ROD PUMPING THE CURVE IN THE PERMIAN

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INTRODUCTION

Elevated oil and gas commodity price environments provide an opportunity to trial higher risk ideas and technology advances for production uplifts (more cash flow) and reserves, as well as lowering of decline rates.

Rod pumping of Permian unconventional and gassy horizontal wells is more complicated and challenging than for vertical wells. During a well's higher productivity and reservoir energy phase, it is common practice for horizontal wells to have a rod pump placed in the vertical section above the wellbore's curve and high above the producing formation.

As a well's productivity declines and the reservoir pressure depletes, producing the well at the lowest possible bottomhole pressure becomes more relevant for maximizing production and reserves recovery. A limitation for producing a horizontal well at the lowest possible bottomhole pressure is placement of a pump high above the producing formation in the vertical section. Another limitation is downhole gas separator and efficiency losses from sluggy inconsistent flows emanating from the horizontal wellbore.

To resolve these limitations, a solution could be to lower the pump down into the curve section of a horizontal well. This presents risks and engineering challenges, including:

- failure frequency of the pump, rods and tubing,
- downhole gas separation efficiency
- solids in the produced fluids, and
- rod pump efficiency at high inclinations.

An economic and engineering feasibility assessment was required comparing the production uplift potential with lowering of a pump into the curve versus likely increased failure frequency and an ability for overcoming technical challenges.

Engineering an efficient and reliable rod pumping system for operating in the curve was undertaken, including adoption of newer technologies. Field implementations have demonstrated a high success rate for dramatically increasing production, but a higher than expected increase in failure frequency has revealed a need for further technology improvements.

WELL INFLOW PERFORMANCE AND PRODUCTION UPLIFT PREDICTIONS

Figure 1 illustrates a common rod pumping practice of positioning a sucker rod pump in the vertical section, immediately above the curve section of a horizontal wellbore. This placement results in the pump being a vertical distance of 600 feet (183 meters) above the producing formation. Some instances can be more than 2000 feet (610 meters). Any vertical distance between the pump and the producing formation imposes a high fluid pressure gradient over that distance, which can undesirably add hydrostatically 200-500 psi (or more) to the producing bottomhole pressure and therefore limit a well's production potential.

Vogel's[i] inflow performance relationship (IPR) for oil and gas wells can generally provide a good expectation for assessing production uplifts resulting from reductions in the producing bottomhole pressure. Although, complexities and error risks can arise for when determining well specific IPR curves. There are notable challenges for when determining a current reservoir pressure, for when determining mutually exclusive individual IPR curves for each the oil, gas and water phases, and for when determining how IPR curves change over time as the reservoir pressure depletes.

Determining a current reservoir pressure is challenging, as previous production from a well has depleted the reservoir pressure to some level below its original virgin pressure. If extensive reservoir pressure surveys and material balance analysis' have not been performed for the targeted well (often the case), an appropriate likelihood range of current reservoir pressures will need to be evaluated as a sensitivity range of possible outcomes. If medium-long term shut-in pressure build-up tests are available this can be used as an estimate of a statistical P50. The risk of using too low of current reservoir pressure will result in an over-prediction of a production uplift (with a lowering of the bottom hole producing pressure). Whereas the opposite occurs for if too high of current reservoir pressure is used, it will under-predict the production uplift.

To resolve the challenge of determining mutually exclusive individual IPR curves for the oil, gas and water phases, a composite IPR equation was derived by Petrobras[ii] based on combination of Vogel's IPR equation for the oil phase flows and a constant productivity index (linear) for water phase flows. For this production uplift analysis, it is important to realize that higher water cut production wells will consequently result in proportionally much greater increases in water production (i.e., the water cut will increase as the producing bottomhole pressure is lowered). Permian wells have shown to behave as composite IPR wells, so it was recommended that production uplift targeted wells should be prioritized to higher oil cut wells. For the gas phase, very low producing bottomhole pressure IPR curves are not well understood, especially for multistage fracced horizontal wells in unconventional and tighter permeability reservoirs. Empirical Permian Basin experience has shown that the producing gas to liquid ratio (GLR) escalates rapidly at low producing bottomhole pressure less than 500 psi, so an expectation of a larger relative increase in gas rates (to the oil and water increases) should be planned for.

Another challenge with IPR curve based analysis is an IPR curve is only for a specific instance in time. As the more fluids are produced from a reservoir, reservoir pressure will continue to deplete and an IPR curve will change/decline accordingly. How the IPR changes with reservoir pressure depletion and time is very challenging to predict with reasonable accuracy. Some level of production decline must be considered with time for a given producing bottom hole pressure. For this analysis, the methodology used for determining an expect decline rate was a regional well average statistical production decline rates relative to reserve recoveries and producing bottomhole pressures.

There remains an ongoing circular debate with respect to production uplifts resulting from lowering of the producing bottomhole pressure – will it only result in a short term "flush production" uplift or will it sustain a long term production uplift "wedge" on over the historic production decline trend. IPR curves are generated from stabilized reservoir conditions. Early time transient reservoir conditions can result in a much higher "flush production" uplift than what was predicted, but it can eventually tail off to a stabilized longer term production uplift in line with the IPR curve prediction. This flush production uplift should not be ignored, as it can provide a significant early-time economics boost. For this project, a 90 day flush production period was used where the IPR production uplift prediction was multiplied by 1.5 times.

Well test and fluid level acoustical shot data can be used to adequately represent a single point on an IPR curve for operating conditions of a well – the current producing bottomhole pressure and the fluid production rate. To get a reasonable expectation of the reduction in producing bottomhole pressure from lower the pump into the curve, the vertical distance change in pump depth can be converted to pressure.

Figure 2 shows oil phase Vogel IPR curves for typical Permian horizontal wells at three different possible current reservoir pressures and a current production of 50 bbls/day and 750 psi producing bottomhole pressure. For likely current reservoir pressures scenarios of 900 psi, 1100 psi and 1300 psi, the respective production uplifts if the producing bottomhole pressure if lowered to 500 psi are 61bbls/day (+11), 69 bbls/day (+18) and 92 bbls/day (+42).

FAILURE FREQUENCY VERSUS PRODUCTION UPLIFT ECONOMICS

Risk[iii] is often defined as the "possibility of loss" or the "possibility of something bad happening". Failure frequency rate is defined as the total number of component failures occurring per well, per year. Failure frequency has often become a risk adverse focus of production engineers. Why would one look to increase production knowing that failure frequency would increase? When assessing the viability of an opportunity, perceived risk can be a barrier to adoption. In any case, it's important to take an objective approach and attempt to quantify risk with the best information available, while providing sensitivities for a range of outcomes to account for the unknowns. In the case for rod pumping in the curve, the primary risk identified was an increase in failure frequency and its financial impact as a result. The author's production engineering team chose a mindset focused on maximizing uplift rather than minimizing failure frequency. The methodology was simply how much production uplift would be required to economically offset increasing failure frequencies. Ultimately the question needing to be answered is: “Does the production uplift potential economically out-weigh the risk increased failure frequency?”

Lowering of a pump down into the curve section of a horizontal well presents several increased failure frequency risks and engineering challenges, including:

- increased wear on the pump, rods and tubing,
- increased slugging reduces gas separation efficiency and increases solids, and
- reduced rod pump efficiency at high inclinations.

Failure frequency is defined as the number of failures per well per year. This metric is often used by operators as a key performance indicator (KPI) to track progress in failure reduction and is often used to develop budgets for expected workover spend throughout the year. It is also used as an indicator of financial margin, since workovers can make up a large portion of yearly lease operating expenses. For this reason, its very important to effectively normalize a cost/benefit analysis, should there be an expectation which negatively impacts failure frequency.

For this analysis, it was decided to represent the impact of failure frequency in oil barrels to directly compare to the IPR projections for production uplift. To account for the entire impact of an increase in failure frequency, both the cost of the failure and deferred production for additional downtime must be included in the analysis. Since the impact of an increase to failure frequency happens at later date, present value of those impacts must be considered.

For example:

Initial Workover Cost	$100,000
Normal WO Cost	$50,000
Pump In Curve WO Cost	$60,000
Downtime for WO	5 days
Oil Price	$55/bbl oil
WI / NRI	100% / 75%
Discount Rate	9%

Figure 3 shows graphical results from an economics analysis lowering a pump into the curve for a production uplift and how much additional oil production would be needed to break even offset an increase in failure frequency.

For example:

Before Failure Frequency	1.0 (once per year)
Before Oil Production	50 bbl/day
After Failure Frequency	1.5 (twice per year)
Breakeven Oil Production Uplift	3.4 bbl/day to be cashflow neutral

FAILURE FRQUENCY OF THE PUMP, RODS AND TUBING

Placement of a rod pump at high inclinations will likely increase the risk of wear on the sucker rods, tubing and pump. For the reciprocating rod pump components, a normal force in the direction of gravity increases with inclination and therefore wear risks increase in relation to the dynamic friction present. The reciprocating rod pump stroke rate and length will dictate level of frictional impacts and will be proportional the wear rate.

There is a greater likelihood of rod buckling at inclinations. The rate of sucker rod free fall on the downstroke reduces as a function of the inclination and the level of dynamic friction present between the rods and tubing. If the sucker free rod fall rate is insufficient relative to the pump jack's stroke rate, buckling of the sucker rods can occur. The risk consequence of buckling is increased failure frequency risk.

Produced fluid water cuts also play a significant factor in the level of dynamic friction that is encountered. Empirical experience from placing pumps at high inclinations in Canadian horizontal wells suggested that the lower water cut the less the wear risk (i.e., less dynamic friction). A high ratio of oil to water means more lubricating oil is present (assuming oil acts as a lubricant) and therefore results in a lower friction factor. It was decided to target wells that had less than 40% water cut.

Gas present in the tubing can also negatively affect rod wear and buckling. With gas present the rods can more freely "slap" the tubing wall (increase the risk of fatigue failures) and with less liquid present friction will be greater. Gas also reduces the hydrostatic pressure gradient inside the tubing, which will reduce the level of rod stretch. This will reduce pump efficiency as it causes a loss of pump compression ratio with the pump spacing itself further "off tap". Achieving higher and more consistent pump fillage from efficient downhole gas separation was desired as a means for achieving less rod wear/damage.

Multiple SROD[iv] design runs were performed. The outcome from analyzing various rod string design scenarios were the following base design parameters:

- all steel rod string,
- fully guide the sucker at inclinations, with 6 to 8 guides per rod
- avoid using lined/plated tubing to save costs, as it was determined there was less rod side loading than uphole and therefore low risk of increased failure frequency

An all steel rod string was chosen over a combination steel and fiberglass. The reason for this decision was the final operating conditions (SPMs, fluid levels, oil/water ratios, fluid gradient inside the tubing, separation efficiency, etc) are unknown. When fiberglass rods are included as part of steel rod string, pump spacing is far less certain and more variable. Maintaining consistent and with a bottomhole pump stroke ending each stroke as close to "off tap" pump as possible is an important operational factor for efficient pumping. At the same time "tapping" of the pump would likely increase failure frequency. Figure 4 shows a table of the rod design scenarios and the bottomhole pump stroke variability between steel and fiberglass/steel rod strings. An all steel rod string has a range of 165 inches to 175 inches of pump plunger travel, which is considerably less variable and with longer overall effective pump plunger travel (for the same surface pump jack stroke length) than a fiberglass/steel rod string (respectively, 135 inches to 160 inches).

Fully guiding the rods with 6 to 8 guides per rod at inclinations is a common rod wear management and rod buckling control practice for other regions that place pumps in the curve. These practices were simply adopted from such empirical experience.

For controlling wear risks in the pump, all pumps were placed at locations were dog leg severity (DLS) was less than 5^o/100 feet (5^o/30 meters) – in other words, keep the pump in as straight of section of wellbore as possible, as any forced curvature of a pump will increase the pump's failure frequency. This threshold of DLS for rod pumps is empirically experienced based an industry accepted practice that above this 5^o/100 feet threshold rod pump failure frequency risks escalate considerably. In most cases and from Permian regional directional drilling practices, the DLS throughout most of the wellbore's curve interval exceeds this threshold. Consequently, the case study wells all have pump placements beyond 75^o inclination (see Figure 5) and all the way to 89^o.

With respect to pump wear at high inclinations, the low side of the pump barrel will experience the normal force weight of the plunger. This will localize the wear to the low side and likely increase the failure frequency, but to what level is unknown. Solids are always a risk in multistage fracced horizontal wells and any pumps placed beyond the angle of repose for solids settling (i.e., solids will not settle beyond approximately 65^o inclination) means that all downhole solids separators will not work – pumps will encounter all solids or debris that reach the separator. All existing downhole solids separators rely on gravity for solids separation and solids will not settle into mud joints if they are placed beyond 65^o. Consequently, pumps placed beyond 65^o degrees inclination will have a high risk of excessive solids wear and damage. The decision was to not add technology features to a pump for controlling wear and solids, as historically, solids in this region have not been recorded as a main root cause of pump failures (very few solids are seen during rod pumping and horizontal wellbore cleanouts have shown little solids present).

