WPX Energy Rocky Mountain, LLC

SG 714-44-23 HN1

Surface Location: 1225' FSL, 773' FEL, SE 1/4 SE 1/4, Section 14 - T7S-R96W
Bottom Hole Location: 189' FSL, 637' FEL, SE 1/4 SE 1/4, Section 26 - T7S-R96W

Garfield County, Colorado

DRILLING PLAN

1. ESTIMATED TOPS OF IMPORTANT GEOLOGIC MARKERS

Formation	*Depth (MD)*	*Depth (TVD)*
Base Fort Union	1,710	1,705
Mesaverde	2,610	2,602
Cameo Coals	5,004	4,987
Rollins SS	5,532	5,512
Cozzette	5,772	5,752
Corcoran	6,013	5,992
Upper Sego	6,210	6,188
Lower Sego	6,556	6,533
Lloyd	6,762	6,738
Castlegate	7,346	7,320
Castlegate Hot GR	7,598	7,570
Mancos-B	7,916	7,887
Top Niobrara	8,997	8,962
Niobrara Hot GR Marker	9,018	8,982
Niobrara HN2	9,124	9,080
Horizontal Target (HN1)	9,438	9,319

2. ESTIMATED DEPTH OF ANTICIPATED WATER, OIL, GAS OR MINERAL FORMATIONS (TVD)

Formation	*Depth (TVD)*	*Substance*
Mesaverde	2602	water, oil and gas
Cameo Coals	4987	water, oil and gas
Rollins SS	5,512	water, oil and gas
Cozzette SS	5,752	water, oil and gas
Corcoran	5,992	water, oil and gas
Upper Sego	6,188	water, oil and gas
Lower Sego	6,533	water, oil and gas
Castlegate	7320	water, oil and gas
Mancos B	7887	water, oil and gas
Niobrara	8962	water, oil and gas

Any usable fresh water zones encountered will be adequately protected and reported. All usable water zones, potential hydrocarbon zones, and valuable mineral zones will be isolated.

3. PRESSURE CONTROL EQUIPMENT – (refer to diagram in *Appendix A*)

A. Type: Eleven (13-5/8) Inch Double Gate Hydraulic BOP
Eleven (13-5/8) Inch Blind Ram Hydraulic BOP
Eleven (13-5/8) Inch Annular Preventer

<u>The Blow-Out Preventer will be equipped as follows</u>:

10K psi annular preventer
2-10K psi pipe rams
1-10K psi blind 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)
3 inch choke line
2 kill line valves (2 inch minimum) and check valve
Remote kill line (2 inch minimum) shall run to the outer edge of the substructure and be unobstructed
Manual and hydraulic choke line valve (3 inch minimum)
<u>3 chokes</u>, 1 being remotely controlled
Pressure gauge on choke manifold
Upper kelly cock valve with handle available
Lower kelly cock valve with handle available
Safety valves and subs to fit all drill string connections in use
Inside BOP or float sub available
Wearing ring in casing head
All BOPE connections subjected to well pressure shall be flanged, welded, or clamped
Fill-up line installed above the uppermost preventer

B. Working Pressure Ratings: 10,000 psi Rams & 10k Annular

Note: 10,000 psi working rated BOP rams and a 10,000 psi working pressure Annular Preventer will be installed. Schematics for the system are attached (Appendix A).

C. Testing Procedure:

<u>Annular Preventer</u>

At a minimum, the Annular Preventer will be pressure tested to 50% of the working pressure for a period of ten (10) minutes or until provisions of the test are met, whichever is longer.

At a minimum, the above pressure test will be performed:

1. *When the annular preventer is initially installed*
2. *Whenever any seal subject to test pressure is broken*
3. *Following related repairs*
4. *At thirty (30) day interval*

In addition, the annular preventer will be functionally operated at least weekly.

<u>Blow-Out Preventer</u>

At a minimum, the BOP, choke manifold, and related equipment will be pressure tested to the working pressure of the stack if isolated from the surface casing by a test plug, or to 70% of the internal yield strength of the surface casing (if the BOP is not isolated from the casing by a test plug). Pressure will be maintained for a period of at least ten (10) minutes or until the requirements of the test are met, whichever is longer. At a minimum, the above pressure test will be performed:

1. *When the BOP is initially installed*
2. *Whenever any seal subject to test pressure is broken*

3. *Following related repairs:" and*
4. *At thirty (30) day intervals*

All pressure test charts shall be on display at the rig and additional copies sent to the regulatory agencies. In addition, the pipe and blind rams will be activated each trip, but not more than once each day. All BOP drills and tests will be recorded in the IADC driller's log.

