IMPROVED RESULTS IN ROD PUMPS WITH ISOLATED TAILPIPE SYSTEMS THROUGH ADVANCMENTS IN COMPONENTS AND ANALYSIS

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ABSTRACT
Rod pumps with isolated tailpipe systems have been growing in popularity over the past few years and applied in basins all over the US. Some earlier system component designs had vital shortcomings that became more evident over time with the growing install base. The important fact is that these lessons learned have been a driving force in making positive strides to improve installation procedures, component design, and material selections. Another vital element leading to improved consistencies and better results is an accelerated and expanded knowledge regarding the required nodal analysis protocol to properly predict required production and reservoir response to yield optimal system function. This paper will cover the process that has been endured to get to the current improved state of operations and how further success is assumed to be obtained as rod pumps with isolated tailpipes are applied in unconventional wells for years to come.

INTRODUCTION
In the world of horizontal well production and artificial lift specifically, there seems to be two distinctly different approaches taken when it comes to production optimization or creating and maintaining best profitability: 1) if it's not broke don't fix it (or maybe if it doesn't break use it) and 2) if there is unrealized opportunity lets seek it out and exploit it.

Unfortunately, these thought processes and methods to obtain success through either one do not historically go hand-in-hand. With option number 1 that adage can be taken many ways. One may see it as the "safe route" or something that is tried and true, where risks are well mitigated through learnings from countless previous failures, work poorly executed, failed components, and maybe something even harder to stomach, which could be the lack of our ability as an industry to be capable of applying more advanced techniques and more customized solutions with repeatable and reliable results on a broad scale. It ultimately becomes a game of statistics; apply the most failproof artificial lift options and super, conservative approaches to everything downhole and a surface to ensure we do our very best to ensure we never see a bobble, we never realize a "miss" that will reflect poorly on our abilities as good engineers, foremen, technicians, consultants, and the many others involved.

There is certainly nothing wrong with working hard to avoid "train wrecks" with that never-ending fishing job or that ugly environmental cleanup. There is also some statistic, if not for the industry then for your organization particularly, to suggest there is are certain best applications for certain artificial lift types and that organizations ability to utilize that lift method at a perceived high level of proficiency. Case in point: There was a significant surge in the use of ESPs in most of the hottest Permian basins plays starting several year ago and riding through the high time of +$100 per barrel oil. That trend continued strongly as the industry took a turn south in the fall of 2014 and into 2015. Six months into the route most operators started taking a hard look around and thinking, "we've got to do something about our poor use of capital, our out-of-control LOE's and associated lifting costs." The tables had turned and the poor economics of our previous modes of operation were being realized to the fullest extent. It was time for a change, very possibly an aggressive change in artificial lift direction that would allow organizations to statistically apply a new lift on a broad scale, rather quickly, with more steady and consistent results on a well-by-well basis that would ultimately upend the ESP revolution to a good degree and that was all because we just could not seem to get a hands around ESP operations being deployed with exceptional results a high percentage of the time.

All of that to get to the point which is, many operators choose the route of the proven and consistent gas lift method in lieu of the just recently very favorable ESPs. Statistics driven decision-making. This was a pure play on the ability to delivery overall better results because the challenge of exceptional ESP operations may have just been too tough to nail down so we would take a knee and concede the potential for maximum production in an effort to maximize profits.

Augmenting Artificial Lift Methods of Old and Creating a New Level of Attainable Performance

There are still plenty of ESPs running in the Permian and many do quite well, but there is no doubt the current economic environment and far deeper assessment of costs drivers and organizational capabilities to make a large swing in operational excellence have all contributed to an altered approach for many when it comes to artificial lift in effort to keep those companies making as much profits as possible. I guess one could say there is more so now than in recent years past a sense that "smooth and steady will win the race" and avoiding potential pitfalls along the way certainly helps with the conservative (or simply more reliable) approach being applied.

That is not to say everyone in basins all across the US have abandoned the idea of "a better way," or looking for those extra barrels while at the same time reducing costs associated; actually, quite the contrary. That's really the holy grail of artificial lift. This thought of a better way almost has to fall directly in the previously mentioned category #2, right? Where we seek out opportunity and do what is necessary to exploit it? There is no doubt when we chase after perceived opportunities there is statistically a high probability of failure: an old lift type applied in a new, uncustomary well environment or run in to an exceedingly aggressive situation regarding wellbore geometry, corrosion, solids etc. and we want to believe new age materials or advanced controls will power us through with satisfactory results. Old, proven lift technologies, in their base forms, can only do so much. We have had many decades to learn through the hundreds of thousands of installs and failures from folks several generations older than most of us in the industry now, what can and cannot be done successfully with each lift form. It can then, for very good reason, be very hard to want to deviate from the path we have all been taught to follow.

