Form 3160-3
(October 2024)

FORM APPROVED
OMB No. 1004-0220
Expires: October 31, 2027

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No.
NMNM77054

6. If Indian, Allotee or Tribe Name

1a. Type of work: ☑ DRILL ☐ REENTER

1b. Type of Well: ☑ Oil Well ☐ Gas Well ☐ Other

1c. Type of Completion: ☐ Hydraulic Fracturing ☑ Single Zone ☐ Multiple Zone

7. If Unit or CA Agreement, Name and No.

8. Lease Name and Well No.
MARGIE 24 FED COM
202H

2. Name of Operator
EOG RESOURCES INCORPORATED

9. API Well No.
30-025-55427

3a. Address
1111 BAGBY SKY LOBBY 2, HOUSTON, TX 77002

3b. Phone No. *(include area code)*
(713) 651-7000

10. Field and Pool, or Exploratory
SALT LAKE; BONE SPRING

4. Location of Well *(Report location clearly and in accordance with any State requirements.*)*
At surface TR D / 358 FNL / 1062 FWL / LAT 32.564942 / LONG -103.724896
At proposed prod. zone TR D / 100 FNL / 1254 FWL / LAT 32.594724 / LONG -103.724291

11. Sec., T. R. M. or Blk. and Survey or Area
SEC 24/T20S/R32E/NMP

14. Distance in miles and direction from nearest town or post office*

12. County or Parish
LEA

13. State
NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any)
100 feet

16. No of acres in lease

17. Spacing Unit dedicated to this well
1280.0

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft.
33 feet

19. Proposed Depth
8417 feet / 18656 feet

20. BLM/BIA Bond No. in file
FED: NMB106709157

21. Elevations (Show whether DF, KDB, RT, GL, etc.)
3538 feet

22. Approximate date work will start*
12/25/2025

23. Estimated duration
25 days

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.
2. A Drilling Plan.
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).
4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification.
6. Such other site specific information and/or plans as may be requested by the BLM.

25. Signature
(Electronic Submission)

Name *(Printed/Typed)*
SHEA BAILEY / Ph: (713) 651-7000

Date
11/27/2024

Title
Regulatory Contractor

Approved by *(Signature)*
(Electronic Submission)

Name *(Printed/Typed)*
CODY LAYTON / Ph: (575) 234-5959

Date
10/09/2025

Title
Assistant Field Manager Lands & Minerals

Office
Carlsbad Field 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.

APPROVED WITH CONDITIONS

(Continued on page 2)

Approval Date: 10/09/2025

*(Instructions on page 2)

C-102 Submit Electronically Via OCD Permitting	State of New Mexico Energy, Minerals & Natural Resources Department OIL CONSERVATION DIVISION	Revised July 9, 2024 Submittal Type: ☒ Initial Submittal ☐ Amended Report ☐ As Drilled

Property Name and Well Number

MARGIE 24 FED COM 202H

WELL LOCATION AND ACREAGE DEDICATION PLAT

API Number	Pool Code	Pool Name
30-025- 55427	~~53565~~ 53560	SALT LAKE; BONE SPRING

Property Code	Property Name	Well Number
337849	MARGIE 24 FED COM	202H
OGRID No.	**Operator Name**	**Ground Level Elevation**
7377	EOG RESOURCES, INC.	3538'

Surface Owner: ☐ State ☐ Fee ☐ Tribal ☒ Federal | Mineral Owner: ☒ State ☐ Fee ☐ Tribal ☒ Federal

Surface Location

UL or Lot No.	Section	Township	Range	Lot	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
D	24	20 S	32 E		358 FNL	1062 FWL	N 32.564942°	W 103.724896°	LEA

Bottom Hole Location If Different From Surface

UL or Lot No.	Section	Township	Range	Lot	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
D	12	20 S	32 E		100 FNL	1254 FWL	N 32.594724°	W 103.724291°	LEA

Dedicated Acres	Infill or Defining Well	Defining Well API	Overlapping Spacing Unit (Y/N)	Consolidated Code
1280	INFILL	PENDING: MARGIE 24 FED COM 203H	N	C

Order Numbers: NSP AND COM PENDING | Well Setbacks are under Common Ownership: ☐ Yes ☐ No

Kick Off Point (KOP)

UL or lot no.	Section	Township	Range	Lot	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
M	13	20 S	32 E		50 FSL	1254 FWL	N 32.566062°	W 103.724275°	LEA

First Take Point (FTP)

UL or lot no.	Section	Township	Range	Lot	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
M	13	20 S	32 E		100 FSL	1254 FWL	N 32.566199°	W 103.724276°	LEA

Last Take Point (LTP)

UL or lot no.	Section	Township	Range	Lot	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
D	12	20 S	32 E		100 FNL	1254 FWL	N 32.594724°	W 103.724291°	LEA

Unitized Area or Area of Uniform Interest	Spacing Unity Type	Ground Floor Elevation
COM AGREEMENT	☒ Horizontal ☐ Vertical	3563'

OPERATOR CERTIFICATION

I hereby certify that the information contained herein is true and complete to the best of my knowledge and belief; and, if the well is a vertical or directional well, that this organization either owns a working interest or unleased mineral interest in the land including the proposed bottom hole location or has a right to drill this well at this location pursuant to a contract with an owner of a working interest or unleased mineral interest, or to a voluntary pooling agreement or a compulsory pooling order heretofore entered by the division.

If this well is a horizontal well, I further certify that this organization has received The consent of at least one lessee or owner of a working interest or unleased mineral interest in each tract (in the target pool or formation) in which any part of the well's completed interval will be located or obtained a compulsory pooling order from the division.

Shea Bailey — 11/25/24

Signature — Date

Shea Bailey

Print Name

shea_bailey@eogresources.com

E-mail Address

SURVEYORS CERTIFICATION

MITCHELL L. McDONALD
NEW MEXICO
29821
PROFESSIONAL SURVEYOR
Mitchell L. McDonald
09/25/2024

Signature and Seal of Professional Surveyor — Date

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true and correct to the best of my belief.

MITCHELL L. MCDONALD, N.M. P.L.S.

Certificate Number	Date of Survey
29821	AUGUST 26, 2024

Note: 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.

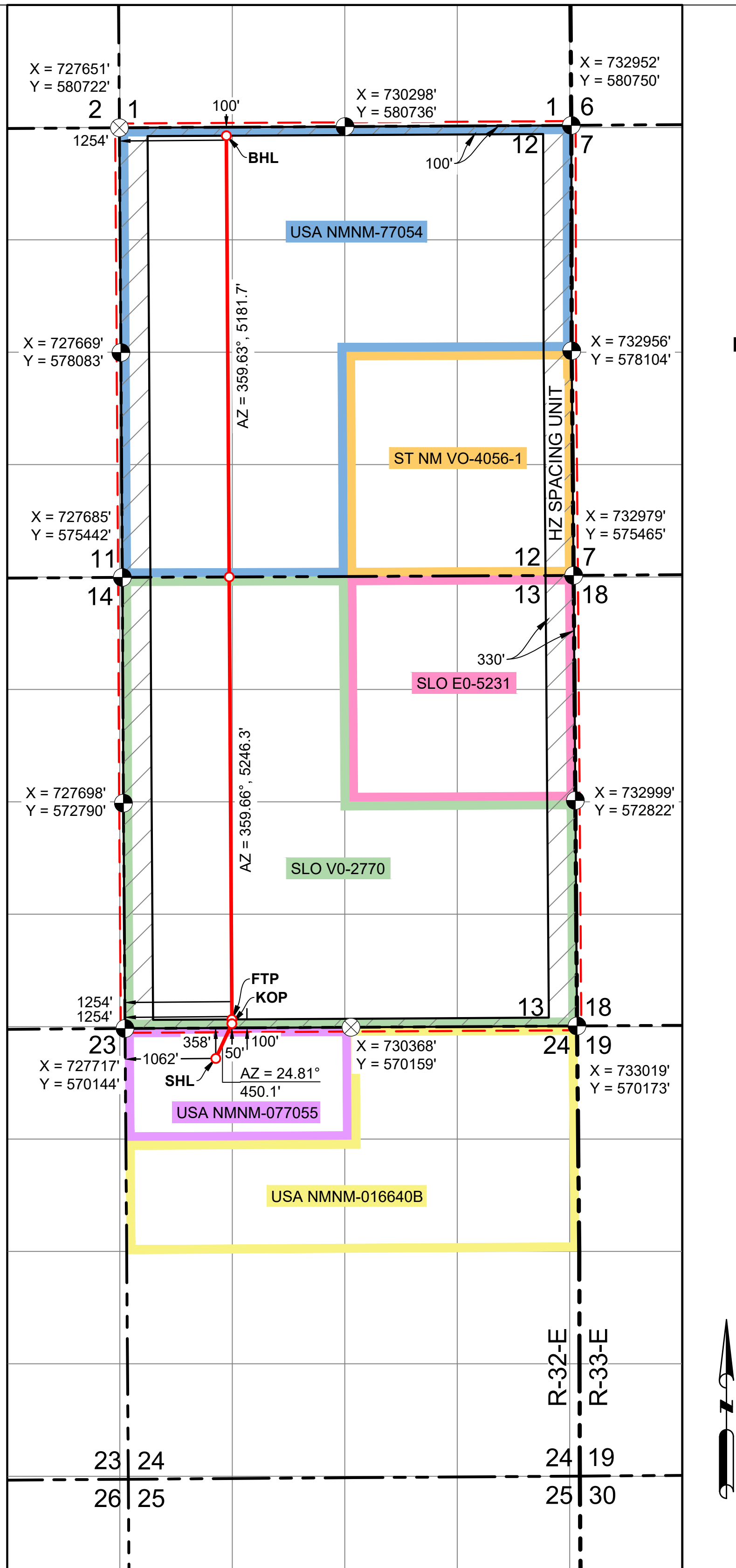
C-102 Submit Electronically Via OCD Permitting	State of New Mexico Energy, Minerals & Natural Resources Department OIL CONSERVATION DIVISION	Revised July 9, 2024 Submittal Type: ☒ Initial Submittal ☐ Amended Report ☐ As Drilled

Property Name and Well Number

MARGIE 24 FED COM 202H

SURFACE LOCATION
NEW MEXICO EAST
NAD 1983
X=728782' Y=569792'
LAT=N32.564942°
LONG=W103.724896°
NAD 1927
X=687601' Y=569730'
LAT=N32.564820°
LONG=W103.724400°
358' FNL 1062' FWL

KOP LOCATION
NEW MEXICO EAST
NAD 1983
X=728971' Y=570201'
LAT=N32.566062°
LONG=W103.724275°
NAD 1927
X=687790' Y=570139'
LAT=N32.565940°
LONG=W103.723780°
50' FSL 1254' FWL



FIRST TAKE POINT
NEW MEXICO EAST
NAD 1983
X=728970' Y=570251'
LAT=N32.566199°
LONG=W103.724276°
NAD 1927
X=687790' Y=570189'
LAT=N32.566077°
LONG=W103.723780°
100' FSL 1254' FWL

LOWER MOST PERF./ BOTTOM HOLE LOCATION
NEW MEXICO EAST
NAD 1983
X=728906' Y=580629'
LAT=N32.594724°
LONG=W103.724291°
NAD 1927
X=687726' Y=580566'
LAT=N32.594603°
LONG=W103.723795°
100' FNL 1254' FWL

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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:** 10/17/2025

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
MARGIE 24 FED COM 202H		D-24-20S-32E	358' FNL & 1062' FWL	+/- 1000	+/- 3500	+/- 3000

IV. Central Delivery Point Name: ___Pretty Good 20 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
MARGIE 24 FED COM 202H		1/10/26	1/25/26	4/01/26	5/01/26	6/01/26

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: Star L Harrell
Printed Name: Star L Harrell
Title: Regulatory Advisor
E-mail Address: Star_Harrell@eogresources.com
Date: 10/17/2025
Phone: (432) 848-9161

OIL CONSERVATION DIVISION **(Only applicable when submitted as a standalone form)**
Approved By:
Title:
Approval Date:
Conditions of Approval:

Natural Gas Management Plan
Items VI-VIII

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

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

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

Drilling Operations

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

Completions/Recompletions Operations

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

Production Operations

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

Performance Standards

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

Measurement & Estimation

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

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

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

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

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Margie 24 Fed Com 202H

1. GEOLOGIC NAME OF SURFACE FORMATION:

Permian

2. ESTIMATED TOPS OF IMPORTANT GEOLOGICAL MARKERS:

Rustler	1,136'
Tamarisk Anhydrite	1,222'
Top of Salt	1,511'
Marker Bed 126	2,030'
Tansill	3,174'
Yates	3,307'
Capitan	3,694'
Cherry Canyon	4,961'
Brushy Canyon	6,187'
Bone Spring Lime	7,883'
Leonard (Avalon) Shale	7,984'
1st Bone Spring Sand	8,911'
2nd Bone Spring Shale	9,221'
2nd Bone Spring Sand	9,464'
3rd Bone Spring Carb	10,119'
3rd Bone Spring Sand	10,529'
Wolfcamp	10,925'
TD	8,417'

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

Upper Permian Sands	0- 400’	Fresh Water
Yates	3,307'	Oil
Cherry Canyon	4,961'	Oil
Brushy Canyon	6,187'	Oil
Bone Spring Lime	7,883'	Oil
Leonard (Avalon) Shale	7,984'	Oil
1st Bone Spring Sand	8,911'	Oil
2nd Bone Spring Shale	9,221'	Oil
2nd Bone Spring Sand	9,464'	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 13-3/8" casing at 1,161' and circulating cement back to surface.

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4. CASING PROGRAM

Hole Size	Interval MD From (ft)	Interval MD To (ft)	Interval TVD From (ft)	Interval TVD To (ft)	Csg OD	Weight	Grade	Conn
16"	0	1,206	0	1,206	13-3/8"	54.5#	J-55	STC
12-1/4"	0	3,242	0	3,224	10-3/4"	45.5#	HCL80	BTC-SC
9-7/8"	0	5,029	0	5,011	8-5/8"	32#	P110-HSCY	GB TBD 9.03
7-7/8"	0	7,958	0	7,940	6"	24.5#	ICYP-110	TXP BTC
7-7/8"	7,958	18,658	7,940	8,417	5-1/2"	20#	P110-EC	DWC/C IS MS
**For highlighted rows above, variance is requested to run entire string of either 6" or 5-1/2" casing string above due to availablility.								

Hole will be full during casing run for well control and tensile SF factor. Casing will be kept at least half full during run for this design to meet BLM collapse SF requirement. External pressure will be reviewed prior to conducting casing pressure tests to ensure that 70% of the yield is not exceeded.

Well is in the KPLA. EOG is aware of the updates to the KPLA requirements resulting in Order R-111-Q, and plans to comply with Order R-111-Q. EOG will monitor and meet the anticollision requirements of R-111-Q. EOG will also monitor the production by 2nd intermediate annulus during frac operations as per design specifications in the Order.

5. CEMENTING PROGRAM:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,206' 13-3/8"	310	13.2	1.73	Lead: Class C/H + Additives (TOC @ Surface)
	80	14.8	1.34	Tail: Class C/H + Additives (TOC @ 965' TVD)
3,224' 10-3/4"	2037	12.7	1.11	Lead: Class C/H + Additives (High Sulface Resistance slurry, min 10% BWOW Salt) + Expansive Additives (TOC @ Surface)
	335	14.8	1.50	Tail: Class C /H + Additives (High Sulface Resistance slurry, min 10% BWOW Salt) + Expansive Additives (TOC @ 2,579' TVD)
5,011' 8-5/8"	687	14.2	1.11	1st Stage (Tail): Class C/H + Additives + Expansive Additives (TOC @ 4,009')
	152	14.8	1.50	2nd Stage: Class C/H + Additives + Expansion Additives (TOC @ surface)
18,658' 6"x5-1/2"	1357	13.2	1.52	Class C/H + Additives (TOC @ 7,833' - NO EXCESS)

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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

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.

6. **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.

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.

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Margie 24 Fed Com 202H

7. 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 – 1,206' Surface	Fresh - Gel	8.6-8.8	28-34	N/c
1,206' – 3,224' 1st Int.	Brine	8.6-10.2	28-34	N/c
3,224' - 5,011' 2nd Int.	Fresh - Gel	8.6-9.2	28-34	N/c - 6
5,011' TVD – 18,658' MD Lateral	Oil Base	8.8-9.5	58-68	N/c - 6

Drill fluid for the 1st intermediate section will consist of water with suficient salts added to completely saturate the fluid, to prevent enlarged bore holes.

