

Well Name: OVERLORD 33-32 W0CD FED COM	Well Location: T20S / R28E / SEC 33 / SWNE / 32.530056 / -104.17999	County or Parish/State: EDDY / NM
Well Number: 1H	Type of Well: CONVENTIONAL GAS WELL	Allottee or Tribe Name:
Lease Number: NMNM95632	Unit or CA Name:	Unit or CA Number:
US Well Number:	Operator: MEWBOURNE OIL COMPANY	

Notice of Intent

Sundry ID: 2824484

Type of Submission: Notice of Intent

Type of Action: APD Change

Date Sundry Submitted: 11/25/2024

Time Sundry Submitted: 03:20

Date proposed operation will begin: 11/25/2024

Procedure Description: Mewbourne Oil Company requests approval for the following changes to the APD (10400087672) 1. Change the well name from Overlord 33/32 W0CD Fed Com 1H to Overlord 33/32 Fed Com 711H 2. Change surface casing from 20" H40 to 18 5/8" 87.5# J55 3. Change production casing from 7" casing with 4.5" liner to 7" casing with 4.5" tapered string as detailed in the attachment 4. A variance is requested to perform BOP testing and offline cementing according to the attached procedures

NOI Attachments

Procedure Description

OVERLORD_33_32_FED_COM_711H_C102_20241211092426.pdf

Overlord_33_32_Fed_Com__711H_Tapered_String_20241211092425.pdf

Overlord_33_32_Fed_Com__711H_CsgAssumptions_C_20241211092425.pdf

MOC_Break_Testing_Variance_20241125151943.pdf

MOC_Offline_Cementing_Variance_20241125151944.pdf

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Conditions of Approval

Additional

OVERLORD_33_32_FED_COM_711H_ENG_COA_20250106160133.pdf
Overlord_33_32_Fed_Com__711H_CsgAssumptions_C_20250106160133.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: BRETT MILLER
Signed on: DEC 11, 2024 09:24 AM
Name: MEWBOURNE OIL COMPANY
Title: ENGINEER
Street Address: 4801 BUSINESS PARK BLVD
City: HOBBS State: NM
Phone: (505) 280-6768
Email address: BRETT.MILLER@MEWBOURNE.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: 01/15/2025
Signature: Cody R. Layton	

PECOS DISTRICT DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	MEWBOURNE OIL COMPANY
WELL NAME & NO.:	OVERLORD 33/32 FED COM 711H
APD ID:	10400087672
LOCATION:	Section 33, T20S, R28E. NMP.
COUNTY:	Eddy County, New Mexico ▼

*Previously known as **OVERLORD 33-32 W0CD FED COM 1H**. Changes approved through engineering via **Sundry 2824484** on 01/06/2025. Any previous COAs not addressed within the updated COAs still apply.*

COA

H ₂ S	☐ No		☒ Yes	
Potash / WIPP	☒ None	☐ Secretary	☐ R-111-Q	☐ Open Annulus ☐ WIPP
Cave / Karst	☐ Low	☐ Medium	☒ High	☐ Critical
Wellhead	☐ Conventional	☒ Multibowl	☐ Both	☐ Diverter
Cementing	☐ Primary Squeeze	☐ Cont. Squeeze	☐ EchoMeter	☒ DV Tool
Special Req	☒ Capitan Reef	☐ Water Disposal	☒ COM	☐ Unit
Waste Prev.	☐ Self-Certification	☐ Waste Min. Plan	☒ APD Submitted prior to 06/10/2024	
Additional Language	☒ Flex Hose	☐ Casing Clearance	☐ Pilot Hole	☒ Break Testing
	☒ Four-String	☒ Offline Cementing	☐ Fluid-Filled	

SEE ORIGINAL COA FOR ALL OTHER REQUIREMENTS.

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

Note: Surface casing set depth was adjusted per BLM geologist's recommendation: "The operator proposes to set surface casing at 280 feet, BLM accepts 313 the Rustler formation plus 70 feet penetration eddy county APD well casing set depth and rock type. Karst is 350 feet from land surface, BLM will institute the 25-foot buffer above salt 313 feet. If salt is encountered, set casing at least 25 feet above the salt."

1. The **18-5/8** inch surface casing shall be set at approximately **313 ft.** (a minimum of 70 feet (Eddy County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. **If salt is encountered set casing at least 25 ft. above the salt.**
 - 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 psi 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 **13-3/8** inch 1st intermediate casing shall be set in a competent bed at approximately **745 ft.** The minimum required fill of cement behind the **13-3/8** inch intermediate casing is:
 - **Cement to surface.** If cement does not circulate see B.1.a, c-d above. Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to **cave/karst, and Capitan Reef.**
 - ❖ In High Cave/Karst Areas if cement does not circulate to surface on the first two casing strings, the cement on the 3rd casing string must come to surface.
 - ❖ In Capitan Reef Areas if cement does not circulate to surface on the first two casing strings, the cement on the 3rd casing string must come to surface.
 - ❖ **Special Capitan Reef requirements.** If lost circulation (50% or greater) occurs below the Base of the Salt, the operator shall do the following: **(Use this for 3 string wells in the Capitan Reef, if 4 string well ensure FW based mud used across the Capitan interval)**
 - Switch to freshwater mud to protect the Capitan Reef and use freshwater mud until setting the intermediate casing. The appropriate BLM office is to be notified for a PET to witness the switch to fresh water.
 - Daily drilling reports from the Base of the Salt to the setting of the intermediate casing are to be submitted to the BLM CFO engineering staff via e-mail by 0800 hours each morning. Any lost circulation encountered is to be recorded on these drilling reports. The daily drilling report should show mud volume per shift/tour. Failure to submit these reports will result in an Incidence of Non-Compliance being issued for failure to comply with the Conditions of Approval. If not already planned, the operator shall run a caliper survey for the intermediate well bore and submit to the appropriate BLM office.
3. The **9-5/8** inch 2nd intermediate casing shall be set in a competent bed at approximately **2,665 ft.** The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:

Option 1 (Single Stage): Cement should tie-back at least **50 feet** above Capitan Reef top or **200 feet** into the previous casing, whichever is greater. Operator shall provide method of verification. Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to **cave/karst, and Capitan Reef**.

Option 2 (Two-Stage): The operator has proposed utilize a DV tool. Operator may adjust depth of DV tool if needed, adjust cement volumes accordingly. The DV tool may be cancelled if cement circulates to surface on the first stage.

- a. **First stage to DV tool:** Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.
 - b. **Second stage above DV tool:** Cement should tie-back at least **50 feet** on top of Capitan Reef top or **200 feet** into the previous casing, whichever is greater. Operator shall provide method of verification. Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to **cave/karst, and Capitan Reef**.
4. Operator has proposed to set 7 x 4-1/2 inch tapered production casing at approximately **17,333 ft.** (8,841 ft. TVD). (Casing and hole size change at the KOP, approximately at 8,672 ft.) The minimum required fill of cement behind the 7 x 4-1/2 inch production casing is:
 - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.

Offline Cementing

Operator has been **(Approved)** to pump the proposed cement program offline in the **Surface and intermediate(s) intervals**. Offline cementing should commence within 24 hours of landing the casing for the interval. Notify the BLM 4hrs prior to the commencement of any offline cementing procedure at **Eddy County: 575-361-2822**.

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. 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**. Before drilling the surface casing shoe out, the BOP/BOPE and annular preventer shall be pressure-tested in accordance with **title 43 CFR 3172**.
 - 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.

BOPE Break Testing Variance

- BOPE Break Testing is ONLY permitted for 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.)**
- 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 **(575-361-2822 Eddy 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 **43 CFR 3172**.
- If in the event break testing is not utilized, then a full BOPE test would be conducted.

D. SPECIAL REQUIREMENT (S)

Communitization Agreement

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

GENERAL REQUIREMENTS

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

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

Contact Eddy County Petroleum Engineering Inspection Staff:

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

1. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval.
 - a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
 - b. When the operator proposes to set surface casing with Spudder Rig
 - i. Notify the BLM when moving in and removing the Spudder Rig.
 - ii. Notify the BLM when moving in the 2nd Rig. Rig to be moved in within 90 days of notification that Spudder Rig has left the location.
 - iii. BOP/BOPE test to be conducted per **43 CFR 3172** as soon as 2nd Rig is rigged up on well.
2. Floor controls are required for 3M or Greater systems. These controls will be on the rig floor, unobstructed, readily accessible to the driller and will be operational at all times during drilling and/or completion activities. Rig floor is defined as the area immediately around the rotary table; the area immediately above the substructure on which the draw works are located, this does not include the doghouse 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.

