NTNU – Trondheim
Norwegian University of
Science and Technology

Up-scaling of Polymer Flooding with regards to Geologic Heterogeneities

Aojie Hong

Petroleum Geoscience and Engineering
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Supervisor: Jon Kleppe, IPT
Co-supervisor: Vegard Kippe, Statoil ASA

Norwegian University of Science and Technology
Department of Petroleum Engineering and Applied Geophysics

Abstract

Up-scaling of reservoir model is required to save computational time and costs in the industry. Due to numerical dispersion caused by enlarged grid size and reduced reservoir heterogeneity during up-scaling, the simulation accuracy is reduced. This means that the simulation results on the coarse grid models cannot correctly represent the performance of polymer flooding. Although many up-scaling methods can be applied to reproduce fine grid simulation results on coarse grid models for water/oil flow, few studies take polymer flooding into account.

Based on previous studies [1], it is found that the performance of polymer flooding is highly dependent on polymer solution viscosity and adsorption. In consideration of the effect of numerical dispersion on these two polymer properties, up-scaling factors of the polymer solution viscosity function (f_v) and of the polymer adsorption function (f_{ad}) are introduced in this thesis to tune coarse grid simulation results for polymer flooding. The aim of this study is to investigate the impact of up-scaling the polymer solution viscosity function and the polymer adsorption function on coarse grid simulation results in order to provide a simple up-scaling method for polymer flooding, and to investigate the impacts of flow dimension and heterogeneity on up-scaling. 1D, 2D and 3D, homogeneous and heterogeneous reservoir models are built and run in ECLIPSE in order to investigate how the values of f_v and of f_{ad} are affected by grid size and heterogeneity. Simulation results are summarized and analyzed in this thesis.

The main conclusions in this study are concluded as follows: (1) the mismatches between fine and coarse grid simulation results of polymer flooding may be reduced by up-scaling the polymer solution viscosity function and the polymer adsorption function, (2) different from water/oil flow, the simulated history of oil recovery can be tuned without touching the relative permeability curves by up-scaling the polymer solution viscosity function and this may be an advantage, (3) the accuracy of predicting polymer loss by doing simulation on a coarse model for a polymer flooding project may be improved by simply up-scaling the polymer adsorption function, (4) increases of flow dimension and of heterogeneity affect significantly up-scaling of the polymer solution viscosity and the polymer adsorption functions, (5) some limitations of this up-scaling method are found and one of them is that too high injector WBHP may appear in some particular cases, and (6) the up-scaling method introduced in this thesis is not a robust method and many other affecting factors have to be consider in further studies.

Preface

Polymer flooding is an effective Enhanced Oil Recovery (EOR) method for viscous oil and/or heterogeneous reservoirs. Polymers in solution act as a mobility control agent by increasing the water phase viscosity and/or reducing the water phase permeability. In order to evaluate a project of injecting polymers and to predict the behavior of polymer flooding, numerical simulations are necessary. Sometimes the simulations are required to be done on an up-scaled/coarse grid model to save computational time and cost. Due to numerical dispersion, the accuracy of predicting the behavior of polymer flooding is always lowered by doing simulations on a coarse grid model compared to a fine grid model. Therefore, a solution to reduce or eliminate the mismatches between the fine grid results and the coarse grid results is essential. However, there are a few articles which give general methods of up-scaling polymer flooding.

In the summer of 2013, I worked as an intern in Statoil Research Centre at Rotvoll, Trondheim, Norway. My tasks were to do some sensitivity analyses for polymer flooding. Important results are summarized in the report [1] of preparation work for this thesis. From the sensitivity analyses, I found that the behavior of polymer flooding is very sensitive to the relative permeability curves, the polymer solution viscosity function and the polymer adsorption function. Lee in his thesis [2] investigated the impacts of using pseudo relative permeabilities and up-scaling the polymer adsorption function on up-scaling polymer flooding. Although the pseudo relative permeability method does eliminate the mismatch caused by numerical dispersion, there may be some practical problems and difficulties to generate these pseudo relative permeabilies in some particular cases. Therefore, I decided to investigate the impacts of up-scaling the polymer solution viscosity function and the adsorption function without touching the relative permeabilities.

All the original simulation models and input data were obtained from Statoil. Some small modifications were made. The simulation models were synthetic. A set of 3D Generic models was built to mimic a real field case. The simulations were run by ECLIPSE 100 simulator and done in the period of February to May 2014. The license of ECLIPSE was provided by NTNU and Statoil.

This thesis is supervised by Professor Jon Kleppe at NTNU and Researcher Vegard Kippe in Statoil, and is submitted to Department of Petroleum Engineering and Applied Geophysics at

NTNU in partial fulfilment of the requirements for the Master's Degree in Petroleum Engineering.

A simple method of up-scaling polymer flooding is introduced in this thesis. Some important concepts of polymer flooding related to this study are presented in Section 2. The up-scaling methodology is described in Section 3. ECLIPSE input data for simulation of polymer flooding are summarized in Section 4. Section 5 introduces the progress in the study work being done. 1D, 2D and 3D homogeneous and heterogeneous cases and their corresponding models are described in Section 6, and the figures of models can be found in Appendix B: Figures of Simulation Models. Simulation results for all the cases are analyzed in Section 7 and the plots of simulation results for oil recovery, polymer adsorption, polymer production, water cut and injector WBHP are attached in Appendix C: Simulation Results. The results are discussed and suggestions for further studies are made in Section 8. Conclusions are concluded in Section 9. In Appendix A: Literature Review, important reviewed literatures and their contribution to this thesis are listed. Examples of input Data- and Include-files in ECLIPSE are attached in Appendix D: Example of Input Files in ECLIPSE. An additional study is done to investigate the impact of the shape of the up-scaled polymer solution viscosity function on up-scaling polymer flooding, and that study is presented in Appendix E (Page 87).

Aojie Hong

June 2014

Trondheim, Norway

Dedication

To Those Whom I Love And Those Who Love Me

And

To Haruki Murakami Whose Words Led, Is Leading and Will Lead Me To Pursue My Own "Norwegian Wood"

Acknowledgement

I am heartily thankful to Vegard Kippe and Ali Mojaddam Zadeh. They led me into this research area. Dr. Kippe checked my work regularly, gave me advice and helped me planning my further work. Dr. Zadeh patiently taught me to use Python and Bash languages, and provided me some examples of ECLIPSE input file for polymer flooding. I appreciate that Dr. Zadeh spent his personal working time on generating the 3D Generic models for me.

Special thanks to Professor Jon Kleppe and Professor Jan Ivar Jensen. They gave me practical advice on the form and structure of this thesis.

A great acknowledgment is deserved by Kurt Petvipusit. Without his help, I can never get access to the theses published by Imperial College London. He also provided me a set of tuning parameters which solved the convergence problems in the simulations on the 2D models.

All my love to my parents, Lei Hong and Xueqing Liao, who always support and encourage me, and to my lovely girlfriend, Wei Zhao, who took very good care of me when I was busy in working for this thesis and always pushed me to finish the thesis as soon as possible at the late stages.

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Nomenclature

Latin

a_p, a_{p1}, a_{p2}	Parameters in Langmuir isotherm (Eq. 2.2-1)
b_p	Parameter in Langmuir isotherm (Eq. 2.1-1)
C_{ad}	Polymer adsorbed concentration
$\widetilde{C_{ad}}$	Up-scaled polymer adsorbed concentration
C_p	Polymer concentration in the aqueous phase
$C_{p,max}$	Maximum polymer concentration in the aqueous phase
C_{ps}	Polymer concentration on the rock phases
C_{se}	Effective salinity for polymer
D_p	Retardation factor
f_{ad}	Up-scaling factor for polymer adsorption function (Eq. 3.2-1)
f_i	Fractional flow of phase i
f_v	Up-scaling factor for polymer solution viscosity function (Eq. 3.1-1)
f_{w1}	Water fractional flow at the oil bank
f_{wf}	Water fractional flow the water flooding front
f_{wi}	Initial water fractional flow at S_{wi}
f_{wp}	Water fractional flow at the polymer shock front
h	Layer thickness
h_i	Thickness of layer i
k	Absolute permeability
k_i	Absolute permeability of layer i
k_{ref}	Reference permeability in Langmuir isotherm
k_{ri}	Relative permeability of phase i
k'_{ri}	End point relative permeability of phase i
k^*	Up-scaled/averaged absolute permeability
M	End point mobility ratio
M_s	Shock mobility ratio
M_v	Viscosity multiplier
$\widetilde{M_v}$	Up-scaled viscosity multiplier
m, n	Exponents in Langmuir isotherm (Eq. 2.2-1)
S_i	Saturation of phase i
S_{oi}	Initial oil saturation
S_{orw}	Residual oil saturation
S_{w1}	Water saturation at the oil bank
S_{wf}	Water saturation at the water flooding front
S_{wi}	Initial water saturation
S_{wp}	Water saturation at the polymer shock front
v_{C_p}	Specific velocity of polymer concentration
v_{ob}	Specific velocity of the front of the oil bank
v_{wb}	Specific velocity of boundary between the denuded water and the initial water
x_D	Distance of displacing
x_{wb}	Distance of boundary between the denuded water and the initial water
x_{wp}	Distance of the polymer shock front

Greek

λ_T	Total mobility
λ_{T0}	Total mobility before the displacing (shock) front
λ_{Ts}	Total mobility at S_w equal to water saturation at the displacing (shock) front
μ_i	Viscosity of phase i
μ_m	Viscosity of fully mixed polymer solution
μ_p	Viscosity of polymer solution at maximum polymer concentration
$\mu_{p,eff}$	Effective polymer viscosity
$\mu_{w,e}$	Partially mixed water viscosity
$\mu_{w,eff}$	Effective water viscosity
$\emptyset$	Bulk porosity
$\emptyset_e$	$\equiv \emptyset_{IPV}/\emptyset$
$\emptyset_{IPV}$	Inaccessible pore volume / Dead pore space
ω	Todd-Longstaff mixing parameter

Subscript

o	Oil phase
p	Polymer solution
w	Water or brine phase
x	x-coordinate direction
y	y-coordinate direction
z	z-coordinate direction

Abbreviation

1D	One-Dimensional
2D	Two-Dimensional
3D	Three-Dimensional
EOR	Enhanced Oil Recovery
Eq.	Equation
IPV	Inaccessible Pore Volume / Dead Pore Space
NTNU	Norwegian University of Science and Technology
PermX	Permeability in x-direction
WBHP	Well Bottom-Hole Pressure

1 Introduction

Polymer flooding is one of the chemical enhanced oil recovery (EOR) methods. It has successfully improved the oil recoveries in a number of oil fields such as Daqing Oilfield [3] and Pelican Lake Field [4]. Polymers in water solution act as a mobility control agent by increasing the water phase viscosity (and decrease the effective permeability), providing stable displacing front and better volumetric sweep efficiency. Compared to other chemical EOR methods, polymer flooding can perform well for a wide range of reservoir conditions at low risk, especially for reservoirs with viscous oil and/or high heterogeneity. Therefore, many polymer flooding projects are ongoing world-widely. In order to evaluate a polymer flooding project and correctly predict the performance of polymer flooding, accurate simulations of polymer flooding are required.

In the industry, a coarse grid model is usually used instead of a fine grid model to save computationally time and costs for project planning. The process of converting the fine grid model to the coarse grid model is called up-scaling. During up-scaling, two very important factors are changed, grid size and heterogeneity. On one hand, increased grid size after up-scaling can lead to numerical dispersion under simulations. Numerical dispersion due to finite difference approximation of differential equations causes a smearing effect on the displacing shock front and makes the polymer performance incorrectly interpreted on a coarse grid model. Fortunately, the numerical dispersion problem can be solved in some degree by standard up-scaling (single-phase and multi-phase up-scaling) methods. However, these standard up-scaling methods are limited to oil/water flow because they do not account for important effects of polymers such as adsorption and permeability reduction. On the other hand, reduced reservoir heterogeneity after up-scaling can also affect the prediction of the performance of polymer flooding by reservoir simulation on a coarse grid model. Therefore, there will be a mismatch between the simulation results on a fine grid model and on its up-scaled model (a coarse model). It is essential to find an up-scaling method for polymer flooding which can reproduce the fine grid results on the coarse grid model. However, researches on up-scaling polymer flooding are still few and a robust up-scaling method for polymer flooding is still missing. The general challenge of up-scaling polymer flooding can therefore considered as quite open.

Although Lee in his thesis [2] has proved that a combination of using pseudo relative permeability method and up-scaling the polymer adsorption isotherm by a factor may improve

the accuracy of the coarse grid results, the way to generate the pseudo relative permeability curves is actually very computational time consuming and can lead to a lot of problems in some practice cases [5]. From the preparation work [1] for this thesis, it is found that simulation result for polymer flooding is also very sensitive to the polymer solution viscosity function in addition to relative permeabilities. Naturally, an idea pops up; is it possible to reproduce the fine grid simulation results on a coarse grid by simply up-scaling the polymer solution viscosity function and the polymer adsorption function without doing any changes on the relative permeability curves? If this method works, the effort to up-scale polymer flooding will be much less than Lee's method.

The purposes of this study is to investigate the impact of up-scaling two important polymer properties, polymer solution viscosity and adsorption, by a simple method on the contrast between fine and coarse grid results, and to investigate the impacts of flow dimension and heterogeneity on up-scaling.

2 Basic Concept of Polymer Flooding

A thorough literature review of concepts of polymer flooding has been done in previous study [1]. Basic concepts of polymer flooding and equations introduced in following sections are essential for this study. There are many other aspects of polymer flooding that are not considered in this thesis. For example, the aqueous permeability may be reduced due to polymer retention, which is called permeability reduction; polymer solution may behave like a non-Newtonian fluid, which causes a non-Newtonian effect; polymer properties may depend on salinity, which is named salinity dependency. All these aspects should be considered in further studies.

2.1 Viscosity Relations

According to previous researches [6], the polymer solution viscosity can be treated as proportional to the water/brine viscosity at a certain polymer concentration as Eq. 2.1-1 [7] shows.

Eq. 2.1-1 $$\mu_m = M_v(C_p) \cdot \mu_w$$

The polymer solution viscosity function which interprets the relation between the viscosity multiplier M_v and the polymer concentration C_p must be specified for modeling polymer flooding.

Some commercial simulators like ECLIPSE attempt to capture segregation between the water and the polymer solution in each grid block by applying Todd-Longstaff technique for calculating effective viscosities. The effective polymer viscosity $\mu_{p,eff}$ and the partially mixed water viscosity $\mu_{w,e}$ are defined as [7]

Eq. 2.1-2 $$\mu_{p,eff} = {\mu_m}^{\omega}{\mu_p}^{1-\omega},$$

Eq. 2.1-3 $$\mu_{w,e} = {\mu_m}^{\omega}{\mu_w}^{1-\omega}.$$

Then, the effective water viscosity $\mu_{w,eff}$ is computed by [7]

Eq. 2.1-4 $$\mu_{w,eff} = \left(\frac{1-C_p/C_{p,max}}{\mu_{w,e}} + \frac{C_p/C_{p,max}}{\mu_{p,eff}}\right)^{-1}.$$

2.2 Adsorption and Desorption

When polymer particles travel in porous media, some of them are adsorbed onto solid surfaces or trapped within small pores. This phenomenon is called polymer retention. The degree of retention depends on the properties of the polymer and of the rock surface. The range of retention is between 7 and 150 μg polymer/cm^3 of bulk volume according to field measurement [8]. Retention leads to loss of polymer concentration in the solution, and thus reduces the effect of polymer flooding. A Langmuir-type isotherm, which is shown as equation below, is usually used to quantitatively describe polymer adsorption [2, 8, 9].

Eq. 2.2-1 $$C_{ps} = \frac{a_p {C_p}^m}{1+b_p C_p}$$

where $a_p = (a_{p1} + a_{p2} C_{se})(\frac{k_{ref}}{k})^n$

Instead of using equation above, the polymer adsorption isotherm is specified as a look-up table of polymer adsorption as a function of polymer concentration in this study. It is an ECLIPSE feature to use this kind of table. This table disables the adsorption dependencies on the salinity and rock permeability. [7]

In addition to adsorption, desorption has also to be considered. Desorption means that the polymer concentration on the rock phases can change as the polymer concentration in the aqueous changes with time. If there is only adsorption but no desorption, the polymer concentration on the rock phases can never decrease with time. The case without desorption is also called irreversible case, and the case with desorption is reversible case.

2.3 Fractional Flow in Polymer Flooding

The fractional flow theory in polymer flooding is often called extended fractional flow theory [10] and is based on the Buckley-Leverett (1942) theory [11, 12]. In a two-phase flow situation, two phases (aqueous and oleic) and three components (water/brine, oil and polymers) are considered. We assume that polymers stay only in aqueous phase (i.e. only oil in oleic phase while water/brine and polymers in aqueous phase), there is a uniform initial water saturation S_{wi}, initial polymer concentration is 0 and injection polymer concentration is C_p. The polymer-oil fractional flow curve is then constructed as shown in Figure 1 for the situation with $S_{w1} < S_{wi}$. Figure 2 illustrates the water saturation profile corresponding to Figure 1.

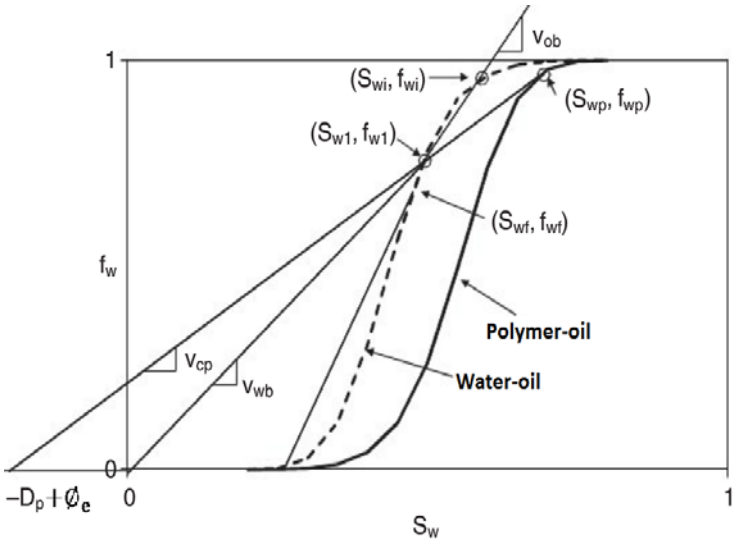


Figure 1: Graphical Construction of Polymer Fractional Flow[1]

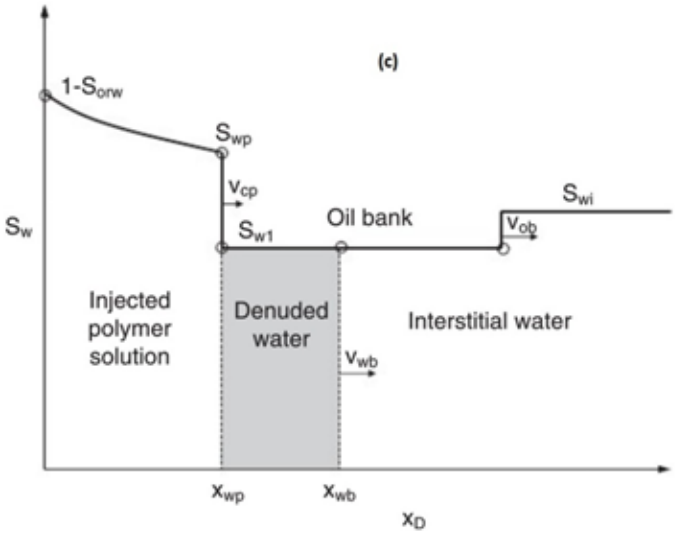


Figure 2: Corresponding Water Saturation Profile[2]

The specific velocity of polymer front (polymer concentration shock) v_{C_p}, the specific velocity of boundary between the denuded water and the initial water v_{wb}, and the specific velocity of the front of the oil bank v_{ob} are computed by [8-10]

Eq. 2.3-1 $$v_{C_p} = \frac{f_{wp}}{S_{wp}+D_p-\emptyset_e} = \frac{f_{wp}-f_{w1}}{S_{wp}-S_{w1}},$$

Eq. 2.3-2 $$v_{wb} = \frac{f_{w1}}{S_{w1}},$$

Eq. 2.3-3 $$v_{ob} = \frac{f_{wi}-f_{w1}}{S_{wi}-S_{w1}}.$$

2.4 Fingering and Stable Displacing Front

Due to higher mobility of the water phase and geologic perturbation, unstable displacing front in the form of viscous fingers will form in reservoirs with viscous oil and/or high heterogeneity, resulting in reduced volumetric sweep efficiency. Therefore, the displacing front has to be stabilized to improve oil recovery.

The end point mobility ratio M, the total mobility λ_T and the shock mobility ratio M_s are defined as [13]

Eq. 2.4-1 $$M = \frac{\mu_o k'_{rw}}{\mu_w k'_{ro}},$$

[1] Reedited figure based on the figure from source: 9. Sheng, J., *Modern Chemical Enhanced Oil Recovery: Theory and Practice*. 2010: Gulf Professional Publishing.
[2] Source: 9. Ibid.

Eq. 2.4-2 $$\lambda_T = Mk_{rw} + k_{ro},$$

Eq. 2.4-3 $$M_s = \frac{\lambda_{Ts}}{\lambda_{To}}.$$

And the criteria for a stable displacing front is M_s<1.0. In this thesis, for simplification, the criteria for maximum displacement efficiency, M<1.0 [2], is used instead of the criteria above.

3 Up-scaling Methodology

The idea to up-scale the polymer solution viscosity function and the polymer adsorption function is based on the fact that the viscosity and adsorption of polymer solution at the polymer shock front drop as the concentration of polymer at the polymer shock front drops due to numerical dispersion. By multiplying factors on these two functions, polymer volumetric sweep efficiency and adsorption may be correctly interpreted on a coarse model.

3.1 Up-scaling Polymer Solution Viscosity Function

The polymer solution viscosity function is up-scaled by introducing a viscosity up-scaling factor f_v. Because the first entry of viscosity multipliers should always be 1.0 corresponding to no polymer injected by using PLYVISC keyword in ECLIPSE, the relation between the original viscosity multiplier M_v and the up-scaled viscosity multiplier $\widetilde{M_v}$ is simply defined as

Eq. 3.1-1 $$\widetilde{M_v} = f_v(M_v - 1) + 1.$$

Figure 3 illustrates the effect of changing the value of f_v.

3.2 Up-scaling Polymer Adsorption Function

The way to up-scale polymer adsorption has been discussed in Lee's thesis [2]. Lee introduced a multiplication factor into Eq. 2.2-1 by changing the value of a_{p1} in ECLIPSE keyword ADSORP. Similar to what Lee did, an adsorption up-scaling factor f_{ad} is introduced to up-scale the polymer adsorption function. The up-scaled concentration of adsorbed polymer $\widetilde{C_{ad}}$ is then computed by

Eq. 3.2-1 $$\widetilde{C_{ad}} = f_{ad} C_{ad}.$$

Curves with different values of f_{ad} are illustrated in Figure 4.

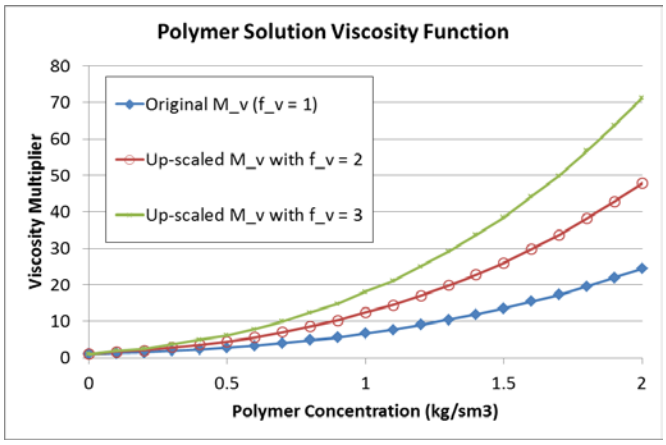


Figure 3: Original and Up-scaled Polymer Solution Viscosity Functions

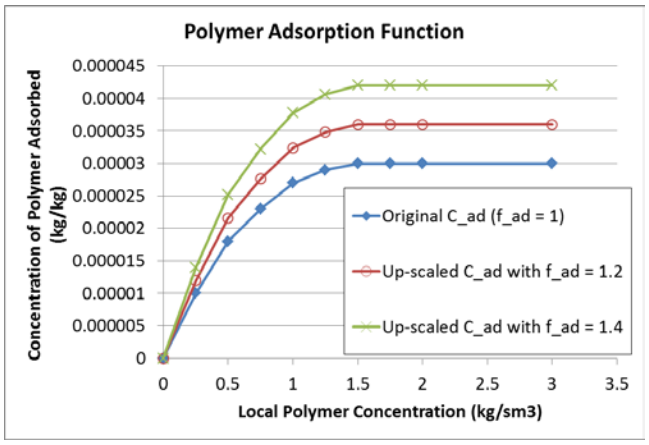


Figure 4: Original and Up-scaled Polymer Adsorption Functions

3.3 Tuning and Matching

Two simulation results, Oil Recovery vs. Time and Total Polymer Adsorbed vs. Time, are the most important for this study. Because of change of grid size, we cannot reproduce the whole histories of oil recovery and of total polymer adsorbed simulated on the fine grid model, on the coarse grid model. It is therefore only possible to tune the coarse grid results of ultimate oil recovery and of ultimate total polymer adsorbed to match the fine grid results by testing different combinations of f_v and f_{ad} values. Matching of ultimate oil recovery and ultimate polymer adsorption is performed by manual, so some errors should be expected, but these errors are small enough to be ignored. Other simulation results like Water Cut vs. Time, Polymer Production vs. Time and Injector WBHP vs. Time are plotted in order to show how well this method can reduce the mismatches between the fine and coarse grid results.

4 Polymer Flooding in ECLIPSE Simulator

Following properties for modeling polymer flooding in ECLIPSE provided by Vegard Kippe, Principal Researcher in Statoil, are used in this study.

- The dead pore space or inaccessible pore volume (IPV) is set to 0.1 which is a moderate value [2]. This means that 10% of the total pore volume cannot be occupied by polymers. In some rock types, the dead pore space can be as high as 30% [8, 14].
- The value of the residual resistance factor is set to 1.0. The residual resistance factor describes how much the rock permeability to the aqueous phase will decrease if polymer adsorption has reached its maximum value [7]. A value of 1.0 represents that polymer adsorption does not cause any permeability reductions, so the effect of permeability reduction is ignored in this study.
- Both irreversible and reversible cases are investigated for each simulation case. An irreversible case means that desorption of polymers is disabled so that the adsorbed polymer concentration cannot decrease again when the local polymer concentration has decreased. If the desorption of polymer is enabled, which means that the adsorbed polymer concentration changes as the local polymer concentration changes, it is then a reversible case.
- The Todd-Longstaff mixing parameter ω describes the degree of segregation between the water and the polymer solution. In this study, the value of ω is assumed to be 1.0. This assumption represents that the water and the polymer solution are fully mixed in each, so the effective polymer viscosity is equal to the polymer solution viscosity.
- For the given polymer solution viscosity function (Figure 5), the polymer concentration of 1.5 kg/sm^3 at injection is enough to give a favorable mobility ratio between the polymer solution mobility and the oil mobility.
- The polymer solution viscosity function as shown in Figure 5 is input by using ECLIPSE keyword PLYVISC. The polymer solution viscosity at injection is 6.75 cp. Thus, the mobility ratio at injection equals to 1.0. Figure 6 shows the mobility ratio as a function of polymer concentration.
- The polymer adsorption function as shown in Figure 7 is input by using ECLIPSE keyword ADSORP. The maximum adsorption is 0.00003 kg/kg, namely 79.5 $\mu g/cm^3$ as the rock density is set to 2650 kg/m^3. Here it is assumed that the polymer adsorption is independent on salinity.

- The polymer solution is assumed to be Newtonian. Therefore, non-Newtonian behavior of polymer solution is not investigated in this thesis.
- For all the cases, polymer is firstly injected and then followed by water injection until the field economic limit (90% water cut) is reached. This corresponds to what is often referred to secondary mode polymer injection (polymer injection from the start). For different reservoir models, different polymer slug sizes are used in order to keep the polymer flooding being the dominant displacing mechanism.

Table 1 lists all the important properties for modeling polymer flooding in ECLIPSE.

Table 1: Important Properties of Polymer Flooding Input in ECLIPSE

Dead pore space (IPV)	0.1
Residual resistance factor	1.0
Desorption	No or Yes
Todd-Longstaff mixing parameter	1.0
Polymer Concentration at Injection	1.5 kg/sm^3
Injection Scheme	For 1D and 2D homogeneous and layered models: 1000 day's polymer injection followed by water injection For 2D areal and 3D homogeneous models: 2000 day's polymer injection followed by water injection For 3D layered models: 1500 day's polymer injection followed by water injection For 3D generic models: 4000 day's polymer injection followed by water injection

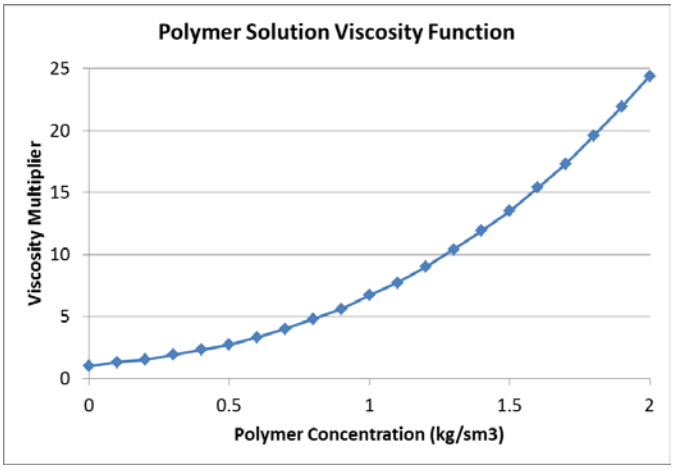


Figure 5: Input Polymer Solution Viscosity Function

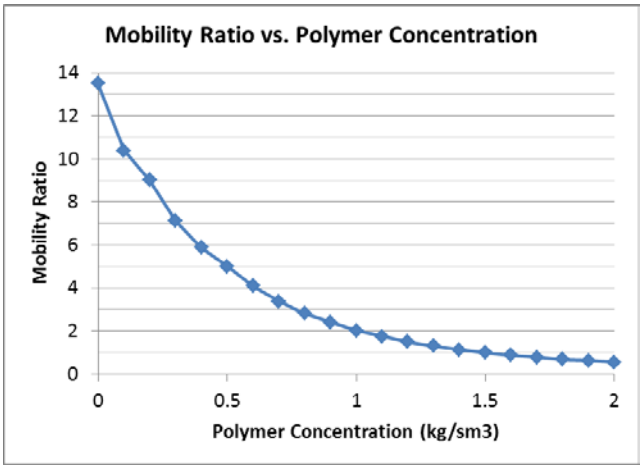


Figure 6: Mobility Ratio vs. Polymer Concentration

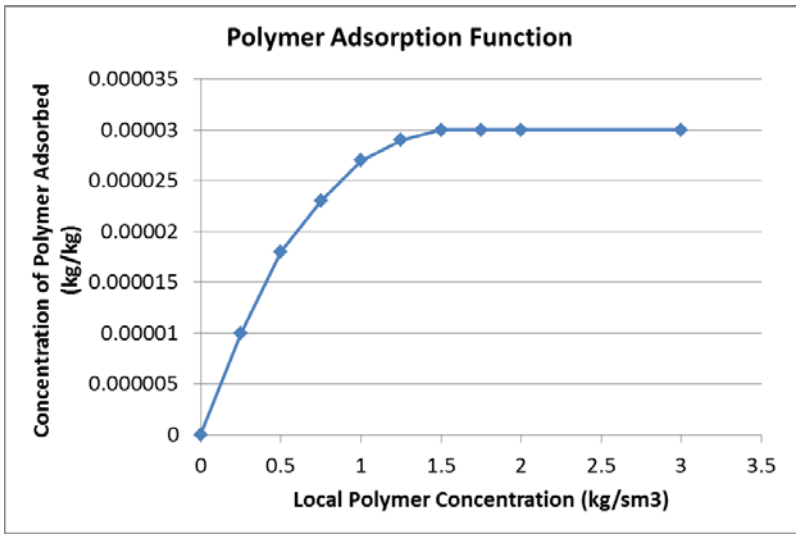


Figure 7: Input Polymer Adsorption Function

5 Study Workflow

A number of 1D, 2D and 3D models are built in order to investigate the impact of up-scaling the polymer solution viscosity function and the polymer adsorption function. The procedure of this study is described below.

1. To do sensitivity analysis for grid size on 1D models to check the effect of changing grid size on oil recovery and on polymer adsorption for both irreversible and reversible cases;
2. To find the values of up-scaling factors, f_v and f_{ad}, for different grid sizes on 1D models to investigate their dependencies of grid size;
3. To compare the 1D simulation results before and after applying the up-scaling factors to see if the mismatches between the fine and the coarse grid results are reduced;
4. To find the up-scaling factors for more complex 2D and 3D, homogeneous and heterogeneous cases;
5. For the heterogeneous cases, the effects of heterogeneity and of grid size are investigate separately and then together;
6. To summarize all the values of the up-scaling factors found for each case and to analyze these values by comparing relative cases.

All the simulations are run in the ECLIPSE 100 black oil simulator. Examples of ECLIPSE input DATA-files as well as their INCLUDE-files which contain the polymer properties, are attached in Appendix D: Example of Input Files in ECLIPSE. These files correspond to the 1D Homogeneous Irreversible Case described in Section 6.1.

6 Description of Cases and Models

General properties of the models are listed in Table 2 and Table 3.

Table 2: General Properties of Models for All Cases

	Homogeneous and Layered Cases	3D Generic Case	
Phases	Water and Oil		
Porosity	0.2	0.13~0.28	
Permeability	Homogeneous Cases: $k_x = k_y = k_z = 500$ Layered Cases: $k_{x1} = k_{y1} = 250$ $k_{x2} = k_{y2} = 500$ $k_z/k_x = 0.1$	$k_x = k_y = 7\sim5600$ $k_z = 2.8\sim2240$	md
Oil Density	800		kg/sm^3
Water Density	1000		kg/sm^3
Rock Density	2650		kg/sm^3
Oil Compressibility	$6.65 \cdot 10^{-5}$		bars^{-1}
Water Compressibility	$4.28 \cdot 10^{-5}$		bars^{-1}
Oil Viscosity	6.4		cp
Water Viscosity	0.5		cp
Initial Water Saturation	0.0	0.1~1.0	
Initial Reservoir Pressure	234		barsa
Field Economic Limit	0.9 (Water Cut)		

Table 3: Well Controls

	Production Well Control		Injection Well Control
	Liquid Rate (sm^3/day)	**WBHP (barsa)**	**Injection Rate (sm^3/day)**
1D and 2D Homogeneous and 2D Layered Cases	-	200	200
2D Areal and 3D Homogeneous and 3D Layered cases			1000
3D Generic Case	1600	85	1600

Table below summarizes the information of reservoir size, fine grid block size and its corresponding coarse grid block size, and distance between wells for all the cases in this thesis. More detailed description of each case is in following sections. All the figures of simulation models are attached in Appendix B: Figures of Simulation Models.

Table 4: Reservoir Sizes, Grid Block Sizes and Distance between Wells

Case	Reservoir Size	Fine Grid Block Size (No. of Grid Blocks)	Coarse (Up-scaled) Grid Block Size (No. of Grid Blocks)	Distance between Injector and Producer
1D Homogeneous Case	940m*100m*40m	20m*100m*40m (47*1*1)	180m*100m*40m (7*1*1)	920m
2D Homogeneous Case	940m*100m*40m	20m*100m*2m (47*1*20)	180m*100m*2m (7*1*20)	920m
2D Layered Case	940m*100m*40m	20m*100m*2m (47*1*20)	180m*100m*20m (7*1*20)	920m
2D Areal Case	940m*940m*40m	20m*20m*40m (47*47*1)	180m*180m*40m (7*7*1)	1301m
3D Homogeneous Case	940m*940m*40m	20m*20m*2m (47*47*20)	180m*180m*2m (7*7*20)	1301m
3D Layered Case	900m*900m*40m	20m*20m*2m (45*45*20)	180m*180m*20m (5*5*2)	1018m
3D Generic Case		20m*20m (219*108*91)	180m*180m (24*12*91)	900m

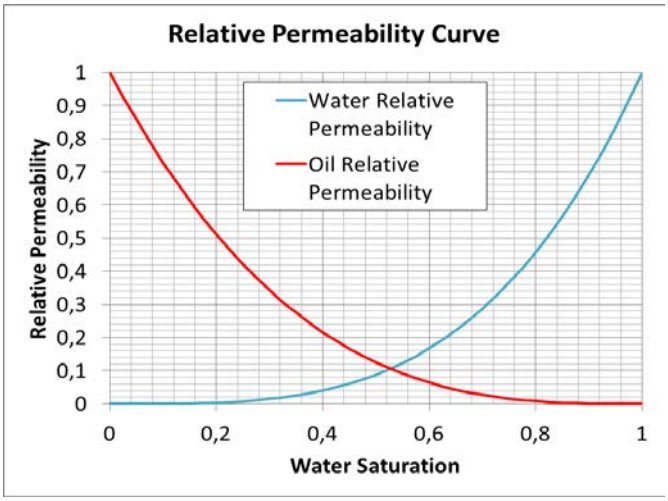


Figure 8: Relative Permeability Curves for Homogeneous and Layered Cases

6.1 1D Homogeneous Case

The dimension of the reservoir model is 940 m × 100 m × 40 m with grid size 20 m × 100 m × 40 m for the fine grid model and 180 m × 100 m × 40 m for the up-scaled coarse grid model

as show in Figure 26. The reservoir is homogeneous and isotropic. Injection well and production well are perforated in the first block and in the last block, respectively. In order to keep the well locations the same before and after up-scaling, the block sizes of the first block and of the last block are not changed during up-scaling. The reservoir parameters are summarized in Table 2 and Table 3. The relative permeability curves for oil and water are shown in Figure 8. The original input polymer solution viscosity function and the polymer adsorption function are illustrated in Figure 5 and Figure 7. Polymer/rock properties are listed in Table 1.

