WATER-HAMMER PRESSURE—AN OFTEN OVERLOOKED DETAIL IN WELL TREATMENT DESIGN

Stan Stephenson, Larry Mitschke and Joe Beisel
Halliburton

ABSTRACT

When fracture-stimulating a well, maximum wellhead pressure can be reached seconds after the high-pressure pumps are stopped, following a rapid pressure increase during a "screenout" or other sudden flow stoppage. This maximum pressure is caused by a water-hammer effect. When this effect is ignored, maximum allowable wellhead and downhole pressures can be exceeded, even if pumping stops before reaching the maximum allowable pressure. This paper explains a method that can be used to calculate the water-hammer pressure. Data from several case-study wells demonstrating the water-hammer effect are compared to the calculated values obtained from the methods described in this paper. For tight formation screenouts, the predictions are within 12% of the maximum pressure recorded. Methods to help minimize the pressure surge are also presented. Use of these methods can minimize the risk to people, the environment, and equipment caused by the potential water-hammer pressure surge often overlooked in well treatment designs.

BACKGROUND

Water-Hammer Wave

When a well suddenly screens out, the kinetic energy of the moving fluid in the well is converted to potential energy (pressure) of a static fluid. This absorbed kinetic energy is the water-hammer pressure. A liquid, although usually considered to be incompressible, is actually slightly compressible. Because a liquid is compressible and has mass, it can be modeled as a mass and a spring. The following mass-and-spring analogy (Figure 1) describes the phenomenon of water-hammer pressure in a liquid.

Consider the fluid flowing down the workstring as multiple masses and springs. For demonstration purposes, two masses and three springs within a frame are used to describe the fluid from the surface to the perforations in a well. The nine frames of Figure 1 follow the progression of the mass-and-spring analogy through one complete cycle. If fluid is being pumped down the workstring and then suddenly stops because of an instantaneous screenout, the upper mass will push on the lower mass through the middle spring.

The push of the upper mass through the middle spring along with the downward push of lower mass will compress the lower spring (Frame 2). This compression of the spring is equivalent to a rise in bottomhole pressure (BHP) in the well. The downward momentum of the masses will continue to compress the middle and lower springs until they absorb all the energy of the moving masses (Frame 3). After fully compressing the middle and lower springs, the masses will rebound, and their upward momentum will cause compression of the upper two springs and extension of the lower spring (Frames 4 through 7). This will cause a rise of surface tubing pressure and a drop of BHP. This movement of the springs and masses can be said to constitute the "water-hammer wave."

If there were no frictional losses, the springs and masses would continue to oscillate indefinitely. However, in real life, the fluid friction in the workstring and leakoff to the formation causes the fluid-pressure oscillations of the water-hammer wave to decay.

Fluid Compression Pressure

In Figure 1, Frames 2 through 4, the upper spring is extended. This is equivalent to a fall in surface pressure. If the fluid flow into the well were magically stopped at the exact instant that the screenout occurs downhole, then there would be a sudden drop of surface tubing pressure after the screenout, as indicated by the mass-and-spring analogy. However, in reality, during the time that the water-hammer pressure is rising downhole, fluid continues to be pumped into the well. The transit time for the water-hammer pressure wave to reach the surface depends on the well's depth and the speed of sound in the fluid. Therefore, the deeper the well, the more the transit time, and consequently, more fluid will be compressed into the tubing before the water-hammer pressure wave reaches the surface. This compressed fluid is the cause of fluid-compression pressure.

Immediately after the screenout, the flow rate at the screenout is zero. As fluid continues to compress on the bottom of the well, the point of zero flow rate rises toward the surface. This reduces the average flow rate and resulting friction pressure in the tubulars. This friction pressure can be further reduced by dropping the flow rate into the tubulars. If the surface flow rate is suddenly cut because of the rise in pressure, there will be some additional reduction in surface pressure, as shown in Figure 1 (Frames 2 through 4). If the reduction in friction pressure and pressure reduction because of flow stoppage at the surface is occurring faster than the rise in fluid compression pressure, then the first reflected wave after the screenout will not be as severe as it could be. As a result, the second reflected wave can be worse than the first. An example of the second wave being larger than the first is shown in Figure 2 from a well treatment in western Oklahoma.

