

DRILLING PLAN

Federal 10/11-14-21

SWSE Sec 21, T6S-R91W,

BLM Lease # COC-066370

Dejour Energy (USA) presents the following Drilling Plan for the Federal 10/11-14-21 well located lat. 39.508573N, long. -107.556047W, located in the southeast quarter of Section 21, T6S, R91W. This well is located on BLM managed lands and is authorized under lease COC-066370. The proposed well will be drilled to a TD 8107 feet Measured Depth (MD) and a True Vertical Depth of 8100 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: 1777' FEL x 803' FSL, SW of SE Section 21-T6S-R91W, Garfield Co., CO

Bottomhole Location: 2001' FEL x 814' FSL, SW of SE Section 21-T6S-R91W, Garfield Co., CO

Geologic Information for the Drilling Plan

Formation Tops (approx.) Federal 10/11-14-21

Formation	Sea Level Elevation	TVD from Surface Pad
Wasatch Formation	Ground-7008	0
Williams Fork	2595	4413
Rollins SS	-900	7908

Depth to Oil, Gas, Water & Minerals - Fed 10/11-14-21

Substance	Formation	TVD from Surface Pad
Water	Wasatch	<500
Gas	Williams Fork	4413

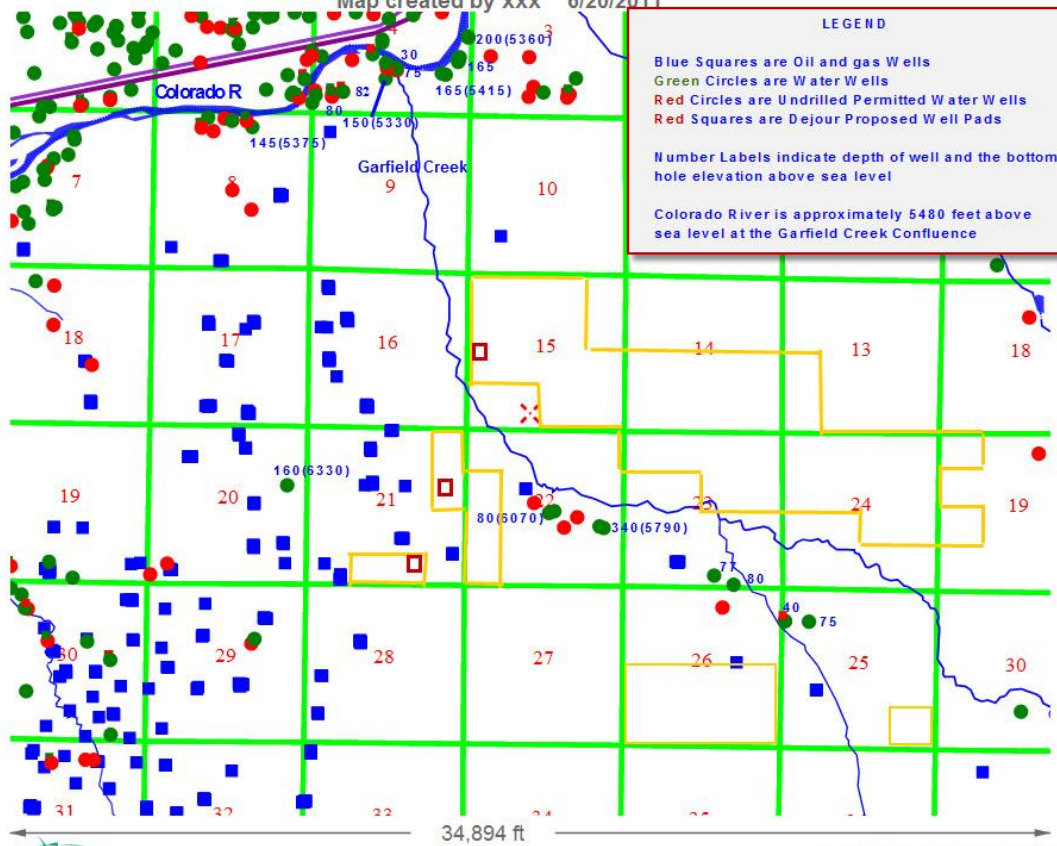
Note: The nearest water wells range, in bottomhole depths, from 5330 feet to 6330 feet above sea level. Casing design is to a consistent depth of 5200 feet above sea level.

