

Horizontal Marmaton Wells in Beaver County, OK

Drilling Improvements
&
Lessons Learned

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Forward Looking Statement

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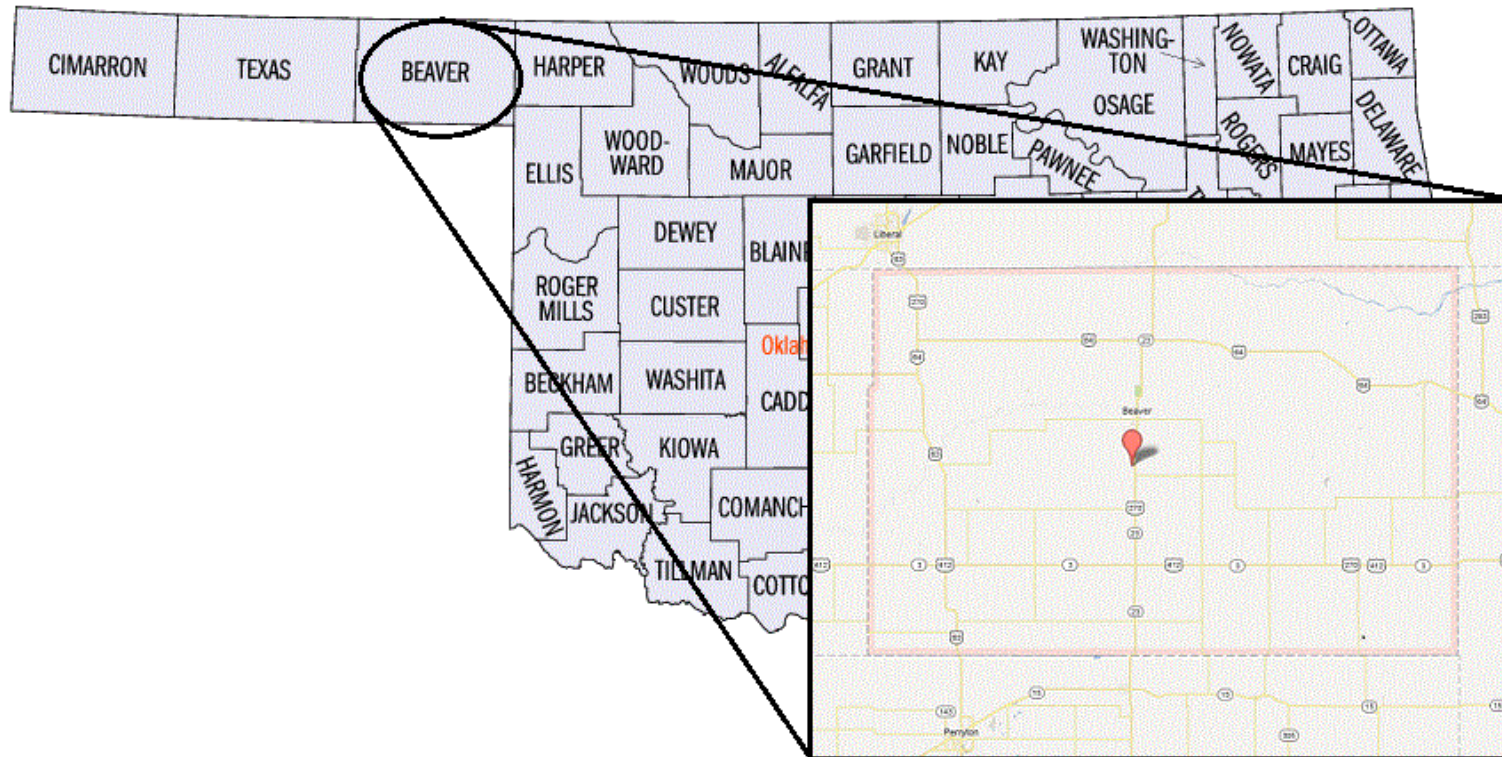
