streamline Methods

The concept was initiated by Haldorsen and Lake (1984) in order to calculate the vertical permeability of a binary shale-sandstone system. An example of this system is shown in Figure 2-8(a). Begg and King (1985) modified the method to remove limitations including the length and the aspect ratio of the gridblocks. Considering a block with a single tortuous steam-tube as shown in Figure 2-8(b), the block is then equally divided into the number of \( N \) stream-tubes \( (N_s) \) (Figure 2-8(c)). Darcy’s law is applied to calculate the flux through each line. As the flux through an equivalent homogeneous medium equals to the sum of the fluxes, the effective vertical permeability can be determined (Figure 2-8(d)). The shale is assumed not permeable.

Figure 2-8: (a) Fine scale grids in shale-sandstone system (b) Single tortuous stream-tube (c) Uniformly spaced stream-tubes sample (d) Equivalent block with a homogeneous \( k_{ve} \) - reprinted from Begg and King (1985).
The geometry of actual streamlines is replaced by rectangular paths. A streamline follows a vertical line until encounters a shale barrier. The part is detoured horizontally until the end of the shale then turned back to a vertical line again. The process is repeated until the streamline reaches the top boundary. Figure 2-9 is a graphical description of this replacement, starting from an actual streamline (left) to the final one used in calculation (right).

![Figure 2-9: Process to convert geometry of streamlines- reprinted from Begg and King (1985).](image)

With the assumptions of no flow boundaries through the sides, constant pressure along the upper and lower boundaries, incompressible fluid, and equal two-dimensional areas of the stream-tubes, the effective vertical permeability of the block can be calculated by Equation (2-35) as follows:

\[
k_{ve} = \frac{(1-F_s)H^2}{N_s} \sum_{i=1}^{N_v} k_{ei} \frac{S_i}{S^2_i}
\]

(2-35)

Where \(k_{ve}\) is the effective vertical permeability, \(k_{ei}\) is the effective permeability of the \(i^{th}\) stream-tube, \(F_s\) is the shale volume fraction, and \(H\) is the model thickness. Since a stream-tube consists of several horizontal and vertical segments, the \(k_{ei}\) is calculated by the harmonic mean of the vertical and horizontal permeabilities weighted according to their portions. \(S_i\) denotes to the length of a streamline and can either be estimated explicitly or statistically. Begg et al. (1989) suggested that Equation (2-35) is only applicable in sands with a slight to moderate anisotropy ratio of 0.01-1.00.
In formations with extreme anisotropy ratios, the stream-tubes follow significantly longer routes. Begg et al. (1989, 1985) adapt the calculation for extreme anisotropy ratio formations. Firstly, multipliers, \(a_y\) and \(a_z\) are introduced. All permeabilities in \(y\)- and \(z\)- directions of a model are rescaled with:

\[
a_y = \left( \frac{k_y}{k_x} \right)^{1/2} \quad \text{and} \quad a_z = \left( \frac{k_z}{k_x} \right)^{1/2}
\]

The sand permeability becomes isotropic and the horizontal permeability, \(k_x\), can be used. Equation (2-35) is replaced by Equation (2-37)

\[
\frac{k_{ve}}{k_x} = \frac{(1-F_s)H^2}{N_x} \sum_{i=1}^{N_y} \frac{1}{S_i}
\]

Each streamline length can be estimated statistically. First randomly select a shale length, \(L_{S_i}\) and a shale width, \(w_{S_i}\), from their cumulative probability distribution functions. Then, calculate the length of a streamline, \(S_i\), using the following equation:

\[
S_i = a_zH + \sum_{j=1}^{Hf+1} \min\left( r_{1ij}L_{S_{ij}}, r_{2ij}a_yw_{S_{ij}} \right)
\]

Where \(r_1, r_2\) is random numbers from 0 to 1, \(i\) is the streamline subscript, \(j\) is the layer subscript, and \(f\) is the frequency of barrier occurrence. If the mean shale lengths and widths are used and \(f\) is much greater than \(1/H\), resulting in \(Hf + 1 > 10\); then, Equation (2-37) is reduced to

\[
\frac{k_{ve}}{k_x} = \frac{(1-F_s)}{(a_x+f\bar{d})^2}
\]

Where,

\[
\bar{d} = \frac{L_s}{2} \text{ for 2D and } \bar{d} = \frac{a_yw_s}{6L_s} \left( 3L_s - a_yw_s \right) \text{ for 3D}
\]

**Wavelets**

Wavelets, which are widely used in image compression, transform data into effective values and associated details using wavelet functions such as the Haar wavelet (Haar, 1910). More details of other wavelet functions can be found in Daubechies (1992). Nilsen and Espedal (1996) applied wavelet
transformations to upscale reservoir models for simulations. The study was conducted on two-dimensional, random lognormal permeability fields \( k = e^{Y} \), where \( Y \) is normally distributed. The result from wavelet upscaling was compared to the geometric averaging method. After comparing variations in a velocity field, they concluded that the wavelet upscaling is better than the geometric average. Pancaldi et al. (2007) compared the upscaled results from renormalization with those obtained using the Haar wavelet. They concluded that both methods are in good agreement.

**Numerical Methods**

In single-phase upscaling, numerical methods are used to solve the single-phase pressure equation (2-4) by applying specified boundary conditions. The approach is also known as the Pressure Solver Method. Numerical methods normally offer better results than analytical methods because the processes take into account fluxes in fine scale models. However, more fine scale simulations are usually required if any boundary condition has changed. This may result in excessive computational processing times and costs.

For a single-phase incompressible fluid, steady-state flow, Equation (2-4) can be expressed by

\[
\nabla \cdot (k(x, y, z) \cdot \nabla p) = 0
\]

(2-40)

The effective permeability can be determined either as a diagonal tensor or a full tensor depending on boundary conditions.

**Directional Effective Permeabilities**

The most common boundary condition is to assume constant pressure at inlet and outlet, and no flow boundaries along the flow path (Begg et al., 1989, Begg & King, 1985). These assumptions are similar to a core flood experiment. The result is a diagonal tensor that can be easily entered to a reservoir simulator (Christie, 1996). Figure 2-10(a) shows a fine scale block containing \( i \times j \times k \) cells with permeability of \( k_{ijk} \) in each gridblock. The flow starts at the bottom to the top (vertical flow) and both sides along the flow path are sealed (no flow boundary). Equation (2-40) is numerically solved for the pressure, \( p_{ijk} \). On the outlet face, Darcy’s law is applied to calculate the flux out of each gridblock. Summation of all fluxes out of the outlet face equals to the flux through an equivalent homogenous medium as shown in Figure 2-10(b).
For vertical flow assuming constant pressure along its top and bottom, and no flow boundary along the sides, the effective permeability can be determined by

\[ k_{ve} = \frac{n_z+1}{n_x n_y (p_i - p_o)} \sum_i^n \sum_j^n k_{ijnz} (p_{ijnz} - p_o) \]  

(2-41)

Where \( p_i \) is the inlet pressure, \( p_o \) is the outlet pressure, \( n_x, n_y, n_z \) are the numbers of blocks in \( x-, y-, z- \) directions (graphically shown in Figure 2-10(a)). Equation (2-41) is only for calculating the effective permeability in \( z \)-direction, \( k_{zz} \). The effective permeabilities in \( x \) and \( y \) directions can be determined in the same technique. This eventually results in a diagonal permeability tensor, \( \tilde{k} = \begin{bmatrix} k_{xx} & 0 & 0 \\ 0 & k_{yy} & 0 \\ 0 & 0 & k_{zz} \end{bmatrix} \).

Begg et al. (1989) found that the results obtained from Equation (2-41) agreed well with the streamline methods and were also in very good agreement with values obtained from history matching with production data.

Full Tensor Effective Permeabilities

Full tensor pressure equations apply when a medium is anisotropic and gridblocks are not aligned with the frame of reference. An example is when having irregular coarse cells. The full tensor method takes
into account the off-diagonal terms in the calculation, i.e. \( \vec{k} = \begin{bmatrix} k_{xx} & k_{xy} & k_{xz} \\ k_{yx} & k_{yy} & k_{yz} \\ k_{zx} & k_{zy} & k_{zz} \end{bmatrix} \). The method is more accurate than the directional tensor calculation. However, the method is very sensitive to boundary conditions. Examples of boundary conditions are periodic (Durlofsky, 1991), partial periodic (King, 1993), perturbed (Pickup et al., 1992), and linear (King & Mansfield, 1997). More details of assumptions and calculations can be found in their papers.

**Two-phase Upscaling Techniques**

In single-phase upscaling, the relative permeabilities of a fine scale model are applied directly to an upscaled model. This may be valid if correlation lengths are much larger or much smaller than the dimensions of upscaled gridblocks. If correlation lengths are much larger, the model can then be considered as fairly homogeneous, whereas the model can be considered homogeneously heterogeneous when correlation lengths are much smaller. On the other hand, if the sizes of upscaled gridblocks are close to correlation lengths, the loss in accuracy of the upscaled values can be significant (Muggeridge, 1991).

In two-phase upscaling, absolute permeability (or transmissibility), porosity, and relative permeability are upscaled. In some cases, capillary pressure and gravity are considered during upscaling processes. Two-phase flow parameters in both pressure equation (Equation (2-12)) and saturation equation (Equation (2-9)) are modified. Therefore, the saturation of each phase in each upscaled gridblock needs to be determined, normally by a weighted averaging algorithm. The effective absolute permeability is upscaled by a selected single-phase upscaling method. The main focus of two-phase upscaling is a method used to scale up relative permeabilities. Relative permeabilities can be upscaled as effective and pseudo relative permeabilities. The term “effective” describes the physical displacement of fluid and represents the effects of heterogeneities. The “pseudo” term also includes corrections for numerical dispersion (Muggeridge, 1991). The generation of pseudo functions (pseudos) in order to obtain pseudo parameters such as pseudo relative permeabilities is the most common technique in two-phase upscaling. As a result, two-phase upscaling is often called pseudoization.

Pseudo functions are transport relations representing flow through permeable media on a scale larger than a directly measurable scale (Lake et al., 1990). The main purpose of pseudoization is to relate
actual fluid flow rate or flux of each phase to an imposed potential difference on a desired coarser scale. In each block, the flow rate and the applied pressure gradient are a function of the saturation distribution. Pseudo functions are applied for properly weighted and scaled-adjusted transport properties. With the use of pseudo functions, coarse scale models should regenerate the same behaviour as that of the fine scale models. The effects of increased numerical dispersion and decreased details of reservoir description in upscaled models should be overcome. In more complex permeability distributions however, pseudo functions are numerically generated by matching coarse grid and fine grid simulations. Numerical simulations of very detailed fine scale models may not be possible due to limited capabilities of computational hardware. Lake et al. (1990) suggested that pseudo functions, regardless of generating methods, must be independent of times for practical use, may depend on positions, and must depend on averaging scales.

Two-phase upscaling techniques can be divided into two categories: analytical methods based on vertical equilibrium and numerical methods such as dynamic pseudoizations.

**Vertical Equilibrium Upscaling Technique**

Analytical pseudoization techniques based on vertical equilibrium allow the reduction of dimensions of reservoir models from three-dimensional to two-dimensional or from two-dimensional to one-dimensional system when the vertical equilibrium criteria are met (Coats et al., 1971). In the vertical equilibrium, the summation of all fluid driving forces in the direction perpendicular to the flow direction is infinite. This results in capillary-gravitation equilibrium that yields uniform fluid phase potentials. The uniform potentials imply non-uniform saturation and pressure profiles through reservoir thickness. In the vertical equilibrium, the transverse fluid movement is assumed maximum. The vertical equilibrium methods can be used if the flow is dominated by gravity and/or capillary effects. These conditions occur in reservoirs with rapid vertical segregation relative to horizontal flooding rates (i.e. low viscous-gravity ratio or low viscous-capillary ratio).

In gravity dominated flow, the key assumption is an absence of a transition zone. This condition can only be true when the reservoir thickness is very large compared to the transition zone or the capillary pressure is small. In this case, pseudo relative permeabilities are a linear function of the average water saturation. For reservoirs with capillary dominated flow, gravity does not counteract imbibition in the vertical direction. The capillary pressure is constant through any cross section. The vertical equilibrium
can only be applied in reservoirs that capillary effects and/or gravity dominate fluid flow under restricted conditions. In reservoirs with viscous dominated flow, the vertical equilibrium is not applicable.

**Dynamic Upscaling Techniques**

In reservoirs with very high injection rates, pseudos created by the vertical equilibrium method should not be used. Dynamic pseudos, which are flow rate dependent and generated from numerical simulation of fine scale models, are applied. A set of pseudos for every coarse gridblock and every direction results in large quantities of data. Cao and Aziz (1999) classified the methods to generate dynamic pseudo functions into three categories as follows:

**Based on Darcy’s Law**

In this category, each pseudo function considers each phase flow rate following Darcy’s law. Pseudo functions are averaged using various algorithms and weighted factors from the quantities of fine scale models and the results of fine scale simulation. These methods include Jacks et al. (1973), Pore Volume Weighted (Emanuel & Cook, 1974), Kyte and Berry (1975), and Flux Weighted Potential (Guzman et al., 1999).

**Based on Total Mobility**

Pseudo functions can be determined by averaging total mobility and matching pressure or potential gradients between upscaled and fine scale models. The techniques described in Stone (1991), Hewett and Berhens (1991), and Beier (1994) are in this category.

**Based on Streamlines**

This technique is similar to the streamline methods in single-phase upscaling. Stream-tubes are used in single-phase fine scale simulation. Pseudo curves are then generated along the stream-tubes. The method presented by Yamada (1995) and Hastings et al. (2001) are examples of dynamic pseudoization based on streamlines.
Detailed algorithms of dynamic upscaling techniques can be found in the reference papers. The calculations of well-known methods were summarized and reviewed in Barker and Thibeau (1997), Barker and Dupouy (1999), and Cao and Aziz (1999). As dynamic pseudo functions are derived from fine scale simulation, large quantities of data are generated. To reduce the quantities, pseudos are generally grouped and assigned to a limited number of rock types (e.g. one set of pseudos for each flow direction). Dynamic pseudos are dependent on flow conditions where they are derived from. If any condition is changed (e.g. injection rates or well locations), the pseudos needs to be calibrated. This may include the rerun of fine scale simulation with the new conditions.

Cao and Aziz (1999) found that pseudo curves do not always provide better results compared to using rock curves. In addition, all but Jacks et al. (1973) methods do not work well in highly heterogeneous cases due to flow reversal.

**Steady-state Upscaling Techniques**

The methods consider steady-state solutions of two-phase flow equations. The main assumption is the steady-state flow in reservoirs. The steady state can be divided into two cases: capillary equilibrium limit and viscous-dominated steady state. If fluid injection rates are very low, reservoirs can be assumed under the capillary equilibrium. In this equilibrium, water saturation distributions depend on capillary pressure curves. This capillary equilibrium is similar to the vertical equilibrium upscaling in but a different methodology is used to determine pseudos. In reservoirs under the viscous-dominated steady state, capillary pressure and gravity are negligible. The fractional flow of water is constant with time; therefore, water saturations can simply be calculated. Upscaling using the viscous-dominated steady-state method can be applied in reservoirs with high flow rates. Pickup and Stephen (2000) excellently outlined step-by-step procedures to determine effective relative permeabilities for both cases. In general, viscous/capillary ratios are used to identify which force dominates the flow. These ratios may be calculated in numerous ways and the cutoffs are varied. In intermediate viscous/capillary ratios, which are not in neither in capillary equilibrium nor viscous-dominated category, simulations must be conducted to determine water saturations. Thus, the effective relative permeabilities cannot be calculated in a simple way. Furthermore, there is no compensation for numerical dispersion in steady state methods, whereas it can be taken into account in dynamic upscaling methods.
Other Techniques

Upscaling is an ongoing research area. New upscaling algorithms and modified upscaling techniques have been continually published. For example, King et al. (1993) presented the use of renormalization for two-phase upscaling. Christie et al. (1995) extended the method for Water-Alternating-Gas (WAG) floods. Another interesting method is the quasisteady-state technique described in Barker and Dupouy (1999).

2.2.2 Classifications Based on Computation Methods of Upscaled Parameters

Some upscaling techniques described in Section 2.2.1 require solutions of the pressure equation from fine scale grids over target coarse regions. Sablok (2004) classified these computation techniques used in upscaling processes into four categories as follows:

Purely Local

Parameters in a coarse scale block are calculated from a fine scale region corresponding to the target block.

Extended Local

Parameters in a coarse scale grid are determined from a fine scale region corresponding to the target block plus a fine scale border region or skin around this region.

Global

The entire fine scale model is considered to determine parameters in each upscaled block. In each flow scenario, a fine scale simulation is required.
Local-global or Quasi Global

This method is similar to the global method. However the global flow data is approximate. For example, in a quasi global two-phase upscaling case, the flow in a fine scale model might be estimated from a single solution of the single-phase pressure equation.

The purely local method is the easiest computational method because only the region of fine scale cells corresponding to the coarse scale block is considered. However, the method does not consider the flow behaviour in the larger scale. In addition, the technique is system independent as only permeabilities of the fine scale cells are considered. An extended local approach attempts to improve the calculations by including the effects of neighbouring regions. Both local and extended local methods require assumptions of local boundary conditions. On the other hand, global upscaling methods solve the global flow problem and extract the solutions to coarse scale quantities. Both global and quasi-global approaches are therefore system dependent. This can limit the use of the global upscaling techniques in field applications because upscaling of geological models happens at the beginning of new field development projects. Many parameters contain high uncertainties. Once the fields are developed and have sufficient production data, the modifications of the simulation (or upscaled) models in order to match the production history are required. These affect the accuracy of the upscaling methods derived from the global flow. History matching of the geological model may be required to generate an updated upscaled model.

The methods to compute upscaled parameters are ongoing research. New or modified approaches have been published throughout decades including the dual mesh method by Audigane and Blunt (2003), the well drive upscaling by Zhang et al. (2005, 2008), and the adaptive local-global approach by Wen et al. (2005) and by Chen and Durlofsky (2006). More details can be found in their papers.

2.3 Upgridding with Single-phase Upscaling

Two-phase upscaling methods take into account both flow and transport problems. The techniques may have an advantage of reducing numerical dispersion. However, each method has its assumptions and application limitations. In addition, pseudo parameters are strongly system dependent. When reservoir
conditions have changed, pseudo functions must be updated. A new simulation of fine scale models
with updated conditions is required as a result. The repeatedly reruns may not be practical in a very
active field where reservoir conditions have frequently updated. Conversely, single-phase upscaling
techniques only consider the flow problem as the methods only take into account the pressure
equation. Much research focuses on the ways to enhance the quality of single-phase upscaling
methodology by improving techniques of grid generation. Books by Thompson et al. (1985) and Knupp
and Steinberg (1993) discuss applications of grid generation in many areas of scientific and engineering
computing. Grid generation is also called upgridding or upscaling structure in reservoir simulation.

Settari and Aziz (1972) presented three schemes for the finite-difference approximation of \( \frac{\partial}{\partial x} \left( K \frac{\partial u}{\partial x} \right) \)
terms with irregular grids (Figure 2-11(a)). Nacul and Aziz (1991) later conducted truncation error
analysis in irregular systems. Their simulation performed on isotropic homogenous blocks of 15×15,
5×5, 9×9 grids as fine, coarse, and refined (irregular) grid models, respectively. Durlofsky et al. (1994)
applied a non-uniform upgridding approach and a single-phase pressure solver upscaling with periodic
boundary conditions to a highly detailed, heterogeneous two-dimensional reservoir under three flood
displacements: waterflood, steamflood, and miscible flood. In the upgridding process, the main intent is
to capture dominant regions of high fluid velocities. These regions are most likely in high permeability
cells and have significantly impact on production predictions as they are main flow paths. Non-uniform
or irregular coarse grids are assigned based on their potential impacts on flow simulation. For example,
more cells are allocated to high fluid velocity regions such as near-wellbore areas and high permeability
zones. These potentially high flow regions can be estimated from single-phase flow computation. The
results revealed that the non-uniformly coarsened models provided very good agreement with those of
the fine scale models in all displacement methods. Durlofsky et al. (1996) extended the study to fully
three-dimensional systems. The regions of potentially high flow rates were identified by an approximate
three-dimensional solution when flow in the x-direction with side-sealed boundaries (i.e. flow through a
series of non-communicating x – z cross sections). A non-uniformly coarsened model was then created.
Effective permeabilities were determined by single-phase pressure solver upscaling with periodic
boundary conditions. They concluded that using non-uniform gridding may help capturing breakthrough
characteristics and water production rates more accurate.

Upgridding is another active research area in both industry and academia. New algorithms and modified
techniques have been continually presented in literature. In the 1980s, an application of Local Grid
Refinement (LGR) as graphically described in Figure 2-11(b)) was an interesting subject because the refinement only happens in high flow regions without having small blocks in low activity regions as occurred in the irregular gridding technique. However, the LGR technique results in a large and irregular sparse matrix. Nacul et al. (1990) developed an iterative version of the LGR method to improve its efficiency and tested with a three-dimensional, three phase, black oil model of 7x3x5 blocks. The result agreed well with the fine scale model. Edwards et al (1998) initiated a new unstructured grid generation technique based on streamlines and equipotentials. The concentration of gridlines is in high velocity regions, which are identified by streamlines. Non-aligned grids are created (Figure 2-11(c)) and converted to flow-based grids (Figure 2-11(d)). Their results showed a significant improvement in accuracy compared to using conventional Cartesian grids. Durlofsky (2003) stated that in many cases reasonably accurate coarse scale models for two phase flow can probably be developed using only single-phase upscaling method in conjunction with flow-based grid generation.

2.4 Errors in Upscaled Models

Production predictions from any reservoir simulator always contain errors even in homogenous reservoir models. This is due to solving the non-linear second order differential equation by the use of finite difference methods. Truncation or discretisation errors associated with the finite difference
approximation is described by the term “numerical dispersion”. In theory, a displacing phase (e.g. water in water flooding) displaces reservoir fluids by a sharp shock front. Displacement rates depend on mobility ratios, e.g. $M = \frac{k_{rw} \mu_o}{k_{ro} \mu_w}$ in water flooding. In numerical reservoir simulation, numerical dispersion smears out the displacement front and can lead to an early water breakthrough prediction. Numerical dispersion can be reduced by decreasing the size of gridblocks, i.e. small $\Delta x, \Delta y, \text{and} \Delta z$. However, this may require an excessive number of gridblocks in a large reservoir. Besides the discretisation error, upscaling of a heterogeneous reservoir also contains an error from the loss of heterogeneity. This error is introduced by an increase in the homogenisation of the medium. This type of error can lead to delay in water breakthrough, which opposes the effect of discretisation error. The total error in prediction when using upscaled models is a combination of the discretisation error and the error due to the loss of heterogeneity. Because the two errors affects forecasts in the opposite direction, the water breakthrough times can either be underestimated or overestimated depending on which error dominates in the systems. Therefore, the predictions from upscaled models are highly system dependent. The total errors generally increase when the number of blocks in models decreases and/or the permeability contrasts of neighbouring blocks in fine scale grids increase. Sablok and Aziz (2008) investigated these two errors separately. They found that the discretisation error in a randomly heterogeneous medium is a major contribution to the total error. However, in a highly upscaled model, the total error is reduced as a result of the competing effects between the two types of errors. Their conclusion however requires further investigation.

