Preprints of the 10th IFAC International Symposium on Dynamics and Control of Process Systems
The International Federation of Automatic Control
December 18-20, 2013. Mumbai, India

Control and Optimization Challenges in Liquid-Loaded Shale Gas Wells

Niket S. Kaisare[1,*], Arun Gupta[1], Vinay Kariwala[1]. Naresh N. Nandola[1]
John W. Green[2], Giulia Seikel[2] and Peter Somdecerff[2]

[1]*ABB Corporate Research, ABB GISL, Bhoruka Tech Park, Whitefield Main Road, Bangalore 560048, India*
[2]*ABB Inc., 7051 Industrial Blvd., Bartlesville OK 74006, US*
**Corresponding Author: Tel: +91–9952034553; E-mail: niket.kaisare@in.abb.com*

Abstract: Shale gas reservoirs are classified as unconventional reservoirs. Their key features include low permeability, rapid decline in production rate, and liquid loading at the well-bottom. An industrial perspective towards automation in Shale gas is provided in this paper. Specifically, the challenges and opportunities in controlling the liquid loading problem and optimizing the production from shale gas wells are discussed. Automation systems and control hierarchy are discussed and parallels with the more familiar Process Industries are highlighted. The key components of reservoir modeling, well-bore modeling, feed-back control, model parameter update, multi-well optimization, and production management are presented. An example of periodic shut-in operation is used to underline the various concepts discussed in this paper.

Keywords: Dewatering; Model-based Control; Production Optimization; Pump-off Control; Shale gas

1. INTRODUCTION

Oil and gas reservoirs are classified into conventional and unconventional depending on the ease of recovery and the quality of reservoirs. Unconventional O&G is expected to make US the largest producer of natural gas in the world by 2020 (World Energy Outlook, 2012). Shale gas is an unconventional resource of natural gas found in shale rock formations, at depths of 6000 to 20000 feet trapped in the low permeability shale rock layers.

Recent advances in horizontal drilling and hydraulic fracturing (called *fracking*) have made extraction of shale gas economically viable. Fracking involves pumping of hydraulic fluids (water with chemicals and *proppants*) at high pressures to induce fractures in the shale formation. The proppant keeps the induced fractures open, increasing the permeability and enabling higher natural gas production. About a third of the hydraulic fluid returns to the surface, while the remaining fluid is produced along with the natural gas during normal well operation. While liquids are initially produced as a mist with the flowing gas, the liquids need to be taken out at later stages using *Artificial Lift* to prevent accumulation at the well-bottom and ensuring gas flow without hindrance.

For shale gas wells to be profitable, it is vital to operate the wells in an optimized manner to extract most of the useful resources. The requirements of control and optimization solutions for artificial lift operations on single well, and at a field-wide level are discussed in this paper. The objectives of production optimization are to increase recovery rates, lower lift costs, and ultimately extend the life of the well.

The remainder of this paper is organized as follows. The problem of liquid loading and the artificial lift techniques for de-liquefaction are discussed in the next section. Section 3 discusses various components of an automation system for shale gas. Control hierarchy and objectives of each layer are discussed in Section 4. An exemplary artificial lift example is used in Section 5 to highlight the key issues, challenges and opportunities. Finally the key points are summarized.

2. LIQUID LOADING

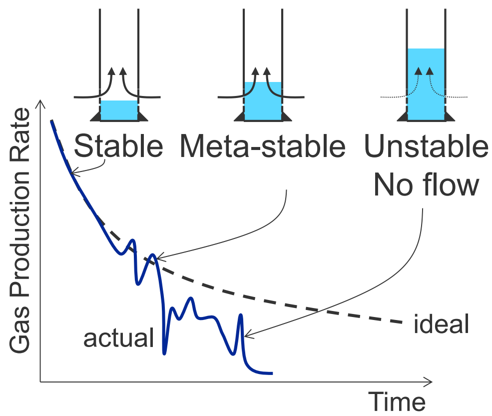

Figure 1: Schematic representation of liquid loading problem in producing wells (Dousi et al., 2006)

2.1 *Effect on Production Rate*

The fracking water and natural gas condensates (heavier hydrocarbons that liquefy at higher pressures) are the main liquids produced along with shale gas. Initially, due to high production rates, the liquids get entrained with the flowing gas. The liquid level at the well-bottom is low and the gas is able to flow freely, without hindrance. This represents "stable" operation of the well in Figure 1, where the actual gas production rate (solid line) closely matches the ideal one.

