

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

*Please refer to approved NOI appended to this application for the most recent details for the planned well.

1a. Type of work: <input checked="" type="checkbox"/> DRILL <input type="checkbox"/> REENTER		5. Lease Serial No. NMNM122624
1b. Type of Well: <input checked="" type="checkbox"/> Oil Well <input type="checkbox"/> Gas Well <input type="checkbox"/> Other		6. If Indian, Allottee or Tribe Name
1c. Type of Completion: <input type="checkbox"/> Hydraulic Fracturing <input checked="" type="checkbox"/> Single Zone <input type="checkbox"/> Multiple Zone		7. If Unit or CA Agreement, Name and No. 8. Lease Name and Well No. WILD WEASEL 22 FED COM 753H 104H
2. Name of Operator EOG RESOURCES INCORPORATED		9. API Well No. PITCHFORK RANCH;WOLFCAMP, SOUTH
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 RED HILLS/UPPER BONE SPRING SHALE PITCHFORK RANCH;WOLFCAMP, SOUTH
4. Location of Well (Report location clearly and in accordance with any State requirements. *) At surface TR B / 644 FNL / 2639 FEL / LAT 32.1214901 / LONG -103.4578067 At proposed prod. zone TR N / 100 FSL / 2178 FWL / LAT 32.0945127 / LONG -103.4593165		11. Sec., T. R. M. or Blk. and Survey or Area SEC 22/T25S/R34E/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 640.0 1280
18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. 15 feet	19. Proposed Depth 9500 feet / 19705 feet	20. BLM/BIA Bond No. in file FED: NM2308
21. Elevations (Show whether DF, KDB, RT, GL, etc.) 3352 feet	22. Approximate date work will start* 08/14/2023	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. | 4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above). |
| 2. A Drilling Plan. | 5. Operator certification. |
| 3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO must be filed with the appropriate Forest Service Office). | 6. Such other site specific information and/or plans as may be requested by the BLM. |

25. Signature (Electronic Submission)	Name (Printed/Typed) CRAIG RICHARDSON / Ph: (713) 651-7000	Date 02/03/2023
Title Regulatory Specialist		
Approved by (Signature) (Electronic Submission)	Name (Printed/Typed) CODY LAYTON / Ph: (575) 234-5959	Date 03/10/2025
Title Assistant Field Manager Lands & Minerals 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.



(Continued on page 2)

*(Instructions on page 2)

INSTRUCTIONS

GENERAL: This form is designed for submitting proposals to perform certain well operations, as indicated on Federal and Indian lands and leases for action by appropriate Federal agencies, pursuant to applicable Federal laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from local Federal offices.

ITEM I: If the proposal is to redrill to the same reservoir at a different subsurface location or to a new reservoir, use this form with appropriate notations. Consult applicable Federal regulations concerning subsequent work proposals or reports on the well.

ITEM 4: Locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local Federal offices for specific instructions.

ITEM 14: Needed only when location of well cannot readily be found by road from the land or lease description. A plat, or plats, separate or on the reverse side, showing the roads to, and the surveyed location of, the well, and any other required information, should be furnished when required by Federal agency offices.

ITEMS 15 AND 18: If well is to be, or has been directionally drilled, give distances for subsurface location of hole in any present or objective productive zone.

ITEM 22: Consult applicable Federal regulations, or appropriate officials, concerning approval of the proposal before operations are started.

ITEM 24: If the proposal will involve hydraulic fracturing operations, you must comply with 43 CFR 3162.3-3, including providing information about the protection of usable water. Operators should provide the best available information about all formations containing water and their depths. This information could include data and interpretation of resistivity logs run on nearby wells. Information may also be obtained from state or tribal regulatory agencies and from local BLM offices.

NOTICES

The Privacy Act of 1974 and regulation in 43 CFR 2.48(d) provide that you be furnished the following information in connection with information required by this application.

AUTHORITY: 30 U.S.C. 181 et seq., 25 U.S.C. 396; 43 CFR 3160

PRINCIPAL PURPOSES: The information will be used to: (1) process and evaluate your application for a permit to drill a new oil, gas, or service well or to reenter a plugged and abandoned well; and (2) document, for administrative use, information for the management, disposal and use of National Resource Lands and resources including (a) analyzing your proposal to discover and extract the Federal or Indian resources encountered; (b) reviewing procedures and equipment and the projected impact on the land involved; and (c) evaluating the effects of the proposed operation on the surface and subsurface water and other environmental impacts.

ROUTINE USE: Information from the record and/or the record will be transferred to appropriate Federal, State, and local or foreign agencies, when relevant to civil, criminal or regulatory investigations or prosecution, in connection with congressional inquiries and for regulatory responsibilities.

EFFECT OF NOT PROVIDING INFORMATION: Filing of this application and disclosure of the information is mandatory only if you elect to initiate a drilling or reentry operation on an oil and gas lease.

The Paperwork Reduction Act of 1995 requires us to inform you that:

The BLM connects this information to a new evaluation of the technical, safety, and environmental factors involved with drilling for oil and/or gas on Federal and Indian oil and gas leases. This information will be used to analyze and approve applications. Response to this request is mandatory only if the operator elects to initiate drilling or reentry operations on an oil and gas lease. The BLM would like you to know that you do not have to respond to this or any other Federal agency-sponsored information collection unless it displays a currently valid OMB control number.

BURDEN HOURS STATEMENT: Public reporting burden for this form is estimated to average 8 hours per response, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect of this form to U.S. Department of the Interior, Bureau of Land Management (1004-0137), Bureau Information Connection Clearance Officer (WO-630), 1849 C Street, N.W., Mail Stop 401 LS, Washington, D.C. 20240.

Additional Operator Remarks

Location of Well

0. SHL: TR B / 644 FNL / 2639 FEL / TWSP: 25S / RANGE: 34E / SECTION: 22 / LAT: 32.1214901 / LONG: -103.4578067 (TVD: 0 feet, MD: 0 feet)

PPP: TR C / 100 FNL / 2178 FWL / TWSP: 25S / RANGE: 34E / SECTION: 22 / LAT: 32.1229871 / LONG: -103.4593283 (TVD: 9235 feet, MD: 9243 feet)

BHL: TR N / 100 FSL / 2178 FWL / TWSP: 25S / RANGE: 34E / SECTION: 27 / LAT: 32.0945127 / LONG: -103.4593165 (TVD: 9500 feet, MD: 19705 feet)

BLM Point of Contact

Name: MARIAH HUGHES

Title: Land Law Examiner

Phone: (575) 234-5972

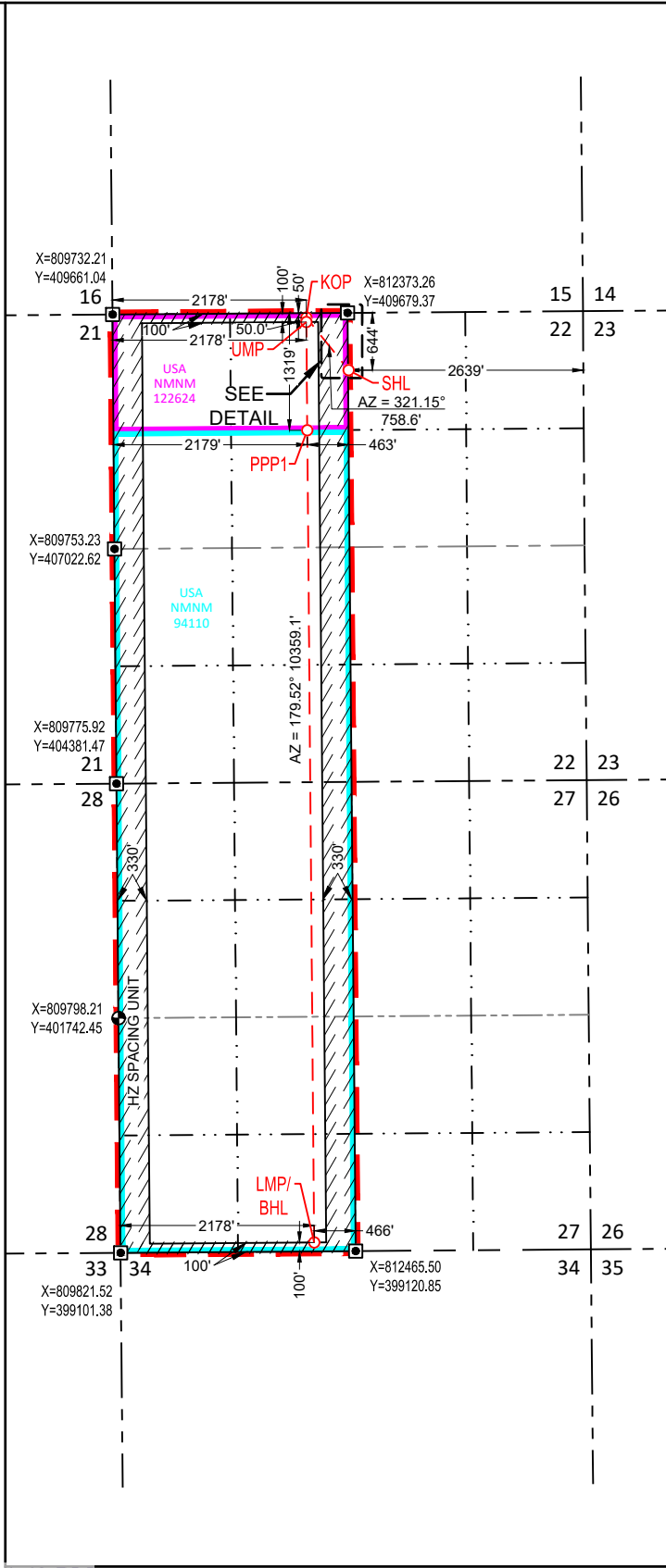
Email: MHUGHES@BLM.GOV

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: <table border="1" style="float: right; margin-left: 10px;"> <tr> <td><input type="checkbox"/> Initial Submittal</td> </tr> <tr> <td><input type="checkbox"/> Amended Report</td> </tr> <tr> <td><input type="checkbox"/> As Drilled</td> </tr> </table>	<input type="checkbox"/> Initial Submittal	<input type="checkbox"/> Amended Report	<input type="checkbox"/> As Drilled
<input type="checkbox"/> Initial Submittal					
<input type="checkbox"/> Amended Report					
<input type="checkbox"/> As Drilled					
*Please refer to approved NOI appended to this application for the most recent details for the planned well.					
Property Name and Well Number <p style="text-align: center;">WILD WEASEL 22 FED COM 104H</p>					

SURFACE LOCATION (SHL)
 NEW MEXICO EAST
 NAD 1983
 X=812386 Y=409035
 LAT.: N 32.1214901
 LONG.: W 103.4578067
 NAD 1927
 X=771200 Y=408977
 LAT.: N 32.1213649
 LONG.: W 103.4573387
 644' FNL 2639' FEL

KICK OFF POINT (KOP)
 NEW MEXICO EAST
 NAD 1983
 X=811911 Y=409626
 LAT.: N 32.1231246
 LONG.: W 103.4593281
 NAD 1927
 X=770724 Y=409568
 LAT.: N 32.1229994
 LONG.: W 103.4588599
 50' FNL 2178' FWL

UPPER MOST PERF. (UMP)
 NEW MEXICO EAST
 NAD 1983
 X=811911 Y=409576
 LAT.: N 32.1229871
 LONG.: W 103.4593283
 NAD 1927
 X=770725 Y=409518
 LAT.: N 32.1228620
 LONG.: W 103.4588601
 100' FNL 2178' FWL



PROPOSED PERF. POINT (PPP1)
 NEW MEXICO EAST
 NAD 1983
 X=811921 Y=408358
 LAT.: N 32.1196377
 LONG.: W 103.4593269
 NAD 1927
 X=770735 Y=408300
 LAT.: N 32.1195125
 LONG.: W 103.4588589
 1319' FNL 2179' FWL

**LOWER MOST PERF. (LMP)
 BOTTOM HOLE LOCATION (BHL)**
 NEW MEXICO EAST
 NAD 1983
 X=811999 Y=399217
 LAT.: N 32.0945127
 LONG.: W 103.4593165
 NAD 1927
 X=770812 Y=399160
 LAT.: N 32.0943874
 LONG.: W 103.4588501
 100' FSL 2178' FWL

SURVEYORS CERTIFICATION
 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.
 01/14/2021
 Date of Survey
 Signature and Seal of Professional Surveyor:

S:\SURVEY\MLA\WILD_WEASEL_22_FED_COM\PRODUCTS\OCD_FED_COM\104H.mxd\SUBSET\WATERMARK_3/17/2025 2:40 PM

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:** 1/29/2026

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
WILD WEASEL 22 FED COM 104H		B-22-25S-34E	644' FNL & 2639' FEL	+/- 1000	+/- 3500	+/- 3000

IV. Central Delivery Point Name: Wild Weasel 22 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
WILD WEASEL 22 FED COM 104H		4/18/26	5/01/26	6/01/26	7/01/26	8/01/26

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: <i>Star L Harrell</i>
Printed Name: Star L Harrell
Title: Regulatory Advisor
E-mail Address: Star_Harrell@eogresources.com
Date: 1/29/2026
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 will be installed.

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

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

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

PECOS DISTRICT DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	EOG Resources, Inc.
WELL NAME & NO.:	Wild Weasel 22 Fed Com 104H
LOCATION:	Section 22, T.25S., R.34E.
COUNTY:	Lea County

*Please refer to approved NOI appended to this application for the most recent details for the planned well.

COA

H2S	<input checked="" type="radio"/> Yes	<input type="radio"/> No	
Potash	<input checked="" type="radio"/> None	<input type="radio"/> Secretary	<input type="radio"/> R-111-P
Cave/Karst Potential	<input checked="" type="radio"/> Low	<input type="radio"/> Medium	<input type="radio"/> High
Cave/Karst Potential	<input type="radio"/> Critical		
Variance	<input type="radio"/> None	<input checked="" type="radio"/> Flex Hose	<input type="radio"/> Other
Wellhead	<input type="radio"/> Conventional	<input checked="" type="radio"/> Multibowl	<input type="radio"/> Both
Wellhead Variance	<input type="radio"/> Diverter		
Other	<input type="checkbox"/> 4 String	<input type="checkbox"/> Capitan Reef	<input type="checkbox"/> WIPP
Other	<input checked="" type="checkbox"/> Fluid Filled	<input type="checkbox"/> Pilot Hole	<input type="checkbox"/> Open Annulus
Cementing	<input checked="" type="checkbox"/> Contingency Cement Squeeze	<input type="checkbox"/> EchoMeter	<input checked="" type="checkbox"/> Primary Cement Squeeze
Special Requirements	<input type="checkbox"/> Water Disposal	<input checked="" type="checkbox"/> COM	<input type="checkbox"/> Unit
Special Requirements	<input type="checkbox"/> Batch Sundry		
Special Requirements Variance	<input checked="" type="checkbox"/> Break Testing	<input checked="" type="checkbox"/> Offline Cementing	<input checked="" type="checkbox"/> Casing Clearance

A. HYDROGEN SULFIDE

A Hydrogen Sulfide (H2S) Drilling Plan shall be activated AT SPUD. As a result, the Hydrogen Sulfide area must meet 43 CFR part 3170 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

B. CASING

Primary Casing Design:

1. The **13-3/8** inch surface casing shall be set at approximately **1000** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **16** inch in diameter.

- a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
 - b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
 - c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
 - d. If cement falls back, remedial cementing will be done prior to drilling out that string.
2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
- Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **5-1/2** inch production casing is:
- Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Casing Alternative Design A:

1. The **13-3/8** inch surface casing shall be set at approximately **2030** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **16** inch in diameter.
 - a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
 - b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
 - c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.

- d. If cement falls back, remedial cementing will be done prior to drilling out that string.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **5-1/2** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Operator has proposed to pump down 9-5/8" X 5-1/2" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 5-1/2" casing to surface after the second stage BH to verify TOC.

Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

If cement does not reach surface, the next casing string must come to surface.

Operator must use a limited flush fluid volume of 1 bbl following backside cementing procedures.

Casing Alternative Design B:

1. The **10-3/4** inch surface casing shall be set at approximately **2030** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **13-1/2** inch in diameter.
 - a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
 - b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8**

- hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
- c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
 - d. If cement falls back, remedial cementing will be done prior to drilling out that string.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **8-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **5-1/2** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Operator has proposed to pump down 8-5/8" X 5-1/2" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 5-1/2" casing to surface after the second stage BH to verify TOC.

Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

If cement does not reach surface, the next casing string must come to surface.

Operator must use a limited flush fluid volume of 1 bbl following backside cementing procedures.

Casing Alternative Design C:

1. The **13-3/8** inch surface casing shall be set at approximately **2030** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **16** inch in diameter.
 - a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature

survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.

- b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
- c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
- d. If cement falls back, remedial cementing will be done prior to drilling out that string.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **6** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Operator has proposed to pump down 9-5/8" X 6" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 6" casing to surface after the second stage BH to verify TOC.

Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

If cement does not reach surface, the next casing string must come to surface.

Operator must use a limited flush fluid volume of 1 bbl following backside cementing procedures.

Casing Alternative Design D:

1. The **13-3/8** inch surface casing shall be set at approximately **2030** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable

fresh water) and cemented to the surface. The surface hole shall be **16** inch in diameter.

- a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
- b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
- c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
- d. If cement falls back, remedial cementing will be done prior to drilling out that string.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **6 X 5-1/2** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Operator has proposed to pump down 9-5/8" X 6" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 6" casing to surface after the second stage BH to verify TOC.

Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

If cement does not reach surface, the next casing string must come to surface.

Operator must use a limited flush fluid volume of 1 bbl following backside cementing procedures.

C. PRESSURE CONTROL

1. Variance approved to use flex line from BOP to choke manifold. Manufacturer's specification to be readily available. No external damage to flex line. Flex line to be installed as straight as possible (no hard bends).'
2. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the **Surface** casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **10,000 (10M)** psi. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 3500 (70% Working Pressure) psi.**
 - a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
 - b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
 - c. Manufacturer representative shall install the test plug for the initial BOP test.
 - d. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
 - e. Whenever any seal subject to test pressure is broken, all the tests in OOGO2.III.A.2.i must be followed.

D. SPECIAL REQUIREMENT (S)

Communitization Agreement

- The operator will submit a Communitization Agreement to the Santa Fe Office, 301 Dinosaur Trail Santa Fe, New Mexico 87508, at least 90 days before the anticipated date of first production from a well subject to a spacing order issued by the New Mexico Oil Conservation Division. The Communitization Agreement will include the signatures of all working interest owners in all Federal and Indian leases subject to the Communitization Agreement (i.e., operating rights owners and lessees of record), or certification that the operator has obtained the written signatures of all such owners and will make those signatures available to the BLM immediately upon request.
- The operator will submit an as-drilled survey well plat of the well completion, but are not limited to, those specified in Onshore Order 1 and 2.
- 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.

BOPE Break Testing Variance

- BOPE Break Testing is ONLY permitted for 5M BOPE or less. (**Annular preventer must be tested to a minimum of 70% of BOPE working pressure and shall be higher than the MASP**)
- BOPE Break Testing is NOT permitted to drilling the production hole section.
- Variance only pertains to the intermediate hole-sections and no deeper than the Bone Springs formation.
- While in transfer between wells, the BOPE shall be secured by the hydraulic carrier or cradle.
- Any well control event while drilling require notification to the BLM Petroleum Engineer (**575-706-2779**) prior to the commencement of any BOPE Break Testing operations.
- A full BOPE test is required prior to drilling the first deep intermediate hole section. If any subsequent hole interval is deeper than the first, a full BOPE test will be required. (200' TVD tolerance between intermediate shoes is allowable).
- The BLM is to be contacted (575-689-5981 Lea County) 4 hours prior to BOPE tests.
- As a minimum, a full BOPE test shall be performed at 21-day intervals.
- In the event any repairs or replacement of the BOPE is required, the BOPE shall test as per Onshore Oil and Gas Order No. 2.
- If in the event break testing is not utilized, then a full BOPE test would be conducted.

Casing Clearance:

Operator casing variance is approved for the utilization of

- Annular clearance to meet or exceed 0.422'' between intermediate casing ID and production casing coupling only on the first 500' overlap between both casing strings.

-Annular clearance less than 0.422'' is acceptable for the production open hole section.

Operator shall clean up cycles until wellbore is clear of cuttings and any large debris, ensure cutting sizes are adequate "coffee ground or less" before cementing.

Offline Cementing:

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)

Lea County

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

1. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval.
 - a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
 - b. When the operator proposes to set surface casing with Spudder Rig
 - 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.

JAM 3/7/2025



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1. GEOLOGIC NAME OF SURFACE FORMATION:

Permian

2. ESTIMATED TOPS OF IMPORTANT GEOLOGICAL MARKERS:

Rustler	890'
Tamarisk Anhydrite	970'
Top of Salt	1,308'
Base of Salt	5,095'
Lamar	5,323'
Bell Canyon	5,354'
Cherry Canyon	6,302'
Brushy Canyon	7,882'
Bone Spring Lime	9,346'
Leonard (Avalon) Shale	9,370'
1st Bone Spring Sand	10,390'
2nd Bone Spring Shale	10,605'
2nd Bone Spring Sand	10,932'
3rd Bone Spring Carb	11,413'
3rd Bone Spring Sand	12,010'
Wolfcamp	12,475'
TD	9,500'

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

Upper Permian Sands	0- 400'	Fresh Water
Bell Canyon	5,354'	Oil
Cherry Canyon	6,302'	Oil
Brushy Canyon	7,882'	Oil
Leonard (Avalon) Shale	9,370'	Oil
1st Bone Spring Sand	10,390'	Oil
2nd Bone Spring Shale	10,605'	Oil
2nd Bone Spring Sand	10,932'	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 1,000' and circulating cement back to surface.



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*Please refer to approved NOI appended to this application for the most recent details for the planned well.

4. CASING PROGRAM

Hole Size	Interval MD		Interval TVD		Csg OD	Weight	Grade	Conn
	From (ft)	To (ft)	From (ft)	To (ft)				
16"	0	1,000	0	1,000	13-3/8"	54.5#	J-55	STC
11"	0	4,000	0	4,000	9-5/8"	40#	J-55	LTC
11"	4,000	5,200	4,000	5,200	9-5/8"	40#	HCK-55	LTC
6-3/4"	0	19,704	0	9,500	5-1/2"	17#	HCP-110	LTC

Variance is requested to waive the centralizer requirements for the 9-5/8" casing in the 11" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 11" hole interval to maximize cement bond and zonal isolation.

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

EOG requests permission to allow deviation from the 0.422" annulus clearance requirement for the intermediate (salt) section from Onshore Order #2 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues.

*Please refer to approved NOI appended to this application for the most recent details for the planned well.

Cementing Program:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,000' 13-3/8"	300	13.5	1.73	Lead: Class C + 4.0% Bentonite Gel + 0.5% CaCl ₂ + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	100	14.8	1.34	Tail: Class C + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 800')
5,200' 9-5/8"	470	12.7	2.22	Lead: Class C + 10% NaCl + 6% Bentonite Gel + 3% MagOx (TOC @ Surface)
	170	14.8	1.32	Tail: Class C + 10% NaCl + 3% MagOx (TOC @ 4160')
19,704' 5-1/2"	330	10.5	3.21	Lead: Class H + 0.4% Halad-344 + 0.35% HR-601 + 3% Microbond (TOC @ 4700')
	750	13.2	1.52	Tail: Class H + 5% NEX-020 + 0.2% NAC-102 + 0.15% NAS-725 + 0.5% NFL-549 + 0.2% NFP-703 + 1% NBE-737 + 0.3% NRT-241 (TOC @ 9030')



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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.

5. MINIMUM SPECIFICATIONS FOR PRESSURE CONTROL:

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

The minimum blowout preventer equipment (BOPE) shown in Exhibit #1 will consist of a single ram, mud cross and double ram-type (10,000 psi WP) preventer and an annular preventer (5,000-psi WP). Both units will be hydraulically operated and the ram-type will be equipped with blind rams on bottom and drill pipe rams on top. All BOPE will be tested in accordance with Onshore Oil & Gas order No. 2.

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.

Before drilling out of the surface casing, the ram-type BOP and accessory equipment will be tested to 10,000/ 250 psig and the annular preventer to 5,000/ 250 psig.

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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6. TYPES AND CHARACTERISTICS OF THE PROPOSED MUD SYSTEM:

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

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

Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 1,000'	Fresh - Gel	8.6-8.8	28-34	N/c
1,000' – 5,200'	Brine	8.6-8.8	28-34	N/c
5,000' – 19,704' Lateral	Oil Base	8.8-9.5	58-68	N/c - 6

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

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

7. AUXILIARY WELL CONTROL AND MONITORING EQUIPMENT:

- (A) A kelly cock will be kept in the drill string at all times.
- (B) A full opening drill pipe-stabbing valve (inside BOP) with proper drill pipe connections will be on the rig floor at all times.
- (C) H2S monitoring and detection equipment will be utilized from surface casing point to TD.

8. LOGGING, TESTING AND CORING PROGRAM:

- (A) Open-hole logs are not planned for this well.
- (B) GR-CCL will be run in cased hole during completions phase of operations.

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

The estimated bottom-hole temperature (BHT) at TD is 165 degrees F with an estimated maximum bottom-hole pressure (BHP) at TD of 4,446 psig and a maximum anticipated surface pressure of 2,356 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 7,882' to intermediate casing point.



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10. ANTICIPATED STARTING DATE AND DURATION OF OPERATIONS:

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

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

11. WELLHEAD & Offline Cementing:

A multi-bowl wellhead system will be utilized.

After running the 13-3/8" surface casing, a 13-3/8" BOP/BOPE system with a minimum working pressure of 10,000 psi will be installed on the wellhead system and will be pressure tested to 250 psi low followed by a 10,000 psi pressure test. This pressure test will be repeated at least every 30 days, as per Onshore Order No. 2.

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

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

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 5000 psi.

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



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EOG Resources Inc. (EOG) respectfully requests a variance from the minimum standards for well control equipment testing of Onshore Order No. 2 (item III.A.2.a.i) to allow a testing schedule of the blow out preventer (BOP) and blow out prevention equipment (BOPE) along with Batch Drilling & Offline cement operations to include the following:

- Full BOPE test at first installation on the pad.
- Full BOPE test every 20 days per Onshore Order No. 2.
- Function test BOP elements per Onshore Order No. 2.
- Break testing BOP and BOPE coupled with batch drilling operations and option to offline cement and/or remediate (if needed) any surface or intermediate sections, according to attached offline cementing support documentation.
- After the well section is secured, the BOP will be disconnected from the wellhead and walked with the rig to another well on the pad.
- TA cap will also be installed per Wellhead vendor procedure and pressure inside the casing will be monitored via the valve on the TA cap as per standard batch drilling ops.
- See attached "EOG BLM Variance 3a -Offline Cement Intermediate Operational Procedure"



Wild Weasel 22 Fed Com 104H

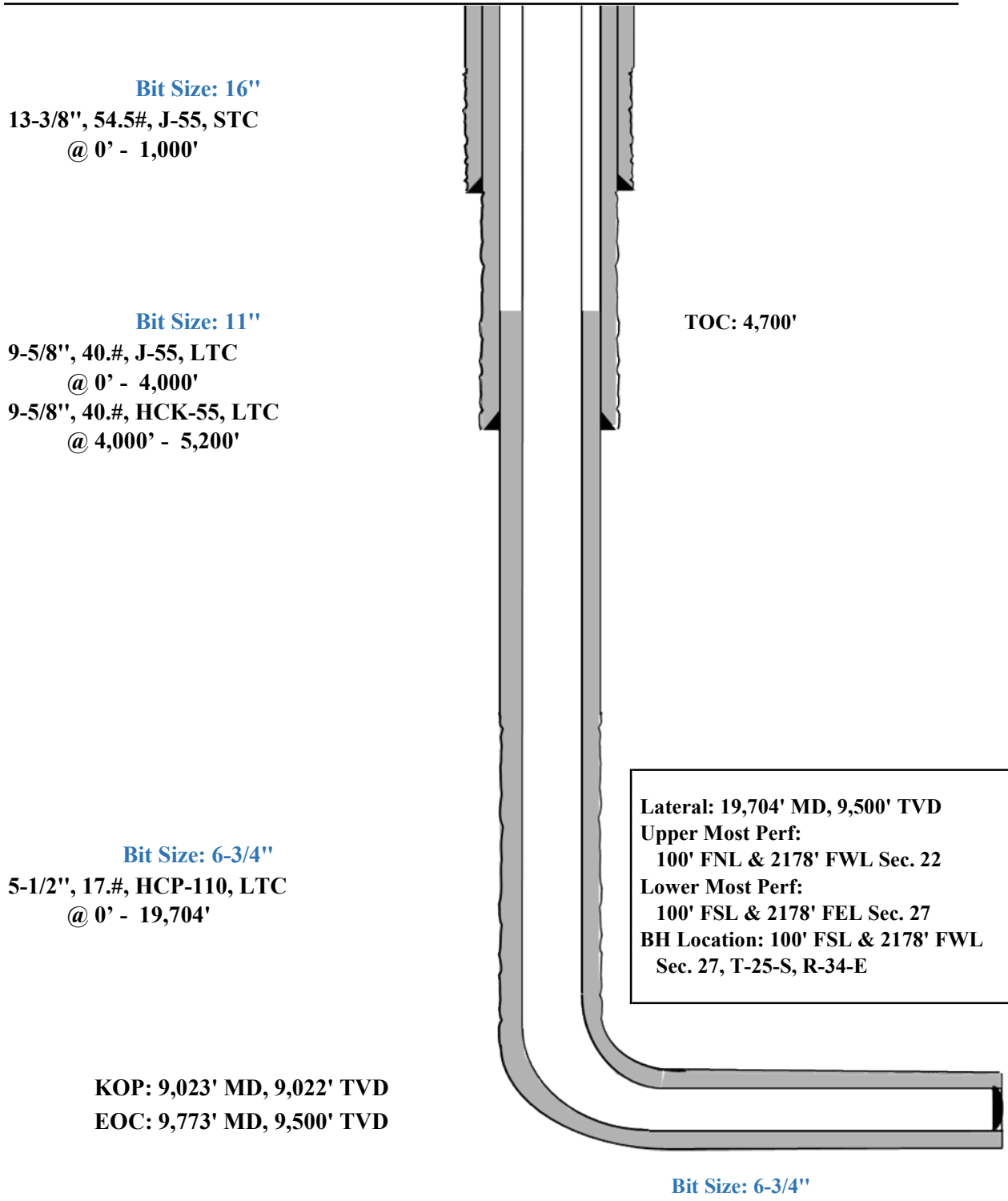
*Please refer to approved NOI appended to this application for the most recent details for the planned well.

644' FNL
2639' FEL
Section 22
T-25-S, R-34-E

Proposed Wellbore A

API: 30-025-*****

KB: 3377'
GL: 3352'





Wild Weasel 22 Fed Com 104H

Well Name: Wild Weasel 22 Fed Com 104H

Location: SHL: 644' FNL & 2639' FEL, Section 22, T-25-S, R-34-E, Lea Co., N.M.

BHL: 100' FSL & 2178' FWL, Section 27, T-25-S, R-34-E, Lea Co., N.M.

*Please refer to approved NOI appended to this application for the most recent details for the planned well.

Casing Program B:

Hole Size	Interval MD		Interval TVD		Csg OD	Weight	Grade	Conn
	From (ft)	To (ft)	From (ft)	To (ft)				
13-1/2"	0	1,000	0	1,000	10-3/4"	40.5#	J-55	STC
9-7/8"	0	4,000	0	4,000	8-5/8"	32#	J-55	BTC-SC
9-7/8"	4,000	5,200	4,000	5,200	8-5/8"	32#	P110-EC	BTC-SC
6-3/4"	0	19,704	0	9,500	5-1/2"	17#	HCP-110	LTC

*Please refer to approved NOI appended to this application for the most recent details for the planned well.

Cementing Program:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,000' 10-3/4"	340	13.5	1.73	Lead: Class C + 4.0% Bentonite Gel + 0.5% CaCl ₂ + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	110	14.8	1.34	Tail: Class C + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 800')
5,200' 8-5/8"	350	12.7	2.22	Lead: Class C + 10% NaCl + 6% Bentonite Gel + 3% MagOx (TOC @ Surface)
	160	14.8	1.32	Tail: Class C + 10% NaCl + 3% MagOx (TOC @ 4,160')
19,704' 5-1/2"	460	10.5	3.21	Lead: Class H + 0.4% Halad-344 + 0.35% HR-601 + 3% Microbond (TOC @ 4,700')
	770	13.2	1.52	Tail: Class H + 5% NEX-020 + 0.2% NAC-102 + 0.15% NAS-725 + 0.5% NFL-549 + 0.2% NFP-703 + 1% NBE-737 + 0.3% NRT-241 (TOC @ 9030')



Wild Weasel 22 Fed Com 104H

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

Wellhead & Offline Cementing:

EOG Resources Inc. (EOG) respectfully requests a variance from the minimum standards for well control equipment testing of Onshore Order No. 2 (item III.A.2.a.i) to allow a testing schedule of the blow out preventer (BOP) and blow out prevention equipment (BOPE) along with Batch Drilling & Offline cement operations to include the following:

- Full BOPE test at first installation on the pad.
- Full BOPE test every 30 days per Onshore Order No. 2.
- Function test BOP elements per Onshore Order No. 2.
- Break testing BOP and BOPE coupled with batch drilling operations and option to offline cement and/or remediate (if needed) any surface or intermediate sections, according to attached offline cementing support documentation.
- After the well section is secured, the BOP will be disconnected from the wellhead and walked with the rig to another well on the pad.
- TA cap will also be installed per Wellhead vendor procedure and pressure inside the casing will be monitored via the valve on the TA cap as per standard batch drilling ops.
- See attached "EOG BLM Variance 3a -Offline Cement Intermediate Operational Procedure"



Wild Weasel 22 Fed Com 104H

*Please refer to approved NOI appended to this application for the most recent details for the planned well.

644'
2639'

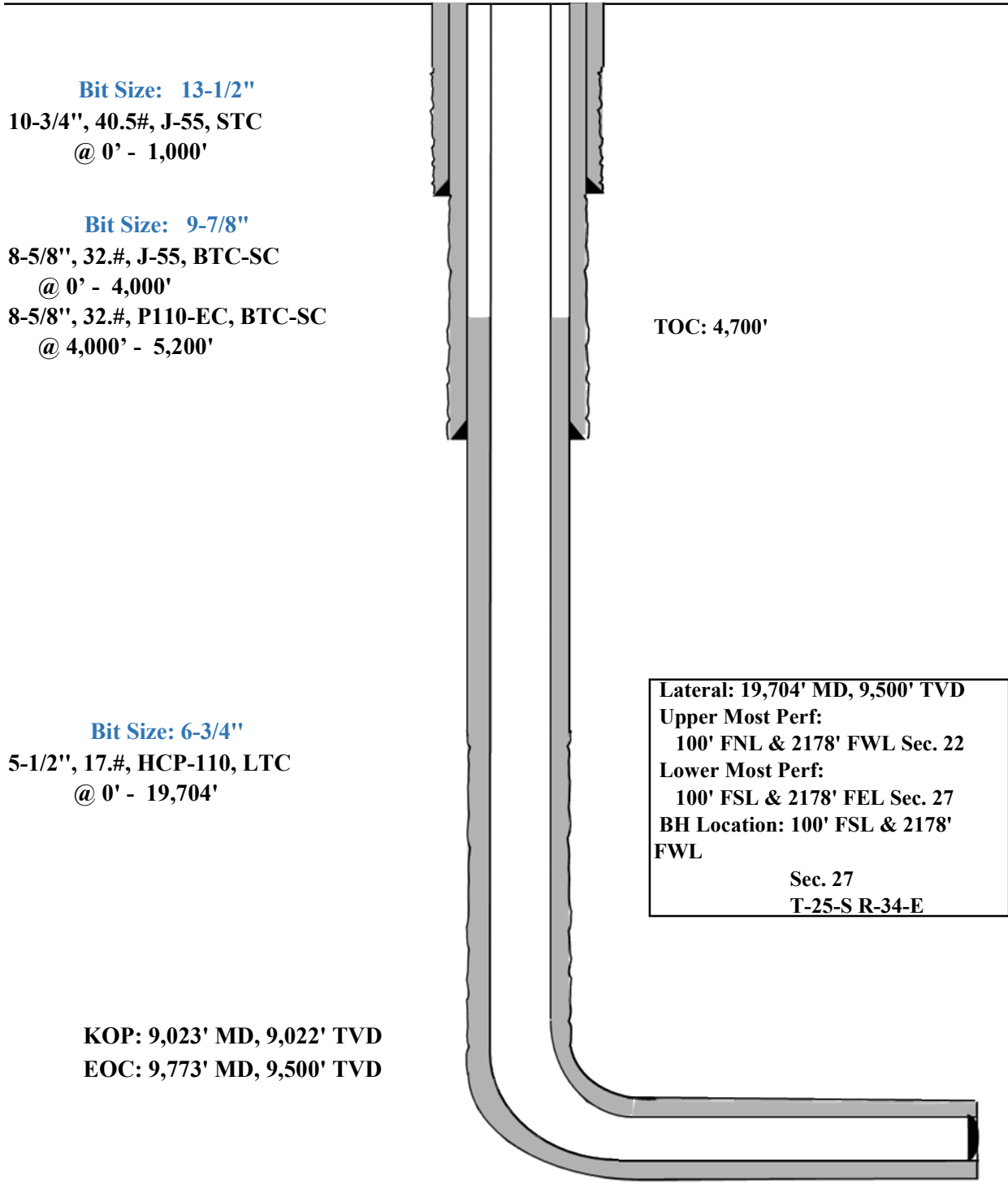
Proposed Wellbore B:

KB: 3377'
GL: 3352'

Section 22

T-25-S, R-34-E

API: 30-025-*****



Bit Size: 13-1/2"
10-3/4", 40.5#, J-55, STC
@ 0' - 1,000'

Bit Size: 9-7/8"
8-5/8", 32.#, J-55, BTC-SC
@ 0' - 4,000'
8-5/8", 32.#, P110-EC, BTC-SC
@ 4,000' - 5,200'

Bit Size: 6-3/4"
5-1/2", 17.#, HCP-110, LTC
@ 0' - 19,704'

TOC: 4,700'

Lateral: 19,704' MD, 9,500' TVD
Upper Most Perf: 100' FNL & 2178' FWL Sec. 22
Lower Most Perf: 100' FSL & 2178' FEL Sec. 27
BH Location: 100' FSL & 2178' FWL
Sec. 27 T-25-S R-34-E

KOP: 9,023' MD, 9,022' TVD
EOC: 9,773' MD, 9,500' TVD

Midland

Lea County, NM (NAD 83 NME)

Wild Weasel 22 Fed Com

#104H

OH

Plan: Plan #0.1 RT

*Please refer to approved NOI appended to this application for the most recent details for the planned well.

