DRILLING PLAN FOR

FEDERAL 2/3-14-22

SWSW Section 22, T6S-R91W,

BLM Lease # COC-66370

Coachman Energy Operating, LLC (Coachman) presents the following Drilling Plan for the Federal 2/3-14-22 well located lat. 39.507052N, long. -107.549034W, located in the SW/4 of SW/4 quarter of Section 22, T6S, R91W. This well is located on CPW managed lands, BLM Mineral leases and is authorized under lease COC- 66370. The proposed well will be drilled to a Total Depth (TD) of 8142 feet Measured Depth (MD) and a True Vertical Depth of 8075 feet (TVD).

In accordance with the requirements of Onshore Oil and Gas Order Number 1 (43 CFR 3162.3), the following detailed drilling plan is provided.

Proposed Locations:

Surface Location: 212' FSL x 193' FWL, SW of SW Sec. 22-T6S-R91W, Garfield Co., CO

Bottomhole Location: 821' FSL x 671'FWL, 13C-10 acre spot in SWSW of Section 22-T6S-R91W, Garfield Co., CO

Geologic Information for the Drilling Plan:

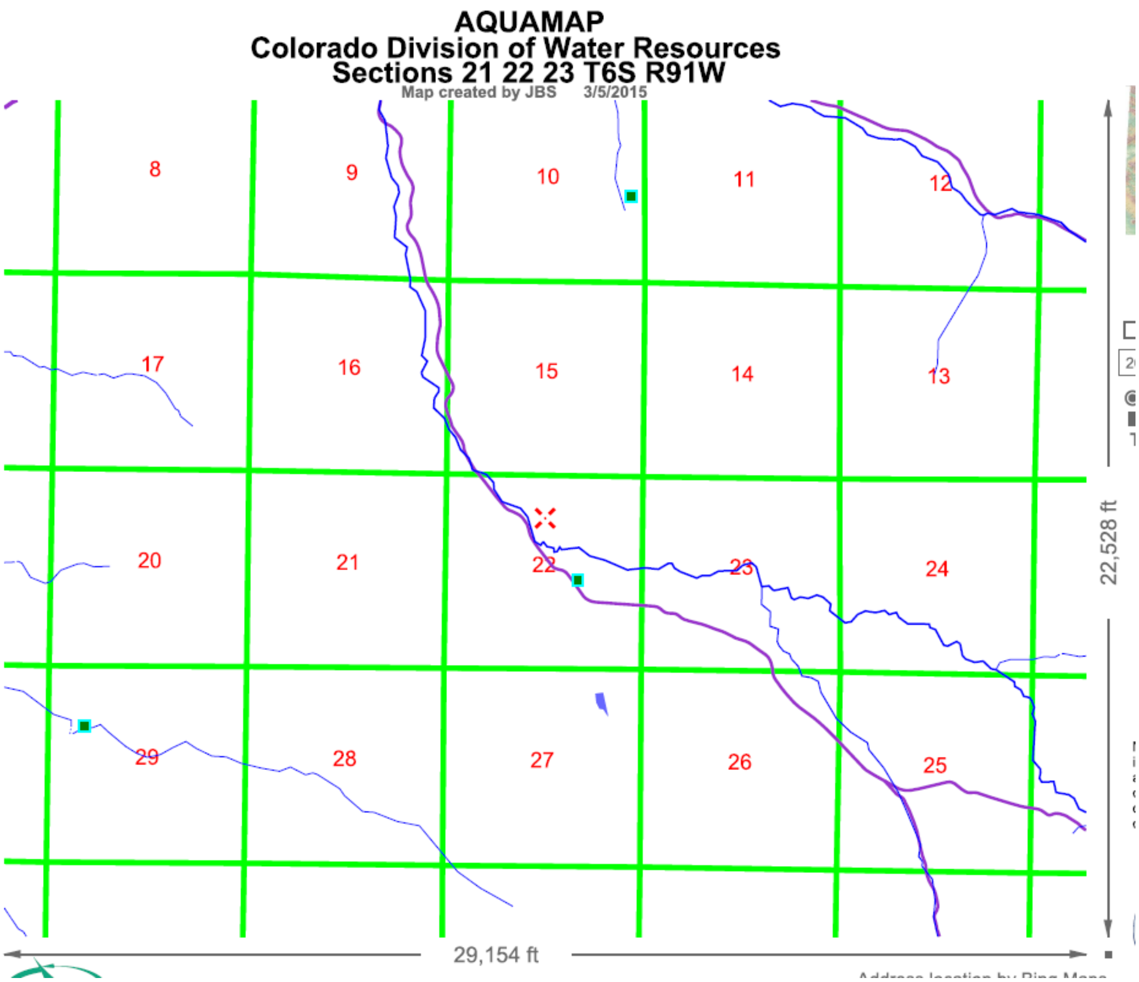
Estimated Formation Tops FEDERAL 2/3-14-22:

