OCD Hobbs

ATS-13-825

Form 3160-3
(March 2012)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

FORM APPROVED
OMB No. 1004-0137
Expires October 31, 2014

5. Lease Serial No.
MN LC 057210

6. If Indian, Allotee or Tribe Name
N/A

7 If Unit or CA Agreement, Name and No.
101615

1a. Type of work:	☑ DRILL	☐ REENTER

8. Lease Name and Well No. ⟨3,422⟩
MCA UNIT #514

1b. Type of Well:	☑ Oil Well ☐ Gas Well ☐ Other	☑ Single Zone ☐ Multiple Zone

2. Name of Operator ConocoPhillips Company ⟨217817⟩

9. API Well No.
30-025- 41400

3a. Address P.O. Box 51810
Midland, TX 79710-1810

3b. Phone No. (include area code)
432-688-6913

10. Field and Pool, or Exploratory ⟨43329⟩
Maljamar; Grayburg/San Andres

4. Location of Well (Report location clearly and in accordance with any State requirements.*)

At surface 810' FSL & 1300' FEL; UL P, Section 27, T17S, R32E

At proposed prod. zone 810' FSL & 1300' FEL; UL P, Section 27, T17S, R32E

11. Sec., T. R. M. or Blk. and Survey or Area
Section 27, T17S, R32E

14. Distance in miles and direction from nearest town or post office*
Approx. 4.5 miles SE from Maljamar, NM

12. County or Parish	13. State
LEA	NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any)	810' FSL	16. No. of acres in lease 1200	17. Spacing Unit dedicated to this well 40

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft.	487' (MCA 185)	19. Proposed Depth 4550' TVD	20. BLM/BIA Bond No. on file ES0085

21. Elevations (Show whether DF, KDB, RT, GL, etc.) 3961' GL	22. Approximate date work will start* 10/06/2013	23. Estimated duration 10 Days

24. Attachments

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No.1, must be attached to this form:

1. Well plat certified by a registered surveyor.
2. A Drilling Plan.
3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO must be filed with the appropriate Forest Service Office).

4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification
6. Such other site specific information and/or plans as may be required by the BLM.

25. Signature Susan B. Maunder	Name (Printed/Typed) Susan B. Maunder	Date 5/21/13

Title
Senior Regulatory Specialist

Approved by (Signature) /s/George MacDonell	Name (Printed/Typed)	Date SEP - 4 2013

Title FIELD MANAGER	Office CARLSBAD FIELD OFFICE

Application approval 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.
Conditions of approval, if any, are attached.

APPROVAL FOR TWO YEARS

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)

09/10/13 Roswell Controlled Water Basin

SEE ATTACHED FOR
CONDITIONS OF APPROVAL

Approval Subject to General Requirements
& Special Stipulations Attached

SEP 1 2 2013

Drilling Plan
ConocoPhillips Company
Maljamar; Grayburg-San Andres

MCA Unit #514

Lea County, New Mexico

1. Estimated tops of geological markers and estimated depths to water, oil, or gas formations:

The datum for these depths is RKB (which is 13' above Ground Level).

Formations	Top Depth FT TVD	Contents
Quaternary	Surface	Fresh Water
Rustler	1000	Anhydrite
Salado (top of salt)	1183	Salt
Tansill	2222	Gas, Oil and Water
Yates	2373	Gas, Oil and Water
Seven Rivers	2739	Gas, Oil and Water
Queen	3376	Gas, Oil and Water
Grayburg	3769	Gas, Oil and Water
Grayburg-6	4032	Gas, Oil and Water
San Andres-7	4189	Gas, Oil and Water
San Andres-9	4350	Gas, Oil and Water
Total Depth	4550	200' below deepest estimated perforation

All of the water bearing formations identified above will be protected by setting of the ___8-5/8"___ surface casing ___25' – 70' into the Rustler formation___ and circulating of cement from casing shoe to surface in accordance with the provisions of Onshore Oil and Gas Order No. 2 and New Mexico Oil Conservation Division Title 19.

The targeted oil and gas bearing formations identified above will be protected by setting of the ___5-1/2"___ production casing ___10' off bottom of TD___ and circulating of cement from casing shoe to surface in accordance with the provisions of Onshore Oil and Gas Order No. 2 and New Mexico Oil Conservation Division Title 19.

2. Proposed casing program:

Type	Hole Size (in)	Interval MD RKB (ft) From	Interval MD RKB (ft) To	OD (inches)	Wt (lb/ft)	Gr	Conn	MIY (psi)	Col (psi)	Jt Str (klbs)	Safety Factors Calculated per ConocoPhillips Corporate Criteria Burst DF	Collapse DF	Jt Str DF (Tension) Dry/Buoyant
Cond	20	0	40' – 85' (30' – 75' BGL)	16	0.5" wall	B	Line Pipe	N/A	N/A	N/A	NA	NA	NA
Alt. Cond	20	0	40' – 85' (30' – 75' BGL)	13-3/8	48#	H-40	PE	1730	740	N/A	NA	NA	NA
Surf	12-1/4	0	1025' – 1070'	8-5/8	24#	J-55	STC	2950	1370	244	1.50	4.40	3.37
Prod	7-7/8	0	4495' – 4540'	5-1/2	17#	J-55	LTC	5320	4910	247	2.25	3.16	2.14

The casing will be suitable for H$_2$S Service. All casing will be new.

