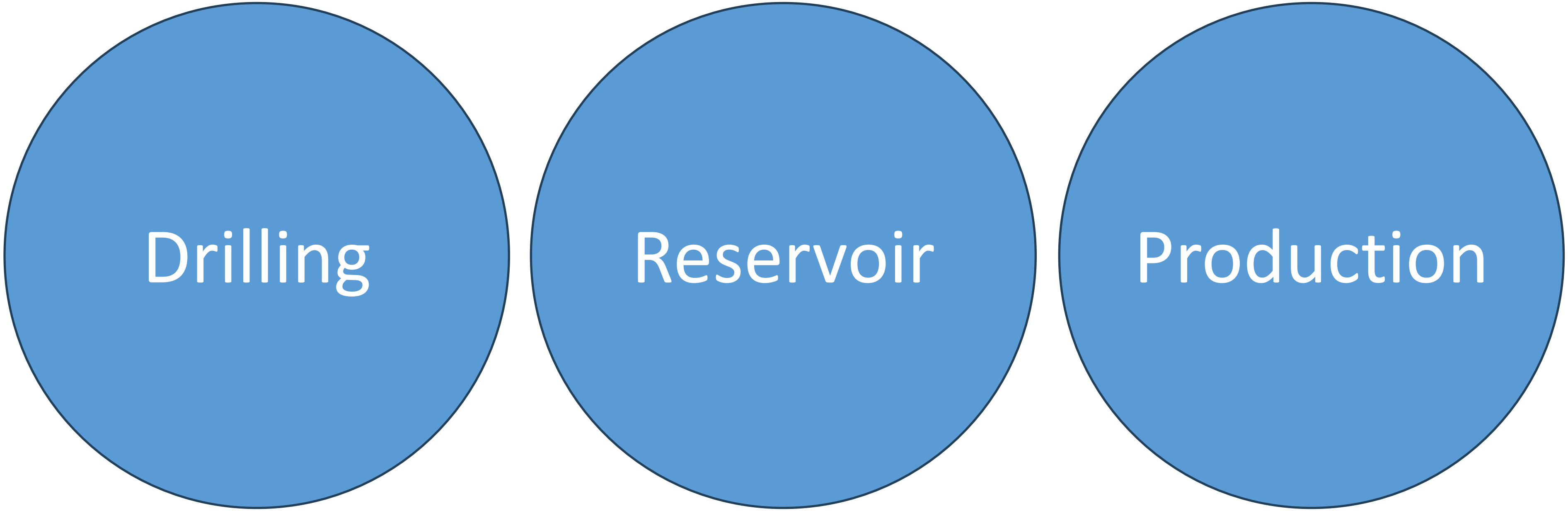
Long-Term Effects of Wellbore Geometry on Mechanical Production Systems

