Attachment to Application for Permit to Drill
Drilling Program

McElvain Energy, Inc.
1050 17th St., Suite 2500
Denver, CO 80265

EK 29 BS2 FEDERAL COM #1H

Horizontal 2nd Bone Spring Oil and Gas Well

Surface Location: 210' FNL - 1210' FEL
Section 29, T18S, R34E N.M.P.M
Latitude = 32.725394°
Longitude = 103.577844°
Ungraded GL Elev. = 4,049'

Proposed Bottom Hole Location: 230' FSL – 660' FEL
Section 29, T18S, R34E N.M.P.M.
Latitude = 32.728753°
Longitude = 103.576025°

Lea County, New Mexico

Drilling Program written in compliance with Onshore Oil and Gas Order No. 1 (OO1 III.D.3, effective May 7, 2007) and Onshore Order No. 2, Dated November 18, 1988

McElvain Energy, Inc. (MEI) will apply for a Non-Standard Location through the New Mexico Oil Conservation Division (NMOCD) prior to commencement of pad building operations.

Drilling Plan:

The EK 29 BS2 FEDERAL COM #1H well is intended to be drilled as horizontal well with extensive directional guidance to the Bone Spring formation. After a 20" conductor is preset at a depth of 40' below ground level, the location will be prepared for operations, including all prudent storm water controls. This well will be drilled using a closed system without the use of an earthen reserve pit.

McElvain Energy, Inc. plans to use a 'spudder' rig to set and cement surface casing at 1,750 ft on the EK 29 BS2 FEDERAL COM #1H.

EK 29 BS2 FEDERAL COM 1H
BLM Drilling Plan

A spudder rig will MIRU to drill the conductor hole, run conductor pipe and cement in place. The spudder rig would then drill the 17 ½ surface hole to 1,750 ft and run centralized 13-3/8" 54.5 lb/ft J-55 STC casing to TD. At a minimum, wireline directional surveys will be run at intervals not exceeding 500'. The spudder rig will remain on location and over the wellbore as a 3rd party vendor cemented the surface casing in place. If, for some reason, the cement is not circulated to surface, or if cement falls further than 10' from ground level, the 17 ½" x 13 3/8" annulus will be filled to the surface from the top of cement using 1" tubing. The spudder rig would wait the appropriate amount of time to ensure the surface casing cement job meets all COA's per the APD. At that point, MEI would weld a plate over the surface casing with a pressure gauge to ensure no debris enters the surface casing and/or BLM personnel can inspect the surface casing at any time to verify that no pressure is present within the surface casing. A drilling rig would then be MIRU 60-90 days after the surface casing has been ran and cemented to drill the remaining intervals per the APD.

After MIRU the production drilling rig, the 13 3/8" shoe will be drilled out with a 12 ¼" bit and performance directional bottom hole assembly (BHA) and brine mud to an intermediate casing point of approximately 4,978'. In this section of hole, some directional work will be required in order to nudge the wellbore out to provide anti-collision clearance for future wells to be drilled from this drill pad and to ensure that the horizontal portion of the wellbore can be drilled at a 180° azimuth. Intermediate casing of 9 5/8" 40#/ft L-80 will be ran at approximately 4970' TVD sufficiently into the Penrose formation and below the Queen formation to isolate any H_2S that may arise from future and current water flood operations. The casing will be cemented into place using centralizers and with sufficient volume to ensure the top of cement reaches surface.

After waiting for cement to reach sufficient compressive strength, the 9 5/8" shoe will be drilled out and the casing shoe will be tested to 4525 psi using an equivalent mud weight. Drilling will continue with an 8 1/2" bit and performance directional BHA and cut brine mud system to a kick off point (KOP) at approximately 9,458'MD (9,437' TVD) adjusted for geology based on mud loggers interpretation of cutting samples in conjunction with gamma measurements provided by measurement while drilling (MWD) tools. The curve section of the hole will also be drilled using a 8 1/2" bit and directional BHA at a rate of 12 degrees per 100 feet until gamma from MWD and cuttings returns from the mud logger indicate the target formation has been reached. Landing point of the well is estimated to be 10,209'MD (9,927' TVD) at 88.4 degrees inclination and 180 degrees azimuth. The lateral will continue to be drilled at this azimuth until total depth is reached. Adjustments may be made to the directional program based on geology.

