

Engineered Chemical Solutions for Enhanced Reliability During Liner-in-Liner Re-Frac Operations

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Abstract

As unconventional reservoirs mature, re-fracturing existing wells has become a strategic and cost-effective method to extend asset life and boost production. Among the more complex re-frac designs is the liner-in-liner completion, which involves installing a new liner inside an existing one to isolate zones and enable targeted stimulation. While operationally advantageous, this approach presents key technical challenges that must be addressed to ensure consistent success.

A critical challenge is achieving a reliable cement job. In under-pressured fracture networks, existing perforations can allow cement to divert to the under-pressured zones, preventing it from reaching the liner top and compromising zonal isolation. To address this, an engineered acid-soluble diverter with an optimized particle size distribution (PSD) was deployed to seal perforations prior to cementing. Field data confirms its effectiveness in enabling proper cement placement and long-term isolation while placing an easily dissolvable material to prevent reservoir damage during the secondary stimulation.

Another challenge is the physical deployment of the new liner within tight annular clearances. Modeling often predicts excessive drag, with potential for pipe buckling. A concentrated pipe-on-pipe lubricant was used to reduce friction and facilitate smooth liner installation. Field results demonstrate repeatable success across multiple wells with coefficient of friction values well below the modeling.

This paper presents a reliable, repeatable methodology for executing liner-in-liner re-fracs using engineered chemical solutions and state-of-the-art equipment for efficient applications. Case studies from multiple basins illustrate improved zonal isolation, reduced mechanical risk, and enhanced operational efficiency.

Introduction

The primary objective of a liner refracturing (liner refrac) intervention is to increase ultimate hydrocarbon recovery from mature, production-declining unconventional wells by enabling access to reservoir intervals that were not effectively stimulated during the initial hydraulic fracturing treatment. As shale and tight-reservoir wells age, depletion, fracture conductivity loss, and increased net effective stress can significantly reduce the effectiveness of the original fracture network. A liner refrac

provides a structured method for re-establishing wellbore integrity and delivering a new, more controlled stimulation treatment that targets previously bypassed or under-stimulated rock.

A key technical advantage of the liner refrac approach is the mechanical isolation it provides. By installing a new casing string or liner and cementing it in place, the operator effectively seals off legacy perforations and depleted fracture clusters. This prevents new fracturing fluids from preferentially flowing into low-pressure, previously stimulated zones, a common failure mode in bullhead refracs. Mechanical isolation ensures that the refracturing energy is correctly directed into unstimulated reservoir sections, improving the probability of generating new fracture initiation points and increasing stimulated rock volume (SRV).

The method also restores internal pressure integrity to the wellbore, which is critical in older wells where casing wear, micro-annuli, or previous frac-induced damage may compromise the ability to safely withstand high treating pressures. By re-establishing a competent pressure envelope, the liner refrac enables the use of modern high-pressure, high-rate fracturing designs that would otherwise pose unacceptable risk of casing burst, collapse, or leak-off into damaged annuli.

Another major benefit is the ability to execute targeted stimulation. Because the new liner allows for the placement of fresh perforations at optimized cluster spacing, operators can design refrac stages that reflect current best practices rather than the often-wide cluster spacing used in early-generation shale completions. This precision enables more uniform cluster efficiency, improved fracture initiation, and better distribution of fluid and proppant across the stage. In many cases, the refrac can be engineered to exploit stress-shadow changes and reservoir pressure gradients that have evolved since the original completion, further enhancing fracture complexity and reservoir contact.

From an economic standpoint, liner refracs offer a compelling alternative to drilling new wells. They leverage existing wellbores, surface infrastructure, and gathering systems, significantly reducing capital expenditure. When executed effectively, liner refracs can deliver production uplifts comparable to or exceeding those of new wells at a fraction of

the cost. This often results in superior capital efficiency relative to bullhead refracs, which suffer from lower stimulation effectiveness due to uncontrolled fluid placement and poor isolation of depleted zones.

Technical Challenges

Casing Integrity Risks Associated With Running a Liner In Liner for Refrac

A liner-in-liner refrac introduces a series of technical challenges that must be carefully evaluated during candidate selection, design, and execution.

