CASING GAS SEPARATOR – A SIMPLE METHOD TO DOUBLE GAS SEPARATION CAPACITY IN NEW WELLS

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ABSTRACT
The number is few to none when thinking of items relating to production-side advancements that have substantially improved our abilities to produce wells with exceptional gas separation in unconventional plays at a completely new level; a real distinguishable and undeniable step-change.

There has been much effort put into material science, manufacturing more resilient and rugged components, and putting all those pieces to work at the direction of very advanced controls, but somehow no level of commercially viable, science-driven product has been able to deliver a substantial and sustainable difference in well production profiles and profitability.

The newly developed CGS (Casing Gas Separator) is poised to change that record and prove that the most effective way to witness a paradigm shift in how wells optimally separate gas to produced at all-new levels of efficiency may also be the most simple and cost effective through the use of this safe to run, low-risk, and efficiency altering tool that pairs naturally with existing wellbore design and work practices to vastly improve gas handling and capacity in virtually any form of artificial lift.

When a new well is drilled the hole is cased and cemented and during that process the tool is run permanently into place on the casing with no alteration to the drilling program whatsoever. The separator is commonly placed at kickoff point or in a tangent further downhole and well work occurs with absolutely no alteration to normal completion processes. The tool may be run and setup with multiple flowpath options and separation capacity is essentially doubled by providing twice the casing flow area inside the tool. The result is the most prolific and flexible gas separation technology horizontal wells have ever had the opportunity to take advantage of.

Introduction

The production phase of a wells lifecycle is often not prioritized like it should be even though more than 90 percent of all wells require some form of AL. Most large investments on a well are made on the drilling and completion (D&C) sides where evident improvements can affect the well's estimated ultimate recovery (EUR) and rate of return (ROR). Typically spending additional capital on premium artificial lift equipment can be a tough enough sale when simply looking for value addition through less failures and downtime that will in-turn increase production, yet other tangible benefits are usually even less clear.

Artificial lift equipment normally does not have a similar track record of being able to clearly alter a well's profitability, that is unless it is for the worst when that well's artificial lift method constantly fails and the high failure frequency adsorbs much, if not all, of the well's ability to make a positive return, much less a high ROR. High failure frequencies in various AL methods are dreadful and often times difficult and seemingly impossible to avoid in difficult unconventionals. As a by-product of the innovations seen on the D&C sides, lift equipment generally is lagging behind as far as complementary advancements are concerned.

The lag in AL advancement has become more clear as those D&C efforts have opened up the door for exceptionally, high volume fluid and gas producers in a wide variety of basins. We now see levels of slugging and aggressive gassing off not typical in years past. There are more fluids to deal with in unmanageable waves with inconsistent and very unpredictable deliveries. It is not uncommon to see most laterals in a play 3 to 5 times longer than they normally where in that same play just 5 years earlier. The well profiles have changed like night and day and our lift mechanisms have not.

There have been no recent and truly notable "innovations" to the base forms of any of the major AL methods: rod pump (RP), electric submersible pump (ESP) and gas lift (GL). This is a major problem as it relates to the lift's inability to cope with the new and uber-challenging downhole environment in even the most widely used forms of AL in unconventional wells, namely RP and ESP. Further, commoditizing lift equipment along with no real step-changes to said equipment has caused a stagnant environment wherein we continue looking for that next big change that will allow our AL methods to thrive and product the utmost from today's super long laterals threaded through the most prolific reservoirs and on a broad, meaningful scale.

Since it is unlikely there will be a game-changing product addition or augmentation directly to the forms of lift to make them more adapted to the most currently unconventional wellbores and resultant production profiles that naturally want to come from them, it looks to highly likely the best alternative to solving the problem of inadequacies for RPs and ESPs in those wells is to change the alter the producing environment they are seeing in their downhole positions. One may think that is easier said than done, but that is very likely incorrect; the newly developed CGS delivers just that.

