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REPORT

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REPORT TITLE: **Two-phase Upscaling in Homogeneous Reservoir Examples. IFRA PASF JIP WP3 Phase 0 Simulation Study**	
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SUMMARY:
The impact of simulation grid size and dimension has been studied for two-phase flow with varying relative permeability, using three different reservoir simulators

KEY WORDS: Upscaling, homogeneous, two-phase, ECLIPSE, IMEX, STARS	

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The department conducts applied research into increased oil exploitation and secure CO2 Storage.

Executive Summary

Phase 0 of the Simulation package of PASF JIP has focused on clarifying some upscaling issues for a *two-phase model* (water injection in an oil reservoir). A family of simple *homogeneous* reservoir simulation models have been studied.

The main findings were,

- Three-dimensional models are needed to provide reliable results.
  - For homogeneous cases with symmetry, 2-D cross-sectional models often suffice.
- Relative permeability is scalable, i.e. even on coarser scales the best strategy is to use the fine-scale relative permeability curves unchanged.
- Upscaling errors can in almost all cases be attributed to numerical diffusion (which is an unavoidable source of error with the commercial simulators that are used in the project).
- For the very-fine resolution models it was found that all models with grid cell sizes less than about 2 m provided identical results. Hence the studies can be restricted to a minimum cell size of about 2 m.
- Cell sizes up to about 20 m provide “almost identical” results, while noticeable differences, but still with acceptable accuracy appear at cell sizes of about 40-50 m. For larger cell sizes than this, the differences become significant, and above about 100 m results may fall in the unacceptable category.
- The main conclusions were also confirmed by varying the following parameters without any change in qualitative results,
  - reservoir slope angle
  - production rates
  - permeability, including vertical to horizontal permeability ratio
  - shape of relative permeability curves
  - Well completion interval
- Two black oil models were built (ECLIPSE and IMEX), and were classified as identical
- The black oil model was converted to an equivalent compositional model and run with the STARS simulator, with an acceptable match.
- The effect of injecting cold water in a warm reservoir was tested, concluding that temperature effects are noticeable but not critical in a water-oil setting.

Introduction

Phase 0 of the Simulation package of PASF JIP focused on clarifying some general issues concerning upscaling of *two-phase* simulation models (water injection in an oil reservoir); primarily

- Relative permeability curves and grid resolution
- Grid resolution in homogeneous models
- Relative permeability “pseudo” curves as correction factors
- Dimension reduction
- Temperature
- Different simulators

It is well known that the scale issue is important in *heterogeneous* reservoirs. The fluid flow is governed by primarily petrophysics property variation, which often occurs at a very small scale, and this small-scale behavior can be difficult or impossible to reproduce on coarser grids.

The reason for studying homogeneous models in phase 0 is exactly to not complicate the analysis by heterogeneity upscaling, which will be studied at a later stage. For the same reason, the focus was on two-phase models in this phase 0; understanding of the water-oil upscaling is a necessary prerequisite for studying the more complex processes that are the actual goal.

For the factors listed above it is important, even crucial, to understand the interplay between scale and the different parameters in simple, well-understood simulation models before advancing to more general or realistic reservoir models.

The mechanisms to be studied in the PASF JIP Simulation package are all dependent on the way the simulator handles flow of tertiary fluids – brine, polymer, and surfactant. Some flow issues are definitely best modeled with a compositional model, and this will be done with the simulator STARS from CMG (Computational Modeling Group). The reference black-oil simulator is ECLIPSE from Schlumberger, which is widely used in the industry. The third simulator that has been used in the project is IMEX, a black-oil simulator from CMG, which shares much of the computational foundations with STARS, and hence can act as a calibration bridge between ECLIPSE and STARS.

A number of different simulation models have been built and tested to address each of the issues above. Detail model description and results will be discussed in the relevant chapters.

1. Series 1: 1-D Scale Dependency

In this series a one-dimensional model was used, and the grid size DX was varied from 1cm to 200m, such that for each "new" level, DX was multiplied by three. All dimensions, well positions, and observation points were chosen such that all the models were identical in those respects.

Table 1: Grid properties	
Total length model	1377.81m
Model width (DY)	50m
Model height (DZ)	50m
Depth (top)	1800m SSL
Hor. perm., K_h	200mD
Vert. perm., K_v	200mD
Porosity, Φ	0.25
Rock compressibility	0.000056 bars^{-1}
Datum depth	1800m SSL
P_{init} at Datum Depth	320 bars
Oil Water Contact	2200 m SSL
Gas Oil Contact	No free gas

Table 2: Fluid properties			
PVT Water	B_w = 1.024 Rm^3/Sm^3	C_w = 4.64E-5 bars^{-1}	μ_w = 0.42 cP
Densities	ρ_o = 883 kg/m^3	ρ_w = 1038 kg/m^3	ρ_g = 0.66 kg/m^3
GOR (R_s) const	80 Sm^3/Sm^3		
Bubble point P_{BP}	221 bars		

Table 3: Dead oil PVT		
P (bars)	B_o (Rm^3/Sm^3)	μ_o (cP)
221.0	1.261	1.038
253.4	1.2555	1.072
281.6	1.2507	1.096
311.1	1.2463	1.118
343.8	1.24173	1.151
373.5	1.2377	1.174
395.5	1.2356	1.2

Relative permeability:

All models: Corey-type curves were used, with Corey exponent = 2 for both water and oil.
End points: k_{ro}' = 0.9 at S_{wc} = 0.1; k_{rw}' = 0.36 at S_w = 1-S_{or} = 0.8

Table 4: Well data		
	Injector	Producer
Diameter	0.01m	0.01m
Inj. / Prod. rate	60.9 Sm^3/D	50 Sm^3/D
Max. liquid prod. rate		57.5 Sm^3/D
Bottomhole pressure constraint	< 350 bars	> 220 bars

Note that this series was run with constant injection and production rates. The rates were tuned such that average reservoir pressure was reasonably constant prior to water breakthrough.

Later series were run with the injector(s) controlled by reservoir voidage rate.

Note also that the "unrealistic" well diameter of 1 cm was necessary, as the smallest grid cell size was 1 cm in this series. A side-effect of the small well diameter was that the well rates had to be kept small to avoid a too large drawdown. But these issues had no influence on the study, as long as all parameters were the same throughout the series.

Table 5: Cell size, number of cells, well positions for the models in Series 1								
1-D	L=1377.81		Well dist=1180.98m			Observation cells		
Model	DX (m)	NX	INJ (I)	PROD (I)		B1	B2	B3
L0	0.01	137781	9842	127940		29529	68891	108257
L1	0.03	45927	3281	42647		9842	22964	36083
L2	0.09	15309	1094	14216		3281	7655	12029
L3	0.27	5103	365	4739		1094	2552	4010
L4	0.81	1701	122	1580		365	851	1337
L5	2.43	567	41	527		122	284	446
L6	7.29	189	14	176		41	95	149
L7	21.87	63	5	59		14	32	50
L8	65.61	21	2	20		5	11	17
L9	196.83	7	1	7		2	5	6

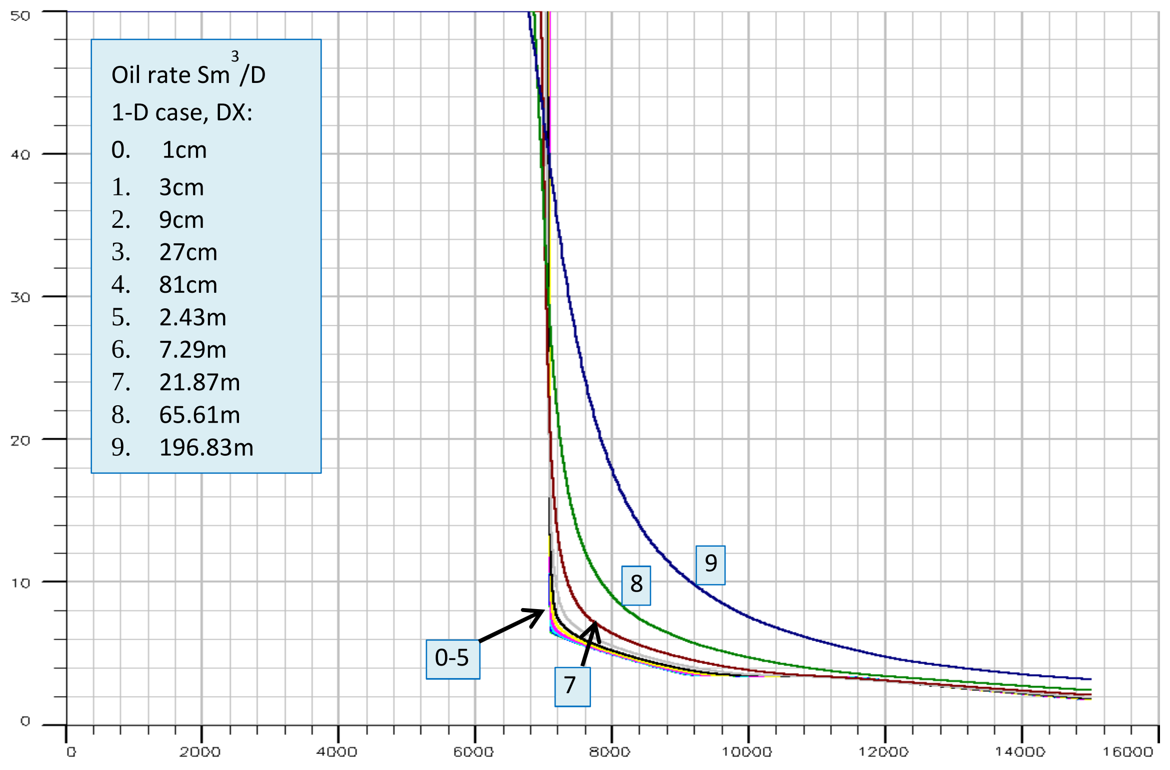

Figure 1. Oil rate (Sm^3/D) vs. time (days), Series 1

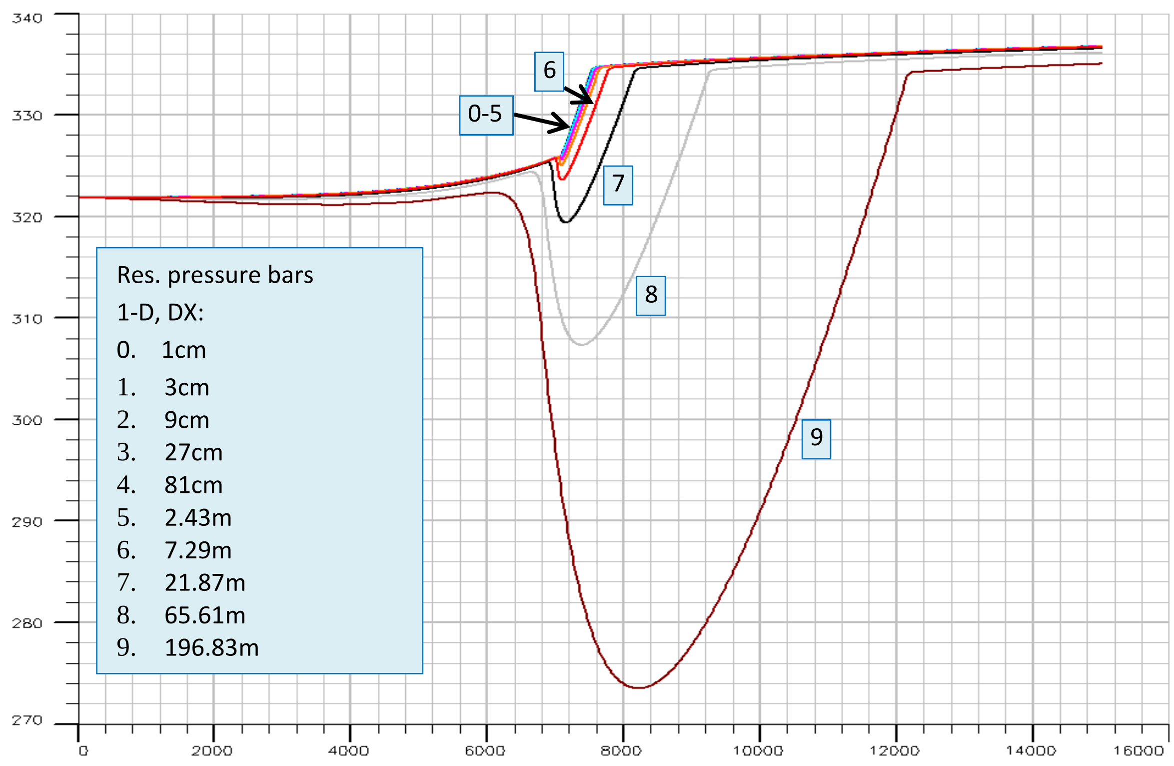

Figure 2. Average pressure (bars) vs. time (days), Series 1.

