Form 3160-5
(June 2015)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB NO. 1004-0137
Expires: January 31, 2018

HOBBS OCD
FEB 26 2018
RECEIVED

# SUNDRY NOTICES AND REPORTS ON WELLS

***Do not use this form for proposals to drill or to re-enter an abandoned well. Use form 3160-3 (APD) for such proposals.***

***SUBMIT IN TRIPLICATE - Other instructions on page 2***

5. Lease Serial No.
NMNM05792

6. If Indian, Allottee or Tribe Name

7. If Unit or CA/Agreement, Name and/or No.
NMNM71019X

1. Type of Well
☒ Oil Well ☐ Gas Well ☐ Other

8. Well Name and No.
RED HILLS UNIT 17H

2. Name of Operator
CIMAREX ENERGY COMPANY OF CO
Contact: ARICKA EASTERLING
E-Mail: aeasterling@cimarex.com

9. API Well No.
30-025-42325-00-X1

3a. Address
202 S CHEYENNE AVE. SUITE 1000
TULSA, OK 74103

3b. Phone No. (include area code)
Ph: 918.560.7060

10. Field and Pool or Exploratory Area
WC-025 G06 S253329D

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Sec 33 T25S R33E NWNW 504FNL 564FWL
32.053800 N Lat, 103.345415 W Lon

11. County or Parish, State

LEA COUNTY, NM

12. CHECK THE APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

| TYPE OF SUBMISSION | TYPE OF ACTION | | | |
|---|---|---|---|---|
| ☒ Notice of Intent | ☐ Acidize | ☐ Deepen | ☐ Production (Start/Resume) | ☐ Water Shut-Off |
| ☐ Subsequent Report | ☐ Alter Casing | ☐ Hydraulic Fracturing | ☐ Reclamation | ☐ Well Integrity |
| ☐ Final Abandonment Notice | ☐ Casing Repair | ☐ New Construction | ☐ Recomplete | ☒ Other |
| | ☐ Change Plans | ☐ Plug and Abandon | ☐ Temporarily Abandon | Change to Original A PD |
| | ☐ Convert to Injection | ☐ Plug Back | ☐ Water Disposal | |

13. Describe Proposed or Completed Operation: Clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports must be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 must be filed once testing has been completed. Final Abandonment Notices must be filed only after all requirements, including reclamation, have been completed and the operator has determined that the site is ready for final inspection.

Cimarex respectfully request approval to change the drilling plan (casing, cement & mud) for the above referenced well. Please see attached drilling plan. Cimarex also requests approval for a multibowl well head, please see attached diagram and procedure.

**Carlsbad Field Office**
**OCD Hobbs**

SEE ATTACHED FOR
CONDITIONS OF APPROVAL

14. I hereby certify that the foregoing is true and correct.
**Electronic Submission #386570 verified by the BLM Well Information System**
**For CIMAREX ENERGY COMPANY OF CO, sent to the Hobbs**
**Committed to AFMSS for processing by PRISCILLA PEREZ on 10/25/2017 (18PP0085SE)**

Name *(Printed/Typed)* ARICKA EASTERLING — Title REGULATORY ANALYST

Signature (Electronic Submission) — Date 08/29/2017

**THIS SPACE FOR FEDERAL OR STATE OFFICE USE**

Approved By ZOTA STEVENS — Title PETROLEUM ENGINEER — Date 02/15/2018

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Office Hobbs

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

**** BLM REVISED ** BLM REVISED ** BLM REVISED ** BLM REVISED ** BLM REVISED ****

## 1. Geological Formations

TVD of target 12,335
MD at TD 21,888

Pilot Hole TD N/A
Deepest expected fresh water

| Formation | Depth (TVD) from KB | Water/Mineral Bearing/Target Zone | Hazards |
|---|---|---|---|
| Groundwater | 185 | N/A | |
| Rustler | 995 | N/A | |
| Salt | 1140 | N/A | |
| Castille | 3380 | N/A | |
| Lamar | 4900 | N/A | |
| Bell Canyon | 4945 | N/A | |
| Cherry Canyon | 6190 | N/A | |
| Brushy Canyon | 7485 | N/A | |
| Bone Spring | 9045 | Hydrocarbons | |
| U. Avalon (Leonard) | 9080 | Hydrocarbons | |
| L. Avalon | 9680 | Hydrocarbons | |

## 2. Casing Program

| Hole Size | Casing Depth From | Casing Depth To | Casing Size | Weight (lb/ft) | Grade | Conn. | SF Collapse | SF Burst | SF Tension |
|---|---|---|---|---|---|---|---|---|---|
| 14 3/4 | 0 | 1040 ~~976~~ | 10-3/4" | 40.50 | J-55 | BT&C | 3.54 | 7.01 | 15.91 |
| 9 7/8 | 0 | 12500 | 7-5/8" | 29.70 | L-80 | BT&C | 2.36 | 1.13 | 1.81 |
| 6 3/4 | 0 | 11837 | 5-1/2" | 20.00 | L-80 | LT&C | 1.15 | 1.19 | 1.87 |
| 6 3/4 | 11837 | 21888 | 5" | 18.00 | P-110 | BT&C | 1.68 | 1.70 | 64.70 |
| | | | | BLM Minimum Safety Factor | | | 1.125 | 1 | 1.6 Dry<br>1.8 Wet |

