ENGINEERING A PORTFOLIO OF SOLUTIONS TO EXPAND THE APPLICATION ENVELOPE AND ADDRESS RELIABILITY CHALLENGES IN MODERN ROD LIFT OPERATIONS

Jordan Anderson, Francisco More, Esteban Oliva
Tenaris

INTRODUCTION

Unconventional wells have pushed reciprocating rod lift into deeper, higher-rate applications, expanding the operating envelope expected from the full system (pumping unit, polished rod, sucker rods, couplings, sinker bars/rods, downhole pumps, gas handling, and accessories). Industry adoption of longer-stroke pumping units, fiberglass rods, and larger-diameter rod strings has enabled higher capacity, but reliability has not always kept pace. In these modern profiles—often characterized by high inclination and dogleg severity, as well as various curve sections—operators commonly see multiple failure mechanisms occurring together, including tubing wear, compression/buckling and related bending fatigue, erosion-corrosion and accelerated corrosion fatigue, and connection reliability issues. This paper focuses on how sucker-rod-string component selection and integrated design practices can expand production capability from deep unconventional wells while improving reliability when operating at higher loads, higher velocities, and in more aggressive environments.

ENGINEERING CHALLENGES IN EXPANDED-ENVELOPE ROD LIFT APPLICATIONS

As operators target higher early-life production in unconventional wells, reliability becomes a limiting factor as operating conditions intensify. The primary challenges observed by the authors in expanded-envelope rod-lift applications include:

- **Tubing wear** driven by complex wellbore profiles, buckling-induced sideloads, higher rod–tubing contact frequency, and abrasive/tribocorrosion mechanisms.
- **Compression and buckling**, leading to elevated rod–tubing contact, loss of connection displacement, and increased risk of bending-related damage.
- **Erosion–corrosion and corrosion-fatigue**, intensified by higher relative fluid velocities, aggressive environments, and complex multiaxial stress states.
- **Connection reliability limitations**, as combined loading, bending, and buckling increasingly exceed legacy design assumptions.

- **Sucker rod true loading envelope being exceeded** resulting in accelerated corrosion-fatigue in standard diameters of both standard and high-strength grades.

Figure 1. Various failures featuring above mentioned mechanisms

SYSTEM ENGINEERING VS. ISOLATED FIXES

The challenges outlined above rarely occur independently. In modern unconventional wells, multiple mechanisms—tubing wear, compression and buckling, corrosion-driven damage, elevated tensile loading, and connection sensitivity—often appear simultaneously or cycle through the same well over its operating life. Relying on reactive, isolated fixes aimed at a single observed failure mode can therefore fall short of expectations. Understanding these challenges at the root-cause level enabled the authors to move from reactive mitigation toward engineered process controls, forming the basis for the solutions discussed in the following sections.

A more robust and repeatable approach is to **anticipate and address the highest-risk mechanisms concurrently**, especially in early-life unconventional wells where high production rates, deeper pump landings, and aggressive operating conditions converge. This means designing and operating rod-lift systems with the expectation that **tension, compression, wear drivers, relative fluid velocity, and corrosive environments** will all influence reliability at the same time and must be managed together rather than in sequence. These wells often require a more aggressive design approach to achieve reliability.

The following sections describe how these major challenges were addressed through root cause analysis, targeted engineering solutions, and how their deliberate integration into a single rod-lift system ultimately delivered reliability gains beyond what any individual solution could achieve.

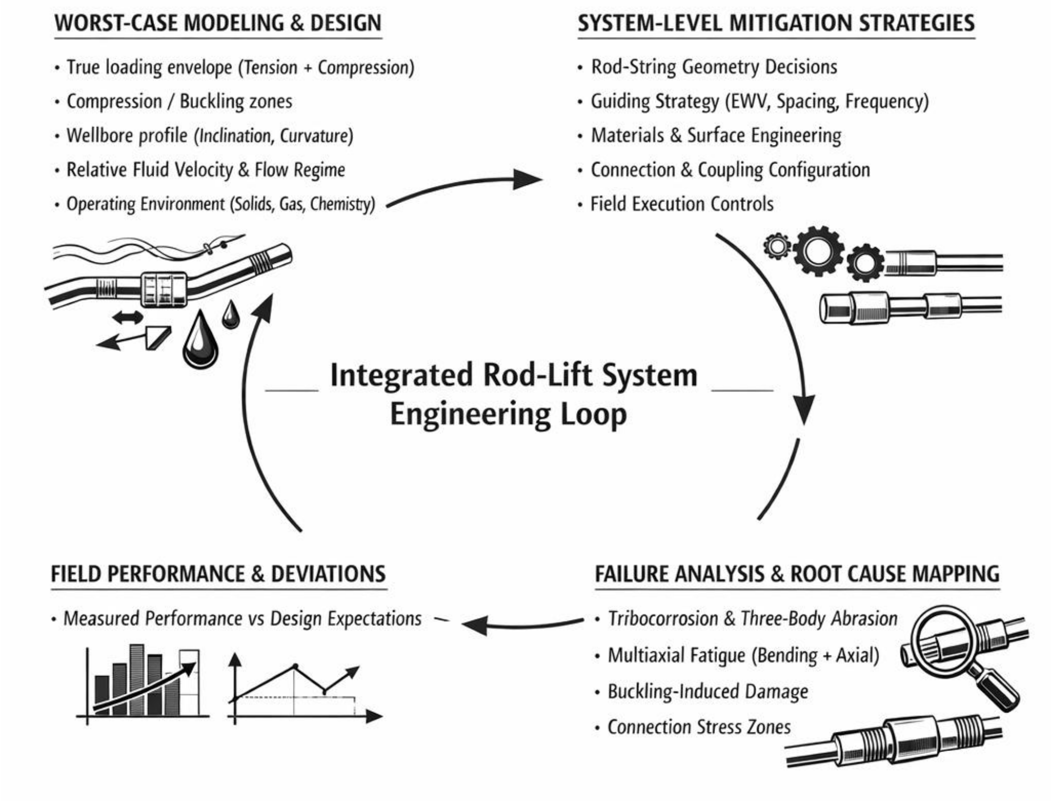


Figure 2. Conceptual Diagram of the system engineering loop

ROD STRING DESIGN UNDER EXPANDED OPERATING ENVELOPES

A key component of this system-level strategy is **holistic rod-string design**—evaluating the string under the combined influence of worst-case tensile and compressive loads, wear scenarios, polished-rod velocity (and therefore relative fluid velocity), and environmental severity. Designing for these coupled conditions establishes a foundation on which guiding strategies, material selection, and connection reliability measures can be layered effectively.

Fatigue Loading Considerations

When evaluating fatigue loading capabilities, the entire load path—from pumping unit to polished rod, through the rod body, couplings, and sinker section—must be considered as a single integrated system. Industry responses to higher tensile demands have included the development of longer-stroke units, higher-capacity gearboxes, fiberglass sections, and larger-diameter steel rods. The authors have advanced several design adaptations intended to increase axial load capacity without requiring larger tubing or major system redesign. These include:

- **high-strength couplings** manufactured using a **high-speed laser deposition process**, offering increased fatigue resistance and improved surface characteristics for environments prone to tribocorrosion and three-body abrasion
- **1-1/8 in. body × 1 in. pin sucker rod geometry**, enabling higher load capacity in the upper tapers while remaining compatible with standard 2-7/8 in. tubing

- **1-1/8 in. × 7/8 in. pin configuration for sinker sections**, providing a stronger connection for high axial load applications, and heavy sinker tapers

Compression and Buckling Loads – Design Best Practices

Compression and buckling remain some of the most evident and impactful challenges in modern rod-lifted wells. The authors previously dedicated an entire SWPSC paper to this topic, *Sinker Section Design to Reduce Buckling-Related Failures*, which provides a detailed explanation of buckling mechanics and sinker-section strategies (Anderson & Oliva, 2024). The key principles relevant to this work are summarized below.

- **Model for worst-case conditions, not average conditions.** This includes iterating pump fillage and pump-intake pressure scenarios, considering the maximum strokes per minute likely to occur, and accounting for buoyancy effects in bottom-minimum-stress calculations.
- **Adding supports through guides is substantially more effective than increasing sinker diameter alone.** Guides reduce lateral displacement and maintain rod alignment, raising the critical buckling load far more efficiently than simply increasing bar diameter.
- **Heavily guided sinker sections with reduced-pin-diameter rods materially reduce buckling risk.** Designs using eight or more guides per rod and reduced-pin geometries add both stiffness and weight where needed, providing meaningful improvements in buckling prevention and tubing-wear mitigation.

Bending Loads and Multiaxial Fatigue

Buckling and compression generate secondary bending loads, producing multiaxial stress states that can accelerate fatigue. When the rod bows or contacts the tubing, stress concentrations form near the upset (Figure 3) or, in some cases, immediately after the end of a guide. These conditions increase effective stress well above the nominal axial load predicted by conventional design software.

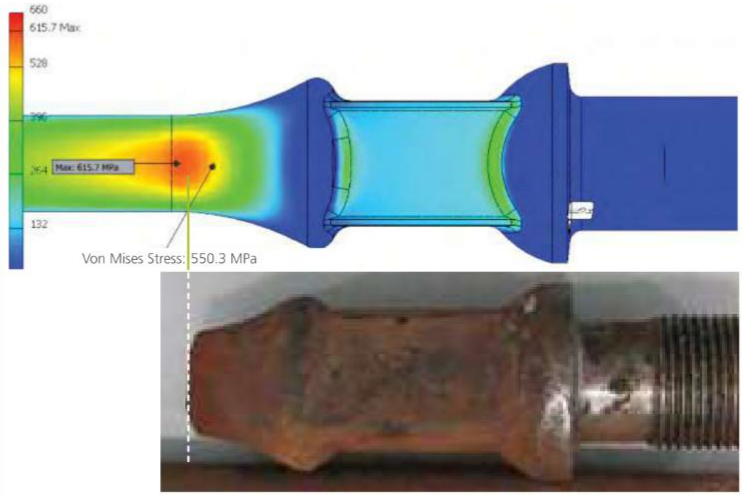


Figure 3. Finite Element Analysis Output of Tension + Bending showing stress concentration and a sucker rod failed in that region

Failure analysis of sections subjected to buckling and compression typically reveals additional cracks (secondary cracks) aligned longitudinally with the area where the failure begins (Figure 4). Lack of secondary cracks on the opposite side (180° from initiation) of the failure zone further supports the hypothesis that the component was subjected to Bending Loads and Multiaxial Fatigue.

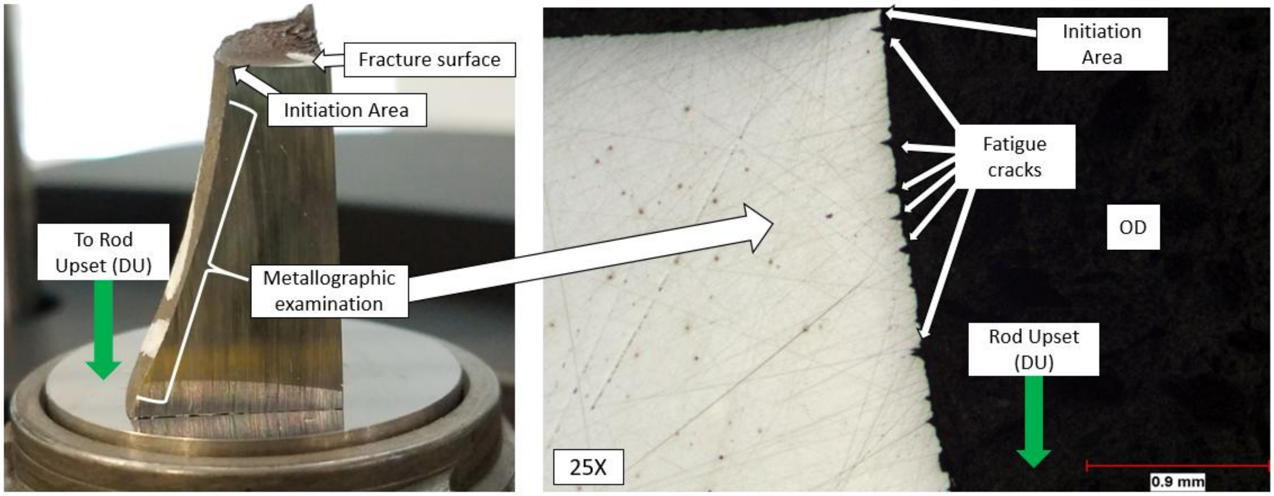


Figure 4. Optical Microscopy images at 25x, of a longitudinal section through the fracture surface.

