

Form 3160-3  
(June 2015)FORM APPROVED  
OMB No. 1004-0137  
Expires: January 31, 2018UNITED STATES  
DEPARTMENT OF THE INTERIOR  
BUREAU OF LAND MANAGEMENT  
**APPLICATION FOR PERMIT TO DRILL OR REENTER**

1a. Type of work: <input type="checkbox"/> DRILL <input type="checkbox"/> REENTER		5. Lease Serial No.
1b. Type of Well: <input type="checkbox"/> Oil Well <input type="checkbox"/> Gas Well <input type="checkbox"/> Other		6. If Indian, Allottee or Tribe Name
1c. Type of Completion: <input type="checkbox"/> Hydraulic Fracturing <input type="checkbox"/> Single Zone <input type="checkbox"/> Multiple Zone		7. If Unit or CA Agreement, Name and No.
2. Name of Operator		8. Lease Name and Well No.
3a. Address		9. API Well No. <b>30-025-52877</b>
3b. Phone No. (include area code)		10. Field and Pool, or Exploratory
4. Location of Well (Report location clearly and in accordance with any State requirements. *) At surface At proposed prod. zone		11. Sec., T. R. M. or Blk. and Survey or Area
14. Distance in miles and direction from nearest town or post office*		12. County or Parish
		13. State
15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any)	16. No of acres in lease	17. Spacing Unit dedicated to this well
18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft.	19. Proposed Depth	20. BLM/BIA Bond No. in file
21. Elevations (Show whether DF, KDB, RT, GL, etc.)	22. Approximate date work will start*	23. Estimated duration
24. Attachments		

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No. 1, and the Hydraulic Fracturing rule per 43 CFR 3162.3-3 (as applicable)

- |  |   |
|--|---|
| 1. Well plat certified by a registered surveyor.   | 4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above). |
| 2. A Drilling Plan.  | 5. Operator certification.  |
| 3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO must be filed with the appropriate Forest Service Office). | 6. Such other site specific information and/or plans as may be requested by the BLM.            |

25. Signature	Name (Printed/Typed)	Date
Title		
Approved by (Signature)	Name (Printed/Typed)	Date
Title		
Office		

Application approval does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.  
Conditions of approval, if any, are attached.

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Continued on page 2)

\*(Instructions on page 2)



Approval Date: 04/24/2024

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 Road, Aztec, NM 87410  
Phone: (505) 334-6178 Fax: (505) 334-6170  
District IV  
1220 S. St. Francis Dr., Santa Fe, NM 87505  
Phone: (505) 476-3460 Fax: (505) 476-3462

State of New Mexico  
Energy, Minerals & Natural Resources  
Department  
OIL CONSERVATION DIVISION  
1220 South St. Francis Dr.  
Santa Fe, NM 87505

FORM C-102

Revised August 1, 2011

Submit one copy to appropriate

District Office

☐ AMENDED REPORT

## WELL LOCATION AND ACREAGE DEDICATION PLAT

<sup>1</sup> API Number <b>30-025-30-025-52877</b>		<sup>2</sup> Pool Code <b>98248</b>	<sup>3</sup> Pool Name <b>WC-025 G-08 S243217P;UPR WC</b>
<sup>4</sup> Property Code <b>325486</b>	<sup>5</sup> Property Name <b>MODELO 10 FED COM</b>		<sup>6</sup> Well Number <b>708H</b>
<sup>7</sup> OGRID No. <b>7377</b>	<sup>8</sup> Operator Name <b>EOG RESOURCES, INC.</b>		<sup>9</sup> Elevation <b>3644'</b>

<sup>10</sup>Surface Location

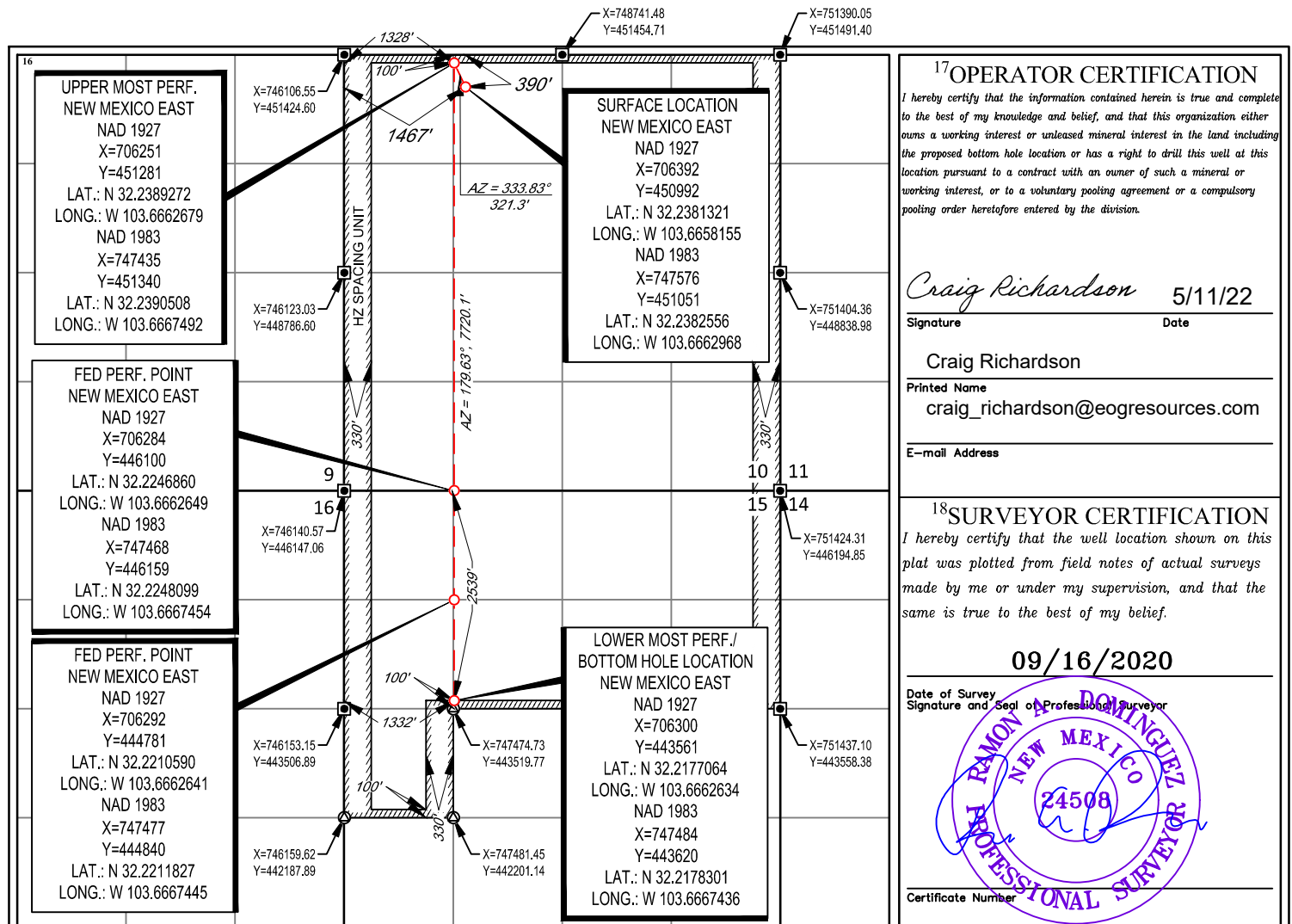
UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
<b>C</b>	<b>10</b>	<b>24-S</b>	<b>32-E</b>	<b>-</b>	<b>390'</b>	<b>NORTH</b>	<b>1467'</b>	<b>WEST</b>	<b>LEA</b>

<sup>11</sup>Bottom Hole Location If Different From Surface

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
<b>F</b>	<b>15</b>	<b>24-S</b>	<b>32-E</b>	<b>-</b>	<b>2539'</b>	<b>NORTH</b>	<b>1332'</b>	<b>WEST</b>	<b>LEA</b>

<sup>12</sup> Dedicated Acres <b>1000.00</b>	<sup>13</sup> Joint or Infill	<sup>14</sup> Consolidation Code	<sup>15</sup> Order No.
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No allowable will be assigned to this completion until all interests have been consolidated or a non-standard unit has been approved by the division.



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:** 04/24/2024

**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
MODELO 10 FED COM 708H		C-10-24S-32E	390' FNL & 1467' FEL	+/- 1000	+/- 3500	+/- 3000

**IV. Central Delivery Point Name:** MODELO 10 FED COM 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
MODELO 10 FED COM 708H		5/1/24	5/16/24	7/16/24	8/16/24	8/16/24

**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>Craig Richardson</i>
Printed Name: CRAIG RICHARDSON
Title: Regulatory Specialist
E-mail Address: craig_richardson@eogresources.com
Date: 4/24/2023
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 60Mcf/d.

Measurement & Estimation

- All volume that is flared or 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.
- After downhole well maintenance, natural gas will be flared until it reaches pipeline specification.



## Midland

Lea County, NM (NAD 83 NME)

Modelo 10 Fed Com

#708H

OH

Plan: Plan #0.1 RT

## Standard Planning Report

28 March, 2022





## Planning Report



<b>Database:</b>	PEDM	<b>Local Co-ordinate Reference:</b>	Well #708H
<b>Company:</b>	Midland	<b>TVD Reference:</b>	kb = 26' @ 3670.0usft
<b>Project:</b>	Lea County, NM (NAD 83 NME)	<b>MD Reference:</b>	kb = 26' @ 3670.0usft
<b>Site:</b>	Modelo 10 Fed Com	<b>North Reference:</b>	Grid
<b>Well:</b>	#708H	<b>Survey Calculation Method:</b>	Minimum Curvature
<b>Wellbore:</b>	OH		
<b>Design:</b>	Plan #0.1 RT		

<b>Project</b>	Lea 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		

<b>Site</b>	Modelo 10 Fed Com		
<b>Site Position:</b>		<b>Northing:</b>	451,286.00 usft
<b>From:</b>	Map	<b>Easting:</b>	750,991.00 usft
<b>Position Uncertainty:</b>	0.0 usft	<b>Slot Radius:</b>	13-3/16 "
		<b>Latitude:</b>	32.2388418°N
		<b>Longitude:</b>	103.6552489°W

<b>Well</b>	#708H		
<b>Well Position</b>	<b>+N/-S</b>	0.0 usft	<b>Northing:</b>
	<b>+E/-W</b>	0.0 usft	<b>Easting:</b>
<b>Position Uncertainty</b>	0.0 usft	<b>Wellhead Elevation:</b>	usft
<b>Grid Convergence:</b>	0.36 °	<b>Latitude:</b>	32.2382546°N
		<b>Longitude:</b>	103.6662981°W
		<b>Ground Level:</b>	3,644.0 usft

<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	9/13/2021	6.56	59.89	47,465.68361275

<b>Design</b>	Plan #0.1 RT				
<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	180.71	

<b>Plan Survey Tool Program</b>	<b>Date</b>	3/28/2022			
<b>Depth From (usft)</b>	<b>Depth To (usft)</b>	<b>Survey (Wellbore)</b>	<b>Tool Name</b>	<b>Remarks</b>	
1	0.0	19,896.1	Plan #0.1 RT (OH)	EOG MWD+IFR1	
				MWD + IFR1	



Planning Report



Database:	PEDM	Local Co-ordinate Reference:	Well #708H
Company:	Midland	TVD Reference:	kb = 26' @ 3670.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3670.0usft
Site:	Modelo 10 Fed Com	North Reference:	Grid
Well:	#708H	Survey Calculation Method:	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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	
1,400.0	0.00	0.00	1,400.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,588.2	3.76	337.42	1,588.1	5.7	-2.4	2.00	2.00	0.00	337.42	
6,992.7	3.76	337.42	6,980.9	333.3	-138.6	0.00	0.00	0.00	0.00	
7,180.9	0.00	0.00	7,169.0	339.0	-141.0	2.00	-2.00	0.00	180.00	
11,853.4	0.00	0.00	11,841.5	339.0	-141.0	0.00	0.00	0.00	0.00	0.00 KOP(Modelo 10 Fed C
12,073.9	26.46	180.00	12,054.2	289.0	-141.0	12.00	12.00	81.65	180.00	180.00 FTP(Modelo 10 Fed C
12,603.4	90.00	179.63	12,318.9	-138.5	-139.1	12.00	12.00	-0.07	-0.42	
17,357.1	90.00	179.63	12,319.0	-4,892.0	-108.0	0.00	0.00	0.00	0.00	0.00 Fed Perf 1(Modelo 10
18,676.1	90.00	179.59	12,319.0	-6,211.0	-99.0	0.00	0.00	0.00	-87.69	Fed Perf 2(Modelo 10
18,680.0	90.00	179.67	12,319.0	-6,214.9	-99.0	2.00	-0.02	2.00	90.48	
19,896.1	90.00	179.67	12,319.0	-7,431.0	-92.0	0.00	0.00	0.00	0.00	0.00 PBHL(Modelo 10 Fed



## Planning Report



<b>Database:</b>	PEDM	<b>Local Co-ordinate Reference:</b>	Well #708H
<b>Company:</b>	Midland	<b>TVD Reference:</b>	kb = 26' @ 3670.0usft
<b>Project:</b>	Lea County, NM (NAD 83 NME)	<b>MD Reference:</b>	kb = 26' @ 3670.0usft
<b>Site:</b>	Modelo 10 Fed Com	<b>North Reference:</b>	Grid
<b>Well:</b>	#708H	<b>Survey Calculation Method:</b>	Minimum Curvature
<b>Wellbore:</b>	OH		
<b>Design:</b>	Plan #0.1 RT		

