Form 3160-5
(March 2012)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

OCD Hobbs
HOBBS OCD
MAR 19 2014
RECEIVED

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

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.

5. Lease Serial No. NM LC 058395
6. If Indian, Allottee or Tribe Name: N/A

***SUBMIT IN TRIPLICATE** – Other instructions on page 2.*

7. If Unit of CA/Agreement, Name and/or No.: N/A

1. Type of Well: [X] Oil Well [ ] Gas Well [ ] Other
8. Well Name and No.: SC Federal #2
2. Name of Operator: ConocoPhillips Company (P10-4054)
9. API Well No.: 30-025-40586
3a. Address: 600 N. Dairy Ashford Rd.; Houston, TX 77079
3b. Phone No. *(include area code)*: (281)206-5281
10. Field and Pool or Exploratory Area: Maljamar; Yeso, West
4. Location of Well *(Footage, Sec., T.,R.,M., or Survey Description)*: 1650' FSL & 940' FEL; UL I, Sec. 22, T17S, R32E
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			
[X] Notice of Intent	[ ] Acidize	[ ] Deepen	[ ] Production (Start/Resume)	[ ] Water Shut-Off
	[ ] Alter Casing	[ ] Fracture Treat	[ ] Reclamation	[ ] Well Integrity
[ ] Subsequent Report	[ ] Casing Repair	[ ] New Construction	[ ] Recomplete	[ ] Other
	[X] Change Plans	[ ] Plug and Abandon	[ ] Temporarily Abandon	
[ ] Final Abandonment Notice	[ ] 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 Company, as most recent operator of record, respectfully requests approval to change the approved plan for this well. The following changes are necessary to drill this well as part of our ongoing Yeso development program.

Please find the attached documents:

- Updated Operator Certification
- Updated Drilling Plan
- Variance from Onshore Order
- Updated H2S Contingency Plan
- Changes to the Surface Use Plan of Operations

SEE ATTACHED FOR
CONDITIONS OF APPROVAL

This well is scheduled to be drilled in December 2013.

14. I hereby certify that the foregoing is true and correct. Name *(Printed/Typed)*: Susan B. Maunder
Title: Senior Regulatory Specialist
Signature: Susan B. Maunder
Date: 10/23/13

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by: /S/ STEPHEN J. CAFFEY
Title:
Date: MAR 17 2014

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:

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)

MAR 24 2014

Operator Certification

SC Federal #2

HOBBS OCD

CONOCOPHILLIPS COMPANY

MAR 19 2014

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CERTIFICATION:

I hereby certify that I, or persons under my direct supervision, have inspected the proposed drill site and access route proposed herein; that I am familiar with the conditions which currently exist; that I have full knowledge of State and Federal laws applicable to this operation; that the statements made in this APD package are, to the best of my knowledge, true and correct; and that the work associated with the operations proposed herein will be performed in conformity with this APD package and the terms and conditions under which it is approved. I also certify that I, or the company I represent, am responsible for the operations conducted under this application with bond coverage provided by Nationwide Bond ES0085. These statements are subject to the provisions of 18 U.S.C. 1001 for the filing of false statements.

Susan B. Maunder

Date: 10/23/13

Susan B. Maunder
Senior Regulatory Specialist

Request Approval to Change Drill Plan
ConocoPhillips Company
Maljamar; Yeso

SC Federal 2
Lea County, New Mexico

Request:

ConocoPhillips Company respectfully requests approval to revise the casing and cementing program, pressure control equipment, the proposed mud systems, diagram and schematic for BOP and choke manifold equipment, location schematic and rig layout, and update H2S contingency plan. This request is made under the provision of Onshore Order No. 2 and No. 6.

1. Proposed casing program:

Type	Hole Size	Interval MD RKB (ft)		OD	Wt	Gr	Conn	MIY	Col	Jt Str	Safety Factors Calculated per ConocoPhillips Corporate Criteria		
	(in)	From	To	(inches)	(lb/ft)			(psi)	(psi)	(klbs)	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	865' – 910'	8-5/8	24#	J-55	STC	2950	1370	244	1.55	3.39	3.54
Option: Prod w/ Bond Coat	7-7/8	3000'	4000'	5-1/2	17#	L-80	LTC	7740	6290	338	NA	NA	NA
Prod	7-7/8	0	7045' – 7090'	5-1/2	17#	L-80	LTC	7740	6290	338	2.10	2.50	1.97

The casing will be suitable for H_2S 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.

