MODELING, IDENTIFICATION AND CONTROL, 1982, VOL. 3, NO. 1, 21–39
doi:10.4173/mic.1982.1.3

Real time simulation of oil drilling operations. The WELLSIM drilling simulator

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Keywords: *Oil drilling, numeric modeling, real time simulation.*

This paper contains the basic numeric model for the oil drilling simulator WELLSIM. As a case study it presents an example from well pressure control. Figure 1 shows a picture of the simulator.

1. Introduction

The WELLSIM simulator has been developed primarily for training purposes. The control panels are designed to let an operator imagine he is remotely controlling a drilling process. The panels are interfaced to a NORD-10 computer. The computer is the host for a numeric model of the drilling process. Specifications for WELLSIM are given by Opdal and Podio (1979). In Opdal, Stuan and Tokle (1980) applications are outlined. The purpose of this paper is to present the numeric model behind the WELLSIM control panels.

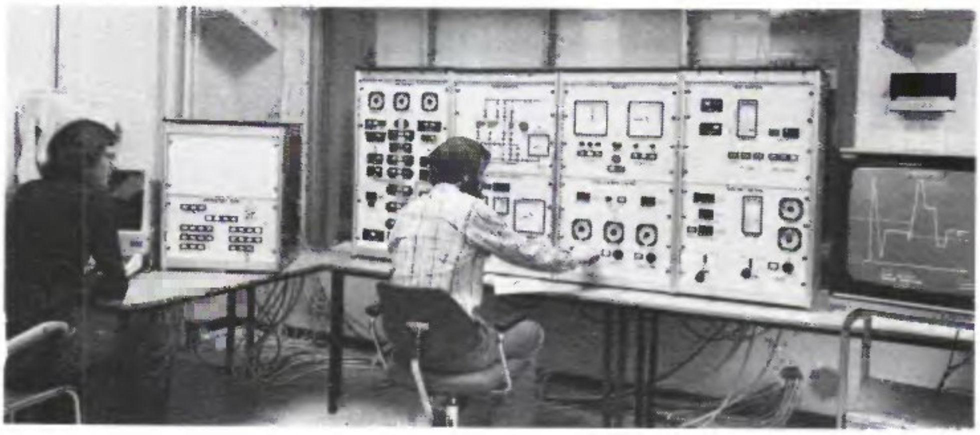

Figure 1. The WELLSIM oil drilling simulator.

2. The drilling process

The drilling process modelled in WELLSIM is shown in Fig. 2. The process consists of a mechanical and a hydraulic system. These systems interact to some extent.

The main part of the mechanical system is the drill string. With a drill bit at the lower end it rotates exercising weight on the well bottom and thus penetrates rock.

Received 15 September 1981
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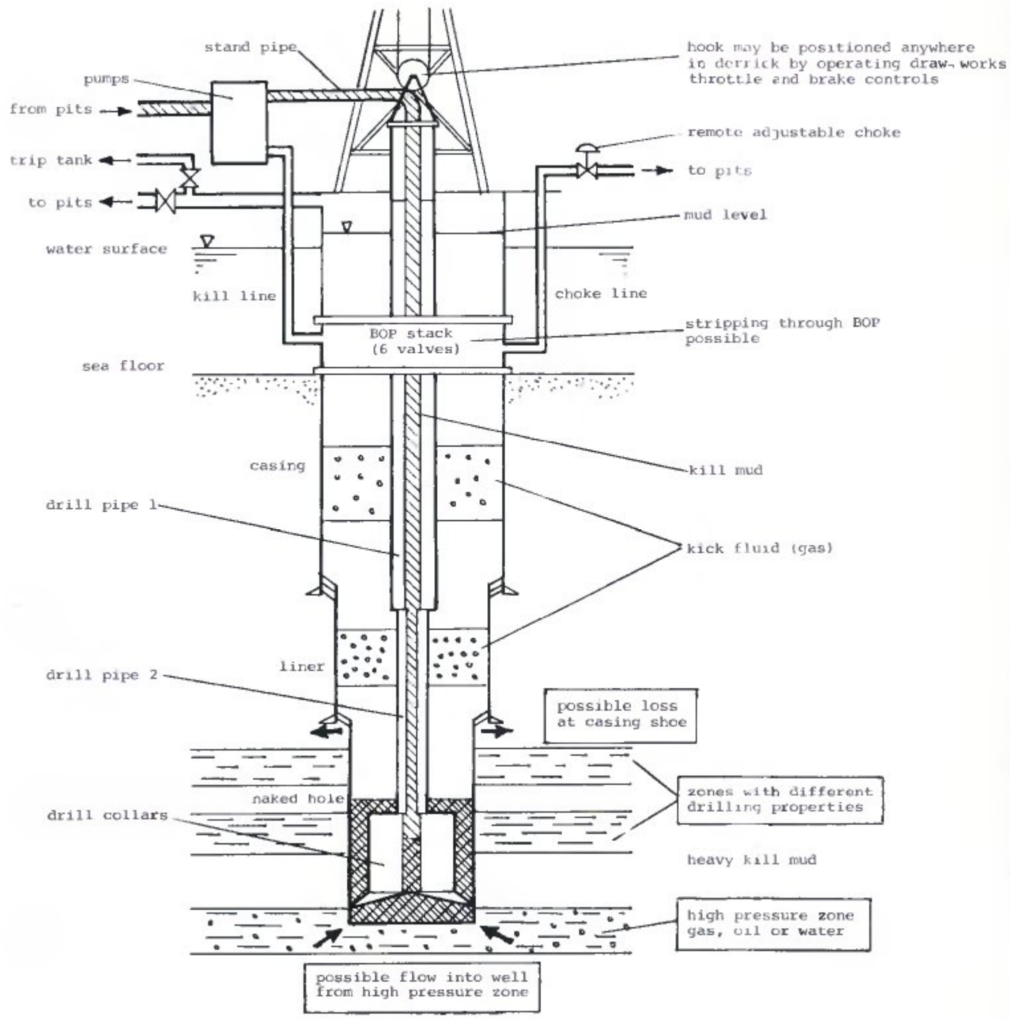

Figure 2. The drilling process modelled in WELLSIM.

Drill collars at the lower string end keep the string stretched. Draw-works and brakes are used to adjust the weight on bottom. These are also used for tripping operations; pull the pipe, change bit and run the pipe back into the hole.

