Form 3160-3
(March 2012)

OCD Hobbs

ATS-14-126

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

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No. NM 0557686
6. If Indian, Allotee or Tribe Name N/A
7. If Unit or CA Agreement, Name and No. N/A NM71041X M
8. Lease Name and Well No. SEMU 185 (31670)
9. API Well No. 30-025-43287

Split Estate

1a. Type of work: [X] DRILL [ ] REENTER

1b. Type of Well: [X] Oil Well [ ] Gas Well [ ] Other [ ] Single Zone [X] Multiple Zone

2. Name of Operator ConocoPhillips Company (217817)

3a. Address 600 N. DAIRY ASHFORD P10-4-4056 HOUSTON, TEXAS 77079

3b. Phone No. *(include area code)* (281)206-5282

HOBBS OCD

10. Field and Pool, or Exploratory (63080) SEMU; BLINEBRY-TUBB-DRINKARD

4. Location of Well *(Report location clearly and in accordance with any State requirements.*)*
At surface UL C, Sec. 14, T20S, R37E; 415' FNL & 2215' FWL
At proposed prod. zone SAME AS ABOVE

JUN 06 2016

RECEIVED

11. Sec., T. R. M. or Blk. and Survey or Area Sec. 14, T20S, R37E

14. Distance in miles and direction from nearest town or post office* Approximately 5 miles SE of Monument, NM

12. County or Parish LEA County
13. State NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) 415'

16. No. of acres in lease 1800

17. Spacing Unit dedicated to this well 40

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. Approximately 500'

19. Proposed Depth 7167'

20. BLM/BIA Bond No. on file ES0085

21. Elevations (Show whether DF, KDB, RT, GL, etc.) 3566'

22. Approximate date work will start* 01/10/2014

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 Kristina Mickens | Name *(Printed/Typed)* KRISTINA MICKENS | Date 10/16/2013

Title REGULATORY SPECIALIST

Approved by *(Signature)* James A. Amos | Name *(Printed/Typed)* | Date JUN 1 - 2016

Title FIELD MANAGER | Office CARLSBAD FIELD OFFICE

Application approval does not ...tify 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

APPROVAL FOR TWO YEARS

See attached NMOCD Conditions of Approval

Title 18 U.S.C. Section 1001 an... States any false, fictitious or fr... ...owingly and willfully to make to any department or agency of the United ... jurisdiction.

(Continued on page 2)

*(Instructions on page 2)

LEA COUNTY CONTROLLED WATER BASIN

KZ 06/06/16

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

SEE ATTACHED FOR CONDITIONS OF APPROVAL

Drilling Plan
ConocoPhillips Company
SEMU; Glorieta / Blinebry, Tubb, Drinkard

SEMU #185

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 Depths FT MD	Contents
Quaternary	Surface	Fresh Water
Rustler	1341	Anhydrite
Salado (top of salt)	1426	Salt
Tansill (base of salt)	2530	Gas, Oil and Water
Yates	2679	Gas, Oil and Water
Seven Rivers	2933	Gas, Oil and Water
Queen	3486	Gas, Oil and Water
Penrose	3611	Gas, Oil and Water
Grayburg	3744	Gas, Oil and Water
San Andres	4042	Gas, Oil and Water
Glorieta	5217	Gas, Oil and Water
Paddock	5351	Gas, Oil and Water
Blinebry	5649	Gas, Oil and Water
Tubb	6354	Gas, Oil and Water
Drinkard	6666	Gas, Oil and Water
Abo	6967	Deepest estimated perf. is above Top of Abo
Total Depth (maximum)	7167	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
see COA Surf	12-1/4	0	~~1366'~~ – 1411'	8-5/8	24#	J-55	STC	2950	1370	244	1.39	2.18	3.07
Option: Prod w/ Bond Coat	7-7/8	4000'	5200'	5-1/2	17#	L-80	LTC	7740	6290	338	NA	NA	NA
Prod	7-7/8	0	7112' – 7157'	5-1/2	17#	L-80	LTC	7740	6290	338	2.08	2.93	1.96

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	1411	24	2950	1370	244000	8.5	4.73	2.20	7.2	8.3
Production Casing	7157	17	7740	6290	338000	10	2.08	1.69	2.78	3.28

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)	1411	24	2950	1370	244000	381000	8.5	1.39	2.18	3.07
Production Casing (5-1/2" 17# L-80 LTC)	7157	17	7740	6290	338000	397000	10	2.08	2.93	1.96