Should McElvain choose to complete the well, production casing will be placed in the wellbore It will consist of approximately 14,700' of 5 ½" 17#/ft P-110 casing centralized at a minimum of every other joint in the lateral section, through the curve and into the intermediate section casing string. Production cement will then be placed in the wellbore with the top of cement 500 feet into the intermediate string of casing.

1. Estimated Tops for Important Geological Formations/ 2. Possible Hydrocarbon

Rustler	1,870 '	1,870 '	Possible Lost Circulation
Salt	1,930 '	1,930 '	
Yates	3,423 '	3,420 '	Oil-Gas-Water
Seven Rivers	3,849 '	3,845 '	
Queen	4,625 '	4,620 '	Oil-Gas-Water
Penrose	4,926 '	4,920 '	Oil-Gas-Water
San Andres	5,452 '	5,445 '	Oil-Gas-Water; Possible Lost Circulation
Delaware	5,678 '	5,670 '	Oil-Gas-Water; Possible Lost Circulation
1st Delaware Sand	5,718 '	5,710 '	Oil-Gas-Water
2nd Delaware Sand	5,878 '	5,870 '	Oil-Gas-Water
Brushy Canyon	6,630 '	6,620 '	
Bone Spring	7,857 '	7,845 '	Oil-Gas-Water
1st Bone Spring Sand	9,085 '	9,070 '	Oil-Gas-Water
2nd Bone Spring Sand	9,696 '	9,670 '	Oil-Gas-Water

2. Anticipated Depths of Prospective Oil, Gas and Other Hydrocarbons
Refer to Table in section above.

3. Minimum Specifications For Pressure Control Equipment
Complies with Onshore Order #2.A.1

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.

Bottom Hole pressure = 10,055' TVD x 0.45 psi/ft = 4,525 psi (based on measured offset bottom hole pressures, see point 8 for details).

Maximum Surface Pressure:

= 4,525 psi - (10,055' TVD x .22 psi/ft)

= 4,525psi – 2212 psi = <u>2313 psi</u> (less than 5000 psi working pressure.)

Therefore 5000 psi BOPE system required.

A. <u>Wellhead Equipment 5,000 PSI System (See Exhibit A)</u>

1. 13 3/8" slip-on / welded x 13 3/8" 5,000 psi casing head.
2. One (1) 13 3/8" 5,000 psi WP single-ram preventer with one (1) set of pipe rams, complete with hand wheels and extension arms.
3. One (1) 13 3/8" 5,000 psi WP drilling spool with side outlets for 2" kill line and minimum 3" choke line
4. One 13 3/8" 5,000 psi WP double-ram preventer with one (1) set of blind rams on bottom & one (1) set of pipe rams on top complete with hand wheels and extension arms.
5. One 13 3/8" 5,000 psi WP Hydril GK (or equivalent) annular preventer.
6. Accumulator - Four Station Koomey (or equivalent) 120 gallon closing unit with remote, backup. The accumulator shall have sufficient capacity to open the hydraulically-controlled gate valve and close all rams plus the annular preventer, with a 50% safety factor and retain a minimum of 200 psi above the

precharge on the closing manifold without the use of the closing unit pumps. The reservoir capacity shall be double the usable accumulator capacity, and the fluid level shall be maintained at the manufacturer's recommendations.

7. The BOP system shall have two (2) independent power sources (electric and air) available for powering the closing unit pumps. Sufficient nitrogen bottles are suitable as a backup power source only, and shall be recharged when the pressure falls below manufacturer's specification.
8. 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.

All BOP equipment will be hydraulically operated with controls accessible both on the rig floor and on the ground.

B. <u>Auxiliary Equipment To Be Used – 5,000 PSI System</u>

1. Upper & lower kelly cock valve with handles available.
2. Safety valve and subs to fit drill pipe, on rig floor.
3. Choke manifold for 5,000 psi system with 2 chokes (pressure gauge on manifold).
4. Two (2) kill lines (2" minimum, one remote to end of substructure) both with 2" kill line full open valves, plus a check valve for each line.
5. Minimum 3" choke line.
6. Two choke line gate valves, 3" minimum, with one choke line gate valve being hydraulically operated.
7. Two chokes (1 remote, 1 manual) on choke manifold
8. Fill-up line above the uppermost preventer.
9. Wear Bushing or Bowl Protector in the casing head.
10. Inside BOP or (float sub) available
11. All BOPE connections subjected to well pressure shall be flanged, welded or clamped.
12. Choke line 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.

