HORIZONTAL WELL CASING DESIGN TO MAXIMIZE PRODUCTION PERFORMANCE

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INTRODUCTION

Producers are continuously challenged to keep drilling costs as low as possible and retain operational flexibility so as not to compromise completion and production performance. Well construction cost saving strategies that include a casing size reduction can cause long-term production inefficiencies.

Smaller casing sizes impact the critical liquid lifting velocity necessary to support efficient artificial lift thereby compromising production. If during the lifting phase, critical liquid lifting velocities are exceeded in the production annulus across and/or above the downhole pump, the producing bottomhole pressures become higher, and the producing rates consequently lower. Preventing the risk of critical liquid lifting velocities in the production annulus maximizes drawdown and production.

This paper introduces a low-risk, cost-effective modification to a standard 5½-inch monobore casing design that controls critical liquid lifting velocities from occurring during the production lifting phase.

THE SIGNIFICANCE OF THE CRITICAL RATE

For a horizontal well to produce effectively the gas rate needs to achieve a gas velocity that can lift liquids to surface. When this critical rate is not present, liquid loading occurs at the bottom of the well causing back pressure against the formation pressure, reducing production. The threshold whereby the gas rate declines to induce liquid loading is uncertain.

Issues with the critical rate have been noticed in earlier field studies intended to address slug flow behaviour in horizontal wells specifically with electric submersible pumps (ESPs). As expected, the researchers observed that the critical rate was easily attained for high-gas rate wells in initial production (Kimery, Saponja, Chacula, & Jensen, 2017). It is known that for both ESPs and rod pumps, if the critical rate is exceeded in the annulus across or above the pump, then downhole separation ceases, and excessive pump gas interference occurs. Liquid loading takes place in the annulus above the largest outside diameter or restrictive component (commonly an ESP or tubing anchor) increasing the bottomhole pressure (BHP) to consequently reduce production. (Kimery et al., 2017; Li, Almudairis, & Zhang, H., 2014; Shekhar, Kelkar, Hearn, & Hain, 2017).

Models to predict liquid loading are extensive in the critical gas velocity literature. The following overview of the evolution of research follows a path that leads to the developments presented in this paper. Turner et al.'s (1969) classic paper analyzed two predictive models for the removal of gas well liquids. Using field data Turner et al. compared two models: (1) liquid movement along the walls of pipe (liquid film) versus (2) liquid droplets entrained in high-velocity gas (liquid droplet fallback). Based on their field data, they concluded that the droplet model better predicted the minimum rate required to lift liquids.

Coleman, Clay, McCurdy, and Norris (1991) applied the Turner model to low-pressure gas wells and resolved that a 20% adjustment, as suggested in Turner's work, was not necessary. Additionally, Coleman et al. made two conclusions of significance to this paper. They noticed that wells that "exhibit slugging behaviour may not follow the liquid-droplet model because of a different transport mechanism (Coleman et al., 1991, p. 331)." They also noticed that wellbore diameter and pressure have a "direct and significant impact (Coleman et al., 1991, p. 331)" on the critical rate.

The notion of slugging was further characterized by Nosseir, Darwich, Sayyouh, and El Sallaly (2000) in their research that accounts for the impact of differing flow regimes on Turner's model and the modifications to the predictability of the critical rate. Their conclusions suggest a set of calculations that relate to the expected flow conditions and recommend applying these calculations at the wellhead pressure where gas velocity is at its maximum value.

Sutton, Cox, Lea, and Rowlan (2010) address Coleman's earlier observation of the implications of wellbore diameter. Their analysis noted the significance of downhole conditions (geometry, pressure, temperature, fluid properties) to the predictability of critical gas velocity. They concluded that calculations completed with data from the bottom of the well provide better predictability for the entire well path.

It is Li et al. (2014) that take the research into the more familiar environment of today by specifically analyzing the predictability of critical gas velocity in deviated and horizontal wells. Their work supports the arguments of others (Zabaras et al. 1986, Westende et al. 2007, Belfroid et al. 2008 and Westende 2008) that the liquid film model provides more accurate predictability in deviations. They highlight the work of Yuan (2011), Guner (2012), Alsaadi (2013), and Luo (2013) who characterize critical gas velocity at different angles. Li et al.'s research shows that the critical rate increases as the deviation angle increases to reach maximum critical gas velocity between 30° to 60°.

With an industry shift to horizontal wells over vertical wells, Shekar et al. (2017) build upon Li et al.'s work to recognize the importance of developing a predictive model that accounts for nearly horizontal or inclined wells of all sorts. They set out to develop a generalized model that can be applied to any inclination and any diameter. Shekar et al. agrees with Li et al. and others that Barnea's (1986) liquid-film reversal model is more suitable for high gas velocity scenarios. Further Shekar et al. concludes their new method is applicable to inclined wells and incorporated an interfacial-friction factor to account for a portion of the inclined pipe being exposed to gas as the liquid film recedes from the pipe. Shekar et al.'s model determines that the maximum critical gas velocity is achievable at 35° inclination. This is explained by the liquid-film thickness at the top of the pipe approaching zero as the angle of tubing changes from vertical to approximately 35°.

CRITICAL LIQUID LIFTING LIMITS PRODUCTION

Achieving the critical rate to avoid liquid loading is particularly challenging in high gas rate horizontal wells. Although critical gas velocity models have evolved to address the uniqueness of horizontals, critical lifting still occurs in an erratic and cyclical manner where instantaneous gas rates exceed the critical rate, but the average daily gas rate is below the critical rate. Horizontal slug flows and foamy fluids compound the problem. The cyclic gas rate and slug flow induce cyclic BHPs that reduce production and pump run life.

