Blowout Simulation

Oliasoft

Abstract

The Blowout simulation is employed to estimate the potential blowout rates from reservoirs through designated wellbores to the surface.

Input

The first necessary input for the inflow model is the description of the reservoir, containing fluid type, reservoir fluid properties, and temperature profile. And more details in the reservoir zone are required, such as top pressure, oil/gas gravity distribution, top depth. In the blowout inflow model, either the productivity indices are provided, or other key parameters, such as permeability and the skin factor are important for the simulations. Additionally, a temperature gradient model is used as input to the flow rate simulations. Other required inputs are formation temperatures for the minimum two points.

The outflow model depends on the geometry of the flowing well. The geometry includes well trajectory, drill string, casing, and open hole, technically speaking, inclinations, depths, inner and outer diameters of each section in wellbores.

Inflow performance relationship

Five different inflow models are implemented, which are Oil Basic (oil/gas), Oil Fractured (oil/gas), Oil Explicit (oil/gas), Gas Deliverability (Gas/Condensate) and Gas Explicit (gas/condensate) to calculate flow rates under the different penetration (100%, 50% and $5m$), where the scenario of 100% penetration is necessary within the calculation of inflow performance relationship (IPR). [1]

The IPR curve is the relation between the flowing bottom-hole pressure P_{wf} and liquid production rate q. Undersaturated oil reservoirs exist as single-phase reservoirs where pressures are above the bubble point pressure. The linear IPR model is given as,

$$q = J(P_{res} - P_{wf}) \tag{1}$$

where J is the productivity index to describe the trends of the IPR curve and P_{res} represents the reservoir pressure.

The solution gas escapes from the oil and becomes free gas when the flowing bottom-hole pressure P_{wf} is below the bubble point pressure P_b [1]. Therefore, Vogel established an empirical equation for two-phase reservoirs in 1968 [2], and it is still widely used in the industry.

If the reservoir pressure $P_{res} < P_b$,

$$q = q_{max}(1 - 0.2\frac{P_{wf}}{P_{res}} - 0.8\frac{P_{wf}}{P_{res}}^2) \tag{2}$$

and,

$$q_{max} = \frac{JP_{res}}{1.8} \tag{3}$$

Otherwise the following is being used,

$$q = J(P_{res} - P_b) + \frac{JP_b}{1.8}(1 - 0.2\frac{P_{wf}}{P_b} - 0.8\frac{P_{wf}}{P_b}^2) \tag{4}$$

As the productivity index J is an unknown variable, it can be estimated according to different flow types. For transient flow around a vertical/horizontal well.

Oil Basic

Productivity index for vertical and deviated wells in rectangular drainage areas with constant pressure boundaries.

$$J = \frac{kh}{18.7 B_o \mu_o (0.5 \log \frac{2.2 x_e y_e}{c_a r_w^2} + S)} \tag{5}$$

Oil Fractured

$$J = \frac{kh}{18.7 B_o \mu_o (0.5 \log \frac{2.2 x_e y_e}{c_a r_w^2} + S)} \tag{6}$$

or when the production time t is smaller than Permeability time,

$$J = \frac{kh}{21.5 B_g \mu_g (\log \frac{kt}{\text{poro} \mu_g c r_w^2} - 3.1 + 0.87 S)} \tag{7}$$

Gas deliverability

Transient productivity index (i.e. productivity index of a well which has not yet seen any of the boundaries (radial flow) is used in this part. Most DST/WFT fall into this category) which can be used to determine the infinite-acting period.

$$J = \frac{kh}{21.5 B_g \mu_g (\log \frac{kt}{\text{poro} \mu_g c r_w^2} - 3.1 + 0.87 S)} \tag{8}$$

Forcheimer model

High velocity flow in porous media and fractures is modeled by the Forchheimer equation in gas reservoir when the reservoir pressure exceeds a cut-off value numerically.

$$P_{wf} = P_{res} - a \cdot q - b \cdot q^2 \tag{9}$$

The parameters a and b are estimated based on pseudo pressure correlations:

$$a = \frac{\hat{P}_a \mu_f z_f}{P_{res}} \tag{10}$$

and

$$b = \frac{\hat{P}_b \mu_f z_f}{P_{res}} \tag{11}$$

Forchheimer equation can be performed for the gas systems, where the nonlinear flow is much more significant, due to the lower gas viscosity which will give high Re numbers for the same velocity as in liquid systems.

