A TUBING ANCHOR ENGINEERED TO MAXIMIZE PRODUCTION FROM HORIZONTAL WELLS

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INTRODUCTION

High gas to oil ratio (GOR) producing horizontal wells is now commonplace. This ratio continues to rapidly escalate as reservoirs suffer regional and basin wide pressure depletion. The North Dakota Bakken[i] formation is a prime example of a concerning GOR trend and can be seen in Figure 1. Higher GOR's and depleted reservoir pressures lead to increased gas rates and multiphase fluid velocities within horizontal wellbores. Increased multiphase fluid velocities can then transport more damaging solids to a sucker rod pump and increase failure frequencies. Consequently, challenges for controlling failure frequencies and workover costs with sucker rod pumping continues to intensify, especially for improving downhole gas and solids separation.

Sucker rod pumping normally requires the tubing string to be secured or anchored to the casing, downhole near the sucker rod pump. Anchoring of tubing prevents tubing movement during a rod pump's operating cycle. Tubing movement can undesirably reduce downhole pumping efficiency and increase risks for damage to the tubing, casing, pump and sucker rods. A downhole tubing anchor (TA) or a downhole tubing anchor catcher (TAC) are a bottomhole assembly component installed for this purpose, but they can present risks for increasing operating expenses and limiting of a well's production potential.

Production can be limited if the annular flow path cross-sectional area of a tubing anchor (to the casing's internal diameter) is a flow path restriction. A flow path restriction negatively impacts downhole gas separation performance by causing multiphase flow instabilities. Further, sluggy and inconsistent multiphase flows that commonly emanate from a horizontal wellbore can worsen from a flow restriction, making downhole gas separation even more challenging.

For minimization of production risks, an ideal tubing anchor should not be annular flow path restrictive or in other words, it should be "invisible" in the flow path. It should also have an equivalent internal diameter to the tubing string above it to allow running of the largest rod pump possible.

For minimization of operational risks, an ideal tubing anchor should have an ability to allow application of the required tubing hanger tension, allow placement at high inclinations, and does not require tubing rotation for setting or unsetting.

Even though a tubing anchor can offer significantly lower operational risks than a packer, a packer can be used as a form of tubing anchor. Packer-style separators provide a dual purpose as a separator for gas and as a tubing anchor. Packer-style separators became popular since they improved gas separation efficiencies over packerless poor-boy separators. As such, producers had to accept greater operational risks as a packer can become challenging and costly to retrieve or recover, for example, if solids have accumulated on top of them.

This paper discusses and discloses how a flow path engineered tubing anchor, which maximizes the annular flowby area equivalent to a tubing coupling outside diameter, improves packerless separator performance to greater than packer-style separators. Improving production performance and lowering operational risks of packerless separators suggests that packer-style separators should be more thoroughly industry investigated for if they should be avoided going forward.

ANCHORING OF TUBING IS FOR CONTROLLING FAILURE FREQUENCIES

A tubing anchor is a crucial component in the operation of a sucker rod pumped well for several reasons. Its primary purpose is to secure the tubing string in place within the wellbore. Rod pumping action each pump stroke can impose a 2,000 lb to 6,000 lb load reversal on the tubing at the depth of the pump, which can axially move the bottom of an unanchored tubing string 10 inches (254 mm) to 30 inches (762 mm) repeatedly each pump stroke.

Samayamantula[ii] appropriately detailed unanchored tubing movement is caused by alternately transferring the hydrostatic load of the fluid column inside the tubing string from the rod string to the tubing string. On the down stroke, the tubing carries the fluid load stroke (i.e., pump's travelling valve is open). On the up stroke, the rods carry the fluid load (i.e., pump's travelling valve is closed). In other words, during the down stroke, the tubing elongates, and the rod string shortens; while in the up stroke, the rod string elongates, and the tubing string shortens.

Anchoring of tubing controls tubing movement increased failure frequency risks such as:

- excessive casing, tubing (see Figure 4), and bottomhole assembly (BHA) wear,
- excessive tubing and sucker rod wear,
- excessive vibration that damages the rod pump, and
- excessive loss of pumping efficiency.

Unanchored tubing movement can cause buckling of the lower portion of a tubing string. Buckling of the lower portion of a tubing string can be highly damaging to the tubing and sucker rods and can increase failure frequencies. Kent[iii] illustrated in Figure 2 unanchored tubing buckling during a rod pump cycle and with increased mechanical stress on the sucker rods.

Downhole pump cards can also show tubing movement from unanchored tubing. Rowlan etal[iv] in Figure 3 provides an illustration of downhole pump cards of anchored and unanchored tubing (i.e., shows tubing movement). The amount tubing movement correspondingly reduces the pump's effective stroke length by the same amount and therefore reduces its efficiencies relative the to the pump jack's surface stroke length.

Vagapov[v] interestingly revealed that unanchored tubing buckling worsens when the pump experience pump gas interference. From the publication, Figure 5 illustrates the buckling conditions worsening with pump gas interference. When excessive gas interference is present, the buckling period is approximately equal to the upstroke period during pumping cycle. He also explained that in some cases, the tubing may be concerningly buckled both on the upstroke and the downstroke for the pump gas interference scenario. In can be concluded that maximizing pump fillage (i.e., minimizing pump gas interference) and maximizing pump fillage consistency are fundamental for improving failure frequencies. To this end, downhole gas separation efficiency is paramount.

Kent[vi] concluded that the type of tubing anchor for the prevention of buckling is one that will hold the tubing at its most elongated position. In other words, a tension anchor landed with adequate set tubing hanger tension to retain the tubing anchor in tension under all possible well condition scenarios (producing or not producing).

A TUBING ANCHOR IS PART OF THE DOWNHOLE GAS SEPARATION SYSTEM

A system-based engineering approach is, by definition, making sense of the complexity of the world by looking at wholes and considering component relationships and interactions, rather than isolated components parts. Studying how components interact with each other enables systems change. A common consequence of changing a specific component of system and not studying how that change impacts the system can lead to the engineering dilemma cliché “fixed one problem, but then created another problem” scenario.

Recognizing that tubing anchors have historically been annular flow path restrictive and have not been designed for today’s gassy-sluggy horizontal wells, it is imperative to study how it impacts downhole gas separation and ultimately how it can limit production.

The main system impacts of an annular flow path restrictive tubing anchor requiring study are as follows:

1. Impact to a well’s producing bottomhole pressure due to the pressure drop or pressure loss of the annular flows past the tubing anchor.
2. Impact to a horizontal well’s multiphase flow slugging severity on downhole gas separation efficiency.

TUBING ANCHORS CAN LIMIT PRODUCTION

Production can be negatively impacted by a tubing anchor. Production can be limited if the cross-sectional area of a tubing anchor’s annular flow path (to the casing’s internal diameter) is restrictive or is less than the tubing’s (or other tubing components) annular flow path above and below it.

Roberts from Marathon Oil[vii] discovered that removing a tubing anchor placed above the perforations in a vertical well led to considerable increases in production, even with accepting tubing movement during pumping. Figure 6 shows their impressive increased production results of three times (or more). They concluded that a restrictive annular flow path past the tubing anchor was “choking” the flow and prevented the well from being “pumped off” to the lowest possible bottomhole producing pressure. TechTAC Co.[viii] also described how annular flow path restricting tubing anchors can impede production.

Any restriction in the flow path can reduce a downhole packerless gas separator’s efficiency, but this loss of separator efficiency is primarily rooted in a system instability problem caused by an annular flow path restrictive tubing anchor and not just the separator component itself. Unstable multiphase conditions within the well’s production flow paths are what ultimately limits the well’s production potential. McCoy, Rowland and Taylor[ix] wrote an outstanding technical publication detailing how unstable flow conditions in vertical wells were caused by an annular flow path restrictive tubing anchor. Figure 7 from their publication shows how a well can become pumped off below a tubing anchor (i.e., gas column exists below the tubing anchor down to the gas separator), yet the well still simultaneously has a high liquid column in the annulus above the tubing anchor. This liquid column in the annulus above the tubing has a hydrostatic pressure that increases the bottomhole producing pressure and therefore undesirably limits production drawdown. Figure 8 from Dawsey[x] illustrated that a restrictive tubing anchor can hold a liquid column in the annulus above it, yet still allow gas to flow past the tubing anchor’s restriction.

Wang[xi] showed that standard tubing anchor catchers are highly annular flow path restrictive by design. They were never designed or engineered for high-rate annular gas flows and nor were they designed for gassy-sluggy inconsistent flow horizontal well production. They were designed to anchor the tubing and to provide a “catcher” feature that prevents the tubing from falling further down the wellbore in event the tubing parts above it. Their research revealed that it is important for when determining the annular flow path cross-sectional area that the area the slips take up when they are set needs to also be included – see Figure 9 showing a restrictive annular flow path tubing anchor with its slips set.

For example:

- a 4.5 inch (114.3 mm) outside diameter mandrel standard Baker B style TAC has an equivalent outside diameter of 4.62 inches (117.3 mm) when the set slip’s area is included.
- In 5.5” (139.7mm) by 20 lb/ft (29.8 kg/m) casing, this has annular flow path cross-sectional area of 1.16 square inches (7.48 cm^2).
- For a 2-7/8” (73.0mm) EUE tubing coupling of 3.668 inch (93.2 mm) outside diameter has an annular flow path cross-sectional area of 7.36 square inches (74.5 cm^2).

Figures 10 and 11 shows various existing tubing anchors and their annular flow path cross-sectional areas. High flow or slimhole type tubing anchors improve the annular flow path cross-sectional area over standard tubing anchors but do not achieve the annular flow path cross-sectional area equivalent to a 2-7/8" (73.0 mm) EUE tubing coupling – they are still restrictive. All existing tubing anchors impose an annular flow path restriction. Further study is recommended for the level of multiphase flow turbulence past a restrictive tubing anchor and the consequences to downhole separation (e.g., turbulence generates smaller gas bubbles which are more difficult to separate from liquid).

Figure 12 shows the new eccentric tubing anchor's annular flow path cross sectional area is equal to that of the 2-7/8" (73.0mm) EUE tubing coupling. In other words, the new eccentric tubing anchor design has an outside diameter equivalent to a 2-7/8" (73.0 mm) EUE tubing coupling.

Flow modelling with MAPe™ [xii] in Figure 13 compares various tubing anchor equivalent outside diameters in a typical Permian 5.5" by 20 lb-ft casing horizontal well rod pumping with 250 barrels/day of liquid and 250 Mscf/day of gas. Producing bottomhole pressures were 388 psi, 290 psi and 220 psi for a standard TAC (4.6-inch equivalent outside diameter), a high flow slimhole TAC (4.1-inch equivalent outside diameter) and for no TAC (3.7-inch equivalent outside diameter) respectively.

In can be concluded that having a tubing anchor with no annular flow path restriction maximizes downhole gas separation performance of packerless separators and therefore is the preferred producing condition for maximizing a horizontal well's production.

FLOW PATH RESTRICTIONS CAN WORSEN SLUGGING

Sluggy, gassy and inconsistent multiphase flows that commonly emanate from a horizontal wellbore can be made worse by an annular flow path restrictive tubing anchor. Slugging[xiii] can cause significant fluctuations in multiphase flow rates, making downhole gas separation even more challenging.

Alegria[xiv] recently published useful multiphase flow research of how a flow restriction affects multiphase flow. The research revealed that, in addition to causing a pressure drop or loss, the flow path restriction also produced changes in the upstream flow, where larger sizes and velocities of the liquid slugs were observed, the main reasons being the deceleration of the gas bubbles approaching the restriction zone, thus generating gas bubbles coalescence (larger gas bubbles) and rearrangement in size and velocity of liquid slugs. Their research also showed that downstream of the restriction there is an increase in the void fraction due to the breaking of bubbles and loss of pressure. Bubbles in slug flow regime were broken into smaller bubbles when passing through a flow path restriction. Smaller gas bubbles are more challenging to separate from liquid, as they rise in liquid at much slower velocities as detailed by Hassan[xv]. It can be concluded that placement of a restrictive annular flow path tubing anchor upstream and in proximity of a gas separator will cause multiphase flow instabilities and will reduce a gas separator's efficiency.