Critical lifting limitations that directly impact production occur in both ESPs and rod pumping. If the critical rate is exceeded in the annulus across or above the pump, then downhole separation ceases and excessive pump gas inference occurs. A column builds in the annulus above the largest outside diameter or restrictive component, commonly a tubing anchor in rod pumping or in an ESP. Tubing anchors placed in rod pumps can restrict gas flow up the casing causing increased backpressure against the formation and limiting production (McCoy, Rowlan, Taylor, & Podio, 2015). Kimery et al. observed the challenge with critical velocity in ESP wells. ESPs have a large diameter downhole assembly that reduces the annular space causing higher velocities (Kimery et al., 2017).

Tubing anchors in rod pumps

In rod pumps with tubing anchors installed, a gaseous liquid column can develop above the tubing anchor resulting in a high-pressure gas column below the tubing anchor eventually restricting flow from the reservoir. The combination of the gaseous liquid column above the tubing anchor and the pressure created from the accumulated gas below the tubing anchor creates high BHP, limiting pump fillage, restricting drawdown and impacting production performance.

ESP larger outside diameter
The larger outside diameter (OD) typical to ESP equipment reduces the annular space for fluid flow causing higher velocities. Figure 2 below shows a Turner critical velocity plot for 4½-inch OD tools in a 5½-inch casing. The 4½-inch OD of the ESP is the most annular restrictive component; therefore, the limiting factor. Liquid lifting occurs above the curve shown in Figure 2. For 5½-inch casing with 4-½ inch OD, ESP critical lifting occurs at 0.4 MMscf/day when the pump intake pressure (PIP) is below 400 psi. At a PIP of 1000 psi, the maximum gas rate is 0.6 MMscf/day.

The high velocity caused by the larger OD creates a condition where the PIP gets trapped at the upper end of what is predicted from the Turner model. This results in gas at the pump and an inability for the well to drawdown. Since wells with ESPs are producing at a higher rate earlier, the high-end stalled PIP increases the likelihood for ESP failures.

In a field trial the Kimery et al. (2017) study shows that drawdown is limited when the critical lifting velocities are exceeded (see Figure 3). The fluid level builds above the restrictive annular space past the larger OD of the ESP body increasing the BHP. The cyclic loading as shown in Figure 3 and Figure 4 results in higher average BHP and reduced ESP life due to frequent shut downs.

WELL CONSTRUCTION ALTERNATIVE – AN ENGINEERED SOLUTION

Restricting the OD for fluid flow has a direct impact on the critical rate required to maintain even flow through the horizontal and sustain production on high gas rate horizontals. Many horizontal wells are cased with 5½-inch casing within a 7-inch wellbore diameter. HEAL Systems developed an engineered solution to leverage existing downhole space in an enlarged interval length that provides flexibility for pump requirements and allows the OD necessary to lower critical lifting velocities and avoid cycling.

The multiple patent pending Production Enhancement Casing Sub™, or PECS™, combined with a HEAL System maximizes production and minimizes OPEX over the life of a horizontal well. PECS does not require any changes to existing casing design because it advantages existing space in an enlarged interval length. The HEAL System and pump can work to design extents mitigating slug flow and instantaneous gas rates from the horizontal without exceeding the critical liquid lifting rate in the annulus. (see Figure 5).

Operationally, this approach requires no change in drilling hole size or drilling costs. There are no changes required in the cementing or fracture stimulation program and no associated additional costs. The annular flow area past the 4½-inch OD equipment is 700% greater with PECS, therefore, PECS can handle a 700% higher gas rate at an equivalent downhole pressure. (See Figure 6.)

The enlarged interval in the vertical section coincidently results in equivalent critical liquid lifting gas rates through the bend section. In other words, liquid loading in 5½-inch casing occurs at relatively the same gas rates as the 7-inch casing in the vertical section. The larger diameter lowers the fluid velocities and sustains rates below the critical liquid lifting rate as suggested by Li et al.'s findings to avoid undesirable liquid lifting in the annulus. (See Figure 7.)

RISK-BASED DESIGN AND INSTALLATION

Thorough design and analysis underpin PECS risk-based design to ensure the system is applicable for multiple downhole assemblies and able to last the life of the well. Four key factors to reduce risk required analysis: (1) erosion potential, (2) stress on the crossover sub, (3) casing mechanical limitations, and (4) potential impacts to cementing.

Erosion Minimization
The DNVGL-RP-O501 (2015) explores sand production and erosion management. It defines erosive wear or erosion as "material loss resulting from the impact of solids/sands particles on the material surface" (p.

21). The movement of solids has an erosive effect on downhole tubulars particularly those with deviations. Minimizing erosion requires an understanding of the erosion rate. The erosion rate is a function of impingement angle. In horizontal wells, erosion rates rise rapidly as the angle of inclination increases peaking at 35° (see Figure 8). Figure 8 shows the impact angle dependency for ductile and brittle materials. The crossover sub, like all casing materials, is considered a ductile material. The star indicates the PECS crossover sub internal angle. The crossover sub was designed with an internal angle of 2.5° to minimize erosion while maintaining a reasonable tool length for machinability.

Crossover sub analysis

A finite element analysis (FEA) was applied to the crossover sub with an extreme load case of 200,000 lbs of tension (full hook load), 15 ksi of internal pressure (above casing burst), and 3500 ft*lb of torque (see Figure 9). The crossover sub material is Q125 rated having an ultimate tensile strength minimum of 135 ksi, a yield strength minimum 125 ksi, and yield strength maximum of 150 ksi. The maximum stress exerted on the crossover sub was calculated at 131 ksi, below the ultimate tensile strength minimum. Analysis showed that across most of the tool all stresses are below the minimum acceptable yield strength for Q125 material. The most highly stressed area was the internal surface of the 5½-inch pin. This location did not exceed the minimum ultimate tensile strength of the material. For all other points on the tool, the stresses were less than the minimum yield strength of the material, therefore, the crossover sub of the PECS exceeds the mechanical properties of the 5½-inch and 7-inch casing. The analysis determines that the crossover sub will not be a point of failure of the system and will not washout.