The surface and production casing will be set approximately 10' off bottom and we will drill the hole with a 45' range uncertainty for casing set depth to fit the casing string so that the cementing head is positioned at the floor for the cement job.

The production casing will be set 155' to 200' below the deepest estimated perforation to provide rathole for the pumping completion and for the logs to get deep enough to log the interval of interest.

Casing Safety Factors - BLM Criteria:

Type	Depth	Wt	MIY	Col	Jt Str	Drill Fluid	Burst	Collapse	Tensile-Dry	Tens-Bouy
Surface Casing	1070	24	2950	1370	244000	8.5	6.24	2.90	9.5	10.9
Production Casing	4540	17	5320	4910	247000	10	2.25	2.08	3.20	3.78

Casing Safety Factors – Additional ConocoPhillips Criteria:

ConocoPhillips casing design policy establishes Corporate Minimum Design Factors (see table below) and requires that service life load cases be considered and provided for in the casing design.

ConocoPhillips Corporate Criteria for Minimum Design Factors

	Burst	Collapse	Axial
Casing Design Factors	1.15	1.05	1.4

Type	Depth	Wt	MIY	Col	Jt Str	Pipe Yield	MW	Burst	Col	Ten
Conductor	85	65	35000	-	-	432966	-	-	-	-
Surface Casing (8-5/8" 24# J-55 STC)	1070	24	2950	1370	244000	381000	8.5	1.50	4.40	3.37
Production Casing (5-1/2" 17# J-55 LTC)	4540	17	5320	4910	247000	273000	10	2.25	3.16	2.14

Safety Factors – ConocoPhillips Criteria

The maximum internal (burst) load on the Surface Casing occurs when the surface casing is tested to 1500 psi (as per BLM Onshore Order 2 - II. Requirements).
The maximum internal (burst) load on the Production Casing occurs during the fracture stimulation where the maximum allowable working pressure
(MAWP) is the pressure that would fit ConocoPhillips Corporate Criteria for Minimum Factors.

Surface Casing Test Pressure =	1500 psi	Predicted Pore Pressure at TD (PPTD) =	8.5 ppg
Surface Rated Working Pressure (BOPE) =	3000 psi	Predicted Frac Gradient at Shoe (CSFG) =	19.23 ppg
Field SW =	10 ppg		

Surface Casing Burst Safety Factor = API Burst Rating / Maximum Predicted Surface Pressure (MPSP) 'OR' Maximum Allowable Surface Pressure (MASP)
Production Casing MAWP for the Fracture Stimulation = API Burst Rating / Corporate Minimum Burst Design Factor

Surface Casing Burst Safety Factor:

Case #1: MPSP (MW$_{hyd}$ next section) =	1070	x	0.052	x	10	=	556			
Case #2. MPSP (Field SW @ Bullhead$_{CSFG}$ + 200 psi) =	1070	x	0.052	x	19.23	-	556	+	200	= 714
Case #3. MPSP (Kick Vol @ next section TD) =	4540	x	0.052	x	8.5	-	347	-	473	= 1187
Case #4. MPSP (PPTD - GG) =	4540	x	0.052	x	8.5	-	454	=	1553	
Case #3 & #4 Limited to MPSP (CSFG + 0.2 ppg) =	1070	x	0.052	x (	19.23	+	0.2	) =	1081	
MASP (MW$_{hyd}$ + Test Pressure) =	1070	x	0.052	x	8.5	+	1500	=	1973	
Burst Safety Factor (Max. MPSP or MASP) =	2950	/	1973	=	1.50					

Production Casing Burst Safety Factor:

Case #1. MPSP (MW$_{hyd}$ TD) =	4540	x	0.052	x	10	=	2360.8	
Case #4. MPSP (PPTD - GG) =	4540	x	0.052	x	8.5	-	454	= 1553
Burst Safety Factor (Max. MPSP) =	5320	/	2361	=	2.25			
MAWP for the Fracture Stimulation (Corporate Criteria) =	5320	/	1.15	=	4626			

Collapse Safety Factors – ConocoPhillips Criteria

The maximum collapse load on the Surface Casing occurs when the pressure is released after bumping the plug on the surface casing cement
job. The maximum collapse load on the production casing occurs with the well is pumped off on production. We plan to cement the production
casing to surface, and therefore the external pressure profile on the production casing should be equal to the pore pressure of the horizons on the
outside of the casing which we estimate to be 8.5 ppg gradient.

