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SINTEF REPORT

TITLE

Proxy model for a near well in a thin oil layer reservoir with high permeability.

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ABSTRACT

This report describes the work performed in the project “Near well modelling”, under the NTNU IO centre. The work has been performed in close collaboration with FMC Technologies.

Near well models based on first principles and Darcy’s law have been developed in the project. The models are developed in order to support fast generation of dynamic GOR values for use in production optimization. The main focus is oil fields with a thin layer of oil and a gas cap. The model has been verified by simulation and gas coning has been illustrated. Moreover, a model describing wells lying in the water zone under the oil layer has been developed. Simulations showing water and gas coning have been presented.

Recommendations for further work have been presented. The main focus is model development for generation of dynamic GOR values, and possible incorporation in FMC Technologies software in the near future. This would also include further development of the near well models to be able to model up-coning of water, development of an estimation scheme for state estimation and a detailed study on the development of more simplified near well models by using black box techniques.

KEYWORDS	ENGLISH	NORWEGIAN
GROUP 1	Reservoir	Reservoir
GROUP 2	Oil production	Olje produksjon
SELECTED BY AUTHOR	Near well area	Nærbrønns området
	Darcy’s law	Darcys lov

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1 Introduction

This project addresses the development of simplified near well models in order to support fast generation of dynamic GOR values for use in production optimization. There exists today a potential for improved near well modelling. Such models must be fast and capture the essential dynamics of the near well area. This report describes the work performed in the project.

The main focus in the project has been near well models based on first principles. The approach described is based on Darcy's law and the developed model has been applied to a reservoir with a thin oil layer with a gas cap on top, see Section 3. Other approaches are possible, such as black box modelling which implies modelling purely based on data, or grey box which combines the physical principles with data driven techniques. The application of such techniques has been mentioned only briefly in the report.

The presented work has been performed in close collaboration with FMC Technologies. FMC Technologies has addressed a specific problem related to near well modelling and this has been the main focus of the project. Due to confidentiality issues this cannot be described in detail in this report.

The outline of the report is as follows. Section 2 gives a short introduction to near well modelling. Some of the development done in this project is presented in Section 3. A short introduction to black box modelling is given in Section 4. Section 5 gives some simulation results and Section 6 holds recommendations for further work. Conclusions are given in Section 7.

2 Background

Mathematical models of the reservoir, as simulators, for use in long term decision making often include large complex reservoir models with high computational time. Full field reservoir models are updated through history matching which is a time consuming task. These models are therefore not suitable for accurate short term predictions. Moreover, the well is the true optimization enabler and the closed loop well-centric production optimization is the mechanism to accelerate production, improve operation, reduce reservoir uncertainty and improve the overall decision making process. Mathematical models for simulation and predictions of actual well performance, compared against measurements will increase well production, reduce production cost and improve oil recovery.

2.1 Short term decision making

For short term decision making it is sufficient to include models describing the fast dynamics of the reservoir optimization process. This would include well models, near well models (inflow models) and facility constraints. The models must describe essential phenomena in the drainage area near the well caused by for instance change in pressure or injection.

The main aim of long and short term optimization is to maximize the profit from the hydrocarbon field given the constraints introduced by the field itself and the installed equipment. This mostly implies to maximize the hydrocarbon production, minimize costs and achieve an optimal drainage of the reservoir or near well bore area. The decision variables are well production rates, gas lift rates and well connections. Bieker et.al (2006) has described the information flow in a production optimization scheme as shown in Figure 2-1.

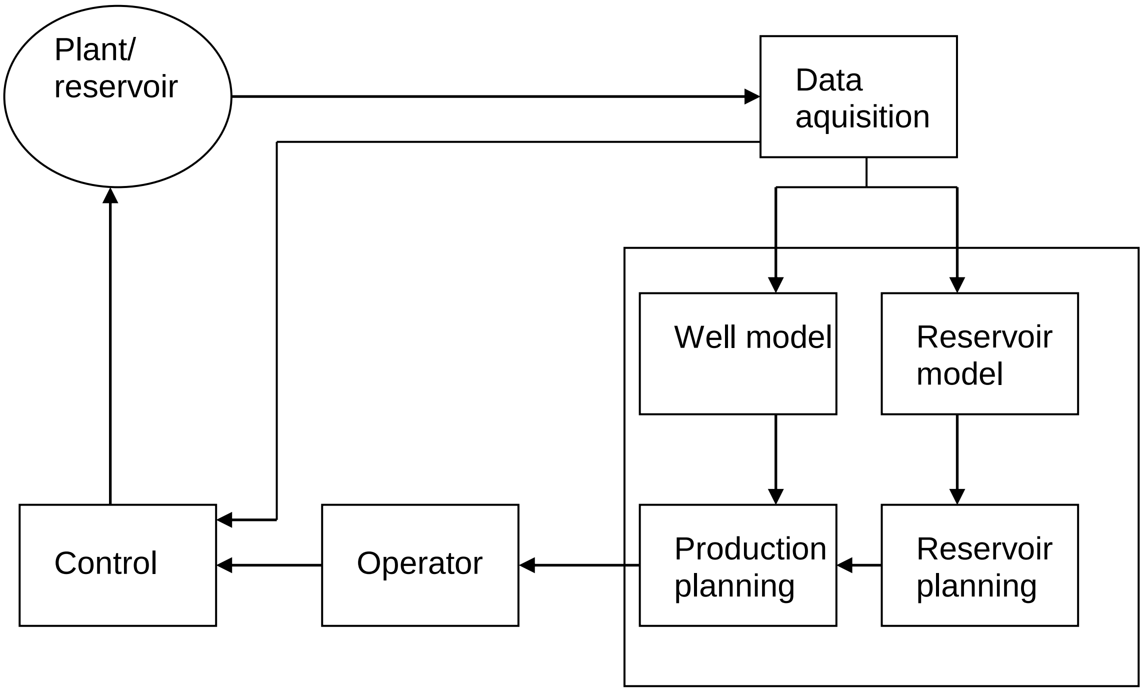

Figure 2-1. Information flow in production optimization

The optimization scheme consists of several parts. Reservoir planning is planning of the long term drainage of the field and development of the injection strategies. An updated reservoir model is applied for developing the strategies. The reservoir model is updated at least once per year using seismic data. Production planning includes well prioritizing, gas lift strategies and network optimization. The cycle time of the plan is weekly or monthly. Well models are used in production planning and are updated regularly (monthly) based on the results of well tests. Data on well temperature, pressure and flow rates are often available, and these data are used for model updating. These data are in some cases applied in closed loop control (e.g. slug control).