Casing stress analysis

The mechanical properties of the casing connected to the crossover needs to withstand running, cementing, fracture stimulation and production. Casing stress analysis for triaxial safety factors on the 7-inch casing was completed and demonstrates that the 7-inch casing portion of the PECS system is more robust than the 5½-inch casing in all expected load cases (see Figure 10). This analysis confirms that the PECS interval can be expected to outperform the mechanical properties of the strongest typical 5½-inch casing grade for the life of the well.

Cementing considerations

A good cement job is essential to all well construction, so sourcing an appropriate wiper plug was vital. The PECS installation incorporates the use of a field-proven, commercially available cement wiper plug able to effectively wipe the 5½-inch and 7-inch casing in a single tool. Cement job simulation calculated a good cement bond with no impact on cement job quality (mud removal, flow regime, etc.). Additionally, there was negligible effect on equivalent circulation density (ECD) because PECS is short and uses API recommended casing size for the typical 5½-inch monobore. Figure 11 shows results from the cement simulation. The upper highlighted rectangular boxed area shows the location of the PECS, whereas the lower highlighted boxed area shows the typical 30°-60° inclination region where cementing is commonly challenging. The PECS cemented interval shows appropriate cement integrity.

CONCLUSION

The Production Enhancement Casing Sub dramatically improves artificial lift gas handling over a well's entire life cycle, without adding material operational risk. The PECS design is risk-based with supporting analysis for the crossover sub and the casing. Existing research in the literature substantiates the PECS design. Installation of PECS does not require any changes to drilling or cementing and does not impact fracture pressures, fracture rates, or fracture flowback operations. Cement simulations confirm strong cement bond with no effect on cement job quality. PECS can be installed at minimal cost compared to other solutions (e.g., running full 7-inch casing string or tapered 5½-inch to 7-inch back to surface).

This paper describes the preparatory background research and analysis to enter formalized field trials. Aggregated results from trials will influence improvements to PECS.

FIGURES

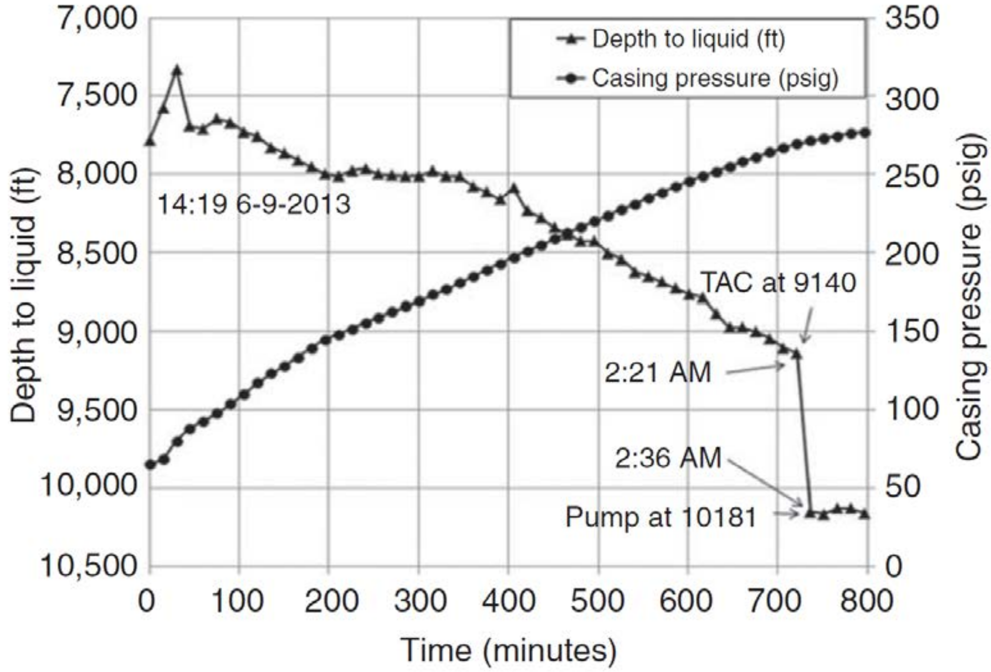

Figure 1. Summary of liquid level depression test. Source: McCoy et al (2015)