Running a liner inside an existing casing for refracturing introduces a distinct set of mechanical and operational risks that can compromise casing integrity even before the stimulation treatment begins. The act of deploying a second liner through an aging, potentially damaged wellbore places additional mechanical loads on the original casing string, which may already be weakened by years of production, pressure cycling, corrosion, or previous interventions. As the liner is run in hole, the combination of axial loads, bending stresses, and localized contact forces can exacerbate pre-existing defects such as ovalization, wear, or micro-cracks. In wells with significant doglegs or tortuosity, the liner may drag or hang up, transferring excessive side-wall forces to the casing and increasing the likelihood of deformation or collapse.

The reduced annular clearance between the new liner and the original casing amplifies these risks. Tight clearances increase the potential for differential sticking, debris bridging, or mechanical interference, any of which can generate sudden load spikes on the casing. If the casing has experienced thinning from corrosion or erosion, these load spikes may exceed its remaining collapse or burst capacity. Additionally, the process of rotating or reciprocating the liner to overcome friction can introduce torsional stresses that the original casing was not designed to withstand in its current degraded condition.

Operational practices can also influence casing failure risk. Running the liner too quickly, applying excessive set-down weight, or forcing the liner through tight spots can all impose loads that exceed the casing's degraded structural capacity. Wells with high dogleg severity or poorly centralized casing are particularly vulnerable, as the liner may apply concentrated forces at specific contact points.

Sealing Off Existing Perforations and Fractures in Liner-in-Liner Refracturing

A fundamental requirement for the success of any liner-in-liner refrac is the complete hydraulic isolation of existing perforations and the fracture networks connected to them. In mature unconventional wells, the original perforations typically communicate with a system of depleted fractures that have undergone significant pressure drawdown since the initial completion. These depleted fracture clusters act as dominant low-pressure sinks during a bullhead refrac treatment. If they remain open, they attract the majority of the injected fluid, preventing the buildup of sufficient near-wellbore pressure to initiate new fractures in unstimulated rock. As a result, the bullhead refrac simply re-pressurizes the legacy fracture

network rather than creating new reservoir contact, yielding minimal incremental recovery.

The pressure contrast between depleted and undepleted zones amplifies this challenge. In unconventional reservoirs, depletion can reduce pore pressure by several thousand psi, creating a strong hydraulic gradient that directs fluid into the old fracture system. This behavior is well documented in field diagnostics, where operators observe rapid pressure drops, erratic treating pressures, and early screenouts when legacy perforations are not effectively isolated. These pressure responses indicate that the treatment is being diverted into the original fracture geometry rather than generating new fracture initiation points. Without sealing off the old perforations, the refrac cannot overcome the breakdown pressure of fresh rock, and the stimulation fails to expand the stimulated rock volume.

Sealing off existing perforations is also essential for restoring wellbore pressure integrity. Many older wells exhibit casing wear, micro-annuli, or localized deformation near the original perforation clusters due to years of production, thermal cycling, and previous frac operations. If high-pressure fracturing fluid is allowed to enter these compromised intervals, it can exacerbate casing damage, initiate new leak paths, or even induce casing failure. Installing a new liner and cement sheath provides a renewed pressure envelope that allows the operator to safely apply the high treating pressures required for modern refrac designs. This restored integrity is particularly important in wells where the original casing has degraded to the point that it can no longer withstand the mechanical loads associated with high-rate stimulation.

Another critical aspect of sealing off legacy perforations is the improvement of fracture initiation control. When these pathways remain open, new fractures tend to re-enter the old system rather than propagate into fresh reservoir rock. By isolating legacy perforations, the operator effectively treats the refracted interval as a new completion, allowing improved control over perforation placement and design and enabling more predictable fracture initiation from newly created clusters. This leads to improved cluster efficiency, more uniform fluid distribution, and a greater likelihood of generating a complex fracture network that accesses previously unstimulated rock.

The economic impact of achieving proper isolation is significant. When refracturing treatments leak off into old perforations, they consume excess fluid and proppant without creating meaningful new reservoir contact, driving up costs while yielding minimal production gains. This makes it imperative to seal near-wellbore perforations prior to the liner run, both to enable effective debris cleanout and to ensure the planned top of cement (TOC) is achieved. Relying on cement alone while legacy perforations remain exposed increases the risk of lost circulation, which can prevent full interval isolation and compromise refrac effectiveness.

By contrast, a liner-in-liner system that fully isolates legacy intervals directs nearly all treatment energy into undepleted rock, maximizing incremental recovery per dollar invested. For many operators, the difference between a successful and unsuccessful refrac program ultimately hinges on the quality and reliability of this isolation.