Dr. Nagoo transiently flow modelled using MAPe the slugging impact of an annular flow path restrictive tubing anchor downstream of downhole packerless separator using the

MAPe model. The modelled slug flow conditions are shown in Figure 14 and indicates that an annular flow path restriction increases the slugging severity of both the slug amplitude and the slug frequency, making downhole gas separation more challenging.

Kubacak [xvi] disclosed, as shown in Figure 15, a case history where the slugging instabilities by a restrictive annular flow path tubing anchor greatly impacted downhole gas separation and pump fillage. In Figure 15, when the annular fluid level was above the restrictive annual flow path tubing anchor, pump fillage was high erratic and averaged around 70 percent. Once the annular fluid level lowered to below the tubing anchor, flow instabilities terminated and pump fillage became high and highly consistent at 95 percent.

In summary, for a horizontal well, if a tubing anchor is designed without a restrictive annular flow path the multiphase flow conditions will be considerably more stable and the overall performance of a packerless separator will likely be maximized.

OTHER LIMITATIONS OF TUBING ANCHOR AND TUBING ANCHOR CATCHERS

In addition to being an annular flow path restriction, there are other limitations with tubing anchors. These include operational risks (setting and unsetting), internal diameter restrictions, and an inability to set a required tubing hanger tension to avoid buckled tubing.

Rotational set mechanical tubing anchor catchers have operational risks. For example, an existing slimhole type TAC[xvii] can require six (6) to eight (8) turns to the left and then the same number of turns, but turning the tubing to the right, to release. With a high number of tubing rotations to release, solids and scale deposition, especially in deeper wells, the risk of solids and scale preventing a rotational release escalates. Shearing out the tubing anchor at a relatively high tubing tension force, using a shear pinned emergency shear release feature of the tubing anchor or fishing it becomes the only options.

Mechanical rotationally set and unsetting tubing anchors can become challenging when wellbores are not vertical. McDaniels[xviii] reported that highly deviated "S" wells began to present problems for setting and retrieving mechanical tubing anchors. Therefore, mechanical rotationally set tubing anchors are operationally risk limited to placements in vertical wells or the vertical section above the curve of a horizontal well bore.

High flow or slim hole tubing anchors can have restrictive internal diameters. To achieve a greater annular flow cross sectional area, smaller internal diameter mandrels have been used in tubing anchors. This can limit the rod pump size for if the tubing anchor is to be run above the pump seat nipple. If a restrictive internal tubing anchor is run below a pump seat nipple, it is placed near the downhole gas separator which can then further reduce downhole gas separation performance. If the tubing anchor is placed below and near a downhole gas separator, excessive annular flow path turbulence can generate much smaller gas bubbles that are more difficult to separate, which reduces downhole gas separation efficiency (see Hassan[xix]).

Hydraulic type tubing anchors have been developed. They set automatically when there is differential pressure from inside the tubing to the annulus. For example, once the pump is seated and the tubing is filled (by pumping the well), a hydrostatic pressure differential will form to the anulus, which sets the anchor. This setting mechanism of hydraulic type tubing anchors has an inherent risk that they are not able to achieve a required pre-set tubing hanger. Hydraulic anchors can also become stuck in the hole from a shallow tubing leak and stuck pump scenario.

A CATCHER FEATURE IN A TUBING ANCHOR IS NOT REQUIRED

A catcher feature in a tubing anchor and hence the name description of tubing anchor catcher, means that once set it can secure the tubing or prevent tubing movement in both the upward tension direction and the downward compression direction. A catcher feature is designed to prevent tubing/BHA from falling down the well in the event tubing parts in half (e.g., from corrosion or erosion) above the tubing anchor.

From an engineering design perspective, it was identified that a catcher feature is too costly to include in a mechanical tubing anchor that has all the ideal tubing anchor features for 5.5” casing. Ideal tubing anchor features such as an annular flow path cross-sectional area equal to a 2-7/8” (73.0 mm) EUE tubing coupling, it does not require rotation to set or unset, and it has an internal diameter equivalent to 2-7/8” (73.0 mm) EUE tubing.

During 2022 and 2023, an extensive multiple producer survey was conducted to assess if a tubing anchor requires a catcher feature. The surveying found that the risk of tubing parts is very low, primarily with more common practice of using L-80 grade tubing and concluded that a catcher feature in a tubing anchor is not required.

A data mine search of the extensive sucker rod pumping workover database from Q2-Trak[xx] also supported this finding with no recorded events of a tubing part as the root cause a workover.

LIMITATIONS OF A PACKER-STYLE SEPARATOR AS A TUBING ANCHOR

Even though a tubing anchor can offer significantly lower operational risks than a packer, a packer can be used as a form of tubing anchor. Packer-style separators provide a dual purpose as a separator for gas and as a tubing anchor. Packer-style separators became popular since they improved gas separation efficiencies over packerless poor-boy separators. As such, producers had to accept greater operational risks as a packer can become challenging to retrieve or recover if, for example, solids have accumulated on top of them.

The flow path through a packer style separator is restrictive and it must pass all the produced fluids and gases at their rates emanating from the well. For example, packer-style separators have a restrictive annular shaped flowpath conduit through their mandrels, as larger outside diameters mandrels would reduce their gas separation cross-sectional area to the casing (i.e., will reduce their gas separation capacity). They also have abrupt flow path changes in directions, which increases flow turbulence and pressure loss. Further, any solids separation features must be placed upstream of packer-style separator, which will also increase the overall pressure loss. Figure 16 illustrates a restrictive flow path through a packer-style separator and some published flow path dimensions of existing packer-style separators. The hydraulic diameter calculation is used to approximate the behavior and flow pressure losses of non-circular conduits based on equations originally developed for circular pipes.

MAPe was again used to model the pressure loss through a packer-style separator under varying liquid and gas rate conditions and under pump intake pressures (at 300 psi and 900 psi). Figure 17 shows the modelling results. Lower pump intake pressures result in high pressure losses through a packer separator. In effect, at lower pump intake pressures, the same multiphase flow instabilities and production limitations of a restrictive annular flow path tubing anchor will be experienced by a packer-style separator, albeit at higher operational risk with a packer in place.

Designing a tubing anchor that is not annular flow path restrictive relative to the tubing couplings, improves the production performance packerless gas separators at lower operational risk, suggests that packer-style separators should be more thoroughly investigated for if they should be avoided going forward.

ENGINEERING AN IDEAL TUBING ANCHOR – MAKE IT FLOW PATH INVISIBLE

An ideal 5.5” (139.7 mm) tubing anchor was envisioned as follows:

1. the cost to benefit of a catcher feature is not justified and therefore is not included, a tension anchor is fit for purpose,
2. is not flow restricting, having an annular flow path cross-sectional area equivalent to a 2-7/8” (73.0 mm) tubing EUE coupling,
3. has full drift internal diameter equivalent to 2-7/8” (73.0 mm) EUE tubing, allowing for placement away from the separator (above or below),
4. does not require rotation to set or unset, reducing operational risks and lowering stuck in hole risks, allowing placement at high inclinations and allowing use of capillary injection strings or electrical cabling,
5. can be placed above or below any packerless gas separator,
6. allows for adequate tubing hanger tension setting weights,
7. minimizes casing scraper requirements,
8. has an emergency shear release feature, and
9. it is cost effective.

To mechanically engineer a non-restricting annular flow path and with a large internal diameter, the tubing anchor was designed with an eccentric position in the casing. Goal is to minimize wall/boundary associated flow by maximizing cross-sectional flow area and minimizing contact surface area. A single, large, ramp activated carbide button slip system was designed. On the opposing side of the tool, which sits close to the casing wall, an auto-retractable drag block and wicker-based holding slip was designed.

An eccentric annular conduit shape also offered opportunity for a 30% increase in gas flowby efficiency. Caetano's[xxi] research in Figure 18 concluded that an eccentrically shaped annular flow path or conduit can escape gas through it 30% more efficiently than a concentrically shaped annulus. An eccentrically "crescent moon" shaped flow path has a larger space for larger gas bubbles to escape through and is therefore more efficient for gas to escape through. Further, applying hydraulic diameter calculations shows that an eccentrically annular flow path has a larger hydraulic diameter for the same cross-sectional area of a concentric annulus (i.e., has less wetted area to restrict gas flow) and therefore will have low flow turbulence in addition to less flow pressure drop. Correspondingly, an eccentrical annular flow path should be more tolerant to gassy-sluggy flows associated with horizontal well production. Phillip's [xxii] studies and experiments also proved that an eccentric annular flow path is more efficient for gas to escape through in multiphase flow conditions.

Figure 20 shows a tubing anchor annular flow path cross sectional are comparative chart of existing tubing anchors versus the new eccentric positioned design. The chart shows allowable gas rate based on a gas velocity limit of 6 feet per second (1.5 meters/second), the point at which a liquid column will undesirably commence building in the anulus on top of a tubing anchor (see Saponja etal[xxiii]). Even through the annular flow path cross sectional area of the new eccentrically positioned design is equal to that of a 2-7/8" EUE tubing coupling, its eccentric flow path provides beneficial greater gas flow by efficiency.

To avoid the risks of rotation for setting and unsetting of a tubing anchor, an auto-J (or autoset) function was engineered into the tool. Auto-J technology comes from coil tubing packer fraccing tools, where they have had extensive successful experience with setting and unsetting with only up/down axial motion and in high solids laden high inclination wellbore conditions. An internal clutch assembly with solids tolerant lugs was designed to follow the Auto-J track and index the tool to a desired condition or position. Figure 21 shows the Auto-J track and the various tool positions for:

1. Run in hole.
2. Set (Anchor).
3. Release.
4. Pull out of hole.

The tool will index through these positions sequentially with up and down tubing string movement. The autoset mandrel was also Teflon coated for smooth function and avoidance of scale adhesion and corrosion. The tool easily sets with pull up by approximately feet. The auto-J track in the mandrel was lengthened for the Run-In-Hole mode which extended the slip cage travel before going into the Set (anchor) mode. This extended travel avoids unplanned setting events during running in the hole, as the amount of travel is significantly more than travel need to lift the tubing string out of the rig's table slips while running in hole.

The mandrel was designed and evaluated to 60,000 lbs tension. An emergency shear release feature was included. Shear pins can be added or subtracted in 5,000 lb increments.

Prototype tool shop bench tests and field trials revealed some slip engagement design deficiencies. The deficiencies were resolved, and an eccentric centralizer "fin" was added to the top coupling of the first 20 pre-commercial prototypes. This fin prevents the tool misalignment while under high tension (i.e., tension force will pull the top of the tool towards the centerline of the casing). To keep the annular flow path cross-sectional area equivalent to a 2-7/8" coupling, the top coupling was machined down to the outside diameter of a special clearance EUE coupling and the material was changed from L-80 equivalent to P-110. A field trial in a high H_2S well condition resulted in hydrogen embrittlement of this coupling, and it cracked (see Case History 3). To prevent recurrence, the commercial design going forward has moved this fin down onto the smaller outside diameter mandrel and the top coupling has been returned to a full-size L-80 EUE coupling.

Figure 22 shows renderings of the resultant final commercial auto-set tension tubing anchor design. The designed achieved all the features from the ideal tubing anchor list as summarized. It was named the SharkTAC™ for being a highly unique tubing anchor casing-scraper – it achieved the design goal of being "invisible" in both the internal and external flow paths.

INTEGRATION OF A CASING SCRAPER FEATURE

A downhole tool that uses an auto-J for slip engagement offers a unique opportunity for integration of an operational cost saving casing scraper feature. Avoidance of a dedicated casing scraper trip prior to running a final BHA saves time and money.

With an auto-J systems, the drag blocks and slips are always in the same axial alignment since they are non-rotating. The drag bock is designed to drag on the casing creating friction force to function the tool's traveling cage slip assembly. A drag force in the order of 2,000 lbs is designed to assure the traveling cage functions and indexes the lug clutch assembly in the J-track. This drag force is applied by Inconel springs that push the drag block against the casing. It was realized that shaping the drag block as a casing scraper blade could be adapted into the drag block, providing low to moderate risk casing scraping requirements. In low to moderate risk casing scraping well scenarios, a dedicated casing scraper trip could be avoided.

Figure 23 shows a rendering of a drag block with a chevron grooved integrated casing scraper feature.

