SPE 90108

Dynamic Reservoir Well Interaction

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This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Houston, Texas, U.S.A., 26–29 September 2004.

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Abstract

In order to develop smart well control systems for unstable oil wells, realistic modeling of the dynamics of the well is essential. Most dynamic well models use a semi-steady state inflow model to describe the inflow of oil and gas from the reservoir. On the other hand, reservoir models use steady state lift curves for modeling of the wells. When producing oil from thin oil rims, this description does not sufficiently describe the well behavior observed in practice. For this reason, a model was built that describes both the dynamic flow of oil and gas towards the well bore and the dynamic flow inside the well. The integrated model provides a realistic description of the well dynamics on a time scale of minutes, which is the time scale that is required for development of a control system. As a result, the integrated model allows the development of model based gas coning control or water coning control schemes, as well as model based interpretation of well data.

Introduction

Oil producing wells often encounter instabilities during production. Various types of automatic control systems can be developed in order to prevent unstable operation. Due to the increasing availability of sensors and actuators applications of smart well control become gradually more feasible[1 2 3]. For the development of smart well control systems realistic modelling of the dynamic well behaviour is essential. From practical experience it appears that in several applications the interaction between the reservoir and the well plays a dominant role in the dynamic behaviour of the well. In order to still be able to develop control systems for these situations, the near well bore reservoir was modelled and was integrated with the well model, resulting in a model describing the dynamic interaction between reservoir and well.

One condition for unstable oil production occurs at low gas lift rates and is known as heading. Although steady-state flow analysis sometimes indicates most efficient production at these gas lift rate, dynamic analysis predicts cyclic variations of liquid and gas production. This often results in periods with reduced or even no liquid production, followed by large peaks of liquid and gas.

Another situation where unstable production occurs, is when oil is produced from a thin oil rim, where the gas cap is close to the perforations of the well. When increasing the drawdown a cone of gas will be formed. Due the formation of a gas cone, not only oil enters the tubing, but also gas will enter the tubing. In some conditions this can lead to excessive production of gas, and as a result a decreased or unstable oil production. In other conditions however a small amount of cone gas entering the well can create natural gas lift, and will stimulate oil production rather then disturbing it. For operation of an oil well where the risk of gas coning is present, it is important to know the conditions that affect the production of cone gas. Cone formation and production of cone gas is a dynamic phenomenon, involving both reservoir and well dynamics. When the well perforations are close to the water layer, also water coning can take place. Also water coning is a dynamic phenomenon, involving reservoir and well dynamics.

A simulation model was developed with the aim to describe the main dynamic phenomena that are important for the development of smart well control systems. This includes the situations mentioned above. The model focusses on the dynamic interaction between the different subsystems, which allows some simplifications in the description of the individual subsystems.

The structure of the model is explained in this paper and typical behaviour indicating reservoir well interaction is pointed out. The simulation results are compared to the results where only the dynamics of the well are described and where the reservoir dynamics are neglected. In addition the model was validated with field data from a thin oil rim reservoir. Finally different applications are mentioned how the model can be used for the optimisation of oil production

Model structure

The system investigated consists of a vertical production tubing, an annulus for the lift gas and the near well bore reservoir region (Fig. A-1, Appendix). A mechanistic model

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was developed describing the dynamic behaviour of the gas and oil flow in the reservoir towards the well bore and the behaviour of the flow in the production tubing. The near well bore region is described with a radial inflow model for both the oil and gas phase.
The two-phase flow in the tubing is described by means of a drift-flux model and in the annulus a single phase gas flow is described.

The different components involved are discussed hereafter.

Dynamic Reservoir Model. The reservoir model comprises a radial inflow model. In this section of the reservoir it is assumed that a fully segregated oil and gas phase exists below a cap rock. The segregated black oil and gas layers are coupled by means of the mass conservation for each phase and the pressures in each layer. The oil flow in the reservoir is described by the Darcy equation according to Dake[4]:

$$q_L = -\frac{k}{\mu} A \frac{\partial p}{\partial r}, \tag{1}$$

with q_L the liquid flow [m^3/s], κ the permeability [m^2], μ the viscosity [Pa s], A the (effective) flow area, p the pressure and r the radial distance to the tubing. The gas flow in the reservoir is calculated with the Forscheimer equation:

$$q_G = -\frac{\mu A}{2\rho\beta}\left(1-\sqrt{1+4\frac{k^2}{\mu^2}\rho\beta\left({}^{dp}\!/_{dr}\right)}\right), \tag{2}$$

with q_G the gas flow [m3/s], ρ the (gas) density [kg/m^3] and β the non-Darcy parameter [1/m].

The Gas Oil Contact (GOC) is the location of the dynamic interface between the gas and oil layer. The GOC is calculated with the mass conservation for the liquid (oil) phase:

$$A\rho_L \frac{\partial x_L}{\partial t} = -\frac{1}{r}\frac{\partial(\rho_L r q_L)}{\partial r}, \tag{3}$$

with ρ_L the oil density and x_L the (relative) oil height (0..1), which corresponds to the GOC.

The pressure in the gas layer is determined with the mass conservation for the gas phase:

$$A\frac{\partial(\rho(1-x_L))}{\partial t} = -\frac{1}{r}\frac{\partial(\rho r q_G)}{\partial r}. \tag{4}$$

The pressure in the liquid layer is related to the pressure in the gas layer and the hydrostatic head:

$$p_L = p_G + \rho_L g h x_L, \tag{5}$$

with h the height of the reservoir section.

With the equations (1) to (5), a radial inflow model was established, comprising a number of radial sections (rings) around the well bore. In each radial section the pressure and the GOC is computed, as well as the flow of oil and gas towards the next radial section. All variables are a function of time, i.e. the dynamic response is calculated. At the perforations, the flow area is corrected with the size of the perforations and the perforation density. The coupling with the tubing is by the inflows of oil and gas from the radial section next to the well bore towards the production tubing.

At the outside of the radial inflow sections, i.e. the far field, a semi-steady state inflow performance characteristic is assumed, i.e. a constant productivity index.

Tubing. In the tubing the two-phase flow is modeled by means of the drift-flux model (Whalley[5]). In this approach the relative motion between the two phases is modeled. Furthermore, fully segregation of the two phases is assumed, so release of gas from the oil due to the decreasing pressure along the well was neglected, i.e. black oil. All relations were derived for a single string, vertical well.

The flow velocity of liquid and gas is computed by combining the impulse balance for the liquid and gas phase and by using the drift flux model:

$$q_G = \frac{1-\alpha_L}{1-C_0(1-\alpha_L)}\left(C_0 q_L + A\cdot u_{bs}\right), \tag{6}$$

with α_L the liquid hold-up, and C_0 and u_{bs} the drift-flux model parameters (Whalley[5], Legius[6]). The parameters C_0 and u_{bs} are flow regime dependent and several descriptions and values are known.