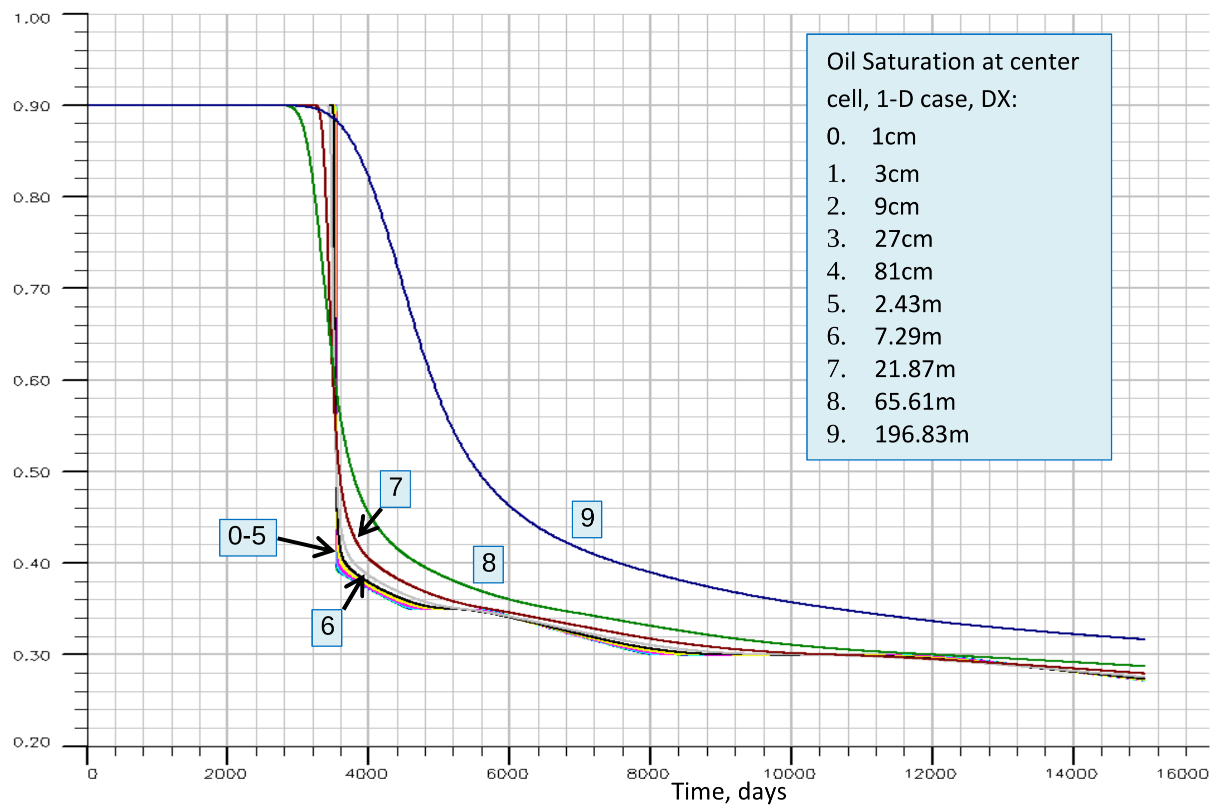

Figure 3. Oil Saturation S_o at center of model, vs. time (days)

Comments:

The most important finding from this series is that the results from scales 0 – 5 are identical (within line thickness). This leads to the conclusions;

- *Relative permeability is scalable*, i.e. changing resolution from 1cm to ~2.5m while using the same relative permeability curves does not affect the results
- All models with resolution (DX) less than about 2m produce the same results, hence it is not necessary to use a grid size less than about two meters to capture small-scale effects. (Note this conclusion is for a homogeneous model). *In later models we can therefore content ourselves with studying cell sizes above about 2m.*
- The differences that appear with increasing DX are solely due to numerical diffusion, and can be explained as such. Observe from the figure that already at DX ~20m, and especially for cell sizes larger than about 50m, the error due to numerical diffusion is significant, and not acceptable.

2. Series 2: Scale and Dimension Dependency

In this series four different families of models were built;

1. One-dimensional models
2. Areal two-dimensional models (XY)
3. Vertical cross-section two-dimensional models (XZ)
4. Three-dimensional models

The models were defined such that physical length, width, height, and well distance were the same in all models in all families. Grid resolution (cell sizes) was varied from 50cm to ~120m, ref. table 9 below.

NOTE: The decision to use a smallest cell size of 50 cm in this series was based on the results from Series 1.

Fluid properties were initially identical to the Series 1 data. The planned schedule was to run the same series also on the other project simulators, IMEX and STARS. As reported later, the conversion to STARS required a redefinition of the PVT data, after which the entire series was rerun with all three simulators.

Only the results from the revised run series are reported here, and in this section we focus on the **ECLIPSE** results. (The result series and conclusions from the initial series, run with the original PVT data, were qualitatively equal to the reported results.)

Table 6: Grid properties	
Total length model	850m
Model width (DY)	48.6m
Model height (DZ)	49.5m
Depth (top)	1800m SSL
Hor. perm., K_h	200mD
Vert. perm., K_v	200mD
Porosity, Φ	0.25
Rock compressibility	0.000056 bars^{-1}
Datum depth	1800m SSL
P_{init} at Datum Depth	340 bars
Oil Water Contact	2200 m SSL
Gas Oil Contact	No free gas

Table 7: Dead oil PVT		
P (bars)	B_o (Rm^3/Sm^3)	μ_o (cP)
180.0	0.998212	1.041
227.0	0.997743	1.042
253.4	0.997479	1.072
281.6	0.997198	1.096
311.1	0.996903	1.118
343.8	0.996577	1.151
373.5	0.996280	1.174
395.5	0.996061	1.2
R_s	16 Sm^3/Sm^3	(const)
P_{BP}	180 bars	

Comment on the B_o-values: The B_o-values in the table are less than unity, and R_s (gas resolution factor) is small. Hence the description used is *not* representative for e.g. North Sea oils. The reason for using this oil type is a practical one, namely difficulties with defining an oil type which could be described (almost) identically in black oil mode (ECLIPSE and IMEX) and compositional mode (STARS). Using a general K-value table in lieu of polynom-fitting coefficients (STARS preferred mode) will probably fix this problem. This will be done in the next generation models. For now we acknowledge the issue, but it has no significance in the analysis.

Relative permeability:
All models: Corey-type curves were used, with Corey exponent = 2 for both water and oil.
End points: k_{ro}' = 0.9 at S_{wc} = 0.1; k_{rw}' = 0.36 at S_w = 1-S_{or} = 0.8

Table 8: Well data		
Well distance	729m	
	Injector	**Producer**
Diameter	0.05m	0.05m
Inj. / Prod. rate	44.5 Sm^3/D / Res. voidage	36 Sm^3/D
Max. liquid prod. rate		36 Sm^3/D
Bottomhole pressure constraint	< 420 bars	> 180 bars

Table 9: Cell size, number of cells, for the models in Series 2

Model	Dim.	DX (m)	DY (m)	DZ (m)	NX	NY	NZ	NX*NY	NX*NY*NZ
1D1	1	0.5	48.6	49.5	1701	1	1		
1D2		1.5			567				
1D3		4.5			189				
1D4		13.5			63				
1D5		40.5			21				
1D6		121.5			7				
2D1	2	0.5	0.6	49.5	1701	81	1	137781	
2D2		1.5	1.8		567	27		15309	
2D3		4.5	5.4		189	9		1701	
2D4		13.5	16.2		63	3		189	
2D5		40.5	16.2		21	3		63	
2D6		121.5	16.2		7	3		21	
XZ1	2	0.5	48.6	2.61	1701	1	19		32319
XZ2		1.5		2.61	567		19		10773
XZ3		4.5		5.5	189		9		1701
XZ4		13.5		9.9	63		5		315
XZ5		40.5		16.5	21		3		63
XZ6		121.5		16.5	7		3		21
3D1	3	0.5	0.6	2.61	1701	81	19	137781	2617839
3D2		1.5	1.8	2.61	567	27	19	15309	290871
3D3		4.5	5.4	5.5	189	9	9	1701	15309
3D4		13.5	16.2	9.9	63	3	5	189	945
3D5		40.5	16.2	16.5	21	3	3	63	189
3D6		121.5	16.2	16.5	7	3	3	21	63

