ATS-10-389

Form 3160-3
(April 2004)

RECEIVED
OCD-Hobbs
JUN 10 2010
HOBBSOCD

FORM APPROVED
OMB No. 1004-0137
Expires March 31, 2007

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No. LC059002

6. If Indian, Allotee or Tribe Name

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

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

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

8. Lease Name and Well No. <31422>
MCA Unit 438

2. Name of Operator
ConocoPhillips Company <217817>

9. API Well No.
30-025- 39780

3a. Address 3300 N. "A" St., Bldg. 6 Midland, TX 79705

3b. Phone No. (include area code)
(432)688-6813

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.*) Unit E
At surface 1330' FNL & 660" FWL
At proposed prod. zone 1330' FNL & 660" FWL

11. Sec., T. R. M. or Blk. and Survey or Area
Sec. 34, T17S, R32E, UL "E"

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

16. No. of acres in lease: 13,786.66

17. Spacing Unit dedicated to this well: 40

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft.: 839' from MCA #406

19. Proposed Depth: 4620'

20. BLM/BIA Bond No. on file: ES0085

21. Elevations (Show whether DF, KDB, RT, GL, etc.): 3948' GR

22. Approximate date work will start*: 01/01/2011

23. Estimated duration: 7 days

24. Attachments

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No.1, shall 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 shall 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 authorized officer.

25. Signature	Name (Printed/Typed)	Date
[signature]	Jalyn N. Fiske	02/12/2010

Title
Regulatory Specialist

Approved by (Signature)	Name (Printed/Typed)	Date
/s/ Don Peterson		JUN 8 2010

Title	Office
FIELD MANAGER	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 Untied States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

*(Instructions on page 2)

Roswell Controlled Water Basin

KZ

SEE ATTACHED FOR
CONDITIONS OF APPROVAL

APPROVAL SUBJECT TO
GENERAL REQUIREMENTS
AND SPECIAL STIPULATIONS
ATTACHED

DISTRICT I
1625 N. French Dr., Hobbs, NM 88240

DISTRICT II
1301 W. Grand Avenue, Artesia, NM 88210

DISTRICT III
1000 Rio Brazos Rd., Aztec, NM 87410

DISTRICT IV
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals & Natural Resources Department
OIL CONSERVATION DIVISION
1220 South St. Frances Dr.
Santa Fe, NM 87505

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Form C-102
Revised October 12, 2005
Submit to Appropriate District Office
State Lease - 4 Copies
Fee Lease - 3 Copies

☐ AMENDED REPORT

WELL LOCATION AND ACREAGE DEDICATION PLAT

API Number	Pool Code	Pool Name	
30-025-39780	43329	MALJAMAR; GRAYBURG-SAN ANDRES	
Property Code	**Property Name**		**Well Number**
31422	MCA UNIT		438
OGRID No.	**Operator Name**		**Elevation**
217817	CONOCOPHILLIPS		3948'

Surface Location

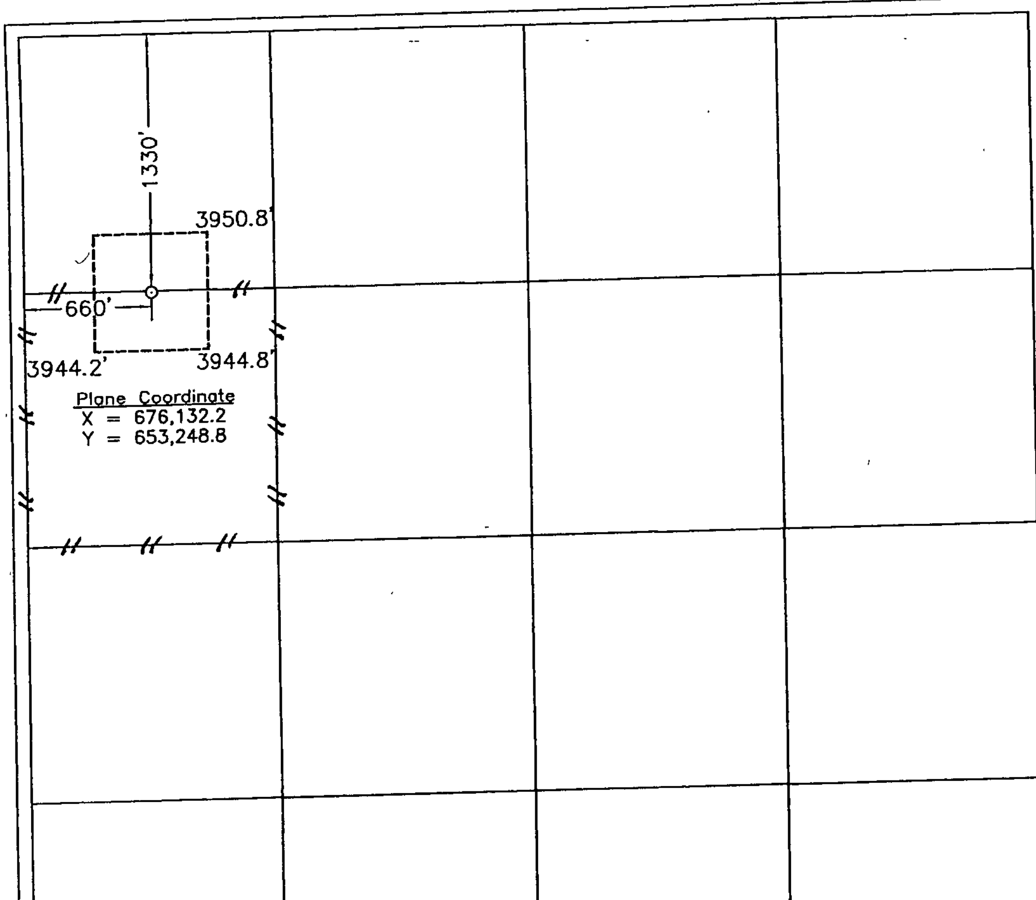
UL or lot No.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
E	34	17 S	32 E		1330	NORTH	660	WEST	LEA

Bottom Hole Location If Different From Surface

UL or lot No.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County

Dedicated Acres	Joint or Infill	Consolidation Code	Order No.
40			

NO ALLOWABLE WILL BE ASSIGNED TO THIS COMPLETION UNTIL ALL INTERESTS HAVE BEEN CONSOLIDATED OR A NON-STANDARD UNIT HAS BEEN APPROVED BY THE DIVISION



NOTE:

1) Plane Coordinates shown hereon are Transverse Mercator Grid and Conform to the "New Mexico Coordinate System", New Mexico East Zone, North American Datum of 1927. Distances shown hereon are mean horizontal surface values.

OPERATOR CERTIFICATION

I hereby certify the the information contained herein is true and complete to the best of my knowledge and belief, and that this organization either owns a working interest or unleased mineral interestin the land including the proposed bottom hole location or has a right to drill this well at this location pursuant to a contract with an owner of such a mineral or working interest, or to a voluntary pooling agreement or a compulsory pooling order heretofore entered by the division.

2/15/10

Signature Date

JALYN N. FISKE

Printed Name

SURVEYOR CERTIFICATION

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervison and that the same is true and correct to the best of my belief.