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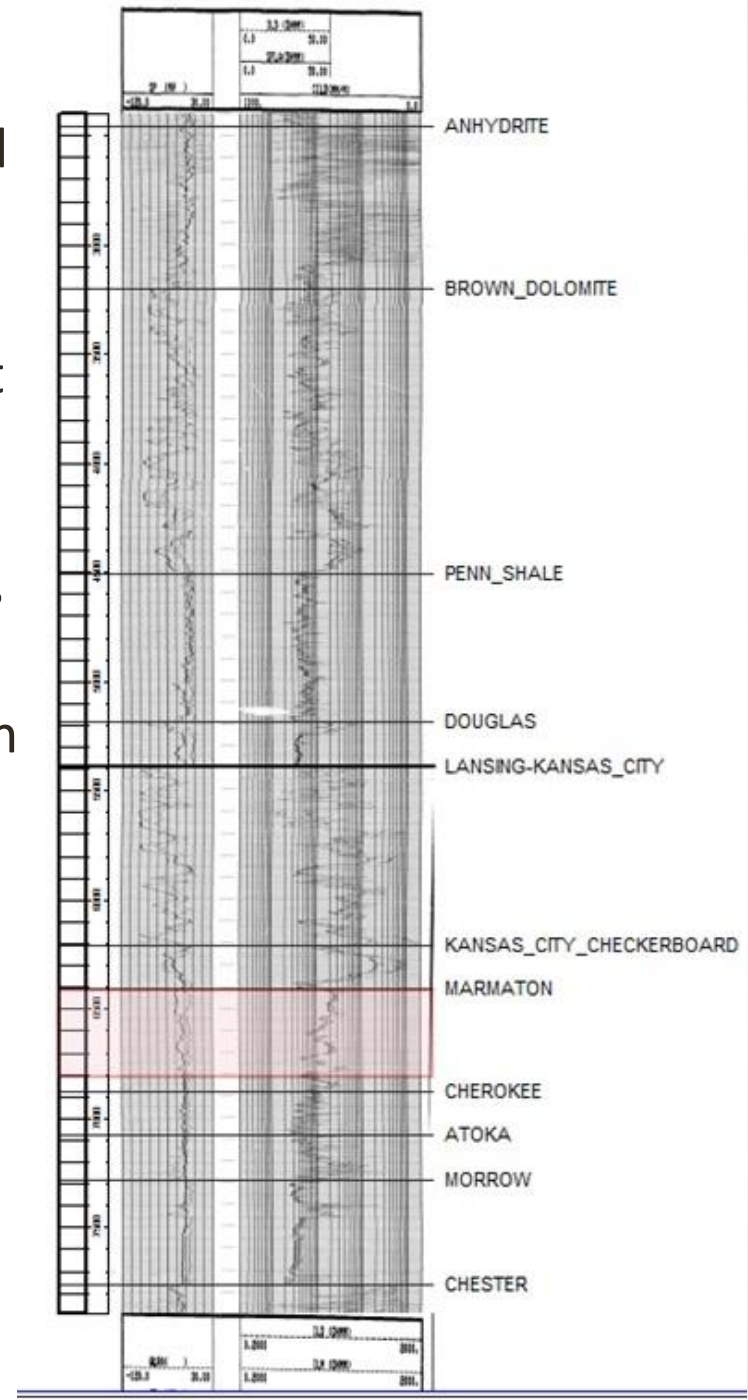
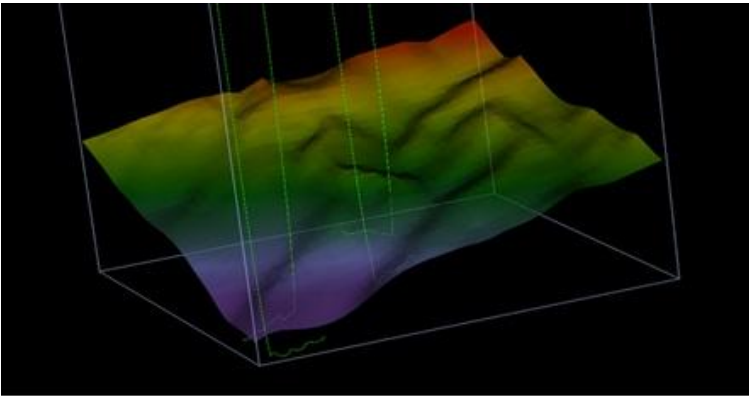
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Where is Beaver County, OK?