As the gas production rate declines, the energy in the flowing gas is insufficient to produce the liquids as a mist. In this *meta-stable* region, some of the liquids fall back and collect at the well-bottom, and slugging is often encountered. The liquid levels at the well-bottom fluctuate and the actual production rate begins to fall below the ideal decline curve.

As the gas flow declines further, the gas flowing from the formation does not have enough energy to consistently produce liquids at the surface. If the wells are not adequately de-liquefied, the liquid levels keep rising hindering the flow of gases. Consequently, significant decline in the production rate is observed and the reservoir may stop producing hydrocarbons at economically viable rates.

2.2 Artificial Lift (AL) Options

A well consists of concentric tubes that run several thousand feet below the surface. The outer tube, called the *casing* (typically 4–6 inches diameter) goes vertically downwards until it reaches the shale formation. It may often deviate from the vertical, and turn right angles to form the horizontal well-bore. The casing is perforated when it reaches the fractures (natural or induced) in the formation. Fluids flow into the well from the formation through these perforations. The inner tube, called the *tubing* (about 2 inches in diameter) often runs through the vertical section and ends above the perforations.

Liquids accumulate at the bottom of a well when the well energy decreases over time. *Artificial Lift* (AL) refers to a wide range of intervention methods employed to de-liquefy wells. Removing the liquids removes hindrance to gas flow, reduces the bottom-hole flowing pressure (against which the flow from the reservoir occurs), ensures production for a longer time, and increases the amount of hydrocarbons that can be recovered from the formation. The AL alternatives may be broadly categorized into two types: those that use well's own energy and those that use mechanical energy to de-liquefy the wells. The former set of options is cheaper than the latter ones, since the latter use positive displacement pumps to de-liquefy the wells.

AL methods using well energy

Examples include periodic operation by intermittent well shut-in; gas lift; plunger lift; and a combination of these. The casing is shut and the gas is produced to the sales line only through the tubing. When the well is flowing, the gas produced from the reservoir flows into both the annular region (between casing and tubing) and tubing. The gas flowing into the tubing is produced at the well-head; whereas the gas accumulates in the annulus, increasing the pressure measured at the well-head. Due to the higher gas pressure in the annulus, the liquids primarily collect in the tubing, than the annulus.

Periodic Shut-In is one of the simplest methods of using well's own energy for de-liquefaction. The well is shut-in for a certain period of time, allowing gas pressure (and liquids) to build-up in both the tubing and annulus. After a certain time, the control valve is opened, gas flows and tubing pressure falls rapidly. The gas in the annulus then flows down the casing, through the liquids at the well-bottom, and up the tubing; the gas is produced at the well-head carrying the liquids along as mist. The de-liquefied well is allowed to flow for certain period of time. Then, as liquids accumulate at the well-bottom, the well is shut-in again and the process is repeated periodically.

Gas Lift is used if the well energy is not sufficient for de-liquefaction using periodic shut-in. A part of the gas produced at the well-head is injected back into the casing. The re-injected gas supplements the energy of the gas in the annulus so that the liquids can be continuously entrained with the flowing gas and the well is kept in de-liquefied condition. Gas lift can be combined with periodic shut-in, if required.

Plunger Lift may be considered as a modification of periodic shut-in by introducing a plunger in the tubing. A plunger is a solid metal rod or tube that traverses up and down the tubing with a small clearance. It forms a physical barrier between the liquid that needs to be removed and the gas below that pushes it to the surface. All of the energy stored in the annulus is used in producing the liquids as a slug above the plunger, instead of using some energy in making of droplets (as in periodic shut-in). A combination of plunger and gas lift (called plunger assisted gas lift) is also used in some fields.

The main aim of trouble-free operation of these AL methods is to ensure enough pressure in the casing-tubing annulus to produce the liquids to the surface. The secondary aim would be to maximize the production of natural gas or combination of oil and gas, as the case may be (see Section 4).