Formation	Sea Level Elevation	TVD from Surface Pad
Wasatch Formation	Ground-7047'	0
Williams Fork	2405	4642
Cameo	-661	7708
Rollins SS	-925	7972

Depth to Oil, Gas, Water & Minerals: FEDERAL 2/3-14-22:

Substance	Formation	TVD from Surface Pad
Water	Wasatch	<500
Gas & Water	Williams Fork	4642

Note: The nearest water wells range, in bottomhole depths, from 5330 feet to 6330 feet above sea level and are shown as turquoise/blue squares on the map below:



Well Control Equipment for Federal 2/3-14-22:

1. Coachman Energy Operating, LLC minimum specifications for pressure control are as follows:

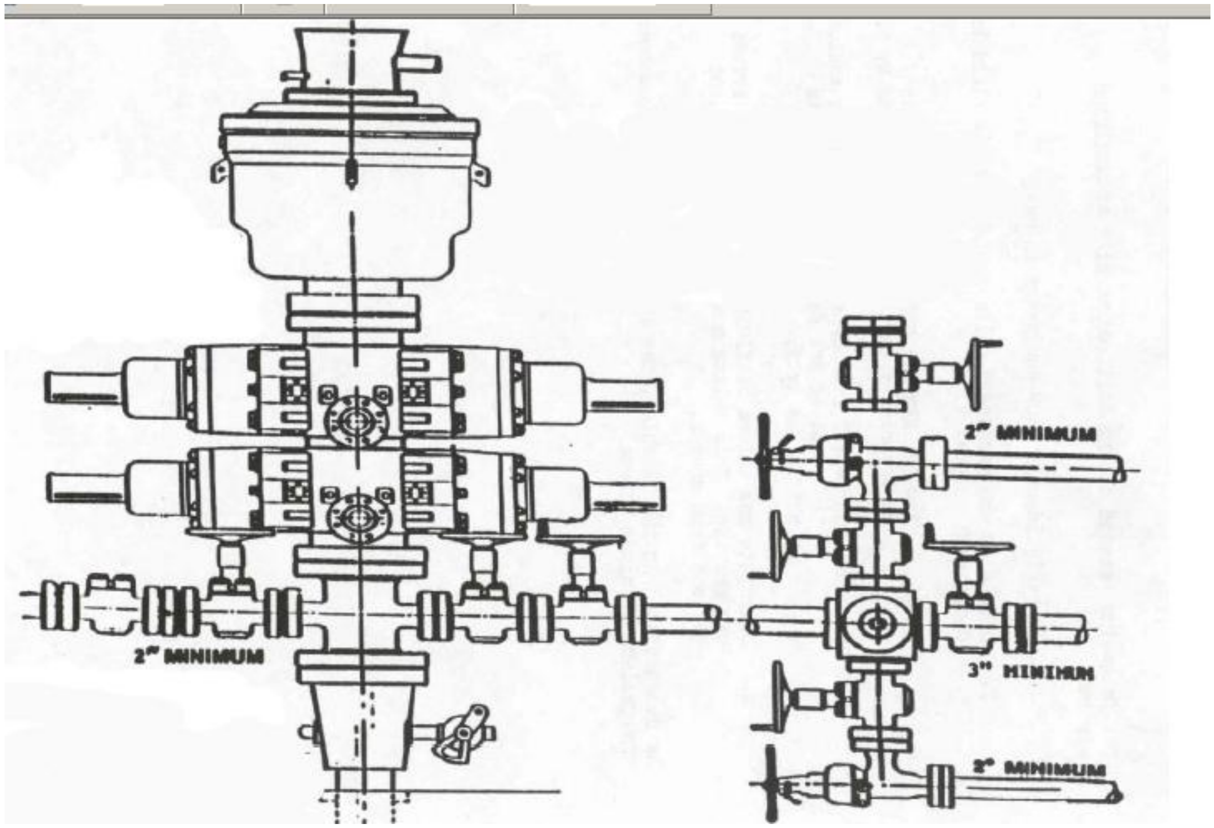
Depth Range	Well Control Equipment
0 - 1250’ (surface interval)	No Control
1250’ – TD	11”, 5000 psi ram type preventers with one set of blind rams, one set of pipe rams and 5000 psi annular type

	preventer with choke manifold as per attached diagram.
No abnormal temperatures or H_2S gas are anticipated. No over-pressured intervals are expected.	