Background and the Solution Proposed

Production engineers, lift technicians, and field supervisors have been left in an endless cycle much like doctors treating the symptoms and not the cause of ailments; meaning these production teams' members work to keep wells producing, but don't have the ability to spend enough to fix the problem and may not have the level of info readily available to make better, more sophisticated corrections. Some of the problems production teams are left to deal with outside of adverse production induced issues are severe doglegs in the vertical or back-builds and proppant flowback creating premature wear on rod strings and pump components. The recent advances in horizontal wells has created a whole new set of problems producing wells. Most often the AL method is no longer below the producing zone and instead above the interval creating a nowhere near ideal situation. Sometimes pumps are being placed through the curve as close to the formation as possible, but pumps placed in curves and laterals create accelerated wear and ultimately failures, downtime, and deferral of production. Undulating laterals create gas slugging which creates more issues with AL systems. On top of this, teams are also prioritizing efforts to reduce LOE instead of trying to improve production, which is leading them to stray from the optimal goal: balance producing unconventional wells to their fullest potential while simultaneously maximizing profit, not necessarily minimizing spend.

Among the major issues with producing unconventional wells is the mixture of liquids and gas at pump intakes. Once a well has flowed off naturally an artificial lift system is placed above or partly into the curve. The system is designed to help maintain production rates. More recently as in the unconventionals previously mentioned, gas interference has become a more pressing issue - reducing pump efficiency in RPs and causing downtime in ESPs for multiple reasons.

Within the last two years a new production system has been developed that's proven manipulating flowpath in effort to maximize separation capacity as well as conditioning the fluids before they go into a pump intake can increase efficiency and increase production/run life. Most recently the CGS technology has been built off a similar set of straight-forward ideals – all in an effort to maximize separation capacity and separate out as much gas is possible before that gas can be taken into the pump intake. Not only does the technology take advantage of the most reliable known form of separation, adding casing ID space, it also combines the well-known benefits of diversion style separation and essentially creates an artificial sump to land the pump within a horizontal well. Just like pumping a vertical well with a huge production casing.

Shortcomings of Typical Casing Design and Resultant Gas Separation Deficiencies

Production casing designs vary a bit from area to area, but generally there are two designs that are most prevalent in today's most active plays: 5.5" longstring or 7"x4.5" linered casing designs. Both of these are used in virtually all of the most actively developed areas in today's oilfield. Each has their upsides and downsides. We will focus mainly on the 5.5" for the intent of this discussion.

The 5.5" casing bore from a separation perspective is not the best performer, but it is probably the most widely utilized and as such we must find a way to make our RPs and ESPs work better in this casing size in the prolific unconventional wells. We are simply limited by space. Space downhole is something we do not have much of and in about all cases, more is better, plain and simple. Adding extra casing ID area directly correlates to improved separation capacity as the more area present makes for a slower pace liquids will fall through the “dead space” or “quite zone,” the space between where gaseous fluids are drawn into a separator and where those fluids make their final attempt to allow gas to escape upward out of the solution before the resultant non-gassy fluids are ingested by the pumps intake point. This is not rocket science, nor it is a new and hard to understand concept; adding more separation area will 100% of the time improve gas separation quality and your well’s ability to maximize liquids extraction on each and every stroke.

There are many separators that can be applied within the ID of the 5.5” casing, but the best is not always the same size or style. You would think there would be a simple matrix to be applied when making this choice, but there are so many variables in today’s unconventionals, that the same one isn’t always the best fit for the job. That is unless one separator could be categorized as the best for all elements that make for exceptional performance and do so simultaneously.