Walter Phillips

wp@wansco.com

Ven Diagram of Discipline Overlap in Oil & Gas

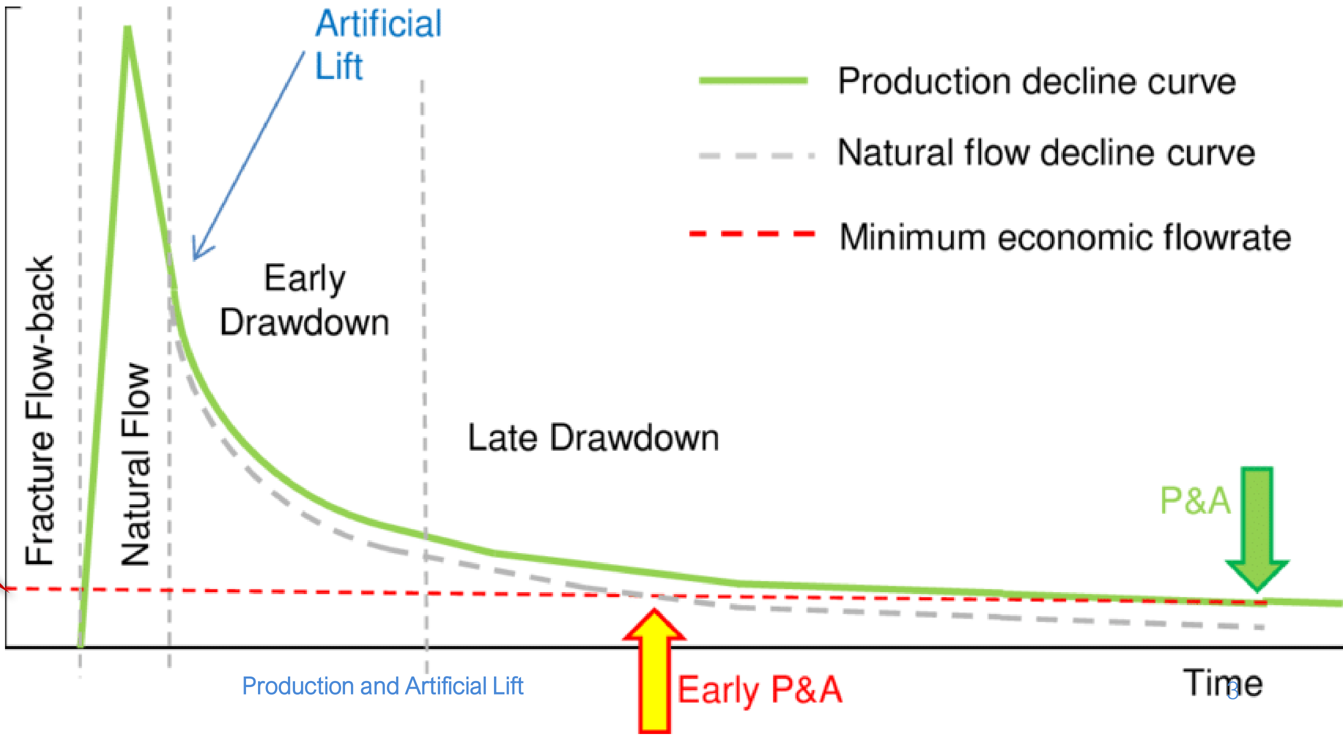


Never the threein shall meet

Why is Production Important?

- Wells spend the majority of their life on artificial lift
- Decline curve

We need to talk about this line!



Artificial Lift overview and perspectives for the production of unconventional resources in the Neuquén basin
Pablo Gristo

Production…
It's that thing we do for the next 100^{+} years

1914 Venezuela

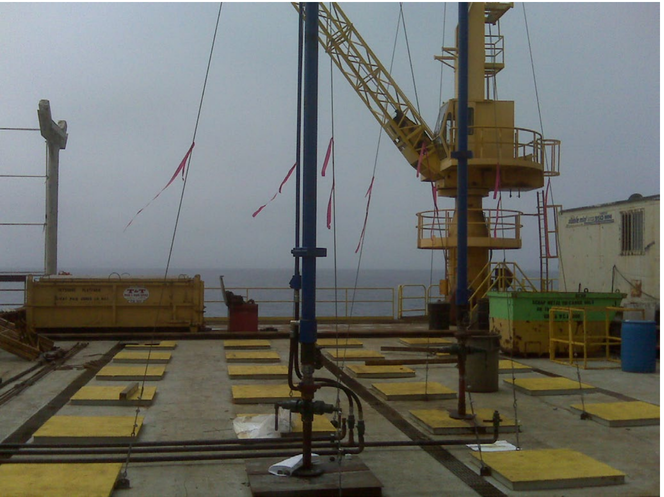
Zumaque Well

1861 McClintock #1

- Drilled in Titusville, Pennsylvania, in 1861, the McClintock well is pumped a few times a year to supply oil for souvenir bottles sold at the Drake Well Museum.

We can produce wells for a long time

- Many wells in Los Angeles from the 1960's that are still economically productive



