Application of the Peak SIM Flowell Surge Device in Slimhole Monobore Wells

Summary

Peak's Flowell device is run, set and retrieved on slickline. The device has been designed to induce a drawdown surge inside a wellbore. That surge is intended to remove formation damage and hence improve well productivity.

This report presents the development of a mathematical model to describe the performance of the Flowell device under conditions typical of those encountered in 2-7/8" monobore wells in South East Asia. The model allows for the wellbore fluids to contain gas and liquid in any proportion.

The model shows that Flowell can generate a very substantial pressure drawdown in the wellbore. The magnitude of the drawdown is highly dependent upon the volume of any free gas present in the sealed annulus around the Flowell device.

Report by

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Date

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Introduction and Objectives

Peak Well Systems Pty Ltd (Peak) has developed a device (known as "Flowell") designed to induce a sudden pressure drawdown in a wellbore, and hence cause a surge of fluid inflow from the reservoir. The device is run, set and retrieved on slickline.

The primary reason for developing Flowell is to improve well productivity by removing certain types of formation damage (eg, crushed zones in perforation tunnels, tenacious filter cakes and scales). Formation damage reduces well productivity through the "skin" effect, with the rule-of-thumb reduction in ideal well productivity in a vertical well being given by the relationship:

$$\eta = 7/(7 + S)$$

where the variables are:

η flow efficiency (100% = undamaged)
S skin factor

Objectives

The objectives of this work are as follows:

- To develop a mathematical model that adequately describes the effect of activating the Peak Flowell device inside a wellbore.
- To use the model to examine the application of the device in a 2-7/8" monobore well, as widely used in South East Asia.

Basis of the Work

In this section of the report the basis upon which the work was carried out is presented. Specific consideration is given to:

- The case for a steady state and isothermal analysis of the problem
- The dimensions and capacities of the wellbore and Flowell device
- The compressibilities of the fluids in the system
- Typical bottom hole conditions to be used in the mathematical model.

The Case for Steady State and Isothermal Analysis

Examination of the transient effects caused by activating a Flowell device is both complicated and uncertain. Setting aside the complexity of transient analysis (which could be dealt with using numerical solution techniques), major causes of uncertainty are:

- Quantification of frictional effects within the Flowell device under downhole conditions, and hence the speed with which the surge chambers are activated;
- Quantification of the impact of individual formation damage mechanisms on well productivity, and hence the inflow rates induced by surging the formation.

In summary, trying to determine the effectiveness of the Flowell device is speculative, at best. Nevertheless, there is much of value to be derived from steady-state analysis of the Flowell device (ie, considering only start and end conditions). Additional useful constraints to apply are:

No well inflow – the largest possible drawdown would be caused by the case of no inflow into the well to replenish the wellbore fluids transferred into the surge chambers.

Isothermal conditions – with no inflow, the largest possible drawdown would be caused by isothermal compression of the air inside the surge chambers. *In fact, rapid activation of the surge tool is likely to result in near-adiabatic compression of the air inside the surge chambers, with consequent temperature rise of the air. However, the compressed air volume will be minimised, and hence the transfer of wellbore fluids maximised, once the heat caused by the adiabatic compression has dissipated and the system temperature returns to the static bottom hole value.*

The reason that the maximum possible drawdown is of great interest is that the potential for casing collapse is surely one of the most important operational risks to be evaluated before deploying the Flowell device. Furthermore, the steady state and isothermal case lends itself to fairly simple analytical methods, which can be solved using a spreadsheet.

Hence this work will consider only isothermal analysis of the system, with no inflow from the reservoir, in an effort to provide well engineers with a practical pre-job evaluation tool.

Dimensions and Capacities

Peak's Flowell device consists of a number of chambers filled with air at atmospheric conditions, positioned between two Peak SIM-plug packing elements. The operation of the device is shown in Appendix A.

