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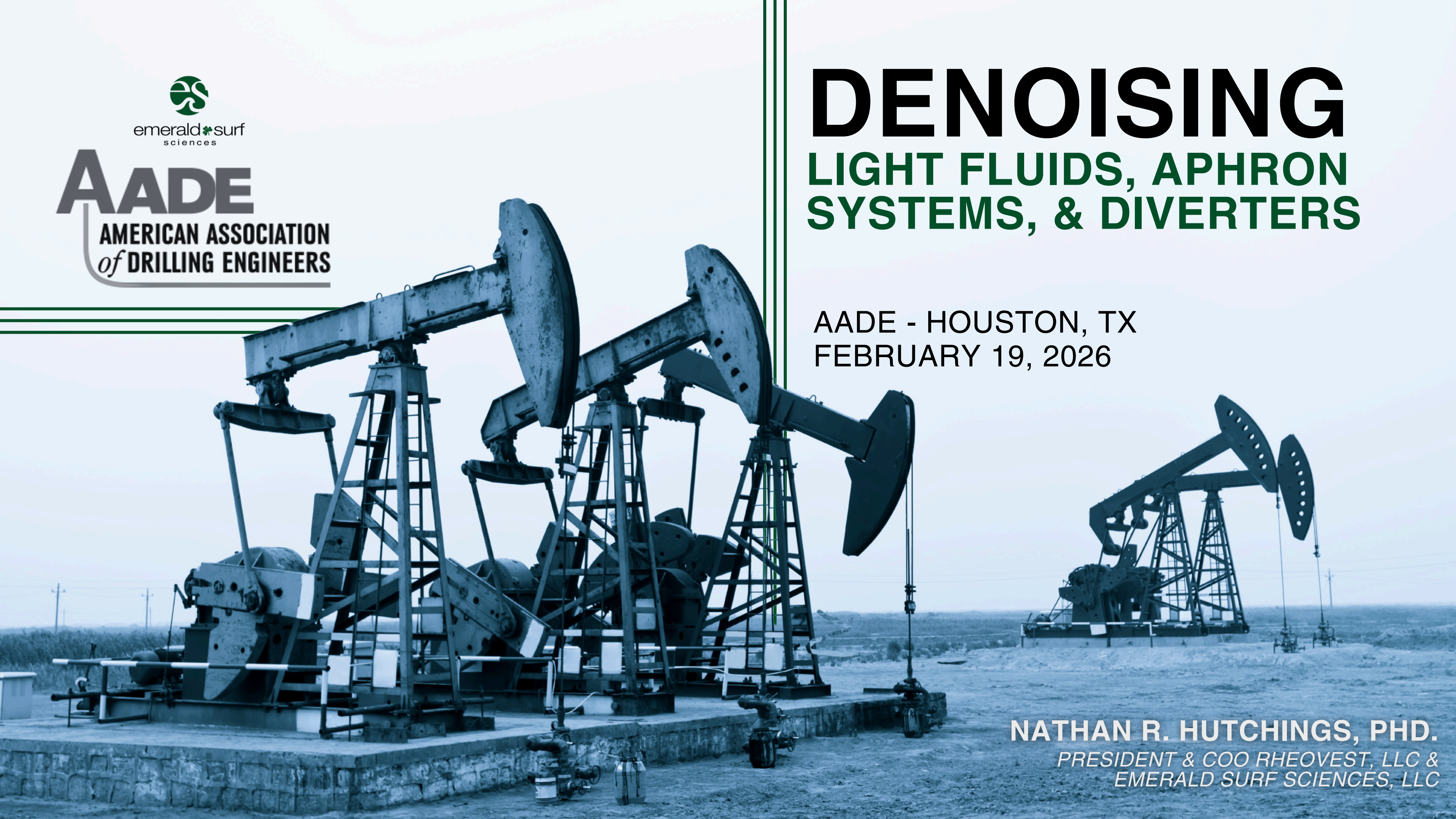
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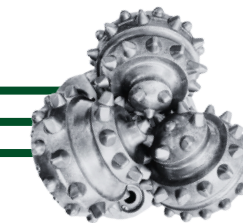
DENOISING

LIGHT FLUIDS, APHRON SYSTEMS, & DIVERTERS

AADE - HOUSTON, TX
FEBRUARY 19, 2026

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EMERALD SURF SCIENCES, LLC





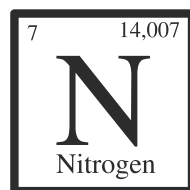
Reliable bit-to-surface circulation is essential for de-risking low-pressure completion & intervention operations

HOW THE INDUSTRY HAS ADDRESSED THIS PROBLEM:

~2010s

NITROGEN-ENERGIZED FLUIDS

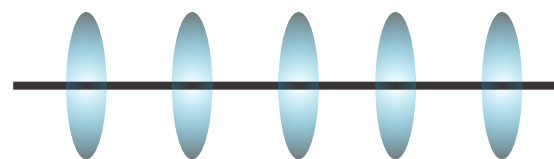
- Predominant circulation method in low-pressure wells
- Effective in select applications, but **often expensive, time-consuming, & inconsistent**
- Still useful for certain mechanical repairs & vertical cleanouts, but unreliable for long horizontal interventions



~2015

FRAC DIVERTERS

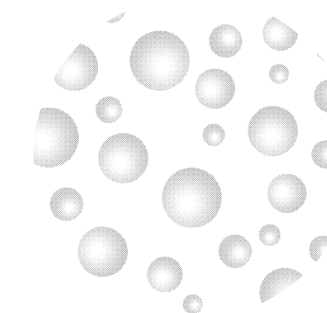
- Occasionally applied in low-pressure interventions
- **Exhibited similar limitations to nitrogen-based approaches**



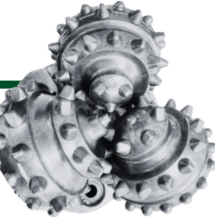
~2018-2020

COLLOIDAL GAS APHRONS (CGA)

- Long used in underbalanced drilling
- Entered completions and intervention workflows promising a **more reliable solution for challenging low-pressure wells**



Each approach reflects a tradeoff between cost, reliability, & operational control

