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Oil production increase in unstable gas lift systems through nonlinear model predictive control

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ABSTRACT

Oil production employing gas lift techniques enable the production of no natural flow wells and supply the energy lost in the reservoir caused by the field depletion, keeping the production in brown fields feasible. The multiphase flow conditions and the long pipes used to transport the fluids from the reservoir to the surface facilities, especially in deep and ultra-deepwater cases, may create unstable flow situations. Several publications in process control have discussed this problem since the 1980s, but the potential multivariable actions on the choke valve and gas lift flow have not been explored so far. In this paper the operating oil production system is treated through a nonlinear predictive control strategy. The strategy evaluation in a rigorous model (OLGA) shows the association between predictive capability and the integrated actuation in the manipulated variables results in an oil production increase and a partial or entire suppression of the instabilities in the multiphase flow. Furthermore, the rate of acting required on the valves is lower in the multivariable approach, allowing the use of slow choke valves as a final control element.

1. Introduction

The onshore oil industry was responsible for supplying 90% of the world's crude oil in the 1970s. This number has dropped to around 70% these days, driven mainly by new discoveries in the offshore environment. The evolution of technologies in seismic has made it possible to improve exploration in saline basins and deeper waters, which reinforces the perspective of increasing the participation of the offshore industry in the world's oil supply in the next years. Notwithstanding, producing hydrocarbons in offshore conditions is more complex than in the onshore environment, which makes exploration and production more dependent on technological capacity building.

In recent years, the most relevant discoveries of new offshore carbon sources were reported in deep or ultra-deepwaters. The Brazilian pre-salt is an example of a new exploratory frontier at high depths of water. Wells installed in this area may require more than 10 km of piping to transport the reservoir fluids to the surface facilities. In deep and ultra-deepwater, pipelines typically carry the multiphase mixture containing oil, gas, water, and sediments across a series of obstacles including rocks, seabed, and ocean, which impose conditions of horizontal, vertical, and inclined flow to the fluids. One of the implications of this configuration is the appearance of instabilities in the transport flow of the multiphase mixture. Depending on the characteristics of the fluids (mass fractions of the phases, viscosity, etc.) and the flow conditions (phase velocity, flow directions, etc.), it is possible to form regions of liquid accumulation with the effect of blocking the incoming gas upstream of the liquid accumulation. This situation forces the pressure in the gas side to increase until this pressure is high enough to push the entire mass of liquid in front of it. This kind of instability is known as terrain slugging and can occur in production columns when the production column presents a horizontal part, or in the subsea flowline where it is most common due to the irregular seabed. When this phenomenon occurs in the connection between the flowline and the riser, also called low point, the instability is known as severe slugging (riser-induced slugging) due to the significant pressure amplitude resulting in the flow. The slugging is a cyclic phenomenon that results in permanent oscillations in the

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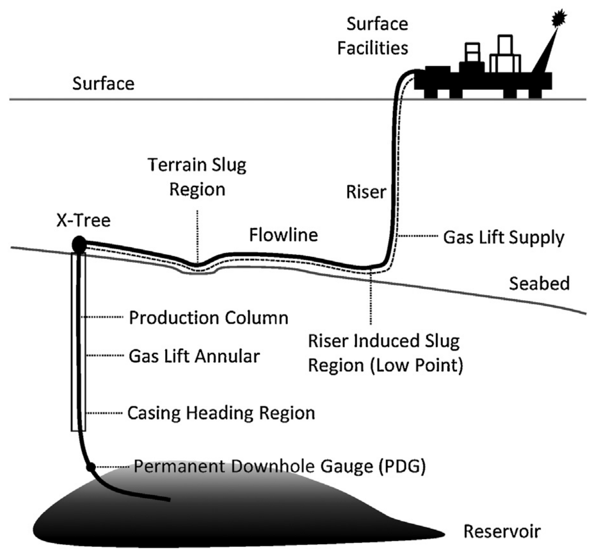

Fig. 1. Typical gas lifted well in a deepwater oil field and its main slugging flow causes.

pressures and flows in the entire production system. The schematic in Fig. 1 helps to understand the regions where instabilities are generated. More details on these slugging mechanisms are discussed in literature [1–5].