6.2 2D Homogeneous Case

The 2D homogeneous models are generated by dividing the 1D homogeneous models into 20 layers, so the block size of fine grid model is 20 m × 100 m × 2 m and 180 m × 100 m × 2 m for the coarse grid model as shown in Figure 27. All the reservoir parameters, fluid properties and polymer properties used in this case are the same as those used in the 1D Homogeneous Case. Injection well and production well are perforated in the first and the last block column, respectively. In order to keep the well locations the same before and after up-scaling, the bock sizes of the first column and of the last column do not change during up-scaling. Comparing the 2D Homogeneous Case to the 1D Homogeneous Case, we can investigate the effects of gravity and of vertical flow.

6.3 2D Layered Case

The fine model used in the 2D Homogeneous Case is divided into 3 permeability zones. The upper and the lower zones are 16 m thick, and the middle zone is 8 m thick. Permeabilities of the upper and the lower zones equal to 250 md in x- and y-directions and 25 md in z-direction, while permeability of the middle zone is set to 500 md in x- and y-direction and 50 md in z-direction. Because the only difference among these layers is permeability, only permeability is up-scaled for up-scaling. The up-scaled permeabilities are computed by power average [15]

Eq. 6.3-1 $$k_j^* = \sum_{i=1}^{n} \left(\frac{h_i}{h} k_{j,i}\right), j = x \text{ or } y,$$

Eq. 6.3-2 $$k_z^* = \frac{h}{\sum_{i=1}^{n} (h_i / k_{z,i})}.$$

Permeabilities in the direction parallel to the flow direction are computed by arithmetic averaging (Eq. 6.3-1), and in the direction perpendicular to the flow direction are computed by harmonic averaging (Eq. 6.3-2). Thus, the averaged permeabilities are 300 md in x- and y-

directions and 27.78 md in z-direction. The up-scaled model and its corresponding permeablities are shown in Figure 28. A refined model illustrated in Figure 28 (c) is also generated by down-scaling the up-scaled model. Comparing the fine model to the refined model, we can investigate the effect of changing heterogeneity; comparing the refined model to the up-scaled coarse grid model, we can investigate the effect of changing grid size; and comparing the fine model to the up-scaled coarse grid model, we can investigate the effect of up-scaling (a combination of effect of changing heterogeneity and effect of changing grid size). The relations of grid size effect, heterogeneity effect and up-scaling effect are illustrated in Figure 20.

6.4 2D Areal Homogeneous Case

2D areal models are built to investigate the up-scaling effect in x- and y-directions. The dimension of the reservoir model is 940 m × 940 m × 40 m with grid size 20 m × 20 m × 40 m for the fine grid model and 180 m × 180 m × 40 m for the up-scaled coarse grid model as show in Figure 29. The reservoir is homogeneous and isotropic. Injection well is located at one of the corners and production well is located at the opposite corner. In order to keep the well locations the same before and after up-scaling, the sizes of blocks along the four edges do not change during up-scaling. All the reservoir parameters, fluid properties and polymer properties used in this case are the same as those used in the 2D Homogeneous Case.

6.5 3D Homogeneous Case

The fine model in 2D Areal Homogeneous Case is refined in z-direction to a 3D homogeneous model. Under up-scaling, grid sizes only change in x- and y-directions. Comparing the 3D Homogeneous Case to the 2D Areal Homogeneous Case, we can investigate the gravity effect and the vertical flow effect. The fine grid model with grid block size 20 m × 20 m × 2 m and the coarse grid model with grid block size 180 m × 180 m × 2 m are shown in Figure 30.

6.6 3D Layered Case

Same as that has been done for the 2D Layered Case, the fine model used in the 3D homogeneous is divided into 3 permeability zones with permeabilities 250 md in x- and y-directions and 25 md in z-direction in the 16 m thick upper and lower zones, and 500 md in x- and y-directions and 50 md in z-direction in the 8 m thick middle zone. Up-scaled model and refined model are generated as well. The corresponding averaged permeabilities are 300 md in x- and y-direction and 27.78 md in z-direction. Injection well located 90 m away from the

two nearest edges at a corner and production well located at the opposite corner 90 m away from its two nearest edges, which means that the injection well and the production well perforate in the blocks of the first column and in the blocks of the last column, respectively, on the up-scaled model. The models and their corresponding permeabilities are shown in Figure 31. Again, the effect of changing heterogeneity, the effect of changing grid size and the effect of up-scaling are investigate in this case.

6.7 3D Generic Case

A set of generic models is provided by Ali Mojaddam Zadeh, Senior Researcher in Statoil. A 219 × 108 × 91 grids model (Model HE_20) with grid size 20 m × 20 m is up-scaled to a 24 × 12 × 91 grids model (Model 180) with grid size 180 m × 180 m. The Model 180 is than down-scaled to a 219 × 108 × 91 grids model (Model GE_20) with grid size 20 m × 20 m. Because the thickness of the layers is varying, they are kept constant under both up- and down-scaling in order to minimize vertical numerical dispersion. Only absolute permeabilities, porosities and saturations are averaged under up-scaling.

Important model parameters and fluid properties are listed in Table 2 and Table 3. Same input relative permeability curves as shown in Figure 9 are used for all the 3 different rock types. End-point scaling is used for the relative permeability curves. The scaled connate water saturation is set to the initial water saturation for each grid block, and its maximum value is set to 0.1. The scaled critical water saturation is also set to the initial water saturation for each grid block and its maximum value is set to 0.70. The scaled critical oil-in-water saturation is set to 0.18. The scaled maximum value of water relative permeability is set to 0.45. Therefore, the real relative permeability curves vary from block to block. Unlike the other cases, the mobility ratio at injection is around 0.55 (more favorable) in this case because a different set of relative permeabilites is used on the 3D Generic models. Polymer properties are the same as those listed in Table 1. Viscosity multiplier curve and adsorption curve are also the same as those shown in Figure 5 and Figure 7.

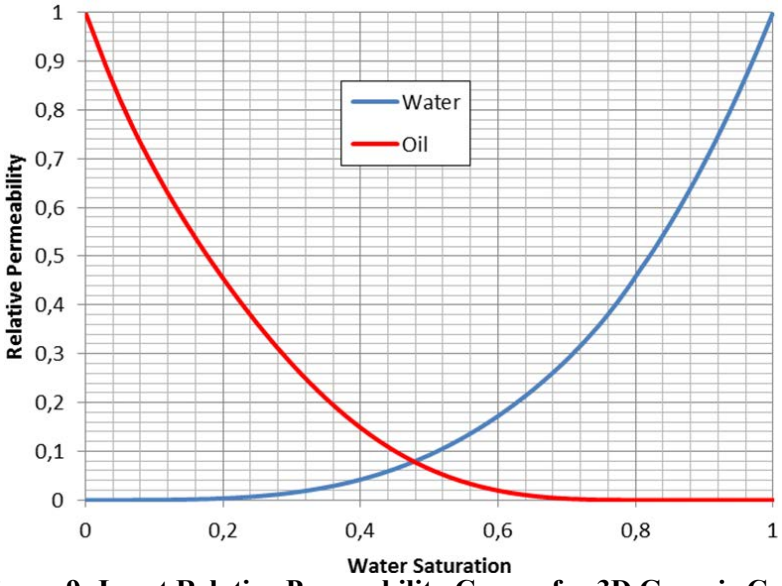


Figure 9: Input Relative Permeability Curves for 3D Generic Case

Both injector and producer are horizontal, 1620 m long and located in Layer 5 for all the models. The distance between the injector and the producer is 900 m. Well controls are liquid rate 1600 sm^3/day and WBHP 85 barsa for the producer and injection rate 1600 sm^3/day for the injector. Polymer is injected for 4000 days and then followed by water injection until field economic limit is reached. The geometry of the model is shown in Figure 32. A side view of initial oil saturation is shown in Figure 33. Well locations, initial oil saturation distributions and x-direction permeability distributions of Layer 5 are shown in Figure 34.

7 Simulation Results

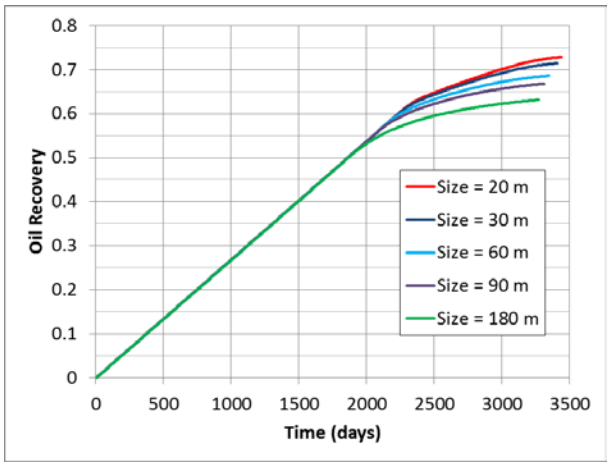
Selected plots of simulation results are presented in this section. Other plots of simulation results can be found in Appendix C: Simulation Results.

7.1 1D Homogeneous Case

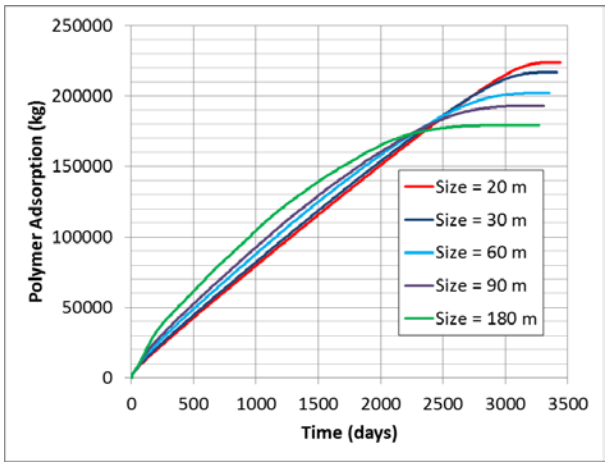
7.1.1 Sensitivity Analysis for Grid Size

Sensitivity analyses for grid size are done for both the irreversible and reversible cases. Simulation results for varying grid sizes in x-direction (20 m, 30 m, 60 m, 90 m and 180 m) are illustrated in Figure 10 and Figure 11. The differences in oil recovery and in polymer adsorption are significant. For both irreversible and reversible cases, the ultimate oil recovery decreases as grid size increases. The ultimate polymer adsorption decreases as grid size increases for the irreversible case, while it increases as grid size increases for the reversible case except a slight non-linearity observed between the 20 m model and the 30 m model. Between the irreversible case and the reversible case, the difference in oil recovery is quite small, but significant difference in polymer adsorption can be observed.

The differences in the simulation results for models with different grid size are caused by numerical dispersion which leads to a so-called smearing effect. Figure 12 - Figure 15 show the smearing effect on polymer solution viscosity and polymer adsorption at 2000 days after production. The polymer solution viscosity smears out on a coarse model resulting in a smaller peak polymer solution viscosity than that on a fine model. This leads to a reduced polymer sweep efficiency and smaller oil recovery on a coarse model. Same for polymer adsorption, a fine grid model has higher peak polymer adsorption than a coarse grid model. For the irreversible case, higher peak polymer adsorption will lead to a higher ultimate polymer adsorption because the adsorbed polymer concentration can never decrease. However, for the reversible case, a very clear trend is observed that the peak polymer adsorption increases as grid size increases, but this kind of very clear trend doesn't exist for the ultimate polymer adsorption; the reason is because complications arise in late stages due to the smearing effect on polymer solution shock fronts [2].

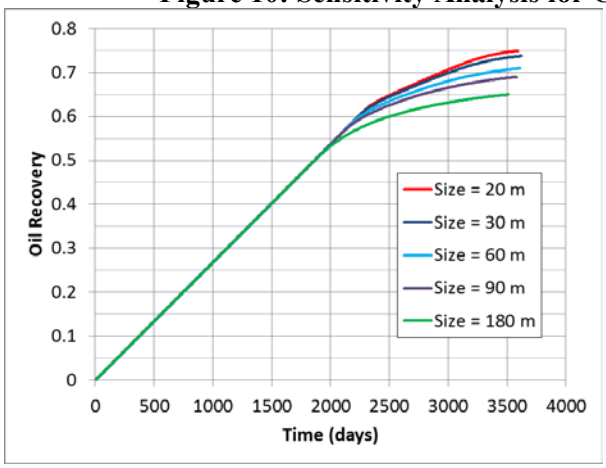


(a) Oil Recovery vs. Time

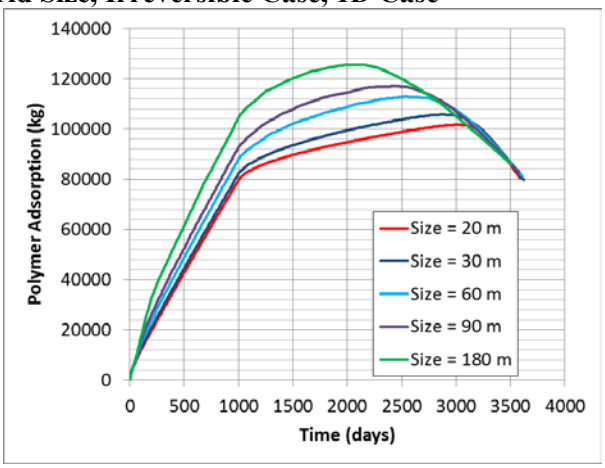


(b) Polymer Adsorption vs. Time

Figure 10: Sensitivity Analysis for Grid Size, Irreversible Case, 1D Case



(a) Oil Recovery vs. Time



(b) Polymer Adsorption vs. Time

Figure 11: Sensitivity Analysis for Grid Size, Reversible Case, 1D Case

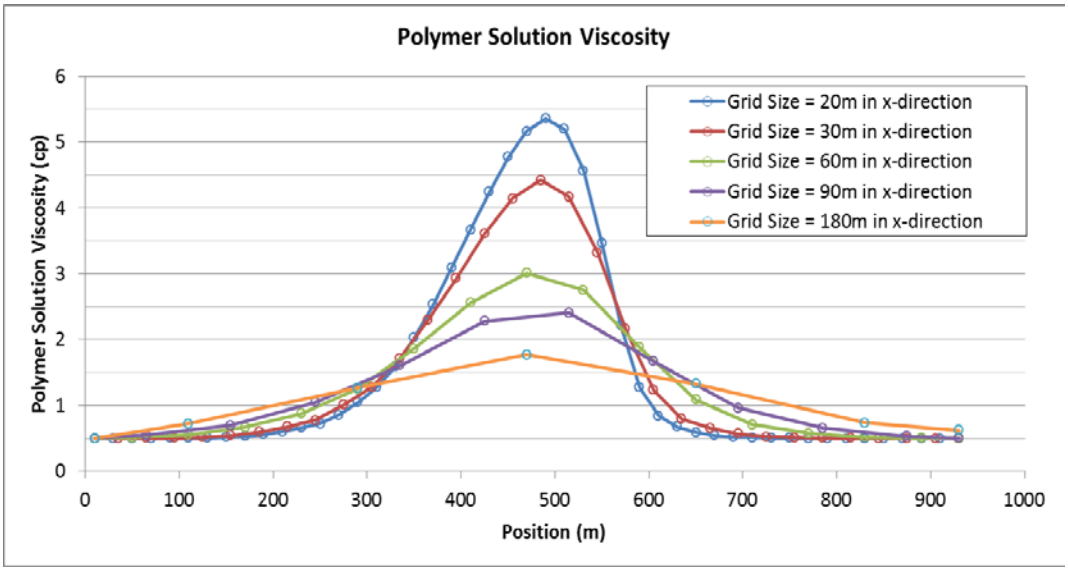


Figure 12: Smearing Effect on Polymer Solution Viscosity, Irreversible Case, 1D Case

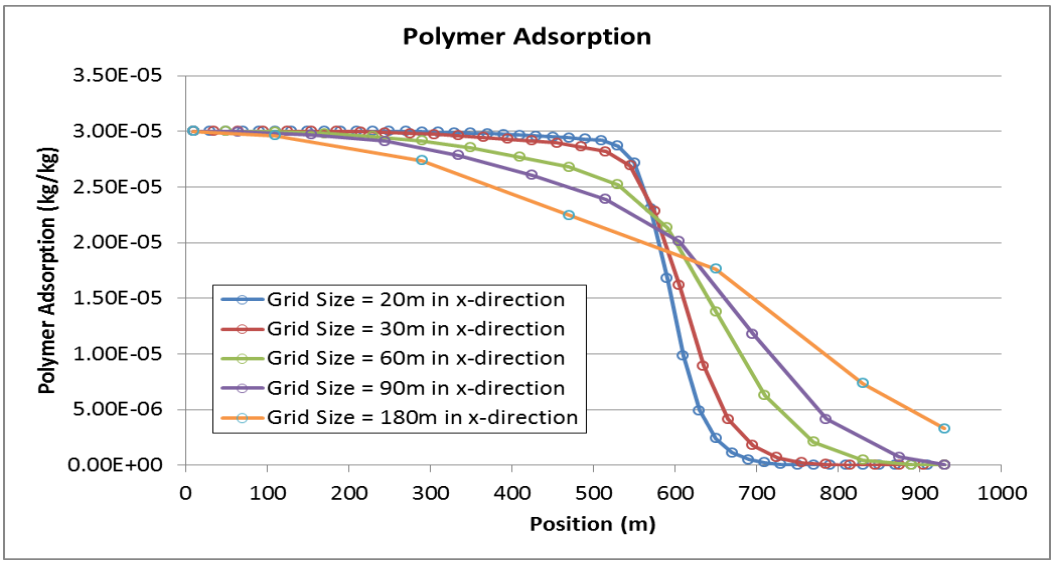


Figure 13: Smearing Effect on Polymer Adsorption, Irreversible Case, 1D Case

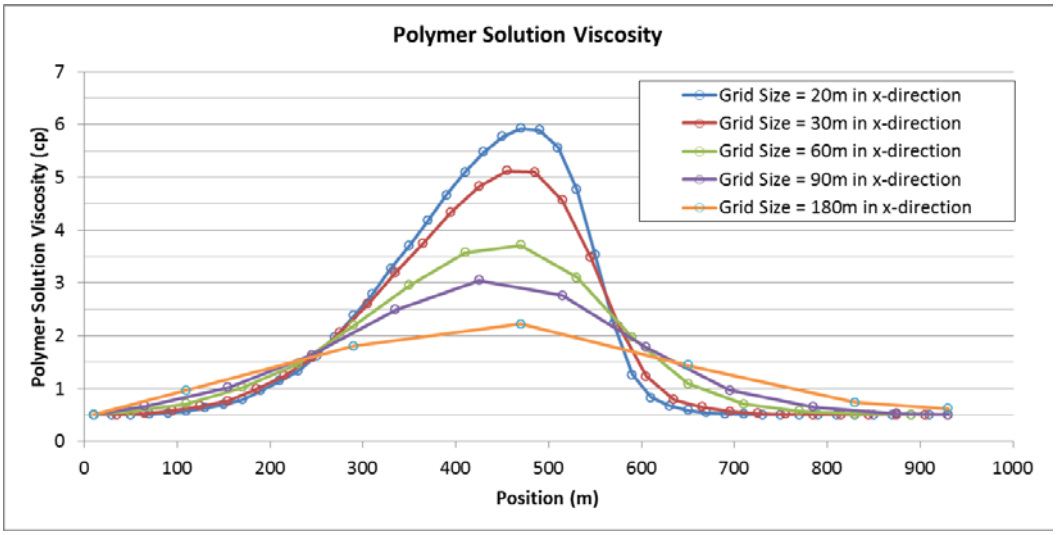


Figure 14: Smearing Effect on Polymer Solution Viscosity, Reversible Case, 1D Case

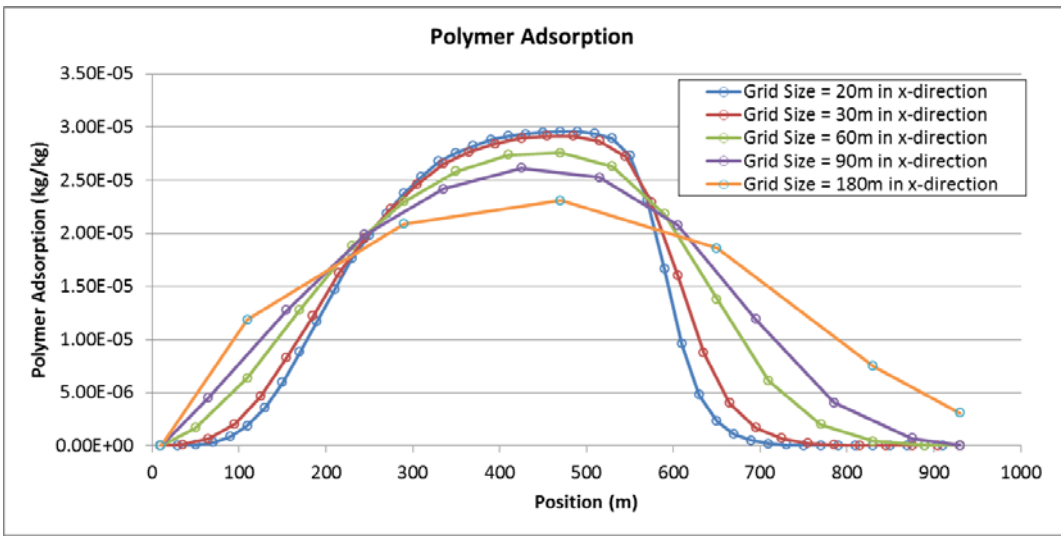
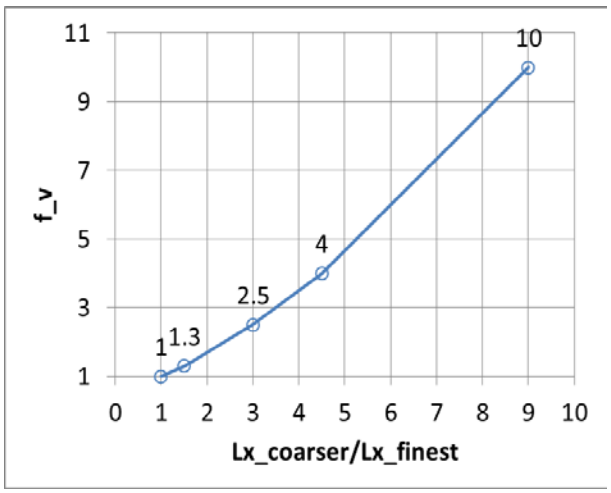


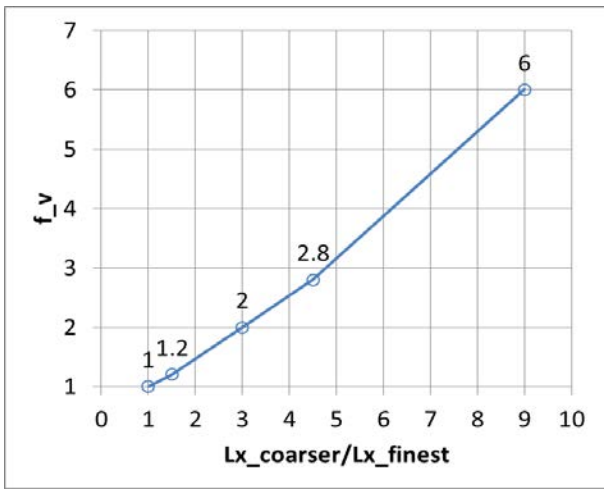
Figure 15: Smearing Effect on Polymer Adsorption, Reversible Case, 1D Case

7.1.2 Polymer Solution Viscosity and Adsorption Up-scaling

The finest grid model (20 m model) is chosen to be the base model. By tuning the simulation results of coarse grid models to match those of the base model, up-scaling factors of polymer solution viscosity and polymer adsorption are obtained for each coarse grid model. Tuned simulation results can be found in Figure 35 and Figure 36. Values of f_v and f_{ad} are plotted in Figure 16 and Figure 17. The figures show that different up-scaling factors should be used for the irreversible case and for the reversible case. It is clear that f_v is larger than 1.0 and increases almost linearly as grid size increases for both cases. For f_{ad}, it is larger than 1.0 and increases as grid size increases for the irreversible case, but it is smaller than 1.0 and decreases as grid size increases for the reversible case except the 30 m model.

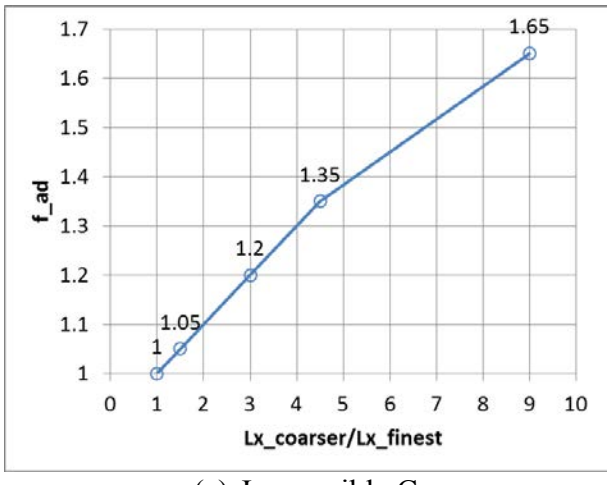


(a) Irreversible Case

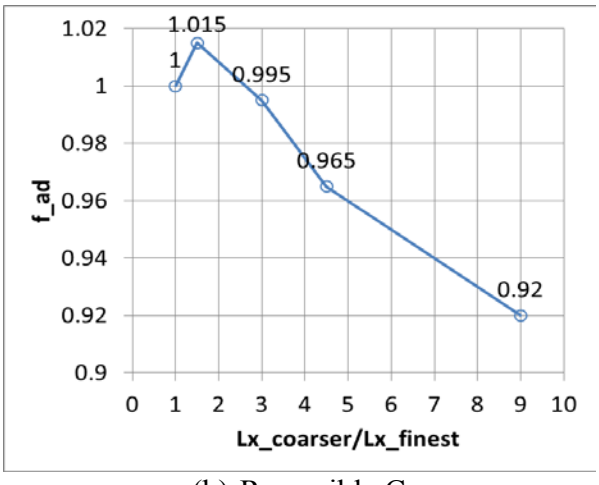


(b) Reversible Case

Figure 16: Values of f_v for Irreversible and Reversible Cases, 1D Case



(a) Irreversible Case

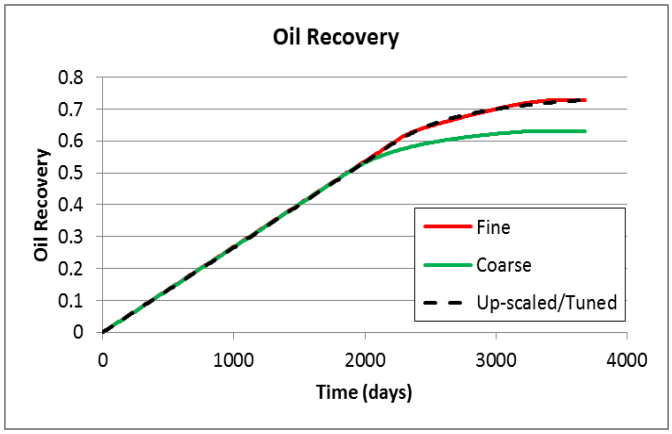


(b) Reversible Case

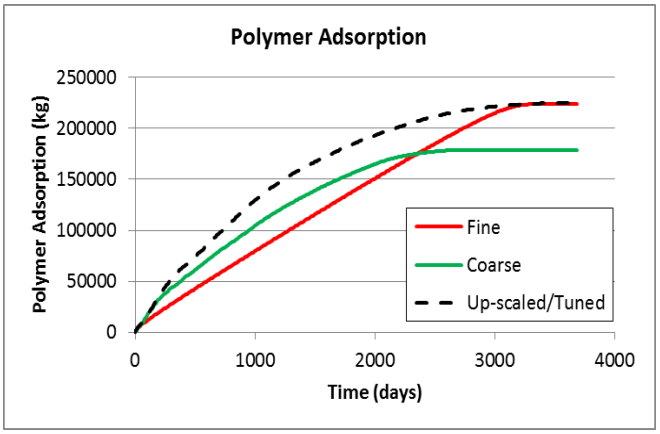
Figure 17: Values of f_ad for Irreversible and Reversible Cases, 1D Case

7.1.3 Results before and after Up-scaling

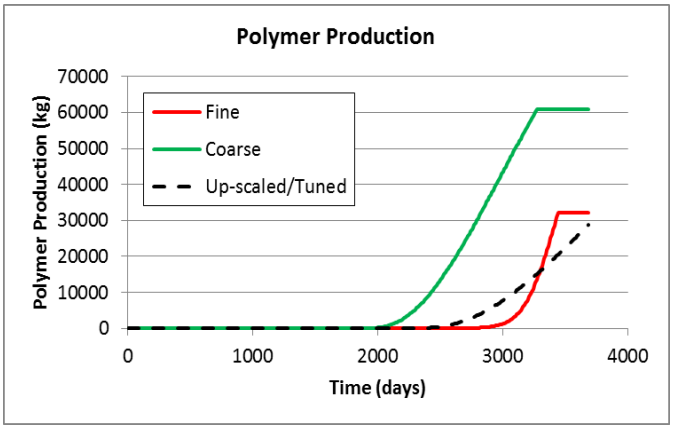
Figure 18 and Figure 19 show the simulation results on the fine grid model (20 m model) and the coarse grid model (180 m model) as well as the up-scaled (tuned) results. The up-scaled results are obtained by applying up-scaling factors (f_v = 10 and f_{ad} = 1.65 for the irreversible case; f_v = 6 and f_{ad} = 0.92 for the reversible case) on the coarse grid model.



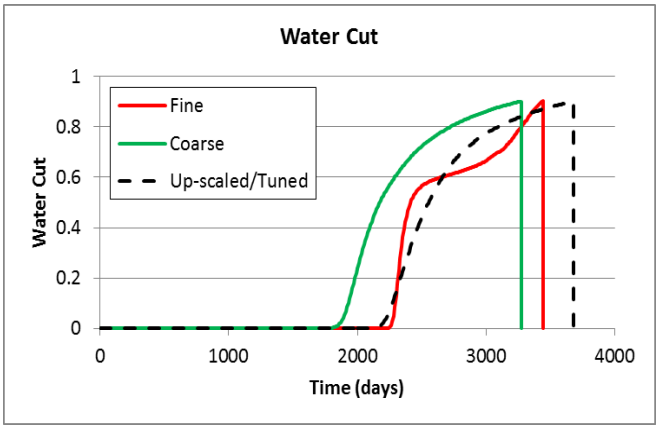
(a) Oil Recovery



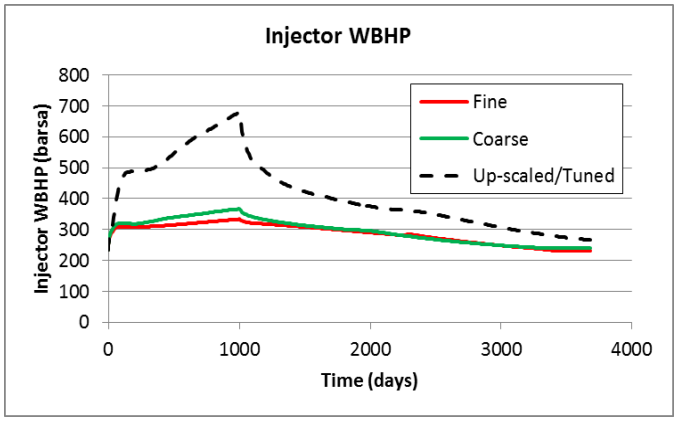
(b) Polymer Adsorption



(c) Polymer Production

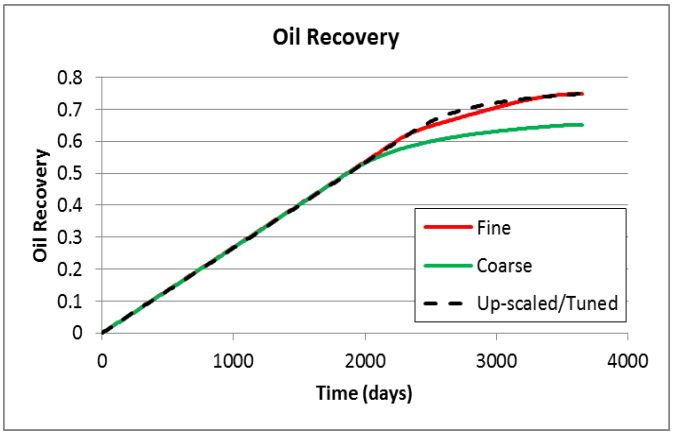


(d) Water Cut

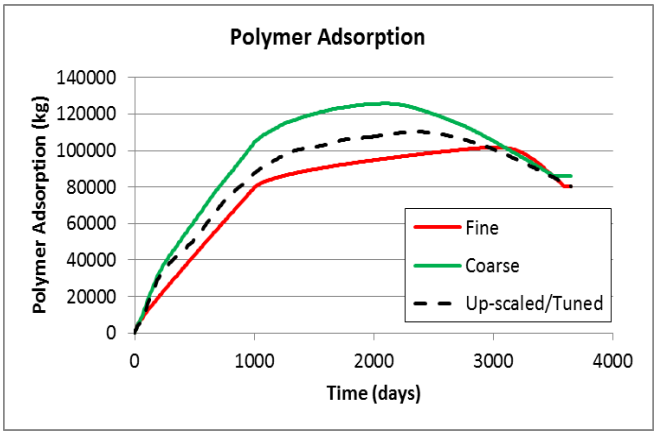


(e) Injector Well Bottom-Hole Pressure

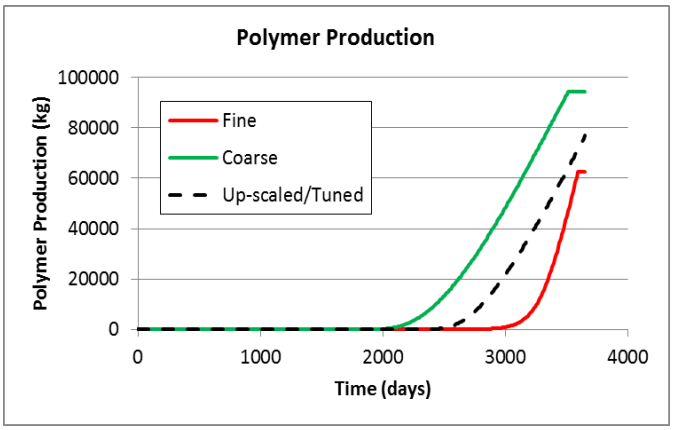
Figure 18: Simulation Results, 1D Irreversible Case



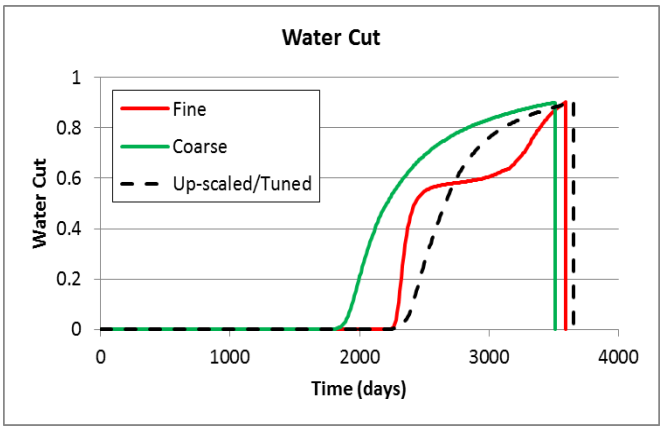
(a) Oil Recovery



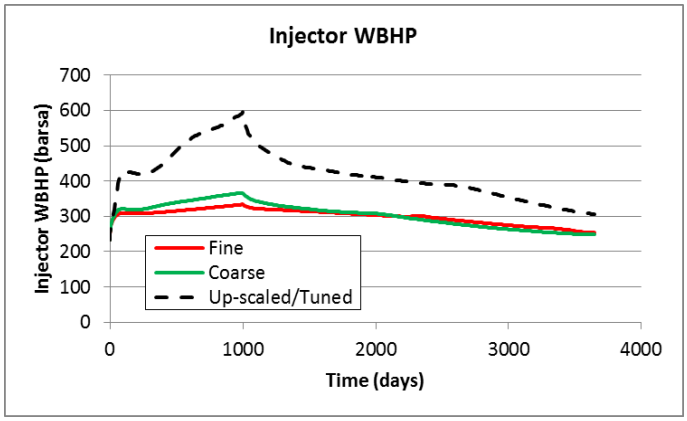
(b) Polymer Adsorption



(c) Polymer Production



(d) Water Cut



(e) Injector Well Bottom-Hole Pressure

Figure 19: Simulation Results, 1D Reversible Case

Although the whole histories of oil recover and of polymer adsorption cannot be reproduced on the coarse grid model by using this up-scaling methodology, the ultimate oil recovery and the ultimate polymer production can be reproduced accurately on the coarse grid model for both irreversible and reversible cases. Moreover, the mismatches in water break-through time and in ultimate polymer production are reduced after tuning. However, drawbacks of applying this up-scaling methodology are that a good match in time when the economic limit (90%

water cut) is reached, is not obtained, and that the injector well bottom-hole pressure becomes much higher after tuning because of increased polymer solution viscosity.

These simulation results in the 1D Homogeneous Case indicate that the up-scaling methods for polymer solution viscosity and for polymer adsorption can generate good matches in most simulation results except unacceptably high injector WBHP. More tests have to be done on the more complex 2D and 3D models in order to check the applicability of this up-scaling method.

7.2 2D Homogeneous Case

The impacts of gravity and of vertical flow which are not involved in the 1D Homogeneous Case, is investigate in this case. Because of density difference between oil and water, injected polymer solution and water sink and travel faster at the bottom of the reservoir, resulting in lower oil recovery for both irreversible and reversible cases, lower ultimate polymer adsorption for the irreversible case and larger ultimate polymer adsorption for the reversible case, compared to the 1D Homogeneous Case. Fine grid and coarse grid results as well as up-scaled results are attached in Appendix C: Simulation Results. The values of f_v and f_{ad} are found to be 4 and 1.1, respectively, for the irreversible case, and 3 and 1.07, respectively, for the reversible case. Compared to the up-scaling factors found in the 1D Homogeneous Case, f_v becomes smaller for both irreversible and reversible case, f_{ad} becomes smaller for the irreversible case and larger for the reversible case. Smaller value of f_v leads to a lower up-scaled injector WBHP as expected. Same as those in the previous case, the mismatches in water break-through time and ultimate polymer production are reduced.

