NTNU – Trondheim
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Study of non-local equilibrium options in reservoir simulators

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

Supervisor 1: Professor Ole Torsæter
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Preface

The work of this Master Thesis has been performed in the fourth semester of my MTPETR Master Program (specialization “Reservoir Engineering”). I worked with Professor Ole Torsæter who oversaw my academic work for NTNU, and Leonardo Patacchini who supervised my work for the French company TOTAL who hosted this project.

The main objective of this work was to study the effects of non-local thermodynamic equilibrium in a compositional reservoir simulator.

Total provided me with several documents, files and software that helped me work more efficiently, and analyze the results of the simulation outputs. I also benefited from the knowledge and the experience of the company, as well as some specific data for real fields, which made it much easier to show the validity of the functionalities developed.

The idea of this project came from the company Total, who is implementing new models for its in-house research reservoir simulator.

Pau, 2013-05-15

(Quentin Pallotta)

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I would also like to express my gratitude to my supervisor Pr. Ole Torsæter for help, guidance and everything that he did for me during the whole semester.

The work in this semester project was made independently and in accordance with the rules set down by the Examination Regulations made by the Norwegian University of Science and Technology.

(Quentin Pallotta)

Abstract

The recent IT improvements in areas such as CPU speed, memory, parallel computing and programming languages have allowed more complex physical models to be created for reservoir simulators. One of the issues that is still not fully resolved is the non-local equilibrium. Indeed, it is not possible to model subgrid heterogeneities causing the thermodynamic phase equilibrium between oil and gas to not be reached at the coarse scale: we can not reduce the scale of the grid enough because it will take too much computational time. Thus, we developed new models in Total's In-House Research Reservoir Simulator (IHRRS) for both Black-Oil and compositional cases. We focused on two different topics: the delay of vaporization and dissolution of light and heavy components as well as the underestimation of residual oil saturation to gas flooding. Indeed, even if the oil is not able to move due to its saturation being below oil-to-water and oil-to-gas residual saturation, unless restrictions are applied it keeps vaporizing into the fresh gas during simulation, which is not physical due to trapped oil in dead-end pores.

We implemented local relaxation models on R_s and R_v in IHRRS, materialized in ECLIPSE by keywords DRSDT and DRVDT. Then, we have adapted them to compositional simulations by applying the relaxation to K_i instead of R_s and R_v. Afterwards, we made a new model assuming that equilibrium is instantaneous but dependent on oil saturation for both Black-Oil and compositional cases, materialized in ECLIPSE 100 by the keyword VAPPARS. We extended this model, allowing it to prevent oil from vaporizing into the gas phase if the saturation is below a defined value. In miscible or nearly-miscible gas flooding compositional simulation, it is possible to use alternative methods, such as alpha-factors, but it is quite complicated to compute the coefficient tables when it comes to non-miscible fluids.

We benchmarked the results given by IHRRS with Eclipse for the relaxation models on R_s and R_v, as well as for the oil-saturation-depend Black-Oil equilibrium model. Then, we created equivalent 2-components data sets for both Black-Oil and compositional simulation. We used it to benchmark the new compositional models in IHRRS. Finally, we compared the results given by our new compositional model to ensure a non-zero residual saturation to gas flooding with alpha-factors or SOR in ECLIPSE 300.

Keywords: non-local equilibrium, non-zero residual oil saturation, gas flooding, reservoir simulator.

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Introduction

1.1 Reservoir simulators

1.1.1 Overview

Petroleum reservoir simulation has evolved a lot since its birth in the 1950s. A reservoir simulator is a software based on well known reservoir engineering techniques and formulas. Using some assumptions on the geology of the reservoir, and the initial state, it is able to predict the evolution of the reservoir properties by iteratively solving constraint and conservation equations. The evolution in reservoir simulation over the last 60 years is due to the incredible increase in computational power and the development of new and more advanced techniques. Figure 1.1 downloaded from Wikipedia shows the number of transistors per year in a CPU. According to Moore's law which is accurate so far, the number of transistors in a CPU is supposed to double up every year. This allows to increase significantly the floating point operations per second (flop/s) that a computer is able to perform, which leads to substantial improvement in reservoir simulation time. Figure 1.2 published by `http://www.top500.org/` shows the evolution of performance for the top 500 computers in the world: the sum of their power increased from 0.42 giga flop/s in 1993 to 76.53 tera flop/s in 2012. It was multiplied by 182 000.

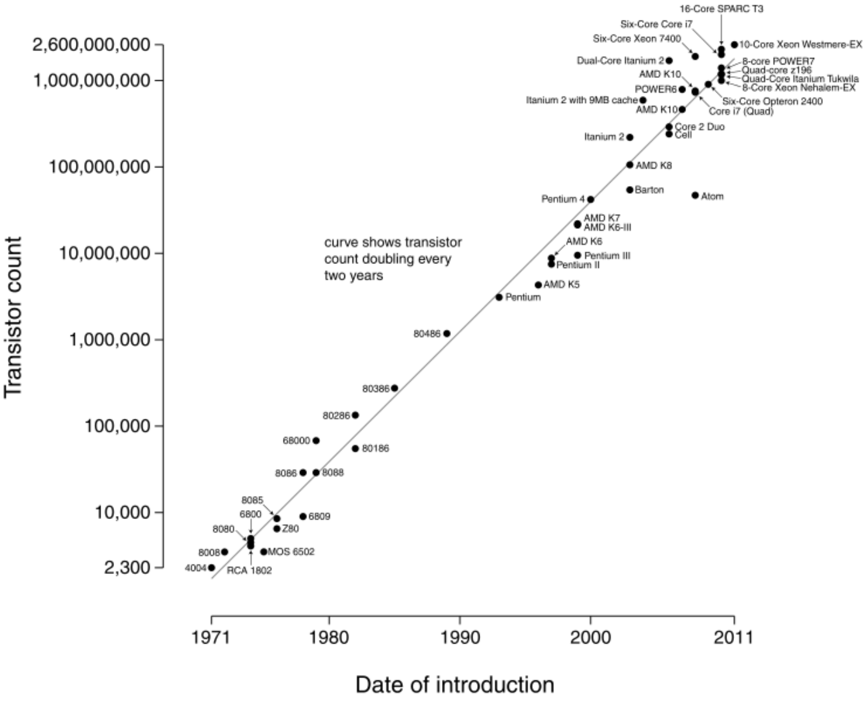


Figure 1.1: Number of transistors per years in a CPU

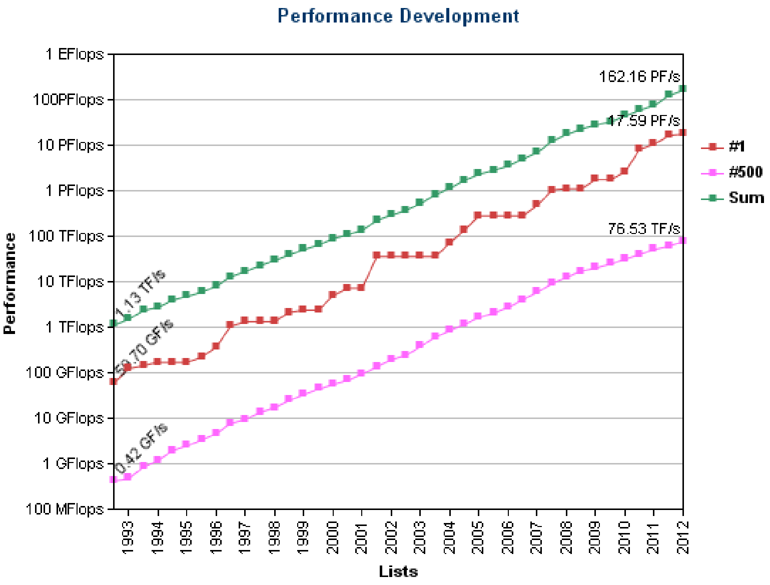


Figure 1.2: Performance of the top 500 best computers in the world between 1993 and 2012 according to http://www.top500.org/

Those changes allowed the new reservoir simulators to perform calculations with immense grids, complex physics, or for long periods. But the principle remains the same as what engineers did before with a simpler model. More detailed information about reservoir simulation can be found in reference [Ode69].

1.1.2 Basics

The main purpose of reservoir simulation is to predict the flow of fluids (oil, gas and water) in a porous media. Oil can refer to the component in a Black-Oil model or the liquid non-water phase. Gas can refer to the component in a Black-Oil model or the gas phase. The reservoir simulator is solving Material Balance Equations with thermodynamic equilibrium at the cell scale, typically a few tens of meters.

The reservoir is divided into small parts that are called “cells”. It is the spacial slicing. Figure 1.3 shows an example of a 50 000 cells reservoir model. Each cell has constant and homogeneous properties at a given time like water, oil and gas saturations, pressure, temperature or permeability. Those properties can be constant over time or change like oil saturation. An input data set is given to the simulator containing all information about the reservoir grid, the properties of the components that are present, and also the initial state. The initial state can be entirely defined by constant values for all the attributes (saturations, pressure, temperature, and so on). But it can also be calculated using a model and an equation with some unknown parameters.

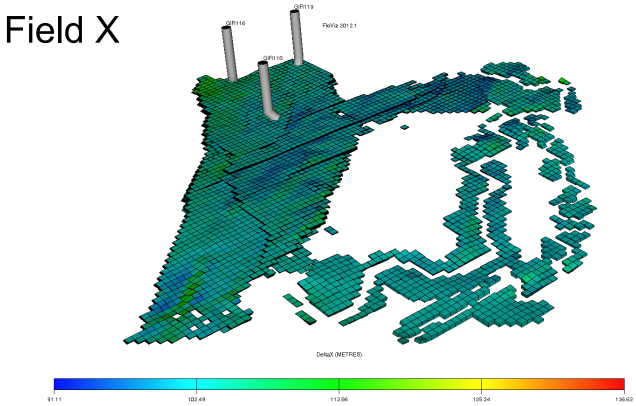


Figure 1.3: 3D view of a field X

The input data set also contains all the information related to the wells with their location, connection with cells and control properties. There is a time slicing as well. At each time step, the simulator is computing new properties for each cell by solving the equations that the models give, and then goes to the new time step. A time step typically lasts for one month but it can be reduced if there are some convergence difficulties. At the end of the simulation, the user retrieves the results that are written in different files that can be read by different post-processing software. It can show the evolution of parameters over time inside the reservoir.

Compositional model

The compositional model is considering the fluid components, or lumped components, separately. Petroleum reservoir fluids contain thousands of chemical components that affect their physical properties and phase behavior during production. It is not always possible and practical to describe petroleum fluids in terms of individual components. Instead, pseudo-components (groups of molecules) with average physical properties or main components are used to describe the reservoir fluids.

The simulator is converging a set of conservation equations for component moles simultaneously with local constraints, using as variables $\mathrm{c}_{i,j}$ (molar fraction of component i in phase j), S_j (saturation of phase j), P_j (pressure of phase j), and T (temperature). The conservation equations with an isothermal run are:

$$\frac{\partial}{\partial t}\left(\phi\sum_{j=1}^{n_p} S_j\rho_j c_{i,j}\right)+\nabla\cdot\left(\sum_{j=1}^{n_p} u_j\rho_j c_{i,j}\right)=0$$

where n_p is the number of phases, ρ_j is the molar density of phase j and u_j is the superficial velocity of phase j obtained from the extension of Darcy's law.

The constraint equations are:

$$\left(\sum_{j=1}^{n_p} S_j\right) - 1 = 0,$$

$$\left(\sum_{j=1}^{n_{cj}} c_{i,j}\right) - 1 = 0.$$

and the thermodynamic constraints are for each component:

$$y_i - K_i^{eq} x_i = 0$$

where y_i is the mole fraction of component i in the gas phase and x_i is is the mole fraction of component i in the oil phase. K_i^{eq} is the K-value of component i: it can be tabulated against pressure in a K-value simulation, or calculated by the ratio of fugacities in an equation of state (EoS) run.

Black-Oil model

The Black-Oil model is a simplified 2-phases and 2-pseudo-components approach: oil and gas. At reservoir conditions, he light component (gas) can be either in the gas phase, or dissolved in oil. Conversely, the heavy component (oil) can be in both phases as well, as shown in figure 1.4. In order to quantify the exchanges between oil and gas, there are 2 volumetric equilibrium coefficients R_s (gas solution ratio) and R_v (oil vaporization ratio):

$$R_s = \frac{V_{gas\ from\ oil\ at\ surface\ conditions}}{V_{oil\ from\ oil\ at\ surface\ conditions}} = \frac{V_{go}}{V_{oo}}$$

$$R_v = \frac{V_{oil\ from\ gas\ at\ surface\ conditions}}{V_{gas\ from\ gas\ at\ surface\ conditions}} = \frac{V_{og}}{V_{gg}}$$

R_s expresses the amount of gas dissolved in the oil phase, and R_v the amount of oil vaporized into the gas phase. Those properties depend on the pressure, the process at reservoir conditions, and also the surface processing.

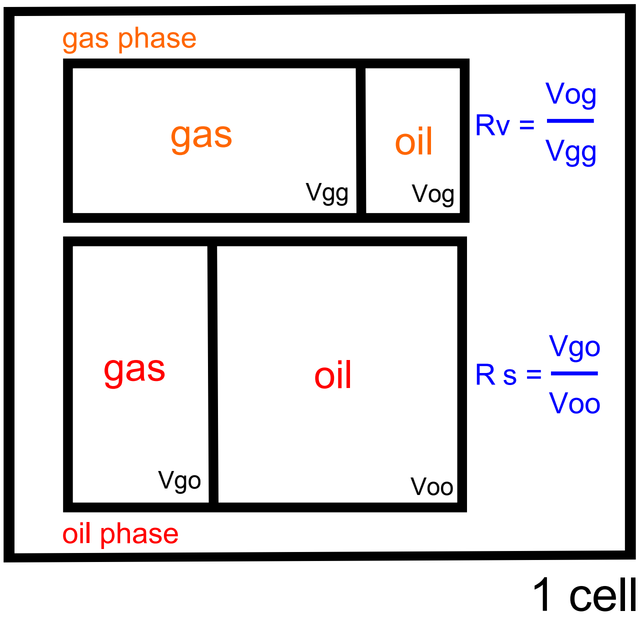


Figure 1.4: The Black Oil model (reservoir)

The Black-Oil model is reasoning with surface volumes. The two volume factors B_o and B_g are defined as follows:

$$B_o = \frac{V_{go} + V_{oo}}{V_{oo}} = \frac{V_o}{V_{oo}}$$

$$B_g = \frac{V_{og} + V_{gg}}{V_{gg}} = \frac{V_g}{V_{gg}}$$

where V_o and V_g are the volume of reservoir oil and gas phases in the considered reservoir cell, V_{go} is the volume of surface gas released from the reservoir oil phase, V_{oo} the volume of surface oil released from the reservoir oil phase, and so on (see figure 1.5).

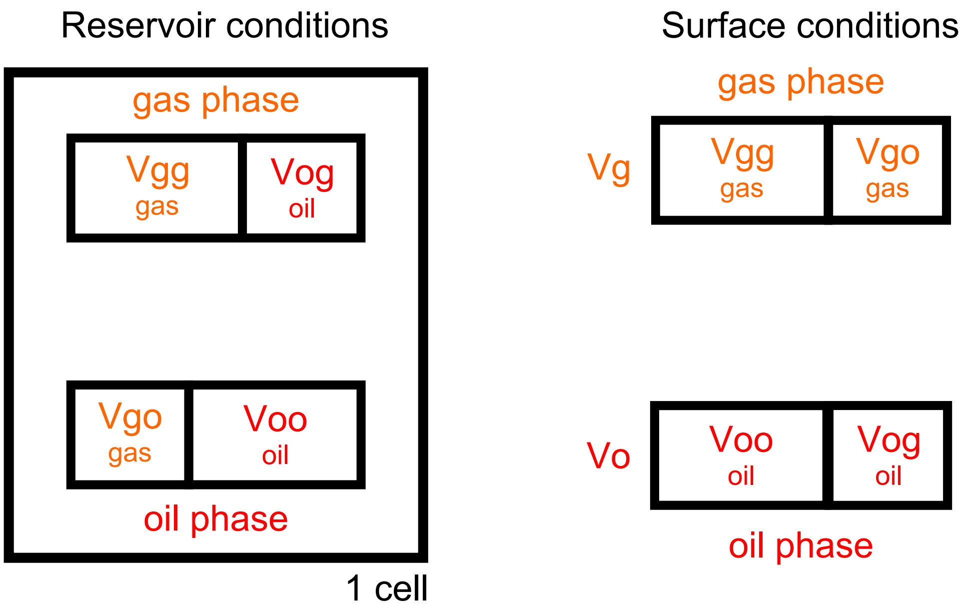


Figure 1.5: The Black Oil model (reservoir and surface)

The simulator is solving the conservation equations for the surface volumes, which write:

$$\frac{\partial}{\partial t}\left[\phi\left(\frac{S_g}{B_g}+R_s\frac{S_o}{B_o}\right)\right]+\nabla\cdot\left(\frac{u_g}{B_g}+R_s\frac{u_o}{B_o}\right)=0$$

$$\frac{\partial}{\partial t}\left[\phi\left(\frac{S_o}{B_o}+R_v\frac{S_g}{B_g}\right)\right]+\nabla\cdot\left(\frac{u_o}{B_o}+R_v\frac{u_g}{B_g}\right)=0$$

The Black-Oil model is equivalent to a thermodynamic binary, where the surface gas phase is identified with a light component “l” and the oil phase with a heavy component “h”. We can freely choose the ratio of surface molar density: $\theta = \frac{\rho_l^{surface}}{\rho_h^{surface}}$. In practice, the user provides the surface mass densities $\bar{\rho}_o^s$ and $\bar{\rho}_g^s$, where s stands for surface, and we are free to choose the molar masses M_l and M_h such that: $\theta = \frac{\bar{\rho}_g^s M_h}{\bar{\rho}_o^s M_l}$.