TUBING HANGER LANDING TENSION REQUIREMENTS ARE CRUCIAL

A tubing string is required to be landed with a pre-tension load above the hanging string weight, otherwise there can be producing conditions that cause the lower portion of tubing to go into undesirable compression and buckle. A tubing anchor that is in a neutral or compressional load condition can become unset during cyclical rod pumping. A tubing anchor with a catcher feature can buckle the buckle the tubing string if it is under a compressional load.

Petrowiki[xxiv] provides a technical reference for tubing movement calculations and the overall dominant impact from temperature changes. The effect of thermal expansion or contraction (i.e., changes in temperature) causes the major change in length of a tubing string.

They detail four effects that cause a change in the length or force in a tubing string:

- Temperature – directly influenced by a change in the average temperature of the string.
- Piston – a change in the pressure in the tubing or annulus above the packer acting on a specific affected area.
- Ballooning – a change in average pressure inside or outside the tubing string.
- Buckling – occurs when internal tubing pressure is higher than the annulus pressure.

There are three well conditions that need to be appropriately tubing movement assessed for when determining the minimum required tubing hanger landing tension. The risk of the lower part of the tubing string becoming loaded in compression (and buckling) must be avoided. Note that this landed tubing hanger tension weight is the amount of load over and above the tubing string's hanging weight prior to setting the tubing anchor.

The net or overall length change (or force) in the tubing is the sum of the length changes (or forces) caused by the temperature change effects, as well as pressure induced piston and ballooning effects. The direction of the length change for each effect (or action of the force) must be considered when summing them under varying well conditions. The important well conditions are:

1. Static Not Producing – when the tubing string and BHA assembly are installed (tubing hanger and TAC are set), with a static fluid level balanced to current reservoir pressure and lower tubing string temperatures resulting from cooler workover load fluids.
2. Dynamic Producing – when the tubing string and BHA assembly are installed, with a pumped off low fluid level, tubing filled to surface and higher tubing string temperatures resulting from produced hotter reservoir fluids.
3. Dynamic Bullhead Pumping of Hot Oiling or Hot Watering or Flushes– when the tubing string and BHA assembly are installed and pumping of a bullhead treatment

down the tubing to casing annulus with its associated temperatures and fluid flow frictional forces across the BHA.

The minimum required tubing hanger tension must also consider and be compensated for other operational conditions, including:

1. Tapping of the pump, which can easily place a downward load on the pump seat nipple of 5,000 lbs.
2. Annular fluid level dropping.
3. Contingency, recommended at 5,000 lbs of added tubing tension if setting overpull limits permit.
4. Need to watch overpulls needed for stretching the tubing to the to rig floor for when installing a tubing hanger or if a shallower well consider a safe set tension tool (ProTension Safe Tension Tool[xxv]).

Detailed tubing hanger tension calculations can be seen in Figure 24. These results are often more tension at the hanger than one expects. It is best practice to error on the side of more tension than is calculated, as there is generally more tubing load capacity in the tubing (using 80% safety factor of the tensile maximum load rating).

McDaniel's[xxvi] field research found that some explanation for mechanical anchors not being set come from the fact that setting appropriate tubing hanger tension in the mechanical rotational anchors was difficult with J-55 tubing and an anchor shear pin rating of 35,000 lbs. Overpull during setting and landing the tubing hanger for achieving tubing tension requirements often exceeded the tensile rating of the J-55 tubing. Consequently, tubing anchors were set with inadequate tubing hanger tension for the producing conditions.

Kent[xxvii] in Figure 25 shows that if a tubing anchor allows for compression in the tubing string, severe buckling can occur. This tubing compression scenario will greatly increase the failure frequency of the tubing and rods. Also, thermal elongation contributes to both upstroke and downstroke buckling of the tubing above the anchor if it is not run high above the pump.

Samayamantula[xxviii] publication explained the importance of conducting tubing movement calculations for the various forces present and how they change from a static wellbore condition to a producing wellbore condition. This technical reference provides some good background and explains but unfortunately made an error in their tubing hanger tension calculations. The temperature difference between the static and producing well conditions was correctly described by Kent[xxix] as being the average change temperature between the static and dynamic conditions – defined as the average temperature increase of the entire tubing string is only one-half the difference between the temperature of the dynamic pumped fluid at the well head and the static mean yearly temperature for the area. See Figure 26 and see Figure 27 for the corrected calculations.

Hydraulic anchors are not able to set wit the required pretension on the tubing hanger. In attempt work around this issues, hydraulic anchors are design to slide downward as their slips are unidirectional to the tension direction only. It is unknown that this sliding occurs in practice and extensive further industry investigation is needed to appropriately assess.

WELLBORE BOTTOMHOLE ASSEMBLY CONFIGURATIONS

Figure 28 shows some example and recommended BHA configurations for the new eccentric tubing anchor. Placement above or below the downhole packerless separator is acceptable, but it is recommended to place the tubing anchor 10 to 20 tubing joints above or 5 or more tubing joints below it respectively. This recommendation is not a requirement as this tubing anchor has been designed to be “invisible” in both its external and internal flow paths.

As noted previously, placement of a tubing anchor immediately above or below the downhole gas separator can cause flow turbulence and generation of smaller gas bubbles which can have the risk of reducing gas separation efficiency.

CASE STUDIES

Field implementations with over 20 installs of this new eccentric tubing anchor and system effective March 2024, statistically meaningful production performance results with these downhole separation system improvements are being compiled. Some relevant case studies are as follows. These case studies will be updated as more time-based performance and reliability results are compiled.

Case Study 1 – Figure 29 shows the results of proactive workover in the Permian that replaced only the slimhole tubing anchor that existed in the well (a tubing anchor with a 4.1-inch equivalent outside diameter) with the new eccentric tubing anchor (with a 3.7-inch equivalent outside diameter. Nothing else in the system was changed and this well had a liquid fallback packerless WhaleShark gas separator installed for the previous 18 months. Production increased by approximately 40 precent.

Case Study 2 – Figure 30 shows the production results of a 40% increase in production with replacement of standard TAC with the new eccentric tubing anchor. No other downhole components were changed, and this well has a liquid fallback WhaleShark gas separator in it.

Figures 31, 32 and 33, detail the flow modelled results using MAPe of replacing this standard TAC wit the new eccentric tubing anchor. In terms of explanation, the transient slugging flow characteristics results from MAPe in the excel results spreadsheet combined with the solved flow pattern outputs show that the standard TAC was likely causing a bubble breaking phenomenon upstream of the TAC thereby breaking the normally slugging and normally churning flow into smaller bubbles that would then more easily carry with the liquids into the WhaleShark separator.

The flow modelling showed significantly reduce slugging tendencies for the horizonal wellbore. Gas volume fractions reduced from an unstable cyclical range of 0.35 to 0.75 to more stable 0.45 to 0.8. Production results from the field showed very stable flow conditions art surface post install of the SharkTAC.

Case Study 3 – Figure 4 shows pictures of two recorded non-productive time incidents. The first picture shows a cracked top tubing anchor coupling. This cracked occurred because of a high H_2S well condition and hydrogen embrittlement of the tubing anchor's top special clearance EUE P-110 coupling. This result in a design change where the top coupling is now a L-80 material (rating for sour service) and is a regular sized EUE coupling. The figure also shows two pictures of solids covering the SharkTAC. It was pulled for not be able to set. Upon investigation, this well was being converted from gas lift to rod lift and was never cleaned out of solids during the workover. The tubing anchor was run into a well that had excessive volumes of solids which prevented the tool from function. A subsequent solids cleanout resulted in the SharkTAC setting with no issues. Corrective action is to always assess the risk of for the level of well preparation required in a well bore when setting slip-based tools for the first time. A third troublesome tubing anchor setting well hade excessive scale present from its ESP pumping phase. In this case, a dedicated casing scraper trip with acid flushes was needed to appropriately prepare the casing for slip-based tool setting.

CONCLUSION

A patent pending new ideal tubing anchor for 5.5" (139.7 mm) casing has been engineered and developed to address production challenges and associated with horizontal wells, so production can be maximized using packer gas separators.

This new mechanical design uses eccentric flow paths, does not require rotation to set or unset, and allows for required tubing hanger tension. Case histories prove this new tubing anchor successfully lowers operational risks and maximizes sucker rod pumping production of horizontal wells.