The relevant dimensions and capacities for a Flowell device set inside a 2-7/8" nominal (6.4 lb/ft) pipe are as follows:

2-7/8" casing internal diameter:	2.441 in
Surge chamber external diameter:	2.250 in
Surge chamber volume:	245.9 in^3 (one chamber)
Surge chamber length:	120 in (one chamber)
Additional Flowell device length:	48 in

Hence, for a Flowell device using three chambers, the overall system dimensions and capacities are:

Length between packing elements:	48 + 3 * 120 in = 408 in
Total surge chamber volume:	3 * 245.9 in^3 = 737.7 in^3
Annular volume outside Flowell device:	$\pi / 4 * (2.441^2 - 2.250^2) * 408\ in^3 = 287.1\ in^3$

Fluid Compressibilities

The wellbore fluids are likely to consist of some or all of the following: oil, saline water and hydrocarbon gas. The isothermal compressibility of these fluids is typically in the following ranges:

Oil:	5.0 E-06 /psi – 30 E-06 /psi (more volatile oils are more compressible)
Water (and aqueous brine):	2.7 E-06 /psi – 4.0 E-06 /psi (depending upon salinity and dissolved gas)
Hydrocarbon gas:	approximately the reciprocal of the *in situ* pressure

Typical Wellbore Conditions Considered

Bottom hole temperature:	350˚F
Bottom hole pressure:	4000 psi, when shut-in
Liquid compressibility:	3.0 E-06 /psi (ie, water or brine)

Model Development and Results

A mathematical model has been created that describes the steady state and isothermal pressure response of the system, assuming no inflow from the reservoir. As described in the previous section, this approach should estimate the maximum drawdown likely to be seen in the wellbore. The creation of this model is shown in Appendix B.

The model allows for a mixture of gas and liquid to be present in the wellbore before the Flowell device is activated. However, the model does not consider the presence of gas-saturated liquids in the wellbore. Appendix B does describe briefly how to account for saturated wellbore fluids.

Upon activating the surge tool, the final system pressure, and hence drawdown, can be estimated by solving the following equation (Appendix B, Eqn 17):

$$X\left\{\alpha\left(\frac{p_a}{p_f}-1\right)+(1-\alpha)\left[e^{c_l(p_a-p_f)}-1\right]\right\}+\frac{p_s}{p_f}-1=0$$

where the variables are:

c_l	wellbore liquid compressibility
p_a	initial wellbore annulus pressure
p_f	final system pressure
p_s	initial surge chamber pressure
X	ratio of annular wellbore volume to total surge chamber volume
α	initial gas volume fraction in wellbore fluids

As the compressibility of the liquid phase is typically very small compared to that of the gas, an approximate solution to the equation above is given by (Appendix B, Eqn 19):