The main part of the hydraulic system is the drilling mud. During drilling the mud is pumped down the drill string and returns through the annulus, the volume between the string and the rock walls. The purpose of the mud is to transport the drilled rock to the surface. It also exercises hole pressure, preventing the hole from falling together. For too high mud pressure, mud will leak into the formations (lost circulation). For too low mud pressure, formation fluid from a high pressure zone will flow into the well. A kick is then going on. The way to stop a kick is to pump the mud through a back pressure choke at the well outlet and to increase the mud weight. During circulation the back pressure ensures that the high pressure zone will not produce. The well filled with heavy mud, hydrostatic mud pressure prevents further inflow.

The hydraulic interaction on the mechanical system is that the drilling rate depends on the mud weight. It is favourable to keep the mud weight down. The drilling rate also, to some extent, depends on the circulation rate. Interaction the other way round is that when running the drill string, the well pressures are affected. Pulling pipe, high pressure formation fluids can enter the well, caused by the decreased mud pressure. Running the pipe back into the hole, the increased mud pressure can break the formations. Of course, formation fluids will also enter the well when drilling underbalanced into a high pressure zone.

Several control panels are interfaced to the WELLSIM numeric model of the drilling process. The BOP control panel opens and closes the sea floor blow out preventer valves used to close the well in a kick situation. The choke manifold panel directs the flow from the choke line to the various chokes. The remote choke control panel adjusts the choke opening when circulating out a kick. The alarms panel tells if the flow out of the well is greater than the flow being pumped into it. This is a kick indication. The pump and mud control panel adjusts the pumping rate and the density of the mud being pumped into the well. The trip control panel is used to measure the mud volumes going into or coming out of the well during tripping operations. The drilling control panel contains breaks and drawwork for tripping and for weight on bit adjustments. It is also used to set the drill string rotary speed.

Indications on the control panels to monitor the drilling process include pump and choke pressures mainly for kick operations, drilling rate, drilling torque and drill bit position.

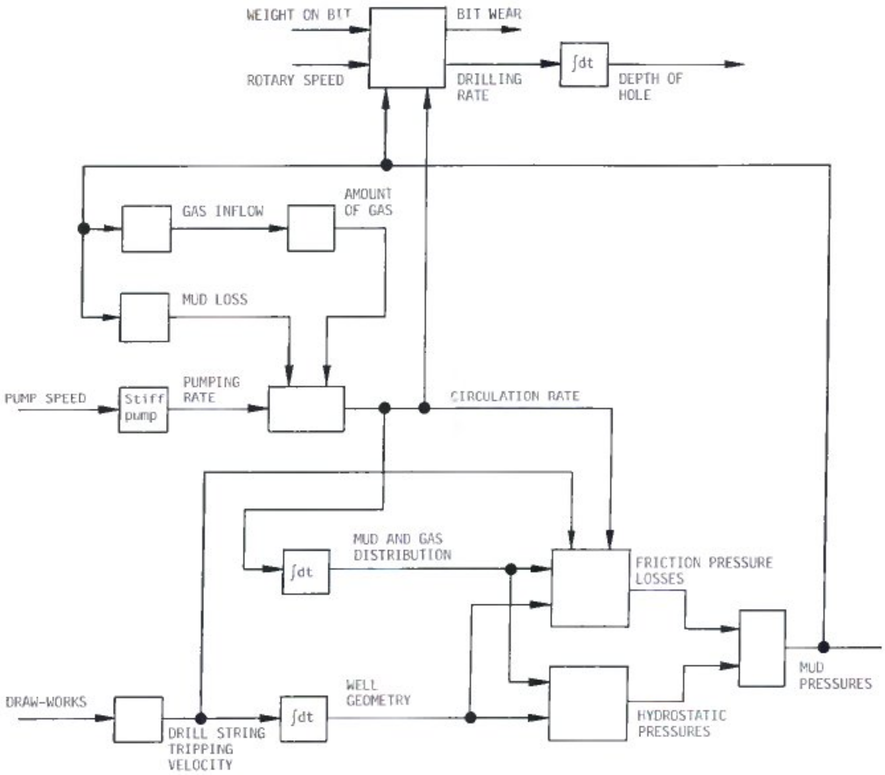

Figure 3. Block diagram for the drilling process.

3. The numeric well model

Main considerations for the numeric model are real time simulation, operator interaction and parametric well description. Real time simulation limits the available computer time. Operator interaction means the simulator has to run for all values of panel inputs, mud flow rate etc. Parametric well description means it has to run for all kinds of well geometries and other well data.

Figure 3 shows a simplified block diagram for the drilling process. The depth of the hole increases as given by the drilling rate. This rate is calculated from rather detailed equations. It depends on the rotary speed and the weight of the bit on the well bottom. It also depends on the wear of the drill bit teeth, the mud circulation rate and the bottom hole mud pressure. The mud pressures in the well are calculated from basic hydrostatic and friction pressure loss equations. The calculations are complicated by the general geometry of the well and by the possible presence of mud loss to the formations or gas inflow from high pressure zones. Anyway, the mud pressures depend on the mud weight distribution in the well, the circulation rate, the drill string position and velocity, the amount and position of gas inflow and the rate of loss to the formations.

3.1 *Drilling rate* (Young 1969)

The drilling rate depends on the rock being drilled, the type of bit, the bit tooth wear, the weight on bit, the rotary speed, the mud pressure and the hydraulic cleaning at the bit.

$$r = 0{\cdot}019 \cdot k_1 \cdot f_1 \cdot \frac{w - w_0}{D} n^\lambda \frac{1 - x_1}{1 + C_2 x_2}$$

$$r \geqslant 0$$

where

- r: Drilling rate [m/hr]. Typical 1–10 m/hr.
- k_1: Drillability factor. Depends on rock and drill bit properties. Typical value 0·008.
- f_1: Differential pressure function, 0–4.
- w: Weight from bit on well bottom [kN], 100–1000 kN. Input from control panel.
- w_0: Threshold weight [kN], 0–100 kN.
- D: Drill bit diameter [m], 0·15–0·30 m.
- n: Speed of rotation [o/min], 25–200 o/min. Input from control panel.
- λ: Rotary speed exponent, 0·8–1·5.
- x_1: Hydraulic cleaning variable, 0–1.
- x_2: Tooth wear variable, 0–1.
- C_2: Tooth wear constant, 2·0.

The rate decreases with the rock hardness. It increases with the weight on bit and with the rotary speed. Both a dulled bit and insufficient bit cleaning slow down penetration. The rate also decreases with increasing mud weight.

