Drilling and Completions Lessons Learned

Planning a Horizontal Fiber Optic Installation in the Permian Basin

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2015 SPE Distributed Fiber-Optic Sensing Workshop in Napa, CA

Abstract

The author will present a planning and deployment strategy focused on drilling and completions lessons learned for a horizontal Wolfcamp fiber installation in the Permian Basin. The presentation highlights the factors that most affect D&C operations including procurement strategy, open hole preparation, risk management, and “dry-run” concepts for deployment and perforating.

Outline

1. Project Background and Objectives

2. Horizontal Plug & Perf Changes the Fiber Game

2. Operator Procurement Strategy

3. General Planning Best Practices

4. Open Hole Preparation and Case Study on Dogleg Severity

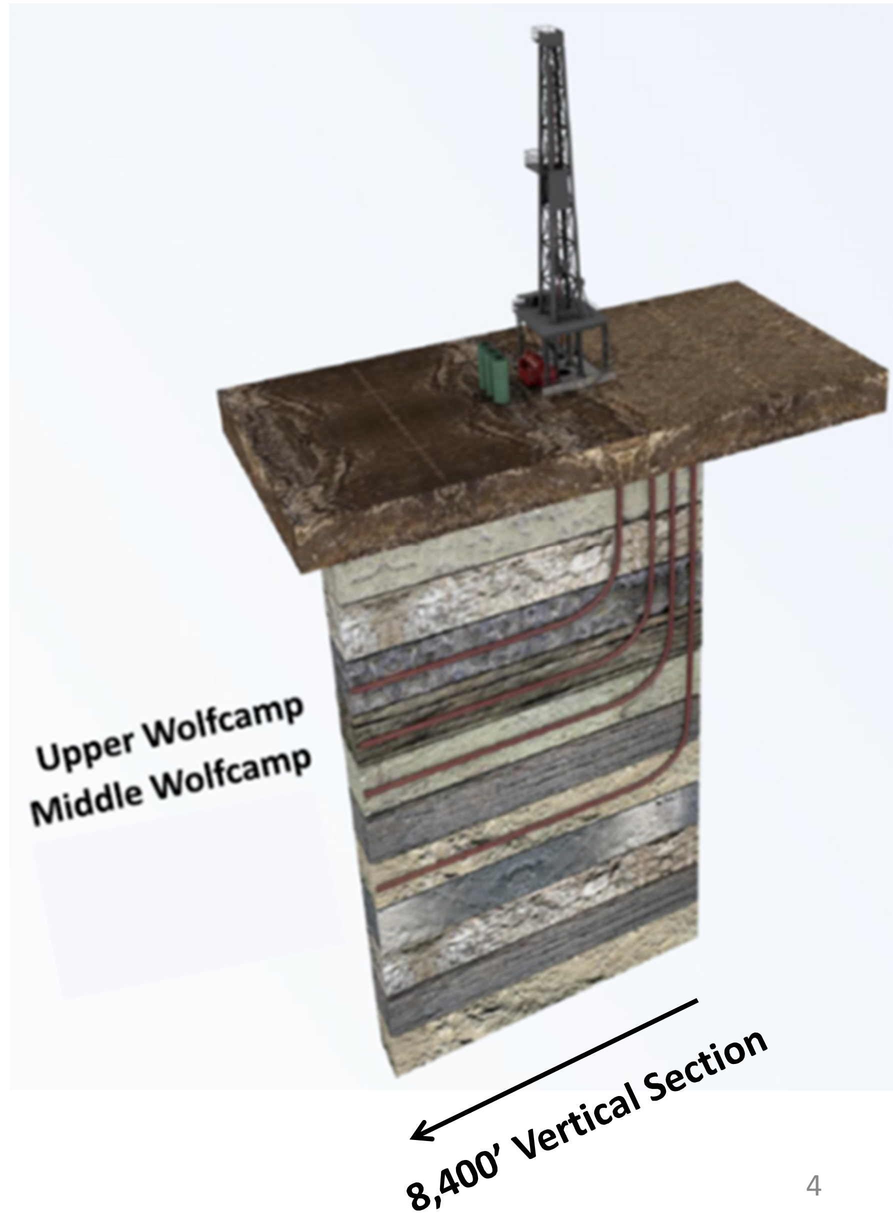
5. Fiber “Dry Run” Concepts for Deployment and Perforation

