Available online at www.sciencedirect.com

ScienceDirect

IFAC-PapersOnLine 49-7 (2016) 296–301

Robust Automatic Well Choke Control – Physical Constraint Based Operation

Pål Kittilsen, Kjetil Fjalestad, Ingvild Løvik Sperle, Robert Aasheim

Statoil Research and Technology, Statoil ASA, Norway (e-mail: {pkit,kfja,inlo,robaas}@statoil.com)

Abstract: Process fluctuations are often equivalent to lost production as the necessary margins to process constraints need to take into account the fluctuations. Better operation is achieved by reduced process fluctuations enabling operation closer to the constraints (reducing the backoff) thus the average production increases. For oil wells, this transition is typically achieved with automatic choke control.

Both oil and gas production wells and injection wells benefit from automatic choke control. The natural variations of the underlying process require frequent adjustments of the well chokes in order to keep key parameters at their optimal values. If not operating the choke at fully open position, it is normally beneficial to replace manual operation with automatic choke control. This approach enables operation close to active well constraints. In addition, automatic actions can be taken to avoid safety issues.

This paper gives practical examples of the benefits obtained by applying automatic choke control to gas coning wells and water injectors. Exchanging manual infrequent choke manipulations with continuous operations close to the true, physical constraints, enable safe and optimal production.

Keywords: automatic control; estimation; robust; constraints; industrial control

1. INTRODUCTION

In the operation of oil and gas fields, both production wells and injection wells benefit from automatic choke control. The natural process variations require operational adjustments to keep key parameters at their optimal values. Process constraints usually imply production loss due to fluctuations and the need for operational margins to the constraints. Increased production is achieved by stabilizing the process by automatic control and moving the average closer to constraints as illustrated in Fig. 1.

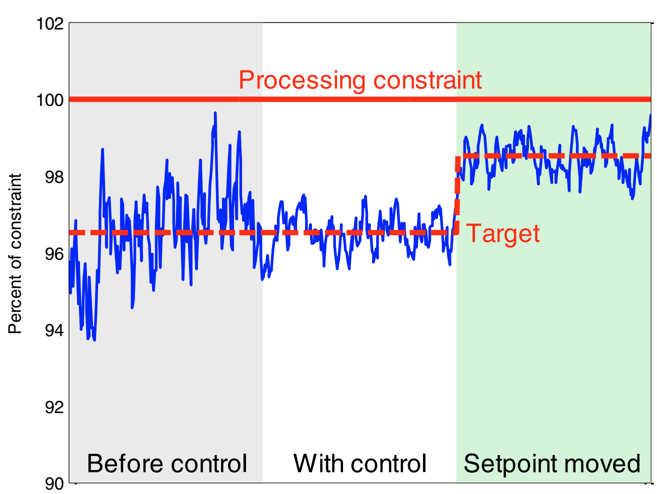

Fig. 1. Automatic control reduces process fluctuations and enables increasing the average closer to constraint.

If the choke is not operated fully open , it is normally beneficial with automatic choke control. Shifting from manual choke position control to automatic, physical based control is moving operation from an infrequent updated, choke position concentrated operation, to continuously, physical based constrained operation.

There are several examples of how active well control improves operation. Eikrem et al. (2008) did a combined modelling and practical work on stabilizing gas-lifted wells. Automatic well choke control was successfully applied to enable operation in regions where manual, fixed choke position operation would require extensive use of gas lift and consequently suboptimal operation.

Many authors have focused on process optimization using automatic control. Gustavsen and Tøndel (2009) showed several ways to optimize production in an offshore plant using single well automatic control and more sophisticated solutions with model predictive control manipulating several wells simultaneously. Single automatic control loops are in the lower level of the control hierarchy, but are nevertheless essential to implement optimization solutions on higher levels.

Hasan et al. (2013) showed an approach on automatic well control applied to gas coning wells with significantly improved production profit compared to conventional operation. They applied a model and an observer to obtain the optimal production rate trajectory and keep the well production at this trajectory. This is an example on how automatic control also can be used to keep production at optimized operation conditions.

Automatic control relies on robust measurements of the controlled variables and a control strategy suitable for a wide range of conditions (Fjalestad, 2013; Kittilsen 2014). Robustness in this context means correct and available (signals not dropping out) values for control. The current paper shows practical examples of how estimators are used to obtain robust measures of key parameters used in stabilizing and controlling gas coning production wells and water injection wells.