Differential pressure function (*Vidrine and Benit* 1973)

The drilling rate depends on the difference Δp_2 between the mud pressure and the pore pressure of the formations being drilled. An increase in the bottom hole mud pressure means a decrease in the drilling rate. The function.

$$f_1 = f_1(\Delta p_2)$$

consists of the straight lines connecting the points

$$(-\infty, 4{\cdot}0), (-207, 4{\cdot}0), (-34, 3{\cdot}0), (34, 1{\cdot}0), (207, 0{\cdot}0), (\infty, 0{\cdot}0)$$

Δp_2: Differential bottom hole fluid pressure [bar].

Hydraulic cleaning variable

The drilling rate depends on the degree of cleaning of loose material at the well bottom. This degree of cleaning again depends on the hydraulic power at the drill bit and on the drilling rate.

$$P_1 = \Delta p_1 \cdot q_0 \bigg/ \left(600 \frac{\pi}{4} D^2\right)$$

$$r_L = 2{\cdot}6\, P_1 - 3{\cdot}0$$

$$\alpha = 0{\cdot}033,\ P_1 < 1{\cdot}16 \text{ (Bit balling)}$$

$$\alpha = -0{\cdot}033,\ P_1 > 4{\cdot}62 \text{ (perfect cleaning)}$$

$$\alpha = 0,\ 1{\cdot}16 < P_1 < 4{\cdot}62,\ r \leqslant r_L$$

$$\alpha = 0{\cdot}044\text{–}0{\cdot}0096\, P_1,\quad 1{\cdot}16 < \mathrm{P}_1 < 4{\cdot}62,\quad r > r_L$$

$$\dot{x}_1 = \alpha(r/12),\ \alpha \geqslant 0$$

$$\dot{x}_1 = \alpha/(1 + r/12),\ \alpha < 0$$

$$0 \leqslant x_1 \leqslant 1$$

where

- P_1: Hydraulic power per unit drill bit area [Mw/m^2].
- Δp_1: Pressure drop over drill bit nozzles [bar].
- q_0: Drilling mud circulation rate [m^3/min]. Input from control panel.
- r_L: Drilling rate limit function [m/hr].
- α: Cleaning factor. $\alpha < 0$ means sufficient cleaning. $\alpha > 0$ means that the drilled material is accumulated at the well bottom.
- $\dot{x}_1$: cleaning rate [1/s].
- x_1: This variable essentially is a measure of the accumulated well bottom material. For $x_1 = 1$ the drill bit is completely balled.

For small drill bit unit area hydraulic power, ($P_1 < 1{\cdot}16$) loose material is accumulated on the well bottom. The cleaning variable x_1 increases with a growth rate going up with the drilling rate. As a consequence, the drilling rate will go down and the drill string torque will increase. Eventually the bit will be completely balled with the drilling rate going to zero. For high hydraulic power ($P_1 > 4{\cdot}62$), the cleaning is perfect. Accumulated material will gradually disappear with a rate becoming smaller for higher drilling rates. Material being drilled loose is cleared away immediately. For intermediate hydraulic powers ($1{\cdot}16 < P_1 < 4{\cdot}62$) the cleaning sufficiency depends on the drilling rate. For small drilling rates ($r < r_L$), drilled material will be transported away, but accumulated material will stay unaffected. For higher drilling rates ($r > r_L$), but material will gradually be accumulated and faster the higher the drilling rate.

Tooth wear variable

The drilling rate also depends on the wear of the drill bit teeth. This wear is dependent on the rotary speed, the weight on the bit and the hydraulic horse power at the bit.

$$\dot{x}_2 = A_f \cdot f_2 \cdot \frac{K_1 n + K_2 n^3}{D_2 - 0{\cdot}22\, D_1 w} \frac{1}{1 + C_1 x_2}$$

$$f_2 = 1, \quad P_1 \leqslant 8{\cdot}1$$

$$f_2 = 1 + (0{\cdot}865 \cdot P_1 - 7)^{1{\cdot}3} \cdot P_1/1{\cdot}2, \; P_1 > 8{\cdot}1$$

where

$\dot{x}_2$: Rate of tooth wear [1/hr]

A_f: Abrasiveness factor of the drilled formations. Typical value is $2{\cdot}10^{-3}$

K_1: Bit type parameter, 0·5–2·5

K_2: Bit type parameter, $0{\cdot}2 \cdot 10^{-4}$–10^{-4}

C_1: Bit type parameter, 2–7

D_1: Bit size parameter, 0·058–0·088

D_2: Bit size parameter, 5·5–7·15

We see that the rate of tooth wear increases with the rotary speed and with the weight on bit. It decreases with the wear itself. When the unit area bit hydraulic power increases above 8·1 Mw/m^2, bit erosion occurs. The rate of tooth wear then increases with the hydraulic power.

3.2. *Well geometry*

WELLSIM allows fluid sections with different densities to be pumped through the well. Varying well and string diameters and a moving drill string makes it somewhat complicated to keep track of the fluid sections, see Fig. 4.

Pumping mud into the well, lost circulation to the drilled formations, inflow of formation fluid and rising of gas relative to mud, means that the fluid density function

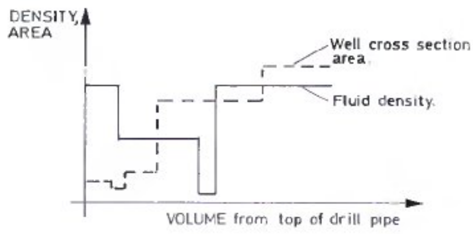

Figure 4. Fluid density and cross section area of well U-tube from top of drill pipe to top of annulus.

will change. Running the drill pipe means that the well cross section area function will take another shape. Knowing these two functions, the positions of the fluid sections in terms of depth is calculated. As one consequence this means that the hydrostatic well pressures can be found.

3.3. *Pressure and flow calculations*

From the point of view of calculating pressures and flows, the drilling well is a U-tube as shown in Fig. 5.

The calculations will be different depending on the presence of gas, if the riser or the choke line is used, if the mud is completely filling the annulus, or if there is a loss flow. This gives a lot of possibilities to be taken care of. The basic equations are given below.

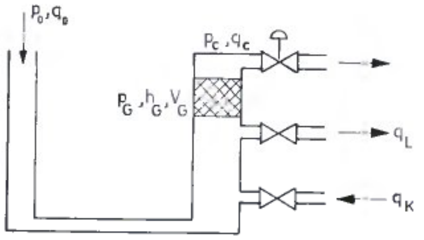

Figure 5. Basic U-tube configuration for calculation of pressures and flows in the drilling well.

The pump

Setting the pump to a delivery rate q_0, it will keep this rate independent of the pumping pressure. Exceeding a predetermined pressure limit, a pump safety valve will come into action.