Surface Casing Collapse Safety Factor = API Collapse Rating / Cement Displacement during Cementing to Surface
Production Casing Collapse Safety Factor = API Collapse Rating / Maximum Predicted Surface Pressure 'OR' Cement Displacement during Cementing to Surface

Cement Displacement Fluid (FW) = 8.34 ppg

Surface Casing Collapse Safety Factor:

Maximum Diff Lift Pressure =	[(	770	x	0.052	x	13.6	) + (	300	x	0.052	x	14.8	) -	464	] = 311
Collapse Safety Factor =	1370	/	311	=	4.40										

Production Casing Collapse Safety Factor:

Maximum Diff Lift Pressure =	[(	1340	x	0.052	x	11.8	) + (	3200	x	0.052	x	14.5	) -	1969	] = 1266
Case #4. MPSP (PPTD-GG) =	4540	x	0.052	x	8.5	-	454	=	1553						
Collapse Safety Factor =	4910	/	1553	=	3.16										

Tensial Strength Safety Factors – ConocoPhillips Criteria

The maximum axial (tension) load occurs if casing were to get stuck and pulled on to try to get it unstuck.
Maximum Allowable Axial Load for Pipe Yield = API Pipe Yield Strength Rating / Corporate Minimum Axial Design Factor
Maximum Allowable Axial Load for Joint = API Joint Strength Rating / Corporate Minimum Axial Design Factor
Maximum Allowable Hook Load (Limited to 75% of Rig Max Load) = Maximum Allowable Axial Load
Maximum Allowable Overpull Margin = Maximum Allowable Hook Load - Bouyant Wt of the String
Tensial Safety Factor = API Pipe Yield 'OR' API Joint Strength 'OR' Rig Max Load Rating / (Bouyant Wt of String + Minimum Overpull Required)

Rig Max Load (300,000 lbs) x 75% =	225000 lbs	
Minimum Overpull Required =	50000 lbs	

Surface Casing Tensial Strength Safety Factor:

Air Wt =	25680					
Bouyant Wt =	25680	x	0.870	=	22347	
Max. Allowable Axial Load (Pipe Yield) =	381000	/	1.40	=	272143	
Max. Allowable Axial Load (Joint) =	244000	/	1.40	=	174286	
Max. Allowable Hook Load (Limited to 75% of Rig Max Load) =	174286					
Max. Allowable Overpull Margin =	174286	- (	25680	x	0.870	) = 151938
Tensial Safety Factor =	244000	/ (	22347	+	50000	) = 3.37

Production Casing Tensial Strength Safety Factor:

Air Wt =	77180					
Bouyant Wt =	77180	x	0.847	=	65397	
Max. Allowable Axial Load (Pipe Yield) =	273000	/	1.40	=	195000	
Max. Allowable Axial Load (Joint) =	247000	/	1.40	=	176429	
Max. Allowable Hook Load (Limited to 75% of Rig Max Load) =	176429					
Max. Allowable Overpull Margin =	176429	- (	77180	x	0.847	) = 111032
Tensial Safety Factor =	247000	/ (	65397	+	50000	) = 2.14

Compression Strength Safety Factors – ConocoPhillips Criteria

The maximum axial (compression) load for the well is where the surface casing is landed on the conductor
with a support of a plate or landing ring. The surface casing is also calculated to bear 60% of the load
but not limited. Any other axial loads such as a snubbing unit or other would need to be added to the load.
Compression Safety Factor = API Axial Joint Strength Rating 'OR' API Axial Pipe Yield Rating / Maximum Predicted Load

Wellhead Load = 3000 lbs

Compression Safety Factor

Surf Casing Wt (Bouyant) =	(	25680	x	0.870	) =	22347				
Prod Casing Wt (Bouyant) =	(	77180	x	0.847	) =	65397				
Tubing Wt (Air Wt) =	4540	x	6.5	=	29510					
Tubing Fluid Wt =	4540	x	0.052	x	6.55	x	0.7854	x	2.441	^2 = 7236
Load on Conductor =	3000	+	22347	+	65397	+	29510	+	7236	= 127491
Conductor Compression Safety Factor =	432966	/	127491	=	3.40					
Load on Surface Casing =	127491	x	60%	=	76494					
Surface Casing Compression Safety Factor =	244000	/	76494	=	3.19					

3. Proposed cementing program:

16" or 13-3/8" Conductor:

Cement to surface with rathole mix, ready mix or Class C Neat cement.
(Note: The gravel used in the cement is not to exceed 3/8" diameter)
TOC at surface.

8-5/8" Surface Casing Cementing Program:

The intention for the cementing program for the Surface Casing is to:
- Place the Tail Slurry from the casing shoe to 300' above the casing shoe,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water

Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft³/sx
Lead	Class C	Surface	725' – 770'	13.6	300	510	+ 2% Extender + 2% CaCl₂ + 0.125 lb/sx Lost Circulation Control Agent + 0.2% Defoamer Excess =200% based on gauge hole volume	1.70
Tail	Class C	725' – 770'	1025' – 1070'	14.8	200	268	1% CaCl2 Excess = 100% based on gauge hole volume	1.34

Displacement: Fresh Water.