The most fluid one could expect to effectively separate in 5.5” casing while using a 2.875” poor-boy is only ~200 barrels of fluid per day (bfpd), a 3.5” poor-boy is good for ~375 bfpd, and even a 2.375” OD packer style is good to ~600 bfpd (all assuming 6”/sec bubble rise velocity). We can all agree that the assumed rise velocity is totally unrealistic in the plays like the Wolfcamp, Sprayberry, Bakken, SCOOP/STACK. It’s been witnessed again and again that rise velocities in the 3.0-4.0”/sec range are much more in line with real world wells, which will knock all those previously mentioned capacities down by as much as 33-50%. That is a very real and troubling predicament since many wells we produce are certainly well above the 100-300 bfpd level and they will be producing in that rage for years to come. 100-300 bfpd is the capacity realized when the actual bubble rise velocity is taken into account for each of the separators mentioned above. With this being the harsh truth, it is not hard to see why we as an industry struggle to produce wells within today’s most attractive plays at very high levels of operational proficiency; the equipment simply will not let you.

Solving Gas Separation Problems with a Simple Solution Once and For All

The most functional way to remedy this shortage of capacity problem generated by the other separators out there is to change the biggest driver: add separation space (aka separation capacity). The way to alter this is not to change length or type of separator, it is made feasible through adding to the casing ID area so we can achieve the desired results. This is where the CGS comes into play to create a huge strategic advantage over any other separation technique used in unconventional wells.

The CGS is run as part of the casing string into a newly drilled well. The bit size used for drilling a 5.5” longstring in the uphole, vertical position is most certainly an 8-3/4” and possibly a 8-1/2”. This hole size created is also, coincidentally, large enough to easily and safely run 7” external coupled casing connection or a 7-5/8” internal and slick coupled casing connection. With this being the case, we can now simply affix a CGS which is essentially a 7” or 7-5/8” full 40’ joint of casing which sheathes a piece of 5.5” casing, matched to the remainder of the longstring, and it is coupled by a patented connection which allows for a super-strong, reliable connection allowing for more aggressive drilling practices like rotating and reciprocating casing. The top lift-sub and the bottom stabbing-subs match up perfectly to the remainder of the casing longstring specs and thus allow seamless and trouble-free integration of your desired CGS size to be run in the hole with no changes required to your drilling program.

This is fantastic news for anyone looking to improve their AL performance as the newly created separation capacity is far beyond anything previously feasible in a 5.5” longstring. Lets review:

Once a 5.5” longstring well is placed on AL, RP in this instance, you are then limited strictly by the flow area between the ID of the outer mud anchor (MA) and the OD of the diptube in a poor-boy or modified poor-boy separator. This is commonly a 2-7/8” MA with a 2.441” ID or maybe even a 3.5” MA with a 2.992” ID coupled with a 1” nominal (aka 1.315” OD) or 1-1/4” nominal (aka 1.660” OD) diptube hung off down inside the MA. The cross-section area between the ID of the MA and the OD of the diptube yields some amount of square inches of area. Each square inch of area in that space is good for 52 bfpd of separation capacity assuming 6”/second bubble rise velocity. This is the purist driving factor in a wells ability to separate gas from fluids so it is very important to be optimized at all costs.

The next, and a bit more advanced, technique in separation is applying a packer type (aka diverter style) separator in the same 5.5" longstring. In this case the typical annular flow path taken by the multiphase fluid mix is not allowed before entering the separator as in the poor-boy styles. In a packer style separator the annular flow is block by a form of isolation at the base of the separator which in turn forces all the multiphase fluid and gas mix to flow through the centerline of the separator and those fluids then discharge out the top of the separator and into the casing ID/separator OD annulus. That annuls is where the gas separation takes place in this type of separator and the resulting capacity is much higher than normal poor-boy styles because there is simply more cross-sectional inches in that space which are also used in the same calculation for separation capacity, again 52 bfpd per square inch of area in that space. Depending on the packer separator OD and the 5.5" casing weight, there is typically 12 square inches of space in that area yielding ~600 bfpd capacity.