The liquid hold up is calculated with the mass balance for the liquid phase:

$$\frac{\partial \alpha_L}{\partial t} = -\frac{1}{A}\frac{\partial q_L}{\partial x} \tag{7}$$

The pressure in the tubing is calculated with the mass balance for the gas phase:

$$\frac{\partial \rho_G}{\partial t} = -\frac{\rho_G}{\alpha_G A}\frac{\partial q_G}{\partial x} - \frac{\rho_G}{\alpha_G A}\frac{\partial q_L}{\partial x} - \frac{q_G}{\alpha_G A}\frac{\partial \rho_G}{\partial x} \tag{8}$$

Using the discretization of the equations (6) to (8) the production tubing is divided in a number of sections, where for each section the pressure and the hold up was calculated, as well as the oil and gas flow to the next section.

Annulus. The annulus was modeled similar to the tubing, however here only one phase is present. The annulus was divided in a number of sections, and the pressure and gas flow are computed for each section.

Production Choke. The flow through the production choke is a multiphase flow. The pressure drop over the production choke was described with:

$$\Delta p = K_{PC}\,\rho_{mixture}\,q_{mixture}^2 \tag{9}$$

where K_{PC} is a constant which depends on the effective size of the restriction (dependent on the valve position).

The flow line pressure downstream of the production choke is regarded as a constant pressure in the simulations shown in this publication.

Cases indicating interaction between reservoir and well

In this section the response behaviour of the system to different process variations is explained. Subsequently, the response of the reservoir to a sudden increase in the drawdown, the response of the reservoir to a sinusoidal variation in the drawdown, the response of the system to a variation in the choke setting and the response of the system in the case of heading are treated.

Height of reservoir section	h	100 m
Porosity	Φ	0.3
Effective permeability (oil and gas)	k	5 10^{-14} m^2
Average reservoir pressure	p_{res}	190 bar
Drainage area boundary	r_e	350 m
Well Bore radius	r_w	0.07 m
Top of the perforated section	x_{pt}	60 m (above bottom of oil rim)
Bottom of the perforated section	x_{pb}	25 m (above bottom of oil rim)
Perforation density	r_p	0.5

ramp in Pwb

Table 1 Reservoir parameters

Response to ramp increase of drawdown. While simulating only the reservoir and imposing an increase in the drawdown (with different slopes) the behaviour of the oil/gas flows and of the GOC is illustrated in Fig. A-2 (Appendix).

This graph shows that the response of the oil flow depends on the slope of the ramp of the drawdown. At a slow increase of the drawdown, the behaviour of the reservoir can be regarded as semi-steady state since the oil flow follows the ramp of the drawdown. However, when the drawdown increases within 10 seconds, there is a large overshoot in oil production, which will not be predicted by a semi-steady state reservoir model. The overshoot is caused by the fact that the pressure in the dynamic reservoir section closest to the well bore remains higher than the pressure in the well, until enough flow has left this section, and a new equilibrium arises.

Up to the time this equilibrium exists the oil flow is larger than the steady state flow that corresponds with this pressure in the well. When the new equillibrium arises the GOC in the region close to the well bore is lower than far away from the well bore. In addition the GOC at the end of the response is lower than at the start of the response, so when increasing the drawdown the region close to the well bore is drained more effectively than the region further away from the well bore.

The response of the gas flow also shows an overshoot. Moreover the GOR response shows an overshoot during a fast increase of the drawdown. This indicates that the gas production increases faster than the oil production, due to the higher mobility of the gas.

When applying a dynamic model for the development of a well control system, it appears that the reservoir dynamics have to be taken into account when the control system operates at a time scale faster than 5 to 10 minutes. The response of the oil and gas flow to a change of the bottom hole pressure (due to a change in production choke, or lift gas rate), cannot be regarded as semi-steady state. With a semi-steady state description of the reservoir the oil flow would exactly follow the ramp of the bottom hole pressure, while with the dynamic description there is an overshoot in liquid production in the first minutes after the ramp starts.

Response to sinusoidal variation of drawdown. To get more insight in the relevant time scales simulations were carried out where the drawdown was varied according to a sine wave. Fig. A-3 (Appendix) shows the dynamic inflow performance relationship (IPR) at sinusoidal variation of the bottom hole pressure, at different period times. The average bottom hole pressure was set to 180 bar, so the average drawdown is 10 bar. The amplitude of the bottom hole pressure is 10 bar, so the drawdown varies between 0 and 20 bar. The straight line indicates the semi-steady state inflow performance curve.

At a certain point the cone gas is entering the well. At this point the IPR line is twisted, and the liquid inflow increases more slowly as a function of drawdown, due to gas entering the well.

At small drawdowns and at long period times of the drawdown the dynamic IPR is close to the steady behaviour. However, when the period time is 1 minute the inflow performance can no longer be regarded as semi-steady state, also when no gas is entering the well. When an average drawdown of 5 bar with an amplitude of 5 bar would have been used, (i.e. the drawdown varies from 0 to 10 bar), the dynamic Inflow Performance curve would be an ellipsis. In this case, it is clear that at a longer period time the dynamic inflow curve would approach a straight line (i.e. the semi-steady state IPR), however, at a short period time the ellipsis shape would differ significantly from a straight line.

The ellipsis is caused by the phase difference between the pressure and the flow, due to the dynamic relation between the pressure and the flow. A fast change in pressure, causes a delayed change in flow. The faster the pressure change, the larger the relative delay, so the radius of the ellipsis increases when a smaller period time for the drawdown variations is applied.

The second phenomena that is observed, is the entering of cone gas into the well. This occurs when the drawdown has reached a certain level for a certain time. At a small period time, a larger drawdown is needed for the production of cone gas, than at a larger period time. When cone gas enters the well, the production of oil decreases and the production of gas increases, as is made clear by the inflow curves in Fig. A-3. It is clear that a steady state IPR is not sufficient to describe the oil production and that instead a dynamic reservoir model should be used to describe the inflow relations at the right level of detail.

coning

Response to change production choke setting. At normal operation, it is expected that if the production choke is opened, the well head pressure decreases. It will be explained that also different responses are possible due to the effect of reservoir dynamics.

Fig. A-4 (Appendix) shows a simulation where the response is displayed to an increase of the production choke opening. In this picture two different situations are compared. First, the response is calculated for the situation where the well inflow is described with semi-steady state relations. The inflow of oil is calculated with a semi-steady state Inflow Performance Relationship (Dake[4]):

$$p_{reservoir} - p_{bottom\ hole} = \frac{q_L \mu}{2\pi kh} \ln\left(\frac{r_e}{r_w} - \frac{1}{2} + S \right) = \frac{q_L}{PI} \quad (10)$$

r_w is the radius of the well, r_e is the outer radius of the reservoir section that is observed. S is the mechanical skin factor. PI is a constant factor, that takes into account the average pressure drop over the near well bore reservoir section, dependent on porosity and permeability of the formation. The reduced permeability close to the well is accounted for by the mechanical skin factor S.