Vertical lift performance relationship

The Vertical lift performance (VLP), known as the outflow model, decribes the relationship between the bottom-hole pressure and the flow rate. Widely used multiphase flow models are implemented to describe the VLP relationship. The analyzation of different flow regimes is important in the empirical models, which are bubble flow, slug flow, transition flow, mist flow, segregated flow, intermittent, distributed flow, plug flow, and froth flow.

Hagedorn-Brown Correlation

The Hagedorn-Brown Correlation applies only to vertical wells. It is a combination of two correlations: Hagedorn-Brown correlation for slug flow and Griffith correlation for bubble flow. Thus, it is necessary to determine the flow pattern before we proceed to the next.

$$A = 1.071 - \frac{0.2218(v_{sl} + v_{sg})^2}{0.3048^2 d} \tag{12}$$

$$B = \frac{v_{sg}}{v_{sg} + v_{sl}} \tag{13}$$

If $B - A \geqslant 0$, continue with the Hagedorn-Brown correlation, or else the Griffith correlation is under consideration.

Griffith correlation

Liquid holdup

$$\lambda = 1 - 0.5 + \left[1 + \frac{v_m}{0.24384} - \sqrt{\left(\left[1 + \frac{v_m}{0.24384}\right]^2 - 4 \cdot \frac{v_{sg}}{0.24384}\right)}\right] \tag{14}$$

Hagedorn-Brown Correlation

Calculate liquid viscosity number and coefficient

$$N_L = \mu_L \left[\frac{g}{\rho_L \sigma_L^3}\right]^{1/4} \tag{15}$$

$$CN_L = \frac{0.0019 + 0.0322 N_L - 0.6642 N_L^2 + 4.9551 N_L^3}{1 - 10.0147 N_L + 33.8696 N_L^2 + 277.2817 N_L^3} \tag{16}$$

Calculate liquid, gas velocity number, and pipe diameter number

$$N_{Lv} = v_{sl} \left[\frac{\rho_L}{g \sigma_L}\right]^{1/4} \tag{17}$$

$$N_{Gv} = v_{sg} \left[\frac{\rho_L}{g \sigma_L}\right]^{1/4} \tag{18}$$

$$N_d = d \left[\frac{g \rho_L}{\sigma_L}\right]^{1/2} \tag{19}$$

$$\phi = \frac{N_{Lv}}{N_{GV}^{0.575}} \left[\frac{\overline{P}}{14.7}\right]^{0.10} \left[\frac{CN_L}{N_d}\right] \tag{20}$$

$$\xi = \left[\frac{0.0047 + 1123.32 \cdot \phi + 729489.64 \cdot \phi^2}{1 + 1097.1566 \cdot \phi + 722153.97 \cdot \phi^2}\right]^{0.5} \tag{21}$$

Calculate liquid holdup

$$\lambda = \phi \cdot \xi \tag{22}$$

At last, the frictional pressure gradient is

$$\left[\frac{dp}{dx}\right]_f = \frac{2 f_{tp} \rho_{ns} v_m^2}{d} \cdot \frac{\rho_{ns}}{\rho_s} \tag{23}$$

Beggs & Brill Correlation

The Beggs & Brill model is developed for tubing strings in inclined wells and pipelines for hilly terrain. This model was developed from experiments using air and water as test fluids over a wide range of parameters. Beggs & Brill uses the no-slip friction factor to calculate frictional pressure losses.

Calculate total flux rate

$$v_m = v_{sg} + v_{sl} \tag{24}$$

Calculate no-slip holdup

$$\lambda_{ns} = \frac{v_{sl}}{v_{sg} + v_{sl}} \tag{25}$$

Calculate the Froude number

$$N_{FR} = \frac{v_m^2}{gd} \tag{26}$$

Calculate liquid velocity number N_{Lv} (17)

In the following calculation, we use the no-slip holdup and the Froude number to determine the flow patterns, such as segregated, transition, intermittent, and distributed.