Mitigation approaches mirror those used for buckling:

- Extending sinker tapers to eliminate compression above the pump
- Adding guides to reduce lateral displacement, and mitigate stress concentrations
- Optimizing guide spacing to minimize bending

The authors contributed to the development of a **9-guides-per-rod optimized for compression (OfC) design**, with three guides placed near each connection and three distributed through the mid-section of the rod. This configuration increases available wear volume at the ends of the rod—where erodible wear volume is needed—while still providing the distributed support needed to prevent mid-span deflection and associated stress concentrations.

Figure 5. Optimized for Compression Guide Configuration

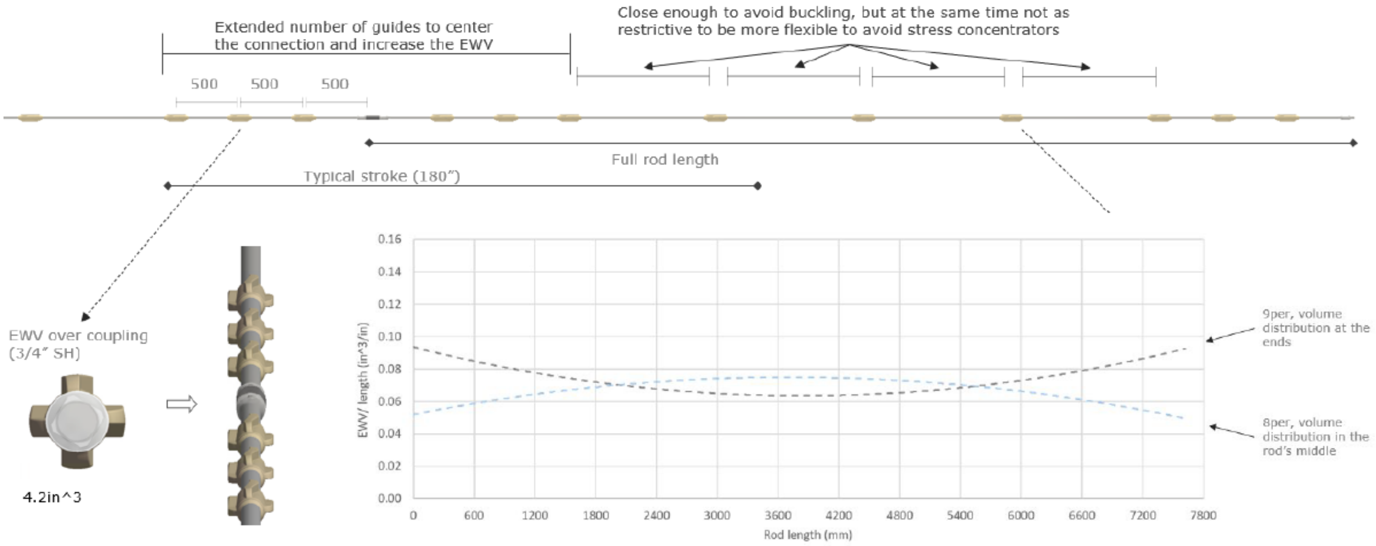


Figure 6. Erodible wear volume distribution comparison

Deviated-Well Bending Effects

Deviation alone can also introduce bending-induced multiaxial stress, independent of compression. Guides help in these scenarios by distributing curvature along the rod body rather than permitting stress to focus near the upset or at abrupt diameter transitions. When designing rod strings for highly deviated sections, it is often advantageous to extend larger-diameter tapers past the highest-curvature intervals to avoid placing taper changes at the most deviated points in the well path.

Across these cases—buckling, compression, and deviation—the design objective is consistent: **maintain rod centralization and prevent concentrated bending near geometric transitions or connection features.**

While optimized rod string design establishes the mechanical foundation for operating at higher loads and deeper depths, field experience showed that these strategies alone were insufficient to manage tubing wear and corrosion-driven damage under modern operating conditions. This necessitated parallel development of advanced guiding strategies.

GUIDING STRATEGIES & ROD–TUBING INTERACTION

As noted earlier, guides play a central role not only in **compression management** and **buckling mitigation**, but also in shaping the overall **stress distribution** along the rod string. Their contribution to tubing-wear prevention is well known—the guide acts as the sacrificial interface between rod and tubing—but in modern rod-lift wells, the operating conditions that drive tubing wear have become far more complex than in conventional applications.

In many unconventional wells, the actual loads acting on the rod string are not fully identified, as highlighted in prior work by Westerkamp and Mills (Westerkamp & Mills, 2025). This uncertainty, combined with hotter produced fluids, higher SPM, increased deviation, and more turbulent multiphase flow, has created a need for **significantly higher-performance guide materials and guide geometries**.

Coupling selection also influences tubing wear, though not always in the ways industry convention suggests. Laboratory testing indicates that the common belief—*"Spray Metal (SM) couplings wear tubing while T-grade couplings do not"*—does not always hold under modern conditions. Beginning in 2022, extensive R&D by the authors and collaborators focused specifically on **mitigating rod and tubing wear mechanisms**, including tribocorrosion and three-body abrasion (Ghione et al., 2025). That testing showed that the Extreme High Speed Laser-deposited couplings had the best performance in coupling tests on tubing wear and expected tubing life in both tribocorrosion and abrasion mechanisms.

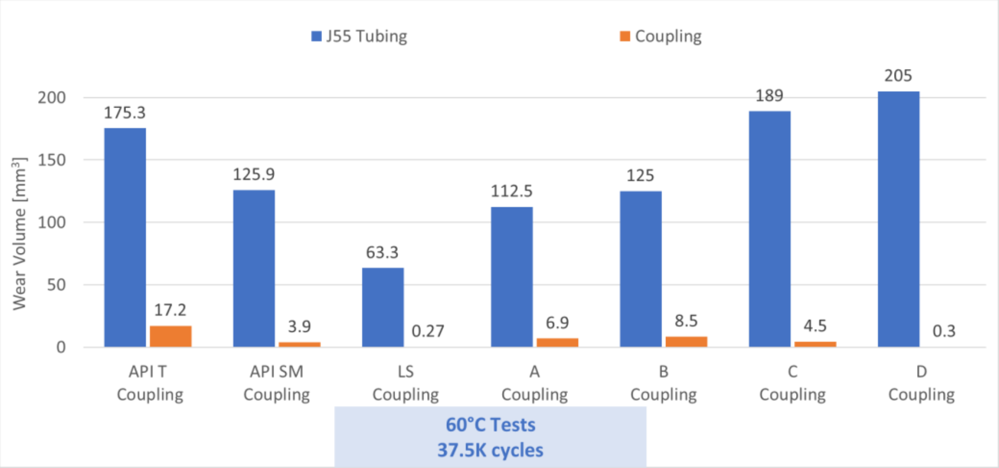


Figure 7. Tubing-coupling wear test results comparing various couplings

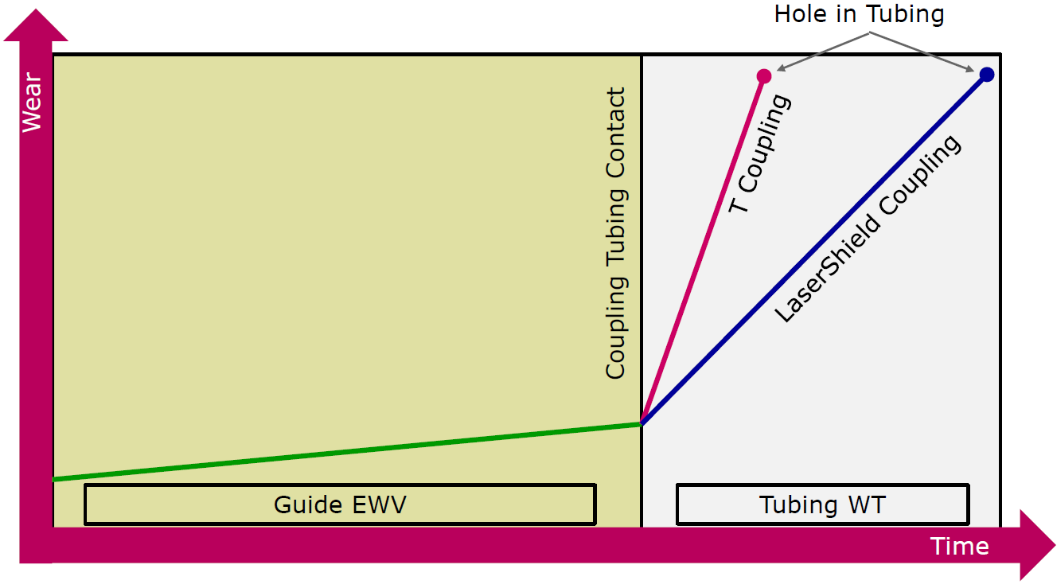


Figure 8. Conceptual graph on tubing wear vs. time

Guide Materials

Guide polymers have undergone a major evolution. The PPA-based materials widely used in conventional wells have increasingly been replaced by **PPS, polyketone (PK) derivatives, and even high-end polymers such as PEEK and PAEK**. These materials offer improved thermal tolerance, reduced chemical degradation, and enhanced wear behavior even in solids-laden environments typical of modern rod-lift operations.

The tribocorrosion and abrasion testing mentioned above demonstrated that **solids and three-body abrasion mechanisms are often the dominant drivers of guide and tubing wear**. Notably, certain PK-based blends showed promising performance in handling sand and solids, reducing both guide wear and tubing material loss compared with other polymers.

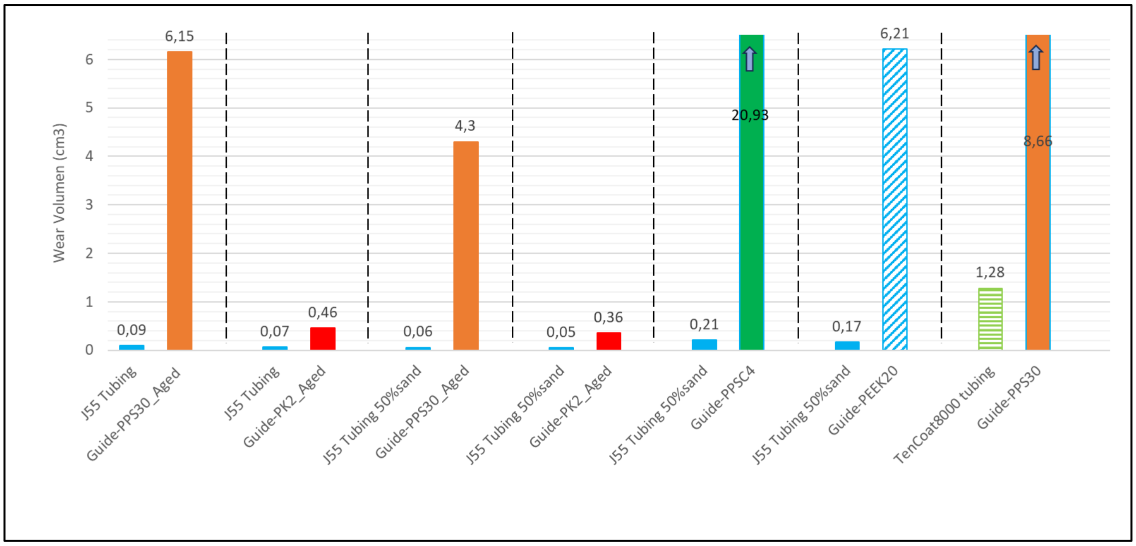


Figure 9. Abrasive wear test results of various guide polymers and tubing

Guide Geometry & Fluid Dynamics

Historically, guide design focused primarily on maximizing **erodible wear volume (EWV)** to extend guide life. While EWV remains essential, recent field observations and CFD analysis have shown that **fluid dynamic behavior** around the guide is equally important. Higher polished-rod velocities and increased relative fluid velocities have amplified **erosion–corrosion mechanisms downstream of guides**, where turbulent eddies disrupt inhibitor films and expose metal surfaces.