### 2.5 Fluid Flow Behaviours

A variety of fluids are injected into reservoirs to increase recovery efficiency. Each displacing fluid has its specific behaviour and characteristics when it interacts with rock and fluids in the reservoir. Fluid flow behaviours can be classified based on their response to external applied pressure or based on the response under the action of a shear stress (Chhabra & Richardson, 1999). The first scheme leads to compressible and incompressible fluids. In this classification, the compressibility is an important factor in flow behaviours. Gases are generally in the compressible fluid category, whereas liquids can usually be assumed as incompressible fluids. In the second scheme, the behaviours under shear stress are more important than the external applied pressure. This scheme separates fluid to Newtonian and non-Newtonian flow behaviours. We focus on the later classification for our thesis in order to differentiate
between water and polymer flooding. Water has Newtonian flow behaviour, whereas polymer is in non-Newtonian flow category.

2.5.1 Newtonian Fluid Flow Behaviour

Figure 2-12 represents a thin layer of fluid contained between two parallel plates. When a force \( F \) applies to the top plate, the fluid is subjected to shear.

![Figure 2-12: Schematic represents shearing fluid flow - reprinted from Chhabra and Richardson (1999).](image)

For an incompressible Newtonian fluid in laminar flow under steady state conditions, the shear stress, \( \tau \) is the product of the shear rate, \( \gamma \), and the fluid viscosity, \( \mu \) as shown in Equation (2-42). The shear rate is the velocity gradient in the perpendicular direction of the shearing force.

\[
\frac{F}{A} = \tau = \mu \gamma \tag{2-42}
\]

The ratio of the shear stress to the rate, \( \mu \), is the constant of proportionality and is called Newtonian viscosity. This viscosity is independent of shear rate or shear stress and only depends on the material and its temperature and pressure. A plot of shear stress against shear rate for a Newtonian fluid, also known as flow curve or rheogram, is therefore a straight line passing through the origin. Water is an example of a Newtonian fluid. Its viscosity is not changed when it is stirred.

2.5.2 Non-Newtonian Fluid Flow Behaviour

The simplest description of non-Newtonian fluids is one whose behaviour is not Newtonian. That means that their flow curves are not linear and/or do not pass through the origin. Shear stress divided by shear rate is called an apparent viscosity and is not constant at a given temperature and pressure. Non-
Newtonian fluid behaviour can be divided into three categories: time-independent, time-dependent, and viscoelastic. Fluids whose properties are a combination of more than one class are described as complex fluids.

**Time-independent Fluid Flow Behaviour**

This group comprises fluids whose shear rate at any point is solely determined by the instantaneous shear stress at that point. The time independent fluid behaviour, also called purely viscous, inelastic, or generalized Newtonian fluids, consists of shear-thinning (pseudoplastic), viscoplastic (Bingham), and shear-thickening (dilatants) fluids.

Shear-thinning fluids are the most common type of the time-independent non-Newtonian fluid behaviour. An apparent viscosity decreases with increasing shear rate and no yield stress involved. Most shear-thinning polymer solutions exhibit Newtonian flow behaviour at very low or very high shear rates (Chhabra & Richardson, 1999). In shear-thickening fluid flow behaviour, the more the shear rate increases, the higher the apparent viscosity is. Lastly, the viscoplastic behaviour is observed if a fluid is deformed or flows only after its yield stress is exceeded. If the externally applied stress is smaller than the yield stress, a material will deform elastically or behave as a rigid body. The flow curves of viscoplastic materials can be either linear or non-linear but do not intercept the origin. Toothpaste is a good example of viscoplastic fluids. The rheological behaviours of the three time-independent fluids are illustrated in Figure 2-13.
Time-dependent Fluid Flow Behaviour

This group consists of fluids whose relationship between shear stress and shear rate depends additionally on the duration of shearing, their kinematic history, and possibly on the time lapse between consecutive applications of stress. This type of flow behaviour includes work softening (thixotropic) and work hardening (rheopectic or antithixotropic). A fluid is thixotropic if its apparent viscosity decreases with the time of shearing when it is sheared at a constant rate. Protein solutions are examples of thixotropic fluids (Barnes, 1997). If the apparent viscosity of a fluid increases with shearing time at a given strain rate and constant temperature, it displays rheopexy or antithixotropy. An illustration of rheopectic behaviour is whipped cream.

Viscoelastic Fluid Flow Behaviour

The characteristics of both ideal fluids and elastic solids are exhibited in viscoelastic fluids. The fluids show partial elastic recovery after deformation. Egg white is an example of viscoelastic behaviour.
2.6 Polymer Flooding

Polymer flooding is a mature EOR technique. The first patent related to an injection of viscous fluids was awarded to Detling in 1944 (Detling, 1944). Extensive research and development in polymer flooding technologies and applications have been conducted since then. Several books dedicated to polymer flooding include those by Littmann (1988) and Sorbie (1991). Chapter eight of “Enhanced oil recovery” by Lake (1989) and Chapter seven of “Enhanced oil recovery - SPE textbook series” by Green and Willhite (1998) are excellent introductions to the polymer flooding process.

The mobility ratio is the mobility of the injected fluid divided by that of the displaced fluid. The water-oil mobility ratio \( M \) is defined as:

\[
M = \frac{\lambda_w}{\lambda_o} = \frac{k_{rw}}{\mu_w} = \frac{k_{rw} \mu_o}{k_{ro} \mu_w}
\]  

(2-43)

Where \( \lambda_w \) is the water mobility and \( \lambda_o \) is the oil mobility. The mobility ratio affects both displacement and volumetric sweep efficiency. The higher efficiency, the more oil production.

The volumetric sweep efficiency is the product of an areal sweep efficiency and a vertical sweep efficiency. Littmann (1988) demonstrated that the areal sweep efficiency increases with decreasing mobility ratio. Adding polymer to injected water helps increase its viscosity \( \mu_w \), hence decrease its mobility \( \lambda_w \) and the mobility ratio. Polymer flooding can therefore improve the volumetric sweep efficiency.

The displacement efficiency for oil is determined by the amount of oil displaced divided by the amount of oil contacted by displacing agent. The displacement of one fluid by an immiscible second fluid is solved by multiphase flow equations (Section 2.1.2). For the isothermal flow of oil and water in two immiscible, incompressible phases in a one-dimensional permeable medium, the multiphase flow equations reduce to

\[
\frac{\partial S_w}{\partial t} + u_t \frac{\partial f_w}{\partial x} = 0
\]  

(2-44)
Equation (2-44) is known as the Buckley-Leverett equation. For two immiscible fluids, oil and water, and in the absence of capillary pressure, the fractional flow of water \( f_w \) is

\[
 f_w = \frac{\lambda_w}{\lambda_w + \lambda_o}
\]  

The fractional flow of the injected fluid reduces when its mobility decreases. This increases the fractional flow of oil. The displacement efficiency of oil increases as a result. Polymers decrease the mobility of injected fluid. Consequently, the oil displacement efficiency improves.

Sorbie (1991) explained how injecting polymer helps improve sweep efficiency of a layered system (Figure 2-14 (left)). AlSofi (2011) extended it to illustrate non-Newtonian effects (Figure 2-14 (right)). This figure is an illustration based on theory not simulation results. In this simple system of three layers, the middle layer has the highest permeability. Displacing fluids are injected from the left side and producers are on the right side. When water is injected (top-left model), the water flows very fast in the middle layer and reaches the producer first. The shock fronts in all three layers are not exactly perpendicular to the flow direction. Polymer injection can help improve vertical sweep but it still exhibits some contrasts between the layers (bottom-left model). The contrasts are worst if the polymer has shear-thinning behaviour (top-right model). The best case is when the polymer has shear-thickening behaviour (bottom-right model). In this case, the velocity contrasts between layers are the lowest. This is due to an increase in apparent viscosity of injected fluid in the high permeability layer. The higher the permeability, the higher the flow velocity and the higher the shear rate.
**Polymer Types and Properties**

Polyacrylamides and polysaccharides are the two main types of polymers used in EOR. In polymer flooding, polyacrylamides are called partial hydrolysed polyacrylamides or HPAM. The molecular structures are shown in Figure 2-15. The viscosity increase arises from the large molecular weight of HPAM. The degree of hydrolysis is chosen to optimise solution properties e.g. water solubility, viscosity, and retention. Polymer is not water soluble if hydrolysis is too small. On the other hand, if hydrolysis is too large, the properties of polymer are too sensitive to salinity and hardness (Shupe, 1981). Although HPAM is inexpensive and can withstand bacterial attack, this sensitivity precludes its applications to many reservoirs (Lake, 1989).

![Structure of Polyacrylamide](image)

Figure 2-15: Molecular structure of polyacrylamide and hydrolysed polyacrylamide - reprinted from Willhite and Dominguez (1977).

Polysaccharide or xanthan (molecular structure shown in Figure 2-16) has an advantage of insensitivity to brine salinity and hardness. Being biopolymer however, polysaccharide is subjected to bacterial attack in the reservoir.
Most polymers used in EOR processes have a shear-thinning effect (AlSofi, 2011). The shear thinning behaviour of polymer solution is caused by the uncoiling and unsnagging of the polymer chains when they are elongated in shear flow (Lake, 1989). Only a few studies conducted were on shear-thickening polymers even though shear-thickening polymers theoretically offer the best in terms of enhanced sweep efficiency. This may due to less favourable injectivity and/or lack of shear-thickening polymers (AlSofi, 2011).

Polymers have been used in many industries. Research and development of polymers are generally in chemical engineering and materials departments. New classes of polymers have frequently been introduced to oil field applications with the main intent of improving recovery efficiency. Hydrophobically modified, water-soluble polymers (or associative polymers) are examples of new promising polymers introduced in petroleum industry (Tripathi et al., 2006). In aqueous solutions, associative polymers form a three-dimensional network structure that can significantly increase the viscosity of the polymer solutions. In addition, associative polymers are less sensitive to brine salinity compared to a conventional polymer solution, as compared to HPAM. Associative polymers exhibit complex rheological behaviours. They have shear-thickening effect at moderate shear rates in steady shear flow followed by marked shear-thinning at high shear rate. Rheology and dynamics of associative polymers in shear and extension are examined in Tripathi et al. (2006).
2.7 Upscaling for Polymer Flooded Reservoirs

Research in upscaling focuses mainly on reservoirs under water flooding, which are Newtonian fluids. Thus far, no research into polymer flow behaviour in porous media at various simulation scales has yet been found in the literature. We proposed an investigation of the impact of upscaling in polymer flooding with non-Newtonian fluids. The majority of polymers used in EOR have shear-thinning behaviour. Some polymers are shear-thickening. A few commercial reservoir simulators have limited abilities to model both behaviours. ECLIPSE from Schlumberger is the main simulator used in our research. The simulator can perform simulations of polymer flooded reservoirs using the power law rheological model. More details are in the next chapter.

2.8 Summary

Polymer flooding projects involve high investment. Detailed assessments of project risks and uncertainties are required. The process involves a study of numerous scenarios that can occur in reservoirs. In most cases, upscaling is necessary. The majority of upscaling methods were reviewed in this chapter.

Many upscaling approaches have been developed with the main intent of reducing errors in predictions. Limitations in each method may make the technique not practical or possible in full field simulations. An example is when simulations of full field models are required every time when reservoir conditions have changed. Errors from using upscaled models in simulations contribute to uncertainties in production forecasts. A proper decision in any field development project can only be achieved if the effect of upscaling errors and its impact in production forecasts are well captured. In other words, an ignorance of significant upscaling errors can lead to a wrong decision in project investment.

All methods in literature are for water flooding and may not be suitable for evaluating polymer flooding. In practice, purely local single-phase upscaled parameters are often used in full field simulations. Although the understanding of upscaling errors is very important in decision making, an assessment of using single-phase upscaled models in two-phase non-Newtonian flow problems is limited. We decided to conduct our research in polymer flooding.
MODEL CONSTRUCTION AND VERIFICATION

In this chapter, we give the equations for polymer flooded modelling. We verify the use of the simulator for the injection of non-Newtonian fluids. This is to ensure that the simulator can be used to model various displacement processes. We then create simple models of layered systems to investigate the results between using layered permeabilities and using an effective permeability. We also study the effect of non-Newtonian flow behaviour in layered systems.

3.1 Flow Equations for the Black Oil Model

The black oil model consists of three components: water, pseudo surface oil component of fixed composition, and pseudo surface gas component of fixed composition. In this model, it is assumed that no mass transfer takes place between the water phase and the other two phases. In undersaturated oil reservoirs, hydrocarbon contains oil and gas in solution. Saturated oil reservoirs are made of oil, gas in solution and possibly some free gas.

The material balance equation in each gridblock is written between the start and the end of each time step as follows:
mass exchange between blocks + production or injection = accumulation mass rate

\( (3-1) \)

This leads to three mass balance equations:

**Water:**

\[
\nabla \cdot \left( \frac{K_{krw}}{\mu_w B_w} (\nabla P_w - \rho_w g \nabla D) \right) + q_w = \frac{\partial}{\partial t} \left( \phi S_w \right) / B_w
\]

\( (3-2) \)

**Oil:**

\[
\nabla \cdot \left( \frac{K_{kro}}{\mu_o B_o} (\nabla P_o - \rho_o g \nabla D) \right) + q_o = \frac{\partial}{\partial t} \left( \phi S_o \right) / B_o
\]

\( (3-3) \)

**Gas:**

\[
\nabla \cdot \left( \frac{K_{krp}}{\mu_g B_g} (\nabla P_g - \rho_g g \nabla D) \right) + \frac{\partial}{\partial t} \left( \phi \left( \frac{S_g}{B_g} + \frac{R_s S_o}{B_o} \right) \right) + q_g
\]

\( (3-4) \)

**Additional equations:**

\[
S_w + S_o + S_g = 1
\]

\( (3-5) \)

\[
P_w = P_o - P_{c,ow}
\]

\( (3-6) \)

\[
P_g = P_o + P_{c,og}
\]

\( (3-7) \)

In gas reservoirs, the dissolved condensate \((R_p)\) is used symmetrically to the solution gas \((R_s)\) in oil reservoirs. With the three equations \((3-2)\) to \((3-4)\) and three independent variables \((P_o, S_w, S_g, R_s, R_p)\), the solution can be obtained.

### 3.2 ECLIPSE 100 Black Oil Model for Polymer Flooding

Several commercial reservoir simulators have the ability to model polymer flooding including ECLIPSE 100 from Schlumberger and STARS from CMG. Both simulators have similar physical and mathematical models as well as assumptions. ECLIPSE 100, a fully implicit, three-phase, three-dimensional black oil simulator, is chosen for this research. It allows an investigation of the polymer flooding efficiency at varying brine concentrations and non-Newtonian flow. The study of the interaction of brine with the
polymer solution is possible. ECLIPSE version 2010.1 (Schlumberger, 2010) ignores the effect of temperature variations on the behaviour of the polymer solution. Mathematical models for polymer flooding are explained in this section.

3.2.1 Conservation Equations

The conservation equations of the hydrocarbon phases (Equations 3-3 and 3-4) are unchanged under the assumption that the flow of the polymer solution through the porous medium has no influence on the flow of the hydrocarbon phases. Modification is however required to the conservation equation of the water phase (Equation 3-2) because the polymer solution is modelled as a soluble component in the aqueous phase. Since the properties of polymer solution may depend on the salinity of the aqueous phase, a salt conservation equation is also applied. In polymer flood modelling, Equation (3-2) is therefore replaced by three equations as follows:

Water:
\[
\nabla \cdot \left( \frac{K k_{rw}}{\mu_{w,eff} B_w R_k} (\nabla P_w - \rho_w g \nabla D) \right) + q_w = \frac{\partial}{\partial t} \left( \frac{\phi S_w}{B_w} \right) \tag{3-8}
\]

Polymer:
\[
\nabla \cdot \left( \frac{K k_{rw}}{\mu_{p,eff} B_w R_k} (\nabla P_w - \rho_w g \nabla D)C_p \right) + q_w C_p = \frac{\partial}{\partial t} \left( \phi \frac{S_w}{B_w} C_p + (1 - \phi) \rho_p C_p^a \right) \tag{3-9}
\]

Salt:
\[
\nabla \cdot \left( \frac{K k_{rw}}{\mu_{w,eff} B_w R_k} (\nabla P_w - \rho_w g \nabla D)C_b \right) + q_w C_b = \frac{\partial}{\partial t} \left( \phi \frac{S_w}{B_w} C_b \right) \tag{3-10}
\]

Where

- \(B_j\) Formation volume factor of phase \(j\) fraction
- \(C_i\) Mass concentration of component \(i\) kg/m\(^3\)
- \(C_i^a\) Adsorbed mass concentration of component \(i\) kg/m\(^3\)
- \(D\) Cell center depth m
- \(g\) Gravitational acceleration (= 9.80665) m/s\(^2\)
- \(K\) Absolute permeability tensor mD
- \(k_{r,j}\) Relative permeability of phase \(j\) mD
- \(P_w\) Pressure Pa
- \(q_i\) Volumetric flow rate in layer \(i\) m\(^3\)
- \(R_k\) Relative permeability reduction factor due to polymer retention fraction
- \(S_j\) Volumetric saturation of phase \(j\) fraction
- \(\mu_{j,eff}\) Effective viscosity after mixing of phase \(j\) Pa.s
- \(\rho_j\) Density of phase \(j\) kg/m\(^3\)


\[ \rho_r \] Density of rock \[ \text{kg/m}^3 \]
\[ \phi \] Porosity \[ \text{fraction} \]

Subscripts

\( b \) Brine
\( o \) Oil
\( p \) Polymer
\( w \) Water

The model assumes that the density and formation volume factor of the aqueous phase are independent of the polymer and salt concentrations. This modification does not take into account non-Newtonian flow behaviour. A further modification for non-Newtonian fluid flows can be found in Section 3.2.3.

During a polymer flood, retention of the polymer in the porous medium may occur due to adsorption on the rock surface and mechanical entrapment of some of the large molecules at the entrance to small pore throats. This causes a reduction in the relative permeability of the polymer solution. The reduction in permeability to the polymer solution is assumed proportional to the quantity of polymer lost to the rock material. The relative permeability of water is therefore permanently reduced after the passage of the polymer. The permeability of the rock to the oil is assumed to be unaffected by the polymer retention. The \( R_k \) term in Equation (3-8) to (3-10) represents the relative permeability reduction factor due to polymer retention.

Fluids in the aqueous phase are considered as miscible components where the viscosity terms in the conservation equations are specified by the degree of mixing. The effective salt component viscosity is set equal to the effective water viscosity in Equation (3-10). \( C_p, C_b \) denote to the polymer and salt concentrations in the aqueous phase, respectively. Some part of the pore space may be inaccessible for large polymer molecules. This results in the reduction of porosity available to polymer, which is represented by \( \phi^* \). The \( \frac{\partial}{\partial t} \left( (1 - \phi) \rho_r C_p^a \right) \) term in Equation (3-9) represents the additional mass accumulation due to polymer adsorption.
3.2.2 Constitutive Models

The effective viscosities use a Todd and Longstaff (1972) mixing model as derived in Bondor et al. (1972). The following expressions are used in ECLIPSE:

Effective polymer viscosity:
\[
\mu_{p,\text{eff}} = \mu_m^{\omega} \mu_p^{1-\omega}
\]  
(3-11)

Effective water viscosity:
\[
\frac{1}{\mu_{w,\text{eff}}} = \frac{1 - \bar{C}}{\mu_{w,e}} + \frac{\bar{C}}{\mu_{p,\text{eff}}}
\]  
(3-12)

Where
\[
\mu_{w,e} = \mu_m^{\omega} \mu_w^{1-\omega}
\]  
(3-13)

and
\[
\bar{C} = \frac{C_p}{C_p^{\text{max}}}
\]  
(3-14)

The viscosity of a fully mixed water and polymer solution as an increasing function of the polymer concentration in solution, \(\mu_m\), is required as an input. The viscosity of the polymer solution at the maximum polymer concentration, \(\mu_p\), is also required. The Todd-Longstaff mixing parameter, \(\omega\), is used to model the degree of segregation between the water and the polymer solution. If \(\omega = 1\), the water and polymer solution are fully mixed in each block. If \(\omega = 0\), the polymer solution is completely segregated from the water.

The polymer adsorption term, \(C_p^a\), in Equation (3-9) can be specified as a look-up table of absorbed polymer as a function of the polymer concentration or a generic analytical adsorption model depends upon the brine salinity and the rock permeability.

The mobility of the aqueous phase is reduced due to an increase in viscosity and a reduction in the relative permeability of water. The adsorption process that causes a reduction in the relative permeability is assumed to be proportional to the amount of polymer adsorbed on the rock. The reduction in the relative permeability due to polymer retention is expressed as

\[
R_k = 1 + (RRF - 1) \frac{C_p^a}{C_p^{a,\text{max}}}
\]  
(3-15)
It is necessary to specify the residual resistance factor, $RRF$, for each rock type and the maximum adsorbed concentration, $C_{p,\text{max}}$.

The dead pore volume, which is the part of the pore space where polymer cannot flow due to molecular size relative to the pore throat size, must be specified. This inaccessible pore space, $\phi_{ipv}$, is assumed to be constant for each rock type, reducing the porosity available to polymer, $\phi^*$:

$$\phi^* = \phi - \phi_{ipv}$$ \hspace{1cm} (3-16)

### 3.2.3 Non-Newtonian Fluid Flows

ECLIPSE offers two options to model the non-Newtonian flow behaviour of the polymer solution. The first option can only model the shear-thinning behaviour of polymer where the polymer viscosity decreases with increasing shear rate. The model assumes that shear rate is proportional to the flow viscosity without taking into account the rock permeability. This research opts for the second option where the shear rate dependence is modelled by applying the Herschel-Bulkley model (1926). The Herschel-Bulkley equation is commonly written as

$$\tau = \tau_o + C\gamma^n$$ \hspace{1cm} (3-17)

Where $\tau$ is the shear stress, $\tau_o$ denotes a yield stress, $C$ is a consistency constant, $\gamma$ is the shear rate, and $n$ is the power law exponent. The value of $n$ governs the fluid behaviour: shear-thinning ($n < 1$), Newtonian ($n = 1$), and shear-thickening ($n > 1$). The Herschel-Bulkley model reduces to the power law model when the yield stress is zero.

Both shear-thinning and shear-thickening flow behaviour of polymer can be modelled in the second option. In this option, Darcy’s law in the conservation equation of the polymer solution is modified for non-Newtonian fluid flow simulation. The Herschel-Bulkley fluid modifier, $B$, is added to the Darcy equation:

$$Q = \frac{AKr}{\mu L} B \Delta P$$ \hspace{1cm} (3-18)
\[ B = \begin{cases} \frac{\left(1 - \frac{d\tau_0}{|\Delta P|}\right)}{12 \left(9 + \frac{3}{n}\right)^{\frac{n}{2}} (72\delta K)^{1-n}} \left(\frac{|Q|}{A}\right)^{1-n}, & \text{if } \frac{d\tau_0}{|\Delta P|} < 1 \\ 0, & \text{otherwise} \end{cases} \quad (3-19) \]

\[ \alpha = \sqrt{\frac{\phi}{2}} \sqrt{\frac{T}{K}} \quad (3-20) \]

Where:

- \( A \) Area through which flow occurs \( \text{m}^2 \)
- \( B \) Herschel-Bulkley fluid modifier
- \( C \) Power law coefficient \( \text{mPa.s}^n \)
- \( K \) Rock permeability in a given direction \( \text{mD} \)
- \( k \) Permeability tensor (symmetric positive definite) \( \text{mD} \)
- \( k_r \) Relative permeability \( \text{mD} \)
- \( L \) Total length \( \text{m} \)
- \( n \) Power law exponent
- \( P \) Pressure \( \text{Pa} \)
- \( \tilde{q} \) Volumetric flow rate \( \text{m}^3 \)
- \( u \) Darcy velocity \( \frac{\tilde{q}}{A} \) \( \text{m/s} \)
- \( x \) Distance in \( x \)-direction \( \text{m} \)
- \( \alpha \) Weighing factor for the yield stress \( \text{fraction} \)
- \( \delta \) Tortuosity \( \text{fraction} \)
- \( \mu \) Viscosity \( \text{Pa.s} \)
- \( \tau_o \) Yield stress \( \text{Pa} \)
- \( \phi \) Porosity \( \text{fraction} \)

As \( B \) depends on the flow rate, the equations for both the flow between two adjacent cells and the flow at the connections between the well and the reservoir need to be solved. The rheological parameters, tortuosity (\( \delta \)), yield stress (\( \tau_o \)), and power law exponent (\( n \)), are set as a function of polymer concentration to allow spatial distribution of the fluid properties in the reservoir. Non-Newtonian rheology modelling can significantly increase the CPU time because the calculation of viscosity has non-linearity resulting from the velocity-dependent viscosity (Schlumberger, 2010).

