

**District I**

1625 N. French Dr., Hobbs, NM 88240  
Phone:(575) 393-6161 Fax:(575) 393-0720

**District II**

811 S. First St., Artesia, NM 88210  
Phone:(575) 748-1283 Fax:(575) 748-9720

**District III**

1000 Rio Brazos Rd., Aztec, NM 87410  
Phone:(505) 334-6178 Fax:(505) 334-6170

**District IV**

1220 S. St Francis Dr., Santa Fe, NM 87505  
Phone:(505) 476-3470 Fax:(505) 476-3462

**State of New Mexico**  
**Energy, Minerals and Natural Resources**  
**Oil Conservation Division**  
**1220 S. St Francis Dr.**  
**Santa Fe, NM 87505**

Form C-101

August 1, 2011

Permit 349594

**APPLICATION FOR PERMIT TO DRILL, RE-ENTER, DEEPEN, PLUGBACK, OR ADD A ZONE**

1. Operator Name and Address EOG RESOURCES INC P.O. Box 2267 Midland, TX 79702		2. OGRID Number 7377
		3. API Number 30-015-54225
4. Property Code 331158	5. Property Name SHERPA 12 STATE COM	6. Well No. 713H

**7. Surface Location**

UL - Lot C	Section 12	Township 25S	Range 27E	Lot Idn	Feet From 802	N/S Line N	Feet From 1339	E/W Line W	County Eddy
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**8. Proposed Bottom Hole Location**

UL - Lot M	Section 13	Township 25S	Range 27E	Lot Idn M	Feet From 230	N/S Line S	Feet From 990	E/W Line W	County Eddy
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**9. Pool Information**

PURPLE SAGE;WOLFCAMP (GAS)	98220
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**Additional Well Information**

11. Work Type New Well	12. Well Type OIL	13. Cable/Rotary	14. Lease Type State	15. Ground Level Elevation 3103
16. Multiple N	17. Proposed Depth 19216	18. Formation Wolfcamp	19. Contractor	20. Spud Date 10/16/2023
Depth to Ground water		Distance from nearest fresh water well		Distance to nearest surface water

☒ We will be using a closed-loop system in lieu of lined pits

**21. Proposed Casing and Cement Program**

Type	Hole Size	Casing Size	Casing Weight/ft	Setting Depth	Sacks of Cement	Estimated TOC
Surf	12.25	9.625	36	1030	370	0
Int1	8.75	7.625	29.7	8129	1460	0
Prod	6.75	5.5	17	19216	990	7560

**Casing/Cement Program: Additional Comments**

EOG respectfully requests the option to use the casing and cement program described in Design B of the drill plan. The NMOCDC will be notified of EOG's election at spud.
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**22. Proposed Blowout Prevention Program**

Type	Working Pressure	Test Pressure	Manufacturer
Double Ram	5000	3000	

23. I hereby certify that the information given above is true and complete to the best of my knowledge and belief. I further certify I have complied with 19.15.14.9 (A) NMAC <input checked="" type="checkbox"/> and/or 19.15.14.9 (B) NMAC <input checked="" type="checkbox"/> if applicable.	<b>OIL CONSERVATION DIVISION</b>	
Signature:		
Printed Name: Electronically filed by Kay Maddox	Approved By: Ward Rikala	
Title: Regulatory Agent	Title:	
Email Address: kay_maddox@eogresources.com	Approved Date: 9/20/2023	Expiration Date: 9/20/2025
Date: 9/5/2023	Phone: 432-686-3658	Conditions of Approval Attached

Form C-102  
Revised August 1, 2011  
Submit one copy to appropriate  
District Office  
☐ AMENDED REPORT

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**Energy, Minerals and Natural Resources**  
**Oil Conservation Division**  
**1220 S. St Francis Dr.**  
**Santa Fe, NM 87505**

Form APD Conditions

Permit 349594

**PERMIT CONDITIONS OF APPROVAL**

Operator Name and Address: EOG RESOURCES INC [7377] P.O. Box 2267 Midland, TX 79702	API Number: 30-015-54225
	Well: SHERPA 12 STATE COM #713H

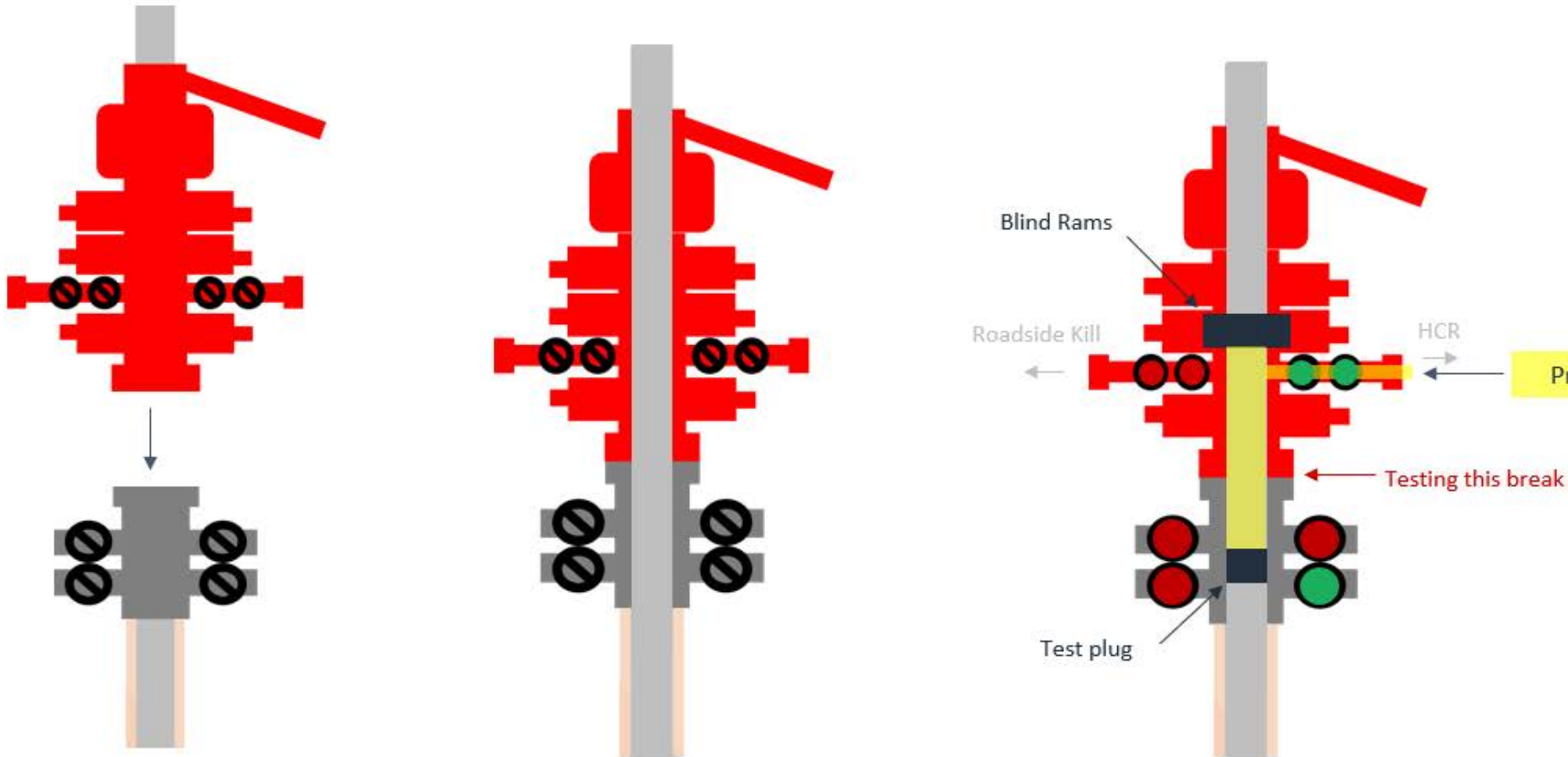
OCD Reviewer	Condition
ward.rikala	Notify OCD 24 hours prior to casing & cement
ward.rikala	Will require a File As Drilled C-102 and a Directional Survey with the C-104
ward.rikala	Once the well is spud, to prevent ground water contamination through whole or partial conduits from the surface, the operator shall drill without interruption through the fresh water zone or zones and shall immediately set in cement the water protection string
ward.rikala	Cement is required to circulate on both surface and intermediate1 strings of casing
ward.rikala	Oil base muds are not to be used until fresh water zones are cased and cemented providing isolation from the oil or diesel. This includes synthetic oils. Oil based mud, drilling fluids and solids must be contained in a steel closed loop system
ward.rikala	The Operator is to notify NMOCD by sundry (Form C-103) within ten (10) days of the well being spud
ward.rikala	If a bradenhead squeeze is used during the cementing of the intermediate casing, then CBL is required to verify the integrity of the cement behind the intermediate casing.
ward.rikala	The Rustler formation is present in this area. As such, a surface casing string will be required to be sat and cemented back to surface after 70' penetration into the Rustler formation.