2.2 Models for fast control loops

Traditional static production optimization methods do not capture the dynamic behaviour of the reservoir, for instance when a water breakthrough occurs. Nor do they take into account that the drainage process changes the reservoir state. These methods are based on reservoir models which are updated at a minimum once a year and not in real time. Therefore a change in the reservoir dynamic would not result in adjustment of the production strategy.

A detailed reservoir model is a large model with a lot of detailed parameters, based on geological models and samples from test wells (i.e ECLIPSE). Such models are not suitable for control and short term optimization purposes. Models for fast control need only capture the short term dynamics of the system. Furthermore, the models must also contain the relation between optimization variables and optimized variables in the criterion.

Reservoir and well models can be incorporated in model based control loops, in order to achieve a more optimal well control. Poor performance prediction from existing models and lack of integration with data acquisition are incentives for developing more efficient modelling strategies. Multivariate optimization techniques have been based on offline models based on first principles or empirical models, and often lacking the connection to real data and dynamic data that can be used to update the models continuously. Process identification has mainly been performed to identity processes that do not vary with time, see Saputelli et al. (2005). Models for use in closed loops must be fast and capture the essential dynamics of the system. The main focus of research work performed so far by others, has been optimal control strategies for oil recovery in steam-, CO_2-, gas- and water injection, and mainly for offline control to optimize field parameters. A common situation on many production facilities is increasing the oil profit by increasing production from low GOR wells and reducing production from high GOR wells until marginal GOR values are equal in all wells.

3 Development of near well models based on Darcy's law

Near well models are simplified models, so called proxy models, and can based on first principles modelling, black box modelling or a combination. A literature review performed prior to the presented project has not identified a common way of determining such models, since most model development is highly dependent on the application. A model for use in short term production optimization must contain a representation of the relationship between the variables entering into the criterion and the degrees and the variables subject to optimization.

Mjaavatten et al. (2006) describes the near well model development for a thin oil layer, high permeability reservoir with a gas cap on top. The model includes only pressure gradients in the horizontal direction as the oil layer is considered thin, and also as permeability in the vertical direction is considered much higher than in the horizontal direction. This model has been applied to the Troll field and used for predicting how the GOR varies with the production rate. The dynamic model describes the essential reservoir dynamics using a simplified description of the interaction between the well and the surrounding reservoir. The predictions of the rate dependent GOR were at Troll essential for successful optimisation of the oil production.

The main focus in this report is near well modelling based on Darcy's law. This is described in more detail in the following sections. The first version of the near well model developed in this project, has been developed from first principles, i.e. based on Darcy's law for flows in porous bodies. Sections 3.2-3.4 describes the model for an oil well with a thin oil layer and a gas cap. Sections 3.5-3.6 describe the case when a water layer has been added below the oil, and the well lies in the water layer.

3.1 Darcy's law

Darcy's model (see e.g.(Golan and Whitson 2003), (Zolotukhin and Ursin 2000)) expresses the volume flow, Q, of a fluid through a porous body as in one direction as

$$Q = -\frac{\kappa}{\mu} A \frac{\Delta p}{L} \tag{3.1}$$

where

κ	-	permeability of the body in the flow direction
μ	-	viscosity of the fluid
A	-	cross sectional area of the body, experienced by the flow
Δp	-	pressure drop of the flow over the body length
L	-	body length in the flow direction

Dividing by the cross sectional area, and letting the length, L, become "small", dx, with a pressure drop along the length of dp, then we obtain the flow flux, *u,* in the x direction, through a unit cross sectional area,

$$u = -\frac{\kappa}{\mu}\frac{dp}{dx} \tag{3.2}$$

If we consider a 3 dimensional body, and allow for flows or fluxes in all directions, we also have to consider whether the permeability is the same in all directions, or not. Generally, in an anisotropic reservoir, i.e. a reservoir with generally different properties in different directions, the permeability κ is directional, i.e.

$$\kappa = \begin{bmatrix} \kappa_{xx} & \kappa_{xy} & \kappa_{xz} \\ \kappa_{xy} & \kappa_{yy} & \kappa_{yz} \\ \kappa_{xz} & \kappa_{yz} & \kappa_{zz} \end{bmatrix} \tag{3.3}$$

The flow flux is then

$$\vec{u} = -\frac{1}{\mu} \begin{bmatrix} \kappa_{xx} & \kappa_{xy} & \kappa_{xz} \\ \kappa_{xy} & \kappa_{yy} & \kappa_{yz} \\ \kappa_{xz} & \kappa_{yz} & \kappa_{zz} \end{bmatrix} \begin{bmatrix} \frac{\partial p}{\partial x} \\ \frac{\partial p}{\partial y} \\ \frac{\partial p}{\partial z} \end{bmatrix} = -\frac{1}{\mu} \kappa \nabla p \tag{3.4}$$

In an isotropic reservoir, the reservoir will have the same permeability in all directions, $\kappa_{xx} = \kappa_{yy} = \kappa_{zz}$, and the off diagonal elements in are 0.

Another expression is what is called "pore velocity", which takes the porosity of the rock, φ, into consideration. The relationship between the flow flux and the pore velocity is

$$\vec{v} = \frac{1}{\varphi} \vec{u} \tag{3.5}$$

3.2 Development of a near well modelling with thin oil layer and gas cap

The assumptions made in the following are similar to those made in Mjaavatten et al. (2006). Mjaavatten et al. (2006) seeks to develop a formulation for the oil/water interface expressed totally in heights and height gradients and solves these equations using a differential equation solver in Matlab. In our work, we remain at a formulation with pressure gradients, areas and flows, due to the choice of solution scheme for the resulting system of equations.