That said, times have changed and our wells have too. The oilfield of today is unlike anything seen 20 years ago. We command much more of all of the equipment run downhole in today's wells than just a few years ago. Much of this is has been driven and exacerbated by the previously unthinkable being applied in the drilling and completion phases. This unthinkable is done every day and the D&C sides have enjoyed significant amounts of break-through technologies which have allowed their rapid progression, yielding todays wellbores and production environments. On the flip side of this are all the original forms of artificial lift that have, for all intents and purposes of this discussion, remained rather unchanged in general form since their inceptions. That is not to say that all those lift forms have not improved and adapted to current needs at all; of course they have to some degree, but none of them are fail-proof, even to this day, and none have taken on a truly "new form." That is likely for good reason too, "if it isn't broke don't fix it" (there that is again) and "if it was easy, it would have been done by now." We are at a crossroads now where we must attain those extra barrels of oil and MCF of gas while also operating in some of the worst, most challenging well environments we've ever seen and it must be done with a high degree of overall success.

Assessing the current day oilfield may lead one to really question, though, "can artificial lift types (rod pump, ESP, gas lift, PCP, plunger lift, etc.) be augmented in such a way as to retain, or possibly even expand, their known application windows allowing for the two different approaches in production optimization regarding safe/reliable/ and more profitable operations to be successfully comingled with that desire to maximize production and output, simultaneously mitigating additional risks and possibly even reducing them to a high degree in some respects?" I believe the answer is a strong, resounding yes. This must be done through application of correctly designed and properly executed installation of augmenting systems run downhole that bring out the best in those lift forms. Allow them to do best what they were designed to do and in the environment they were designed to do it in. One of the most widely applied "artificial lift augmenting systems" for horizontal wells that has been progressing quickly over the past three years, especially as they apply to rod pumps and ESPs, has been isolated tailpipe systems (Reference Figure. 1 - Simple Visual of an Early General Design vs Current Design Isolated-Tailpipe System). These in one form or another are now likely to be well-known by most operators in unconventionals all over the US, but essentially they are intended to deliver on a few key elements:

- Deliver fluids and gas from the lateral to an uphole position, keeping pumps out of unfavorable setting positions
- This is done with no penalty on production since the manipulated flow path reduces backpressure on the formation even though the pump remains higher in the wellbore
- The right equipment allows for significant reduction in realized slugging
- Reduction in slugging leads to less solids transport uphole to the pumps and also significantly less and far more tolerable cycles of gassing off (lateral geometry driven)
- Less gassing off results in less turbulence in areas of flow near the separator intake, thus less gas is entrained in the produced solution and average pump fillage is increased.

The previously mentioned benefits allow for a typical rod pump system to thrive in unconventional wells and is made feasible only when paired with additional equipment enabling those things to occur. Horizontal wells yield challenging production conditions that must be met head-on if your desire is to reach a truly optimal level of performance and profitability. Application of a performance augmenting production system on a lift selection of old will likely be the only avenue to tame today's wells and squeeze the utmost production out of them all while keeping failures at a minimum and creating the lowest possible lease operating expense.

Progress of Proven Artificial Lift Methods has Been Tedious, but Rewarding

Over the past three years an estimated 1200 isolated tailpipe systems have been install in basins all across the United State. No basin is an exception; there is a home for such system in almost every play as the benefits are so far reaching and attainable and all for a very low capital investment. Is quite surprising there aren't 1000 more such type artificial lift installs with these systems installed given the significant upside potential and mitigated risks.

The earliest version of one such system intentionally kept the design very simple and componentry at an absolute minimum as to keep costs and complication low and to attract a significant amount of trials. This plan was executed well, but like most new technologies and processes in the oilfield it was quickly found that design elements that made for extremely low costs and an overly simplistic approach proved to not be nearly rugged or forgiving enough and many integrity issues were witnessed early on with regard to the isolation technique. Much of those failures could be linked to proper processes not being adhered to during installations regarding running speed and/or proper casing preparation prior to running the tools, but there where still a very large number of exceptional results or "homeruns" that kept the desire to pursue system improvements alive and well and allowing for hundreds of additional installations.