ConocoPhillips Company respectfully requests the option to run bond coated production casing with the two-stage cementing option for the intension to protect the casing from corrosion if needed.

Casing Safety Factors - BLM Criteria:

Type	Depth	Wt	MIY	Col	Jt Str	Drill Fluid	Burst	Collapse	Tensile-Dry	Tens-Bouy
Surface Casing	910	24	2950	1370	244000	8.5	7.33	3.41	11.2	12.8
Production Casing	7090	17	7740	6290	338000	10	2.10	1.71	2.80	3.31

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)	910	24	2950	1370	244000	381000	8.5	1.55	3.39	3.54
Production Casing (5-1/2" 17# L-80 LTC)	7090	17	7740	6290	338000	397000	10	2.10	2.50	1.97

Burst – ConocoPhillips Required Load Cases

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 - III. 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) = 8.55 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 (MWhyd next section) = 910 x 0.052 x 10 = 473
Case #2. MPSP (Field SW @ Bullhead$_{CSFG}$ + 200 psi) = 910 x 0.052 x 19.23 - 473 + 200 = 637
Case #3. MPSP (Kick Vol @ next section TD) = 7090 x 0.052 x 8.55 - 618 - 402 = 2132
Case #4. MPSP (PPTD - GG) = 7090 x 0.052 x 8.55 - 709 = 2443
Case #3 & #4 Limited to MPSP (CSFG + 0.2 ppg) = 910 x 0.052 x (19.23 + 0.2) = 919
MASP (MWhyd + Test Pressure) = 910 x 0.052 x 8.5 + 1500 = 1902
Burst Safety Factor (Max. MPSP or MASP) = 2950 / 1902 = 1.55

Production Casing Burst Safety Factor:

Case #1. MPSP (MWhyd TD) = 7090 x 0.052 x 10 = 3686.8
Case #4. MPSP (PPTD - GG) = 7090 x 0.052 x 8.55 - 709 = 2443
Burst Safety Factor (Max. MPSP) = 7740 / 3687 = 2.10
MAWP for the Fracture Stimulation (Corporate Criteria) = 7740 / 1.15 = 6730

Collapse – ConocoPhillips Required Load Cases

The maximum collapse load on the Surface Casing occurs when cementing to surface, 1/3 evacuation to the next casing setting depth, or deepest depth of exposure (full evacuation).
The maximum collapse load on the Production Casing occurs when cementing to surface, or 1/3 evacuation to the deepest depth of exposure; and therefore, the external pressure profile for the evacuation cases should be equal to the pore pressure of the horizons on the outside of the casing which we assumed to be PPTD.

Surface Casing Collapse Safety Factor = API Collapse Rating / Full Evacuation 'OR' 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 — Top of Cement = Cement to Surface
Surface Cement Lead = 13.6 ppg — Prod Cement Lead = 11.8 ppg
Surface Cement Tail = 14.8 ppg — Prod Cement Tail = 16.4 ppg
Top of Surface Tail Cement = 300 ft — Top of Prod Tail Cement = 5200 ft

Surface Casing Collapse Safety Factor:

Full Evacuation Diff Pressure = 910 x 0.052 x 8.55 = 405
Cementing Diff Lift Pressure = [(610 x 0.052 x 13.6) + (300 x 0.052 x 14.8) - 395] = 268
Collapse Safety Factor = 1370 / 405 = 3.39

Production Casing Collapse Safety Factor:

1/3 Evacuation Diff Pressure = [(7090 x 0.052 x 8.55) - (7090 / 3 x 0.052 x 8.34)] = 2127
Cementing Diff Lift Pressure = [(1890 x 0.052 x 11.8) + (5200 x 0.052 x 16.4) - 3075] = 2519
Collapse Safety Factor = 6290 / 2519 = 2.50

Tensial Strength – ConocoPhillips Required Load Cases

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 = 21840
Bouyant Wt = 21840 x 0.870 = 19006
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 - (21840 x 0.870) = 155280
Tensial Safety Factor = 244000 / (19006 + 50000) = 3.54

Production Casing Tensial Strength Safety Factor:

Air Wt = 120530
Bouyant Wt = 120530 x 0.847 = 102128
Max. Allowable Axial Load (Pipe Yield) = 397000 / 1.40 = 283571
Max. Allowable Axial Load (Joint) = 338000 / 1.40 = 241429
Max. Allowable Hook Load (Limited to 75% of Rig Max Load) = 225000
Max. Allowable Overpull Margin = 225000 - (120530 x 0.847) = 122872
Tensial Safety Factor = 300000 / (102128 + 50000) = 1.97

Compression Strength – ConocoPhillips Required Load Cases

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

Conductor & Surface Compression Safety Factor

Surf Casing Wt (Bouyant) = (21840 x 0.870) = 19006
Prod Casing Wt (Bouyant) = (120530 x 0.847) = 102128
Tubing Wt (Air Wt) = 7090 x 6.5 = 46085
Tubing Fluid Wt = 7090 x 0.052 x 6.55 x 0.7854 x 2.441 ^2 = 11301
Load on Conductor = 3000 + 19006 + 102128 + 46085 + 11301 = 181520
Conductor Compression Safety Factor = 432966 / 181520 = 2.39
Load on Surface Casing = 181520 x 60% = 108912
Surface Casing Compression Safety Factor = 244000 / 108912 = 2.24

2. **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 ft^3/sx
Lead	Class C	Surface	565' – 610'	13.6	300	510	2% Extender 2% $CaCl_2$ 0.125 lb/sx LCM if needed 0.2% Defoamer Excess =75% based on gauge hole volume	1.70
Tail	Class C	565' – 610'	865' – 910'	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 ft^3/sx
Lead	50:50 Poz/C	Surface	5200'	11.8	700	1820	10% Bentonite 5% Salt 0.2%-0.4% Fluid loss additive 0.125 lb/sx LCM if needed Excess = 220% or more if needed based on gauge hole volume	2.6
Tail	Class H	5200'	7045' – 7090'	16.4	400	428	0.2% Fluid loss additive 0.3% Dispersant 0.15% Retarder 0.2% Antifoam Excess = 100% or more if needed based on gauge hole volume	1.07

Displacement: Fresh Water with approximately 250 ppm gluteraldehyde biocide.

5-1/2" Production Casing Cementing Program – Two-Stage Cementing w/ Comingle 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 water flow if either of these events occurs while drilling the well.
- Place the Stage 1 Cement from the casing shoe to the stage tool,
- 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 ft^3/sx
Lead	50:50 Poz/H	3000'	7045' – 7090'	13.2	800	1120	0.5% Fluid loss additive 0.10% Retarder 0.2% Antifoam 0.125 lb/sx LCM if needed Excess = 150% or more if needed based on gauge hole volume	1.40

Stage 2 - Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft^3/sx
Lead	50:50 Poz/C	Surface	Stage Tool ~ 3000'	11.8	500	1300	+ 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 = 50 % or more if needed based on gauge hole volume	2.6

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.

3. 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:
- Rotating Head
- Annular BOP, 11" 3M
- Blind Ram, 11" 3M
- 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.** The BOPE may be configured to use flexible hose. Pressure test data and hose specification information will be provided to BLM prior to site construction.

4. 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.	120 – 160
Surface Casing Point to TD	Brine (Saturated $NaCl_2$) in Steel Pits	10	29	N.C.	10 – 11	1250 - 2500
Conversion to Mud at TD	Brine Based Mud ($NaCl_2$) in Steel Pits	10	34 – 45	5 – 10	10 – 11	0 - 1250

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.

Drilling mud containing H2S shall be degassed in accordance with API RP-49, item 5.14. The gases shall be piped into the flare system. Gas detection equipment and pit level flow monitoring equipment will be on location. Gas detecting equipment 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.

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.

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 in 2013 after receiving approval of the APD.

Attachments:

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

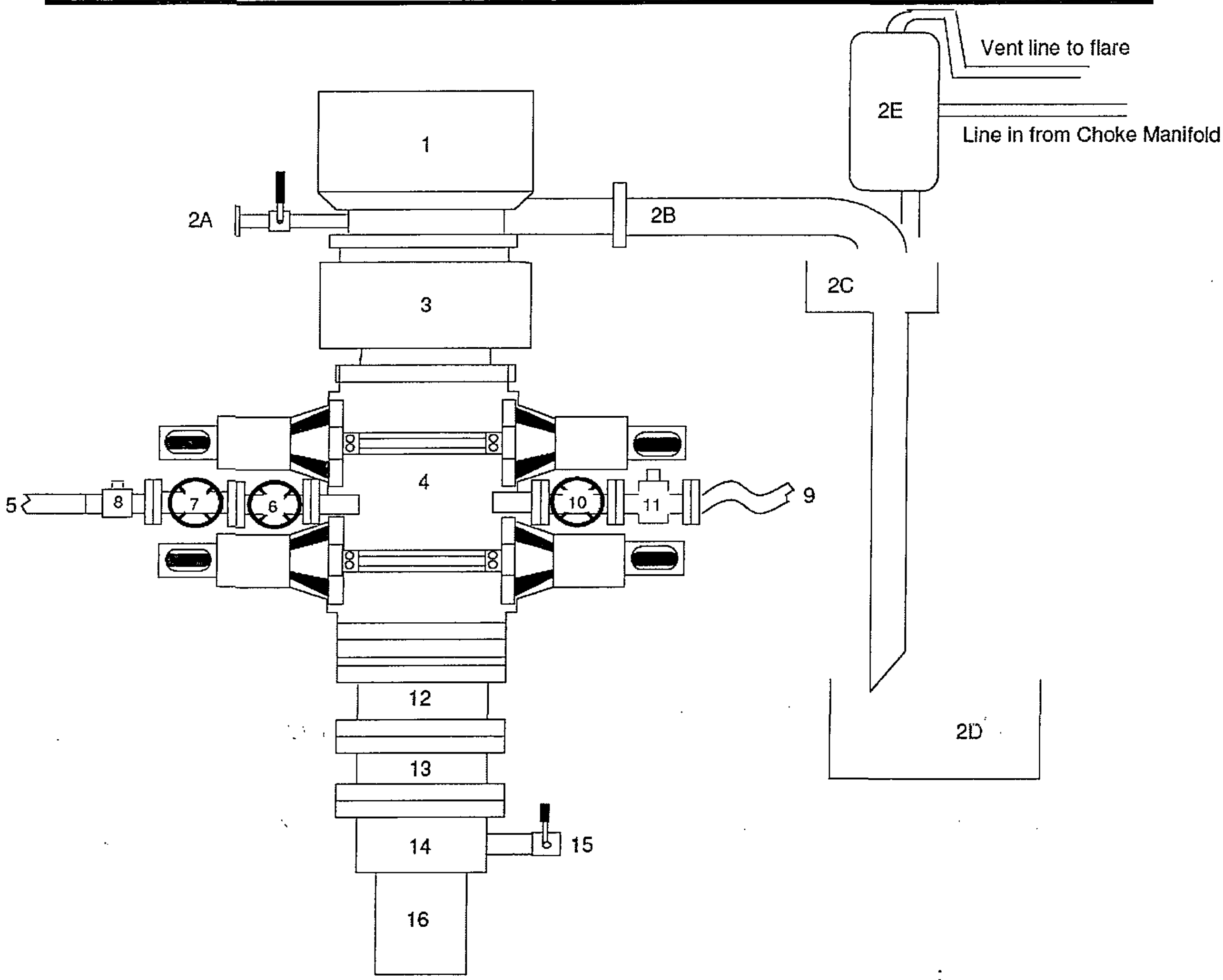
Contact Information:

Sundry Request proposed 16 October 2013 by:
James Chen
Drilling Engineer, ConocoPhillips Company
Phone (832) 486-2184
Cell (832) 768-1647

Attachment # 1

BLOWOUT PREVENTER ARRANGEMENT

3M System per Onshore Oil and Gas Order No. 2 utilizing 3M and 5M Rated Equipment