$$p_f \cong \frac{\alpha X p_a + p_s}{1+\alpha X}$$

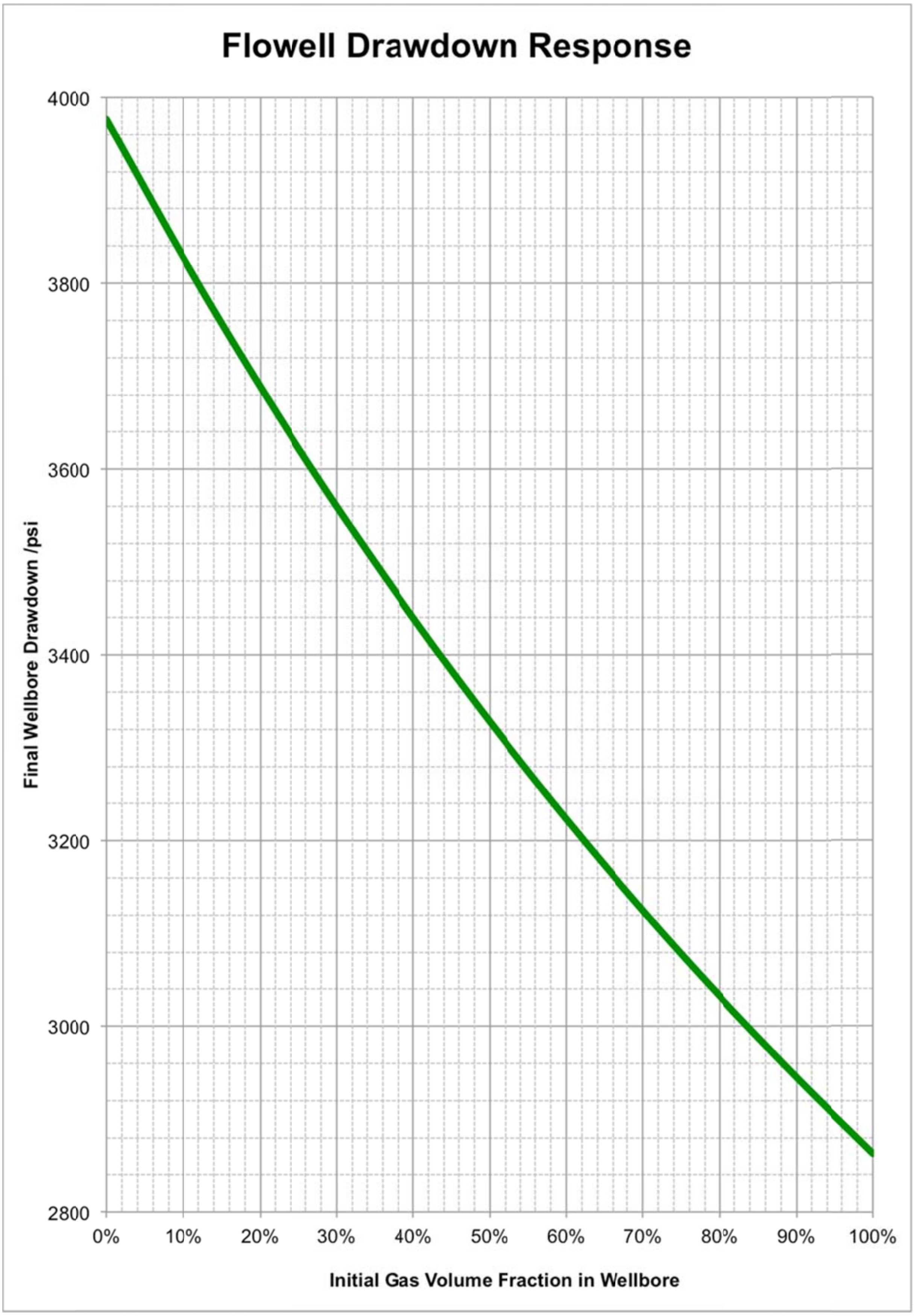
The wellbore drawdown is given by:

$$\Delta p = p_a - p_f$$

Application of the Flowell Device in a 2-7/8" Monobore Well

The equations above have been solved for the system described in the previous section (ie, 4000 psi at 350˚F). The results are shown on the chart overleaf, for the full range of possible initial gas fractions in the wellbore. The graph shows the solution the more comprehensive treatment, including both gas and liquid compressibility. If liquid compressibility is ignored (the approximate solution shown above), the results agree to within better than 0.3% over the entire range.

The chart shows that the presence of free gas in the wellbore has a significant effect in reducing the drawdown induced by the Flowell device.


Flowell Drawdown Response
Final Wellbore Drawdown /psi
4000
3800
3600
3400
3200
3000
2800
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Initial Gas Volume Fraction in Wellbore

Conclusions and Recommendations

The objectives of the work have been met:

- A simple, but useful, mathematical model has been developed.
- The performance of the Flowell device has been examined under bottom hole conditions typical in 2-7/8" monobore wells, as widely used in South East Asia.

The results of the modelling show that Flowell device is capable of generating a substantial pressure drawdown inside the wellbore. The magnitude of the drawdown is very dependent upon the volume of any free gas present in the sealed annulus around the Flowell device.