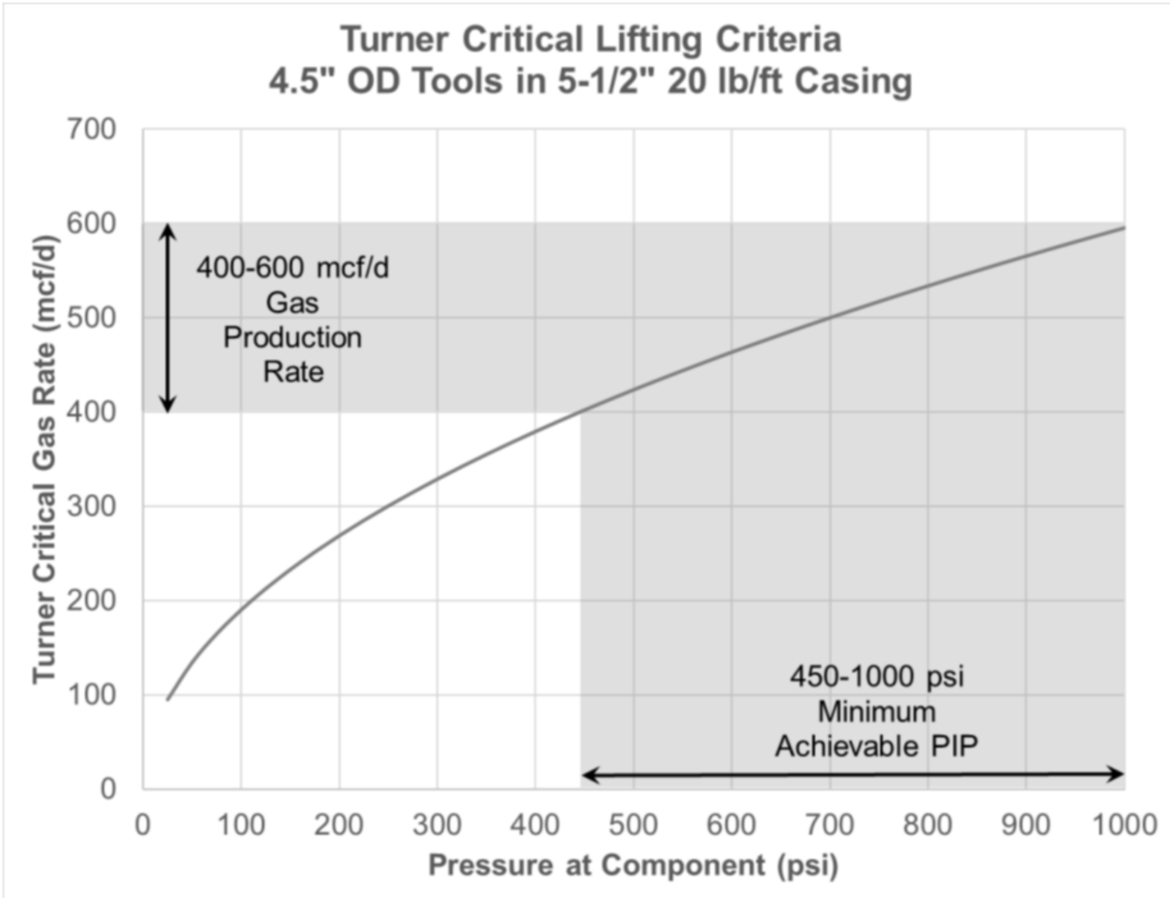

Figure 2. Turner critical velocity plot. Source: Kimery et al. (2017)

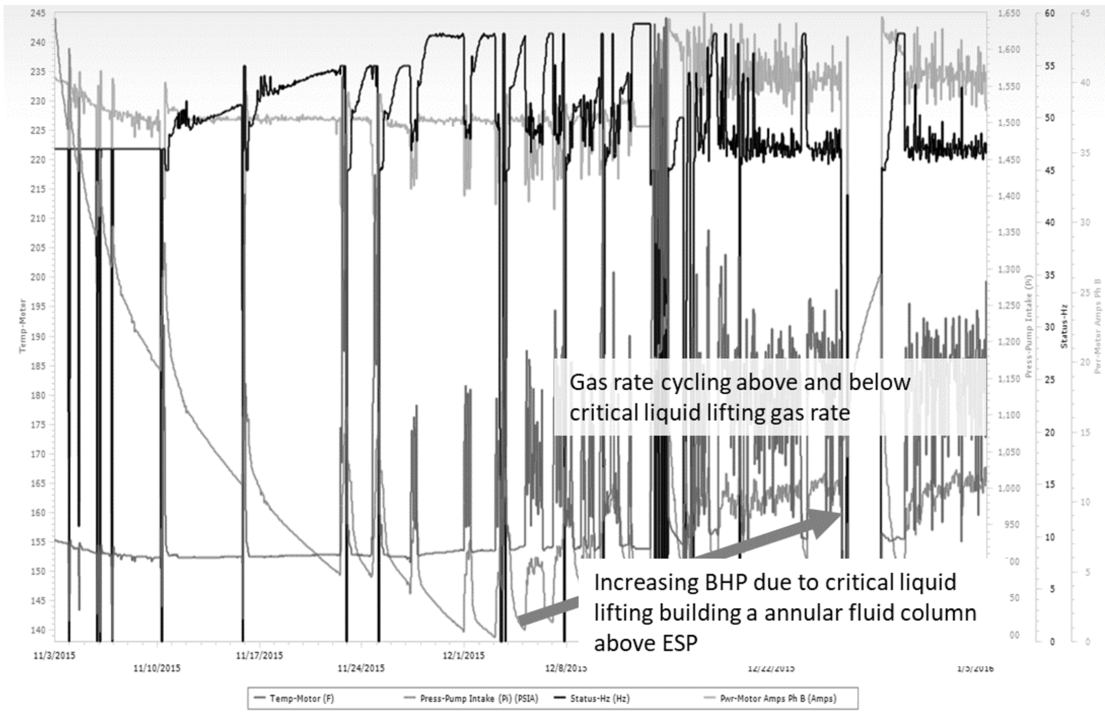

Figure 3. Downhole ESP parameters. Source: Kimery et al. (2017)

