**Sucker Rod Pumping Short Course**

**Downhole Gas Separator (DHGS):**

**How to Avoid Gas Interference:**
1. Design the DHGS (and its placement) so that gas naturally bypasses the Fluid Entry Ports on the Mud Anchor.
   - Best achieved by lumping the pump. If lumping above perfs, it might be beneficial to decentralize the DHGS (set the TAC 2-4 jts above SN), & since no well is 100% ‘vertical’, the gas will rise the high side while the DHGS (& liquid) occupy the low side.
2. Design the DHGS so the downward fluid velocity is slower than the Gas Bubble Rise Velocity: allowing the gas to escape.
3. If the gas cannot be adequately removed look to install a specialty pump that is better equipped to “pass gas”.
   - Managing gas: close pump spacing & long SL; hold more TP (to prevent gas from heading the top of the tbg dry).
4. Sand-Screens or other frictional restrictions can strain the gas out of solution leading to gas interference.
5. In certain situations (depending on the producing zones, TAC placement, & more), the TAC—in conjunction w/ a column of fluid (providing back-P.)—can bottle up high-pressure gas below the anchor leading to severe gas interference.

**How to Design DHGS:**
- Efficient gas separation requires that the **downward fluid velocity in the Quiet Zone** be less than the **gas bubble rise velocity**.
- Gas Bubble Rise Velocity occurs due to the density difference between gas & liquid and is proportional to the diameter of the bubble.
- Industry Rule of Thumb: a 1/4” gas bubble rises at 6 inch/sec. Thus, design to achieve a fluid velocity <6 in/sec (the slower the better).
- The best separation can be achieved by lumping the pump.
- To improve performance: increase X-sec Area & reduce the bbls/time pumping rate (compensate by increasing run-time).

**Downward Fluid Velocity in DHGS:**

\[
V_{\text{fluid}} = \frac{d_p^2 \times SL_{\text{DHGS}} \times SPM}{60 \times (ID_{\text{GA}}^2 - OD_{\text{GA}}^2)}
\]

**Comparison of X-Sectional Area**

<table>
<thead>
<tr>
<th>OD</th>
<th>ID</th>
</tr>
</thead>
<tbody>
<tr>
<td>3/4” GA</td>
<td>0.82</td>
</tr>
<tr>
<td>1” GA</td>
<td>1.05</td>
</tr>
<tr>
<td>1-1/2” GA</td>
<td>1.38</td>
</tr>
<tr>
<td>1-1/2” GA</td>
<td>1.61</td>
</tr>
<tr>
<td>2-3/8” MA</td>
<td>1.995</td>
</tr>
<tr>
<td>2-7/8” MA</td>
<td>2.441</td>
</tr>
<tr>
<td>3-1/2” MA</td>
<td>3.5</td>
</tr>
</tbody>
</table>

**Casing as ID of Mud Anchor**

| 4-1/2” | 4.5 |
| 5-1/2” | 5.5 |
| 7” | 6.276 |

**Note:** Nomenclature table with units for all figures & equations given on the last page.

**Fluid Load on Pump**

\[
F_O = \left( A \times \Delta P \right)_p = \frac{\pi}{4} d_p^2 \times (PDP - PIP)
\]

\[
PIP = CP \left( 1 + h_{D,FL} + \frac{0.433 \times SG_o \times GFLAP}{40,000} \right)
\]

\[
PDP = TP + 0.433 \times SG_{GW} \times h_{SN}
\]

**Note:**
1) Only use TVD depths with hydrostatic calculations (if well is not vertical).
2) In steady-state production, only oil (no water) resides above the pump in the annulus.
3) For a pumped off well, as the SN depth increases the ΔP_{p,D} increases—and the potential for gas interference worsens due to the higher compression required to admit fluid into the bg. Good gas separation and longer SL’s can mitigate this problem.

**Downhole Pump Operation:**
- Up-Stoke: the PIP charges the pump chamber full of fluid.
- Down-Stroke: the TV does not open (and thus no net fluid moved) until the fluid in the Pump Chamber is compressed to a pressure >PDP.
- Due to its compressible nature, free gas in the pump requires the plunger to travel much further into the down-stk before the gas becomes compressed enough (>PDP) for the TV to open. Additionally, as the plunger rises at the start of the up-stk the free gas expands to fill the new chamber volume created by the vacuuming plunger. This prevents the pressure in the chamber from rapidly dropping & necessitates the plunger travel further before P_{chamber} < PIP (so the SV will open to admit new fluid into the pump).

**Table:**

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Interpreting Pump Card Shapes:

- **Ideal Card:** fully anchored tbg, 100% liquid fillage, & pump in good condition.
- **Slanted:** Unanchored tbg indicated by the card being slanted at the kbg (Tubing Spring Constant).
- **Fluid Pound:** sudden impact load. Inefficient and very damaging to pump, rods, tubing, and GBox. The impact load causes rod buckling & rod-on-tbg slap.
- **Gas Interference (or Gas Pound):** a more gradual load transfer as gas compresses (pneumatic cushioning). Greatly reduces the pumping efficiency and indicates the well is not pumped off (=Fluid# @ a higher PIP).
- **Hole In Barrel:** as the bottom of the plunger passes the hole (arrow) the hydrostatic pressure is equalized across the plunger causing the F₀ to be lost.
- **Worn Pump:** slow to pick up & quick to release the fluid load, due to: TV leaking or plunger/ barrel wear.

Cycles of Pump Card:

1. **Bottom of Stroke:** Both valves initially closed.
2. **Expansion:** Pgr moves up picking up the fluid load, F₀. As F₀ transfers from tbg to rods, the tbg un-stretches & moves with the Pgr. Unanchored tbg, excessive slippage or gas expansion increase this stage.
3. **Intake:** SV opens @ #2 to admit new fluid. Now: rods carry the full F₀.
4. **Top of Stroke:** SV closes as Pgr stops vacating the chamber.
5. **Compression:** Pgr begins down. As F₀ transfers from rods to tbg the unanchored tbg stretches. TV opens @ #4 when P_{GBox} > PDP.
6. **Discharge:** Pgr moves through the fluid to repeat the cycle.

The 3 Causes of Incomplete Pump Fillage:

1. **Pumped Off:** Pump Capacity > Reservoir Inflow.
2. **Gas Interference:** gas compressibility interfering with the normal actuation of the SV & TV.
3. **Choked Pump:** restricted inflow to pump (plugged sand-screen or excessively high fluid friction).

Compression Ratio of the Pump:

- Anything that increases the compression ratio improves the pump’s ability to compress the fluid in the pump chamber & minimizes the percentage of the downhole stroke lost to gas compression.
- Longer SL’s dramatically help, but minimizing the Unswept Volume is the most crucial & is achieved by: close pump spacing along with good pump design (type of pump, high-compression cages, etc.).

\[
\text{Comp Ratio} = \frac{\text{Swept} + \text{Unswept Volume}}{\text{Unswept Volume}} = \frac{\text{Vol (@ Top of Stk)}}{\text{Vol (@ Bot of Stk)}}
\]

Pump Card Interpretation:

1. The Pump Card only represents the load on the plunger: no rod stretch or anything above the plunger is displayed on it.
2. The card shape indicates how the plunger picks up, holds, and releases the fluid load each stroke.
3. Keep in Mind: the TV & SV are one-way check valves & they only open when the pressure below becomes greater than the pressure above.
4. The key to interpretation:

   The card shape depends only on how the pressure changes inside the pump barrel relative to the plunger movement.
   - A slow load loss on the down-stk indicates the gradual release of F₀ due to gas compression or tubing breathing.
   - A sudden load loss on the down-stk indicates fluid-pound as the load transfers almost instantly as the plunger belly-flops into the fluid.
   - On up-stk, a gradual load pick-up indicates the pump’s Chamber-P. is not quickly dropping to PIP, indicating: tbg movement (unanchored), fluid slippage (worn pump), or gas expansion—or all 3 combined.

Note: except for DH friction assumptions, this is true for a horseshoe or donut load-cell (installed between the Bridle & PR Clamp). For many reasons, most Dyno’s commonly used by Well Techs are the quick-install PRT Dyno (Polished Rod Transducer) that measures the radial strain (change in diameter) of the PR each stroke & uses this data to back-calculate the F₀—& these Pump Cards can sometimes be slightly tilted due to surface misalignment & bending of the PR.
Sucker RP Equipment Design: Considerations

Equipment Design:
- The pumping system should be designed for the long-haul.
- Don’t oversize. If the well is expected to pump-off in 9-months—at which point the production can be maintained with a slower SPM & downsized pump (decreasing the loadings)—great savings can be incurred by temporarily (fully) taxing a smaller GBox or Grd D Rods (vs HS Rods) for those 9-months instead of upsizing.
- Longer SL’s and slower SPM is preferable. Advantages include:
  - With a Longer SL- Rod-stretch, gas compression, or unanchored tbg breaching will consume a smaller percentage of each stroke.
  - Long SL’s increase the compression ratio & the ability to pump gas, & require fewer down-stks (rod buckling) to achieve the same prod.
  - Slow SPM reduces: buckling tendencies & rod-on-tbg wear, rod loadings & the impact force of the plunger if it does #Fluid or tag.

Rod Design:
Sucker Rods are designed to only be operated in tension (hence K-bars). Rods operate in a pulsating tension along each stroke as the F<sub>0</sub> is picked up & released—and as a result of the stress reversal cycles—they have a limited run life.

The API Modified Goodman Diagram (MGD) is the industry design guide that that attempts to quantify a rod’s estimated run life based on the Max & Min stress loadings the rod will experience under the operating conditions. Using this guide, rod loadings are reported as “Percentage of Goodman”.

In a noncorrosive environment, a steel rod operating at 100% MGD Loading is expected to have a run-life greater than 10 x 10<sup>6</sup> cycles (or 10 SPM pumping for ~2 years), while FG rods @ 100% MGD have an expected >7.5 x 10<sup>6</sup> cycles @ 160°F. As the MGD loading decreases below 100%, the run-life increases exponentially. Since the MGD loading value does not take into account corrosion [or buckling, mishandling damage, etc.] the MGD run-life must then be de-rated by a Service Factor related to the corrosivity of the downhole environment.

Fiberglass Rods: (AKA, FRP Rods: Fiber Reinforced Plastic)
- Weigh 70% less & are 4x more elastic than steel, are corrosion resistant (not de-rated for corrosive environments), have an undersize pin (allowing 1" FG rods to be used in 2-3/8" tbg, etc.) & have mechanical strengths comparable to HS-steel rods. Their expected run-life if temperature dependent.
- FG elasticity is advantageous for fast pumping wells with high fluid levels (leads to plunger Over-Travel). Their elasticity is disadvantageous for slower pumping wells with large F<sub>0</sub> (SL<sub>0</sub> is lost to rod-stretch). This is why on pumped-off FG wells, downsizing the pump often does not substantially reduce production: the downsized 1<sub>d</sub> increases the DH<sub>0</sub> (due to smaller F<sub>0</sub>.

Steel Rods:
- Rod Grade(3, C, K, D, & HS): selection should be made based on the mechanical loadings on each taper and the downhole corrosivity.
- Grd D rods: DC (carbon), DA (alloy), & DS (special).
- Different heat treating processes create different mechanical properties. Generally, as rod strength is increased the rod becomes more susceptible to corrosive attack & mishandling damage (nicks & dings that cause Stress Risers & become the nucleation point for future corrosive attack).
- Sinkers Bars: are designed to absorb the DH compressive forces & keep the other rods in tension. Their larger OD distributes side-loads from buckling forces over a larger area—so they do not cut as incisively into the tubing.

Rod Boxes: (AKA: Rotary-Connected, Shoulder-Friction-Held Connections)
- The make-up torque (checked by Circumferential Displacement) puts tension in the rod pin and friction locks the box to the face of the pin shoulder. This pre-stress put into the connection must be greater than the up-stk dynamic load which attempts to pull the connection apart.

Pump:
- Tbg Pumps: largest bore pumps (d<sub>eff</sub> just a 1/4" < ID of tbg).
- Rod (Insert) Pumps, 3-types: based on where the hold-down is located (top or bottom) & whether the barrel is Stationary or Traveling.
- First efforts should be made to exclude gas & solids from entering the pump before resorting to a pump design that attempts to accommodate them.
- A favorite pump of ours is the 2S-HVR (2-Stage Hollow Valve Rod). The upper TV (on the HVR) holds back the hydrostatic pressure allowing the lower TV to more easily open when pumping gaseous fluids. It also distributes fluid discharge across the whole SL (greatly minimizing Pump Discharge Leaks), & the hollow valve rod is more stiff & less inclined to buckle.

Tubing & TAC: (Tubing Anchor Catcher)
- Unless anchored with pre-tension, the tubing will stretch and contract each stroke as the rods pick up & release F<sub>0</sub>. This “breathing” decreases the pumping efficiency because only the net relative movement of the plunger to the pump barrel contributes to fluid displacement.
- With unanchored tbg: on the down-stk, as the rods start down & begin to release the F<sub>0</sub> (onto the tbg) the tbg stretches accordingly. On the up stk, the tbg recoils & helically buckles [wrapping around the stretched rods] causing the pump barrel to initially move upward w/ the plunger.
- Smaller diameter pumps will cause less tbg breathing. In a pumped off 8000' well with 2-3/8" tbg: 1-1/16" pump (7.5") vs 1-1/2" pump (15").
- Eq. for Tbg Stretch or to calculate the Depth to Free-Point (stuck pipe):

\[
Tbg \text{ Stretch} = k_{tbg} \times L_{tbg} \times F_{Pull} \quad k_{tbg} = 0.4 / A_{tbg.x/sec}
\]
- Note: Stretch (inches); L<sub>tbg</sub> (in 1000’s of ft); F<sub>Pull</sub>(1000’s of #’s).
- k<sub>tbg</sub> = Stretch Constant: is not affected by the grade of steel, only the x-area (given on .p or use above equation).
- L<sub>tbg</sub> = Length of tbg being stretched by the force, F<sub>Pull</sub>.
- Proper TAC Setting Procedure: after 8 left-hand turns (or until it torques up) continue to hold the torque as the operator alternates 10 pts tension & compression before releasing the pipe wrenches (this works the torque downhole & fully engages the TAC slips so it will not turn loose).

*Generally Accepted Service Factors for Sucker Rods:

<table>
<thead>
<tr>
<th>Environment</th>
<th>Grd C</th>
<th>Grd K</th>
<th>Grd D</th>
<th>HS Rods</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Corrosive</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>Salt Water</td>
<td>0.65</td>
<td>0.90</td>
<td>0.90</td>
<td>0.70</td>
</tr>
<tr>
<td>H2S</td>
<td>0.45</td>
<td>0.70</td>
<td>0.65</td>
<td>0.50</td>
</tr>
</tbody>
</table>

High-Strength Rods: due to their heightened susceptibility to corrosion, many rod pumping gurus recommend loading Grd D rods up to 100% MGD Loading (using a 1.0 Service Factor) before resorting to the use HS rods.

Load on the Polished Rod (PR):

\[
F_{PR,Up-Stk} = W_{tfg} + F_0 + F_{Dynamic/friiction}
\]
\[
F_{PR,Down-Stk} = W_{tfg} - F_{Dynamic/friiction}
\]
- W<sub>tfg</sub> = Weight of rods in fluid (compared to W<sub>0</sub>: weight of rods in air).
- In fresh water, FG rods weigh 58% of W<sub>0</sub> & steel rods = 87% of W<sub>0</sub>.
- Dynamic Loads: result from PPU kinematics & acceleration forces.
- Friction Loads: result from rod-on-tbg engagement, fluid friction ("viscous drag"), paraffin sticking, stuffing box friction, & pump friction (AKA “plunger drag”).
- Proper Counter-Weight Balance requires balancing the average load on the Polished Rod, thus:

\[
CW \text{ Bal} = W_{tfg} + 0.5 \times F_0
\]

Laboratory Measured Loads to Buckle Rods:
- Test conducted with rods in air (Long & Bennett, 1996).
- Notice the large difference even between the 3/4” & 7/8” rods.

<table>
<thead>
<tr>
<th>Rod Force to Diam.</th>
<th>Buckle</th>
</tr>
</thead>
<tbody>
<tr>
<td>3/4</td>
<td>23#</td>
</tr>
<tr>
<td>7/8</td>
<td>162#</td>
</tr>
<tr>
<td>1 3/8</td>
<td>641#</td>
</tr>
</tbody>
</table>

Equation for FG RodSpacing:
Inches Off Bottom

\[
FG \text{ Spacing} = \frac{9 \times h_{FG,Rod} + 2 \times h_{SN}}{1,000}
\]
- Space 9” for every 1000’ of FG Rods & 2” for every 1000’ to SN.
- Slow-stoking units can space closer than the calculated inches.
- For proper pump spacing (especially w/ FG rods due to their elasticity), load the tbg with fluid prior to spacing the pump out.

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Design Considerations:
- On 1.5" K-bars, run 3/4" SH-boxes (1.5" OD) instead of FH-boxes. This creates a uniform diameter over the bar section & spreads out any side loading on the tbg over a larger area, minimizing stress (Stress = F/Area).
- Install boronized (EndurAlloy) tbg or Poly-Lined tbg in bottommost jts where most tbg leaks occur.
- Spray Metal Boxes: corrosion resistant and made for highly erosive/corrosive environments. The SM coating is more abrasive on the tbg because the tbg will wear down before the box does (as opposed to T-boxes where the protruding edge will wear out & conform to the tbg ID).

Pulling the Well:
- Create a Pre-Pull Plan: review location of recent failures, latest well tests, and FL/Dyno reports to see if DH should be modified.
- On 1st tbg failure, scan the tbg out of hole: to get an initial rod wear profile on the new tbg, & to check chemical program (pitting).
- During a tbg job: rotate ~10 jts of “fresh” tbg from top to bottom.
- During a rod job: can rotate a steel pony rod (≥ 2L) to bottom. This shifts all the boxes up out of their existing wear tracks to rub on fresh tbg.
- Root-Cause Failure Analysis: identify the cause! Clean corrosion deposits off with a wire brush/diesel, cut failed tbg jts open, discuss with Chemical Co. & take pictures to include in the pull report for future reference.

Operations & Monitoring:
- Stoke her long & stroke her slow—and match her inflow.
- Keep the pump barrel full. Ensure proper run-time by calibrating it with a FL Shot/Dyno Survey, a POC, well tests, or by hiring a good pumper.
- As the well pumps off, reduce the SPM: this improves run-life, improves downhole gas separation, & is insurance by reducing the force of impact generated if (or when) the plunger pounds fluid or tbg.
- Mix in biocide with any fluids introduced into the well. Bacterial pitting can be the most aggressive in drilling holes in your rods & tbg.

Fluid Level Gun & Dyno:
- Fluid Level & Dyno Surveys are noninvasive diagnostic tools that quantify the well’s Producing Performance—in terms of the well’s Production Potential (reservoir drawdown) & the Operational Lifting Efficiency of the rod pumping system (how efficiently the fluid is being lifted to surface).
- By interpreting the diagnostic data in context of the well, producing inefficiencies can be detected & corrected. Diagnostic data lays the foundation from which prudent operational decisions can be made & justified.
- Dyno’s: measure rod/pump performance (see Pump & Dyno page).
- Fluid Level Gun: generates an acoustic wave (pressure pulse) that travels down the well, reflects off cross-sectional changes in area (collars, perfs, TAC) until the wave encounters the fluid level & completely reflects back. The gun’s internal microphone records the amplitude and polarity of the reflections on an Acoustic Trace and allows the depth to the top of the Gaseous Fluid Level to be determined.
- The subsequent Casing Pressure Build-Up Test allows for the quantification of the MCFPD of gas producing up the casing and, consequently, allows for the determination of the GFLAP (Gas Free Liquid Above Pump) and BHP’s (Bottom Hole Pressures), like: PIP, PBHP, & SBHP.
- Polarity of Acoustic Reflections:

Objectives of Rod Pumping Optimization:
- Fully achieve the well’s maximum producing potential with minimum expenditure (including time & attention).

How RP Optimization is Achieved:
1. Good Equipment Design: rod/pump/PPU design, gas separation, SPM × SL, metallurgy, SN placement, etc.
2. Equip. Installation: properly torque, avoid damaging, etc.
5. Chemical Program: Both active and reactive.
6. Inspiration: Field hands must buy into the program.

Changing PPU SPM:

$$SPM_{New} = SPM_1 \frac{d_{New}}{d_1}$$

- To change the SPM the existing motor sheave size (d1) & the motor shaft diameter (measured or correlated with Frame Size on motor) must be known.
- Drive belts sit “4/10” within the sheave OD, thus a measured 7.4” sheave OD is really a 7” sheave.
- For an expanded list of frame sizes: www.downholecison.com
- The smallest sheave size is 5”. If the desired SPM would require a sheave size smaller than 5” look into: upsizing the Bull sheave (on GBox), install a jack-shaft or a VFD (Variable Frequency Drive), or consider shortening the SL. FYI: “sheave” is pronounced “shiv.”

Gas Interference (or “Gas Pound”) & Fluid Pound:
- Gas Pound is essentially Fluid Pound but at a higher PIP & with more compressible gas in the pump. Gas# is just as inefficient as Fluid# due the cushioning effect of the gas—it is less destructive to the downhole equipment.
- Although less damaging, wells experiencing gas interference are not achieving maximum production due to the additional fluid column that cannot be pumped down. At least with Fluid#, you know your getting ALL the production (and trying to get some more…).
- Pounding is a shock loading that induces the rods to helically buckle as they bow out and engage the tbg walls. The force of the impact is proportional to: F = (thus d3). The velocity of the plunger at the time of impact, and the time duration for the load transfer to occur.
- Gas or Fluid# in the middle of the down-stk can be much more damaging because here the plunger is at peak downward velocity.
- Fluid# can often be detected by listening for GBox “thuds,” motor speed changes, & watching for the bridle/Polished Rod to twitch on the down-stk. However, for slower SPM or FG rod-strings it can be more difficult to identify without the aid of a Dynamometer analysis.

Vogel’s IPR (Inflow Performance Relationship):

$$q_{WT} = \left[1 - 0.2 \frac{PBHP_{WT}}{P} - 0.8 \left( \frac{PBHP_{WT}}{P} \right)^2 \right] \left( \frac{P}{SBHP} \right)$$

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### Mechanical Properties of EUE (External Upset End) Tubing:

| Tubing API Grade | "Letter Grade"—"Min. Yield Strength (1000’s of psi)"
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>&quot;A&quot;</td>
<td>35,000 psi</td>
</tr>
<tr>
<td>&quot;B&quot;</td>
<td>41,000 psi</td>
</tr>
<tr>
<td>&quot;C&quot;</td>
<td>46,000 psi</td>
</tr>
</tbody>
</table>

*Note: ft/bbl has been rounded.*

### Buoyancy Force

**Buoyancy Force:** is equal to the weight of the fluid displaced by the immersed object.

\[
W_{Buoyant} = \rho_{fluid} \cdot V_{pipe} = \rho_{plate} \cdot V_{plate}
\]

- \( \rho_{fluid} = 489 \text{ lb/ft}^3 \) and \( \rho_{plate} = 150 \text{ lb/ft}^3 \).
- In Fresh Wtr (SG=1.0): FG weighs 58% & Steel 87% the WAir.

\[
W_{Buoyant} = W_{Air} \left(1 - \frac{62.4 \cdot SG_{O/W}}{\rho_{Material}}\right)
\]

### Capacity Factor (CF)

**Capacity Factor (CF):** for any size hole or annulus (in bbbls/ft)

- Set OD = 0" if no concentric string is inside the pipe.
- Ex: ignoring upsets/boxes, the C.F. between 2-3/8” ID and a string of 3-4/8” (OD=7.5") is 0.00332 bbbls/ft.

\[
CF = \frac{ID^2 - OD^2}{1029}
\]
Nomenclature, API, & EQ’s

API Pumping Unit (PPU) Description:

C 320D — 305 — 100

a: #1, b: #2

Max SL: in.

A: PPU Type:
- C: Crank Balanced
- B: Beam Balanced
- R: Reverse
- A: Air Balanced
- M: Mark II (grasshopper)

B: PPU Structure Rating,
- 100’s of lbs.

RM: Reverse Mark
- G: Gear
- B: Belt
- D: Double Reduction

Note: PPU’s that have the Equalizer Bearing residing directly over the GBox Crankshaft will use equal degrees of crank rotation for both the up & down-stroke. The equalizer bearing is shifted forward towards the horsehead on the Reverse Mark & Mark II making their up-stk 12% (RM) & 18% (Mi) slower than their down-stk.

Nomenclature:

< or > Less than or Greater than: Ex: 1 < 1.01; A&M > UT

Δ Delta, represents the change in a quantity

% Percentage (use a fraction: 25% = 0.25)

ε Efficiency, fraction (85% = 0.85)

ρ Density, lb./ft³ (36.2 lb./ft³ at 70°F)

μ Viscosity of Fluid, cp

μc Math & Greek

A Area, in²

API American Petroleum Institute, industry guidelines

d Diameter, in.

BFPD Bbls Fluid Per Day (i.e. Oil+Water: BOPD + BWPD)

BHP Bottom Hole Pressure, psi

BP Bottom Pressure, psi

Cqg Pressure (usually Flowline P.), psi

DH Downhole (abbrev.)

DHGS Downhole Gas Separator/Separation

F Force, lb.

F0 Fluid Load on Pump, lb.

GA Gas Anchor: inner tube of DHGS

GFLAP Gas Free Liquid Above Pump, ft.

h Height, ft

ID Internal Diameter, in.

k Spring Constant, units: in.x1000 lb./1000 ft

L Length, ft. (unless noted)

MGP Modified Goodman Diagram (% rod loadings)

OD Outer Diameter, in.

P Pressure, psi

PBHP Producing BHP (@ bottom perf), psi

Pgr Plunger

Pip Pump Intake Pressure, psi

PDP Pump Displacement Pressure, psi

ppg Pounds per Gallon, Lb./gal (Bine = 10 ppg)

PPU Pumping Unit (AKA Pumpjack, Nodding Donkey)

PPM Parts Per Million

PR Polished Rod (top connecting rod)

PRHSH Static BHP (local avg. Reservoir P.), psi

SG Specific Gravity (FW = 1.0 SG = 8.34 ppg)

SL Stroke Length, in

SMP Spring Pressure, min

SV Standing Valve (pump’s non-moving valve)

Tbg Tubing (abbrev.)

TAC Tubing Anchor Cachter (for tbg tension)

TV Traveling Valve (moving/stroking valve of pump)

TVD True Vertical Depth (vs Measured Depth), ft

TP Tubing Pressure, psi

W Weight, lb.

Subscripts:
- D,FL Dead Fluid Level (FL when gas volume subtracted)
- DH Downhole (e.g. @ the pump)
- DT Dip Tube: inner barrel of DHGS
- EPT Effective Pgr Travel (“pumping” part of DH SL)
- FGRods Length of Fiberglass Rods, ft.
- FL Fluid Level (the “kick” on the Acoustic FL Trace)
- MA Mud Anchor: outer barrel of DHGS
- P Pump
- O or W Oil or Water; O/W = Oil & Wtr (mixture)
- rf Rods in Fluid (considering buoyancy force)
- RT Run Time, fraction of the day the wells pump
- SN Seating Nipple (i.e. pump depth)
- Tbg.x-sec Cross sectional area of tbg metal, in²

API Pump Designation:

20—125 R H B C 20—5—4—0

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<th>#1</th>
<th>#2</th>
<th>a</th>
<th>b</th>
<th>c</th>
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<tbody>
<tr>
<td>Tubing Size, ID - 20 = 2.0” (2-3/8”); 25 (2-7/8”); 30 (3.5”)</td>
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<td>Pump Bore, ID - 125 = 1.25”</td>
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<tr>
<td>Pump Type: R: Rod, T: Tbg</td>
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<tr>
<td>Plunger Type &amp; Barrel Thickness: H: Heavy, W: Thin</td>
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</table>
| Seating Assembly Location: A: Top, B: Bottom, T: Bot. (Traveling-Barrel)
| Seating Assembly Type: C: Cup, M: Mechanical |
| Barrel Length, ft. |
| Plunger Length, ft. |
| Length of Upper Extension, ft. |
| Length of Lower Extension, ft. |

Also important to know:
- Plunger & Barrel Metallurgy, Plunger Clearance (“Fit”), & the Valve Metallurgy.

Helpful Reference EQ’s:

S.G. of Oil: \[ SG_{O/W} = \frac{SG_{API}}{API+131.5} \]

S.G. of Produced Water:

The Specific Gravity of produced water is a function of the TDS (Total Dissolved Solids), not just Chlorides. So a Wolfberry well producing 100K CI probably has a S.G. closer to ~1.09.

Assuming gas-free.

Bottom Hole Pressure: \[ BHP = P_{Surface} + 0.433 \times SG \times h_{TVD} = P_{Surface} + 0.052 \times ppg \times h_{TVD} \]

Avg Polished Rod Velocity: \[ \bar{V}_{PR} = \frac{2 \times SL \times SPM}{12} \] (ft/min)

For comparing pumping speeds (velocity) of wells w/ different SL’s.

Fluid Slippage: \[ Slippage = [1 + 0.14 \times SPM] \times 453 \times \frac{d_{pgr}}{L_{pgr}} \times \frac{\Delta P_{pgr} \times C_{pgr}^{1.52}}{\mu} \] (BFPD)

(2006, Patterson Equation)

L_{pgr}: Pgr Length (inches). \( \mu \): fluid viscosity (cp)

Failure Frequency: \[ \text{Failure Frequency} = \frac{# \text{ of Failures/Year}}{\Sigma \text{Producing Wells}} \]

(A F.F. of 0.25 = 4-yr avg Run Life per well)

APB’s & SRB’s are the oilfield’s STD’s! Both set-up shop on downhole metallurgy & wear havoc. Acid Producing Bacteria excrete acids while Sulfate Reducing Bacteria generate H₂S— which both rapidly corrode the steel. Worse yet, the byproducts of the corroded steel further inhibit the ability of chemicals to penetrate & kill the underlying colonies. MIC (Microbial Influenced Corrosion) is highly penetrating and can quickly initiate rod parts & tbg leaks. Protect your producers by biocide-treating any fluids introduced into a well (including frac jobs). If introduced into the deepest part of each and every frac stage, there is no possible recourse for their removal from the formation—only Hope & Faith remain. And if APB’s & SRB’s are the oilfield STD’s—that would make Pump Trucks the licentious couriers propagating this most pernicious seed from lease-to-lease, operator-to-operator.

“An ounce of prevention is worth a pound of cure.” -Benjamin Franklin

SRB pitting with the characteristic pits-within-pits. All the black splotches are the corrosion byproduct (iron sulfide scale) with colonies residing underneath (center pits cleaned out with wire brush).