Only 7 months ago in the summer of 2018, after 30 months of trials and errors and roughly 280 installations had taken place, did the tides begin to quickly turn in favor or significant improvements regarding system reliability (generally functioning well a very high % of the time). There were many lessons learned and design changes made that first 30 months, but only once the weakness in the original isolation was found and eliminated were enough quality performance installations able to be monitored at such levels of detail with several E&P partner companies to progressively lead to the evolution of the system components that created what is offered today. The end result: a fully customized per the application, artificial lift performance altering system with many unique forms that could be applied in an immensely broad array of candidate wells in basins across the country with results that are reliable, repeatable, and sustainable all while minimizing up-front costs and ongoing operational expenses.

Review of the Major Component Progressions and Analysis Improvements

There have been a handful of vital component progressions that have taken place and, likely no surprise, the most significant coming at the aid of system tests which were heavily instrumented with live gauges placed at multiple positions along the system string with very high-resolution data being taken from each of those points over several months and varying downhole conditions.

The gauge data allowed us to see a number of things: differential pressure across the tailpipe, producing bottom-hole pressure (PBHP) at the end of the tailpipe, pressure at the top of the tailpipe, pressure at the separator discharge or pump intake pressure (PIP), and discharge pressure at the pump. Gas spot rates, fluid production, tubing and casing pressure were also available. From that data artifacts of specific production traits were made clear or could be derived from the data; smooth flow in the tailpipe, slugging in the tailpipe, gas and fluid surges in and through the system, etc. (Reference Figure. 2 Isolated Tailpipe Gauge Data from Horizontal Rod Pumped Well).

Interestingly one may look at much of the data and say, "well that's not what I was hoping to see!" but that information was absolutely invaluable in determining upon much deeper analysis and review that there were several things amiss in the system design that could be addressed directly in effort to create the desired result.

Nodal Analysis Correlation Error Found and Corrected, Results in New Tailpipe Sizing Guidance The gauge data led to a further understanding of the flow regime generated in a given flow area at a specific pressure and fluid condition such that it became clearer the effect inclination was having on the string's ability to consistently flow that multi-phase mix smoothly across the most difficult to lift portion of the curve, which is at 45 degrees.

I was then further reminded of the information previously presented at an industry consortia that made very explicit reference to that exact thing: there is a notable higher required critical velocity (CV) to effectively sweep the center portion of the curve clean of fluids as they are being flowed from the lateral, through the curve, and uphole to a pump placed above. In instances where adequate velocity was not held across the curve of the wellbore, loading occurs and high differential pressure results across the tailpipe indicating fluid stalling or a collection of fluids and very low gas saturation (Reference Figure 3 – Isolated Tailpipe Gauge Data Across Tailpipe in Horizontal Rod Pumped Well).

With that in mind I went back to review previous nodal analysis and the CV or superficial gas velocity requirements predicting to be exceeded and maintained for optimal results and effective lift to occur. Very interestingly those nodal outputs, although they were certainly built with deviation survey data and details of the full curved section were input into the calculations, there was absolutely no sign that inclination played any role in the output as the "loading lines" did not ever deviate form their trajectory created for the vertical uphole position as they passed through the curve of the wellbore (Reference Figure 4 – Nodal Analysis of Multi-Taper vs Straight-Taper Isolated Tailpipe in Horizontal Rod Pumped Well). This was a defining moment to alter the process of nodal analysis that had been trusted to yield accurate guidance for hundreds of previously design isolated tailpipe system for rod pumps and ESPs.

Accurate Superficial Velocity Correlation Lead to Custom Flow ID Profile Requirements in Tailpipe

A modifier to the preferred flow correlation is now taken into account on each nodal run to ensure proper flow regime and an effective sweeping of curve takes place at given conditions. The ID of the tailpipe obviously has a profound effect in this effort and as such that lead to a few of remaining major component progressions.

For hundreds of the first installed systems the simple and inexpensive approach of using bare macaroni sized (1.660" OD aka 1-1/4" or 1.90" aka 1-1/2" nominal) tubing was employed for about 98% of all jobs up until that time. Upon the revelation of the incorrect flow correlation within the nodal program for use in designing these systems, a look back at the ID profile of the tailpipes applied to date quickly proved there were many "non-optimal" or poorly sized applications with little chance to result in excellent performance since the required velocities had no shot at being hit and maintained.