Long-term production performance also depends on sealing off existing perforations. A fully isolated liner ensures that the refrac creates a new, independent fracture network capable of sustaining production over the long term. This independence is particularly important in reservoirs where depletion-driven stress changes have altered fracture conductivity or where the original fracture network has become partially propped-off or damaged.

In summary, sealing off existing perforations and fractures is not merely a procedural step but a foundational requirement for the technical and economic success of a liner-in-liner refracturing operation. It enables controlled fracture initiation, restores wellbore integrity, prevents fluid loss into depleted zones, and ensures that the refrac treatment generates new reservoir contact rather than re-stimulating old, ineffective fracture pathways. Without complete hydraulic isolation, the refrac cannot achieve its intended objectives, and the well is unlikely to realize meaningful incremental recovery.

Pre-Application Design and Modeling

Modeling the deployment of a liner inside an existing casing for refracturing is essential for quantifying mechanical loads, anticipating operational risks, and defining safe operating envelopes in mature wells. Because the original casing is often degraded by corrosion, wear, and prior stimulation cycles, the margin between predicted loads and remaining structural capacity can be narrow. A robust modeling process therefore focuses on torque and drag behavior, side forces, triaxial stress states, and stuck-risk scenarios along the entire well trajectory, with particular emphasis on high-dogleg and horizontal sections where contact forces are greatest.

At the core of most liner-running models is a torque-and-drag calculation that resolves axial tension, compression, and frictional forces along the liner as it is run in hole. These models incorporate wellbore geometry, dogleg severity, liner and casing dimensions, friction coefficients, and fluid properties to estimate hook load, surface torque, and side forces at each depth increment. By simulating different running practices—such as varying running speed, rotation, or circulation rates—the engineer can identify depth intervals where drag is likely to approach critical levels or where buckling and excessive side loading may occur. Advanced implementations extend this analysis to full triaxial stress evaluation, allowing prediction of local stress states in the casing and liner under combined axial, bending, and torsional loads.

An assessment of the risk of stuck pipe is a key outcome of this modeling. By combining torque-and-drag predictions with real-time or historical friction data, operators can identify zones where the liner is most likely to experience differential sticking, debris bridging, or mechanical interference. Simulation tools are increasingly used to test contingency strategies—such as the use of reamers, circulation subs, or modified running procedures—before field execution, enabling teams to evaluate how changes in circulation, fluid rheology, or string configuration affect drag trends and recovery options if the liner begins to stick. This proactive approach is particularly

important in liner-in-liner refracs, where annular clearances are small and the consequences of a stuck liner can be severe.

Mechanical modeling also provides a basis for evaluating casing integrity during liner deployment. By mapping predicted side forces and contact points along the wellbore, engineers can identify locations where the liner is likely to impose high localized loads on a weakened casing. These loads can then be compared against the reduced burst, collapse, and yield capacities of the aged casing, considering corrosion-induced wall loss and prior plastic deformation. In some models, torque-and-drag outputs are coupled with structural models that compute buckling risk, enabling a more rigorous assessment of whether the casing can safely withstand the combined effects of liner running and subsequent refracturing pressures.

Hydraulic effects are also incorporated into the modeling of liner-in-liner deployment. Circulation modeling helps predict equivalent circulating density, pressure losses, and the impact of fluid rheology on drag and torque. In narrow clearances, small changes in fluid properties or pump rates can significantly alter frictional behavior and the risk of surge and swab. Simulation of circulation paths and pressure profiles allows engineers to optimize fluid systems and pumping schedules to minimize surge-induced casing loads while maintaining sufficient hole cleaning and cooling of the liner during deployment.

Finally, modeling plays a critical role in defining operational envelopes and real-time monitoring strategies. Pre-job simulations generate expected hook-load, torque, and stand-by-stand trends that can be compared with surface measurements during the actual liner run. Deviations from modeled behavior—such as unexpected increases in drag or torque—serve as early indicators of developing problems, prompting adjustments in running speed, rotation, or circulation before a stuck event or casing overload occurs. In this way, mechanical modeling of liner-in-liner deployment is not merely a design tool but an integral part of risk management and real-time decision-making in refracturing operations.

Application

Sealing Existing Fractures Considerations

The use of Single Sack Acid-Soluble Sealants (SSASS) with an engineered Particle Size Distribution (PSD) range is a critical technique for temporarily sealing existing fractures and perforations during refracturing operations. Chemical diverters—particularly SSASS systems—provide a temporary, degradable barrier that isolates depleted fracture networks creating a favorable environment to successfully perform a cement job, without losses and achieving top of cement to the desired height. The SSASS role is especially critical in wells where mechanical isolation alone cannot fully eliminate communication with old fracture clusters.