September 10, 2009

Date of Survey LVA

Signature & Seal of Professional Surveyor

MACON McDONALD
NEW MEXICO
12185
REGISTERED PROFESSIONAL SURVEYOR

W.O. Num. 2009-0573

Certificate No. MACON McDONALD 12185

MCA 438

Formation Tops and Planned Total Depth

Formation Call Points	Top (ft MD)
Rustler	1029
Salado	1246
Grayburg	3778
Grayburg - 6	4052
San Andres	4241
San Andres - 7	4241
San Andres - 9	4518
Total Depth (minimum)	4575
Total Depth (maximum)	4620

Casing Depths

String	Minimum Depth	Maximum Depth
Surface Casing	1054	1099
Production Casing	4565	4610

Note: The Surface Casing and the Production Casing programs reflect an uncertainty of 45' in the setting depth for the shoe because that is the approximate length of a full joint of Range 3 casing. This range for the setting depth will allow us to drill the hole to fit the casing string based on how the tally comes out and will provide for the cementing head to be positioned at the rig floor for safety and efficiency in cementing operations. The casing will be set approximately 10 ft off bottom.

Master Drilling Plan
ConocoPhillips Company
MCA Unit
February 28, 2008
(Revised July 23, 2008)

Lea County, NM
Pool: Maljamar; Grayburg-San Andres

MCA UNIT AREA

Lease	Sfx	Lessor	Twn	Rng	Sec	QQ
N/A		USA LC 061842	17	32	14	E2
N/A		Fee	17	32	14	W2
N/A		USA LC 059576	17	32	15	NE
088907	000	USA LC 054687	17	32	15	N2, SW, W2SE
269411	000	USA NM-080258	17	32	15	E2SE
N/A		State of New Mexico B-2366-16	17	32	16	NE, N2SE
N/A		State of New Mexico VO-3555	17	32	16	N2SW
109063	000	State of New Mexico B 155-5	17	32	16	S2SW
109063	000	State of New Mexico B 155-5	17	32	16	NW
088913	000	State of New Mexico B 2366-11	17	32	16	SWSE
088908	000	State of New Mexico B 4062-3	17	32	16	SESE
088912	000	USA LC 029405-B	17	32	17	W2
088912	000	USA LC 029405-B	17	32	17	W2E2
109069	000	USA NM LC 060329	17	32	17	E2E2
088912	000	USA LC 029405-B	17	32	18	E2
088912	000	USA LC 029405-B	17	32	18	E2W2
109069	000	USA NM LC 060329	17	32	18	NWNW
109069	000	USA NM LC 060329	17	32	18	SWSW
088911	000	USA LC 029405-A	17	32	19	N2
088912	000	USA LC 029405-B	17	32	19	S2
088911	000	USA LC 029405-A	17	32	20	N2
088912	000	USA LC 029405-B	17	32	20	S2
088909	000	USA LC 029509-A	17	32	21	N2, SW, N2SE
088910	000	USA LC 029509-B	17	32	21	S2SE
088909	000	USA LC 029509-A	17	32	22	W2NW
088910	000	USA LC 029509-B	17	32	22	NE
088910	000	USA LC 029509-B	17	32	22	E2NW
088910	000	USA LC 029509-B	17	32	22	NWSE
088910	000	USA LC 029509-B	17	32	22	SW
253943	000	USA LC 058395	17	32	22	E2SE
253943	000	USA LC 058395	17	32	22	SWSE
101798	000	USA LC 029400-A	17	32	23	NWSW
109067	000	USA LC 058697-A	17	32	23	S2SE
109066	000	USA LC 058698-A	17	32	23	N2SE
109066	000	USA LC 058698-A	17	32	23	NESW
109066	000	USA LC 058698-A	17	32	23	S2SW
109068	000	USA LC 058698-B	17	32	23	N2
N/A		USA LC 058697-B	17	32	25	All
262724	000	USA LC 058408-A	17	32	26	W2NE
262723	000	USA LC 058408-B	17	32	26	NESE, NWSE, S2SE
109066	000	USA LC 058698-A	17	32	26	S2NW
253944	000	USA LC 058699	17	32	26	SW
109062	000	USA LC 061841	17	32	26	N2NW
256034	000	USA NM 94188	17	32	26	E2NE
109065	000	USA LC 057210	17	32	27	NENE, SE, SWNE,

						W2
253947	000	USA LC 058396	17	32	27	NWNE, SENE
109065	000	USA LC 057210	17	32	28	All
256050	000	USA LC 029410-A	17	32	29	All
N/A		USA LC 029410-B	17	32	30	W2, SE, W2NE
253946	000	USA LC 060199-B	17	32	30	E2NE
N/A		USA LC 029410-B	17	32	31	E2SE, N2
N/A		USA LC 069105	17	32	31	E2SE
		USA NM 03428	17	32	31	SW
N/A		State of NM B-4109	17	32	32	NE, N2NW,
N/A		State of NM B-6768	17	32	32	SE, NESW S2SW, NWSW,
N/A		State of NM OG-5119	17	32	32	S2NW
109072	000	USA LC 029409-A	17	32	33	SW
109071	000	USA LC 059001-A	17	32	33	E2, N2NW, S2NW
109060	000	USA LC 058514	17	32	34	NE
109059	000	USA LC 058728	17	32	34	E2NW
109061	000	USA LC 059002	17	32	34	W2NW
N/A		USA LC 068140	17	32	34	SW
N/A		USA LC 060503	17	32	34	N2SE
N/A		USA NM 036852	17	32	34	S2SE
109068	000	USA LC 058698-B	17	32	35	W2
109068	000	USA LC 058407-B	17	32	35	NE
109068	000	USA LC 058409-B	17	32	35	SE
109070	000	USA LC 058697-B	17	33	30	W2

1. **Geologic Name of Surface Formation:**
   - Quaternary Alluvium and Dunes

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

In the MCA Unit, the estimated tops of the geological markers and proposed Total Depth (TD) vary within a range of approximately 550' to 775'. The range of minimum to maximum depth for these markers and proposed TD range is presented in the table below. The datum for these depths is RKB or Rig Floor (which is 10' - 12' above Ground Level).

Formation Call	Top (MD)		Contents
	Minimum	Maximum	
Above top of Rustler			Fresh Water
Rustler	600'	1,170'	
Salado	775'	1,380'	
Grayburg	3,270'	3,940'	Oil, Gas, Salt Water and possible CO2 from old injection Program
Grayburg 6	3,480'	4,170'	Oil, Gas, Salt Water and possible CO2 from old injection Program
San Andres 7	3,610'	4,345'	Oil, Gas, Salt Water and possible CO2 from old injection Program
San Andres 9	3,810'	4,585'	Oil, Gas, Salt Water and possible CO2 from old injection Program
Proposed TD	4,155'	4,705'	Oil, Gas, Salt Water and possible CO2 from old injection Program

Note: For each individual well we will include with our Application for Permit to Drill (APD) our correlation pick depths for the formation tops and proposed TD for that individual well.

Protection of fresh water will be accomplished by setting the surface casing 25' - 70' into the Rustler Anhydrite formation and **cementing** the surface casing from the casing shoe **to the surface of ground** in accordance with the provisions of Onshore Oil and Gas Order No. 2 and New Mexico Oil Conservation Division Title 19.

3. Proposed casing program:

Type	Hole Size (in)	Interval MD RKB (ft) From	To	OD (inches)	Wt (lb/ft)	Gr	Conn	Condition	Safety Factors Calculated per BLM Load Formulas Burst	Collapse	Tension Dry/Buoyant
Cond	17-1/2"	0	40' – 87' (30' – 75' BGL)	13-3/8"	48#	H-40	STC	New	NA	NA	NA
Surf	12-1/4"	0	625'– 1,240'	8-5/8"	24#	J-55	STC	New	5.49	2.5	8.2 / 9.42
Prod	7-7/8"	0	4,155' – 4,705'	5-1/2"	17#	J-55	LTC	New	2.17	2.01	3.09 / 3.64

We propose to set the surface and production casing approximately 10' off bottom and to drill the hole to fit the casing string so that the cementing head is positioned at the floor for the cement job.