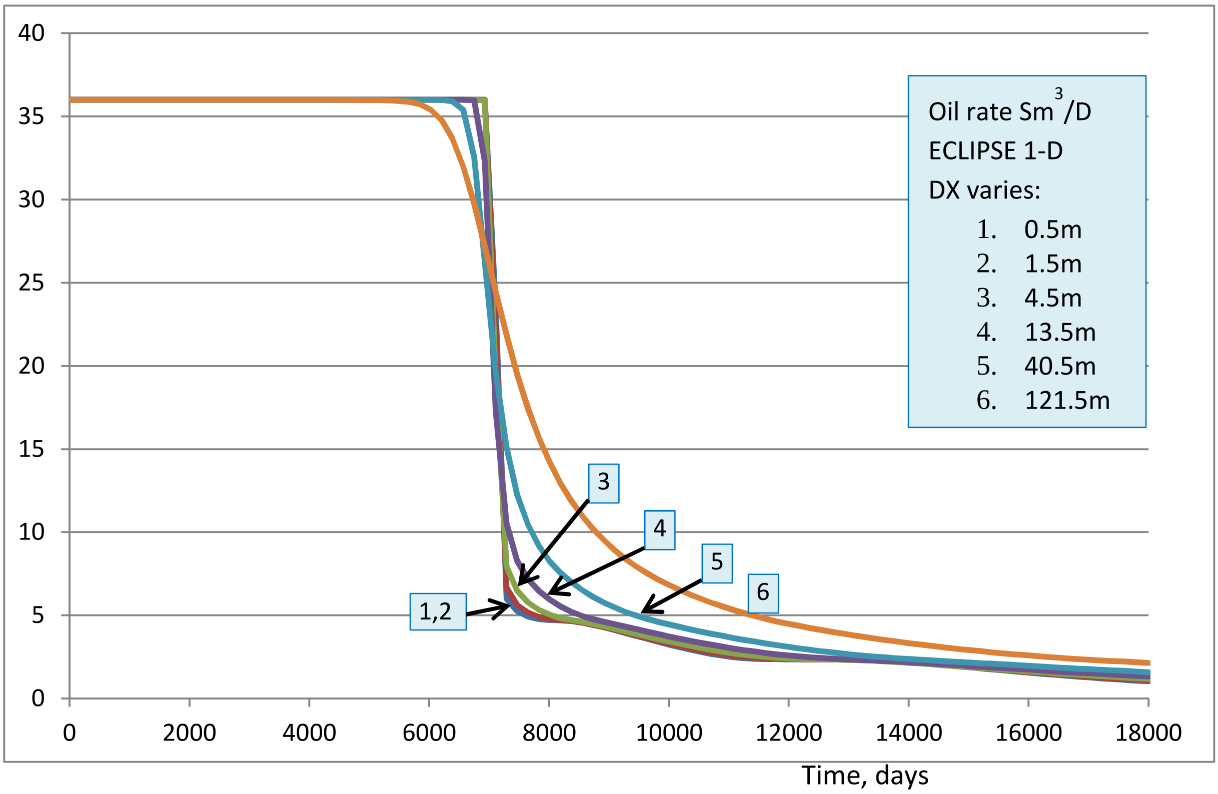

Figure 4. Oil Rate (Sm^3/D) vs Time; 1-D Series

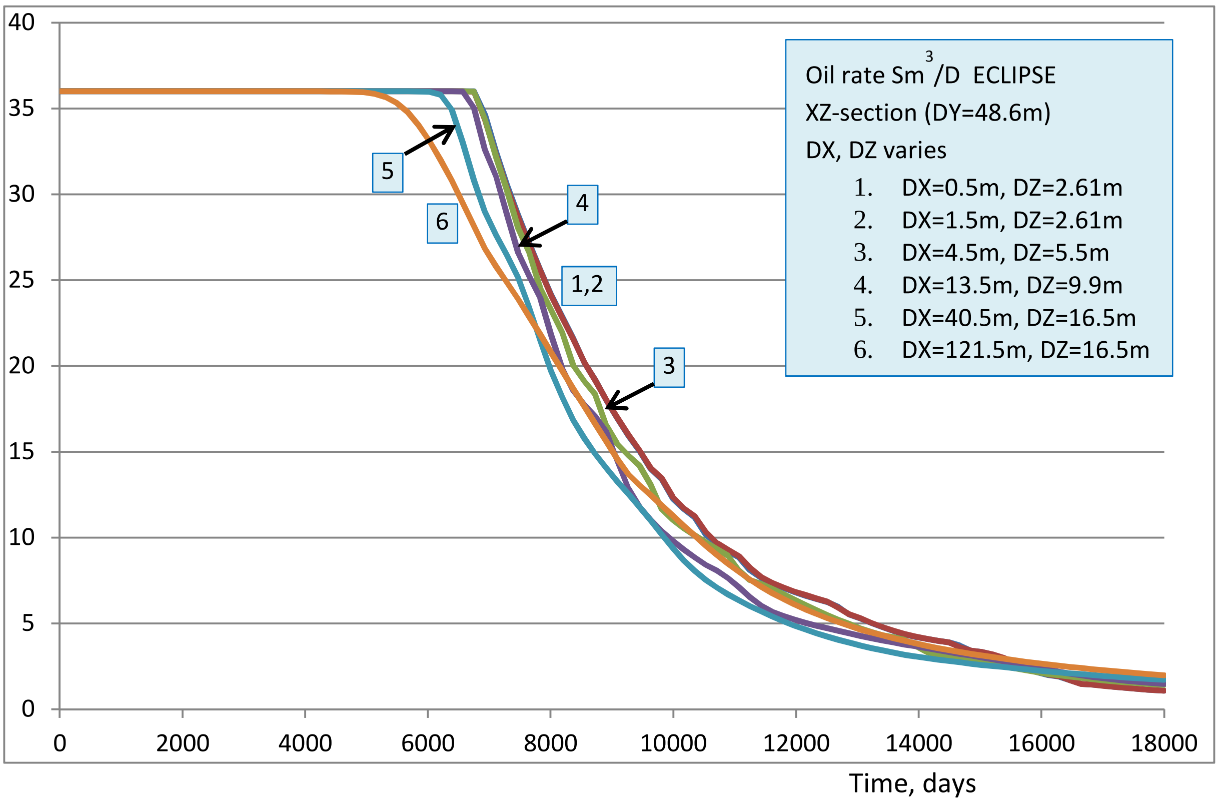

Figure 5. Oil Rate (Sm^3/D) vs Time; 2-D XZ-Section Series

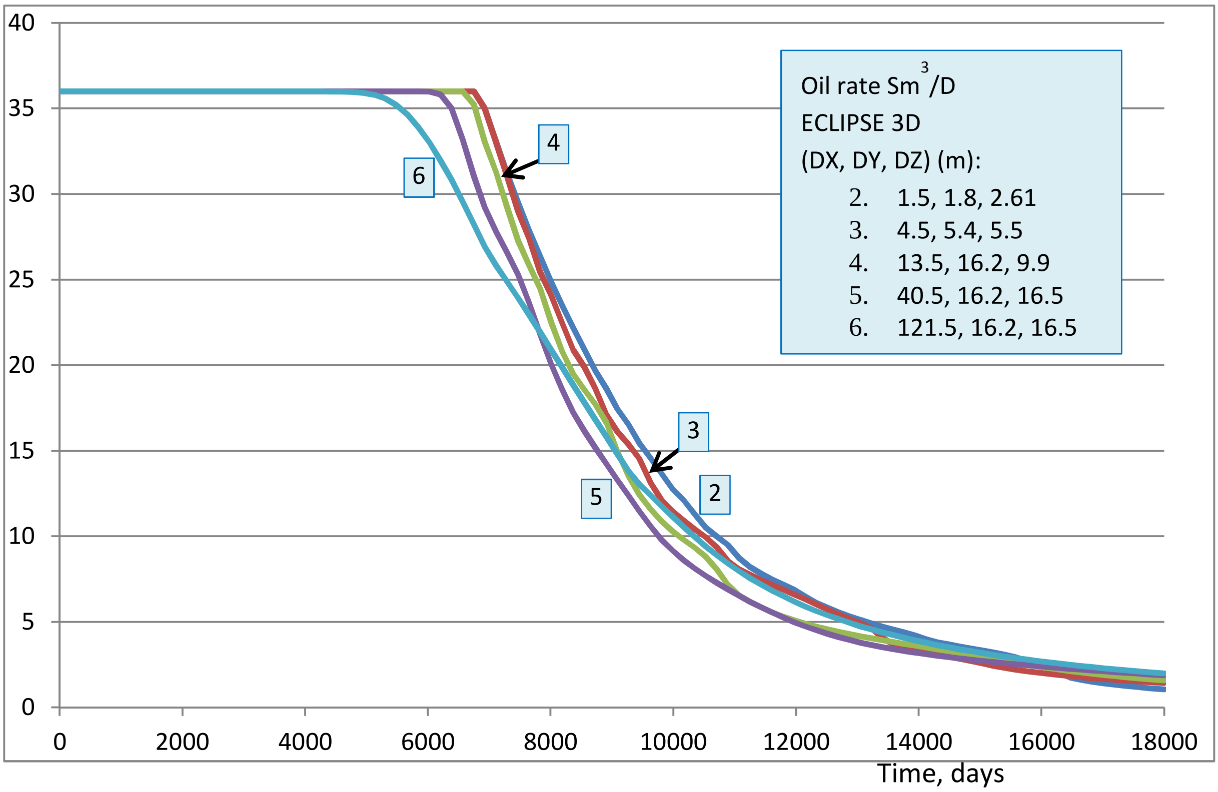

Figure 6. Oil Rate (Sm^3/D) vs Time; 3-D Series

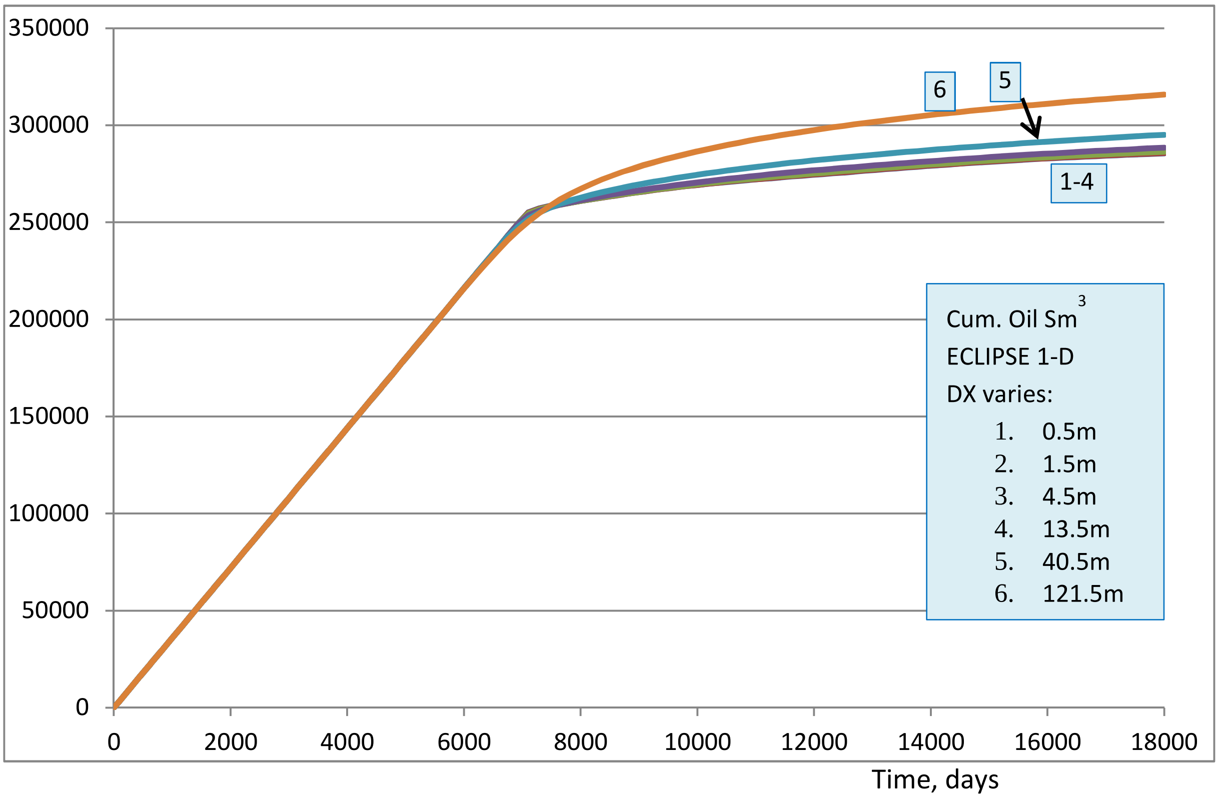

Figure 7. Total Oil Prod. (Sm^3) vs Time; 1-D Series

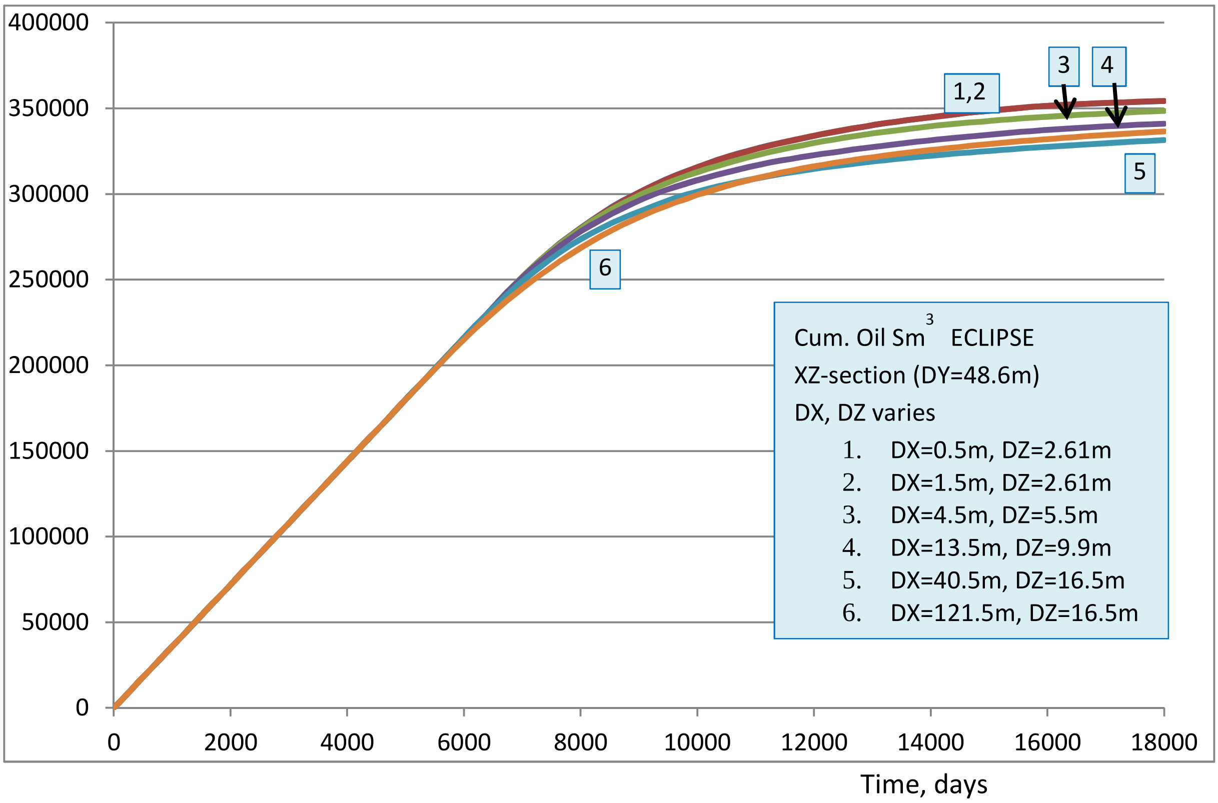

Figure 8. Total Oil Prod. (Sm^3) vs Time; 2-D XZ-Section Series

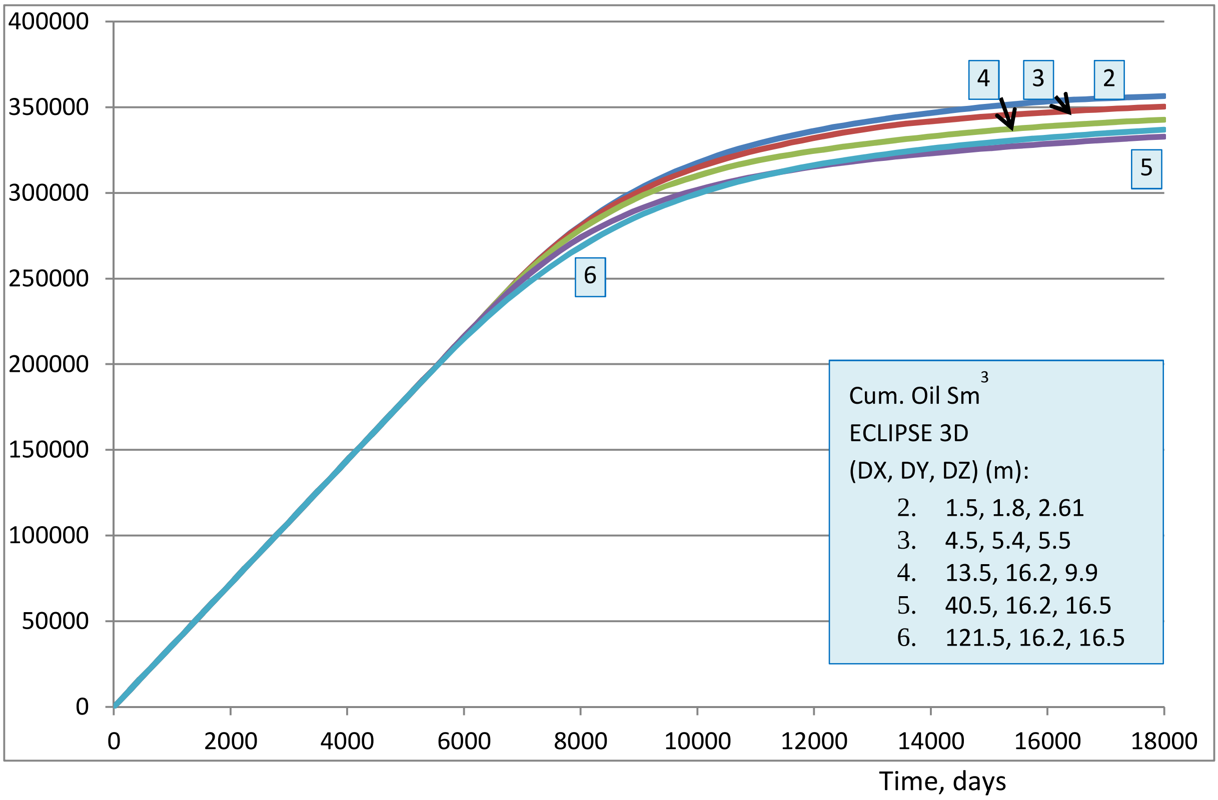

Figure 9. Total Oil Prod. (Sm^3) vs Time; 3-D Series

Comments:

- Results from the one-dimensional models differ significantly from the 3-D models, which we take as reference results. This is mainly due to the influence of gravity, which we hence conclude should not be neglected except perhaps in very thin reservoirs.
- 2-D areal (XY) models (not shown here) showed results similar to the 1-D models, hence underpinning that it is the gravity effect, not the area geometry that is important.
- For the three-dimensional models the difference between the finest and coarsest models was actually smaller than in the corresponding 1-D series. This can be explained by the gravity effect in some sense counteracts the errors due to numerical diffusion.
- Results from Series 1 were confirmed:
    - Results from cell sizes up to about 20 m were as good as equal
    - At cell size about 40 m the results were still within acceptable uncertainty variation
    - At cell sizes above about 50 m the results started to deviate noticeably from the small-scale results, and at about 100 m cell size, results were significantly different, perhaps in the "not acceptable" category.
      Note that this is a typical cell size used in standard industry simulations.
- Results from the 2D Cross-sectional model were almost identical to the 3-D results. I.e., for problems of this kind, namely a reservoir and well pattern with no lateral variation, XZ-models can be used in place of full 3-D models without noticeably loss of accuracy.

Findings / conclusions

- A cell size of about 40 m is a good choice for future studies, as a good compromise between a manageable number of cells and acceptable accuracy.
- In general 3-D models should be used, but 2-D cross-section is an acceptable alternative in many cases

Related issues

A number of sensitivity runs were done on the models in Series 2. These include:

- Varying slope of reservoir, horizontal, 3 and 6 degrees slope (injector in deep end)
- Varying production / injection rates, 1.5 and twice the base case
- Varying permeability, Horizontal permeability K_h = 200 mD (base case), 800 mD, 80 mD
- Varying vertical conductivity;
  Ratio vertical to horizontal permeability K_v/K_h = 1.0, 0.1, 0.01, 0.
- Varying perforated interval, entire vertical section (base case), 50% of section, only midpoint.

All results from these sensitivity tests were in agreement with the findings above, and hence are not shown here.

3. Relative permeability curves

Most relative permeability curves used in the study were of Corey-type, but some alternative shapes with a "plateau" in the mid-range were also tested.

In this section we study the effect of varying relative permeability shape on production curves, and then address the question of pseudoization; is it possible to counter the errors due to grid coarsening or dimension reduction by modifying the shape of the relative permeability curves.

The main test series was obtained by varying oil and water Corey exponents from 5 to 0.5 (10 different test values), and running all possible combinations of k_{ro} and k_{rw}. In all these cases the end point values were kept fixed: S_{wc} = 0.31, S_{or} = 0.28; k_{rw}' = $k_{rw}(1\text{-}S_{or})$ = 0.36 – 0.5, k_{ro}' = $k_{ro}(S_{wc})$ = 0.9.

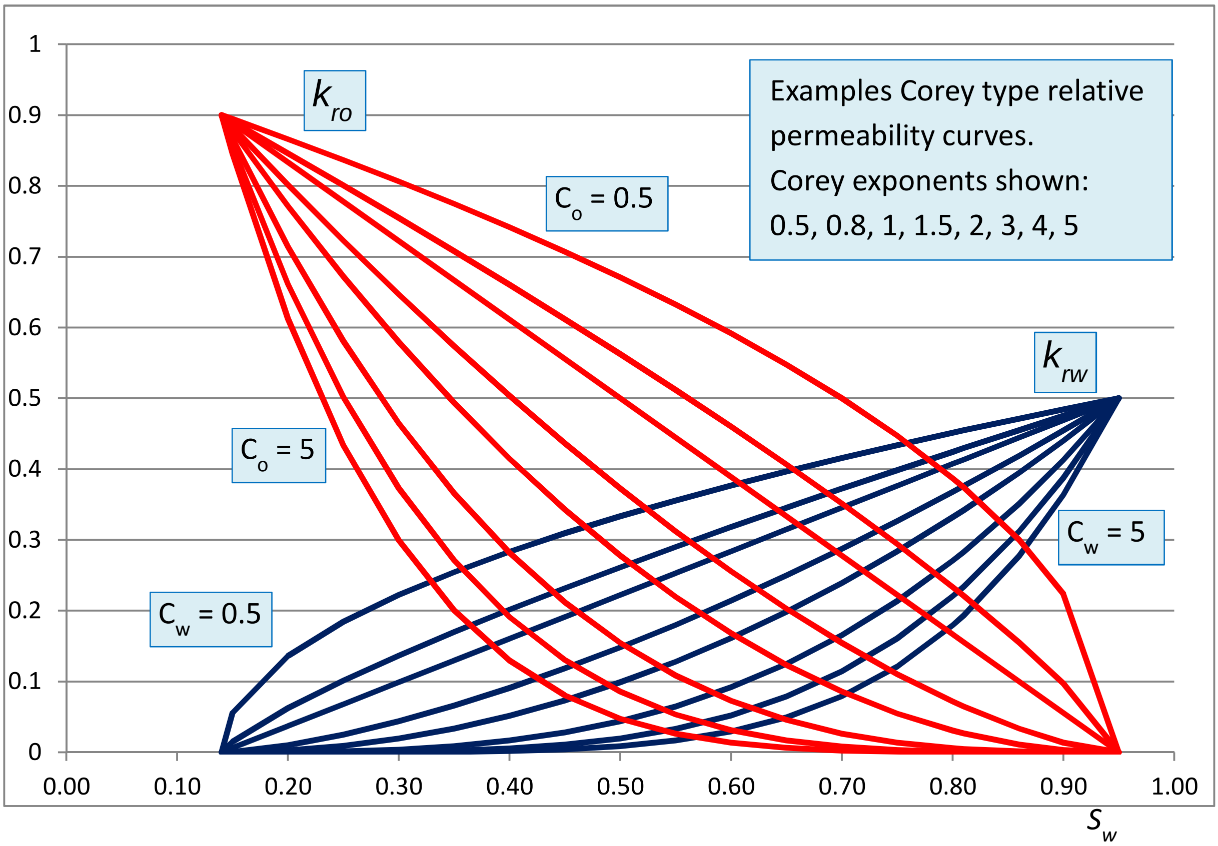

Figure 10. Examples Relative Permeability Curves used in test series

In addition to the curves shown in Figure 10, some curves with a mid-range "plateau" were tested (same end point values).

Some results are presented below for series with oil Corey exponent = 2 and varying water Corey, and vice versa, water Corey exponent = 2 and varying oil Corey.
(No essential features are lost by restricting the figures to these series, as the remaining of the total more than 100 series were qualitatively of the same kind.)

All simulations in this series were done using ECLIPSE.

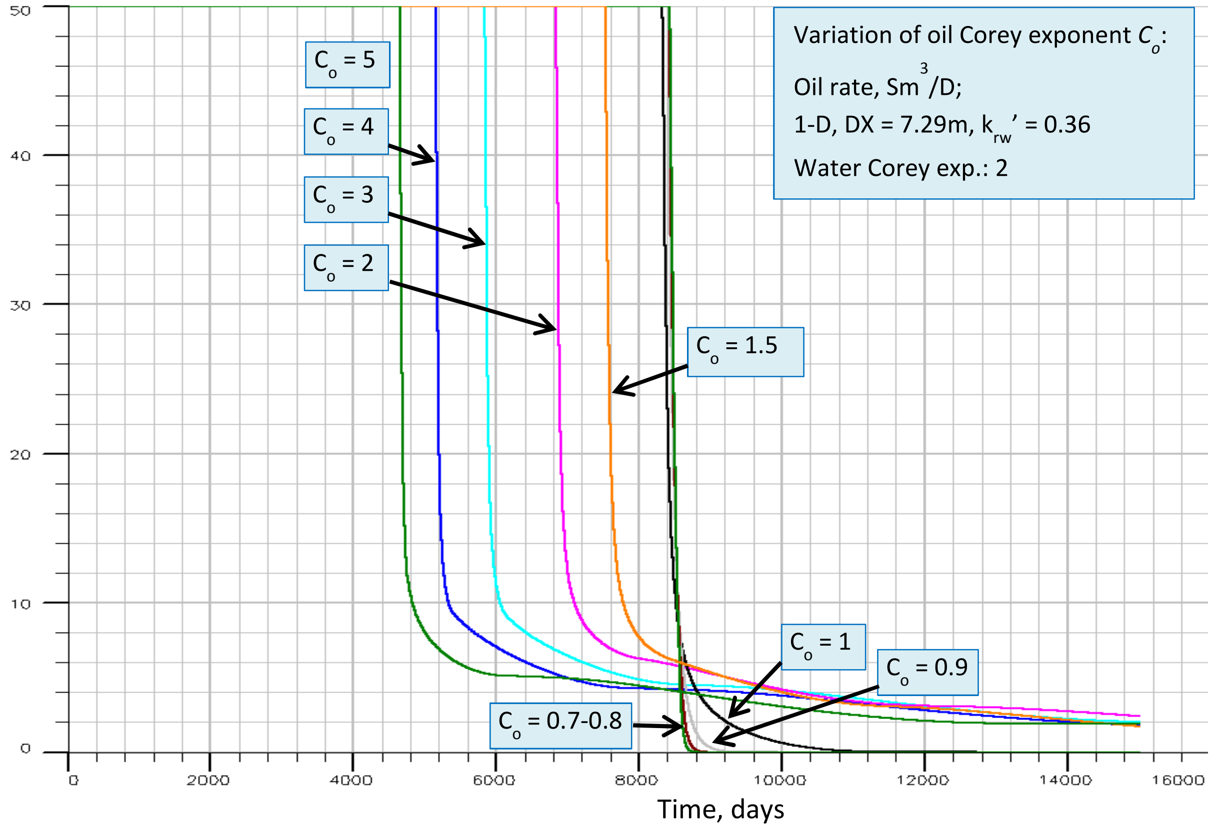

Figure 11. Oil rate with varying Oil Corey Exponent, 1-D case. (Note this family of curves was run with the "Series 1" data set, so differs a little from the others.)

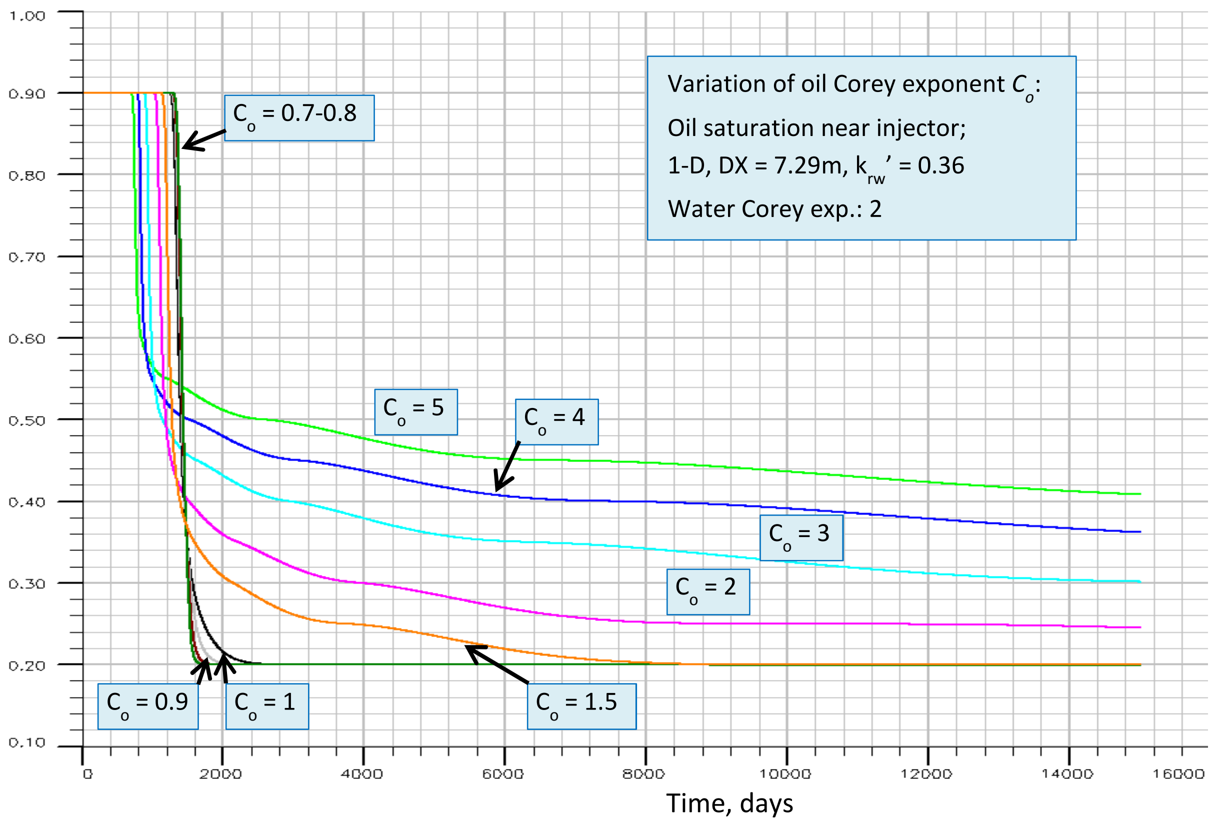

Figure 12. Oil Saturation near injector, with varying Oil Corey Exponent, 1-D case. (Note this family of curves was run with the "Series 1" data set, so differs a little from the others.)