DOWNHOLE GAS SEPARATION EFFICIENCY

For rod pumping, high and consistent pump fillage is desired, which means efficient downhole gas separation is required. To achieve efficient downhole gas separation in a horizontal well, system and comprehensive flow path engineering is necessary, as a "better separator" by itself will likely not provide an effective solution due to multiphase flow complexities. Complexities arise with multiphase fluid flow behaviour in horizontal wells due to differences such as:

- varying wellbore inclinations through tubular and annular conduits,
- tubular and annular conduit flow paths that have co-current gas and liquid flows,

- tubular and annular conduit flow paths that have counter-current gas and liquid flows,
- an annular conduit flow path that has gas migrating upwards through a static liquid column, and
- pressures, temperatures, and fluid compositions.

If gas is present in the produced fluids, horizontal wells will have unstable and sluggy flow tendencies. Sluggy flows means there will be inconsistent ratios of gas and liquid flowing at any point in the wellbore at any point in time. Figure 6 from Nagoo etal[v] describes in detail the propensity for horizontal wells to have slug flows. The severity of slugging can be affective by the horizontal wellbore's trajectory. Horizontal wellbores that have toe-up trajectories generally have less frequent slugs but of greater amplitude/magnitude. Toe down trajectories generally have more frequent slugs but of less amplitude/magnitude. Figure 7 from Nagoo[vi] etal shows an example of excessive sluggy flow behaviour from a toe-up trajectory horizontal wellbore that was effectively controlled by a reduced internal diameter flow regulating tailpipe in the curve.

Hernandez-Perez[vii] showed in Figure's 8 and 9 that multiphase flow patterns or regimes behave differently at inclined orientations versus a vertical orientation. At inclinations, gas escapes more easily on the high side of the wellbore and liquid falls backwards more easily on the low side of the wellbore (in the slug and churn flow regimes). Ghajar's[viii] research in Figure 10 revealed that gas volume fraction reduces at inclinations and liquid hold-up increase (i.e., a high liquid volume fraction will exist in the same multiphase flow stream at inclinations versus in a vertical orientation).

Sluggy inconsistent flows emanating from a horizontal wellbore can also limit achieving a low producing bottomhole pressure. Sluggy flows can worsen as they progress through a wellbore's curve section and can consequently reduce the performance of a downhole separator and pump. This can lead to an inability to pump the well off and cause an undesirable 300-800 psi fluid column remaining above the pump in the annulus.

Sluggy flows can reduce downhole gas separation efficiency. Saponja etal[ix] discusses this at length the need for engineering the flow path of a downhole separator, in combination as a system, with other downhole components. A downhole engineered flow path (and components) is necessary for tolerating sluggy flow conditions. This led to development of a highly slug flow tolerant liquid fallback separator that takes advantage of multiphase flow reversals present in sluggy flows.

This paper also revealed a very important engineered annular flow path design requirement for tubing anchors and tubing anchor catchers (TAC's). If a TAC has a restrictive annular flow-by cross sectional area, it can limit production. The TAC's annular flow-by clearance can be the root cause of excessive pump gas interference. McCoy etal[x] revealed this flow path engineering design issue that must be addressed as part of engineering the system's flow path. Figure 11 shows a dramatic production uplift result from replacing an annular flowby restrictive TAC and a downhole poor-boy gas separator (that are not slug flow tolerant) with a downhole liquid fallback gas separator.

Use of slimhole type high annular flow-by TAC's is necessary to maximize the annular flow-by cross sectional area. The flow-by area past a TAC (including the area taken up by the TAC's slips when set) needs to be maximized to ensure gas velocities stay well below the critical liquid lifting gas velocity and ideally below 6 ft/second (1.8 m/second), to a maximum of 10 ft/second (3.0 metres /second). If the gas velocity reaches a certain such velocities, liquid will not be able to fall back and therefore liquid will collect in the annulus on top of TAC (i.e., builds a gasified fluid column), causing excessive and erratic pump gas interference, limiting production drawdown.

Figures 12 and 13 show pump cards with a restrictive annular flowby TAC. In can be seen that once the fluid level in the annulus drops below (is pumped down) a restrictive annular flowby TAC, flow becomes stable and pump fillage becomes consistently high.

Inclination, diameter, conduit shape and pressure (gas density) all have pronounced effects on gas volume fraction (GVF). Flow regimes and slugging tendencies are different in the horizontal, curve and vertical sections of the wellbore and these sections can compound each other for a bad unmanageable slugging condition at the pump's location. The authors refer to this as a “Bad Slugging” condition, as large Taylor Gas Bubbles are present in high unstable slugging flow conditions, which lead to gas separation efficiency challenges. Such inconsistent flows make efficient downhole pump gas separation very challenging. Figures 8 and 9 also show multiphase flow Taylor Gas Bubbles, which are large and continuous gas phase only bubbles. Taylor Gas Bubbles commonly exist in the slug flow regime, with them being larger on the left side of a flow pattern map and smaller to right. As the flow regime transitions from slug flow to churn flow, Taylor Gas Bubbles no longer exists, as flow turbulence and high gas phase velocities prevent them from forming or they are destroyed. Figure 14 is provided to help explain liquid hold up (liquid volume fraction) versus gas hold up (gas volume fraction). This multiphase flow behavior provided an opportunity to improve downhole gas separation and slug flow tolerance.

Figure 15 from Time[xi] shows flow regimes relative to gas volume fraction. Empirically it has been found that when multiphase flows exceed 0.6 gas volume fraction (60% of the flow path becomes volumetrically dominated by gas) throughout the wellbore system, a condition of slugging stability is achieved and Taylor Bubble size is considerably reduced to a level where they become manageable for a downhole liquid fallback gas separator. This is referred by the authors as a “Good Slugging” condition.

Control of slugging was system engineered by lowering the pump in the curve, reducing the tubing to 2-3/8” EUE in the curve, placement of slimhole type TAC in vertical section above the curve, use of a gas separator that takes advantage of liquid fallback for improved efficiency at inclinations. Figure 16 shows the downhole assembly and system for maximizing gas separation efficiency.

SOLIDS IN THE PRODUCED FLUIDS

With a lower producing bottomhole pressure, gas volumes increase for the same gas rate. With gas expansion, gas velocities throughout the wellbore increase accordingly. The risk for solids is the velocities reach a threshold where solids become mobile and are transported to the separator and pump. Sugging severity may worsen this condition and transports solids in concentrated masses.

If solids are not separated at the separator they will continue onward to the pump and likely increase its failure frequency.

REDUCED ROD PUMP EFFICIENCY AT HIGH INCLINATIONS

A rod pump's valves use gravity to assist a ball reaching its seat and achieving efficient valve closure. At inclinations, gravity assistance for valve closure diminishes and risk arise with valves not opening/closing efficiently (efficacy).

A proven technology chosen to control these risks and to minimize pressure loss through a pump valve was vortexed valves. Coyes etal[xii] describes in detail the successful long term performance of vortex style valves. See Figure 17.

A new technology development adopted from plunger lift technology was also incorporated to address the risk of valve closure at inclinations. A "barbell" shaped ball assembly guides the barbell shaped seat ball and allows the valve to close consistently and quickly while disallowing seat ball to disengage from seat when the downhole rod pump is at inclinations. See Figure 18.

CASE STUDIES

Relevant case studies are as follows.

Case Study 1 – Figure 19 shows multiphase flow modelling with a pump placed in the vertical above the curve, using a restrictive TAC. Modelling predicted that multiphase flow in a bad slugging state. Figure 20 shows the wells unstable and sluggy gas rate and erratic poor pump fillage versus time.

Figure 21 shows multiphase flow modelling of the pumping the in curve system and a prediction of stable good slugging conditions. Figures 22 and 23 shows the positive results. Figure 22 shows excellent production results.

Figure 24 show debris found in the pump that prevented the standing valve from close. It was realized that no strainer nipple was run on the bottom of the pump. Not running of a strainer nipple is practice that has been observed, the thought process is that strainer nipple impose a high pressure loss during the pump's upstroke and gas is "flashed" from the liquid, thus reducing pump efficiency.

Figure 25 shows failed pump plunger wear damage.

Case Study 2 – Figure 26 shows multiphase flow modelling with a pump placed in the vertical above the curve, using a slimhole TAC. Modelling predicted that multiphase flow in a bad slugging state. Figure 27 shows the wells unstable and sluggy gas rate and erratic poor pump fillage versus time.

Figure 28 shows multiphase flow modelling of the pumping the in curve system and a prediction of stable good slugging conditions. Figures 29 and 30 shows the positive results. Figure 31 shows excellent production results.

Case Study 3 – Production uplift have averaged over doubling of the production of the historic trend, statistically demonstrating that lowering fog the pump in the curve, establishing good slugging for efficient downhole gas separation and minimizing the producing bottomhole producing pressure. Failure frequency from twelve (12) well implementations has averaged approximately 3 to 6 months. All failures have been pump related, primarily plunger and barrel wear from solids. This was close to the economic analysis assumption of a failure frequency of 1.5, but certainly there is room for improvement.

IMPROVING RODPUMP RELIABILITY WHEN PLACED AT HIGH INCLINATIONS

With a realization that low producing bottomhole pressure will result in more solids reaching the pump, further design work is ongoing for improve pump failure frequency at high inclination placements. Improving solids tolerance will be key.

CONCLUSION

A system based approach (i.e., a group of components working harmoniously together) versus a component based approach, allowed for a significant improvement rod pumping production performance. Achieving production uplifts of over double the previous production levels demonstrated the benefit of producing a well at the lost possible producing bottomhole pressure.

Lowering the rod pump into the curve section of a horizontal was effectively achieved the goal of a low producing bottomhole pressure, but failure frequencies of the pump itself were high than anticipated. The focus going forward is improving rod pump reliabilities when placed at high inclinations, with a realization that low producing bottomhole pressure will result in more solids reaching the pump.