Casing Design (Safety) Factors – BLM Criteria:

BLM Criteria for Minimum Design Factors

	Burst	Collapse	Tension
Casing Design Safety Factors	1.0	1.125	1.6 dry / 1.8 Buoyant

Joint Strength Design (Safety) Factor: SFt
SFt = Fj / Wt;
Where

- Fj is the rated pipe Joint Strength in pounds (lbs)
- Wt is the weight of the casing string in pounds (lbs)

The criteria for Minimum Acceptable Joint Strength Design (Safety) Factor SFT = 1.6 dry or 1.8 buoyant

Collapse Design (Safety) Factor: SFc
SFc = Pc / (MW x .052 x Ls)
Where

- Pc is the rated pipe Collapse Pressure in pounds per square inch (psi)
- MW is mud weight in pounds per gallon (ppg)
- Ls is the length of the string in feet (ft)

The criteria for Minimum Acceptable Collapse Design (Safety) Factor SFc = 1.125

Burst Design (Safety) Factor: SFb
SFb = Pi / BHP
Where

- Pi is the rated pipe Burst (Minimum Internal Yield) Pressure in pounds per square inch (psi)
- BHP is bottom hole pressure in pounds per square inch (psi)

The criteria for Minimum Acceptable Burst Design (Safety) Factor SFb = 1.0

Joint Strength Design (Safety) Factors – BLM Criteria

Surface Casing:

- SFj Dry = 244,000 lbs / (1240 ft x 24 lb/ft) = 244,000 lbs / 29,760 lbs = 8.20 Dry
- SFj Buoyant = 244,000 lbs / (1240 ft x 24 lb/ft) [1-(8.5/65.5)= 244,000 lbs / 25,898 lbs = 9.42 buoyant

Production Casing:

- SFj Dry = 247,000 lbs / (4705 ft x 17 lb/ft) = 247,000 lbs / 79,985 lbs = 3.09 Dry
- SFj Buoyant = 247,000 lbs / (4705 ft x 17 lb/ft) [1-(10.0/65.5)= 247,000 lbs / 67,773 lbs = 3.64 Buoyant

Collapse Design (Safety) Factors – BLM Criteria

Surface Casing:

SFc = 1370 psi / (8.5 ppg x .052 x 1240 ft) = 1370 psi / 548psi = 2.50

Production Casing:

SFc = 4910 psi / (10 ppg x .052 x 4705 ft) = 4910 psi / 2447 psi = 2.01

Burst Design (Safety) Factors – BLM Criteria

Surface Casing:

SFb = 2950 psi / (8.33 ppg x .052 x 1240 ft) = 2950 psi / 537 psi = 5.49

Production Casing:

SFb = 5320 psi / (7.15 ppg x .052 x 4705 ft) = 5320 psi / 1750 psi = 3.04 based on reservoir pressure data

SFb = 5320 psi / (10 ppg x .052 x 4705 ft) = 5320 psi / 2447 psi = 2.17 based on brine density used to drill to TD

Casing Design (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

Surface Casing:

The maximum internal (burst) load on the Surface Casing occurs when the surface casing is tested to 1500 psi. We will pressure up to 1600 psi and let the pressure settle for 1 minute after shutting down the pump. Therefore the maximum pressure that the surface casing will be exposed to will be 1600 psi.

Surface Casing Burst Design Factor

DF Burst = Burst Rating / Maximum Pressure During Casing Pressure Test = 2950 psi / 1600 psi = 1.84

The maximum collapse load on the Surface Casing occurs when we release the pressure after bumping the plug on the surface casing cement job.

Surface Casing Collapse Design Factor

DF Collapse = Collapse Rating / (Cement Column Hydrostatic Pressure – Displacement Fluid Hydrostatic Pressure)

DF Collapse = 1370 psi / {[(300 ft x .052 x 14.8 ppg) + (940 ft x .052 x 13.5 ppg)] – (1240 ft x .052 x 8.33 ppg)}

DF Collapse = 1370 psi / 354 psi

DF Collapse = 3.87

The maximum axial load on the Surface Casing would be the buoyant weight of the full string of casing plus an allowance for potential overpull in the amount of 30,000 lbs.

Surface Casing Axial (Tension) Design Factor
DF Tension = Joint Strength Rating / Buoyant Weight + Overpull Margin
Buoyancy Factor for fresh water (8.34 ppg fluid) = 1 – (8.34 / 65.5) = .873
Overpull Margin is selected to be 30,000 lbs
DF Tension = 244,000 lbs / [(1240 ft x 24 lb/ft x .873) + 30,0000 lbs]
DF Tension = 244,000 lbs / 55980 lbs
DF Tension = 4.36

Production Casing:

The maximum internal (burst) load would occur either during during fracture initiation or screen out. Fracture initiation occurs with 2% KCL water in the hole. Screen-out might occur with up to 12 ppg frac fluid in the hole.

For the fracture initiation load case, the design factor calculated at surface is:
DF Burst @ Surface for Fracture Initiation = Burst Rating / Maximum Applied Surface Pressure
DF Burst @ Surface for Fracture Initiation = 5320 psi / 4260 psi
DF Burst @ Surface for Fracture Initiation = 1.25

For the fracture initiation load case, the design factor calculated at TD is:
DF Burst @ TD for Fracture Initiation = Burst Rating / (Internal Pressure – Pore Pressure)
Internal Pressure at TD = Surface Pressure + Hydrostatic Pressure at TD of 2% KCL Water Column
Hydrostatic Pressure at TD of 2% KCL Water Column = 4705 ft x .052 x 8.6 ppg = 2104 psi
Surface Pressure at the time of Fracture Initiation = 4260 psi maximum
Internal Pressure at TD = 4260 psi + 2104 psi = 6364 psi
Pore Pressure in the Reservoir = 1750 psi approximately
DF Burst @ TD for Fracture Initiation = 5320 psi / (6364 psi - 1750 psi)
DF Burst @ TD for Fracture Initiation = 5320 psi / 4614 psi
DF Burst @ TD for Fracture Initiation = 1.15

For the screen out load case, the maximum burst loading occurs at TD and is calculated as follows:
DF Burst @ TD for Screen Out = Burst Rating / (Internal Pressure – Pore Pressure)
Internal Pressure at TD = Surface Pressure + Hydrostatic Pressure at TD of 12 ppg frac fluid
Hydrostatic Pressure at TD of 12 ppg frac fluid = 4705 ft x .052 x 12.0 ppg = 2936 psi
Maximum Allowable Surface Pressure at the time of Screen Out = 3450 psi maximum
Internal Pressure at TD at time of Screen Out = 3450 psi + 2936 psi = 6386 psi
Pore Pressure in the Reservoir = 1750 psi approximately
DF Burst @ TD for Fracture Initiation = 5320 psi / (6386 psi - 1750 psi)
DF Burst @ TD for Fracture Initiation = 5320 psi / 4636 psi
DF Burst @ TD for Fracture Initiation = 1.15

The maximum collapse load on the production casing occurs with the well pumped off on production. The maximum potential pore pressure in the well would be equal to or less 10 ppg which is the density of the brine drilling fluid used in drilling production hole interval from the Surface Casing Shoe to TD.