In fairness, this is how we got most of our surveys

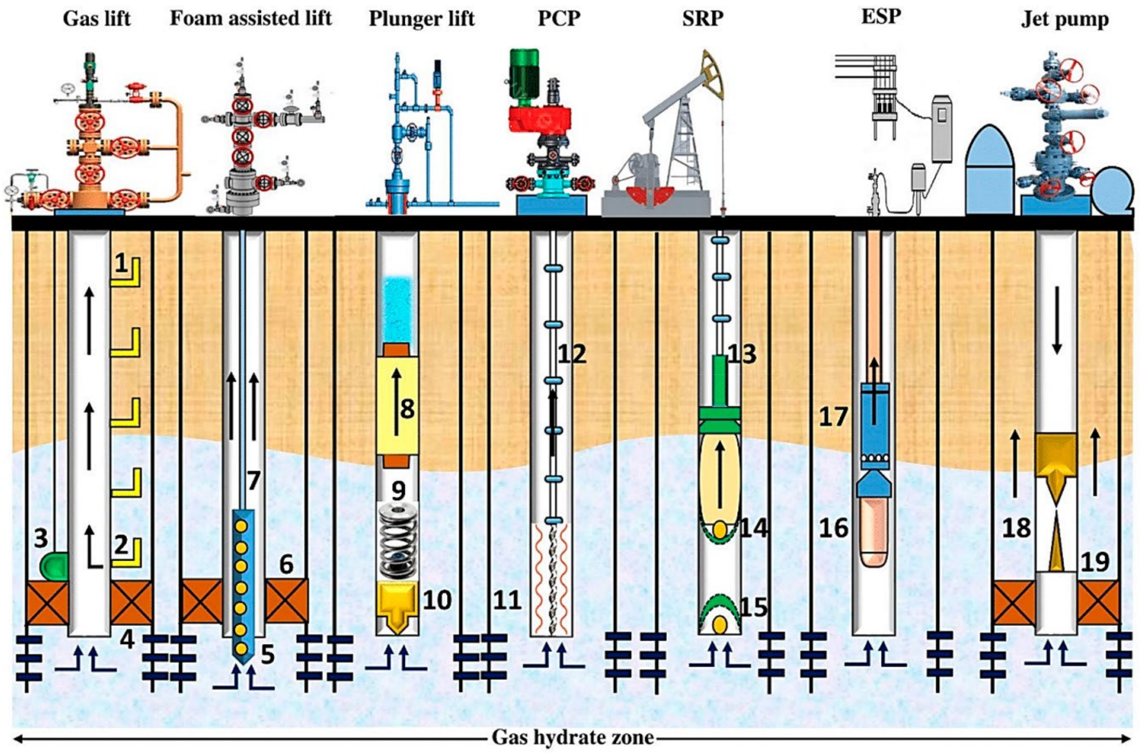
This is how we get most of our surveys…

Artificial Lift

- Gas Lift
- ESP (Electric Submersible)
- Plunger Lift
- Jet Pump
- Progressing Cavity (PCP)

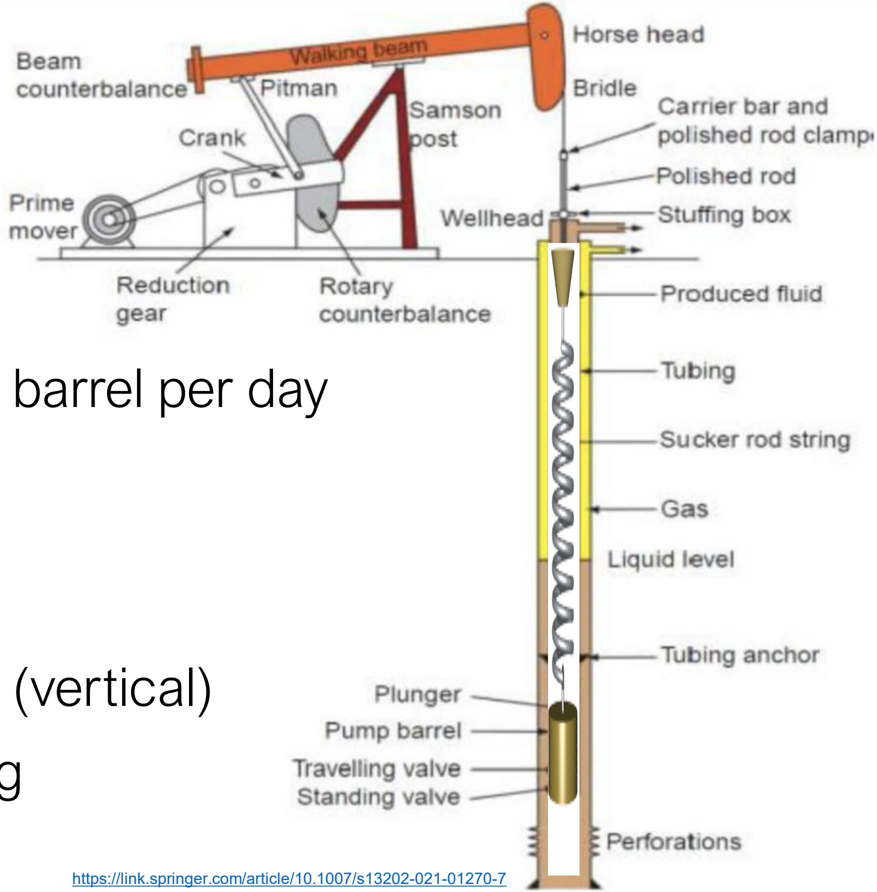
- Rod Pump

Where many wells go to die



Rod Pump Overview

- Most common lift method
- Casing, Tubing, Rods
- Thousands of barrels per day, down to ~1 barrel per day
- A long rod pulls up on a downhole pump
  - That pump pushes fluid to the surface
  - Gravity pulls the rods back down
- Deepest one I've worked on was 14,500ft (vertical)
- The rod acts as a giant complicated spring



Rod Pumps

https://link.springer.com/article/10.1007/s13202-021-01270-7

What can go wrong?

- Rod-on-Tubing friction from deviation
- Equipment restrictions
- Gas slugging & separation

Straighter wellbores, deeper kickoffs

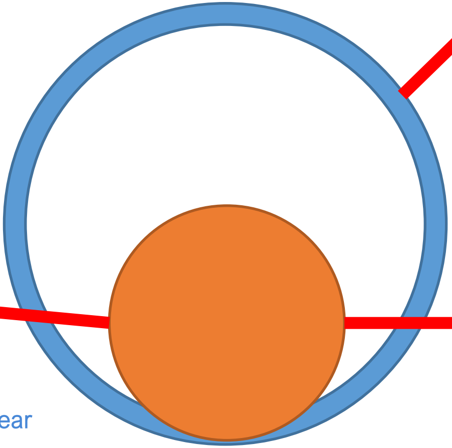
Larger boreholes

Larger boreholes, particularly near the artificial lift pump intake. Control undulations in the lateral

Rod Wear in Production Tubing

- Rods move up and down inside the tubing
- Deviations cause sideload & frictional wear