FIGURES

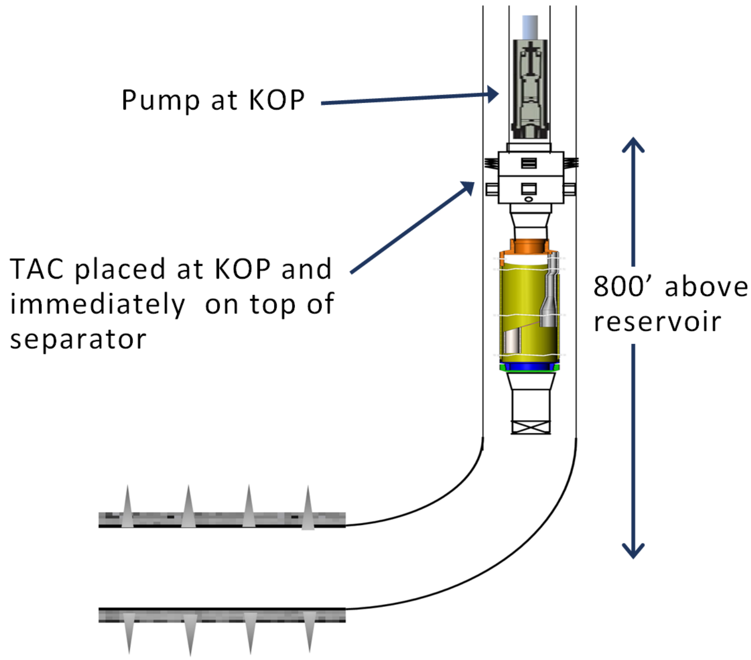

FIGURE 1 – PUMP PLACED ABOVE THE WELLBORE CURVE

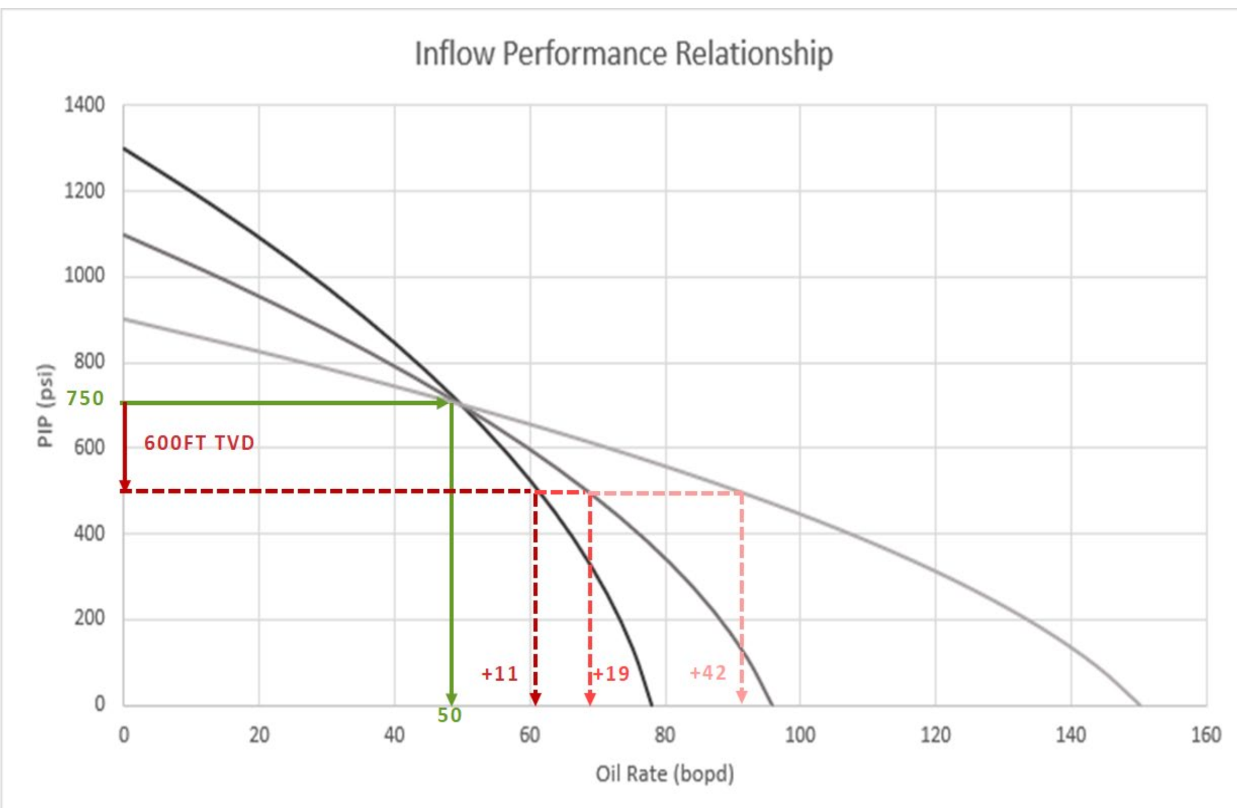

FIGURE 2 – INFLOW PERFORMANCE CURVES

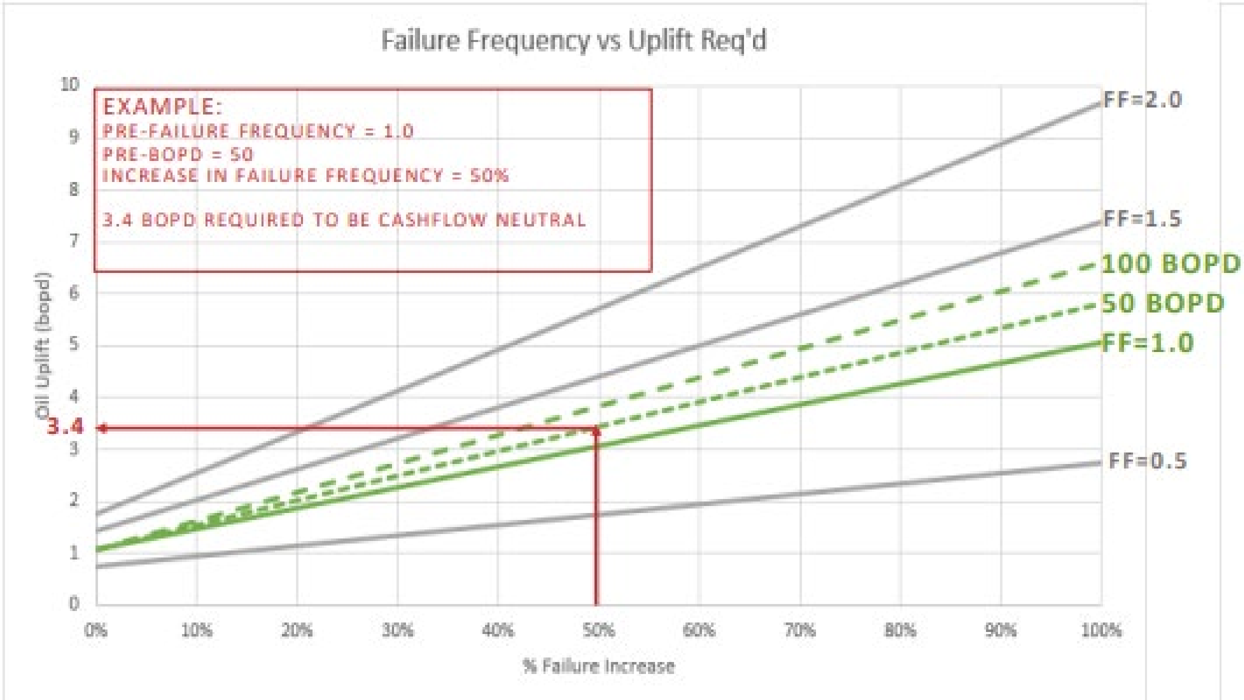

FIGURE 3 – FAILURE FREQUENCY VERSUS PRODUCTION UPLIFT ECONOMICS

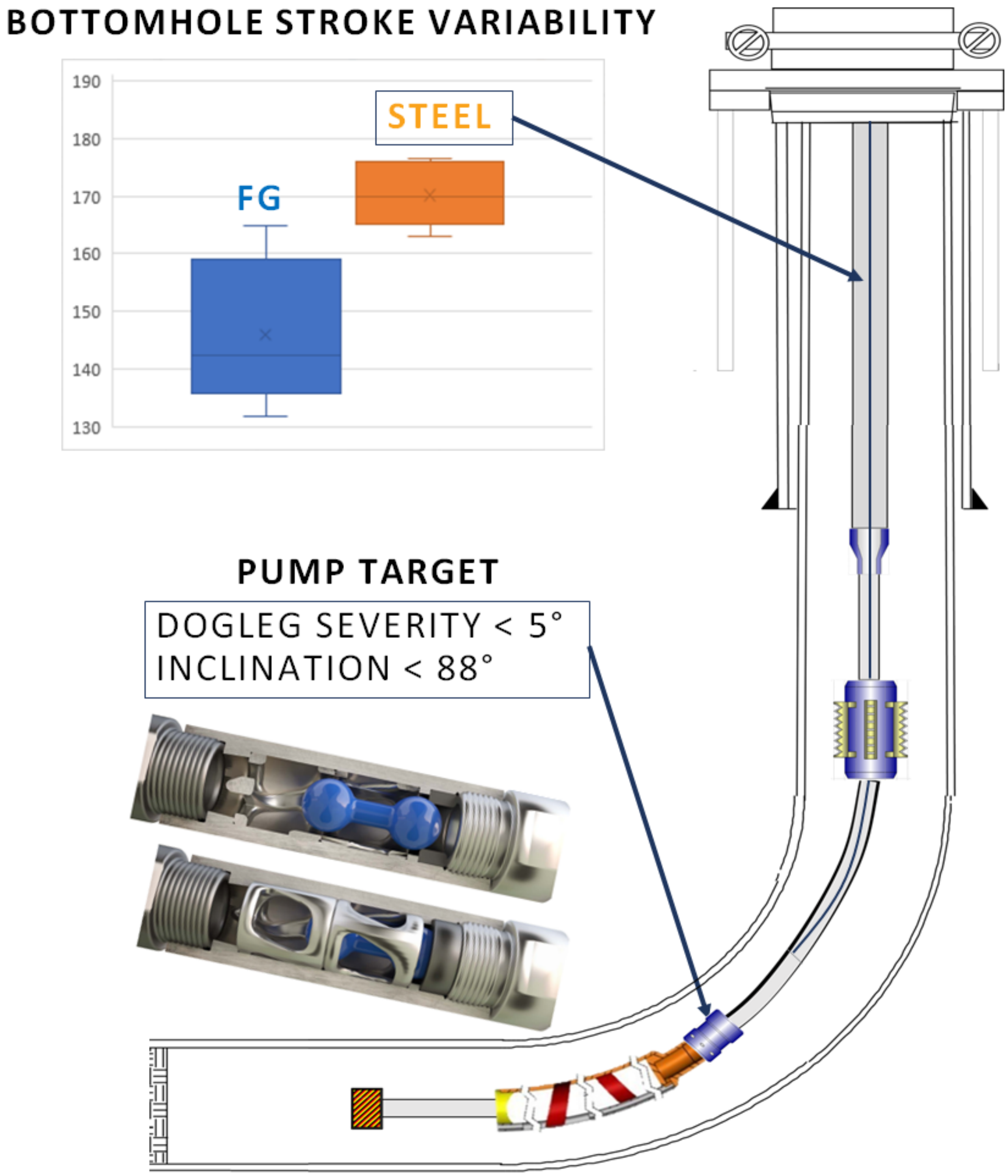

FIGURE 4 – HIGH ANGLE PUMPING SUCKER ROD AND PUMP DESIGN

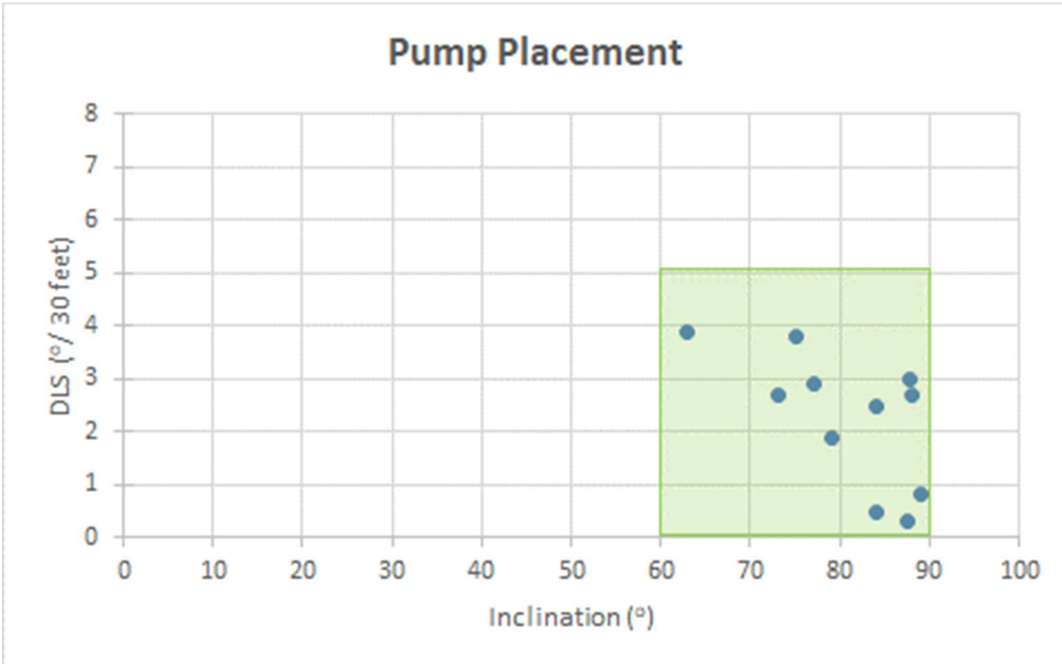

FIGURE 5 – CASE STUDY SUMMARY OF PUMP PLACEMENTS INCLINATIONS

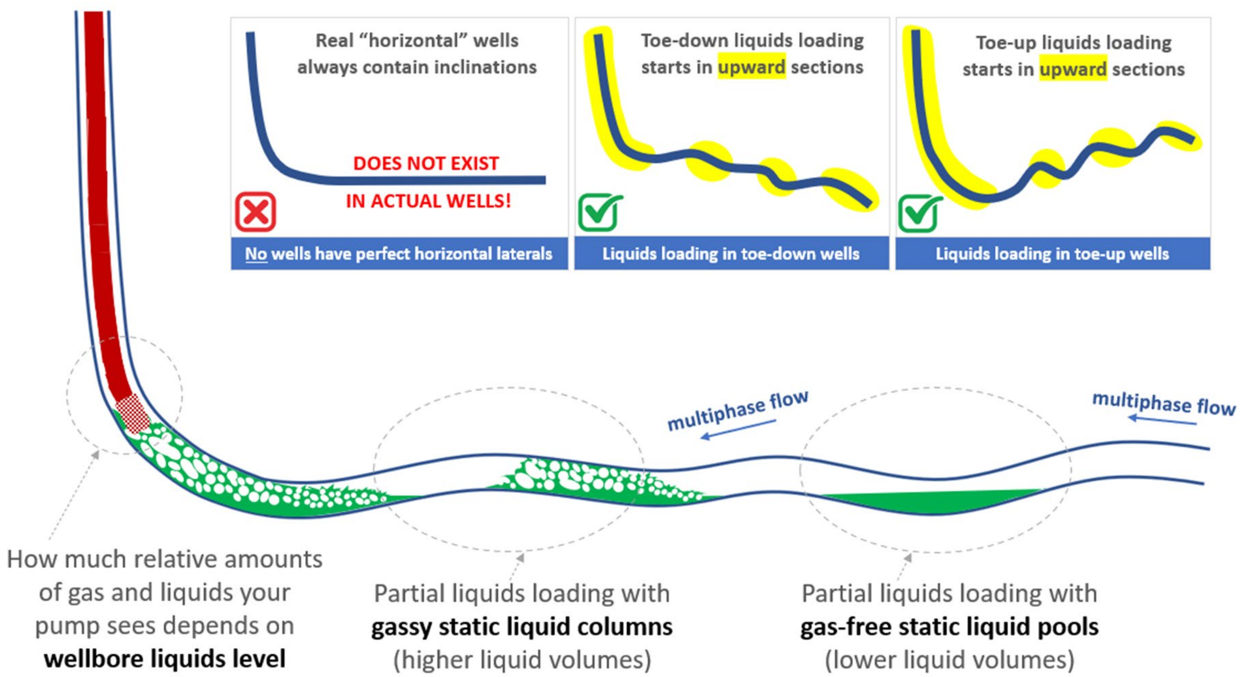

FIGURE 6 – HORIZONTAL WELLBORE SLUGGING TENDENCIES