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.

8. 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) H2S monitoring and detection equipment will be utilized from surface casing point to TD.

9. 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.

10. ABNORMAL CONDITIONS, PRESSURES, TEMPERATURES AND POTENTIAL HAZARDS:

The estimated bottom-hole temperature (BHT) at TD is 154 degrees F with an estimated maximum bottom-hole pressure (BHP) at TD of 3,939 psig and a maximum anticipated surface pressure of 2,087 psig (based on 9.0 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 6,187' to intermediate casing point.

eog resources

Margie 24 Fed Com 202H

11. 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.

12. WELLHEAD:

A multi-bowl wellhead system will be utilized.

After running the surface casing, a 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 Title 43 CFR Part 3170.

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.

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 Title 43 CFR Part 3170 to at least 0.22 psi/ft or 1,500 psi, whichever is greater.

13. TUBING REQUIREMENTS

EOG respectively requests an exception to the following NMOCD rule:

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

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

14. VARIANCE REQUESTS:

EOG requests the additional variance(s) in the attached document(s):

- Break-test BOP and Offline Cementing: see attached "EOG BLM Variance 3a_b - BOP Break-test and Offline Intermediate Cement 8.15.2023" document
- Production Offline Cement - EOG BLM Variance 3d document

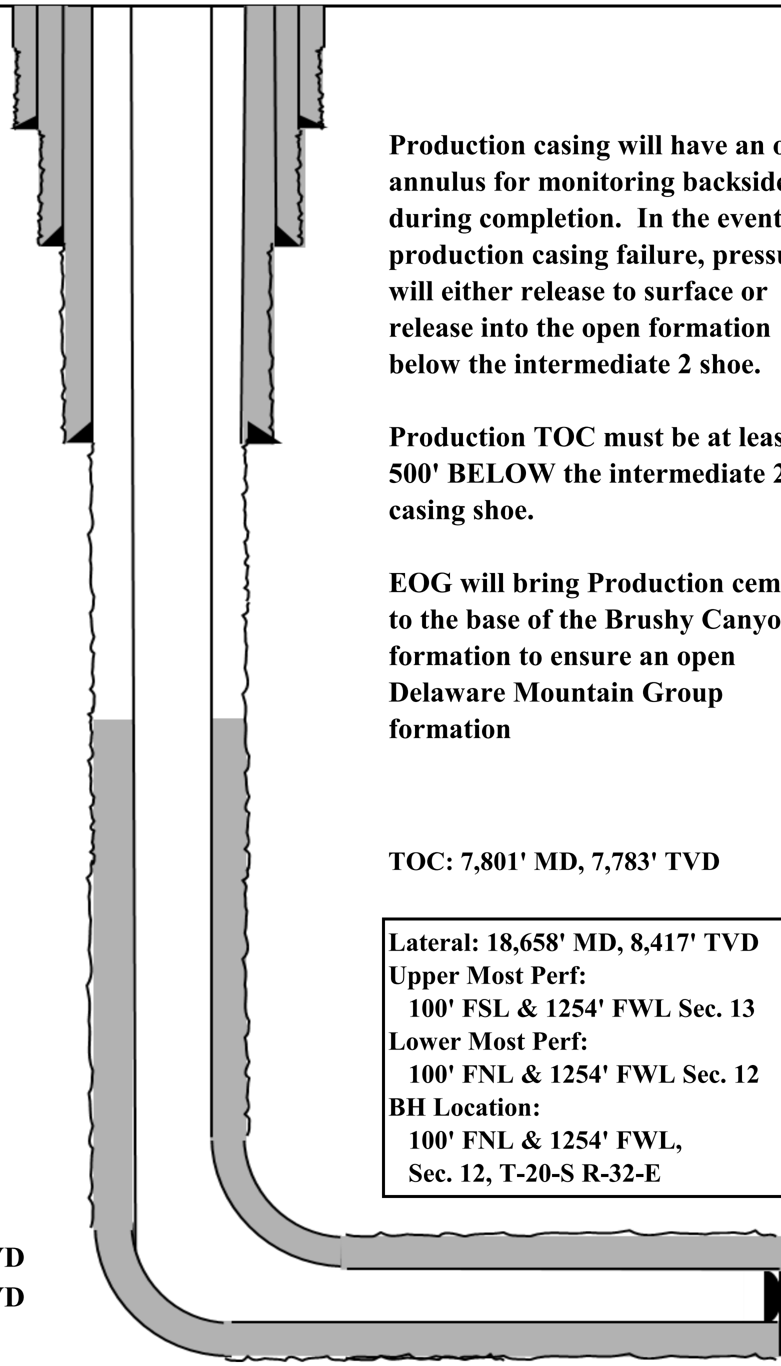
Margie 24 Fed Com 202H

358' FNL
1062' FWL
Section 24
T-20-S, R-32-E

Proposed Wellbore

API: 30-025-***

KB: 3563'
GL: 3538'



Bit Size: 16"
13-3/8", 54.5#, J-55, STC
@ 0' - 1,206' MD
@ 0' - 1,206' TVD

Bit Size: 12-1/4"
10-3/4", 45.5#, HCL80, BTC-SC
@ 0' - 3,242' MD
@ 0' - 3,224' TVD

Bit Size: 9-7/8"
8-5/8", 32#, P110-HSCY, GB TBD 9.03
@ 0' - 5,029' MD
@ 0' - 5,011' TVD

Bit Size: 7-7/8"
6", 24.5#, ICYP-110, TXP BTC
@ 0' - 7,958' MD
@ 0' - 7,940' TVD
5-1/2", 20.#, P110-EC, DWC/C IS MS
@ 7,958' - 18,658' MD

KOP: 7,958' MD, 7,940' TVD
EOC: 8,708' MD, 8,417' TVD

Production casing will have an open annulus for monitoring backside during completion. In the event of a production casing failure, pressure will either release to surface or release into the open formation below the intermediate 2 shoe.

Production TOC must be at least 500' BELOW the intermediate 2 casing shoe.

EOG will bring Production cement to the base of the Brushy Canyon formation to ensure an open Delaware Mountain Group formation

TOC: 7,801' MD, 7,783' TVD

Lateral: 18,658' MD, 8,417' TVD
Upper Most Perf:
100' FSL & 1254' FWL Sec. 13
Lower Most Perf:
100' FNL & 1254' FWL Sec. 12
BH Location:
100' FNL & 1254' FWL,
Sec. 12, T-20-S R-32-E

Midland

Lea County, NM (NAD 83 NME)
Margie 24 Fed Com
#202H

OH

Plan: Plan #0.1 RT

Standard Planning Report

07 May, 2025

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #202H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3564.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3564.0usft
Site:	Margie 24 Fed Com	**North Reference:**	Grid
Well:	#202H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

Project	Lea County, NM (NAD 83 NME)		
Map System:	US State Plane 1983	**System Datum:**	Mean Sea Level
Geo Datum:	North American Datum 1983		
Map Zone:	New Mexico Eastern Zone		

Site	Margie 24 Fed Com				
Site Position:		**Northing:**	569,792.00 usft	**Latitude:**	32° 33' 53.789 N
From:	Map	**Easting:**	728,767.00 usft	**Longitude:**	103° 43' 29.797 W
Position Uncertainty:	0.0 usft	**Slot Radius:**	13-3/16 "		

Well	#202H					
Well Position	**+N/-S**	0.0 usft	**Northing:**	569,792.00 usft	**Latitude:**	32° 33' 53.788 N
	+E/-W	0.0 usft	**Easting:**	728,782.00 usft	**Longitude:**	103° 43' 29.622 W
Position Uncertainty		0.0 usft	**Wellhead Elevation:**	usft	**Ground Level:**	3,538.0 usft
Grid Convergence:		0.33 °				

Wellbore OH

Magnetics	Model Name	Sample Date	Declination (°)	Dip Angle (°)	Field Strength (nT)
	IGRF2020	11/5/2024	6.25	60.07	47,325.34354839

Design Plan #0.1 RT

Audit Notes:

Version:		**Phase:**	PLAN	**Tie On Depth:**	0.0

Vertical Section:	Depth From (TVD) (usft)	+N/-S (usft)	+E/-W (usft)	Direction (°)
	0.0	0.0	0.0	0.66

Plan Survey Tool Program **Date** 5/7/2025

	Depth From (usft)	Depth To (usft)	Survey (Wellbore)	Tool Name	Remarks
1	0.0	18,658.3	Plan #0.1 RT (OH)	EOG MWD+IFR1 MWD + IFR1	

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #202H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3564.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3564.0usft
Site:	Margie 24 Fed Com	**North Reference:**	Grid
Well:	#202H	**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	
2,100.0	0.00	0.00	2,100.0	0.0	0.0	0.00	0.00	0.00	0.00	
2,333.8	4.68	24.80	2,333.5	8.7	4.0	2.00	2.00	0.00	24.80	
7,627.4	4.68	24.80	7,609.5	400.3	185.0	0.00	0.00	0.00	0.00	
7,861.1	0.00	0.00	7,843.0	409.0	189.0	2.00	-2.00	0.00	180.00	
7,957.6	0.00	0.00	7,939.5	409.0	189.0	0.00	0.00	0.00	0.00	KOP(Margie 24 Fed C
8,178.1	26.46	358.85	8,152.2	459.0	188.0	12.00	12.00	-0.52	358.85	FTP(Margie 24 Fed C
8,707.6	90.00	359.66	8,416.9	886.4	183.6	12.00	12.00	0.15	0.90	
18,658.3	90.00	359.66	8,417.0	10,837.0	124.0	0.00	0.00	0.00	0.00	PBHL(Margie 24 Fed

eog resources

Planning Report

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Site:	Margie 24 Fed Com	**North Reference:**	Grid
Well:	#202H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	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	0.00	0.00	1,500.0	0.0	0.0	0.0	0.00	0.00	0.00
1,600.0	0.00	0.00	1,600.0	0.0	0.0	0.0	0.00	0.00	0.00
1,700.0	0.00	0.00	1,700.0	0.0	0.0	0.0	0.00	0.00	0.00
1,800.0	0.00	0.00	1,800.0	0.0	0.0	0.0	0.00	0.00	0.00
1,900.0	0.00	0.00	1,900.0	0.0	0.0	0.0	0.00	0.00	0.00
2,000.0	0.00	0.00	2,000.0	0.0	0.0	0.0	0.00	0.00	0.00
2,100.0	0.00	0.00	2,100.0	0.0	0.0	0.0	0.00	0.00	0.00
2,200.0	2.00	24.80	2,200.0	1.6	0.7	1.6	2.00	2.00	0.00
2,300.0	4.00	24.80	2,299.8	6.3	2.9	6.4	2.00	2.00	0.00
2,333.8	4.68	24.80	2,333.5	8.7	4.0	8.7	2.00	2.00	0.00
2,400.0	4.68	24.80	2,399.5	13.6	6.3	13.6	0.00	0.00	0.00
2,500.0	4.68	24.80	2,499.2	21.0	9.7	21.1	0.00	0.00	0.00
2,600.0	4.68	24.80	2,598.9	28.4	13.1	28.5	0.00	0.00	0.00
2,700.0	4.68	24.80	2,698.5	35.8	16.5	35.9	0.00	0.00	0.00
2,800.0	4.68	24.80	2,798.2	43.2	19.9	43.4	0.00	0.00	0.00
2,900.0	4.68	24.80	2,897.9	50.6	23.4	50.8	0.00	0.00	0.00
3,000.0	4.68	24.80	2,997.5	58.0	26.8	58.3	0.00	0.00	0.00
3,100.0	4.68	24.80	3,097.2	65.3	30.2	65.7	0.00	0.00	0.00
3,200.0	4.68	24.80	3,196.9	72.7	33.6	73.1	0.00	0.00	0.00
3,300.0	4.68	24.80	3,296.5	80.1	37.0	80.6	0.00	0.00	0.00
3,400.0	4.68	24.80	3,396.2	87.5	40.5	88.0	0.00	0.00	0.00
3,500.0	4.68	24.80	3,495.9	94.9	43.9	95.4	0.00	0.00	0.00
3,600.0	4.68	24.80	3,595.5	102.3	47.3	102.9	0.00	0.00	0.00
3,700.0	4.68	24.80	3,695.2	109.7	50.7	110.3	0.00	0.00	0.00
3,800.0	4.68	24.80	3,794.9	117.1	54.1	117.8	0.00	0.00	0.00
3,900.0	4.68	24.80	3,894.5	124.5	57.6	125.2	0.00	0.00	0.00
4,000.0	4.68	24.80	3,994.2	131.9	61.0	132.6	0.00	0.00	0.00
4,100.0	4.68	24.80	4,093.9	139.3	64.4	140.1	0.00	0.00	0.00
4,200.0	4.68	24.80	4,193.5	146.7	67.8	147.5	0.00	0.00	0.00
4,300.0	4.68	24.80	4,293.2	154.1	71.2	154.9	0.00	0.00	0.00
4,400.0	4.68	24.80	4,392.9	161.5	74.6	162.4	0.00	0.00	0.00
4,500.0	4.68	24.80	4,492.5	168.9	78.1	169.8	0.00	0.00	0.00
4,600.0	4.68	24.80	4,592.2	176.3	81.5	177.3	0.00	0.00	0.00
4,700.0	4.68	24.80	4,691.9	183.7	84.9	184.7	0.00	0.00	0.00
4,800.0	4.68	24.80	4,791.5	191.1	88.3	192.1	0.00	0.00	0.00
4,900.0	4.68	24.80	4,891.2	198.5	91.7	199.6	0.00	0.00	0.00
5,000.0	4.68	24.80	4,990.9	205.9	95.2	207.0	0.00	0.00	0.00
5,100.0	4.68	24.80	5,090.5	213.3	98.6	214.5	0.00	0.00	0.00
5,200.0	4.68	24.80	5,190.2	220.7	102.0	221.9	0.00	0.00	0.00

