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

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.

HOBBS OCD

AUG 21 2019

RECEIVED

SUBMIT IN TRIPLICATE - Other instructions on page 2

5. Lease Serial No.
NMLC062749B

6. If Indian, Allottee or Tribe Name

7. If Unit or CA/Agreement, Name and/or No.
NMNM138329X

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

8. Well Name and No.
ZIA HILLS 19 FEDERAL COM 116H

2. Name of Operator
CONOCOPHILLIPS COMPANY
Contact: JEREMY LEE
E-Mail: jeremy.l.lee@cop.com

9. API Well No.
30-025-44242-00-X1

3a. Address
925 N ELDRIDGE PARKWAY
HOUSTON, TX 77079

3b. Phone No. (include area code)
Ph: 832-486-2510

10. Field and Pool or Exploratory Area
WOLFCAMP

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
Sec 19 T26S R32E SENW 2638FNL 1699FWL
32.028282 N Lat, 103.717560 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 to Original A PD
	☐ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
	☐ 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.

ConocoPhillips respectfully requests to change the approved drilling plan as reflected in the attached documents:
Zia Hills 19 Fed Com 116H Kelly Cock
Zia Hills 19 Fed Com 116H Choke Manifold
Zia Hills 19 Fed Com 116H BOPE
Zia Hills 19 Fed Com 116H Csg Design
Zia Hills 19 Fed Com 116H Cement
Zia Hills 19 Fed Com 116H Drill Plan

OCD Hobbs

In particular the casing design is being modified due to availability of casing. As such we request approval at your earliest convenience.

14. I hereby certify that the foregoing is true and correct.
Electronic Submission #471763 verified by the BLM Well Information System
For CONOCOPHILLIPS COMPANY, sent to the Hobbs
Committed to AFMSS for processing by PRISCILLA PEREZ on 07/02/2019 (19PP2370SE)

Name *(Printed/Typed)* JEREMY LEE — Title REGULATORY COORDINATOR

Signature (Electronic Submission) — Date 07/02/2019

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved By NDUNGU KAMAU — Title PETROLEUM ENGINEER — Date 07/18/2019

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 **

KZ

Revisions to Operator-Submitted EC Data for Sundry Notice #471763

	Operator Submitted	BLM Revised (AFMSS)
Sundry Type:	APDCH NOI	APDCH NOI
Lease:	NMLC062749B	NMLC062749B
Agreement:		NMNM138329X (NMNM138329X)
Operator:	CONOCOPHILLIPS COMPANY 925 N. ELDRIDGE PARKWAY SUITE EC3-10-W305 HOUSTON, TX 77079 Ph: 832-486-2510	CONOCOPHILLIPS COMPANY 925 N ELDRIDGE PARKWAY HOUSTON, TX 77079 Ph: 281 206 5281
Admin Contact:	JEREMY LEE REGULATORY COORDINATOR E-Mail: jeremy.l.lee@cop.com Ph: 832-486-2510	JEREMY LEE REGULATORY COORDINATOR E-Mail: jeremy.l.lee@cop.com Ph: 832-486-2510
Tech Contact:	JEREMY LEE REGULATORY COORDINATOR E-Mail: jeremy.l.lee@cop.com Ph: 832-486-2510	JEREMY LEE REGULATORY COORDINATOR E-Mail: jeremy.l.lee@cop.com Ph: 832-486-2510
Location: State: County:	 NM LEA COUNTY	 NM LEA
Field/Pool:	WOLFCAMP	WOLFCAMP
Well/Facility:	ZIA HILLS 19 FEDERAL COM 116H Sec 19 T26S R32E Mer NMP 2638FNL 1699FWL	ZIA HILLS 19 FEDERAL COM 116H Sec 19 T26S R32E SENW 2638FNL 1699FWL 32.028282 N Lat, 103.717560 W Lon

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME: CONCO PHILLIPS COMPANY
LEASE NO.: NMLC062749B
COUNTY: LEA

ZIA HILLS 19 FEDERAL COM 113H
LOCATION: Section 19, T.26 S., R.32 E., NMPM
SURFACE HOLE FOOTAGE: 2638'/N & 1600'/W
BOTTOM HOLE FOOTAGE: 50'/S & 1320'/W

ZIA HILLS 19 FEDERAL COM 114H
LOCATION: Section 19, T.26 S., R.32 E., NMPM
SURFACE HOLE FOOTAGE: 2638'/N & 1633'/W
BOTTOM HOLE FOOTAGE: 50'/S & 1650'/W

ZIA HILLS 19 FEDERAL COM 115H
LOCATION: Section 19, T.26 S., R.32 E., NMPM
SURFACE HOLE FOOTAGE: 2638'/N & 1666'/W
BOTTOM HOLE FOOTAGE: 50'/S & 1980'/W

ZIA HILLS 19 FEDERAL COM 116H
LOCATION: Section 19, T.26 S., R.32 E., NMPM
SURFACE HOLE FOOTAGE: 2638'/N & 1699'/W
BOTTOM HOLE FOOTAGE: 50'/S & 2130'/W

ALL PREVIOUS COAs STILL APPLY.

A. CASING

Primary Casing Design:

1. The **13-3/8** inch surface casing shall be set at approximately _ feet (a minimum of **25 feet (Lea County)** 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.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:

Option 1 (Single Stage):

- Cement to surface. If cement does not circulate see B.1.a, c-d above. **Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.**

Option 2:

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.
  Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.

❖ In Medium Cave/Karst Areas if cement does not circulate to surface on the first two casing strings, the cement on the 3rd casing string must come to surface.

3. The minimum required fill of cement behind the **5-1/2** inch production casing is:

Option 1 (Single Stage):

- Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Option 2:

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 should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

B. 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.

Option 1:

a. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **10,000 (10M)** psi. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 5000 (5M) psi.**

Option 2:

1. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the surface casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **10,000 (10M)** psi. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 5000 (5M) psi.**

    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.

C. SPECIAL REQUIREMENT (S)

Communitization Agreement

- The operator will submit a Communitization Agreement to the Carlsbad Field Office, 620 E Greene St. Carlsbad, New Mexico 88220, at least 90 days before the anticipated date of first production from a well subject to a spacing order issued by the New Mexico Oil Conservation Division. The Communitization Agreement will include the signatures of all working interest owners in all Federal and Indian leases subject to the Communitization Agreement (i.e., operating rights owners and lessees of record), or certification that the operator has obtained the written signatures of all such owners and will make those signatures available to the BLM immediately upon request.
- If the operator does not comply with this condition of approval, the BLM may take enforcement actions that include, but are not limited to, those specified in 43 CFR 3163.1.
- In addition, the well sign shall include the surface and bottom hole lease numbers. When the Communitization Agreement number is known, it shall also be on the sign.