Defining x_l, x_h, y_l and y_h the molar fractions of “l” and “h” in the reservoir oil and gas phase, respectively, we can derive the following relationships between molar and volumetric properties:

$$\begin{cases} x_h = \frac{\theta}{\theta + R_s} , \\ x_l = \frac{R_s}{\theta + R_s} , \end{cases}$$

$$\begin{cases} y_h = \frac{\theta R_v}{1 + \theta R_v} , \\ y_l = \frac{1}{1 + \theta R_v} , \end{cases}$$

$$\begin{cases} R_s = \theta \frac{x_l}{1 - x_l} , \\ R_v = \frac{1}{\theta} \frac{y_h}{1 - y_h} . \end{cases}$$

1.1.3 Eclipse

The ECLIPSE software is a reservoir simulator which was primarily developed by the company ECL (Exploration Consultants Limited). Now, it is owned, developed, marketed and maintained by a division of Schlumberger called SIS.

ECLIPSE means "ECL's Implicit Program for Simulation Engineering", and Schlumberger kept this name after the switch of owners. ECLIPSE is written in Fortran 77 and has been used to help debug F77 compilers at IBM and Cray Research [Res].

ECLIPSE uses the finite volumes method to solve equations modeling a subsurface petroleum reservoir. It is composed of 2 different versions:

- ECLIPSE 100 for a Black-Oil model.
- ECLIPSE 300 for compositional hydrocarbon descriptions and thermal simulation.

ECLIPSE 300 can also interpret a Black-Oil data set. Schlumberger launched recently a new faster simulator called Intersect, developed in partnership with Chevron and Total since July 2012 [Sch].

1.1.4 IHRRS

IHRRS is Total's In-House Research Reservoir Simulator. The SPE paper [MPL12] describes and explains its operating principles. Many ECLIPSE's functionalities are not available in IHRRS, but the purpose of IHRRS is to test novel functionalities.

The main goal of this study is to implement new functionalities and models related to non-local equilibrium into IHRRS, and to validate them by matching the results given by Eclipse, if possible, or through alternate methods otherwise.

1.2 Non-local equilibrium

1.2.1 Main problem

Reservoir simulators usually make several assumptions in order to find the equations to be solved within a reasonable computing time. Therefore, the approximate models need to be close to what happen in the reality, otherwise, the results will be totally wrong. For instance, if one wants to inject gas in a cell containing only undersaturated oil, as showed in figure 1.6, the reservoir simulation software assumes that the oil and gas reach equilibrium instantly.

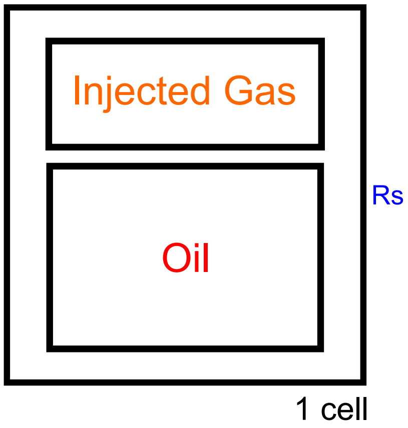


Figure 1.6: Injecting gas in an oil cell

Thus, the new composition of the mixture will be as shown in figure 1.7 if there is not enough gas to saturate all the oil in place. Otherwise, there will be oil and gas in equilibrium in that cell.

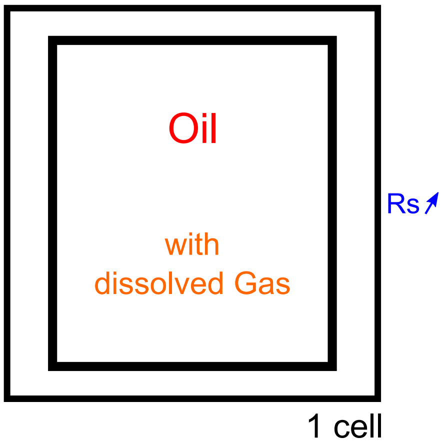


Figure 1.7: Gas dissolved in the undersaturated oil instantly

The previous assumption can be adequate if the reservoir is homogeneous and with a low rate of gas injection. But it becomes false if there are local heterogeneities, or if we want to inject a large amount of gas, within a short time. In this case, all the gas will not be able to dissolve into the oil: it will take some time, and between 2 timesteps, only a small part of the gas will be able to dissolve.

This phenomenon can explain why sometimes there is a gas breakthrough a few years before what is calculated in a simulation. For example, if the average permeability is **x** mD in a cell, the simulator will assume the cell is homogeneous. But the upper part of the cell can have a **0.2 x** mD permeability while the lower part will have **1.8 x** mD. Hence, only half of the oil in the cell will be in contact with the injected gas, and that oil will saturate faster than expected. It was experimentally highlighted in the article [AWUMG06].

To summarize, with cells at the pore scale, the local equilibrium assumption would be correct, but Darcy's Law does not apply. At Darcy scale, with very tiny cells, some pores could be not connected to the others, otherwise the local equilibrium is acceptable. But with macroscopic cells, there are always subgrid heterogeneities that make the local equilibrium assumption false, especially with gas injection (bypass) and when pressure increases.

1.2.2 Different models

In order to take into account the non-local equilibrium, it is possible to implement different models. Even if the equilibrium is not reached, there is still component exchange between the phases. The oil in equilibrium is the conserved oil which is moving, like shown in figure 1.8, not the oil inside the cell that changed with time. The equilibrium local system should have equations regarding each phases and also inter-phase transfers. Those transfer rates depend on the deviation from equilibrium, but also oil and gas saturations. Thus, a proper physical model should have conservation of elements **per phase** instead of **cell**. It will generate twice more conservation equations: adding the equations of 2 different phases will lead to the same conservation equations as before, but subtract them will introduce a divergence term in the constraint equations. It is too difficult and complicated to implement because it would require a complete overhaul of the operation of the simulator. Therefore, we made adopted some simpler models and assumptions presented below.

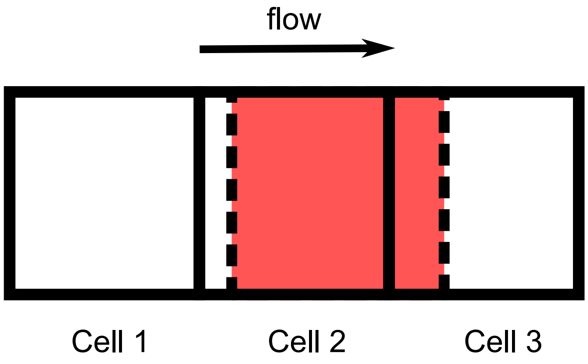


Figure 1.8: Fluid flow from left to right

When the pressure is increasing after a depletion, we study the case where there is not much movement inside the reservoir, and we only keep the term in relation to time derivative (DRSDT, DRVDT in ECLIPSE 100). With gas injection, we assume that equilibrium is instantaneous with saturation dependence (VAPPARS in ECLIPSE 100).

Back oil solution: DRSDT and DRVDT

The first model that limits the exchanges between oil and gas in a Black-Oil approach is used when the keywords DRSDT and DRVDT are present in an ECLIPSE 100 input data set. Those 2 keywords control the rate at which the solution gas-oil ratio (or vapor oil-gas ratio for DRVDT) is allowed to rise. The value of R_s is given in $sm^3/sm^3/day$ for metric units or Mscf/stb/day for field units. The value of R_v is given in $sm^3/sm^3/day$ for metric units or stb/Mscf/day for field units.

It only limits the increase in R_s or R_v. Indeed, the reduction is physically instantaneous. For instance, when there is only saturated oil in a cell: if the pressure decreases, the dissolved gas will evaporate and a gas phase will appear. But this process happens everywhere in the oil at the same time, because small bubbles of gas form. Later on, if the pressure increases with oil and gas phases in the cell, the process for dissolving gas into the oil will occur at the interface between the 2 phases and will take some time.

Here is an example of the use of those keywords:

```
DRSDT
1E-4 / every day, the Rs value can only increase by 1E-4 Mscf/stb or less


DRVDT
1E-5 / every day, the Rv value can only increase by 1E-5 stb/Mscf or less
```

Limitations of that model

Setting DRSDT to 0 means that the solution gas-oil ratio is not allowed to rise. But it can create some nonphysical situations if gas is not present. Indeed, if oil with a given R_s is moving into a cell where oil has a lower R_s, the solution gas-oil ratio will remain at the lower R_s value, because it could not increase in that cell, and free gas will appear. But we only mixed less saturated oil with more saturated oil. This problem can be solved using the flag “FREE” in the DRSDT keyword. If this flag is present, the model will only apply to cells containing both oil and gas phases, as shown in figure 1.9. By default, or if the flag “ALL” is used, the model will apply for all cells in the reservoir.

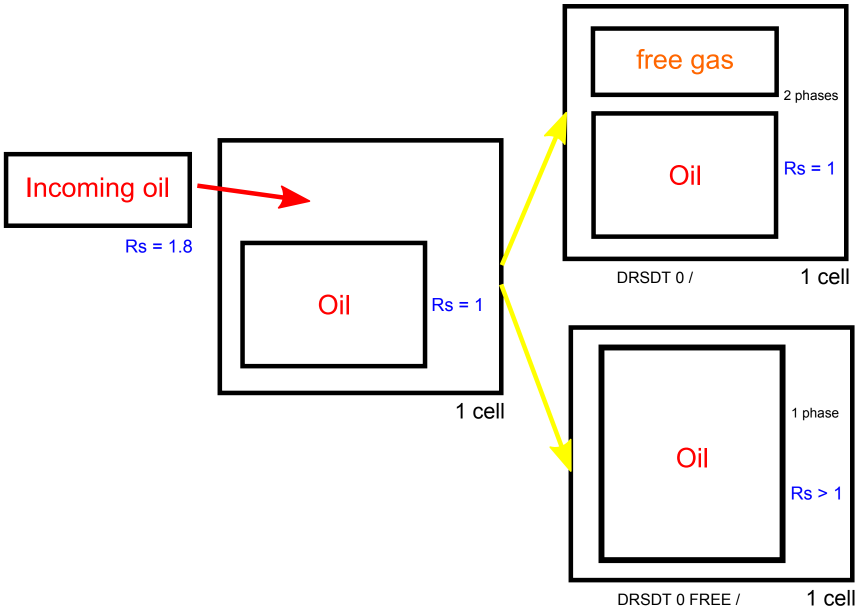


Figure 1.9: Problem with using DRSDT 0 / with only one oil phase and different Rs

It is not possible to use the "FREE" tag with the DRVDT keyword because it is not implement in ECLIPSE, although analog nonphysical situations can occur.

Furthermore, the model is not really "user friendly", because the input data is the maximum rate of increase for R$_s$ or R$_v$. But it is quite difficult to estimate that value, and we would prefer a model such as $\frac{dR_s}{dt} = -v\,(R_s - R_{sat})$, with a constant input value v defined by the user.

New Black-Oil solution: VAPPARS

Instead of limiting the increase of R$_s$ and R$_v$, the VAPPARS keyword offers a new model for calculating the R$_s$ and R$_v$ values, by reducing them as the oil saturation decreases. For example, if the target value for R$_s$ is 1.8, this keyword will reduce it to 1.75: less gas will be vaporized. In order to calculate those values, the VAPPARS model is using the following formulas:

$$R_v = R_{v\ sat}\left(\frac{S_o}{S_{o\ max}}\right)^{vap\ 1}$$

$$R_s = R_{s\ sat}\left(\frac{S_o}{S_{o\ max}}\right)^{vap\ 2}$$

Where vap 1 is the first real number argument in the VAPPARS keyword, and vap 2 is the second one. Like that, the R$_s$ and R$_v$ values will be decreased, and equilibrium will not be reached in the cell. Furthermore, when the oil saturation is reduced due to vaporization, further vaporization becomes more inhibited: the less oil saturation is, the more residual oil could not be connected to the newtork. The parameters are usually between 0 and 5, and they are dimensionless. High values can cause convergence difficulties. Here is an example of the use of this keyword, with the first argument referring to R$_v$ and the second one to R$_s$:

```
VAPPARS
2  0.5 / The first parameter is related to Rv (vap1), and the second one is related to Rs (vap2)
```

New model for compositional simulator

After implementing those models in the Black-Oil IHRRS, we needed to find something similar for compositional models. It is more complicated because we can have more than 2 components, and it is difficult to quantify the amount of light into the heavy and vice versa. We do not have R$_s$ and R$_v$ coefficients in an Equation of State approach.

This is why we adopt a quite similar model, but with some modifications. To remind, for a component *i*, the K-value is defined by the ratio:

$$K_i = \frac{y_i}{x_i}$$

where y$_i$ is the mole fraction of component i in the gas phase and x$_i$ is is the mole fraction of component i in the oil phase. We arbitrarily decided that a component i is light if $K_i > 1$ (meaning that $y_i > x_i$) and heavy otherwise.

As an equivalent of the DRSDT and DRVDT keywords, we created an EQUILRELAX model which is replacing the $y_i - K_i^{eq} x_i = 0$ thermodynamic constraint of each hydrocarbon component by: $y_i - K_i x_i = 0$.

$$\text{Where} \begin{cases} K_i = K_i^{eq} \;\; \text{if light component vaporization or heavy component condensation.} \\ \dfrac{dK_i}{dt} = -\nu_i (K_i - K_i^{eq}) \;\; \text{else.} \end{cases}$$

The value of ν_i, which is a relaxation time constant in day^{-1}, is given by the user. This allows the exchange between the oil and gas phases to be limited for each component. And the input data is more physical and easy to estimate and understand than a variation of R$_s$ or R$_v$ for a period of time.

If all EQUILRELAX constants are set to 0, and we only have 2 components (which is equivalent to a Black-Oil model), it is exactly the same as using DRSDT and DRSDT set to 0 in ECLIPSE 100.

But when we integrated the DRSDT, DRVDT and VAPPARS models in the Black-Oil IHRRS, we did not allow to use it with the default “ALL” flag. We only allow to use it with the “FREE” flag, when there are both oil and gas phases present in the cell. It is the only physically acceptable model, and the only one that we implemented. It is not possible to set that option for DRVDT in Eclipse, therefore, we benchmarked it when both phases where present, with oil and gas in the initial state, in order to be able to compare something similar. The EQUILRELAX model does not have this problem.

Here is an example of the use of this keyword, with 4 components:

EQUILRELAX

0.5 0.5 0.5 0.5 /

−− Each parameter is related to a specific corresponding component *i*.

−− Unit is day^{-1}

New VAPPARS model for compositional simulator

Using the same way as above, we have integrated the compositional equivalent of VAPPARS, with the following formulas for the compositional case:

$$K_i = K_{i\ eq} \left(\frac{S_o}{S_{o\ max}} \right)^{\pm vap\ i}$$

The symbol ± is equal to "+" if the component is heavy ($K_{eq} < 1$) and "-" otherwise ($K_{eq} > 1$). Indeed, if the K-value is greater than 1, the component is light, and we should increase the value of K in order to move away from equilibrium. But if K is less than 1, we should decrease it, and multiply the saturated value by a number lower than 1.

1.2.3 Modification of our model

In order to have a different EoS model that can ensure a non-zero residual saturation for immiscible gas flooding, we have chosen to implement a new feature with the VAPPARS model in IHRRS: the minimal residual oil saturation (SORM). We dynamically change the formula for the K-value, depending on the oil saturation. And when the oil saturation reaches a defined value, it is not possible for the oil to further vaporize into the gas. The fresh gas will not reduce the oil saturation in the cell. The formula for compositional VAPPARS now becomes:

$$K_i = K_{i\ eq}\left(\frac{S_o - S_{orm}}{S_{o\ max} - S_{orm}}\right)^{\pm vap\ i}$$

where S_{orm} is the desired residual oil saturation. When the oil saturation reaches this value, the K-value will be equal to 0 for heavy components (only present in the oil phase) and infinity for light components (only present in the gas phase). It will limit the residual oil saturation to approximately that value, even if it can slightly change because of the compressibilities. It is only possible to do that with an immiscible gas flooding simulation, because otherwise K-values might not be defined. Black-Oil models only treat the immiscible case, therefore the problem is not present.

This model for an EoS simulation was also adapted with the Black-Oil case with the corresponding formulas:

$$R_v = R_{v\ sat}\left(\frac{S_o - S_{orm}}{S_{o\ max} - S_{orm}}\right)^{vap\ 1}$$

$$R_s = R_{s\ sat}\left(\frac{S_o - S_{orm}}{S_{o\ max} - S_{orm}}\right)^{vap\ 2}$$

It is so far the only Black-Oil model that can ensure a non-zero oil saturation at the end of the simulation, indeed all the other methods have been developed for compositional simulations, like the alpha factors. When the oil saturation reaches the predefined value, the R_s and R_v coefficients are set to 0. Like that there is no oil component in the gas phase, and no gas component in the oil phase. The oil is not allowed to vaporize into the gas, and the residual oil saturation stays constant in time. Other black oil models implemented in simulators are not able to prevent a part of oil from moving or dissolving into the gas, and they all lead to 0 % oil saturation if the simulation of gas injection lasts long enough.

Here is an example of the use of those two keywords combined, with 4 components:

```
VAPPARS
0.5  0.5  0.5  0.5 / each parameter is related to a specific component i


SORM
0.10 / the oil saturation should not go below 10 %
```

1.3 Objectives

The main objectives of this Master Thesis are:

- To benchmark the existing models that were adapted for IHRSS (DRSDT, DRVDT, and Black-Oil VAPPARS).
- To benchmark the new models that were created for the compositional simulator (EQUILRELAX, VAPPARS).
- To test the new models that enforce a residual oil saturation with VAPPARS and SORM (both black oil and compositional cases).

1.4 Other ways of enforcing non-zero residual oil saturation

Most models do not take into account that injecting fresh gas will always allow oil to vaporize, and can finally lead to a zero oil saturation, especially in the cells near the injector. But it is not physically possible to achieve it because some small pores are not connected, and there are tiny heterogeneities that can trap oil. Thus, we should take that phenomenom into account and be able to ensure that the final oil saturation will be low but not zero: we modified our model with SORM for that purpose. Here is an overview of other ways to achieve a similar result.