AL methods using positive displacement pumps

Primary examples include rod pump, progressive cavity pump (PCP), and electrical submersible pump (ESP). These pumps consist of a moving pump element that "pushes" the liquids through the tubing. The aim of the pump is to keep the annulus free of liquids so that the gas can flow through the annulus unhindered. The liquids are produced through the tubing, and gas through the casing.

"Pump-off control" is the main aim of trouble-free operation of these pumps. Liquid pump-off refers to a condition where the pump runs dry due to lack of liquids. Introduction of gas into the pump can result in poor pump performance and, in many cases, damages the pump. For example, introduction of gas in the rod pump reduces its stroke length (the distance through which the pump displaces the fluids), and increases the possibility of buckling and failure. Pump-off control refers to operational practices that prevent pump from running dry. The secondary aim of the controller is to ensure low liquid levels in the annulus, and hence maximize the production of natural gas and/or oil.

2.3 Current Practices in Shale Gas Fields

Control and optimization of shale gas field introduces new challenges due to inland nature of these fields, greater well depths, lower flow rate from the reservoir, and lack of down-hole measurements. The industry is dominated by heuristic control strategies derived from operators' experience with the wells. Control strategies tend to be very conservative, aimed at trouble-free operation rather than maximizing productivity. For example, significantly higher amount of gas may be recycled in gas-lift (thus increasing operational cost) than the amount required to keep the well flowing at its optimum.

Even when automation solutions are used, these are often based on comparing the current *surface* measurements with threshold values, thus ignoring the dynamics of the well. Consequently, there exist opportunities for using improved control and optimization solutions in the Shale gas fields.

3. AUTOMATION COMPONENTS

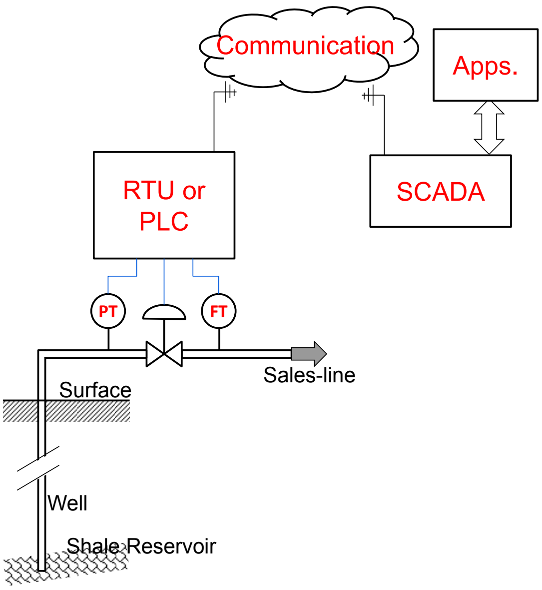

Figure 2: Various components in a typical automation system in upstream oil and gas applications

Figure 2 shows the various automation components for a typical shale gas operation. The lowest level in the hierarchy consists of the field devices: sensors, transducers, actuators, etc. Pressure, temperature and flow rate sensors are common and reliable over a wide range of conditions. Down-hole sensors and multi-phase flow measurements are typically not available due to cost and reliability issues.

These field devices are connected to a remote terminal unit (RTU) or a programmable logical controller (PLC). A single RTU/PLC may control several wells. A regulatory control algorithm sits on the RTU that manipulates the actuator action based on simple logic.

Since the wells in a typical shale field are scattered over a large geographical area, the RTU is provided with wireless communication module to transmit the data to a centrally located SCADA system. Various applications can be run on the SCADA to analyse production data, detect and identify problems, and optimize production. The hierarchy for implementation of control and optimization is discussed next.

4. PROCESS CONTROL ISSUES AND CHALLENGES

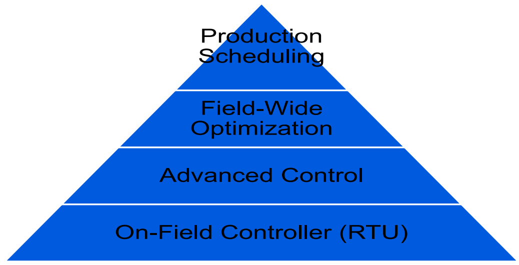

Figure 3: Control hierarchy in upstream Oil and Gas

Figure 3 shows the typical control hierarchy in upstream O&G, similar to the familiar one from process industry. The lowermost level is on-field controller, which performs regulatory control. The advanced control (APC) and field-wide optimization levels generate set-points for regulatory control by considering a single well operation and a multi-well optimization, respectively. These operations are typically performed on the SCADA and pushed to the RTU. Finally, production scheduling and management performs higher-level strategic production planning decisions.