FIGURES

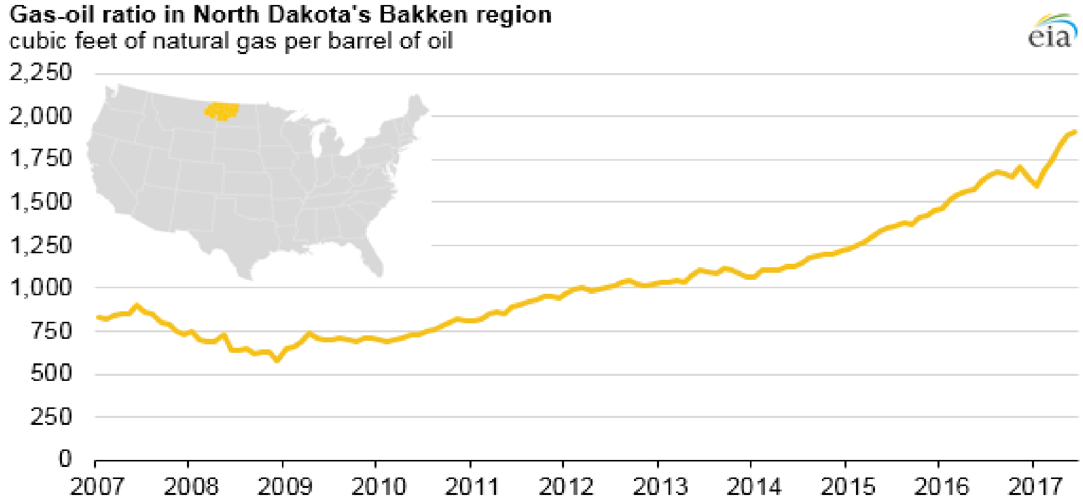

FIGURE 1 – ESCALATING BAKKEN GOR DUE TO BASIN WIDE RESERVOIR PRESSURE DEPLETION

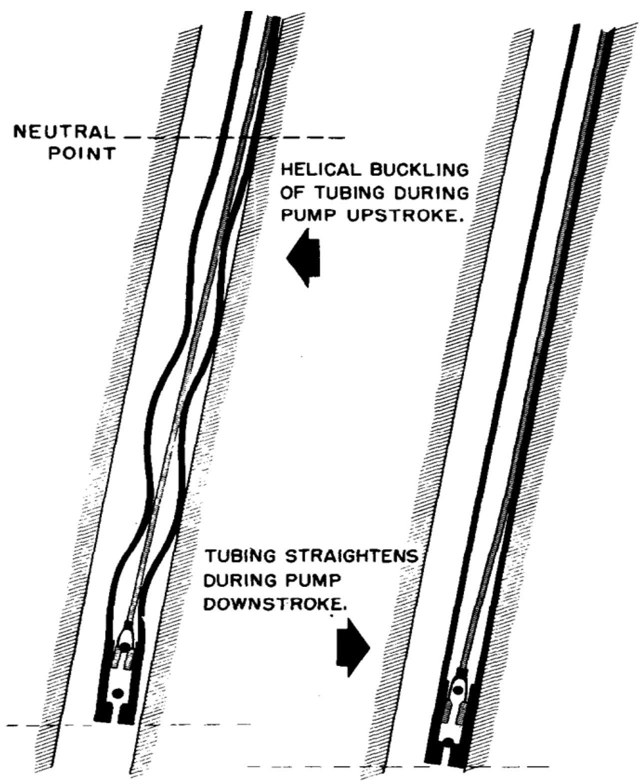

FIGURE 2 – TUBING STRING CAN BEND AND BUCKLE DUE TO TUBING MOVEMENT FORCES DURING ROD PUMPING

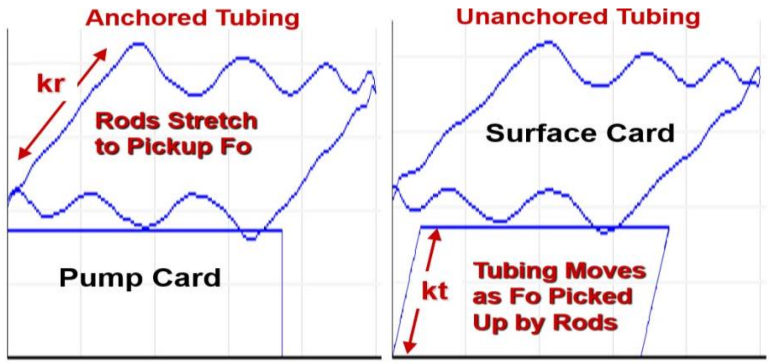

FIGURE 3 – ANCHORED AND UNANCHORED TUBING SURFACE AND DOWNHOLE PUMP CARDS

FIGURE 4 – UNANCHORED TUBING MOVEMENT TUBING COUPLING WEAR

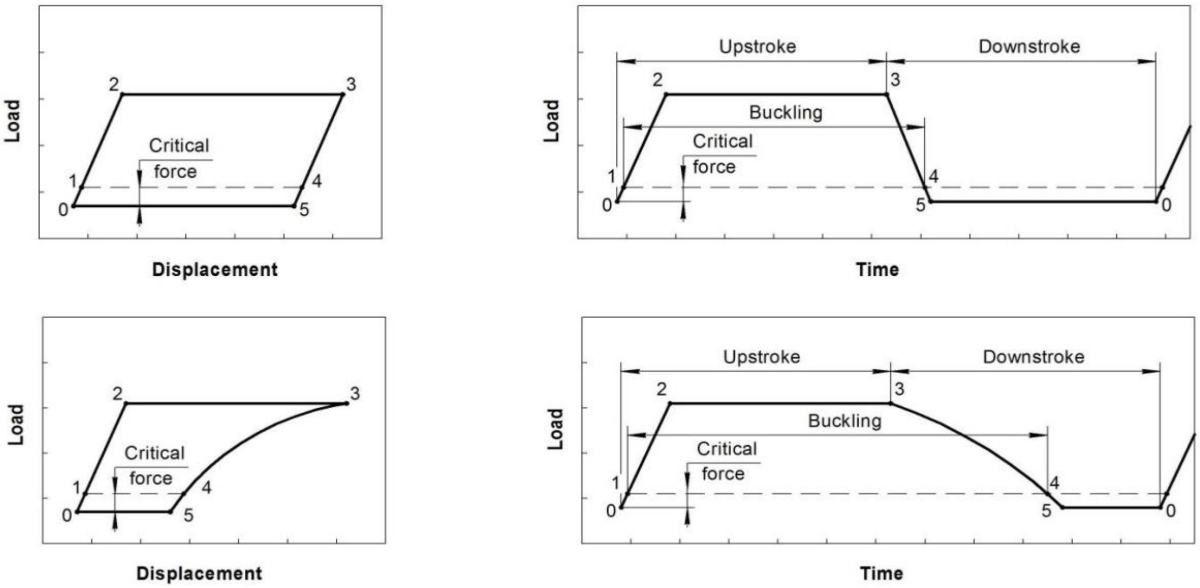

FIGURE 5 – UNANCHORED TUBING BUCKLING OF THE LOWER TUBING PORTION WORSENS WITH GAS INTERFERENCE

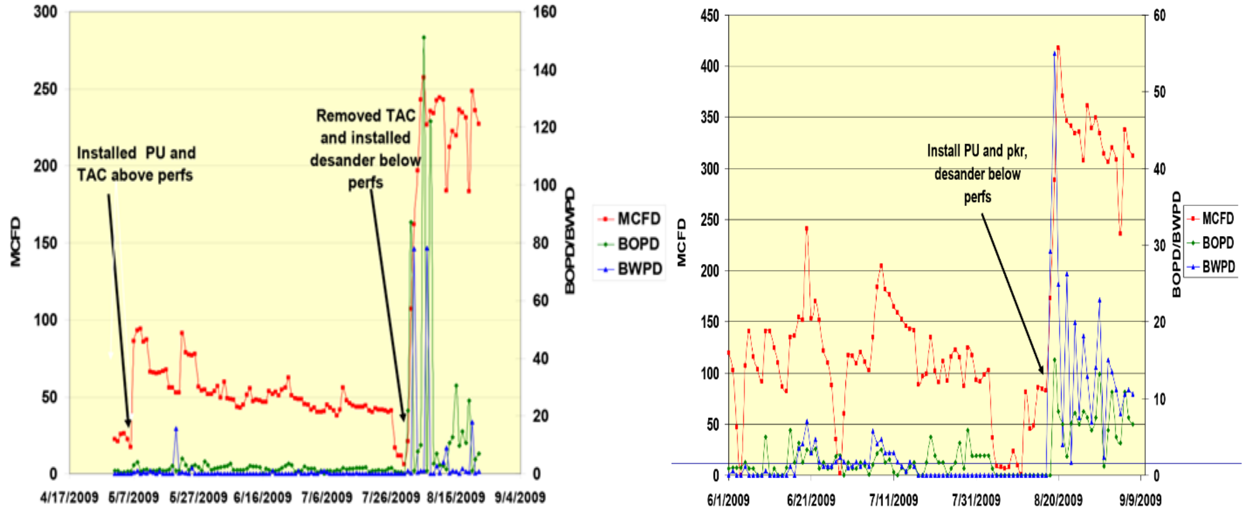

FIGURE 6 – REMOVAL OF TAC'S ABOVE PERFORATIONS RESULTED IN CONSIDERABLE PRODUCTION INCREASES

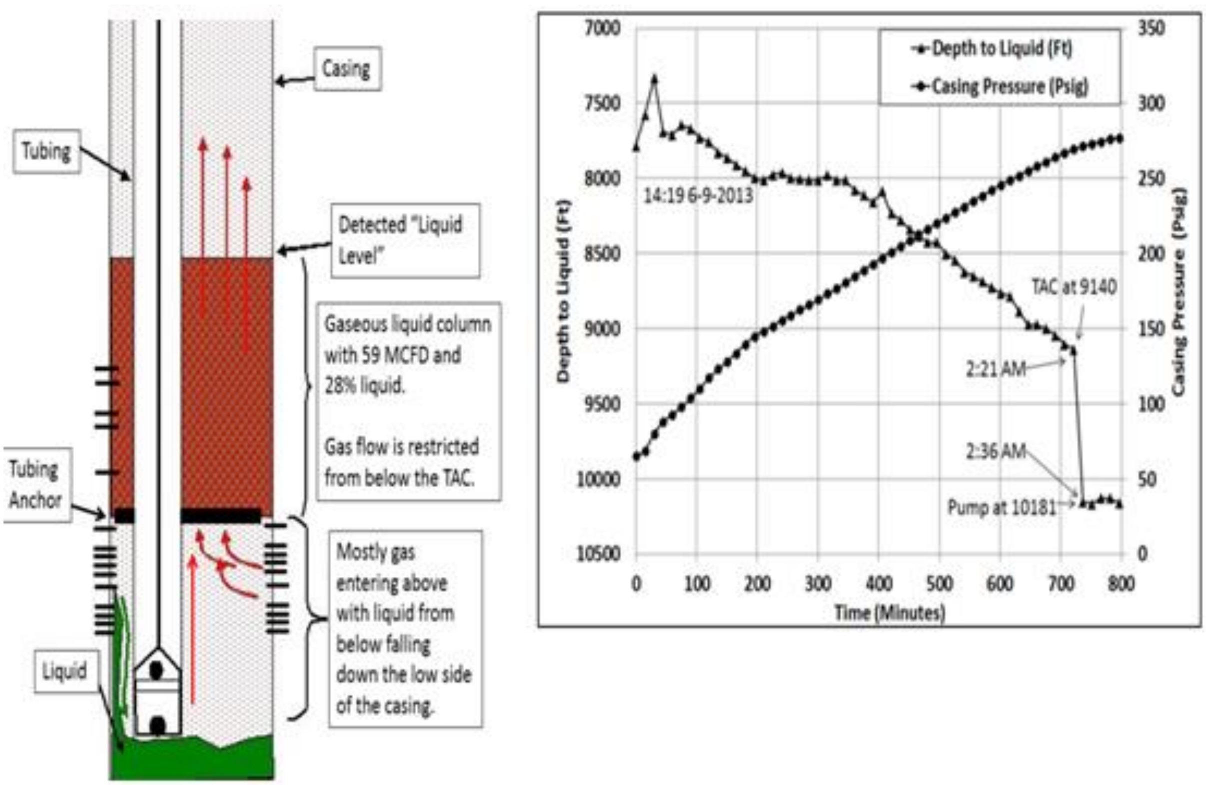

FIGURE 7 – A RESTRICTIVE TAC CAN HOLD A LIQUID COLUMN IN THE ANNULUS ABOVE IT, LIMITING DRAWDOWN

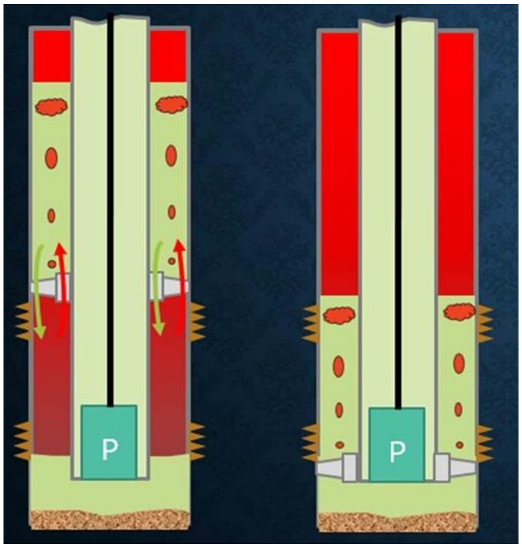

FIGURE 8 – ILLUSTRATION OF GAS VELOCITIES PAST RESTRICTIVE TAC PREVENTING LIQUID FALLING BACK THROUGH IT

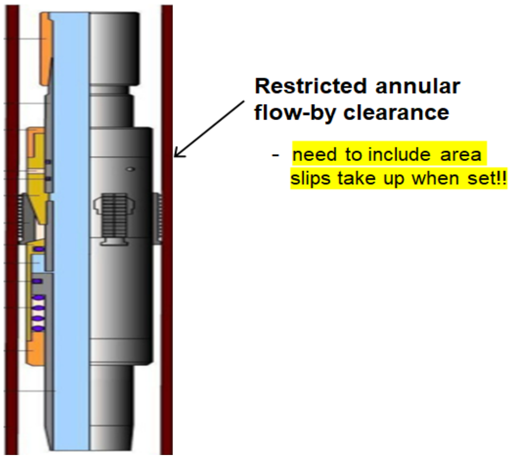

FIGURE 9 – ANNULAR FLOWPATH RESTRICTION INCLUDES AREA OF SLIPS

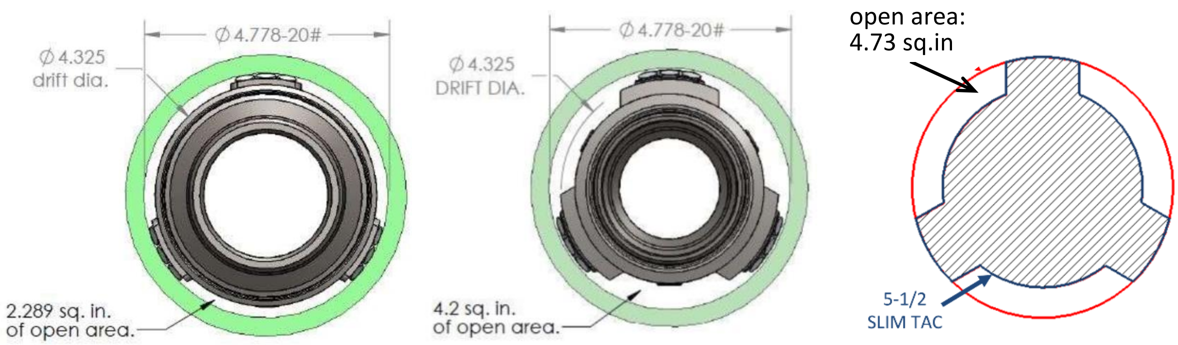

FIGURE 10 – 5.5" CASING ANNULAR FLOW PATH AREA COMPARISON OF STANDARD VERSUS HIGH FLOW MECHANICAL TUBING ANCHOR CATCHERS

FIGURE 11 – 5.5" CASING ANNULAR FLOWBY AREA COMPARISON OF HYDRAULIC TUBING ANCHOR VERSUS STANDARD MECHANICAL TUBING ANCHOR CATCHER

