Form 3160-3
(June 2015)

FORM APPROVED
OMB No. 1004-0137
Expires: January 31, 2018

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No.

6. If Indian, Allotee or Tribe Name

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

8. Lease Name and Well No.

1a. Type of work: ☐ DRILL ☐ REENTER

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

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

2. Name of Operator

9. API Well No.
30-025-54103

3a. Address

3b. Phone No. *(include area code)*

10. Field and Pool, or Exploratory

4. Location of Well *(Report location clearly and in accordance with any State requirements.*)*
At surface
At proposed prod. zone

11. Sec., T. R. M. or Blk. and Survey or Area

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

12. County or Parish

13. State

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

16. No of acres in lease

17. Spacing Unit dedicated to this well

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

19. Proposed Depth

20. BLM/BIA Bond No. in file

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

22. Approximate date work will start*

23. Estimated duration

24. Attachments

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

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

25. Signature

Name *(Printed/Typed)*

Date

Title

Approved by *(Signature)*

Name *(Printed/Typed)*

Date

Title

Office

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

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

APPROVED WITH CONDITIONS

(Continued on page 2)

*(Instructions on page 2)

Approval Date: 11/25/2024

Additional Operator Remarks

Location of Well

0. SHL: SENW / 1650 FNL / 1405 FWL / TWSP: 22S / RANGE: 32E / SECTION: 25 / LAT: 32.3655151 / LONG: -103.6323517 (TVD: 0 feet, MD: 0 feet)

PPP: SWSW / 100 FSL / 1100 FWL / TWSP: 22S / RANGE: 32E / SECTION: 24 / LAT: 32.3703215 / LONG: -103.6333427 (TVD: 11830 feet, MD: 12272 feet)

PPP: SWNW / 2640 FNL / 1102 FWL / TWSP: 22S / RANGE: 32E / SECTION: 24 / LAT: 32.3773046 / LONG: -103.6333411 (TVD: 11868 feet, MD: 14813 feet)

PPP: SWSW / 0 FNL / 1102 FWL / TWSP: 22S / RANGE: 32E / SECTION: 13 / LAT: 32.3845609 / LONG: -103.6333394 (TVD: 11909 feet, MD: 17453 feet)

BHL: NWNW / 20 FNL / 1100 FWL / TWSP: 22S / RANGE: 32E / SECTION: 13 / LAT: 32.3990264 / LONG: -103.6333673 (TVD: 11990 feet, MD: 22717 feet)

BLM Point of Contact

Name: TENILLE C MOLINA
Title: Land Law Examiner
Phone: (575) 234-2224
Email: TCMOLINA@BLM.GOV

Approval Date: 11/25/2024

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

WELL LOCATION INFORMATION

API Number 30-025-54103	Pool Code 51683	Pool Name RED TANK; BONE SPRING	
Property Code 336558	Property Name TUNA NUT 24_13 FED COM		Well Number 311H
OGRID No. 16696	Operator Name OXY USA INC.		Ground Level Elevation 3765'
Surface Owner: ☐ State ☐ Fee ☐ Tribal ☑ Federal		Mineral Owner: ☐ State ☐ Fee ☐ Tribal ☑ Federal	

Surface Location

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
F	25H	22S	32E		1650' FNL	1405' FWL	32.36551511	-103.63235177	LEA

Bottom Hole Location

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
D	13	22S	32E		20' FNL	1100' FWL	32.39902644	-103.63336736	LEA

Dedicated Acres	Infill or Defining Well	Defining Well API	Overlapping Spacing Unit (Y/N)	Consolidation Code
640.00	INFILL	PENDING- TUNA NUT 23H	NO	
Order Numbers.			Well setbacks are under Common Ownership: ☐Yes ☐No	

Kick Off Point (KOP)

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
D	25	22S	32E		300' FNL	1100' FWL	32.6922201	-103.63334194	LEA

First Take Point (FTP)

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
M	24	22S	32E		100' FSL	1100' FWL	32.37032150	-103.63334272	LEA

Last Take Point (LTP)

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
D	13	22S	32E		20' FNL	1100' FWL	32.39880654	-103.63336712	LEA

Unitized Area or Area of Uniform Interest	Spacing Unit Type ☑ Horizontal ☐ Vertical	Ground Floor Elevation: 3765'

OPERATOR CERTIFICATIONS

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

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

Sara Guthrie 12/3/2024

Signature Date

Sara Guthrie

Printed Name

sara_guthrie@oxy.com

Email Address

SURVEYOR CERTIFICATIONS

I hereby certify that the well location shown on this ... surveys made by me or under my supervision, and th... my belief.

[18] *SURVEYOR 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.

Lloyd P. Short

Date of Survey: JULY 5, 2023

Signature and Seal of Professional Surveyor

LLOYD P. SHORT NEW MEXICO 21653 PROFESSIONAL SURVEYOR

Signature and Seal of Professional Surveyor

Certificate Number	Date of Survey
21653	July 5, 2023

Note: No allowable will be assigned to this completion until all interests have been consolidated or a non-standard unit has been approved by the division.

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 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.

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BHL (NAD83)
X:757375.94' / Y:509604.29'
LAT:32.39902644 / LON:-103.63336736

BHL (NAD27)
X:716193.54' / Y:509543.68'
LAT:32.39890336 / LON:-103.63288091

LTP (NAD83)
X:757376.54' / Y:509524.29'
LAT:32.39880654 / LON:-103.63336712

LTP (NAD27)
X:716194.14' / Y:509463.68'
LAT:32.39868346 / LON:-103.63288068

PI-1/PPP-3 (NAD83)
X:757419.00' / Y:504341.76'
LAT:32.38456092 / LON:-103.63333944

PI-1/PPP-3 (NAD27)
X:716236.47' / Y:504281.30'
LAT:32.38443779 / LON:-103.63285350

PPP-2 (NAD83)
X:757435.76' / Y:501701.92'
LAT:32.37730469 / LON:-103.63334112

PPP-2 (NAD27)
X:716253.16' / Y:501641.54'
LAT:32.37718153 / LON:-103.63285543

FTP (NAD83)
X:757451.89' / Y:499161.43'
LAT:32.37032150 / LON:-103.63334272

FTP (NAD27)
X:716269.22' / Y:499101.11'
LAT:32.37019832 / LON:-103.63285728

PPP-1 (NAD83)
X:757452.60' / Y:499061.43'
LAT:32.37004663 / LON:-103.63334253

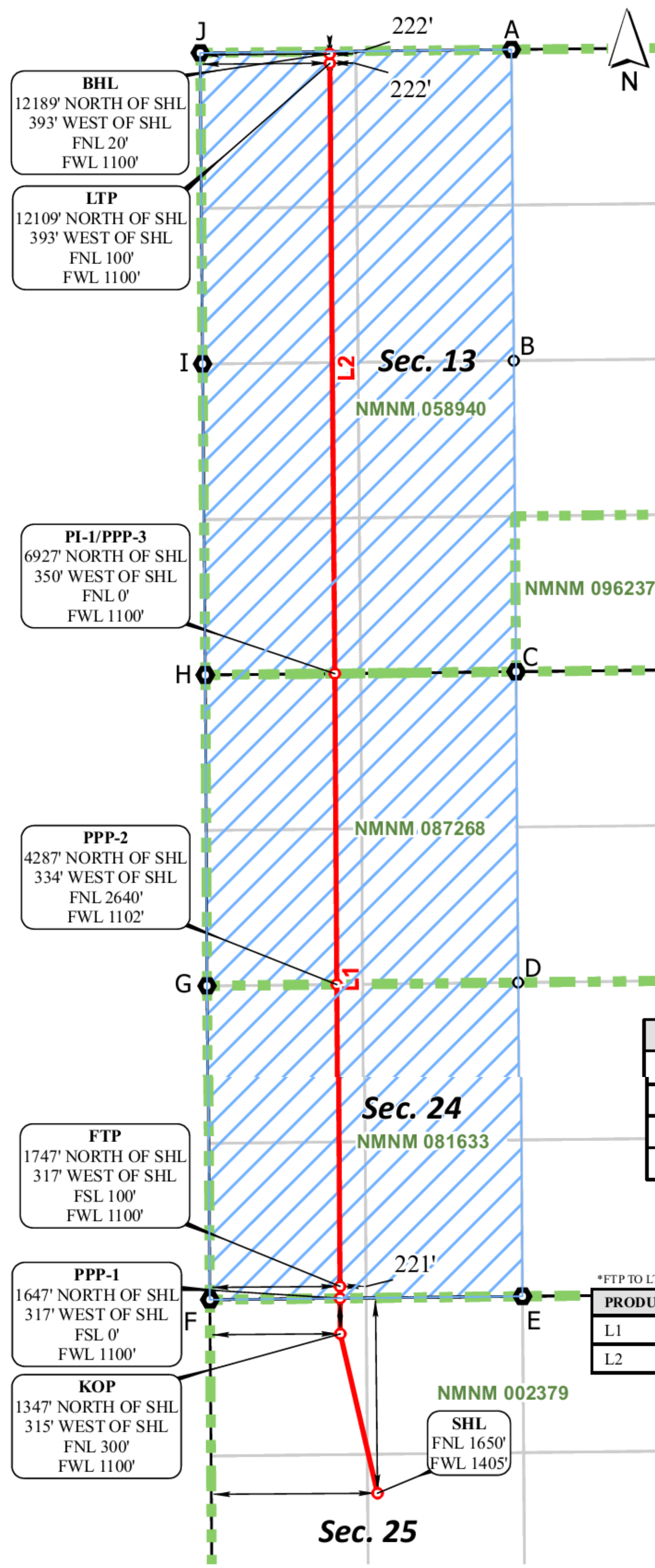
PPP-1 (NAD27)
X:716269.93' / Y:499001.12'
LAT:32.36992345 / LON:-103.63285710