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
100.0	0.00	0.00	100.0	0.0	0.0	0.0	0.00	0.00	0.00
200.0	0.00	0.00	200.0	0.0	0.0	0.0	0.00	0.00	0.00
300.0	0.00	0.00	300.0	0.0	0.0	0.0	0.00	0.00	0.00
400.0	0.00	0.00	400.0	0.0	0.0	0.0	0.00	0.00	0.00
500.0	0.00	0.00	500.0	0.0	0.0	0.0	0.00	0.00	0.00
600.0	0.00	0.00	600.0	0.0	0.0	0.0	0.00	0.00	0.00
700.0	0.00	0.00	700.0	0.0	0.0	0.0	0.00	0.00	0.00
800.0	0.00	0.00	800.0	0.0	0.0	0.0	0.00	0.00	0.00
900.0	0.00	0.00	900.0	0.0	0.0	0.0	0.00	0.00	0.00
1,000.0	0.00	0.00	1,000.0	0.0	0.0	0.0	0.00	0.00	0.00
1,100.0	0.00	0.00	1,100.0	0.0	0.0	0.0	0.00	0.00	0.00
1,200.0	0.00	0.00	1,200.0	0.0	0.0	0.0	0.00	0.00	0.00
1,300.0	0.00	0.00	1,300.0	0.0	0.0	0.0	0.00	0.00	0.00
1,400.0	0.00	0.00	1,400.0	0.0	0.0	0.0	0.00	0.00	0.00
1,500.0	2.00	337.42	1,500.0	1.6	-0.7	-1.6	2.00	2.00	0.00
1,588.2	3.76	337.42	1,588.1	5.7	-2.4	-5.7	2.00	2.00	0.00
1,600.0	3.76	337.42	1,599.8	6.4	-2.7	-6.4	0.00	0.00	0.00
1,700.0	3.76	337.42	1,699.6	12.5	-5.2	-12.4	0.00	0.00	0.00
1,800.0	3.76	337.42	1,799.4	18.5	-7.7	-18.4	0.00	0.00	0.00
1,900.0	3.76	337.42	1,899.2	24.6	-10.2	-24.5	0.00	0.00	0.00
2,000.0	3.76	337.42	1,999.0	30.7	-12.8	-30.5	0.00	0.00	0.00
2,100.0	3.76	337.42	2,098.8	36.7	-15.3	-36.5	0.00	0.00	0.00
2,200.0	3.76	337.42	2,198.5	42.8	-17.8	-42.6	0.00	0.00	0.00
2,300.0	3.76	337.42	2,298.3	48.9	-20.3	-48.6	0.00	0.00	0.00
2,400.0	3.76	337.42	2,398.1	54.9	-22.8	-54.6	0.00	0.00	0.00
2,500.0	3.76	337.42	2,497.9	61.0	-25.4	-60.7	0.00	0.00	0.00
2,600.0	3.76	337.42	2,597.7	67.0	-27.9	-66.7	0.00	0.00	0.00
2,700.0	3.76	337.42	2,697.5	73.1	-30.4	-72.7	0.00	0.00	0.00
2,800.0	3.76	337.42	2,797.3	79.2	-32.9	-78.7	0.00	0.00	0.00
2,900.0	3.76	337.42	2,897.0	85.2	-35.4	-84.8	0.00	0.00	0.00
3,000.0	3.76	337.42	2,996.8	91.3	-38.0	-90.8	0.00	0.00	0.00
3,100.0	3.76	337.42	3,096.6	97.3	-40.5	-96.8	0.00	0.00	0.00
3,200.0	3.76	337.42	3,196.4	103.4	-43.0	-102.9	0.00	0.00	0.00
3,300.0	3.76	337.42	3,296.2	109.5	-45.5	-108.9	0.00	0.00	0.00
3,400.0	3.76	337.42	3,396.0	115.5	-48.1	-114.9	0.00	0.00	0.00
3,500.0	3.76	337.42	3,495.7	121.6	-50.6	-121.0	0.00	0.00	0.00
3,600.0	3.76	337.42	3,595.5	127.6	-53.1	-127.0	0.00	0.00	0.00
3,700.0	3.76	337.42	3,695.3	133.7	-55.6	-133.0	0.00	0.00	0.00
3,800.0	3.76	337.42	3,795.1	139.8	-58.1	-139.0	0.00	0.00	0.00
3,900.0	3.76	337.42	3,894.9	145.8	-60.7	-145.1	0.00	0.00	0.00
4,000.0	3.76	337.42	3,994.7	151.9	-63.2	-151.1	0.00	0.00	0.00
4,100.0	3.76	337.42	4,094.4	158.0	-65.7	-157.1	0.00	0.00	0.00
4,200.0	3.76	337.42	4,194.2	164.0	-68.2	-163.2	0.00	0.00	0.00
4,300.0	3.76	337.42	4,294.0	170.1	-70.7	-169.2	0.00	0.00	0.00
4,400.0	3.76	337.42	4,393.8	176.1	-73.3	-175.2	0.00	0.00	0.00
4,500.0	3.76	337.42	4,493.6	182.2	-75.8	-181.2	0.00	0.00	0.00
4,600.0	3.76	337.42	4,593.4	188.3	-78.3	-187.3	0.00	0.00	0.00
4,700.0	3.76	337.42	4,693.2	194.3	-80.8	-193.3	0.00	0.00	0.00
4,800.0	3.76	337.42	4,792.9	200.4	-83.3	-199.3	0.00	0.00	0.00
4,900.0	3.76	337.42	4,892.7	206.4	-85.9	-205.4	0.00	0.00	0.00
5,000.0	3.76	337.42	4,992.5	212.5	-88.4	-211.4	0.00	0.00	0.00
5,100.0	3.76	337.42	5,092.3	218.6	-90.9	-217.4	0.00	0.00	0.00
5,200.0	3.76	337.42	5,192.1	224.6	-93.4	-223.5	0.00	0.00	0.00



## Planning Report



<b>Database:</b>	PEDM	<b>Local Co-ordinate Reference:</b>	Well #708H
<b>Company:</b>	Midland	<b>TVD Reference:</b>	kb = 26' @ 3670.0usft
<b>Project:</b>	Lea County, NM (NAD 83 NME)	<b>MD Reference:</b>	kb = 26' @ 3670.0usft
<b>Site:</b>	Modelo 10 Fed Com	<b>North Reference:</b>	Grid
<b>Well:</b>	#708H	<b>Survey Calculation Method:</b>	Minimum Curvature
<b>Wellbore:</b>	OH		
<b>Design:</b>	Plan #0.1 RT		

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)
5,300.0	3.76	337.42	5,291.9	230.7	-96.0	-229.5	0.00	0.00	0.00
5,400.0	3.76	337.42	5,391.6	236.8	-98.5	-235.5	0.00	0.00	0.00
5,500.0	3.76	337.42	5,491.4	242.8	-101.0	-241.5	0.00	0.00	0.00
5,600.0	3.76	337.42	5,591.2	248.9	-103.5	-247.6	0.00	0.00	0.00
5,700.0	3.76	337.42	5,691.0	254.9	-106.0	-253.6	0.00	0.00	0.00
5,800.0	3.76	337.42	5,790.8	261.0	-108.6	-259.6	0.00	0.00	0.00
5,900.0	3.76	337.42	5,890.6	267.1	-111.1	-265.7	0.00	0.00	0.00
6,000.0	3.76	337.42	5,990.3	273.1	-113.6	-271.7	0.00	0.00	0.00
6,100.0	3.76	337.42	6,090.1	279.2	-116.1	-277.7	0.00	0.00	0.00
6,200.0	3.76	337.42	6,189.9	285.2	-118.6	-283.8	0.00	0.00	0.00
6,300.0	3.76	337.42	6,289.7	291.3	-121.2	-289.8	0.00	0.00	0.00
6,400.0	3.76	337.42	6,389.5	297.4	-123.7	-295.8	0.00	0.00	0.00
6,500.0	3.76	337.42	6,489.3	303.4	-126.2	-301.8	0.00	0.00	0.00
6,600.0	3.76	337.42	6,589.1	309.5	-128.7	-307.9	0.00	0.00	0.00
6,700.0	3.76	337.42	6,688.8	315.6	-131.2	-313.9	0.00	0.00	0.00
6,800.0	3.76	337.42	6,788.6	321.6	-133.8	-319.9	0.00	0.00	0.00
6,900.0	3.76	337.42	6,888.4	327.7	-136.3	-326.0	0.00	0.00	0.00
6,992.7	3.76	337.42	6,980.9	333.3	-138.6	-331.6	0.00	0.00	0.00
7,000.0	3.62	337.42	6,988.2	333.7	-138.8	-332.0	2.00	-2.00	0.00
7,100.0	1.62	337.42	7,088.1	337.9	-140.6	-336.2	2.00	-2.00	0.00
7,180.9	0.00	0.00	7,169.0	339.0	-141.0	-337.2	2.00	-2.00	0.00
7,200.0	0.00	0.00	7,188.1	339.0	-141.0	-337.2	0.00	0.00	0.00
7,300.0	0.00	0.00	7,288.1	339.0	-141.0	-337.2	0.00	0.00	0.00
7,400.0	0.00	0.00	7,388.1	339.0	-141.0	-337.2	0.00	0.00	0.00
7,500.0	0.00	0.00	7,488.1	339.0	-141.0	-337.2	0.00	0.00	0.00
7,600.0	0.00	0.00	7,588.1	339.0	-141.0	-337.2	0.00	0.00	0.00
7,700.0	0.00	0.00	7,688.1	339.0	-141.0	-337.2	0.00	0.00	0.00
7,800.0	0.00	0.00	7,788.1	339.0	-141.0	-337.2	0.00	0.00	0.00
7,900.0	0.00	0.00	7,888.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,000.0	0.00	0.00	7,988.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,100.0	0.00	0.00	8,088.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,200.0	0.00	0.00	8,188.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,300.0	0.00	0.00	8,288.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,400.0	0.00	0.00	8,388.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,500.0	0.00	0.00	8,488.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,600.0	0.00	0.00	8,588.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,700.0	0.00	0.00	8,688.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,800.0	0.00	0.00	8,788.1	339.0	-141.0	-337.2	0.00	0.00	0.00
8,900.0	0.00	0.00	8,888.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,000.0	0.00	0.00	8,988.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,100.0	0.00	0.00	9,088.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,200.0	0.00	0.00	9,188.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,300.0	0.00	0.00	9,288.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,400.0	0.00	0.00	9,388.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,500.0	0.00	0.00	9,488.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,600.0	0.00	0.00	9,588.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,700.0	0.00	0.00	9,688.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,800.0	0.00	0.00	9,788.1	339.0	-141.0	-337.2	0.00	0.00	0.00
9,900.0	0.00	0.00	9,888.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,000.0	0.00	0.00	9,988.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,100.0	0.00	0.00	10,088.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,200.0	0.00	0.00	10,188.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,300.0	0.00	0.00	10,288.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,400.0	0.00	0.00	10,388.1	339.0	-141.0	-337.2	0.00	0.00	0.00



## Planning Report



<b>Database:</b>	PEDM	<b>Local Co-ordinate Reference:</b>	Well #708H
<b>Company:</b>	Midland	<b>TVD Reference:</b>	kb = 26' @ 3670.0usft
<b>Project:</b>	Lea County, NM (NAD 83 NME)	<b>MD Reference:</b>	kb = 26' @ 3670.0usft
<b>Site:</b>	Modelo 10 Fed Com	<b>North Reference:</b>	Grid
<b>Well:</b>	#708H	<b>Survey Calculation Method:</b>	Minimum Curvature
<b>Wellbore:</b>	OH		
<b>Design:</b>	Plan #0.1 RT		

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)
10,500.0	0.00	0.00	10,488.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,600.0	0.00	0.00	10,588.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,700.0	0.00	0.00	10,688.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,800.0	0.00	0.00	10,788.1	339.0	-141.0	-337.2	0.00	0.00	0.00
10,900.0	0.00	0.00	10,888.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,000.0	0.00	0.00	10,988.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,100.0	0.00	0.00	11,088.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,200.0	0.00	0.00	11,188.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,300.0	0.00	0.00	11,288.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,400.0	0.00	0.00	11,388.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,500.0	0.00	0.00	11,488.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,600.0	0.00	0.00	11,588.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,700.0	0.00	0.00	11,688.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,800.0	0.00	0.00	11,788.1	339.0	-141.0	-337.2	0.00	0.00	0.00
11,853.4	0.00	0.00	11,841.5	339.0	-141.0	-337.2	0.00	0.00	0.00
11,875.0	2.59	180.00	11,863.1	338.5	-141.0	-336.7	12.00	12.00	0.00
11,900.0	5.59	180.00	11,888.0	336.7	-141.0	-335.0	12.00	12.00	0.00
11,925.0	8.59	180.00	11,912.8	333.6	-141.0	-331.9	12.00	12.00	0.00
11,950.0	11.59	180.00	11,937.4	329.3	-141.0	-327.5	12.00	12.00	0.00
11,975.0	14.59	180.00	11,961.8	323.6	-141.0	-321.8	12.00	12.00	0.00
12,000.0	17.59	180.00	11,985.8	316.7	-141.0	-314.9	12.00	12.00	0.00
12,025.0	20.59	180.00	12,009.4	308.5	-141.0	-306.7	12.00	12.00	0.00
12,050.0	23.59	180.00	12,032.6	299.1	-141.0	-297.3	12.00	12.00	0.00
12,073.9	26.46	180.00	12,054.2	289.0	-141.0	-287.2	12.00	12.00	0.00
12,075.0	26.59	180.00	12,055.2	288.5	-141.0	-286.7	12.00	12.00	-0.20
12,100.0	29.59	179.95	12,077.3	276.7	-141.0	-275.0	12.00	12.00	-0.18
12,125.0	32.59	179.92	12,098.7	263.8	-141.0	-262.1	12.00	12.00	-0.15
12,150.0	35.59	179.89	12,119.4	249.8	-141.0	-248.0	12.00	12.00	-0.12
12,175.0	38.59	179.86	12,139.3	234.7	-140.9	-233.0	12.00	12.00	-0.11
12,200.0	41.59	179.84	12,158.4	218.6	-140.9	-216.9	12.00	12.00	-0.09
12,225.0	44.59	179.81	12,176.7	201.6	-140.8	-199.8	12.00	12.00	-0.08
12,250.0	47.59	179.80	12,194.0	183.5	-140.8	-181.8	12.00	12.00	-0.08
12,275.0	50.59	179.78	12,210.4	164.7	-140.7	-162.9	12.00	12.00	-0.07
12,300.0	53.59	179.76	12,225.7	144.9	-140.6	-143.2	12.00	12.00	-0.06
12,325.0	56.59	179.75	12,240.0	124.4	-140.5	-122.7	12.00	12.00	-0.06
12,350.0	59.59	179.73	12,253.3	103.2	-140.4	-101.5	12.00	12.00	-0.05
12,375.0	62.59	179.72	12,265.3	81.3	-140.3	-79.6	12.00	12.00	-0.05
12,400.0	65.59	179.71	12,276.3	58.9	-140.2	-57.1	12.00	12.00	-0.05
12,425.0	68.59	179.70	12,286.0	35.8	-140.1	-34.1	12.00	12.00	-0.05
12,450.0	71.59	179.69	12,294.5	12.3	-140.0	-10.6	12.00	12.00	-0.04
12,475.0	74.59	179.68	12,301.8	-11.6	-139.8	13.3	12.00	12.00	-0.04
12,500.0	77.59	179.67	12,307.8	-35.9	-139.7	37.6	12.00	12.00	-0.04
12,525.0	80.59	179.66	12,312.5	-60.4	-139.6	62.1	12.00	12.00	-0.04
12,550.0	83.59	179.65	12,316.0	-85.2	-139.4	86.9	12.00	12.00	-0.04
12,575.0	86.59	179.64	12,318.1	-110.1	-139.3	111.8	12.00	12.00	-0.04
12,600.0	89.59	179.63	12,318.9	-135.0	-139.1	136.8	12.00	12.00	-0.04
12,603.4	90.00	179.63	12,318.9	-138.5	-139.1	140.2	12.00	12.00	-0.04
12,700.0	90.00	179.63	12,318.9	-235.0	-138.4	236.7	0.00	0.00	0.00
12,800.0	90.00	179.63	12,318.9	-335.0	-137.8	336.7	0.00	0.00	0.00
12,900.0	90.00	179.63	12,318.9	-435.0	-137.1	436.7	0.00	0.00	0.00
13,000.0	90.00	179.63	12,318.9	-535.0	-136.5	536.7	0.00	0.00	0.00
13,100.0	90.00	179.63	12,319.0	-635.0	-135.8	636.7	0.00	0.00	0.00
13,200.0	90.00	179.63	12,319.0	-735.0	-135.2	736.7	0.00	0.00	0.00
13,300.0	90.00	179.63	12,319.0	-835.0	-134.5	836.6	0.00	0.00	0.00