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)

☒ Chaves and Roosevelt Counties
Call the Roswell Field Office, 2909 West Second St., Roswell NM 88201.
During office hours call (575) 627-0272.
After office hours call (575)

☒ Eddy County
Call the Carlsbad Field Office, 620 East Greene St., Carlsbad, NM 88220, (575) 361-2822

☒ 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. <u>Wait on cement (WOC) for Potash Areas:</u> 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 <u>24 hours</u>. 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. <u>Wait on cement (WOC) for Water Basin:</u> 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 <u>8 hours</u>. 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: 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. Whenever any seal subject to test pressure is broken, all the tests in OOGO2.III.A.2.i must be followed.
    e. 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.

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 not a cup or J-packer. The operator also has the option of utilizing an independent tester to test without a plug (i.e. against the casing) pursuant to Onshore Order 2 with the pressure not to exceed 70% of the burst rating for the casing. Any test against the casing must meet the WOC time for water basin (8 hours) or potash (24 hours) or 500 pounds compressive strength, whichever is greater, prior to initiating the test (see casing segment as lead cement may be critical item).

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. The results of the test shall be reported to the appropriate BLM office.

f. 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.

g. 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 if test is done with a test plug and 30 minutes without a test plug. This test shall be performed prior to the test at full stack pressure.

h. 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.

NMK71819

ConocoPhillips Wild Well Control Plan

1. Drilling Well Control Plan

1.1 Well Control - CERTIFICATIONS

Required IADC/IWCF Well Control Certifications Supervisor Level:

Any personnel who supervises or operates the BOP must possess a valid current IADC training certification and photo identification. This would include the onsite drilling supervisor, tool pusher/rig manager, driller, and any personnel that will be acting in these capacities. Another example of this may be a wireline or snubbing crew rigged up on the rig to assist the rig, the operator of each system must also have a valid control certification for their level of operation.

BLM recognizes IADC training as the industry approved accredited training. Online self-certifications will not be acceptable. Enforcement actions for the lack of a valid Supervisory Level certificate shall be prompt action to correct the deficiency. **Enforcement actions include but are not limited to immediate replacement of personnel lacking certifications, drilling operations being shut down or installment of a 10M annular.**

IADC Driller Level for all Drillers and general knowledge for the Assistant Driller, Derrick Hands, Floor Hands and Motor Hands is recognized by the BLM; however, a Driller Level certification will need to be presented only if acting in a temporary Driller Level certification capacity.

Well Control-Position/Roles

IADC Well control training and certification is targeted toward each role, e.g., Supervisor Level toward those who direct, Driller Level to those who act, Introductory to those who need to know.

- **Supervisor Level**
  - Specifies and has oversight that the correct actions are carried out
  - Role is to supervise well control equipment, training, testing, and well control events
  - Directs the testing of BOP and other well control equipment
  - Regularly direct well control crew drills
  - Land based rigs – usually runs the choke during a well kill operation
  - Due to role on the rig, training and certification is targeted more toward management of well control and managing an influx out of the well

- **Driller Level**
  - Performs an action to prevent or respond to well control accident
  - Role is to monitor the well via electronic devices while drilling and detect unplanned influxes
  - Assist with the testing of BOP and other well control equipment
  - Regularly assist with well control crew drills
  - When influx is detected, responsible to close the BOP
  - Due to role on the rig, training and certification is targeted more toward monitoring and shutting the well in (closing the BOP) when an influx is detected

(Well Control-Positions/Roles Continued)

- **Derrick Hand, Assistant Driller Introductory Level**
  - Role is to assist Driller with kick detection by physically monitoring the well at the mixing pits/tanks
  - Regularly record mud weights/viscosity for analysis by the Supervisor level and mud engineer so pre-influx signs can be detected
  - Mix required kill fluids as directed by Supervisor or Driller
  - Due to role on the rig, training and certification is targeted more toward monitoring for influxes, either via mud samples or visual signs on the pits/tanks

- **Motorman, Floor Hand Introductory Level**
  - Role is to assist the Supervisor, Driller, or Derrick Hand with detecting influxes
  - Be certain all valves are aligned for proper well control as directed by Supervisor
  - Perform Supervisor or Driller assigned tasks during a well control event
  - Due to role on the rig, training and certification is targeted more toward monitoring for influxes

1.2 WELL CONTROL-COMPONENT AND PREVENTER COMPATIBILITY CHECKLIST

The table below, which covers the drilling and casing of the 10M Stack portion of the well, outlines the tubulars and the compatible preventers in use. This 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.

- **Example 8-3/4" Production hole section, 10M requirement**

Component	OD	Preventer	RWP
Drill pipe	5"	Fixed lower 5" Upper 4.5-7" VBR	10M
HWDP	5"	Fixed lower 5" Upper 4.5-7" VBR	10M
Drill collars and MWD tools	6.25-6.75"	Upper 4.5-7" VBR	10M
Mud Motor	6.75"	Upper 4.5-7" VBR	10M
Production casing	5.5"	Upper 4.5-7" VBR	10M
ALL	0-13-5/8"	Annular	5M
Open-hole	-	Blind Rams	10M

- VBR = Variable Bore Ram. Compatible range listed in chart.

1.3 WELL CONTROL-BOP TESTING

BOP Test will be completed per Onshore Oil and Gas Order #2 Well Control requirements. The 5M Annular Preventer on a required 10M BOP stack will be tested to 70 % of rated working pressure including a 10 minute low pressure test. Pressure shall be maintained at least 10 minutes.

