

Chokes

Control of flowing wells is done with chokes. There are two types, adjustable and bean chokes. Chokes are typically sized in 64th of an inch. Chokes are most commonly set at the surface but there are downhole chokes used mostly offshore.

The flow rate in a flowing well is usually restricted by pressure constraints of the surface equipment. The ideal condition is when small variations in downstream pressure do not effect the tubing head flowing pressure. This implies a fluid flow through the choke at velocities greater than that of sound. This is critical flow of the fluid. A good rule of thumb is a tubing head pressure that is double the average flow line pressure.

$$p_{tf} = \frac{C \times GLR^5 \times q}{S^2} \quad (3-66)$$

where p_{tf} = THP, flowing, psia
GLR = Gas Liquid Ratio, scf/bbl
 q = gross liquid flow rate, bbls/day
 S = choke size, 64th of an inch
 C = Constant

Is the equation to calculate the flowing tubing head pressure given the flow rate, GLR and size of the choke for knife edge chokes with several simplified assumptions. This is not for an adjustable chokes, just bean chokes.

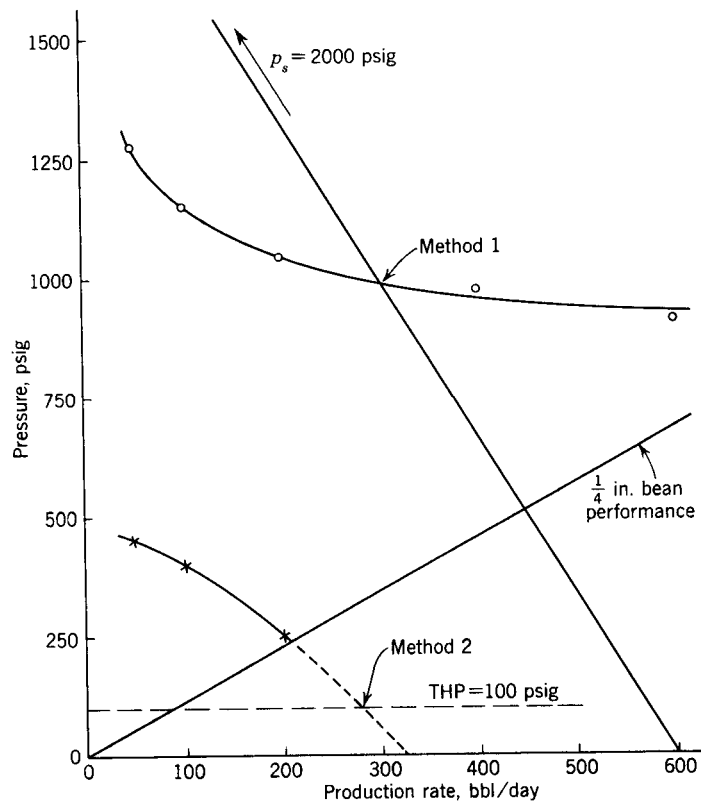
Gilbert using data from the Ten Section Field of California obtained an empirical formula,

$$p_{tf} = \frac{10 \times GLR^{.546} \times q}{S^{1.89}} \quad (3-67)$$

Ros also found an empirical choke equation

$$P_{wf} = \frac{17.40 \times GLR^{.5} \times q}{S^2} \quad (3-68)$$

Using these formulas a choke performance graph for different size chokes can be obtained and plotted with the IPR and THP curve to help in the production planning of the well.



Choke for Gas Wells

The equation for single phase gas flow through a choke is the following:

$$q_{sc} = 3.505 D_{64}^2 \left(\frac{p_1}{p_{sc}} \right) \alpha \sqrt{\left(\frac{1}{\gamma_g T_1} \right) \left[\frac{\gamma}{\gamma - 1} \right] \left[\left(\frac{p_2}{p_1} \right)^{\frac{2}{\gamma}} - \left(\frac{p_2}{p_1} \right)^{\frac{(\lambda+1)}{\gamma}} \right]} \quad (3-69)$$

