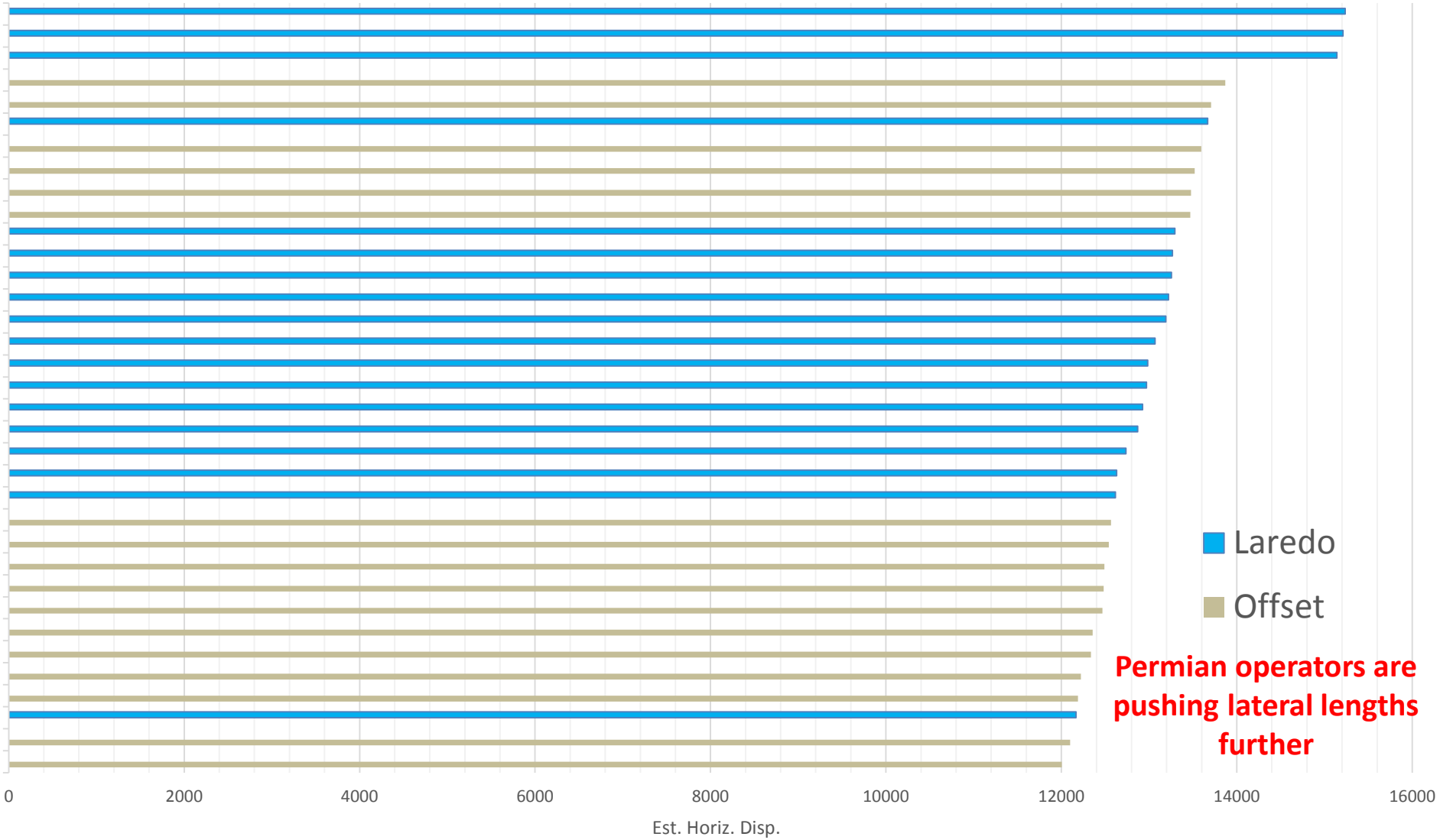
LAREDO PETROLEUM

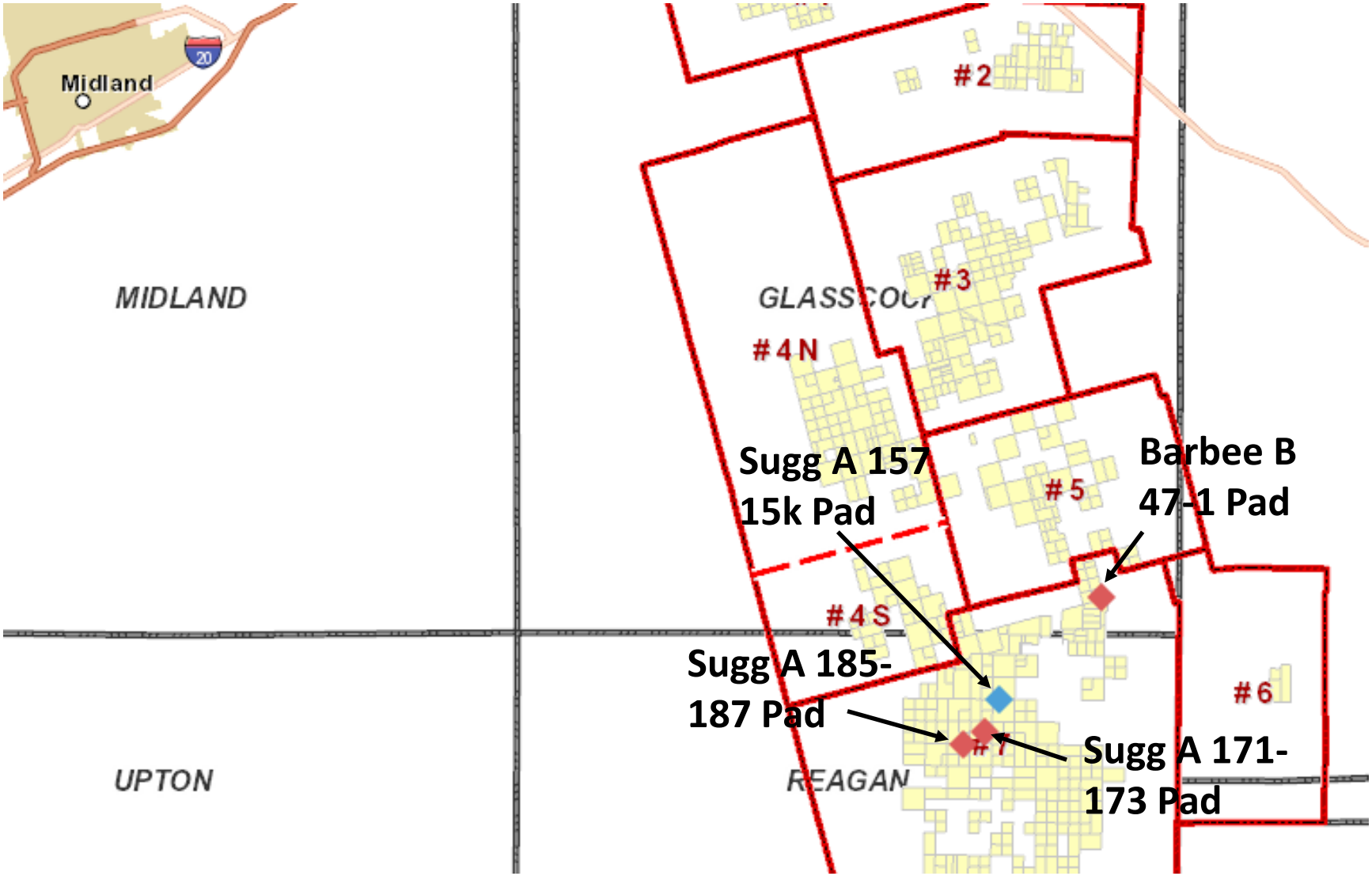
Permian Basin ERD Development: The 15k Project

Permian Basin ERD Wells



*IHS data dating January 2016 through October 2017 across Howard, Midland, Martin, Glasscock & Reagan Counties. Estimated horizontal displacement greater than 12,000'

Case Study: Laredo's ERD History



Sugg A 171-173 Package

- 4 Well Package
  - Average Vertical Section = 13,435’
  - 2 wells drilled each w/ RSS and conventional directional tools
  - Average Rig Accept to Rig Release:
    - RSS = 16.25 days (2,576 ft/day avg. in lateral)
    - Conventional = 19.07 days (2,102 ft/day avg. in lateral)
- Issues
  - Insufficient Build Rates in 8 ¾” Curve – performance below 8 ½” curve
  - Difficulty Sliding w/ Conventional Tools
  - Had to Rotate Casing to Bottom on 1 Well (fastest RSS run w/ highest average DLS)
  - Justify RSS Cost

Sugg A 185-187 Package

- 3 Well Package
  - Average Vertical Section = 12,784’
  - All wells drilled w/ conventional directional tools
  - Average Rig Accept to Rig Release = 17.53 days
- Issues
  - No major issues
  - Further examine RSS vs. conventional BHA performance

Barbee B 47-1 Package

- 2 Well Package
  - Average Vertical Section = 13,842’
  - Both wells drilled w/ RSS BHA
  - Average Rig Accept to Rig Release = 25.74 days
    - 1st Well = 20.67 days
    - 2nd Well = 30.81 days
- Issues
  - 1st well, no major issues
  - 2nd well, hole instability, stuck pipe

Early ERD Lessons Learned

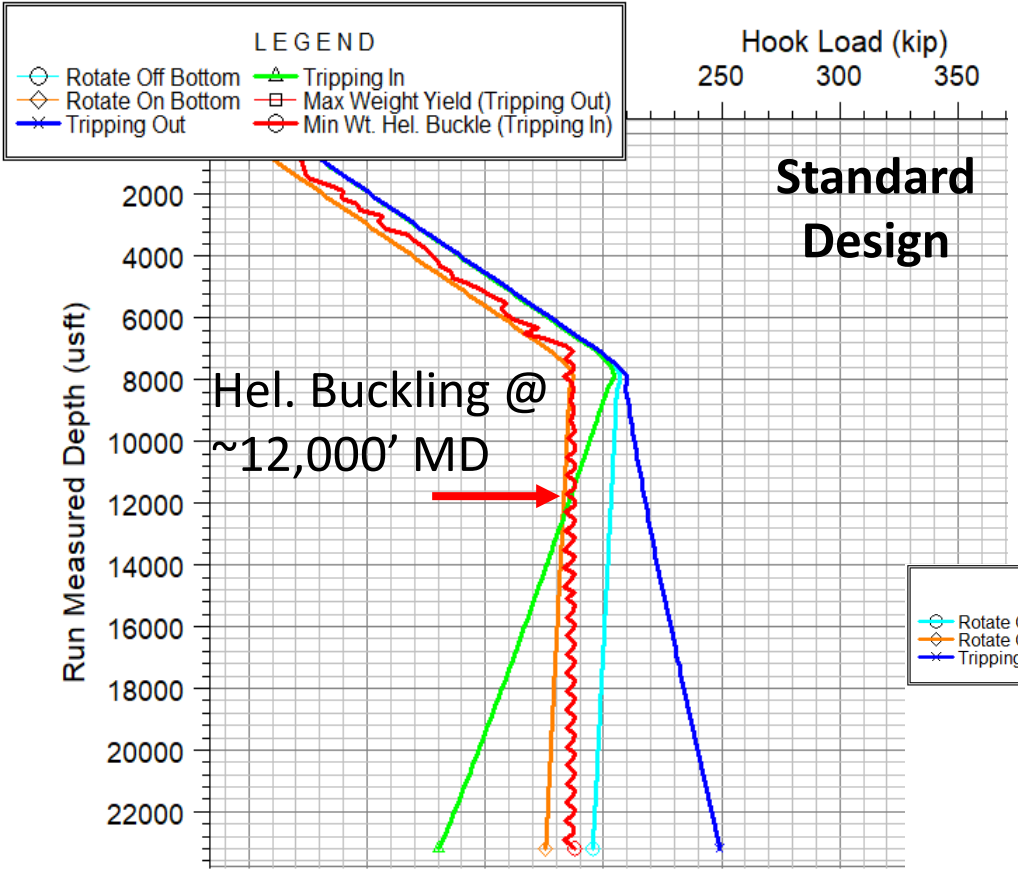
- BHA Limits
  - +/- 13,500’ VS appears to be the practical limit for conventional directional tools under standard well design – 8 deg/100’ curve
  - RSS seen as a need rather than an optimization tool
  - Conventional BHA optimization ongoing
- 8 ¾” Curve Optimization
  - Significant performance difference from 8 ½” curve
  - Reduce planned build rates to mitigate performance impacts and benefit torque and drag effects in lateral
- Fundamentals Are Key
  - Mud Properties
  - Hole Cleaning
  - Minimize DLS in Lateral
  - Communication

