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BHA Selection Logic

9/2025

Agenda

- Goals of App
  - Scope of Recommendations
  - Role of Each Component
- BHA Selection Workflow
  - Requirements
  - Workflow and Flow Diagram
    - Comparable Offset Selection
    - Pre-Comparison Data Collection
    - Grading and Matching of Components
  - Gaps in Functionality on Corva

Goals of BHA Selection App

- **Provide BHA Component Recommendations to complete section in lowest time**
  - High On Bottom Performance & Low Failure Rate
- **Data driven approach**
  - Driven by observations, not models
- **Start with Bits and Motor**
  - Biggest impact on performance
  - Flexibility on sourcing

BHA Selection Workflow (w/o failure analysis)

1: User Inputs

- Target Well
- Search Radius
- Section for search (12.25 Int, 8.75” Lat, etc)
- Target formation
- List of comparable targets (lateral)
- Inputs on BHA Categorization

2: Search for All BHAs in similar sections

Pull BHAs in search radius that match on **hole size**, **formation** (same stratigraphy for vt), **BHA type**, **vertical vs. lateral**,

3: Group BHAs into groups of Equivalent BHAs

Divide BHAs runs into groups of similar BHAs (**similar RPG and diff limit and Bit cutter & Blade Count**)

4: Create ROP(x, Slide/Rot) curves for each run

By looking at ROP as a function of distance drilled (lateral) or % formation (vertical) and Slide/Rot, we can control for impactful parameters

5: Compile Runs into P50 Performance by Similar BHA

Create P50 performance curves by similar BHA

6: Calculate Expected Drill Time by BHA

Calculate drill time for target well based on P50 performance curves. **Best BHA is BHA with lowest drill time to TD.**

General Problem Statement

We want to select the BHA that gives us the lowest time to TD. However there are several variables affecting Time to TD outside of BHA Components. We can either filter out (red) or control for these factors in our analysis (yellow). Only looking at bits and motors (for now).

INPUTS

- BHA Components & Synergy
- Run Length
- Slide and Rotate %
- Hole Size
- Formation
- Area
- Failures/NPT
- Spud Date
- Parameters Applied

OUTPUT

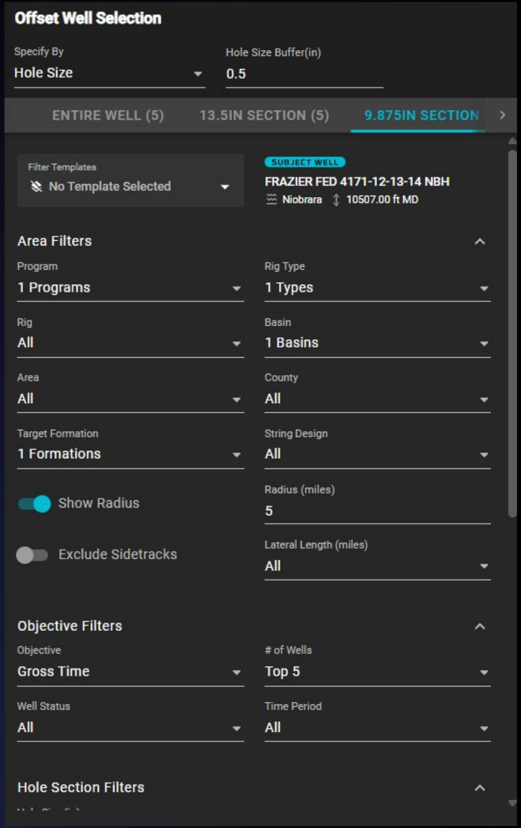
Time to TD (Minimize)

App: Offset Well Selection

Step 1: User Inputs

- ## Data Needed:

  Target Section Information:
  - Hole Size
  - Geo-Information (Target Formation - Lateral. Start and End Formations - Vertical)
  - Planned Length (Start and End Depths)
  - Run Specific Information (Curve/Lateral, Dedicated Curve, Dedicated Lateral)
    - Consider Runs that start and end in the same formation as comparable
  - Location of well
  - Search Radius
  - Comparable Targets (Lateral only)
  - Expected Slide %



Use offset Well Selection with mods (Expected Slide %, section start/end, spud date, vert./lat.)

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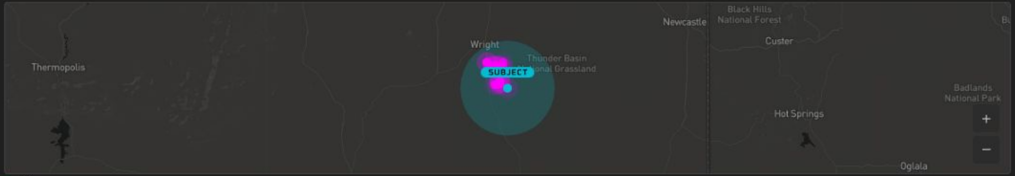
Step 2: Pull Wells

Use modified Offset Well Selection app to pull all comparable runs based off of search criteria. Will need to find all runs within section list.

Map 34 Selected



Niobrara

Entire Well 34 Selected

	Well Name	Program	Rig Type	Rig	Basin	Area	County	Target Formation	String Design	Well S
28	LEIA FE ... 5-16S NH	Anschutz	Land	Cyclone 39	Powder River Basin	Cross Bow East	Campbell	Niobrara	3	comp
29	ROSS FE ... 7-15E NH	Anschutz	Land	Cyclone 39	Powder River Basin	Crossbow	Campbell	Niobrara	3	comp
30	FRAZIER ... 3-13 NBH	Anschutz	Land	Cyclone 36	Powder River Basin	Buffalo	Campbell	Niobrara	3	comp
31	Lizzy F ... 4-15E NH	Anschutz	Land	Cyclone 37	Powder River Basin		Campbell	Niobrara	3	comp
32	Custer ... 9-3W NBH	Anschutz	Land	Cyclone 36	Powder River Basin		Campbell	Niobrara	3	comp
33	LIZZY F ... 21-1E NH	Anschutz	Land	Cyclone 36	Powder River Basin		Campbell	Niobrara	3	comp
34	ATLAS ... 7-5W NH	Anschutz	Land	Cyclone 33 (A)	Powder River Basin	Crossbow	Campbell	Niobrara	3	comp

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Step 3: Aggregate Runs into Equivalent BHAs

What is an Equivalent BHA and Why Do we Need it?