SSASS diverters function by bridging and plugging existing fractures, perforations, and high-permeability pathways. These materials are engineered to enter the fracture system and form a temporary seal that withstands the differential pressures encountered during cementing and while running the liner. This

diversion effect is central to the success of liner-in-liner refracs, where the reduced annular space and altered stress environment make it difficult to rely solely on mechanical isolation.

During liner deployment, SSASS diverters are spotted in the wellbore to pre-emptively seal existing perforations and fractures that might otherwise take fluid. This is especially important in wells with significant depletion, where legacy fractures act as low-pressure sinks. If these fractures remain open during liner running, they can draw in completion fluids, destabilize the wellbore, or create pressure imbalances that complicate liner placement. By temporarily sealing these pathways, diverters help maintain a stable hydraulic environment, reduce fluid losses, and improve the ability to condition the wellbore before the liner is set.

Once the liner is installed, SSASS diverters continue to play a critical role in ensuring effective refracturing. Even with a new liner in place, micro-annuli, cement channels, or natural fracture intersections may allow communication with depleted zones. SSASS diverters in place before the cement job temporarily plug these pathways and provide a more conducive environment for a successful cement job with superior bond, no losses and required cement height.

The effectiveness of SSASS diverters in sealing fractures depends heavily on particle-size distribution and material properties. Research and field data show that multimodal particulate blends are capable of bridging a wide range of fracture apertures, enabling diversion in both near-wellbore and far-field regions. This capability is essential in refracturing environments, where fracture widths vary due to stress changes, depletion, and prior stimulation. When pumped ahead of or during liner deployment, diverters can temporarily block these variable-width pathways, reducing the risk of fluid loss and improving cement placement once the liner is in position. The placement of diverters is a critical operational step. Numerical simulations and laboratory studies show that granular diverter materials can effectively seal old fractures when pumped at appropriate concentrations and PSDs. The field generated data highlights the importance of matching diverter particle size to the aperture of existing fractures to achieve effective bridging and sealing. In refracturing environments, where fracture widths vary due to depletion and stress changes, multimodal or engineered particle blends are often required to ensure robust plugging performance.

In summary, acid-soluble diverters play a vital role in liner-in-liner refracturing by providing temporary, degradable seals that isolate depleted fracture networks and enable effective deployment of the new liner and successful cementing. Their ability to temporarily plug existing fractures, withstand high differential pressures, and then dissolve with a cursory acid treatment without damaging the formation makes them an indispensable tool in modern refrac design. When combined with mechanical isolation provided by the new liner, SSASS diverters significantly enhance the probability of achieving meaningful incremental recovery from mature unconventional wells.

Application Procedure - A 25-bbl loss-circulation pill was prepared and deployed to seal the near-wellbore perforations

prior to the liner run. This step was critical for minimizing fluid losses, enabling effective debris cleanout, and ensuring that the planned top of cement (TOC) could be achieved during subsequent cementing operations. The following procedure was executed:

System Preparation -The mixing pit and mixing manifold were thoroughly rinsed with clean water to remove residual solids and prevent cross-contamination with previous fluids. Establishing a clean system ensured consistent rheology and predictable hydration of the viscosifying agents.

Base Fluid Conditioning - Fresh water was added to the mixing pit and conditioned to a funnel viscosity of 50–60 sec/qt. Achieving this baseline viscosity prior to SSASS addition was essential for maintaining suspension stability and preventing premature settling of the bridging materials.

SSASS Pill Formulation (25 bbl, 40 ppb total concentration) The pill was mixed in a controlled sequence to ensure proper hydration and dispersion of all components:

- Liquid Xanthan (5–10 gal) was added first and allowed to hydrate for 5–10 minutes. This step established the foundational viscosity required to support the high-solids load. Additional Liquid Xanthan was added as needed to maintain the target 50–60 sec/qt viscosity.

- SSASS was then introduced to achieve the required 40 ppb concentration. The material was added gradually to ensure uniform dispersion and prevent agglomeration.

Continuous agitation was maintained throughout mixing to keep the solids fully suspended and to ensure a homogeneous pill.