We have noticed that the shear rate is not required as a simulation input. Other simulators such as STARS (CMG, 2010) have an option to enter polymer viscosity as a function of shear rate. Only three parameters, \( \delta, \tau_o, n \), as a function of the polymer concentration are required. Although the ECLIPSE manual does not mention the absence of the shear rate, Fadili et al. (2009) made a reference to a paper by Al-Fariss and Pinder (1984). In that paper, Equation (3-17) is replaced by a simplified form of the flow of a Herschel-Bulkley fluid in long straight capillary tubes. Based on their assumptions, the shear rate is substituted by other parameters including pressure drop and flow area. Full details can be found in Al-
Fariss and Pinder (1984). The final equations in Al-Fariss and Pinder (1984) are similar to the equations used in ECLIPSE. We believe that ECLIPSE has adapted the method derived in Al-Fariss and Pinder (1984) with some unpublished modifications.

3.3 Parameters for All Models

All models are constructed based on the second dataset of the Tenth SPE Comparative Solution Project (Christie & Blunt, 2001) as shown in Table 3-1, Table 3-2, and Figure 3-1. Additional parameters including the permeability field, porosity, and the properties of fluid injection, which are varied in each case study, are described in its section.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Symbols</th>
<th>Values</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water formation volume factor</td>
<td>(B_w)</td>
<td>1.01</td>
<td></td>
</tr>
<tr>
<td>Water compressibility</td>
<td>(c_w)</td>
<td>4.35×10^{-4}</td>
<td>MPa^{-1}</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>(\mu_w)</td>
<td>0.3</td>
<td>mPa.s</td>
</tr>
<tr>
<td>Reservoir depth</td>
<td></td>
<td>3658</td>
<td>m</td>
</tr>
<tr>
<td>Surface density of oil</td>
<td>(\rho_o)</td>
<td>849</td>
<td>kg/m^3</td>
</tr>
<tr>
<td>Surface density of water</td>
<td>(\rho_w)</td>
<td>1026</td>
<td>kg/m^3</td>
</tr>
<tr>
<td>Rock compressibility</td>
<td>(c_r)</td>
<td>1.45×10^{-4}</td>
<td>MPa^{-1}</td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td></td>
<td>41</td>
<td>MPa</td>
</tr>
<tr>
<td>Maximum injection bottomhole pressure</td>
<td></td>
<td>69</td>
<td>MPa</td>
</tr>
<tr>
<td>Producer bottomhole pressure</td>
<td></td>
<td>28</td>
<td>MPa</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pressure (MPa)</th>
<th>Oil formation volume factor, (B_o)</th>
<th>Oil viscosity, (\mu_o) (mPa.s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.07</td>
<td>1.05</td>
<td>2.85</td>
</tr>
<tr>
<td>5.52</td>
<td>1.02</td>
<td>2.99</td>
</tr>
<tr>
<td>55.16</td>
<td>1.01</td>
<td>3.00</td>
</tr>
</tbody>
</table>
In ECLIPSE, the viscosity of a fully mixed water and polymer solution is entered as a function of polymer concentration by the keyword - PLYVISC. We apply the viscosity distribution of 7 million molecular weight HPAM in 2.52% total dissolved solids brine from Seright (2010) to our models (Figure 3-2). The concentration of 1000 ppm is approximately 1 kg/m$^3$. ECLIPSE determines the viscosity of the solution by multiplying the water viscosity with the corresponding factor. In our case, the solution viscosity is equal to 3 mPa.s at an injected polymer concentration of 1 kg/m$^3$ as the water viscosity is 0.3 mPa.s.
3.4 Verification of non-Newtonian Fluid Flows in a Two-dimensional Homogenous Model

Before investigating the effects of non-Newtonian flow behaviour at various grid scales in more complex reservoirs, we first study its impact in a simple model with the same parameters to be used in the complex models except porosity and permeability fields. In previous versions, ECLIPSE can only simulate models with shear-thinning effects by multiplying shear-thinning factors as a function of aqueous phase velocity. The multiplier must be decreased monotonically when the aqueous phase velocity increases. Thus, shear-thickening rheology could not be modelled. In ECLIPSE 2010.1, an option to model non-Newtonian fluid by the Herschel-Bulkley fluid model is offered. This rheological model is capable of modelling both shear-thinning and shear-thickening flow behaviour. Using a simple two-dimensional homogenous model, we are able to verify whether the simulator has an ability to generate proper results for non-Newtonian flow behaviour, especially for shear-thickening polymer flooding.

Table 3-3: Input parameters for the two-dimensional homogenous model

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Symbols</th>
<th>Values</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>( \phi )</td>
<td>0.20</td>
<td></td>
</tr>
<tr>
<td>Permeability (isotropic)</td>
<td>( k )</td>
<td>50</td>
<td>mD</td>
</tr>
<tr>
<td>Number of gridblocks</td>
<td>( N_x \times N_y \times N_z )</td>
<td>128×128×1</td>
<td>cells</td>
</tr>
<tr>
<td>Size of gridblocks</td>
<td>( dx \times dy \times dz )</td>
<td>6.1×6.1×6.1</td>
<td>m</td>
</tr>
<tr>
<td>Injection rate</td>
<td>( Q )</td>
<td>0.003</td>
<td>PV/d</td>
</tr>
<tr>
<td>Injected polymer concentration</td>
<td>( C_p )</td>
<td>1</td>
<td>kg/m³</td>
</tr>
<tr>
<td>Todd-Longstaff mixing parameter</td>
<td>( \omega )</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Viscosity of fully mixed solution</td>
<td>( \mu_m )</td>
<td>3</td>
<td>mPa.s</td>
</tr>
<tr>
<td>(at 1 kg/m³ polymer concentration)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power law exponent for polymer rheology</td>
<td>( n )</td>
<td>0.5 for shear-thinning</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>1 for Newtonian</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>2 for shear-thickening</td>
<td></td>
</tr>
<tr>
<td>Polymer adsorbed by the rock formation</td>
<td></td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Dead pore volume</td>
<td></td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Salt concentration</td>
<td></td>
<td>0</td>
<td>kg/m³</td>
</tr>
</tbody>
</table>

We build a 128×128×1 homogenous model to understand its physics when injecting various fluid rheologies. Input parameters are shown in Table 3-3. For shear-thinning polymer, the power law exponents are between zero and one. We choose the midpoint for our study. The power law exponent of shear-thickening polymer can be any number greater than one. For our study, we select two, which we found in literature including AlSofi (2011). We generate a quarter five-spot pattern by injecting at
one corner of the model via an injector (I1) and produce at the diagonal corner via a producer (P1). Three scenarios with different injected fluids are monitored for 1,000 days or three pore volume injection. Figure 3-3 shows the results from this simulation. The effective polymer viscosity profiles (top left) monitored at the producer shows the effective polymer viscosities after 3 PVI of 5.1 mPa.s, 3 mPa.s, and 2.4 mPa.s for shear-thickening, Newtonian, and shear-thinning cases, respectively. As the input viscosity of the fully mixed solution is 3 mPa.s, the results verifies that the solution viscosity of Newtonian fluid remains the same while the effective viscosity is less in the shear-thinning case and more in the shear-thickening case. The top right figure shows oil production rates. The shear thinning injection gives the peak oil rate very slightly sooner. This is due to the least effective viscosity of the displacing phase. The shear-thinning injected fluid reaches the producer early and leads to the earliest water breakthrough (bottom left). The shear-thickening fluid offered a slightly better sweep efficiency because of a higher effective viscosity. Although the oil peak comes later, the delay of the water breakthrough provides the highest oil recovery efficiency.
Figure 3-3: Simulation results of the 128×128 homogenous model under various fluid rheologies.

Figure 3-4 shows the saturation profiles after 0.6 PVI of shear-thinning, Newtonian, and shear-thickening fluids. This top view of the models has the injector at the bottom right corner and the producer at the top left. The shear-thinning fluid arrives at the producer fastest and leads to early water breakthrough and the least sweep efficiency. This impact is solely from shear effects as the other parameters are the same. Figure 3-5 shows the viscosity profiles after 0.6 PVI of three different fluid displacements. In the Newtonian case, the viscosity of the displacing fluid remains the same as input at 3 mPa.s. The viscosity in the shear-thickening case is greater than 3 mPa.s, whereas the viscosity is less 3 mPa.s in the shear-thinning case.
Figure 3-4: Saturation profiles of the 128x128 homogenous model after 0.6 PVI under (a) shear-thinning (b) Newtonian (c) shear-thickening polymer flooding.

Figure 3-5: Viscosity profiles of the 128x128 homogenous model after 0.6 PVI under (a) shear-thinning (b) Newtonian (c) shear-thickening polymer flooding.

Although Figure 3-5 confirmed that the viscosity of the injected fluid is dependent on the power law exponent in the rheological model due to the shear rate dependency, we further investigated the shear effects by studying the relationship between viscosity and velocity for each fluid injection. A MATLAB script was written to extract the total velocity and polymer viscosity of each gridblock and plot them against each other. Figure 3-6 is a log-log plot of the polymer viscosity with respect to the total velocity at 0.6 PVI. In the Newtonian case, the viscosity remains constant regardless of the velocity. When the fluid velocity increases, the viscosity also rises in the shear-thickening case, whereas the opposite
response is found in the shear-thinning case. The results confirm that that the simulator has the ability to model shear-thickening, shear-thinning, and Newtonian fluid injection.

![Graph showing viscosity as a function of velocity with different fluid rheologies.]

Legend

<table>
<thead>
<tr>
<th>Legend</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pink</td>
<td>2D homogenous model, quarter 5-spot pattern, shear-thinning polymer flooding ((n = 0.5)), injection rate of 0.003 PV/d</td>
</tr>
<tr>
<td>Blue</td>
<td>2D homogenous model, quarter 5-spot pattern, Newtonian flooding ((n = 1)), injection rate of 0.003 PV/d</td>
</tr>
<tr>
<td>Green</td>
<td>2D homogenous model, quarter 5-spot pattern, shear-thickening polymer flooding ((n = 2)), injection rate of 0.003 PV/d</td>
</tr>
</tbody>
</table>

Figure 3-6: A log-log plot of viscosity as a function of velocity after 0.6 PVI of various fluid rheologies.

### 3.5 Model Verification in Layered Systems

We created simple models of layered systems for parallel and serial flow studies. We determined the effective permeability from analytical solutions. We applied the effective permeability to all gridblocks to generate a homogenous model with that effective permeability. We then analysed the simulation results obtained from a layered model and a homogenous model. After this verification, the same set of parameters was applied to more complex models for further studies.

For horizontal, linear, incompressible, Newtonian fluid flow, the effective permeability was determined analytically as follows:
Parallel flow: \[ k_{\text{eff}} = \frac{\sum k_i h_i}{\sum h_i} \text{ arithmetic average} \]

Serial flow: \[ k_{\text{eff}} = \frac{\sum l_i}{\sum \frac{1}{k_i}} \text{ harmonic average} \]

Where
- \( h_i \): Thickness of cell \( i \)
- \( k_{\text{eff}} \): Effective permeability
- \( k_i \): Permeability of cell \( i \)
- \( l_i \): Length of cell \( i \)

### 3.5.1 Verification for Newtonian Fluid in Parallel Flow Pattern

We built a 10×10 gridblock model with the same parameters as in Section 3.3 and additional parameters from Table 3-4. The model was layered with an isotropic permeability in each layer. The permeability of each layer are from 35 to 75 mD (Figure 3-7(a)). Polymer solution was injected to all layers through an injector (I1) on the left side and all layers are produced through a producer (P1) on the right side. We assumed a no flow boundary condition from the top and bottom layers. This gave a parallel flow pattern. The injected fluid was assumed to be Newtonian flow with no effect of polymer adsorption. Analytical solutions for parallel flow of Newtonian fluid can be obtained by applying an effective permeability calculated by Equation (3-21) to all gridblocks (Figure 3-7(b)). Figure 3-8 compares the simulation results between the 10-layered model and the homogenous model with the effective permeability. A good match was obtained for oil recovery efficiency. The breakthrough times were slightly different because of the variety of permeabilities in the 10-layered model. In the 10-layered model, the injected fluid flows faster in high permeability layers hence reaches the producer earlier than in the homogenous model. This is also confirmed by the water saturation profiles in Figure 3-9. Besides the breakthrough times, the water cut predictions were very close.
Table 3-4: Input parameters for parallel flow study

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Symbols</th>
<th>Values</th>
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<tr>
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<td>PV/d</td>
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<tr>
<td>Injected polymer concentration</td>
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<td>kg/m$^3$</td>
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<td>Dead pore volume</td>
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<tr>
<td>Salt concentration</td>
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Figure 3-7: Permeability fields for parallel flow simulation: (a) model with 10 layers (b) model with an effective permeability.
Figure 3-8: Comparison of water cut and oil recovery predictions between the 10-layered model and the homogenous model with the effective permeability under Newtonian fluid parallel flow.

Figure 3-9: Water saturation profiles after 0.30 PV injected of Newtonian fluid parallel flow: (a) model with 10 layers (b) model with an effective permeability.

3.5.2 Verification for Newtonian Fluid in Serial Flow Pattern

We studied flow behaviour of Newtonian fluid in serial layers using similar input parameters and same assumptions as for the parallel flow study. A 10×1×1 gridblock model with parameters from Section 3.3 and additional parameters in Table 3-5 was created. Figure 3-10 shows permeability fields of a 10-layered model and a homogenous model with an effective permeability used in this study. The effective
permeability was calculated by the harmonic average (Equation (3-22)). Polymer solution was injected via an injector (I1) and produced by a producer (P1). We assumed a no flow boundary condition at the top and bottom layers. This created a serial flow pattern. The displacing fluid was assumed to be Newtonian with no polymer adsorption. Figure 3-11 shows that the predictions of water cut and oil recovery efficiency from the 10-layered model and the homogenous model are perfectly matched. Both models gave the same water breakthrough time, unlike the parallel flow case, because the layers were perpendicular to the flow direction.

**Table 3-5: Input parameters for serial flow study**

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<th>Parameters</th>
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<td></td>
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<tr>
<td>Permeability</td>
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<td>Figure 3-10</td>
<td>mD</td>
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<td>PV/d</td>
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<td>Injected polymer concentration</td>
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<td>kg/m³</td>
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<tr>
<td>Todd-Longstaff mixing parameter</td>
<td>$\omega$</td>
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<td>Viscosity of fully mixed solution</td>
<td>$\mu_m$</td>
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<td>mPa.s</td>
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<td>(at 1 kg/m³ polymer concentration)</td>
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<td>Polymer rheology</td>
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<td>Polymer adsorbed by the rock formation</td>
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<td>Dead pore volume</td>
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<tr>
<td>Salt concentration</td>
<td></td>
<td>0</td>
<td>kg/m³</td>
</tr>
</tbody>
</table>

Figure 3-10: Permeability fields for serial flow simulation: (a) model with 10 layers (b) model with an effective permeability
3.6 Study of non-Newtonian Fluid Flows in Layered Systems

In this section, we studied the impact of non-Newtonian fluid displacement in layered systems. We used the verified models from Section 3.5. We also investigated the possibility of applying an effective permeability to all layers instead of its layered permeability in non-Newtonian fluid displacement. This was not an upscaling study because the numbers of cells in the models are the same.

3.6.1 Flow of Non-Newtonian Fluid in Parallel Layers

We studied models under parallel displacement of non-Newtonian fluid. We used the 10-layered model from parallel flow verification of Newtonian flooding (Section 3.5.1) and changed polymer rheology by adjusting the power law exponent \( (n) \). More details are in Section 3.2.3. We used \( n = 0.5 \) for shear-thinning behaviour and \( n = 2 \) for a shear-thickening fluid. Figure 3-12 shows that the shear-thinning flow behaviour accelerated water breakthrough time, whereas shear-thickening rheology delays water
breakthrough time. Shear-thickening displacement offers the best oil recovery at breakthrough. This is due to better sweep efficiency as an appearance viscosity of the injecting fluid increases.

We then apply the non-Newtonian fluid to the homogenous model for parallel flow validation of Newtonian flooding (Figure 3-7(b)) and compare results with those obtained from the 10-layered model. Figure 3-13 shows the water cut and oil recovery profiles of shear-thinning fluid flooding (left) and shear-thickening injection (right) in the 10-layered model and the homogenous model. The results for both reveal that the homogenous model with the effective permeability, calculated by arithmetic average, offers good predictions for the 10-layered model. We conclude that for a simple layered model with parallel flow, arithmetic mean can be applied to all grid blocks and yield the same results in both Newtonian and non-Newtonian flow behaviour.
3.6.2 Flow of Non-Newtonian Fluid in Serial Layers

We investigated the effect of non-Newtonian fluid in serial flow pattern. We changed the polymer rheology of the 10-layered model for serial flow (Section 3.5.2) from Newtonian to shear-thinning \((n = 0.5)\) and shear-thickening \((n = 2)\) fluids. The simulation results (Figure 3-14) led to the same conclusions as the parallel flow case that the water breakthrough was early in the shear-thinning fluid flooding. The shear-thickening fluid displacement helped delay the breakthrough time and resulted in highest oil recovery at breakthrough.

We also studied the effects of non-Newtonian fluid injection in the 10-layered model and the homogenous model with serial flow pattern. Figure 3-15 shows the simulation results. We found that applying the effective permeability, which was determined by the harmonic average, to all layers can provide exact results when the flow direction was perpendicular to the layers.
CHAPTER 3: MODEL CONSTRUCTION AND VERIFICATION

Figure 3-14: Comparison of water cut and oil recovery predictions of the 10-layered model under serial flow of non-Newtonian fluid.

Figure 3-15: Comparison of water cut and oil recovery predictions between the 10-layered model and the homogenous model with the effective permeability under shear-thinning (left) and shear-thickening (right) fluid injection in serial flow pattern.
In the previous chapter, we verified that our models with given parameters can be used to study non-Newtonian fluid displacement. In this chapter, we investigated the impact of upscaling in two-dimensional heterogeneous models under non-Newtonian fluid flooding. Two models were selected for this study. The first model had a lognormal permeability distribution, whereas the second model represented a channelled system. Both models were upscaled to given levels with selected upscaling methods. All models were then simulated under water, shear-thinning polymer, and shear-thickening polymer flooding. The predictions of oil recovery and water cut were analysed.

4.1 Two-dimensional Models with Lognormal Permeability Fields

We investigated the impact of upscaling when polymer was injected instead of water. The results were compared with the same models under water flooding. This was to evaluate whether the errors in predictions of upscaled models in polymer flooding cases are significant compared to those results of water flooding cases.
For the fine scale model, we used a heterogeneous grid of 128x128 cells where all the other parameters are the same as in the previous chapter. One heterogeneous model had a correlated lognormal distribution generated by a simple moving circle averaging technique, similar to a moving ellipse averaging technique described in Wallstrom et al. (1999). In our research, correlation lengths are referred to the radii of the circle, whereas some papers use circle diameters. In the moving ellipse averaging method, the correlation lengths in x- and y- directions are \( L_x \) and \( L_y \), respectively. The \( L_x \) and \( L_y \) are equal in the moving circle averaging technique. Three parameters are required in the generating processes: a desired mean and a standard deviation of the Gaussian random numbers, and a selected correlation length (a number of cells correlated as a radius). For our 128x128 model, the lognormal permeability field was randomly generated using a MATLAB function in Appendix A.1 with correlation length of 0.1. The 128x128 fine scale permeability field and its histogram in logarithmic scale are shown in Figure 4-1. The mean and standard deviation of the permeability field are 1,588 and 6,676 mD.

![Figure 4-1: Fine scale permeability field (left) and the histogram of permeabilities in logarithmic scale (right).](image)

### 4.1.1 Two-dimensional Model Validation

We now had the 128x128 heterogeneous model. We calculated a global geometric mean (averaged from all cells) and applied this value to all cells creating a 128x128 homogenous model. We then conducted a simulation of water flooding using ECLIPSE. The predictions of water cut and cumulative oil production were compared against analytical solutions calculated by the Buckley-Leverett equation.
(Buckley & Leverett, 1942). Equations (4-1) to (4-12) were used in this analysis. More details can be found in Chapter 14 of “Reservoir engineering handbook” by Ahmed (2006).

**Fractional flow**

\[
f_w(S_w) = \frac{k_{rw}(S_w)}{\mu_w} \cdot \frac{k_{rw}(S_w)}{k_{ro}(S_w)} \cdot \frac{\mu_w}{\mu_o} \quad (4-1)
\]

**Derivative of fractional flow**

\[
f'_w(S_w) = \frac{df_w}{dS_w} \quad (4-2)
\]

**Dimensionless distance**

\[
(x_d)_w = \left\{ \begin{array}{ll}
\text{(PVI)} & \left( \frac{df_w}{dS_w} \right)_{swf}, S_w \in (S_{wi}, S_{wf}) \\
\text{(PVI)} & \left( \frac{df_w}{dS_w} \right)_{sw}, S_w \in (S_{wf}, 1 - S_{gr})
\end{array} \right. \quad (4-3)
\]

**Recovery performance to breakthrough**

**Pore Volume Injection at breakthrough:**

\[
Q_{iBT} = \frac{1}{\left( \frac{df_w}{dS_w} \right)_{swf}} = \bar{S}_{wBT} - S_{wi} \quad (4-4)
\]

**Breakthrough time:**

\[
t_{BT} = \frac{\text{(Pore Volume)}}{i_w \left( \frac{df_w}{dS_w} \right)_{swf}} \quad (4-5)
\]

**Displacement efficiency at breakthrough:**

\[
E_{DBT} = \frac{\bar{S}_{wBT} - S_{wi}}{1 - S_{wi}} \quad (4-6)
\]

**Cumulative oil production to breakthrough:**

\[
N_{pBT} = N_o E_{DBT} E_{ABT} E_{vBT} \quad (4-7)
\]

**Recovery performance after breakthrough**

**Average water saturation after breakthrough:**

\[
\bar{S}_{w2} = S_{w2} + \frac{1 - f_{w2}}{\left( \frac{df_w}{dS_w} \right)_{sw2}} \quad (4-8)
\]

**Displacement efficiency for each \( S_{w2} \):**

\[
E_D = \frac{\bar{S}_{w2} - S_{wi}}{1 - S_{wi}} \quad (4-9)
\]

**Cumulative oil production:**

\[
N_p = N_o E_D E_A E_v \quad (4-10)
\]
Cumulative water injected in pore volumes:
\[ Q_t = \frac{1}{\left( \frac{d f_w}{d S_w} \right)_{S_{w2}}} \]  
(4-11)

Time:
\[ t = i_w \left( \frac{d f_w}{d S_w} \right)_{S_{w2}} \]  
(4-12)

For two immiscible fluids, oil and water, the fractional flow of water is defined as the water flow rate divided by the total flow rate. Assuming the steady-state linear flow of two immiscible fluids through a horizontal reservoir and that the capillary pressure is negligible, the fractional flow can be simplified to Equation (4-1). We used the relative permeabilities from the second dataset of the Tenth SPE Comparative Solution Project (Christie & Blunt, 2001) as shown in Figure 4-2. The oil and water viscosities were 3 mPa.s and 0.3 mPa.s, respectively. The fraction flow curve and its derivative were calculated from Equations (4-1) and (4-2) and plotted against the water saturation as shown in Figure 4-3. A straight line was drawn from initial water saturation \( (S_{wi}) \) and tangent to the fraction flow curve. The coordinates of point of tangency and the slope of the tangent gave the front water saturation \( (S_{wf}) \) of 0.38, the fractional flow \( (f_{wf}) \) of 0.64, the fractional flow derivative \( (f'_{swf}) \) of 3.48, and the average water saturation behind front at breakthrough \( (\bar{S}_{wBT}) \) of 0.487. The breakthrough time of 0.287 can be calculated by Equation (4-4).
We selected dimensionless times of 0.1, 0.2, 0.287, and 1 pore volume injection (PVI). The water saturation profile as a function of distance and time can be determined by Equation (4.3). Figure 4-4 shows the results from the calculation. The injector and producer were at the dimensionless distance of zero and one, respectively. As the time increases, the water front (leading edge) moved toward the producer and eventually reached the production well and water breakthrough occurred at 0.287 PVI.