- An equivalent BHA is a way to group BHAs with comparable Bits and Motors.
- Allows us to Group BHA runs together.
- Needs to have user input in grouping through drop menus

Bit Grouping Criteria:
- Bit Mfg.
- Blade Count
- Cutter Size
- Cutter Shape (not default)

Mtr Grouping Criteria:
- Power Section Mfg (PV and Abbaco)
- RPG (+/- 10%)
- Max Diff (+/- 10%)
- Fit (not default and in bands)
- Compound Type (not default)

Motors are harder to source. so we may need to limit to a catalog or drop menu.

Step 3: Equivalent BHAs: Bits

Finding Bit Grouping Criteria:
- Bit Mfg. (Bit Mfg Field)
- Blade Count (Model # by Mfg)
- Cutter Size (Model # by Mfg)
- Cutter Morphology (Model # by Mfg)

Bits -

230 XOM - Upton Co- Lateral Runs WIth Baker Bits

35 Unique Bit Models

ATD506
ATD506X
ATD506X
ATD506TX
DD306WSX
DD406THX
DD406TSX
DD406TX
DD406TWSX
DD407TX
DD407VTHX
DD505TX
DD506TDX
DD506THX
DD506TVTH
DD506TX
DD506VTHX
DD506VTWHX
DD506VTX
DD507TX
DD507TWX
DD507VTHX
D406VTHX
D506TWX
D506VTWHX
D506VTHX
D507TX
D507VTHX
D507VTWX
Dd406TWSX
GTD55DM
GTD64C
MDSi611
MDi611
P506H

Halliburton Bits

Group By Cutter Size and Blade Count

Baker Model Prefix

DD406THX

Cutter Size (1/8th")

Blades

4 Baker Bits

306
406
506
507

*Need Bit Model Instructions for Shape (call reps)

Workflow for BHA Selection

Motors	Bit Manufacturer	Cutter Size (mm)	Blades
7/8 6.4	Baker	13	6
5/6 8.3	Reed	15	
	Halliburton		

- 12 options to consider for BHA in this example

Step 3: Equivalent BHA: Motor

Mtr Grouping Criteria:

- **Power Section Mfg** (Look at Motor Stg and Ratio. Each design is patented.)
- **RPG** (Current Field)
- **Max Diff** (Current Field)
- **Fit** (Current Field)
- **Compound Type** (Not in BHA Selection but in Drillstring)

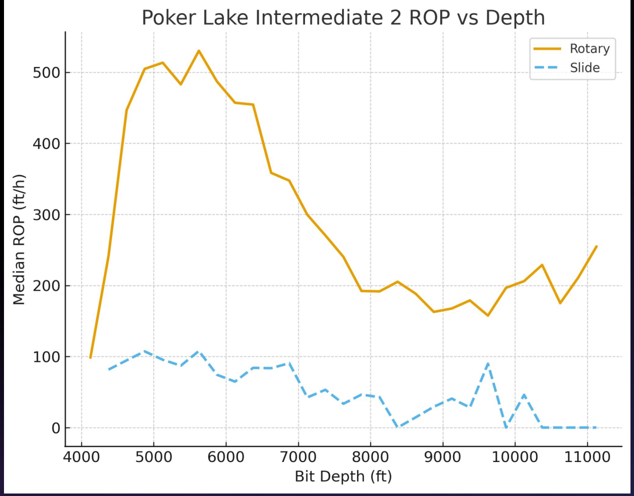
XOM 6.75″ OH Motor Run Count - Upton County

Lobe Ratio	Stages	Count
5.6	8.1	1
5.6	8.2	2
5.6	8.4	15
5.6	11.2	2
6.7	5	9
6.7	5.7	1
6.7	6	1
6.7	6.4	1
6.7	6.5	27
6.7	7.8	4
6.7	8.4	27
6.7	9	2
6.7	10.4	1
6.7	10.7	8
7.8	5	87
7.8	5.7	47
7.8	6	17
7.8	6.1	77
7.8	6.4	147
7.8	6.8	3
7.8	6.9	8
7.8	8.4	1
7.8	8.5	19
7.8	9.4	13
8.9	8	12

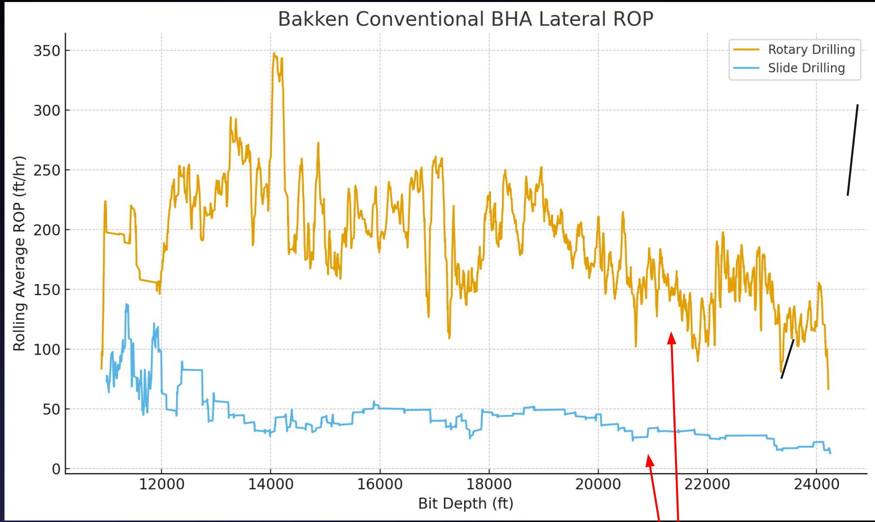
*Need Motor Catalog for PV and Abbaco

Step 4/5: ROP Type Curves

Vertical Section



Lateral Section



Average ROP By:

- Formation % (Vertical)
- Run Length (Lateral
- Rotary and Slide

Lateral ROP often function of run length (esp long laterals)

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Step 4: Vertical Type Curve Generation

Part A: Make the Subject Well Blank Roadmap

1) Determine Start and End TVD
2) Correlate Start and End to % Formation
3) Discretize Well into 10% Formation Segments

Section Start: 3500′ **Section End:** 6500′ → Section Start: Wilcox 50% Section End: Chalk 50%

Formation	Top (TVD)	Top (MD)	Thickness (MD)
Wilcox	3000	3000	1000
Reklaw	4000	4000	1000
Anacacho	5000	5000	1000
Chalk	6000	6000	1000
Eagleford	7000	7000	-

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Step 4/5: Vertical Type Curve Generation