DF Collapse = Collapse Rating / Maximum Possible Pore Pressure
DF Collapse = 4910 / (10 ppg x .052 x 4705 ft) = 4910 psi / 2447 psi = 2.01

Production Casing Axial (Tension) Design Factor
DF Tension = Joint Strength Rating / Buoyant Weight + Overpull Margin
Buoyancy Factor for 10 ppg brine = 1 – (10.0 / 65.5) = .847
Overpull Margin is selected to be 30,000 lbs
DF Tension = 247,000 lbs / [(4705 ft x 17 lb/ft x .847) + 30,0000 lbs]
DF Tension = 247,000 lbs / 97,747 bs
DF Tension = 2.53

We propose options to our casing program as follows:

- **Single Stage Cementing:** We propose an option to perform a Single Stage cement job on the 5-1/2" production casing.

- **Two Stage Cementing:** We propose an option to run a Stage Tool in the 5-1/2" production casing and perform a two-stage cement job if losses are observed to occur while drilling the 7-7/8" production hole. The stage tool would be positioned near the top of the Grayburg formation. In any event in which we would propose to implement this contingency, a call would be made to the authorized officers at BLM and NMOCD to confirm permission prior to proceeding. **Also, if we do not circulate out any cement from the top of the Stage Tool, we must and will contact BLM and NMOCD to report this and obtain permission prior to proceeding with the 2nd Stage. A Cement Bond Log or other cement evaluation log will be run after moving off the drilling rig and prior to perforating to determine the top of cement on the Stage 1 cement job and this information will be communicated to BLM and NMOCD and permission will be obtained prior to continuing with the completion.**

- **Two Stage Cementing with External Casing Packers:** In the event that a waterflow is experienced while drilling the 7-7/8" production hole, we propose an option / contingency plan to run a Stage Tool with two each External Casing Packers (ECP's) in the 5-1/2" production casing and to perform a two stage cement job.

  The placement of the Stage Tool and External Casing Packers would be as follows:
  - The Lower External Casing Packer would be placed approximately 200' to 270' below the top of the Grayburg formation and would be above the shallowest planned perforation depth.
  - The Upper External Casing Packer would be placed approximately 500' to 1600' above the top of the Grayburg formation and would be above the waterflow.
  - The Stage Tool would be placed immediately above the Upper External Casing Packer.

  The execution of the Two Stage cement job with External Casing Packers would be as follows

  a. The Stage 1 cement would be pumped, placing cement from the casing shoe to the Stage Tool.

  b. The two ECP's would be simultaneously set by hydraulic pressure after bumping the Stage 1 cement Wiper Dart on the baffle on the float collar. The setting of the ECP's should shut off the water flow – isolating it between the ECP's.

  c. After setting the ECP's the Stage Tool would be opened by hydraulic pressure (or with the free fall opening cone if necessary) and the excess cement above the top of the Stage Tool would be circulated out. **Note: If we do not circulate out any cement from the top of the Stage Tool, we must and will contact BLM and NMOCD to report this and obtain permission prior to proceeding with the 2nd Stage. A Cement Bond Log or other cement evaluation log will be run after moving off the drilling rig and prior to perforating to determine the top of cement on the Stage 1 cement job and this information will be communicated to BLM and NMOCD and permission will be obtained prior to continuing with the completion.**

  d. The Stage 2 cement would be pumped placing cement from the Stage Tool to Surface. The closing wiper plug would be bumped on the stage tool and the Stage Tool would be closed with hydraulic pressure.

  In any event in which we would propose to implement this contingency, a call would be made to the authorized officers at BLM and NMOCD to confirm permission prior to proceeding.

Diagrams / schematics of the proposed casing program alternatives are attached.

4. Proposed cementing program:

For the cementing program a range is presented for the number of sacks of cement and for the bottom, top, and length of the lead slurries and tail slurries due to the variation in formation tops and planned TD for the planned / contemplated wells for which this Master Drilling Plan is intended.

13-3/8" Conductor:

Cement to surface with rat hole mix, ready mix or Class C Neat cement.

(Note: The gravel used in the cement is not to exceed 3/8" dia)

TOC at surface.

8-5/8" Surface Casing:

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

Lead Slurry Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 80 deg F by UCA Method	
							Time	Strength
207 – 599 sx Class C + 4% bentonite + 2% CaCl2 + 0.125% LCM if needed Excess = 170%	325' to 940'	Surface	325' to 940'	13.5	1.75	9.18	12 hrs 15 hrs 24 hrs	402 psi 500 psi 713 psi

Tail Slurry Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 91 deg F by UCA Method	
							Time	Strength
220 sx Class C + 2% CaCl2 + 0.125% LCM if needed Excess = 100%	625' to 1,240'	325' to 940'	300'	14.8	1.35	6.36	3 hrs 9 hrs 12 hrs 24 hrs 48 hrs	50 psi 500 psi 793 psi 1,266 psi 2,183 psi

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 of the cement on the Surface Casing in order to achieve at least 500 psi compressive strength in both the Lead Slurry and Tail Slurry cements prior to drilling out of the Surface Casing.

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 the top of the Grayburg formation,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water with an option to follow this with 1,000 gallons SuperFlush 102 and 20 additional bbls Fresh Water.

Lead Slurry Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
							Time	Strength
440 – 654 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.4% Fluid Loss Additive + 0.125% LCM if needed	3,270' to 3,940'	Surface	3,270' to 3,940'	11.8	2.51	14.64	12 hrs 24 hrs 48 hrs 72 hrs 116 hrs	93 psi 234 psi 382 psi 468 psi 584 psi
Excess = 88% - 135% (based on caliper if available)								

Tail Slurry (this is a CO_2 resistant cement) Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by UCA Method	
							Time	Strength
118 – 223 sx 50% Class C 50% POZ +1 lb/sx LAP-1 +0.5% CFR-3 + 0.25% D-AIR 3000 CO_2 Resistant CMT	4,155' to 4,705'	3,270' to 3,940'	636' to 885'	14.5	1.25	5.57	8 hrs 12 hrs 24 hrs 48 hrs 72 hrs	549 psi 928 psi 1,642 psi 2,184 psi 2,379 psi
Excess = 26% - 83% (based on caliper if available)								

Displacement: 2% KCL water with approximately 250 ppm gluteraldehyde biocide.

5-1/2" Production Casing Cementing Program - Two-Stage Cementing Option (for Loss of Circulation Events):

We propose an option to use the two-stage cementing method for cementing the production casing if any loss of circulation events or heavy seepage is experienced while drilling the 7-7/8" hole. (see discussion in Item 3 above). The proposed two-stage cementing program would be as follows:

- Stage 1: Would place cement from the casing shoe to the stage tool.
- Stage 2: Would place cement from the stage tool to Surface.

Stage 1:

Spacer: 20 bbls Fresh Water with an option to follow this with 1,000 gallons SuperFlush 102 and 20 additional bbls Fresh Water

Stage 1 – Lead Surry: None

Stage 1 – Tail Slurry (this is a CO_2 resistant cement)								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by UCA Method	
							Time	Strength
118 – 223 sx 50% Class C 50% POZ +1 lb/sx LAP-1 +0.5% CFR-3 + 0.25% D-AIR 3000 CO_2 Resistant CMT	4,155' to 4,705'	3,270' to 3,940'	636' to 885'	14.5	1.25	5.57	8 hrs 12 hrs 24 hrs 48 hrs 72 hrs	549 psi 928 psi 1,642 psi 2,184 psi 2,379 psi
Excess = 26% - 83% (based on caliper if available)								

Displacement: A volume of Fresh Water equal to the capacity volume from the stage tool to the float collar, followed by brine based mud.

