ATS-11-501

OCD Hobbs

Form 3160-3
(August 2007)

HOBBS OCD

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

DEC 12 2011

APPLICATION FOR PERMIT TO DRILL OR REENTER

RECEIVED

FORM APPROVED
OMB No 1004-0137
Expires July 31, 2010

5. Lease Serial No.
NMNM-012612

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

7. If Unit or CA Agreement, Name and No.
COOPER JAL NMNM-070926X

8. Lease Name and Well No. <306443>
COOPER JAL UNIT 109

9. API Well No.
30-025-11133

10. Field and Pool, or Exploratory
JALMAT;TAN-YATES-7 RVRS (OIL)

11. Sec., T. R. M. or Blk. and Survey or Area
NESW 18-24S-37E NMPM

1a. Type of work: ☐ DRILL ☑ REENTER

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

2. Name of Operator RESACA OPERATING COMPANY <263848> Split Estate

3a. Address 1331 LAMAR, SUITE 1450
HOUSTON, TX 77010-3039

3b. Phone No. (include area code)
713 650-1246

4. Location of Well (Report location clearly and in accordance with any State requirements *)
At surface 1979' FSL & 2005' FWL
At proposed prod. zone SAME

14. Distance in miles and direction from nearest town or post office*
7 AIR MILES NORTH OF JAL, NM

12. County or Parish
LEA

13. State
NM

15. Distance from proposed* location to nearest property or lease line, ft (Also to nearest drig. unit line, if any) 661'

16. No. of acres in lease
312.45

17. Spacing Unit dedicated to this well
N/A

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. 806' (Cooper Jal 505)

19. Proposed Depth
3,300'

20. BLM/BIA Bond No. on file
NM ~~B005247~~ 624

21. Elevations (Show whether DF, KDB, RT, GL, etc.)
3,304.9' UNGRADED

22. Approximate date work will start*
07/31/2011

23. Estimated duration
1 WEEK

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 [signature]
Name (Printed/Typed) BRIAN WOOD (505 466-8120)
Date 07/23/2011

Title
CONSULTANT
(FAX 505 466-9682)

Approved by (Signature) /s/ James Stovall
Name (Printed/Typed)
Date DEC 06 2011

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.

(Continued on page 2)

WFX-888

*(Instructions on page 2)

Capitan Controlled Water Basin

KE 12/13/11

SEE ATTACHED FOR
CONDITIONS OF APPROVAL

Approval Subject to General Requirements & Special Stipulations Attached

DEC 13 2011

REVISED RE-ENTRY PROGNOSIS

Resaca Operating Co.
Cooper Jal Unit #109
API No. 30-025-11133
1,980' FSL, 1980' FWL
Section 18, T-24S, R-37E
Lea Co., New Mexico

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RECEIVED

DESCRIPTION OF OPERATION

Resaca proposes to re-enter and deepen subject well which was drilled in 1948 and plugged in 2000 as part of an effort to re-develop certain acreage within the Cooper Jal Unit, an existing Secondary Recovery project. The Unitized Interval includes both the Jalmat and Langlie Mattix pools. Due to the existence of an internal liner in subject well, only the Jalmat pool will be accessed through this wellbore, which will be utilized as an injection well. Injection authority will be obtained prior to injection.

1) SURFACE DESCRIPTION

The surface is a mildly undulating dunal plain consisting of Quaternary alluvium sediments. Vegetation is sparse, and includes snakeweed, shinoak, yucca cactus, assorted grasses and, on a more limited basis, other flora. The ground elevation at the wellsite is 3,311' above sea level.

2) FORMATION TOPS

Formation	Estimated Top - MD (ft)	Lithology	Fluid Content
Alluvium	0	Sand, Caliche	Fresh Water
Ogalalla	145	Red Beds	None
Rustler	1,202	Anhydrite	None
Salado	1,305	Salt	None
Tansill	2,870	Anhydrite, Dolomite	None
Yates	2,974	Sandstone, Dolomite	Oil
Seven Rivers	3,206	Sandstone, Dolomite	Oil
Queen	3,608	Sandstone, Dolomite	Oil

The surface casing previously set and cemented in this well isolates and thereby protects the fresh water interval. The production casing previously set and cemented in this well isolates various productive intervals. It is not anticipated that any additional casing or remedial cementing will be required.