Section Start: Wilcox 50% Section End: Chalk 50%

Subject Well				Offset 1		Offset 2		Offset 3		Offset 4		Offset 5	
Formtation	% Formation	Median Rotary ROP	Median Slide ROP	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP
Wilcox	50%												
Wilcox	60%												
Wilcox	70%												
Wilcox	80%												
Wilcox	90%												
Reclaw	0%												
Reclaw	10%												
Reclaw	20%												
Reclaw	30%												
Reclaw	40%												
Reclaw	50%												
Reclaw	60%												
Reclaw	70%												
Reclaw	80%												
Reclaw	90%												
Anacacho	0%												
Anacacho	10%												
Anacacho	20%												
Anacacho	30%												
Anacacho	40%												
Anacacho	50%												
Anacacho	60%												
Anacacho	70%												
Anacacho	80%												
Anacacho	90%												
Chalk	0%												
Chalk	10%												
Chalk	20%												
Chalk	30%												
Chalk	40%												

Greyed out sections indicate where offsets didn't have data with an Equi. BHA

1) Generate Roadmap Blank Based on Formation Start and End
2) For each run of Equi. BHA look at:
- WITSML-1ft data for ROP, Rig State. Need TVD too.
-Formation Tops to determine TVD tops for each 10% formation
3) Find Median ROP for each discretized segment 4) Average Offset Runs of Equi BHA to find average on bottom performance in each section

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Step 4/5: Lateral Type Curve Generation

Part A: Make the Subject Well Blank Roadmap

1) Determine Start and End MD (from planned start and end of lateral)
2) Discretize Well into 100′ Sections

Section Start: 12100′ **Section End:** 14200′

Target Well			Offset 1		Offset 2		Offset 3		Offset 4		Offset 5	
Section Start	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP	Rotary ROP	Slide ROP
0												
100												
200												
300												
400												
500												
600												
700												
800												
900												
1000												
1100												
1200												
1300												
1400												
1500												
1600												
1700												
1800												
1900												
2000												

Greyed out sections indicate where offsets didn’t have data with an Equi. BHA

1) Generate Roadmap Blank Based on Start and End (run length. Start ad LP (start of lateral section)
2) For each run of Equi. BHA look at:
- WITSML-1ft data for ROP and Rig State. Need BHA Depth In and section start. **Slide ROP needs to be a function of lateral length and not run length**
3) Find Median ROP for each discretized segment
4) Average Offset Runs of Equi BHA to find average on bottom performance in each section

Step 6: Calculate Time to TD with Each Equi. BHA

	Equi BHA 1			Equi BHA 2			Equi BHA 3			Equi BHA 4			Equi BHA 5		
Section Start	Rotary ROP	Slide ROP	TTD	Rotary ROP	Slide ROP	TTD	Rotary ROP	Slide ROP	TTD	Rotary ROP	Slide ROP	TTD	Rotary ROP	Slide ROP	TTD
0															
100															
200															
300															
400															
500															
600															
700															
800															
900															
1000															
1100															
1200															
1300															
1400															
1500															
1600															
1700															
1800															
1900															
2000															
		Sum (hours)	120		Sum (hours)	147		Sum (hours)	132		Sum (hours)	110		Sum (hours)	134

1) Take all of the average ROPs for each Equivalent BHA.
2) Calculate the Time To Drill (TTD)each segment.

TTD_seg = Segment Length * (1 - Slide %) /Rotary ROP + Segment Length * Slide % / Slide ROP

3) Calculate TTD sectio (sum of segment TTD)

4) Recommended Equivalent BHA = BHA with lower TTD. In this case if BHA 4 with a TTD of 110 hours

Incorporating Failures into TTD

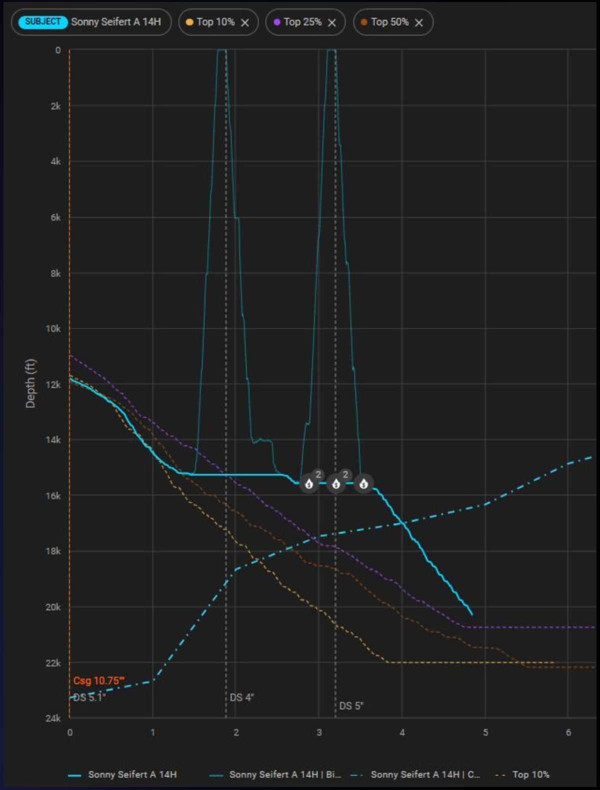
Why and How to Implement?

- Long laterals lead to higher likelihood of failures which have material impact on total section time
- Example to the right had 2 failures in the lateral accounting for 2 days (41%) of the 4.84 days on this section.
- By identifying BHAs and parameters that show a lower failure probability can help reduce Spud to TD.

How to?

- Look at failure rates by equivalent BHA and use rig performance (tip speed and turnaround time) to estimate expected time on failures for the section
- Include failure time in TTD:

$$TTD = \text{Drill Time} + \text{Failure Time}$$



Failure Time Workflow

1: Pull In Failure Data and Rig Performance

- Bit Pull ReasonFound in BHA Optimization or Pull Reason for the Bit in Drillstrings
- Pulled from Wellview **(OFTEN NOT IN CORVA)**
- Pull average trip speed and turnaround time for the rig.

2: Perform Kaplan-Meier Survival Analysis

Perform statistical failure analysis on each Equivalent BHA.

3: Failure Time for Well

Calculate the failure time by looking at expected failures for the section by Equi. BHA.

Incorporate into TTD

Add in Failure time to TTD and evaluate each Equi. BHA

Step 1: Pull in Failures, Trip Speed, and Turnaround Time

- Bit Reason Pulled
  - **What?** - IADC Bit reason pulled indicates why that BHA was pulled out of the hole. (DMF, DTF, BHA, LIH) as failures
  - **Where?** Found in Pull Reason for bits. Often not populated in Corva
- Trip Speed
  - **What?** - Speed at which rig can trip useful when estimating time for tripping for BHA
  - **Where?** - Last Assest on Rig Line - Average Trip in and Trip Out.
- Turnaround Time
  - **What?** - Time to L/D old BHA and P/U new BHA
  - **Where?** - Composite Design (last 5 wells) BHA PU/LD or user input

60 out of 143 lateral runs since 2024 for BPX populated

Step 2: Perform Survival Analysis

What Is a Kaplan-Meier Survival Analysis?