Stage 2:

Spacer: 20 bbls Fresh Water with an option to follow this with 1000 gallons SuperFlush 102 and 20 additional bbls Fresh Water

Stage 2 – Lead Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
							Time	Strength
386 – 602 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.4% Fluid Loss Additive + 0.125% LCM if needed	3,000' to 3,670'	Surface	3,000' to 3,670'	11.8	2.51	14.64	12 hrs 24 hrs 48 hrs 72 hrs 116 hrs	93 psi 234 psi 382 psi 468 psi 584 psi
Excess = 81% - 130% based on caliper if available								

Stage 2 – Tail Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
							Time	Strength
100 sx Class C + 0.1% Retarder (if needed)	3,270' to 3,940'	3,000' to 3,670'	270'	14.8	1.33	6.34	1 hrs 05 min 2 hrs 38 min 24 hrs 72 hrs	50 psi 500 psi 2,800 psi 3,182 psi
Excess = 184%								

Displacement: Fresh Water

5-1/2" Production Casing Cementing Program – Two-Stage Cementing Option with Stage Tool and External Casing Packers (for Water Flow Events):

We propose an option to use the two-stage cementing method with a Stage Tool and two each External Casing Packers if any waterflow event is experienced while drilling the 7-7/8" hole as discussed above in Item 3. The proposed two-stage cementing program would be as follows:

- Stage 1: Would place cement from the casing shoe to the stage tool
- Stage 2: Would place cement from the stage tool to Surface.

Stage 1:

Spacer: 20 bbls Fresh Water with an option to follow this with 1000 gallons SuperFlush 102 and 20 additional bbls Fresh Water

Stage 1 – Lead Slurry Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
							Time	Strength
78 – 369 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.4% Fluid Loss Additive + 0.125% LCM if needed	3,270' to 3,940'	1,670' to 3,440'	500' to 1,600'	11.8	2.51	14.64	12 hrs 24 hrs 48 hrs 72 hrs 116 hrs	93 psi 234 psi 382 psi 468 psi 584 psi
Excess = 126% - 234% based on caliper if available								

Stage 1 – Tail Slurry Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
							Time	Strength
118 – 202 sx 50% Class C 50% POZ +1 lb/sx LAP-1 +0.5% CFR-3 + 0.25% D-AIR 3000 CO_2 Resistant CMT	4,155' to 4,705'	3,270' to 3,940'	636' to 885'	14.5	1.25	5.57	8 hrs 12 hrs 24 hrs 48 hrs 72 hrs	549 psi 928 psi 1,642 psi 2,184 psi 2,379 psi
Excess = 26% - 83% based on caliper if available								

Displacement: A volume of Fresh Water equal to the capacity volume from the stage tool to the float collar, followed by brine based mud.

Stage 2:

Spacer: 20 bbls Fresh Water with an option to follow this with 1000 gallons SuperFlush 102 and 20 additional bbls Fresh Water

Stage 2 – Lead Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
							Time	Strength
145 – 584 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.2% Fluid Loss Additive + 0.125% Polyflake	1,400' to 3,170'	Surface	1,400' to 3,170'	11.8	2.55	14.88	12 hrs 24 hrs 48 hrs 72 hrs	100 psi 200 psi 245 psi 310 psi
Excess = 42% - 162% based on caliper if available								

Stage 2 – Tail Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
							Time	Strength
100 sx Class C + 0.1% Retarder (if needed)	1,670' to 3,440'	1,400' to 3,170'	270'	14.8	1.33	6.359	1 hrs 05 min 2 hrs 38 min 24 hrs 72 hrs	50 psi 500 psi 2,800 psi 3,182 psi
Excess = 184%								

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 options presented above are estimates based on data from previous wells. We propose an option to adjust these volumes based on the caliper log data for this proposed well if available. Also, if no caliper log is available for this proposed well, we would propose an option to possibly increase the production casing cement volumes to account for any uncertainty in regard to the hole volume.

5. **Pressure Control Equipment:**

The blowout preventer equipment (BOP) will consist of 11", 2M equipment to conform to the requirements for a 2M System as described in Onshore Oil and Gas Order No. 2, III.A.2.a.ii. The blowout preventer equipment will be installed after running and cementing the surface casing and installing the wellhead and will be tested by a third party using a test plug. Ram type preventers and associated equipment will be tested to approved stack working pressure of 2000 psi. Annular type preventers, if used, will be tested to 50 percent of rated working pressure, and therefore will be tested to 1000 psi. The above tests will be performed:

- When initially installed
- Whenever any seal subject to test pressure is broken
- Following related repairs, and
- At 30 day intervals

Annular preventers, if used, will be functionally operated at least weekly.

Pipe and Blind rams shall be activated each trip, but not more than once per day.

All of the above described tests will be recorded in the drilling log.

A diagram of the proposed BOPs and choke manifold is attached.

6. **Proposed Wellhead Program:**

Casing Head: 8-5/8" Slip on and Weld x 11" 5M Casing Head installed on 8-5/8" surface casing
Tubing Head: 11" 5M x 7-1/6" 5M Tubing Head installed after setting 5-1/2" production casing

Or, alternatively:

Casing Head: 8-5/8" Slip on and Weld x 11" 3M Casing Head installed on 8-5/8" surface casing
Tubing Head: 11" 3M x 7-1/6" 5M Tubing Head installed after setting 5-1/2" production casing

7. **Proposed Mud System:**

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

DEPTH	TYPE and VOLUME	WEIGHT	VISCOSITY	WATERLOSS
0 – Surface Casing Point	Fresh Water Native Mud 320 bbls in lined earth pit	8.5 – 9.0 ppg	28 – 40 sec	N.C.
Surface Casing Point to TD	Brine 640 bbls in lined earth pit	10 ppg	29 sec	N.C.
Conversion to Mud at TD	Brine Based Mud 300 bbls in steel mud pits	10 ppg	34 – 45 sec	5 – 10 cc/30 min

12-1/4" hole from surface of ground to surface casing point: The circulating media will be either a native mud or fresh water with high viscosity sweeps. The mud components will be:

- Fresh Water
- Bentonite (if needed)
- Lime
- Soda Ash
- Starch (if needed)
- Drilling Paper
- Other loss of circulation material if needed (nut plug or fiberous material)
- Soap sticks (if needed)

7-7/8" hole from the surface casing shoe to TD: The circulating media will be 10 ppg brine and will be converted to a mud with starch, attapulgite, and lime upon reaching Total Depth (TD). The mud components will be:

- Brine (approximately 10 lb/gal density)
- Attapulgite
- Lime
- Starch
- Drilling Paper
- Other loss of circulation material if needed (nut plug, fiberous material, gilsonite, or asphalt)
- Soap Sticks if needed
- Diesel in sweeps if needed
- Lease crude oil as a spotting fluid if needed in the event of differential sticking

We do not plan to keep any weighting material at the wellsite.

The circulating system we plan to use while drilling would be a "U" shaped brine reserve pit. We plan to monitor the pit level visually, not with float type pit level monitoring system.

After reaching TD, if the well is not flowing from a waterflow, then we would bring circulation into the steel mud pits and circulate the hole and convert to a brine based mud circulating through the steel mud pits. In such event we would propose to monitor the pit level visually, not with a float type pit level monitoring system.