TVD was used on all calculations.
Request Variance for 5-1/2" x 7-5/8" annular clearance. The portion that does not meet clearance will not be cemented.
All casing strings will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.h

| | Y or N |
|---|---|
| Is casing new? If used, attach certification as required in Onshore Order #1 | Y |
| Does casing meet API specifications? If no, attach casing specification sheet. | Y |
| Is premium or uncommon casing planned? If yes attach casing specification sheet. | N |
| Does the above casing design meet or exceed BLM's minimum standards? If not provide justification (loading assumptions, casing design criteria). | Y |
| Will the intermediate pipe be kept at a minimum 1/3 fluid filled to avoid approaching the collapse pressure rating of the casing? | Y |
| Is well located within Capitan Reef? | N |
| If yes, does production casing cement tie back a minimum of 50' above the Reef? | N |
| Is well within the designated 4 string boundary. | N |
| Is well located in SOPA but not in R-111-P? | N |
| If yes, are the first 2 strings cemented to surface and 3rd string cement tied back 500' into previous casing? | N |
| Is well located in R-111-P and SOPA? | N |
| If yes, are the first three strings cemented to surface? | N |
| Is 2nd string set 100' to 600' below the base of salt? | N |
| Is well located in high Cave/Karst? | N |
| If yes, are there two strings cemented to surface? | N |
| (For 2 string wells) If yes, is there a contingency casing if lost circulation occurs? | N |
| Is well located in critical Cave/Karst? | N |
| If yes, are there three strings cemented to surface? | N |

### 3. Cementing Program

| Casing | # Sks | Wt. lb/gal | Yld ft3/sack | H2O gal/sk | 500# Comp. Strength (hours) | Slurry Description |
|---|---|---|---|---|---|---|
| Surface | 328 | 13.50 | 1.72 | 9.15 | 15.5 | Lead: Class C + Bentonite |
| | 156 | 14.80 | 1.34 | 6.32 | 9.5 | Tail: Class C + LCM |
| | | | | | | |
| Intermediate Stage 1 | 600 | 10.3 | 3.64 | 22.18 | | Lead: Tuned Light + LCM |
| | 207 | 14.20 | 1.30 | 5.86 | 14:30 | Tail: 50:50 (Poz:H) + Salt + Bentonite + Fluid Loss + Dispersant + SMS |
| | | | | | | |
| Intermediate Stage 2 | 700 | 12.9 | 1.88 | 9.65 | 12 | Lead: 35:65 (Poz:C) + Salt + Bentonite |
| | | | | | | |
| | | | | | | |
| Production | 711 | 14.20 | 1.30 | 5.86 | 14:30 | Tail: 50:50 (Poz:H) + Salt + Bentonite + Fluid Loss + Dispersant + SMS |
| | | | | | | |

| Casing String | TOC | % Excess |
|---|---|---|
| Surface | 0 | 42 |
| Intermediate Stage 1 | 4888 | 50 |
| Intermediate Stage 2 | 0 | 48 |
| Production | 12300 | 9 |

DV tool with possible annular casing packer as needed is proposed at the depth of the Lamar at +/- 4,888'.

## 4. Pressure Control Equipment

| | |
|---|---|
| | A variance is requested for the use of a diverter on the surface casing. See attached for schematic. |

| BOP installed and tested before drilling which hole? | Size | Min Required WP | Type | | Tested To |
|---|---|---|---|---|---|
| 9 7/8 | 13 5/8 | 5M | Annular | X | 50% of working pressure |
| | | | Blind Ram | | 5M |
| | | | Pipe Ram | X | |
| | | | Double Ram | X | |
| | | | Other | | |
| 6 3/4 | 13 5/8 | 10M | Annular | X | 50% of working pressure |
| | | | Blind Ram | | 10M |
| | | | Pipe Ram | X | |
| | | | Double Ram | X | |
| | | | Other | | |

BOP/BOPE will be tested by an independent service company to 250 psi low and the high pressure indicated above per Onshore Order 2 requirements. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested.