Calculate the horizontal holdup

$$\lambda_o = \frac{a\lambda_{ns}^b}{N_{FR}^c} \tag{27}$$

Calculate the inclination correction factor coefficient

$$C = (1 - \lambda_{ns}) ln(d\lambda_{ns}^e N_{Lv}^f N_{FR}^g) \tag{28}$$

where the values of parameters a, b, c, d, e, f, and g are dependent of flow patterns and flow conditions (uphill or downhill).

Calculate the liquid holdup inclination correction factor

$$\phi = 1 + c[sin(1.8\theta) - 0.333 sin^3(1.8\theta)] \tag{29}$$

where θ is the deviation from horisontal axis.

Calculate the liquid holdup

$$\lambda = \lambda_o \phi \tag{30}$$

and more correlations can be added for different flow patterns and conditions.

Calculate the friction factor ratio

$$\frac{f_{tp}}{f_{ns}} = e^S \tag{31}$$

where S is a fucntion of λ_{ns}/λ^2.

Calculate no-slip Reynolds number

$$(N_{Re})_{ns} = \rho_{ns} v_m de/\mu_{ns} \tag{32}$$

The two-phase friction factor is

$$f_{tp} = f_{ns} \cdot e^S \tag{33}$$

where f_{ns} is the fanning friction factor.

At last, the frictional pressure gradient is

$$\left[\frac{dp}{dx}\right]_f = \frac{2 f_{tp} \rho_{ns} v_m^2}{d} \tag{34}$$

Orkiszewski

The Orkiszewski correlation is applicable for two-phase pressure drops in vertical wells for different flow regimes (bubble, slug, transition, annular mist). The correlation has been proven accurate in the estimation of high-velocity flow in both gas condensate wells and oil wells.

In this correlation, the superficial velocity for each phase has been estimated to find out the flow regimes. The liquid holdup corresponding to different flow regimes can be obtained, such as Griffith correlation for bubble flow, Duns & Ros correlation for transition/mist flow and Chierici et. al. (1974)'s work for slug flow. And then, the Reynolds number and friction factor are yielded in each flow regime, thus the frictional pressure loss can be calculated out.

Gray correlation

A vertical flow correlation for gas condensate wells was developed by H. E. Gray. It is an empirical model, which employs a pressure balance equation with the gas volume fraction ξ.

The pressure balance equation

$$dP = \frac{g}{g_c}[\xi\rho_g + (1-\xi)\rho_l]dh + \frac{f_t G^2}{2g_c DP_{mf}dh} + \frac{G^2}{g_c} d\left[\frac{1}{\rho_{mi}}\right] \tag{35}$$

The gas volume fraction

$$\xi = \frac{1-\exp\left[-0.2314\left[N_v\left[1+\frac{205.0}{N_D}\right]\right]^B\right]}{R+1} \tag{36}$$

$$B = 0.0814\left[1-0.0554\ln\left[1+\frac{730R}{R+1}\right]\right] \tag{37}$$

Gray modified

Gray modified is developed based on the Gray model combined with the hydrostatic pressure loss calculated using no slip density.

Duns & Ros correlation

The Duns & Ros correlation is developed for slip velocity and friction factor for each of the three flow regimes.

Calculate liquid viscosity number N_L in equation (15), liquid velocity number N_{Lv} (17), gas velocity number N_{Gv} using equaiton (18), and pipe dimeter number N_d (19).

Calculate dimensionless quantities

$$L_s = 50 + 36N_{Lv} \tag{38}$$

$$L_m = 75 + 84N_{Lv}^{0.75} \tag{39}$$

By comparison of N_{Gv} and the above two values combining N_{Lv}, the flow regimes can be determined. Then, slip factor S is obtained corresponding to different flow regimes.