- Shows the probability of some outcome occurring (BHA failure related pull reason) as a function of an independent variable, in this case distance drilled.

Steps:

1) **Sort** all runs by distance drilled.
2) Create buckets for failure distance (x_i) (in this case every 250′)
3) At each unique failure distance x_i
   a) n_i = **number at risk** just *before* x_i
      (i.e., all runs with distance ≥ x_i; already failed or censored earlier are excluded
      Event Failure = 0 in your bucket)
   b) d_i= **number of failures** exactly at x_i (Sum of failures in bucket. Event Failure = 1)
4) **Conditional survival (S) at x_i**: the proportion that *survive past* x given they were at risk just before it:

   S = 1- d_i/n_i

5) Overall Survival S(x_i) (overall failure rate = product of the observed 250′ failure rate):

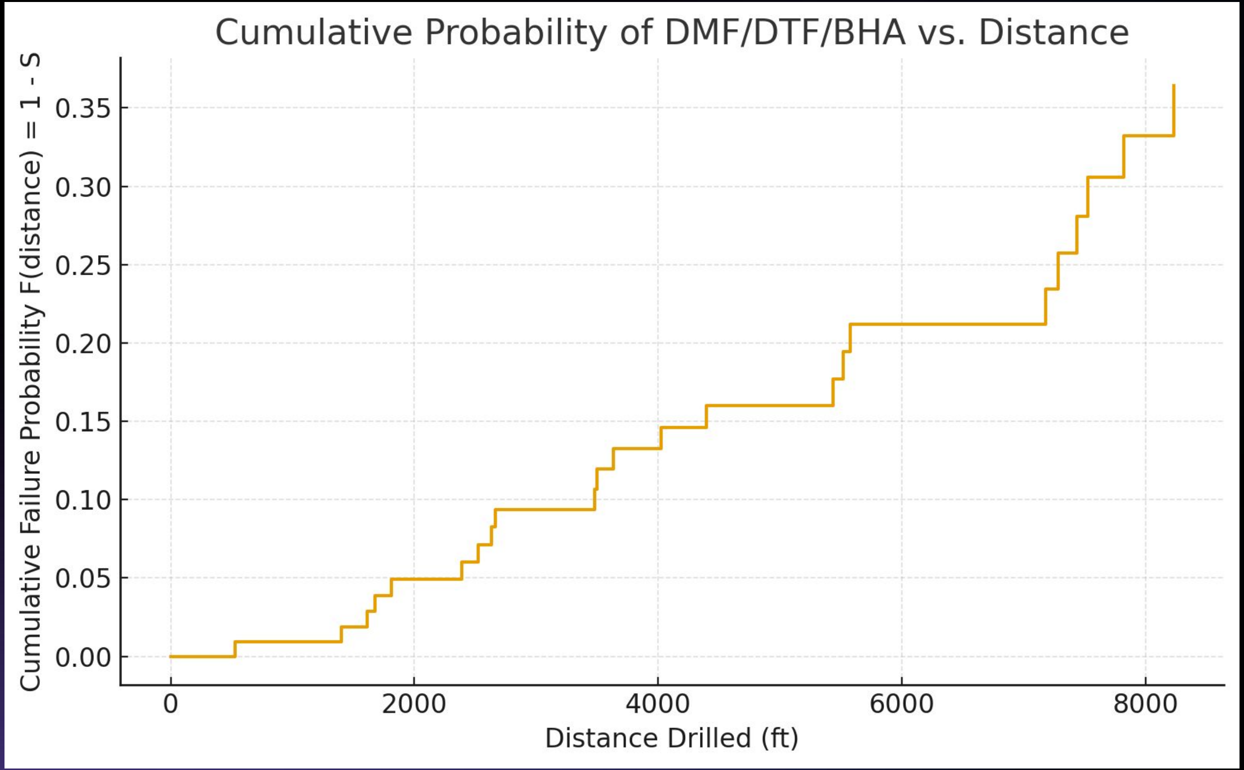
   S(x_i) = $\prod$ (1 - d_j/n_j) from j = 1 to i

6) Failure Rate = 1 - Survival Rate

	A	B	C
1	Distance_Drilled	Bit_Reason_Pulled	Event Failure?
4	3483.88	TD	0
5	2522.31	DTF	1
6	2213.97	TD	0
7	8202.99	WT	0
8	4741.65	TD	0
9	3475.65	DMF	1
10	2389.05	DMF	1
12	1894.56	TD	0
13	7821.24	BHA	0
16	2243.12	WC	0
59	1814	BHA	0
61	4002.6	BHA	0
62	7179.6	BHA	0
63	4234.3	BHA	0
64	2142	BHA	0
66	6050	BHA	0
69	1401.9	BHA	0
70	2660.9	BHA	0
71	5432.2	BHA	0
72	8199	BHA	0
73	3500.1	BHA	0
74	5516.9	BHA	0
75	8092	BHA	0
76	2629.17	TD	0
77	4693.17	TD	0
78	652.35	BHA	0
79	2336.99	TD	0
80	530.9	DMF	1
81	1610.01	DMF	1
82	1678.9	DMF	1
84	3634.84	DMF	1
86	10492.28	TD	0

Sample Input for Kaplan Meier

Example of Failure Curve - BPX Eagleford



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Step 3: Option 1: Single Failure Max

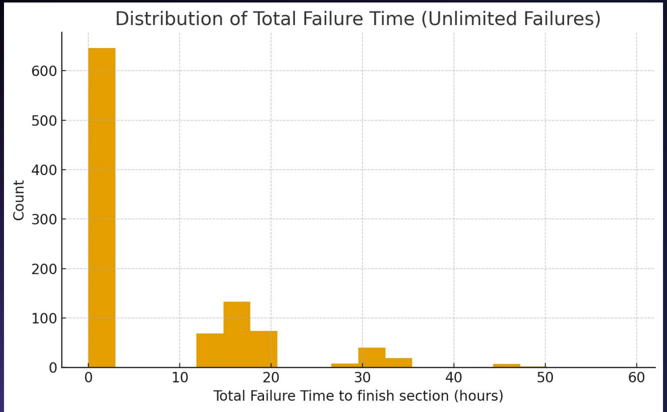
- Assume max of 1 failure and look at all possibilities and probabilities of TDing section:
- Example Objective Run:
    - Distance Drilled: 7250′
    - Start MD: 12500′
    - Rig Trip Speed: 3000′
    - Turnaround Time: 6hrs
- Failure-Time_i = Marginal-Failure-Rate*(Distance-Drilled_i+Start-MD)∗2/Trip-Speed+Turnaround-Time)
- Total-Failure-Time = ΣFailure-Time_i
- This is a simpler option to implement but assumes there can only be one failure per run