The Jalmat Pool is defined, in this area, as the interval from the top of the Tansill formation to a point 100' above the base of the Seven Rivers formation, thereby including all of the Yates formation. The top of the Tansill formation is at a depth of 2,870' in subject well.

The Langlie Mattix Pool is defined as the interval from 100' above the base of the Seven Rivers formation to the base of the Queen formation. The base of the Queen formation is estimated from offset well logs to be below the proposed total depth of subject well.

3) WELL CONTROL EQUIPMENT

A 2M system (as defined by BLM Onshore Oil and Gas Order No. 2), including a 3,000 PSI dual ram BOP dressed with 2-1/16" pipe rams and blind rams and choke manifold will be utilized throughout the proposed operations. The configuration and components of the BOP stack are set forth on Exhibit A, attached hereto. The configuration and components of the choke manifold are set forth on Exhibit B, attached hereto. The serial number and a copy of the test certificate for the rubber hose which will connect the BOP stack to the choke manifold will be provided by sundry notice prior to commencement of operations. Flex line request will be approved when sundry submitted.

See COA

All blowout prevention equipment will meet the minimum standards outlined in BLM Onshore Oil and Gas Order 2. A schematic indicating the routing to the choke manifold and the closed loop system is attached hereto as Exhibit C. A safety valve and crossovers to facilitate make-up to each workstring component will be kept on or near the rig floor.

The blowout preventers and choke manifold will be tested in accordance with the provisions of BLM Onshore Oil and Gas Order 2 upon installation. Pipe rams will be function tested once each 24-hour period, and blind rams will be function tested each time the workstring is out of the hole.

4) WELL CONSTRUCTION

Surface and production casing were set and cemented when the well was drilled in 1948. A 3,000 psi socket weld wellhead will be installed on the 8-5/8" surface casing and the 5-1/2" production casing, and a 3,000 psi socket weld tubing head will be installed on the 3-1/2" internal liner.

Existing casing is as follows:

Hole Size (in)	Setting Depth (ft)	Outer Diameter (in)	Weight (ppf)	Grade	Threads
Unknown	284	8.625	24	Unknown	Unknown
Unknown	3,345	5.500	14	Unknown	Unknown
5.012	3,306	3.500	9.3	J-55	Unknown

A casing design audit has been conducted as follows:

- Maximum collapse loading was assumed to occur at the bottom of each casing string. An external pressure equivalent to that which would be exerted by a column of 10 ppg brine water (0.520 psi/ft), and an internal pressure of 0 psi were assumed.

- Maximum burst loading was assumed to occur at the top of each casing string. An internal pressure equivalent to that which would be exerted at setting depth by a column of 10 ppg brine water (0.520 psi/ft), and an external pressure of 0 psi were assumed.
- Tensile loading was not evaluated as all casing strings have been run and are cemented in place.
- To the extent the casing grade is unknown, the lowest applicable API grade was assumed.

Based upon these evaluation criteria, the surface casing was determined to have a collapse safety factor of 9.28 and a burst safety factor of 19.98, and the production casing was determined to have a collapse safety factor of 1.51 and a burst safety factor of 1.79. The internal liner was determined to have a collapse safety factor of 4.30 and a burst safety factor of 4.06.

The surface casing was cemented with 150 sacks of cement of unknown composition and yield. Available well records do not document circulation of the cement to surface; however, the calculated cement top, based on an assumed hole size of 12-1/4", yield of 1.18 ft^3/sk (neat Class A,) and hole enlargement factor of 20 percent, is at the surface.

The production casing was cemented with 500 sacks of cement of unknown composition and yield. Available well records do not document the top of cement; however, the calculated cement top, based on an assumed hole size of 7-7/8", yield of 1.18 ft^3/sk (neat Class A), and hole enlargement factor of 20 percent, is at 621'. It is noted that a total of 1625 sx of cement were squeezed behind the production casing through casing leaks over the interval from 599' to 914' during remedial operations performed prior to running the internal liner.

The internal liner was cemented with 290 sacks of class H cement. Cement was circulated to surface.

5) WORKING FLUID

Working fluid will be fresh water with 2% KCl, with a density of 8.4 ppg. Gelled sweeps and lost circulation material will be utilized as necessary. Working volume will be approximately 500 barrels. Given the low anticipated bottom-hole pressure, use of weighting materials is not anticipated, and no circulating system monitoring equipment will be utilized.