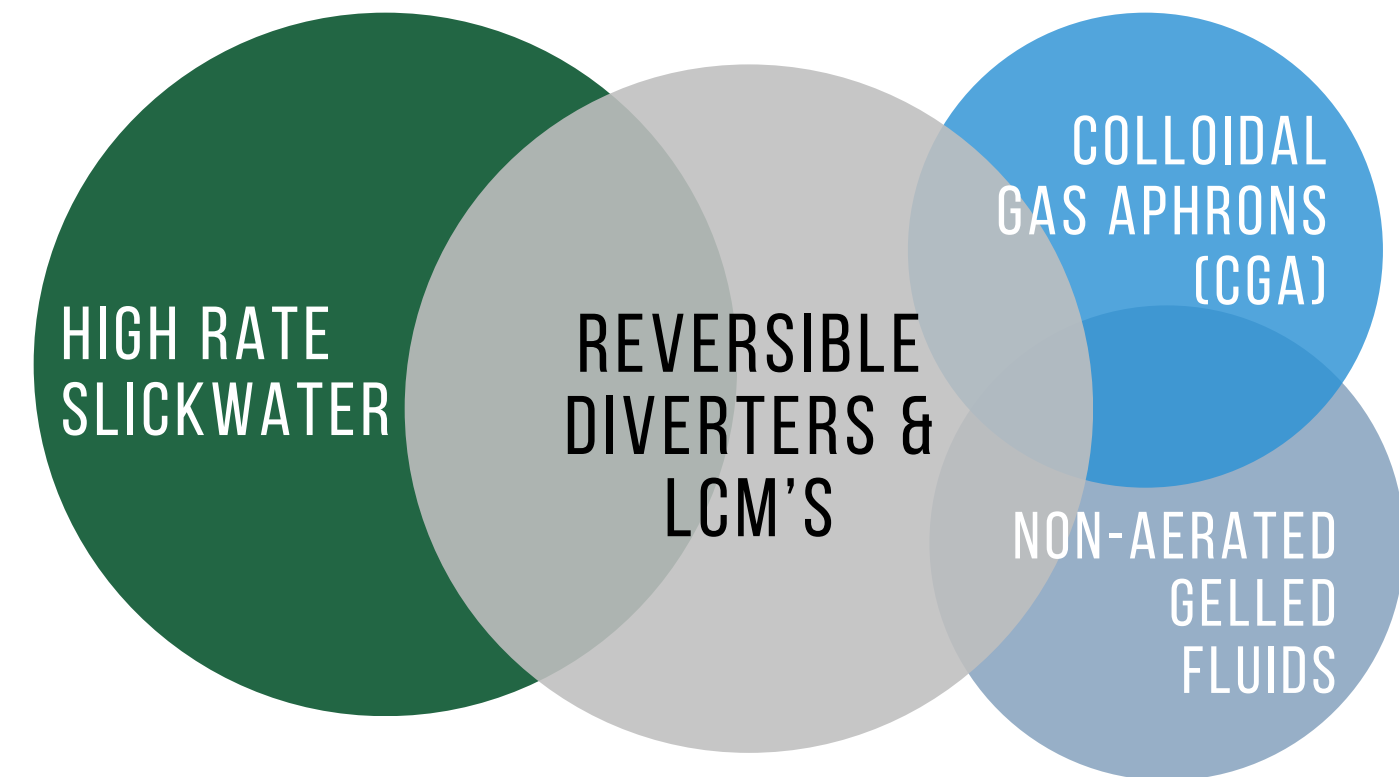


WHY APHRON ADOPTION PLATEAUED

- **MISAPPLICATION**
 - Over-kill for many jobs
 - Insufficient LSRV & filtration control for certain wells
- **HIGH COST**
 - Relative to other fluids, not to stuck pipe
- **TECHNICAL CHALLENGES**
 - Failure to recognize leak-off control limitations
 - Failure to keep (recirculated) fluids in-spec
 - Too much focus on density instead of low shear-rate viscosity

WHAT THE CURRENT MARKET ACTUALLY LOOKS LIKE

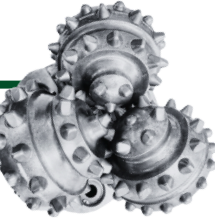
Illustrative overlap of common low-pressure intervention applications



Applied properly, CGA fluid (with diverter assist) is still the most consistently successful fluid system for very low-pressure, pump/return rate-limited, interventions

...but that is only a relatively small portion of the total low-pressure intervention market.

OPTIMIZING YOUR LOW PRESSURE INTERVENTIONS FLUID SYSTEM CHOICE BEGINS BY ASKING -
HOW BIG IS YOUR LOW-PRESSURE DRAGON?

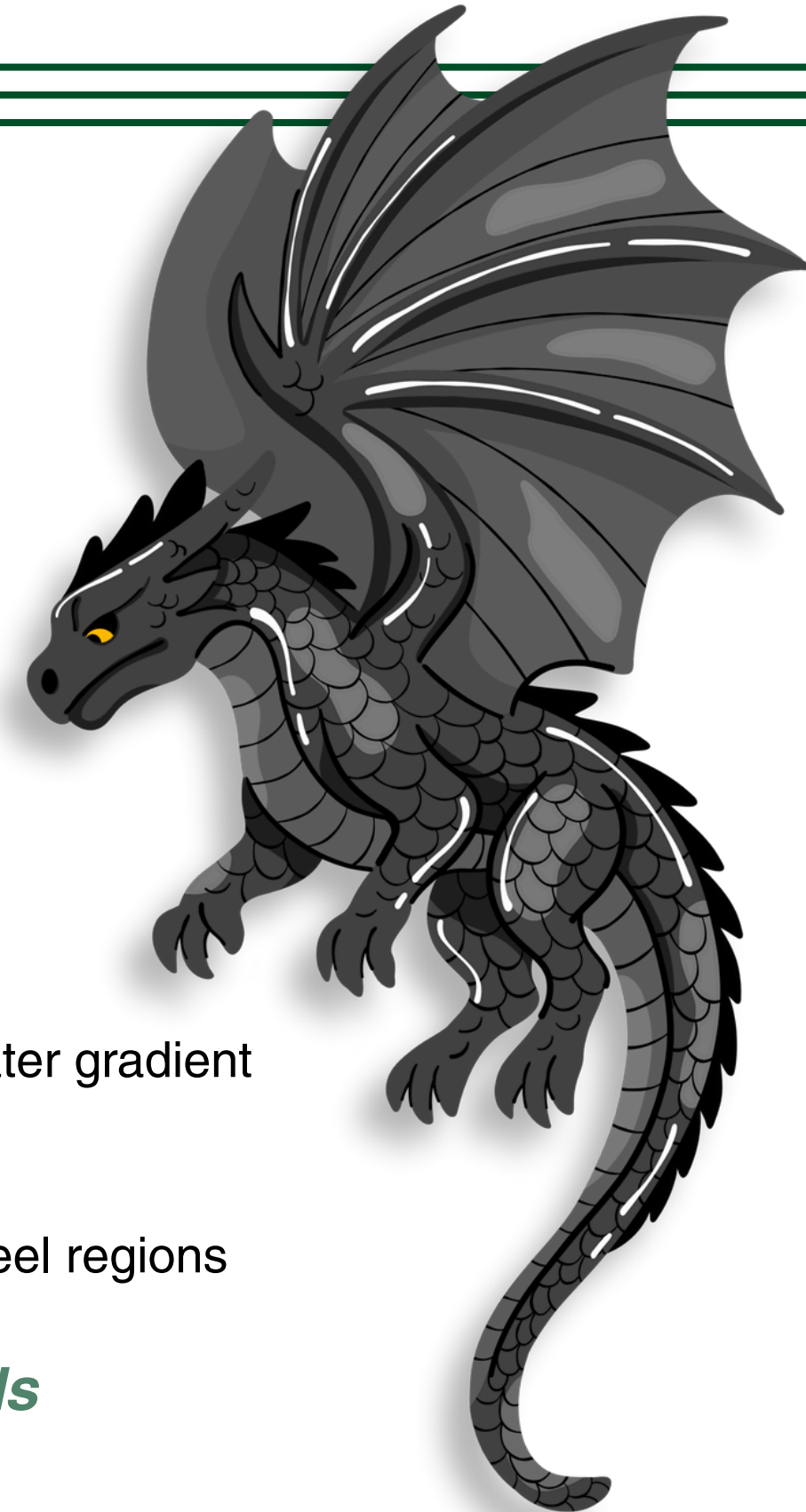


SEMI-LOW PRESSURE

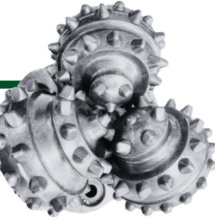
- Reservoir pressure within ~1.5 ppg of freshwater gradient and / or
- Most zones above freshwater gradient; BUT one or more are below