Note: In accordance with the Pecos District Conditions of Approval, we will Wait on Cement (WOC) for a period of not less than 18 hrs after placement or until at least 500 psi compressive strength has been reached in both the Lead Slurry and Tail Slurry cements on the Surface Casing, whichever is greater.

5-1/2" Production Casing Cementing Program – Single Stage Cementing Option:

The intention for the cementing program for the Production Casing – Single Stage Cementing Option is to:
- Place the Tail Slurry from the casing shoe to above the top of the Paddock,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water

Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft³/sx
Lead	50:50 Poz/C	Surface	3200'	11.8	450	1031	+ 10 % Extender + 5 % NaCl + 0.2 % Defoamer + 5 lb/sx LCM/Extender + 0.125 lb/sx Lost Circulation Control Agent + 0.5 % Fluid Loss Excess = 20% or more if needed based on gauge hole volume	2.29
Tail	Poz/C CO2 Resistant Cement	3200'	4495' – 4540'	14.5	300	378	+ 1 % Extender + 0.5 % Fluid Loss + 0.4 % Dispersant + 0.2 % Defoamer Excess = 60% or more if needed based on gauge hole volume	1.26

Displacement: Fresh Water with approximately 250 ppm gluteraldehyde biocide.

5-1/2" Production Casing Cementing Program – Two-Stage Cementing Option:

ConocoPhillips Company respectfully requests the options to our cementing program. The intention for the cementing program for the Production Casing – Two-Stage Cementing Option is to:

- Provide a contingency plan for using a Stage Tool and Annulus Casing Packer(s) to isolate losses or waterflow if either of these events occurs while drilling the well.
- Place the Stage 1 Cement from the casing shoe to the stage tool, @ 3200
- Bring Stage 2 Cement from the stage tool to surface.

Spacer: 20 bbls Fresh Water

Stage 1 - Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft³/sx
Lead	Poz/C CO2 Resistant Cement	3200'	4495' – 4540'	14.5	300	378	+ 1 % Extender + 0.5 % Fluid Loss + 0.4 % Dispersant + 0.2 % Defoamer Excess = 60% or more if needed based on gauge hole volume	1.26

Stage 2 - Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft³/sx
Lead	50:50 Poz/C	Surface	1400'	11.8	250	573	+ 10 % Extender + 5 % NaCl + 0.2 % Defoamer + 5 lb/sx LCM/Extender + 0.125 lb/sx Lost Circulation Control Agent + 0.5 % Fluid Loss Excess = 120% or more if needed based on gauge hole volume	2.29
Tail	Poz/C CO2 Resistant Cement	1400'	Stage Tool ~ 3200'	14.5	400	504	+ 1 % Extender + 0.5 % Fluid Loss + 0.4 % Dispersant + 0.2 % Defoamer Excess = 10% or more if needed based on gauge hole volume	1.26

Displacement: Fresh Water

Proposal for Option to Adjust Production Casing Cement Volumes:

The production casing cement volumes for the proposed single stage and two-stage option presented above are estimates based on gauge hole. We will adjust these volumes based on the caliper log data for each well and our trends for amount of cement returns to surface. Also, if no caliper log is available for any particular well, we would propose an option to possibly increase the production casing cement volume to account for any uncertainty in regard to the hole volume.

4. Pressure Control Equipment:

A __11" 3M__ system will be installed, used, maintained, and tested accordingly as described in Onshore Oil and Gas Order No. 2.

Our BOP equipment will be:
- o   Rotating Head
- o   Annular BOP, 11" 3M
- o   Blind Ram, 11" 3M
- o   Pipe Ram, 11" 3M

After nippling up, and every 30 days thereafter or whenever any seal subject to test pressure is broken followed by related repairs, blowout preventors will be pressure tested. BOP will be inspected and operated at least daily to insure good working order. All pressure and operating tests will be done by an independent service company and recorded on the daily drilling reports. BOP will be tested using a test plug to isolate BOP stack from casing. BOP test will include a low pressure test from 250 to 300 psi for a minimum of 10 minutes or until requirements of test are met, whichever is longer. Ram type preventers and associated equipment will be tested to the approved stack working pressure of 3000 psi isolated by test plug. Annular type preventers will be tested to 50 percent of rated working pressure, and therefore will be tested to 1500 psi. Pressure will be held for at least 10 minutes or until provisions of test are met, whichever is longer. Valve on casing head below test plug will be open during testing of BOP stack. BOP will comply with all provisions of Onshore Oil and Gas Order No. 2 as specified. **See Attached BOPE Schematic.** A variance is respectfully requested to allow for the use of flexible hose. The variance request is included as a separate enclosure with attachments.