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Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #202H
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Site:	Margie 24 Fed Com	**North Reference:**	Grid
Well:	#202H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	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	4.68	24.80	5,289.9	228.1	105.4	229.3	0.00	0.00	0.00
5,400.0	4.68	24.80	5,389.5	235.5	108.8	236.8	0.00	0.00	0.00
5,500.0	4.68	24.80	5,489.2	242.9	112.3	244.2	0.00	0.00	0.00
5,600.0	4.68	24.80	5,588.9	250.3	115.7	251.6	0.00	0.00	0.00
5,700.0	4.68	24.80	5,688.5	257.7	119.1	259.1	0.00	0.00	0.00
5,800.0	4.68	24.80	5,788.2	265.1	122.5	266.5	0.00	0.00	0.00
5,900.0	4.68	24.80	5,887.9	272.5	125.9	274.0	0.00	0.00	0.00
6,000.0	4.68	24.80	5,987.5	279.9	129.4	281.4	0.00	0.00	0.00
6,100.0	4.68	24.80	6,087.2	287.3	132.8	288.8	0.00	0.00	0.00
6,200.0	4.68	24.80	6,186.9	294.7	136.2	296.3	0.00	0.00	0.00
6,300.0	4.68	24.80	6,286.5	302.1	139.6	303.7	0.00	0.00	0.00
6,400.0	4.68	24.80	6,386.2	309.5	143.0	311.1	0.00	0.00	0.00
6,500.0	4.68	24.80	6,485.9	316.9	146.5	318.6	0.00	0.00	0.00
6,600.0	4.68	24.80	6,585.5	324.3	149.9	326.0	0.00	0.00	0.00
6,700.0	4.68	24.80	6,685.2	331.7	153.3	333.5	0.00	0.00	0.00
6,800.0	4.68	24.80	6,784.9	339.1	156.7	340.9	0.00	0.00	0.00
6,900.0	4.68	24.80	6,884.5	346.5	160.1	348.3	0.00	0.00	0.00
7,000.0	4.68	24.80	6,984.2	353.9	163.5	355.8	0.00	0.00	0.00
7,100.0	4.68	24.80	7,083.9	361.3	167.0	363.2	0.00	0.00	0.00
7,200.0	4.68	24.80	7,183.5	368.7	170.4	370.6	0.00	0.00	0.00
7,300.0	4.68	24.80	7,283.2	376.1	173.8	378.1	0.00	0.00	0.00
7,400.0	4.68	24.80	7,382.9	383.5	177.2	385.5	0.00	0.00	0.00
7,500.0	4.68	24.80	7,482.5	390.9	180.6	393.0	0.00	0.00	0.00
7,600.0	4.68	24.80	7,582.2	398.3	184.1	400.4	0.00	0.00	0.00
7,627.4	4.68	24.80	7,609.5	400.3	185.0	402.4	0.00	0.00	0.00
7,700.0	3.22	24.80	7,682.0	404.9	187.1	407.0	2.00	-2.00	0.00
7,800.0	1.22	24.80	7,781.9	408.4	188.7	410.5	2.00	-2.00	0.00
7,861.1	0.00	0.00	7,843.0	409.0	189.0	411.1	2.00	-2.00	0.00
7,900.0	0.00	0.00	7,881.9	409.0	189.0	411.1	0.00	0.00	0.00
7,957.6	0.00	0.00	7,939.5	409.0	189.0	411.1	0.00	0.00	0.00
7,975.0	2.08	358.85	7,956.9	409.3	189.0	411.5	12.00	12.00	0.00
8,000.0	5.09	358.85	7,981.8	410.9	189.0	413.0	12.00	12.00	0.00
8,025.0	8.09	358.85	8,006.6	413.7	188.9	415.9	12.00	12.00	0.00
8,050.0	11.09	358.85	8,031.3	417.9	188.8	420.0	12.00	12.00	0.00
8,075.0	14.09	358.85	8,055.7	423.4	188.7	425.5	12.00	12.00	0.00
8,100.0	17.09	358.85	8,079.8	430.1	188.6	432.2	12.00	12.00	0.00
8,125.0	20.09	358.85	8,103.5	438.0	188.4	440.2	12.00	12.00	0.00
8,150.0	23.09	358.85	8,126.7	447.2	188.2	449.4	12.00	12.00	0.00
8,175.0	26.09	358.85	8,149.4	457.6	188.0	459.8	12.00	12.00	0.00
8,178.1	26.46	358.85	8,152.2	459.0	188.0	461.1	12.00	12.00	0.00
8,200.0	29.09	358.94	8,171.6	469.2	187.8	471.3	12.00	12.00	0.39
8,225.0	32.09	359.02	8,193.1	481.9	187.6	484.0	12.00	12.00	0.32
8,250.0	35.09	359.09	8,213.9	495.8	187.3	497.9	12.00	12.00	0.27
8,275.0	38.09	359.15	8,234.0	510.7	187.1	512.8	12.00	12.00	0.24
8,300.0	41.09	359.20	8,253.3	526.6	186.9	528.7	12.00	12.00	0.21
8,325.0	44.09	359.24	8,271.7	543.5	186.7	545.6	12.00	12.00	0.18
8,350.0	47.09	359.29	8,289.2	561.4	186.4	563.5	12.00	12.00	0.16
8,375.0	50.09	359.32	8,305.7	580.1	186.2	582.2	12.00	12.00	0.15
8,400.0	53.09	359.36	8,321.2	599.7	186.0	601.8	12.00	12.00	0.14
8,425.0	56.09	359.39	8,335.7	620.1	185.8	622.1	12.00	12.00	0.13
8,450.0	59.09	359.42	8,349.1	641.2	185.5	643.2	12.00	12.00	0.12
8,475.0	62.09	359.45	8,361.4	662.9	185.3	665.0	12.00	12.00	0.11
8,500.0	65.09	359.47	8,372.5	685.3	185.1	687.4	12.00	12.00	0.10
8,525.0	68.09	359.50	8,382.4	708.3	184.9	710.3	12.00	12.00	0.10

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #202H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3564.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3564.0usft
Site:	Margie 24 Fed Com	**North Reference:**	Grid
Well:	#202H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	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)
8,550.0	71.09	359.52	8,391.1	731.7	184.7	733.8	12.00	12.00	0.10
8,575.0	74.09	359.54	8,398.6	755.5	184.5	757.6	12.00	12.00	0.09
8,600.0	77.09	359.57	8,404.8	779.7	184.3	781.8	12.00	12.00	0.09
8,625.0	80.09	359.59	8,409.8	804.3	184.1	806.3	12.00	12.00	0.09
8,650.0	83.09	359.61	8,413.4	829.0	184.0	831.0	12.00	12.00	0.09
8,675.0	86.09	359.63	8,415.8	853.9	183.8	855.9	12.00	12.00	0.08
8,700.0	89.09	359.65	8,416.9	878.8	183.6	880.9	12.00	12.00	0.08
8,707.6	90.00	359.66	8,416.9	886.4	183.6	888.5	12.00	12.00	0.08
8,800.0	90.00	359.66	8,416.9	978.8	183.0	980.9	0.00	0.00	0.00
8,900.0	90.00	359.66	8,416.9	1,078.8	182.4	1,080.9	0.00	0.00	0.00
9,000.0	90.00	359.66	8,416.9	1,178.8	181.8	1,180.8	0.00	0.00	0.00
9,100.0	90.00	359.66	8,416.9	1,278.8	181.2	1,280.8	0.00	0.00	0.00
9,200.0	90.00	359.66	8,416.9	1,378.8	180.6	1,380.8	0.00	0.00	0.00
9,300.0	90.00	359.66	8,416.9	1,478.8	180.0	1,480.8	0.00	0.00	0.00
9,400.0	90.00	359.66	8,416.9	1,578.8	179.4	1,580.8	0.00	0.00	0.00
9,500.0	90.00	359.66	8,416.9	1,678.8	178.8	1,680.8	0.00	0.00	0.00
9,600.0	90.00	359.66	8,416.9	1,778.8	178.2	1,780.7	0.00	0.00	0.00
9,700.0	90.00	359.66	8,416.9	1,878.8	177.7	1,880.7	0.00	0.00	0.00
9,800.0	90.00	359.66	8,416.9	1,978.8	177.1	1,980.7	0.00	0.00	0.00
9,900.0	90.00	359.66	8,416.9	2,078.8	176.5	2,080.7	0.00	0.00	0.00
10,000.0	90.00	359.66	8,416.9	2,178.8	175.9	2,180.7	0.00	0.00	0.00
10,100.0	90.00	359.66	8,416.9	2,278.8	175.3	2,280.7	0.00	0.00	0.00
10,200.0	90.00	359.66	8,416.9	2,378.8	174.7	2,380.7	0.00	0.00	0.00
10,300.0	90.00	359.66	8,416.9	2,478.8	174.1	2,480.6	0.00	0.00	0.00
10,400.0	90.00	359.66	8,416.9	2,578.8	173.5	2,580.6	0.00	0.00	0.00
10,500.0	90.00	359.66	8,416.9	2,678.8	172.9	2,680.6	0.00	0.00	0.00
10,600.0	90.00	359.66	8,416.9	2,778.8	172.3	2,780.6	0.00	0.00	0.00
10,700.0	90.00	359.66	8,416.9	2,878.8	171.7	2,880.6	0.00	0.00	0.00
10,800.0	90.00	359.66	8,416.9	2,978.8	171.1	2,980.6	0.00	0.00	0.00
10,900.0	90.00	359.66	8,416.9	3,078.8	170.5	3,080.5	0.00	0.00	0.00
11,000.0	90.00	359.66	8,416.9	3,178.8	169.9	3,180.5	0.00	0.00	0.00
11,100.0	90.00	359.66	8,416.9	3,278.8	169.3	3,280.5	0.00	0.00	0.00
11,200.0	90.00	359.66	8,416.9	3,378.8	168.7	3,380.5	0.00	0.00	0.00
11,300.0	90.00	359.66	8,416.9	3,478.8	168.1	3,480.5	0.00	0.00	0.00
11,400.0	90.00	359.66	8,416.9	3,578.8	167.5	3,580.5	0.00	0.00	0.00
11,500.0	90.00	359.66	8,416.9	3,678.8	166.9	3,680.5	0.00	0.00	0.00
11,600.0	90.00	359.66	8,416.9	3,778.8	166.3	3,780.4	0.00	0.00	0.00
11,700.0	90.00	359.66	8,416.9	3,878.8	165.7	3,880.4	0.00	0.00	0.00
11,800.0	90.00	359.66	8,416.9	3,978.8	165.1	3,980.4	0.00	0.00	0.00
11,900.0	90.00	359.66	8,416.9	4,078.8	164.5	4,080.4	0.00	0.00	0.00
12,000.0	90.00	359.66	8,416.9	4,178.8	163.9	4,180.4	0.00	0.00	0.00
12,100.0	90.00	359.66	8,416.9	4,278.8	163.3	4,280.4	0.00	0.00	0.00
12,200.0	90.00	359.66	8,416.9	4,378.8	162.7	4,380.4	0.00	0.00	0.00
12,300.0	90.00	359.66	8,416.9	4,478.8	162.1	4,480.3	0.00	0.00	0.00
12,400.0	90.00	359.66	8,416.9	4,578.8	161.5	4,580.3	0.00	0.00	0.00
12,500.0	90.00	359.66	8,416.9	4,678.8	160.9	4,680.3	0.00	0.00	0.00
12,600.0	90.00	359.66	8,416.9	4,778.8	160.3	4,780.3	0.00	0.00	0.00
12,700.0	90.00	359.66	8,417.0	4,878.8	159.7	4,880.3	0.00	0.00	0.00
12,800.0	90.00	359.66	8,417.0	4,978.8	159.1	4,980.3	0.00	0.00	0.00
12,900.0	90.00	359.66	8,417.0	5,078.8	158.5	5,080.2	0.00	0.00	0.00
13,000.0	90.00	359.66	8,417.0	5,178.8	157.9	5,180.2	0.00	0.00	0.00
13,100.0	90.00	359.66	8,417.0	5,278.8	157.3	5,280.2	0.00	0.00	0.00
13,200.0	90.00	359.66	8,417.0	5,378.8	156.7	5,380.2	0.00	0.00	0.00
13,300.0	90.00	359.66	8,417.0	5,478.8	156.1	5,480.2	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #202H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3564.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3564.0usft
Site:	Margie 24 Fed Com	**North Reference:**	Grid
Well:	#202H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	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	359.66	8,417.0	5,578.8	155.5	5,580.2	0.00	0.00	0.00
13,500.0	90.00	359.66	8,417.0	5,678.8	154.9	5,680.2	0.00	0.00	0.00
13,600.0	90.00	359.66	8,417.0	5,778.8	154.3	5,780.1	0.00	0.00	0.00
13,700.0	90.00	359.66	8,417.0	5,878.7	153.7	5,880.1	0.00	0.00	0.00
13,800.0	90.00	359.66	8,417.0	5,978.7	153.1	5,980.1	0.00	0.00	0.00
13,900.0	90.00	359.66	8,417.0	6,078.7	152.5	6,080.1	0.00	0.00	0.00
14,000.0	90.00	359.66	8,417.0	6,178.7	151.9	6,180.1	0.00	0.00	0.00
14,100.0	90.00	359.66	8,417.0	6,278.7	151.3	6,280.1	0.00	0.00	0.00
14,200.0	90.00	359.66	8,417.0	6,378.7	150.7	6,380.0	0.00	0.00	0.00
14,300.0	90.00	359.66	8,417.0	6,478.7	150.1	6,480.0	0.00	0.00	0.00
14,400.0	90.00	359.66	8,417.0	6,578.7	149.5	6,580.0	0.00	0.00	0.00
14,500.0	90.00	359.66	8,417.0	6,678.7	148.9	6,680.0	0.00	0.00	0.00
14,600.0	90.00	359.66	8,417.0	6,778.7	148.3	6,780.0	0.00	0.00	0.00
14,700.0	90.00	359.66	8,417.0	6,878.7	147.7	6,880.0	0.00	0.00	0.00
14,800.0	90.00	359.66	8,417.0	6,978.7	147.1	6,980.0	0.00	0.00	0.00
14,900.0	90.00	359.66	8,417.0	7,078.7	146.5	7,079.9	0.00	0.00	0.00
15,000.0	90.00	359.66	8,417.0	7,178.7	145.9	7,179.9	0.00	0.00	0.00
15,100.0	90.00	359.66	8,417.0	7,278.7	145.3	7,279.9	0.00	0.00	0.00
15,200.0	90.00	359.66	8,417.0	7,378.7	144.7	7,379.9	0.00	0.00	0.00
15,300.0	90.00	359.66	8,417.0	7,478.7	144.1	7,479.9	0.00	0.00	0.00
15,400.0	90.00	359.66	8,417.0	7,578.7	143.5	7,579.9	0.00	0.00	0.00
15,500.0	90.00	359.66	8,417.0	7,678.7	142.9	7,679.8	0.00	0.00	0.00
15,600.0	90.00	359.66	8,417.0	7,778.7	142.3	7,779.8	0.00	0.00	0.00
15,700.0	90.00	359.66	8,417.0	7,878.7	141.7	7,879.8	0.00	0.00	0.00
15,800.0	90.00	359.66	8,417.0	7,978.7	141.1	7,979.8	0.00	0.00	0.00
15,900.0	90.00	359.66	8,417.0	8,078.7	140.5	8,079.8	0.00	0.00	0.00
16,000.0	90.00	359.66	8,417.0	8,178.7	139.9	8,179.8	0.00	0.00	0.00
16,100.0	90.00	359.66	8,417.0	8,278.7	139.3	8,279.8	0.00	0.00	0.00
16,200.0	90.00	359.66	8,417.0	8,378.7	138.7	8,379.7	0.00	0.00	0.00
16,300.0	90.00	359.66	8,417.0	8,478.7	138.1	8,479.7	0.00	0.00	0.00
16,400.0	90.00	359.66	8,417.0	8,578.7	137.5	8,579.7	0.00	0.00	0.00
16,500.0	90.00	359.66	8,417.0	8,678.7	136.9	8,679.7	0.00	0.00	0.00
16,600.0	90.00	359.66	8,417.0	8,778.7	136.3	8,779.7	0.00	0.00	0.00
16,700.0	90.00	359.66	8,417.0	8,878.7	135.7	8,879.7	0.00	0.00	0.00
16,800.0	90.00	359.66	8,417.0	8,978.7	135.1	8,979.7	0.00	0.00	0.00
16,900.0	90.00	359.66	8,417.0	9,078.7	134.5	9,079.6	0.00	0.00	0.00
17,000.0	90.00	359.66	8,417.0	9,178.7	133.9	9,179.6	0.00	0.00	0.00
17,100.0	90.00	359.66	8,417.0	9,278.7	133.3	9,279.6	0.00	0.00	0.00
17,200.0	90.00	359.66	8,417.0	9,378.7	132.7	9,379.6	0.00	0.00	0.00
17,300.0	90.00	359.66	8,417.0	9,478.7	132.1	9,479.6	0.00	0.00	0.00
17,400.0	90.00	359.66	8,417.0	9,578.7	131.5	9,579.6	0.00	0.00	0.00
17,500.0	90.00	359.66	8,417.0	9,678.7	130.9	9,679.5	0.00	0.00	0.00
17,600.0	90.00	359.66	8,417.0	9,778.7	130.3	9,779.5	0.00	0.00	0.00
17,700.0	90.00	359.66	8,417.0	9,878.7	129.7	9,879.5	0.00	0.00	0.00
17,800.0	90.00	359.66	8,417.0	9,978.7	129.1	9,979.5	0.00	0.00	0.00
17,900.0	90.00	359.66	8,417.0	10,078.7	128.5	10,079.5	0.00	0.00	0.00
18,000.0	90.00	359.66	8,417.0	10,178.7	127.9	10,179.5	0.00	0.00	0.00
18,100.0	90.00	359.66	8,417.0	10,278.7	127.3	10,279.5	0.00	0.00	0.00
18,200.0	90.00	359.66	8,417.0	10,378.7	126.7	10,379.4	0.00	0.00	0.00
18,300.0	90.00	359.66	8,417.0	10,478.7	126.1	10,479.4	0.00	0.00	0.00
18,400.0	90.00	359.66	8,417.0	10,578.7	125.5	10,579.4	0.00	0.00	0.00
18,500.0	90.00	359.66	8,417.0	10,678.7	124.9	10,679.4	0.00	0.00	0.00
18,600.0	90.00	359.66	8,417.0	10,778.7	124.3	10,779.4	0.00	0.00	0.00
18,658.3	90.00	359.66	8,417.0	10,837.0	124.0	10,837.7	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #202H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3564.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3564.0usft
Site:	Margie 24 Fed Com	**North Reference:**	Grid
Well:	#202H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	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)

Design Targets

Target Name - hit/miss target - Shape	Dip Angle (°)	Dip Dir. (°)	TVD (usft)	+N/-S (usft)	+E/-W (usft)	Northing (usft)	Easting (usft)	Latitude	Longitude
KOP(Margie 24 Fed Cor - plan hits target center - Point	0.00	0.00	7,939.5	409.0	189.0	570,201.00	728,971.00	32° 33' 57.825 N	103° 43' 27.386 W
FTP(Margie 24 Fed Con - plan hits target center - Point	0.00	0.00	8,152.2	459.0	188.0	570,251.00	728,970.00	32° 33' 58.319 N	103° 43' 27.395 W
PBHL(Margie 24 Fed Cc - plan hits target center - Point	0.00	0.00	8,417.0	10,837.0	124.0	580,629.00	728,906.00	32° 35' 41.013 N	103° 43' 27.448 W

eog resources

Lea County, NM (NAD 83 NME)