The model developed in this project utilizes the properties of the modelled reservoir for in subsequent simplifications.
The properties of the reservoir are assumed to be:

- There is a relatively thin oil layer (5-15 m thick) with a gas cap above
- No mixing at the interfaces is assumed (capillary forces neglected)
- The permeability in the vertical direction is assumed much higher than in the horizontal direction.
- Homogenuous permeability throughout the reservoir.

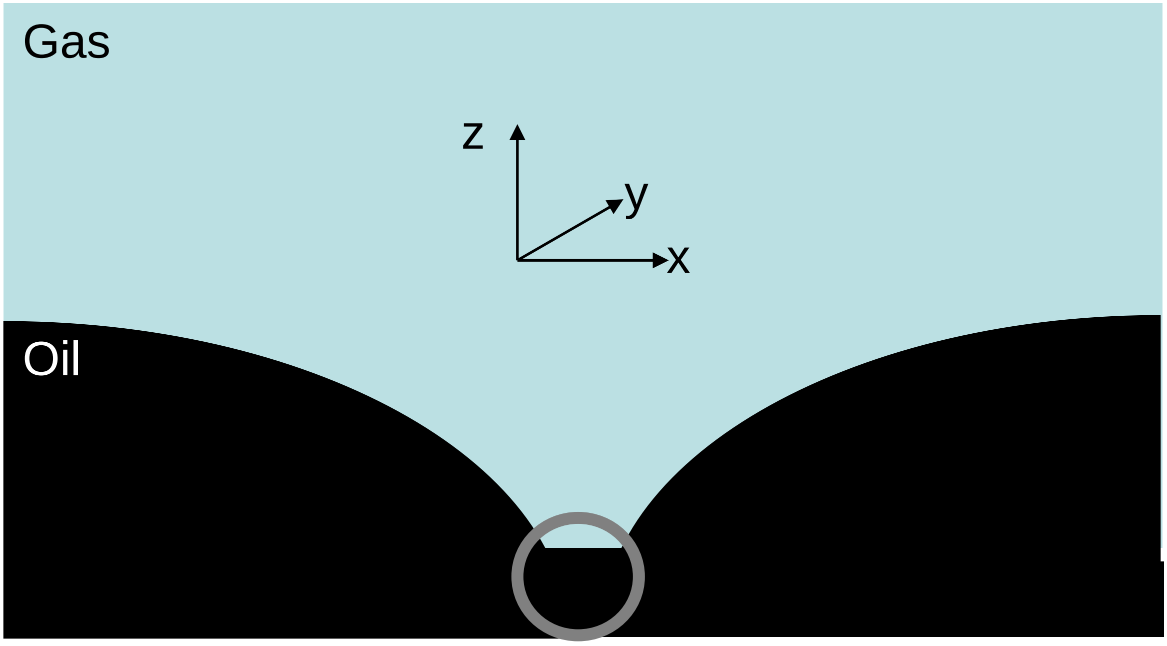

Figure 3-1. Reservoir with thin oil layer and gas cap.

The fundamental properties of the model utilize the properties of the reservoir in order to arrive at a simplified model, and the model properties are the following:

- Only pressure gradients in the horizontal direction (x-direction) are considered as permeability in the vertical direction (z-direction) is considered much higher than permeability in the x-direction.
- The well lies in the y-direction, and inflows are therefore assumed orthogonal to the direction of the well.
- The (near well reservoir) is modelled as finite volumes, with flows between them driven by the pressure gradient. This gives a "slice" of the reservoir producing into a correspondingly large (in the y-direction) section of the well.

The pressure at any point in the oil layer is
The pressure at a point x,y,z within the oil layer is

$$p(x,y,z) = p_0 + \rho_g g(h_0 - h(x,y)) + \rho_o g(h(x,y) - z) \tag{3.6}$$

where

$h(x,y)$	-	height of the gas oil interface as a function
p_o	-	Pressure at the top of the gas cap
h_0	-	Level at the top of the gas cap
ρ_g, ρ_o	-	Gas and oil densities

As only pressure gradients in the x direction are considered, differentiating pressure p gives

$$\frac{dp}{dx} = -\rho_g g \frac{h(x,y)}{dx} + \rho_o g \frac{h(x,y)}{dx} = \Delta\rho g \frac{h(x,y)}{dx} \tag{3.7}$$

giving the oil flux

$$u = -\frac{\kappa}{\mu} \Delta\rho g \frac{dh}{dx} \tag{3.8}$$

A finite volume approach is used for spatial discretisation, see Figure 3-2. This results in a "sliced" reservoir, with width Δy where each slice produces into one section of the well, with length Δy. The change in oil volume in one such volume, *i*, is then

$$\frac{dV_i}{dt} = \frac{1}{\rho_o}(q_{i,in} - q_{i,out}) \tag{3.9}$$

For all volumes except the well volume, $q=Au$ then

$$q_{i,in} = A_{i,in} u_{i,in} = -A_{i,in} \frac{\kappa}{\mu} \left(\frac{dp}{dx}\right)_{i,in}$$

Where

$$\left(\frac{dp}{dx}\right)_{i,in} = \Delta\rho g \left(\frac{dh}{dx}\right)_{i,in} \tag{3.10}$$

And the pressure gradient out, correspondingly

$$\left(\frac{dp}{dx}\right)_{i,out} = \Delta\rho g \left(\frac{dh}{dx}\right)_{i,out} \tag{3.11}$$

