Upscaling polymer flooding

Developing a workflow based on Particle Swarm Optimization

by

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Abstract

In this research a workflow for upscaling polymer flooding is developed. The workflow generates pseudo-relative permeabilities (pseudos) to represent flow behaviour affected by fine scale heterogeneities in a coarse grid. With this workflow, a better estimate of the difference in production from a polymer flood compared to a water flood can be made. In case history-matched pseudos for a water flood are readily available, the workflow provides insight in whether and how the pseudos generated for water should be adjusted to correctly model a polymer flood. In case no production data and no pseudos are available for a water flood, the workflow can be used to generate pseudos for both a water and a polymer flood.

Using pseudos in a coarse model is needed because heterogeneity affecting connectivity and thereby flow behaviour is not (fully) represented as a result of upscaling. Therefore an error may be made in cumulative oil and water production when simulating a water or a polymer flood in a coarse model. Pseudos can be used to represent flow behaviour from a fine grid in a coarse grid. Polymer flooding improves sweep around heterogeneities compared to water flooding. This means flow behaviour differs for water and polymer flooding. As a result, pseudos for water and polymer flooding may differ (depending on circumstances). The need for the use of pseudos when using an upscaled grid is assessed by comparing cumulative production from a coarse grid simulated with optimized pseudos to cumulative production from a coarse grid simulated with rock relative permeabilities. The difference in upsampling a water flood from a polymer flood and the need for adjustment of pseudos generated for a water flood when simulating a polymer flood is assessed by comparing simulating a polymer flood in a coarse grid with pseudos optimized for polymer flooding to simulating a polymer flood in a coarse grid with pseudos optimized for a water flood.

A sector model is used as a basis for upscaling. The upscaling procedure is based on adjustment of relative permeabilities using Particle Swarm Optimization, which is an exploring optimization algorithm. Endpoint water relative permeability, $k_{r,we}$, and the Brooks-Corey coefficient for oil, $n_o$, are selected as optimizing parameters. The least square difference between cumulative oil production from the fine grid and from the coarse grid is taken as the objective function to be minimized. Results are post-processed by converting non-unique pseudos resulting from the optimization in unique fractional flow curves. A novel way of characterizing the fractional flow curve is developed, which allows representation of the entire curve through $v_{shock}$. This provides insight in how pseudos change in sensitivity studies.

Generally, the match in cumulative production is very good. The models investigated in this work show that the improvement of generating pseudos compared to simulating a coarse grid with fine grid relative permeabilities is significant. In 3D channelized turbidite models, shale draping causes a too late breakthrough and an overestimation in recovery when pseudos are not adjusted, e.g. when rock relative permeabilities are used in the coarse grid. Errors in breakthrough time are reduced from 0.3 PV injected when not adjusting relative permeabilities to 0.05 PV injected. Errors in late time recovery are reduced from a 0.2 to 0 difference in recovery (fraction of OIIP). The required adjustment in rock relative permeabilities to match cumulative production depends on heterogeneity and method and degree of upscaling.

Sensitivity of pseudos to polymer concentration, and thus the need for adjustment of water pseudos when simulating a polymer flood, differs for surface-based upscaled models and voxelized models and depends on heterogeneity. Deriving a general trend for the difference between water and polymer pseudos from this work is therefore not possible. In surface-based upscaled models, $v_{shock}$ increases, e.g. the fractional flow curve shifts left, with increasing polymer concentration. As a result, breakthrough time is estimated too late and recovery is overestimated when simulating a polymer flood with water pseudos. In voxelized models, $v_{shock}$ decreases, e.g. the fractional flow curve shifts right, with increasing polymer concentration. As a result, breakthrough time is estimated too early and recovery is underestimated when simulating a polymer flood with water pseudos. Robustness of generated pseudos to changes in injection rate, amount of PV injected and streamlines due to different perforated intervals or well-placement is tested and found to be good for the simulated cases.
Before you lies my work of the past ten months, which marks the end of my time as a student and the beginning of my time as a young professional.

I hope that you will enjoy reading the results of my project as much as I have enjoyed working on it. It was a full experience, in which I have learned a lot about doing research and the topics of upscaling, reservoir modelling and optimization. I have started to actually like topics such as Buckley Leverett and capillary trapping, which weren’t my favourite during classes. Like I have experienced many times before, this shows that everything that you start to understand better becomes more fun.

I would like to thank Gerard Glasbergen for his excellent supervision and especially for the very motivating way in which he did so. This definitely got me to get more out of my project. I would also like to thank Cor van Kruisdijk for the critical view on my work and results, increasing the quality of my work by pushing me a step further every time. Also, thanks to the other colleagues and interns at Shell, both for helping with my project as well as for the good time I had.

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A big thanks for my friends and family, especially to Laurens, for supporting me and sharing in my enthusiasm about my project and my studies in general. A special thanks to my roommates Lotte and Jeanine, for always being my listening ear when I came home from my relperm and upscaling adventures. Surely, you now know more about polymer flooding and upscaling than you ever could have imagined. Last but not least, many thanks and a big hug for my mother, for without her I would not have been where I am today, both professionally and as a person.

With that said, I would say have fun reading and if you want to discuss the inexhaustible topic of upscaling further, let me know. A great location that comes to mind is the excellent cafe at the Noordeinde in Delft.

H.C. de Vries
Delft, September 2016
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In this research a workflow is developed for upscaling polymer flooding in turbidite reservoirs. In this chapter the research objectives and scope are discussed. In chapter 2 more background on polymer flooding and Enhanced Oil Recovery (EOR) in general is given.

1.1. Upscaling

Reservoir models are necessary to simulate flow in the subsurface, which is done to optimize and predict recovery of hydrocarbons. Ideally, one would do this with a detailed geological model. However, computational power is limited and simulations should be reasonably fast to use them in practice. Therefore the fine grid model needs to be upscaled to a coarser grid model. A region with heterogeneous properties, which are represented in fine grid cells, is substituted by a coarse grid cell with one effective property value (Figure 1.1).

![Figure 1.1: Concept of upscaling](Grindheim et al., 2007)

It has been shown that it is not sufficient to upscale absolute properties (porosity, permeability) only [Durlølsky et al., 1994, Muggeridge, 1991]. This is because fine scale heterogeneities affect connectivity and therefore flow behaviour is not represented correctly when they disappear in a coarse grid. For example, high permeability streaks cause water to propagate faster, while small shale baffles counteract gravity and as such cause the water front to be more piston-like.

Another feature that is not captured by upscaling absolute properties only is capillary trapping as a result of grain size variations (discussed in more detail in section 3.1.2). Research by van Lingen and Knight [1997] shows that as heterogeneity on the laminae scale becomes more important, such as in a meandering system, up to 40% of the movable oil volume ($MOV = 1 - S_{wc} - S_{or}$) can be trapped.

A more accurate way to upscale is by the use of pseudo-relative permeabilities, from now on referred to as pseudos. As the name implies, the aim of pseudos is to represent fine grid flow behaviour on a coarse scale. Rather than just representing porosity and permeability from the fine in the coarse grid, the physical behaviour is
what should be represented for upscaling to be most efficient. This is recognized by many researchers, among others [Cao and Aziz [1999], Coll et al. [2000]].

Ideally, flow in and out the set of fine grid cells that make up a coarse grid cell is exactly equal to the flow in and out a coarse grid cell, at a particular pressure and time during the simulation. However, this requires a different pseudo for each grid cell, which is computationally expensive and difficult to generalize. More general quantities that can be matched are cumulative production of oil and water, in which breakthrough time (BT) and Ultimate Recovery (UR) are most important. Although less accurate, this is much more easy to implement and generalize. The difference between the different methods of upscaling will be discussed in more detail in chapter 5.

1.2. Upscaling polymer flooding

Although methods for upscaling water flooding have been researched extensively (section 5.2), pseudos are often found by history matching in practice. The way that is done is as follows:

Initially the reservoir is simulated using relative permeabilities (from now on referred to as relperms) obtained from core-flood experiments or data from adjacent or similar reservoirs. When production data becomes available, the relperms are adjusted so that simulation data matches production data. It is clear that with this way of working, the pseudos only have predictive value for a simulation similar to the situation the history match was done for. The 'situation' comprises all aspects that influence flow behaviour, among others viscosity of the injected and produced fluid, flowrate, number of wells, well placement and of coarse geology.

Polymer viscosifies water, which results in different flow behaviour (illustrated in Figure 1.2, discussed in more detail in chapter 4). Not adjusting relative permeabilities, e.g. using the rock relperms, or using pseudos that are generated for water flooding therefore may result in an erroneous prediction of oil and water production from a polymer flood (Figure 1.3).

Figure 1.2: Experimental data showing that a polymer flood and a water flood exhibit very different flow behaviour [Sheng, accessed:2016-08-01]

1.3. Research objectives

It has been illustrated that water and polymer exhibit different flow behaviour and therefore may require different pseudos when upscaling. In addition to that, if one wants to screen a reservoir for polymer flooding, it is necessary to find pseudos in advance rather then base them on production data. The objective of this research is therefore to develop a workflow for upscaling polymer flooding which can be applied to a full field model.

In order to meet this objective the following research questions are addressed:

- What is the best way to generate pseudos? The method should be easy to implement in practice and generate pseudos that represent flow on the fine scale within reasonable accuracy. It should allow generalization and in terms of computational time, it should be reasonably fast.

- What is the dependency of pseudos to heterogeneity, polymer concentration and method / degree of upscaling? This provides insight in the need for adjusting rock relative permeabilities when upscaling and in the need for adjustment of water pseudos when simulating a polymer flood.

- What is the validity range of the generated pseudos or pseudo set? This is related to practice: when
1.4. Scope

The scope of this research is limited to the following:

- This research is focused on offshore turbidite reservoirs, and therefore uses models with heterogeneities as they are typically found there. However, the workflow can be applied to any kind of heterogeneities.
- Oil viscosity is varied between 0.3 to 10 cp.
- Water viscosity is varied between 1 to 10 cp.
- Phases are limited to oil and water. Thus, it is assumed that pressure is above bubblepoint everywhere in the system at any time during the simulation.
- Pressure is not taken into account in the optimization. Therefore, pressures in the fine and the coarse grid do not necessarily match.

However, the work could potentially be extended beyond this scope. See also chapter 15.
This chapter provides information about polymer flooding. Polymer flooding is an EOR technique which aims to increase recovery from an oil reservoir by increasing the viscosity of injected water.

2.1. Relevance of increasing oil recovery

Studies on the future of the world's energy supplies show that fossil fuels will dominate the energy mix in this century. Renewables are being developed, but technologies are not mature and will not be able to fulfill the world's growing energy demand. The International Energy Agency (IEA) developed three scenarios to predict primary energy supply. In all three, oil demand will increase and oil will remain the single largest fuel [van der Hoeven, 2013]. Figure 2.1 shows the energy supply by fuel in the 'New Policies' scenario.

To meet this demand, oil recovery from existing fields has to be increased. New (giant) fields are becoming more and more difficult to find. Most sedimentary basins that might contain oil have already been explored and new discoveries tend to be small. Small improvements count: a 1% increase in the average recovery factor (RF) could add more than 80 billion barrels, or 6%, to global proven oil reserves [van der Hoeven, 2013].

In addition to that, new discoveries that are done are located in more challenging circumstances: on remote locations and in environmentally sensitive areas (e.g. the Arctic, deepwater). This means capital costs are higher and an increased revenue is needed for investments to be economically feasible.

The recovery factor for primary (pressure depletion) and secondary (pressure maintenance by water injection) recovery together is typically between 15% and 45%, with a worldwide average of 35% [Schulte, 2005]. Although the RF is strongly dependent on conditions such as reservoir heterogeneity, oil viscosity and well cost, this average indicates there is a huge size of price for EOR techniques.

Figure 2.1: Primary energy supply by fuel in 'New Policies' scenario, IEA 2013 [van der Hoeven, 2013]
2.2. Recovery Factor

As noted above the RF depends on several conditions. It is a function of 4 factors [Smaale et al., 2007]:

\[ RF = f(E_{PS}, E_S, E_D, E_C) \]  \hspace{1cm} (2.1)

where

- \( RF \) is the recovery factor, defined as the volume of oil recovered over the oil initially in place (OIIP).
- \( E_{PS} \) is the microscopic displacement efficiency, describing the fraction of oil that is displaced from the pores that are contacted with injected water. This concerns oil being trapped by capillary forces and is thus related to interfacial tension (IFT).
- \( E_S \) is the macroscopic sweep efficiency, describing the fraction of connected reservoir volume that is swept (e.g. contacted) by the injected water. This is strongly related to reservoir heterogeneity and the viscosity ratio of the injected and the displaced fluid.
- \( E_D \) is the connected volume factor, describing the proportion of total reservoir volume connected to the wells. It is linked to compartmentalization by faults or low permeability barriers.
- \( E_C \) is the economic efficiency factor, which represents physical and commercial constraints on field life. These include facilities life, capacity to deal with storage and production of fluids and reservoir pressure.

EOR methods aim at increasing \( E_{PS} \) and \( E_S \). IOR, Improved Oil Recovery, aims to increase \( E_D \) and to some extent \( E_S \). Improving \( E_C \) is mainly the role of production and facilities engineers [Muggeridge et al., 2014]. It is important to realize that EOR is related to \( E_C \), as different fluids and chemicals have to be stored and processed on the platform and the amount of produced fluids may change by applying EOR. In addition to that, economic feasibility may change due to production being brought forward, lower water production or increased recovery.

The most important EOR techniques will be discussed briefly below. A detailed explanation of the physics related to \( E_{PS} \) and \( E_S \), and what the effect of polymer flooding is, will be given later in chapters 3 and 4.

2.2.1. Methods that alter macroscopic sweep efficiency

Increasing sweep efficiency, \( E_S \), can be done by increasing the viscosity of the displacing fluid or decreasing the viscosity of the displaced fluid. The first is achieved by adding polymer to the water or using foam flooding, the latter by heating up the oil using either steam flooding, in situ combustion of (part of) the oil or applying a solvent or miscible gas.

Improving sweep efficiency results in an earlier recovery of the oil and thereby increases the NPV. If an economic cut-off is considered, e.g. a water cut at which production is no longer profitable, polymer flooding increases recovery at this cut-off and thus the ultimate recovery from a field.

2.2.2. Methods that alter microscopic sweep efficiency

Microscopic displacement efficiency, \( E_{PS} \), is related to capillary pressure and thereby to IFT and wettability. EOR methods which aim to increase \( E_{PS} \) either decrease the IFT between water and oil, change wettability or inject fluids which have a very low IFT with oil. Theoretically, oil recovery can go up to 100% when the IFT is decreased sufficiently. However, the macroscopic sweep efficiency, \( E_S \), is often low [McGuire et al., 1995].

Techniques that alter IFT or wettability are: miscible gas injection (nitrogen, hydrocarbon gases, carbon-dioxide), surfactant flooding and low salinity flooding (LSF). One of the techniques that aims to mitigate poor sweep efficiency while altering IFT and/or wettability is Alkaline Surfactant Polymer flooding (ASP) [Muggeridge et al., 2014].

2.3. Polymer flooding compared to other EOR techniques

One cannot generally state which EOR technique is best, or cheapest, since cost and incremental recovery vary with circumstances. One can however qualify which EOR techniques suit certain circumstances, based on technical feasibility. Those EOR techniques can then be compared in terms of costs, incremental oil, technical
2. Background

and environmental risk. EOR screening criteria are (among others): oil viscosity, permeability, on- or offshore environment and reservoir depth (e.g. temperature) [Figuera et al., 2007]. Figure A.1 in Appendix A gives a more detailed overview of the applicability of different EOR methods.

Polymer flooding is a suitable technique for offshore turbidite reservoirs, where sweep efficiency around heterogeneities is an important factor. Also, it is desirable to delay water breakthrough. Oil viscosity is generally low, between 1 and 10 cp, which means polymer can sufficiently alter the mobility ratio. Permeability is relatively good, between 250 - 2000 mD, resulting in sufficient injectivity. Preferred temperature for polymer flooding is less than about 200 deg F, which is related to the stability of polymers [Figuera et al., 2007; Taber et al., 1997].
To fully understand and successfully apply any EOR method, a solid understanding of involved physics, chemistry and geology is required. This chapter deals with physics of multiphase flow in heterogeneous porous media and the governing equations describing this. Chapter 4 deals with chemistry and physics related to polymer flooding specifically.

3.1. Forces acting on multiphase flow in a reservoir

Four different forces play a role in multiphase transport in porous media: gravity, capillary, viscous and dispersion (diffusion) forces.

3.1.1. Gravity forces

Gravity forces are driven by a density difference between fluids in the reservoir. They cause fluids to segregate and may lead to gravity over- (such as in case of gas injection) or underride (generally in case of water injection).

3.1.2. Capillary forces

Capillary forces are driven by a pressure difference across the interface between two different fluids and defined as the pressure in the non-wetting minus the pressure in the wetting phase (Figure 3.1a). During a water-flood, capillary pressure smears out the front (Figure 3.1b).

In a tube, capillary pressure is a function of interfacial tension, tube radius and contact angle (Figure 3.2, Eq. 3.1). Note that for the purpose of this thesis, oil will be considered the non-wetting phase and water the wetting phase.

\[ P_c = P_{nw} - P_w = \frac{2\sigma \cos \theta}{R} \]  

(3.1)

where \( \sigma \) is interfacial tension, \( \theta \) is the angle between the non-wetting phase and the solid surface and \( R \) is the radius of the tube.

Capillary pressure decreases with increasing wetting phase saturation. At a certain wetting phase saturation, capillary pressure will rise towards infinity and the wetting phase saturation cannot be lowered further. The connate water saturation, \( S_{wc} \), is reached.

In pore structures capillary forces cause trapping of so-called residual oil, \( S_{or} \). Capillary trapping of oil takes place on different scales: the pore scale (micrometers) and the scale at which grain sizes vary (millimeters to meters). Since the latter is relevant in upscaling, the two processes will be discussed in a bit more detail.
Capillary trapping of oil occurs when the oil network loses its continuity. Viscous and gravitational pressure gradients become insufficient to mobilize the remaining oil, trapped against capillary barriers in the porous medium. On a pore level, these barriers are formed by pore throats in water-wet conditions and pore bodies in oil-wet conditions [van Lingen and Knight, 1997]. In water wet conditions, trapping increases with decreasing pore size. Mobilizing trapped oil on a pore level is mainly done through lowering the IFT between fluids. On a millimeter to meter scale, grain size variations as they occur in for example fluvial crossbeds, turbidite current ripples or aeolian sedimentary structures form barriers for capillary trapping. Some examples are shown in Figure 3.3.

Permeability scales roughly quadratically to grain size [Carman, 1956; Kozeny, 1925] (Eq. 3.2) and capillary pressure scales approximately with the square root of permeability [Leverett, 1941b] (Eq. 3.3).

\[ k = \frac{d_p^2 (1 - \phi)^2}{C \phi^3} \]  

(Eq. 3.2)
3.1 Forces acting on multiphase flow in a reservoir

\[ p_c(S_w) = J(S_w)\sigma\sqrt{\frac{\phi}{k}} \]  

(3.3)

where \( d_p \) is grain size, \( C \) is a constant describing tortuosity, \( \phi \) is porosity, \( \sigma \) is interfacial tension and \( k \) is permeability. \( J(S_w) \) is the Leverett-J function, which is a function to describe capillary pressure in rock types with similar pore types and wettability, but different permeability.

This means capillary pressure is approximately proportional to grain size. It is this difference in capillary pressure curves which results in capillary trapping, as researched by van Lingen and Knight [1997] and illustrated with their example in Figure 3.4.

In this example, alternating laminae 1 and 2 are shown. The grain size in laminae 1 equals about twice the grain size in laminae 2. This means the capillary pressure curve of laminae 2 lies approximately twice as high as the curve of laminae 1.

During steady-state flow capillary pressure in laminae 2 will be higher than in laminae 1. Correspondingly, water saturation in laminae 2 will be lower than in laminae 1. In his work, van Lingen [1998] shows that at sufficiently low fractional flow of water, both phases will be flowing with a certain (dis)continuous capillary pressure distribution in the laminae. No trapping takes place. This is explained and illustrated in detail in Appendix B. For clarity, only the trapping case will be discussed here.

Capillary trapping will occur when the water fraction in the system increases such that saturation in laminae 2 reaches \( 1 - S_{or} \) at \( P_{c,end2} \) (point C in Figure 3.4b). Since saturation is at \( 1 - S_{or} \) already, it can not increase further to decrease capillary pressure and in order to become continuous with the capillary pressure in laminae 1. Capillary pressure becomes discontinuous at the boundary from laminae 2 to laminae 1 (Figure 3.4c). With oil fully immobile in laminae 2, it can no longer move from one laminae 1 to another and gets trapped in laminae 1. The saturation is between \( 1 - S_{or} \) and \( S_{w1}^* \) and oil is trapped against the fine laminae (Figure 3.4d).

The amount of trapped oil increases with increasing grain size variations. As explained above, the effects are more pronounced at higher water saturations, e.g. higher amounts of injected water [van Lingen, 1998]. Trapping is most severe for flow perpendicular to the heterogeneity boundaries and becomes less important towards flow parallel to these [Kortekaas, 1985, van Lingen, 1998].

3.1.3 Viscous forces

Viscous forces are a measure of a fluids resistance against flow, caused by internal friction between the molecules in a fluid. The viscous force on a small sphere moving through a viscous fluid is given by Stokes’ Law [Batchelor, 1967]:

\[ F_d = 6\pi \mu RV \]  

(3.4)

where \( \mu \) is the fluids viscosity, \( R \) is the radius of the sphere and \( V \) is the spheres velocity. Note that in porous media, this should not be taken as the Darcy velocity but as the interstitial velocity:

\[ u_i = \frac{u_t}{\phi} \]  

(3.5)

where \( u_i \) is the interstitial velocity, \( u_t \) is the Darcy velocity and \( \phi \) is porosity.