Marmaton Geology Slide

- TVD variance across the field ~1,200'.
- Brown Dolomite can be under-pressured and is most likely culprit of lost returns.
 - Not as problematic as the Brown Dolomite in the Texas Panhandle.
- Kansas City / Checkboard can give low BUR.



Marmaton Experience

- Unit Petroleum drilled its first Marmaton horizontal 1st Quarter, 2010.
 - Spud to TD took almost 50 days!
- Since then, Unit has drilled almost 90 Marmaton horizontals in Beaver County, OK.
- Average lateral length is 4,560'
- Longest lateral length is 9,870'
- Average Spud to TD is 11.3 days.
- Fastest Spud to TD is under 7.5 days.

Current Well Design

Hole Size: 12-1/4"
Surf. Csg: 9-5/8" 36# J-55 LT&C
Set @ 2,000'

Hole Size: 8-3/4" from 1,978' - 6,54

KOP MD: 6,100'

Inter. Csg: 7" 26 #/ft N-80 LTC/HDL

Set @ 6,549' MD 67*

Lateral Hole Size: 6-1/8" from 6549' - 11,146'

Liner Csg: 4 1/2" 11.6# N-80 LTC

Pkr/sleeve system: Baker Frac Point System

TD: 11,146' MD

Surface Casing Point

Why Set it so Deep?

- Surface casing point started at ~1,500' to mimic offset wells.
- Focus shifted to optimizing surface casing.
 - Well by well, slowly reduced surface casing depth.
 - Set as shallow as 680'.
 - Settled on ~1,000' until...

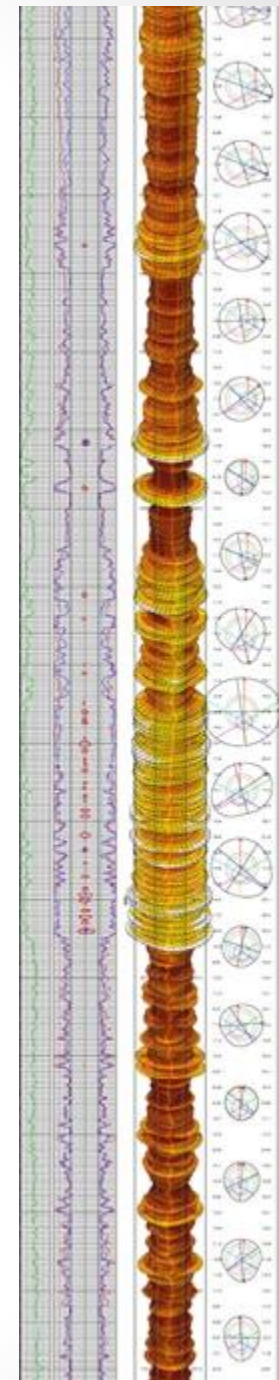
Surface Casing Point Stuck Pipe. Oh, that's why...

- Lost returns while drilling ahead in 8.75" interval -- vertical or curve.
- POOH to address losses from above.
 - Most likely culprit of losses is the Brown Dolomite.
- Stuck pipe!
 - 10% of wells had fishing jobs that could be traced back to the exposed sands above 2,000'.
 - Some fishing jobs were successful. Others were not.
 - Worst case was skidding the rig and re-drilling well.

Surface Casing Point

We got stuck. Why?

- Caliper logged some of the wells that had trouble.
- Significantly over gage (20"+) intervals seen.
- When losses occur, fluid level on backside drops.
- When fluid level on backside drops, unstable sands come into wellbore.
- So, why don't we just keep the backside full?
 - We tried that...
 - Keeping the backside full while losses are occurring causes downward fluid movement in the annulus and washes sand into wellbore.