10.1016/j.ifacol.2016.07.308

2. STABLIZING GAS CONING WELLS

In the current application, the objective was to improve process operation by stabilizing gas coning wells. These wells are producing a combination of liquid (oil/water) and free gas, and often the gas-oil-ratio (GOR) is rate dependent. When mature, such wells often show a relatively small increase in oil rate with an increase in gas rate. This makes it profitable to operate with just enough gas to lift out the oil (Aasheim and Alstad 2008; Mjaavatten et al. 2008).

An increasing well stream GOR gives a lower liquid hold-up in the well, which in turn means less static pressure drop across the well. The wellhead pressure eventually increases. Normally, the pressure downstream the well head choke is controlled, and thus the pressure drop across the choke increases. This results in a higher gas rate that makes the well stream GOR increase. In total there is an unstable well-reservoir system. Production trends from manual operation of a gas coning well are shown in the left part of Fig. 6. The gas and oil rates drift over time.

To operate a gas coning well exploiting the lift of free gas, it is necessary to operate with a certain excess of free gas. More free gas means less influence from gas rate variations. However, this is at the cost of more gas produced per barrel of oil. Artificial gas lift means to force a given gas rate into the well, and is by nature more stable than operation with free gas. This is at the cost of compression and recirculation of gas, and also reduces the oil production when producing at subcritical rates.

An alternative philosophy is automatic gas rate control manipulating the wellhead choke. This will stabilize the produced gas flow rate, and enable operation close to the critical gas rate that is needed. This in turn improves utilization of the plant's gas processing capacity thus increasing oil production. In addition, the operator workload is reduced.

The idea of stabilizing gas coning wells by controlling the gas rate was used by Aasheim and Alstad (2008). They applied robust and simple methods for gas rate estimation. Based on practical experience, the model has now been extended to cover a wider operational range. The original control strategy was also more relaxed than the strategy presented in this work.

2.1 Gas rate estimate

The gas coning well flow is a multiphase flow of water, oil and gas. It is challenging to accurately and robustly measure or estimate the flow of each phase. However, for automatic control with the main purpose of stabilization, robustness is more important than accuracy. This can be utilized to simplify and enable a solution.

The gas flow rate estimate is based on a combination of two main contributions, assuming this is sufficient:

1. The mass fraction of gas in the well flow, and
2. The total well flow

The two parts are outlined below. This work is based on the following assumptions:

- The frictional pressure drop in the well is neglected
- The gas flashing is neglected
- The liquid density is constant along the well
- The gas density is calculated with the mean pressure of the bottomhole and the wellhead, and assumed constant throughout the well
- The slip factor (ratio of gas and liquid velocities) is constant (tuning factor).

2.1.1 Estimation of gas fraction

The gas mass fraction is estimated from the pressure drop across the well, from the bottomhole to the wellhead. It is assumed that the bottomhole pressure is measured. It could as well be assumed constant (for a high permeable reservoir) or calculated iteratively from the estimated well flow and estimated draw down.

At low rates, the frictional pressure drop is negligible compared to the static pressure drop. The total pressure drop is thus given as:

$$p_{BH} - p_{WH} \approx \Delta p_{static} = \rho_W g H. \tag{1}$$

The average well density, ρ_W, varies with the gas content in the well:

$$\frac{1}{\rho_W} = \frac{x_G^H}{\rho_G} + \frac{1 - x_G^H}{\rho_L}, \tag{2}$$

where x_G^H is the average mass fraction gas when considering fluid hold-up in the well.

The gas and liquid densities are average values for the whole well. Liquid density varies with water cut but is assumed constant for now. Gas density varies with molar mass, pressure and temperature. It is assumed that the representative pressure for density calculation equals the average of bottomhole and wellhead.

The mass fraction of gas in the flowing medium is the interesting quantity for gas rate estimation. This needs to be calculated from the hold-up based mass fraction (2). The difference between the flowing and hold-up based mass fractions is caused by gas and liquid moving with different velocities in the well. The relation between flowing and hold-up mass fractions is:

$$\frac{x_G^w}{x_L^w} = \frac{v_G}{v_L} \frac{x_G^H}{x_L^H} = \alpha \frac{x_G^H}{x_L^H}, \tag{3}$$

Where α is the slip factor defined as the gas to the liquid velocity ratio. For production wells, the gas moves faster than liquid and the slip factor is always greater than 1, typically between 1.3 and 2.0. The slip factor is considered constant and is a tuning parameter in the current application. The rate based mass fraction of gas can be expressed as a function of the hold-up based mass fraction by solving (3) for the gas phase: