STABILIZATION OF GAS LIFTED WELLS

Gisle Otto Eikrem * **Bjarne Foss** * **Lars Imsland** *
Bin Hu ** **Michael Golan** **

* *Department of Engineering Cybernetics, NTNU, Trondheim, e-mail: (gisle.otto.eikrem bjarne.foss lars.imsland)@itk.ntnu.no*
** *Department of Petroleum Engineering and Applied Geophysics, NTNU, Trondheim, e-mail: (hubin mgolan)@ipt.ntnu.no*

Abstract: Increased production from gas lifted oil wells can be achieved by use of feedback control. Without control the well system may have large oscillations in the flow rate or stabilize itself at a non-optimal production point. These non-optimal production conditions give lower production and/or poor oil/water downstream separation. The study extends the newly introduced approach for controlling gas lifted one-well systems to gas lifted two-well systems. Different control structures are considered and their performance are studied using simulations of a two-well system. The simulation results show that the different control structures do not have the same ability to stabilize the system at low downhole pressures. The structure which stabilizes the system at the lowest downhole pressure requires pressure measurement downhole in the well.

Keywords: Process Control, Oil Production, Multiphase Flow, Gas Lifted Wells

1. INTRODUCTION

Hydrocarbons are produced from wells that penetrate geological formations rich on oil and gas. The wells are perforated in the oil and gas bearing zones. The hydrocarbons can flow to the surface provided the reservoir pressure is high enough to overcome the back pressure from the flowing fluid column in the well and the surface facilities. Detailed information on wells and well completion can be found in Golan and Whitson (1991).

Gaslift is a technology to produce from wells with low reservoir pressure by reducing the hydrostatic pressure. This is done by injecting gas into the tubing close to the bottom of the well, see figure 2. The gas is routed from the surface, into the annular conduit (annulus) between the casing and the tubing, and enters the tubing through a valve, injection orifice, at the wellbore.

Gaslift can result in highly oscillating well flow when there is a gravity dominant flow in the tubing and a large annulus volume filled with compressible gas. In this case the pressure buildup inside the tubing under no-flow conditions is faster than the pressure buildup in the annulus. If the pressure in the annulus is able to overcome the pressure in the tubing at a later point, the gas will be injected into the tubing and the oil and gas will be lifted out. After the fluid is removed from the tubing a new pressure buildup period starts. This type of oscillations is described as casing-heading instability. More information can be found in Xu and Golan (1989).

The gaslift curve shows the produced oil and gas as a function of gas injected into the well at steady state. The curve also shows in which areas the well is stable and not stable, see figure 1. The region of optimum lift gas utilization is lying in the unstable region, it is therefore necessary to apply control.

A gas lifted system may exhibit unstable flow at the desired equilibrium condition or stabilize itself at a non-optimal production point. These non-

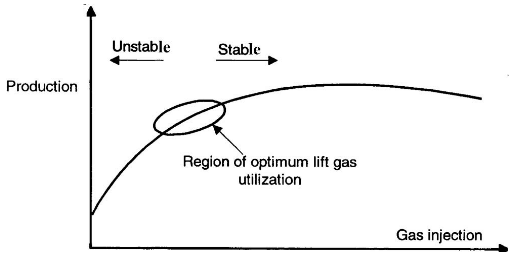

Fig. 1. The gaslift curve with the region of optimum lift gas utilization.

optimal production conditions give lower production. The focus of this paper is to study the possibility to stabilize the flow at optimal equilibria. The tool of choice is feedback control of pressure in the system.

Large oscillations in the flow rate causes poor oil/water downstream separation, limits the production capacity and causes flaring. A reduction of the oscillations will result in increased processing capacity because of the reduced need for buffer capacity in the process equipment.

Feedback control has to a limited degree been studied for single well systems. Some earlier work has been reported, (Jansen *et al.*, 1999) and (Kinderen, 1998). This study moves beyond earlier studies because it considers realistic two-well systems where one gas source supplies two gas lifted wells.

We will use the transient multiphase flow simulator OLGA (Scandpower, 2000), commonly used in the petroleum industry. This simulator has been used to study a set of realistic wells. The controllers are implemented in Matlab (The MathWorks, 2000).

A detailed well system model is prepared in OLGA, which includes the geometry of the well system, initial conditions and boundary conditions. OLGA is based on a modified two-fluid two-phase flow model. It uses semi-implicit time integration, which allow relatively long time steps. OLGA contains choke models, check valves models and valve models, the users specify the parameters and integrate them into the models as needed.

The scope of the paper is to develop and assess a control strategy for the above problem and investigate alternative solutions depending on the availability of downhole online measurements. We believe that the paper introduces a new field for process control technology with a huge potential.

2. SYSTEM DESCRIPTION

2.1 *Single well system*

The basis for this study is a realistic gas lifted well model. The parameters of this well are given as:

- Well parameters:
  - · 2048 m vertical well
  - · 5 inch tubing
  - · 2.75 inch production choke
  - · 0.5 inch injection orifice
- Reservoir parameters
  - · $P_R = 160$ bara
  - · $T_R = 108\ ^oC$
  - · PI = 2.47E-6 kg/s/Pa
- Separator inlet pressure
  - · 15 bara
- Gas injection into annulus
  - · 0.5 kg/s
  - · 120 bara

P_R : Pressure in the reservoir

T_R : Temperature in the reservoir

The productivity index, PI, is defined by:

$$PI = \frac{\dot{m}}{\Delta P} \tag{1}$$

Where $\dot{m}$ is the total mass flow rate from the reservoir to the well and ΔP is the pressure difference between the reservoir and the well. This index relates the mass flow from the reservoir and into the well to the corresponding pressure drop. The PI is assumed constant.

We assume that there is no water in the produced fluids, only oil and gas. The gas/oil ratio, GOR, is 80 Sm^3/Sm^3. GOR is defined by:

$$GOR = \frac{\dot{q}_{gas}}{\dot{q}_{oil}} \tag{2}$$

The gas-oil-ratio, GOR, is defined as the ratio between the volumetric gas rate and the volumetric oil rate at standard temperature and pressure.

2.2 *Two well system*

The two-well system is shown in figure 2. Well 1 is defined above and well 2 is identical to well 1 except that it has a higher productivity index, PI = 3.00E-6 kg/s/Pa. The two wells produce the same reservoir fluid and connect to the same separator. It is assumed that the separator is located close to the wellheads.

The two wells share the same gas source. The total gas injection rate is 1.1 kg/s. This study reflects the case where there is a shortage of gas supply for gas lift operation.

2.3 *Gas allocation*

Since there is a limited gas supply, the question becomes how to use this limited lift gas to maxi-

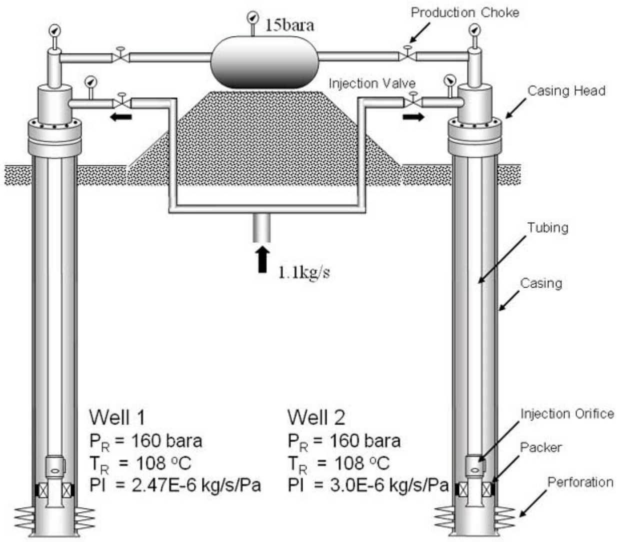

Fig. 2. Two-well system with common gassupply source.

mize the oil production. Oil has a much larger sales value than gas, hence maximizing oil production is the vital point. Steady state analysis of the system shows that total oil production is maximized if the gas injection rate equals 0.5 kg/s to well 1 and 0.6 kg/s to well 2.

2.4 *OLGA and Matlab*

The multiphase flow simulator OLGA is used for well simulation, while Matlab is used for controller development and implementation. Matlab will read the process outputs from OLGA, calculate new process inputs and return them to OLGA. The connection between OLGA and Matlab is managed by the OSI (OLGA Server Interface) toolbox for Matlab (ABB, 1998).

3. CONTROL OF SINGLE WELL SYSTEM

The measurements which are assumed available in this study are pressures at the wellhead, downhole and in the annulus, mass flow through the production chokes and the injection chokes. The pressure measurement downhole is often not reliable and hence it can be disadvantageous to make the control structure dependent on this measurement.