Calculate slip velocity

$$v_s = \frac{S}{(\rho_L/(\sigma_L g))^{0.25}} \tag{40}$$

Calculate liquid holdup

$$H_L = \frac{v_s - v_{sg} - v_{sl} + \sqrt{(v_s - v_{sg} - v_{sl})^2 - 4v_s v_{sl}}}{2v_s} \tag{41}$$

Calculate Reynolds number

$$N_{Re} = \frac{\rho_L v_{sl} d}{\mu_L} \tag{42}$$

At last, the frictional pressure gradient for bubble and slug flow

$$\left[\frac{dp}{dx}\right]_f = \frac{f_m \rho_L v_{sl} v_m}{2 g_c d} \tag{43}$$

The frictional pressure gradient for mist flow

$$\left[\frac{dp}{dx}\right]_f = \frac{f \rho_g v_{sg}^2}{2 g_c d} \tag{44}$$

In the transition zone, a linear interpolation between the flow regime boundaries is applied to obtain the frictional pressure gradient.

PVT model

The pressure-volume-temperature (PVT) handling of fluids in many fluid flow simulations describes the phase behavior of gas, oil, and water at different conditions. A mixture with known composition consists of defined number of phases, phase amounts, phase compositions, phase properties (molecular weight, density, and viscosity), and the interfacial tension between phases. In addition, it is important to define the phase behavior of mixtures at a specific pressure and acquire the derivatives of all phase properties corresponding to pressure and composition.

Vasquez-Beggs oil

Vasquez-Beggs is a generally applicable correlation containing equations for solution gas oil ratio R_s, oil formation volume factor (FVF) B_o, and oil compressibility c_o. The correlation was developed based on experimental data collected from fields all over the world. The data used in the development of the correlation covers a wide range of pressures, temperatures, and oil properties.

The bubble point pressure

$$p_b = \left(\frac{R_s}{C_1 \gamma_g \exp\left(C_3\left(\frac{\gamma_o}{T+460.0}\right)\right)}\right)^{\frac{1}{C_2}} \tag{45}$$

where the parameters C_1, C_2, and C_3 have two groups of values when the oil gravity γ_o is at a critical value of 30 API.

Solution Gas Oil Ratio

$$R_s = C_1 \gamma_g p^{C_2} \exp\left(C_3\left(\frac{\gamma_o}{T+460.0}\right)\right) \tag{46}$$

Oil FVF - Saturated

$$B_o = 1 + A_1 R_s + S_2 (T-60)\left(\frac{\gamma_{API}}{\gamma_g}\right) + A_3 R_s (T-60)\left(\frac{\gamma_{API}}{\gamma_g}\right) \tag{47}$$

Oil compressibility at gas saturated condition

$$c_o = \frac{\left(B_g - \frac{dB_o}{dR_s}\right) \cdot \frac{dR_s}{dp}}{B_o} \tag{48}$$

Oil FVF - Undersaturated

$$B_0 = B_{ob} e(c_o(p_b - p)) \tag{49}$$

Oil compressibility at undersaturated condition

$$c_o = \frac{-1433 + 5R_s + 17.2T - 1180\gamma_g + 12.61\gamma_o}{10^5 \cdot p} \tag{50}$$

Standing oil

The Standing correlation contains equations for estimating bubble point pressure, solution gas oil ratio, and oil formation volume factor for California oils.

The bubble point pressure

$$p_b = 18.2\left(\left(\frac{R_s}{\gamma_g}\right)^{0.83}\frac{10^{0.00091T}}{10^{\gamma_{API}}}\right) - 1.4 \tag{51}$$

Solution Gas Oil Ratio

$$R_s = \left(\left(\frac{p}{18.2} + 1.4\right)\frac{10^{0.00091T}}{10^{\gamma_{API}}}\right)^{\frac{1}{0.83}}\gamma_g \tag{52}$$

Oil FVF - Saturated

$$B_o = 0.972 + 1.4710^{-4}\left(R_s\left(\frac{\gamma_g}{\gamma_o}\right) + 1.25T\right)^{1.175} \tag{53}$$

Oil FVF - Undersaturated applies equation (49)

The oil compressibility used in this equation is obtained from the Vasquez-Beggs correlation.

