# LOW-PRESSURE LATERAL CLEANOUTS: CANDIDATE SELECTION, TECHNIQUES, & TRIAL

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## BACKGROUND:

Modern horizontal oil and gas field development programs often require cleaning out a lateral to reverse negative production impacts and to maximize well performance. Improving our ability to select, execute, and optimize lateral cleanout (CO) jobs will be critical both now and in the decades ahead to maximize asset value.

This paper specifically addresses horizontal low-pressure lateral COs. This category of well work has grown in favor as a technique to restore production. Its most common use is to reverse the negative production impact on a base well or parent well after a frac hit, due to a sand bridge (or bridges) in the lateral section.

This type of work should not be confused with a lateral frac plug drill out (DO). DO operations are the last phase of the completion operations prior to a well being brought online for flowback (FB), which is outside the scope of this discussion. The heart of this discussion involves jobs hereinafter referred to as lateral COs–performed after the completion phase and later in the life of a horizontal well.

**Why are lateral COs relevant?**
The high pressure generated while pumping frac water and sand during stimulation of a new well often connects to the base well (a completed well adjacent to or near the well that is being stimulated). This connection is made within the reservoir through previously stimulated rock volume (SRV), newly created SRV, existing natural fracs within the reservoir matrix, and/or faulting. This connection during the frac can shear the previously placed proppant pack near-wellbore and transport the sand from the base well's original completion back into its own lateral. This transported sand, now back in the lateral, either reduces the cross-sectional flow area or forms a solid bridge, both of which negatively affect production.

Herein lies the relevance of this topic: clearing laterals and removing bridges to restore base wells to original production levels.

Laterals can also benefit from being cleaned out for several other reasons, including wellbore prep ahead of a re-frac, production enhancement as part of an acid stimulation along a lateral, running casing patches, cleaning out on top of a fish, and a variety of other applications.

**Why can lateral COs be difficult and what is meant by "low pressure"?**
Cleaning out laterals can be difficult jobs with inherent risk. Additionally, these jobs only become more challenging as wells age and the bottom hole pressure (BHP) diminishes. Often, the volume of sand that was brought into the well from the offset frac is significant and dictates that circulation is the only economical method to clean out the lateral.

Circulation, in this scenario, means pumping down either tubing or the annulus and taking returns up the other side to clean out debris inside lateral wellbore. Basically, fluid is pumped down and circulated back out with the sand coming out on the "returns" side.

Other tools and techniques, such as Venturi tools that vacuum the sand out into catch chambers (or cavities), similar to a shop vac, can be an excellent option in some circumstances. However, for wells with high sand volumes, these tools can be uneconomical. The high volume of sand would require numerous trips in and out of the hole. In cases of higher volumes of sand with long laterals, the circulation method is the most efficient and economic method to clean out the lateral.

The level of difficulty in establishing circulation for a CO in these jobs is dictated by numerous factors, including shut-in bottom hole pressure (SIBHP), true vertical depth (TVD), and the extent of hydraulic leakoff. Hydraulic leakoff is determined by the amount of wellbore connection to the SRV, general matrix natural fracture connectivity, and the degree of faulting that may be present. In many wells in the Delaware basin (and often in other basins, as well), these factors will not allow for circulating straight fresh water during workover operations to clean out the lateral. The hydrostatic pressure of the fluid pumped during circulation attempts in the vertical section of the well can exceed the SIBHP of the well. If water is applied in these conditions, due to hydraulics, the fluid applied will simply leak into the matrix (reservoir) and be lost. This is commonly referred to as the well “drinking” the fluid applied. For purposes of this document, a well that drinks fluid and is not capable of circulation with water will be referred to as a “low-pressure” well.

Therefore, without an alternative method to establish circulation, low-pressure lateral COs cannot be performed. This paper presents and evaluates alternatives for consideration.

## OVERVIEW:

In today’s world, mastering low-pressure lateral cleanouts is a critical skill set for production/operations engineers. These jobs can often be the last tool in their toolbox to optimize and maximize asset value from a horizontal oil and gas well. This paper is intended to increase industry awareness and understanding of this tool and help engineers/operators reach this goal.

