TUBING BACKPRESSURE ON ROD PUMP WELLS

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ABSTRACT
One of the most misunderstood issues in sucker rod pumping is tubing back pressure. The great majority of wells that I have encountered in various fields have back pressure valves installed on the tubing side of a wellhead. However, a great many field personnel do not understand why back pressure is applied, how much to apply, and/or how it affects a well's performance. This paper will discuss the why, when, and how tubing back pressure is applied along with some misunderstandings and issues of its application.

INTRODUCTION

The use of back pressure valves on the tubing side of rod pump wells continues to be one of the most misunderstood and mismanaged practices. Leading factors are misconceptions due to a lack of knowledge, experience, and oilfield fallacies perpetuated by others. These can add costs and/or hurt production, but seldom get directly addressed.

BACKGROUND

Ideally, gas breaks out in the tubing-casing annulus such that little enters the tubing keeping the tubing relatively gas free. However, due to gas separator related issues and high pump inlet pressures, free and dissolved gas enters the tubing. As the fluid rises in the tubing and the hydrostatic pressure decreases, free gas will begin to form larger gas bubbles and dissolved gas will come out of solution forming more bubbles and lightening the fluid column. Ultimately the fluid may begin to flow out of the tubing potentially emptying several thousands of feet of tubing. This is found frequently in horizontal shale wells.

This issue can be reduced or resolved with improved gas separation and/or pumping a well off. Gas separation will remove free gas and pumping the fluid level down to near the separator inlet will reduce the pump inlet pressure to a point that relatively little gas comes out of solution in the tubing. Separator issues requires pulling a well while reducing the fluid level may potentially require multiple solutions that take time. In the meantime, keeping backpressure on the tubing can help reduce gas breakout and minimize a well flowing. However, misconceptions prevent field personnel from successfully applying backpressure.

MISCONCEPTIONS

Adding backpressure to the tubing does not affect formation productivity. The formation is affected by the producing bottomhole pressure that is determined by the hydrostatic pressure in the annulus. This may or may not be equivalent to the pump inlet pressure depending on the placement of the pump relative to the perforations. The hydrostatic pressure in the tubing or pump discharge pressure is "isolated" from the annulus by the downhole pump. The traveling and standing valves act as a type of "check valve" to minimize any leakage, fluid and pressure, to the annulus. Tubing backpressure will not reduce formation productivity.

Tubing pressure shall be limited to no more than 250 psi. This is true on heritage wells with wellheads that were built with low pressure connections and valves. In recent years, most wellheads have been built to a standard of 1500 psi with a double packed stuffing box being the limiting equipment. However, due to offset fracs many operators have raised the pressure rating of their rod pump wellheads to 5,000 or 10,000 psi with the limiting equipment being the backpressure valves that have max ratings to 2,500 psi. Despite this, many field personnel are hesitant to increase backpressure much above about 250 psi when additional pressure is required.

Adding backpressure makes a pump operate better. This is typically based upon getting more "movement" on the surface pressure gauge as the backpressure is increased. The reality is that a gauge with too high a range is utilized masking upstroke swings at low pressure. Raising the tubing pressure increases pressure swings on these gauges giving the appearance that the pump is pumping better.

Adding backpressure makes a pump operate better. Though, additional backpressure will raise the pump discharge pressure increasing the downward force on a traveling valve that may help it seal better but it also requires the pump to build more compressive pressure to unseat the ball which can be bad when battling gas in the pump. Backpressure will also increase the leakage rate on the upstroke reducing effective production on each stroke, but that may help increase pump fillage. Increasing pump fillage may result in a VFD controlled well speeding up which can further affect leakage and fillage. Depending on the downhole environment, additional tubing backpressure may help the pump operation positively or negatively or it may be a delusion. Issues arise when the focus is on one factor and other factors are disregarded resulting in an overall negative impact.

Gas at the bleeder is not a sign that a well is gas locked and bleeding the tubing or casing off will not improve the issue. The term “gas lock” refers to the pump – not the tubing. Bleeding the tubing or casing off may help to remove free gas from the system, but it will not make the pump operate better nor will it fill the tubing faster. Misunderstanding this will only result in gas being leaked to the atmosphere and the well will flow again.

IMPACT

The impact of raising the tubing pressure is that it will increase the pump discharge pressure thus raising the fluid load requiring more horsepower resulting in higher electrical costs and potentially overloading a pumping unit or changing the counterbalance. While these factors can impact operating costs, normally they are overshadowed by spills and/or loss production. Optimization is a balancing act that can be achieved with additional backpressure by raising awareness to all related impacts.