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.

8. <u>Logging, Coring, and Testing Program:</u>

a. No drill stem tests will be done
b. No mud logging is planned
c. No whole cores are planned
d. The open hole electrical logging program is planned to be as follows:
    - Total Depth to top of Grayburg or possibly to the surface casing shoe: Resistivity, Density, Spectral Gamma Ray and possibly BHC Sonic.
    - Total Depth to Surface Casing Shoe: Caliper
    - Total Depth to 200' MD, Gamma Ray and Neutron
    - Formation pressure data (XPT) on electric line if needed (optional)
    - Rotary Sidewall Cores on electric line if needed (optional)

9. Abnormal Pressures and Temperatures:

- It is possible that abnormal pressures may be encountered while drilling in the 7-7/8" hole interval from the surface casing shoe to TD. If encountered, it is expected that a water flow would occur with some gas, oil, and/or CO_2 associated with it. The source of any such abnormal pressure would be from CO_2 injection (from our previous CO_2 injection program) and water injection that got out of zone and charged up in natural fractures above the reservoir. On three of the six wells drilled by ConocoPhillips in MCA Unit in 2006, such waterflows with associated gas, oil, or CO_2 were encountered. In these wells, the waterflow was encountered in the upper Queen or Grayburg interval above the reservoir. However there have also been cases in the history of this field in which occurrences of water flow, or in some cases CO_2 flow, have occurred at shallower depths. But in all such cases that we are aware of, the flow has been somewhere below the surface casing shoe. We are not aware of any such flows occurring above the surface casing shoe. Other than these occasional charged up zones, no abnormal pressures are expected. We plan to shut in and bleed off our injectors in the area before drilling each well in order to relieve the injection pressure in reservoir in the area. Our experience is that this is very helpful in regard to reducing the pressure in the reservoir, but may not relieve all pressure from charged up zones above the reservoir.

  If a waterflow is encountered, our proposed plan is to let it flow while drilling to TD, and then run and cement the production casing using the two-stage method and employing a Stage Tool and two each External Casing Packers as described and discussed above. Our proposed plan in this regard is to shut off any such waterflow by the action of setting the External Casing Packers – containing any such waterflow zone between the two External Casing Packers.

  We will ensure that we have sufficient storage capacity at surface to provide for the possibility that the well may flow water. The estimated maximum rate of water flow (based on observations on past wells) is 120 bbl/hr flow rate.

- The expected maximum bottom hole pressure in the reservoir is approximately 1750 psi. However with our injectors operating we have some wells that exhibit higher pressure up to approximately 2750 psi in the reservoir. In this regard we judge that these wells have a highly permeable avenue of communication to the injectors thus causing them to exhibit this higher pressure in the reservoir. We anticipate that when we shut down and bleed off the injectors in the respective areas in preparation for the drilling program the pressure in the reservoir on these wells will be reduced to the normal reservoir pressure in the field which is approximately 1750 psi.

- Above the reservoir, it is possible that there may be charged up zones (charged up from water injection and/ or CO2 injection that got out of zone). Such charged up zones are not found on each well drilled in this field, but are found occasionally. We do not have any measurement of the pressure of such charged up zones – but we feel it is not practical to attempt to control such zones with hydrostatic mud weight. The typical practices in this field have been to let these zones flow while drilling to TD, and our observation is that these zones will typically deplete and stop flowing water after several days or can be isolated between external casing packers as is proposed in this Master Drilling Plan.

- The expected bottom hole temperature is 110 degrees F during logging or 115 degrees F bottom hole static temperature.

- The estimated H2S concentrations in the MCA Field is 11,000 – 14,000 ppm H2S with a gas rate of zero to 38 MCFPD. The 100 ppm H2S ROE is 0 - 59'. The 500 ppm ROE is 0 - 27'. ConocoPhillips will comply with the provisions of Oil and Gas Order # 6, Hydrogen Sulfide Operations and will provide H2S monitoring equipment which will be rigged up, tested, and operational prior to drilling out from surface casing. All persons arriving on location will have H2S certification & training that occurred within the last year. Each occurrence of H2S gas at surface is to be noted on the daily reports and any occurrence of H2S in excess of 100 ppm will be reported to the authorized officer as soon as possible but no later than the next business day per 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 drilling operations.

10. **Anticipated starting date and duration of operations:**

Road and location construction will begin after the BLM and NMOCD have approved the APD and will take into account any closure stipulations that may be attached or specified in order to avoid operations in any closure period. Also, rig availability may impact our schedule. With consideration of these limiting factors, we would intend / plan to drill the wells in our proposed program MCA Unit within two years after receiving approval of the APD.

Attachments:

- Attachment # 1....... Proposed Casing and Cementing Program with Single Stage Cementing of Production Casing
- Attachment # 2....... Proposed Casing and Cementing Program with Two-Stage Cementing of Production Casing
- Attachment # 3....... Proposed Casing and Cementing Program with External Casing Packers and Two-Stage Cementing of Production Casing
- Attachment # 4....... Diagram of Choke Manifold Equipment (Excerpted 54 FR 39528, Sept 27, 1989)
- Attachment # 5....... BOP and Choke Manifold Schematic – 2M System (Figure 3-1, Appendix G, from BLM)
- Attachment # 6....... BOP and Choke Manifold Schematic – 2M System (Figure 3-1A, Appendix G, from BLM)

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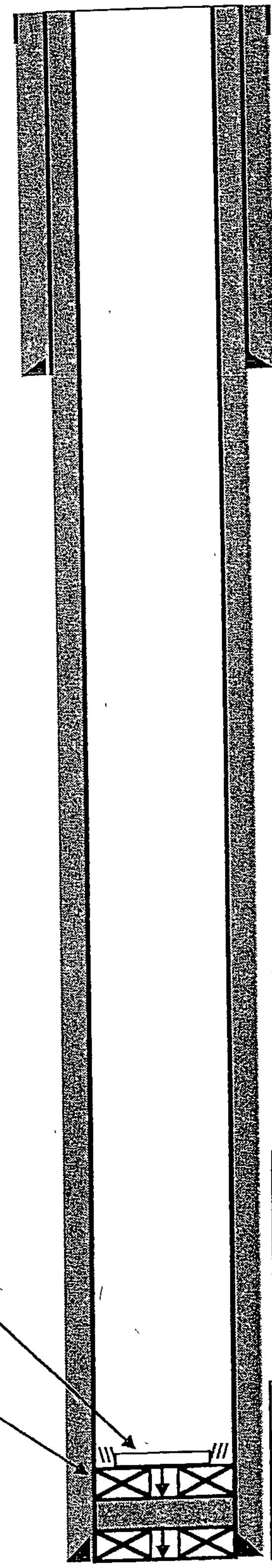
ConocoPhillips

Attachment # 1

MCA Unit
Proposed Casing & Cementing Program with Single-Stage Cementing of Production Casing (Alternative # 1)

Datum: RKB (10' -12' above ground level)

The intent of this alternative casing program is to provide a contingency plan for using Single-Stage Cementing for the production casing cement job if hole conditions are favorable (with no severe loss of circulation, heavy seepage, or waterflow events occurring during the drilling operations).



Conductor: 13-3/8" 48# H-40 ST&C set at 30' to 75' below ground level (40' to 87' MD RKB) and cemented to surface.

Surface Casing: 8-5/8" 24# J-55 ST&C set in the Rustler formation and cemented to surface.

A Single-Stage cement job is pumped placing cement from the Production Casing shoe to surface.