5. Proposed Mud System:

The mud systems that are proposed for use are as follows:

DEPTH	TYPE	Density ppg	FV sec/qt	API Fluid Loss cc/30 min	pH	Vol bbl
0 – Surface Casing Point	Fresh Water or Fresh Water Native Mud in Steel Pits	8.5 – 9.0	28 – 40	N.C.	N.C.	300 – 500
Surface Casing Point to TD	Brine (Saturated $NaCl_2$) in Steel Pits	10	29	N.C.	10 – 11	500 – 1000
Conversion to Mud at TD	Brine Based Mud ($NaCl_2$) in Steel Pits	10	33 – 40	5 – 10	10 – 11	0 – 500

Gas detection equipment and pit level flow monitoring equipment will be on location. A flow paddle will be installed in the flow line to monitor relative amount of mud flowing in the non-pressurized return line. Mud probes will be installed in the individual tanks to monitor pit volumes of the drilling fluid with a pit volume totalizer. Gas detecting equipment and H2S monitor alarm will be installed in the mud return system and will be monitored. A mud gas separator will be installed and operable before drilling out from the Surface Casing. The gases shall be piped into the flare system. Drilling mud containing H2S shall be degassed in accordance with API RP-49, item 5.14.

In the event that the well is flowing from a waterflow, then we would discharge excess drilling fluids from the steel mud pits through a fas-line into steel frac tanks at an offset location for containment. Depending on the rate of waterflow, excess fluids will be hauled to an approved disposal facility, or if in suitable condition, may be reused on the next well.

No reserve pit will be built.

Proposal for Option to Not Mud Up at TD:
FW, Brine, and Mud volume presented above are estimates based on gauge 12-1/4" or 7-7/8" holes. We will adjust these volume based on hole conditions. We do not plan to keep any weighting material at the wellsite. Also, we propose an option to not mud up leaving only brine in the hole if we have good hole stability.

6. Logging, Coring, and Testing Program:

    a. No drill stem tests will be done
    b. Remote gas monitoring planned for the production hole section (optional).
    c. No whole cores are planned
    d. The open hole electrical logging program is planned to be as follows:

- Total Depth to 1700': Spectral GR, Gamma Ray, Resistivity, Density, and BHC Sonic
- Total Depth to surface Casing Shoe: Caliper
- Total Depth to surface, Gamma Ray and Neutron
- Total Depth to 3200'; Dielectric Scanner
- Formation pressure data (XPT) on electric line
- Rotary Sidewall Cores on electric line if needed (optional)
- FMI (Formation MicroImager) if needed (optional)
- UBI (Ultrasonic Borehole Imager) if needed (optional)

7. Abnormal Pressures and Temperatures:

- No abnormal pressures are expected to be encountered.

- Loss of circulation is a possibility in the horizons below the Top of Grayburg. We expect that normal Loss of Circulation Material will be successful in healing any such loss of circulation events.

      ○ The bottom hole pressure is expected to be 8.55 ppg gradient.
      ○ The expected Bottom Hole Temperature is 115 degrees F.

- The estimated H_2S concentrations and ROE calculations for the gas in the zones to be penetrated are presented in the table below for the various producing horizons in this area:

FORMATION / ZONE	H2S (PPM)	Gas Rate (MCFD)	ROE 100 PPM	ROE 500 PPM
Grayburg / San Andres (from MCA)	14000	38	59	27

ConocoPhillips will comply with the provisions of Oil and Gas Order # 6, Hydrogen Sulfide Operations. Also, ConocoPhillips will provide an H2S Contingency Plan (please see copy attached) and will keep this plan updated and posted at the wellsite during the drilling operation.

8. Anticipated starting date and duration of operations:

Well pad and road constructions will begin as soon as all agency approvals are obtained. Anticipated date to drill these wells begin in late 2013 after receiving approval of the APD.

Attachments:

- Attachment # 1 ...... Two-stage Cementing Schematic
- Attachment # 2 .... BOP and Choke Manifold Schematic – 3M System
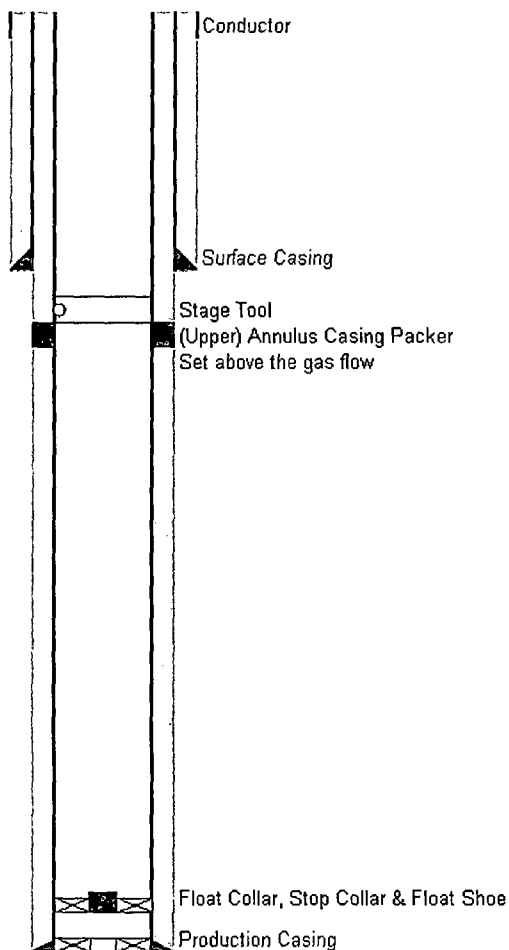- Attachment # 3 .... Diagram of Choke Manifold Equipment