**Break-test BOP & Offline Cementing:**

EOG Resources Inc. (EOG) respectfully requests a variance from the minimum standards for well control equipment testing of ECFR Title 43 Part 3172.6(b)(9)(iv) to allow a testing schedule of the blow out preventer (BOP) and blow out prevention equipment (BOPE) along with Batch Drilling & Offline cement operations to include the following:

- Full BOPE test at first installation on the pad.
- Full BOPE test every 21 days.
- This test will be conducted for 5M rated hole intervals only.
- Each rig requesting the break-test variance is capable of picking up the BOP without damaging components using winches, following API Standard 53, Well Control Equipment Systems for Drilling Wells (Fifth edition, December 2018, Annex C. Table C.4) which recognizes break testing as an acceptable practice.
- Function tests will be performed on the following BOP elements:
  - Annular ð during each full BOPE test
  - Upper Pipe Rams ð On trip ins where FIT required
  - Blind Rams ð Every trip
  - Lower Pipe Rams ð during each full BOPE test
- Break testing BOP and BOPE coupled with batch drilling operations and option to offline cement and/or remediate (if needed) any surface or intermediate sections, according to attached offline cementing support documentation.
- After the well section is secured, the BOP will be disconnected from the wellhead and walked with the rig to another well on the pad.
- TA cap will also be installed per Wellhead vendor procedure and pressure inside the casing will be monitored via the valve on the TA cap as per standard batch drilling ops.

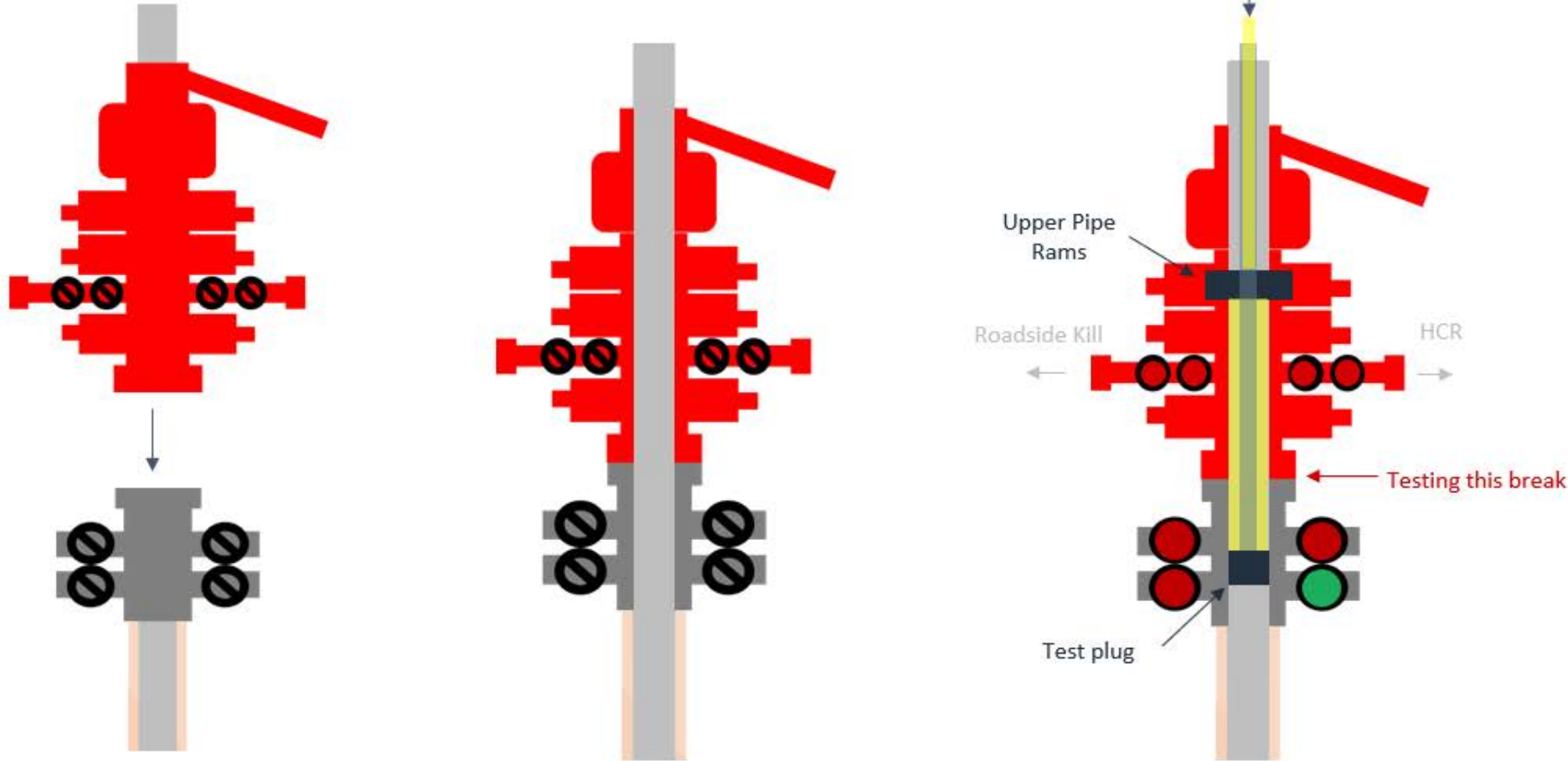
# Break Test Diagram (HCR valve)