Hydrostatic pressure

The increase in hydrostatic mud pressure for each well section where ρ and A are constant is given by

$$\Delta p = \rho g(\Delta V/A) \cdot 10^{-5}$$

where

- Δp: Differential pressure [bar]
- ρ: Mud density [kg/m^3]
- g: 9·81 m/s^2
- ΔV: Volume of well section [m^3]
- A: Area of well section [m^2]

Friction pressure loss for turbulent flow

The turbulent friction pressure loss for mud flowing in a pipe or an annular tube is calculated according to (Moore 1978).

$$\Delta p = 4{\cdot}28\,\frac{(\mu/10)^{0\cdot 2}(\rho/1000)^{0\cdot 8}q^{1\cdot 8}(l/1000)}{(10(d_o-d_i))^3\cdot(10(d_o+d_i))^{1\cdot 8}}$$

where

μ: Mud viscosity [cP]

q: Flow rate [m^3/min]

l: Length of pipe [m]

d_o: Outer flow diameter [m]

d_i: Inner flow diameter [m]

This means that the pressure loss is 4·28 bar for $\mu=10$ cP, $\rho=1000$ kg/m^3 (water), $q=1$ m^3/min (265 gpm), $l=1000$ m, $d_o=0{\cdot}1$ m and $d_i=0$ m (pipe flow). The same formula is used both for pipe and annular flow.

Friction pressure loss for laminar flow

The laminar pipe or annular tube flow pressure loss is also calculated according to Moore (1974):

$$\theta_{300}=\mu+2{\cdot}09\cdot\tau$$

$$\theta_{600}=\theta_{300}+\mu$$

$$b=3{\cdot}32\log_{10}(\theta_{600}/\theta_{300})$$

$$a=1{\cdot}91\cdot\theta_{300}/(511)^b$$

$$\Delta p=a\left[0{\cdot}25\,\frac{2b+1}{3b}\,\frac{|q|}{(d_o-d_i)^2(d_o+d_i)}\right]^b\frac{l}{(d_o-d_i}\,10^{-5}$$

where

τ: Mud yield point [N/m^2]

θ_{300}: Mud viscometer reading at 300 o/min

θ_{600}: Mud viscometer reading at 600 o/min

a: Auxiliary variable

b: Auxiliary variable

For $\theta_{300}=40$, $\theta_{600}=65$, $q=1$ m^3/min, $l=1000$ m, $d_o=0{\cdot}1$ m, $d_i=0$, the formula give $b=0{\cdot}7$, $a=0{\cdot}97$ and $\Delta p=5{\cdot}1$ bar.

Pipe and annular tube friction pressure losses

The problem is to determine if the flow is turbulent or laminar. One way is to use the largest value from the two pressure loss formulae. In WELLSIM, however, we assume turbulent flow inside the pipe and the choke line. In the annulus the flow is assumed to be laminar.

The flow rate in the pipe is always set equal to the pumping rate. In the annulus the flow rate for the purpose of calculating pressure losses, is set equal to

$$q=q_0-21{\cdot}2[d_o^{\,2}+1{\cdot}22\,d_i^{\,2}]v_p$$

where

v_p: Pipe velocity [m/s]. Input from control panel. Positive for pipe going out of hole.

q_0: Pump delivery rate [m^3/min]. Input from control panel.

q: Flow rate to calculate friction pressure loss for each section in the annulus [m^3/min]. Positive for upward flow.

Running the drill pipe into the hole, the flow will increase and so will the down hole pressures (surging). This can lead to lost circulation. Pulling pipe, the flow and the downhole pressures will decrease (swabbing). The consequence can be inflow from a high pressure zone. Usually the pump delivery rate is zero during tripping operations. In WELLSIM there is then no flow through the drill bit, neither when pulling pipe nor when running it back into the hole.

Pressure loss in an orifice

For flow through an orifice, the formula is also taken from Moore (1974).

$$\Delta p = 0{\cdot}5 \cdot 10^{-5} \cdot \rho \cdot [q/60)/(0{\cdot}95 \cdot A)]^2$$

where

A: Area of orifice opening $[m^2]$

This formula is applied for the pressure loss in the drill bit orifices and for the choke pressure loss.

Flow from the formations into the well (*Matthews and Russell* 1967)

The gas flow from a high pressure zone into the well is given by the following equation

$$\dot{e}_G = \int 6{\cdot}10^{-5} \cdot k_F \cdot p_M \cdot \Delta p_2(h)\, dh$$

where

e_G: Amount of gas in the well [bar · m³] = [10^5 joule]

$\dot{e}_G$: Rate of change of e_G [bar · m³/min]

k_F: Formation permeability [mD], 1–100

p_M: Well pressure at the top of the high pressure zone [bar]

$\Delta p_2(h)$: Pressure difference between high pressure zone and well pressure [bar]

h: Height variable for interface between high pressure zone and well [m]

The pressure difference is integrated over the height where the pressure in the high pressure zone is higher than the well pressure. Where the well pressure is the highest, no gas or mud flows from the well into the high pressure zone.

Flow from the well into the formations

The critical point to loose mud to the formations is at the casing shoe. In WELLSIM loss always takes place at this point. The mud loss equation is

$$q_L = 0{\cdot}06\,(p_s - 0{\cdot}9 p_F), \quad q_L \geqslant 0$$

where

q_L: Loss flow rate [m³/min]

p_s: Well pressure at casing shoe [bar]

p_F: Formation fracture pressure at casing shoe [bar]

Loss will occur the first time $p_s > p_F$ is valid. The formation at the casing shoe will then be permanently weakened to 90% of its previous value. Loss will then take place as long as $p_s > 0{\cdot}9\, p_F$ is true.

Passing the casing shoe, gas will also leak to the formations for a sufficiently high pressure. The gas loss equation is

$$\dot{e}_G = -0{\cdot}06 \cdot p_s(p_s - 0{\cdot}9\, p_F), \quad \dot{e}_G \leqslant 0$$

This means that the amount of gas in the well is reduced.

Gas behaviour

For modeling convenience gas in the well is present in the form of a gas bubble. The bubble moves with the mud and with its own velocity relative to the mud. This migration velocity is set to 100 m/hour. When gas flows from a high pressure zone into the well, it is placed in the gas bubble independent of the bubble position. The gas equation being used is

$$p_G \cdot V_G = e_G$$

where

p_G: Gas pressure [bar]

V_G: Gas volume [m^3]

This means ideal gas and no temperature dependence. When the gas flows through the choke, the following equation is used

$$\dot{e}_G = -14200 \cdot A_c \cdot p_G$$

where

A_c: Choke opening [m^2]. Input from control panel.