6. Incremental Cost of Project

7. A Survey of Fiber Operators and Project Managers on Risks

Background

- Midland Basin
- SE Glasscock and NE Reagan Counties
- Two well stacked pad
- 3 String Well Design: 13-3/8" x 9-5/8" x 5-1/2"
- Upper & Middle Wolfcamp
- Target TVDs 7000 – 8000'
- 7500' lateral lengths
- 28 stage completions (plug & perf)
- Pressure gauge at toe w/ TEC, DTS, DAS



Objectives

Utilize Open Hole Logs, Micro-seismic, and Fiber Data to correlate wellbore petrophysics, formation imaging data, and stage/cluster contribution to Earth Model data

Completion Test Well #1 - Cost Effectiveness: vary clusters per stage alternated by multiple control stages

Completion Test Well #2 - Productivity Effectiveness: vary proppant type or volume alternated by control stages

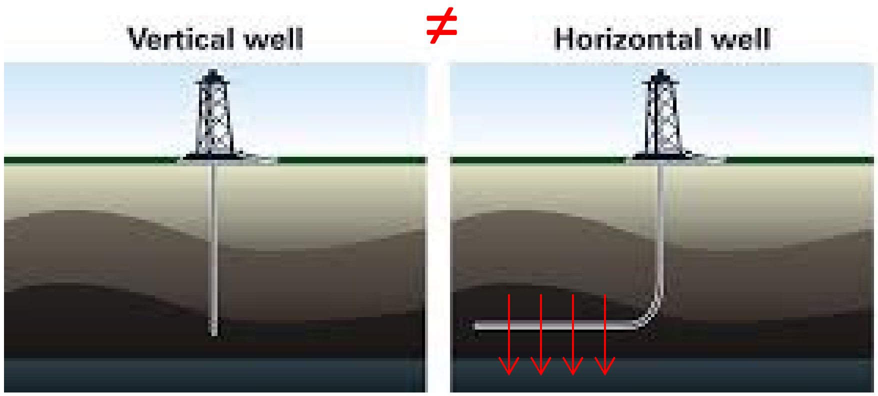
Measure cluster contribution in UWC[1] with Fiber Data and Production Log

Measure stage contribution in UWC[1] with oil and water tracers

Evaluate fracture geometry and effectiveness for UWC[1] and MWC[1] completions using Acoustic Monitoring (DAS Fiber) and Temperature Monitoring (DTS Fiber)

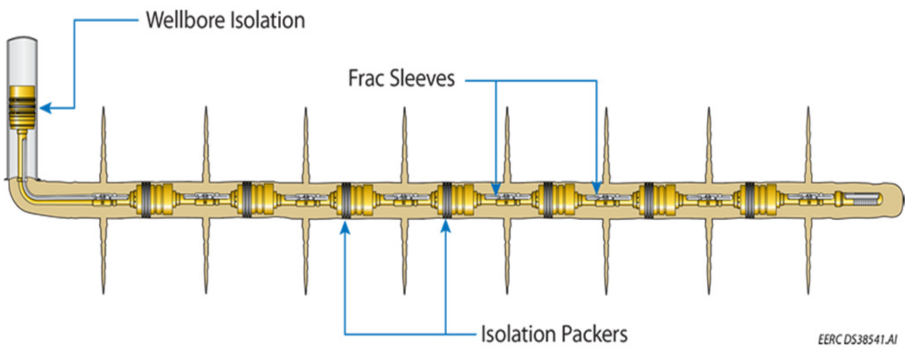
[1]UWC and MWC refers to Upper Wolfcamp and Middle Wolfcamp