The inflow of gas is described with the following semi-steady state relation (Dake[4]):

$$p^2_{reservoir} - p^2_{bottom\ hole} = Aq_G + Fq^2_G \quad (11)$$

The parameter A describes the pressure loss over the porous formation, whereas F gives the pressure loss near the tubing, often accounting for the occurence of turbulent flow. The parameters A and F are both dependent on porosity and permeability of the reservoir.

Fig. A-4 shows the response of the dynamic well model, where the well inflow is described with the above mentioned semi-steady state reservoir model. This is a classical way of simulating well dynamics. The response to an increased opening of the production choke is a decrease of the well head pressure. The production of oil increases fast when the choke is opened, but later decreases due to the decreased bottom hole pressure.

The next line in Fig. A-4 shows the response when also the reservoir dynamics are taken into account. Also in this situation the well head pressure decreases fast after opening the production choke. The bottom hole pressure decreases from 100 to 70 bar. At the start of the simulation the GOC is above the perforations, so no cone gas is entering the well. Due to the increased drawdown the GOC migrates to a lower position, which causes cone gas flowing into the well. This increased gas flow causes the well head pressure to increase, because the pressure drop over the production choke rises, due to the increased flow through the choke. As a result the response of the well head pressure to opening the production choke, is first a decrease of the well head pressure, and after some time an increase of the well head pressure.

In the simulation with the steady state model the gas flow at the start of the simulation is not zero, because the semi-steady state relation for gas inflow does not take into account the formation of a cone.

Again here a dynamic well model, in combination with a semi-steady state reservoir model, does not sufficiently the describe the phenomena that take place on a short time scale. Since this is the time scale that is important for control system development, the semi-steady model is not sufficient for the development of well control schemes, and instead the integrated reservoir and well model provides a better description of the relevant behaviour.

Well performance during heading instability. In gas lifted wells, instability in the oil production may occur when the lift gas injection rate is too low. This effect is known as heading instability and is caused by the interaction between the flow dynamics in the annulus and in the tubing. When heading instability occurs a cyclic variation of oil flow and well head pressure is observed. It is interesting to analyze the effect of dynamic reservoir modelling on the well behaviour during a heading cycle. For this reason two simulations were carried out. In the first simulation the semi-steady state reservoir model was used (equation (10)). The result of this simulation is indicated in Fig. A-5 (Appendix). After 125 minutes, the lift gas injection rate was reduced. As a result, the heading cycle occurs, and the well head pressure oscillates with a slowly increasing amplitude. Next, a second simulation was carried out, where the dynamic reservoir model replaced the semi-steady state reservoir model. The results of this simulation are illustrated in Fig. A-6 (Appendix). Again after 125 minutes the lift gas injection rate was reduced to exactly the same value as was used in the first simulation. Again a heading cycle occurs, however the amplitude of the changing well head pressure is much lower than in the first case. This shows that the dynamics of the reservoir decrease the amplitude of the pressure fluctuations in the well.

The reason is that due to the short terms variation of the bottom hole pressure, the oil flow from the reservoir to the well is not in phase with the pressure fluctuations. The oil flow is high, when the bottom hole pressure is low and as a result this causes a stabilizing effect on the well performance.

This example shows that due to the mutual interaction beween the reservoir and the well the near well bore dynamics cannot be neglected. So in order to achieve an accurate description of the dynamic phenomena in the well in this case, the dynamic interaction with the near well bore reservoir must be taken into account.

Comparison with field data

The developed model was compared with field data. The aim of the model is to qualitatively describe the behaviour of the well, as observed by operator personnel. For this reason, data was obtained from a Shell operated field, where gas break through often is encountered, due to the thin oil rims from which production takes place. In reality production takes place from a horizontal well, but the model for a vertical well already allows to qualitatively investigate the effect of dynamic interaction of well and reservoir. Therefor only a qualitative comparison between the model predictions and the measured data was made. This comparison is shown in Fig. A-7.

At the start of the measurement there is no oil production. The well is started up by opening the production choke, and by opening the lift gas valve. At t=1000 s the production choke opening is increased, and also the oil and gas flow increase. At t=3000 s a further increase of gas flow starts, while the (average) production choke opening is not increased. This increase of gas flow is caused by the formation of a gas cone in the reservoir. The gas flow gradually increases from 2 to 10 Million standard cubic feet/day during the next 1.5 hours. Due to the huge increase of gas flow the Gas Oil Ratio increases from 2000 to 6000 scf/bbl.

The well head pressure decreases at t=1000 s when the production choke is opened, but increases at t=3000 s when the gasflow increases. At approximately an equal production choke opening the well head pressure rises from 15 bar at t=2000 s to 35 bar at t=5000 s (1 hour later). In the same period the oil production has dropped from 3000 bbl/day to 2000 bbl/day.

The problem with the operation of a well where gas coning takes place, is that at low gas lift rates there is no production of oil. However, while increasing the gas lift rate, there is an intermediate increase of oil production, but when the cone gas flow increases the oil production again is strongly reduced. A feasible operating point for the well can only be obtained by finding the right combination of lift gas rate and production choke setting. In the example in Fig. A-7 the only way to stop the increase of cone gas flow is to decrease the production choke opening, which was done from t=5000 s.

The red line in Fig. A-7 shows the predictions of the simulation model. The qualitative comparison shows that the dynamic model realistically predicts the measured increase of gas flow due to the formation of a cone. Since only a qualitative validation was carried out, the numeric values are not identical (they are displayed on the right y-axis). Also the dynamic behaviour of GOR was predicted well. At the start of the measurement there is a mismatch in the prediction of oil production and well head pressure. However, the dynamic effects are predicted well, like the initial decrease of the well head pressure followed by an increase. It is expected that a better match will be obtained when a dynamic model for flow towards a horizontal well is built and when segregation of gas from the oil is incorporated in the model.

Applications

The model of dynamic reservoir and well behaviour can be used as a tool to analyze the behaviour of a well and to understand the dynamic phenomena that take place. Modification to the well design or well operation, can be computed and different options can be analyzed before considering applying a modification to the well.

Moreover, the integrated dynamic model can be used in the development of smart well control systems. It has been demonstrated that the integrated model realistically describes the dynamic behaviour on the same time scale as a well control system. As a result, the integrated model provides the knowledge of the dynamic behaviour of the well, which is required for the development of a well control system.

It was shown that the integrated model gives a realistic description of the instabilities in a gas lifted oil well. In the development of a control system for an unstable oil well, it appears that the integrated model, where both the reservoir dynamics and the well dynamics are taken into account, gives a realistic description of the instabilities that take place in the well. In addition it was shown that water and gas coning can be modelled, so for the development of algorithms for gas coning control or water coning control the integrated model can be used.