The current state, and future enhancements and challenges in automation of shale gas production are discussed next.

4.1 Regulatory Control on the RTU

Each well has a closed-loop feedback controller to implement a control action (e.g., opening or closing a control valve, or adjusting the pump speed) based on comparing the measurements with pre-determined operating criteria. Control algorithms with low computational complexity are run on the RTU. For example, in case on periodic shut-in operation, the control heuristic to close the valve may be time-based (i.e., keep the valve flowing for certain period of time) or when the flow rate or surface pressure falls below a certain threshold.

In its simplest form, these set-points or threshold values are keyed in by the operator. Alternatively, they may be obtained from the advanced control or optimization level.

4.2 Advanced Control of Individual Well De-Liquefaction

The APC layer is often a weak link in the control hierarchy in Shale gas automation. The distributed nature of inland wells makes implementation of online APC more challenging. Hence, advanced control would be performed on the SCADA. The control actions are in the form of set-points or threshold values for well operation. The APC (as well as optimization) level can work in *feedback* or *advisory* modes. In the former, the set-point/threshold values are communicated to the RTU in an automated way; in the latter, an operator reads the APC suggestions and pushes them to the RTU. In either case, the set-points are communicated back to the RTU less frequently, at pre-determined periods (e.g., once every few hours).

APC algorithms may be model-free or may use an explicit model for control calculation.

In *model-free algorithm*, the controller measures or calculates key performance indices (KPIs) of the process and uses this information to determine the next control action. An example of this for controlling a PCP is presented by Woolsey (2012). The motor speed of the PCP is increased in steps (step-size is pre-determined) until a condition is reached when a further increase in step size results in a decrease in the production rate compared to the previous step. A similar algorithm is used for periodic shut-in as well: the time for which the well is kept closed is incremented in subsequent cycles until the production rate from the current cycle is lower than that from the previous cycle. Opportunity exists to enhance this current practice through the use of control theory. Applying concepts from adaptive control is one example of possible enhancement in control implementation.

The model-based control algorithms currently used in this industry are currently based on a *static model* of a part of the system. For example, the aim of periodic shut-in is to keep the valve open as long as the gas flow rate is able to entrain the liquid. Turner et al. (1969) solved a force balance on a single water droplet to obtain its terminal velocity as:

$$v_t = C\frac{\sigma_{water}\left(\rho_{water}-\rho_{gas}\right)^{1/4}}{\left(\rho_{gas}\right)^{1/2}} \tag{1}$$

The valve is closed when the gas velocity falls below this threshold value. The controller calculates the average gas density using the current measurements at the well-head. The dynamics of the overall process is ignored.

As the computational power of RTU increases in the near future, a part of the APC calculation may be done on the RTU itself. For example, the static-model gives the condition for closing the valve (close if $v_{\text{meas}} > v_t$); this algorithm is computationally tractable to be run in an RTU.

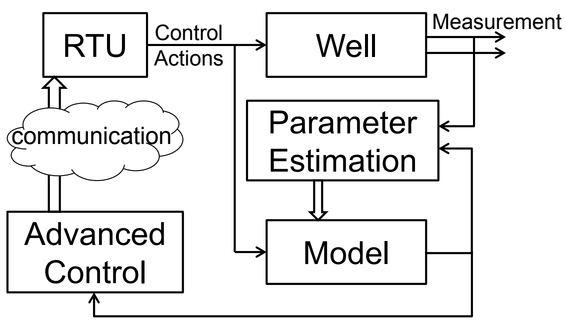

Figure 4: Block-diagram for model-based advanced control component. APC computes set-points that are communicated to an on-field RTU and implemented.

The third option is APC based on a *dynamic model* of the system. While popular in the process industry, model-based control using a physics-based or black box model is mostly non-existent in this field. Figure 4 shows a block diagram for bringing the familiar model-based estimation and control methods from the process industry to unconventional O&G. Surface measurements are obtained at regular intervals. Parameter estimation can be performed and the model updated at regular intervals (once in a few days) since the reservoir behaviour is transient and declines more rapidly than conventional O&G. The updated model is then used in the model-based control. Periodically, well testing may be performed to update the model and improve its performance.