Times 659, 669, 679, and 689 are some of the decaying peaks of the water-hammer wave which occur at equal time increments of approximately 10 seconds corresponding to the water-hammer wave travel time from surface to bottomhole and back to the surface. Midway between these surface peaks are valleys that correspond to maximum pressure peaks downhole. Therefore, five seconds before from 659 is the point where the bottomhole pressure reached its first peak. Another five seconds before this at 649 is where the final tight screenout occurred downhole. Times 649 and 654 correspond to Frames 1 and 3, respectively, from Figure 1. From 649 to 657, fluid continues to be pumped into the wellbore even though it has already screened out downhole at 649. During this time, as previously mentioned, fluid is compressed in the wellbore while the average flow rate in the wellbore decreases. At 657, the flow rate starts going down and there is an additional loss of friction pressure, which results in the first peak being less than the second.

EQUATIONS

To solve for the water-hammer pressure, the kinetic-energy equation is set equal to the potential-energy equation and then the resulting equation is rearranged to yield the pressure. This is shown in the following equations.

Kinetic energy = energy of a moving mass

$$KE = \frac{1}{2}\rho L A v^2 \qquad \textbf{(1)}$$

Potential energy = energy of a mass at rest

$$PE = \frac{1}{2}\frac{LAfP^2}{\beta_e} \qquad \textbf{(2)}$$

At screenout: kinetic energy = potential energy

$$P = v\sqrt{\frac{\rho\beta_e}{f}} \qquad \textbf{(3)}$$

Where:

KE = kinetic energy term
PE = potential energy term
ρ = absolute fluid density
L = flow length
A = flow area
v = fluid velocity
f = liquid fraction of proppant laden gel

$$f = \frac{\left(\frac{Denb + Avgpc}{1 + \Pr opsv * Avgpc}\right)}{Denb * \Pr opsv - 1} \Pr opsv - 1 \quad \textbf{(4)}$$

Denb = density of base gel
Avgpc = average proppant concentration
Propsv = proppant specific volume
P = water-hammer pressure in fluid
$\boldsymbol{\beta_e}$ = effective bulk modulus of pipe and fluid

From the equation for water-hammer pressure above, it is apparent that the higher the velocity, density, and bulk modulus of the fluid, the higher the pressure wave will be when the fluid is suddenly stopped. A lower volume fraction of liquid also increases this final pressure. Because only the velocity is outside the square root, the velocity will have the greatest impact on the pressure.

Fluid Compression

The basic equation used to calculate the fluid-compression pressure is the equation defining the bulk modulus.

$$\beta = \frac{\Delta P * V * f}{\Delta V} \quad \textbf{(5)}$$

Where:

β = bulk modulus
ΔP = compression pressure
V = volume of fluid
ΔV = change in volume (how much additional fluid is pumped into a closed system)

Rearranging this equation allows for the calculation of the compression pressure:

$$\Delta P = \frac{\Delta V * \beta}{V * f} \quad (6)$$

An effective bulk modulus can be calculated from the bulk modulus of the fluid and the bulk modulus of the tubing or casing. The following equations are used to combine these.

$$\beta e = \frac{1}{\frac{1}{\beta p} + \frac{1}{\beta f}} \quad \textbf{(7)}$$

$$\beta p = \frac{TE}{D} \quad \textbf{(8)}$$

where:

β_p= bulk modulus of tubing or casing
T = wall thickness
E = modulus of elasticity = 30,000,000 psi
D = ID of tubing or casing
β_f = 300,000 psi to 400,000 psi