Should be round



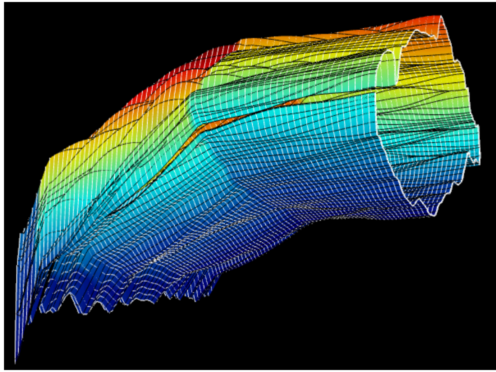
Rod-on-Tubing Wear

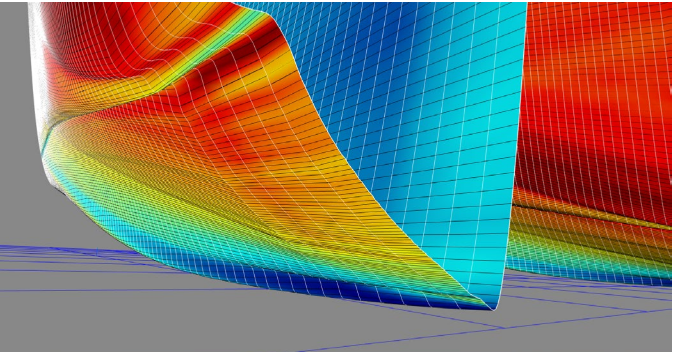
The cost of failure

- $20,000 to “touch a well”
- $175,000 for un-conventionals when tubing needs replacement
    - Once a year, for 100 years? $17,500,000 (we’d abandon this well pretty early)
- Downtime = lost production
    - Days, weeks, longer – small wells go to the bottom of the list
- Pulling tubing is risky – both to personnel and to the well itself

We know a lot about how to rod pump wells

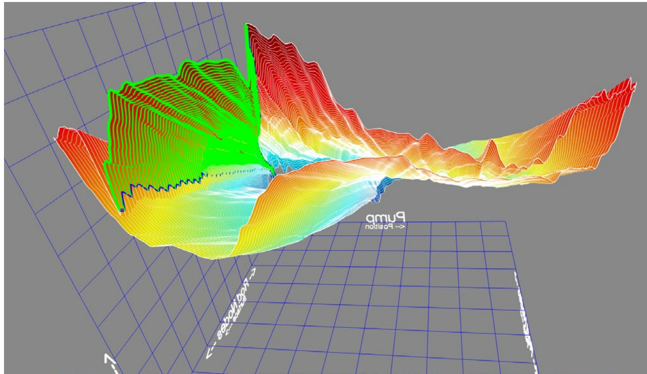
- We can diagnose the pump condition from the surface from just load and position measurements on the rods
- We can diagnose all kinds of conditions
- Fun multi-dimensional plots that only exist in time
- Friction distorts our analysis