7.3 2D Layered Case

The impact of heterogeneity is investigated in this case. Because there are both changes of heterogeneity and of grid size under up-scaling process, the heterogeneity effect and the grid size effect are investigated separately and then together. For the heterogeneity effect, the values of $f_{v,HE}$ and $f_{ad,HE}$ are found by tuning the results on the refined model to match the fine grid results; for the grid size effect, the values of up-scaling factors, $f_{v,GE}$ and $f_{ad,GE}$, are found by tuning the simulation results on the coarse grid model to match the results on the refined model. The values of up-scaling factors for the heterogeneity effect, for the grid size effect and for up-scaling are listed in Table 6. The values of $f_{v,GE}$ are larger than 1.0, which agrees with the fact found in the previous cases. The values of $f_{v,HE}$ are smaller than 1.0, which means that introducing heterogeneity may reduce the up-scaling factor of polymer

solution viscosity, f_v. The reason is that the coarse grid model becomes less heterogeneous due to averaging of reservoir properties under up-scaling process, resulting in higher sweep efficiency and higher oil recovery. For polymer adsorption, $f_{ad,HE}$ is smaller than 1.0 for the irreversible case while larger than 1.0 for the reversible case, and $f_{ad,GE}$ is larger than 1.0 for the irreversible case while smaller than 1.0 for the reversible case. This means that the impacts on ultimate polymer adsorption are opposite for the irreversible case and for the reversible case.

Because up-scaling effect is a combination of the heterogeneity effect and the grid size effect, the relations of up-scaling factors for these three effects should be like that illustrated in Figure 20. However, the simulation results show that f_{ad} is indeed smaller than $f_{ad,HE} \cdot f_{ad,GE}$ for the irreversible case, and f_v is smaller than $f_{v,HE} \cdot f_{v,GE}$ and f_{ad} is larger than $f_{ad,HE} \cdot f_{ad,GE}$ for the reversible case. Plots of the simulation results for this case can be found in Appendix C: Simulation Results. Same as those observed in previous case, the mismatches in water break-through time and ultimate polymer production are reduced while the mismatch in injector WBHP is enlarged after tuning.

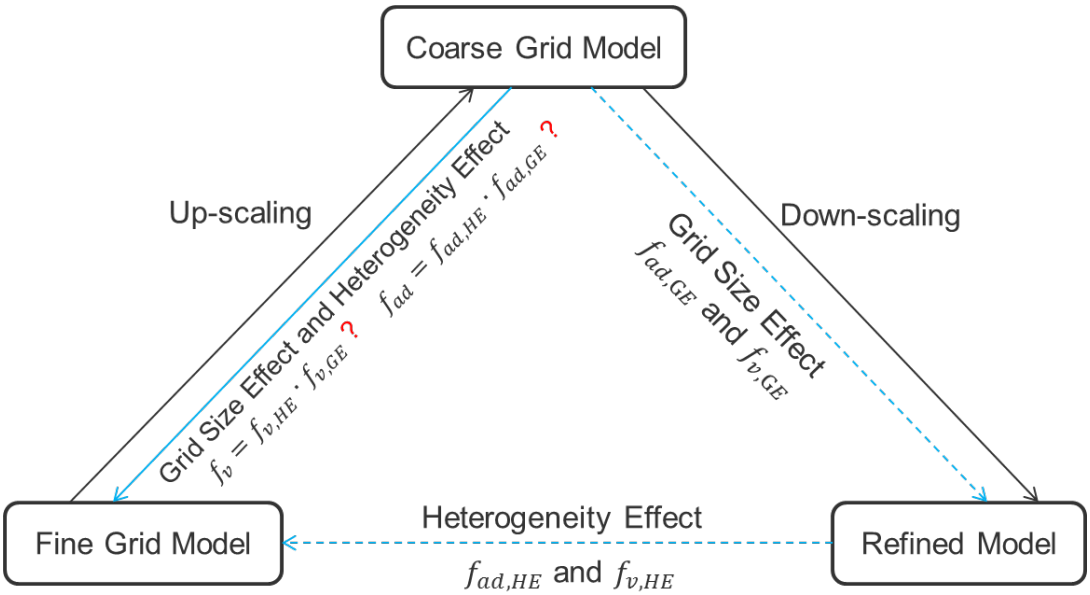


Figure 20: Relations of Heterogeneity Effect, Grid Size Effect and Up-scaling Effect

7.4 2D Areal Homogeneous Case

In this case, the impact of areal flow is investigated. Simulation results and tuned results are attached in Appendix C: Simulation Results. After tuning, the mismatch in ultimate polymer production is reduced for both the irreversible and reversible cases, and the accuracy in water

break-through time is improved only for the irreversible case. Extremely high tuned injector WBHP is still a problem.

The values of up-scaling factors are found to be f_v = 5.5 and f_{ad} = 1.35 for the irreversible case, and f_v = 5 and f_{ad} = 0.94 for the reversible case. Compared to the 1D Homogeneous Case, the values of f_v for both irreversible and reversible cases become smaller; the value of f_{ad} becomes smaller for the irreversible case and larger for the reversible case. The possible explanation for the differences is as follows.

On the fine model, the polymer concentration is high in the middle of the displacing front, but it is very low at the sides. However, on the coarse model, the contrast between the polymer concentration in the middle and at the sides of the displacing front is not as high as that on the fine model as shown in Figure 21. Therefore, compared to the 1D Homogeneous Case, the drop in the sweep area/efficiency is larger on the fine model than on the coarse model. This leads to a smaller difference in oil recovery between the fine model and the coarse model in this case. For the polymer adsorption, due to larger drop in sweep area on the fine model, the drop in the polymer adsorption is also larger on the fine model for the irreversible case. The impact on the polymer adsorption for the reversible case is opposite to that for the irreversible case.

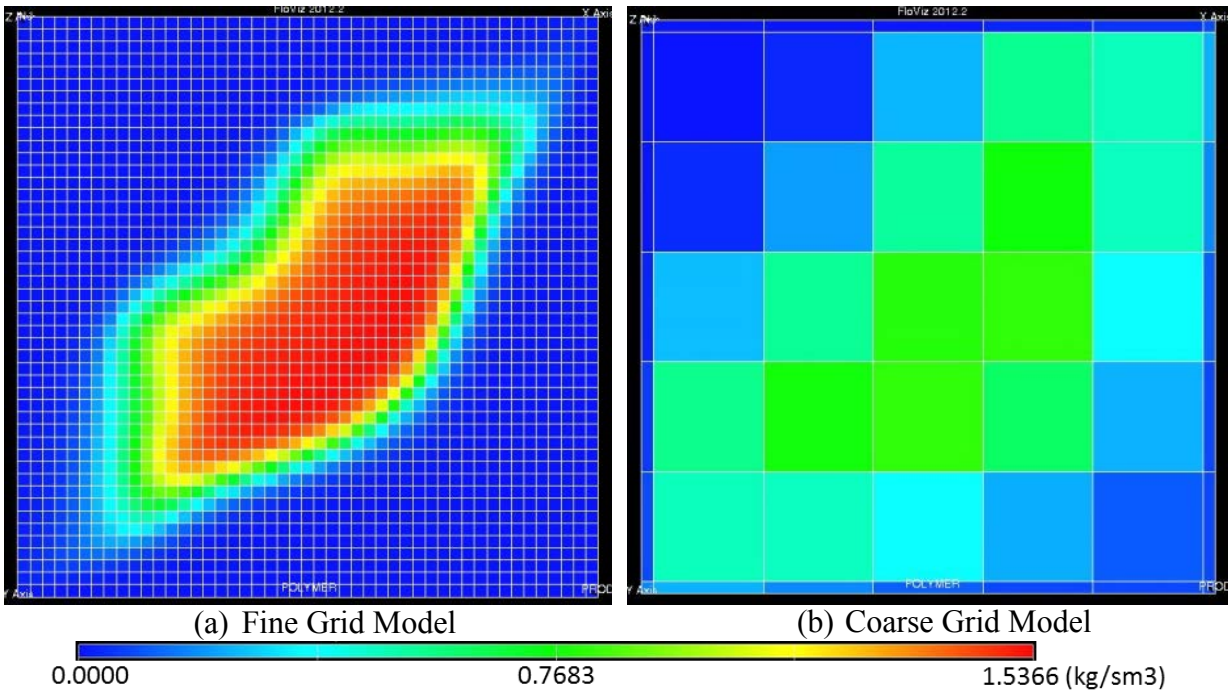


Figure 21: Polymer Concentration at 4000 Days, Irreversible Case, 2D Areal Homogeneous Case

7.5 3D Homogeneous Case

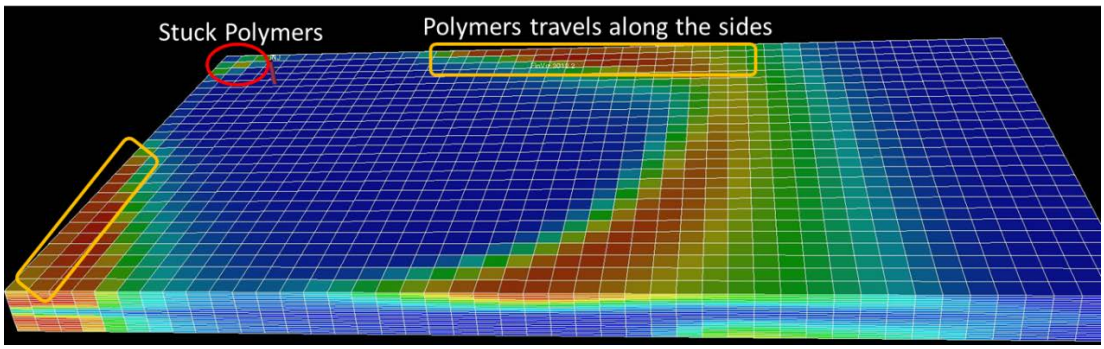
The impacts of gravity and of vertical flow are again investigated in this case. The values of up-scaling factors are listed in Table 5. Comparing this case to the 2D Areal Homogeneous Case, we can get the same conclusion as that we get from comparison between the 2D Homogeneous Case and the 1D Homogeneous Case. Again, when gravity and vertical flow are involved, f_v becomes smaller for both irreversible and reversible case, f_{ad} becomes smaller for the irreversible case and larger for the reversible case.

Figure 47 and Figure 48 show the plots of simulation results. For both the irreversible and reversible case, the accuracies in water break-through time and in ultimate polymer production are improved in some degrees after tuning. However, the tuned injector WBHP is still too high.

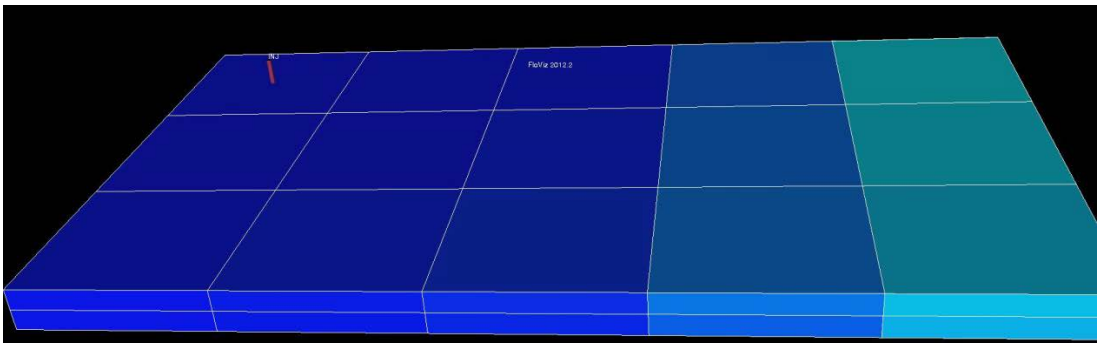
7.6 3D Layered Case

Same as that has been done in the 2D Layered Case, the heterogeneity effect and the grid size effect are investigated separately. The values of up-scaling factors are listed in Table 6. Again, the values of $f_{v,HE}$ are found to be smaller than 1.0, which indicates that the value of f_v will decrease when heterogeneity is introduced into a model. And the values of $f_{v,GE}$ are larger than 1.0 as we found in the previous cases. The values of f_v found by history matching are smaller than $f_{v,HE} \cdot f_{v,GE}$ for both irreversible and reversible cases. The value of f_{ad} is smaller than $f_{ad,HE} \cdot f_{ad,GE}$ for the irreversible case.

Figure 49 - Figure 54 show the simulation results. We can see that the mismatches in water break-through time and in ultimate polymer production are not reduced as we expected. This is probably due to the location of the injector. Because the injector is no longer at the very corner, some injected polymers don't travel in the direction to the producer on the fine grid model; some of them are stuck in area between the injector and the corner, and some of them travels along the sides as shown in Figure 22. However, this phenomenon does not exist on the coarse grid model. Thus, this difference affects the tuned results. The case here shows that the grid size effect which can cause a change of boundary condition, sometimes play a more important role than the heterogeneity effect, and the applicability of this up-scaling method can be affected by the change of boundary conditions when the fine grid model is up-scaled.



(a) Fine Grid Model



(b) Coarse Grid Model

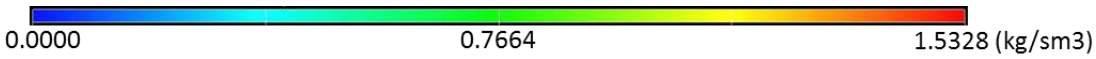


Figure 22: Polymer Concentration at 5000 Days, Irreversible Case, 3D Layered Case

7.7 3D Generic Case

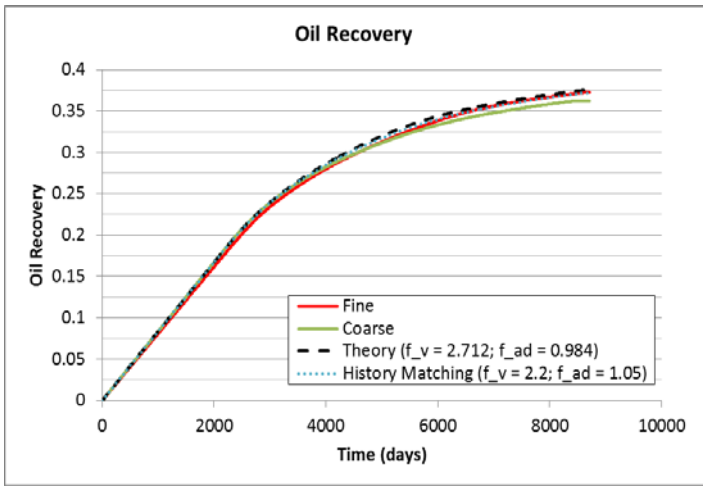
The heterogeneity effect, the grid size effect and the up-scaling effect are investigated in this highly heterogeneous case. The values of the up-scaling factors for all the three effects are listed in Table 6. Same as before, the values of $f_{v,HE}$ are smaller than 1.0 and the values of $f_{v,GE}$ are larger than 1.0. For the irreversible case, the value of f_v found by history matching is smaller than $f_{v,HE} \cdot f_{v,GE}$ and the value of f_{ad} is larger than $f_{ad,HE} \cdot f_{ad,GE}$. For the reversible case, the values of f_v and of f_{ad} found by history matching are very close to $f_{v,HE} \cdot f_{v,GE}$ and $f_{ad,HE} \cdot f_{ad,GE}$, respectively.

The plots of simulation results are shown in Figure 23 and Figure 24. After tuning, good matches are obtained in oil recovery and ultimate polymer adsorption. Because there is almost no mismatch in water break-through time, the water break-through time is not affected after applying the up-scaling method. However, applying the up-scaling method indeed affects the history of water cut a lot. As Figure 23 (d) and Figure 24 (d) show, the coarse grid result of

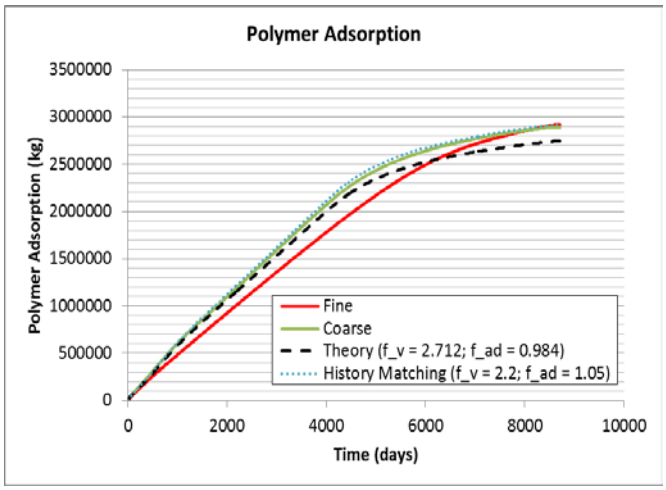
water cut matches well the fine grid result at the early stages after water break-through and the mismatch in the time when the economic limit is reached, is reduced.

Unexpectedly, the accuracy in ultimate polymer production is reduced. The reason is that because the polymer solution viscosity is up-scaled by the factor f_v after tuning, the front of polymer solution travels more slowly and the water bank becomes clearer than that before tuning. As we can see from the plot of polymer in solution (Figure 23 (f) and Figure 24 (f)), the tuned curve of polymer in solution gets closer to the curve for the fine grid model, resulting in good match in polymer production at early stages after polymer break-through; after the tuned curve crosses the fine grid model curve, the tuned result of polymer in solution becomes larger than that simulated on the fine grid model, so the deviation in polymer production becomes larger at late stages.

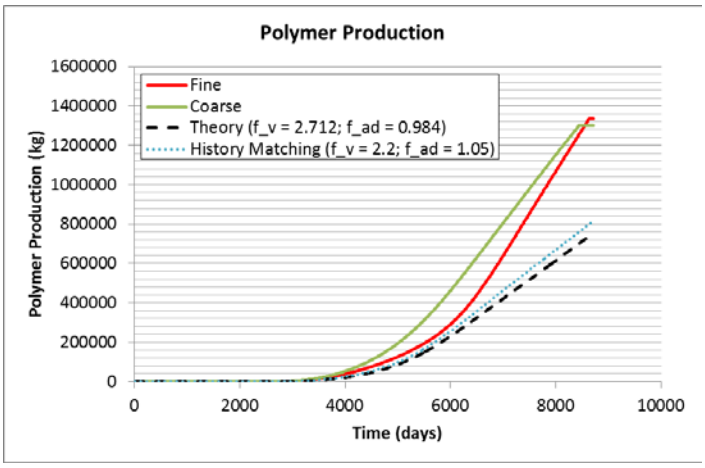
Different from previous cases, there is no longer problem of extremely high injector WBHP on the coarse grid model and the mismatch in injector WBHP is reduced in this case. The reason is that: (1) the injector is far away from the boundaries, (2) the size of the gird blocks which is perforated increases on the coarse grid, and (3) the producer WBHP of well control is lowered to 85 barsa. Thus, opposite to previous cases, the injector WBHP simulated on coarse grid model is actually lower than that of fine grid model as Figure 23 (e) and Figure 24 (e) show. When the polymer solution viscosity function is up-scaled on coarse grid model, increased polymer viscosity makes the injector WBHP higher and closer to the fine grid result.



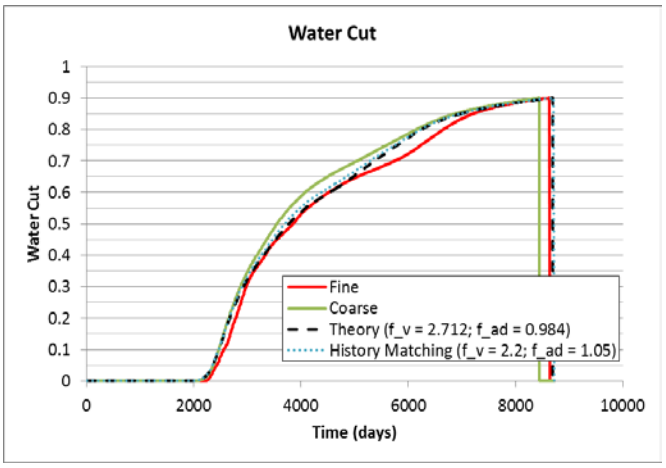
(a) Oil Recovery vs. Time



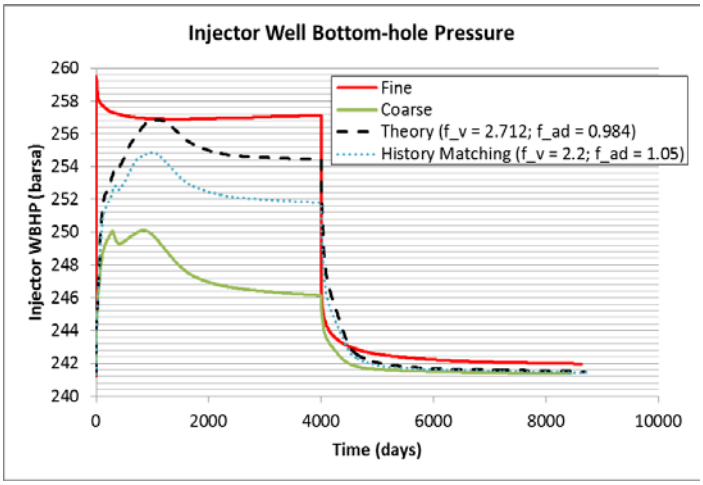
(b) Polymer Adsorption vs. Time



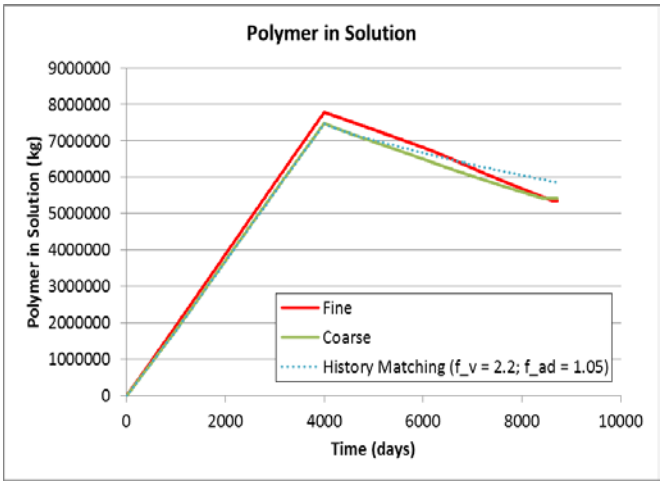
(c) Polymer Production vs. Time



(d) Water Cut vs. Time

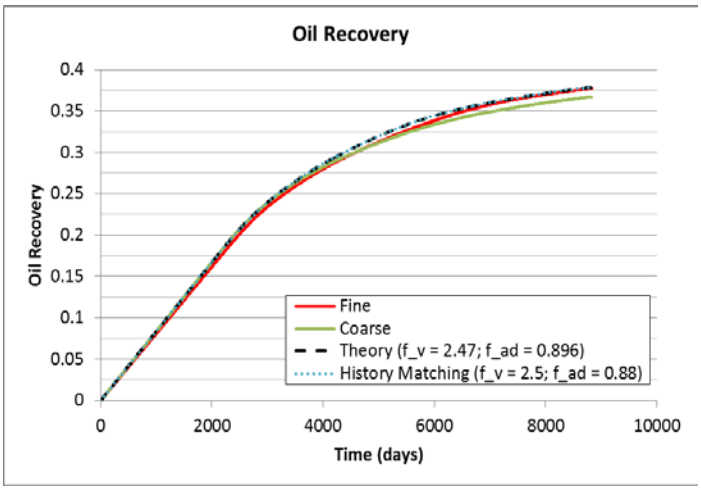


(e) Injector Well Bottom-Hole Pressure vs. Time

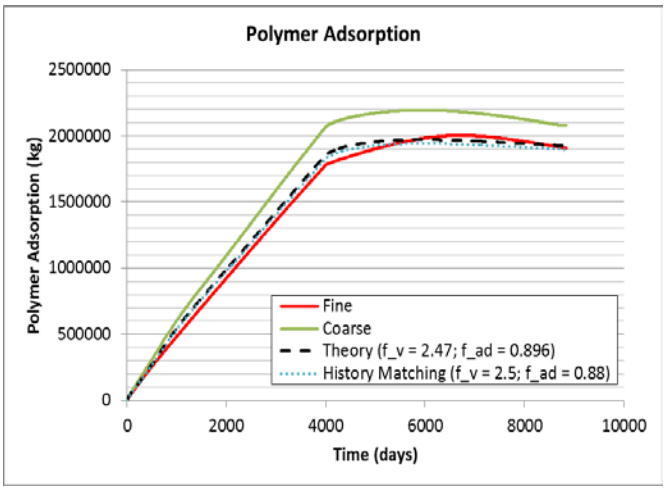


(f) Polymer in Solution vs. Time

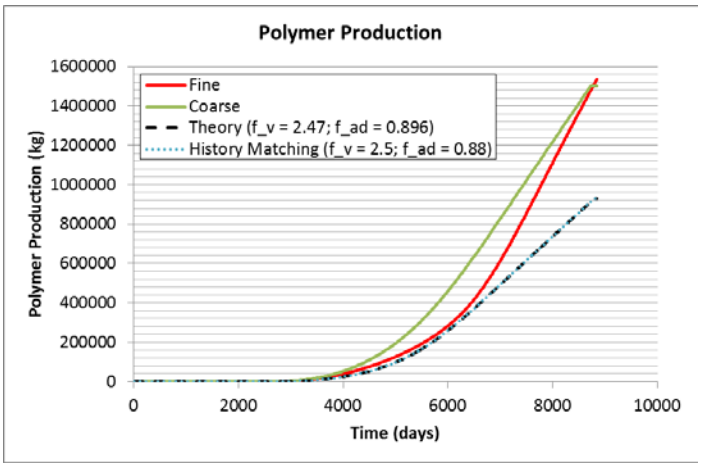
Figure 23: Simulation Results, Up-scaling Effect, Irreversible Case, 3D Generic Case



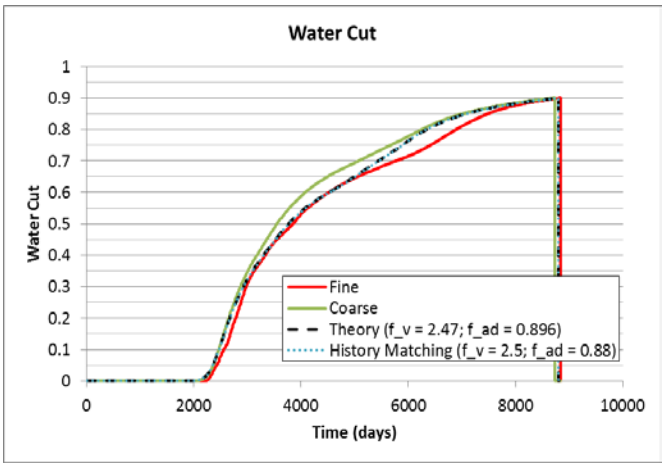
(a) Oil Recovery vs. Time



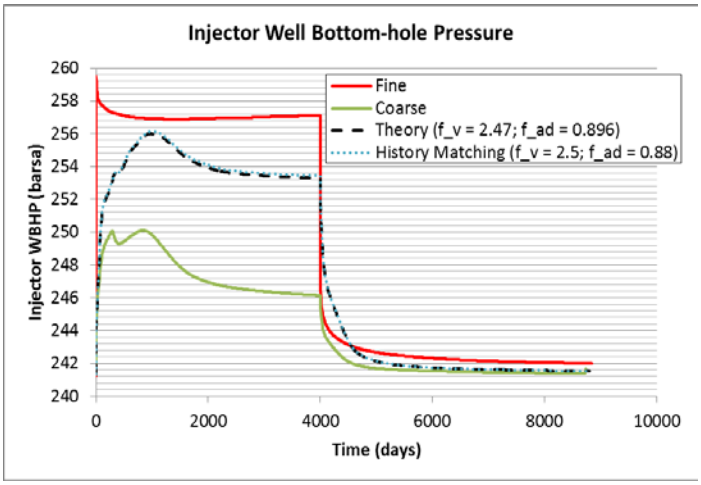
(b) Polymer Adsorption vs. Time



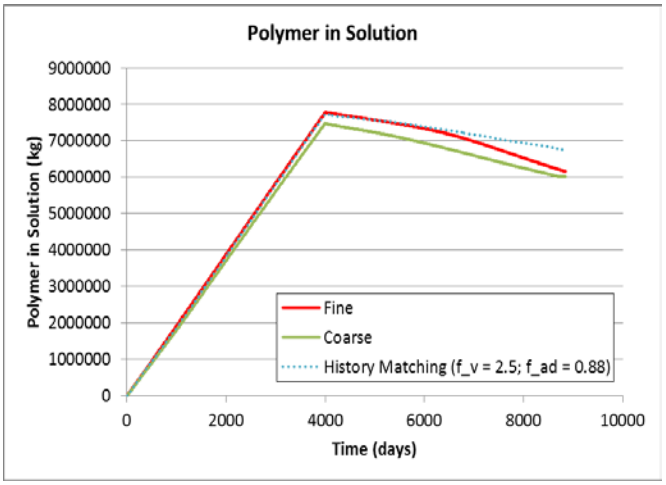
(c) Polymer Production vs. Time



(d) Water Cut vs. Time



(e) Injector Well Bottom-Hole Pressure vs. Time



(f) Polymer in Solution vs. Time

Figure 24: Simulation Results, Up-scaling Effect, Reversible Case, 3D Generic Case

7.8 Summary of Simulation Results

Table 5 and Table 6 show all the values of up-scaling factors for all cases. From the tables, we can see following characteristics.

- For all the cases with only grid size enlarged (Grid Size Effect), the values of $f_{v,GE}$ are larger than 1.0. For the cases where only heterogeneity changes (Heterogeneity Effect), the values of $f_{v,HE}$ are smaller than 1.0. When both heterogeneity effect and grid size effect are involved under up-scaling, the value of f_v is larger than 1.0 in most cases. f_v found by history matching is normally smaller than that calculated by $f_{v,HE} \cdot f_{v,GE}$.
- When only grid size effect is involved, the value of $f_{ad,GE}$ is larger than 1.0 in most irreversible cases, while it is smaller than 1.0 in most reversible cases. For heterogeneous cases, the value of $f_{ad,HE}$ is normally smaller than 1.0 no matter the case is reversible or not. However, it is hard to say the value of f_{ad} is smaller or larger than 1.0 when both heterogeneity effect and grid size effect are involved under up-scaling.
- For the homogenous cases, the value of f_v becomes smaller when a model is refined in z-direction (1D Homogeneous Case vs. 2D Homogeneous Case, and 2D Areal Homogeneous Case vs. 3D Homogeneous Case) because of gravity and vertical flow. This means that a larger value of f_v should be expected if a fine grid model is coarsened in z-direction. For the homogenous cases without desorption, the value of f_{ad} becomes smaller when a model is refined in z-direction. However, the value of f_{ad} becomes larger when a model is refined in z-direction for the homogeneous cases with desorption.

Table 5: Values of Up-scaling Factors for Homogeneous Cases

		Grid Size Effect	
		$f_v = f_{v,GE}$	$f_{ad} = f_{ad,GE}$
1D Homogeneous Case	**irreversible**	10	1.65
	reversible	6.0	0.920
2D Homogeneous Case	**irreversible**	4.0	1.10
	reversible	3.0	1.07
2D Areal Homogeneous Case	**irreversible**	5.5	1.35
	reversible	5.0	0.940
3D Homogeneous Case	**irreversible**	2.7	0.980
	reversible	2.9	0.950

Table 6: Values of Up-scaling Factors for Heterogeneous Cases

		Heterogeneity Effect		Grid Size Effect		Up-scaling in theory		Up-scaling by history matching	
		$f_{v,HE}$	$f_{ad,HE}$	$f_{v,GE}$	$f_{ad,GE}$	$f_v = f_{v,HE} \cdot f_{v,GE}$	$f_{ad} = f_{ad,HE} \cdot f_{ad,GE}$	f_v	f_{ad}
2D Layered Case	**irr.**	0.400	0.765	8.00	1.48	3.200	1.132	3.2	1.000
	rev.	0.350	1.16	7.50	0.90	2.625	1.044	2.2	1.130
3D Layered Case	**irr.**	0.680	0.820	1.50	0.97	1.020	0.9754	0.88	0.8200
	rev.	0.800	0.857	1.45	1.12	1.160	0.9598	0.98	0.9598
3D Generic Case	**irr.**	0.904	0.820	3.00	1.20	2.712	0.9840	2.2	1.050
	rev.	0.824	0.933	3.00	0.96	2.472	0.8957	2.5	0.8800

(irr. = irreversible; rev. = reversible)

Table 7 and Table 8 summarize the effect of up-scaling the polymer solution viscosity function and the polymer adsorption function on the mismatches between the fine and coarse grid results. We can see from the tables that:

- For almost all the homogeneous cases, the mismatches in water break-through time and in ultimate polymer production are reduced as well when the fine grid simulation results of ultimate oil recovery and ultimate polymer adsorption are reproduced on the coarse grid model.
- However, the tuned/up-scaled injection WBHP becomes extremely high and the mismatch in injector WBHP is enlarged in most cases. The reason is that polymer viscosity is increased as the polymer solution viscosity function is up-scaled and the no flow boundaries, unchanged size of grid blocks where the injector locates and high producer WBHP of well control lead to higher injector WBHP in these cases. As we can see from the 3D Generic Cases, the problem of extremely high injector WBHP no longer exists and the mismatch in injector WBHP is reduced because except for the increased polymer viscosity, other factors which lead to higher injector WBHP no longer arise in the 3D Generic Cases.
- The mismatches in water break-through time and in ultimate polymer production is enlarged in some heterogeneous cases, which means that heterogeneity may cause difficulties to apply the up-scaling method introduced in this thesis in some cases.
- Different from other cases, few improvements are made on coarse grid simulation results by applying the up-scaling method for 3D Layered Case. The reason has been discussed in Section 7.6.

- Simulation results for 3D Generic Case show some differences compared to the other cases. They have been analyzed in detail in Section 7.7.
- Generally, to up-scale the polymer solution viscosity function and the adsorption function may reduce some mismatches between the fine and coarse grid results caused by numerical dispersion.

Table 7: Summary of Mismatches between Fine and Coarse Grid Model, Homogeneous Cases

		Ultimate Oil Recovery	Ultimate Polymer Adsorption	Water Break-Through Time	Ultimate Polymer Production	Injector WBHP
1D Homogeneous Case	**irreversible**	Match	Match	Reduced	Reduced	Enlarged
	reversible	Match	Match	Reduced	Reduced	Enlarged
2D Homogeneous Case	**irreversible**	Match	Match	Reduced	Reduced	Enlarged
	reversible	Match	Match	Reduced	Reduced	Enlarged
2D Areal Homogeneous Case	**irreversible**	Match	Match	Reduced	Reduced	Enlarged
	reversible	Match	Match	-	Reduced	Enlarged
3D Homogeneous Case	**irreversible**	Match	Match	Reduced	Reduced	Enlarged
	reversible	Match	Match	Reduced	Reduced	Enlarged

(Reduced = mismatch reduced after tuning; Enlarged = mismatch enlarged after tuning)

Table 8: Summary of Mismatches between Fine and Coarse Grid Model, Heterogeneous Cases

		2D Layered Case		3D Layered Case		3D Generic Case	
		Irreversible	**Reversible**	**Irreversible**	**Reversible**	**Irreversible**	**Reversible**
Heterogeneity Effect	**Ultimate Oil Recovery**	Match	Match	Match	Match	Match	Match
	Ultimate Polymer Adsorption	Match	Match	Match	Match	Match	Match
	Water Break-Through Time	Reduced	-	Reduced	-	-	-
	Ultimate Polymer Production	Enlarged	-	Reduced	Reduced	Reduced	Reduced
	Injector WBHP	Enlarged	Enlarged	Enlarged	Enlarged	-	-
Grid Size Effect	**Ultimate Oil Recovery**	Match	Match	Match	Match	Match	Match
	Ultimate Polymer Adsorption	Match	Match	Match	Match	Match	Match
	Water Break-Through Time	Reduced	Reduced	Reduced	Reduced	-	-
	Ultimate Polymer Production	Reduced	Reduced	Reduced	Reduced	Enlarged	Enlarged
	Injector WBHP	Enlarged	Enlarged	Enlarged	Enlarged	Reduced	Reduced
Up-scaling	**Ultimate Oil Recovery**	Match	Match	Match	Match	Match	Match
	Ultimate Polymer Adsorption	Match	Match	Match	Match	Match	Match
	Water Break-Through Time	Reduced	Reduced	Enlarged	-	-	-
	Ultimate Polymer Production	Reduced	Reduced	Enlarged	-	Enlarged	Enlarged
	Injector WBHP	Enlarged	Enlarged	Reduced	-	Reduced	Reduced
(Reduced = mismatch reduced after tuning; Enlarged = mismatch enlarged after tuning; - = no big change)							

8 Discussion and Suggestion for Further Studies

Because of numerical dispersion, the polymer concentration smears out on an up-scaled coarse model, leading to smaller peak value of polymer solution viscosity and peak value of polymer adsorption on a coarse model than on a fine model. Therefore, two up-scaling factors for the polymer solution viscosity function (f_v) and for the polymer adsorption function (f_{ad}) are introduced in this study, and the impact of up-scaling these two functions is investigated on different reservoir models.

The simulation results prove that this up-scaling method can reproduces the fine grid simulation results of oil recovery and of ultimate polymer adsorption on a coarse model. Moreover, the mismatches in water break-through time and in ultimate polymer production are also reduced in most cases after these two functions are up-scaled. However, extremely high tuned injector WBHP in most cases is a problem for this method. Factors like no flow boundaries, unchanged size of grid block where injector locates and high producer WBHP of well control can lead to this kind of high WBHP after up-scaling. As we can see in the 3D generic case, high tuned injector WBHP no longer exists on the real field size model. Some methods such as local grid refinement can be used to treat high WBHP caused by up-scaling, but they are not involved in this study and should be considered in further studies.