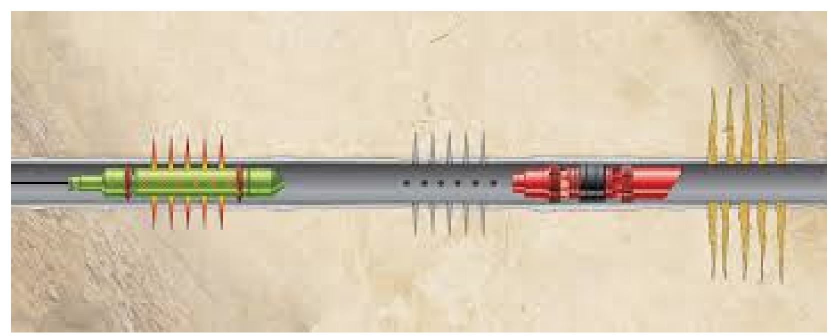
Horizontal Plug & Perf Changes the Fiber Game



- ➢ **Casing & Wireline is no longer assisted by gravity**
- ➢ **Increased drag and sensitivity to hole conditions when running casing in curve/lateral**
- ➢ **Wireline tools must be pumped down**

Sliding Sleeve System ≠ **Plug & Perf System**





- ➢ **Sliding sleeve systems do not require downhole orientation (Ball drop system opens frac ports)**
- ➢ **With plug and perf, the fiber must be mapped and each frac stage must be wireline-oriented and perforated away from fiber to avoid catastrophic failure**

Photo credits: geology.com (top), undeerc.org (left), drillingcontractor.org (right)

How Else Does Fiber Affect Horizontal D&C Ops?

Long equipment lead time – up to 5 months in 2H 2014

Data gathering operations add complexity

- Open hole logging (drill pipe conveyed)
- Downhole pressure gauges with rupture disks
- Microseismic logistics with drilling schedule and offset activity
- Variables due to Completion Testing Program

Casing conveyed fiber cannot be rotated

- Curve doglegs and wellbore tortuosity must be carefully limited
- Wellbore must be very clean
- Smaller tolerances b/w hole size and downhole equipment (8” OD in 8-1/2” hole)
- Problematic hole conditions may require fiber deployment to be delayed or even canceled

Special casing running equipment

Special wellhead equipment

Operator Procurement Strategy

Prior to awarding contracts or presenting plans to management…

Analyze each vendor's installation history to compare and quantify risk

- Ensure statistics are relevant for your specific well type (plug & perf ≠ ball drop sleeve)
- Provide an estimate for chance of success based on relevant historical data

Minimize or eliminate custom equipment to allow re-stocking

Negotiate re-stocking fees for all equipment where possible

Negotiate vendor project management fee for run case and re-stock case

Review all costs from cradle to the grave (hint: mapping, orienting, and perforating may be more expensive than you think)

Keep installation as simple as possible

General Best Practices for Planning

Assign key roles & responsibilities for F.O. Team. At minimum, assign a lead for:

- Data gathering, project objectives, and upper management liaison (Reservoir Engineer)
- Deployment (Drilling Engineer)
- Completion testing and perforating (Completion Engineer)
- IT management

Keep a project outline with action items and deadlines

Drilling rig audit with Casing Supervisor and Fiber Vendor Project Manager

Perform wellhead stack-up months in advance

Hire an independent fiber Project Manager Consultant to QA/QC vendor plans

Peer Review and Risk Asses with 1) Company Engineers & Vendors and 2) Independent Consultant

Share best practices with D&C engineers from other operators running fiber

Open Hole Preparation

Modify casing & drilling BHA design to provide 8-3/4” hole for extra clearance

- Vendor’s fiber system originally designed for 8-1/2” hole
- Standard casing design did not drift 8-3/4” BHA

Reduce planned curve dogleg severity from 10°/100’ to 8°/100’

- Higher micro-doglegs are unavoidable; mitigated by lower planned DLs at expense of 150’ LL

Work w/ geologist to plan a smooth wellbore path w/ minimal TVD change

Utilize established best practices for hole cleaning and tripping when drilling

- 80-100 rpms when drilling lateral (1.5 – 1.83° motor bend)
- At TD, circulate minimum of 1 hour per 1000’ of lateral length at 100 rpms
- Add 0.1 to 0.3 ppg mud weight trip margin at TD for hole stability to account for loss of ECD and swab
- POOH at controlled rate to minimize swab pressure (± 700 fph average trip progress)

Run (2) 1/8” under gauge Reamer Tools spaced at least 1500’ back from bit

- This will ensure RT is not engaging curve until after curve is landed and BHA rotate drills ahead in lateral
- Make a dedicated hole cleaning reamer trip at TD or after any logging ops with same BHA design

Upfront Team agreement to Hole Conditions Checklists

- If any conditions are not met, the fiber would be deployed on a future well

Case Study on Curve Dogleg Severity: Which 3 wells failed to land?