SA 01/06/2025

Mewbourne Oil Company, Overlord 33/32 Fed Com 711H
Sec 33, T20S, R28E
SHL: 2610' FNL 1735' FEL (Sec 33)
BHL: 500' FNL 100' FWL (Sec 32)

Casing Program Design C						BLM Minimum Safety Factors	1.125	1.0	1.6 Dry	1.6 Dry
									1.8 Wet	1.8 Wet
String	Hole Size	Top MD	Top TVD	Bot MD	Bot TVD	Csg. Size	SF Collapse	SF Burst	SF Jt Tension	SF Body Tension
Surface	26"	0'	0'	280'	280'	18 5/8" 87.5# J55 BTC	5.03	17.97	54.24	55.80
Intermediate 1	17.5"	0'	0'	745'	745'	13.375" 48# H40 STC	1.95	4.38	9.00	15.13
Intermediate 2	12.25"	0'	0'	2665'	2665'	9.625" 36# J55 LTC	1.70	2.95	4.72	5.88
Production	8.75"	0'	0'	8672'	8371'	7" 26# P110 LTC	1.38	2.21	3.07	3.68
Production	8.5"	8672'	8371'	17333'	8841'	4.5" 13.5# RYS110 CDC HTQ	1.91	2.23	3.66	3.61

Cement Program

Casing		# Sacks	Wt. lb/gal	Yield ft³/sack	TOC/BOC	Volume ft³	% Excess	Slurry Description
18.625 in	LEAD	350	12.5	2.12	0' - 205'	750	100%	Class C: Salt, Gel, Extender, LCM
	TAIL	200	14.8	1.34	205' - 280'	268		Class C: Retarder
13.375 in	LEAD	210	12.5	2.12	0' - 467'	450	50%	Class C: Salt, Gel, Extender, LCM
	TAIL	200	14.8	1.34	467' - 745'	268		Class C: Retarder
1st Stg 9.625 in	LEAD	370	12.5	2.12	0' - 1990'	790	25%	Class C: Salt, Gel, Extender, LCM
	TAIL	200	14.8	1.34	1990' - 2665'	268		Class C: Retarder
7 in - 4.5 in	LEAD	820	12.5	2.12	773' - 7155'	1740	25%	Class C: Salt, Gel, Extender, LCM, Defoamer
	TAIL	1500	13.5	1.85	7155' - 17333'	2775		Class H: Retarder, Fluid Loss, Defoamer

Design A - Mud Program

Depth	Mud Wt	Mud Type
0' - 280'	8.4 - 8.6	Fresh Water
280' - 745'	10-10.2	Brine
745' - 2665'	8.4-8.6	Fresh Water
2665' - 8672'	8.6 - 9.5	Cut-Brine
8672' - 17333'	10.0 - 11.	OBM

Geology

Formation	Est. Top (TVD)	Mineral Resources	Formation	Est. Top (TVD)	Mineral Resources
Rustler	338'	None	Yeso	2743'	Oil/Natural Gas
Castile			Delaware (Lamar)		
Salt Top			Bell Canyon		
Marker Bed 126			Cherry Canyon		
Salt Base	485'	None	Manzanita Marker	5155'	Oil/Natural Gas
Yates	589'	Oil/Natural Gas	Basal Brushy Canyon		
Seven Rivers	823'	Usable Water	Bone Spring		
Queen			1st Bone Spring	6364'	Oil/Natural Gas
Capitan			2nd Bone Spring	7184'	Oil/Natural Gas
Grayburg			3rd Bone Spring	8410'	Oil/Natural Gas
San Andres			Wolfcamp	8818'	Oil/Natural Gas

All casing strings will be tested in accordance with 43 CFR Part 3170 Subpart 3172. Must have table for contingency casing.

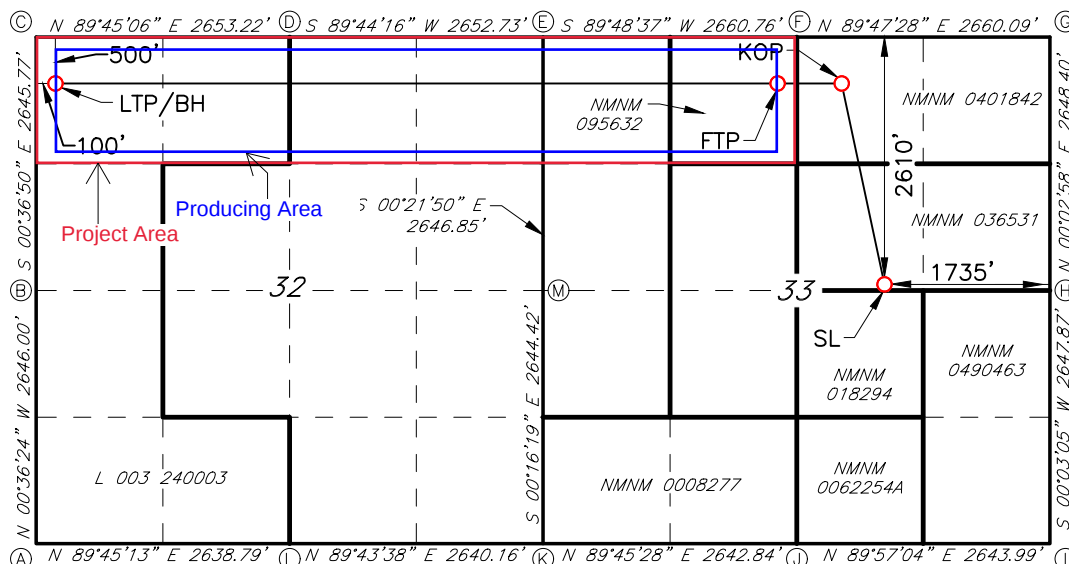
	Y or N
Is casing new? If used, attach certification as required in Onshore Order #1	Y
Is casing API approved? If no, attach casing specification sheet.	Y
Is premium or uncommon casing planned? If yes attach casing specification sheet.	Y
Does the above casing design meet or exceed BLM’s minimum standards? If not provide justification (loading assumptions, casing design criteria).	Y
Will the pipe be kept at a minimum 1/3 fluid filled to avoid approaching the collapse pressure rating of the casing?	Y
Is well located within Capitan Reef?	Y
If yes, does production casing cement tie back a minimum of 50’ above the Reef?	Y
Is well within the designated 4 string boundary.	Y
Is well located in SOPA but not in R-111-Q?	N
If yes, are the first 2 strings cemented to surface and 3 rd string cement tied back 500’ into previous casing?	
Is well located in R-111-Q and SOPA?	N
If yes, are the first three strings cemented to surface?	
Is 2 nd string set 100’ to 600’ below the base of salt?	
Is an open annulus used to satisfy R-111-Q? If yes, see cement design.	
Is an engineered weak point used to satisfy R-111-Q?	
If yes, at what depth is the weak point planned?	
Is well located in high Cave/Karst?	Y
If yes, are there two strings cemented to surface?	Y
(For 2 string wells) If yes, is there a contingency casing if lost circulation occurs?	
Is well located in critical Cave/Karst?	N
If yes, are there three strings cemented to surface?	

ACREAGE DEDICATION PLATS

This grid represents a standard section. You may superimpose a non-standard section, or larger area, over this grid. Operators must outline the dedicated acreage in a red box, clearly show the well surface location and bottom hole location, if it is a directionally drilled, with the dimensions from the section lines in the cardinal directions. If this is a horizontal wellbore show on this plat the location of the First Take Point and Last Take Point, and the point within the Completed interval (other than the First Take Point or Last Take Point) that is closest to any outer boundary of the tract.

Surveyors shall use the latest United States government survey or dependent resurvey. Well locations will be in reference to the New Mexico Principal Meridian. If the land is not surveyed, contact the OCD Engineering Bureau. Independent subdivision surveys will not be acceptable.