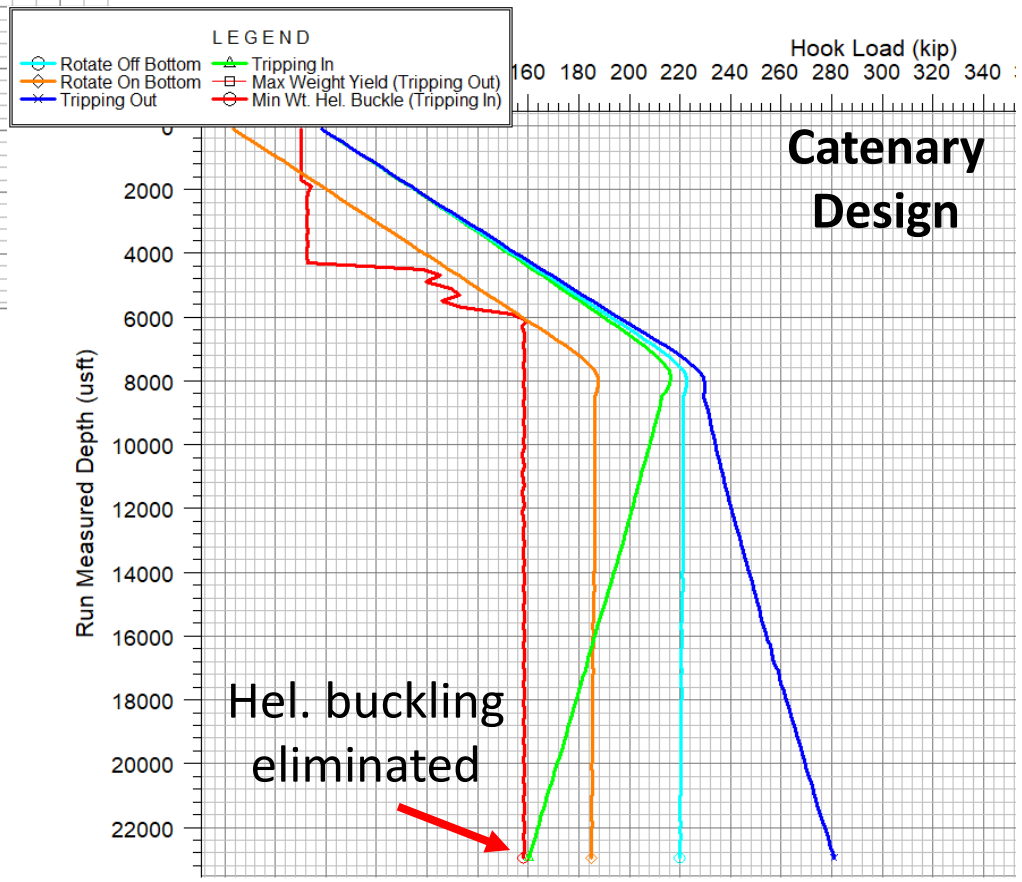
Pseudo-Catenary Curve

- Pros
  - Reduce build rates
  - Improve T&D in lateral
  - Reduce risk of issues tripping RSS through curve
- Cons
  - Lose vertical section in lateral
  - Requires directional work in 12 ¼” section