Standard Planning Report

25 February, 2026

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #104H
Company:	Midland	TVD Reference:	kb = 26' @ 3378.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3378.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#104H	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	Wild Weasel 22 Fed Com				
Site Position:		Northing:	409,434.00 usft	Latitude:	32° 7' 21.137 N
From:	Map	Easting:	814,510.00 usft	Longitude:	103° 27' 3.375 W
Position Uncertainty:	0.0 usft	Slot Radius:	13-3/16 "		

Well	#104H					
Well Position	+N/-S	0.0 usft	Northing:	409,035.00 usft	Latitude:	32° 7' 17.361 N
	+E/-W	0.0 usft	Easting:	812,386.00 usft	Longitude:	103° 27' 28.109 W
Position Uncertainty	0.0 usft		Wellhead Elevation:	usft	Ground Level:	3,352.0 usft
Grid Convergence:	0.47 °					

Wellbore	OH				
Magnetics	Model Name	Sample Date	Declination (°)	Dip Angle (°)	Field Strength (nT)
	IGRF2020	1/12/2023	6.30	59.77	47,280.48018318

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	182.26

Plan Survey Tool Program	Date	2/25/2026		
Depth From (usft)	Depth To (usft)	Survey (Wellbore)	Tool Name	Remarks
1	0.0	19,731.6 Plan #0.1 RT (OH)	EOG MWD+IFR1 MWD + IFR1	

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #104H
Company:	Midland	TVD Reference:	kb = 26' @ 3378.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3378.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#104H	Survey Calculation Method:	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

Plan Sections										
Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)	TFO (°)	Target
0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,300.0	0.00	0.00	1,300.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,646.7	6.93	321.21	1,645.8	16.3	-13.1	2.00	2.00	0.00	321.21	
7,580.4	6.93	321.21	7,536.2	574.7	-461.9	0.00	0.00	0.00	0.00	
7,927.1	0.00	360.00	7,882.0	591.0	-475.0	2.00	-2.00	0.00	180.00	
9,067.6	0.00	360.00	9,022.5	591.0	-475.0	0.00	0.00	0.00	0.00	0.00 KOP(Wild Weasel 22
9,288.0	26.46	180.00	9,235.2	541.0	-475.0	12.00	12.00	-81.65	180.00	FTP(Wild Weasel 22 I
9,817.5	90.00	179.47	9,499.9	113.6	-472.3	12.00	12.00	-0.10	-0.59	
10,608.1	90.00	179.47	9,500.0	-677.0	-465.0	0.00	0.00	0.00	0.00	Fed Perf 1(Wild Weas
19,749.5	90.00	179.55	9,500.0	-9,818.0	-387.0	0.00	0.00	0.00	84.41	PBHL(Wild Weasel 22

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #104H
Company:	Midland	TVD Reference:	kb = 26' @ 3378.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3378.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#104H	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	2.00	321.21	1,400.0	1.4	-1.1	-1.3	2.00	2.00	0.00
1,500.0	4.00	321.21	1,499.8	5.4	-4.4	-5.3	2.00	2.00	0.00
1,600.0	6.00	321.21	1,599.5	12.2	-9.8	-11.8	2.00	2.00	0.00
1,646.7	6.93	321.21	1,645.8	16.3	-13.1	-15.8	2.00	2.00	0.00
1,700.0	6.93	321.21	1,698.8	21.3	-17.2	-20.7	0.00	0.00	0.00
1,800.0	6.93	321.21	1,798.0	30.8	-24.7	-29.8	0.00	0.00	0.00
1,900.0	6.93	321.21	1,897.3	40.2	-32.3	-38.9	0.00	0.00	0.00
2,000.0	6.93	321.21	1,996.6	49.6	-39.8	-48.0	0.00	0.00	0.00
2,100.0	6.93	321.21	2,095.8	59.0	-47.4	-57.1	0.00	0.00	0.00
2,200.0	6.93	321.21	2,195.1	68.4	-55.0	-66.2	0.00	0.00	0.00
2,300.0	6.93	321.21	2,294.4	77.8	-62.5	-75.3	0.00	0.00	0.00
2,400.0	6.93	321.21	2,393.6	87.2	-70.1	-84.4	0.00	0.00	0.00
2,500.0	6.93	321.21	2,492.9	96.6	-77.7	-93.5	0.00	0.00	0.00
2,600.0	6.93	321.21	2,592.2	106.0	-85.2	-102.6	0.00	0.00	0.00
2,700.0	6.93	321.21	2,691.5	115.4	-92.8	-111.7	0.00	0.00	0.00
2,800.0	6.93	321.21	2,790.7	124.9	-100.3	-120.8	0.00	0.00	0.00
2,900.0	6.93	321.21	2,890.0	134.3	-107.9	-129.9	0.00	0.00	0.00
3,000.0	6.93	321.21	2,989.3	143.7	-115.5	-139.0	0.00	0.00	0.00
3,100.0	6.93	321.21	3,088.5	153.1	-123.0	-148.1	0.00	0.00	0.00
3,200.0	6.93	321.21	3,187.8	162.5	-130.6	-157.2	0.00	0.00	0.00
3,300.0	6.93	321.21	3,287.1	171.9	-138.2	-166.3	0.00	0.00	0.00
3,400.0	6.93	321.21	3,386.3	181.3	-145.7	-175.4	0.00	0.00	0.00
3,500.0	6.93	321.21	3,485.6	190.7	-153.3	-184.5	0.00	0.00	0.00
3,600.0	6.93	321.21	3,584.9	200.1	-160.8	-193.6	0.00	0.00	0.00
3,700.0	6.93	321.21	3,684.1	209.5	-168.4	-202.7	0.00	0.00	0.00
3,800.0	6.93	321.21	3,783.4	218.9	-176.0	-211.8	0.00	0.00	0.00
3,900.0	6.93	321.21	3,882.7	228.4	-183.5	-221.0	0.00	0.00	0.00
4,000.0	6.93	321.21	3,981.9	237.8	-191.1	-230.1	0.00	0.00	0.00
4,100.0	6.93	321.21	4,081.2	247.2	-198.7	-239.2	0.00	0.00	0.00
4,200.0	6.93	321.21	4,180.5	256.6	-206.2	-248.3	0.00	0.00	0.00
4,300.0	6.93	321.21	4,279.7	266.0	-213.8	-257.4	0.00	0.00	0.00
4,400.0	6.93	321.21	4,379.0	275.4	-221.4	-266.5	0.00	0.00	0.00
4,500.0	6.93	321.21	4,478.3	284.8	-228.9	-275.6	0.00	0.00	0.00
4,600.0	6.93	321.21	4,577.6	294.2	-236.5	-284.7	0.00	0.00	0.00
4,700.0	6.93	321.21	4,676.8	303.6	-244.0	-293.8	0.00	0.00	0.00
4,800.0	6.93	321.21	4,776.1	313.0	-251.6	-302.9	0.00	0.00	0.00
4,900.0	6.93	321.21	4,875.4	322.5	-259.2	-312.0	0.00	0.00	0.00
5,000.0	6.93	321.21	4,974.6	331.9	-266.7	-321.1	0.00	0.00	0.00
5,100.0	6.93	321.21	5,073.9	341.3	-274.3	-330.2	0.00	0.00	0.00
5,200.0	6.93	321.21	5,173.2	350.7	-281.9	-339.3	0.00	0.00	0.00

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #104H
Company:	Midland	TVD Reference:	kb = 26' @ 3378.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3378.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#104H	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	6.93	321.21	5,272.4	360.1	-289.4	-348.4	0.00	0.00	0.00
5,400.0	6.93	321.21	5,371.7	369.5	-297.0	-357.5	0.00	0.00	0.00
5,500.0	6.93	321.21	5,471.0	378.9	-304.5	-366.6	0.00	0.00	0.00
5,600.0	6.93	321.21	5,570.2	388.3	-312.1	-375.7	0.00	0.00	0.00
5,700.0	6.93	321.21	5,669.5	397.7	-319.7	-384.8	0.00	0.00	0.00
5,800.0	6.93	321.21	5,768.8	407.1	-327.2	-393.9	0.00	0.00	0.00
5,900.0	6.93	321.21	5,868.0	416.6	-334.8	-403.0	0.00	0.00	0.00
6,000.0	6.93	321.21	5,967.3	426.0	-342.4	-412.1	0.00	0.00	0.00
6,100.0	6.93	321.21	6,066.6	435.4	-349.9	-421.2	0.00	0.00	0.00
6,200.0	6.93	321.21	6,165.9	444.8	-357.5	-430.4	0.00	0.00	0.00
6,300.0	6.93	321.21	6,265.1	454.2	-365.0	-439.5	0.00	0.00	0.00
6,400.0	6.93	321.21	6,364.4	463.6	-372.6	-448.6	0.00	0.00	0.00
6,500.0	6.93	321.21	6,463.7	473.0	-380.2	-457.7	0.00	0.00	0.00
6,600.0	6.93	321.21	6,562.9	482.4	-387.7	-466.8	0.00	0.00	0.00
6,700.0	6.93	321.21	6,662.2	491.8	-395.3	-475.9	0.00	0.00	0.00
6,800.0	6.93	321.21	6,761.5	501.2	-402.9	-485.0	0.00	0.00	0.00
6,900.0	6.93	321.21	6,860.7	510.6	-410.4	-494.1	0.00	0.00	0.00
7,000.0	6.93	321.21	6,960.0	520.1	-418.0	-503.2	0.00	0.00	0.00
7,100.0	6.93	321.21	7,059.3	529.5	-425.5	-512.3	0.00	0.00	0.00
7,200.0	6.93	321.21	7,158.5	538.9	-433.1	-521.4	0.00	0.00	0.00
7,300.0	6.93	321.21	7,257.8	548.3	-440.7	-530.5	0.00	0.00	0.00
7,400.0	6.93	321.21	7,357.1	557.7	-448.2	-539.6	0.00	0.00	0.00
7,500.0	6.93	321.21	7,456.3	567.1	-455.8	-548.7	0.00	0.00	0.00
7,580.4	6.93	321.21	7,536.2	574.7	-461.9	-556.0	0.00	0.00	0.00
7,600.0	6.54	321.21	7,555.6	576.5	-463.3	-557.8	2.00	-2.00	0.00
7,700.0	4.54	321.21	7,655.2	584.0	-469.4	-565.0	2.00	-2.00	0.00
7,800.0	2.54	321.21	7,755.0	588.8	-473.2	-569.7	2.00	-2.00	0.00
7,900.0	0.54	321.21	7,854.9	590.9	-474.9	-571.7	2.00	-2.00	0.00
7,927.1	0.00	360.00	7,882.0	591.0	-475.0	-571.8	2.00	-2.00	0.00
8,000.0	0.00	0.00	7,954.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,100.0	0.00	0.00	8,054.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,200.0	0.00	0.00	8,154.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,300.0	0.00	0.00	8,254.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,400.0	0.00	0.00	8,354.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,500.0	0.00	0.00	8,454.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,600.0	0.00	0.00	8,554.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,700.0	0.00	0.00	8,654.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,800.0	0.00	0.00	8,754.9	591.0	-475.0	-571.8	0.00	0.00	0.00
8,900.0	0.00	0.00	8,854.9	591.0	-475.0	-571.8	0.00	0.00	0.00
9,000.0	0.00	0.00	8,954.9	591.0	-475.0	-571.8	0.00	0.00	0.00
9,067.6	0.00	360.00	9,022.5	591.0	-475.0	-571.8	0.00	0.00	0.00
9,075.0	0.89	180.00	9,029.9	590.9	-475.0	-571.8	12.00	12.00	0.00
9,100.0	3.89	180.00	9,054.9	589.9	-475.0	-570.7	12.00	12.00	0.00
9,125.0	6.89	180.00	9,079.8	587.6	-475.0	-568.4	12.00	12.00	0.00
9,150.0	9.89	180.00	9,104.5	583.9	-475.0	-564.7	12.00	12.00	0.00
9,175.0	12.89	180.00	9,129.0	579.0	-475.0	-559.8	12.00	12.00	0.00
9,200.0	15.89	180.00	9,153.2	572.8	-475.0	-553.6	12.00	12.00	0.00
9,225.0	18.89	180.00	9,177.1	565.3	-475.0	-546.1	12.00	12.00	0.00
9,250.0	21.89	180.00	9,200.5	556.6	-475.0	-537.4	12.00	12.00	0.00
9,275.0	24.89	180.00	9,223.4	546.6	-475.0	-527.5	12.00	12.00	0.00
9,288.0	26.46	180.00	9,235.2	541.0	-475.0	-521.9	12.00	12.00	0.00
9,300.0	27.89	179.97	9,245.8	535.5	-475.0	-516.4	12.00	12.00	-0.26
9,325.0	30.89	179.91	9,267.6	523.3	-475.0	-504.2	12.00	12.00	-0.23
9,350.0	33.89	179.86	9,288.7	509.9	-475.0	-490.8	12.00	12.00	-0.19

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #104H
Company:	Midland	TVD Reference:	kb = 26' @ 3378.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3378.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#104H	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)
9,375.0	36.89	179.82	9,309.1	495.4	-474.9	-476.3	12.00	12.00	-0.16
9,400.0	39.89	179.79	9,328.7	479.9	-474.9	-460.8	12.00	12.00	-0.14
9,425.0	42.89	179.76	9,347.5	463.3	-474.8	-444.3	12.00	12.00	-0.13
9,450.0	45.89	179.73	9,365.3	445.9	-474.7	-426.8	12.00	12.00	-0.11
9,475.0	48.89	179.70	9,382.2	427.5	-474.6	-408.4	12.00	12.00	-0.10
9,500.0	51.89	179.68	9,398.2	408.2	-474.5	-389.2	12.00	12.00	-0.09
9,525.0	54.89	179.66	9,413.1	388.1	-474.4	-369.2	12.00	12.00	-0.09
9,550.0	57.89	179.64	9,426.9	367.3	-474.3	-348.4	12.00	12.00	-0.08
9,575.0	60.89	179.62	9,439.6	345.8	-474.1	-326.9	12.00	12.00	-0.07
9,600.0	63.89	179.60	9,451.2	323.7	-474.0	-304.7	12.00	12.00	-0.07
9,625.0	66.89	179.58	9,461.6	300.9	-473.8	-282.0	12.00	12.00	-0.07
9,650.0	69.89	179.57	9,470.8	277.7	-473.7	-258.8	12.00	12.00	-0.06
9,675.0	72.89	179.55	9,478.8	254.0	-473.5	-235.2	12.00	12.00	-0.06
9,700.0	75.89	179.54	9,485.5	229.9	-473.3	-211.1	12.00	12.00	-0.06
9,725.0	78.89	179.52	9,491.0	205.5	-473.1	-186.7	12.00	12.00	-0.06
9,750.0	81.89	179.51	9,495.2	180.9	-472.9	-162.1	12.00	12.00	-0.06
9,775.0	84.89	179.50	9,498.1	156.1	-472.7	-137.3	12.00	12.00	-0.06
9,800.0	87.89	179.48	9,499.6	131.1	-472.4	-112.4	12.00	12.00	-0.06
9,817.5	90.00	179.47	9,499.9	113.6	-472.3	-94.9	12.00	12.00	-0.05
9,900.0	90.00	179.47	9,500.0	31.1	-471.5	-12.5	0.00	0.00	0.00
10,000.0	90.00	179.47	9,500.0	-68.9	-470.6	87.4	0.00	0.00	0.00
10,100.0	90.00	179.47	9,500.0	-168.9	-469.7	187.2	0.00	0.00	0.00
10,200.0	90.00	179.47	9,500.0	-268.9	-468.8	287.1	0.00	0.00	0.00
10,300.0	90.00	179.47	9,500.0	-368.9	-467.8	387.0	0.00	0.00	0.00
10,400.0	90.00	179.47	9,500.0	-468.9	-466.9	486.9	0.00	0.00	0.00
10,500.0	90.00	179.47	9,500.0	-568.9	-466.0	586.8	0.00	0.00	0.00
10,608.1	90.00	179.47	9,500.0	-677.0	-465.0	694.8	0.00	0.00	0.00
10,700.0	90.00	179.47	9,500.0	-768.8	-464.2	786.5	0.00	0.00	0.00
10,800.0	90.00	179.47	9,500.0	-868.8	-463.2	886.4	0.00	0.00	0.00
10,900.0	90.00	179.48	9,500.0	-968.8	-462.3	986.3	0.00	0.00	0.00
11,000.0	90.00	179.48	9,500.0	-1,068.8	-461.4	1,086.2	0.00	0.00	0.00
11,100.0	90.00	179.48	9,500.0	-1,168.8	-460.5	1,186.1	0.00	0.00	0.00
11,200.0	90.00	179.48	9,500.0	-1,268.8	-459.6	1,285.9	0.00	0.00	0.00
11,300.0	90.00	179.48	9,500.0	-1,368.8	-458.7	1,385.8	0.00	0.00	0.00
11,400.0	90.00	179.48	9,500.0	-1,468.8	-457.8	1,485.7	0.00	0.00	0.00
11,500.0	90.00	179.48	9,500.1	-1,568.8	-456.8	1,585.6	0.00	0.00	0.00
11,600.0	90.00	179.48	9,500.1	-1,668.8	-455.9	1,685.5	0.00	0.00	0.00
11,700.0	90.00	179.48	9,500.1	-1,768.8	-455.0	1,785.4	0.00	0.00	0.00
11,800.0	90.00	179.48	9,500.1	-1,868.8	-454.1	1,885.2	0.00	0.00	0.00
11,900.0	90.00	179.48	9,500.1	-1,968.8	-453.2	1,985.1	0.00	0.00	0.00
12,000.0	90.00	179.48	9,500.1	-2,068.8	-452.3	2,085.0	0.00	0.00	0.00
12,100.0	90.00	179.49	9,500.1	-2,168.8	-451.4	2,184.9	0.00	0.00	0.00
12,200.0	90.00	179.49	9,500.1	-2,268.8	-450.5	2,284.8	0.00	0.00	0.00
12,300.0	90.00	179.49	9,500.1	-2,368.8	-449.6	2,384.7	0.00	0.00	0.00
12,400.0	90.00	179.49	9,500.1	-2,468.8	-448.7	2,484.5	0.00	0.00	0.00
12,500.0	90.00	179.49	9,500.1	-2,568.8	-447.8	2,584.4	0.00	0.00	0.00
12,600.0	90.00	179.49	9,500.1	-2,668.8	-447.0	2,684.3	0.00	0.00	0.00
12,700.0	90.00	179.49	9,500.1	-2,768.8	-446.1	2,784.2	0.00	0.00	0.00
12,800.0	90.00	179.49	9,500.1	-2,868.8	-445.2	2,884.1	0.00	0.00	0.00
12,900.0	90.00	179.49	9,500.1	-2,968.8	-444.3	2,984.0	0.00	0.00	0.00
13,000.0	90.00	179.49	9,500.1	-3,068.8	-443.4	3,083.8	0.00	0.00	0.00
13,100.0	90.00	179.49	9,500.1	-3,168.7	-442.5	3,183.7	0.00	0.00	0.00
13,200.0	90.00	179.49	9,500.1	-3,268.7	-441.6	3,283.6	0.00	0.00	0.00
13,300.0	90.00	179.50	9,500.1	-3,368.7	-440.8	3,383.5	0.00	0.00	0.00

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #104H
Company:	Midland	TVD Reference:	kb = 26' @ 3378.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3378.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#104H	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	179.50	9,500.1	-3,468.7	-439.9	3,483.4	0.00	0.00	0.00
13,500.0	90.00	179.50	9,500.1	-3,568.7	-439.0	3,583.3	0.00	0.00	0.00
13,600.0	90.00	179.50	9,500.1	-3,668.7	-438.1	3,683.1	0.00	0.00	0.00
13,700.0	90.00	179.50	9,500.1	-3,768.7	-437.2	3,783.0	0.00	0.00	0.00
13,800.0	90.00	179.50	9,500.1	-3,868.7	-436.4	3,882.9	0.00	0.00	0.00
13,900.0	90.00	179.50	9,500.1	-3,968.7	-435.5	3,982.8	0.00	0.00	0.00
14,000.0	90.00	179.50	9,500.1	-4,068.7	-434.6	4,082.7	0.00	0.00	0.00
14,100.0	90.00	179.50	9,500.1	-4,168.7	-433.8	4,182.6	0.00	0.00	0.00
14,200.0	90.00	179.50	9,500.1	-4,268.7	-432.9	4,282.4	0.00	0.00	0.00
14,300.0	90.00	179.50	9,500.1	-4,368.7	-432.0	4,382.3	0.00	0.00	0.00
14,400.0	90.00	179.50	9,500.1	-4,468.7	-431.2	4,482.2	0.00	0.00	0.00
14,500.0	90.00	179.51	9,500.1	-4,568.7	-430.3	4,582.1	0.00	0.00	0.00
14,600.0	90.00	179.51	9,500.1	-4,668.7	-429.4	4,682.0	0.00	0.00	0.00
14,700.0	90.00	179.51	9,500.1	-4,768.7	-428.6	4,781.9	0.00	0.00	0.00
14,800.0	90.00	179.51	9,500.1	-4,868.7	-427.7	4,881.8	0.00	0.00	0.00
14,900.0	90.00	179.51	9,500.1	-4,968.7	-426.8	4,981.6	0.00	0.00	0.00
15,000.0	90.00	179.51	9,500.2	-5,068.7	-426.0	5,081.5	0.00	0.00	0.00
15,100.0	90.00	179.51	9,500.2	-5,168.7	-425.1	5,181.4	0.00	0.00	0.00
15,200.0	90.00	179.51	9,500.2	-5,268.7	-424.3	5,281.3	0.00	0.00	0.00
15,300.0	90.00	179.51	9,500.2	-5,368.7	-423.4	5,381.2	0.00	0.00	0.00
15,400.0	90.00	179.51	9,500.2	-5,468.7	-422.6	5,481.1	0.00	0.00	0.00
15,500.0	90.00	179.51	9,500.1	-5,568.7	-421.7	5,580.9	0.00	0.00	0.00
15,600.0	90.00	179.51	9,500.1	-5,668.7	-420.9	5,680.8	0.00	0.00	0.00
15,700.0	90.00	179.52	9,500.1	-5,768.7	-420.0	5,780.7	0.00	0.00	0.00
15,800.0	90.00	179.52	9,500.1	-5,868.6	-419.2	5,880.6	0.00	0.00	0.00
15,900.0	90.00	179.52	9,500.1	-5,968.6	-418.3	5,980.5	0.00	0.00	0.00
16,000.0	90.00	179.52	9,500.1	-6,068.6	-417.5	6,080.4	0.00	0.00	0.00
16,100.0	90.00	179.52	9,500.1	-6,168.6	-416.7	6,180.3	0.00	0.00	0.00
16,200.0	90.00	179.52	9,500.1	-6,268.6	-415.8	6,280.1	0.00	0.00	0.00
16,300.0	90.00	179.52	9,500.1	-6,368.6	-415.0	6,380.0	0.00	0.00	0.00
16,400.0	90.00	179.52	9,500.1	-6,468.6	-414.2	6,479.9	0.00	0.00	0.00
16,500.0	90.00	179.52	9,500.1	-6,568.6	-413.3	6,579.8	0.00	0.00	0.00
16,600.0	90.00	179.52	9,500.1	-6,668.6	-412.5	6,679.7	0.00	0.00	0.00
16,700.0	90.00	179.52	9,500.1	-6,768.6	-411.7	6,779.6	0.00	0.00	0.00
16,800.0	90.00	179.52	9,500.1	-6,868.6	-410.8	6,879.5	0.00	0.00	0.00
16,900.0	90.00	179.53	9,500.1	-6,968.6	-410.0	6,979.4	0.00	0.00	0.00
17,000.0	90.00	179.53	9,500.1	-7,068.6	-409.2	7,079.2	0.00	0.00	0.00
17,100.0	90.00	179.53	9,500.1	-7,168.6	-408.3	7,179.1	0.00	0.00	0.00
17,200.0	90.00	179.53	9,500.1	-7,268.6	-407.5	7,279.0	0.00	0.00	0.00
17,300.0	90.00	179.53	9,500.1	-7,368.6	-406.7	7,378.9	0.00	0.00	0.00
17,400.0	90.00	179.53	9,500.1	-7,468.6	-405.9	7,478.8	0.00	0.00	0.00
17,500.0	90.00	179.53	9,500.1	-7,568.6	-405.1	7,578.7	0.00	0.00	0.00
17,600.0	90.00	179.53	9,500.1	-7,668.6	-404.2	7,678.6	0.00	0.00	0.00
17,700.0	90.00	179.53	9,500.1	-7,768.6	-403.4	7,778.4	0.00	0.00	0.00
17,800.0	90.00	179.53	9,500.1	-7,868.6	-402.6	7,878.3	0.00	0.00	0.00
17,900.0	90.00	179.53	9,500.1	-7,968.6	-401.8	7,978.2	0.00	0.00	0.00
18,000.0	90.00	179.53	9,500.1	-8,068.6	-401.0	8,078.1	0.00	0.00	0.00
18,100.0	90.00	179.54	9,500.1	-8,168.6	-400.2	8,178.0	0.00	0.00	0.00
18,200.0	90.00	179.54	9,500.1	-8,268.6	-399.4	8,277.9	0.00	0.00	0.00
18,300.0	90.00	179.54	9,500.1	-8,368.6	-398.5	8,377.8	0.00	0.00	0.00
18,400.0	90.00	179.54	9,500.1	-8,468.6	-397.7	8,477.7	0.00	0.00	0.00
18,500.0	90.00	179.54	9,500.1	-8,568.6	-396.9	8,577.5	0.00	0.00	0.00
18,600.0	90.00	179.54	9,500.1	-8,668.6	-396.1	8,677.4	0.00	0.00	0.00
18,700.0	90.00	179.54	9,500.1	-8,768.5	-395.3	8,777.3	0.00	0.00	0.00

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #104H
Company:	Midland	TVD Reference:	kb = 26' @ 3378.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3378.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#104H	Survey Calculation Method:	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

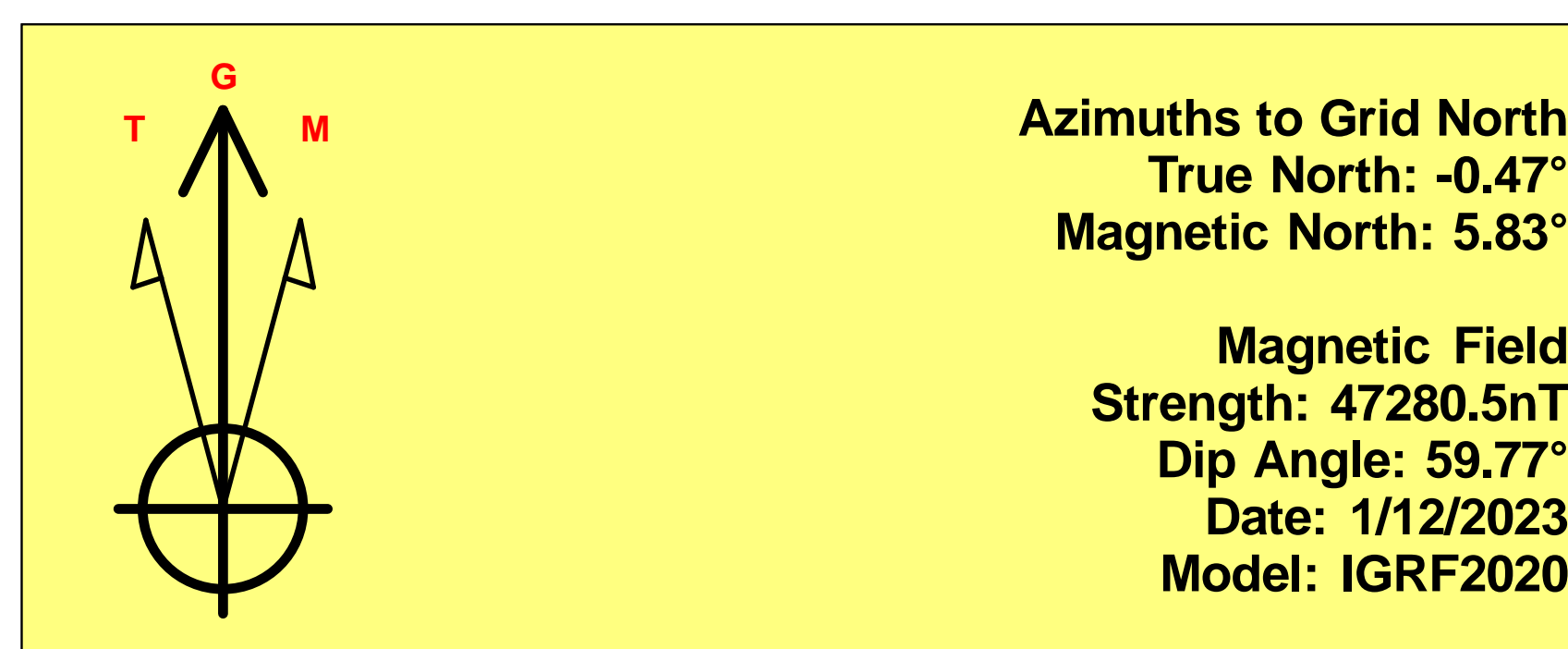
Planned Survey										
Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Vertical Section (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)	
18,800.0	90.00	179.54	9,500.1	-8,868.5	-394.5	8,877.2	0.00	0.00	0.00	
18,900.0	90.00	179.54	9,500.1	-8,968.5	-393.7	8,977.1	0.00	0.00	0.00	
19,000.0	90.00	179.54	9,500.0	-9,068.5	-392.9	9,077.0	0.00	0.00	0.00	
19,100.0	90.00	179.54	9,500.0	-9,168.5	-392.1	9,176.9	0.00	0.00	0.00	
19,200.0	90.00	179.55	9,500.0	-9,268.5	-391.3	9,276.8	0.00	0.00	0.00	
19,300.0	90.00	179.55	9,500.0	-9,368.5	-390.5	9,376.6	0.00	0.00	0.00	
19,400.0	90.00	179.55	9,500.0	-9,468.5	-389.8	9,476.5	0.00	0.00	0.00	
19,500.0	90.00	179.55	9,500.0	-9,568.5	-389.0	9,576.4	0.00	0.00	0.00	
19,600.0	90.00	179.55	9,500.0	-9,668.5	-388.2	9,676.3	0.00	0.00	0.00	
19,700.0	90.00	179.55	9,500.0	-9,768.5	-387.4	9,776.2	0.00	0.00	0.00	
19,749.5	90.00	179.55	9,500.0	-9,818.0	-387.0	9,825.6	0.00	0.00	0.00	

Design Targets										
Target Name	Dip Angle (°)	Dip Dir. (°)	TVD (usft)	+N/-S (usft)	+E/-W (usft)	Northing (usft)	Easting (usft)	Latitude	Longitude	
KOP(Wild Weasel 22 Fe - plan hits target center - Point	0.00	0.00	9,022.5	591.0	-475.0	409,626.00	811,911.00	32° 7' 23.247 N	103° 27' 33.577 W	
FTP(Wild Weasel 22 Fe - plan hits target center - Point	0.00	0.00	9,235.2	541.0	-475.0	409,576.00	811,911.00	32° 7' 22.752 N	103° 27' 33.581 W	
Fed Perf 1(Wild Weasel - plan hits target center - Point	0.00	0.00	9,500.0	-677.0	-465.0	408,358.00	811,921.00	32° 7' 10.699 N	103° 27' 33.580 W	
PBHL(Wild Weasel 22 F - plan hits target center - Point	0.00	0.00	9,500.0	-9,818.0	-387.0	399,217.00	811,999.00	32° 5' 40.242 N	103° 27' 33.535 W	

Lea County, NM (NAD 83 NME)

Wild Weasel 22 Fed Com #104H

Plan #0.1 RT



Azimuths to Grid North
 True North: -0.47°
 Magnetic North: 5.83°
 Magnetic Field
 Strength: 47280.5nT
 Dip Angle: 59.77°
 Date: 1/12/2023
 Model: IGRF2020

To convert a Magnetic Direction to a Grid Direction, Add 5.83°
 To convert a Magnetic Direction to a True Direction, Add 6.30° East
 To convert a True Direction to a Grid Direction, Subtract 0.47°

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: #104H

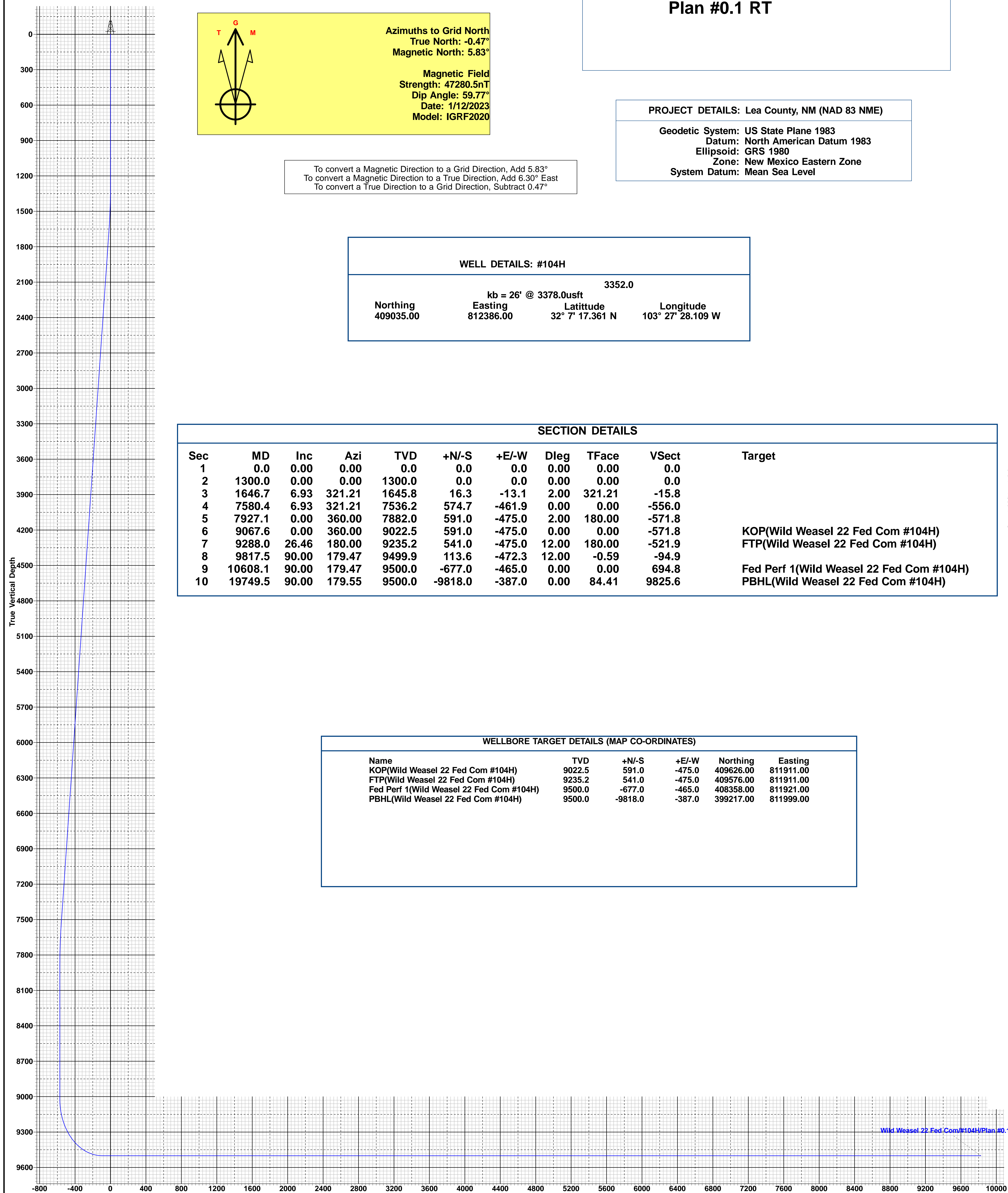
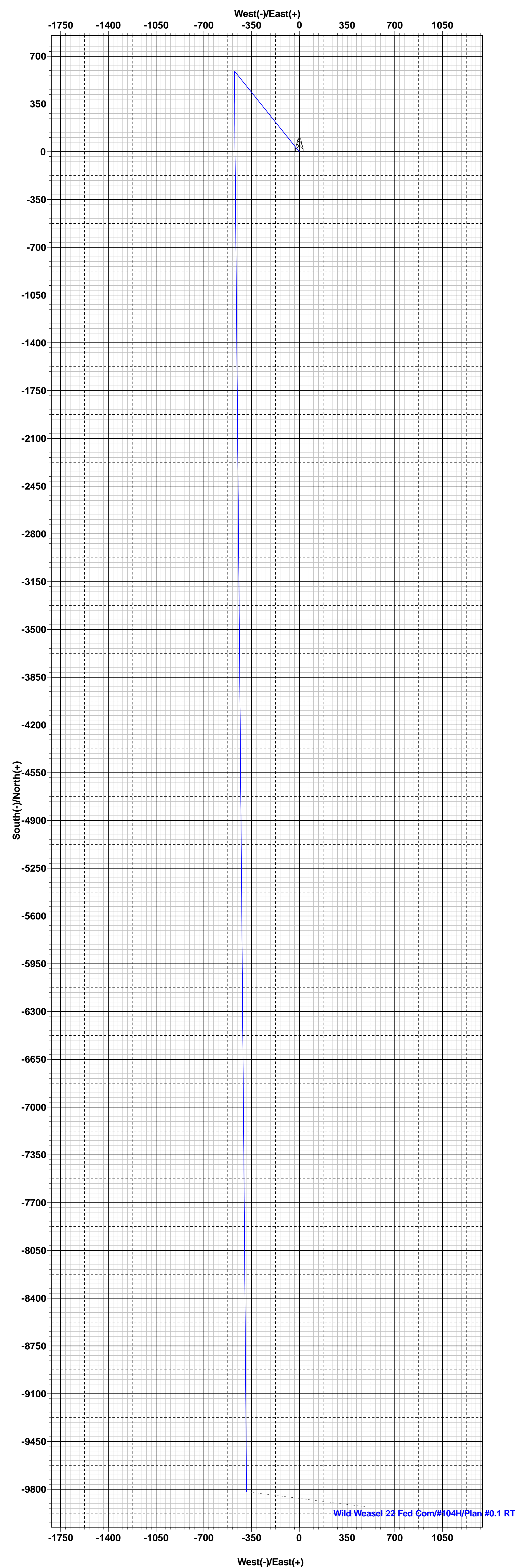
kb = 26' @ 3378.0usft 3352.0
 Northing 409035.00 Easting 812386.00 Latitude 32° 7' 17.361 N Longitude 103° 27' 28.109 W

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	1300.0	0.00	0.00	1300.0	0.0	0.0	0.00	0.00	0.0	
3	1646.7	6.93	321.21	1645.8	16.3	-13.1	2.00	321.21	-15.8	
4	7580.4	6.93	321.21	7536.2	574.7	-461.9	0.00	0.00	-556.0	
5	7927.1	0.00	360.00	7882.0	591.0	-475.0	2.00	180.00	-571.8	
6	9067.6	0.00	360.00	9022.5	591.0	-475.0	0.00	0.00	-571.8	KOP(Wild Weasel 22 Fed Com #104H)
7	9288.0	26.46	180.00	9235.2	541.0	-475.0	12.00	180.00	-521.9	FTP(Wild Weasel 22 Fed Com #104H)
8	9817.5	90.00	179.47	9499.9	113.6	-472.3	12.00	-0.59	-94.9	
9	10608.1	90.00	179.47	9500.0	-677.0	-465.0	0.00	0.00	694.8	Fed Perf 1(Wild Weasel 22 Fed Com #104H)
10	19749.5	90.00	179.55	9500.0	-9818.0	-387.0	0.00	84.41	9825.6	PBHL(Wild Weasel 22 Fed Com #104H)

WELBORE TARGET DETAILS (MAP CO-ORDINATES)

Name	TVD	+N/-S	+E/-W	Northing	Easting
KOP(Wild Weasel 22 Fed Com #104H)	9022.5	591.0	-475.0	409626.00	811911.00
FTP(Wild Weasel 22 Fed Com #104H)	9235.2	541.0	-475.0	409576.00	811911.00
Fed Perf 1(Wild Weasel 22 Fed Com #104H)	9500.0	-677.0	-465.0	408358.00	811921.00
PBHL(Wild Weasel 22 Fed Com #104H)	9500.0	-9818.0	-387.0	399217.00	811999.00



Vertical Section at 182.26°

PECOS DISTRICT DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	EOG Resources, Inc.
WELL NAME & NO.:	Wild Weasel 22 Fed Com 104H
LOCATION:	Section 22, T.25S., R.34E.
COUNTY:	Lea County

*Please refer to approved NOI appended to this application for the most recent details for the planned well.