This paper will cover three parts:

- Part 1 – Overview of candidate selection criteria for lateral cleanouts
- Part 2 – Lateral cleanout techniques and remediation method selection guide
- Part 3 – Trial overview of microbubble/aphron fluid system

## PART 1 - OVERVIEW OF CANDIDATE SELECTION CRITERIA FOR LATERAL CLEANOUTS:

This paper focuses on low-pressure lateral COs, not horizontal frac plug DO. Specifically, this paper addresses wells that were frac hit and have suffered significant production impairment.

A frac hit can impact a well’s production in various degrees, listed below in order of severity:

1. positive (uplift)
2. no change (neutral)
3. mild (negative)
4. moderate (negative)
5. severe – no flow (negative)

This paper will focus on severity levels 4 and 5 with moderate to severe negative impacts. It will not address candidate selection for other reasons for CO (such as potential re-fracs, liner/casing repairs, and lateral enhancement for distributed acid jobs). However, many of the fundamentals of candidate well selection will apply to those situations, to some degree.

As with many activities in well work, successful lateral COs begin with proper well selection. Across our industry, literally thousands of laterals could be cleaned out.

**A key point to remember is that *all* wells have some kind of debris in the lateral and *could* be cleaned out. However, that does not mean all laterals *should* be cleaned out. Ultimately, it comes down to economics.**

To gauge the projected economic return for the job in question, it is important to evaluate several factors before proceeding with project execution.

Paying close attention to candidate selection criteria is critical because lateral COs should not be considered routine or "cookie-cutter" jobs. They require keen engineering judgment and technical discipline for both candidate well selection and execution. When someone in the industry says, "we can just clean out the lateral," an appropriate response is to pause and complete a detailed engineering evaluation before moving forward. Evaluation should include a scrutiny of the well history, production potential, determining contingency(ies) required, and an assessment of risk. These considerations should apply when collecting costs to build an Approval for Expenditure (AFE), which requires forecasting production response and running economic returns.

Primary candidate selection criteria for the well being considered for a lateral CO after a frac hit should be based on the following criteria:

1. **Is there a sharp drop in total fluids?** - **<u>Primary Indicator #1</u>**
   Perform proper decline curve analysis (DCA) to evaluate past performance and well expectations. **If a sharp drop in total fluids was not observed, discontinue evaluation – this is not a good well for a lateral cleanout.** Do not focus on only the oil phase—the total fluids must be the evaluation metric.

2. **After attempting to bring the well back online (BOL) after the frac hit, does the pressure indication at the surface (or downhole gauge—DHG—if available) indicate that there is no more connection from surface to the reservoir, that a bridge potentially has been formed?** – **<u>Primary Indicator #2</u>**
   If there is a clear indication during the frac or after the well is BOL that the well will no longer build up pressure in a manner that is consistent with normal operating conditions, then the well may have a sand bridge. Either condition one (described above) or condition two (described here) are a requirement for lateral CO.

3. **Did the well see a pressure spike that aligns with timing of an adjacent frac job?**
   An otherwise unexplained surge in pressure aligned with pumping frac stages on target well coupled with criteria 1 (above) begins to make a stronger case for a CO candidate. This is not a hard requirement, especially if measurement systems are not available. However, not seeing a clear indication of a pressure signature should offer pause and a deeper evaluation before selecting that well as a CO candidate.

4. **Is this area known to be highly connected rock?** Have other analog wells in this area, bench, and/or formation had negative-impact frac hits prior to this? Is there micro seismic or other geologic information telling us that the reservoir can easily transmit pressure?
   Other prior frac responses in the area and results from prior production recoveries with or without a lateral cleanout should be considered. Also, if there is faulting or severe connectivity, establishing circulation could be extremely difficult; therefore, proceed with caution.

5. **Has there been an increase in sand observed at the surface?**
   If an increase and/or large influx of sand has been observed in separators, other surface equipment, or flow lines, etc., then this is evidence that the well did, indeed, get hit by a frac. This alone definitely does not warrant a CO, but it is another piece of evidence to consider.