Cement Wiper Plug

Float Shoe, one joint of casing, and Float Collar

Production casing: 5-1/2" 17# J-55 LT&C set 10' above TD and cemented to surface with single-stage cementing method.

Schematic prepared by:
Steven O. Moore, Staff Drilling Engineer
28-February-2008

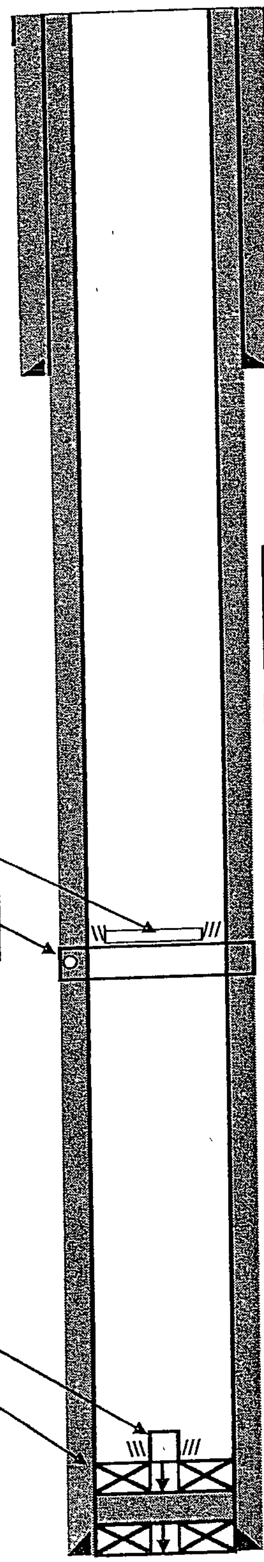
ConocoPhillips

Attachment # 2

MCA Unit
Proposed Casing & Cementing Program with Two-Stage Cementing of Production Casing (Alternative # 2)

Datum: RKB (10' - 12' above ground level)

The intent of this alternative casing program is to provide a contingency plan for using Two-Stage Cementing for the production casing cement job if loss of circulation occurs during the drilling operations. See comments in "Step 1" to "Step 3" of this schematic.



Conductor: 13-3/8" 48# H-40 ST&C set at 30' to 75' below ground level (40' to 87' MD RKB) and cemented to surface.

Surface Casing: 8-5/8" 24# J-55 ST&C set in Rustler formation and cemented to surface.

Step 3:
Stage 2 Cement is pumped placing cement from the Stage Tool to surface.

Step 2:
The Stage Tool is opened by hydraulic pressure and the excess cement is circulated out from above the stage-tool. Circulation is continued for approximately 4 to 6 hrs until the Stage 1 cement has set and thus isolated the potential loss of circulation zone(s).

Stage 2 Wiper Plug / Closing Plug

Stage Tool at top of Grayburg

Step 1:
Stage 1 Cement is pumped placing cement from Production Casing shoe to the Stage Tool.

Stage 1 Wiper Dart

Float Shoe, one joint of casing, and Float Collar

Production casing: 5-1/2" 17# J-55 LT&C set 10' above TD and cemented to surface with two-stage cementing method.

Schematic prepared by:
Steven O. Moore, Staff Drilling Engineer
28-February-2008

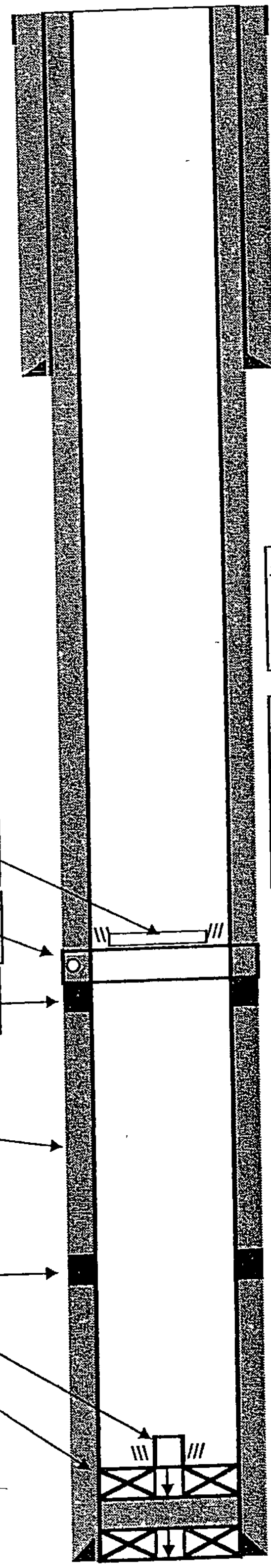
ConocoPhillips

Attachment # 3

MCA Unit
Proposed Casing & Cementing Program with ECP's and Two-Stage Cementing of Production Casing (Alternative # 3)

Datum: RKB (10' - 12' above ground level)

The intent of this alternative casing program is to provide a contingency plan for using External Casing Packers (ECP's) and Two-Stage Cementing to shut off a waterflow if such waterflow occurs while drilling the well. See comments in "Step 1" to "Step 4" of this schematic.



Step 4:
Stage 2 Cement is pumped placing cement from the Stage Tool to surface.

Step 3:
After setting the External Casing Packers, the Stage Tool is opened by hydraulic pressure and the excess cement is circulated out from above the stage-tool.

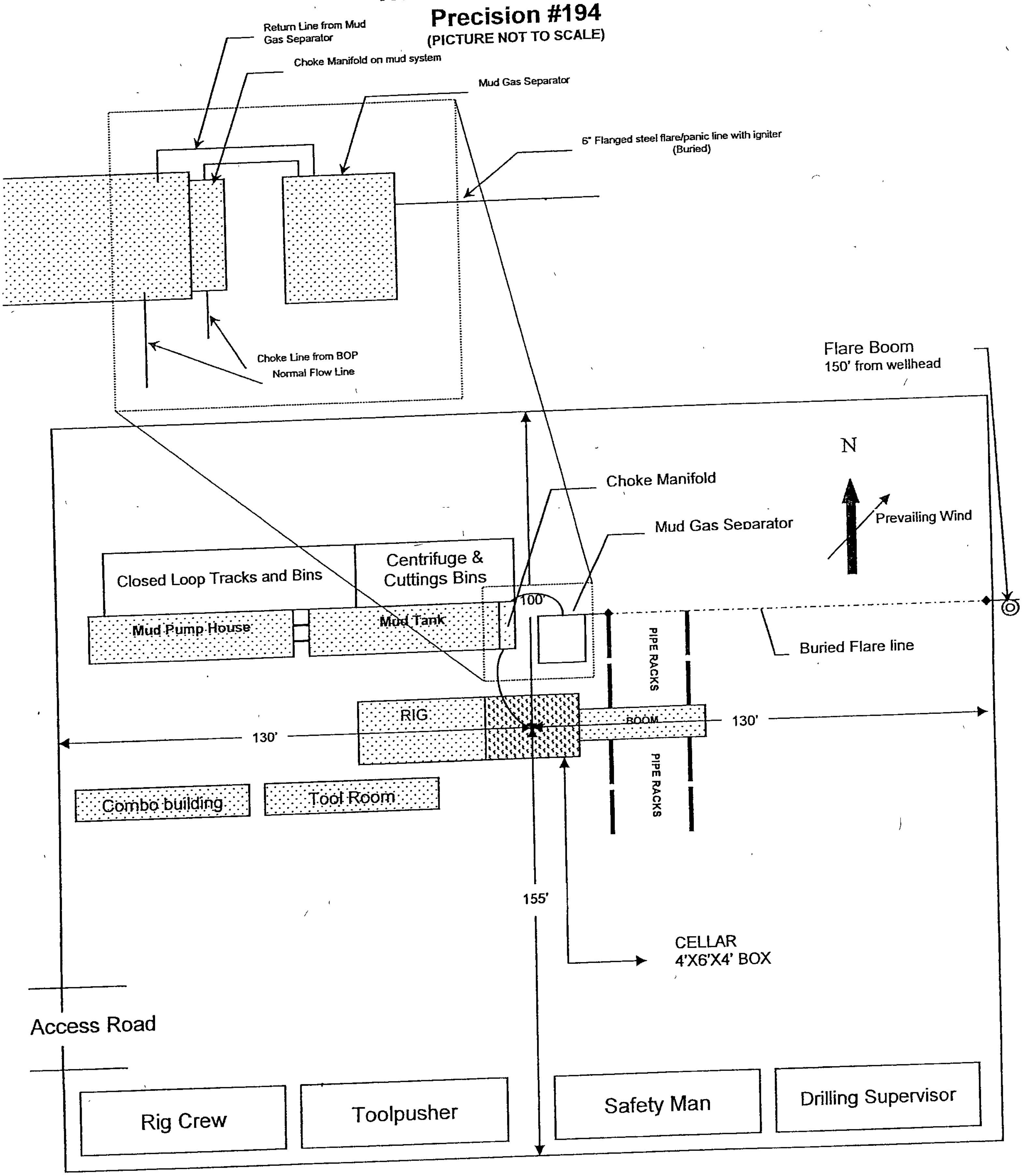
Step 2:
The two External Casing Packers (ECP's) are simultaneously set by hydraulic pressure after bumping the Stage 1 Cement Wiper Dart on the baffle on the float collar. The setting of the ECP's should shut off the waterflow - isolating it between the two ECP's.