COA

H2S	<input checked="" type="radio"/> Yes	<input type="radio"/> No	
Potash	<input checked="" type="radio"/> None	<input type="radio"/> Secretary	<input type="radio"/> R-111-P
Cave/Karst Potential	<input checked="" type="radio"/> Low	<input type="radio"/> Medium	<input type="radio"/> High
Cave/Karst Potential	<input type="radio"/> Critical		
Variance	<input type="radio"/> None	<input checked="" type="radio"/> Flex Hose	<input type="radio"/> Other
Wellhead	<input type="radio"/> Conventional	<input checked="" type="radio"/> Multibowl	<input type="radio"/> Both
Wellhead Variance	<input type="radio"/> Diverter		
Other	<input type="checkbox"/> 4 String	<input type="checkbox"/> Capitan Reef	<input type="checkbox"/> WIPP
Other	<input checked="" type="checkbox"/> Fluid Filled	<input type="checkbox"/> Pilot Hole	<input type="checkbox"/> Open Annulus
Cementing	<input checked="" type="checkbox"/> Contingency Cement Squeeze	<input type="checkbox"/> EchoMeter	<input checked="" type="checkbox"/> Primary Cement Squeeze
Special Requirements	<input type="checkbox"/> Water Disposal	<input checked="" type="checkbox"/> COM	<input type="checkbox"/> Unit
Special Requirements	<input type="checkbox"/> Batch Sundry		
Special Requirements Variance	<input checked="" type="checkbox"/> Break Testing	<input checked="" type="checkbox"/> Offline Cementing	<input checked="" type="checkbox"/> Casing Clearance

A. HYDROGEN SULFIDE

A Hydrogen Sulfide (H2S) Drilling Plan shall be activated AT SPUD. As a result, the Hydrogen Sulfide area must meet 43 CFR part 3170 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

B. CASING

Primary Casing Design:

- The **13-3/8** inch surface casing shall be set at approximately **1000** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **16** inch in diameter.

- a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
 - b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
 - c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
 - d. If cement falls back, remedial cementing will be done prior to drilling out that string.
2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
 3. The minimum required fill of cement behind the **5-1/2** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Casing Alternative Design A:

1. The **13-3/8** inch surface casing shall be set at approximately **2030** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **16** inch in diameter.
 - a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
 - b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
 - c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.

- d. If cement falls back, remedial cementing will be done prior to drilling out that string.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **5-1/2** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Operator has proposed to pump down 9-5/8" X 5-1/2" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 5-1/2" casing to surface after the second stage BH to verify TOC.

Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

If cement does not reach surface, the next casing string must come to surface.

Operator must use a limited flush fluid volume of 1 bbl following backside cementing procedures.

Casing Alternative Design B:

1. The **10-3/4** inch surface casing shall be set at approximately **2030** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **13-1/2** inch in diameter.
 - a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
 - b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8**

- hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
- c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
 - d. If cement falls back, remedial cementing will be done prior to drilling out that string.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **8-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **5-1/2** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Operator has proposed to pump down 8-5/8" X 5-1/2" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 5-1/2" casing to surface after the second stage BH to verify TOC.

Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

If cement does not reach surface, the next casing string must come to surface.

Operator must use a limited flush fluid volume of 1 bbl following backside cementing procedures.

Casing Alternative Design C:

1. The **13-3/8** inch surface casing shall be set at approximately **2030** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **16** inch in diameter.
 - a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature

survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.

- b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
- c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
- d. If cement falls back, remedial cementing will be done prior to drilling out that string.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **6** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Operator has proposed to pump down 9-5/8" X 6" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 6" casing to surface after the second stage BH to verify TOC.

Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

If cement does not reach surface, the next casing string must come to surface.

Operator must use a limited flush fluid volume of 1 bbl following backside cementing procedures.

Casing Alternative Design D:

1. The **13-3/8** inch surface casing shall be set at approximately **2030** feet (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable

fresh water) and cemented to the surface. The surface hole shall be **16** inch in diameter.

- a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
- b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
- c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
- d. If cement falls back, remedial cementing will be done prior to drilling out that string.

Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:
 - Cement to surface. If cement does not circulate see B.1.a, c-d above. **Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.**
3. The minimum required fill of cement behind the **6 X 5-1/2** inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Operator has proposed to pump down 9-5/8" X 6" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 6" casing to surface after the second stage BH to verify TOC.

Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

If cement does not reach surface, the next casing string must come to surface.

Operator must use a limited flush fluid volume of 1 bbl following backside cementing procedures.

C. PRESSURE CONTROL

1. Variance approved to use flex line from BOP to choke manifold. Manufacturer's specification to be readily available. No external damage to flex line. Flex line to be installed as straight as possible (no hard bends).'
2. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the **Surface** casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **10,000 (10M)** psi. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 3500 (70% Working Pressure) psi.**
 - a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
 - b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
 - c. Manufacturer representative shall install the test plug for the initial BOP test.
 - d. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
 - e. Whenever any seal subject to test pressure is broken, all the tests in OOGO2.III.A.2.i must be followed.

D. SPECIAL REQUIREMENT (S)

Communitization Agreement

- The operator will submit a Communitization Agreement to the Santa Fe Office, 301 Dinosaur Trail Santa Fe, New Mexico 87508, at least 90 days before the anticipated date of first production from a well subject to a spacing order issued by the New Mexico Oil Conservation Division. The Communitization Agreement will include the signatures of all working interest owners in all Federal and Indian leases subject to the Communitization Agreement (i.e., operating rights owners and lessees of record), or certification that the operator has obtained the written signatures of all such owners and will make those signatures available to the BLM immediately upon request.
- The operator will submit an as-drilled survey well plat of the well completion, but are not limited to, those specified in Onshore Order 1 and 2.
- 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.

BOPE Break Testing Variance

- BOPE Break Testing is ONLY permitted for 5M BOPE or less. (**Annular preventer must be tested to a minimum of 70% of BOPE working pressure and shall be higher than the MASP**)
- BOPE Break Testing is NOT permitted to drilling the production hole section.
- Variance only pertains to the intermediate hole-sections and no deeper than the Bone Springs formation.
- While in transfer between wells, the BOPE shall be secured by the hydraulic carrier or cradle.
- Any well control event while drilling require notification to the BLM Petroleum Engineer (**575-706-2779**) prior to the commencement of any BOPE Break Testing operations.
- A full BOPE test is required prior to drilling the first deep intermediate hole section. If any subsequent hole interval is deeper than the first, a full BOPE test will be required. (200' TVD tolerance between intermediate shoes is allowable).
- The BLM is to be contacted (575-689-5981 Lea County) 4 hours prior to BOPE tests.
- As a minimum, a full BOPE test shall be performed at 21-day intervals.
- In the event any repairs or replacement of the BOPE is required, the BOPE shall test as per Onshore Oil and Gas Order No. 2.
- If in the event break testing is not utilized, then a full BOPE test would be conducted.

Casing Clearance:

Operator casing variance is approved for the utilization of

- Annular clearance to meet or exceed 0.422'' between intermediate casing ID and production casing coupling only on the first 500' overlap between both casing strings.

-Annular clearance less than 0.422'' is acceptable for the production open hole section.

Operator shall clean up cycles until wellbore is clear of cuttings and any large debris, ensure cutting sizes are adequate "coffee ground or less" before cementing.

Offline Cementing:

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)

Lea County

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

1. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval.
 - a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
 - b. When the operator proposes to set surface casing with Spudder Rig
 - 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.

JAM 3/7/2025



Wild Weasel 22 Fed Com #104H

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/Escapes packs — 4 packs shall be stored on the rig floor with sufficient air hose not to restrict work activity.
 - iii. Emergency Escape Packs — 4 packs shall be stored in the doghouse for emergency evacuation.
 - b. Auxiliary Rescue Equipment:
 - i. Stretcher
 - ii. Two OSHA full body harness
 - iii. 100 ft 5/8 inch OSHA approved rope
 - iv. 1-20# class ABC fire extinguisher
 - **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.



Wild Weasel 22 Fed Com #104H

■ **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.



Wild Weasel 22 Fed Com #104H

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



Offline Intermediate Cementing Procedure

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Cement Program

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

Summarized Operational Procedure for Intermediate Casing

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



Offline Intermediate Cementing Procedure

2/24/2022

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



Offline Intermediate Cementing Procedure

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Example Well Control Plan Content

A. Well Control Component Table

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

Intermediate hole section, 5M requirement

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

B. Well Control Procedures

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

General Procedure While Circulating

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

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Offline Intermediate Cementing Procedure

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

General Procedure While Cementing

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

General Procedure After Cementing

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



Figure 1: Cameron TA Plug and Offline Adapter Schematic

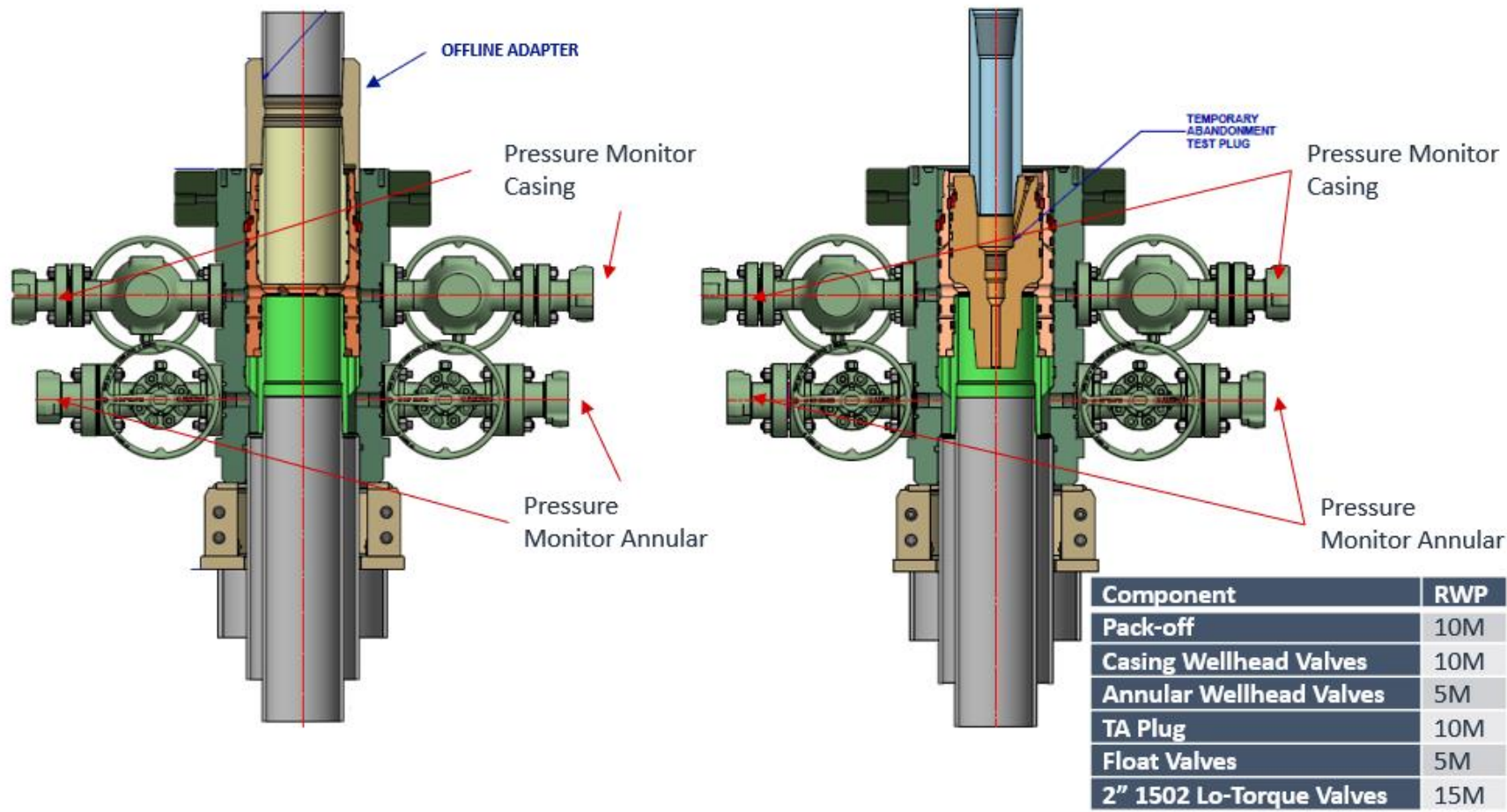
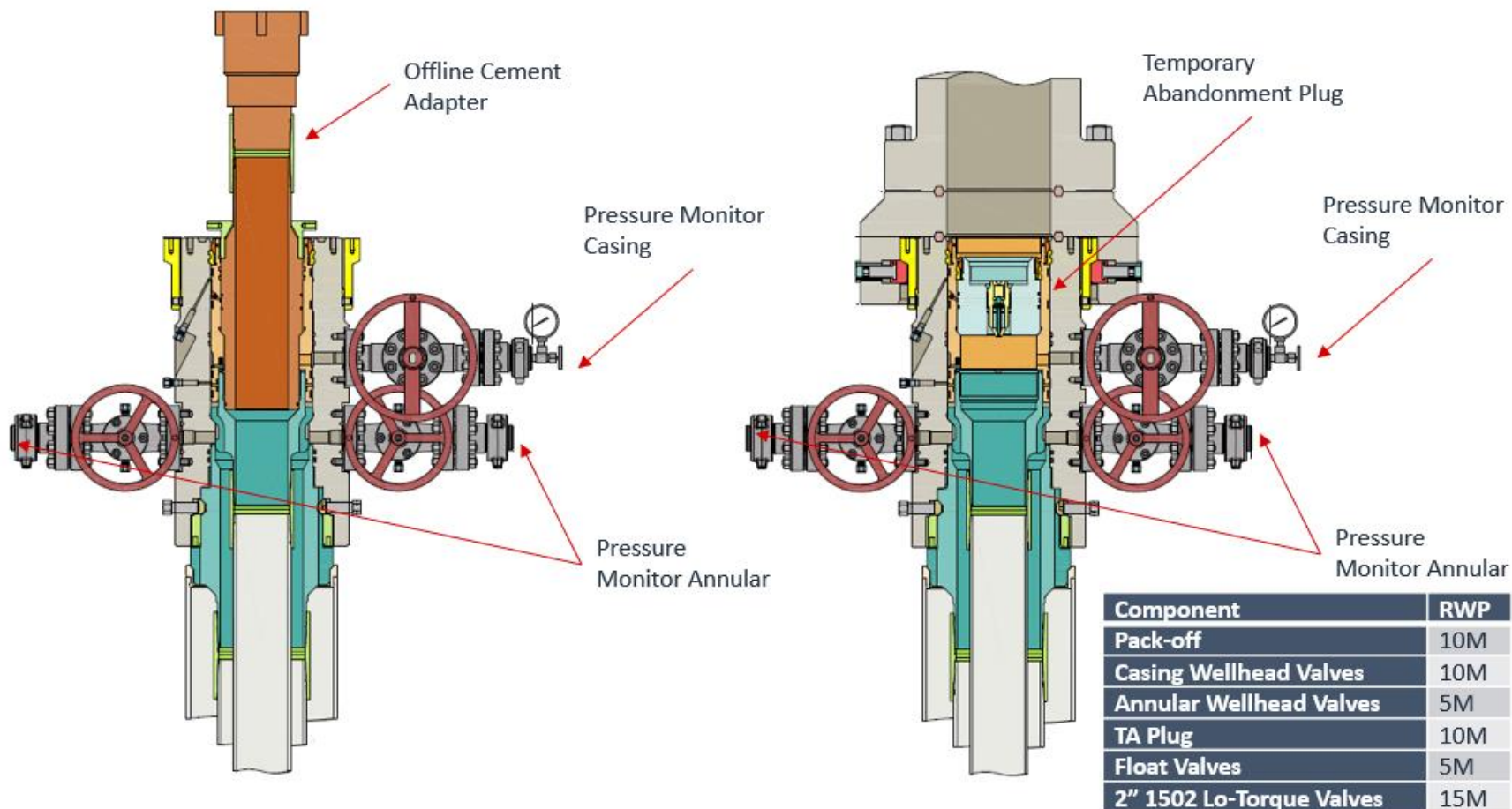




Figure 2: Cactus TA Plug and Offline Adapter Schematic

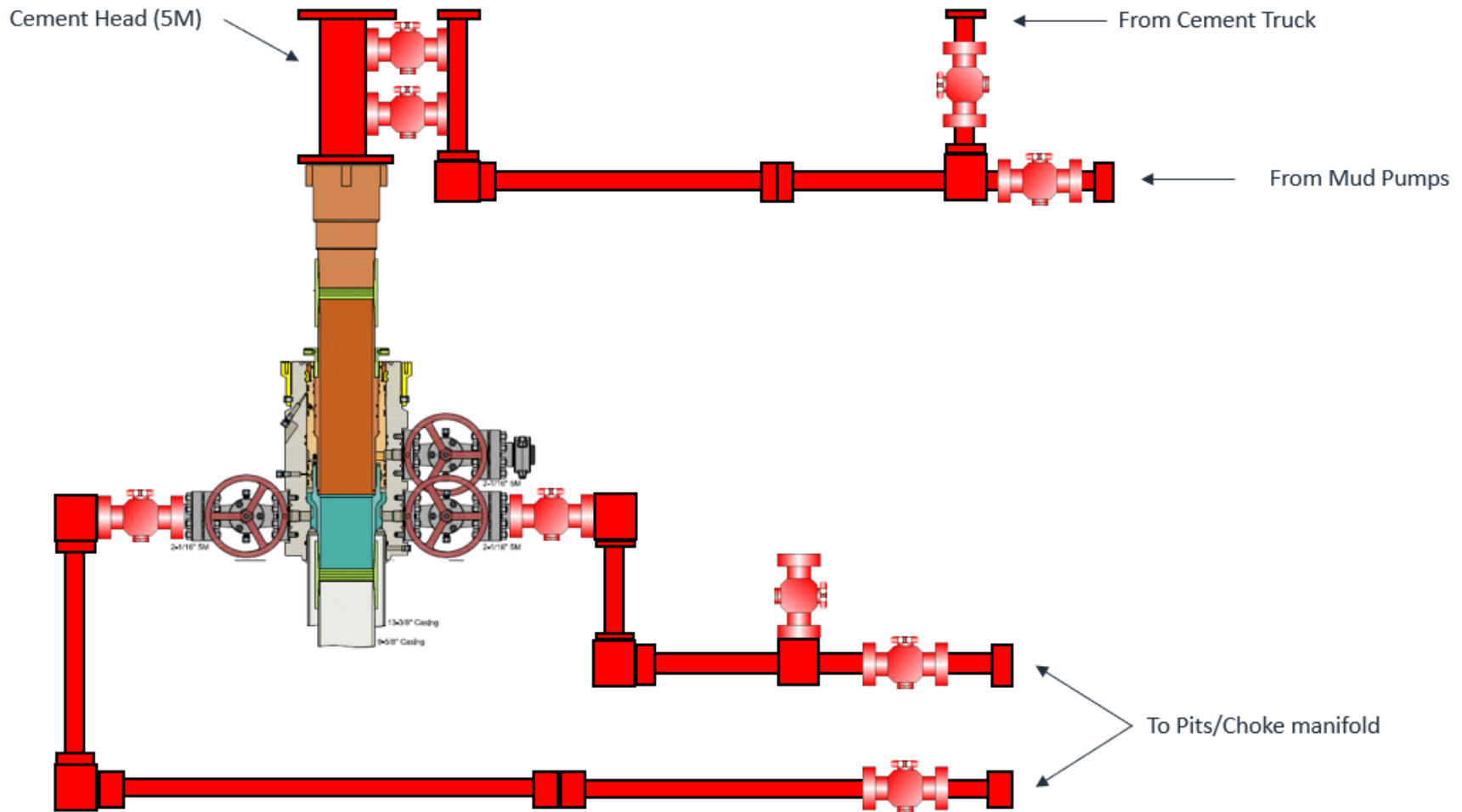




Offline Intermediate Cementing Procedure

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Figure 3: Back Yard Rig Up



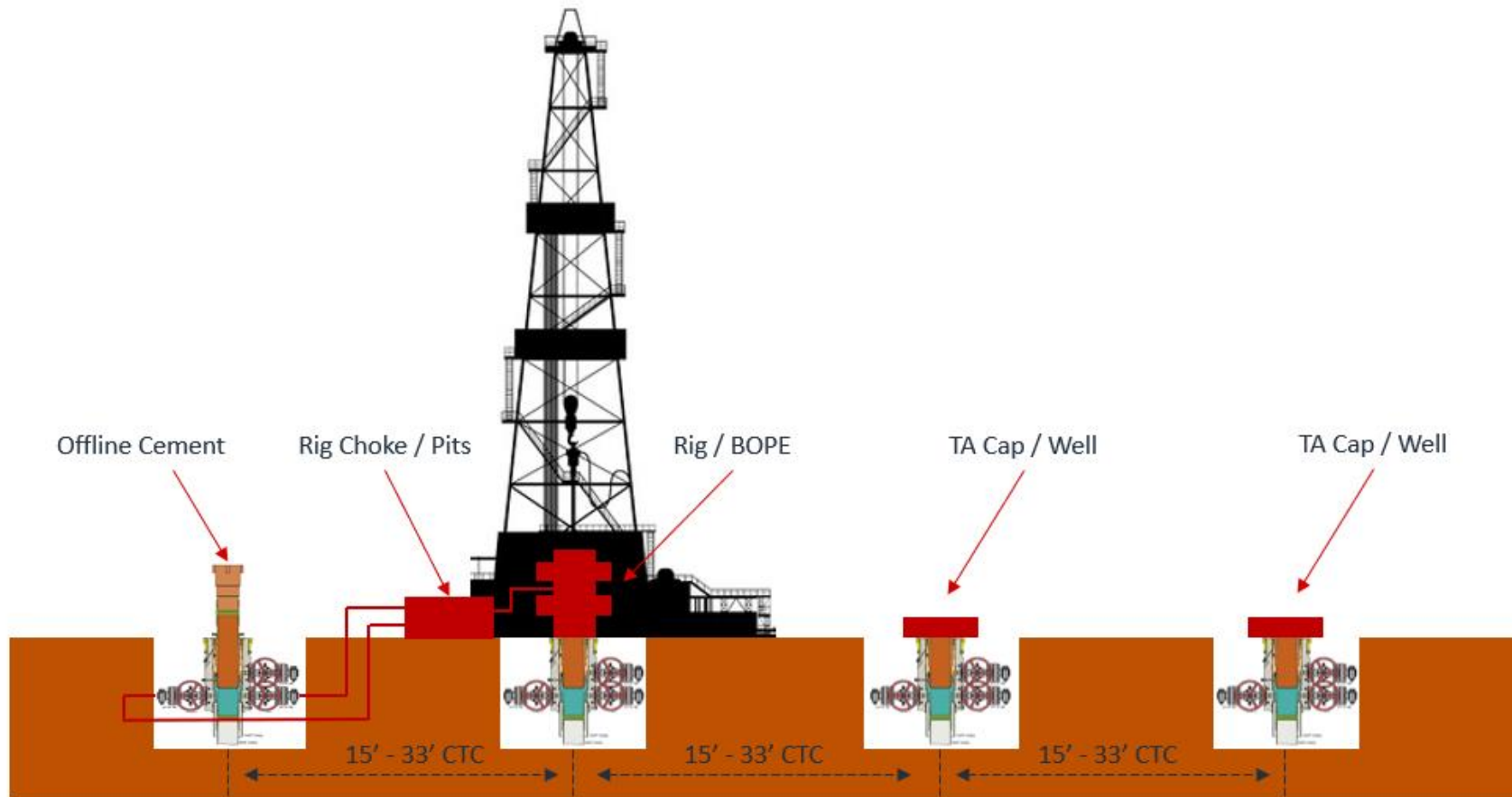
*** All Lines 10M rated working pressure



Offline Intermediate Cementing Procedure

2/24/2022

Figure 4: Rig Placement Diagram



VALLOUREC STAR 8.625 32# P110EC S S2L2 DA 7.875 W/O# SLN# PO# MADE IN USA FT LB



API 5CT, 10th Ed. Connection Data Sheet

O.D. (in)	WEIGHT (lb/ft)	WALL (in)	GRADE	*API DRIFT (in)	RBW %
8.625	Nominal: 32.00 Plain End: 31.13	0.352	P110EC	7.796	87.5

Material Properties (PE)	
Pipe	
Minimum Yield Strength:	125 ksi
Maximum Yield Strength:	140 ksi
Minimum Tensile Strength:	135 ksi
Coupling	
Minimum Yield Strength:	125 ksi
Maximum Yield Strength:	140 ksi
Minimum Tensile Strength:	135 ksi

Pipe Body Data (PE)	
Geometry	
Nominal ID:	7.92 inch
Nominal Area:	9.149 in ²
*Special/Alt. Drift:	7.875 inch
Performance	
Pipe Body Yield Strength:	1,144 kips
Collapse Resistance:	4,000 psi
Internal Yield Pressure: (API Historical)	8,930 psi

THIS SIZE/GRADE IS NOT VALIDATED BY API TO HAVE AN API CONNECTION

API Connection Data	
Coupling OD: 9.625"	
STC Performance	
STC Internal Pressure:	8,930 psi
STC Joint Strength:	793 kips
LTC Performance	
LTC Internal Pressure:	8,930 psi
LTC Joint Strength:	887 kips
SC-BTC Performance - Cplg OD = 9.125"	
BTC Internal Pressure:	6,340 psi
BTC Joint Strength:	1,120 kips

API Connection Torque			
STC Torque (ft-lbs)			
Min:	5,948	Opti:	7,930
Max:	9,913		
LTC Torque (ft-lbs)			
Min:	6,653	Opti:	8,870
Max:	11,088		
BTC Torque (ft-lbs)			
<i>follow API guidelines regarding positional make up</i>			

*Alt. Drift will be used unless API Drift is specified on order.

**If above API connections do not suit your needs, VAM® premium connections are available up to 100% of pipe body ratings.

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API 5CT, 10th Ed. Connection Data Sheet

O.D. (in)	WEIGHT (lb/ft)	WALL (in)	GRADE	*API DRIFT (in)	RBW %
8.625	Nominal: 32.00 Plain End: 31.13	0.352	J55	7.796	87.5

Material Properties (PE)

Pipe	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi
Coupling	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi

Pipe Body Data (PE)

Geometry	
Nominal ID:	7.92 inch
Nominal Area:	9.149 in ²
*Special/Alt. Drift:	7.875 inch
Performance	
Pipe Body Yield Strength:	503 kips
Collapse Resistance:	2,530 psi
Internal Yield Pressure: (API Historical)	3,930 psi

API Connection Data

Coupling OD: 9.625"

STC Performance	
STC Internal Pressure:	3,930 psi
STC Joint Strength:	372 kips
LTC Performance	
LTC Internal Pressure:	3,930 psi
LTC Joint Strength:	417 kips
SC-BTC Performance - Cplg OD = 9.125"	
BTC Internal Pressure:	3,930 psi
BTC Joint Strength:	503 kips

API Connection Torque

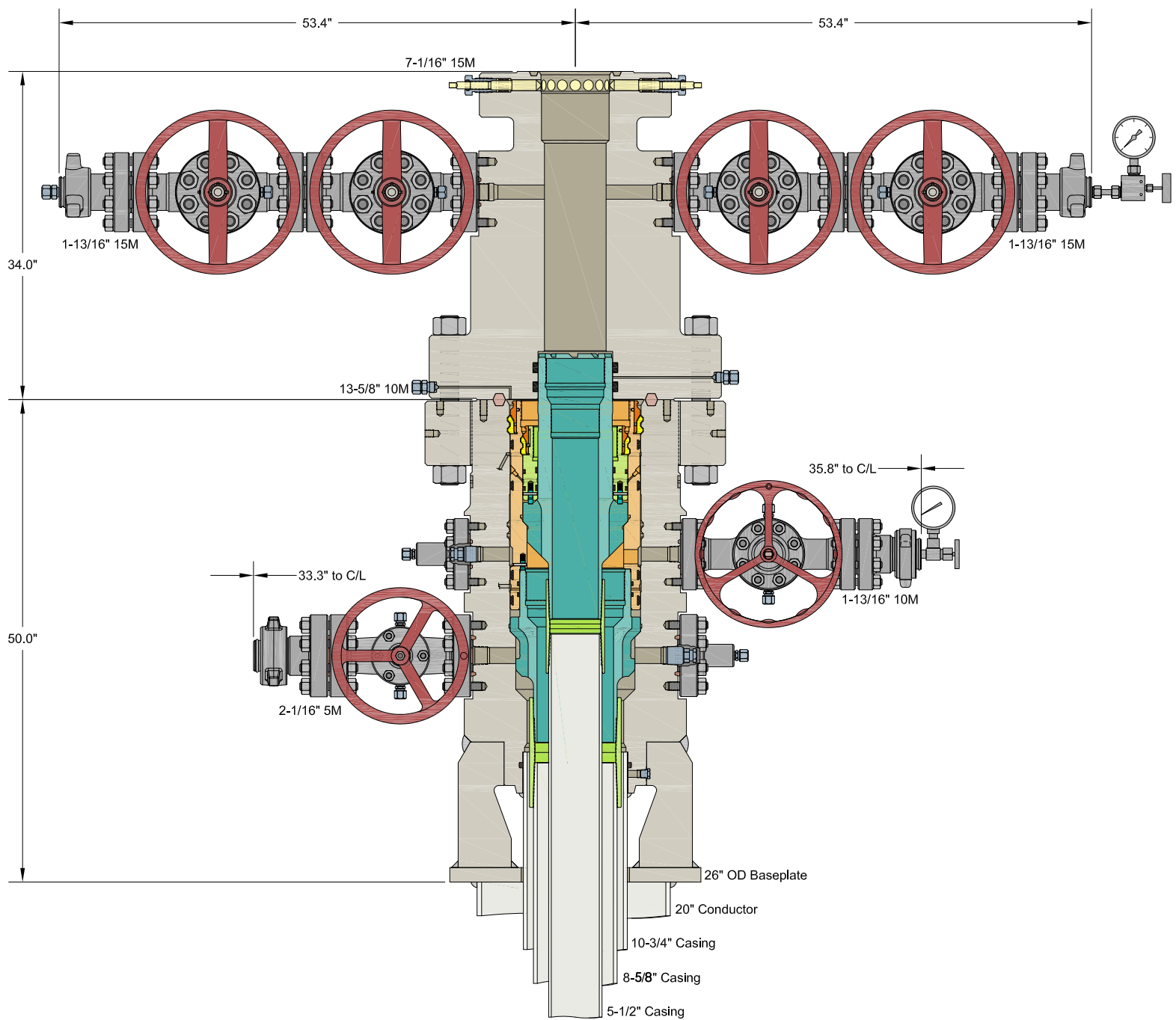
STC Torque (ft-lbs)					
Min:	2,793	Opti:	3,724	Max:	4,655
LTC Torque (ft-lbs)					
Min:	3,130	Opti:	4,174	Max:	5,217
BTC Torque (ft-lbs)					
<i>follow API guidelines regarding positional make up</i>					

*Alt. Drift will be used unless API Drift is specified on order.

**If above API connections do not suit your needs, VAM® premium connections are available up to 100% of pipe body ratings.

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VALLOUREC STAR 8.625 32# J55 S S2L2 DA 7.875 W/O# SLN# PO# MADE IN USA FT LB



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ALL DIMENSIONS APPROXIMATE

CACTUS WELLHEAD LLC

EOG RESOURCES

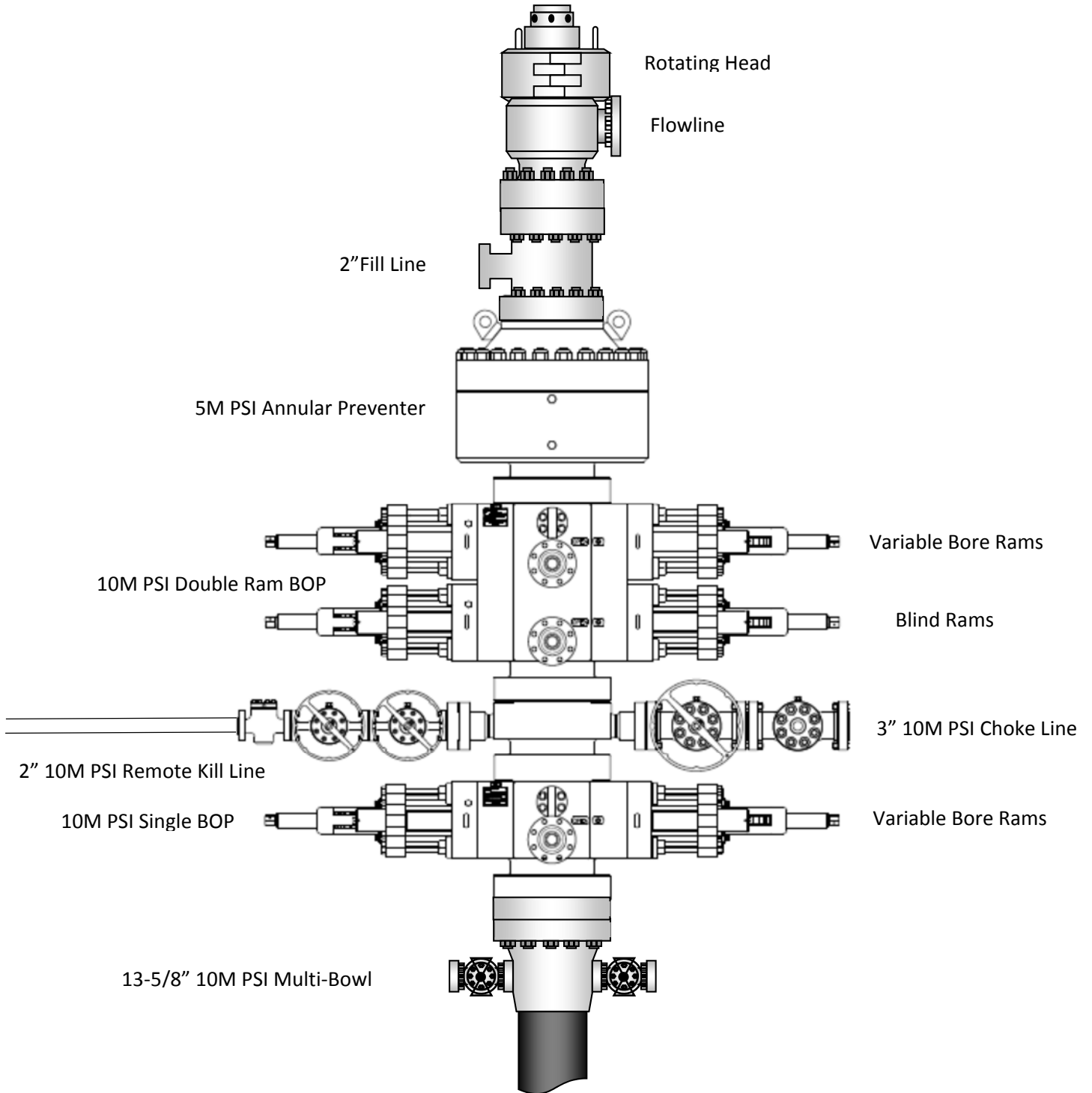
10-3/4" x 8-5/8" x 5-1/2" MBU-3T-SF-SOW Wellhead System
 With 8-5/8" & 5-1/2" Pin Bottom Mandrel Casing Hangers
 And 13-5/8" 10M x 7-1/16" 15M CTH-DBLHPS Tubing Head

DRAWN	DLE	14APR21
APPRV		
DRAWING NO.	SDT-3141	

Exhibit 1

EOG Resources

13-5/8" 10M PSI BOP Stack





**American
Petroleum
Institute**



2018-151

Certificate of Authority to use the Official API Monogram

License Number: 7K-0519

ORIGINAL

The American Petroleum Institute hereby grants to

**GATES ENGINEERING AND SERVICES
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Houston, TX
United States**

the right to use the Official API Monogram® on manufactured products under the conditions in the official publications of the American Petroleum Institute entitled API Spec Q1® and **API-7K** and in accordance with the provisions of the License Agreement.