LOW PRESSURE

- Majority of zones >1.5 ppg below freshwater gradient and / or
- mature wells with significantly depleted heel regions



More dramatic pressure gradients between the reservoir and the fluids require more elegant and more expensive fluid system solutions



▶▶▶ EXAMPLE: INITIAL COMPLETION CONDITIONS

- New completion or frac with homogeneous reservoir pressure below freshwater gradient
- New completion or frac with heterogeneous reservoir pressure (some zones above, some below freshwater gradient)

▶▶▶ EXAMPLE: DEPLETION OR DAMAGE

- Intervention on a well that has experienced a FDI (frac hit)
- Intervention in debris-impaired mature wells:
 - Originally completed to the toe (including frac liner set)
 - Not originally completed to the toe (plugs left in well)



KEY INSIGHT:

Each of these examples MAY be low pressure or semi-low pressure, it all depends on the magnitude of the pressure gradient

SEMI-LOW PRESSURE CAN RATE SOLVE THIS PROBLEM?



FLUID SELECTION LOGIC FOR SEMI-LOW PRESSURE WELLS

WELL CONDITION:

**Uniformly Under-Pressured
Reservoir**

Consistent reservoir pressure
slightly below freshwater
gradient (7.0–8.3 ppg)

PRIMARY RISK QUESTION

**Can annular velocity be
maintained as zones are
incrementally exposed?**

WELL CONDITION:

**Localized Under-Pressured
Thief Zones**

Most zones above freshwater
gradient; one or more below

PRIMARY RISK QUESTION

**Can loss of bit-to-surface
communication be
detected early enough to
respond?**

FLUID SELECTION LOGIC FOR LOW PRESSURE WELLS

WELL CONDITION:

**Dominant Under-Pressured
Across Most Intervals**

Majority of zones > ~1.5 ppg
below freshwater gradient

PRIMARY RISK QUESTION

**Is the pressure gradient too
steep to sustain circulation
at reasonable pump rates?**

WELL CONDITION:

**Severely Depleted Heel with
Potential Higher-Pressure
intervals Towards the Toe**

Higher pressure expected once
debris impairment is removed

PRIMARY RISK QUESTION

**Can an effective heel seal be
established to enable debris
removal and sustained fluid
returns?**

IF NO? ADJUST YOUR FLUID SYSTEM

Have a plan to adjust your fluid system in response to dynamic reservoir conditions

CONTROLLING FLUID LOSSES IN LOW-PRESSURE WELLS: A DARCY'S LAW FRAMEWORK



DARCY'S LAW

$$Q = \frac{(K \times \Delta P)}{\mu}$$

Fluid gains or losses (Q) are controlled by three levers:

1. Permeability (K)
2. Pressure Differential (ΔP)
3. Fluid Viscosity (μ)



1 EMPTY THE POND

Primary Increase
lever: ΔP (rate)

*Outrun losses
with pump rate*

$$(Q_{pump} > Q_{res})$$



2 KATY BAR THE DOOR

Primary Reduce K (eff.
lever: permeability)

*Diverters physically
restrict leak-off paths*

$$(K_{eff} \downarrow \Rightarrow Q_{loss} \downarrow)$$



3 THICK AS MOLASSES

Primary Increase μ
lever: (viscosity)

*Reduce flow
through pores*

$$(\mu \uparrow \Rightarrow Q_{loss} \downarrow)$$



4 FOAM PARTY

Primary Reduce K +
lever: increase apparent μ

*Gas bubble lamella
restrict flow*

$$(K_{eff} \downarrow + \mu_{app} \uparrow \Rightarrow Q_{loss} \downarrow)$$



KEY INSIGHT: *Most successful low-pressure interventions combine multiple Darcy levers rather than relying on just one.*

HOW MUCH ΔP RELIEF DO APHRONS ACTUALLY PROVIDE?



Even aggressive aphron systems typically reduce hydrostatic pressure by only **~300 psi at 10,000 ft**, not the thousands of psi often assumed

Field example (10,000 ft TVD):

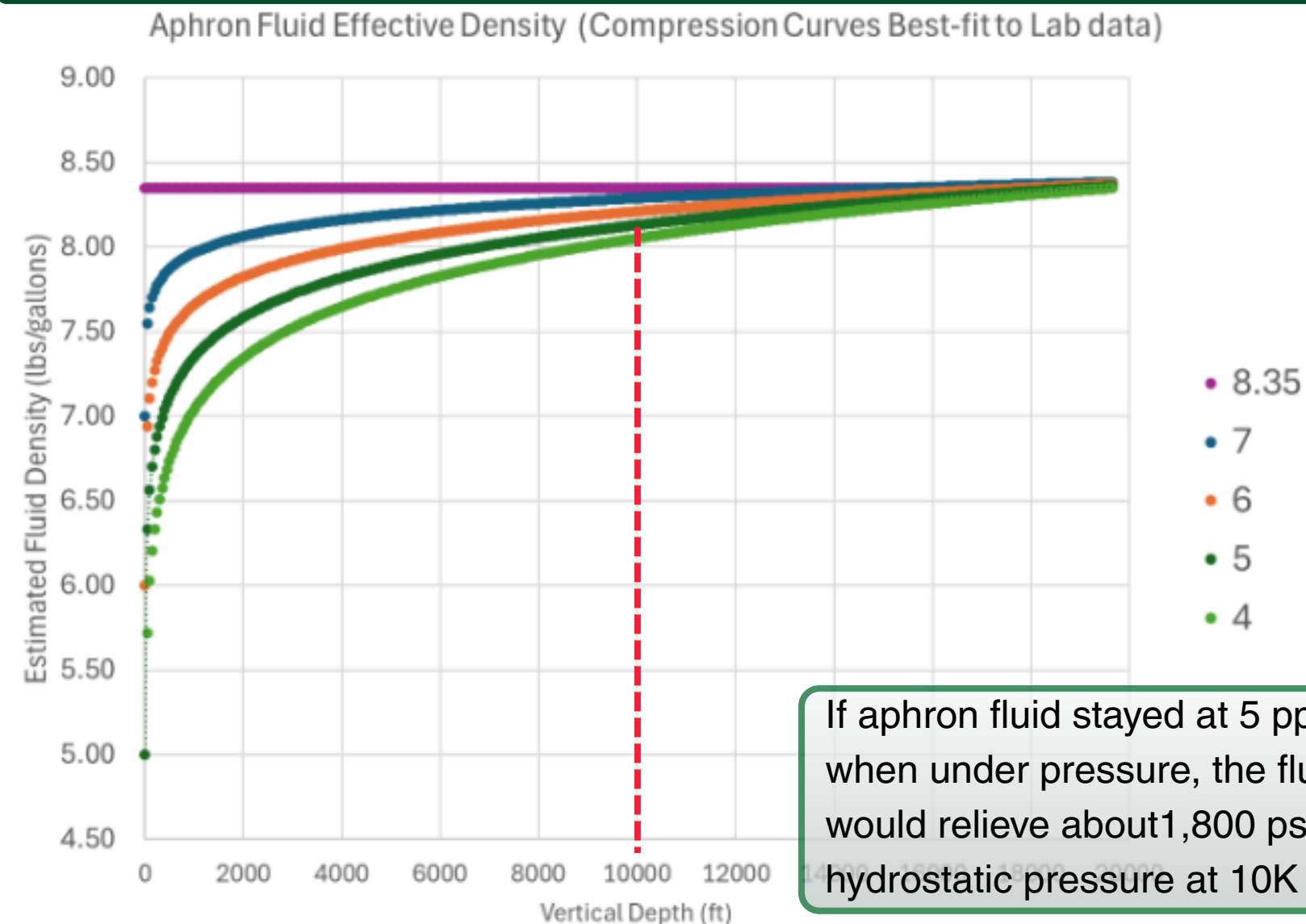
- Surface CGA density: 5 ppg
- Effective Density @TVD: ~8.1 ppg
- Net Est. hydrostatic relief: ~300 psi

DARCY'S LAW

$$Q = \frac{(K \times \Delta P)}{\mu}$$

Loss control from aphrons is driven more by μ (low-shear viscosity) & K reduction than by hydrostatic pressure relief

APHRONS COMPRESS RAPIDLY UNDER PRESSURE

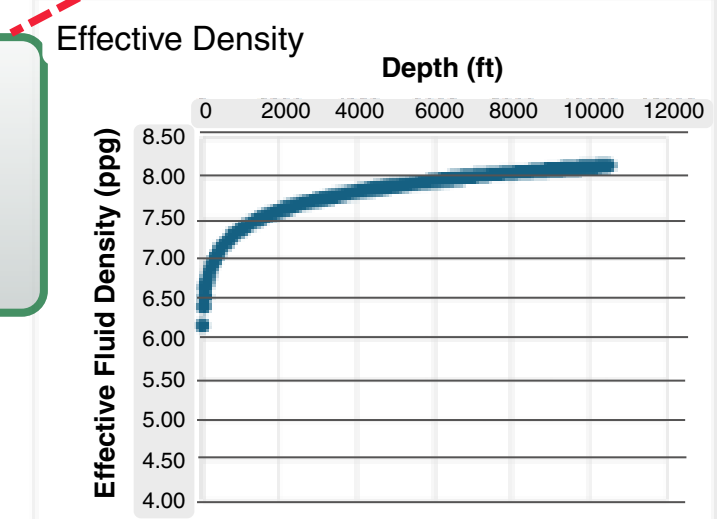
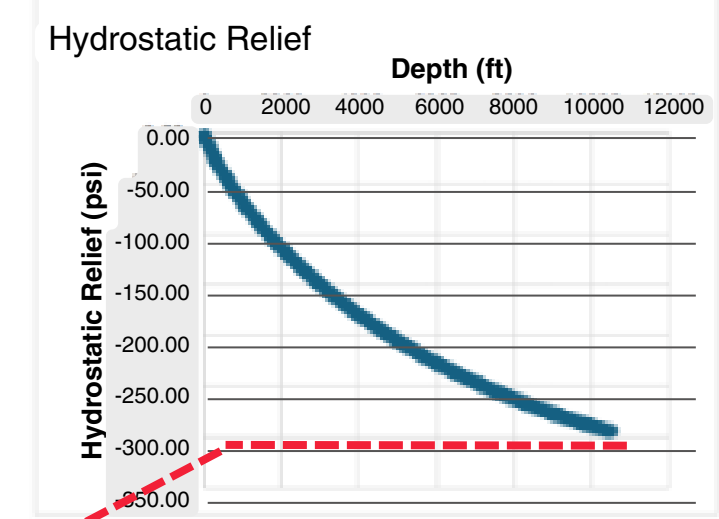


If aphron fluid stayed at 5 ppg when under pressure, the fluid would relieve about 1,800 psi of hydrostatic pressure at 10K ft....

SUPPORTING CALCULATIONS

Aphron Est. Hydrostatic Relief Calculator

INPUTS	
MODEL INPUTS	
Base fluid density (ppg)	8.35
TV Depth (ft)	10,000
Surface Fluid Density (ppg)	5
Interval step (ft)	30
Compression Coefficient	0.34
Compressed Density @ TVD	8.132



KEY INSIGHT:

Aphrons reduce hydrostatic pressure, but not nearly as much as people intuitively expect. Their real power is not ΔP reduction — it's viscosity and permeability effects.

WHAT DOES “DIVERTER SUCCESS” REALLY LOOK LIKE?



WELL CONTEXT: Low-pressure intervention where uncontrolled losses are preventing rig from being able to wash out any debris

JOB SCOPE: WOR intervention of previously producing well with severe heel depletion where aphrons alone would not be an economical solution

Did the treatment successfully restrict the dominant loss pathway?

NO SEAL ESTABLISHED WITH DIVERTER “A”

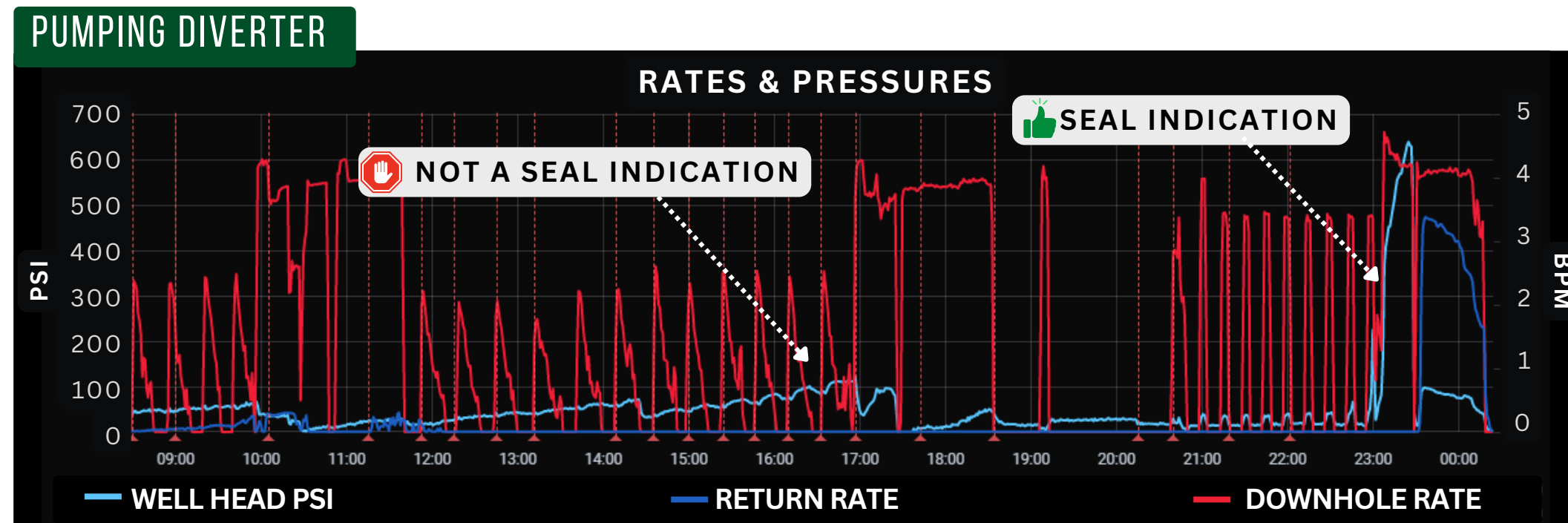
Diagnosis: Diverter failed to restrict the active loss pathway or insufficient pill volume / LCM concentration to establish a seal

- No sustained injection pressure increase
- Returns remain unstable or absent
- Rate changes do not result in circulation

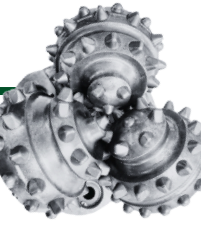
SEAL ESTABLISHED WITH DIVERTER “B”

Diagnosis: Loss path successfully restricted by a larger volume of a different blend of diverter, enabling stable circulation

- Step-change in circulating pressure
- Stabilized returns following treatment
- Clear timing alignment with LCM placement



FIELD EXAMPLE: THIEF ZONE ISOLATION & CIRCULATION RECOVERY



WELL CONTEXT:

Low-pressure intervention dominated by localized thief zone interrupting circulation; lost returns 1/3 of the way through lateral

Did the treatment successfully isolate the thief zone & restore circulation?

THIEF ZONE DOMINATING

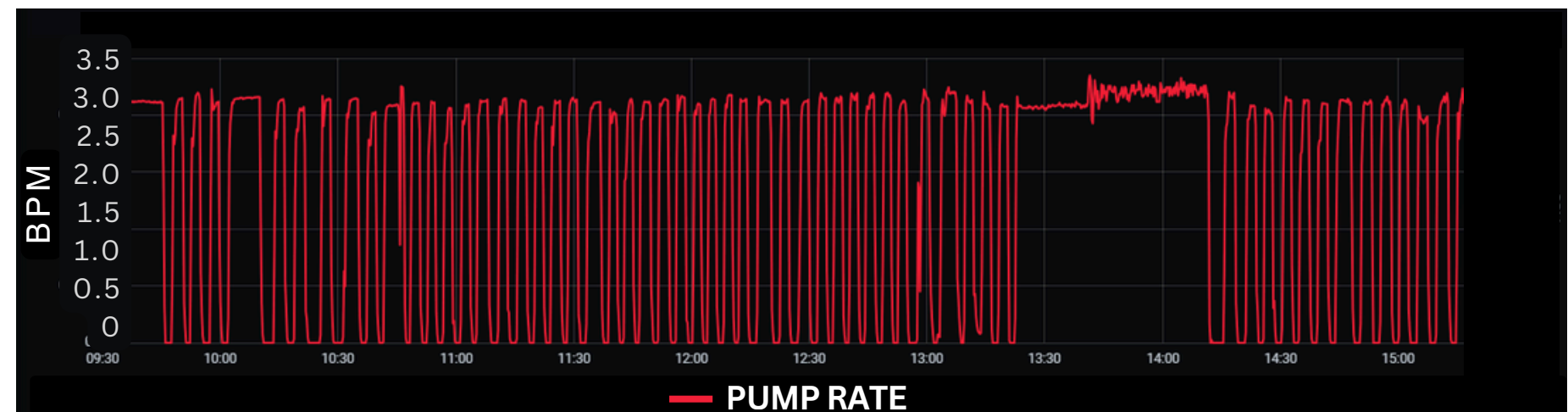
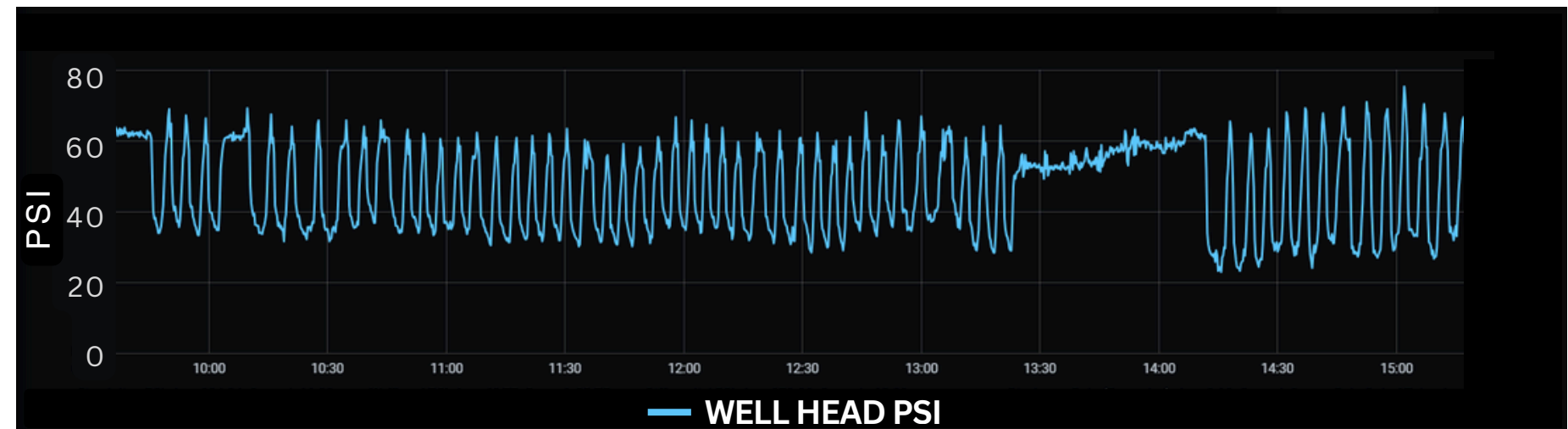
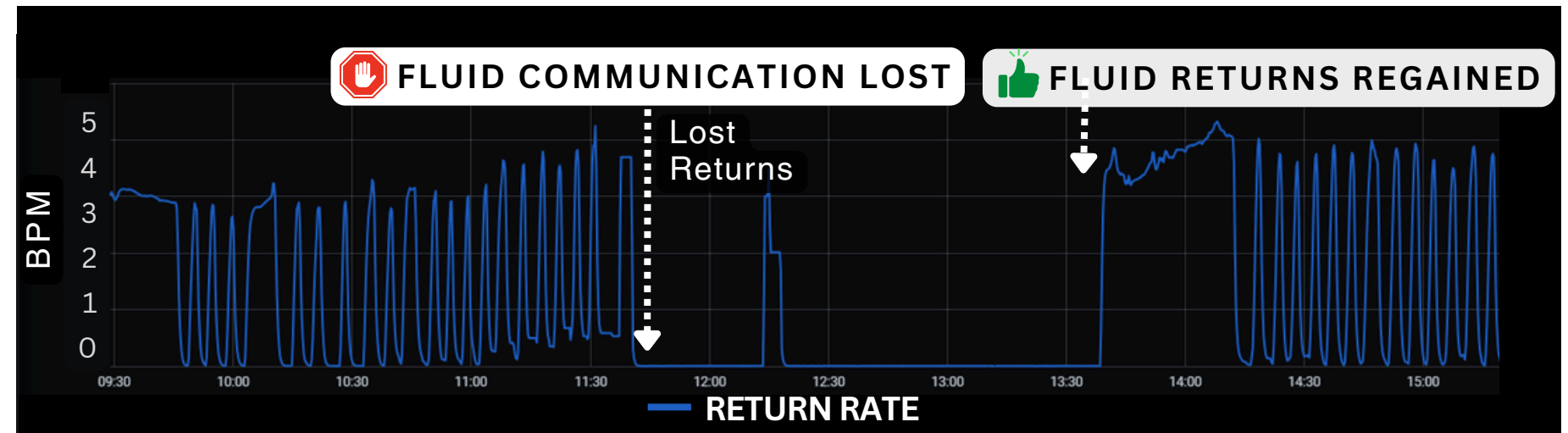
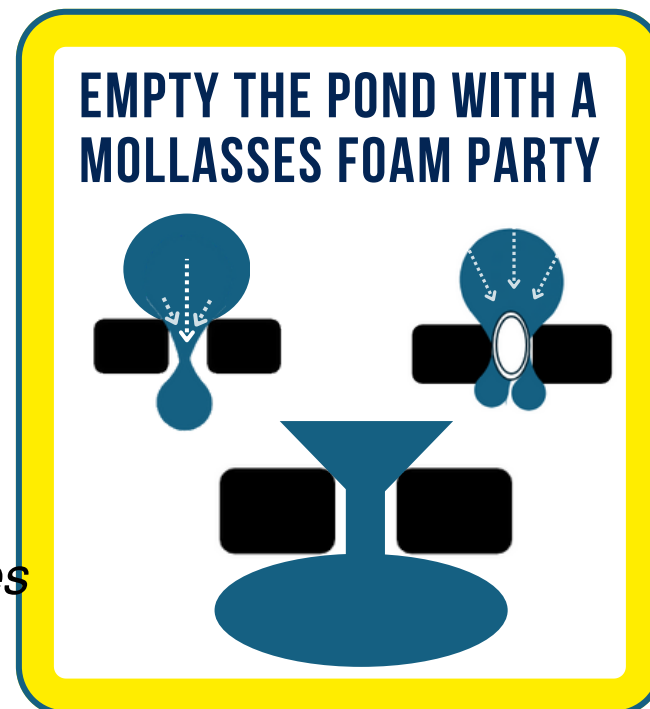
- Lost returns when washing through debris bed
- Returns unstable then became absent
- Operator continued to RIH & pump only while sinking joints

THIEF ZONE RESTRICTED / RECHARGED

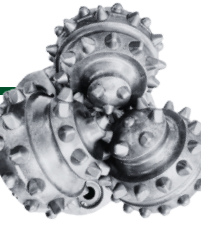
- Operator stopped RIH & allowed time for fluid properties to restrict the thief zone
- Returns re-observed at surface
- Full-volume circulation achieved

CHALLENGE QUESTION:

How long would you circulate without seeing returns before changing the fluid system properties or adding diverter into the fluid?



FIELD EXAMPLE: MAINTAINING CIRCULATION OVER 4 MILES IN A LOW-PRESSURE SYSTEM



WELL CONTEXT:

Semi-low pressure extended (4 mile) lateral drill-out where maintaining returns required coordinated control of target fluid density (aphrons), viscosity, & circulation periods (clean-up cycles)

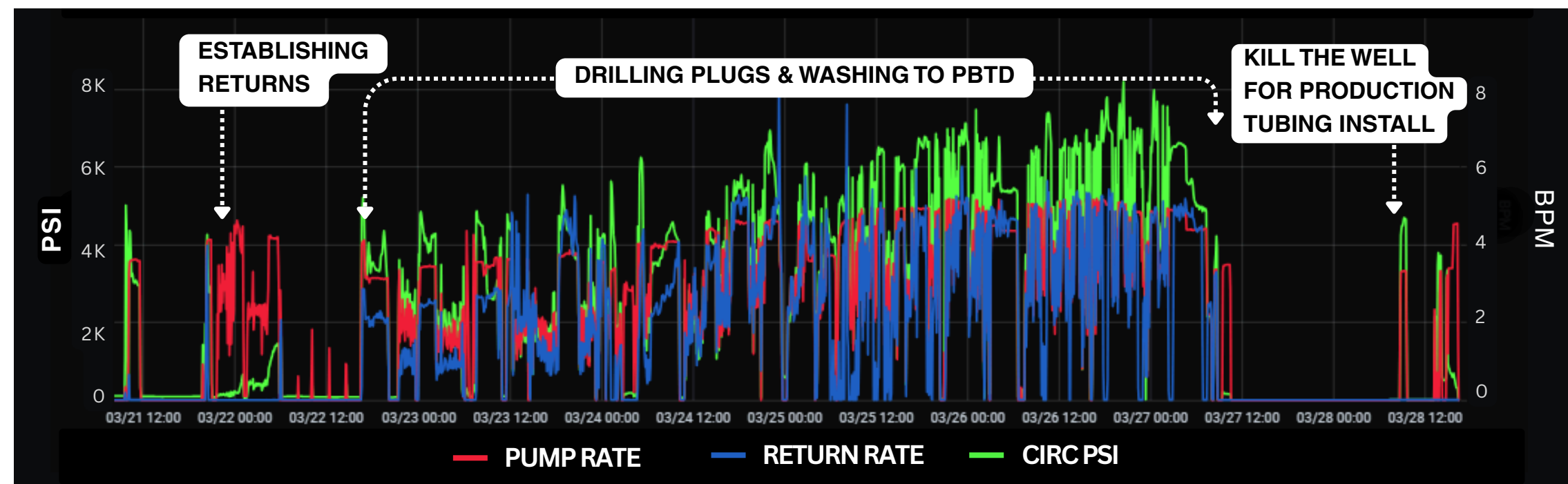
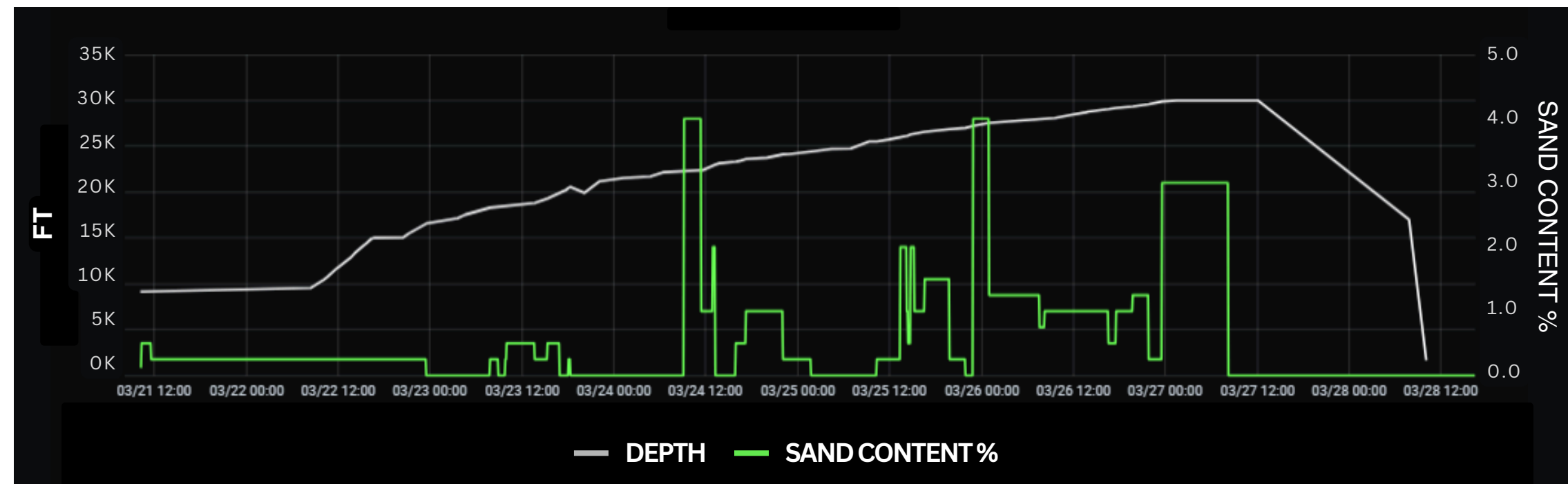
Circulation and drilling progress can be sustained over a long low-pressure interval when fluid properties and well conditions are stable.

OBSERVED FIELD PERFORMANCE

- Sustained circulation from 10,000 to ~30,000 ft
- Single run to bottom
- Average fluid density: 7.5 ppg (minimum 6.2 ppg)
- Circulating pressure: ~6,600 psi at 4.87 bpm
- Drilling rate: ~180 ft/hr
- Returns maintained using low-density fluid + LCM
- Average fluid balance: ~0.45 bpm loss

KEY INSIGHT:

Sustained circulation over extremely long lateral exposure required balancing debris transport & loss control with minor adjustments to the fluid properties.



COMMON ILLOGICAL FRAMING #1: "SCARED SH**LESS"

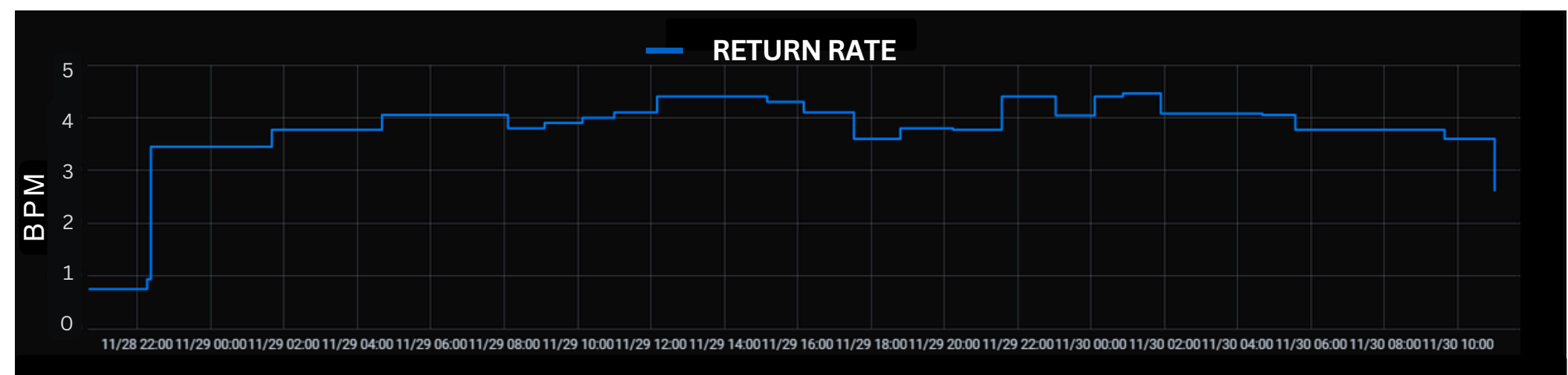
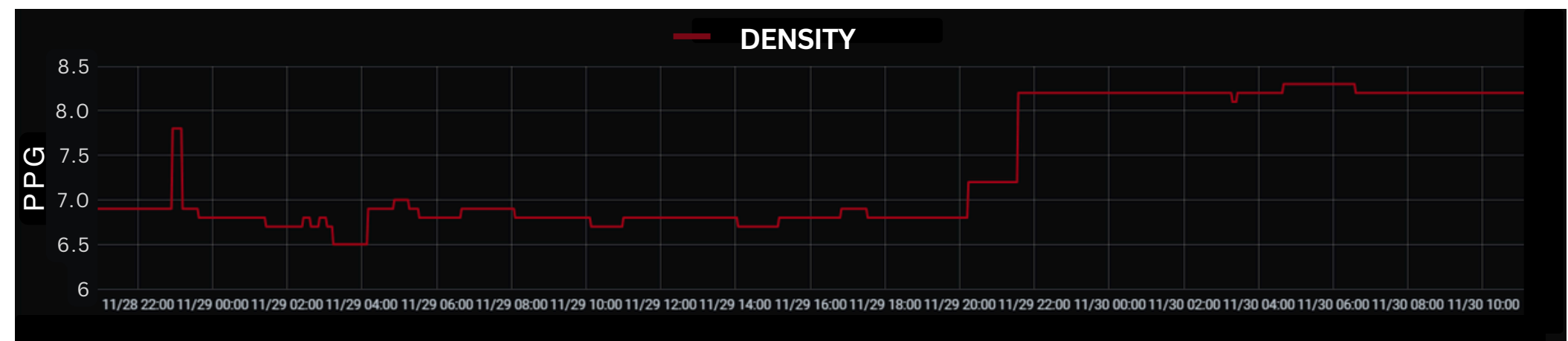
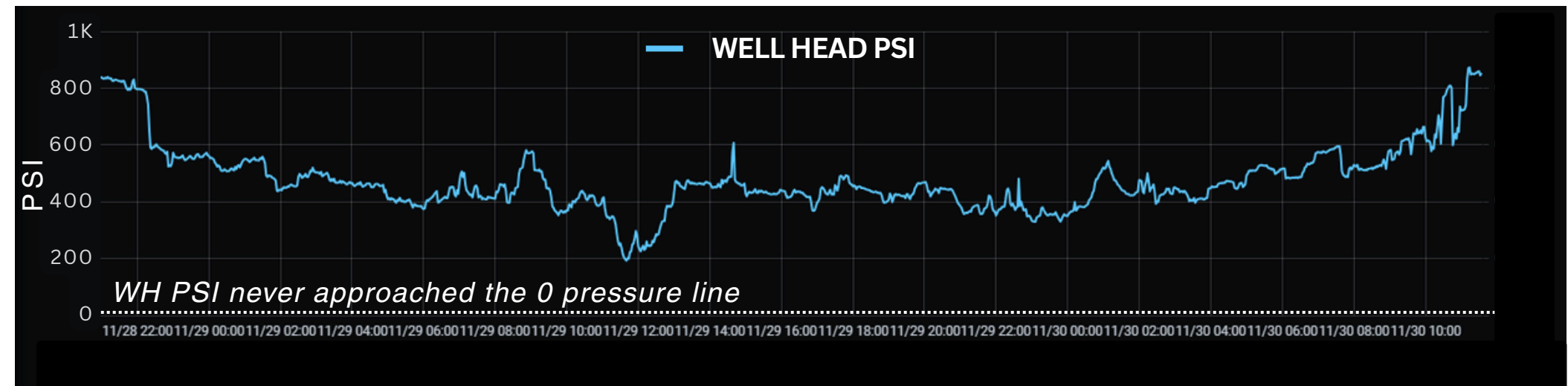
\$5000 SOLUTION TO A \$50 PROBLEM



WELL CONTEXT:

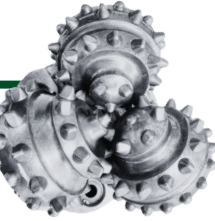
Semi-low pressure drill-out where wellhead pressure was adequate to gain & maintain circulation with non-aerated fluid (e.g. slickwater)

- Wellhead pressure ranged from 400-800 psi
 - In this pressure regime, a simpler slickwater system would have been sufficient to support cleanout, without escalating to higher-cost & complexity fluid systems
- Contingency in the event of losses would have been to increase rate, use diverter, or increase viscosity if needed
- Only escalate the cost of the fluid system if the well dictates



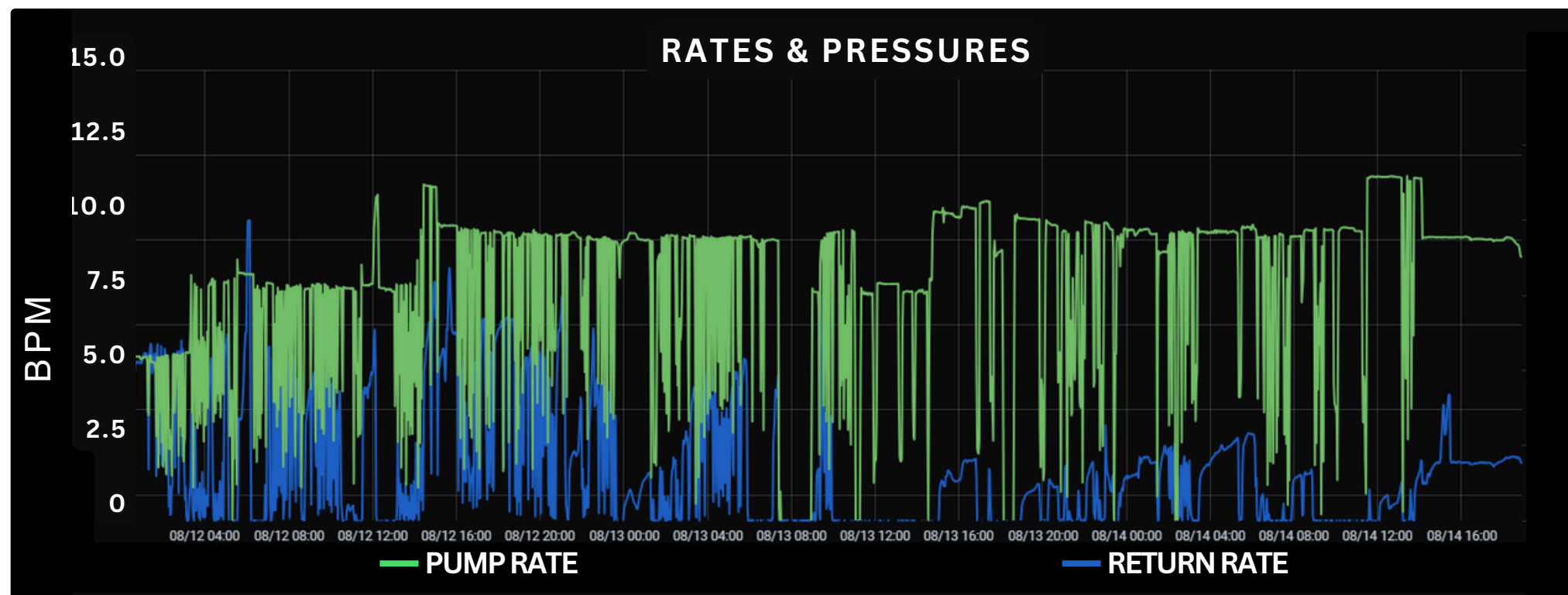
COMMON ILLOGICAL FRAMING #2: "JUST OVERPOWER IT"

\$500 SOLUTION TO A \$50,000 PROBLEM

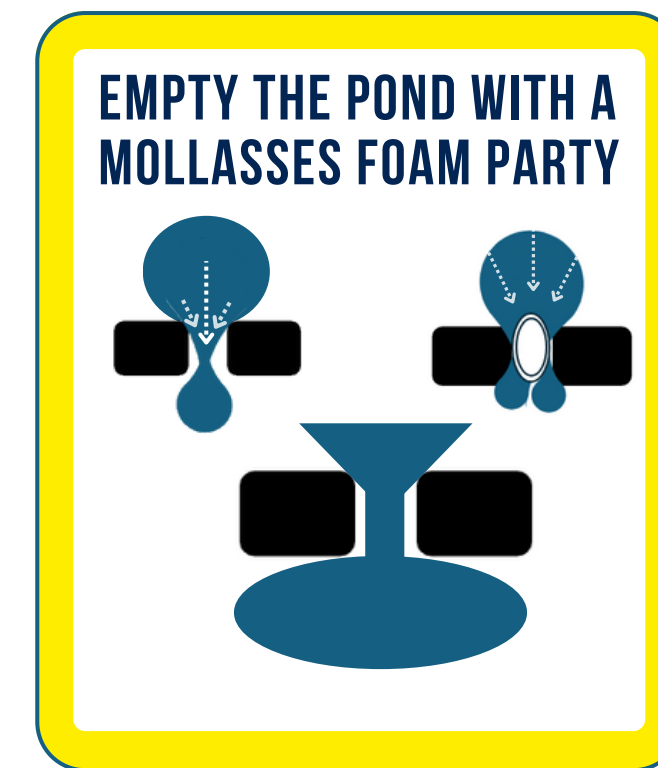


WELL CONTEXT:

Very low-pressure drill-out where even high viscosity low density aphron fluid system was not adequate to maintain bbl in/bbl out, so the operator tried to overcome losses with rate instead of using flow diverters



*Lost nearly 30,000 bbls of aphron fluid; needed to reduce permeability increase returns



...but whatever you do, don't invite Katy

- Pump rate of ~10 bpm on aphron fluid with avg return rate of ~3.7 bpm
 - Return-rate % indicates the dominant loss pathways were not being effectively restricted by CGA alone
 - LCM addition would have led to a higher return rate percentage and reduced fluid losses
 - Higher return rate percentage would allow for use of a WOR pump instead of a frac pump
 - Cost associated with the high loss rate of a CGA fluid could have paid for A LOT of diverter

“HOW GOOD IS GOOD ENOUGH?”

THE ULTIMATE PRICE VS. PERFORMANCE QUESTION



THE PRICE VS. PERFORMANCE TRADEOFF MUST BE EVALUATED IN THE CONTEXT OF EACH WELL

Low-Pressure Fluid system options:

- Water / Slickwater
- Gel
- Colloidal Gas Aphron
- Energized foam (N₂)
- + / – reversible diverters

What limits the optimal choice?

- Well parameters
- Economic constraints
- Logistical constraints
- Mechanical limits

The optimal solution is the lowest-cost fluid system that maintains operational control under the well's constraints & enables an efficient, complete intervention.

» — Fishing pipe or losing the well always costs more than the most expensive fluid system choice — «

When in doubt

- Stay flexible. Choose based on the best information available BUT plan contingencies for changing well conditions
- Use data from similar wells / previous interventions to refine field-specific patterns



KEY INSIGHT:

Success in low-pressure interventions results from a combination of good engineering judgment & appropriately applied fluid systems