Legacy guide geometries were not designed with these erosion-corrosion mechanisms in mind. In response, the authors' organizations developed successive generations of guide profiles that reduce turbulence, shorten eddy length, and smooth transitions between guide fins and rod body (Oliva & Abarca, 2025).

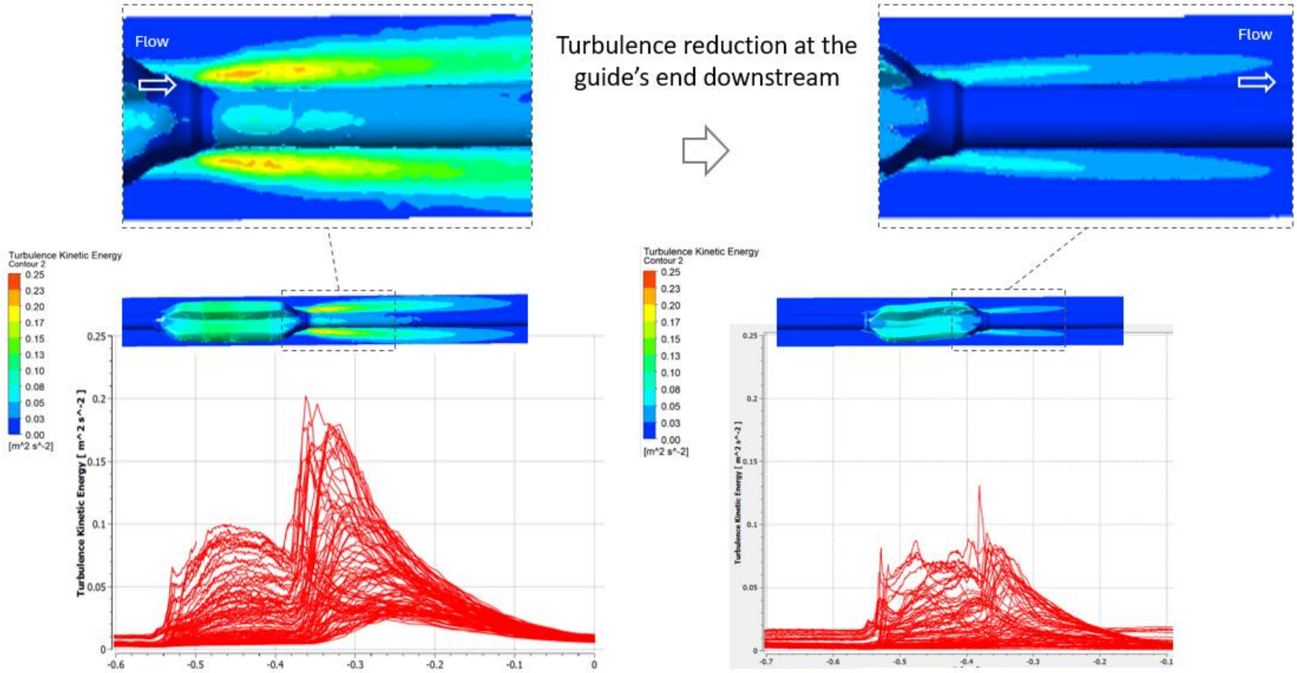


Figure 10. Computation Flow Dynamics (CFD) output showing two guide designs

Guide Frequency & System-Level Effects

A rising trend in the industry is the increased use of **highly guided rod strings**. While partly driven by the need to manage high deviation and compression, the economics are equally compelling. Higher guide count increases:

- Expected runtime before guide and rod replacement
- The period before coupling contact occurs
- Distribution of sideloads, reducing peak normal force per guide
- Resistance to both tribocorrosion and abrasion

As slick rods are replaced with guided rods, system friction does increase. Not due to guide count per rod, but due to replacing steel-on-steel contact with plastic-on-steel interfaces over a larger portion of the string. This introduces an upper practical limit to guide deployment that must be balanced against buckling mitigation and wear control benefits. To be clear, adding more guides in an already guided section does not add more friction because it distributes the normal load over more guides, and the friction coefficient is generally not changing.

Determining the optimal guide usage is therefore a complex engineering judgment requiring scenario modeling, understanding of buckling behavior, load and deviation patterns, and field experience and Root Cause Analysis (RCA) data for the application.

As a result, guiding strategy again has the need for a system-level design approach rather than isolated optimization.

MATERIALS & METALLURGY

Materials and metallurgy remain foundational levers for extending the rod-lift operating envelope. While each individual component—rod body, coupling, guide polymer—has its own requirements, the dominant material-driven limitation across modern wells continues to be **corrosion fatigue**. Elevated tensile loading, intermittent compression, bending, turbulent multiphase flow, and corrosive fluids combine to accelerate crack initiation at the steel surface. Historical practice focused on alloy selection and heat treatment to improve toughness and corrosion tolerance. In recent years, greater emphasis has been placed on **surface finishing and texturing techniques** to delay crack initiation and improve corrosion-fatigue resistance in demanding unconventional environments (Anderson et al., 2023).

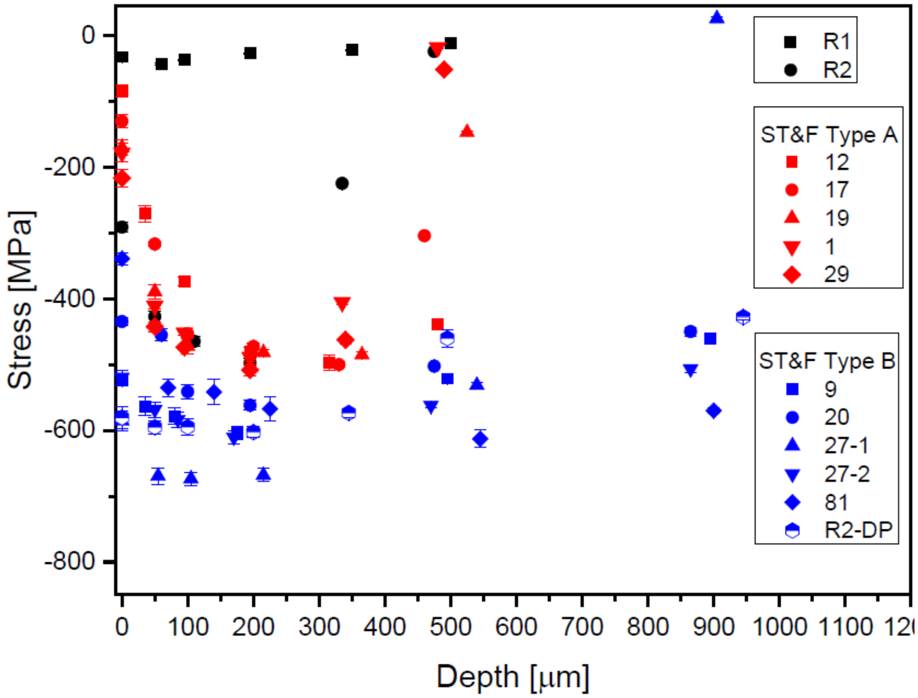


Figure 11. XRD results for various surface texturing and finishing processes.

Rod Materials for High-Load and Corrosive Environments

Premium grades such as high-strength (HS) and critical service (CS) rods leverage low-alloy compositions, quench and tempered heat treatment, and improved cleanliness to enhance toughness and corrosion tolerance. However, as wells move deeper and loads increase, even premium grades can experience elevated corrosion-fatigue when exposed to complex multiaxial stress states. Recent developments in surface-texturing and finishing (ST&F) demonstrate measurable gains in corrosion-fatigue life by reducing surface roughness, redistributing residual stresses, and delaying micro-crack initiation (Anderson et al., 2023).

CONNECTION & COUPLING CONSIDERATIONS

As rod-lift systems are pushed into deeper, higher-load, and more complex wellbores, the sucker-rod connection often becomes the practical limit of the string. Even though connections are typically larger than the rod body, their performance is governed by the combination of **geometry, makeup quality, coupling selection, and how loads are transferred through the threads and shoulders**. When axial loading, bending from deviation, and intermittent compression are all present, fatigue at or near the connection can become the dominant concern.

Connection Mechanics and Makeup

Previous work by the authors on sucker-rod connections has shown that the last engaged threads and the shoulder region are particularly sensitive to how the connection is made up and loaded. Inadequate circumferential displacement, contamination on threads or shoulders, or under-performing tongs can reduce preload and alter how loads are shared between the pin and coupling. Any loss of displacement or face contact increases the stress carried by the thread roots and accelerates fatigue. For this reason, connection reliability is treated as a **process to control**, supported by rod-tong diagnostics, in-field training and running assistance, and systematic failure analysis rather than a procedural step.

Coupling Material, Coating, and Fatigue Capabilities

Coupling selection interacts directly with connection performance. Material and heat treatment define the **fatigue capability** of the connection. Conventional options such as T-grade couplings and traditional spray-metal coatings present limitations for expanded-envelope applications. T-grade couplings provide limited fatigue strength and corrosion fatigue tolerance, and many spray-metal processes reduce base-metal strength during deposition. High-strength uncoated couplings can meet tensile requirements but can be extremely sensitive to corrosive environments and corrosion fatigue.

High Speed Laser-deposited couplings were developed to address these fatigue limitations. Testing has shown that the process preserves the base-metal heat treatment while producing a smooth, uniform surface. In air fatigue testing, these couplings demonstrated fatigue limits near uncoated high strength couplings and the coating successfully isolates the base metal from corrosive environments.

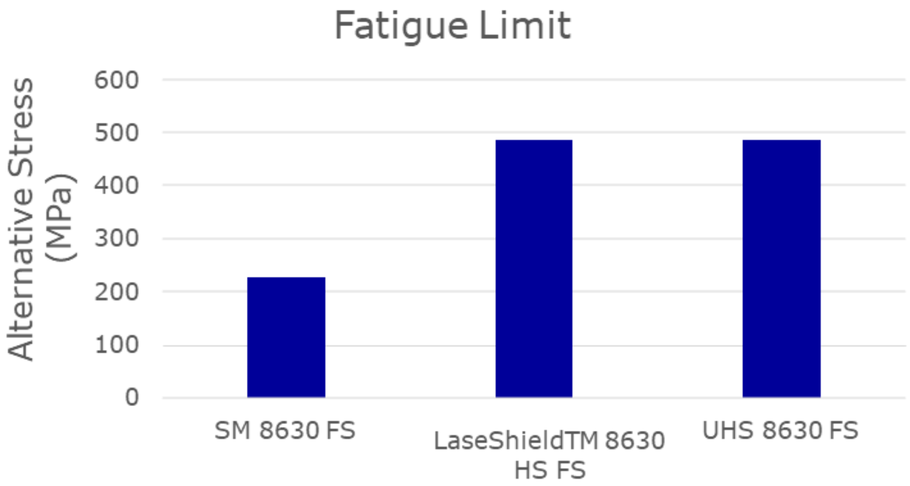


Figure 12. Fatigue testing results of the same coupling base material with various surface conditions

Coupling Size – Guiding Interaction

Material selection must be paired with geometric and guiding strategies. Coupling OD affects available **erodible wear volume** (EWV) of guides; slim-hole couplings can increase EWV, improving wear life in guided sections. Similarly, base-metal strength and coating integrity must align with expected bending, compression, and axial loading—especially in high-load tapers or deviated profiles.