In all cases where the Official API Monogram is applied, the API Monogram shall be used in conjunction with this certificate number: **7K-0519**

The American Petroleum Institute reserves the right to revoke this authorization to use the Official API Monogram for any reason satisfactory to the Board of Directors of the American Petroleum Institute.

The scope of this license includes the following: High Pressure Mud and Cement Hoses at FSL 0, at FSL 1, at FSL 2

QMS Exclusions: No Exclusions Identified as Applicable

Effective Date: OCTOBER 24, 2024

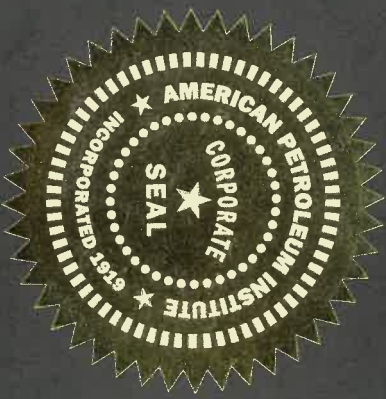
Expiration Date: DECEMBER 18, 2027

Senior Vice President of Global Industry Services

To verify the authenticity of this license, go to www.api.org/compositelist.



American Petroleum Institute



2018-151

Certificate of Authority to use the Official API Monogram
License Number: 16C-0485

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The scope of this license includes the following: Flexible Choke and Kill Lines atFSL 0, FSL 1, FSL 2, FSL 3

QMS Exclusions: No Exclusions Identified as Applicable

Effective Date: OCTOBER 24, 2024

Expiration Date: DECEMBER 18, 2027

To verify the authenticity of this license, go to www.api.org/compositelist.



Senior Vice President of Global Industry Services



REGISTRATION NO. Q1-3650

Certificate of Registration

The American Petroleum Institute certifies that the quality management system[®] of

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Houston, TX
United States

has been assessed by the American Petroleum Institute and found to be in conformance with the following:

API Spec Q1, 9th Edition

The scope of this registration and the approved quality management system applies to the

**Assembly and Pressure Test of High Pressure Mud and Cement Hoses,
Flexible Choke and Kill Lines and General Rubber Hydraulic Hose Assemblies**

API approves the organization's justification for excluding

No Exclusions Identified as Applicable



Effective Date: OCTOBER 24, 2024
Expiration Date: DECEMBER 18, 2027
Registered Since: DECEMBER 18, 2018

Senior Vice President of Global Industry Services

This certificate is valid for the period specified herein. The registered organization must continually meet all requirements of API Spec Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry*, and the requirements of the Registration Agreement. Registration is maintained and regularly monitored through annual full system audits. This certificate has been issued from API offices located at 200 Massachusetts Avenue, NW Suite 1100, Washington, DC 20001-5571, U.S.A. It is the property of API and must be returned upon request. **To verify the authenticity of this certificate, go to www.api.org/compositelist.**



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FAX: +1 (281) 602-4147
EMAIL: gesna.quality@gates.com
WEB: gates.com/ollandgas

CERTIFICATE OF CONFORMANCE

This is to verify that all Parts and/or Materials included in this shipment have been manufactured and/or processed in Conformance with applicable drawings and specifications, and that Records of Required Tests are on file and subject to examination. The following items were purchased via **Gates Engineering & Services North America** facilities in Houston, TX, USA. This hose assembly was designed and manufactured to meet requirements of API Spec 16C, 3rd Edition.

CUSTOMER: HELMERICH & PAYNE INTERNATIONAL DRILLING CO.
CUSTOMER P.O.#: 740399823 (TAG WITH H&P I.D # 88076545 &H&P P.O. # 740399823 (UK S/O 34557))
CUSTOMER P/N: 3.035.016C4116FX-FLTSSA
PART DESCRIPTION: 3" X 35 FT GATES API 16C CHOKE & KILL FSL 3 TEMP B HOSE ASSEMBLY WITH STAINLESS STEEL ARMOR C/W 4 1/16" 10K H2S SUITED FLOAT X FLOAT FLANGES WITH BX 155 RING GROOVE SUPPLIED WITH SAFETY CLAMPS/LIFT EYE CLAMPS
SALES ORDER #: 525112
QUANTITY: 1
SERIAL #: SN 139321 HOSE BATCH 139244

SIGNATURE: _____
TITLE: _____ **QUALITY ASSURANCE** _____
DATE: _____ **2/10/2023** _____


Gates Engineering & Services UK Ltd		CERTIFICATE OF CONFORMITY	
Doc. Ref.	Form-056		
Revision	4		


Gates SO No. 34557	Customer Name & Address:
Customer PO No: 1803964/ 1	Gates Engineering & Services NA Inc
Description: 3" 10K API 16C CHOKE & KILL HOSE ASSEMBLY X 35FT OAL (QTY 5)	Accounts payable
	7N GESNA
	1144 Fifteenth Street, Suite 1400 Denver, CO 80202 USA

This is to certify that the components listed below have been supplied in accordance with API 16C & the above referenced order number. The assemblies listed below have been manufactured and tested in the UK.

SPECIFICATION

ITEM	DESCRIPTION	BATCH NUMBER	QTY
1	3" 10K API 16C CHOKE & KILL HOSE ASSEMBLY X 35FT OAL PART NO: HA34539-001 END A: 4.1/16" 10K API SPEC 6A TYPE FLANGE WITH BX155 RING GROOVE END B: 4.1/16" 10K API SPEC 17D SV SWIVEL FLANGE WITH BX155 RING GROOVE EACH END HAS AN INCONEL 625 INLAID RING GROOVE HOSE METALLIC PARTS MEET NACE-MR-0175 LATEST EDITION REQUIREMENTS WORKING PRESSURE: 10,000 PSI TEST PRESSURE: 15,000 PSI STANDARD: API 16C FSL3 MONOGRAMMED, 3RD EDITION EXTERNAL PROTECTION: STAINLESS STEEL ARMOUR INCLUDED FIRE RATED: API 16C STANDARD SECTION B.12.4 (704° FOR 30 MINS) H2S SERVICE SUITABLE TEMPERATURE CLASS B(-25 TO 100°C) HIGH TEMPERATURE EXPOSURE / SURVIVAL @ 177°C (INTERNAL IN A KICK SITUATION) SAFETY EQUIPMENT: INCLUDED 2 X HOSE SAFETY CLAMPS 2 X 3.6T SHACKLES 2 X 10MM OD X 6FT PCP COATED CHAINS HOSE ASSEMBLY WORKS ORDERS NUMBERS: 139051 139052 139053 139054 139321	139062	5
		139063	
		139064	
	139065		
		139244	
	SAFETY/LIFTER CLAMP 195MM 1.7T PART NO: HCC108	MYB59483	10
	SAFETY CHAIN 10MM C/S PCP 6FT PART NO: CHC001	ACU59481	10


J. Winkler
06 DEC 2022
 Accepted by..... for and on behalf of Gates Engineering & Services UK Ltd

Gates Engineering & Services UK Ltd		PRESSURE TEST CERTIFICATE	
Doc. Ref.	Form-051		
Revision	9		


<input type="checkbox"/> BURST	<input checked="" type="checkbox"/> HYDROSTATIC	<input type="checkbox"/> CYCLIC	Certificate No: PTC-139321
--------------------------------	---	---------------------------------	-----------------------------------

Product:	CK03F	Hose WO/Batch:	139244
Assembly WO:	139321	Length:	35FT
SO No:	34557	Date:	25/11/22
Customer:	Gates Engineering & Services NA Inc	Customer Reference:	PO 1803964/ 1

Inner Diameter:	3	Inch	
Working Pressure:	10000	Psi	690 bar
Test Pressure:	15000	Psi	1034 bar
Burst Pressure:	22500	Psi	1551 bar

Hose Description:		3" 10K API 16C CHOKE & KILL HOSE ASSEMBLY X 35FT OAL END A: 4.1/16" 10K API SPEC 6A TYPE FLANGE WITH BX155 RING GROOVE END B: 4.1/16" 10K API SPEC 17D SV SWIVEL FLANGE WITH BX155 RING GROOVE	
Item No	Qty	Part Code	Customer Tag No (if applicable)
1	1	HA34539-001	N/A

Details of Test:	Pressure tested with water at ambient temperature for a minimum of 60 minutes at test pressure 1034 BAR Pressure Transducer S/N: 131203 (CH1) Chart Recorder S/N: S5VB14523 Calibration Certificate No: IKMCERTU823
Results:	Pressure Loss: 8.43 BAR Acceptance Criteria: Pressure loss not to exceed 500 PSI (34.47 BAR)

GESUK Ltd	Third Party
 <i>J. W. W. W.</i> 06 DEC 2022	

1/1

File Message : CH1 139321
 Device Type : GX20
 Serial No. : S5VB14523

Start Time : 2022/11/25 00:53:50.000 (UTC+08:00)
 Stop Time : 2022/11/25 03:53:20.000 (UTC+08:00)

Print Groups : GROUP 1
 Print Range : 2022/11/25 00:53:50.000 - 2022/11/25 03:53:20.000 (UTC+08:00)



06 DEC 2022

Section	427	787	2022/11/25 02:05:00.000		2022/11/25 03:05:00.000	
Channel	MIN	MAX	P-P	Mean	RMS	
CH0001[bar g]	1050.12	1058.55	8.43	1053.28	1053.28	1053.28

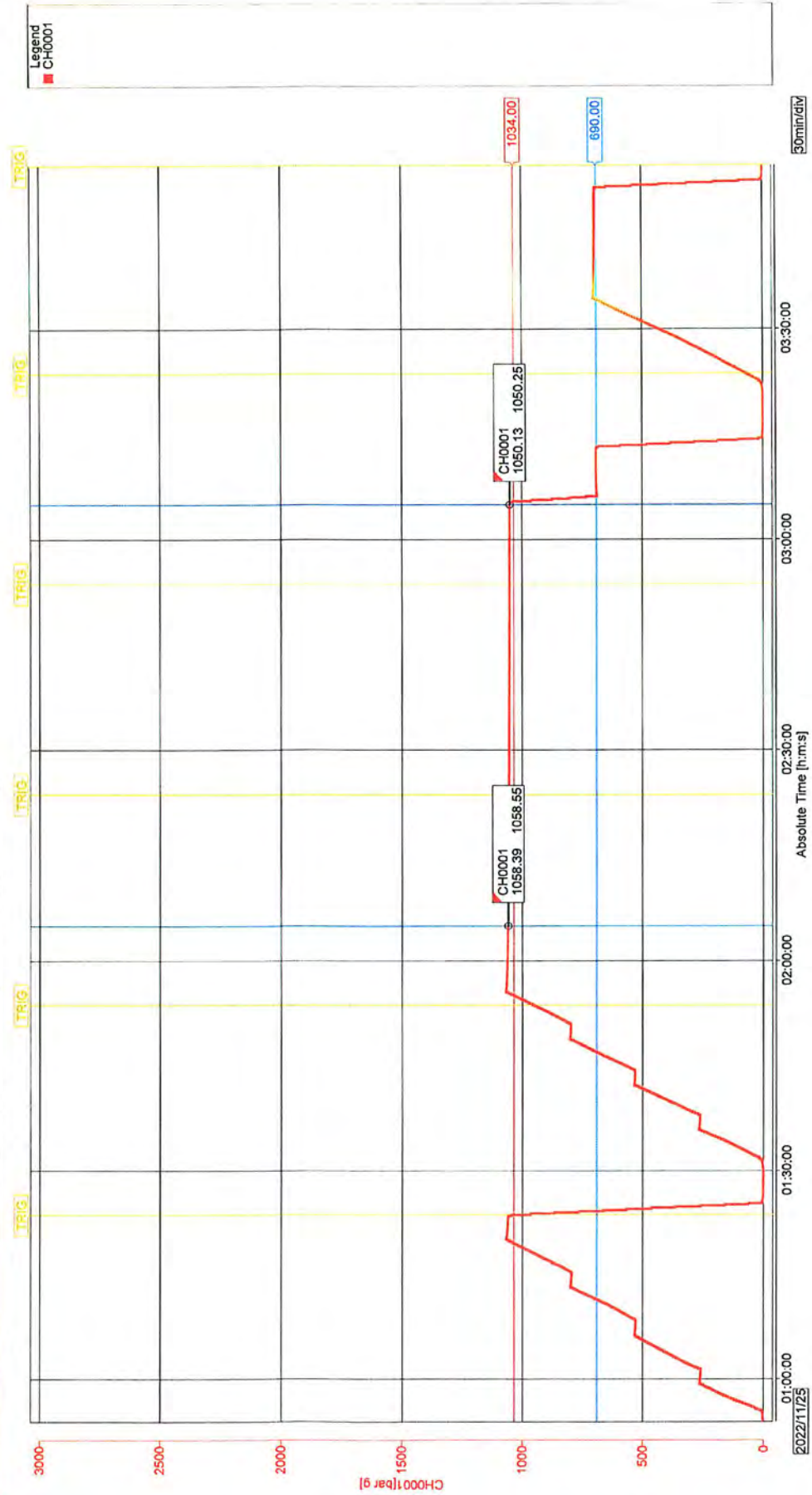
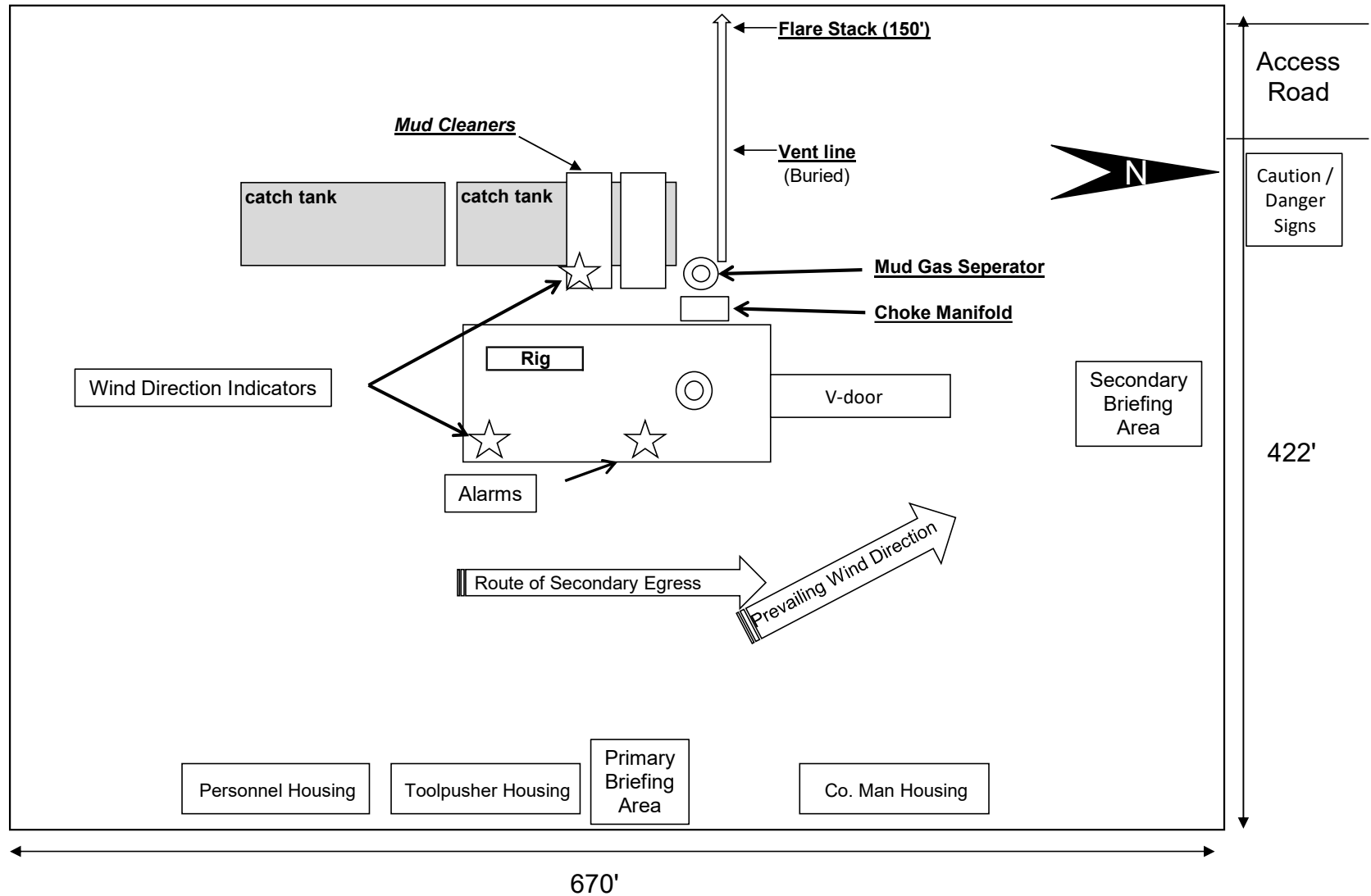


Exhibit 4
EOG Resources
Wild Weasel 22 Fed Com #104H

Well Site Diagram





Wild Weasel 22 Fed Com Package

Wells in package:	Tgt TVD
Wild Weasel 15 Fed Com #203H	10,287
Wild Weasel 15 Fed Com #303H	10,410
Wild Weasel 15 Fed Com #304H	10,410
Wild Weasel 15 Fed Com #504H	11,000
Wild Weasel 15 Fed Com #505H	11,000
Wild Weasel 22 Fed Com #101H	9,500
Wild Weasel 22 Fed Com #102H	9,500
Wild Weasel 22 Fed Com #103H	9,500
Wild Weasel 22 Fed Com #104H	9,500
Wild Weasel 22 Fed Com #105H	9,500
Wild Weasel 22 Fed Com #106H	9,500
Wild Weasel 22 Fed Com #201H	10,287
Wild Weasel 22 Fed Com #202H	10,287
Wild Weasel 22 Fed Com #204H	10,287
Wild Weasel 22 Fed Com #205H	10,287
Wild Weasel 22 Fed Com #301H	10,410
Wild Weasel 22 Fed Com #302H	10,410
Wild Weasel 22 Fed Com #305H	10,410
Wild Weasel 22 Fed Com #306H	10,410
Wild Weasel 22 Fed Com #501H	11,000
Wild Weasel 22 Fed Com #502H	11,000
Wild Weasel 22 Fed Com #503H	11,000
Wild Weasel 22 Fed Com #506H	11,000
Wild Weasel 22 Fed Com #507H	11,000
Wild Weasel 22 Fed Com #508H	11,000



Salt Section Annular Clearance Variance Request

Daniel Moose

Current Design (Salt Strings)

0.422" Annular clearance requirement

- Casing collars shall have a minimum clearance of 0.422 inches on all sides in the hole/casing annulus, with recognition that variances can be granted for justified exceptions.

- 12.25" Hole x 9.625" 40# J55/HCK55 LTC Casing
 - 1.3125" Clearance to casing OD
 - 0.8125" Clearance to coupling OD
- 9.875" Hole x 8.75" 38.5# P110 Sprint-SF Casing
 - 0.5625" Clearance to casing OD
 - 0.433" Clearance to coupling OD

Annular Clearance Variance Request

EOG request permission to allow deviation from the 0.422” annulus clearance requirement for the intermediate (salt) section from Onshore Order #2 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues

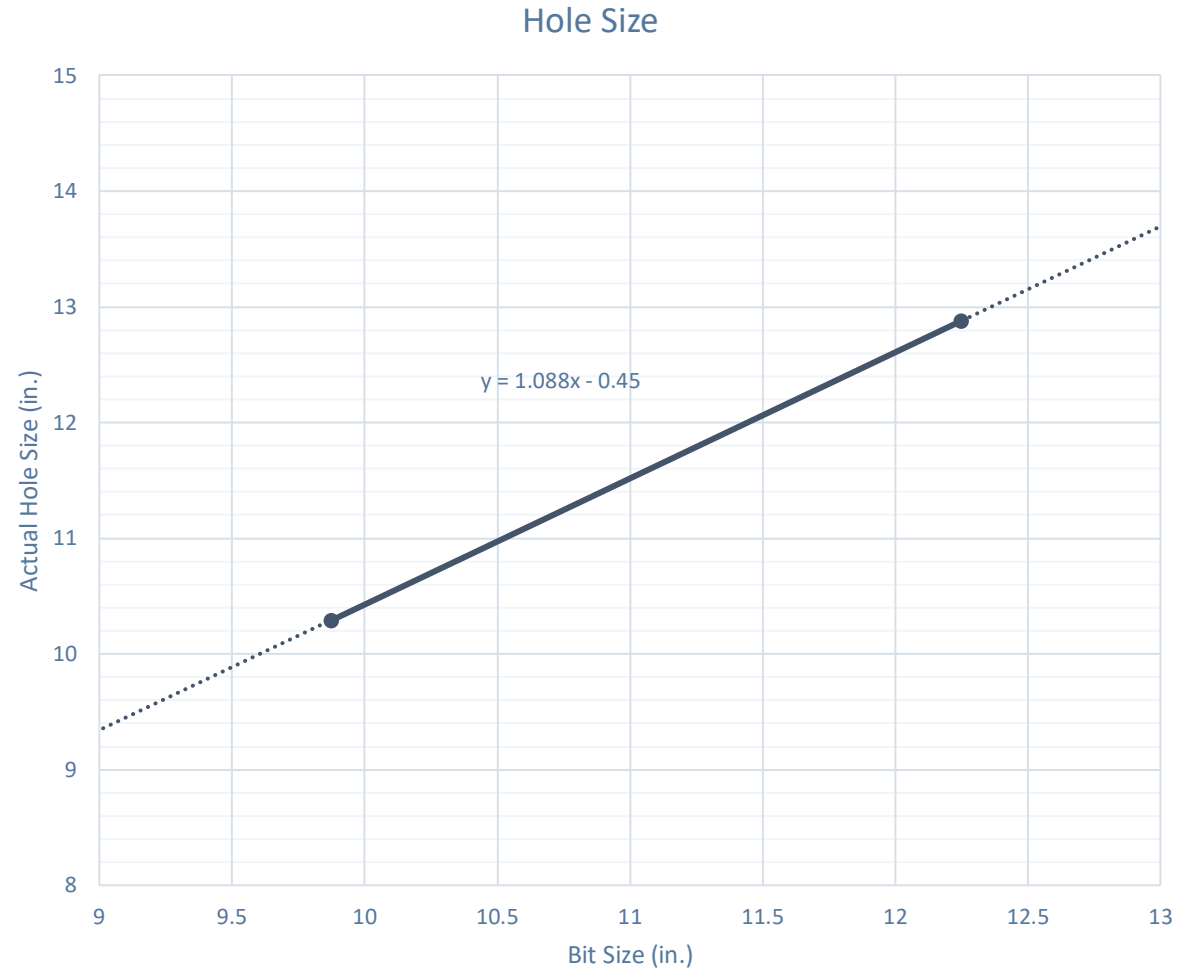
Volumetric Hole Size Calculation

Hole Size Calculations Off Cement Volumes

- Known volume of cement pumped
- Known volume of cement returned to surface
- Must not have had any losses
- Must have bumped plug

Average Hole Size

- 12.25" Hole
 - 12.88" Hole
 - 5.13% diameter increase
 - 10.52% area increase
 - 0.63" Average enlargement
 - 0.58" Median enlargement
 - 179 Well Count
- 9.875" Hole
 - 10.30" Hole
 - 4.24% diameter increase
 - 9.64% area increase
 - 0.42" Average enlargement
 - 0.46" Median enlargement
 - 11 Well Count

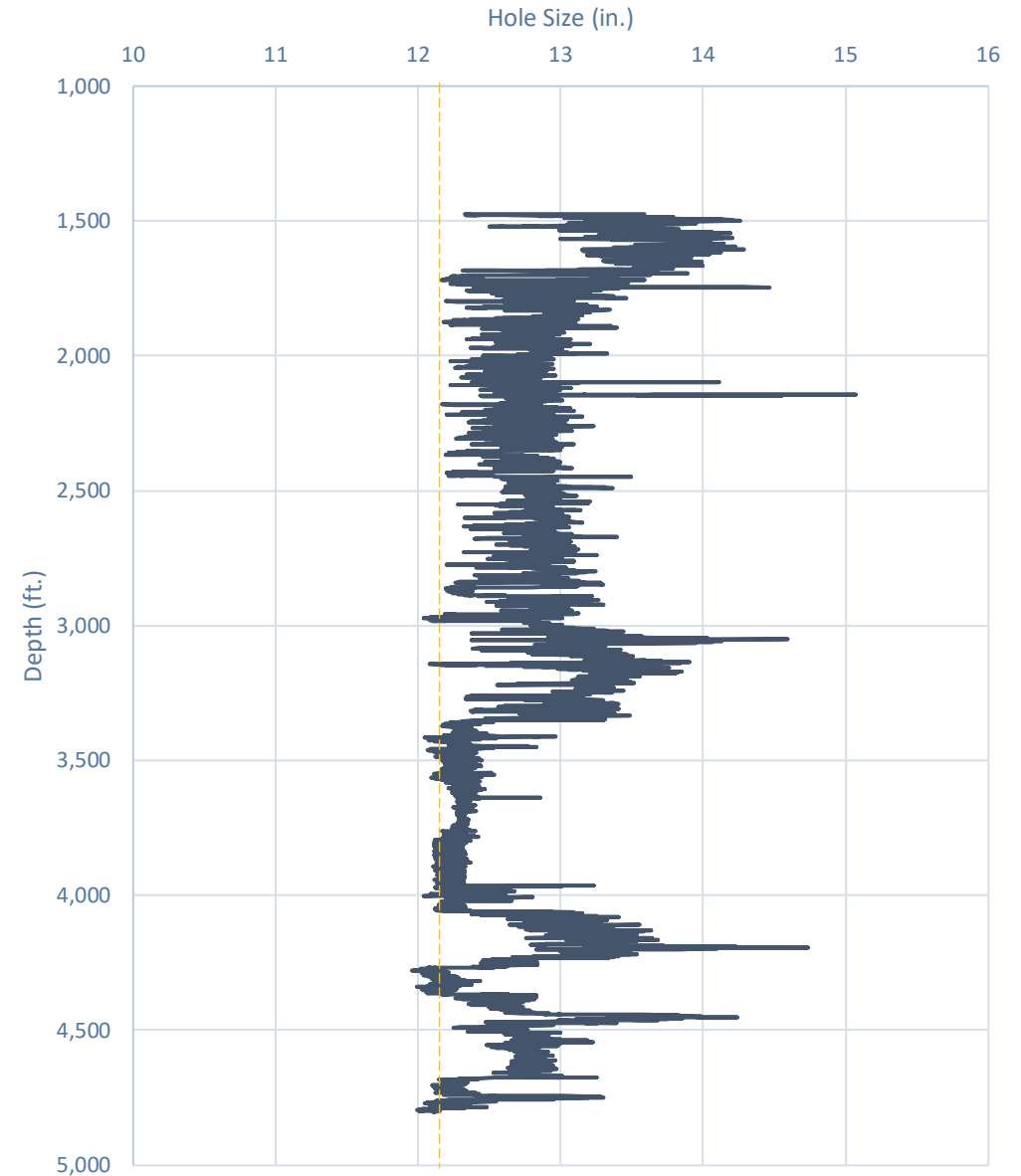


Caliper Hole Size (12.25")

Average Hole Size

- 12.25" Bit
 - 12.76" Hole
 - 4.14% diameter increase
 - 8.44% area increase
 - 0.51" Average enlargement
 - 0.52" Median enlargement
 - Brine

Modelo 10 Fed Com #501H

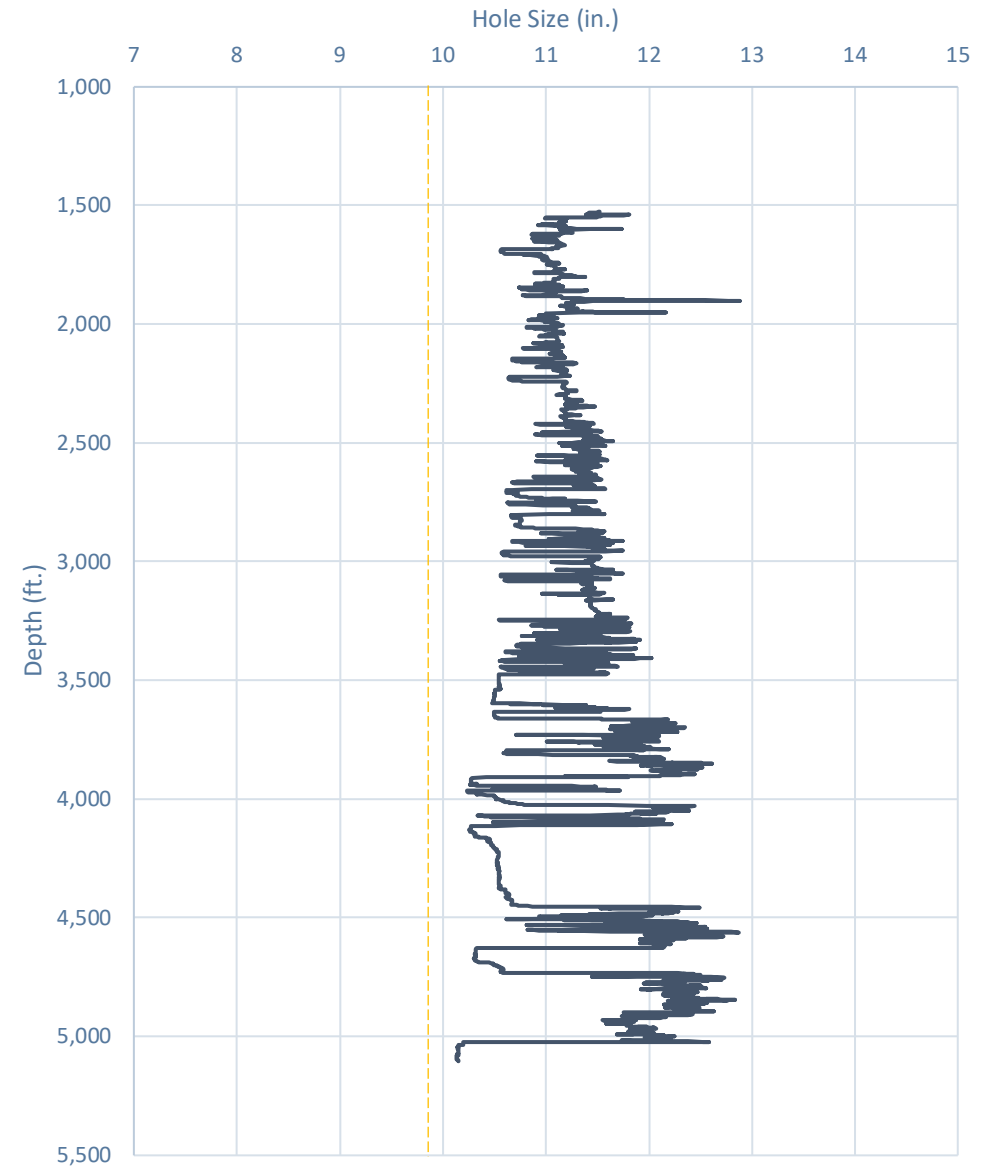


Caliper Hole Size (9.875")

Average Hole Size

- 9.875" Hole
 - 11.21" Hole
 - 13.54% diameter increase
 - 28.92% area increase
 - 1.33" Average enlargement
 - 1.30" Median enlargement
 - EnerLite

Whirling Wind 11 Fed Com #744H



Design A

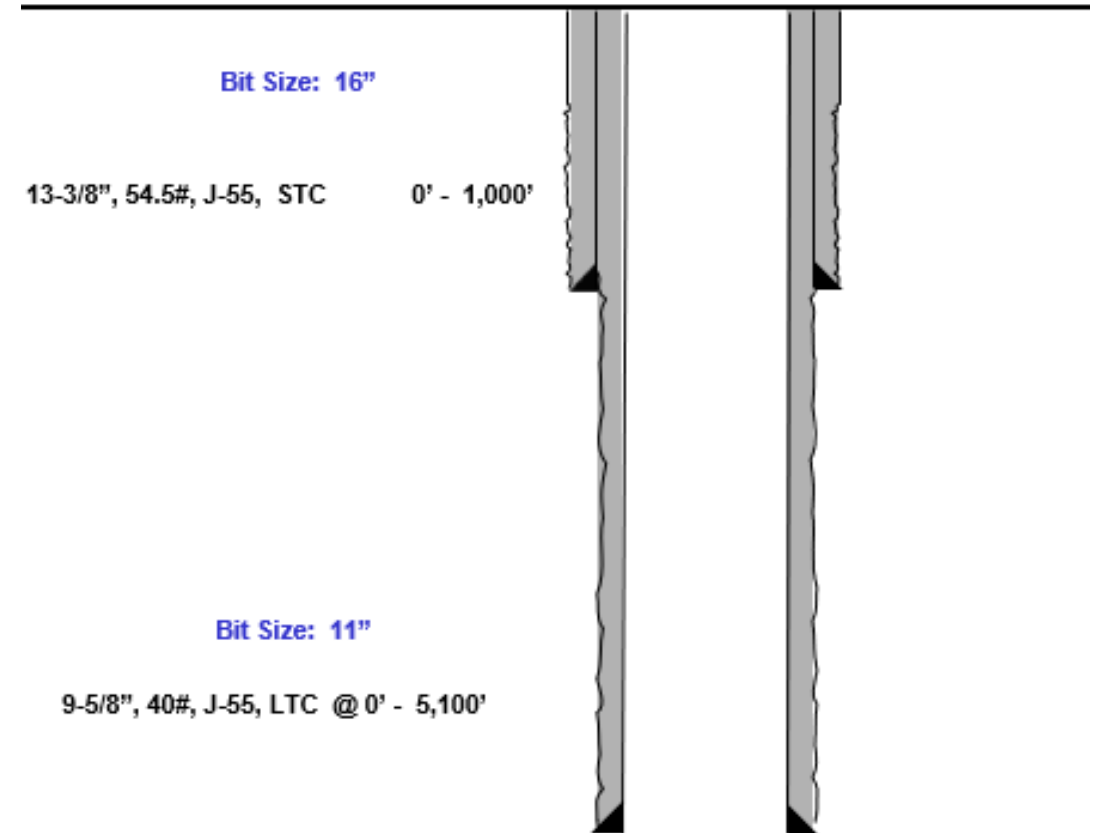
Proposed 11" Hole with 9.625" 40# J55/HCK55 LTC Casing

- 11" Bit + 0.52" Average hole enlargement = 11.52" Hole Size
 - 0.9475" Clearance to casing OD

$$= \frac{11.52 - 9.625}{2}$$
 - 0.4475" Clearance to coupling OD

$$= \frac{11.52 - 10.625}{2}$$
- Previous Shoe – 13.375" 54.5# J55 STC
 - 0.995" Clearance to coupling OD (~1,200' overlap)

$$= \frac{12.615 - 10.625}{2}$$



Design B

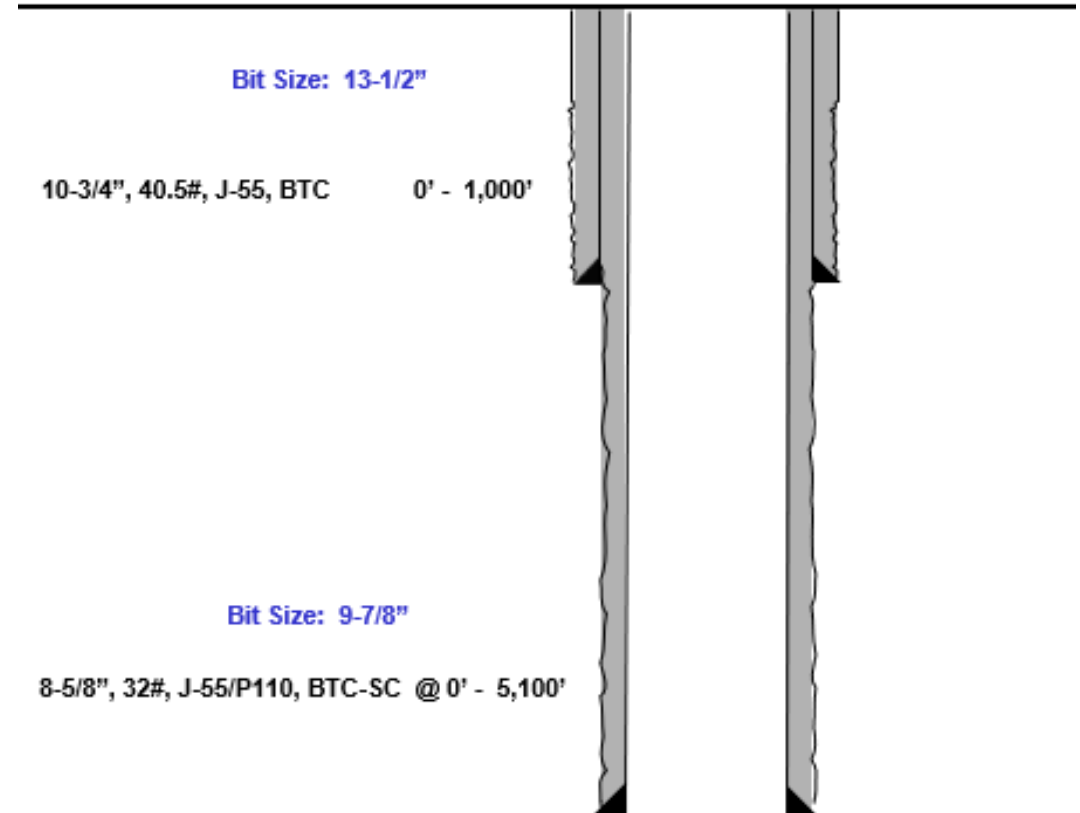
Proposed 9.875" Hole with 8.625" 32# J55/P110 BTC-SC Casing