Surface Casing Point Economics:

- Fishing job costs:
 - \$200k - \$800k
 - 5 – 12 days of rig time
- Costs of additional surface casing:
 - Rig time to drill extra footage in 12.25" hole = \$5k
 - Extra casing = \$28k
 - Extra time TOOH, C&C hole, mud costs, ect = \$4k
 - Extra cement = \$8k
- Drill 40 wells per year:
 - Fishing costs are very unpredictable and lead to AFE overages
 - \$800,000 - \$3,200,000 / year
 - Extra casing costs are very predictable...
 - \$1,800,000 / year

Surface Casing Point Conclusion

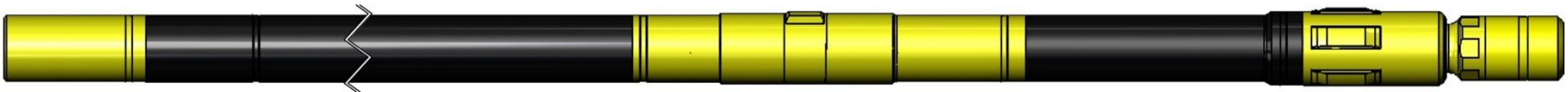
- Set casing at 2,000’.
- Pay the costs of insurance and avoid the AFE overages of an avoidable fishing job.
- Is it cheaper? Maybe. Maybe not. Is it a predictable cost? YES!
- Although lost circulation still plagues us occasionally, no fishing jobs in 8.75” hole since increasing surface casing depth in January, 2012.

Pay for the Insurance!

Vertical Mud motors

Are they Economical?

- No mud motors used in the vertical interval early in the drilling program.
 - Average ROP was 75 ft/hr
- Tried a variety of mud motors with the best results coming from 0.29 rev/gal mud motors.
 - Average ROP 150 ft/hr
 - Current ROP record is 202 ft/hr for 3,687'
 - Save ~24 hours of rig time per well.



Problematic KOP Trip

- Sometimes, the Brown Dolomite required back-reaming out/in the hole on KOP_{Curve} trip.
 - Could cause up to 24 hours of delays.
- Attempted Solutions:
 - Uphole reamers (1,000'+ above bit)
 - Drilling parameters???
 - Near bit reamers
 - Improved up-cutting abilities
 - Short trips immediately after drilling.
 - How quick does wall cake form?
 - Bent house mud motors
 - Hero or zero



Problematic KOP Trip

Mud is the Blood of a Well!

- Tighten up the water loss, right? Nope!
- Solution:
 - Changed mud system from dispersed to polymer hybrid system.
 - Run just enough vis to carry the LCM across the pits.
 - Easier/less pre-mixes allows rig crews to keep up with mud properties during high ROP better.
 - Reduced mud costs.
 - Disperse the mud system as we drill ahead in the curve.

Curve Design

How to Make it Faster?

- In the beginning:
 - Wells were drilled with 8 – 9* BUR curves.
 - The original curve design was 7% of total well footage and took 25% of the drilling time!
- What are we doing now?
 - 14x5* ➔ 14* BUR to 7" casing point and 5* from casing point to heel.
 - Predictable BUR are important! Tri-cone or PDC?

Curve Design

Tri-cone or PDC

- Tri-cone

- Happy directional company!
- Consistent tool face control
- High WOB helps ROP
- Aggressive bit options aren't as big a problem for the directional company.
- Watch your k-revs and train drillers on symptoms of cone interference.