This was the drive behind making a shift to requiring Thermo-Plastic Tubing (TPL) for best performance. TPL has many customizable ID profiles to match the well condition and makes for optimal flow and fluid delivery through the system in a huge range of volumes, lengths, pressures, etc. Also, the TPL provide exceptional corrosion protection in the tailpipe ID which in a smaller ID isolated tailpipe system the velocities in-situ can exacerbate CO_2 corrosion and create pre-mature failures in wells where bare pipe is used and chemical treatments are not adequately upheld and executed.

Prediction of Loading Across Tools Set Leads to Custom Flow ID Profile Requirements

The added attention and emphasis on accurate nodal runs being put into the designs than led to another discovery in effort to ensure flow cleanly traverses across the tool set. The tools previously run in early systems were essentially non-custom parts with the IDs provided being a byproduct of the raw stock that was used to make the main components (Flow-Isolator, slimline TAC, Tool Saver). The tool IDs ranged from 1.91" to a 2.41" iD and the overall length was around 9' long with the diverter separator on top of that run.

When more attention was put into modeling this segment and the likelihood of loading and significant heading occurring through the section was deemed 100% likely and it was determined necessary to develop tools with ID profiles custom fit to the application; there's no point in expending so much effort in installing an isolated tailpipe system if the flow created by the system further downhole was only setup for failure by the large IDs of the tools uphole and the resultant velocity trap they were creating (Figure 5 – Pump Fillage Tightened Up by Predicted CV Being Maintained Through Tool Set). This was a necessary correction that obviously was made without hesitation.

Addition of the more Rugged 2.375" TPL Allows for Slug Reducing Toe-Isolator

The next major component addition, made capable by the use of 2.375" TPL tubing, was the Toe-Isolator. It was originally thought proper placement of the end of tubing (EOT) around 60 degrees where uptake would occur with the most homogeneous mix of fluids and gases along with an open annulus between the tailpipe and casing ID serving as a "gas cushion" would yield not only the need for less downhole componentry, but also would damp out any slugging as fluids were delivered in an inconsistent or aggressive fashion to the EOT.

This was found to be inaccurate as multiple wells data was analyzed and events were overlapped with high-resolution data to finally lead to the conclusion the open annular space between the tailpipe and the isolation tool uphole creates a very large gas accumulation tank and that tank loads with gas when a large fluid slug is delivered out and the lateral and lifts up the tailpipe to the pump hundreds of feet uphole. Once the fluid slug migrates through the tailpipe system and hydrostatic lift requirement is alleviated, the pent-up backside gas then heaves around the EOT and flows off at very high rate through the tailpipe and ultimately creating a turbulent outflow of gas at the diverter separators discharge. This in effect leads to cyclical gas purging cycles that create concurrent cycles of turbulence and gas entrainment wherein that gas laden fluid is then be pulled down into the separator intake and directly into the pump. The application of proper toe-isolation is another step forward in effort to create a focused uptake of as clean a multi-phase mix as possible, but in the event the well gives up a larger load of fluid the side-effects of gas purging through the system can now be mitigated.

Solution Applied to Equalize Negative Effects of Fluid Stall and Backwash via Fluid-Catch SVAs

The most recent addition to the isolated tailpipe system is firmly believed after numerous installs to widen the application window to wells previously through to be totally unrealistic candidate with little upside potential as well as provide low to medium producers a huge gain on production consistency with readily available fluids.

The application of a plurality of Fluid-Catch Standing Valve Assemblies (SVAs) has proven to allow horizontal wells with very low gas rates the ability to unlock otherwise unobtainable production gains. Two Fluid-Catch SVAs are strategically placed in the system. The purpose of the valves is to ensure all fluids being produced from the well, once washed uphole, do not fall all the way back down to the base of the curve if they first make it past the most difficult to lift through portion of the curve and secondly if they make it all the way uphole to be pumped away. In weaker wells it is wise to take advantage of any burst of energy the well is willing to give up. In the case of an isolated tailpipe system in a very low gas rate rod pumped well, the nodal predictives will show every indication that the system will not yield a significant benefit to well production, but real well tests prove differently (Reference Figures 6 & 7 – Super Low Volume Producer Pre & Post-Isolated Tailpipe System Install).

