Mustang Creek Operating LLC
Prescott Ranches 32-34
512’ FSL 1,963’ FEL (SW/4 SE/4)
Sec. 32 T12S R59W
Elbert County, Colorado
Surface: Fee
Mineral Lease: Fee

DRILLING PROGRAM

Please contact Chris Hanson at 303-513-9963, if there are any questions or concerns regarding this Drilling Program.

SURFACE ELEVATION – 6,066’ (Ungraded ground elevation)

SURFACE FORMATION – Pierre Shale – Fresh water possible

1. ESTIMATED FORMATION TOPS – (Water, oil, gas and/or other mineral-bearing formations)

Formation	MD	Geology
Pierre Shale	Surface	Shale
Sharron Springs	4,350’	Shale
Niobrara	4,690’	Limestone/Shale
Niobrara D Bench	5,105’	Limestone/Shale
Codell	5,230’	Sandstone
Carlile	5,255’	Shale
Green Horn	5,355’	Limestone/Shale
Dakota	5,635’	Sandstone
Permian	6,625’	Limestone/Shale
Pennsylvanian	7,420’	Limestone/Shale
Lansing	8,600’	Limestone/Shale
Marmaton	8,990’	Limestone
Cherokee	9,110’	Limestone/Shale
Atoka	9,440’	Sandstone/Limestone/Shale
Morrow	10,040’	Sandstone/shale
Keyes	10,170’	Sandstone
Mississippian	10,270’	Limestone/Dolomite
Arbuckle	10,520’	Sandstone/Limestone/Shale
Precambrian	10,760’	Granite
TOTAL DEPTH	**11,000’**	

2. ESTIMATED DEPTHS OF ANTICIPATED WATER, OIL, GAS, OR MINERAL BEARING FORMATIONS

Estimated depths at which water, oil, gas or other mineral-bearing formations are expected to be encountered:

Formation	MD	Lithology
Pierre Shale	Surface	
Sharron Springs	4,350’	
Niobrara	4,690’	Oil
Niobrara D Bench	5,105’	Oil
Codell	5,230’	Oil
Carlile	5,255’	

Green Horn	5,355’	Oil
Dakota	5,635’	Oil
Permian	6,625’	
Penn	7,420’	
Lansing	8,600’	Oil
Marmaton	8,990’	Primary Oil
Cherokee	9,110’	Primary Oil
Atoka	9,440’	Primary Oil
Morrow	10,040’	Oil
Keyes	10,170’	Oil/Gas
Mississippian	10,270’	Oil
Arbuckle	10,520’	Oil
Precambrian	10,760’	

All fresh water and prospectively valuable minerals encountered during drilling will be recorded by depth and protected.

3. BLOWOUT PREVENTION & PRESSURE CONTROL

- See attached blowout preventer diagram.

Blowout preventer (BOP) and related equipment (BOPE) will be installed, used, maintained, and tested in the manner necessary to assure well control and will be in place and operational prior to drilling the surface sassing show unless otherwise approved by the APD. The BOP and related control equipment will be suitable for operations in those areas which are subject to sub-freezing conditions. The BOPE will be based on known or anticipated sub-surface pressures, geologic conditions, accepted engineering practice, and surface environment. The working pressure of all BOPE will 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.

The choke manifold and accumulator will meet or exceed Colorado Oil and Gas Commission (COGCC) standards. All choke lines will be straight lines unless turns use tee blocks or are targeted with running tees, and will be anchored to prevent whip and reduce vibration. The BOP equipment will be tested when initially installed, whenever any seal subject to test pressure is broken, after any repairs to the equipment and at 30-day intervals. Pipe rams, blind rams and annular preventer will be activated on each trip and weekly BOP drills will be conducted with each crew. All tests, maintenance, and BOP drills will be documented on rig “tower sheets”.

BOP’s and choke manifold will be installed and pressure tested before drilling out of surface casing (subsequent pressure test will be performed whenever pressure seals are broken), and then will be checked daily as to mechanical operating condition. BOP’s will be pressure tested at least once every 30 days. Ram type preventers and related pressure control equipment will be pressure tested to related working pressure of the stack assembly, if a test plug is used. If a plug is not used, the stack assembly will be tested to the rated working pressure of the stack assembly, or 70% of the minimum internal yield of the casing, whichever is less. Annular type preventers will be pressure tested to 50% of their working pressure. All casing strings will be pressure tested to 0.22 psi/ft or 1,500 psi, whichever is greater, not to exceed 70% of the internal yield.