4.3 Process Model

Detailed simulation models for well and reservoir behaviour are available commercially. They are primarily targeted towards prediction of reservoir capacity, understanding multi-phase flow problems, operator training and design of artificial lift. Such models are typically too complex. The use of such models or their reduced-order counterparts in model-based control or optimization is virtually non-existent.

Reservoir model is the most uncertain part in modelling of a shale gas operation, due to its low permeability and porosity, and unavailability of reservoir information to calibrate the model. The standard Inflow Performance Relationship (IPR):

$$q_{in} = C\left(P_{res}^2 - P_{wf}^2\right)^n \tag{3}$$

is often used due to familiarity. Here, P_{res} is the reservoir pressure, P_{wf} is the bottom-hole pressure, and C and n are the model parameters.

Alternatively, models that better capture the transient decline in shale reservoir productivity have been proposed. Hudson (2011) showed that the shale gas transport in the reservoir can be described by mass transfer phenomena in the shale structure at micro-scale level. The structure of shale can be described by following quad-porosity sub-systems: (i) Gas-bearing organic pores, (ii) Water-wet inorganic pores, (iii) Natural fractures, and (iv) Induced fractures. These micro-systems are connected with each other via free gas region, which enables flow between different sub-systems.

Commercial simulators use various abstract forms of the quad-porosity system to simplify the shale reservoir model. Widely used abstractions of the shale gas system include single porosity model, dual porosity model and dual-permeability model. It results in a set of nonlinear partial differential equations (PDEs), which are computationally intractable for control, scheduling and planning applications, where long term predictions are required.

In order to simplify the modeling, Hudson (2011) proposed a lumped parameter tank model; each porosity is represented using a cylindrical tank and connection between them is represented by various valves. The parameters of the models are obtained using historical production data. Another important model is the so-called “proxy model” of Knudsen et al. (2012).

4.4 Field-Wide Optimization

Figure 5 shows an example of a multi-well network. Several wells are connected to a node and downstream units (not shown). These eventually feed into a compressor station, which then directs the hydrocarbons to a production pipeline.

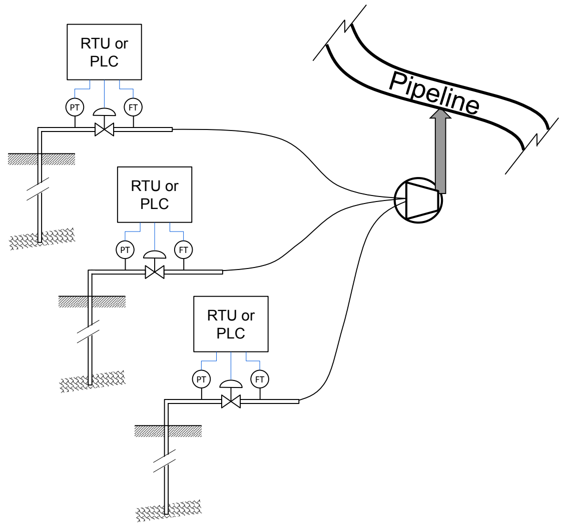

Figure 5: Field-wide optimization layer maximizes net production from a multi-well shale field.

The capacity of the downstream equipment and the compressor station is usually less than the maximum capacity of all the wells. Hence, one needs to optimally prioritize the wells. For example, Dutta-Roy and Kattapuram (1997) compared the optimal operation of single, two and a network of wells having gas lift operation. They found that the optimal operating conditions differed significantly in all these three cases. This motivates the need for field-wide optimization to maximize the net productivity.

In its simpler form, production maximization can be cast as a linear programming problem (Lo and Holden, 1992):

$$Q_{total} = \max_{u_i} \sum_i u_i Q_i \tag{2}$$

where Q_i is the production rate from i^{th} well and $u_i \in [0\ 1]$ represents percentage valve opening. The net flow rates of oil, water and gas have to meet capacity constraints from pipeline, separator and other equipment. Lo and Holden (1992) assumed constant gas-liquid and water-oil ratios.