2. Coachman will comply with all requirements pertaining to well control as listed in Onshore Oil and Gas Order No. 2 as well as Colorado Oil and Gas Conservation Commission (COGCC) Rules and Regulations.
3. Coachman will comply with Onshore Oil and Gas Order No. 2 as well as COGCC regulations concerning the testing of blow out prevention (BOP) equipment to include the following:
    a. Ram type preventers and associated equipment shall be tested to the equipment rated stack working pressure if isolated by test plug or to 70% 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% 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.
    b. All BOP tests will be performed by a tester and not by the rig pumps using clear water or an appropriate clear liquid for subfreezing temperatures. Annular type preventers shall be tested to 50% of rated working pressure. Pressure shall be maintained at least 10 minutes or until provisions of test are met, whichever is longer.
    c. As a minimum, the above test shall be performed:
        i. When initially installed;
        ii. Whenever any seal subject to test pressure is broken;
        iii. Following related repairs;
        iv. At 30-day intervals; and
        v. Valves shall be tested from working pressure side during BOP tests with all down-stream valves open.
    d. When testing the kill line valve(s), the check valve shall be held open or the ball removed.
    e. Annular preventers shall be functionally operated at least weekly.
    f. Pipe and blind rams shall be activated each trip, however, this function need not be performed more than once a day.
    g. A BOP pit level drill shall be conducted weekly by each drilling crew.
    h. Pressure tests shall apply to all related well control equipment.
    i. All of the above described tests and/or drills shall be recorded in the drilling log.
    j. See Figure 3 for a typical BOP diagram.

Figure 3: Typical Blowout Preventer Diagram

5,000 psi BOP stack minimum equipment. The actual dimensions and specifications will be determined when the drilling rig is selected.



.

5M psi system:

-Double ram with blind rams and pipe rams*

- Annular Preventers
- 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

Casing Program

Hole Size (in)	Casing/Tubing Size (in)	Wt. (#/ft)	Grade	Connection	Length (ft)	Setting Depth (MDft)
13-½”	9-5/8”	36	J-55	STC	1250	1250
8-3/4”	4- ½”	11.6	N-80 (I-80)	LTC	8142	8142

9 5/8”, 36#, J55, STC	Collapse	Burst	Tensile, Joint St.	ID	Make-Up Torque Ft-lbs
100%	2,020 psi	3,520 psi	394,000 lbs	8.921” 8.765” drift	Min – 2960 Opt – 3940 Max - 4930
80%	1,616 psi	2,816 psi	315,200 lbs		

The surface casing string 9 5/8” will be centralized using bow spring centralizers. The bottom (3) joints of casing will be centralized, from that point up, one centralizer will be run on every third joint to surface.

4 ½ ”, 11.6#, N-80 or I-80, LTC	Collapse	Burst	Tensile	ID	Make-Up Torque Ft-lbs
100%	6,350 psi	7,780 psi	267,000 lbs	4.00” 3.875” drift	Min – 1710 Opt – 2280 Max - 2850
80%	5,080 psi	6,224 psi	213,600 lbs		

The production casing 4 ½” will be centralized using bow spring centralizers and/or ridged body centralizers as follows: Every joint for first 3 joints, then approximately every other joint to 4500’, then every 3rd joint to 1000’.

I. Cementing Program Casing and Cementing Program:

A. Conductor Casing: 16” or 20” conductor casing will be pre-set and cemented prior to moving in the drilling rig. Conductor casing will be of sufficient weight & grade, and set in either a 20” or 30” hole size depending on the final determination of conductor size to be run, and when the final rig selection is made. Conductor casing will be set at 75’ to 100’, depending on “as-drilled” rock conditions, and adequately cemented to surface with construction grade (Redi-Mix) cement.

B. Surface Casing

1. Hole Size: 13-1/2”
2. Casing: Approximately 1250’ of 9-5/8”, 36#, J-55, ST&C casing.
3. Casing Hardware: 1 Guide Shoe, 1 Float Collar, 1 Stop Ring, 14 Centralizers, 1 Thread Lock, 2 Cement Baskets and 1 Top Plug.
4. Cement: Calculate for 30% excess (which Coachman has found works very well in the direct offset Kokopelli Field) to bring cement to surface with casing on bottom. Cement as follows:

   Lead: 185 sxs Varicem CJ5 Blend w/ 2% Gel & 2% $CaCl_2$, 12.3 ppg, 2.45 ft3/sx yld.