1.4.1 SOR keyword in Eclipse 300

The first method to ensure that a strictly positive residual oil saturation will remain at the end of the simulation is to exclude a portion of oil from the flash. It will only allow a reduced amount of oil to move and to leave a cell. Therefore, the residual oil saturation will not be lower than that predefined value.

It is what Schlumberger implemented on Eclipse 300 with the keyword SOR. Any user can exclude 5, 10, 15 % or any amount of each component saturation in the oil. It does not change the equilibrium, constraints, and other calculations, but it will not be possible to flow out the cell.

Below is an example of the use of this keyword with only 1 saturation region. The user chooses each amount (between 0 and 1) of each component that will be excluded from the flash calculation in every saturation region.

```
SOR
0.10 / 10 % of oil can’t flow out the cells
```

1.4.2 Transport coefficients

The full description of this method is detailed on the paper [BTG11]. The purpose of alpha factors, also called transport coefficients, is to differentiate the composition of the fluid flowing out of a cell from the fluid composition in said cell. The heavy components are slowed down, (alpha factors less than 1), while the light component speed is increased (alpha factors greater than 1). Like that, when we reach the required residual oil saturation, the heavy components of oil will not be able to move because their speed will be close to 0, and those components will remain in place.

The main problem is that it is quite difficult and long to calculate all those coefficients, and it is not an easy method to use.

Chapter 2

New methods and Benchmarks

2.1 Different simulations

We prepared some synthetic data sets to test the new models that we created for the IHRRS. We compared the results with the outputs given by Eclipse when possible. Otherwise, if the counterpart does not exist in Eclipse, or if it is not possible to directly benchmark the results, we created the same data set for an EoS or K-value case. In order to do that, we took 2 components very differentiated at surface conditions (one light and one heavy) and used their properties for all 3 data sets: Black-Oil, EoS and K-values. We have chosen the components C_1 and C_{12}.

2.1.1 Matching Eclipse and IHRRS data sets

The first step is to compare the results given by the Black-Oil model: we can directly compare the results obtained with Eclipse and IHRSS, because the DRSDT, DRVDT and VAPPARS models are available on both simulators. We just need to ensure that there is both oil and gas in all cells at the beginning of the simulation if we put the DRVDT keyword, because Eclipse can't accept the “FREE” tag for that keyword which activates the model only with both phases present.

We created simple grids for the simulation as shown in figure 2.1.

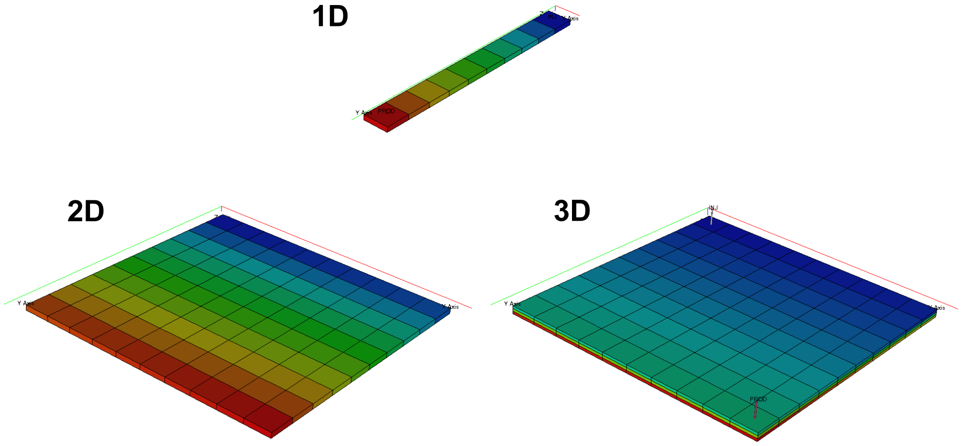


Figure 2.1: Different grids used for 1D, 2D and 3D simulations

```
DX
100 / all cells have the same dimensions: 100 x 100 x 10 feet.
DY
100 /
DZ
10 /
```

We put only two wells: one injector and one producer furthest away from each other, and we started to produce oil by depletion for 3 years before injecting gas until the end of the simulation, which is in the order of 25 years.

We have chosen different PVT properties (initial pressure, BHP for injector and producer, and so on) for different simulations, and we check that both data sets give the same results in Eclipse 100 and IHRRS for:

- **FGPR** The gas production rate

- **FPR** The average pressure in the reservoir

- **FOPR** The oil production rate

- **Initial state**

Then, we can apply the new models in the input data set and compare the result differences that they implied.

2.1.2 Validating new models

In order to verify that the new models with EQUILRELAX, VAPPARS and SORM in an EoS approach have been implemented correctly, it is not possible to compare the results given by Eclipse and IHRRS, because Eclipse does not support those new models.

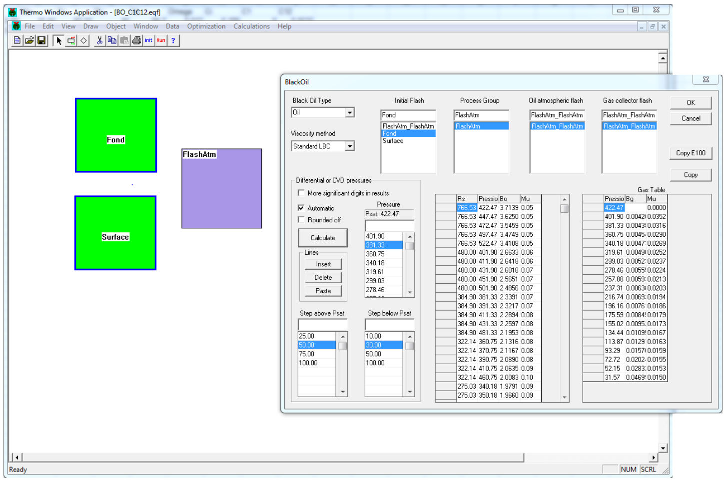
This is why we made some equivalent data sets for Black-Oil, EoS and K-value models with 2 components only: light (gas) and heavy (oil). We used BEST, Total's PVT software in order to compute the data, as shown in figure 2.2. We generated the Black-Oil table for different component couples such as C_1 and C_{12}. Then, we could calculate the KVTABLE which consists of the different pressures and the corresponding K-value for the components, which is necessary for the K-value input data set.

For instance, with the two components C_1 and C_{12}, we have the following data with an EOS approach:

Component	$1 = C_1$	$2 = C_{12}$
Molecular weight	$MW_1 = 16.04$ lb/lb-mol	$MW_2 = 170.33$ lb/lb-mol
Critical Temperature	$T_{C_1} = 343.08$ °R	$T_{C_2} = 1189.2$ °R
Critical Pressure	$P_{C_1} = 667.138$ psi	$P_{C_2} = 268.74$ psi
Acentric Factor	$ACF_1 = 0.012$	$ACF_2 = 0.575$
Binary interaction coef	BIC = 0.0532	BIC = 0.0532
Surface density (at st. condition)	0.041890347 lb/ft^3	46.44835198 lb/ft^3

BEST gave us the Black-Oil tables, for gas see B.1 and for oil see B.2. All the undersaturated branches are not displayed in the appendix, but they were calculated and used in the simulations.

With the different data sets, we could then run the same cases, with the same wells and injection rate, and it has been possible to compare the results obtained with the validated Black-



Thermo Windows Application - [BO_C1C12.eqf]

BlackOil

Black Oil Type: Oil

Viscosity method: Standard LBC

Initial Flash: Fond

FlashAtm_FlashAtm
Fond
Surface

Process Group: FlashAtm

FlashAtm

Oil atmospheric flash: FlashAtm_FlashAtm

FlashAtm_FlashAtm

Gas collector flash: FlashAtm_FlashAtm

FlashAtm_FlashAtm

Differential or CVD pressures

☐ More significant digits in results
☑ Automatic
☐ Rounded off

Pressure
Psat: 422.47

401.90
381.33
360.75
340.18
319.61
299.03
278.46

Step above Psat

25.00
50.00
75.00
100.00

Step below Psat

10.00
30.00
50.00
100.00

Rs	Pressio	Bo	Mu
766.53	422.47	3.7139	0.05
766.53	447.47	3.6250	0.05
766.53	472.47	3.5459	0.05
766.53	497.47	3.4749	0.05
766.53	522.47	3.4108	0.05
480.00	401.90	2.6633	0.06
480.00	411.90	2.6418	0.06
480.00	431.90	2.6018	0.07
480.00	451.90	2.5651	0.07
480.00	501.90	2.4856	0.07
384.90	381.33	2.3391	0.07
384.90	391.33	2.3217	0.07
384.90	411.33	2.2894	0.08
384.90	431.33	2.2597	0.08
384.90	481.33	2.1953	0.08
322.14	360.75	2.1316	0.08
322.14	370.75	2.1167	0.08
322.14	390.75	2.0890	0.08
322.14	410.75	2.0635	0.09
322.14	460.75	2.0083	0.10
275.03	340.18	1.9791	0.09
275.03	350.18	1.9660	0.09

Gas Table

Pressio	Bg	Mu
422.47		0.0000
401.90	0.0042	0.0352
381.33	0.0043	0.0316
360.75	0.0045	0.0290
340.18	0.0047	0.0269
319.61	0.0049	0.0252
299.03	0.0052	0.0237
278.46	0.0055	0.0224
257.88	0.0059	0.0213
237.31	0.0063	0.0203
216.74	0.0069	0.0194
196.16	0.0076	0.0186
175.59	0.0084	0.0179
155.02	0.0095	0.0173
134.44	0.0109	0.0167
113.87	0.0129	0.0163
93.29	0.0157	0.0159
72.72	0.0202	0.0155
52.15	0.0283	0.0153
31.57	0.0469	0.0150

Figure 2.2: BEST software to compute Black-Oil table for C1-C12

Oil model and the new EoS model. As plotted in figure 2.3, the field oil production rates are really close. It is the same for the gas produced, displayed in figure 2.4 and the pressure in figure 2.5. In all the graphs, the Black-oil run is plotted in blue, the EOS one is green and the K-value is red. We could then use the new models on each data set, and compare the results afterwards.

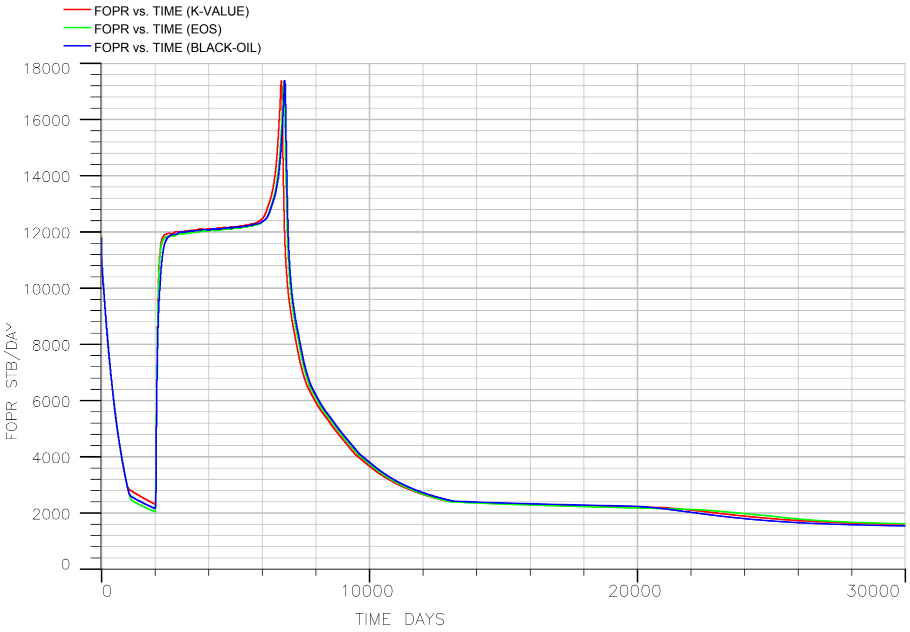


Figure 2.3: Different FOPR for Black-Oil, EOS and K-value models with C1 / C12 components

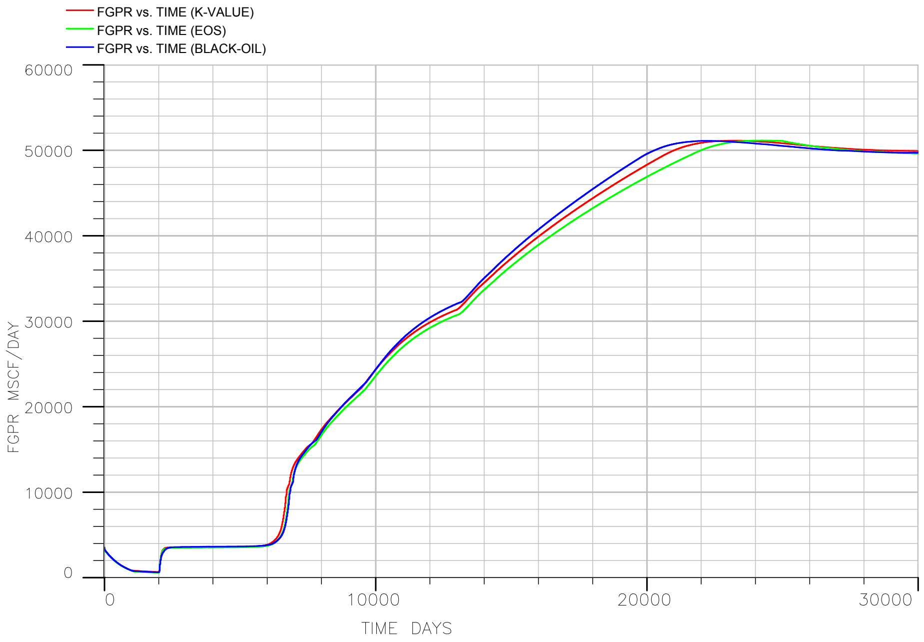


Figure 2.4: Different FGPR for Black-Oil, EOS and K-value models with C1 / C12 components

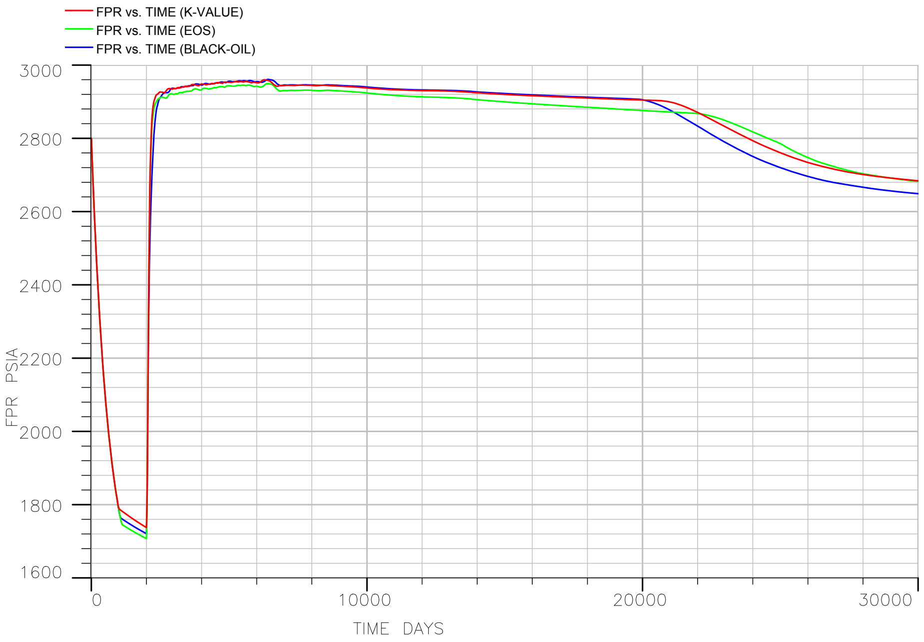


Figure 2.5: Different FPR for Black-Oil, EOS and K-value models with C1 / C12 components

The match between Black-Oil and EOS is almost perfect, because it is mathematically equivalent. But it was more difficult to get a proper match for the K-value. Indeed, the viscosity and density formulas used in this model were not precise enough to give the same curves. Therefore, the other parameters like viscosity and density were computed with the equation of state (EoS), using the keyword "KVALUES" in Eclipse.

2.2 Benchmarks

2.2.1 Black-Oil simulations

DRSDT and DRVDT

In order to test the correct implementation of DRSDT and DRVDT models for the IHRSS simulator, we ran different simulations with a 2-dimensional grid (10x10) for 11 000 days (almost 30 years). We started with oil (83 %), gas (5 %) and water (12 %) at a pressure of 5 800 psi. We only placed 2 wells: one producer at one extremity which is always producing with a fixed BHP equals to 4 500 psi, and one injector at the opposite side which is only injecting after 2 000 days at a BHP equals to 5 500 psi.

Figure 2.6 shows the oil production rate for the base case. Eclipse results are displayed with the markers while IHRRS results are shown by lines. The match is perfect, both simulators give the same outputs. Figure 2.7 shows the results with a DRSDT and DRVDT equal to 0. The match is good because we started with a 5 % gas saturation at the beginning of the simulation. As a consequence, all cells contain both oil and gas phases. Figure 2.8 is an intermediate case, with a DRSDT equal to $5 \cdot 10^{-5}$ Mscf/stb/day and a DRVDT equal to 10^{-5} stb/Mscf/day.