3.3 Calculation of the well flows in oil/gas well

Drawdown is defined as the pressure drop between the general reservoir pressure (sufficiently far from the well) and the well pressure p_w, here assumed measured at the well heel

$$\Delta p = p_r - p_w \tag{3.12}$$

Drawdown will however vary depending on the location in the well due to the distributed inflow of fluids along the well causing the flow to have a higher velocity at the heel than at the toe., i.e. with y, with the largest drawdown at the well heel, where the fluid velocity is the largest. Instead of modelling the fluid hydraulics inside the well, Mjaavatten et al. (2006) use a simplified linear model for the variation in the drawdown along the well, ($y=L$ at the toe)

$$\Delta p(y) = ((\beta - 1)\frac{y}{L} + 1)\Delta p_{heel} = K_1(y)\Delta p_{heel} \tag{3.13}$$

giving a drawdown of $\beta\Delta p_{heel}$ in the well toe. However, since the pressure drop inside the well (not drawdown) is normally related to the square of the fluid flow, we also want the drawdown to follow a similar shape, therefore a slightly modified version of is used here, ($y=L$ at the toe):

$$\Delta p(y) = (\beta - (\beta - 1)\frac{(L - y)^2}{L^2})\Delta p_{heel} = K_2(y)\Delta p_{heel} \tag{3.14}$$

Using this model, the pressure in the well as a function of position *y* will be

$$p(y) = p_r - (\beta - (\beta - 1)\frac{(L - y)^2}{L^2})(p_r - p_{well}) \tag{3.15}$$

Further, the above is utilized in developing an expression for the flow of gas and oil into each section of the well.

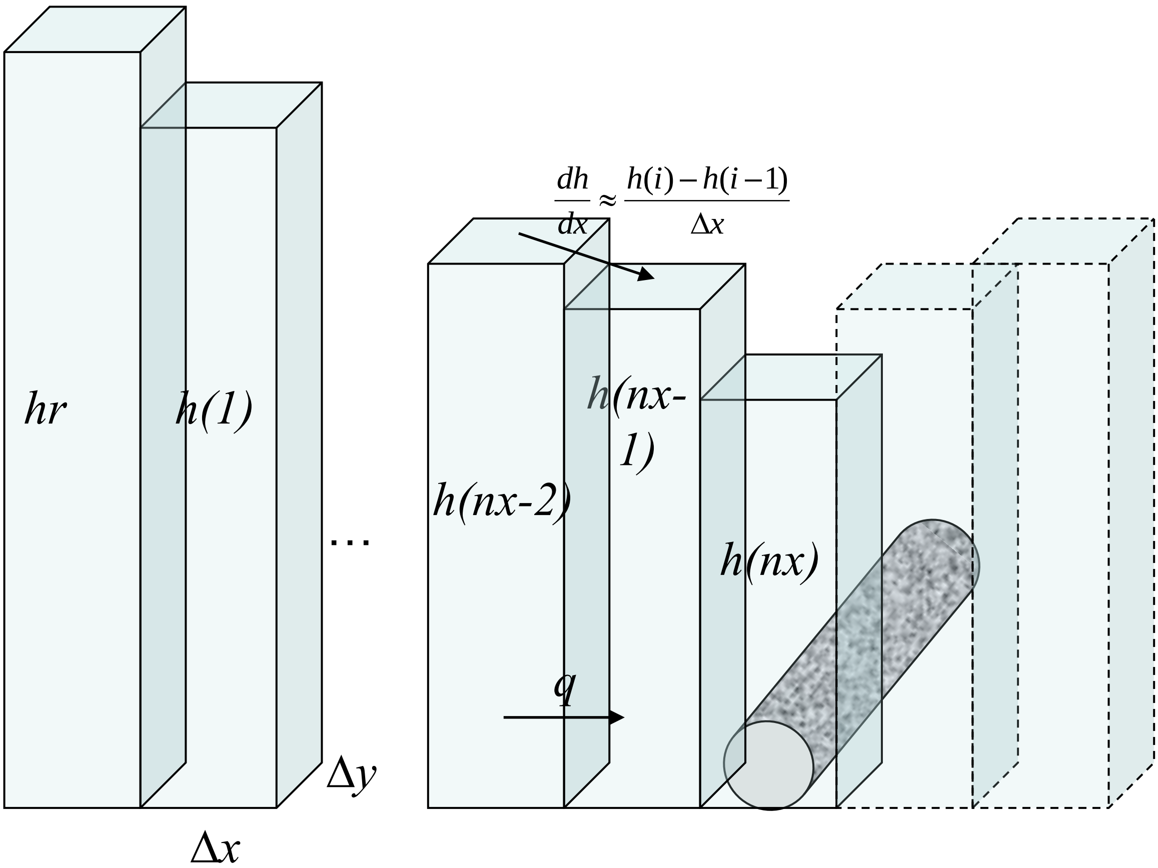

Figure 3-2. Spatial discretization of reservoir in finite volumes results in a "sliced" reservoir where each reservoir section produces into a well section of length Δy.

The productivity index for gas of a well is defined as

$$J_g = \frac{q_g}{p_r - p_{well}} \tag{3.16}$$

The production of gas per unit length of well is defines as in Mjaavatten et al. (2006)

$$\tilde{q}_g(y) = J_g \delta(y)^2 \Delta p(y) \tag{3.17}$$

where

$$\delta(y) = \frac{z_{well} - h_{ow}(y)}{d_{well}} \tag{3.18}$$

Ad z_w is the position of the top of the well, d_{well} is the well diameter, and $h_{ow}(y)$ is the oil gas contact interface.
The productivity index for gas of a well is defined as

$$J_o = \frac{q_g}{p_r - p_{well}} \tag{3.19}$$

The production of oil per unit well length is similarly to (3.17),

$$\tilde{q}_o(y) = J_o(1-\delta(y)^2)\Delta p(y) \tag{3.20}$$

3.4 Total algorithm, oil/gas well

The model equations are solved in an explicit solution scheme as follows:

1. Assume that the heights of the oil/gas interface are known
2. Calculate pressure gradients in and out of every element
3. Calculate inflow and outflow areas for oil and water for all elements
4. Calculate well flows
5. Calculate inflows and outflows of oil and water for all elements (well elements have well flows as outflow) according to Darcy's law for oil and water. For the well element, the inflow is doubled to handle symmetry. The well outflows were calculated in 4.