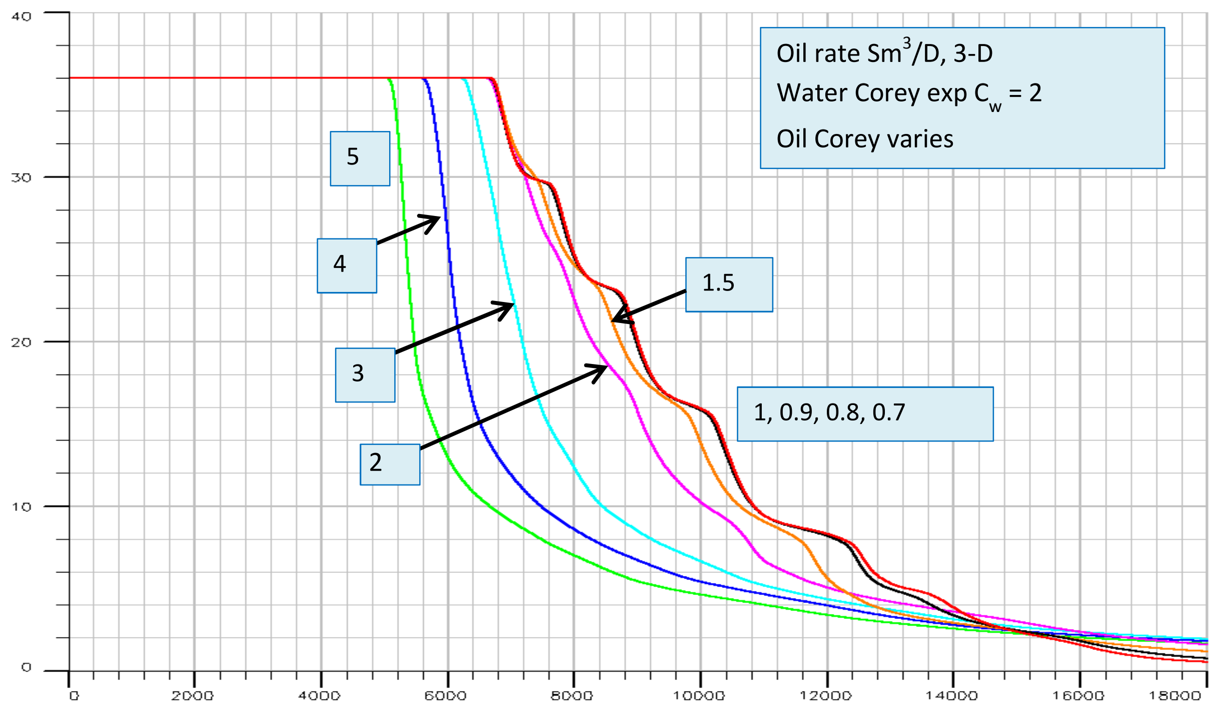

Figure 13. Oil rate vs. time (days) with varying Water Corey Exponent, 3-D case

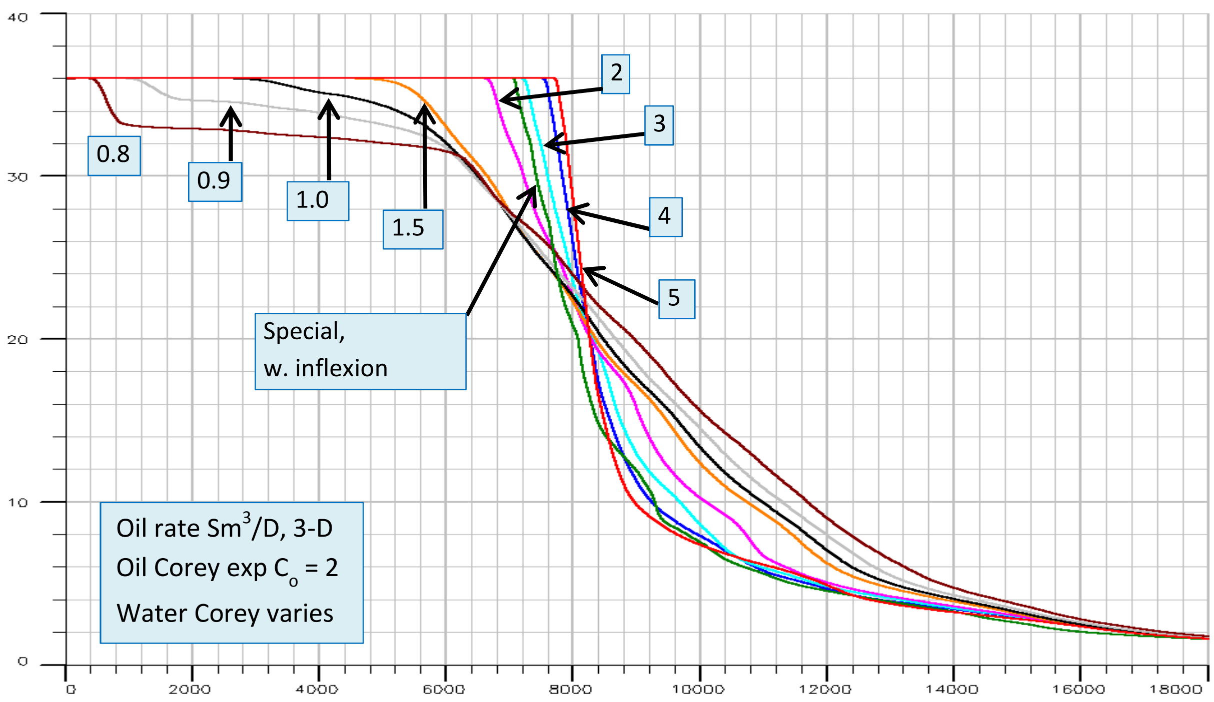

Figure 14. Oil rate vs. time (days) with varying Oil Corey Exponent, 3-D case

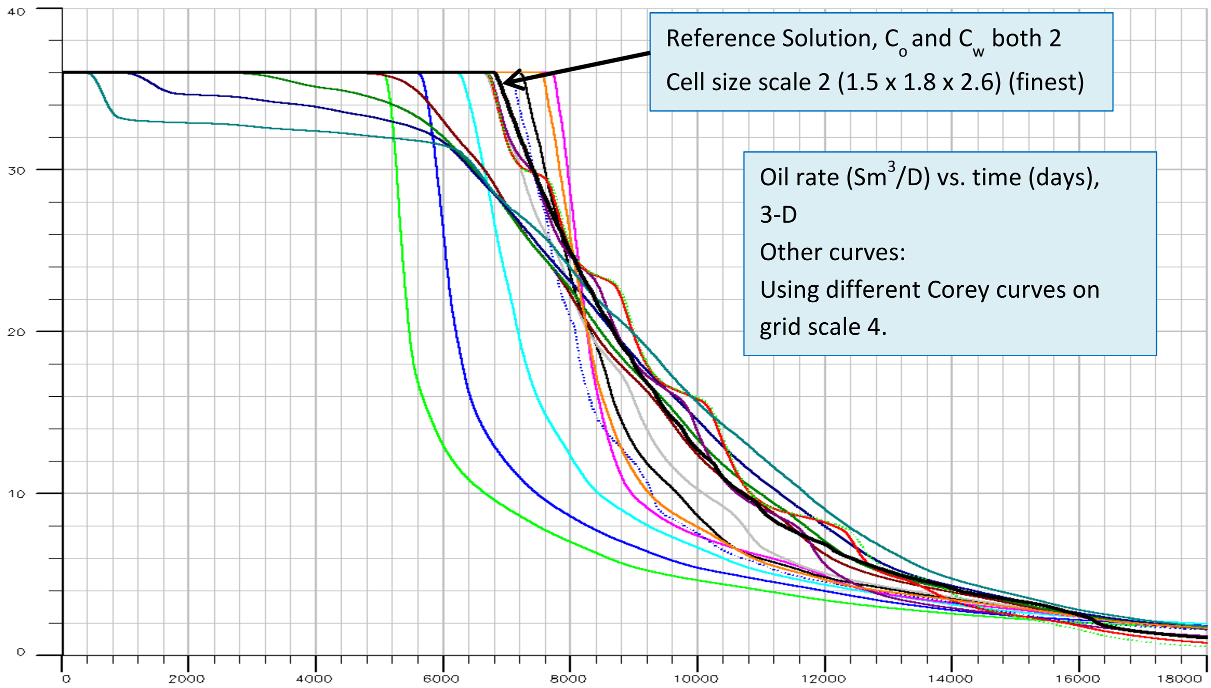

Figure 15. Oil rate (Sm^3/D) vs time (days). Comparing q_o from Corey 2, 2 on finest grid with many different Corey combinations on a coarser grid (see text)

Comments:

- Varying Corey exponents (both C_o and C_w) affects the water breakthrough time, and also the slope of the oil rate decrease after breakthrough.
- For exponents smaller than 1 tendencies to instability were observed
- The relationship between the shape of the oil rate curve and relative permeability curves is different than the effect of numerical diffusion, hence it would be difficult or impossible to counter-effect the numerical diffusion error by modifying the relative permeability curve. (See note below.)
- The small scale relative permeability should be used unchanged also for coarser grids. (Note that this conclusion is for homogeneous petrophysics.)

Note on "pseudoization"

A priori it was expected that changing the relative permeability curve shape could compensate for computational or upscaling errors, as in the traditional "Kyte & Berry" pseudoization studies. It appears that such pseudo-curves are useful and valid for dimension reduction, primarily for reducing a full 3-D case to an areal 2-D model (which was the main goal in their work).

For pure grid resolution change (no dimension change) we found that the best match was actually found by using the original curves. While many cases were studied we limit the discussion to one example, depicted in figure 15 above. There a case with Corey exponents $C_o = C_w = 2$ was run on the finest grid scale (DX, DY, DZ = 1.5, 1.8, 2.6 m), and compared to results from another series, where all possible combinations of Corey exponents plus some non-Corey curves were tested on a grid of scale 4 (DX, DY, DZ = 13.5, 16.2, 9.9 m). A representative selection of these results are shown in Figure 15, where the "reference" fine scale result is shown by a heavy line. As seen, the rel-perm's influence on oil rate shape implies that most of the curves deviate significantly from the reference curve. The coarse scale curve that comes closest to the fine scale reference curve is actually the one using the same Corey exponents, $C_o = C_w = 2$. This observation was the same for all the series that were tested, leading to the conclusion above.

4. Simulator Dependency

The main objective in this project is simulation of tertiary processes, namely injection of brine, low salinity brine (LoSal), surfactant, and polymers. It is believed that one of the most reliable simulators in such respects is STARS from CMG (Computational Modeling Group, Calgary, Canada). On the other hand, ECLIPSE is the most widely used simulator in oil companies in Norway (and Europe), whereby it is essential to enable running and comparing the test cases in the present project also in ECLIPSE.

This adds a new dimension to the project; not only should dependency on scale and dimension be studied, but also how different simulators handle “identical input”, classify differences, strength and weaknesses (reliability) of different simulators.

We have chosen to focus on three different simulators:

- **ECLIPSE** (Schlumberger). Black oil. Industry standard. Not focused on tertiary processes. Has a very rich set of simulator options.
- **STARS** (CMG). Compositional. CMG have focused on tertiary processes in all their simulators and is counted as experts in the field. The CMG simulators are therefore a priori expected to be reliable regarding tertiary flow
- **IMEX** (CMG). Black oil. The primary reason for including this simulator is that it is a black oil simulator from CMG. I.e., different computational procedures can be compared by comparing IMEX to ECLIPSE (black oil to black oil, different developers), while different strategies can be compared by comparing IMEX to STARS (same developers, shared computational procedures and input syntax, black oil vs. compositional). In a sense, IMEX can be viewed as a bridge between ECLIPSE and STARS.