In response to increasing operational demands and ongoing feedback from operators, the authors developed a quick-reference guide for coupling selection based on rod choice. This guidance is intended to support preliminary engineering decisions; however, final coupling selection should always be made in consultation with a Tenaris Rods Technical Sales representative to ensure the optimal rod–coupling combination for a given application (Table 1).

Table 1. Tenaris Coupling Class and Type recommendation, rev 05-2025.

		Coupling Class and Type									
		T FS	T SH	SM FS	SM SH	AlphaCS FS	Alpha CS SH	Alpha HS FS	AlphaHS SH	LaserShield FS	LaserShield SH
Rod Grade	AlphaRod HS	A	NR	NR	NR	A	A	TR	TR	TR	TR
	AlphaRod CS	A	A	A	A	TR	TR	A	A	TR	TR
	MMS/UHS	A	NR	A	NR	A	NR	TR	TR	TR	TR
	D	TR	A	A	A	TR	TR	TR	TR	TR	TR
	KD	TR	A	A	A	TR	TR	A	A	TR	TR
Sinker Rod	KD	NR	NR	NR	NR	NR	NR	NR	NR	A*	TR
Sinker Rod	AlphaRod CS	NR	NR	NR	NR	NR	NR	NR	NR	A*	TR

Legend:

TR	Tenaris Recommended
A	Acceptable - May need to derate
A*	Wear and/or EWV considerations. For Alpha cplg please beware of corrosive environment
NR	Not Recommended - serious derate or failure risk

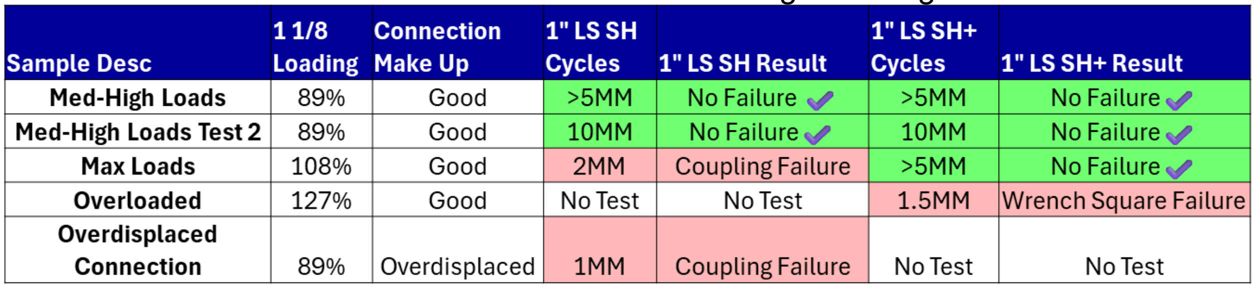
It is recommended that you consult with your Tenaris Rods technical Sales representative to select the best combination of rod and coupling for your application

1-1/8 in. Body × 1 in. Pin Geometry

As rod-lift designs move to deeper pump landings and higher rod weights, standard 1 in. pins can become a limiting geometry even when rod grades and couplings are upgraded. The **1-1/8 in. body × 1 in. pin** configuration was developed to increase load capacity in the upper tapers while retaining compatibility with 2-7/8 in. tubing. The design offers improved thread geometry modified pin design to reduce thread-root stress concentration and provide more tolerance to suboptimal make up.

Full-scale testing of this geometry with laser-deposited SH and SH**+** couplings confirmed that the connection can safely sustain the full 1-1/8 in. rod-body load range, including fatigue testing at high percentages of rated load, without shifting the weak point into the pin region (Table 2). This allows the envelope to be expanded in high-load wells without upsizing the tubing or moving to nonstandard connections.

Table 2. Results of 1 1/8 x 1” fatigue testing



Sample Desc	1 1/8 Loading	Connection Make Up	1" LS SH Cycles	1" LS SH Result	1" LS SH+ Cycles	1" LS SH+ Result
Med-High Loads	89%	Good	>5MM	No Failure ✓	>5MM	No Failure ✓
Med-High Loads Test 2	89%	Good	10MM	No Failure ✓	10MM	No Failure ✓
Max Loads	108%	Good	2MM	Coupling Failure	>5MM	No Failure ✓
Overloaded	127%	Good	No Test	No Test	1.5MM	Wrench Square Failure
Overdisplaced Connection	89%	Overdisplaced	1MM	Coupling Failure	No Test	No Test

INTEGRATED ENGINEERING SYSTEM SUMMARY

Modern rod-lift reliability cannot be improved through isolated fixes. As the operating envelope expands, the dominant challenges—tubing wear, buckling-related bending, corrosion-fatigue, and connection stress concentration—interact in ways that amplify one another. Field experience consistently shows that upgrading a single component may address one failure mode while exposing another, resulting in reliability plateaus unless multiple root causes are addressed together.

The engineering strategy developed through this work focuses on integrated process controls across four complementary levers:

1. **Rod String Design:** Manages tension, compression, and buckling, stabilizes the load path, and distributes stresses away from geometric transitions.
2. **Guiding Strategy**: Controls rod motion, reduces sideload concentration, delays tubing–coupling contact as guides wear, and mitigates bending- and wear-driven mechanisms.
3. **Materials & Surface Engineering**: Improves fatigue and wear tolerance at the rod body and coupling, increases resistance to surface-initiated damage, and enhances performance under elevated mechanical demand.
4. **Connection & Coupling Configuration:** Provides the geometric and fatigue margin necessary to transfer loads without creating localized stress intensification. Because the connection is uniquely sensitive to field variation, process controls such as running assistance, tong diagnostics, clean-and-dry preparation, and on-site failure analysis are incorporated to maintain connection performance in real-world conditions.

When these measures are engineered and deployed together, the rod-lift system behaves differently. Compression in the sinker section is reduced, tubing wear slows, connection fatigue resistance increases, and the system becomes more tolerant to variability in production rate, pump fillage, relative velocity, and deviation profile. This integrated approach forms the basis for the field examples presented in the following section, where multiple solutions were deliberately combined to control the true root causes affecting modern rod-lift reliability.

FIELD IMPLEMENTATION

This section presents several field examples where the integrated engineering strategies described above were applied to improve reliability under high-load, high-deviation, or high-production conditions. While each well had unique operating constraints, all designs followed the same portfolio-based approach: managing combined tension and compression, stabilizing rod motion, optimizing guiding strategy, ensuring adequate fatigue margin at connections, and applying appropriate field-execution practices to preserve connection integrity.

Case 1 – ESP Conversion in a Highly Deviated Bakken Well (~400 BBL/D)

Operating Challenge:
A 10,200-ft well with 10–15° inclination and side loads approaching 600 lb. required conversion from ESP to rod lift at ~375 BBL/D initial production. The deviation and high cyclic loads presented elevated risks of tubing wear, buckling, and multiaxial fatigue. The goal was to minimize production loss during conversion..

Integrated Solution:
A long-stroke unit and 97 taper AlphaRod HS string were installed, including a 1-1/8 × 1 in. top taper to increase load capacity. A 2,000-ft 1 × ¾ in. guided sinker interval (9-per, optimized for compression) was deployed to manage compression near the pump. Guided rods were intentionally used above the sinker section to reduce buckling where compression could not be eliminated. The full string was equipped with LaserShield couplings, with SH+ couplings used in the 1-1/8 × 1 in. interval to match the required fatigue resistance.

Outcome:
The well showed a modest production increase immediately after conversion (~25 BBL/D). Around 75 days after conversion, there were well test errors on water volumes, showing much higher, then much lower overall fluid volumes, but stable oil volumes proved the production has been stable and within the expected range since install in August 2025.