The impact of increasing flow dimension is investigated. When a dimension is added in z-direction, the effects of gravity and of vertical flow are involved. When a dimension is added in y-direction, the effect of areal flow is involved. For both of these changes, increasing dimension makes the value of f_v smaller for both irreversible and reversible cases, the value of f_{ad} smaller for the irreversible case and larger for the reversible case. This means that increasing dimension will normally reduce the contrasts in oil recovery and in polymer adsorption between the fine grid model and the coarse grid model.

In order to investigate the impact of heterogeneity, the heterogeneity effect and the grid size effect are considered separately in this study. All $f_{v,HE}$ are found to be smaller than 1.0 and all $f_{v,GE}$ larger than 1.0. This indicates that the heterogeneity effect acts opposite to the grid size effect and introducing heterogeneity into a model will reduce the oil recovery contrast between the fine and the coarse models. However, the heterogeneity effect on the polymer adsorption contrast varies from case to case, so it is still unclear how the heterogeneity will affect the polymer adsorption contrast. Polymer adsorption is highly dependent on the rock type. More polymers will travel in a high permeable and high porous rock and polymer

adsorption will be consequently high in this kind of rock. Thus, different polymer adsorption up-scaling factors, f_{ad}, should be subjected to different rock types. This is beyond the scope of this thesis and should be considered in further studies.

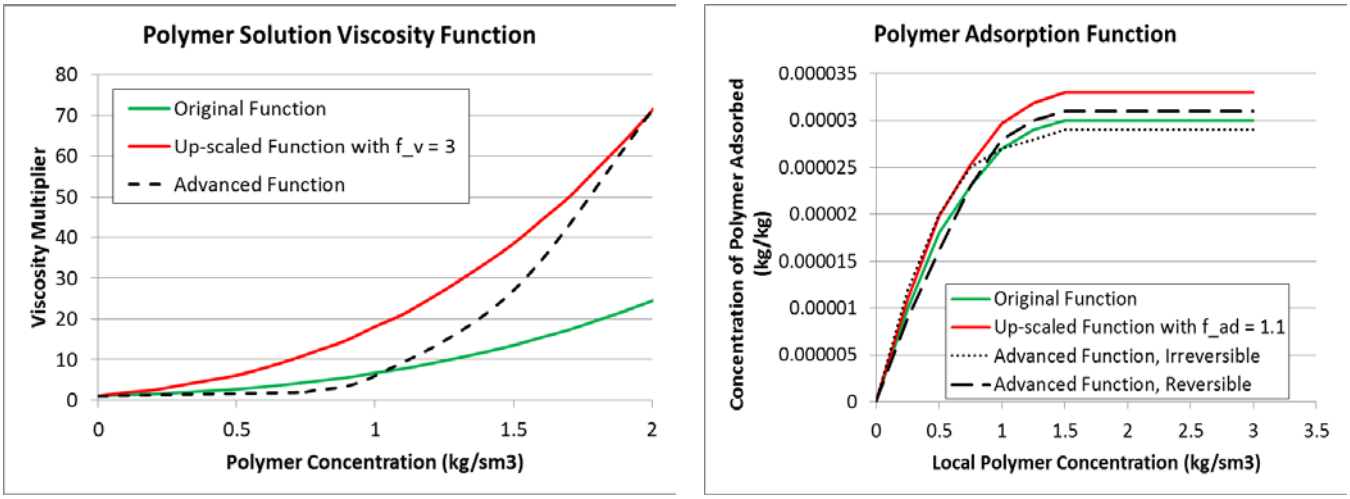
In this thesis, the polymer solution viscosity function and the polymer adsorption function are simply up-scaled by factors f_v and f_{ad}, respectively, but according to Figure 12 - Figure 15, the up-scaled polymer solution viscosity should be lower than the original one at low concentration and higher at high concentration; the up-scaled polymer adsorption should be higher than the original one at low concentration and lower at high concentration for the irreversible case; the up-scaled polymer adsorption should be lower than the original one at low concentration and higher at high concentration for the reversible case. Therefore, more advanced functions shown in Figure 25 should be used in further studies. As the shape of the up-scaled function changes, more coefficients have to be determined by history matching or by equations. A method to determine the shape of the polymer solution viscosity function is introduced in an additional study attached in Appendix E: Impact of Shape of Up-scaled Polymer Solution Viscosity Function on Up-scaling Polymer Flooding.

As the simulation results for the 3D layered case show, almost none of the accuracies in water break-through time, in ultimate polymer production and in injector WBHP is improved after up-scaling the polymer solution viscosity and the adsorption functions. The reason may be because of different boundary conditions between the fine and the coarse grid models. This case shows that the impact of up-scaling the two functions can easily be affected by other factors such as near well conditions.

The main aim of this thesis is to show that the polymer solution viscosity function and the polymer adsorption function need to be up-scaled for polymer flooding under up-scaling process and that these two functions can be up-scaled by a simple method. For this aim, this thesis has successfully proved that to up-scale these two functions may generally reduce the mismatch between the fine and coarse grid results caused by numerical dispersion. One thing which should be noticed is that this up-scaling methodology can only improve the polymer results on the coarse models when the dominant displacing mechanism is polymer flooding, because only polymer properties are up-scaled in this study. When the dominant displacing mechanism is water flooding, to up-scale polymer solution viscosity and adsorption will make no significant improvement on the coarse grid results.

Polymer properties considered in this thesis are limited in two functions. Other properties like Non-Newtonian effects and permeability reduction are not involved in this thesis. They may affect the values of f_v and f_{ad}. Besides, different polymer solution viscosity functions and adsorption functions may lead to different polymer behaviors and may produce different results. Moreover, the oil viscosity is only 6.4 cp which is far lower than that for a heavy oil case where the oil viscosity can be over 100 cp. Different from the favorable mobility ratio used in this thesis, the mobility ratio may not be favorable in a real heavy oil reservoir. Unfavorable mobility ratio may have an impact on up-scaling polymer properties. None of these factors mentioned above is investigated in this thesis and they should be considered in a thorough study in the future.

All the models used in this study are synthetic and simple. However, a real field model is much more complex in terms of geology such as faults, fractures and sealed layers. Therefore, tests of applying this up-scaling method should be done on one or more real field models in further studies.



(a) Polymer Solution Viscosity Functions (b) Polymer Adsorption Functions

Figure 25: Examples of Possible Shapes of Advanced Functions

9 Conclusion

This study provides a method and summarizes the simulation results for up-scaling the polymer solution viscosity function and the polymer adsorption function for polymer flooding. Although the method used here is not a robust solution to reproduce fine grid results on a coarse grid model, the study proves the idea that the mismatches between fine and coarse grid results may be reduced by up-scaling the polymer solution viscosity function and the polymer adsorption function.

By up-scaling the polymer solution viscosity function, the simulated history of oil recovery can be tuned without touching the relative permeability curves. For oil/water flow, the relative permeability curves have to be up-scaled during up-scaling and sometimes pseudo relative permeabilities need to be generated. To up-scale the relative permeability curves will cause a lot of complexities and computational efforts. Therefore, it is an advantage that the relative permeability curves are not changed by the method introduced in this thesis. As the simulation results show, the values of f_v are found to be larger than 1.0 for most cases. It indicates that ultimate oil recovery is generally underestimated on a coarse model without up-scaled polymer solution viscosity, so larger viscosity multipliers should be applied on the coarse grid model in order to increase the accuracy of predicting the behavior of polymer flooding.

Because the mismatch in polymer adsorption is still large after only polymer solution viscosity function up-scaled, the polymer adsorption function has also to be up-scaled as Lee [2] did. As the simulation results show, the mismatches in ultimate polymer adsorption and production are reduced using this up-scaling method. Thus, the accuracy of predicting polymer loss by doing simulation on a coarse model for a polymer flooding project may be improved by simply up-scaling the polymer adsorption function. However, the values of f_{ad} vary from case to case. It, therefore, is hard to predict the polymer adsorption is over- or underestimated on a coarse model without up-scaling the polymer viscosity and adsorption functions, and it is still unclear that larger or smaller polymer adsorption concentration should be applied on coarse grid model for up-scaling.

When the flow dimension of a reservoir model is increased, the contrasts in oil recovery and in polymer adsorption between the fine grid model and the coarse grid model will normally be reduced.

An increase in heterogeneity may reduce the contrast in oil recovery, but its impact on the contrast in polymer adsorption is not clear. High heterogeneity may bring difficulties to up-scaling those two functions mentioned in this thesis and lead to wrong prediction of polymer behavior. Thus, more advanced up-scaling methods, as discussed in Section 8, should be applied for highly heterogeneous reservoir models.

Some limitations of using the up-scaling method introduced in this thesis are summarized as follows.

1. Extremely high injector WBHP caused by up-scaled polymer solution viscosity may appear in some particular cases, but his problem may be solved by carefully up-scaling near well area.
2. A change of boundary condition caused by a change of grid size during up-scaling process may make the up-scaling method inapplicable.
3. High heterogeneity may cause difficulties to apply the up-scaling method.

The applicability of up-scaling the polymer solution viscosity function and the polymer adsorption function in a real project of up-scaling polymer flooding will remain uncertain until it is tested in thorough study which includes all the aspect of polymer properties (Non-Newtonian effect, permeability reduction …) and all the other affecting factors (well locations, boundary conditions, local grid refinement …). In addition, the tests should be done on real field models instead of synthetic models.

Reference

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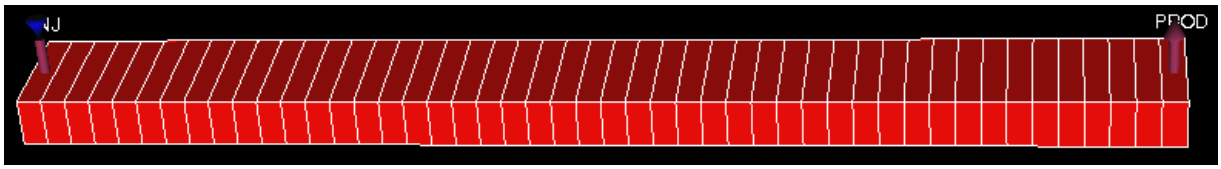
Appendices

Appendix A: Literature Review

Table 9: List of Literature Review

Year	Title	Author(s)	Type	Contribution to this thesis
1942	*Mechanism of fluid displacement in sand*	Buckley, S.E. Leverett, M.	Journal Article	Concept of Buckley-Leverett theory for fractional flow
1972	*Inaccessible Pore Volume in Polymer Flooding*	DAWSON, R. LANTZ, R.B.	Journal Article	Concept of inaccessible pore volume, and its effect
1989	*Enhanced oil recovery*	Lake, L.W.	Book	Overview of concept of polymer flooding, polymer properties, fractional flow theory for polymer flooding
1999	*An analysis of dynamic pseudo-relative permeability methods for oil-water flows*	Barker, J.W Dupouy, P.	Journal Article	Properties and limitations of six widely used dynamic pseudo-relative permeability methods: Kyte and Berry's, Pore Volume Weighted, Stone's, Total Mobility, Quasi-Steady State, and Weighted Relative Permeability Methods
2006	*Influence of relative permeability on the stability characteristics of immiscible flow in porous media*	Riaz, A. Tchelepi, H.A.	Journal Article	Definitions of end point mobility ratio, total mobility and shock mobility ratio; criteria for stable displacing front
2007	*Modelling of multiscale structures in flow simulations for petroleum reservoirs*	Aarnes, J.E Kippe, V. Lie, K.-A. Rustad, A.B.	Book Section	Different model scales, usage of up-scaling, and approaches of single- and multi-phase up-scaling
2010	*Modern Chemical Enhanced Oil Recovery: Theory and Practice*	Sheng, J.	Book	Overview of concept of polymer flooding, polymer properties, fractional flow theory for polymer flooding
2012	*Viscous Fingering/Unstable Displacement*	Kippe, V. Zadeh, A.M.	Memo	the criteria of stable displacing front, the effect of grid size on the displacing front, some samples of unstable displacing front simulated in 2D model
2013	*Upscaling polymer flooding in heterogeneous reservoirs*	Lee, J.	MSc Thesis	Up-scaling polymer flooding by the pore volume weighted method for pseudo functions and the multiplication factor method for adsorption.

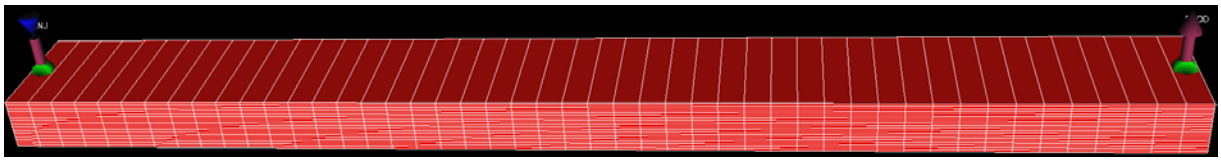
Appendix B: Figures of Simulation Models



(a) Fine Grid Model (Grid Block Size = 20m*100m*40m)

(b) Coarse Grid Model (Grid Block Size = 180m*100m*40m)

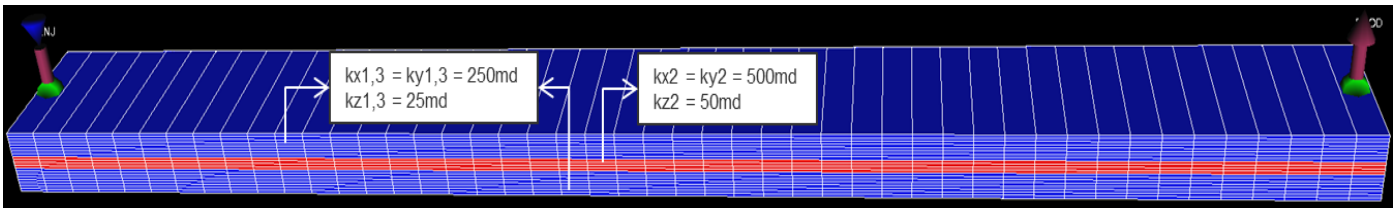
Figure 26: Simulation Models for 1D Homogeneous Case



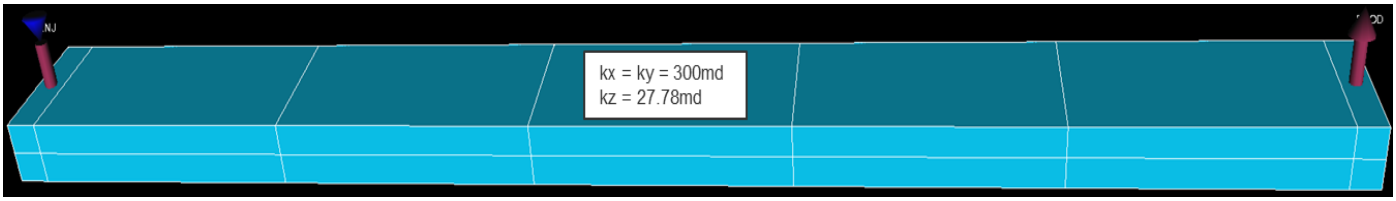
(a) Fine Grid Model (Grid Block Size = 20m*100m*2m)

(b) Coarse Grid Model (Grid Block Size = 180m*100m*2m)

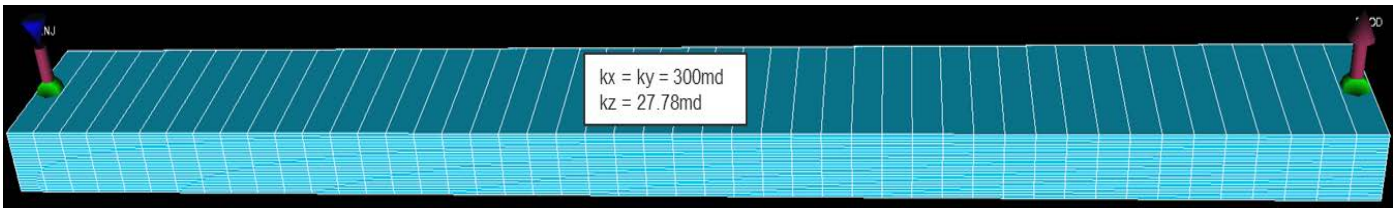
Figure 27: Simulation Models for 2D Homogeneous Case



(a) Fine Grid Model (Grid Block Size = 20m*100m*2m)

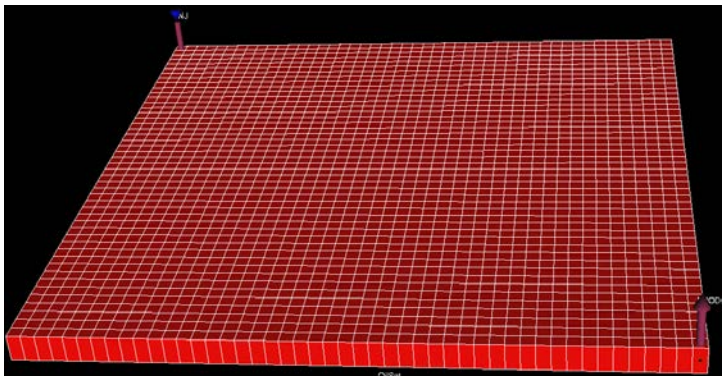


(b) Up-scaled/Coarse Grid Model (Grid Block Size = 180m*100m*20m)

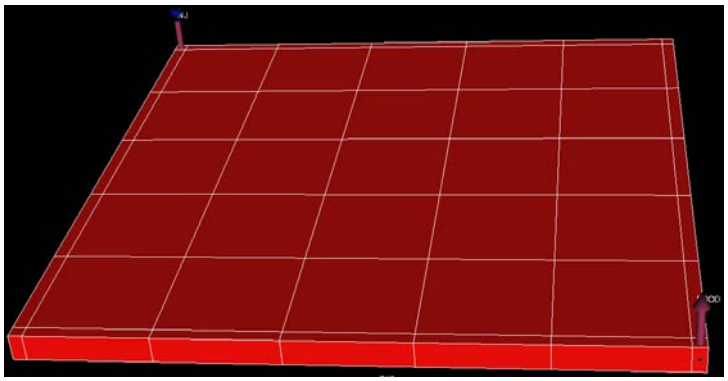


(c) Down-scaled/Refined Model (Grid Block Size = 20m*100m*2m)

Figure 28: Simulation Models for 2D Layered Case

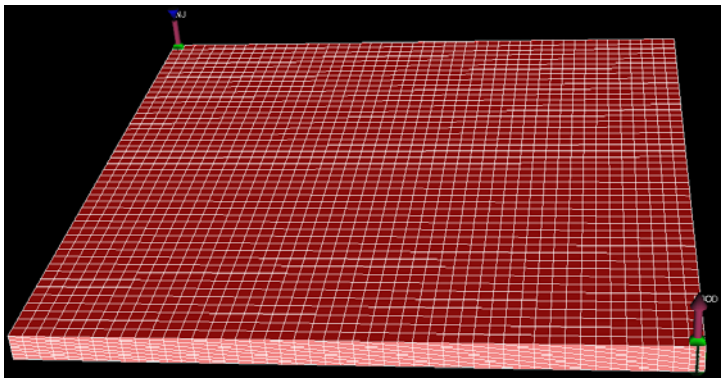


(a) Fine Grid Model (Grid Block Size = 20m*20m*40m)

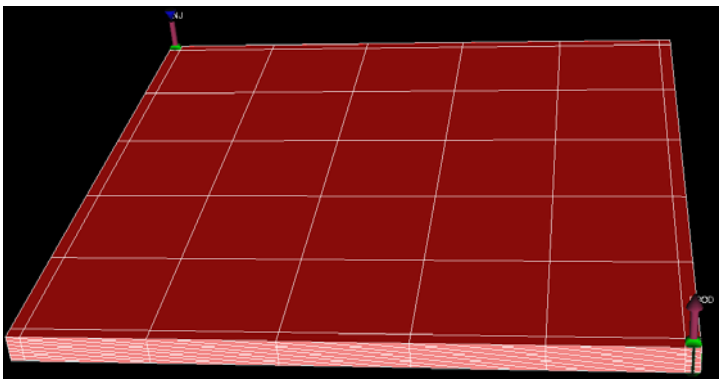


(b) Coarse Grid Model (Grid Block Size = 180m*180m*40m)

Figure 29: Simulation Models for 2D Areal Homogeneous Case

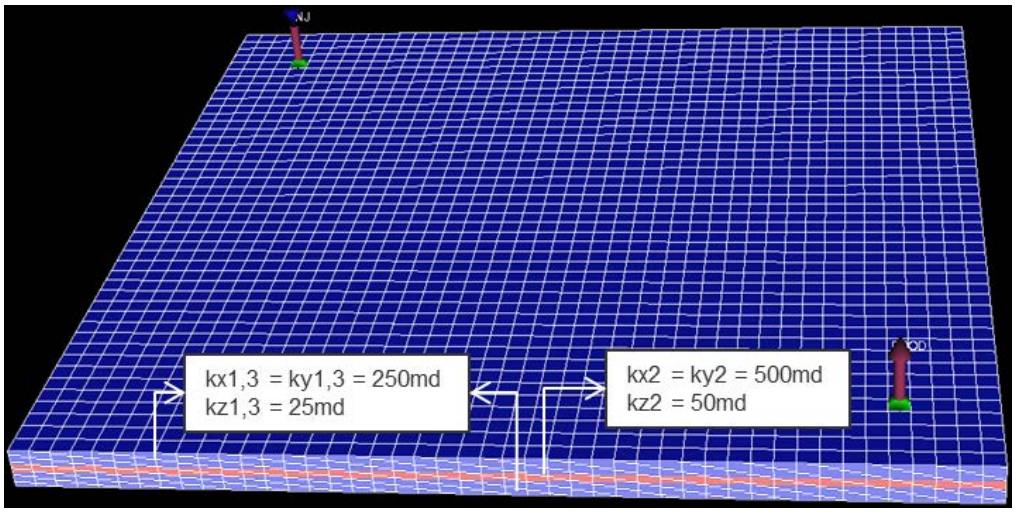


(a) Fine Grid Model (Grid Block Size = 20m*20m*2m)

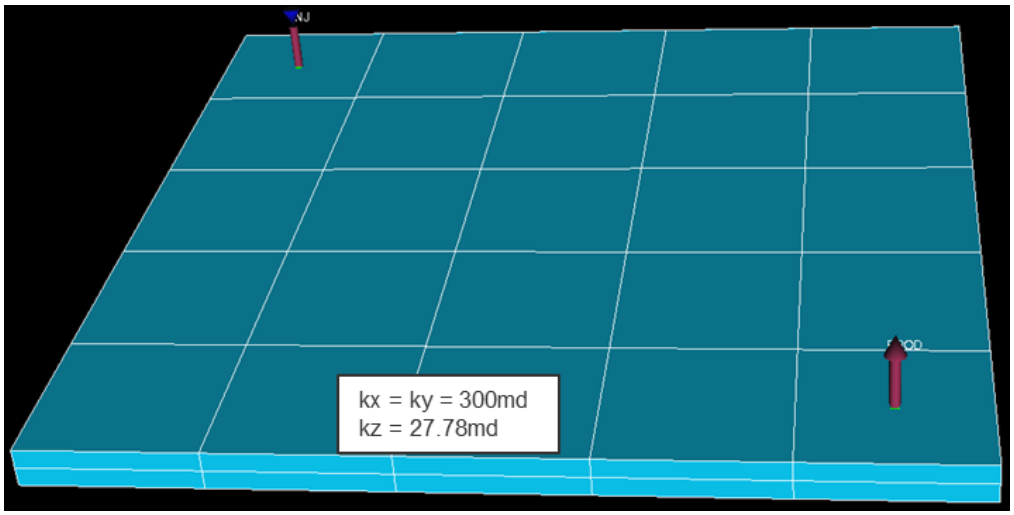


(b) Coarse Grid Model (Grid Block Size = 180m*180m*2m)

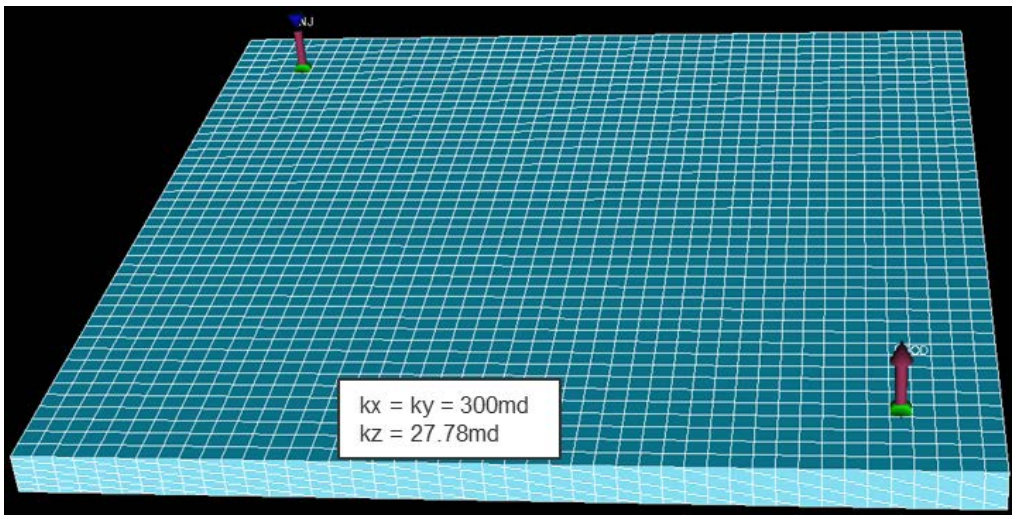
Figure 30: Simulation Models for 3D Homogeneous Case



(a) Fine Grid Model (Grid Block Size = 20m*20m*2m)



(b) Up-scaled/Coarse Grid Model (Grid Block Size = 180m*180m*20m)



(c) Down-scaled/Refined Model (Grid Block Size = 20m*20m*2m)

Figure 31: Simulation Models for 3D Layered Case

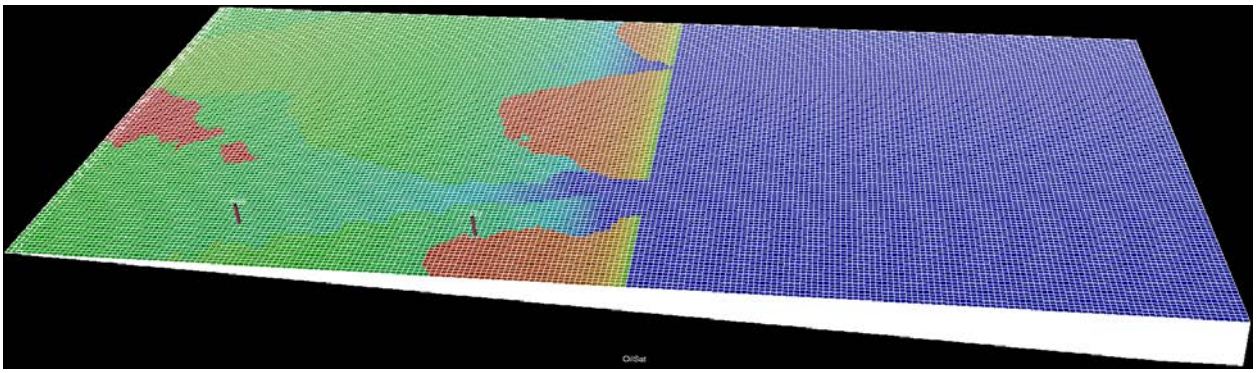


Figure 32: Geometry of Models for 3D Generic Case

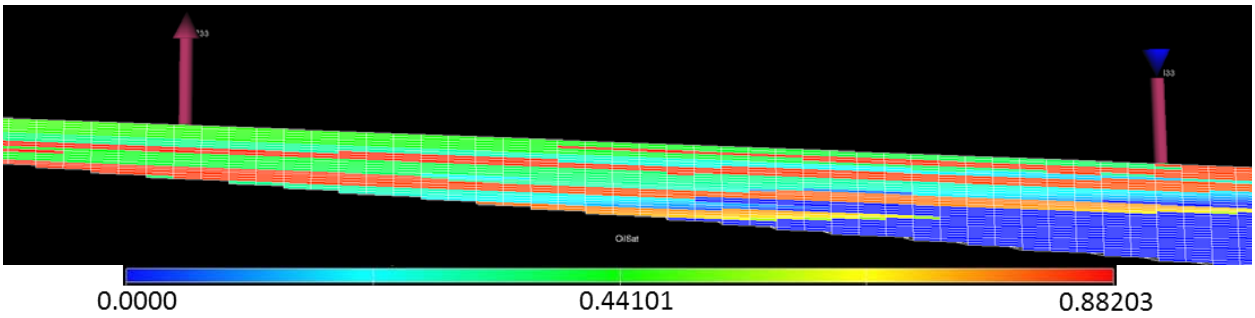
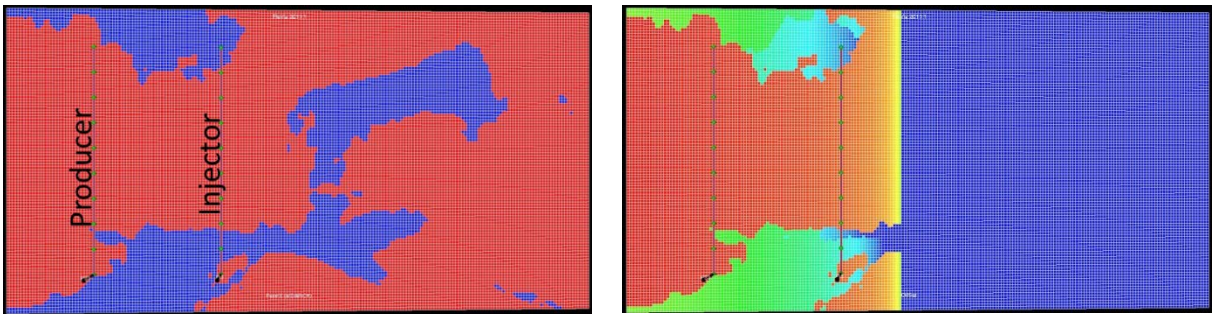
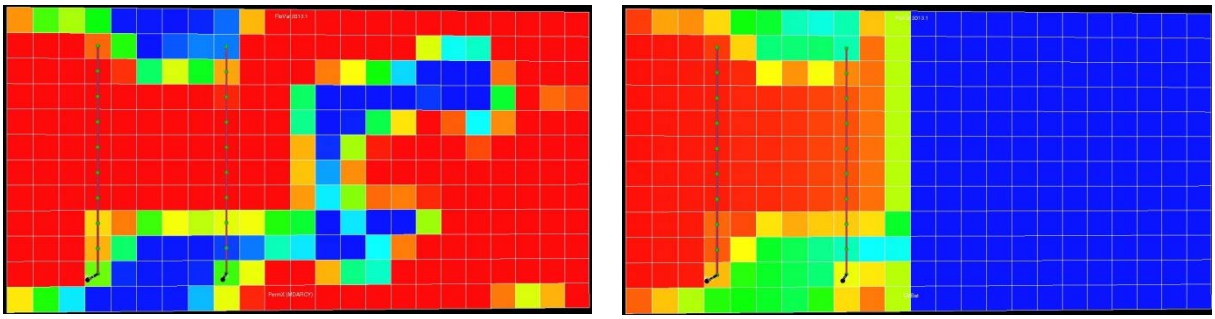


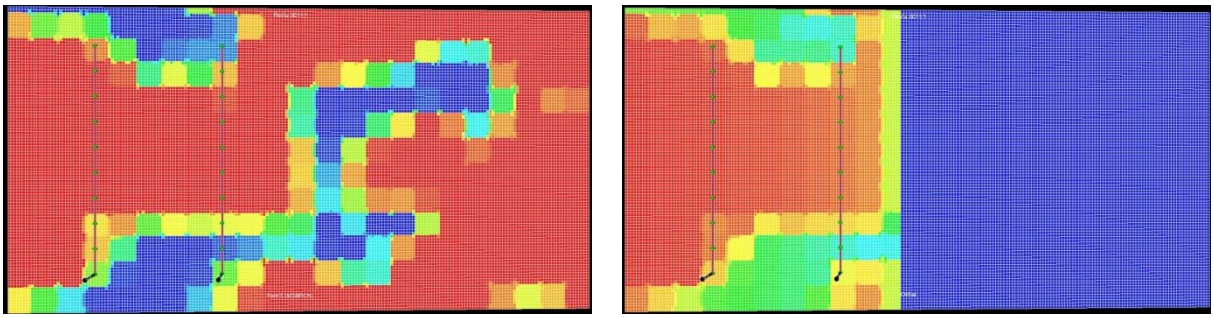
Figure 33: Initial Oil Saturation (Side View), Fine Grid Model, 3D Generic Case



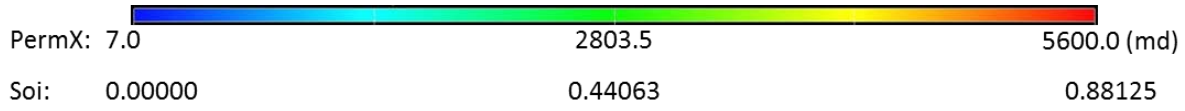
Fine Grid Model (Model HE_20) (20m*20m)



Up-scaled/Coarse Grid Model (Model 180) (180m*180m)



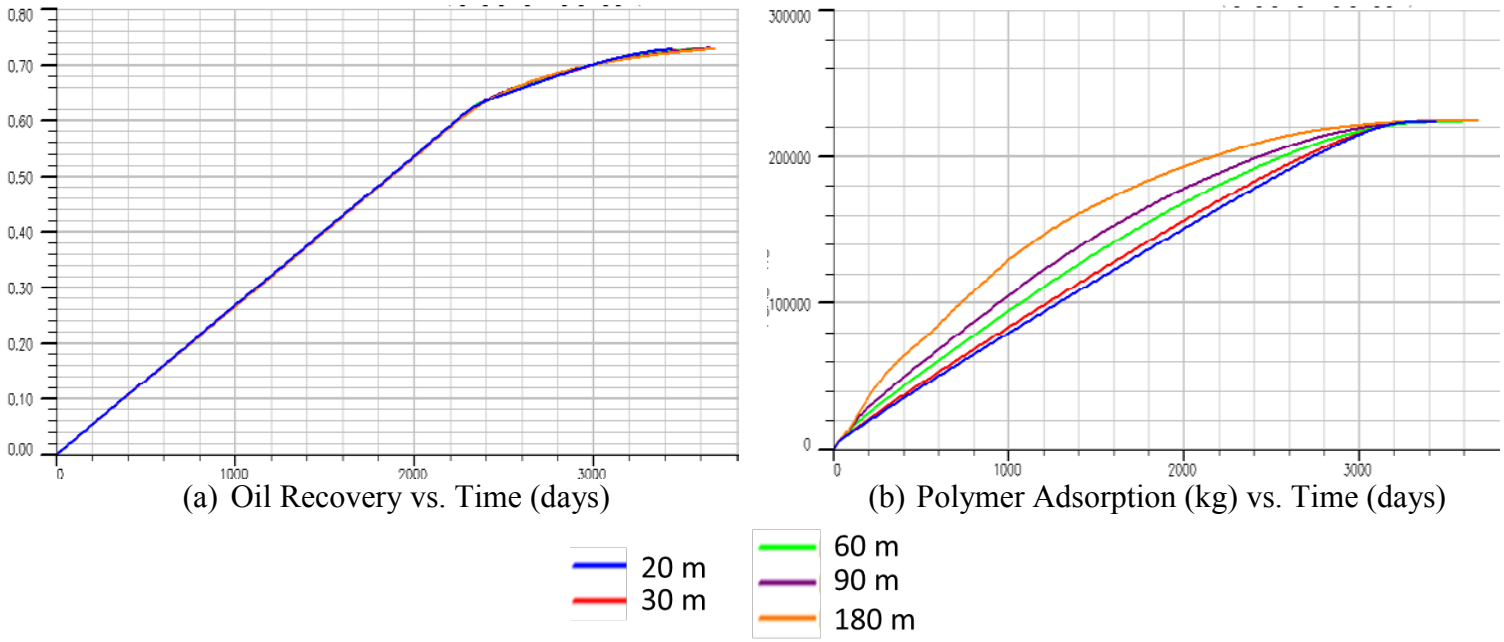
Down-scaled/Refined Model (Model GE_20) (20m*20m)



(a) Permeability in x-direction (PermX) (b) Initial Oil Saturation (Soi)