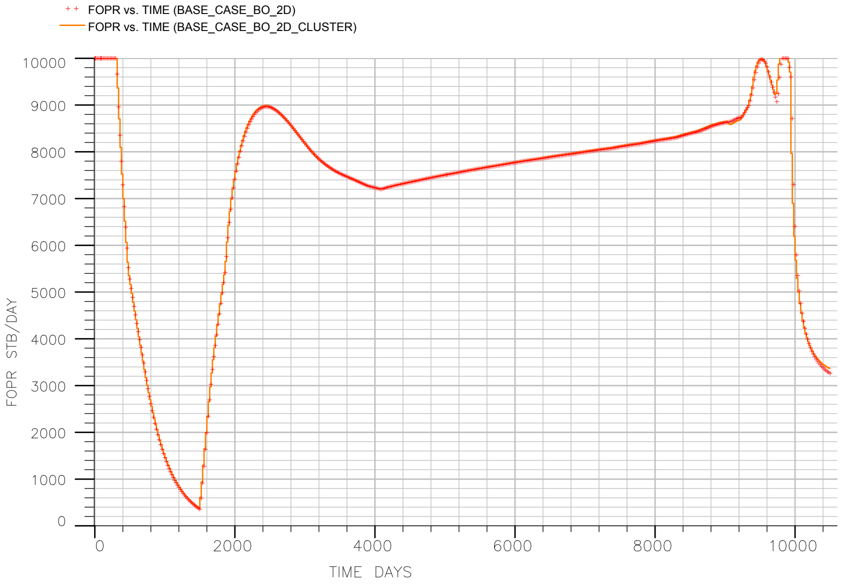


Figure 2.6: FOPR for the base case (DRSDT and DRVDT are infinite)

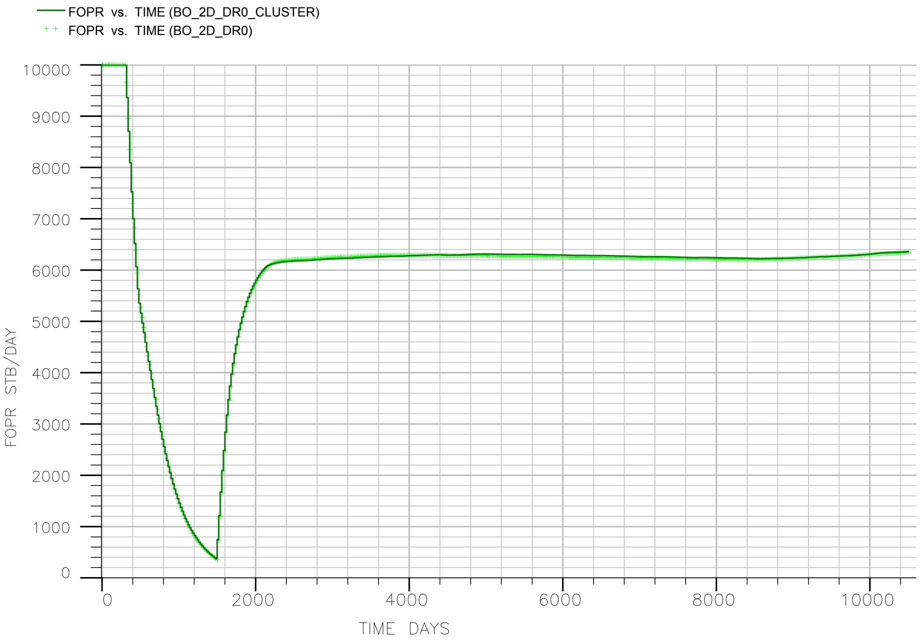


Figure 2.7: FOPR with DRSDT = 0 Mscf/stb/day and DRVDT = 0 stb/Mscf/day

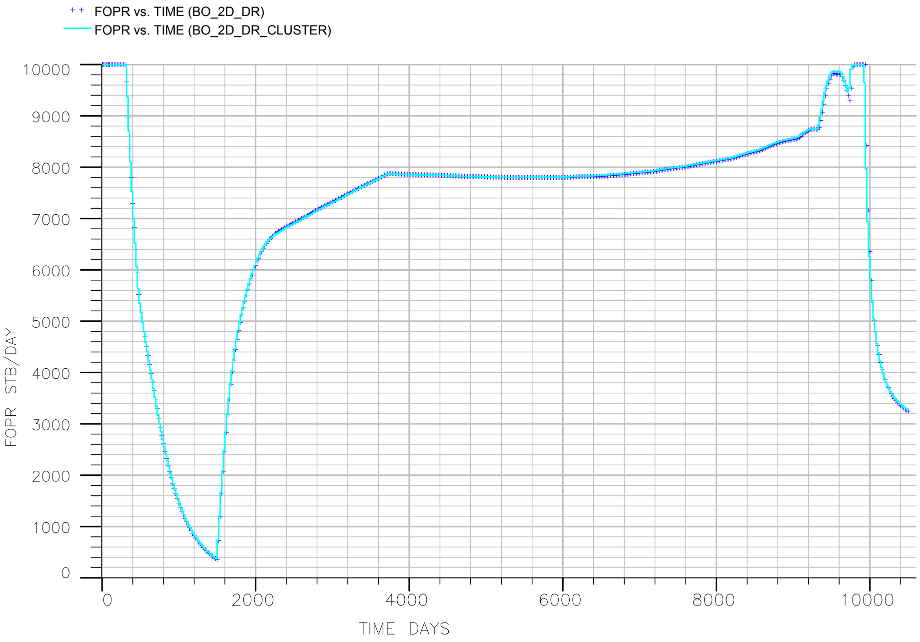


Figure 2.8: FOPR with DRSDT = 5E-5 Mscf/stb/day and DRVDT = 1E-5 stb/Mscf/day

The results in Eclipse and IHRRS are the same. This proves that the model was implemented correctly. But it is interesting to check that the physics of the results make sense. We plotted the pressure (FPR), gas production rate (FGPR), and oil production rate (FOPR) for the 3 cases on the same graph. We obtained figures 2.9 for oil production rate, 2.10 for gas production rate and 2.11 for pressure.

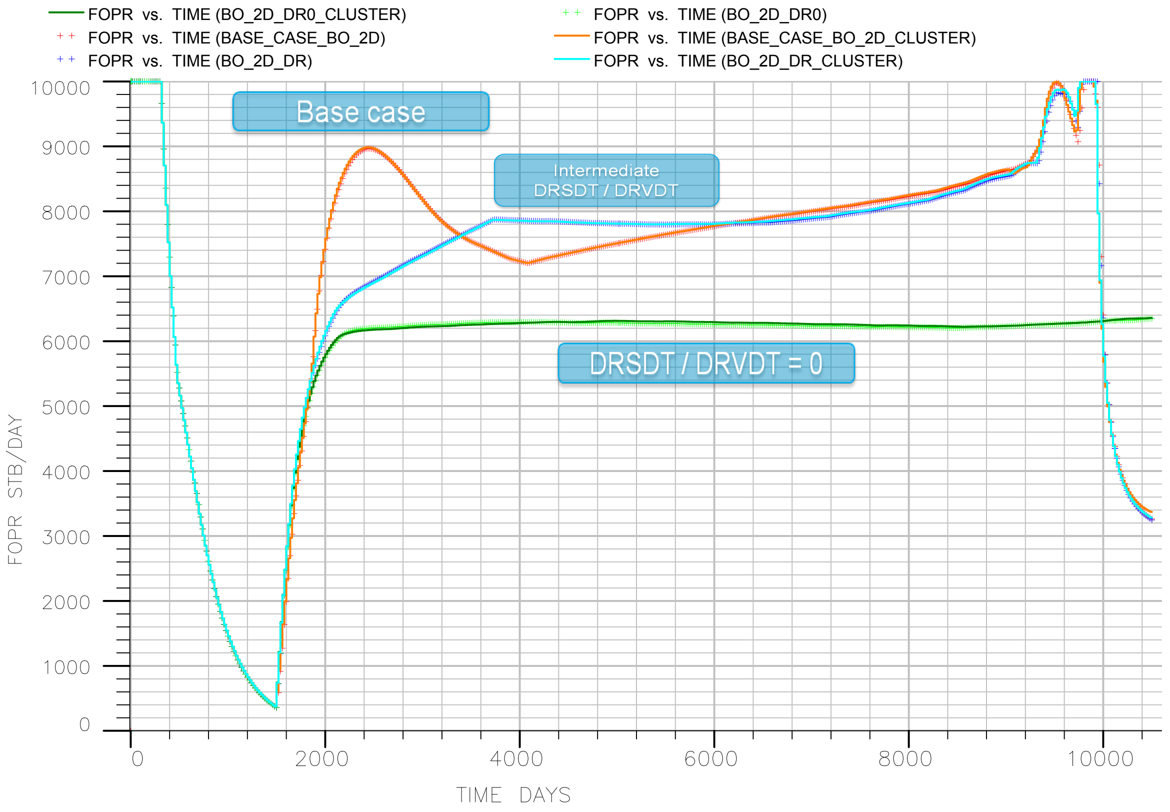


Figure 2.9: Comparison of FOPR for the 3 runs with different values for DRSDT and DRVDT

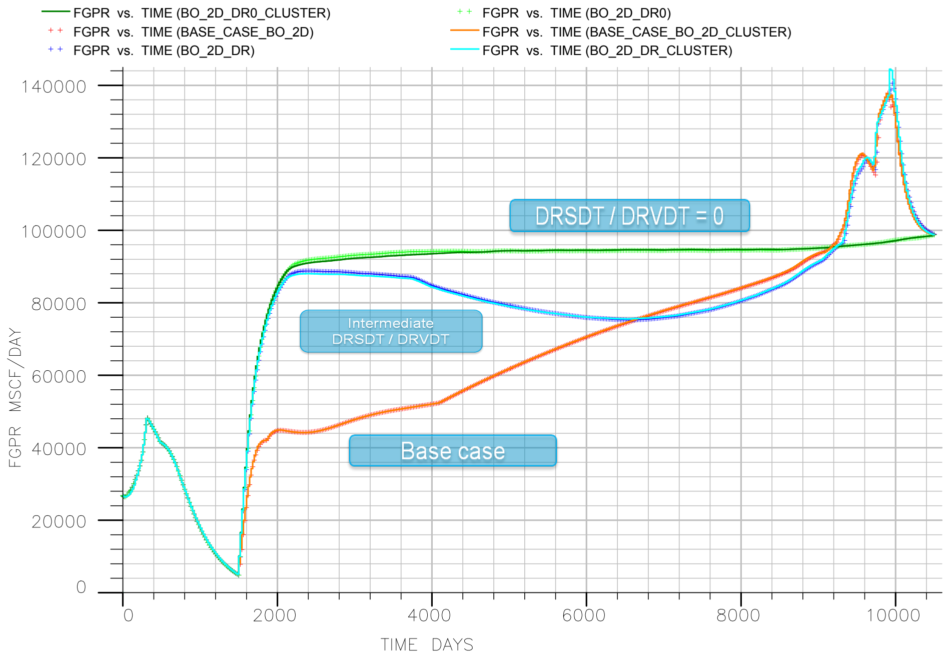


Figure 2.10: Comparison of FGPR for the 3 runs with different values for DRSDT and DRVDT

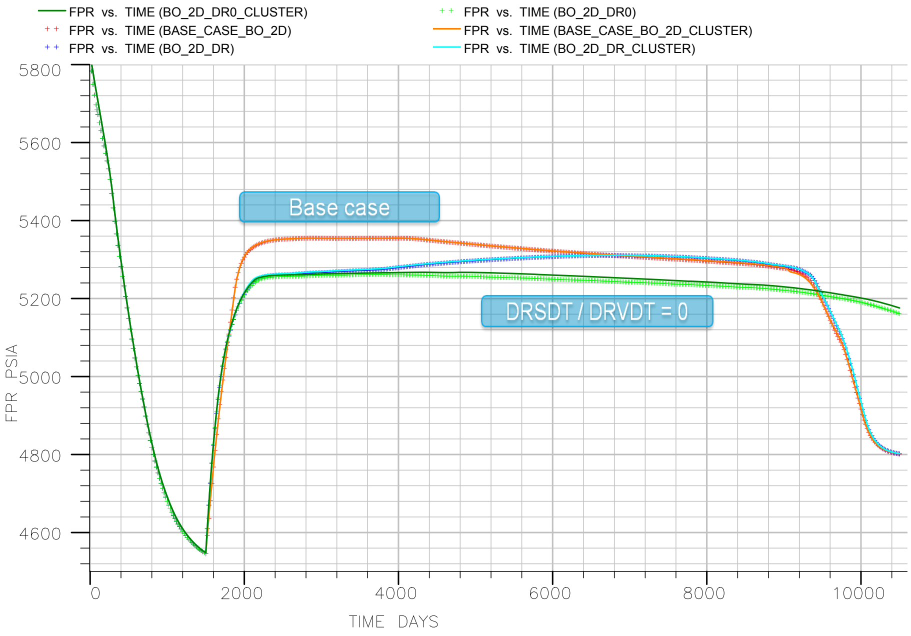


Figure 2.11: Comparison of FPR for the 3 runs with different values for DRSDT and DRVDT

The average reservoir pressure (FPR) is almost the same for the 3 runs. But the oil and gas production rates are totally different. Indeed, when DRSDT and DRVDT are set to 0, the oil and gas are not allowed to mix: therefore, when the pressure is increasing after the start of gas injection, the oil can not vaporize into the gas. The production of oil is reduced, while the gas production is increased because the injected gas is produced without any oil inside. The base case is the opposite: oil and gas reach an instantaneous equilibrium, and we produce more oil and less gas. The third case is intermediate. The double bump at the end of the oil production rate is due to the coarse grid and would disappear with a finer grid.

We tested the DRSDT and DRVDT models on a 3D-grid (10x10x3). The results given by the new models implemented in IHRRS are coherent with the Eclipse reference, and they are also physically consistent, so we consider the Black-Oil model in IHRRS as trustworthy.

We also checked the number of Newton iterations during every timestep in order to see if the new IHRRS models are converging well and quickly or if there is any trouble. We obtained figure 2.12 (cumulative curve). The number of Newton iterations is often between 1 and 2: the shape of the cumulative curves for the IHRRS runs is similar to ECLIPSE's ones. So, the convergence is fine in IHRRS.

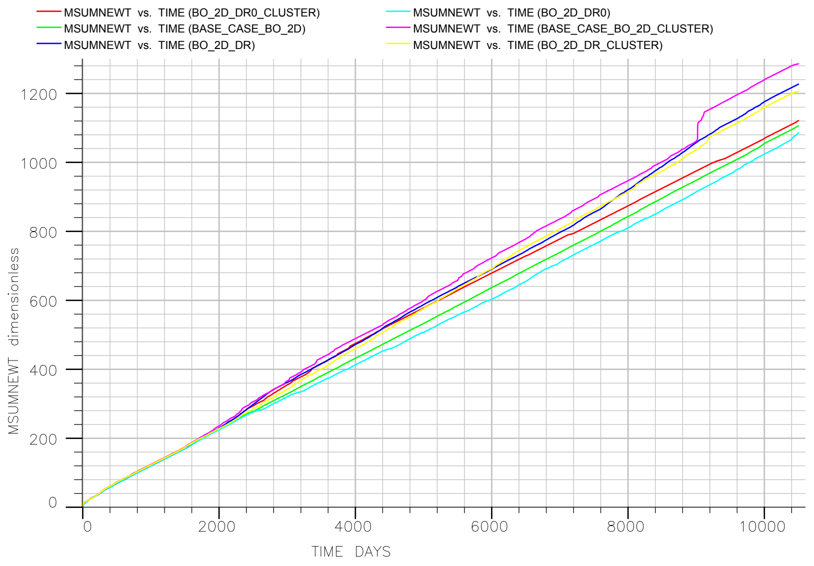


Figure 2.12: Cumulative number of Newton iterations for each runs with the DRSDT and DRVDT Black-Oil models

VAPPARS

We took the same base case as before: 2 000 days of depletion followed by 9 000 days of gas injection in a 2D-grid with 100 cells and only 2 wells (one injector and one producer). We added a VAPPARS keyword with 0.5 for the R_v parameter and 0 for the R_s parameter. We ran the simulations with ECLIPSE and IHRRS, and then, we added a 10 % target residual oil saturation in IHRRS.

Our SORM model assumes that when the oil saturation comes close the the desired value, almost all the light component is in the gas phase and almost all the heavy component is in the oil phase. But it can create a problem as shown in figure 2.13: if the SORM value defined by the user is greater than the oil saturation coming from the oil component in the oil phase, then, when we will trigger the limit, the oil saturation will be $S_{min} < S_{orm}$. It is difficult to evaluate or calculate S_{min}, that is why it is not possible to be sure that the heavy component in the oil phase will remain at a higher level than S_{orm}. Therefore, we put a 0 value for R_s in the VAPPARS model to solve this problem.

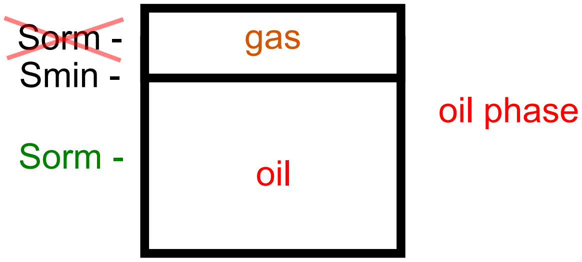


Figure 2.13: Oil phase in a cell with a SORM defined by the user

We obtained the curves plotted in figure 2.14 for the oil production rate, in figure 2.15 for the gas production rate and in figure 2.16 for the average reservoir pressure. ECLIPSE results are displayed with markers, and IHRRS results are displayed with lines.