DL > 12°/100' in RED

A

Fail Cases		
6.57	9.69	4.72
4.27	11.10	12.80
9.03	10.12	14.19
8.16	10.51	10.02
7.80	9.38	5.53
8.14	9.96	5.62
5.53	4.15	7.58
9.32	7.65	7.69
8.72	9.40	8.22
8.22	6.71	8.86
9.13	11.19	8.14
10.70	10.40	10.97
9.47	9.54	11.84
7.82	9.97	11.40
8.06	9.87	9.88
8.86	9.68	9.00
6.09	9.85	12.13
9.72	8.62	11.88
5.41	6.65	11.65
6.73	9.68	11.06
10.41	8.34	10.81
10.86	6.48	11.91
14.93	7.64	10.22
14.17	6.32	11.08
13.98	6.91	9.86
9.61	8.77	11.28
10.15	15.86	9.41
9.31	13.57	10.06
11.16	16.84	12.47
10.96	8.58	10.47
8.55	14.04	10.46
9.47	10.49	7.25
5.70	0.81	10.87
6.19	5.64	14.93

B

Success Cases		
7.48	7.20	5.04
12.04	7.05	6.09
12.19	7.91	3.81
10.18	8.33	6.24
11.70	8.20	1.27
9.79	10.62	6.12
9.47	12.04	6.14
6.43	6.54	9.33
6.90	6.09	8.69
6.78	6.88	8.55
8.08	7.33	7.82
7.50	6.16	8.64
5.13	7.66	9.35
5.38	2.94	9.81
7.50	4.63	9.67
7.96	2.04	10.20
10.34	3.20	9.59
11.19	1.29	10.53
10.33	0.71	9.89
3.81	1.65	9.46
10.12	1.43	8.09
7.95	1.12	5.69
11.32	0.67	2.06
8.29	1.68	8.76
9.27	1.32	6.34
9.27	3.20	1.57
4.69	2.83	8.16
6.93	2.36	9.34
2.64	0.24	7.87
6.70	1.24	9.04
11.57	1.89	4.56
10.78	2.13	11.06
11.97	2.81	13.79
9.29	1.38	12.02

****Curve Dogleg severity > 12 highlighted in red. 6 well fiber survey data set provided by fiber vendor without any well info**

****All 3 fail case curves were planned on 10° DLS. Author recommended strict 8° DLS for safety factor and to mitigate micro-doglegs.**

Fiber Deployment "Dry Run" Strategy

Provides a low-cost test of our hole preparation, downhole tolerances, and casing running strategy for the actual rig team without the risk of junking the well or the expensive fiber

Select a direct offset well with similar target and lateral length of the proposed fiber installation and schedule to drill with the same rig that is preparing to run the fiber

Drill the same 8-3/4" hole size with the same BHA design and the same hole preparation practices

Rig up the same casing crews

Run the production casing with the same fiber optic centralizer program to simulate the same geometry as upcoming fiber deployment… ***but leave out the expensive fiber***

If problematic hole conditions are encountered, rotate casing to bottom and rework your deployment strategy with no harm to the bottom line

Orienting/Perforating "Dry Run" Strategy

Provides a low-cost test of well mapping and orienting process without the risk of junking the expensive fiber installation

Procure 2 joints of actual production casing, blast protectors, and wire rope to be run in fiber deployment

Install replica of actual casing conveyed fiber equipment in shop

Shop test wireline orienting process with casing replica, actual wireline unit, mapping tool, and orienting tool

Consider shop testing actual perf guns with different phasing to determine perf hole size vs. orientation/phasing (significant difference for low side vs. high side). Perf hole size critical for calibrating pressure and flow for frac model[1]