## Planning Report



<b>Database:</b>	PEDM	<b>Local Co-ordinate Reference:</b>	Well #708H
<b>Company:</b>	Midland	<b>TVD Reference:</b>	kb = 26' @ 3670.0usft
<b>Project:</b>	Lea County, NM (NAD 83 NME)	<b>MD Reference:</b>	kb = 26' @ 3670.0usft
<b>Site:</b>	Modelo 10 Fed Com	<b>North Reference:</b>	Grid
<b>Well:</b>	#708H	<b>Survey Calculation Method:</b>	Minimum Curvature
<b>Wellbore:</b>	OH		
<b>Design:</b>	Plan #0.1 RT		

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)
13,400.0	90.00	179.63	12,319.0	-935.0	-133.9	936.6	0.00	0.00	0.00
13,500.0	90.00	179.63	12,319.0	-1,035.0	-133.2	1,036.6	0.00	0.00	0.00
13,600.0	90.00	179.63	12,319.0	-1,135.0	-132.6	1,136.6	0.00	0.00	0.00
13,700.0	90.00	179.63	12,319.0	-1,235.0	-131.9	1,236.6	0.00	0.00	0.00
13,800.0	90.00	179.63	12,319.0	-1,335.0	-131.2	1,336.5	0.00	0.00	0.00
13,900.0	90.00	179.63	12,319.0	-1,435.0	-130.6	1,436.5	0.00	0.00	0.00
14,000.0	90.00	179.63	12,319.0	-1,535.0	-129.9	1,536.5	0.00	0.00	0.00
14,100.0	90.00	179.63	12,319.0	-1,635.0	-129.3	1,636.5	0.00	0.00	0.00
14,200.0	90.00	179.63	12,319.0	-1,735.0	-128.6	1,736.5	0.00	0.00	0.00
14,300.0	90.00	179.63	12,319.0	-1,835.0	-128.0	1,836.5	0.00	0.00	0.00
14,400.0	90.00	179.63	12,319.0	-1,935.0	-127.3	1,936.4	0.00	0.00	0.00
14,500.0	90.00	179.63	12,319.0	-2,035.0	-126.7	2,036.4	0.00	0.00	0.00
14,600.0	90.00	179.63	12,319.0	-2,135.0	-126.0	2,136.4	0.00	0.00	0.00
14,700.0	90.00	179.63	12,319.0	-2,235.0	-125.4	2,236.4	0.00	0.00	0.00
14,800.0	90.00	179.63	12,319.0	-2,335.0	-124.7	2,336.4	0.00	0.00	0.00
14,900.0	90.00	179.63	12,319.0	-2,435.0	-124.1	2,436.3	0.00	0.00	0.00
15,000.0	90.00	179.63	12,319.0	-2,535.0	-123.4	2,536.3	0.00	0.00	0.00
15,100.0	90.00	179.63	12,319.0	-2,635.0	-122.8	2,636.3	0.00	0.00	0.00
15,200.0	90.00	179.63	12,319.0	-2,735.0	-122.1	2,736.3	0.00	0.00	0.00
15,300.0	90.00	179.63	12,319.0	-2,835.0	-121.4	2,836.3	0.00	0.00	0.00
15,400.0	90.00	179.63	12,319.0	-2,935.0	-120.8	2,936.3	0.00	0.00	0.00
15,500.0	90.00	179.63	12,319.0	-3,035.0	-120.1	3,036.2	0.00	0.00	0.00
15,600.0	90.00	179.63	12,319.0	-3,135.0	-119.5	3,136.2	0.00	0.00	0.00
15,700.0	90.00	179.63	12,319.0	-3,235.0	-118.8	3,236.2	0.00	0.00	0.00
15,800.0	90.00	179.63	12,319.0	-3,335.0	-118.2	3,336.2	0.00	0.00	0.00
15,900.0	90.00	179.63	12,319.0	-3,435.0	-117.5	3,436.2	0.00	0.00	0.00
16,000.0	90.00	179.63	12,319.0	-3,535.0	-116.9	3,536.2	0.00	0.00	0.00
16,100.0	90.00	179.63	12,319.0	-3,635.0	-116.2	3,636.1	0.00	0.00	0.00
16,200.0	90.00	179.63	12,319.0	-3,735.0	-115.6	3,736.1	0.00	0.00	0.00
16,300.0	90.00	179.63	12,319.0	-3,835.0	-114.9	3,836.1	0.00	0.00	0.00
16,400.0	90.00	179.63	12,319.0	-3,935.0	-114.3	3,936.1	0.00	0.00	0.00
16,500.0	90.00	179.63	12,319.0	-4,035.0	-113.6	4,036.1	0.00	0.00	0.00
16,600.0	90.00	179.63	12,319.0	-4,135.0	-112.9	4,136.0	0.00	0.00	0.00
16,700.0	90.00	179.63	12,319.0	-4,235.0	-112.3	4,236.0	0.00	0.00	0.00
16,800.0	90.00	179.63	12,319.0	-4,335.0	-111.6	4,336.0	0.00	0.00	0.00
16,900.0	90.00	179.63	12,319.0	-4,435.0	-111.0	4,436.0	0.00	0.00	0.00
17,000.0	90.00	179.63	12,319.0	-4,535.0	-110.3	4,536.0	0.00	0.00	0.00
17,100.0	90.00	179.63	12,319.0	-4,635.0	-109.7	4,636.0	0.00	0.00	0.00
17,200.0	90.00	179.63	12,319.0	-4,734.9	-109.0	4,735.9	0.00	0.00	0.00
17,300.0	90.00	179.63	12,319.0	-4,834.9	-108.4	4,835.9	0.00	0.00	0.00
17,357.1	90.00	179.63	12,319.0	-4,892.0	-108.0	4,893.0	0.00	0.00	0.00
17,400.0	90.00	179.62	12,319.0	-4,934.9	-107.7	4,935.9	0.00	0.00	0.00
17,500.0	90.00	179.62	12,319.0	-5,034.9	-107.1	5,035.9	0.00	0.00	0.00
17,600.0	90.00	179.62	12,319.0	-5,134.9	-106.4	5,135.9	0.00	0.00	0.00
17,700.0	90.00	179.62	12,319.0	-5,234.9	-105.7	5,235.8	0.00	0.00	0.00
17,800.0	90.00	179.61	12,319.0	-5,334.9	-105.1	5,335.8	0.00	0.00	0.00
17,900.0	90.00	179.61	12,319.0	-5,434.9	-104.4	5,435.8	0.00	0.00	0.00
18,000.0	90.00	179.61	12,319.0	-5,534.9	-103.7	5,535.8	0.00	0.00	0.00
18,100.0	90.00	179.61	12,319.0	-5,634.9	-103.0	5,635.8	0.00	0.00	0.00
18,200.0	90.00	179.60	12,319.0	-5,734.9	-102.3	5,735.8	0.00	0.00	0.00
18,300.0	90.00	179.60	12,319.0	-5,834.9	-101.6	5,835.7	0.00	0.00	0.00
18,400.0	90.00	179.60	12,319.0	-5,934.9	-100.9	5,935.7	0.00	0.00	0.00
18,500.0	90.00	179.60	12,319.0	-6,034.9	-100.2	6,035.7	0.00	0.00	0.00
18,600.0	90.00	179.59	12,319.0	-6,134.9	-99.5	6,135.7	0.00	0.00	0.00



## Planning Report



<b>Database:</b>	PEDM	<b>Local Co-ordinate Reference:</b>	Well #708H
<b>Company:</b>	Midland	<b>TVD Reference:</b>	kb = 26' @ 3670.0usft
<b>Project:</b>	Lea County, NM (NAD 83 NME)	<b>MD Reference:</b>	kb = 26' @ 3670.0usft
<b>Site:</b>	Modelo 10 Fed Com	<b>North Reference:</b>	Grid
<b>Well:</b>	#708H	<b>Survey Calculation Method:</b>	Minimum Curvature
<b>Wellbore:</b>	OH		
<b>Design:</b>	Plan #0.1 RT		

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)	
18,676.1	90.00	179.59	12,319.0	-6,211.0	-99.0	6,211.7	0.00	0.00	0.00	
18,680.0	90.00	179.67	12,319.0	-6,214.9	-99.0	6,215.7	2.00	-0.02	2.00	
18,700.0	90.00	179.67	12,319.0	-6,234.9	-98.9	6,235.7	0.00	0.00	0.00	
18,800.0	90.00	179.67	12,319.0	-6,334.9	-98.3	6,335.6	0.00	0.00	0.00	
18,900.0	90.00	179.67	12,319.0	-6,434.9	-97.7	6,435.6	0.00	0.00	0.00	
19,000.0	90.00	179.67	12,319.0	-6,534.9	-97.1	6,535.6	0.00	0.00	0.00	
19,100.0	90.00	179.67	12,319.0	-6,634.9	-96.6	6,635.6	0.00	0.00	0.00	
19,200.0	90.00	179.67	12,319.0	-6,734.9	-96.0	6,735.6	0.00	0.00	0.00	
19,300.0	90.00	179.67	12,319.0	-6,834.9	-95.4	6,835.6	0.00	0.00	0.00	
19,400.0	90.00	179.67	12,319.0	-6,934.9	-94.8	6,935.5	0.00	0.00	0.00	
19,500.0	90.00	179.67	12,319.0	-7,034.9	-94.3	7,035.5	0.00	0.00	0.00	
19,600.0	90.00	179.67	12,319.0	-7,134.9	-93.7	7,135.5	0.00	0.00	0.00	
19,700.0	90.00	179.67	12,319.0	-7,234.9	-93.1	7,235.5	0.00	0.00	0.00	
19,800.0	90.00	179.67	12,319.0	-7,334.9	-92.6	7,335.5	0.00	0.00	0.00	
19,896.1	90.00	179.67	12,319.0	-7,431.0	-92.0	7,431.6	0.00	0.00	0.00	

Design Targets									
Target Name	Dip Angle (°)	Dip Dir. (°)	TVD (usft)	+N/-S (usft)	+E/-W (usft)	Northing (usft)	Easting (usft)	Latitude	Longitude
KOP(Modelo 10 Fed Co - plan hits target center - Point	0.00	0.00	11,841.5	339.0	-141.0	451,390.00	747,435.00	32.2391888°N	103.6667473°W
FTP(Modelo 10 Fed Cor - plan hits target center - Point	0.00	0.00	12,054.2	289.0	-141.0	451,340.00	747,435.00	32.2390514°N	103.6667483°W
PBHL(Modelo 10 Fed C - plan hits target center - Point	0.00	0.01	12,319.0	-7,431.0	-92.0	443,620.00	747,484.00	32.2178305°N	103.6667448°W
Fed Perf 2(Modelo 10 F - plan hits target center - Point	0.00	0.00	12,319.0	-6,211.0	-99.0	444,840.00	747,477.00	32.2211840°N	103.6667429°W
Fed Perf 1(Modelo 10 F - plan hits target center - Point	0.00	0.00	12,319.0	-4,892.0	-108.0	446,159.00	747,468.00	32.2248097°N	103.6667456°W

Lea County, NM (NAD 83 NME)

Modelo 10 Fed Com #708H

Plan #0.1 RT



To convert a Magnetic Direction to a Grid Direction, Add 6.21°  
To convert a Magnetic Direction to a True Direction, Add 6.56° East  
To convert a True Direction to a Grid Direction, Subtract 0.36°

PROJECT DETAILS: Lea 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: #708H

kb = 26' @ 3670.0usft 3644.0

Northing	Easting	Latitude	Longitude
451051.00	747576.00	32.2382546°N	103.6662981°W

SECTION DETAILS

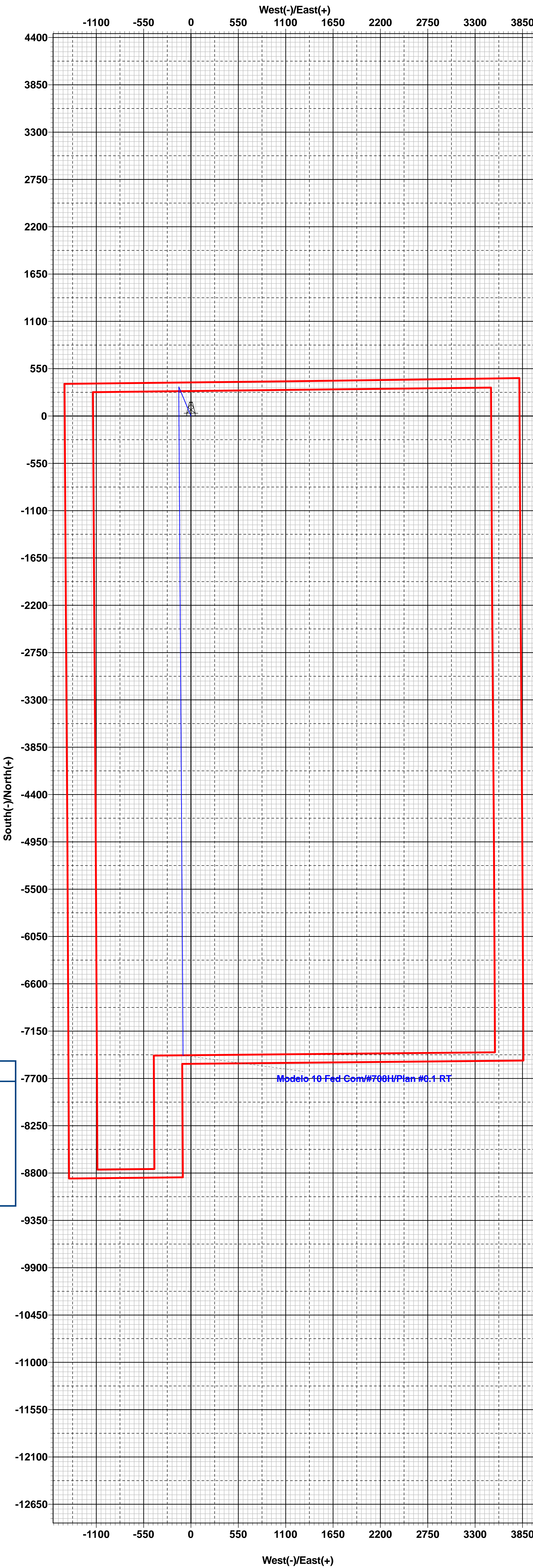
Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Target
1	0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.0	
2	1400.0	0.00	0.00	1400.0	0.0	0.0	0.00	0.00	0.0	
3	1588.2	3.76	337.42	1588.1	5.7	-2.4	2.00	337.42	-5.7	
4	6992.7	3.76	337.42	6980.9	333.3	-138.6	0.00	0.00	-331.6	
5	7180.9	0.00	0.00	7169.0	339.0	-141.0	2.00	180.00	-337.2	
6	11853.4	0.00	0.00	11841.5	339.0	-141.0	0.00	0.00	-337.2	KOP(Modelo 10 Fed Com #708H)
7	12073.9	26.46	180.00	12054.2	289.0	-141.0	12.00	180.00	-287.2	FTP(Modelo 10 Fed Com #708H)
8	12603.4	90.00	179.63	12318.9	-138.5	-139.1	12.00	-0.42	140.2	
9	17357.1	90.00	179.63	12319.0	-4892.0	-108.0	0.00	0.00	4893.0	Fed Perf 1(Modelo 10 Fed Com #708H)
10	18676.1	90.00	179.59	12319.0	-6211.0	-99.0	0.00	-87.69	6211.7	Fed Perf 2(Modelo 10 Fed Com #708H)
11	18680.0	90.00	179.67	12319.0	-6214.9	-99.0	2.00	90.48	6215.7	
12	19896.1	90.00	179.67	12319.0	-7431.0	-92.0	0.00	0.00	7431.6	PBHL(Modelo 10 Fed Com #708H)