OVERLORD 33/32 FED COM #711H



GEODETTIC DATA
NAD 83 GRID — NM EAST

SURFACE LOCATION (SL)
N: 556598.9 — E: 588596.6

LAT: 32.530056° N
LONG: 104.179990° W

KICK OFF POINT (KOP)
500' FNL — 2186' FEL SEC. 33
N: 558706.8 — E: 588147.9

LAT: 32.535851° N
LONG: 104.181436° W

FIRST TAKE POINT (FTP)
500' FNL — 2559' FWL SEC. 33
N: 558704.8 — E: 587575.1

LAT: 32.535848° N
LONG: 104.183295° W

LAST TAKE POINT (LTP)/
BOTTOM HOLE (BH)
N: 558673.1 — E: 579814.5

LAT: 32.535789° N
LONG: 104.208478° W

CORNER DATA
NAD 83 GRID — NM EAST

A: FOUND BRASS CAP "1941"
N: 553882.3 — E: 579765.6

B: FOUND BRASS CAP "1942"
N: 556527.5 — E: 579737.6

C: FOUND BRASS CAP "1942"
N: 559172.5 — E: 579709.2

D: FOUND BRASS CAP "1942"
N: 559184.0 — E: 582361.8

E: FOUND BRASS CAP "1942"
N: 559196.2 — E: 585013.8

F: FOUND BRASS CAP "1942"
N: 559205.0 — E: 587674.0

G: FOUND BRASS CAP "1942"
N: 559214.7 — E: 590333.4

H: FOUND BRASS CAP "1942"
N: 556566.9 — E: 590331.1

I: FOUND BRASS CAP "1942"
N: 553919.7 — E: 590328.7

J: FOUND BRASS CAP "1942"
N: 553917.4 — E: 587685.4

K: FOUND BRASS CAP "1942"
N: 553906.2 — E: 585043.2

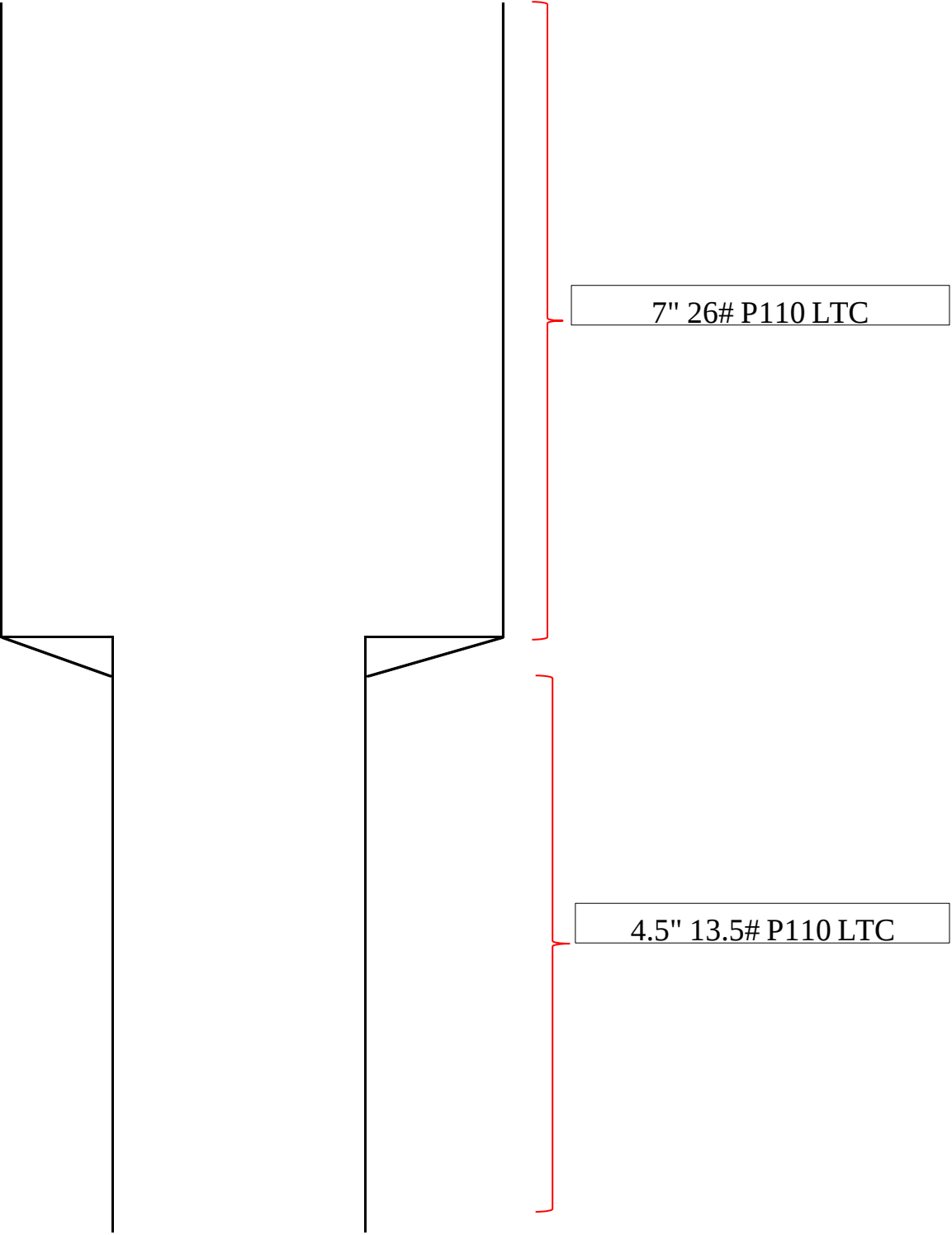
L: FOUND BRASS CAP "1942"
N: 553893.7 — E: 582403.7

M: FOUND BRASS CAP "1942"
N: 556550.0 — E: 585030.7

Mewbourne Oil Company, Overlord 33/32 Fed Com 711H
Sec 33, T20S, R28E
SHL: 2610' FNL & 1735' FEL (Sec 33)
BHL: 500' FNL & 100' FWL (Sec 32)

Casing Design C

Hole Size	From	To	Csg. Size	#/ft	Grade	Conn.	SF Collapse	SF Burst	SF Jt Tension	SF Body Tension
8.75	0'	8672'	7" 26# P110 LTC				1.38	2.21	3.07	3.68
8.5	8672'	17333'	4.5" 13.5# RYS110 CDC HTQ				1.91	2.23	3.66	3.61



Mewbourne Oil Company, Overlord 33/32 Fed Com 711H
Sec 33, T20S, R28E
SHL: 2610' FNL 1735' FEL (Sec 33)
BHL: 500' FNL 100' FWL (Sec 32)

Casing Program Design C						BLM Minimum Safety Factors	1.125	1.0	1.6 Dry	1.6 Dry
									1.8 Wet	1.8 Wet
String	Hole Size	Top MD	Top TVD	Bot MD	Bot TVD	Csg. Size	SF Collapse	SF Burst	SF Jt Tension	SF Body Tension
Surface	26"	0'	0'	280'	280'	18 5/8" 87.5# J55 BTC	5.03	17.97	54.24	55.80
Intermediate 1	17.5"	0'	0'	745'	745'	13.375" 48# H40 STC	1.95	4.38	9.00	15.13
Intermediate 2	12.25"	0'	0'	2665'	2665'	9.625" 36# J55 LTC	1.70	2.95	4.72	5.88
Production	8.75"	0'	0'	8672'	8371'	7" 26# P110 LTC	1.38	2.21	3.07	3.68
Production	8.5"	8672'	8371'	17333'	8841'	4.5" 13.5# RYS110 CDC HTQ	1.91	2.23	3.66	3.61

Cement Program

Casing		# Sacks	Wt. lb/gal	Yield ft³/sack	TOC/BOC	Volume ft³	% Excess	Slurry Description
18.625 in	LEAD	350	12.5	2.12	0' - 205'	750	100%	Class C: Salt, Gel, Extender, LCM
	TAIL	200	14.8	1.34	205' - 280'	268		Class C: Retarder
13.375 in	LEAD	210	12.5	2.12	0' - 467'	450	50%	Class C: Salt, Gel, Extender, LCM
	TAIL	200	14.8	1.34	467' - 745'	268		Class C: Retarder
9.625 in	LEAD	370	12.5	2.12	0' - 1990'	790	25%	Class C: Salt, Gel, Extender, LCM
	TAIL	200	14.8	1.34	1990' - 2665'	268		Class C: Retarder
7 in - 4.5 in	LEAD	460	12.5	2.12	773' - 7370'	980	25%	Class C: Salt, Gel, Extender, LCM, Defoamer
	TAIL	800	13.5	1.85	7370' - 8672'	1480		Class H: Retarder, Fluid Loss, Defoamer

Design A - Mud Program

Depth	Mud Wt	Mud Type
0' - 280'	8.4 - 8.6	Fresh Water
280' - 745'	10-10.2	Brine
745' - 2665'	8.4-8.6	Fresh Water
2665' - 8672'	8.6 - 9.5	Cut-Brine
8672' - 17333'	10.0 - 11.	OBM

Geology

Formation	Est. Top (TVD)	Mineral Resources	Formation	Est. Top (TVD)	Mineral Resources
Rustler	338'	None	Yeso	2743'	Oil/Natural Gas
Castile			Delaware (Lamar)		
Salt Top			Bell Canyon		
Marker Bed 126			Cherry Canyon		
Salt Base	485'	None	Manzanita Marker	5155'	Oil/Natural Gas
Yates	589'	Oil/Natural Gas	Basal Brushy Canyon		
Seven Rivers	823'	Usable Water	Bone Spring		
Queen			1st Bone Spring	6364'	Oil/Natural Gas
Capitan			2nd Bone Spring	7184'	Oil/Natural Gas
Grayburg			3rd Bone Spring	8410'	Oil/Natural Gas
San Andres			Wolfcamp	8818'	Oil/Natural Gas

All casing strings will be tested in accordance with 43 CFR Part 3170 Subpart 3172. Must have table for contingency casing.

	Y or N
Is casing new? If used, attach certification as required in Onshore Order #1	Y
Is casing API approved? If no, attach casing specification sheet.	Y
Is premium or uncommon casing planned? If yes attach casing specification sheet.	Y
Does the above casing design meet or exceed BLM’s minimum standards? If not provide justification (loading assumptions, casing design criteria).	Y
Will the pipe be kept at a minimum 1/3 fluid filled to avoid approaching the collapse pressure rating of the casing?	Y
Is well located within Capitan Reef?	Y
If yes, does production casing cement tie back a minimum of 50’ above the Reef?	Y
Is well within the designated 4 string boundary.	Y
Is well located in SOPA but not in R-111-Q?	N
If yes, are the first 2 strings cemented to surface and 3 rd string cement tied back 500’ into previous casing?	
Is well located in R-111-Q and SOPA?	N
If yes, are the first three strings cemented to surface?	
Is 2 nd string set 100’ to 600’ below the base of salt?	
Is an open annulus used to satisfy R-111-Q? If yes, see cement design.	
Is an engineered weak point used to satisfy R-111-Q?	
If yes, at what depth is the weak point planned?	
Is well located in high Cave/Karst?	Y
If yes, are there two strings cemented to surface?	Y
(For 2 string wells) If yes, is there a contingency casing if lost circulation occurs?	
Is well located in critical Cave/Karst?	N
If yes, are there three strings cemented to surface?	



Mewbourne Oil Co.

BOP Break Testing Variance

Mewbourne Oil Company requests a variance from the minimum standards for well control equipment testing of 43 CFR 3172 to allow a testing schedule of the blow out preventer (BOP) and blow out prevention equipment (BOPE) along with batch drilling & offline cementing operations. Modern rig upgrades which facilitate pad drilling allow the BOP stack to be moved between wells on a multi-well pad without breaking any BOP stack components apart. Widespread use of these technologies has led to break testing BOPE being endorsed as safe and reliable. American Petroleum Institute (API) best practices are frequently used by regulators to develop their regulations. API Standard 53, *Well Control Equipment Systems for Drilling Wells* (5th Ed., Dec. 2018) Section 5.3.7.1 states "A pressure test of the pressure containing component shall be performed following the disconnection or repair, limited to the affected component."