where

α is the flow coefficient of the choke

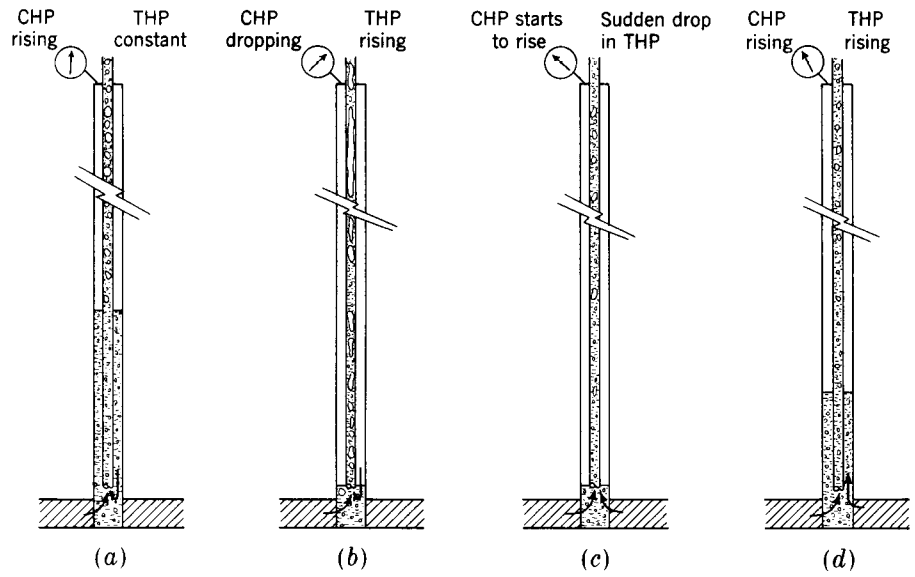
γ is the heat capacity ratio, C_p/C_v

p_1 is the upstream pressure, psi

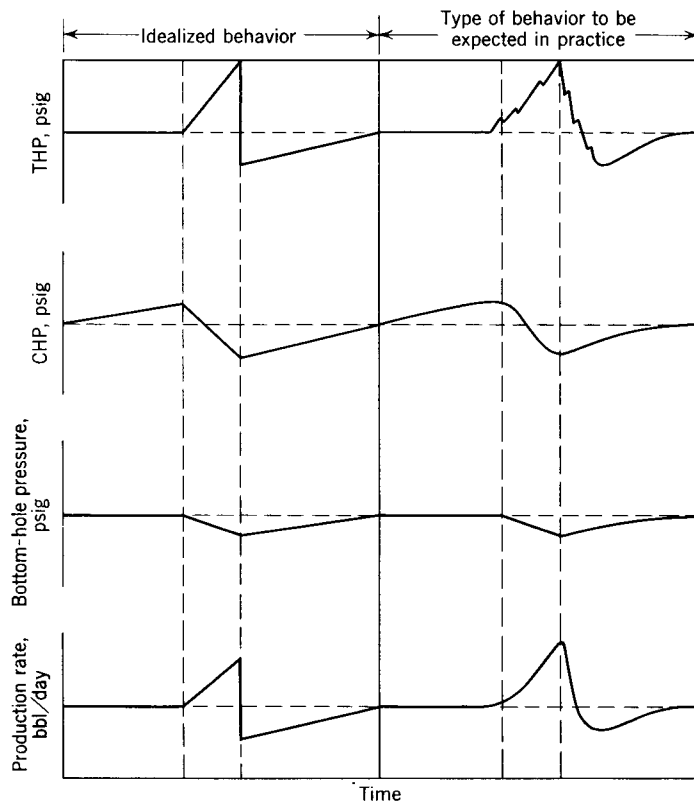
p_2 is the downstream pressure, psi

Heading Cycle

Heading can occur in wells with no packer and with relatively low GLR, and producing free gas from the formation. An example of this is when a well that is flowing at a stable rate is opened up to increase the flow by lowering the THP. The well starts with the liquid level in the casing at the tubing shoe, the decrease in producing BHP from the increase in production causes the flow of some of the gas stored in the casing annulus into the tubing which increases the GLR of the fluid in the tubing which lowers the BHP even more again increasing the flow rate from the formation. This flow rate cannot be sustained by the GLR from the formation so when the flow of gas from the annulus stops, the flow rate that can be accommodated up the tubing drops and the surplus liquid being produced by the formation starts going up the annulus. This results in the BHP increasing because of the weight of the liquid in the annulus, which causes the flow rate from the formation to decrease down to what the tubing and the choke size can handle. At this point the free gas produced by the formation starts migrating back into the annulus displacing the liquid, the CHP at this point will start to rise, this will continue till all the liquid is displaced and the free gas level is at the tubing shoe. When this occurs the GLR in the tubing starts to increase since all the gas being produced by the formation is now going up the tubing and this will start the cycle to begin again by lowering the producing BHP and then allowing the casing gas to be produced up the tubing. The following figure shows the heading cycle starting with the annulus liquid being displaced. The next figure shows the pressure profiles during the heading cycle.



In (a) the liquid from the annulus is being produced up the tubing, (b) the gas is now being produced up the tubing, (c) all formation production is going up the tubing and no annulus production, (d) liquid starts to move in the annulus.



The example here started with opening the well up but it can be seen that if the assumed conditions exist any disturbance in the flow can cause heading. The time involved can vary greatly, from a few hours to a day for a cycle to be complete. It will usually occur in well with low flowing rates and pressures. Also the storage of the annulus is needed for the heading to occur so a production packer can solve the problem. We have no control over the problem of free gas production from the reservoir except by possibly lowering the production thereby rising the pressure in the formation, but this may also result in killing the well since we are almost always dealing with wells well below bubble point pressure that are producing at low rates and pressures in these cases.

The heading cycle is an inefficient use of the reservoir energy for production. A stable GLR will produce more fluid of a period of time than will the varying GLRs of the heading cycle. The heading cycle can also be an indication that the well will need to be put on artificial lift to maintain production, the reservoir energy is starting to get to low to lift the fluid to the surface at the wanted rates.

The way to monitor a well for heading is the CHP. A recordable pressure gauge can be put on the well if heading is suspected because of lower production or if the pumper starts to notice a variation in the CHP. The THP is not a good indicator of heading because some of the flow regimes vary the pressure at the choke, such as slug flow.