AQUAMAP

Colorado Division of Water Resources

Department of Natural Resources

Map created by xxx 6/20/2011



Based on work developed at <http://www.carto.net>

Address location by Yahoo Maps
AquaMap Version 3.0.1 July 5, 2009

Well Control Equipment for all wells drilled off of Pad 21a

1. Dejour Energy (USA) (Dejour) minimum specifications for pressure control are as follows:

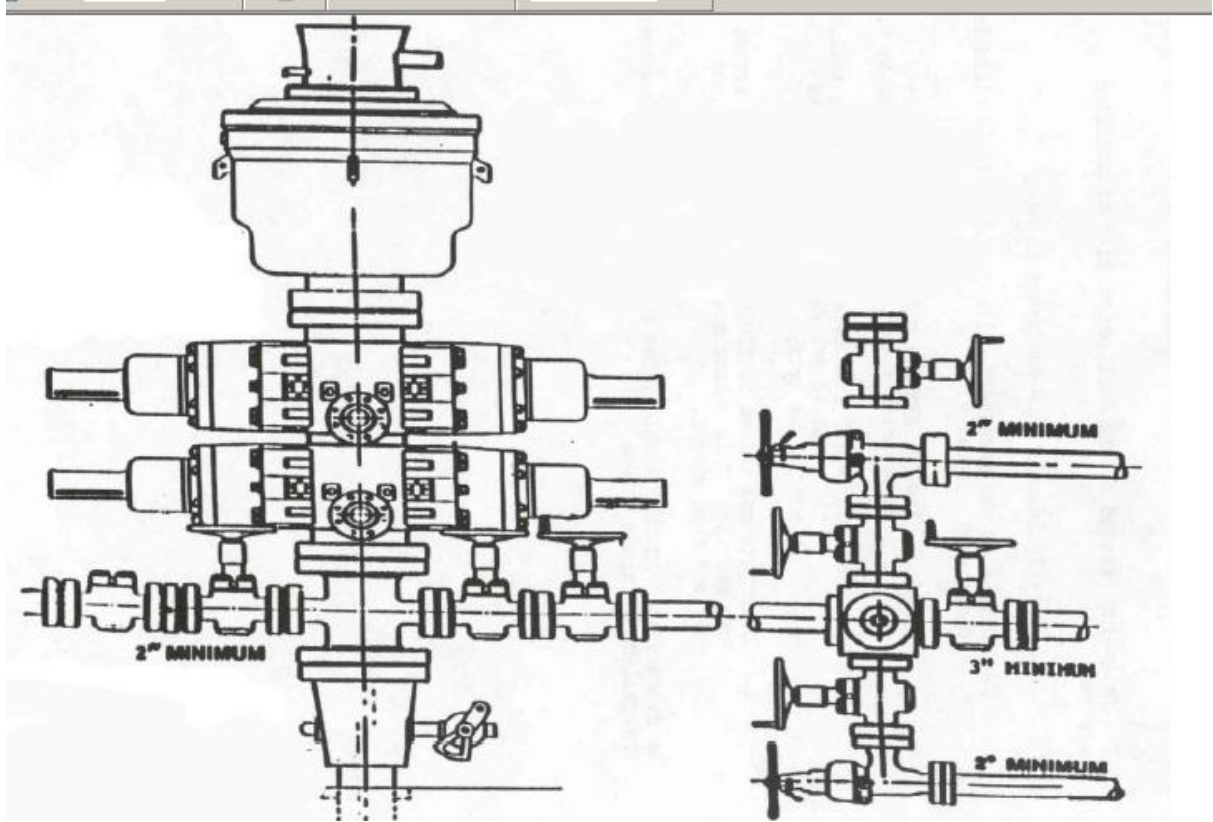
Depth Range	Well Control Equipment
0 - 1500' (surface interval)	No Control
1500' – TD	11", 5000 psi ram type preventers with one set of blind rams, one set of pipe rams and 5000 psi annular type preventer with choke manifold as per attached diagram.
No abnormal temperatures or H ₂ S gas are anticipated. No over-pressured intervals are expected.	

2. Dejour 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. Dejour 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:
- 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.
 - 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.
 - As a minimum, the above test shall be performed:
 - When initially installed;
 - Whenever any seal subject to test pressure is broken;
 - Following related repairs;
 - At 30-day intervals; and
 - Valves shall be tested from working pressure side during BOP tests with all down-stream valves open.
 - When testing the kill line valve(s), the check valve shall be held open or the ball removed.
 - Annular preventers shall be functionally operated at least weekly.
 - 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	1500	1500
7 7/8"	4- ½"	11.6	N-80	LTC	8107	8107

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"	Min – 2960
80%	1,616 psi	2,816 psi	315,200 lbs	8.765" drift	Opt – 3940 Max - 4930

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

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, every other joint to 1300' and every third joint from 1300 ft back to surface.

I. Cementing Program Casing and Cementing Program:

B. Surface Casing

1. Hole Size: 13-1/2"
2. Casing: Approximately 1500' of 9-5/8", 36#, J-55, ST&C casing.
3. Casing Hardware: 1 Guide Shoe, 1 Float Collar, 1 Stop Ring, 19 Centralizers, 1 Thread Lock, 2 Cement Baskets and 1 Top Plug.
4. Cement: Calculate for 75% excess to bring cement to surface with casing on bottom. Cement as follows:
Lead: 342 sxs Econocem w/ 2% Gel & 2% CaCl₂, 12.3 ppg, 2.38 ft³/sx yld
Tail: 350 sxs Class G w/ 2% Gel & 2% CaCl₂, 14.8 ppg, 1.34 ft³/sx yld
Top job as 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: 7-7/8"
2. Casing: Approximately 8107' of 4-1/2", 11.6#, N-80, LT&C casing.
3. Casing Hardware: 1 Float Shoe, 1 Float Collar, 1 Stop Ring, 132 Centralizers, 1 Thread Lock, 1 Bottom Plug, 2 Cement Baskets and 1 Top Plug.
4. Cement: 15% excess cement over hole volume to bring top of cement to a depth of 1300' (200' inside surface casing). Cement as follows:
Lead: 240 sxs Premium Type V Cmt w/ 16% gel, 11.0 ppg, 3.82 ft³/sx yld
Tail: 500 sxs Premium Lite w/ 65% Class G, 35% Poz w/ 6% Gel, 13.1 ppg, 1.70 ft³/sx yld

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

Mud Program

Interval	Mud Description	Weight	Viscosity	Wtr Loss
Surface to 1500' MD	LSND/PHPA	8.4–8.6	30 – 45	Less than 8 – 12 cc's
1500-8107'MD (8100' TVD)	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.

Products to be used:

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

Logging Program

Type Log Suite	Interval Top	Interval Bottom
Resistivity	Surface	TD
Density-Neutron	Surface	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: 3312 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 4° with an Azimuth of 272°, KOP will be at 200 ft.
- 6) Bottomhole target will be a 100' radius.

Attached to Form 3160-3