KOP (NAD83)
X:757454.74' / Y:498761.44'
LAT:32.36922201 / LON:-103.63334194

KOP (NAD27)
X:716272.06' / Y:498701.13'
LAT:32.36909883 / LON:-103.63285654

SHL (NAD83)
X:757769.29' / Y:497414.86'
LAT:32.36551511 / LON:-103.63235177

SHL (NAD27)
X:716586.57' / Y:497354.60'
LAT:32.36539191 / LON:-103.63186653



CORNER COORDINATES NAD 83, SPCS NM EAST	CORNER COORDINATES NAD 27, SPCS NM EAST
A - X: 758919.12' / Y: 509640.71'	A - X: 717736.71' / Y: 509580.10'
B - X: 758938.76' / Y: 506998.56'	B - X: 717756.28' / Y: 506938.02'
C - X: 758958.38' / Y: 504358.45'	C - X: 717775.83' / Y: 504297.99'
D - X: 758976.00' / Y: 501718.62'	D - X: 717793.39' / Y: 501658.23'
E - X: 758993.62' / Y: 499078.62'	E - X: 717810.94' / Y: 499018.31'
F - X: 756352.66' / Y: 499049.16'	F - X: 715169.99' / Y: 498988.85'
G - X: 756333.80' / Y: 501689.98'	G - X: 715151.20' / Y: 501629.59'
H - X: 756319.04' / Y: 504329.83'	H - X: 715136.51' / Y: 504269.37'
I - X: 756295.56' / Y: 506970.96'	I - X: 715113.10' / Y: 506910.43'
J - X: 756275.91' / Y: 509612.69'	J - X: 715093.52' / Y: 509552.08'

17 ***OPERATOR CERTIFICATION***

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

Leslie T. Reeves 7/10/23

Signature Date

LESLIE REEVES

Printed Name

LESLIE_REEVES@OXY.COM

E-mail Address

18 ***SURVEYOR 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.

Lloyd P. Short

Date of Survey: JULY 5, 2023

Signature and Seal of Professional Surveyor

LLOYD P. SHORT
NEW MEXICO
21653
PROFESSIONAL SURVEYOR

FEDERAL LEASE ID	LENGTH
NMNM 081633	2540.55'
NMNM 087268	2639.88'
NMNM 058940	5182.71'
TOTAL	10363.14'

*FTP TO LTP LINE BEARINGS

PRODUCTION LINE	BEARING/LENGTH
L1	N00°21'49"W ~ 5180.43'
L2	N00°28'10"W ~ 5182.71'

Drill Line Events | Section Corners | Drill Line | Dimension Lines | Federal Leases | HSU | HSU Corners

SHEET 1 OF 1
JOB No. R4195_004_10599
REV 2 MWS 6/27/2023

All bearings and coordinates refer to New Mexico State Plane coordinate system, East Zone, U.S. Survey Feet.

Distances/areas relative to NAD 83 Combined Scale Factor: 0.99975697 Convergence Angle: 0.070667°

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: OXY USA INC. **OGRID:** 16696 **Date:** 06/07/23

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
SEE ATTACHED						

IV. Central Delivery Point Name: Red Tank 26 CPF and Red Tank 19 CTB (Pending NSHSU Approval) [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
SEE ATTACHED						

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: Roni Mathew
Printed Name: Roni Mathew
Title: Regulatory Advisor
E-mail Address: roni_mathew@oxy.com
Date: 6/7/2023
Phone: 713-215-7827

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

III. Well(s)

Well Name	API	WELL LOCATION (ULSTR)	Footages	ANTICIPATED OIL BBL/D	ANTICIPATED GAS MCF/D	ANTICIPATED PROD WATER BBL/D
TUNA NUT 24_13 FED COM 11H	Pending	C-25-22S-32E	300 FNL 1450 FWL	1200	4600	3000
TUNA NUT 24_13 FED COM 12H	Pending	C-25-22S-32E	300 FNL 1510 FWL	1200	4600	3000
TUNA NUT 24_13 FED COM 13H	Pending	C-25-22S-32E	300 FNL 1570 FWL	1200	4600	3000
TUNA NUT 24_13 FED COM 14H	Pending	A-25-22S-32E	1096 FNL 1245 FEL	1200	4600	3000
TUNA NUT 24_13 FED COM 15H	Pending	A-25-22S-32E	1089 FNL 1186 FEL	1200	4600	3000
TUNA NUT 24_13 FED COM 16H	Pending	A-25-22S-32E	1082 FNL 1126 FEL	1200	4600	3000
TUNA NUT 24_13 FED COM 1H	Pending	C-25-22S-32E	300 FNL 1480 FWL	700	3100	2600
TUNA NUT 24_13 FED COM 21H	Pending	N-24-22S-32E	275 FSL 1365 FWL	2000	4200	7000
TUNA NUT 24_13 FED COM 22H	Pending	N-24-22S-32E	275 FSL 1395 FWL	2000	4200	7000
TUNA NUT 24_13 FED COM 23H	Pending	N-24-22S-32E	275 FSL 1425 FWL	2000	4200	7000
TUNA NUT 24_13 FED COM 24H	Pending	B-25-22S-32E	210 FNL 1569 FEL	2000	4200	7000
TUNA NUT 24_13 FED COM 25H	Pending	B-25-22S-32E	210 FNL 1539 FEL	2000	4200	7000
TUNA NUT 24_13 FED COM 26H	Pending	B-25-22S-32E	210 FNL 1509 FEL	2000	4200	7000
TUNA NUT 24_13 FED COM 2H	Pending	C-25-22S-32E	300 FNL 1540 FWL	700	3100	2600
TUNA NUT 24_13 FED COM 311H	Pending	F-25-22S-32E	1650 FNL 1405 FWL	3100	5500	8500
TUNA NUT 24_13 FED COM 312H	Pending	A-25-22S-32E	1207 FNL 1201 FEL	3100	5500	8500
TUNA NUT 24_13 FED COM 313H	Pending	A-25-22S-32E	1200 FNL 1142 FEL	3100	5500	8500
TUNA NUT 24_13 FED COM 31H	Pending	F-25-22S-32E	1650 FNL 1375 FWL	3100	5500	8500
TUNA NUT 24_13 FED COM 32H	Pending	F-25-22S-32E	1650 FNL 1435 FWL	3100	5500	8500
TUNA NUT 24_13 FED COM 33H	Pending	F-25-22S-32E	1650 FNL 1465 FWL	3100	5500	8500
TUNA NUT 24_13 FED COM 34H	Pending	A-25-22S-32E	1203 FNL 1171 FEL	3100	5500	8500
TUNA NUT 24_13 FED COM 35H	Pending	A-25-22S-32E	1196 FNL 1112 FEL	3100	5500	8500
TUNA NUT 24_13 FED COM 3H	Pending	A-25-22S-32E	1093 FNL 1215 FEL	700	3100	2600
TUNA NUT 24_13 FED COM 4H	Pending	A-25-22S-32E	1085 FNL 1156 FEL	700	3100	2600
TUNA NUT 24_13 FED COM 71H	Pending	C-25-22S-32E	300 FNL 1360 FWL	1300	4200	1750
TUNA NUT 24_13 FED COM 72H	Pending	C-25-22S-32E	300 FNL 1390 FWL	1300	4200	1750
TUNA NUT 24_13 FED COM 73H	Pending	B-25-22S-32E	1221 FNL 1320 FEL	1300	4200	1750
TUNA NUT 24_13 FED COM 74H	Pending	A-25-22S-32E	1218 FNL 1290 FEL	1300	4200	1750

V. Anticipated Schedule

Well Name	API	Spud Date	TD Reached Date	Completion Commencement Date	Initial Flow Back Date	First Production Date
TUNA NUT 24_13 FED COM 11H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 12H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 13H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 14H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 15H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 16H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 1H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 21H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 22H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 23H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 24H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 25H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 26H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 2H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 311H	Pending	Dec-2024	Feb-2024	Feb-2024	3/10/2025	3/11/2025
TUNA NUT 24_13 FED COM 312H	Pending	Dec-2024	Feb-2024	Feb-2024	3/10/2025	3/11/2025
TUNA NUT 24_13 FED COM 313H	Pending	Dec-2024	Jan-2024	Feb-2024	3/10/2025	3/11/2025
TUNA NUT 24_13 FED COM 31H	Pending	Dec-2024	Jan-2024	Feb-2024	3/10/2025	3/11/2025
TUNA NUT 24_13 FED COM 32H	Pending	Dec-2024	Jan-2024	Feb-2024	3/10/2025	3/11/2025
TUNA NUT 24_13 FED COM 33H	Pending	Dec-2024	Jan-2024	Feb-2024	3/10/2025	3/11/2025
TUNA NUT 24_13 FED COM 34H	Pending	Dec-2024	Jan-2024	Feb-2024	3/10/2025	3/11/2025
TUNA NUT 24_13 FED COM 35H	Pending	Dec-2024	Jan-2024	Feb-2024	3/10/2025	3/11/2025
TUNA NUT 24_13 FED COM 3H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 4H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 71H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 72H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 73H	Pending	Pending	Pending	Pending	Pending	Pending
TUNA NUT 24_13 FED COM 74H	Pending	Pending	Pending	Pending	Pending	Pending

Central Delivery Point Name : Red Tank 26 CPF and Red Tank 19 CTB (Pending NSHSU Approval)

Part VI. Separation Equipment

Operator will size the flowback separator to handle 11,000 Bbls of fluid and 6-10MMscfd which is more than the expected peak rates for these wells. Each separator is rated to 1440psig, and pressure control valves and automated communication will cause the wells to shut in in the event of an upset at the facility, therefore no gas will be flared on pad during an upset. Current Oxy practices avoid use of flare or venting on pad, therefore if there is an upset or emergency condition at the facility, the wells will immediately shut down, and reassume production once the condition has cleared.