In heterogeneous porous media viscous forces cause viscous crossflow between different layers. In case of a favourable (endpoint) mobility ratio \( M \) (Eq. 3.6), viscous crossflow causes oil to flow from the high permeable into the low permeable layer or region, e.g. increasing the sweep efficiency. In case of unfavourable \( M \), a mixing zone develops [Sorbie and Clifford, 2009, Zapata and Lake, 1981].

\[ M^0 = \frac{\lambda w^0}{\lambda o^0} = \frac{k o w^0 \mu w^0}{k r o \mu o^0} \]  

(3.6)
3. Theory - Multiphase flow in porous media

3.1.4. Dispersion and diffusion forces

During a polymer flood diffusion and dispersion of polymer and salts take place.

(Molecular) diffusion is the transport of mass, driven by spatial concentration differences. Diffusion is described by Fick’s Second Law [Fick, 1855]:

\[
\frac{\partial C}{\partial t} = D_{mol} \nabla^2 C
\]  

where \( C \) is the concentration, \( t \) is time and \( D_{mol} \) is the diffusion coefficient.

Dispersion is the mixing of two miscible fluids, caused by diffusion and by variations in the velocity within and between each flow channel in a porous medium. At low velocities, diffusion is the dominant process. At higher velocities, mixing dominates [Arya et al., 1988, Lake et al., 2014] find that this is the case for interstitial velocities greater than approximately 3 cm/day, which translates to a Darcy velocity of about 10-15 cm/day for most porous media. Assuming a field scale displacement of about 1 ft/day = 30 cm/day (based on field pilots from Shell - Gerard Glasbergen, personal communication), mixing will mostly dominate the process.

The dispersion coefficient is given in tensor form by [John et al., 2008]:

\[
D = \left( \alpha_t |v| + D_{mol} \right) I + \frac{\alpha_t - \alpha_l}{\nu} v |v|
\]

from which it can be observed that dispersion is dependent on velocity \( v \), longitudinal and transverse dispersivities, \( \alpha_l \) and \( \alpha_t \) respectively, the molecular diffusion coefficient \( D_{mol} \).

Dispersion increases with heterogeneity (Dykstra Parson coefficient) and the correlation length of heterogeneity [Arya et al., 1988, John et al., 2008, Lake et al., 2014].
3.2. Multiphase flow equations

The different forces described in section 3.1 are represented in the governing equations described below. These are the cornerstones for reservoir simulation.

3.2.1. Immiscible transport equation

There are different formulations for two-phase immiscible flow. Based on mass conservation and Darcy’s Law (Eq. 3.10), the formulation for water saturation in global pressure is (among others) derived by Chen et al. [2006] for incompressible fluids:

$$
\phi \frac{\partial S_w}{\partial t} = -\nabla \cdot \left( k \lambda_o f_w \left( \frac{dp_c}{dS} \nabla S - (\rho_o - \rho_w) g \nabla z \right) + f_w u \right) - S \frac{\partial \phi}{\partial t} + \frac{q_w}{\rho_w}
$$

(3.9)

$$
Q = \frac{k A}{\mu} \left( \frac{d\rho}{dx} \right)
$$

(3.10)

where $\phi$ is the porosity of the porous medium, $S_w$ is water saturation, $k$ is the absolute permeability tensor of the porous medium, $\lambda_o$ is the mobility of oil, $\frac{k_{ro}}{\mu_o}$, $k_{ro}$ is the relative permeability of oil, $\mu_o$ is oil viscosity, $f_w$ is the fractional flow of water, $\lambda_o \frac{d\rho}{dx}$ (here excluding effects of gravity and capillary pressure, as these are taken into account explicitly in the equation), $p_c$ is capillary pressure, $p_{nw} - p_w$, $g$ is gravitational acceleration, $z$ is depth, $u$ is a tensor with the total velocity (of all phases), $q_w$ is a source/sink term and $\rho_o$ and $\rho_w$ are density of oil and water respectively.

For compressible fluids, density is dependent on pressure. For a slightly compressible fluid this dependency is given by:
\[ \rho = \rho^0 \left(1 + C^0 (p - p^0)\right) \]  

(3.11)

where \( \rho^0 \) is density at reference pressure \( p^0 \), \( p \) is pressure and \( C^0 \) is a constant for compressibility. When no source term is present and the rock is incompressible the last two terms in equation 3.9 disappear:

\[ \phi \frac{\partial S_w}{\partial t} = -\nabla \cdot \left( k \lambda_o f_w \left( \frac{d p}{d S} \nabla S - (\rho_o - \rho_w) g \nabla z \right) \right) + f_w u \]  

(3.12)

In equation (3.12) the different forces can be recognized in the different terms: the first term represents capillary forces, the second term gravitational forces and the last term viscous forces.

Since the system is two-phase, one of the saturations is always found after solving the saturation of the other:

\[ 1 = S_o + S_w \]  

(3.13)

### 3.2.2. Dispersion and diffusion equation

An equation to model diffusion and dispersion in a fluid phase in a porous medium is derived by Chen et al. [2006]:

\[ \frac{\partial (\phi c_i \rho)}{\partial t} = -\nabla \cdot \left( c_i \rho u - \rho D_i \nabla c_i \right) + q_i, \quad i = 1, 2, ..., N_c \]  

(3.14)

with the sum of concentrations of the total amount of components (\( N_c \)) constraint to 1:

\[ \sum_{i=1}^{N_c} c_i = 1 \]  

(3.15)

where \( c_i \) is the volumetric concentration of a component, \( \rho \) is density of the fluid phase, \( u \) is a tensor with fluid phase velocity, \( q_i \) is a source/sink term, \( D_i \) the dispersion coefficient of the \( i^{th} \) component and \( N_c \) is the number of components. Sources and sinks of a component can result from injection and production. They can also result from various processes within the fluid phase, such as chemical reactions between components and bio-degradation.
4

Theory - Polymer properties and effect on oil recovery

This chapter deals with both polymer properties and the effect polymer has on oil recovery.

4.1. Effect of polymer on oil recovery

As mentioned earlier in chapter 2, polymer brings recovery forward, increasing NPV and resulting in a higher recovery when an economic cut-off value for the water cut is considered. Recovery is primarily increased by improving the sweep efficiency, defined as [Lake et al., 2014]:

\[
E_S = \frac{\text{amount of oil contacted}}{\text{amount of oil in place}}
\]  (4.1)

Sweep efficiency is improved by increasing front stability, by enhancing viscous crossflow and by improving sweep around heterogeneities.

The increase in front stability has been shown earlier in Figure 1.2. If the mobility ratio \( M \) (Eq. 3.6) is lower than 1, displacement is stable while for \( M > 1 \), displacement is unstable and fingering may occur.

Viscous crossflow has also been explained earlier (section 3.1.3). Figure 3.5 shows that for \( M < 1 \), viscous crossflow causes oil to move from low into high permeable layers and water breakthrough is retarded. Polymer lowers \( M \) and thus enhances viscous crossflow. It is important to note that viscous crossflow takes place at both smaller scale (decimeter - meter) and larger scale (tens of meters). Part of viscous crossflow may therefore get lost in upscaling. This has been investigated, the results will be discussed in chapter 10.

In section 4.1.1 below, analytical Buckley-Leverett theory is used to explain the effect of mobility ratio on displacement and oil recovery.

4.1.1. Front stability - fractional flow theory

Buckley and Leverett [1942] showed that the fractional flow of water \( f_w \) is dependent on mobility ratio \( M \) (excluding effects of gravity and capillary pressure):

\[
f_w = \frac{1}{1 + \frac{1}{M}}
\]  (4.2)

where \( M \) is the ratio between the mobility of the displacing and the displaced fluid:
4. Theory - Polymer properties and effect on oil recovery

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

(4.3)

Figure 4.1 shows the saturation front and the recovery for three different \( M \). It can be observed that for lower \( M \), the shape of the front is more piston-like, water breakthrough is later and recovery is earlier.

Fractional flow theory can be applied to secondary and tertiary polymer flooding to analyze the different saturation fronts that develop. This is shown in Figure 4.2.

For a secondary flood the reservoir is assumed to be at connate water saturation initially. When polymer solution is injected, this connate water is displaced miscibly, while oil is displaced immiscibly. This results in the formation of a connate water bank, travelling ahead of the polymer front (Figure 4.2b).

For a tertiary flood, e.g. when polymer solution is injected after a period of waterflooding, the reservoir is initially at some water saturation resulting from the waterflood. The polymer front displaces the oil at a lower remaining oil saturation than the water front did. This results in the formation of an oil bank (Figure 4.2c). Ahead of the polymer front are water resulting from the prior waterflood and injected polymer solution that might have a different viscosity, due to adsorption and hydrodynamic acceleration (discussed in section 4.2.2).

4.2. Polymer rheology

As mentioned earlier, polymer is dissolved in water and increases the viscosity of the solution. Thus naturally, viscosity depends on the polymer concentration, but many other factors play a role. Polymer solution rheology is related to several parameters in bulk (e.g. in absence of a porous medium), but is also affected by the presence of the porous medium specifically. In the latter case rheology and viscosity are referred to as apparent rheology and viscosity.

4.2.1. Bulk rheology

To understand polymer rheology one has to understand how a polymer molecule looks. Polymer molecules are composed of a large number of repeating units of identical structure (Figure 4.3) \cite{Rubinstein2006}. They occur with different length and architecture (Figure 4.4).
4.2. Polymer rheology

The different groups in the polymer molecule are negatively charged, causing electrostatic repulsion between them. This increases the size of the molecule and thereby the viscosity of the solution. Knowing the above, the factors affecting bulk rheology are:

- Polymer type, more specifically the molecular weight (representing chain length) and internal architecture.
- Water composition, reflected in pH and salinity. Positively charged cations in the solution shield the negatively charged groups on a molecule, causing the molecule to shrink [Lee et al., 2009].
- Shear rate. Polymer solutions exhibit non-Newtonian rheological behaviour, which means viscosity de-
pends on shear rate. Polymer solutions can exhibit shear-thinning as well as shear-thickening behaviour. Shear thinning behaviour means molecules uncoil as a result of shear. Uncoiling results in a decrease in size lateral to the flow direction and thereby a decrease in viscosity [Lake et al., 2014]. Shear thickening behaviour generally does not occur in bulk, but is related to the presence of a porous medium and will be discussed hereafter in section 4.2.2.

4.2.2. Apparent rheology

In addition to the factors mentioned above, the presence of a porous medium affects the viscosity of a polymer solution as well. The different processes that play a role are described by [Sorbie, 2013]:

- Shear thickening. Shear thickening behaviour occurs above a certain flow velocity. When the long and coiled polymer molecules do not have sufficient time to stretch and recoil in order to adjust to the flow through the porous medium, elastic strain causes the apparent viscosity to increase. Shear thickening behaviour becomes more important at increasing molecular weight. Given the molecular weight of the polymers that are mostly used in EOR and the flow velocities in the reservoir, it usually does not play a role [Delshad et al., 2008].

- Polymer degradation. Interaction with the rock and the fluids present in the rock cause the molecular structure of the polymers to break. This happens mechanically (shear), chemically, thermally and biologically.

- Hydrodynamic acceleration. Due to the large size of the polymer molecules, their center of gravity is somewhat further away from the pore walls, where velocity is highest, compared to the center of gravity of the water molecules. This causes the average velocity of the polymer molecules to be somewhat higher than the average velocity of the water molecules. The effect is a lower polymer concentration in the originally injected solution and the presence of some polymer in the water ahead of the front.

- Polymer retention. Polymer propagation is slowed down due to adsorption of polymer on the rock and mechanical entrapment. The effect of retention is a decrease in polymer concentration in the original solution and a decrease in effective rock permeability. The latter may affect the mobility of fluids injected during and after the polymer flood.

4.2.3. Polymer use in practice

When using polymer solutions, several practical challenges may arise. These are mainly related to getting the polymer into the reservoir as effectively as possible, e.g. at the designed rate and optimum viscosity, to maximize polymer benefit. Experimental testing, simulation of the different processes polymer will be subjected to and learning from field pilots help to mitigate the risks mentioned below. This is important since they can be decisive for the economic and practical feasibility of a polymer flood.

The viscosity of polymer solutions may cause injectivity issues, resulting in a lower than optimal injection rate. Sufficient permeability reduces this problem. In field pilots conducted by Shell, it has been observed that injectivity is often better than what is expected based on simulations. This is found to be due to fracturing around the well, a very high water quality due to treatments for the use of polymer and shear thinning behaviour of the polymer. In a simulation this can be included in the form of a “kh multiplier”.

In offshore polymer flooding, fluids are generally injected through a central riser and thereafter distributed through chokes. Over these chokes the pressure drop and thus shear is very high. This causes polymer degradation and can have a significant effect on the resulting viscosity. Recent research shows that (some) biopolymers may be less affected by shear degradation than synthetically generated polymers (for example HPAM) [Sorbie, 2013].

Finally, storage and processing capacity play an important role, especially in offshore applications where space is limited. Firstly, the polymer (mother) solution has to be stored. Secondly, the polymer flood changes the amounts of produced water and oil. Some of the produced water contains polymer and has to be processed in order to be disposed, or must be reinjected. A possible solution for minimizing the amount of polymer needed is “lean polymer”. This concept is a smart injection schedule with varying concentrations of polymer, which maximizes efficiency while using a minimal amount of polymer (Gerard Glasbergen, Shell. Personal communication).
The concept and purpose of upscaling have been briefly introduced in sections 1.1 and 1.2. As mentioned there as well, upscaling absolute properties (permeability and porosity) by locally averaging fine grid properties does not represent flow behaviour from the fine grid in a coarse grid. This is because heterogeneities on all scales affect flow behaviour through connectivity. The effect that heterogeneities, smaller than coarse grid size, have on connectivity and therefore on flow behaviour disappears in upscaling. Somehow, this must be accounted for.

In this chapter the different scales on which heterogeneity occurs in a reservoir will be discussed. This is important to understand the implications of upscaling and the use of pseudo-relative permeabilities. Note that the discussion here will not go into geological detail but will be conceptual. Geology and heterogeneity of turbidites will be discussed later in Chapter 6.

Afterwards, an overview of upscaling methods that have been developed in the past to capture flow behaviour during a waterflood will be given. The overview is limited to upscaling two-phase flow. In Section 7.4, where the development of the workflow is discussed, the methods will be reviewed for application on upscaling of polymer flooding and the goals of this research.

5.1. Scales of heterogeneity

In order to understand the scales on which heterogeneity occurs, definitions relating to scale can be defined [Li and Lake, 1995]. A global window is a subregion of the world coordinates that represents the maximum size of interest to a particular problem. In the context of this research, this is the reservoir full field model (km to tens of km in length and width, ten to hundreds of m in height). The smallest size resolvable in a given problem is the pixel scale. In this research this is the core plug on which the relative permeability curve is measured in the lab (cm). In between the pixel scale and the global window is a moving window. This is defined by the interest of the user. In this research, this can be an upscaled coarse grid block of a user-defined size (tens to hundreds of m in length, m to tens of m in height).

Li and Lake [1995] adjusted the classical semivariogram representation to illustrate heterogeneity as a function of scale. Figure 5.1 shows that for a moving window at any particular scale, heterogeneity with length scales below this scale must be implicitly modeled through pseudos. Heterogeneity above this scale can be explicitly modeled in the reservoir model. It is good to realize that a relative permeability measurement on a core plug (about 5 cm) already implicitly captures heterogeneity within this plug.

Apart from very small scale heterogeneities, relperm measurements on a core also include pore-scale effects. The architecture and geometry of the pore network influence flow behaviour through among others dispersion, adsorption, capillary trapping and wettability. In a relperm measurement on a core, capillary trapping is represented through $S_{wpc}$ and $S_{orp}$ (see section 3.1.2). Wettability is represented through the endpoints, which are the relative permeabilities at irreducible saturation of the other phase. The wetting phase has a lower endpoint relative permeability than the non-wetting phase. This is because the non-wetting phase is present in the larger pores, blocking flow for the wetting phase. By contrast, the wetting phase at irreducible saturation is present in the smallest pores, leaving the largest pores open for the non-wetting phase to flow [Lake et al., 2014]. Pore-scale effects and translating pore-scale effects to macroscopic rock properties have been researched by many authors, among others [Bakke and Øren, 1997] and [Blunt et al., 2013]. Although this research focuses on...
5. Theory - Upscaling

Figure 5.1: Semivariogram illustrating heterogeneity as a function of scale. For a moving window at a particular scale, heterogeneity with length scales below this resolution must be captured implicitly through pseudos. Heterogeneity with length scales above this resolution can be modeled explicitly in the reservoir model. Edited from [Li and Lake, 1995].

the translation from core scale measurement to coarse grid block scale, it is important to be aware of the effect of the pore-scale on the macroscopic rock properties.

Figure 5.2 conceptually illustrates the types of heterogeneities that occur on different scales. The box annotates heterogeneity that will completely or to a large extent disappear in upscaling to the resolution of a dynamic reservoir model. This is where this research will focus on. Larger scales are explicitly modeled in the reservoir model and the smallest scale is on a pore level. It can be observed that lamination and cross bedding mainly affect oil recovery through increasing $S_{or}$ in swept parts (see section 3.1.2). By changing the ratio of viscous to capillary forces polymer could alter this. Baffles and permeability zonation affect the sweep efficiency, which may differ for a water and a polymer flood (section 4.1).

5.2. Methods to develop pseudo-relative permeabilities

Pseudo-relative permeabilities (pseudos) aim to represent fine grid flow behaviour in the coarse grid through altering the relative permeability curves from the fine grid. Relative permeability curves describe the ability of a phase to flow through a porous medium in the presence of another phase. To date, a lot of research has been conducted, in which pseudos are derived in different ways, under different assumptions. This research can be roughly divided in two types of pseudo methods: those that derive local pseudos, e.g. an individual pseudo for each grid block, and those that derive global pseudos, e.g. one pseudo for either all gridblocks or one pseudo for all gridblocks within a particular zone or facies.

Methods that derive local pseudos include those derived under the assumption of Vertical Equilibrium (section 5.2.1) and dynamic pseudos (section 5.2.2). Methods that derive global pseudos are pseudos based on a Connectivity Factor and pseudos based on History Matching. These are discussed in sections 5.2.3 and 5.2.4 respectively.

In section 7.4 all methods are critically reviewed for their applicability to upscaling polymer flooding and the goals of this research. Here, the difference between global and local pseudos is discussed as well.

5.2.1. Vertical Equilibrium pseudos

One of the first methods to create (local) pseudos is developed by [Coats et al., 1967]. The method is derived under the assumption of Vertical Equilibrium (V.E.).

Vertical Equilibrium

V.E. is the state in which the sum of all driving forces in the direction perpendicular to the bulk fluid flow is zero [Lake et al., 2014]. For flow in the horizontal direction:
5.2. Methods to develop pseudo-relative permeabilities

\[ \frac{\partial \Phi_{w}}{\partial z} = \frac{\partial \Phi_{nw}}{\partial z} = 0 \]  \hspace{1cm} (5.1)

where \( \Phi \) is potential and \( w \) and \( nw \) denote the wetting and the non-wetting phase respectively.

V.E. implies that saturation and pressure changes in the vertical direction decay much faster then in the horizontal direction. Thus, the saturation profile will remain similar while moving horizontally through the reservoir. It occurs for low viscous to gravity ratio, i.e. for good vertical communication, relatively low flowrates, little heterogeneity and high aspect ratios (length to height ratio) [Lake et al., 2014].

Vertical communication and aspect ratio are captured in the effective length-to-thickness ratio by [Lake et al., 2014]:

\[ R_L = \left( \frac{L}{H} \left( \frac{k_z}{k} \right) \right)^{\frac{1}{2}} \]  \hspace{1cm} (5.2)

where \( L \) and \( H \) are reservoir length and height respectively, \( k \) is average horizontal permeability and \( k_z \) is average vertical permeability. It has been shown that V.E. is a reasonable assumption for \( R_L > 10 \), although good results for \( R_L = 2 \) have been reported as well [Zapata and Lake, 1981].
Derivation of pseudos

A huge advantage of the assumption of V.E. is that it reduces the problem from three to two dimensions. In this two-dimensional system, Coats et al. [1967] scales up one column of fine grid cells in the vertical direction to one coarse grid cell. Using V.E., he integrates the different terms in the governing equations over reservoir thickness \( h \) to yield the following integrals:

\[
\frac{k_{rw}}{k_{rw}} = \frac{\int_0^h k_{abs} \phi(z) k_{rw}(z) \, dz}{\int_0^h k_{abs} \phi(z) \, dz} \tag{5.3}
\]

\[
S_w = \frac{\int_0^h \phi(z) S_w(z) \, dz}{\int_0^h \phi(z) \, dz} \tag{5.4}
\]

The pseudo for a coarse grid cell is then equal to the (absolute) permeability weighted average of the relative permeabilities in the fine grid cells. Corresponding saturation values are calculated as the porosity weighted average. The finite difference approximation of these equations is:

\[
\frac{k_{rw}}{k_{rw}} = \frac{\sum_{k=1}^K \left( T_x k_{rw} \right)_k}{\sum_{k=1}^K T_x} \tag{5.5}
\]

\[
S_w = \frac{\sum_{k=1}^K \left( V_p S_w \right)_k}{\sum_{k=1}^K (V_p)_k} \tag{5.6}
\]

where \( \cdot \) stands for the pseudo-values and \( k \) are indices for the fine grid layers in vertical direction. Grid block transmissibility \( T \) is defined as \( \Delta y \Delta z \Delta x \) and \( V_p \) is the pore volume of a grid block, equal to \( \phi \Delta x \Delta y \Delta z \).

5.2.2. Dynamic pseudos

Jacks [1973]

Another method for local pseudos is developed by Jacks [1973]. He was one of the first to develop a method based on simulations (therefore called dynamic pseudos) and tries to overcome the V.E. assumption. In his work it is assumed that reservoir behaviour can be simulated in 2D (x-z). This is done based on a comparison of 2D and 3D simulation results on part of the field, which was found satisfactory.

Again, each vertical column of fine grid blocks is upscaled into one coarse grid block. It is assumed that the potential differences between each set of vertically stacked fine grid blocks are equal and that these are equal to the potential difference in the coarse grid.

