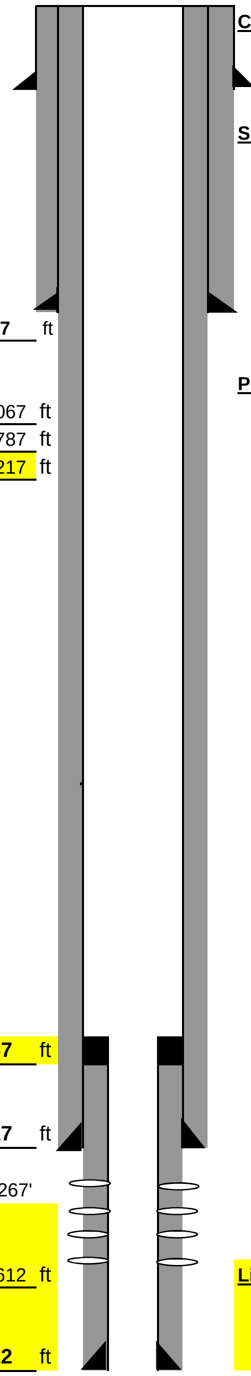
PROPOSED WELL SCHEMATIC

Well Name **Cow Canyon B-3 (CB-3)**
Pilot API # **05-083-06715-00**
S/T API # : **05-083-06715-01**
Section **11** **Township** **38N** **Range** **19W**
Surface Hole: 1608' FNL, 2404' FEL Section 11, T38N, R19W NMPM Ground Elevation 6720.4'

Spud Date: **TBD**
Pilot Completion/TA Date: **TBD**
S/T Completion Date: **TBD**

Updated: 8/28/14 VC



Conductor Casing
Size 16 in
Set at 105 ft
Conductor @ **105** ft

Conductor Cement
cement with ready-mix to suface

Surface Casing
Size 10-3/4 in
Set at 2987 ft
Wt. 40.5 ppf Grade J-55 surface to 2987 ft
Hole Size 14-3/4 in
Est. T.O.C. surface ft
Csg Shoe @ **2987** ft

Surface Cement
Date Cemented: TBD
Lead : 1500 sx Vericem, 1/8# Poly-E-Flake, .1% Halad®-9
5# Kol-seal; yield 1.9
Tail : 300 sx Lifecem, .1% Halad®-9, 1/8# Poly-E-Flake;
yield 1.15
Note :

Production Casing
Size 7 in
Wt. 29 ppf Grade 13 CR from surface to 6067 ft
Wt. 32 ppf Grade 13 CR from 6067 to 7787 ft
Wt. 29 ppf Grade 13 CR from 7787 to 8217 ft
Hole Size 8-3/4 in
Est. T.O.C. surface ft

Prod Cement
Date Cemented: TBD
Lead: 1800 sx Halcem, .2% Halad 766, .2% Versaset,
1.5% Chem-Foamer 760; yield 1.46
Tail: 300 sx Halcem, .2% Halad 766, .2% Versaset;
yield 1.3
Note : 100 sx cap job

Hanger Set @ 8067 ft

Csg Shoe @ 8217 ft

Top of Leadville @ 8267'

Perforation depths will be determined
from log analysis

Production Liner
Size 4-1/2 in
Wt. 12.75 ppf Grade 13CR from 8067 to 8612 ft
Hole Size 6-1/2 in

Liner Shoe @ 8612 ft

Liner Cement
Date Cemented: TBD
Lead: 100 sx Halcem, .2% Versaset, .15% Halad-766
Note: 1.43 yield

WELL PROGNOSIS OVERVIEW

This well prognosis is organized to follow the Bureau of Land Management (BLM) Eight Point Drilling Plan referenced in the Onshore Order #1. The Eight Points correspond to the following Eight Sections of the Prognosis

1. Estimated tops of important geological markers and formations.
2. Estimated depths at which top and bottom of anticipated water (particularly fresh water), oil, gas or other mineral-bearing formations are expected to be encountered and the lessee's or operator's plans for protecting such resources.
3. Lessee's or operator's minimum specifications for pressure control equipment to be used and a schematic diagram thereof showing sizes, pressure ratings (or API series), and the testing procedures and testing frequency.
4. Any supplementary information more completely describing the drilling equipment and casing program.
5. Type and characteristics of the proposed circulating mechanism to be employed in drilling, the quantities and types of mud and weighting material to be maintained, and the monitoring equipment to be used on the mud system.
6. The anticipated type and amount of testing, logging and coring.
7. The expected bottom hole pressure and any anticipated abnormal pressures or temperatures or potential hazards, such as hydrogen sulfide, expected to be encountered, along with contingency plans for mitigating such identified hazards.
8. Any other facets of the proposed operations which the lessee or operator wishes to point out for BLM's consideration of the application.

Three attachments are referenced in sections of the document

1. Paradox Salt Drilling Procedure (Appendix A)
2. H2S Contingency Plan
3. Directional Plan

SECTION 1 & 2 – Estimated Geologic Markers/Formations, Anticipated Fluids, and Isolation Plan

Formation	Top (TVD, ft)	Bottom (TVD, ft)	Composition	Anticipated Fluids
Entrada	1092	1892	Sandstone	Fresh Water
Chinle	1892	2887	Sandstone	Fresh Water
Cutler	2887	4567	Shales	None Anticipated
Upper Hermosa	4567	5577	Carbonate	None Anticipated
Paradox	5577	5937	Carbonate/Anhydrite	None Anticipated
Desert Creek	5937	6167	Carbonate	Gas
Paradox Salt	6167	6627	Carbonate/Anhydrite	None Anticipated
Killer Shales	6627	7687	Shales	Gas, **Hydrogen Sulfide**
Base Salt	7687	7997	Carbonate/Anhydrite	None Anticipated
Molas	7997	8267	Siltstones/Shale	None Anticipated
Leadville	8267	8512	Carbonate	Gas, Carbon Dioxide

10-3/4" Surface casing will be set ~100' into the Cutler formation and cemented to surface to isolate the usable quality fresh water bearing sandstone formations above.