## Steps

1. Set plug in wellhead (lower barrier)
2. Close Blind Rams (upper barrier)
3. Close roadside kill
4. Open HCR (pressure application)
5. Open wellhead valves below test plug to ensure if leak past test plug, pressure won't be applied to wellbore
6. Tie BOP testers high pressure line to main choke manifold crown valve
7. Pressure up to test break
8. Bleed test pressure from BOP testing unit

# Break Test Diagram (Test Joint)



## Steps

1. Set plug in with test joint wellhead (lower barrier)
2. Close Upper Pipe Rams (upper barrier)
3. Close roadside kill
4. Close HCR
5. Open wellhead valves below test plug to ensure if leak past test plug, pressure won't be applied to wellbore
6. Tie BOP testers high pressure line to top of test joint
7. Pressure up to test break
8. Bleed test pressure from BOP testing unit





## Offline Intermediate Cementing Procedure

2/24/2022

**Cement Program**

1. No changes to the cement program will take place for offline cementing.

**Summarized Operational Procedure for Intermediate Casing**

1. Run casing as per normal operations. While running casing, conduct negative pressure test and confirm integrity of the float equipment back pressure valves.
  - a. Float equipment is equipped with two back pressure valves rated to a minimum of 5,000 psi.
2. Land production casing on mandrel hanger through BOP.
  - a. If casing is unable to be landed with a mandrel hanger, then the **casing will be cemented online**.
3. Break circulation and confirm no restrictions.
  - a. Ensure no blockage of float equipment and appropriate annular returns.
  - b. Perform flow check to confirm well is static.
4. Set pack-off
  - a. If utilizing a fluted/ported mandrel hanger, ensure well is static on the annulus and inside the casing by filling the pipe with kill weight fluid, remove landing joint, and set annular packoff through BOP. Pressure test to 5,000 psi for 10 min.
  - b. If utilizing a solid mandrel hanger, ensure well is static on the annulus and inside the casing by filling the pipe with kill weight fluid. Pressure test seals to 5,000 psi for 10 min. Remove landing joint through BOP.
5. After confirmation of both annular barriers and the two casing barriers, install TA plug and pressure test to 5,000 psi for 10 min. Notify the BLM with intent to proceed with nipple down and offline cementing.
  - a. Minimum 4 hrs notice.
6. With the well secured and BLM notified, nipple down BOP and secure on hydraulic carrier or cradle.
  - a. **Note, if any of the barriers fail to test, the BOP stack will not be nipped down until after the cement job has concluded and both lead and tail slurry have reached 500 psi.**
7. Skid/Walk rig off current well.
8. Confirm well is static before removing TA Plug.
  - a. Cementing operations will not proceed until well is under control. (If well is not static, notify BLM and proceed to kill)
  - b. Casing outlet valves will provide access to both the casing ID and annulus. Rig or third party pump truck will kill well prior to cementing.
  - c. Well control plan can be seen in Section B, Well Control Procedures.
  - d. If need be, rig can be moved back over well and BOP nipped back up for any further remediation.



## Offline Intermediate Cementing Procedure

2/24/2022

- e. Diagram for rig positioning relative to offline cementing can be seen in Figure 4.
9. Rig up return lines to take returns from wellhead to pits and rig choke.
  - a. Test all connections and lines from wellhead to choke manifold to 5,000 psi high for 10 min.
  - b. If either test fails, perform corrections and retest before proceeding.
  - c. Return line schematics can be seen in Figure 3.
10. Remove TA Plug from the casing.
11. Install offline cement tool.
  - a. Current offline cement tool schematics can be seen in Figure 1 (Cameron) and Figure 2 (Cactus).
12. Rig up cement head and cementing lines.
  - a. Pressure test cement lines against cement head to 80% of casing burst for 10 min.
13. Break circulation on well to confirm no restrictions.
  - a. If gas is present on circulation, well will be shut in and returns rerouted through gas buster.
  - b. Max anticipated time before circulating with cement truck is 6 hrs.
14. Pump cement job as per plan.
  - a. At plug bump, test casing to 0.22 psi/ft or 1500 psi, whichever is greater.
  - b. If plug does not bump on calculated, shut down and wait 8 hrs or 500 psi compressive strength, whichever is greater before testing casing.
15. Confirm well is static and floats are holding after cement job.
  - a. With floats holding and backside static:
    - i. Remove cement head.
  - b. If floats are leaking:
    - i. Shut-in well and WOC (Wait on Cement) until tail slurry reaches 500 psi compressive strength and the casing is static prior to removing cement head.
  - c. If there is flow on the backside:
    - i. Shut in well and WOC until tail slurry reaches 500 psi compressive strength. Ensure that the casing is static prior to removing cement head.
16. Remove offline cement tool.
17. Install night cap with pressure gauge for monitoring.
18. Test night cap to 5,000 psi for 10 min.





Offline Intermediate Cementing Procedure

2/24/2022

## Example Well Control Plan Content

### A. Well Control Component Table

The table below, which covers the cementing of the **5M MASP (Maximum Allowable Surface Pressure) portion of the well**, outlines the well control component rating in use. This table, combined with the mud program, documents that two barriers to flow can be maintained at all times, independent of the BOP nipped up to the wellhead.

Intermediate hole section, 5M requirement

Component	RWP
Pack-off	10M
Casing Wellhead Valves	10M
Annular Wellhead Valves	5M
TA Plug	10M
Float Valves	5M
2" 1502 Lo-Torque Valves	15M

### B. Well Control Procedures

Well control procedures are specific to the rig equipment and the operation at the time the kick occurs. Below are the minimal high-level tasks prescribed to assure a proper shut-in while circulating and cementing through the Offline Cement Adapter.

#### General Procedure While Circulating

1. Sound alarm (alert crew).
2. Shut down pumps.
3. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
4. Confirm shut-in.
5. Notify tool pusher/company representative.



## Offline Intermediate Cementing Procedure

2/24/2022

6. Read and record the following:
  - a. SICP (Shut in Casing Pressure) and AP (Annular Pressure)
  - b. Pit gain
  - c. Time
  - d. Regroup and identify forward plan to continue circulating out kick via rig choke and mud/gas separator. Circulate and adjust mud density as needed to control well.