Contact Information:

Proposed 1 May 2013 by:
James Chen
Drilling Engineer, ConocoPhillips Company
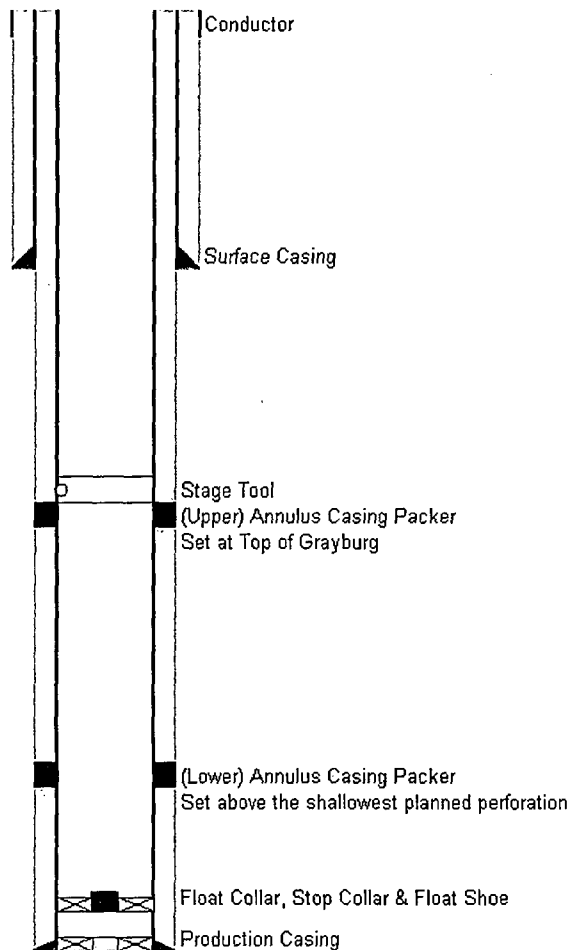Phone (832) 486-2184
Cell (832) 768-1647

Attachment # 1

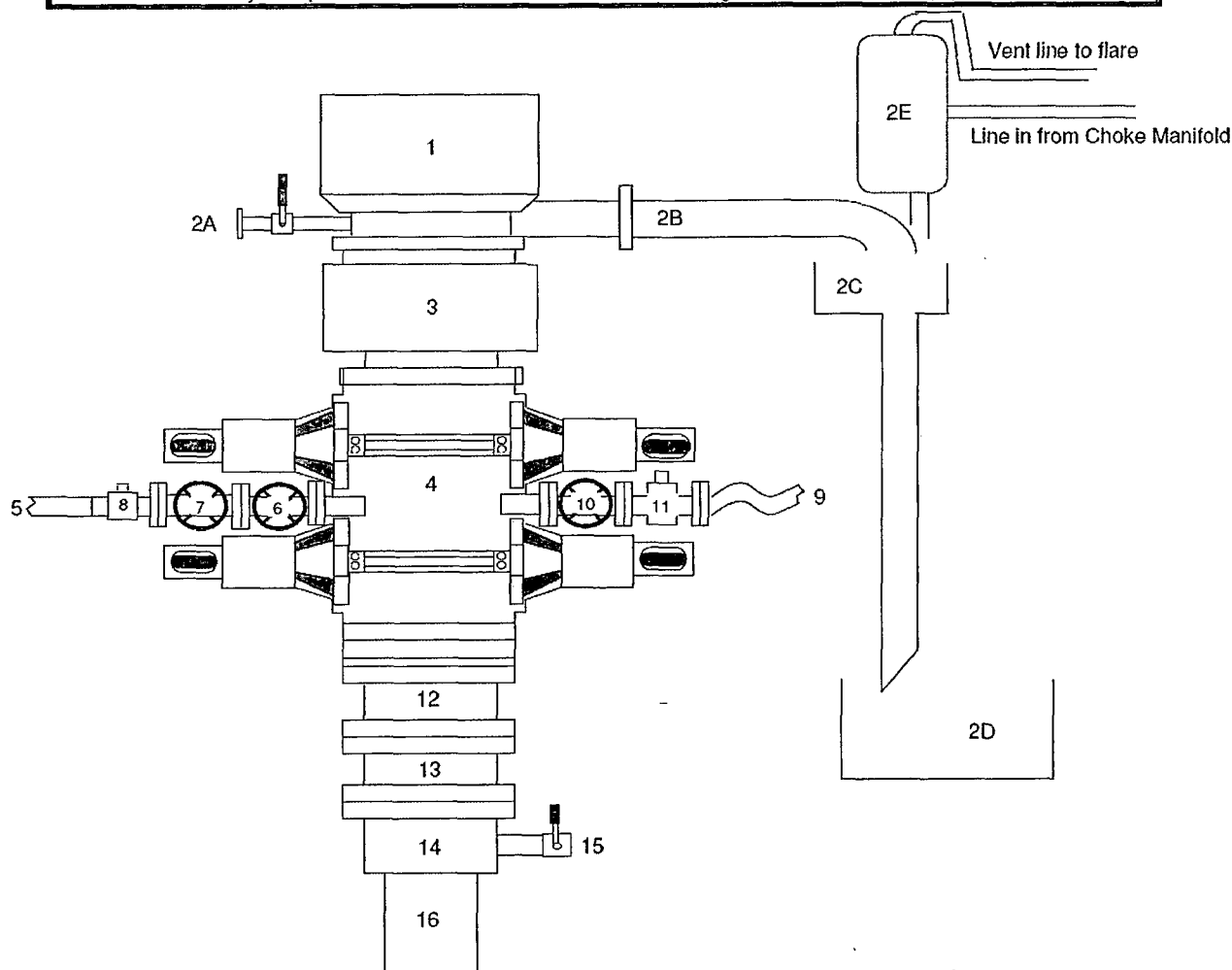| **Two-Stage Cementing (Alternative for Shallow Gas)**	**Two-Stage Cementing (Alternative for Oil / Water / Gas & Water Flow)**
Provide contingency plan for using two-stage cementing for the production casing cement job if gas flow occurs during the drilling operations. See APD Drill Plan Section 3. Proposed cementing program.	*Provide contingency plan for using two-stage cementing for the production casing cement job if oil or water flow occurs during the drilling operations. See APD Drill Plan Section 3. Proposed cementing program.*