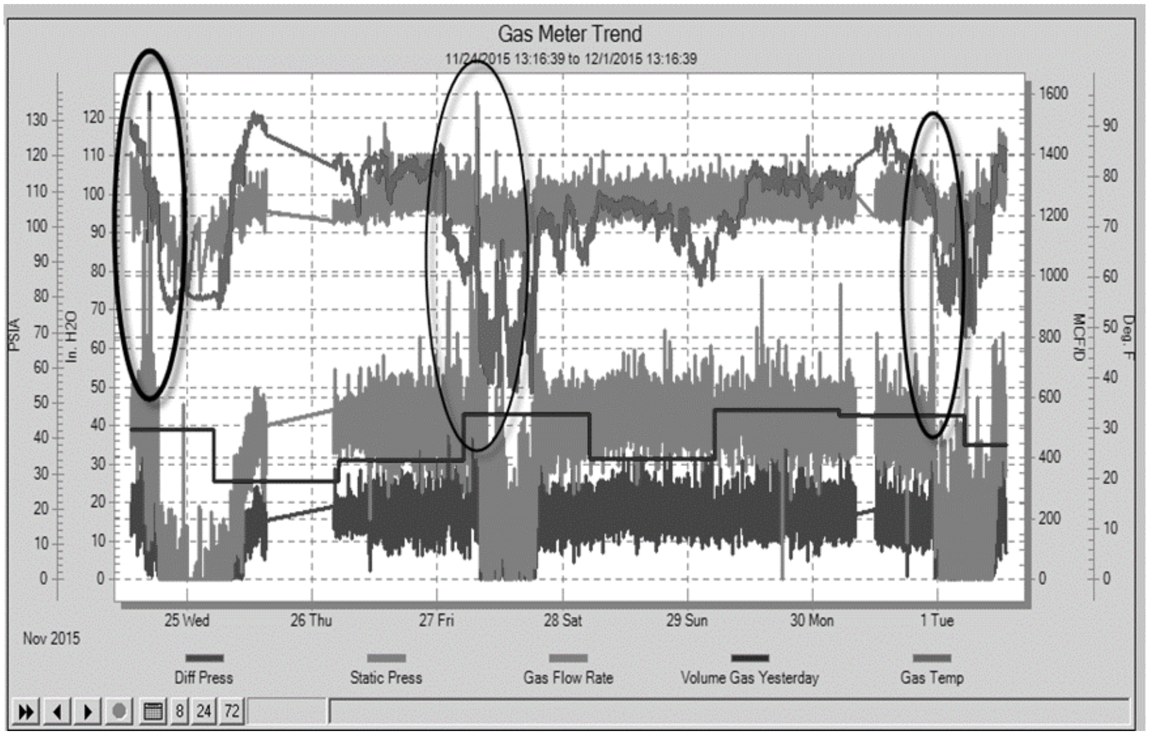

Figure 4. Gas rate cycling above and below critical rate.

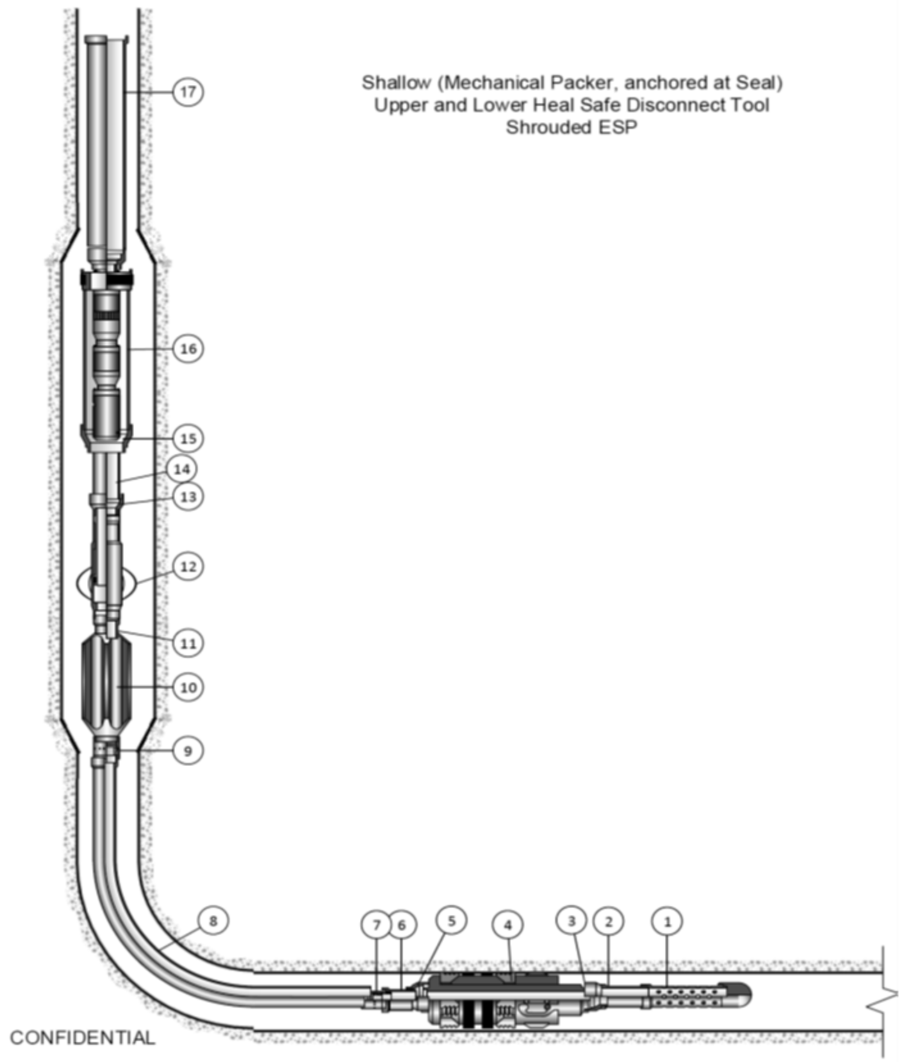

Figure 5. Production Enhancement Casing Sub (PECS)
Note. PECS has multiple patents pending