The wellhead BOP equipment will be nippled-up on the 9-5/8" x 13 3/8" 5,000 psi WP casing head prior to drilling out from under surface casing. All ram preventers and related equipment will be tested to 5,000 psi for 10 minutes. Annular preventers will be tested to 50% of rated working pressure for 10 minutes. Surface casing will be tested to 70% of internal yield pressure. All preventers and surface casing will be tested before drilling out of surface casing. BOP equipment will be tested every 14 days, after any repairs are made to the BOP equipment, and after the BOP equipment is subjected to pressure. Annular preventers will be functionally operated at least once per week. Pipe rams will be activated daily and blind rams shall be activated each trip or at least weekly. The New Mexico Oil & Gas Conservation Commission and the BLM will be notified 24 hours in advance of testing of BOPE.

4. Proposed Bit and Casing Program

Bit Program

17 1/2" Surface Hole = Surface to 1750'MD/TVD = 13 3/8" Casing point
12 1/4"Nudge = 1750'MD to 4978'MD/4970'TVD = 9 5/8" Casing point
8 1/2" Nudge = 4978' MD to 9458' MD/9437' TVD
8 1/2" Curve = 9458'MD to 10209' MD/9927'TVD
8 1/2" Lateral = 10209' MD to 14410' MD/10055'TVD = 5 ½" Casing point

* See COA for casing depth changes

Casing Program – all casing stings are new casing

Casing & Hole Size	Weight	Grade	Coupling	Setting Depth (MD)	Comments
20" Conductor				0' – 40' BGL	New
13 3/8" (17 ½")	54.5 ppf	J-55	ST&C	0'-~~1,750'~~ MD 1900'	New Casing Cement to surface Centralized
9-5/8" (12 1/4")	40 ppf	L-80	LT&C	0' - 4,978'MD	New Casing. Cement to surface. Centralized
5 ½" (8 1/2")	17 ppf	P-110	BPN	0' – 14,410' MD	New Casing. Cement 500' inside ICP Centralized every other joint into ICP

Casing strings below the conductor casing will be tested to .22 psi per foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield.

Minimum casing design factors used: Collapse - 1.125
Burst - 1.0
Jt. Strength - 1.2

Surface casing shall have a minimum of 1 centralizer per joint on the bottom three (3) joints, starting with the shoe joint for a total of (4) minimum centralizers. Centralizers will be placed 10' above the shoe on the shoe joint, on the 1st, 2nd and 3rd casing collars.

The intermediate casing will be centralized using 1 centralizer the first 6 jts and spaced appropriately into the surface casing.

The production casing will be centralized every other joint through the curve section of the well-bore and then spaced +/- 1 centralizer / 4 jts through the remainder of the cement column, using approximately 60 centralizers.

5. <u>Proposed Cementing Program</u>

<u>Surface Casing Single Stage Job – (0-1750'MD/TVD):</u>
Excess – 100% over gauge hole – 17-1/2" hole and 13-3/8" casing (1.3893ft3/ft)
Top of Cement - Surface
12.5 ppg
Yield – 2.21 ft3/sx,
Water requirement – 12.66 gal/sx
Compressive strength: 24 hr – 2450 psi
<u>Total sacks of cement pumped = 1110sx</u>

<u>Intermediate Casing –(0-4978'MD):</u>
Excess – 25% over gauge hole – 12 1/4" hole and 9 5/8" casing (0.1503 ft3/ft)
Top of Cement – surface
<u>Stage #1:</u>
Lead - (0'-4478'): 1130 sx - 12.9 ppg, 35:65 Dak G, conventional cement
Yield – 1.875 ft3
Water requirement – 10.08 gal/sx.