6. **Ultimate Key: Does the project for the well under consideration meet the required economic metrics?**
   Using proper DCA, generate forecasts of oil, gas, and water for expected uplift, if the project were executed. Gather the best cost estimate to build the AFE, making sure to build in appropriate contingency into the cost estimate. Calculate break-even costs accordingly. After careful review, determine if the job makes sense based on the given risk/reward criteria.

Other considerations not listed above may be relevant considerations, as this is not intended to be an exhaustive list of criteria.

**In summary:** Evaluate the totality of the circumstances by answering the questions discussed above and using engineering judgment, then consider if the job makes sense for your given application. **Remember, *all* wells have debris in the lateral and CAN be cleaned out, but it does not necessarily mean that they SHOULD be cleaned out.**

## PART 2 – LATERAL CLEANOUT TECHNIQUES & REMEDIATION METHOD SELECTION GUIDE:

As stated earlier, this discussion is focused on low-pressure lateral COs that have been frac hit and have significant volumes of sand that would require circulation to be established for the well to be economically cleaned out. Also established that since the well is low pressure, circulation cannot be established without some alternative technique that would keep the well from "drinking" the traditional fluid systems.

***Options presented here are:***

1. Divert perforations to control losses (not the focus of this paper)
2. Lower the hydrostatic gradient of the fluid system with nitrogen or foam air systems
3. Lower the hydrostatic gradient of the fluid system with microbubbles

***Option 1 - Diverter:***

Traditional methods to divert perforations have been around for quite a while. These include pumping sweeps and stages of rock salt or "bio-balls" that are intended to eventually plug off and seal the thief perforations throughout the lateral. These have been tried with varying degrees of success. However, it is generally accepted in industry today that these methods are challenging to work successfully as a diversion technique and thus are not commonly used anymore.

Additionally, traditional methods included pumping various types and forms of Loss Control Material (LCM). In many applications, LCM can be very effective, but placing them and dosing them can be challenging and is critical for them to be successful. However, if faulting and/or very heavy fracture conditions are present, LCM still might not be capable of controlling losses enough to plug thief zones and establish circulation. Additionally, the LCM that is pumped must be removed by pumping breakers properly and fully removing these products to not cause skin damage. If the LCM is not "broken" sufficiently, production may be impeded.

***Option 2 – Nitrogen / Foam Air:***

Lowering the hydrostatic gradient of the fluid pumped during circulation can be a viable option for establishing circulation. Fresh water has a density of 8.4 ppg (pounds per gallon). When evaluating fluid systems required to establish circulation in the given well, first look at the TVD of the well and estimate SIBHP to determine what ppg fluid would be required to balance hydraulics. Then, compare the required ppg to that of commercially-available fluid systems.

Mixing water with nitrogen ($N_2$) has been a common practice to help reduce the hydrostatic burden with varying levels of success. Nitrogen injection can be an effective tool; however, it is often difficult to accurately estimate the AFE for jobs with $N_2$ as the primary plan to reduce ppg because it is unknown how much $N_2$ is needed. Wide variability in $N_2$ requirements have yielded wide ranges in costs for $N_2$, which can significantly affect project economics.

In addition to $N_2$ + water systems, foam air systems have also been used with some degree of success across multiple basins and should be closely evaluated.

***Option 3 – Microbubble:***

As an alternative, operators may consider microbubble (also referred to as aphron) fluid systems as an option for lowering the hydrostatic gradient. Microbubble systems can provide water-based fluids at 6.5 ppg and even some can be as low as to 4.5 ppg. The well's hydraulic conditions must be closely evaluated, and an engineering judgment made to determine if a microbubble fluid system is appropriate for the well. Depending on well specifics, it may be possible to use LCM in concert with a microbubble system to CO a lateral. These jobs are complex and should be planned out carefully and executed with experienced personnel to respond to the well conditions in real time.

An aphron-based fluid system creates microbubbles encapsulated with air in a multi-layer shell consisting of water, surfactant, and xanthan (Peurifoy et al. 2022). The chemistry and technical description of microbubble fluid systems are well documented in industry research, therefore will not be included herein. These products have been used since the early 1990s, originally and most commonly in under-balanced drilling. However, in the past few years, they are becoming more widely used in workover and horizontal well applications, with varying degrees of success (Peurifoy et al. 2022).