Figure 4-3: Fractional flow curve and its derivative.
Equations (4-4) to (4-12) were used to calculate cumulative oil production analytically. The results can be shown either as a function of time (days) or dimensionless time (PVI). We used dimensionless units in this validation. The simulation results obtained from ECLIPSE were converted to dimensionless units and compared with the analytical results as shown in Figure 4-5. The calculated oil recovery was determined by assuming the areal sweep efficiency \((E_A)\) and the vertical sweep efficiency \((E_V)\) of one for case 1 (green dot line) and 0.8 for case 2 (purple dot line). The calculated water breakthrough time of 0.287 PVI was similar to the simulation result of 0.233 PVI. We suspected that the difference between the simulation and analytic results may be because the Buckley-Leverett equation is for a one-dimensional system with linear flow, whereas our model was a two-dimensional system with a quarter five-spot pattern water flooding. We therefore conducted a simulation for a quasi one-dimensional system by converting our model from the quarter five-spot pattern to a line drive pattern. All other parameters were the same. The results in Figure 4-6 show that the water breakthrough time of the one-dimensional model was almost identical to the calculated value. Its shock front was also much sharper compared to the two-dimensional system with a quarter five-spot pattern. Therefore, we can conclude that the difference between our two-dimensional model and the analytic results was mainly due to the...
flow patterns. Other factors that may contribute to the differences were the values of fractional flow derivatives (Equation (4-2)) used in this analytic calculation (minor contribution) and numerical dispersion (well-known issue in reservoir simulation).

Numerical dispersion is due to the use of finite difference approximation that introduces truncation error. AlSofi (2011) studied the effect of numerical dispersion on polymer flooding. The results showed that the fewer the number of cells in simulation models, the more smearing the shock fronts. The smearing effects in polymer flooding were worse compared to water flooding. This was due to the concentration profiles of polymer solutions used for the fractional flow calculations. He concluded that finer simulation models were required when studying polymer flooding to reasonably capture saturation fronts and obtain more accurate production forecasts. The investigation also suggested that numerical dispersion may cause overestimating the early time production and overpredicting optimal polymer concentration. Using more polymers resulted in less profit in an economic evaluation or even uneconomic for investment.

The main purpose of this section is to verify that our model can be used in future studies. We can confirm that our two-dimensional model is acceptable for further simulations and analyses.
CHAPTER 4: UPSCALING OF NON-NEWTONIAN FLUID FLOWS IN TWO-DIMENSIONAL MODELS

Figure 4-5: Comparison of the results between the two-dimensional simulation model (a quarter five-spot pattern) and the Buckley-Leverett equation.

Figure 4-6: Comparison of the results between the one-dimensional simulation model (line drive pattern) and the Buckley-Leverett equation.
We also analysed the effect of injecting viscous fluids on fluid displacements. We determined fractional flow curves and water saturation profiles when more viscous fluids were injected instead of water. The main parameter in the analytic calculations was the viscosity of injecting fluid. The fluid rheology was not part of the formulae. The apparent viscosities of 2.4 mPa.s (shear-thinning), 3 mPa.s (Newtonian), and 5.1 mPa.s (shear-thickening) from Section 3.4 were used in the calculations to compare with the water viscosity of 0.3 mPa.s. Figure 4-7 shows the fractional flow curves of different fluid displacement. Injecting more viscous fluids such as polymer helped shift the water curve to the right and gives better oil flow at the same water saturation. With the shear-thinning rheology, the fractional flow curve moved to the left due to the reduction in its viscosity. The more shear-thinning, the more shifting to the left and the closer to the water curve. On the other hand, the more shear-thickening, the further moving to the right side and the better oil flow. As polymer flooding did not affect on the residue oil saturation, the end of the fractional flow curves, where $f_{wf} = 1$, remained at 0.2. Figure 4-8 shows the water saturation profiles as a function of dimensionless distance at 0.25 PVI of various fluid viscosities. Considering the breakthrough times, the water flooding approached the producer at the dimensionless distance of one first followed by shear-thinning, Newtonian, and shear-thickening polymer flooding, respectively. The shear-thinning rheology made the front arrived at the producer faster but still after the water front. Conversely, the shear-thickening rheology can delay the front reaching the producer. Based on the apparent viscosities used in these calculations, injecting polymer can help increase the water saturation of the front from 0.38 to 0.58 in shear-thinning case, 0.64 in Newtonian case, and 0.70 in shear-thickening case. These increases resulted in the higher average water saturation behind front, the better displacement efficiency, and ultimately the more oil recovered.
Figure 4-7: Fractional flow curves when displacing with various fluid viscosities.

Figure 4-8: Water saturation profiles as a function of dimensionless distance at 0.25 PVI of various fluid viscosities.
4.1.2 Upscaling of the Permeability Field

We upscaled the 128×128 model to 64×64, 32×32, 16×16, 8×8 models. The permeability fields were averaged by the harmonic, the geometric, and the arithmetic averaging methods as shown in Figure 4-9 to Figure 4-11. We can obviously notice that the permeability heterogeneity was lost when the size of the cell increased. Regardless of the upscaling method, the models were almost unrecognisable when we upscaled from 128×128 to 8×8 cells. It was difficult to see from these figures which upscaling method gave the closest permeability field to the fine scale model. We therefore applied a Quantile-Quantile (Q-Q) plot for this analysis. In statistics, a Q-Q plot is a graphical method used to compare two probability distributions. Selected quantiles of each distribution are plotted against each other. If the two distributions are the same, the Q-Q plot will lie on the y = x line (45° angle). The Q-Q plot is a statistical measure whereas one may only focus on which upscaled permeability gives a good estimate of the flow, even if the statistics are very different. However, we conducted this comparison as we believed that the upscaled permeabilities should be similar in some sense statistically to the fine grid permeabilities.

Figure 4-9: Permeability fields of the fine scale model and the upscaled models by the harmonic average.
We plotted the quantiles of the upscaled permeability fields against those of the fine scale permeability distribution. Figure 4-12 to Figure 4-15 showed the Q-Q plots between the fine scale model and the upscaled models. Reference lines drawn through the 0.25 and 0.75 quantiles were used for evaluation. The closer to the 45° reference line, the greater the similarity of the distributions. In our comparisons,
the upscaled permeabilities were higher when the plot angle was greater than 45°. On the other hand, the permeabilities of upscaled models were lower when the plot angle was less than 45°. As the models were coarser, the Q-Q plots were further away from the reference line (45° angle). In all upscaling levels, the arithmetic average provided higher values, whereas the harmonic average offered the lower values. The geometric mean gave the closest permeabilities fields to the fine scale model. We concluded that the higher the upscaling levels, the more scatter of the permeabilities. In addition, the arithmetic mean provided the upper bound while the harmonic mean was the lower bound and the geometric mean offered the closest value (Matheron, 1967). This is consistent with the statement “$k_{\text{harmonic}} < k_{\text{geometric}} < k_{\text{arithmetic}}$” by Matheron (1967).

![Figure 4-12: Q-Q plots between the 128×128×1 fine scale model and the 64×64×1 upscaled models.](image)

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<td>KfineRef</td>
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Axis:
x-axis = sorted permeability values of 128×128×1 model, mD
y-axis = sorted permeability values of 64×64×1 model, mD
Legend:
KariRef = Reference lines drawn through the 0.25 and 0.75 quantiles of the 64×64×1 model upscaled by the arithmetic average
Kari = 64×64×1 model upscaled by the arithmetic average
KgeoRef = Reference lines drawn through the 0.25 and 0.75 quantiles of the 64×64×1 model upscaled by the geometric average
Kgeo = 64×64×1 model upscaled by the geometric average
KharRef = Reference lines drawn through the 0.25 and 0.75 quantiles of the 64×64×1 model upscaled by the harmonic average
Khar = 64×64×1 model upscaled by the harmonic average
KfineRef = 128×128×1 fine scale model
CHAPTER 4: UPSCALING OF NON-NEWTONIAN FLUID FLOWS IN TWO-DIMENSIONAL MODELS

Axis

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Legend

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<td>KariRef</td>
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</tr>
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<td>KgeoRef</td>
<td>Reference lines drawn through the 0.25 and 0.75 quantiles of the 32x32x1 model upscaled by the geometric average</td>
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<tr>
<td>Kgeo</td>
<td>32x32x1 model upscaled by the geometric average</td>
</tr>
<tr>
<td>KharRef</td>
<td>Reference lines drawn through the 0.25 and 0.75 quantiles of the 32x32x1 model upscaled by the harmonic average</td>
</tr>
<tr>
<td>Khar</td>
<td>32x32x1 model upscaled by the harmonic average</td>
</tr>
<tr>
<td>KfineRef</td>
<td>128x128x1 fine scale model</td>
</tr>
</tbody>
</table>

Figure 4-13: Q-Q plots between the 128x128x1 fine scale and the 32x32x1 upscaled models.
CHAPTER 4: UPSCALING OF NON-NEWTONIAN FLUID FLOWS IN TWO-DIMENSIONAL MODELS

Axis

x-axis = sorted permeability values of 128×128×1 model, mD
y-axis = sorted permeability values of 16×16×1 model, mD

Legend

KariRef = Reference lines drawn through the 0.25 and 0.75 quantiles of the
         16×16×1 model upscaled by the arithmetic average
Kari = 16×16×1 model upscaled by the arithmetic average
KgeoRef = Reference lines drawn through the 0.25 and 0.75 quantiles of the
          16×16×1 model upscaled by the geometric average
Kgeo = 16×16×1 model upscaled by the geometric average
KharRef = Reference lines drawn through the 0.25 and 0.75 quantiles of the
          16×16×1 model upscaled by the harmonic average
Khar = 16×16×1 model upscaled by the harmonic average
KfineRef = 128×128×1 fine scale model

Figure 4-14: Q-Q plots between the 128×128×1 fine scale and the 16×16×1 upscaled models.
4.1.3 Effects of non-Newtonian Flow Behaviour

Although the geometric average offered the closest match of permeability fields to the fine scale model in all upscaling levels, the production forecasts from geometric upscaled models may not provide the closest results. This is due to the fact that the oil production does not depend on the permeability values. The correlation of permeabilities in the main flow path between injectors and producers also play a significant role on the production forecasts. Therefore, we kept all upscaled models in this study.

In this section, we investigated the effects of upscaling on production forecasts when the displacing fluid had non-Newtonian flow behaviour. The models in this study were the fine scale model of 128×128 cells...
and twelve upscaling models (64×64, 32×32, 16×16, 8×8 cells by the arithmetic, harmonic, and geometric averages). All models were produced under water flooding, shear-thinning polymer flooding, and shear-thickening polymer flooding using a quarter five-spot injection scheme. We used parameters as stated in the previous section with additional parameters in Table 4-1. The power law exponents of 0.643 for shear-thinning and 2 for shear-thickening polymer were applied to this study followed the polymer flooding study by AlSofi (2011).

Table 4-1: Input parameters for the two-dimensional models with lognormal Permeability distributions

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<thead>
<tr>
<th>Parameters</th>
<th>Symbols</th>
<th>Values</th>
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<tr>
<td>Porosity</td>
<td>( \phi )</td>
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<td></td>
</tr>
<tr>
<td>Fine scale permeability (isotropic)</td>
<td>( k )</td>
<td>Figure 4-1</td>
<td>mD</td>
</tr>
<tr>
<td>Number of gridblocks in fine scale model</td>
<td>( N_x \times N_y \times N_z )</td>
<td>128×128×1</td>
<td>cells</td>
</tr>
<tr>
<td>Size of gridblocks in fine scale model</td>
<td>( dx \times dy \times dz )</td>
<td>6.1×6.1×6.1</td>
<td>m</td>
</tr>
<tr>
<td>Injection rate</td>
<td>( Q )</td>
<td>0.001</td>
<td>PV/d</td>
</tr>
<tr>
<td>Injected polymer concentration</td>
<td>( C_p )</td>
<td>1</td>
<td>kg/m³</td>
</tr>
<tr>
<td>Todd-Longstaff mixing parameter</td>
<td>( \omega )</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Viscosity of fully mixed solution (at 1 kg/m³ polymer concentration)</td>
<td>( \mu_m )</td>
<td>3</td>
<td>mPa.s</td>
</tr>
<tr>
<td>Power law exponent for polymer rheology</td>
<td>( n )</td>
<td>0.643 for shear-thinning 2 for shear-thickening</td>
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</tr>
<tr>
<td>Polymer adsorbed by the rock formation</td>
<td></td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Dead pore volume</td>
<td></td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Salt concentration</td>
<td></td>
<td>0</td>
<td>kg/m³</td>
</tr>
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</table>

Thirty nine simulations were conducted using ECLIPSE. Figure 4-16 shows water saturation and polymer concentration profiles after injecting different fluids for one pore volume. The profiles of polymer concentration in water flooding cases represented injected water. The fine scale model of 128×128 cells was upscaled by the harmonic average. The displacing fluids were injected to the bottom right corner and the reservoir fluids were produced from the top left corner. This created a quarter five-spot pattern. In the 128×128 model, injecting polymer offered noticeably higher recovery as the higher volume of pore space was displaced (higher values in the water saturation profile). This was due to better sweep efficiency (higher coverage of polymer concentration). In water flooding, the displacing fluid moved fast from the injector to the producer. This resulted in low sweep efficiency in the surrounding area. As the viscosity of displacing fluid in both shear-thinning and shear-thickening polymer flooding was higher than water, the injected fluid had more chance to displace the surrounding area and resulted in higher sweep efficiency. Shear-thickening polymer gave the best sweep efficiency.
as the apparent viscosity increased. However, we can still see some areas that have not yet been displaced (the yellow areas in the water saturation profile). These yellow areas had become smaller when the cell sizes increased because the models were more homogeneous. In the 8×8 model, no yellow area was present in the shear-thickening case. This meant the reservoir fluid in all cells was displaced by the injected fluid and leads to higher recovery compared to the 128×128 model.
Figure 4-16: Water saturation and polymer concentration profiles at various model scales, upscaled by the harmonic average, after 1 PVI of water, shear-thinning polymer, and shear-thickening polymer.
Effects on Oil Production Predictions

We exported the simulation results of thirty nine scenarios to Excel and analysed pore volumes of oil produced as a function of pore volume injection. Figure 4-17 to Figure 4-19 show the simulation results when the harmonic upscaled models were produced under water flooding, shear-thinning polymer flooding, and shear-thickening polymer flooding. Comparing fine scale models of all scenarios after one pore volume injection, oil production can be increased from 0.227 to 0.260 pore volumes when injecting a shear-thinning polymer (a 15% increase). Injecting shear-thickening polymer offered much better incentive and can raise oil recovery by 0.129 pore volumes (a 57% increase). In all flooding scenarios, the oil production predictions were increasingly overestimated as the cell size increases. In the water flooding case, the coarsest scale of 8×8 cells can overpredict the oil production by 0.050 pore volumes after one pore volume injection (a 22% overestimated compared with the fine scale model under water flooding). The difference was only 0.033 pore volumes in the shear-thinning case (a 13% overpredicted compared with the fine scale model under shear-thinning polymer flooding). The error in prediction was worst in the shear-thickening case as the oil production can be overestimated by 0.099 pore volumes (a 28% overpredicted compared with the fine scale model under shear-thickening polymer flooding).
Figure 4-17: Comparison of oil production predictions between the fine scale model (128×128 cells) and the harmonic upscaled models (64×64, 32×32, 16×16, and 8×8 cells) under water flooding.

Figure 4-18: Comparison of oil production predictions between the fine scale model (128×128 cells) and the harmonic upscaled models (64×64, 32×32, 16×16, and 8×8 cells) under shear-thinning polymer flooding.
Figure 4-19: Comparison of oil production predictions between the fine scale model (128×128 cells) and the harmonic upscaled models (64×64, 32×32, 16×16, and 8×8 cells) under shear-thickening polymer flooding.

Figure 4-20: Pore volume of oil produced at various levels of upscaling after 1 PVI of water, shear-thinning polymer, and shear-thickening polymer.
We compared oil recovery after 1 PVI of all 39 cases. The results are shown in Figure 4-20. The level of upscaling shows how many times the fine scale model was scaled up in each direction. For example, the level of upscaling of four represents the 32x32 model as the number of cells in each direction of the fine scale model was divided by four i.e. from 128x128 to 32x32 grid cells. The results of the fine scale cases were at the upscaling level of zero instead of one for graphic display so that the distance on the x-axis between 128x128 grid cells (level zero) and 64x64 grid cells (level two) equals to the distance on the x-axis between 64x64 grid cells and 32x32 grid cells (level four). In all cases, the predictions of oil production increased as a function of upscaling level. The oil prediction in upscaling cases was closer to the fine scale cases when the line was nearer to a horizontal line (line slope= 0). The higher the degree of upscaling the greater the overestimation of recovery. In water and shear-thinning polymer flooding, the arithmetic average gave the closest results to the fine scale model in all upscaling levels followed by the geometric average and the harmonic average, respectively. Conversely, upscaling using either the harmonic or geometric averages gave better results than by using the arithmetic mean in the shear-thickening cases. We conclude that the best upscaling method for water flooding may not be the best one for shear-thickening polymer flooding.

One of our research objectives is to understand how the prediction of upscaled models under non-Newtonian flooding is different from water flooding. In Figure 4-20, we considered the water flooding cases as the base cases. We found that the oil predictions in the shear-thinning cases were even closer to the fine scale model in all upscaled algorithms (the line slopes were closer to zero). On the other hand, the oil prediction in the shear-thickening cases was much worst. Comparing between the fine scale models and the 8x8 arithmetic upscaled models (the upscaling level of 16), the pore volume of oil produced was overestimated from 0.227 to 0.266 in the water flooding case, from 0.260 to 0.278 in the shear-thinning case, and from 0.356 to 0.461 in the shear-thickening case. The differences of pore volumes of oil produced between the fine scale models and the 8x8 arithmetic upscaled models were 0.039 in water, 0.018 in shear-thinning, and 0.105 in shear-thickening cases. As we considered the water flooding case as the base case, meaning the difference of 0.039 pore volumes was acceptable, the shear-thinning case gave a closer result to the fine model, whereas the shear-thickening case gave a significant difference.

Another way to analyse the results in Figure 4-20 was to consider the difference in predictions of the same model scale. In the fine scale model, injecting polymer instead of water can increase oil
production by 0.033 pore volumes (from 0.227 to 0.260) if the polymer was shear-thinning. The production can improve by 0.129 pore volumes (from 0.227 to 0.356) if the polymer was shear-thickening. If the 8×8 arithmetic upscaled model was used for evaluating a project, we can only see an improvement of 0.012 pore volumes (from 0.266 to 0.278) of oil recovered when switching from water to shear-thinning polymer and an increase of 0.195 (from 0.266 to 0.461) when changing from water to shear-thickening polymer. Therefore, we concluded that when coarse scale models were used to compare different fluid injection, the results were underestimated in shear-thinning polymer flooding and overpredicted in shear-thickening polymer flooding.

**Effects on Water Cut Predictions**

An accurate prediction of water breakthrough time was one of important factors in the economic evaluation of a project, especially in a field with a limited water treatment facility. Therefore, we investigated the impact of non-Newtonian flooding at various simulation scales on water cut predictions. Figure 4-21 through Figure 4-23 show water cut profiles when the harmonic upscaled models were used in simulations under water flooding, shear-thinning polymer flooding, and shear-thickening polymer flooding. In the fine scale cases, injecting polymer can delay water breakthrough time from 0.084 to 0.099 (an 18% delay) in the shear-thinning case and to 0.133 (a 58% delay) in the shear-thickening case. Comparing between water and shear-thinning polymer flooding in the 8×8 upscaled cases, the water breakthroughs were only slightly different. This can lead to the wrong conclusion that injecting a shear-thinning polymer did not help delay the amount of produced water, whereas the benefit can be seen when using the fine scale model for simulations (the 18% delay). On the other hand, the breakthrough time was overpredicted by 0.067 (an 80% delay) in the 8×8 upscaled case when changing from water to shear-thickening polymer, compared to the difference of 0.049 (the 58% delay) in the fine scale model. This would be too optimistic in an economic evaluation.
Figure 4-21: Comparison of water cut predictions between the fine scale model (128×128 cells) and the harmonic upscaled models (64×64, 32×32, 16×16, and 8×8 cells) under water flooding.

Figure 4-22: Comparison of water cut predictions between the fine scale model (128×128 cells) and the harmonic upscaled models (64×64, 32×32, 16×16, and 8×8 cells) under shear-thinning polymer flooding.
Figure 4-23: Comparison of water cut predictions between the fine scale model (128x128 cells) and the harmonic upscaled models (64x64, 32x32, 16x16, and 8x8 cells) under shear-thickening polymer flooding.

Figure 4-24: Water breakthrough predictions of all cases.
We investigated the breakthrough time predictions of all 39 cases. As we have the water cut profiles of all cases, the breakthrough time in terms of pore volume injection, where water starts to be produced, was plotted against the upscaling level. The results are shown in Figure 4-24. Similar to the comparison of oil production predictions, the closer the line slope was to zero, the better the water breakthrough prediction was to the fine scale model. In all cases, the predicted water breakthrough time increases as a function of the upscaling level. Upscaling using the harmonic average gave the closest water breakthrough prediction to the fine scale model in all upscaling levels and all types of fluid injection. Comparing between the water and shear-thinning injection, some delay in the water breakthrough time when switching from water to shear-thinning polymer can be observed in the fine scale model. However, the benefit was not obvious in the upscaled models. In the 8×8 models upscaled using either the harmonic average or the arithmetic average, the water breakthrough time of the water and the shear-thinning polymer flooding cases were identical. In the shear-thickening polymer cases, on the other hand, the water breakthrough prediction was more delayed when the upscaling level was higher.