Coarse grid cell saturation is the porosity weighted average of the fine grid cells (same as Eq. 5.6). Coarse grid cell flowrate is the sum of flowrates in the fine grid cells, here for oil:

\[
\bar{q}_o = \sum_k q_{ok} \tag{5.7}
\]

For ease of reading, the lower and upper bounds of the summation are left out. This also applies to the next equations. Substituting Darcy’s Law (Eq. 3.10) in Eq. 5.7 and assuming the potential difference to be equal for each fine grid cell and the total to be equal to the coarse grid cell potential difference results in the relative permeability for each grid cell:

\[
- \frac{k_{rw}}{\mu_o} (\Delta \Phi_o) = - \sum_k \left( T_x k_{rw} \right)_k \frac{k_{rwk}}{\mu_{ok}} (\Delta \Phi_o)_k \tag{5.8}
\]

\[
k_{rw} = \frac{\mu_o \sum_k \left( T_x k_{rwk} \right)}{T_x} \tag{5.9}
\]
Pseudo-viscosity is taken as the flowrate weighted average of the fine grid viscosity. $\overline{\mu_o}$ is taken as the sum of the fine grid values in the coarse grid:

$$\overline{\mu_o} = \frac{\sum_k (q_o \mu_{ok})}{\sum_k o} \quad (5.10)$$

$$\overline{T_x} = \sum_k (T_x)_k \quad (5.11)$$

**Kyte and Berry [1975]**

Kyte and Berry [1975] aim to improve the method from Jacks [1973] by calculating the coarse grid potential from the fine grid. Coarse grid potential is taken as the $k^r_k r^h_h$ weighted average of the fine grid cells in the middle column of a coarse grid cell:

$$\overline{p_o} = \frac{\sum_k \left( k_{abs} k_{r_o} h (\Phi_o)_k \right)}{\sum_k \left( k_{abs} k_{r_o} h \right)} \quad (5.12)$$

Similar to Jacks [1973], fine grid flowrate is taken as the sum of coarse grid flowrates (Eq. 5.7) and Darcy’s Law is substituted. Pressures no longer cancel out and the equation for pseudo-relative permeability becomes:

$$k_{ro} = -\left( \frac{\overline{\mu_o}}{\overline{T_x} \Delta \Phi_o} \right) \sum_k q_{ok} \quad (5.13)$$

With the contribution of Kyte and Berry it is now also possible to coarsen the grid in the areal direction. A large disadvantage of the work is that the method can lead to stability issues in the simulator. This is related to the calculation of the potential differences, where relative permeabilities may become negative or infinite when calculated pressures and flowrate are not in accordance. This is derived in a critical review by Stone [1991].

Methods which are similar to Kyte and Berry [1975] but differ in the pressure calculation have been developed by Emanuel and Cook [1974] and Woods and Khurana [1977]. However, these can cause instability as well [Stone, 1991].

**Stone [1991]**

In an attempt to overcome the stability issues from the method of Kyte and Berry [1975], Stone [1991] proposes a fractional flow formulation where pressures are not calculated. The coarse grid fractional flow is a total flow rate weighted average of the fine grid fractions. Again, total flowrate in the coarse grid equals the sum of fine grid flowrates (Eq. 5.7). The fractional flow of oil times the total flow rate is substituted:

$$q_{tf}_o = \sum_j \sum_k (q_{tf} f_{o})_{jk} \quad (5.14)$$

where $k$ denotes the vertical direction as before and $j$ denotes the areal direction. Substituting Eq. 5.7 and rewriting yields the fractional flow of oil in the coarse grid. It becomes the total flowrate weighted average of the fine grid fractional flow:

$$\overline{f_o} = \frac{\sum_j \sum_k (q_{tf} f_{o})_{jk}}{\sum_j \sum_k q_{ijk}} \quad (5.15)$$

The pressure level throughout the reservoir is matched with flowrate by making the coarse grid potential gradient in the coarse grid cells a transmissibility, total mobility weighted average of the fine grid cells.
5. Theory - Upscaling

5.2.3. Pseudos based on Connectivity Factor

Alpak et al. [2008] derive pseudos based on a "3D Connectivity Factor" (CF). This method differs from the previously mentioned methods in that it generates global pseudos. It does not generate an individual pseudo for each grid block, but one pseudo for the entire fine grid model, or otherwise one pseudo per zone or facies within the model. Another difference is that the authors assume that the upscaling workflow is done on a sector or small conceptual model and that the results are then feed back into the full field model. A fine grid full field model is thus not necessary.

The CF is defined as the ratio of recovery factor (RF) in the fine and the coarse grid:

\[
CF = \frac{RF@t, \text{ fine scale 3D model}}{RF@t, \text{ coarse scale 3D model}}
\]

The closer the CF is to 1, the better connected is the reservoir. The more heterogeneity that disappears in the coarse model, the lower the CF in general will be, as the authors focus on fine scale heterogeneities such as shale drapes, which hamper flow.

The authors distinguish two effects of fine scale heterogeneity that should be captured in pseudos: increased oil trapping due to stratigraphic dead ends and baffles and early water breakthrough. These effects are represented in the CF at Ultimate Recovery (UR) and Breakthrough Time (BT) respectively.

It is assumed that the relative permeability curves can be described with modified Brooks-Corey equations (see section 8.2). The authors reason that the increase in trapped oil can be represented through adjusting \(S_{or}\). This is done with a straightforward equation:

\[
\overline{S_{or}} = S_{or, \text{fine grid}} + (1 - CF_{UR}) \times (1 - S_{wc} - S_{or, \text{fine grid}})
\]

Adjustment of the early BT effect is captured through \(n_w\). For this the authors make the assumption that the transport processes can be approximated by Buckley-Leverett theory (discussed earlier in section 4.1.1) and combine this with the modified Brooks Corey equations to arrive at the following equation:

\[
M^{ref} S_{w_f D_h} \left[ (1 - S_{w_f D_h})^{n_o - 1} \left[ n_w (1 - S_{w_f D_h}) + n_o S_{w_f D_h} \right] \right] \epsilon = \left( M^{ref} S_{w_f D_h} \left[ (1 - S_{w_f D_h})^{n_o - 1} \left[ n_w (1 - S_{w_f D_h}) + n_o S_{w_f D_h} \right] \right] \right)
\]

where subscripts \(c\) and \(f\) denote the coarse and the fine grid respectively and subscript \(w_f D_h\) denotes the normalized displacement front saturation at the time of BT.

The authors solve for \(n_w\) only, using the Wijngaarden-Dekker-Brent method [Alpak et al. 2008]. It is assumed that \(n_o\) is similar in the fine and the coarse grid. The authors found that solving for both \(n_o\) and \(n_w\) results in non-uniqueness of the results and non-physical curves. They do not explain why they have chosen \(n_o\) instead of \(n_w\). The endpoint relative permeabilities, \(k_{rwc}\) and \(k_{rcw}\), are not touched in the derivation or resolving of the equation. Reasoning is not explicitly mentioned, the values in the fine and the coarse grid are just cancelled out against each other. Hence, it seems that the authors assume the endpoints do not change during upscaling.

5.2.4. Pseudos based on History Matching

Another way of generating pseudos is through History Matching (HM). HM is defined as the act of adjusting a reservoir model until it closely reproduces observed data. It is done to gain understanding about the subsurface and to optimize a reservoir model for prediction purposes [Rwechungura et al. 2011]. It differs from the methods discussed previously in that there is no "true" reference case. In the previously discussed methods the objective was to match a coarse grid with a fine grid, which was taken as the "truth". In actual field applications, the subsurface will always remain unknown and therefore there is no "truth".

The objective of a history match is often to match cumulative oil and water production and pressure data. The objective of a history match may also include parameters such as tracer concentration in the production well. Because the subsurface is unknown, HM does not only comprise changing the relative permeabilities, but aspects from the entire reservoir model: geological features and properties variations, reservoir connectivity, petrophysical characterization and drive mechanisms such as aquifer strength [Rwechungura et al. 2011].
would be wrong to only alter the relative permeability curves if the other aspects are not modeled correctly: even if cumulative production would be matched the saturation distributions and pressures would be wrong. The model would then not be useful in practice. For example, it would not be useful for infill drilling proposals and modeling of constraints.

Traditionally, HM is done using a trial and error procedure. The Reservoir Engineer analyses the difference between the simulated and the observed value and manually adjusts one or a few parameters. The quality of this type of history match largely depends on the engineer’s experience and the budget. Reservoir models comprise hundreds of thousands of gridblocks and therefore doing a manual history match is often not feasible for long periods. In addition to that uncertainties will remain high, as searching the parameter space is time consuming [Rwechungura et al., 2011]. To improve HM results and simplify the procedure computers can be employed to automatically vary the parameters. This is called Assisted History Matching (in literature sometimes also referred to as semi-automatic History Matching). Assisted History Matching (AHM) is defined as the construction of an initial model with an initial approximation of the reservoir parameters which then goes through a systematic process reduction of an objective function that represents the mismatch between observed and calculated response by perturbing the relevant parameters [Guohua et al., 2004].

Assisted History Matching Algorithms

In AHM an algorithm is used to search a parameter space so that the objective function is minimized. Optimizing algorithms can be classified in terms of how the methods explore parameter space versus exploit local regions in order to find the minimum value of the objective function [Tavassoli et al., 2004].

In the oil and gas industry, focus has initially been on exploiting the parameter space. The single best combination of parameters that minimize the objective function is found. However, over the past years exploring the parameter space is considered increasingly important. In exploring the parameter space multiple combinations of parameters that minimize the objective function can be found. The advantage of having multiple parameter combinations that fit production to date is that uncertainty in forecasting can be quantified. When exploiting the parameter space, not all models which fit production data may be found and uncertainty may not be even recognized [Tavassoli et al., 2004].

Methods that fall under exploiting the parameter space are gradient based methods, such as Gauss-Newton and sequential quadratic programming. Methods that fall under exploring the parameter space are genetic algorithms, swarm algorithms and Simulated Annealing [Rwechungura et al., 2011].

The advantage of exploiting methods is that the methods are fast. A drawback is that implementation and usage is difficult, due to the requirement of first and sometimes second derivative calculations. This can be done directly, through the adjoint method or by finite difference approximation [Oliver et al., 2008]. As mentioned, the advantage of exploring methods is that multiple solutions are found which can be used for uncertainty quantification. In addition to that they are easy to understand and implement. The drawback is that the methods are computationally intensive. Also, it may be necessary to refine the model after exploring the parameter space. This can be done manually or through gradient methods [Rwechungura et al., 2011].
This research focuses on turbidite reservoirs and in particular on heterogeneities within these reservoirs that disappear in upscaling, but affect connectivity and thereby flow behaviour. Turbidite geology and the kind of heterogeneities that occur on both the larger and the smaller scale will be discussed in this chapter. The geological models used in the sensitivity studies of this work are based on this.

6.1. Depositional system

Turbidite deposits, also referred to as submarine fans, deep-sea fans or abyssal fans, originate from turbidity currents that come down from the continental slope. These currents are driven by gravity and carry sediment from the continental shelf into the deep sea. Sediment may be transported through one or more channels. An example of a turbidite depositional system with three supplying channels is shown in Figure 6.1.

Turbidites can be deposited on both passive and active continental margins [Shanmugan et al., 1988]. On active continental margins, deposition takes place in the foredeep basin. On passive margins, slope incision takes place and sediment is deposited on the basin floor (Figure 6.2).

Turbidites on both passive and active margins are generally deposited during periods of low sea level [Shanmugan et al., 1988]. In terms of Sequence Stratigraphy, this is during the Falling Stage Systems Tract (FSST) and the Low Stage Systems Tract (LST). During this period, Relative Sea Level is low, meaning sediment supply exceeds accommodation space. On passive margins, rivers start to incise valleys and form canyons, through which sediment is transported onto the basin floor [Catuneanu et al., 2009].

Generally, turbidites on active margins are less muddy due to the closer proximity of the sediment source and higher gradients. This closer proximity also causes shorter and less sinuous channels on active margins. In this work, a general description of turbidite deposits and the internal architecture is presented. For a detailed description of the differences in deposition and architecture between active and passive margins, one may refer to Shanmugan et al. [1988].
6.2. Large scale architecture

Figure 6.2 shows the different sedimentary structures deposited by a turbidity current, described by Bouma [1962]. These units are related to the movement and characteristics of a turbidity current. The different units are deposited as the current moves down the slope. As a result, the sequence is almost never completely deposited at one location, but units laterally vary across the slope [Tucker, 2001] (Figure 6.3b).

Throughout the turbidite depositional system energy decreases along the continental slope towards the basin. As a result, facies change along the slope. This is combined with the previously described change in units along the slope, meaning that units $T_a$ and $T_b$ of the Bouma sequence will occur in the proximal facies (channels) and the other units will mainly occur in the distal facies (lobes).

On the continental slope sediment transport is confined by channels. On the upper part of the slope, energy is highest and most of the erosion takes place. Here, channels are relatively straight with almost no overbank deposits. Along the slope the gradient decreases and the current starts to lose its energy. Channels become more sinuous and may form fine-grained overbank deposits (levees). Finally, the sediment reaches the basin floor, where it is no longer confined and is deposited as lobes [Funk et al., 2012].

Although the deposition of one turbidity current is a sudden, fast event, they can repeat for millions of years. As a result, sediment can accumulate up to hundreds to thousands of meters. In between deposition of different turbidity currents, hemipelagic sedimentation takes place. This means that very fine grained hemipelagic sediment will be present in between sandy turbidite deposits.

Figure 6.4 schematically shows deposition of different facies within the system. In the cross-sections it can be observed that the channels and lobes are surrounded by fine grained hemipelagic sediment. It can also be observed that the different channels in the confined setting may cut into each other. When confinement is less, amalgamation decreases, resulting in lower N/G and lower connectivity. At the end of the channels, wide lobes form which may partly overlap. Within the lobes, small distributary channels are present. The stacking pattern and connectivity of different channel bodies depends on the frequency of turbidite events, the type of sediment being transported, the rate of hemipelagic sedimentation, the slope and basin floor morphology,
tectonic activity and climate. These factors may change in time [Funk et al., 2012].

Figure 6.4: Sediment deposition along continental slope. Edited from [Funk et al., 2012]

6.3. Internal architecture

In this section the internal architecture and reservoir connectivity of the three main turbidite architectural elements (channels, levees and sheet lobes) will be discussed.

6.3.1. Channel elements

Based on a study on both outcrops and present-day analogues, [Alpak et al., 2013] find that channel architecture is multiscale. They recognize three elements: channel stories, channel story sets and channel complexes (Figure 6.5).

A channel story can be vertically aggrading or laterally accreting (A in Figure 6.5) and is made up of various turbidity currents passing through the channel. It is scaled to the size of the turbidity currents that passed through it and is between 3 and 20 m thick and 50 to 400 m wide (approximate, general numbers, exceptions may occur). A vertically aggradaded channel is coarsest in the center and finer towards the channel margins. A laterally accreting channel is fining upwards. A channel story set (B in Figure 6.5) consists of a set of channel stories and their associated levee deposits. It can be compared to a meander belt in fluvial geology. Multiple channel story sets that are genetically related are referred to as channel complexes (C in Figure 6.5). All channel elements are typically bounded by an erosional surface at the bottom, followed by deposition of so-called bypass facies. The bypass facies is characterized by coarse sediment, which is significantly reworked and partly eroded.

[Alpak et al., 2013] interpret the different scales of channelization as adjustments to the equilibrium profile of the system. The equilibrium profile continuously changes as Relative Sea Level changes (subsidence, eustacy, sediment supply) and as sediment is being deposited. As a result, energy changes, avulsions take place and depositional mechanisms shift laterally. In this context, the erosional surface and bypass facies represent the high energy within the channel when it first finds its new path of steepest descend and cuts into previously deposited sediment.

The change in energy as a function of time and the resulting change in deposited facies is shown in more detail in Figure 6.6 from [Mayall and Stewart, 2000]. Although their terminology is slightly different, they describe a channel story set in agreement with [Alpak et al., 2013]. At the base of the channel a bypass facies is deposited. This is overlain by high N/G channel stories, which erode into each other. As more sediment is deposited, the gradient changes and energy is lower. Channels with higher sinuosity and fine grained levees form.

6.3.2. Channel connectivity

In their research [Alpak et al., 2013] have found three types of mudstone or heterolithic strata that block channel connectivity. These are referred to as *shale drapes*, an expression that will be used in this work as well. Shale drapes occur within all three elements in the architecture discussed earlier. Shale drapes have previously been researched by [Barton et al., 2010], who have also described the underlying processes discussed in the next paragraph.
The first type of shale drapes are abandonment drapes (A in Figure 6.7). When a channel is formed by erosion, but initially no siliclastic sediment is transported through it, hemipelagic sedimentation takes place. A fine
grained layer is formed in between the erosional surface and the later on deposited sediment.

The next type of shale drapes, convergent margin drapes, are formed when a channel progressively fills (B in Figure 6.7). In the center of the channel, where energy is highest, coarse grained material is deposited. Towards the margins, fine grained material is deposited. As the channel fills up, the fine grained material converges at the margins of the channel to form drapes.

The last type of shale drapes are bypass drapes (C in Figure 6.7). These are formed when a turbidity current bypasses a channel and fine grained sediment from the tail of the current remains. These shale drapes are commonly characterized by the presence of coarse grained, reworked sediment in between them.

![Figure 6.7: Different types of shale drapes occurring in channels](Barton et al., 2010)

[Alpak et al., 2013] conducted dynamic simulations on detailed inter-well sector models (light oils, 20-40 °API) to assess which factors are most influential on the RF in channelized turbidite reservoirs. For water flooding, most of the important parameters are related to meander belts: number of meander belts, meander belt N/G, meander belt degree of amalgamation, channel continuity and well spacing. Of equal importance are parameters describing shale drapes on all three scales.

Parameters that influence the balance between viscous and gravity forces are found to be of little influence [Alpak et al., 2013]. This is probably because the displacement of such light oils by water will always be favourable or very mildly unfavourable. It will be interesting to assess how this changes for polymer flooding and oils of somewhat higher viscosity, so that mobility ratio is more variable.

6.3.3. Levees

When a channel overflows, sediment is deposited on both sides of the channel and levees are formed. Levee deposits consist primarily out of mud and laminated sands and silts.

During a flooding event, coarser material is deposited first while finer material is transported further. Therefore the N/G of the proximal levee is higher than the N/G of the distal levee. Levees are connected with the channel via highly heterogeneous channel margins. In these margins slumps and discontinuities may be present [Beaubois, 2004].
6.3.4. Sheet lobes

The proximal lobe consists of amalgamated sheet sands with very good N/G (Figure 6.8a). This is because coarser grained material is deposited first and because it is more likely that different lobes overlap each other in the proximal part. The distal lobe is finer grained and shales are present in between the sands (Figure 6.8b) [Mutti, 1985].

Figure 6.8: Sheet lobe deposits as observed in an outcrop with corresponding schematic stratigraphic column [Mutti, 1985].
Workflow development

In this chapter the development of the workflow is discussed. First the conceptual basis for the workflow is presented. From this, some of the uncertainties related to the results of the upscaling procedure become clear. Then, requirements for the workflow are identified based on the goals of this research (section 1.3). These requirements are used to select an upscaling method from the methods that have been presented earlier in section 5.2. Definition of the objective function and selection of the optimizing parameters are discussed. An overview of the final workflow is given at the end of this chapter in section 7.6.

7.1. Conceptual basis

Before the upscaling method can be selected the basis on which the workflow will be developed should be clear.

This research aims to develop a workflow for upscaling polymer flooding, by which the effect of polymer around small scale heterogeneity affecting connectivity is represented in a coarse grid simulation. It aims to do so through adjusting the relative permeability curves. The workflow should be applicable for screening a reservoir for the possibility of polymer flooding (forward modelling). This means there is no actual production data available on which the polymer flooding pseudos can be based. Thus the workflow should be based on upscaling flow behaviour in a fine grid to a coarse grid. The fine grid should be taken as the "truth" and the objective is to match fine grid data.

For the upscaling workflow a fine grid sector model is used. Running a full field model on a fine grid is computationally not feasible. If so, upscaling would not be required. For the sector models to be of most use they should be chosen in a way that they represent geology and well placement of the full field model. Examples are an injector-producer pair offshore or a 5 spot pattern onshore.

In reality there is a large uncertainty in the fine grid geology. However, there often is a conceptual idea of geology or geological features within the reservoir. A conceptual fine grid can provide insights in how the pseudos would differ for polymer flooding compared to water flooding, despite the uncertainty. Then, these insights can be used to adjust pseudos derived for water flooding to pseudos suitable for screening a reservoir for polymer. When full field pseudos have not yet been derived, the results of the upscaling can be applied directly in the full field as it is the best available at that moment. Of course, when a polymer flood would be conducted and production data becomes available, Assisted History Matching can be done to improve the pseudos and/or other parameters in the model.

One of the ways that could reduce uncertainty about the fine grid is by checking whether the pseudos derived for water flooding in the fine grid match the history matched pseudos of the full field model (if they exist).
7.2. Assumptions

7.2.1. Fine grid relative permeabilities

In the workflow the fine grid will be populated with relative permeabilities measured from core floods. This causes uncertainty, since fine grid blocks are larger than the size of a core. However, there is no basis for other curves to be used as this would require a fine grid model with the resolution of the size of a core or another upscaling procedure for this step. That is outside the scope of this work, although a forward upscaling procedure from the core scale to the fine grid scale could be conducted of course. This would be an upscaling step prior to upscaling from the fine grid scale to the coarse grid scale.

7.2.2. Upscaling absolute properties

In this research, the focus is on capturing flow behaviour resulting from fine scale heterogeneity in an upscaled grid and in particular on the difference between capturing this for polymer and water flooding. Since the fine grid serves as the "truth", there is no geological uncertainty in the coarse grid (note that this should not be confused with the uncertainty regarding selection of the fine grid representing the actual subsurface).

However, the way of upscaling absolute properties from the fine grid does affect the results. In order to describe fluid flow in the subsurface as accurately as possible, absolute properties should be upscaled as optimally as possible. This is researched and discussed by many authors, among others by Li and Beckner [2000]. To illustrate the importance and to give the reader a feeling about this, their results of two different ways of upscaling absolute properties are shown in Figure 7.1. One can indeed imagine the lack of accuracy that arises in the reservoir simulator as a result of inaccurate upscaling of absolute properties. If the deviation is too big, pseudo-relative permeabilities can never, and should not be used to, compensate for this. This research does not go into detail about the optimum way of upscaling absolute properties. However, a sensitivity study is conducted to assess the difference in results for two different methods and degrees of upscaling on the results (section 11.2.3).