An additional benefit of microbubble systems when mixed with xanthan is that the carrying capacity of solids entrained in the fluids is greatly improved compared to Newtonian-based fluids (i.e., water) and gels. This residual carrying capacity improvement helps not only clean the hole better, but it also reduces risk. With traditional fluid systems, if a failure (such as surface leak or pump failure) causes the job to be shut down for a period of time, sand might settle around the pipe. This settling of solids in a pure Newtonian fluid can easily "bury" or restrict the pipe (workstring or coil), risking getting stuck. However, this rheological property of microbubble systems provides for an alternative with an excellent ability to clean a wellbore and keep sands/solids in suspension for much longer, while repairs can be made in order to resume pumping.

Even though microbubble systems can: a) lower ppg, b) improve hole cleaning properties, and c) reduce risk of getting stuck, potential concerns should be considered. Care should be taken to minimize the amount of the microbubble system fluids that are leaked off into the rock. This paper does not examine nor claim damage is certain with this leak off. However, if xanthan leaks off out into the matrix / fracture network, it could cause skin damage that could negatively impact well performance after the job.

## **PART 3 - TRIAL RESULTS FROM MICROBUBBLE/APHRON FLUID SYSTEM:**

An interesting technique that has been field tested by Oxy Delaware basin (Texas and New Mexico) over the past few years worthy of evaluation and consideration is microbubble CO. A twenty-three well CO trial was conducted with microbubble fluids and a look-back review was performed. See the below table highlighting the categories of results:

| Cat # | Categories of Results | Percent of Jobs |
|---|---|---|
| 1 | Restored Production (back on trend) | 36% |
| 2 | No impact, Unsure of the reason | 8% |
| 3 | No impact, Poor candidate well | 32% |
| 4 | Negative production performance impact | 4% |
| 5 | Could not establish circulation – known faults in area | 12% |
| 6 | Cleanout with $H_20$ or Brine, no microbubble needed (sufficient pressure) | 8% |

Each category of post lateral CO results is described below:

*Category 1* – Well performance was restored to pre-frac conditions. This was the goal of the cleanout.

*Category 2* – No positive production impact was observed even if circulation was established and considerable sand volumes were recovered. It is undetermined at this time why production restoration was not achieved.

*Category 3* – No positive production impact was observed and it was discovered during the post-job lookback process that it was not a great candidate as it did not meet proper conditions described earlier in this paper. Determining what makes the best candidates is still a work in progress, but much has been learned for future candidate selection.

*Category 4* – Negative production impact, even after cleaning out considerable sand volumes. No known reason for the negative response. Possible skin damage by fluid system leakoff, may have occurred, but there was no evidence of this.

*Category 5* – Known faults were in the area of these jobs; however, attempts were made to establish circulation to better understand the capability of the fluid systems and if a microbubble fluid system would be a good solution. Circulation in the presence of known faults was not achieved.

*Category 6* – During the CO, in real time, it was discovered that the well conditions did not need microbubble systems to establish circulation. SIBHP was higher than expected.

## CONCLUSION:

Cleaning out horizontal low-pressure laterals to reverse negative production and maximize performance requires careful candidate well selection and complete engineering evaluation. Three techniques for well cleanout are described, focusing on lowering hydrostatic gradient of fluid pumped during circulation with microbubbles. The trial results of 25 wells in the Delaware basin were presented, with categories of results discussed. Overall, microbubble systems can be an effective technique for cleaning out low-pressure laterals; however, more industry work needs to be done to understand and minimize potential skin damage in the future.

## ACKNOWLEDGMENTS

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## REFERENCE

Peurifoy, David, McGraw, Mike, Martinez, Stephen, Morales, Adrian, Farish, Maddie, Perkins, Reece, and Merrill, Allan. 2022. Utilizing Low-Density Mud Systems to Improve Operational Efficiency for Post Frac Cleanout of Unconventional Wells in Depleted Areas. Presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, 3-5 October 2022, SPE-209991-MS. https://doi.org/10.2118/209991-MS