Conductor

Surface Casing

Stage Tool
(Upper) Annulus Casing Packer
Set above the gas flow

Float Collar, Stop Collar & Float Shoe

Production Casing

Conductor

Surface Casing

Stage Tool
(Upper) Annulus Casing Packer
Set at Top of Grayburg

(Lower) Annulus Casing Packer
Set above the shallowest planned perforation

Float Collar, Stop Collar & Float Shoe

Production Casing

Attachment # 2

Item	Description
1	Rotating Head, 11"
2A	Fill up Line and Valve
2B	Flow Line (10")
2C	Shale Shakers and Solids Settling Tank
2D	Cuttings Bins for Zero Discharge
2E	Rental Mud Gas Separator with vent line to flare and return line to mud system
3	Annular BOP (11", 3M)
4	Double Ram (11", 3M, equipped with Blind Rams and Pipe Rams)
5	Kill Line (2" flexible hose, 3000 psi WP)
6	Kill Line Valve, Inner (3-1/8", 3000 psi WP)
7	Kill Line Valve, Outer (3-1/8", 3000 psi WP)
8	Kill Line Check Valve (2-1/16", 3000 psi WP
9	Choke Line (5M Stainless Steel Coflex Line, 3-1/8" 3M API Type 6B, 3000 psi WP)
10	Choke Line Valve, Inner (3-1/8", 3000 psi WP)
11	Choke Line Valve, Outer, (Hydraulically operated, 3-1/8", 3000 psi WP)
12	Adapter Flange (11" 5M to 11" 3M)
13	Spacer Spool (11", 5M)
14	Casing Head (11" 5M)
15	Ball Valve and Threaded Nipple on Casing Head Outlet, 2" 5M
16	Surface Casing

Submitted by: James Chen, Drilling Engineer, Mid-Continent Business Unit, ConocoPhillips Company, 25-Sep-2012

CHOKE MANIFOLD ARRANGEMENT
3M System per Onshore Oil and Gas Order No. 2 utilizing 3M and 5M Equipment

2" line to rig's steel mud pits

2" line

2" line

3" line

3" line to burn box 150' from WH
Line must be secured.

3" Choke Line

2" line to buffer tank and
rental mud gas separator

All Tees must be targeted

Item	Description
1	Manual Adjustable Choke, 2-1/16", 3M
2	Remote Controlled Hydraulically Operated Adjustable Choke, 2-1/16", 3M
3	Gate Valve, 2-1/16" 5M
4	Gate Valve, 2-1/16" 5M
5	Gate Valve, 2-1/16" 5M
6	Gate Valve, 2-1/16" 5M
7	Gate Valve, 3-1/8" 3M
8	Gate Valve, 2-1/16" 5M
9	Gate Valve, 2-1/16" 5M
10	Gate Valve, 2-1/16" 5M
11	Gate Valve, 3-1/8" 3M
12	Gate Valve, 2-1/16" 5M
13	Pressure Gauge
14	2" hammer union tie-in point for BOP Tester

We will test each valve to 3000 psi from the upstream side.