Although the match between the coarse and the fine grid may not be equally good in all cases, the workflow that has been developed can be used for any method of upscaling absolute properties. This is as long as it is used consistently. When a sector model is used to develop pseudos for a full field model, method and degree of upscaling should be in agreement for the pseudos to be valid. This flexibility is favourable since an upscaled full field model is often already in place. If a history match has been done a lot of time and money is spent already. It is much easier to apply the same upscaling procedure for absolute properties to the sector model in the polymer upscaling workflow then to adjust the full field coarse model.

![Figure 7.1: Different methods of upscaling absolute properties](Li and Beckner, 2000)

7.3. Selection of upscaling method

7.3.1. Requirements

Requirements for the workflow are based on the research objectives (section 1.3) and the conceptual framework presented above. Three questions are addressed in the research objectives:

- What is the best way to generate pseudos for upscaling polymer flooding?
• What is the dependency of pseudos to heterogeneity, polymer concentration and method / degree of upscaling?

• What is the validity range of generated pseudos?

Requirements for the upscaling process are then as follows:

• Generated pseudos should result in an accurate match between a fine grid sector model and the corresponding upscaled, coarse grid. The polymer size of price should be correctly represented.

• The upscaling process should be reasonably fast (both computationally and with respect to the human effort and time required).

• The upscaling process should be easy to implement in practice. This means it should be easy to generalize results and to apply them in a full field model, either as global pseudos for an entire model or, when geology varies in the field, as global pseudos for a facies or zone in the model.

Requirements for the workflow are:

• The workflow and model should allow easy variation of parameters of interest, in order to assess the sensitivity of pseudos to those parameters.

• The workflow should provide an idea of the validity range of a generated pseudo. It should return the error you make in the match within a range of interest.

7.4. Selection of upscaling method

Different methods for upscaling water flooding have been presented in section 5.2. In this section, these will be critically reviewed and their applicability for upscaling polymer flooding will be discussed. Based on this, a choice is made for the type of upscaling process that will be used in the workflow.

7.4.1. Review - Local pseudo methods (V.E. and dynamic)

A characteristic of both the V.E. and dynamic pseudos is that each coarse grid cell is assigned an individual pseudo. The advantage of this is that the flow behaviour and saturation profile are theoretically matched perfectly. In case of dynamic methods the pressure profile is matched as well. However, in terms of computational memory, stability and the ability to generalize results this is a disadvantage. An example of a case with problems in generalizing results is presented in Appendix D. Also, pseudos may become unphysical (negative or far above 1) which causes a simulator to crash. Equations are derived for 2D and therefore only valid when the third dimension does not change much.

A full field fine grid is always required, because it is difficult to generalize pseudos generated for different gridblocks. Thus, it is not possible to use some sort of sector model or conceptual model to upscale and apply this to a full field model. In practice, a full field model, on the fine scale required to represent the type of heterogeneity of interest here, is often unfeasible for two reasons. Firstly, the subsurface is uncertain. Well spacing is large, seismic resolution is below the type of heterogeneities discussed here and core data is scarce or absent. If, despite this uncertainty, a full field model with the level of detail required does exist, it is likely to exceed computational power available when using it for a dynamic simulation (otherwise upscaling would not be necessary).

Considering $k_v/k_h$ and $h/L$ ratios that occur in a reservoir (for example take 0.05 and 10 respectively), the V.E. assumption can be valid in terms of length-to-thickness ratio (Eq. 5.2). However, it is questionable whether it is a good assumption for polymer flooding, where viscous forces are important. For this work, the assumption becomes even less appropriate as small scale heterogeneities are considered. These disturb the decay of saturation and pressure in the vertical direction required for V.E.

7.4.2. Review - pseudos based on Connectivity Factor

The disadvantages relating to the need of a full field model are bypassed in the workflow of Alpak et al. [2008]. A sector model is used, which represents the type of heterogeneities expected to exist in the reservoir. Global pseudos are derived, which makes implementation in the full field model feasible.

Adjusting the pseudos is done on an analytical basis. This makes the process transparent, although there seem
to be some assumptions regarding the selected solving parameters which are not fully explained and under-
stood (section 5.2.3). Although transparent, an analytical derivation also entails limitations. Effects, such as
viscous crossflow, that are not captured analytically are not included in the pseudos. In that perspective,
history-matched pseudos are more flexible.

7.4.3. Review - pseudos based on History Matching

(Assisted) History Matching is an extremely flexible process and can be defined after the users need. This
flexibility is an advantage but may also be a pitfall. Parameters should be varied consciously and with sound
reasoning, in order for solutions to be physical and geologically realistic.

A disadvantage of AHM is that it is computationally intensive. Depending on the type of optimization and the
number of parameters varied several to many (in the order of hundreds) simulations are required. This too is a
reason to carefully select and constrain the parameters that are varied.

7.4.4. Selected upscaling process

Given the requirements for this work V.E. and dynamic pseudos are unfavorable. The most important reasons
are stability issues and the difficulty of generalizing results and translating them into a full field model.

Global pseudos are much easier to apply to a full field model. The disadvantage compared to local pseudos
is that the match is less precise. Another disadvantage is that global pseudos are usually more sensitive to
boundary conditions, such as well placement, than local pseudos. Objectives that are defined at the wells
(cumulative production, possibly also pressure) are matched, but the saturation and pressure profile between
the wells is not. Using global pseudos will also provide a clearer trend in how pseudos change for changing
viscosity ratios, which is another goal of this work.

The method developed by Alpak et al. [2008] is rather inflexible. Another disadvantage is that the workflow
finds one optimum parameter combination, while there could be more. The uncertainty of the selected com-
bination on the forecasted polymer size of prize can therefore not be quantified.

For this work, it is therefore decided to use an Assisted History Matching approach. Instead of matching ac-
tual production data, production data from a fine grid is matched. The largest advantage of AHM compared
to the method developed by Alpak et al. [2008] is its flexibility in terms of defining the objective function and
the varying parameters. Dependent on the selected method, there is the possibility to find multiple param-
eter combinations if they exist. This allows uncertainty quantification and insight in the uniqueness of the
results. The disadvantage of AHM is that it is computationally expensive. However, since a sector model is
small compared to a full field model this is feasible.

7.5. Selection of optimizing algorithm

7.5.1. Exploring versus exploiting methods

As explained in section 5.2.3 there are several AHM methods, which can be characterized as exploring or ex-
ploring the parameter space. For this work a method which explores the parameter space is preferred. As the
problem at hand is non-linear an exploring method has a larger chance of finding the global optimum instead
of a local optimum. An exploring method finds multiple parameter combinations if they exist, allowing insight
in the uniqueness of the results and uncertainty quantification in forecasting.

7.5.2. Selection of exploring algorithm

The next step is then to select an exploring algorithm. In view of optimum use of time for this research and
practical implementation of the workflow within Shell in the future, it is preferred to use a method that is
readily available in MoReS, Shell’s reservoir simulator. Two fully exploring methods available in MoReS are
Particle Swarm Optimisation (PSO) and Ensemble Very Fast Simulated Annealing (ENVFSA).

Simulated Annealing (SA) algorithms, first described independently by Kirkpatrick et al. [1983] and Cerny
[1985], are based on the concept of physical annealing of a material. This occurs when a solid in a heat bath is
initially heated by increasing the temperature, such that all the particles are distributed randomly in a liquid
phase and then, a slow cooling follows, such that the particles arrange themselves in a lower energy ground
state where crystallization occurs. In a similar way, the optimisation process simulates the evolution of the
physical system as it cools and anneals into a state of minimum energy. The temperature of the system during
the optimisation determines the acceptance of moving to a (possibly worse) neighbour solution during the
optimisation.

PSO is based on the natural behaviour of birds, fish and other animals that travel in groups or swarms and is
originally developed by [Kennedy and Eberhart] [1995]. The strength of the method is that particles communi-
cate with each other about the best solution known by the members of the swarm, as in nature.

[Ethni et al. 2009] compared PSO with SA methods for fault identification in induction motors. Similar to the
problem in this research, fault identification is a non-linear and multi-variable problem. The authors found
that PSO was both faster as well as more accurate in fault identification: compared to actual data PSO suc-
ceded in 99% of identifications compared to a 60% success rate of SA. This is in agreement with the work of
[Angeline 1998], who found that PSO is a robust method for non-linear problems with very low dependence on
how parameters are initialized. [Mohamed et al. 2009] investigated the efficiency of three stochastic sampling
algorithms (Hamiltonian Monte Carlo (HMC), PSO and the Neighborhood Algorithm) by generating multi-
ple history matched reservoir models and comparing the P10-P50-P90 uncertainty bounds of each algorithm.
They conclude that PSO and HMC can potentially be an effective tool in quantifying uncertainty in the oil
industry.

Based on the above, PSO is selected as optimizing algorithm for this work. Testing the algorithm gave very good
results in terms of the quality of the match and the computational time required. Thus, there was no reason to
change the selected. However, note that this does not mean that SA is unsuitable method for history matching
a fine grid.

7.5.3. Particle Swarm Optimisation

In this section the selected algorithm, PSO, will be explained in more detail.

With the PSO algorithm particles are initially randomly spread across a multidimensional parameter space and
fly through this space at velocity \( \vec{v} \). The parameter space consists of \( n \) dimensions, representing \( n \) optimizing
parameters. At each iteration, the objective function is calculated for each particle. The global optimum,
\( g_{\text{best}} \) is communicated across the particles (social learning) and the objective function value of each particle is
compared to its previously encountered optimum value, \( p_{\text{best}} \) (cognitive learning). Based on this comparison
the velocity of each particle is adjusted in the next iteration (Equations from [Kennedy and Eberhart 1995] with
symbols adjusted to Figure 7.2):

\[
v_{n+1} = v_n + c_p u (p_{\text{best}} - x_n) + c_g u (g_{\text{best}} - x_n)
\]  

(7.1)

where \( v_n \) and \( v_{n+1} \) are the velocity before and after the iteration respectively, \( x_n \) is the particles current po-
sition, \( \omega \) represents momentum, \( c_p \) and \( c_g \) represent random variation and \( u \) is an acceleration constant. \( \omega, c_p \) en \( c_g \) are used to balance between exploiting and exploring the parameter space by determining the im-
portance of the particles previous velocity and the adjustments to the previous velocity. A large \( \omega \) puts more
emphasis on a global search, while a small \( \omega \) results in a more local search [Bansal et al. 2011].

\[\text{Figure 7.2: Adjustment of parameters during Particle Swarm Optimisation} [\text{Wang et al., 2010}]\]
7.6. Workflow overview

In this section the final workflow is presented. The workflow is developed in MATLAB and MoRes, Shells reservoir simulator. Simulations and optimization are done in MoRes. Export and analysis of the results are done with MATLAB.

A schematic overview of the different steps is shown in Figure 7.3. Below, the steps are explained in more detail. Applications of the workflow and examples will be presented later with the sensitivity studies in chapter 10 to 12.

Figure 7.3: Workflow overview. In general around 15 cases with 8 iterations are used to optimize in step 2c. The range of input files in a sensitivity study is usually kept between 10 to 30 in this research but can be as large as the user requires.

7.6.1. Upscaling

The first step for developing pseudos is to select a fine grid sector model representing the type of heterogeneity and well pattern occurring in the field. For example, in the sensitivity studies in this work, an injector-producer pair as found in offshore turbidite fields is considered.

Then, the fine grid should be simulated to establish the objective function: the cumulative production of oil as a function of PV injected. As the system is more or less incompressible, matching oil production means water production will be matched as well. Sufficient PV should be injected so that water breakthrough takes place and afterwards there is stabilization in the RF during the simulation (discussed later in section 12.2).

The fine grid is upscaled to a coarse grid. This can be done in various ways, but since results depend on the gridding of the coarse grid (discussed later in section 11.2.3) it should be a similar grid as in the full field model. In this work upscaling of absolute properties is done either with Surface-Based upscaling or Voxelization. These methods are explained in more detail when they are applied in section 11.1. Now simulations can be conducted in the coarse, upscaled grid and relperms can be adjusted to develop pseudos that minimize the objective function (the least square difference between cumulative oil production in the fine and in the coarse grid). Self evidently, all parameters but the relperm parameters should be kept equal to the parameters in the fine grid when simulating in the coarse grid.

7.6.2. Sensitivity studies

The workflow provides the possibility to assess the effect of different parameters, such as polymer concentration, on resulting pseudos. It is then also possible to assess the error made in cumulative production when using a pseudo that is optimized for a different case (e.g. when a pseudo optimized for water is used to simulate a polymer flood). Similarly, the error when not adjusting relperms at all, e.g. when using the rock relperms in the coarse grid, can be assessed. In order to do this, the coarse grid is simulated with the rock relperms and/or pseudos obtained for a different case.

The current workflow provides the possibility to vary about 10 parameters, which include polymer concentra-
tion, injection rate, density difference, well placement, perforated intervals of both wells, heterogeneity, coarse grid configuration (grid size, upscaling method) and capillarity through the interfacial tension. The modelling of capillary pressure is presented in Appendix C. Heterogeneity can be varied by varying the degree of shale draping in the StratSweep 3D channelized turbidite models (discussed in more detail in section 11.1) and by varying the type of heterogeneity and permeability in the simple 3D box models. Heterogeneity types are a homogeneous reservoir, alternating layers of sands and shales/silts and fining upwards models. The workflow is written in a way so that it can easily be adjusted to include variation of other parameters.

Quantifying the error when using non-optimized pseudos is not unambiguous and the way of measurement is dependent on what is aspired with a polymer flood. The error measurement between two curves when aspiring a delay in water breakthrough is different compared to when the goal is to increase NPV or UR.

Based on its strong relation to practice, in this work it is chosen to quantify the error both as the time in between water breakthrough (defines as when the watercut equals 1%) as well as the difference in recovery when the watercut equals 88 %, where 88 % is chosen as a non-economic production rate. An example of the measurement of the error is shown in Figure 7.4.

Other possibilities that may be used to quantify the error are more related to the NPV of a project. One of the possibilities is to quantify the error as the error in discounted oil revenue over the entire simulation time (Eq. 7.2). This provides an error measure over the entire curve.

\[ R_o = \sum_{n=0}^{N} \frac{C_n}{(1+i)^n} \]  

where \( R_o \) is the discounted revenue from oil production over the total number of years \( N \), \( C_n \) denotes the revenue from oil in year \( n \) and \( i \) is the discount rate.

![Figure 7.4: Error measurement between two cumulative production profiles. Error is calculated by subtracting fine grid from coarse grid value. Thus, a positive value implies a too late breakthrough or overestimation in recovery. A negative value implies a too early breakthrough or underestimation in recovery.](image)

**7.7. Constraints to the workflow**

Constraints to the workflow are presented below. Corresponding recommendations to extend the workflow are given in chapter 13.

**7.7.1. Two-phase flow of oil and water**

In the workflow optimization of pseudos is limited to two-phase flow conditions. Therefore if gas is present in the model, hydrostatic initialization is done with the GOC sufficiently far above the reservoir and residual gas saturation equal to zero so that no gas is present at any time. Furthermore, the workflow has only been tested for the OWC far below the reservoir, so that the only water present in the model is the connate water present initially and the water that is injected.

Oil is modeled as dead oil by equating stock tank density to density at the reference pressure of 100 bar, which
Table 7.1: PVT parameters used in model, based on West-African field. Reference pressure is 100 bar.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water density</td>
<td>1002 kg/m³</td>
</tr>
<tr>
<td>Water compressibility</td>
<td>2.9e-6 1/bar</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>0.45 cP</td>
</tr>
<tr>
<td>Water viscosibility</td>
<td>5.6e-5 1/bar</td>
</tr>
<tr>
<td>Oil density</td>
<td>916 kg/m³</td>
</tr>
<tr>
<td>Oil compressibility</td>
<td>2.9e-6 1/bar</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>4 cP</td>
</tr>
<tr>
<td>Oil viscosibility</td>
<td>5.6e-5 1/bar</td>
</tr>
</tbody>
</table>

is again to ensure no gas is present in the system at any time (see above).

7.7.2. Pressure

In the workflow global pseudos are derived. This implies that pressure at and in between the wells is not matched in the fine and in the coarse grid. This brings along constraints to ensure consistency between the fine and the coarse grid.

Adjustments in compressibility and viscosibility are required so that fluid properties are consistent. Viscosity should be set sufficiently small to ensure viscosity does not differ in the fine and coarse grid due to different pressures. Compressibility should be set sufficiently small to ensure no production due to depletion takes place, as this would differ due to different pressures in the fine and the coarse grid.

The PVT in the models used in this work is based on the PVT of an offshore field in west-Africa. The parameters used are given in Table 7.1.

7.7.3. Constant viscosity

The workflow has only been tested for a displacement with a constant viscosity. Thus, it has not been tested for cases where water is already present in the system (aquifer, tertiary flooding) or when an injection scheme with varying polymer concentration is used. To set the viscosity equal at all times and to avoid the influence of different pressure in the fine and in the coarse grid, the effects of shear, hydrodynamic acceleration and adsorption are not taken into account. Salinity is kept constant and the salinity of the injected water is equal to the salinity of the formation water. The relation between the water viscosity and the salinity and polymer concentration is specified in the polymer rheology table (Figure 7.5).

![Figure 7.5: Viscosity as function of concentration for salinity equal to 28000 ppm and a shear rate of 8 * 1/s, as used in the model](image-url)
Objective function and optimizing parameters

8.1. Objective function definition

As the purpose of polymer flooding is to increase oil recovery and to reduce early water breakthrough, cumulative production of oil and water is what should be correctly captured when simulating the difference between a water and a polymer flood. Thus, the objective is to match cumulative water and oil production in a coarse grid with that in the fine grid, where especially the breakthrough time of water is important. Ideally pressure would be captured as well, but this is outside the scope of this work for now. Recommendations to include pressure are given in chapter 15.

The objective function to be minimized is defined as the sum of the squared differences between the coarse and fine oil cumulative production:

\[
f = \sum_{i=0}^{T} (Q_{o,\text{coarse},t} - Q_{o,\text{fine},t})^2 \]

(8.1)

8.2. Parameterization of relative permeability

In order to use an AHM approach with optimizing parameters relative permeability curves are parametrized according to Brooks and Corey [1964]. Relative permeabilities are written as power-law relationships as a function of saturation [Lake et al., 2014]:

\[
k_{rw} = k_{rw}^0 \left( \frac{S_w - S_{wc}}{1 - S_{wc} - S_{or}} \right)^{n_w}
\]

(8.2)

\[
k_{ro} = k_{ro}^0 \left( \frac{1 - S_w - S_{or}}{1 - S_{wc} - S_{or}} \right)^{n_o}
\]

(8.3)

where \(S_w\) and \(S_o\) are the saturation of water and oil respectively, \(S_{or}\) is the residual oil saturation and \(S_{wc}\) is the connate water saturation. \(n_w\) and \(n_o\) are the so-called Brooks Corey coefficients and describe the curvature of the relative permeabilities. When these equal 1, the curves become linear. This is the case for zero capillary pressure. \(k_{rw}^0\) and \(k_{ro}^0\) are the endpoint relative permeabilities, which are the relative permeabilities at irreducible saturation of the other phase. Figure 8.1 illustrates a set of relative permeability curves as an example.
8.3. Number of optimizing parameters

The number of optimizing parameters is kept as small as possible, while still giving an accurate result.

A low number of optimizing parameters decreases simulation time. Fewer cases are required for a similar case density when the number of dimensions of the parameter space is smaller.

Another reason for keeping the number of optimizing parameters as low as possible is because it increases the uniqueness of the solution. With fewer parameters, less interference between the parameters takes place and less combinations resulting in the same result are likely to occur. This is in agreement with Alpak et al. [2008], who found that the non-uniqueness increases and the robustness of their method decreases when solving for \( S_{or} \), \( n_w \) and \( n_o \) compared to when solving for \( S_{or} \) and \( n_w \) only.

To determine the required number of optimizing parameters for a good match, simulations have been run with 1, 2, 3 and 4 parameters for all combinations. It has been found that the match is satisfactory for two or more parameters. Thus, two parameters will be used in the workflow.

8.4. Selection of optimizing parameters

Now that the number of optimizing parameters is selected, a decision has to be made on which ones should be varied.

It is assumed that \( S_{wc} \) and \( S_{or} \) do not change during upscaling, although there are situations in which \( S_{or} \) could change. Varying \( S_{or} \) could be required to upscale capillary trapping due to grain size variations (section 3.1.2). Trapping of oil due to stratigraphic dead ends could also require adjustment of \( S_{or} \) (section 5.2.3, Alpak et al., 2008).

However, this work mainly focuses on heterogeneities on the meter to tens of meter scale and on that scale \( S_{or} \) is not likely to change. By choosing \( S_{or} \) constant, ultimate recovery (here meant as the recovery when the water cut equals 100 %) can not be adjusted. However, since \( n_o \) alters the shape of the rarefaction part and especially where \( f_w \) approaches zero (see section 8.4.2, Figure 8.3d), adjusting \( n_o \) can delay recovery sufficiently to approximate the behaviour of trapped oil at water cuts that practically occur.

Conclusively, the selection here is made between the endpoints \( k_{ro,e} \) and \( k_{rw,e} \) and the Brooks Corey coefficients \( n_w \) and \( n_o \).

In order to do this, insight in the effect of the parameters on flow behaviour is needed. Therefore the analytical Buckley Leverett solution is studied. The goal is to assess the effect of the different parameters describing relative permeability on fractional flow and thereby on Breakthrough Time (BT), the development of the water cut after breakthrough and late time recovery.

8.4.1. Fractional flow theory

The fractional flow formulation of Buckley and Leverett [1942] excluding gravity and capillary pressure has been given earlier (Eq. 4.2 and 4.3). Substitution with the Brooks Corey formulation for relative permeability...
(Eq. 8.2 and 8.3) gives:

\[
f_w = \frac{1}{1 + \frac{\mu_w}{\mu_o} \frac{k_{r_w,e}}{k_{r_o,e}} \left(1 - s_{w,e} - s_{or}ight)^n_w \left(1 - s_{w,e} - s_{wc}ight)^n_o}
\]

(8.4)

With the fractional flow curve the frontal advance equation can be derived (Appendix E). With the frontal advance equation the propagation of the saturation in time can be determined. The concept is shown graphically in Figures 8.4a and 8.4b.