Comparing between the fine scale model and the 8×8 arithmetic upscaled model, the water breakthrough time was delayed from 0.084 to 0.136 in the water flooding case (a 62% error), from 0.099 to 0.136 in the shear-thinning case (a 37% error), and from 0.133 to 0.226 in the shear-thickening case (a 70% error). The differences in prediction were 0.052 in water, 0.037 in shear-thinning, and 0.093 in shear-thickening cases. As we consider the water flooding case as the base case (meaning the difference of 0.052 pore volumes was acceptable), the water breakthrough prediction in the shear-thinning case was closer to the fine model as the difference of 0.037 was less than that of water, whereas the difference of 0.093 in the shear-thickening case would be too high.

**Effects on Field Average Pressure**

The predictions of field average pressure of all runs are shown in Figure 4-25. The upscaled models are calculated by the geometric average. The differences between the upscaled cases and the fine scale case were less apparent in water flooding runs. The variation was more obvious in the non-Newtonian cases. In the shear-thickening cases, the field average pressure dropped before started to increase after around 0.15 PVI. This is due to an increase in viscosity of the displacing fluid from the shear-thickening behaviour. In this case, the reservoir fluid viscosity was significantly lower than the apparent viscosity of the shear-thickening polymer. As a result, the reservoir fluid flowed out via the producer faster than the
injected fluid flowed in; hence the drop in reservoir pressure in the beginning. There was no clear
direction of field average pressure predictions when the model was coarser i.e. we cannot conclude that
upscaled models gave lower field average pressure predictions. Our results were the same as the
concluded that the quality of the water and oil predictions and the quality of the field average pressure
prediction were almost independent.

Almost all upscaling techniques assume an approximately linear flow regime and the pressure field is
slowly varying; however, the flow pattern in the near-well regions likely to be radial with a high pressure
gradient (Ding, 1995). In the near-well region, coarse scale permeabilities computed by assuming linear
flow may not adequately capture key features of the fine scale flow (Durlofsky et al., 2000). In our
simulations, the differences in the pressure predictions between the fine scale simulations and coarse
scale simulations are because the effect of high pressure gradient in the near-well regions is not
properly captured in the coarse scale models. The calculation of pressure profiles in the upscaled
models can be improved by the near-well upscaling presented by Ding (1995).

We only upcaled absolute permeabilities without taking into account productivity indices and
transmissibilities in the near-well region. This contributed to the inaccuracy of our pressure profiles in
the coarse scale models. According to Christie and Blunt (2001), the quality of the production
predictions and the quality of the field average pressure prediction were almost independent.
Therefore the near-well upscaling may not be necessary for economic evaluation of fluid flooding
projects where only production predictions are used in the evaluation. On the other hand, in pressure
maintenance projects, where reservoir pressure is maintained, for example to prevent oil-water contact
moves up, the near-well upscaling may be necessary.
Figure 4.25: Field average pressure profiles of all cases. The upscaled models are calculated by the geometric average.
4.1.4 Effects of Relative Permeability Curves

We extended our study to investigate the impact of different relative permeability curves. The relative permeabilities from the second dataset of the Tenth SPE Comparative Solution Project (Christie & Blunt, 2001) as shown in Figure 4-2 were obtained by assuming Corey exponents of two for both oil and water phase (Corey, 1954). In this section, we studied five relative permeability curves:

a) Oil and water Corey exponents of two (SPE 10 Model 2 used in Section 4.1.1)
b) Oil and water Corey exponents of three
c) Water-wet curves
d) Mixed-wet curves
e) Oil-wet curves

The relative permeability curves of case a and b were calculated using Corey correlations (Corey, 1954). The relative permeability curves of case c, d, e were generated from the Relative Permeability Suite (Koederitz & Ibrahim, 2002). The program was created based on 416 relative permeability datasets from literature. The wettability of a rock strongly affect its relative permeability and flood behaviour (Anderson, 1987). Wetting fluid is generally located in smaller pores and coated as a thing film in the larger pores, while the non-wetting fluid is located in the centres of the larger pores. In water-wet rocks, injected water tends to imbibe into any small pores, moving oil into the larger pores and then to a producer. In oil-wet case, displacing water forms continuous channels through the centres of large pores, pushing oil in front of it to a producer. Oil is left in the smaller pores until water invades to form additional channels. Generally, water-wet rocks have higher connate water saturation and lower residual oil saturation compared with oil-wet rocks (Anderson, 1987). To make it easier to compare results, we used the same connate water saturation and lower residual oil saturation for all cases in this study.

Figure 4-26 shows the five relative permeability curves used to investigate the impact of different relative permeability curves. At any given water saturation, the relative permeabilities of oil and water at the Corey exponents of three were lower than the relative permeabilities of oil and water at the
Corey exponents of two. The water relative permeability in the oil-wet case was higher than the water-wet case at any water saturation.

Figure 4-27 and Figure 4-28 are fractional flow curves and water saturation profiles as a function of dimensionless distance calculated by the Buckley-Leverett equation. Figure 4-29 through Figure 4-34 are simulation results associated with the five relative permeability curves.
Figure 4-26: Five relative permeability curves used to investigate the impact of different relative permeability curves.
Figure 4-27: Fractional flow curves when displacing with various fluid viscosities.
Figure 4-28: Water saturation profiles as a function of dimensionless distance at 0.25 PVI of various fluid viscosities.
Figure 4-29: Comparison of oil production predictions between the fine scale model (128×128 cells) and the geometric upscaled models (64×64, 32×32, 16×16, and 8×8 cells) under water flooding.
Figure 4-30: Comparison of water cut profiles between the fine scale model (128×128 cells) and the geometric upscaled models (64×64, 32×32, 16×16, and 8×8 cells) under water flooding.
Figure 4.31: Comparison of oil production predictions between the fine scale model (128x128 cells) and the geometric upscaled models (64x64, 32x32, 16x16, and 8x8 cells) under shear-thinning polymer flooding.
Figure 4-32: Comparison of oil production predictions between the fine scale model (128x128 cells) and the geometric upscaled models (64x64, 32x32, 16x16, and 8x8 cells) shear-thinning polymer flooding.
Figure 4-33: Comparison of oil production predictions between the fine scale model (128x128 cells) and the geometric upscaled models (64x64, 32x32, 16x16, and 8x8 cells) under shear-thickening polymer flooding.
Figure 4-34: Comparison of oil production predictions between the fine scale model (128×128 cells) and the geometric upscaled models (64×64, 32×32, 16×16, and 8×8 cells) shear-thickening polymer flooding.
In the previous section, we noticed the errors in predictions when simulate upscaled models under shear-thickening polymer flooding. The main purpose of this section is to investigate the impact of different relative permeability curves. We can conclude that errors in predictions were significant when the models were under shear-thickening polymer flooding despite the different relative permeability curves. In addition, the upscaled models under shear-thinning polymer injection offered the closest predictions to the fine scale model.

4.1.5 Summary

We examined the effects of non-Newtonian flow behaviour at various upscaling levels of the simulation models when the fine scale model has the lognormal permeability distribution with a correlation length of 0.1. We found that the oil recovery and water production forecasts were overestimated when the model scale was coarsened. For layer 47, coarse scale models under shear-thinning polymer injection gave the closest results to those obtained from fine scale simulation. The results from shear-thickening polymer injection were dramatically different. Using the coarse scale model to predict the performance of shear-thickening polymer flooding could be significantly over predicted.

In addition, we confirmed that the field average pressure prediction was almost independent of the water and oil predictions. We also investigated the impact of different relative permeability curves. We found that the comparative predictions were not dependant on the choice of relative permeability curves. This meant the difference in prediction between the upscaled models and fine scale model under the shear-thickening polymer flooding were the worst in all five relative permeability curves used in this study. We concluded that an upscaled model, which has been used under water flooding, can be employed for a study of shear-thinning polymer flooding in a model with a lognormal permeability distribution. However, this upscaled model may not be suitable for shear-thickening polymer flooding study as its oil and water cut predictions would be too optimistic. These differences would have a significant impact on an economic evaluation. The project may look very attractive for investment but could not actually be achieved and could ultimately result in the loss of investment.
4.2 Two-dimensional Fluvial System: SPE 10 Model 2 Layer 47

We extended our investigation to a reservoir with a channelled system. We chose layer 47 of the second model from the Tenth SPE Comparative Solution Project (Christie & Blunt, 2001) for this study. This represents part of Upper Ness formation, which was a fluvial environment. Our fine scale model consisted of 60×220×1 cells. The cell size was 6.1×3.1×0.6 metres. The porosity distribution and its histogram are shown in Figure 4-35. The average porosity of the whole domain was 0.1374. The histogram showed two peaks due to the channelled system. The first group, where the mode was about 0.08, represented the background area, whereas the second group with the peak at around 0.25 corresponded to the channels. The total pore volume was 20,548 m³. Figure 4-36 shows the permeability field in x- and y- directions and its histogram in logarithmic scale. Similar to the histogram of porosities, the first group in the permeability histogram denoted to the background area with the mode at approximately 0.15 mD. The channels had the mode at around 200 mD. The arithmetic averaged permeability of the whole domain was 288 mD. The vertical permeability (z-direction) was set to have a vertical-horizontal permeability ratio of 0.3 in the channels and 0.001 in the background.

![Figure 4-35: Fine scale porosity field (left) and the histogram of porosities (right).](image-url)
4.2.1 Upscaling of the Permeability Field

The permeability field of the 60×220 fine scale model were upscaled to 30×110 and 15×55 cells by harmonic, geometric, and arithmetic averaging methods. We also added the renormalization method in this study. Therefore, we had eight upscaled models as shown in Figure 4-37. We saw that the channel characteristics change when the size of the cell increased. Using the harmonic average, low values dominated the averaging, leading to discontinuities in the channels. The arithmetic average caused the opposite effect. The channel sizes became larger when the upscaling level was higher. Some discontinuities were connected because of averaging with neighbour cells. Graphically, geometric and renormalization methods can capture the channels very well.
Figure 4-37: Permeability fields of fine scale and upscaled models.

The Q-Q plots between the fine scale and the upscaled models are shown in Figure 4-38 and Figure 4-39. In both upscaling levels, the renormalization method offered the closest distribution to the fine scale permeability field followed by either the arithmetic average or the geometric average. The harmonic average was the worst averaging method and causes very low permeability distribution. Upscaling using the arithmetic average was the only method that offered the higher upscaled permeability field than the fine scale permeability field.
Figure 4-38: Q-Q plots between the 60×220×1 fine scale and the 30×110×1 upscaled models.
Axis

x-axis = sorted permeability values of 60×220×1 model, mD
y-axis = sorted permeability values of 15×55×1 model, mD

Legend

| KariRef | Reference lines drawn through the 0.25 and 0.75 quantiles of the 15×55×1 model upscaled by the arithmetic average |
| Kari    | 15×55×1 model upscaled by the arithmetic average |
| KgeoRef | Reference lines drawn through the 0.25 and 0.75 quantiles of the 15×55×1 model upscaled by the geometric average |
| Kgeo    | 15×55×1 model upscaled by the geometric average |
| KharRef | Reference lines drawn through the 0.25 and 0.75 quantiles of the 15×55×1 model upscaled by the harmonic average |
| Khar    | 15×55×1 model upscaled by the harmonic average |
| KfineRef | 60×220×1 fine scale model |

Figure 4-39: Q-Q plots between the 60×220×1 fine scale and the 15×55×1 upscaled models.

4.2.2 Effects of non-Newtonian Flow Behaviour

We had a total of nine models to investigate the effects of non-Newtonian flow behaviour. All models were injected with water, shear-thinning polymer, and shear-thickening polymer using a quarter five-spot injection scheme, the total of twenty seven scenarios for this study. We applied the same set of parameters from the previous section but adjust some parameters as shown in Table 4-2. The injection rate was altered to 0.038 PV/d, corresponding to 5,000 rb/d used in the tenth SPE comparative solution project. The oil and water viscosities remain the same at 3 and 0.3 mPa.s. We first applied the same viscosity of fully mixed solution of 3 mPa.s at 1 kg/m³ polymer concentration. However, the productions were ceased and the simulations were terminated by ECLIPSE. After an investigation, we found that this
was because the displacing solution was too viscous. Therefore, the viscosity of fully mixed solution was changed to 1 mPa.s at 5 kg/m$^3$ polymer concentration. The injected polymer concentration was adjusted to 5 kg/m$^3$. These values were obtained after running numerous simulations to ensure that none of the twenty seven scenarios in this study will be terminated without results.

Table 4-2: Input parameters for the SPE 10 Model 2 Layer 47

<table>
<thead>
<tr>
<th>Parameters</th>
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<th>Values</th>
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<td>Figure 4-35</td>
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</tr>
<tr>
<td>Fine scale permeability in $x$- and $y$-</td>
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<td>mD</td>
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<tr>
<td>directions</td>
<td>$k_z$</td>
<td>0.001$k_x$ in background</td>
<td></td>
</tr>
<tr>
<td>Fine scale permeability in $z$-direction</td>
<td>$k_z$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of gridblocks in fine scale model</td>
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</tr>
<tr>
<td>Size of gridblocks in fine scale model</td>
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<td>Injection rate</td>
<td>$Q$</td>
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<tr>
<td>Injected polymer concentration</td>
<td>$C_p$</td>
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<td>kg/m$^3$</td>
</tr>
<tr>
<td>Todd-Longstaff mixing parameter</td>
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</tr>
<tr>
<td>Viscosity of fully mixed solution (at 5 kg/m$^3$</td>
<td>$\mu_m$</td>
<td>= 1</td>
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</tr>
<tr>
<td>polymer concentration)</td>
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<td>Power law exponent for polymer rheology</td>
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<td>Polymer adsorbed by the rock formation</td>
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<tr>
<td>Dead pore volume</td>
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<td>None</td>
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</tr>
<tr>
<td>Salt concentration</td>
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<td>kg/m$^3$</td>
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Figure 4-40 shows water saturation and polymer concentration profiles after 0.6 PVI of water, shear-thinning polymer, and shear-thickening polymer at various upscaling levels, which were averaged by the geometric method. The fluids were injected at the bottom left corner while produced at the top right corner. In any upscaling level, we saw the benefit of injecting polymer as the number of cells with high water saturation (blue and green colours) and high polymer concentration (red colour) were much more than in water flooding cases. These can lead to higher sweep efficiency and ultimately higher oil recovery. However, the difference between shear-thinning and shear-thickening polymer was not obvious. Further investigations on oil recovery and water breakthrough are conducted in the next two sections.
Under any rheology of displacing fluids, the high water saturation covered a larger area in the coarse models, upscaled by the geometric average, because of larger cell sizes and lower permeability contrast between adjacent cells. In the fine scale model, the channels were the main flow paths from the injector to the producer with minimal flows in the background. As the cell permeabilities were averaged in the upscaled models, the fluids had more chances to flow in the background and covered more cells in the models. A similar effect occurred in the distribution of polymer concentration. Considering any type of fluid injection, the coarser models had more cells containing high polymer concentration. This implied a more optimistic prediction and can result in over estimation of oil recovery.
Figure 4-40: Water saturation and polymer concentration profiles at various model scales (upscaled by the geometric average) after 0.6 PVI of water, shear-thinning polymer, and shear-thickening polymer.

**Effects on Oil Production Predictions**

We exported the simulation results of all cases to Excel then analyse the oil recovery after 0.6 PVI. The results are shown in Table 4-3 (graphically displayed in Figure 4-41). In the fine scale model, after 0.6 PVI, shear-thinning polymer flooding gave the highest pore volume of oil produced at 0.338 followed by shear-thickening polymer flooding at 0.330 and water flooding at 0.285. This differed from the case
with the lognormal permeability distribution where the shear-thickening polymer flooding was the best displacement process. We believed this was due to channel characteristics and well locations. In the fluvial environment, the channels are the main flow paths from the injector to the producer. When the shear-thickening polymer was injected, the viscosity of the displacing fluid in each cell of any channel was increased because of high shear rates. The flow rates in the channels were reduced, whereas the flows in the background were increased.

If the displacing fluid viscosities in the channels become too high, the flow in those cells ceased. In the shear-thinning case, the higher viscosity (compared with water viscosity) of the injecting fluid provides better sweep efficiency in the channels and surrounding cells initially. The displacing fluid viscosities in the channels were then reduced as the shear rates increase. Therefore the injected fluid was still able to flow in the channels and reach the producer via the channels. Our observation was supported by water saturation and polymer concentration profiles of the fine scale model as shown in Figure 4-42 (zoomed in from Figure 4-40). We observed the better displacement of the shear-thickening polymer in the blue circle area. Unfortunately, this area was not connected to any producer; hence there was no production gain. On the other hand, the shear-thinning polymer covered more in the orange rectangular area, which was connected to the main flow paths, resulting in higher oil recovery. Additionally, injecting either shear-thinning or shear-thickening polymer gave higher recovery compared to water flooding because of the higher viscosity of the injected fluid. In the water flooding case, the water flowed directly from the injector to the producer via the channels with a minimal displacement in the backgrounds.

We investigated the effects of upscaling on oil recovery predictions. Unlike the lognormal model where all upscaled methods and upscaling levels overestimated oil recovery, the results of the channelled system were diverse. The harmonic and geometric methods overestimated oil production for all upscaling levels. The predictions from the arithmetic average and the renormalization methods varied. At the upscaling level of two, the arithmetic average offered very close prediction in shear-thickening polymer flooding case but very much under estimated oil recovery in the water flood and shear-thinning polymer cases. At the level of upscaling of four, arithmetic upscaling gave very good agreement in the water flood and shear-thinning polymer cases, whereas overestimated in the shear-thickening polymer case. The renormalization upscaling also provided variable results, either over or under predicted, but overall this method was the closest prediction under water and shear-thinning polymer flooding. For
this model, the arithmetic average was the best for the shear-thickening polymer flooding. Renormalization also gave acceptable results. At the level of upscaling of four, we can choose between the arithmetic average and renormalization methods when studying water flooding and shear-thinning polymer flooding. The predictions from these coarse models were comparable to the results from the fine scale model. In the shear-thickening cases, however, all upscaling methods overpredicted oil recovery.

Another comparison was between non-Newtonian and Newtonian flow behaviour of any upscaling method. We compared the oil predictions of the upscaled models under non-Newtonian injection with water flooding. The water flooding case was considered as a base case in any upscaling method. For example, we compared “Arithmetic/Shear-thinning” and “Arithmetic/Shear-thickening” plots to the “Arithmetic/Water” plot. For any upscaling method, if the trend and the slope of polymer cases were similar to the water case, this upscaling method can be used for polymer cases. For all upscaling methods, the results of shear-thinning cases were in good agreement with water flooding cases because the plots have similar trends and slopes. Conversely, the results of shear-thickening cases did not have the same trends as for the water cases. We concluded that in layer 47, which was a fluvial system, models upscaled under water flooding can be used in shear-thinning polymer flooding for oil recovery estimation. However, these models may not be suitable for studying shear-thickening polymer flooding as the results may be too optimistic.

Additionally, the harmonic average gave the worst oil recovery prediction in all upscaling cases and for all types of fluid injection. The oil predictions were excessively high which seemed to be incorrect considering the harmonic average gave the lowest permeability distribution. We further investigated these harmonic upscaled models and found that this was due to an increase in homogeneity of the models. By lowering the permeability values, the channels were disconnected and become more homogenous with the background, fluids had no preferred paths (as in the channels) which results in a higher sweep efficiency.
Table 4-3: Summary of oil recovery predictions from the simulations of SPE 10 Model 2 Layer 47

<table>
<thead>
<tr>
<th>Upscaling methods/Fluids</th>
<th>Pore Volume of Oil Produced after 0.6 PVI at upscaling of</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0</td>
</tr>
<tr>
<td>Harmonic / Water</td>
<td>0.285</td>
</tr>
<tr>
<td>Arithmetic / Water</td>
<td>0.285</td>
</tr>
<tr>
<td>Geometric / Water</td>
<td>0.285</td>
</tr>
<tr>
<td>Renormalization / Water</td>
<td>0.285</td>
</tr>
<tr>
<td>Harmonic / Shear-thinning</td>
<td>0.338</td>
</tr>
<tr>
<td>Arithmetic / Shear-thinning</td>
<td>0.338</td>
</tr>
<tr>
<td>Geometric / Shear-thinning</td>
<td>0.338</td>
</tr>
<tr>
<td>Renormalization / Shear-thinning</td>
<td>0.338</td>
</tr>
<tr>
<td>Harmonic / Shear-thickening</td>
<td>0.330</td>
</tr>
<tr>
<td>Arithmetic / Shear-thickening</td>
<td>0.330</td>
</tr>
<tr>
<td>Geometric / Shear-thickening</td>
<td>0.330</td>
</tr>
<tr>
<td>Renormalization / Shear-thickening</td>
<td>0.330</td>
</tr>
</tbody>
</table>
Figure 4-41: Pore volume of oil produced at various levels of upscaling after 0.6 PVI of water, shear-thinning polymer, and shear-thickening polymer.
CHAPTER 4: UPSCALING OF NON-NEWTONIAN FLUID FLOWS IN TWO-DIMENSIONAL MODELS

Effects on Water Cut Predictions

The impact of non-Newtonian flooding at various simulation scales on water cut predictions was investigated. Figure 4-43 shows water cut profiles from twenty seven simulations. The red lines representing the 60×220 fine scale cases were used as reference lines for each fluid injection. The closer the lines to the red lines, the better match of water cut predictions to the fine scale cases. For water and shear-thinning polymer flooding at any upscaling level, at least one of the upscaling methods gave a very close water cut profile to the fine scale case. The water cut predictions in the shear-thickening upscaled cases were significantly different from the fine scale case. No prediction from the 15×55 upscaled models under shear-thickening polymer flooding matched the fine scale prediction.
Considering the water flooding cases as base cases, the results of the shear-thinning cases were in good agreement with water flooding cases for all upscaling methods. On the other hand, the results of the shear-thickening cases were different for most upscaling methods. Therefore, coarse models originally upscaled for water flood modelling can be used in shear-thinning polymer flood modelling as the results should be in an acceptable range but not in shear-thickening polymer flood modelling.
Table 4-4: Summary of breakthrough predictions from the simulations of SPE 10 Model 2 Layer 47

<table>
<thead>
<tr>
<th>Upscaling methods/Fluids</th>
<th>Pore Volume Injection at Breakthrough at upscaling of 0 2 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Harmonic / Water</td>
<td>0.156 0.183 0.232</td>
</tr>
<tr>
<td>Arithmetic / Water</td>
<td>0.156 0.148 0.190</td>
</tr>
<tr>
<td>Geometric / Water</td>
<td>0.156 0.182 0.203</td>
</tr>
<tr>
<td>Renormalization / Water</td>
<td>0.156 0.178 0.173</td>
</tr>
<tr>
<td>Harmonic / Shear-thinning</td>
<td>0.186 0.217 0.260</td>
</tr>
<tr>
<td>Arithmetic / Shear-thinning</td>
<td>0.186 0.174 0.214</td>
</tr>
<tr>
<td>Geometric / Shear-thinning</td>
<td>0.186 0.206 0.226</td>
</tr>
<tr>
<td>Renormalization / Shear-thinning</td>
<td>0.186 0.205 0.198</td>
</tr>
<tr>
<td>Harmonic / Shear-thickening</td>
<td>0.181 0.260 0.273</td>
</tr>
<tr>
<td>Arithmetic / Shear-thickening</td>
<td>0.181 0.193 0.239</td>
</tr>
<tr>
<td>Geometric / Shear-thickening</td>
<td>0.181 0.215 0.250</td>
</tr>
<tr>
<td>Renormalization / Shear-thickening</td>
<td>0.181 0.215 0.227</td>
</tr>
</tbody>
</table>

Figure 4-44: Water breakthrough predictions of all cases.
### 4.2.3 Effect of Injection Rate

We performed sensitivity runs on injection rate to investigate how it affects non-Newtonian fluid flooding performance. We used the geometric average for upscaled models. We selected seven injection rates from 0.005 rb/day (3.8E-8 PV/day) to 5,000 rb/day (0.038 PV/day) with an increment of ten times. The breakthrough time and oil recovery efficiency profiles of all runs are shown in Figure 4-45. For water flooding, the breakthrough time and oil recovery efficiency predictions were almost constant as expected in Newtonian flow behaviour. The slight differences were because of simulation time steps. In the non-Newtonian cases, when the injection rates were less than 3.8E-5 PV/day, the predictions were also as expected - the increase in oil recovery and delay breakthrough with the increase in injection rates of the shear-thickening polymer (or with the decrease in injection rates of the shear-thinning polymer). This was because of the non-Newtonian effect. In shear-thickening polymer, for example, the higher the flow rate, the higher the shear rate and the higher the fluid viscosity. The high viscosity fluid flowed at a lower rate in the reservoir resulting in the delay in breakthrough time and better sweep efficiency. The breakthrough time and oil recovery efficiency were constant when the injection rates were higher than 3.8E-5 PV/day. This was because ECLIPSE switched the control mode from the reservoir volume rate target to the maximum injection bottomhole pressure target of 10,000 psi (69 MPa). The maximum injection bottomhole pressure was used to prevent the reservoir from fracturing. The switching of the control mode only affects water injection rates. We cannot inject more than 3.8E-5 PV/day. This switching did not affect our study on production predictions as Non-Newtonian behaviour was still presented in all injection rates.