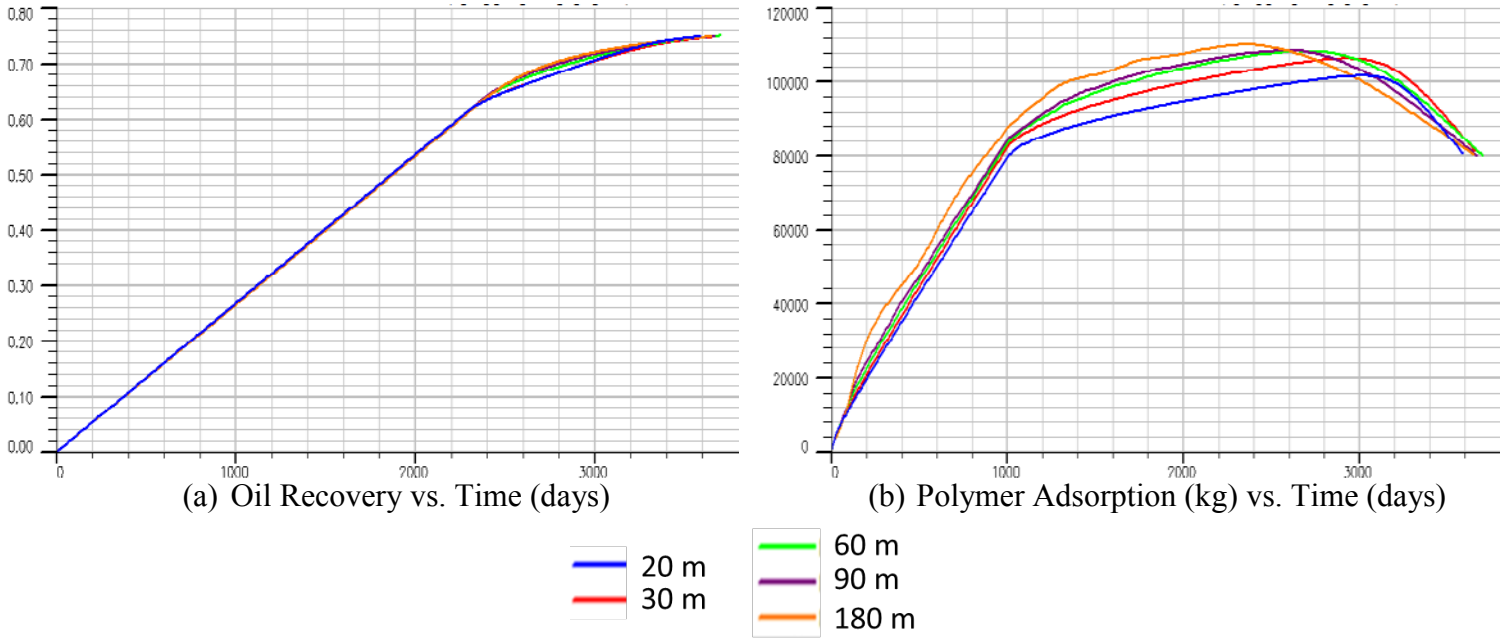
Figure 34: PermX and Soi Distributions, Layer 5, 3D Generic Case

Appendix C: Simulation Results



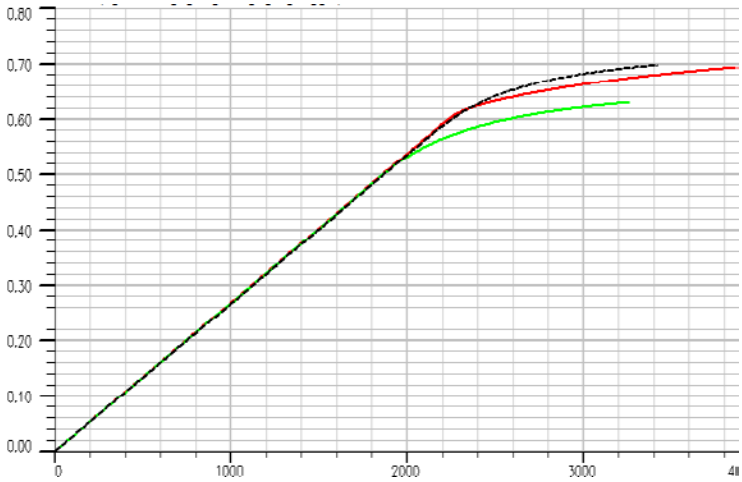
(a) Oil Recovery vs. Time (days) (b) Polymer Adsorption (kg) vs. Time (days)

Figure 35: Tuned Simulation Results, Irreversible Case, 1D Homogeneous Case

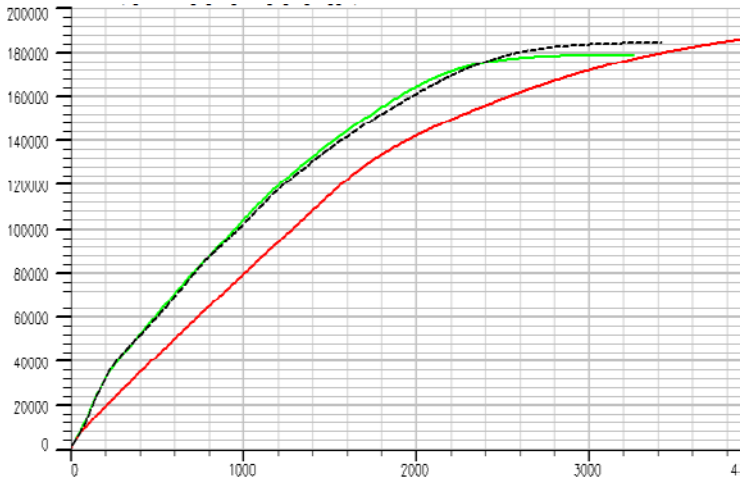


(a) Oil Recovery vs. Time (days) (b) Polymer Adsorption (kg) vs. Time (days)

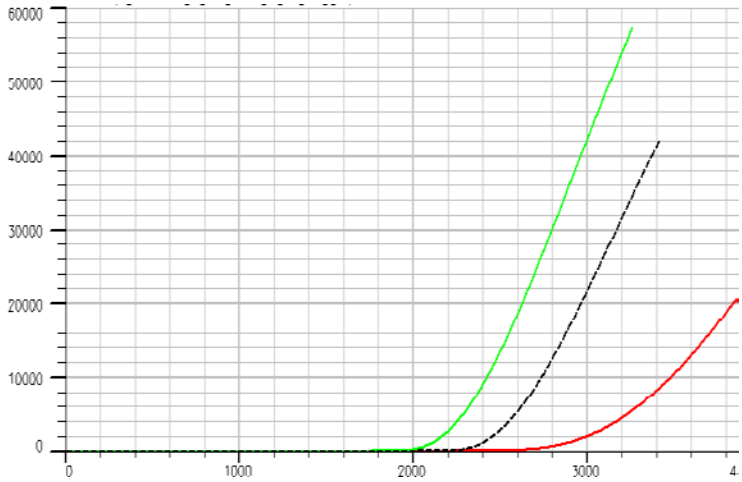
Figure 36: Tuned Simulation Results, Reversible Case, 1D Homogeneous Case



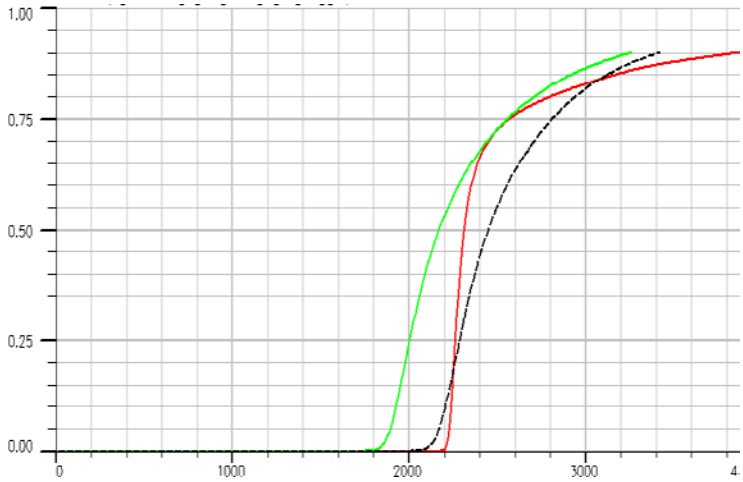
(a) Oil Recovery vs. Time (days)



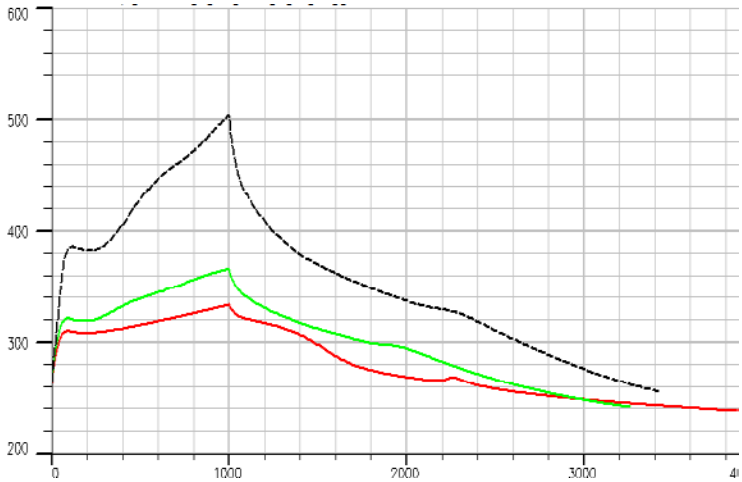
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)

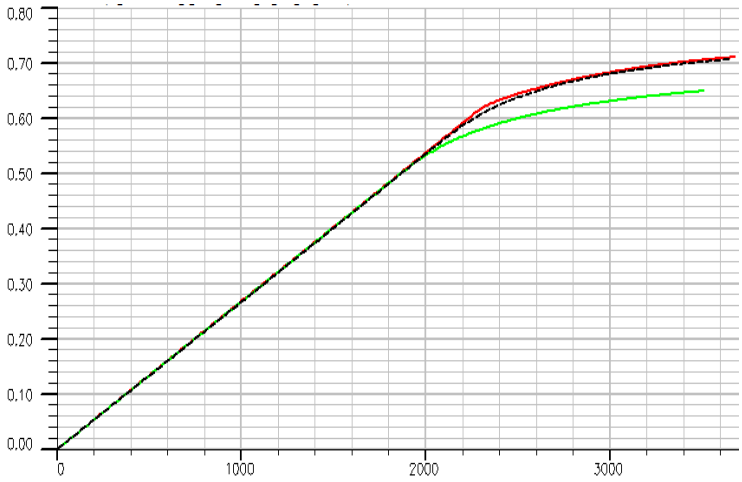


(d) Water Cut vs. Time (days)

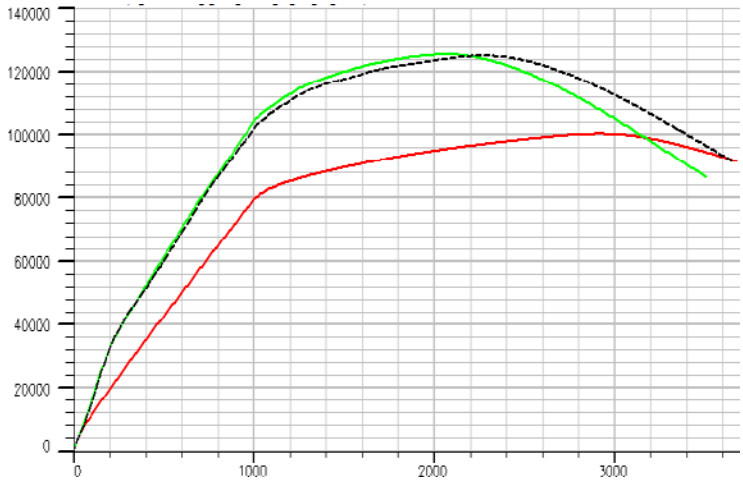


(e) Injector WBHP (barsa) vs. Time (days)

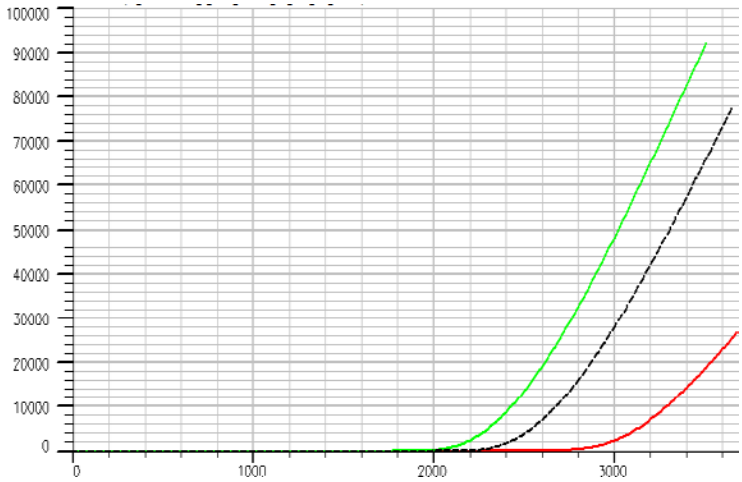
Figure 37: Simulation Results, Irreversible Case, 2D Homogeneous Case



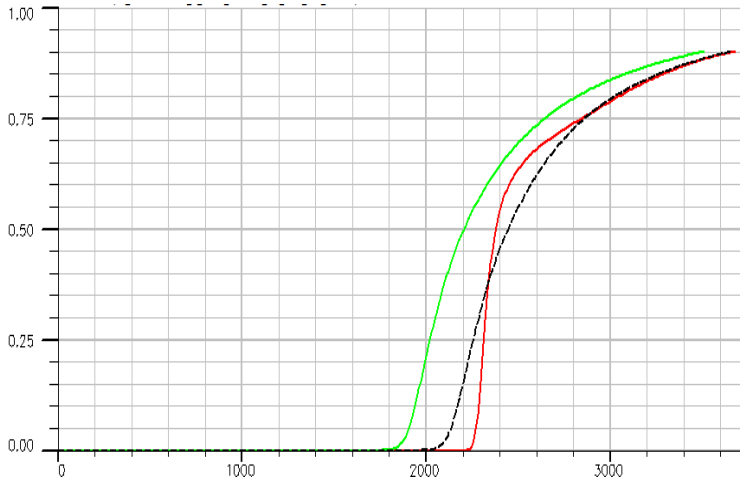
(a) Oil Recovery vs. Time (days)



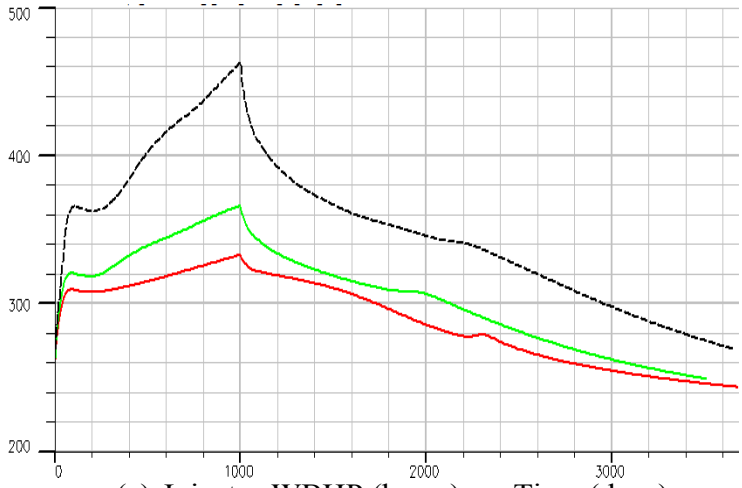
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



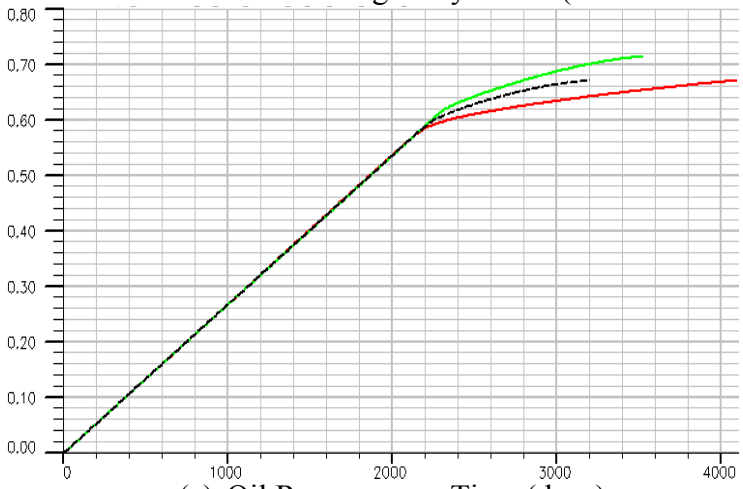
(d) Water Cut vs. Time (days)



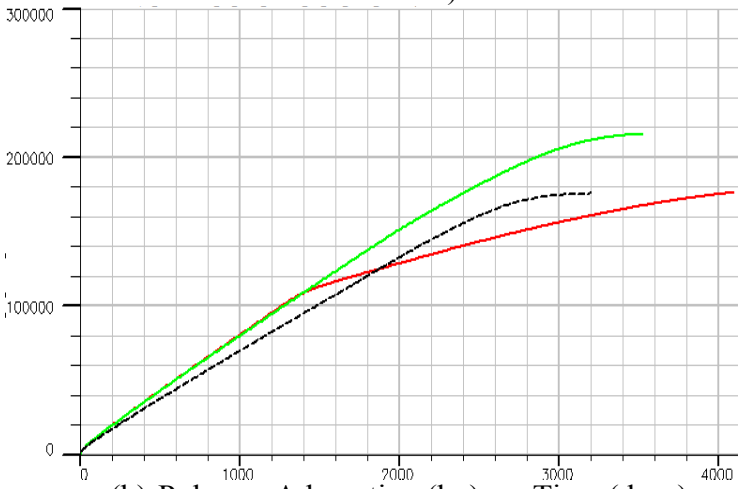
(e) Injector WBHP (barsa) vs. Time (days)

Figure 38: Simulation Results, Reversible Case, 2D Homogeneous Case

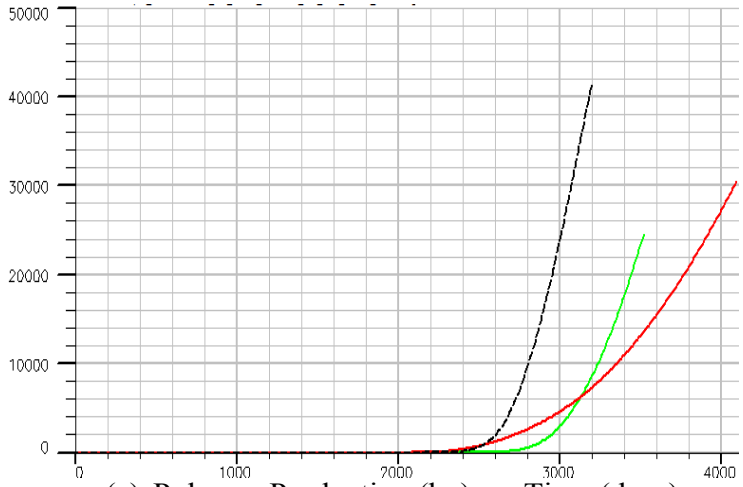
Heterogeneity Effect (Fine Grid Model vs. Down-scaled/Refined Model)



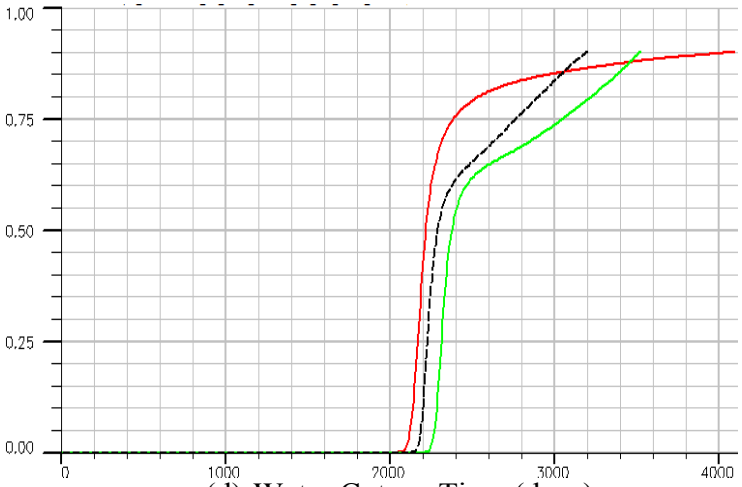
(a) Oil Recovery vs. Time (days)



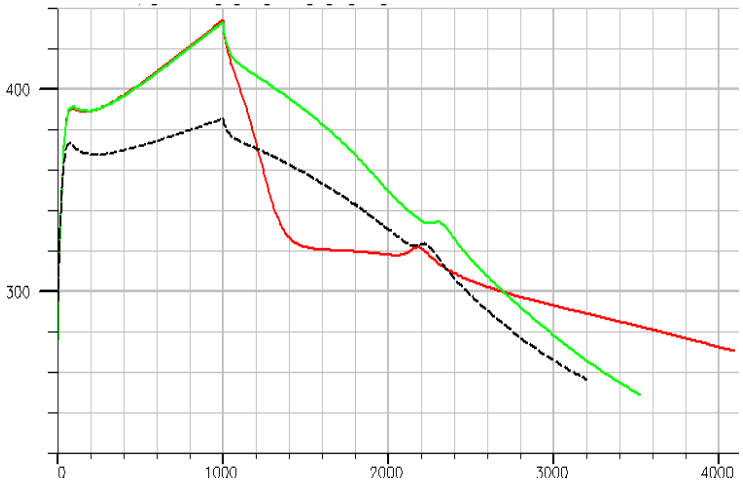
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



(d) Water Cut vs. Time (days)



(e) Injector WBHP (barsa) vs. Time (days)

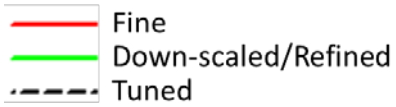
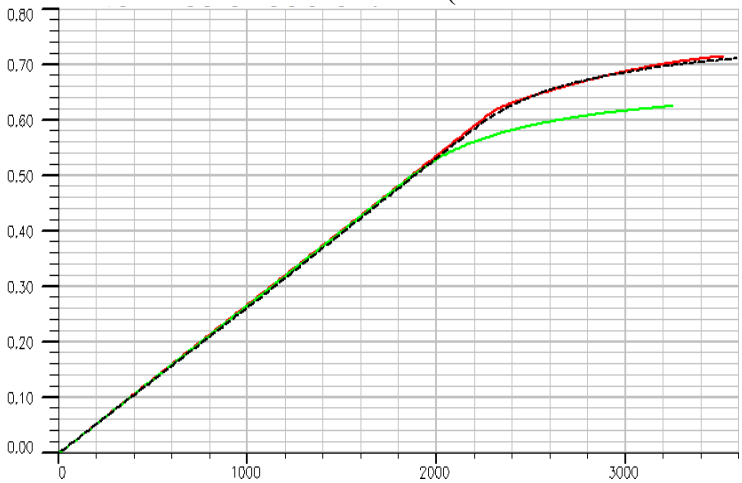
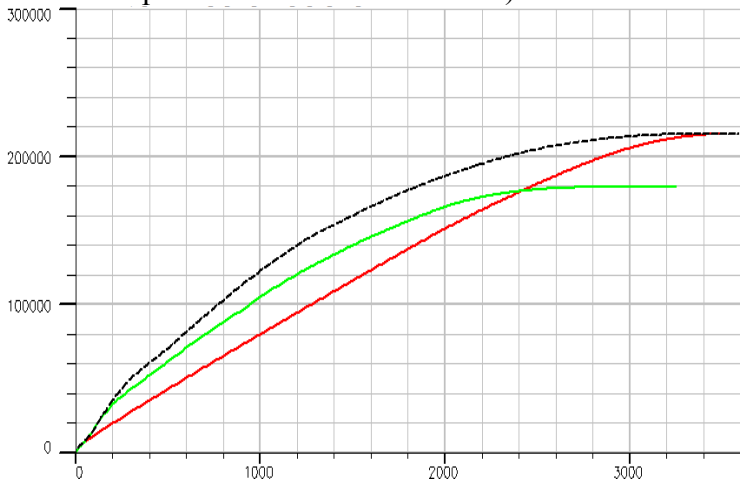


Figure 39: Simulation Results, Heterogeneity Effect, Irreversible Case, 2D Layered Case

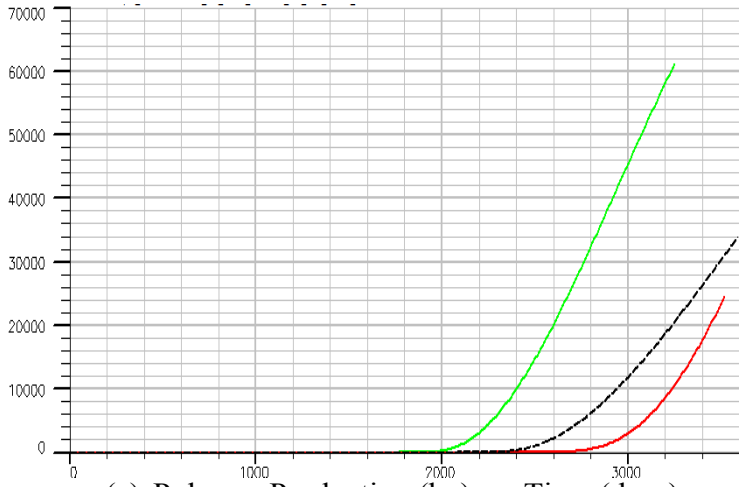
Grid Size Effect (Down-scaled/Refined Model vs. Up-scaled/Coarse Grid Model)



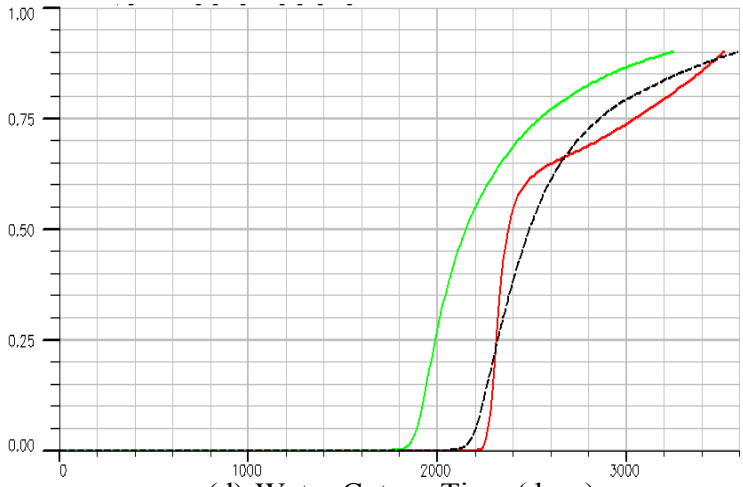
(a) Oil Recovery vs. Time (days)



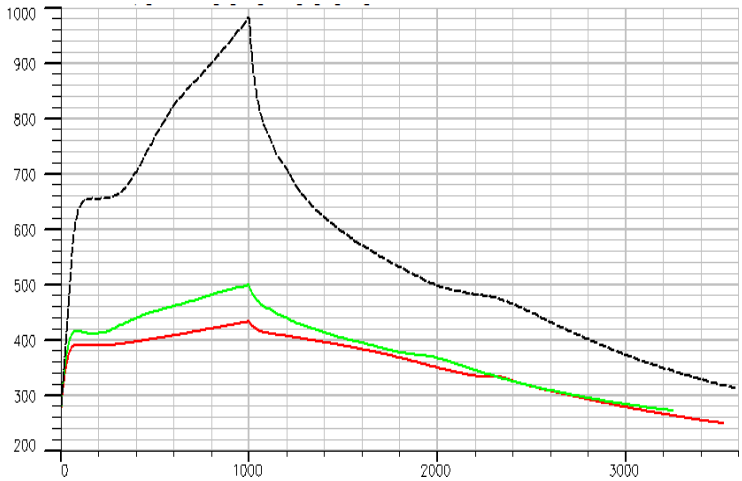
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



(d) Water Cut vs. Time (days)



(e) Injector WBHP (barsa) vs. Time (days)

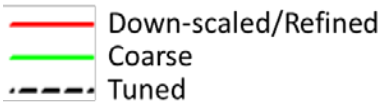


Figure 40: Simulation Results, Grid Size Effect, Irreversible Case, 2D Layered Case

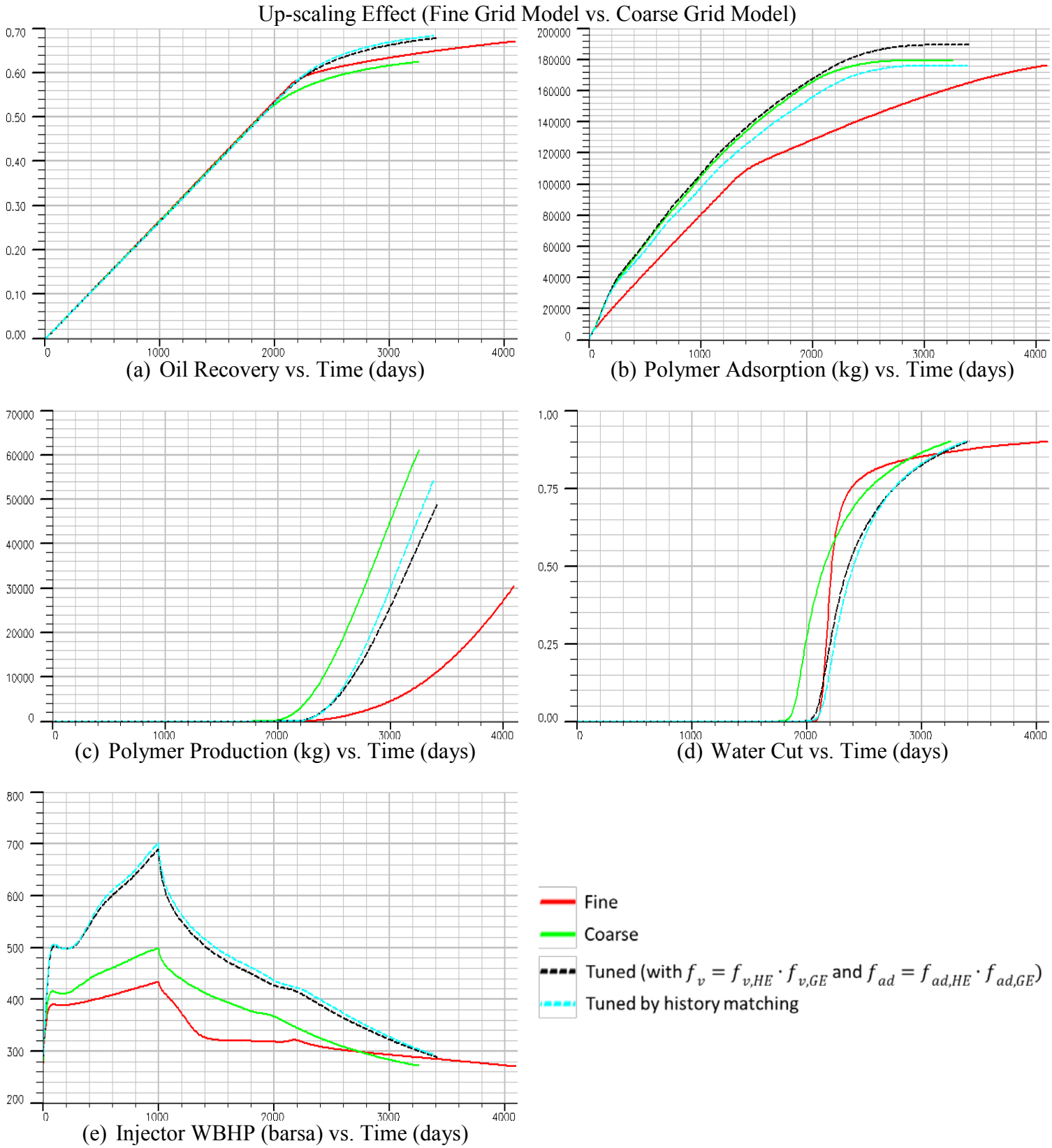
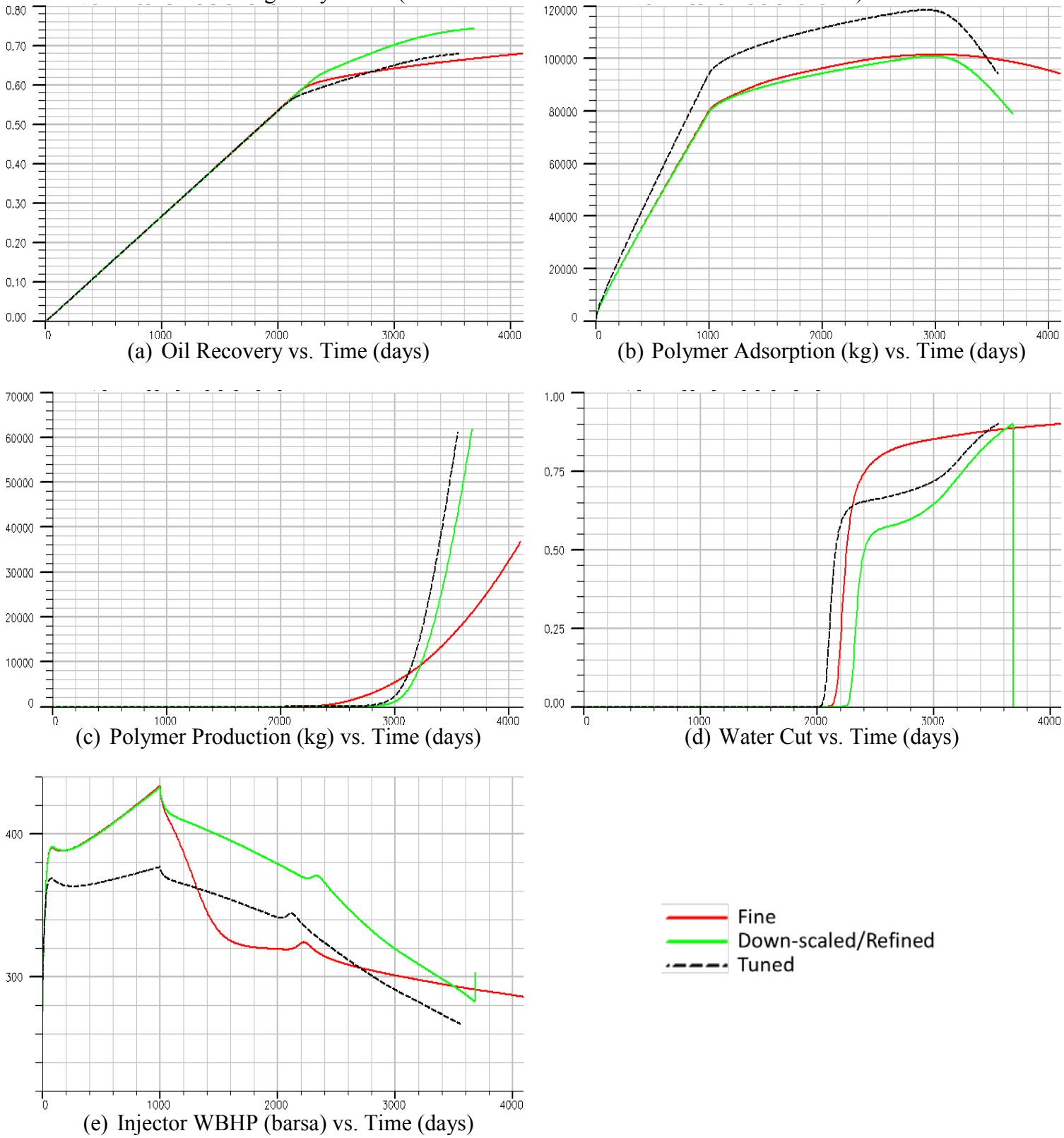


Figure 41: Simulation Results, Up-scaling Effect, Irreversible Case, 2D Layered Case

Heterogeneity Effect (Fine Grid Model vs. Down-scaled/Refined Model)



(a) Oil Recovery vs. Time (days)

(b) Polymer Adsorption (kg) vs. Time (days)

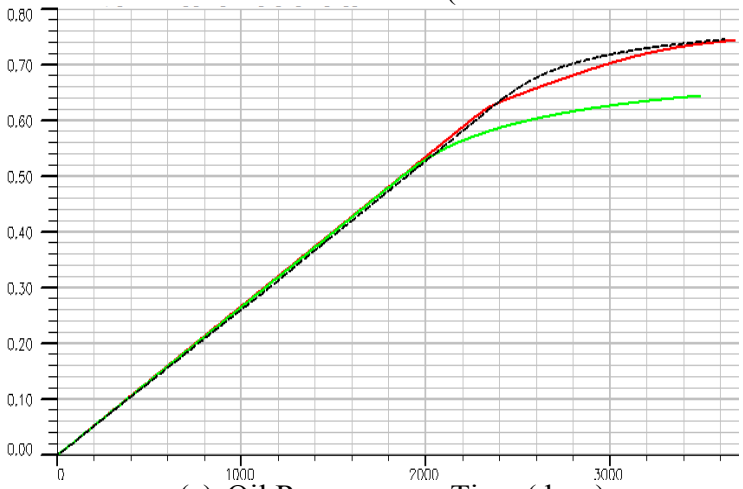
(c) Polymer Production (kg) vs. Time (days)

(d) Water Cut vs. Time (days)

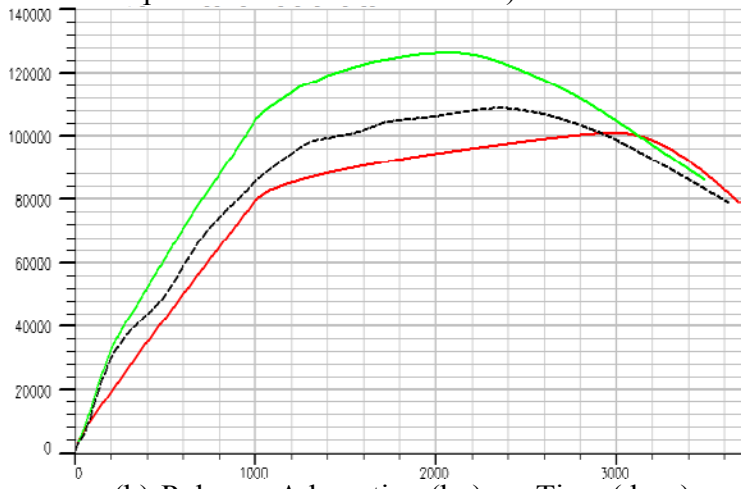
(e) Injector WBHP (barsa) vs. Time (days)

Figure 42: Simulation Results, Heterogeneity Effect, Reversible Case, 2D Layered Case

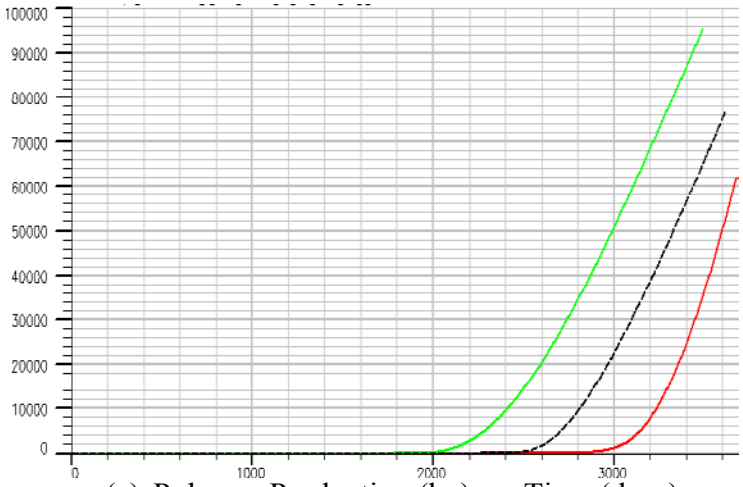
Grid Size Effect (Down-scaled/Refined Model vs. Up-scaled/Coarse Grid Model)