Procedures

1. Full BOPE test at first installation on the pad.
 - Full BOPE test at least every 21 days.
 - Function test BOP elements per 43 CFR 3172.
 - Contact the BLM if a well control event occurs.
2. After the well section is secured and the well is confirmed to be static, the BOP will be disconnected from the wellhead and walked with the rig to another well on the pad. Two breaks on the BOPE will be made (Fig. 1).
 - Connection between the flex line and the HCR valve
 - Connection between the wellhead and the BOP quick connect (Fig. 5 & 6).
3. A capping flange will be installed after cementing per wellhead vendor procedure & casing pressure will be monitored via wellhead valve.
4. The BOP will be removed and carried by a hydraulic carrier (Fig. 3 & 4).
5. The rig will then walk to the next well.
6. Confirm that the well is static and remove the capping flange.
7. The connection between the flex line and HCR valve and the connection between the wellhead and the BOP quick connect will be reconnected.
8. Install a test plug into the wellhead.
9. A test will then be conducted against the upper pipe rams and choke, testing both breaks (Fig. 1 & 2).
10. The test will be held at 250 psi low and to the high value submitted in the APD, not to exceed 5000 psi.
11. The annular, blind rams and lower pipe rams will then be function tested.
12. If a pad consists of three or more wells, steps 4 through 11 will be repeated.



13. A break test will only be conducted if the intermediate section can be drilled and cased within 21 days of the last full BOPE test.

Barriers

Before Nipple Down:

- Floats in casing
- Kill weight fluid in casing
- Kill weight fluid in annulus
- Solid body mandrel and/or packoff

After Nipple Down:

- Floats in casing
- Kill weight fluid in casing
- Kill weight fluid in annulus
- Solid body mandrel and/or packoff
- Offline cementing tool and/or cement head
- Capping flange after cementing

Summary

A variance is requested to only test broken pressure seals on the BOPE when moving between wells on a multi-well pad if the following conditions are met:

- A full BOPE test is conducted on the first well on the pad. API Standard 53 requires testing annular BOP to 70% of RWP or 100% of MASP, whichever is greater.
- If the first well on the pad is not the well with the deepest intermediate section, a full BOPE test will also be performed when moving to a deeper well.
- The hole section being drilled has a MASP under 5000 psi.
- If a well control event occurs, Mewbourne will contact BLM for permission to continue break testing.
- If significant (>50%) losses occur, full BOPE testing will be required going forward.
- Full BOPE test will be required prior to drilling the production hole.

While walking the rig, the BOP stack will be secured via hydraulic winch or hydraulic carrier. A full BOPE test will be performed at least every 21 days.

