District I
1625 N. French Dr., Hobbs, NM 88240
Phone: (575) 393-6161 Fax: (575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone: (575) 748-1283 Fax: (575) 748-9720
District III
1000 Rio Brazos Road, Aztec, NM 87410
Phone: (505) 334-6178 Fax: (505) 334-6170
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505
Phone: (505) 476-3460 Fax: (505) 476-3462

State of New Mexico
Energy Minerals and Natural Resources
Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-101
Revised November 14, 2012

☐ AMENDED REPORT

APPLICATION FOR PERMIT TO DRILL, RE-ENTER, DEEPEN, PLUGBACK, OR ADD A ZONE

1. Operator Name and Address 2. CHEVRON U.S.A. INC. 3. 15 SMITH ROAD 4. MIDLAND, TEXAS 79705	2. OGRID Number 4323
	3. API Number 30-025-32497

4. Property Code	5. Property Name	6. Well No.
29408	B.F. HARRISON "B"	17

7. Surface Location

UL - Lot	Section	Township	Range	Lot Idn	Feet from	N/S Line	Feet From	E/W Line	County
D	9	23S	37E		990	NORTH	910	WEST	LEA

8. Proposed Bottom Hole Location

UL - Lot	Section	Township	Range	Lot Idn	Feet from	N/S Line	Feet From	E/W Line	County

HOBBS OCD

9. Pool Information

Pool Name	Pool Code
LANGLIE MATTIX 7 RIVERS QUEEN GRAYBURG	37240

DEC 23 2013

RECEIVED

Additional Well Information

11. Work Type	12. *Well* Type	13. Cable/Rotary	14. Lease Type	15. Ground Level Elevation
RECOMPLETE	OIL		S	3318' GL
16. Multiple	**17. Proposed *Depth***	**18. Formation**	**19. Contractor**	**20. Spud Date**
	7750'	GRAYBURG		

Depth to Ground water	Distance from nearest fresh water well	Distance to nearest surface water

21. Proposed Casing and Cement Program

Type	Hole Size	Casing Size	Casing Weight/ft	Setting Depth	Sacks of Cement	Estimated TOC
			NO CHANGE			

Casing/Cement Program: Additional Comments

22. Proposed Blowout Prevention Program

Type	Working Pressure	Test Pressure	Manufacturer

23. I hereby certify that the information given above is true and complete to the best of my knowledge and belief.
I further certify that I have complied with 19.15.14.9 (A) NMAC ☑ and/or 19.15.14.9 (B) NMAC ☑, if applicable.
Signature: Denise Pinkerton

Printed name: DENISE PINKERTON

Title: REGULATORY SPECIALIST

E-mail Address: leakejd@chevron.com

Date: 12/17/2013 Phone: 432-687-7375

OIL CONSERVATION DIVISION

Approved By:

Title: Petroleum Engineer

Approved Date: 12/26/13 Expiration Date: 12/26/15

Conditions of Approval Attached

DEC 30 2013

DURING THE PROCEDURE WE PLAN TO USE THE CLOSED LOOP SYSTEM WITH A STEEL TANK AND HAUL TO THE REQUIRED DISPOSAL, PER THE OCD RULE 19.15.17.

INTENDED PROCEDURE IS AS FOLLOWS

Pull Production Tbg.

RIH & set CIBP @ 6575' & dump 35' cmt on CIBP. Test w/pkr & tbg.

RIH & set CIBP @ 6310' & dump 35' cmt on CIBP. Test w/pkr & tbg.

TIH & set CIBP @ 6050' & dump 35' cmt on CIBP. Test csg & CIBP.

Perforate Grayburg from 3732-3735, 3738-3742, 3752-3756, 3758-3764, 3767-3773, 3786-3796, 3804-3808, 3814-3821, 3840-3846, 3870-3880, 3885-3888, 3892-3900. 3 JSPF.

Frac Grayburg w/3,000 gals HCL, 171.000 sand, & 2520 bbls fluid.