Other applications of the dynamic model are to assist the operator personnel with a tool that predicts the future behaviour of the well as response to changing choke settings. This can be implemented as an on-line operation support tool, where the model is coupled to the data acquisition system that presents the well data. The operator can fill in the adjustments he wants to use in future (e.g. future production choke setting), and the operation support tool predicts the future response of the well (e.g. oil and gas production). The system can also be used as a training tool for operators, to get acquainted with the dynamic behaviour of a gas coning well.

When the dynamic model is on-line with the data acquisition system of the well, non-measured parameters (e.g. down hole flow estimation) can be computed during production based on available measured signals and on detailed knowledge of the reservoir and well dynamics that are captured by the model (Bloemen)[7]. The model has to be brought on line and the model must be tracked with the well data by applying Kalman filtering techniques. The same methodology can be used in the interpretation of well test data.

Conclusions

A model was build that describes both the flow of oil and gas towards the well bore and the dynamic flow inside the well. The Inflow Performance Relationship of the dynamic model was compared to the IPR of a semi-steady state model and it was demonstrated that at a time scale of minutes, the dynamic behaviour of the near well bore reservoir significantly affects the IPR.

Therefore, it is concluded that a dynamic well model, in combination with a semi-steady state well inflow model, is not sufficient to accurately describe the dynamic phenomena, that play a role in the development of a control system. Instead it is required to take into account the interaction between near well bore reservoir and well, since this can play a dominant role in the description of the dynamic behaviour of the complete system.

The dynamic model that was developed describes the dynamics of a vertical well in combination with the dynamics of the near well bore reservoir. The simulation results were qualitatively compared to field data. This shows the trends predicted by the model correspond to the trends observed in practice. Further model development has to take place to cope with the current mismatch. Future model development will focus on modelling horizontal wells and segregation of gas.

Possible applications of the dynamic model are analyzing dynamic well behaviour, development of well control schemes, or supporting operators and engineers in the operation of a well and interpretation of well data.

Acknowledgment

The authors wish to thank Shell Global Solutions for their valuable contribution to this research project, and for making available measured well data.

Nomenclature

A	=	Area [m^2]
C_0	=	Drift flux model parameter
g	=	Gravitational constant [m/s^2]
h	=	Height of reservoir section
k	=	Permeability [m^2]
K_{PC}	=	Valve constant [-]
p	=	Pressure [Pa]
PI	=	Productivity Index [m^3/s/bar]
q	=	Flow [m^3/s]
r	=	Radius [m]
S	=	Mechanical skin factor [bar]
t	=	Time [s]
u	=	Flow velocity [m/s]
x	=	Relative Height [0..1]
α	=	Hold up [-]
β	=	non-Darcy parameter [1/m]
μ	=	Viscosity [Pa s]
ρ	=	Density [kg/m^3]

subscripts

L	=	Liquid (Oil)
G	=	Gas
bs	=	Bubble rise velocity (u_{bs})
mix	=	Mixture (Liquid and Gas)
e	=	Outer radius of reservoir section (r_e)
w	=	Well radius (r_w)