Submitted by:
James Chen
Drilling Engineer, Mid-Continent Business Unit, ConocoPhillips Company
Date: 21-March-2013

Request for Variance

ConocoPhillips Company
Lease Number: NM LC 057210
Well: MCA Unit #514
Location: Sec. 27, T17S, R32E
Date: 05-01-13

Request:

ConocoPhillips Company respectfully requests a variance to install a flexible choke line instead of a straight choke line prescribed in the Onshore Order No. 2, III.A.2.b Minimum standards and enforcement provisions for choke manifold equipment. This request is made under the provision of Onshore Order No. 2, IV Variances from Minimum Standard. The rig to be used to drill this well is equipped with a flexible choke line if the requested variance is approved and determined that the proposed alternative meets the objectives of the applicable minimum standards.

Justifications:

The applicability of the flexible choke line will reduce the number of target tees required to make up from the choke valve to the choke manifold. This configuration will facilitate ease of rig up and BOPE Testing.

Attachments:

- Attachment # 1 Specification from Manufacturer
- Attachment # 2 Mill & Test Certification from Manufacturer

Contact Information:

Program prepared by:
James Chen
Drilling Engineer, ConocoPhillips Company
Phone (832) 486-2184
Cell (832) 768-1647
Date: 26 September 2012

RELIANCE
Industrial Products USA, Ltd.

RELIANCE

Reliance Eliminator Choke & Kill

This hose can be used as a choke hose which connects the BOP stack to the bleed-off manifold or a kill hose which connects the mud stand pipe to the BOP kill valve.

The *Reliance Eliminator Choke & Kill* hose contains a specially bonded compounded cover that replaces rubber covered Asbestos, Fibreglass and other fire retardant materials which are prone to damage. This high cut and gouge resistant cover overcomes costly repairs and downtime associated with older designs.

The Reliance Eliminator Choke & Kill hose has been verified by an independent engineer to meet and exceed EUB Directive 36 (700°C for 5 minutes).

Nom. ID		Nom OD		Weight		Min Bend Radius		Max WP	
in.	mm.	in.	mm	lb/ft	kg/m	in.	mm.	psi	Mpa
3	76.2	5.11	129.79	14.5	21.46	48	1219.2	5000	34.47
3-1/2	88.9	5.79	147.06	20.14	29.80	54	1371.6	5000	34.47

Fittings	**Flanges**	**Hammer Unions**	**Other**
RC4X5055	R35 - 3-1/8 5000# API Type 6B	All Union Configurations	LP Threaded Connectio
RC3X5055	R31 - 3-1/8 3000# API Type 6B		Graylock
RC4X5575			Custom Ends

MCA Unit #514

Variance Request
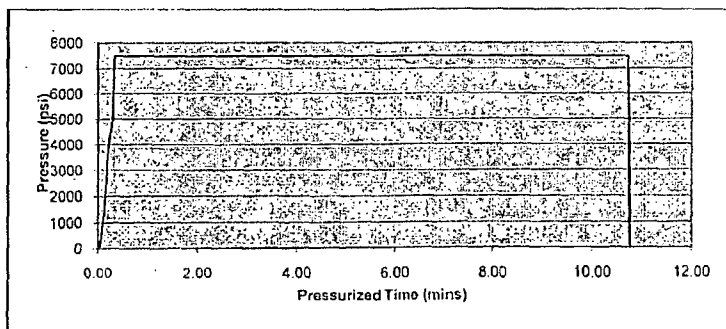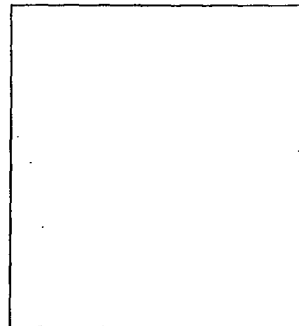
RELIANCE
Industrial Products USA, Ltd.

2030 E. 8th Street, Suite B • Greeley, CO 80631
Ph: (970) 346-3751 • Fax: (970) 353-3168 • *Toll Free:* (866) 771-9739

T E S T   C E R T I F I C A T E

Customer:	PRECISION DRILLING	Cert No.:	27792
P.O. #:	RIG 822	Date:	9/21/2012
Invoice #:	27792		
Material:	3 1/2" FIREGUARD		
Description:	3 1/2" X 10'		
Coupling 1:	3 1/2" FLANGE R31		
" Serial:			
" Quality:			
Coupling 2:	3 1/2" FLOATING R31		
" Serial:			
" Quality:			
Working Pressure :	3000		
Test Pressure:	7500		
Duration (mins):	10		

Conducted By: ___FLORES M.___
Test Technician

☑ Acceptable
☐ Not Acceptable

MCA Unit #514   Variance Request