6) LOGGING, CORING AND TESTING

No mud-logging, coring, or testing are anticipated. The Unitized Interval may be logged in whole or part. Specific logs to be run have not yet been determined.

7) ANTICIPATED PRESSURES AND DRILLING HAZARDS

All formations above the Unitized Interval are cased off. The previous producing intervals, as well as the interval through which the well will be deepened, are believed to be partially pressure depleted due to production from the Unit and surrounding wells.

Based on a static fluid level survey conducted in April 2007 in an offset well (the Cooper Jal #505), reservoir pressure was 274 psi at a depth of 3,362'. Since that time, injection rates have been increased, and reservoir pressure is likely to have risen; however, it is anticipated that the working fluid will create an overbalanced condition, and lost circulation may occur.

Hydrogen Sulfide may be present in the Yates and Seven Rivers. H_2S equipment will be operational prior to drilling out any cement plugs, and all operations will be conducted in accordance with BLM Onshore Oil and Gas Order 6. An H_2S plan is attached.

GENERAL PROCEDURE

1) Remove dry hole marker. Dress casing as necessary. Install 3,000 psi socket weld wellhead on 8-5/8" casing. Install 3,000 psi socket weld wellhead on 5-1/2" casing. Install 3,000 psi socket weld tubing head on 3-1/2" internal liner. Install 3,000 psi drilling flange.

2) MIRU pulling unit and reverse unit. Closed loop system to be utilized. Install H_2S equipment.

3) N/U and test 2M BOP system as depicted on Exhibits A and B.

See CoA *

4) P/U 2-7/8" bit on 2-1/16" workstring (BHA design to be determined), and drill out:

   a. Cement plug surface – 3,300' +/-.

See CoA

5) Circulate well clean. Test casing ~~to 500~~ psi. If leaks occur, isolate and repair per supplemental procedure. POOH and L/D 2-7/8" bit and workstring.

6) Log per supplemental procedure.

7) Perforate 2 spf (120 degree phasing) as follows:

   a. 3,249' – 3,268'
   b. 3,190' – 3,204'
   c. 3,174' – 3,184'
   d. 3,139' – 3,152'
   e. 3,103' – 3,132'
   f. 3,079' – 3,101'
   g. 3,053' – 3,073'
   h. 3,042' – 3,049'
   i. 3,008' – 3,034'
   j. 2,972' – 3,005'

8) Acidize well and flow back per supplemental procedure.

9) P/U 3-1/2" tension packer and RIH w/ 2-1/16" lined tubing. Set packer @ 2,925'. Land tubing.

10) N/D BOPs. N/U injection head.

11) Test casing to 500 psi.

12) RDMO pulling unit and other equipment.