A well that flows off the tubing results in a loss of lubrication in the stuffing box that may ultimately burn out the packing resulting in a spill. Higher backpressures may require the stuffing boxes to be slightly tighter to prevent leakage during normal operations and can contribute to a short packing life. A stuffing box lubricator can help keep the polished rod and packing lubricated, but it is a short-term fix if produced fluids are absent as it can take hours to fill the tubing back up depending how much fluid flowed off and the pump rate. Keeping enough backpressure to keep a well from flowing will minimize spills, resultant costs, and loss production while increasing packing life.

Loss production can occur when a well is temporarily shut while troubleshooting a loss of fluid at the wellhead. A well can be improperly diagnosed as having a tubing leak or a bad pump or even a rod part after a well has flowed the tubing semi dry. Fluid loss in the tubing will reduce the fluid load and rod buoyancy which are signs of a tubing leak. A major fluid load loss may make one suspect a deep rod part. The inability to build pressure with a closed valve may make one suspect a downhole failure. Many companies will load and test the tubing, but inexperienced drivers have resulted in bad tests that seem to confirm a downhole problem. A misdiagnosis can result in a costly repair job that does not find a problem. Unfortunately, this happens more times than we care to admit due to inexperienced personnel. Load and test procedures and troubleshooting training help decrease this issue.

The loss of a fluid load due to the well flowing will often shut a well down when the controller senses a minimum fluid load or a malfunction setpoint due to a reduction in a peak load. These setpoints often require a manual reset resulting in downtime until someone can make it by the well. This may occur multiple times before it is recognized and addressed.

Some operators have pressure switches on the wellhead to shut the well down if a set maximum pressure is reached. The switch itself can create additional problems if the gauge’s maximum allowable pressure setting is too low restricting the setpoint. A Murphy switch is ideal as the pumper can adjust the set point on a well-to-well basis, but sometimes an enclosed switch is used that may require a technician to set. A question that should be asked is what the pressure switch is protecting. If the switch is located upstream of the backpressure valve, then it only protects the wellhead whereas if it is downstream then it protects the flowline. Many are installed upstream with pressure ranges up to 600 psi on a 5000psi rated wellhead.

Beyond not being able to set the needed backpressure, this alarm typically requires a manual reset resulting in more downtime.

Backpressure affects continuous chemical injection by changing flush volumes and in some cases chemical volumes. Flush and chemical injection volumes are set while the well is operating with a set amount of wellhead pressure. The pressure will increase while the well is flowing and decrease after it stops. Those pressure changes will affect the chemical program plus if the well is shut down for reasons previously mentioned then chemical injection continues without any flush volume. This issue can affect downhole treating and potentially change a failure's root cause.

The backpressure valve itself will have issues that can cause a low operating pressure if the ball and/or seat is cut out or breaks, or the spring is damaged. An overpressure issue can result from a plugged valve due to paraffin or a foreign material. In one case, an operator had to put their backpressure valves on an annual PM program to minimize stuffing box leaks due to overpressure incidents.

SETTING BACKPRESSURE

There is no set procedure to determine how much backpressure is needed to minimize the chance that a well will flow. There are wells with up to 900 psi backpressure, but around 400-500 psi is typical in the Permian Basin. Ideally, one can add backpressure on a well that is actively flowing until it stops flowing, monitor it, and adjust as needed. I recommend raising the pressure in 100 psi increments until a well quits flowing off and reduce the pressure in 50 psi increments if one is uncertain if the current pressure is required. Settings will change over time.

Automation that monitors and can trend tubing pressures is invaluable in being able to see spikes in pressure that are indicative of a well flowing. The maximum pressure can be obtained to assist in determining backpressure settings and assist in troubleshooting.

RECOMMENDATIONS

Develop best practices for adding backpressure to a rod pumped well, maximum allowable pressure setting for each lease or field based upon wellhead ratings, and well troubleshooting. Procedures to properly load and test a well help ensure a good test is accomplished. Distributing this information to new hires is essential to minimizing the impacts.

Continuous training is critical. Classroom training is helpful, but onsite training better. Identifying "problem" wells that intermittently flow and reviewing them monthly with all personnel can increase understanding and knowledge.

Communicating and questioning the norm can often lead to easy solutions. Do all wells that shut down due to a high pressure situation require a manual reset or can they automatically reset? Why was a 2000 psi pressure gauge installed rather than a 1000 psi or less gauge? Does the pressure switch help or hinder setting the backpressure?

CONCLUSION

Backpressure adds operational costs to a well and at the same time can prevent additional costs due to leaks, downtime, and preventable repair costs.

Misconceptions, and a lack of field training and recommended practices decrease optimizing backpressure settings, troubleshooting, and related equipment.

REFERENCES

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