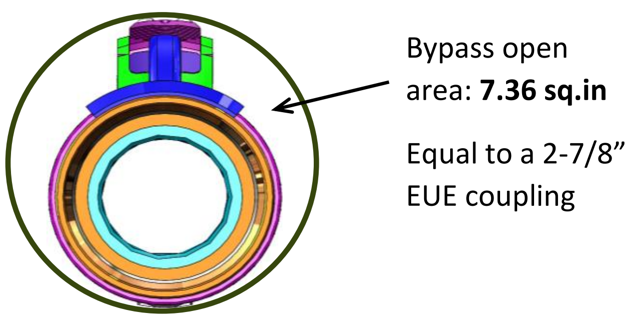

FIGURE 12 – 5.5" CASING ANNULAR FLOWBY AREA OF THE NEW ECCENTRIC TUBING ANCHOR IS EQUIVALENT TO A 2-7/8" EUE COUPLING

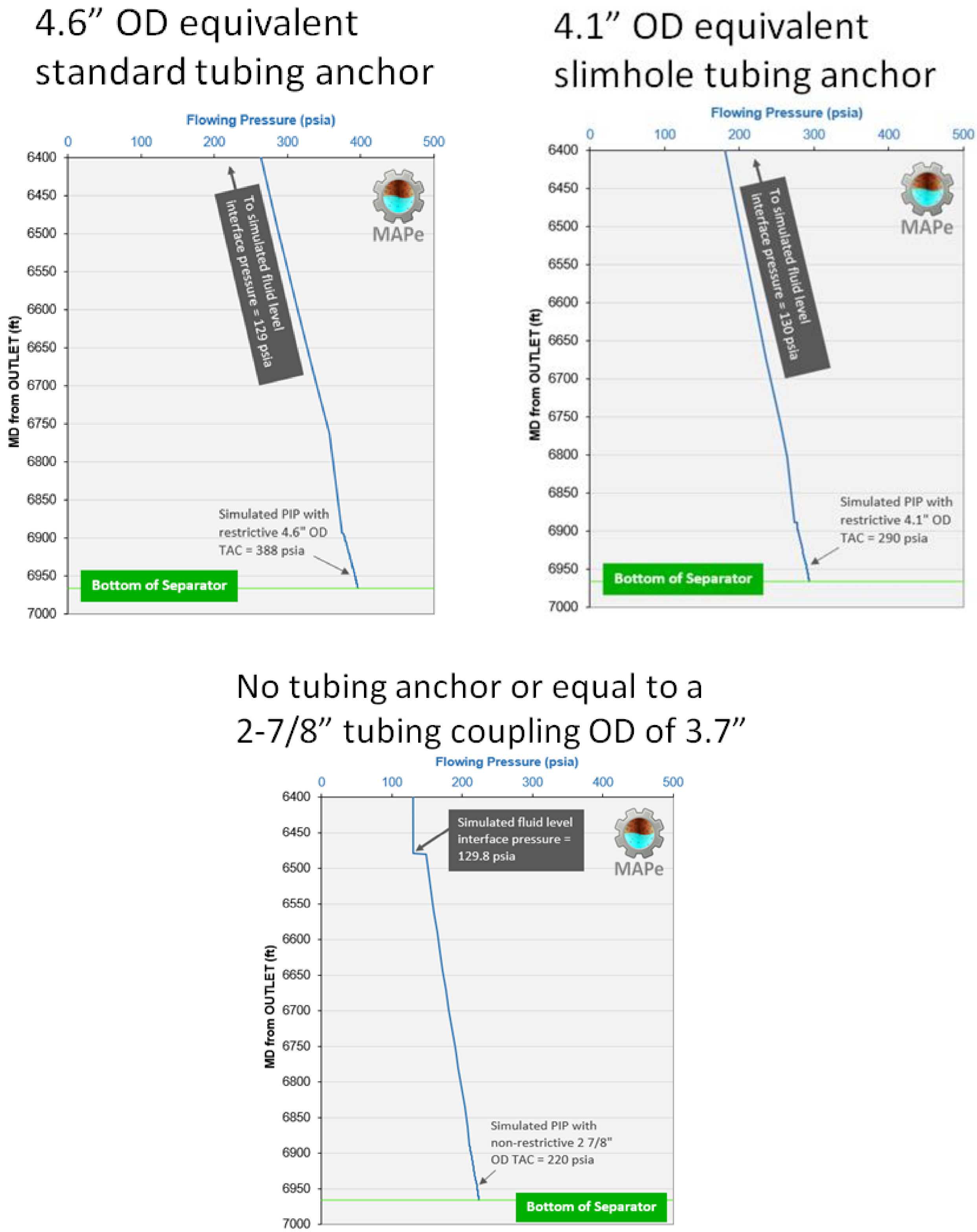

FIGURE 13 – 5.5" CASING MAPe FLOW MODELLED TUBING ANCHOR ANNULAR PRESSURE LOSS SCENARIOS (STANDARD TAC, SLIMHOLE TAC AND NO TAC)