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Appendix A

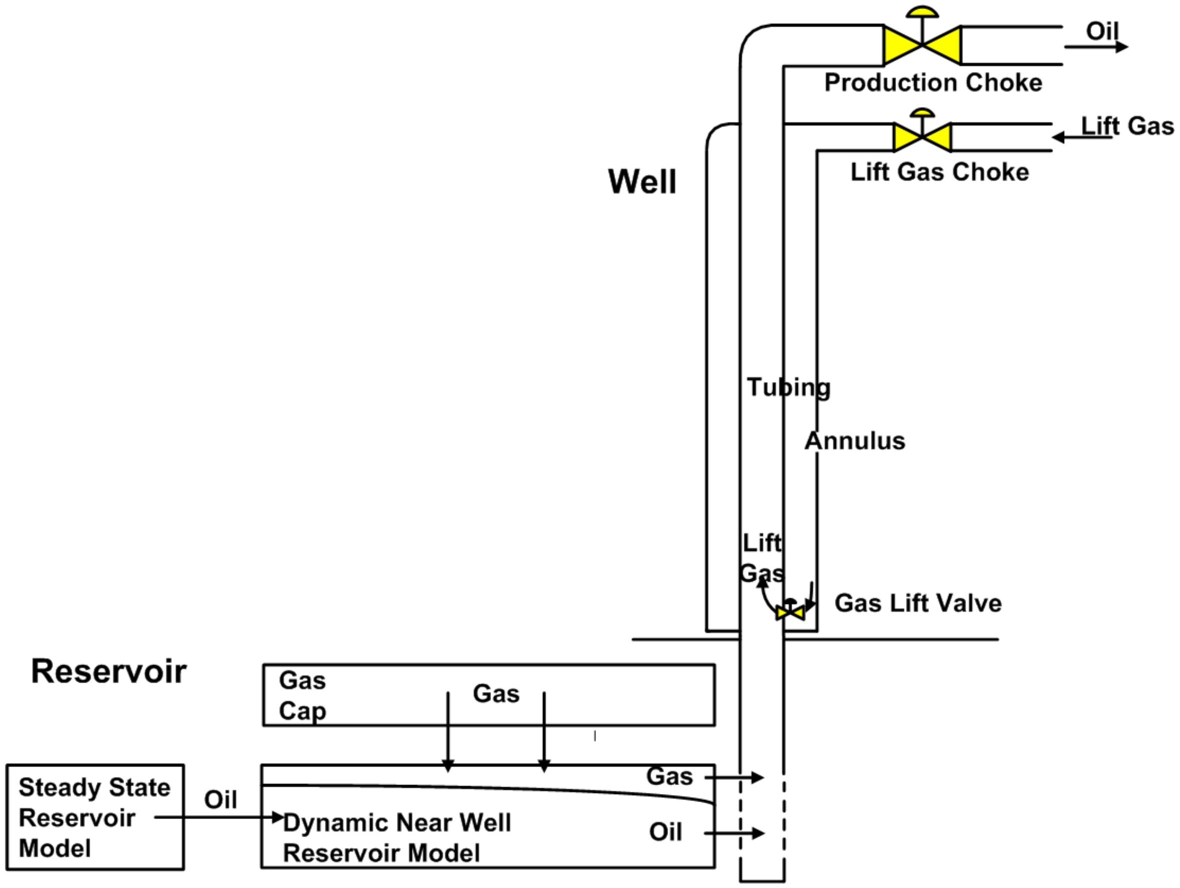
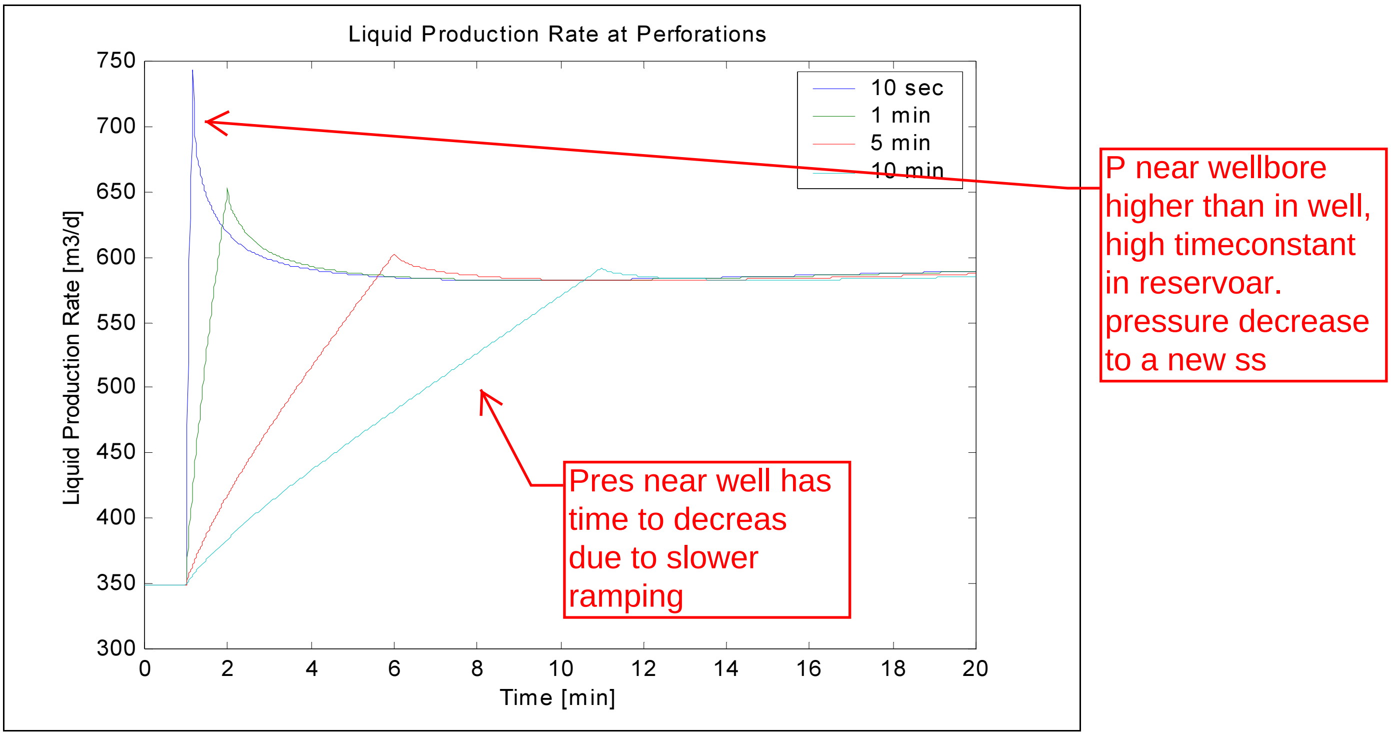
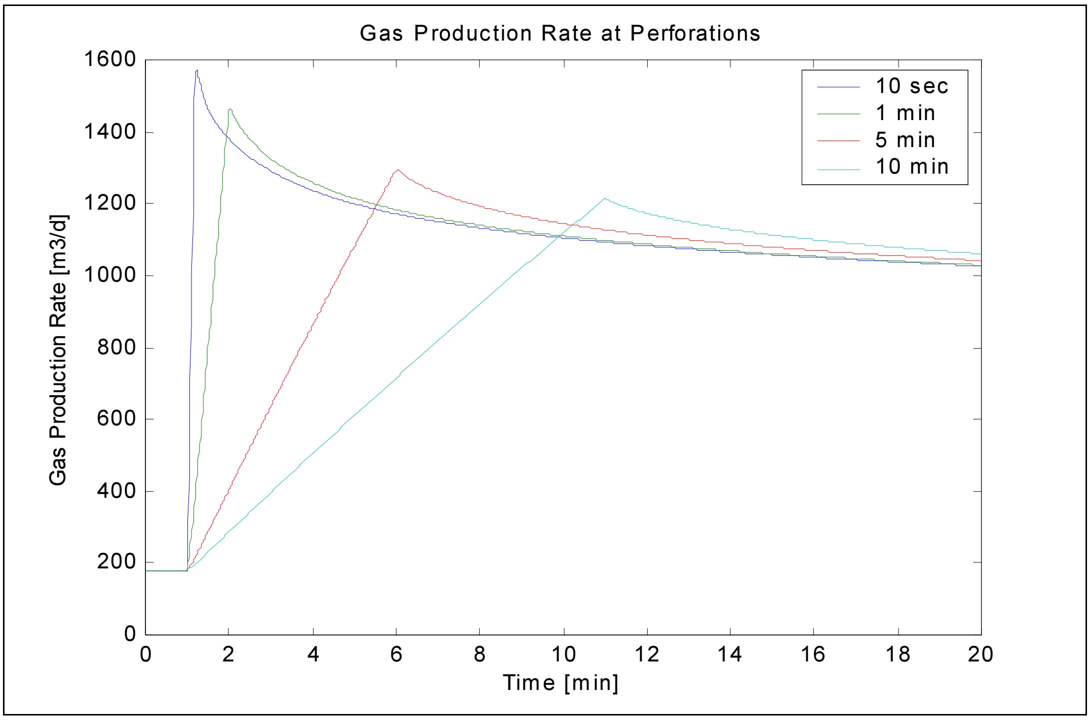
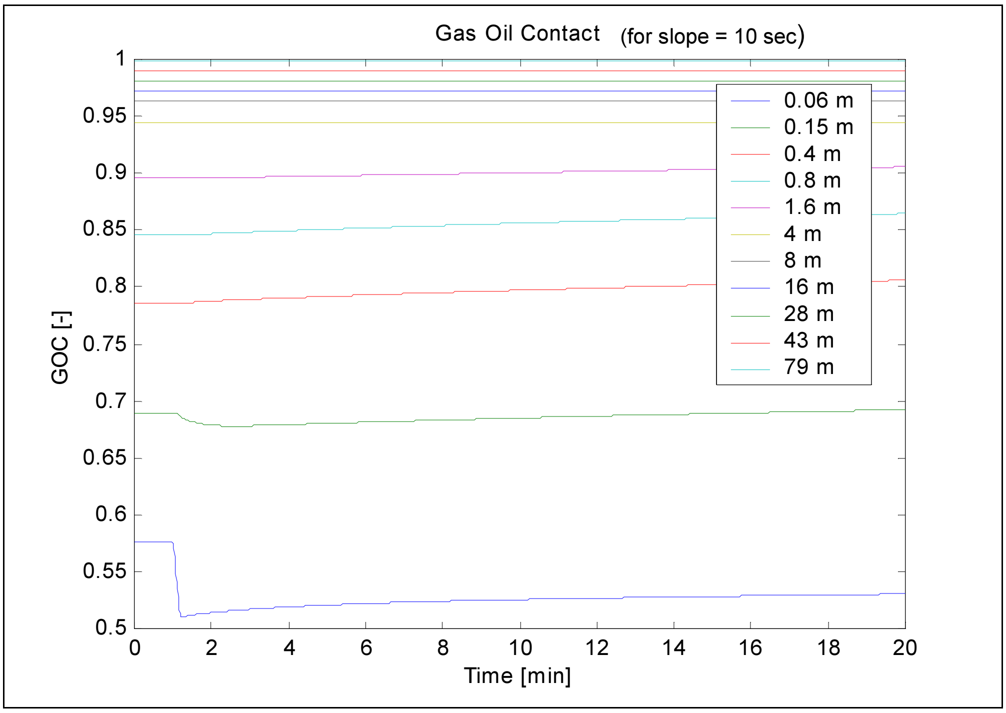