VII. Operational Practices

Gathering System and Pipeline Notification

Well(s) will be connected to a production facility and fluids will be sent to the facility after initial flowback operations are complete, where a gas transporter system is in place. The gas produced from production facility will be dedicated to MarkWest Energy West Texas Gas Company LLC ("MarkWest") and will be connected to MarkWest's high pressure gathering system located in Lea and Eddy Counties, New Mexico and Loving and Culberson Counties, TX. OXY USA INC. ("OXY") will provide (periodically) to MarkWest a production forecast for wells being sent to their system. In addition, OXY and MarkWest will have periodic conference calls to discuss changes to production forecasts arising out of changes to drilling and completion schedules. Gas from these wells will be processed at MarWest's Preakness and Tornado Processing Plants located in Culberson County, TX and Loving County, Texas respectively. The actual flow of the gas will be based on compression operating parameters and gathering system pressures.

Flowback Strategy

After the fracture treatment/completion operations, well(s) will be produced to temporary production tanks and gas will be flared or vented. During flowback, the fluids and sand content will be monitored. When the produced fluids contain minimal sand, the wells will be turned to production facilities. Gas sales should start as soon as the wells start flowing through the production facilities, unless there are operational issues on MarkWest's system at that time. Based on current information, it is OXY's belief the system can take this gas upon completion of the well(s).

Safety requirements during cleanout operations from the use of underbalanced air cleanout systems may necessitate that sand and non-pipeline quality gas be vented and/or flared rather than sold on a temporary basis.

VIII. Best Management Practices

Alternatives to Reduce Flaring

Below are alternatives considered from a conceptual standpoint to reduce the amount of gas flared.

Power Generation – On lease

Only a portion of gas is consumed operating the generator, remainder of gas will be flared

Compressed Natural Gas – On lease

Gas flared would be minimal, but might be uneconomical to operate when gas volume declines

NGL Removal – On lease

Plants are expensive, residue gas is still flared, and uneconomical to operate when gas volume declines

Oxy USA Inc. - Tuna Nut 24_13 Fed Com 311H
Drill Plan

1. Geologic Formations

TVD of Target (ft):	11990	Pilot Hole Depth (ft):	
Total Measured Depth (ft):	22718	Deepest Expected Fresh Water (ft):	1041

Delaware Basin

Formation	MD-RKB (ft)	TVD-RKB (ft)	Expected Fluids
Rustler	1041	1041	
Salado	1687	1687	Salt
Castile	3468	3468	Salt
Delaware	4905	4905	Oil/Gas/Brine
Bell Canyon	4996	4996	Oil/Gas/Brine
Cherry Canyon	5792	5789	Oil/Gas/Brine
Brushy Canyon	7120	7091	Losses
Bone Spring	8796	8730	Oil/Gas
Bone Spring 1st	9927	9837	Oil/Gas
Bone Spring 2nd	10630	10524	Oil/Gas
Bone Spring 3rd	11809	11646	Oil/Gas
Wolfcamp			Oil/Gas
Penn			Oil/Gas
Strawn			Oil/Gas

*H2S, water flows, loss of circulation, abnormal pressures, etc.

2. Casing Program

		MD		TVD					
Section	Hole Size (in)	From (ft)	To (ft)	From (ft)	To (ft)	Csg. OD (in)	Csg Wt. (ppf)	Grade	Conn.
Surface	17.5	0	1101	0	1101	13.375	54.5	J-55	BTC
Salt	12.25	0	4905	0	4905	10.75	45.5	L-80 HC	BTC-SC
Intermediate	9.875	0	11398	0	11274	7.625	26.4	L-80 HC	BTC
Production	6.75	0	22718	0	11990	5.5	20	P-110	Sprint-SF

All casing strings will be tested in accordance with 43 CFR part 3170 Subpart 3172

All Casing SF Values will meet or exceed those below			
SF Collapse	**SF Burst**	**Body SF Tension**	**Joint SF Tension**
1.00	1.100	1.4	1.4

	Y or N
Is casing new? If used, attach certification as required in 43 CFR 3160	Y
Does casing meet API specifications? 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 intermediate 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?	N
If yes, does production casing cement tie back a minimum of 50' above the Reef?	
Is well within the designated 4 string boundary.	
Is well located in SOPA but not in R-111-P?	N
If yes, are the first 2 strings cemented to surface and 3rd string cement tied back 500' into previous casing?	
Is well located in R-111-P and SOPA?	N
If yes, are the first three strings cemented to surface?	
Is 2nd string set 100' to 600' below the base of salt?	
Is well located in high Cave/Karst?	N
If yes, are there two strings cemented to surface?	
(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?	

3. Cementing Program

Section	Stage	Slurry:	Sacks	Yield (ft^3/ft)	Density (lb/gal)	Excess:	TOC	Placement	Description
Surface	1	Surface - Tail	1150	1.33	14.8	100%	-	Circulate	Class C+Accel.
Int.1	1	Intermediate - Tail	85	1.33	14.8	20%	4,405	Circulate	Class C+Accel.
Int.1	1	Intermediate - Lead	690	1.73	12.9	50%	-	Circulate	Class Pozz+Ret.
Int. 2	1	Intermediate 1S - Tail	541	1.68	13.2	5%	7,370	Circulate	Class C+Ret., Disper.
Int. 2	2	Intermediate 2S - Tail BH	1026	1.71	13.3	25%	-	Bradenhead	Class C+Accel.
Prod.	1	Production - Tail	669	1.84	13.3	25%	10,898	Circulate	Class C+Ret.

Offline Cementing Request

Oxy requests a variance to cement the 9.625” and/or 7.625” intermediate casing strings offline in accordance to the approved variance, EC Tran 461365. Please see Offline Cementing Variance attachment for further details.

Bradenhead CBL Request

Oxy requests permission to adjust the CBL requirement after bradenhead cement jobs, on 7-5/8” intermediate casings, as per the agreement reached in the OXY/BLM meeting on September 5, 2019. Please see Bradenhead CBL Variance attachment for further details.

4. Pressure Control Equipment

BOP installed and tested before drilling which hole?	Size?	Min. Required WP	Type	✓	Tested to:	TVD Depth (ft) per Section:
12.25" Hole	13-5/8”	5M	Annular	✓	70% of working pressure	4905
		5M	Blind Ram	✓	250 psi / 5000 psi	
			Pipe Ram			
			Double Ram	✓		
			Other*			
9.875" Hole	13-5/8”	5M	Annular	✓	70% of working pressure	11274
		5M	Blind Ram	✓	250 psi / 5000 psi	
			Pipe Ram			
			Double Ram	✓		
			Other*			
6.75" Hole	13-5/8”	5M	Annular	✓	100% of working pressure	11990
		10M	Blind Ram	✓	250 psi / 10000 psi	
			Pipe Ram			
			Double Ram	✓		
			Other*			

*Specify if additional ram is utilized

BOP/BOPE will be tested by an independent service company to 250 psi low and the high pressure indicated above per 43 CFR part 3170 Subpart 3172 requirements. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested.

Pipe rams will be operationally checked each 24 hour period. Blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets. Other accessories to the BOP equipment will include a Kelly cock and floor safety valve (inside BOP) and choke lines and choke manifold.

5M Annular BOP Request

Per BLM’s Memorandum No. NM-2017-008: *Decision and Rationale for a Variance Allowing the Use of a 5M Annular Preventer with a 10M BOP Stack*, Oxy requests to employ a 5M annular with a 10M BOPE stack in the pilot and lateral sections of the well and will ensure that two barriers to flow are maintained at all times. Please see Annular BOP Variance attachment for further details.

	Formation integrity test will be performed per 43 CFR part 3170 Subpart 3172.	
	On Exploratory wells or 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. Will be tested in accordance with 43 CFR part 3170 Subpart 3172.	
	A variance is requested for the use of a flexible choke line from the BOP to Choke Manifold. See attached for specs and hydrostatic test chart.	
	Y	Are anchors required by manufacturer?
	A multibowl or a unionized multibowl wellhead system will be employed. The wellhead and connection to the BOPE will meet all API 6A requirements. The BOP will be tested per 43 CFR part 3170 Subpart 3172 after installation on the surface casing which will cover testing requirements for a maximum of 30 days. If any seal subject to test pressure is broken the system must be tested. We will test the flange connection of the wellhead with a test port that is directly in the flange. We are proposing that we will run the wellhead through the rotary prior to cementing surface casing as discussed with the BLM on October 8, 2015. See attached schematics.	

BOP Break Testing Request

Oxy requests permission to adjust the BOP break testing requirements as per the agreement reached in the OXY/BLM meeting on September 5, 2019. Please see BOP Break Testing Variance attachment for further details.

Oxy will use Cameron ADAPT wellhead system that uses an OEC top flange connection. This connection has been fully vetted and verified by API to Spec 6A and carries an API monogram.