EXAMPLE ANALYSIS

The water-hammer seen at the end of the well treatment shown in Figures 3 and 4 was a textbook example observed and analyzed many times before. Figure 3 shows the pressure and rate during this treatment. Figure 4 shows data around the time of the sudden screenout. At Flag 1, some pumps have already been brought offline from the treating rate of 35 bbl/min. A loss of friction pressure and thereby a lower treating pressure with the lower flow rate would be expected. Because the treating pressure did not lower with a lower flow rate, the screenout has started. Between Flag 1 and 2, the rate is again dropped with no drop in pressure. The screenout continues. At Flag 3, there is a rapid pressure rise. This is the result of a final tight screenout downhole. On Figure 4, the time between pressure peaks is shown to be about 4.5 seconds. Therefore, the travel time for a pressure wave from bottomhole to the surface is about 2.25 seconds. Flag 2 is drawn 4.5 seconds before the first surface pressure peak. Therefore, Flag 2 is the point in time where the tight screenout happened downhole but is not seen at the surface for another 4.5 seconds (2.25 seconds to compress on bottom and another 2.25 seconds to reflect to the surface). At Flag 2, the rate was 23.5 bbl/min at the tight screenout downhole. The water-hammer calculator based on the equations listed in the description above determined that the water-hammer pressure would be about 3,500 psi when the 23.5 bbl/min column of fluid is suddenly stopped. In the 2.25 seconds after the screenout, fluid continues to be pumped into the wellbore while little or no fluid is leaving to the formation. During this time, friction pressure is lost (no flow near the screenout) to offset the compression pressure. Typically, the maximum compression pressure is the lesser of the calculated compression pressure or the friction-pressure. When the compression pressure becomes larger than the friction pressure, there is no additional friction pressure loss and the surface pressure starts rising whether or not the wave has reached the surface. In this case, the compression pressure became larger than the friction pressure, so the friction pressure of about 1,800 psi was used in place of the compression pressure. When this pressure and water-hammer pressure are added to the surface treating pressure, the maximum peak pressure to be expected is about 12,800 psi (1,800+3,500+7,500). In Figure 4, the peak pressure measured was 12,700 psi. The100-psi difference between the actual and calculated pressure was 0.8% error.

If the flow rate had not been reduced because of a rising pressure and the tight screenout had occurred while still pumping 35 bbl/min, the peak pressure could have been 14,500 psi as compared to the 12,800 psi for this case.

In this case, as in the one shown in Figure 2, the first reflected peak is less than the second. This peak occurs between Flag 3 and Flag 4. Flag 4 shows the slight dip between the first two peaks.

Table 1 shows the measured and calculated pressures from 10 other well treatments. If there is a sudden tight screenout, the calculated pressure is very close to the measured pressure. This follows the fact that the calculation method is based off conversion of all of the kinetic energy (moving mass of fluid) to potential energy (pressure in a fluid at rest). If there is substantial leakoff (not a tight screenout), then the predicted pressure can be substantially higher.

CONCLUSIONS

1. The peak pressure after a sudden flow stoppage is because of both a water-hammer component and a fluid-compression component.
2. Fluid velocity during the treatment has the greatest impact on the water-hammer portion of the peak pressure after a sudden screenout. The fluid velocity is also the only component that can be changed to have an immediate impact on the potential pressure after the screenout.
3. The fluid density and bulk modulus, which also affect the water-hammer portion of peak pressure, cannot be quickly altered because the fluid in the wellbore must be displaced to alter these parameters.
4. Because the friction pressure is partially offset by the compression pressure after the screenout, keeping the friction pressure minimized also minimizes the portion of the peak pressure caused by fluid compression.

Table 1
Measure and Calculated Peak Pressures.