Fig. A-1 Overview of the model for reservoir and well


Liquid Production Rate at Perforations
Liquid Production Rate [m3/d]
Time [min]
10 sec
1 min
5 min
10 min
P near wellbore higher than in well, high timeconstant in reservoar. pressure decrease to a new ss
Pres near well has time to decreas due to slower ramping


Gas Production Rate at Perforations
Gas Production Rate [m3/d]
Time [min]
10 sec
1 min
5 min
10 min



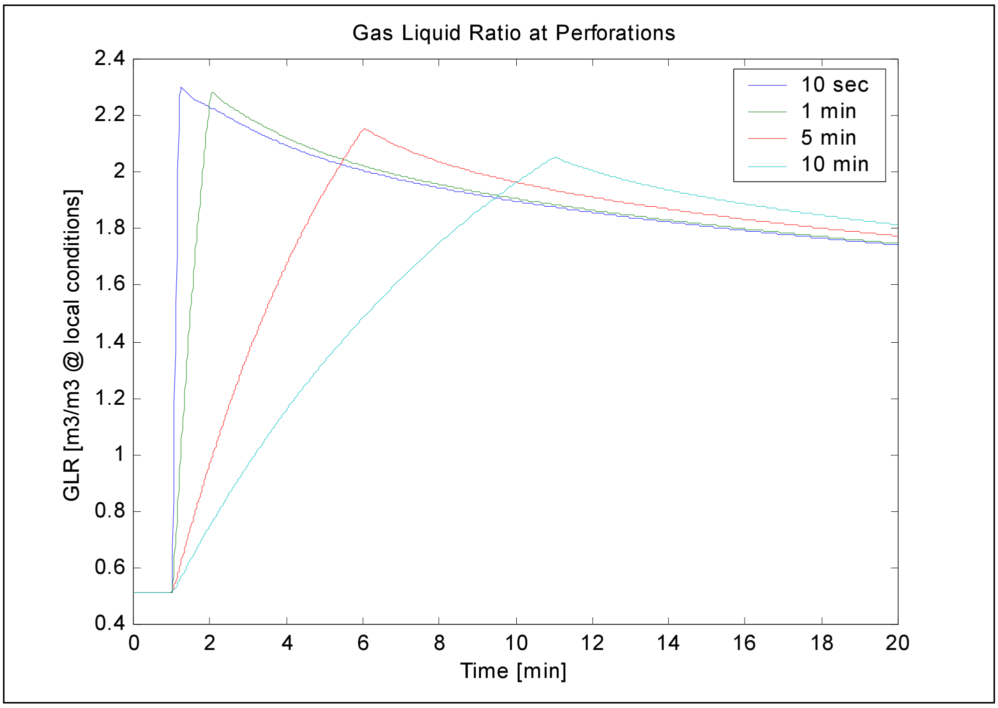


Fig. A- 2 Response to drawdown increase from 10 to 20 bar, with different slopes

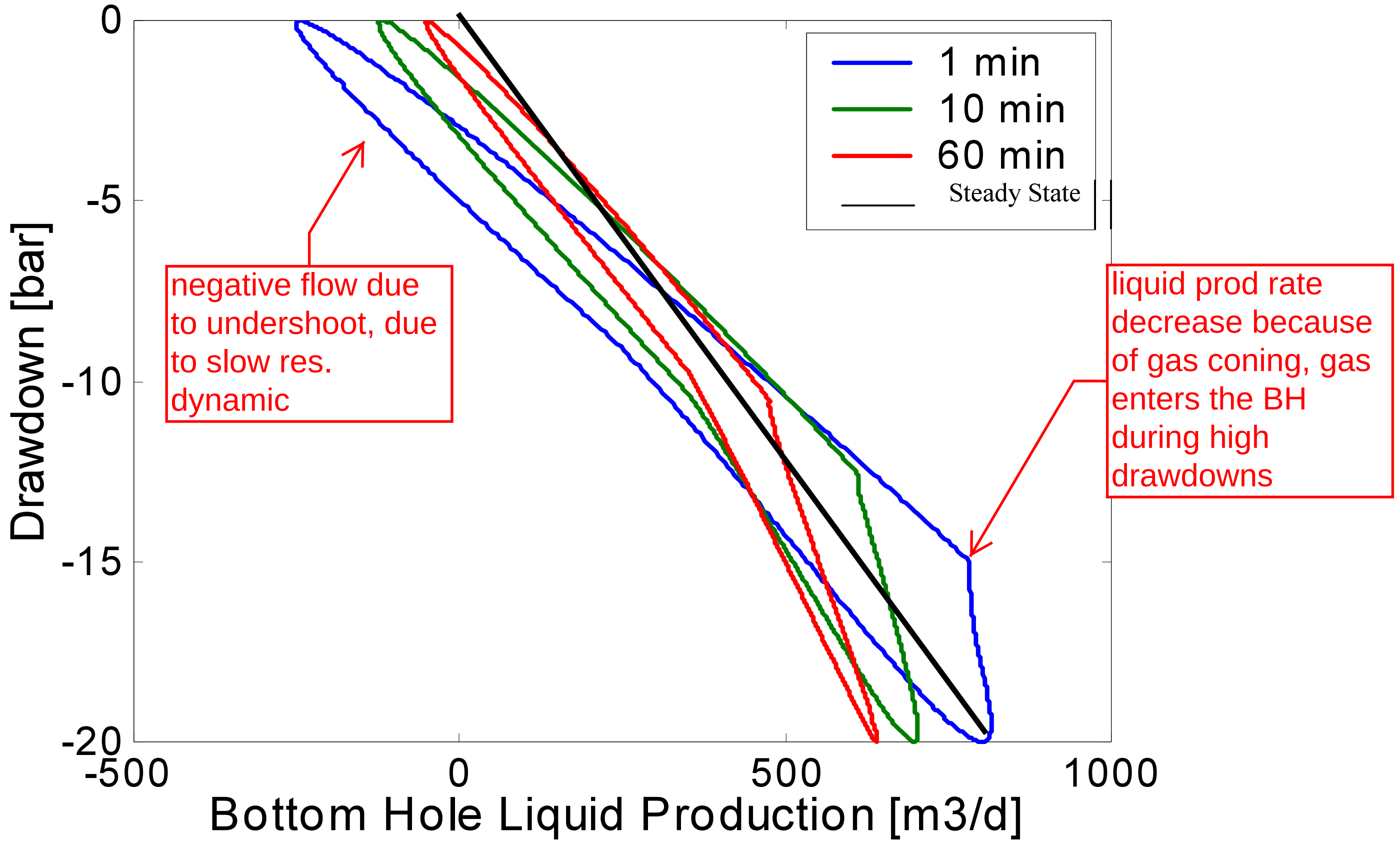


Fig. A-3 Dynamic Inflow Performance Relationship at sinusoidal variation of Drawdown, with different period times