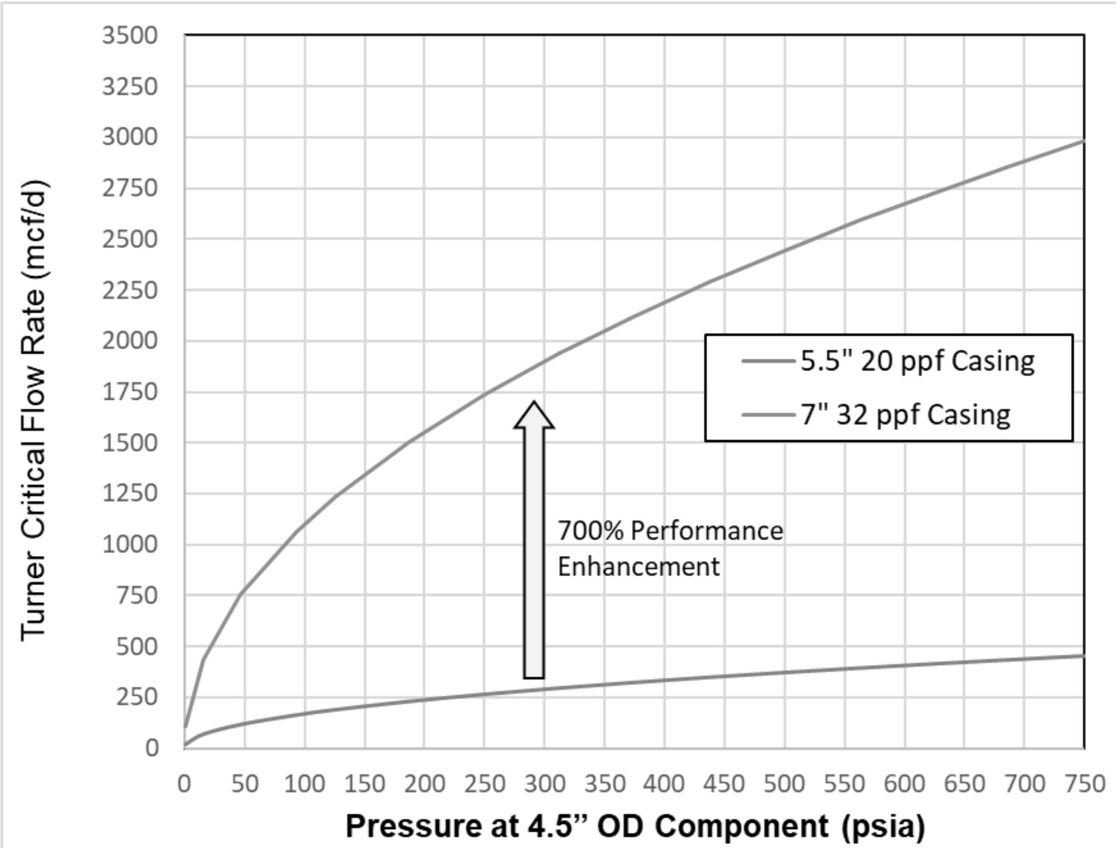

Figure 6. Annular flow area past a 4½ inch OD equipment is 700% greater with PECS.