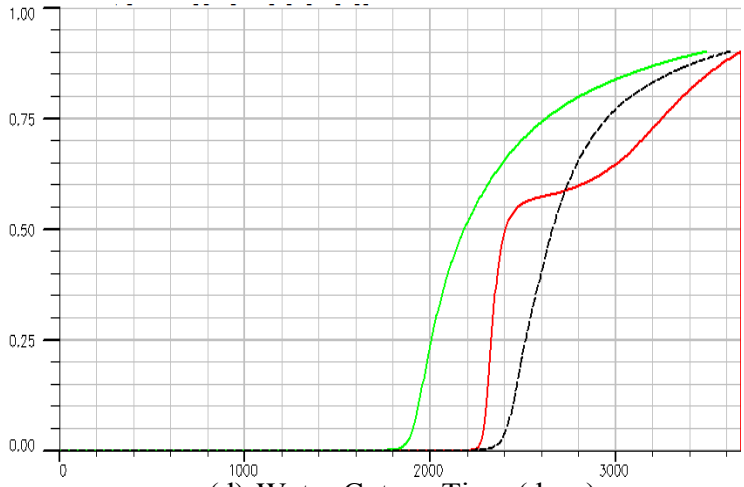
(a) Oil Recovery vs. Time (days)



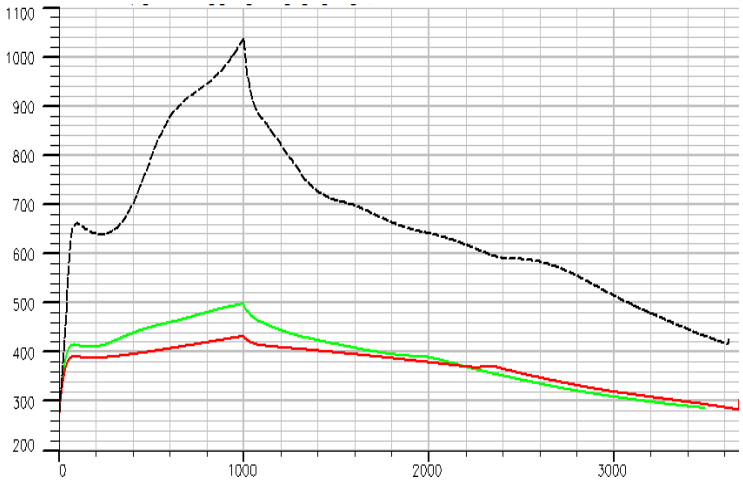
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



(d) Water Cut vs. Time (days)



(e) Injector WBHP (barsa) vs. Time (days)

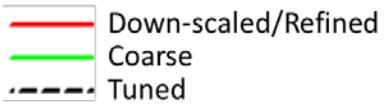


Figure 43: Simulation Results, Grid Size Effect, Reversible Case, 2D Layered Case

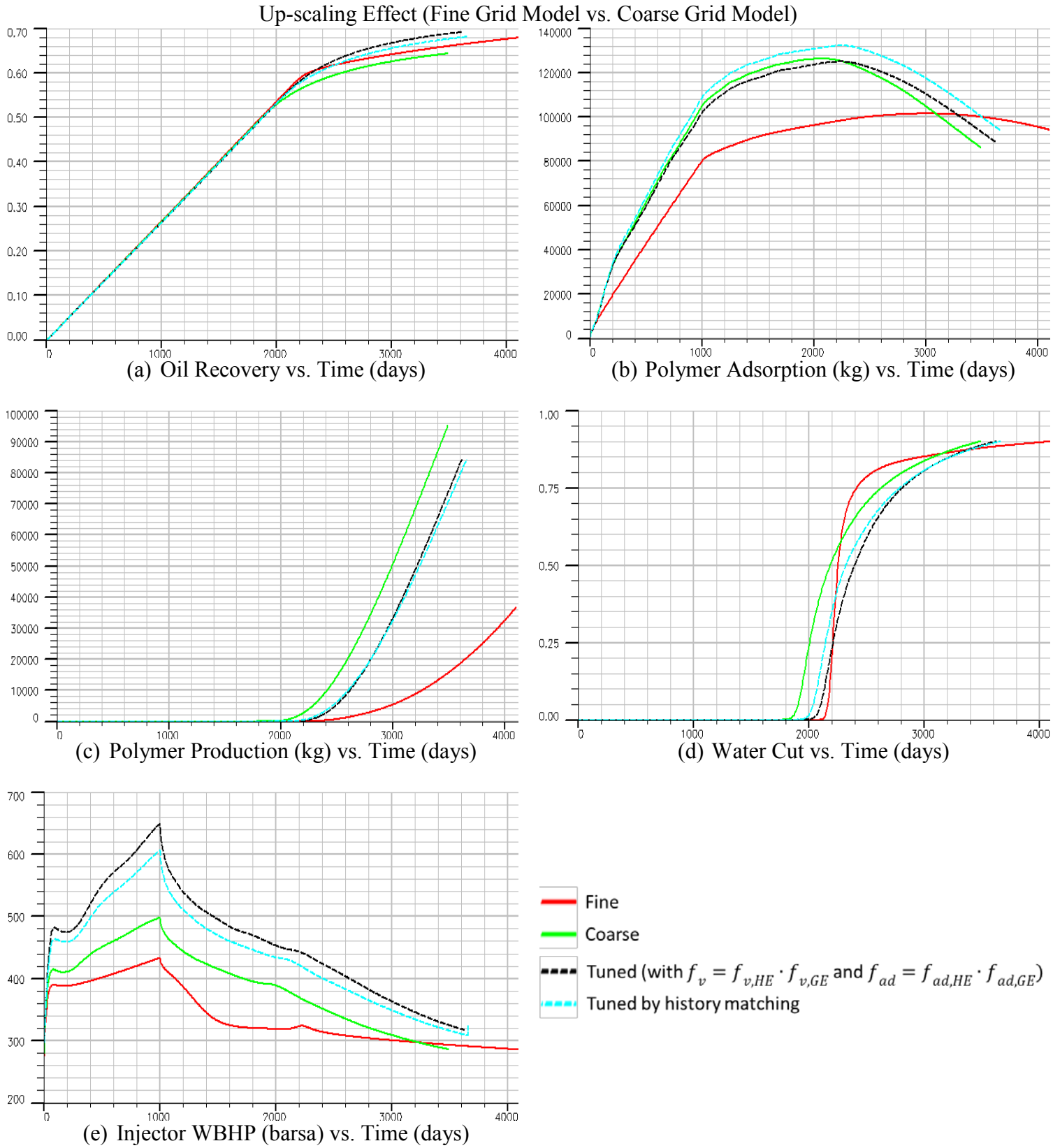
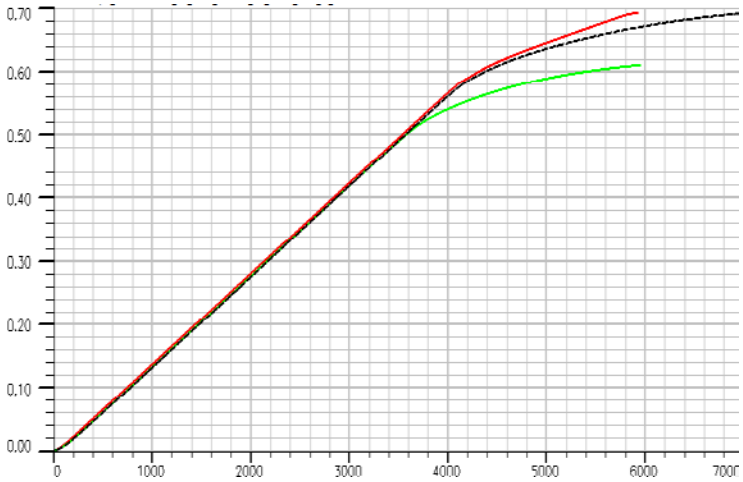
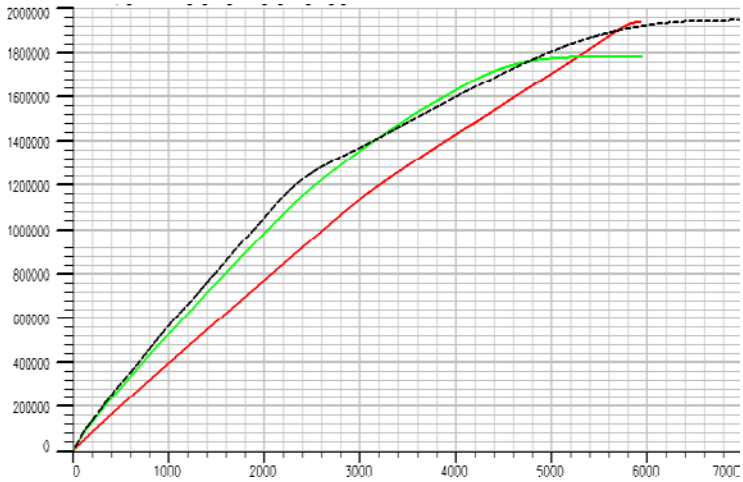


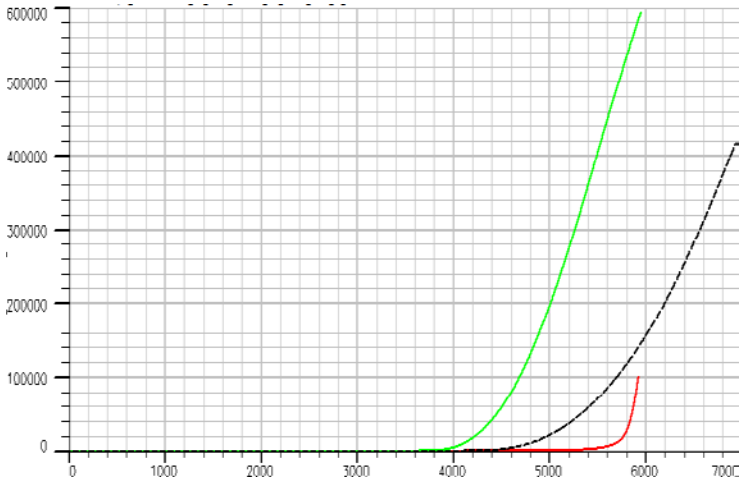
Figure 44: Simulation Results, Up-scaling Effect, Reversible Case, 2D Layered Case



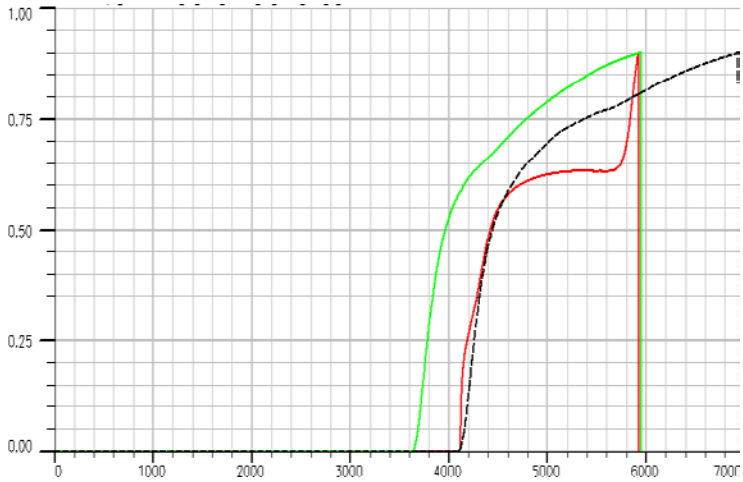
(a) Oil Recovery vs. Time (days)



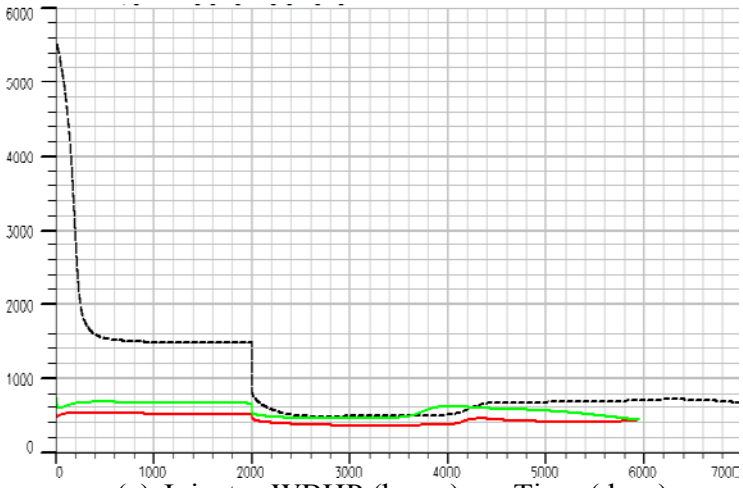
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)

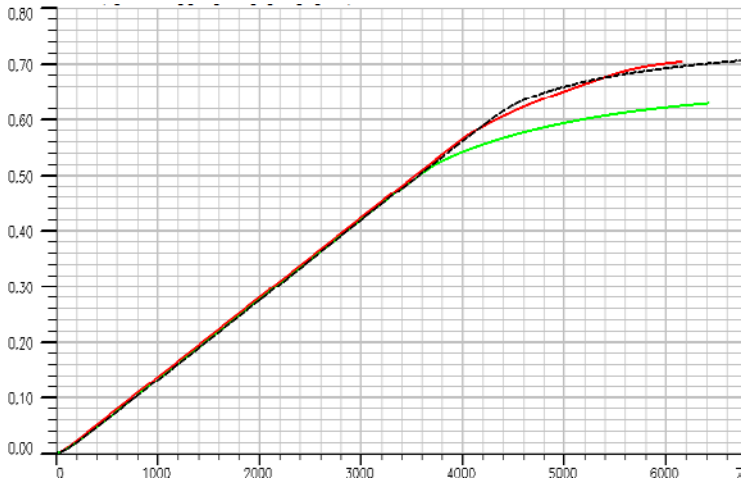


(d) Water Cut vs. Time (days)

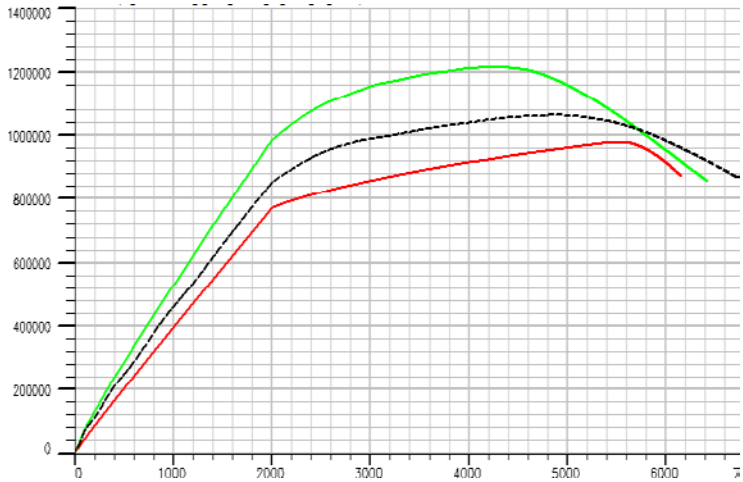


(e) Injector WBHP (barsa) vs. Time (days)

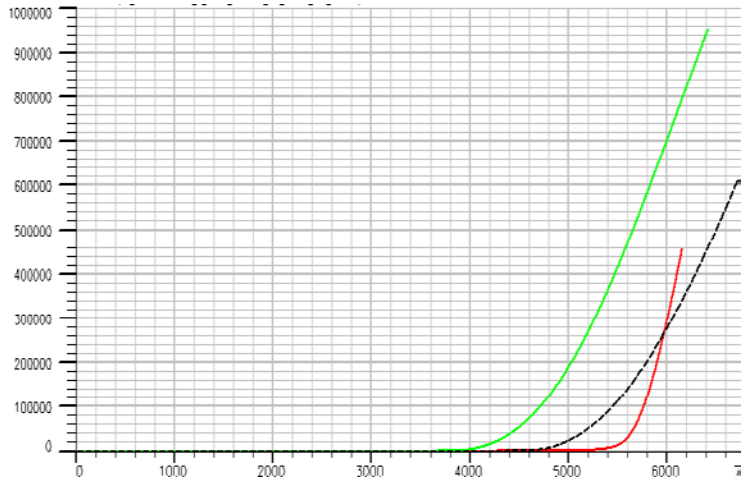
Figure 45: Simulation Results, Irreversible Case, 2D Areal Homogeneous Case



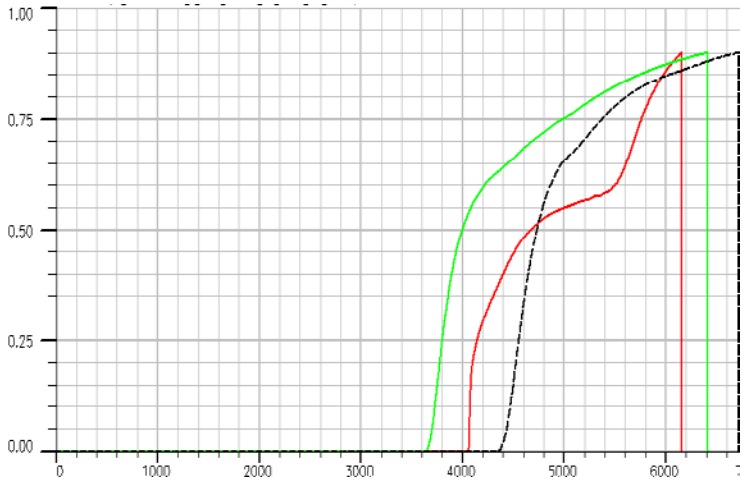
(a) Oil Recovery vs. Time (days)



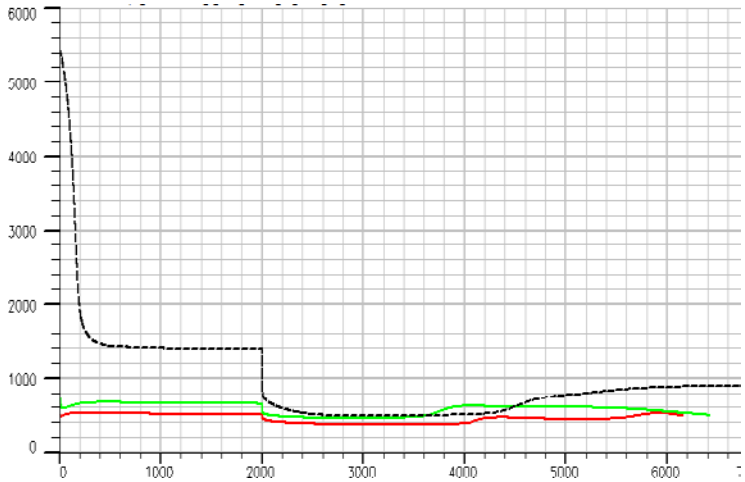
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)

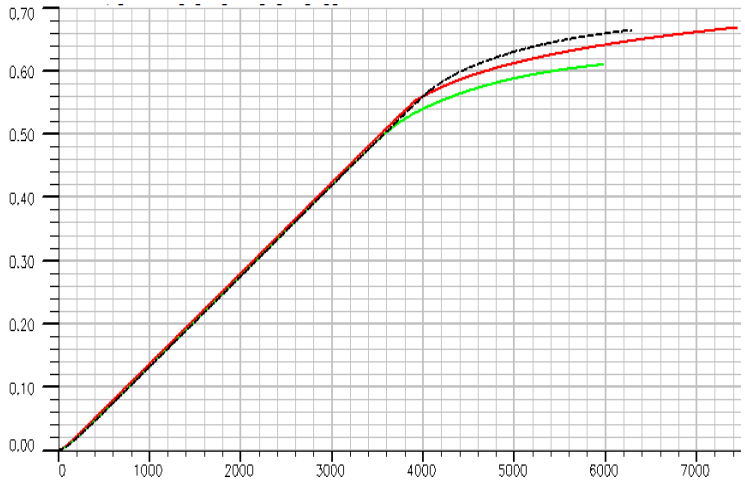


(d) Water Cut vs. Time (days)

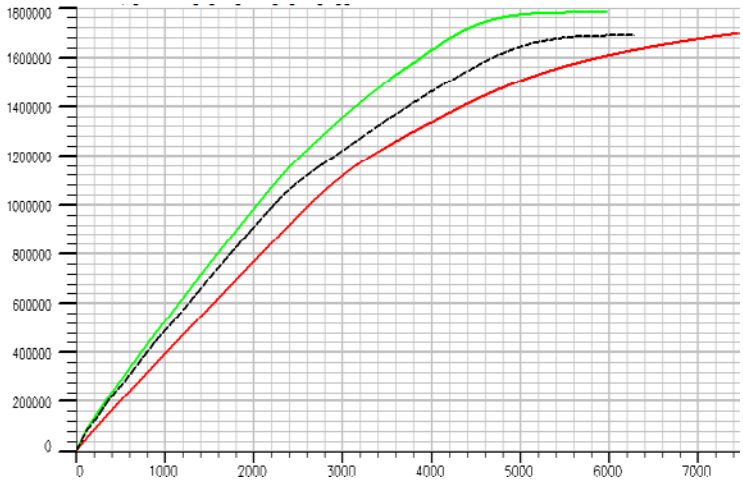


(e) Injector WBHP (barsa) vs. Time (days)

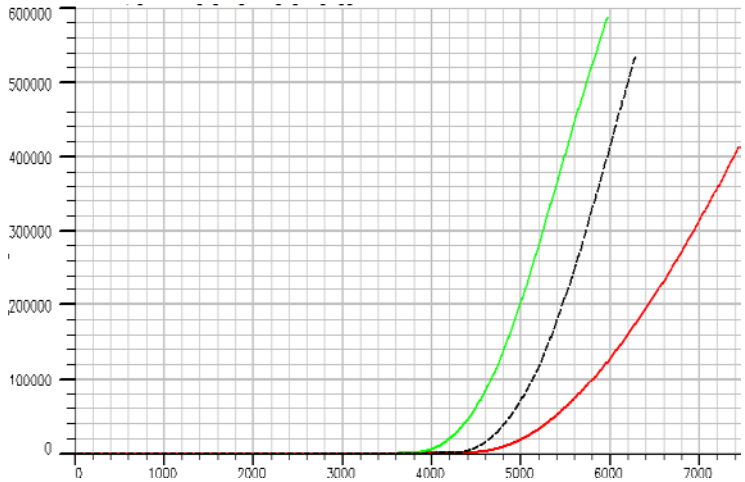
Figure 46: Simulation Results, Reversible Case, 2D Areal Homogeneous Case



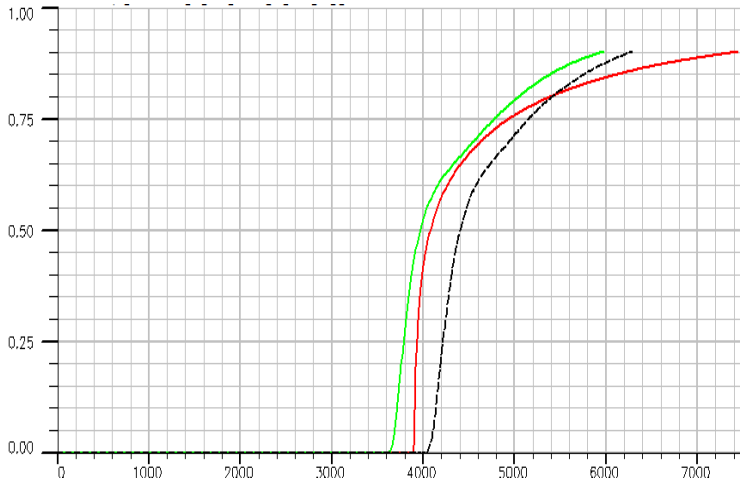
(a) Oil Recovery vs. Time (days)



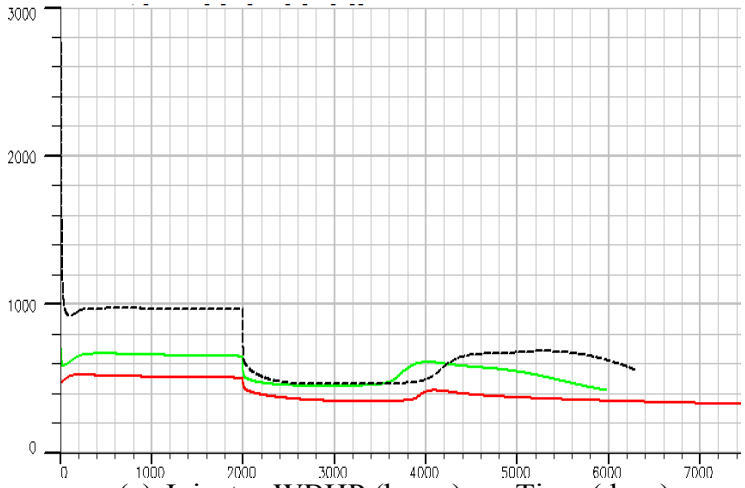
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)

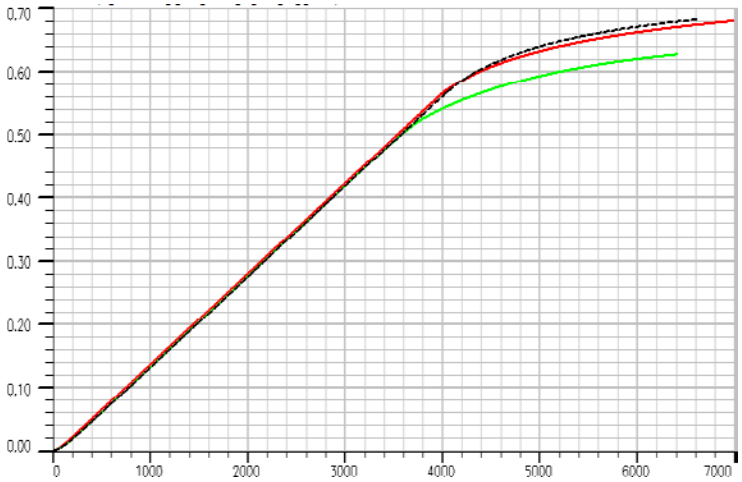


(d) Water Cut vs. Time (days)

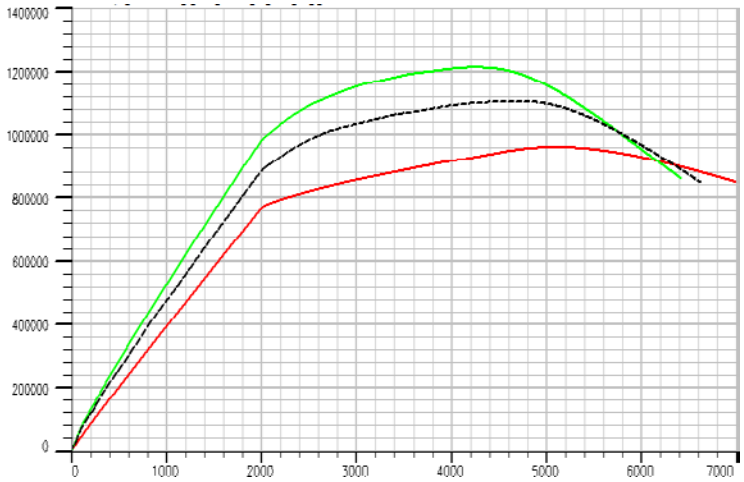


(e) Injector WBHP (barsa) vs. Time (days)

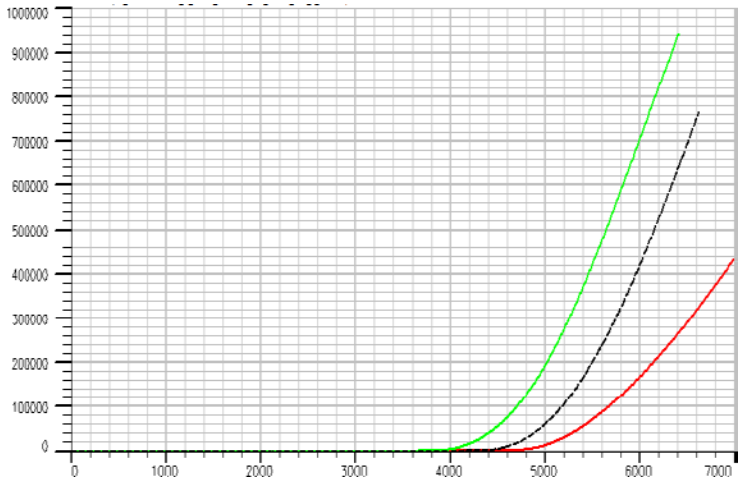
Figure 47: Simulation Results, Irreversible Case, 3D Homogeneous Case



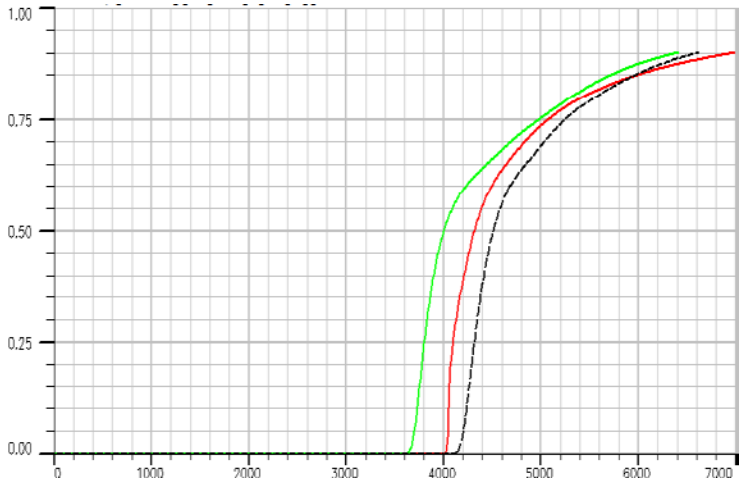
(a) Oil Recovery vs. Time (days)



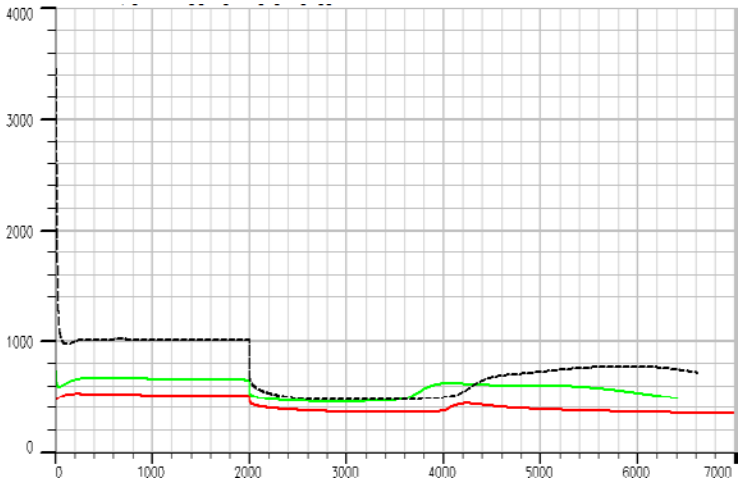
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



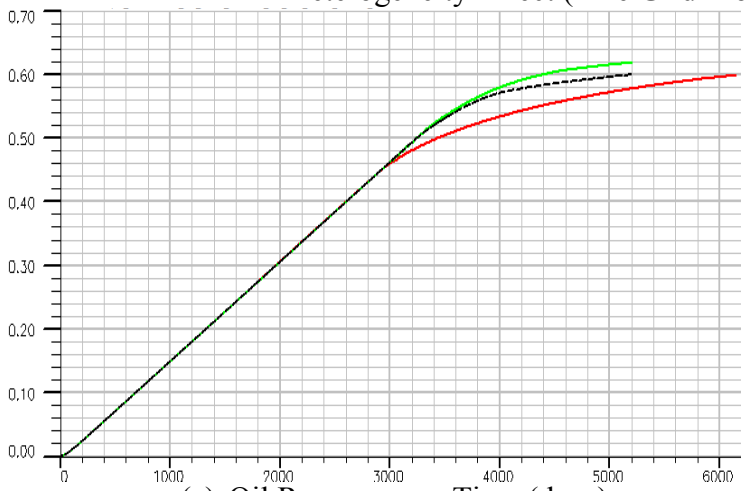
(d) Water Cut vs. Time (days)



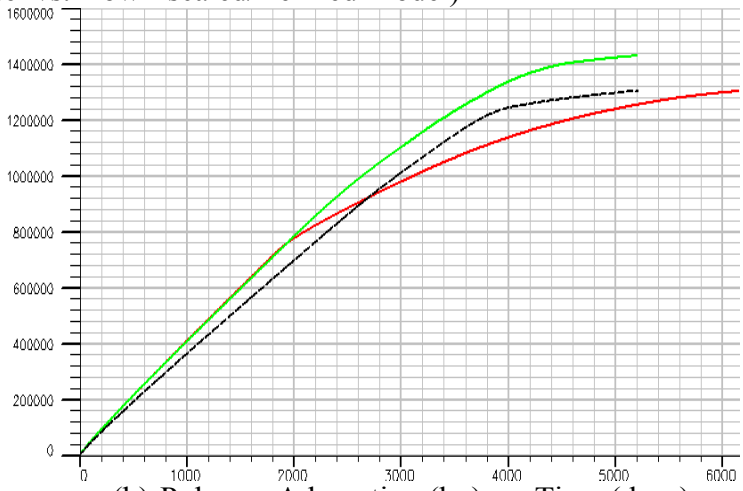
(e) Injector WBHP (barsa) vs. Time (days)

Figure 48: Simulation Results, Reversible Case, 3D Homogeneous Case

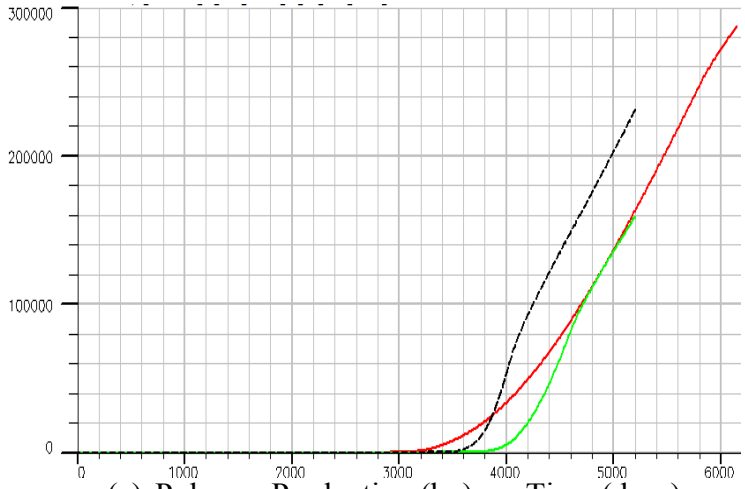
Heterogeneity Effect (Fine Grid Model vs. Down-scaled/Refined Model)



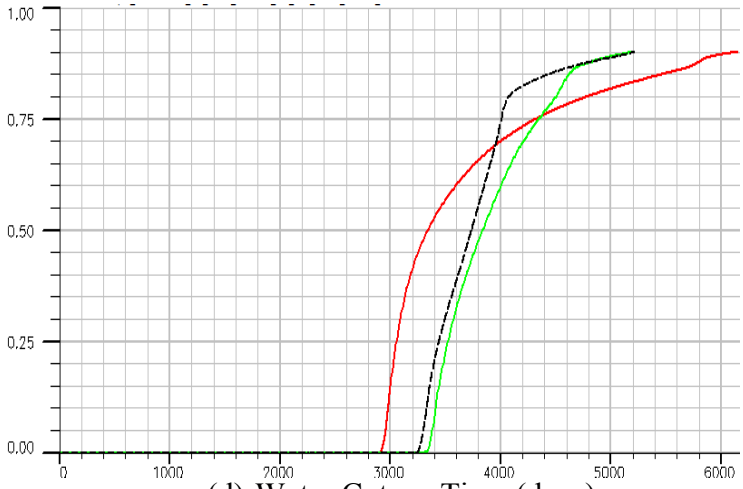
(a) Oil Recovery vs. Time (days)



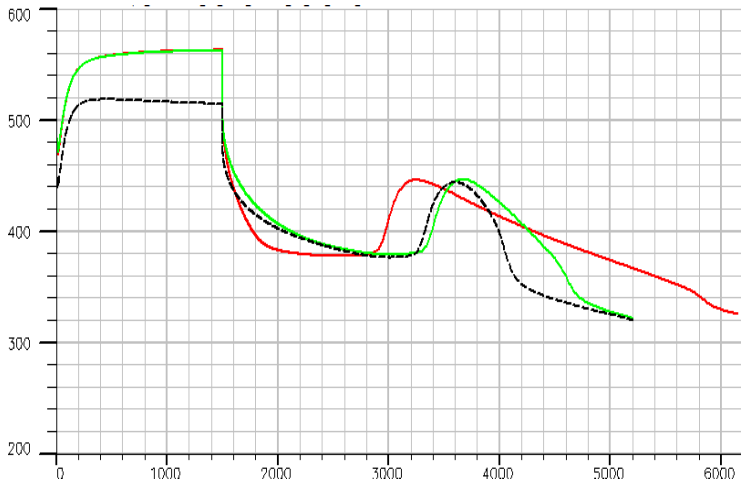
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



(d) Water Cut vs. Time (days)



(e) Injector WBHP (barsa) vs. Time (days)