Pill Placement - Once fully mixed, the entire 25-bbl pill was pumped down the tubing. Fresh water was used as a displacement fluid to push the pill across the perforated interval. Pumping pressures were monitored closely as the pill passed the perforations to identify sealing response, fluid-loss reduction, and pressure-build signatures indicative of fracture bridging.

This pre-liner SSASS treatment was sufficient to seal near-wellbore perforations, reduce losses during the liner run, and create a stable environment for cement placement. Without this step, running cement across exposed perforations could have resulted in significant lost circulation, preventing the TOC from being achieved and compromising interval isolation.

Liner Installation Considerations

Running a liner inside an existing casing during a refracturing operation imposes significant mechanical stresses on both the liner and the host casing. These stresses arise from frictional contact, drag forces, torque buildup, and the risk of differential sticking—conditions that are amplified in mature wells with tortuosity, doglegs, debris, or casing wear. Concentrated Pipe on Pipe Lubricants (CPOP) play a critical role in mitigating these risks by reducing friction coefficients, lowering torque and drag, and improving the overall mechanical efficiency of liner deployment.

CPOP lubricants designed for well construction and casing-running operations have been shown to significantly reduce torque and drag forces. Field data demonstrate that

specialized lubricants can reduce friction coefficients by 35–45%, enabling smoother movement of tubulars through high-deviation or high-contact-force sections. This reduction in friction is particularly important in liner-in-liner refracs, where the annular clearance is already limited and the liner must pass through sections of casing that may have experienced deformation or wear. The ability of CPOP to maintain performance under downhole temperatures and loads makes them critical for liner-in-liner refrac operations, where the liner must traverse long horizontal sections with high normal forces. The result of field applications compared to mechanical modeling conclusively demonstrates that without proper CPOP application, buckling and other pipe failures are much more likely.

CPOP Lubricants also play a key role in preventing stuck pipe during liner deployment. CPOP lubricants are specifically formulated to minimize this risk by reducing the adhesion forces between the liner and the casing or formation surfaces. This is particularly important in refrac candidates where depletion has altered the stress environment and increased the likelihood of sticking events.

The use of CPOP lubricants also contributes to improved operational efficiency. Field data shows that friction-reducing lubricants can decrease drag sufficiently to reduce running time and avoid nonproductive time associated with stuck-pipe events. For example, friction-reducing additives have been shown to decrease friction factors by approximately 10%, resulting in measurable reductions in operational time during tubular deployment. In liner-in-liner refracs, where the margin for mechanical error is small, these efficiency gains translate directly into reduced operational risk and improved reliability. Finally, lubricants help protect the structural integrity of the host casing. By reducing metal-to-metal contact and lowering drag forces, lubricants minimize casing wear during liner deployment. This is especially important in refracturing operations, where the casing must subsequently withstand high treating pressures. Mechanical wear reduction provided by bead-based lubricants has been specifically highlighted as a benefit in casing-running applications.

Application Procedure - Wellbore Cleaning and Lubricant Pill Placement Procedure

Step 1 – Wellbore Cleaning to Remove Debris - Effective wellbore cleaning is essential prior to spotting the lubricant pill and initiating the liner run. The objective is to remove residual solids, perforation debris, and fines that could impede pill placement or interfere with liner deployment.

- **Circulation on Bottom** - Once the clean out assembly is on bottom, the well should be circulated for a minimum of two bottoms-up at a pump rate of 4–5 bpm. The Reynolds method should be used to confirm that the selected flow rate achieved turbulent flow, maximizing hole-cleaning efficiency throughout the lateral.

- **Monitoring Returns** - Returns should be monitored continuously to verify that debris removal is effective and that solids content at surface has decreased to minimal levels. This will ensure that the wellbore is sufficiently conditioned before proceeding.

- **Maintaining Full Circulation** - If any indication of reduced returns or partial losses are observed, 5–10 bbl sweeps of SSASS were pumped as needed to maintain full circulation and stabilize the wellbore.

- **Optional Gel Sweeps** - To further enhance debris transport, operators have the option to pump two 10-bbl gel sweeps. These high-viscosity sweeps help lift any remaining fines or cuttings to surface. Each sweep should be circulated completely out of the wellbore before transitioning to the lubricant pill stage.

Step 2 – Lubricant Liner Pill Placement - Following wellbore cleaning, a lubricant pill is prepared and placed to reduce friction, improve trip-out efficiency, and condition the wellbore ahead of the liner run.