The amount of gas in the gas bubble is reduced proportional to the gas pressure.

Total system

In WELLSIM the flow pressure calculations are taking place in real time under the influence of control panel manipulations. There are also limitations on the computer capacity. Solving the equations, the emphasis is on stable algorithms and robustness.

Roughly the equation for flow through a pipe reads

$$L\dot{q} + Rq^2 + f(q) = p, \quad q(0) = Q \tag{1}$$

The pressure loss is due to inertia, to orifices and to pipe friction. Inertia forces are not very important in drilling. Consequently the inertia term is disregarded. The equation to be solved is then

$$Rq^2 + f(q) = p \tag{2}$$

This equation gives the stationary flow solution. For given flow q, the pressure p is easily calculated. On the other hand, to solve eqn. (2) for flow has to be done by iteration. Annular friction pressure losses are small. To determine annular flows, these losses are, therefore, disregarded. The equation to be solved is then

$$Rq^2 = p \tag{3}$$

Having determined q, the corresponding pressure is calculated from eqn. (2).

In WELLSIM the pump is assumed to be completely stiff. The pipe flow is always set equal to the pump delivery rate. This means the pipe flow will be given and the pipe pressure loss is calculated from eqn. (2). For normal mud circulation the annular flow will also be equal to the pumping rate, and the pressure loss will be determined from eqn. (2). In the presence of loss at the casing shoe or in a kick situation, the annular flow will not be determined by a stiff pump. Equation (3) is then used to calculate the flows. At last the pressures are adjusted according to eqn. (2).

4. Pressure control in drilling

Figure 6 illustrates a pressure control problem in drilling.

A gas kick is being circulated out of the well. Using the backpressure choke, the problem is to keep the well pressure between the indicated limits. The lower limit to prevent inflow of more gas. The higher limit to avoid well damage resulting in serious loss conditions. The worst case is underground blowout with gas entering the wellbore and finding its own way outside the well from the casing shoe to the surface.

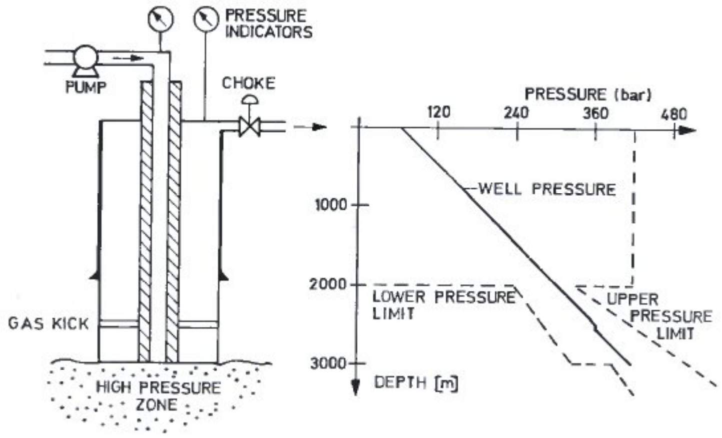

Figure 6. Drilling well with a gas kick being circulated out.

Circulating out the kick is a feedback control problem. The pump is running at a constant speed, and the well pressure is controlled by manipulating the choke opening. There is no measurement of downhole pressures. Observing the pressure at the pump and the choke, the downhole pressures have to be calculated. The normal practice is to adjust the choke to keep the pump pressure equal to a predetermined set point. The set point is usually determined to keep the well pressure at the high pressure zone at a sufficiently high value. This constant value must be checked against the requirements of the upper well pressure limit.

The gas out of the well, heavy mud is pumped into it. The backpressure is gradually reduced to zero. The heavy mud then completely fills the well and balance the pressure of the high pressure zone. The new trend is to pump heavy mud at the same time as the gas is circulated out.

4.1. *Perfect choke operation*

For the problem under consideration, the high pressure zone is situated at the bottom of the well. Assuming a constant bottom hole pressure, the flows and pressures of the well can be calculated. Disregarding annular friction pressure losses and gas migration, the equations are from Chapter 2:

Gas below surface:

$$p_G = p_B - \rho g(q_0 \cdot t/A) \cdot 10^{-5}$$

$$h_G = e_G/(p_G \cdot A)$$

$$q_c = q_0 + \dot{h}_G \cdot A = q_0[1 + \rho g h_G \cdot 10^{-5}/p_G]$$

$$p_c = p_B - \rho g(H_w - h_G) \cdot 10^{-5}$$

$$A_c = [q_c/(0{\cdot}95 \cdot 60)][p_c/(0{\cdot}5 \cdot 10^{-5} \cdot \rho)]^{-0{\cdot}5}$$

Gas flowing to the atmosphere:

$$p_G = p_B - \rho g(q_0 \cdot t/A) \cdot 10^{-5}$$

$$h_G = H_w - q_0 \cdot t/A$$

$$\dot{e}_G = \dot{p}_G \cdot h_G \cdot A + p_G \cdot \dot{h}_G \cdot A = -q_0 \cdot p_G[1 + \rho g h_G \cdot 10^{-5}/p_G]$$

$$A_c = [q_0/14200][1 + \rho g h_G \cdot 10^{-5}/p_G]$$

List of variables:

- e_G: Amount of gas in the well [bar · m³]
- p_G: Gas pressure [bar]
- h_G: Gas height [m]
- q_C: Mud flow through choke [m³/min]
- p_c: Choke pressure [bar]
- A_c: Choke opening [m²]
- p_B: Bottom hole pressure [bar]
- t: Time [min]

List of parameters:

- ρ: Mud density, 1200 kg/m³
- g: 9·81 m/s²
- q_0: Pump rate, 1 m³/min
- A: Area of well annulus, 0·025 m²
- H_w: Well depth, 3000 m
- H_s: Casing depth, 2000 m

The equations are simulated using SIM (Opdal 1977), as shown in Fig. 7. The simulations are for two different bottom hole pressures, 400 bar and 440 bar. The greater choke opening corresponds to the smallest pressures and the highest gas column.

Keeping the bottom hole pressure at 440 bar, the maximum casing shoe pressure is close to its limit 334 bar. For a bottom hole pressure of 400 bar, however, the margin for the well pressure at the casing shoe is 44 bar. At the well bottom there is a margin of 17 bar to the 383 bar of the high pressure zone. The maximum surface pressure at the choke will be 87 bar. The gas column expands from 70 m to 320 m. The operation takes 75 min. We note the need to decrease the choke opening when the gas arrives at the surface.

