Tabula Rasa Energy, LLC
Caddell 2
SHL: 1,349’ FSL 1306’FEL (NE/4 SE/4)
BHL: 1,924’ FSL 1,106’ FEL (NE/4 SE/4)
Sec. 4 T29S R69W
Huerfano County, Colorado
Surface Ownership: Fee
Mineral Lease: Fee

DRILLING PROGRAM

(All Drilling Procedures will be followed as Per Onshore Orders No. 1 and No. 2)

Please contact Bob Sutherland Tabula Rasa, 281-668-8488, if there are any questions or concerns regarding this Drilling Program.

SURFACE ELEVATION – 7,833’ (Ungraded ground elevation)

SURFACE FORMATION – Pierre Shale – Fresh water possible

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

Formation	TVD	MD	Geology
Pierre Shale	0’	0’	Sandstone, shales, siltstones & volcanic sills
Fort Hayes	4,498’	4,572’	Sandstone, shales, siltstones & volcanic sills
Codell	4,566’	4,640’	Sandstone, shales, siltstones & volcanic sills
Dakota	5,172’	5,246’	Sandstone, shales, siltstones & volcanic sills
Morrison	5,354’	5,428’	Sandstone, shales, siltstones & volcanic sills
Entrada	5,694’	5,768’	Sandstone, shales, siltstones & volcanic sills
Total Depth	**5,920’**	**5,994’**	

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	TVD	MD	Formation Thickness	Lithology
Pierre Shale	0’	0’	4,498’	Some water, nat. gas & oil bearing
Fort Hayes	4,498’	4,572’	68’	Some water, nat. gas & oil bearing
Codell	4,566’	4,640’	606’	Some water, nat. gas & oil bearing
Dakota	5,172’	5,246’	182’	Some water, CO2 and minor nat. gas bearing
Morrison	5,354’	5,428’	340’	Some water, CO2 and minor nat. gas bearing
Entrada	5,694’	5,768’	225’	Some water, CO2 and minor nat. gas bearing

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 0.31 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 0.31 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 for 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
17-1/2"	13 3/8"	0' – 100'	Conductor	48	ST&C	New
12-1/4"	9-5/8"	0' – 600'	J-55	36	ST&C	New
8 3/4"	7"	0' – 5,394'	J-55	26	LT&C	New
8 3/4"	7"	5,394' – 5,994'	CR13- L80	29	VAM	New

Design Criteria:

Size	Grade	Weight (lbs/ft)	Thread/ Coupling	Tension/ Joint Strength	Burst	Collapse
9-5/8"	J-55	36	ST&C	639,000	3,520	2,020
7"	J-55	26	LT&C	490,000	4,980	4,330
7"	CR13- L80	29	VAM	818,000	8,160	7,030

5. CEMENT PROGRM

Cement Interval	Sacks	Cement
0' – 100'	±110	Baker Hughes Class "G"
0' – 600'	±300	Baker Hughes Class "G"*
0' – 5,994'	±401	Baker Hughes Premium Lite **

** Cement calculated at gauge hole +100% excess
* Cement calculated at gauge hole +30% excess.

Yields:

Surface:	Baker Hughes Premium Lite	=	1.24 ft^3/sx (15.8 ppg)
Production:	Baker Hughes Premium Lite	=	Lead 3.25 ft^3/sx (9.8 ppg) Tail 2.19 ft^3/sx (12.5 ppg)

Cement additives – (Note: Some additives are proprietary products. If another cement contractor is used, these blends and products may vary slightly).

Cement additives:

Surface:	Lead:	
	Tail:	**Baker Hughes Class "G"** 2% $CaCl_2$ 1/4 lbs/sx Cello Flake 0.05 lbs/sack Static Free 5 lbs/sack Kol-Seal 0.5% FL-52 5 lbs/sack CSE-2 0.2% FL-52A
Production:	Lead:	**271 Sacks Baker Hughes Premium Lite** 1/4 lbs/sx Cello Flake 0.2% R-3 61.9% LW-6 0.3% CD-32 5 lbs/sack Kol-Seal 0.6% FL-52 0.4% Sodium Metasilicate
	Tail:	**130 Sacks Baker Hughes Premium Lite High Strength** 1/4 lbs/sx Cello Flake 1.5% $CaCl_2$ 0.05 lbs/sack Static Free 0.002 gps FP-6L 0.3% BA-59 5 lbs/sack Kol-Seal 0.9% FL-52 0.6% Sodium Metasilicate

6. MUD PROGRAM

0'	-	100'	**LSND Fresh Water** MW: 8.4 – 8.8 ppg Visc.: 26 – 30 sec WL: NC
100'	-	600'	**LSND** MW: 8.5 – 9.0 ppg Visc.: 40-55 sec WL: LT 10 cc
600'	-	TD	**Diesel Invert Emulsion Closed-Loop Mud System** MW: 9.0 – 12.0 ppg Visc.: 45 - 55 sec WL: LT 8 cc

Sufficient mud materials to maintain mud properties, control lost circulation and to contain a "kick" will be available on location. Cuttings and fluids will be hauled to an approved disposal/recycle facility.

7. LOGGING, CORING TESTING PROGRAM

Logging:	Induction Log: TD to 600’
	Density Porosity Log: TD to 600’
	Neutron Porosity Log: TD to 600’
Coring:	None.
Testing:	No openhole testing.

8. GEOLOGIC CONDITIONS

Estimated bottom-hole pressure gradient: 0.18 to 0.31 psi/ft
Estimated maximum bottom-hole pressure: 1,776 psi
Abnormal pressures: None anticipated
Abnormal temperatures: None anticipated
Additional potential hazards: None anticipated

9. ADDITIONAL FACETS OF PROPOSED OPERATIONS

Anticipated Start Date: October 25, 2013

Completion:
The location pad will be sufficient size to accommodate all completion equipment activities and equipment. A string of 3 1/2”, 12.7#, CR13-110, will be run as production tubing with packer. A Sundry Notice (SN) will be submitted with a revised completion program, if warranted.

Minimum BOP Requirements
3000 PSI W.P.