- 9.875" Bit + 0.42" Average hole enlargement = 10.295" Hole Size
 - 0.835" Clearance to casing OD

$$= \frac{10.295 - 8.625}{2}$$
 - 0.585" Clearance to coupling OD

$$= \frac{10.295 - 9.125}{2}$$
- Previous Shoe – 10.75" 40.5# J55 STC
 - 0.4625" Clearance to coupling OD (~1,200' overlap)

$$= \frac{10.05 - 9.125}{2}$$





Index



Casing Spec Sheets

PERFORMANCE DATA

API LTC 9.625 in 40.00 lbs/ft K55 HC
 Technical Data Sheet

Tubular Parameters

Size	9.625	in	Minimum Yield	55	ksi
Nominal Weight	40.00	lbs/ft	Minimum Tensile	95	ksi
Grade	K55 HC		Yield Load	629	kips
PE Weight	38.94	lbs/ft	Tensile Load	1088	kips
Wall Thickness	0.395	in	Min. Internal Yield Pressure	3,950	psi
Nominal ID	8.835	in	Collapse Pressure	3600	psi
Drift Diameter	8.750	in			
Nom. Pipe Body Area	11.454	in ²			

Connection Parameters

Connection OD	10.625	in
Coupling Length	10.500	in
Threads Per Inch	8	tpi
Standoff Thread Turns	3.50	turns
Make-Up Loss	4.750	in
Min. Internal Yield Pressure	3,950	psi

Pipe Body and API Connections Performance Data

13.375 54.50/0.380 J55

PDF

New Search »

« Back to Previous List

USC Metric

6/8/2015 10:04:37 AM

Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	Pipe	BTC	LTC	STC	
Outside Diameter	13.375	14.375	--	14.375	in.
Wall Thickness	0.380	--	--	--	in.
Inside Diameter	12.615	12.615	--	12.615	in.
Standard Drift	12.459	12.459	--	12.459	in.
Alternate Drift	--	--	--	--	in.
Nominal Linear Weight, T&C	54.50	--	--	--	lbs/ft
Plain End Weight	52.79	--	--	--	lbs/ft
Performance	Pipe	BTC	LTC	STC	
Minimum Collapse Pressure	1,130	1,130	--	1,130	psi
Minimum Internal Yield Pressure	2,740	2,740	--	2,740	psi
Minimum Pipe Body Yield Strength	853.00	--	--	--	1000 lbs
Joint Strength	--	909	--	514	1000 lbs
Reference Length	--	11,125	--	6,290	ft
Make-Up Data	Pipe	BTC	LTC	STC	
Make-Up Loss	--	4.81	--	3.50	in.
Minimum Make-Up Torque	--	--	--	3,860	ft-lbs
Maximum Make-Up Torque	--	--	--	6,430	ft-lbs

Casing Spec Sheets

Pipe Body and API Connections Performance Data

10.750 40.50/0.350 J55

PDF

New Search »

« Back to Previous List

USC Metric

6/8/2015 10:14:05 AM

Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	Pipe	BTC	LTC	STC	
Outside Diameter	10.750	11.750	--	11.750	in.
Wall Thickness	0.350	--	--	--	in.
Inside Diameter	10.050	10.050	--	10.050	in.
Standard Drift	9.894	9.894	--	9.894	in.
Alternate Drift	--	--	--	--	in.
Nominal Linear Weight, T&C	40.50	--	--	--	lbs/ft
Plain End Weight	38.91	--	--	--	lbs/ft
Performance	Pipe	BTC	LTC	STC	
Minimum Collapse Pressure	1,580	1,580	--	1,580	psi
Minimum Internal Yield Pressure	3,130	3,130	--	3,130	psi
Minimum Pipe Body Yield Strength	629.00	--	--	--	1000 lbs
Joint Strength	--	700	--	420	1000 lbs
Reference Length	--	11,522	--	6,915	ft
Make-Up Data	Pipe	BTC	LTC	STC	
Make-Up Loss	--	4.81	--	3.50	in.
Minimum Make-Up Torque	--	--	--	3,150	ft-lbs
Maximum Make-Up Torque	--	--	--	5,250	ft-lbs



API 5CT, 10th Ed. Connection Data Sheet

O.D. (in)	WEIGHT (lb/ft)	WALL (in)	GRADE	*API DRIFT (in)	RBW %
8.625	Nominal: 32.00 Plain End: 31.13	0.352	J55	7.796	87.5

Material Properties (PE)

Pipe	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi
Coupling	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi

Pipe Body Data (PE)

Geometry	
Nominal ID:	7.92 inch
Nominal Area:	9.149 in ²
*Special/Alt. Drift:	7.875 inch
Performance	
Pipe Body Yield Strength:	503 kips
Collapse Resistance:	2,530 psi
Internal Yield Pressure: (API Historical)	3,930 psi

API Connection Data

Coupling OD: 9.625"

STC Performance	
STC Internal Pressure:	3,930 psi
STC Joint Strength:	372 kips
LTC Performance	
LTC Internal Pressure:	3,930 psi
LTC Joint Strength:	417 kips
SC-BTC Performance - Cplg OD = 9.125"	
BTC Internal Pressure:	3,930 psi
BTC Joint Strength:	503 kips

API Connection Torque

STC Torque (ft-lbs)		
Min:	2,793	Opti: 3,724
		Max: 4,655
LTC Torque (ft-lbs)		
Min:	3,130	Opti: 4,174
		Max: 5,217
BTC Torque (ft-lbs)		
follow API guidelines regarding positional make up		

*Alt. Drift will be used unless API Drift is specified on order.

**If above API connections do not suit your needs, VAM® premium connections are available up to 100% of pipe body ratings.

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Rev 3, 7/30/2021

10/21/2022 15:24

10,000 PSI BOP Annular Variance Request (EOG Variance 1c)

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

1. Component and Preventer Compatibility Tables

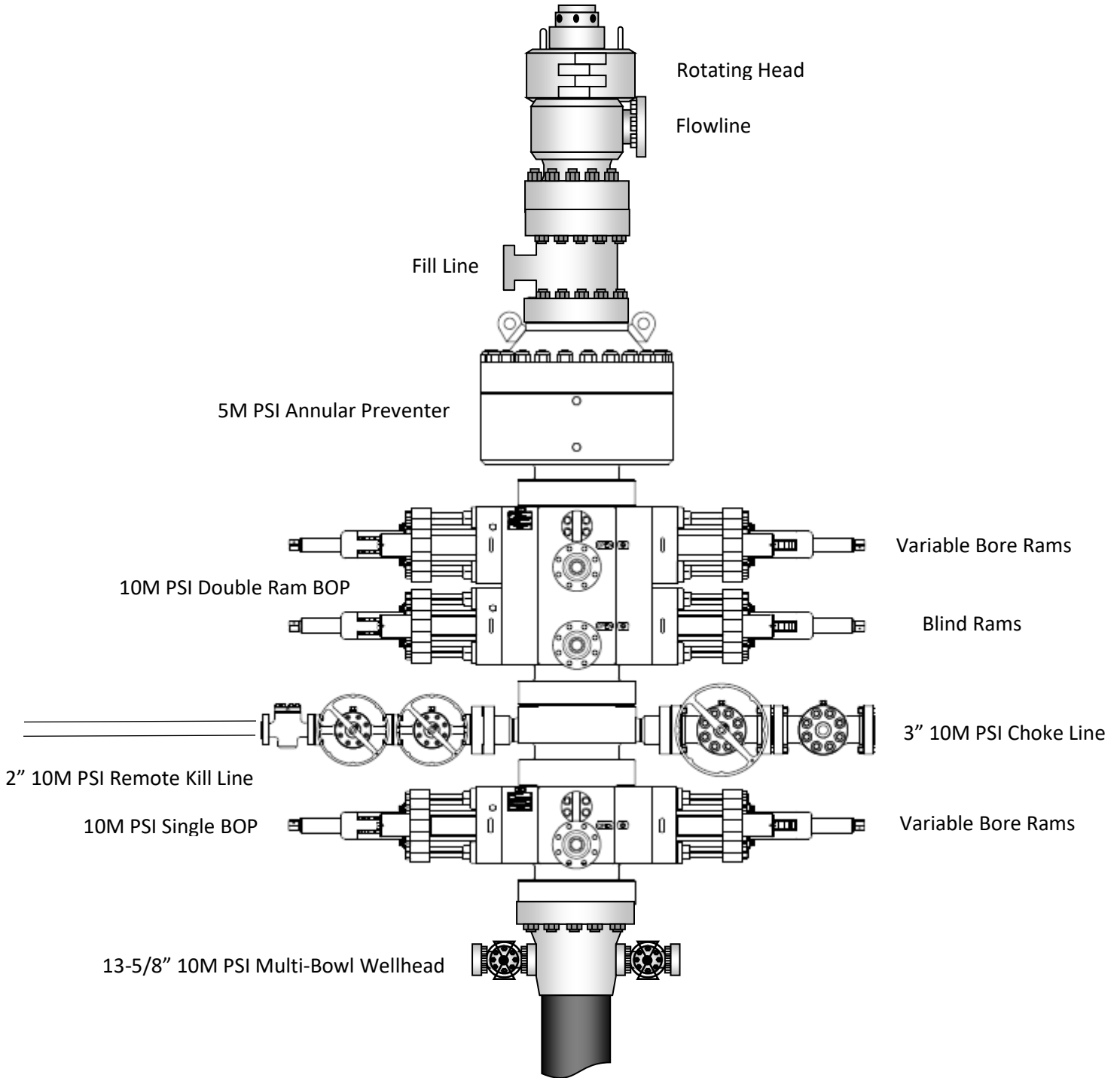
The tables below outlines the tubulars and the compatible preventers in use. This table, combined with the drilling fluid, documents that two barriers to flow will be maintained at all times.

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

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

VBR = Variable Bore Ram

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



2. Well Control Procedures

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

General Procedure While Drilling

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

General Procedure While Tripping

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

General Procedure While Running Production Casing

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

General Procedure With No Pipe In Hole (Open Hole)

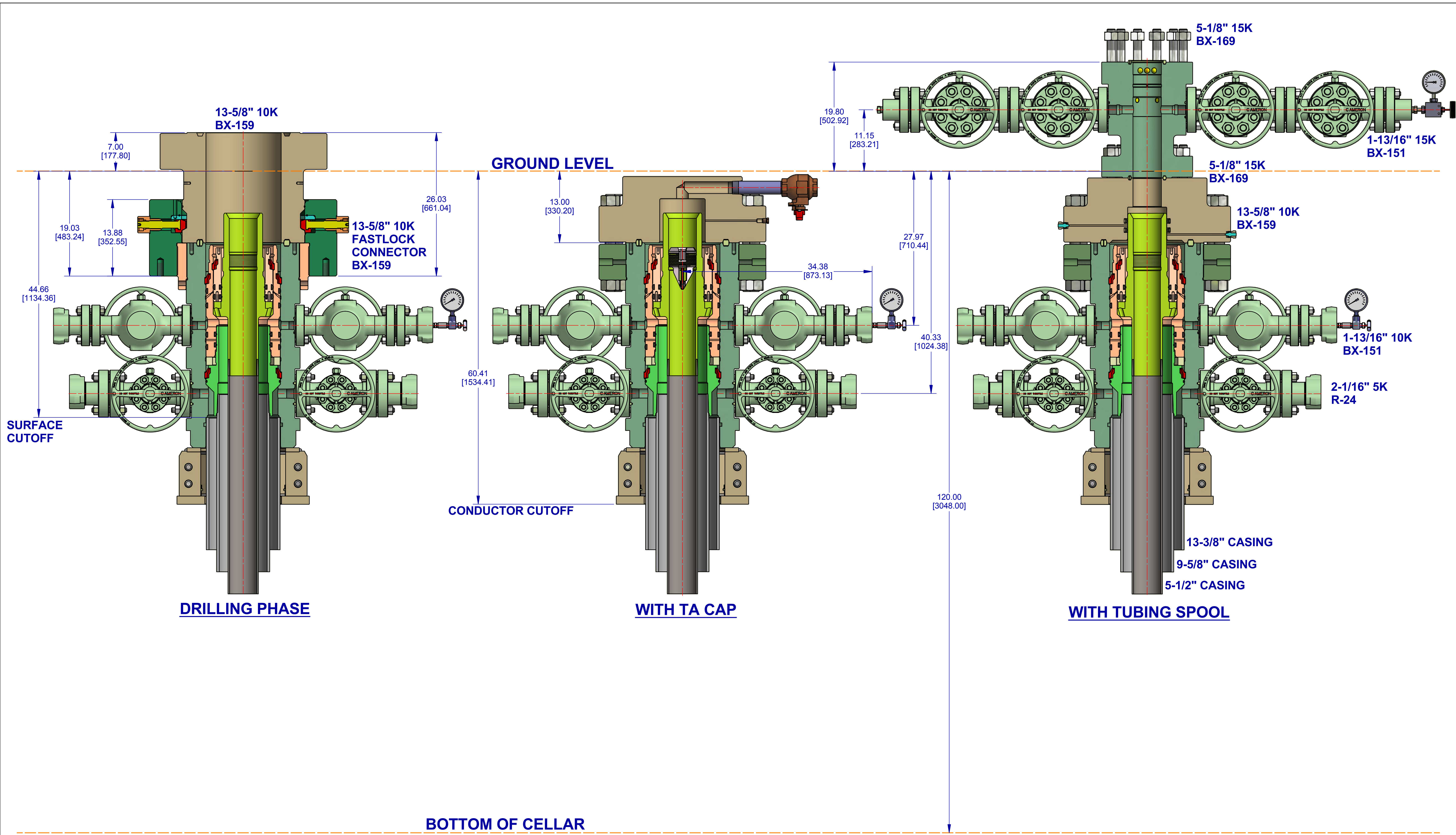
1. Sound alarm (alert crew)
2. Shut-in with blind rams. (HCR and choke will already be in the closed position.)
3. Confirm shut-in
4. Notify toolpusher/company representative
5. Read and record the following:
 - a. SICP
 - b. Pit gain
 - c. Time
6. Regroup and identify forward plan

General Procedures While Pulling BHA thru Stack

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

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

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



<p>THIRD ANGLE</p>		<p>DESIGNED IN INCHES</p> <p>DIMENSIONAL UNITS</p> <p>INCHES [MILLIMETERS]</p>	<p>MACHINING TOLERANCES UNLESS OTHERWISE SPECIFIED</p> <p>X [0] ± = []</p> <p>XX [0.X] ± = []</p> <p>XXX [0.XX] ± = []</p>	<p>ANGLES</p> <p>± °</p>	<p>SURFACE TREATMENT</p> <p>DO NOT SCALE</p> <p>DRAWN BY: KEN REED DATE: 6 Nov 18</p> <p>CHECKED BY: PA DATE: 6 Nov 18</p> <p>APPROVED BY: APPROVER NAME DATE: 6 Nov 18</p>	<p>CONFIDENTIAL</p> <p> SURFACE SYSTEMS</p> <p>EOG RESOURCES, INC</p> <p>13-5/8" 10K MN-DS WELLHEAD</p> <p>13-3/8" X 9-5/8" X 5-1/2"</p>	<p>ESTIMATED WEIGHT: 8147.2 LBS [3695.5 KG] INITIAL USE BM: EWR:650353762</p> <p>SHEET 1 of 1</p> <p>REV: 01</p> <p>INVENTOR: D</p>
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10.750 40.50/0.350 J55

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New Search »

« Back to Previous List

USC Metric

6/8/2015 10:14:05 AM

Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimenstons	Pipe	BTC	LTC	STC	
Outside Diameter	10.750	11.750	--	11.750	in.
Wall Thickness	0.350	--	--	--	in.
Inside Diameter	10.050	10.050	--	10.050	in.
Standard Drift	9.894	9.894	--	9.894	in.
Alternate Drift	--	--	--	--	in.
Nominal Linear Weight, T&C	40.50	--	--	--	lbs/ft
Plain End Weight	38.91	--	--	--	lbs/ft
Performance	Pipe	BTC	LTC	STC	
Minimum Collapse Pressure	1,580	1,580	--	1,580	psi
Minimum Internal Yield Pressure	3,130	3,130	--	3,130	psi
Minimum Pipe Body Yield Strength	629.00	--	--	--	1000 lbs
Joint Strength	--	700	--	420	1000 lbs
Reference Length	--	11,522	--	6,915	ft
Make-Up Data	Pipe	BTC	LTC	STC	
Make-Up Loss	--	4.81	--	3.50	in.
Minimum Make-Up Torque	--	--	--	3,150	ft-lbs
Maximum Make-Up Torque	--	--	--	5,250	ft-lbs

Released to Imaging: 4/15/2026 4:04:48 PM

Well Name: WILD WEASEL 22 FED COM	Well Location: T25S / R34E / SEC 22 / TR B / 32.1214901 / -103.4578067	County or Parish/State: LEA / NM
Well Number: 104H	Type of Well: OIL WELL	Allottee or Tribe Name:
Lease Number: NMNM122624	Unit or CA Name:	Unit or CA Number:
US Well Number:	Operator: EOG RESOURCES INCORPORATED	

Notice of Intent

Sundry ID: 2900066

Type of Submission: Notice of Intent

Type of Action: APD Change

Date Sundry Submitted: 03/11/2026

Time Sundry Submitted: 02:44

Date proposed operation will begin: 03/25/2026

Procedure Description: EOG respectfully requests an amendment to our approved APD for this well to reflect the following changes: Wild Weasel 22 Fed Com 753H (FKA 104H) API #: 10400090538 Change name from Wild Weasel 22 Fed Com 104H to Wild Weasel 22 Fed Com 753H. Change SHL from T-25-S, R-34-E, Sec 22, 644' FNL, 2639' FEL, LEA Co., NM, to T-25-S, R-34-E, Sec 22, 629' FNL, 2639' FEL, LEA Co., N.M. Change BHL from T-25-S, R-34-E, Sec 27, 100' FSL, 2178' FWL, LEA Co., NM, to T-25-S, R-34-E, Sec 27, 100' FSL, 1870' FEL, LEA Co., N.M. Change target formation to Wolfcamp M1. Update casing and cement program to current design. Update the Pool from FAIRVIEW MILLS; BONESPRING to PITCHFORK RANCH; WOLFCAMP, SOUTH as reflected in the C-102.

NOI Attachments

Procedure Description

Wild_Weasel_22_Fed_Com_753H_Planning_Report_20260311144259.pdf

Wild_Weasel_22_Fed_Com_753H_Wall_Plot_20260311144259.pdf

EOG_BLM_Master_Variance_Document_04.24.25_V2_20260311144247.pdf

WILD_WEASEL_22_FED_COM__753H_PLAT_20260311144247.pdf

Blanket_Casing_Design___Wild_Weasel_22_Fed_Com_Deep_2.12.2026_20260311144247.pdf

Wild_Weasel_22_Fed_Com_753H_Sundry_Info___Rev_Name__SHL__BHL__tgt__csg__Pool_2.12.2026_20260311144247.pdf

Wild_Weasel_22_Fed_Com_753H_Variiances_20260311144247.pdf

Well Name: WILD WEASEL 22 FED COM

Well Location: T25S / R34E / SEC 22 / TR B / 32.1214901 / -103.4578067

County or Parish/State: LEA / NM

Well Number: 104H

Type of Well: OIL WELL

Allottee or Tribe Name:

Lease Number: NMNM122624

Unit or CA Name:

Unit or CA Number:

US Well Number:

Operator: EOG RESOURCES INCORPORATED

Conditions of Approval

Additional

WILD_WEASEL_22_FED_COM__SUNDRY_COA__03312026__DEEP_TARGET_20260331150723.pdf

Operator

I certify that the foregoing is true and correct. 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. Electronic submission of Sundry Notices through this system satisfies regulations requiring a

Operator Electronic Signature: SHEA BAILEY

Signed on: MAR 11, 2026 02:43 PM

Name: EOG RESOURCES INCORPORATED

Title: Regulatory Contractor

Street Address: 5509 CHAMPIONS BLVD

City: MIDLAND

State: TX

Phone: (432) 214-9797

Email address: SHEA_BAILEY@EOGRESOURCES.COM

Field

Representative Name:

Street Address:

City:

State:

Zip:

Phone:

Email address:

BLM Point of Contact

BLM POC Name: CHRISTOPHER WALLS

BLM POC Title: Petroleum Engineer

BLM POC Phone: 5752342234

BLM POC Email Address: CWALLS@BLM.GOV

Disposition: Approved

Disposition Date: 04/08/2026

Signature: Chris Walls

GENERAL INSTRUCTIONS

This form is designed for submitting proposals to perform certain well operations and reports of such operations when completed as indicated on Federal and Indian lands pursuant to applicable Federal law and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local area or regional procedures and practices, are either shown below, will be issued by or may be obtained from the local Federal office.

SPECIFIC INSTRUCTIONS

Item 4 - Locations on Federal or Indian land should be described in accordance with Federal requirements. Consult the local Federal office for specific instructions.

Item 13: Proposals to abandon a well and subsequent reports of abandonment should include such special information as is required by the local Federal office. In addition, such proposals and reports should include reasons for the abandonment; data on any former or present productive zones or other zones with present significant fluid contents not sealed off by cement or otherwise; depths (top and bottom) and method of placement of cement plugs; mud or other material placed below, between and above plugs; amount, size, method of parting of any casing, liner or tubing pulled and the depth to the top of any tubing left in the hole; method of closing top of well and date well site conditioned for final inspection looking for approval of the abandonment. If the proposal will involve **hydraulic fracturing operations**, you must comply with 43 CFR 3162.3-3, including providing information about the protection of usable water. Operators should provide the best available information about all formations containing water and their depths. This information could include data and interpretation of resistivity logs run on nearby wells. Information may also be obtained from state or tribal regulatory agencies and from local BLM offices.

NOTICES

The privacy Act of 1974 and the regulation in 43 CFR 2.48(d) provide that you be furnished the following information in connection with information required by this application.

AUTHORITY: 30 U.S.C. 181 et seq., 351 et seq., 25 U.S.C. 396; 43 CFR 3160.

PRINCIPAL PURPOSE: The information is used to: (1) Evaluate, when appropriate, approve applications, and report completion of subsequent well operations, on a Federal or Indian lease; and (2) document for administrative use, information for the management, disposal and use of National Resource lands and resources, such as: (a) evaluating the equipment and procedures to be used during a proposed subsequent well operation and reviewing the completed well operations for compliance with the approved plan; (b) requesting and granting approval to perform those actions covered by 43 CFR 3162.3-2, 3162.3-3, and 3162.3-4; (c) reporting the beginning or resumption of production, as required by 43 CFR 3162.4-1(c) and (d) analyzing future applications to drill or modify operations in light of data obtained and methods used.

ROUTINE USES: Information from the record and/or the record will be transferred to appropriate Federal, State, local or foreign agencies, when relevant to civil, criminal or regulatory investigations or prosecutions in connection with congressional inquiries or to consumer reporting agencies to facilitate collection of debts owed the Government.

EFFECT OF NOT PROVIDING THE INFORMATION: Filing of this notice and report and disclosure of the information is mandatory for those subsequent well operations specified in 43 CFR 3162.3-2, 3162.3-3, 3162.3-4.

The Paperwork Reduction Act of 1995 requires us to inform you that:

The BLM collects this information to evaluate proposed and/or completed subsequent well operations on Federal or Indian oil and gas leases.

Response to this request is mandatory.

The BLM would like you to know that you do not have to respond to this or any other Federal agency-sponsored information collection unless it displays a currently valid OMB control number.

BURDEN HOURS STATEMENT: Public reporting burden for this form is estimated to average 8 hours per response, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect of this form to U.S. Department of the Interior, Bureau of Land Management (1004-0137), Bureau Information Collection Clearance Officer (WO-630), 1849 C St., N.W., Mail Stop 401 LS, Washington, D.C. 20240

Additional Information

Additional Remarks

Change target formation to Wolfcamp M1. Update casing and cement program to current design.

Update the Pool from FAIRVIEW MILLS; BONESPRING to PITCHFORK RANCH; WOLFCAMP, SOUTH as reflected in the C-102.

Location of Well

0. SHL: TR B / 644 FNL / 2639 FEL / TWSP: 25S / RANGE: 34E / SECTION: 22 / LAT: 32.1214901 / LONG: -103.4578067 (TVD: 0 feet, MD: 0 feet)

PPP: TR C / 100 FNL / 2178 FWL / TWSP: 25S / RANGE: 34E / SECTION: 22 / LAT: 32.1229871 / LONG: -103.4593283 (TVD: 9235 feet, MD: 9243 feet)

BHL: TR N / 100 FSL / 2178 FWL / TWSP: 25S / RANGE: 34E / SECTION: 27 / LAT: 32.0945127 / LONG: -103.4593165 (TVD: 9500 feet, MD: 19705 feet)

PECOS DISTRICT DRILLING CONDITIONS OF APPROVAL

Pad Name: Wild Weasel 22 Fed Com Deep
SHL: Section 22, Township 25-S, Range 34-E, LEA County, NM

Well Name	API #	Surface		Intermediate		Production	
		MD	TVD	MD	TVD	MD	TVD
Wild Weasel 22 Fed Com #743H (103H)	30-025-****	974	974	12,766	12,557	23,448	13,034
Wild Weasel 22 Fed Com #753H (104H)	30-025-****	974	974	12,740	12,671	23,421	13,148
Wild Weasel 22 Fed Com #754H (106H)	30-025-****	974	974	13,117	12,671	23,797	13,148

Create COAs

H₂S	Cave / Karst	Waste Prevention Rule
Present	Low	Waste Minimization Plan
Potash	R-111-Q Design	
None		
Wellhead	Casing	
Multibowl	3-String Well	
<input checked="" type="checkbox"/> Flex Hose	<input type="checkbox"/> Liner <input checked="" type="checkbox"/> Fluid <input type="checkbox"/> Casing Clearance	
<input checked="" type="checkbox"/> Break Testing	Cementing	
	<input type="checkbox"/> DV Tool <input checked="" type="checkbox"/> Bradenhead <input type="checkbox"/> Echometer <input checked="" type="checkbox"/> Offline Cement <input type="checkbox"/> Open Annulus <input type="checkbox"/> Pilot Hole	
Special Requirements		
<input checked="" type="checkbox"/> Capitan Reef	<input type="checkbox"/> Water Disposal	<input checked="" type="checkbox"/> COM <input type="checkbox"/> Unit

A. HYDROGEN SULFIDE

A Hydrogen Sulfide (H₂S) Drilling Plan shall be activated AT SPUD. As a result, the Hydrogen Sulfide area must meet 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.

B. CASING

- The 10-3/4 inch surface casing shall be set at approximately 974 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 **8-5/8** inch intermediate casing is **cement to surface**. If cement does not circulate, see B.1.a, c-d above.

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.

- a. **First stage:** Operator will cement with intent to reach the top of the **Brushy Canyon**.
- 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 **Surface X Intermediate 1** 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 **Intermediate 1** casing to tieback requirements listed above after the second stage BH to verify TOC.

Keep casing 2/3 full during run for collapse SF.

3. The mini/mum required fill of cement behind the **6** inch X **5-1/2** inch tapered production casing is at least **200 feet** into previous casing string. Operator shall provide method of verification. Operator has requested to run either 6 inch or 5-1/2 inch casing only. Reviewed and is OK.
 - If cement does not circulate to surface on the previous casing, this string must come to surface.

Keep casing 1/2 full during run for collapse SF.

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 intermediate casing shoe shall be **10,000**

(10M) psi. Variance is approved to use a 5000 (5M) annular which shall be tested to 3500 (3.5M) psi.

- a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
 - b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
 - c. Manufacturer representative shall install the test plug for the initial BOP test.
 - d. If the cement does not circulate and one-inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
 - e. Whenever any seal subject to test pressure is broken, all the tests in 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. **(Annular preventer must be tested to a minimum of 70% of BOPE working pressure and shall be higher than the MASP.)** If in the event break testing is not utilized, then a full BOPE test would be conducted.
- a. Variance only pertains to the intermediate hole-sections and no deeper than the Bone Springs formation. **BOPE Break Testing is NOT permitted to drilling the production hole section for this well.**
 - b. While in transfer between wells, BOPE shall be secured by the hydraulic carrier or cradle.
 - c. A full BOPE test is required prior to drilling the first deep intermediate hole section. If any subsequent hole interval is deeper than the first, a full BOPE test will be required. (200' TVD tolerance between intermediate shoes is allowable).
 - d. As a minimum, a full BOPE test shall be performed at 21-day intervals.
 - e. In the event any repairs or replacement of the BOPE is required, the BOPE shall test as per **43 CFR 3172**. Any well control event while drilling require notification to the BLM Petroleum Engineer (**575-706-2779**) prior to the commencement of any BOPE Break Testing operations.

D. SPECIAL REQUIREMENT(S)

Communitization Agreement:

- The operator will submit a Communitization Agreement to the Santa Fe Office, 301 Dinosaur Trail Santa Fe, New Mexico 87508, at least 90 days before the anticipated date

of first production from a well subject to a spacing order issued by the New Mexico Oil Conservation Division. The Communitization Agreement will include the signatures of all working interest owners in all Federal and Indian leases subject to the Communitization Agreement (i.e., operating rights owners and lessees of record), or certification that the operator has obtained the written signatures of all such owners and will make those signatures available to the BLM immediately upon request.

- 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.
- 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)

For multi-well pads, notifications for the following operations may be made together going from one well to the next. This does NOT apply to notifications for wells in the R111Q potash area:

- Casing run
- Offline cementing
- Break testing

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](mailto: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.

KPI 3/31/2026

Midland

Lea County, NM (NAD 83 NME)
Wild Weasel 22 Fed Com
#753H

OH

Plan: Plan #0.1 RT

Standard Planning Report

05 March, 2026

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #753H
Company:	Midland	TVD Reference:	kb = 26' @ 3377.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3377.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#753H	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	Wild Weasel 22 Fed Com				
Site Position:		Northing:	409,434.00 usft	Latitude:	32° 7' 21.137 N
From:	Map	Easting:	814,510.00 usft	Longitude:	103° 27' 3.375 W
Position Uncertainty:	0.0 usft	Slot Radius:	13-3/16 "		

Well	#753H					
Well Position	+N/-S	0.0 usft	Northing:	409,050.00 usft	Latitude:	32° 7' 17.509 N
	+E/-W	0.0 usft	Easting:	812,386.00 usft	Longitude:	103° 27' 28.108 W
Position Uncertainty	0.0 usft		Wellhead Elevation:	usft	Ground Level:	3,351.0 usft
Grid Convergence:	0.47 °					

Wellbore	OH				
Magnetics	Model Name	Sample Date	Declination (°)	Dip Angle (°)	Field Strength (nT)
	IGRF2025	3/5/2026	6.13	59.66	46,888.80632625

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	175.04

Plan Survey Tool Program	Date	3/5/2026		
Depth From (usft)	Depth To (usft)	Survey (Wellbore)	Tool Name	Remarks
1	0.0	23,421.1	Plan #0.1 RT (OH)	EOG MWD+IFR1 MWD + IFR1

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #753H
Company:	Midland	TVD Reference:	kb = 26' @ 3377.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3377.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#753H	Survey Calculation Method:	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

Plan Sections										
Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)	TFO (°)	Target
0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,071.0	0.00	0.00	1,071.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,494.1	8.46	52.59	1,492.6	18.9	24.8	2.00	2.00	0.00	52.59	
7,614.6	8.46	52.59	7,546.4	566.1	740.2	0.00	0.00	0.00	0.00	
8,037.7	0.00	0.00	7,968.0	585.0	765.0	2.00	-2.00	0.00	180.00	
12,740.2	0.00	0.00	12,670.5	585.0	765.0	0.00	0.00	0.00	0.00	KOP(Wild Weasel 22
12,960.7	26.46	178.85	12,883.2	535.0	766.0	12.00	12.00	81.13	178.85	FTP(Wild Weasel 22 I
13,490.1	89.99	179.61	13,147.9	107.6	770.6	12.00	12.00	0.14	0.85	
14,280.8	89.99	179.61	13,148.0	-683.0	776.0	0.00	0.00	0.00	0.00	Fed Perf 1(Wild Weas
23,421.1	90.01	179.42	13,148.0	-9,823.0	853.0	0.00	0.00	0.00	-86.32	PBHL(Wild Weasel 22

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #753H
Company:	Midland	TVD Reference:	kb = 26' @ 3377.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3377.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#753H	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
1,071.0	0.00	0.00	1,071.0	0.0	0.0	0.0	0.00	0.00	0.00
1,100.0	0.58	52.59	1,100.0	0.1	0.1	-0.1	2.00	2.00	0.00
1,200.0	2.58	52.59	1,200.0	1.8	2.3	-1.6	2.00	2.00	0.00
1,300.0	4.58	52.59	1,299.8	5.6	7.3	-4.9	2.00	2.00	0.00
1,400.0	6.58	52.59	1,399.3	11.5	15.0	-10.1	2.00	2.00	0.00
1,494.1	8.46	52.59	1,492.6	18.9	24.8	-16.7	2.00	2.00	0.00
1,500.0	8.46	52.59	1,498.4	19.5	25.5	-17.2	0.00	0.00	0.00
1,600.0	8.46	52.59	1,597.3	28.4	37.2	-25.1	0.00	0.00	0.00
1,700.0	8.46	52.59	1,696.2	37.3	48.8	-33.0	0.00	0.00	0.00
1,800.0	8.46	52.59	1,795.1	46.3	60.5	-40.9	0.00	0.00	0.00
1,900.0	8.46	52.59	1,894.0	55.2	72.2	-48.8	0.00	0.00	0.00
2,000.0	8.46	52.59	1,993.0	64.2	83.9	-56.7	0.00	0.00	0.00
2,100.0	8.46	52.59	2,091.9	73.1	95.6	-64.6	0.00	0.00	0.00
2,200.0	8.46	52.59	2,190.8	82.0	107.3	-72.5	0.00	0.00	0.00
2,300.0	8.46	52.59	2,289.7	91.0	119.0	-80.3	0.00	0.00	0.00
2,400.0	8.46	52.59	2,388.6	99.9	130.7	-88.2	0.00	0.00	0.00
2,500.0	8.46	52.59	2,487.5	108.9	142.4	-96.1	0.00	0.00	0.00
2,600.0	8.46	52.59	2,586.4	117.8	154.0	-104.0	0.00	0.00	0.00
2,700.0	8.46	52.59	2,685.3	126.7	165.7	-111.9	0.00	0.00	0.00
2,800.0	8.46	52.59	2,784.2	135.7	177.4	-119.8	0.00	0.00	0.00
2,900.0	8.46	52.59	2,883.2	144.6	189.1	-127.7	0.00	0.00	0.00
3,000.0	8.46	52.59	2,982.1	153.6	200.8	-135.6	0.00	0.00	0.00
3,100.0	8.46	52.59	3,081.0	162.5	212.5	-143.5	0.00	0.00	0.00
3,200.0	8.46	52.59	3,179.9	171.4	224.2	-151.4	0.00	0.00	0.00
3,300.0	8.46	52.59	3,278.8	180.4	235.9	-159.3	0.00	0.00	0.00
3,400.0	8.46	52.59	3,377.7	189.3	247.6	-167.2	0.00	0.00	0.00
3,500.0	8.46	52.59	3,476.6	198.3	259.3	-175.1	0.00	0.00	0.00
3,600.0	8.46	52.59	3,575.5	207.2	270.9	-183.0	0.00	0.00	0.00
3,700.0	8.46	52.59	3,674.4	216.1	282.6	-190.9	0.00	0.00	0.00
3,800.0	8.46	52.59	3,773.4	225.1	294.3	-198.8	0.00	0.00	0.00
3,900.0	8.46	52.59	3,872.3	234.0	306.0	-206.7	0.00	0.00	0.00
4,000.0	8.46	52.59	3,971.2	242.9	317.7	-214.6	0.00	0.00	0.00
4,100.0	8.46	52.59	4,070.1	251.9	329.4	-222.4	0.00	0.00	0.00
4,200.0	8.46	52.59	4,169.0	260.8	341.1	-230.3	0.00	0.00	0.00
4,300.0	8.46	52.59	4,267.9	269.8	352.8	-238.2	0.00	0.00	0.00
4,400.0	8.46	52.59	4,366.8	278.7	364.5	-246.1	0.00	0.00	0.00
4,500.0	8.46	52.59	4,465.7	287.6	376.1	-254.0	0.00	0.00	0.00
4,600.0	8.46	52.59	4,564.7	296.6	387.8	-261.9	0.00	0.00	0.00
4,700.0	8.46	52.59	4,663.6	305.5	399.5	-269.8	0.00	0.00	0.00
4,800.0	8.46	52.59	4,762.5	314.5	411.2	-277.7	0.00	0.00	0.00
4,900.0	8.46	52.59	4,861.4	323.4	422.9	-285.6	0.00	0.00	0.00
5,000.0	8.46	52.59	4,960.3	332.3	434.6	-293.5	0.00	0.00	0.00
5,100.0	8.46	52.59	5,059.2	341.3	446.3	-301.4	0.00	0.00	0.00