5. Mud Program

Section	Depth		Depth - TVD		Type	Weight (ppg)	Viscosity	Water Loss
	From (ft)	To (ft)	From (ft)	To (ft)				
Surface	0	1101	0	1101	Water-Based Mud	8.6 - 8.8	40-60	N/C
Intermediate 1	1101	4905	1101	4905	Saturated Brine-Based or Oil-Based Mud	8.0 - 10.0	35-45	N/C
Intermediate 2	4905	11398	4905	11274	Water-Based or Oil-Based Mud	8.0 - 10.0	38-50	N/C
Production	11398	22718	11274	11990	Water-Based or Oil-Based Mud	9.5 - 12.5	38-50	N/C

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept on location at all times. The following is a general list of products: Barite, Bentonite, Gypsum, Lime, Soda Ash, Caustic Soda, Nut Plug, Cedar Fiber, Cotton Seed Hulls, Drilling Paper, Salt Water Clay, CACL2. Oxy will use a closed mud system.

What will be used to monitor the loss or gain of fluid?	PVT/MD Totco/Visual Monitoring

6. Logging and Testing Procedures

Logging, Coring and Testing.	
Yes	Will run GR from TD to surface (horizontal well – vertical portion of hole).
	Stated logs run will be in the Completion Report and submitted to the BLM.
No	Logs are planned based on well control or offset log information.
No	Drill stem test? If yes, explain
No	Coring? If yes, explain

Additional logs planned		Interval
No	Resistivity	
No	Density	
Yes	CBL	Production string
Yes	Mud log	Bone Spring – TD
No	PEX	

7. Drilling Conditions

Condition	Specify what type and where?
BH Pressure at deepest TVD	7794 psi
Abnormal Temperature	No
BH Temperature at deepest TVD	176°F

Pump high viscosity sweeps as needed for hole cleaning. The mud system will be monitored visually/manually as well as with an electronic PVT. The necessary mud products for additional weight and fluid loss control will be on location at all times. Appropriately weighted mud will be used to isolate potential gas, oil, and water zones until such time as casing can be cemented into place for zonal

Hydrogen Sulfide (H2S) monitors will be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the operator will comply with the provisions of 43 CFR part 3170 Subpart 3172. If Hydrogen Sulfide is encountered, measured values and formations will be provided to the BLM.	
N	H2S is present
Y	H2S Plan attached

8. Other facets of operation

	Yes/No
Will the well be drilled with a walking/skidding operation? If yes, describe. We plan to drill the 4 well pad in batch by section: all surface sections, intermediate sections and production sections. The wellhead will be secured with a night cap whenever the rig is not over the well.	Yes
Will more than one drilling rig be used for drilling operations? If yes, describe. Oxy requests the option to contract a Surface Rig to drill, set surface casing, and cement for this well. If the timing between rigs is such that Oxy would not be able to preset surface, the Primary Rig will MIRU and drill the well in its entirety per the APD. Please see the attached document for information on the spudder rig.	Yes

Total Estimated Cuttings Volume: 1999 bbls

Oxy USA Inc. - Tuna Nut 24_13 Fed Com 311H
Drill Plan

1. Geologic Formations

TVD of Target (ft):	11990	Pilot Hole Depth (ft):	
Total Measured Depth (ft):	22718	Deepest Expected Fresh Water (ft):	1041

Delaware Basin

Formation	MD-RKB (ft)	TVD-RKB (ft)	Expected Fluids
Rustler	1041	1041	
Salado	1687	1687	Salt
Castile	3468	3468	Salt
Delaware	4905	4905	Oil/Gas/Brine
Bell Canyon	4996	4996	Oil/Gas/Brine
Cherry Canyon	5792	5789	Oil/Gas/Brine
Brushy Canyon	7120	7091	Losses
Bone Spring	8796	8730	Oil/Gas
Bone Spring 1st	9927	9837	Oil/Gas
Bone Spring 2nd	10630	10524	Oil/Gas
Bone Spring 3rd	11809	11646	Oil/Gas
Wolfcamp			Oil/Gas
Penn			Oil/Gas
Strawn			Oil/Gas

*H2S, water flows, loss of circulation, abnormal pressures, etc.

2. Casing Program

		MD		TVD					
Section	Hole Size (in)	From (ft)	To (ft)	From (ft)	To (ft)	Csg. OD (in)	Csg Wt. (ppf)	Grade	Conn.
Surface	17.5	0	1101	0	1101	13.375	54.5	J-55	BTC
Intermediate	9.875	0	11398	0	11274	7.625	26.4	L-80 HC	BTC
Production	6.75	0	22718	0	11990	5.5	20	P-110	Sprint-SF

All casing strings will be tested in accordance with 43 CFR part 3170 Subpart 3172

*Oxy requests the option to run the 10.75” Intermediate I as a contingency string to be run only if severe hole conditions dictate an additional casing string necessary. This would make the planned 7.625" / 7.827" Casing the Intermediate II.
**If 4S Contingency is not required, Oxy requests permission to transition from 12.25" to 9.875" Intermediate I at 1st trip point below Brushy top (estimated top in formation table above). Cement volumes will be updated on C103 submission.

All Casing SF Values will meet or exceed those below			
SF Collapse	**SF Burst**	**Body SF Tension**	**Joint SF Tension**
1.00	1.100	1.4	1.4

	Y or N
Is casing new? If used, attach certification as required in 43 CFR 3160	Y
Does casing meet API specifications? 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 intermediate 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?	N
If yes, does production casing cement tie back a minimum of 50' above the Reef?	
Is well within the designated 4 string boundary.	
Is well located in SOPA but not in R-111-P?	N
If yes, are the first 2 strings cemented to surface and 3rd string cement tied back 500' into previous casing?	
Is well located in R-111-P and SOPA?	N
If yes, are the first three strings cemented to surface?	
Is 2nd string set 100' to 600' below the base of salt?	
Is well located in high Cave/Karst?	N
If yes, are there two strings cemented to surface?	
(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?	

3. Cementing Program

Section	Stage	Slurry:	Sacks	Yield (ft^3/ft)	Density (lb/gal)	Excess:	TOC	Placement	Description
Surface	1	Surface - Tail	1150	1.33	14.8	100%	-	Circulate	Class C+Accel.
Int.	1	Intermediate 1S - Tail	541	1.68	13.2	5%	7,370	Circulate	Class C+Ret., Disper.
Int.	2	Intermediate 2S - Tail BH	1339	1.71	13.3	25%	-	Bradenhead	Class C+Accel.
Prod.	1	Production - Tail	669	1.84	13.3	25%	10,898	Circulate	Class C+Ret.

Offline Cementing Request

Oxy requests a variance to cement the 9.625” and/or 7.625” intermediate casing strings offline in accordance to the approved variance, EC Tran 461365. Please see Offline Cementing Variance attachment for further details.

Bradenhead CBL Request

Oxy requests permission to adjust the CBL requirement after bradenhead cement jobs, on 7-5/8” intermediate casings, as per the agreement reached in the OXY/BLM meeting on September 5, 2019. Please see Bradenhead CBL Variance attachment for further details.

4. Pressure Control Equipment

BOP installed and tested before drilling which hole?	Size?	Min. Required WP	Type		✓	Tested to:	Deepest TVD Depth (ft) per Section:
9.875" Hole	13-5/8"	5M	Annular		✓	70% of working pressure	11274
		5M	Blind Ram		✓	250 psi / 5000 psi	
			Pipe Ram				
			Double Ram		✓		
			Other*				
6.75" Hole	13-5/8"	5M	Annular		✓	100% of working pressure	11990
		10M	Blind Ram		✓	250 psi / 10000 psi	
			Pipe Ram				
			Double Ram		✓		
			Other*				

*Specify if additional ram is utilized

BOP/BOPE will be tested by an independent service company to 250 psi low and the high pressure indicated above per 43 CFR part 3170 Subpart 3172 requirements. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested.

Pipe rams will be operationally checked each 24 hour period. Blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets. Other accessories to the BOP equipment will include a Kelly cock and floor safety valve (inside BOP) and choke lines and choke manifold.

5M Annular BOP Request

Per BLM's Memorandum No. NM-2017-008: *Decision and Rationale for a Variance Allowing the Use of a 5M Annular Preventer with a 10M BOP Stack*, Oxy requests to employ a 5M annular with a 10M BOPE stack in the pilot and lateral sections of the well and will ensure that two barriers to flow are maintained at all times. Please see Annular BOP Variance attachment for further details.

	Formation integrity test will be performed per 43 CFR part 3170 Subpart 3172.	
	On Exploratory wells or 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. Will be tested in accordance with 43 CFR part 3170 Subpart 3172.	
	A variance is requested for the use of a flexible choke line from the BOP to Choke Manifold. See attached for specs and hydrostatic test chart.	
	Y	Are anchors required by manufacturer?
	A multibowl or a unionized multibowl wellhead system will be employed. The wellhead and connection to the BOPE will meet all API 6A requirements. The BOP will be tested per 43 CFR part 3170 Subpart 3172 after installation on the surface casing which will cover testing requirements for a maximum of 30 days. If any seal subject to test pressure is broken the system must be tested. We will test the flange connection of the wellhead with a test port that is directly in the flange. We are proposing that we will run the wellhead through the rotary prior to cementing surface casing as discussed with the BLM on October 8, 2015. See attached schematics.	

BOP Break Testing Request

Oxy requests permission to adjust the BOP break testing requirements as per the agreement reached in the OXY/BLM meeting on September 5, 2019. Please see BOP Break Testing Variance attachment for further details.

Oxy will use Cameron ADAPT wellhead system that uses an OEC top flange connection. This connection has been fully vetted and verified by API to Spec 6A and carries an API monogram.