According to literature, composite overburden stress gradient for all normally compacted Gulf Coast formations ranges from 0.85 to 1.00 psi/ft (Eaton, 1969). A normal reservoir pressure gradient is 0.465 psi/ft (Hottmann & Johnson, 1965). Our reservoir depth is at 12,000 feet. The initial bottomhole pressure of 6,000 psi and the maximum injection bottomhole pressure of 10,000 psi equal to 0.5 psi/ft reservoir pressure and 0.83 psi/ft overburden stress gradient. Both gradients are in reasonable ranges found in literature. Hoss (1963) presented water flood data from 38 projects. Water injection rates were between 0.09 and 0.78 bbl/day/acre-foot of pay, equivalent to 1.16E-5 to 1E-4 PV/day. This is within our study ranges.
Figure 4-45: Profiles of breakthrough time and oil recovery efficiency at various injection rates. The upscaled models are calculated by the geometric average.
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4.2.4 Effects of non-Newtonian Flow on Pressure Profiles

The field average pressure profiles of all runs when injecting at 5,000 rb/day are shown in Figure 4-46. As the control mode was switched to be controlled by the bottomhole pressure target of 10,000 psi (68.95 MPa), the well BHP at the injector was almost constant at 10,000 psi. For all type of injected fluids, the field average pressure profiles in upscaled models were higher than the predictions from the fine scale model; unlike the stochastic model where the coarser scales trended to predict lower field average pressure. We observed that in all types of fluid injection the field average pressure decreases almost monotonically in the fine grid simulations but decreases and then increases in the coarser grid simulations. This is because of the channel systems and the constant bottomhole pressure at the injector and producer. In the fine scale models, where the main flow occurs in channels, the cell pressure in the channels are maintained by the constant bottomhole pressure at the injector and producer, whereas the cell pressure in the backgrounds continuously decreases. This is because in the backgrounds the reservoir fluid can flow out of the cells but the injected fluid could not flow into some of this low permeability cells. This results in consistently decreasing in the field average pressure in the fine grid simulations. In the upscaled cases, the models become more homogenous. The field average pressure decreases in the beginning when the main flow path is in the channels. However, the injected fluid has a chance to invade the backgrounds later as the permeability contrast between the channels and the backgrounds was reduced due to upscaling. This results in the increase in field average pressure after the initial decrease. This effect happened in all types of fluid injection.
Figure 4-46: Field average pressure profiles of all cases when injecting at 5,000 rb/day. The upscaled models are calculated by the geometric average.

Figure 4-47 shows the profiles of field average pressure and well BHP at the injector when injecting at 0.50 rb/day. At this injection rate, the simulation control modes are the constant injection rate of 0.50 rb/day and the constant production pressure of 4,000 psi. For all types of fluids, the fine scale models gave the lowest field average pressure curves as well as the highest injector BHP curves.
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We investigated the pressure profiles of all cases and found that the accuracy of field average pressure and injector bottomhole pressure in the coarse scale models is not good. This is because the field...
average pressure is determined by both the absolute values of the well productivity indices (PIs) and the pressure drop between the wells. The well PI might have changed significantly even though the wells had been moved a small distance. The computed field average pressure is potentially sensitive to small changes in the well locations (Christie & Blunt, 2001). Wells are located in the centre of the cells in simulation models. The wells in the fine scale model and the upcaled models are therefore not in the same locations and result in the inaccuracy of pressure profiles. Another factor affects the well PI is the near-well flow regime. In the vicinity of wells, the general flow character is likely to be radial flow pattern with a high pressure gradient, whereas almost all upscaling techniques assume an approximately linear flow regime and the pressure field is slowly varying (Ding, 1995). The near-well flow pattern has a significant impact in coarse scale models. In the near-well region, coarse scale permeabilities computed by assuming linear flow may not adequately capture key features of the fine scale flow (Durlofsky et al., 2000). In addition, according to Muggeridge et al. (2002), the results for wells producing at constant bottom hole pressure, which we used in all cases, may be less good than for those producing at constant rate. This is because the constant rate case is likely to be closer to pseudo-steady state. Theoretically, wells producing at constant bottom hole pressure may require near-well upscaling that take into account of well indices and well block transmissibilities.

We only upscaled absolute permeabilities without taking into account productivity indices and transmissibilities in the near-well region. This contributed to the inaccuracy of our pressure profiles in the coarse scale models. However, the quality of the water and oil production predictions is almost independent of the quality of the field average pressure prediction (Christie & Blunt, 2001). Therefore, our study on oil recovery efficiency and water breakthrough times when injecting with non-Newtonian fluid were not affected.

4.2.5 Summary

We investigated the effects of non-Newtonian flow behaviour at various upscaling levels of the simulation models when the reservoir was in the fluvial environment. We found that the errors in predictions of oil recovery and water production were higher in the coarser models. In addition, the forecasts tended to overestimate the production and delay water breakthrough. However, an acceptable estimation can be obtained from some upscaling methods when studying water or shear-thinning polymer flooding but not in shear-thickening polymer flooding. We also discovered that the
harmonic average upscaling was the worst method for a channelled system. The channels were disconnected because the low permeabilities of the backgrounds dominated the averaged values. This resulted in higher oil recovery from the backgrounds as well as delay in water breakthroughs. We also studied the effect of non-Newtonian flow behaviour compared to Newtonian flow in the same model scales. We concluded that in this fluvial environment an upscaled model that has been used for water flooding can be employed for a study of shear-thinning polymer flooding. However, this upscaled model may not be suitable for shear-thickening polymer flooding study.

We discovered that for Layer 47 with a quarter five-spot pattern non-Newtonian fluid flooding offered significantly higher oil recovery compared to water flooding. This was because the higher apparent viscosities offer the better sweep efficiency. The shear-thinning polymer flooding works better than the shear-thickening polymer flooding. With the shear-thickening behaviour, the apparent viscosities in some grid cells become too high and the flows cease. In the shear-thinning behaviour, on the other hand, the flows in those grid cells continue as the apparent viscosities decrease and reach the producer. As a result, the shear-thinning polymer flooding performs better than the shear-thickening polymer flooding.

We found that the field average pressure profiles were poorly predicted. This is due to the effect of high flow rate region around the wells. The accuracy of pressure profiles in the coarse scale models could be improved by near-well upscaling that considers productivity indices and transmissibilities in the near-well region. We did not exam the near-well upscaling as the main focus is on production predictions.

In this investigation, we noticed the significantly shorter simulation times when using coarser scale models. All simulations were conducted by the HP Z200 Small Form Factor Workstation (Intel Xeon Processor X3470 2.93 GHz, 8MB cache, 1333 MHz memory, Quad-Core, 8GB RAM), which was considerably high performance workstation. For the 60×220 fine scale model, the range of simulation times was between 8-12 hours depends on the type of fluid injection. The simulation times of the 30×110 model takes around 1-1.5 hours and only 15-30 minutes when using the 15×55 model. For any grid scale, water flood simulation was the fastest followed by shear-thinning. The shear-thickening polymer takes the longest simulation time. In addition, the sizes of the simulation files for 60×220, 30×110, and 15×55 models were about 530, 75, and 35 MB, respectively. The much shorter simulation
time and less storage are the main reasons why upscaled models are preferred for sensitivity analysis even when conducting full field simulations of geological models was possible.

4.3 Two-dimensional Fluvial System: SPE 10 Model 2 Layer 12, 59, and 79

We extended our investigation to three additional layers, which were layer 12, 59, and 79, of the second model from the Tenth SPE Comparative Solution Project (Christie & Blunt, 2001). We used the geometric average for the coarse models. Figure 4-48 through Figure 4-50 shows the datasets of Layer 12, 59, and 79, respectively. Figure 4-51 through Figure 4-57 show simulation results of all runs of these three additional layers at three different scales and three injected fluids.

Figure 4-48: SPE 10 Layer 12's dataset (a) the porosity field (b) the porosity histogram (c) the permeability field in $x$- and $y$- directions (d) the permeability histogram in logarithmic scale.
Figure 4-49: SPE 10 Layer 59’s dataset (a) the porosity field (b) the porosity histogram (c) the permeability field in $x$- and $y$- directions (d) the permeability histogram in logarithmic scale.

Figure 4-50: SPE 10 Layer 79’s dataset (a) the porosity field (b) the porosity histogram (c) the permeability field in $x$- and $y$- directions (d) the permeability histogram in logarithmic scale.
Figure 4-51: Comparison of oil recovery efficiency (left) and water cut (right) from all runs (a) layer 12 (b) layer 59 (c) layer 79. The upscaled models are calculated by the geometric average.
Figure 4-52: Comparison of oil recovery efficiency (left) and water cut (right) between SPE 10 Layer 12 fine scale model (60x220 cells) and geometric upscaled models (30x110 and 15x55 cells) under (a) water flooding (b) shear-thinning polymer flooding (c) shear-thickening polymer flooding.
Figure 4-53: Comparison of oil recovery efficiency (left) and water cut (right) between SPE 10 Layer 59 fine scale model (60x220 cells) and geometric upscaled models (30x110 and 15x55 cells) under (a) water flooding (b) shear-thinning polymer flooding (c) shear-thickening polymer flooding.
Figure 4-54: Comparison of oil recovery efficiency (left) and water cut (right) between SPE 10 Layer 79 fine scale model (60x220 cells) and geometric upscaled models (30x110 and 15x55 cells) under (a) water flooding (b) shear-thinning polymer flooding (c) shear-thickening polymer flooding.
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Figure 4-55: SPE 10 Layer 12’s field average pressure profiles of all runs.

Figure 4-56: SPE 10 Layer 59’s field average pressure profiles of all runs.
Based on the simulation results of all four layers (layer 12, 47, 59, and 79), we concluded that

- Comparing the fine grid predictions (Table 4-3 for layer 47 and Figure 4-51 for layer 12, 59, 79), the shear-thinning polymer flooding offered the best recovery factor in all four layers.

- Comparing the coarse grid predictions of all four layers upscaled by the geometric average (Table 4-3 for layer 47, Figure 4-52 for layer 12, Figure 4-53 for layer 59, and Figure 4-54 for layer 79), the coarse grid models gave the closest predictions when simulating under shear-thinning polymer flooding (the plots are closer to the fine scale curve shown in the red lines) but predict too optimistic production when injecting shear-thickening polymer flooding.

- The water cut profiles were highly system dependent. We cannot conclude that the upscaled models delay or accelerate breakthrough time.

- The field average pressure profiles were poorly predicted. This is due to the effect of high flow rate region around the wells as described in Section 4.2.4. The accuracy of pressure profiles in the coarse scale models can be improved by taking into account productivity indices and transmissibilities in the near-well region as presented by Ding (1995).
4.4 Comparison between Upscaled and Refined Scale Models

We compared upscaled and refined scale with the fine scale model. The 60×220 model was upscaled to a 15×55 model by the geometric average. The upscaled permeabilities were applied to corresponded grid cells in the fine scale model. This approach was for the refined cases. We would have liked to examine the effect of local grid refinement around the wells but Eclipse does not support this when modelling shear thinning and shear thickening polymers at this time. The three cases are as follows:

- Case 1 – Base case: 60×220 fine scale model
- Case 2 – Upscaled case: 15×55 geometric upscaled model
- Case 3 – Refined case: 60×220 refined from the 15×55 geometric upscaled model

Figure 4-58 shows the three cases used for this study. The top picture was the Layer 47, 671 metres by 366 metres (2,200 ft × 1,200 ft), 60×220 cells. The bottom three sets were the near-well section of the Layer 47, 49 metres × 98 metres (160 ft × 320 ft), 16×16 cells in Case 1 and 3, and 4×4 cells in Case 2. The differences in predictions between Case 1 and Case 2 were the total upscaling errors. The differences in predictions between Case 2 and Case 3 are the discretization error from numerical dispersion due to the coarsening of computational grids. The error due to homogenization of the reservoir or the loss of heterogeneity error can be determined by finding the differences of results between Case 1 and Case 3. The difference in simulation results was solely from the loss of heterogeneity due to upscaling because the same number of grid cells was used in both cases.

We performed simulations on the three cases in four layers: layer 47, 12, 59, 79 under water, shear-thinning polymer, and shear-thickening polymer flooding. The results are shown in Figure 4-59 through Figure 4-62. These results confirm that upscaling was highly system dependant. Although, we cannot draw a definite conclusion, the refined cases were most likely to give closer production predictions to the fine scale models in all three types of fluid injection in this study.

ECLIPSE can only assign wells in the centre of gridblock. The well locations in the upscaled models were not exactly the same as in the fine scale model. The computed field average pressure is potentially sensitive to small changes in the well locations (Christie & Blunt, 2001). However, we could not exam this effect by applying local grid refinement due to ECLIPSE limitations. Another important factor is the
high flow regions near wellbore that affect well productivity indices and field pressure profiles as explained in Section 4.2.4. In the layer 47 (Figure 4-59), well productivity indices significantly affect the pressure profiles. In this layer, near-well upscaling should be considered in order to better capture the high flow, radial pattern near the injector and the producer. In the layer 12 and 59 (Figure 4-60 and Figure 4-61), the average field pressure is at the limit of 10,000 psi maximum injection bottomhole pressure. The cell pressure is slowly varying. The near-well upscaling may not be necessary. In the layer 79 (Figure 4-62), we observed good predictions of the pressure profiles. This is because its reservoir characteristics. The producer and the injector are located in the backgrounds (Figure 4-50). In all upscaled model, the wells are also located in the backgrounds. The pressure gradient around the wells is considerably lower compared with those in layer 47. In this layer, the near-well upscaling may not be necessary.
Figure 4-58: Layer 47’s permeability field (top). The bottom three sets are zoomed in pictures around injectors (blue border) and producers (red border) of the three cases.
Figure 4-59: Comparison of oil recovery efficiency and water cut profiles (left) and field average pressure curves (right) between Case 1, 2, 3 using Layer 47 under (a) water flooding (b) shear-thinning polymer flooding (c) shear-thickening polymer flooding.
Figure 4-60: Comparison of oil recovery efficiency and water cut profiles (left) and field average pressure curves (right) between Case 1, 2, 3 using Layer 12 under (a) water flooding (b) shear-thinning polymer flooding (c) shear-thickening polymer flooding.
Figure 4-61: Comparison of oil recovery efficiency and water cut profiles (left) and field average pressure curves (right) between Case 1, 2, 3 using Layer 59 under (a) water flooding (b) shear-thinning polymer flooding (c) shear-thickening polymer flooding.
Figure 4-62: Comparison of oil recovery efficiency and water cut profiles (left) and field average pressure curves (right) between Case 1, 2, 3 using Layer 79 under (a) water flooding (b) shear-thinning polymer flooding (c) shear-thickening polymer flooding.
5

UPSCALING OF MODELS UNDER POWER LAW FLUID FLOODING

In the previous chapter, we found problems when models upscaled for water flooding were used for shear-thickening polymer flooding. In this chapter, we focused solely on how to improve errors in predictions. Firstly, we investigated the possibility of using a new algorithm for upscaling power law fluid displacement. Unfortunately, the new algorithm did not work when using the commercial simulator because of the custom numerical algorithms used by the simulator. We can either develop a new simulator or find an approach to upscaling models appropriate for the commercial simulator to study shear-thickening polymer flooding. We opted for the latter and found the best approach to use upscaled models for shear-thickening polymer flooding study. The recommended approach was described in this chapter. In addition, we demonstrated how much error one should expect if upscaled models under water flooding were used for polymer flooding study without any adjustment.
5.1 Effective Permeability in Layered Systems when Displacing with Power Law Fluids

We derived an analytical calculation for the effective permeability when studying power law fluid flooding. We followed the well known strategy when deriving an average permeability in layered systems under Darcy's law that resulted in using the arithmetic average for parallel flow and the harmonic average for serial flow. However, here we replaced Darcy's law with the appropriate equation for non-Newtonian flow. A semi-empirical equivalent of Darcy's law – the Blake-Kozeny equation (Bird et al., 1960) is the most successful expression describing the laminar flow of Newtonian fluid through a packed bed. Christopher and Middleman (1965) modified the Blake-Kozeny equation for a power law, non-Newtonian fluid with laminar flow though a packed bed. The theory was based on a capillary model and the Blake-Kozeny equation of permeability; then experiments were conducted by flowing of polymer solutions through packed porous materials. The modified Blake-Kozeny equation, which has been widely used for single-phase laminar flow of power law fluids, is as follows:

\[ u = \left( \frac{k}{\mu} \left[ - \frac{\partial P}{\partial x} \right] \right)^{1/n} \]  \hspace{1cm} (5-1)

Where

\[ \mu = \frac{C}{12} \left( 9 + \frac{3}{n} \right)^n \left( 150k\phi \right)^{(1-n)/2} \]  \hspace{1cm} (5-2)

The power law exponent, \( n \), governs three fluid flow regimes: shear-thinning if \( n < 1 \), Newtonian when \( n = 1 \), and shear-thickening if \( n > 1 \).

For linear parallel flow, where permeability varies across several horizontal layers, the pressure drop for each layer is the same, whereas the total flow rate is the sum of the flow rates in all layers. The effective permeability can be determined by the following derivation:

\[ q_e = \sum_{i=1}^{m} q_i \]
\[
\left( \frac{k_{eff} \Delta P}{\mu_{eff} \ L} \right)^{1/n} H w = \sum_{i=1}^{m} \left[ \left( \frac{k_i \Delta P}{\mu_i \ L} \right)^{1/n} h_i w_i \right]
\]

(5-3)

As \[ \frac{\Delta P}{L} = \text{Constant} \]

Assuming \[ w = w_i \]

Resulting in

\[
k_{eff} = \left( \frac{\sum_{i}^{m} \left[ \left( \frac{k_i \Delta P}{\mu_i \ L} \right)^{1/n} h_i \right]}{H} \right)^{n} \mu_{eff}
\]

(5-4)

Where

\[
\mu_{eff} = \frac{C}{12} \left( 9 + \frac{3}{n} \right)^n \left( 150k_{eff} \phi \right)^{(1-n)/2}
\]

(5-5)

and

\[
\mu_i = \frac{C}{12} \left( 9 + \frac{3}{n} \right)^n \left( 150k_i \phi \right)^{(1-n)/2}
\]

(5-6)

Replacing Equation (5-5) and (5-6) in Equation (5-4) gives

For linear, parallel flow:

\[
k_{eff} = \left( \frac{\sum_{i}^{m} \left[ h_i (k_i)_{(1+n)/2n} \right]}{H} \right)^{2n/(1+n)}
\]

(5-7)

In Newtonian flow (when \( n = 1 \)), Equation (5-7) gives the arithmetic average.

For linear serial flow, where permeability varies across several vertical layers, the total flow rate is the same for each layer, whereas the total pressure drop is a summation of pressure drop across layers. The effective permeability can be determined by:

\[
\Delta P_t = \sum_{i=1}^{m} \Delta P_i
\]
Replacing Equation (5-5) and (5-6) in Equation (5-8) gives

For linear, serial flow:

\[ k_{eff} = \left( \frac{L}{\sum_{1}^{m} \frac{l_i}{(k_i)^{(1+n)/2}}} \right)^{2/(1+n)} \]  (5-9)

In Newtonian flow (when \( n = 1 \)), Equation (5-9) reduces to the harmonic average.

We validated the use of effective permeability calculated by Equations (5-7) and (5-9) in the layered models used in Chapter 3. There were ten layers in the models with ten permeability values. We created four cases with ten permeability values assigned to the layers. These four cases had different permeability contrasts. We calculated standard deviations and Dykstra-Parsons coefficients (Dykstra & Parsons, 1950) to compare the permeability contrasts. Model 1 had the lowest permeability contrast, whereas Model 4 had the highest permeability contrast. For each model, the effective permeabilities calculated by the arithmetic average (or the harmonic average for the serial case) and by Equation (5-7) (or Equation (5-9) for serial flow) were determined. Table 5-1 summarises the parameters and the calculated results of the four 10-layered models. The location of each layer is displayed in Figure 5-1. The relative permeabilities are shown in Figure 5-2. Figure 5-3 and Figure 5-4 are the simulation results of all runs.

Firstly, we concentrated on Model 1. We solely focused on shear-thickening fluids where the power law exponents were greater than one. These exponents theoretically have no upper limit; however, we have only seen values between 1.1 and 3.0 in literature. We applied the power law exponent of two to Model 1. In both the parallel and serial flow cases, we compared water cut and oil recovery profiles of the 10-layered model with two homogenous models. One of the homogenous models used the effective permeability calculated by the arithmetic average (or the harmonic average for the serial case) and the other used Equation (5-7) (or Equation (5-9) for serial flow). We did not notice any differences in water cut and oil recovery predictions. We then increased the values of the power law exponents up to four but still no differences. This is probably due to very close effective permeabilities of the models.
We applied the power law exponent of four for all cases. We analysed the results of Model 2, Model 3, and Model 4. The homogenous model used the effective permeability calculated by the arithmetic average (or the harmonic average for the serial case) and the model used Equation (5-7) (or Equation (5-9) for serial flow) gave the same predictions in all four models with four set of permeability contrasts.