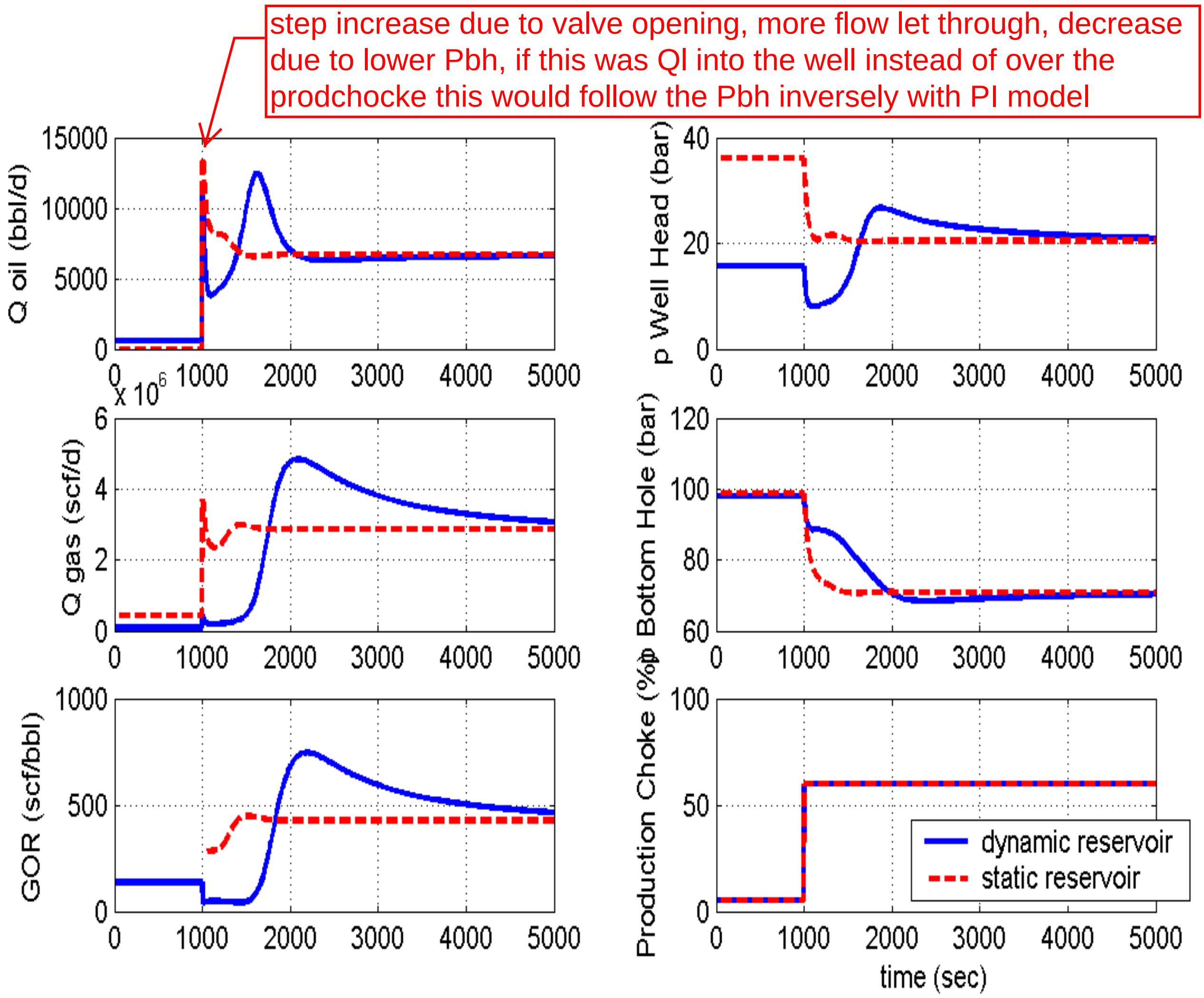


Fig. A-4 Response to opening production choke

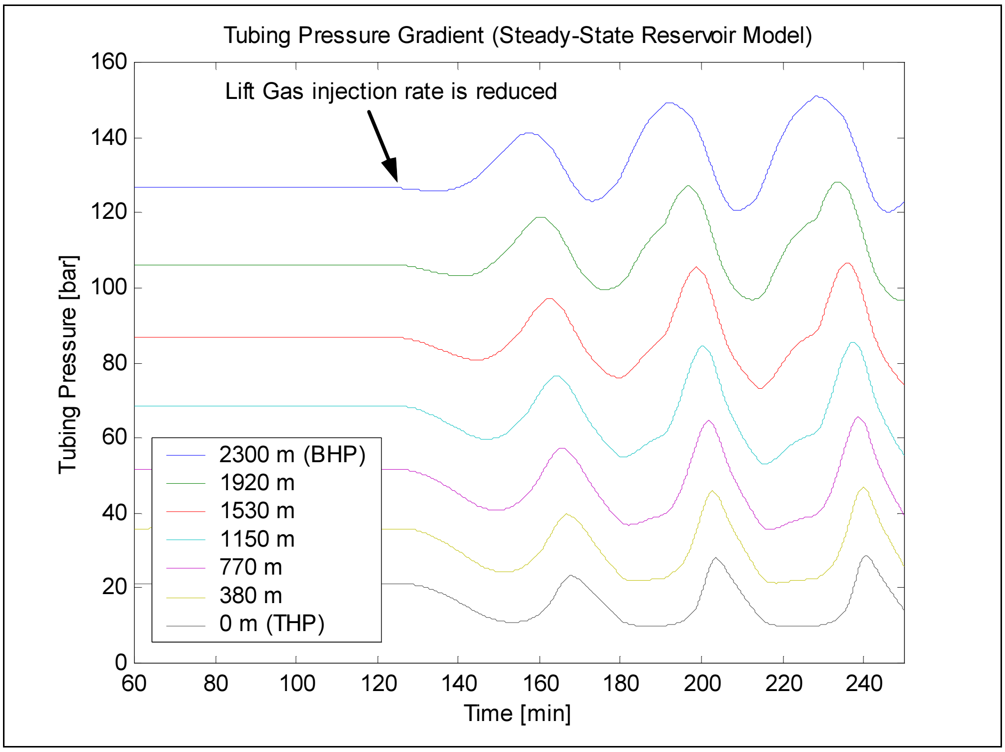


Fig. A-5 Heading Cycle, using steady state reservoir model