1.4 WELL CONTROL - DRILLS

The following drills are conducted and recorded in the Daily Drilling Report and the Contractor's reporting system while engaged in drilling operations:

Type	Frequency	Objective	Comments
Shallow gas kick drill - drilling	Once per well with crew on tour	Response training to a shallow gas influx	To be done prior to drilling surface hole if shallow gas is noted
Kick drill - drilling	Once per week per crew	Response training to an influx while drilling (bit on bottom)	Only one kick drill per week per crew is required, alternating between drilling and tripping.
Kick drill - tripping	Once per week per crew	Response training to an influx while tripping (bit off bottom). Practice stabbing TIW valve	
Choke drill	Once per well with crew on tour	Practice in operating the remotely operated choke with pressure in the well	Before drilling out of the last casing set above a prospective reservoir Include the scenario of flowing well with gas on drill floor as a table top
H_2S drill	Prior to drilling into a potential H_2S zone/reservoir	Practice in use of respiratory equipment	

1.5 WELL CONTROL – MONITORING

- Drilling operations which utilize static fluid levels in the wellbore as the active barrier element, a means of accurately monitoring fill-up and displacement volumes during trips are available to the driller and operator. A recirculating trip tank is installed and equipped with a volume indicator easily read from the driller's / operator's position. This data is recorded on a calibrated chart recorder or digitally. The actual volumes are compared to the calculated volumes.
- The On-Site Supervisor ensures hole-filling and pit monitoring procedures are established and documented for every rig operation.
- The well is kept full of fluid with a known density and monitored at all times even when out of the hole.
- Flow checks are a minimum of 15 minutes.
- A flow check is made:
  - In the event of a drilling break.
  - After indications of down hole gains or losses.
  - Prior to all trips out of the hole.
  - After pulling into the casing shoe.
  - Before the BHA enters the BOP stack.
  - If trip displacement is incorrect.

Well Control-Monitoring (Continued)

  - Prior to dropping a survey instrument.
  - Prior to dropping a core ball.
  - After a well kill operation.
  - When the mud density is reduced in the well.
- Flow checks may be made at any time at the sole discretion of the driller or his designate. The Onsite Supervisor ensures that personnel are aware of this authority and the authority to close the well in immediately without further consultation.
- Record slow circulating rates (SCR) after each crew change, bit trip, and 500' of new hole drilled and after any variance greater than 0.2 ppg in MW. Slow pump rate recordings should include return flow percent, TVD, MD & pressure. SCR's will be done on all pumps at 30, 40 & 50 SPM. Pressures will be recorded at the choke panel. SCR will be recorded in the IADC daily report and MRO Wellview daily report
- Drilling blind (i.e. without returns) is permissible only in known lithology where the absence of hydrocarbons has been predetermined and written approval of the Drilling Manager.
- All open hole logs to be run with pack-off, lubricator or Drilling Manager approved alternative means.
- The Drilling Contractor has a fully working pit level totalizer / monitoring system with read out for the driller and an audible alarm set to 10 BBL gain / loss volume. Systems are selectable to enable monitoring of all pits in use. Pit volumes are monitored at all times, especially when transferring fluids. Both systems data is recorded on a calibrated chart recorder or electronically.
- The Drilling Contractor has a fully working return mud flow indicator with drillers display and an audible alarm, and is adjustable to record any variance in return volumes.

1.6 WELL CONTROL – SHUT IN

- The "hard shut in" method (i.e. against a closed choke using either an annular or ram type preventer) is the Company standard.
- The HCR(s) or failsafe valves are left closed during drilling to prevent any erosion and buildup of solids. The adjustable choke should also be left closed.
- The rig specific shut in procedure, the BOP configuration along with space-out position for the tool joints is posted in the Driller's control cabin or doghouse.
- No well kill operation commences until there is a plan agreed by the Superintendent, On-Site Supervisor and the Drilling Manager.
- During a well kill by circulation, constant bottom hole pressure is maintained throughout.
- Kill sheets are maintained by the Driller and posted in the Driller's control cabin or doghouse. The sheet is updated at a minimum every 500 feet.

2. Shut-in Procedures:

2.1 Procedure While Drilling

- Sound alarm (alert crew)
- Space out drill string – Stop rotating, pick the drill string up off bottom, and space out to ensure no tool joint is located in the BOP element selected for initial closure.
- Shut down pumps (stop pumps and observe well.)
- Shut-in Well - If flow is suspected or confirmed, close uppermost applicable BOP element. (HCR and choke will already be in the closed position.)
    - **Note:** Either the uppermost pipe ram or annular preventer can be used.
- Confirm shut-in
- Notify toolpusher/company representative
- Gather all relevant data required:
    - SIDPP and SICP
    - Hole Depth and Hole TVD
    - Pit gain
    - Time
    - Kick Volume
    - Pipe depth
    - MW in, MW out
    - SPR's (Slow Pump Rate's)
- Regroup and identify forward plan (let well stabilize, update kill sheet, inventory mud additives and mud volumes on location)
- Company Representative, Drilling Superintendent, Drilling Engineer and Drilling Manager will discuss well control kill method to be utilized. A verbal Risk Assessment and preferred kill method will be finalized. Initial Risk Assessment will be finalized within 1 hour of initial shut in.
- <u>No well kill operation commences until there is a plan agreed by the Superintendent, On-Site Supervisor and the Drilling Contractor PIC</u>.
- Recheck all pressures and fluid volume on accumulator unit
- If pressure has built or is anticipated during the kill to reach 2,500 psi or greater, the annular preventer CANNOT be used as per Oil Company Well Control Policy, swap to the upper BOP pipe ram.

2.2 Procedure While Tripping

- Sound alarm (alert crew)
- Stab full opening safety valve in the drill string and close.
- Space out drill string (ensure no tool joint is located in the BOP element selected for initial closure).
- Shut down pumps (stop pumps and observe well.)
- Shut-in Well - If flow is suspected or confirmed, close uppermost applicable BOP element. (HCR and choke will already be in the closed position.)
    - **Note:** Either the uppermost pipe ram or annular preventer can be used.
- Confirm shut-in
- Notify tool pusher/company representative
- Gather all relevant data required:
    - SIDPP and SICP
    - Hole Depth and Hole TVD
    - Pit gain

Procedure While Tripping (Continued)

  - Time
  - Kick Volume
  - Pipe depth
  - MW in, MW out
  - SPR's (Slow Pump Rate's)
- Regroup and identify forward plan (let well stabilize, update kill sheet, inventory mud additives and mud volumes on location)
- Company Representative, Drilling Superintendent, Drilling Engineer and Drilling Manager will discuss well control kill method to be utilized. A verbal Risk Assessment and preferred kill method will be finalized. Initial Risk Assessment will be finalized within 1 hour of initial shut in.
- <u>No well kill operation commences until there is a plan agreed by the Superintendent, On-Site Supervisor and the Drilling Contractor PIC.</u>
- Recheck all pressures and fluid volume on accumulator unit
  If pressure has built or is anticipated during the kill to reach X,XXX psi or greater, the annular preventer CANNOT be used as per Company Well Control Policy, swap to the upper BOP pipe ram.