CASING DETAILS

No casing data is available

WELLBORE TARGET DETAILS (MAP CO-ORDINATES)

Name	TVD	+N/-S	+E/-W	Northing	Easting
KOP(Modelo 10 Fed Com #708H)	11841.5	339.0	-141.0	451390.00	747435.00
FTP(Modelo 10 Fed Com #708H)	12054.2	289.0	-141.0	451340.00	747435.00
Fed Perf 1(Modelo 10 Fed Com #708H)	12319.0	-4892.0	-108.0	446159.00	747468.00
Fed Perf 2(Modelo 10 Fed Com #708H)	12319.0	-6211.0	-99.0	444840.00	747477.00
PBHL(Modelo 10 Fed Com #708H)	12319.0	-7431.0	-92.0	443620.00	747484.00



Modelo 10 Fed Com #708H Plan #0.1 RT

Vertical Section at 180.71°

## PECOS DISTRICT DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	EOG Resources Incorporated
LEASE NO.:	NMNM119276
WELL NAME & NO.:	MODELO 10 FED COM 708H
SURFACE HOLE FOOTAGE:	390'/N & 1467'/W
BOTTOM HOLE FOOTAGE:	2539'/N & 1332'/W
LOCATION:	Section 10, T.24 S., R.32 E.
COUNTY:	Lea County, New Mexico

COA

H2S	<input checked="" type="radio"/> Yes	<input type="radio"/> No	
Potash	<input checked="" type="radio"/> None	<input type="radio"/> Secretary	<input type="radio"/> R-111-P
Cave/Karst Potential	<input checked="" type="radio"/> Low	<input type="radio"/> Medium	<input type="radio"/> High
Cave/Karst Potential	<input type="radio"/> Critical		
Variance	<input type="radio"/> None	<input checked="" type="radio"/> Flex Hose	<input type="radio"/> Other
Wellhead	<input type="radio"/> Conventional	<input checked="" type="radio"/> Multibowl	<input type="radio"/> Both
Other	<input type="checkbox"/> 4 String Area	<input type="checkbox"/> Capitan Reef	<input type="checkbox"/> WIPP
Other	<input type="checkbox"/> Fluid Filled	<input checked="" type="checkbox"/> Cement Squeeze	<input type="checkbox"/> Pilot Hole
Special Requirements	<input type="checkbox"/> Water Disposal	<input checked="" type="checkbox"/> COM	<input type="checkbox"/> Unit

### A. HYDROGEN SULFIDE

A Hydrogen Sulfide (H2S) Drilling Plan shall be activated AT SPUD. As a result, the Hydrogen Sulfide area must meet Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

### B. CASING

#### Primary Casing Design:

1. The 9-5/8 inch surface casing shall be set at approximately **1,250** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite and above the salt) and cemented to the surface.
  - a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after

- completing the cement job.
- b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
  - c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
  - d. If cement falls back, remedial cementing will be done prior to drilling out that string.
2. The **7-5/8** inch intermediate casing shall be set at approximately **11,270** feet. The minimum required fill of cement behind the **7-5/8** inch intermediate casing is:

**Option 1 (Single Stage):**

- Cement to surface. If cement does not circulate see B.1.a, c-d above.  
**Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.**

**Option 2:**

Operator has proposed a DV tool, the depth may be adjusted as long as the cement is changed proportionally. The DV tool may be cancelled if cement circulates to surface on the first stage.

- a. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.
- b. Second stage above DV tool:
  - Cement to surface. If cement does not circulate, contact the appropriate BLM office.  
**Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.**

**Operator has proposed to pump down 9-5/8" X 7-5/8" annulus. Operator must top out cement after the bradenhead squeeze and verify cement to surface. Operator can also check TOC with Echo-meter. CBL must be run from TD of the 7-5/8" casing to surface if confidence is lacking on the quality of the bradenhead squeeze cement job. Submit results to BLM.**

3. The **5-1/2** inch production casing shall be set at approximately **19,896** feet. The minimum required fill of cement behind the **5-1/2** inch production casing is:

**Option 1 (Single Stage):**

- Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

### **Option 2:**

Operator has proposed a DV tool, the depth may be adjusted as long as the cement is changed proportionally. The DV tool may be cancelled if cement circulates to surface on the first stage.

- a. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.
- b. Second stage above DV tool:
  - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

### **Alternate Casing Design:**

1. The **10-3/4** inch surface casing shall be set at approximately **1,250** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite and above the salt) and cemented to the surface.
  - e. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
  - f. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
  - g. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
  - h. If cement falls back, remedial cementing will be done prior to drilling out that string.
2. The **8-3/4** inch intermediate casing shall be set at approximately **11,270** feet. **KEEP HOLE FULL FOR COLLAPSE SF.** The minimum required fill of cement behind the **8-3/4** inch intermediate casing is:

### **Option 1 (Single Stage):**

- Cement to surface. If cement does not circulate see B.1.a, c-d above.  
**Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.**

**Option 2:**

Operator has proposed a DV tool, the depth may be adjusted as long as the cement is changed proportionally. The DV tool may be cancelled if cement circulates to surface on the first stage.

- c. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.
- d. Second stage above DV tool:
  - Cement to surface. If cement does not circulate, contact the appropriate BLM office.  
**Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.**

**Operator has proposed to pump down 10-3/4" X 8-3/4" annulus. Operator must top out cement after the bradenhead squeeze and verify cement to surface. Operator can also check TOC with Echo-meter. CBL must be run from TD of the 8-3/4" casing to surface if confidence is lacking on the quality of the bradenhead squeeze cement job. Submit results to BLM.**

3. The 6 inch production casing shall be set at approximately **19,896** feet. The minimum required fill of cement behind the 6 inch production casing is:

**Option 1 (Single Stage):**

- Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

**Option 2:**

Operator has proposed a DV tool, the depth may be adjusted as long as the cement is changed proportionally. The DV tool may be cancelled if cement circulates to surface on the first stage.

- c. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.
- d. Second stage above DV tool:

- Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

### C. PRESSURE CONTROL

1. Variance approved to use flex line from BOP to choke manifold. Manufacturer's specification to be readily available. No external damage to flex line. Flex line to be installed as straight as possible (no hard bends).'
2. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the surface casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **10,000 (10M) psi. Variance is approved to use a 5000 (5M) Annular which shall be tested to 3500 (3.5M) psi.**
  - a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
  - b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
  - c. Manufacturer representative shall install the test plug for the initial BOP test.
  - d. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
  - e. Whenever any seal subject to test pressure is broken, all the tests in OOGO2.III.A.2.i must be followed.

#### **BOPE Break Testing Variance (Note: For 5M BOPE or less)**

- BOPE Break Testing is ONLY permitted for 5M BOPE or less.
- BOPE Break Testing is NOT permitted to drilling the production hole section.
- While in transfer between wells, the BOPE shall be secured by the hydraulic carrier or cradle.
- Any well control event while drilling require notification to the BLM Petroleum Engineer prior to the commencement of any BOPE Break Testing operations.
- A full BOPE test is required prior to drilling the first deep intermediate hole section. If any subsequent hole interval is deeper than the first, a full BOPE test will be required.
- The BLM is to be contacted (575-689-5981 Lea County) 4 hours prior to BOPE tests.
- As a minimum, a full BOPE test shall be performed at 21-day intervals.
- In the event any repairs or replacement of the BOPE is required, the BOPE shall test as per Onshore Oil and Gas Order No. 2.

OFFLINE CEMENTING AND BREAK TESTING IS APPROVED FOR THE SURFACE AND INTERMEDIATE SECTIONS.

**D. SPECIAL REQUIREMENT (S)****Communitization Agreement**

- The operator will submit a Communitization Agreement to the Santa Fe Office, 301 Dinosaur Trail Santa Fe, New Mexico 87508, at least 90 days before the anticipated date of first production from a well subject to a spacing order issued by the New Mexico Oil Conservation Division. The Communitization Agreement will include the signatures of all working interest owners in all Federal and Indian leases subject to the Communitization Agreement (i.e., operating rights owners and lessees of record), or certification that the operator has obtained the written signatures of all such owners and will make those signatures available to the BLM immediately upon request.
- If the operator does not comply with this condition of approval, the BLM may take enforcement actions that include, but are not limited to, those specified in 43 CFR 3163.1.
- In addition, the well sign shall include the surface and bottom hole lease numbers. When the Communitization Agreement number is known, it shall also be on the sign.

**GENERAL REQUIREMENTS**

The BLM is to be notified in advance for a representative to witness:

- a. Spudding well (minimum of 24 hours)
- b. Setting and/or Cementing of all casing strings (minimum of 4 hours)
- c. BOPE tests (minimum of 4 hours)

☒ Eddy County

Call the Carlsbad Field Office, 620 East Greene St., Carlsbad, NM 88220,  
(575) 361-2822

☒ Lea County

Call the Hobbs Field Station, 414 West Taylor, Hobbs NM 88240, (575)  
689-5981

1. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval.
  - a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure

- rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
- b. When the operator proposes to set surface casing with Spudder Rig
    - Notify the BLM when moving in and removing the Spudder Rig.
    - Notify the BLM when moving in the 2<sup>nd</sup> Rig. Rig to be moved in within 90 days of notification that Spudder Rig has left the location.
    - BOP/BOPE test to be conducted per Onshore Oil and Gas Order No. 2 as soon as 2nd Rig is rigged up on well.
  2. Floor controls are required for 3M or Greater systems. These controls will be on the rig floor, unobstructed, readily accessible to the driller and will be operational at all times during drilling and/or completion activities. Rig floor is defined as the area immediately around the rotary table; the area immediately above the substructure on which the draw works are located, this does not include the dog house or stairway area.
  3. The record of the drilling rate along with the GR/N well log run from TD to surface (horizontal well – vertical portion of hole) shall be submitted to the BLM office as well as all other logs run on the borehole 30 days from completion. If available, a digital copy of the logs is to be submitted in addition to the paper copies. The Rustler top and top and bottom of Salt are to be recorded on the Completion Report.

#### A. CASING

1. Changes to the approved APD casing program need prior approval if the items substituted are of lesser grade or different casing size or are Non-API. The Operator can exchange the components of the proposal with that of superior strength (i.e. changing from J-55 to N-80, or from 36# to 40#). Changes to the approved cement program need prior approval if the altered cement plan has less volume or strength or if the changes are substantial (i.e. Multistage tool, ECP, etc.). The initial wellhead installed on the well will remain on the well with spools used as needed.
2. Wait on cement (WOC) for Potash Areas: After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi for all cement blends, 2) until cement has been in place at least 24 hours. WOC time will be recorded in the driller's log. The casing integrity test can be done (prior to the cement setting up) immediately after bumping the plug.
3. Wait on cement (WOC) for Water Basin: After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least 8 hours. WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements. The casing integrity test can be done (prior to the cement setting up) immediately after bumping the plug.

4. Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string. Have well specific cement details onsite prior to pumping the cement for each casing string.
5. No pea gravel permitted for remedial or fall back remedial without prior authorization from the BLM engineer.
6. On that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.
7. If hardband drill pipe is rotated inside casing, returns will be monitored for metal. If metal is found in samples, drill pipe will be pulled and rubber protectors which have a larger diameter than the tool joints of the drill pipe will be installed prior to continuing drilling operations.
8. Whenever a casing string is cemented in the R-111-P potash area, the NMOCD requirements shall be followed.

**B. PRESSURE CONTROL**

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in Onshore Oil and Gas Order No. 2 and API RP 53 Sec. 17.
2. If a variance is approved for a flexible hose to be installed from the BOP to the choke manifold, the following requirements apply: The flex line must meet the requirements of API 16C. Check condition of flexible line from BOP to choke manifold, replace if exterior is damaged or if line fails test. Line to be as straight as possible with no hard bends and is to be anchored according to Manufacturer's requirements. The flexible hose can be exchanged with a hose of equal size and equal or greater pressure rating. Anchor requirements, specification sheet and hydrostatic pressure test certification matching the hose in service, to be onsite for review. These documents shall be posted in the company man's trailer and on the rig floor.
3. 5M or higher system requires an HCR valve, remote kill line and annular to match. The remote kill line is to be installed prior to testing the system and tested to stack pressure.
4. If the operator has proposed a multi-bowl wellhead assembly in the APD. The following requirements must be met:
  - a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.

- b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
  - c. Manufacturer representative shall install the test plug for the initial BOP test.
  - d. Whenever any seal subject to test pressure is broken, all the tests in OOGO2.III.A.2.i must be followed.
  - e. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
- 5. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.
  - a. In a water basin, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. The casing cut-off and BOP installation can be initiated four hours after installing the slips, which will be approximately six hours after bumping the plug. For those casing strings not using slips, the minimum wait time before cut-off is eight hours after bumping the plug. BOP/BOPE testing can begin after cut-off or once cement reaches 500 psi compressive strength (including lead when specified), whichever is greater. However, if the float does not hold, cut-off cannot be initiated until cement reaches 500 psi compressive strength (including lead when specified).
  - b. In potash areas, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. For all casing strings, casing cut-off and BOP installation can be initiated at twelve hours after bumping the plug. However, **no tests** shall commence until the cement has had a minimum of 24 hours setup time, except the casing pressure test can be initiated immediately after bumping the plug (only applies to single stage cement jobs).
  - c. The tests shall be done by an independent service company utilizing a test plug not a cup or J-packer. The operator also has the option of utilizing an independent tester to test without a plug (i.e. against the casing) pursuant to Onshore Order 2 with the pressure not to exceed 70% of the burst rating for the casing. Any test against the casing must meet the WOC time for water basin (8 hours) or potash (24 hours) or 500 pounds compressive strength, whichever is greater, prior to initiating the test (see casing segment as lead cement may be critical item).
  - d. The test shall be run on a 5000 psi chart for a 2-3M BOP/BOP, on a 10000 psi chart for a 5M BOP/BOPE and on a 15000 psi chart for a 10M BOP/BOPE. If a linear chart is used, it shall be a one hour chart. A circular chart shall

have a maximum 2 hour clock. If a twelve hour or twenty-four hour chart is used, tester shall make a notation that it is run with a two hour clock.

- e. The results of the test shall be reported to the appropriate BLM office.
- f. All tests are required to be recorded on a calibrated test chart. A copy of the BOP/BOPE test chart and a copy of independent service company test will be submitted to the appropriate BLM office.
- g. The BOP/BOPE test shall include a low pressure test from 250 to 300 psi. The test will be held for a minimum of 10 minutes if test is done with a test plug and 30 minutes without a test plug. This test shall be performed prior to the test at full stack pressure.
- h. BOP/BOPE must be tested by an independent service company within 500 feet of the top of the Wolfcamp formation if the time between the setting of the intermediate casing and reaching this depth exceeds 20 days. This test does not exclude the test prior to drilling out the casing shoe as per Onshore Order No. 2.