Now thinking about what is generated by a CGS in the otherwise same 5.5" longstring wellbore, we must take into account the cross-section area of the ID of the outer body, either 7" or 7-5/8", and subtract all equipment that is to be hung off inside of the upper discharge slot area, likely 2-3/8" or 1.90" heavy-walled tubing which will generate approximately an area of ~24 square inches in the 7" and ~31 square inches in the 7-5/8" version. This will yield DOUBLE the capacity of 5.5" with the 7" CGS applied and a whopping <u>2.67x</u> capacity of 5.5" with the 7-5/8" applied.

Thinking back to the more realistic bubble rise velocities of 3.0-4.0"/second, this is reason why one should seriously consider running a CGS whenever possible even though the proclaimed capacities may be far beyond what your wells now produce. Applying those real rise velocities in the CGS has the same effect as their application in poor-boy or packer separators, which is you will end up cutting down to 33-50% of the advertised capacities. Many wells in today's unconventionals may not produce 1200 bfpd especially on RP, but there are many that produce at 500-600 a day and a huge % that the desired production would in 300-500 bfpd IF it were possible and it often is not since we see so much gas entrainment and thus incomplete pump fillage with conventional separation techniques applied. The CGS would allow higher volumes to be pumped away, with perfectly square cards, and with less wear and tear on pump components no matter how adverse the fluids condition is compared to any other separator that can be run in 5.5" casing.

Without the CGS these separation capacities are otherwise 100% not feasible and this opens a new door for a substantial improvement in AL operations in 5.5" wells that has never been seen to date.

The tool is commonly placed at the kickoff point but can be run lower and set in a tangent as well. The CGS is cemented in place for the life of the well. Completions and flowback are conducted as designed, without any changes to normal operations. The system has a full bore inside diameter to match the rest of the casing in the well.

Once the well is placed on artificial lift, such as an ESP or rod pump, a lift-specific isolation tool is run and set to generate the route the fluid flow, between the ID of the CGS larger outer body and the OD of the 5.5" inner string. Liquid is dropped out through the top slots and falls into the newly created "sump" where the pump inlet is located, while gases are flowed freely up the annulus.

Introducing an All New and Far More Proficient Method to Produce Unconventionals

Due to the huge new separation area generated at the top of the tool to maximize separation capacity, this also concurrently creates a "stall zone" in that same space across the upper discharge slots. This stalling of fluids due to a significant drop in velocity profile makes for a new opportunity to produce wells in a completely new way.

As fluids fall well below the critical velocity to lift further uphole beyond the upper slots fluids will fall into the area crated inside the CGS inner-string best described as the "artificial sump." This allows for smooth, easy take-away of all the fluids as the drop continuously into the area for uptake into the pump while the gases still flow rapidly upward, across the stall zone, and then crosses back into the annular flow area created by the ID of the 5.5" longstring and the OD of the tubing string run down from surface. This area in some very high gas rate wells will likely have a tendency to "flow off" or in other words the well will naturally lift its own fluid accumulation from above the separator as the pump provides help to lift the fluids feeding it from below simultaneously. This can be most accurately described as a "controlled flumping" of flowing-and-pumping operation. This will yield a very low PBHP and more fluids can then be produced than by simply relying on what the RP can lift on its own.

The system creates an opportunity to use multiple lift forms much earlier in the life of a well rather than wait for the well to sputter out deep into the initial decline; this can be common in long lateral unconventionals. This new condition generated in the augmented casing design with the CGS applied creates an otherwise unobtainable and very conducive environment to aiding that well with AL and to do so without endangering that lift by placing it in a terribly difficult to succeed downhole condition. The ability to safely and reliable apply a form of artificial lift earlier in the life of a well would have a positive impact on that wells ability to produce more valuable oil and gas through a predictable amount of incremental production to be gained in that earlier stage (Figure 1), but the benefits would continuing for the life of well with that form or successive forms of AL being used in concert with the CGS.

Conclusions

The CGS is an extremely simple method to greatly increase gas separation in conventional well casing designs often by as much and 2.0-2.67x that of a typical design.