Another common feature of an offshore oil production system is the use of artificial elevation methods. Throughout the depletion of the field, the pressure in the reservoir drops and, consequently, decreasing the driving force to transport the oil to the surface facilities. There are several ways to supplement this energy loss. The most common alternative is using natural gas injection at the bottom of the production column to reduce the column weight of the production system. This method of artificial elevation is called the gas lift. The gas used in this strategy, provided by surface facilities, is led by a subsea line to the wellhead, called a Christmas Tree or X-Tree, which is located on the seabed, precisely on the top of the production column (or tubing), as shown in Fig. 1. The gas enters the gas lift annular, a kind of piping that covers the production column, and it is then injected into the production column by valves whose positions are defined in the well design stage. When the gas supply is low, or when the pressure in the production column is high, an instability known as casing heading might occur. Briefly, when the annular pressure is less than the pressure in the production column, there is no gas injection. Thus, the gas accumulates in the annulus until the annular pressure becomes sufficient for the injection of the accumulated gas. When the gas is injected into the production column, its expansion and also the reduction of the specific mass of the multiphase mixture takes place. These effects lead to a decrease in the production column pressure that increases the pressure difference from the bottom of the column to the reservoir, increasing the flow produced by the well. As a result, the pressure in the production column also increases and the pressure in the annulus drops, leading to a new blockage in the gas injection at the gas lift valve. After that, the process of accumulating pressure in the annulus starts again and another oscillation mechanism is created, also referred to as severe slugging. This process occurs slightly differently in wells without a packer [6] and can be reduced or avoided using venturi gas lift valves [7–10] in the production column. More details about this mechanism can be found in the previous works [6,11–14].

There are two main consequences of an oil production system operating at a limit cycle: operational risks associated with equipment integrity resulting in the possibility of a shutdown in surface installations and the loss of production inherent to the unstable region. The general behavior of the oil production follows the trend of Fig. 2(a) due to the opening of the topside choke valve that represents the connection of the well to the processing plant, and of Fig. 2(b) regarding the gas lift flow. Fig. 2(a) shows the appearing of a Hopf point during the opening of the choke valve that reflects the change in the flow stability with the consequent loss of production due to the theoretically unstable equilibrium [15]. This kind of behavior is mainly related to the riser-induced slugging. Fig. 2(b) shows the necessity of a minimum gas lift flow for the system to achieve stability. The operation with flowrates below the Hopf point refers to the loss of production due to the theoretical equilibrium [16]. This behavior is the casing heading and can generate losses of up to 20–40% in production [12,17].

Considering the multivariable nature of the gas lift problem, as well as the complexity of its dynamics, this paper aims to present a control solution based on NMPC (Nonlinear Model Predictive Control) for the production system operation. The control structure proposed in this paper uses the surface choke valve and the gas lift flow as manipulated variables, while the controlled variable is the pressure in the Permanent Downhole Gauge (PDG). According to literature, this is the first time that this approach is explored to treat a gas lifted oil well. The results discussed throughout this paper show that the strategy can optimize and improve production stability, subject to reducing the choke and gas lift rates of change, which allows its implementation in systems with slow-speed choke valves.

The article is structured as follows: first a discussion about the operation mode of the gas lift oil wells is presented as well as the evolution of the possibilities of dealing with instabilities in the flow; in a second moment, the control structure proposed in this work is described; further, the model used in the predictive controller is reported; next, the main dynamic characteristics of a virtual well used as a case study in the evaluation tests of the control strategy is briefly presented; and finally the results and discussions are addressed.

2. The oil production system operation

Conventionally, a gas lift oil well operation enables interventions through two variables in the surface facilities: the choke valve opening and the gas lift flow. Usually, these variables are kept constant during the operation. While attempting to work with the choke valve as open as possible, the gas lift flow is usually set to its supposed optimal flow. The gas may not be sufficient to ensure a flow that stabilizes the well or, if used in excess, can reduce oil production. Also, some wells may have a subsea production choke valve, especially if they are attached to subsea manifolds. However, due to the high maintenance costs of this type of equipment and the risks involved, few manipulations are accepted on these valves. Another variable that may be used to act in the well is adding a demulsifier in the Christmas Tree or even in the production column by the gas lift valves. As the name suggests, its action is related to reducing the emulsions generated in the multiphase flow whose effect raises the viscosity of the fluid. Viscosity reduction facilitates the flow and reduces instabilities. However, due to its very complex physicochemical nature, which is highly dependent on the type of oil, the demulsifiers do not always have positive results. Besides, it adds costs to the operation by increasing the transport and storage logistics of chemicals, which is a frequent problem in offshore units. Thus, the most readily available variables for well actuation are the topside choke valve and the gas lift flow. Depending on the level of the slugging, it is possible to keep the well producing without significant operational problems. However, when the oscillation intensity becomes a potential risk to the surface facilities, the actions taken by the operation are usually to increase the