7" Intermediate casing will be set ~50' above the Leadville producing formation and cemented to surface to isolate all zones above, including the killer shale section which may contain hydrogen sulfide gas.

A detailed explanation of the casing and cementing program is shown in Section 4, and a contingency plan to mitigate the hydrogen sulfide hazard is referenced in Section 7 and attached to this prognosis.

SECTION 3 – Pressure Control Equipment

A 3M system will be utilized. The following procedures, diagrams, and guidelines are included for review with all personnel, and MUST be adhered to at all times:

- Kinder Morgan 3M BOP and Associated Equipment Installation and Testing Procedure for Doe Canyon and McElmo Dome Wells.
- Kinder Morgan BOP and Choke Manifold diagrams including minimum requirements.
- BLM 43 CFR 3160 Section III-A 3M specifications for pressure control equipment including minimum requirements.

3M BOP and Associated Equipment Installation and Testing Procedure

Kinder Morgan CO_2 Company, L.P.

Doe Canyon and McElmo Dome Wells

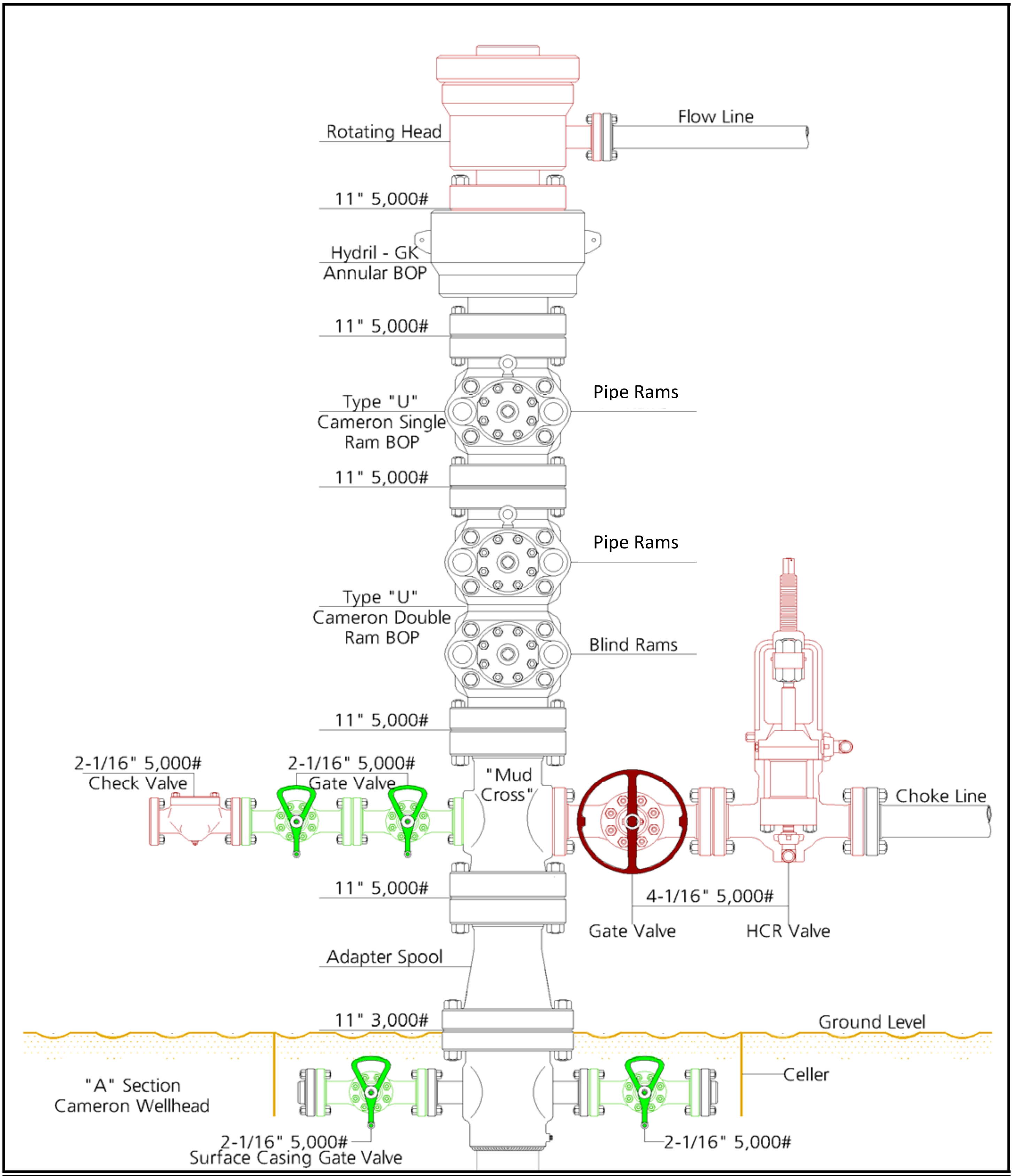
***While drilling the surface hole, a 16-3/4" 3M annular preventer with a diverter will be used.**