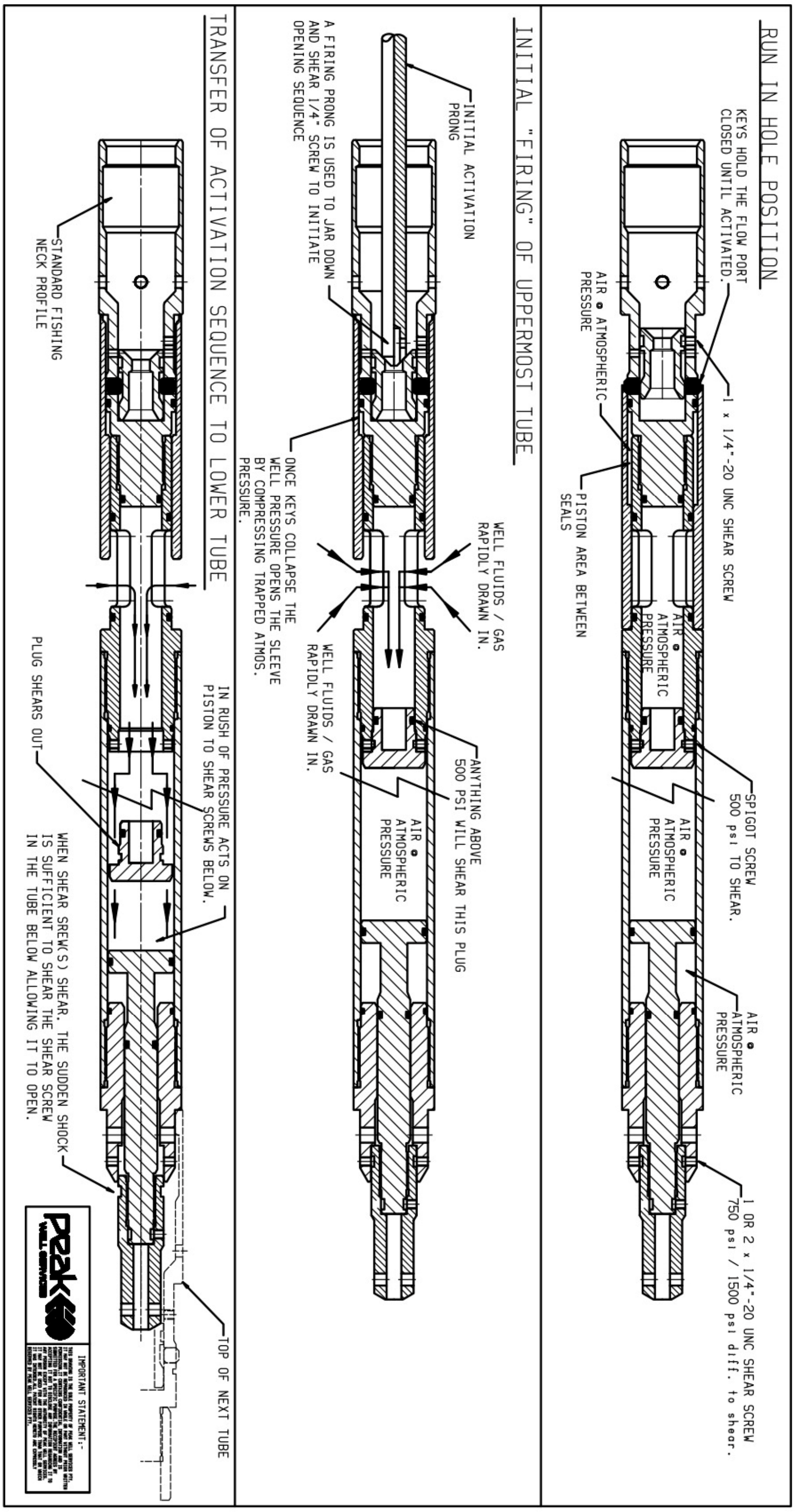
The primary purpose of this report is not to assess the stress state of the casing induced by activating the surge tool. However, it is worth noting that maximum drawdown in the system considered in this report is far below the API collapse rating of 2-7/8" tubulars typically used in slimhole monobores (eg, being 11,170 psi for 6.4 lb/ft, 80 ksi yield pipe).

Recommendations

It is recommended that well engineers use this model to examine the performance of the Flowell device under specific bottom hole conditions that may be encountered.

Furthermore, if deemed worthwhile, a more rigorous model could be developed to account for the presence of gas-saturated liquids in the wellbore.