#### C. DRILLING MUD

Mud system monitoring equipment, with derrick floor indicators and visual and audio alarms, shall be operating before drilling into the Wolfcamp formation, and shall be used until production casing is run and cemented.

#### D. WASTE MATERIAL AND FLUIDS

All waste (i.e. drilling fluids, trash, salts, chemicals, sewage, gray water, etc.) created as a result of drilling operations and completion operations shall be safely contained and disposed of properly at a waste disposal facility. No waste material or fluid shall be disposed of on the well location or surrounding area.

Porto-johns and trash containers will be on-location during fracturing operations or any other crew-intensive operations.

**KPI – 2/13/2023**



## Modelo 10 Fed Com 708H

### 1. GEOLOGIC NAME OF SURFACE FORMATION:

Permian

### 2. ESTIMATED TOPS OF IMPORTANT GEOLOGICAL MARKERS:

Rustler	1,165'
Tamarisk Anhydrite	1,225'
Top of Salt	1,460'
Base of Salt	4,650'
Lamar	4,889'
Bell Canyon	4,916'
Cherry Canyon	5,690'
Brushy Canyon	7,169'
Bone Spring Lime	8,800'
Leonard Shale	8,967'
1 <sup>st</sup> Bone Spring Sand	9,975'
2 <sup>nd</sup> Bone Spring Shale	10,220'
2 <sup>nd</sup> Bone Spring Sand	10,559'
3 <sup>rd</sup> Bone Spring Carb	11,170'
3 <sup>rd</sup> Bone Spring Sand	11,889'
Wolfcamp	12,246'
TD	12,319'

### 3. ESTIMATED DEPTHS OF ANTICIPATED FRESH WATER, OIL OR GAS:

Upper Permian Sands	0- 400'	Fresh Water
Bell Canyon	4,916'	Oil
Cherry Canyon	5,690'	Oil
Brushy Canyon	7,169'	Oil
Leonard (Avalon) Shale	8,967'	Oil
1 <sup>st</sup> Bone Spring Sand	9,975'	Oil
2 <sup>nd</sup> Bone Spring Shale	10,220'	Oil
2 <sup>nd</sup> Bone Spring Sand	10,559'	Oil
3 <sup>rd</sup> Bone Spring Carb	11,170'	Oil
3 <sup>rd</sup> Bone Spring Sand	11,889'	Oil
Wolfcamp	12,246'	Oil

No other Formations are expected to give up oil, gas or fresh water in measurable quantities. Surface fresh water sands will be protected by setting 9-5/8" or 10-3/4" casing at 1,250' and circulating cement back to surface.



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## 4. CASING PROGRAM - Design A

Hole Size	Interval MD		Interval TVD		Csg OD	Weight	Grade	Conn
	From (ft)	To (ft)	From (ft)	To (ft)				
12-1/4"	0	1,250	0	1,250	9-5/8"	36#	J-55	LTC
8-3/4"	0	11,270	0	11,260	7-5/8"	29.7#	HCP-110	FXL
6-3/4"	0	10,770	0	10,760	5-1/2"	20#	P110-EC	DWC/C IS MS
6-3/4"	10,770	11,270	10,760	11,260	5-1/2"	20#	P110-EC	Vam Sprint SF
6-3/4"	11,270	19,896	11,260	12,319	5-1/2"	20#	P110-EC	DWC/C IS MS

Variance is requested to waive the centralizer requirements for the 7-5/8" casing in the 8-3/4" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 8-3/4 hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive any centralizer requirements for the 5-1/2" casing in the 6-3/4" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 6-3/4" hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive the annular clearance requirements for the 5-1/2" casing by 7-5/8" casing annulus to the proposed top of cement.

EOG requests permission to allow deviation from the 0.422" annulus clearance requirement from Onshore Order #2 under the following conditions:

- Annular clearance to meet or exceed 0.422" between intermediate casing ID and production casing coupling only on the first 500' overlap between both casing strings.
- Annular clearance less than 0.422" is acceptable for the production open hole section.

**Cementing Program:**

Depth	No. Sacks	Wt. ppg	Yld Ft <sup>3</sup> /sk	Slurry Description
1,250' 9-5/8"	340	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)
	80	14.8	1.34	Tail: Class C + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1,050')
11,270' 7-5/8"	510	14.2	1.11	1st Stage (Tail): Class C + 0.6% Halad-9 + 0.45% HR-601 + 3% Microbond (TOC @ 6,970')
	1190	14.8	1.5	2nd Stage (Bradenhead squeeze): Class C + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
19,896' 5-1/2"	790	14.2	1.31	Lead: Class H + 0.4% Halad-344 + 0.35% HR-601 + 3% Microbond (TOC @ 10,770')

**Modelo 10 Fed Com 708H**

Additive	Purpose
Bentonite Gel	Lightweight/Lost circulation prevention
Calcium Chloride	Accelerator
Cello-flake	Lost circulation prevention
Sodium Metasilicate	Accelerator
MagOx	Expansive agent
Pre-Mag-M	Expansive agent
Sodium Chloride	Accelerator
FL-62	Fluid loss control
Halad-344	Fluid loss control
Halad-9	Fluid loss control
HR-601	Retarder
Microbond	Expansive Agent

EOG requests variance from minimum standards to pump a two stage cement job on the 7-5/8" intermediate casing string with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon (7,169') 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 190 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. Top will be verified by Echo-meter.

EOG will include the Echo-meter verified fluid top and the volume of displacement fluid above the cement slurry in the annulus in all post-drill sundries on wells utilizing this cement program.

EOG will report to the BLM the volume of fluid (limited to 5 bbls) used to flush intermediate casing valves following backside cementing procedures.

Cement integrity tests will be performed immediately following plug bump.

Note: Cement volumes based on bit size plus at least 25% excess in the open hole plus 10% excess in the cased-hole overlap section.

## **5. MINIMUM SPECIFICATIONS FOR PRESSURE CONTROL:**

Variance is requested to use a co-flex line between the BOP and choke manifold (instead of using a 4" OD steel line).

The minimum blowout preventer equipment (BOPE) shown in Exhibit #1 will consist of a single ram, mud cross and double ram-type (10,000 psi WP) preventer and an annular preventer (5,000 psi WP). Both units will be hydraulically operated and the ram-type will be equipped with blind rams on bottom and drill pipe rams on top.



### Modelo 10 Fed Com 708H

EOG will utilize wing unions on BOPE connections that can be isolated from wellbore pressure through means of a choke. All wing unions will be rated to a pressure that meets or exceeds the pressure rating of the BOPE system.

Variance is requested to use a 5,000 psi annular BOP with the 10,000 psi BOP stack.

Pipe rams and blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets.

A hydraulically operated choke will be installed prior to drilling out of the intermediate casing shoe.

## 6. TYPES AND CHARACTERISTICS OF THE PROPOSED MUD SYSTEM:

During this procedure we plan to use a Closed-Loop System and haul contents to the required disposal.

The applicable depths and properties of the drilling fluid systems are as follows:

Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 1,250'	Fresh - Gel	8.6-8.8	28-34	N/c
1,250' – 11,270'	Brine	10.0-10.2	28-34	N/c
11,270' – 11,853'	Oil Base	8.7-9.4	58-68	N/c - 6
11,853' – 19,896' Lateral	Oil Base	10.0-14.0	58-68	4 - 6

The highest mud weight needed to balance formation is expected to be 11.5 ppg. In order to maintain hole stability, mud weights up to 14.0 ppg may be utilized.

An electronic pit volume totalizer (PVT) will be utilized on the circulating system, to monitor pit volume, flow rate, pump pressure and stroke rate.

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept at the wellsite at all times.

## 7. AUXILIARY WELL CONTROL AND MONITORING EQUIPMENT:

- (A) A kelly cock will be kept in the drill string at all times.
- (B) A full opening drill pipe-stabbing valve (inside BOP) with proper drill pipe connections will be on the rig floor at all times.
- (C) H<sub>2</sub>S monitoring and detection equipment will be utilized from surface casing point to TD.



## Modelo 10 Fed Com 708H

### 8. LOGGING, TESTING AND CORING PROGRAM:

Open-hole logs are not planned for this well.

GR-CCL Will be run in cased hole during completions phase of operations.

### 9. ABNORMAL CONDITIONS, PRESSURES, TEMPERATURES AND POTENTIAL HAZARDS:

The estimated bottom-hole temperature (BHT) at TD is 193 degrees F with an estimated maximum bottom-hole pressure (BHP) at TD of 8,968 psig and a maximum anticipated surface pressure of 6,258 psig (based on 14.0 ppg MW). No hydrogen sulfide or other hazardous gases or fluids have been encountered, reported or are known to exist at this depth in this area. Severe loss circulation is expected from 7,169' to intermediate casing point.

### 10. ANTICIPATED STARTING DATE AND DURATION OF OPERATIONS:

The drilling operation should be finished in approximately one month. If the well is productive, an additional 60-90 days will be required for completion and testing before a decision is made to install permanent facilities.

EOG Resources requests the option to contract a Surface Rig to drill, set surface casing, and Cement on the subject well. After WOC 8 hours or 500 psi compressive strength (whichever is greater), the Surface Rig will move off so the wellhead can be installed. A welder will cut the casing to the proper height and weld on the wellhead (both "A" and "B" sections). The weld will be tested to 1,500 psi. All valves will be closed and a wellhead cap will be installed (diagram attached). If the timing between rigs is such that EOG Resources would not be able to preset the surface, the Primary Rig will MIRU and drill the well in its entirety per the APD.

### 11. WELLHEAD:

A multi-bowl wellhead system will be utilized.

After running the 9-5/8" surface casing, a 9-5/8" BOP/BOPE system with a minimum working pressure of 10,000 psi will be installed on the wellhead system and will be pressure tested to 250 psi low followed by a 10,000 psi pressure test. This pressure test will be repeated at least every 30 days, as per Onshore Order No. 2.

The minimum working pressure of the BOP and related BOPE required for drilling below the surface casing shoe shall be 10,000 psi.

The multi-bowl wellhead will be installed by vendor's representative(s). A copy of the installation instructions for the Cactus Multi-Bowl WH system has been sent to the NM BLM office in Carlsbad, NM.



### **Modelo 10 Fed Com 708H**

The wellhead will be installed by a third party welder while being monitored by WH vendor's representative.

All BOP equipment will be tested utilizing a conventional test plug. Not a cup or J-packer type. EOG Resources reserves the option to conduct BOPE testing during wait on cement periods provided a test plug is utilized.

A solid steel body pack-off will be utilized after running and cementing the intermediate casing. After installation the pack-off and lower flange will be pressure tested to 5,000 psi.

Casing strings will be tested as per Onshore Order No. 2 to at least 0.22 psi/ft or 1,500 psi, whichever is greater.

EOG Resources Inc. (EOG) respectfully requests a variance from the minimum standards for well control equipment testing of Onshore Order No. 2 (item III.A.2.a.i) 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 30 days per Onshore Order No. 2.
- Function test BOP elements per Onshore Order No. 2.
- 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.
- See attached "EOG BLM Variance 3a -Offline Cement Intermediate Operational Procedure"



Modelo 10 Fed Com 708H

390' FNL  
1467' FWL  
Section 10  
T-24-S, R-32-E

Proposed Wellbore

KB: 3669'  
GL: 3644'

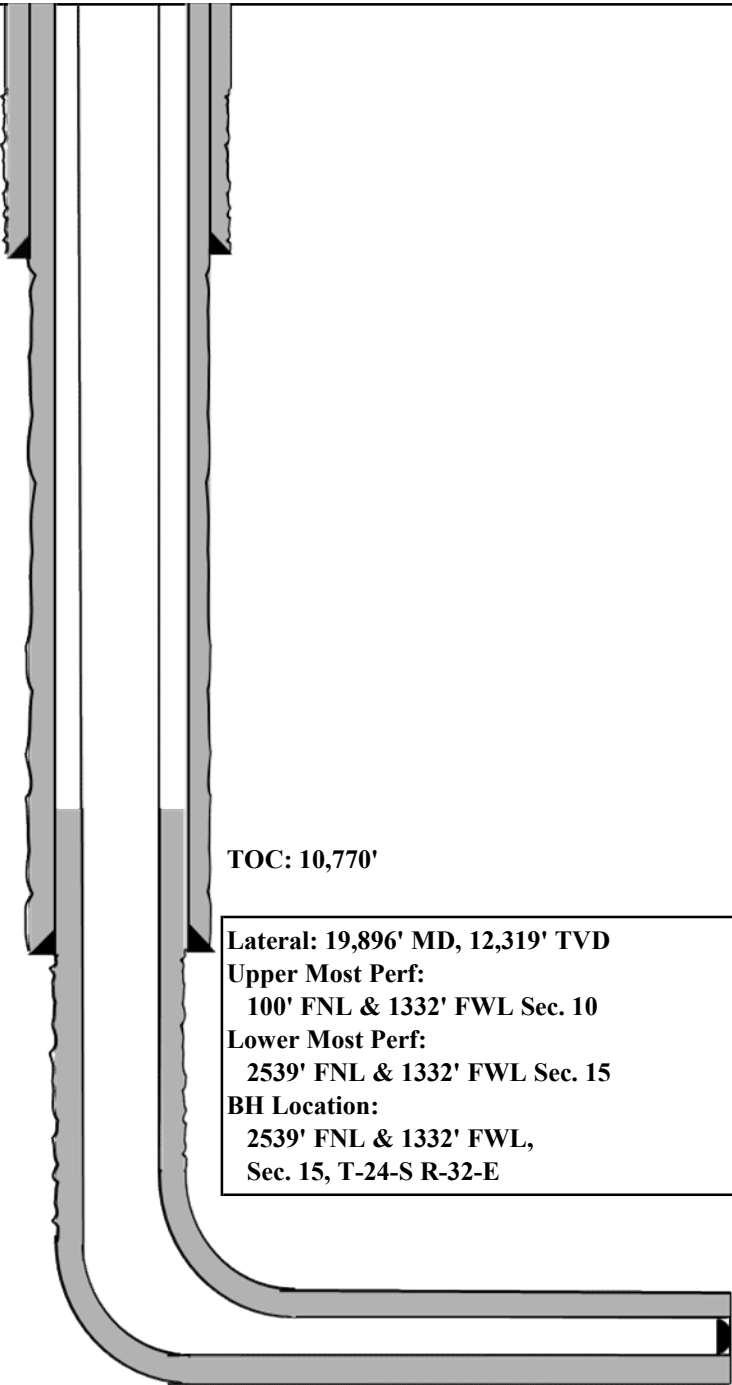
API: 30-025-\*\*\*\*\*

Bit Size: 12-1/4"  
9-5/8", 36#, J-55, LTC, 0' - 1,250'

Bit Size: 8-3/4"  
7-5/8", 29.7#, HCP-110, FXL, 0' - 11,270'

Bit Size: 6-3/4"  
5-1/2", 20.#, P110-EC, DWC/C IS MS  
@ 0' - 10,770'  
5-1/2", 20.#, P110-EC, Vam Sprint SF  
@ 10,770' - 11,270'  
5-1/2", 20.#, P110-EC, DWC/C IS MS  
@ 11,270' - 19,896'

KOP: 11,853' MD, 11,842' TVD  
EOC: 12,603' MD, 12,319' TVD





## Modelo 10 Fed Com 708H

**Design B****4. CASING PROGRAM**

Hole Size	Interval MD		Interval TVD		Csg OD	Weight	Grade	Conn
	From (ft)	To (ft)	From (ft)	To (ft)				
13"	0	1,250	0	1,250	10-3/4"	40.5#	J-55	STC
9-7/8"	0	11,270	0	11,258	8-3/4"	38.5#	P110-EC	Vam Sprint-SF
7-7/8"	0	19,896	0	12,319	6"	24#	P110-HP	Eagle SFH SC

Variance is requested to waive the centralizer requirements for the 8-3/4" casing in the 9-7/8" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 9-7/8" hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive any centralizer requirements for the 6" casing in the 7-7/8" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 7-7/8" hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive the annular clearance requirements for the 6" casing by 8-3/4" casing annulus to the proposed top of cement.