1. **NIPPLE UP ON 10 3/4" X 11" 3000# SCREW ON WELLHEAD**
2. **INSTALL 11"X 11" 3000# SPOOL W/TWO SIDE OUTLET (4" OUTLET & 2" OUTLET)**
3. **INSTALL 11" 3000# SINGLE HYDRAULIC BOP (NO RAM BLOCK INSTALLED)**
4. **INSTALL 11"X 11" 3000# SPACER SPOOL (8" TO 10" LONG)**
5. **INSTALL 11" 3000# DOUBLE RAM BOP (BLIND RAMS ON BOTTOM, PIPE RAMS ON TOP)**
6. **INSTALL 11" 3000# HYDRIL ANNULAR BOP**
7. **INSTALL 11" 3000# ROTATING HEAD**
8. **NIPPLE UP FLOW LINES TO ROTATING HEAD**
9. **INSTALL 4" 3000# MANUAL VALVE ON SIDE OF SPOOL**
10. **INSTALL 4" 3000# HCR VALVE ON SIDE OF MANUAL VALVE**
11. **NIPPLE UP HCR VALVE TO 3000# CHOKE MANIFOLD (IF H2S IS EXPECTED A HYDRAULIC SUPER CHOKE SHOULD BE INSTALLED)**
12. **FUNCTION TEST BLIND RAMS, PIPE RAMS, HCR VALVE (USE CLEAR WATER TO TEST AND MAKE SURE ALL BOP's ARE HOOKED UP TO ACCUMULATOR AND ALL RAMS, HYDRIL AND HCR VALVE FUNCTION PROPERLY)**
13. **CLOSE BLIND RAMS AND TEST 10 3/4" CSG & BLIND RAMS TO 300# & 1000# FOR 30 MIN. FOR A TEST NOT UTILIZING A TEST PLUG. (IF A DECLINE OF MORE THAN 10% IN 30 MIN. OCCURS, THE TEST SHALL BE CONSIDERED FAILED)**
14. **INSTALL TEST PLUG IN 10 3/4" X 11" 3000# WELL HEAD (WITH ALL VALVES OPEN BELOW TEST PLUG)**
15. **MAKE SURE BOP's ARE FULL OF WATER AND VALVES SHALL BE TESTED FROM WORKING PRESSURE SIDE DURING BOP TEST**
16. **CLOSE PIPE RAMS (TEST TO 300# FOR 10 MIN. & 1000# FOR 10 MIN. WITH NO PRESSURE LOST)**
17. **REMOVE DRILL PIPE WITH TEST PLUG IN PLACE**
18. **CLOSE BLIND RAMS (TEST BLIND RAMS, HCR VALVE, MANUAL VALVE & CHOKE MANIFOLD TO 300# & 3000# 10 MIN.)**
19. **OPEN BLIND RAMS, INSTALL DRILL PIPE**
20. **CLOSE HYDRIL (TEST HYDRIL TO 300# & 1500# FOR 10 MIN. EACH WITH NO LOST IN PRESSURE)**

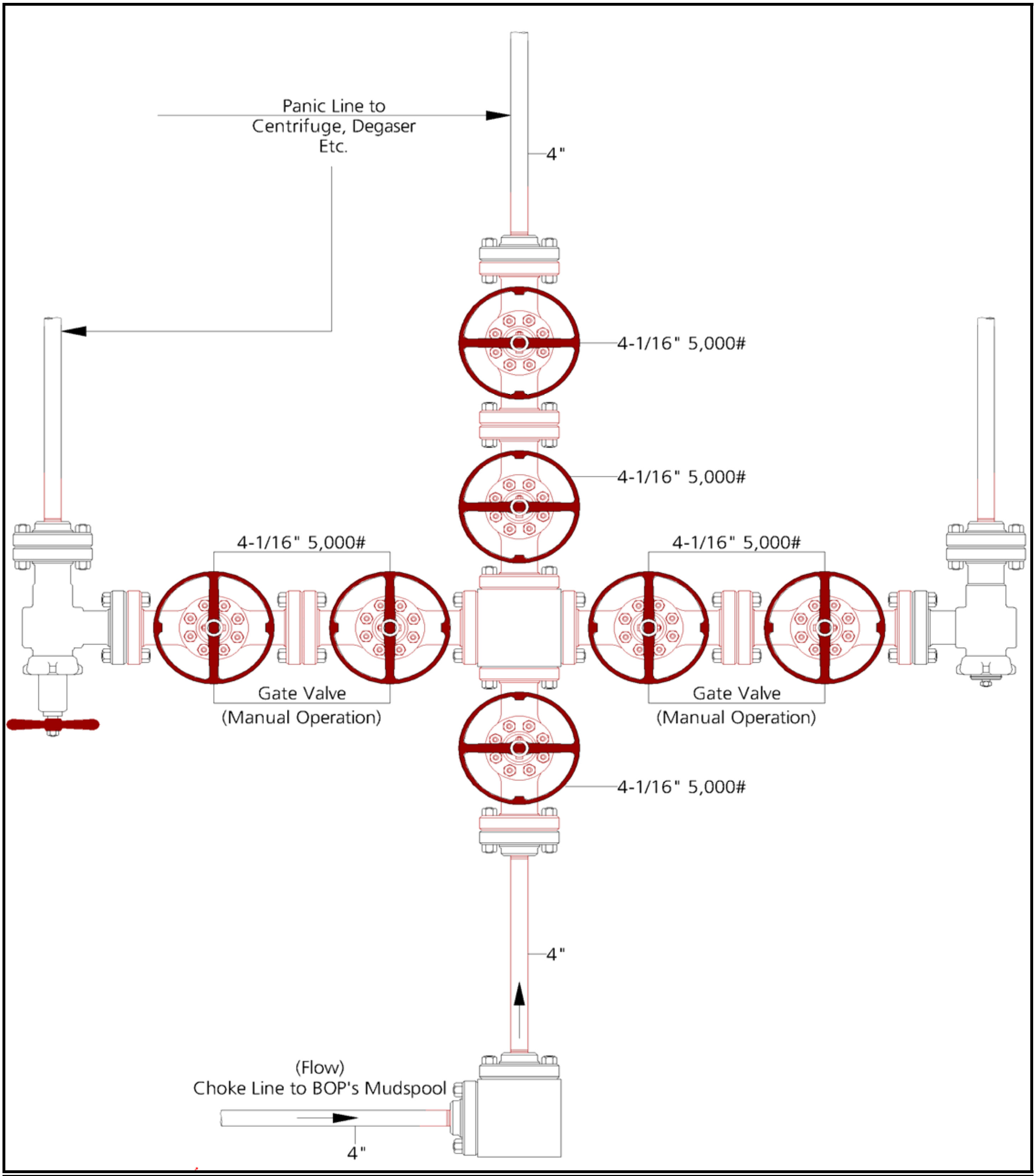
*****EMAIL KM REGULATORY REP 24HOURS PRIOR TO BOPE TEST*****

******ALL TESTS MUST BE CHARTED FOR CO&G & BLM******

BOP CONFIGURATION



CHOKE MANIFOLD



BUREAU OF LAND MANAGEMENT
43 CFR 3160
Federal Register / Vol. 53, No. 223
Friday, November 18, 1988
Effective date: December 19, 1988

Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases;
Onshore Oil and Gas Order No. 2, Drilling Operations

III. Requirements

A. Well Control Requirements

1. Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD. Commencement of drilling without the approved BOPE installed, unless otherwise approved, shall subject the operator to immediate assessment under 43 CFR 3163.1(b)(1). The BOP and related control equipment shall be suitable for operations in those areas which are subject to sub-freezing conditions. The BOPE shall be based on known or anticipated sub-surface pressures, geologic conditions, accepted engineering practice, and surface environment. The working pressure of all BOPE shall exceed the anticipated surface pressure to which it may be subjected, assuming a partially evacuated hole with a pressure gradient of 0.22 psi/ft.