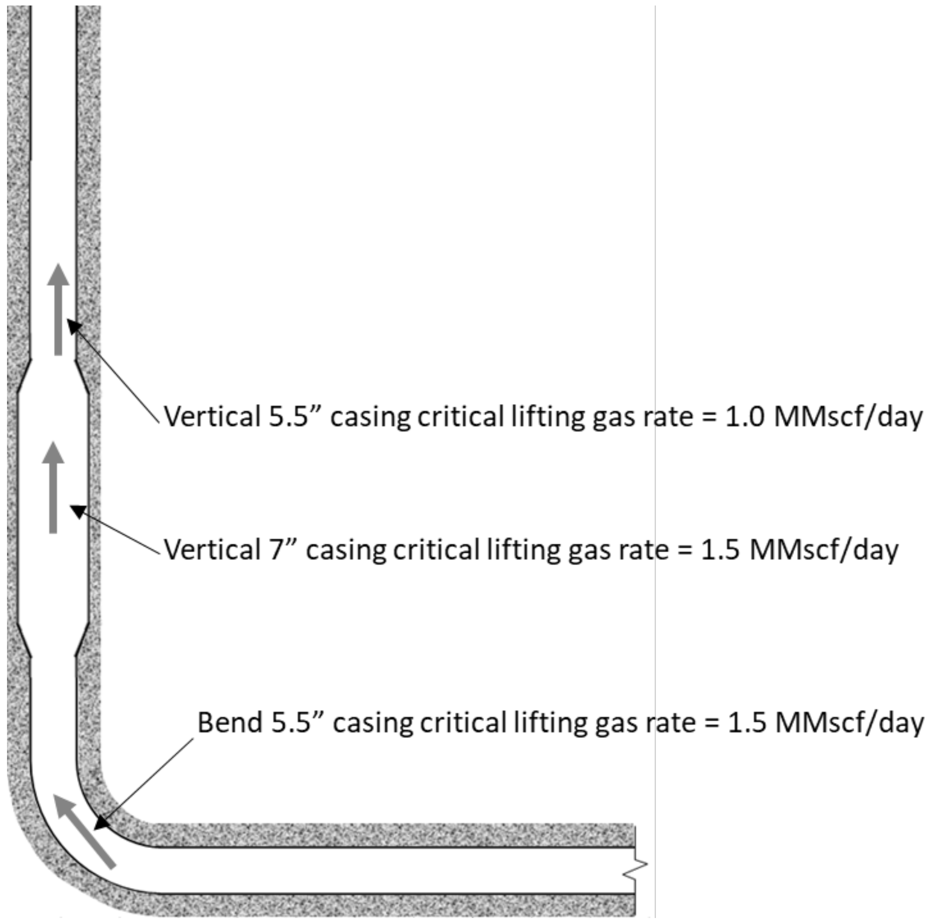

Figure 7. Inclinations in the bend section

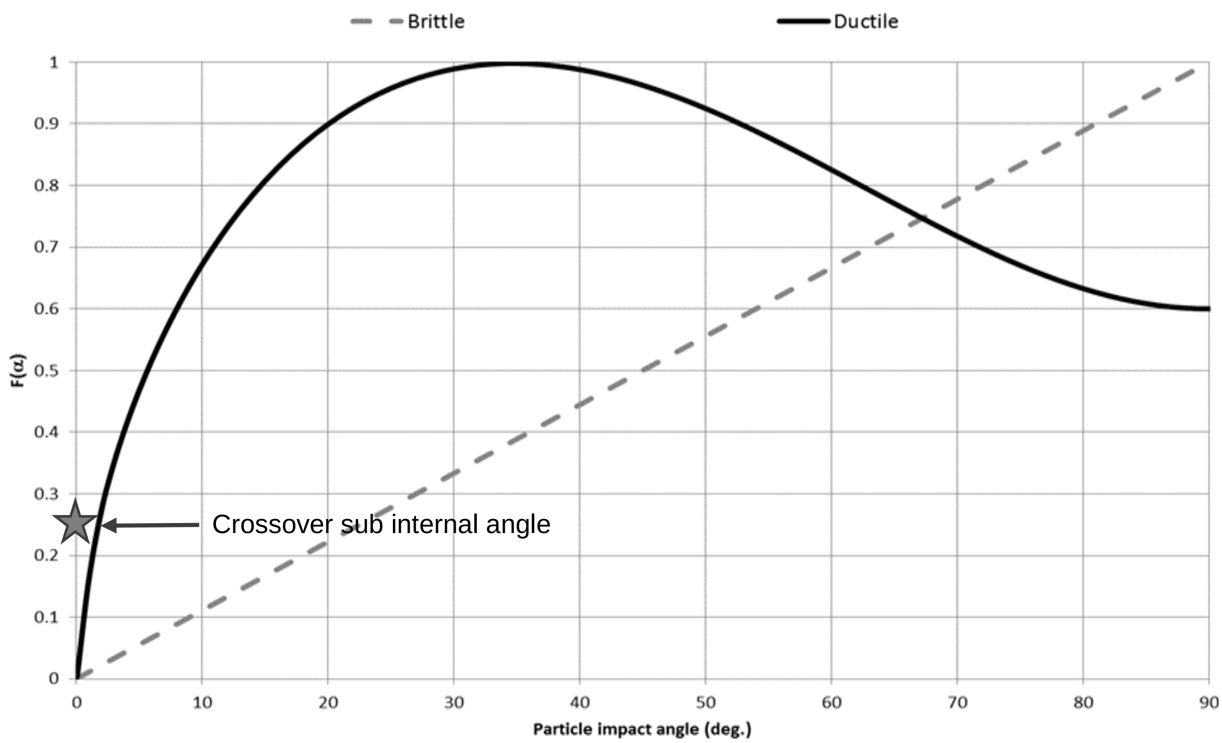

Figure 8. Erosion impact angle dependency. Source. DNVGL-RP-O501 (2015).

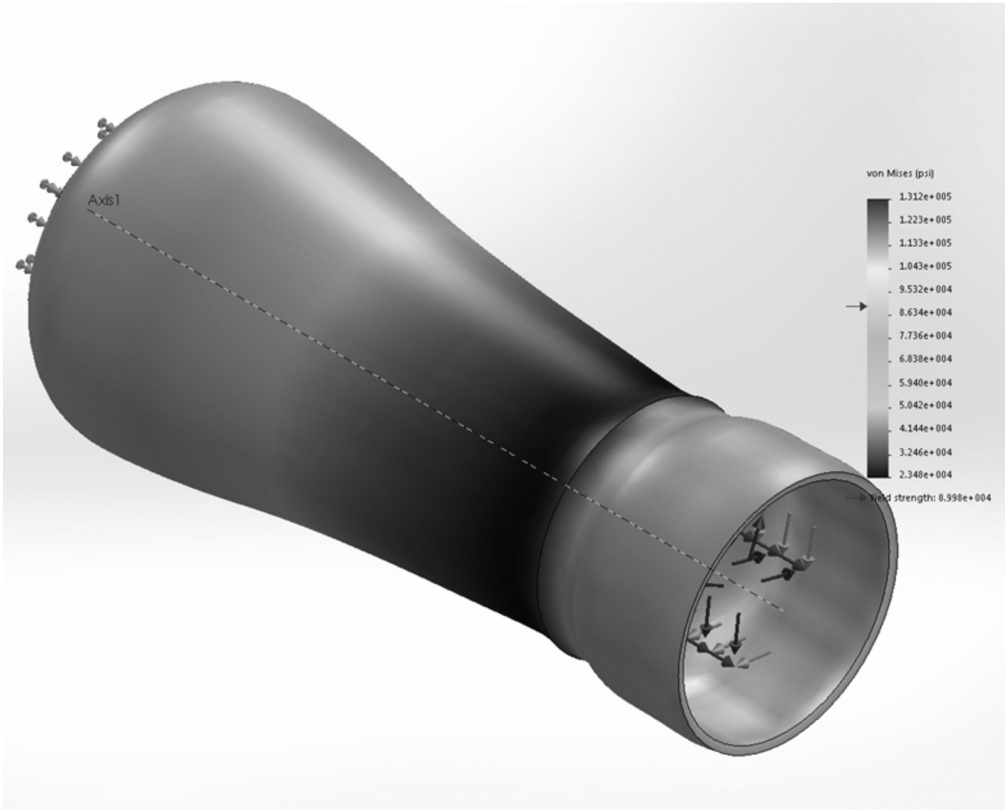

Figure 9. Crossover sub FEA analysis.