2.3 PROCEDURE WHILE RUNNING CASING

- Sound alarm (alert crew)
- Stab crossover and full opening safety valve and close
- Space out casing (ensure no coupling is located in the BOP element selected for initial closure).
- Shut down pumps (stop pumps and observe well.)
- Shut-in Well - If flow is suspected or confirmed, close uppermost applicable BOP element. (HCR and choke will already be in the closed position.)
  - **Note:** Either the uppermost pipe ram or annular preventer can be used.
- Confirm shut-in
- Notify tool pusher/company representative
- Gather all relevant data required:
  - SIDPP and SICP
  - Hole Depth and Hole TVD
  - Pit gain
  - Time
  - Kick Volume
  - Pipe depth
  - MW in, MW out
  - SPR's (Slow Pump Rate's)
- Regroup and identify forward plan (let well stabilize, update kill sheet, inventory mud additives and mud volumes on location)
- Company Representative, Drilling Superintendent, Drilling Engineer and Drilling Manager will discuss well control kill method to be utilized. A verbal Risk Assessment and preferred kill method will be finalized. Initial Risk Assessment will be finalized within 1 hour of initial shut in.
- <u>No well kill operation commences until there is a plan agreed by the Superintendent, On-Site Supervisor and the Drilling Contractor PIC.</u>
- Recheck all pressures and fluid volume on accumulator unit
  If pressure has built or is anticipated during the kill to reach 2,500 psi or greater, the annular preventer CANNOT be used, swap to the upper BOP pipe ram.

2.4 Procedure With No Pipe in Hole (Open Hole)

- Sound alarm (alert crew)
- Shut-in with blind rams or BSR. (HCR and choke will already be in the closed position.)
- Confirm shut-in
- Notify toolpusher/company representative
- Gather all relevant data required:
  - Shut-In Pressure
  - Hole Depth and Hole TVD
  - Pit gain
  - Time
  - Kick Volume
  - MW in, MW out
  - SPR's (Slow Pump Rate's)
- Regroup and identify forward plan (let well stabilize, update kill sheet, inventory mud additives and mud volumes on location)
- Company Representative, Drilling Superintendent, Drilling Engineer and Drilling Manager will discuss well control kill method to be utilized. A verbal Risk Assessment and preferred kill method will be finalized. Initial Risk Assessment will be finalized within 1 hour of initial shut in.
- <u>No well kill operation commences until there is a plan agreed by the Superintendent, On-Site Supervisor and the Drilling Contractor PIC</u>.
- Recheck all pressures and fluid volume on accumulator unit.

2.5 Procedure While Pulling BHA thru Stack

- PRIOR to pulling last joint of drill pipe thru the stack.
- Perform flow check, if flowing.
- Sound alarm (alert crew).
- Stab full opening safety valve and close
- Space out drill string with tool joint just beneath the upper pipe ram.
- Shut-in using upper pipe ram. (HCR and choke will already be in the closed position).
- Confirm shut-in.
- Notify toolpusher/company representative
- Read and record the following:
  - SIDPP and SICP
  - Pit gain
  - Time
- Regroup and identify forward plan

- **With BHA in the stack and compatible ram preventer and pipe combo immediately available.**
  - Sound alarm (alert crew)
  - Stab crossover and full opening safety valve and close
  - Space out drill string with upset just beneath the compatible pipe ram.
  - Shut-in using compatible pipe ram. (HCR and choke will already be in the closed position.)
  - Confirm shut-in
  - Notify toolpusher/company representative
  - Read and record the following:
    - SIDPP and SICP
    - Pit gain

Procedures While Pulling BHA thru Stack (Continued)

    - Time
- Regroup and identify forward plan

- **With BHA in the stack and <u>NO</u> compatible ram preventer and pipe combo immediately available.**
    - Sound alarm (alert crew)
    - If possible to pick up high enough, pull string clear of the stack and follow "Open Hole" scenario.
    - If impossible to pick up high enough to pull the string clear of the stack:
    - Stab crossover, make up one joint/stand of drill pipe, and full opening safety valve and close
    - Space out drill string with tool joint just beneath the upper pipe ram.
    - Shut-in using upper pipe ram. (HCR and choke will already be in the closed position.)
    - Confirm shut-in
    - Notify toolpusher/company representative
    - Read and record the following:
        - SIDPP and SICP
        - Pit gain
        - Time

Zia Hills 19 116H **Sec 19 T26S R32E** **Lea, Co, NM** **7/2/2019**

SURFACE CASING DESIGN INFORMATION

Setting Depth: 1,169' MD 1,169' TVD

PIPE BODY DIMENSIONAL / PERFORMANCE DATA:

SIZE (Inches)	WEIGHT (LB/FT)	GRADE	CPLG TYPE	BORE ID (Inches)	DRIFT ID (Inches)	COLLAPSE (PSI) API / CoP	BURST (PSI) API / CoP	TENSION (1k LBS) API / CoP
13.375	54.5	J-55	BTC	12.612	12.459	1,130 / 960	2,730 / 2,320	909 / 772

CONNECTION DIMENSIONAL / PERFORMANCE DATA:

OD (Inches)	ID (Inches)	DRIFT (Inches)	CPLG TYPE	COLLAPSE (PSI) API / CoP	BURST (PSI) API / CoP	TENSION (1k LBS) API / CoP
14.375	12.612	12.459	BTC	1,130 / 960	2,730 / 2,320	909 / 772

Surface Casing Test Pressure = 1,500 psi

Pressure Test Prior to Drill Out

Minimum Design / Safety Factors COP

Burst	Collapse	Tension (Body &
1.15	1.05	1.40

Actual Design / Safety Factors

Burst	Collapse	Tension (Body)	
5.22	3.23	14.27	Dry
		16.42	Bouyed

INTERMEDIATE CASING DESIGN INFORMATION

Setting Depth: 12,174' MD 11,619' TVD

PIPE BODY DIMENSIONAL / PERFORMANCE DATA:

SIZE (Inches)	WEIGHT (LB/FT)	GRADE	CPLG TYPE	BORE ID (Inches)	DRIFT ID (Inches)	COLLAPSE (PSI) API / CoP	BURST (PSI) API / CoP	TENSION (1k LBS) API / CoP
9.625	40.0	L80-IC	BTC	8.835	8.75	3,870 / 3,685	5,750 / 5000	916 / 654

CONNECTION DIMENSIONAL / PERFORMANCE DATA:

OD (Inches)	ID (Inches)	DRIFT (Inches)	CPLG TYPE	COLLAPSE (PSI) API / CoP	BURST (PSI) API / CoP	TENSION (1k LBS) API / CoP
10.625	8.835	8.75	BTC	3,870 / 3,685	5,750 / 5000	947 / 676

Production Casing Test Pressure = TBD

Minimum Design / Safety Factors

Burst	Collapse	Tension (Body & Connection)
1.15	1.05	1.40

Actual Design / Safety Factors

Burst	Collapse	Tension (Body)	
1.68	2.54	1.90	Dry
		2.22	Bouyed

PRODUCTION CASING DESIGN INFORMATION

Setting Depth: 21,435' MD 11,619' TVD

PIPE BODY DIMENSIONAL / PERFORMANCE DATA:

SIZE (Inches)	WEIGHT (LB/FT)	GRADE	CPLG TYPE	BORE ID (Inches)	DRIFT ID (Inches)	COLLAPSE (PSI) API / CoP	BURST (PSI) API / CoP	TENSION (1k LBS) API / CoP
5.5	20	P-110 ICY	TXP	4.778	4.653	12,100 / 11,524	14,360 / 12,487	729 / 521

CONNECTION DIMENSIONAL / PERFORMANCE DATA:

OD (Inches)	ID (Inches)	DRIFT (Inches)	CPLG TYPE	COLLAPSE (PSI) API / CoP	BURST (PSI) API / CoP	TENSION (1k LBS) API / CoP
6.1	4.766	4.653	TXP	12,100 / 11,524	14,360 / 12,487	729 / 521

Production Casing Test Pressure = TBD

Minimum Design / Safety Factors

Burst	Collapse	Tension (Body & Connection)
1.15	1.05	1.40

Actual Design / Safety Factors

Burst	Collapse	Tension (Body)	
2.46	3.86	3.14	Dry
		3.95	Bouyed

Zia Hills 19 116H
Sec 19 T26S R32E

13-3/8" Surface Casing:

Surface Casing Depth (Ft)	1,169
Surface Casing O.D. (In.)	13 3/8
Surface Casing ID (In)	12.612
Hole O.D. (In)	17 1/2
Excess (%)	200%
Volume Tail (Sx)	[redacted]
Yield Tail (Cu. Ft./Sx)	1.33
Yield Lead (Cu. Ft./Sx)	1.73
Shoe Joint (Ft)	40
Shoe Volume (Cu. Ft)	34.7
Tail feet of cement	400
Calculated Total Volume (Cu. Ft.)	2,471
Calc. Tail Volume (Cu. Ft.)	868
Calc. Lead Volume (Cu. Ft.)	1,603
Calc. Lead Volume (Sx)	[redacted]
Lead Volume (bbls)	285.4
Tail volume (bbls)	154.6
Displacement Volume (bbls)	174.5

Lead Cement Description:
Mix Weight 12.8 ppg
Control Set 'C'
1.0% $CaCl_2$
1.0% SMS
1.0% OGC-60
¼ lb/sk Polyflake
½ ppb FiberBlock

Tail Cement Description:
Mix Weight 14.8 ppg
0:1:0 'Type III'
0.5% $CaCl_2$
¼ lb/sk Polyflake
½ ppb FiberBlock

Stage 1
9-5/8" Intermediate Casing (Lead):

Production Casing O.D. (In.)	9.625
Production Casing ID (In)	8.835
Hole O.D. (In)	12.25
Excess (%)	70%
DV Tool Depth	5,169'
Yield Lead (Cu. Ft./Sx)	2.7
Calculated Total Lead (Cu. Ft.)	2,811
Calc. Lead Volume (Sx)	[redacted]
Lead Volume (bbls)	[redacted]

Intermediate Lead Cement Description:
Mix Weight 11 ppg
WBL
0.5% CFL-4
0.6% LTR
0.2% SPC-II
0.4% CDF-4P
¼ lb/sk Polyflake
½ ppb FiberBlock

9-5/8" Intermediate Casing (Tail):

Production Casing Depth (Ft)	12,174'
Production Casing O.D. (In.)	9.625
Production Casing ID (In)	8.835
Hole O.D. (In)	12.25
Excess (%)	30%
KOP	10,949'
Top Tail (Ft) - 1000' above KOP	10,449'
Yield Tail (Cu. Ft./Sx)	1.59
Shoe Joint (Ft)	90
Shoe Volume (Cu. Ft)	38.3
Calc. Tail Volume (Cu. Ft.)	741
Required Tail Volume (Sx)	[redacted]
Tail Volume (bbls)	[redacted]
Displacement Volume (bbls)	[redacted]

Intermediate Tail Cement Description:
Mix Weight 13.2 ppg
Thermal 35
10% NaCl
0.9% CFR
0.7% CFL-4
0.1% LTR
0.2% SPC-II
0.4% CDF-4P
¼ lb/sk Polyflake
½ ppb FiberBlock

Stage 2
9-5/8" Intermediate Casing (Tail):

Surface Casing Depth (ft)	1,169'
Surface Casing I.D. (In)	12.612
DV Tool Depth (Ft)	5,169'
Production Casing O.D. (In.)	9.625
Production Casing ID (In)	8.835
Hole O.D. (In)	12.25
Excess (%)	200%
Top Cement (Surface)	31'
Yield Tail (Cu. Ft./Sx)	1.73
Calc. Tail Volume (Cu. Ft.)	4,161
Required Tail Volume (Sx)	[redacted]
Tail Volume (bbls)	[redacted]
Displacement Volume (bbls)	

Intermediate Tail Cement Description:
Mix Weight ppg
Thermal 35
10% NaCl
0.9% CFR
0.7% CFL-4
0.1% LTR
0.2% SPC-II
0.4% CDF-4P
¼ lb/sk Polyflake
½ ppb FiberBlock

8-1/2" Production Liner (Tail):

Intermediate Casing Depth (Ft)	12,174'
Intermediate Casing O.D. (In.)	9.625
Intermediate Casing ID (In)	8.835
Production CasingTop Depth (Ft)	9,949'
Production Casing Depth (Ft)	21,435'
Production Casing O.D. (In.)	5.500
Production Casing ID (In)	4.778
Hole O.D. (In)	8.50
Excess (%)	10%
Yield Tail (Cu. Ft./Sx)	1.19
Shoe Joint (Ft)	12
Shoe Volume (Cu. Ft)	1.5
Calc. Tail Volume (Cu. Ft.)	2,914
Required Tail Volume (Sx)	[redacted]
	519.050744