2. The gravity of the violations for many of the well control minimum standards listed below are shown as minor. However, very short abatement periods in this Order are often specified in recognition that by continuing to drill, the violation which was originally determined to be of a minor nature may cause or threaten immediate, substantial and adverse impact on public health and safety, the environment, production accountability, or royalty income, which would require it reclassification as a major violation.

    a. Minimum standards and enforcement provisions for well control equipment.

        i. A well control device shall be installed at the surface that is capable of complete closure of the well bore. This device shall be closed whenever the well is unattended.

iii. 3M system:
-Annular preventers*
-Double ram with blind rams and pipe rams*
-Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter)*

-Kill line (2 inch minimum)
-A minimum of 2 choke line valves (3 inch minimum)*
-3 inch diameter choke line
-2 kill line valves, one of which shall be a check valve (2 inch minimum)*

-2 chokes (refer to diagram in Attachment 1)
-Pressure gauge on choke manifold
-Upper Kelly cock valve with handle available
-Safety valve and subs to fit all drill string connections in use
-All BOPE connections subjected to well pressure shall be flanged, welded, or clamped*
-Fill-up line above the uppermost preventer.

vi. If repair or replacement of the BOPE is required after testing, this work shall be performed prior to drilling out the casing shoe.

vii. When the BOPE cannot function to secure the hole, the hole shall be secured using cement, retrievable packer or a bridge plug packer, bridge plug, or other acceptable approved method to assure safe well conditions.

b. Minimum standards and enforcement provisions for choke manifold equipment.

i. All choke lines shall be straight lines unless turns use tee blocks or are targeted with running tees, and shall be anchored to prevent whip and reduce vibration.

Violation: Minor.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: 24 hours.

ii. Choke manifold equipment configuration shall be functionally equivalent to the appropriate example diagram shown in Attachment 1 of this Order. The configuration of the chokes may vary.

Violation: Minor.
Corrective Action: Install the equipment as specified.
Normal Abatement Period: Prompt correction required.

iii. All valves (except chokes) in the kill line choke manifold, and choke line shall be a type that does not restrict the flow (full opening) and that allows a straight through flow (same enforcement as item ii).

iv. Pressure gauges in the well control system shall be a type designed for drilling fluid service (same enforcement as above).

[57 FR 3025, Jan 27, 1992]

c. Minimum standards and enforcement provisions for pressure accumulator system.

i. 2M system accumulator shall have sufficient capacity to close all BOP's and retain 200 psi above pre-charge. Nitrogen bottles that meet manufacturer's specifications may be used as the backup to the required independent power source.

Violation: Minor.
Corrective Action: Install the equipment as specified
Normal Abatement Period: 24 hours.

ii. 3M system accumulator shall have sufficient capacity to open the hydraulically-controlled choke line valve (if so equipped), close all rams plus the annual preventer, and retain a minimum of 200 psi above pre-charge on the closing manifold without the use of the closing pumps. This is a minimum requirement. The fluid reservoir capacity shall be double the usable fluid volume of the accumulator system capacity and the fluid level shall be maintained at the manufacturer's recommendations. The 3M system shall have 2 independent power sources to close the preventers. Nitrogen bottles (3 minimum) may be 1 of the independent power sources and, if so, Shall maintain a charge equal to the manufacturer's specifications.

d. Minimum standards and enforcement provisions for accumulator pre-charge pressure test. This test shall be conducted prior to connecting the closing unit to the BOP stack and at least Once every 6 months. The accumulator pressure shall be corrected if the measured pre-charge Pressure is found to be above or below the maximum or minimum limit specified below (only Nitrogen gas may be used to pre-charge):

Accumulator working pressure rating	Minimum acceptable operating pressure	Desired pre-charge pressure	Maximum acceptable pre-charge pressure	Minimum acceptable pre-charge pressure
1,500 psi	1,500 psi	750 psi	800 psi	700 psi
2,000 psi	2,000 psi	1,000 psi	1,100 psi	900 psi
3,000 psi	3,000 psi	1,000 psi	1,100 psi	900 psi

e. Minimum standards and enforcement provisions for power availability. Power for the closing unit pumps shall be available to the unit at all times so that the pumps shall automatically start when the closing valve manifold pressure has decreased to the pre-set level.

f. Minimum standards and enforcement provisions for accumulator pump capacity. Each BOP closing unit shall be equipped with sufficient number and sizes of pumps so that, with the accumulator system isolated from service, the pumps shall be capable of opening the hydraulically-operated gate valve (if so equipped), plus closing the annular preventer on the smallest size drill pipe to be used within 2 minutes, and obtain a minimum of 200 psi above specified accumulator pre-charge pressure.

g. Minimum standards and enforcement provisions for locking devices. A manual locking device (i.e. hand wheels) or automatic locking devices shall be installed on all systems of 2M or greater. A valve shall be installed in the closing line as close as possible to the annular preventer to act as a locking device. This valve shall be maintained in the open position and shall be closed only when the power source for the accumulator system is inoperative.

h. Minimum standards and enforcement provisions for remote controls. Remote controls shall be readily accessible to the driller. Remote controls for all 3M or greater systems shall be capable of closing all preventers. Remote controls for 5M or greater systems shall be capable of both opening and closing all preventers. Master controls shall be at the accumulator and shall be capable of opening and closing all preventers and the choke line valve (if so equipped). No remote control for a 2M system is required.