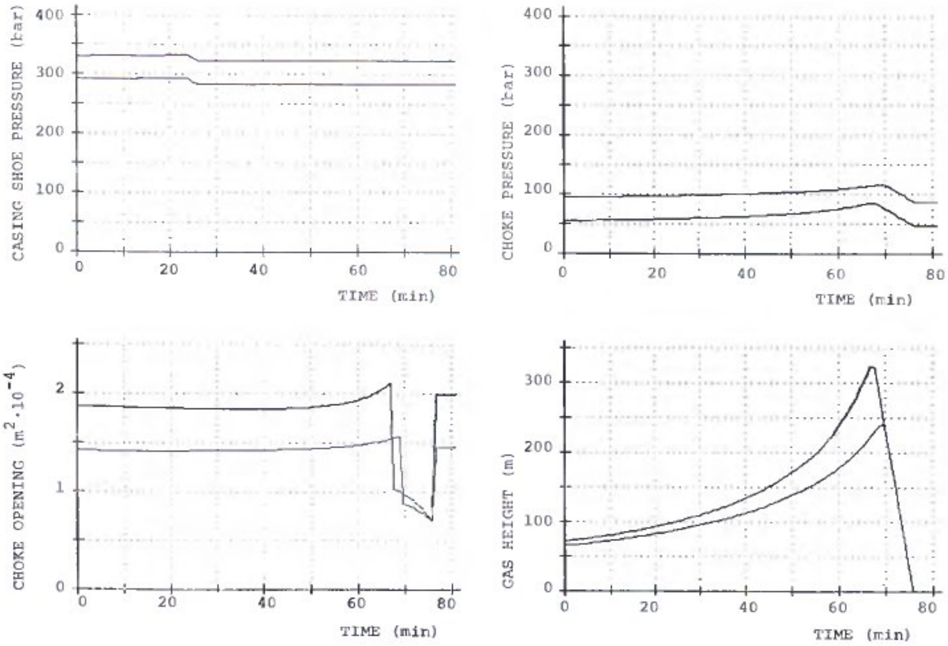

Figure 7. Circulating out the gas kick keeping a constant bottom hole pressure. Simulations for 400 and 440 bar.

Calculating the annular pressure loss, we find 6·7 bar, based on $\theta_{300}=40$, $\theta_{600}=65$, $d_o=0{\cdot}2125$ and $d_i=0{\cdot}1125$. This gives slight adjustments of the calculated pressures. Disregarding the annular pressure loss is just one of many simplifications, however.

Circulating out a gas kick, it is not possible to keep the bottom hole pressure truly constant. The value of the present calculations is to predict the maximum pressures which will occur at the casing shoe and at the surface. For the purpose of this paper, the calculations illustrate an application of the equations constituting the WELLSIM numeric model.

4.2. *Constant choke opening*

The calculations of the previous section is not a numeric model for the drilling well. A restricted version of the model used in WELLSIM will be:

Gas below surface:

$$p_G=e_G/(h_G \cdot A)$$

$$p_c=p_G-\rho g(H_w-q_0 \cdot t/A-h_G) \cdot 10^{-5}$$

$$q_c=[60 \cdot 0{\cdot}95 \cdot A_c][p_c/(0{\cdot}5 \cdot 10^{-5} \cdot \rho)]^{0{\cdot}5}$$

$$\dot{h}_G=(q_c-q_0)/A$$

$$\dot{e}_G=0$$

Gas flowing to the atmosphere:

$$h_G = H_w - q_0 \cdot t/A$$

$$p_G = e_G / V_G$$

$$\dot{e}_G = -14200 \cdot A_c p_G$$

This is a dynamic model. The flows and the pressures of the well depend on the initial volume and amount of gas. They also depend on the choke opening. The purpose of this section is to observe the sensitivity of the circulation pressures to the selection of the choke opening. The opening is chosen to be constant. The following values are used

$$h_G(0) = 80 \text{ m}$$

$$e_G(0) = 775{\cdot}2 \text{ bar} \cdot \text{m}^3$$

$$A_c = 1{\cdot}4 \cdot 10^{-4} \text{ m}^2 = 1{\cdot}4 \text{ cm}^2$$

The present model is valid only when the well pressure stays between the inflow and the casing shoe loss limits. These limits exceeded it has to be extended.

The model is simulated using SIM, as shown in Fig. 8. Both the casing shoe pressure limit of 334 bar and the high pressure zone limit of 383 bar are touched leading to well damage and more inflow with the possible result of underground blowout. In real life, to prevent well damage at the casing shoe, the maximum allowable choke pressure is found by a leak off test. The choke is opened to not exceed this pressure. Decreasing the backpressure, it is better to have more gas enter the well than well damage.

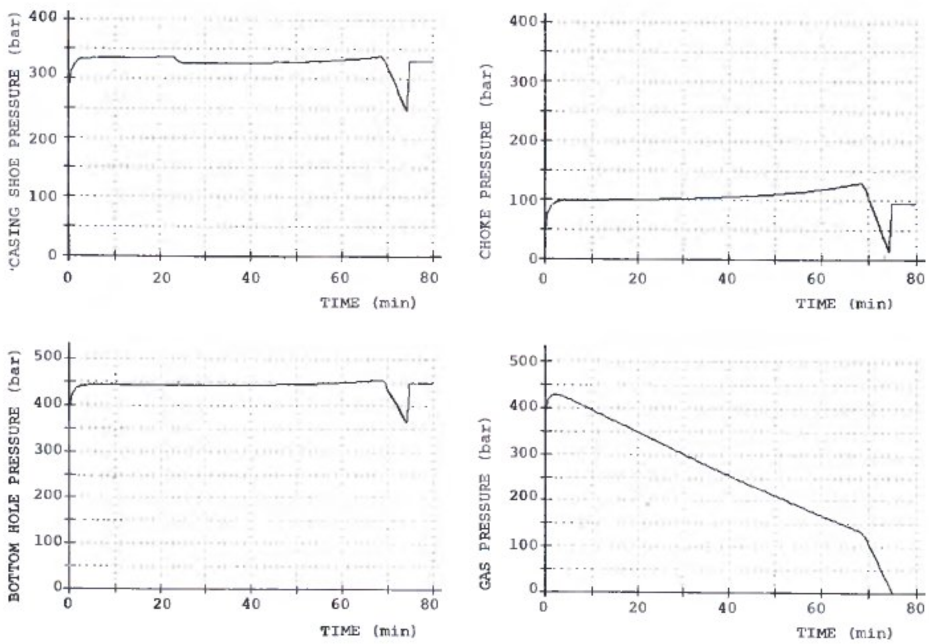

Figure 8. Circulating out the gas kick keeping a constant choke opening.