Considering real-world bubble rise velocities and fluid consistencies in today's hottest plays has created a real need for an increase in separation capacity and this improvement to capacity is easily delivered on a broad scale, reliably, and cost-effectively with the application of CGS technology.

The new system was engineered to be integrated seamlessly into an existing casing program. Casing OD and burst is designed for each application and has already been proven through existing casing practices and API burst requirements.

CFD modeling and Nodal analysis was also done to validate fluid falling out at the top outlet of the system and into the artificial sump. Both models confirmed fluid would fall out at the top outlets and into the sump at extreme gas rates and very low PBHP.

The simplest way to increase gas handling separation capacity within casing is to combine an increase in casing capacity (increasing casing size) combined with diversion separation. The new system described above combines a larger flowing area while also using diversion separation.

Having an artificial sump where fluids can drop into the pump intake and gas flows up the annulus is a great way to emulate the more simple,old way of pumping as in producing vertical wells from below the perfs.

References

1. https://www.aogr.com/magazine/cover-story/advanced-technologies-optimize-artificial-lift-production-operations

Nomenclature:

AL= Artificial Lift
GL = Gas Lift
RP = Rod Pump
ESP = Electric Submersible Pump
ID = Inner diameter
OD = Outer diameter
MA = Mud Anchor
BHA = Bottom hole assembly
EOT = End of tubing
PBHP = Pumping bottom hole pressure

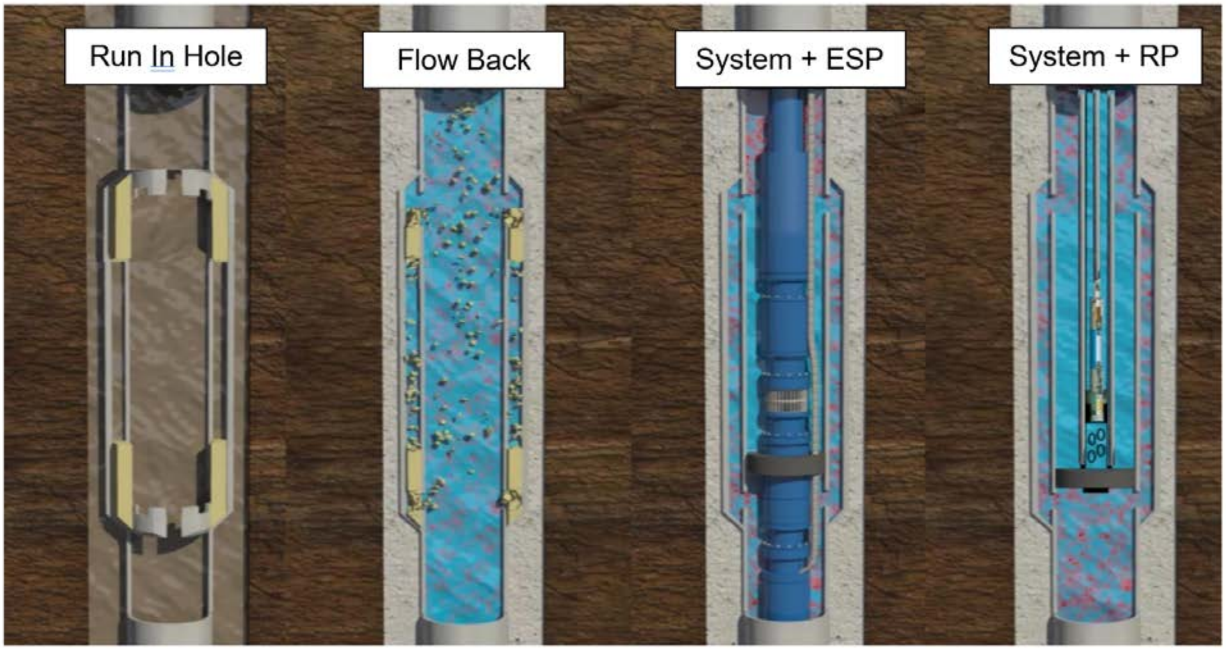

Figure 1 - Run in hole, degradable sleeves degrading, system producing with ESP, system producing with RP