- **Pill Composition and Volume** - A 200-bbl lubricant pill should be mixed and spotted across the lateral and curve. The pill should contain sufficient CPOP, equivalent to approximately 2% by volume, providing enhanced lubricity and improved tubular movement during the liner run.

Liner-Running Performance, Drag Modeling, Field Execution, and Cement Placement Summary

The liner-running operation on Case Study Well 1H provided a high-fidelity dataset for validating the mechanical drag model and assessing the feasibility of deploying a 4-in. refract liner in a long-reach horizontal wellbore. Throughout the run-in-hole sequence, measured hookloads consistently corresponded to low friction factors, with both pick-up and slack-off values ranging from 0.15 to 0.20. These friction factors were significantly below the modeled upper limit at which the liner would continue to slide under its own weight, confirming that the wellbore frictional environment was more favorable than the conservative design case.

A gradual increase in drag was observed below approximately 13,000 ft, coinciding with the transition into higher-inclination sections where normal forces and low-side contact typically rise. Despite this trend, friction factors remained stable and predictable, and at final setting depth the liner continued to move freely with a slack-off friction factor (SOFF) of approximately 0.20. Pre-job modeling had indicated that the worst-case allowable SOFF for self-weight sliding was 0.27, meaning the field-measured values provided a substantial mechanical margin. This close agreement between modeled and measured drag behavior validated the assumptions used to evaluate the remaining subject wells.

Mechanical modeling predicted the onset of helical buckling in the 3½-in. landing string above the kickoff point, and field execution confirmed this behavior. Even with localized buckling, the landing string retained sufficient axial stiffness to transfer weight to the liner shoe. The ability to maintain effective weight transfer under these conditions was critical, as buckling can rapidly degrade axial load transmission if friction factors approach modeled limits. In this case, the measured friction factors remained well below the threshold at which buckling would have become operationally limiting.

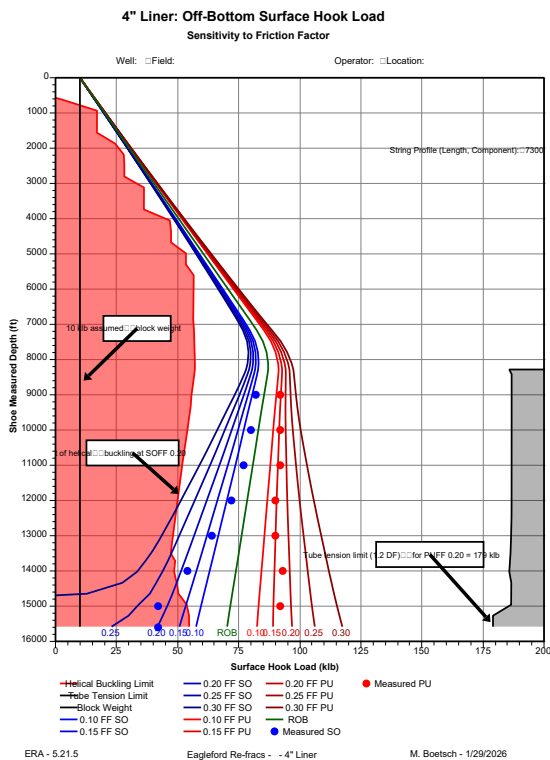


Figure 1 – Off Bottom Hookload – Case Study Well 1H

distributions were comparable. Modeling showed that all wells maintained sufficient axial force transfer for the liner to slide to setting depth, with allowable SOFF values ranging from 0.27 to 0.33 depending on trajectory-specific features. Wells with lower lateral inclination exhibited reduced low-side drag, while wells with higher doglegs experienced increased combined loads when picking up into tension. Even in the most mechanically demanding cases, a moderate and operationally acceptable overpull margin, between 18 and 42 thousand pounds force (klbf), remained available at setting depth.

A key enabler of this predictable mechanical behavior was the hydraulic stability established prior to liner deployment. Before intervention, the static bottomhole pressure (BHP) was estimated at only about 1,500 psi, reflecting the degree of reservoir depletion and the presence of open, low-pressure pathways. In this state, the wellbore was highly susceptible to lost circulation during circulation or cementing. The application of Single Sack Acid Soluble Sealant (SSASS)-based lost-circulation material fundamentally altered this hydraulic environment. By the time the full SSASS program had been applied, the well was supporting a stable hydrostatic column of approximately 3,225 psi BHP, more than double the pre-intervention static pressure. This demonstrated that the near-wellbore sealing was not only effective but also mechanically robust, capable of withstanding the incremental pressure increases associated with liner deployment and cement placement.