EOG requests permission to allow deviation from the 0.422" annulus clearance requirement from Onshore Order #2 under the following conditions:

- Annular clearance to meet or exceed 0.422" between intermediate casing ID and production casing coupling only on the first 500' overlap between both casing strings.
- Annular clearance less than 0.422" is acceptable for the production open hole section.

**Cementing Program:**

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,250' 10-3/4"	320	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 @ 1,050')
11,270' 8-3/4"	570	14.2	1.11	1st Stage (Tail): Class C + 0.6% Halad-9 + 0.45% HR-601 + 3% Microbond (TOC @ 6,970')
	1350	14.8	1.5	2nd Stage (Bradenhead squeeze): Class C + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
19,896' 6"	1280	14.2	1.31	Lead: Class H + 0.4% Halad-344 + 0.35% HR-601 + 3% Microbond (TOC @ 10,770')



### Modelo 10 Fed Com 708H

EOG requests variance from minimum standards to pump a two stage cement job on the 7-5/8" intermediate casing string with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon (7,169') 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 350 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. Top will be verified by Echo-meter.

EOG will include the Echo-meter verified fluid top and the volume of displacement fluid above the cement slurry in the annulus in all post-drill sundries on wells utilizing this cement program.

EOG will report to the BLM the volume of fluid (limited to 5 bbls) used to flush intermediate casing valves following backside cementing procedures.

Cement integrity tests will be performed immediately following plug bump.

Note: Cement volumes based on bit size plus at least 25% excess in the open hole plus 10% excess in the cased-hole overlap section.

#### **Wellhead:**

EOG Resources Inc. (EOG) respectfully requests a variance from the minimum standards for well control equipment testing of Onshore Order No. 2 (item III.A.2.a.i) 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 30 days per Onshore Order No. 2.
- Function test BOP elements per Onshore Order No. 2.
- 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.
- See attached "EOG BLM Variance 3a -Offline Cement Intermediate Operational Procedure"



Modelo 10 Fed Com 708H

390' FNL  
1467' FWL  
Section 10  
T-24-S, R-32-E

Proposed Wellbore  
  
API: 30-025-\*\*\*\*\*

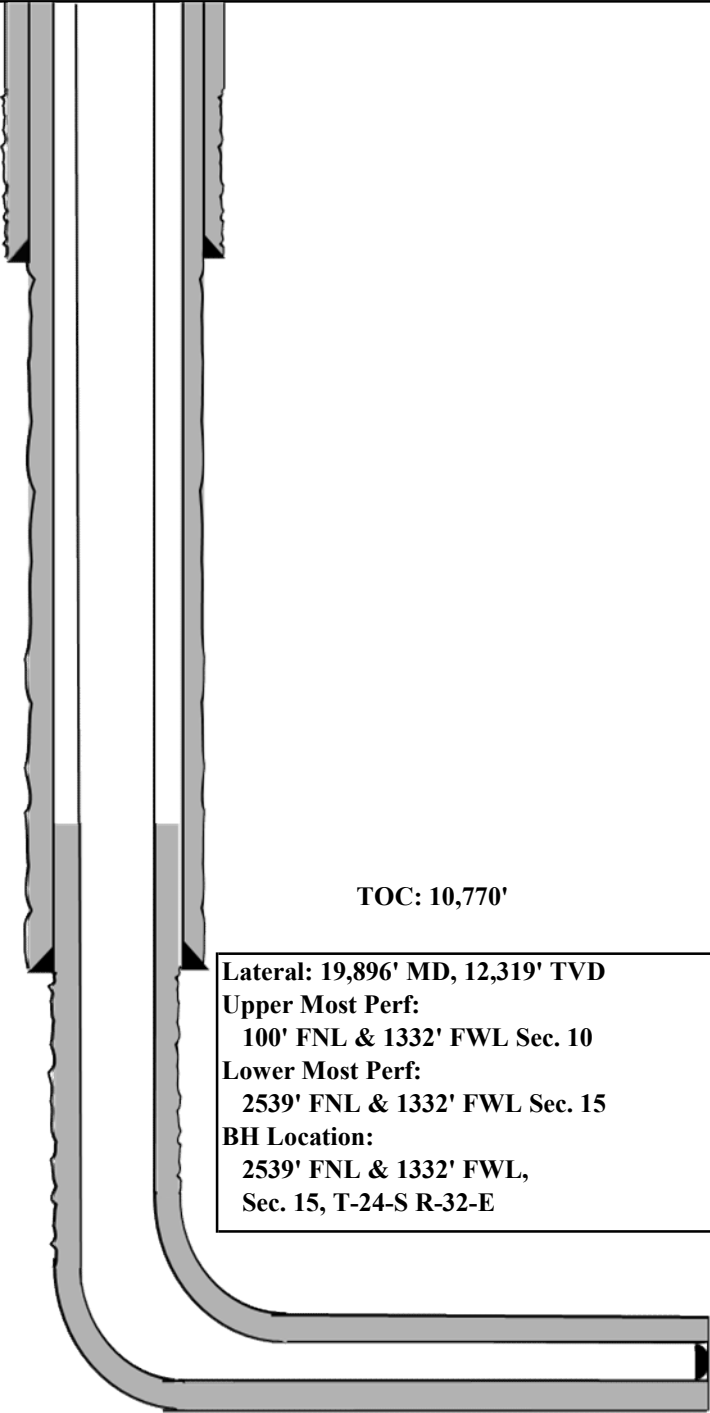
KB: 3669'  
GL: 3644'

Bit Size: 13"  
10-3/4", 40.5#, J-55, STC,  
0' - 1,250'

Bit Size: 9-7/8"  
7-5/8", 29.7#, HCP-110, FXL  
@ 0' - 11,270'

Bit Size: 7-7/8"  
6", 24#, P110-HP, Eagle SFH SC,  
@ 0' - 19,896'

KOP: 11,853' MD, 11,842' TVD  
EOC: 12,603' MD, 12,319' TVD



TOC: 10,770'

Lateral: 19,896' MD, 12,319' TVD  
Upper Most Perf:  
100' FNL & 1332' FWL Sec. 10  
Lower Most Perf:  
2539' FNL & 1332' FWL Sec. 15  
BH Location:  
2539' FNL & 1332' FWL,  
Sec. 15, T-24-S R-32-E



Modelo 10 Fed Com #708H

## 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:**
    - a. Breathing Apparatus:
      - i. Rescue Packs (SCBA) — 1 unit shall be placed at each breathing area, 2 shall be stored in the safety trailer.
      - ii. Work/Escapes packs — 4 packs shall be stored on the rig floor with sufficient air hose not to restrict work activity.
      - iii. Emergency Escape Packs — 4 packs shall be stored in the doghouse for emergency evacuation.
    - b. Auxiliary Rescue Equipment:
      - i. Stretcher
      - ii. Two OSHA full body harness
      - iii. 100 ft 5/8 inch OSHA approved rope
      - iv. 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 System:**
    - 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.



Modelo 10 Fed Com #708H

■ **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.



Modelo 10 Fed Com #708H

## Emergency Assistance Telephone List

<b>PUBLIC SAFETY:</b>	<b>911 or</b>
<b>Lea County Sheriff's Department</b>	(575) 396-3611
Corey Helton	
<b>Fire Department</b>	
Carlsbad	(575) 885-3125
Artesia	(575) 746-5050
<b>Hospitals</b>	
Carlsbad	(575) 887-4121
Artesia	(575) 748-3333
Hobbs	(575) 392-1979
<b>Dept. of Public Safety/Carlsbad</b>	(575) 748-9718
<b>Highway Department</b>	(575) 885-3281
<b>U.S. Department of Labor</b>	(575) 887-1174
<b>Bureau of Land Management - Hobbs (Lea Co)</b>	(575) 393-3612
PET On Call - Hobbs	(575) 706-2779
<b>Bureau of Land Management - Carlsbad (Eddy Co)</b>	(575) 234-5972
PET On Call - Carlsbad	(575) 706-2779
<b>New Mexico Oil Conservation Division - Artesia</b>	(575) 748-1283
Inspection Group South - Gilbert Gordero	(575) 626-0830
<b>EOG Resources, Inc.</b>	
EOG Midland	(432) 686-3600
<b>Company Drilling Consultants:</b>	
Jett Dueitt	(432) 230-4840
Blake Burney	
<b>Drilling Engineers</b>	
Daniel Moose	(432) 312-2803
Esteban Del Valle	(432) 269-7063
Stephen Davis	(432) 235-9789
<b>Drilling Managers</b>	
AJ Dach	(817) 480-1167
Branden Keener	(210) 294-3729
<b>Drilling Superintendents</b>	
Chris Hale	(432) 215-5531
Lance Hardy	(432) 215-8152
Ryan Reynolds	(432) 215-5978
Steve Kelly	(210) 416-7894
<b>H&amp;P Drilling</b>	
H&P Drilling	(432) 563-5757
<b>Nabors Drilling</b>	
Nabors Drilling	(432) 363-8180
<b>Patterson UTI</b>	
Patterson UTI	(432) 561-9382
<b>EOG Safety</b>	
Brian Chandler (HSE Manager)	(817) 239-0251

## 10,000 PSI BOP Annular Variance Request

EOG Resources request a variance to use a 5000 psi annular BOP with a 10,000 psi BOP stack. The component and compatibility tables along with the general well control plans demonstrate how the 5000 psi annular BOP will be protected from pressures that exceed its rated working pressure (RWP). The pressure at which the control of the wellbore is transferred from the annular preventer to another available preventer will not exceed 3500 psi (70% of the RWP of the 5000 psi annular BOP).

### 1. Component and Preventer Compatibility Tables

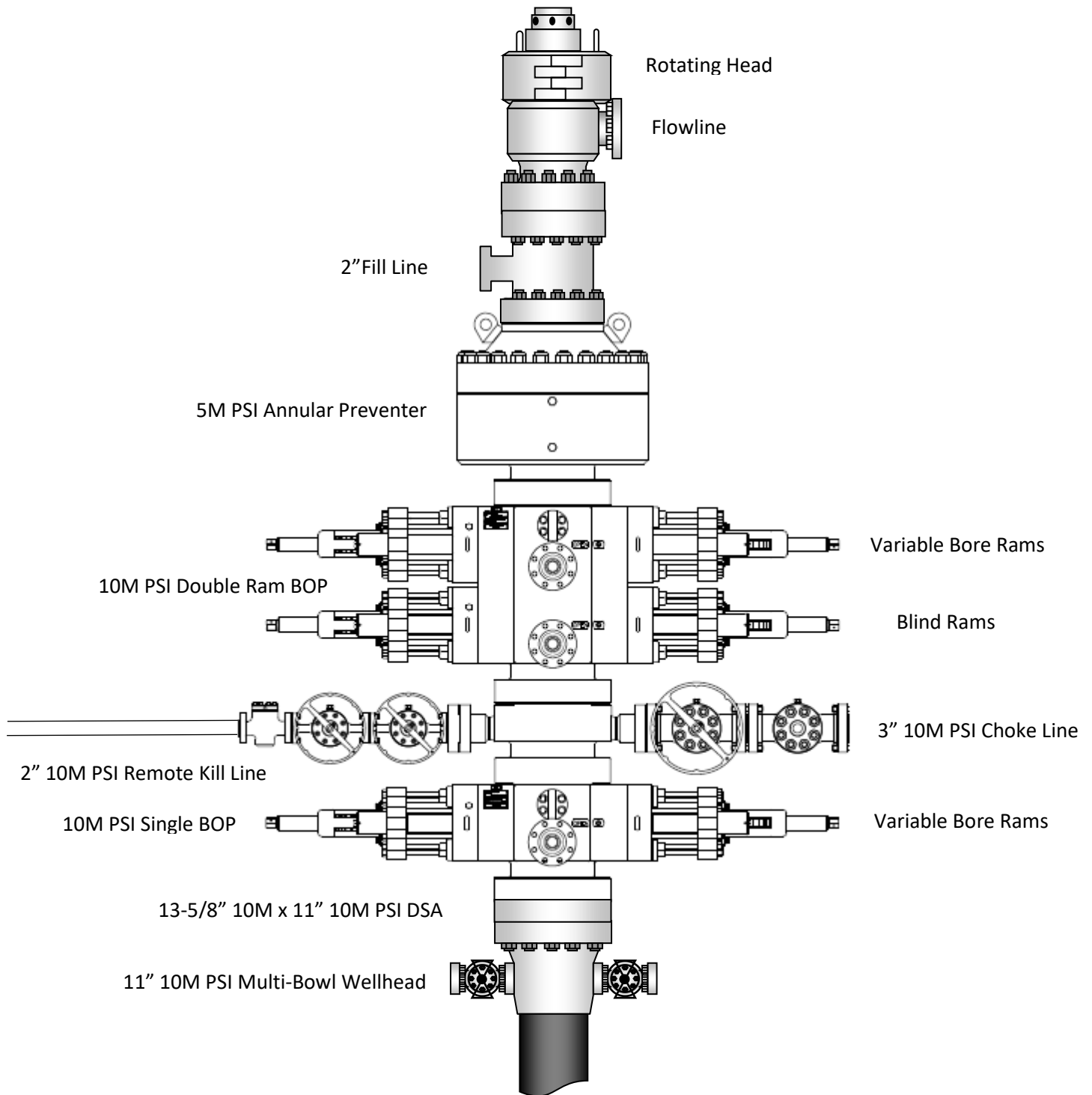
The tables below outlines the tubulars and the compatible preventers in use. This table, combined with the drilling fluid, documents that two barriers to flow will be maintained at all times.