### General Procedure While Cementing

1. Sound alarm (alert crew).
2. Shut down pumps.
3. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
4. Confirm shut-in.
5. Notify tool pusher/company representative.
6. Open rig choke and begin pumping again taking returns through choke manifold and mud/gas separator.
7. Continue to place cement until plug bumps.
8. At plug bump close rig choke and cement head.
9. Read and record the following
  - a. SICP and AP
  - b. Pit gain
  - c. Time
  - d. Shut-in annulus valves on wellhead

### General Procedure After Cementing

1. Sound alarm (alert crew).
2. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
3. Confirm shut-in.
4. Notify tool pusher/company representative.
5. Read and record the following:
  - a. SICP and AP
  - b. Pit gain
  - c. Time
  - d. Shut-in annulus valves on wellhead



## Offline Intermediate Cementing Procedure

2/24/2022

Figure 1: Cameron TA Plug and Offline Adapter Schematic





## Offline Intermediate Cementing Procedure

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Figure 2: Cactus TA Plug and Offline Adapter Schematic





## Offline Intermediate Cementing Procedure

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Figure 3: Back Yard Rig Up





Offline Intermediate Cementing Procedure

2/24/2022

Figure 4: Rig Placement Diagram







Sherpa 12 State Com #713H  
Eddy County, New Mexico  
Proposed Wellbore  
Design A

802' FNL  
1339' FWL  
Section 12  
T-25-S, R-27-E

KB: 3128'  
GL: 3103'

API: 30-015-\*\*\*\*\*

Bit Size: 12-1/4"  
9-5/8", 36#, J-55, LTC, 0' - 1,030'

Bit Size: 8-3/4"  
7-5/8", 29.7#, HCP-110, FXL, 0' - 8,060'

TOC: 7,560'

Bit Size: 6-3/4"  
5-1/2", 17#, HCP-110, LTC, @ 19,216

Bit Size: 6-3/4"

KOP: 8,805' MD, 8,742' TVD  
EOC: 9,555' MD, 9,220' TVD

Lateral: 19,216' MD, 9,220' TVD  
BH Location: 230' FSL & 990' FWL  
Sec. 13  
T-25-S R-27-E



Sherpa 12 State Com #713H  
Eddy County, New Mexico  
Proposed Wellbore  
Design B

802' FNL  
1339' FWL  
Section 12  
T-25-S, R-27-E

KB: 3128'  
GL: 3103'

API: 30-015-\*\*\*\*\*

Bit Size: 13"  
10-3/4", 40.5#, J-55, STC,  
0' - 1,030'

Bit Size: 9-7/8"  
7-5/8", 29.7#, HCP-110, FXL  
@ 0' - 8,060'

Bit Size: 7-7/8"  
6", 22.3#, P110-EC, DWC/C IS,  
@ 0' - 19,216'

TOC: 7,560'

Bit Size: 7-7/8"

KOP: 8,805' MD, 8,742' TVD  
EOC: 9,555' MD, 9,220' TVD

Lateral: 19,216' MD, 9,220' TVD  
BH Location: 230' FSL & 990' FWL  
Sec. 13  
T-25-S R-27-E



## Sherpa 12 State Com #713H

### Permit Information:

Well Name: Sherpa 12 State Com #713H

### Location:

SHL: 802' FNL & 1339' FWL, Section 12, T-25-S, R-27-E, Eddy Co., N.M.

BHL: 230' FSL & 990' FWL, Section 13, T-25-S, R-27-E, Eddy Co., N.M.

### Design A

### Casing Program:

Hole Size	Interval MD From (ft) To (ft)		Interval TVD From (ft) To (ft)		Csg OD	Weight	Grade	Conn
12-1/4"	0	1,030	0	1,030	9-5/8"	36#	J-55	LTC
8-3/4"	0	8,129	0	8,060	7-5/8"	29.7#	HCP-110	FXL
6-3/4"	0	19,216	0	9,220	5-1/2"	17#	HCP-110	LTC

### Cement Program:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,030'	290	13.5	1.73	Class C + 4.0% Bentonite + 0.6% CD-32 + 0.5% CaCl <sub>2</sub> + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	80	14.8	1.34	Class C + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate
8,060'	460	14.2	1.11	1st Stage (Tail): Class C + 5% Salt (TOC @ 4,144')
	1000	14.8	1.5	2nd Stage (Bradenhead squeeze): Class C + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
19,216'	990	14.2	1.31	Class H + 0.1% C-20 + 0.05% CSA-1000 + 0.20% C-49 + 0.40% C-17 (TOC @ 7,560')

### Mud Program:

Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 1,030'	Fresh - Gel	8.6-8.8	28-34	N/c
1,030' – 8,060'	Brine	10.0-10.2	28-34	N/c
8,060' – 8,805'	Oil Base	8.7-9.4	58-68	N/c - 6
8,805' – 19,216' Lateral	Oil Base	10.0-14.0	58-68	4 - 6



## Sherpa 12 State Com #713H

**Design B****CASING PROGRAM**

Hole Size	Interval MD		Interval TVD		Csg OD	Weight	Grade	Conn
	From (ft)	To (ft)	From (ft)	To (ft)				
13"	0	1,030	0	1,030	10-3/4"	40.5#	J-55	STC
9-7/8"	0	8,129	0	8,060	8-3/4"	38.5#	P110-EC	SLIJ II NA
7-7/8"	0	19,216	0	9,220	6"	22.3#	P110-EC	DWC/C IS

**Cementing Program:**

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,030' 10-3/4"	270	13.5	1.73	Lead: Class C + 4.0% Bentonite Gel + 0.5% CaCl <sub>2</sub> + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	70	14.8	1.34	Tail: Class C + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 830')
8,060' 8-3/4"	520	14.2	1.11	1st Stage (Tail): Class C + 0.6% Halad-9 + 0.45% HR-601 + 3% Microbond (TOC @ 4,140')
	1000	14.8	1.5	2nd Stage (Bradenhead squeeze): Class C + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
19,216' 6"	1510	14.2	1.31	Lead: Class H + 0.4% Halad-344 + 0.35% HR-601 + 3% Microbond (TOC @ 7,560')

EOG requests variance from minimum standards to pump a two stage cement job on the 8-3/4" intermediate casing string with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon (4,344') and the second stage performed as a 1000 sack bradenhead squeeze with planned cement from the Brushy Canyon to surface. If necessary, a top out consisting of 100 sacks of Class C cement + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (2.30 yld, 12.91 ppg) will be executed as a contingency.

**Mud Program:**

Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 1,030'	Fresh - Gel	8.6-8.8	28-34	N/c
1,030' – 2,290'	Brine	10.0-10.2	28-34	N/c
2,290' – 8,060'	Oil Base	8.7-9.4	58-68	N/c - 6
8,060' – 19,216' Lateral	Oil Base	10.0-14.0	58-68	4 - 6



## Sherpa 12 State Com 713H

### TUBING REQUIREMENTS

EOG respectfully requests an exception to the following NMOCD rule:

- 19.15.16.10 Casing AND TUBING REQUIREMENTS:  
J (3): “The operator shall set tubing as near the bottom as practical and tubing perforations shall not be more than 250 feet above top of pay zone.”