The lowest saturations travel faster than the higher saturations, causing a shock front to develop with rarefaction taking place thereafter. Breakthrough time and the water cut at breakthrough are controlled by the shock, which is the tangent to the fractional flow curve that starts from the initial water saturation \(S_w I\). The development of the water cut after breakthrough is controlled by the rarefaction part. Thus, the important points on the fractional flow curve are the shock saturation, the shape of the rarefaction part and the saturation at which the fractional flow curve approaches 0. The lower part of the fractional flow curve is less important.

8.4.2. Effect of different parameters on fractional flow curve

With Eq. 8.4 the fractional flow curve can be adjusted as a function of the parameters describing the relative permeability curves.

Figure 8.3 shows the results of varying the parameters describing relative permeability on a base case with \(S_w I = 0.2\), \(s_{wc} = 0.2\), \(\mu_w = 2\), \(\mu_o = 2\), \(k_{r_w,e} = 0.7\), \(k_{r_o,e} = 0.7\), \(n_w = 2\) and \(n_o = 2\). It can be observed that for varying endpoints, the fractional flow curve shifts horizontally but the shape does not change much. Varying the Brooks Corey coefficients does result in a different shape of the curve. \(n_w\) mainly affects the lower part of the curve, while \(n_o\) mainly affects the upper part of the curve. The saturation at which the curve approaches 1 is very much affected by \(n_o\). \(n_w\) has a similar effect on the saturation at which the curve approaches 0.

8.4.3. Correlation with relative permeability parameters

Using the frontal advance equation and the equations following from that (Appendix E), breakthrough time and recovery thereafter can be calculated. Hence, the relationship between the parameters describing relative permeability and BT, the development of the water cut thereafter and late time recovery can be assessed analytically.

From the results of the sensitivity study discussed previously (section 8.4.2), it is clear that the effect of the different relperm parameters on these points is not unambiguous, in particular when considering the shock and rarefaction part. By looking at the variations in shape and horizontal shifting it can be imagined that different parameters can lead to a similar effect, depending on the value of the remaining parameters. Due to this dependency it is not possible to select a base case and vary the different parameters in isolation.
Design of Experiment

Instead, a Design of Experiments (DoE) is used to establish insight in the correlation between relperm parameters and the shock saturation and rarefaction part of the fractional flow curve. In the DoE the parameters are varied so that the entire parameter space that may occur realistically is covered (Figure 8.4).

The sensitivities of BT, late time recovery and water cut development against changes in relperm parameters have been assessed for both the analytical Buckley Leverett solution as well as for a 3D simulations in an up-scaled channelized turbidite model (presented later in Figure 11.3e). As the fractional flow curves are also a function of viscosity and as viscosity changes play an important role in this research, the sensitivity studies have been done for $\frac{\mu_w}{\mu_o}$ equal to 0.35, 1 and 4.

In the sensitivity studies, late time recovery is taken as recovery when the water cut equals 97%. It is chosen very high to capture the effect of the fractional flow curve approaching 1. A feature important in practice is the development of the water cut after water breakthrough. This is defined as the time between when the watercut is equal to 10 and 50%. BT is defined as when the water cut equals 1%.
Results

The results of the sensitivity studies using the Buckley Leverett solution for $\frac{\mu_w}{\mu_o} = 0.35$ are shown in Figure 8.5 and 8.6. These show the change in BT, late time recovery as a function of the different relperm parameters respectively. Figure 8.7 shows the change in water cut development as a function of the different relperm parameters (measured in 3D simulations for $\frac{\mu_w}{\mu_o} = 0.35$).

For each parameter combination, the correlation coefficient and the relative impact are calculated.

Developed by Pearson [1895], the Pearson correlation coefficient is a measure of the linear correlation between two variables. It has a value between $-1$ and $1$, where $1$ represents total positive correlation, $0$ represents no correlation and $-1$ represents total negative correlation. Note, that the absence of a linear correlation does not mean there is some other form of correlation between the parameters. For a sample, the coefficient is given by Benesty et al. [2009]:

$$r = \frac{\sum_{i=1}^{n}(x_i - \bar{x})(y_i - \bar{y})}{\sqrt{\sum_{i=1}^{n}(x_i - \bar{x})^2 \sum_{i=1}^{n}(y_i - \bar{y})^2}}$$

(8.5)

The impact of the relative permeability parameters on BT, late time recovery and the water cut development is measured by the slope of the trend lines approximating the data points of the sensitivity studies (for example Figure 8.5). All values are normalized between 0 and 1 so that slopes can be compared across plots. This is done by dividing over the maximum value occurring in the data set.

The correlation coefficient and the relative impact calculated from the 1D Buckley Leverett solution and from the 3D simulations are shown in Figure 8.8 for viscosity ratios $\frac{\mu_w}{\mu_o} = 0.33, 1$ and $4$. It can be observed that $n_o$ is the only parameter with a reasonable correlation to late time recovery and that late time recovery is also most sensitive to change in $n_o$. It can furthermore be observed that the development of the water cut after breakthrough is controlled by $n_w$ and $n_o$. $k_{r,we}$ and $n_o$ are negatively correlated to BT, while $k_{r,oe}$ and $n_w$ are positively correlated. The results of the analytical BL solution are in agreement with the observations from the 3D simulations. They are consistent for the different viscosity ratios.

Figure 8.5: Effect of relative permeability parameters on Breakthrough Time (BT)
8.4. Selection of optimizing parameters

Figure 8.6: Effect of relative permeability parameters on late time recovery, defined as recovery when the water cut equals 97%.

(a) $k_{r,we}$  
(b) $k_{r,oe}$  
(c) $n_w$  
(d) $n_o$

Figure 8.7: Effect of relative permeability parameters on the development of the watercut after water breakthrough. Measured as the time between 10 and 50% water cut.

(a) $k_{r,we}$  
(b) $k_{r,oe}$  
(c) $n_w$  
(d) $n_o$

8.4.4. Selection of two parameters

$n_o$ is selected as the first optimizing parameter, based on the parameter solely affecting late time recovery and on its strong effect on the upper part of the fractional flow curve, which describes water cut development after breakthrough.

The sensitivity studies are most insight full when the results are as unique as possible. That means, different combinations of parameters should not result in similar outcomes in cumulative oil and water production. Therefore the aim is to select the second parameter such that when it varies together with $n_o$, it gives fractional
(a) Pearson correlation coefficient (Eq. 8.5)

(b) Gradient of the slope in the normalized plots

Figure 8.8: Effect of relative permeability parameters on BT (watercut = 1 %), late time recovery (watercut = 97 %) and watercut development (time in between watercut = 10 % and watercut = 50 %). Expressed as the correlation coefficient and the slope in the normalized plots

flow curves that overlap as little as possible with other combinations.

From Eq. 8.4 it can be observed that for a given viscosity ratio it is the ratio \( \frac{k_{ro}}{k_{rw}} \) that determines \( f_w \) at a particular \( S_{sw} \). Selecting a parameter that, together with \( n_o \), could result in a similar ratio at some \( S_{sw} \), would result in the fractional flow curve overlapping at these \( S_{sw} \) and thus a non-unique solution. Intuitively, it seems more likely that overlap occurs when both relative permeability curves are adjusted than when only one of the curves is adjusted. It has been explored whether this is really the case.

Examples of adjusting both curves resulting in fully overlapping or very similar fractional flow curves are illustrated in Figure 8.9 and 8.10. In Figure 8.9 the endpoints are varied but their ratio remains 1, resulting in completely overlapping fractional flow curves. This is explained by considering Eq. 8.4 that shows that the endpoints are present as a ratio. In Figure 8.10 one curve is adjusted through the endpoint and one curve through the Brooks Corey coefficient, resulting in partial overlap. However, it has been found that partially overlapping or similar fractional flow curves also occur when only one of the curves is adjusted. This is illustrated in Figure 8.11 where \( n_o \) and \( k_{ro,e} \) are adjusted. It therefore may be concluded that when optimizing 2 parameters there will always be non-uniqueness in the solution. This will be further elaborated on in chapter 9.

As the uniqueness does not distinguish one parameter from the others, different arguments are used to select the second parameter.

\( n_w \) is not preferred as it mainly affects the part of the fractional flow curve that is below the shock. Since \( n_o \) already can be used to adjust the shape of the fractional flow curve, \( k_{ro,w} \) or \( k_{ro,e} \) is better as it allows for shifting the curve horizontally, adjusting the shock velocity and saturation. In Figure 8.3a and 8.3b it can be observed that the effect of \( k_{ro,w} \) and \( k_{ro,e} \) is almost similar. However, it can be observed that the effect on the curve is larger on the right side for \( k_{ro,w} \) and on the left side for \( k_{ro,e} \). Another subtle difference is that for \( k_{ro,e} \) the spread in saturation for where the curve approaches 1 is smallest for \( k_{ro,e} \). Similarly, the spread in saturation where the curve approaches 0 is smallest for \( k_{ro,e} \).

Since \( n_o \) strongly affects the saturation where the curve approaches 1 and interference or similar effects of parameters are aimed to be avoided as much as possible, \( k_{ro,w} \) is favourable over \( k_{ro,e} \). In addition to that, the stronger effect of \( k_{ro,w} \) on the right side of the curve is favourable, since polymer generally shifts the curve to the right. In cases where \( n_w \) would be low initially, this provides means to still achieve the required shift in the curve. Therefore, \( n_o \) and \( k_{ro,w} \) are selected as optimizing parameters.
8.4. Selection of optimizing parameters

(a) Relative permeability curves
(b) Corresponding fractional flow curves

Figure 8.9: Relative permeabilities with different endpoints, illustrating the effect of the ratio $\frac{k_{ro}}{k_{rw}}$ on the fractional flow curves

(a) Relative permeability curves
(b) Corresponding fractional flow curves

Figure 8.10: Relative permeabilities adjusted through $k_{r,wc}$ (Case 1) and $n_o$ (Case 2), resulting in similar fractional flow curves

(a) Relative permeability curves
(b) Corresponding fractional flow curves

Figure 8.11: Different oil relative permeability curves, resulting in similar fractional flow curves
Post-processing the optimization results

In chapter 8, $k_{r_w}$ and $n_o$ have been selected as optimizing parameters based on an analysis of the fractional flow curve. An important observation was that the fractional flow curves are not uniquely related to relative permeability curves, e.g. multiple combinations of parameters lead to (partly) overlapping fractional flow curves (section 8.4.4). It is desired to express the results of the upscaling process in unique parameters, because this provides clearer insight in the effects of different variables when running sensitivity studies. Therefore a method has been developed to express the upscaled relative permeabilities as function of a unique parameter through the fractional flow curve. Using fractional flow curves also provides a more direct insight of the effect of pseudos on flow behaviour than the relative permeability curves do themselves. The method will be presented in this chapter.

9.1. Concept

As explained in section 8.4.1, the most important parts of the fractional flow curve are the shock and the rarefaction part. The shock describes the breakthrough time (BT) of water and the water cut at this point, whereas the rarefaction part determines the development of the water cut after BT and the Ultimate Recovery (recovery at a certain abandonment water cut, can be defined according to users need). The aim is therefore to find (a) parameter(s) related to the shock saturation and to the rarefaction part of the curve. Then, relative permeability curves can be converted to fractional flow curves, described by these parameters.

The boundary conditions (B.C.) which apply to the fractional flow curve are:

$$f_w(S_{wc}) = 0 \quad (9.1)$$

$$f_w(S_{w,shock}) = f_{w,shock} \quad (9.2)$$

$$\frac{df_w}{dS_w}(S_{w,shock}) = v_{shock} \quad (9.3)$$

where $v_{shock}$ is the shock velocity.

When capillary forces do not play a role in trapping oil other than pore scale trapping $S_{or}$ does not change during upscaling (section 3.1.2). Then, a fourth boundary condition holds for the fractional flow curves of both the fine and the upscaled grid:

$$f_w(1 - S_{or}) = 1 \quad (9.4)$$

Using these B.C. (a) parameter(s) describing the fractional flow curve are derived in the following sections.
9.2. Proxy for shock front

The shock is described with a tangent to the fractional flow curve from $S_{w, I}$ (Figure 9.4a), e.g. a linear equation:

$$f_w = A S_w + B$$  \hspace{1cm} (9.5)

where $A$ equals $v_{\text{shock}}$. $B$ follows from B.C. 9.1:

$$0 = A S_{w,c} + B$$  \hspace{1cm} (9.6)

$$B = -A S_{w,c}$$  \hspace{1cm} (9.7)

Thus, assuming $S_{w,c}$ is known, the linear part is described with one parameter $v_{\text{shock}}$.

9.3. A proxy for the rarefaction part

For the rarefaction part two different proxies have been tested (Figure 9.1). The first proxy that has been tested is based on a third degree polynomial (Eq. 9.8), the second one is based on an exponential function (Eq. 9.9).

$$f_w = a S_w^3 + b S_w^2 + c S_w + d$$  \hspace{1cm} (9.8)

$$f_w = 1 - c e^{(-b S_w)}$$  \hspace{1cm} (9.9)

Testing both proxies for a range of very low and very high shock saturations has shown that the polynomial does not give a good fit for low shock saturations due to local optima (Figure 9.1a), a property of polynomial functions. The exponential function does give a good fit for both low and high shock saturations (Figure 9.1).
To solve the rarefaction part with the exponential proxy two B.C. are required. B.C. 9.4 is not used. This means the curve is not forced to go to 1 at $S_w = 1$, which also shows from the plot in Figure 9.1. For the tested cases however, the fit is sufficiently good. This is also related to the choice of describing relative permeability with Brooks-Corey coefficients, which gives very smooth relperm curves. For relative permeabilities that are less smooth (but still monotonically increasing, as required), the exponential proxy would probably result in a less good fit with the fractional flow curve.

Below, the proxy based on the exponential function is derived. As the proxy based on the polynomial function is not used further in this work, the derivation and resulting equations for the parameters are not presented here but in Appendix F.

9.3.1. Exponential proxy

To solve the exponential function for a parameter describing the rarefaction part B.C. 9.2 and 9.3 are substituted in Eq. 9.9:

\[ f_{w,\text{shock}} = 1 - ce^{-bS_{w,\text{shock}}} \]  (9.10)

\[ v_{\text{shock}} = be^{-bS_{w,\text{shock}}} \]  (9.11)

These equations are solved for $b$ and $c$:

Rewriting Eq. 9.10 gives:

\[ \frac{1-f_{w,\text{shock}}}{c} = e^{-bS_{w,\text{shock}}} \]  (9.12)

\[ c = \frac{1-f_{w,\text{shock}}}{e^{-bS_{w,\text{shock}}}} \]  (9.13)

Substitution of Eq. 9.13 in Eq. 9.11 gives:

\[ v_{\text{shock}} = b \left( \frac{1-f_{w,\text{shock}}}{e^{-bS_{w,\text{shock}}}} \right) e^{-bS_{w,\text{shock}}} \]  (9.14)

\[ \frac{v_{\text{shock}}}{b} = 1 - f_{w,\text{shock}} \]  (9.15)

\[ b = \frac{v_{\text{shock}}}{1-f_{w,\text{shock}}} \]  (9.16)

Substitution of $b$ in Eq. 9.13 results in $c$ as a function of $v_{\text{shock}}, f_{w,\text{shock}}$ and $S_{w,\text{shock}}$:

\[ c = \frac{1-f_{w,\text{shock}}}{e^{-v_{\text{shock}}/S_{w,\text{shock}}} S_{w,\text{shock}}} \]  (9.17)

Equating the equation for the linear part (Eq. 9.5) and the equation for the rarefaction part (Eq. 9.10) at $S_w = S_{w,\text{shock}}$ results in $S_{w,\text{shock}}$ and $f_{w,\text{shock}}$. Thus, the entire fractional flow curve can be approximated as a function of $v_{\text{shock}}$ (Figure 9.2) (for the relative permeabilities described by Brooks-Corey coefficients tested here).
9.4. Example

In this section an example is given of how the pseudos resulting from optimizing in the coarse grid are characterized using the exponential proxy. This representation is used in the following chapters, where the results of the sensitivity studies are discussed.

Consider the optimized pseudos for four different viscosity ratios (Figure 9.3a) in some 3D model. Knowing the viscosity of oil and water, the pseudos correspond to four fractional flow curves (Figure 9.3b). By putting the viscosity ratio equal to 1 for both the fine grid fractional flow curve and the fractional flow curves corresponding to the optimization for the different viscosity ratios, the effect of the differences in relative permeability on the fractional flow curves can be isolated (Figure 9.3c). The fractional flow curves corresponding to the optimized pseudos can then be compared amongst each other and to the fine grid fractional flow curves (and thus relperms).

In the example, optimized fractional flow curves for the coarse grid are left of the fine grid fractional flow curves. Optimized fractional flow curves are further right for increasing viscosity ratios when viscosity ratio is included (Figure 9.3b). When the difference in viscosity ratio is excluded and the effect of the pseudos on fractional flow curves is isolated (Figure 9.3c), fractional flow curves shift left for increasing viscosity ratios. It becomes clear that for a higher viscosity ratio, pseudos lower recovery relatively more than for a higher viscosity ratio. The recovery from a polymer flood is overestimated more than recovery from a water flood when using rock relative permeabilities in a coarse grid (note that this is an example, not a general finding). This does not become clear from analyzing the fractional flow curves when viscosity is included. The fractional flow curves can be characterized with $\nu_{shock}$ and a (possible) trend can be quantified (Figure 9.3d). An increase in $\nu_{shock}$ describes a shift of the fractional flow curve to the left. A decrease in $\nu_{shock}$ describes a shift of the fractional flow curve to the right.

An approximation of the fractional flow curve may also be reconstructed based on $\nu_{shock}$. Hence, the information of the optimization is stored in a unique parameter $\nu_{shock}$ and knowing $S_{wc}$, $S_{or}$ and the viscosities a (non-unique) relperm can be found that fits this curve. When the relperm obeys this fractional flow curve, it will give similar simulation results as the relperm originally underlying this fractional flow curve.
9. Post-processing the optimization results

(a) Optimized pseudos for different viscosity ratios. In blue the fine grid relative permeability

(b) Optimized pseudos with viscosity included. Blue curves denote fine grid relative permeabilities at each viscosity

(c) Fractional flow curves with all viscosity ratios equal to 1 to isolate the effect of relative permeability adjustments. In blue the curve corresponding to the fine grid relative permeability

(d) $\nu_{shock}$ corresponding to fractional flow curves including viscosity and with viscosity ratio equal to 1 for all fractional flow curves. Excluding the effect of viscosity ratio makes it possible to analyze the effect of pseudos on fractional flow curves and to compare pseudos generated for different viscosity ratios. Colour coding: white corresponds to fine grid value, green and red to values above and below this value respectively

<table>
<thead>
<tr>
<th>Viscosity ratio (w/o)</th>
<th>Viscosity Included</th>
<th>Viscosity excluded</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.2</td>
<td>2.42</td>
<td>1.67</td>
</tr>
<tr>
<td>0.5</td>
<td>1.87</td>
<td>1.83</td>
</tr>
<tr>
<td>1.8</td>
<td>1.86</td>
<td>2.00</td>
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<tr>
<td>2.9</td>
<td>1.72</td>
<td>1.97</td>
</tr>
<tr>
<td>Fine</td>
<td>-</td>
<td>1.75</td>
</tr>
</tbody>
</table>

Figure 9.3: Example of characterizing relative permeability curves with $\nu_{shock}$
Sensitivity studies results - simple 3D geometries

To assess the importance of upscaling in different displacement processes sensitivity studies in simple 3D models have been conducted. Results are presented through the fractional flow curves as presented in chapter 9.

Firstly, the effect of the direction of upscaling compared to the direction of displacement and the direction of saturation variation is assessed. Furthermore, upscaling viscous crossflow and upscaling in case of dominating gravitational effects are looked into.

The error when not upscaling relative permeability is assessed by conducting the simulations with the rock relative permeabilities. It is measured as the error in breakthrough time (BT), defined as the watercut equal to 0.01. BT time is taken as the dimensionless amount of PV injected. It is also measured as the error in recovery at the economical limit, here defined as the watercut being equal to 0.88. Both errors are presented as the coarse grid value minus the fine grid value. Error definition has been discussed earlier in section 7.6.2. For optimal clarity, the error in the sensitivity studies is presented according to the color coding in Figure 10.1. This color coding will be used in all sensitivity studies in this work.

![Figure 10.1: Color coding of error. \( v_{\text{shock}} \) corresponding to the rock relative permeability is shown in white](image)

10.1. **Direction of saturation variation in relation to direction of upscaling**

The effect of upscaling on flow behaviour depends on saturation variations in the direction of upscaling. When upscaling is done in a direction in which saturation varies, the saturation profile as in the fine grid cannot be captured accurately in the coarse grid. As a result, propagation of the displacing fluid front is not modelled accurately. In those cases relative permeabilities should be adjusted (pseudos) in order to capture flow behaviour in the fine grid and the rate of propagation of the fluid front. On the other hand, when saturation is constant or varies with a certain pattern in a direction, pseudos are not required. In the coarse grid the saturation is simply modelled by some average saturation in that direction. This is established through the altered absolute...
permeability.

During a two-phase displacement with water being injected saturation will always vary in the horizontal direction, across the front. However, there are cases where the saturation in the vertical direction is similarly distributed over the entire height, e.g. when there is no jump in saturation. In this section, an upscaling procedure parallel and perpendicular to the direction in which saturation varies is performed.

A simple geometry (Figure 10.2a) with alternating layers of higher and lower permeability sands and silts is considered. A vertical injector is located at the corner of gridblock (NX,1) and a vertical producer at the corner of gridblock (1,NY). The wells are perforated over the entire reservoir height. Water (0.7 cp) displaces oil (3 cp). Gravity is set to zero.

![Figure 10.2: Fine grid with alternating sands and silts, no gravity. NX = NY = 25, NZ = 50](image)

Figure 10.2 shows the saturation profile after 1.5 PV is injected. Water has displaced more oil in the higher permeability (“high perm”) layers than in the lower permeability (“low perm”) layers. As gravity does not play a role, the saturation in each vertical column of fine grid blocks is similar in each high perm layer. The same holds for the low perm layers. There is no jump in saturation in the vertical direction over the entire reservoir height that marks a front.