Area Comparison

Casing Size	Weight	ID	Area	Volume/40'
	lbs	in	in^2	bbl
5.5	17	4.892	18.798	0.932
7	26	6.276	30.939	1.532
7.875	29.7	6.875	37.127	1.836

Table 1- Area and volume comparison between 5-1/2” casing and 7” casing volume

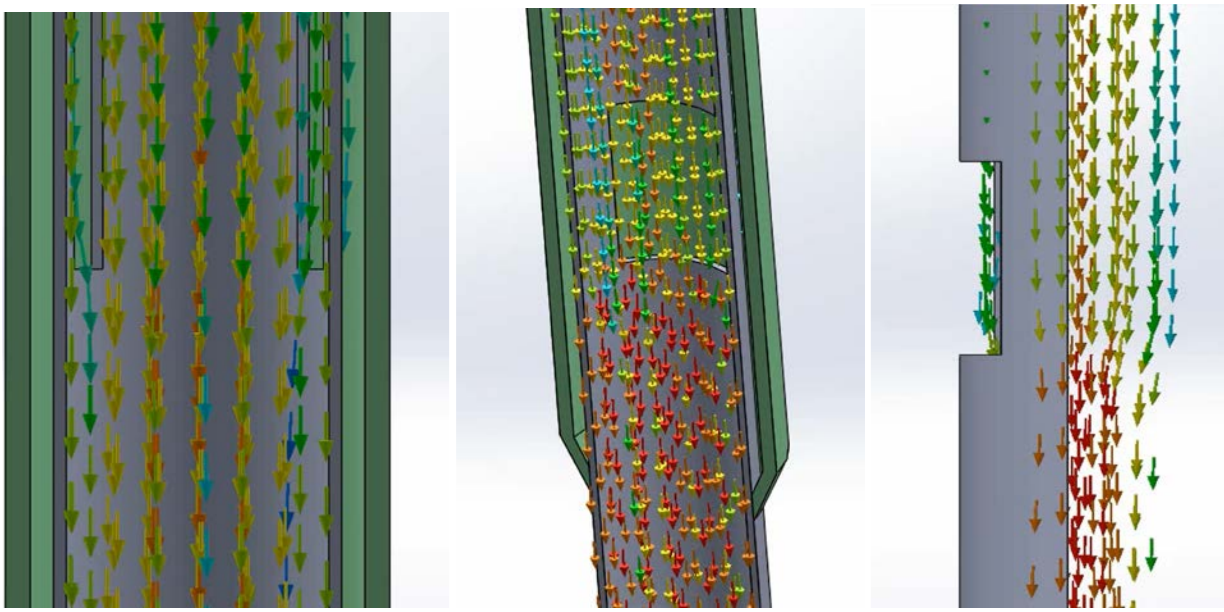

Figure 2 - CFD at 100bpm of bottom slot with degradable sleeve not present- no turbulence present