Pipe rams will be operationally checked each 24 hour period. Blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets. Other accessories to the BOP equipment will include a Kelly cock and floor safety valve (inside BOP) and choke lines and choke manifold. See attached schematics.

| | | |
|---|---|---|
| X | Formation integrity test will be performed per Onshore Order #2.<br>On Exploratory wells or on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed.<br>Will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.i. | |
| X | A variance is requested for the use of a flexible choke line from the BOP to Choke Manifold. See attached for specs and hydrostatic test chart. | |
| | N | Are anchors required by manufacturer? |

## 5. Mud Program

| Depth | Type | Weight (ppg) | Viscosity | Water Loss |
|---|---|---|---|---|
| 0' to ~~976'~~ 1040 | FW Spud Mud | 8.30 - 8.80 | 30-32 | N/C |
| 976' to 12500' | Brine Diesel Emulsion | 9.00 - 9.50 | 30-35 | N/C |
| 12500' to 21888' | OBM | 12.00 - 12.50 | 50-70 | N/C |

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept on location at all times.

The Brine Emulsion is completely saturated brine fluid that ties diesel into itself to lower the weight of the fluid. The drilling fluid is completely salt saturated.

| | |
|---|---|
| What will be used to monitor the loss or gain of fluid? | PVT/Pason/Visual Monitoring |

## 6. Logging and Testing Procedures

| Logging, Coring and Testing | |
|---|---|
| X | Will run GR/CNL fromTD to surface (horizontal well – vertical portion of hole). Stated logs run will be in the Completion Report and submitted to the BLM. |
| | No logs are planned based on well control or offset log information. |
| | Drill stem test? |
| | Coring? |

| Additional Logs Planned | Interval |
|---|---|

## 7. Drilling Conditions

| Condition | |
|---|---|
| BH Pressure at deepest TVD | 8017 psi |
| Abnormal Temperature | No |

Hydrogen Sulfide (H2S) monitors will be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the operator will comply with the provisions of Onshore Oil and Gas Order #6. If Hydrogen Sulfide is encountered, measured values and formations will be provided to the BLM.

| | |
|---|---|
| X | H2S is present |
| X | H2S plan is attached |

## 8. Other Facets of Operation

## 9. Wellhead

A multi-bowl wellhead system will be utilized.

After running the 10-3/4" surface casing, a 13 5/8" BOP/BOPE system with a minimum working pressure of 10000 psi will be installed on the wellhead system and will be pressure tested to 250 psi low followed by a 10000 psi test. Annular will be tested to 50% of working pressure. The pressure test will be repeated at least every 30 days, as per Onshore Order No. 2.

The multi-bowl wellhead will be installed by vendor's representative. A copy of the installation instructions has been sent to the BLM field office.

The wellhead will be installed by a third-party welder while being monitored by the wellhead vendor representative.

All BOP equipment will be tested utilizing a conventional test plug. Not a cup or J-packer type.

A solid steel body pack-off will be utilized after running and cementing the intermediate casing. After installation the pack-off and lower flange will be pressure tested to 10000 psi.

The surface casing string will be tested as per Onshore Order No. 2 to at least 0.22 psi/ft or 1500 psi, whichever is greater.

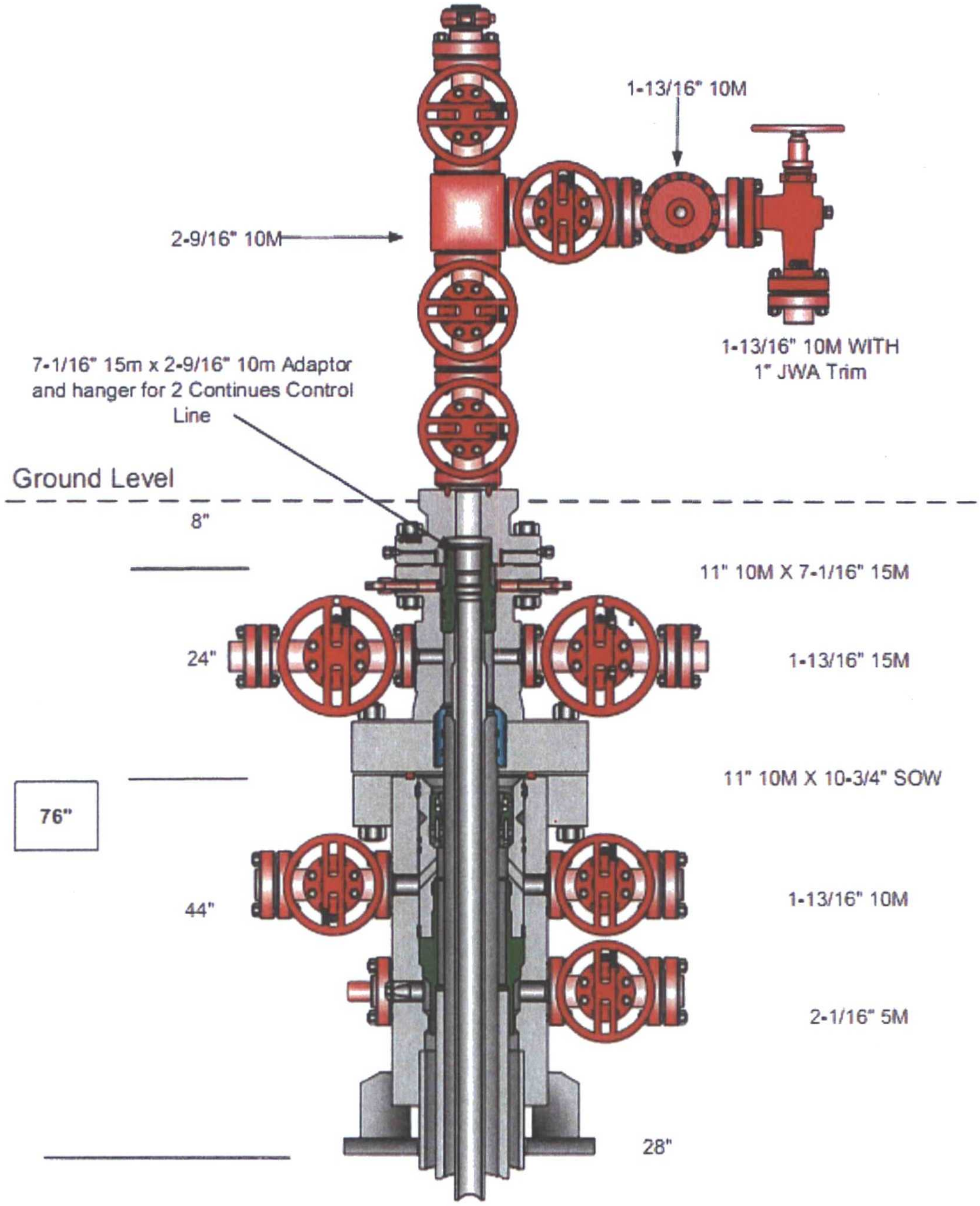
The casing string utilizing steel body pack-off will be tested to 70% of casing burst.