By this comparison test we address differences / weaknesses in the three simulators, and to the extent that some simulator is proven to be “weak” in some modelling aspect, the goal is to provide guidelines for how to overcome such weaknesses.

The physics behind compositional and black oil modeling are fundamentally different, so it is undoubtedly a challenge to construct a compositional model that is “identical” to a corresponding black oil model.

4.1 ECLIPSE to IMEX

This conversion was straightforward, as mostly there is a one-to-one correspondence between keywords in ECLIPSE and in STARS. Naturally some difference in simulator philosophy implies a different attack angle in some areas, but the end product was an IMEX model that appeared to be identical to the ECLIPSE reference model.
One major difference is that ECLIPSE has a “dead oil mode”, which allows for simplified PVT input, with the restriction that no pressure value may go below initial bubble point. IMEX has no such simplified mode, and it is the user’s responsibility to mimic such behavior if desired.

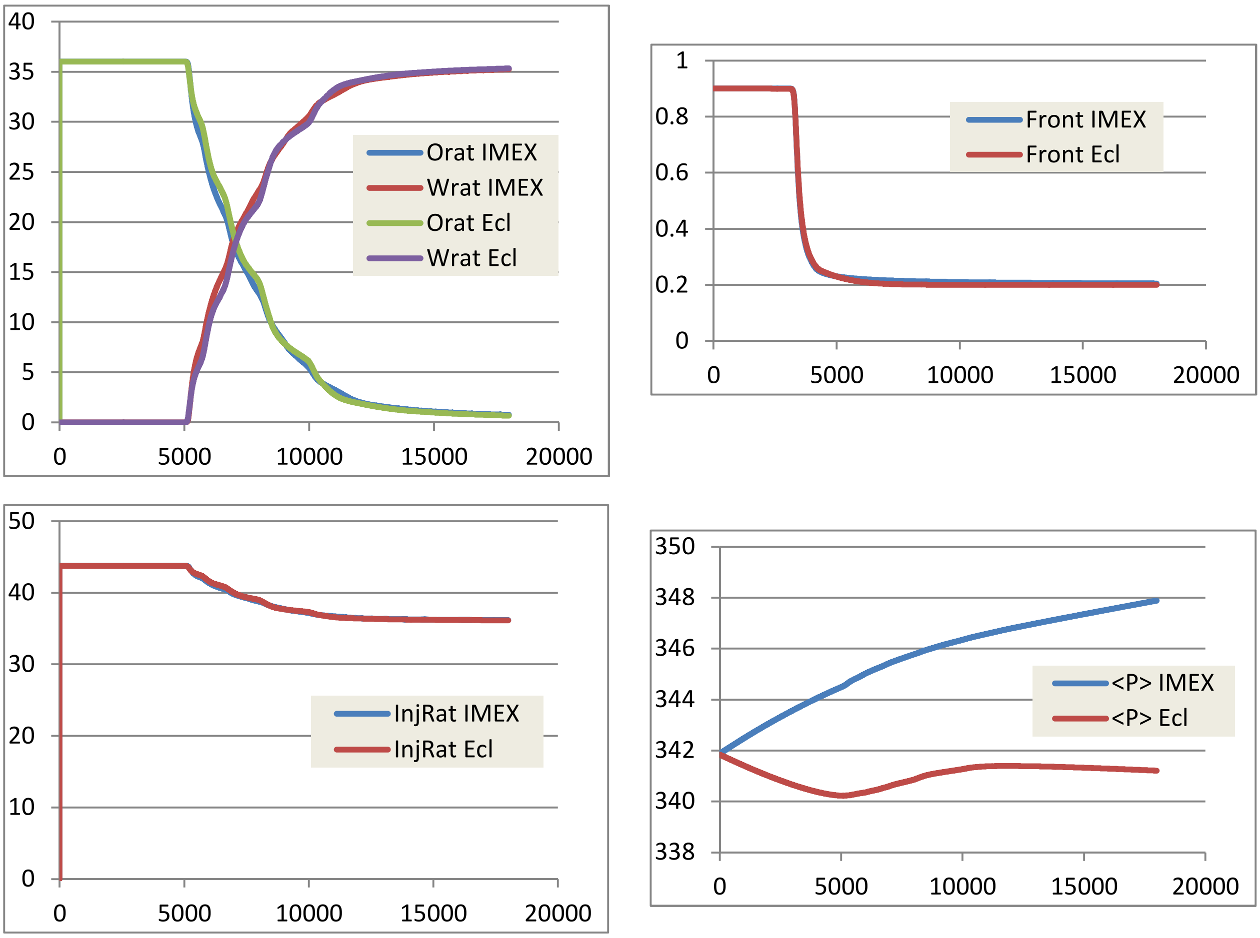

Figure 16. Comparison ECLIPSE vs. IMEX. Upper left: Oil and Water rates vs. time. Upper Right: Oil Saturation near injector vs. time. Lower Left: Injection rates vs. time. Lower Right: Average reservoir pressures vs. time.

From this figure we conclude,

- Simulation of saturation front, oil and water production is as good as identical in the two simulators
- Simulated water injection rate is as good as identical. This is reassuring, as the injection is determined by voidage rate, a property derived from fluid production rate and pressure.
- Simulated reservoir pressure differs by almost 7 bars at most.
  This is surprising, as the two left-hand figures confirms identical material balance in the two models. (Reservoir voidage is set to 1, which means that the volume injected water at any time should balance the produced oil + water. Hence material balance should be perfect, and the theoretical pressure should be constant.)
  ECLIPSE shows an almost-constant reservoir pressure, and hence appears to be the most correct here. It should also be noted that both simulators were run with the same numerical scheme, and with the same convergence tolerances. So … difficult to explain, but all in all, acceptable match.

4.2 Black Oil to Compositional

Attempting to converting the black oil model to a compositional one revealed that the oil volume factor vs. pressured dependency that had been used in the black oil models was not physical consistent with the (constant) gas-oil-resolution factor. This primarily affected the conversion from reservoir to standard conditions, and is not essential if the main focus is on the reservoir volumes. But still the discovery was disturbing, as we would prefer the models to be identical in all respects. This lead to a study of "permissible parameters in black oil models". The conversion process and some side issues are described in the blog at *folk.uib.no/fciop/sim_cmg.*

The base STARS model was defined with the parameters;

Total number of components: 3
Number of fluid components: 3
Number of liquid components: 3
Number of aqueous comp's: 1

Components: Water, Dead Oil, and Solution Gas (denoted 'Water', 'DeadOil', 'SolGas')
Solution gas was allowed to mix with dead oil, the other two components only occur as pure.
K-values were defined by their polynomial approximation, which is the standard way in STARS.
Example of K-value components are found in the table below, however these were used as main matching parameter when comparing black oil to STARS.

Table 10: Component properties

Property \ Component	Water	Dead Oil	Solution Gas
Molecular weight	0.018	0.06	0.035
Density at std. cond. (kg/m^3)	1038	883	0.66
Liquid compressibility (1/kPa)*	4.64E-7	1.0E-7	1.9E-4
First coeff of termal expansion	0.000184146	0.000184146	0.000184146
K-values by coefficients			
Kv_1	0.0	0.0	0.0
Kv_2	0.0	0.0	0.0006
Kv_3	0.0	0.0	2.0
Kv_4	0.0	0.0	0.0
Kv_5	0.0	0.0	0.0

Relative permeability and viscosity were set equal to the black oil model.

(* 1 bar = 100 kPa)

Note that liquid compressibility for oil and gas components is not the same as phase compressibility in a black oil model!

Many sensitivities were run, varying molecular weights, compressibility, and K-values.

No perfect match between IMEX and STARS was found. The deviation is mainly due to the transformation from reservoir to surface conditions, and many of the runs had a good match when reservoir condition rates were compared. As these runs were done with voidage control, the composition description and mixing rules only need to be accurate at the relevant pressure. On this background the match was found to be satisfactory.

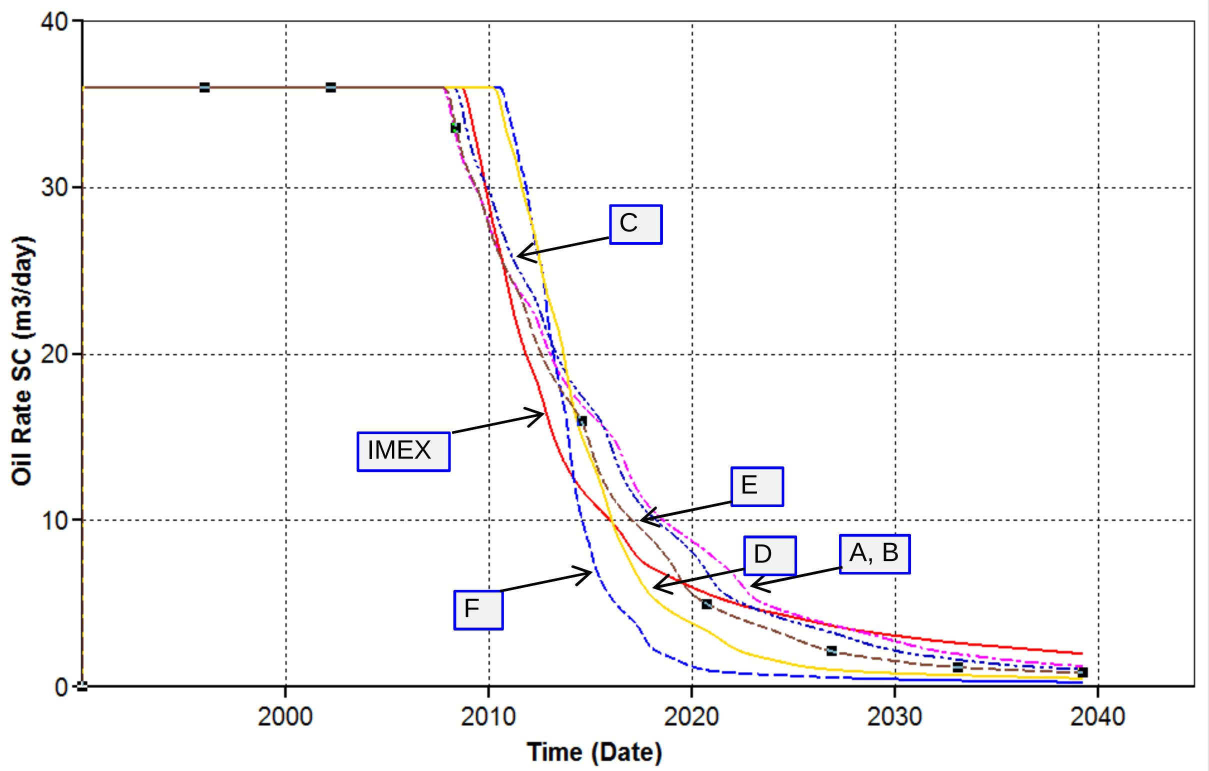

Figure 17. Oil rate vs time, Varying K-values in STARS, ref. case: IMEX

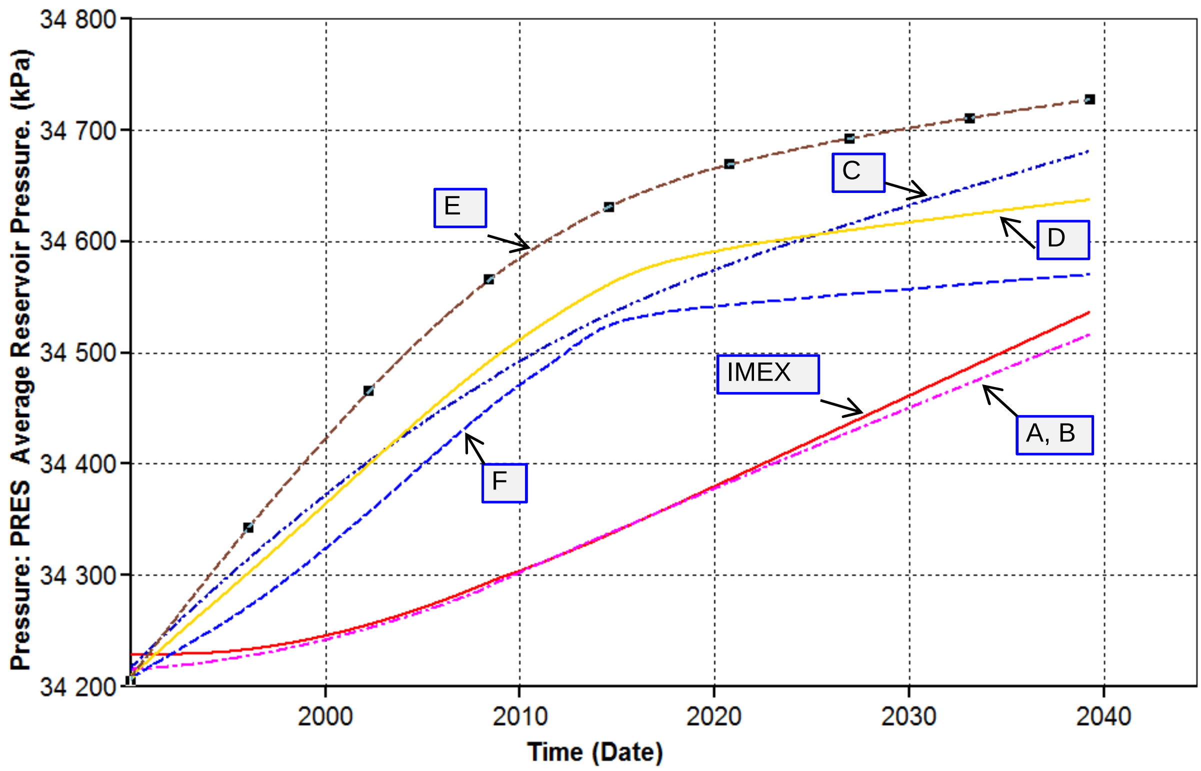

Figure 18. Reservoir pressure vs time, Varying K-values in STARS, ref. case: IMEX

The tests above didn't challenge the composition and mixing rules, as the producing pressure was relatively constant. For reference the models were therefore also run in a depletion process, where reservoir pressure was allowed to decrease to (initial) bubble point pressure during production. Figure 19 shows the comparison between three different component descriptions (K-values) in STARS vs. the IMEX reference run.