5. Mud Program

Section	Depth - MD		Depth - TVD		Type	Weight (ppg)	Viscosity	Water Loss
	From (ft)	To (ft)	From (ft)	To (ft)				
Surface	0	1101	0	1101	Water-Based Mud	8.6 - 8.8	40-60	N/C
Intermediate	1101	11398	1101	11274	Saturated Brine-Based or Oil-Based Mud	8.0 - 10.0	35-45	N/C
Production	11398	22718	11274	11990	Water-Based or Oil-Based Mud	9.5 - 12.5	38-50	N/C

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept on location at all times. The following is a general list of products: Barite, Bentonite, Gypsum, Lime, Soda Ash, Caustic Soda, Nut Plug, Cedar Fiber, Cotton Seed Hulls, Drilling Paper, Salt Water Clay, CACL2. Oxy will use a closed mud system.

What will be used to monitor the loss or gain of fluid?	PVT/MD Totco/Visual Monitoring

6. Logging and Testing Procedures

Logging, Coring and Testing.	
Yes	Will run GR from TD to surface (horizontal well – vertical portion of hole).
	Stated logs run will be in the Completion Report and submitted to the BLM.
No	Logs are planned based on well control or offset log information.
No	Drill stem test? If yes, explain
No	Coring? If yes, explain

Additional logs planned		Interval
No	Resistivity	
No	Density	
Yes	CBL	Production string
Yes	Mud log	Bone Spring – TD
No	PEX	

7. Drilling Conditions

Condition	Specify what type and where?
BH Pressure at deepest TVD	7794 psi
Abnormal Temperature	No
BH Temperature at deepest TVD	176°F

Pump high viscosity sweeps as needed for hole cleaning. The mud system will be monitored visually/manually as well as with an electronic PVT. The necessary mud products for additional weight and fluid loss control will be on location at all times. Appropriately weighted mud will be used to isolate potential gas, oil, and water zones until such time as casing can be cemented into place for zonal

Hydrogen Sulfide (H2S) monitors will be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the operator will comply with the provisions of 43 CFR part 3170 Subpart 3172. If Hydrogen Sulfide is encountered, measured values and formations will be provided to the BLM.	
N	H2S is present
Y	H2S Plan attached

8. Other facets of operation

	Yes/No
Will the well be drilled with a walking/skidding operation? If yes, describe. We plan to drill the 4 well pad in batch by section: all surface sections, intermediate sections and production sections. The wellhead will be secured with a night cap whenever the rig is not over the well.	Yes
Will more than one drilling rig be used for drilling operations? If yes, describe. Oxy requests the option to contract a Surface Rig to drill, set surface casing, and cement for this well. If the timing between rigs is such that Oxy would not be able to preset surface, the Primary Rig will MIRU and drill the well in its entirety per the APD. Please see the attached document for information on the spudder rig.	Yes

Total Estimated Cuttings Volume: 1805 bbls

Oxy USA Inc. - Blanket Design Pad Document

OXY - Blanket Design A

Pad Name: REDTNK_T22SR32E_2505

SHL: 1650' FNL 1375' FEL, Sec 25,T22S-R32E

Oxy requests for the bellow wells to be approved for the two designs listed in the Blanket Design document (**Blanket Design A – OXY – 3S Slim v7**.) The MDs and TVDs for all intervals are within the boundary conditions. The max inclination and DLS are also within the boundary conditions (directional plans attached separately for review.)

1. Blanket Design - Wells

Well Name	APD #	Surface		Intermediate		Production	
		MD	TVD	MD	TVD	MD	TVD
TUNA NUT 24_13 FED COM 311H	n/a - New Permit	1101	1101	11398	11274	22718	11990
TUNA NUT 24_13 FED COM 31H	n/a - New Permit	1104	1104	11781	11611	23107	12220
TUNA NUT 24_13 FED COM 32H	n/a - New Permit	1098	1098	11658	11535	22978	12190
TUNA NUT 24_13 FED COM 33H	n/a - New Permit	1097	1097	11866	11665	23189	12379

2. Review Criteria Table

	Y or N
Is casing new? If used, attach certification as required in 43 CFR 3160	Y
Does casing meet API specifications? 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 intermediate 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?	N
If yes, does production casing cement tie back a minimum of 50' above the Reef?	
Is well within the designated 4 string boundary.	
Is well located in SOPA but not in R-111-P?	N
If yes, are the first 2 strings cemented to surface and 3rd string cement tied back 500' into previous casing?	
Is well located in R-111-P and SOPA?	N
If yes, are the first three strings cemented to surface?	
Is 2nd string set 100' to 600' below the base of salt?	
Is well located in high Cave/Karst?	N
If yes, are there two strings cemented to surface?	
(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?	

3. Geologic Formations

Formation	MD-RKB (ft)	TVD-RKB (ft)	Expected Fluids
Rustler	1041	1041	
Salado	1687	1687	Salt
Castile	3468	3468	Salt
Delaware	4905	4905	Oil/Gas/Brine
Bell Canyon	4996	4996	Oil/Gas/Brine
Cherry Canyon	5792	5789	Oil/Gas/Brine
Brushy Canyon	7120	7091	Losses
Bone Spring	8796	8730	Oil/Gas
Bone Spring 1st	9927	9837	Oil/Gas
Bone Spring 2nd	10630	10524	Oil/Gas
Bone Spring 3rd	11809	11646	Oil/Gas
Wolfcamp			Oil/Gas
Penn			Oil/Gas
Strawn			Oil/Gas

OXY USA Inc
APD ATTACHMENT: SPUDDER RIG DATA

OPERATOR NAME / NUMBER: OXY USA Inc

1. SUMMARY OF REQUEST:

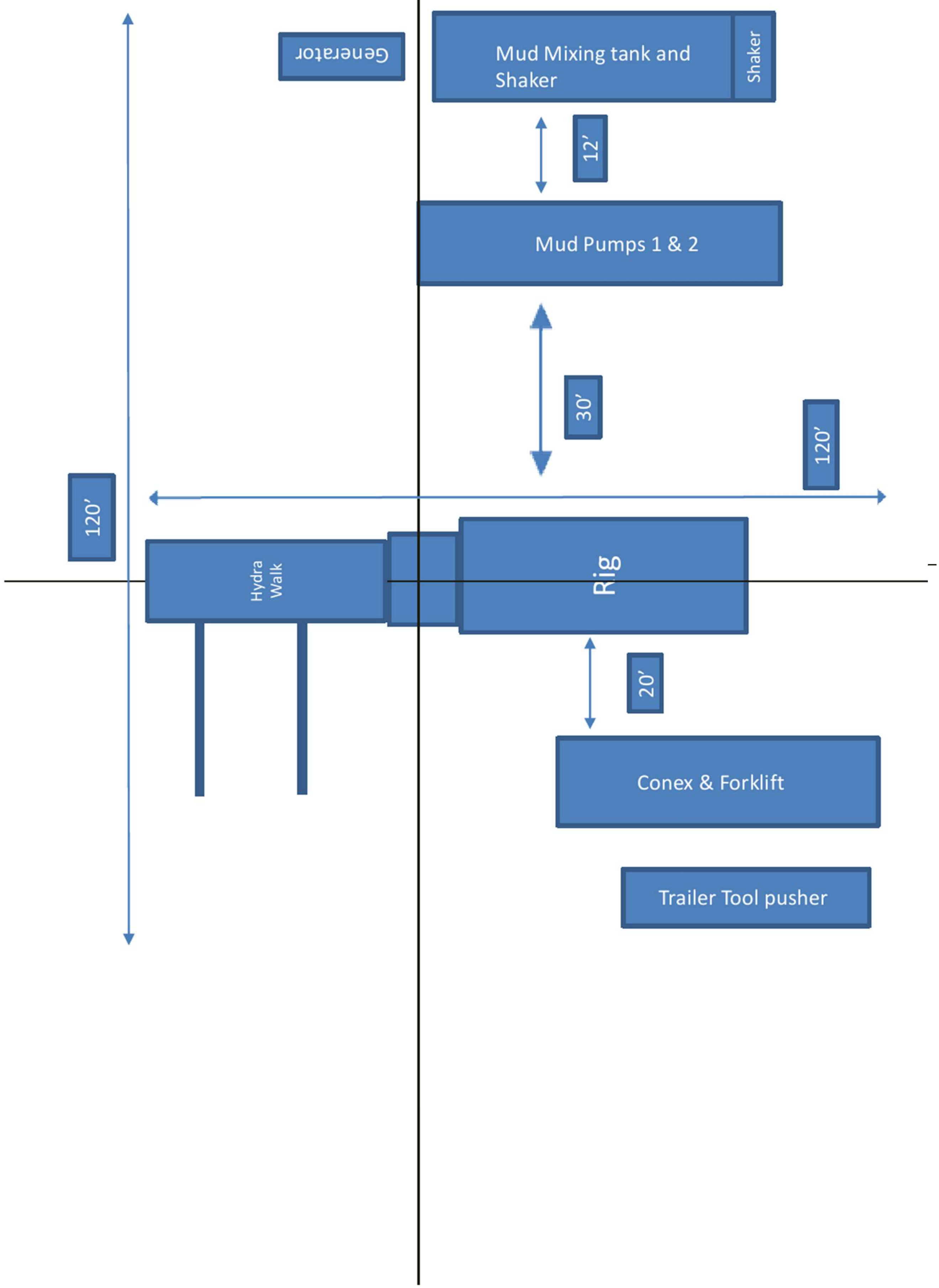
Oxy USA respectfully requests approval for the following operations for the surface hole in the drill plan:

1. Utilize a spudder rig to pre-set surface casing for time and cost savings.

2. Description of Operations

1. Spudder rig will move in to drill the surface hole and pre-set surface casing on the well.
    a. After drilling the surface hole section, the spudder rig will run casing and cement following all of the applicable rules and regulations (43 CFR part 3170 Subpart 3172, all COAs and NMOCD regulations).
    b. The spudder rig will utilize fresh water-based mud to drill the surface hole to TD. Solids control will be handled entirely on a closed loop basis. No earth pits will be used.
2. The wellhead will be installed and tested as soon as the surface casing is cut off and the WOC time has been reached.
3. A blind flange at the same pressure rating as the wellhead will be installed to seal the wellbore. Pressure will be monitored with needle valves installed on two wingvalves.
    a. A means for intervention will be maintained while the drilling rig is not over the well.
4. Spudder rig operations are expected to take 2-3 days per well on the pad.
5. The BLM will be contacted and notified 24 hours prior to commencing spudder rig operations.
6. Drilling operations will begin with a larger rig and a BOP stack equal to or greater than the pressure rating that was permitted will be nippled up and tested on the wellhead before drilling operations resume on each well.
    a. The larger rig will move back onto the location within 90 days from the point at which the wells are secured and the spudder rig is moved off location.
    b. The BLM will be contacted / notified 24 hours before the larger rig moves back on the pre-set locations.
7. Oxy will have supervision on the rig to ensure compliance with all BLM and NMOCD regulations and to oversee operations.
8. Once the rig is removed, Oxy will secure the wellhead area by placing a guard rail around the cellar area.

Spudder Rig Layout



Oxy Bulk Design - Casing Design "A"

1. Casing Program

The designs and associated details listed in this document are the "worst case scenario" boundaries for design safety factors.

Location and lithology have NOT been accounted for in these designs; however, the designs are NOT valid for wells within KPLA Boundaries or Capitan Reef areas. The specific well details will be based on the APD/Sundry package and the information listed in the COA.

The mud program listed below will remain the same between each design variation.

Hole will be full during casing run for well control and tensile SF.

Casing will be kept at least half full during run for these designs to meet BLM collapse SF requirement.

Design Variation "A1"

		MD		TVD					
Section	Hole Size (in)	From (ft)	To (ft)	From (ft)	To (ft)	Csg. OD (in)	Csg Wt. (ppf)	Grade	Conn.
Surface	14.75	0	1200	0	1200	10.75	45.5	J-55	BTC
Intermediate	9.875	0	13111*	0	12775*	7.625	26.4	L-80 HC	BTC Axis HT
Production	6.75	0	23361	0	12775	5.5	20	P-110	Wedge 461 Sprint SF DWC/C-HT-IS

*Curve could be in intermediate or production section

Design Variation "A2" - Option to Pivot to Design "B" for Contingency 4S

		MD		TVD					
Section	Hole Size (in)	From (ft)	To (ft)	From (ft)	To (ft)	Csg. OD (in)	Csg Wt. (ppf)	Grade	Conn.
Surface	17.5	0	1200	0	1200	13.375	54.5	J-55	BTC
Intermediate	12.25†	0	13111*	0	12775*	7.625	26.4	L-80 HC	BTC Axis HT
Production	6.75	0	23361	0	12775	5.5	20	P-110	Wedge 461 Sprint SF DWC/C-HT-IS

*Curve could be in intermediate or production section

†If 4S Contingency is not required, Oxy requests permission to transition from 12.25" to 9.875" Intermediate at some point during the hole section. Cement volumes will be updated on C103 submission.

All casing strings will be tested in accordance with 43 CFR part 3170 Subpart 3172

All Casing SF Values will meet or exceed those below			
SF Collapse	**SF Burst**	**Body SF Tension**	**Joint SF Tension**
1.00	1.100	1.4	1.4

Oxy Bulk Design - Casing Design "A"

§Annular Clearance Variance Request

As per the agreement reached in the Oxy/BLM face-to-face meeting on Feb 22, 2018, Oxy requests permission to allow deviation from the 0.422" annular clearance requirement. Please see Annular Clearance Variance attachment for further details.

§Annular Clearance Variance Request may not apply to all connections used or presented.

2. Trajectory / Boundary Conditions

	MD		TVD			
Section	**Deepest KOP (ft)**	**End Build (ft)**	**Deepest KOP (ft)**	**End Build (ft)**	**Max. Angle**	**Max. Planned DLS**
Surface	0	1200	0	1200	5°	1°/100 ft
Intermediate	5000 (inside Cherry Canyon)	6500	4980	6390	20°	2°/100 ft
	12211	13111	12202	12775	92° ‡	12°/100 ft ‡
Production	12211 (~100' MD past ICP)	13111	12202	12775	92° ‡	12°/100 ft ‡

‡ Applies only when intermediate casing depth is deepened to landing point to match TVD of production in some areas where required to accommodate higher MWs in depleted areas.

Oxy has reviewed casing burst, collapse, and axial loadcases in Landmark StressCheck with the boundary conditions in the table above which satisfies Oxy and BLM minimum design criteria. Triaxial plots for each casing string is shown in Section 7 and intermediate load case inputs are shown in Section 8.

Oxy Bulk Design - Casing Design "A"

3. Cementing Program

NOTE: Blanket design is for technical review only. The cement volumes will be adjusted to ensure cement tops meet BLM requirements.

Design Variation "A1"

Section	Stage	Slurry:	Sacks	Yield (ft^3/ft)	Density (lb/gal)	Excess:	TOC	Placement	Description
Surface	1	Surface - Tail	819	1.33	14.8	100%	-	Circulate	Class C+Accel.
Int.	1	Intermediate 1S - Tail	658	1.68	13.2	5%	7,206	Circulate	Class C+Ret., Disper.
Int.	2	Intermediate 2S - Tail BH	1111	1.71	13.3	25%	-	Bradenhead	Class C+Accel.
Prod.	1	Production - Tail	665	1.84	13.3	25%	11,611	Circulate	Class C+Ret.
Prod.	2*	Production - Tail BH*	TBD	1.84	13.3	50%	500' inside prev csg	Circulate	Class C+Ret.

**Only applies in scenario where planned single stage job TOC is not 500' above previous shoe as designed/programmed requiring bradenhead 2nd stage to meet requirements*

Design Variation "A2"

Section	Stage	Slurry:	Sacks	Yield (ft^3/ft)	Density (lb/gal)	Excess:	TOC	Placement	Description
Surface	1	Surface - Tail	1023	1.33	14.8	100%	-	Circulate	Class C+Accel.
Int.	1	Intermediate 1S - Tail	658	1.68	13.2	5%	7,206	Circulate	Class C+Ret., Disper.
Int.	2	Intermediate 2S - Tail BH	1293	1.71	13.3	25%	-	Bradenhead	Class C+Accel.
Prod.	1	Production - Tail	665	1.84	13.3	25%	11,611	Circulate	Class C+Ret.
Prod.	2*	Production - Tail BH*	TBD	1.84	13.3	50%	500' inside prev csg	Circulate	Class C+Ret.

**Only applies in scenario where planned single stage job TOC is not 500' above previous shoe as designed/programmed requiring bradenhead 2nd stage to meet requirements*

Offline Cementing Request

Oxy requests a variance to cement the 9.625" and/or 7.625" intermediate casing strings offline in accordance to the approved variance, EC Tran 461365. Please see Offline Cementing Variance attachment for further details.

Bradenhead CBL Request

Oxy requests permission to adjust the CBL requirement after bradenhead cement jobs, on 7-5/8" intermediate casings, as per the agreement reached in the OXY/BLM meeting on September 5, 2019. Please see Bradenhead CBL Variance attachment for further details.

Oxy Bulk Design - Casing Design "A"

4. Pressure Control Equipment

<table>
<tr><th>BOP installed and tested before drilling which hole?</th><th>Size?</th><th>Min. Required WP</th><th colspan="2">Type</th><th>✓</th><th>Tested to:</th><th>Deepest TVD Depth (ft) per Section:</th></tr>
<tr><td rowspan="5">9.875" Hole</td><td rowspan="5">13-5/8"</td><td>5M</td><td colspan="2">Annular</td><td>✓</td><td>70% of working pressure</td><td rowspan="5">12775**</td></tr>
<tr><td rowspan="4">5M</td><td colspan="2">Blind Ram</td><td>✓</td><td rowspan="4">250 psi / 5000 psi</td></tr>
<tr><td colspan="2">Pipe Ram</td><td></td></tr>
<tr><td colspan="2">Double Ram</td><td>✓</td></tr>
<tr><td>Other*</td><td></td><td></td></tr>
<tr><td rowspan="5">6.75" Hole</td><td rowspan="5">13-5/8"</td><td>5M</td><td colspan="2">Annular</td><td>✓</td><td>100% of working pressure</td><td rowspan="5">12775</td></tr>
<tr><td rowspan="4">10M</td><td colspan="2">Blind Ram</td><td>✓</td><td rowspan="4">250 psi / 10000 psi</td></tr>
<tr><td colspan="2">Pipe Ram</td><td></td></tr>
<tr><td colspan="2">Double Ram</td><td>✓</td></tr>
<tr><td>Other*</td><td></td><td></td></tr>
</table>

*Specify if additional ram is utilized
**Curve could be in intermediate or production section

BOP/BOPE will be tested by an independent service company to 250 psi low and the high pressure indicated above per 43 CFR part 3170 Subpart 3172 requirements. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested.