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #753H
Company:	Midland	TVD Reference:	kb = 26' @ 3377.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3377.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#753H	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)	
5,200.0	8.46	52.59	5,158.1	350.2	458.0	-309.3	0.00	0.00	0.00	
5,300.0	8.46	52.59	5,257.0	359.2	469.7	-317.2	0.00	0.00	0.00	
5,400.0	8.46	52.59	5,355.9	368.1	481.4	-325.1	0.00	0.00	0.00	
5,500.0	8.46	52.59	5,454.9	377.0	493.0	-333.0	0.00	0.00	0.00	
5,600.0	8.46	52.59	5,553.8	386.0	504.7	-340.9	0.00	0.00	0.00	
5,700.0	8.46	52.59	5,652.7	394.9	516.4	-348.8	0.00	0.00	0.00	
5,800.0	8.46	52.59	5,751.6	403.8	528.1	-356.6	0.00	0.00	0.00	
5,900.0	8.46	52.59	5,850.5	412.8	539.8	-364.5	0.00	0.00	0.00	
6,000.0	8.46	52.59	5,949.4	421.7	551.5	-372.4	0.00	0.00	0.00	
6,100.0	8.46	52.59	6,048.3	430.7	563.2	-380.3	0.00	0.00	0.00	
6,200.0	8.46	52.59	6,147.2	439.6	574.9	-388.2	0.00	0.00	0.00	
6,300.0	8.46	52.59	6,246.1	448.5	586.6	-396.1	0.00	0.00	0.00	
6,400.0	8.46	52.59	6,345.1	457.5	598.2	-404.0	0.00	0.00	0.00	
6,500.0	8.46	52.59	6,444.0	466.4	609.9	-411.9	0.00	0.00	0.00	
6,600.0	8.46	52.59	6,542.9	475.4	621.6	-419.8	0.00	0.00	0.00	
6,700.0	8.46	52.59	6,641.8	484.3	633.3	-427.7	0.00	0.00	0.00	
6,800.0	8.46	52.59	6,740.7	493.2	645.0	-435.6	0.00	0.00	0.00	
6,900.0	8.46	52.59	6,839.6	502.2	656.7	-443.5	0.00	0.00	0.00	
7,000.0	8.46	52.59	6,938.5	511.1	668.4	-451.4	0.00	0.00	0.00	
7,100.0	8.46	52.59	7,037.4	520.1	680.1	-459.3	0.00	0.00	0.00	
7,200.0	8.46	52.59	7,136.3	529.0	691.8	-467.2	0.00	0.00	0.00	
7,300.0	8.46	52.59	7,235.3	537.9	703.5	-475.1	0.00	0.00	0.00	
7,400.0	8.46	52.59	7,334.2	546.9	715.1	-483.0	0.00	0.00	0.00	
7,500.0	8.46	52.59	7,433.1	555.8	726.8	-490.8	0.00	0.00	0.00	
7,600.0	8.46	52.59	7,532.0	564.7	738.5	-498.7	0.00	0.00	0.00	
7,614.6	8.46	52.59	7,546.4	566.1	740.2	-499.9	0.00	0.00	0.00	
7,700.0	6.75	52.59	7,631.1	572.9	749.2	-506.0	2.00	-2.00	0.00	
7,800.0	4.75	52.59	7,730.6	579.0	757.2	-511.3	2.00	-2.00	0.00	
7,900.0	2.75	52.59	7,830.3	583.0	762.4	-514.9	2.00	-2.00	0.00	
8,000.0	0.75	52.59	7,930.3	584.8	764.8	-516.5	2.00	-2.00	0.00	
8,037.7	0.00	0.00	7,968.0	585.0	765.0	-516.6	2.00	-2.00	0.00	
8,100.0	0.00	0.00	8,030.3	585.0	765.0	-516.6	0.00	0.00	0.00	
8,200.0	0.00	0.00	8,130.3	585.0	765.0	-516.6	0.00	0.00	0.00	
8,300.0	0.00	0.00	8,230.3	585.0	765.0	-516.6	0.00	0.00	0.00	
8,400.0	0.00	0.00	8,330.3	585.0	765.0	-516.6	0.00	0.00	0.00	
8,500.0	0.00	0.00	8,430.3	585.0	765.0	-516.6	0.00	0.00	0.00	
8,600.0	0.00	0.00	8,530.3	585.0	765.0	-516.6	0.00	0.00	0.00	
8,700.0	0.00	0.00	8,630.3	585.0	765.0	-516.6	0.00	0.00	0.00	
8,800.0	0.00	0.00	8,730.3	585.0	765.0	-516.6	0.00	0.00	0.00	
8,900.0	0.00	0.00	8,830.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,000.0	0.00	0.00	8,930.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,100.0	0.00	0.00	9,030.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,200.0	0.00	0.00	9,130.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,300.0	0.00	0.00	9,230.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,400.0	0.00	0.00	9,330.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,500.0	0.00	0.00	9,430.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,600.0	0.00	0.00	9,530.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,700.0	0.00	0.00	9,630.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,800.0	0.00	0.00	9,730.3	585.0	765.0	-516.6	0.00	0.00	0.00	
9,900.0	0.00	0.00	9,830.3	585.0	765.0	-516.6	0.00	0.00	0.00	
10,000.0	0.00	0.00	9,930.3	585.0	765.0	-516.6	0.00	0.00	0.00	
10,100.0	0.00	0.00	10,030.3	585.0	765.0	-516.6	0.00	0.00	0.00	
10,200.0	0.00	0.00	10,130.3	585.0	765.0	-516.6	0.00	0.00	0.00	
10,300.0	0.00	0.00	10,230.3	585.0	765.0	-516.6	0.00	0.00	0.00	

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #753H
Company:	Midland	TVD Reference:	kb = 26' @ 3377.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3377.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#753H	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)
10,400.0	0.00	0.00	10,330.3	585.0	765.0	-516.6	0.00	0.00	0.00
10,500.0	0.00	0.00	10,430.3	585.0	765.0	-516.6	0.00	0.00	0.00
10,600.0	0.00	0.00	10,530.3	585.0	765.0	-516.6	0.00	0.00	0.00
10,700.0	0.00	0.00	10,630.3	585.0	765.0	-516.6	0.00	0.00	0.00
10,800.0	0.00	0.00	10,730.3	585.0	765.0	-516.6	0.00	0.00	0.00
10,900.0	0.00	0.00	10,830.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,000.0	0.00	0.00	10,930.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,100.0	0.00	0.00	11,030.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,200.0	0.00	0.00	11,130.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,300.0	0.00	0.00	11,230.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,400.0	0.00	0.00	11,330.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,500.0	0.00	0.00	11,430.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,600.0	0.00	0.00	11,530.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,700.0	0.00	0.00	11,630.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,800.0	0.00	0.00	11,730.3	585.0	765.0	-516.6	0.00	0.00	0.00
11,900.0	0.00	0.00	11,830.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,000.0	0.00	0.00	11,930.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,100.0	0.00	0.00	12,030.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,200.0	0.00	0.00	12,130.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,300.0	0.00	0.00	12,230.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,400.0	0.00	0.00	12,330.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,500.0	0.00	0.00	12,430.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,600.0	0.00	0.00	12,530.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,700.0	0.00	0.00	12,630.3	585.0	765.0	-516.6	0.00	0.00	0.00
12,740.2	0.00	0.00	12,670.5	585.0	765.0	-516.6	0.00	0.00	0.00
12,750.0	1.18	178.85	12,680.3	584.9	765.0	-516.5	12.00	12.00	0.00
12,775.0	4.18	178.85	12,705.3	583.7	765.0	-515.4	12.00	12.00	0.00
12,800.0	7.18	178.85	12,730.1	581.3	765.1	-512.9	12.00	12.00	0.00
12,825.0	10.18	178.85	12,754.8	577.5	765.2	-509.1	12.00	12.00	0.00
12,850.0	13.18	178.85	12,779.3	572.4	765.3	-504.1	12.00	12.00	0.00
12,875.0	16.18	178.85	12,803.5	566.1	765.4	-497.8	12.00	12.00	0.00
12,900.0	19.18	178.85	12,827.3	558.5	765.5	-490.2	12.00	12.00	0.00
12,925.0	22.18	178.85	12,850.7	549.7	765.7	-481.4	12.00	12.00	0.00
12,950.0	25.18	178.85	12,873.6	539.6	765.9	-471.4	12.00	12.00	0.00
12,960.7	26.46	178.85	12,883.2	535.0	766.0	-466.7	12.00	12.00	0.00
12,975.0	28.18	178.91	12,895.9	528.4	766.1	-460.2	12.00	12.00	0.38
13,000.0	31.18	178.99	12,917.7	516.0	766.4	-447.8	12.00	12.00	0.32
13,025.0	34.18	179.06	12,938.7	502.5	766.6	-434.3	12.00	12.00	0.27
13,050.0	37.18	179.11	12,959.0	488.0	766.8	-419.8	12.00	12.00	0.23
13,075.0	40.18	179.17	12,978.5	472.3	767.1	-404.2	12.00	12.00	0.20
13,100.0	43.18	179.21	12,997.2	455.7	767.3	-387.6	12.00	12.00	0.18
13,125.0	46.18	179.25	13,015.0	438.1	767.5	-370.1	12.00	12.00	0.16
13,150.0	49.18	179.29	13,031.8	419.7	767.8	-351.7	12.00	12.00	0.14
13,175.0	52.18	179.32	13,047.6	400.3	768.0	-332.4	12.00	12.00	0.13
13,200.0	55.18	179.35	13,062.4	380.2	768.2	-312.3	12.00	12.00	0.12
13,225.0	58.18	179.38	13,076.2	359.3	768.5	-291.5	12.00	12.00	0.11
13,250.0	61.18	179.40	13,088.8	337.7	768.7	-270.0	12.00	12.00	0.11
13,275.0	64.18	179.43	13,100.3	315.5	768.9	-247.8	12.00	12.00	0.10
13,300.0	67.18	179.45	13,110.5	292.7	769.1	-225.1	12.00	12.00	0.10
13,325.0	70.18	179.48	13,119.6	269.5	769.4	-201.9	12.00	12.00	0.09
13,350.0	73.18	179.50	13,127.5	245.7	769.6	-178.2	12.00	12.00	0.09
13,375.0	76.18	179.52	13,134.1	221.6	769.8	-154.2	12.00	12.00	0.08
13,400.0	79.18	179.54	13,139.4	197.2	770.0	-129.8	12.00	12.00	0.08
13,425.0	82.18	179.56	13,143.5	172.5	770.2	-105.3	12.00	12.00	0.08

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #753H
Company:	Midland	TVD Reference:	kb = 26' @ 3377.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3377.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#753H	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)
13,450.0	85.18	179.58	13,146.2	147.7	770.4	-80.5	12.00	12.00	0.08
13,475.0	88.18	179.60	13,147.7	122.7	770.5	-55.6	12.00	12.00	0.08
13,490.1	89.99	179.61	13,147.9	107.6	770.6	-40.5	12.00	12.00	0.08
13,500.0	89.99	179.61	13,147.9	97.7	770.7	-30.7	0.00	0.00	0.00
13,600.0	89.99	179.61	13,147.9	-2.3	771.4	69.0	0.00	0.00	0.00
13,700.0	89.99	179.61	13,147.9	-102.3	772.1	168.7	0.00	0.00	0.00
13,800.0	89.99	179.61	13,147.9	-202.3	772.7	268.4	0.00	0.00	0.00
13,900.0	89.99	179.61	13,148.0	-302.3	773.4	368.0	0.00	0.00	0.00
14,000.0	89.99	179.61	13,148.0	-402.3	774.1	467.7	0.00	0.00	0.00
14,100.0	89.99	179.61	13,148.0	-502.3	774.8	567.4	0.00	0.00	0.00
14,200.0	89.99	179.61	13,148.0	-602.2	775.5	667.1	0.00	0.00	0.00
14,280.8	89.99	179.61	13,148.0	-683.0	776.0	747.6	0.00	0.00	0.00
14,300.0	89.99	179.61	13,148.0	-702.2	776.1	766.8	0.00	0.00	0.00
14,400.0	89.99	179.61	13,148.0	-802.2	776.8	866.4	0.00	0.00	0.00
14,500.0	89.99	179.61	13,148.0	-902.2	777.5	966.1	0.00	0.00	0.00
14,600.0	89.99	179.60	13,148.0	-1,002.2	778.2	1,065.8	0.00	0.00	0.00
14,700.0	89.99	179.60	13,148.0	-1,102.2	778.9	1,165.5	0.00	0.00	0.00
14,800.0	89.99	179.60	13,148.1	-1,202.2	779.6	1,265.2	0.00	0.00	0.00
14,900.0	89.99	179.60	13,148.1	-1,302.2	780.3	1,364.9	0.00	0.00	0.00
15,000.0	89.99	179.60	13,148.1	-1,402.2	781.0	1,464.5	0.00	0.00	0.00
15,100.0	90.00	179.59	13,148.1	-1,502.2	781.7	1,564.2	0.00	0.00	0.00
15,200.0	90.00	179.59	13,148.1	-1,602.2	782.4	1,663.9	0.00	0.00	0.00
15,300.0	90.00	179.59	13,148.1	-1,702.2	783.1	1,763.6	0.00	0.00	0.00
15,400.0	90.00	179.59	13,148.1	-1,802.2	783.8	1,863.3	0.00	0.00	0.00
15,500.0	90.00	179.59	13,148.1	-1,902.2	784.5	1,963.0	0.00	0.00	0.00
15,600.0	90.00	179.58	13,148.1	-2,002.2	785.3	2,062.6	0.00	0.00	0.00
15,700.0	90.00	179.58	13,148.1	-2,102.2	786.0	2,162.3	0.00	0.00	0.00
15,800.0	90.00	179.58	13,148.1	-2,202.2	786.7	2,262.0	0.00	0.00	0.00
15,900.0	90.00	179.58	13,148.1	-2,302.2	787.5	2,361.7	0.00	0.00	0.00
16,000.0	90.00	179.58	13,148.1	-2,402.2	788.2	2,461.4	0.00	0.00	0.00
16,100.0	90.00	179.57	13,148.2	-2,502.2	788.9	2,561.1	0.00	0.00	0.00
16,200.0	90.00	179.57	13,148.2	-2,602.2	789.7	2,660.8	0.00	0.00	0.00
16,300.0	90.00	179.57	13,148.2	-2,702.2	790.4	2,760.4	0.00	0.00	0.00
16,400.0	90.00	179.57	13,148.2	-2,802.2	791.2	2,860.1	0.00	0.00	0.00
16,500.0	90.00	179.57	13,148.2	-2,902.2	791.9	2,959.8	0.00	0.00	0.00
16,600.0	90.00	179.56	13,148.2	-3,002.2	792.7	3,059.5	0.00	0.00	0.00
16,700.0	90.00	179.56	13,148.2	-3,102.2	793.5	3,159.2	0.00	0.00	0.00
16,800.0	90.00	179.56	13,148.2	-3,202.2	794.2	3,258.9	0.00	0.00	0.00
16,900.0	90.00	179.56	13,148.2	-3,302.2	795.0	3,358.6	0.00	0.00	0.00
17,000.0	90.00	179.56	13,148.2	-3,402.2	795.8	3,458.3	0.00	0.00	0.00
17,100.0	90.00	179.55	13,148.2	-3,502.2	796.5	3,558.0	0.00	0.00	0.00
17,200.0	90.00	179.55	13,148.2	-3,602.2	797.3	3,657.6	0.00	0.00	0.00
17,300.0	90.00	179.55	13,148.2	-3,702.2	798.1	3,757.3	0.00	0.00	0.00
17,400.0	90.00	179.55	13,148.2	-3,802.2	798.9	3,857.0	0.00	0.00	0.00
17,500.0	90.00	179.55	13,148.2	-3,902.2	799.7	3,956.7	0.00	0.00	0.00
17,600.0	90.00	179.54	13,148.2	-4,002.2	800.5	4,056.4	0.00	0.00	0.00
17,700.0	90.00	179.54	13,148.2	-4,102.2	801.3	4,156.1	0.00	0.00	0.00
17,800.0	90.00	179.54	13,148.2	-4,202.2	802.1	4,255.8	0.00	0.00	0.00
17,900.0	90.00	179.54	13,148.2	-4,302.1	802.9	4,355.5	0.00	0.00	0.00
18,000.0	90.00	179.53	13,148.2	-4,402.1	803.7	4,455.2	0.00	0.00	0.00
18,100.0	90.00	179.53	13,148.2	-4,502.1	804.5	4,554.9	0.00	0.00	0.00
18,200.0	90.00	179.53	13,148.2	-4,602.1	805.3	4,654.6	0.00	0.00	0.00
18,300.0	90.00	179.53	13,148.2	-4,702.1	806.2	4,754.2	0.00	0.00	0.00
18,400.0	90.00	179.53	13,148.2	-4,802.1	807.0	4,853.9	0.00	0.00	0.00

Planning Report

Database:	EDT_18	Local Co-ordinate Reference:	Well #753H
Company:	Midland	TVD Reference:	kb = 26' @ 3377.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3377.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#753H	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)
18,500.0	90.00	179.52	13,148.2	-4,902.1	807.8	4,953.6	0.00	0.00	0.00
18,600.0	90.00	179.52	13,148.2	-5,002.1	808.6	5,053.3	0.00	0.00	0.00
18,700.0	90.00	179.52	13,148.2	-5,102.1	809.5	5,153.0	0.00	0.00	0.00
18,800.0	90.00	179.52	13,148.2	-5,202.1	810.3	5,252.7	0.00	0.00	0.00
18,900.0	90.00	179.52	13,148.2	-5,302.1	811.2	5,352.4	0.00	0.00	0.00
19,000.0	90.00	179.51	13,148.2	-5,402.1	812.0	5,452.1	0.00	0.00	0.00
19,100.0	90.00	179.51	13,148.2	-5,502.1	812.9	5,551.8	0.00	0.00	0.00
19,200.0	90.00	179.51	13,148.2	-5,602.1	813.7	5,651.5	0.00	0.00	0.00
19,300.0	90.00	179.51	13,148.2	-5,702.1	814.6	5,751.2	0.00	0.00	0.00
19,400.0	90.00	179.51	13,148.2	-5,802.1	815.4	5,850.9	0.00	0.00	0.00
19,500.0	90.00	179.50	13,148.2	-5,902.1	816.3	5,950.6	0.00	0.00	0.00
19,600.0	90.00	179.50	13,148.2	-6,002.1	817.2	6,050.3	0.00	0.00	0.00
19,700.0	90.00	179.50	13,148.2	-6,102.1	818.0	6,150.0	0.00	0.00	0.00
19,800.0	90.00	179.50	13,148.2	-6,202.1	818.9	6,249.7	0.00	0.00	0.00
19,900.0	90.00	179.50	13,148.2	-6,302.1	819.8	6,349.4	0.00	0.00	0.00
20,000.0	90.00	179.49	13,148.2	-6,402.1	820.7	6,449.1	0.00	0.00	0.00
20,100.0	90.00	179.49	13,148.2	-6,502.1	821.5	6,548.8	0.00	0.00	0.00
20,200.0	90.00	179.49	13,148.2	-6,602.1	822.4	6,648.5	0.00	0.00	0.00
20,300.0	90.00	179.49	13,148.2	-6,702.1	823.3	6,748.2	0.00	0.00	0.00
20,400.0	90.00	179.49	13,148.2	-6,802.1	824.2	6,847.9	0.00	0.00	0.00
20,500.0	90.00	179.48	13,148.2	-6,902.1	825.1	6,947.6	0.00	0.00	0.00
20,600.0	90.00	179.48	13,148.2	-7,002.0	826.0	7,047.3	0.00	0.00	0.00
20,700.0	90.00	179.48	13,148.2	-7,102.0	826.9	7,147.0	0.00	0.00	0.00
20,800.0	90.00	179.48	13,148.2	-7,202.0	827.8	7,246.7	0.00	0.00	0.00
20,900.0	90.00	179.48	13,148.2	-7,302.0	828.8	7,346.4	0.00	0.00	0.00
21,000.0	90.00	179.47	13,148.2	-7,402.0	829.7	7,446.1	0.00	0.00	0.00
21,100.0	90.00	179.47	13,148.2	-7,502.0	830.6	7,545.8	0.00	0.00	0.00
21,200.0	90.00	179.47	13,148.2	-7,602.0	831.5	7,645.5	0.00	0.00	0.00
21,300.0	90.00	179.47	13,148.2	-7,702.0	832.5	7,745.2	0.00	0.00	0.00
21,400.0	90.00	179.46	13,148.2	-7,802.0	833.4	7,844.9	0.00	0.00	0.00
21,500.0	90.00	179.46	13,148.2	-7,902.0	834.3	7,944.6	0.00	0.00	0.00
21,600.0	90.00	179.46	13,148.2	-8,002.0	835.3	8,044.3	0.00	0.00	0.00
21,700.0	90.00	179.46	13,148.1	-8,102.0	836.2	8,144.0	0.00	0.00	0.00
21,800.0	90.00	179.46	13,148.1	-8,202.0	837.2	8,243.7	0.00	0.00	0.00
21,900.0	90.00	179.45	13,148.1	-8,302.0	838.1	8,343.4	0.00	0.00	0.00
22,000.0	90.00	179.45	13,148.1	-8,402.0	839.1	8,443.1	0.00	0.00	0.00
22,100.0	90.00	179.45	13,148.1	-8,502.0	840.0	8,542.8	0.00	0.00	0.00
22,200.0	90.00	179.45	13,148.1	-8,602.0	841.0	8,642.5	0.00	0.00	0.00
22,300.0	90.00	179.45	13,148.1	-8,702.0	841.9	8,742.2	0.00	0.00	0.00
22,400.0	90.00	179.44	13,148.1	-8,802.0	842.9	8,841.9	0.00	0.00	0.00
22,500.0	90.00	179.44	13,148.1	-8,902.0	843.9	8,941.6	0.00	0.00	0.00
22,600.0	90.00	179.44	13,148.1	-9,002.0	844.9	9,041.3	0.00	0.00	0.00
22,700.0	90.01	179.44	13,148.1	-9,102.0	845.8	9,141.0	0.00	0.00	0.00
22,800.0	90.01	179.44	13,148.1	-9,201.9	846.8	9,240.7	0.00	0.00	0.00
22,900.0	90.01	179.43	13,148.1	-9,301.9	847.8	9,340.4	0.00	0.00	0.00
23,000.0	90.01	179.43	13,148.0	-9,401.9	848.8	9,440.1	0.00	0.00	0.00
23,100.0	90.01	179.43	13,148.0	-9,501.9	849.8	9,539.8	0.00	0.00	0.00
23,200.0	90.01	179.43	13,148.0	-9,601.9	850.8	9,639.5	0.00	0.00	0.00
23,300.0	90.01	179.43	13,148.0	-9,701.9	851.8	9,739.2	0.00	0.00	0.00
23,400.0	90.01	179.42	13,148.0	-9,801.9	852.8	9,838.9	0.00	0.00	0.00
23,421.1	90.01	179.42	13,148.0	-9,823.0	853.0	9,860.0	0.00	0.00	0.00

Planning Report

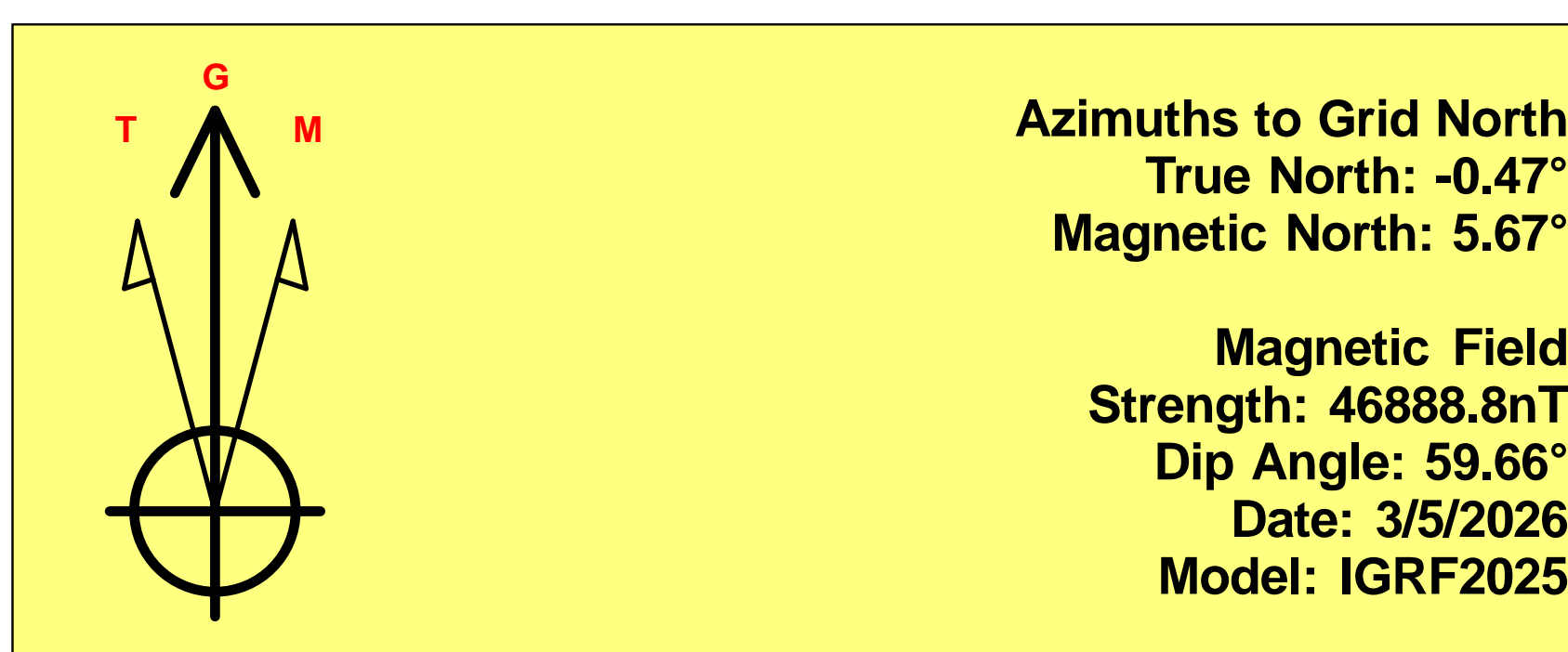
Database:	EDT_18	Local Co-ordinate Reference:	Well #753H
Company:	Midland	TVD Reference:	kb = 26' @ 3377.0usft
Project:	Lea County, NM (NAD 83 NME)	MD Reference:	kb = 26' @ 3377.0usft
Site:	Wild Weasel 22 Fed Com	North Reference:	Grid
Well:	#753H	Survey Calculation Method:	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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(Wild Weasel 22 Fe - plan hits target center - Point	0.00	0.00	12,670.5	585.0	765.0	409,635.00	813,151.00	32° 7' 23.236 N	103° 27' 19.158 W
FTP(Wild Weasel 22 Fer - plan hits target center - Point	0.00	0.00	12,883.2	535.0	766.0	409,585.00	813,152.00	32° 7' 22.741 N	103° 27' 19.151 W
PBHL(Wild Weasel 22 F - plan hits target center - Point	0.00	0.00	13,148.0	-9,823.0	853.0	399,227.00	813,239.00	32° 5' 40.241 N	103° 27' 19.120 W
Fed Perf 1(Wild Weasel - plan hits target center - Point	0.00	0.00	13,148.0	-683.0	776.0	408,367.00	813,162.00	32° 7' 10.688 N	103° 27' 19.150 W

Lea County, NM (NAD 83 NME)

Wild Weasel 22 Fed Com #753H

Plan #0.1 RT



Azimuths to Grid North
 True North: -0.47°
 Magnetic North: 5.67°
 Magnetic Field
 Strength: 46888.8nT
 Dip Angle: 59.66°
 Date: 3/5/2026
 Model: IGRF2025

To convert a Magnetic Direction to a Grid Direction, Add 5.67°
 To convert a Magnetic Direction to a True Direction, Add 6.13° East
 To convert a True Direction to a Grid Direction, Subtract 0.47°

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: #753H

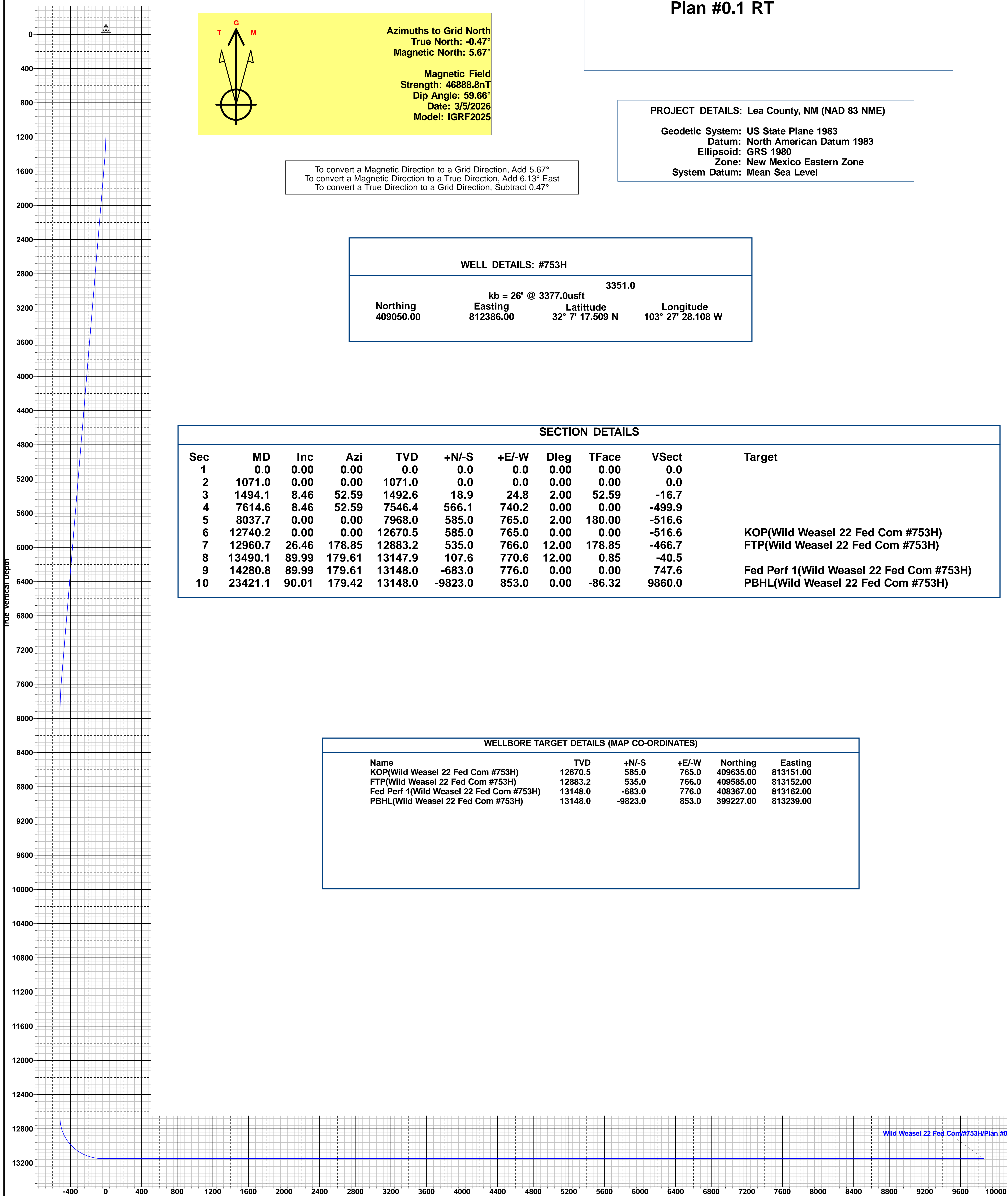
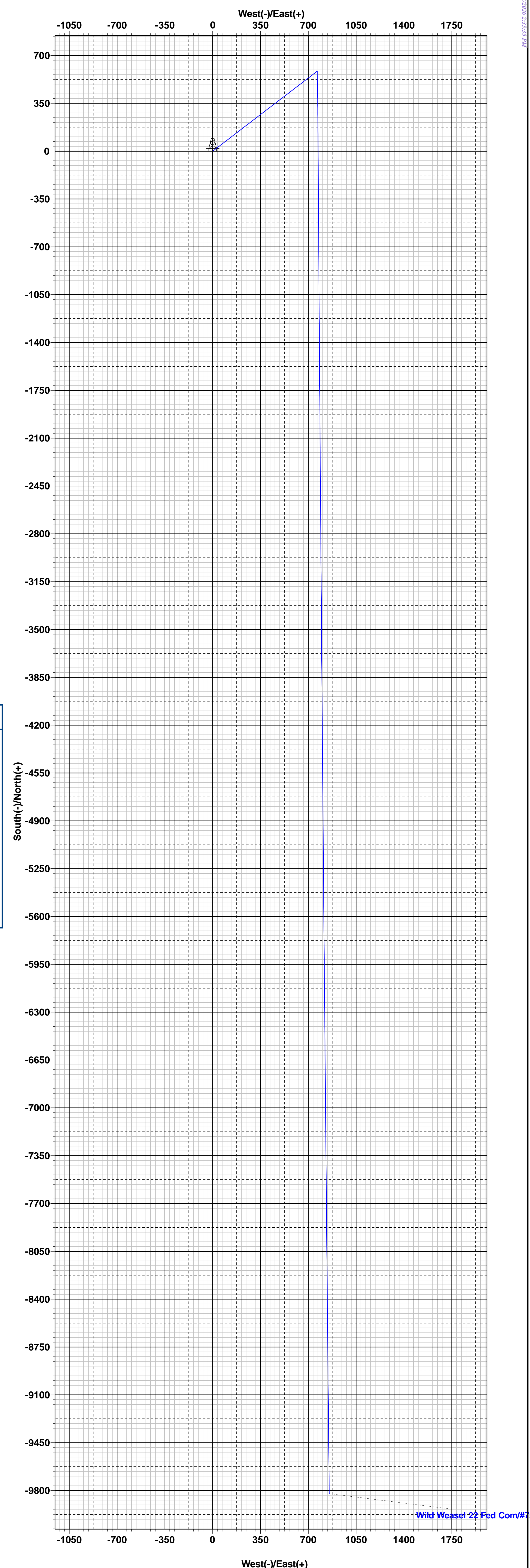
kb = 26' @ 3377.0usft 3351.0
 Northing 409050.00 Easting 812386.00 Latitude 32° 7' 17.509 N Longitude 103° 27' 28.108 W

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	1071.0	0.00	0.00	1071.0	0.0	0.0	0.00	0.00	0.0	
3	1494.1	8.46	52.59	1492.6	18.9	24.8	2.00	52.59	-16.7	
4	7614.6	8.46	52.59	7546.4	566.1	740.2	0.00	0.00	-499.9	
5	8037.7	0.00	0.00	7968.0	585.0	765.0	2.00	180.00	-516.6	
6	12740.2	0.00	0.00	12670.5	585.0	765.0	0.00	0.00	-516.6	KOP(Wild Weasel 22 Fed Com #753H)
7	12960.7	26.46	178.85	12883.2	535.0	766.0	12.00	178.85	-466.7	FTP(Wild Weasel 22 Fed Com #753H)
8	13490.1	89.99	179.61	13147.9	107.6	770.6	12.00	0.85	-40.5	
9	14280.8	89.99	179.61	13148.0	-683.0	776.0	0.00	0.00	747.6	Fed Perf 1(Wild Weasel 22 Fed Com #753H)
10	23421.1	90.01	179.42	13148.0	-9823.0	853.0	0.00	-86.32	9860.0	PBHL(Wild Weasel 22 Fed Com #753H)

WELBORE TARGET DETAILS (MAP CO-ORDINATES)

Name	TVD	+N/-S	+E/-W	Northing	Easting
KOP(Wild Weasel 22 Fed Com #753H)	12670.5	585.0	765.0	409635.00	813151.00
FTP(Wild Weasel 22 Fed Com #753H)	12883.2	535.0	766.0	409585.00	813152.00
Fed Perf 1(Wild Weasel 22 Fed Com #753H)	13148.0	-683.0	776.0	408367.00	813162.00
PBHL(Wild Weasel 22 Fed Com #753H)	13148.0	-9823.0	853.0	399227.00	813239.00



Vertical Section at 175.04°

Wild Weasel 22 Fed Com/#753H/Plan #0.1 RT



Master Variance Document

Table of Contents

- [BOPE Break Test \(3/25/2025\)](#)
- [Offline Surface/Intermediate Cement \(8/15/2023\)](#)
- [Intermediate Bradenhead Cement \(Deep Targets\) \(8/15/2023\)](#)
- [Wolfcamp Intermediate Casing Setpoint \(6/26/2024\)](#)
- [Offline Production Cement \(11/12/2024\)](#)
- [Production Bradenhead Cement \(8/9/2024\)](#)
- [Salt Section Annular Clearance \(11/8/2022\)](#)



BOPE Break Test Variance

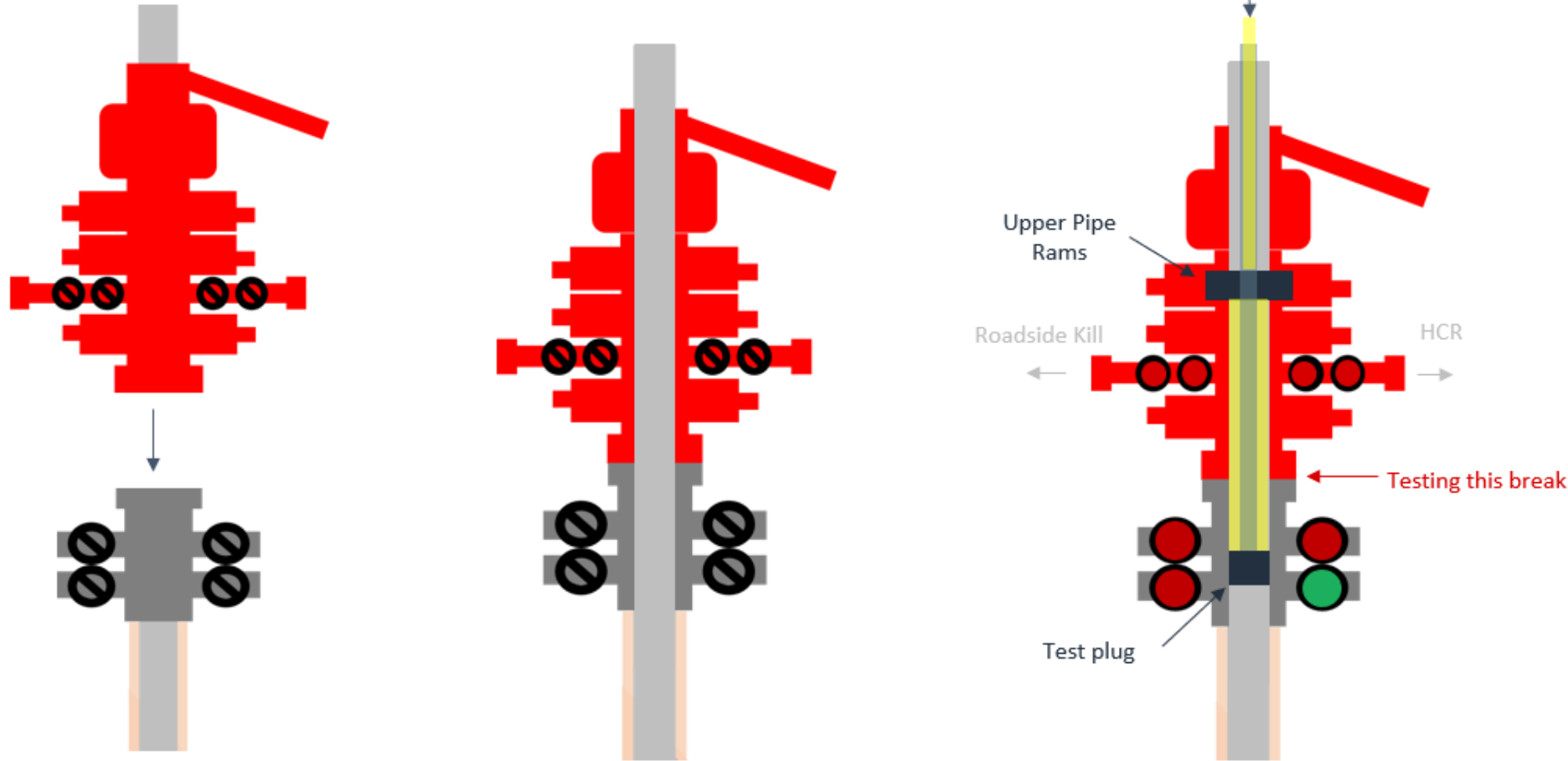
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EOG BOPE Break Test Variance (Intervals 5M MASP or less)