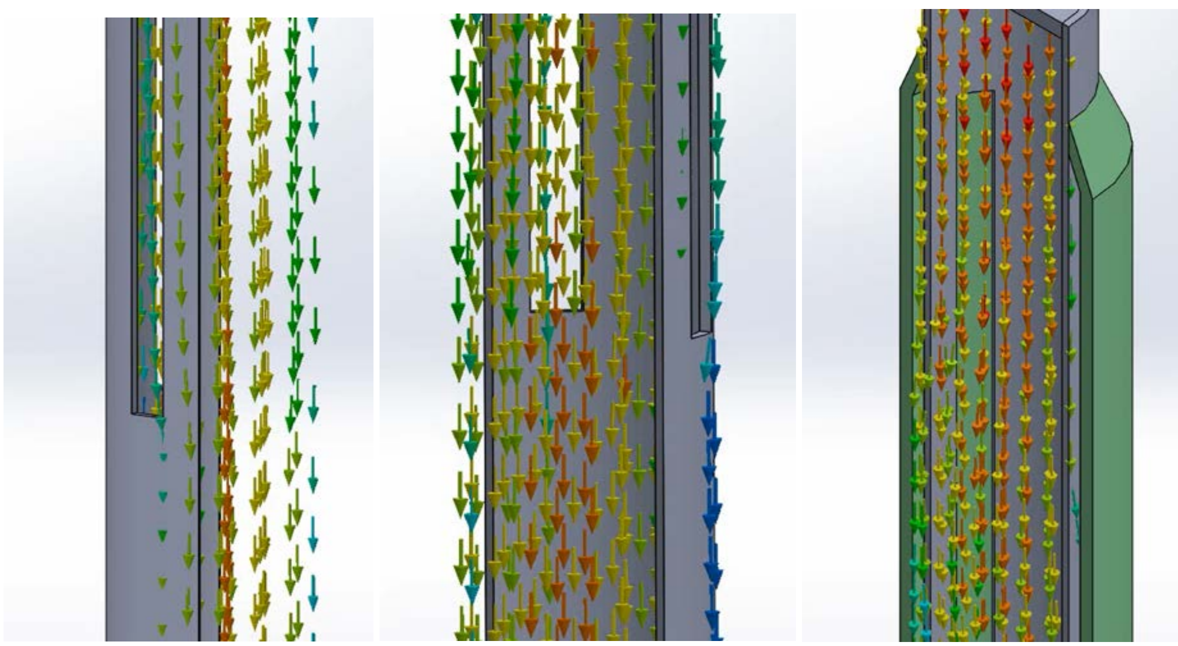

Figure 3 - CFD at 100bpm of top slot with degradable sleeve not present- no turbulence present

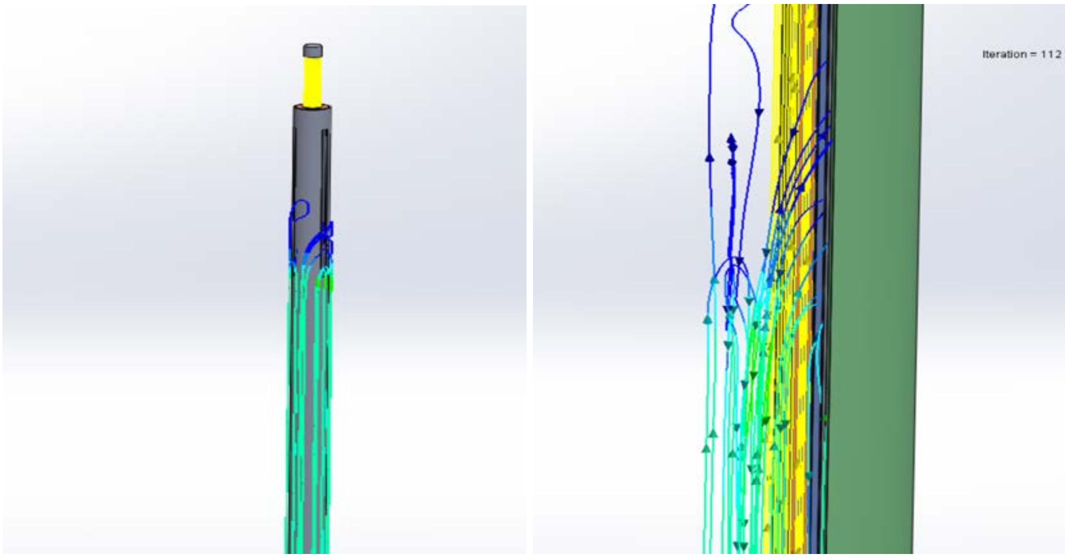

Figure 4 - Production phase with fluid falling out of phase and into artificial sump (tubing to surface show in middle).