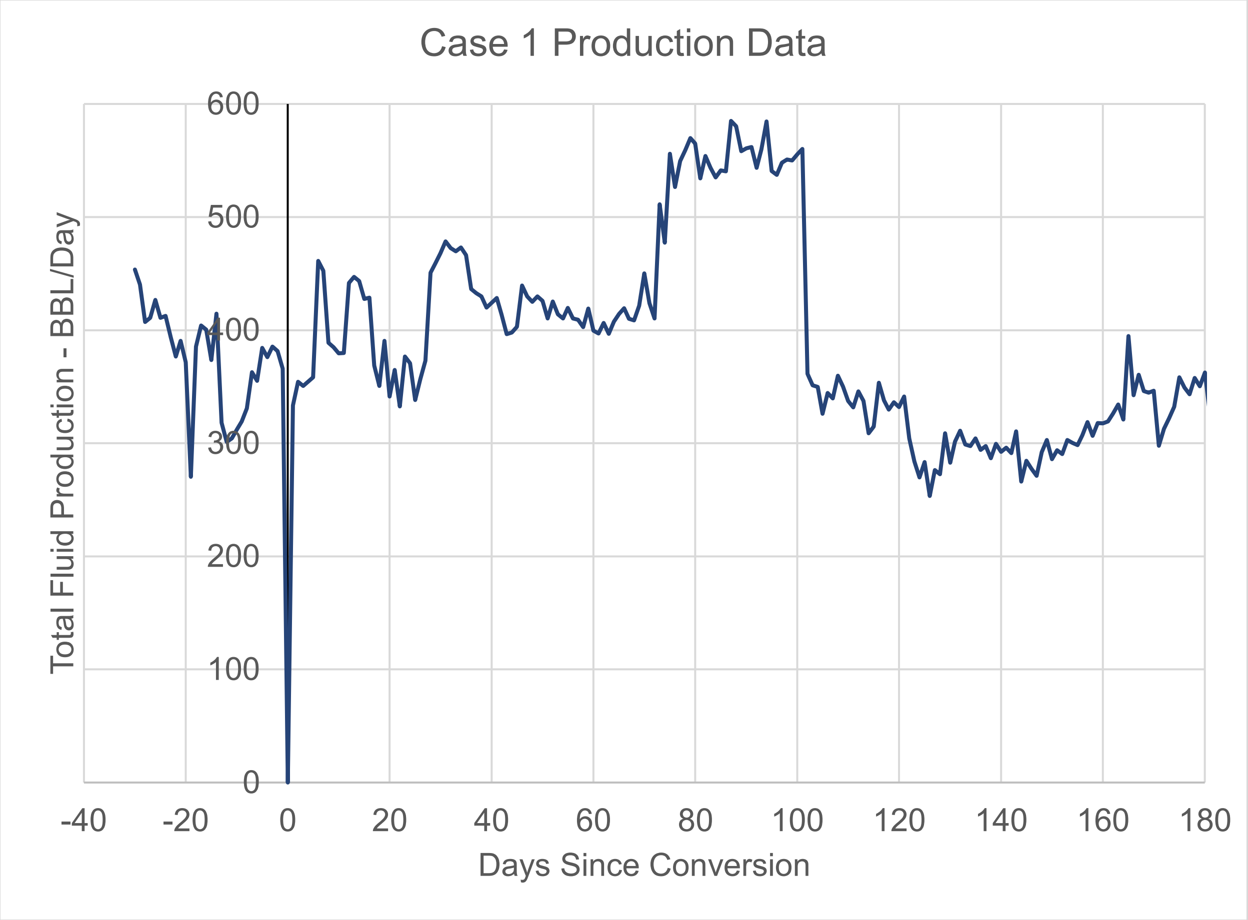
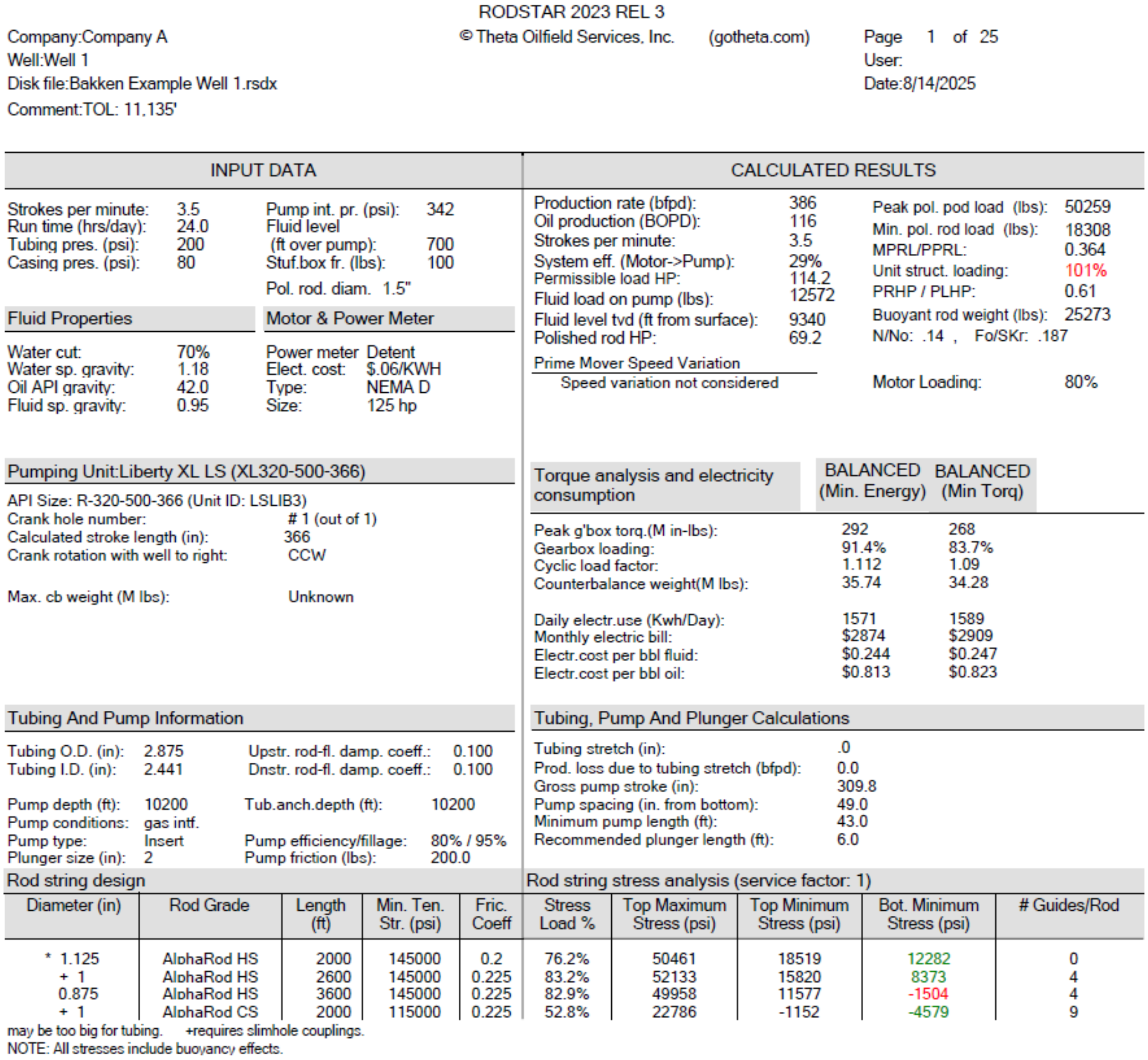


Figure 13. Production data from case 1



RODSTAR 2023 REL 3

© Theta Oilfield Services, Inc. (gotheta.com)

Company:Company A
Well:Well 1
Disk file:Bakken Example Well 1.rsdx
Comment:TOL: 11,135'

Page 1 of 25
User:
Date:8/14/2025

INPUT DATA

Strokes per minute:	3.5	Pump int. pr. (psi):	342
Run time (hrs/day):	24.0	Fluid level (ft over pump):	700
Tubing pres. (psi):	200	Stuf.box fr. (lbs):	100
Casing pres. (psi):	80	Pol. rod. diam.	1.5"

Fluid Properties

Water cut:	70%
Water sp. gravity:	1.18
Oil API gravity:	42.0
Fluid sp. gravity:	0.95

Motor & Power Meter

Power meter	Detent
Elect. cost:	$.06/KWH
Type:	NEMA D
Size:	125 hp

Pumping Unit:Liberty XL LS (XL320-500-366)

API Size: R-320-500-366 (Unit ID: LSLIB3)

Crank hole number:	# 1 (out of 1)
Calculated stroke length (in):	366
Crank rotation with well to right:	CCW
Max. cb weight (M lbs):	Unknown

CALCULATED RESULTS

Production rate (bfpd):	386	Peak pol. pod load (lbs):	50259
Oil production (BOPD):	116	Min. pol. rod load (lbs):	18308
Strokes per minute:	3.5	MPRL/PPRL:	0.364
System eff. (Motor->Pump):	29%	Unit struct. loading:	101%
Permissible load HP:	114.2	PRHP / PLHP:	0.61
Fluid load on pump (lbs):	12572	Buoyant rod weight (lbs):	25273
Fluid level tvd (ft from surface):	9340	N/No: .14 , Fo/SKr: .187	
Polished rod HP:	69.2		

Prime Mover Speed Variation

Speed variation not considered

Motor Loading: 80%

Torque analysis and electricity consumption	BALANCED (Min. Energy)	BALANCED (Min Torq)
Peak g'box torq.(M in-lbs):	292	268
Gearbox loading:	91.4%	83.7%
Cyclic load factor:	1.112	1.09
Counterbalance weight(M lbs):	35.74	34.28
Daily electr.use (Kwh/Day):	1571	1589
Monthly electric bill:	$2874	$2909
Electr.cost per bbl fluid:	$0.244	$0.247
Electr.cost per bbl oil:	$0.813	$0.823

Tubing And Pump Information

Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	10200	Tub.anch.depth (ft):	10200
Pump conditions:	gas intf.		
Pump type:	Insert	Pump efficiency/fillage:	80% / 95%
Plunger size (in):	2	Pump friction (lbs):	200.0

Tubing, Pump And Plunger Calculations

Tubing stretch (in):	.0
Prod. loss due to tubing stretch (bfpd):	0.0
Gross pump stroke (in):	309.8
Pump spacing (in. from bottom):	49.0
Minimum pump length (ft):	43.0
Recommended plunger length (ft):	6.0

Rod string design / Rod string stress analysis (service factor: 1)

Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
* 1.125	AlphaRod HS	2000	145000	0.2	76.2%	50461	18519	12282	0
+ 1	AlphaRod HS	2600	145000	0.225	83.2%	52133	15820	8373	4
0.875	AlphaRod HS	3600	145000	0.225	82.9%	49958	11577	-1504	4
+ 1	AlphaRod CS	2000	115000	0.225	52.8%	22786	-1152	-4579	9

may be too big for tubing. +requires slimhole couplings.
NOTE: All stresses include buoyancy effects.