Calculate new heights of the oil/gas interface according to

$$h_i(t) = h_i(t-1) + \frac{(\Delta t)}{(\Delta y \Delta x)}(q_{i,in}(t-1) - q_{i,out}(t-1)) \tag{3.21}$$

3.5 Development of a near well modelling with thin oil layer with gas cap above and water below

In the following, a layer of water has been included below the oil level. The well lies in the water zone as shown in the following figure and oil and gas have to be coned down to the well.

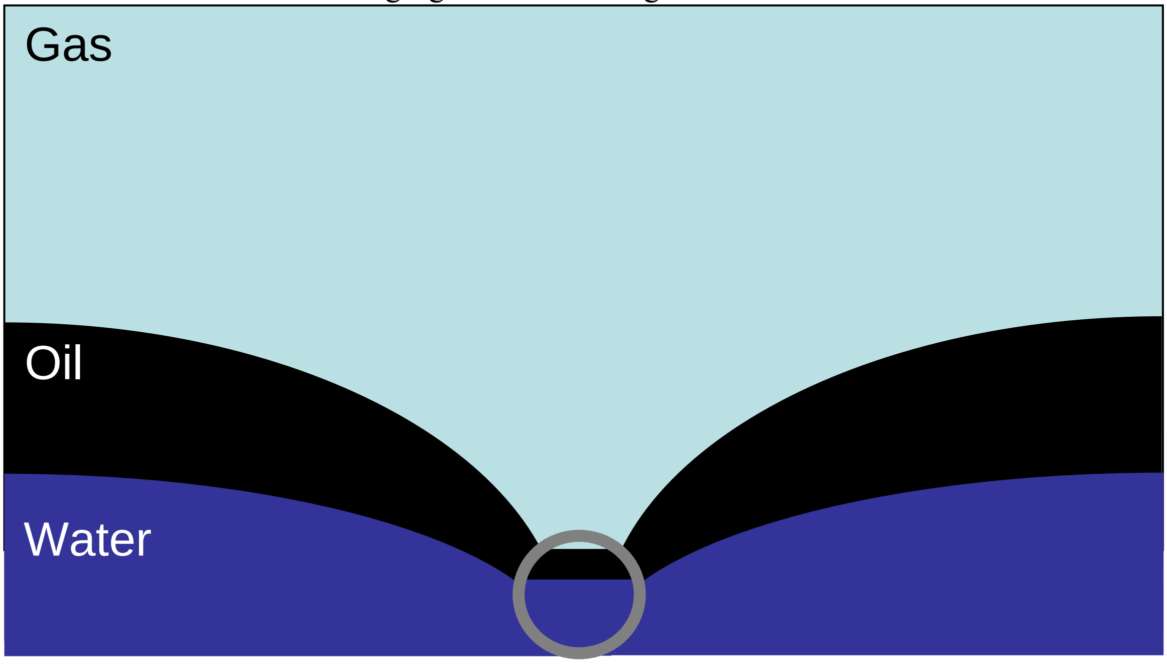

Figure 3-3. Reservoir where the well is placed in the water zone.

The modelling done in this section follows the same course as for the oil/gas model, i.e. modelling is based on the assumptions listed in section 3.2. The modelling follows the same course as in section 3.2 assuming only horizontal pressure gradients also in the water zone.

3.6 Calculation of the well flows in water/oil/gas well

The drawdown has been calculated in the same way as for the oil/gas well, see equation (3.13). Also, the productivity indexes for oil and gas are as defined in (3.16) and (3.19). The production index for water is defined accordingly

$$J_w = \frac{q_w}{p_r - p_w} \tag{3.22}$$

As for the oil/gas well, we define

$$\delta(y) = \frac{z_{well} - h_{og}(y)}{d_{well}} \tag{3.23}$$

The gas production per unit length of well is defined as in equation (3.17). However, δ is now taken as the liquid level fraction of the cross section, and this fraction is split between the oil and water relative to the height of the oil and water zones within the well.

4 Black box modelling

The main advantage of black-box models is that they can be established without detailed knowledge about the underlying physics and system dynamics. These models are computationally efficient once they have been established.

Black-box models can be divided in two groups, linear and non-linear models. These models can be dynamic or static. Artificial neural networks (ANN) are examples of non-linear dynamic models. ANN’s has for years been successfully applied in traditional time series forecasting. Saputelli et. al. (2002) gives an overview of successful applications of neural networks in the petroleum industry, i.e. for reservoir characterisation and in optimization of field operations.

Bertrand et. al (2005) used a neural network scheme for estimation of gas-saturation changes and quantification of the gas-oil contact movement at the Troll West Gas Province. The analysis showed coning along the tracks of a number of wells. Jong-Se (2005) showed how fuzzy logic and neural networks could be used to determine reservoir properties from well logs.

Commercial reservoir simulator providing for instance reservoir flow rates, pressures and temperature are updated on a yearly basis, and does not capture the short term dynamics in the near well drainage area. A near well model based on black box techniques, using simulator data as training and verification data could be a solution. The output from such a model can be downhole pressure, gas/oil/water flow rates from the near well area into the well.

It is therefore relevant in this context to evaluate the performance of different types of black-box models for use in near well modelling. One possibility is to compare different black box models ability to identify reservoir flow rates using day as well as week resolution. The effect of increasing model order is of interest as well as including down whole pressure and temperature.

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Black-box models can be divided in two groups, linear and non-linear models. These models can be dynamic or static. In this work the focus is on dynamic model structures, see (Sjøberg, 2004) for more details. A linear auto regressive exogenous (ARX) model is a linear dynamic model structure given by

$$A(q)y(t) = B(q)u(t) + e(t) \tag{4.1}$$

where $y(t)$ is the model output, $u(t)$ is model input and $e(t)$ is the noise vector. $A(q)$ and $B(q)$ are polynomials in the shift operator q. An extended version of the ARX model is the ARMAX model where noise description is included. The models given by Equation (4.1) can describe linear systems but have limited abilities to identify non-linear systems.