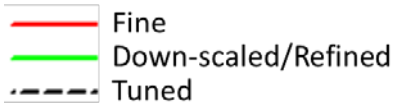
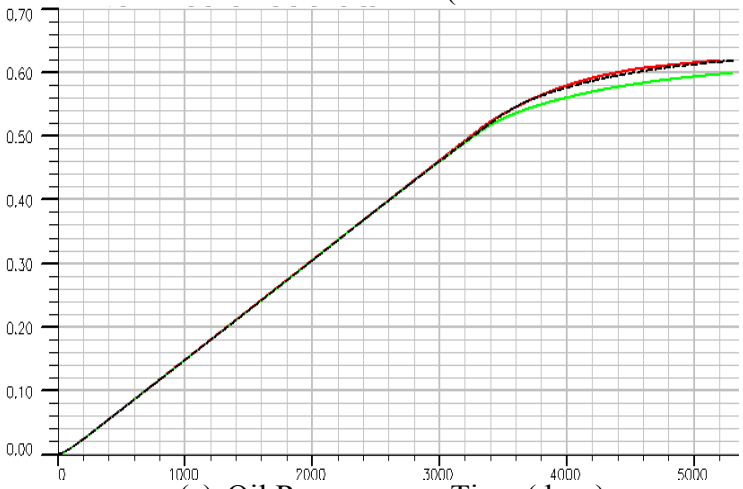
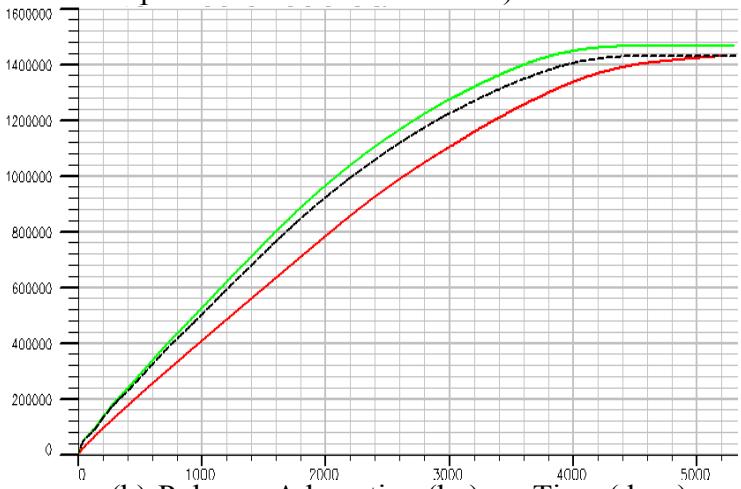


Figure 49: Simulation Results, Heterogeneity Effect, Irreversible Case, 3D Layered Case

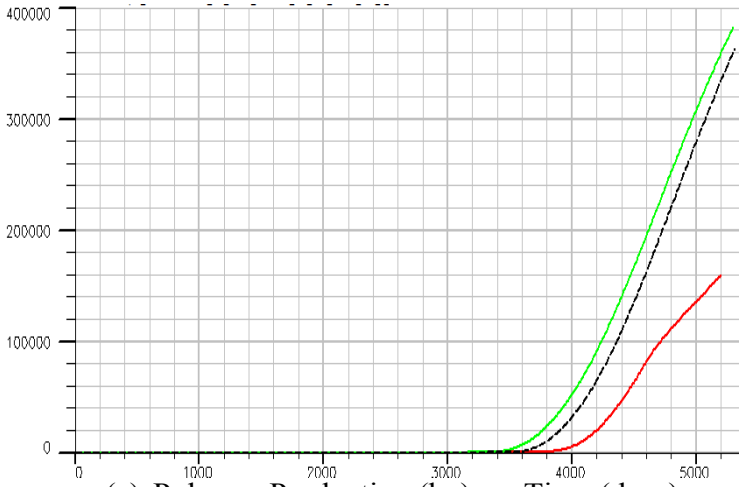
Grid Size Effect (Down-scaled/Refined Model vs. Up-scaled/Coarse Grid Model)



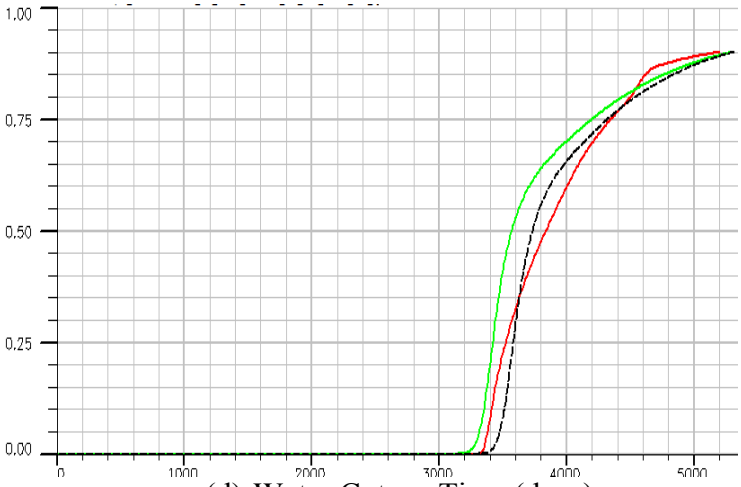
(a) Oil Recovery vs. Time (days)



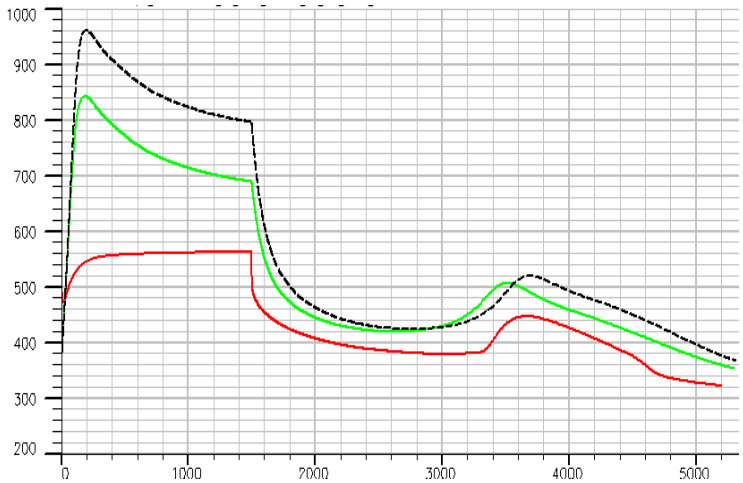
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



(d) Water Cut vs. Time (days)



(e) Injector WBHP (barsa) vs. Time (days)

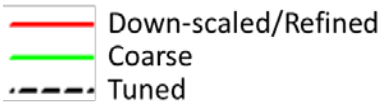


Figure 50: Simulation Results, Grid Size Effect, Irreversible Case, 3D Layered Case

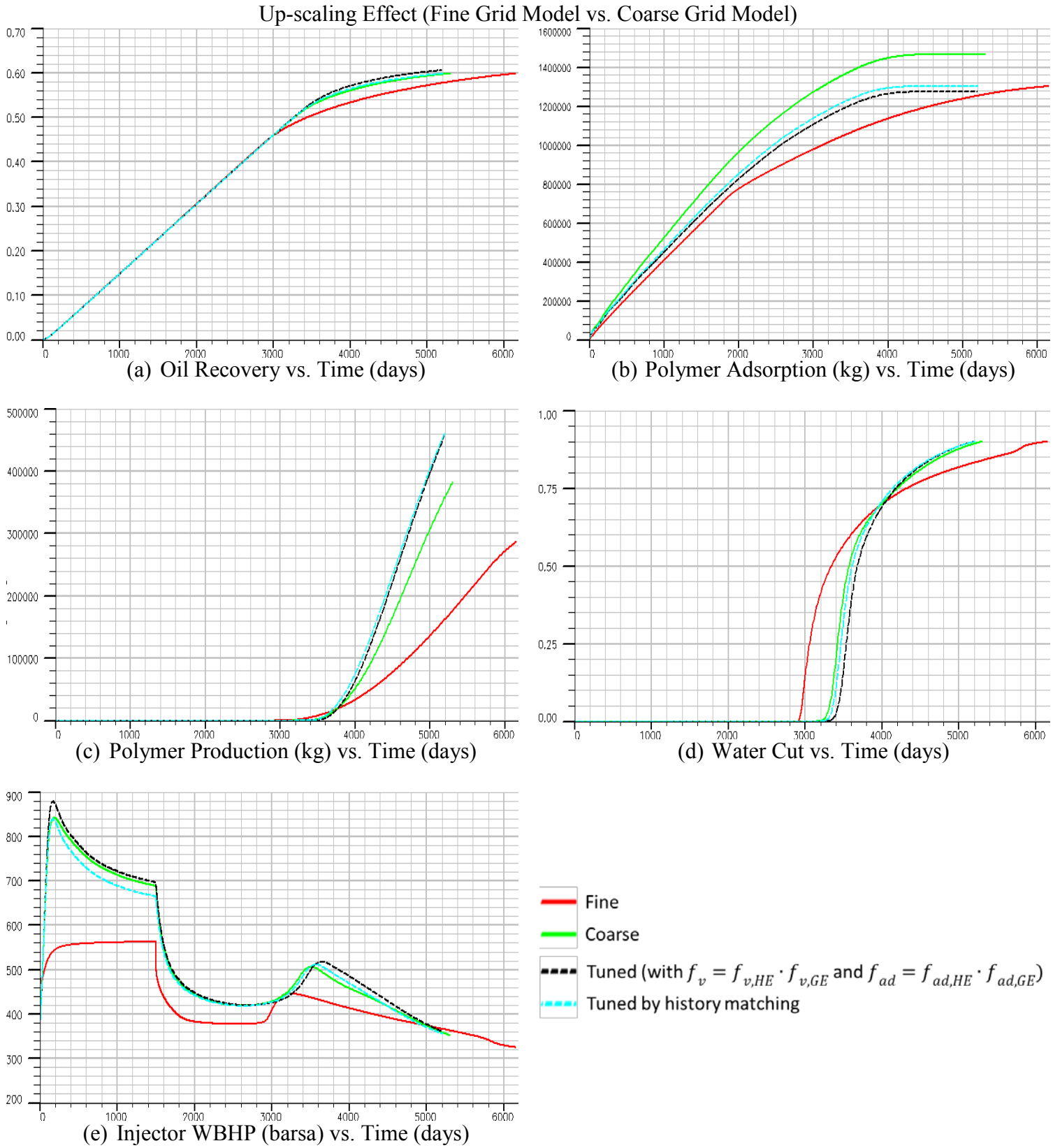


Figure 51: Simulation Results, Up-scaling Effect, Irreversible Case, 3D Layered Case

Heterogeneity Effect (Fine Grid Model vs. Down-scaled/Refined Model)

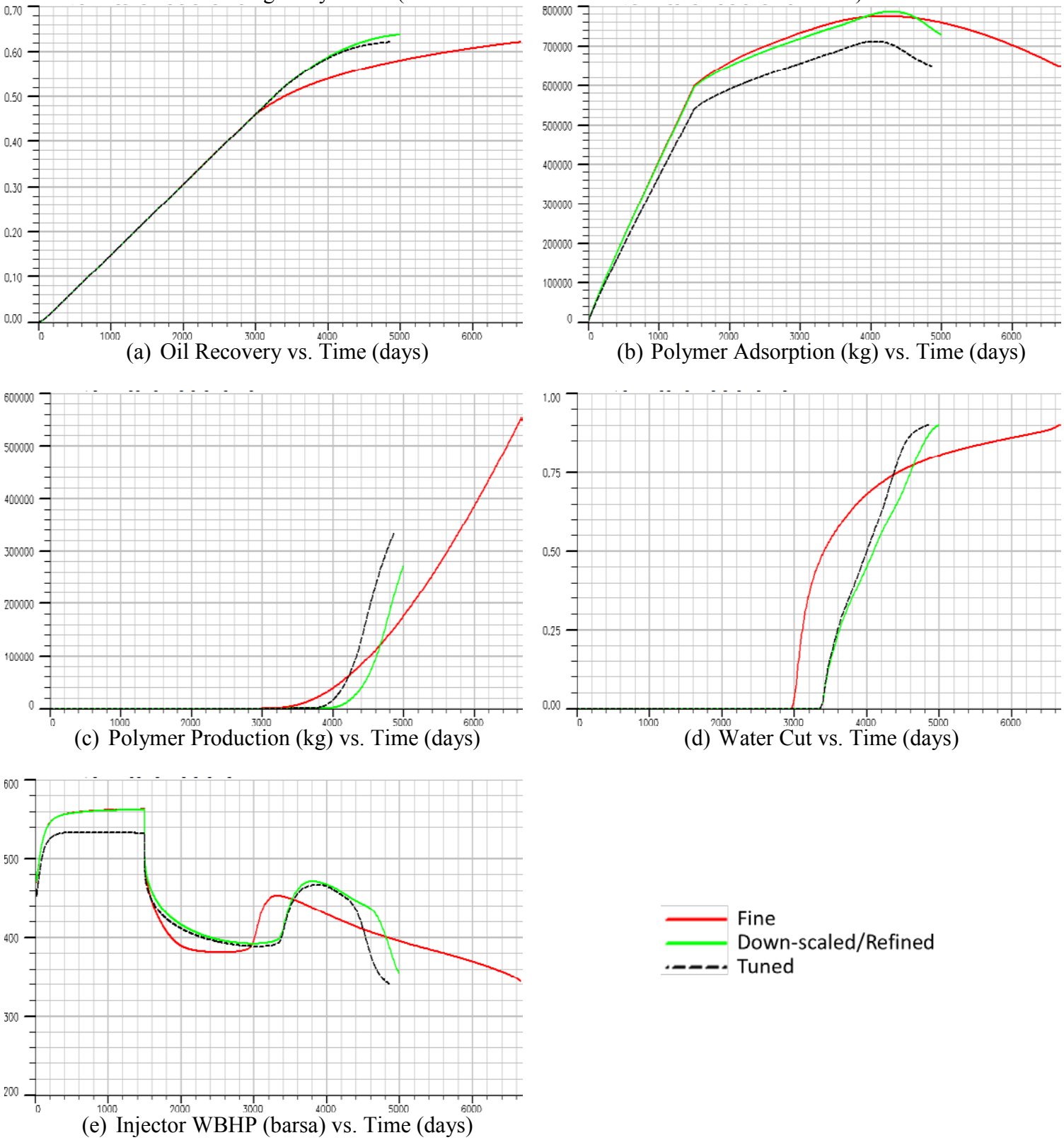
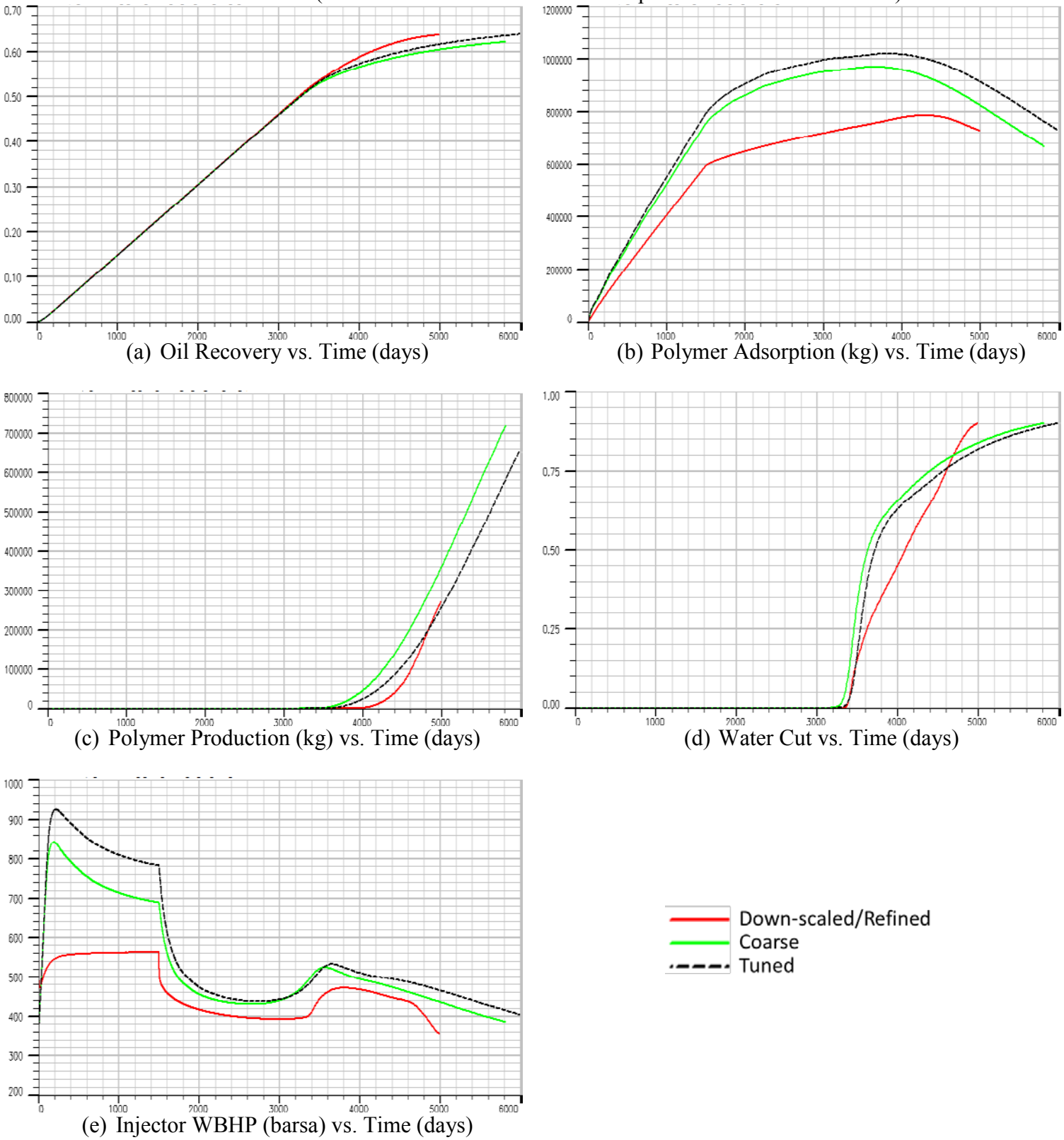


Figure 52: Simulation Results, Heterogeneity Effect, Reversible Case, 3D Layered Case

Grid Size Effect (Down-scaled/Refined Model vs. Up-scaled/Coarse Grid Model)



(a) Oil Recovery vs. Time (days)

(b) Polymer Adsorption (kg) vs. Time (days)

(c) Polymer Production (kg) vs. Time (days)

(d) Water Cut vs. Time (days)

(e) Injector WBHP (barsa) vs. Time (days)

Figure 53: Simulation Results, Grid Size Effect, Reversible Case, 3D Layered Case

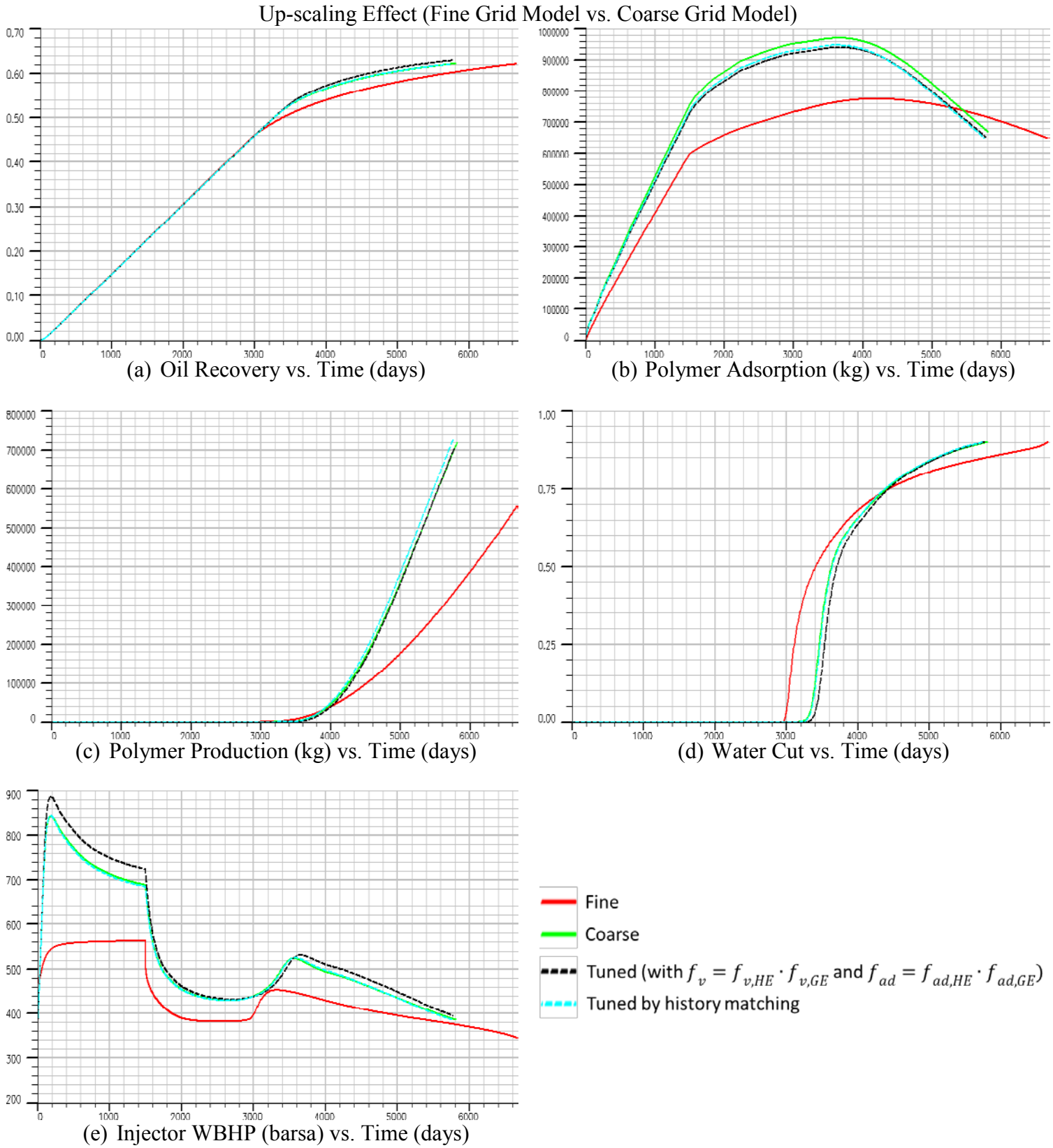
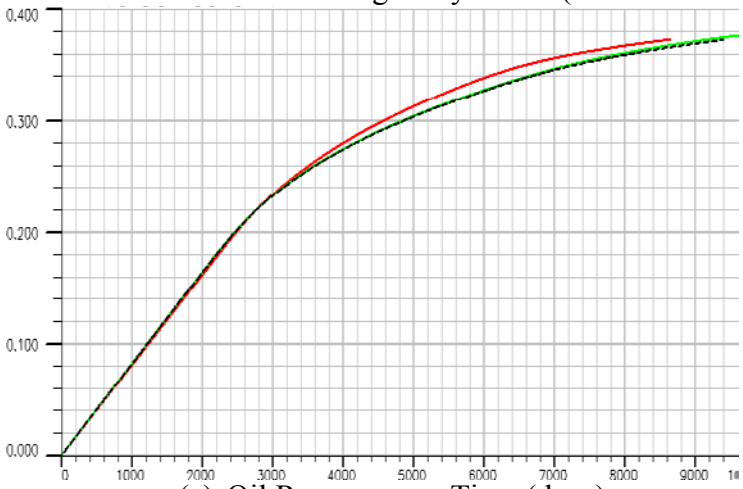
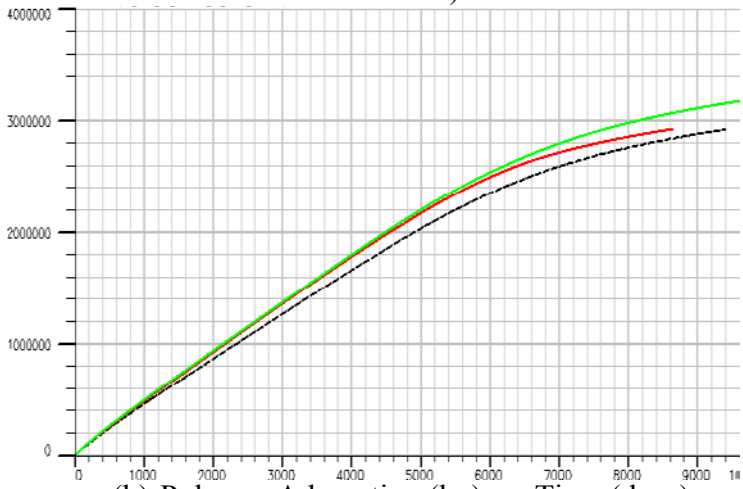


Figure 54: Simulation Results, Up-scaling Effect, Reversible Case, 3D Layered Case

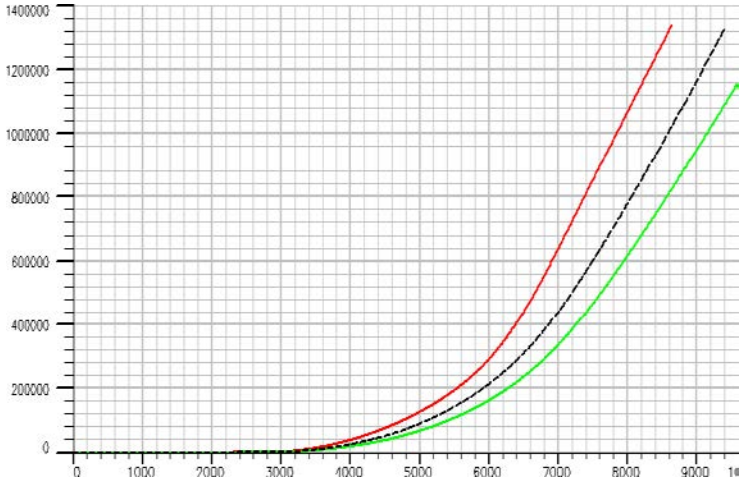
Heterogeneity Effect (Fine Grid Model vs. Down-scaled/Refined Model)



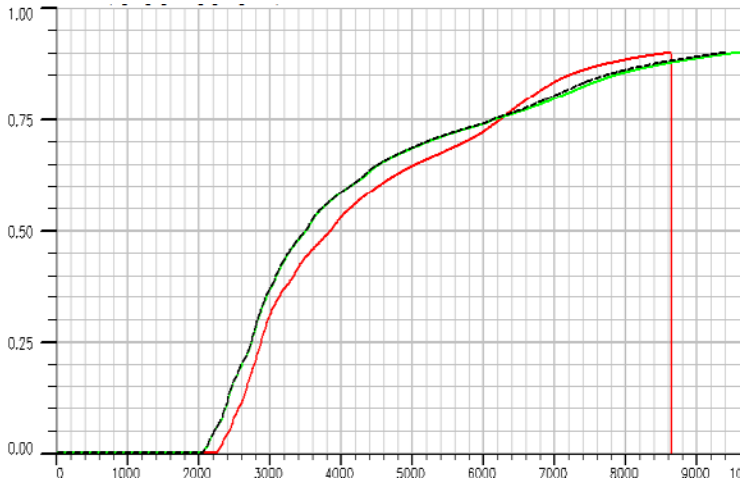
(a) Oil Recovery vs. Time (days)



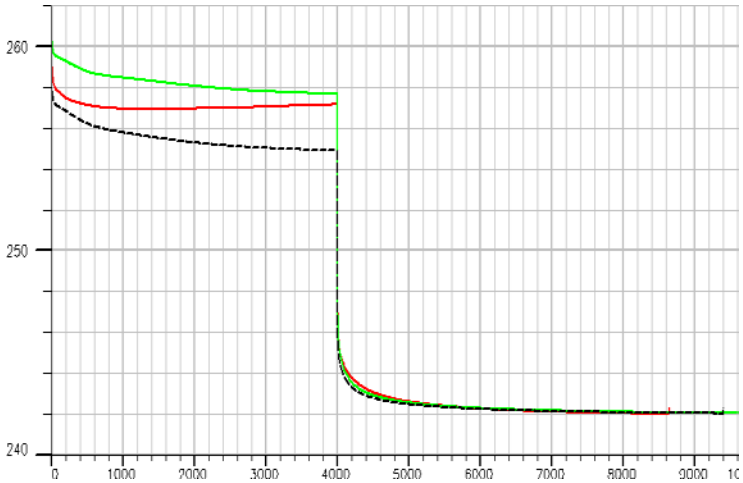
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



(d) Water Cut vs. Time (days)



(e) Injector WBHP (barsa) vs. Time (days)

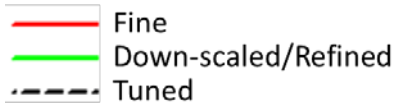
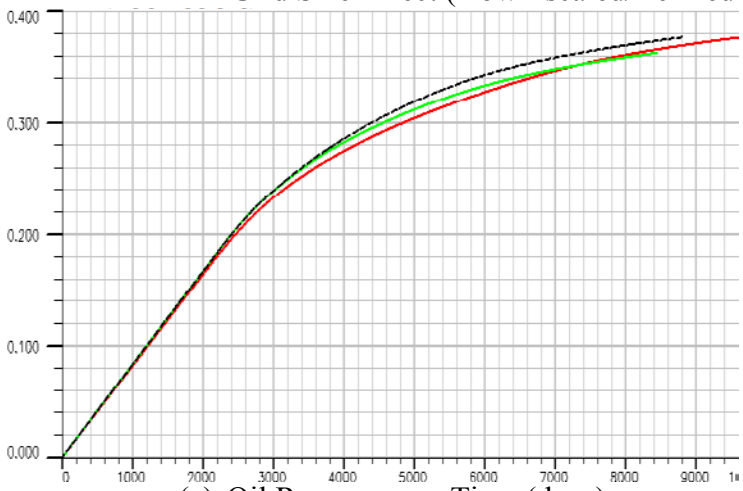
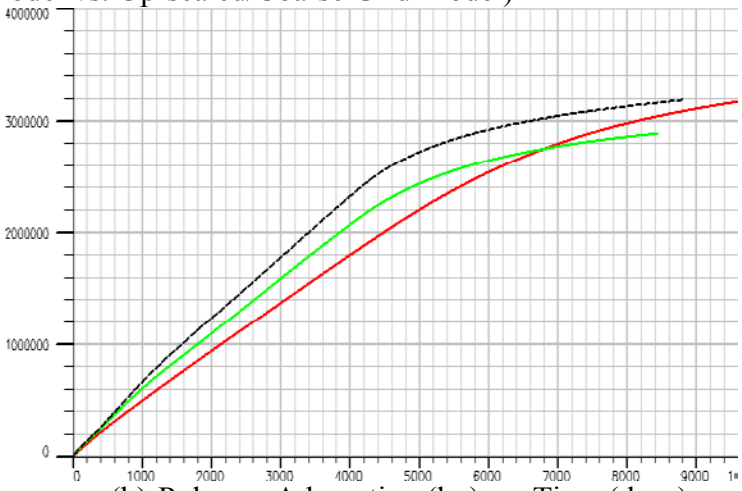


Figure 55: Simulation Results, Heterogeneity Effect, Irreversible Case, 3D Generics Case

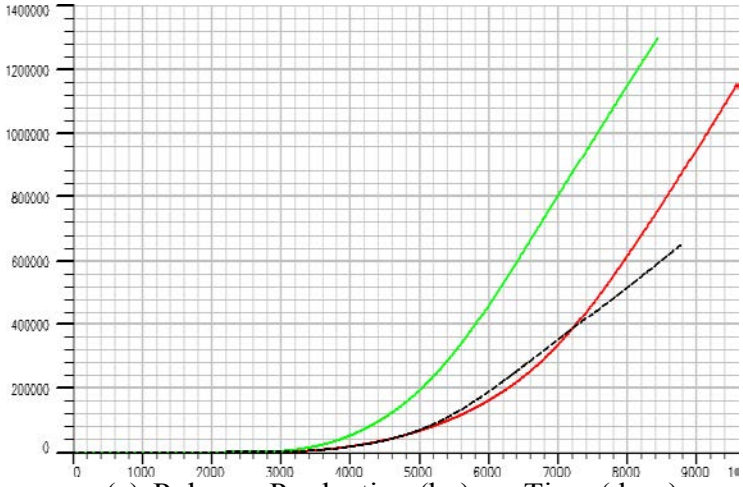
Grid Size Effect (Down-scaled/Refined Model vs. Up-scaled/Coarse Grid Model)



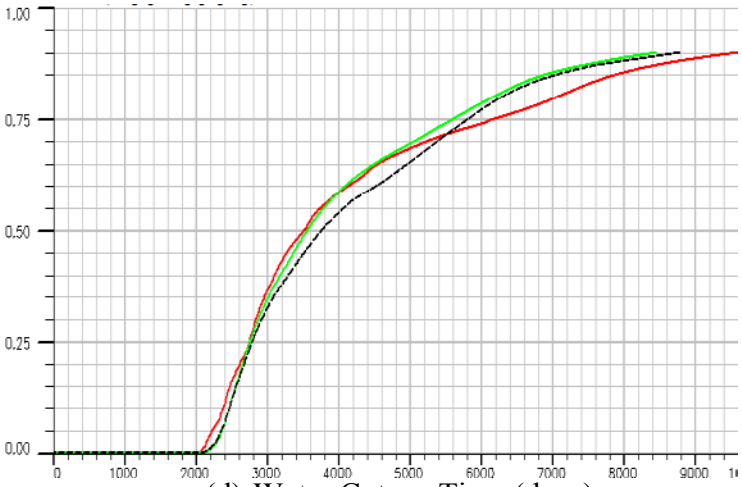
(a) Oil Recovery vs. Time (days)



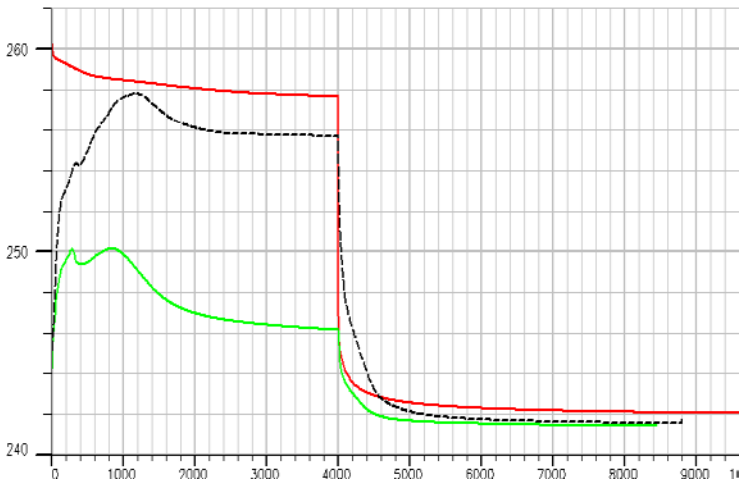
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



(d) Water Cut vs. Time (days)



(e) Injector WBHP (barsa) vs. Time (days)

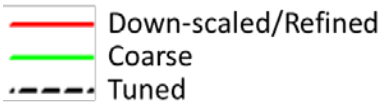
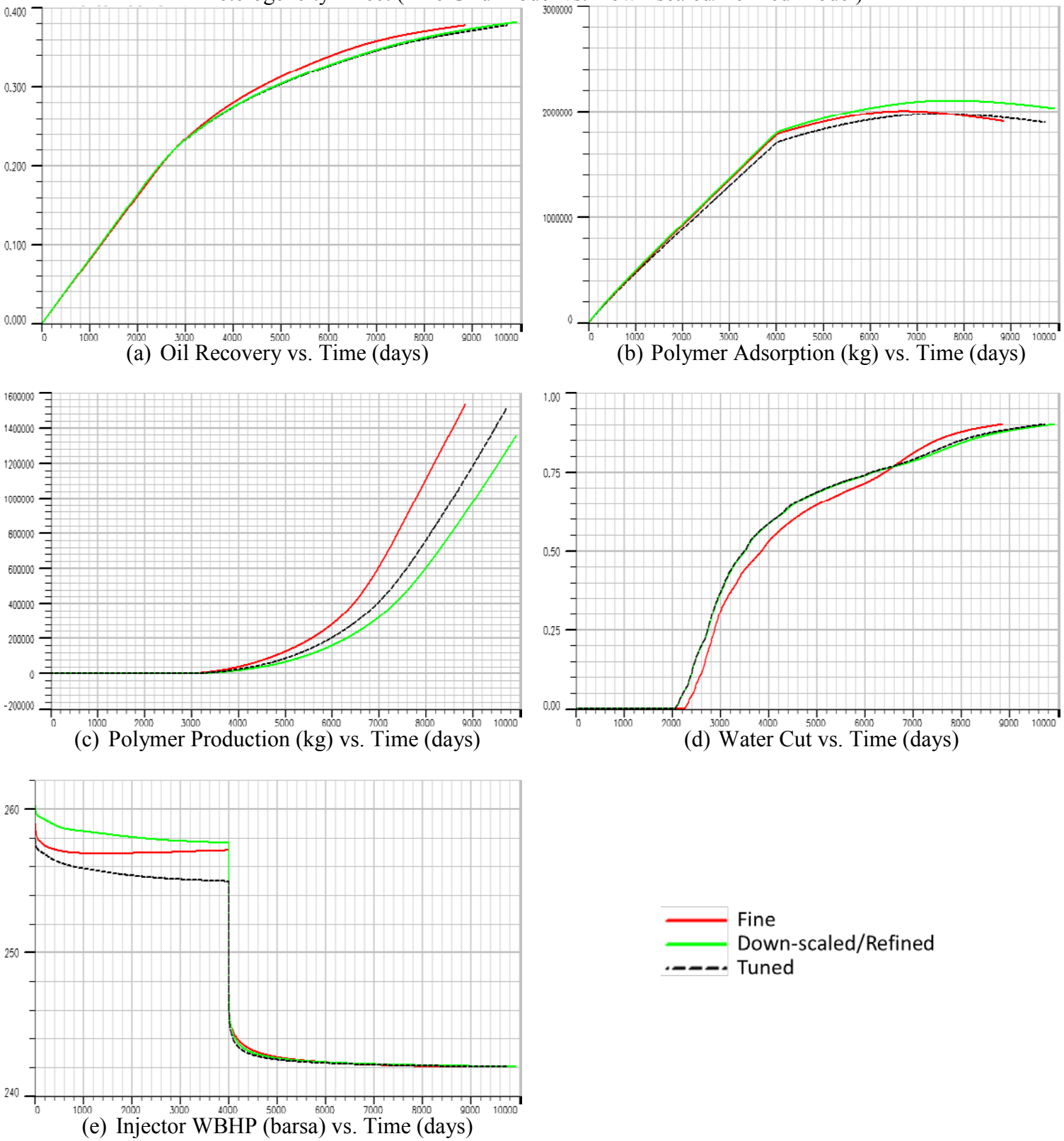