A manual locking device (i.e. hand wheels) or automatic locking devices shall be installed on the system. A valve will be installed in the closing line as close as possible to the annular preventer to act as a locking devise. The valve will be maintained the open position and will be closed only when the power source for the accumulator system is inoperative. Remote controls will be readily accessible to the driller.

Remote controls for the 3M system will be capable of closing all preventers. Master controls will be at the accumulator and will be capable of opening and closing all preventers and the choke line valves (if so equipped).

The drilling rig has not been selected for this well. Selection will take place after approval of this application is granted. Manual and/or hydraulic controls will be in compliance with COGCC standards 3,000 psi system.

Auxiliary Equipment:
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, 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, and fill-up line above the uppermost preventer.

If expected pressures approach the working pressure of the system, one remote kill line tested to stack pressure will be utilized.

4. CASING PROGRAM

Proposed Casing:

Hole Diameter	Casing Diameter	Setting Depth	Grade	Weight (lbs/ft)	Thread/ Coupling	Condition
Augured	20”	0’ – 60’	Conductor	53		
17-1/2”	13-3/8”	0 - 300’	K-55	54.5	ST&C	New
12-1/4”	9-5/8”	0’ – 5,000’	K-55	36	LT&C	New
7-7/8”	5-1/2”	0’ – 11,000’	N-80	17	LT&C	New

Design Criteria:

Size	Grade	Weight (lbs/ft)	Thread/ Coupling	Tension/ Joint Strength	Burst	Collapse
13-3/8”	K-55	54.5	ST&C	514,000	2,730	1,130
9-5/8”	K-55	36	LT&C	605,000	3,520	2,980
5-1/2”	N-80	17	LT&C	397,000	7,740	6,280

5. CEMENT PROGRM

Cement Interval	Sacks	Cement
0' – 60'	±50	Augured and set with Redi-Mix
0' – 300'	±220	Halliburton Lite
0' – 5,000'	±900	Halliburton Lite
0' – 11,000'	±1,200	Halliburton Lite *

* Cement calculated at gauge hole +25% excess.

Yields:

Surface:	Halliburton Lite	=	2.21 ft^3/sx (11 ppg)
Intermediate	Halliburton Lite	=	2.21 ft^3/sx (11 ppg)
Production:	Halliburton Lite	=	2.21 ft^3/sx (11 ppg)

If necessary, 100' of the casing top will be 1-inched with Class "G" cement.

6. MUD PROGRAM

0'	-	300'	**LSND** MW: 8.4 – 8.8 ppg Visc.: 26 – 30 sec WL: NC
300'	-	5,000'	**LSND - DAP** MW: 9.7 – 10.4 ppg Visc.: 36 - 42 sec WL: LT 10 cc
5,000'	-	TD	**LSND - DAP** MW: 9.0 ppg Visc.: 36 - 42 sec WL: LT 10 cc

Sufficient mud materials to maintain mud properties, control lost circulation and to contain a "kick" will be available on location.

7. LOGGING, CORING TESTING PROGRAM

Logging: Triple Combo: TD to 5,000'
Sonic Scanner: TD to 5,000'

Coring: Sidewall cores will be determined after logging. Samples will be taken every 10' in primary target zones and every 30' for the remainder of the well.

Testing: Drill Stem tests will be determined after logging and may be run on shows of interest.