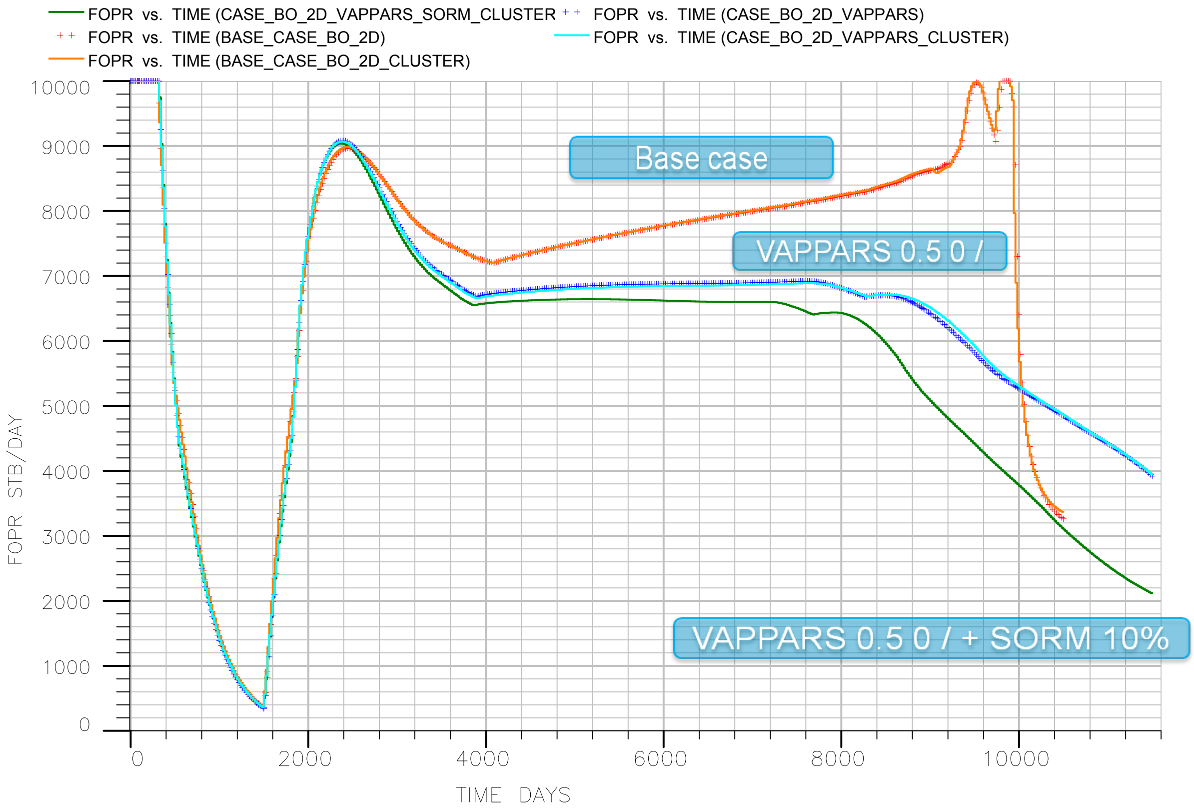


Figure 2.14: Comparison of FOPR with VAPPARS and SORM keywords

We observed the same phenomenon as described before: with VAPPARS the oil production is a little bit lower than previously, because there is less oil vaporized into the injected gas. At the end of the simulation, the residual oil saturation is 0 % near the injector, as shown in figure 2.17. The last green curve has a VAPPARS keyword set at 0.5 0 / but also a SORM set at 10 %. It produced less oil than the previous run, and we also check with a 3D visualization software that the constraint was successful. Indeed, the residual oil saturation in this case is 9.996 % near the injector as shown in figure 2.18.

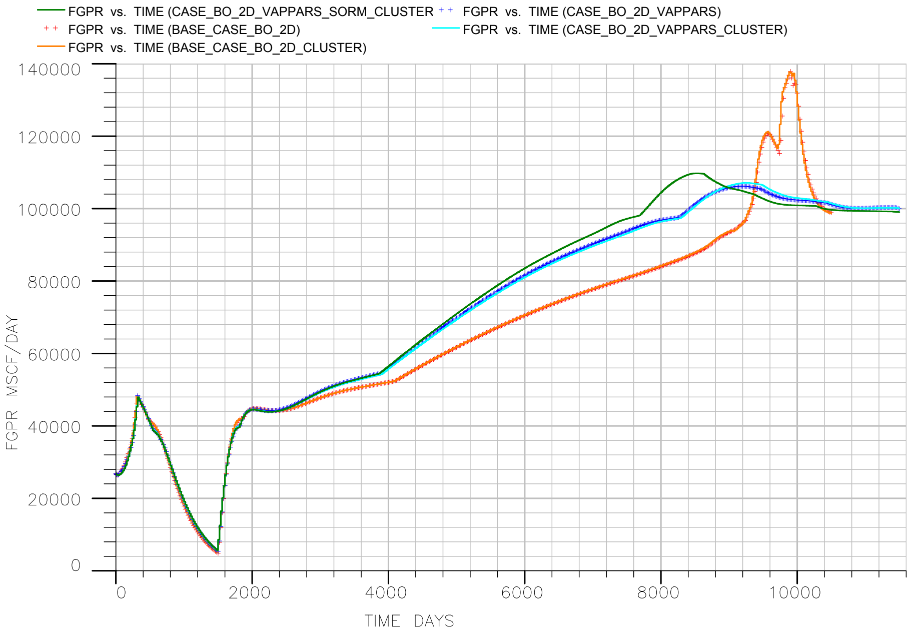


Figure 2.15: Comparison of FGPR with VAPPARS and SORM keywords

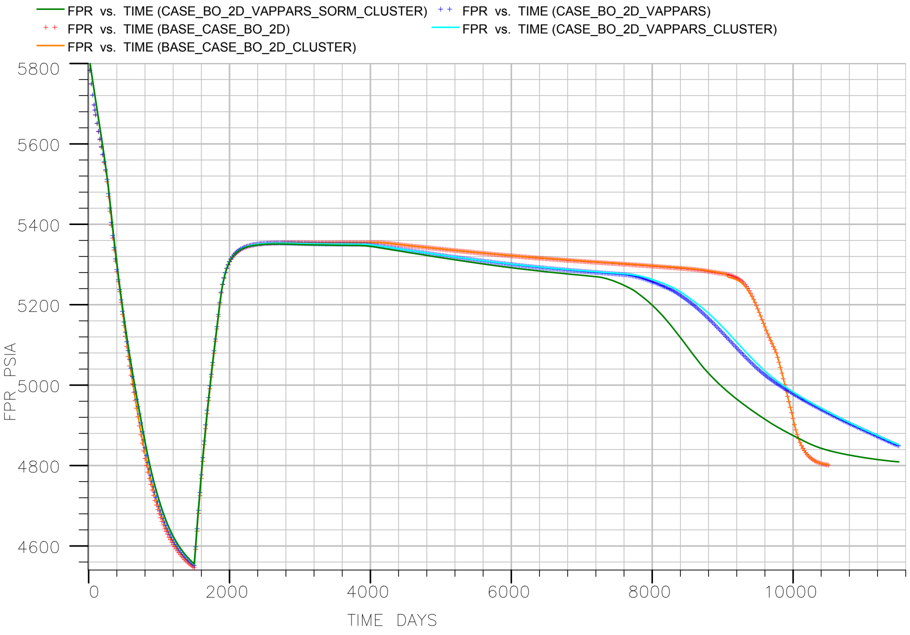


Figure 2.16: Comparison of FPR with VAPPARS and SORM keywords

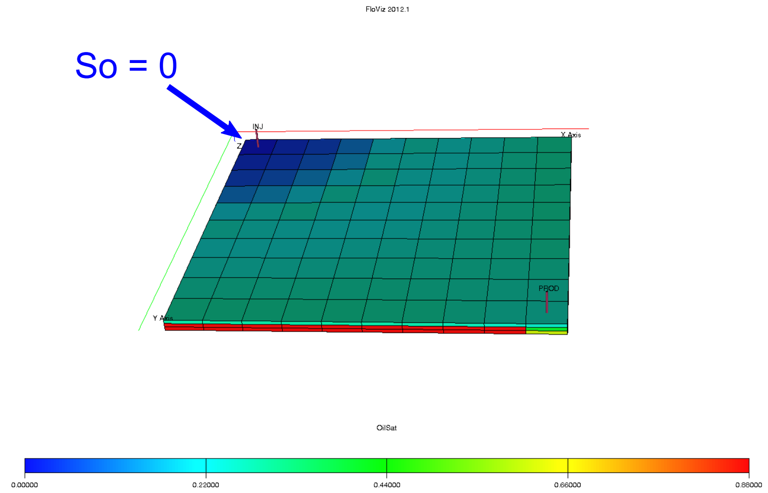


Figure 2.17: Oil saturation at the end of the VAPPARS simulation

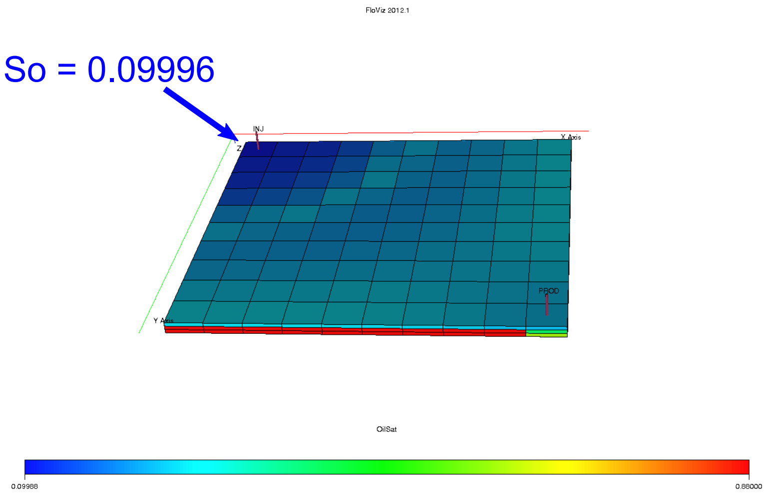


Figure 2.18: Oil saturation at the end of the VAPPARS simulation with 10 % SORM

Finally, we checked the number of Newton iterations. We obtained figure 2.19. The convergence is fine, even if the IHRRS simulations increase a little bit the required number of Newton iterations at the beginning of the gas injection. But it is still acceptable, the number of Newton iterations does not increase too much.

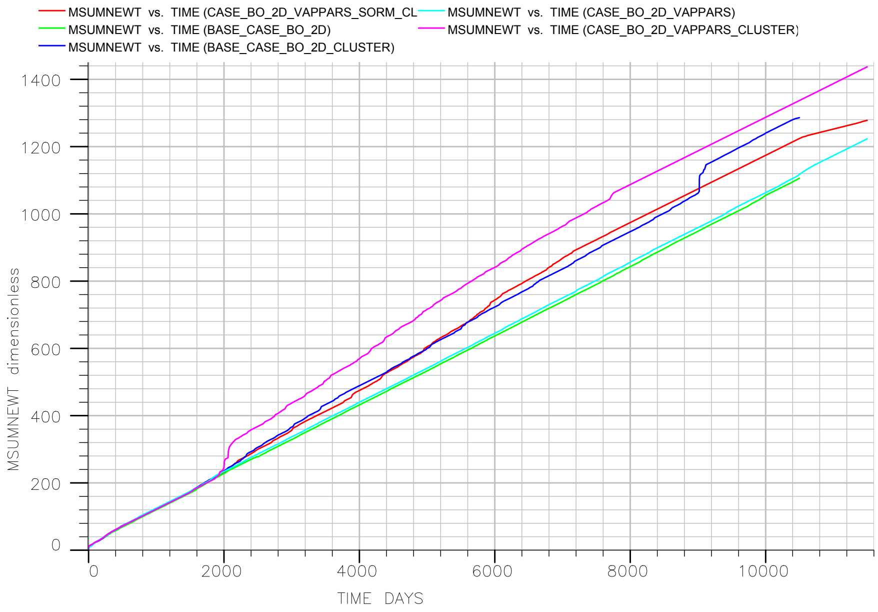


Figure 2.19: Cumulative number of Newton iterations for each runs with the VAPPARS Black-Oil models

Therefore, the implementation of the ECLIPSE Black-Oil models into the IHRRS simulator is successful, and the additional SORM functionality can limit the residual oil saturation to a predetermined value. The compressibility effects can yield a slightly different value, but it is still acceptable.

2.2.2 Compositional simulations

EQUILRELAX model

In order to test the EQUILRELAX model, we started by creating a simple 1D data set, without any well, with K-values that do not vary with pressure. We started with a composition far away from equilibrium and we waited 500 days with the EQUILRELAX parameters defined for every component. Then, we took the x_i and y_i for each component i, computed the K_i values and plotted them against time with Excel.

Figure 2.20 shows the evolution of K_i for each component from 1 to 4. EQUILRELAX was set to 0.01 day^{-1}, meaning that it would require 100 days to reach equilibrium if the evolution were linear. We plotted the values given by the simulation in blue, but also the theoretical values in red, using the formula:

$$K_i(t) = K_i(t=0) + [K_i(t=\infty) - K_i(t=0)] \cdot (1 - e^{-\nu t})$$

We observed that the curves fit perfectly, meaning that the model that we implemented works as expected.

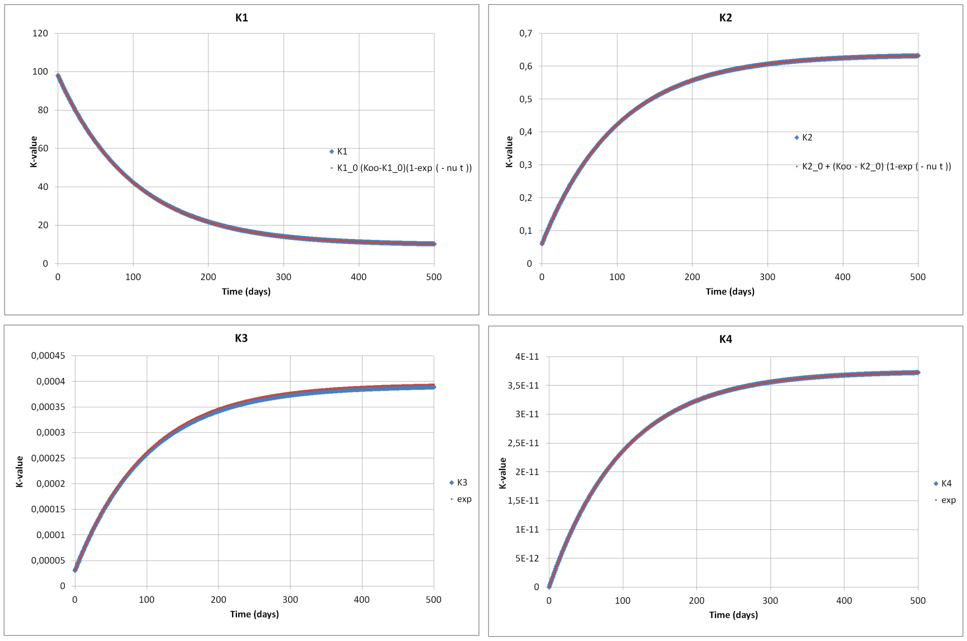


Figure 2.20: Ki-values versus time with EQUILRELAX = 0.01 day^{-1}

Then, we created a simple 2D-case in order to try the new EQUILRELAX model in IHRRS. We made a 10x10 grid (100 cells), with 2 components : C_1 and C_{12}. We put only two wells, one injector and one producer furthest away from each other. We started producing for 4 years, and then we injected gas until the end of the simulation, around 25 years. We did 6 different runs in IHRRS with the Black-Oil simulation as a reference:

- The basic Black-Oil model.
- The Black-Oil model with DRSDT and DRVDT set to 0 Mscf/stb/day and 0 stb/Mscf/day.
- The Black-Oil model with DRSDT and DRVDT set to 10^{-5} Mscf/stb/day and 10^{-5} stb/Mscf/day.
- The basic EoS model.
- The EoS model with EQUILRELAX set to 0 day^{-1}.
- The EoS model with EQUILRELAX set to $3 \cdot 10^{-4}$ day^{-1}.

We obtained the curves showed in figure 2.21 for the oil production rate, in figure 2.22 for the gas production rate, and in figure 2.23 for the average reservoir pressure.