If well conditions dictate conventional slips will be set and BOPE will be tested to appropriate pressures based on permitted pressure requirements.

**Cactus Multi-Bowl Wellhead Steps:**

1. Drill 14-3/4" Hole to Surface TD.
2. Trip out of hole.
3. Run and cement 10-3/4" casing.
4. Weld on Cactus Multi-Bowl Wellhead per Manufacturer's procedure.
5. Test weld to 70% of 10-3/4" surface casing collapse.
6. Manufacturer representative will install test plug
7. Test BOPE equipment to 10,000 psi per permitted test pressure for drilling below 7-5/8" intermediate shoe.
8. Install Wear Bushing
9. Drill to 7-5/8" casing shoe with 9-7/8" hole.
10. Trip out of hole.
11. Remove Wear Bushing.
12. Run 7-5/8" casing and land 7-5/8" casing hanger.
13. Cement casing.
14. Washout stack. Run wash tool to clean hanger.
15. Run and Install Packoff.
16. Test Packoff Seals.
17. Run Wear Bushing.
18. TIH to float collar.
19. Test Casing per COA WOC times. (500 psi compressive strength and 8 hours, whichever is greater)
20. Drill to production hole TD.
21. Trip out of hole.
22. Run 5.5" x 5" Production Casing.
23. Cement production Casing.
24. N/D and Set 5.5" Casing Slips.

**Note: We will not Test BOP's after welding on the Surface head until the 7" casing is ran and cemented unless we exceed the 30 day limit per Onshore Order #2.**




**PREPARED ON 8-25-17**

# Cimarex 10M Well Control Plan

Version 1.0

# BOPE Preventer Utilization

The table below displays all BHA components, drill pipe, casing, or open hole that could be present during a required shut in and the associated preventer component that would provide a barrier to flow. It is specific to the hole section that requires a 10M system. The mud system being utilized in the hole will always assumed to be the first barrier to flow. The below table, combined with the mud program, documents that two barriers to flow can be maintained at all times, independent of the rating of the annular preventer.

| Drill String Element | OD | Preventer | RWP |
|---|---|---|---|
| 4" Drillpipe | 4" | Lower Ram 3 1/2" - 5 ½" VBR*<br>Upper Ram 3 1/2" - 5 ½" VBR* | 10M |
| 4.5" Drillpipe | 4.5" | Lower Ram 3 1/2" - 5 ½" VBR*<br>Upper Ram 3 1/2" - 5 ½" VBR* | 10M |
| 4" HWDP Drillpipe | 4" | Lower Ram 3 1/2" - 5 ½" VBR*<br>Upper Ram 3 1/2" - 5 ½" VBR* | 10M |
| 4.5" HWDP Drillpipe | 4.5" | Lower Ram 3 1/2" - 5 ½" VBR*<br>Upper Ram 3 1/2" - 5 ½" VBR* | 10M |
| Drill Collars (including non-magnetic) | 4.75-5.25" | Lower Ram 3 1/2" - 5 ½" VBR*<br>Upper Ram 3 1/2" - 5 ½" VBR* | 10M |
| Production Casing | 5.5" | Lower Ram 3 1/2" - 5 ½" VBR*<br>Upper Ram 3 1/2" - 5 ½" VBR* | 10M |
| Production Casing | 5" | Lower Ram 3 1/2" - 5 ½" VBR*<br>Upper Ram 3 1/2" - 5 ½" VBR* | 10M |
| Production Casing | 4.5" | Lower Ram 3 1/2" - 5 ½" VBR*<br>Upper Ram 3 1/2" - 5 ½" VBR* | 10M |
| ALL | 0-13 5/8" | Annular | 5M |
| Open Hole | | Blind Rams | 10M |

*VBR – Variable Bore Ram

# Well Control Procedures

Proper well control response is highly specific to current well conditions and must be adapted based on environment as needed. The procedures below are given in "common" operating conditions to cover the basic and most necessary operations required during the wellbore construction. These include drilling ahead, tripping pipe, tripping BHA, running casing, and pipe out of the hole/open hole. In some of the procedures below, there will be a switch of control from the lesser RWP annular to the appropriate 10M RWP ram. The pressure at which this is done is variable based on overall well conditions that must be evaluated situationally. The pressure that control is switched may be equal to or less than the RWP but at no time will the pressure on the annular preventer exceed the RWP of the annular. The annular will be tested to 5,000 psi. This will be the RWP of the annular preventer.

***Shutting In While Drilling***

1. Sound alarm to alert crew
2. Space out drill string
3. Shut down pumps
4. Shut in uppermost BOPE preventer (typically the annular preventer) and open HCR.
5. Verify well is shut-in and flow has stopped
6. Notify supervisory personnel
7. Record data (SIDP, SICP, Pit Gain, and Time)
8. Hold pre-job safety meeting and discuss kill procedure

9. If pressure is anticipated to climb to the RWP of the annular preventer during kill procedure, swap control of the well to the upper pipe ram

***Shutting In While Tripping***

1. Sound alarm and alert crew
2. Install open, full open safety valve and close valve
3. Shut in uppermost BOPE preventer (typically the annular preventer) and open HCR.
4. Verify well is shut-in and flow has stopped
5. Notify supervisory personnel
6. Record data (SIDP, SICP, Pit Gain, and Time)
7. Hold pre-job safety meeting and discuss kill procedure
8. If pressure is anticipated to climb to the RWP of the annular preventer during kill procedure, swap control of the well to the upper pipe ram

***Shutting In While Running Casing***

1. Sound alarm and alert crew
2. Install circulating swedge. Close high pressure, low torque valves.
3. Shut in uppermost BOPE preventer (typically the annular preventer) and open HCR.
4. Verify well is shut-in and flow has stopped
5. Notify supervisory personnel
6. Record data (SIDP, SICP, Pit Gain, and Time)
7. Hold Pre-job safety meeting and discuss kill procedure
8. If pressure is anticipated to climb to the RWP of the annular preventer during kill procedure, swap control of the well to the upper pipe ram

***Shutting in while out of hole***

1. Sound alarm
2. Shut-in well: close blind rams
3. Verify well is shut-in and monitor pressures
4. Notify supervisory personnel
5. Record data (SIDP, SICP, Pit Gain, and Time)
6. Hold Pre-job safety meeting and discuss kill procedure

***Shutting in prior to pulling BHA through stack***

1. Prior to pulling last joint of drill pipe thru the stack space out and check flow. If flowing see steps below.
2. Sound alarm and alert crew
3. Install open, full open safety valve and close valve
4. Shut in upper pipe ram and open HCR.

5. Verify well is shut-in and flow has stopped
6. Notify supervisory personnel
7. Record data (SIDP, SICP, Pit Gain, and Time)
8. Hold pre-job safety meeting and discuss kill procedure

***Shutting in while BHA is in the stack and ram preventer and combo immediately available***

1. Sound alarm and alert crew
2. Stab Crossover and install open, full open safety valve and close valve
3. Space out drill string with upset just beneath the compatible pipe ram.
4. Shut in upper compatible pipe ram and open HCR.
5. Verify well is shut-in and flow has stopped
6. Notify supervisory personnel
7. Record data (SIDP, SICP, Pit Gain, and Time)
8. Hold pre-job safety meeting and discuss kill procedure

***Shutting in while BHA is in the stack and no ram preventer or combo immediately available***

1. Sound alarm and alert crew
2. If possible pick up high enough, to pull string clear and follow "Open Hole" scenario
3. If not possible to pick up high enough:
    1. Stab Crossover, make up one joint/stand of drill pipe, and install open, full open safety valve and close valve
4. Space out drill string with upset just beneath the compatible pipe ram.
5. Shut in upper compatible pipe ram and open HCR.
6. Verify well is shut-in and flow has stopped
7. Notify supervisory personnel
8. Record data (SIDP, SICP, Pit Gain, and Time)
9. Hold pre-job safety meeting and discuss kill procedure

# PECOS DISTRICT
# DRILLING CONDITIONS OF APPROVAL

| | |
|---|---|
| OPERATOR'S NAME: | CIMAREX ENERGY COMPANY OF CO |
| LEASE NO.: | NMNM05792 |
| WELL NAME & NO.: | RED HILLS UNIT 17H |
| SURFACE HOLE FOOTAGE: | 504' FNL & 564' FWL |
| BOTTOM HOLE FOOTAGE | 330' FSL & 380' FWL |
| LOCATION: | Section 33, T. 25 S., R 33 E., NMPM |
| COUNTY: | Eddy County, New Mexico |

COA

| | | | |
|---|---|---|---|
| H2S | ○ Yes | ◉ No | |
| Potash | ◉ None | ○ Secretary | ○ R-111-P |
| Cave/Karst Potential | ◉ Low | ○ Medium | ○ High |
| Variance | ○ None | ◉ Flex Hose | ○ Other |
| Wellhead | ○ Conventional | ◉ Multibowl | ○ Both |
| Other | ☐ 4 String Area | ☐ Capitan Reef | ☐ WIPP |

## A. Hydrogen Sulfide

Hydrogen Sulfide (H2S) monitors shall be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the Hydrogen Sulfide area shall meet Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, provide measured values and formations to the BLM.

## B. CASING

1. The **10-3/4** inch surface casing shall be set at approximately **1040** feet (a minimum of 25 feet into the Rustler Anhydrite and above the salt) and cemented to the surface.

   a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
   b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)

c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
d. If cement falls back, remedial cementing will be done prior to drilling out that string.

**Operator shall filled 1/3rd intermediate casing with fluid while running casing to maintain collapse safety factor.**

2. The minimum required fill of cement behind the **7-5/8** inch intermediate casing is:

   Operator has proposed a DV tool, the depth may be adjusted as long as the cement is changed proportionally. The DV tool may be cancelled if cement circulates to surface on the first stage.

   a. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.

   b. Second stage above DV tool:Cement to surface. If cement does not circulate, contact the appropriate BLM office.**Additional cement maybe required. Excess calculates to 23%.**

**A variance is approved for a annular spacing between 5 ½ inches x 7 5/8 inch.**

3. The minimum required fill of cement behind the **5-1/2** inch production casing is:
   c. Cement should tie-back at least 200 feet into previous casing string. Operator shall provide method of verification. **Additional cement maybe required. Excess calculates to 15%.**

## C. PRESSURE CONTROL

1. Variance approved to use flex line from BOP to choke manifold. Manufacturer's specification to be readily available. No external damage to flex line. Flex line to be installed as straight as possible (no hard bends).

2. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **5000 (5M)** psi.

Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **7-5/8** intermediate casing shoe shall be **10,000 (10M)** psi. **Variance approved to use a 5M annular. The annular must be tested to full working pressure (5000 psi.)**

# GENERAL REQUIREMENTS

The BLM is to be notified in advance for a representative to witness:

a. Spudding well (minimum of 24 hours)
b. Setting and/or Cementing of all casing strings (minimum of 4 hours)
c. BOPE tests (minimum of 4 hours)

☒ Lea County
Call the Hobbs Field Station, 414 West Taylor, Hobbs NM 88240, (575) 393-3612

1. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval.
   a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
   b. When the operator proposes to set surface casing with Spudder Rig
      - Notify the BLM when moving in and removing the Spudder Rig.
      - Notify the BLM when moving in the 2nd Rig. Rig to be moved in within 90 days of notification that Spudder Rig has left the location.
      - BOP/BOPE test to be conducted per Onshore Oil and Gas Order No. 2 as soon as 2nd Rig is rigged up on well.

2. Floor controls are required for 3M or Greater systems. These controls will be on the rig floor, unobstructed, readily accessible to the driller and will be operational at all times during drilling and/or completion activities. Rig floor is defined as the area immediately around the rotary table; the area immediately above the substructure on which the draw works are located, this does not include the dog house or stairway area.

3. The record of the drilling rate along with the GR/N well log run from TD to surface (horizontal well – vertical portion of hole) shall be submitted to the BLM office as well as all other logs run on the borehole 30 days from completion. If available, a digital copy of the logs is to be submitted in addition to the paper copies. The Rustler top and top and bottom of Salt are to be recorded on the Completion Report.

A. CASING

1. Changes to the approved APD casing program need prior approval if the items substituted are of lesser grade or different casing size or are Non-API. The Operator can exchange the components of the proposal with that of superior strength (i.e. changing from J-55 to N-80, or from 36# to 40#). Changes to the approved cement program need prior approval if the altered cement plan has less volume or strength or if the changes are substantial (i.e. Multistage tool, ECP, etc.). The initial wellhead installed on the well will remain on the well with spools used as needed.

2. Wait on cement (WOC) for Potash Areas: After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi for all cement blends, 2) until cement has been in place at least 24 hours. WOC time will be recorded in the driller's log. The casing intergrity test can be done (prior to the cement setting up) immediately after bumping the plug.

3. Wait on cement (WOC) for Water Basin: After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least 8 hours. WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements. The casing intergrity test can be done (prior to the cement setting up) immediately after bumping the plug.

4. Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string. Have well specific cement details onsite prior to pumping the cement for each casing string.

5. No pea gravel permitted for remedial or fall back remedial without prior authorization from the BLM engineer.

6. **On that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.**

7. If hardband drill pipe is rotated inside casing, returns will be monitored for metal. If metal is found in samples, drill pipe will be pulled and rubber protectors which have a larger diameter than the tool joints of the drill pipe will be installed prior to continuing drilling operations.

8. Whenever a casing string is cemented in the R-111-P potash area, the NMOCD requirements shall be followed.

B. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in Onshore Oil and Gas Order No. 2 and API RP 53 Sec. 17.

2. If a variance is approved for a flexible hose to be installed from the BOP to the choke manifold, the following requirements apply: The flex line must meet the requirements of API 16C. Check condition of flexible line from BOP to choke manifold, replace if exterior is damaged or if line fails test. Line to be as straight as possible with no hard bends and is to be anchored according to Manufacturer's requirements. The flexible hose can be exchanged with a hose of equal size and equal or greater pressure rating. Anchor requirements, specification sheet and hydrostatic pressure test certification matching the hose in service, to be onsite for review. These documents shall be posted in the company man's trailer and on the rig floor.

3. 5M or higher system requires an HCR valve, remote kill line and annular to match. The remote kill line is to be installed prior to testing the system and tested to stack pressure.

4. If the operator has proposed a multi-bowl wellhead assembly in the APD. The following requirements must be met:
    a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
    b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
    c. Manufacturer representative shall install the test plug for the initial BOP test.
    d. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
    e. Whenever any seal subject to test pressure is broken, all the tests in OOGO2.III.A.2.i must be followed.

5. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.

    a. In a water basin, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. The casing cut-off and BOP installation can be initiated four hours after installing the slips, which will be approximately six hours after bumping the plug. For those casing strings not using slips, the minimum wait time before cut-off is eight hours after bumping the plug. BOP/BOPE testing can begin after cut-off or once cement reaches 500 psi compressive strength (including lead when specified), whichever is greater. However, if the float does not hold, cut-off cannot be initiated until cement reaches 500 psi compressive strength (including lead when specified).

b. In potash areas, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. For all casing strings, casing cut-off and BOP installation can be initiated at twelve hours after bumping the plug. However, **no tests** shall commence until the cement has had a minimum of 24 hours setup time, except the casing pressure test can be initiated immediately after bumping the plug (only applies to single stage cement jobs).

c. The tests shall be done by an independent service company utilizing a test plug. The results of the test shall be reported to the appropriate BLM office.

d. The test shall be run on a 5000 psi chart for a 2-3M BOP/BOP, on a 10000 psi chart for a 5M BOP/BOPE and on a 15000 psi chart for a 10M BOP/BOPE. If a linear chart is used, it shall be a one hour chart. A circular chart shall have a maximum 2 hour clock. If a twelve hour or twenty-four hour chart is used, tester shall make a notation that it is run with a two hour clock.

e. All tests are required to be recorded on a calibrated test chart. A copy of the BOP/BOPE test chart and a copy of independent service company test will be submitted to the appropriate BLM office.

f. The BOP/BOPE test shall include a low pressure test from 250 to 300 psi. The test will be held for a minimum of 10 minutes. This test shall be performed prior to the test at full stack pressure.

g. BOP/BOPE must be tested by an independent service company within 500 feet of the top of the Wolfcamp formation if the time between the setting of the intermediate casing and reaching this depth exceeds 20 days. This test does not exclude the test prior to drilling out the casing shoe as per Onshore Order No. 2.

## C. DRILLING MUD

Mud system monitoring equipment, with derrick floor indicators and visual and audio alarms, shall be operating before drilling into the Wolfcamp formation, and shall be used until production casing is run and cemented.

## D. WASTE MATERIAL AND FLUIDS

All waste (i.e. drilling fluids, trash, salts, chemicals, sewage, gray water, etc.) created as a result of drilling operations and completion operations shall be safely contained and disposed of properly at a waste disposal facility. No waste material or fluid shall be disposed of on the well location or surrounding area.

Porto-johns and trash containers will be on-location during fracturing operations or any other crew-intensive operations.

**Waste Minimization Plan (WMP)**

In the interest of resource development, submission of additional well gas capture development plan information is deferred but may be required by the BLM Authorized Officer at a later date.