This hydraulic stabilization was essential not only for liner running but also for the subsequent cement job. Cement-design software had significantly overestimated equivalent circulating densities (ECDs), predicting bottomhole circulating pressures (BHCP) that appeared marginal relative to the fracture gradient. Field data showed that the true maximum BHCP during cementing was approximately 6,400 psi. While this pressure was insufficient to initiate new fractures in intact rock, it was likely high enough to reopen or extend depleted fracture networks if they had not been sealed beforehand. Because SSASS diverters had already isolated these depleted pathways, the wellbore behaved hydraulically like an intact system, allowing the cement slurry to be placed without losses, pressure fluctuations, or premature dehydration. This stability ensured that the cement column reached the planned top of cement (TOC) without being siphoned into depleted zones.

Equally important to the liner-running performance was the use of Concentrated Pipe-on-Pipe (CPOP) lubricants, which reduced friction coefficients by 35 to 45 percent and played a decisive role in achieving the low friction factors observed in the field. The lubricants minimized metal-to-metal contact, reduced torque buildup, and prevented drag lock-up as the liner traversed worn or ovalized casing sections. Without effective lubrication, the liner would likely have encountered significantly higher drag, potentially exceeding the SOFF threshold for self-weight sliding and increasing the risk of buckling or sticking.

The combined effect of accurate drag modeling, hydraulic stabilization through SSASS diverters, friction reduction through CPOP lubricants, and sufficient landing-string stiffness

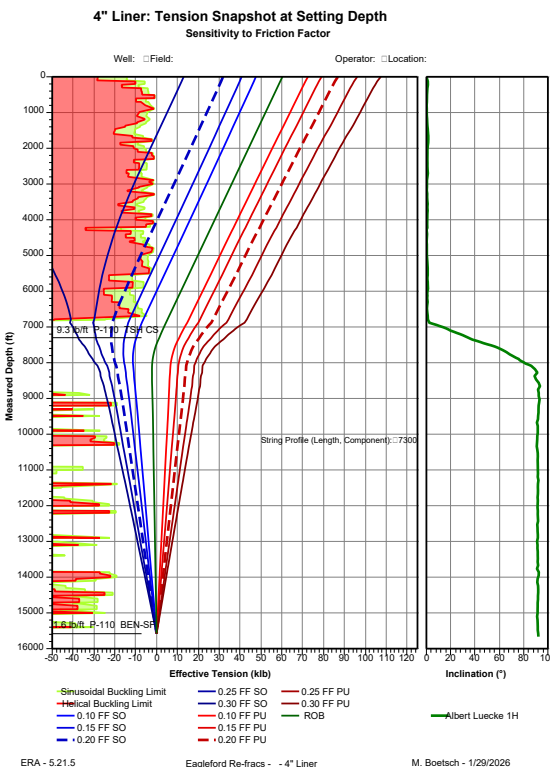


Figure 2 – Tension Snapshot at Setting Depth– Case Study Well 1H

The validated drag model from Case Study Well 1H was then applied to the remaining four subject wells. Because the wells share similar build rates, lateral inclinations, and casing geometries, the predicted drag margins and axial load

resulted in a liner-running operation that remained well within mechanical limits. The liner reached setting depth without requiring rotation or excessive overpull, and the measured hookload behavior closely matched modeled predictions. The same hydraulic stability that enabled predictable drag behavior also ensured a successful cement job, with full TOC and no losses. Case Study Well 1H therefore serves as a high-confidence mechanical and hydraulic benchmark for the remaining wells, demonstrating that liner-in-liner refract installations can be executed reliably when both mechanical and hydraulic conditions are properly controlled.

| Load Summary | Case Study Well 1H |
|--|--------------------|
| Liner Setting Depth, ft | 15582 |
| Liner Top, ft | 7300 |
| Length of Liner, ft | 8282 |
| Worst-Case Allowable SOFF to slide to setting depth, unitless | 0.27 |
| Slackoff tension at setting depth, SOFF 0.20-0.25, klb | 35-21 |
| Pickup tension at setting depth, PUFF 0.20-0.30, klb | 87-107 |
| Available overpull to shoe at setting depth, PUFF 0.20-0.30, klb | 47-29 |
| Maximum allowable surface tension, picking up at setting depth for PUFF 0.20-0.30, klb | 169-174 |
| Maximum bending stress rotating at setting depth, relative to fatigue endurance limit, % | 47% |

Figure 3 – Load Table Summary– Case Study Well 1H

Summary

The liner running operation on Case Study Well 1H provided strong field validation of the drag model used to assess refract liner deployment across a series of long-reach horizontal wells. Measured hookloads corresponded to low effective friction factors in the range of 0.15 to 0.20, well below the modeled self-weight sliding limit of 0.27. These results confirmed that the liner could be deployed to setting depth without rotation or excessive overpull, even in the presence of localized helical buckling within the landing string. Following this validation, the drag model was applied to the remaining wells, demonstrating sufficient drag margin and overpull capacity across all evaluated trajectories.