In the parallel flow models (Figure 5-3), we noticed differences in predictions between the 10-layered model and the two homogenous models. The water breakthrough of Model 2 was sooner than Model 3 even though Model 2 has lower permeability contrast. This was because Model 2 had only one high permeability layer (Layer 2). The flow rate in this layer was much higher than the other nine layers hence the early water breakthrough in Layer 2. In Model 3, at the constant injection rate, the high flow rates were allocated to three high permeability layers (Layer 2, 5, and 8), resulting lower flow rates in high permeability zone compared to Model 2 Layer 2 hence later water breakthrough. When the permeability contrast was very high as in Model 4, the water breakthrough was much sooner and the oil recovery was much less than the homogenous models. This was because the flow bypasses low permeability layers. The effective permeabilities cannot represent the layered model. In the serial flow models (Figure 5-4), the layered model and the two homogenous models predicted the exact same curves for oil recovery efficiency and water cut in all four cases.

All except Model 4, both parallel and serial flow cases, no significant difference was shown in both water cut and oil recovery profiles. This is probably due to the simplicity of the models. We investigated the use of Equations (5-7) and (5-9) in more complex models in the next section.
Table 5-1: Summary of the four 10-layered models.

<table>
<thead>
<tr>
<th>Layer</th>
<th>Model 1</th>
<th>Model 2</th>
<th>Model 3</th>
<th>Model 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Layer 1</td>
<td>75</td>
<td>75</td>
<td>15</td>
<td>2,000</td>
</tr>
<tr>
<td>Layer 2</td>
<td>35</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Layer 3</td>
<td>45</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Layer 4</td>
<td>70</td>
<td>70</td>
<td>70</td>
<td>1</td>
</tr>
<tr>
<td>Layer 5</td>
<td>50</td>
<td>50</td>
<td>200</td>
<td>1,000</td>
</tr>
<tr>
<td>Layer 6</td>
<td>40</td>
<td>40</td>
<td>40</td>
<td>50</td>
</tr>
<tr>
<td>Layer 7</td>
<td>60</td>
<td>60</td>
<td>20</td>
<td>5,000</td>
</tr>
<tr>
<td>Layer 8</td>
<td>35</td>
<td>25</td>
<td>150</td>
<td>300</td>
</tr>
<tr>
<td>Layer 9</td>
<td>55</td>
<td>55</td>
<td>5</td>
<td>500</td>
</tr>
<tr>
<td>Layer 10</td>
<td>65</td>
<td>65</td>
<td>90</td>
<td>5</td>
</tr>
</tbody>
</table>

Standard deviation: 14.38, 25.71, 65.70, 1,574.58
Dykstra–Parsons coefficient: 0.27, 0.50, 0.75, 0.96

Effective permeabilities (mD) calculated by

- Arithmetic average: 53.00, 55.00, 70.00, 896.60
- Harmonic average: 49.45, 36.65, 20.46, 7.48
- Eq (5-7) with n = 4.0 (parallel flow, shear-thickening): 52.33, 52.49, 59.03, 551.40
- Eq (5-9) with n = 4.0 (serial flow, shear-thickening): 47.02, 23.33, 11.38, 2.49

(a) 10-layered model for parallel flow
(b) 10-layered model for serial flow

Figure 5-1: Locations of Layer 1-10 in the layered systems for (a) parallel flow (b) serial flow.
Figure 5-2: Relative permeabilities used to study the layered systems.
CHAPTER 5: UPSCALING OF MODELS UNDER POWER LAW FLUID FLOODING

Figure 5-3: Comparison of water cut and oil recovery predictions of the four 10-layered models under parallel flow of shear-thickening polymer flooding.
Figure 5-4: Comparison of water cut and oil recovery predictions of the four 10-layered models under serial flow of shear-thickening polymer flooding.

5.2 Effects of Power Law Fluids Flow in SPE 10 Model 2 Layer 47

We studied the effects of upscaling in production forecasts when the injected fluid had a power law viscosity. Our fine scale model was the SPE 10 Model 2 Layer 47, which had been used in the previous chapter. This 60×220 model was upscaled to 30×110 models by the arithmetic average, harmonic
average, geometric average, renormalization, power law exponent (parallel) – Equation (5-7), and power law exponent (serial) – Equation (5-9). All models were then simulated under the injection of various power law viscosities. We applied injected fluids with power law exponents from 0.2 to 2, with an increment of 0.2. Other parameters in these simulations were exactly the same as in Section 3.3. Seventy simulations were performed in this investigation. We mainly focused on the predictions of oil recovery and water breakthrough time.

5.2.1 Simulation Results

**Oil Recovery**

Figure 5-5 shows the oil recovery predicted from all simulation cases. In the fine scale model, the oil recovery ranged from 0.371 to 0.381 pore volumes (a difference of 0.010 pore volumes) when varying the power law exponents between 0.2 and 2. The difference of oil recovery can be as high as 0.088 pore volumes when using the upscaled models. In the harmonic upscaled cases, where the permeabilities were the lowest, the predictions of oil recovery were the highest. This was because of the loss of the channel characteristics as explained in Section 4.2. This led to higher flows in the background hence higher sweep efficiency. The figure also shows that we can match the upscaled results to the fine scale results at only some power law exponents. For example, an upscaling model by renormalization or the geometric average can be used instead of the fine scale model for oil predictions only when the power law exponents were between 0.6 and 0.7, which is a very narrow range.

Most noticeable in this figure was the different trends between the fine scale cases and all upscaled cases. In theory, the shear-thickening polymer (when the power law exponent was greater than one) helps increase in sweep efficiency and results in higher oil recovery. In our fine scale model, however, less oil was recovered when the power law exponent increases. On the other hand, all upscaling methods gave the opposite trend. The higher the power law exponent, more oil was recovered. Further investigation is in the next section.
CHAPTER 5: UPSCALING OF MODELS UNDER POWER LAW FLUID FLOODING

Figure 5-5: Oil recovery of the models under a variety of power law exponents of fluid injection.

Shear Rates

We investigated the cases to understand why the simulator predicted the opposite trend between the fine scale model and the coarse scale models. The best approach is to compare shear rates in the coarse scale models with the fine scale model. However, the ECLIPSE simulator does not use shear rates in the simulation as explained in Chapter 3. ECLIPSE can display the face-centred velocity fields in each direction of each gridblock at any time step.

For two-dimensional models, shear rates can be determined by
\[
\gamma = \frac{\partial u}{\partial y} + \frac{\partial v}{\partial x} \quad (5-10)
\]

For discrete cases:
\[
\gamma = \frac{\Delta u}{\Delta y} + \frac{\Delta v}{\Delta x} \quad (5-11)
\]

Where:
- \( \gamma \) Shear rate
- \( u \) Face-centred velocity in \( x \) direction
- \( v \) Face-centred velocity in \( y \) direction
- \( x \) Distance in \( x \) direction
- \( y \) Distance in \( y \) direction
- \( \Delta x \) Cell width
- \( \Delta y \) Cell length

In the finite-volume formation, when the centre of gridblocks has location \((x_{ij}, y_{ij})\), Equation (5-11) may be approximated by Equation (5-12). The parameters associated with this equation were graphically displayed in Figure 5-6.

\[
\gamma \left( i + \frac{1}{2}, j + \frac{1}{2} \right) = \frac{u \left( i + \frac{1}{2}, j + 1 \right) - u \left( i + \frac{1}{2}, j \right)}{\Delta y} + \frac{v \left( i + 1, j + \frac{1}{2} \right) - v \left( i, j + \frac{1}{2} \right)}{\Delta x} \quad (5-12)
\]

Figure 5-6: Schematic showing positions of parameters used in Equation (5-12)- reprinted from Rashid et al.(2010).
As the outputs from the simulator were face-centred velocity fields, we modify Equation (5-12) to calculate the face-centred shear rate in each gridblock as shown in Equation (5-13).

\[ \gamma(i,j) = \frac{u(i,j + 1) - u(i,j - 1)}{2\Delta y} + \frac{v(i + 1,j) - v(i - 1,j)}{2\Delta x} \]  

For this investigation, we exported two velocity fields (\(x\)- and \(y\)- directions) at several selected time steps from ECLIPSE; then calculated shear rates in MATLAB, and imported the shear rates to Petrel for analysis using the Petrel time player. The time player can animate a parameter through time. It is very useful tool to observe how the shear rate has changed with time.

Figure 5-7 shows the histograms of shear rates in the fine scale model and the arithmetic upscaled model at 0.5PVI of the injected fluid with the power law exponent of 1.2. The shear rates in the coarse scale model were noticeably lower than the fine scale model.
We compared the difference in shear rates between the fine scale model and the arithmetic upscaled model. As the number of cells was not equalled, the shear rates in the fine scale model were averaged by the arithmetic mean and compared with the shear rates in the upscaled model in the same regions. The difference in shear rates between the fine scale model and the arithmetic upscaled model (shear rate error) is graphically displayed in Figure 5-8 (a) actual error and (b) logarithm of error. The injector was at the bottom right corner and the producer was at the top left corner. Figure 5-8 (c) shows the permeabilities of the 30×110 arithmetic upscaled model for reference purposes. The shear rates in the fine scale model were visibly higher than the coarse scale model.
The mean and standard deviation of parameters in this comparison were calculated by Equations (5-14) and (5-15). Table 5-2 is the summary of the calculation. The average velocities in both directions and the average shear rate of the fine scale model were about three times the mean of the coarse scale model. All parameters in the fine scale model had extremely high standard deviation compared with the values in the upscaled model due to the large ranges of their values.

\[
Mean = \bar{x} = \frac{1}{n} \sum_{a=1}^{n} x_a
\]  
(5-14)

\[
Standard Deviation = SD = \left( \frac{1}{n-1} \sum_{a=1}^{n} (x_a - \bar{x})^2 \right)^{1/2}
\]  
(5-15)
Table 5-2: Mean and standard deviation of parameters in the shear rate comparison

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Units</th>
<th>60×220 Fine Scale Model</th>
<th>30×110 Arithmetic Upscaled Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean of velocity in $x$-direction</td>
<td>m/s</td>
<td>$4.24 \times 10^{-6}$</td>
<td>$1.45 \times 10^{-6}$</td>
</tr>
<tr>
<td>$SD$ of velocity in $x$-direction</td>
<td>m/s</td>
<td>$58.15 \times 10^{-6}$</td>
<td>$3.98 \times 10^{-6}$</td>
</tr>
<tr>
<td>Mean of velocity in $y$-direction</td>
<td>m/s</td>
<td>$4.43 \times 10^{-6}$</td>
<td>$1.32 \times 10^{-6}$</td>
</tr>
<tr>
<td>$SD$ of velocity in $y$-direction</td>
<td>m/s</td>
<td>$63.43 \times 10^{-6}$</td>
<td>$5.73 \times 10^{-6}$</td>
</tr>
<tr>
<td>Mean of shear rate</td>
<td>1/s</td>
<td>$1.90 \times 10^{-6}$</td>
<td>$0.48 \times 10^{-6}$</td>
</tr>
<tr>
<td>$SD$ of shear rate</td>
<td>1/s</td>
<td>$16.4 \times 10^{-6}$</td>
<td>$1.14 \times 10^{-6}$</td>
</tr>
<tr>
<td>Mean of shear rate error</td>
<td>1/s</td>
<td></td>
<td>$1.42 \times 10^{-6}$</td>
</tr>
<tr>
<td>$SD$ of shear rate error</td>
<td>1/s</td>
<td></td>
<td>$12.75 \times 10^{-6}$</td>
</tr>
</tbody>
</table>

This comparison (Figure 5-7, Figure 5-8, and Table 5-2) demonstrated how the shear rates at one time step (0.5 PVI) of two models were calculated and compared. We had seventy simulation models. Each model had a hundred time steps. Two parameters: velocities in $x$- and $y$- direction in each time step were required in the shear rate calculation. That was 14,000 datasets. To the best of our knowledge, it is not possible to automatically export the velocities from ECLIPSE, calculate the shear rates in MATLAB, and import the shear rates to Petrel for analysis using the time player. Therefore, we calculated the shear rates at selected time intervals enough to understand the different trends between the fine scale model and the coarse scale models. We discovered that the difference trends were due to the homogeneity of the models. In the fine scale model, where the model was highly heterogeneous, the shear-thinning fluid (the power law exponent is less than one) can help recover more oil because of its low viscosity at high shear rates. As the reservoir was a fluvial system, where the main flow was in the channels, the shear-thinning polymer helped sweep oil around the channels and was still able to flow to the producer. On the other hand, in the shear-thickening fluid injection, the viscosity dramatically increases along the channels. Some cells in the channels with very high shear rates, mostly in very high permeability cells, the flows may be ceased because the fluid was too viscous to move and this resulted in lower oil recovery. This phenomenon was not detected in the upscaled models because the cell permeabilities, averaged from four neighbour cells of the fine scale model, were more homogeneous. The exceptionally high permeability cells in the fine scale model were averaged with other cells. This average led to more homogeneous models and consequently resulted in lower shear rates. The shear rates in the coarse scale models were considerably lower than in the fine scale model. As a result, the non-Newtonian effect was significantly lower. The viscosity of the injected shear-thickening fluid in the
upscaled models did not increase high enough for the fluid to refuse to flow. The injected fluid was able to flow from the injector to the producer without any blockages (or dead cells in reservoir simulation). Therefore, the oil recovery increased when the power law exponent increased.

**Breakthrough Times**

Similar to the oil recovery study, Figure 5-9 shows the breakthrough times in terms of pore volume injection for various power law exponents. The results were in the similar trends as the oil recovery for each model. The water breakthrough times were brought forward when the power law exponents increased in the fine scale model. The opposite trend occurred in all upscaling methods. Once again, this was due to an increase in homogeneity in the upscaled models. In the fine scale model under the shear-thickening polymer flooding, as explained previously, when the shear rates were high, the cells were blocked and become dead cells in simulations. The channels were however not completely disconnected. The flow was continuous to the producer via active cells, mainly in the channels. Since there were fewer active cells, the water reached at the producer sooner than in the shear-thinning cases. In the upscaled cases, the higher flow areas and the lower number of very high permeability cells can delay water breakthroughs. As the shear rates were not high enough to reduce the flow, the breakthrough time in the shear-thickening cases were later than the shear-thinning cases of the same upscaling methods.
Findings

We included the analytical calculations of effective permeability when flow is parallel (Equation (5-7)) and when flow is serial (Equation (5-9)) in these simulations. However, the calculated oil recovery and breakthrough time predictions were not good when compared with ECLIPSE. The results of the upscaled model using Equation (5-9) were almost identical to the results of the harmonic average. Equation (5-7) only offered the best estimations in a small range of the power law exponents (1.1-1.4). We believed one of the reasons in the prediction errors was because the way ECLIPSE modelled non-Newtonian flow behaviour (more details were in Section 3.2.3). Table 5-3 shows the equations used in ECLIPSE compared to the modified Blake-Kozeny equation that we used to derive the effective permeability. In
our derivation of the effective permeability, the analytical calculations of the effective permeability (Equations (5-7) and (5-9)) can provide the exact solutions for linear, parallel or serial flows when the effective permeability is put directly in the modified Blake-Kozeny equation to calculate the flow rate.

ECLIPSE however applies the Herschel-Bulkley fluid modifier, $B$, as an addition to Darcy’s equation. The permeability presents in both the Herschel-Bulkley fluid modifier and Darcy’s equation. Using Equation (5-7) or (5-9) and then ECLIPSE means the effective permeability is manipulated twice.

### Table 5-3: Comparison between ECLIPSE and the modified Blake-Kozeny equations

<table>
<thead>
<tr>
<th>Equations used in ECLIPSE</th>
<th>The modified Blake-Kozeny equation</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\bar{q} = \frac{AKk_r}{\mu L} B \Delta P$</td>
<td>$u = \left( \frac{k}{\mu} \left[ -\frac{\partial P}{\partial x} \right] \right)^{1/n}$</td>
</tr>
</tbody>
</table>
| $B = \begin{cases} 
1 - \frac{d\alpha_0}{|\Delta P|} & \text{if } \frac{d\alpha_0}{|\Delta P|} < 1 \\
0 & \text{otherwise}
\end{cases}$ | $\mu = \frac{C}{12} \left( \frac{\phi}{n} + \frac{\frac{3}{n}}{(150k\phi)^{1-n}/2} \right)$ |
| $\alpha = \sqrt{\frac{\phi}{2} \sqrt{\frac{\delta}{K}}}$                                |                                   |

Where:

- $A$ Area through which flow occurs
- $B$ Herschel-Bulkley fluid modifier
- $C$ Power law coefficient
- $d$ Distance between cells
- $K$ Rock permeability in a given direction
- $k$ Permeability tensor (symmetric positive definite)
- $k_r$ Relative permeability
- $L$ Total length
- $n$ Power law exponent
- $P$ Pressure
- $\bar{q}$ Volumetric flow rate
- $u$ Darcy velocity ($\bar{q}/A$)
- $x$ Distance in $x$-direction
- $\alpha$ Weighing factor for the yield stress
- $\delta$ Tortuosity
- $\mu$ Viscosity
- $\tau_o$ Yield stress
- $\phi$ Porosity
An analytical calculation of the effective permeability based on the equations used in ECLIPSE cannot be determined unless \( \frac{d\tau}{|\Delta P|} = 0 \). When \( \frac{d\tau}{|\Delta P|} = 0 \), the only difference between these two methods is the use of \( 72\delta \) in ECLIPSE instead of \( 150\phi \) in the modified Blake-Kozeny equation. In this case, we can use the effective permeability calculated by Equations (5-7) or (5-9) with ECLIPSE. However, these conditions only happen in a homogenous reservoir (homogenous permeability and porosity fields), no dead pore volume in polymer flooding (constant porosity), constant tortuosity, and a polymer has constant yield stress. These conditions however do not need any upscaling because of the homogenous permeability field. Therefore, we can conclude that it is not possible to find an analytical solution of the effective permeability to be used with ECLIPSE. We can either find an alternate approach to be used with ECLIPSE or develop a new simulator using the modified Blake-Kozeny equation. We opt for the first as our project focuses on upscaling techniques to be applied in a reservoir under polymer flooding not to develop a new simulator. In addition, ECLIPSE is a well-known and widely used reservoir simulator in the industry. Finding the better approach to model a reservoir under polymer flooding could be at more use to larger audiences than developing a new simulator that is required more testing and verifying. Our recommended approach was explained in Section 5.3.

5.2.2 Error Analysis when Upscaled Models under Newtonian Fluid Flooding are Used for Non-Newtonian Fluid Modelling

It is usual to study the benefits of polymer flooding compared with water flooding. An intense sensitivity analysis is conducted with numerous scenarios. To make this assessment more practical, a detailed geological model is upscaled to a simulation model. The upscaled model assumed under water flooding is matched to the fine scale model. Reservoir parameters such as permeability, relative permeability, and sometime mobility were adjusted to achieve the best match. This upscaled model with the pseudo functions is then used to study polymer flooding by just changing the properties of the injected fluid without comparison with the fine scale model again. The purpose of this section is to demonstrate how much error one should expect when using models upscaled for Newtonian fluid flooding that have been adjusted to match results from a fine scale model to study non-Newtonian fluid displacement.

We had the results of oil recovery and water breakthrough time as shown in Figure 5-5 and Figure 5-9. We studied normalised plots from both figures by assuming all upscaled models under Newtonian fluid
flooding were matched to the fine scaled model, the results at the power law exponent of one were the same as the fine scale model results. The differences between the 60×220 fine scale model and the upscaled models were the errors due to the change from water to non-Newtonian fluid flooding. For example, Figure 5-10 is the normalised plots of Figure 5-9, meaning all upscaled models under Newtonian fluid flooding ($n = 1$) were assumed to give the same prediction of water breakthroughs as using the fine scale model.

Figure 5-10: The normalised plots of Figure 5-9 to study error in water breakthroughs when using upscaled models under Newtonian fluid flooding to model non-Newtonian fluid flooding.

Figure 5-11 and Figure 5-12 show the errors in predictions of water breakthrough time and oil recovery due to non-Newtonian flooding. Using Newtonian fluid flooded upscaled models in shear-thinning polymer flooding study can underestimate its performance by nine percent. The predictions in shear-
thickening polymer flooding were overestimated if Newtonian fluid flooded upscaled models were used. The errors in shear-thickening polymer flooding were higher than shear-thinning polymer flooding. This was due to the conflict between the results of the fine scale models and upscaled models (the predicted trends go in the opposite direction).
CHAPTER 5: UPSCALING OF MODELS UNDER POWER LAW FLUID FLOODING

Figure 5-11: Percent error of breakthrough time due to non-Newtonian flooding.

Figure 5-12: Percent error of oil recovered due to non-Newtonian flooding.
5.2.3 Summary

We investigated the effect of injecting power law fluids in the channelled system. The simulation results of oil recovery and water breakthrough times lead to several findings. The most important was the opposite forecasting trends between the fine scale model and the upscaled models when non-Newtonian fluid was injected in the channelled system. These different trends can have a significant impact on an economic evaluation, especially when studying the benefits of implementing shear-thickening polymer flooding. Another finding was that none of the fast upscaling methods can offer a good match in the predictions of oil production or water cut in polymer flooding. An upscaled model that was manipulated for a perfect match to a fine scale model under water flooding should not be used for polymer flooding study. At present, there is no analytical calculation of the effective permeability that can be applied directly to the ECLIPSE simulator.

5.3 Recommended Approach for Non-Newtonian Fluid Flow Simulations

As demonstrated in the previous section, an analytical method for calculating an effective permeability to be used with the ECLIPSE simulator cannot be determined. We investigated an approach that should be applied in upscaled models when studying non-Newtonian fluid flooding using ECLIPSE. We found that the most important parameter is the power law exponent. From Table 5-3, the value of the power law exponent affects the Herschel-Bulkley fluid modifier, \( B \), which consequently impacts the flow equation used in ECLIPSE. Additionally, in the modified Blake-Kozeny equation, the fluid viscosities and fluxes are a function of the power law exponent. The rheological models for both methods are based on the same theory and can be simplified to the power law model when the yield stress is zero. The effective viscosity can be determined by:

\[
\mu_{\text{eff}} = C \gamma^{n-1} \tag{5-16}
\]

Where:
- \( \mu_{\text{eff}} \): Effective viscosity
- \( C \): Power law coefficient
- \( \gamma \): Shear rate
- \( n \): Power law exponent
Figure 5-13 shows the relationship between the shear rate and the viscosity at various power law exponents calculated by Equation (5-16) when the power law coefficient is 5 mPa.S\(^n\). The viscosity is constant (slope = 0) when the power law exponent equals to one (Newtonian fluid). At the same shear rate, the higher the power law exponent value is, the higher the viscosity is.

In a fine scale model under shear-thickening polymer flooding, high flow velocities occur in high permeability cells. These cause the high shear rates on the boundaries between these cells and the low permeability neighbours and eventually result in exceptionally high shear viscosities. The upscaled permeabilities are averaged from several cells in the fine scale model, hence lower values. The shear rates in the coarse scale models are considerably lower than in the fine scale model. As a result, the non-Newtonian effect is significantly lower. The apparent viscosities in the coarse scale models are lower than those in the fine scale cells. These ultimately affect production forecasts as viscosity is a parameter in any fluid flow equations. In order to replicate similar viscosities as in the fine scale model, we suggest adjusting the power law exponent used in the coarse scale models. For example, the shear rate in the fine scale model is 100 s\(^{-1}\) when the injected fluid has the power law exponent of 1.4, the apparent viscosity is 32 mPa.s. In the coarse scale model, if the shear rate is only 10 s\(^{-1}\), the power law exponent of 1.8 is suggested for simulations to reproduce the apparent viscosity of 32 mPa.s.
The main purpose of adjusting the power law exponents is to manipulate the apparent viscosities of injected fluids. In a shear-thickening polymer, the fluid is more viscous if the power law exponent is higher. Increasing the power law exponent of injected fluid in a coarse scale model helps increase the apparent viscosities in the upscaled cells at the lower shear rates than those of the fine scale cells. This adjustment can offer closer predictions to the fine scale model.