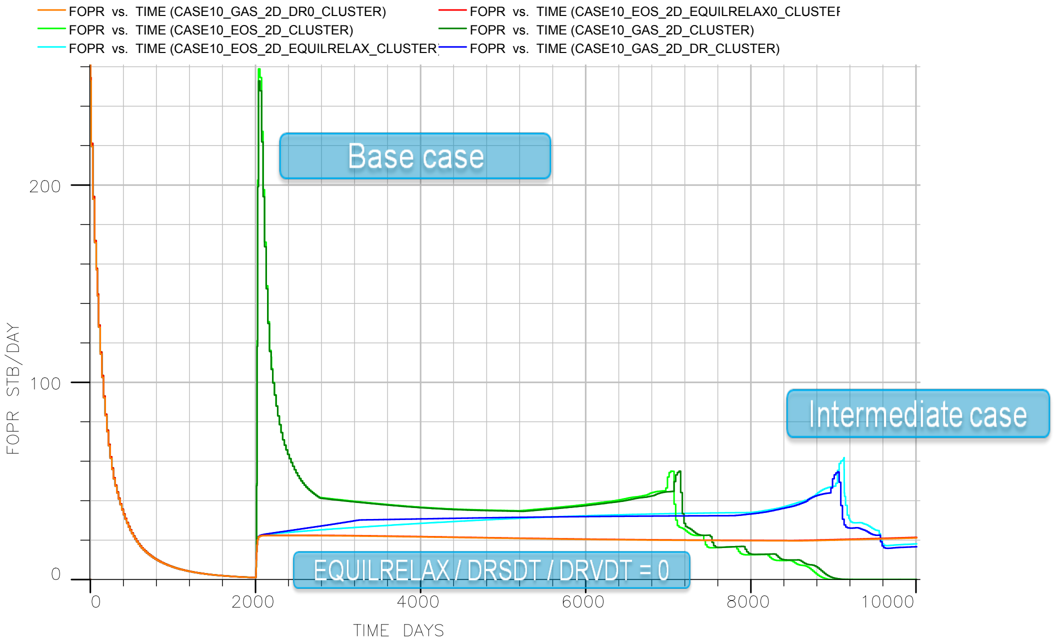


Figure 2.21: FOPR for the 6 runs comparing DRSDT/DRVDT and EQUILRELAX models

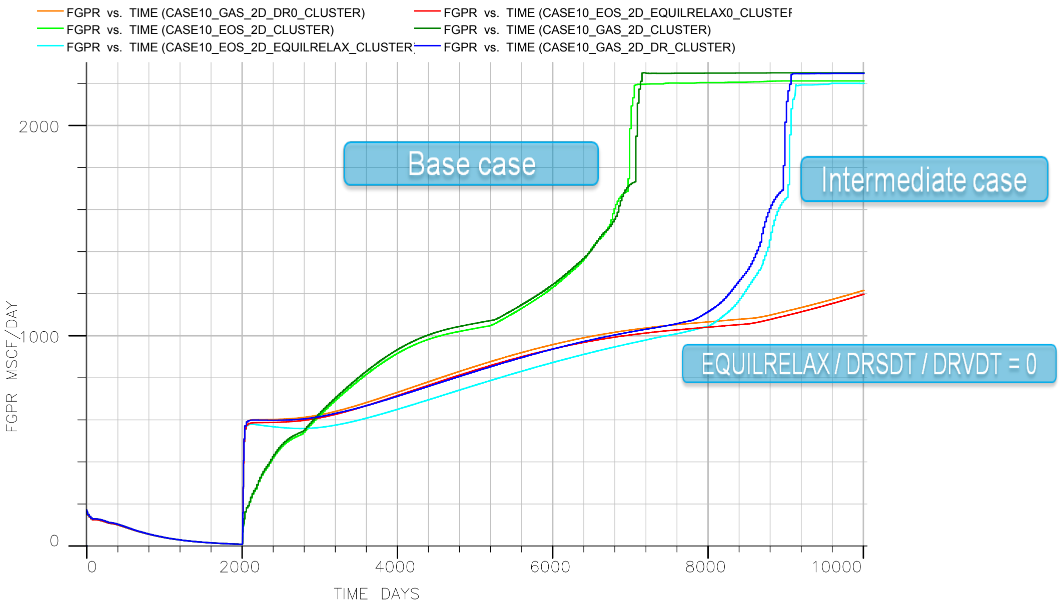


Figure 2.22: FGPR for the 6 runs comparing DRSDT/DRVDT and EQUILRELAX models

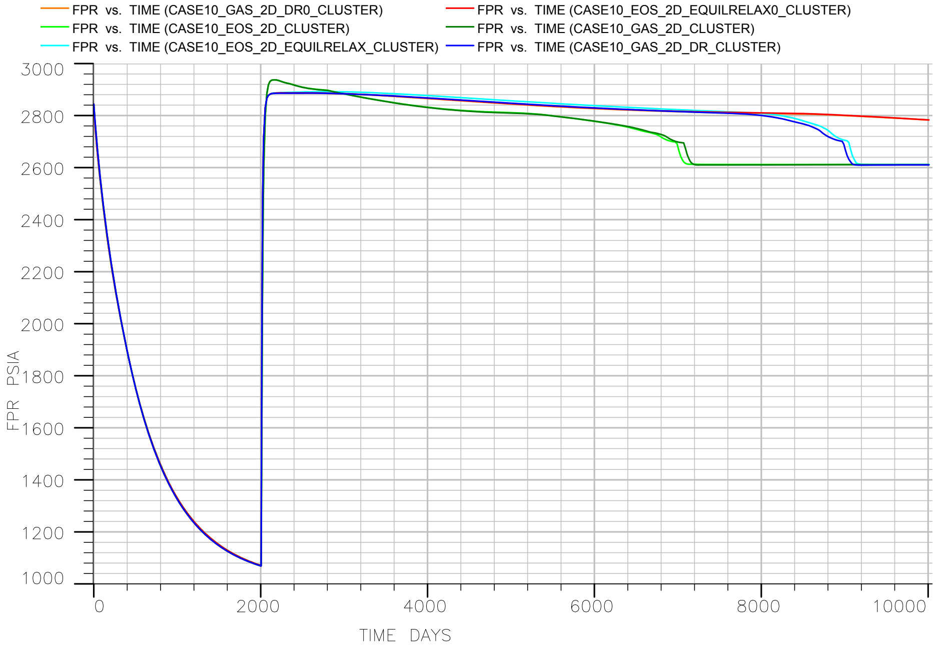


Figure 2.23: FPR for the 6 runs comparing DRSDT/DRVDT and EQUILRELAX models

The green curves are for the base cases, the red curves are with a zero value for EQUILRELAX or DRSDT and DRVDT and the blue curves are intermediate. As we can see in the figures, the Black-Oil and EOS models give very similar results. Even if the input values for EQUILRELAX ($3 \cdot 10^{-4}$ day^{-1}) and DRSDT/DRVT (10^{-5} Mscf/stb/day and 10^{-5} stb/Mscf/day) are different. It is normal because DRVDT and DRSDT are limiting the global increase of R_s and R_v, while EQUILRELAX is only slowing down the equilibrium process with a relaxation time. It proves that the new model with a compositional simulator is accurate, and gives exactly the same result as the Black-Oil one.

With an EQUILRELAX set to 0, it is not possible for the oil and gas to mix. Therefore, when the pressure rises in the reservoir after the start of gas injection, there is no swelling effect, and the oil production stays almost constant with time, like pressure. But if EQUILRELAX is not defined, meaning that it is set to infinity, then the oil will mix with undersaturated gas and the production will increase significantly, especially when the gas front reaches the producer. An intermediate value for EQUILRELAX delays the gas front, and reduces the impact of those effects described above, but they will still be present. Therefore, the oil production rate will be delayed but not reduced like before.

We also plotted the cumulative number of Newton iterations for all runs in figure 2.24. The number of Newton iterations is still approximately the same for all runs, and there is no convergence issue.

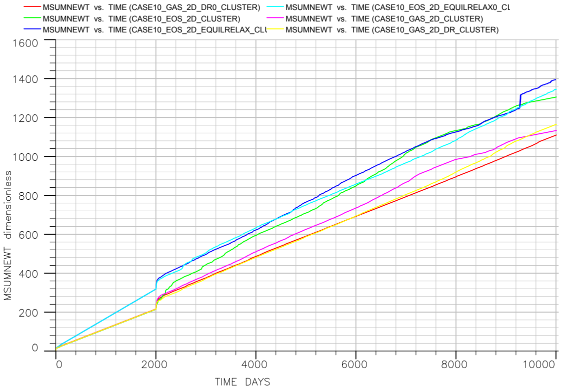


Figure 2.24: Cumulative number of Newton iterations for the 6 runs comparing DRSDT/DRVDT and EQUILRELAX models

Finally, we made a last test with that model and with more components. We took the 3D-grid with 300 cells (10x10x3), and we changed the PVT data with a 6-components data set taken from SPE 5 comparative project. We kept one injector and one producer with 2 steps: first, a depletion, and then the start of gas injection until the end of the simulation. We got the curves showed in figures 2.25, 2.26 and 2.27. The red curve is the base case, without the EQUILRELAX model. The blue curve has an EQUILRELAX set to 0 day^{-1}, and the green one is an intermediate curve with an EQUILRELAX equals to 0.001 day^{-1} for each component.

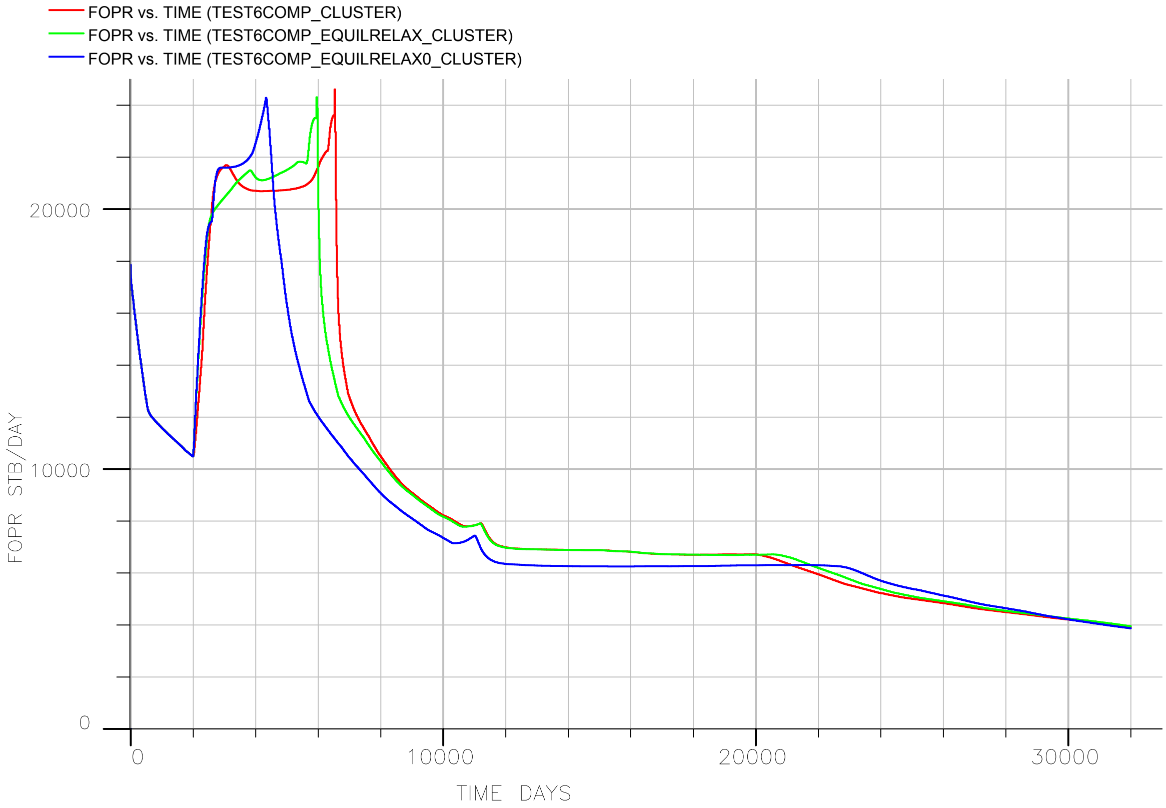


Figure 2.25: FOPR with 6 components for different values of EQUILRELAX

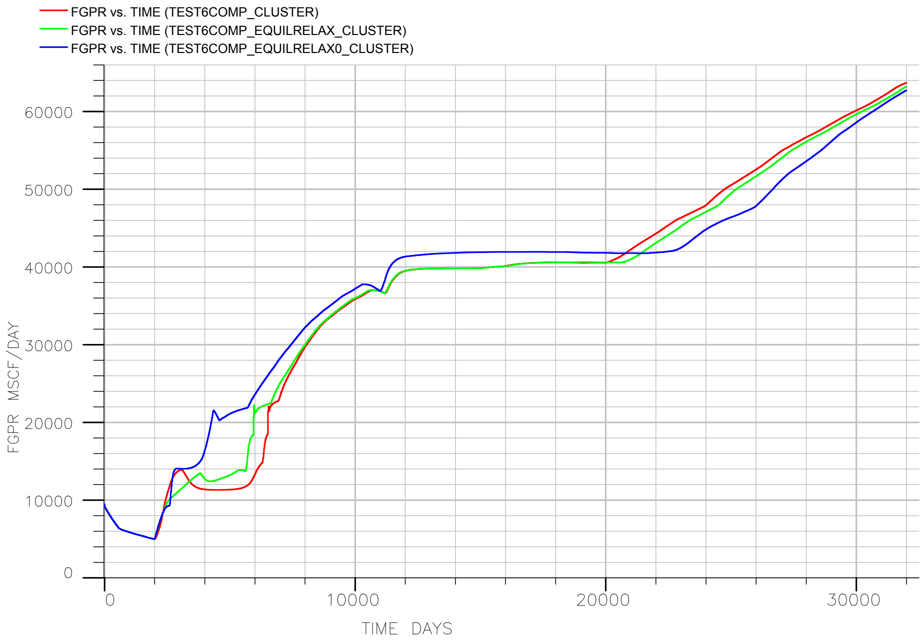


Figure 2.26: FGPR with 6 components for different values of EQUILRELAX

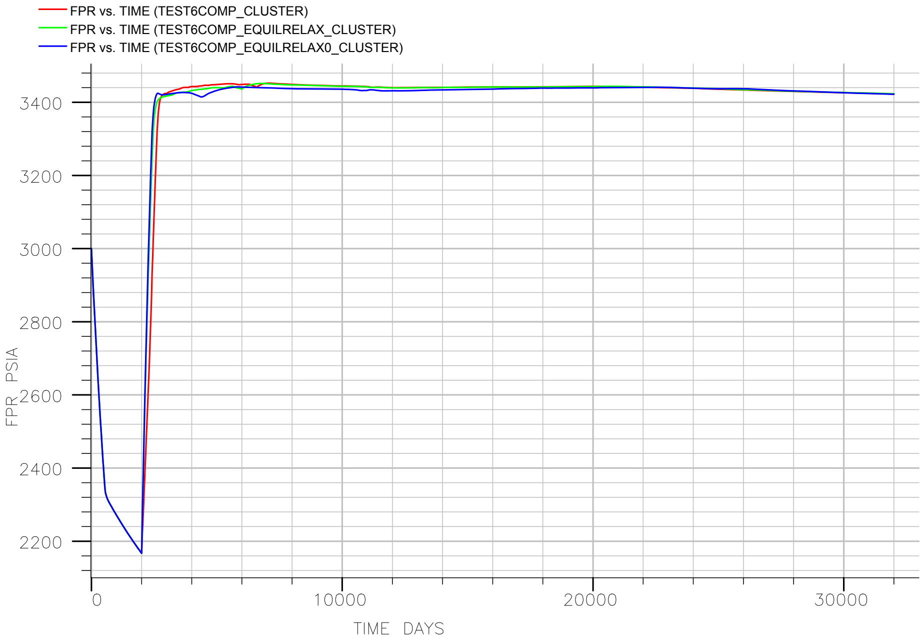


Figure 2.27: FPR with 6 components for different values of EQUILRELAX

The pressure is almost constant for the 3 runs, but we can clearly see that the oil production rates are different. With an EQUILRELAX set to 0, the gas can not mix with oil, and it reaches the producer really quickly. But without that model, it needs to swell more oil and it moves slower. That is why it eventually produces more oil, although it takes more time to happen.

2.2.3 VAPPARS keyword

In order to validate the VAPPARS keyword for an EoS case, we have chosen a simple 2-D data set. We took the basic grid with 100 cells, with 2 wells furthest away from each other. We started with only oil (88 %) and water (12 %) without gas, at a pressure of 2 900 psi. We took R_s = 0.2 Mscf/stb (the saturated value is around 0.6 Mscf/stb at this pressure) and R_v = 0 stb/Mscf (but no gas is present at the beginning of the simulation so it does not really matter). We have chosen the C_1 (gas) and C_{12} (oil) properties for the Black-Oil and EoS model that we calculated with BEST software. We produced at a constant BHP value equals to 1 000 psi and we started injecting gas after 2 000 days with a BHP control set to 3 000 psi. This is the base case. The validated Black-Oil VAPPARS model is taken as a reference, and we want to benchmark the EoS case. All runs are made with IHRRS.

We ran the base case simulations for the Black-Oil model and the EoS one, and then we added the VAPPARS keyword with the values 0.1 0.8 / for the EoS model and 0.8 0.1 / for the Black-Oil one. Indeed, the first parameter in the VAPPARS keyword is related to the light component in VAPPARS EoS (first component), but it is related to the R_v in the Black-Oil model (like in Eclipse), so the heavy component! Finally, we added the keyword SORM with a defined value at 15 %. We got the results shown in figure 2.28 for the oil production rate, figure 2.29 for the gas production rate and figure 2.30 for the average reservoir pressure. The green curves are the base case (Black-Oil and EoS), the blue curves are with the VAPPARS model, and the red curves got an additional SORM sets to 15 %.