Margie 24 Fed Com #202H

Plan #0.1 RT

Azimuths to Grid North
True North: -0.33°
Magnetic North: 5.92°

Magnetic Field
Strength: 47325.3nT
Dip Angle: 60.07°
Date: 11/5/2024
Model: IGRF2020

To convert a Magnetic Direction to a Grid Direction, Add 5.92°
To convert a Magnetic Direction to a True Direction, Add 6.25° East
To convert a True Direction to a Grid Direction, Subtract 0.33°

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: #202H

3538.0
kb = 26' @ 3564.0usft

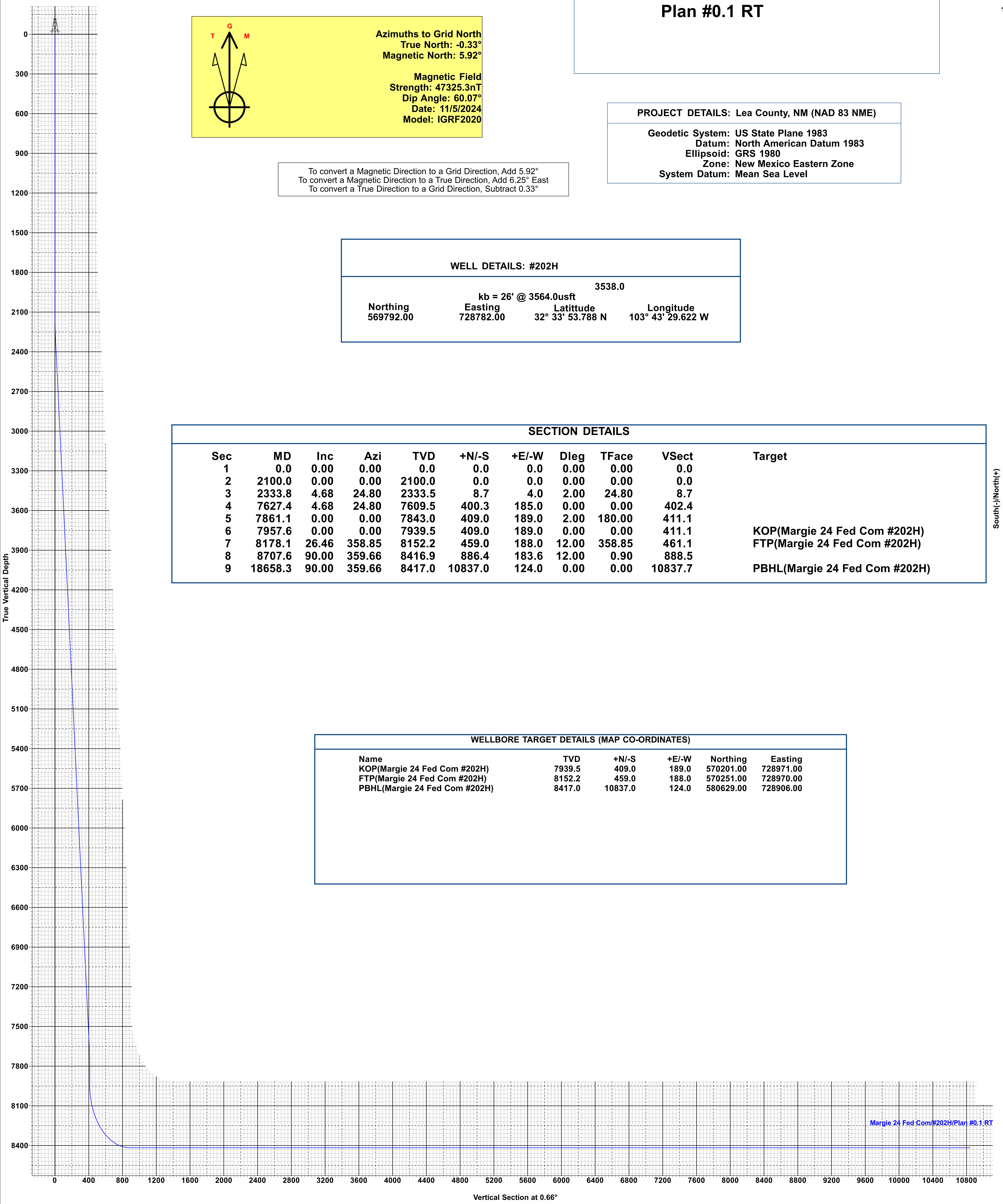
Northing	Easting	Latittude	Longitude
569792.00	728782.00	32° 33' 53.788 N	103° 43' 29.622 W

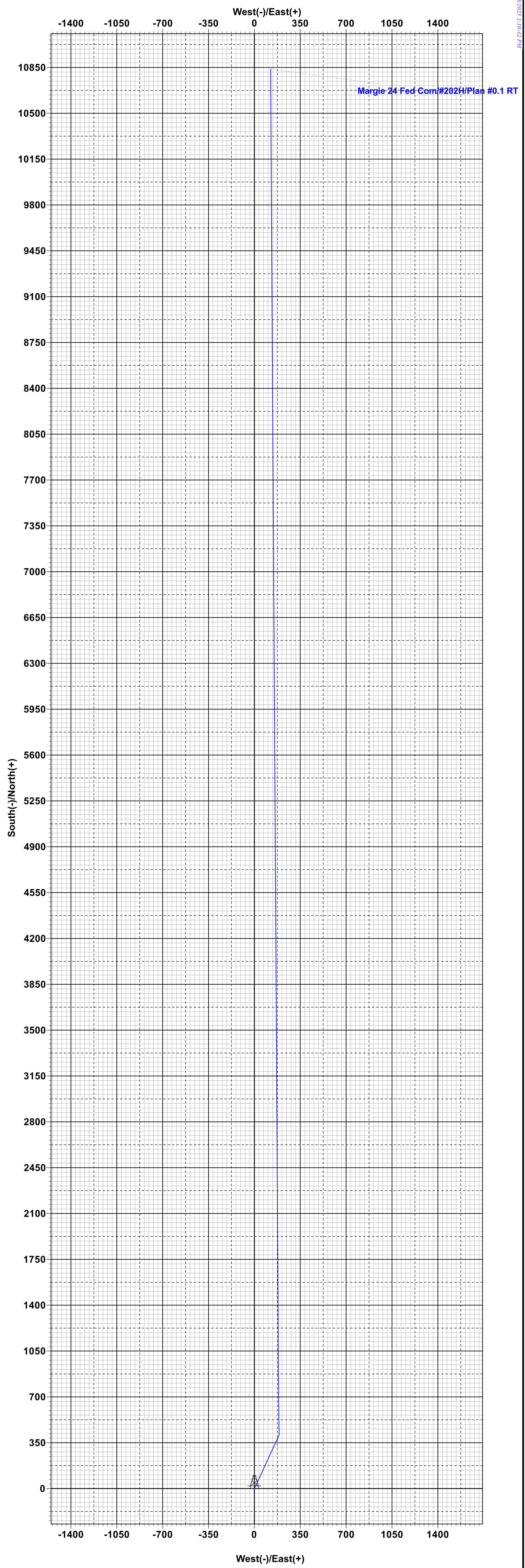
SECTION DETAILS

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	2100.0	0.00	0.00	2100.0	0.0	0.0	0.00	0.00	0.0	
3	2333.8	4.68	24.80	2333.5	8.7	4.0	2.00	24.80	8.7	
4	7627.4	4.68	24.80	7609.5	400.3	185.0	0.00	0.00	402.4	
5	7861.1	0.00	0.00	7843.0	409.0	189.0	2.00	180.00	411.1	
6	7957.6	0.00	0.00	7939.5	409.0	189.0	0.00	0.00	411.1	KOP(Margie 24 Fed Com #202H)
7	8178.1	26.46	358.85	8152.2	459.0	188.0	12.00	358.85	461.1	FTP(Margie 24 Fed Com #202H)
8	8707.6	90.00	359.66	8416.9	886.4	183.6	12.00	0.90	888.5	
9	18658.3	90.00	359.66	8417.0	10837.0	124.0	0.00	0.00	10837.7	PBHL(Margie 24 Fed Com #202H)

WELLBORE TARGET DETAILS (MAP CO-ORDINATES)

Name	TVD	+N/-S	+E/-W	Northing	Easting
KOP(Margie 24 Fed Com #202H)	7939.5	409.0	189.0	570201.00	728971.00
FTP(Margie 24 Fed Com #202H)	8152.2	459.0	188.0	570251.00	728970.00
PBHL(Margie 24 Fed Com #202H)	8417.0	10837.0	124.0	580629.00	728906.00





Lea County, NM (NAD 83 NME)
Margie 24 Fed Com
#202H
OH
Plan #0.1 RT
8:58, May 07 2025

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	EOG RESOURCES INC.
WELL NAME & NO.:	MARGIE 24 FED COM 202H
LOCATION:	SEC24 T20S R32E-NMP
COUNTY:	Lea County, New Mexico

Create COAs

H_2S	**Cave / Karst**	**Waste Prevention Rule**
Present	Medium	Waste Minimization Plan
Potash	**R-111-Q Design**	
R-111-Q	4-String: Open 2nd Int x Production (ICP 2 above Relief Zone)	
Wellhead	**Casing**	
Multibowl	4-String Well	
	☐ Liner ☐ Fluid Filled ☐ Casing Clearance	
☑ Flex Hose ☑ Break Testing	**Cementing**	
	☐ DV Tool ☑ Bradenhead ☐ Echometer	
	☑ Offline Cement ☑ Open Annulus ☐ Pilot Hole	
Special Requirements		
☑ Capitan Reef ☐ Water Disposal ☑ COM ☐ Unit		

A. HYDROGEN SULFIDE

A Hydrogen Sulfide (H_2S) Drilling Plan shall be activated AT SPUD. As a result, the Hydrogen Sulfide area must meet all requirements from 43 CFR 3176, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

APD is within the R-111-Q defined boundary. Operator must follow all procedures and requirements listed within the updated order.

B. CASING

***SET POINT ADJUSTMENTS MADE BASED ON GEOTOPS.**

 Approval Date: 10/09/2025

1. The **13-3/8** inch surface casing shall be set at approximately **1206** feet (a minimum of **70’** into the Rustler Anhydrite, above the salt, and below usable fresh water) 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 (including 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 minimum required fill of cement behind the **10-3/4** inch 1st intermediate casing is **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 the presence of cave/karst, Capitan Reef, or potash features.

3. The **8-5/8** inch surface casing shall be set at approximately **5011** feet (50’ below the Capitan Reef.) The minimum required fill of cement behind the **8-5/8** inch 2nd intermediate casing is **cement to surface**. If cement does not circulate, see B.1.a, c-d above.

For Four-String Wells in the Capitan Reef:

❖ **Special Capitan Reef Requirement:** Ensure freshwater based mud is used across the Capitan interval.
   - **Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry** due to the presence of cave/karst, Capitan Reef, or potash features.

4. The minimum required fill of cement behind the **5-1/2** inch production casing is **500 feet** into the previous casing AND **50’ ABOVE THE CAPITAN REEF TOP but below USGS Marker Bed No. 126** (base of the McNutt Potash ore zone.) Annulus to be left open as per specified design and tie-back to be achieved within 180 days.
   - Operator must verify top of cement per R-111-Q requirements. Submit results to the BLM. 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 the presence of cave/karst, Capitan Reef, or potash features.

   Bradenhead Squeeze: Operator has proposed to cement in two stages by conventionally cementing the first stage and performing a bradenhead squeeze on the second stage, contingent upon no returns to surface.

 Approval Date: 10/09/2025

a. **First stage:** Operator will cement with intent to reach the top of the **Brushy Canyon**. **ON BLM REVIEW, BRADENHEAD VOLUMES HAVE ~10% EXCESS. PLEASE REVIEW VOLUMES BASED ON CASING USED TO ENSURE THE DELAWARE GROUP IS OPEN FOR SECOND STAGE SQUEEZE POST FRAC.**
b. **Second stage:** Operator to squeeze and top-out. Cement to meet requirements listed for this casing string. If cement does not circulate see B.1.a, c-d above.

Operator has proposed to pump down **Production X Intermediate 2** annulus. Submit results to the BLM. If cement does not tie-back into the previous casing shoe, a third stage remediation BH may be performed. The appropriate BLM office shall be notified.

- Operator shall run a CBL from TD of the **Production** casing to tieback requirements listed above after the second stage BH to verify TOC.
- **A monitored open annulus will be incorporated during completion by leaving the above annulus un-cemented and monitored.** Operator must follow **all** monitoring requirements listed within R-111-Q. Tieback shall be met within **180 days.**
- Operator has proposed an open annulus completion in R-111-Q. Operator shall provide a method of verification pre-completion top of cement. **Submit results to the BLM.**
- Pressure monitoring device and Pressure Safety Valves must be installed at surface on both the intermediate annulus and the production annulus for the life of the well.
- **In the event of a casing failure during completion,** the operator **must** contact the BLM at engineers (575-706-2779) and inspection staff (575-393-3612 Lea County).

C. PRESSURE CONTROL

1. Operator has proposed a multi-bowl wellhead assembly. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **5000 (5M)** psi and below the intermediate casing shoe shall be **5000 (5M)** psi. **Variance is approved to use a 5000 (5M) annular which shall be tested to 5000 (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 43 CFR 3172 must be followed.

2. 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).

3. Break testing has been approved for this well ONLY on those intervals utilizing a 5M BOPE or less.

- BOPE Break Testing is ONLY permitted for hole sections with 5M MASP or less.
- The break test should involve a shell test that includes testing the upper pipe rams as proposed.
- Variance only pertains to the hole-sections in and shallower than the Wolfcamp formation. Break testing is NOT allowed when planning to penetrate the Penn group.
- While in transfer between wells, the BOPE shall be secured by the hydraulic carrier or cradle in accordance with API STD 53.
- Any well control event while drilling require notification to the BLM Petroleum Engineer.
- A full BOPE test is required prior to drilling the first intermediate section.
- If a hole section tends to show more background gas than normal, please notify BLM Engineer prior to proceeding with break testing on the next well.
- The BLM PET is to be contacted 4 hours prior to BOPE tests.
- *Eddy County Petroleum Engineering Inspection Staff: (575) 361-2822*
- *Lea County Petroleum Engineering Inspection Staff: (575) 689-5981*
- 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
  43 CFR 3172.
- If in the event break testing is not utilized, then a full BOPE test would be conducted.

D. SPECIAL REQUIREMENT(S)

<u>Communitization Agreement:</u>

- 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.
- The operator will submit an as-drilled survey well plat of the well completion, but are not limited to, those specified in 43 CFR 3171 and 3172.

Approval Date: 10/09/2025

- 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.

Offline Cementing

Offline cementing has been approved for **all hole sections.** Contact the BLM prior to the commencement of any offline cementing procedure.

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)

Contact Lea County Petroleum Engineering Inspection Staff:

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

Contact Eddy County Petroleum Engineering Inspection Staff:

Email or call the Carlsbad Field Office, 620 East Greene St., Carlsbad, NM 88220; **BLM_NM_CFO_DrillingNotifications@BLM.GOV**; (575) 361-2822

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
      i. Notify the BLM when moving in and removing the Spudder Rig.
      ii. Notify the BLM when moving in the 2nd Rig. Rig to be moved in within 90 days of notification that Spudder Rig has left the location.
      iii. BOP/BOPE test to be conducted per **43 CFR 3172** 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. For intervals in which cement to surface is required, cement to surface should be verified with a visual check and density or pH check to differentiate cement from spacer and drilling mud. The results should be documented in the driller's log and daily reports.