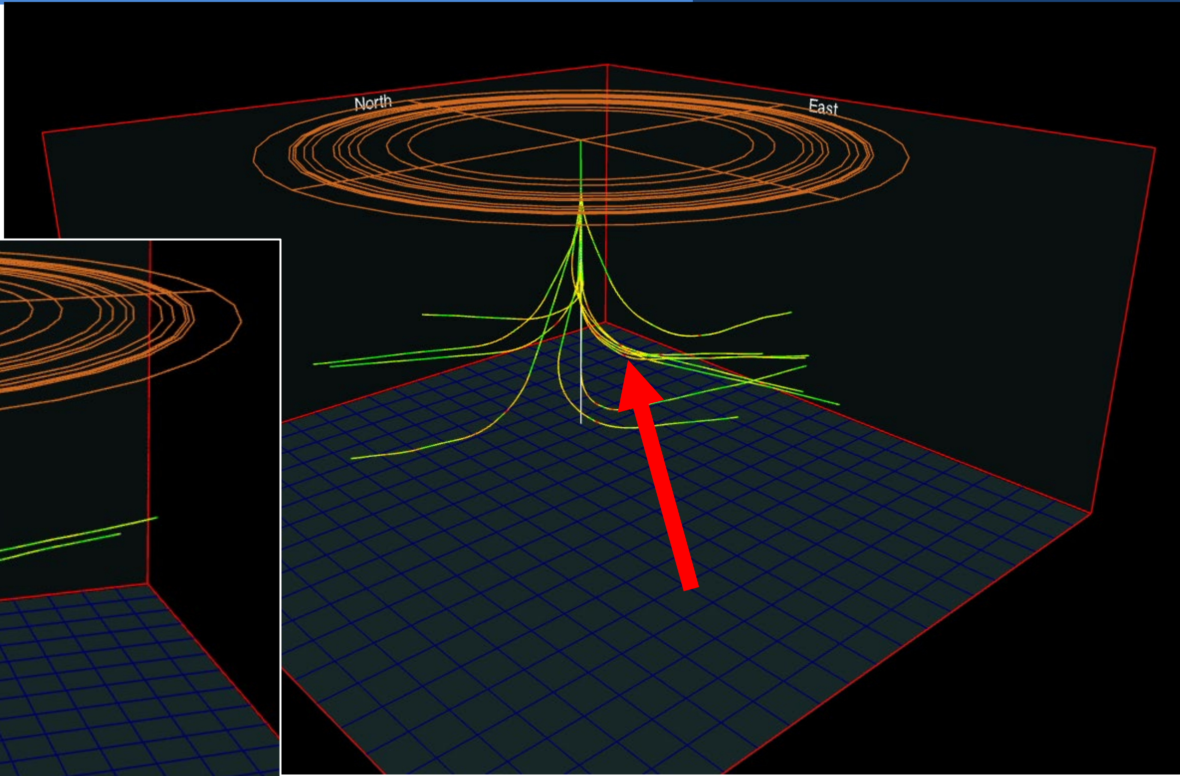


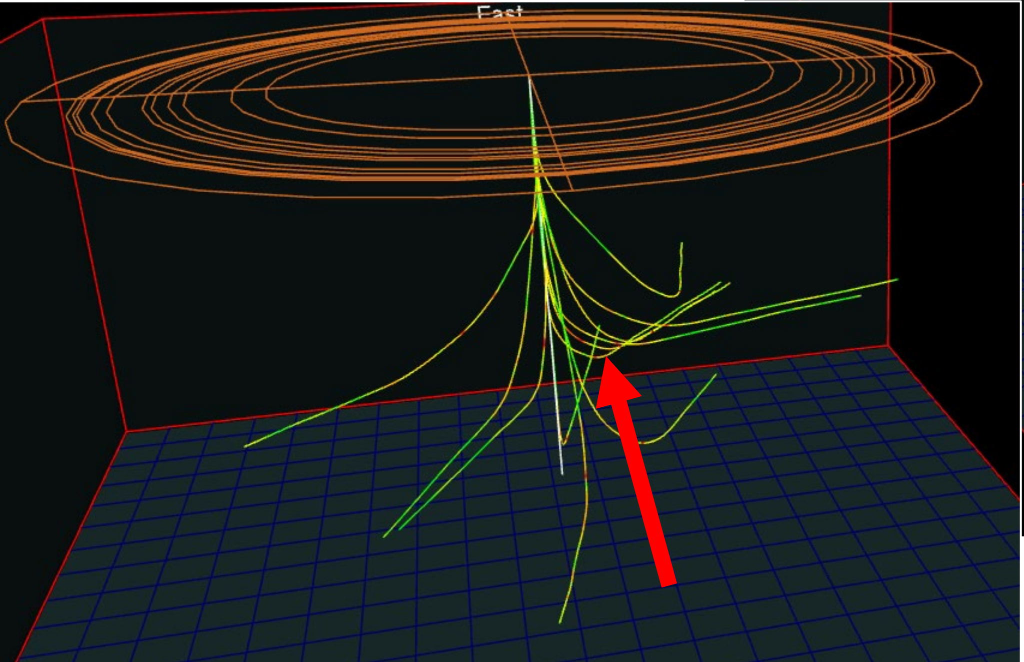
See SPE 190920

Rod pumps in 4D



Problem Wells

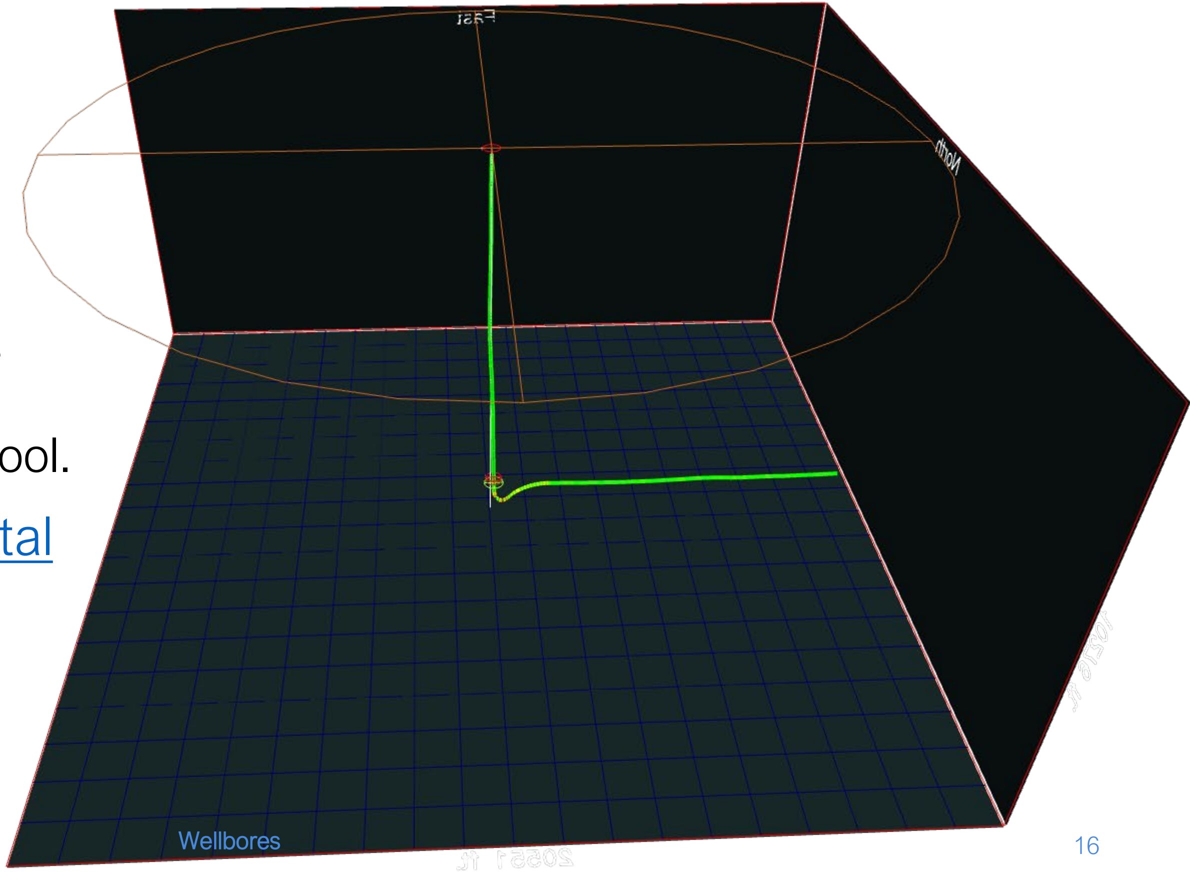




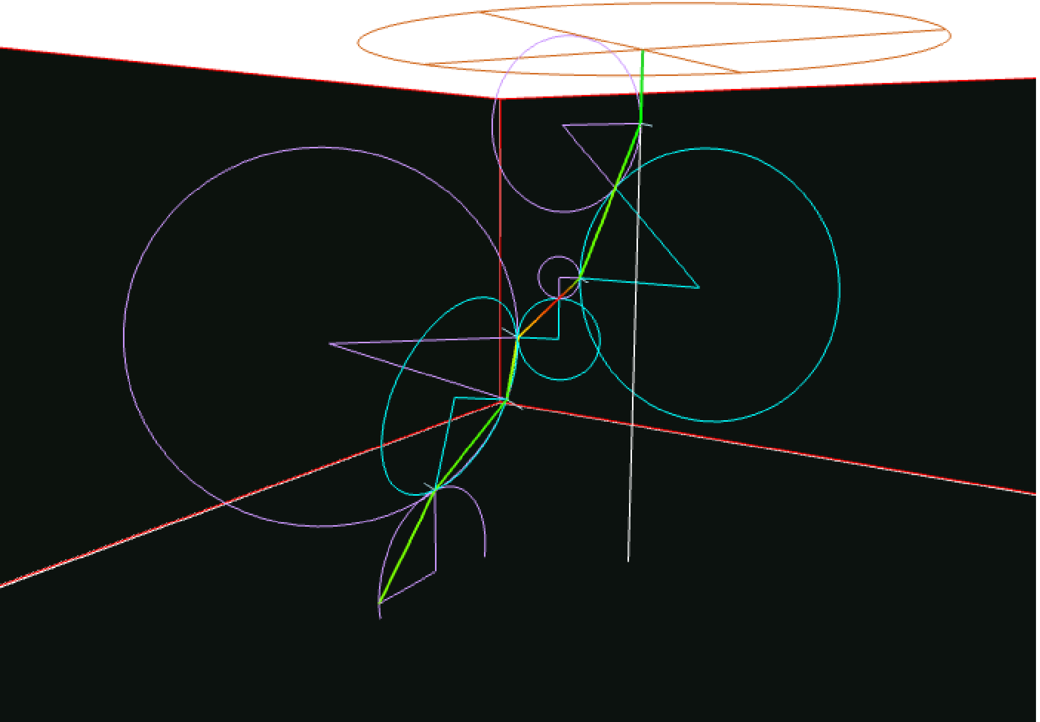
Shameless Plug

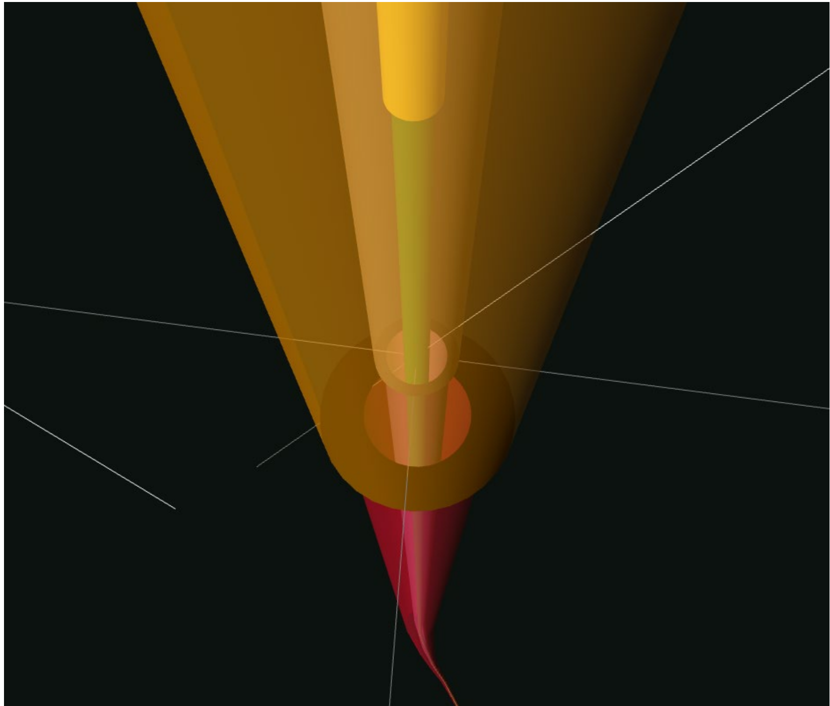
- http://3dwellbore.com/demo
- I'm not selling anything.
  - Production engineers have terrible tools for visualizing their wells, so I made this tool.
- http://3dwellbore.com/u-zontal

See SPE 174024



More Screenshots





Dogleg Severity (DLS)

- Degrees per 100ft is a terrible way to quantify a well but we use it anyways – it's a common measure

- Shallow doglegs are worse
  - More weight hanging below