The process inputs which can be used to control the one-well system are the production choke and the injection choke. The single well system is defined by well 1, with a gaslift supply rate of 0.5 kg/s.

3.1 *Control structure*

Two different control strategies are used to stabilize this system. The first strategy controls the downhole pressure, DHP, by feedback control, the control structure is the same as for well 1 in figure 5. The second control strategy controls the pressure in the annulus, this control structure is the same as for well 1 in figure 7. A PID controller is used in both cases to control the pressure. The controllers are tuned using a combination of process knowledge and iterative simulations. The valve models include saturation and limitations on the valve opening/closing rate. The pressure measurements in both control strategies are low pass filtered

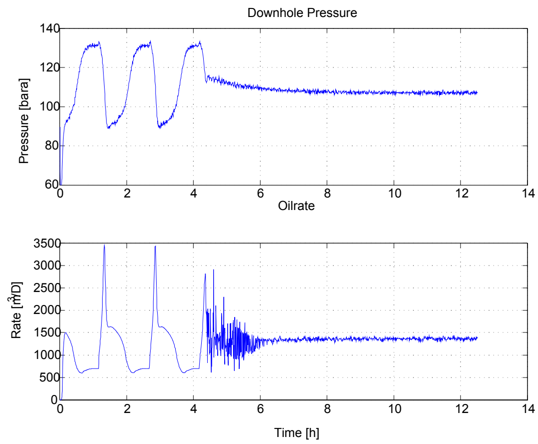

Fig. 3. Simulation results of single well system using downhole pressure as controlled variable.

3.2 *Simulation results*

The results from the simulations of the one-well system are given in figure 3 and figure 4. White noise is added to the measurements of the downhole pressure and the pressure in the annulus. The white noise has a Gaussian distribution with zero mean and unity variance multiplied by a scaling factor, the noise is approximately 0.5% of the measured value. The system was run in open loop for about 1.5 hours before the controller was activated. The simulation study shows that control stabilizes the system and increases the amount of produced oil by 10-15%. It is possible to stabilize the system at a lower downhole pressure when using the downhole pressure as measurement compared to using the pressure in the annulus. This gives an increased production of oil by about 5%. The valve movement for controlling these systems are very low, this gives low degree of wear on the actuators.

The oscillations in the open-loop part of the simulations result from the casing-heading instability.

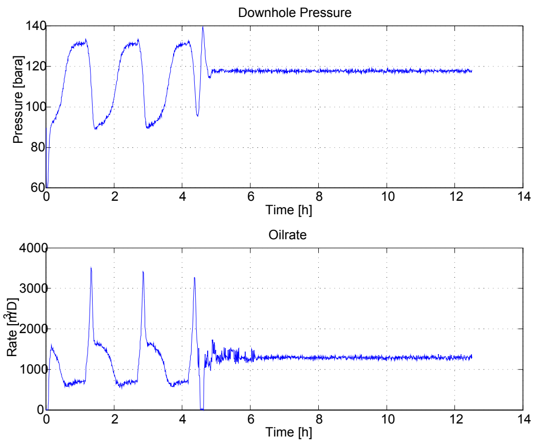

Fig. 4. Simulation results of single well system using pressure in annulus as controlled variable.

4. CONTROL OF TWO-WELL SYSTEM

4.1 *Control of downhole pressure by production chokes*

The oil flow rate from the well should be maximized, and at the same time stable to prevent downstream handling problems. A means to achieve this is to keep the downhole pressure constant at the lowest possible level. This will result in a stable inflow of gas from the annulus and a high inflow of oil from the reservoir. To be able to use this production strategy the pressure in the well has to be controlled and the liftgas distributed with an optimal ratio between the two wells. The control structure in figure 5 is proposed to achieve this.

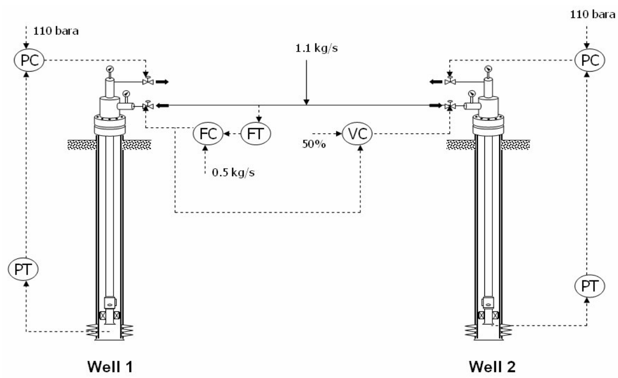

Fig. 5. Control stucture for stabilizing DHP with use of production chokes.