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 of both lead and tail cement, 2) until cement has been in place at least 8 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-Q 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 **43 CFR 3172**.
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:
   i. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
   ii. 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.
   iii. Manufacturer representative shall install the test plug for the initial BOP test.
   iv. Whenever any seal subject to test pressure is broken, all the tests in 43 CFR 3172.6(b)(9) must be followed.
   v. 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.
   i. 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 cement), 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).
   ii. 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 cement plug. The BOPE test can be initiated after bumping the cement plug with the casing valve open. (only applies to single stage cement jobs, prior to the cement setting up.)

iii. The tests shall be done by an independent service company utilizing a test plug not a cup or J-packer and can be initiated immediately with the casing valve open. The operator also has the option of utilizing an independent tester to test without a plug (i.e. against the casing) pursuant to **43 CFR 3172** 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 8 hours or 500 pounds compressive strength, whichever is greater, prior to initiating the test (see casing segment as lead cement may be critical item).

iv. 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.

v. The results of the test shall be reported to the appropriate BLM office.

vi. 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.

vii. 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.

viii. 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 **43 CFR 3172**.

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.

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Margie 24 Fed Com #202H

Hydrogen Sulfide Plan Summary

A. All personnel shall receive proper H2S 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/Escape 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

- **H2S 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.

- **Mud Program:**

The mud program has been designed to minimize the volume of H2S circulated to surface. The operator will have the necessary mud products to minimize hazards while drilling in H2S 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 H2S service.

- **Communication:**

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

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Margie 24 Fed Com #202H

Emergency Assistance Telephone List

PUBLIC SAFETY:	911 or
Lea County Sheriff's Department	(575) 396-3611
Corey Helton	
Fire Department	
Carlsbad	(575) 885-3125
Artesia	(575) 746-5050
Hospitals	
Carlsbad	(575) 887-4121
Artesia	(575) 748-3333
Hobbs	(575) 392-1979
Dept. of Public Safety/Carlsbad	(575) 748-9718
Highway Department	(575) 885-3281
U.S. Department of Labor	(575) 887-1174
Bureau of Land Management - Hobbs (Lea Co)	(575) 393-3612
PET On Call - Hobbs	(575) 706-2779
Bureau of Land Management - Carlsbad (Eddy Co)	(575) 234-5972
PET On Call - Carlsbad	(575) 706-2779
New Mexico Oil Conservation Division - Artesia	(575) 748-1283
Inspection Group South - Gilbert Gordero	(575) 626-0830
EOG Resources, Inc.	
EOG Midland	(432) 686-3600
Company Drilling Consultants:	
Jett Dueitt	(432) 230-4840
Blake Burney	
Drilling Engineers	
Stephen Davis	(432) 235-9789
Matt Day	(210) 296-4456
Drilling Managers	
Branden Keener	(210) 294-3729
Drilling Superintendents	
Lance Hardy	(432) 215-8152
Ryan Reynolds	(432) 215-5978
Steve Kelly	(210) 416-7894
H&P Drilling	
H&P Drilling	(432) 563-5757
Nabors Drilling	
Nabors Drilling	(432) 363-8180
Patterson UTI	
Patterson UTI	(432) 561-9382
EOG Safety	
Brian Chandler (HSE Manager)	(817) 239-0251

Margie 24 Fed Com 202H API #: 30-025-*** Variances**

EOG respectfully requests the below variances to be applied to the above well:

- Bradenhead will be the primary option for production cementing. EOG also requests to have the conventional option in place to accommodate for logistical or wellbore conditions. The tie back requirements will be met if the cement is pumped conventionally, and cement volumes will be adjusted accordingly. TOC will be verified by CBL.

- Variance is requested to use a co-flex line between the BOP and choke manifold (instead of using a 4" OD steel line).- Variance is requested to use a 5,000 psi annular BOP with the 10,000 psi BOP stack.
- 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.

EOG requests the additional variance(s) in the attached document(s):

- EOG BLM Variance 3e - BOP Break-test and Offline Surface and Intermediate Cement
- EOG BLM Variance 3d - Production Offline Cement

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EOG Batch Casing

Pad Name: Margie 24 Fed Com SHALLOW

SHL: Section 24, Township 20-S, Range 32-E, LEA County, NM

Well Name	API #	Surface		Intermediate 1		Intermediate 2		Intermediate 3		Production	
		MD	TVD	MD	TVD	MD	TVD	MD	TVD	MD	TVD
Margie 24 Fed Com #201H	30-025-*****	1,206	1,206	3,289	3,224	5,076	5,011	N/A	N/A	18,702	8,417
Margie 24 Fed Com #202H	30-025-*****	1,206	1,206	3,242	3,224	5,029	5,011	N/A	N/A	18,658	8,417
Margie 24 Fed Com #203H	30-025-*****	1,206	1,206	3,286	3,224	5,073	5,011	N/A	N/A	18,699	8,417
Margie 24 Fed Com #204H	30-025-*****	1,206	1,206	3,245	3,224	5,032	5,011	N/A	N/A	18,660	8,417
Margie 24 Fed Com #205H	30-025-*****	1,206	1,206	3,295	3,224	5,082	5,011	N/A	N/A	18,707	8,417
Margie 24 Fed Com #206H	30-025-*****	1,206	1,206	3,231	3,224	5,018	5,011	N/A	N/A	18,645	8,417
Margie 24 Fed Com #301H	30-025-*****	1,206	1,206	3,285	3,224	5,072	5,011	N/A	N/A	19,268	8,987
Margie 24 Fed Com #302H	30-025-*****	1,206	1,206	3,367	3,224	5,154	5,011	N/A	N/A	19,343	8,987
Margie 24 Fed Com #303H	30-025-*****	1,206	1,206	3,245	3,224	5,032	5,011	N/A	N/A	19,230	8,987
Margie 24 Fed Com #304H	30-025-*****	1,206	1,206	3,265	3,224	5,052	5,011	N/A	N/A	19,250	8,987
Margie 24 Fed Com #305H	30-025-*****	1,206	1,206	3,261	3,224	5,048	5,011	N/A	N/A	19,246	8,987
Margie 24 Fed Com #306H	30-025-*****	1,206	1,206	3,250	3,224	5,037	5,011	N/A	N/A	19,233	8,987
Margie 24 Fed Com #501H	30-025-*****	1,206	1,206	3,322	3,224	5,109	5,011	N/A	N/A	20,229	9,917
Margie 24 Fed Com #502H	30-025-*****	1,206	1,206	3,489	3,224	5,276	5,011	N/A	N/A	20,356	9,917
Margie 24 Fed Com #503H	30-025-*****	1,206	1,206	3,257	3,224	5,044	5,011	N/A	N/A	20,171	9,917
Margie 24 Fed Com #504H	30-025-*****	1,206	1,206	3,281	3,224	5,068	5,011	N/A	N/A	20,193	9,917
Margie 24 Fed Com #505H	30-025-*****	1,206	1,206	3,286	3,224	5,073	5,011	N/A	N/A	20,197	9,917
Margie 24 Fed Com #506H	30-025-*****	1,206	1,206	3,259	3,224	5,046	5,011	N/A	N/A	20,172	9,917

EOG Batch Casing

GEOLOGIC NAME OF SURFACE FORMATION:

Permian

ESTIMATED TOPS OF IMPORTANT GEOLOGICAL MARKERS:

Rustler	1,136'
Tamarisk Anhydrite	1,222'
Top of Salt	1,511'
Marker Bed 126	2,030'
Tansill	3,174'
Yates	3,307'
Capitan	3,694'
Cherry Canyon	4,961'
Brushy Canyon	6,187'
Bone Spring Lime	7,883'
Leonard (Avalon) Shale	7,984'
1st Bone Spring Sand	8,911'
2nd Bone Spring Shale	9,221'
2nd Bone Spring Sand	9,464'
3rd Bone Spring Carb	10,119'
3rd Bone Spring Sand	10,529'
Wolfcamp	10,925'
TD	8,009'

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

Upper Permian Sands	0- 400' Fresh Water
Yates	3,307' Oil
Cherry Canyon	4,961' Oil
Brushy Canyon	6,187' Oil
Bone Spring Lime	7,883' Oil
Leonard (Avalon) Shale	7,984' Oil
1st Bone Spring Sand	8,911' Oil
2nd Bone Spring Shale	9,221' Oil
2nd Bone Spring Sand	9,464' Oil

EOG Batch Casing

Variances

EOG requests the additional variance(s) in the attached document(s):

- EOG BLM Variance 2a - Intermediate Bradenhead Cement
- EOG BLM Variance 3d - Production Offline Cement
- EOG BLM Variance 3a_b - BOP Break-test and Offline Intermediate Cement

Variances r

- BOP Bı
- Offline
- Salt Int
- Blanke

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Margie 24 Fed Com 202H

EOG is aware of the updates to the KPLA requirements in R-111-Q and plans to comply with the R-111-Q order. Anticollision requirements will be monitored and met.

R-111-Q Casing and Cementing Requirements:

The surface casing string shall have at least the following centralization program:
- One centralizer per joint across the shoe track
- One centralizer per 2 joints from casing shoe to the top of useable fresh water
- Not less than one centralizer every 3 joints for surface casing

A casing pressure test shall be made before drilling below the casing seat or at the time of plug bump. The casing shall be tested to 0.22 psi/ft of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of casing burst. If a drop of 10% or more should occure within 30 minutes, corrective measures shall be applied. Shoe integrity shall be verified via a formation integrity test (FIT).

The well path may be deviated from vertical after completely penetrating USGS Marker Bed No. 126

The 1st intermediate casing string shall be set at least 100 ft below the base of the salt interval and above the highest known oil/gas zone, and have at least the following centralization program:
- One centralizer per joint across the shoe track and not less than 1 centralizer every 3 joints to surface
- EOG will confirm the effectiveness of centralization program with cement placement simulations
- The Division (NMOCD) may require addional centalizers on the salt string, if it deems it necessary

The 1st intermediate cement slurry shall have the following characteristics:
- Cement will be a high sulfate resistance (HSR) slurry
- Include a minimum of 10% BWOW salt
- Include an expansion additive (1-3% BWO Magnesium Oxide or equivalent)

A casing pressure test shall be made before drilling below the casing seat or at the time of plug bump. The casing shall be tested to 0.22 psi/ft of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of casing burst. If a drop of 10% or more should occure within 30 minutes, corrective measures shall be applied.

Shoe integrity shall be verified via a formation integrity test (FIT).

The 2nd intermediate casing string is required in areas of the Capitan Reef (unless exempted by the Division), and shall be set 150 ft above the Base of the Capitan formation.

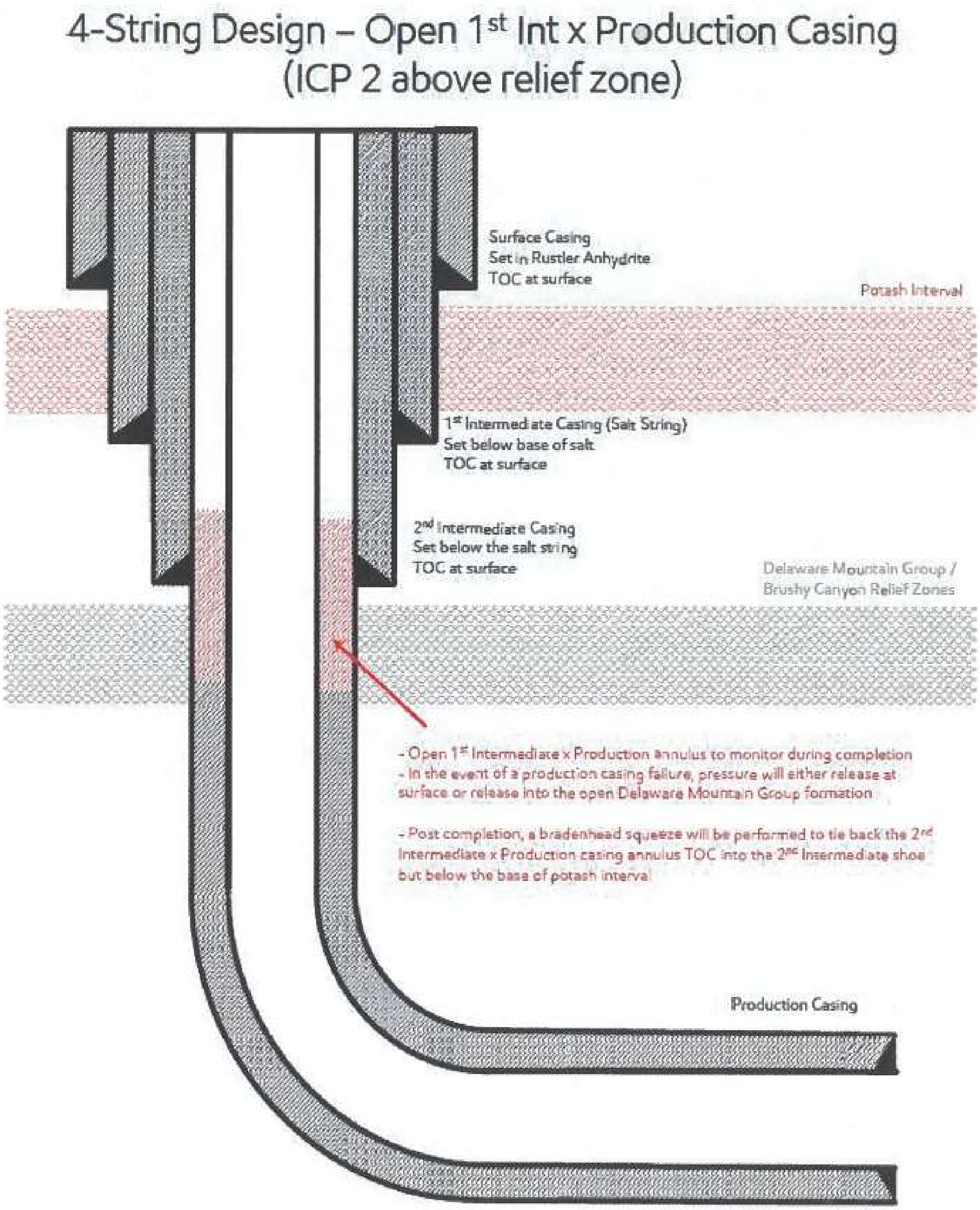
EOG will incoporate method C(5)(c)(iii) for the 4 string designs, leaving the annulus between the 2nd intermediate and the production string open and monitored. The top of production cement will be at least 500 ft below the 2nd intermediate casing point, and ZERO EXCESS will be pumped to ensure no tie-back into the 2nd intermediate.

EOG will incoporate a modified method C(5)(c)(ii) for the 5 string designs, leaving the annulus between the 2nd and 3rd intermediates open and monitored. The top of the 3rd intermediate cement will be at least 500 ft below the 2nd intermediate casing point, and ZERO EXCESS will be pumped to ensure no tie-back into the 2nd

eog resources

After hydraulic fracturing operations have been concluded/no more than 180 days after the well is brought online, EOG will bradenhead cement to ensure at least 500 ft of tie-back inside the 2nd intermediate casing, but not higher than USGS Marker Bed No. 126., and at least 50' above the Capitan formation.

See Attached Figure E from R-111-Q for 4 String - Uncemented Annulus WBD.