A modification of the above for periodic shut-in operation would be with u_i as binary variables (open or close), and the multi-phase flow being captured rigorously. Additionally, the threshold flow rate from Eq. (1) forms the lower limit. These modifications will result in a mixed integer nonlinear programming (MINLP) problem.

5. EXAMPLE: PERIODIC SHUT-IN OPERATION

We start with the simplified "proxy model" of Knudsen et al. (2012), which models cylindrical reservoir with an inner fractured region. The fractured region is the shaded cylinder in Figure 6. The objective of the proxy model is to capture the dominating dynamics during shut-ins and re-openings, while being computationally simple enough to be included in a full-space optimization problem without sacrificing accuracy. The proxy model is given as below,

$$\varepsilon\mu c \frac{\partial m}{\partial t} = \frac{1}{r}\frac{\partial}{\partial r}\left[kr\frac{\partial m}{\partial r}\right] \tag{4}$$

where ε is porosity of the formation, μ is gas viscosity, c is the compressibility, k is radial dependent permeability, r_w is horizontal well radius and r_c is radial extent. In this equation, m is the so-called pseudo pressure. The following boundary conditions are applied to the system:

$$\left.\frac{\partial m}{\partial r}\right|_{r_c} = 0; \left.\frac{\partial m}{\partial r}\right|_{r_w} = q\frac{TP_{sc}}{T_{sc}\pi hk} \tag{5}$$

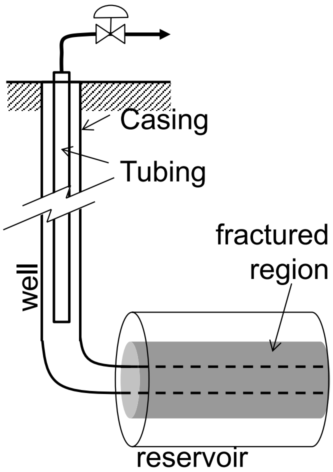

Figure 6: Schematic of a shale gas well and a reservoir (adapted from Knudsen et al., 2012). The grey-shaded region represents fractured region.

Flow rate from the reservoir to the well-bore is determined by the reservoir pressure and bottom-hole pressure. Knudsen et al. (2012) assumed single-phase flow and neglected liquid accumulation at the well-bottom. This was justified because they used a lower bound for gas flow rate: The gas flow rate with valve open was greater than the threshold Turner flow rate given by Eq. (1). Consequently, the gas flow rate through the well was expressed in the following form:

$$q(t) = cW\left[m(r_w) - m(P_{wf})\right] \tag{6}$$

The above expression implies that the flow rate is directly proportional to the difference in the pseudo-pressures at the well inlet (r_w) and the well-bottom. However, the actual well-bore dynamics are much more complex.

A well consists of concentric tubes: casing and tubing. During shut-in, gas flows into both of them and the liquid collects at the well bottom. When the well is opened, gas flows and tubing pressure drops. The pressure built up in the annular region (between casing and tubing) pushes out the liquid when valve is opened. A straight-forward modification accounts for gas mass in tubing (m_{tube}) and annulus (m_{ann}) and liquid level in the tubing (L_{tube}):

$$\frac{dm_{tube}}{dt} = \rho_g q_{t,in} - u \cdot \rho_g q_{out} \tag{7}$$

$$\frac{dL_{tube}}{dt} = \frac{q_{Liq,in} - u \cdot q_{Liq,out}}{A_{tube}} \tag{8}$$

$$\frac{dm_{ann}}{dt} = \rho_g q_{a,in} \tag{9}$$

where, ρ is the density, A is the cross-sectional area and q are the mass flow rates. The expressions for flow rates are similar to those of Baiker et al. (2007). The control variable u takes the values of 0 and 1 to represent shut-in and flowing conditions, respectively.

The above is still a rather simple model, which does not account for the flow behaviour in the well, especially in presence of liquid loading. A more complex model consisting of 226 states was developed in-house. While developed using similar concepts, this model captures dynamics accurately.