i. Minimum Standards and enforcement provisions for well control equipment testing.

i. Perform all tests described below using clear water or an appropriate clear liquid for subfreezing temperatures with a viscosity similar to water.

ii. Ram type preventers and associated equipment shall be tested to approved (see item I.D.1. of this order) stack working pressure if isolated by test plug or to 70 percent of internal yield pressure of casing if BOP stack is not isolated from casing. Pressure shall be maintained for at least 10 minutes or until requirements of test are met, whichever is longer. If a test plug is utilized, no bleed-off of pressure is acceptable. For a test not utilizing a test plug, if a decline in pressure of more than 10 percent in 30 minutes occurs, the test shall be considered to have failed. Valve on casing head below test plug shall be open during test of BOP stack.

iii. Annular type preventers shall be tested to 50 percent of rated working pressure. Pressure shall be maintained at least 10 minutes or until provisions of test are met, whichever is longer.

iv. As a minimum, the above test shall be performed:

A. When initially installed;
B. Whenever any seal subject to test pressure is broken:
C. Following related repairs: and
D. At 30-day intervals.

v. Valves shall be tested from working pressure side during BOPE tests with all down stream valves open.

vi. When testing the kill line valve(s), the check valve shall be held open or the ball removed.

vii. Annular preventers shall be functionally operated at least weekly.

viii. Pipe and blind rams shall be activated each trip, however, this function need not be performed more than once a day.

ix. A BOPE pit level drill shall be conducted weekly for each drilling crew.

x. Pressure tests shall apply to all related well control equipment.

xi. All of the above described tests and/or drills shall be recorded in the drilling log.

Violation: Minor.
Corrective action: Perform the necessary test or provide documentation.
Normal Abatement Period: 24 hours or next trip, as most appropriate.

[54 FR 39528, Sept. 27, 1989]

SECTION 4 – Drilling Equipment, Casing, and Cementing Programs

PROSPECT INFORMATION

The Cow Canyon B-3 (CB-3) will be one of several wells to be drilled during the 2014 drilling program at McElmo Dome. The wellplan calls for a 10-3/4” x 7” 13-Chrome casing program.

WELL OBJECTIVE

The main objectives for the drilling operation on the CB-3 are:

1. Maintain a focused effort by everyone on location to eliminate all accidents.
2. Drill, evaluate, case and complete the well at or under the AFE cost estimate.
3. Run the 7” 13-Chrome production casing to ~50’ above the top of the Leadville formation.
4. Isolate the 7” 13-Chrome to surface with high quality cement.
5. Run the 4-1/2” 13-Chrome liner to cover the Molas formation.
6. Isolate the 4-1/2” 13-Chrome liner with high quality cement.
7. ~~Drill the 4-3/4” horizontal production hole with minimal fluid loss / damage to the formation.~~
8. ~~Set 7-5/8” casing packer ~150’ above 7-5/8” shoe and tie back 4-1/2” 13-Chrome tubing to surface.~~

POTENTIAL PROBLEMS

The main problems for the CB-3 are the typical problems expected while drilling in the area:

1. **Lost Circulation in the 14-3/4” Surface Hole:** Lost circulation can be expected at any depth while drilling the surface hole. Maintain a clean fresh water system, utilizing the closed loop system while drilling this hole section. Pump LCM pills as required to control the losses. No losses in surface hole were encountered on offsets.

2. **Gas Kick from the Desert Creek @ 5937’ TVD/MD:** Gas kicks have been encountered while drilling the Desert Creek formation. A planned mud weight schedule will be utilized to help minimize the chance of kicks in this section.

3. **Gas and H_2S from the Killer Shales:** Geo-pressured shales from the P4 on down will contain varying amounts of gas and associated H_2S. Circulate the salt water of the closed loop system to remove excess gas. Pre-treat the mud using H_2S scavenger for H_2S contamination.

4. **Stuck Pipe in the Killer Shales:** The Killer Shale is a high pressure, low volume shale which “flows” into the well causing stuck pipe. An attached list of recommendations for drilling the Killer Shale, titled “Paradox Salt Drilling Procedure”, is located in Appendix A of this prognosis. The recommendations have proven to be very successful in recent drilling programs and are strongly recommended they be followed. Educate the drillers prior to drilling the killer shale and discuss in detail the procedure for drilling the shale.

5. **Gas Kick from Leadville after Production Casing set:** Gas kicks have been encountered during the drilling/well stimulation within the open hole segment of the Leadville. The primary barrier is the BOPE and the hydrostatic pressure of the kill fluid (fresh water). Drill pipe/workstrings will be utilized with double float valves inserted. This will prevent kicks from occurring up the drill pipe/workstring during drilling or stimulation in the Leadville.

GENERAL DRILLING PROCEDURE

16” conductor pipe will be set at ~80’ prior to moving in the drilling rig. It is necessary to rig up a 16-3/4” 3M annular preventer with diverter to drill the surface hole.

A 14-3/4” hole will be drilled from surface to 2987’ TVD/MD, located ~100’ below the top of the Cutler. A full string of 10-3/4” surface casing will be run to 2987’ with cement circulated to surface. The 10-3/4” surface casing will protect the groundwater in the area. After the casing is run and cemented, screw on the 10-3/4” X 11” 3M casing head housing and nipple-up the 11” 3M BOP. Wait on cement 12 hours and pressure test the casing to 1500 psi and the BOP’s to their rating prior to drilling out.

A 8-3/4” hole will be drilled out from the surface casing point to the 7” casing point at 8217’ TVD/MD, located ~50’ above the Leadville formation. At 8067’ TVD/MD a measurement while drilling (MWD) gamma ray (GR) system will be picked up. This, along with mud logging, will be used to pick the 7” casing point. A string of 7” 13-Chrome casing will be run and set ~50’ above the Leadville. The well integrity is dependent on the 13-Chrome casing being handled and run correctly. The 7” 13-Chrome requires special handling and is to be handled according to the procedures specified on site. The 7” casing will be cemented back to surface in one stage with foamed cement. A CBL log will be run.