Benefit > Burden

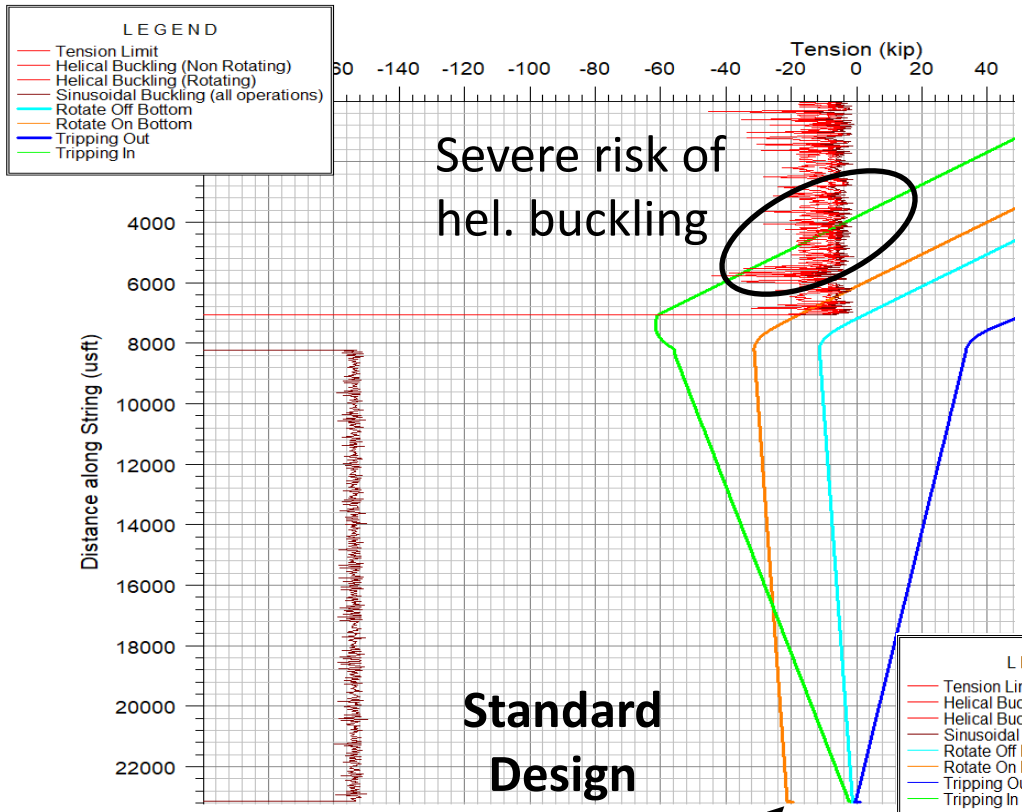
Tripping in Hole with Drilling Assembly





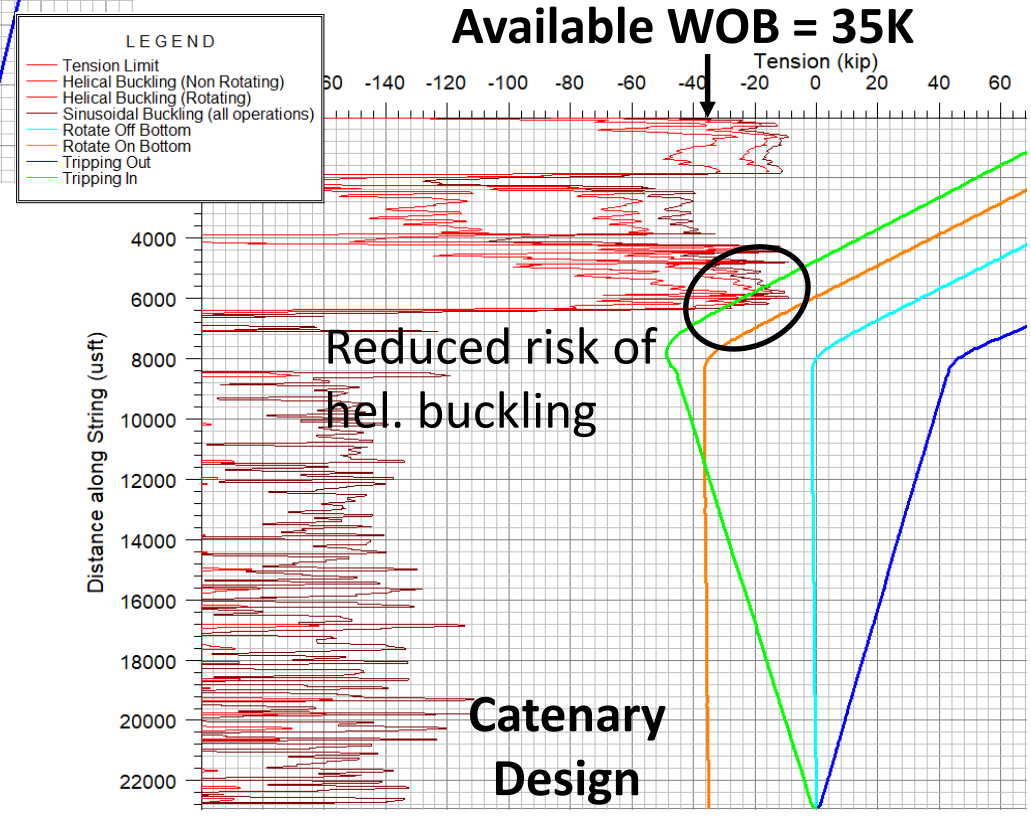
<u>Eliminates helical buckling</u>

Rotating with Drilling Assembly



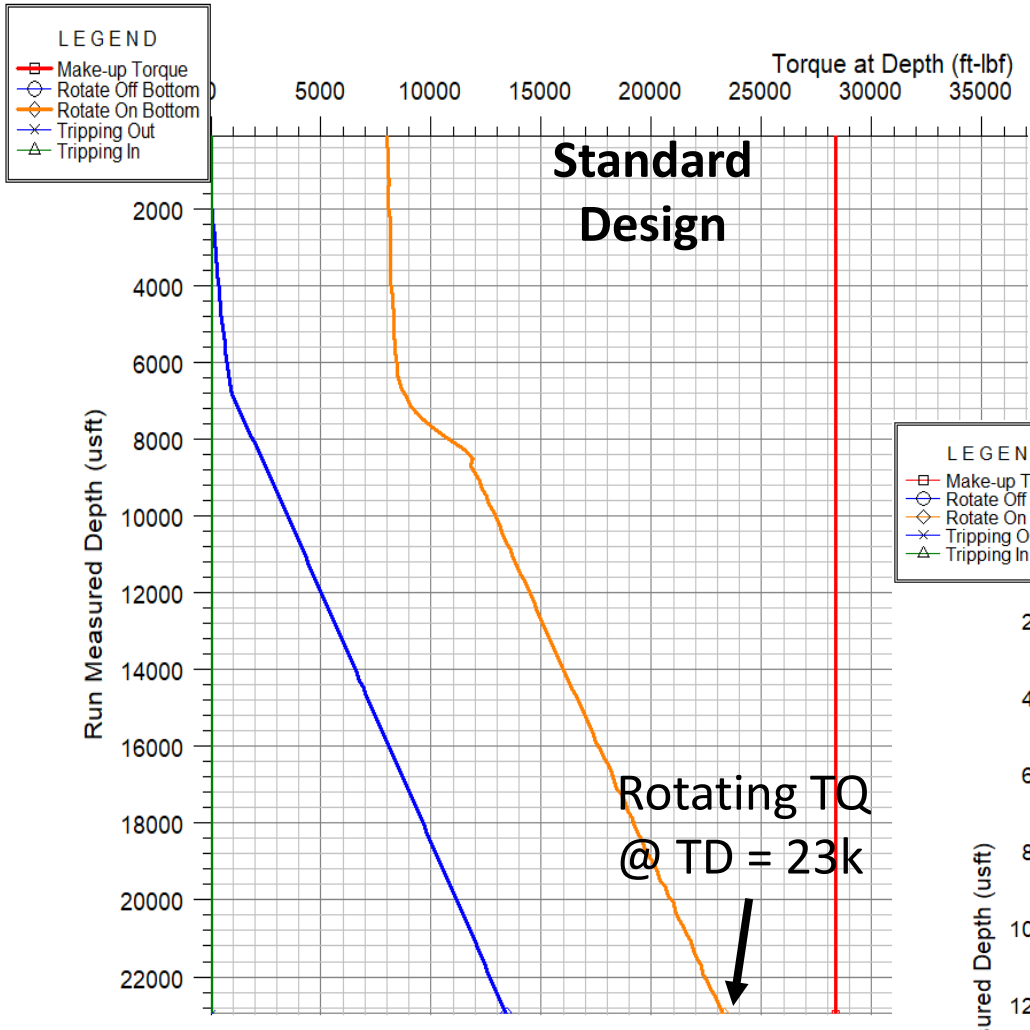
Available WOB = 20K

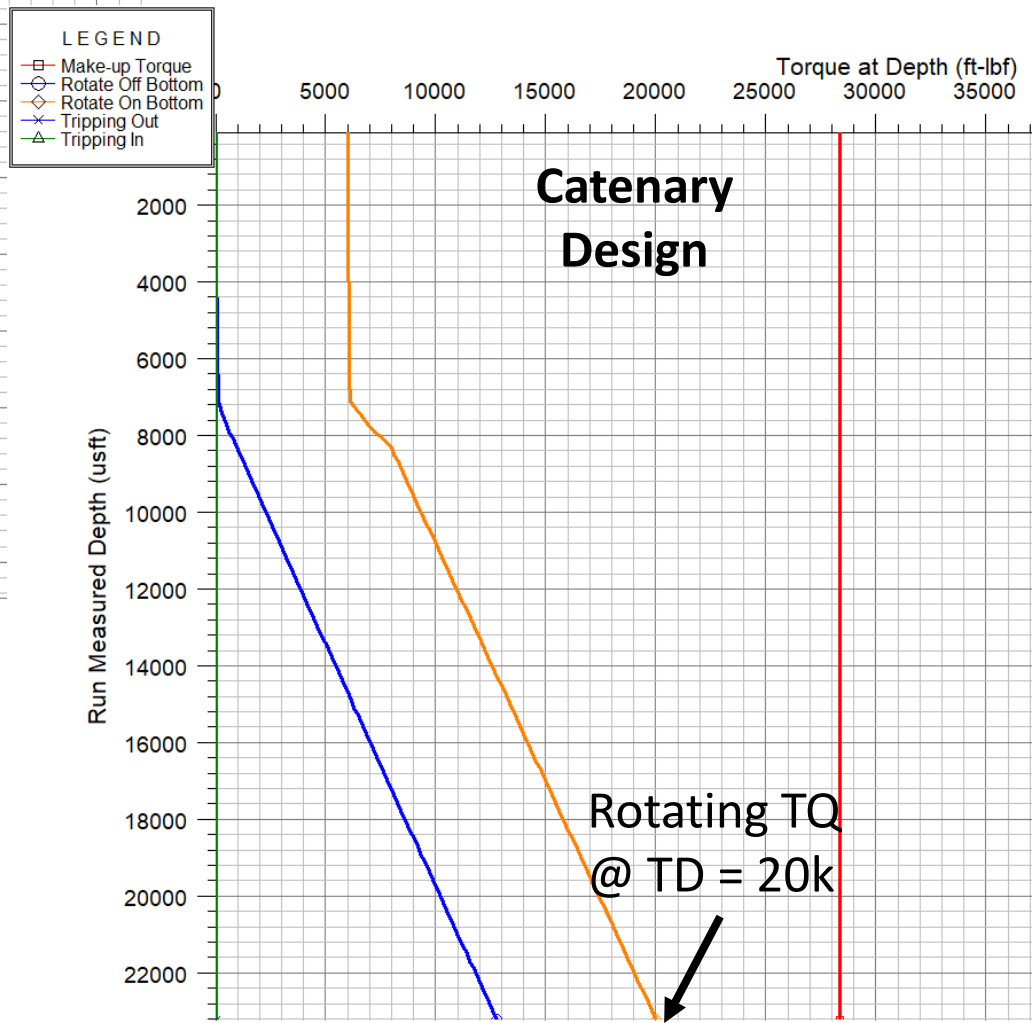
Available WOB = 35K



<u>75% increase in available WOB @ TD</u>

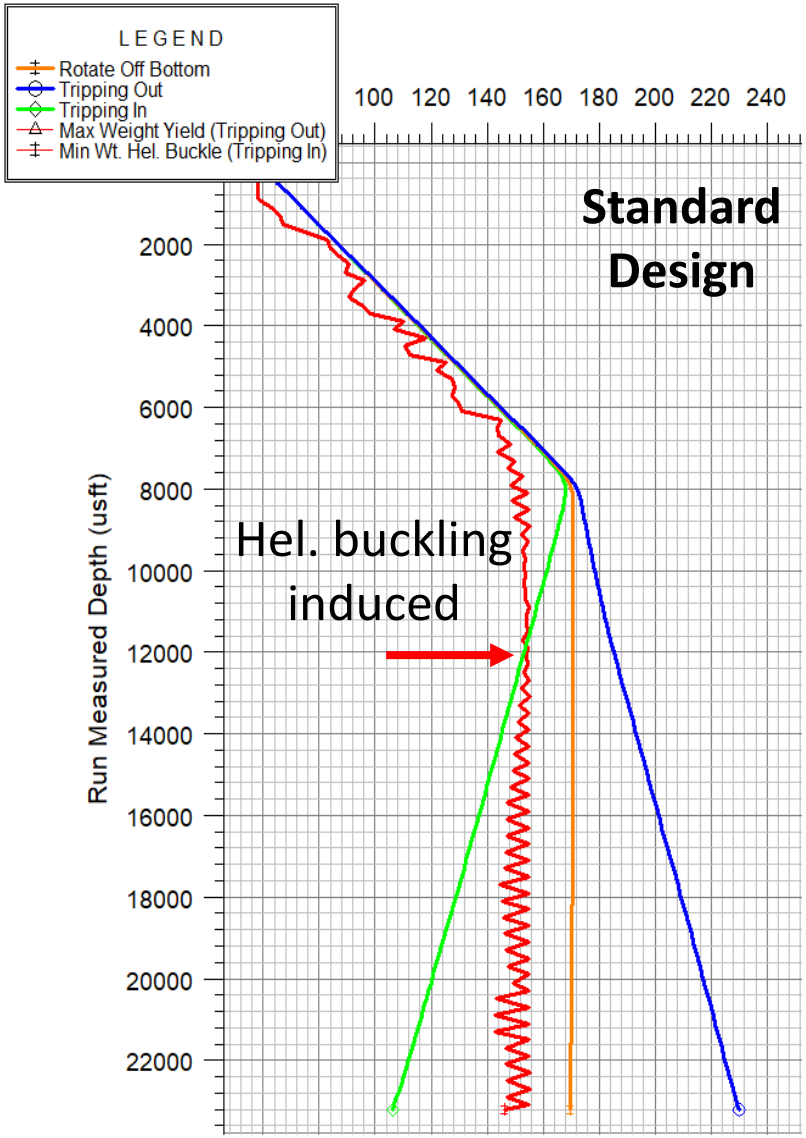
Rotating with Drilling Assembly



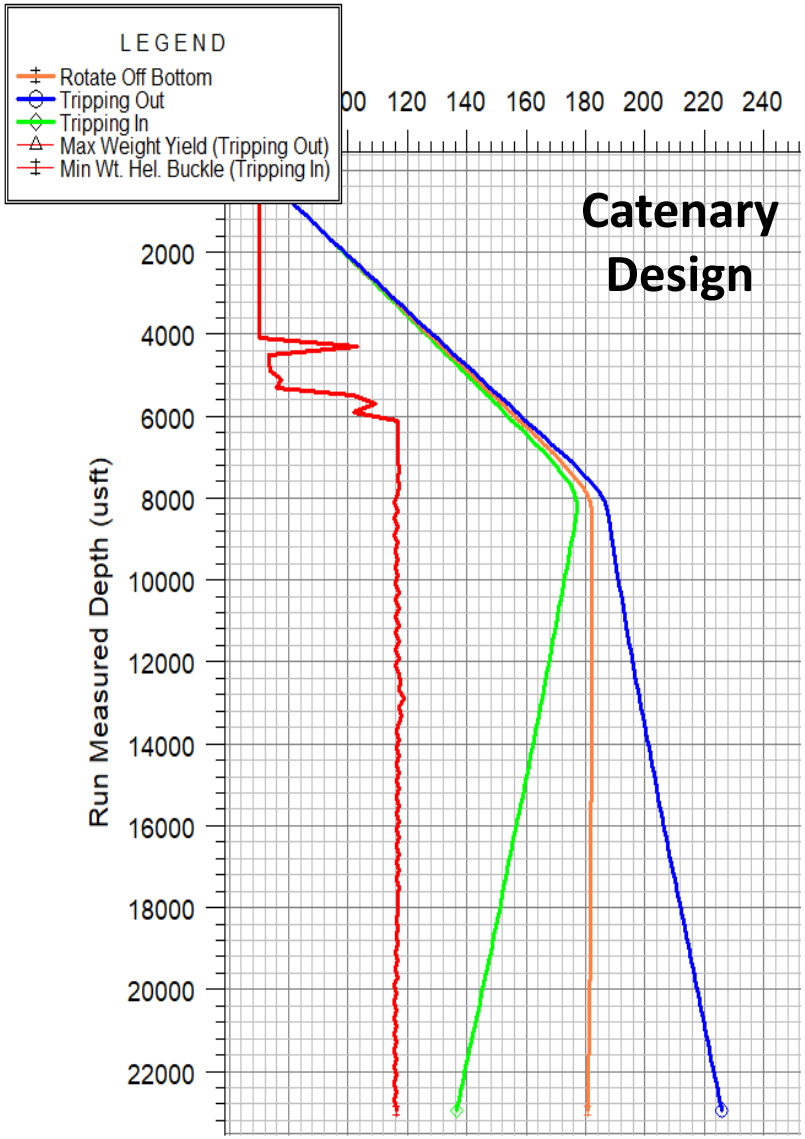


~15% reduction in drilling torque @ TD

5 ½” Casing Run

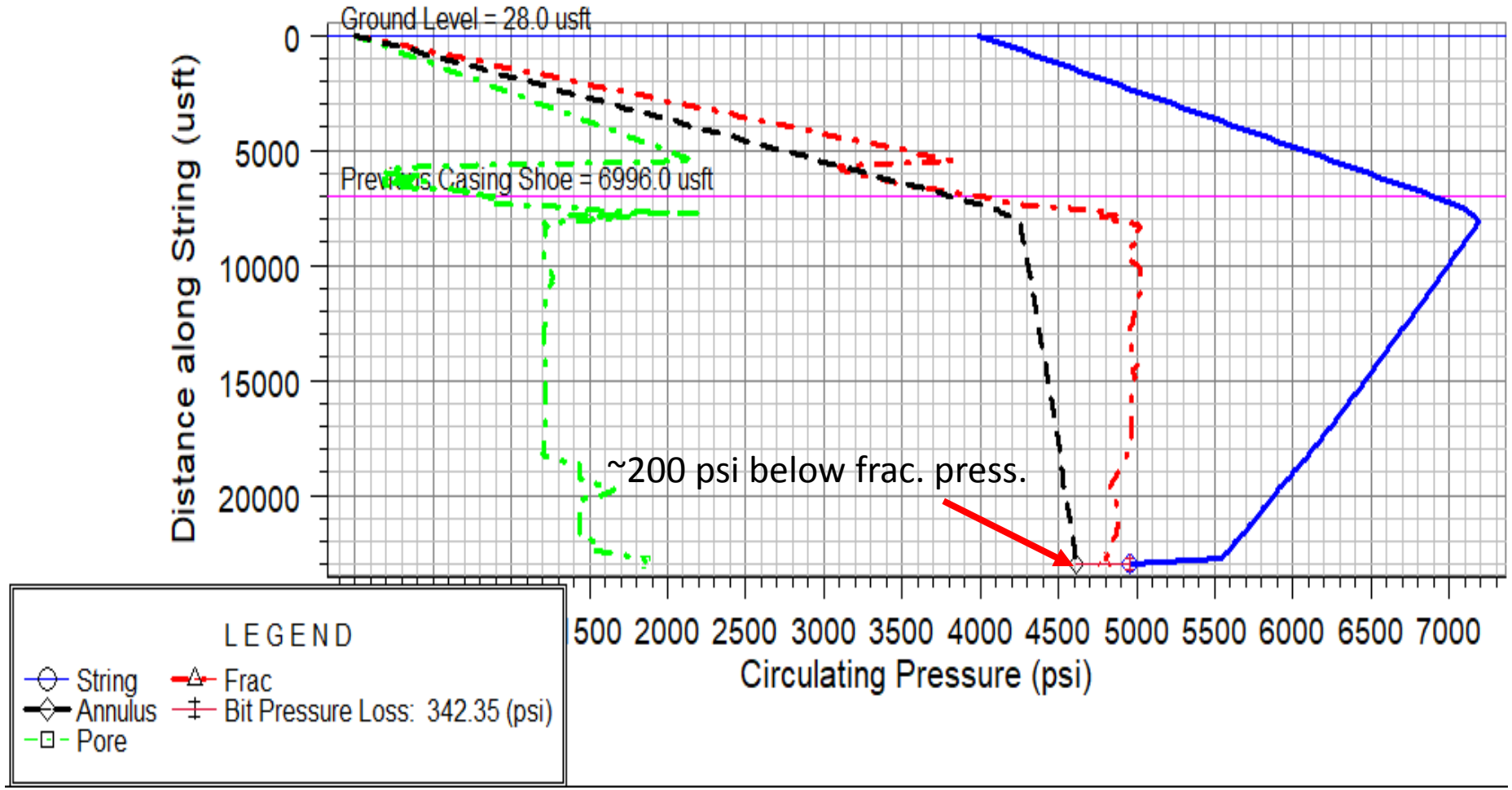


Buckling reduces chance of success



Success highly probable

Surface Pressure While Drilling