  - Translates into a sideload
- Deep doglegs are generally "less bad"
- Rod pumps can be set in the lateral

DLS Paper

- *DOG LEG SERVERITY (DLS) AND SIDE LOAD (SL) RECOMMENDATIONS TO DRILLING*
  Norman W. Hein, Jr.,
  O. Lynn Rowlan
- 2019 SWPSC
  (email me for the paper)

Recommended Dogleg Severity Limits to Control Drilling a Wellbore

Dogleg Severity (Deg)	Wellbore Location Above Kickoff
< 0.50	0 to 1,500 feet
< 1.00	1,500 feet to 25% of distance to Kickoff
< 1.25	25 to 50% of distance to Kickoff
< 1.50	50 to 75% of distance to Kickoff
< 2.50	75% to 50 feet above top of pump
< 1.00	50 feet above top pump to Kickoff

Use predictive rod design software to limit the degree of Dogleg Severity to calculated side loading acting on a 25 foot rod will be less than 200 lbs.

Equipment Restrictions

- Narrow wellbores limit the equipment options available to production
- ESP pump & motor assembly may not fit through a deviation
- Tubing, pumps, anchors, etc. all need to fit through the casing

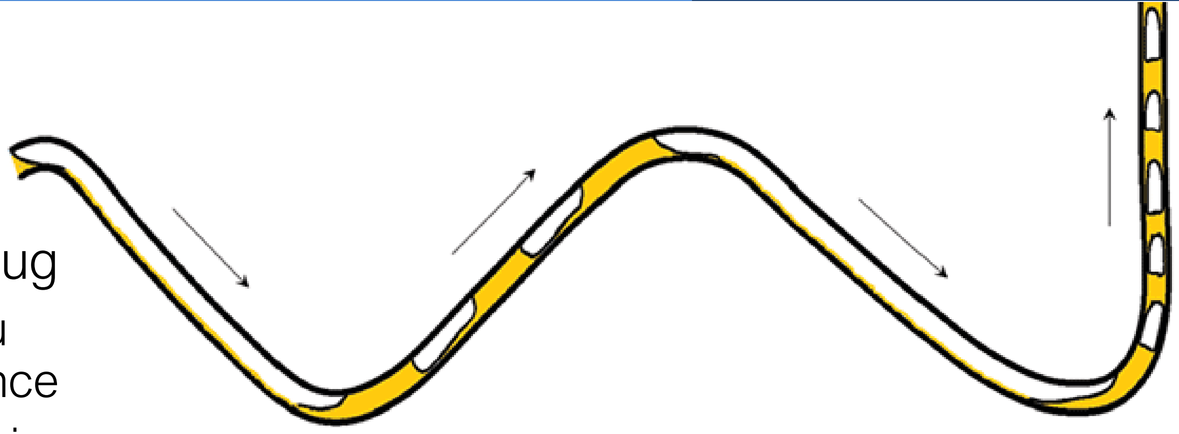
- Cramming large bottomhole assemblies into the wellbore affects gas flow up the casing
    - (email me for papers)

Gas Separation

- Rod pumps can pump gas, but their efficiency goes way down
- Mechanical issues arise when pumping gas

- Better to separate the gas up the casing before it enters the pump
- Narrow casing makes this natural gas separation difficult