9-7/8" & 8-3/4" Intermediate Hole Section 10M psi requirement					
Component	OD	Primary Preventer	RWP	Alternate Preventer(s)	RWP
Drillpipe	4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
HWDP	4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Jars	4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
DCs and MWD tools	6.500 – 8.000"	Annular	5M	-	-
Mud Motor	6.750 – 8.000"	Annular	5M	-	-
Intermediate casing	7.625"	Annular	5M	-	-
Open-hole	-	Blind Rams	10M	-	-

6-3/4" Production Hole Section 10M psi requirement					
Component	OD	Primary Preventer	RWP	Alternate Preventer(s)	RWP
Drillpipe	4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
HWDP	4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
DCs and MWD tools	4.750 – 5.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Mud Motor	4.750 – 5.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Mud Motor	5.500 – 5.750"	Annular	5M	-	-
Production casing	5.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Open-hole	-	Blind Rams	10M	-	-

VBR = Variable Bore Ram

## EOG Resources 11" 10M PSI BOP Stack



## 2. Well Control Procedures

Below are the minimal high-level tasks prescribed to assure a proper shut-in while drilling, tripping, running casing, pipe out of the hole (open hole), and moving the BHA through the BOPs. At least one well control drill will be performed weekly per crew to demonstrate compliance with the procedure and well control plan. The well control drill will be recorded in the daily drilling log. The type of drill will be determined by the ongoing operations, but reasonable attempts will be made to vary the type of drill conducted (pit, trip, open hole, choke, etc.). This well control plan will be available for review by rig personnel in the EOG Resources drilling supervisor's office on location, and on the rig floor. All BOP equipment will be tested as per Onshore O&G Order No. 2 with the exception of the 5000 psi annular which will be tested to 100% of its RWP.

### General Procedure While Drilling

1. Sound alarm (alert crew)
2. Space out drill string
3. Shut down pumps (stop pumps and rotary)
4. Shut-in Well (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
  - a. SIDPP and SICP
  - b. Pit gain
  - c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

### General Procedure While Tripping

1. Sound alarm (alert crew)
2. Stab full opening safety valve and close
3. Space out drill string
4. Shut-in (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
  - a. SIDPP and SICP
  - b. Pit gain
  - c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

### General Procedure While Running Production Casing

1. Sound alarm (alert crew)
2. Stab crossover and full opening safety valve and close
3. Space out string

4. Shut-in (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
  - a. SIDPP and SICP
  - b. Pit gain
  - c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

#### General Procedure With No Pipe In Hole (Open Hole)

1. Sound alarm (alert crew)
2. Shut-in with blind rams. (HCR and choke will already be in the closed position.)
3. Confirm shut-in
4. Notify toolpusher/company representative
5. Read and record the following:
  - a. SICP
  - b. Pit gain
  - c. Time
6. Regroup and identify forward plan

#### General Procedures While Pulling BHA thru Stack

1. PRIOR to pulling last joint of drillpipe thru the stack.
  - a. Perform flowcheck, if flowing:
  - b. Sound alarm (alert crew)
  - c. Stab full opening safety valve and close
  - d. Space out drill string with tool joint just beneath the upper variable bore rams.
  - e. Shut-in using upper variable bore rams. (HCR and choke will already be in the closed position.)
  - f. Confirm shut-in
  - g. Notify toolpusher/company representative
  - h. Read and record the following:
    - i. SIDPP and SICP
    - ii. Pit gain
    - iii. Time
  - i. Regroup and identify forward plan
2. With BHA in the stack and compatible ram preventer and pipe combo immediately available.
  - a. Sound alarm (alert crew)
  - b. Stab crossover and full opening safety valve and close
  - c. Space out drill string with upset just beneath the upper variable bore rams.
  - d. Shut-in using upper variable bore rams. (HCR and choke will already be in the closed position.)
  - e. Confirm shut-in
  - f. Notify toolpusher/company representative
  - g. Read and record the following:
    - i. SIDPP and SICP

- ii. Pit gain
    - iii. Time
  - h. Regroup and identify forward plan
- 3. With BHA in the stack and NO compatible ram preventer and pipe combo immediately available.
  - a. Sound alarm (alert crew)
  - b. If possible to pick up high enough, pull string clear of the stack and follow “Open Hole” scenario.
  - c. If impossible to pick up high enough to pull the string clear of the stack:
  - d. Stab crossover, make up one joint/stand of drillpipe, and full opening safety valve and close
  - e. Space out drill string with tooljoint just beneath the upper variable bore ram.
  - f. Shut-in using upper variable bore ram. (HCR and choke will already be in the closed position.)
  - g. Confirm shut-in
  - h. Notify toolpusher/company representative
  - i. Read and record the following:
    - i. SIDPP and SICP
    - ii. Pit gain
    - iii. Time
  - j. Regroup and identify forward plan

## 10,000 PSI BOP Annular Variance Request

EOG Resources request a variance to use a 5000 psi annular BOP with a 10,000 psi BOP stack. The component and compatibility tables along with the general well control plans demonstrate how the 5000 psi annular BOP will be protected from pressures that exceed its rated working pressure (RWP). The pressure at which the control of the wellbore is transferred from the annular preventer to another available preventer will not exceed 3500 psi (70% of the RWP of the 5000 psi annular BOP).

### 1. Component and Preventer Compatibility Tables

The tables below outlines the tubulars and the compatible preventers in use. This table, combined with the drilling fluid, documents that two barriers to flow will be maintained at all times.

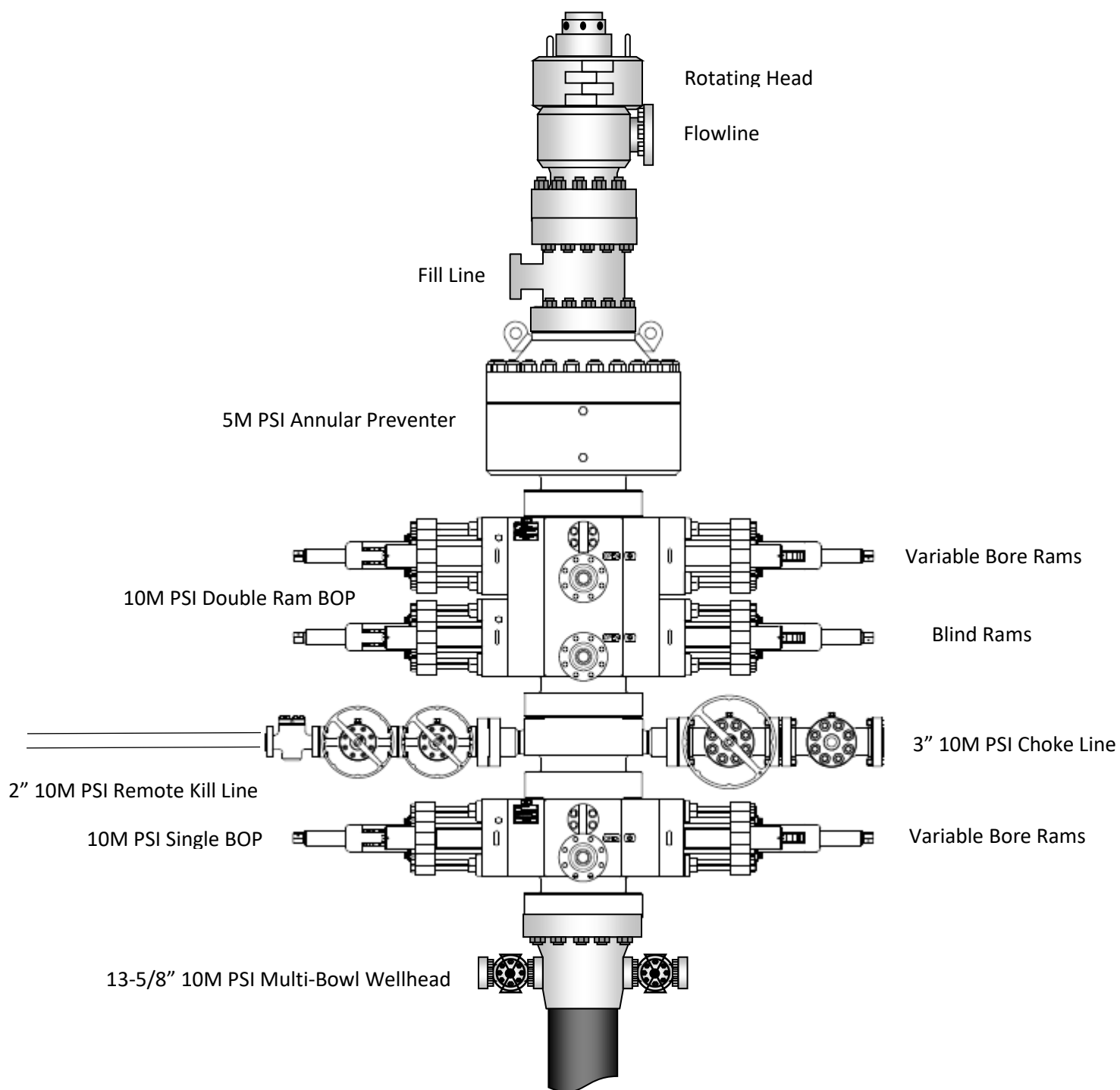
12-1/4" Intermediate Hole Section 10M psi requirement					
Component	OD	Primary Preventer	RWP	Alternate Preventer(s)	RWP
Drillpipe	5.000" or 4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
HWDP	5.000" or 4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Jars	6.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
DCs and MWD tools	6.500" – 8.000"	Annular	5M	-	-
Mud Motor	8.000" – 9.625"	Annular	5M	-	-
1 <sup>st</sup> Intermediate casing	9.625"	Annular	5M	-	-
Open-hole	-	Blind Rams	10M	-	-

8-3/4" Intermediate Hole Section 10M psi requirement					
Component	OD	Primary Preventer	RWP	Alternate Preventer(s)	RWP
Drillpipe	5.000" or 4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
HWDP	5.000" or 4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Jars	6.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
DCs and MWD tools	6.500" – 8.000"	Annular	5M	-	-
Mud Motor	6.750" – 8.000"	Annular	5M	-	-
2 <sup>nd</sup> Intermediate casing	7.625"	Annular	5M	-	-
Open-hole	-	Blind Rams	10M	-	-

6-3/4" Production Hole Section 10M psi requirement					
Component	OD	Primary Preventer	RWP	Alternate Preventer(s)	RWP
Drillpipe	4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
HWDP	4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
DCs and MWD tools	4.750" – 5.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Mud Motor	4.750" – 5.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Mud Motor	5.500" – 5.750"	Annular	5M	-	-
Production casing	5.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Open-hole	-	Blind Rams	10M	-	-

VBR = Variable Bore Ram

## EOG Resources 13-5/8" 10M PSI BOP Stack



## 2. Well Control Procedures

Below are the minimal high-level tasks prescribed to assure a proper shut-in while drilling, tripping, running casing, pipe out of the hole (open hole), and moving the BHA through the BOPs. At least one well control drill will be performed weekly per crew to demonstrate compliance with the procedure and well control plan. The well control drill will be recorded in the daily drilling log. The type of drill will be determined by the ongoing operations, but reasonable attempts will be made to vary the type of drill conducted (pit, trip, open hole, choke, etc.). This well control plan will be available for review by rig personnel in the EOG Resources drilling supervisor's office on location, and on the rig floor. All BOP equipment will be tested as per Onshore O&G Order No. 2 with the exception of the 5000 psi annular which will be tested to 100% of its RWP.

### General Procedure While Drilling

1. Sound alarm (alert crew)
2. Space out drill string
3. Shut down pumps (stop pumps and rotary)
4. Shut-in Well (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
  - a. SIDPP and SICP
  - b. Pit gain
  - c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

### General Procedure While Tripping

1. Sound alarm (alert crew)
2. Stab full opening safety valve and close
3. Space out drill string
4. Shut-in (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
  - a. SIDPP and SICP
  - b. Pit gain
  - c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

### General Procedure While Running Production Casing

1. Sound alarm (alert crew)
2. Stab crossover and full opening safety valve and close
3. Space out string

4. Shut-in (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
  - a. SIDPP and SICP
  - b. Pit gain
  - c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

#### General Procedure With No Pipe In Hole (Open Hole)

1. Sound alarm (alert crew)
2. Shut-in with blind rams. (HCR and choke will already be in the closed position.)
3. Confirm shut-in
4. Notify toolpusher/company representative
5. Read and record the following:
  - a. SICP
  - b. Pit gain
  - c. Time
6. Regroup and identify forward plan

#### General Procedures While Pulling BHA thru Stack

1. PRIOR to pulling last joint of drillpipe thru the stack.
  - a. Perform flowcheck, if flowing:
  - b. Sound alarm (alert crew)
  - c. Stab full opening safety valve and close
  - d. Space out drill string with tool joint just beneath the upper variable bore rams.
  - e. Shut-in using upper variable bore rams. (HCR and choke will already be in the closed position.)
  - f. Confirm shut-in
  - g. Notify toolpusher/company representative
  - h. Read and record the following:
    - i. SIDPP and SICP
    - ii. Pit gain
    - iii. Time
  - i. Regroup and identify forward plan
2. With BHA in the stack and compatible ram preventer and pipe combo immediately available.
  - a. Sound alarm (alert crew)
  - b. Stab crossover and full opening safety valve and close
  - c. Space out drill string with upset just beneath the upper variable bore rams.
  - d. Shut-in using upper variable bore rams. (HCR and choke will already be in the closed position.)
  - e. Confirm shut-in
  - f. Notify toolpusher/company representative
  - g. Read and record the following:
    - i. SIDPP and SICP

- ii. Pit gain
    - iii. Time
  - h. Regroup and identify forward plan
- 3. With BHA in the stack and NO compatible ram preventer and pipe combo immediately available.
  - a. Sound alarm (alert crew)
  - b. If possible to pick up high enough, pull string clear of the stack and follow “Open Hole” scenario.
  - c. If impossible to pick up high enough to pull the string clear of the stack:
  - d. Stab crossover, make up one joint/stand of drillpipe, and full opening safety valve and close
  - e. Space out drill string with tooljoint just beneath the upper variable bore ram.
  - f. Shut-in using upper variable bore ram. (HCR and choke will already be in the closed position.)
  - g. Confirm shut-in
  - h. Notify toolpusher/company representative
  - i. Read and record the following:
    - i. SIDPP and SICP
    - ii. Pit gain
    - iii. Time
  - j. Regroup and identify forward plan



## 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

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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