<u>Stage #2:</u>
Lead - (4478'-4978'): 180 sx – 14.8 ppg, 35:65 Dak G, conventional cement
Yield – 1.325 ft3
Water requirement – 6.32 gal/sx.
<u>Total sacks of cement pumped = 1310</u>

<u>Production Casing Single Stage Job – (4478-14950'):</u>
Excess – 19% over gauge hole – 8 1/2"hole and 5 ½" casing (0.3075ft3/ft & .2291 ft3/ft respectively)
Top of Cement – 4478 (500' inside intermediate casing set at 4978')
12.5 ppg
Yield – 2.21 ft3/sx,
Water requirement – 12.66 gal/sx
Compressive strength: 24 hr – 2450 psi
<u>Total sacks of cement pumped = 1110sx</u>

Cement volumes are minimums and may be adjusted based on caliper log results.

6. **Characteristics for Drilling Fluids**

This well will be drilled using brine/cut brine drilling fluid in a closed loop mud system. Pit Volume Totalizer (PVT) equipment will be on each pit to monitor pit levels. A trip tank equipped with a PVT will be used to monitor trip volumes. Sufficient mud materials will be kept on location to weight mud up to 11.0 PPG, if required. Additional material will also be available to combat lost circulation. In order to run casing, the viscosity, water loss and other properties may have to be altered to ensure success.

7. Testing, Logging, Coring and Completion Program

A. Drill-Stem Testing Program: None

B. Logging Program:
From KOP of curve to Surface casing shoe (pull GR to surface):
Density/Laterolog/Spontaneous Potential/Caliper

Minimum logging requirements for the entire well shall consist of a calibrated gamma ray (GR) log scaled in API units from total measured depth to surface, with a repeat section. Maximum logging speed 3,600 feet/hour in open hole and 2,000 feet/hour in cased hole. An MWD GR log is sufficient for this requirement in the curved and lateral portions of the well.
Minimum logging requirements above the kick off point (KOP) shall consist of:

1. Compensated density-neutron logs over potential hydrocarbon producing zones or,
2. A cased hole pulsed neutron log if there are open hole compensated density-neutron, gamma ray, and multiple depth-of-investigation resistivity logs (such as medium and deep induction and shallow laterlog, or array induction logs) suitable for calibration within one-half mile. The pulsed neutron log should be run from KOP to the base of surface casing no faster than 1,800 feet/hour.

A cement bond log shall be run if the well is cased for production. The logged interval should extend from at least 50 feet below the KOP, if practical, to 200 feet above the top of cement. In no case shall the cement bond log begin above the KOP.

BLM shall be provided with a directional survey to establish the location of the horizontal lateral and bottom of the well including the surface reference, inclination, horizontal angle, reference, and direction turned. If reduced data are provided, the algorithm, datum, and projection should also be provided.

Submission of digital logging data shall be in Log ASCII Standard (LAS) file format.

C. Mud Logging
Geologist & a manned mud-logging unit will be operational @ +/- 7,000' on the main hole to TD of the horizontal hole.

D. Coring: None.

E. Cement Bond Log: Will be run after the drilling of the well has been completed and as the start of the completion process. The CBL will confirm the quality of the cement bond and the actual TOC. If either of these two data points were not satisfactory per BLM, State and standard procedure, remedial cement work, if required, will be performed after consultation and approval of a plan from both the BLM and State agencies.
A cement bond log shall be run if the well is cased for production, injection, or disposal. The logged interval should extend from at least 50 feet below the KOP, if practical, to 200 feet above the top of cement. In no case shall the cement bond log begin above the KOP.

8. Expected bottom hole pressure and any anticipated abnormal pressures, temperatures or other potential hazards

A. Expected bottom-hole pressure @ the 2nd BoneSpring Formation is 0.45 psi x 10,055'TVD = 4525 psi based on offset measured reservoir pressure.

Well	Total Vertical Depth (ft)	BHP (PSI)	Pressure Gradient (psi/ft)	EMW (ppg)
EK 30 BS2 Federal Com #3H	9929		0.50276132	
EK 31 BS2 Federal Com #4H	10070		0.433446597	
Average			0.470760537	
Estimated BHP	**10055**	**4525**		**8.65**

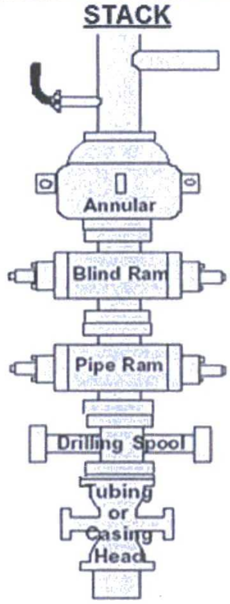
B. Expected bottom-hole temperature @ the 2nd Bone Spring Formation is 150 deg F.
C. Lost circulation is possible while drilling the upper zones and loss circulation material will be on hand.
D. No H_2S sour gas is known to exist in the formations that we will drill through, but an appropriate H_2S contingency plan will be in place.