5.3.1 Verification of the Recommended Approach

We verified our recommended approach in Layer 47 of the SPE 10 model 2. The fine scale model of 60×220 cells was simulated under the injection of the shear-thickening polymer with the power law exponent of 1.2. The oil recovery and breakthrough time were compared with the results from the 30×110 arithmetic upscaled model as shown in Figure 5-14. The x-axis can be viewed in the dimensionless form by dividing by 129,242 STB (1 PVI). The scale on the top is the estimated PVI associated with the x-axis. Firstly, the power law exponent of 1.2 was applied to the injected fluid in the coarse scale model. However, the oil recovery efficiency and water cut predictions were not in good agreement with the predictions when using the fine scale model. The predictions from the upscaled model were closer to the fine scale model when the power law exponent of 1.5 was applied instead of 1.2. This matching was done empirically because the rheological model used in ECLIPSE is not a simplified power law model as shown in Table 5-3.
Figure 5-14: Comparison of water cut and oil recovery predictions of the fine scale model and the arithmetic upscaled model under shear-thickening fluid flooding.

Figure 5-15 shows the water saturation distributions of the models at 0.5 PVI (top) and 0.7 PVI (bottom) of the shear-thickening polymer. The injector was at the bottom right corner; the producer was at the top left corner. The water saturation distributions of the 30×110 coarse model injected with the \( n = 1.5 \) polymer (right) noticeably better matched those of the 60×220 fine scale model with \( n = 1.2 \) (left) in both 0.5 and 0.7 PVI compared with using \( n = 1.2 \) in the coarse model (centre).
Figure 5-15: Water saturation distributions after 0.5 PVI (top) and 0.7 PVI (bottom) of the fine scale model under the injection of the shear-thickening polymer with the power law exponent of 1.2 (left) and the arithmetic upscaled models under injection of the shear-thickening polymer with the power law exponent of 1.2 (centre) and 1.5 (right).

During the shear rate study, we discovered that the water velocity vectors, which are available in Petrel, can be used instead of the shear rates for model comparisons. Comparing the velocity vectors between the models gave the same conclusion as comparing the shear rates of the models (in terms of which coarse scale model was better). This helped to reduce time spent on the shear rate calculation dramatically.
The velocity distributions after 0.5 and 0.7 PVI of the models are shown in Figure 5-16. The green dots represented the velocity vectors in the flow direction from the injector (bottom-right) to the producer (top-left). The red dots were cross flows. The line thickness represented the magnitudes of the velocities. In the fine scale model, the velocities in the cells, especially in high permeability cells near the producer and the injector, were higher. As the permeability values were averaged in the coarse scale model, the velocities were not as high as in the finer model. These affected the production forecasts of the models. Using our recommended approach, increasing the power law exponent of the injected fluid from 1.2 to 1.5, can offer a better match of the velocity profiles. The production predictions were much closer to the fine scale model.
60x220 n=1.2  30x110Ari n=1.2  30x110Ari n=1.5

Figure 5-16: Velocity vectors after 0.5 PVI (top) and 0.7 PVI (bottom) of the fine model under the injection of the shear-thickening polymer with the power law exponent of 1.2 (left) and the arithmetic upscaled models under injection of the shear-thickening polymer with the power law exponent of 1.2 (centre) and 1.5 (right).

We extended our verification to a three-dimensional model. Our 50×50×5 three-dimensional model was a section from Layer 59-63 of the SPE 10 model 2 (Figure 5-17, left). The model was upscaled by the geometric average to a 10×10×1 (Figure 5-17, right). The shear-thinning polymer was injected at a constant rate of 0.001 PVI. The power law exponent of 1.4 was applied to the injected fluid. The power
lay exponent used in the upscaled model was adjusted to match the fine scale predictions. We found that the prediction of oil recovery efficiency when using the power law exponent of 4.0 was the best match. However, the power law exponent of 2.8 gave the better water cut curve. Unlike the two-dimensional model, we were unable to find a power law exponent that can match both oil recovery and water cut predictions.

Figure 5-17: the permeabilities in $x$- and $y$- directions of part of SPE 10 Layer 59-63, 50x50x5 fine scale model (left) and 10x10x1 geometric upscaled model (right).
5.3.2 Summary

We proposed a new approach for modelling shear-thickening polymer flooding in upscaled models that can better represent fine scale models. We found that the most important parameter in shear-thickening polymer flooding when modelling with the ECLIPSE simulator was the power law exponent of injected fluids. This parameter has a direct impact on the apparent viscosity of the injected fluid in each cell. In coarse scale models where the cell permeabilities were averaged, the apparent viscosities were lower than those in the fine scale model. In order to have a better simulation result, the power law exponent used in the upscaled models should be increased to compensate the lower shear rates. By simply adjusting the power law exponent, a single-phase upscaled model can represent a fine scale model and can be used for economic evaluations.
6

SUMMARY OF RESULTS AND CONCLUSIONS

6.1 Summary

6.1.1 Overview

In this thesis, we have investigated upscaling for polymer flooding to understand how it differs compared with upscaling in water flooding. We found that commercial reservoir simulators have limited abilities to model polymer floods for both shear-thickening and shear-thinning flow described with a power law rheological model. We verified the use of the ECLIPSE reservoir simulator by Schlumberger for polymer flooding in Chapter 3 to ensure that the simulator can predict non-Newtonian flow as claimed. In Chapter 4, we conducted an upscaling study of non-Newtonian fluid flow in two types of models representing a lognormal distribution of permeabilities and a reservoir with channels. We applied four upscaling methods: arithmetic averaging, harmonic averaging, geometric averaging, and renormalization. We found that the best upscaling method is highly system dependent. However, the error was worst when a shear-thickening polymer was injected in any upscaled case compared to shear-thinning polymer injection. In addition, we found that field average pressure was poorly predicted and near-well upscaling should be considered. In Chapter 5, we attempted to find a new upscaling algorithm to simulate polymer flooding. We found that, at present, it was not possible to apply any upscaling
algorithm to the ECLIPSE reservoir simulator with polymer flooding option with success. This was due to the non-Newtonian flow equations and assumptions used in the simulator. In addition, we demonstrated that upscaled models that give a good match for water flooding only can give significant error in forecasts and ultimately affect the economic evaluation of projects when used on for polymer flooding. This can impact feasibility studies of new investment. We then suggested a new approach to be used in upscaled models in order to have a better production prediction. Adjusting the power law exponent of displacing fluid in upscaled models can compensate the lower apparent viscosity in coarser models and ultimately result in closer production forecasts to fine scale models.

6.1.2 ECLIPSE Limitations

The non-Newtonian flow behaviour of the injected fluids is the key factor in polymer flood modelling. The conservation equations for polymer flooding in ECLIPSE assume the density and formation volume factor of the aqueous phase are independent of the polymer and salt concentrations. For non-Newtonian fluid flow simulation, ECLIPSE introduces the Herschel-Bulkley fluid modifier as an additional parameter to Darcy’s equation. With many assumptions, only three parameters: tortuosity, yield stress, and power law exponent, as a function of polymer concentration are required. Shear rate is not required as an input as explained in Chapter 3. The apparent viscosity of non-Newtonian fluids is dependent on shear rate. Since the shear rate is not required for simulations, the apparent viscosity calculated based on other parameters may not be accurate. As the parameter in Darcy’s law, this inaccuracy of the apparent viscosity affects production forecasts. For example, if the calculated apparent viscosity is higher than the real apparent viscosity, the simulations may predict too optimistic oil recovery efficiency. This may be a big issue when evaluating a field that barely meets economic cut-offs. To improve the predictions, the apparent viscosity must be adjusted as we recommended in Section 5.3.

For shear-thinning polymer flooding, these limitations may not be significant as fluid behaviour is closer to water. However, we believed that these limitations of ECLIPSE can be an issue in shear-thickening polymer flooding as simulations may not correctly represent what is happening in an actual reservoir. In addition, ECLIPSE can only model polymers that are fitted in the power law fluid rheology. In reality, there are lots of additives such as crosslinkers and friction reducers that make the mixing fluids have more complex behaviour. This affects the shear rate and the apparent viscosity. The simulator can be
improved to add an option of manually input an apparent viscosity as a function of shear rate, which is typically obtained from laboratory, for better representing the complex behaviour.

### 6.1.3 Effective Fluid Viscosity in Upscaled Models

For non-Newtonian fluid injection, in addition to upscaling permeability, viscosity should be modified. Our recommended approach considers the input parameters and limitations of ECLIPSE. The power law exponent in the rheological model is the main influence on non-Newtonian flow behaviour. We therefore suggest the use of an effective viscosity function parameterised by an effective exponent in the rheological law. As the shear rate in a coarser model is lower, the effective power law exponent can increase the apparent viscosity hence increase non-Newtonian effect in the upscaled model. As a result, production predictions are closer to its fine scale model compared to when using the original power law exponent.

### 6.2 Conclusions

The main purpose of reservoir simulation is to predict what will happen when we start producing. There is no point to conduct any simulation if the models cannot represent what actually happen in reality - like the well known phrase in computer science - “garbage in, garbage out”. With current computational capabilities, it may not be practical or in some cases not possible to conduct full field simulation of geological models with numerous scenarios for sensitivity analysis and obtain reasonable results in timely manner using grids with fine scale detail. Core plugs, the scale at which properties are measured, are generally around one centimetre. To model the whole reservoir at this scale would require around $10^{13}$ cells. Due to computational capabilities, we need to change this to at most $10^5$ or $10^6$ cells. Upscaling, therefore, still plays an important role in reservoir simulation and will do for decades to come. Extensive research on upscaling focuses mainly on water flooding. Thus far, no study has been conducted on polymer flooded reservoirs. As the world energy demand has continually increased throughout the century, the water flooding alone is not enough to supply this high demand. Polymer flooding, as one method for Enhanced Oil Recovery (or tertiary recovery), can help increase recovery factors better than displacing with water alone. In practice, engineers tend to use simulation models that have been manipulated to match to fine scale models under water flooding to evaluate performance of polymer flooding. We have shown in this thesis that this approach can give significant
errors in predictions when switching from water to polymer displacement without any adjustment. Based on the models and assumptions in this research, the accuracy in production predictions when displacing with the shear-thickening polymer is likely to be significant poor. We found that the best way to get a good match is to manipulate the power law exponents of the injected fluids.

6.3 Remarks and Future Work

ECLIPSE assumes that the density of the aqueous phase is independent of the polymer and salt concentrations. In addition, we assumed continuously polymer flooding as well as no polymer adsorption and dead pores for our study. These factors affect polymer flooding performance in reality. Polymer adsorption and dead pores reduced the polymer flooding performance as less polymers pass through pores from an injector to a producer. The density of aqueous phase is important in a case when the density difference between displaced and displacing fluid is significant. In this case, gravity effects cannot be ignored. Some polymers are sensitive to salinity and do not perform well in high salinity environment. For example, hydrolyzed polyacrylamide (HPAM) shows a large sensitivity to salinity and hardness. This obstructs the use of HPAM in many reservoirs. In addition, high salinity means high density, which contributes to gravity effects. High salinity also means high polymer adsorption. Injecting polymer slugs can increase polymer flooding performance as well as reduce flooding costs. For example, preflush with water in high salinity reservoirs help reducing polymer sensitivity to salinity and therefore improve polymer flooding performance.

In this thesis, we investigated the non-Newtonian flow behaviour at various grid scales. Our work assumed continuously polymer injection with several assumptions. The impacts of reservoir salinity, density, polymer adsorption, reduced flow areas due to dead pore volume, and polymer slugs were not considered. Using a coarse grid when applying these factors might change simulation results. Polymer adsorption can cause a reduction in the relative permeability of the polymer solution. The reduction in permeability to the polymer solution is assumed proportional to the quantity of polymer lost to the rock material. The relative permeability of water is therefore permanently reduced after the passage of the polymer. If the relative permeability curves are significantly changed, pseudo relative permeability in upscaled models may be necessary. If the difference in density between the displaced and displacing fluid is significant and lead to gravity dominated flow, two-phase upscaling may be required. Using a coarse model for polymer slugs modelling may not provide good results due to numerical dispersion. In
polymer slugs, several fluids with a variety of fluid properties are injected. Using a coarse model, the fluid fronts may not be observed and the fluid properties in cells may be mixed.

In the last phase of this study, we have been introduced to another reservoir simulator – STARS by Computer Modelling Group Ltd. (CMG, 2010). The basic concepts of polymer flood modelling are similar to ECLIPSE by Schlumberger that have been used previous sections of this thesis. The shear effects of displacing polymer can be specified using the power law relation. In addition, the CMG software suite offers a Computer Assisted History Matching, Optimisation, and Uncertainty Assessment Tool (CMOST). This software can generate simulation runs automatically from base cases and apply optimisation algorithms to find the optimal solution. The run configurations in CMOST include parameters with their range of values, a number of simulations, and “Local Objective Functions” terms. The local objective functions such as matching cumulative oil production and matching cumulative water production are weighted average to produce a Global Objective Function. CMOST automatically creates datasets, sends command to conduct simulations in STARS, and analyse the outputs. The datasets and results are saved in a number format as a “Job ID”. Figure 6-1 is an example of run status monitoring in CMOST. The x-axis is the “Job ID” and the y-axis is the percentage of the global objective function. The closer to zero the global objective function percentage, the better match to the base case of that job id. The suggested jobs are shown by the red dots. For this example, Job ID-65 is the best. We then check the dataset and results of Job ID-65 manually.

![Figure 6-1: Run status monitoring in CMOST.](image-url)
Although, the power law exponent of the injected fluid is not currently available in CMOST Studio with a user friendly window for input values, we believe that it is possible to add a script in a base case file to set the power law exponents of injected fluids as a CMOST variable. If this idea is possible, we can set a fine scale model as a base case. Then set permeabilities (by several upscaling methods) and power law exponents as CMOST variables. Then CMOST will suggest the optimal dataset (e.g. arithmetic averaged permeabilities and the power law exponent of 1.5) to be used in the coarse model. This concept needs further investigations. Unfortunately, converting datasets from ECLIPSE to STARS is not straightforward. It is recommended to create a new model from scratch in the CMG suite.

6.4 Future Work

The main areas of this thesis needing further work are the investigations of more realistic polymer floods, i.e. pre-flush followed by polymer slugs then flushed with water, to have more realistic physical diffusion in simulations. In addition, an effect of parameters that were ignored including reservoir salinity, density, and polymer adsorption should be added in the investigation as they can change the results obtained using a coarse scale model. The future study would be performed by conducting sensitivity runs on polymer concentration, salt concentration, reservoir fluid viscosity, etc. In addition, the near-well upscaling, which follows Darcy’s law, should be modified and investigated for non-Newtonian flow behaviour by using the modified Blake-Kozeny equation. The new algorithm should be evaluated in two-dimensional and three dimensional models with several scenarios including a simple vertical well, a horizontal well, and a partially perforating well.

Another interesting research area is to develop a new algorithm for upscaling polymer-oil displacement that can be a plug-in option to any commercial reservoir simulation software. As we discovered in Chapter 5 that ECLIPSE only adds the Herschel-Bulkley fluid modifier to Darcy’s equation. Many assumptions and limitations are involved in this modifier. We found that equations used in ECLIPSE for polymer flooding are derived from the modified Blake-Kozeny equation. The idea is to investigate a new algorithm to calculate effective permeabilities based on the modified Blake-Kozeny equation. Then apply the algorithm directly to Darcy’s law in commercial reservoir simulation software. This concept will eliminate the use of the polymer flooding option in the reservoir simulator. This development will offer fewer assumptions. Parameters are more flexibility to adjust. The research will require mathematical analysis and advanced programming.
APPENDIX

A.1 MATLAB Function to Generate Two-dimensional Grids with Lognormal Distribution from Gaussian Random Numbers

A MATLAB function file used to create the lognormal permeability field for the investigation in Chapter 4 is as follows:

**Function: lognormalcor.m**

```matlab
function [normrand, perm, meann, sd] = lognormalcor(big, num, cor)

%Input
big=5.5+50.*randn(500);
num=128; for 128x128 cells
for i=1:cor
    for j=1:cor
        tot=0;
        count=0;
        % coords of small grid in st:
```
We generate permeability fields with various correlation lengths from zero to 128 cells (the dimensionless correlation lengths from zero to one). Figure A-1 shows several permeability fields at various correlation lengths. The top left picture, where $L_{xD} = L_{yD} = 0$, represents a permeability field when all cell permeabilities are uncorrelated with neighbours. In other words, this permeability field has a random lognormal distribution. In this model, the permeability field is too scattered. On the other hand, the bottom right picture, where $L_{xD} = L_{yD} = 1$, the permeability in every cells are correlated. This leads to a highly homogeneous permeability field. We therefore decide to eliminate these two correlation lengths. Figure A-2 shows the logarithm of permeability fields at the dimensionless correlation lengths of 0.1, 0.2, 0.4, 0.6, and 0.8. For our research, the correlation length of 0.1 is selected.
Figure A-1: Permeability fields at various correlation lengths of 128x128 cells.

Figure A-2: Logarithm of the permeability fields at various correlation lengths of 128x128 cells.
A.2  Input Data for ECLIPSE Polymer Flooded Modelling

Below is the script of the file used for the simulations of the fine scale model in Section 4.2. This main file does not include porosity, permeability in x-direction, and permeability in z-direction datasets. These three datasets are saved in three text files: PORO.TXT, KXFINE.TXT, KZFINE.TXT and must be presented in the same folder.

Main Data File: MODEL11111.DATA

RUNSPEC

TITLE
MODEL11111-SPE10Model2Layer47-60x220x1

DIMENS
60 220 1/

START
1 JAN 2010/

-- Field Units
FIELD
OIL
WATER
-- Activate polymer modelling
POLYMER

UNIFIN
UNIFOUT
ENDSCALE
/

-- Activate Herschel-Bulkley Fluid
NNEWTF
1 2/

WELLDIMS
7 10 2 7 /

REGDIMS
12 2 /

NSTACK
50 /
EQLDIMS
  1 /

TABDIMS
  1 1 26 20 1* 20 20 5* 1 /

MESSAGES
  12*1000000 /

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

RPTGRID
  TRANX ALLNNC /

-- Both EGRID and Extended GRID file output
GRIDFILE
  2 1 /

INIT
NOECHO

-- Basic gridblock sizes
DX
  13200*20 /

DY
  13200*10 /

DZ
  13200*2 /

-- Cell top depths - only for first layer specified
TOPS
  13200*12000 /

-- Read KXFINE.TXT file for PERMX keyword
INCLUDE
  'KXFINE.TXT' /

-- Read KZFINE.TXT file for PERMZ keyword
INCLUDE
  'KZFINE.TXT' /

-- Read PORO.TXT file for PORO keyword
INCLUDE
  'PORO.TXT' /

ACTNUM
  13200*1 /

COPY
  'PERMX' 'PERMY' /
/

EDIT

PROPS

DENSITY
-- oil water gas
-- lb/ft³ lb/ft³ lb/ft³
53 64 0.0971 /

PVTW
-- Pref Bw Cw Vw Cvis
13000 1.01 3E-6 0.3 0.0 /

PVDO
300 1.05 2.85
800 1.02 2.99
8000 1.01 3 /

ROCK
-- Pref Cr
12000 1E-6 /

SWOF
-- Swat Krw Krow Pcow
0.20 0.000 1.000 1*
0.25 0.007 0.840 1*
0.30 0.028 0.694 1*
0.35 0.063 0.563 1*
0.40 0.111 0.444 1*
0.45 0.174 0.340 1*
0.50 0.250 0.250 1*
0.55 0.340 0.174 1*
0.60 0.444 0.111 1*
0.65 0.562 0.063 1*
0.70 0.694 0.028 1*
0.75 0.840 0.007 1*
0.80 1.000 0.000 1*
/

-- Herschel-Bulkley Fluid as a function of polymer concentration
FHERCHBL
--Cp Tortuosity n YieldStress
0 1.414 1 0
10 1.414 2 0 /

PLYVISC
--Polymer Concentration (lb/stb) Multiplication Factor (Conc^2)
0   1
0.35 10
0.75 30
1   60 /

PLYROCK
0.15 2.67 1000.0 2 0.0035 /

PLYADS
0.0 0.00
20.0 0.00
70.0 0.00 /

TLMIXPAR
1.0 /

PLYMAX
6 0.0 /

RPTPROPS
-- PROPS Reporting Options
'PLYVISC' /

--------------------------------------------------------------------
REGIONS
--------------------------------------------------------------------
--------------------------------------------------------------------
SOLUTION
--------------------------------------------------------------------

RPTSOL
-- Initialisation Print Output
'PRES' 'SWAT' 'RESTART=1' 'FIP=3' 'PBLK' 'SALT' 'PLYADS' 'RK' 'VOIL'
'VWAT '/

EQUIL
--Datum  Pres  OWC  Pc  GOC  Pc  RSVD  RVVD  N
12000 6000 14000 0 0 0 0 0 0 /

SUMMARY
--------------------------------------------------------------------
ALL

RUNSUM
--Field quantities
FWCT
FCPR
FCPT
FCIR
FCIT
FCIP
FCAD
FPR
FAQR
FOPR
FWPR
FGPR
FOPT
FWIR
FGIR
FVPR
FVIR
FOE
FOEIW
CCFR
'P1' 1 1 1 /
/
CCPT
'P1' 1 1 1 /
/
CCIT
'I1' 60 220 1 /
/
RCIP
1 2 /
RCFT
1 2 /
/
RCAD
1 2 /
BCCN
1 1 1 /
/
BCIP
1 1 1 /
/
BCAD
1 1 1 /
/
BEPVIS
1 1 1 /
/
BEWV_POL
1 1 1 /
/
BEMVIS
1 1 1 /
/
RPTSMRY
1 /

--Well quantities
WOPR
SCHEDULE
-- CONTROLS ON OUTPUT AT EACH REPORT TIME
RPTSCED
'PRES' 'SWAT' 'RESTART=1' 'FIP=3' 'WELLS=2' 'SUMMARY=2' 'CPU=2' 'WELSPECS'
'NEWTON=2' 'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPSALT=2' 'VOIL' 'VWAT'/

RPTST
'ALLPROPS' 'VISC' 'VOIL' 'VWAT' /

-- WELL SPECIFICATION DATA
-- WELL  GROUP LOCATION  BHP  PI
-- NAME   NAME   I   J   DEPTH DEFN
WELSPECS
  P1   G    1   1   1*   OIL  /
  I1   G   60  220  1*   WATER  /

-- COMPLETION SPECIFICATION DATA
-- WELL -LOCATION- OPEN/ SAT CONN WELL EFF SKIN
-- NAME I J K1 K2 SHUT TAB FACT  ID  KH

COMPDAT

P1 1 1 1 1 OPEN 0 1* .833 1* /
I1 60 220 1 1 OPEN 0 1* .833 1* /

-- PRODUCTION WELL CONTROLS

-- WELL OPEN/ CNTL OIL WATER GAS LIQU RES BHP
-- NAME SHUT MODE RATE RATE RATE RATE RATE

WCONPROD

P1 OPEN BHP 1* 1* 1* 1* 1* 50 /

WCONINJE

I1 WATER OPEN RESV 1* 5000 10000 7* /

WPOLYMER

--Well PolyConc SaltConc
'I1' 1.75 0.0 /

--Time steps
TSTEP
100*2000

SAVE

END
BIBLIOGRAPHY