Figure 14. Rod design details of case 1

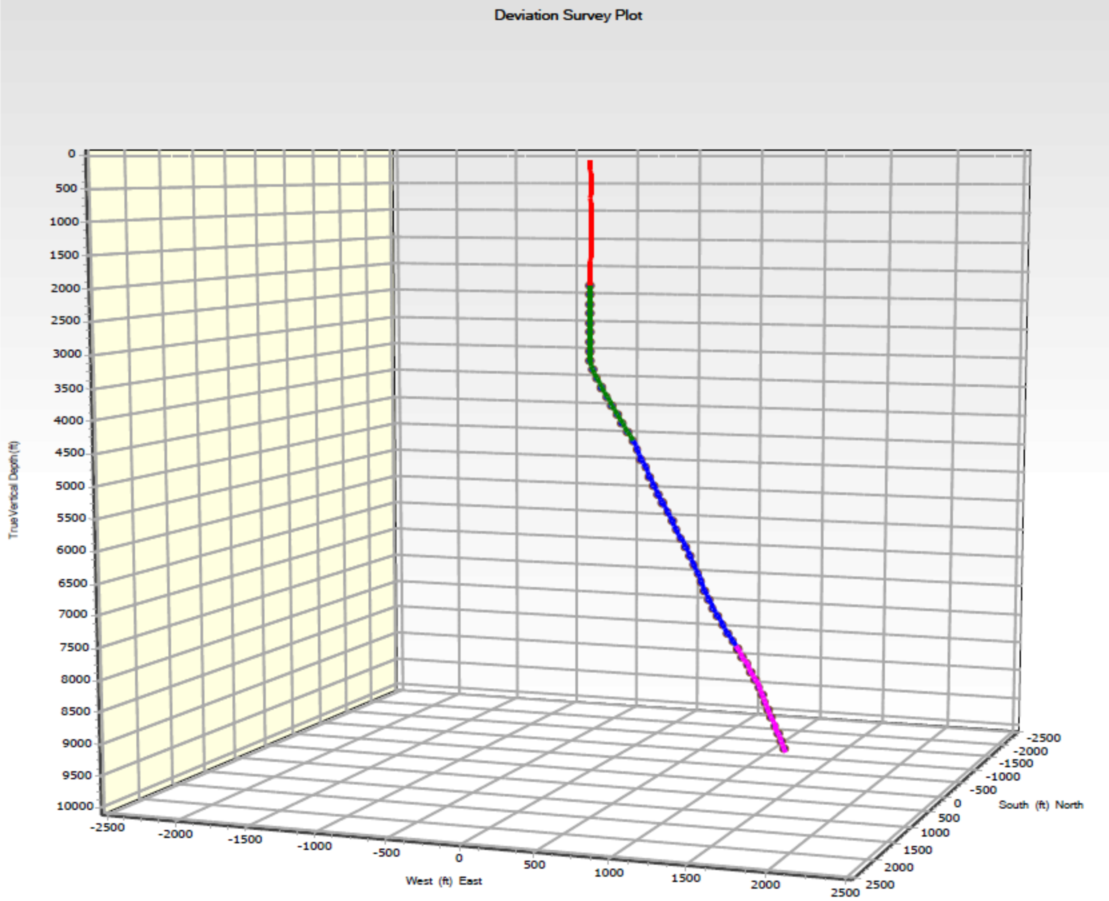


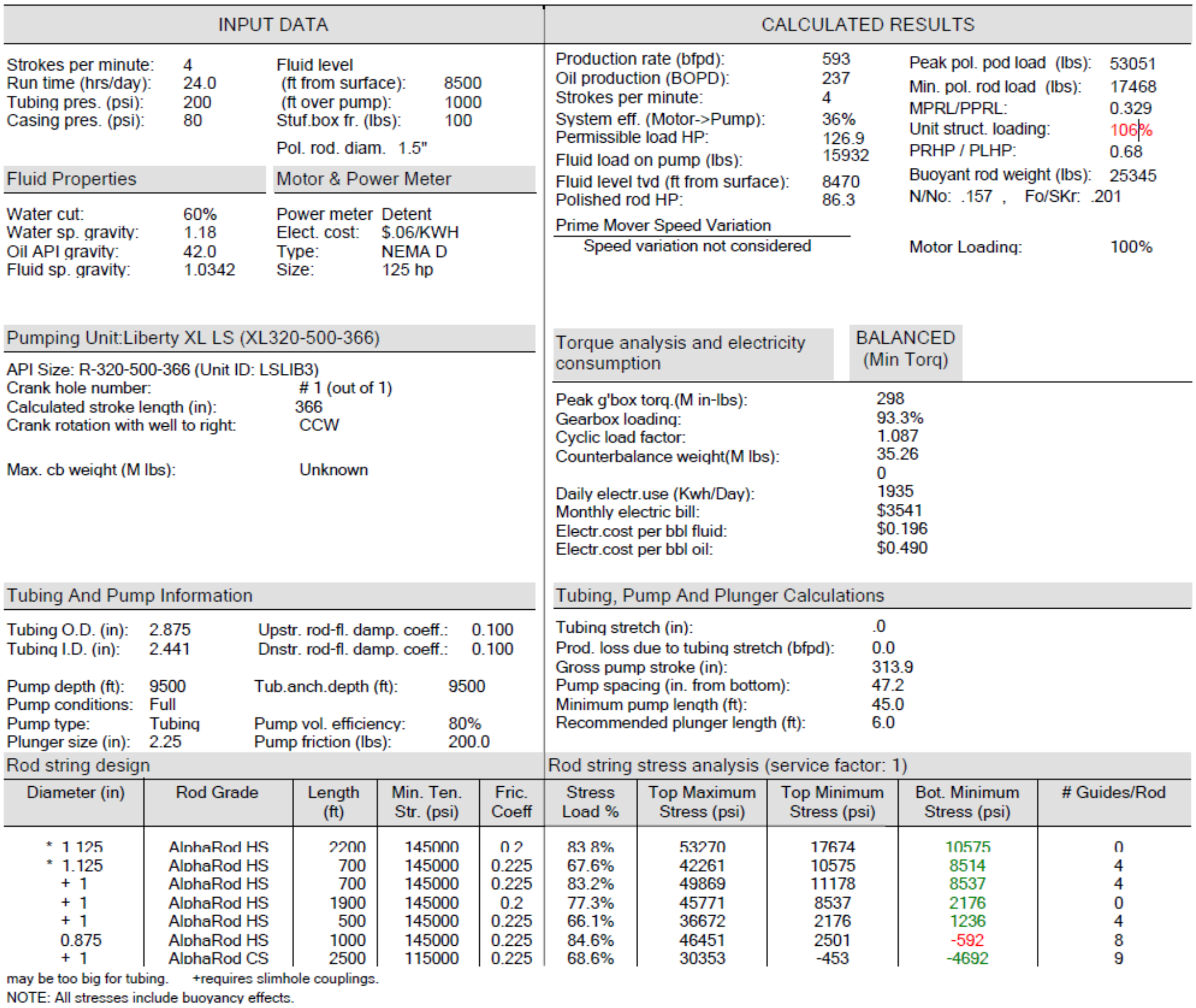
Figure 15. Deviation survey plot from case 1

Case 2 – High-Rate ESP Conversion in Moderate-Deviation Bakken Well

Operating Challenge:
A second ESP conversion for the same operator required maximizing production in a less severe but still deviated profile (5–8° inclination, <300 lb sideload). Previous ESP-level production (~700 BBL/D) was known to be difficult to sustain on rod lift.

Integrated Solution:
The design applied the same engineering principles but adapted to higher rates: a larger 2.25-in. pump, increased SPM, and an 8-per guided interval directly above the sinker section to mitigate compression and minimize buckling sensitivity at higher speeds and with a larger pump. Rod-string geometry, guiding, and coupling selection were coordinated to balance production targets and mechanical limits.

Outcome:
The well achieved ~480 BBL/D for ~3 months before transitioning into expected decline behavior. Reliability was maintained during the high-rate period, confirming that the portfolio approach can extend rod-lift application.



INPUT DATA

Strokes per minute: 4
Run time (hrs/day): 24.0
Tubing pres. (psi): 200
Casing pres. (psi): 80

Fluid level
(ft from surface): 8500
(ft over pump): 1000
Stuf.box fr. (lbs): 100

Pol. rod. diam. 1.5"

Fluid Properties

Water cut: 60%
Water sp. gravity: 1.18
Oil API gravity: 42.0
Fluid sp. gravity: 1.0342

Motor & Power Meter

Power meter Detent
Elect. cost: $.06/KWH
Type: NEMA D
Size: 125 hp

Pumping Unit:Liberty XL LS (XL320-500-366)

API Size: R-320-500-366 (Unit ID: LSLIB3)
Crank hole number: # 1 (out of 1)
Calculated stroke length (in): 366
Crank rotation with well to right: CCW

Max. cb weight (M lbs): Unknown

Tubing And Pump Information

Tubing O.D. (in): 2.875
Tubing I.D. (in): 2.441
Upstr. rod-fl. damp. coeff.: 0.100
Dnstr. rod-fl. damp. coeff.: 0.100

Pump depth (ft): 9500
Pump conditions: Full
Pump type: Tubing
Plunger size (in): 2.25
Tub.anch.depth (ft): 9500
Pump vol. efficiency: 80%
Pump friction (lbs): 200.0

CALCULATED RESULTS

Production rate (bfpd): 593
Oil production (BOPD): 237
Strokes per minute: 4
System eff. (Motor->Pump): 36%
Permissible load HP: 126.9
Fluid load on pump (lbs): 15932
Fluid level tvd (ft from surface): 8470
Polished rod HP: 86.3

Peak pol. pod load (lbs): 53051
Min. pol. rod load (lbs): 17468
MPRL/PPRL: 0.329
Unit struct. loading: 106%
PRHP / PLHP: 0.68
Buoyant rod weight (lbs): 25345
N/No: .157 , Fo/SKr: .201

Prime Mover Speed Variation
Speed variation not considered

Motor Loading: 100%

Torque analysis and electricity consumption

BALANCED
(Min Torq)

Peak g'box torq.(M in-lbs): 298
Gearbox loading: 93.3%
Cyclic load factor: 1.087
Counterbalance weight(M lbs): 35.26
0
Daily electr.use (Kwh/Day): 1935
Monthly electric bill: $3541
Electr.cost per bbl fluid: $0.196
Electr.cost per bbl oil: $0.490

Tubing, Pump And Plunger Calculations

Tubing stretch (in): .0
Prod. loss due to tubing stretch (bfpd): 0.0
Gross pump stroke (in): 313.9
Pump spacing (in. from bottom): 47.2
Minimum pump length (ft): 45.0
Recommended plunger length (ft): 6.0

Rod string design | Rod string stress analysis (service factor: 1)

Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
* 1.125	AlphaRod HS	2200	145000	0.2	83.8%	53270	17674	10575	0
* 1.125	AlphaRod HS	700	145000	0.225	67.6%	42261	10575	8514	4
+ 1	AlphaRod HS	700	145000	0.225	83.2%	49869	11178	8537	4
+ 1	AlphaRod HS	1900	145000	0.2	77.3%	45771	8537	2176	0
+ 1	AlphaRod HS	500	145000	0.225	66.1%	36672	2176	1236	4
0.875	AlphaRod HS	1000	145000	0.225	84.6%	46451	2501	-592	8
+ 1	AlphaRod CS	2500	115000	0.225	68.6%	30353	-453	-4692	9

may be too big for tubing. +requires slimhole couplings.
NOTE: All stresses include buoyancy effects.