D. Choke Manifold Equipment:

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 to reduce vibration.

Flexible choke lines may be used (if employed) and shall be effectively anchored and configured to the manufacturer's specifications. These specifications will be kept with the rig at all times and supplied to the authorized officer upon request. Specifications, at a minimum, shall include acceptable bend radius, heat range, anchoring, and working pressures.

E. Accumulator:

The accumulator will have sufficient capacity to open the hydraulically-controlled choke line valve (if so equipped), close all rams plus the annular preventer (plus an additional 50% volume for safety factor), and retain a minimum of 200 psi above pre-charge on the closing manifold without the use of the closing unit pumps. The fluid reservoir capacity will be double the usable fluid volume of the accumulator system capacity and the fluid level of the reservoir will be maintained at the manufacturer's recommendations.

Two (2) independent power sources shall be available for powering the closing unit pumps. Nitrogen bottles are suitable of a backup power source and will maintain a charge equal to the manufacturer's specifications.
The accumulator pre-charge pressure test will be conducted prior to connecting the closing unit to the BOP stack and at least once every six (6) months thereafter. The accumulator pressure will be corrected if the measured pre-charge pressure is found to be above or below the maximum or minimum limits.

Remote controls shall be readily accessible to the driller. Remote controls for the systems will be capable of both opening and closing all preventers. Master controls will be at the accumulator and will be capable of opening and closing all preventers and the choke line valve (if so equipped).

F. Miscellaneous Information:

The Blow-Out Preventer and related pressure control equipment will be installed, used, tested and maintained in a manner necessary to assure well control and shall be in place and operational prior to drilling out of the surface casing shoe.

The choke manifold and BOP extensions rods with hand wheels will be located outside the rig sub-structure. The hydraulic BOP closing unit will be located at least twenty-five (25) feet from the well head but readily accessible to the driller. Exact locations and configurations of the hydraulic BOP closing unit will depend upon the particular rig contracted to drill this hole.

A rotating head shall be nippled up prior to drilling out the surface casing shoe and the stripper rubber periodically checked to maintain a positive pack-off throughout the drilling process. As a minimum, the stripper rubber will be visually inspected each trip out of the hole.

A flare system with automatic ignition will be in place during intermediate and production hole drilling operations. The flare system will be agreed upon with the local BLM inspector in the field. The flare system shall be anchored and require a flare pit/tank. Depending on the surface location, the normal length of the flare line will be 100' from well center. It will have straight lines unless turns are targeted with running tees. Noncombustible gas is not likely or expected.

4. CASING AND CEMENTING PROGRAM

A. Casing Program: All new

Hole Size	Casing Size	Wt./Ft.	Grade	Joint	Depth Set (MD)	Depth Set (TVD)
24”	20”	52.7 ppf (1/4” wall)		Welded	0 - 80’	0 - 80’
17-1/2”	13-3/8”	68#	P-110	BTC	0 - 1865’	0 - 1860’
12-1/4”	9-5/8”	47#	P-110	BTC	0 – 8747’	0 – 8715’
8-1/2”	5-1/2”	23#	P-110	DQX	0 – 19050’	0 - 9110’

***9-5/8” casing will utilize a stage tool placed at 2800’**

B. Cementing Program:

18” Conductor — Cemented to surface with construction cement (30 sacks of cement)

Surface Cement (based on 17-1/2” gauge hole and 10% excess)

Lead Cement				Tail Cement		
Slurry Type	VersaCem	™		Slurry Type	VersaCem	™
Slurry Density	12.30	ppg		Slurry Density	12.80	ppg
Water	13.71	gal/sk		Water	11.72	gal/sk
Yield	2.37	cu ft/sk		Yield	2.11	cu ft/sk
Calc. Fill	1865	ft		Fill footage	500	ft
Est. Sacks	440	sacks		Est. Sacks	181	sacks

- Full cement returns back to surface will be attempted.
- Prior to drilling out the surface shoe, the lead and/or remedial cement shall have developed 100 psi compressive strength at surface, and 500 psi at the shoe.
- Tail volume shall be designed and pumped to cover at least 500 annular feet above the shoe.
- Sufficient circulation and conditioning will be completed prior to cementing operations.
- 10 % excess is planned, final volumes will be adjusted to actual conditions (i.e. these are minimum volumes)

Intermediate Cement (based on 12-1/4” gauge hole and no excess)