9. Plugging and Abandonment

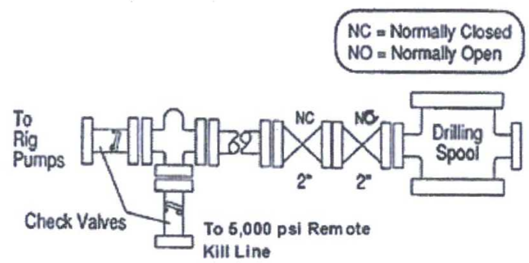
No plugging and abandonment of the well would occur until after the well has been drilled, completed, fraced and production tested, unless extenuating circumstances arise. Full authorization will be verbally sought from the Bureau of Land Management and the Wyoming Oil & Gas Commission prior to actual plugging operations being initiated with written reports submitted as a followed up.

Exhibit A: Blow Out Prevention Equipment

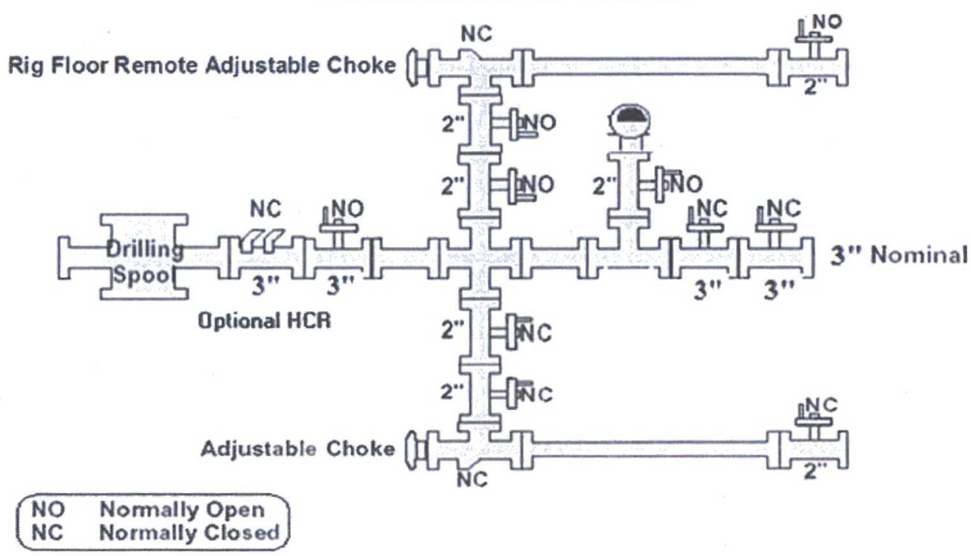
CLASS IV 5,000 psi BOP STACK



5,000 psi KILL LINE (2" MINIMUM ID)



5,000 psi CHOKE MANIFOLD



PERFORMANCE DATA

TMK UP ™ BPN | **5.500 in** | **17.00 lbs/ft** | **P-110 CY**

Technical Data Sheet

Tubular Parameters

Size	5.500	in	Minimum Yield	110,000	psi
Nominal Weight	17.00	lbs/ft	Minimum Tensile	125,000	psi
Grade	P-110 CY		Yield Load	546,000	lbs
PE Weight	16.89	lbs/ft	Tensile Load	620,000	lbs
Wall Thickness	0.304	in	Min. Internal Yield Pressure	10,600	psi
Nominal ID	4.892	in	Collapse Pressure	7,500	psi
Drift Diameter	4.767	in			
Nom. Pipe Body Area	4.962	in²			

Connection Parameters

Connection OD	6.050	in
Connection ID	4.892	in
Make-Up Loss	4.125	in
Critical Section Area	4.962	in²
Tension Efficiency	100.0	%
Compression Efficiency	100.0	%
Yield Load In Tension	546,000	lbs
Min. Internal Yield Pressure	10,600	psi
Collapse Pressure	7,500	psi
Uniaxial Bending	92	°/100 ft