With horizontal flowing and gas lifted wells an end of tubing depth placed at or slightly above KOP is a conservative way to ensure the tubing stays clean from debris, plugging, and allows for fewer well interventions post offset completion. The deeper the tubulars are run into the curve, the higher the probability is that the tubing will become stuck in sand and or well debris as the well produces over time. An additional consideration for EOT placement during artificial lift installations is avoiding the high dog leg severity and inclinations found in the curve section of the wellbore to help improve reliability and performance. Dog leg severity and inclinations tend not to hamper gas lifted or flowing wells, but they do effect other forms of artificial lift like rod pump or ESP (electric submersible pump). Keeping the EOT above KOP is an industry best practice for those respective forms of artificial lift.

**Sherpa 12 State Com #713H****Hydrogen Sulfide Plan Summary**

A. All personnel shall receive proper H<sub>2</sub>S training in accordance with Onshore Order III.C.3.a.

B. Briefing Area: two perpendicular areas will be designated by signs and readily accessible.

C. Required Emergency Equipment:

■ Well control equipment

- a. Flare line 150' from wellhead to be ignited by flare gun.
- b. Choke manifold with a remotely operated choke.
- c. Mud/gas separator

■ Protective equipment for essential personnel.

Breathing apparatus:

- a. Rescue Packs (SCBA) — 1 unit shall be placed at each breathing area, 2 shall be stored in the safety trailer.
- b. Work/Escape packs — 4 packs shall be stored on the rig floor with sufficient air hose not to restrict work activity.
- c. Emergency Escape Packs — 4 packs shall be stored in the doghouse for emergency evacuation.

Auxiliary Rescue Equipment:

- a. Stretcher
- b. Two OSHA full body harness
- c. 100 ft 5/8 inch OSHA approved rope
- d. 1-20# class ABC fire extinguisher

■ H<sub>2</sub>S detection and monitoring equipment:

The stationary detector with three sensors will be placed in the upper dog house if equipped, set to visually alarm @ 10 ppm and audible @ 14 ppm. Calibrate a minimum of every 30 days or as needed. The sensors will be placed in the following places: Rig floor / Bell nipple / End of flow line or where well bore fluid is being discharged.

(Gas sample tubes will be stored in the safety trailer)

■ Visual warning systems.

- a. One color code condition sign will be placed at the entrance to the site reflecting the possible conditions at the site.
- b. A colored condition flag will be on display, reflecting the current condition at the site at the time.
- c. Two wind socks will be placed in strategic locations, visible from all angles.





## Sherpa 12 State Com #713H

### ■ Mud program:

The mud program has been designed to minimize the volume of H<sub>2</sub>S circulated to surface. The operator will have the necessary mud products to minimize hazards while drilling in H<sub>2</sub>S bearing zones.

### ■ Metallurgy:

All drill strings, casings, tubing, wellhead, blowout preventer, drilling spool, kill lines, choke manifold and lines, and valves shall be suitable for H<sub>2</sub>S service.

### ■ Communication:

Communication will be via cell phones and land lines where available.



**Sherpa 12 State Com #713H**  
**Emergency Assistance Telephone List**

**PUBLIC SAFETY:** **911 or**

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Lea County Sheriff's Department		(575) 396-3611
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Rod Coffman

Fire Department:

Carlsbad		(575) 885-3125
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Artesia		(575) 746-5050
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Hospitals:

Carlsbad		(575) 887-4121
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Artesia		(575) 748-3333
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Hobbs		(575) 392-1979
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Dept. of Public Safety/Carlsbad		(575) 748-9718
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Highway Department		(575) 885-3281
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New Mexico Oil Conservation		(575) 476-3440
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NMOCD Inspection Group - South		(575) 626-0830
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U.S. Dept. of Labor		(575) 887-1174
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**EOG Resources, Inc.**

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EOG / Midland	Office	(432) 686-3600
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**Company Drilling Consultants:**

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David Dominique	Cell	(985) 518-5839
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Mike Vann	Cell	(817) 980-5507
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**Drilling Engineer**

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Stephen Davis	Cell	(432) 235-9789
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Matt Day	Cell	(432) 296-4456
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**Drilling Manager**

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Branden Keener	Office	(432) 686-3752
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	Cell	(210) 294-3729
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**Drilling Superintendent**

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Ryan Reynolds	Cell	(432) 215-5978
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Steve Kelly	Cell	(210) 416-7894
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**H&P Drilling**

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H&P Drilling	Office	(432) 563-5757
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H&P 651 Drilling Rig	Rig	(903) 509-7131
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**Tool Pusher:**

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Johnathan Craig	Cell	(817) 760-6374
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Brad Garrett

**Safety:**

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Brian Chandler (HSE Manager)	Office	(432) 686-3695
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	Cell	(817) 239-0251
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## **Midland**

**Eddy County, NM (NAD 83 NME)**

**Sherpa 12 State Com**

**#713**

**OH**

**Plan: Plan #0.1**

## **Standard Planning Report**

**01 September, 2023**



## Planning Report

<b>Database:</b>	PEDM	<b>Local Co-ordinate Reference:</b>	Well #713
<b>Company:</b>	Midland	<b>TVD Reference:</b>	kb=25' @ 3128.0usft
<b>Project:</b>	Eddy County, NM (NAD 83 NME)	<b>MD Reference:</b>	kb=25' @ 3128.0usft
<b>Site:</b>	Sherpa 12 State Com	<b>North Reference:</b>	Grid
<b>Well:</b>	#713	<b>Survey Calculation Method:</b>	Minimum Curvature
<b>Wellbore:</b>	OH		
<b>Design:</b>	Plan #0.1		

<b>Project</b>	Eddy County, NM (NAD 83 NME)		
<b>Map System:</b>	US State Plane 1983	<b>System Datum:</b>	Mean Sea Level
<b>Geo Datum:</b>	North American Datum 1983		
<b>Map Zone:</b>	New Mexico Eastern Zone		Using geodetic scale factor

Site	Sherpa 12 State Com				
Site Position:		Northing:	418,435.00 usft	Latitude:	32° 9' 0.749 N
From:	Map	Easting:	601,280.00 usft	Longitude:	104° 8' 22.728 W
Position Uncertainty:	0.0 usft	Slot Radius:	13-3/16 "		

Well	#713					
Well Position	+N/-S	0.0 usft	Northing:	418,255.00 usft	Latitude:	32° 8' 59.014 N
	+E/-W	0.0 usft	Easting:	598,605.00 usft	Longitude:	104° 8' 53.848 W
Position Uncertainty		0.0 usft	Wellhead Elevation:	usft	Ground Level:	3,103.0 usft
Grid Convergence:		0.10 °				