Distance Drilled	Overall Failure Rate	Marginal Failure Rate	Failure-Time_i (hours)	Total-Failure-Time (hours)
0	0	0	0.00	0.0
250	0.1	0.1	1.45	1.5
500	0.11	0.01	0.15	1.6
750	0.12	0.01	0.15	1.7
1000	0.13	0.01	0.15	1.9
1250	0.14	0.01	0.15	2.0
1500	0.15	0.01	0.15	2.2
1750	0.16	0.01	0.16	2.4
2000	0.17	0.01	0.16	2.5
2250	0.18	0.01	0.16	2.7
2500	0.19	0.01	0.16	2.8
2750	0.2	0.01	0.16	3.0
3000	0.21	0.01	0.16	3.2
3250	0.22	0.01	0.17	3.3
3500	0.23	0.01	0.17	3.5
3750	0.24	0.01	0.17	3.7
4000	0.25	0.01	0.17	3.8
4250	0.26	0.01	0.17	4.0
4500	0.27	0.01	0.17	4.2
4750	0.28	0.01	0.18	4.3
5000	0.29	0.01	0.18	4.5
5250	0.3	0.01	0.18	4.7
5500	0.31	0.01	0.18	4.9
5750	0.32	0.01	0.18	5.1
6000	0.33	0.01	0.18	5.2
6250	0.34	0.01	0.19	5.4
6500	0.35	0.01	0.19	5.6
6750	0.36	0.01	0.19	5.8
7000	0.37	0.01	0.19	6.0
7250	0.38	0.01	0.19	6.2
7500	0.39	0.01		
7750	0.4	0.01		
8000	0.41	0.01		
8250	0.42	0.01		
8500	0.43	0.01		

Step 3: Option 2: Monte Carlo Simulation

Monte Carlo Simulation Option

- I personally have not implemented this solution
- Use the same observed failure rate but runs simulations that calculate n number of possible ways the well will drill (and fail) based on the probability curve
- Use Failure Time = (Distance-Drilled + Start-MD)*2/Trip-Speed + Turnaround
- I used ChatGPT to run a monte carlo simulation (1000 simulations) based on the failure curve and the same inputs on failures



	A	B	C
1	Distance Drilled	Overall Failure Rate	Marginal Failure Rate
2	0	0	0
3	250	0.1	0.1
4	500	0.11	0.01
5	750	0.12	0.01
6	1000	0.13	0.01
7	1250	0.14	0.01
8	1500	0.15	0.01
9	1750	0.16	0.01
10	2000	0.17	0.01
11	2250	0.18	0.01
12	2500	0.19	0.01
13	2750	0.2	0.01
14	3000	0.21	0.01
15	3250	0.22	0.01
16	3500	0.23	0.01
17	3750	0.24	0.01
18	4000	0.25	0.01
19	4250	0.26	0.01
20	4500	0.27	0.01
21	4750	0.28	0.01
22	5000	0.29	0.01
23	5250	0.3	0.01
24	5500	0.31	0.01
25	5750	0.32	0.01
26	6000	0.33	0.01
27	6250	0.34	0.01
28	6500	0.35	0.01
29	6750	0.36	0.01
30	7000	0.37	0.01
31	7250	0.38	0.01
32	7500	0.39	0.01
33	7750	0.4	0.01
34	8000	0.41	0.01
35	8250	0.42	0.01
36	8500	0.43	0.01

Average = 9.8 hrs
(3.6 hrs longer
than single failure)

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Step 4: Incorporate Failure Time into TTD

Add in Failure Time to the TTD and Reevaluate the best BHA

- TTD = Drill-Time + Failure-Time
- Find Equivalent BHA that has the lowest expected TTD

Questions?

Can We Just Apply Filters?

XOM - Delaware

-12 Rigs * 30 wells / year = **360 lateral runs / year**

Variable	Variations
BHAs	10 bits * 2 Motors
Degradation (run length)	4 bins (2000' range)
Formation	15 targets (4 bins of equivalent)
Hole Size	2 Hole Sizes
Area	4 areas
Slide / Rotate %	4 bins
Parameters	-
Failures	-

640 permutations
(~2x number of runs)

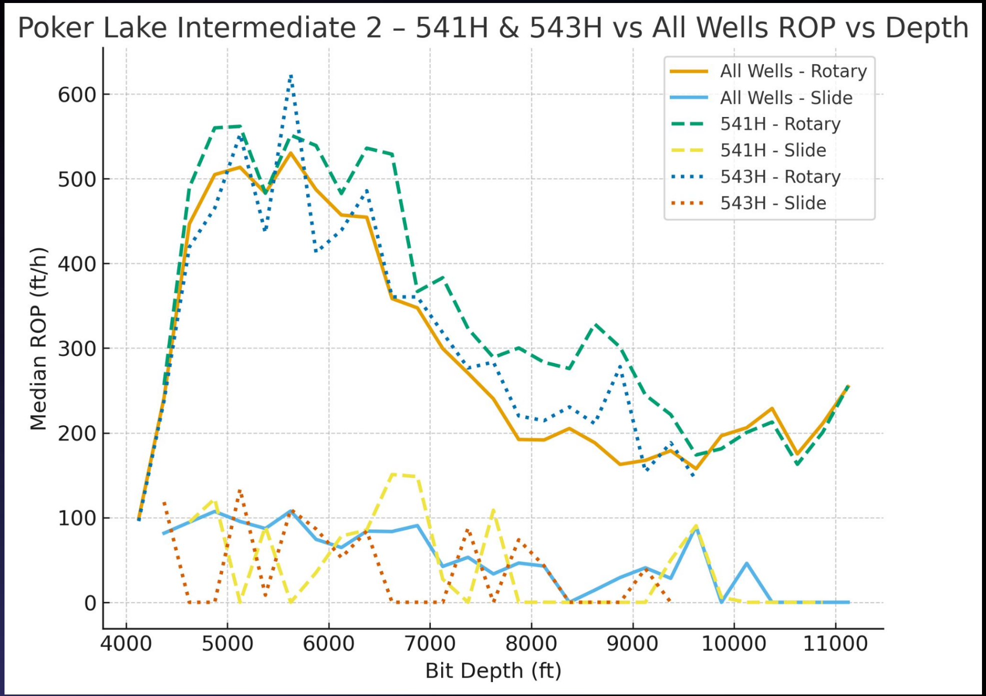
Controlling for Other Variables

INPUTS

- BHA Components & Synergy
- Run Length
- Hole Size ← Filter Runs Considered (0.5″)
- Formation ← Filter Runs (Lateral) - Have option to consider multiple targets
- Area ← Filter Runs Considered (Radius, County, Basin, or Operator Designation)
- Parameters Applied
- Slide and Rotate %
- Failures/NPT
- Spud Date ← Filter Runs Considered