When the gas arrives at the surface, the choke opening must be decreased to prevent reduction in the well pressures. Holding the choke opening constant, the pressure reduction is seen to be 80 bar in 6 min.

4.3. *Manual choke operation*

The pressure control problem under consideration is simulated on WELLSIM. To give a bottom hole pressure of 400 bar, the pump pressure has to be 173 bar at kill rate 1 m^3/min. During circulation the choke opening is adjusted manually to try to keep the pump pressure at 173 bar. After the simulation run, the various well variables can be displayed.

Figure 9 shows the bottom hole pressure and the casing shoe pressure. Circulation starts at 4 min. During circulation the bottom hole pressure stays above the 383 bar inflow limit. The casing shoe pressure has good margin to the 334 lost circulation limit.

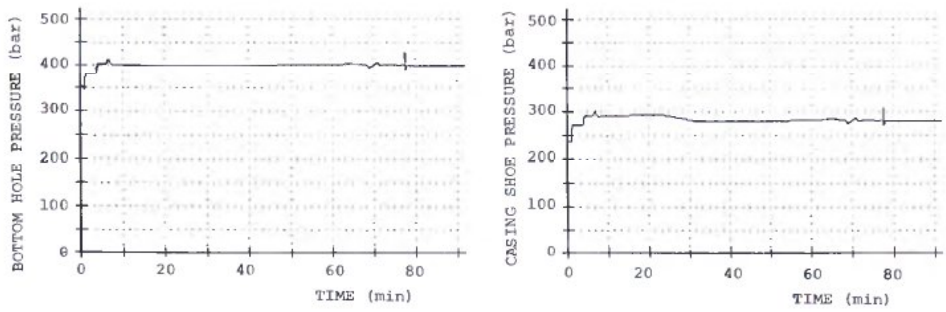

Figure 9. Circulating out the gas kick by manual choke operation. Simulation on WELLSIM.

From 8 min to 60 min, the WELLSIM automatic choke was applied and the time scale increased. This to dispose of the more uninteresting part of the kill operation. The critical parts are to start the kill flow and also when the gas arrives at the surface.

Figure 10 shows the starting of the circulation operation. To stop a kicking well, the first thing to do is to shut it in. Gas entering the well, the well pressure will increase until it balances the gas reservoir. Shut in pressures can be observed at the pump and the choke side of the well. These pressures tell the pressure of the gas reservoir and also if the inflow is gas or not. Opening the choke, the well pressure will now decrease. Starting the pump, it will increase. The trick is to do both keeping the well pressure constant. Before the pump has reached kill rate, the choke pressure gives the best indication of the well pressures.

After 68 min, the gas arrives at the surface. The choke opening has to be reduced to keep the pump pressure at 173 bar. Due to the gas compressibility this is not a simple task. As seen from Fig. 11, the deviations are quite acceptable, however. The gas flows to the atmosphere for 10 min. Then again mud passes through the choke. The well pressures increase until the choke opening has been adjusted to the new situation.

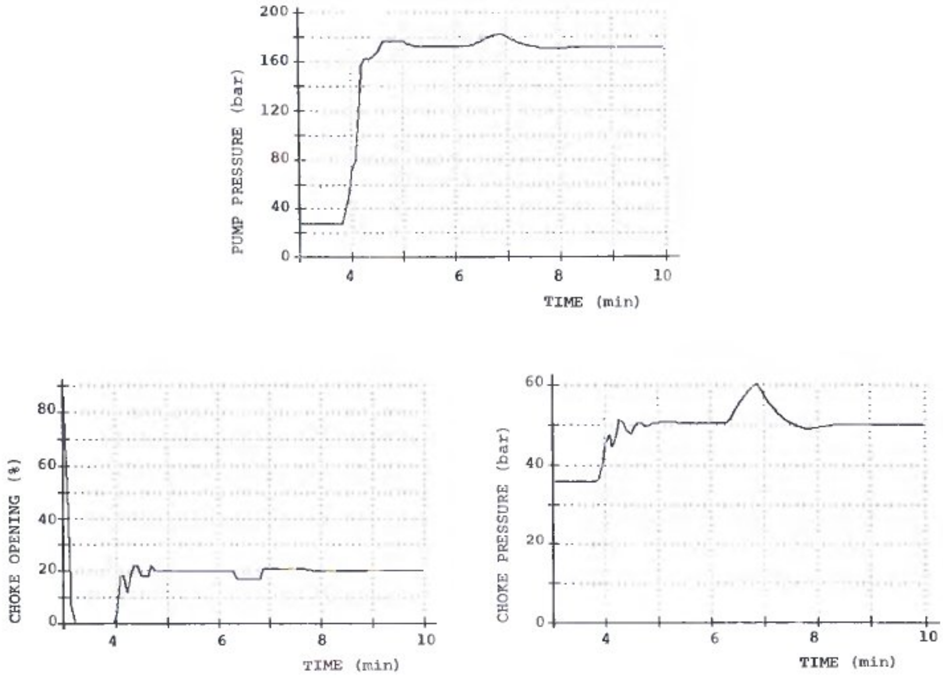

Figure 10. Circulating out the gas kick simulated on WELLSIM. Starting the pump and opening the shut in well.

4.4. *Automatic choke operation*

Automatic feedback control of the choke has been implemented in WELLSIM. The equation for the choke is

$$\dot{A}_c = (A_o/T_c)\beta \cdot u, \quad 0 \leqslant A_c \leqslant A_o$$

where

- A_c: Choke opening $(m^2]$
- A_o: Full choke opening $[m^2]$. Typical value is $25 \cdot 10^{-4}$ m^2
- T_c: Minimum time to fully open or close the choke. 10 sec.
- β: Choke rate input from the choke control panel $0 \leqslant \beta \leqslant 1$
- u: Control signal. For manual operation u is selected on the choke control panel; $u \in [-1, 0, 1]$. In any case $|u| \leqslant 1$.