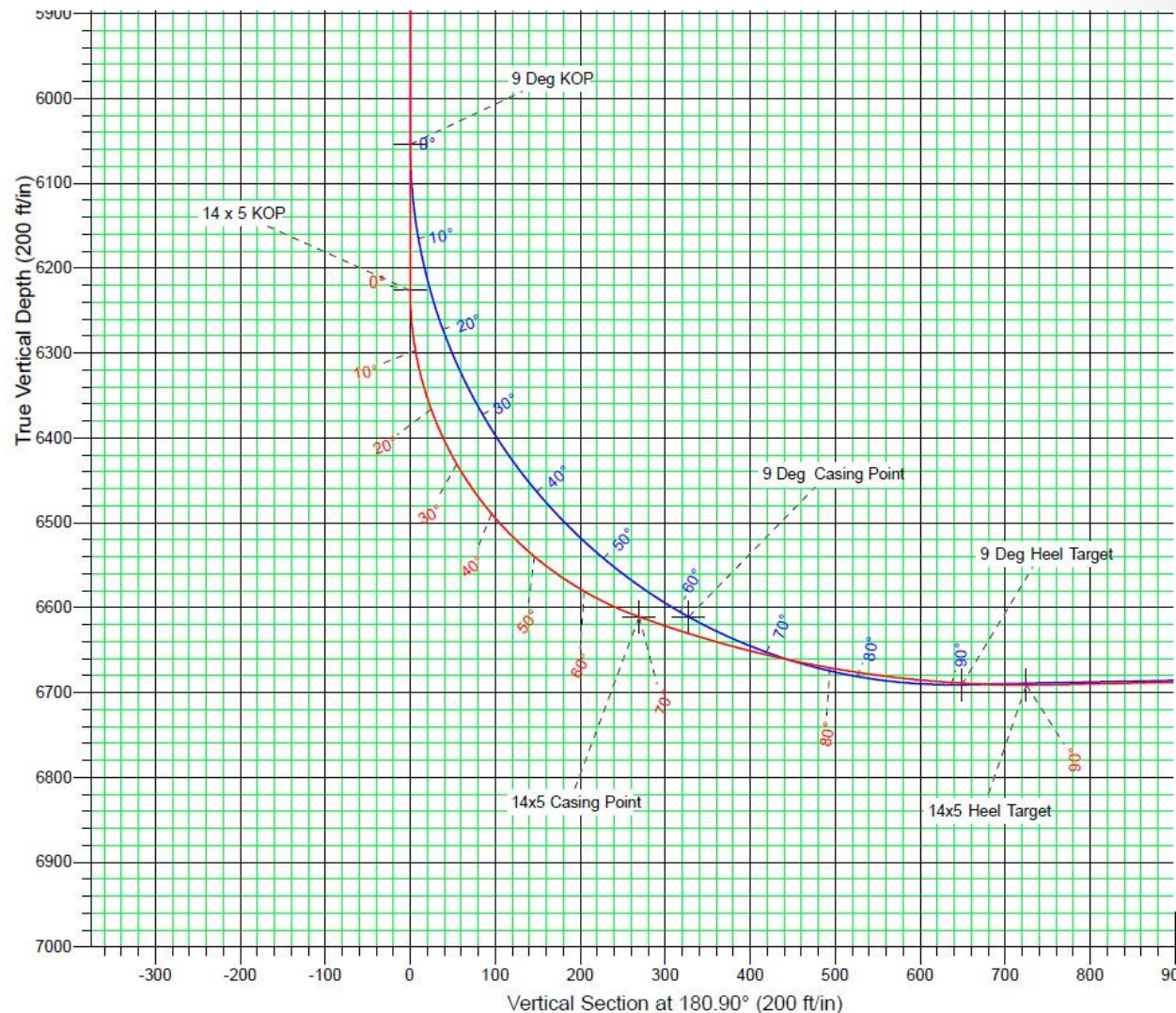


- PDC

- Proper bit selection is imperative for success.
- Sometimes, ROP is great.
- No cones or bearings to worry about.
- More technology in today's PDC bits.
- Potentially, limited drilling parameters due to inconsistent tool face in transition zones.
 - Weak BUR goes hand-in-hand with poor tool face control.

Curve Design – 14x5* BUR

- 27% less curve footage drilled
- Drops KOP 172'
- Gains 58' of lateral
- Saves 32 hours per well!
- 4.5% of footage takes 12% of drilling time.



Uphole Directional Work We Want More Lateral!

- Modeling suggest the greatest T&D benefits occur when the back-build is placed right above the KOP_{Curve} . We tried it...
 - What if the improved T&D isn't necessary?
 - Drill out of the surface casing with directional services? Or, trip out of the hole to pick up directional tools when you get to $KOP_{Back-build}$?
 - ROP was slow and painful.
 - Ratty formations and transition zones makes tool face control difficult → angry directional company.