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.
- Break-test only available for the Base of the Wolfcamp or shallower
 - If anything out of the ordinary is observed during drilling, tripping or casing running operations in the production hole section, break testing will not be performed in the subsequent well's production hole section.
 - Furthermore, break testing in the production hole section will not be performed if offset frac operations are observed within 1 mile and within the same producing horizon.
- 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 → during each full BOPE test and at least weekly
 - Pipe Rams → Every trip and on trip ins where FIT required
 - Blind Rams → Every trip
- Break testing BOP and BOPE coupled with batch drilling operations and option to offline cement and/or remediate (if needed) any surface, intermediate or production 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 (Test Joint)



Steps

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



Offline Surface + Intermediate Variance

—

Offline Surface + Intermediate Cement

Cement Program

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

Summarized Operational Procedure for Intermediate Casing

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

Offline Surface + Intermediate Cement

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

Offline Surface + Intermediate Cement

Example Well Control Plan Content

A. Well Control Component Table

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

Intermediate hole section, 5M requirement

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

B. Well Control Procedures

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

General Procedure While Circulating

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

Offline Surface + Intermediate Cement

Example Well Control Plan Content

A. Well Control Component Table

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

Intermediate hole section, 5M requirement

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

B. Well Control Procedures

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

General Procedure While Circulating

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

Offline Surface + Intermediate Cement

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

General Procedure While Cementing

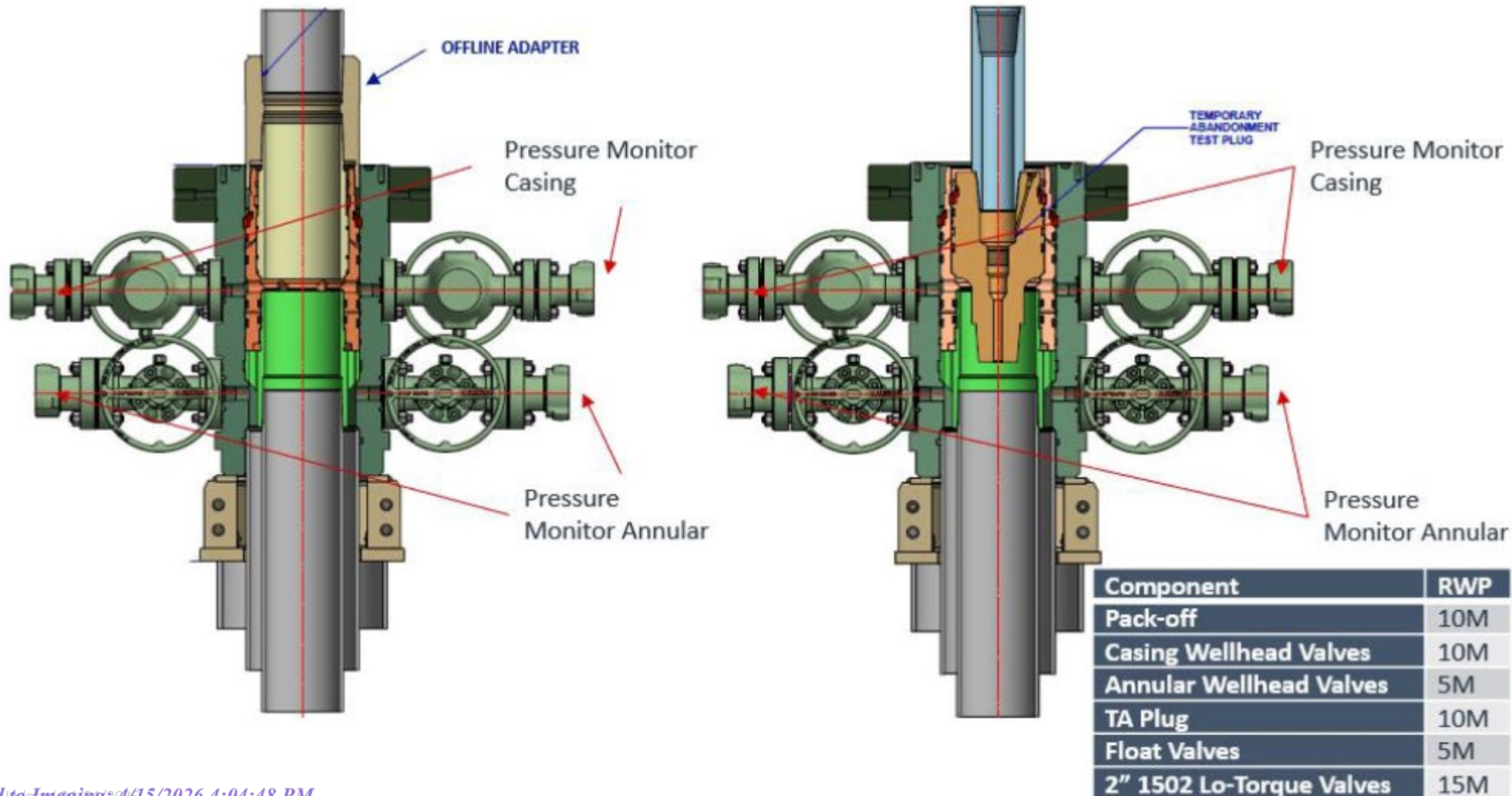
1. Sound alarm (alert crew).
2. Shut down pumps.
3. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
4. Confirm shut-in.
5. Notify tool pusher/company representative.
6. Open rig choke and begin pumping again taking returns through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

General Procedure After Cementing

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

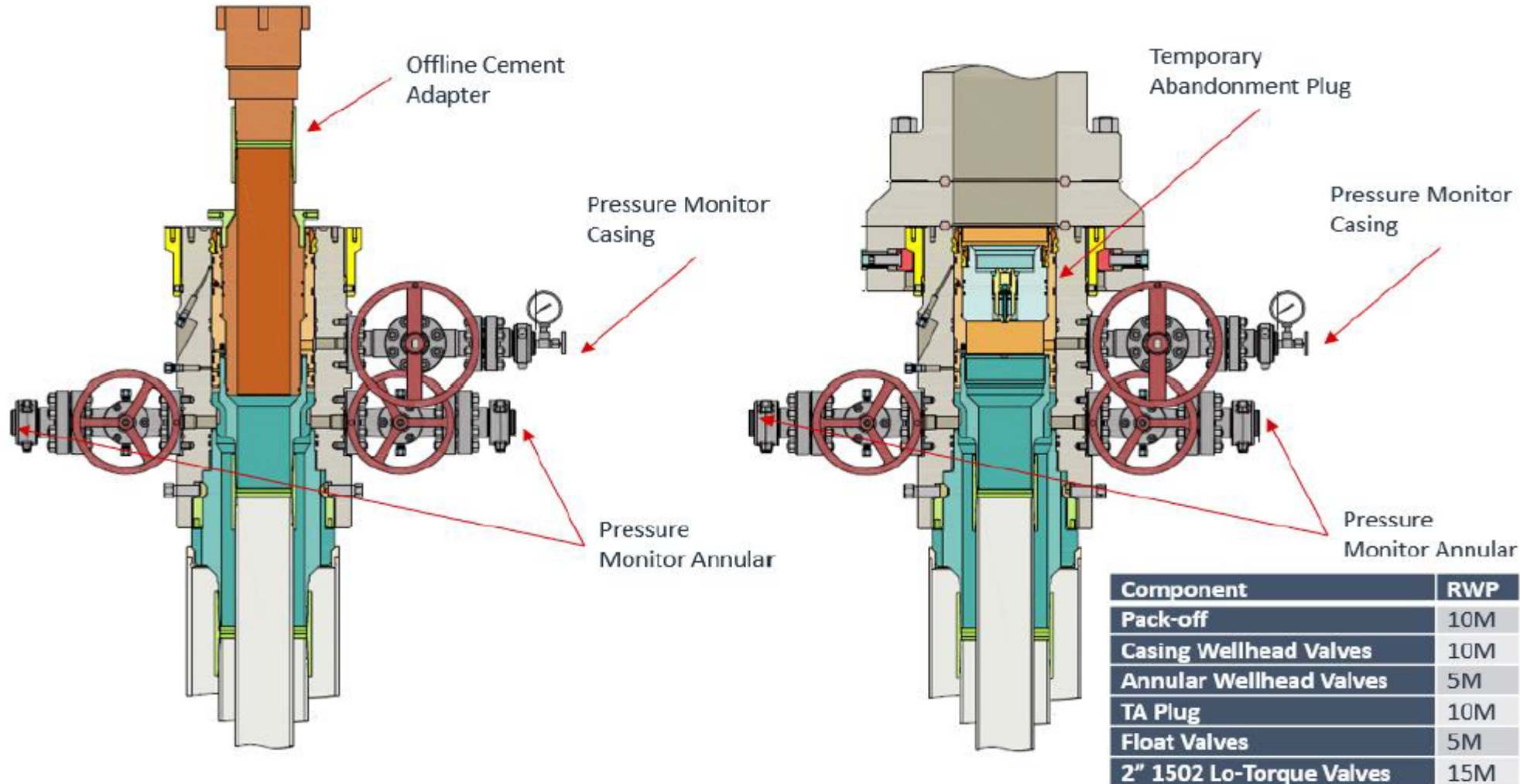
Offline Surface + Intermediate Cement

Figure 1: Cameron TA Plug and Offline Adapter Schematic



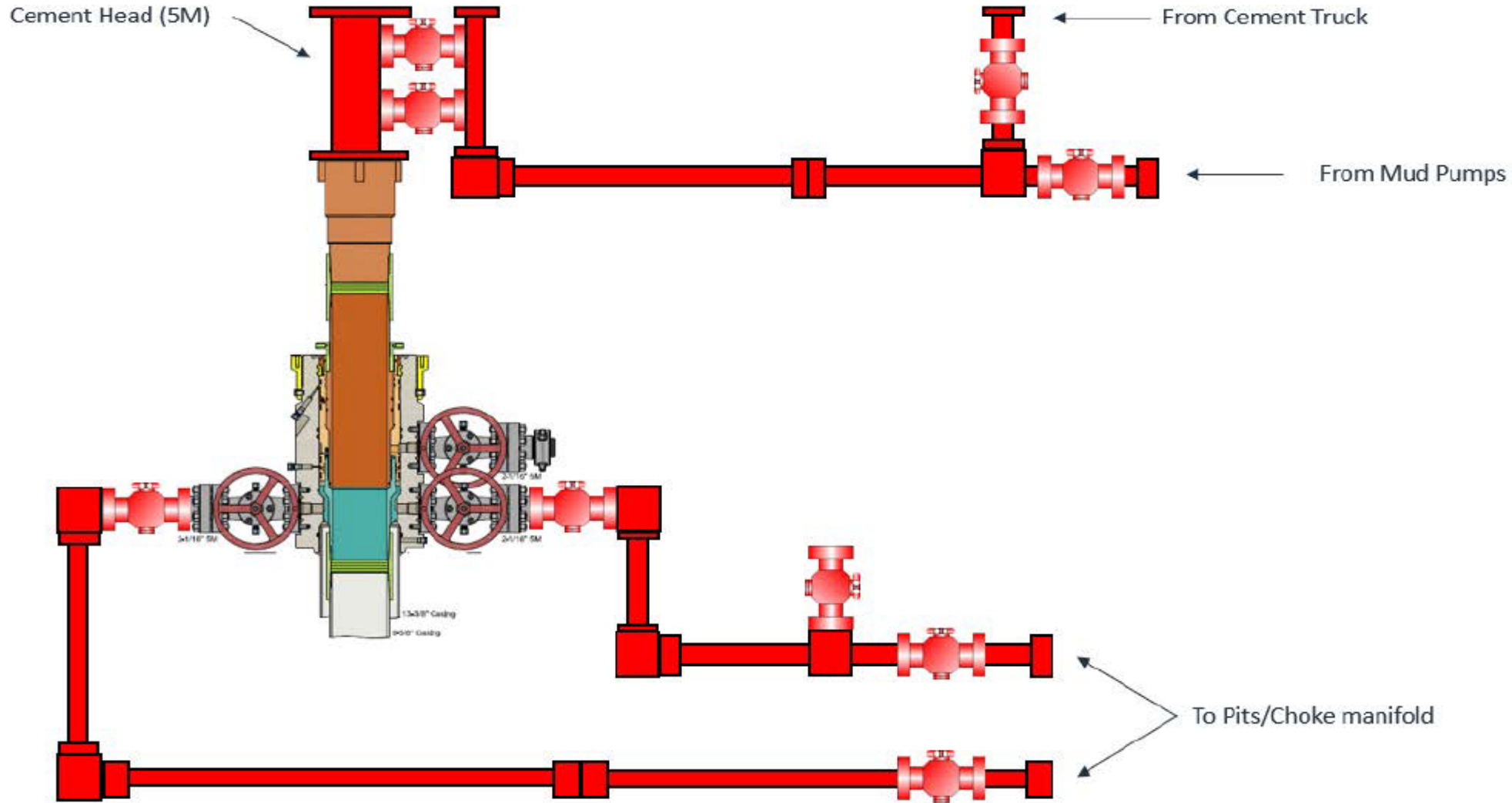
Offline Surface + Intermediate Cement

Figure 2: Cactus TA Plug and Offline Adapter Schematic



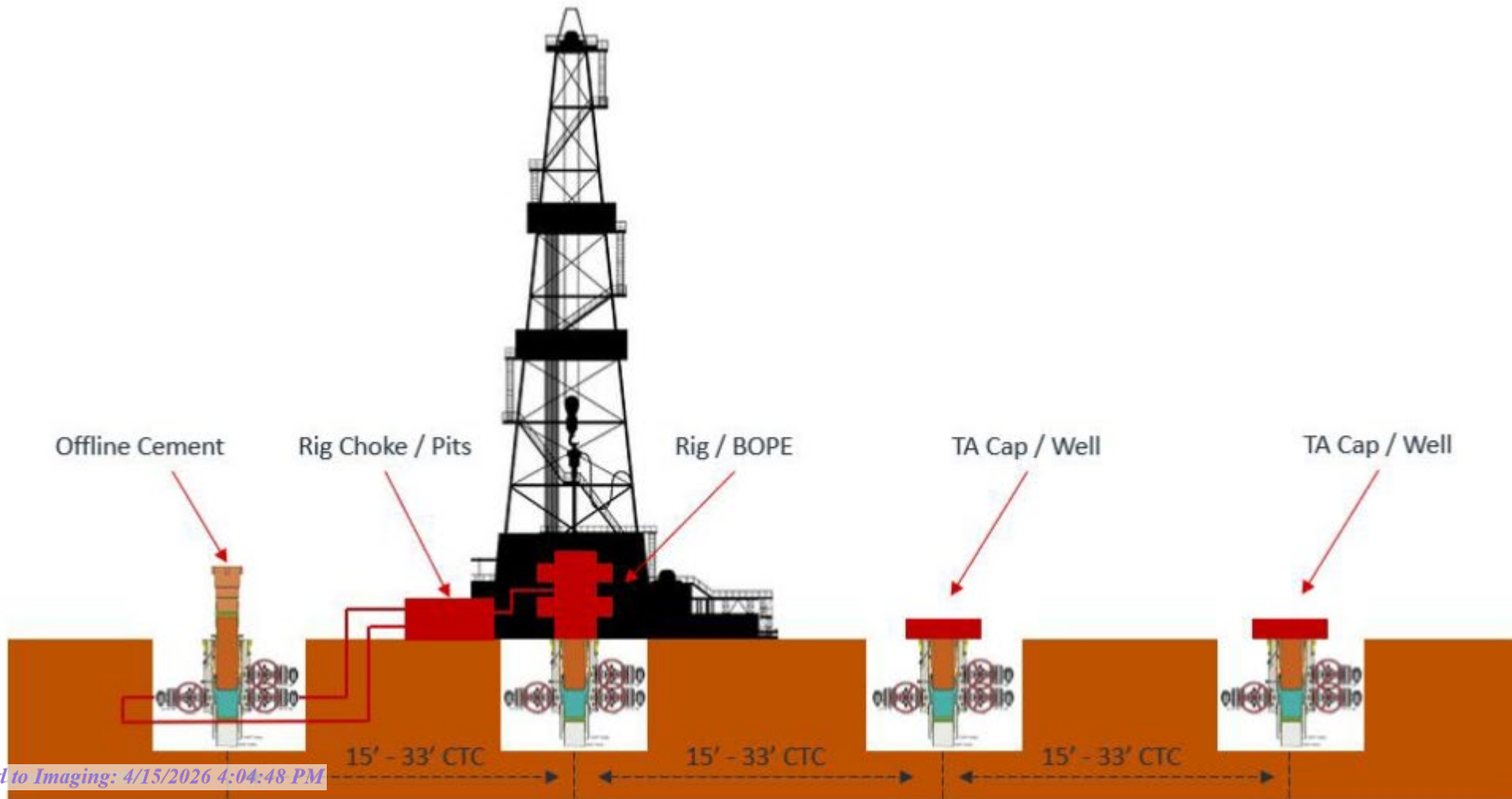
Offline Surface + Intermediate Cement

Figure 3: Back Yard Rig Up



Offline Surface + Intermediate Cement

Figure 4: Rig Placement Diagram





Intermediate Bradenhead Cement Variance

Intermediate Bradenhead Cement

Deep Target Intermediate Bradenhead:

EOG requests variance from minimum standards to pump a two stage cement job on the intermediate casing string **when set below the Delaware Mountain Group** with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon and the second stage bradenhead squeezed to be performed at a minimum of **50% of OH excess (typically increased to ~1,000 sacks)** with planned cement from the Brushy Canyon to surface. If necessary, a top out consisting of Class C/H cement + additives (2.30 yld, 12.91 ppg) will be executed as a contingency. Top of cement will be verified by Echo-meter.

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

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



Wolfcamp Intermediate Casing Setpoint

Intermediate Bradenhead Cement

EOG Resources Inc. (EOG) requests a variance to set the intermediate casing shoe in the Bone Spring formation OR the Wolfcamp formation, depending on depletion in the area and well conditions. EOG will monitor the well and ensure the well is static before casing operations begin.



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 **are applicable for the Base of the Wolfcamp or shallower.**
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 nipped down if:
 - a) ANY barrier fails to test.
 - b) 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 nipped 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.

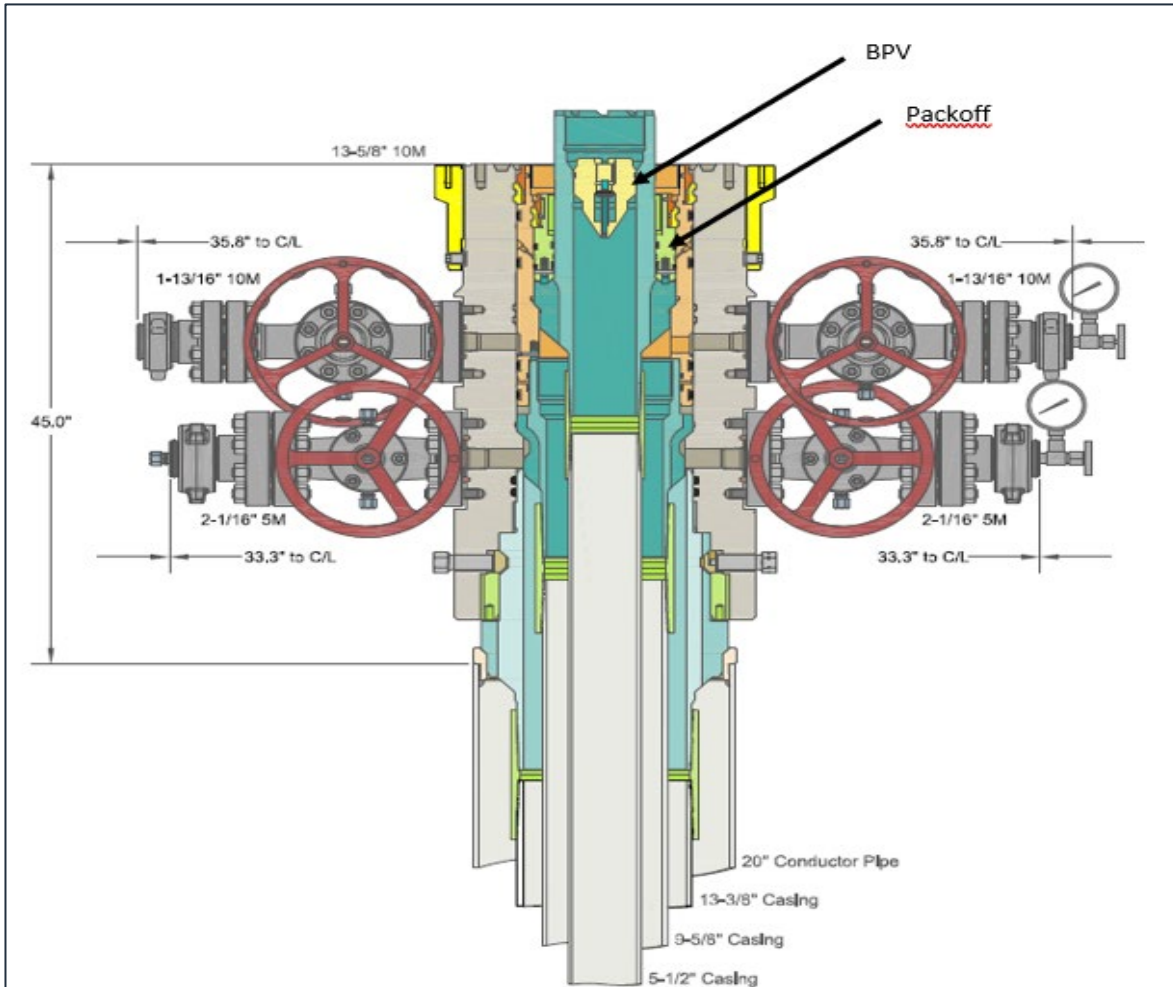
Offline Procedure

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 nipped 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



ALL DIMENSIONS APPROXIMATE

CACTUS WELLHEAD LLC		EOG RESOURCES PERMIAN	
13-3/8" x 9-5/8" x 5-1/2" MBU-3T-CFL-DBLO-SF Wellhead System		DRAWN	DLE
And 13-3/8", 9-5/8" & 5-1/2" Pin Bottom Mandrel Casing Hangers		APPRV	28AUG19
		DRAWING NO.	SDT-2297-2

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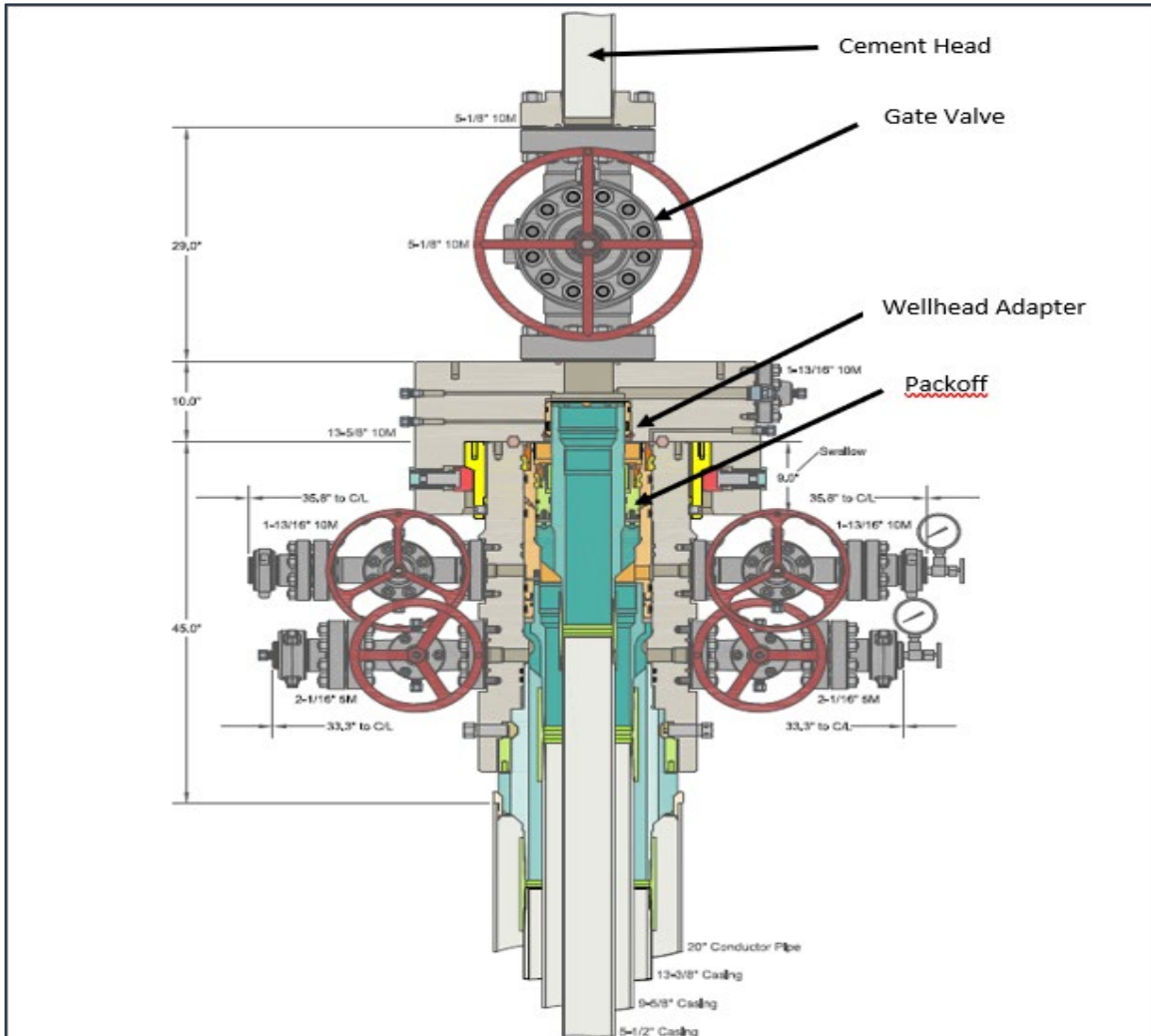
Barriers in Place during removal of BOP

Operation	Casing	Annulus
Nipling 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



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CACTUS WELLHEAD LLC		EOG RESOURCES PERMIAN	
13-3/8" x 9-5/8" x 5-1/2" MBU-3T-CFL-DBLO-SF Wellhead System		DRAWN DLE	28AUG19
Offline Cement Package		APPRV	
And 13-3/8", 9-5/8" & 5-1/2" Pin Bottom Mandrel Casing Hangers		DRAWING NO.	SDT-2297-3

Barriers in Place during removal of BOP

Operation	Casing	Annulus
Nipling 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

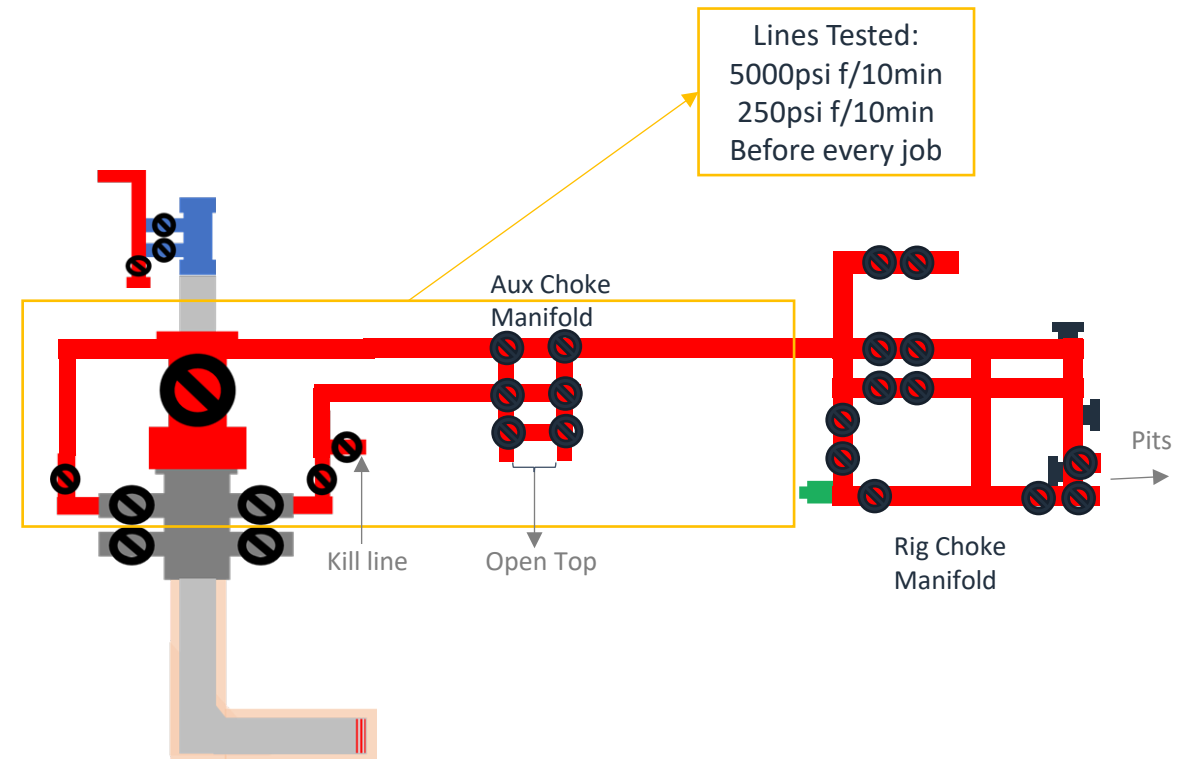
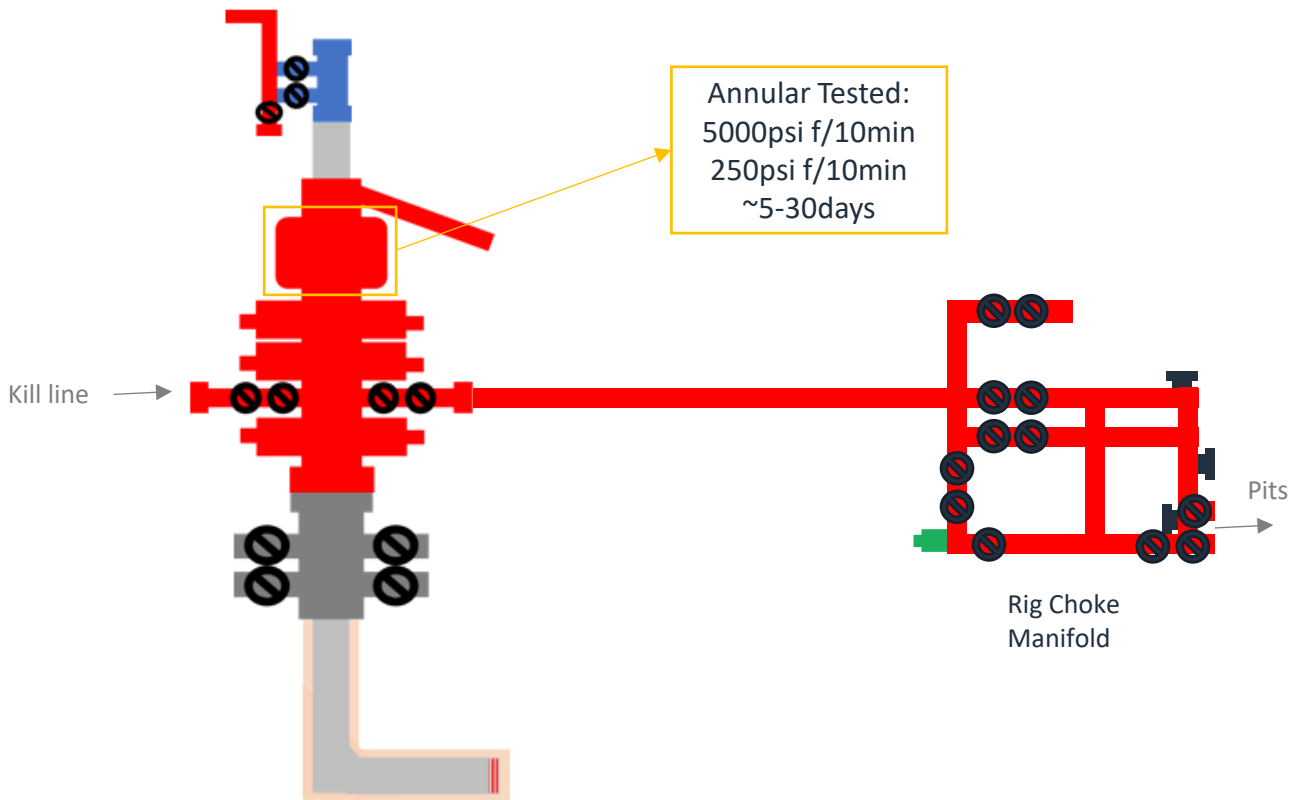
Casing Barriers – Online vs Offline		
Operation	Online	Offline
Install Cement Head	1. Hydrostatic Barrier 2. Float Valves	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve
Cement Job	1. Hydrostatic Barrier 2. Float Valves 3. Cement Head	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve 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



Production Bradenhead Cement Variance

Production Bradenhead Cement

Shallow Target Production 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.



Salt Section Annular Clearance

—

Current Design (Salt Strings)

0.422" Annular clearance requirement

- Casing collars shall have a minimum clearance of 0.422 inches on all sides in the hole/casing annulus, with recognition that variances can be granted for justified exceptions.