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 (MW_{hyd} next section) =	1411	x	0.052	x	10	=	734				
Case #2. MPSP (Field SW @ $Bullhead_{CSFG}$ + 200 psi) =	1411	x	0.052	x	19.23	-	734	+	200	=	877
Case #3. MPSP (Kick Vol @ next section TD) =	7157	x	0.052	x	8.55	-	574.6	-	624	=	*1984*
Case #4. MPSP (PPTD - GG) =	7157	x	0.052	x	8.55	-	715.7	=	*2466*		
Case #3 & #4 Limited to MPSP (CSFG + 0.2 ppg) =	1411	x	0.052	x (	19.23	+	0.2	) =	1426		
MASP (MW_{hyd} + Test Pressure) =	1411	x	0.052	x	8.5	+	1500	=	2124		
Burst Safety Factor (Max. MPSP or MASP) =	2950	/	2124	=	1.39						

Production Casing Burst Safety Factor:

Case #1. MPSP ($MW_{hyd\ TD}$) =	7157	x	0.052	x	10	=	3721.64		
Case #4. MPSP (PPTD - GG) =	7157	x	0.052	x	8.55	-	715.7	=	2466
Burst Safety Factor (Max. MPSP) =	7740	/	3722	=	2.08				
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 =	14.2	ppg
Top of Surface Tail Cement =	350	ft	Top of Prod Tail Cement =	4000	ft

Surface Casing Collapse Safety Factor:

Full Evacuation Diff Pressure =	1411	x	0.052	x	8.55	=	627										
Cementing Diff Lift Pressure =	[(	1061	x	0.052	x	13.6	) + (	350	x	0.052	x	14.8	) -	612	] =	408	
Collapse Safety Factor =	1370	/	627	=	2.18												

Production Casing Collapse Safety Factor:

1/3 Evacuation Diff Pressure =	[(	7157	x	0.052	x	8.55	) - (	7157	/	3	x	0.052	x	8.34	)] =	2147		
Cementing Diff Lift Pressure =	[(	3157	x	0.052	x	11.8	) + (	4000	x	0.052	x	14.2	) -	3104	] =	1787		
Collapse Safety Factor =	6290	/	2147	=	2.93													

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 =	33864							
Bouyant Wt =	33864	x	0.870	=	29469			
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	- (	33864	x	0.870	) =	144816	
Tensial Safety Factor =	244000	/ (	29469	+	50000	) =	3.07	

Production Casing Tensial Strength Safety Factor:

Air Wt =	121669						
Bouyant Wt =	121669	x	0.847	=	103094		
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	- (	121669	x	0.847	) =	121906
Tensial Safety Factor =	300000	/ (	103094	+	50000	) =	1.96

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) =	(	33864	x	0.870	) =	29469					
Prod Casing Wt (Bouyant) =	(	121669	x	0.847	) =	103094					
Tubing Wt (Air Wt) =	7157	x	6.5	=	46521						
Tubing Fluid Wt =	7157	x	0.052	x	6.55	x	0.7854	x	2.441	^2 =	11408
Load on Conductor =	3000	+	29469	+	103094	+	46520.5	+	11408	=	193491
Conductor Compression Safety Factor =	432966	/	193491	=	2.24						
Load on Surface Casing =	193491	x	60%	=	116095						
Surface Casing Compression Safety Factor =	244000	/	116095	=	2.10						

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 ft^3/sx
Lead	Class C	Surface	1016' – 1061'	13.6	450	765	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	1016' – 1061'	1366' – 1411'	14.8	230	308	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	4000'	11.8	600	1560	10% Bentonite 8 lbs/sx Salt 0.4% Fluid loss additive 0.125% LCM if needed Excess = 115 % or more if needed based on gauge hole volume	2.6
Tail	50:50 Poz/H	4000'	7112' – 7157'	14.2	450	612	+ 5 % NaCl + 0.2% Defoamer + 5 lb/sx Extender + 0.125 lb/sx LCM if needed + 0.3% Fluid Loss Excess = 50 % or more if needed based on gauge hole volume	1.33 ~ 1.36

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 waterflow 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	4000'	7112' – 7157'	14.2	450	612	+ 5 % NaCl + 0.2% Defoamer + 5 lb/sx Extender + 0.125 lb/sx LCM if needed + 0.3% Fluid Loss Excess = 30 % or more if needed based on gauge hole volume	1.33 ~ 1.36

Stage 2 - Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft^3/sx
Lead	50:50 Poz/C	Surface	Stage Tool ~ 4000'	11.8	600	1560	+ 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.