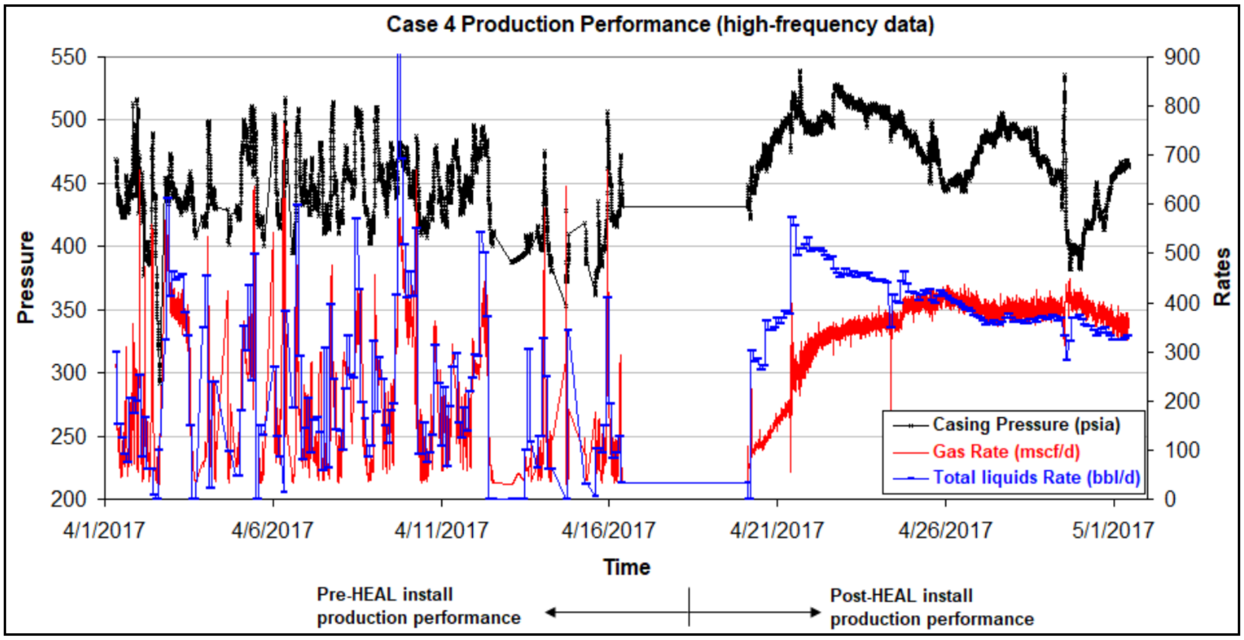

FIGURE 7 – SLUGGY HORIZONTAL WELL

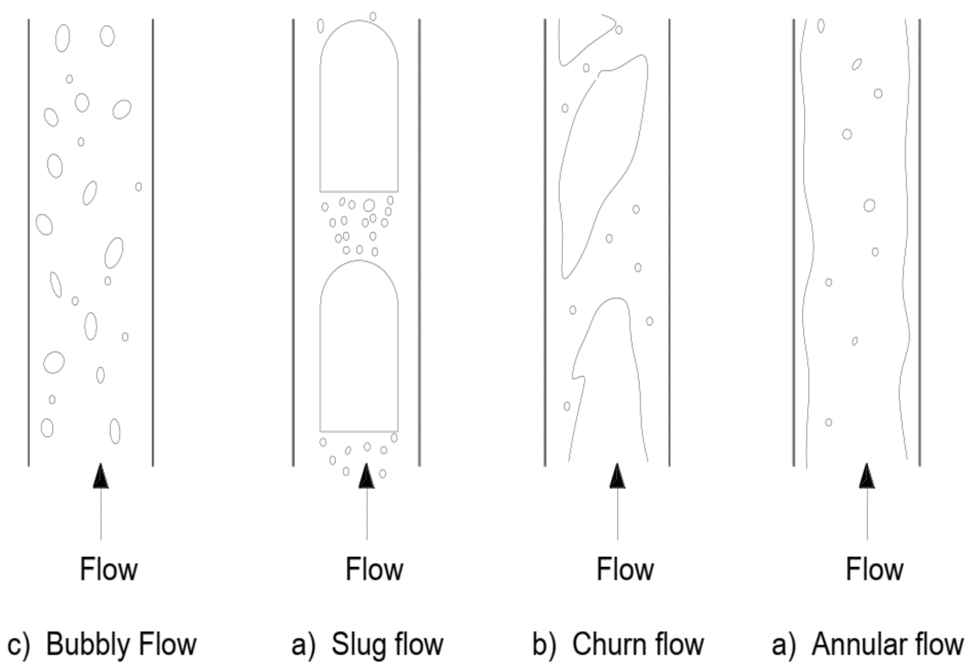

FIGURE 8 – FLOW PATTERNS OR REGIMES AT VERTICAL INCLINATION

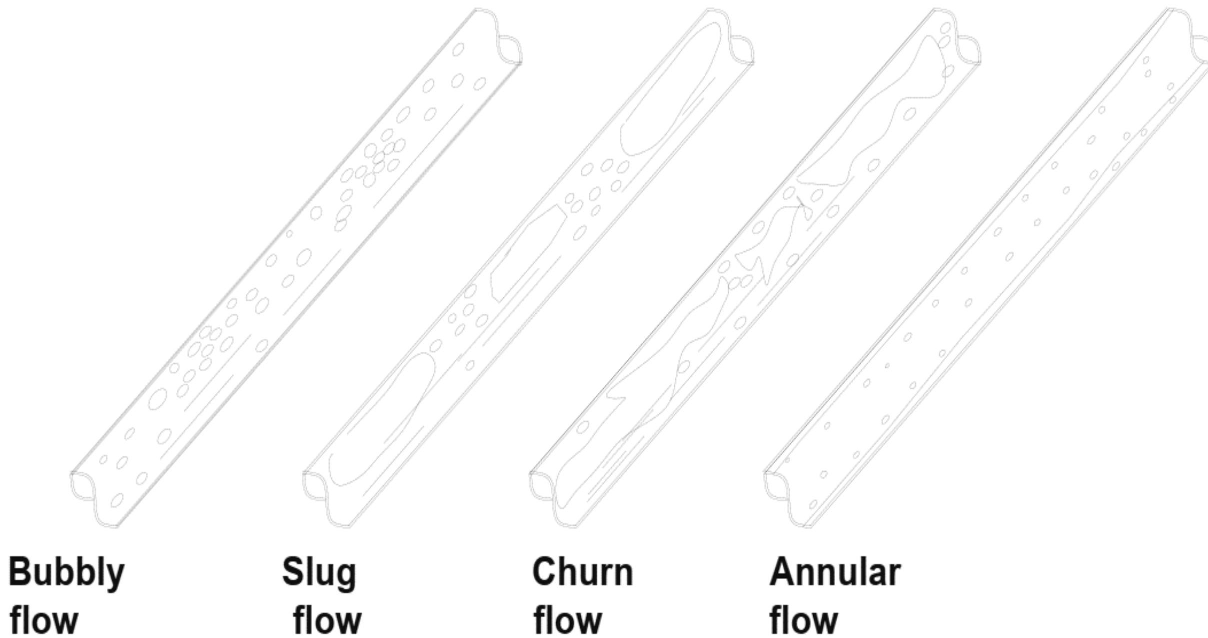

FIGURE 9 – FLOW PATTERNS OR REGIMES AT INCLINATIONS

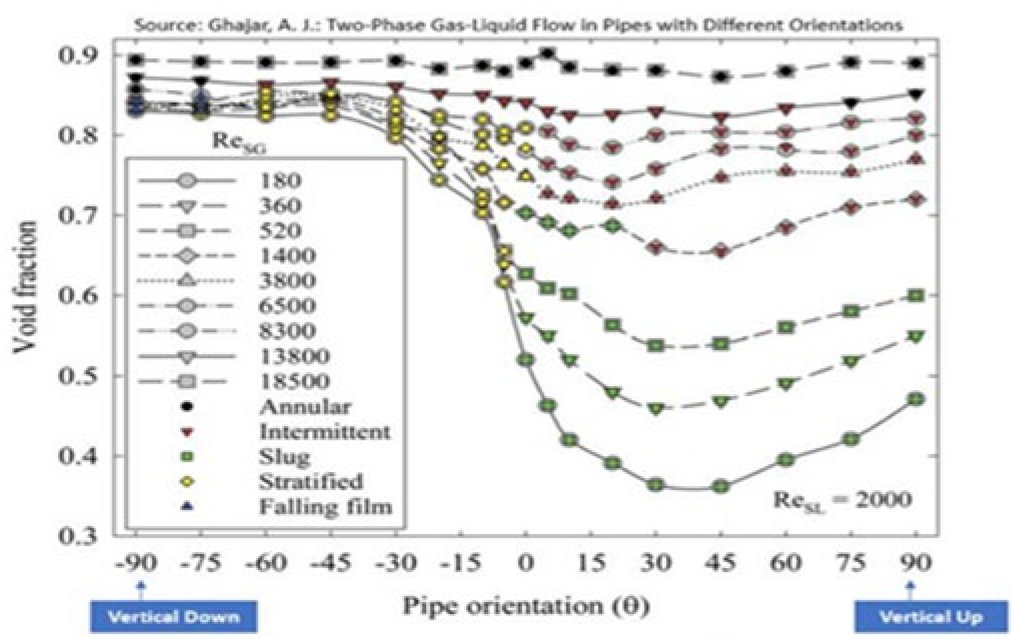

FIGURE 10 – EFFECT OF INCLINATION ON GAS VOLUME FRACTION

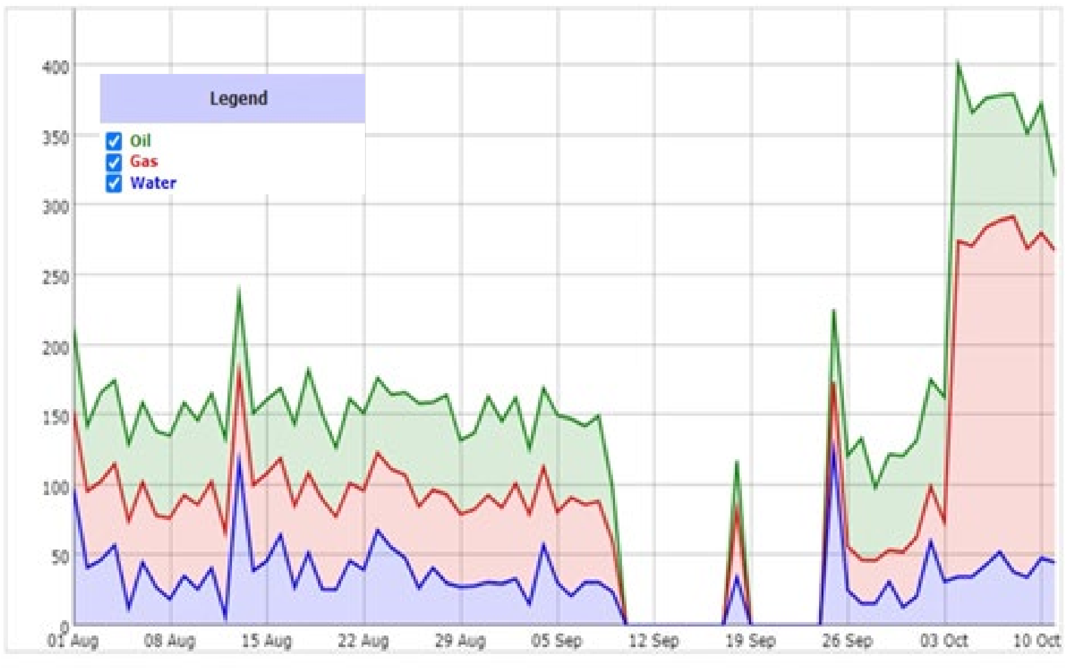

FIGURE 11 – PRODUCTION UPLIFT FROM REMOVAL OF RESTRICTIVE TAC AND INSTALLING A HIGH PERFORMANCE LIQUID FALLBACK SEPARATOR