[1]Credit and suggested reading if available: 2014 SPE Fiber Optic Workshop presentation on perforating by Craig Wittenhagen, Production Engineering Advisor, Chesapeake

Estimates of Incremental Rig Time and % Cost Increase

"Dry Run" Activities	Rig Days	% increase to D&C AFE
Rig time to make dry run on prev. well	3	4%
Fiber Optic Centralizers on Dry Run		1%
Well mapping shop test "dry run"		1%
Total		**4%**

Fiber Optic Equipment & Installation	Rig Days	% increase to D&C AFE
Wellhead with pressure control fiber exit		1%
Specialized casing running tools		1%
DTS, DAS, and 1 Pressure Gauge at toe		16%
Incremental time for hole preparation	3	4%
Incremental rig time to run fiber lines	2	2%
Well mapping and perforating		7%
Total		**31%**

Data Gathering Activities	Rig Days	% increase to D&C AFE
Rig time to run drill pipe conveyed logs	3	4%
Open hole log wireline costs		9%
Proppant tracers		5%
Oil & Water tracers		2%
Microseismic		11%
Frac tests (cluster, proppant, etc.)		12%
Production Log		4%
Total		**47%**

- **“Dry run” activities are cheap insurance policies**

A Survey of Fiber Operators and Project Managers on Risk

Sent to 49 operator engineers and vendor PMs from 2014 Workshop attendee list

What is the biggest risk to the success of a fiber optics installation on a horizontal well with a plug & perf completion?

17%	A) Deployment of Casing Conveyed Equipment
17%	B) Orienting & Perforating
67%	C) Arriving at valuable conclusions from Data Collection and Analysis

Notable responses for C)

"All three are significant risks but can be mitigated with sufficient effort, not to be underestimated**. The field trial experiment must have well thought out objectives along with a plan consistent with achieving those objectives**"

"If you take care of the details, A & B are less risky. Companies may not do enough analysis… or they make conclusions based on field reports. **Management needs to make the commitment on time, computing power, and manpower to properly evaluate these data sets**."

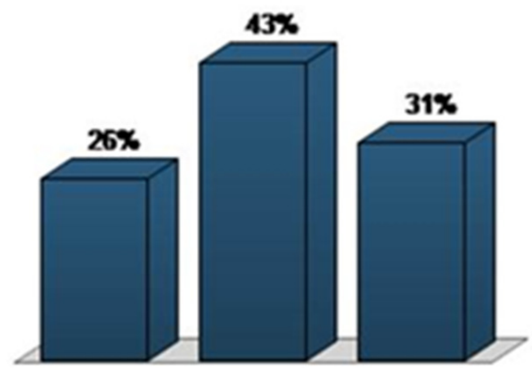
"We do get meaningful / valuable observations / conclusions from fiber optics BUT **do we apply them to make a difference in the completions going forward?"**

A Survey of Fiber Operators and Project Managers on Risk

Same question posed to 96 attendees at 2015 SPE DFOS Workshop

6. What do you feel is the biggest risk to the success of a fiber optics installation on a horizontal well with a plug & perf completion? (Multiple Choice)

	Responses	
	Percent	**Count**
Deployment of Casing Conveyed Equipment	26.04%	25
Orienting and Perforating	42.71%	41
Arriving at valuable conclusions from Data Collection and Analysis	31.25%	30
Totals	**100%**	**96**



Takeaways

Project objectives, plans, and next steps must be well thought out and agreed upon with management team

Negotiate re-stocking and management fees with fiber vendor prior to order

Hire independent consultant to review fiber vendor and project plans

Keep installation and testing program as simple as possible

Open hole preparation is paramount to successful deployment

Upfront agreement to Hole Conditions Checklist

Consider "dry run" strategies for deployment and perforating

Peer review & risk assess each phase of project

Seek out other operator engineers working with fiber and share D&C Lessons Learned and Best Practices