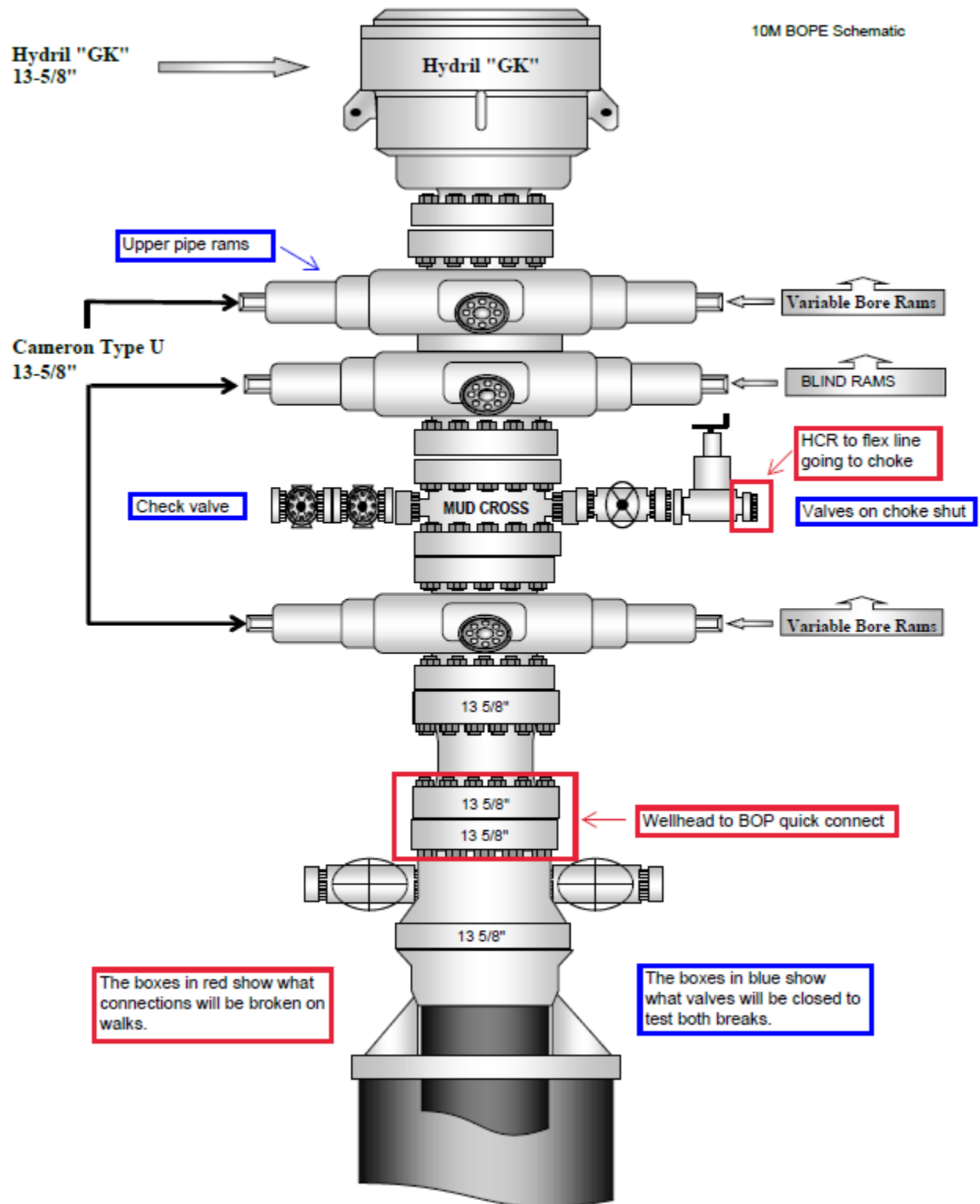


Figure 1. BOP diagram



5M BOPE & Closed Loop Equipment Schematic

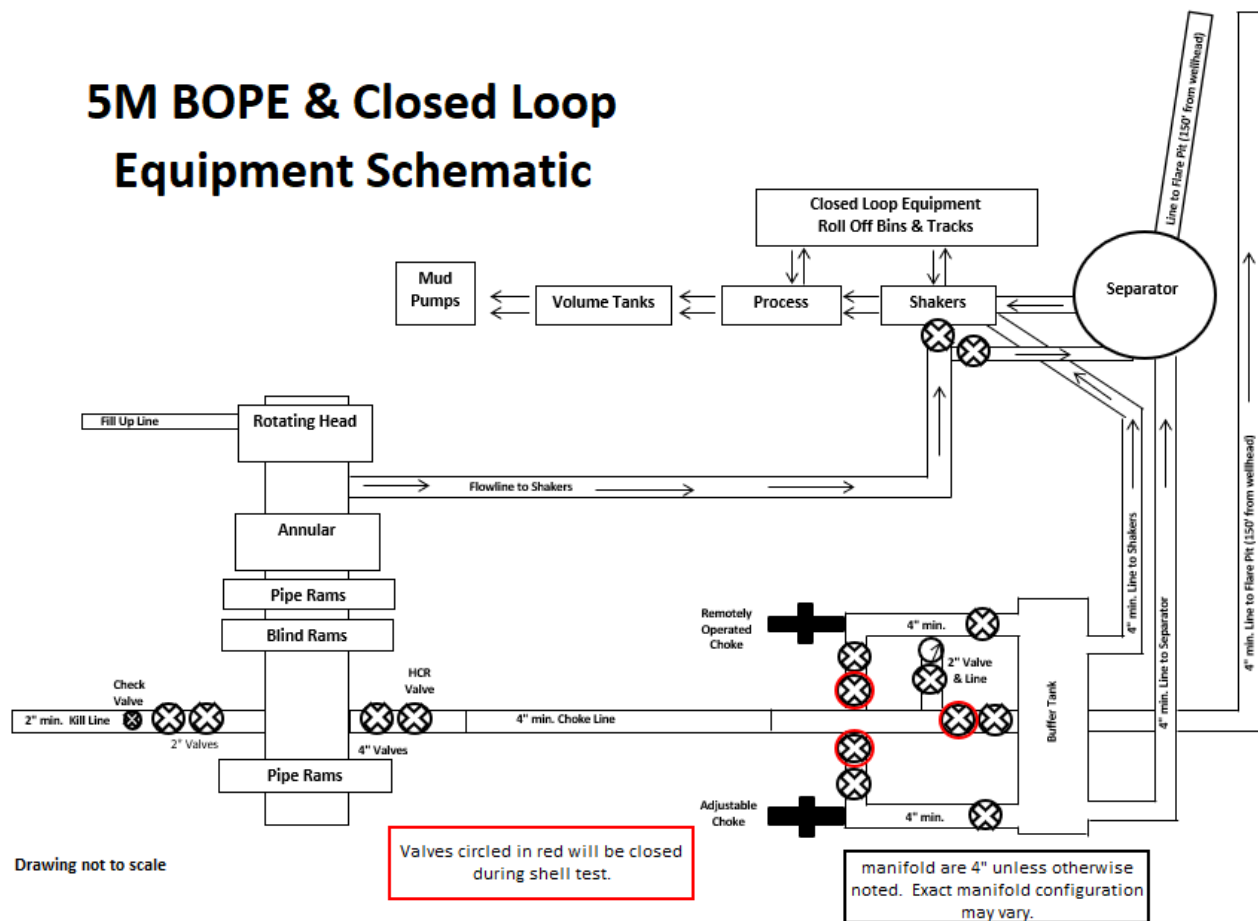


Figure 2. BOPE diagram



Figure 3. BOP handling system



Figure 4. BOP handling system

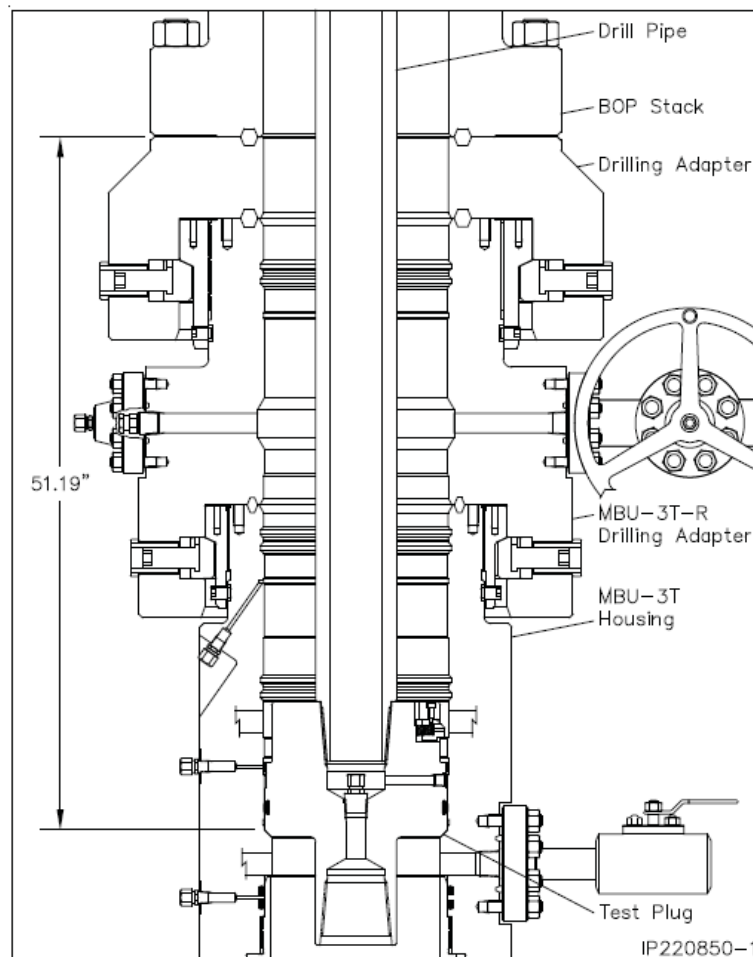


Figure 5. Cactus 5M wellhead with BOP quick connect

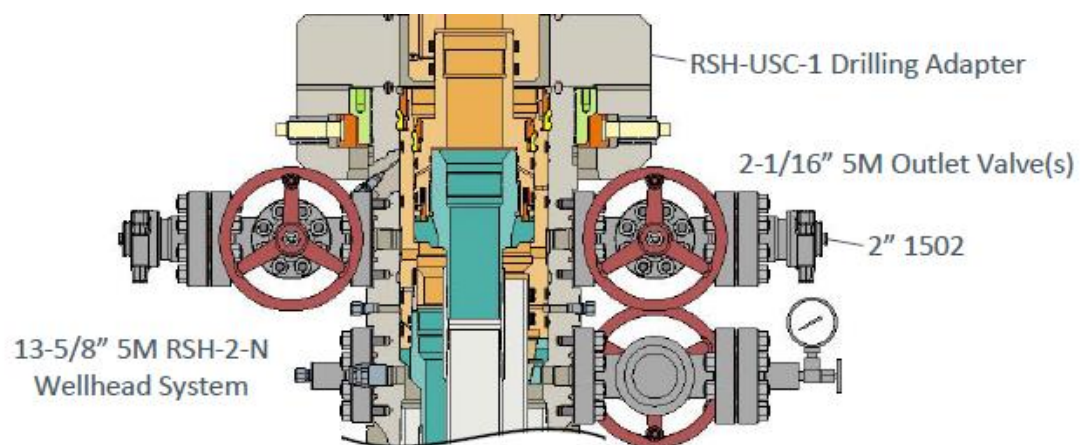


Figure 6. Vault 5M wellhead with BOP quick connect



Mewbourne Oil Co.

Surface & Intermediate Offline Cementing Variance

Mewbourne Oil Company requests a variance to perform offline cementing for surface and intermediate casing strings with the following conditions:

- Offline cementing will not be performed on production casing.
- Offline cementing will not be performed on a hole section with MASP > 5000 psi.
- Offline cementing will not be performed concurrently with offset drilling.

Surface Casing Order of Operations:

1. Run 13 3/8" surface casing as per normal operations (TPGS and float collar).
2. Perform negative pressure test to confirm integrity of float equipment while running casing.
3. Confirm well is static.
4. Make up 13 5/8" wellhead or wellhead landing ring assembly and land on 20" conductor.
5. Fill pipe, circulate casing capacity and confirm float(s) are still holding.
6. Confirm well is static.
7. Back out landing joint and pull to rig floor. Lay down landing joint.
8. Walk rig to next well on pad with cement crew standing by to rig up.
9. Make up offline cement tool with forklift per wellhead manufacturer (Fig. 1 & 2).
10. Make up cement head on top of offline cement tool with forklift.
11. Commence cement operations.
12. If cement circulates, confirm well is static and proceed to step 16.
13. If cement does not circulate, notify the appropriate BLM office, wait a minimum of six hours, and run a temperature survey to determine the top of cement.
14. Use 1" pipe for remedial cement job until the surface casing is cemented to surface.
15. Confirm well is static.
16. Once cement job is complete, the cement head and offline cementing tool are removed. The wellhead technician returns to cellar to install wellhead/valves.
17. Install wellhead capping flange.

Barriers

Before Walk:

- Float(s) in casing
- Kill weight fluid in casing
- Kill weight fluid in annulus

**After Walk:**

- Float(s) in casing
- Kill weight fluid in casing
- Kill weight fluid in annulus
- Offline cementing tool tested to 5000 psi and cement head
- Capping flange after cementing

20" Surface Casing Order of Operations (4 string area):

1. Run 20" surface casing as per normal operations (TPGS and float collar).
2. Perform negative pressure test to confirm integrity of float equipment while running casing.
3. Fill pipe, circulate casing capacity and confirm float(s) are still holding.
4. Confirm well is static.
5. Back out landing joint and pull to rig floor. Lay down landing joint.
6. Make up cement head.
7. Walk rig to next well on pad with cement crew standing by to rig up.
8. Commence cement operations.
9. If cement circulates, confirm well is static and proceed to step 13.
10. If cement does not circulate, notify the appropriate BLM office, wait a minimum of six hours, and run a temperature survey to determine the top of cement.
11. Use 1" pipe for remedial cement job until the surface casing is cemented to surface.
12. Confirm well is static.
13. Once cement job is complete, remove cement head and install cap.

Barriers**Before Walk:**

- Float(s) in casing
- Kill weight fluid in casing
- Kill weight fluid in annulus
- Cement Head

After Walk:

- Float(s) in casing
- Kill weight fluid in casing
- Kill weight fluid in annulus
- Cement head
- Capping flange after cementing



Intermediate Casing Order of Operations:

1. Run casing as per normal operations (float shoe and float collar).
2. Perform negative pressure test to confirm integrity of float equipment while running casing.
3. Confirm well is static (if running SBM).
4. Land casing.
5. Fill pipe, circulate casing capacity and confirm floats are still holding.
6. Confirm well is static.
7. Back out landing joint and pull to rig floor. Lay down landing joint. Install packoff & test.
8. Nipple down BOP.
9. Walk rig to next well on pad with cement crew standing by to rig up.
10. Make up offline cement tool using forklift per wellhead manufacturer (Fig. 3 - 8).
11. Make up cement head on top of offline cement tool.
12. Commence cement operations.
13. If cement circulates, confirm well is static and proceed to step 16.
14. If cement does not circulate (when required), notify the appropriate BLM office, wait a minimum of six hours, and run a temperature survey to determine the top of cement.
15. Pump remedial cement job if required.
16. Confirm well is static.
17. Remove cement head and offline cementing tool.
18. Install wellhead capping flange and test.

Barriers

Before Nipple Down:

- Floats in casing
- Kill weight fluid in casing
- Kill weight fluid in annulus
- Solid body mandrel and/or packoff

After Nipple Down:

- Floats in casing
- Kill weight fluid in casing
- Kill weight fluid in annulus
- Solid body mandrel and/or packoff
- Offline cementing tool tested to 5000 psi and cement head
- Capping flange after cementing

**Risks:**

- Pressure build up in annulus before cementing
 - Contact BLM if a well control event occurs.
 - Rig up 3rd party pump or rig pumps to pump down casing and kill well.
 - Returns will be taken through the wellhead valves to a choke manifold (Fig 9 & 10).
 - Well could also be killed through the wellhead valves down the annulus.