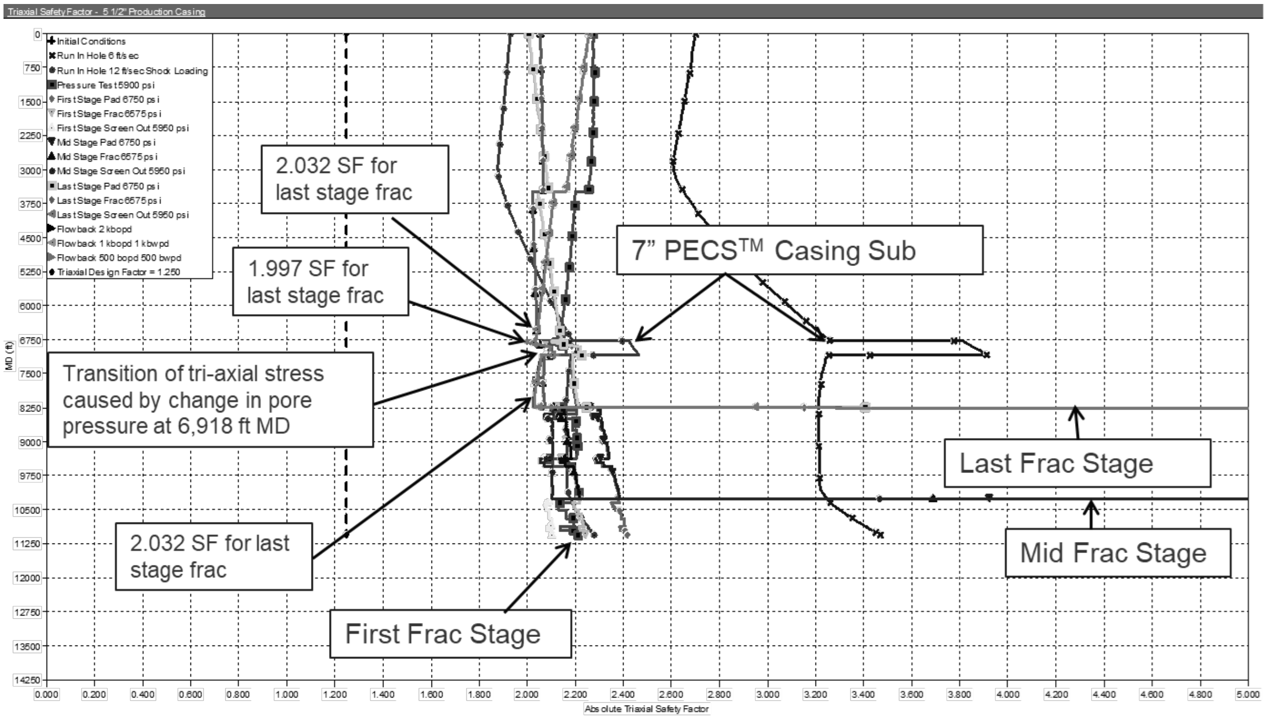

Figure 9. Casing stress analysis for triaxial safety factors.

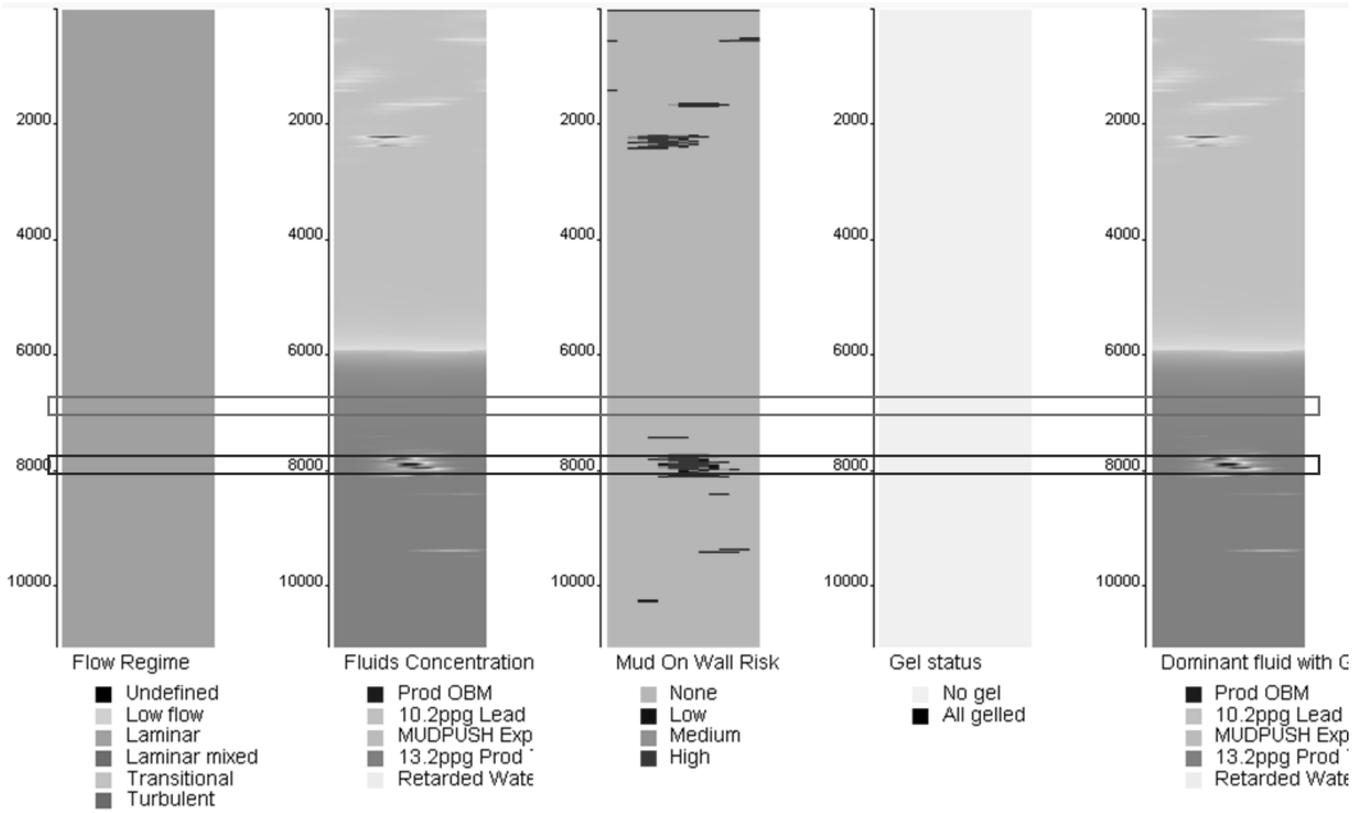

Figure 10. PECS cement job simulation.

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NOMENCLATURE

API	American Petroleum Institute
BHP	bottomhole pressure
ECD	equivalent circulation density
ESP	electric submersible pump
FEA	finite element analysis
OD	outside diameter
PECS	Production Enhancement Casing Sub
PIP	pump intake pressure