Questions

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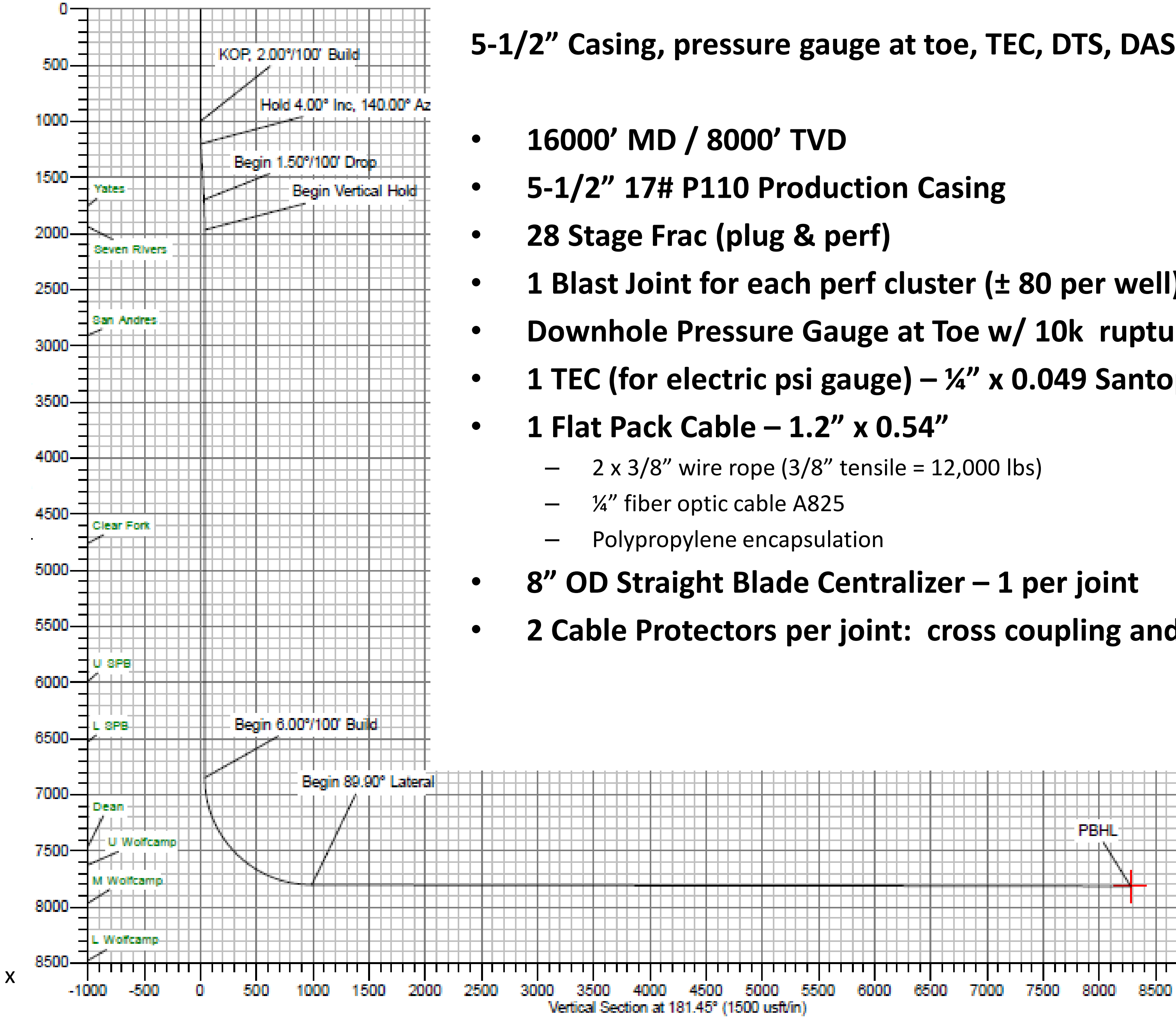
Backup