Artificial neural networks are examples of non-linear dynamic models. The output of the neural network (NN) is described by the function

$$y(t) = \sum_j b_j f_j(\sum_k (w_k x_k(t) + \theta_k)) \tag{4.2}$$

where b and w are weights, f is a non-linear function, x is the input signal and θ is the bias. The main challenge using neural networks is the identification of the parameters. Due to the non-linear function f one is not guaranteed to reach global optima. Therefore the identification of the neural network is highly dependent on good starting points.

More detailed work on these schemes will be part of the follow up project, starting up in 2008.

5 Simulation results

The model described in Section 3 was implemented in Matlab. Simulations were performed to illustrate gas coning in two different cases.
In the first case, the well lies in the oil zone, and gas will cone into the well after a while. In the second case, the well lies in the water zone, and oil and gas will eventually cone down into the well.
It is worth noting that in the presented models the well lies at what appears as the bottom of the reservoir. The reason for this is that since no vertical pressure gradients are included in the model, no up-coning of fluids below the well bottom is possible, and fluids below the well bottom are therefore “nonexistent” to the model.
The following figures show the parameters used in the simulations

Table 1 Physical parameters of the simulation model

Parameter	Value
Well length	800 m
Oil layer thickness	15 m
Water layer thickness	3 m
Well diameter	0.025*oil layer thickness
Permeability	3.5e-12 (m2)
Density oil	889 kg/m3
Density water	1045 kg/m3
Density gas	1.223 kg/m3
Viscosity oil	0.027 Pas
Viscosity water	0.01 Pas
Drawdown at heel	1 bar

Here we have assumed that all fluids are pure, i.e. that there is no gas dissolved in the oil etc. Due to this, the simulations show no gas production before gas coning actually occurs. Representing a gas fraction in the oil phase would only give a minor extension to the model.

5.1.1 Simulations with thin oil layer and gas cap

In the following simulations, the parameters of Table 1 have been used, only that the water level is set to zero, thus the well produces only oil and gas. Figure 5-1 shows the oil and gas production, respectively. The initial state of the reservoir is with a horizontal gas oil interface. We see that gas coning appears after approximately 600 days.

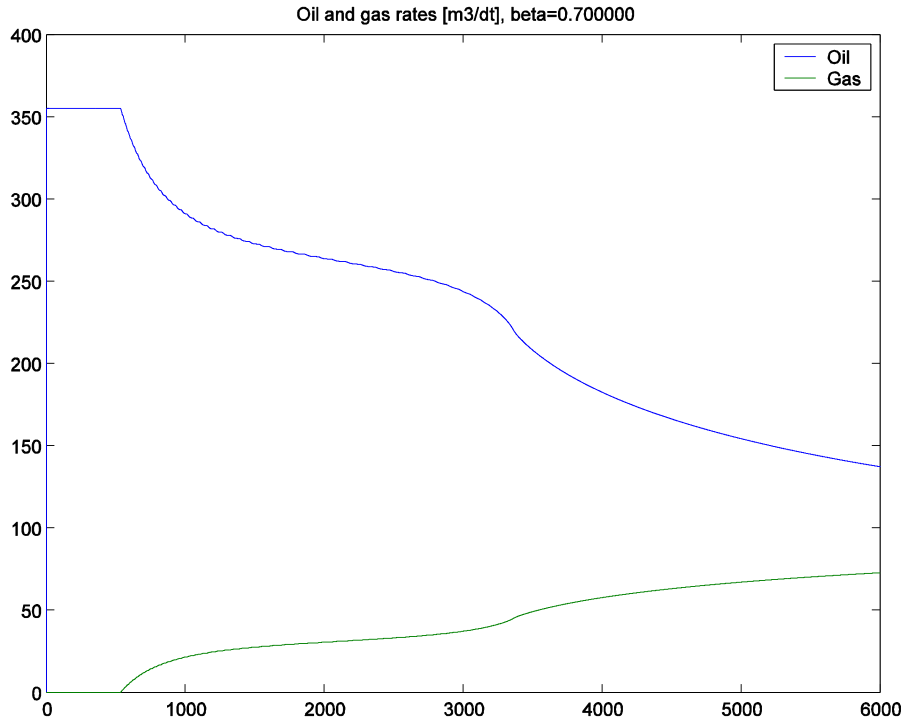

Figure 5-1. Oil and gas production with gas coning after approx. 600 days

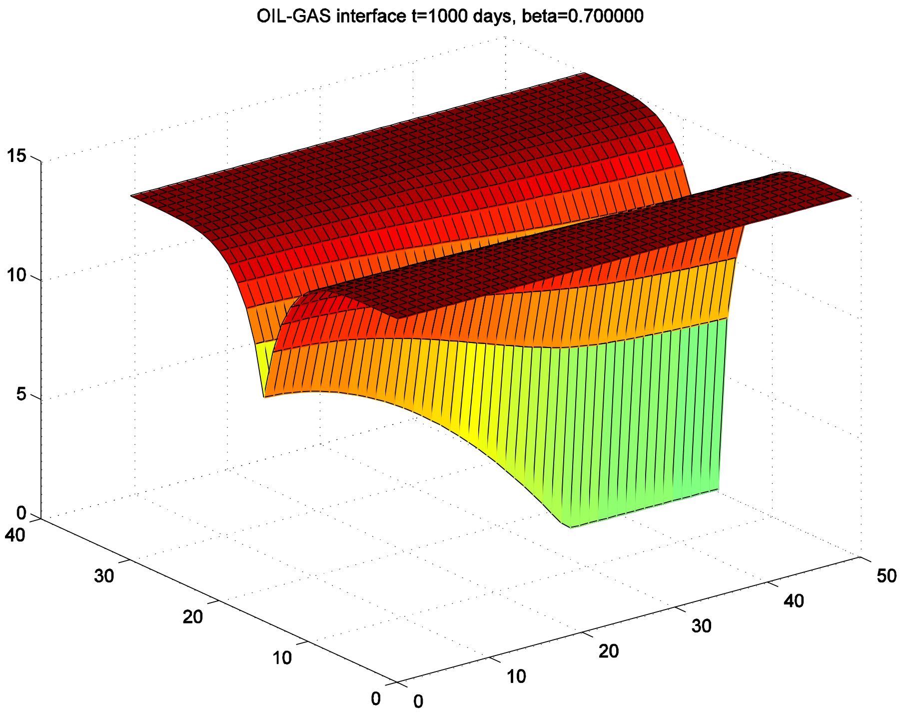

Figure 5-2. Gas oil interface after production in 1000 days.