A 6” pilot hole will be drilled out from the 7” casing to ~400’ below the Leadville top. A gyro will be dropped at TD of the pilot hole on the trip out of the hole. The pilot hole will then be logged from TD to ~500’ inside the 7” casing shoe. After logging, a 4-1/2” 13-Chrome liner will be run to cover the Molas formation and cemented in place. The liner will then be perforated, tested for CO_2 production and/or acid stimulated to be left as a vertical well. If the test results and log analysis show that the well will not be sufficient as a vertical well, the liner will be plugged back and a horizontal will be drilled out of the 7” 13-Chrome casing.

~~A 4-3/4” horizontal hole will be drilled out from KOP to TD. The build rate and target elevation of the lateral will be determined from the pilot log analysis, usually ~120’ below the top of the Leadville formation. A string of 2-7/8” drill pipe will be picked up and a 4-3/4” hole will be drilled to a vertical section of ~2000’ MD. A directional drilling plan is attached to this prognosis. After drilling the horizontal section, the well will be tested and depending on the results may be acid stimulated with coil tubing.~~ The well will then be shut in until production facilities are built and ready for production.

This well will be drilled with a closed loop, pitless system.

SURVEY DETAIL

Normal well deviation is not a concern.
Inclination surveys :

- 500’ intervals from spud to the 10-3/4” casing point and
- ~1000’ intervals from below the 10-3/4” casing point to the top of the Paradox Salt
- **Do not drop surveys while drilling below the Paradox Salt due to potential sticking**
- ~30’ intervals from below the Killer Shales to TD

CASING DETAIL **CASING RATING / DESIGN FACTORS**

SIZE	INTERVAL	DESCRIPTION	COLLAPSE	BURST	TENSION
10-3/4"	**0' – 2987'**	**40.5# J-55 STC**	**1580 / 1.27**	**3130 / 1.92**	**629 / 2.13**
7"	**0' – 6067'**	**29# CR13 FOX**	**7310 / 2.40**	**8670 / 2.88**	**718 / 3.42** **(100' above top of Paradox Salt)**
7"	**6067' –7787'**	**32# CR13FOX**	**9000 / 1.92**	**9630 / 3.07**	**792 / 3.05** **(run to 100' below Base Salt)**
7"	**7787' – 8217'**	**29# CR13 FOX**	**7310 / 1.80**	**8670 / 2.73**	**718 / 2.62** **(run to TD)**
4-1/2"	**8067' – 8612'**	**12.6# CR13 VAM TOP**	**7500 / 2.13**	**8430 / 2.81**	**288 / 2.80** **(hanger set 150' in 7" to TD)**

All of the 32# casing will be coated with Rytwrap (ICO in Odessa) prior to arriving on location.

DESIGN ASSUMPTIONS:

10-3/4" Surface	Tension:	Buoyed weight in 8.4 ppg fresh water, DF = 1.6
	Collapse:	Full evacuation w/ 9.0 ppg on outside, DF = 1.0
	Burst:	2000 psi shut in pressure at the surface, DF = 1.32
7" Intermediate	Tension:	Buoyed weight in 10.0 ppg brine
	Collapse:	Full evacuation in 10.0 ppg brine for 29#, 1.0 psi/ft for 32#
	Burst:	2500 psi shut in pressure at the surface with 10.0 ppg inside and 9.0 ppg outside
4-1/2" Liner	Tension:	Buoyed weight in 8.4 ppg fresh water
	Collapse:	Full evacuation w/ 9.0 ppg on outside
	Burst:	3000 psi shut in pressure at the surface

CEMENTING PROCEDURE

10-3/4" SURFACE CASING → Single stage

Use API 9-7/8" drift on location

Shoe Type:	Regular Guide Shoe
Collar Type:	Regular Float collar, 40' above shoe
Centralizers:	18 required → Place centralizers on shoe joint, and every 4th joint to surface
Flag Joints:	None Required
Other Equipment:	Stop clamp, thread lock the bottom 2 joints of casing + all float equipment, top and bottom plugs
Reciprocate:	Not required, limit of 294,000 lbs based on 40.5# J-55 STC w/ a 1.6 SF
Preflush:	10 bbls → Fresh water 20 bbls → Chemical wash 10 bbls → Fresh water
Lead CMT Slurry: Specifications: **100% Excess**	1500 sks → Light Premium → 5 lbm/sk KOL-SEAL + 0.125 lbm/sk POLY-E-FLAKE + 0.1% Halad®-9 12.4 ppg / 1.9 ft^3 / sk / 9.68 gal / sk
Tail CMT Slurry: Specifications: **100% Excess**	300 sks → Premium Cement → 94 lbm/sk Class G Cement + 0.125 lbm/sk POLY-E-Flake + 0.1% Halad-9 15.6 ppg / 1.18 ft3 / sk / 5.19 gal / sk
Displacement:	~300 bbls → Fresh Water @ 8 - 10 bbls / min
Volume Based:	All volumes listed are estimates only, for calculations use 14-3/4" X 10-3/4" annulus + 100% excess + shoe joints + ~100 sks circulated @ surface, attempt to circulate cement to surface, excess volume is based on experience.
Pressure Limits:	2000psi while pumping or bumping plug due to collapse rating of the 10-3/4" 40.5# J-55 STC w/ a 1.0 SF
Test Required:	Lab test w/ field water, want a 2 hr minimum @ 105° BHST
Temperature Survey:	Required if cement does not circulate at surface, call Todd Gentles @ (713) 369-8487 or 713-249-2805 for details
Wellhead:	Install section "A" assembly

Special Note:

1. Report the volume of cement circulated to the surface.
2. WOC for a minimum of 12 hours prior to drilling out.
3. NU 3M - 11 - BOP and test to rating.
4. Test the casing to 500 psi.
5. Cement Co. → Send copy of pressure charts, job log and summary to:

Kinder Morgan, Attn: Todd Gentles, 1001 Louisiana St, Suite 1000, Houston, TX 77002