Pipe rams will be operationally checked each 24 hour period. Blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets. Other accessories to the BOP equipment will include a Kelly cock and floor safety valve (inside BOP) and choke lines and choke manifold. See attached schematics.

5M Annular BOP Request

Per BLM's Memorandum No. NM-2017-008: *Decision and Rationale for a Variance Allowing the Use of a 5M Annular Preventer with a 10M BOP Stack*, Oxy requests to employ a 5M annular with a 10M BOPE stack in the pilot and lateral sections of the well and will ensure that two barriers to flow are

Oxy Bulk Design - Casing Design "A"

Formation integrity test will be performed per 43 CFR part 3170 Subpart 3172.
On Exploratory wells or 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. Will be tested in accordance with 43 CFR part 3170 Subpart 3172.

A variance is requested for the use of a flexible choke line from the BOP to Choke Manifold. Coflex hoses are in compliance with API 16C and meets inspection and testing requirements. See attached for specs and hydrostatic test chart.	
Y	Are anchors required by manufacturer?

A multibowl or a unionized multibowl wellhead system will be employed. The wellhead and connection to the BOPE will meet all API 6A requirements. The BOP will be tested per 43 CFR part 3170 Subpart 3172 after installation on the surface casing which will cover testing requirements for a maximum of 30 days. If any seal subject to test pressure is broken the system must be tested. We will test the flange connection of the wellhead with a test port that is directly in the flange. We are proposing that we will run the wellhead through the rotary prior to cementing surface casing as discussed with the BLM on October 8, 2015.

See attached Schematics.

BOP Break Testing Request

Oxy requests permission to adjust the BOP break testing requirements as per the agreement reached in the OXY/BLM meeting on September 5, 2019. Please see BOP Break Testing Variance attachment for further details.

Hammer Union Variance

Oxy requests permission for hammer unions behind the choke to be routed to the gas buster. The hammer unions will not be subject to wellbore pressure in compliance with API STD 53.

Oxy will use Cameron ADAPT wellhead system that uses an OEC top flange connection. This connection has been fully vetted and verified by API to Spec 6A and carries an API monogram.

Oxy Bulk Design - Casing Design "A"

5. Mud Program & Drilling Conditions

Section	Depth - MD		Depth - TVD		Type	Weight (ppg)	Viscosity	Water Loss
	From (ft)	To (ft)	From (ft)	To (ft)				
Surface	0	1200	0	1200	Water-Based Mud	8.6 - 8.8	40-60	N/C
Intermediate	1200	13111*	1200	12775*	Saturated Brine-Based or Oil-Based Mud	8.0 - 10.0	35-45	N/C
Production	13111	23361	12775	12775	Water-Based or Oil-Based Mud	9.5 - 13.5	38-50	N/C

Curve could be in intermediate or production section

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept on location at all times. The following is a general list of products: Barite, Bentonite, Gypsum, Lime, Soda Ash, Caustic Soda, Nut Plug, Cedar Fiber, Cotton Seed Hulls, Drilling Paper, Salt Water Clay, CACL2. Oxy will use a closed mud system.

Drilling Blind Request

In the event total losses are encountered in the intermediate section, Oxy requests permission to drill blind due to depleted formations where risk of hydrocarbon kicks are unlikely.

- Oxy will first attempt to cure losses before proceeding with drilling blind
- Drilling blind will only be allowed in the Castille and formations below
- While drilling blind, will monitor backside by filling-up on connections and utilize gas monitors
- Depths at which losses occurred and attempt to cure losses with relevant details (LCM sweep info, etc.) will be documented in the drillers log and Subsequent Reports to the BLM.
- If a well control event (hydrocarbon kick) occurs while drilling blind, the BLM will be notified after the well is secured and returned to static.

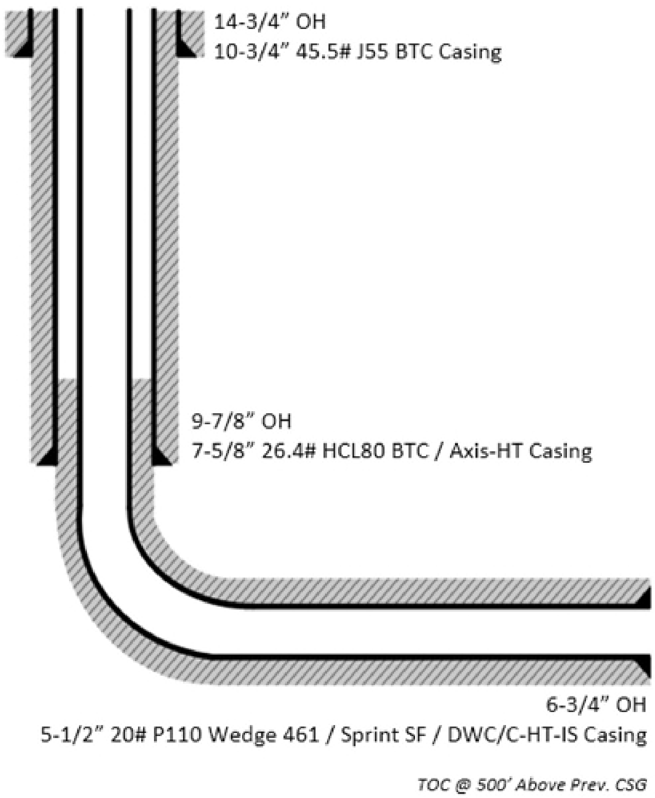
What will be used to monitor the loss or gain of fluid?	PVT/MD Totco/Visual Monitoring

Pump high viscosity sweeps as needed for hole cleaning. The mud system will be monitored visually/manually as well as with an electronic PVT. The necessary mud products for additional weight and fluid loss control will be on location at all times. Appropriately weighted mud will be used to isolate potential gas, oil, and water zones until such time as casing can be cemented into place for zonal isolation.

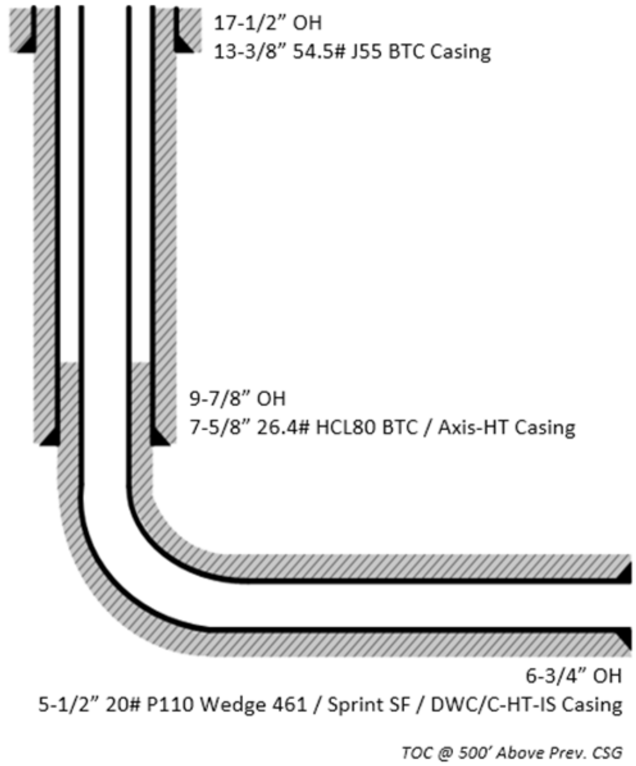
Oxy Bulk Design - Casing Design “A”

6. Wellbore Diagram(s)

Design Variation “A1”