Figure 16. Rod design details from case 2

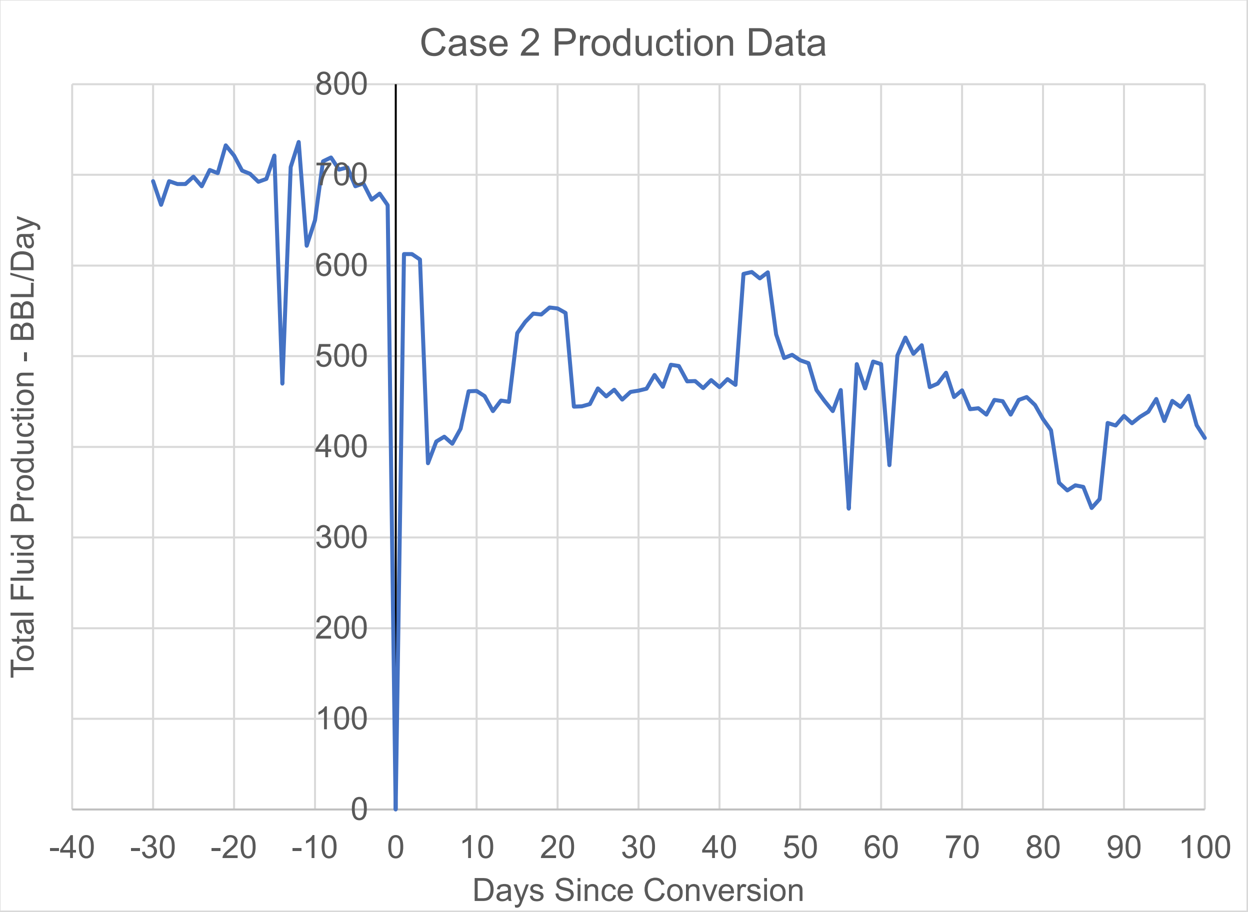


Figure 17. Production Data from Case 2

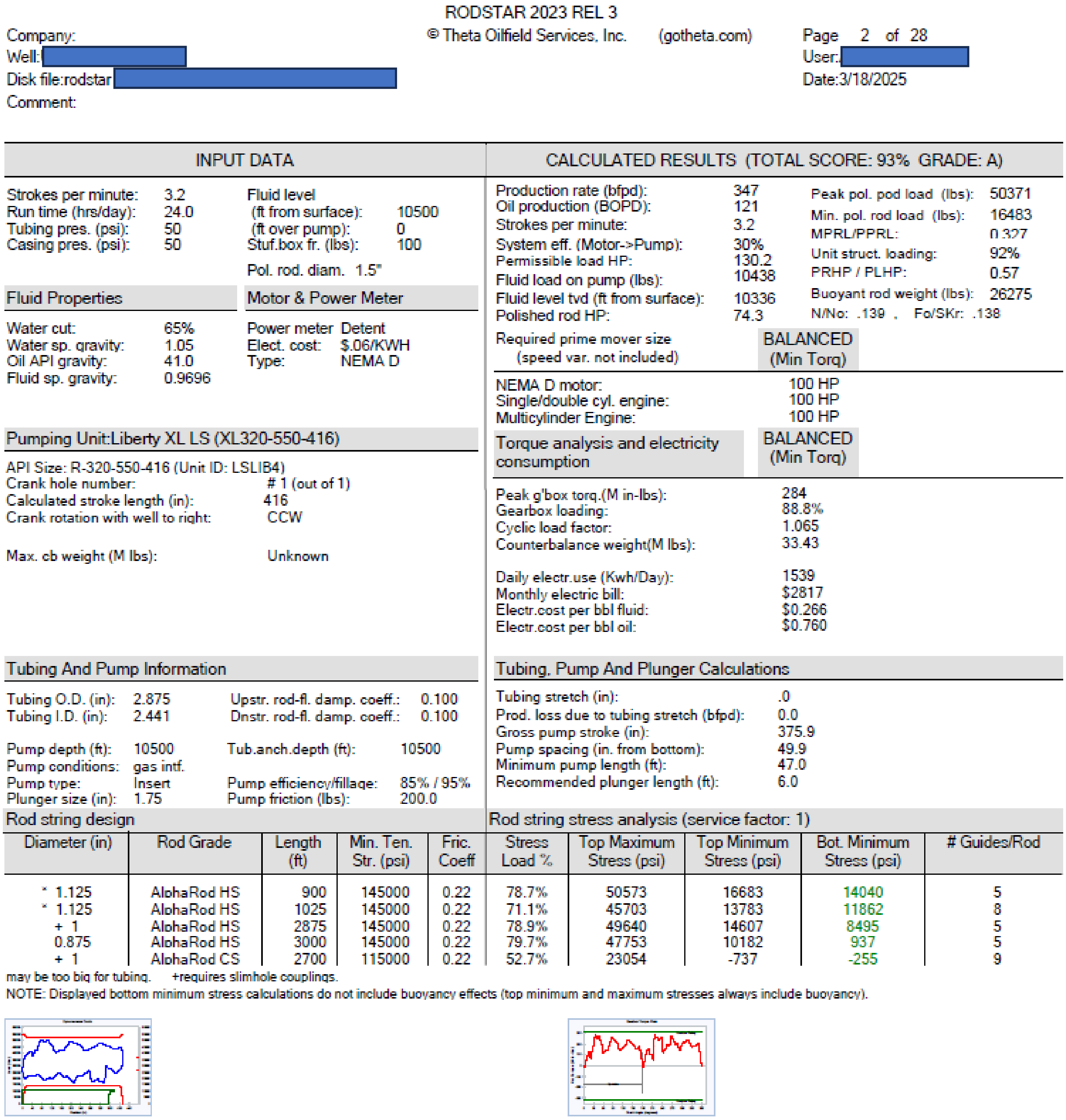
Case 3 – High-Deviation Permian Well Converted from Continuous to Stick Rods

Operating Challenge:
A deep Permian well (10,500 ft) with a complex profile and high deviation generated side loads above 740 lbs, creating simultaneous risks of wear, compression, and fatigue failures. Previous continuous-rod runs experienced tubing damage.

Integrated Solution:
A long-stroke unit was deployed with a 96-taper HS string including a 1-1/8 × 1 in. top section to increase load capacity while remaining compatible with 2-7/8-in. tubing. A 1 × ¾ in. guided sinker interval addressed compression near the pump. LaserShield couplings (SH and SH+) were used throughout to provide the required fatigue strength in both slim-hole and full-size geometries. Guide density increased to 8-per in the highest-load interval and maintained at 5-per elsewhere.

Outcome:

The system operated for 10 months with no downhole failures. A later tubing pull due to a hole in tubing revealed wear remaining with legacy continuous-rod operation, not with the integrated design, confirming the system's ability to operate reliably under high deviation and loading.



RODSTAR 2023 REL 3
© Theta Oilfield Services, Inc. (gotheta.com)

Company:
Well: [redacted]
Disk file:rodstar [redacted]
Comment:

Page 2 of 28
User: [redacted]
Date:3/18/2025

INPUT DATA

Strokes per minute: 3.2
Run time (hrs/day): 24.0
Tubing pres. (psi): 50
Casing pres. (psi): 50

Fluid level
(ft from surface): 10500
(ft over pump): 0
Stuf.box fr. (lbs): 100
Pol. rod. diam. 1.5"

Fluid Properties

Water cut: 65%
Water sp. gravity: 1.05
Oil API gravity: 41.0
Fluid sp. gravity: 0.9696

Motor & Power Meter

Power meter Detent
Elect. cost: $.06/KWH
Type: NEMA D

Pumping Unit:Liberty XL LS (XL320-550-416)

API Size: R-320-550-416 (Unit ID: LSLIB4)
Crank hole number: # 1 (out of 1)
Calculated stroke length (in): 416
Crank rotation with well to right: CCW

Max. cb weight (M lbs): Unknown

Tubing And Pump Information

Tubing O.D. (in): 2.875
Tubing I.D. (in): 2.441
Upstr. rod-fl. damp. coeff.: 0.100
Dnstr. rod-fl. damp. coeff.: 0.100

Pump depth (ft): 10500
Tub.anch.depth (ft): 10500
Pump conditions: gas intf.
Pump type: Insert
Pump efficiency/fillage: 85% / 95%
Plunger size (in): 1.75
Pump friction (lbs): 200.0

CALCULATED RESULTS (TOTAL SCORE: 93% GRADE: A)

Production rate (bfpd): 347
Oil production (BOPD): 121
Strokes per minute: 3.2
System eff. (Motor->Pump): 30%
Permissible load HP: 130.2
Fluid load on pump (lbs): 10438
Fluid level tvd (ft from surface): 10336
Polished rod HP: 74.3

Peak pol. pod load (lbs): 50371
Min. pol. rod load (lbs): 16483
MPRL/PPRL: 0.327
Unit struct. loading: 92%
PRHP / PLHP: 0.57
Buoyant rod weight (lbs): 26275
N/No: .139 , Fo/SKr: .138

Required prime mover size
(speed var. not included)
BALANCED
(Min Torq)

NEMA D motor: 100 HP
Single/double cyl. engine: 100 HP
Multicylinder Engine: 100 HP

Torque analysis and electricity consumption
BALANCED
(Min Torq)

Peak g'box torq.(M in-lbs): 284
Gearbox loading: 88.8%
Cyclic load factor: 1.065
Counterbalance weight(M lbs): 33.43

Daily electr.use (Kwh/Day): 1539
Monthly electric bill: $2817
Electr.cost per bbl fluid: $0.266
Electr.cost per bbl oil: $0.760

Tubing, Pump And Plunger Calculations

Tubing stretch (in): .0
Prod. loss due to tubing stretch (bfpd): 0.0
Gross pump stroke (in): 375.9
Pump spacing (in. from bottom): 49.9
Minimum pump length (ft): 47.0
Recommended plunger length (ft): 6.0

Rod string design					Rod string stress analysis (service factor: 1)				
Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
* 1.125	AlphaRod HS	900	145000	0.22	78.7%	50573	16683	14040	5
* 1.125	AlphaRod HS	1025	145000	0.22	71.1%	45703	13783	11862	8
+ 1	AlphaRod HS	2875	145000	0.22	78.9%	49640	14607	8495	5
0.875	AlphaRod HS	3000	145000	0.22	79.7%	47753	10182	937	5
+ 1	AlphaRod CS	2700	115000	0.22	52.7%	23054	-737	-255	9

may be too big for tubing. +requires slimhole couplings.
NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).

Figure 18. Rod Design Details from Case 3

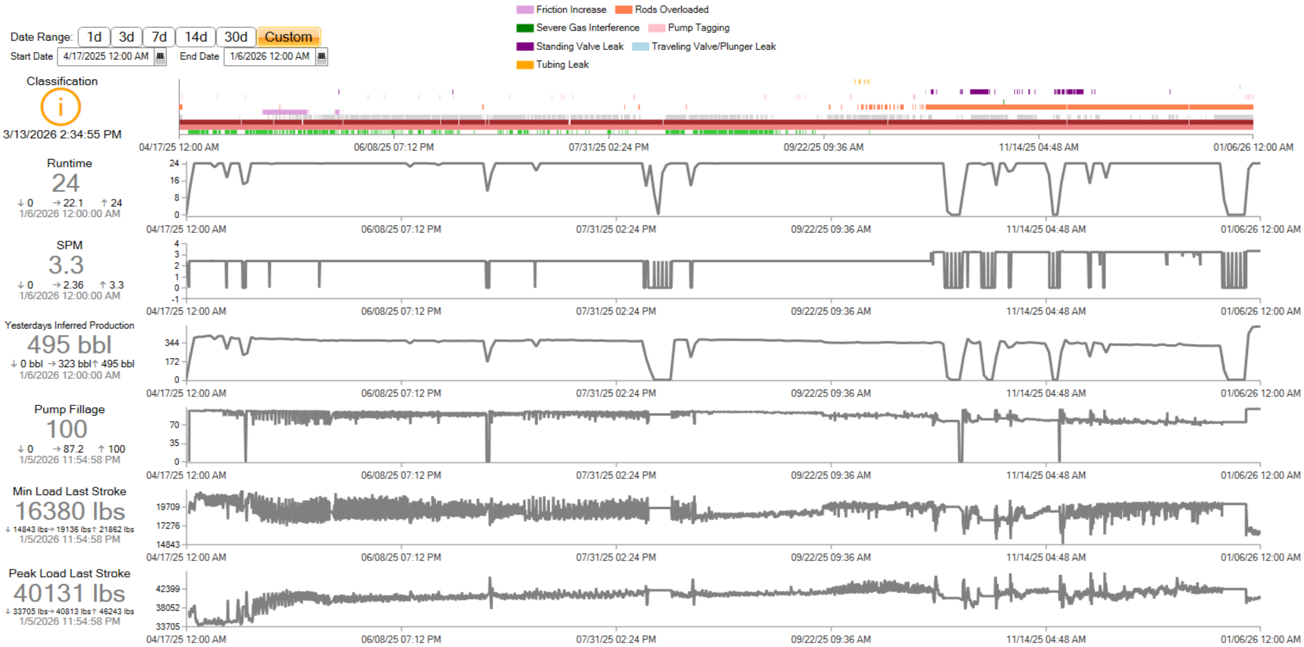


Figure 19. Operating Data from Case 3

Case 4 – Fiberglass-Over-Steel Rod Lift in a High-Deviation Permian Well

Operating Challenge:

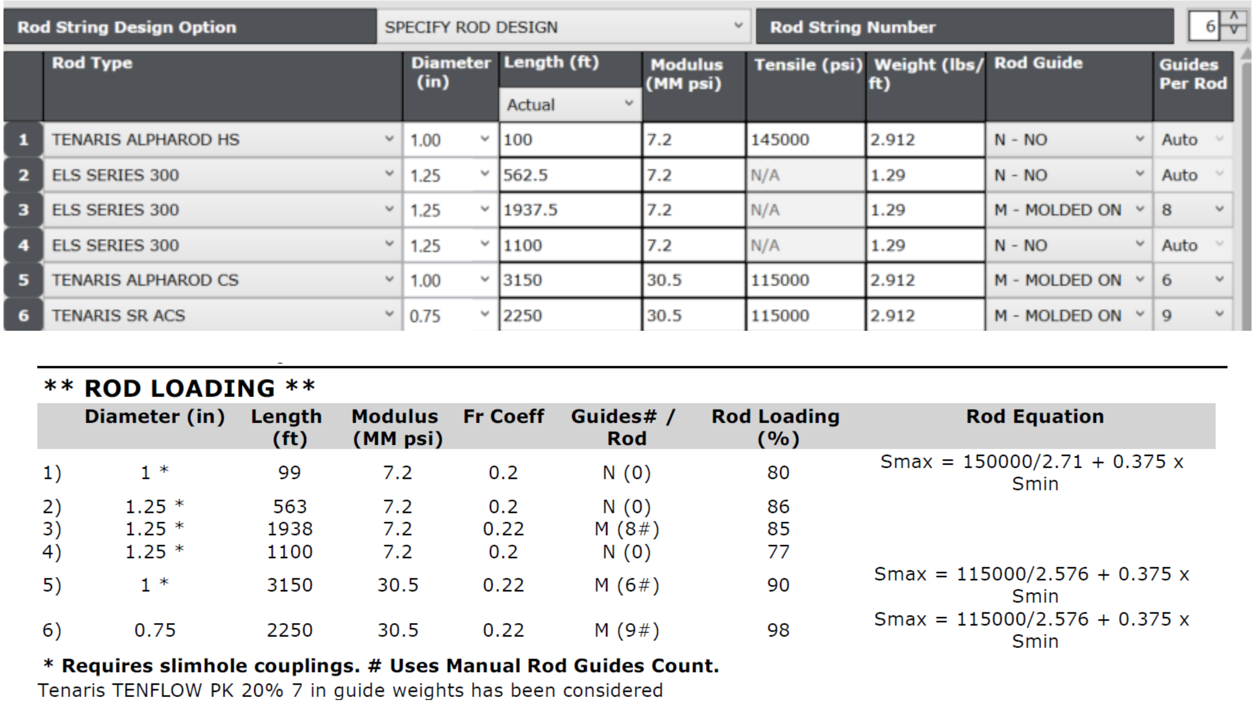
This well required a 40/60 fiberglass-to-steel string to manage surface loading while avoiding compression in the fiberglass interval. The well exhibited DLS peaks of 6–7° and side loads up to 760 lbs near the top. The production goal was 300 BBL/D.

Integrated Solution:

A 1-in. CS steel section with 6-per guides was paired with 1 × ¾ in. guided sinker rods (9-per optimized for compression). LaserShield couplings were used throughout, including on fiberglass sections, to ensure consistent coupling-to-tubing behavior and adequate fatigue strength. The guiding strategy was designed to eliminate compression in the fiberglass interval and stabilize motion through high-curvature sections.

Outcome:

The well operated reliably for 12 months. The only intervention was a proactive pull for a broken TAC mandrel; no downhole damage attributable to the rod-string system was observed. The well then resumed operation in December 2025. The well produced at 300-350 BBL/D and was able to match natural decline.



Rod String Design Option	SPECIFY ROD DESIGN	Rod String Number	6

	Rod Type	Diameter (in)	Length (ft) Actual	Modulus (MM psi)	Tensile (psi)	Weight (lbs/ ft)	Rod Guide	Guides Per Rod
1	TENARIS ALPHAROD HS	1.00	100	7.2	145000	2.912	N - NO	Auto
2	ELS SERIES 300	1.25	562.5	7.2	N/A	1.29	N - NO	Auto
3	ELS SERIES 300	1.25	1937.5	7.2	N/A	1.29	M - MOLDED ON	8
4	ELS SERIES 300	1.25	1100	7.2	N/A	1.29	N - NO	Auto
5	TENARIS ALPHAROD CS	1.00	3150	30.5	115000	2.912	M - MOLDED ON	6
6	TENARIS SR ACS	0.75	2250	30.5	115000	2.912	M - MOLDED ON	9

**** ROD LOADING ****

	Diameter (in)	Length (ft)	Modulus (MM psi)	Fr Coeff	Guides# / Rod	Rod Loading (%)	Rod Equation
1)	1 *	99	7.2	0.2	N (0)	80	Smax = 150000/2.71 + 0.375 x Smin
2)	1.25 *	563	7.2	0.2	N (0)	86	
3)	1.25 *	1938	7.2	0.22	M (8#)	85	
4)	1.25 *	1100	7.2	0.2	N (0)	77	
5)	1 *	3150	30.5	0.22	M (6#)	90	Smax = 115000/2.576 + 0.375 x Smin
6)	0.75	2250	30.5	0.22	M (9#)	98	Smax = 115000/2.576 + 0.375 x Smin

*** Requires slimhole couplings. # Uses Manual Rod Guides Count.**
Tenaris TENFLOW PK 20% 7 in guide weights has been considered

Figure 20. Rod Design Details from Case 4

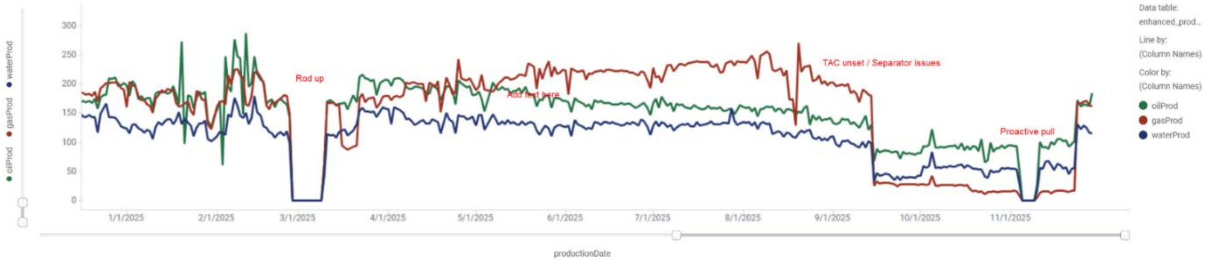


Figure 21. Production Details from Case 4

Case 5 – High-Load Permian Well With Extended Runtime Objective

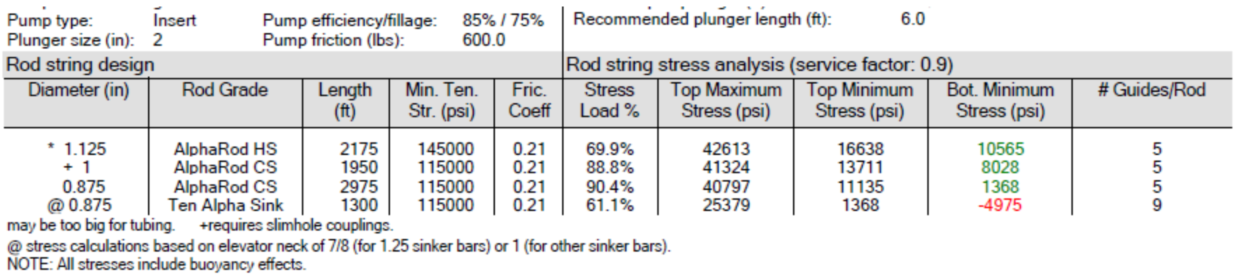
Operating Challenge:

A Permian well with high-load expectations required a design that prioritized runtime extension while maintaining flexibility for future production increases.

Integrated Solution:

A top section of HS rods with a 1-1/8 × 1 in. geometry provided load-path reinforcement, while a lower CS taper was used for toughness and compatibility. A 1-1/8 × 7/8 in. guided sinker interval (9-per) was implemented to manage compression, paired with LaserShield couplings to provide consistent fatigue performance and reduce tubing wear risk in the high-load lower sections.

Outcome:
The design demonstrated strong runtime performance (>15 months currently) and delivered the expected reliability improvements. The configuration supported stable production (~350 BFPD at moderate SPM) while suppressing wear and buckling tendencies.



Pump type: Insert
Plunger size (in): 2
Pump efficiency/fillage: 85% / 75%
Pump friction (lbs): 600.0
Recommended plunger length (ft): 6.0

Rod string design					Rod string stress analysis (service factor: 0.9)				
Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
* 1.125	AlphaRod HS	2175	145000	0.21	69.9%	42613	16638	10565	5
+ 1	AlphaRod CS	1950	115000	0.21	88.8%	41324	13711	8028	5
0.875	AlphaRod CS	2975	115000	0.21	90.4%	40797	11135	1368	5
@ 0.875	Ten Alpha Sink	1300	115000	0.21	61.1%	25379	1368	-4975	9

may be too big for tubing. +requires slimhole couplings.
@ stress calculations based on elevator neck of 7/8 (for 1.25 sinker bars) or 1 (for other sinker bars).
NOTE: All stresses include buoyancy effects.

Figure 22. Rod Design Details from Case 5

CONCLUSIONS

Modern rod-lift wells operate under combined tension, compression, deviation, and fluid-driven wear conditions that interact to create multiple root-cause failure mechanisms. No single upgrade can address these mechanisms reliably on its own. The work presented in this paper shows that reliability improvements in expanded-envelope applications come from **system-level engineering**, where rod-string design, guiding strategy, materials and surface finishing, connection configuration, and field-execution practices are applied together as coordinated process controls.

Across the cases presented, this integrated approach consistently reduced buckling-related bending, slowed tubing wear progression, improved connection fatigue performance, and delivered stable performance under varying production rates and complex wellbore geometry. The results demonstrate that rod-lift performance in deeper and higher-load unconventional wells can be improved not by optimizing components independently, but by engineering the entire system around the true root causes governing reliability.

As rod lift continues to expand into more demanding applications, designing for worst-case loading, validating through testing and RCA, and implementing complementary controls across the system will remain essential to achieving consistent, long-term performance.

REFERENCES

Anderson, J., Oliva, E., Richardson, C., Mogus, S., & Morin, D. (2022). *Sucker Rod Connection Failure Reduction Using a Three-Pronged Approach.* SPE Artificial Lift Conference and Exhibition – Americas, Galveston, TX, USA. SPE-209750-MS.

Anderson, J., Oliva, E., Lopez, E., Buhler, M., Latchem, T., & Hoerner, J. (2023). *A Novel Technique to Maximize Corrosion-Fatigue Resistance of Sucker Rods Using Optimized Surface Texture & Finishing.* Southwestern Petroleum Short Course, Lubbock, TX.

Anderson, J., & Oliva, E. (2024). *Sinker Section Design to Reduce Buckling-Related Failures.* Southwestern Petroleum Short Course, Lubbock, TX.

Anderson, J., Oliva, E., & Mogus, S. (2024). *Sucker Rod Make-Up: All About Displacement, or Is It?* SPE Artificial Lift Conference and Exhibition – Americas. SPE-219514-MS.

Ghione, G., Pereyra, M., Zupanc, P., Oliva, E., & More, F. (2025). *Full-Scale Tribocorrosion and Abrasive Testing to Mitigate Rod and Tubing Wear.* Southwestern Petroleum Short Course, Lubbock, TX.

Oliva, E., Abarca, J., & Pereyra, M. (2025). *Optimizing Sucker Rod Components Using Computational Fluid Dynamics to Reduce Turbulence-Induced Erosion-Corrosion.* Southwestern Petroleum Short Course, Lubbock, TX.

Westerkamp, P., & Mills, T. (2025). *A New Wave Equation Formulation with a Focus on Deviated Well Applications Derived from Downhole Dynamometer Measured Data.* Southwestern Petroleum Short Course, Lubbock, TX.