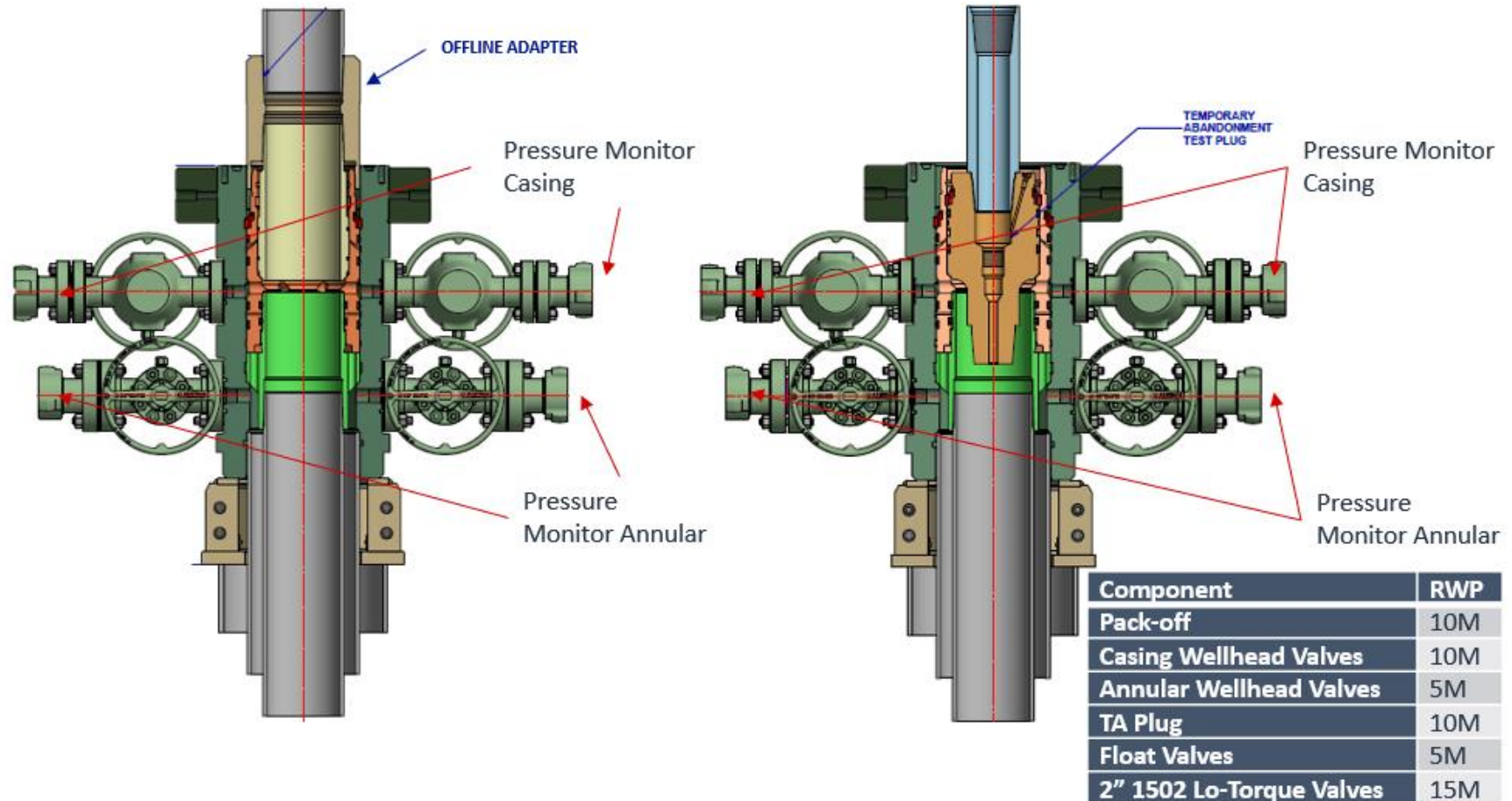
1. Sound alarm (alert crew).
2. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
3. Confirm shut-in.
4. Notify tool pusher/company representative.
5. Read and record the following:
  - a. SICP and AP
  - b. Pit gain
  - c. Time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



## Offline Intermediate Cementing Procedure

2/24/2022

Figure 1: Cameron TA Plug and Offline Adapter Schematic

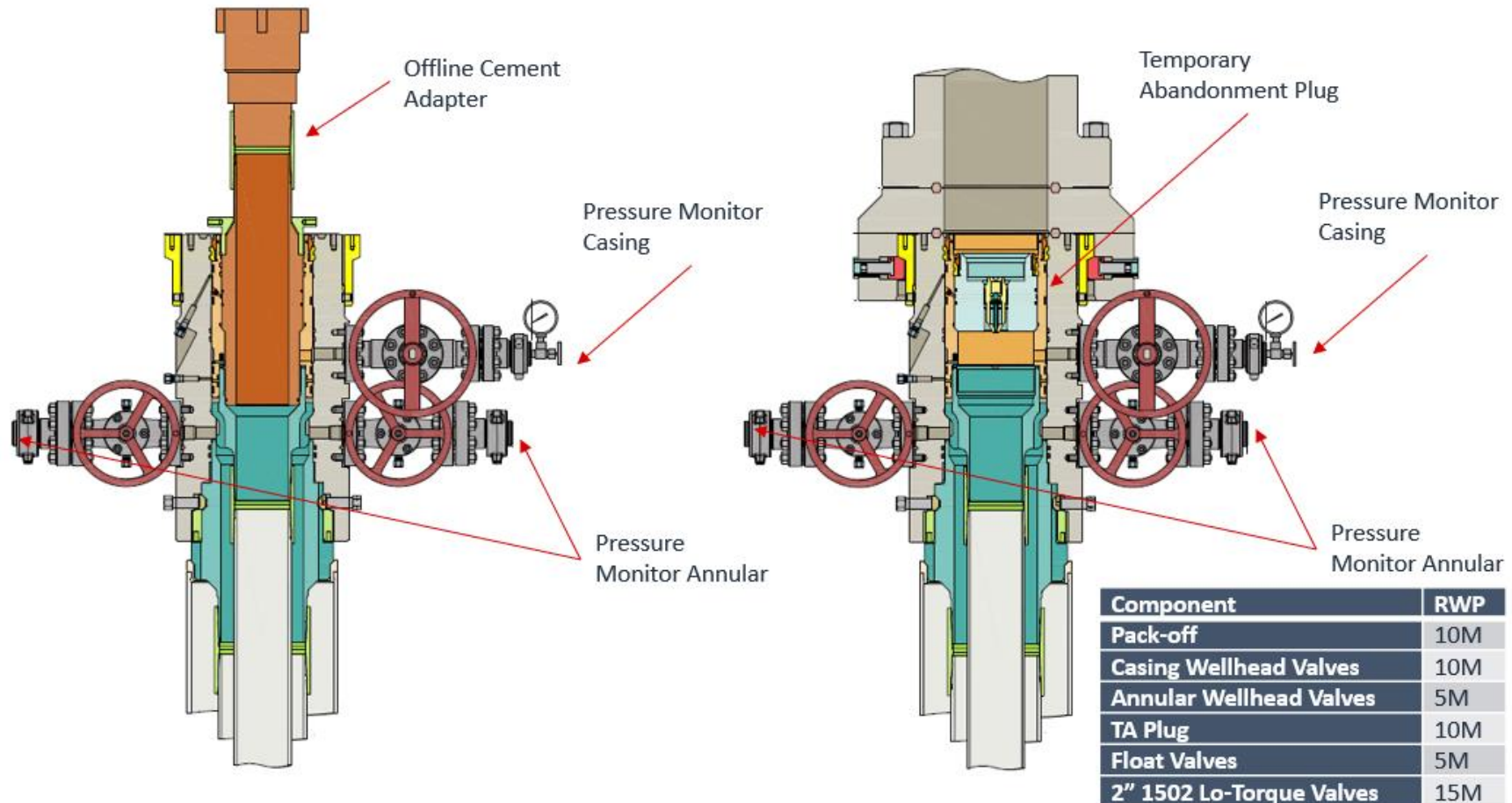




## Offline Intermediate Cementing Procedure

2/24/2022

Figure 2: Cactus TA Plug and Offline Adapter Schematic

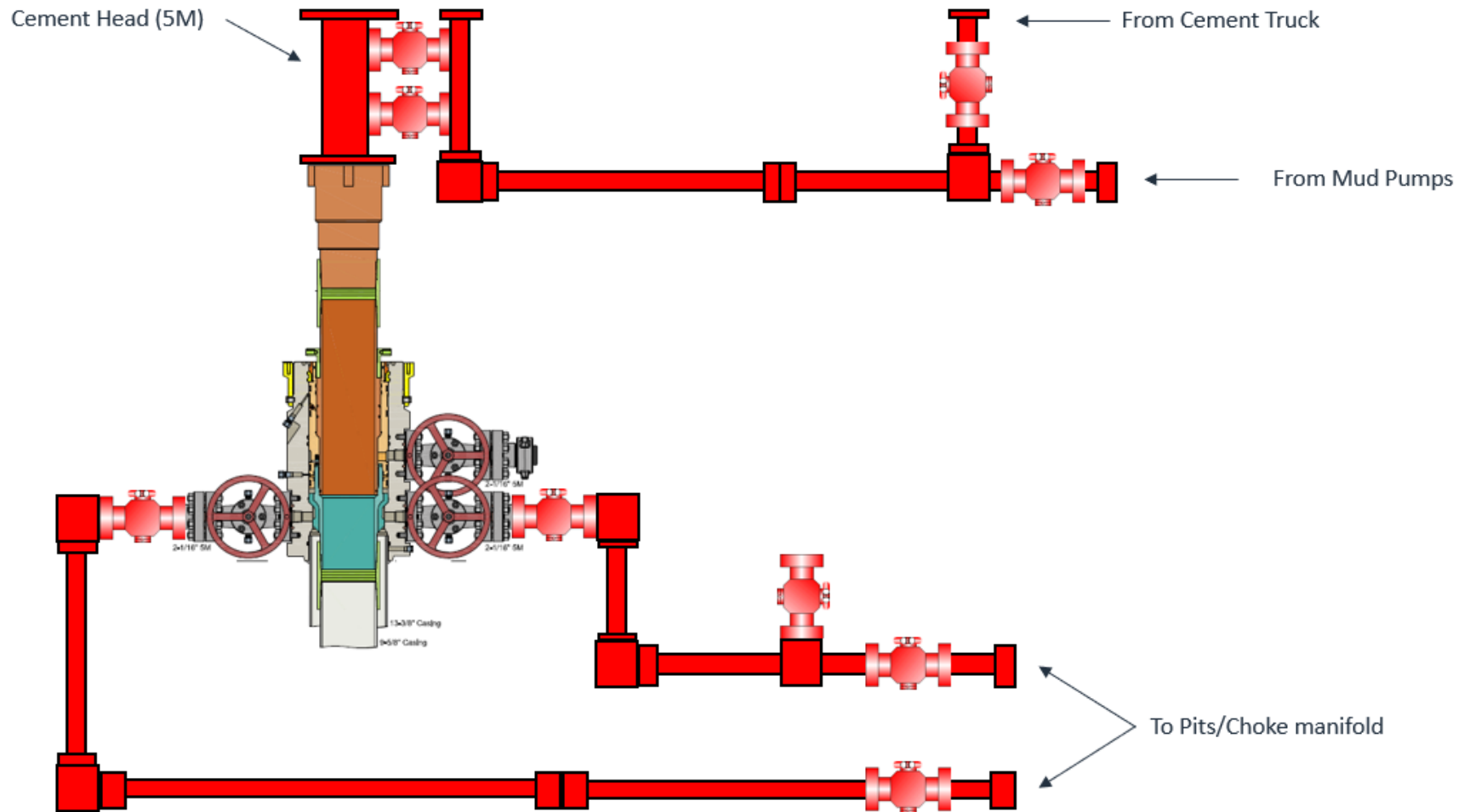




## Offline Intermediate Cementing Procedure

2/24/2022

Figure 3: Back Yard Rig Up



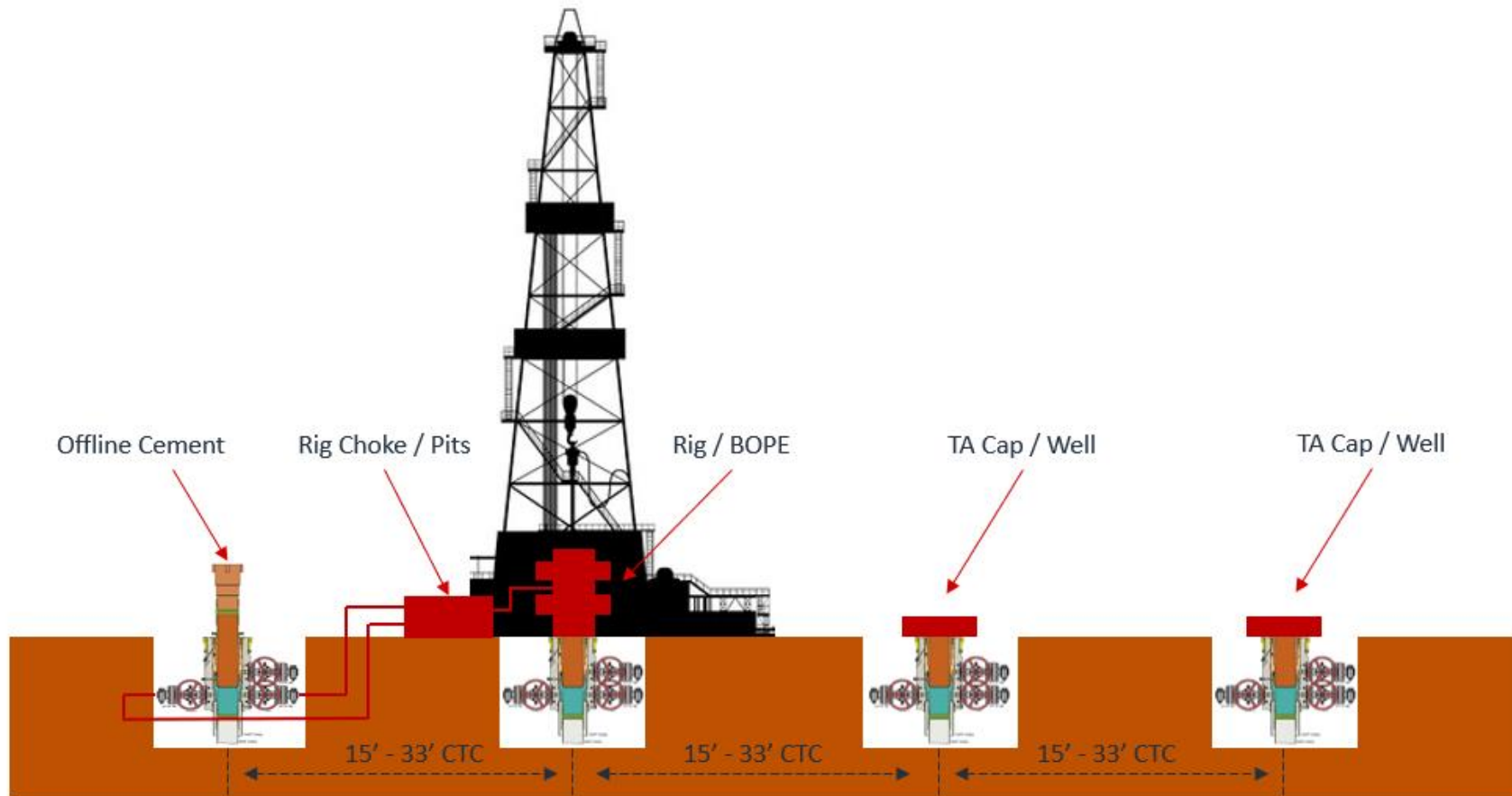
\*\*\* All Lines 10M rated working pressure



Offline Intermediate Cementing Procedure

2/24/2022

Figure 4: Rig Placement Diagram



**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**

CONDITIONS  
  
Action 337312

CONDITIONS

Operator: EOG RESOURCES INC 5509 Champions Drive Midland, TX 79706	OGRID:
	7377
	Action Number: 337312
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

CONDITIONS

Created By	Condition	Condition Date
pkautz	Will require a File As Drilled C-102 and a Directional Survey with the C-104	4/30/2024
pkautz	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	4/30/2024
pkautz	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	4/30/2024
pkautz	Cement is required to circulate on both surface and intermediate1 strings of casing	4/30/2024
pkautz	If cement does not circulate on any string, a CBL is required for that string of casing	4/30/2024