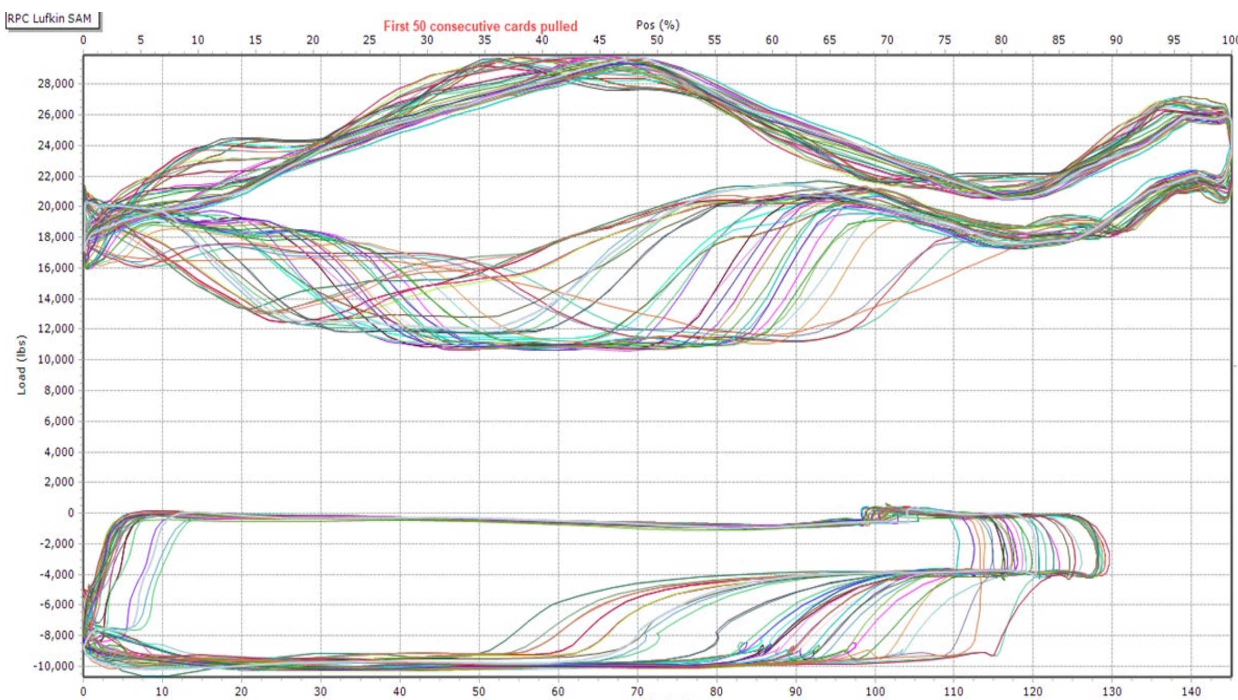

FIGURE 12 – ANNULAR FLUID LEVEL ABOVE TAC, UNSTABLE FLOW AND PUMP FILLAGE

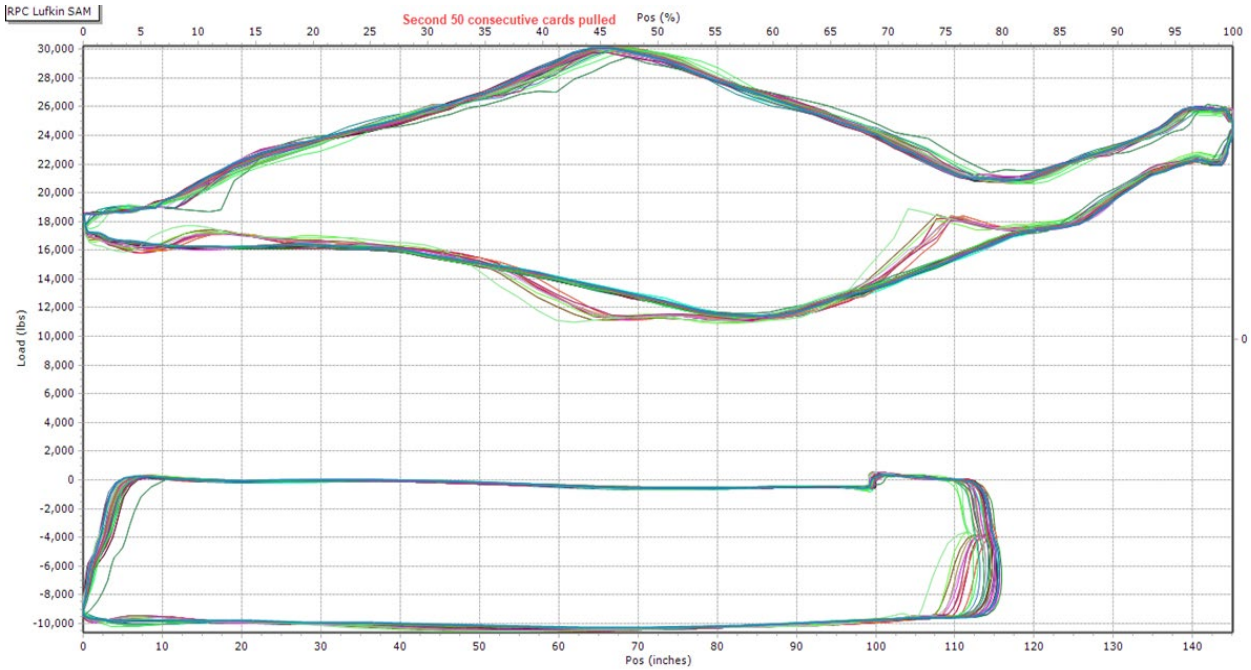

FIGURE 13 – ANNULAR FLUID LEVEL BELOW TAC, STABLE FLOW AND PUMP FILLAGE

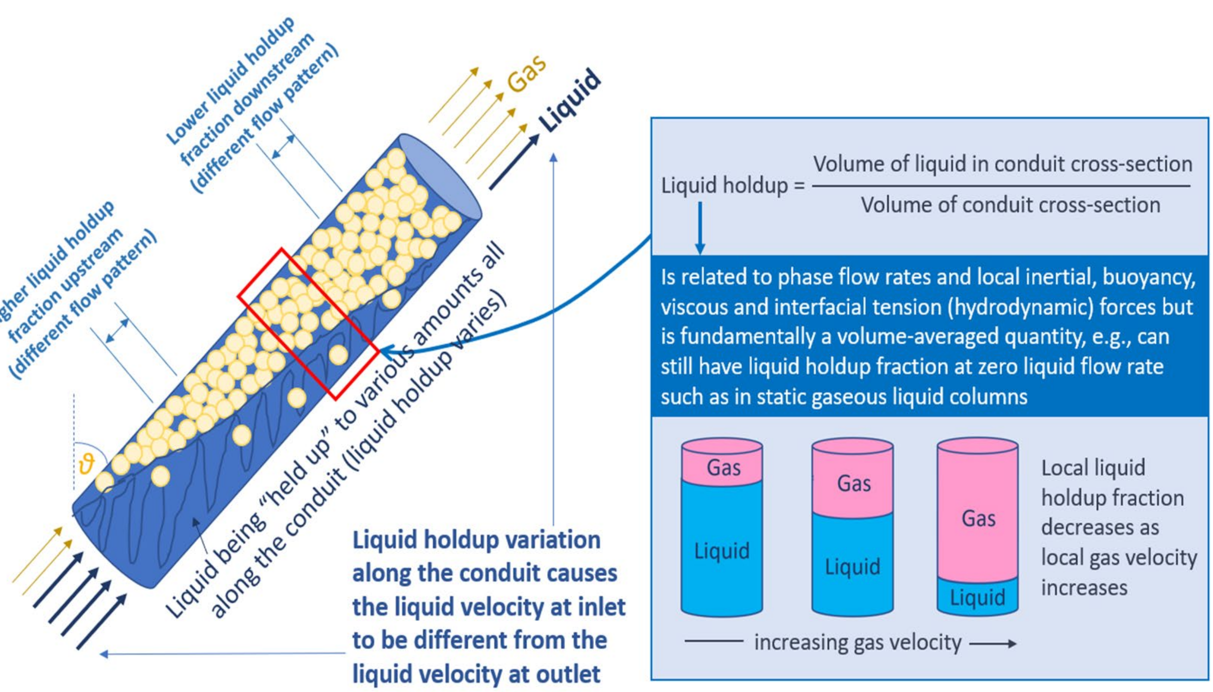

FIGURE 14 – LIQUID HOLDUP (LIQUID VOLUME FRACTION) AND GAS HOLDUP (GAS VOLUME FRACTION)