Production Liner Tail Cement Description:
Mix Weight 15.6 ppg
1:1:0 'Poz:Lafarge G'
20% Silica Flour
8% Silica Flume
2% FWCA-H (FWC-2)
0.3% HTR
0.5% CR-4 (MCR-4)
1% TAE-1 (SEA-1)
1% CFL-4
0.2% CFR-5
0.3% ASM-3 (AS-3)

Production Displacement

Volume to Latch down collar +/- .15 BBLS (half shoe track)			
Component	Capacity	Length	Volume
Drill Pipe	.0108 bbl/ft	0	0
Liner (Liner top to Float Collar)	.01493bbl/ft	0	0
Total	.		0

ConocoPhillips

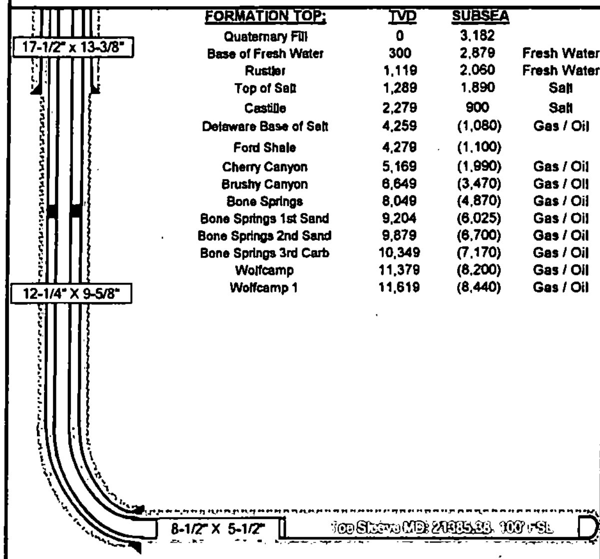
WELL PLAN SUMMARY
1280 Extended Reach Single Lateral

Date: Jul 02, 2019
Version: 1
Prepared by: M. Callahan

WELL: Zia Hills 19 116H
SURFACE LOC: Sec 19 T26S R32E 2638' FNL 1699' FWL
BH LOC: Sec 31 T26S R32E 50' FSL 2310' FWL
ELEVATIONS: GL 3,182.4' KB +30.5'

COUNTY,STATE: Lea, Co, NM
API No.:
TRRC Permit:
BLM Permit:
WH Coord.: (NAD-27) LAT 32° 1' 41.36" N; LON 103° 43' 1.52" W

AFE: WAF.OND.
Drilling Network No.:
Invoice Handler ID: VENNECP
COST ESTIMATE
DRILLING
COMPLETION
FACILITIES
TOTAL



FORMATION TOP:	TVD	SUBSEA	
Quaternary Fill	0	3,182	
Base of Fresh Water	300	2,879	Fresh Water
Rustler	1,119	2,060	Fresh Water
Top of Salt	1,289	1,890	Salt
Castile	2,279	900	Salt
Delaware Base of Salt	4,259	(1,080)	Gas / Oil
Ford Shale	4,279	(1,100)	
Cherry Canyon	5,169	(1,990)	Gas / Oil
Brushy Canyon	6,649	(3,470)	Gas / Oil
Bone Springs	8,049	(4,870)	Gas / Oil
Bone Springs 1st Sand	9,204	(6,025)	Gas / Oil
Bone Springs 2nd Sand	9,879	(6,700)	Gas / Oil
Bone Springs 3rd Carb	10,349	(7,170)	Gas / Oil
Wolfcamp	11,379	(8,200)	Gas / Oil
Wolfcamp 1	11,619	(8,440)	Gas / Oil

Objective
This well is to be drilled with safety and protection of the environment as the primary objectives.

The objective is to drill a 1280 single lateral well in the Wolfcamp formation and completed with 5-1/2"cemented casing.

Notes
1.) Refer to drilling procedure for additional detail and information.
2.) The primary regulatory agency is the BLM.
3.) Surface: 2° max., 1°/ 100' DLS: svy every 500'
4.) Int: 90° max., 8 / 100'; svy every 90' (svy every 30' in build and drop, 30' in curve)
5.) Losses to be expected in Cherry and Brushy Canyon formations. Overpressure may be encountered throughout Delaware.

Goals
Have no lost time or recordable accidents.
Have no spills or adverse environmental impact.
Have no stuck pipe incidents.
Avoid lost circulation incidents.
Maintain well control and follow ConocoPhillips well control policy.
Obtain good mud log data.
Deliver usable wellbore to production department.

9 5/8 in. shoe 12173.85'
MD 3434.24'FNL

TARGET	21,435	11,619	Gas / Oil
Formation Dip Rate:	est 90.1° (up dip)		
PBTD	21,435	11,619	Gas / Oil

Estimated BH Static Temperature (°F): 185
Max. Anticipated BH Pressure: 0.700 psi/ft 8,133 psi 13.5 ppg
Max Anticipated Surface Pressure: 1,145 psi

CONTACTS

	Name	Office	Cell
Drilling Engineer:	Mike Callahan	832-486-2480	907-231-2176
Geologist:	Josh Day	281-206-5620	423-512-0347
Onsite Drilling Rep.:	Greg Rivera	432-309-9007	
	Manny Castillo		
Field Drilling Supt.:	James Taylor	830-583-4828	956-229-1393
	Patrick Wellman		432-215-7079
Drilling Supt.:	Troy McGinn	832-486-2575	346-242-4551

DRILLING FLUID:

	Type	Interval (MD)	Density ppg	Vis sec/qt	PV cP	YP #/100ft2	pH	FL mL	LGS % by vol	NaCl ppb sol	Remarks
Surface:	Fresh Water	Surface - 1,169'	8.6	28-50	1-5	2-6	7.5-8.5	NC	< 5.0	10,000	Rig Tanks
Intermediate 1:	Emulsified Brine	1169' - 12174'	9.5	28-50	1-5	2-6	7.5-8.5	NC	< 5.0	180,000	Rig Tanks
Production:	OBM	12174' - 21435'	13.5	50-70	18-25	8-14	9.5-10	< 8	< 8.0	400 - 00	Rig Tanks

Reference Drilling Fluids Program

CASING:

	Hole	TOP (MD)	BTM (MD)	Length	Size	Wt	Grade	Connection
Surface:	17-1/2"	31'	1,169'	1,139'	13 3/8	54.50	J-55	BTC
	ACP/DV Tool run 100' below water board depth if necessary							
Intermediate	12-1/4"	31'	12,174'	12,143'	9 5/8	40.00	L80-IC	BTC
Production:	8-1/2"	31'	21,435'	21,405'	5 1/2	20.00	P-110 ICY	TXP