Insights with this Approach

Well Name	Rotary ROP	Footage/D
PLU 23 DTD 541H	286 ft/h	4609
PLU 23 DTD 543H	290 ft/h	3923



Controlling for Other Variables

INPUTS

- BHA Components & Synergy
- Run Length ← ROP(Distance Drilled, Type)
- Hole Size ← Filter Runs Considered (0.5″)
- Formation ← Filter Runs (Lateral) - Have option to consider multiple targets
- Area ← Filter Runs Considered (Radius, County, Basin, or Operator Designation)
- Parameters Applied
- Slide and Rotate % ← ROP(Distance Drilled, Type)
- Failures/NPT
- Spud Date ← Filter Runs Considered

Use PD to Control for Parameters Applied?

- PD Estimates Max ROP as a function of Parameter Limits
- Estimate On Bottom ROP based on Single Set of Limits
    - Use P90 WOB, Diff, and RPM as limits
- Likely very computationally heavy (hundreds of automated reruns per analysis)

- ROP(Distance Drilled, Drilling Type) → ROP(Distance Drilled, Drilling Type, Single Set of Parameter Limits)

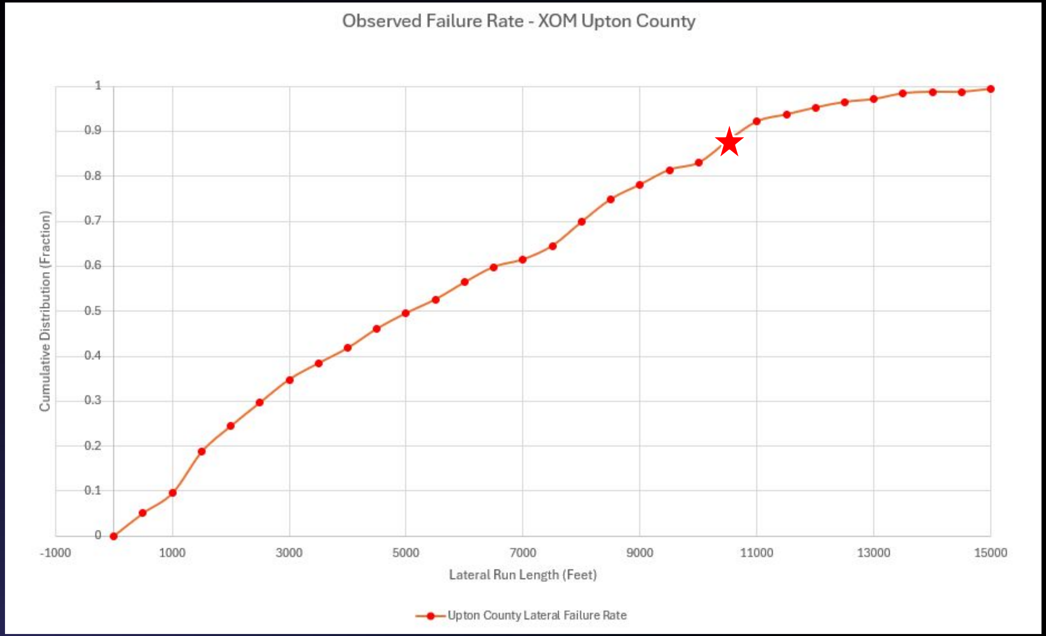
Controlling for Other Variables

INPUTS

- BHA Components & Synergy
- Run Length ← ROP(Distance Drilled, Type)
- Hole Size ← Filter Runs Considered (0.5″)
- Formation ← Filter Runs (Lateral) - Have option to consider multiple targets
- Area ← Filter Runs Considered (Radius, County, Basin, or Operator Designation)
- Parameters Applied ← PD??
- Slide and Rotate % ← ROP(Distance Drilled, Type)
- Failures/NPT
- Spud Date ← Filter Runs Considered

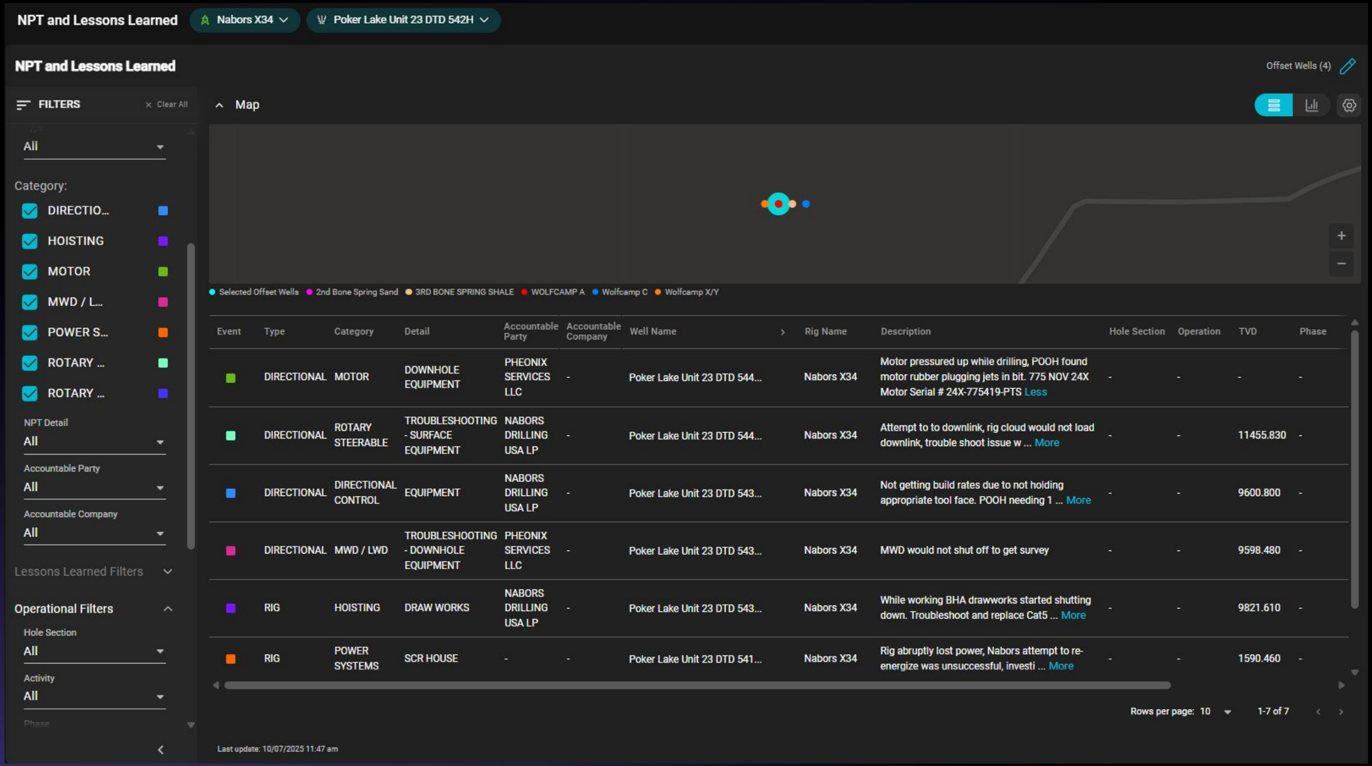
How To Control for NPT/Failures?