- Max. Anticipated ECD @ TD = 11.3 ppg
- Max. Anticipated ECD @ CSG Shoe = 10.4 ppg
  - FIT test to 11.5 ppge

Cement Considerations

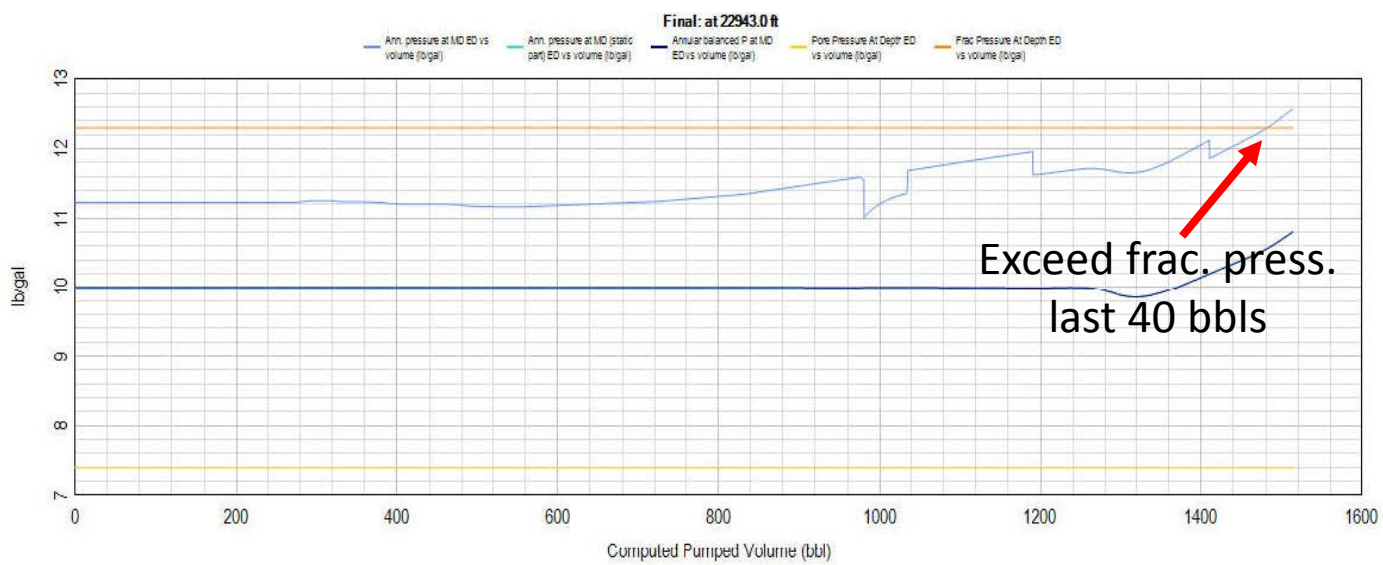
Pumping Schedule						
Fluid Name	Duration hr:mn	Volume bbl	Pump Rate bbl/min	Injection Temperature degF	Comment	Cumulated Time hr:mn
Gelled Water	00:07	40.0	6.0	68		00:07
10.5 ppg MPE Spacer	00:03	20.0	6.0	68		00:10
11.8 ppg Lead	00:26	154.3	6.0	68		00:36
13.2 ppg Tail 1	00:17	105.0	6.0	68		00:53
15.0 ppg ASH Tail	02:11	655.9	5.0	68		03:04

Completion requirement for acid soluble tail slurry

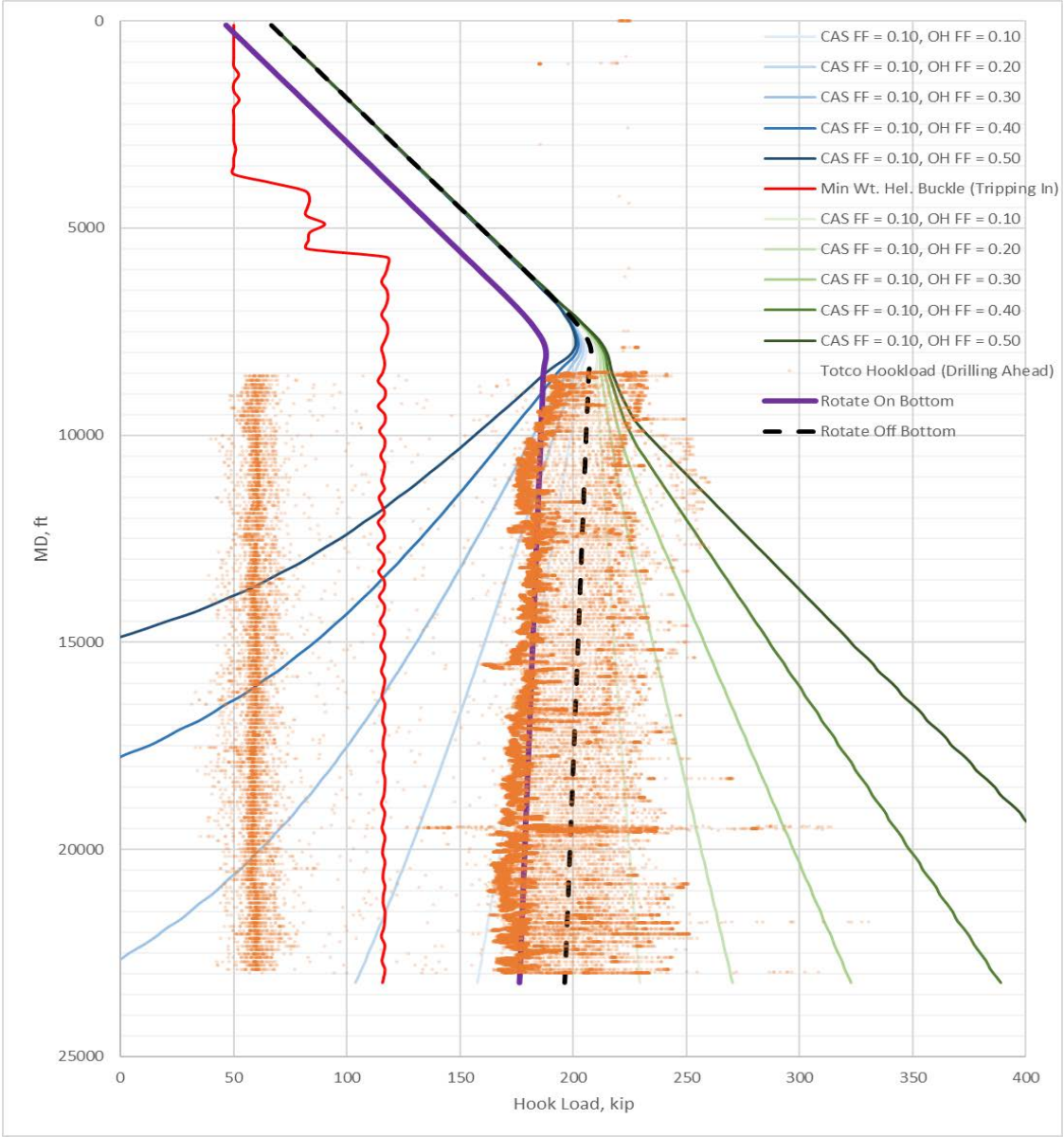
Three slurry blend reduces ECD @ TD and meets completion requirements