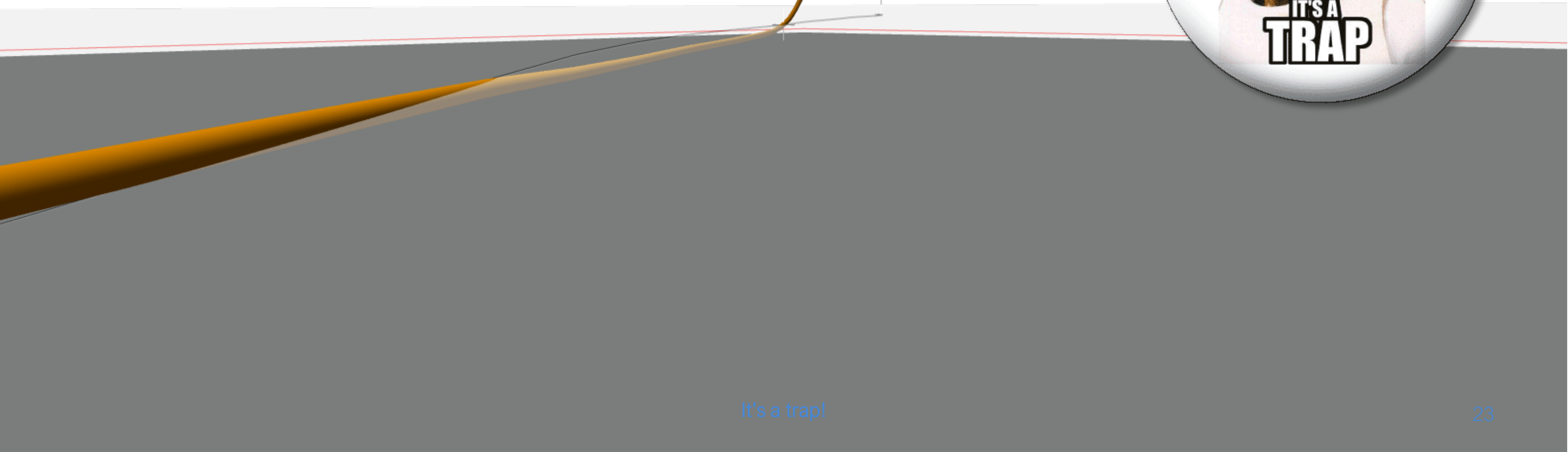
Gas Slugging



- Undulations cause traps for the gas to build up and slug
  - Hard to separate when you get a bunch of gas all at once
  - Larger boreholes reduce this
- Pumps like steady state – gas slugs change the system in a hurry
  - Is it transient? We don't know so we react/over-react

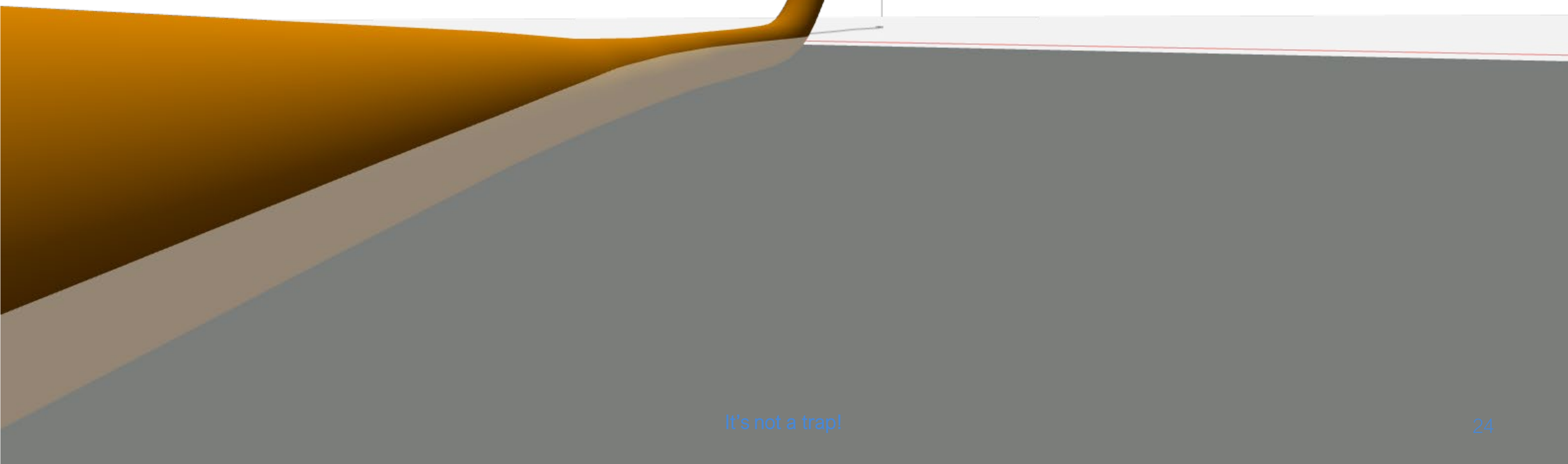
Narrow borehole

- It's a trap!



Large Borehole

- Not a trap! (or not as bad)



What can we do from here?

- Know that onshore wells will likely end up on rod pump
- The production guys want you to have a bigger budget
    - Not to drill more wells faster…
    - But to drill wells straighter and larger
- Communicate with the production team
    - They can help justify increased resources for drilling wells suitable for the next 100 years
- We're not drilling wells like we used to (just a few years ago)