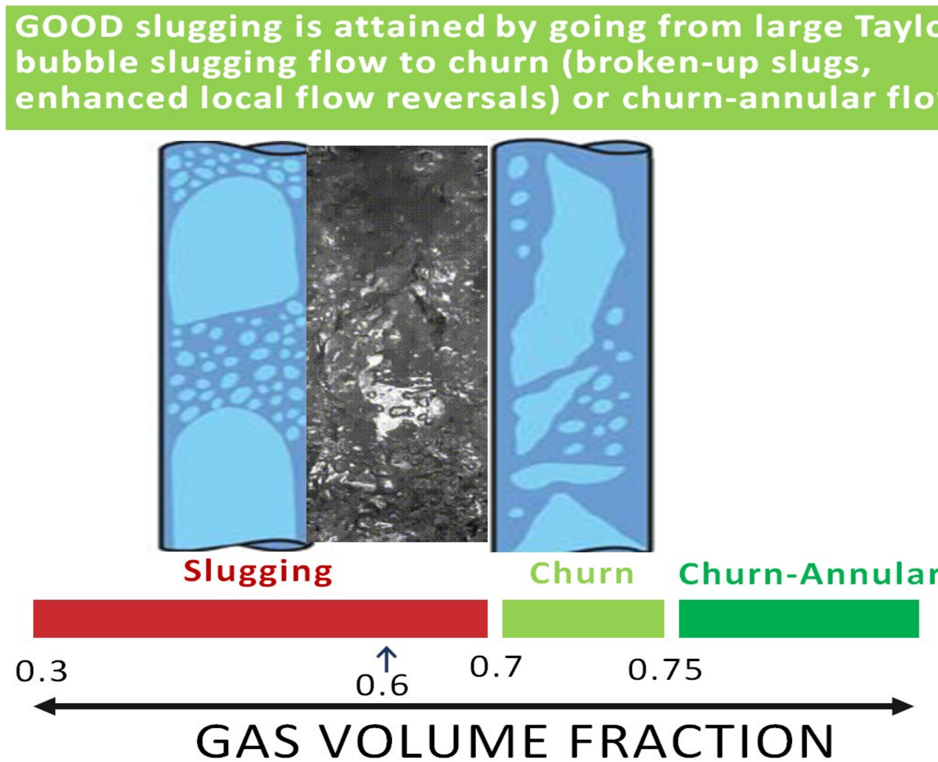

FIGURE 15 – MULTIPHASE FLOW GAS VOLUME FRACTION (GOOD SLUGGING) STABILITY LIMIT

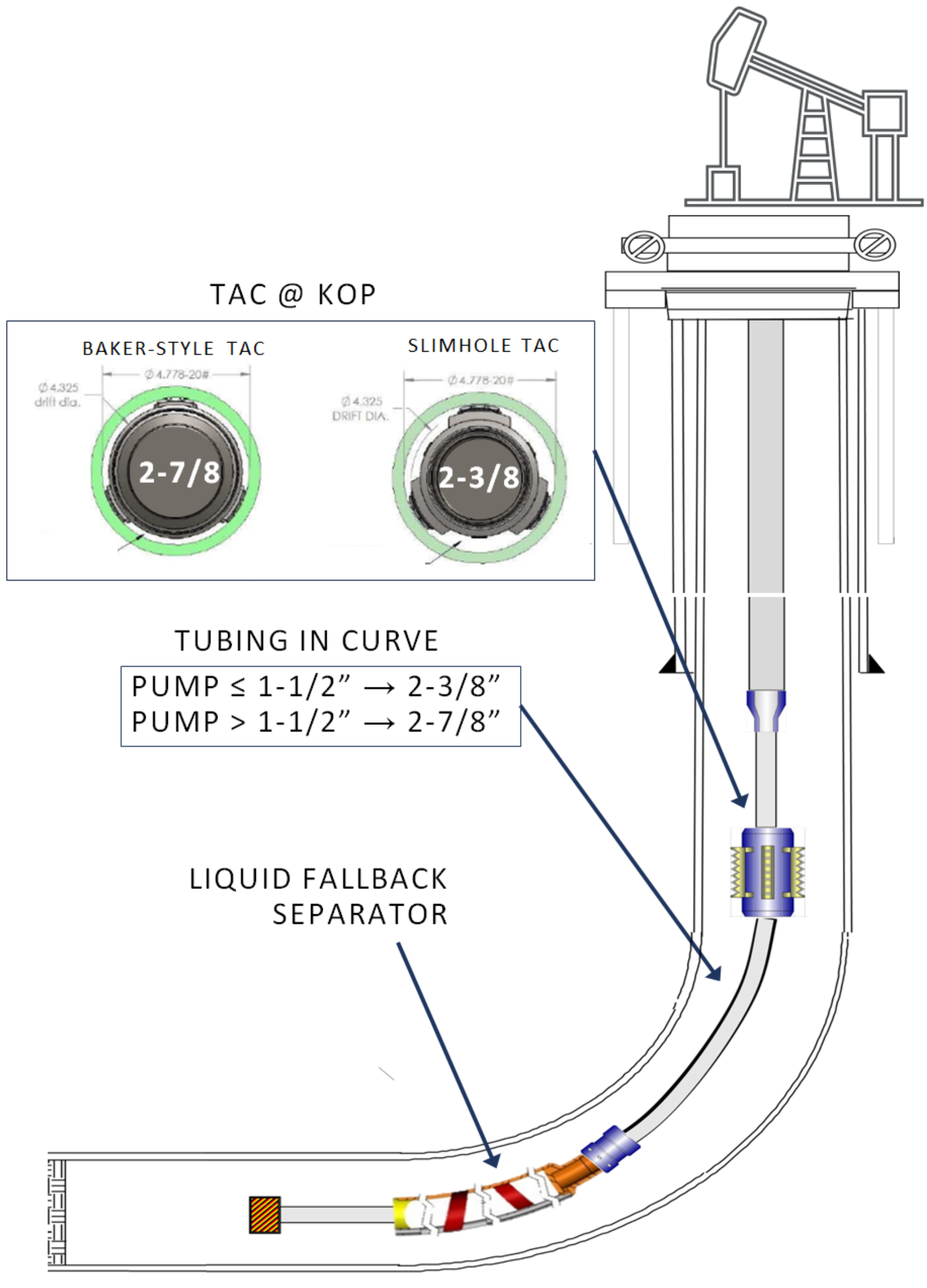

FIGURE 16 – HIGH GAS SEPARATION EFFICIENCY DOWNHOLE DESIGN

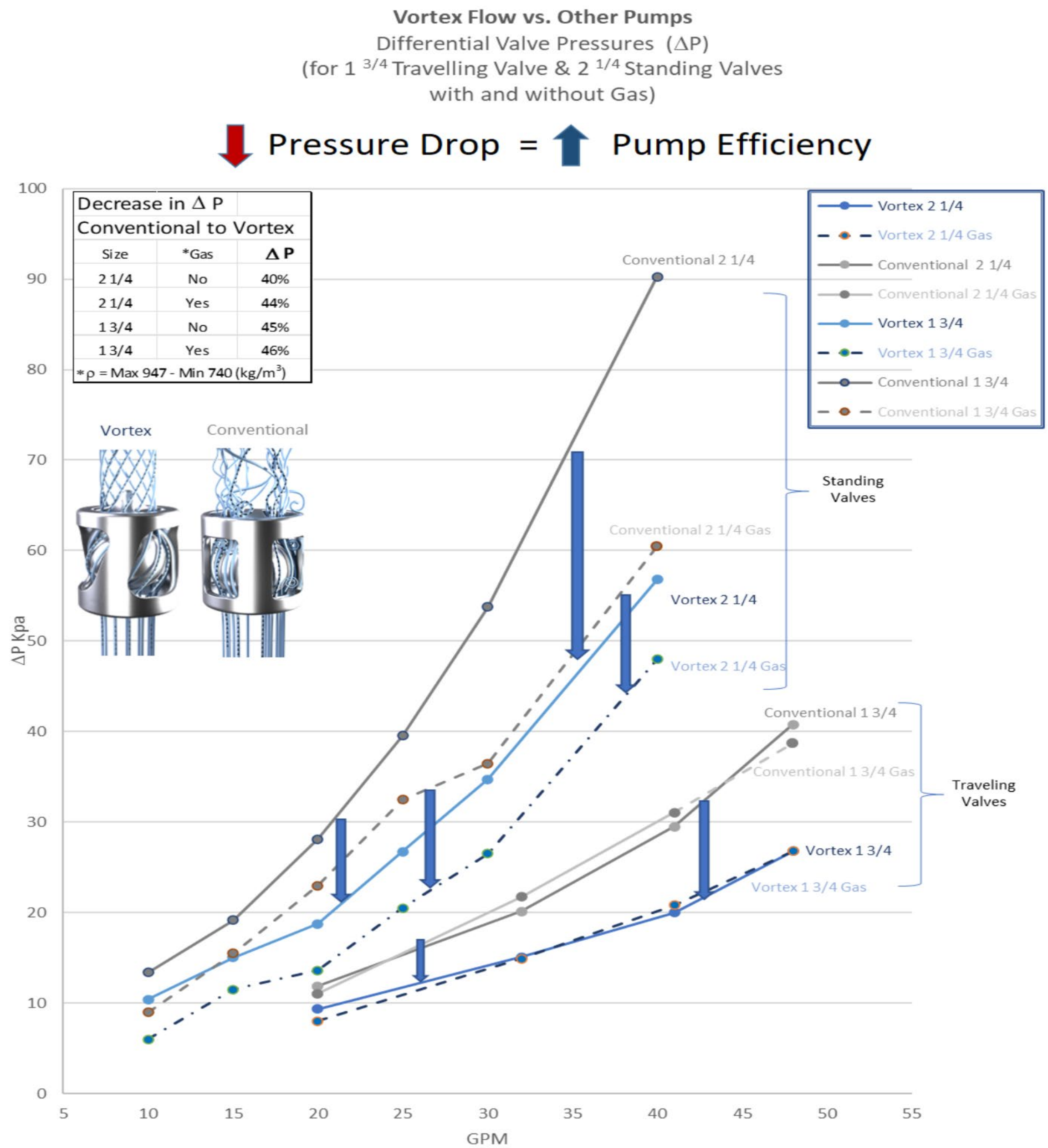

FIGURE 17 – Q2 FLOW VORTEX FLOW PUMP VALVES REDUCE FLUID FLOW PRESSURE LOSS

FIGURE 18 – Q2 ARTIFICIAL LIFT SERVICES HORIZONTAL VALVE SYSTEM(HVS)