CEMENTING PROCEDURE

7" PRODUCTION CASING → Single stage foam

Shoe Type:	Differential Fill Float Shoe
Collar Type:	Differential Fill Float Collar, 40' above shoe
Centralizers:	84 required => 10' above shoe and every other joint excluding wrapped casing
Flag Joints:	Cross overs from 29# to 32# will serve as flag joints
Other Equipment:	Thread lock the bottom 3 joints of casing + all float equipment.
Reciprocate:	If required, limit @ 100,000 lbs
Preflush:	10 bbls → Fresh water 20 bbls → Chemical wash 10 bbls → Fresh water
Lead Slurry: Specifications: 50% Excess	1800 sks → HalCem™ System → 0.2% Versaset + 0.15% Halad-766 + 1.5% Chem-Foamer 760 13.0 ppg / 1.43 ft3 / sk / 6.76 gal / sk
Tail Slurry: Specifications: 50% Excess	300 sks → HalCem™ System → 0.2% Halad-766 + 0.2% Versaset 13.5 ppg / 1.28 ft3 / sk / 5.67 gal / sk
Cement Cap Slurry: Specifications:	100 sks => HalCem™ System → 2% $CaCl_2$ 15.8 ppg / 1.17 ft3 / sk / 5.02 gal / sk
Displacement:	~300 bbls freshwater @ 8 - 10 bbls / min
Volume Based:	Use 9" hole diameter to calculate cement volume
Test Required:	Lab test w/ field water, 3.25 hr minimum @ 200° BHST Lab test w/ field water, 3.50 hr minimum @ 170° BHST
Temperature Survey:	Possible survey if severe lost circulation occurs
CBL Survey:	A CBL will be run after setting and cementing of this casing.
Wellhead:	Install section "B" assembly

Special Note:

1. Circulate 3 annular volumes prior to cementing @ maximum rate possible.
2. Displace cement at the maximum rate possible.
3. Report volumes of cement circulated.
4. Report any circulation problems on the morning report.
5. Cement Co. → Send copy of pressure charts, job log and summary to:

Kinder Morgan, Attn: Todd Gentles 1001 Louisiana St., Suite 1000, Houston, TX 77002

CEMENTING PROCEDURE

4-1/2" PRODUCTION LINER → Single stage

Shoe Type:	Differential Fill Float Shoe
Collar Type:	None
Centralizers:	None
Flag Joints:	None
Other Equipment:	Thread lock the bottom 3 joints of casing + all float equipment.
Reciprocate:	If required, limit @ 50,000 lbs
Preflush:	10 bbls → Fresh water 20 bbls → Chemical wash 10 bbls → Fresh water
Lead Slurry:	100 sks → HalCem™ System → 0.2% Versaset + 0.15% Halad-766
Specifications:	13.0 ppg / 1.43 ft3 / sk / 6.76 gal / sk
100% Excess	
Displacement:	~300 bbls freshwater @ 8 - 10 bbls / min
Volume Based:	Use 6" hole diameter to calculate cement volume
Test Required:	Lab test w/ field water, 3.25 hr minimum @ 200° BHST Lab test w/ field water, 3.50 hr minimum @ 170° BHST
Temperature Survey:	None
CBL Survey:	A CBL will be run after setting and cementing this casing
Wellhead:	None
Special Note:	

1. Displace cement at the maximum rate possible.
2. Report any circulation problems on the morning report.
3. Cement Co. → Send copy of pressure charts, job log and summary to:
Kinder Morgan, Attn: Todd Gentles 1001 Louisiana St., Suite 1000, Houston, TX 77002

SECTION 5 – Mud Program

The “standard” mud program and procedures used during the previous drilling programs at McElmo Dome will be employed during the drilling operation of the well.

Surface - 2987’ TVD/MD (10-3/4” Casing Point):

Hole Size: 14-3/4”
Mud Type: Spud mud

Spud the 14-3/4” surface hole with spud mud and circulate the closed loop system. Maintain the fluid as clean as possible to help prevent lost circulation. Use paper to control any seepage and pump LCM sweeps if lost circulation becomes a problem. Pump viscous sweeps if tight connections are encountered and prior to running the 10-3/4” casing.

2987’ - 5837’ TVD/MD (100’ above the Desert Creek):

Hole Size: 8-3/4”
Mud Type: Spud mud
Problems: Seepage, hole cleaning

Drill out of the 10-3/4” casing with clean spud mud. Circulate the closed loop system to keep solids to a minimum. Sweep the hole as required for hole cleaning and / or lost circulation problems. Use paper to control any seepage problems.

5837’ – 8217’ TVD/MD (50’ above the Leadville / 7” Casing Point):

Hole Size: 8-3/4”
Mud Type: Salt saturated brine
pH: 11+, as required to control H2S
Maximum salt concentration expected: 190,000 ppm
Problems: H2S, killer Shale gas influx, hole cleaning

Displace the fresh water system with salt saturated brine 100’ above the Desert Creek formation. Circulate through the closed loop system to maintain a clean fluid and to assist in breaking out any entrained gas. Pre-treat mud for H2S prior to drilling the P4 Shale.

Follow the attached guidelines for drilling the Killer Shale, titled “Paradox Salt Drilling Procedure”, which is located in Appendix A of this prognosis. The recommendations have proven to be very successful in recent drilling programs.

8217’ – 8612’ TVD (Pilot Hole) & 8297’ – 10370’ MD (Lateral ~2000’):

Hole Size: 6” & ~~4-3/4”~~
Mud Type: Fresh water
pH: 9-9.5 with caustic soda
Problems: LC, Hole cleaning, Lubricity

During the pilot hole drill the fresh water will be treated so that the Cl_2 content is ~20,000ppm. This is for logging purposes. Acid soluble LCM will be added to mitigate losses. ~~Expect complete losses while drilling the lateral~~. If circulation is lost and unable to be regained, nitrogen (or air) will be added to the mud system to help lift the fluid for circulation and cuttings movement. A specific description of this process is discussed in Section 8 of this prognosis.

SECTION 6 – Evaluation Program

Mud logging services will be used from surface to TD.