The fine grid is upscaled in the horizontal and vertical direction with varying coarseness (Figure 10.3). Optimization results and the error when not altering relative permeabilities are shown in Figure 10.4.

![Figure 10.3: Dimensions of upscaled grids](image)

In Figure 10.4b it can be observed that \( v_{\text{shock}} \) does not change very much for varying NZ and that the match between cumulative production in the fine and in the coarse grid is very good for vertical upscaling. The error in BT is within -0.02 PV injected and the error at late time recovery is close to zero. \( v_{\text{shock}} \) is somewhat lower than \( v_{\text{shock}} \) corresponding to the fine grid relperms (1.73), meaning the shock is delayed and shock saturation is higher. This however can be attributed to the (constant) degree of upscaling in the horizontal direction (see the similarity to \( v_{\text{shock}} \) for NX = NY = 4 in Figure 10.4b), rather than to dependency on upscaling in the vertical direction.

Optimization results do depend on upscaling in the horizontal direction (Figure 10.4a). The coarser the grid becomes in the horizontal direction, the lower \( v_{\text{shock}} \), e.g. the further the fractional flow curve shifts to the right. As the grid becomes coarser, the front wrongly propagates faster (as the entire coarse grid block gets the same saturation). To correct for this the shock is delayed. The match is good for most cases but when the grid becomes too coarse (NZ too small), an error in BT is inevitable. The shift of \( v_{\text{shock}} \) to the right corresponds to correcting for a too early breakthrough when simulating with rock relperms, which in turn corresponds to an underestimated recovery at late times.
10.2. Viscous crossflow and improved sweep efficiency in low perm layers

The concept of viscous crossflow has been discussed in section 3.1.3. There, it is explained that viscous crossflow causes the fronts in different permeability layers to be closer to each other due to water flowing towards the low perm layers and oil towards the high perm layers. A sensitivity study has been done to understand the modelling of viscous crossflow, occurring on a small scale, in a coarse grid. For this sensitivity study the 3D layered system shown in Figure 10.5a is taken and upscaled to a grid with \( NX = NY = NZ = 4 \) (Figure 10.5b). A polymer solution with a viscosity of 8.5 cp is displacing oil (3.5 cp). Gravity forces are set to zero. The effect of viscous crossflow on pseudos is assessed by varying \( \frac{k_v}{k_h} \). Improved sweep efficiency in lower perm layers is assessed by varying polymer concentration.

(a) Fine grid, \( NX = NY = 24, NZ = 52 \).

(b) Coarse grid, \( NX = NY = NZ = 4 \).

Figure 10.5: Relative permeability in X and Y direction, vertical cross-section
10.2.1. Varying $\frac{k_v}{k_h}$

The amount of crossflow that can take place is varied by varying $\frac{k_v}{k_h}$. Figure 10.6 shows the oil saturation after 2 years for $\frac{k_v}{k_h} = 0.001$ and $\frac{k_v}{k_h} = 1$. Two fronts can be observed. The first front is water speeding through the high permeability layers. The second front is the complete water breakthrough in all layers. Viscous crossflow causes the fronts in the different permeability layers to be closer to each other.

![Figure 10.6: Oil saturation after 0.1 PV injected, vertical cross-section](image)

Figure 10.6: Oil saturation after 0.1 PV injected, vertical cross-section

Figure 10.7 shows the results for varying $\frac{k_v}{k_h}$.

$\nu_{shock}$ corresponding to optimized pseudos is almost constant and a little lower than for the fine grid relperm, for which it is 1.73. The match is not perfect: the error in BT is up to 0.08 PV injected. The error in BT is similar when simulating with optimized pseudos and when simulating with rock relative permeabilities. This indicates that despite altering the relative permeability curves, production from the fine grid cannot be fully matched in the coarse grid. Two fronts breaking through cannot be represented in the coarse grid blocks. This is assessed further in the next section.

<table>
<thead>
<tr>
<th>Crossflow</th>
<th>Optimization results</th>
<th>Error using optimized pseudos</th>
<th>Error when simulating with rock relperms</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\frac{k_v}{k_h}$</td>
<td>$\nu_{shock}$</td>
<td>In BT (PV injected)</td>
<td>In recovery at watercut = 0.88</td>
</tr>
<tr>
<td>0.001</td>
<td>0.68</td>
<td>1.70</td>
<td>0.07</td>
</tr>
<tr>
<td>0.01</td>
<td>0.68</td>
<td>1.69</td>
<td>0.08</td>
</tr>
<tr>
<td>0.1</td>
<td>0.67</td>
<td>1.70</td>
<td>0.02</td>
</tr>
<tr>
<td>1</td>
<td>0.67</td>
<td>1.70</td>
<td>-0.04</td>
</tr>
</tbody>
</table>

Figure 10.7: Relative error in discounted oil revenue, for optimized coarse grid and for when not upscaling (e.g. using rock curves). Error is calculated as the fine grid value minus the coarse grid value. Colour coding in Figure 10.1

10.2.2. Improved sweep efficiency in lower permeability layers

In section 10.2.1 it is shown that if two fronts get further apart the error in BT increases. In this section, this is further explored by assessing the same layered system with alternating permeabilities without viscous crossflow ($\frac{k_v}{k_h} = 0$). It is also assessed whether pseudos change with improved sweep, caused by more viscous water, in lower perm layers. Results are presented in Figure 10.8. An example of the difference in saturation profile for varying viscosity is shown in Figure 10.9.

The error in UR is small and of the same order when simulating with optimized pseudos and when simulating with fine grid relperms. This indicates that to represent the improved sweep in lower perm layers there is no need for adjusting relperms. The effect is captured by the upscaled absolute properties, as there are no saturation variations in the vertical direction (section 10.1).
10.2. Viscous crossflow and improved sweep efficiency in low perm layers

Figure 10.8: Results of sensitivity study on crossflow by varying polymer concentration

Similar to varying \( \frac{K_v}{K_h} \), an error exist in BT for both optimizing the pseudos and for not adjusting the relative permeabilities. The error when not adjusting relperms is about 1.5 to 2 times the error when doing so. This error arises due to the occurrence of two fronts. An example of the resulting cumulative production of water is shown in Figure 11.14b. It can be observed that when optimizing pseudos, breakthrough of the first front is not captured. Breakthrough of the second, main, front is captured by shifting the curve to the left. This results in a good match in recovery later on. When not optimizing pseudos, e.g. when using the rock relperms, breakthrough time is too late.

For increasing polymer concentration the delay between the first and the second front is larger. This is because more water goes into the lower permeability layers. The larger delay is the reason \( \nu_{\text{shock}} \) is increasing with increasing polymer concentration.

Figure 10.9: Oil saturation after two years of flooding, showing the difference in sweep in the low perm layers for different viscosity ratios

For increasing polymer concentration the delay between the first and the second front is larger. This is because more water goes into the lower permeability layers. The larger delay is the reason \( \nu_{\text{shock}} \) is increasing with increasing polymer concentration.

Figure 10.10: Cumulative production for a system in which breakthrough occurs with multiple fronts, showing production from the fine grid, the coarse grid with optimized pseudos and the coarse grid when not adjusting relperms
10.3. Gravity effects

In this section the effect of gravity on upscaling is assessed. In case of gravity dominance, higher density water underrides lower density oil and there is a jump in saturation in both the vertical and the horizontal direction. This means that the saturation profile and thus the propagation of the front are affected both by both upscaling in the vertical and in the horizontal direction.

Gravity is varied by varying the density difference between oil and water. Water (0.7 cp) is displacing 2.1 cp oil in a homogeneous isotropic grid. In the fine grid NX = 36, NY = 24 and NZ = 52. This is upscaled to NX = NY = NZ = 4 in the coarse grid. Figure 10.11 shows the oil saturation (fine grid) after 0.15 PV injected for different density differences. It can be observed that gravity underride causes a higher sweep in the bottom part of the reservoir but that the top part of the reservoir will not see water until late times compared to flooding with a lower density difference.

![Figure 10.11: Saturation vertical cross-section in homogeneous reservoir for different density differences. 0.15 PV injected](image)

Figure 10.12 shows the results of the sensitivity study. $v_{\text{shock}}$ for the optimized pseudos is much lower than for the fine grid relperm (1.73). No clear trend can be observed.

The error in BT is of the same order when optimizing and when not adjusting the relative permeabilities, around 0.05 PV injected. The match in UR is good in the optimized grid, while it is up to -0.05 when not adjusting the relperms. This shows that the pseudos affect recovery after breakthrough in this case. An example of the cumulative production curves is given in Figure 10.13.

![Figure 10.12: Results of sensitivity study on density difference](image)

A comparison between saturation profiles from the fine and coarse grid with and without optimized pseudos shows how flow behaviour is affected by the pseudos (Figure 10.14). When not adjusting the relative permeabilities, too much water propagates through the middle and upper part of the reservoir compared to the fine grid, where most water moves through the lower part, gradually moving upwards and pushing the oil out at high remaining oil saturation. This difference results in a too low UR when not adjusting relative permeabilities.
10.3. Gravity effects

Figure 10.13: Cumulative production for a system in which gravity dominates, showing production from the fine grid, the coarse grid with optimized pseudos and the coarse grid when not adjusting relperms

Figure 10.14: Saturation profile after 0.3 PV injected in fine and coarse grid with and without optimized pseudos, $\Delta \rho = 350 \text{ kg/m}^3$
Sensitivity study results - heterogeneities and the degree of upscaling

In this chapter the results of sensitivity studies on the effect of shale drapes (section 6.3.2) on upscaled pseudos are presented. Also, the sensitivity of pseudos to polymer concentration is assessed in the context of of shale draping as well as the sensitivity to the method and degree of upscaling. Note that results will be presented according to the post-processing method discussed in chapter 9 where an example is given as well.

The error when not upscaling relative permeability is assessed by conducting the simulations with the rock relative permeabilities. The difference between upscaling water and polymer flooding is assessed by simulating the coarse grid with the pseudo optimized for water. The error is measured as the error in BT time, defined as when the watercut is equal to 0.01. BT time is taken as the amount of PV injected. The error is also measured as the error in recovery at the economical limit, here defined as the watercut being equal to 0.88. Both errors are presented as the coarse grid value minus the fine grid value. The error is shown according to the color coding presented earlier in Figure 10.1.

11.1. Geological models

In this section the geological models used for the sensitivity studies are presented. The basis for the models is a channelized turbidite model from the StratSweep library. The models in this library are the same type of models as used in the work of Alpak et al. [2008]. In the model six channel belts are present, which are moderately amalgamated. The channel-to-non-channel ratio is 65% and in each channel 5 infill shales are present. This model is selected based on the geology of a turbidite field in Africa.

In the models shale drapes (section 6.3.2) are present around the meander belts, around the channel belts and within the channels. In the sensitivity study three different degrees of shale draping are assessed, presented in Figure 11.1. These models are upscaled using the StratSweep upscaling workflow, which provides “Surface Based Upscaling” and “Voxelization” as upscaling methods.

Surface Based Upscaling results in a surface-based coarse model. This upscaling method only coarsens in the vertical direction and excludes geological features based on user input [Alpak et al., 2008]. The features present in the models at the different degrees of coarseness are listed in Figure 11.2. Figure 11.3 shows the grids resulting from different degrees of Surface Based upscaling for medium shale draping (0.6), e.g. with the fine grid shown in Figure [11.1b] as a basis.

With Voxelization a voxel-based grid, very similar to the upscaled grids from Petrel, is created in three steps. First, a new grid is proportionally created in between the top and bottom surfaces of the fine grid. Then, absolute properties are averaged based on the fine grid. Finally, areal upscaling is performed. Since a new grid is created, all shale drapes disappear in this process and grid block dimensions will be very close to user specifications [Alpak et al., 2008]. The voxelized grid for medium shale draping (Figure 11.1b) is shown in Figure 11.3e. Figure 11.3f shows the grid dimensions for all upscaled models. NZ decreases as the surface-based upscaled models get coarser. NX and NY do not change. The voxelized grid is much coarser in horizontal direction than the surface-based upscaled models.
11.2. Results

The results of the sensitivity study are presented in this section. Optimized pseudos are represented through $v_{shock}$ and $S_{w,shock}$ in Figure 11.8. Figure 11.6 shows the error when simulating with optimized pseudos. By comparing the error to the error when using optimized pseudos to the error made when not altering relative permeabilities (Figure 11.7) it can be observed that the improvement from the upscaling workflow is very large. Figure 11.9 shows the error when simulating with pseudos optimized for water. The results will be discussed in more detail in the next sections. Section 11.2.1 goes into the quality of the match in cumulative production. In
11. Sensitivity study results - heterogeneities and the degree of upscaling

(a) L1, intra-channel shale drapes not modelled. Drapes around channels and around meander belts modelled

(b) L2, drapes within and around channels not modelled, channels preserved. Drapes around meander belts modelled

(c) L3, meander belts including meander belt drapes modelled. Channels and channel drapes not modelled

(d) L4, meander belts modelled but no shale drapes included at all

(e) Voxel-based model

(f) Grid dimensions for different upscaling levels

Figure 11.3: Cross-section of permeability through different degrees of upscaled model with medium draping (Figure 11.1b). Shale drapes are shown in light blue and occur around meander belts, around channels and within channels. Vertical scale exaggerated with 1200%

Section 11.2.2 focuses on the differences resulting from the degree of shale draping in the fine grid. Section 11.2.3 focuses on the differences resulting from the degree and/or method of upscaling.

Figure 11.4 shows the Recovery Factor for different degrees of shale draping. It can be observed that more severe shale draping results in lower recovery due to a poor connectivity. Furthermore, a higher water viscosity
11.2. Results

Results in higher recovery. Since the shale drapes affect recovery and flow behaviour it is expected that they affect pseudos, as upscaling will cause the shale drapes to partly or fully disappear.

<table>
<thead>
<tr>
<th>Viscosity ratio (w/o)</th>
<th>Light draping (0.35)</th>
<th>Medium draping (0.6)</th>
<th>Heavy draping (0.85)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.2</td>
<td>0.53</td>
<td>0.49</td>
<td>0.41</td>
</tr>
<tr>
<td>0.5</td>
<td>0.62</td>
<td>0.57</td>
<td>0.48</td>
</tr>
<tr>
<td>1.8</td>
<td>0.70</td>
<td>0.66</td>
<td>0.53</td>
</tr>
<tr>
<td>2.9</td>
<td>0.72</td>
<td>0.68</td>
<td>0.55</td>
</tr>
</tbody>
</table>

Figure 11.4: RF for different degrees of shale draping, fine grid simulations

11.2.1. Quality of match and relevance of upscaling

A comparison of Figure 11.6 and 11.7 shows that optimizing pseudos very much improves the fit with both the breakthrough time (BT) and late time recovery in the fine grid compared to not altering relative permeabilities. When not adjusting relperms, breakthrough occurs too late and correspondingly late time recovery is too high.

When optimizing pseudos, errors in BT of 0.15 to 0.34 PV injected when not adjusting relperms are decreased to 0.06 and 0 PV injected. When using optimized pseudos, the error in late time recovery is reduced from a difference up to 0.2 in recovery (fraction OIIP) to 0. An example of the cumulative production curves using optimized and rock relperms is shown in Figure 11.5.

The error in late time recovery is approximately zero for all cases at all levels of upscaling and degrees of shale draping. The error in BT is small but not zero. It is larger for more severe shale draping and for water compared to polymer. This can be attributed to the presence of multiple fronts, as discussed earlier in section 10.2 and shown in Figure 10.10.

11.2.2. Sensitivity to shale draping

In this section the sensitivity to the degree of shale draping is discussed in more detail. Figure 11.8 shows the optimized pseudos represented by $v_{shock}$ and $S_{shock}$. For all levels of upscaling $v_{shock}$ increases, e.g. the fractional flow curve shifts left, with the degree of draping. This is to account for the hampering of flow and deteriorated sweep as a result of shale draping. When simulating with rock relative permeabilities in a coarse grid, where shale draping is not explicitly modelled, BT is too late and recovery is overestimated. Of course, the adjustment is larger with an increasing degree of draping.

11.2.3. Sensitivity to method and/or degree of upscaling

In this section the sensitivity to the degree and method of upscaling is analyzed. The sensitivity of the pseudos to the degree of draping increases with an increased level of upscaling. This is shown by the change in $v_{shock}$ as a function of draping at each level of upscaling (Figure 11.8) and by the error when simulating with the rock relative permeabilities at each level of upscaling (Figure 11.7). Both the error in BT and late time recovery...
11. Sensitivity study results - heterogeneities and the degree of upscaling

(a) L1, intra-channel shale drapes not modelled

<table>
<thead>
<tr>
<th>Viscosity ratio (w/o)</th>
<th>L1 Error in breakthrough time (PV injected, [-])</th>
<th>L1 Error in Recovery factor at watercut = 0.88 [-]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Light draping (0.35)</td>
<td>Medium draping (0.6)</td>
</tr>
<tr>
<td>0.2</td>
<td>-0.01</td>
<td>0.02</td>
</tr>
<tr>
<td>0.5</td>
<td>0.04</td>
<td>0.02</td>
</tr>
<tr>
<td>1.8</td>
<td>0.03</td>
<td>0.00</td>
</tr>
<tr>
<td>2.9</td>
<td>-0.01</td>
<td>0.02</td>
</tr>
</tbody>
</table>

(b) L2, drapes around channels not modelled, channels preserved

<table>
<thead>
<tr>
<th>Viscosity ratio (w/o)</th>
<th>L2 Error in breakthrough time (PV injected, [-])</th>
<th>L2 Error in Recovery factor at watercut = 0.88 [-]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Light draping (0.35)</td>
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</tr>
<tr>
<td>0.2</td>
<td>0.01</td>
<td>0.02</td>
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<td>0.5</td>
<td>0.05</td>
<td>0.03</td>
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<tr>
<td>1.8</td>
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<td>-0.02</td>
</tr>
<tr>
<td>2.9</td>
<td>0.01</td>
<td>0.01</td>
</tr>
</tbody>
</table>

(c) L3, meander belts including meander belt drapes modelled

<table>
<thead>
<tr>
<th>Viscosity ratio (w/o)</th>
<th>L3 Error in breakthrough time (PV injected, [-])</th>
<th>L3 Error in Recovery factor at watercut = 0.88 [-]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Light draping (0.35)</td>
<td>Medium draping (0.6)</td>
</tr>
<tr>
<td>0.2</td>
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<td>0.09</td>
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<tr>
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<td>0.09</td>
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<td>0.00</td>
</tr>
<tr>
<td>2.9</td>
<td>0.04</td>
<td>0.01</td>
</tr>
</tbody>
</table>

(d) L4, meander belts modelled but no shale drapes included

<table>
<thead>
<tr>
<th>Viscosity ratio (w/o)</th>
<th>L4 Error in breakthrough time (PV injected, [-])</th>
<th>L4 Error in Recovery factor at watercut = 0.88 [-]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Light draping (0.35)</td>
<td>Medium draping (0.6)</td>
</tr>
<tr>
<td>0.2</td>
<td>0.08</td>
<td>0.05</td>
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<tr>
<td>0.5</td>
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<td>1.8</td>
<td>0.01</td>
<td>0.00</td>
</tr>
<tr>
<td>2.9</td>
<td>0.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>

(e) Voxel-based model

Figure 11.6: Error in BT and late time recovery with when simulating the coarse grid with optimized pseudos for varying shale draping, viscosity ratio and degree of upscaling. Colour coding explained in Figure [10.1].

increase with an increased level of upscaling. This is expected, as pseudos have to account for more of the heterogeneity as the grid gets coarser.

In a model with heavy draping removing the intra-channel drapes (level L1) already incorrectly delays the BT, such that an error of up to 0.14 PV injected arises when not adjusting relperms. This increases further with every subsequent removal of geological features (level L2 to L4).

It is interesting to note that a larger adjustment in pseudos is required for the voxelized grid LV compared to the surface-based upscaled L4 grid. This arises from the difference in gridding (Figure [11.3]). The voxelized grid is upsampled in the horizontal direction, while the surface-based upscaled models are not. This means the error in the saturation profile in horizontal direction is larger in the voxelized grid. As a result, zones far outside of the meanderbelt are swept in the voxelized grid while they are not in the actual fine grid. The difference in sweep pattern in the surface-based upscaled L4 grid and the voxelized grid LV is shown in Figure [11.10].

To correct for the overestimated sweep, $v_{shock}$ increases for the LV grid and the fractional flow curve shifts towards the left. This mimics a poorer sweep efficiency, although the saturation profile is not matched as well as in the surface-based upscaled grid.
11.2. Results

(a) L1, intra-channel shale drapes not modelled

(b) L2, drapes around channels not modelled, channels preserved

(c) L3, meander belts including meander belt drapes modelled

(d) L4, meander belts modelled but no shale drapes included

(e) Voxel-based model

Figure 11.7: Error when not adjusting relperms, e.g. when simulating with rock relperms in the coarse grid, for different degrees of shale draping and upscaling. Color coding shown in Figure 10.1

11.2.4. Sensitivity to polymer concentration

The sensitivity to polymer concentration has been assessed as well. This provides insight in the difference between upscaling a water and a polymer flood. The analysis is based on differences in $v_{shock}$ (Figure 11.8) as well as on the error made when simulating a polymer flood in the coarse grid with pseudos optimized for water (Figure 11.9).

Displacement in the fine grid is unfavourable for the water flood ($\frac{\mu_w}{\mu_o} = 0.2$), with $M$ equal to 2.53. When polymer is added, displacement becomes favourable. For $\frac{\mu_w}{\mu_o} = 0.5$, 1.8 and 2.9 $M$ equals 0.85, 0.24 and 0.15 respectively.