The SVAs are fully back-flushable and as such sand/solids can be backwashed through them and other well treatments can also be administered like corrosion inhibitor, scale treatments, or acid jobs, etc. The SVAs are self-regulating and a pre-determined spring constant is chosen to allow for only a specific amount of differential or hydrostatic head to be held above, the remainder of the fluids that attempt to stack on the assembly are flushed backwards down the wellbore.

CONCLUSION

The application of the most popular forms of artificial lift, namely rod pump and ESP are, in their basic and stand-alone forms, incapable of operating at the highest level of production potential without risking significant equipment damage, downtime, costs of repair, and lost revenues in unconventional wells.

There were many hard lessons learned over hundreds of installations in the first 30 months of development of this Isolated-Tailpipe system, now perseverance and follow-through allow a very useful artificial lift augmenting system to be widely applied and benefits enjoyed by the industry.

A safe to run and well-designed Isolated-Tailpipe system is likely the best and most proven option in applying an “artificial lift augmenting system” to maximize profit and optimize costs matrix in unconventional wells.

Poor modeling/analysis technique and a lack of understanding will lead to bad design choices and a poor performing system; trust someone that understands this to do the work or teach you how.

Off the shelf componentry will not work well in virtually any application where a system like this is to be applied. Correct flow generation and maintenance are imperative to success.

Not just one of the evolved components can be deemed the biggest driver in the most recent and largest success stories to date. Each component in an excellent system serves a purpose and together the sum of the parts is greater than the individual pieces.

REFERENCES

1. None

Figure 1 – Simple Visual of an Early General Design vs Current Design Isolated Tailpipe System

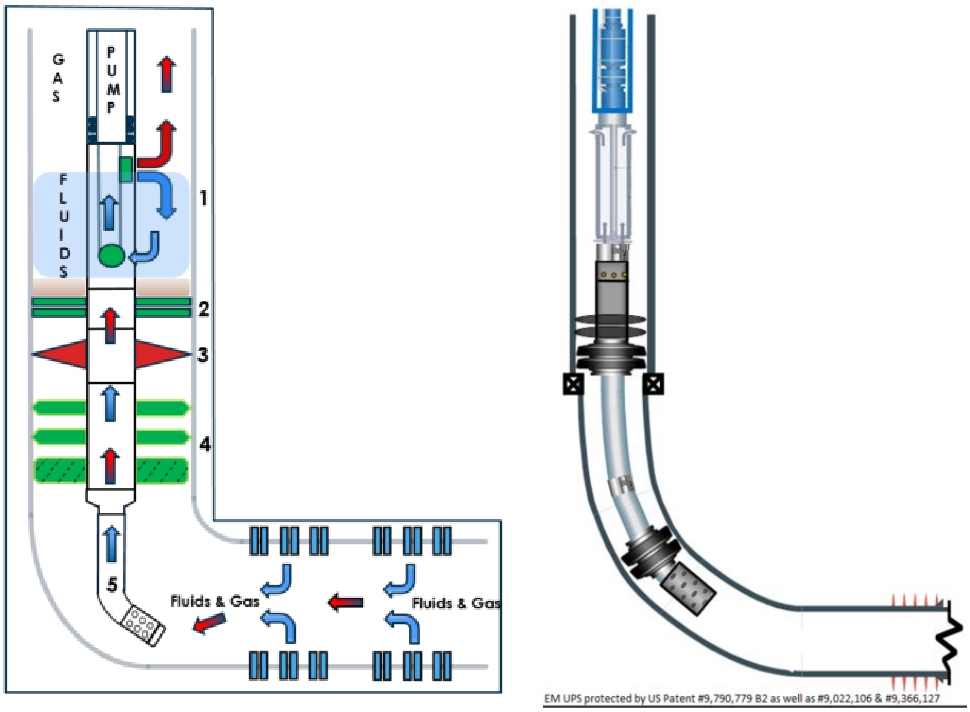

Figure 2 – Isolated Tailpipe Multi-Gauge Data from Horizontal Rod Pumped Well

Figure 3 – Isolated Tailpipe Gauge Data Across Tailpipe in Horizontal Rod Pumped Well