Appendix A


RUN IN HOLE POSITION
KEYS HOLD THE FLOW PORT CLOSED UNTIL ACTIVATED.
AIR @ ATMOSPHERIC PRESSURE
1 x 1/4"-20 UNC SHEAR SCREW
PISTON AREA BETWEEN SEALS
AIR @ ATMOSPHERIC PRESSURE
SPIGOT SCREW 500 psi TO SHEAR.
AIR @ ATMOSPHERIC PRESSURE
AIR @ ATMOSPHERIC PRESSURE
1 OR 2 x 1/4"-20 UNC SHEAR SCREW 750 psi / 1500 psi diff. to shear.
INITIAL "FIRING" OF UPPERMOST TUBE
INITIAL ACTIVATION PRONG
A FIRING PRONG IS USED TO JAR DOWN AND SHEAR 1/4" SCREW TO INITIATE OPENING SEQUENCE
WELL FLUIDS / GAS RAPIDLY DRAWN IN.
ONCE KEYS COLLAPSE THE WELL PRESSURE OPENS THE SLEEVE BY COMPRESSING TRAPPED ATMOS. PRESSURE.
WELL FLUIDS / GAS RAPIDLY DRAWN IN.
ANYTHING ABOVE 500 PSI WILL SHEAR THIS PLUG
AIR @ ATMOSPHERIC PRESSURE
TRANSFER OF ACTIVATION SEQUENCE TO LOWER TUBE
STANDARD FISHING NECK PROFILE
IN RUSH OF PRESSURE ACTS ON PISTON TO SHEAR SCREWS BELOW.
PLUG SHEARS OUT
WHEN SHEAR SREW(S) SHEAR. THE SUDDEN SHOCK IS SUFFICIENT TO SHEAR THE SHEAR SCREW IN THE TUBE BELOW ALLOWING IT TO OPEN.
TOP OF NEXT TUBE
IMPORTANT STATEMENT:-

Appendix B

The definition of isothermal compressibility for a single-phase fluid is

Eqn 1 $$c = -\frac{1}{V}\left(\frac{\partial V}{\partial p}\right)_T$$

Gas Compressibility

If the fluid is a perfect gas, the isothermal compressibility is found by differentiating the (Boyle's Law) equation

Eqn 2 $$pV = constant$$

Hence, the compressibility of a perfect gas can be shown to be

Eqn 3 $$c_g = \frac{1}{p}$$

For a real gas, isothermal compressibility can be shown to be

Eqn 4 $$c_g = \frac{1}{p} - \frac{1}{z}\frac{\partial z}{\partial p}$$

By way of example, the effect of using perfect gas compressibility for air is to overstate compressibility, compared to actual values, by 16% at 4000 psi and 350˚F, and by 6% at 2000 psi and 350˚F. Below 2000 psi, the errors diminish rapidly. Nevertheless, for the purposes of this work, the approximation of perfect gas behaviour will be used for all gaseous phases. Hence, for a gas changing isothermally from state 1 to state 2:

Eqn 5 $$p_2V_2 = p_1V_1$$

Liquid Compressibility

If the fluid is a liquid, with small and constant compressibility, the effect of an isothermal change of the liquid from state 1 to state 2 can be found by integrating Eqn 1 as follows

Eqn 6 $$\int_1^2 dp = -\frac{1}{c_l}\int_1^2 \frac{1}{V} dV$$

Hence

Eqn 7 $$p_2 = p_1 - \frac{1}{c_l}\ln\frac{V_2}{V_1}$$

Application to the Flowell Device Surge Chambers

The Flowell device is sealed on surface, with atmospheric air trapped in its surge chambers. As the tool is lowered into the well, the air will be heated at constant volume. Hence, the pressure inside the Flowell device surge chambers before the device is activated will be closely approximated by

Eqn 8 $$p_s = 14.7\left(\frac{\frac{T}{°F}+460}{520}\right)psi$$

After the surge tool has been activated, the pressure inside the surge chambers will rise as the trapped air is compressed. The pressure in the wellbore will fall as wellbore fluids transfer into the surge chambers. The surge operation is complete once the wellbore pressure and surge chamber pressure have equalised.