- Currently only grading runs based on ROP.
- Need to include Bit/Motor Relevant NPT.
- Need Bit Pull Reason.
- Categorize into two groups:
  - Successful Runs (TD and Non-BHA Failure Runs)
  - Failures
- Run a survival analysis to create observed failure rate by BHA
  - Kaplan-Meier Estimator
- **Limitation: Needs 50++ Runs**
  - Overcome by:
    - Looking only at single component
    - Looking at multiple operators runs
- **Limitation: Doesnt account for how the BHA was used.**
  - Potential Solution: Motor_Failures(Time, Diff/Motor_Max)



Gaps in Current NPT Recording

- **<u>Overall necessary field are there:</u>**
  - Categories
  - Responsible Parties
  - DDR Description
- **<u>Added Fields:</u>**
  - **Sub-category:** E.g. - Power Section or Lower End. Pulser or Battery.
  - **Corresponding BHA**
- **<u>GAP:</u>** Does not get capture all failure events (~40% of trips on this Pad)



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Step 2: Aggregate Runs into Similar BHAs

Match Motors on:

1) RPG
2) Number of Stages
3) Vendor

Match Bits on:

1) Number of Blades
2) Cutter Size
3) Special Geometry
4) Vendor

This data is not currently available in Corva. Some vendors keep multiple cutter sizes in same model number

Match Sections On:

1) Bit Diameter
2) Formation

Either an input of comparable formations or we have lists

Need to set a minimum number to be considered e.g. - 3

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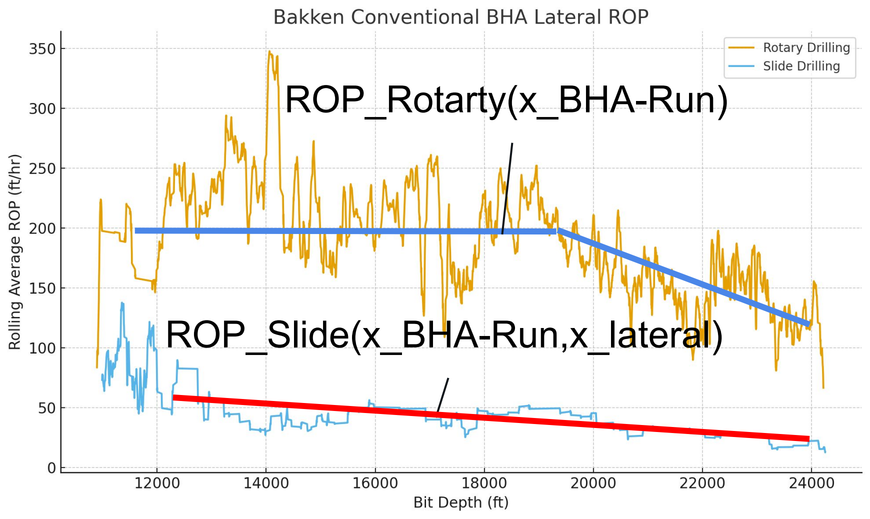
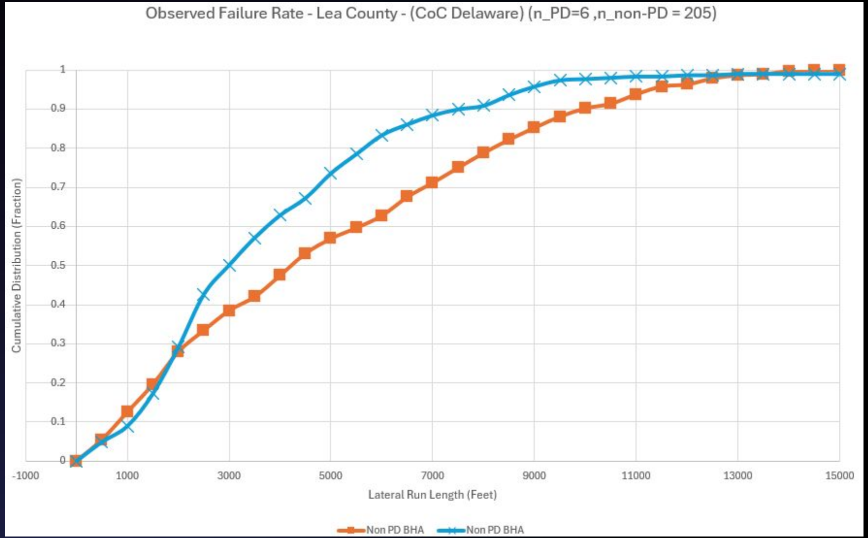
Step 3: Define Median Performance by BHA

ROP



Ideally Rotary and Slide ROP as function of run / lateral length.