BOP:
Minimum - COP Class 3 Well Control Requirements
Rig - 13-5/8"x10M psi Rams / 4-1/16"x10M psi Manifold
Stackup - Rotating Head, Annular Preventer, Pipe Ram, Blind Ram, Mud Cross (Choke & Kill Valves), Pipe Ram
Waste Handling: Closed loop cuttings disposal system with haul off to approved facility.
Mud Pit: Float Based Electronic PVT with Flow Sensor and Gravity Trip Tank, Alarms +/- 10 BBLS
Wellhead: 13-5/8" x 10M psi (Casing Head - "A" Section)

CENTRALIZATION:
Surface Casing: 1 per 4 joints.
Intermediate Casing: Shoe joint. 1 per joint from FC to 7,800'. 1 per 2 joints 7,800' to 2,300'. 1 per 4 joints 2,300' to surface.
Production Liner: Rigid body 1 per 2 joints TD to Int Shoe. Bow Spring 1 per 2 joints Int shoe to 100' above KOP. 1 per 4 joints to surface

CEMENT:

	Hole	MD	TVD	Spacer	Lead	Tail	COMMENTS
Surface:	17-1/2"X13-3/8"	1,169'	1,169'	20 bbl FW	930 sx Control Set 'C' + adds 11.5ppg 2.66 ft3/sk	660 sx Type 'III' + adds 13ppg 1.34 ft3/sk	Cemented to surface w/ 200%XS Add FiberBlock
Intermediate:	12-1/4"X9-5/8"	12,174'	11,619	40 bbl Invert Spacer + 100 bbl SW	1050 sx WBL + adds 11.5ppg 1.77 ft3/sk	470 sx Thermal 35 + adds 15ppg 1.63 ft3/sk	TOC 500' into previous casing shoe w/ 70%L / 30%T XS calc'd on 12.25" Add FiberBlock
Production:	8-1/2"X5-1/2"	21,435'	11,619'	40 bbl Visweep	2449 sx 1:1:0 'Poz:Lafarge G' + 20% Silica Flour + 8% Silica Fume + adds 15.6 ppg 1.19ft3/sk		Cemented to TOL w/ 10% XS calc'd on 8.5" hole, Displ. = volume to float collar +/- half shoe track

Reference Cementing Recommendation

DIRECTIONAL PLAN:

Comments	MD (ft)	INC (deg)	AZI (deg)	TVD (ft)	NS (ft)	EW (ft)	DLS (°/100')	VS (ft)	SEC-T-R	Section Line Distance	
Build @ 1.5°/100'	4,000'	0	0	4,000'	0	0	0	0	Sec 19 T26S R32E	2638' FNL	1699' FWL
End Build @ 9°	4,599'	9	97	4,597'	-6	47	1.5	9	Sec 19 T26S R32E	2644' FNL	1746' FWL
Drop @ 1.5°/100'	7,947'	9	97	7,903'	-74	565	0.0	113	Sec 19 T26S R32E	2712' FNL	2264' FWL
Complete Drop, Hold to KOP	8,546'	0	0	8,500'	-80	612	1.5	123	Sec 19 T26S R32E	2718' FNL	2311' FWL
KOP Build @ 8°/100'	10,949'	0	0	10,903'	-80	612	0	123	Sec 19 T26S R32E	2718' FNL	2311' FWL
Curve LP	12,074'	90	179	11,619'	-796	619	8	838	Sec 19 T26S R32E	3434' FNL	2318' FWL
Toe Sleeve 2	21,335'	90	0	11,619'	-10057	715	0	10,082	Sec 31 T26S R32E	150' FSL	2310' FWL
Toe Sleeve 1	21,385'	90	0	11,619'	-10107	715	0	10,132	Sec 31 T26S R32E	100' FSL	2310' FWL
PBHL/TD	21,435'	90	179	11,619'	-10157	715	0	10,182	Sec 31 T26S R32E	50' FSL	2310' FWL

Reference Directional Plan MWD Surveys will be taken at 90' interval below surface casing, 30' while building curve, and every 90' while drilling lateral.

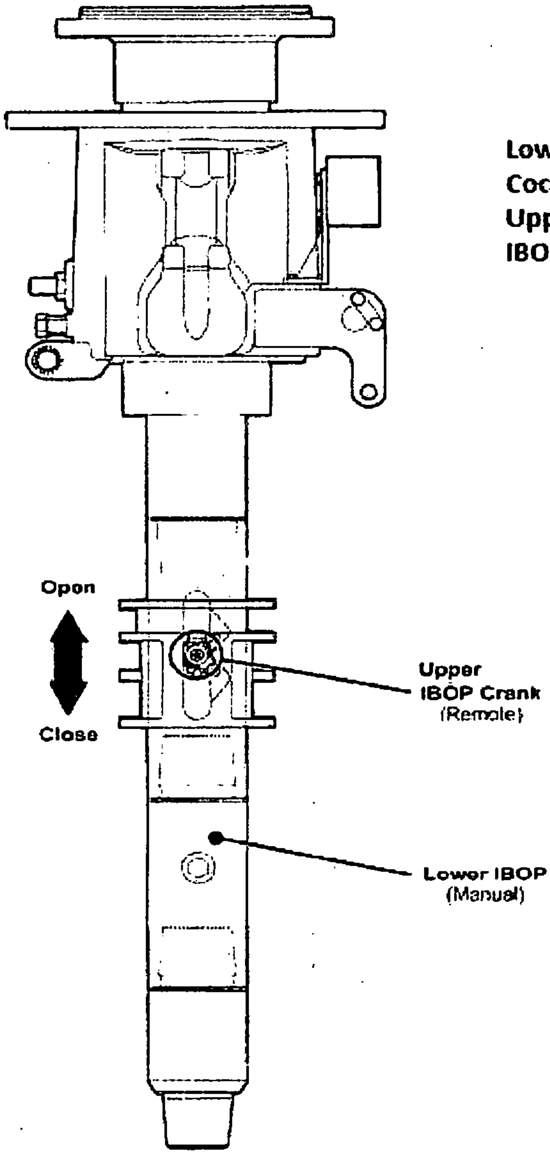
FORMATION EVALUATION:

Mud Logging -	One-Man:	First surface hole to TD, First intermediate hole to TD
Mud Logging -	Two-Man:	Intermediate Casing Point to TD
Open Hole -	PEX	None
Cased Hole -	GR/CBL/USIT	NA
MWD -	GR	200' above KOP to TD