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:
- 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.** 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.	150 – 300
Surface Casing Point to TD	Brine (Saturated $NaCl_2$) in Steel Pits	10	29	N.C.	10 – 11	300 – 1000
Conversion to Mud at TD	Brine Based Mud ($NaCl_2$) in Steel Pits	10	33 – 40	5 – 10	10 – 11	0 – 1000

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 2350' MD: (Spectral Gamma Ray, PE, Resistivity (laterologs), Bulk Density, and Sonic
      - Total Depth to surface Casing Shoe: Caliper
      - Total Depth to surface, Total Gamma Ray and Neutron
      - Total Depth to 2350' MD ; Mud Log (optional)
      - Total Depth to 2350' MD ; Dielectric Scanner (optional)
      - Formation pressure data (XPT) on electric line if needed (optional)
      - Rotary Sidewall Cores on electric line if needed (optional)
      - FMI (Formation MicroImager) if needed (optional)
      - UBI (Ultrasonic Borehole Imager) if needed (optional)
   e. Cement Bond Log (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 8.5 ppg gradient.
  - The expected Bottom Hole Temperature is 113 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
Seven Rivers	6	50 - 100 MCFD	0	0
Grayburg / San Andres	18360	20 - 50 MCFD	95	43
Glorieta	41000	0 – 6 MCFD	41	19
Blinebry / Tubb / Drinkard	6535	200 - 220 MCFD	126	57

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 2014 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

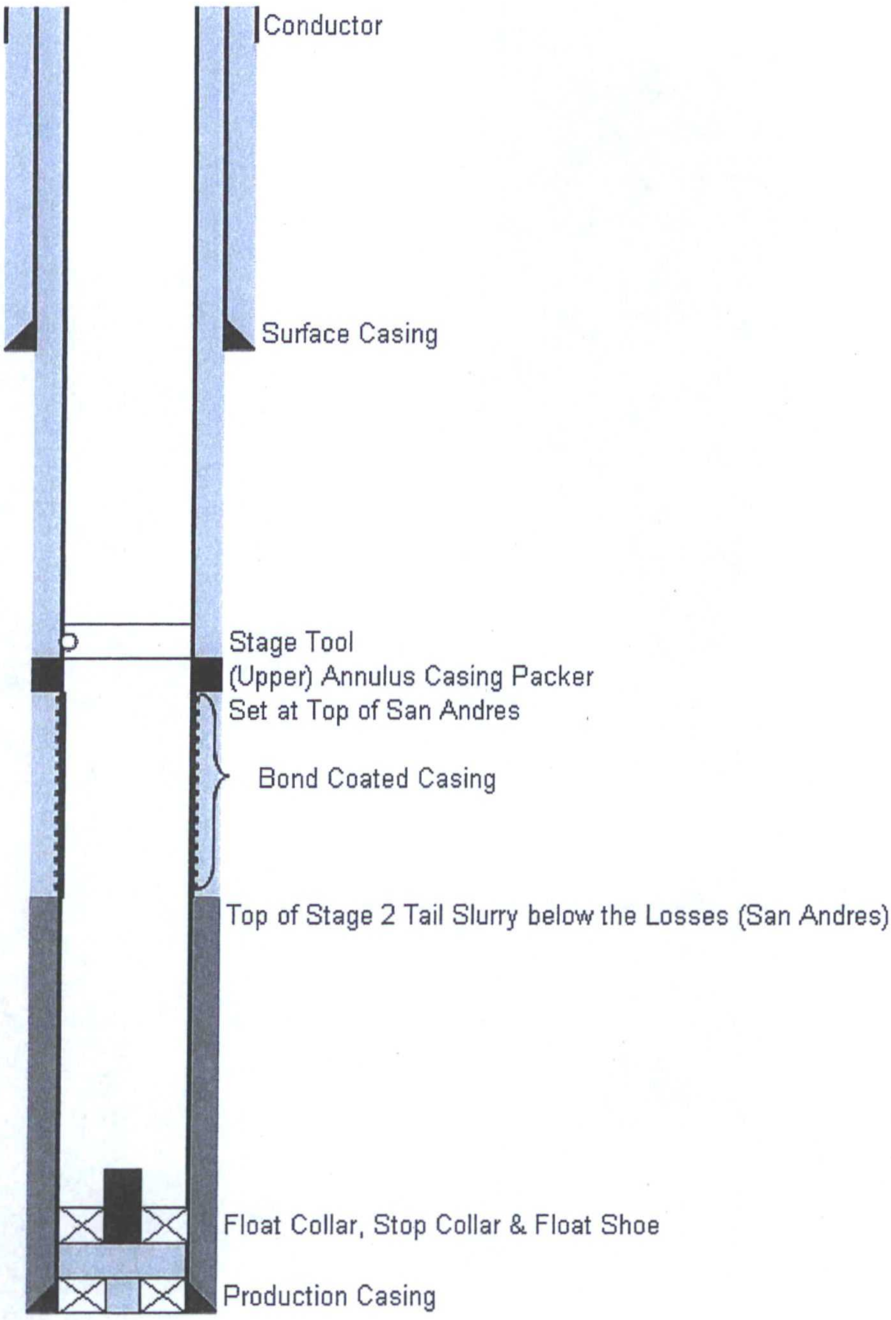
Contact Information:

Proposed 15 October 2013 by:
James Chen
Drilling Engineer, ConocoPhillips Company
Phone (832) 486-2184
Cell (832) 768-1647

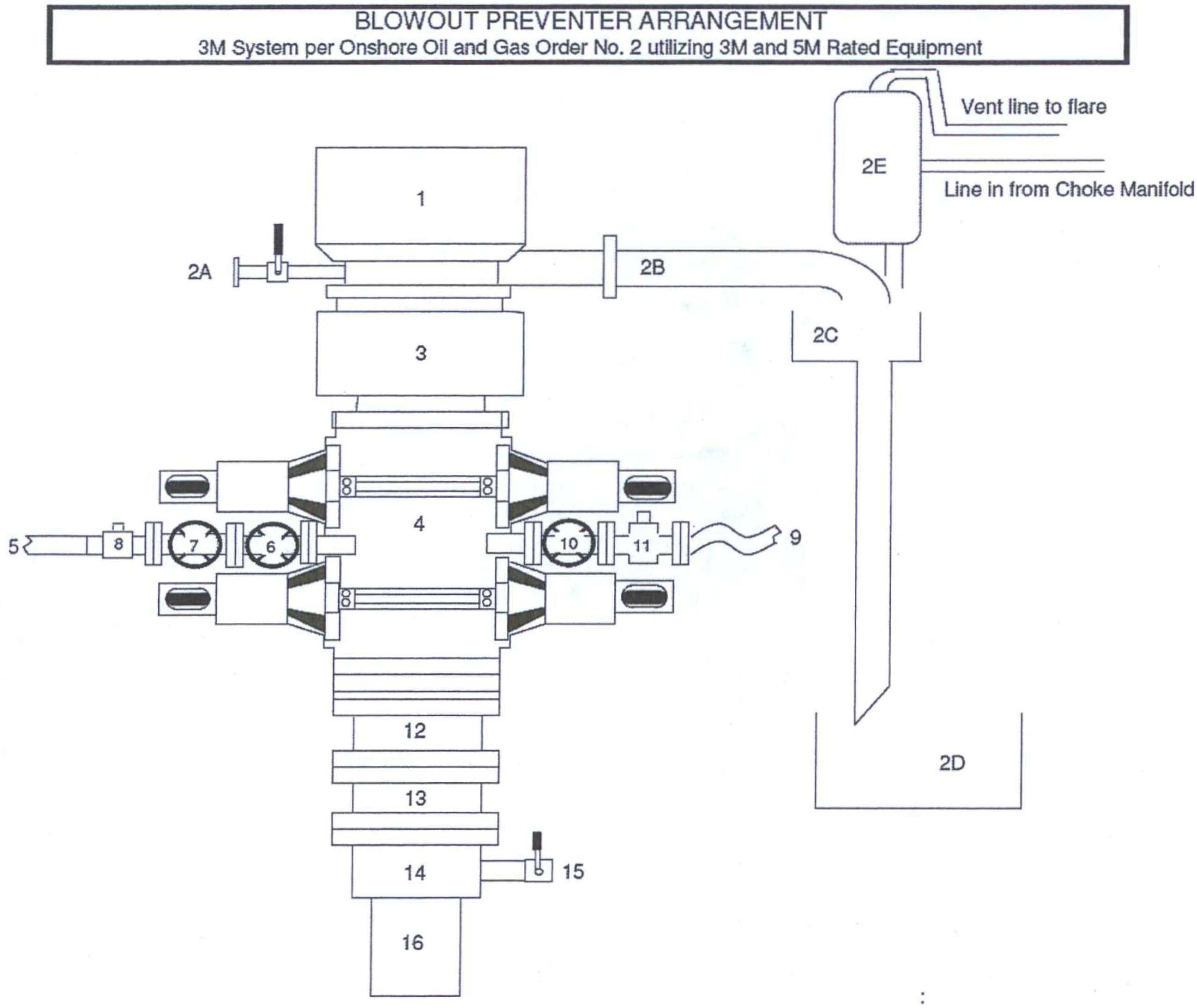
Attachment # 1

Two-Stage Cementing (Alternative for Severe Loss Zone)

Provide contingency plan for using two-stage cementing for the production casing cement job if severe losses occurs during the drilling operations. See APD Drill Plan Section 3. Proposed cementing program.



Attachment # 2



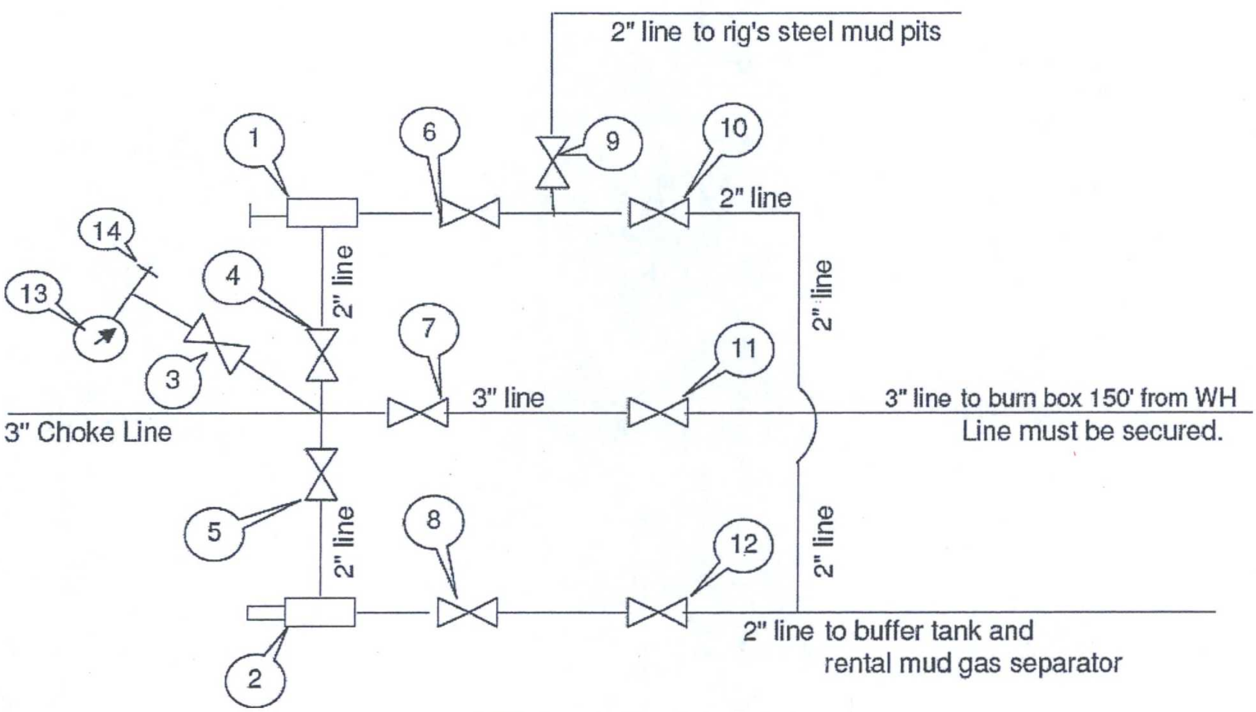
Item	Description
1	Rotating Head, 11"
2A	Fill up Line and Valve
2B	Flow Line (10")
2C	Shale Shakers and Solids Settling Tank
2D	Cuttings Bins for Zero Discharge
2E	Rental Mud Gas Separator with vent line to flare and return line to mud system
3	Annular BOP (11", 3M)
4	Double Ram (11", 3M, equipped with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

Attachment # 3

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	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