This control structure focuses on controlling the downhole pressure. The pressure transmitters are located downhole in the wells. A stable pressure at this location results in a continuous inflow of hydrocarbons from the reservoir.

The pressure downhole in the wells is influenced by changes in the opening of the production choke. An opening of the valve results in a reduced pressure drop over the valve and this gives a reduced back pressure for the well, and the well is hence able to increase the production. With a reduction in the opening of the production choke, the pressure drop over the valve is increased. This results in a lower mass flow out of the well because of higher back pressure.

Since the amount of liftgas is limited to 1.1 kg/s because of external reasons, this gas has to be shared between the wells in an optimal ratio. To achieve these optimal gas rates it is necessary to include a control structure on the distribution system of the gas. A constant mass rate of 1.1 kg/s is fed to the system.

The control structure used for allocation of optimal gas rates is given in figure 6. Since the inflow of gas is constant at 1.1 kg/s, it is sufficient to control the gas flow rate to one of the wells. The mass flow rate to well 1 is controlled with the use of one PID-controller. To avoid saturation of injection choke 1, a controller is connected to injection choke 2, this valve is connected to a PD controller and is adjusted until the opening of injection choke 1 is about 50%. This second control loop is significantly slower than the flow rate control loop. This is a variant of the parallel control structure as found in e.g. (Balchen and Mummé, 1988).

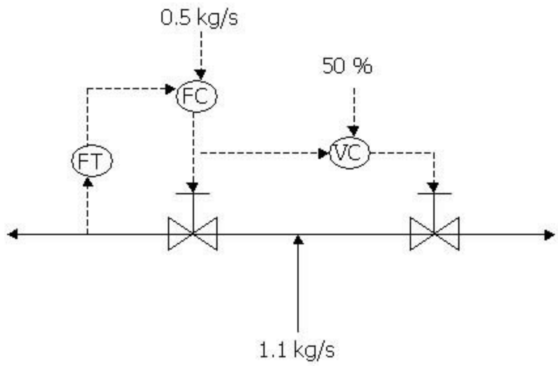

Fig. 6. Control structure for gas allocation system.

4.2 *Control of pressure in annulus by production chokes*

This strategy has the advantage of easier access to measurements. Downhole pressure measurements are more rare and generally not regarded reliable by the industry. The recommended control structure for this strategy is given in figure 7.

This control structure controls the two-well system by measuring the pressure at the top of the annulus. When the rates of injection gas to each well is constant, a constant pressure in the top of the annulus means a constant mass flow of gas out of the annulus and into the tubing. Since it can be argued that the instability is caused by compressibility of the gas in the annulus, the idea is that controlling the pressure in the annulus will stabilize the system.

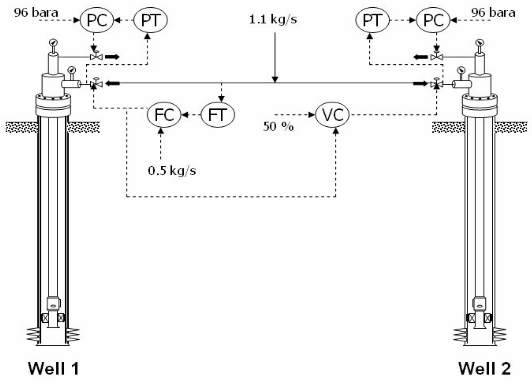

Fig. 7. Control of pressure in annulus with use of production chokes.

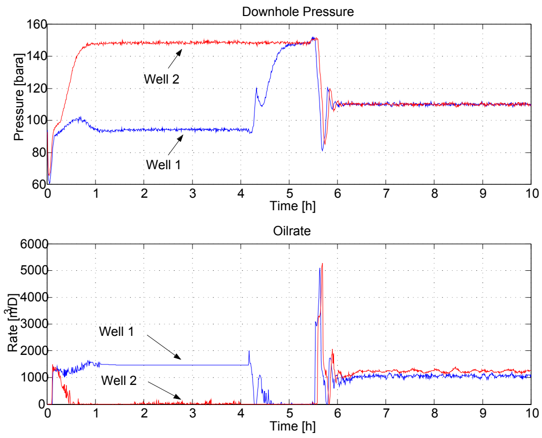

Fig. 8. Simulation results from control of downhole pressure in well.