Make-Up Torques

Min. Make-Up Torque	5,100	ft-lbs
Opt. Make-Up Torque	11,900	ft-lbs
Max. Make-Up Torque	15,300	ft-lbs
Yield Torque	17,000	ft-lbs

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TMK IPSCO

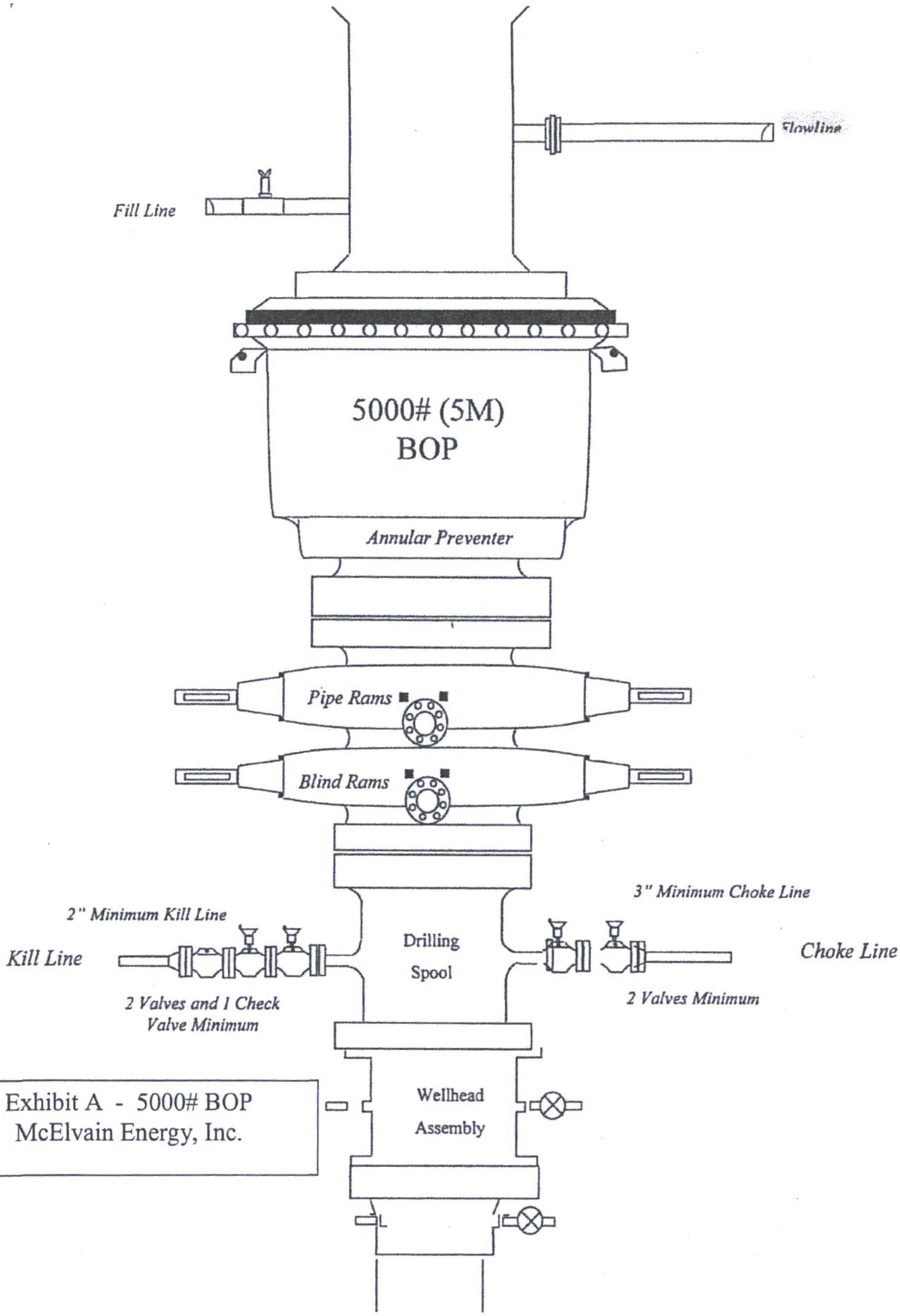

Exhibit A - 5000# BOP
McElvain Energy, Inc.