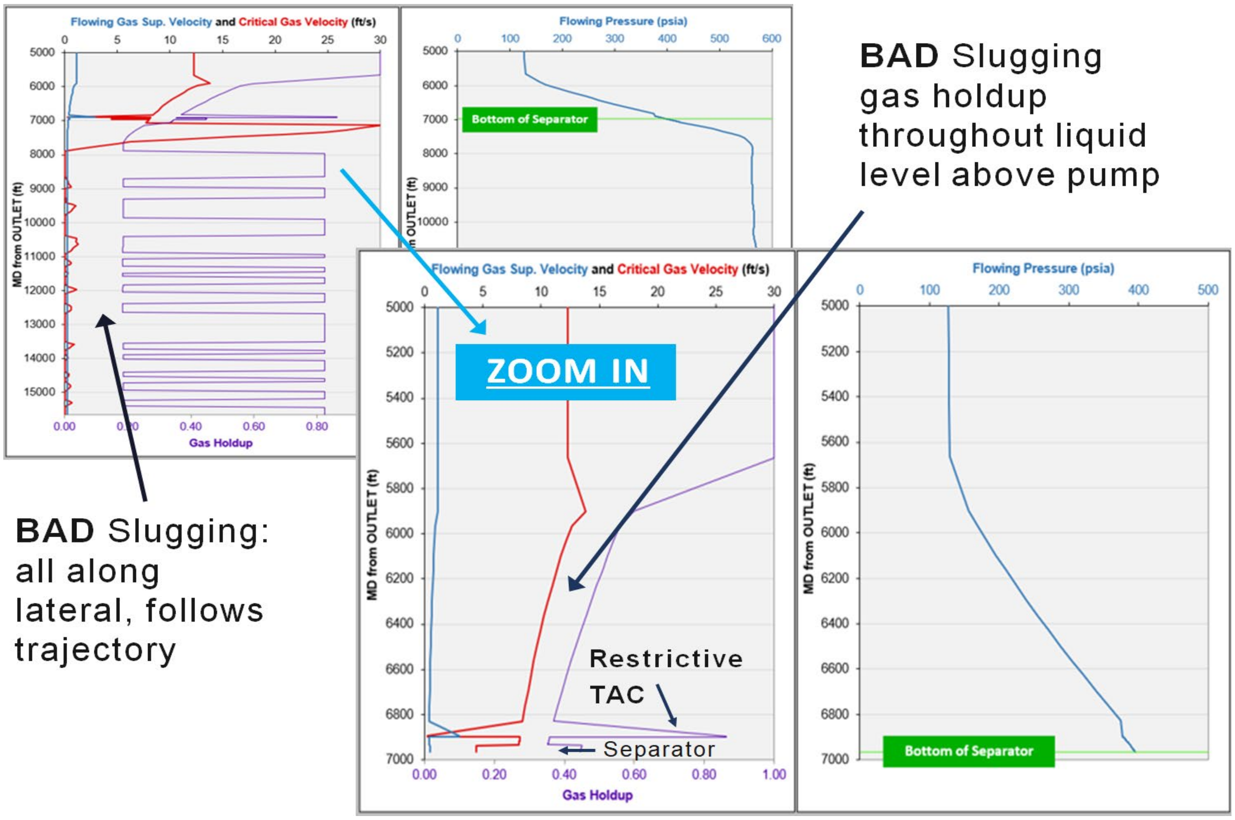

FIGURE 19 – CASE STUDY #1, FLOW MODELLED PUMP ABOVE KOP WITH RESTRICTIVE TAC

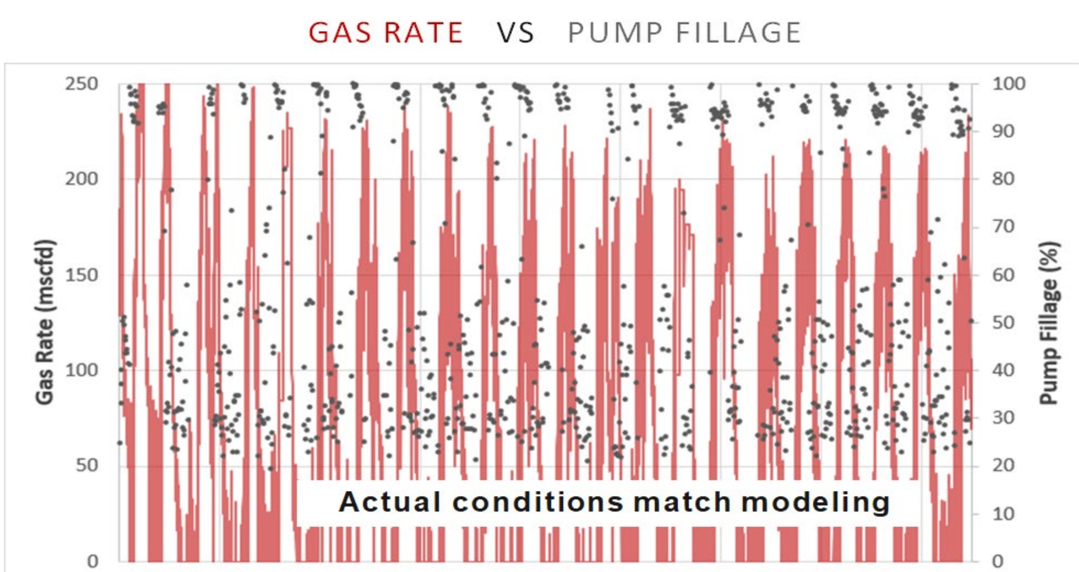

FIGURE 20 – CASE STUDY #1, UNSTABLE FLOW CONDITIONS AND POOR ERRATIC PUMP FILLAGE

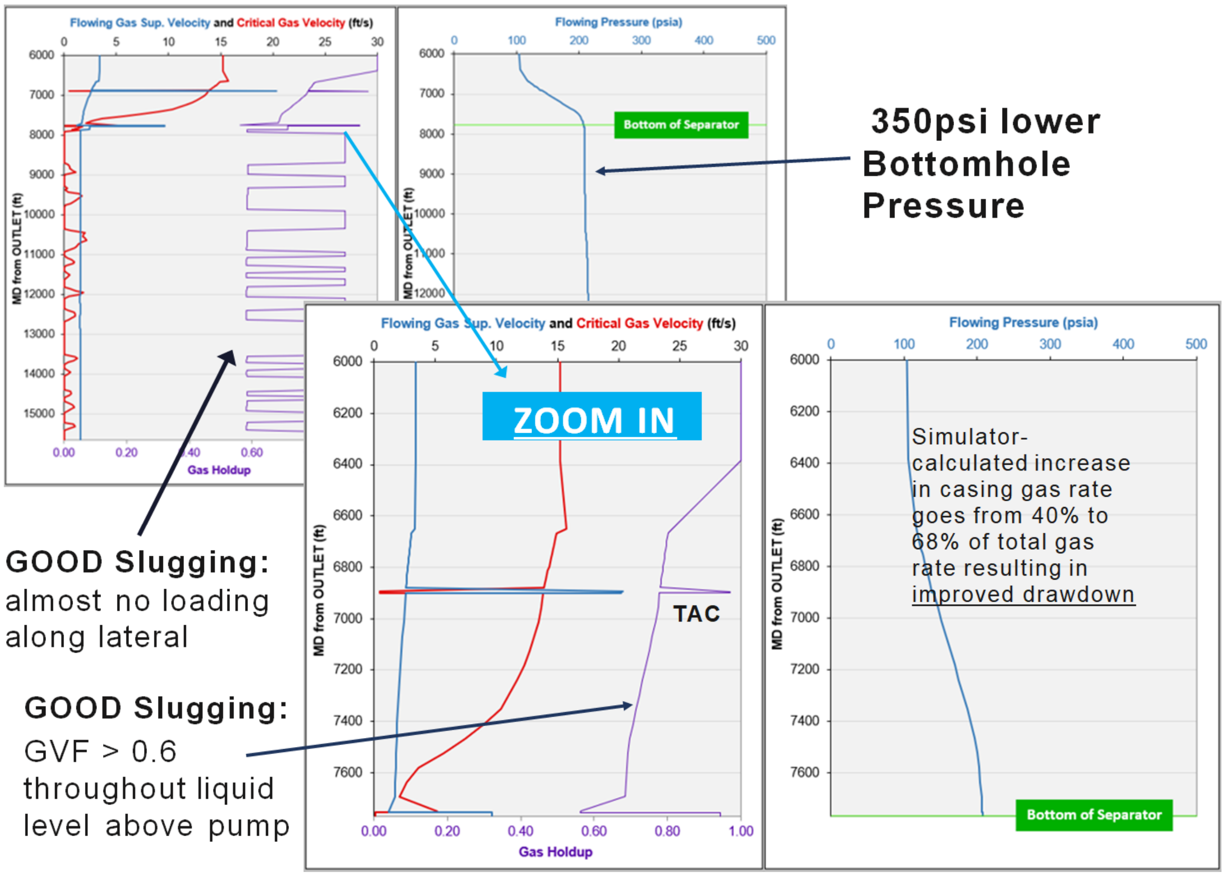

FIGURE 21 – CASE STUDY #1, FLOW MODELLED PUMP IN CURVE SYSTEM

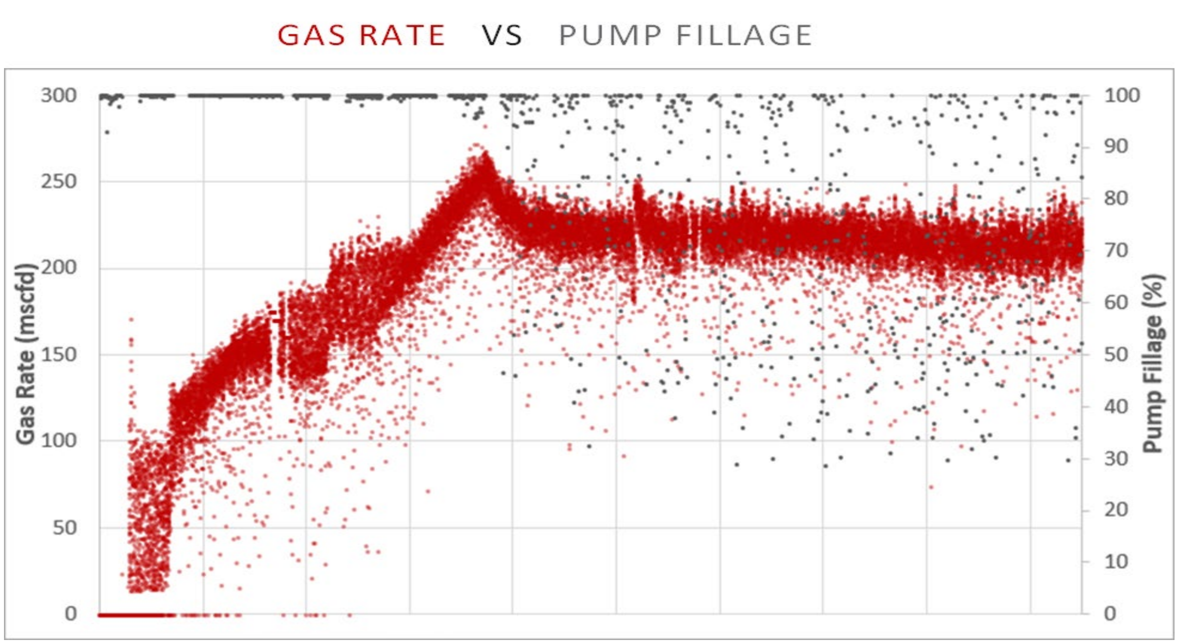

FIGURE 22 – CASE STUDY #1, STABLE FLOW CONDITIONS AND CONSISTENT HIGH PUMP FILLAGE

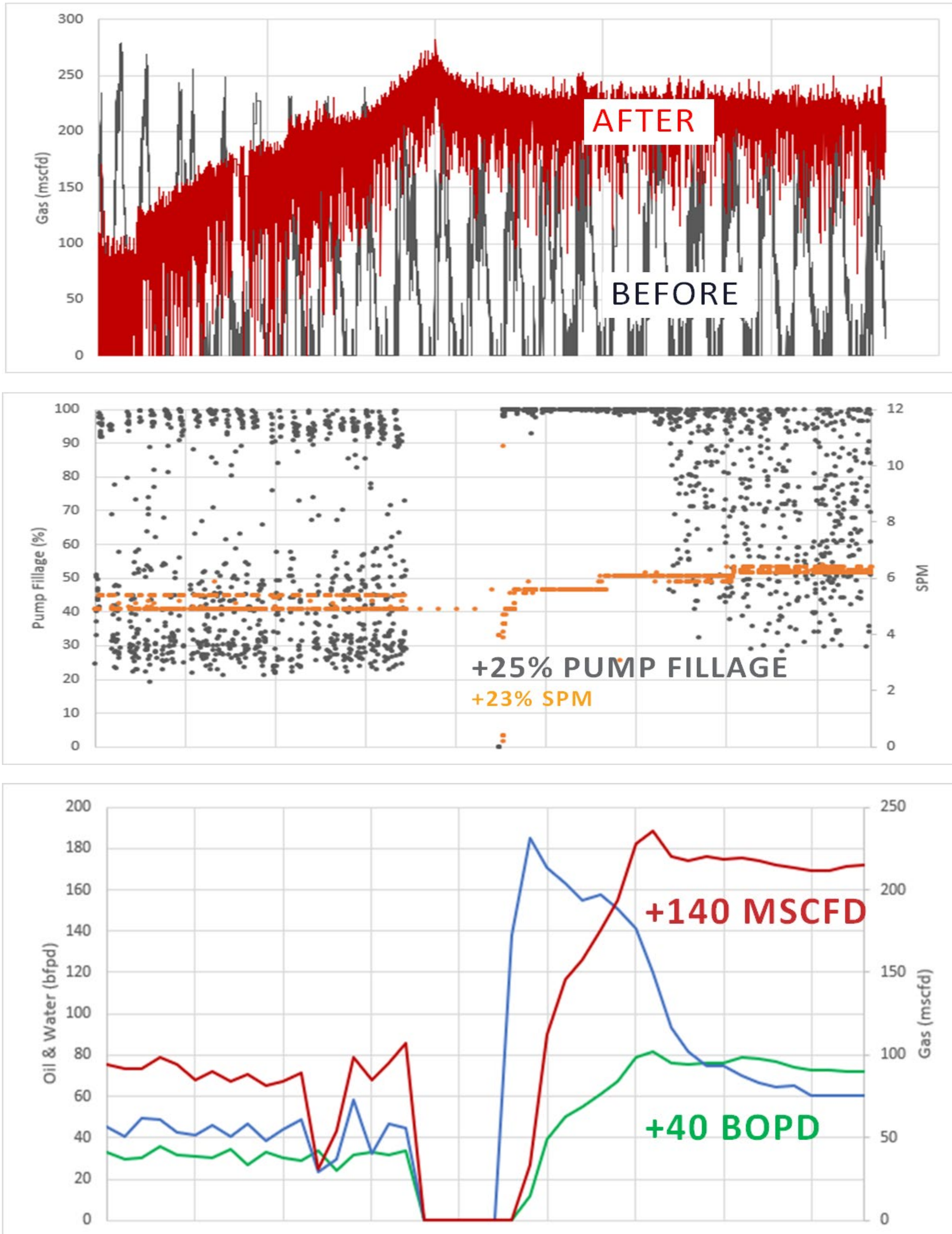

FIGURE 23 – CASE STUDY #1, EXCELLENT PRODUCTION RESULTS

FIGURE 24 – CASE STUDY #1, DEBRIS IN PUMP FAILED STANDING VALVE

FIGURE 25 – CASE STUDY #1, FAILED PUMP PLUNGER WEAR