Well	Tubing ID,-in.	Calculated Depth, ft	Rate Before Screenout, bbl/min	Treating Pressure Before Screenout, psi	Friction Pressure Before Screenout, psi	Maximum Surface Pressure Predicted, psi	Maximum Surface Pressure Measured, psi	Error, %
1	3.92	10,057	26.2	7,384	1,854	11,276	9,251	21.9
2	3.92	9,820	43.9	7,227	2,465	13,861	7,826	77.1
3	—	10,733	25.8	5,347	1,306	9,563	7,572	26.3
4	3.92	9,788	20.4	5,973	973	9,135	8,160	**12.0**
5	4	7,052	34.6	4,820	1,164	10,048	5,687	76.7
6	4	10,297	25.3	5,692	977	9,529	8,508	**12.0**
7	2.992	7,820	4.6	5,868	1,325	6,625	6,607	**0.3**
8	2.992	10,915	22.6	6,776	2,817	12,775	7,776	64.3
9	2.441	7,220	26.5	7,506	4,329	16,957	12,017	41.1
10	2.441	6,608	25	6,842	3,974	16,313	7,320	122.9

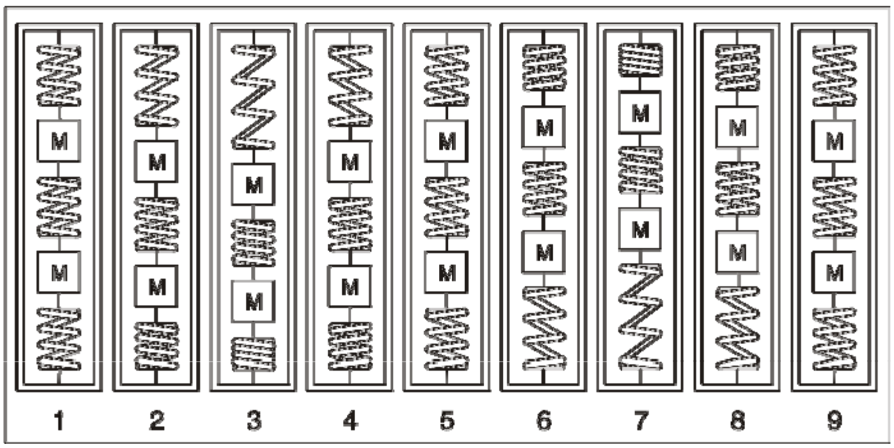

Figure 1 – Mass-and-spring analogy.

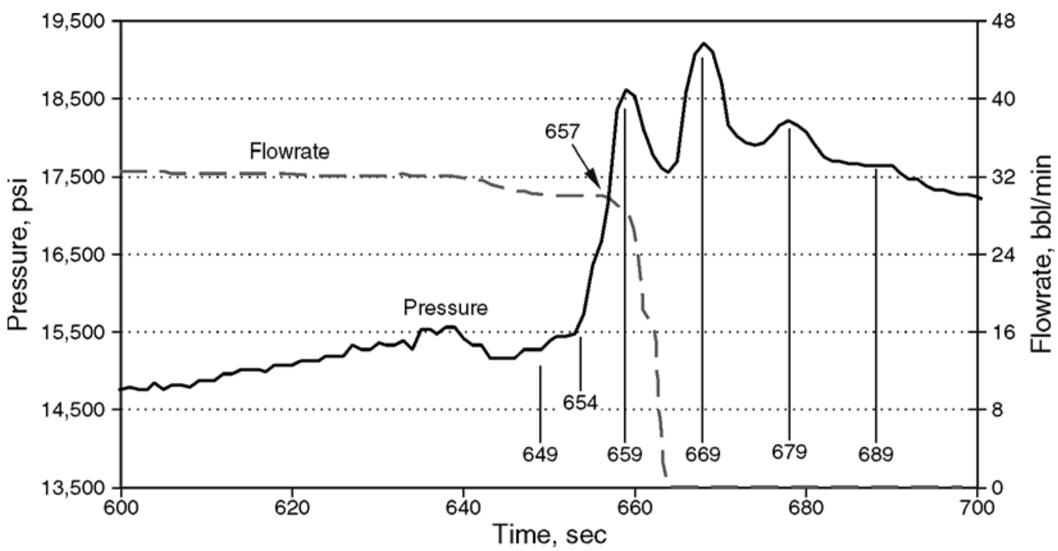

Figure 2 – Second pressure wave larger than first.