De Ghetto oil

The De Ghetto et al. correlation contains modified PVT correlations for estimating bubble point pressure, solution gas oil ratio, oil formation volume factor (FVF), oil compressibility for heavy and extra-heavy oils.

Heavy oil

The bubble point pressure

$$p_b = \left(\frac{56.434 \cdot R_s}{\gamma_g 10^{10.9267}\left(\frac{\gamma_{API}}{T+459.67}\right)}\right)^{\frac{1}{1.2057}} \tag{54}$$

Solution Gas Oil Ratio

$$R_s = \frac{\gamma_g \cdot p^{1.2057}}{56.434} \cdot 10^{10.9267} \cdot \frac{\gamma_{API}}{T+459.67} \tag{55}$$

Oil FVF uses equation (47) and (49).

Oil compressibility - Saturated

$$c_o = \frac{-2841.8 + 2.9646R_{sb} + 25.5439T - 1230.5\gamma_g + 41.91\gamma_{API}}{p \cdot 10^5} + \frac{B_g}{5.6145B_o} \cdot \frac{dR_s}{dp} \tag{56}$$

Oil compressibility - Undersaturated

$$c_o = \frac{-2841.8 + 2.9646R_{sb} + 25.5439T - 1230.5\gamma_g + 41.91\gamma_{API}}{p \cdot 10^5} \tag{57}$$

Extra heavy oil

The bubble point pressure

$$p_b = \left(\frac{R_s}{\gamma_g}\right)^{\frac{1}{1.1128}} \cdot \frac{10.7025}{10^{(0.0169\gamma_{API} - 0.00156T)}} \tag{58}$$

Solution Gas Oil Ratio

$$R_s = \gamma_g \left(\frac{p}{10.7025} \cdot 10^{(0.00169\gamma_{API} - 0.00156)} \right)^{1.1128} \tag{59}$$

Oil FVF uses equation (47) and (49).

Oil compressibility - Saturated

$$c_o = \frac{-889.6 + 3.1374R_{sb} + 20T - 627.3\gamma_g + 81.4476\gamma_{API}}{p \cdot 10^5} + \frac{B_g}{5.6145B_o} \cdot \frac{dR_s}{dp} \tag{60}$$

Oil compressibility - Undersaturated

$$c_o = \frac{-889.6 + 3.1374R_{sb} + 20T - 627.3\gamma_g + 81.4476\gamma_{API}}{p \cdot 10^5} \tag{61}$$

Glasø oil

The Glasø correlation contains equations for estimating bubble point pressure, solution gas oil ratio, and oil formation volume factor for North Sea oils.

The bubble point pressure

$$\log(p_b) = 1.7669 + 1.7447\log(\chi_1) - 0.30218\log(\chi_1)^2 \tag{62}$$

Solution Gas Oil Ratio

$$R_s = \left(\frac{\chi_2 \gamma_{API}^{0.989}}{T^{0.172}} \right)^{\frac{1}{0.816}} \gamma_g \tag{63}$$

Oil FVF - Saturated

$$\log(B_o - 1) = -6.58511 + 2.91329\log(y) - 0.27683\log(y)^2 \tag{64}$$

Oil FVF at undersaturated condition uses equation (49).

The oil compressibility used the equation obtained from the Vasquez-Beggs correlation.

Oil viscosity models

The oil viscosity models are presented in this section.

Vasquez-Beggs

Vasquez-Beggs correlation from 1978 was based on a large database, and is therefore applicable to a wide range of oils.

First, Beggs and Robinson developed an empirical correlation for determining the viscosity of dead oil.

$$\mu_{od} = 10^x - 1 \tag{65}$$

Second, the visocity at saturated condition

$$\mu_{os} = 10.715(R_s + 100)^{-0.515}(\mu_{od}^{5.44((R_s+150)^{-0.338})}) \tag{66}$$

Third, the visocity at Undersaturated condition

$$\mu_o = \mu_{os} \cdot \left(\frac{p}{p_b} \right)^{C_1 p^{C_2} (C_3 + C_4)^p} \tag{67}$$

Standing

This model, often referred to as either Beal or Standing, was developed by Beal and fitted by Standing.