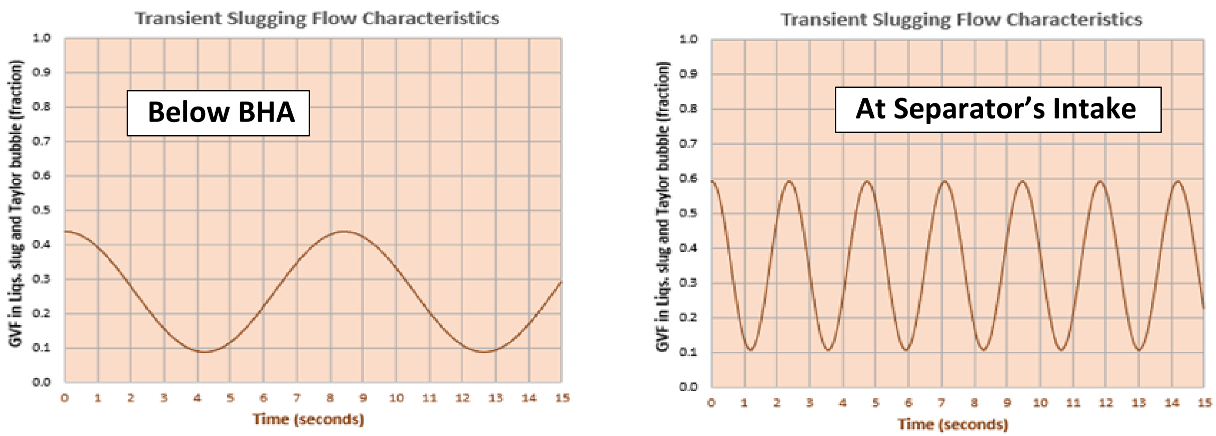

FIGURE 14 – MAPe MODELLED HORIZONTAL WELL SLUGGING WORSENING DUE TO A RESTRICTIVE ANNULAR FLOW PATH TAC

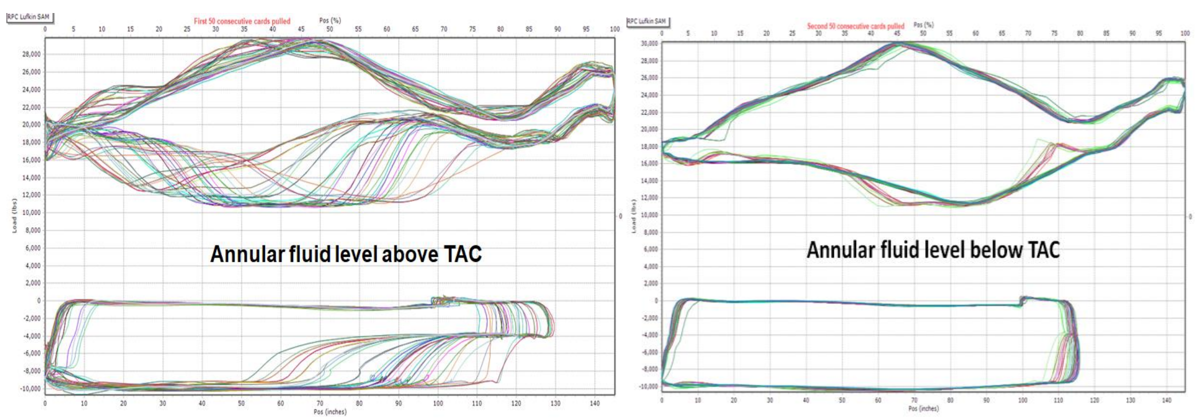

FIGURE 15 – FLOW SYSTEM INSTABILITIES AFFECTING GAS SEPARATION EFFICIENCY AND PUMP FILLAGE CAUSED BY RESTRICTIVE TAC

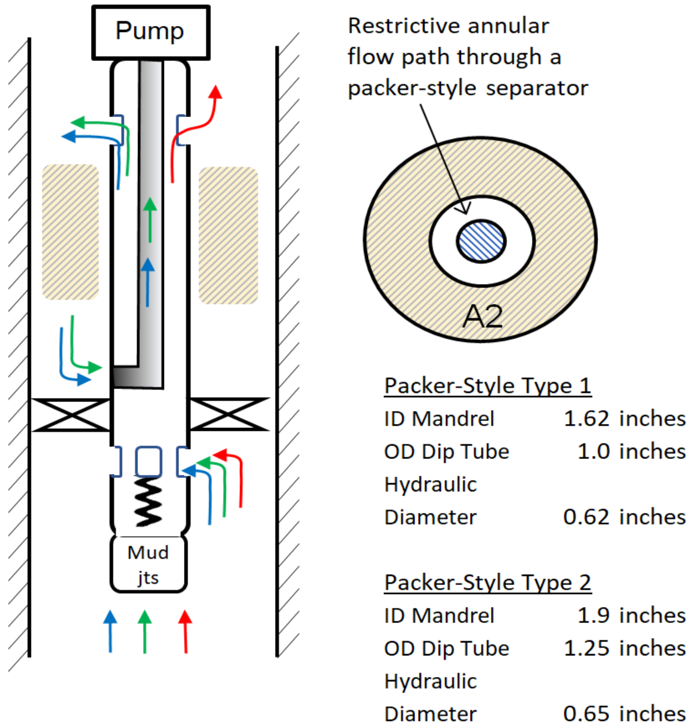

FIGURE 16 – PACKER-STYLE SEPARATOR RESTRICTIVE FLOW PATH

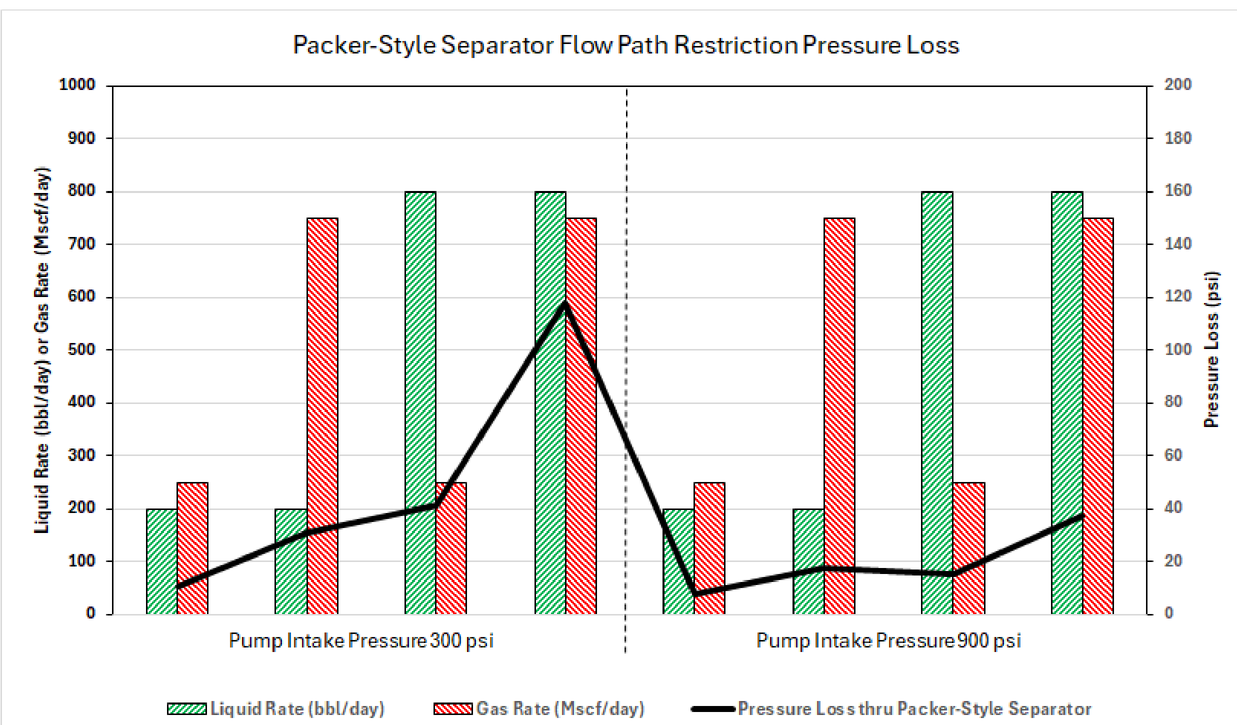

FIGURE 17 – MAPe PRESSURE LOSS THROUGH A PACKER-STYLE SEPARATOR

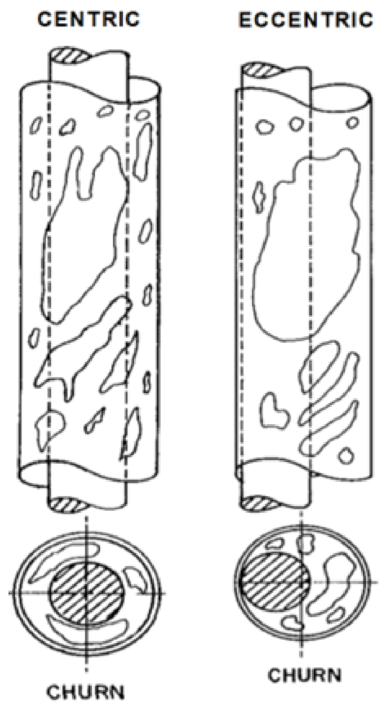

FIGURE 18 – ECCENTRIC ANNULAR FLOW PATH IS LESS RESTRICTING THAN A CONCENTRIC ANNULAR FLOW PATH

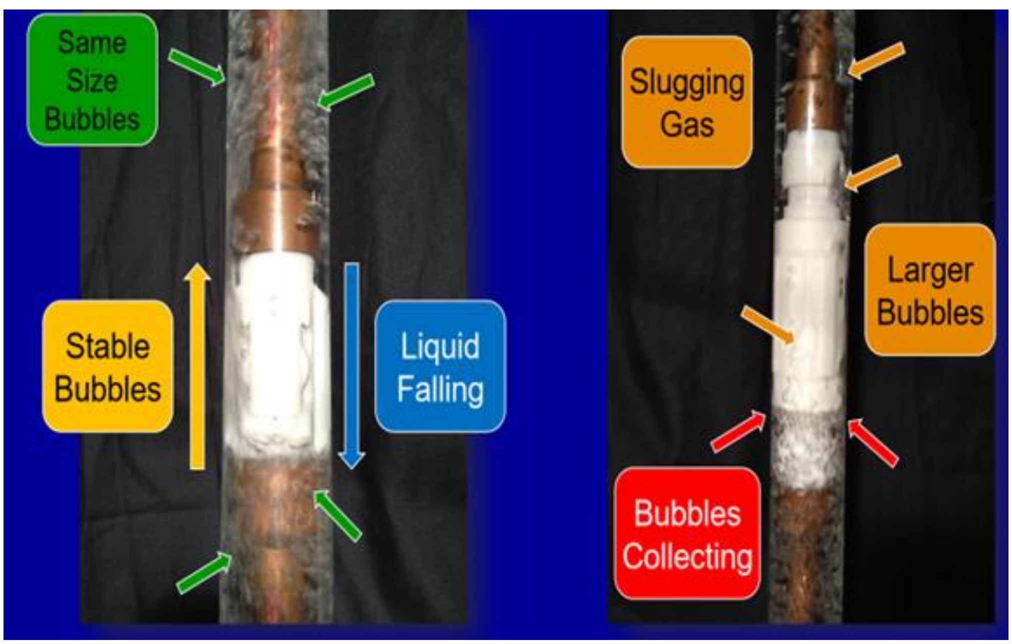

FIGURE 19 – HYDRAULIC TUBING ANCHOR ECCENTRIC ANNULAR FLOWPATH RESEARCH PROVES BENEFIT

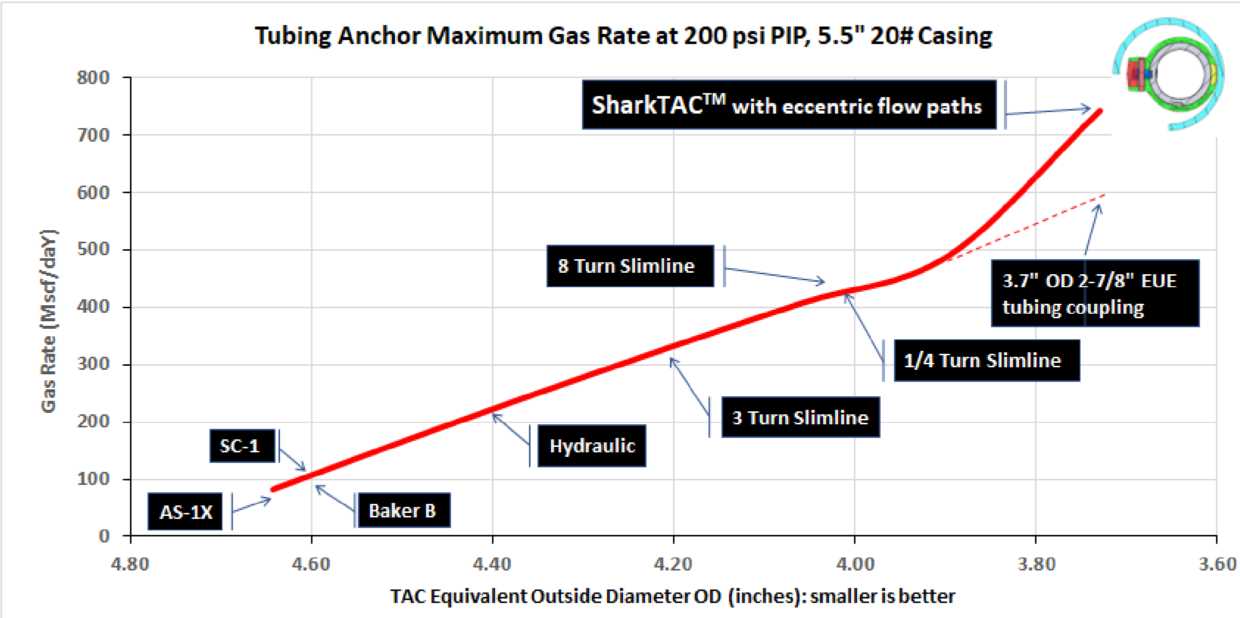

FIGURE 20 – TUBING ANCHOR ANNULAR FLOWBY AREA COMPARATIVE AS FUNCTION OF MAXIMUM GAS RATE

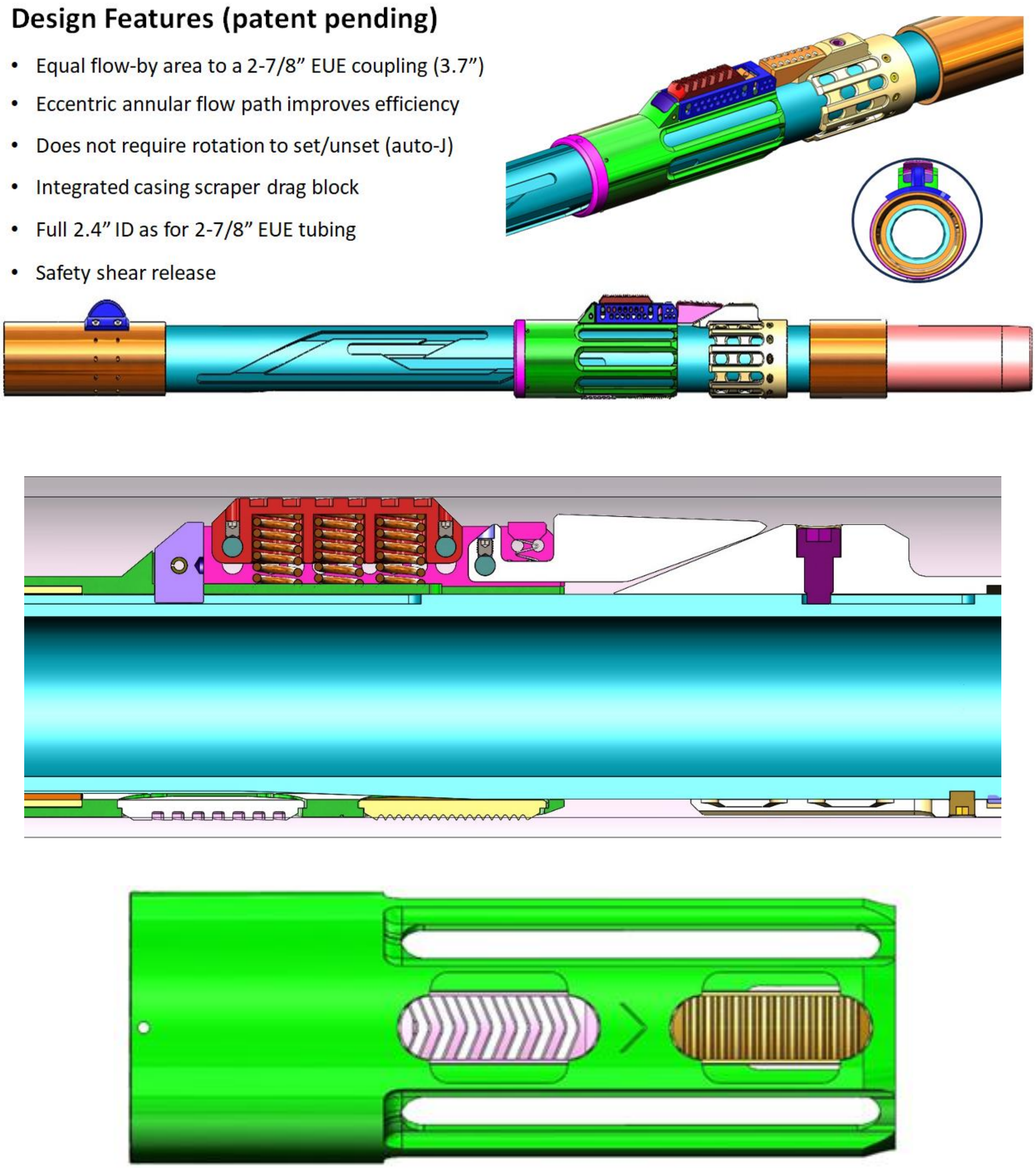

FIGURE 21 – ECCENTRIC AUTO-SET MECHANICAL TUBING ANCHOR CALLED THE SHARKTAC

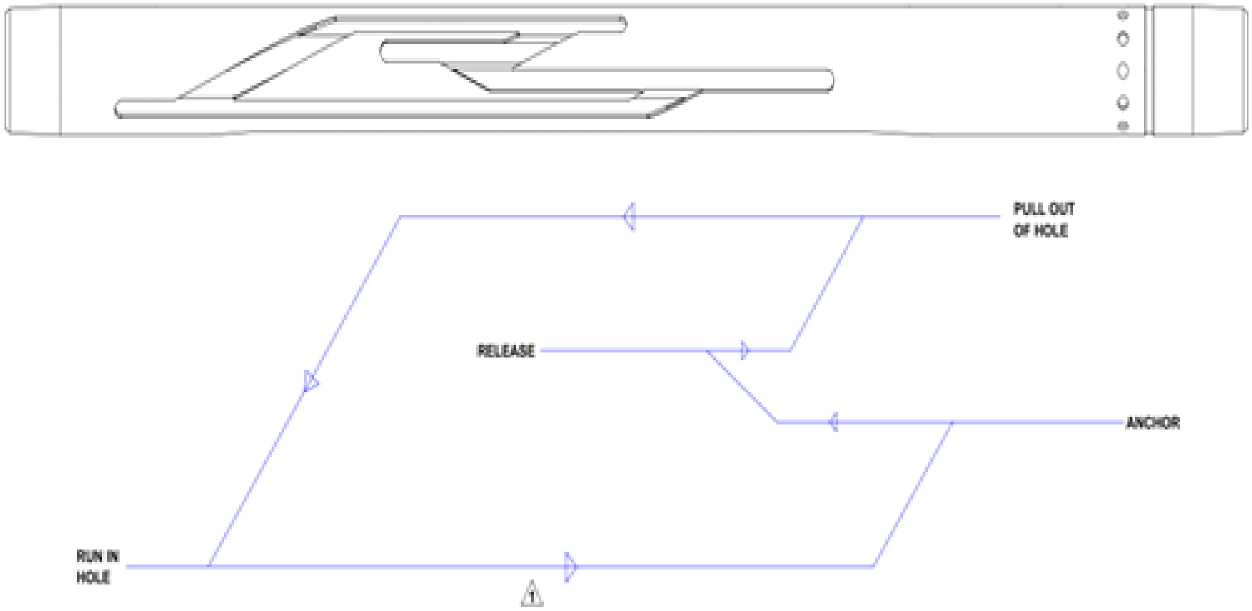

FIGURE 22 – AUTO-SET MANDREL MECHANICAL J-TRACK SEQUENCE

FIGURE 23 – DRAG BLOCK WITH INTEGRATED CASING SCRAPER FEATURE

Tubing Anchor Tension Calculator		
Update yellow cells only		
	Imperial	Metric
Tubing OD (inches)	2.875	73.0 mm
Tubing ID (inches)	2.441	62.0 mm
Tubing Type	L80	
Reservoir temp (^{o}F)	175	80 ^{o}C
Producing wellhead temp (^{o}F)	85	29 ^{o}C
Static wellhead temp (^{o}F)	65	18 ^{o}C
Pump Depth (MD-ft)	7995	2437 mMD
Packer or Anchor Depth (MD-ft)	7614	2321 mMD
PIP at Pumped Off (psi)	150	1034 kPa
Annular Surface pressure (psi)	100	689 kPa
Running Tubing pressure (psi)	250	1724 kPa
Overpull Required at Surface (in)	12	0.30 m
Extra load for "pump tap" case (lbs)	5000	2200 daN