From the error made when simulating a polymer flood in the coarse grid with pseudos generated for the unfavourable water flood, it can be observed that sensitivities to polymer concentration differ amongst the surface-based upscaled grids L1 to L4 and the voxelized grid LV. Sensitivities also differ for light draping com-
11. Sensitivity study results - heterogeneities and the degree of upscaling

<table>
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<tr>
<th></th>
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<th>L2</th>
<th>L3</th>
<th>L4</th>
<th>LV</th>
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<tr>
<td></td>
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<td>Medium draping (0.6)</td>
<td>Heavy draping (0.85)</td>
<td>Light draping (0.35)</td>
<td>Medium draping (0.6)</td>
</tr>
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<td>v shock [-]</td>
<td>Sw shock [-]</td>
<td>v shock [-]</td>
<td>Sw shock [-]</td>
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<td>1.36</td>
<td>0.67</td>
<td>1.53</td>
<td>0.72</td>
</tr>
</tbody>
</table>

(a) L1, intra-channel shale drapes not modelled

(b) L2, drapes around channels not modelled, channels preserved

(c) L3, meander belts including meander belt drapes modelled

(d) L4, meander belts modelled but no shale drapes included

(e) Voxel-based model

Figure 11.8: $v_{shock}$ of fractional flow curves corresponding to optimized pseudos for varying degree of shale draping, upscaling and viscosity ratio. All $v_{shock}$ are shown here with viscosity ratio equal to 1, to isolate effect of relative permeabilities on the fractional flow curve and to make comparison across cases possible. This is explained in more detail in section 9.4. Color coding shown in Figure 10.1. A white color is given to the value of $v_{shock}$ corresponding to fine grid relperms pared to medium and heavy shale draping.

Light draping

For light draping there is almost no difference in $v_{shock}$ as a function of polymer concentration on levels L1 to L4. For LV, $v_{shock}$ does differ with viscosity ratio: it decreases with increasing viscosity ratio. This is significant, as shown by the error in late time recovery (an underestimation up to -0.09 fraction OIIP) when simulating with pseudos optimized for a water flood. An example of the cumulative production curves for the LV grid with light draping and $\mu_w/\mu_o$ equal to 1.8 is given in Figure 11.11.

An explanation for this difference lies in the difference in gridding, discussed in section 11.2.3 earlier and shown in Figure 11.10. In the voxelized grid sweep in the areal direction tends to be overestimated due to the coarse resolution in horizontal direction. Thus, fractional flow curves corresponding to the optimized pseudos
11.2. Results

(a) L1, intra-channel shale drapes not modelled

(b) L2, drapes around channels not modelled, channels preserved

(c) L3, meander belts including meander belt drapes modelled

(d) L4, meander belts modelled but no shale drapes included

(e) Voxel-based model

Figure 11.9: Error when simulating coarse grid with pseudos optimized for water for varying degree of shale draping and upscaling. Color coding shown in Figure 10.1. With the endpoint relative permeabilities from the fine grid relperms, displacement is unfavorable in the water flood (M = 2.54), while it becomes favorable for the different polymer floods (M = 0.85, 0.24 and 0.15) have a higher $v_{shock}$ than the fractional flow curve corresponding to the fine grid relperms. To account for the improved sweep in the lightly draped grid when adding polymer to the water (Figure 11.13), $v_{shock}$ decreases with increasing viscosity ratio. As a result, polymer recovery is underestimated when simulating with a pseudo generated for water. In the surface-based upscaled grid, gridding causes the saturation profile to be more in agreement with the fine grid saturation profile. Improved sweep is taken into account with the improved mobility ratio, without adjusting pseudos. Hence, water pseudos are similar to polymer pseudos and no error is made when using water pseudos to simulate a polymer flood.
11. Sensitivity study results - heterogeneities and the degree of upscaling

Figure 11.10: Saturation profile, showing the difference in saturation around the meander belt between a surface-based (L4) and a voxelized grid (LV) when using rock relperms. PV injected equals 1.5 for both

Figure 11.11: Cumulative production for a system with light shale draping, showing production from the fine grid, the coarse grid (LV) with optimized pseudos and the coarse grid when using water pseudos. The viscosity ratio equals 1.8. It can be observed that BT is estimated too early and that late time recovery is underestimated when using water pseudos to simulate a polymer flood

Medium and heavy draping

For medium and heavy draping on levels L3 and L4, $v_{shock}$ increases with increasing polymer concentration, shifting the fractional flow curve to the left. Correspondingly, breakthrough is estimated too late and recovery
is overestimated when simulating a polymer flood with water pseudos. An explanation is given by analyzing the saturation profiles from a water and a polymer flood in a heavily draped grid (Figure 11.12). It is shown that shale drapes prevent the polymer flood from sweeping everything, despite the favourable mobility ratio. Shale drapes are not represented in the coarse grid and as such the improvement in recovery from a polymer flood is overestimated when simulating with a more viscous water. To correct, $\nu_{\text{rock}}$ increases with increasing polymer concentration and as a result, recovery is overestimated when simulating a polymer flood with water pseudos. An example of the cumulative production curves is given in Figure 11.14.

The sensitivity in LV is smaller. The trend is similar as it is observed for light draping in the LV coarse grid: $\nu_{\text{rock}}$ decreases with increasing polymer concentration and recovery from a polymer flood is underestimated when using water pseudos. As the improvement in sweep by the polymer flood compared to the waterflood is smaller, pseudos have to account for a smaller increase and thus variation is lower.
Figure 11.14: Cumulative production for a surface-based coarse grid (L4) with light shale draping, showing production from the fine grid, the coarse grid with optimized pseudos and the coarse grid when using water pseudos. The viscosity ratio equals 1.8 and the coarse grid is the LV grid. It can be observed that BT is estimated too early and that late time recovery is underestimated when using water pseudos to simulate a polymer flood.
In this chapter the robustness of the generated pseudos is tested. Pseudos should be robust in terms of generating them and in terms of using them. Two of the things that might vary in simulating the sector model to obtain pseudos are the amount of PV injected and well placement. Things that are often varied in assessing a field’s optimal potential for polymer flooding are well placement, the perforated interval(s) and injection rate.

The sensitivity of the pseudos against these factors is assessed and presented in this chapter. Results are expressed in $v_{\text{shock}}$, according to the method presented in chapter 9. There, an example is presented as well. Robustness is assessed by analyzing variation in $v_{\text{shock}}$ and by simulating the coarse grid with a pseudo optimized for a different case, e.g. a different injection rate. The error is then measured as the error in BT and in late time recovery. BT is defined as when the watercut equals 0.01, late time recovery is measured at watercut 0.88. BT time is taken as the dimensionless amount of PV injected. Both errors are presented as the coarse grid value minus the fine grid value. The error is shown according to the color coding presented earlier in Figure 10.1.

The studies are conducted in a channelized turbidite model which is upscaled to different degrees of coarseness. The models are discussed in section 11.1. As viscosity and in particular the difference in results for varying viscosity play an important role in this research all sensitivities have been carried out for both an unfavourable displacement with $\frac{\mu_w}{\mu_o} = 0.2$ (M in fine grid equals 2.54) and a favourable displacement with $\frac{\mu_w}{\mu_o} = 2.9$ (M in fine grid equals 0.15). Upscaling levels L3, L4 and LV (shown in Figure 11.3 earlier) are considered, as these are typically the levels at which channelized turbidites are modeled in a coarse grid [Alpak et al., 2008]. The case with medium shale draping is considered.

12.1. Sensitivity to injection rate

Figure 12.1 shows the recovery factor (RF) for the different cases. RF does not change with flowrate, meaning heterogeneity in the fine grid causes the flowrate to not alter flow behaviour (poor vertical connectivity, gravity plays no significant role). This shows from the saturation profiles in Figure 12.2 as well.

<table>
<thead>
<tr>
<th>Inj. rate [PV/year]</th>
<th>RF water flood [-]</th>
<th>RF polymer flood [-]</th>
</tr>
</thead>
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<tr>
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<td>0.125</td>
<td>0.52</td>
<td>0.70</td>
</tr>
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</table>

Figure 12.1: Recovery factor for different injection rates, fine grid simulations

Figure 12.4 shows the results of the sensitivity study on flowrate. The spread in values of $v_{\text{shock}}$ for varying
### 12. Sensitivity studies results - robustness of pseudos

Injection rate is low (about 0.1) for all levels of upscaling for both the water- and the polymer flood. Thus, the robustness against varying injection rate is good. This is confirmed by the very low error when simulating different injection rates in a coarse grid with pseudos obtained for a flowrate of 0.05 PV / year. The error when using a pseudo obtained for an injection rate of 0.05 PV / year is similar to the error made when using an optimized pseudo. In other words: the match when optimizing pseudos for a particular flowrate is as good as the match when using pseudos optimized for a different injection rate. An example of the cumulative production when simulating the coarse grid at an injection rate of 0.125 PV / year with optimized pseudos and with pseudos optimized for an injection rate of 0.05 PV / year is given in Figure 12.3b.

For level LV, the voxelized grid, the spread in values for $v_{\text{shock}}$ is somewhat higher (maximally 0.24, for the waterflood). There is a trend visible: $v_{\text{shock}}$ decreases, e.g. the fractional flow curve shifts right, with increasing injection rate.

An explanation for this could lie in upscaling in the vertical direction. At level L3 and L4 gravity does not play a big role due to the gridding in vertical direction (Figure 12.5a and 12.5b). Changes in flowrate therefore do not alter the balance between viscous and gravity forces. At level LV gravity does play a role in the coarse grid (Figure 12.5c and 12.5d), while it does not in the fine grid (Figure 12.2).

At lower injection rates gravity plays a larger role in the LV grid. As a result, sweep is overestimated, corresponding to the improved sweep from gravity forces seen earlier in section 10.3. To correct, $v_{\text{shock}}$ increases with decreasing injection rate. This explanation is in agreement with the fact that the spread in values is larger for the water than for the polymer flood, as gravity effects are smaller for the polymer flood. Note however that the error is still very small (within -0.02 difference in recovery, see also Figure 12.3b) and that the conclusion is thus that at this range of injection rates variations pseudos are robust against changes.
12.2. Sensitivity to PV injected

To gain insight in the consistency of the results generated with a sector model the sensitivity of the results against PV injected has been assessed.

Table 12.6 shows the RF for different PV injected. From this it can be observed that the cumulative oil produc-
(a) Level L4, injection rate = 0.025 PV / year
(b) Level L4, injection rate = 0.125 PV / year
(c) Level LV, injection rate = 0.025 PV /year
(d) Level LV, injection rate = 0.125 PV /year

Figure 12.5: Saturation vertical cross-section at levels L4 and LV for different injection rate, when simulating with pseudos optimized for injection rate 0.05 PV / year. Total PV injected = 0.065 for all cases

Simulation is more or less stabilized from 1.7 PV injected and further for the water flood ($\mu_w/\mu_o = 0.29$) and from 1.1 PV injected and further for the polymer flood ($\mu_w/\mu_o = 2.9$). It is now interesting to see whether the quality of the optimization is affected by simulation length, e.g. the amount of PV injected.

Figure 12.6: Recovery factor for different PV injected, fine grid simulations

The results of the different cases are presented in Figure 12.7. It can be observed that optimization results ($\psi_{shock}$) are very constant. As the error is measured at a fixed watercut it is equal for all PV injected when simulating with a certain relperm. From these results it is shown that pseudos are robust in terms of sensitivity to simulation time, when simulated sufficiently long after breakthrough. Stabilization of the RF seems to be a good indicator for the simulated time after breakthrough required to give stable results.
12.3. Sensitivity to streamlines

The robustness of optimized pseudos against changes in streamlines is assessed in two ways: by altering the location of the wells (section 12.3.1) and by altering the perforated interval of the wells (section 12.3.2).

12.3.1. Well placement

For this sensitivity study five different combinations of well locations have been considered (Figure 12.8). All wells are perforated over the entire reservoir height. Results are shown in Figure 12.9. It can be observed that the optimized \( v_{shock} \) are not much different for the different well locations. This is confirmed by the small error made when simulating the course grid with the different well locations with the pseudo optimized for configuration 1.

12.3.2. Perforated interval(s)

Robustness against variations in streamlines is also assessed by varying perforated intervals of both the injector and producer (Figure 12.10). Results are shown in Figure 12.11.

Optimization results from all levels are insensitive to perforated intervals: \( v_{shock} \) corresponding to the optimized pseudos is about constant and the error when simulating with a pseudo generated for perforation type 1 is of the same order as when optimizing pseudos for all cases. This good robustness is explained by the grid configuration in the coarse grids (Figure 11.3). In the surface-based upscaled grids L3 and L4 the individual channels are mostly made up of 1 coarse grid block in the vertical direction. In the voxelized grid (LV), grid blocks have very good connectivity with each other, meaning that despite a different injection interval water will flow through similar paths.
### 12. Sensitivity studies results - robustness of pseudos

(a) L3, waterflood

<table>
<thead>
<tr>
<th>PV injected</th>
<th>Optimization results</th>
<th>Error using optimized pseudos</th>
<th>Error when simulating with rock</th>
<th>Error when simulating with pseudos</th>
<th>Initial rate [PV/year]</th>
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(b) L4, waterflood

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<th>Error when simulating with rock</th>
<th>Error when simulating with pseudos</th>
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(c) LV, waterflood

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(d) L3, polymerflood

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(e) L4, polymerflood

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(f) LV, polymerflood

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Figure 12.7: Results of sensitivity study on effect of PV injected on relperms. Tables contain $\Delta_{vshock}$ of fractional flow curves corresponding to optimized pseudos, the error made when simulating with the optimized pseudos and the error made when simulating with the rock relative permeabilities. $\frac{\mu_w}{\mu_o} = 0.2$ and $\frac{\mu_w}{\mu_o} = 2.9$ for the water and polymer flood respectively. Color coding shown in Figure 10.7.
12.3. Sensitivity to streamlines

Figure 12.8: Well configuration for sensitivity on streamline changes, showing the high perm channels only (colors do not represent a property, just for illustration purposes). All wells are perforated over the entire reservoir height.
### 12. Sensitivity studies results - robustness of pseudos

#### Figure 12.9: Results of sensitivity study on streamlines by changing well locations (Figure 12.8). Tables contain $v_{\text{shock}}$ of fractional flow curves corresponding to optimized pseudos, the error made when simulating with the optimized pseudos and the error made when simulating with the rock relative permeabilities. $\mu_w/\mu_o = 0.2$ and $\mu_w/\mu_o = 2.9$ for the water and polymer flood respectively. Color coding shown in Figure 10.1

<table>
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<tr>
<th>Configuration</th>
<th>Optimization results</th>
<th>Error using optimized pseudos</th>
<th>Error when simulating with rock rel. permeabilities</th>
<th>Error when simulating with pseudos generated for configuration 1</th>
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**(a) L3, waterflood**

<table>
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<th>Error using optimized pseudos</th>
<th>Error when simulating with rock rel. permeabilities</th>
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**(b) L4, waterflood**

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**(c) LV, waterflood**

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**(d) L3, polymerflood**

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**(e) L4, polymerflood**

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**(f) LV, polymerflood**
12.3. Sensitivity to streamlines

(a) Type 1: injector perforated from 0 - 37 m, producer from 0 - 37 m.
(b) Type 2: injector perforated from 0 - 18 m, producer from 18 - 37 m.
(c) Type 3: injector perforated from 18 - 37, producer from 0 - 18 m.
(d) Type 4: injector perforated from 10 - 20 m, producer from 15 - 25 m.

Figure 12.10: Different combinations of perforated intervals, assessed in sensitivity study on changes in streamlines. Only the channels are shown, colors denote different channels but do not represent a property.
12. Sensitivity studies results - robustness of pseudos

<table>
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<tr>
<th>Perforation type</th>
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<td>( v_{shock} )</td>
<td>( \beta_{inj} )</td>
<td>( \beta_{water \rightarrow \text{oil}} )</td>
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Figure 12.11: Results of sensitivity study on effect of streamline changes due to different perforated intervals. Tables contain \( v_{shock} \) of fractional flow curves corresponding to optimized pseudos, the error made when simulating with the optimized pseudos and the error made when simulating with the rock relative permeabilities \( \frac{\mu_w}{\mu_o} = 0.2 \) and \( \frac{\mu_w}{\mu_o} = 2.9 \) for the water and polymer flood respectively.
Discussion

In this research a workflow for upscaling polymer flooding has been developed. The upscaling procedure is based on adjustment of relative permeabilities using Particle Swarm Optimization, which is an exploring optimization algorithm. Results are post-processed using a novel way of characterizing the fractional flow curve, which allows representation of both the shock and the rarefaction part of the curve through $v_{\text{shock}}$, given $S_{\text{wc}}$ is known. An indication of the error made when not upscaling and when using pseudos upscaled for a different case, e.g. viscosity or flowrate, is provided by the workflow as well.

In this chapter, strengths and limitations of the developed upscaling workflow are discussed and the most important uncertainties are explained.

13.1. Strengths and limitations

Both the workflow and the selected optimizing algorithm, Particle Swarm Optimization, have strengths and limitations.

13.1.1. PSO performance

In literature, PSO is described as a very powerful method for optimization of non-linear problems [Angeline 1998, Mohamed et al. 2009]. In this research, PSO also performed very well in finding an accurate match between the cumulative production of a fine and an upscaled grid. In the vast majority of the simulations, the match was satisfactory during the first optimization (meaning a number of cases that has been iterated for a number of times). For very few situations, the optimization has been run again to improve the match further. The cases for which the match between the fine and coarse grid cumulative production is less good are the cases in which water breaks through in two (or more) stages. This is for example the case with a fine grid in which alternating layers of higher and lower permeability are present or when heavy shale draping occurs.

This is related to the way relative permeabilities are modelled in this work, namely with Brooks-Corey coefficients. Using Brooks-Corey coefficients gives very smooth and regularly increasing curves. Two fronts could be taken into account by altering the relperm curves into a shape that (monotonically) increases less regularly and has steeper and less steep parts. However, the developed method to use an exponential function as a proxy to describe the fractional flow curves would probably not fit with such curves. Alteration is likely to be required.

The most important disadvantage of PSO, namely the computational intensity, is overcome by minimizing the number of optimizing parameters. With 2 optimizing parameters, 20 cases with 8 iterations are generally used to upscale a 3D model. As simulations are done on a sector model, this is found to be practically well feasible.

The pseudos resulting from the optimizations are physically realistic and do not go into extremes. PSO is an exploring algorithm, meaning it returns multiple possible parameter combinations that exist. This has proven to be very valuable since it has lead into insight in the uniqueness of the results and subsequent development of a novel method of characterizing the fractional flow curve.
13.1.2. Assumptions underlying the workflow

In the workflow global pseudos are developed, e.g. pseudos for the entire model. The objective function is defined as the least square difference between fine and coarse grid cumulative oil production. This implies that pressure and saturation in between the wells are not necessarily matched. Recommendations regarding including pressure in the optimization are given in chapter 15. Here, implications of ignoring pressure are discussed.

The difference in pressures requires some assumptions to ensure consistency between the fine and the coarse grid. Oil (and water) viscosibility are set very small to ensure similar viscosities in the fine and coarse grid. Compressibility is set very small to ensure no depletion takes place as a result of existing reservoir pressure, which may differ.

These assumptions do not influence the results of the sensitivity studies in this work. However, to extend the applicability of the method to oils with higher viscosibility and compressibility and to include the effect of shear thinning it is desired to obtain a better match for the pressure profile between the wells.

13.2. Applications

The upscaling workflow results in pseudos that give a much better match with fine grid cumulative oil cumulative production than when not adjusting pseudos, e.g. using rock relperms. The error in breakthrough time when using rock relperms in the coarse grid is between 0.2 and 0.4 PV injected in the coarsest models. It is reduced to an error of about 0.07 PV when using optimized pseudos. The error in late time recovery (fraction OIIR taken as when the water cut equals 0.88) is reduced from a range of 0.15 - 0.2 when not adjusting relative permeabilities to 0 when optimizing pseudos. The workflow also provides insight in the need for adjustment of water pseudos when simulating a polymer flood. In case history-matched pseudos for a water flood are readily available, the workflow provides insight in how the pseudos generated for water should be adjusted to correctly model a polymer flood. In case no production data and no pseudos are available for a water flood, the workflow can be used to generate pseudos for both a water and a polymer flood.

Pseudos are found to be sufficiently robust against changing injection rate, changes in streamlines and the amount of PV injected. This makes the workflow a valuable tool in upscaling and simulating both a water flood and a polymer flood in a coarse grid. The workflow contributes to predicting recovery and assessing uncertainty and as such to making good investment decisions, designing surface facilities and operating a field as profitably as possible.

PSO is found to be a very strong optimizing algorithm which finds multiple solutions fulfilling the objective function. This might be valuable in History Matching (HM) too. In HM, a reservoir model is improved based on production data. In doing so, it is important to gain insight in the uncertainty of the outcome. PSO can therefore contribute to both improving the match and in finding multiple parameter combinations that fit production data.

13.3. Uncertainty

The most important uncertainty the workflow is subject to is the fine grid geology. This is unknown but taken as the basis for the upscaling procedure. There is no way to overcome this as the subsurface will always remain uncertain.

However, despite this uncertainty the workflow provides insight in the difference in pseudos for different viscosity ratios. It therefore is valuable in assessing whether pseudos generated or history matched for water should be adjusted when simulating a polymer flood. Analyzing different fine grid geologies provides insight in the uncertainty of the change in pseudos with viscosity. These can be used to quantify uncertainty in expected production from the full field model. If history matched water pseudos already exist, uncertainty can be narrowed down by selecting a fine grid model resulting in similar water pseudos.
Conclusions

The objective of this study is to develop a workflow for upscaling polymer flooding, so that the difference in recovery between a water and a polymer flood can be estimated better. The developed workflow can be used to upscale both a water and a polymer flood and provides insight in the need for adjustment of water pseudos when simulating a polymer flood. Using the workflow, sensitivity studies are conducted to assess the robustness of the results and to gain insight in the effects of geology, degree and method of upscaling and polymer concentration (e.g. viscosity ratio) on the results and the need for upscaling.

Upscaling method and workflow

The first research question concerns selection of a method that is suitable for upscaling polymer flooding and applying results to a full field model. Based on a literature study an upscaling method which generates global pseudos using an exploring algorithm, Particle Swarm Optimization, is selected. A sector model representing the well pattern, degree and method of upscaling and kind of heterogeneity occurring in a field is used to generate the pseudos. The objective function is defined as the least square difference between cumulative oil production in the fine and in the coarse grid.