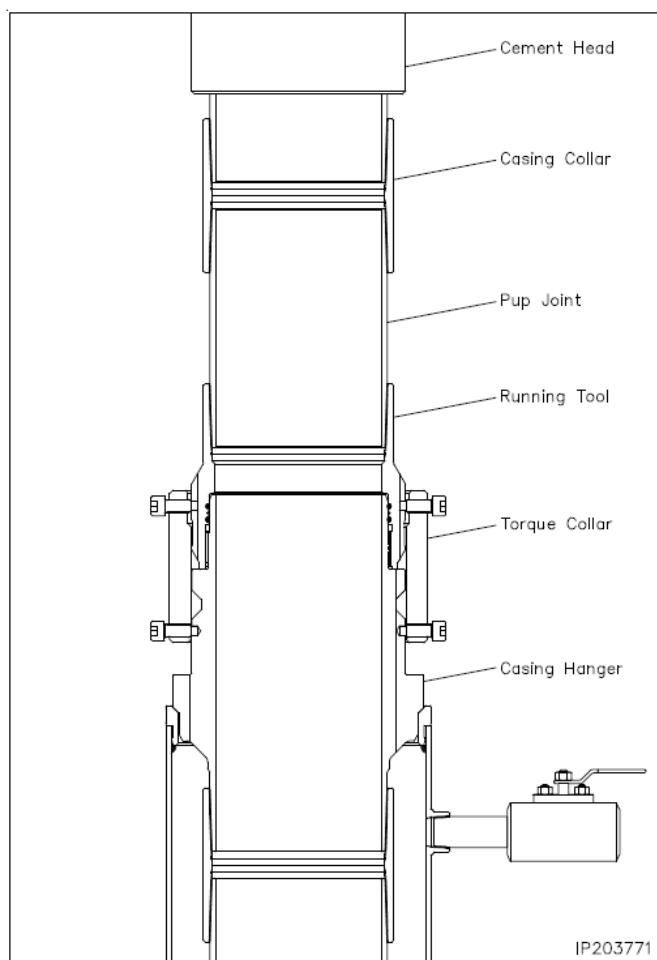


Figure 1. Cactus 13 3/8" 5M offline cementing tool. Pressure rating limited by the lesser of 5M tool rating or the 13 3/8" pup joint and casing.

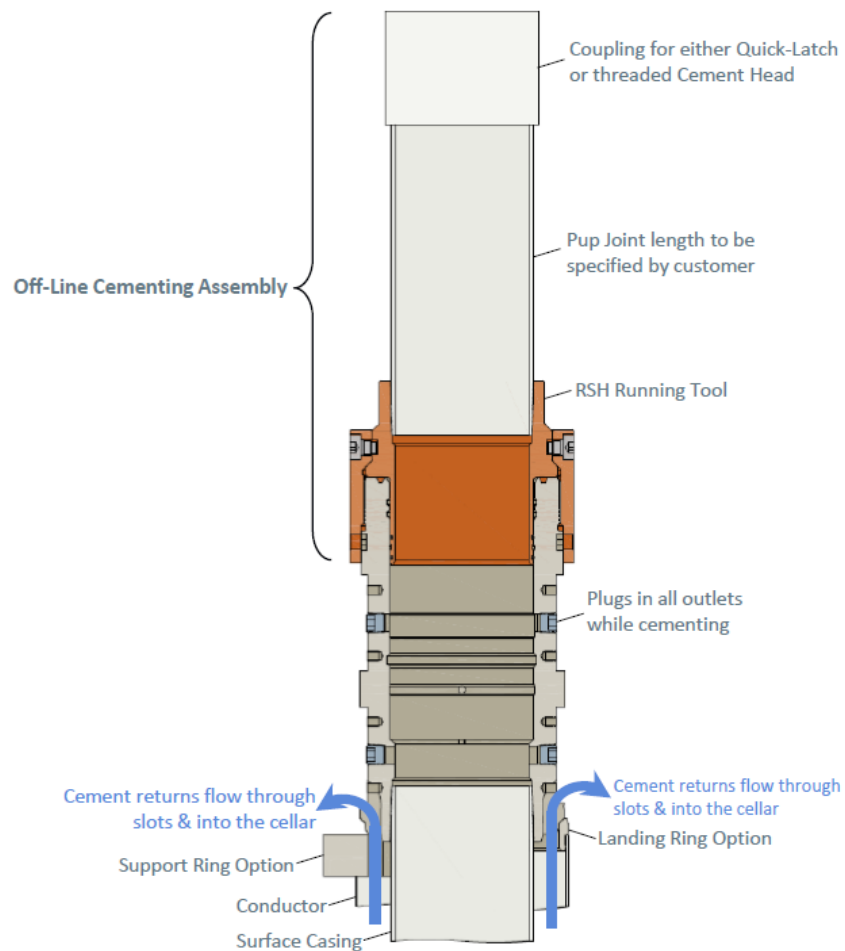


Figure 2. Vault 13 3/8" 5M offline cementing tool. Pressure rating limited by the lesser of 5M tool rating or the 13 3/8" pup joint and casing.

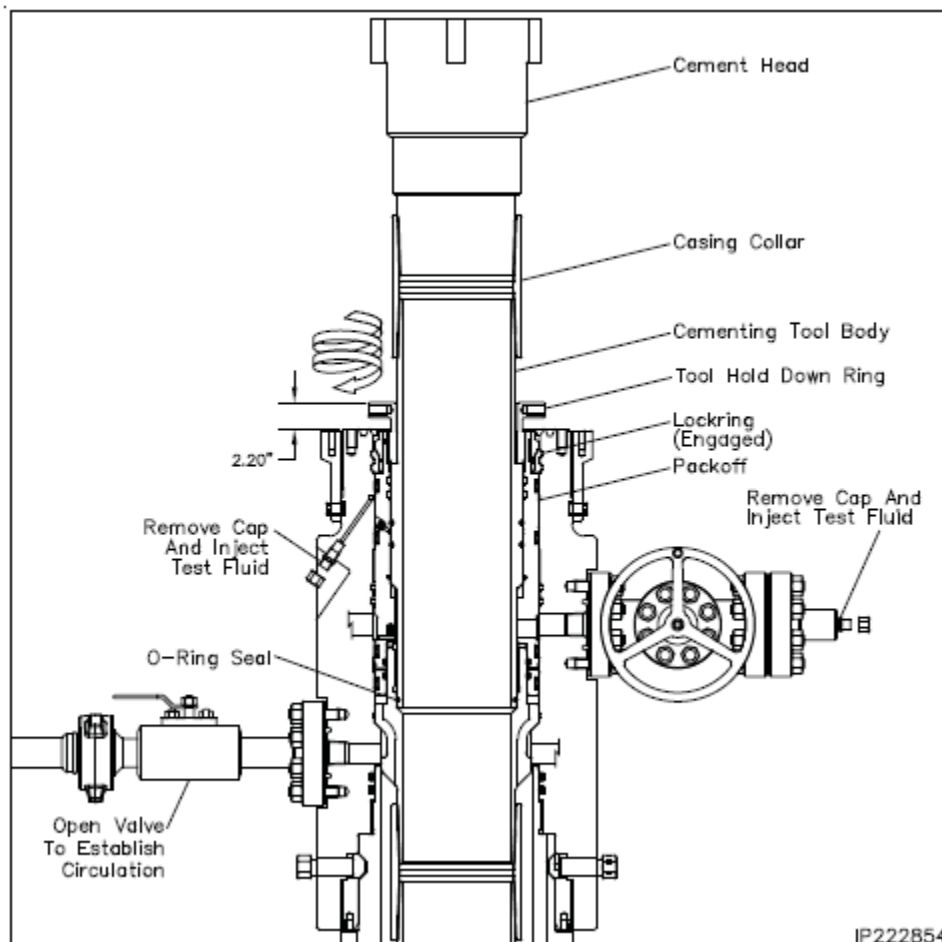


Figure 3. Cactus 9 5/8" 5M offline cementing tool. Pressure rating limited by the lesser of 5M tool rating or the 9 5/8" pup joint and casing.