The automatic feedback controller is given by the following transfer function

$$u = u_1, \quad u \leqslant 1$$

$$u_1 = \frac{1 + 10s}{100(1+s)}(p_B - p_{\mathrm{REF}})$$

where

- u_1: PD control signal
- p_B: Well pressure at high pressure zone [bar]
- p_{REF}: Wanted well pressure [bar]

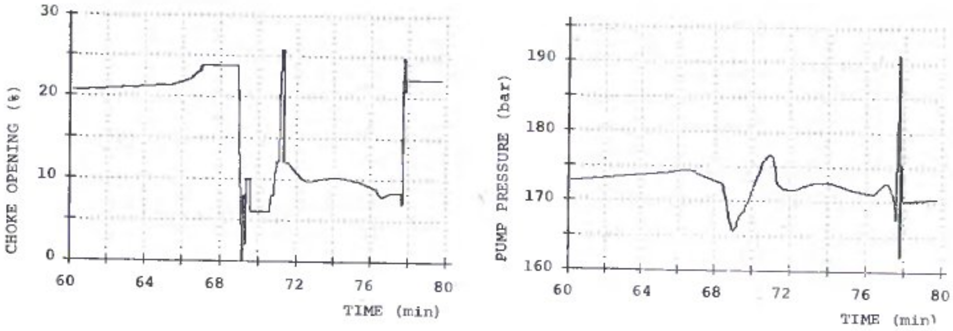

Figure 11. Circulating out the gas kick simulated on WELLSIM. Flowing the gas to the atmosphere.

This means the down hole pressure is measured and then used to control the choke opening. In WELLSIM this is possible. For a practical well, the down hole pressure would have to be calculated as accurately as possible. This is a problem of estimation.

As seen in the previous section, the automatic choke can be used to speed up the duller parts of a kick simulation. As a second illustration, the standard problem of this chapter is used. The only difference is the well is being drilled offshore at a water depth of 500 m. A 0·075 m diameter choke line of 500 m lead from the sea bottom wellhead to the choke which is situated on the drilling platform. Figure 12 shows how the automatic feedback loop adjusts the choke opening when the gas kick arrives at the surface.

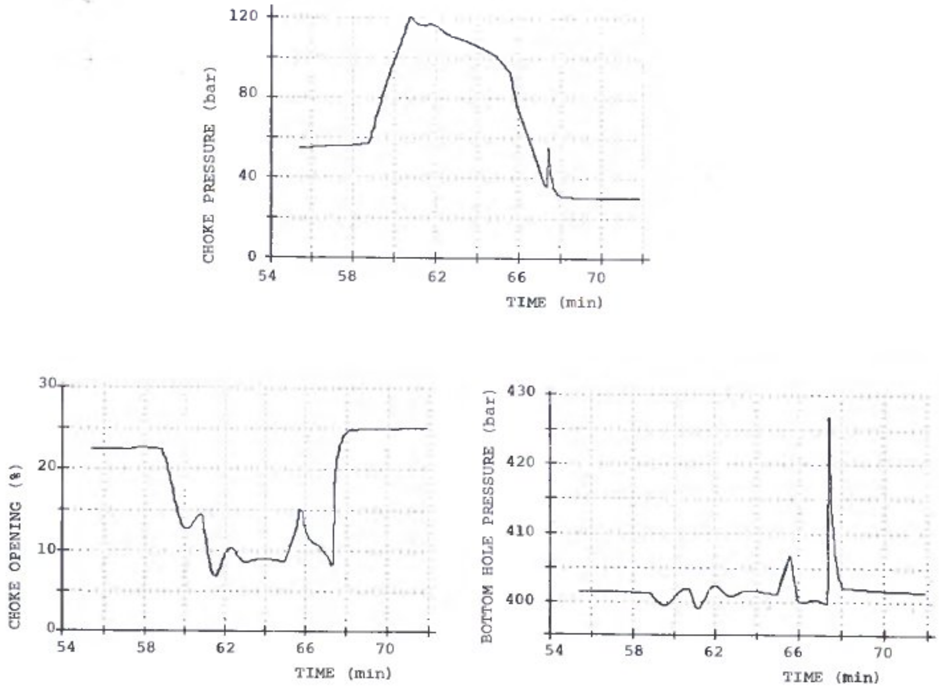

Figure 12. Flowing a gas kick to the atmosphere. Automatic choke control implementation simulated on WELLSIM.

When the gas arrives at the sea floor after 59 min, it enters the smaller cross area of the choke line. This means that the total gas height increases more rapidly. In two minutes the gas entirely fills the choke line. The hydrostatic well pressure decreases with approximately 50 bar. As seen from the figure, this is compensated for by the choke opening decreasing, which forces up the choke pressure. When the choke line is filled, the gas arrives at the surface. The choke is then closed even more. After 65 min the last of the gas enters the choke line and the well mud level increases faster in the smaller cross area. The choke opens letting out more gas to compensate for this. After 66 min too much gas has been let out, and the pressure drops. The choke closes. The pressure peaks at 67·5 min show when the mud level reaches the choke and all the gas has been circulated out. The choke then opens to bring down the pressure peak.

The automatic feedback pressure control loop is slightly oscillatory. The faster it is made, the more oscillatory it will be. For the simulated case, the loop is fully satisfactory. The pressures stay with good margins away from their tolerable limits. The critical point is when the last of the gas leaves the well and mud again flows through the choke. In fact to keep the choke pressure down, the choke then has to be opened in advance. In real life there is not such a sudden transition from gas to mud and the problem of adjusting the choke will be smaller.

4.5. *Estimation of down hole pressures*

As an optional part of WELLSIM, there is a colour graphic display. One of several pictures allows an operator to 'look down into the well', see Fig. 5. The left part of the picture shows the well geometry including position of drill string and kicks if present. The right part shows the well pressure as function of depth and also displays the pressure limits.

Circulating out a kick is a perfect manual feedback control situation. The operator adjusts the choke looking at the display to keep the well pressure profile between the pressure limits. Closing the choke, the well pressure profile moves to the right. Opening the choke, it moves to the left.

To use the above scheme for a practical drilling process, it is necessary with an on-line computer, algorithms to estimate down hole pressures and a graphic display connected to the computer. Even to have available an on-line estimate of the bottom hole pressure would be a great help in kick situations. The pump pressure should change when pumping heavy mud into the well. The pump pressure should also change if varying the circulation rate. Instead of tracking a varying pump pressure by choke adjustments, the bottom hole pressure estimate should be kept constant.

5. Conclusion

This paper has described the numeric model used in WELLSIM. The model has been applied to a pressure control problem. At the moment a Norwegian company produces a version of WELLSIM with modified control panels. The modified version is going to be installed in colleges in Stavanger and Tønsberg. There it will be tested against the requirements of training and education.

Acknowledgement

WELLSIM is the result of a joint effort between the Automatic Control and Petroleum Engineering divisions of SINTEF. The work has been carried out by

Vegard Stuan, Karl Tokle and the author. The simulator panels were assembled by Per-Inge Løvold and Gunnar Meland. The project has been sponsored by the Petroleum Directorate, the Ministry of Education, the Council for Scientific and Industrial Research, SEAGULL A/S and internal funds of SINTEF.

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