Predicted **92% of acid soluble tail to be displaced with full returns**

Must follow pre-planned pump down schedule

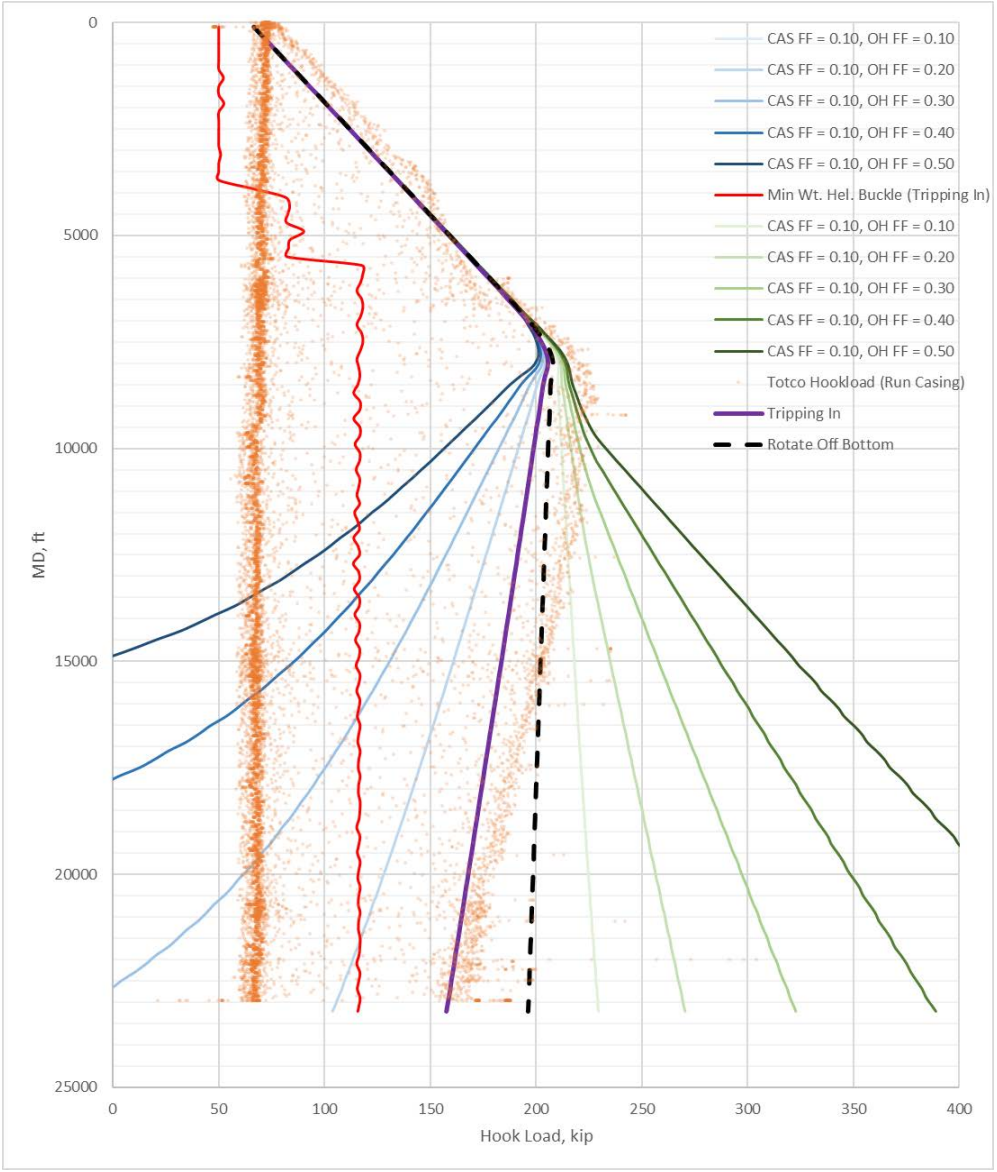


Planned vs. Actual Rotating on Bottom



Actual hook load values averaged **within 5%** of anticipated values while drilling ahead

Planned vs. Actual
5 ½” Casing Run



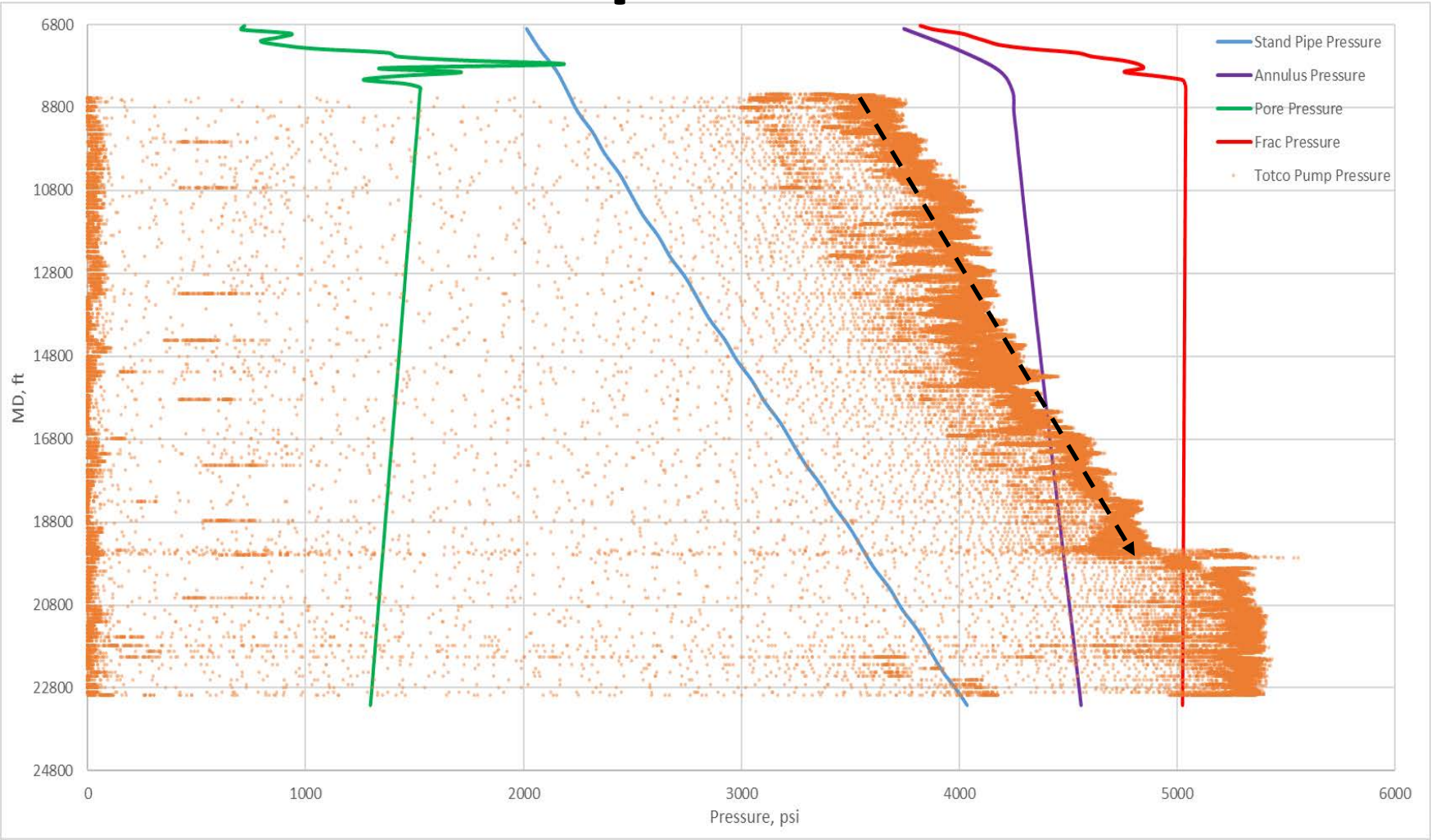
Close correlation @ TD

Friction factor around 0.1 in open hole (anticipated 0.1-0.2)

Average lateral DLS = 1.06 deg/100’

No rotation necessary to reach TD

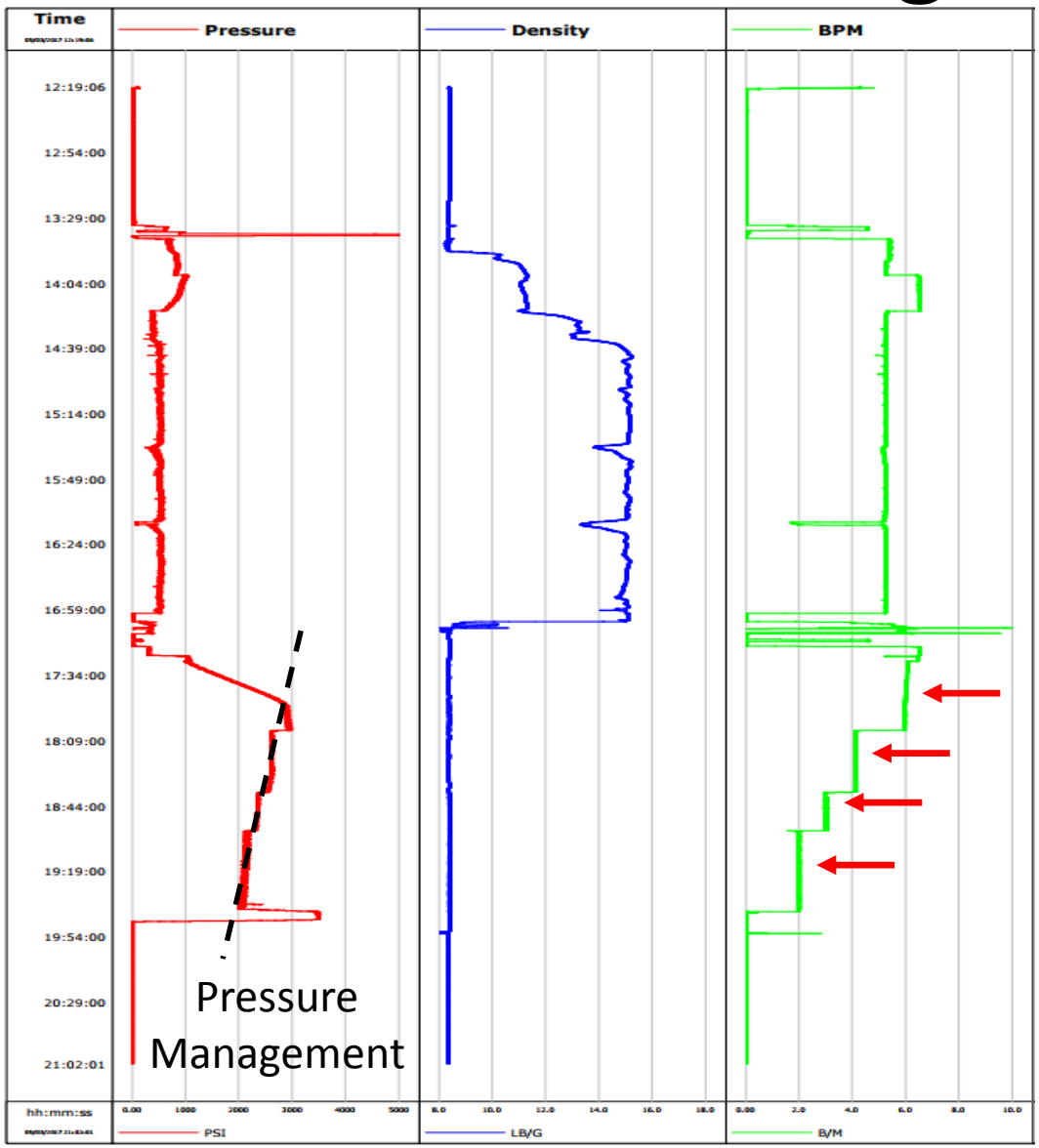
Planned vs. Actual Pump Pressure



No losses observed – annular pressure remained below fracture pressure

Increase in pump pressure trend likely due to debris in RSS tool

Planned vs. Actual Cementing Pressure



Pre-Planned pump down schedule manages downhole pressure

Full returns until 380 bbls displaced (514 bbls total displacement or **74% of displacement**)

Applied Learnings

- Rotary Steerable System
  - Initial perception of conventional motor assembly drove decision
  - Re-designed curve challenging this notion
- 8 ¾” Curve
  - Reduced build rates increases success rate
  - 2 out of 2 wells drilled 8 ¾” curve on first attempt w/ minimal performance loss
  - Third well attempted 8 ½” curve w/ RSS
- Real time monitoring of parameters, T&D, cuttings return, etc. led to high quality wellbore
  - Compared against modeling to determine the state of the well
  - Accuracy of model increases confidence to predict future wells