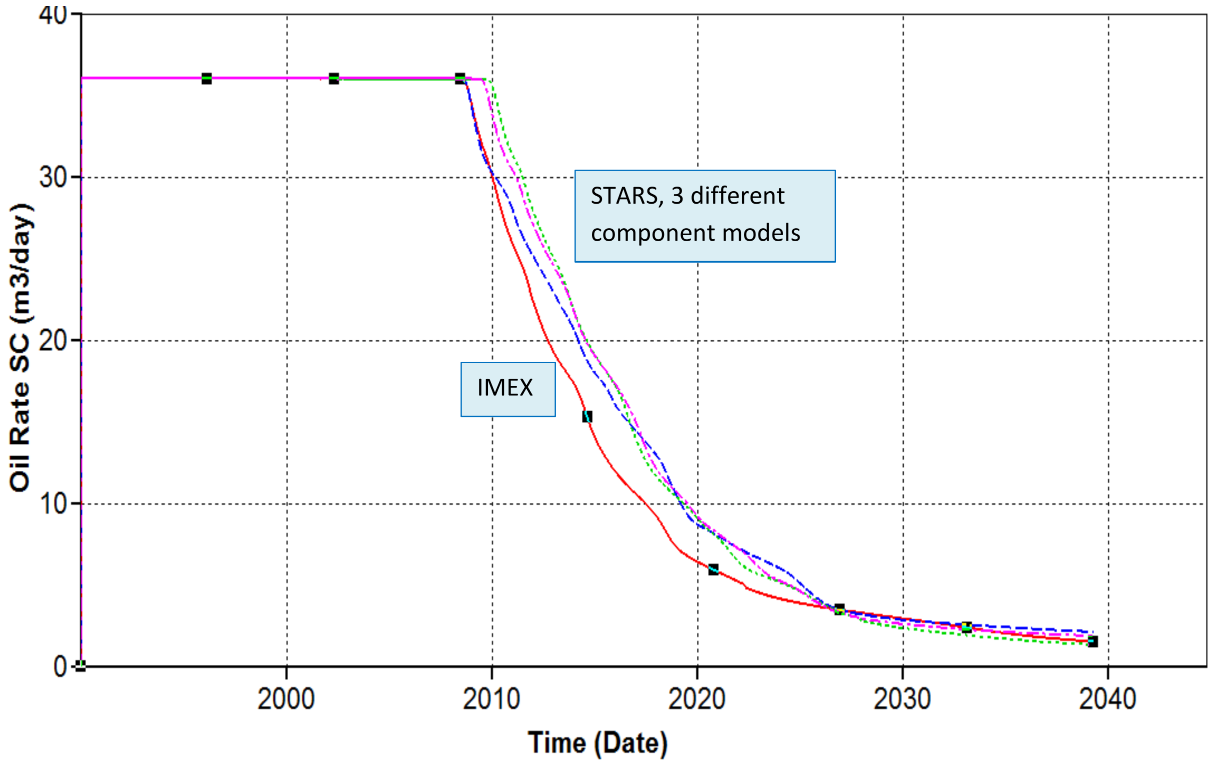

Figure 19. Comparison STARS vs IMEX, production with decreasing pressure

The match is acceptable.

Note: We expect the model setup to be more challenging when including tertiary fluids, so this must be regarded as a preliminary exercise.

5. Thermal Effects in a Water-oil Model

As it is expected that temperature effects may be significant in tertiary processes, it was of interest to test the temperature option in STARS first for a two-phase water-oil system.

The main difference from the isothermal models was to define a temperature-dependent viscosity. (For other parameters, as conductivity, enthalpy,… STARS default relationships were used.)

Pressure / temperature dependent viscosities were generated from standard formulas in the STARS manual.

Table 11: Viscosity		
Temp. °C	Water	Sol. Gas
4	1.1265	0.026426
20	0.8355	0.022618
50	0.5168	0.017612
72	0.3831	0.015070
90	0.3081	0.013454
110	0.2478	0.012010

Table 12: Oil Viscosity at different pressures (bars)					
Temp. °C	P = 180	P = 253	P = 311	P = 374	P = 396
4	3.6419	3.6729	3.7189	3.7749	3.8009
20	2.5957	2.6267	2.6727	2.7287	2.7547
50	1.4885	1.5195	1.5655	1.6215	1.6475
72	1.0410	1.0720	1.1180	1.1740	1.2000
90	0.7958	0.8268	0.8728	0.9288	0.9548
110	0.6024	0.6334	0.6794	0.7354	0.7614

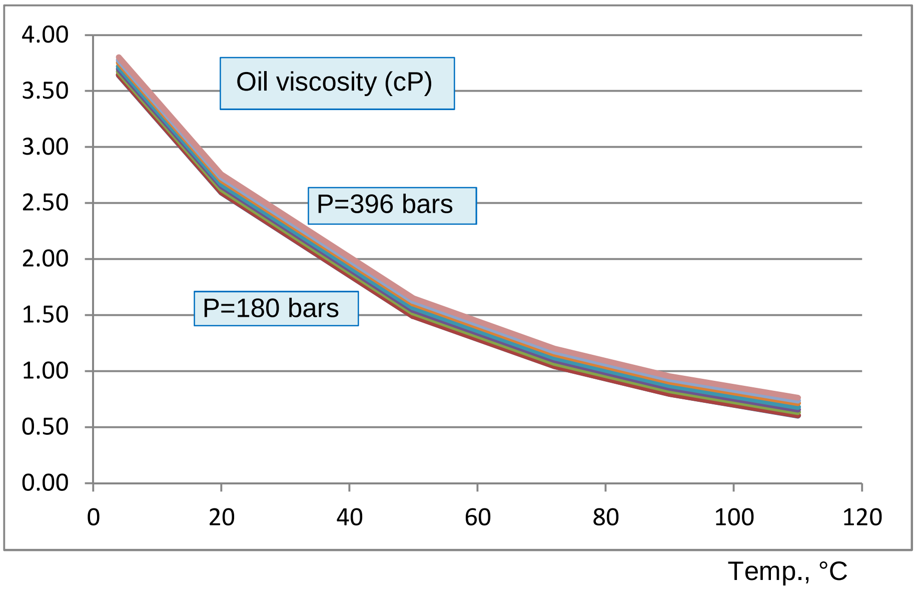

Figure 20. Oil viscosity vs. temperature for different pressures

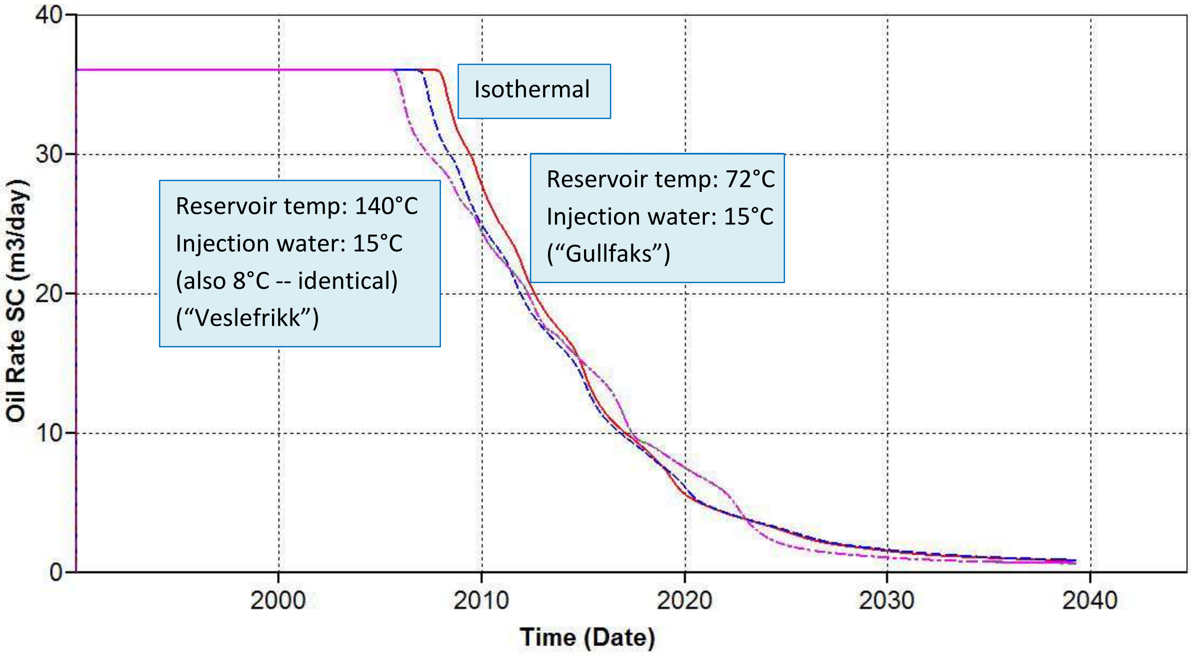

Figure 21. Oil rate vs. time for isothermal and two temperature dependent processes.

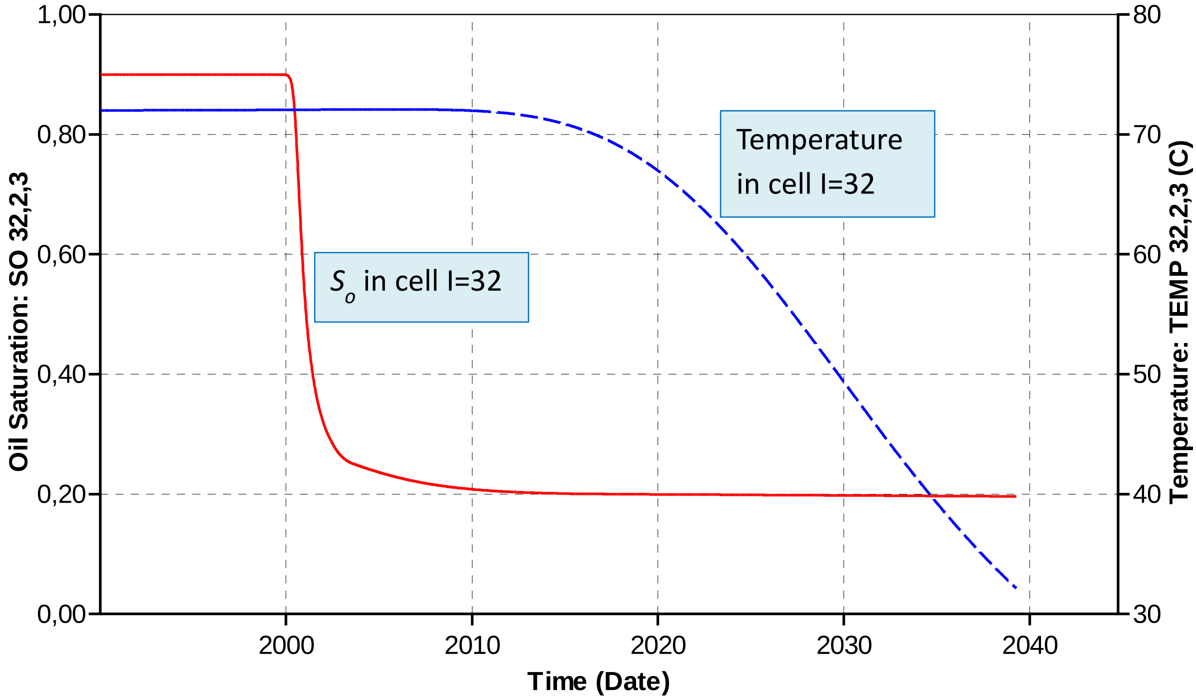

Figure 22. Water and temperature fronts passing through cell (32, 2, 3)

The results shown in Figure 21 show that although there is a noticeable difference between the isothermal and thermal models, the difference is not large enough to challenge the established procedure of running standard black-oil problems as isothermal.