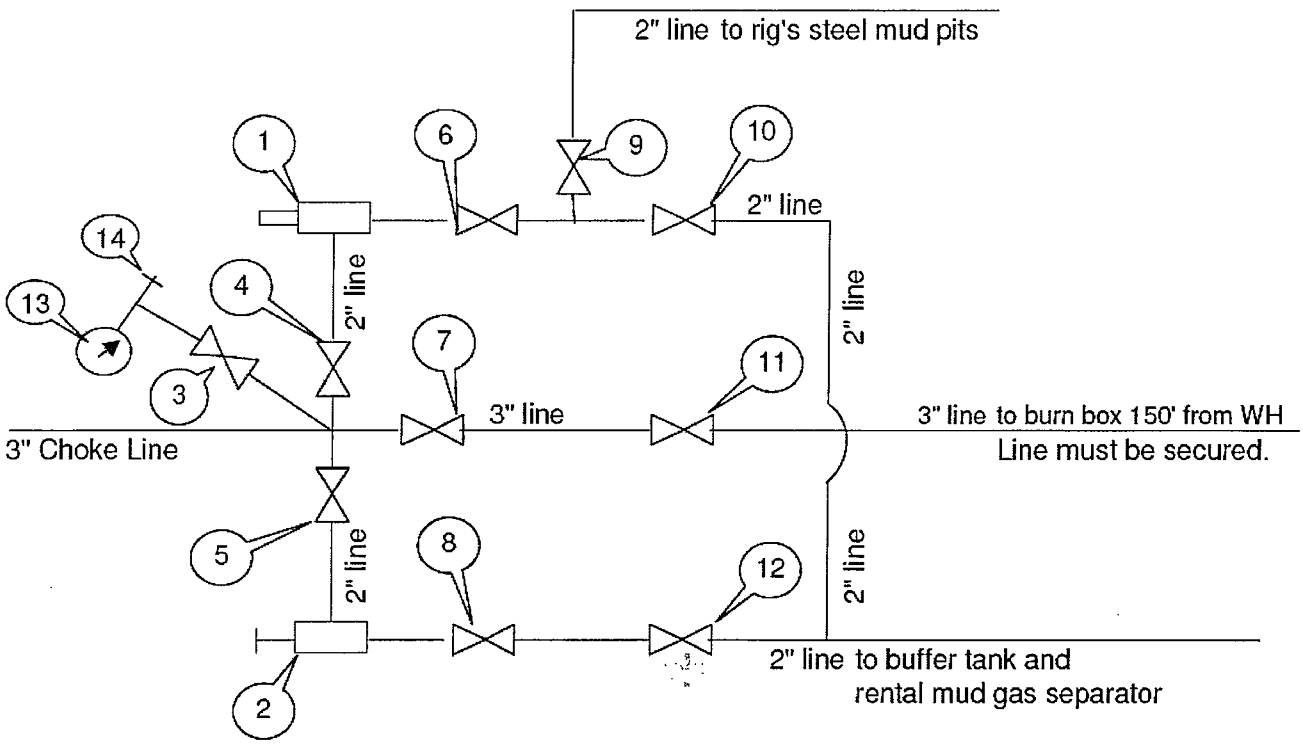
Item	Description
1	Rotating Head, 11"
2A	Fill up Line and Valve
2B	Flow Line (10")
2C	Shale Shakers and Solids Settling Tank
2D	Cuttings Bins for Zero Discharge
2E	Rental Mud Gas Separator with vent line to flare and return line to mud system
3	Annular BOP (11", 3M)
4	Double Ram (11", 3M, equipped with 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

Attachment # 2

CHOKE MANIFOLD ARRANGEMENT

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



All Tees must be targeted

Item	Description
1	Remote Controlled Hydraulically Operated Adjustable Choke, 2-1/16", 3M
2	Manual 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.

Drawn by:
Steven O. Moore
Chief Drilling Engineer, Mid-Continent Business Unit, ConocoPhillips Company
Date: 25-Sept-2012

Request for Variance

ConocoPhillips Company
Lease Number: USA LC 058395
Well: SC Federal #2
Location: Sec. 22, T17S, R32E
Date: 10-15-13

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

Attachment # 1

RELIANCE
Industrial Products USA, Ltd.

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

Attachment # 2

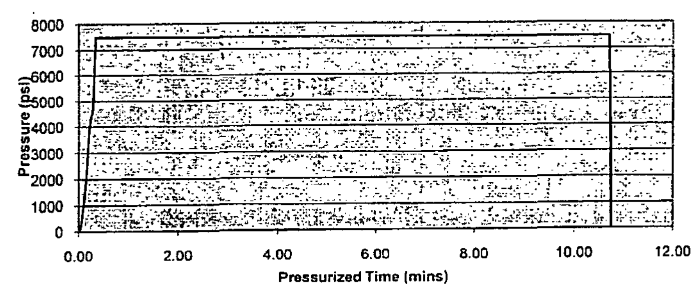
RELIANCE
Industrial Products USA, Ltd.

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

Cert No.: 27792
Date: 9/21/2012

Customer:	PRECISION DRILLING
P.O. #:	RIG 822
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