<b>Wellbore</b>	OH				
<b>Magnetics</b>	<b>Model Name</b>	<b>Sample Date</b>	<b>Declination (°)</b>	<b>Dip Angle (°)</b>	<b>Field Strength (nT)</b>
	IGRF2020	9/1/2023	6.54	59.67	47,163.18906859

<b>Design</b>	Plan #0.1				
<b>Audit Notes:</b>					
<b>Version:</b>		<b>Phase:</b>	PLAN	<b>Tie On Depth:</b>	0.0
<b>Vertical Section:</b>	<b>Depth From (TVD) (usft)</b>	<b>+N/-S (usft)</b>	<b>+E/-W (usft)</b>	<b>Direction (°)</b>	
	0.0	0.0	0.0	181.58	

<b>Plan Survey Tool Program</b>	<b>Date</b>	9/1/2023			
<b>Depth From (usft)</b>	<b>Depth To (usft)</b>	<b>Survey (Wellbore)</b>	<b>Tool Name</b>	<b>Remarks</b>	
1	0.0	19,216.4 Plan #0.1 (OH)	EOG MWD+IFR1		
			MWD + IFR1		



## Planning Report

<b>Database:</b>	PEDM	<b>Local Co-ordinate Reference:</b>	Well #713
<b>Company:</b>	Midland	<b>TVD Reference:</b>	kb=25' @ 3128.0usft
<b>Project:</b>	Eddy County, NM (NAD 83 NME)	<b>MD Reference:</b>	kb=25' @ 3128.0usft
<b>Site:</b>	Sherpa 12 State Com	<b>North Reference:</b>	Grid
<b>Well:</b>	#713	<b>Survey Calculation Method:</b>	Minimum Curvature
<b>Wellbore:</b>	OH		
<b>Design:</b>	Plan #0.1		

Plan Sections										
Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)	TFO (°)	Target
0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.00	0.00	
816.0	0.00	0.00	816.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,425.0	12.18	325.88	1,420.4	53.4	-36.2	2.00	2.00	0.00	325.88	
3,797.6	12.18	325.88	3,739.6	467.8	-317.0	0.00	0.00	0.00	0.00	
4,406.6	0.00	0.00	4,344.0	521.2	-353.1	2.00	-2.00	0.00	180.00	
8,805.1	0.00	0.00	8,742.5	521.2	-353.1	0.00	0.00	0.00	0.00	KOP(Sherpa 12 State
9,025.5	26.47	180.00	8,955.2	471.2	-353.1	12.01	12.01	81.65	180.00	FTP(Sherpa 12 State
9,555.0	90.00	179.50	9,219.9	43.8	-350.5	12.00	12.00	-0.09	-0.56	
19,116.4	90.00	179.50	9,220.0	-9,517.3	-267.1	0.00	0.00	0.00	0.00	LTP(Sherpa 12 State
19,216.4	90.00	179.35	9,220.0	-9,617.4	-266.1	0.15	0.00	-0.15	-89.40	PBHL(Sherpa 12 Stat

Planned Survey										
Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Vertical Section (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)	
0.0	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.00	0.00	
816.0	0.00	0.00	816.0	0.0	0.0	0.0	0.00	0.00	0.00	
1,425.0	12.18	325.88	1,420.4	53.4	-36.2	-52.4	2.00	2.00	0.00	
3,797.6	12.18	325.88	3,739.6	467.8	-317.0	-458.9	0.00	0.00	0.00	
4,406.6	0.00	0.00	4,344.0	521.2	-353.1	-511.2	2.00	-2.00	0.00	
8,805.1	0.00	0.00	8,742.5	521.2	-353.1	-511.2	0.00	0.00	0.00	
9,025.5	26.47	180.00	8,955.2	471.2	-353.1	-461.2	12.01	12.01	0.00	
9,555.0	90.00	179.50	9,219.9	43.8	-350.5	-34.0	12.00	12.00	-0.09	
19,116.4	90.00	179.50	9,220.0	-9,517.3	-267.1	9,521.1	0.00	0.00	0.00	
19,216.4	90.00	179.35	9,220.0	-9,617.4	-266.1	9,621.0	0.15	0.00	-0.15	

Design Targets									
Target Name - hit/miss target - Shape	Dip Angle (°)	Dip Dir. (°)	TVD (usft)	+N/-S (usft)	+E/-W (usft)	Northing (usft)	Easting (usft)	Latitude	Longitude
KOP(Sherpa 12 State Cc - plan hits target center - Point	0.00	0.00	8,742.5	521.2	-353.1	418,776.00	598,252.00	32° 9' 4.176 N	104° 8' 57.944 W
FTP(Sherpa 12 State Cc - plan hits target center - Point	0.00	0.00	8,955.2	471.2	-353.1	418,726.00	598,252.00	32° 9' 3.681 N	104° 8' 57.945 W
PBHL(Sherpa 12 State Cc - plan hits target center - Point	0.00	0.00	9,220.0	-9,617.4	-266.1	408,640.00	598,339.00	32° 7' 23.867 N	104° 8' 57.134 W
LTP(Sherpa 12 State Cc - plan hits target center - Point	0.00	0.00	9,220.0	-9,517.3	-267.1	408,740.00	598,338.00	32° 7' 24.857 N	104° 8' 57.143 W



Eddy County, NM (NAD 83 NME)

Sherpa 12 State Com #713

Plan #0.1

PROJECT DETAILS: Eddy County, NM (NAD 83 NME)

Geodetic System: US State Plane 1983  
Datum: North American Datum 1983  
Ellipsoid: GRS 1980  
Zone: New Mexico Eastern Zone  
System Datum: Mean Sea Level

WELL DETAILS: #713

kb=25' @ 3128.0usft 3103.0  
Northing 418255.00 Easting 598605.00 Latitude 32° 8' 59.014 N Longitude 104° 8' 53.848 W