A measure while drilling (MWD) tool with gamma ray (GR) capability will be run from 8067' TVD/MD to casing point. GR response, mud logs, and penetration rate will be used to determine the top of the Leadville formation and final casing point.

The 6" pilot hole will be logged with 4 runs as follows:

- 1st run dual laterolog
- 2nd run triple combo, spectral GR
- 3rd run oriented X-dipole sonic, imager, GR
- 4th run VSP

SECTION 7 – Expected Pressures and Identified Hazards

BOTTOM HOLE PRESSURE

The Leadville formation is approximately 325' thick in the Doe Canyon and McElmo Dome area. This horizontal hole will be drilled in the Leadville formation. The expected bottom-hole pressure is currently about 2500 psi in the McElmo Dome area. Original field pressures were in the range of 2500 psi; 2500 psi would be the maximum pressure expected should there to be compartmentalization within the reservoir. This reservoir is unpressured; given the well depths of approximately 8400' TVD, a fresh water column provides approximately 3650 psi for well control. During drilling/well stimulation operations, the drill pipe/workstring will have double float valves installed to prevent kicks from coming up the string.

H_2S POTENTIAL

H_2S is expected to be circulated to the surface during the drilling of the Killer Shales located at 6205' – 7695' TVD/MD. The H_2S contingency plan that was used in the previous programs has been updated and revised and will be in force. This plan is located in Appendix A of this prognosis. All the necessary precautions, drills, and training will be done to protect personnel on location. H_2S monitors and safety equipment will be on location and operational prior to drilling the section and remain until rig release.

SECTION 8 – Other Items

LOST CIRCULATION CONTINGENCY PLAN

Circulation may be lost in the production hole. In this situation, managed pressure drilling techniques will be implemented. A normal fresh water fluid column of water is approximately 3650 psi downhole pressure, and the reservoir pressure is 2500 psi - therefore an overbalanced condition exists. The fracture gradient of the formation is estimated at 0.6 to 0.7 psi/ft, which equates to approximately 5050 to 5850 psi downhole pressure, which indicates fractures are not being induced; however, when a high porosity zone is encountered in the Leadville, and the pore volume exists to take the fluid. At this point, there is a high probability of sticking drill pipe as the cuttings flowing up the annulus immediately fallback.

A nitrogen managed pressure drilling package will be on location while drilling the horizontal production hole should this situation occur. The nitrogen will be added into the mud system to lighten the hydrostatic pressure and regain circulation in a managed pressure scenario. Managed pressure drilling equipment will be used to handle the return flow of nitrogen and any influx of CO_2 gas through a separator and vent stack. Well control is maintained by reducing or stopping the flow of nitrogen, which will kill the well. A dedicated rig pump and kill line are also hooked up and ready to boost the water flow if needed.

CONTACT INFORMATION	OFFICE	CELL
Operations Manager -- Todd Gentles	713-369-8487	713-249-2805
Drilling Director – Doug Frederick	713-369-9208	281-421-2333
Drilling Engineer – Beau Sumrow	713-369-9729	832-472-3589
Drilling Engineer – Valerie Cawthorn	713-369-8509	281-798-8769
Geologist – Ernest Nuckols	713-369-8821	361-563-6451
Geologist - Tabitha Bittinger	713-369-9065	713-398-3241

APPROVAL

Douglas A. Frederick
Drilling Director
Kinder Morgan CO2 Company, L.P.

Appendix A: Paradox Salt Drilling Proceudre

Ten distinct shale bodies occur in the Paradox Salt formation. Most notably, shale numbers 4, 5 and 6, and their associated anhydrite, in the sequence of the Paradox Salt are called the "Killer Shales" for their high H_2S content and tendency to stick pipe.
The "Killer Shale" section lies approximately 400'-500' into the Paradox and usually has a 20'-30' salt section between shale number 4 and 5. Because these shales are subject to plastic flow, to prevent sticking, the following procedure has worked in the past and is recommended.

Preparing to drill the Paradox Salt Formation

1. Test the BOPs on the last bit trip prior to drilling the Paradox Salt.
2. Pick up a set of mechanical Daily Oil Tool drilling jars on the last bit trip prior to drilling into the Paradox.
3. Run a survey to the top of the salt. This will help to avoid shutting down while drilling the sticky shales.
4. Use the salt formation cross-section as an indicator for predicting where each of the shale bodies will be encountered. Shales number 4, 5 and 6 are considered to be the most troublesome.
5. Increase flow rate to an annular velocity of at least 200 ft/min. Limitations of the rig's hydraulic system should be considered when selecting bit nozzle sizes.

Drilling the Paradox Salt Formation

6. The Driller will hand drill the interval beginning at the top of the Paradox Salt and continue until all problem shales have been penetrated and normal conditions return.
7. Control drill the Paradox while noting the normal torque values for the salts. If there is any fluctuation in pump pressure or torque, pick up off bottom and ream until hole conditions stabilize. Drill a maximum of 5' of salt and 1'-2' of shale before picking up 15'- 20' and reaming to bottom slowly to clean the wellbore. The severity of torque, and increases in pump pressure, should dictate the interval lengths. Some portions of the hole may require drilling only a few inches before picking up and reaming.
8. After 1' to 2' of shale is penetrated, expect 50,000-100,000 lbs drag to free the bit initially. After freeing the bit, pick up 15'-20' and start reaming back to bottom. If the torque increases 20-30 ft-lb above normal, pick up and expect 25,000-50,000 lb drag.
9. On each Kelly down, have the Driller pick up a full Kelly plus one single, then ream back to bottom. Reaming serves two purposes:
   a. It conditions the walls of the wellbore
   b. It allows for the cuttings to be carried away from the bit and collars before making a connection.
10. Pipe should be pulled and run slowly to avoid problems in the tight sections of the hole. Torque should dictate the frequency of the short trips. Periodic short trips through the entire salt section have proven useful in reducing high torque due to sticky shale.

At the present time, the key to drilling these sticky shales in the Paradox Salt is **PATIENCE.** It should be noted that good gas shows are also present in these shale stringers, and as the gas out of the sticky shales starts to subside, the hole starts to stabilize.