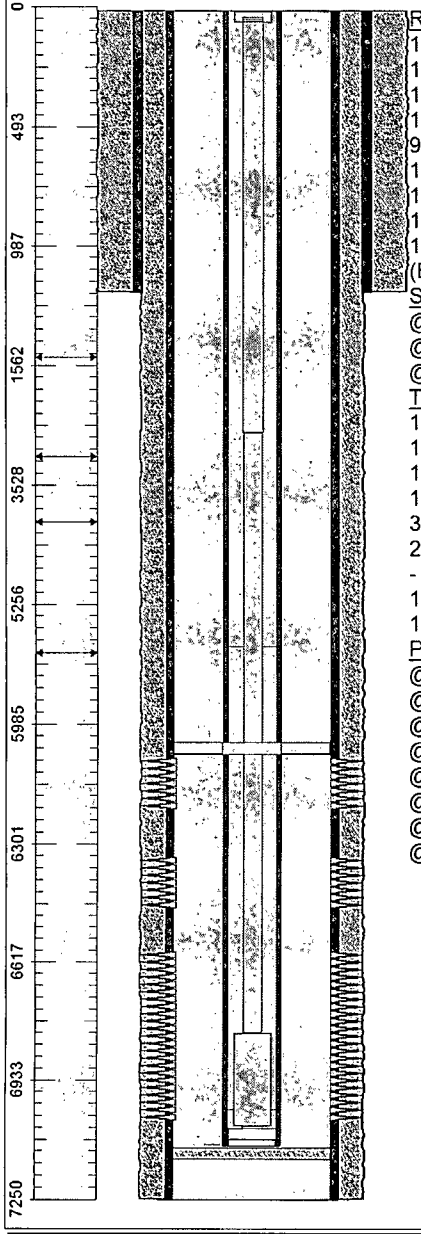
Swab well & CO

Run production eqpt.

Put on production

Chevron U.S.A. Inc. Wellbore Diagram : HARRISONB17DHC

Lease: OEU EUNICE FMT	**Well No.:** HARRISON B 17 PARENT FOR DHC	**Field:** FLD-NM TEAGUE NORTH	
Location: 990FNL910FWL	**Sec.:** N/A	**Blk:**	**Survey:** N/A
County: Lea **St.:** New Mexico	**Refno:** QY2616	**API:** 3002532497	**Cost Center:** UCU820500
Section: 9	**Township:** 023 S		**Range:** 037 E
Current Status: ACTIVE		**Dead Man Anchors Test Date:** 11/08/2011	
Directions:			



Rod String Quantity (Top-Bottom Depth) Desc
1 @(14-40) 1.500 (1 1/2 in.) Spray Metal x 26-
1 @(40-48) 0.875 (7/8 in.) N-78 (D) x 8 Rod Sub-
1 @(48-54) 0.875 (7/8 in.) N-78 (D) x 6 Rod Sub-
1 @(54-56) 0.875 (7/8 in.) N-78 (D) x 2 Rod Sub-
99 @(56-2531) 0.875 (7/8 in.) N-78 (D) x 25 Rod-
171 @(2531-6806) 0.750 (3/4 in.) N-78 (D) x 25 Rod-
10 @(6806-7056) 1.500 (1 1/2 in.) K x 25 Sinker Bar-
1 @(7056-7060) 0.875 (7/8 in.) N-78 (D) x 4 Rod Sub-
1 @(7060-7084) Rod Pump (Insert) (NON-SERIALIZED) - 20-125-R H BC -5-24-19-0 (Bore = 1.25)-

Surface Casing (Top-Bottom Depth) Desc
@(14-1180) Wellbore Hole OD-12.2500-
@(14-1180) Unknown 9.625 OD/ 36.00# Round Short 8.921 ID 8.764 Drift-
@(14-1180) Cement-