8. GEOLOGIC CONDITIONS

Estimated bottom-hole pressure gradient: 0.43 psi/ft
Estimated maximum bottom-hole pressure: 4,730 psi
Abnormal pressures: None anticipated
Abnormal temperatures: None anticipated

Additional potential hazards: None anticipated

9. ADDITIONAL FACETS OF PROPOSED OPERATIONS

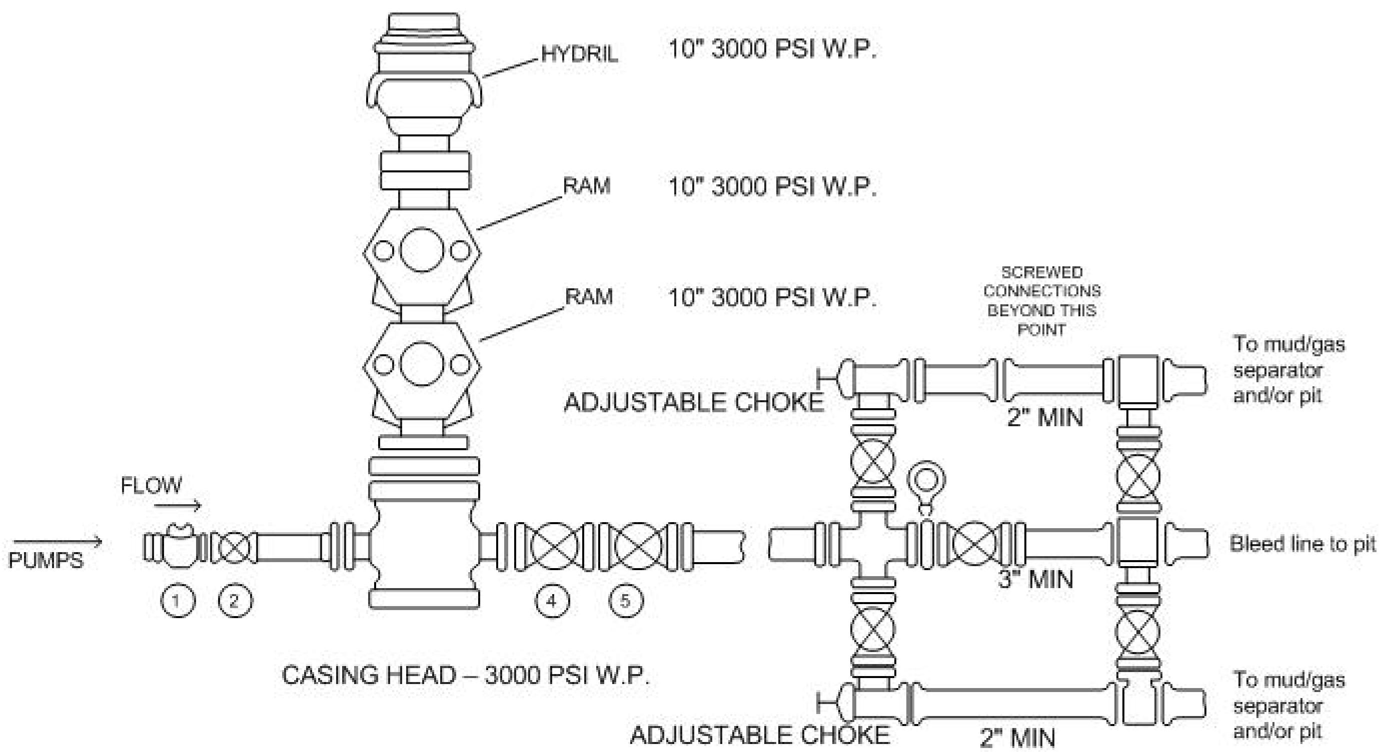
Anticipated Start Date: September 30, 2013

Completion:

The location pad will be sufficient size to accommodate all completion equipment activities and equipment. A string of 2 3/8", 4.7#, N-80, EUE 8rnd will be run as production tubing. A Sundry Notice (SN) will be submitted with a revised completion program, if warranted.

MINIMUM
BOP Requirements

3000 PSI W.P.



KILL LINE

Valve #1 – Flanged check valve
Full working pressure of BOP

Valve #2 – Flanged, minimum 2" bore
Full working pressure of BOP

CHOKE LINE

Valves #4 & 5 – Flanged minimum 3" bore

Full working pressure of BOP

(Note: An HCR can be used instead of Valve # 5)

GENERAL RULES AND RECOMMENDATIONS

All lines to manifold are to be at right angles (90 deg.). No 45 deg. angles are to be used.
Blind flanges are to be used for blanking.
All studs and nuts are to be installed on all flanges.