Figure 22 shows that the temperature front passes a given point much later than the corresponding saturation front – meaning that the temperature lags significantly behind the water front. Theoretically the speed of the temperature front should be about 1/3 of the speed of the water front, which appears to be supported by this figure.

6. Correction Curves

In this section we look at examples of "correction curves", or "adjustment curves". As noted in the introduction, the purpose of these curves is to establish some sort of means to adjust simulated results which are known to be incorrect for some reason (for the models in this phase the numerical diffusion is the main factor). At this stage we are able to run the models both at fine and coarse scale, and compare the results. For later, more realistic models, it may prove impossible to run the models at the finest scales, and then the correction curves may be used to tune the coarse scale results towards what we would expect to achieve from a (hypothetical) fine-scale run.

The examples have been taken from the simulations in Series 2.
The correction curves are constructed as the percentage difference between current run and a reference run, typically the reference run will be the fine-scale simulation.

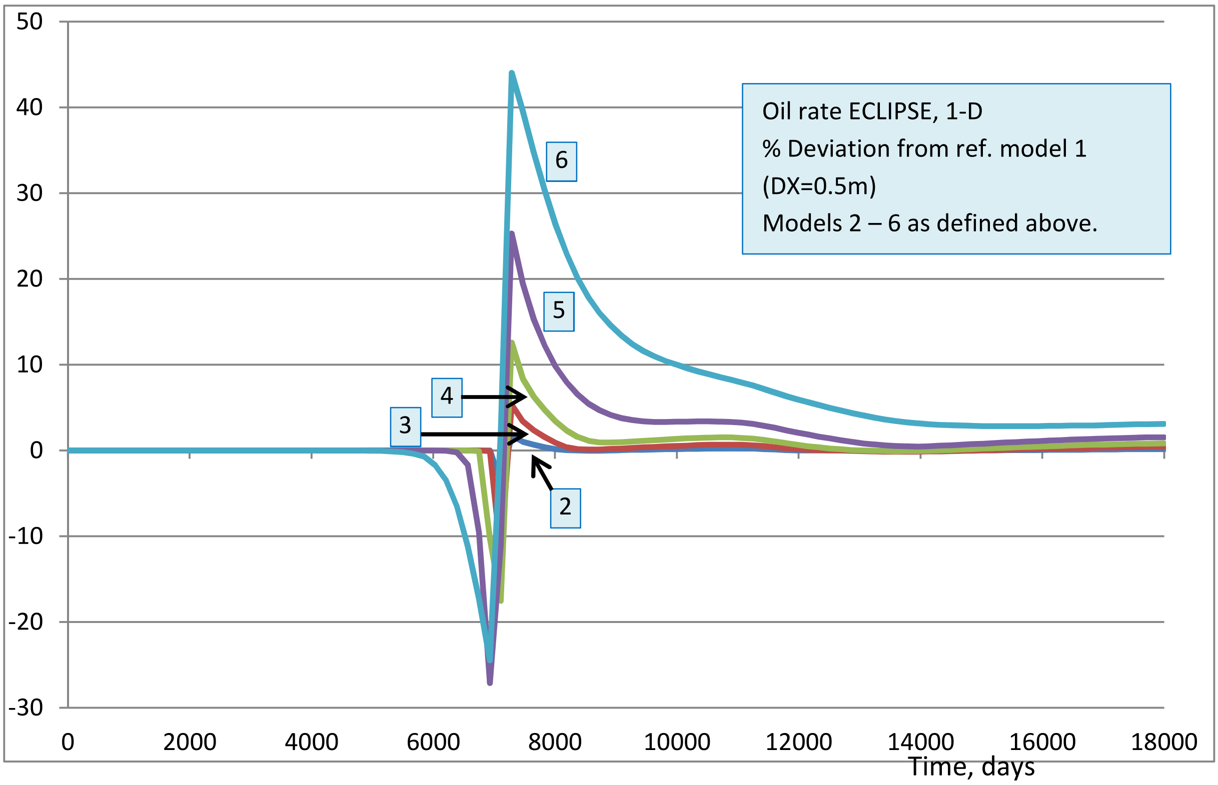

Figure 23. Oil rate, % difference from ref. model (Scale 1), 1-D Series

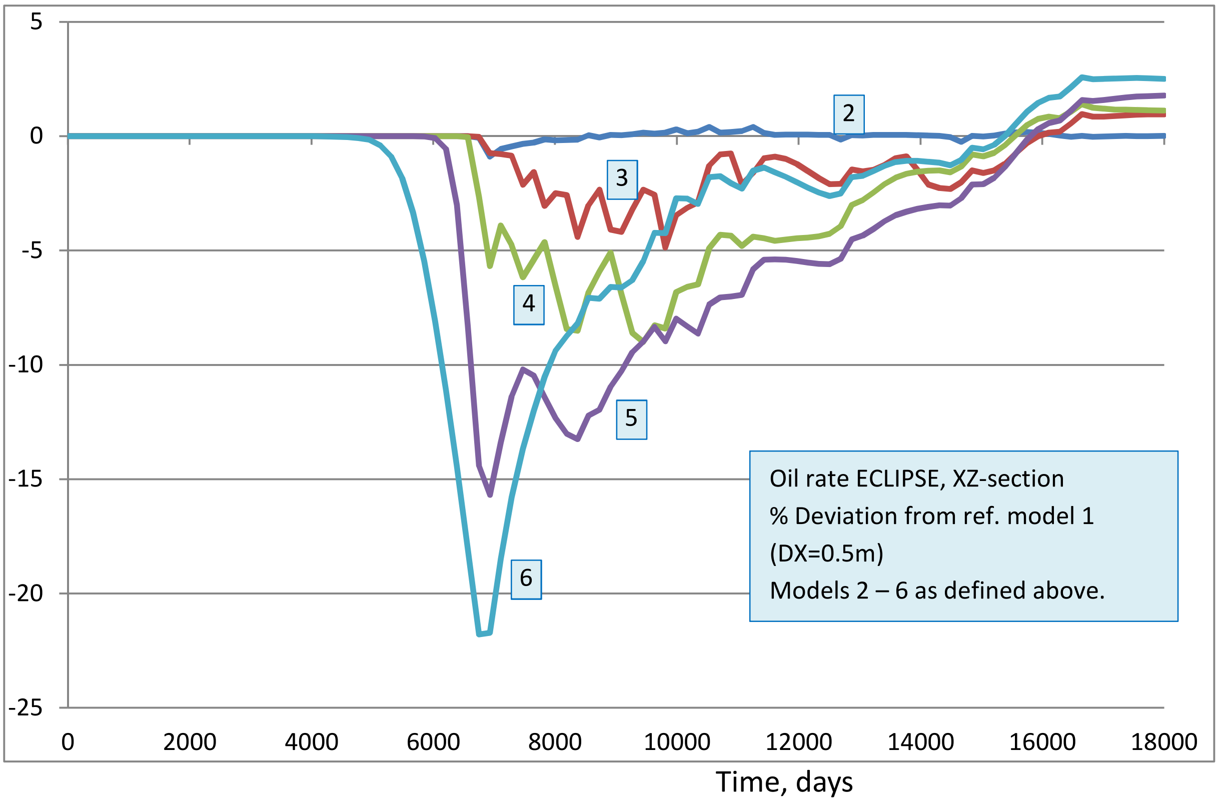

Figure 24. As Figure 23, but for vertical cross-section series

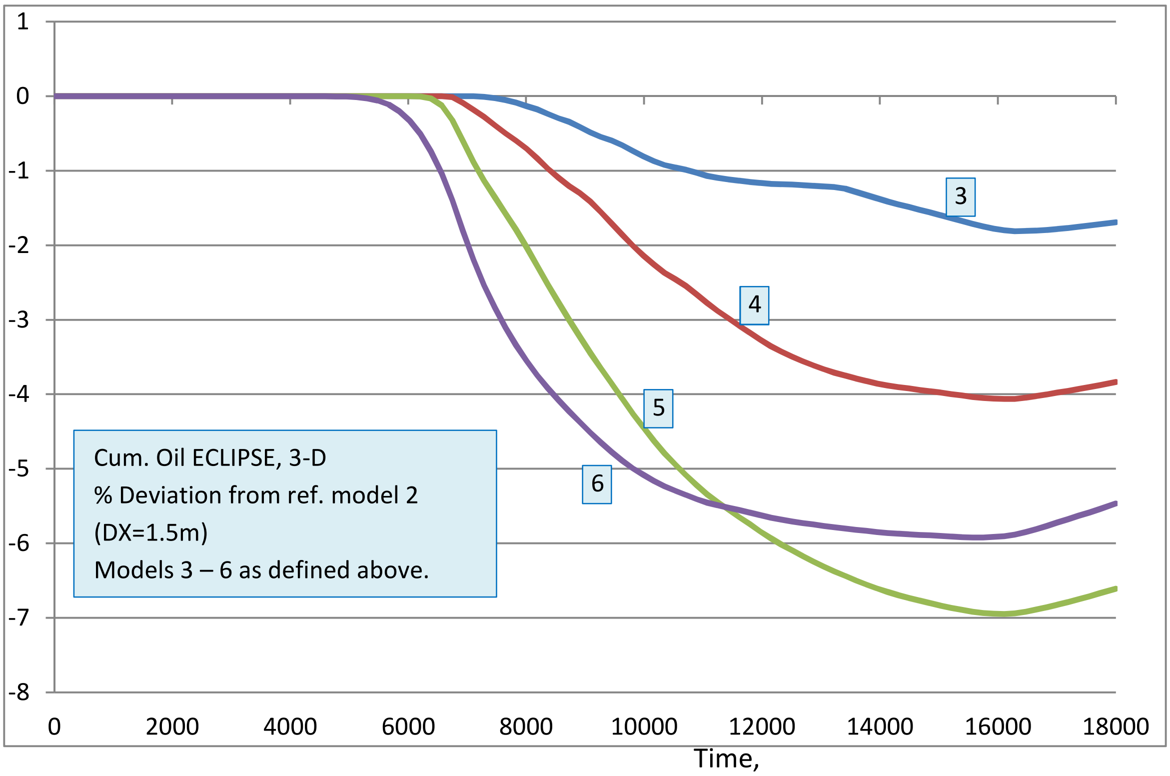

Figure 25. Cumulative oil, 3-D series, difference vs. finest scale (2)

In Figure 23, we clearly see the large effect of the numerical diffusion in the one-dimensional models, and the error with upscaling becomes disturbingly large.

Figure 24 shows the corresponding family of curves for the series vertical cross-section. The deviation is smaller, but still the scale we defined as “just acceptable”, scale 5, has a maximum error of 15% compared to the finest scale.

The differences in the 3-D series when comparing cumulative (total) oil production is shown in Figure 25. (Recall that scale 1 was not run in 3-D, so scale 2 becomes the reference scale).As local fluctuations are removed, the differences are somewhat smaller when comparing cumulatives.

Figure 26 is a confirmation that the difference between 3-D and vertical cross-section is small for these models, actually the difference is less than 1% at all times.

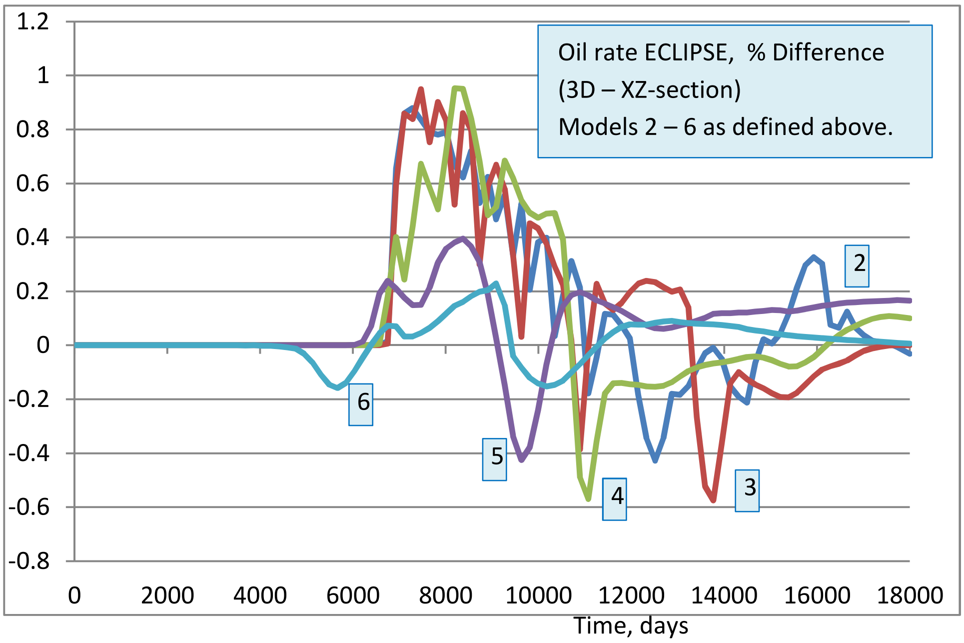

Figure 26. Oil rate, % difference between 3D and vertical cross-section.