Uphole Directional Work

What About the Surface Interval?

- Surface interval (~2,000') normally takes 12 - 18 hours to drill conventionally.
- Even if the back-build doubles the average drilling time, we're \$\$\$ ahead compared to the deeper directional work.
- Bring the directional company out for one day and release them until you reach KOP.
- No worries about uncontrolled deviation in surface interval.
- Up to 425' of VS can be accomplished and back to vertical by surface TD.

Uphole Directional Work

We tried Surface Directional...Results?

- Average ROP actually increased because of the mud motor!
- No consequential T&D realized
- The backbuild on wells with 9* BUR curves had a VP to 25 – 50' from the section line.
 - Keep it vertical or cross a line.
- The backbuild, combined with the 14x5* BUR curves, moved the BP to 75 – 100' from the section line.
 - That extra clearance to the section line was very appreciated.
- Increased average lateral length 100'!

Directional Work

How Much Does this All Equate To?

- So, let's recap the last few slides
 - Improved curve design drills faster, is more consistent, and is easier to 'follow the line'
 - This additional confidence allows us to plan a POP closer to the 330' hardline.
 - Surface directional is better than downhole directional (just above curve) for these wells.
- With the focus on the well's directional work, average lateral length has increased 350'.
 - Drilling faster, more consistent, and getting more lateral length. How much \$\$\$ is that lateral worth to your company?

Lateral Drilling

Drilling with 100% Lost Circulation

- Most wells are drilled with 100% losses.
- Drill with water and periodic sweeps.
 - Cheap mud bill!
- MWD issues
 - MWD equipment requires adjustments because the fluid column continues to drop in the drill pipe for several minutes during connections. The MWD tool senses this as 'pumping' and doesn't take a survey.

Lateral Drilling

% Time Sliding vs Rotating

- How do you maximize average footage drilled per day in a lateral?
 - Disclaimer
 - Minimize sliding hours and maximize rotating hours.
 - Notice I did not say anything about sliding ROP vs rotating ROP. Maximum rotating ROP rarely yields maximum footage per day in a lateral if you spend 25% of your time sliding.
 - Steering in rotation
 - Teeter-Totter: Find the drilling parameters that gently tilt the teeter-totter up or down. In other words, adjust drilling parameters to help control inclination in rotation.
 - Minimize micro dog-legs

Lateral Drilling

Build/Drop Tendency in Rotation?

- What is the BHA's build or drop tendency in rotation?
 - Formation dip vs lateral dip
 - North bound vs south bound lateral
 - Can you adjust drilling parameters enough to push the bit up/down? Or, is one direction very difficult or impossible?
 - Can you stay in the geologist' window?

Lateral Drilling BHA Design

- Near bit stabilizer & Nortrac
- Adjust size of near bit stabilizer and Nortrac stabilizers to help create a teeter totter affect.
- Don't forget about differences between north and sound bound laterals and lateral dip vs formation dip.