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| 10 3/4 | surface csg in a | | 14 3/4 | inch hole. | | Design Factors | | SURFACE | |
|---|---|---|---|---|---|---|---|---|---|
| Segment | #/ft | Grade | | Coupling | Joint | Collapse | Burst | Length | Weight |
| "A" | 40.50 | J 55 | | ST&C | 9.97 | 3.32 | 0.52 | 1,040 | 42,120 |
| "B" | | | | | | | | 0 | 0 |
| w/8.4#/g mud, 30min Sfc Csg Test psig: | | | 1,500 | Tail Cmt | does not | circ to sfc. | Totals: | 1,040 | 42,120 |

Comparison of Proposed to Minimum Required Cement Volumes

| Hole Size | Annular Volume | 1 Stage Cmt Sx | 1 Stage CuFt Cmt | Min Cu Ft | 1 Stage % Excess | Drilling Mud Wt | Calc MASP | Req'd BOPE | Min Dist Hole-Cplg |
|---|---|---|---|---|---|---|---|---|---|
| 14 3/4 | 0.5563 | 484 | 773 | 604 | 28 | 8.80 | 3364 | 5M | 1.50 |

Burst Frac Gradient(s) for Segment(s) A, B = , b All > 0.70, OK.

| 7 5/8 | casing inside the | | 10 3/4 | | | Design Factors | | INTERMEDIATE | |
|---|---|---|---|---|---|---|---|---|---|
| Segment | #/ft | Grade | | Coupling | Body | Collapse | Burst | Length | Weight |
| "A" | 29.70 | L 80 | | BUTT | 1.84 | 0.82 | 0.86 | 11,837 | 351,559 |
| "B" | 29.70 | L 80 | | BUTT | 62.40 | 0.79 | 0.86 | 663 | 19,691 |
| w/8.4#/g mud, 30min Sfc Csg Test psig: | | | | | | | Totals: | 12,500 | 371,250 |
| B ; would be: | | | | | 34.70 | 0.79 | if it were a vertical wellbore. | | |
| No Pilot Hole Planned | | | MTD | Max VTD | Csg VD | Curve KOP | Dogleg° | Severity° | MEOC |
| | | | 12500 | 12300 | 12300 | 11837 | 73 | -1 | 0 |
| The cement volume(s) are intended to achieve a top of | | | | | 0 | ft from surface or a | | 1040 | overlap. |
| Hole Size | Annular Volume | 1 Stage Cmt Sx | 1 Stage CuFt Cmt | Min Cu Ft | 1 Stage % Excess | Drilling Mud Wt | Calc MASP | Req'd BOPE | Min Dist Hole-Cplg |
| 9 7/8 | 0.2148 | look ↘ | 0 | 2716 | | 9.50 | 5296 | 10M | 0.69 |
| D V Tool(s): | | | 4888 | | | | sum of sx | Σ CuFt | Σ%excess |
| t by stage % : | | 49 | 23 | | | | 1507 | 3769 | 39 |

Class 'C' tail cmt yld > 1.35

MASP is within 10% of 5000psig, need

Burst Frac Gradient(s) for Segment(s): A, B, C, D = 0.58, 0.56, c, d
<0.70 a Problem!!

**ALT. COLLAPSE SF= 0.79*1.5 = .79*1.5 = 1.185**

Tail cmt

| 5 1/2 | casing inside the | | 7 5/8 | A Buoyant | | Design Factors | | PRODUCTION | |
|---|---|---|---|---|---|---|---|---|---|
| Segment | #/ft | Grade | | Coupling | Joint | Collapse | Burst | Length | Weight |
| "A" | 20.00 | L 80 | | LT&C | 2.45 | 1.15 | 1.15 | 11,837 | 236,740 |
| "B" | 18.00 | P 110 | | BUTT | 7.59 | 1.56 | 1.7 | 10,051 | 180,918 |
| w/8.4#/g mud, 30min Sfc Csg Test psig: | | | 1,268 | | | | Totals: | 21,888 | 417,658 |
| B would be: | | | | | 64.73 | 1.68 | if it were a vertical wellbore. | | |
| No Pilot Hole Planned | | | MTD | Max VTD | Csg VD | Curve KOP | Dogleg° | Severity° | MEOC |
| | | | 21888 | 12335 | 12335 | 11837 | 90 | 11 | 12670 |
| The cement volume(s) are intended to achieve a top of | | | | | 12300 | ft from surface or a | | 200 | overlap. |
| Hole Size | Annular Volume | 1 Stage Cmt Sx | 1 Stage CuFt Cmt | Min Cu Ft | 1 Stage % Excess | Drilling Mud Wt | Calc MASP | Req'd BOPE | Min Dist Hole-Cplg |
| 6 3/4 | 0.0835 | 711 | 924 | 807 | 15 | 12.50 | | | 0.35 |

Class 'H' tail cmt yld > 1.20