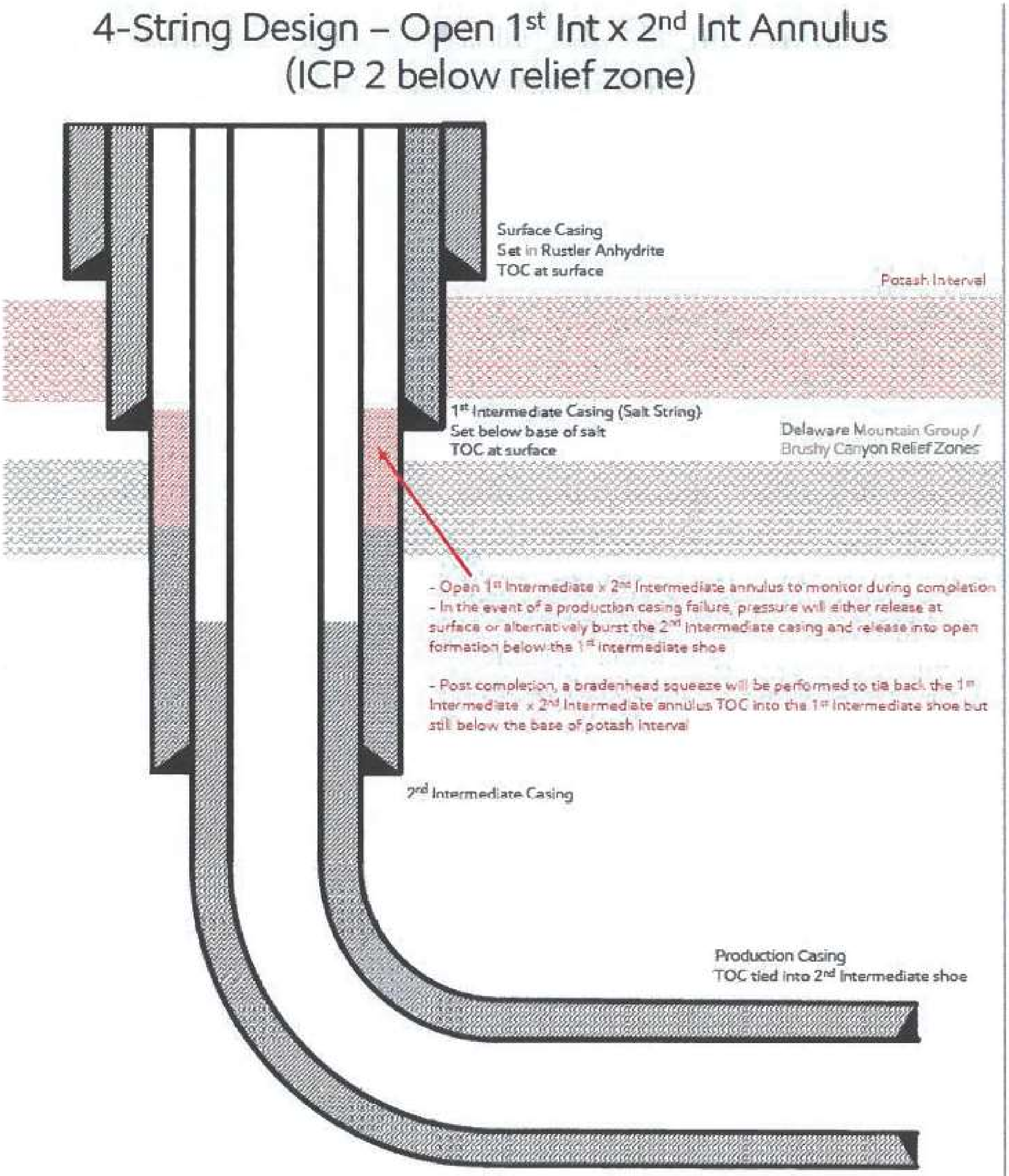


[Figure E] 4 String – Uncemented Annulus between 2nd Intermediate and Production Casing Strings

eog resources

After hydraulic fracturing operations have been concluded/no more than 180 days after the well is brought online, EOG will bradenhead cement to ensure at least 500 ft of tie-back between the 3rd and the 2nd intermediate casings, but not higher than USGS Marker Bed No. 126, and at least 50' above the Capitan formation.

See Attached Figure D from R-111-Q. This design will be modified for EOG's 5 string designs, where the annulus between the 3rd and 2nd intermediate casings will be left open below the 2nd intermediate casing shoe.

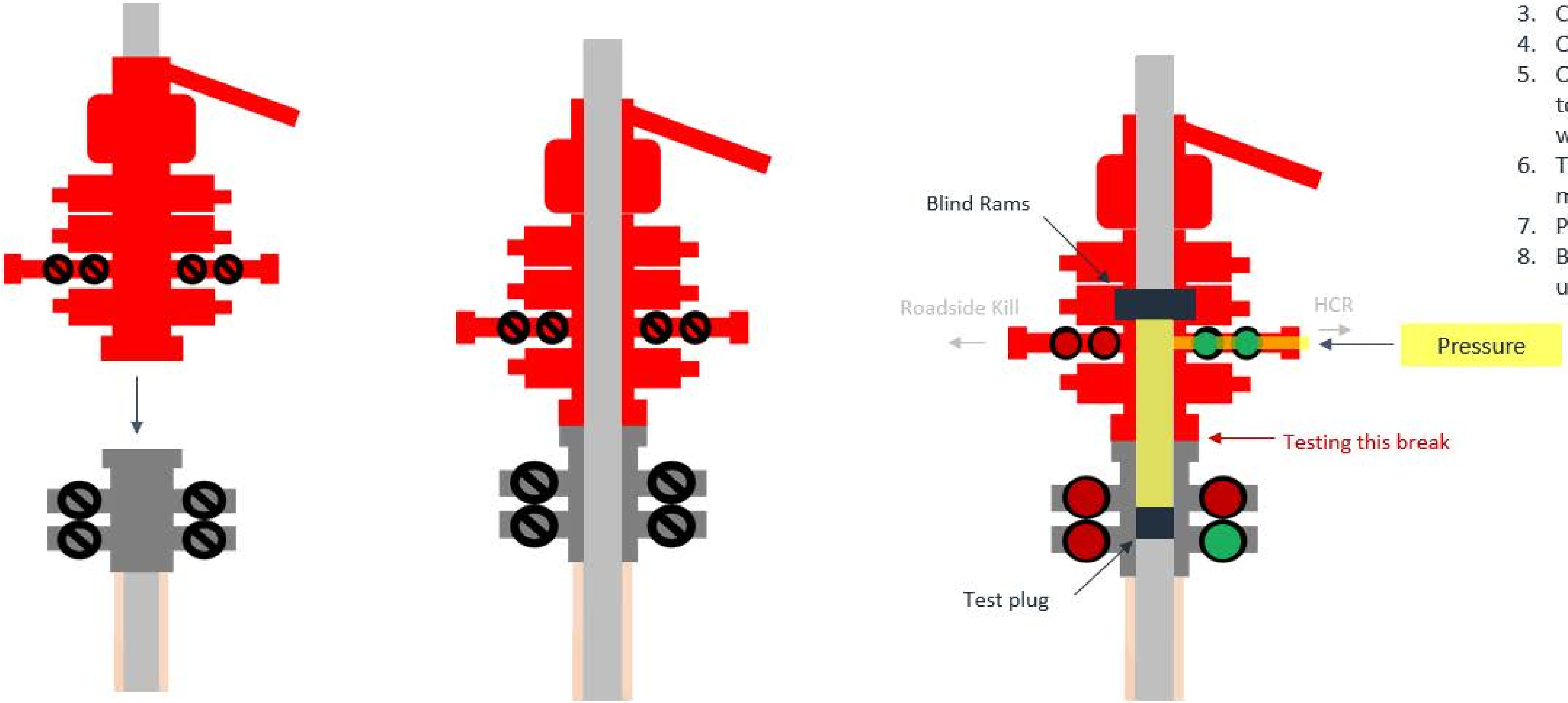


[Figure D] 4 String – Uncemented annulus between 1st and 2nd Intermediate casing strings

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

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

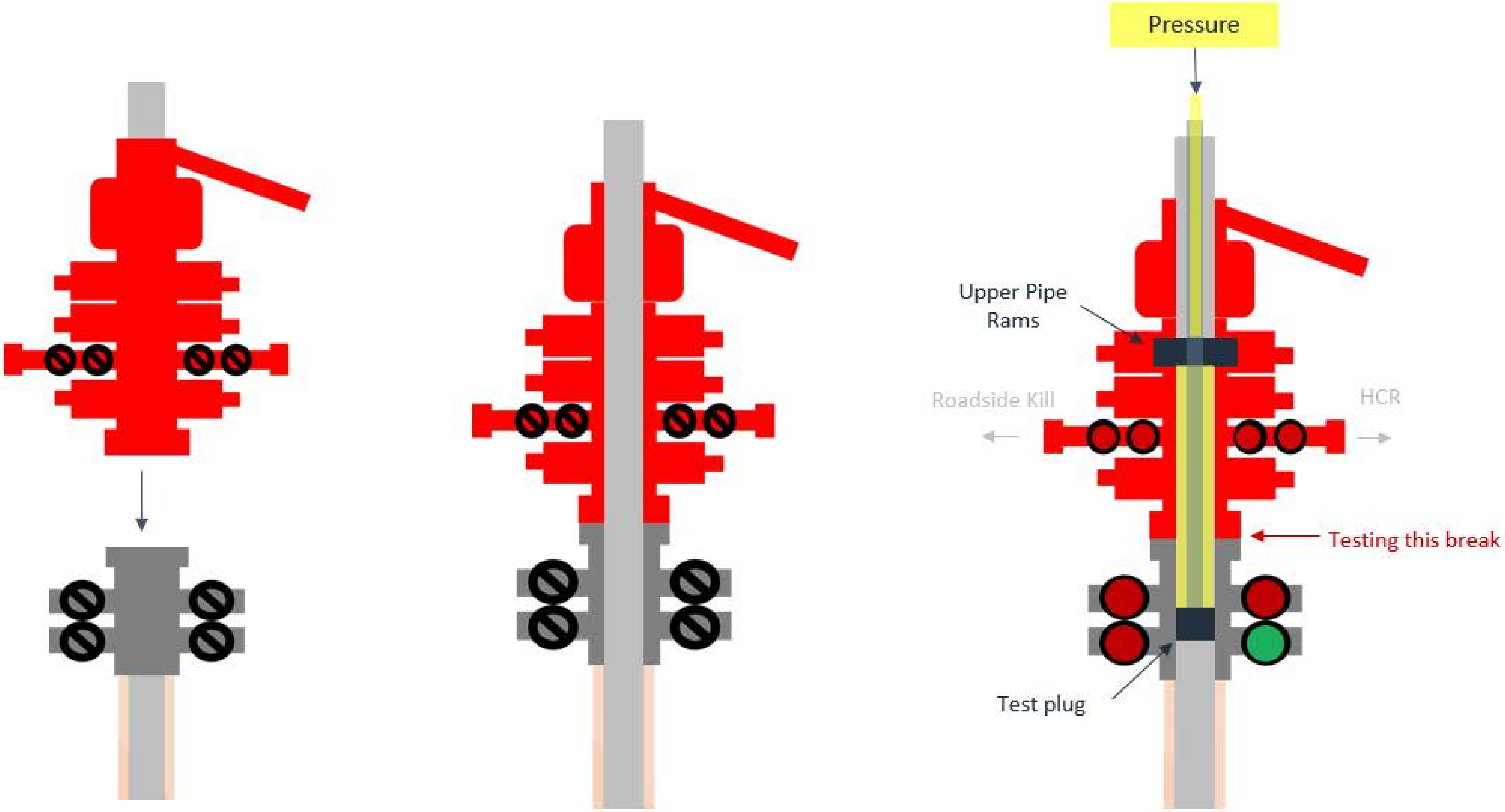
Break Test Diagram (HCR valve)



Steps

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

Break Test Diagram (Test Joint)



Steps

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

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 nippled 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 nippled back up for any further remediation.

   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.

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 nippled 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.

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.

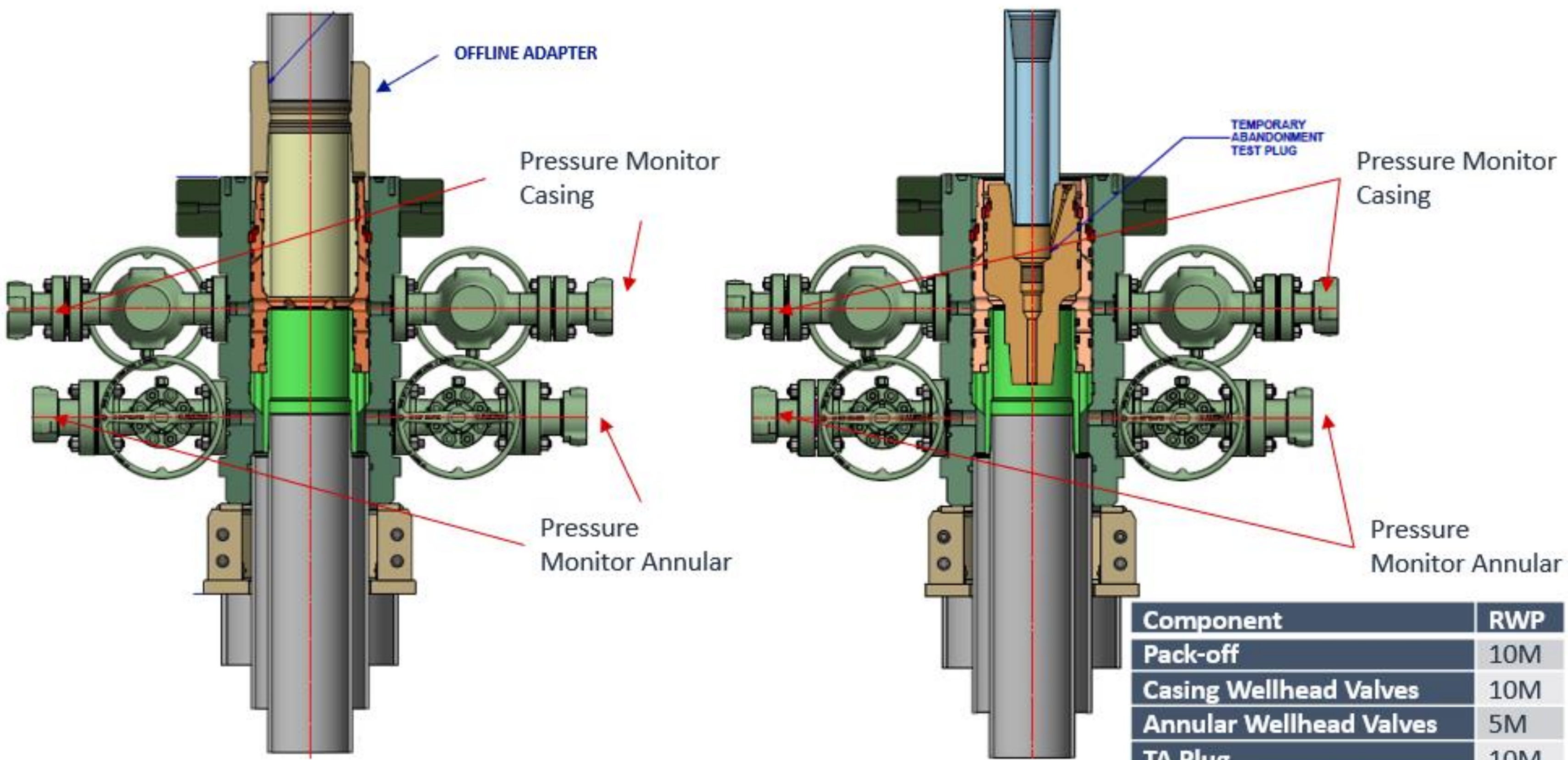
General Procedure While Cementing

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

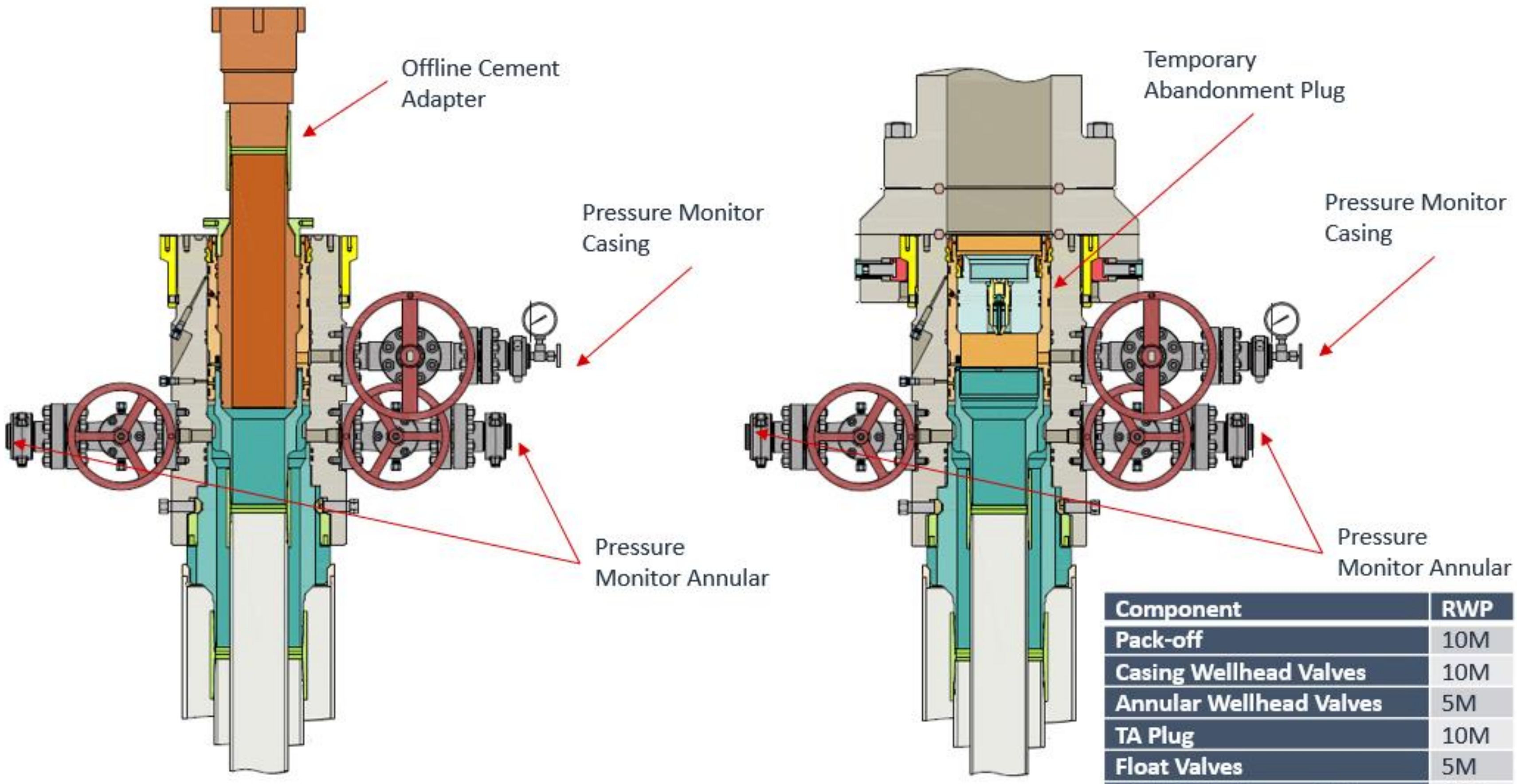
1. Sound alarm (alert crew).
2. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
3. Confirm shut-in.
4. Notify tool pusher/company representative.
5. Read and record the following:
    a. SICP and AP
    b. Pit gain
    c. Time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