   Tail: 160 sxs Varicem CJ5 Blend cement, 12.8 ppg, 2.18 ft3/sx yld. Top of Tail cement is calculated to be at 700’ from surface.

   Top job (if required) to fill 9-5/8” x 13-1/2” annulus to surface with Class G cement containing 2% Calcium Chloride. Wait on cement four hours before slacking off casing.

C. Production Casing:

1. Hole Size: 8-3/4”
2. Casing: Approximately 8142’ of 4-1/2”, 11.6#, N-80 (or I-80), LT&C casing.
3. Casing Hardware: 1 Float Shoe, 1 Float Collar, 1 Stop Ring, 70-each (+/-) Centralizers, 1 Thread Lock, 1 Bottom Plug, 2 Cement Baskets and 1 Top Plug.
4. Cement: 20% excess cement over hole volume to bring top of cement to a depth of 1000’ (250’ inside surface casing). Cement as follows:

   Lead 1: 300 sxs Expandaseal System, 11.5 ppg, 2.28 ft3/sx yield

   Lead 2: 350 sxs Premium Type V Versacem Cmt, 12.5 ppg, 1.83 ft3/sx yld

   Tail: 835 sxs Premium Expandacem Class G, 35% Poz w/ 6% Gel, 13.1 ppg, 1.67 ft3/sx yld

A water quality analysis will be performed on the mix water used in cementing to ensure adequate cement properties. This analysis can be submitted to the BLM, if requested.

Mud Program

Interval	Mud Description	Weight	Viscosity	Wtr Loss
Surface to 1250’ MD	LSND/PHPA	8.4–8.6	30 – 45	Less than 8 – 12 cc’s
1250’ to Total Depth	LSND/PHPA	8.6– 9.2	30 - 45	Less than 10 cc’s at TD

Both electrical and mechanical fluid monitoring will be used to monitor the drilling fluid in the well bore. Each tank volume, flow rate, as well as total hole and surface volumes will be monitored on a continuous basis using a Mud Monitoring system.

A closed loop system shall consist of steel tanks and solids control equipment to hold the drilling fluid while the cuttings are routed to the cuttings trench.

Mud Products to be used:

Product	Description	Function	Concentration
New Bar	Barium Sulfate	Weighting Material	As required for slugs and mud weight
NewGel	Bentonite	Viscosifier	15-20 ppb
Caustic Soda	Sodium Hydroxide	Alkalinity Control	0.15-0.25 ppb
NewPHPA	PHPA	Viscosifier / Encapsulator	0.5 ppg
NewPac	Polyanionic Cellulose	Fluid Loss	0..5-1.0 ppb
Soda Ash	NA_2CO_2	Calcium Precipitant	As required
Maxiseal	LCM Blend	LCM Material	As required
Sawdust	Wood Fibers	LCM Material	As required
NewCarb	Calcium Carbonate	LCM Material	As required
DynaFiber	Microcellulose Fiber	LCM	As required
NewEase	Proprietary	ROP enhancer	As required
KCL	Potassium Chloride	Inhibitor	2%

Logging Program (Note: Not all wells on this 10 well pad will be openhole logged, generally only 1 or 2 wells will be. The remaining wells will be cased hole logged)

Type Log Suite	Interval Top	Interval Bottom
Resistivity	Base of Surface Casing	TD
Density-Neutron	Base of Surface Casing	TD
Gamma Ray	Surface	TD

Coring Program

Core No.	Formation	Est. Depth ft	Core Length (ft)
None planned			

Water Source

The freshwater required for the drilling operation will be trucked in from the nearest local water source (Newcastle). Estimated water usage is ~4000 bbls.

Additional Information

1) Normal pressures are expected.
2) Maximum expected bottom hole pressure: 3139 psi
3) Maximum expected bottom hole temperature: 180 deg F
4) H2S is not expected.
5) The well will be directionally drilled. Please see Directional vertical section plan as well as the side view along with the trajectory for deviation program. Maximum angle is 10° with an Azimuth of 37°, KOP will be at 350 ft.
6) Bottomhole Target Radius will be 75’ radius.
7) Top of Pay (Top of Gas) is approximately 5100’ TVD, where the well is back to vertical, and thus have the same approx. BHL as at Total Depth, and will be approx. 330 feet distance from the closest producing well. Based on 10 acre Williams Fork spacing.
8) This document to be attached to COGCC Form 2 and BLM Form 3160-3.