4.3 *Controller development*

To control the two-well system, it was decided to use conventional PID controllers to control the downhole pressure and the pressure in the annulus. The pressure measurements are low pass filtered. The controllers have again been tuned in an iterative way, and the valve models includes saturation and limitations on the valve opening/closing rate.

5. TWO-WELL SIMULATION STUDY

5.1 *Simulations and measurements*

The simulations run in open-loop for 4 hours. The initial values equal steady-state conditions. The sampling time for the controllers is 30 seconds.

5.2 *Results from control of downhole pressure*

The results from the simulations with the control structure in figure 5 are given in figure8.

The results from the open-loop simulations show that the downhole pressure in well 1 is stabilized at 94 bara while well 2 is stabilized at 148 bara. This is because all the injection gas is routed to well 1.

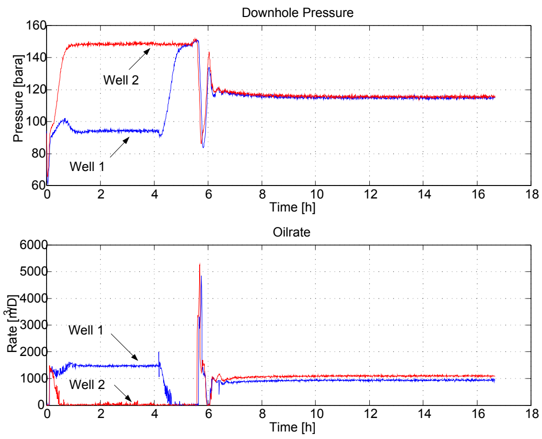

Fig. 9. Simulation results from control of pressure in top of annulus.

The gas flows to the well with the lowest pressure, which is well 1, because this well has the lowest productivity index, PI. The productivity index is the only difference between the two wells. The well with the highest PI therefore gets the highest liquid level in the tubing and thereby the highest hydrostatic pressure. Well 2 dies because of lack of liftgas, while well 1 produces at a relatively high rate because of the low downhole pressure. This shows the need for a control structure for the allocation of injection gas. Note that the gaslift flow rate to well 1 is 1.1 kg/s in open-loop, as opposed to 0.5 kg/s in section 3. This is why well 1 exhibits stable flow condition in open-loop.

After the control loops have been closed, it takes almost 2 hours until the system is stabilized at the desired setpoints. This is roughly the time it is takes to build up the pressure in the annulus. There is a significant increase in production of oil from the two wells when the injection of gas is allocated between the two wells in an optimal ratio. The production is almost doubled, see figure 8.

5.3 *Results from control of pressure in annulus*

The results from the simulations using the pressure in the annulus as the controlled variable, see figure 7, show that this control structure also is able to stabilize the two-well system, see figure 9. The setpoint for the pressure in the annulus is reduced as much as possible. With this control structure, the lowest DHP is 115 bara, as opposed to 110 bara in section 5.2.

6. DISCUSSION

6.1 *Control of two-well system*

Increased use of liftgas made it possible to stabilize the two-well system at a lower downhole pressure.

This is because the increased rate of gas in the tubing results in a lower hydrostatic pressure in the well.

The most important control design decision is the choice of control structure. The study shows that a decentralized structure stabilizes the well system. Tuning of the four controllers did not prove to difficult. In particular it was not necessary to resort to nonlinear control by for instance gain scheduling. Linear controllers could handle the operating range in question.

Both control structures save good performance. The study shows however a clear compromise between the inclusion of downhole measurements and the reduction of downhole pressure and thereby increased oil production. In this case a 5 bar reduction in downhole pressure increases oil production per year with 86 000 Sm^3 corresponding to 15 million euro with present oil prices.

Further work will evaluate the use of a model-based estimator to compute the downhole pressure instead of placing a sensor downhole and study more complex well systems.

7. CONCLUSION

This paper shows how control can improve the performance of gas lifted wells by stabilizing the well flow. The choice of control structure is critical. Finally, the study indicates that there is potential benefit, in the sense that oil production increases, by placing pressure sensors downhole.

8. ACKNOWLEDGEMENT

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