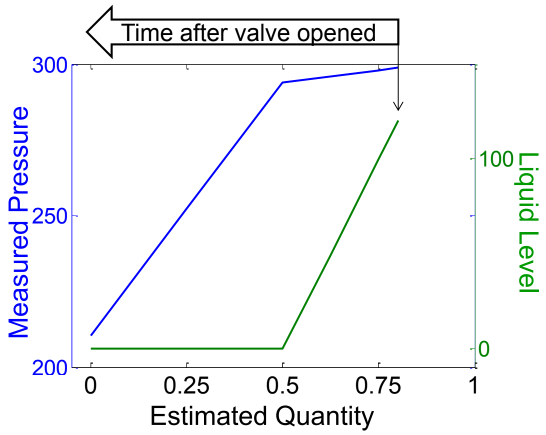

Figure 7: Measured well-head pressure (psig) and estimated liquid level in the well (ft) variation as a function of estimated quantity.

The role of the APC layer is to determine the conditions for opening and closing the valve. One challenge is that the data transfer from on-field controller to the APC is infrequent. Hence, the APC is not truly "online". The APC uses the model and past data to determine controller actions.

To this end, Figure 7 shows how the measured pressure and liquid level varies after valve is opened (t=0 is at the right). Pressure falls rapidly after liquid is removed from the well. Note that the X-axis is an estimated quantity within the well (normalized so that the value lies between 0 and 1).

When the measured pressure is plotted against time, the profile is relatively smooth. However, there is a clear change in slope of the measured pressure in Figure 7. Based on these results, the following model-based operation strategy may be implemented:

(i) The model shown above is used to calculate the time period for which the valve must be closed. After this time is elapsed, the valve is opened.

(ii) The valve is kept open if the flow rate is greater than the threshold value calculated as per Eq. (1). Valve is closed when flow-rate decreases below this value.

The decision (i) above ensures that the well is de-liquefied; the decision (ii) ensures that the well is kept flowing as long as the flow rate exceeds the threshold value for mist-flow.

6. CONCLUSIONS

Control and optimization of shale gas production has some overlap with conventional oil and gas, as well as certain unique issues and challenges. These arise due to the transient nature of the reservoir, unavailability of direct down-hole measurements and hardware constraints due to distributed in-land nature of wells in a field. Various artificial lift options are discussed in this paper, and themes common to automation highlighted.

Regulatory controllers are implemented using on-field controller. Advanced control and real time optimization are performed on a centrally located SCADA system and communicated to the regulatory controller. When faced with communication constraints, the traditional APC and RTO algorithms are suitably modified for Shale gas production. Periodic shut-in operation for artificial lift is used to underline some of these points.

REFERENCES

Bieker H.P., Slupphaug, O., and Johansen, T.A. (2007). "Real Time Production Optimization of Offshore Oil and Gas Production Systems: A Technology Survey," SPE 99446, *Intelligent Energy Conference*, Amsterdam, The Netherlands.

Dutta-Roy, K., and Kattapuram, J. (1997). "A New Approach to Gas-Lift Allocation Optimization," SPE 38333, *SPE Western Regional Meeting*, Long Beach, CA, USA.

Dousi, N., Veeken, C.A.M., and Currie, P.K. (2006). "Numerical and Analytical Modeling of the Gas-Well Liquid-Loading Process", *SPE Production & Operations*, **21**, 475-482

Hudson, J. D., Quad-Porosity Model for Description of gas Transport in Shale Gas Reservoirs, Master of Science Thesis, University of Oklahoma, 2011.

Knudsen, B.R., Bjarne, F., Whitson, C. H. and Conn, A. R. (2012). Target-rate tracking for shale-gas multi-well pads by scheduled shut-ins, *In Proceedings of ADCHEM* 2012, Singapore.

Low, K.K., and Holden, C.W. (1992). "Use of well management schemes for target rate forecasts," SPE 24071, *SPE Western Regional Meeting*, Bakersfield, CA.

Turner, R.G., Hubbard, M.G., and Dukler, A.E. (1969). "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells," *Journal of Petroleum Technology*, **21**, 1475-1482.

WEO (2012). *World Energy Outlook* – 2012, International Energy Agency, Paris, France. http://www.worldenergyoutlook.org/publications/weo-2012/ (last accessed: Nov. 26, 2012).

Woolsey, K.A. (2012). "Improving Progressing-Cavity-Pump Performance through Automation and Surveillance," *Journal of Canadian Petroleum Technology*, **51**, 74-81.