SECTION DETAILS

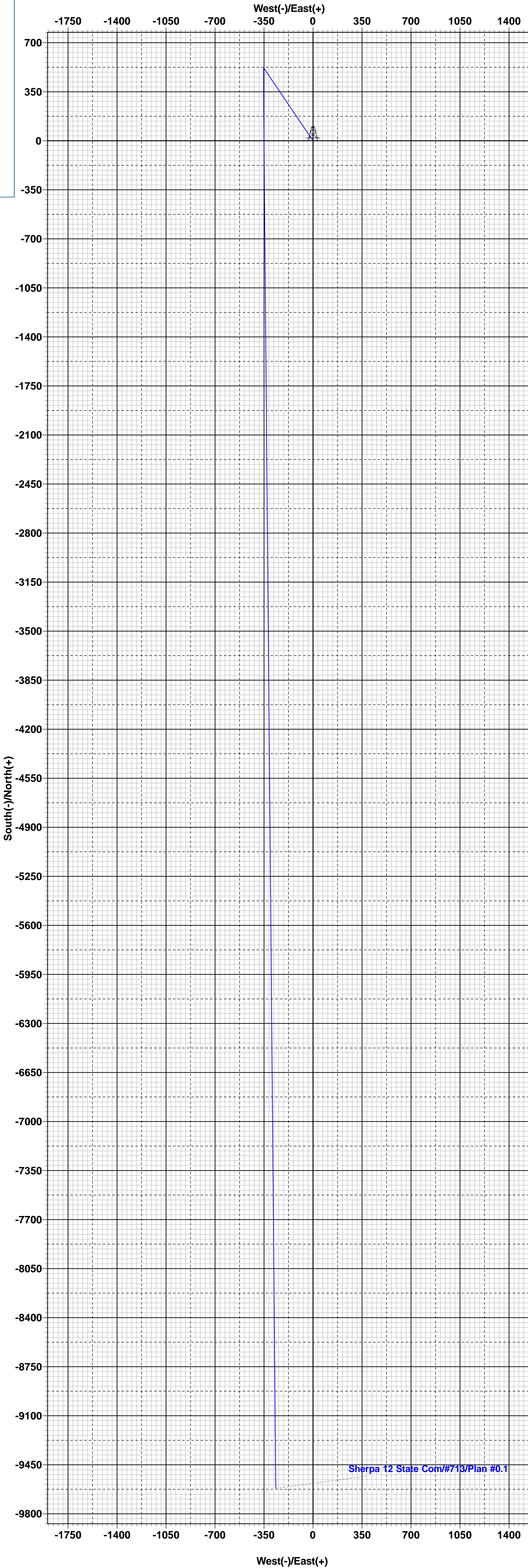
Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Target
1	0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.0	
2	816.0	0.00	0.00	816.0	0.0	0.0	0.00	0.00	0.0	
3	1425.0	12.18	325.88	1420.4	53.4	-36.2	2.00	325.88	-52.4	
4	3797.6	12.18	325.88	3739.6	467.8	-317.0	0.00	0.00	-458.9	
5	4406.6	0.00	0.00	4344.0	521.2	-353.1	2.00	180.00	-511.2	
6	8805.1	0.00	0.00	8742.5	521.2	-353.1	0.00	0.00	-511.2	KOP(Sherpa 12 State Com #713H)
7	9025.5	26.47	180.00	8955.2	471.2	-353.1	12.01	180.00	-461.2	FTP(Sherpa 12 State Com #713H)
8	9555.0	90.00	179.50	9219.9	43.8	-350.5	12.00	-0.56	-34.0	
9	19116.4	90.00	179.50	9220.0	-9517.3	-267.1	0.00	0.00	9521.1	LTP(Sherpa 12 State Com #713H)
10	19216.4	90.00	179.35	9220.0	-9617.4	-266.1	0.15	-89.40	9621.0	PBHL(Sherpa 12 State Com #713H)

CASING DETAILS

No casing data is available

WELLBORE TARGET DETAILS (MAP CO-ORDINATES)

Name	TVD	+N/-S	+E/-W	Northing	Easting
KOP(Sherpa 12 State Com #713H)	8742.5	521.2	-353.1	418776.00	598252.00
FTP(Sherpa 12 State Com #713H)	8955.2	471.2	-353.1	418726.00	598252.00
LTP(Sherpa 12 State Com #713H)	9220.0	-9517.3	-267.1	408740.00	598338.00
PBHL(Sherpa 12 State Com #713H)	9220.0	-9617.4	-266.1	408640.00	598339.00



Sherpa 12 State Com #713/Plan #0.1

Vertical Section at 181.58°



State of New Mexico  
Energy, Minerals and Natural Resources Department

Submit Electronically  
Via E-permitting

Oil Conservation Division  
1220 South St. Francis Dr.  
Santa Fe, NM 87505

## NATURAL GAS MANAGEMENT PLAN

This Natural Gas Management Plan must be submitted with each Application for Permit to Drill (APD) for a new or recompleted well.

### Section 1 – Plan Description

Effective May 25, 2021

**I. Operator:** EOG Resources, Inc. **OGRID:** 7377 **Date:** 9/5/2023

**II. Type:** ☒ Original ☐ Amendment due to ☐ 19.15.27.9.D(6)(a) NMAC ☐ 19.15.27.9.D(6)(b) NMAC ☐ Other.

If Other, please describe: \_\_\_\_\_

**III. Well(s):** Provide the following information for each new or recompleted well or set of wells proposed to be drilled or proposed to be recompleted from a single well pad or connected to a central delivery point.

Well Name	API	ULSTR	Footages	Anticipated Oil BBL/D	Anticipated Gas MCF/D	Anticipated Produced Water BBL/D
SHERPA 12 STATE COM 713H		C-12-25S-27E	802' FNL & 1339' FWL	+/- 1000	+/- 3500	+/- 3000

**IV. Central Delivery Point Name:** COBALT 32 STATE CTB [See 19.15.27.9(D)(1) NMAC]

**V. Anticipated Schedule:** Provide the following information for each new or recompleted well or set of wells proposed to be drilled or proposed to be recompleted from a single well pad or connected to a central delivery point.

Well Name	API	Spud Date	TD Reached Date	Completion Commencement Date	Initial Flow Back Date	First Production Date
SHERPA 12 STATE COM 713H		10/16/23	10/31/23	12/08/23	1/08/24	2/08/24

**VI. Separation Equipment:** ☒ Attach a complete description of how Operator will size separation equipment to optimize gas capture.

**VII. Operational Practices:** ☒ Attach a complete description of the actions Operator will take to comply with the requirements of Subsection A through F of 19.15.27.8 NMAC.

**VIII. Best Management Practices:** ☒ Attach a complete description of Operator's best management practices to minimize venting during active and planned maintenance.

## **Section 2 – Enhanced Plan**

### **EFFECTIVE APRIL 1, 2022**

Beginning April 1, 2022, an operator that is not in compliance with its statewide natural gas capture requirement for the applicable reporting area must complete this section.

☒ Operator certifies that it is not required to complete this section because Operator is in compliance with its statewide natural gas capture requirement for the applicable reporting area.

#### **IX. Anticipated Natural Gas Production:**

Well	API	Anticipated Average Natural Gas Rate MCF/D	Anticipated Volume of Natural Gas for the First Year MCF

#### **X. Natural Gas Gathering System (NGGS):**

Operator	System	ULSTR of Tie-in	Anticipated Gathering Start Date	Available Maximum Daily Capacity of System Segment Tie-in

**XI. Map.** ☐ Attach an accurate and legible map depicting the location of the well(s), the anticipated pipeline route(s) connecting the production operations to the existing or planned interconnect of the natural gas gathering system(s), and the maximum daily capacity of the segment or portion of the natural gas gathering system(s) to which the well(s) will be connected.