Figure 5-2 shows the gas oil interface after production for 1000 days, referring to Figure 5-1.

In Figure 5-3 the model has been simulated for 3500 days, but production is stopped in two intervals, letting the gas oil contact rise again, before restarting production. However, the gas oil contact will not be able to reach a fully horizontal level during this period, and we can see that gas coning happens faster in the second and third production interval than in the first when production started from a fully horizontal gas oil contact.

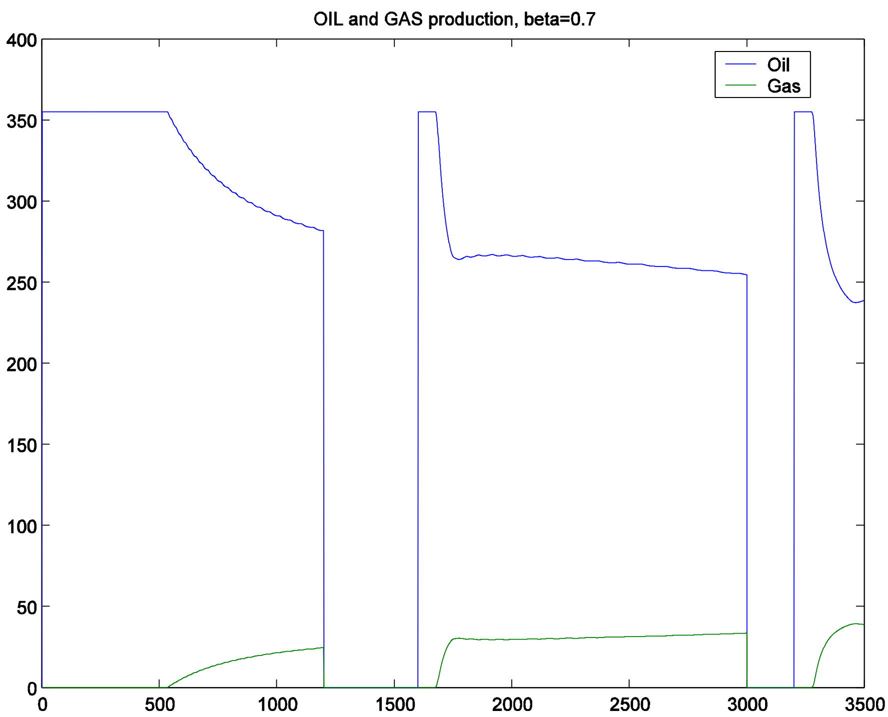

Figure 5-3. Oil and gas production with including stops and restart of production.

5.1.2 Simulations with thin oil layer, gas and water cap

The production of oil water and gas are shown in figure. The time scale is in days, and from a realistic point of view a bit long. However, the simulations clearly demonstrate the model's ability to represent water, oil and gas production. The well starts with horizontal gas-oil and oil-water interfaces. The water layer is 3 m thick, and the oil layer is 15 m thick. As the well is fully in the water zone to begin with (3 meters under the oil-water contact), it will only produce water in approximately 100 days with before oil is coned down. Oil production will steadily rise until gas cones into the well after approximately 800 days.

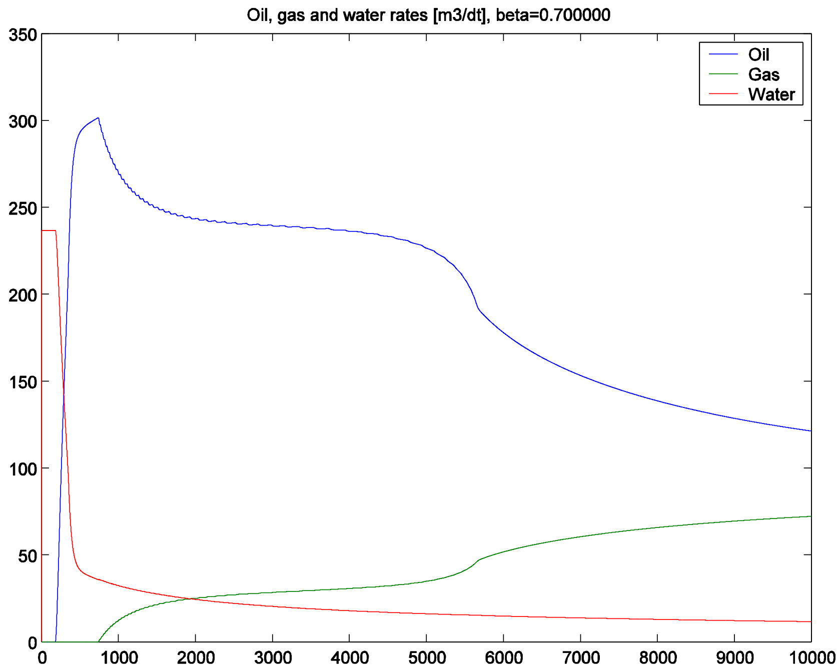

Figure 5-4. Oil water and gas rates with 3m water, 15m oil layer and gas cap.