Figure 1: Cameron TA Plug and Offline Adapter Schematic



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

Figure 2: Cactus TA Plug and Offline Adapter Schematic



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

Figure 3: Back Yard Rig Up

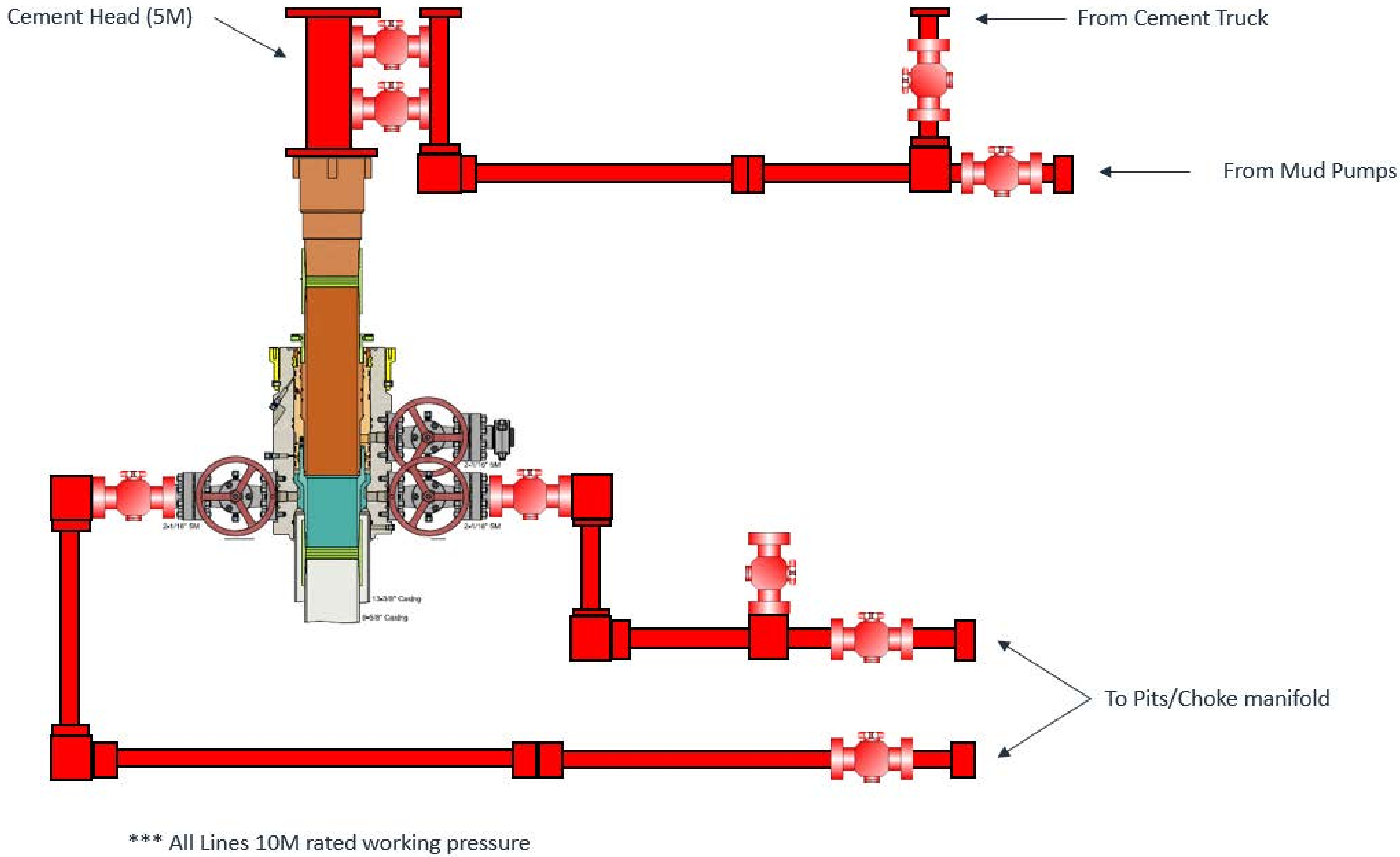
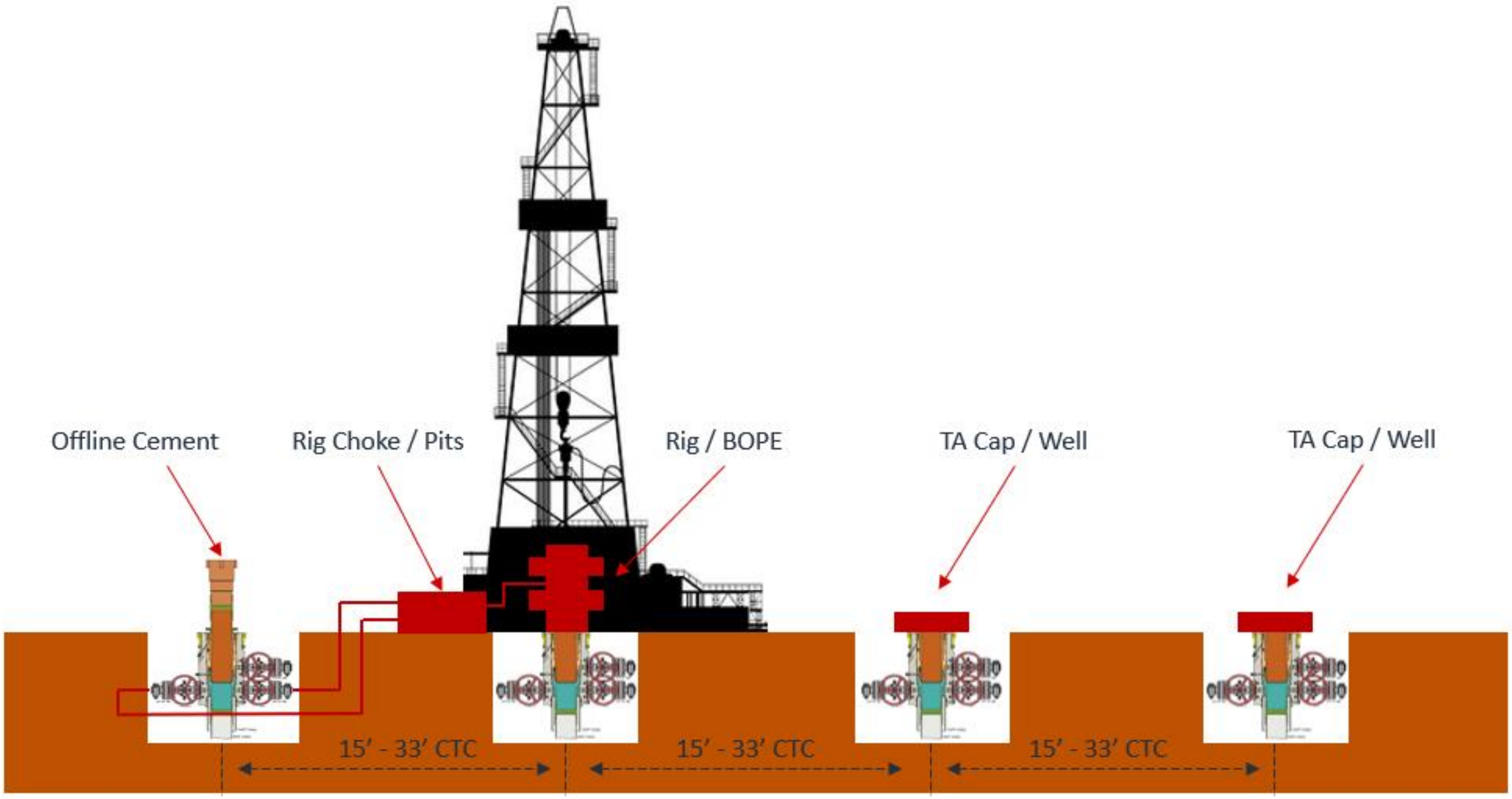


Figure 4: Rig Placement Diagram



Offline Production Cement Variance

EOG Offline Production Checklist

Offline Checklist

All items below must be met. If not, the production cement will be done online.

1. Offline production cement jobs must be above the Atoka formation.
2. Nothing out of the ordinary observed during drilling, tripping or casing running operations in the Production Hole Section.
3. Casing must be landed with Hanger.
4. EOG Company Man and Superintendent with Well Control certification must be present to monitor returns.
5. EOG Cement Advisor must be present to oversee the Cement Job.
6. Rig Manager is responsible for walking the rig to the next well.
7. The BOP will ***NOT*** be nippled down if:
    1. **ANY** barrier fails to test.
    2. **ANY** offset frac operations are observed within 1 mile and within the same producing horizon.
8. After all barriers test and the BLM has been notified, the BOP may be nippled down to proceed with offline operations.
9. EOG will not Drill out of the next well until Cement Operations have concluded on the offline well.

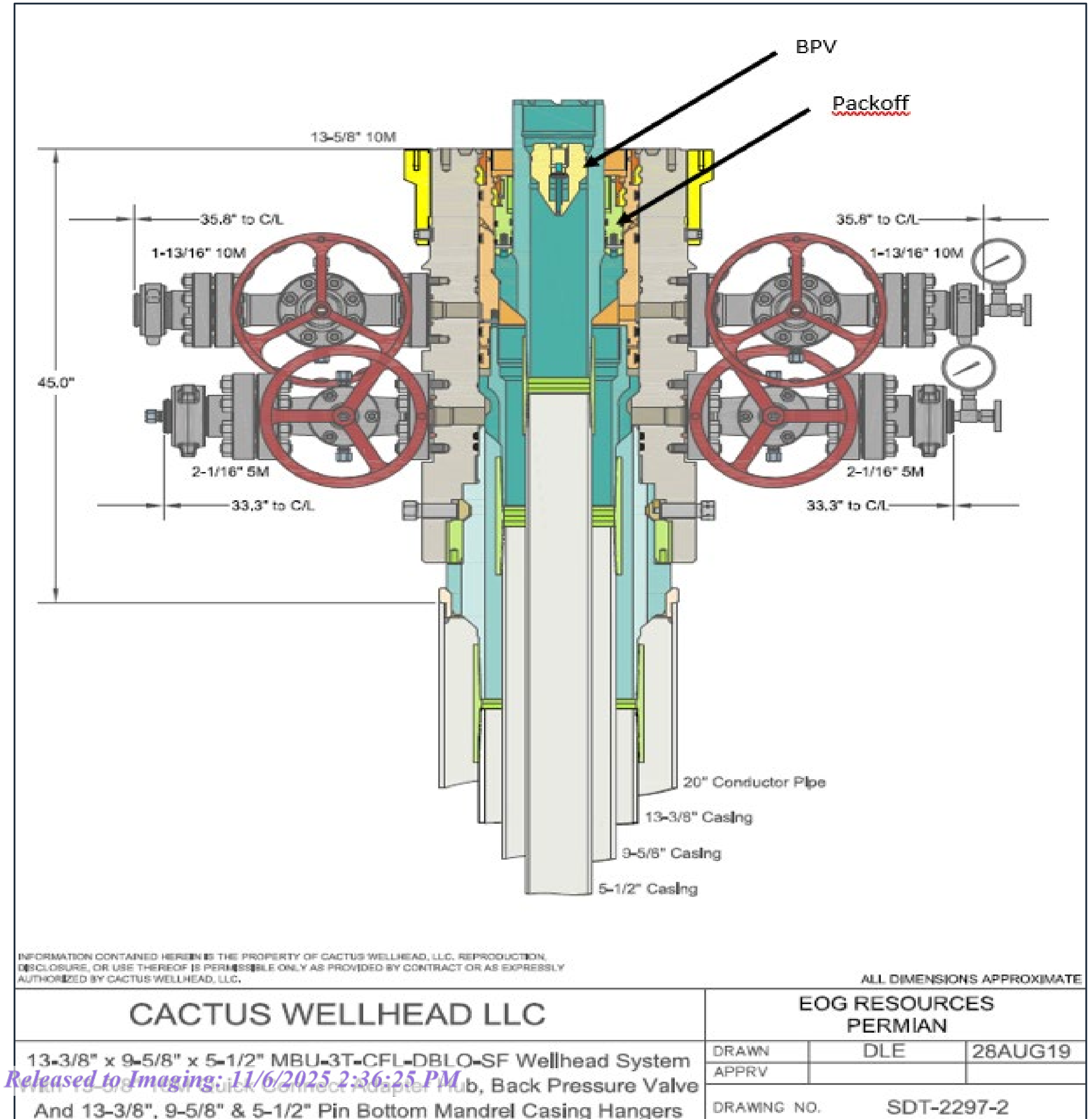
Offline Procedure

1. Run casing as per normal operations. Review EOG Offline Requirements Checklist, if the well is a candidate for Offline Cement on the Production continue following this procedure. Conduct negative pressure test while running casing and confirm integrity of the float equipment back pressure valves.
    a. Float equipment is equipped with two back pressure valves rated to 15,000 psi.
2. Land production casing on mandrel hanger.
    a. If casing is unable to be landed with a mandrel hanger, then the casing will be cemented online.
    b. 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 rated to 10,000 psi. Pressure test same to 10,000 psi.
    c. 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 10,000 psi. Remove landing joint.
3. Install back pressure valve in the casing for a 3rd casing barrier.
    a. Back pressure valve rated to a minimum of 10,000 psi.
4. With the well Secured and BLM notified; Nipple down BOP and secure on hydraulic carrier or cradle and Skid/Walk rig to next well on pad.
    a. Note, if any of the barriers fail to test, the BOP stack will not be nippled down until after the cement job has concluded.
    b. Note, EOG Company Man and Cement Advisor will oversee Cementing Operations while Rig Manager walks the rig and nipples up the BOP.
    c. Note, EOG will not drill out of the subsequent well until after plug bump.
5. Install 10M Gate Valve, with Wellhead Adapter.
    a. This creates an additional barrier on the annulus and inside the casing.
    b. Gate valve rated to a minimum of 10,000 psi.
6. Test connection between Wellhead Adapter seals against hanger neck and ring gasket to 10,000 psi.
7. Remove backpressure valve from the casing.
8. Rig up cement head and cementing lines.
9. After rig up of cement head and cement lines, and confirmation of the annular barriers and casing barriers, notify the BLM with intent to proceed offline cementing.
10. Perform cement job.
11. *Note* – Procedure continued on the next page.

Offline Procedure

12. If an influx is noted during the Cement Job:
    a. It is the Company Man and Superintendent's responsibility to maintain well control.
    b. The aux manifold will be redirected to the rig's chokes.
    c. Backpressure will be held on the well with the chokes to ensure well control is maintained through the remainder of the cement job while circulating out the influx.
    d. If annular surface pressure approaches 90% tested pressure of the manifold or if circulating the influx out with the cementing pumps is not feasible, the well can be secured by closing the casing valves (10M).
    e. Once cement is in place, we will close the casing valves and confirm the well is static and floats are holding.
    f. If the floats fail, the gate valve (10M) or cement head (10M) can be closed to secure the well.
13. Confirm well is static and floats are holding after cement job.
14. Remove cement head.
15. Install back pressure valve.
16. Remove 10M Gate Valve and Wellhead Adapter.
17. Install night cap with pressure gauge for monitoring.
18. Test night cap to 5,000 psi.