**XII. Line Capacity.** The natural gas gathering system ☐ will ☐ will not have capacity to gather 100% of the anticipated natural gas production volume from the well prior to the date of first production.

**XIII. Line Pressure.** Operator ☐ does ☐ does not anticipate that its existing well(s) connected to the same segment, or portion, of the natural gas gathering system(s) described above will continue to meet anticipated increases in line pressure caused by the new well(s).

☐ Attach Operator's plan to manage production in response to the increased line pressure.

**XIV. Confidentiality:** ☐ Operator asserts confidentiality pursuant to Section 71-2-8 NMSA 1978 for the information provided in Section 2 as provided in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and attaches a full description of the specific information for which confidentiality is asserted and the basis for such assertion.

### **Section 3 - Certifications**

**Effective May 25, 2021**

Operator certifies that, after reasonable inquiry and based on the available information at the time of submittal:

☒ Operator will be able to connect the well(s) to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced from the well(s) commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system; or

☐ Operator will not be able to connect to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced from the well(s) commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system.

***If Operator checks this box, Operator will select one of the following:***

**Well Shut-In.** ☐ Operator will shut-in and not produce the well until it submits the certification required by Paragraph (4) of Subsection D of 19.15.27.9 NMAC; or

**Venting and Flaring Plan.** ☐ Operator has attached a venting and flaring plan that evaluates and selects one or more of the potential alternative beneficial uses for the natural gas until a natural gas gathering system is available, including:

- (a) power generation on lease;
- (b) power generation for grid;
- (c) compression on lease;
- (d) liquids removal on lease;
- (e) reinjection for underground storage;
- (f) reinjection for temporary storage;
- (g) reinjection for enhanced oil recovery;
- (h) fuel cell production; and
- (i) other alternative beneficial uses approved by the division.

### **Section 4 - Notices**

1. If, at any time after Operator submits this Natural Gas Management Plan and before the well is spud:

(a) Operator becomes aware that the natural gas gathering system it planned to connect the well(s) to has become unavailable or will not have capacity to transport one hundred percent of the production from the well(s), no later than 20 days after becoming aware of such information, Operator shall submit for OCD's approval a new or revised venting and flaring plan containing the information specified in Paragraph (5) of Subsection D of 19.15.27.9 NMAC; or

(b) Operator becomes aware that it has, cumulatively for the year, become out of compliance with its baseline natural gas capture rate or natural gas capture requirement, no later than 20 days after becoming aware of such information, Operator shall submit for OCD's approval a new or revised Natural Gas Management Plan for each well it plans to spud during the next 90 days containing the information specified in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and shall file an update for each Natural Gas Management Plan until Operator is back in compliance with its baseline natural gas capture rate or natural gas capture requirement.

2. OCD may deny or conditionally approve an APD if Operator does not make a certification, fails to submit an adequate venting and flaring plan which includes alternative beneficial uses for the anticipated volume of natural gas produced, or if OCD determines that Operator will not have adequate natural gas takeaway capacity at the time a well will be spud.

I certify that, after reasonable inquiry, the statements in and attached to this Natural Gas Management Plan are true and correct to the best of my knowledge and acknowledge that a false statement may be subject to civil and criminal penalties under the Oil and Gas Act.

Signature: <i>Star L Harrell</i>
Printed Name: Star L Harrell
Title: Sr Regulatory Specialist
E-mail Address: Star_Harrell@eogresources.com
Date: 9/5/2023
Phone: (432) 848-9161
<b>OIL CONSERVATION DIVISION</b> <b>(Only applicable when submitted as a standalone form)</b>
Approved By:
Title:
Approval Date:
Conditions of Approval:

**Natural Gas Management Plan****Items VI-VIII****VI. Separation Equipment: Attach a complete description of how Operator will size separation equipment to optimize gas capture.**

- Separation equipment will be sized to provide adequate separation for anticipated rates.
- Adequate separation relates to retention time for Liquid – Liquid separation and velocity for Gas-Liquid separation.
- Collection systems are appropriately sized to handle facility production rates on all (3) phases.
- Ancillary equipment and metering is selected to be serviced without flow interruptions or the need to release gas from the well.

**VII. Operational Practices: Attach a complete description of the actions Operator will take to comply with the requirements of Subsection A through F 19.15.27.8 NMAC.****Drilling Operations**

- All flare stacks will be properly sized. The flare stacks will be located at a minimum 100' from the nearest surface hole location on the pad.
- All natural gas produced during drilling operations will be flared, unless there is an equipment malfunction and/or to avoid risk of an immediate and substantial adverse impact on safety and the environment, at which point the gas will be vented.

**Completions/Recompletions Operations**

- New wells will not be flowed back until they are connected to a properly sized gathering system.
- The facility will be built/sized for maximum anticipated flowrates and pressures to minimize waste.
- For flowback operations, multiple stages of separation will be used as well as excess VRU and blowers to make sure waste is minimized off the storage tanks and facility.
- During initial flowback, the well stream will be routed to separation equipment.
- At an existing facility, when necessary, post separation natural gas will be flared until it meets pipeline specifications, at which point it will be turned into a collection system.
- At a new facility, post separation natural gas will be vented until storage tanks can safely function, at which point it will be flared until it meets pipeline spec.

**Production Operations**

- Weekly AVOs will be performed on all facilities.
- All flares will be equipped with auto-ignition systems and continuous pilot operations.
- After a well is stabilized from liquid unloading, the well will be turned back into the collection system.
- All plunger lift systems will be optimized to limit the amount of waste.
- All tanks will have automatic gauging equipment installed.
- Leaking thief hatches found during AVOs will be cleaned and properly re-sealed.

**Performance Standards**

- Production equipment will be designed to handle maximum anticipated rates and pressure.
- All flared gas will be combusted in a flare stack that is properly sized and designed to ensure proper combustion.
- Weekly AVOs will be performed on all wells and facilities that produce more than 60 Mcfd.

**Measurement & Estimation**

- All volume that is flared and vented that is not measured will be estimated.
- All measurement equipment for flared volumes will conform to API 14.10.
- No meter bypasses will be installed.

- When metering is not practical due to low pressure/low rate, the vented or flared volume will be estimated.

**VIII. Best Management Practices: Attach a complete description of Operator's best management practices to minimize venting during active and planned maintenance.**

- During downhole well maintenance, EOG will use best management practices to vent as minimally as possible.
- Prior to the commencement of any maintenance, the tank or vessel will be isolated from the rest of the facilities.
- All valves upstream of the equipment will be closed and isolated.
- After equipment has been isolated, the equipment will be blown down to as low a pressure as possible into the collection system.
- If the equipment being maintained cannot be relieved into the collection system, it shall be released to a tank where the vapor can either be captured or combusted if possible.
- After downhole well maintenance, natural gas will be flared until it reaches pipeline specification.