A critical enabler of this mechanical performance was the hydraulic stability established prior to liner deployment. The well initially exhibited a static bottomhole pressure of approximately 1,500 psi, indicative of significant depletion and open fracture pathways. Application of Single Sack Acid Soluble Sealant (SSASS) restored near-wellbore integrity and increased the supported hydrostatic column to approximately 3,225 psi, preventing fluid losses that would have otherwise compromised cleanout operations, liner deployment, and cement placement. Importantly, SSASS remained hydraulically effective throughout extended operational windows, ensuring that circulation could be maintained even when liner running was delayed due to reaming, casing cleanup, or other operational constraints. This sealing treatment also ensured that the maximum bottomhole circulating pressure during cementing, approximately 6,400 psi, did not induce losses into depleted intervals.

Unlike degradable materials such as polylactic acid (PLA), which are designed to dissolve over time at temperature and impose strict execution windows, SSASS does not dissolve until it is intentionally removed through acidization. Once placed, SSASS continues to provide fracture isolation and loss

control throughout the entire sequence of cleanout, liner placement, and cementing. This eliminates the risk of premature degradation during operational delays and removes the need to re-apply lost circulation material during liner deployment. As a result, once SSASS is placed, the operator is no longer constrained by dissolution timing and can focus on executing the liner installation and cement job without loss-related uncertainty.

Mechanical drag reduction was further supported through the use of Concentrated Pipe-on-Pipe (CPOP) lubricant. CPOP reduced steel-to-steel contact forces between the liner, workstring, and existing casing, particularly across worn or locally ovalized casing sections where contact stresses and frictional resistance are elevated. This friction reduction was critical to maintaining sliding conveyance and minimizing hookload escalation, thereby avoiding the need for rotation in wells where conveyance tools and workstrings are not designed for sustained torsional loading. By lowering frictional demand, CPOP also reduced the severity of helical buckling response within the landing string and preserved overpull margin throughout liner deployment.

In liner-in-liner refract applications, the relevance of SSASS is best framed around its ability to reliably establish and maintain circulation during cleanout, liner placement, and cementing, rather than as a pre-refract diverter intended to directly influence production outcomes. While sealing legacy fracture networks is frequently discussed in the context of bullhead refract diversion efficiency, these mechanisms remain less well quantified for liner-in-casing refracs and are more appropriately addressed within fracture design disciplines. Observations from HFTS-1 Phase 3 further suggest that depleted fracture networks may, in some cases, act as a barrier or repellent to newly initiated fractures, reinforcing the importance of execution quality over assumed fracture re-activation behavior.

Regardless of post-stimulation fracture interaction mechanisms, the prerequisite for a successful liner refract remains the ability to place the liner at depth and achieve a competent cement sheath without losses. Without effective near-wellbore sealing, hydraulic stability, and friction control, liner deployment and cementing execution become the limiting factors, ultimately constraining refract effectiveness. In Case Study Well 1H, the combined application of SSASS, CPOP lubrication, and validated drag modeling allowed these mechanical and hydraulic requirements to be met consistently.

Overall, Case Study Well 1H demonstrated that liner-in-liner refract installations can be executed reliably when near-wellbore hydraulic integrity is preserved and frictional risks are actively managed, establishing a strong operational benchmark for similar wells in the development area.

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Nomenclature

PSD – Particle Size Distribution
SRV – Simulated Rock Volume
TOC – Top of Cement
SSASS – Single Sack Acid Soluble Sealants
CPOP - Concentrated Pipe on Pipe Lubricants
BPM – Barrels per Minute
BBL - Barrel
SOFF - Slack-Off Friction Factor
Klbf - thousand pounds force
BHP- Bottom Hole Pressure
ECD – Equivalent Circulating Density
BHCP – Bottom Hole Circulating Pressure
PLA – Polylactic acid