Minimum Anchor Tension (lbs)	5000	2200 daN
Surface Pull Required (lbs) with 12" of overpull	68,800	30,272 daN
Tubing Strength (80% of book value)	116,000	51,040 daN
Expected RIH string weight (lbs) (assumed pump depth fluid)	48,900	21,516 daN
Expected RIH string weight (lbs) (assuming tubing full of water)	42,600	18,744 daN
Required Tension on Tubing Hanger when landed (lbs, daN)	**19,400**	**8,536** daN
Tubing Stretch Over String Weight (in)	**32.6**	**0.83** m
Maximum Emergency Shear Pinning (lbs)	**60,000**	**26,700** daN
Minumum Emergency Shear Pinning (lbs)	**24,900**	**11,081** daN

FIGURE 24 – EXAMPLE TUBING HANGER TENSION CALCULATIONS

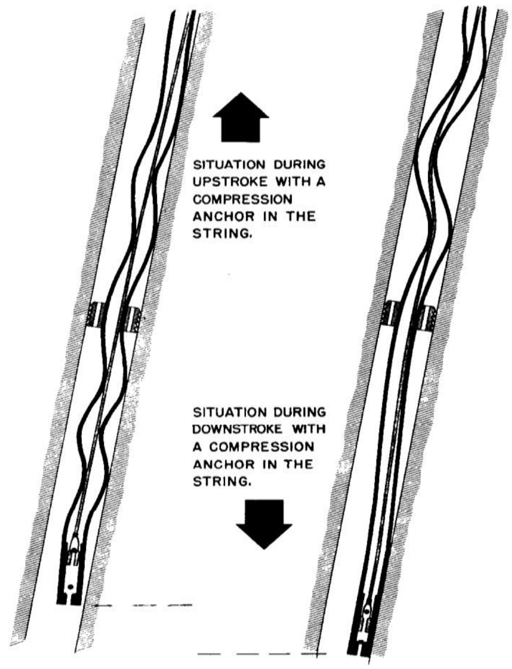

FIGURE 25 – INADEQUATE TUBING HANGER TENSION CAN CAUSE EXCESSIVE TUBING BUCKING DURING ROD PUMPING

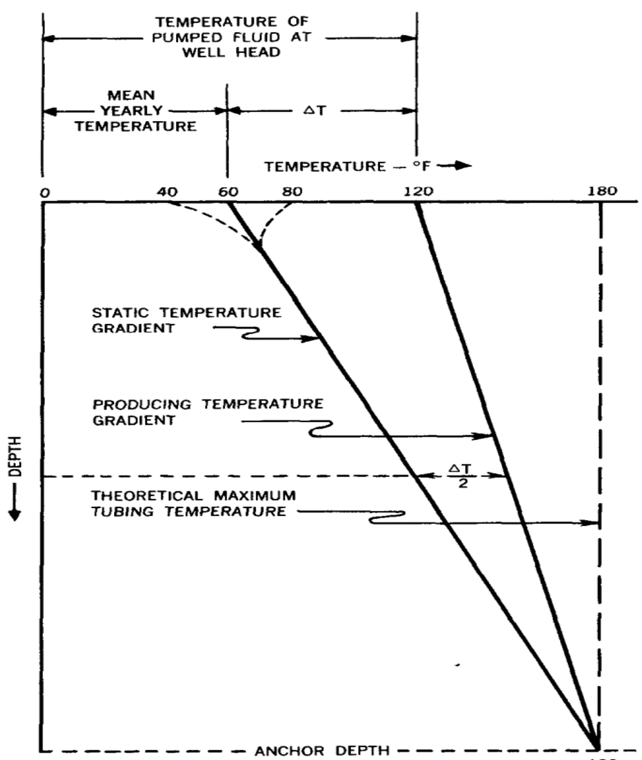

FIGURE 26 – IMPACT OF TEMPERATURE FOR TUBING HANGER TENSION

$\Delta L_T = C_T L \Delta T$

C_T = coefficient of thermal expansion (°F^{-1})
ΔT = is the average change in temperature from the base case to the load case (°F)
L = length of the tubing (same units as ΔL_T)

Fluid temperature at surface: 90°F
Mean yearly temperature for area: 60°F

$F_T = C_T E \Delta T\ (A_o - A_i)$

$\mathbf{F_T = 7 \times 10^{-6} \times 30 \times 10^{6} \times 30 \times 1.304 = 8{,}215}$ **lbs.**

CORRECTED CALCULATION:

The average string temperature in any given operating mode is approximately one-half the sum of the temperatures at the top and the bottom of the tubing.

Average ΔT = T average producing minus T average not producing
= (T bottom - T top prod)/2 - (T bottom - T top not prod)/2
= T bottom/2 - T bottom/2 - T top prod/2 + T top not prod /2
= T top prod/2 - T top not prod/2
= 90/2 - 60/2
= 15 (and not 30, as cited in the publication)