Failure Rate



Need to filter out non motor and bit related failures

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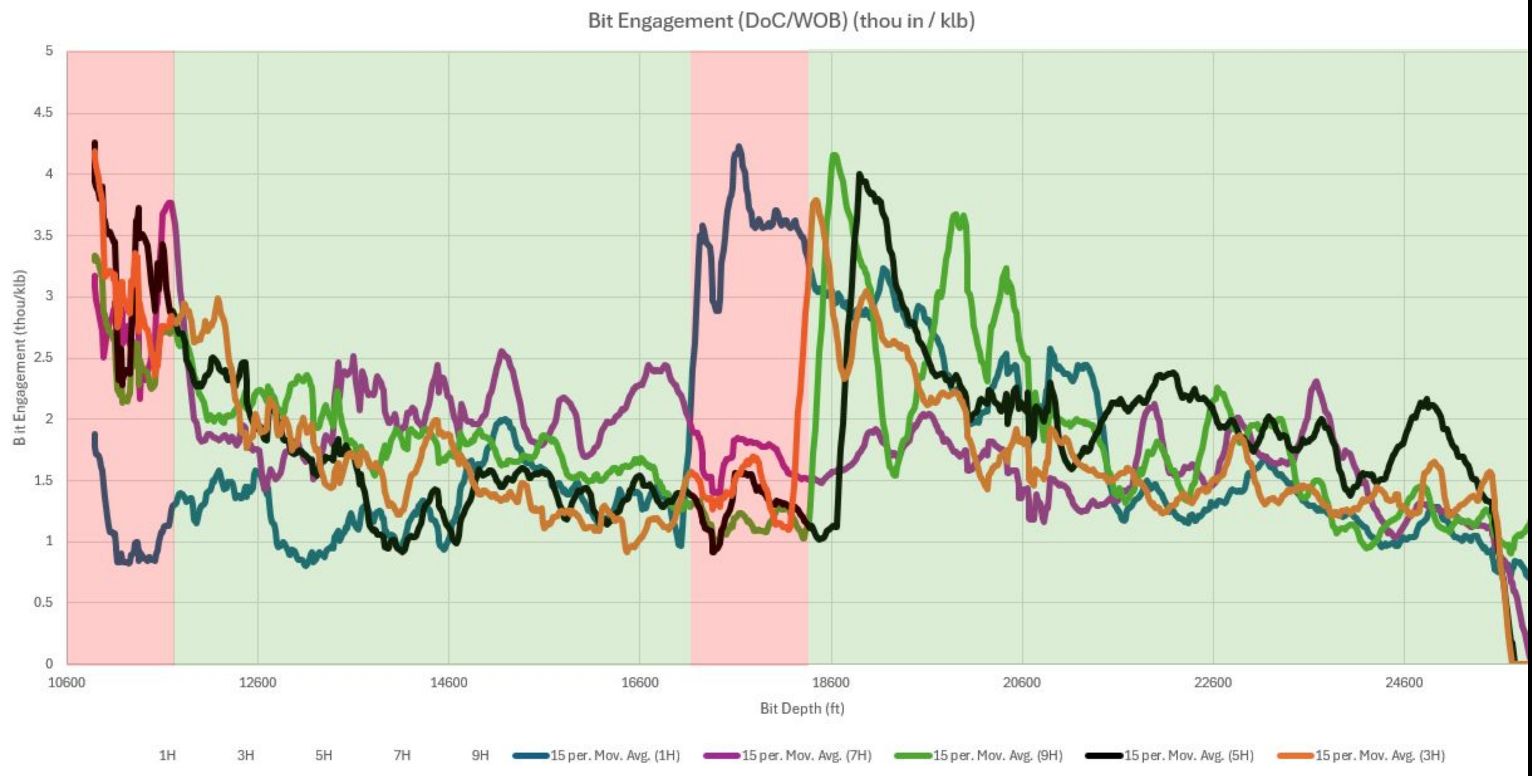
Example of ROP Degradation (Delaware Basin)



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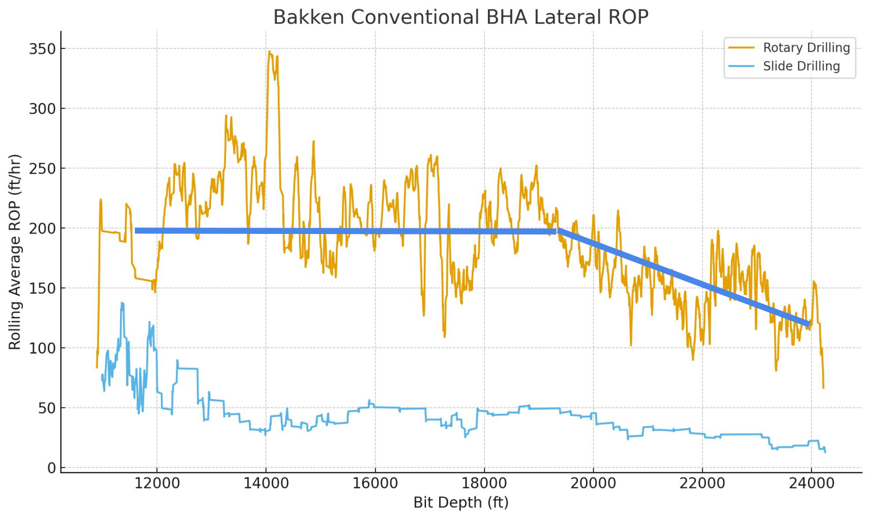
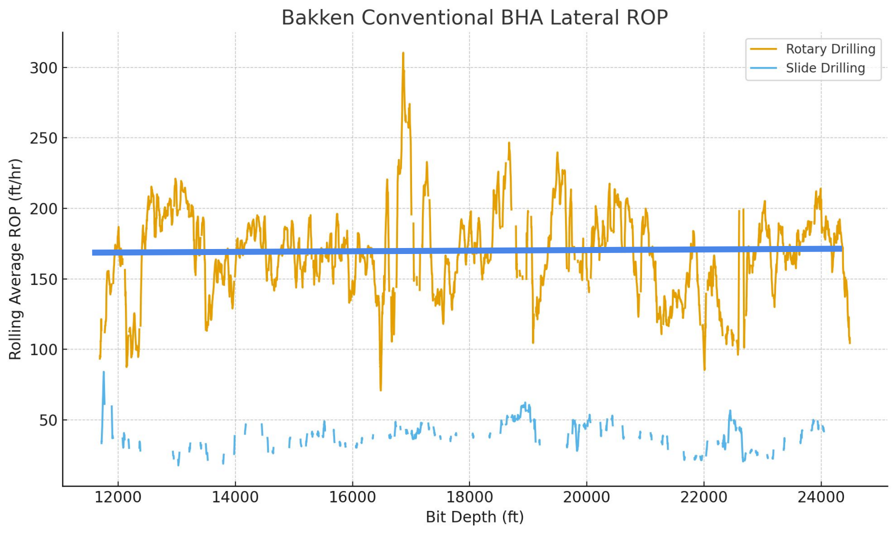

Bakken Conventional BHA Lateral ROP
Rotary Drilling
Slide Drilling
Rolling Average ROP (ft/hr)
Bit Depth (ft)
0
50
100
150
200
250
300
350
12000
14000
16000
18000
20000
22000
24000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