Tubing String Quantity (Top-Bottom Depth) Desc
182 @(14-5715) J-55 2.375 OD/ 4.70# T&C External Upset 1.995 ID 1.901
1 @(5715-5719) J-55 2.375 OD/ 4.70# T&C External Upset 1.995 ID 1.901
10 @(5719-6033) J-55 2.375 OD/ 4.70# T&C External Upset 1.995 ID 1.901
1 @(6033-6036) Tubing Anchor/Catcher 2.375-
31 @(6036-7012) J-55 2.375 OD/ 4.70# T&C External Upset 1.995 ID 1.901
2 @(7012-7077) J-55 2.375 OD/ 4.70# T&C External Upset 1.995 ID 1.901 Drift - Internal Plastic Ctg-TK-99-
1 @(7077-7078) Seat Nipple - Heavy Duty (2.375) Cup Type-
1 @(7078-7088) Mule Shoe (Tubing) 2.375 OD - Bare-

Production Casing (Top-Bottom Depth) Desc
@(1180-7250) Wellbore Hole OD- 8.7500-
@(14-7250) Cement-
@(14-7250) Unknown 7.000 OD/ 23.00# Round Long 6.366 ID 6.241 Drift-
@(6074-7036) Producing Interval 99 PR-
@(6074-6198) Perforations - Open-
@(6336-6472) Perforations - Open-
@(6591-7036) Perforations - Open-
@(7115-7115) Plug Back Total Depth-

Ground Elevation (MSL): 3319.00	**Spud Date:** 08/04/1994	**Compl. Date:** 01/01/1970
Well Depth Datum: Kelly Bushing	**Elevation (MSL):** 3333.00	**Correction Factor:** 14.00
Last Updated by: fitecl	**Date:** 02/13/2012	

Well: B.F. Harrison B # 17 Field: Langlie Mattix Reservoir: Grayburg

Location:
990' FNL & 910' FWL
Section: 9
Township: 23S
Range: 37E Unit: Ð
County: Lea State: NM

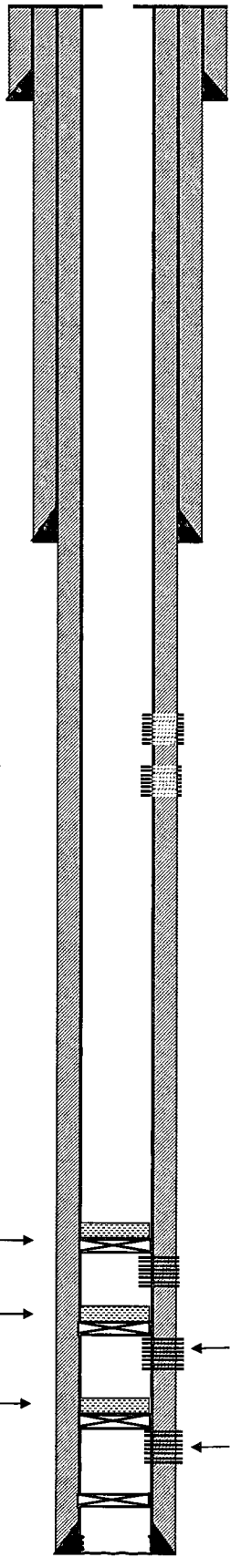
Elevations:
GL: 3318'
KB: 3332'
DF:

Proposed Wellbore Diagram

Well ID Info: Wellbore #
Chevno: QY2616
API No: 30-025-32497
Cost Center
Spud Date: 8/4/1994
Completion Date 12/5/1994

Intermediate Csg: 9 5/8" 36# Round Short
Set: @ 1180
Hole Size: 12 1/4" to 3685'
Circ: No **TOC: Surface'**
TOC By: TS

Prod. Csg: 7" 23# Round Long
Set: @ 7,250
Hole Size: 8 3/4"
Circ: Yes **TOC:** Surface'
TOC By: Circulation



New Perfs
3732-3735 3 JSPF
3738-3742
3752-3756
3758-3764
3767-3773
3786-3796
3804-3808
3814-3821
3840-3846
3870-3880
3885-3988
3892-3900

CIBP @ 6,250'
cap w/35' cmt

CIBP set @ 6,310'
cap w/35' cmt

CIBP set @ 6,575'
cap w/35' cmt

7510'-7540' Tubb - Perfs (Plugged Back)

8900'-8928' Drinkard - Perfs (Plugged Back)

Perfs
6.591' -7,036 Abo - Perfs (Plugged Back)

PBTD: 7,115'
TD: 7,750'

Updated: 12/17/2013

B.F. Harrison #17 **12.10.2013**
Fld-Langlie Mattix North, Grayburg Reservoir
T23S, R37E, Sec. 9
N 32° 19' 23.34", W -103° 10' 22.368" (NAD27)
Job: PB to Grayburg and Frac

PREWORK:

1. Utilize the rig move check list, **verifying route and power line heights with FMT.**
2. Check anchors and verify that pull test has been completed in the last 24 months.
3. Ensure location of & distance to power lines (from wellhead) is in accordance with MCA SWP. Complete and electrical variance and electrical variance RUMS if necessary.
4. Ensure that location is of adequate build and construction, and will support operations.
5. Ensure that elevators and other lifting equipment are inspected. For wells to be worked on or drilled in an H_2S field/area, include the anticipated maximum amount of H_2S that an individual could be exposed to along with the ROE calculations for 100 ppm and 500 ppm.
6. Review JSA and hazards with rig crew. Visually inspect wellhead, casing and tubing valves. Decide whether tubing and casing valves can be used; replace as needed.
7. Scout location and mark off anything that might be hazardous to daily operations.

Reminders:

8. Caliper all lifting equipment at the beginning of each day or when sizes change. **Note in JSA and record on Elevator Change-out Log when and what items are callipered.**
9. When NU anything over an open wellhead (BOP, EPA, etc.) ensure the hole is covered to avoid dropping anything downhole.
10. Ensure well is secure/shut in with blind rams between job stages (nothing in well).
11. If pumping any cement, plugging back a well or changing producing intervals, always contact the OCD and give the details.
12. Hold safety meetings with all personnel on location prior to any major or abnormal operation.

Procedure:

This procedure is meant to be followed. It is up to the WSM, Workover Engineer and Production Engineer to make decisions necessary to SAFELY do what is best for the well. In the extent that this procedure does not reflect actual operations, please contact WE, PE and Superintendent for MOC/RUMS assessment.

NOTE: Schedule LAS to be present before & during frac. (Doug Guiley 432-813-3971)

1. Verify that well does not have pressure or flow. If the well has pressure, note tubing and casing pressures on Wellview report. Bleed down well; if necessary, kill with cut brine fluid (8.6 ppg).

2. MIRU workover unit & associated surface equipment (i.e. tanks, reverse unit, pipe racks).

3. ND wellhead, unset TAC, NU BOP dressed with 2-3/8" pipe rams on top and blind rams on btm. NU EPA equipment & RU floor. POOH and LD 1 jt 2-3/8" tbg. PU 7", 23# rated packer along with a joint of 2-3/8" tubing and set below WH @ ~25'. Test BOP pipe rams to 250/1000 psi. Note testing pressures on Wellview report. Release and LD packer.

4. POOH and LD 2 3/8" tbg. (Changing out with new or used 2 7/8" tbg.) (Perfs 7,036-6591', 6474-6336', & 6198-6074' EOT 7,088, PBTD 7,115').

5. MIRU wireline unit. **Set up exclusion zone around WL unit.** R/U lubricator and test to 1000 psi against blind rams. RIH with 6.25" gauge ring to 6,580' (Top perf @ 6,074') to make sure well is free of obstructions. Note in WV and contact WE if gauge ring sets down, drags, or hangs up inside 7" csg. If gauge run was

clear, RIH with 7" CIBP and set @ 6,575'. PU and set down on CIBP to ensure it set. RIH with dump bailer and dump 35' of cmt on top of CIBP.

6. Change out pipe rams to 2 7/8". RIH with 2-7/8" tbg. and 7" packer to 6500'. Set packer and test CIBP to 500 psi. POOH. Notify WE if pressure doesn't hold.

7. RIH with 7" CIBP and set @ 6,310'. PU and set down on CIBP to ensure it set. RIH with dump bailer and dump 35' of cmt on top of CIBP.

8. RIH with 2-7/8" tbg. and 7" packer to 6,250'. Set packer and test CIBP to 500 psi. POOH. Notify WE if pressure doesn't hold.

9. RIH with 7" CIBP and set @ 6,050'. PU and set down on CIBP to ensure it set. RIH with dump bailer and dump 35' of cmt on top of CIBP. POOH, fill up csg and test down to CIBP to 250/500 psi. Notify WE if pressure doesn't hold. (Record csg test in WellView in time log and safety/inspections). Notify WE if pressure doesn't hold.

10. If CIBP/csg tested good to 250/500 psi, continue to step #11. If test failed, PU 7" packer and TIH to top of CIBP. Set pkr and test again to 250/500 psi. Test backside to 250/500 psi. Notify WE after establishing which direction leak-off is occurring.

11. PU 7" RBP & 7" compression packer. RIH on 2-7/8" production tubing. Set RBP at 3,975'. Release from RBP and POOH one jt. Set packer and test down tubing to RBP to 250/500 psi. Release packer.

12. POOH LD 2-7/8" prodn tubing and packer. Dump 300 lbs of sand to fall on top of RBP. Allow 1-2 hrs for sand to settle onto RBP (Plan for EOD if possible).

13. MI & RU Wireline Unit (Prefer Gray). **Set up an exclusion zone and establish radio silence when running perf guns.** Install Lubricator and test to 250/1000 psi against blind rams. GIH with CMT bond gamma and ccl log. **Send Log to John Taxiarchou (john.taxiarchou@chevron.com) to confirm cmt behind pipe and perfs selection.** Once confirmed proceed to step 14

14. GIH with 3 3/8" casing guns (0.42" EH & 47" penetration) and perforate from 3732-3735, 3738-3742, 3752-3756, 3758-3764, 3767-3773, 3786-3796, 3804-3808, 3814-3821, 3840-3846, 3870-3880, 3885-3888, 3892-3904, & 3920-3923, with 3 JSPF at 120 degree phasing, using 32 gram premium charges. POOH. RD & release electric line unit.

15. Dump 750 gals of 15% HCL acid down casing to breakdown.

16. MIUL & strap +/- 120 jts 3 ½" 9.3# L80 tbg as frac string. Change out pipe rams to 3 ½". PU 7" testing packer on one joint 3 ½" tubing and set @ ~25'. Test BOP pipe rams to 250/1000 psi. Note testing pressures on WellView report (Time log and safety/inspections). Release and LD packer.

17. PU and GIH w/ 7" Arrow-Set 10K pkr & On-Off tool w/ frac hardened 2.25" "F" profile, blast joint, and 3 ½", 9.3# 8RD L-80 work string, hydrotesting to 9000 psi. Set pkr at approximately ~3,675'. Install 10k frac valve and test 3-1/2" connection to 9000 psi with hydrotesters. Install goat head above FV. Pressure 3-1/2" x 5 1/2" annulus to 500 psi to test csg and pkr. Bleed down backside after testing.

18. RDMO pulling unit & associated surface equipment (i.e. tanks, reverse unit, pipe racks).

19. Prep location for frac:
    Coordinate with Baker Hughes frac rep (Mike Moody 325-207-2211)
    Move in and fill frac tanks (6-7 tanks), move in half-frac pit for flowback, manlift (if needed), trash trailer/port-a-potty, etc.
    Mark off anything on location that may pose a hazard to multiple trucks moving on location.

Schedule LAS to be present before & during frac. (Doug Guiley 432-813-3971)

20. MI Baker frac crew and equipment. **Set up exclusion zone around stimulation unit & surface treating lines.** Shut in wells within 600' (B.F. Harrison #4, #7, #8,#13, #16 & #18)

21. Test treating lines to 7400 psi and set pop-off at 7450 psi. Set 3-1/2" x 7" annulus mechanical pop-off to 500 psi. Pressure up to 300 psi (with pump truck) on backside to monitor during job (After pressuring up, isolate pump truck from backside using 5000 psi ball valve).

22. Frac well down 3 ½" tubing at **40 BPM** with 12,386 gals #30 Linear Gel, 3,000 gals 15% HCl, 90,500 gals of Viking 3000, 8,000 100 mesh white, 138,000 lbs. 16/30 mesh white, and 25,000 lbs **resin-coated** Super LC 16/30 mesh. Observe a maximum surface treating pressure of **7400 psi**. Pump job per attached Baker frac design.

PROCEDURE

Stage	Fluid		Proppant			
	Type	Volume (gal)	Conc. (ppa)	Type	Stage (lbs)	Cum (lbs)
1	30# Linear Gel	1000		Breakdown		
2	15% HCL	3000		Spearhead		
3	30# Linear Gel	2000		Pad		
4	30# Linear Gel	8000	1.000	100%Sand, White, 100 m	8000	8000
5	Spectra Frac 3000	14000		Pad		8000
6	Spectra Frac 3000	12000	0.500	100%Sand, White, 16/30	6000	14000
7	Spectra Frac 3000	20000	1.000	100%Sand, White, 16/30	20000	34000
8	Spectra Frac 3000	17000	2.000	100%Sand, White, 16/30	34000	68000
9	Spectra Frac 3000	12000	3.000	100%Sand, White, 16/30	36000	104000
10	Spectra Frac 3000	10500	4.000	100%Sand, White, 16/30	42000	146000
11	Spectra Frac 3000	5000	5.000	100%Super LC, 16/30	25000	171000
12	30# Linear Gel	1386		Flush		171000
Total		105886				171000

TREATMENT SCHEDULE

Stage	Surface Treating Pressure (psi)	Rates			Volume				Stage Pump Time hh:mm:ss
		Slurry (bpm)	Clean Fluid (bpm)	Prop. Rate (lb/min)	Slurry		Fluid		
					Stage (bbls)	Cum. (bbls)	Stage (bbls)	Cum. (bbls)	
1	2090	10.0	10.0		23.8	23.8	23.8	23.8	00:02:22
2	2234	10.0	10.0		71.4	95.2	71.4	95.2	00:07:08
3	3757	40.0	40.0		47.6	142.9	47.6	142.9	00:01:11
4	3678	40.0	38.3	1606.8	199.2	342.0	190.5	333.3	00:04:58
5	4074	40.0	40.0		333.3	675.3	333.3	666.7	00:08:19
6	4036	40.0	39.1	821.4	292.2	967.5	285.7	952.4	00:07:18
7	3994	40.0	38.3	1607.3	497.7	1465.2	476.2	1428.6	00:12:26
8	3901	40.0	36.7	3081.3	441.4	1906.6	404.8	1833.3	00:11:02
9	3801	40.0	35.2	4438.0	324.5	2231.1	285.7	2119.0	00:08:06
10	3699	40.0	33.9	5690.7	295.2	2526.3	250.0	2369.0	00:07:22
11	3590	40.0	32.5	6826.8	146.5	2672.8	119.0	2488.1	00:03:39
12	3757	40.0	40.0		33.0	2705.8	33.0	2521.1	00:00:49
								Total Pump Time:	01:14:47

23. Flush to 3,732' **Do not overflush.** Shut well in. Record ISIP, 5, 10, and 15 minute SI tbg pressures. SWI. RD & Release Baker Services. **Leave well SI overnight.**

24. Check well for pressure. If well has pressure, MIRU flowback crew & associated equipment (choke manifold, flowback iron with straps, etc.). Flowback well starting 24 hours after the frac. Open up at 20 bph and work up to 50 bph over the first 6 hours. Flow down until the well dies, putting flowback down the flowline if possible. Consult with the pumper and OS if flowback is sent down the flowline.

25. MIRU pulling unit & associated surface equipment (i.e. tanks, reverse unit, pipe racks).

26. Test 3 ½" pipe rams to 250/500 psi against packer.

27. ND frac valve, release packer, and circulate kill weight fluid. POOH standing back 3-1/2" frac string and LD 5-1/2" packer.