The Little Stuff Adds Up

Incremental Makes a Difference

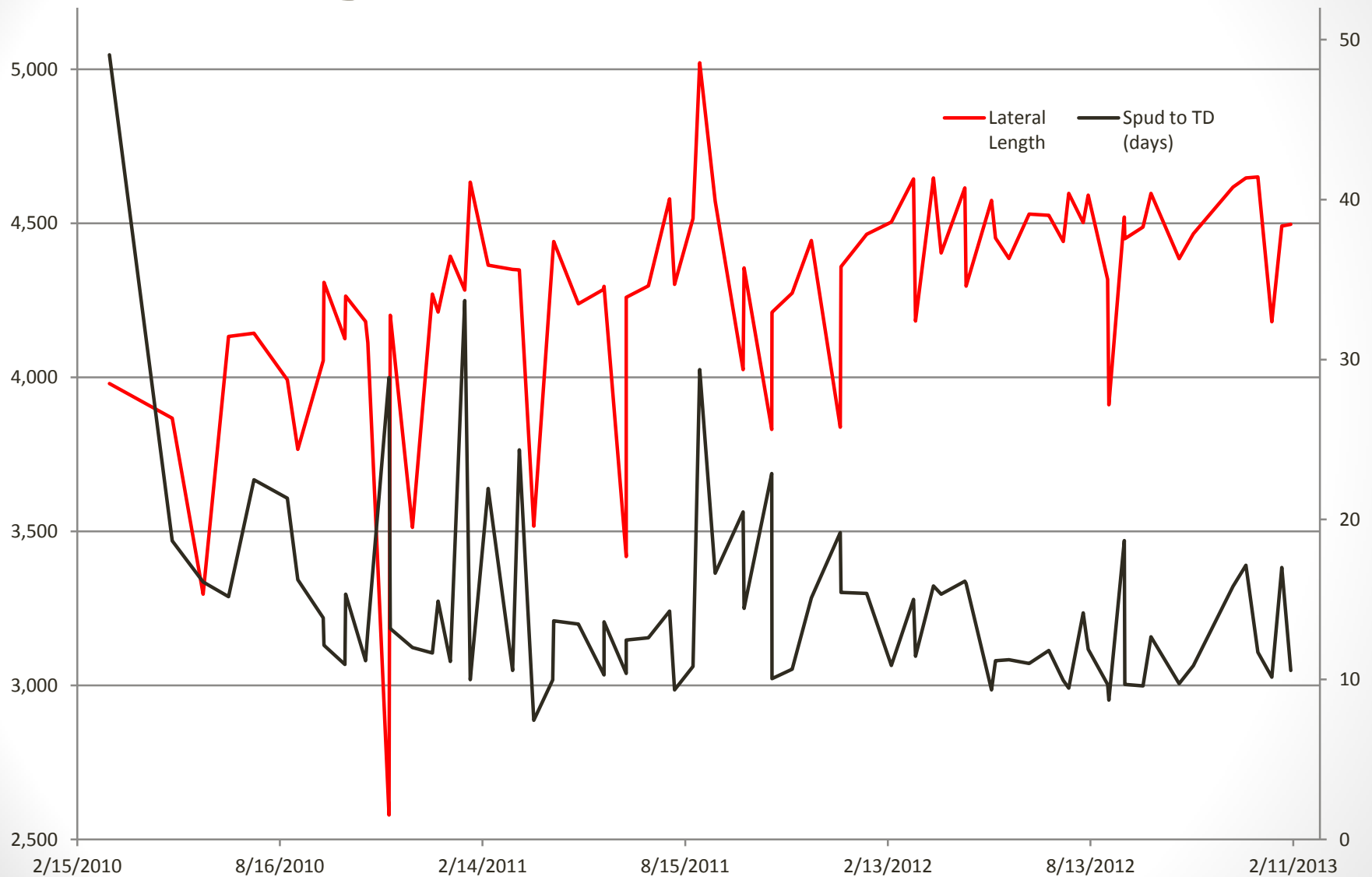
- The small details can make a significant difference in the final results. Saving a few minutes here and a few minutes there adds up quickly.
 - Are the directional tools loaded on the pipe racks before they're needed? Do they already have lifting subs screwed in and tightened?
 - Is the mud motor's bend correctly set before it arrives on location?
 - Picking up stands of 4" DP while sliding ahead in the curve. By curve TD, 65+ stands of 4" DP are normally racked back already.
 - Does the surface BHA mimic the vertical BHA?
 - If you're running HWDP in the vertical interval, why not put it in while you're drilling ahead in the surface interval?
 - Is the new bit already on the floor and dressed before you are on the bank with the old bit?

The Little Stuff Adds Up

Don't Discount Its Importance

- Do you displace the mud system on the fly? Or, shut down drilling operations?
- Is the collar clamp setup for the size of DCs you're running before you start tripping?
 - If needed, get two collar clamps – one for 6.25" DC and another for 8" DC.
- Are the tong dies freshened up BEFORE you start tripping?
- Are the mud pits designed in a such a manner to allow quick and efficient dumping and cleaning?
- Does the casing crew have the tongs unloaded and next to the cat walk?
- Does the casing crew have the hydraulic hoses run up the stairs to the rig floor already?
- Is the lay down truck's flag pole unchained and ready to be picked up?
- Once you get the team's mindset thinking this direction, you'll be amazed at what improvements might be found!