1st Stage Lead Cement				1st Stage Tail Cement		
Slurry Type	VERSACEM	™		Slurry Type	HALCEM	™
Slurry Density	13.50	ppg		Slurry Density	14.00	ppg
Water	6.85	gal/sk		Water	6.39	gal/sk
Yield	1.57	cu ft/sk		Yield	1.57	cu ft/sk
Calc. Fill	4447	ft		Fill footage	1,500	ft
Est. Sacks	887	sacks		Est. Sacks	298	sacks
2nd Stage Lead Cement				2nd Stage Tail Cement		
Slurry Type		™		Slurry Type	HALCEM	™
Slurry Density		ppg		Slurry Density	14.00	ppg
Water		gal/sk		Water	6.28	gal/sk
Yield		cu ft/sk		Yield	1.40	cu ft/sk
Calc. Fill		ft		Fill footage	1935	ft
Est. Sacks		sacks		Est. Sacks	450	sacks

- The top of cement shall be at least 250’ above the Mesaverde.

- Sufficient circulation and conditioning will be completed prior to cementing operations.
- Final volumes will be adjusted to actual conditions (i.e. these are minimum volumes)

Production Cement (based on 8-1/2" gauge hole and no excess included)

	Lead Cement					
Slurry Type	ThermaCem	™				
Slurry Density	17.20	ppg				
Water	9.26	gal/sk				
Yield	2.26	cu ft/sk				
Calc. Fill	11303	ft				
Est. Sacks	1154	sacks				

- The top of cement shall be 1000' above the 9-5/8" intermediate shoe.
- Sufficient circulation and conditioning will be completed prior to cementing operations.
- Final volumes with excess will be adjusted to actual conditions (i.e. these are minimum volumes)

5. MUD PROGRAM – Visual Monitoring

Interval	*Mud Type*	*Weight*	*Viscosity*	*Fluid Loss*
0 – 1865'	Fresh Water	8.5 – 9.6	45 – 50	6 – 12 ml
1865' – 8747'	Fresh Water/Gel	9.6 – 12.5	45 – 60	6 – 8 ml
8747' – 19050'	Fresh Water/Gel	12.5 – 15.0	45 – 60	6 – 8 ml

Sufficient mud material(s) to maintain mud properties, control lost circulation and maintain well control will be available at the well during drilling operations.

6. EVALUATION PROGRAM

Anticipated logging program

Open Hole (Intermediate casing interval)

Trade Name	Log Type	Base Interval (from)	Top Interval (to)
Triple Combo	Spectral Gamma Ray	Intermediate TD	Base Surface Casing
	DIL-SP	Intermediate TD	Base Surface Casing
	Neutron-Density	Intermediate TD	Base Surface Casing

Cased Hole (Intermediate casing interval)

Trade Name	Log Type	Base Interval (from)	Top Interval (to)
CBL	Cement Bond Log	Intermediate shoe	Surface

Open Hole (Production casing interval)

Trade Name	Log Type	Base Interval (from)	Top Interval (to)
LWD	Gamma Ray	TD	Intermediate TD

7. ABNORMAL CONDITIONS

No abnormal temperatures or pressures are anticipated. No H_2S has been encountered or known to exist in previous wells drilled to similar depths in the general area.

Maximum anticipated bottom hole pressure equals approximately **7,385 psi** and maximum anticipated surface pressure equals approximately **5,302 psi*** (bottom hole pressure minus the pressure of a partially evacuated hole calculated at 0.22 psi/foot).

*maximum surface pressure = Max BHP – (0.22 x TD)

8. ANTICIPATED STARTING DATES AND NOTIFICATION OF OPERATIONS

A. Anticipated Starting Dates:

Anticipated Start Date:	2015
Drilling Days:	Approximately 50 Days
Completion Days:	Approximately 30 Days

9. Notifications:

Event	Who to notify	Contact Media	Notification due date
Well control events and/or injuries	Colorado River Valley PE	970-876-9000 CRVFO_PE@blm.gov	24 hours from the time of the event
Frac or post frac bradenhead increase above 100 psi, and failed casing test	Colorado River Valley PE	970-876-9000 CRVFO_PE@blm.gov	24 hours from the time of the event
Low top of Cement and/or poor cement job	Colorado River Valley PE	970-876-9000 CRVFO_PE@blm.gov	96 hours prior to commencing frac operations
Remedial work and/or changes to the APD and/or COA	Colorado River Valley PE	970-876-9000 CRVFO_PE@blm.gov	Prior to commencing operations
BOP tests, spudding, running casing strings, and production tests	Julie King David Giboo Greg Rios Tim Barrett Alex Provstgaard Brandon Jamison	Cell 970-456-5262 970-876-9064 970-876-9064 970-876-9064 970-876-9064 970-876-9064	Spud notification: 24 hours prior to and 24 hours afterward; Remaining notification: 24 hours prior to

Appendix A

Typical 10k BOP Schematic