Downhole Equipment



5-1/2" Casing, pressure gauge at toe, TEC, DTS, DAS

- **16000' MD / 8000' TVD**
- **5-1/2" 17# P110 Production Casing**
- **28 Stage Frac (plug & perf)**
- **1 Blast Joint for each perf cluster (± 80 per well)**
- **Downhole Pressure Gauge at Toe w/ 10k rupture disk**
- **1 TEC (for electric psi gauge) – ¼" x 0.049 Santoprene A825**
- **1 Flat Pack Cable – 1.2" x 0.54"**
  - 2 x 3/8" wire rope (3/8" tensile = 12,000 lbs)
  - ¼" fiber optic cable A825
  - Polypropylene encapsulation
- **8" OD Straight Blade Centralizer – 1 per joint**
- **2 Cable Protectors per joint: cross coupling and mid joint**

Determining the Economic Point of No Return

Decisions when running casing in tight hole are time sensitive and stressful and stakes are raised significantly with a multi-million dollar fiber project

Let's agree to the rules of engagement during the planning phase

- Assign a set value to the fiber optic data
- Calculate NPV per 1000' of producing lateral
- Create a decision matrix vs. 1000' of lateral cased

Now, if we encounter tight hole at any point in the lateral, management can make an educated and/or pre-determined decision to:

a) POOH, laydown casing/fiber, re-condition hole, and re-run
b) Set casing off bottom and preserve integrity of fiber (and subsequent data)
c) Rotate casing through tight hole to gain well NPV and give up Fiber data

Casing Running Best Practices

Conventional Float Equip. & TCP Ops to eliminate complexity of wet shoe and toe gauge

Casing equipment to be inspected for fatigue cracks just prior to operations

Install dedicated electric plug for casing equip. on driller side

Pre-install centralizers on racks with 2-3 set screws, then slide up to collar after MU w/ CRT

2 Spools of cables on driller side (1 TEC and 1 Flat Pack)

Sheave in Derrick on driller side installed on rig move

Rotary Mounted Spider w/ control line (fiber) roller and guides

Blast Protector and Cable Protectors installation at well center

100% redundancy of all casing equipment

If hole conditions are good, do not stop to circulate (but keep casing full)

40 ft/min running speed

What Can Go Wrong? Notes from Risk Mitigation with Drilling Team and Fiber PMs

1. Well control due to offset frac job– fiber optics moved to a different well – review frac schedule in detail
2. Well Control Shut In - Wire ropes can be removed at BOP without splicing fiber to shut in on annular
3. Safety incident due to abnormal rig up / FO handling operations in derrick – hold a detailed JSA
4. Communication problem at surface with servers, power supply, surge or line strike
5. Mishandling of casing slips once cemented causing parted line – review slip design at wellhead stackup – ensure a fluted design
6. Orientation of floor spider relative to sheave placement putting tension on lines – install pad eye during initial rig move (confirm on rig audit)
7. Poor hole conditions observed while drilling causing project to be moved to a different well
8. Curve drilled with doglegs over 12 deg/100' – make a reamer run to "knock out" doglegs or move to a different well if we still have concerns
9. Dropped object in hole while drilling – fiber optics moved to a different well
10. Improper make up of FO equipment – will be using industry leader casing crews that have experience with this type of equipment. 100% backup on all tools. Crews will be put on standby 48 hours in advance to keep them reserved.
11. Stuck casing off bottom– refer to economic decision matrix per 1,000' lateral. Fiber has been laid down, spooled up, and re-run successfully in almost all cases.
12. Dropped casing causing fiber cable and wire ropes / sheaves / spools to be pulled toward well center – will plan to set spool anchors during rig move and chain down spools once they arrive. Also need a secondary line attached to the sheave.
13. Mishandling of casing/fiber at surface causing parted line – splice time is 6-8 hours (1-1/16" OD splice connection) and data quality is reduced
14. Accidental rotation of casing causing parted line – utilize drillers topdrive brake lockout for rotary function
15. Failed float equipment allowing cement to cover pressure gauge burst disk – plan to hold pressure on cement for 4-6 hrs
16. Ruptured pressure gauge disk prior to cementing causing gauge to be covered with cement – 10,000 psi absolute allows for 3,500 psi safety factor
17. Dropped tools in hole when installing equipment on rig floor – utilizing apron and tethered tools at all times
18. Power supply problems with casing equipment – installed dedicated power supply outlet for casing equipment
19. Agreed to pump until we bump but shut down prior to displacing 250' of calculated annulus capacity (equivalent of 1 frac stage)