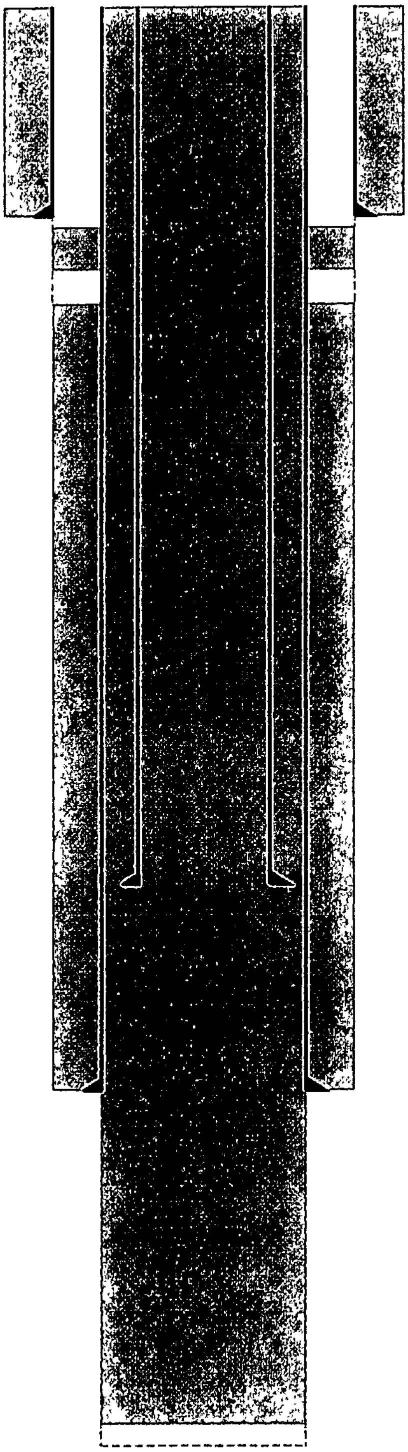
CURRENT WELLBORE SCHEMATIC

Operator	Resaca Operating Co
Well Name:	Cooper Jal #109
Well Location:	
Calls	1980' FSL, 1980' FWL
Unit	K
Section	18
Township	24S
Range	37E

csg leak 539' - 914'
sqz multiple times; 1625 sx cmt total

120 sx cmt plug surf - 2900'

80 sx cmt plug 2900' - 3515'



Surface Casing

Hole Size (in).	Unknown
Casing Size (in)	8 5/8
Casing Weight (ppf).	24
Setting Depth (ft)	284
Amount Cement (sx)	150
Top of Cement (ft).	Unknown
TOC Method	----------

Internal Liner

Casing Size (in):	3.5
Casing Weight (ppf):	9.3
Setting Depth (ft).	3306
Amount Cement (sx):	290
Top of Cement (ft):	0
TOC Method.	Circulated

Production Casing

Hole Size (in)	Unknown
Casing Size (in)	5 1/2
Casing Weight (ppf).	14
Setting Depth (ft).	3345
Amount Cement (sx)	500
Top of Cement (ft):	Unknown
TOC Method:	----------

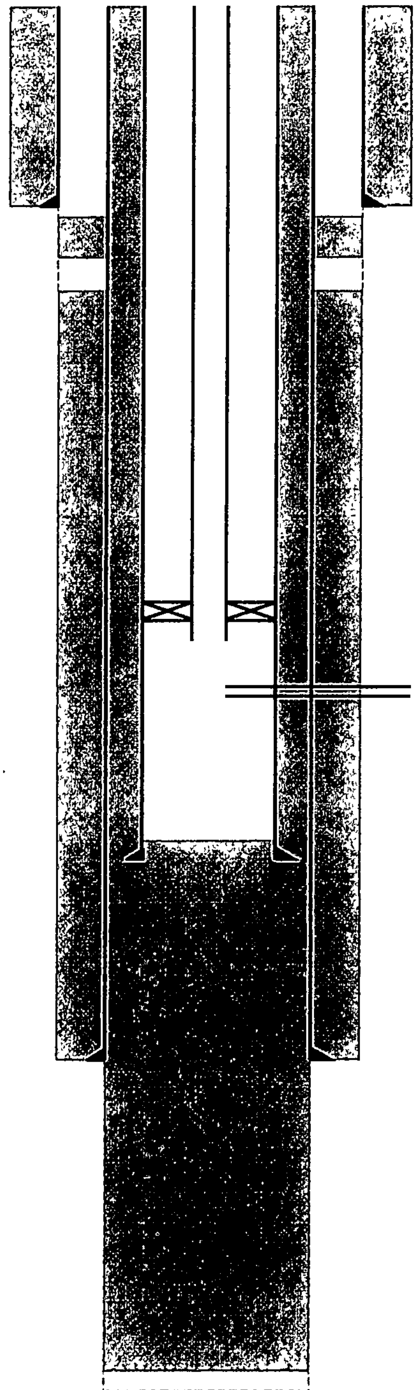
Open Hole

Hole Size (in):	Unknown
Top (ft):	3345
Bottom (ft)	3638

Total Depth (ft) 3638

PROPOSED WELLBORE SCHEMATIC

Operator:	Resaca Operating Co
Well Name.	Cooper Jal #109
Well Location.	
Calls	1980' FSL, 1980' FWL
Unit	K
Section	18
Township	24S
Range	37E



csg leak 539' - 914'
sqz multiple times, 1625 sx cmt total

80 sx cmt plug 2900' - 3515'
(drilled out to 3300')

Surface Casing

Hole Size (in):	Unknown
Casing Size (in)	8 5/8
Casing Weight (ppf)	24
Setting Depth (ft)	284
Amount Cement (sx)	150
Top of Cement (ft)	Unknown
TOC Method	----------