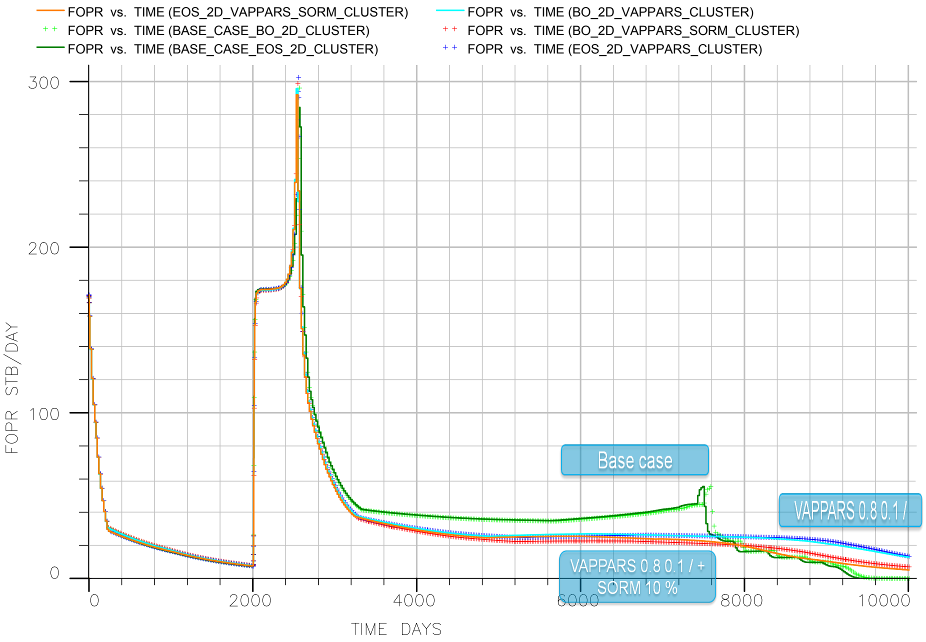


Figure 2.28: FOPR with and without VAPPARS model (Black-Oil and EoS cases)

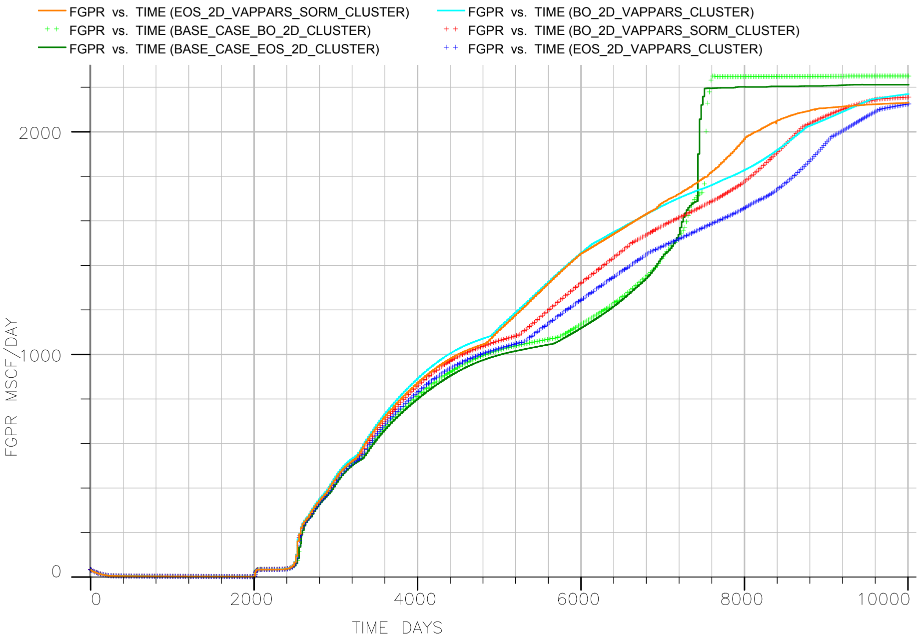


Figure 2.29: FGPR with and without VAPPARS model (Black-Oil and EoS cases)

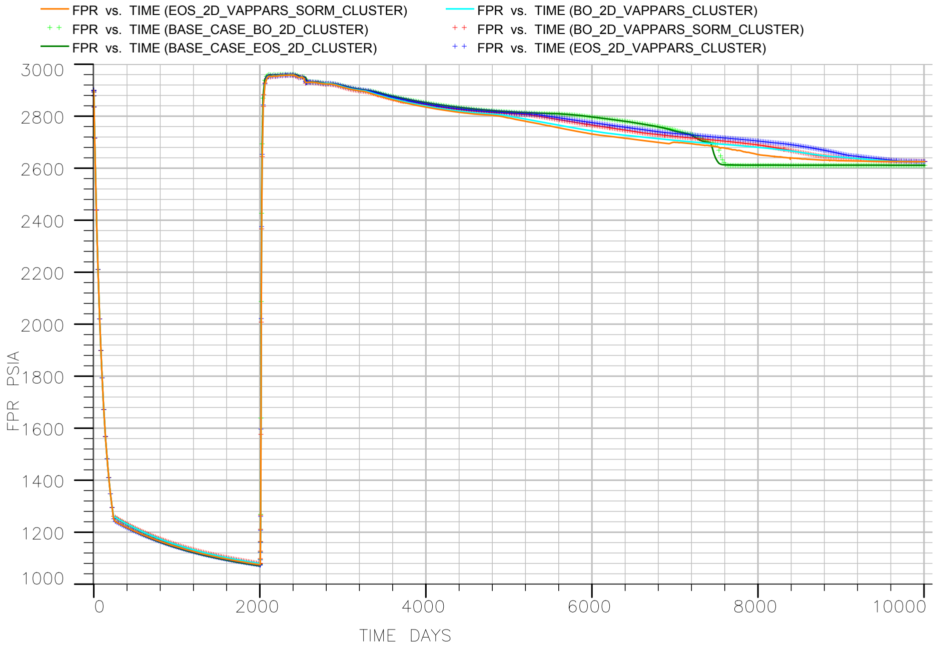


Figure 2.30: FPR with and without VAPPARS model (Black-Oil and EoS cases)

The oil production curves show 3 steps: first, the injector is shut, and the production is decreasing because the pressure drops in the reservoir. Then, we start the injector and the production is increasing. There is a peak when the gas front reaches the producer, and finally the production is decreasing with a small jump when the 0 % oil front reaches the producer, with a decay afterwards. When the VAPPARS keyword is present, the oil production is lowered during phases 2 and 3. And with also SORM, the production is even lower than previously. But the main point is that the new EoS model is matching perfectly the Black-Oil one. Indeed, the base cases were the same, but even with VAPPARS and SORM, the curves are identical. It proves that even if the EoS model is not exactly the same as the Black-Oil one, because we use the formula with K_i instead of R_s and R_v, it still gives similar results.

The gas production rate and the reservoir pressure evolution are almost identical, regardless of whether VAPPARS is present or not because it does not matter if we want to stay above 15 % oil saturation or not. It is not linked.

We also computed the value of oil saturation at the end of the simulation for each case. The results are presented below.

Case	Average oil saturation (%)	Minimum oil saturation (%)	Maximum oil saturation (%)
Base case Black Oil	0	0	0
Base case EoS	0	0	0
Black Oil + VAPPARS	6.17	0	31.29
EoS + VAPPARS	5.31	0	29.76
Black Oil + VAPPARS + SORM	14.78	11.37	28.68
EoS + VAPPARS + SORM	15.11	10.52	24.91

As we can see, the minimum value for oil saturation is a little bit lower than what entered in the SORM keyword (15 %), but it does not fall to 0 like in the other simulations. The average oil saturation is close to 15 %.

We also plotted the number of Newton iterations, and we obtained the graph shown in figure 2.31. The number of newtons is usually quite high, a little bit more than previously, but it is still acceptable.

The benchmark is fine, the results are consistent and matching the previous ones and the Black-Oil model so we validated the new model.

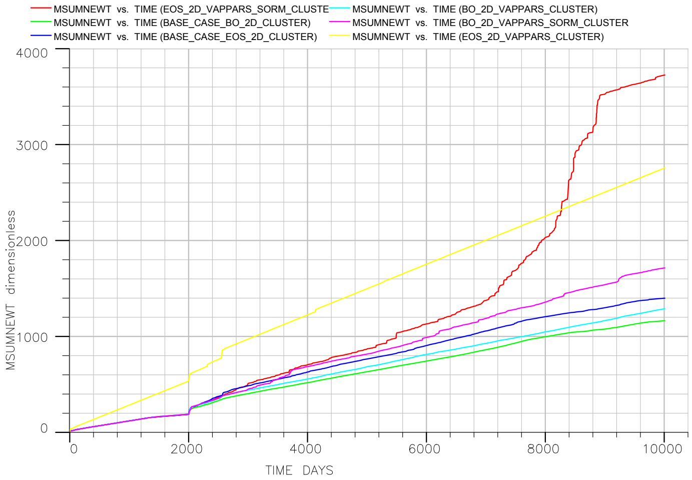


Figure 2.31: Number of Newton iterations for each runs with the new EOS VAPPARS model

2.2.4 K-value simulations

We only used the K-value case in order to test and debug the EoS case. The K-value data set give exactly the same curves and results as shown previously. So we also validated that model.

Figure 2.32 shows an example of the oil production rate with different runs: base case, VAPPARS, VAPPARS + SORM in both EoS and K-value runs.

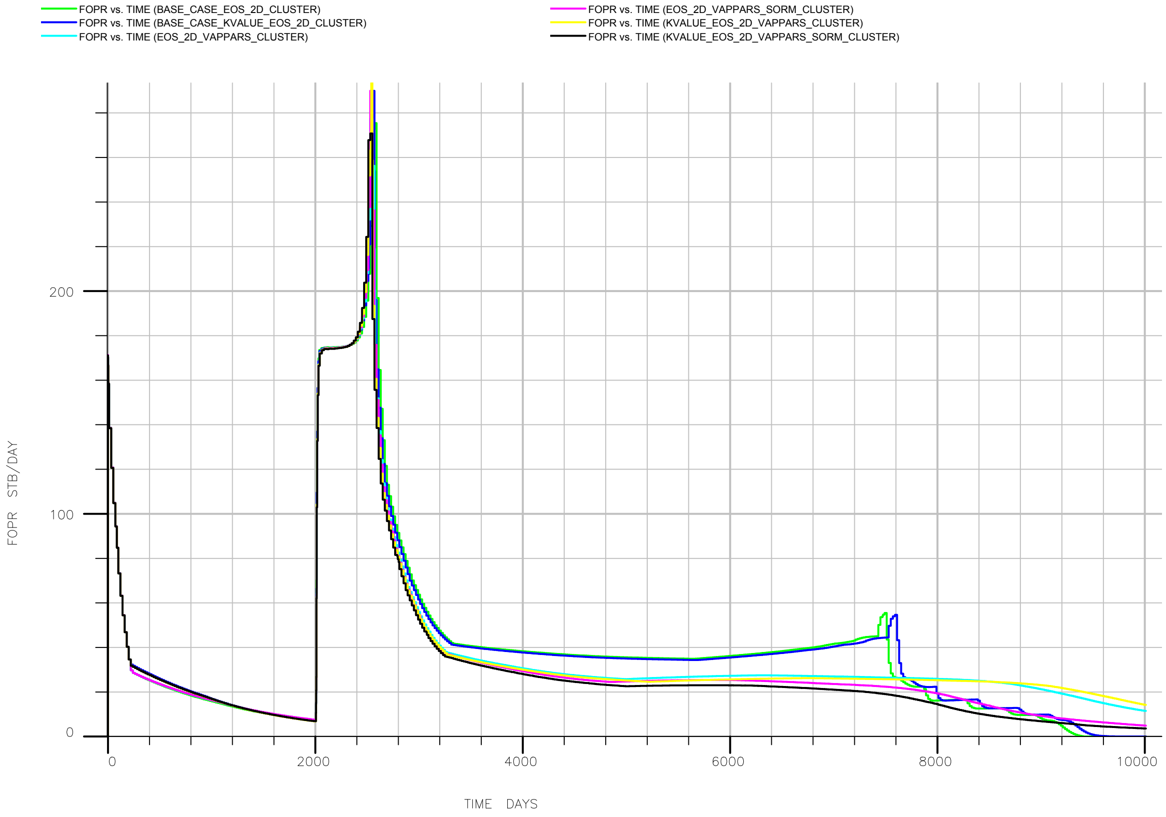


Figure 2.32: FOPR with and without VAPPARS model (K-value and EoS cases)

Chapter 3

Comparison with other methods

3.1 ECLIPSE SOR

The main difference between the SOR Eclipse model, and the new SORM and VAPPARS one is that SOR in Eclipse does not change the transport, or anything. It just prevents the residual oil saturation to go below a predefined value.

Instead, the VAPPARS model is changing the overall physical behavior of the mixture. Therefore, the equilibrium is not obtained exactly during the simulation, and the oil cannot vaporize into the gas if it is immobile and below the predefined value.

The two approaches cannot give exactly the same results, because the models are different, but we can show how they work and compare them. The SOR model is excluding a part of the oil in place from the transport calculations, and dividing oil into 2 different entities: oil that can flow, and immobile oil. More details are explained in the manual [Sch11].

We compared a simple 2 components case with 1 producer and 1 injector: first, the producer is depleting the reservoir and producing while the injector is shut, and then both wells are open. We ran the simulations for the base case, and with the new models. It is very similar to the simulation we did before, but we used a finer grid here (2 500 cells).

3.2 Alpha factors

The transport coefficients, also called alpha factors, were introduced in the middle of the 90's, in the article [BF94]. they were used in order to change the speed of components, slowing the heavy ones, and accelerating the light ones. They were also used in order to delay gas breakthrough with gas injection as shown in the paper [BGG12]. We did not implement this method because it was too difficult to compute the alpha factors for each components, but we used a simplified method exposed in the article [HS07].

We doubled the number of components. The first type of each component can move and flow as usual, and the second one of them is immobile. We excluded 10 % of the initial oil components and we put them as immobile. We started with oil only, and we ran the same cases as above, with 1 injector and 1 producer.

3.3 Comparison

The oil production rates that we obtained are shown in figure 3.1. The blue and green curves are the base case, for K-value and EoS runs. The orange one is with 10 % SOR (ECLIPSE), the black curve is with alpha factors and the red one with the new model that we implemented with VAPPARS.

The base case is the same as before, with 3 steps: depletion, gas injection resulting in pressure increase, and finally decay. The SOR model did not change the physics of the problem, and the oil production matches for years, until the reservoir reaches the 10 % oil saturation. Then, the reservoir produces less oil, but with the same physics and trends. It is just faster. But for the alpha-factors case it is totally different: the oil production is lower than the base case since the beginning because a portion of oil cannot move, even at the initial state with 88 % of oil. Therefore, the producer can only produce a part of the oil in the reservoir, and not 100 % of the oil in the reservoir cells can be produced. This phenomenon impacts the flow of oil since the beginning, and not when the oil saturation wants to go under 10 %. It is quite similar to what happens in the VAPPARS and SORM case, but this case also changes the physics of the problem, and since the equilibrium not reached, it speeds up the gas and the oil influx at the producer. We almost matched the results given by our new model and the alpha factors, but we do not know exactly why the first plateau is a little bit lower when we use alpha factors.

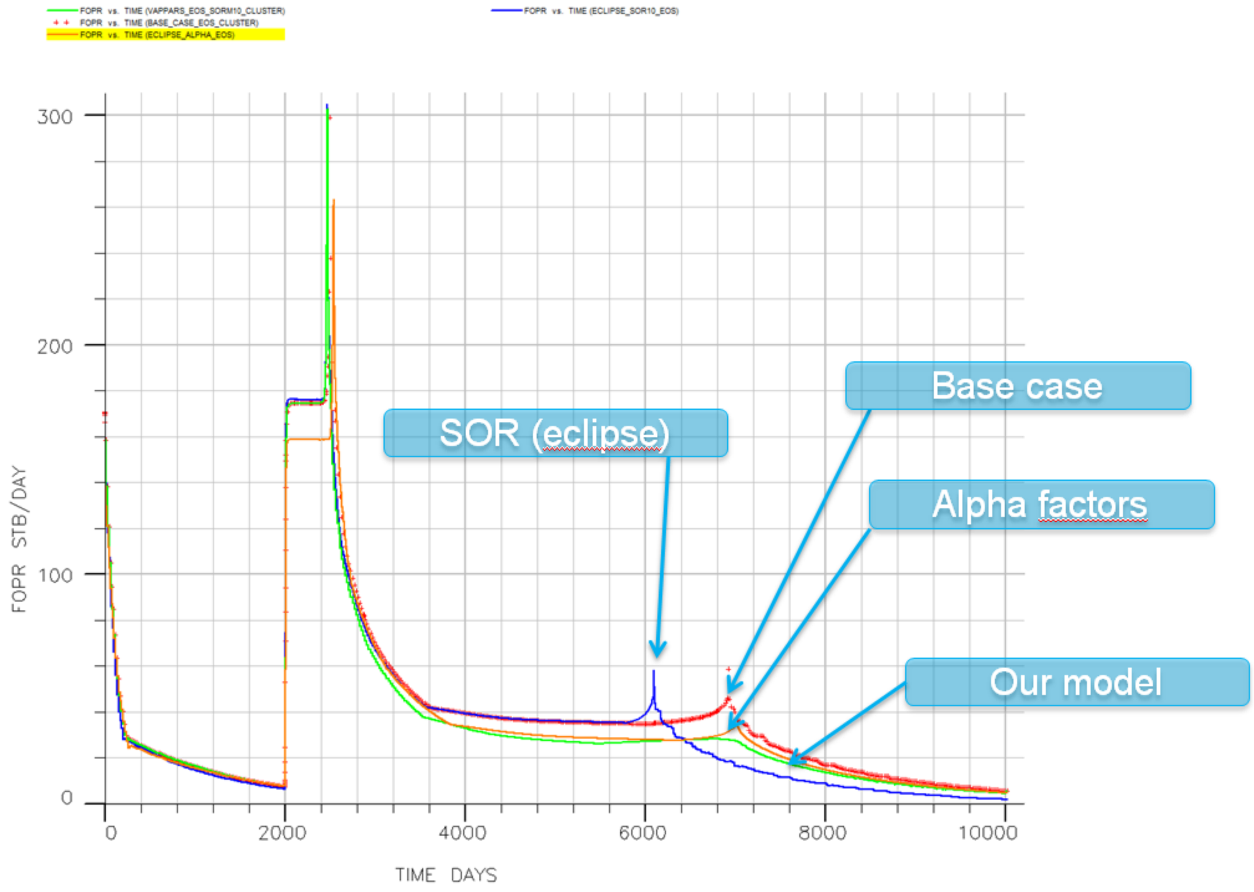


Figure 3.1: FOPR plots for the different runs

We can then use a 3D visualization software in order to check the residual oil saturation. The base case has an overall oil saturation equal to 0. The keyword SOR in Eclipse has also a constant oil saturation in each cell which is 10 %. The VAPPARS and SORM case has an oil saturation which is between 10 % and 10.42 %, and finally the alpha-factor case has an oil saturation which is between 8.26 % and 9.05 %. The residual oil saturation is a little bit lower than the expected value with the alpha factors because a part of the immobile oil in place at the beginning vaporized into the gas phase, but still cannot move.

The new models that we implemented can only be used with immiscible gas injection, with K-values. If we are above the critical point, there is no K-value and it is not possible to use this method. But the new methods with VAPPARS and SORM can be used with a Black-Oil simulation as well, while the previous models are only working with a compositional simulation.

Chapter 4

Summary and Recommendations for Further Work

4.1 Summary and Conclusions

We have created different new models for the IHRRS simulator in order to take into account the non-local equilibrium. We started with a simple Black-Oil model limiting the increase of R$_s$ or R$_v$. Then, we transposed the VAPPARS Eclipse model: the model for calculating the R$_s$ or R$_v$ values depending on oil saturation with the generic formula $R_x = R_{x\ sat}\left(\frac{S_o}{S_{o\ max}}\right)^{vap}$ in a Black-Oil simulation. And finally we adapted a new model similar to this VAPPARS model for the EoS and K-value cases.