Correlation Well:

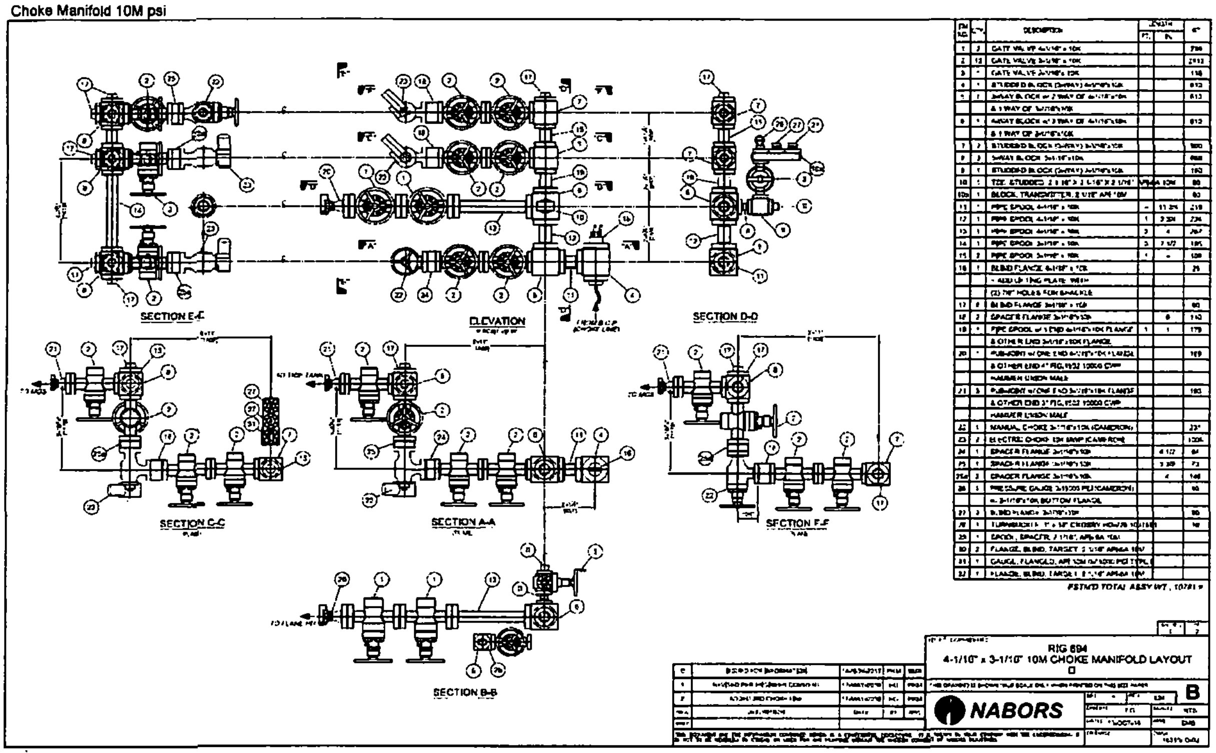
OUR WORK IS NEVER SO URGENT OR IMPORTANT THAT WE CANNOT TAKE THE TIME TO DO IT SAFELY!

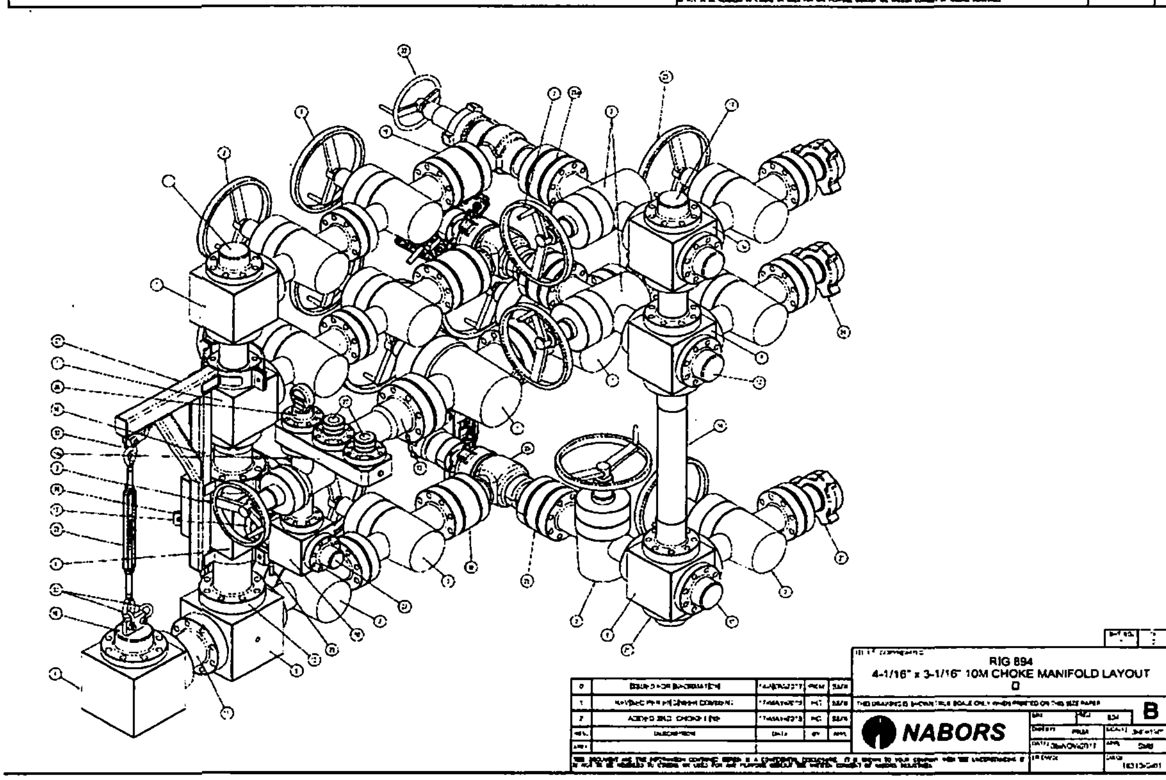
the IBOP valves



Lower Kelly Cock and Upper Kelly Cock function are performed by Upper IBOP (inside BOP) and Lower IBOP in Top Drive

Choke Manifold 10M psi





BOPE Configuration & Specifications
13-5/8" x 10,000 psi System