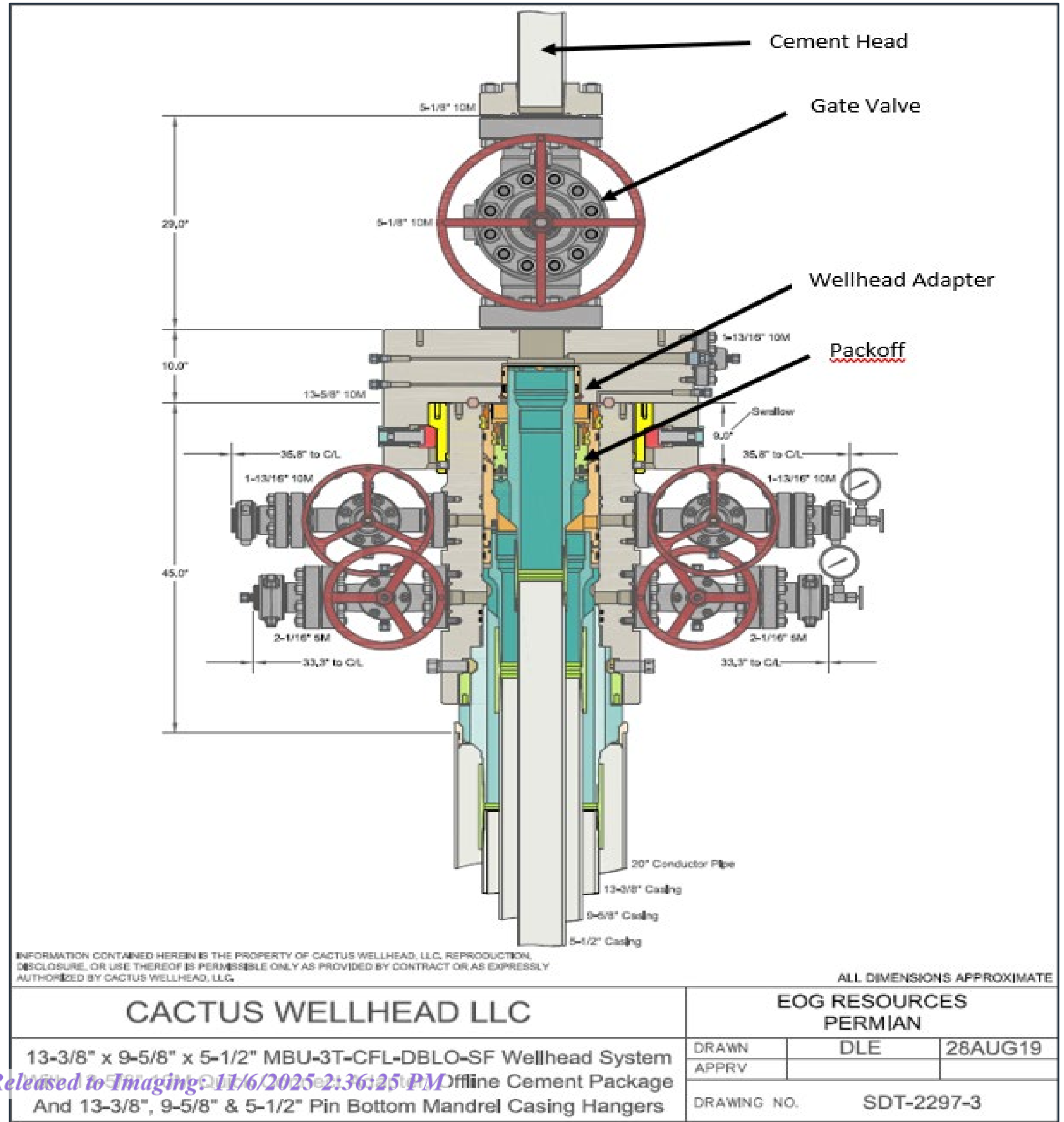
Offline Barrier Overview



Barriers in Place during removal of BOP		
Operation	**Casing**	**Annulus**
Nippling Down BOP	1. BPV 2. Hydrostatic Barrier 3. Float Valves	1. Hydrostatic Barrier 2. Mechanical 10M Packoff

Barriers in Place during Offline Cementing of Production Casing		
Operation	**Casing**	**Annulus**
Pull BPV	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical Packoff 3. 10M Wellhead Adapter
Install Cement Head	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Cement Job	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve 4. Cement Head	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Remove Cement Head	1. Float Valves 2. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Install BPV	1. Float Valves 2. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Remove 10M Gate Valve	1. Float Valves 2. BPV	1. Hydrostatic Barrier 2. Mechanical 10M Packoff
Nipple Up TA Cap	1. Float Valves 2. BPV	1. Hydrostatic Barrier 2. Mechanical 10M Packoff

Offline Barrier Overview



Barriers in Place during removal of BOP

Operation	Casing	Annulus
Nippling Down BOP	1. BPV 2. Hydrostatic Barrier 3. Float Valves	1. Hydrostatic Barrier 2. Mechanical 10M Packoff

Barriers in Place during Offline Cementing of Production Casing

Operation	Casing	Annulus
Pull BPV	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical Packoff 3. 10M Wellhead Adapter
Install Cement Head	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Cement Job	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve 4. Cement Head	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Remove Cement Head	1. Float Valves 2. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Install BPV	1. Float Valves 2. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Remove 10M Gate Valve	1. Float Valves 2. BPV	1. Hydrostatic Barrier 2. Mechanical 10M Packoff
Nipple Up TA Cap	1. Float Valves 2. BPV	1. Hydrostatic Barrier 2. Mechanical 10M Packoff

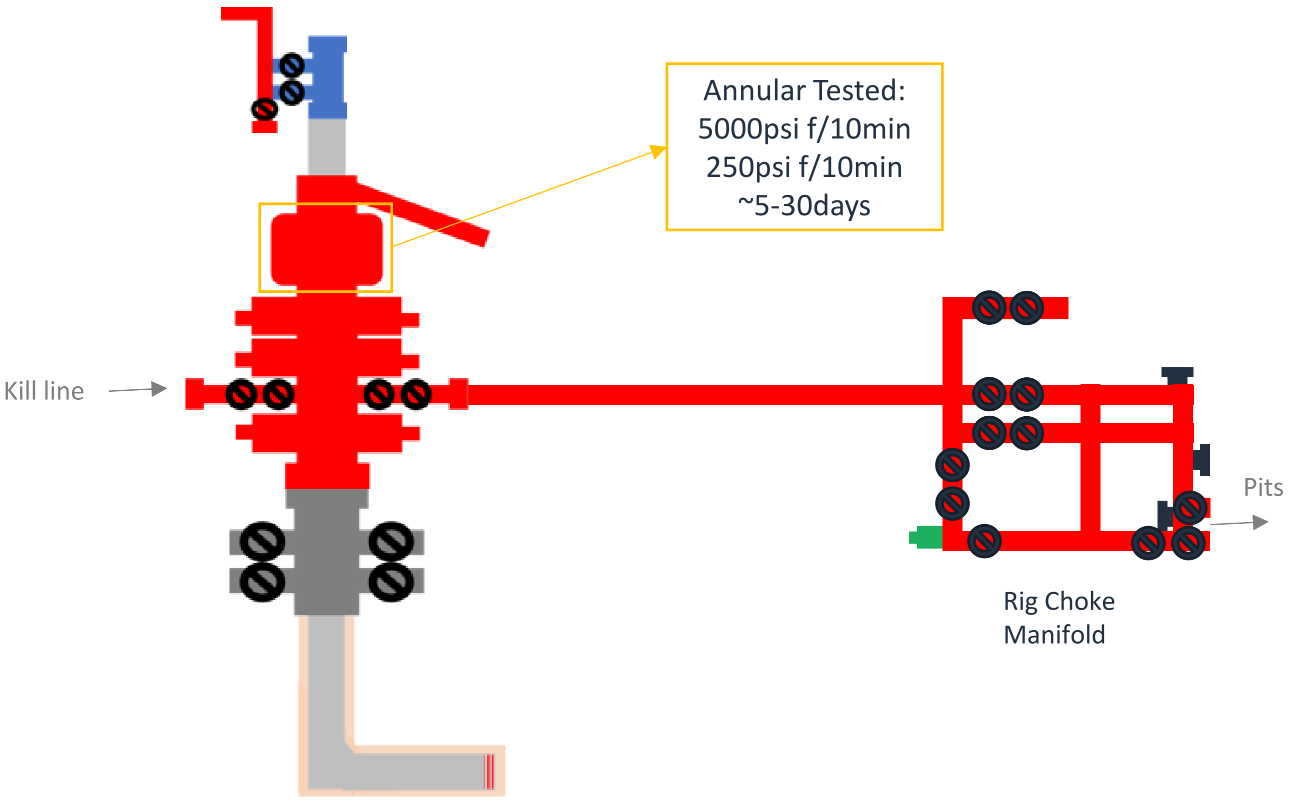
More Control: Meeting/Exceeding Barrier Requirements

Casing Barriers – Online vs Offline		
Operation	Online	Offline
Install Cement Head	1. Hydrostatic Barrier 2. Float Valves	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve ✓
Cement Job	1. Hydrostatic Barrier 2. Float Valves 3. Cement Head	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve 4. Cement Head ✓
Remove Cement Head	1. Float Valves	1. Float Valves 2. 10M Gate Valve ✓
Install BPV & Nipple Down BOP / Offline Adapter	1. Float Valves	1. Float Valves 2. BPV ✓
Nipple Up TA Cap	1. Float Valves	1. Float Valves 2. BPV ✓

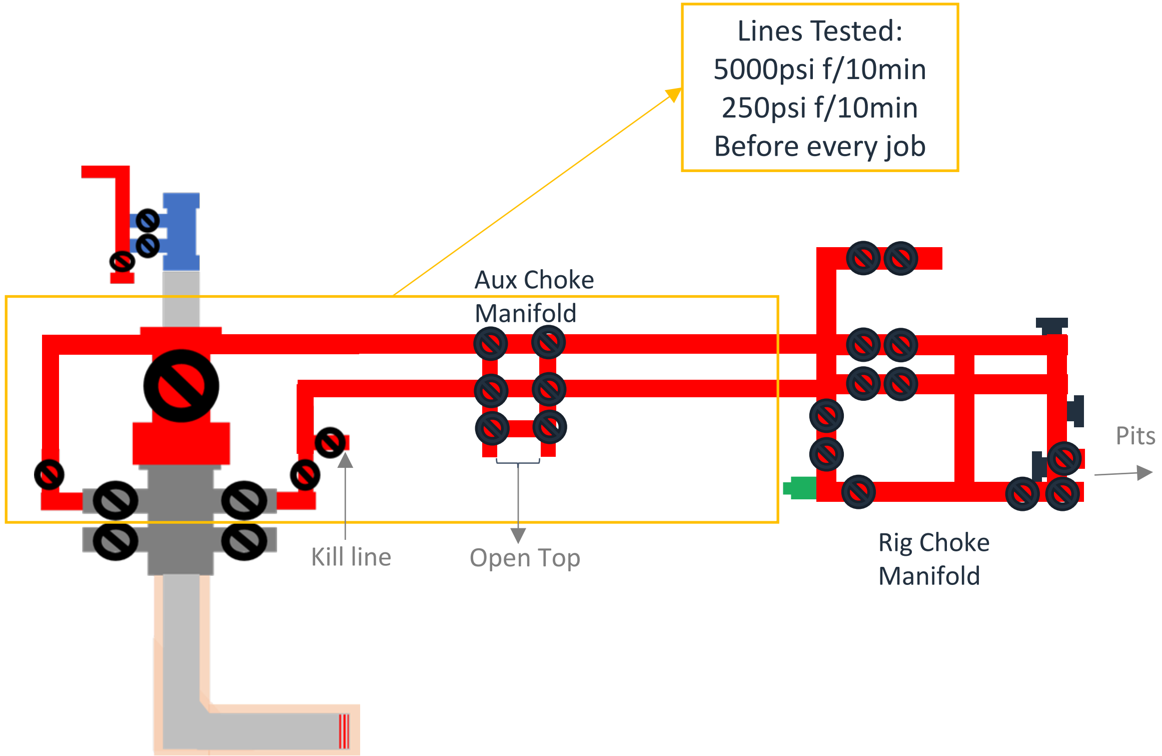
Annulus Barriers – Online vs Offline		
Operation	Online	Offline
Install Cement Head	1. Hydrostatic Barrier 2. Annular 3. VBR	1. Hydrostatic Barrier 2. Mechanical Pack-off 3. 10M Wellhead Adapter ✓
Cement Job	1. Hydrostatic Barrier 2. Annular 3. VBR	1. Hydrostatic Barrier 2. Mechanical Pack-off 3. 10M Wellhead Adapter ✓
Remove Cement Head	1. Hydrostatic Barrier 2. Annular 3. VBR	1. Hydrostatic Barrier 2. Mechanical Pack-off 3. 10M Wellhead Adapter ✓
Install BPV & Nipple Down BOP / Offline Adapter	1. Hydrostatic barrier 2. Mechanical Pack-off	1. Hydrostatic Barrier 2. Mechanical Pack-off ✓
Nipple Up TA Cap	1. Hydrostatic barrier 2. Mechanical Pack-off	1. Hydrostatic Barrier 2. Mechanical Pack-off ✓

Return Rig Up Diagram

Online



Offline



Note:

1) Have the Rig's same Well Control Capabilities as Online
2) Have more flexibility with Gate Valve than with a Landing Joint through BOP
3) Never had to circulate out a kick during Offline

Shallow Target Offline Bradenhead:

EOG Resources Inc. (EOG) respectfully requests a variance from the minimum standards to allow for offline bradenhead cementing of the production string after primary cementing operations have been completed. The primary cement job will be pumped conventionally (online) to top of the Brushy Canyon and will cover the target production intervals, and after production pack-off is set and tested, bradenhead will be pumped through casing valves between the production and intermediate casings (offline). For the bradenhead stage of production cementing, the barriers remain the same for offline cementing compared to performing it online.

The bradenhead will be the primary option for production cementing. EOG also requests to have the conventional option in place to accommodate for logistical or wellbore conditions. The tie back requirements will be met if the cement is pumped conventionally, and cement volumes will be adjusted accordingly. TOC will be verified by CBL.

Sante Fe Main Office
Phone: (505) 476-3441

General Information
Phone: (505) 629-6116

Online Phone Directory
https://www.emnrd.nm.gov/ocd/contact-us

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

ACKNOWLEDGMENTS

Action 520700

ACKNOWLEDGMENTS

Operator: EOG RESOURCES INC 5509 Champions Drive Midland, TX 79706	OGRID: 7377
	Action Number: 520700
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

ACKNOWLEDGMENTS

☑	I hereby certify that no additives containing PFAS chemicals will be added to the completion or recompletion of this well.

Sante Fe Main Office
Phone: (505) 476-3441

General Information
Phone: (505) 629-6116

Online Phone Directory
https://www.emnrd.nm.gov/ocd/contact-us

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

CONDITIONS

Action 520700

CONDITIONS

Operator:	
EOG RESOURCES INC 5509 Champions Drive Midland, TX 79706	OGRID: 7377
	Action Number: 520700
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

CONDITIONS

Created By	Condition	Condition Date
sharrell1	Cement is required to circulate on both surface and intermediate1 strings of casing.	10/28/2025
sharrell1	If cement does not circulate on any string, a Cement Bond Log (CBL) is required for that string of casing.	10/28/2025
matthew.gomez	Administrative order required for non-standard spacing unit prior to production.	11/6/2025
matthew.gomez	Notify the OCD 24 hours prior to casing & cement.	11/6/2025
matthew.gomez	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.	11/6/2025
matthew.gomez	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.	11/6/2025
matthew.gomez	File As Drilled C-102 and a directional Survey with C-104 completion packet.	11/6/2025
matthew.gomez	This well is within the Capitan Reef. The first intermediate casing string shall be sat and cemented back to surface immediately above the Capitan Reef. The second intermediate string shall be set and cemented back to surface immediately below the base of the Capitan Reef.	11/6/2025
matthew.gomez	Only freshwater based mud shall be utilized across the Capitan interval.	11/6/2025
matthew.gomez	This well is proposed to be within the R-111-Q defined boundary. Operator must follow all procedures and requirements listed within the order.	11/6/2025