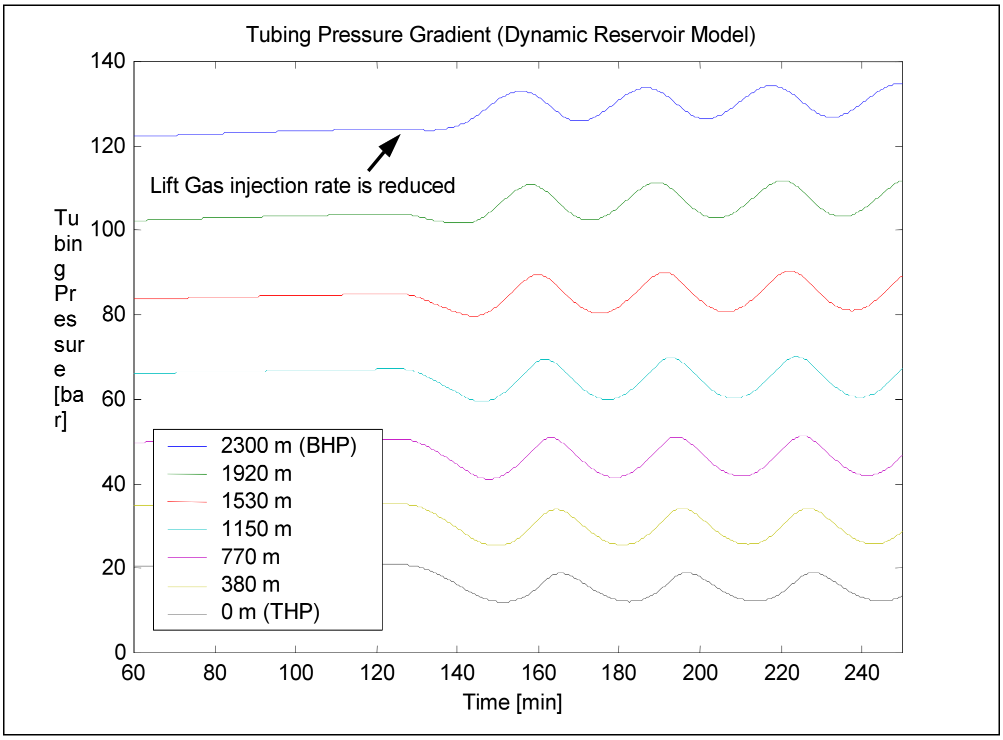


Fig. A-6 Heading Cycle, using dynamic reservoir model

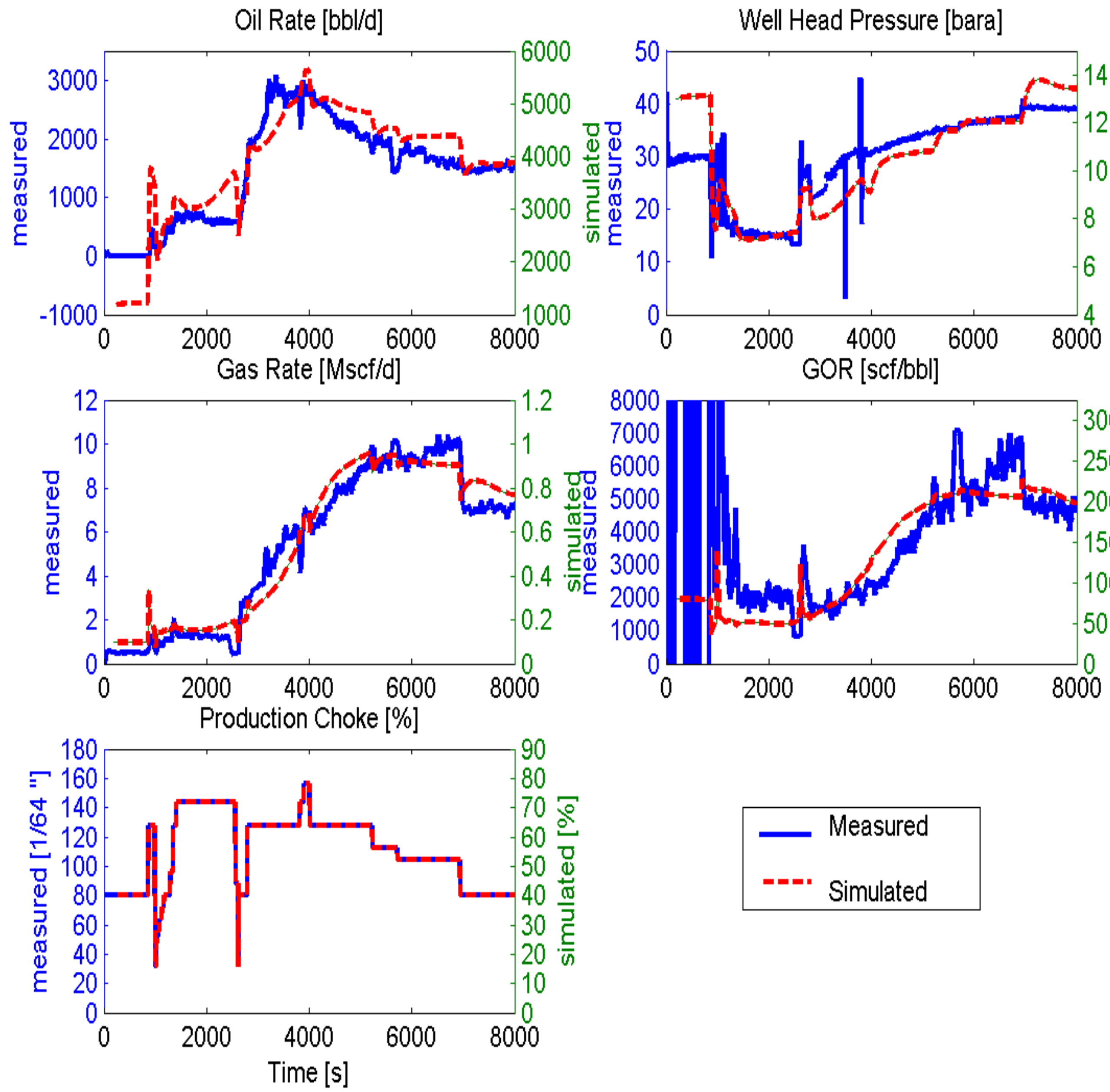


Fig. A-7 Qualitative comparison with field data