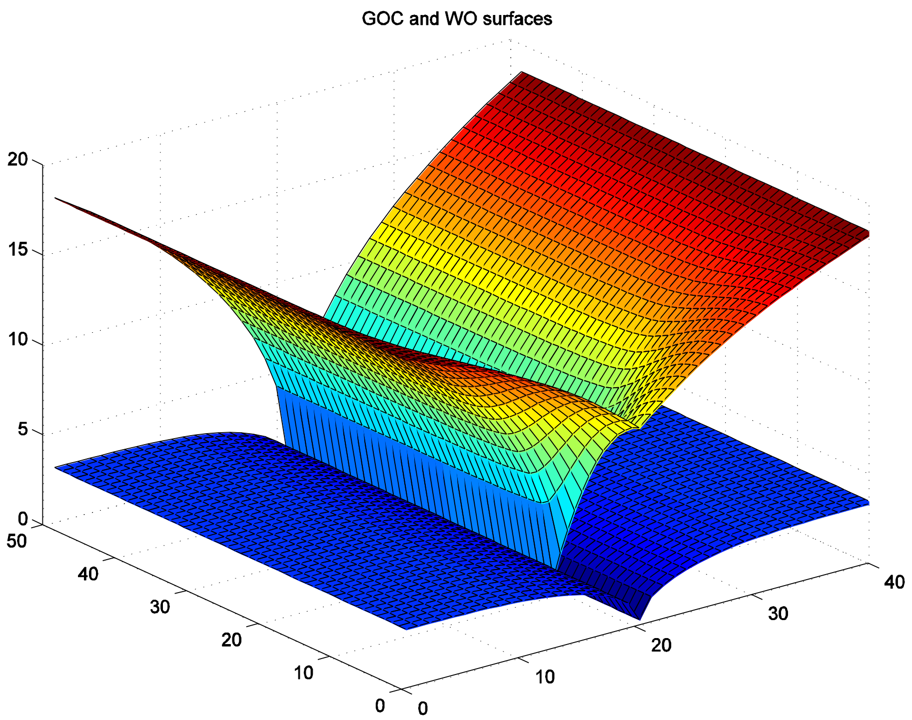

Figure 5-5. Water-oil and oil-gas interfaces with oil and gas coning, seen from well toe.

6 Further work

The simulations show that the project has a near well model which can be used to simulate water, oil and gas rates. However, extensions to the model could be made, including:

- Demonstrate fast generation of dynamic GOR values from the near well model
- Modelling of vertical pressure gradients to represent up-coning
- Modelling of the pressure profile inside the well based on Bernoulli's equations
- Implementing varying grid in the near of the well
- Extended model verification

Black box approaches have not studied as planned in this project. It is relevant to analyse whether near well models based on black box techniques are more efficient and sufficient for modelling the near well drainage area as a basis for fast generation of dynamic GOR values. This work would include:

- Study the use of ARX regression models with varying order for predicting gas/oil/water flow rates, based on data from a reservoir simulator. These data are generated with varying frequency and techniques for data handling will be included.
- Study the use of ANN for predicting dynamic GOR values, using data from a reservoir simulator for training and verification.

The work in the presented project has identified the need for development of an estimation scheme for state and parameter estimation. A schematic overview of such a scheme is given in Figure 6-1.

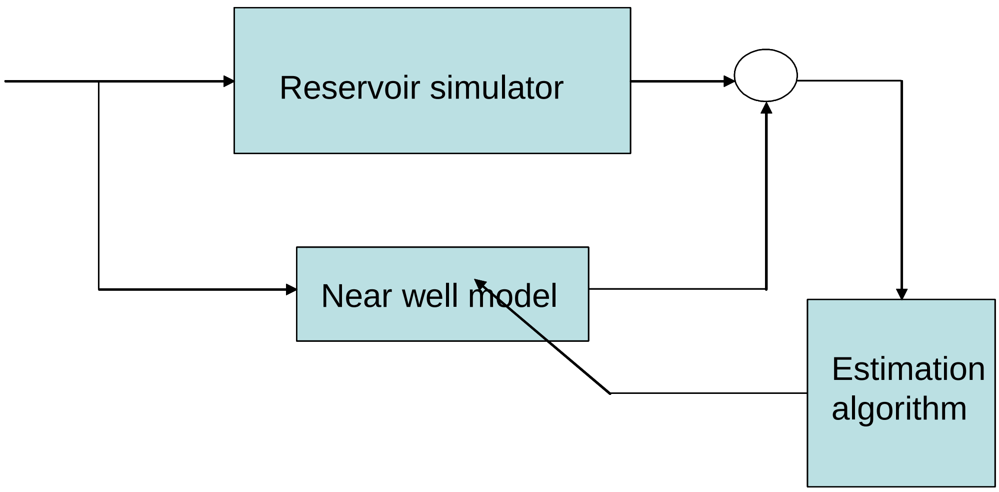

Figure 6-1. Estimation scheme

This work would include adjustments of the developed near well model, for use in the estimation scheme, observability/identifiability analysis, formulation of the estimation problem and design/implementation of an estimation algorithm

FMC Technologies has in this project identified specific challenges concerning the development of near well models and generation of dynamic GOR values. Further work would include additional model development, for possible incorporation in FMC Technologies software in the near future.

7 Conclusions

This report describes the work performed in the project “Near well modelling”, under the NTNU IO centre. The work has been performed in close collaboration with FMC Technologies.

Near well models based on first principles and Darcy’s law have been developed in the project. The models are developed in order to support fast generation of dynamic GOR values for use in production optimization. The main focus is oil fields with a thin layer of oil and a gas cap. The model has been verified by simulation and gas coning has been illustrated. Moreover, a model describing wells lying in the water zone under the oil layer has been developed. Simulations showing water and gas coning have been presented.

Recommendations for further work have been presented. This would include further development of the near well models to be able to model up-coning of water, development of an estimation scheme for state estimation and a detailed study on the development of more simplified near well models by using black box techniques. Further work, would also include additional model development, for possible incorporation in FMC Technologies software in the near future.

8 References

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