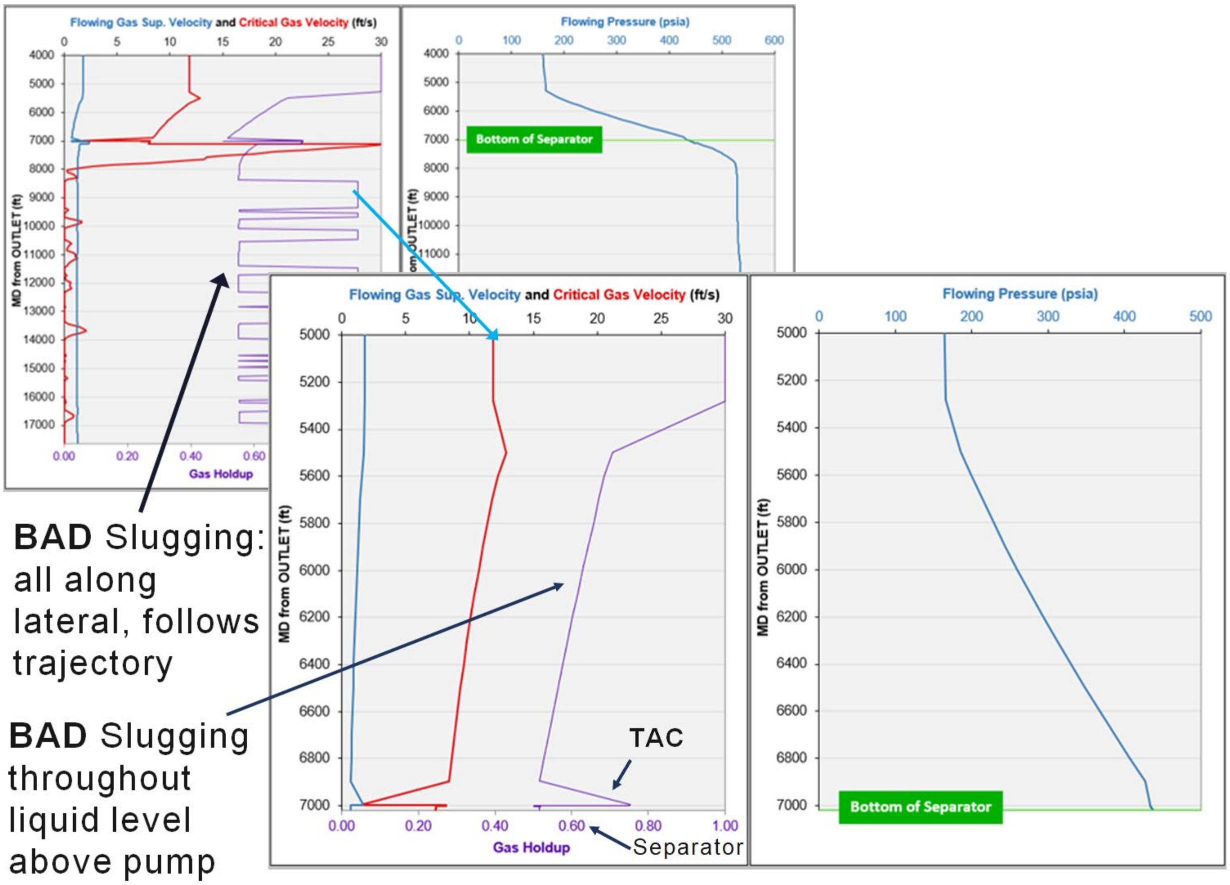

FIGURE 26 – CASE STUDY #2, FLOW MODELLED PUMP ABOVE KOP WITH SLIMHOLE TAC

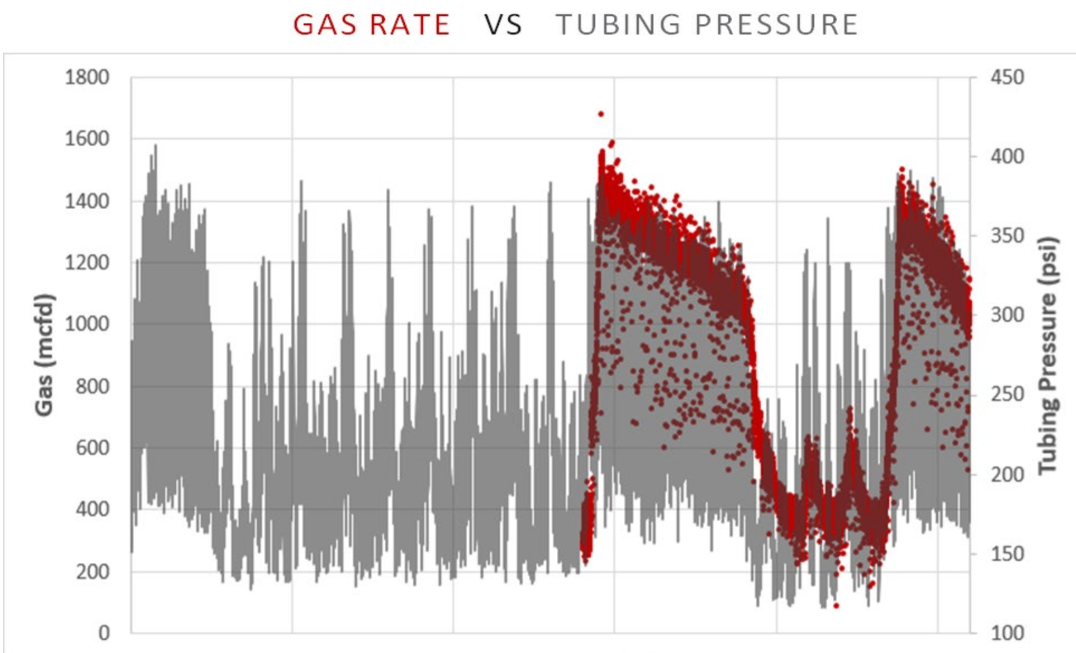

FIGURE 27 – CASE STUDY #2, UNSTABLE SLUGGY FLOW CONDITIONS

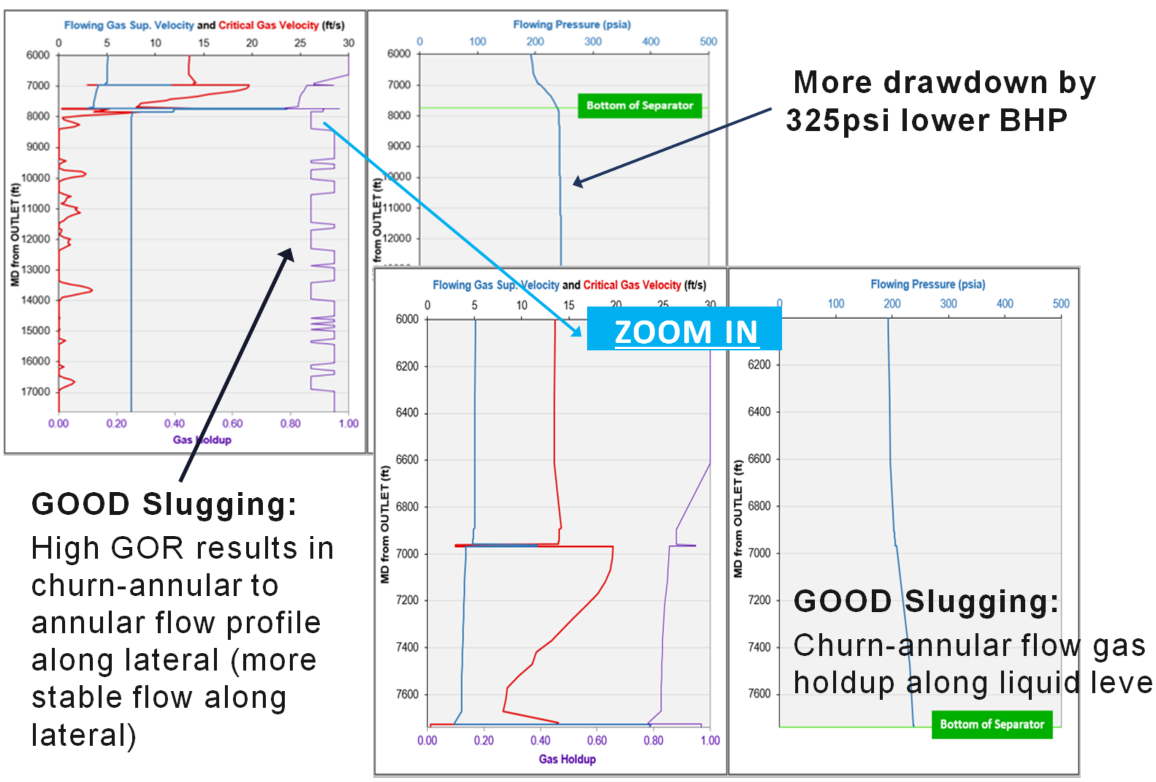

FIGURE 28 – CASE STUDY #2, FLOW MODELLED PUMP IN CURVE SYSTEM

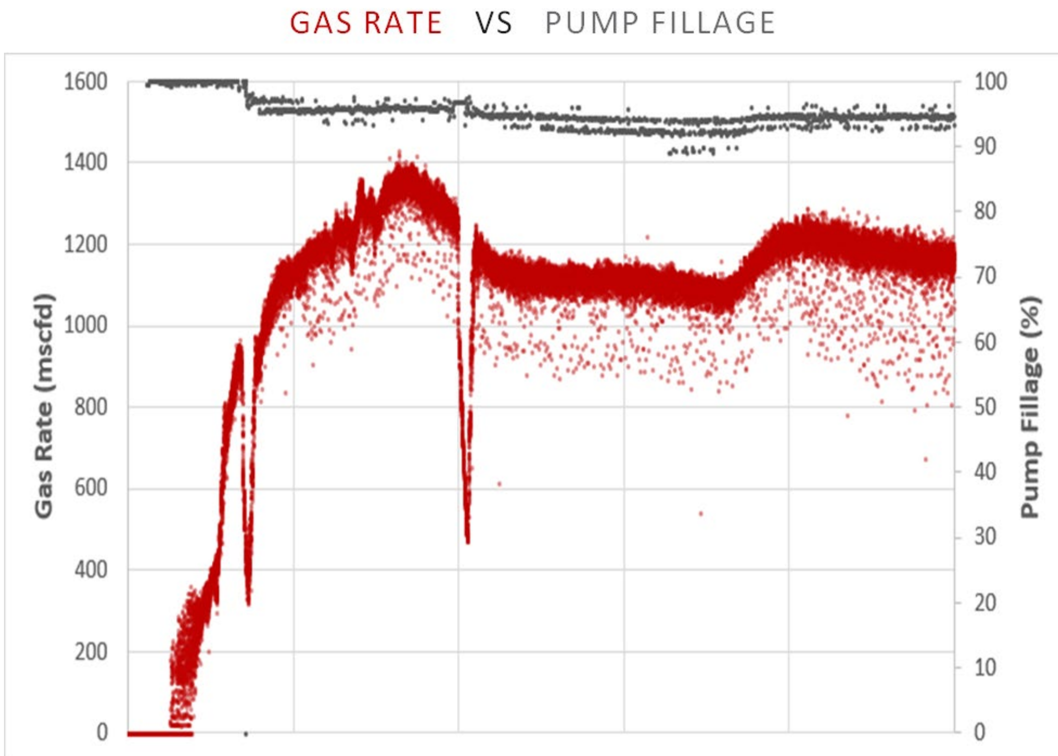

FIGURE 29 – CASE STUDY #2, STABLE FLOW CONDITIONS AND CONSISTENT HIGH PUMP FILLAGE

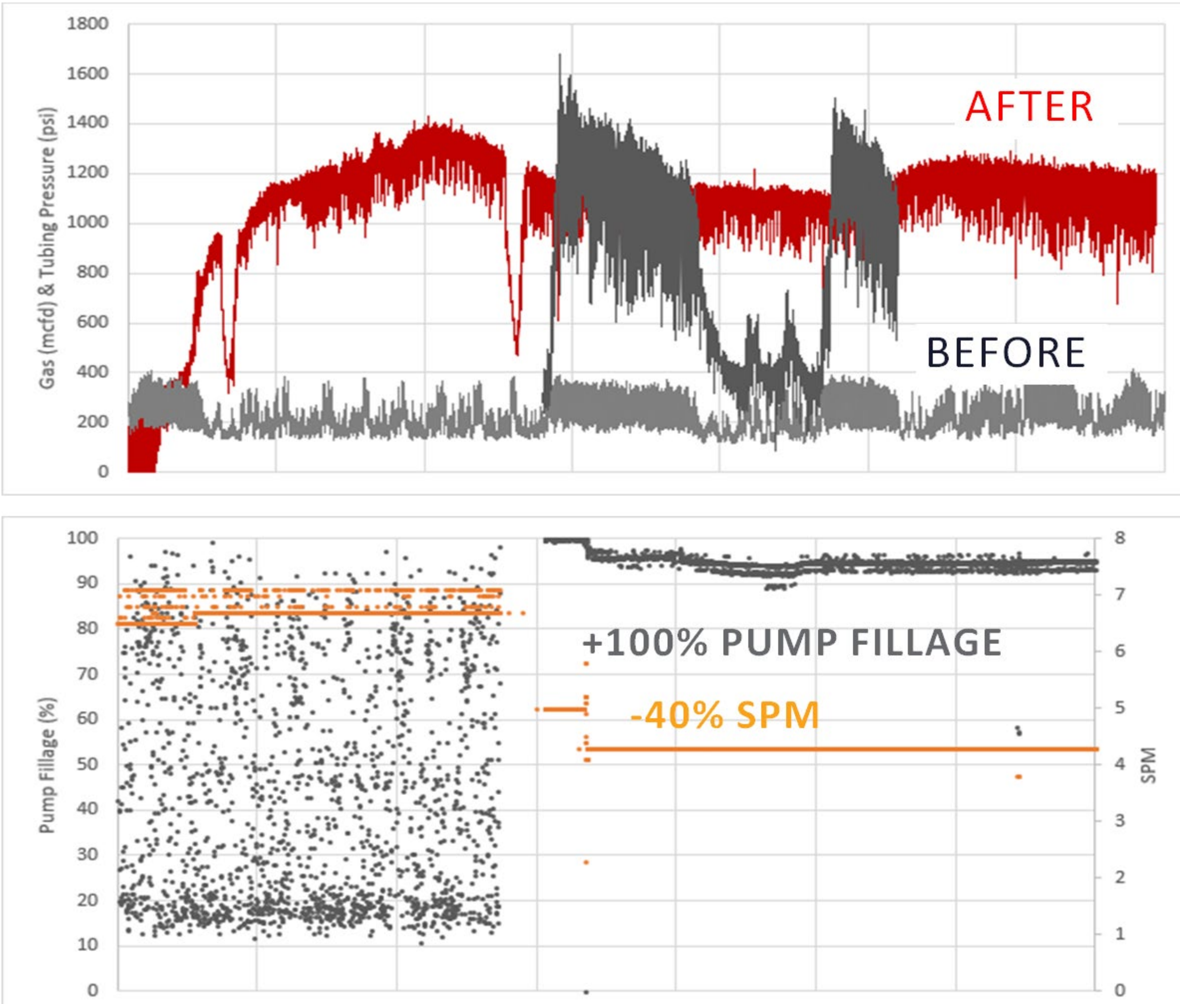

FIGURE 29 –

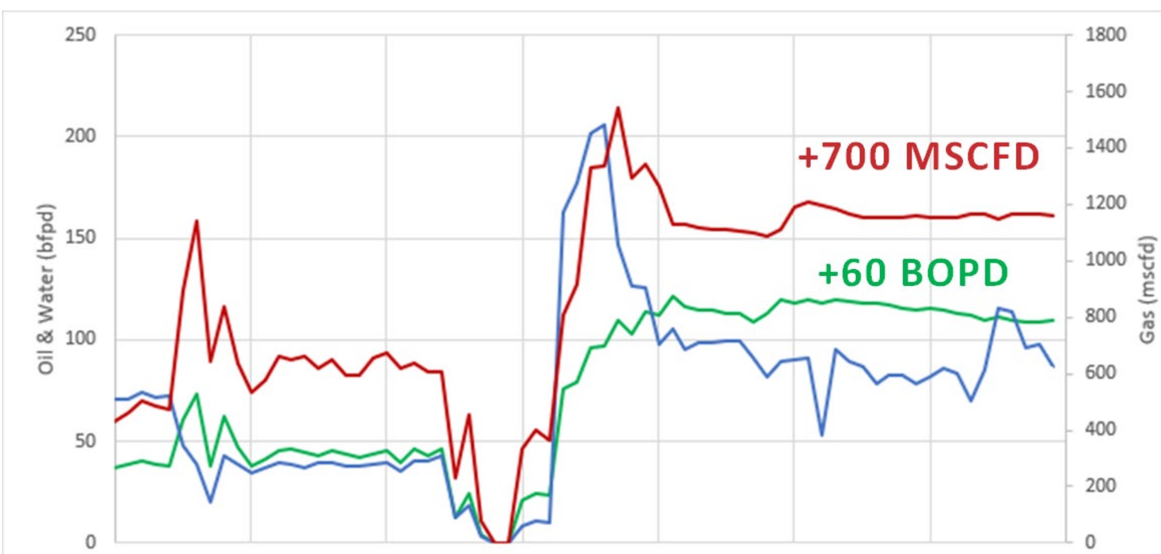

FIGURE 30 – CASE STUDY #1, EXCELLENT PRODUCTION RESULTS

ENDNOTES

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