28. PU and GIH with 4-3/4" MT bit on 3-1/2" work string and clean out to top of RBP at approximately 4,000' using 8.6 PPG cut brine water and air unit if necessary **(continue to supplemental procedure and in accordance with attached SOG).** POOH standing back 3-1/2" work string and bit. LD bit.

29. RIH with RBP retrieval tool on 3-1/2" WS to pull RBP at 4000'. Wash down through any remaining sand and latch onto RBP. Release RBP, POOH LD 3-1/2" WS & RBP. Close blind rams.
30. MIUL & strap 2-7/8" production tubing. Change 3 ½" pipe rams to 2 $^{7}/_{8}$". Open blind rams. PU/RIH and set 7" 23# rated packer @ ~ 25' to test 2 $^{7}/_{8}$" pipe rams to 250/1000 psi. Release and LD packer.

31. **Prior to this step, contact Production Engineer (John) to discuss necessity of swabbing.** PU & GIH with 7" pkr on 2-7/8" production tubing. Set pkr at 3,700'. RU swabbing equipment.

    Before/During swabbing: Inspect sandline to be sure it's free of excessive rust, bird's nests, frays, kinks, knots, etc.

32. GIH and swab well until there is no sand inflow. Report number of runs, fluid levels, sample % oil cut, and recovered fluid volumes. Release pkr. POOH standing back 2 7/8" production tubing and LD packer.

33. RIH with 2-7/8" production tubing hydrotesting to 6,000 psi. Set TAC per ALCR recommendation. ND BOP. NU WH. RIH with rods and pump per ALCR. Hang well on. RD and release workover unit.

34. Turn well over to production (See contacts). Clean location prior to moving rig.

FOAM / AIR CLEANOUT PROCEDURE

- This procedure is an addition to the original procedure.

1. Install flowback manifold with two chokes. All components on flowback manifold must be rated to at least 5,000 psi. If possible, flowback manifold components should be hydrotested before delivery. Hardline pipes from 2" casing valve to manifold to half pit with gas buster. **Set up an exclusion zone around flowback line.**
2. Install flowback tank downwind from rig.
3. Position Air unit upwind from Rig next to water tanks. Have vacuum truck on standby to empty halfpit. (if needed)
4. RIH with 4 3/4" MT bit, 4 (3-1/2") drill collars on 2-7/8" 6.5# L-80 WS.
5. NU stripper head with **NO Outlets** (Check stripper cap for thread type - course threads preferred). **Stripper head to be stump tested to 1,000 psi before being delivered to rig.** Check chart or test at rig.
6. RU foam air unit. Make quality foam on surface before going down hole with foam/air. Install flapper float at surface before beginning to pump. Break circulation with foam/air. Evacuate fluid from well.

Pump high quality foam at all times. Do not pump dry air at any time. Fluid injection rates will generally be above 12 gallons per minute

Whenever there is pressure on the stripper head, have a dedicated person continuously monitor pressure at choke manifold and have a dedicated person at accumulator ready to close annular BOP in case stripper leaks. Do not allow pressure on stripper head to exceed 500 psi. If pressure cannot be controlled below 500 psi, stop pumping, close BOP and bleed off pressure.

7. Clean out fill to 3,975' with low RPM's rotation and circulation, always keep pipe moving. Short trips can be beneficial to hole cleaning. Circulate well clean for at least 1 hour at the end of the day and pull up above the perforations before shut down for night. If the foam/air unit goes down, pull above the perforations.
8. When tripping out of hole, have special float bleed off tool available to relieve trapped pressure below float.

Ensure that high quality, stiff foam is pumped while circulating the fill. Stiff foam is required to prevent segregation while circulating. Monitor flow and pressures carefully when cleaning out.

Before rigging up power swivel to rotate, carefully inspect Kelly hose to ensure that it is in good condition. Ensure that swivel packing is in good condition.

Continue on with original procedure for completion.