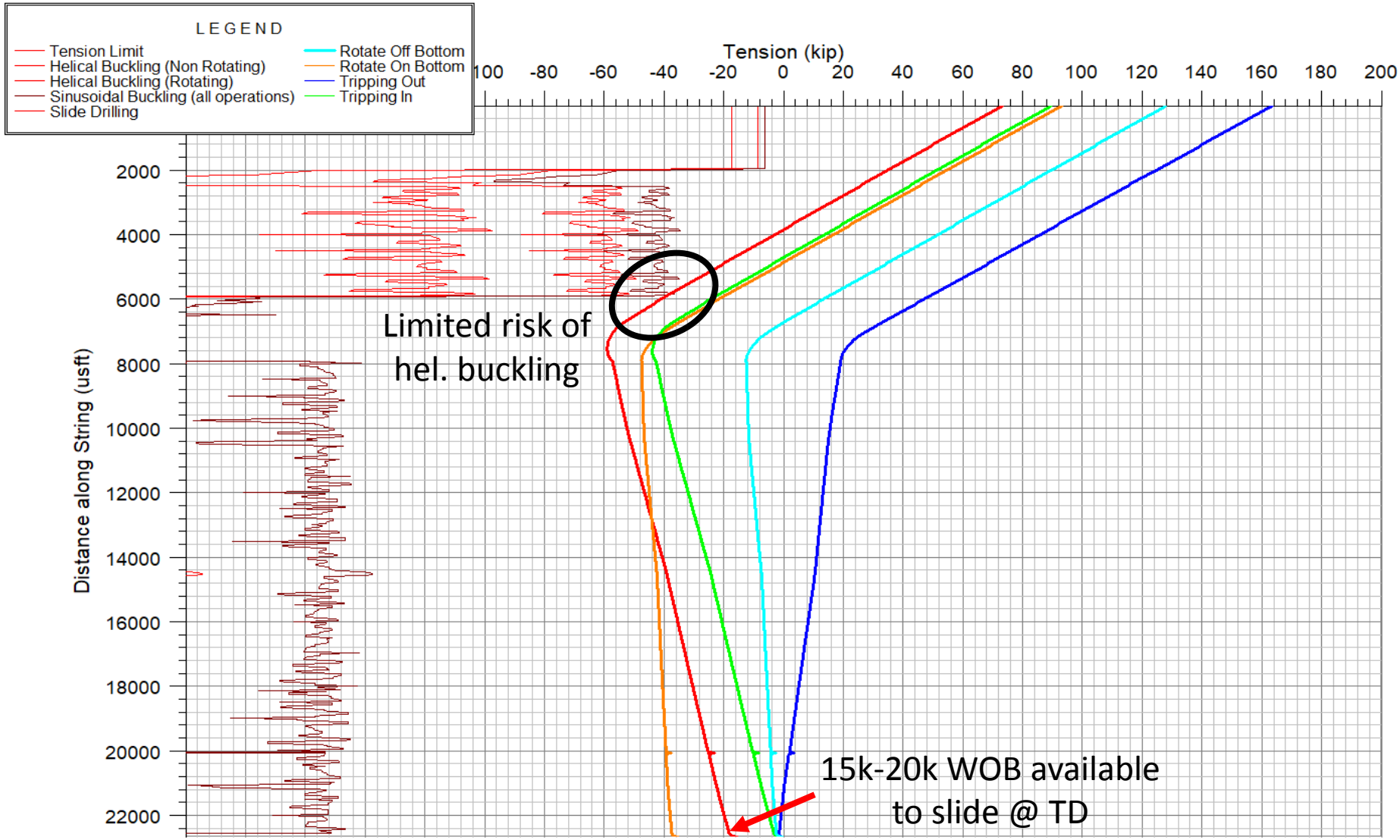
Sugg A 157 Package Results

- 3 Well Package
  - Average Vertical Section = 15,636’
  - All three wells drilled w/ RSS BHA
  - Average Rig Accept to Rig Release = 20.5 days
    - Max. = 22.0 days
    - Min. = 19.3 days
    - Avg. 2,073 ft/day in lateral
- No Major Issues
- 1 out of 3 wells drilled lateral w/ one BHA run
  - Other 2 wells both used 2 BHAs due to tool failures
- Average DLS below 1.1 for all 3 laterals
- Performance on par with 10k laterals

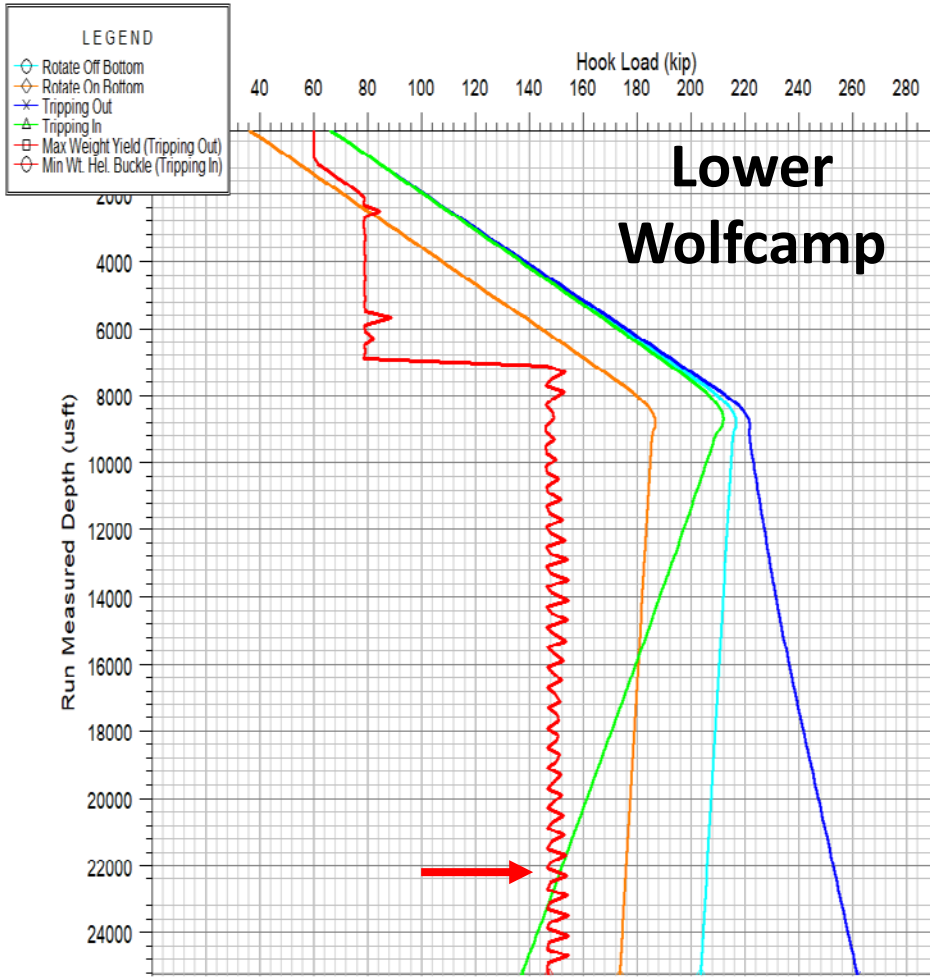
Future ERD Development

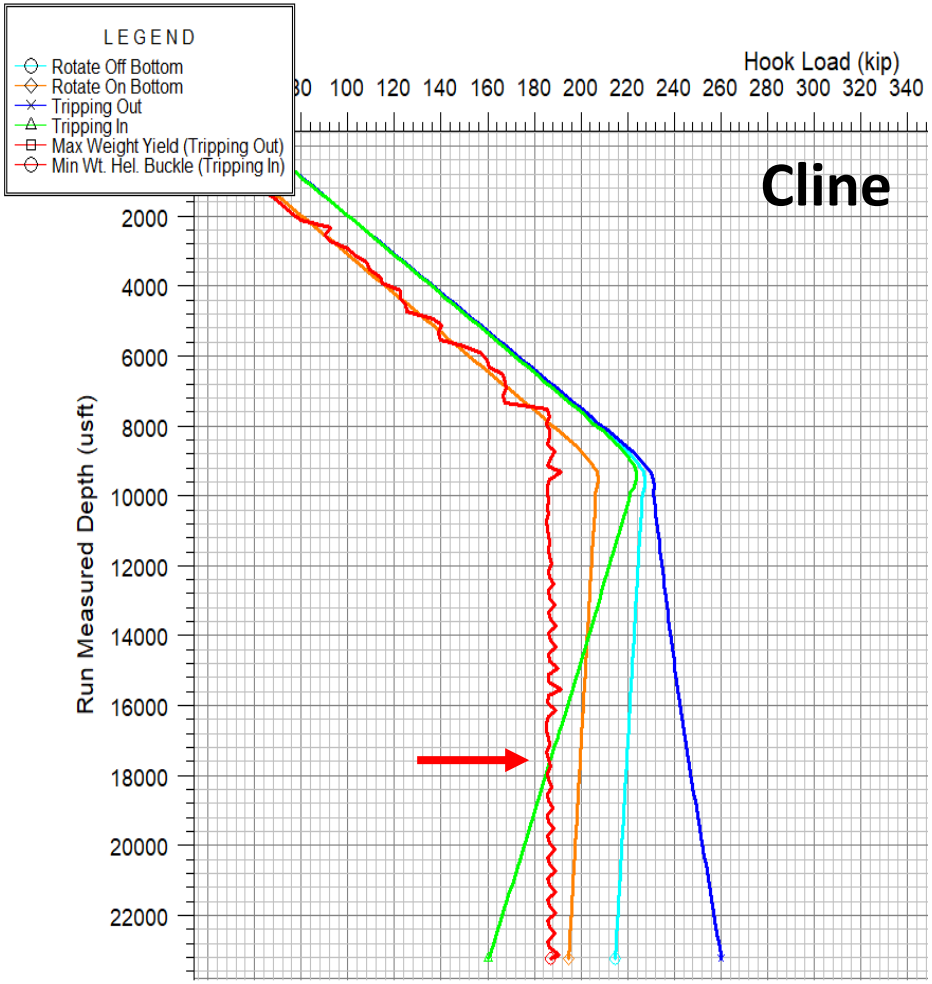
- Conventional 15k Laterals
  - No RSS BHA = significant cost savings
- Multi-Horizon 15k Laterals
  - Proven in Upper/Middle Wolfcamp
  - Potential to expand to Lower Wolfcamp & Cline targets
- 20k Lateral
  - Challenge technical limitations

Conventional 15k Laterals
Available Slide WOB



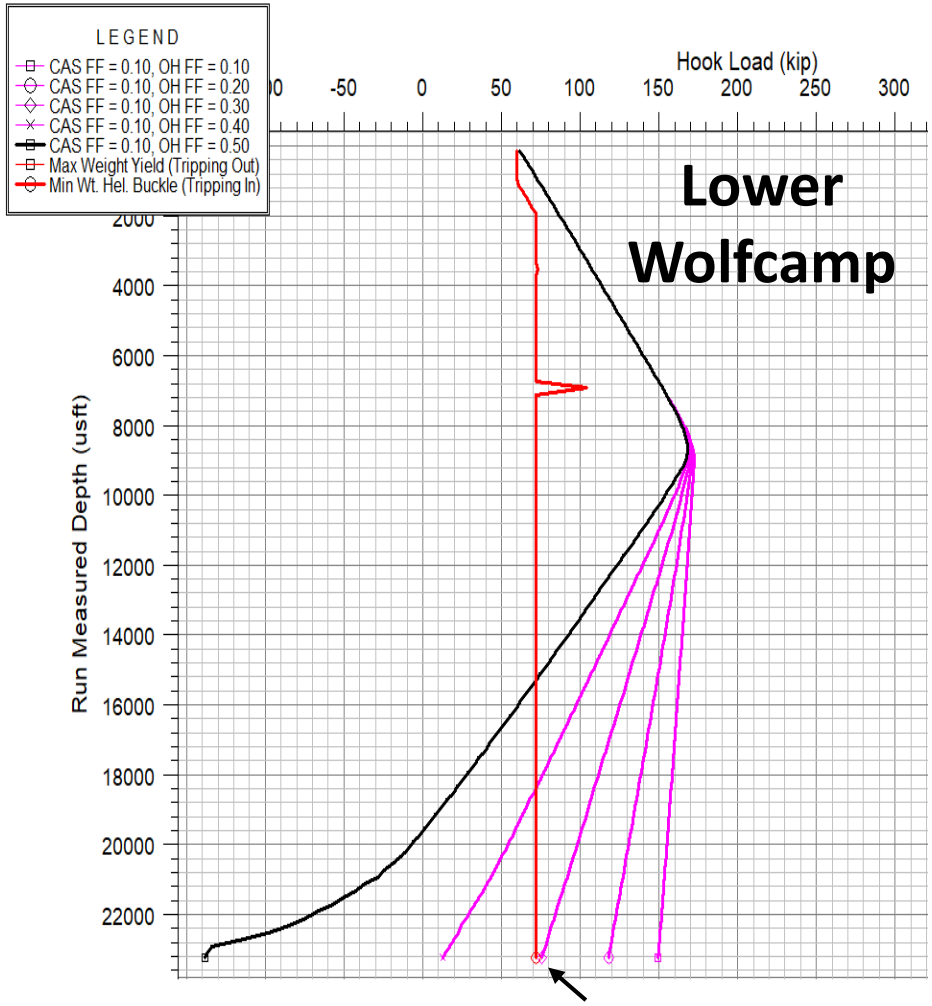
Multi-Horizon 15k Laterals
Tripping in Hole w/ Drilling Assembly