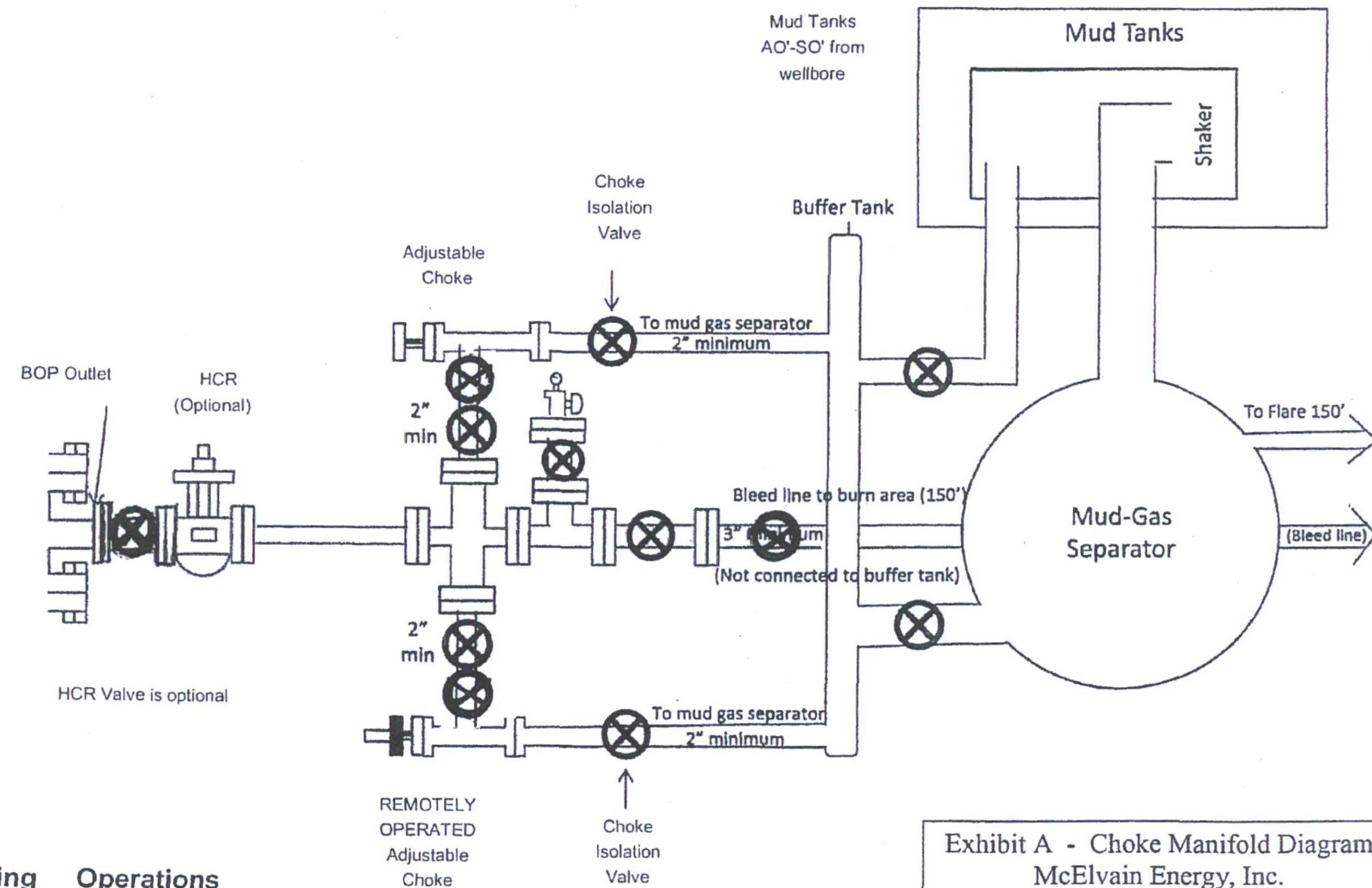

Exhibit A - Choke Manifold Diagram
McElvain Energy, Inc.

Drilling Operations
Choke Manifold