Using Eqn 5, the final surge chamber pressure (p_f) is given by

Eqn 9 $$p_f(V_s - \Delta V) = p_s V_s$$

where ΔV is the volume change of the air inside the surge chambers (and the corresponding volume change of the wellbore annulus). Now, if this volume change is expressed as a fraction of the total surge chamber volume, then

Eqn 10 $$p_f(V_s - fV_s) = p_s V_s$$

and hence the equation to describe the fractional volume change inside the surge chambers is

Eqn 11 $$f = 1 - \frac{p_s}{p_f}$$

Application to the Wellbore Annulus Outside the Flowell Device

Consider the general case in which the wellbore annulus around the surge tool is initially filled with a mixture of gas and liquid. As a simplification, the gas is assumed not to be soluble in the liquid (and hence no additional gas will be liberated as the wellbore pressure falls). For a specified initial gas fraction (α), the pressure in the wellbore after the Flowell device has been activated is given by

Eqn 12 $$p_f(\alpha V_a + \Delta V_g) = p_a \alpha V_a$$

If the annular wellbore volume is expressed in terms of the volume of the surge chambers (ie, $V_a = XV_s$), the volume change of the wellbore gas, expressed as a fraction of the total surge chamber volume. Is given by

Eqn 13 $$f_g = \alpha X\left(\frac{p_a}{p_f} - 1\right)$$

For the portion of annular space filled with liquid, the pressure change is given by

Eqn 14 $$p_f = p_a - \frac{1}{c_l}\ln\frac{(1-\alpha)V_a + \Delta V_l}{(1-\alpha)V_a}$$

From which

Eqn 15 $$f_l = (1-\alpha)X\left[e^{c_l(p_a - p_f)} - 1\right]$$

The total fractional volume change is given by

Eqn 16 $$f = f_g + f_l$$

Hence adding Eqn 14 and Eqn 15 and setting the sum equal to Eqn 11 gives the general equation for finding the final system pressure:

Eqn 17 $$X\left\{\alpha\left(\frac{p_a}{p_f}-1\right)+(1-\alpha)\left[e^{c_l(p_a-p_f)}-1\right]\right\}+\frac{p_s}{p_f}-1=0$$

As the liquid compressibility is typically very small compared to the gas compressibility, a reasonable approximation to Eqn 17 is obtained by considering only the gas expansion:

Eqn 18 $$\alpha X\left(\frac{p_a}{p_f}-1\right)+\frac{p_s}{p_f}-1\cong 0$$

From which the final system pressure is obtained as

Eqn 19 $$p_f\cong\frac{\alpha X p_a+p_s}{1+\alpha X}$$

Consideration of Saturated Wellbore Liquids

The previous treatment has assumed that the gas and liquid phases are not soluble in each other. However, if the wellbore was filled with, say, saturated reservoir oil and an associated gas cap, such a simplification will underestimate the compressibility of the wellbore fluids. As the pressure falls, gas will come out of solution in the liquid, increasing the volume of the gas cap. The general equation for the compressibility of a saturated liquid and gas system is

Eqn 20 $$c=\alpha\left[\frac{-1}{B_g}\left(\frac{\partial B_g}{\partial p}\right)_T\right]+(1-\alpha)\left[\frac{-1}{B_l}\left(\frac{\partial B_l}{\partial p}\right)_T+\frac{B_g}{B_l}\left(\frac{\partial R}{\partial p}\right)_T\right]$$

Solution of Eqn 20 is not considered in this work. As mentioned above, considering the effect of gas coming out of solution is to increase the total system compressibility, and hence reduce the drawdown, compared to the gas/liquid system considered in Eqn 17. Nevertheless, if one has suitable pressure-volume-temperature data from a differential liberation experiment, Eqn 20 can be used to predict the isothermal pressure change due to expansion of saturated wellbore fluids.

Nomenclature

B formation volume factor
c compressibility
f fraction of total surge chamber volume
p pressure
R solution gas/liquid ratio
T bottom hole temperature
V volume
X ratio of annular wellbore volume to total surge chamber volume
z gas compressibility factor
α initial gas volume fraction in wellbore fluids

Subscripts

a wellbore annulus outside surge chambers
f final system (pressure)
g gas
l liquid
s surge chambers
T constant temperature