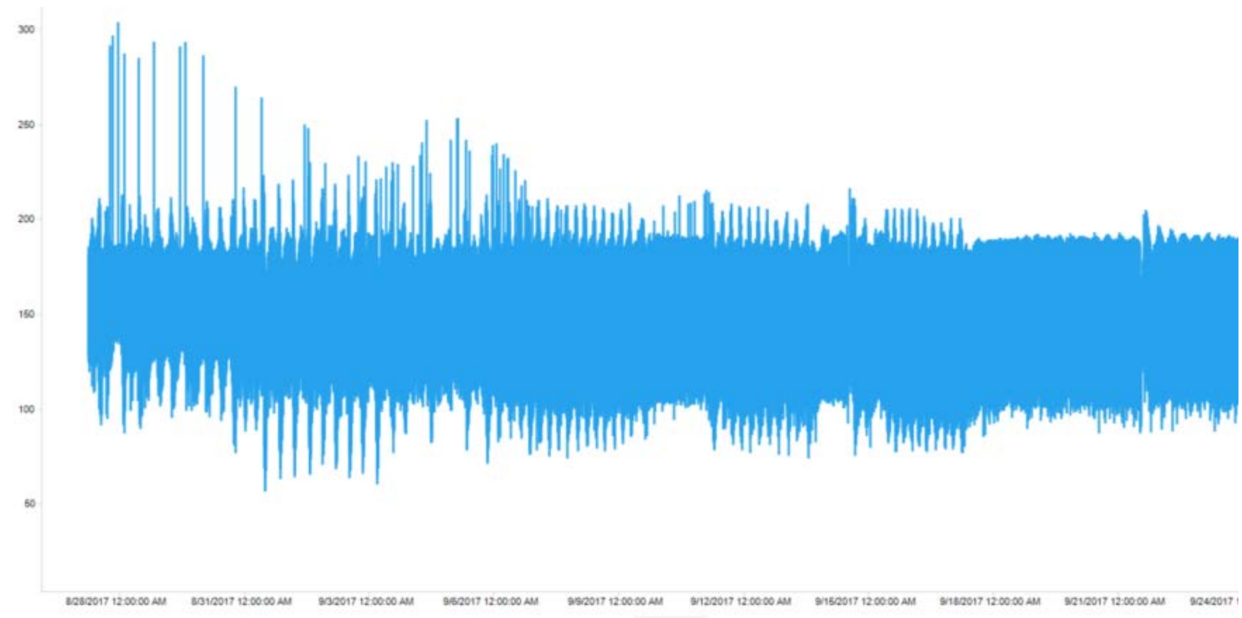

Figure 4 – Nodal Analysis of Multi-Taper vs Straight-Taper Isolated Tailpipe in Horizontal Rod Pumped Well