Viscosity - Dead oil

$$\mu_{od} = (0.32 + 1.8 \cdot 10^7/\gamma_o^{4.53}) \left(\frac{360}{T + 200} \right)^{(10^{0.43+8.33/\gamma_o})} \tag{68}$$

Viscosity - Staurated

$$\mu_{os} = (0.20 + 0.80 \cdot 10^{-0.00081Rs}))\mu_{od}^{0.43+0.57\cdot 10^{-0.00072Rs}} \tag{69}$$

Visocity - Undersaturated

$$\mu_o = \mu_{os} + 0.001(p - p_b)(0.024\mu_{os}^{1.6} + 0.038\mu_{os}^{0.56}) \tag{70}$$

Egbogah

The Egbogah correlation contains two methods for calculating dead oil viscosity using a modified Beggs and Robinson viscosity correlation and a correlation that uses the pour point temperature T_{pp}.

Viscosity - Dead oil

$$\begin{aligned} \log(\mu_{od} + 1) = & -1.7095 - 0.0087917T_{pp} + 2.7523\gamma_o \\ & + (-1.2943 + 0.0033214T_pp + 0.9581957\gamma_o)\log(T - T_{pp}) \end{aligned} \tag{71}$$

Viscosity - Staurated use equation (66).

Viscosity - Undersaturated

$$\mu_o = \mu_{ob} \left(\frac{p}{p_b} \right)^{(2.6p^{1.187}\exp(-11.513-8.98\cdot 10^{-5}p))} \tag{72}$$

De Ghetto

The De Ghetto et al. correlation estimates the oil viscosity for both heavy and extra-heavy oils.

Heavy oil Viscosity - Dead oil

$$\log(\mu_{od} + 1) = 2.06429 - 0.0179\gamma_{API} - 0.70226\log(T) \tag{73}$$

Viscosity - Staurated

$$\mu_{os} = 0.6311 + 1.078x - 0.003653x^2 \tag{74}$$

Visocity - Undersaturated

$$\mu_o = 0.9886\mu_{os} + 0.002763(p - p_b)(-0.01153\mu_{os}^{1.7933} + 0.0316\mu_{os}^{1.5939}) \tag{75}$$

Extra heavy oil Viscosity - Dead oil

$$\log(\mu_{od} + 1) = 1.090296 - 0.021619\gamma_{API} - 0.61784\log(T) \tag{76}$$

Viscosity - Staurated

$$\mu_{os} = 2.3945 + 0.8927x + 0.001576x^2 \tag{77}$$

Visocity - Undersaturated

$$\mu_o = \mu_{os} - (1 - \frac{p}{p_b})\left(\frac{10^{-2.19}\mu_{od}^{1.055}p_b^{0.3132}}{10^{0.0099\gamma_o}} \right) \tag{78}$$

Gas PVT model

The Gas PVT model contains the calculation of gas viscosity estimation, gas pseudo critical model, and gas compressibility Z-factor model with known composition. Z-factor in the PVT property always needs accurate determination in a gas condensate reservoir.

Gas viscosity models

The gas viscosity models employ Lee and Lee modified.

Lee

$$\mu_g = 10^{-4} \frac{(9.4 + 0.02M)T^{1.5}}{209 + 19M + T} \exp[X\rho_g^{2.4-0.2X}] \tag{79}$$

where M is the molar weight and $X = 3.5 + 986/T + 0.01M$.

Lee modified

$$K = \frac{(k_1 + k_2 M)T_3^k}{k_4 + k_5 M + T} \tag{80}$$

$$X = x_1 + x_2/T + x_3 M \tag{81}$$

$$Y = y_1 - y_2 X \tag{82}$$

$$\mu_g = 10^{-4} K \exp(X\rho_g^Y) \tag{83}$$

References

[1] B. Guo, W. C. Lyons, and A. Ghalambor. *Petroleum production engineering, a computer-assisted approach*. Elsevier Science & Technology Books, 2007.

[2] J. V. Vogel. Inflow performance relationship for solution gas drive wells. *Journal of Petroleum Technology*, pages 83–93, 1968.