FIGURE 27 – PUBLICATION'S TUBING MOVEMENT AVERAGE TEMPERATURE CALCULATION ERROR AND CORRECTED CALCULATION

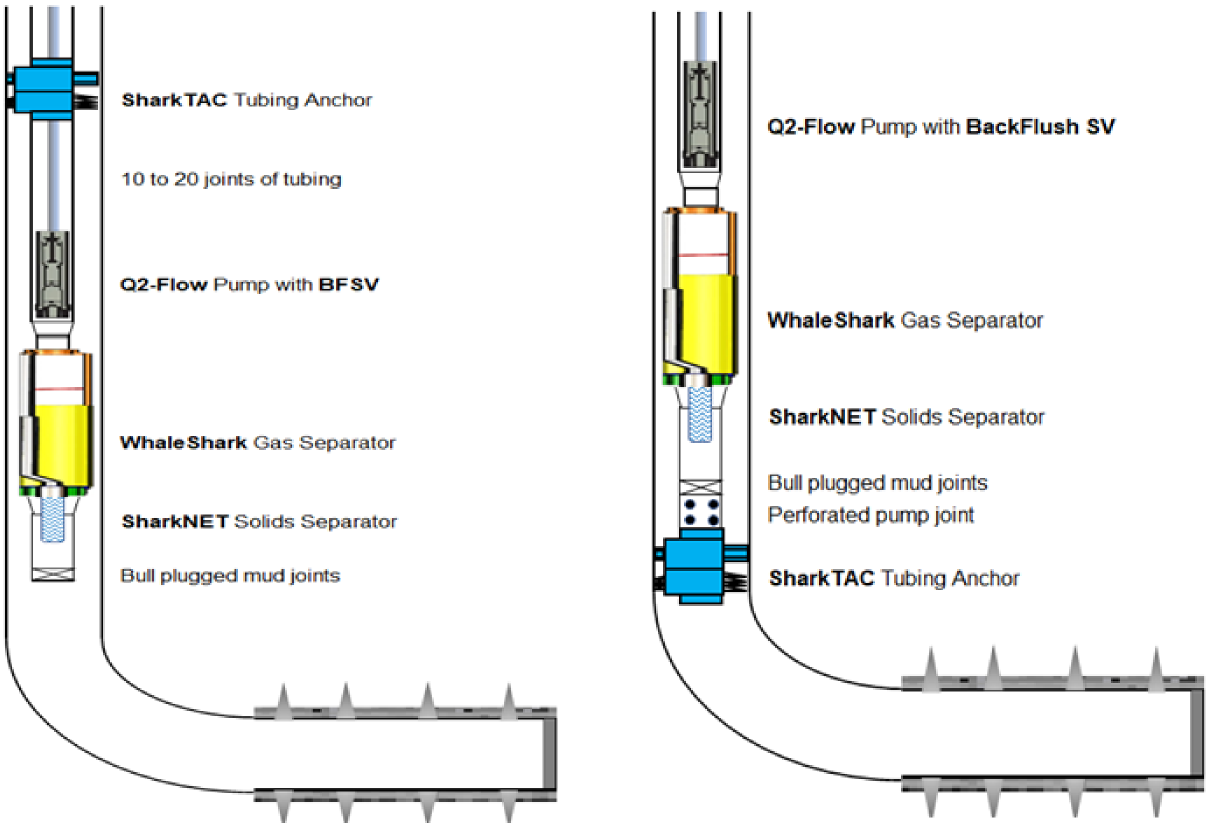

FIGURE 28 – WELLBORE CONFIGURATIONS, WITH GAS SEPARATOR

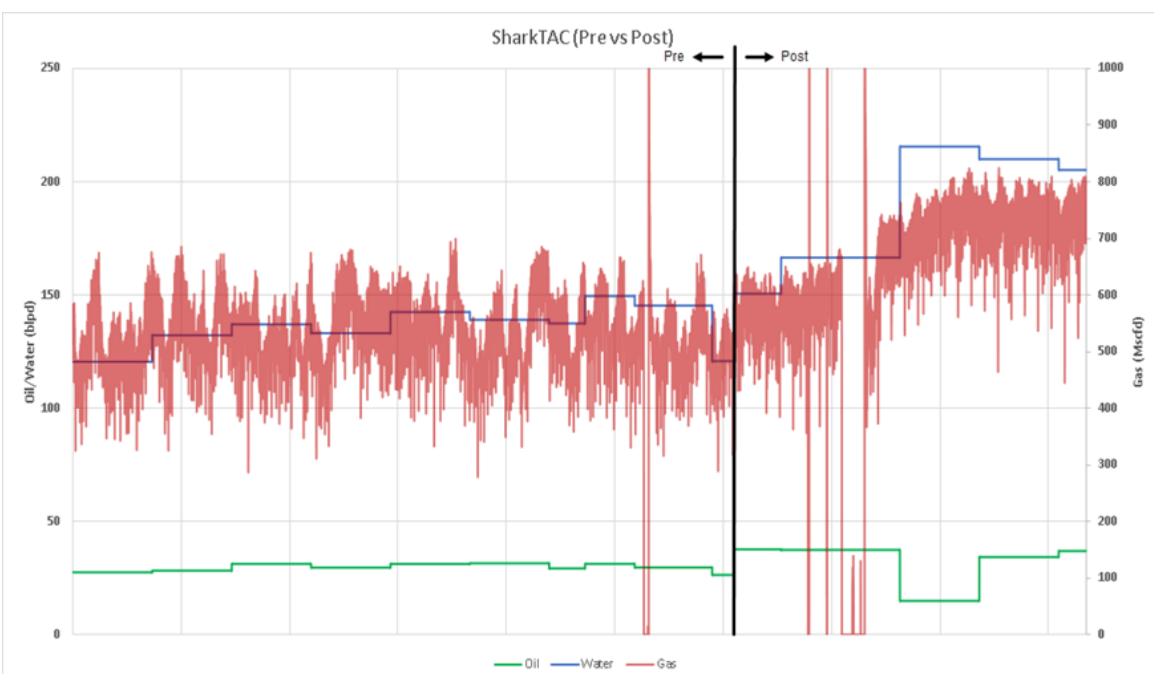

FIGURE 29 – CASE STUDY #1, CHANGING SLIMHOLE TAC TO NEW SHARKTAC

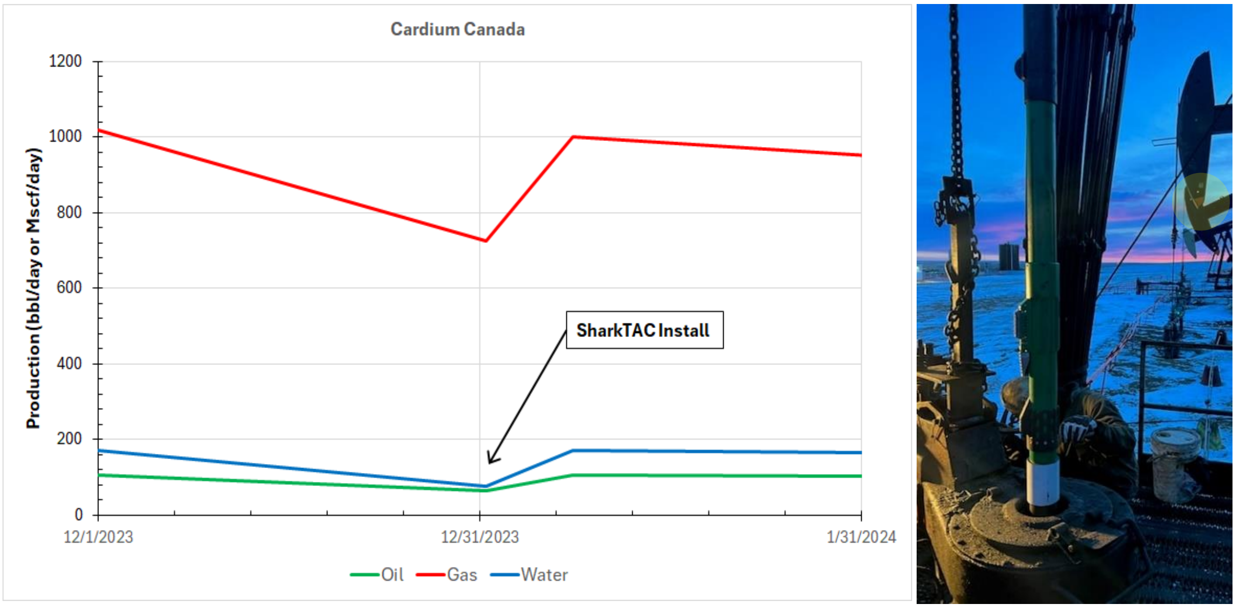

FIGURE 30 – CASE STUDY #2, REPLACING A RESTRICTIVE STANDARD TAC

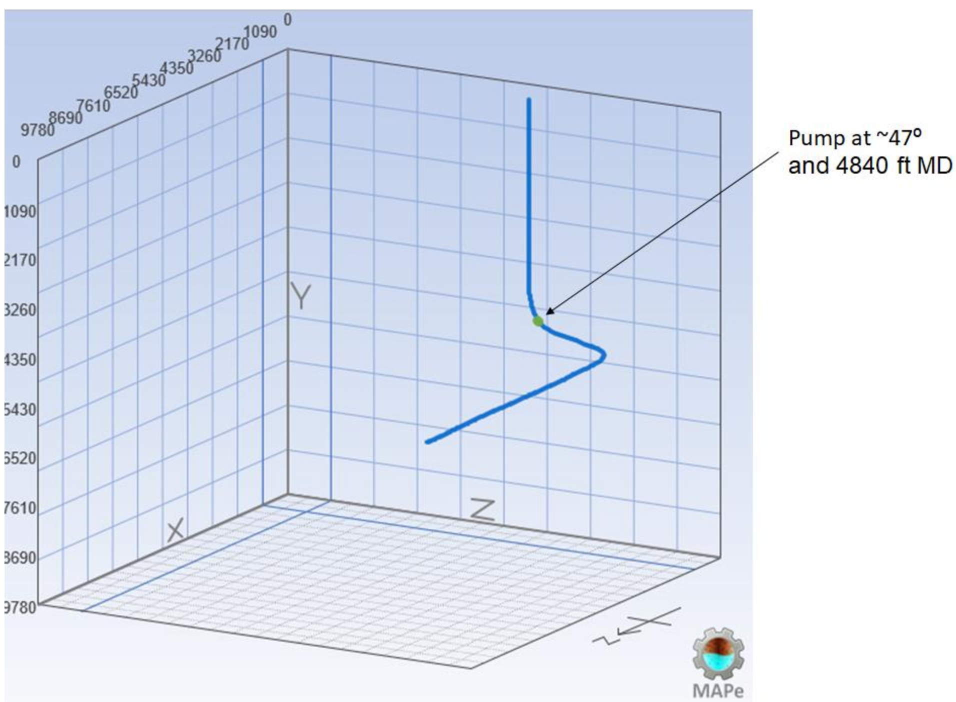

FIGURE 31 – CASE STUDY #2, WELLBORE PROFILE FOR REPLACING A RESTRICTIVE STANDARD TAC WITH SHARKTAC

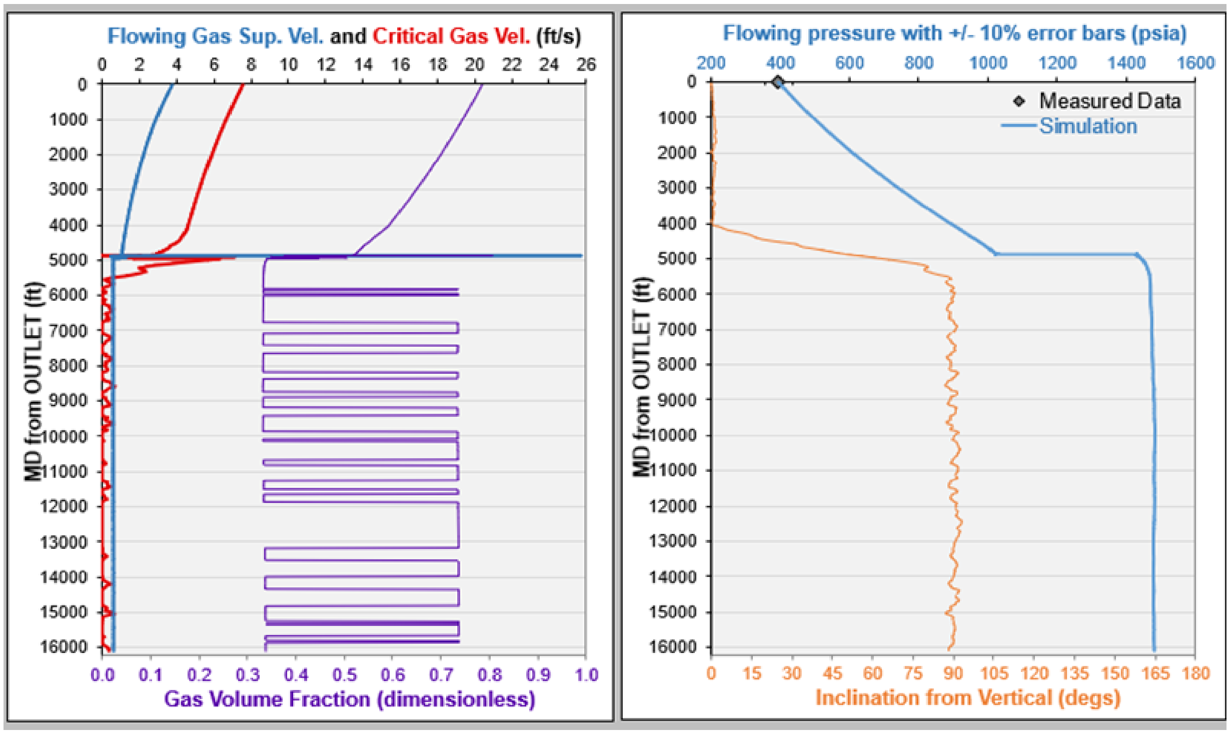

FIGURE 32 – CASE STUDY #2, MODELLED CONDITIONS WITH RESTRICTIVE STANDARD TAC (600 PSI PRESSURE LOSS AT TAC)

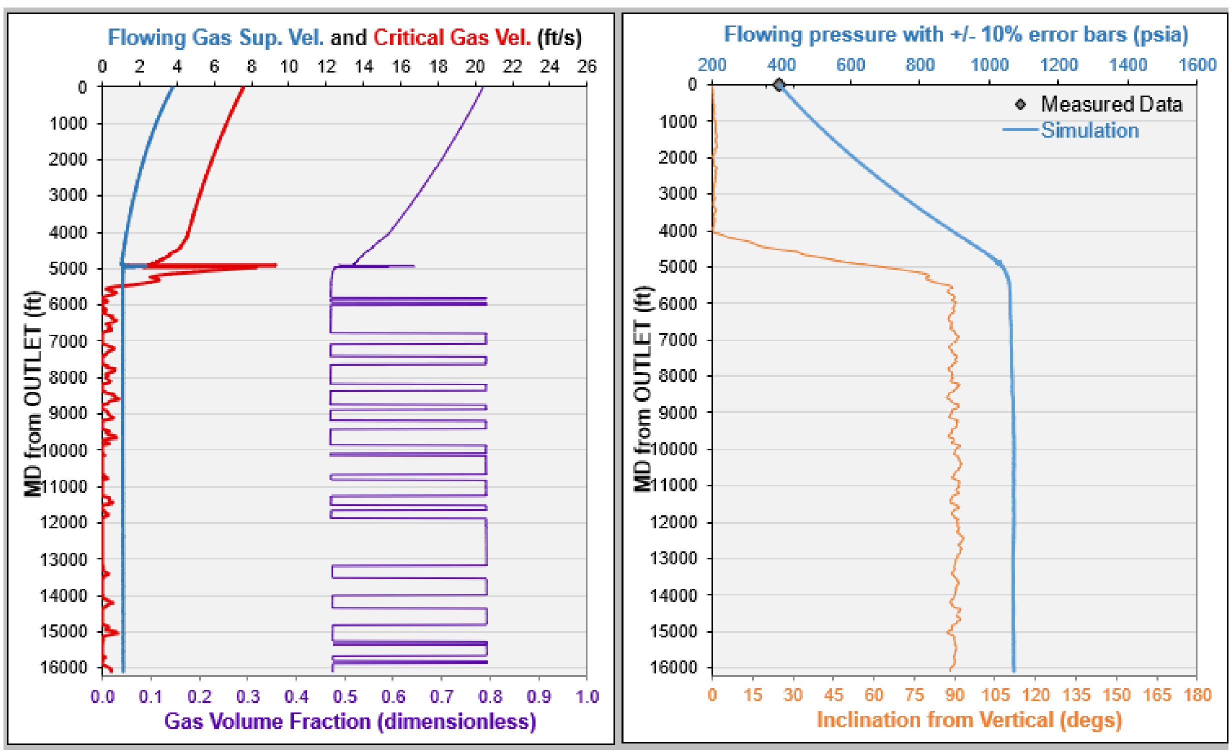

FIGURE 33 – CASE STUDY #2, MODELLED CONDITIONS WITH 3.7" OD EQUIVALENT SHARKTAC (0 PSI PRESSURE LOSS AT TAC)

FIGURE 34 – CASE STUDIES #3 AND #4

ENDNOTES

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