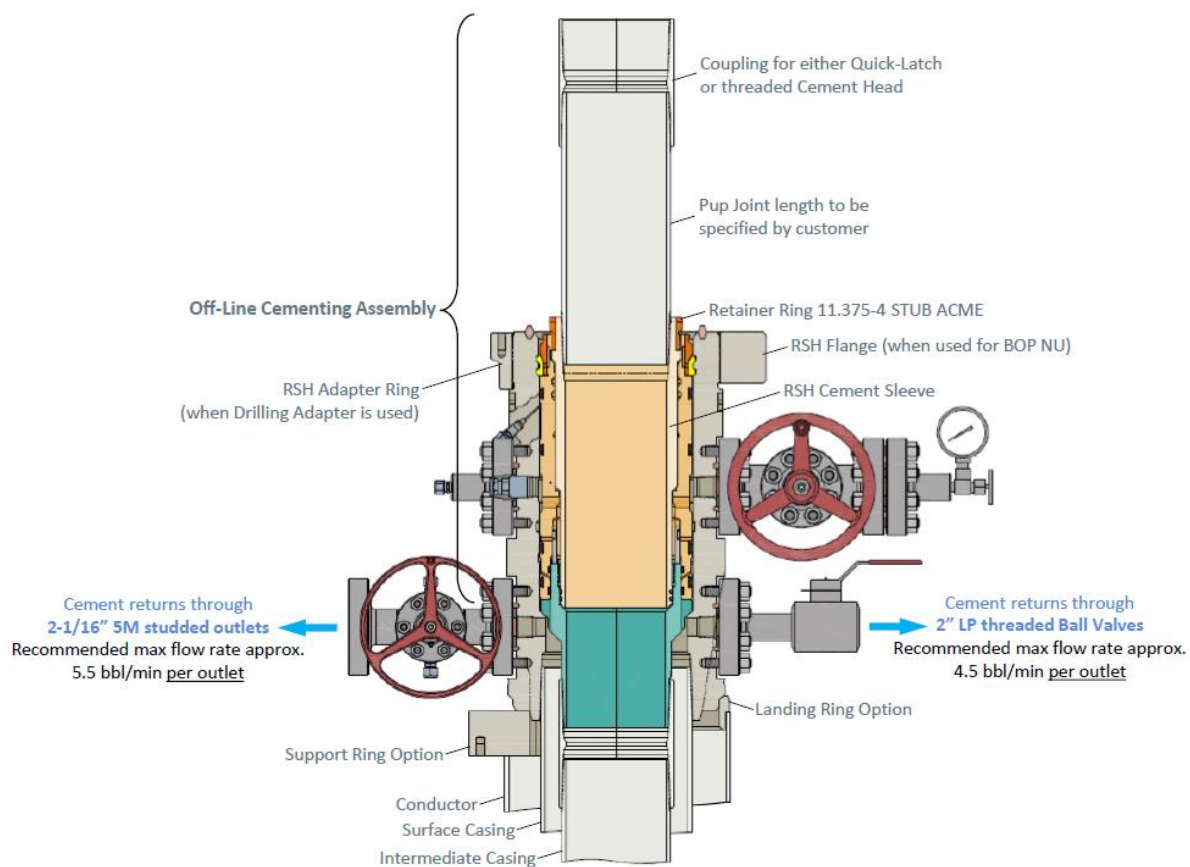


Figure 4. Vault 9 5/8" 5M offline cementing tool. Pressure rating limited by the lesser of 5M tool rating or the 9 5/8" pup joint and casing.

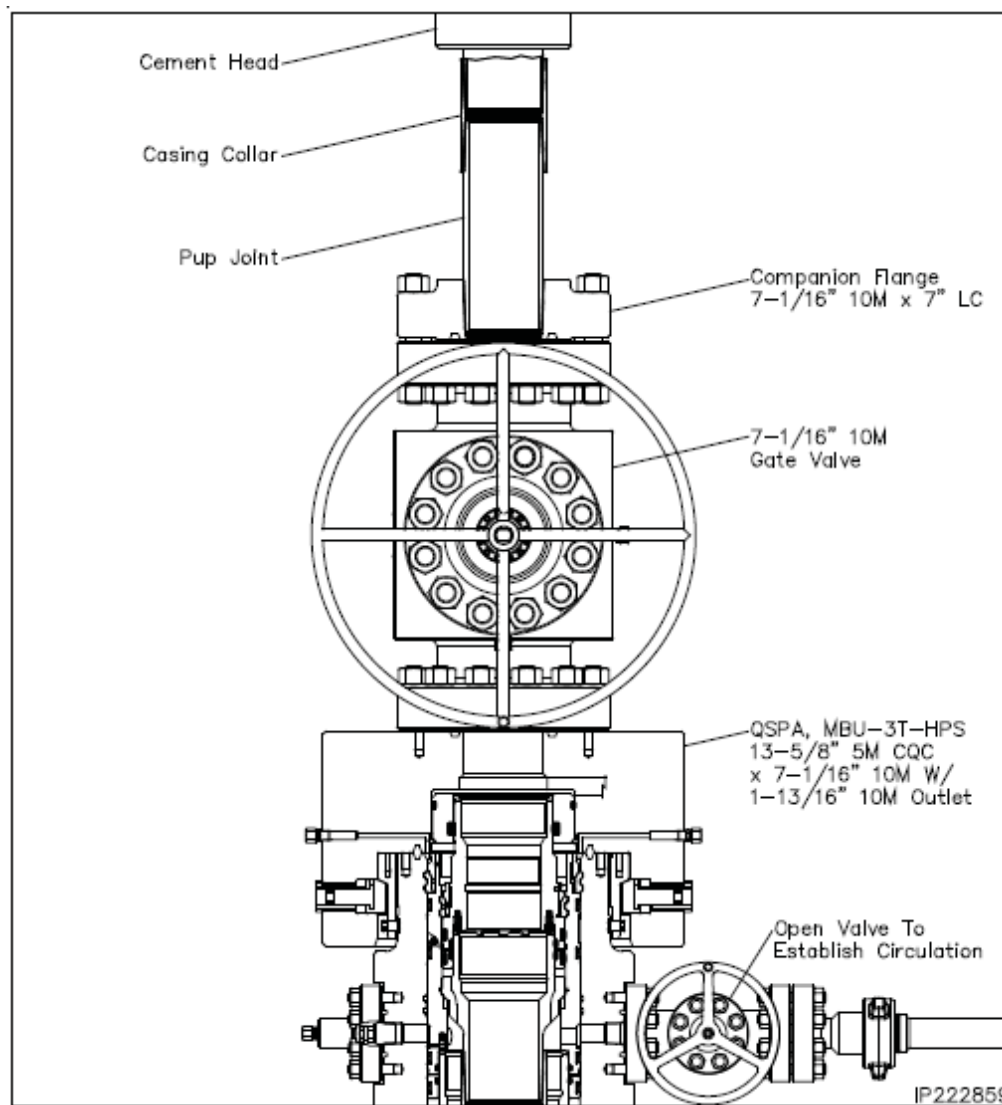


Figure 5. Cactus 7" 5M offline cementing tool. Pressure rating limited by the lesser of 5M tool rating or the 7" pup joint and casing.

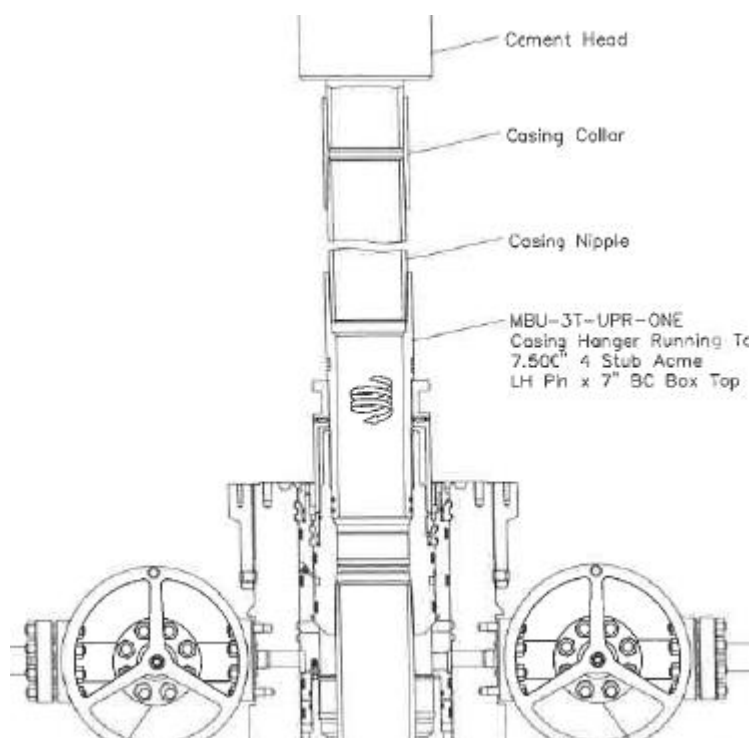


Figure 6. Cactus 7" 5M offline cementing tool. Pressure rating limited by the lesser of 5M tool rating or the 7" pup joint and casing.