Injection Tubing

Tubing Size (in):	2 1/16
Tubing Weight (ppf):	3.25
Packer Depth (ft)	2925
Setting Depth (ft)	2950

Perforations

Top (ft)	2972
Bottom (ft)	3268

Internal Liner

Casing Size (in)	3 5
Casing Weight (ppf)	9 3
Setting Depth (ft)	3306
Amount Cement (sx):	290
Top of Cement (ft)	0
TOC Method	Circulated

Production Casing

Hole Size (in)	Unknown
Casing Size (in):	5 1/2
Casing Weight (ppf).	14
Setting Depth (ft):	3345
Amount Cement (sx)	500
Top of Cement (ft)	Unknown
TOC Method	----------

Open Hole

Hole Size (in)	Unknown
Top (ft)	3345
Bottom (ft)	3638

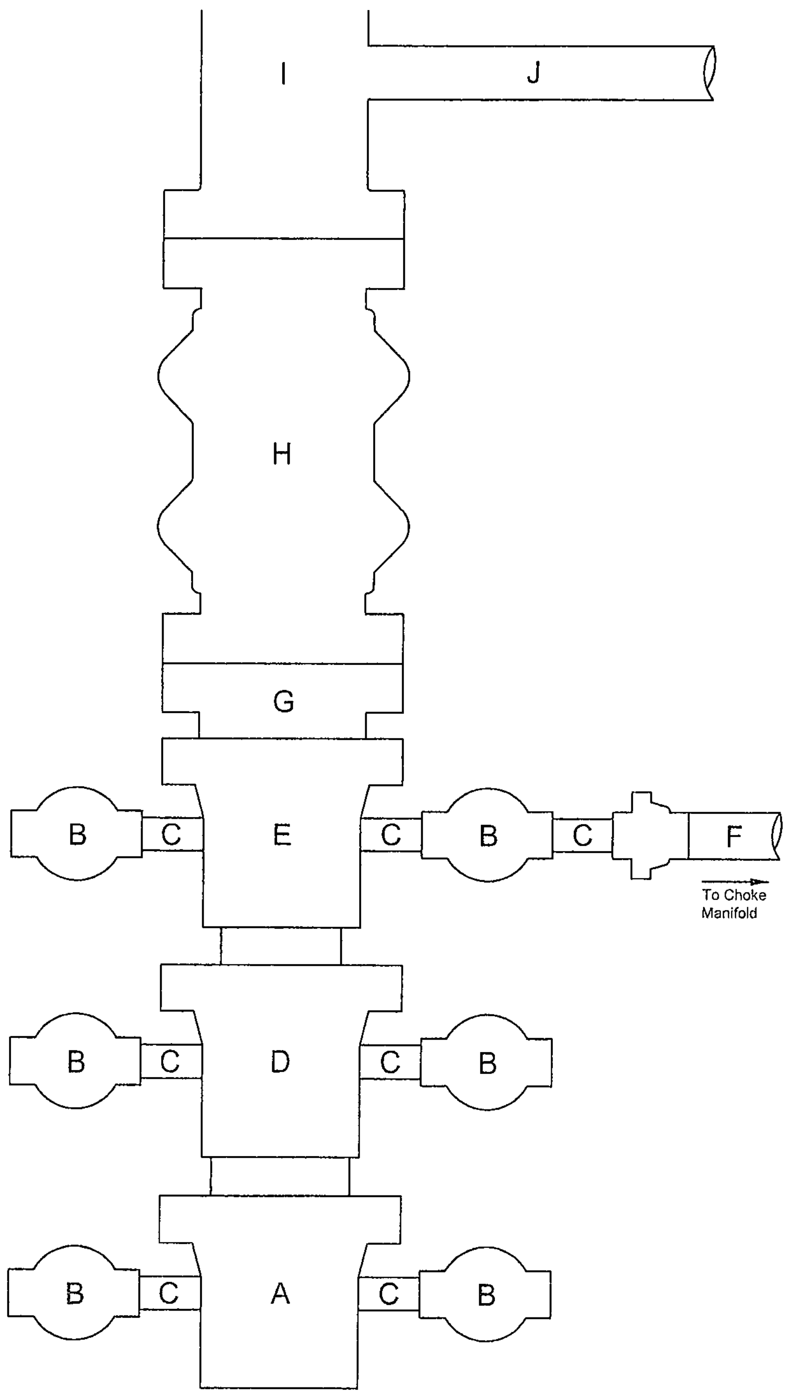
PBTD (ft):	3300
Total Depth (ft).	3638

REVISED EXHIBIT A:

2M BOP STACK CONFIGURATION - CJU #109

See COA *

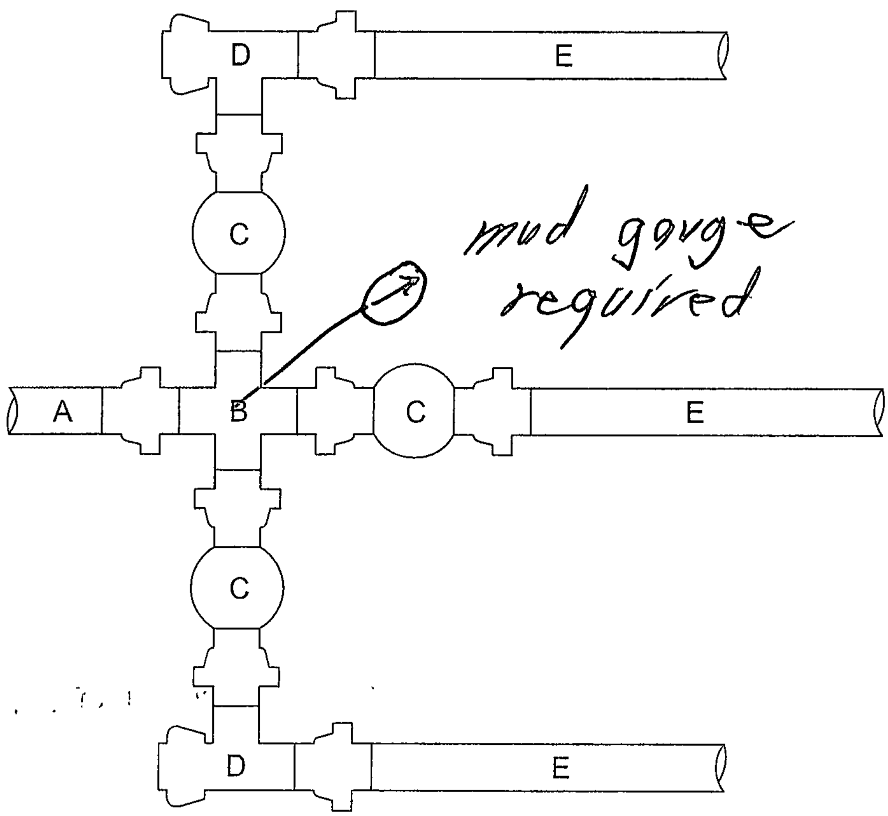
A. 8 ⅝" SW x 10 ¾" 3000 PSI WP Casing Mandrel w/ Threaded Outlets
B. 2 $1/16$" 3000 PSI WP Ball Valve
C. 2" Schedule 80 Nipple
D. 5 ½" SW x 8 ⅝" 3000 PSI WP Casing Mandrel w/ Threaded Outlets
E. 3 ½" SW x 8 ⅝" 3000 PSI WP Tubing Head w/ Threaded Outlets
F. 2" 2500 PSI WP Rubber Hose See COA
G. 8 ⅝" x 7 $1/16$" 3000 PSI WP Drilling Flange
H. 7 $1/16$" 3000 PSI WP Type "U" Double Ram Type BOP w/ Blind Rams & 2 $1/16$" Pipe Rams
I. Bell Nipple
J. Fill-Up Line



REVISED EXHIBIT B:

<u>2M CHOKE MANIFOLD CONFIGURATION</u>

A. 2" 2500 PSI WP Rubber Hose
B. 2 $\frac{1}{16}$" 3000 PSI WP Cross
C. 2 $\frac{1}{16}$" 3000 PSI WP Ball Valve
D. 2 $\frac{1}{16}$" 3000 PSI WP Manual Choke
E. 2" Schedule 80 Line Pipe



mud gauge required

Note: All connections are hammer unions.