To adjust the relative permeabilities they are parametrized with \(S_{wc}, S_{or}, k_{rw,e}, k_{ro,e}, n_o \) and \(n_w \) [Brooks and Corey, 1964]. \(S_{wc} \) and \(S_{or} \) are kept constant. It is found that out of the remaining four, at least two parameters are needed to obtain a good match between cumulative oil and water production from the coarse and fine grid. Based on an analysis of the effect of the different relperm parameters on breakthrough time, water cut development after breakthrough and late time recovery in a 1D Buckley-Leverett displacement and 3D simulations in a channelized turbidite model, \(n_o \) and \(k_{rw,e} \) are selected as optimizing parameters.

The pseudos resulting from the workflow are not unique, e.g. multiple combinations of \(n_o \) and \(k_{rw,e} \) result in similar cumulative production curves. The fractional flow curves corresponding to the pseudos are unique. Through a newly developed analytical method, the shock and rarefaction part of the fractional flow curve can be approximated based on one parameter \(v_{\text{shock}} \) using an exponential function, given \(S_{wc} \) is known. The approximation gives a good match for a wide range of fractional flow curves (very favourable and very unfavourable displacements). \(v_{\text{shock}} \) is found suitable in characterizing trends in the results of sensitivity studies. \(v_{\text{shock}} \) can be used to reconstruct the fractional flow curve and with that, the pseudos fitting this fractional flow curve can be found.

Generally, the match in cumulative production obtained with the developed method is very good. Both the error in BT and late time recovery are reduced.

Sensitivity to heterogeneity, polymer concentration and method and degree of upscaling

The second research question is about the dependency of pseudos on polymer concentration, degree and method of upscaling and heterogeneity. Results from adjusting relative permeabilities, e.g. creating pseudos, are compared to simulating a coarse model with rock relative permeabilities, e.g. to not adjusting relperms at all, and to simulating a coarse model with pseudos generated for water flooding. The first gives insight in the relevance of adjusting relperms when upscaling, the latter in the relevance of adjusting pseudos generated for water when simulating a polymer flood.

Sensitivity studies in a simple 3D box model have shown that when creating pseudos the fit with fine grid
cumulative production improves (compared to using rock relperms) in case of dominating gravity forces and for the occurrence of different fronts due to differences in permeability. The fit for dominating gravity forces is mainly improved with respect to late time recovery while the fit for a layered system with different fronts is mainly improved for breakthrough time.

In a 3D channelized turbidite system with shale draping pseudos improve both the fit with breakthrough time and with late time recovery (compared to using rock relperms). For more severe shale draping and coarser up-scaled models, the need for generating pseudos when upscaling is higher and correspondingly the change in pseudos is larger. Shale draping causes a too late breakthrough and an overestimation in recovery when pseudos are not adjusted, e.g. when rock relative permeabilities are used in the coarse grid. Errors in breakthrough time are reduced from 0.3 PV injected when not adjusting relative permeabilities to 0.05 PV injected. Errors in late time recovery are reduced from a 0.2 to 0 difference in recovery (fraction of OOIP).

Sensitivity of pseudos to polymer concentration is tested in a 3D channelized turbidite system as well. Sensitivity differs for surface-based upscaled models and voxelized models and also depends on the degree of shale draping. In surface-based upscaled models, $v_{\text{shock}}$ increases, e.g. the fractional flow curve shifts left, with increasing polymer concentration. As a result, breakthrough time is estimated too late and recovery is overestimated when simulating a polymer flood with water pseudos. The error in BT is between 0.03 and 0.11 PV injected. The error in late time recovery is between 0 and 0.07 (fraction OOIP). In voxelized models, $v_{\text{shock}}$ decreases, e.g. the fractional flow curve shifts right, with increasing polymer concentration. As a result, breakthrough time is estimated too early and recovery is underestimated when simulating a polymer flood with water pseudos. The error in late time recovery is maximally -0.09 (fraction OOIP).

Robustness

Finally, robustness of generated pseudos is assessed. The sensitivity of generated pseudos against flowrate, changes in streamlines (well placement and perforated interval) and the amount of PV injected is tested. For a channelized turbidite model with one injector - producer pair, pseudos are robust against changes in those parameters.
Recommendations

Recommendations for follow-up following from this research are given below.

Pressure

Firstly, it is recommended to include pressure in the optimization. Currently the pressure profile is not taken into account, which requires fluid properties (viscosity, density) to be independent of pressure to ensure consistency between the fine and the coarse grid. Due to heterogeneities, such as shale drapes, higher pressures occur in the fine than in the coarse grid. This could be overcome by lowering $k_{r_w,e}$ in the coarse grid. Including pressure in the objective function can be done based on the BHP in the injection and production well.

Capillary pressure

The theory behind the effects of capillary trapping has been explained in this research (section 3.1.2). However, upscaling capillary trapping is not investigated further due to time constraints. It is recommended to do sensitivity studies regarding upscaling of capillary trapping in laminae of alternating grain size and regarding parts of the reservoir not being swept due to shale draping. The workflow already provides the structure for easy variation of capillary pressure (appendix C). Capillarity is dependent on porosity and permeability and therefore it should be investigated how the capillary pressure curves change due to upscaling and how this is interlinked with an altered relative permeability.

Varying viscosity

This research has shown that pseudos depend on viscosity ratio. Sensitivities have only been ran for constant viscosity. It should be investigated whether it is necessary to apply different pseudos when viscosity varies within the reservoir (for example during tertiary flooding or tapering). It should be investigated whether pseudos derived for constant viscosity can be applied or whether they behave differently and should be derived in a different way. This also applies to changing viscosities as a result of shear, adsorption and hydrodynamic acceleration, which are not taken into account in this research. In this research light oils (1-10 cp) are considered. The mobility ratio therefore easily changes from unfavourable to favourable when adding polymer. For application in heavy oil fields, it would be interesting to see in more detail whether sensitivity to changes in viscosity ratio is similar when the mobility ratio is lowered, but remains unfavourable, for changing polymer concentration.

Robustness

The robustness of the pseudos is assessed in a channelized turbidite with medium shale draping. In this geology heterogeneity affects flow behaviour quite strongly. It should be assessed whether pseudos are still robust for a case with less shale draping, where for example an altered gravity - viscous ratio due to flowrate plays a role.

Robustness against well placement should be further investigated, as in this work well placement has only been varied within 1 meanderbelt. It should be assessed whether results are still robust when wells are placed in a
different meander belt. In this work the sector models include only 1 type of geology (channelized turbidites). It should be assessed whether 1 global pseudo can still be derived for a model in which different types of facies occur, for example for a model which includes channels and lobes, or whether pseudos for each different facies are required. For global pseudos in a model with different facies it should be verified whether generated pseudos are still robust against changes in well placement.

It would be useful to express conditions for robustness in terms of dimensionless numbers, such as the gravity number. To do so a systematic variation of parameters and many simulations are required.

**Sensitivity**

Sensitivity of pseudos against heterogeneity has been assessed by varying shale draping. However, there are many more variations possible in channelized turbidites, such as the degree of amalgamation for meander belts and the meander belt N/G. As Alpak et al. [2008] have found that these factors also play an important role in flow behaviour (section 6.3.2) it would be interesting to assess the sensitivity of pseudos against changes in these factors. This would provide more information on the need for upscaling and the need of adjustment of water pseudos when simulating a polymer flood in different geological settings.

**Upscaling of absolute properties**

In this research two types of upscaling absolute properties have been looked in to: surface-based upscaling and voxelization. Optimization results were quite different for the different upscaling methods. The voxelized grid was quite coarse in the horizontal direction compared to the surface-based upscaled grid. It should be assessed whether optimization results are still so different for a voxelized grid that is less coarse in the horizontal direction.

**Rock relative permeabilities**

In this work one rock relative permeability is used. It would be interesting to assess whether and if so how optimization results change for different rock relative permeabilities. The relative change between rock relperms and the pseudos could be compared for different rock relperms to see whether it is constant.

**Optimizing parameters**

In this work a novel analytical method of characterizing the fractional curve with $v_{shock}$ is developed. This is used to post-process non-unique pseudos resulting from the optimization into the unique parameter $v_{shock}$. If the relative permeabilities can be expressed in terms of $v_{shock}$ optimization could be done directly on $v_{shock}$ instead of using the Brooks-Corey coefficients $k_w, e$ and $n_o$. This would eliminate one step of the workflow.
Bibliography


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Nomenclature

Symbols

\( c_i \)  
(volumetric) concentration of component \( i \)

\( C^0 \)  
compressibility constant

\( C \)  
constant describing tortuosity (C-K eq.)

\( d_p \)  
grain size

\( D_t \)  
dispersion/diffusion coefficient of component \( i \)

\( E_{PS} \)  
microscopic displacement efficiency

\( E_s \)  
macroscopic displacement efficiency

\( E_D \)  
connected volume factor

\( E_C \)  
economic efficiency factor

\( f_\alpha \)  
fractional flow of phase \( \alpha \)

\( g \)  
gravitational acceleration

\( J(S_w) \)  
Leverett J function

\( k \)  
permeability

\( \lambda_\alpha \)  
mobility of phase \( \alpha \)

\( \mu \)  
viscosity

\( N_c \)  
number of components

\( \phi \)  
porosity

\( p \)  
pressure

\( p_c \)  
capillary pressure

\( p_r \)  
reference pressure

\( q \)  
flowrate

\( R \)  
radius of a sphere (Stoke's Law)

\( \rho \)  
density

\( \rho_o \)  
density at reference pressure

\( S \)  
saturation

\( \sigma \)  
interfacial tension

\( t \)  
time

\( u \)  
Darcy velocity

\( V \)  
velocity of a sphere (Stokes Law)

\( z \)  
depth

Subscripts and superscripts

\( w \)  
water

\( o \)  
oil

\( w \)  
wetting phase (here considered water)

\( nw \)  
non-wetting phase (here considered oil)

\( w, c \)  
connate water

\( o, r \)  
residual oil

Abbreviations

AHM  
Assisted History Matching

BT  
Breakthrough Time (of injected fluid)

BRV  
Bulk Rock Volume

CF  
Connectivity Factor [Alpak et al., 2008]

ENVFSA  
Ensemble Very Fast Simulated Annealing

EOR  
Enhanced Oil Recovery

FSST  
Falling Stage Systems Tract

HM  
History Matching

HMC  
Hamiltonian Monte Carlo

IFT  
interfacial tension
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<td>IOR</td>
<td>Improved Oil Recovery</td>
</tr>
<tr>
<td>LST</td>
<td>Lowstand Systems Tract</td>
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<tr>
<td>MOV</td>
<td>Movable Oil Volume, ( 1 - S_{wc} - S_{or} )</td>
</tr>
<tr>
<td>OIIP</td>
<td>Oil Initially In Place, defined as ( PV * S_{oi} )</td>
</tr>
<tr>
<td>PSO</td>
<td>Particle Swarm Optimization</td>
</tr>
<tr>
<td>&quot;reperm&quot;</td>
<td>relative permeability, here used as non-upscaled relative permeabilities</td>
</tr>
<tr>
<td>PV</td>
<td>Pore Volume, here defined as ( BRV * \phi )</td>
</tr>
<tr>
<td>PVT</td>
<td>Pressure, Volume, Temperature, properties of fluids</td>
</tr>
<tr>
<td>WF</td>
<td>Water flood</td>
</tr>
<tr>
<td>&quot;pseudo&quot;</td>
<td>pseudo-relative permeability, here used as upscaled relative permeabilities</td>
</tr>
<tr>
<td>RF</td>
<td>recovery factor</td>
</tr>
<tr>
<td>SA</td>
<td>Simulated Annealing</td>
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<td>UR</td>
<td>Ultimate Recovery</td>
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<td>V.E.</td>
<td>Vertical Equilibrium</td>
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<td>Very Fast Simulated Annealing</td>
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Applicability of different EOR methods

(a) Depth

(b) Permeability

(c) Oil viscosity

Figure A.1: Applicability of different EOR methods [Figuera et al., 2007, Taber et al., 1997]
Capillary trapping

Process of capillary trapping as a result of grain size variations, as researched by van Lingen [1998]. Figure B.1 shows increasing water fractional flow, eventually leading to capillary trapping of oil in laminae 1. The arrows on the capillary pressure curves indicate the trajectory in the downstream direction; from A to B in the coarse grained section, and then from C to D in the fine grained section.

(a) Continuous capillary pressure at boundary, both phases flowing
(b) Discontinuous capillary pressure at boundary, both phases flowing
(c) Discontinuous capillary pressure at boundary, oil is at $S_{or}$ in laminae 2. As a result, oil is trapped in laminae 1

Figure B.1: Steady-state capillary pressure and saturation profiles in two laminae types with different grain size van Lingen, 1998
In order to be able to vary capillary pressure easily and systematically in sensitivity studies it is parametrized. A well-known way of parametrizing capillary pressure is through a Leverett-J function. The Leverett-J function builds on the assumption the capillary pressure curve is similar for similar rock types and that it is a function of porosity, permeability and surface tension [Leverett, 1941a]:

\[ J(S_w) = \frac{p_c(S_w)}{\sigma} \sqrt{\frac{K}{\phi}} \]  

(C.1)

However, the Leverett-J function is originally only developed for strongly water wet rocks. [Skjaerveland et al., 2000] developed a different correlation, for rocks with varying wettability. Later, [Masalmeh and Jing, 2006] further improved the correlation for dual porosity rocks, by adding an additional parameter. [Boekhout, 2015] tested this correlation for turbidite rocks and found that this parameter results in an improved fit. However, the correlation is not generalized and can therefore not be varied easily. [Boekhout, 2015] then combined the improved correlation from [Masalmeh and Jing, 2006] with the correlation from [Leverett, 1941a]. This results in the following formulation of the Leverett-J function, which is used to model capillary pressure in this work:

\[ J(S_w) = \frac{p_c(S_w)}{\sigma_{ow}} \sqrt{\frac{K}{\phi}} = \left( c_w^* + \frac{c_o^*}{1-S_w-1-S_{wc}} \right) S_w + b_d^* (S_{wc} - S_w) \]  

(C.2)

where \( c_w^* = \frac{c_w}{\sigma_{ow}} \sqrt{\frac{K}{\phi}} \), \( c_o^* = \frac{c_o}{\sigma_{ow}} \sqrt{\frac{K}{\phi}} \) and \( b_d^* = \frac{b_d}{\sigma_{ow}} \sqrt{\frac{K}{\phi}} \) are fitting parameters. With this correlation, capillary pressure is dependent on porosity and permeability and can easily be varied by varying \( \sigma \), the interfacial tension.

In the sensitivity studies in this work capillary pressure does not play a significant role. The Leverett-J function shown in Figure C.1 is used.

Figure C.1: Capillary pressure used for sensitivity studies in StratSweep models (unless mentioned otherwise). Based on a reference \( k \) of 1500 mD, \( \phi \) of 0.2 and \( \sigma \) equal to \( 20 \times 10^{-3} \) N/m
Experimental results of using the upscaling method by Kyte and Berry [1975]

In this chapter the results of the upscaling method from Kyte and Berry [1975] are presented for three different geologies. It can be observed that the relative permeability curves derived for the individual gridblocks are very different, making it hard to generalize these results for a full field application.

Figure D.1: Pseudos for x direction, resulting from upscaling workflow of Kyte and Berry [1975] for different geologies
Eq. [8.4] gives the fractional flow equation from Buckley Leverett, neglecting gravity and capillary pressure. The fractional flow formulation can be used to derive the frontal advance equation, which describes the velocity of constant saturation planes. Taking Eq. [3.12] for two-phase immiscible flow and neglecting capillary pressure and gravity, the equation reduces to:

$$-\frac{\partial f_w}{\partial x} = \frac{A\phi}{q} \frac{\partial S_w}{\partial t} \tag{E.1}$$

since $f_w = f_w(S_w)$, the equation may be rewritten as:

$$-\frac{df_w}{dS_w} \frac{\partial S_w}{\partial x} = \frac{A\phi}{q} \frac{\partial S_w}{\partial t} \tag{E.2}$$

Based on this equation the position of a plane of constant saturation at time $t$ is given by:

$$x_f = qt \frac{df_w}{dS_w} \tag{E.3}$$

However, $\frac{df_w}{dS_w}$ results the mathematically valid, but physically impossible result of multiple saturations at one position. This is solved by the construction of a shock saturation, which is a discontinuous change in saturation based on the lower saturations bypassing the faster saturations. The shock saturation and shock speed are found by taking the tangent of the fractional flow curve from the initial saturation $S_{w,I}$ and satisfy the following equation:

$$\frac{df_w}{dS_w}(S_{w,shock}) = f_w(S_{w,shock}) - f_w(S_{w,I}) \tag{E.4}$$

where subscript $I$ denotes the initial saturation of water in the system and $J$ denotes the saturation at the boundary, e.g. the injected saturation.

With the position of the planes of constant saturations known, the frontal advance equation can also be used to determine the average water saturation in the system and therefore to calculate the Recovery Factor $RF$. Before BT, the amount of oil produced equals the amount of water injected. The average water saturation in the system is then given by:

$$S_{w} = S_{w,I} + tD(f_{w,J} - f_{w,I}) \tag{E.5}$$

where subscript $I$ denotes the initial saturation of water in the system and $J$ denotes the saturation at the boundary, e.g. the injected saturation.

After BT, the average water saturation behind dimensionless position $x_D$ is:
\[ \overline{S_w} = S|_{x_D} - \frac{t_D}{x_D} (f|_{x_D} - f_j) \] (E.6)

where \( x_D \) is usually taken equal to 1 so that the average water system in the entire system is calculated.

The average water saturation is used to calculate oil recovery, here as fraction of the mobile oil recovered:

\[ RF = \frac{\overline{S_w} - S_{wc}}{1 - S_{wc} - S_{or}} \] (E.7)
Proxy based on polynomial for rarefaction part of fractional flow

In this chapter the derivation for the parameter describing the rarefaction part of the fractional flow curve with a polynomial function is presented.

The polynomial is of the form (Eq. 9.8):

\[ f_w = aS_w^3 + bS_w^2 + cS_w + d \]  (E1)

Substitution of B.C.

Substituting Eq. 9.4, 9.2 and 9.3 in Eq. 9.8 the following system of equations is obtained:

\[ a(1 - S_{or})^3 + b(1 - S_{or})^2 + c(1 - S_{or}) + d = 1 \]  (E2)

\[ aS_{w, shock}^3 + bS_{w, shock}^2 + cS_{w, shock} + d = f_{w, shock} \]  (E3)

\[ 3aS_{w, shock}^2 + 2bS_{w, shock} + c = v_{shock} \]  (E4)

This system is solved for \( a, b \) and \( c \). Hence, the rarefaction part can then be described with one parameter \( d \).

Eq. [E2 to E4] are in written in matrix form and thereafter solved with Gaussian elimination. For ease of reading, subscript \( shock \) is from now on denoted with 1.

The system in matrix form:

\[
\left[ \begin{array}{ccc}
(1 - S_{or})^3 & (1 - S_{or})^2 & (1 - S_{or}) \\
S_{w,1}^3 & S_{w,1}^2 & S_{w,1} \\
3S_{w,1}^2 & 2S_{w,1} & 1
\end{array} \right] \begin{bmatrix} a \\ b \\ c \end{bmatrix} = \begin{bmatrix} 1 - d \\ f_{w,1} - d \\ v_{1}(= A) \end{bmatrix}
\]

The matrix for Gauss elimination, conducting elementary row operations to convert the matrix to echelon form:

\[
\left[ \begin{array}{ccc}
(1 - S_{or})^3 & (1 - S_{or})^2 & (1 - S_{or}) \\
S_{w,1}^3 & S_{w,1}^2 & S_{w,1} \\
3S_{w,1}^2 & 2S_{w,1} & 1
\end{array} \right] \begin{bmatrix} a \\ b \\ c \end{bmatrix} = \begin{bmatrix} 1 - d \\ f_{w,1} - d \\ v_{1} \end{bmatrix} \cdot \frac{1}{S_{w,1}}
\]

**Operation 1: Multiply row 2 and switch rows 1 and 3 to obtain:**

99
With the matrix in echelon form it is solved to ultimately obtain parameters $a$, $b$ and $c$ as function of $d$, $v_1$, $s_{w1}$, $f_{w1}$ and $S_{or}$:

\[
a = \frac{v_1(s_{w1}^2(1-S_{or}) - s_{w1}(1-S_{or})^2) + f_{w1}(1-S_{or})^2 - d(1-S_{or})^2 + s_{w1}(2d(1-S_{or}) - 2f_{w1}(1-S_{or})) + (1-d)s_{w1}^2}{s_{w1}^2(1-S_{or})^3 - 2s_{w1}(1-S_{or})^2 + s_{w1}^4(1-S_{or})} \]

\[
b = \frac{-v_1(s_{w1}^3(1-S_{or}) - s_{w1}(1-S_{or})^3) + f_{w1}(1-S_{or})^3 - d(1-S_{or})^3 + s_{w1}(3d(1-S_{or}) - 3f_{w1}(1-S_{or})) + (2-2d)s_{w1}^3}{s_{w1}^2(1-S_{or})^3 - 2s_{w1}^3(1-S_{or})^2 + s_{w1}^4(1-S_{or})} \]

\[
c = \frac{v_1(s_{w1}^2(1-S_{or})^2 - s_{w1}(1-S_{or})^3) + 2f_{w1}(1-S_{or})^3 - 2d(1-S_{or})^3 + s_{w1}(3d(1-S_{or})^2 - 3f_{w1}(1-S_{or})^2) + (1-d)s_{w1}^2}{s_{w1}(1-S_{or})^3 - 2s_{w1}^2(1-S_{or})^2 + s_{w1}^3(1-S_{or})} \]
Solving for \(a\)

For a given fractional flow curve \(A\) can now be determined by calculating the tangent from \(s_{wI}\). \(d\), the parameter describing the rarefaction part of the curve is found by implicitly solving Eq. (9.39). This is done by minimizing the sum of the least square differences in the rarefaction domain:

\[
S = \sum_{i \text{in } D} \left[ f_{w}(k_{r_o,e}, k_{r_w,e}, n_{w}, n_e) - f_{w}(A, d) \right]^2
\]

(E8)

\[
D: \left[ f_{w}(s_w = s_{w,\text{shock}}), f_{w}(s_w = 1) \right]
\]

(E9)