We benchmarked those new models with some simple grids and simulations IHRRS versus ECLIPSE and we obtained satisfactory matches. The Black-Oil models are quite fast and efficient, but the number of Newton iterations in the EoS models can increase and sometimes cause convergence difficulties. If it happens, we only have to slightly change the parameters in the VAPPARS keyword in order to fix the convergence issue. In addition, if the simulation finishes, the results are consistent and the new models allow to ensure a residual oil saturation in both cases, even with a Black-Oil model.

The different means to enforce non-zero residual saturation such as alpha factors and the keyword SOR in Eclipse give quite similar oil saturation at the end of the simulation, but the physics of the problem can change abruptly.

4.2 Discussion

The DRSDT and DRVDT keywords were easy to implement and to test, but they are not really user-friendly because it is often difficult to find an accurate value for those parameters. Indeed, most of the simulations that are using those keywords set them to 0 or to a very high value. The VAPPARS keyword is quite efficient, because it is simple to modulate its parameters, and it is now possible to end with a non-zero residual oil saturation. It can cause some convergence issues, but then, it is possible to reduce the timesteps or to slightly change the input parameters in order to fix most of the problems without affecting the outputs.

The EQUILRELAX model is an approximation very similar to DRSDT and DRVDT in the Black-Oil model. It would be too long and difficult to integrate a proper model for the oil moving in the reservoir that should keep the same constraints, but it is acceptable in most cases.

4.3 Recommendations for Further Work

It is possible to extend this work, and improve the results that we obtained by:

- Testing the models on real fields and try to improve history matching.
- Improve the convergence issue with the VAPPARS model.
- Take into account the divergence term in the constraint equations and make a more accurate physical model, but this would require a lot of changes in the simulator.

Appendix A

Acronyms

BHP Bottom Hole Pressure

EOS Equation of state

FGPR Field Gas Production Rate

FOPR Field Oil Production Rate

FPR Pressure average value in the field

FVF Formation Volume Factor

IHRRS In-House Research Reservoir Simulator

Psat Saturation pressure

PVT Pressure, Volume and Temperature

SORM Minimal Residual Oil Saturation

Appendix B

Additional Information

This is an example of a 3D data set for testing the DRSDT and DRVDT model in Eclipse and IHRRS.

```
RUNSPEC

TITLE
   3D PROBLEM

DIMENS
   10   10    3  /

NONNC

OIL
WATER
GAS
VAPOIL
DISGAS

FIELD

EQLDIMS
    1  100   10    1    1 /

TABDIMS
    1    1   40   40    1   40 /

WELLDIMS
    2    1    1    2 /

NUPCOL
    4 /

START
  1 JAN 2013  /

NSTACK
   24 /

UNIFIN
UNIFOUT
--==============================================================
GRID
--==============================================================

INIT

EQUALS
      ’DX’    1000      /
```

```
      'DY'    1000      /
      'PORO'  0.3       /
      'TOPS'  8325      1  10  1  10  1  1  /

      'DZ'    50        1  10  1  10  1  1  /
      'PERMX' 1000       /
      'PERMY' 1000       /
      'PERMZ' 1000       /


      'DZ'    50        1  10  1  10  2  2  /
      'PERMX' 800       /
      'PERMY' 800       /
      'PERMZ' 800       /

      'DZ'    50        1  10  1  10  3  3  /
      'PERMX' 600       /
      'PERMY' 600       /
      'PERMZ' 600       /

/

COPY
      'PERMX'    'PERMY'   1  10  1  10  1  3  /
      'PERMX'    'PERMZ'   /
/

PROPS    ================================================================

--  SWAT   KRW   PCOW
SWFN
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    1.0   0.00001 0  /

--  SGAS   KRG   PCOG
SGFN
    0     0       0
    0.02  0       0
    0.05  0.005   0
    0.12  0.025   0
    0.2   0.075   0
    0.25  0.125   0
    0.3   0.19    0
    0.4   0.41    0
    0.45  0.6     0
    0.5   0.72    0
    0.6   0.87    0
    0.7   0.94    0
    0.85  0.98    0
    0.88   1.0     0
/

--  SOIL     KROW     KROG
SOF3
    0        0        0
    0.18     0        0
    0.28     0.0001   0.0001
    0.38     0.001    0.001
    0.43     0.01     0.01
    0.48     0.021    0.021
    0.58     0.09     0.09
    0.63     0.2      0.2
    0.68     0.35     0.35
    0.76     0.7      0.7
    0.83     0.98     0.98
    0.86     0.997    0.997
    0.879    1        1
    0.88     1        1    /


-- PVT PROPERTIES OF WATER
--    REF. PRES. REF. FVF  COMPRESSIBILITY  REF VISCOSITY  VISCOSIBILITY
PVTW
4014.7     1.029        3.13E-6           0.31            0 /
```

```
-- ROCK COMPRESSIBILITY
--    REF. PRES   COMPRESSIBILITY
ROCK
        14.7          3.0E-6          /

-- SURFACE DENSITIES OF RESERVOIR FLUIDS
--        OIL   WATER   GAS
DENSITY
         46.41   64.79  0.041926618  /

PVTG
--       Pg             Rv           Bg           vg
--     PSIG       STB/MSCF      RB/MSCF       CPOISE
  14.7        0.00000        178.10708     0.0125    /
1054.318186   0.015105687    3.640132565   0.0155487 /
1352.577373   0.015765407    2.834503276   0.0158847 /
1650.83656    0.017096423    2.324481372   0.0162775 /
1949.095747   0.018951438    1.974100708   0.016735  /
2247.354933   0.021284323    1.719681794   0.0172643 /
2545.614265   0.024094721    1.527441616   0.0178725 /
2843.873452   0.027410417    1.377808021   0.0185672 /
3142.132639   0.031282172    1.258676654   0.0193566 /
3440.391826   0.03578408     1.162179505   0.0202506 /
3738.651158   0.04101998     1.083006761   0.0212614 /
4036.910345   0.047135743    1.017477242   0.0224051 /
4335.169532   0.054339936    0.963004079   0.0237039 /
4633.428719   0.062944608    0.917785869   0.0251911 /
4931.687906   0.073444905    0.880649578   0.0269199
              0.062944608    0.876942574   0.0261403
              0.054339936    0.873968137   0.0255214
              0.047135743    0.871513247   0.025018
              0.04101998     0.869449486   0.0246017
              0.03578408     0.867693678   0.0242537
              0.024094721    0.863794672   0.0235061
              0.017096423    0.8614625     0.0230787 /
5229.947238   0.086702701    0.851041105   0.0289838 /
5528.206425   0.104455994    0.829295477   0.0315737 /
5826.465612   0.131340629    0.818025745   0.0352042 /
6124.724799   0.207069439    0.845127497   0.0443065
              0.131340629    0.795741869   0.03634
              0.086702701    0.770029375   0.0319773
              0.073444905    0.762867038   0.0307395
              0.047135743    0.749229511   0.028381  /
/

PVTO
-- Rs         Pbub              Bo          Vo
0.0            14.7         1.0         0.35     /
0.063354668   457.7996669   1.1630229   0.307533 /
0.110807029   756.0588538   1.1888849   0.289382 /
0.216515693   1352.577373   1.2462995   0.252078
              1650.83656    1.2351165   0.268711
              1949.095747   1.2250253   0.285289
              2247.354933   1.2158504   0.301815
              2545.614265   1.2074545   0.31829
              2843.873452   1.1997289   0.334714
              3142.132639   1.1925854   0.351085
              3440.391826   1.1859522   0.367401
              3738.651158   1.1797693   0.383659
              4036.910345   1.1739867   0.399856
              4335.169532   1.1685621   0.41599
              4633.428719   1.1634593   0.432058
              4931.687906   1.158647    0.448056
              5229.947238   1.1540985   0.463981
              5528.206425   1.1497902   0.479832
              5826.465612   1.1457015   0.495606
              6124.724799   1.1418143   0.511299
              6483.14496    1.1373869   0.53005
              6845.73696    1.1331556   0.548894
              7208.32896    1.129151    0.56761
              7570.92096    1.1253538   0.586196 /
```

```
0.339570266   1949.095747   1.3129537   0.216354 /
0.484875077   2545.614265   1.3916488   0.183879 /
0.659849531   3142.132639   1.4866965   0.155151 /
0.876470608   3738.651158   1.6051824   0.130071 /
1.156012071   4335.169532   1.7599399   0.108221 /
1.542489024   4931.687906   1.9781322   0.088949
              5229.947238   1.951778    0.092955
              5528.206425   1.9277836   0.096995
              5826.465612   1.905814    0.101071
              6124.724799   1.8855977   0.105183
              6483.14496    1.8633117   0.110174
              6845.73696    1.8426957   0.115276
              7208.32896    1.8237577   0.120432
              7570.92096    1.8062817   0.125639 /
1.806354444   5229.947238   2.1302677   0.079976 /
2.157611251   5528.206425   2.3370589   0.071151 /
2.688963169   5826.465612   2.6595471   0.061905 /
4.201551008   6124.724799   3.6437563   0.047757
              6483.14496    3.55848     0.049596
              6845.73696    3.4816166   0.051442
              7208.32896    3.4126706   0.053277
              7570.92096    3.3504184   0.055109 /
/

RTEMP
320 /

RPTPROPS
1  1  1  0  1  1  1  1  /

SOLUTION ===============================================================

PRESSURE
300*5800 /

SGAS
300*0.00 /

SWAT
300*0.12 /

RS
300*1.52 /

RV
300*0.01 /


RPTRST
PRESSURE DENG DENO DENW VGAS VOIL VWAT KRG KRO KRW VOIL VGAS /

SUMMARY  ===============================================================

RUNSUM

FPR
FGPR
FGIR
FWPR
FOPR
FOPT
FOSAT
PERFORMA

-- WELL GAS-OIL RATIO FOR PRODUCER
WGOR
Inj  Prod
/
-- WELL BOTTOM-HOLE PRESSURE
WBHP
  Inj  Prod
/

-- GAS AND OIL SATURATIONS IN INJECTION AND PRODUCTION CELL
BGSAT
```

```
10 10 3
1  1  1
/
BOSAT
10 10 3
1  1  1
/

-- PRESSURE IN INJECTION AND PRODUCTION CELL
BPR
10 10 3
1  1  1
/

SCHEDULE ===============================================================

RPTSCHED
WELSPECS /

TUNING
1* 20 /
/
/

VAPPARS
1 0 /

SORM
0.10 /

WELSPECS
--nom      gp   I    J   refBHP(ft)  phase
   Inj      WELL   1    1      8400     GAS  3*   /
   Prod     WELL   10   10     8335     OIL  3*   /
/

COMPDAT
--Define connection data
--name  I  J  K1 K2  status
  Inj   1  1  1  1  ’OPEN’ 1* 10.81651284  /
  Prod  10 10 3  3  ’OPEN’ 1* 6.489907702  /
/

WCONPROD
--  name  status  ctrl
 Prod     OPEN    BHP   30000  4*   4500 /
/

WCONINJE
--  name  fluid  status  ctrl
 Inj            GAS    SHUT    BHP  100000 1* 5500 /
/

TSTEP
20*100 /

WCONPROD
--  name  status  ctrl
 Prod     OPEN    BHP   30000  4*   4500 /
/

WCONINJE
--  name  fluid  status  ctrl
 Inj            GAS    OPEN    BHP  100000 1* 5500 /
/

TSTEP
60*100 /

END     ================================================================
```

Table B.1: PVTG for C_1 and C_{12} components

Pressure (psia)	**R_v (stb/Mscf)**	**Bg (rb/Mscf)**	**Gas viscosity (cP)**
1054.318185792	0.01510568721	3.64013256483	0.0155487
1352.5773727104	0.01576540665	2.83450327551	0.0158847
1650.8365596288	0.01709642268	2.32448137209	0.0162775
1949.0957465472	0.01895143833	1.97410070844	0.016735
2247.3549334656	0.02128432311	1.71968179437	0.0172643
2545.6142654208	0.0240947208	1.52744161563	0.0178725
2843.8734523392	0.02741041656	1.37780802054	0.0185672
3142.1326392576	0.03128217174	1.2586766535	0.0193566
	0.02741041656	1.2586392504	0.0192459
	0.0240947208	1.25857602135	0.0191542
	0.02128432311	1.25849889972	0.0190786
	0.01895143833	1.25841785967	0.0190173
3440.391826176	0.0357840801	1.16217950526	0.0202506
3738.6511581312	0.04101997977	1.0830067605	0.0212614
4036.9103450496	0.04713574284	1.01747724174	0.0224051
4335.169531968	0.05433993612	0.96300407934	0.0237039
	0.04713574284	0.96134035383	0.0232779
	0.04101997977	0.95992829775	0.0229278
	0.0357840801	0.95871483432	0.0226368
	0.03128217174	0.95766523209	0.0223931
	0.02741041656	0.95675615865	0.0221885
	0.0240947208	0.9559715841	0.0220169
	0.02128432311	0.95530135617	0.0218742
	0.01895143833	0.95474102211	0.0217576
4633.4287188864	0.06294460833	0.91778586876	0.0251911
4931.6879058048	0.07344490527	0.88064957754	0.0269199

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Table B.1 – *Continued from previous page*

Pressure (psia)	**R_v (stb/Mscf)**	**Bg (rb/Mscf)**	**Gas viscosity (cP)**
5229.94723776	0.08670270123	0.85104110547	0.0289838
	0.07344490527	0.84553056018	0.0279043
	0.06294460833	0.84129457005	0.0270757
	0.05433993612	0.83789676558	0.0264157
	0.04713574284	0.83509598583	0.0258772
	0.04101997977	0.83274511194	0.0254307
	0.0357840801	0.83074867695	0.0250565
	0.03128217174	0.82904202693	0.024741
	0.0240947208	0.82633172706	0.0242497
	0.02128432311	0.82527553476	0.0240619
	0.01895143833	0.82439958978	0.0239079
5528.2064246784	0.10445599359	0.82929547746	0.0315737
5826.4656115968	0.13134062943	0.81802574532	0.0352042
6124.7247985152	0.20706943923	0.84512749725	0.0443065
	0.13134062943	0.79574186889	0.03634
	0.10445599359	0.77995348605	0.033679
	0.08670270123	0.77002937496	0.0319773
	0.07344490527	0.76286703753	0.0307395
	0.06294460833	0.75733707825	0.0297815
	0.05433993612	0.75289323375	0.0290126
	0.04713574284	0.74922951105	0.028381
	0.04101997977	0.74615711355	0.0278541
	0.0357840801	0.74355207669	0.0274101
	0.03128217174	0.74132979822	0.0270339
	0.0240947208	0.73781159139	0.0264444
	0.02128432311	0.73644513147	0.0262178
	0.01895143833	0.73531431108	0.0260314

Table B.2: PVTO for C_1 and C_{12} components

R$_s$ (Mscf/stb)	**Pressure (psia)**	**Oil FVF (rb/stb)**	**Oil viscosity (cP)**
0.0	14.7	1.0	0.35
0.0633546684633	457.7996669184	1.1630229	0.307533
0.110807029363876	756.0588538368	1.1888849	0.289382
0.161732805569592	1054.318185792	1.2165725	0.270707
0.216515692549548	1352.5773727104	1.2462995	0.252078
0.275612318230307	1650.8365596288	1.2783229	0.233878
0.339570265566223	1949.0957465472	1.3129537	0.216354
0.409053281679861	2247.3549334656	1.3505723	0.19966
0.484875077199483	2545.6142654208	1.3916488	0.183879
0.568047442591657	2843.8734523392	1.4367729	0.169043
0.659849531188591	3142.1326392576	1.4866965	0.155151
	3440.391826176	1.4707242	0.164199
	3738.6511581312	1.4562447	0.173296
	4036.9103450496	1.4430312	0.18244
	4335.169531968	1.4309035	0.19163
	4633.4287188864	1.4197164	0.200865
	4931.6879058048	1.4093513	0.210141
	5229.94723776	1.3997098	0.219456
	5528.2064246784	1.3907099	0.228806
	5826.4656115968	1.3822823	0.238188
	6124.7247985152	1.3743678	0.2476
0.761930829262815	3440.391826176	1.5423981	0.142176
0.876470608051204	3738.6511581312	1.6051824	0.130071
1.0064344506204	4036.9103450496	1.6768428	0.118777
1.15601207119196	4335.169531968	1.7599399	0.108221
	4633.4287188864	1.7383406	0.113636

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Table B.2 – *Continued from previous page*

R_s (Mscf/stb)	Pressure (psia)	Oil FVF (rb/stb)	Oil viscosity (cP)
	4931.6879058048	1.7187	0.119098
	5229.94723776	1.7007332	0.124606
	5528.2064246784	1.6842115	0.130159
	5826.4656115968	1.6689481	0.135759
	6124.7247985152	1.6547891	0.141403
	6483.14496	1.6390553	0.148243
	6845.73696	1.6243847	0.155223
	7208.32896	1.6108109	0.162262
	7570.92096	1.5982033	0.169356
1.331416371905	4633.4287188864	1.8583153	0.098314
1.54248902363708	4931.6879058048	1.9781322	0.088949
1.80635444388299	5229.94723776	2.1302677	0.079976
	5528.2064246784	2.1004397	0.08336
	5826.4656115968	2.0732708	0.08677
	6124.7247985152	2.0483874	0.090209
	6483.14496	2.0210839	0.094381
	6845.73696	1.9959428	0.098647
	7208.32896	1.9729444	0.102958
	7570.92096	1.9518018	0.107316
2.15761125147381	5528.2064246784	2.3370589	0.071151
2.68896316882825	5826.4656115968	2.6595471	0.061905
4.20155100780417	6124.7247985152	3.6437563	0.047757
	6483.14496	3.55848	0.049596
	6845.73696	3.4816166	0.051442
	7208.32896	3.4126706	0.053277
	7570.92096	3.3504184	0.055109

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