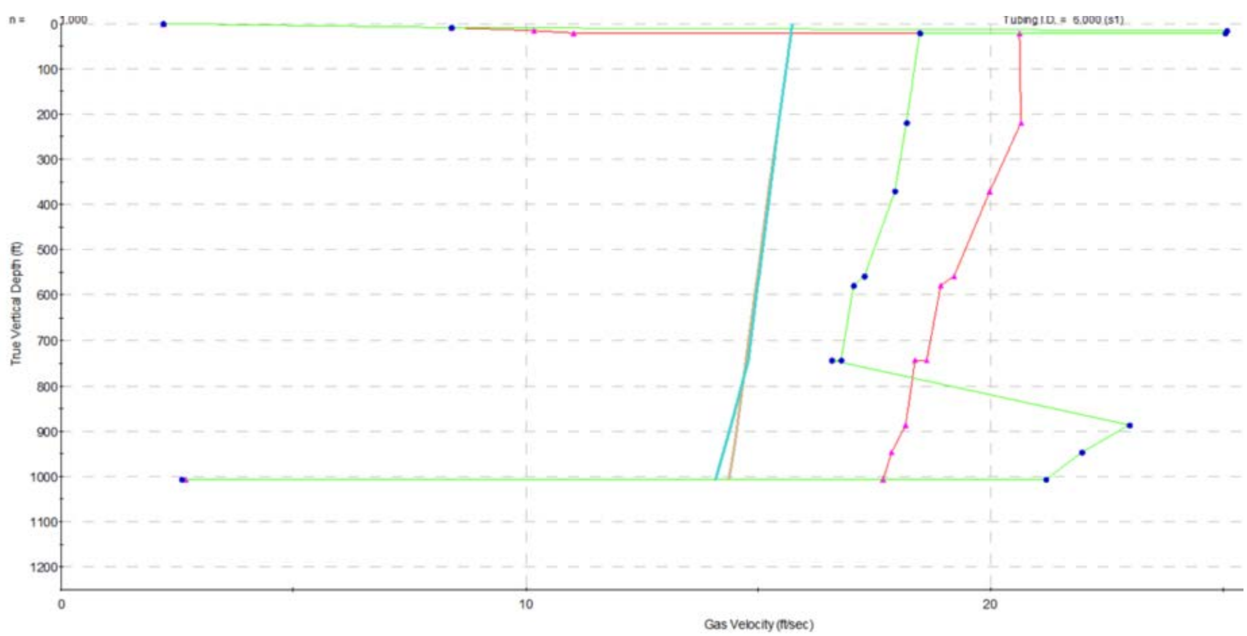

Figure 5 – Pump Fillage Tightened Up by Predicted CV Being Maintained Through Tool Set