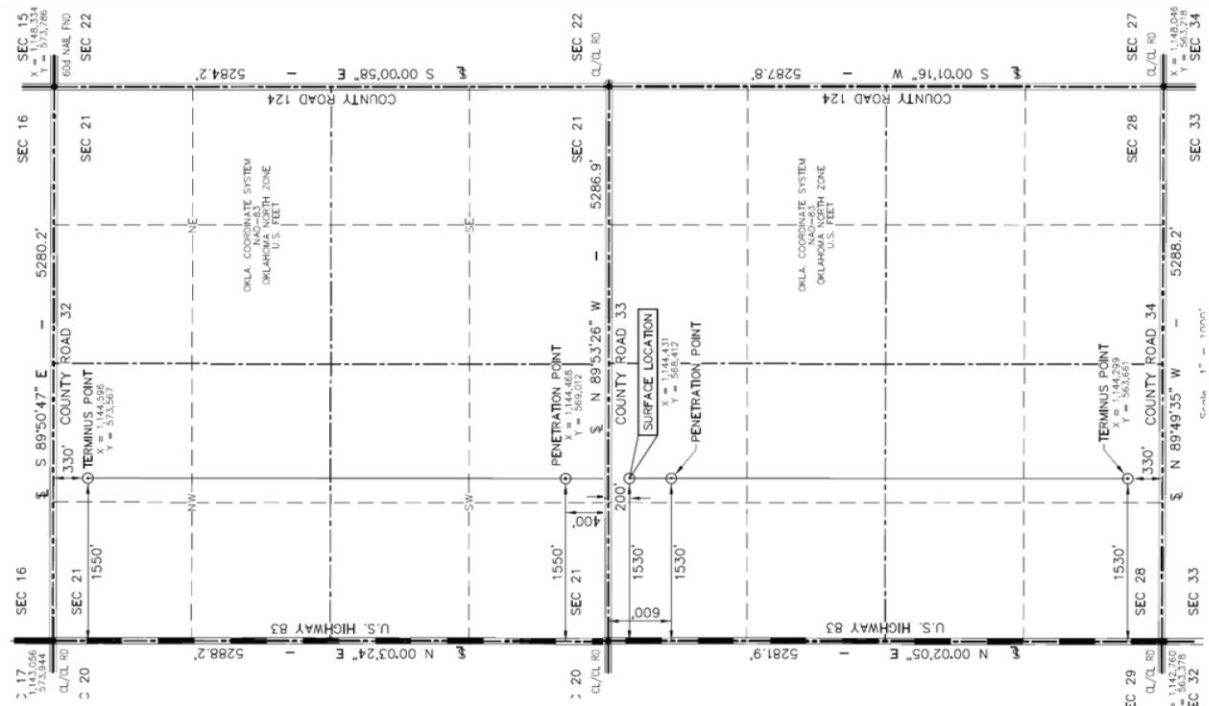
Drilling Results



Rig Moves

Multi-well Pads

- Accounts for 20% of rig time.
- Multi-well Pads
 - One north bound
 - One south bound
- Decreased rig move costs
- Decreased location costs.
- Improved completions and production efficiency.
- Skidding the rig saves two days of rig time per rig move.



Rig Moves

Miscellaneous Improvements

- Drilling consistent, trouble-free wells gives drilling contractor more confidence to schedule trucks sooner in the well.
 - Less downtime waiting on trucks = \$\$\$ savings
 - More wells drilled in a given time period
 - More consistent scheduling for completions operations
- Pay for extra crew on rig move.
 - Break tower faster
 - Rig up faster
 - Spud faster
- Move with the top drive in the derrick
 - Save ~15 hours per well
- Average (total) time savings = ~1.25 days per well

Thank You!

Questions?