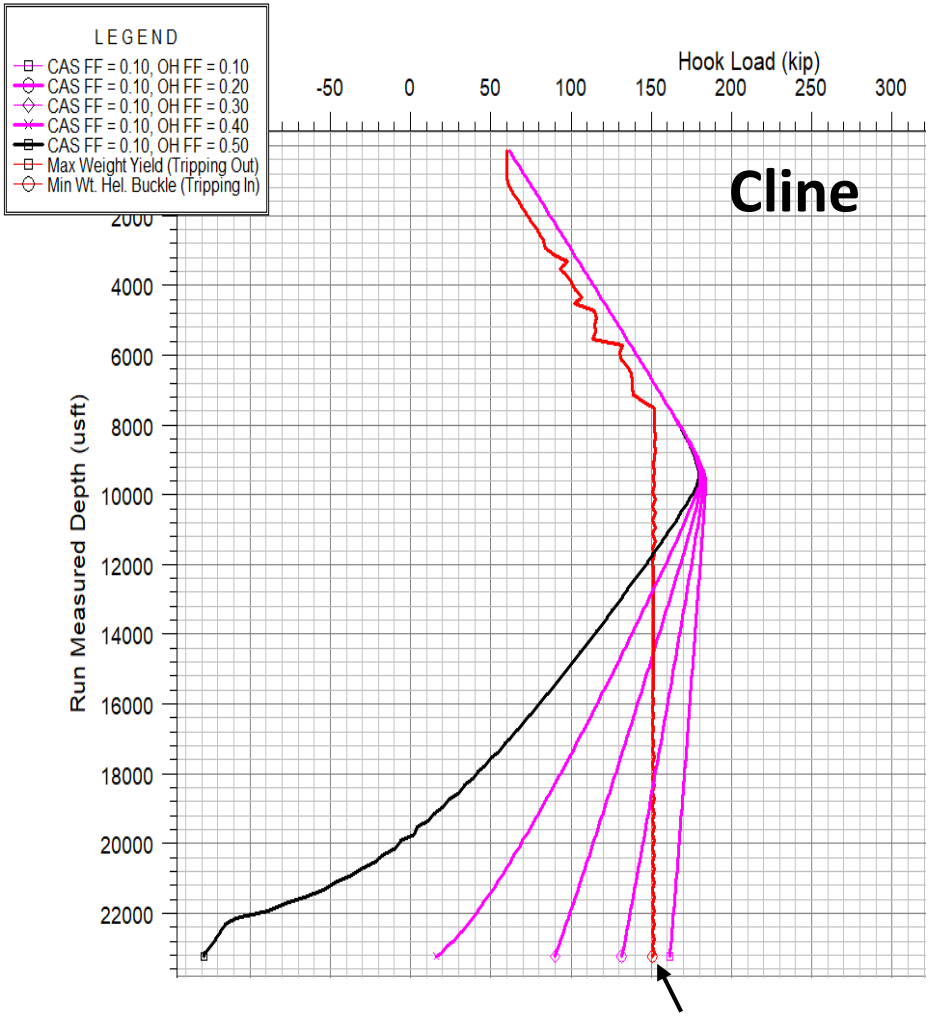


→ Continue to explore options to reduce and/or mitigate risk of helical buckling

Multi-Horizon 15k Laterals
5 ½” Casing Run



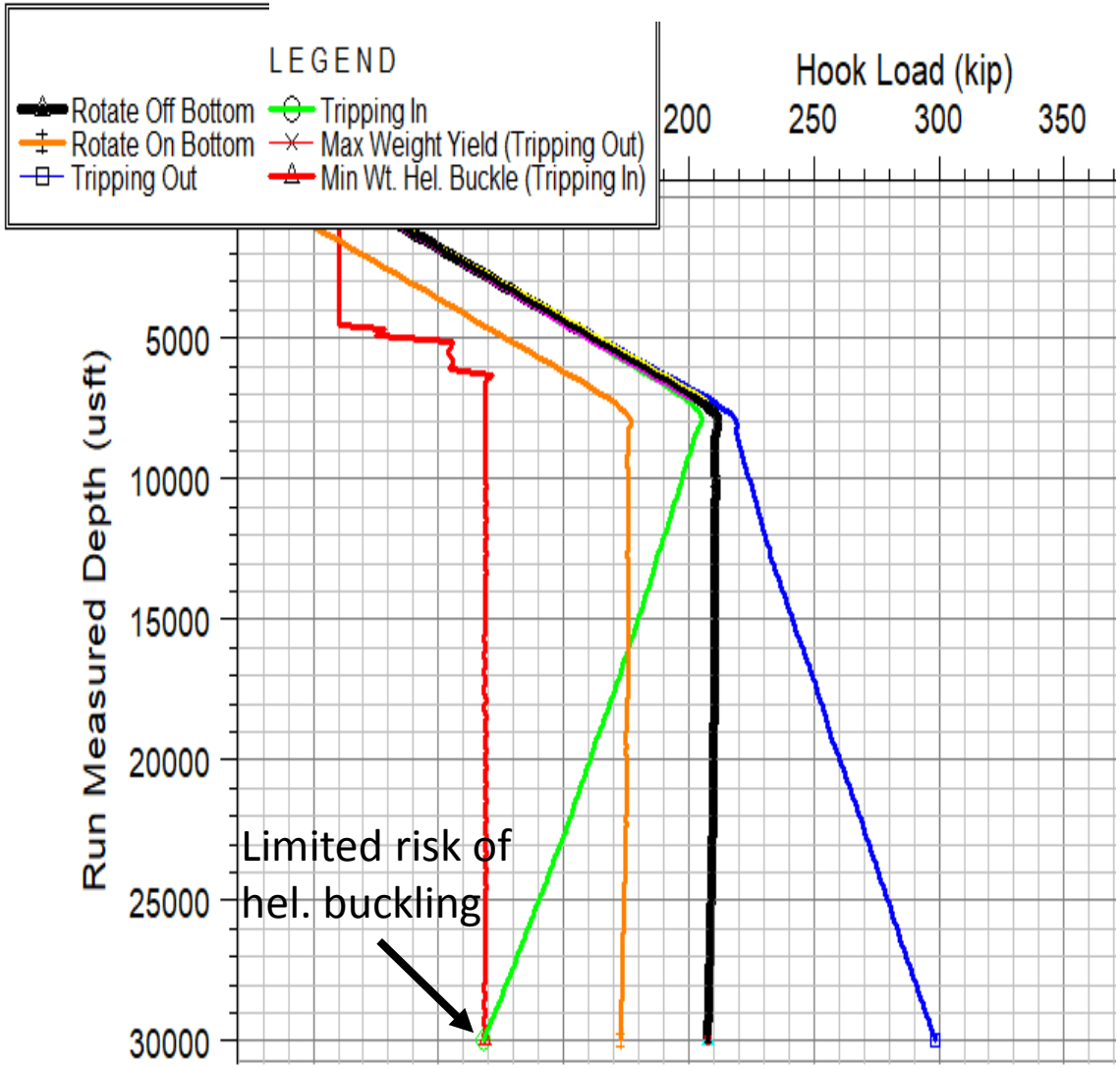
0.3 FF Tolerance



0.15 FF Tolerance*

*Ability to rotate and/or float casing

20K Lateral Potential
Tripping in Hole with Drilling Assembly



Modeling suggests 30,000' MD (+/- 20k vertical section) is **feasible across Wolcamp horizons**