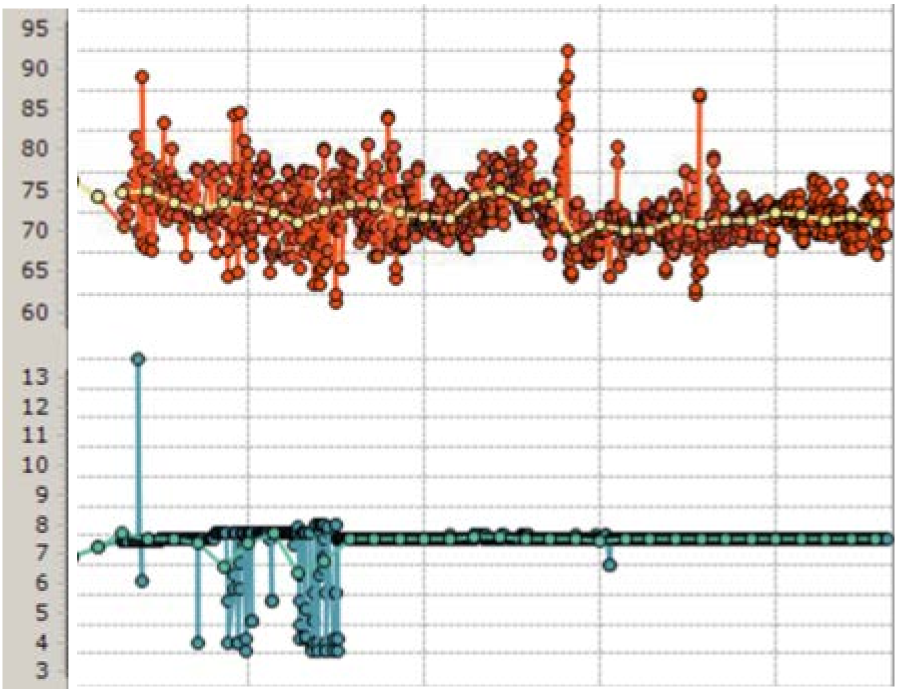

Figure 6 – Super Low Volume Producer Pre-Isolated Tailpipe System Install

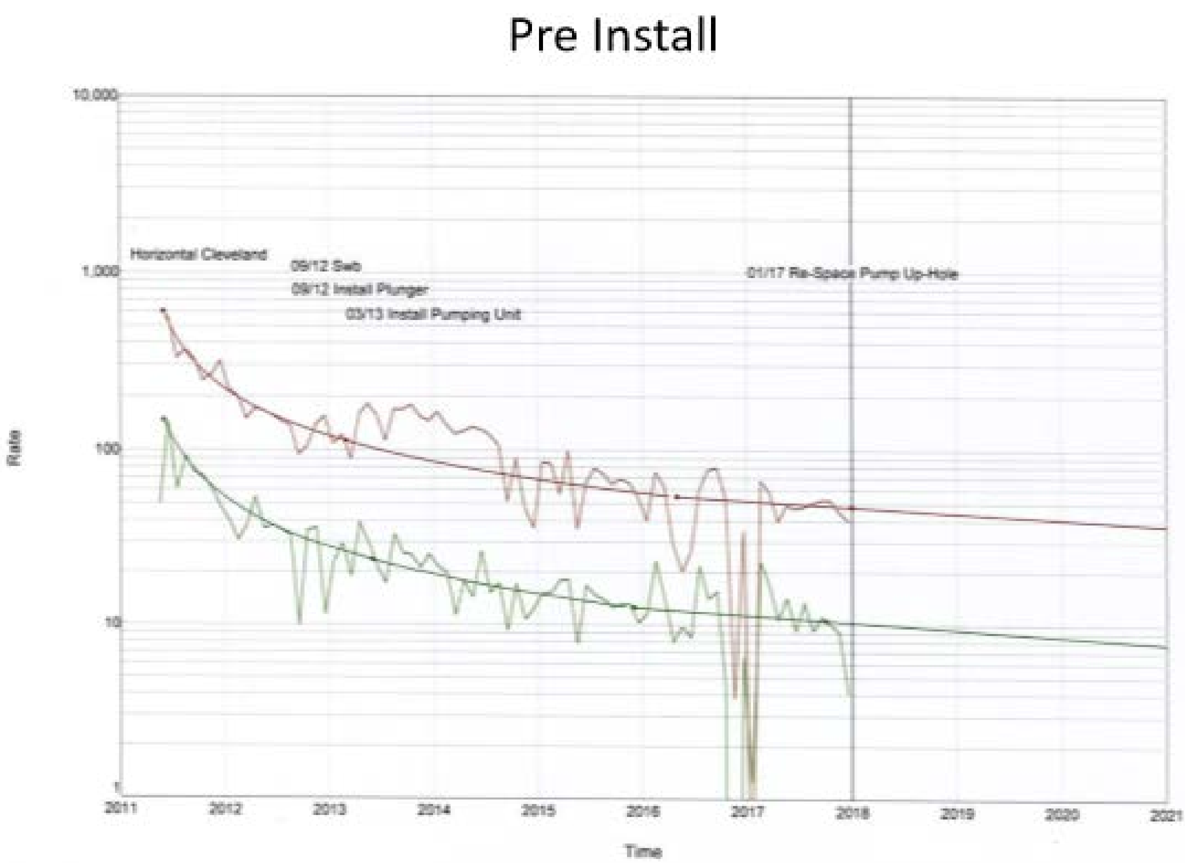

Figure 7 – Super Low Volume Producer Post-Isolated Tailpipe System Install

Post Install

							SALES	SPOT							Prod	
Date	**Hrs**	**Tp**	**Cp**	**Lp**	**BO**	**BW**	**MCF**	**MCF**	**Total**	**% Oil**	**BPH**	**BLWTR**	**Tot BLW**	**% Rec**	**GOR**	**Comments**
												256	256	0.0%		
Before	**24**	**100**	**110**	**70**	**10**	**2**	**37**	**37**	**12**	**83.3%**	**0.5**	**254**	**256**	**0.8%**	**3700**	**Before Gas Separator**
3/9/2018	20	130	0	67	0	30	0	0	30	0.0%	1.5	224	256	12.5%	0	Unit Running on Propane
3/10/2018	24	120	75	63	0	54	30	40	54	0.0%	2.3	170	256	33.6%	0	Unit Running on Natural Gas
3/11/2018	23	120	75	63	15	35	50	55	50	30.0%	2.2	135	256	47.3%	3333	Daylight Savings Time
3/12/2018	24	120	75	63	18	42	76	80	60	30.0%	2.5	93	256	63.7%	4222	Can Hear Gas Flow
3/13/2018	24	120	75	61	18	18	75	77	36	50.0%	1.5	75	256	70.7%	4167	
3/14/2018	24	120	75	63	20	21	56	58	41	48.8%	1.7	54	256	78.9%	2800	Down Size Plate
3/15/2018	24	120	75	61	23	17	59	61	40	57.5%	1.7	37	256	85.5%	2565	
3/16/2018	24	120	75	63	20	20	58	59	40	50.0%	1.7	17	256	93.4%	2900	
3/17/2018	24	120	75	63	24	18	56	57	42	57.1%	1.8	-1	256	100.4%	2333	
3/18/2018	24	120	75	62	21	20	57	55	41	51.2%	1.7	-21	256	108.2%	2714	**Final Daily Report**
Additional Production					**11**	**BO**	**20**	**MCF**								
Additional Revenue					**730**	**$/Day**										
Cost				**$**	**40,415**											
Payout					**84**	**Days**										