- 12.25" Hole x 9.625" 40# J55/HCK55 LTC Casing
 - 1.3125" Clearance to casing OD
 - 0.8125" Clearance to coupling OD
- 9.875" Hole x 8.75" 38.5# P110 Sprint-SF Casing
 - 0.5625" Clearance to casing OD
 - 0.433" Clearance to coupling OD

Annular Clearance Variance Request

EOG request permission to allow deviation from the 0.422" annulus clearance requirement for the intermediate (salt) section from Onshore Order #2 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues

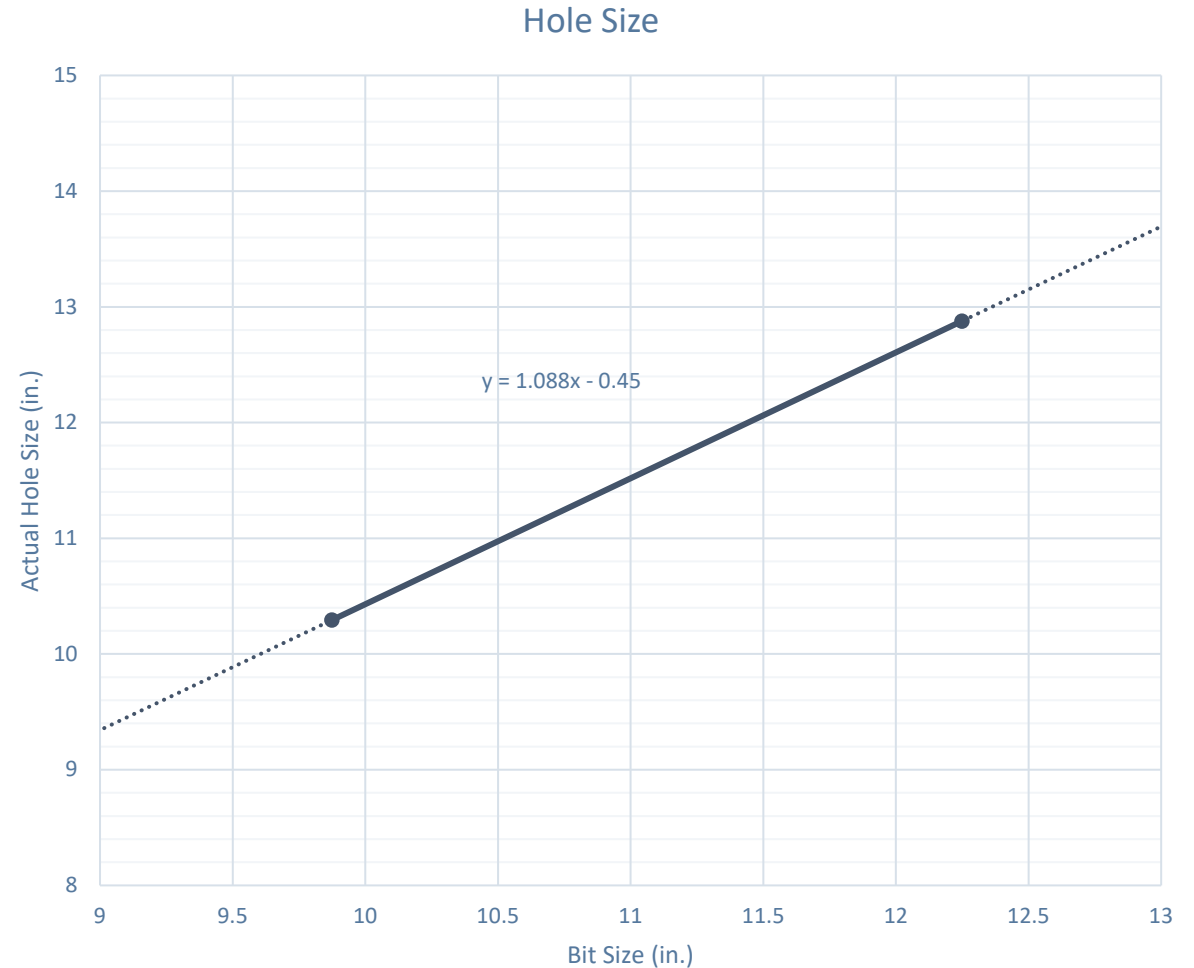
Volumetric Hole Size Calculation

Hole Size Calculations Off Cement Volumes

- Known volume of cement pumped
- Known volume of cement returned to surface
- Must not have had any losses
- Must have bumped plug

Average Hole Size

- 12.25" Hole
 - 12.88" Hole
 - 5.13% diameter increase
 - 10.52% area increase
 - 0.63" Average enlargement
 - 0.58" Median enlargement
 - 179 Well Count
- 9.875" Hole
 - 10.30" Hole
 - 4.24% diameter increase
 - 9.64% area increase
 - 0.42" Average enlargement
 - 0.46" Median enlargement
 - 11 Well Count

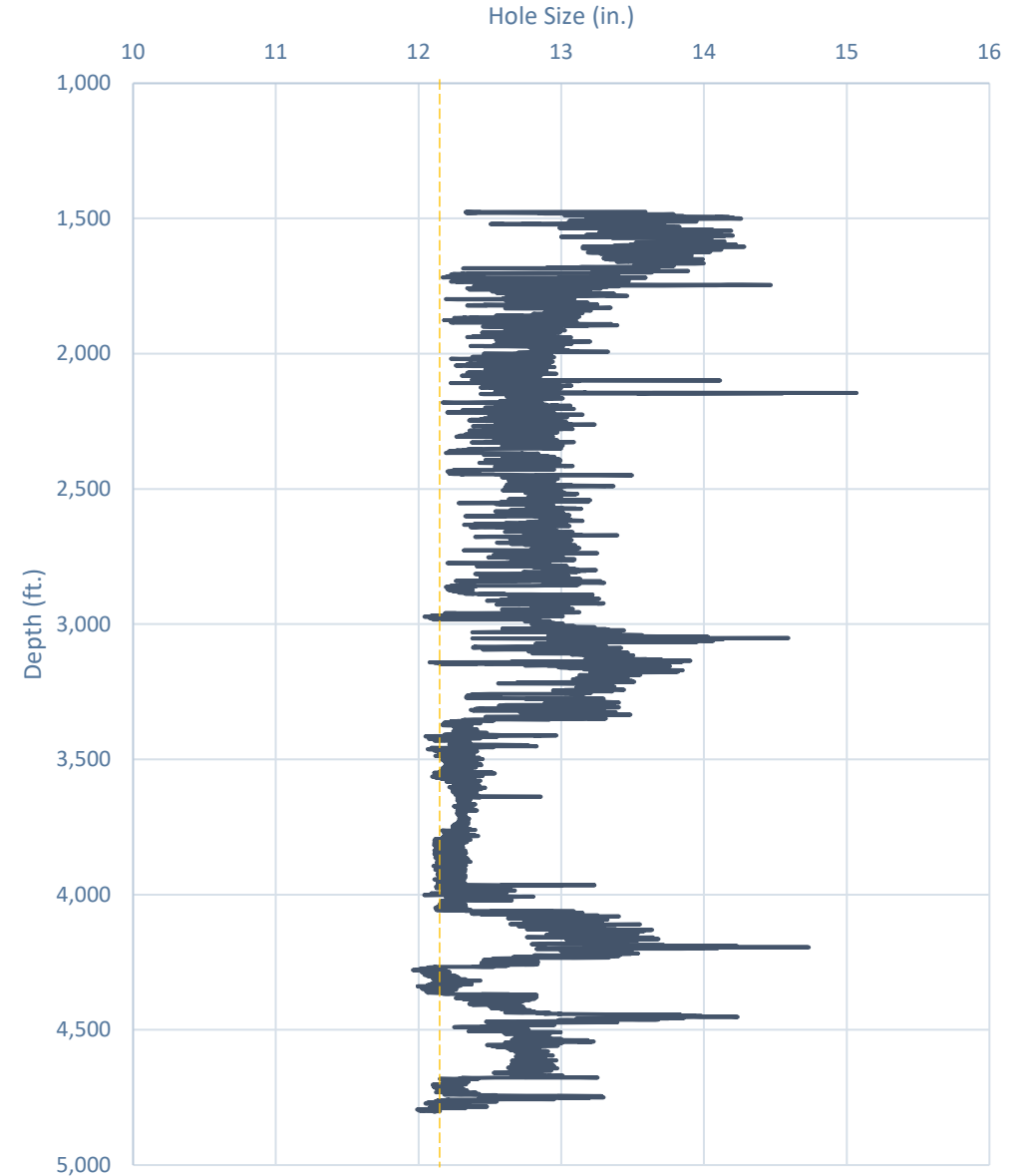


Caliper Hole Size (12.25")

Average Hole Size

- 12.25" Bit
 - 12.76" Hole
 - 4.14% diameter increase
 - 8.44% area increase
 - 0.51" Average enlargement
 - 0.52" Median enlargement
 - Brine

Modelo 10 Fed Com #501H

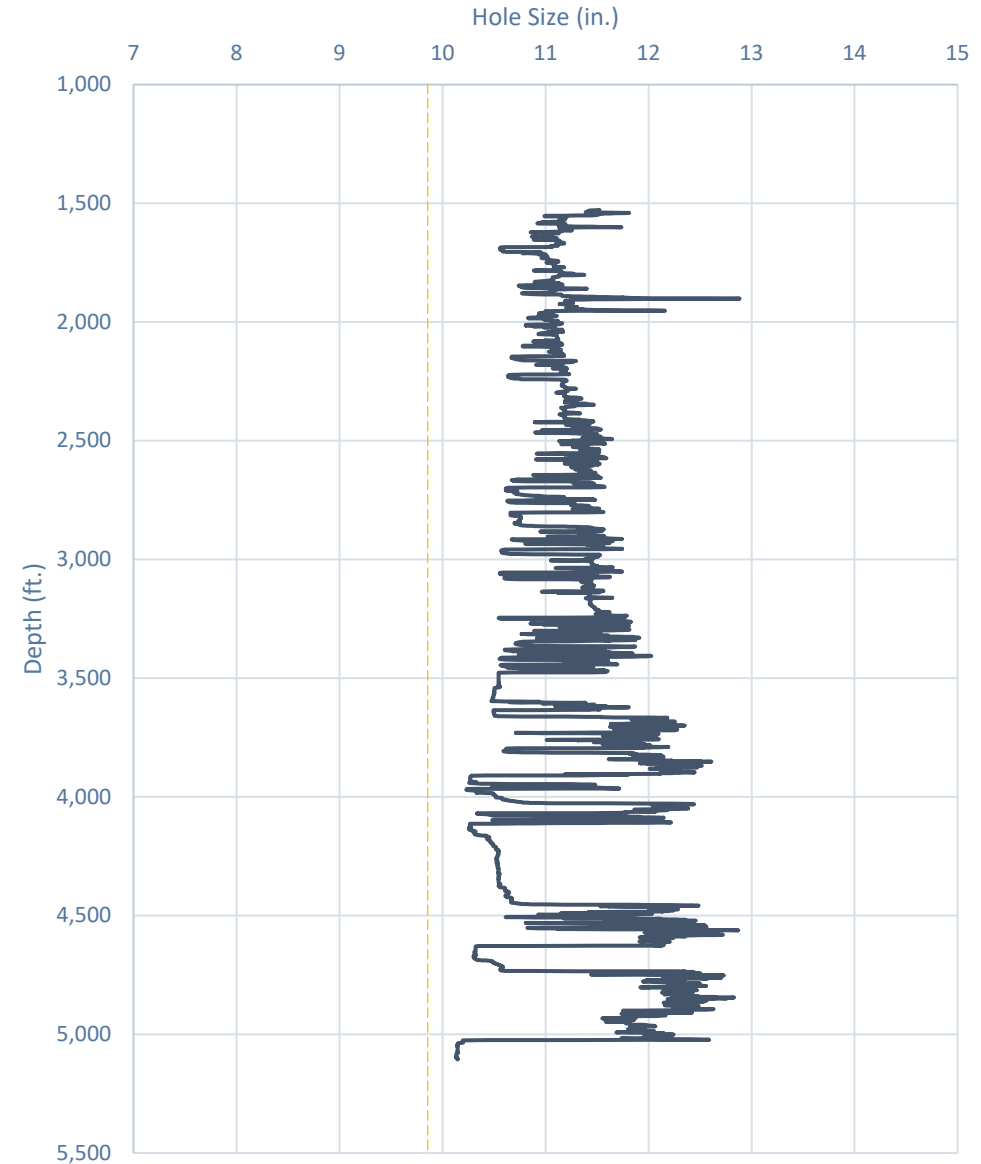


Caliper Hole Size (9.875")

Average Hole Size

- 9.875" Hole
 - 11.21" Hole
 - 13.54% diameter increase
 - 28.92% area increase
 - 1.33" Average enlargement
 - 1.30" Median enlargement
 - EnerLite

Whirling Wind 11 Fed Com #744H



Design A

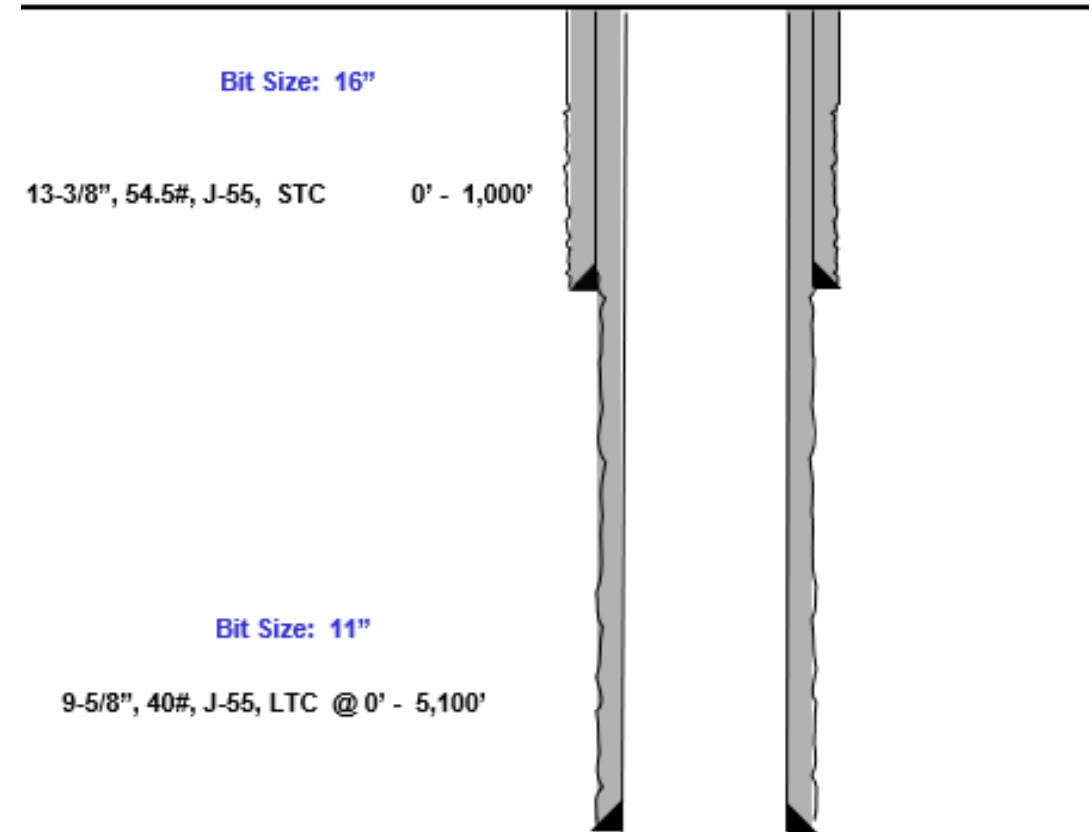
Proposed 11" Hole with 9.625" 40# J55/HCK55 LTC Casing

- 11" Bit + 0.52" Average hole enlargement = 11.52" Hole Size
 - 0.9475" Clearance to casing OD

$$= \frac{11.52 - 9.625}{2}$$
 - 0.4475" Clearance to coupling OD

$$= \frac{11.52 - 10.625}{2}$$
- Previous Shoe – 13.375" 54.5# J55 STC
 - 0.995" Clearance to coupling OD (~1,200' overlap)

$$= \frac{12.615 - 10.625}{2}$$



Design B

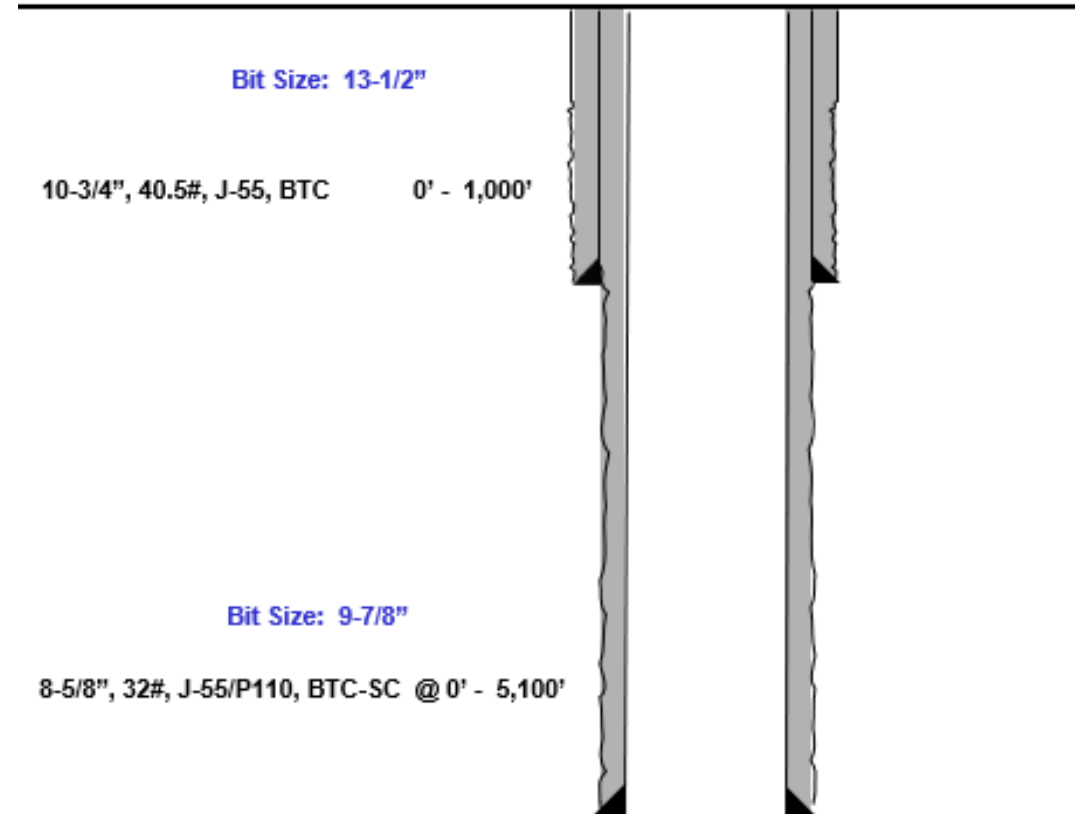
Proposed 9.875" Hole with 8.625" 32# J55/P110 BTC-SC Casing

- 9.875" Bit + 0.42" Average hole enlargement = 10.295" Hole Size
 - 0.835" Clearance to casing OD

$$= \frac{10.295 - 8.625}{2}$$
 - 0.585" Clearance to coupling OD

$$= \frac{10.295 - 9.125}{2}$$
- Previous Shoe – 10.75" 40.5# J55 STC
 - 0.4625" Clearance to coupling OD (~1,200' overlap)

$$= \frac{10.05 - 9.125}{2}$$





Index



Casing Spec Sheets

Pipe Body and API Connections Performance Data

10.750 40.50/0.350 J55

PDF

New Search »

« Back to Previous List

USC Metric

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Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	Pipe	BTC	LTC	STC	
Outside Diameter	10.750	11.750	--	11.750	in.
Wall Thickness	0.350	--	--	--	in.
Inside Diameter	10.050	10.050	--	10.050	in.
Standard Drift	9.894	9.894	--	9.894	in.
Alternate Drift	--	--	--	--	in.
Nominal Linear Weight, T&C	40.50	--	--	--	lbs/ft
Plain End Weight	38.91	--	--	--	lbs/ft
Performance	Pipe	BTC	LTC	STC	
Minimum Collapse Pressure	1,580	1,580	--	1,580	psi
Minimum Internal Yield Pressure	3,130	3,130	--	3,130	psi
Minimum Pipe Body Yield Strength	629.00	--	--	--	1000 lbs
Joint Strength	--	700	--	420	1000 lbs
Reference Length	--	11,522	--	6,915	ft
Make-Up Data	Pipe	BTC	LTC	STC	
Make-Up Loss	--	4.81	--	3.50	in.
Minimum Make-Up Torque	--	--	--	3,150	ft-lbs
Maximum Make-Up Torque	--	--	--	5,250	ft-lbs



API 5CT, 10th Ed. Connection Data Sheet

O.D. (in)	WEIGHT (lb/ft)	WALL (in)	GRADE	*API DRIFT (in)	RBW %
8.625	Nominal: 32.00 Plain End: 31.13	0.352	J55	7.796	87.5

Material Properties (PE)

Pipe	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi
Coupling	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi

Pipe Body Data (PE)

Geometry	
Nominal ID:	7.92 inch
Nominal Area:	9.149 in ²
*Special/Alt. Drift:	7.875 inch
Performance	
Pipe Body Yield Strength:	503 kips
Collapse Resistance:	2,530 psi
Internal Yield Pressure: (API Historical)	3,930 psi

API Connection Data

Coupling OD: 9.625"

STC Performance

STC Internal Pressure:	3,930 psi
STC Joint Strength:	372 kips

LTC Performance

LTC Internal Pressure:	3,930 psi
LTC Joint Strength:	417 kips

SC-BTC Performance - Cplg OD = 9.125"

BTC Internal Pressure:	3,930 psi
BTC Joint Strength:	503 kips

API Connection Torque

STC Torque (ft-lbs)

Min:	2,793	Opti:	3,724	Max:	4,655
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LTC Torque (ft-lbs)

Min:	3,130	Opti:	4,174	Max:	5,217
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BTC Torque (ft-lbs)

follow API guidelines regarding positional make up

*Alt. Drift will be used unless API Drift is specified on order.

**If above API connections do not suit your needs, VAM® premium connections are available up to 100% of pipe body ratings.

ALL INFORMATION IS PROVIDED BY VALLOUREC OR ITS AFFILIATES AT USER'S SOLE RISK, WITHOUT LIABILITY FOR LOSS, DAMAGE OR INJURY RESULTING FROM THE USE THEREOF, AND ON AN "AS IS" BASIS WITHOUT WARRANTY OR REPRESENTATION OF ANY KIND, WHETHER EXPRESS OR IMPLIED, INCLUDING WITHOUT LIMITATION ANY WARRANTY OF MERCHANTABILITY, FITNESS FOR PURPOSE, ACCURACY OR COMPLETENESS. THE INFORMATION CONTAINED IN THIS DOCUMENT IS PROVIDED FOR INFORMATIONAL PURPOSES ONLY AND IS BASED ON ESTIMATES THAT HAVE NOT BEEN VERIFIED OR TESTED. IN NO EVENT SHALL VALLOUREC OR ITS AFFILIATES BE RESPONSIBLE FOR ANY INDIRECT, SPECIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR CONSEQUENTIAL LOSS OR DAMAGE (INCLUDING WITHOUT LIMITATION, LOSS OF USE, LOSS OF BARGAIN, LOSS OF REVENUE, PROFIT OR ANTICIPATED PROFIT) HOWEVER CAUSED OR ARISING, AND WHETHER SUCH LOSSES OR DAMAGES WERE FORESEEABLE OR VALLOUREC OR ITS AFFILIATES WERE ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

Rev 3, 7/30/2021

10/21/2022 15:24



<p>C-102</p> <p>Submit Electronically Via OCD Permitting</p>	<p>State of New Mexico Energy, Minerals & Natural Resources Department OIL CONSERVATION DIVISION</p>	<p>Revised July 9, 2024</p>		
		<table border="1" style="width:100%; border-collapse: collapse;"> <tr> <td style="width:15%; vertical-align: top;"> <p>Submittal Type:</p> </td> <td> <input type="checkbox"/> Initial Submittal <input type="checkbox"/> Amended Report <input type="checkbox"/> As Drilled </td> </tr> </table>	<p>Submittal Type:</p>	<input type="checkbox"/> Initial Submittal <input type="checkbox"/> Amended Report <input type="checkbox"/> As Drilled
<p>Submittal Type:</p>	<input type="checkbox"/> Initial Submittal <input type="checkbox"/> Amended Report <input type="checkbox"/> As Drilled			
<p>Property Name and Well Number</p> <p style="text-align: center; font-weight: bold;">WILD WEASEL 22 FED COM 753H</p>				

<p>SURFACE LOCATION (SHL)</p> <p>NEW MEXICO EAST NAD 1983 X=812386 Y=409050 LAT.: N 32.1215314 LONG.: W 103.4578067</p> <p style="text-align: center;">NAD 1927</p> <p>X=771200 Y=408993 LAT.: N 32.1214064 LONG.: W 103.4573390 629' FNL 2639' FEL</p> <p>KICK OFF POINT (KOP)</p> <p>NEW MEXICO EAST NAD 1983 X=813151 Y=409635 LAT.: N 32.1231211 LONG.: W 103.4553200</p> <p style="text-align: center;">NAD 1927</p> <p>X=771965 Y=409577 LAT.: N 32.1229962 LONG.: W 103.4548524 50' FNL 1870' FEL</p> <p>UPPER MOST PERF. (UMP)</p> <p>NEW MEXICO EAST NAD 1983 X=813152 Y=409585 LAT.: N 32.1229836 LONG.: W 103.4553200</p> <p style="text-align: center;">NAD 1927</p> <p>X=771965 Y=409527 LAT.: N 32.1228587 LONG.: W 103.4548523 100' FNL 1870' FEL</p>	<p style="text-align: center;">USA NMNM-122624</p> <p style="text-align: center;">USA NMNM-94110</p> <p style="text-align: center;">NSP-2162; COM AGREEMENT NMNM 105689262</p> <p style="text-align: center;">HZ SPACING UNIT</p>	<p>PROPOSED PERF. POINT (PPP1)</p> <p>NEW MEXICO EAST NAD 1983 X=813162 Y=408367 LAT.: N 32.1196345 LONG.: W 103.4553191</p> <p style="text-align: center;">NAD 1927</p> <p>X=771976 Y=408309 LAT.: N 32.1195095 LONG.: W 103.4548516 1318' FNL 1867' FEL</p> <p>LOWER MOST PERF. (LMP) BOTTOM HOLE LOCATION (BHL)</p> <p>NEW MEXICO EAST NAD 1983 X=813239 Y=399227 LAT.: N 32.0945102 LONG.: W 103.4553123</p> <p style="text-align: center;">NAD 1927</p> <p>X=772052 Y=399169 LAT.: N 32.0943848 LONG.: W 103.4548461 100' FSL 1870' FEL</p>
<p style="text-align: right;">SURVEYORS CERTIFICATION</p> <p><i>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.</i></p> <p style="text-align: right;">02/14/2026</p> <p>Date of Survey Signature and Seal of Professional Surveyor:</p> <div style="text-align: right;"> </div> <p style="text-align: right;">2/23/2026 6:59:44 AM</p>		



EOG Batch Casing

Pad Name: Wild Weasel 22 Fed Com Deep
 SHL: Section 22, Township 25-S, Range 34-E, LEA County, NM

Well Name	API #	Surface		Intermediate		Production	
		MD	TVD	MD	TVD	MD	TVD
Wild Weasel 22 Fed Com #743H (103H)	30-025-*****	974	974	12,766	12,557	23,448	13,034
Wild Weasel 22 Fed Com #753H (104H)	30-025-*****	974	974	12,740	12,671	23,421	13,148
Wild Weasel 22 Fed Com #754H (106H)	30-025-*****	974	974	13,117	12,671	23,797	13,148



EOG Batch Casing

GEOLOGIC NAME OF SURFACE FORMATION:

Permian

ESTIMATED TOPS OF IMPORTANT GEOLOGICAL MARKERS:

Rustler	874'
Tamarisk Anhydrite	949'
Top of Salt	1,287'
Base of Salt	5,100'
Lamar	5,383'
Bell Canyon	5,416'
Cherry Canyon	6,378'
Brushy Canyon	7,968'
Bone Spring Lime	9,326'
Leonard (Avalon) Shale	9,345'
1st Bone Spring Sand	10,387'
2nd Bone Spring Shale	10,643'
2nd Bone Spring Sand	10,930'
3rd Bone Spring Carb	11,455'
3rd Bone Spring Sand	12,015'
Wolfcamp	12,424'

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

Upper Permian Sands	0- 400' Fresh Water
Lamar	5,383' Oil
Cherry Canyon	6,378' Oil
Brushy Canyon	7,968' Oil
Bone Spring Lime	9,326' Oil
Leonard (Avalon) Shale	9,345' Oil
1st Bone Spring Sand	10,387' Oil
2nd Bone Spring Shale	10,643' Oil
2nd Bone Spring Sand	10,930' Oil
3rd Bone Spring Carb	11,455' Oil
3rd Bone Spring Sand	12,015' Oil
Wolfcamp	12,424' Oil



EOG Batch Casing

Variations

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 2b - Wolfcamp Intermediate Casing Setpoint
- EOG BLM Variance 3e - BOP Break-test and Offline Surface and Intermediate Cement



Wild Weasel 22 Fed Com 753H

Revised Permit Information 02/12/2026:

Well Name: Wild Weasel 22 Fed Com 753H

Location: SHL: 629' FNL & 2639' FEL, Section 22, T-25-S, R-34-E, LEA Co., N.M.

BHL: 100' FSL & 1870' FEL, Section 27, T-25-S, R-34-E, LEA Co., N.M.

CASING PROGRAM Primary APD Design A:

Hole Size	Interval MD		Interval TVD		Csg OD	Weight	Grade	Conn
	From (ft)	To (ft)	From (ft)	To (ft)				
13"	0	974	0	974	10-3/4"	40.5#	J-55	STC
9-7/8"	0	12,740	0	12,671	8-5/8"	32#	P110-HSCY	GB CD Butt 9.03
7-7/8"	0	12,940	0	12,871	6"	22.3#	P110-EC	DWC/C IS
6-3/4"	12,940	23,421	12,871	13,148	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 availability.

Variance is requested to waive the centralizer requirements for the 8-5/8" casing in the 9-7/8" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 9-7/8" hole interval to maximize cement bond and zonal isolation.

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

Variance is also requested to waive the annular clearance requirements for the 6" and 5-1/2" casings by 8-5/8" casing annulus to the proposed top of cement.

EOG requests permission to allow deviation from the 0.422" annulus clearance requirement from Title 43 CFR Part 3170 under the following conditions:

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

Cementing Program:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
974' 10-3/4"	260	13.5	1.73	Lead: Class C/H + additives (TOC @ Surface)
	70	14.8	1.34	Tail: Class C/H + additives (TOC @ 774')
12,671' 8-5/8"	1820	14.2	1.11	1st Stage (Tail): Class C/H + additives (TOC @ 7,768')
	1000	13.2	1.85	2nd Stage (Bradenhead squeeze): Class C/H + additives (TOC @ surface)
23,421' 5-1/2"	1770	13.2	1.31	Lead: Class C/H + additives (TOC @ 11,671')



Wild Weasel 22 Fed Com 753H

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

EOG requests variance from minimum standards to pump a two stage cement job on the 8-5/8" intermediate casing string with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon (7,968') and the second stage performed as a bradenhead squeeze with planned cement from the Brushy Canyon to surface. If necessary, a top out consisting of 100 sacks of Class C/H cement + additives (2.30 yld, 12.91 ppg) will be executed as a contingency. Top will be verified by Echo-meter.

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

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

EOG requests a variance to set the intermediate casing shoe in the Bone Spring formation OR the Wolfcamp formation, depending on depletion in the area and well conditions. EOG will monitor the well and ensure the well is static before casing operations begin.

Mud Program:

Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 974'	Fresh - Gel	8.6-8.8	28-34	N/c
974' – 12,671'	Brine	9.8-10.8	28-34	N/c
12,671' – 12,740'	Water - Gel	8.7-9.4	58-68	N/c - 6
12,740' – 23,421'	Oil Base	10.0-14.0	58-68	4 - 6



Wild Weasel 22 Fed Com 753H

TUBING REQUIREMENTS

EOG respectfully requests an exception to the following NMOCD rule:

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

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

VARIANCE REQUESTS:

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

- EOG BLM Variance 2a - Intermediate Bradenhead Cement
- EOG BLM Variance 2b - Wolfcamp Intermediate Casing Setpoint
- EOG BLM Variance 3e - BOP Break-test and Offline Surface and Intermediate Cement
- EOG BLM Variance 3d - Production Offline Cement



Wild Weasel 22 Fed Com 753H

629' FNL
2639' FEL
Section 22
T-25-S, R-34-E

Revised Wellbore
Primary APD Design A

KB: 3376'
GL: 3351'

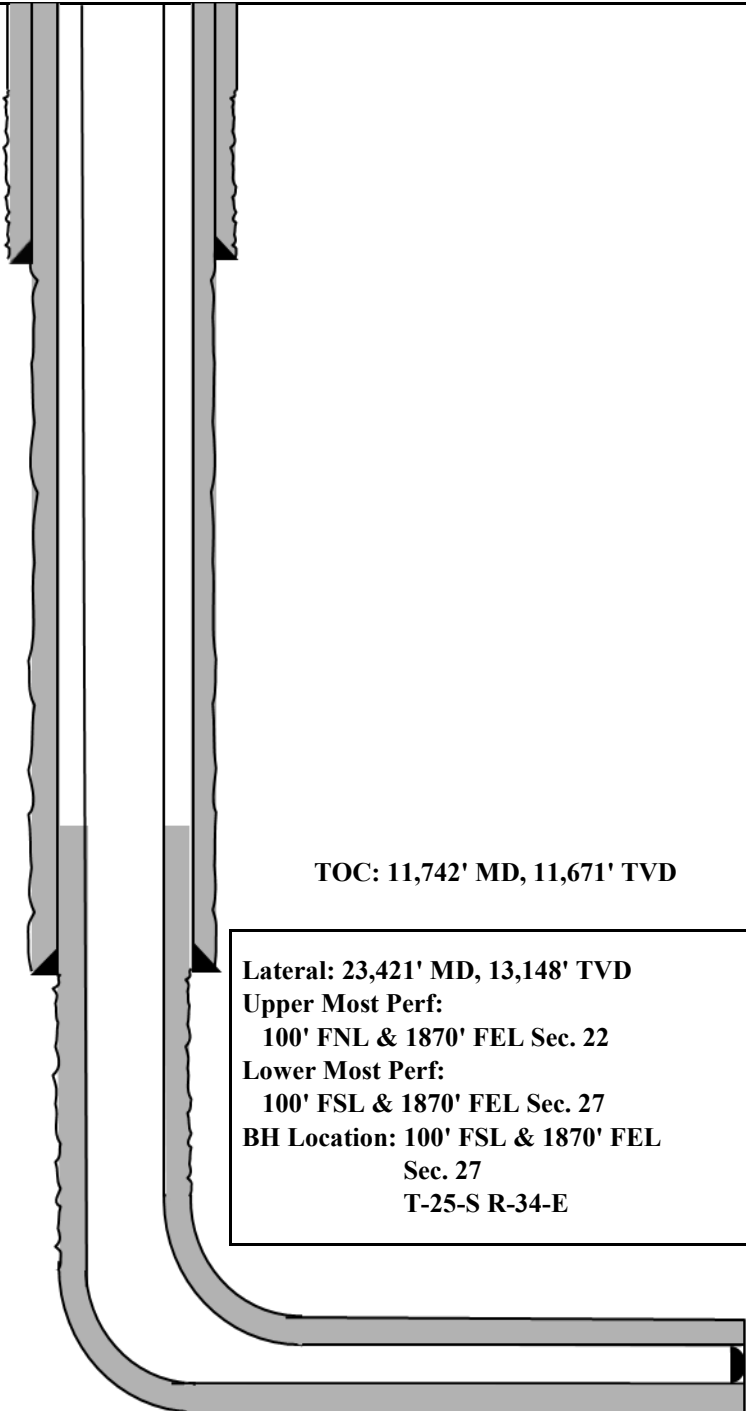
API: 30-025-*****

Bit Size: 13"
10-3/4", 40.5#, J-55, STC,
@ 0' - 974' MD
@ 0' - 974' TVD

Bit Size: 9-7/8"
8-5/8", 32#, P110-HSCY, GB CD
Butt 9.03,
@ 0' - 12,740' MD
@ 0' - 12,671' TVD

Bit Size: 7-7/8" | 6-3/4"
6", 22.3#, P110-EC, DWC/C IS
@ 0' - 12,940' MD
@ 0' - 12,871' TVD
5-1/2", 20.#, P110-EC, DWC/C IS
MS
@ 12,940' - 23,421' MD
@ 12,871' - 13,148' TVD

KOP: 12,740' MD, 12,671' TVD
EOC: 13,490' MD, 13,148' TVD



TOC: 11,742' MD, 11,671' TVD

Lateral: 23,421' MD, 13,148' TVD
Upper Most Perf:
100' FNL & 1870' FEL Sec. 22
Lower Most Perf:
100' FSL & 1870' FEL Sec. 27
BH Location: 100' FSL & 1870' FEL
Sec. 27
T-25-S R-34-E



Wild Weasel 22 Fed Com 753H

GEOLOGIC NAME OF SURFACE FORMATION:

Permian

ESTIMATED TOPS OF IMPORTANT GEOLOGICAL MARKERS:

Rustler	874'
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3rd Bone Spring Carb	11,455'
3rd Bone Spring Sand	12,015'
Wolfcamp	12,424'
TD	13,148'

ESTIMATED DEPTHS OF ANTICIPATED FRESH WATER, OIL OR GAS:

Upper Permian Sands	0- 400'	Fresh Water
Lamar	5,383'	Oil
Cherry Canyon	6,378'	Oil
Brushy Canyon	7,968'	Oil
Bone Spring Lime	9,326'	Oil
Leonard (Avalon) Shale	9,345'	Oil
1st Bone Spring Sand	10,387'	Oil
2nd Bone Spring Shale	10,643'	Oil
2nd Bone Spring Sand	10,930'	Oil
3rd Bone Spring Carb	11,455'	Oil
3rd Bone Spring Sand	12,015'	Oil
Wolfcamp	12,424'	Oil



Wild Weasel 22 Fed Com 753H (FKA 104H) API #: 30-025-*** Variances**

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

- Variance is requested to waive the centralizer requirements for the intermediate casing in the intermediate hole. An expansion additive will be utilized, in the cement slurry, for the entire length of the intermediate interval to maximize cement bond and zonal isolation.
- Variance is also requested to waive the centralizer requirements for the production casing in the production hole. An expansion additive will be utilized, in the cement slurry, for the entire length of the production interval to maximize cement bond and zonal isolation.
- EOG requests a variance to set the intermediate casing shoe in the Bone Spring formation or the Wolfcamp formation, depending on depletion in the area and well conditions. EOG will monitor the well and ensure the well is static before casing operations begin.

- 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 2a - Intermediate Bradenhead Cement
- EOG BLM Variance 2b - Bonespring/Wolfcamp Intermediate Casing Setpoint
- EOG BLM Variance 3a_b - BOP Break-test and Offline Intermediate Cement
- EOG BLM Variance 3d - Production Offline Cement

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 574688

ACKNOWLEDGMENTS

Operator: EOG RESOURCES INC 5509 Champions Drive Midland, TX 79706	OGRID: 7377
	Action Number: 574688
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

ACKNOWLEDGMENTS

<input checked="" type="checkbox"/>	I hereby certify that no additives containing PFAS chemicals will be added to the completion or recompletion of this well.
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Sante Fe Main Office
Phone: (505) 476-3441

General Information
Phone: (505) 629-6116

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

CONDITIONS

Action 574688

CONDITIONS

Operator: EOG RESOURCES INC 5509 Champions Drive Midland, TX 79706	OGRID: 7377
	Action Number: 574688
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

CONDITIONS

Created By	Condition	Condition Date
kayla_mcconnell	Cement is required to circulate on both surface and intermediate1 strings of casing.	4/13/2026
jeffrey.harrison	If the method of isolation was not by circulation, a CBL must be performed; if strata isolation is not achieved, then remediation will be required before further operations.	4/15/2026
jeffrey.harrison	All logs run on the well must be submitted to NMOCD.	4/15/2026
jeffrey.harrison	File As Drilled C-102 and a directional Survey with C-104 completion packet.	4/15/2026
jeffrey.harrison	Notify the OCD 24 hours prior to casing & cement.	4/15/2026
jeffrey.harrison	Once the well is spud, to prevent ground water contamination through whole or partial conduits from the surface, the operator shall drill without interruption through the fresh water zone or zones and shall immediately set in cement the water protection string.	4/15/2026
jeffrey.harrison	Oil base muds are not to be used until fresh water zones are cased and cemented providing isolation from the oil or diesel. This includes synthetic oils. Oil based mud, drilling fluids and solids must be contained in a steel closed loop system.	4/15/2026
jeffrey.harrison	Approval is only for Primary APD design A presented in approved BLM NOI attached to permit application.	4/15/2026
jeffrey.harrison	NSP required prior to production if not included in an existing order or not an infill to an appropriate defining well in the same pool and spacing unit.	4/15/2026