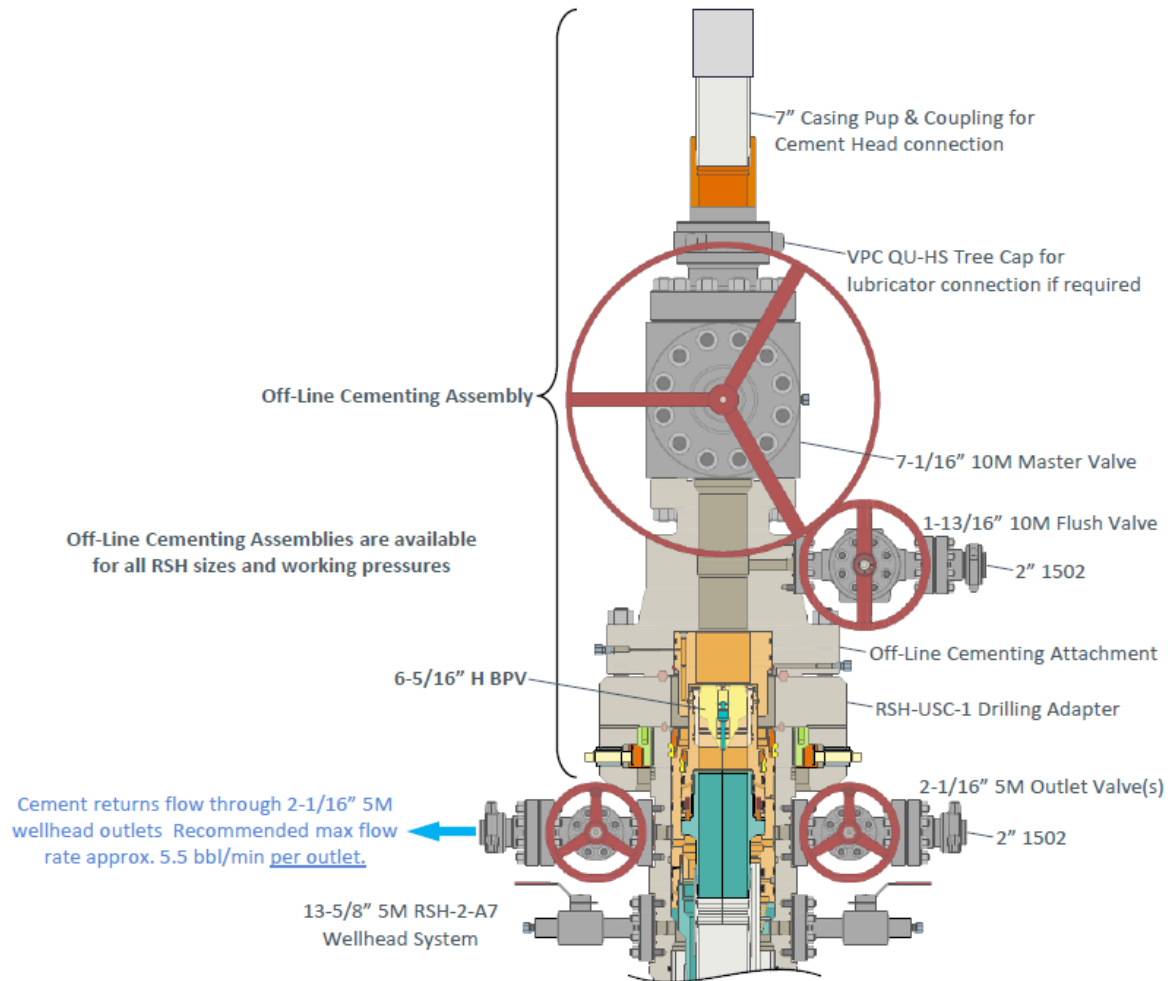


Figure 7. Vault 7" 5M offline cementing tool. Pressure rating limited by the lesser of 5M tool rating or the 7" pup joint and casing.

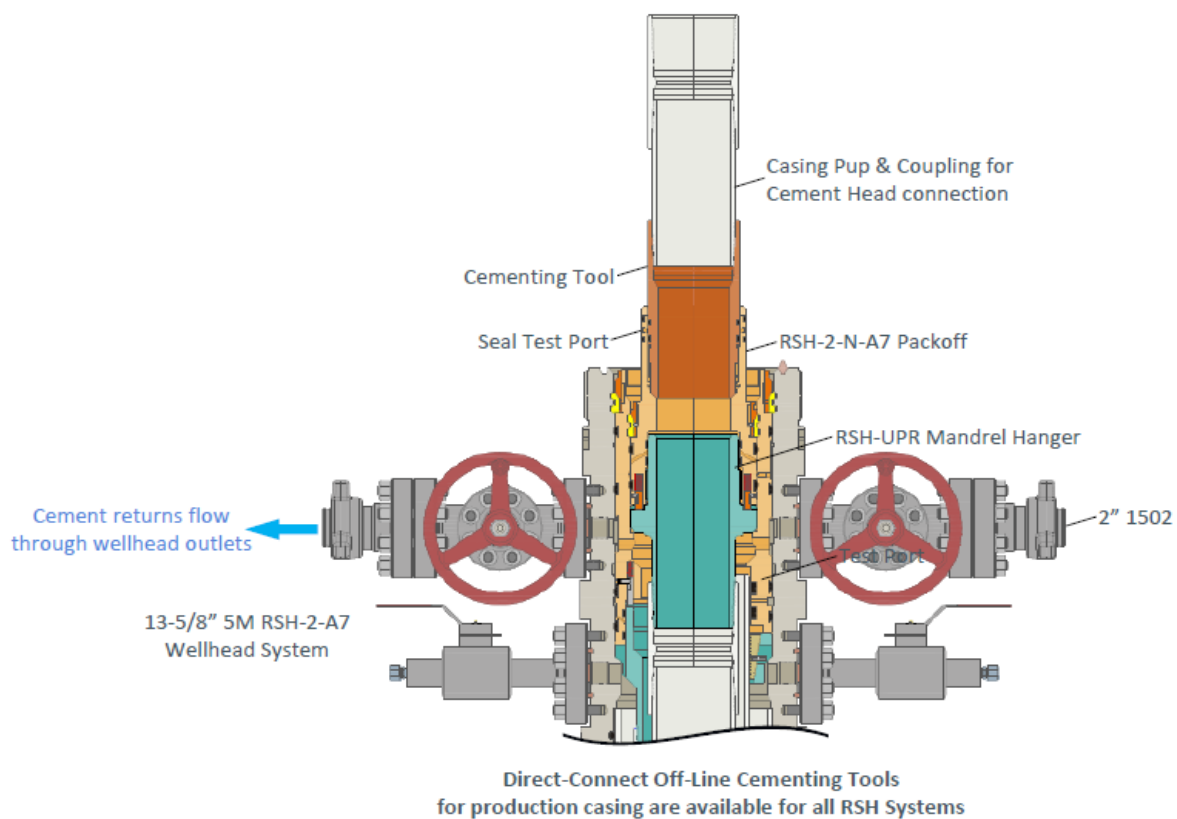


Figure 8. Vault 7" 5M offline cementing tool. Pressure rating limited by the lesser of 5M tool rating or the 7" pup joint and casing.

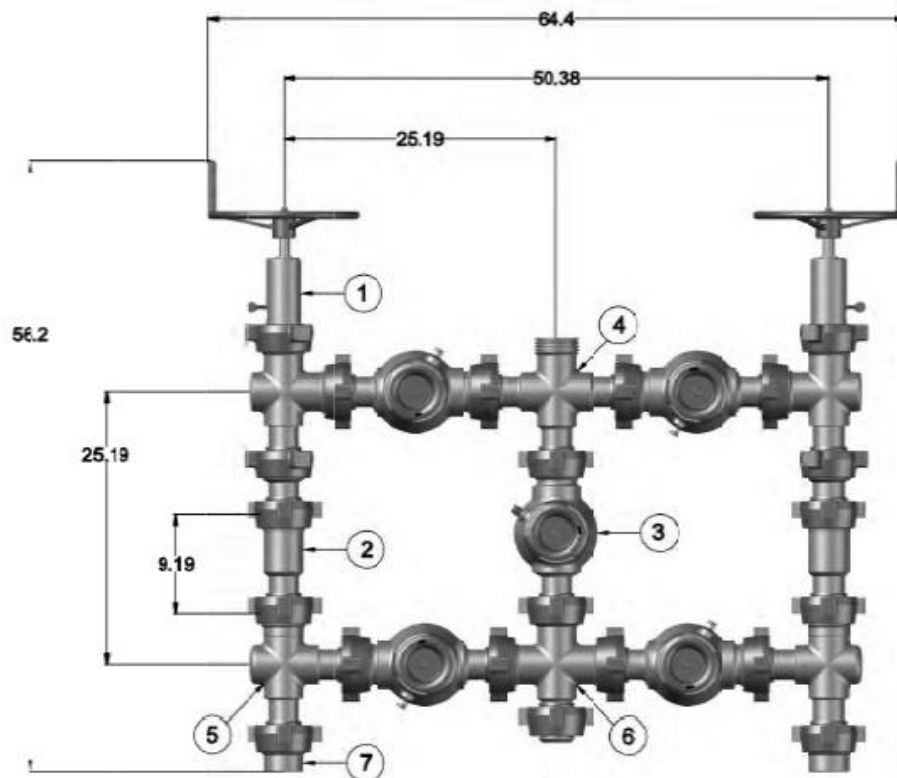


Figure 9. Five valve 15k choke manifold.

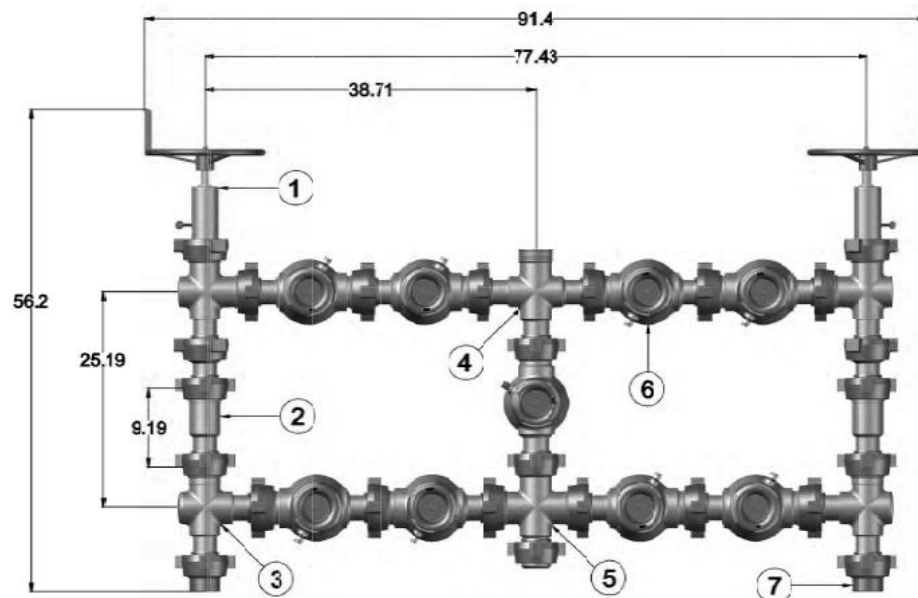


Figure 10. Nine valve 15k choke manifold.

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

General Information
Phone: (505) 629-6116

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

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

CONDITIONS

Action 421780

CONDITIONS

Operator: MEWBOURNE OIL CO P.O. Box 5270 Hobbs, NM 88241	OGRID: 14744
	Action Number: 421780
	Action Type: [C-103] NOI Change of Plans (C-103A)

CONDITIONS

Created By	Condition	Condition Date
ward.rikala	No additives containing PFAS chemicals will be added to the drilling fluids or completion fluids used during drilling, completions, or recompletions operations.	10/21/2025
ward.rikala	Any previous COA's not addressed within the updated COA's still apply.	10/21/2025