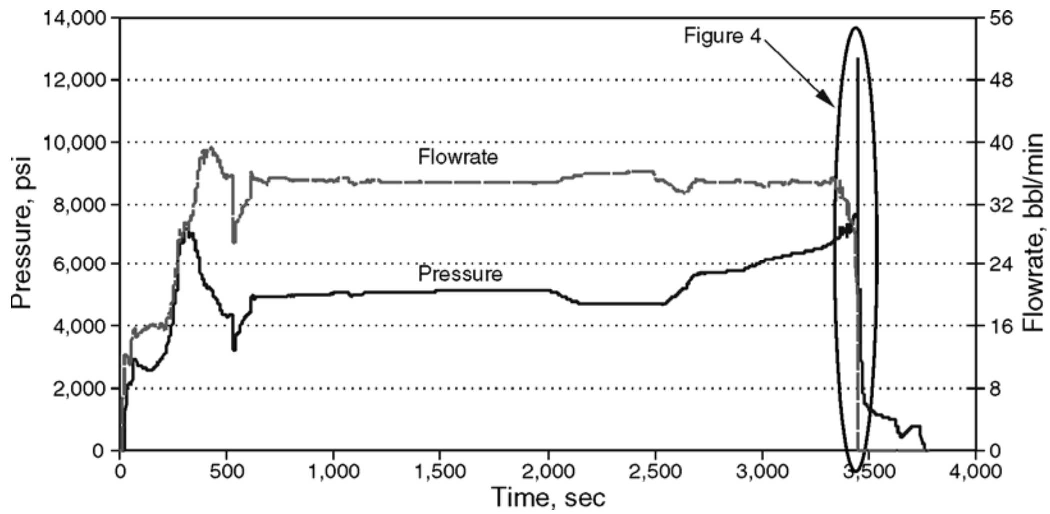

Figure 3 – Water-hammer at the end of a well treatment.

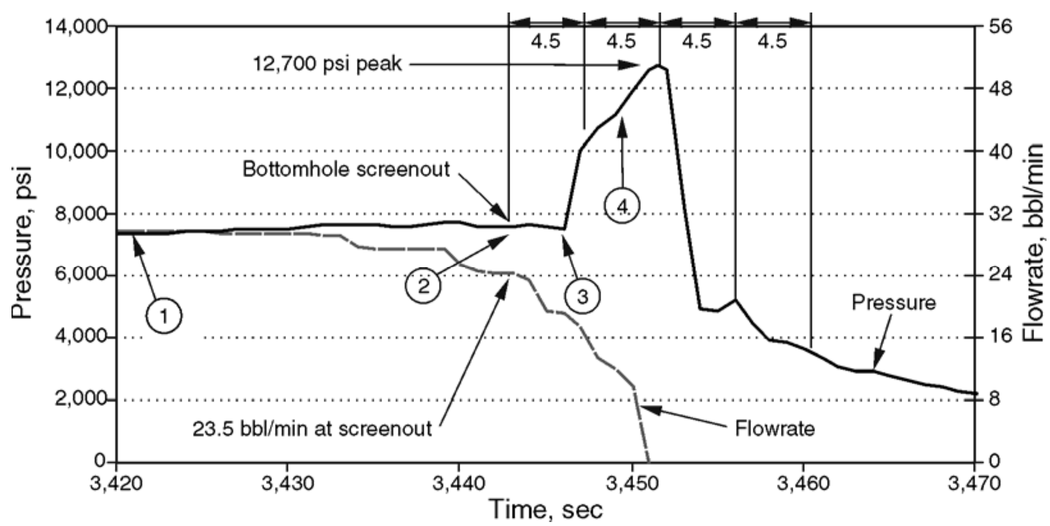

Figure 4 – Magnification of water-hammer in Figure 3.