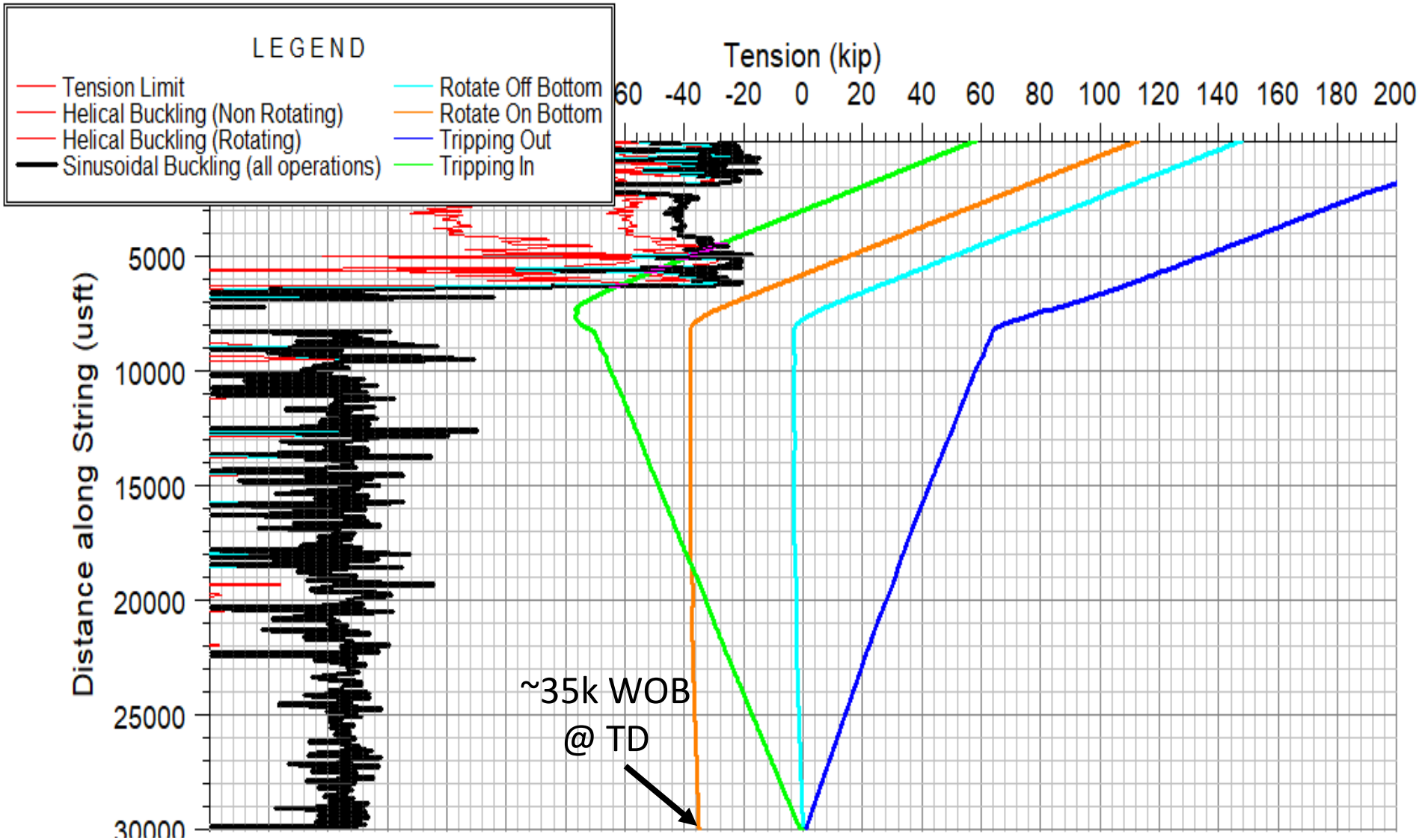
Available WOB to reach TD with RSS

Torque below make up value

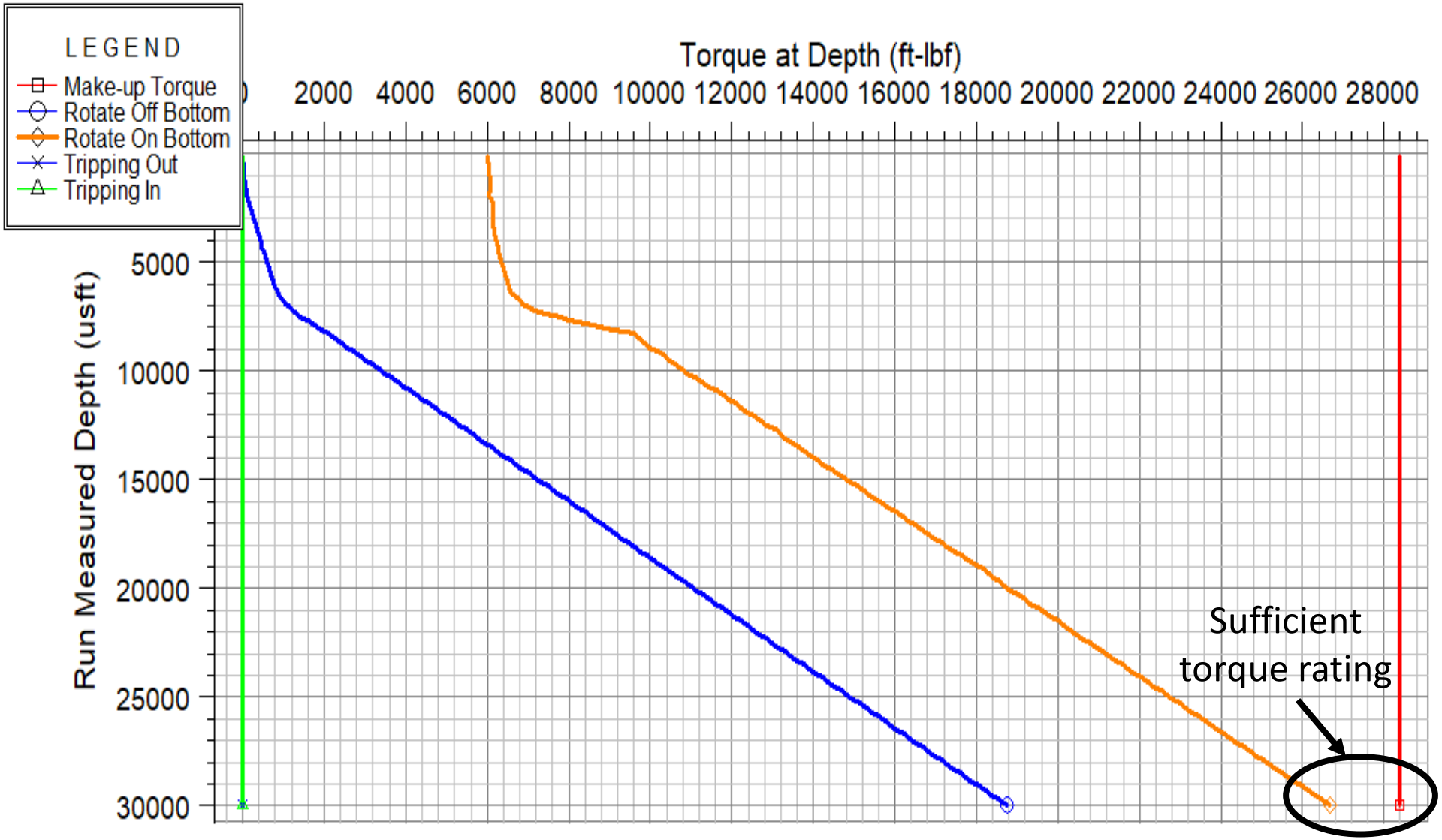
Remain under **fracture pressure** while drilling

Reach TD with **5 ½" casing** without the need for rotation or flotation

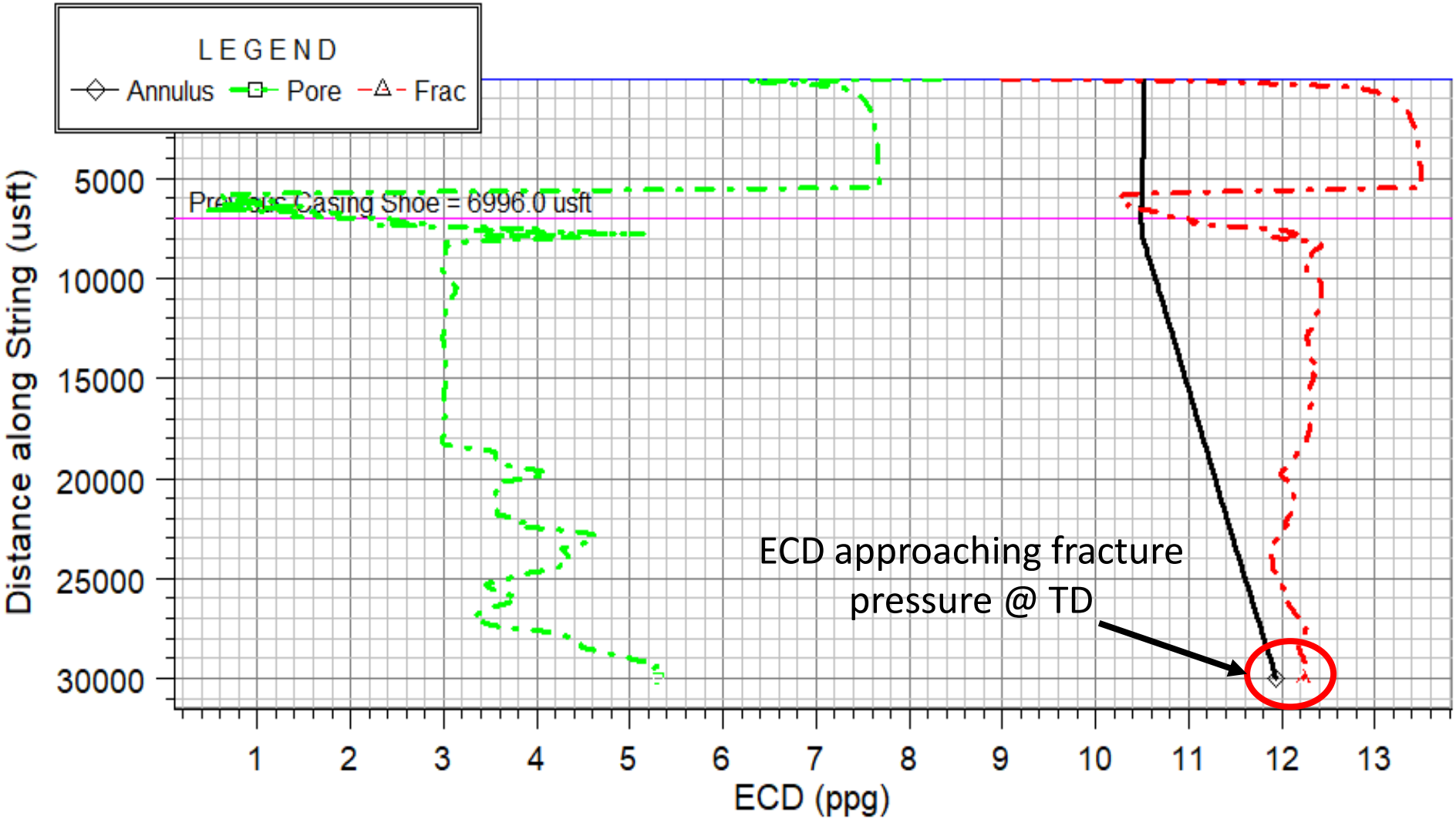
20K Lateral Potential Available WOB



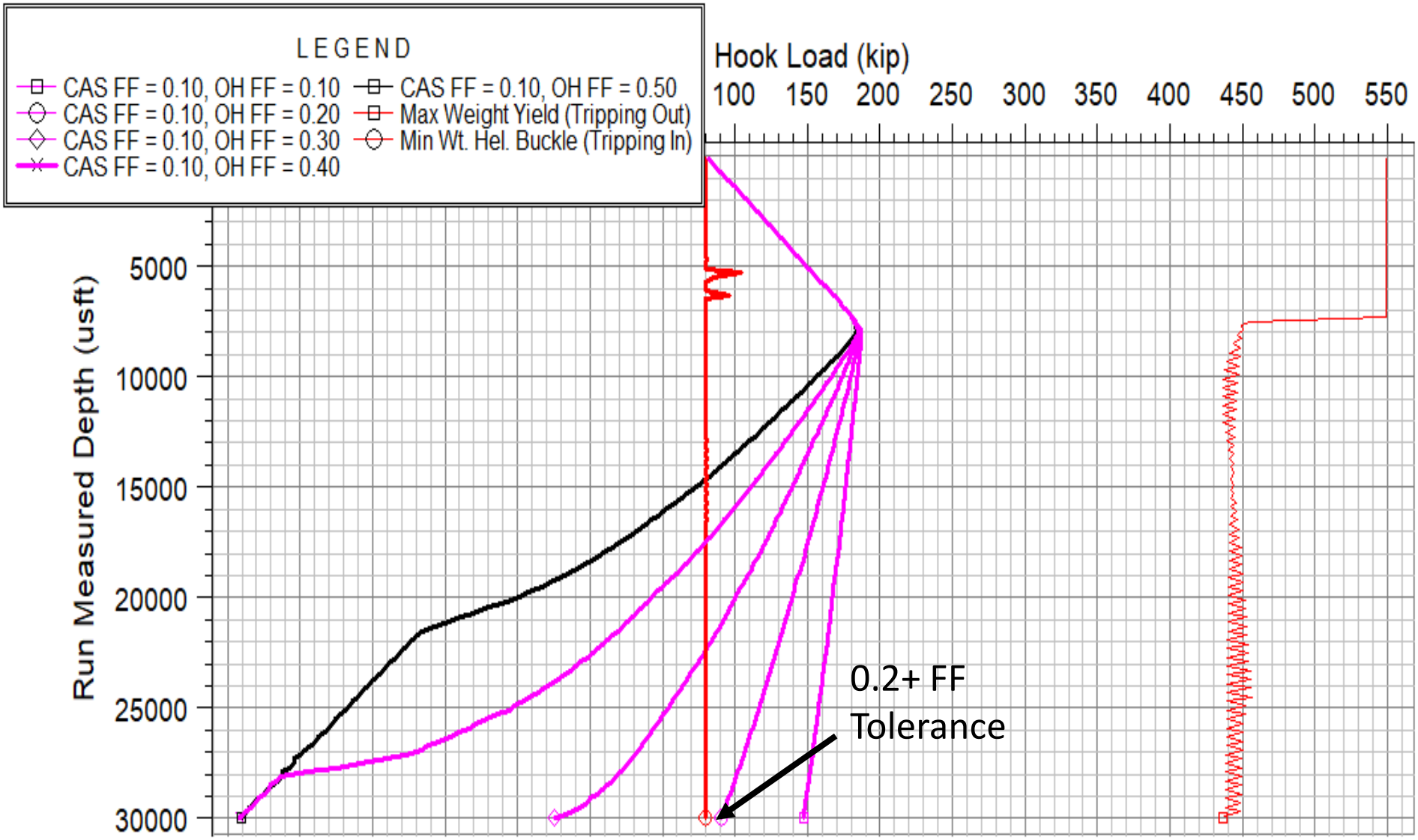
20K Lateral Potential Drilling Torque



20K Lateral Potential
ECD vs. Depth



20K Lateral Potential
5 ½” Casing Run



Conclusion

- Permian Basin is currently the most innovative oil & gas play
  - Opportunities exist to more efficiently develop natural resources
- Challenge technical “limitations” and conventional wisdom
  - Limitation today can be standard practice tomorrow
  - No room for complacency within our industry
- Continuous learning drives process improvement
  - Build on previous successes
  - Thorough understanding of failures