Step 1:
Stage 1 Cement is pumped placing cement from Production Casing shoe to the Stage Tool.

Schematic prepared by:
Steven O. Moore, Staff Drilling Engineer
28-February-2008

Attachment # 4

ConocoPhillips
Location Schematic and Rig Layout for Closed Loop System
Precision #194
(PICTURE NOT TO SCALE)



Attachment # 5

2000 psi System

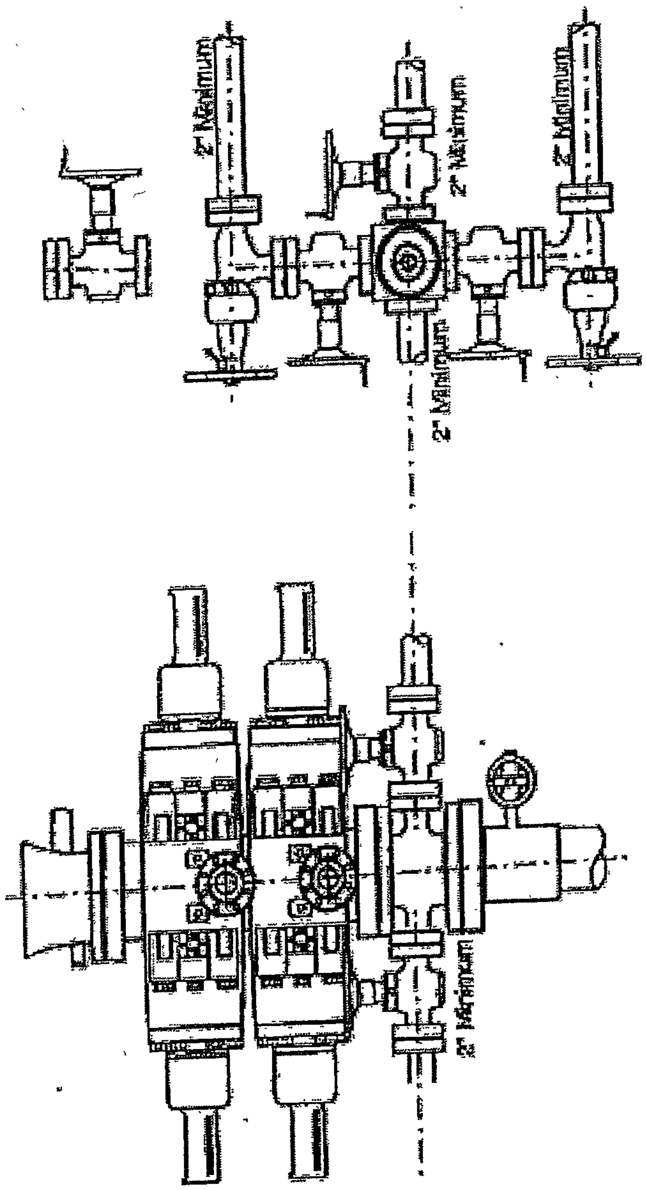


Figure 3-1

Appendix G

Attachment # 6

2000 psi System

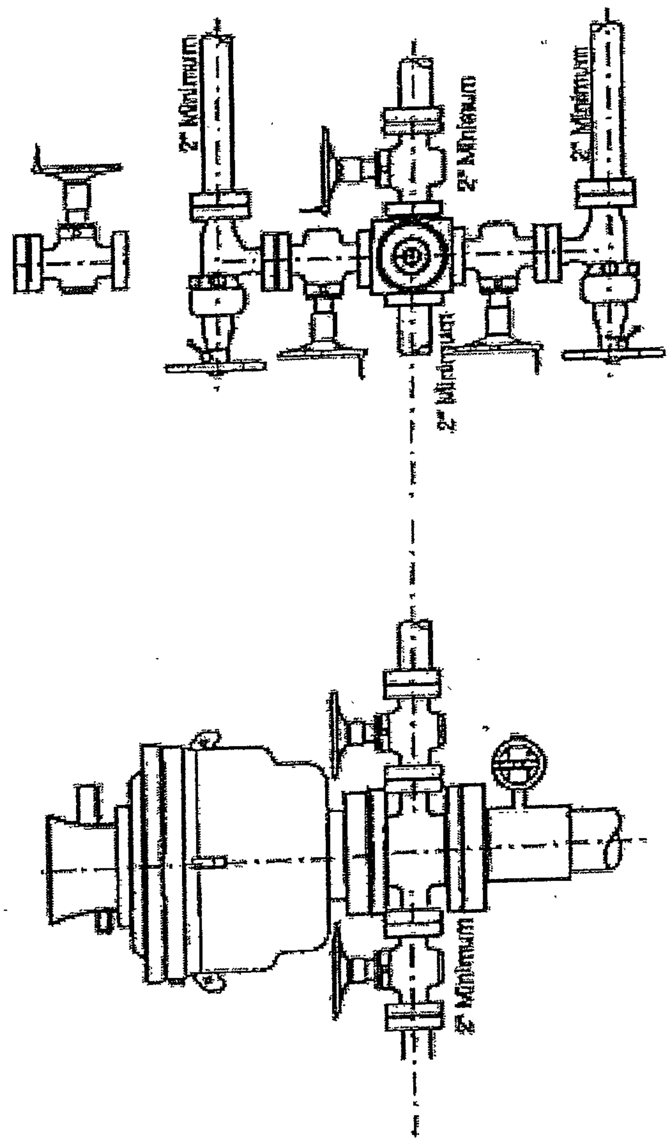


Figure 3-1A

Appendix G