Figure 56: Simulation Results, Grid Size Effect, Irreversible Case, 3D Generics Case

Heterogeneity Effect (Fine Grid Model vs. Down-scaled/Refined Model)



(a) Oil Recovery vs. Time (days)

(b) Polymer Adsorption (kg) vs. Time (days)

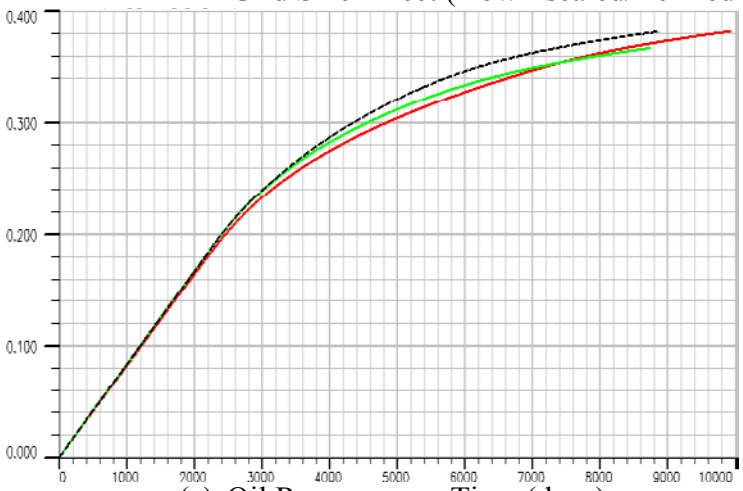
(c) Polymer Production (kg) vs. Time (days)

(d) Water Cut vs. Time (days)

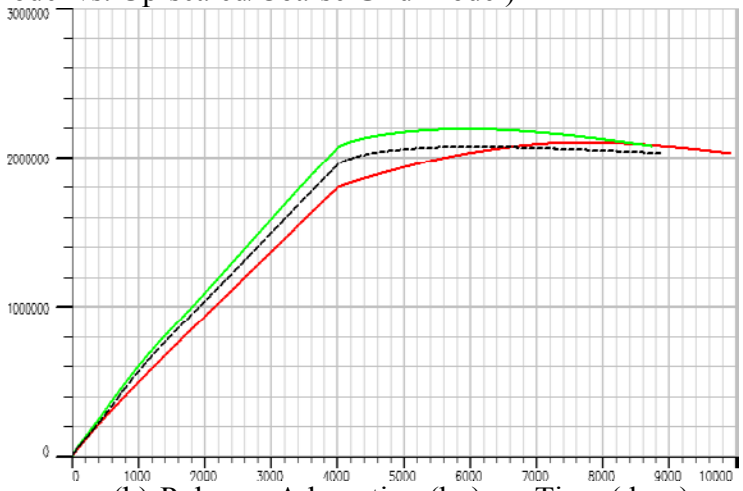
(e) Injector WBHP (barsa) vs. Time (days)

Figure 57: Simulation Results, Heterogeneity Effect, Reversible Case, 3D Generics Case

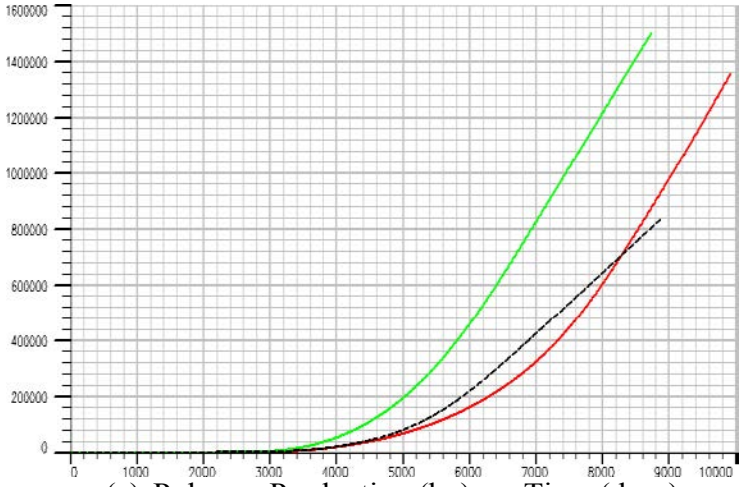
Grid Size Effect (Down-scaled/Refined Model vs. Up-scaled/Coarse Grid Model)



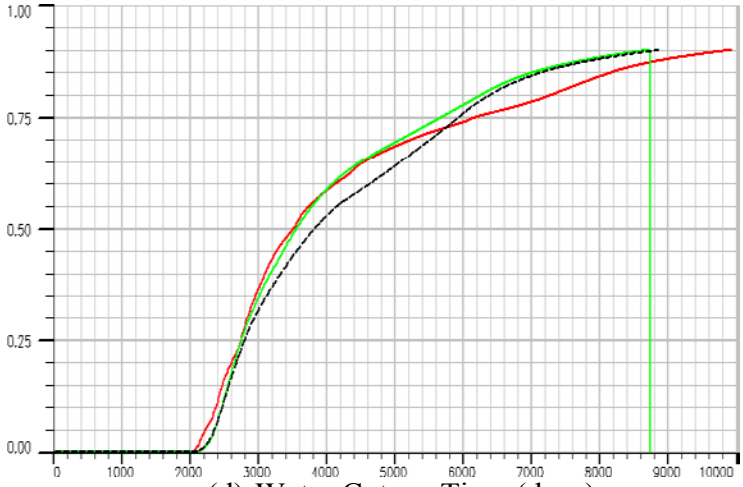
(a) Oil Recovery vs. Time (days)



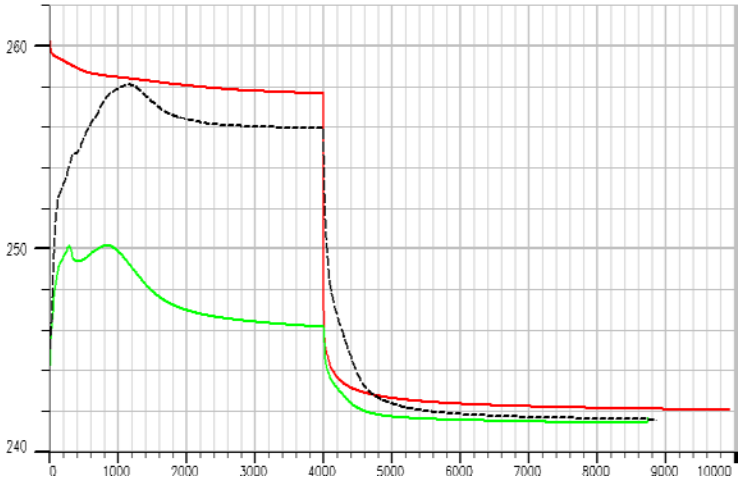
(b) Polymer Adsorption (kg) vs. Time (days)



(c) Polymer Production (kg) vs. Time (days)



(d) Water Cut vs. Time (days)



(e) Injector WBHP (barsa) vs. Time (days)

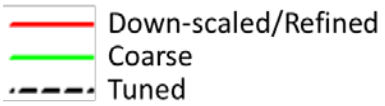


Figure 58: Simulation Results, Grid Size Effect, Reversible Case, 3D Generics Case

Appendix D: Example of Input Files in ECLIPSE

ECLIPSE DATA-File: Fine Grid Model, Irreversible Case, 1D Homogeneous Case

```
-- 1D model (20m*100m*40m and (45+2) Blocks), Polymer Flooding Study
-- Irreversible Case (No Desorption)
-- Sw,initial (initial water saturation) = 0
-- Model made by Ali Mojaddam Zadeh, Modified by Aojie Hong
================================================================
NOECHO
================================================================
RUNSPEC
================================================================

TITLE
 1D model (20m*100m*40m and (45+2) Blocks), Polymer Flooding Study

--Model dimensions
DIMENS
-- NX  NY  NZ
   47  1   1  /

-- Phases present
OIL
POLYMER
WATER

ENDSCALE
/

-- Units
METRIC

NSTACK
100
/

-- unified and ascii-formatted files in&out
UNIFIN
UNIFOUT
--FMTOUT
--FMTIN

-- Run start date
START
--  DAY   MONTH  YEAR
    01 'Jan' 2014   /

-----------------------------------------------------
-- Dimensions
-----------------------------------------------------

TABDIMS
-- NTS  NTPVT  NSS  NPPVT  NTFIP
    1    1     100   40    1  /

REGDIMS
```

```
-- NTFIP  NMFIPR  NRFREG  NTFREG
     1     1       0       0  /

-- Well dimensions
WELLDIMS
-- NWMAXZ  NCWMAX  NGMAXZ  NWGMAX
     2      156      2     1  /

WSEGDIMS
-- NSWLMX   NSEGMX   NLBRMX
    1        240      135   /

-----------------------------------
-- Run control settings
-----------------------------------

--NOSIM

========================================================================
--   GRID SECTION
========================================================================
GRID

NOECHO

--Grid size in x-direction
DXV
20 45*20 20
/

--Grid size in y-direction
DYV
 100
/

--Grid size in z-direction
DZ
 47*40
/

EQUALS
      'PORO'    0.2                /
      'TOPS'    2240    1 47  1 1 1 1    /
      'PERMX'   500    1 47  1 1 1  1 /
/

COPY
 'PERMX'  'PERMY'   /
 'PERMX'  'PERMZ'   /
/

INIT

GRIDFILE
  0 1 /
```

```
RPTGRID
 22*0 /

=====================================================================
--            EDIT SECTION
=====================================================================
EDIT

=====================================================================
--     PROPS SECTION
=====================================================================
PROPS

DENSITY
 800  1000  0.824 /

PVCDO
-- Pref      FVFo       Coil       Viso      Visco
--(bara)   (rb/stb)   (1/bara)     (cp)    (1/bara)
    234     1.06541    6.65e-5      6.4     192.e-5    /

RSCONSTT
  0.00  43.8 /

PVTW
 234  1.012  4.28e-5  0.5 /

INCLUDE
'relperm.inc'  /

-- Pref     Cr
ROCK
   234    1E-8 /

PCW
47*73 /

RPTPROPS
PCW /

--Polymer properties
INCLUDE
'POL_ND.INC'  /

=====================================================================
-- REGIONS SECTION
=====================================================================
REGIONS

=====================================================================
-- SOLUTION SECTION
=====================================================================
SOLUTION


MESSAGES
```

```
12*9999999 /
--6* 2* 2*200 2* /

--EQUIL
-- DATUM   DATUM   OWC   OWC    GOC   GOC   RSVD   RVVD   SOLN
-- DEPTH   PRESS  DEPTH  PCOW  DEPTH  PCOG  TABLE  TABLE  METH
--  2240    234   99999   5*                          0 /

PRESSURE
47*234 /

SWAT
47*0 /

-- INITIAL RESTART FILE
RPTSOL
 RESTART=2  FIP=3  FIPRESV SWATINIT /

================================================================
--     SUMMARY SECTION
================================================================
SUMMARY

INCLUDE
'summary.inc'  /

================================================================
--  SCHEDULE SECTION
================================================================
SCHEDULE

RPTRST         Controls on output to the RESTART file
-- Controls output of .UNRST file
-- BASIC=4 => Restart file is written every 3. year
   BASIC=1    FREQ=1    FIP=3    ALLPROPS  PCOW WELLS    /

--RPTSCHED
-- 'NEWTON=1'       -- linear eq summary for each time step to prt-
file (=1)
-- 'SUMMARY=1'      -- solution summary for each time step to prt-
file (=1)
-- 'WELSPECS'
--/

-- Basic tuning
TUNING
-- Record 1: Time stepping controls
-- TSINIT TSMAXZ TSMINZ TSMCHP TSFMAX TSFMIN TSFCNV TFDIFF
    0.5    30.0  0.0001 0.00015  2*           0.3    1.25  /
-- Record 2: Time truncation and convergence controls
--TRGTTE TRGCNV TRGLCV 3XTTE 3XCNV 3XMBE 3XLCV 3XWFL TRGFIP
    0.5   0.01  1.0E-6 5.0E-4 10    0.01 1.0E-4 0.001 0.01 0.1 /
--Record 3
-- NEWTMX  NEWTMN  LITMAX  LITMIN   MXWSIT
      10     1       50       1        30      8   /
```

```
WELSPECS
INJ   WELL1   1  1  1*  WATER 2* SHUT YES  1*  AVG 0 /
PROD  WELL2   47  1  1*  OIL   2* SHUT YES  1*  AVG 0 /
/

COMPDAT
INJ     1  1  1  1  OPEN  1*  1*  0.177  1*  2*  Z  1*    /
PROD    47  1  1  1  OPEN  1*  1*  0.177  1*  2*  Z  1*    /
/

WCONPROD
PROD   OPEN    BHP  5*  200  /
/

WCONINJE
--INJ     WATER  OPEN BHP 2* 500  /
INJ    WATER  OPEN  RATE  200  /
/

GECON
--        Water Cut
FIELD  2*     0.9     2*  WELL   YES  /
/

-- Volume of injected polymer solution
INCLUDE
 'PVI.INC'  /

END
```

ECLIPSE DATA-File: Coarse Grid Model, Irreversible Case, 1D Homogeneous Case

```
-- 1D model (180m*100m*40m and (5+2) Blocks), Polymer Flooding Study
-- Irreversible Case (No Desorption)
-- Sw,initial (initial water saturation)= 0
-- Model made by Ali Mojaddam Zadeh, Modified by Aojie Hong
========================================================================
NOECHO
========================================================================
RUNSPEC
========================================================================

TITLE
 1D model (180m*100m*40m and (5+2) Blocks), Polymer Flooding Study

--Model dimensions
DIMENS
-- NX  NY  NZ
   7    1   1  /

-- Phases present
OIL
POLYMER
WATER

ENDSCALE
/

-- Units
METRIC

NSTACK
100
/

-- unified and ascii-formatted files in&out
UNIFIN
UNIFOUT
--FMTOUT
--FMTIN

-- Run start date
START
--  DAY   MONTH  YEAR
    01 'Jan' 2014   /

-----------------------------------------------------
-- Dimensions
-----------------------------------------------------
TABDIMS
-- NTS  NTPVT  NSS  NPPVT  NTFIP
    1    1     100   40    1  /

REGDIMS
-- NTFIP  NMFIPR  NRFREG  NTFREG
     1     1       0       0  /
```

```
-- Well dimensions
WELLDIMS
-- NWMAXZ  NCWMAX  NGMAXZ  NWGMAX
     2      156      2     1  /

WSEGDIMS
-- NSWLMX   NSEGMX   NLBRMX
    1        240      135   /

-----------------------------------
-- Run control settings
-----------------------------------

--NOSIM

=====================================================================
--          GRID SECTION
=====================================================================
GRID

NOECHO

--Grid size in x-direction
DXV
20 5*180 20
/

--Grid size in y-direction
DYV
 100
/

--Grid size in z-direction
DZ
 7*40
/

EQUALS
      'PORO'    0.2                /
      'TOPS'    2240    1 7  1 1 1 1    /
      'PERMX'   500    1 7  1 1 1  1  /
/

COPY
 'PERMX'  'PERMY'   /
 'PERMX'  'PERMZ'   /
/

INIT

GRIDFILE
  0 1 /

RPTGRID
 22*0 /
```

```
================================================================
--             EDIT SECTION
--
================================================================
EDIT

================================================================
--             PROPS SECTION
================================================================
PROPS

DENSITY
 800  1000  0.824 /

PVCDO
-- Pref      FVFo       Coil       Viso      Visco
--(bara)   (rb/stb)   (1/bara)     (cp)    (1/bara)
    234      1.06541   6.65e-5     6.4     192.e-5    /

RSCONSTT
  0.00  43.8 /

PVTW
 234  1.012  4.28e-5  0.5 /

INCLUDE
'relperm.inc'  /

-- Pref     Cr
ROCK
   234    1E-8 /

PCW
7*73 /

RPTPROPS
PCW /

--Polymer properties
INCLUDE
'POL_ND.INC'  /

================================================================
-- REGIONS SECTION
================================================================
REGIONS

================================================================
-- SOLUTION SECTION
================================================================
SOLUTION

MESSAGES
12*9999999 /
--6* 2* 2*200 2* /
```

```
--EQUIL
-- DATUM   DATUM   OWC  OWC    GOC   GOC  RSVD  RVVD  SOLN
-- DEPTH   PRESS  DEPTH  PCOW  DEPTH  PCOG  TABLE  TABLE  METH
--   2240      234    99999   5* 0 /

PRESSURE
7*234 /

SWAT
7*0 /

-- INITIAL RESTART FILE
RPTSOL
 RESTART=2  FIP=3  FIPRESV SWATINIT /

=====================================================================
--     SUMMARY SECTION
=====================================================================
SUMMARY

INCLUDE
'summary.inc'  /

=====================================================================
--  SCHEDULE SECTION
=====================================================================
SCHEDULE

RPTRST         Controls on output to the RESTART file
-- Controls output of .UNRST file
-- BASIC=4 => Restart file is written every 3. year
   BASIC=1    FREQ=1    FIP=3    ALLPROPS  PCOW WELLS    /

--RPTSCHED
-- 'NEWTON=1'       -- linear eq summary for each time step to prt-
file (=1)
-- 'SUMMARY=1'      -- solution summary for each time step to prt-
file (=1)
-- 'WELSPECS'
--/

-- Basic tuning
TUNING
-- Record 1: Time stepping controls
-- TSINIT TSMAXZ TSMINZ TSMCHP TSFMAX TSFMIN TSFCNV TFDIFF
    0.5    30.0  0.0001 0.00015  2*            0.3   1.25  /
-- Record 2: Time truncation and convergence controls
--TRGTTE TRGCNV TRGLCV 3XTTE 3XCNV 3XMBE 3XLCV 3XWFL TRGFIP
    0.5   0.01  1.0E-6 5.0E-4  10   0.01 1.0E-4 0.001 0.01   0.1 /
--Record 3
-- NEWTMX  NEWTMN  LITMAX  LITMIN   MXWSIT
      10     1       50       1        30      8   /
```

```
WELSPECS
INJ   WELL1   1  1  1*  WATER 2* SHUT YES  1*  AVG 0 /
PROD  WELL2   7  1  1*  OIL   2* SHUT YES  1*  AVG 0 /
/

COMPDAT
INJ     1  1  1  1  OPEN  1*  1*  0.177  1*  2*  Z  1*    /
PROD    7  1  1  1  OPEN  1*  1*  0.177  1*  2*  Z  1*    /
/

WCONPROD
PROD   OPEN    BHP  5*  200  /
/

WCONINJE
--INJ     WATER  OPEN BHP 2* 500  /
INJ    WATER  OPEN  RATE  200  /
/

GECON
--        Water Cut
FIELD  2*     0.9     2*  WELL   YES  /
/

-- Volume of injected polymer solution
INCLUDE
 'PVI.INC'  /

END
```

ECLIPSE INCLUDE-File: Polymer Properties

```
--Polymer properties

--Polymer solution viscosity function
--Polymer Concentration vs. Viscosity Multiplier
PLYVISC
0.0   1.0
0.1   1.3
0.2   1.5
0.3   1.9
0.4   2.3
0.5   2.7
0.6   3.3
0.7   4.0
0.8   4.8
0.9   5.6
1.0   6.7
1.1   7.7
1.2   9.0
1.3   10.4
1.4   11.9
1.5   13.5
1.6   15.4
1.7   17.3
1.8   19.6
1.9   21.9
2.0   24.4
2.1   27.1
2.2   30.0
2.3   33.1
2.4   36.5
2.5   40.0
2.6   43.8
2.8   52.0
3.0   61.3
3.4   83.0
3.7   102.3
4.0   124.4
4.3   149.5
4.9   209.5
5.5   283.7
6.0   357.6
6.1   373.8
6.5   443.3
/

PLYROCK
--Dead   Residual    Rock       Max
--Pore   Resistance  Mass       Polymer
--Space  Factor      Density    Adsorption
--                        ?(1=Desorption, 2=No Desorption)
   0.1     1.0       2650  2    0.000030 /
```

```
--Polymer adsorption function
--Local Polymer Concentration vs. Polymer Adsorbed
PLYADS
0.00  0.0
0.25  0.000010
0.50  0.000018
0.75  0.000023
1.00  0.000027
1.25  0.000029
1.50  0.000030
1.75  0.000030
2.00  0.000030
3.00  0.000030 /

--Todd-Longstaff mixing parameter
PLMIXPAR
1  /

PLYMAX
 7.7  0  /
```

ECLIPSE INCLUDE-File: Relative Permeability Curves corresponding to Figure 8

```
SWOF
--Sw      Krw       Kro     Pcow
0.0000    0.0000    1.0000  2.000000
0.0250    0.0000    0.9269  0.772667
0.0500    0.0000    0.8574  0.457464
0.0750    0.0001    0.7915  0.298384
0.1000    0.0003    0.7290  0.200292
0.1250    0.0007    0.6699  0.132954
0.1500    0.0013    0.6141  0.083467
0.1750    0.0022    0.5615  0.045323
0.2000    0.0036    0.5120  0.014857
0.2250    0.0054    0.4655  -0.010161
0.2500    0.0078    0.4219  -0.031176
0.2750    0.0109    0.3811  -0.049166
0.3000    0.0148    0.3430  -0.064821
0.3250    0.0196    0.3075  -0.078643
0.3500    0.0254    0.2746  -0.091009
0.3750    0.0323    0.2441  -0.102209
0.4000    0.0405    0.2160  -0.112473
0.4250    0.0500    0.1901  -0.121984
0.4500    0.0611    0.1664  -0.130897
0.4750    0.0739    0.1447  -0.139344
0.5000    0.0884    0.1250  -0.147441
0.5250    0.1048    0.1072  -0.155293
0.5500    0.1234    0.0911  -0.163002
0.5750    0.1442    0.0768  -0.170665
0.6000    0.1673    0.0640  -0.178388
0.6250    0.1930    0.0527  -0.186281
0.6500    0.2214    0.0429  -0.194470
0.6750    0.2527    0.0343  -0.203108
0.7000    0.2870    0.0270  -0.212377
0.7250    0.3245    0.0208  -0.222515
0.7500    0.3654    0.0156  -0.233837
0.7750    0.4098    0.0114  -0.246780
0.8000    0.4579    0.0080  -0.261972
0.8250    0.5100    0.0054  -0.280363
0.8500    0.5662    0.0034  -0.303469
0.8750    0.6267    0.0020  -0.333880
0.9000    0.6916    0.0010  -0.376441
0.9250    0.7612    0.0004  -0.441413
0.9500    0.8357    0.0001  -0.555077
0.9750    0.9152    0.0000  -0.811342
1.0000    1.0000    0.0000  -2.000000
/
```

ECLIPSE INCLUDE-File: Injection Scheme

```
--Injection Scheme for 1D Homogeneous Case
--1000 day's polymer flooding followed by water flooding

--1000 day's Polymer Flooding
WPOLYMER
--Polymer Concentration at Injection
INJ  1.5 /
/

TSTEP
100*10
/

-- Water post-flush until field economic limit reached
WPOLYMER
INJ  0.0 /
/

TSTEP
400*10
/
```

Appendix E: Impact of Shape of Up-scaled Polymer Solution Viscosity Function on Up-scaling Polymer Flooding

Introduction

In the main part of this thesis, it is proved that it is possible to reproduce some fine grid results, for example ultimate oil recovery, by up-scaling the polymer solution viscosity function (viscosity function) for polymer flooding. An up-scaling factor f_v was introduced to up-scale the viscosity function. However, that method didn't consider the shape of the viscosity function. From the plot of polymer solution viscosity at each grid block for different grid sizes (Figure 12), it can be seen that a big difference is between the polymer solution viscosities for the fine grid model (20m model) and the coarse grid model (180m model) due to numerical dispersion. In order to up-scale the coarse grid viscosities to the same level as the fine grid viscosities, the up-scaled polymer solution viscosity should be lower than the original one at low concentration and higher at high concentration. Different methods have been tried to determine the shape of the viscosity function, but only a few is effective. The way to determine the shape of the viscosity function and the impact of the shape of the viscosity function will be introduced in this additional study.

Up-scaling Methods

Method 1

This method is the one used in the main part of this thesis. The polymer solution viscosity function is up-scaled by introducing a viscosity up-scaling factor f_v. Eq. 3.1-1 represents the relation between the original viscosity multiplier M_v and the up-scaled viscosity multiplier $\widetilde{M_v}$. This method doesn't take the shape of the viscosity function into account.

Method 2

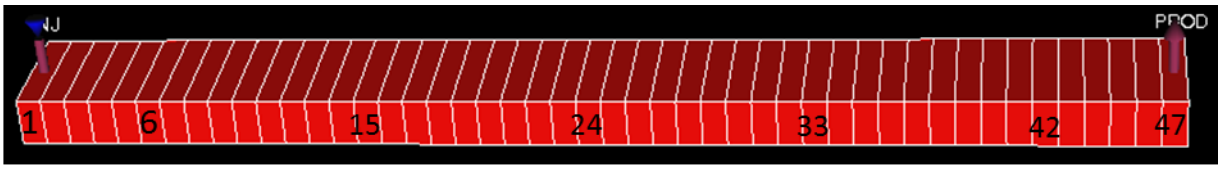
The idea is to make the coarse grid model have the same polymer solution viscosity as that simulated on fine grid model. However, it is almost impossible because the difference between the polymer solution viscosities for fine and coarse grid model changes for each grid block and for time. Thus, we only consider the time when the viscosity difference is the biggest for each grid block.

Take the 1D Homogeneous Irreversible Case for example. Detailed description of the case and the models can be found in Section 6.1. The coarse grid model has 7 grid blocks numbered in Figure 59 (b). The positions of the middle point of these grid blocks correspond

to the middle point of the numbered grid blocks on the fine grid model as shown in Figure 59 (a). After running simulations in ECLIPSE, we can get the simulated histories of fine and coarse grid polymer solution viscosities for each of the numbered grid blocks, and the simulated history of coarse grid polymer concentration for each of the numbered grid blocks. For each coarse grid block, by dividing the fine grid polymer solution viscosities by the coarse grid polymer solution viscosities, we can find at what time the difference between fine and coarse grid polymer solution viscosities is the biggest. For example for Coarse Grid Block No. 4, it is found that the maximum difference happens at 1950 days. Dividing the polymer solution viscosity at each numbered fine grid block at 1950 days by water viscosity, we get the viscosity multiplier at each numbered fine grid block at 1950 days. Plotting viscosity multiplier at each numbered fine grid block at 1950 days vs. polymer concentration at each numbered coarse grid block at 1950 days, we can get a curve shown as the blue dashed curve in Figure 60. Repeating that for all the coarse grid blocks, we get the dashed curves shown in Figure 60. Then, it is needed to combine all these dashed curves into one curve. Because the viscosity function must be a monotone increasing function as defined in ECLIPSE, the points that don't satisfy that requirement must be eliminated. And we assume that the up-scaled function follows the original function when the polymer concentration is higher than that we can get from the output simulation results. Finally, the up-scaled viscosity function is shown as the red solid curve in Figure 60.

Method 3

As the simulation result shows, up-scaled viscosity function by Method 2 doesn't make the fine grid ultimate oil recovery reproduced on the coarse gird model even though the mismatch is reduced. Therefore, the up-scaled function generated by Method 2 needs to be up-scaled again by Method 1. The functions generated by these 3 methods are plotted in Figure 61.



(a) Fine Grid Model

(b) Coarse Grid Model

Figure 59: 1D Homogeneous Models with Numbered Grid Blocks

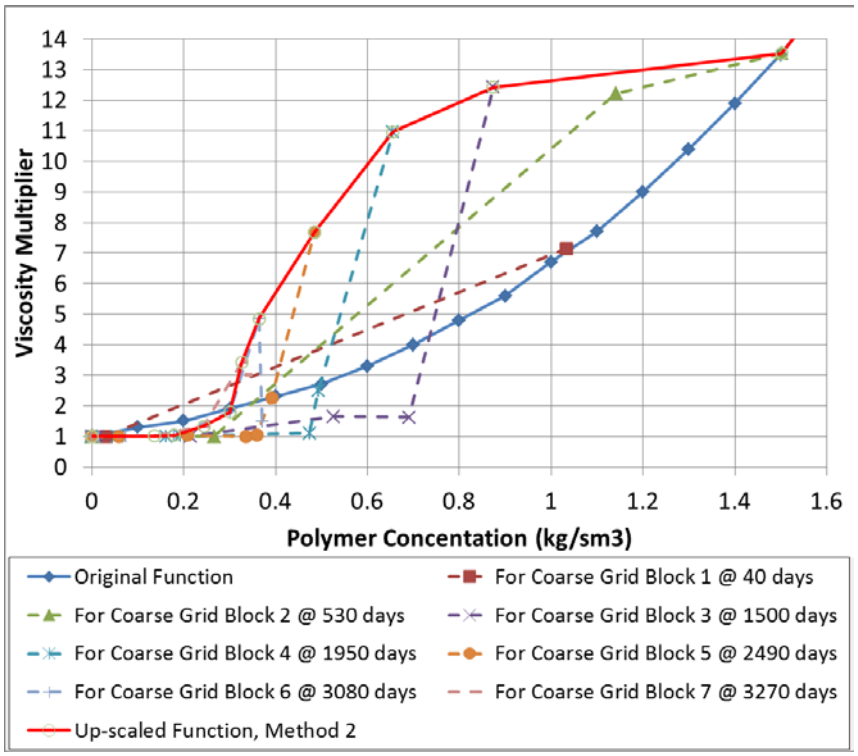


Figure 60: Up-scaling Viscosity Function Using Method 2

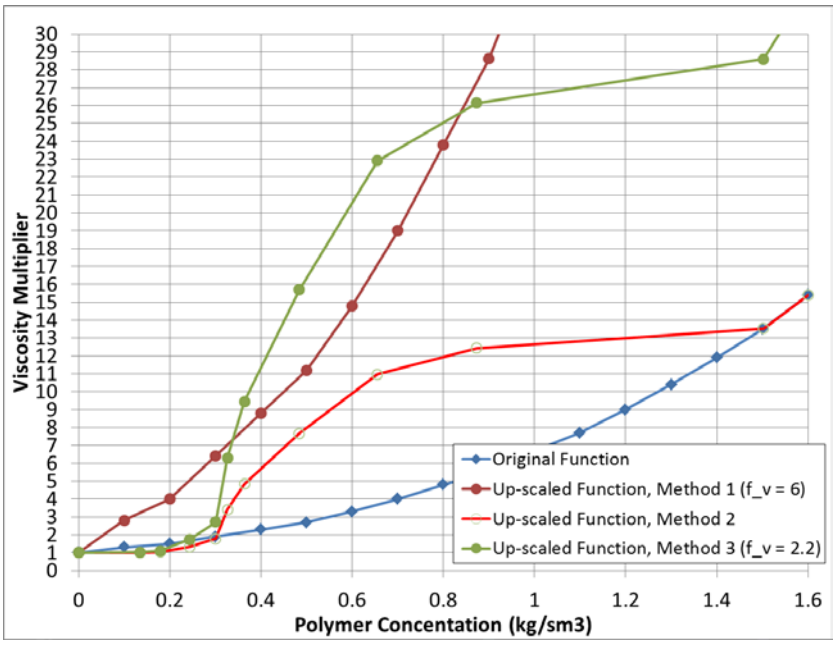


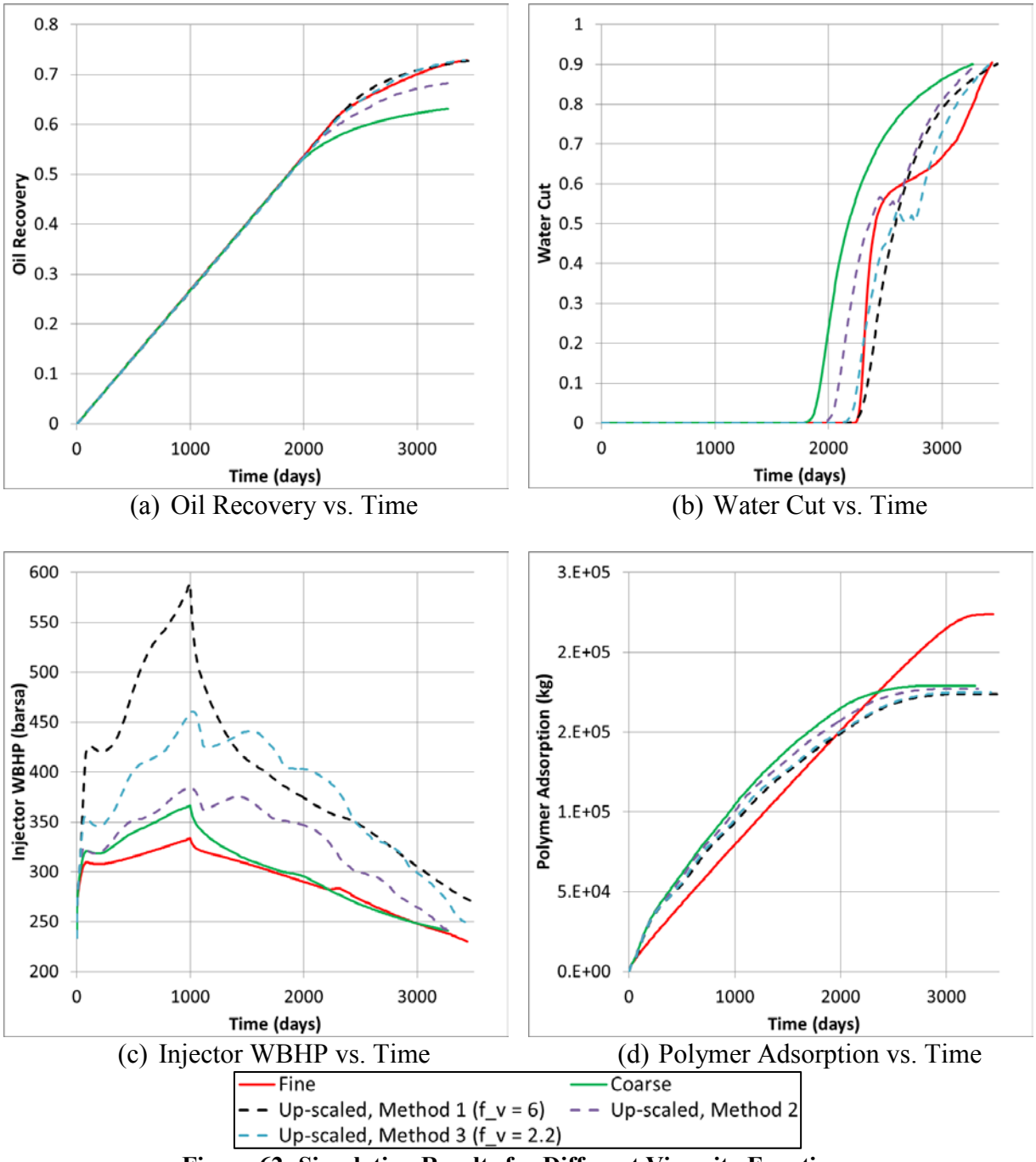
Figure 61: Up-scaled Viscosity Functions by 3 Methods

Results

All the simulations are run on a set of 1D homogeneous models (Section 6.1) in ECLIPSE 100 simulator. Time steps for data output are set to 10 days. The plots of simulation results are shown in Figure 62. By applying Method 2, the accuracy of prediction of oil recovery is improved; the history of water cut is changed a lot and its shape becomes closer to the fine grid water cut; and the maximum injector WBHP is much lower than that generated by Method 1 even though it is still higher than the injector WBHP of fine grid model. However, the fine grid ultimate oil recovery is not reproduced on coarse grid model only using Method 2. The function generated by Method 2 has to be up-scaled again by multiplying an up-scaling factor as we has discussed for Method 3.

The up-scaled factor is found to be 2.2 for Method 3, which is smaller than that found for Method 1 (f_v = 6). When Method 3 is applied, the fine grid ultimate oil recovery is reproduced on the coarse grid model; the accuracy of predicting the water break-through time is improved; as expected, the injector WBHP becomes larger than that generated by Method 2 become the polymer viscosities are enlarged, but the maximum value of injector WBHP is still much lower than that generated by Method 1. A lower maximum injector WBHP is due to that the up-scaled viscosity multipliers by Method 3 are smaller than those up-scaled by Method 1 at high polymer concentrations as Figure 61 shows.

From Figure 62 (d), we can see that none of these methods reduces the mismatch in polymer adsorption. Therefore, the polymer adsorption function has to be up-scaled also.



(a) Oil Recovery vs. Time

(b) Water Cut vs. Time

(c) Injector WBHP vs. Time

(d) Polymer Adsorption vs. Time

Figure 62: Simulation Results for Different Viscosity Functions

Conclusion

Following points can be concluded from the study on impact of the shape of the polymer solution viscosity function on up-scaling polymer flooding:

- The shape of the up-scaled polymer solution viscosity function can make big impact on up-scaling polymer flooding, especially on water cut and injector WBHP;
- The simulated history of water cut on fine grid model may be reproduced properly on coarse grid model if the shape of up-scaled polymer solution viscosity function is determined correctly;
- The problem of extremely high up-scaled injector WBHP caused by simply multiplying a viscosity up-scaling factor f_v (Method 1) can be solved by correctly determining the shape of up-scaled polymer solution viscosity function;
- The impact is investigated only on 1D homogeneous models in this additional study, so more complex models should be used to investigate this impact in further studies;
- The method used to determine the shape of the viscosity function (Method 2) is not a robust method and there is other ways to determine the shape of the viscosity function, for example base on flow equations. Therefore, different ways to determine the shape of the viscosity function should be investigated in further studies.