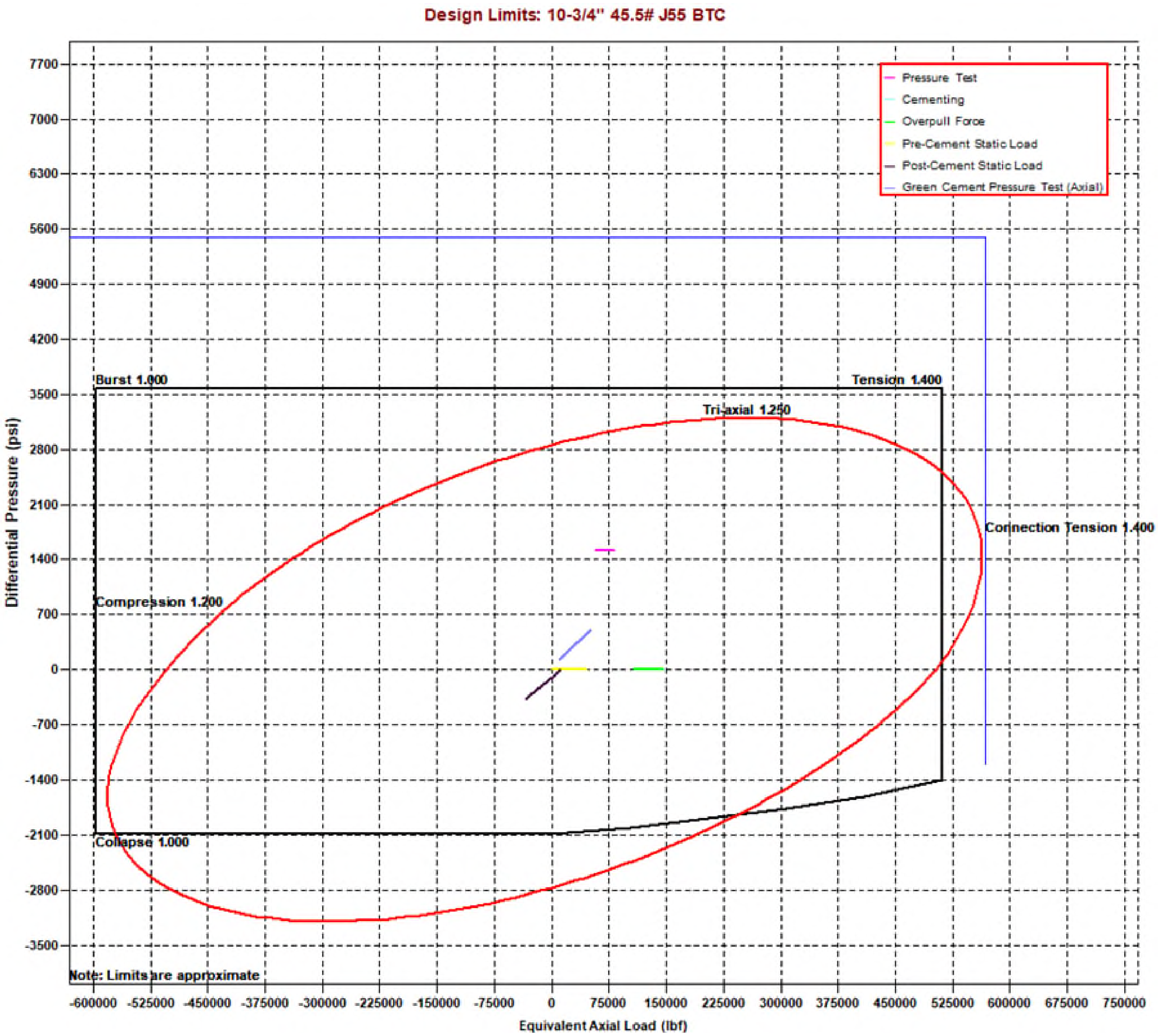


Design Variation “A2”

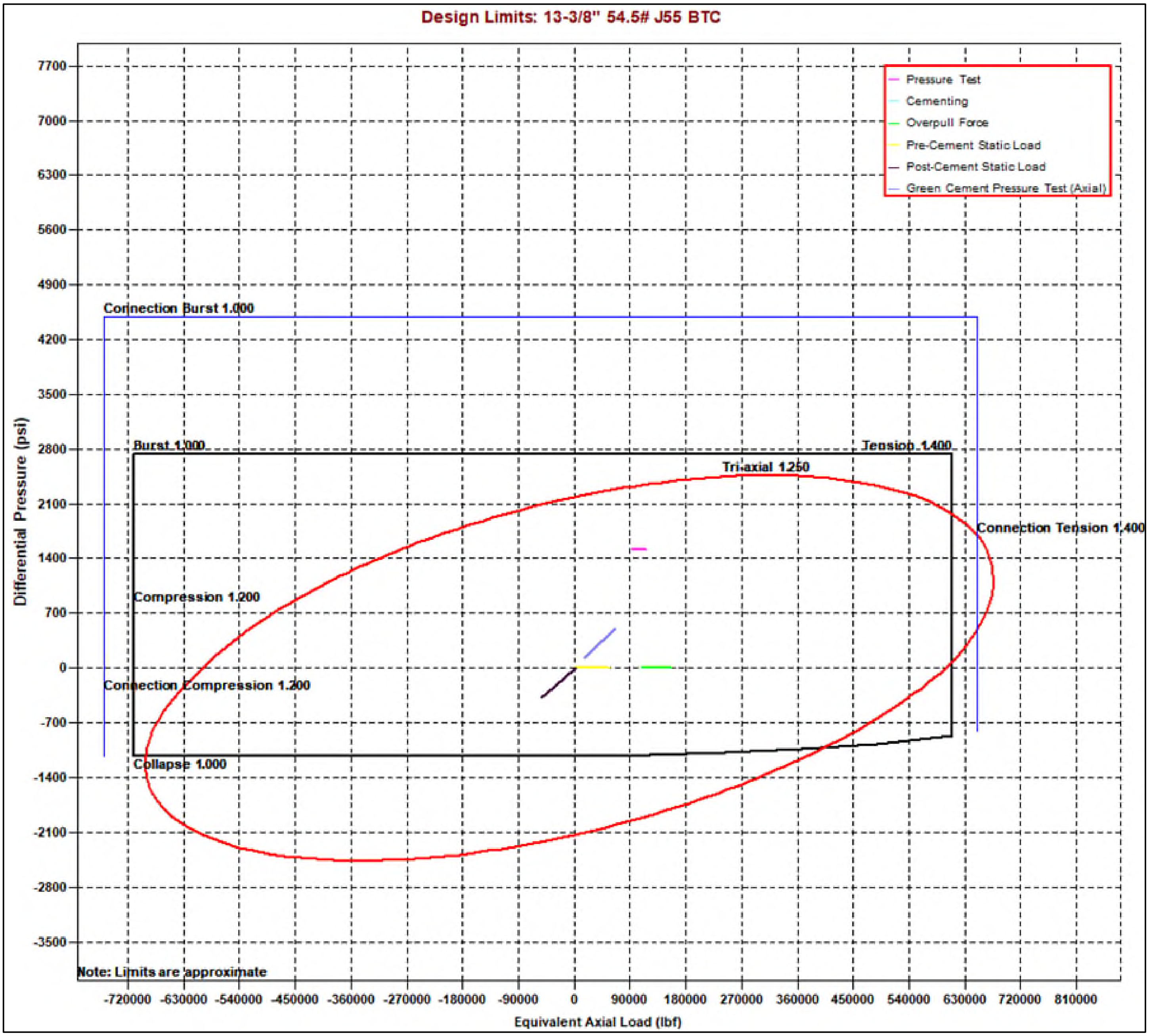


Oxy Bulk Design - Casing Design "A"

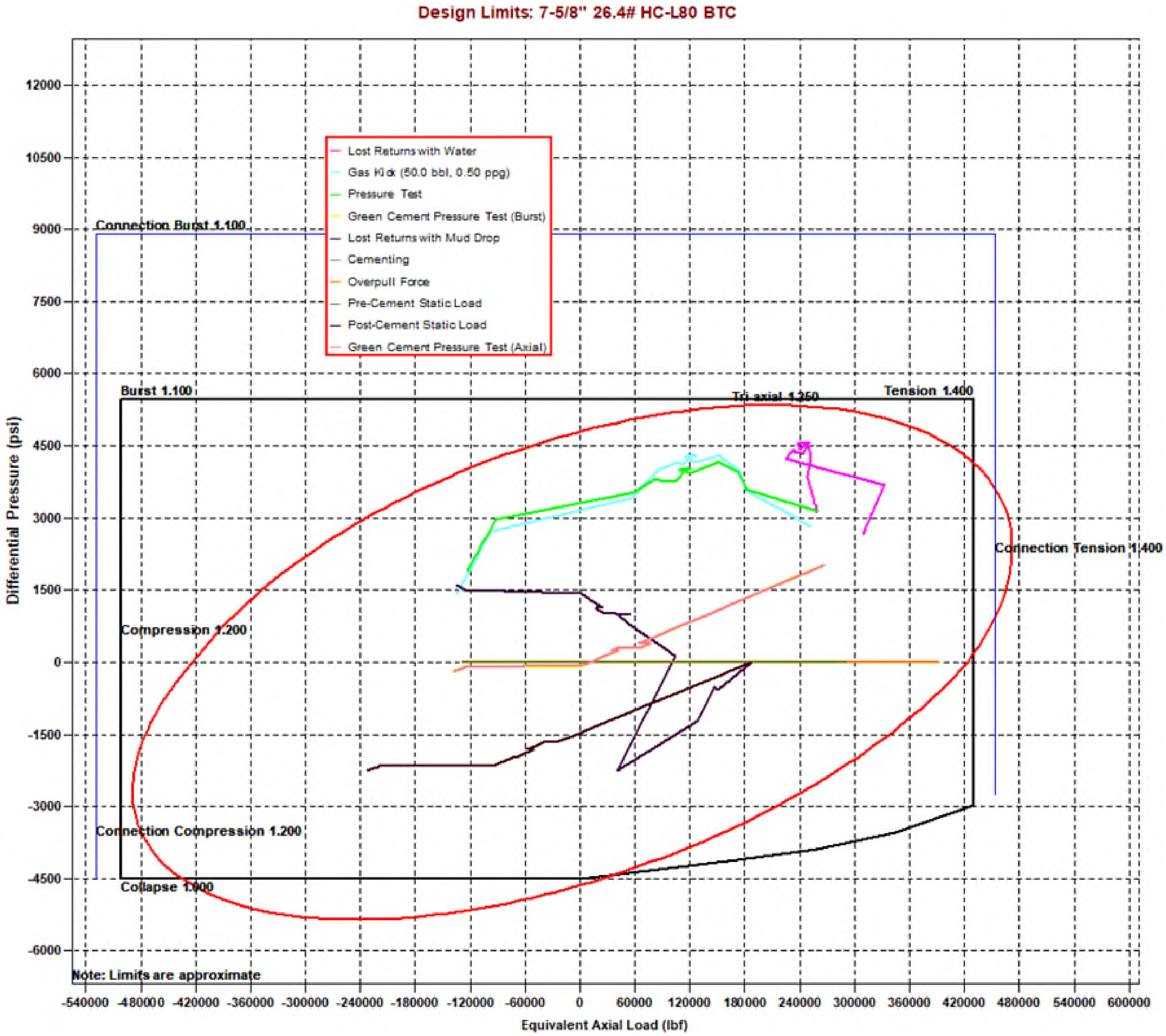
7. Landmark StressCheck Screenshots – Triaxial Output



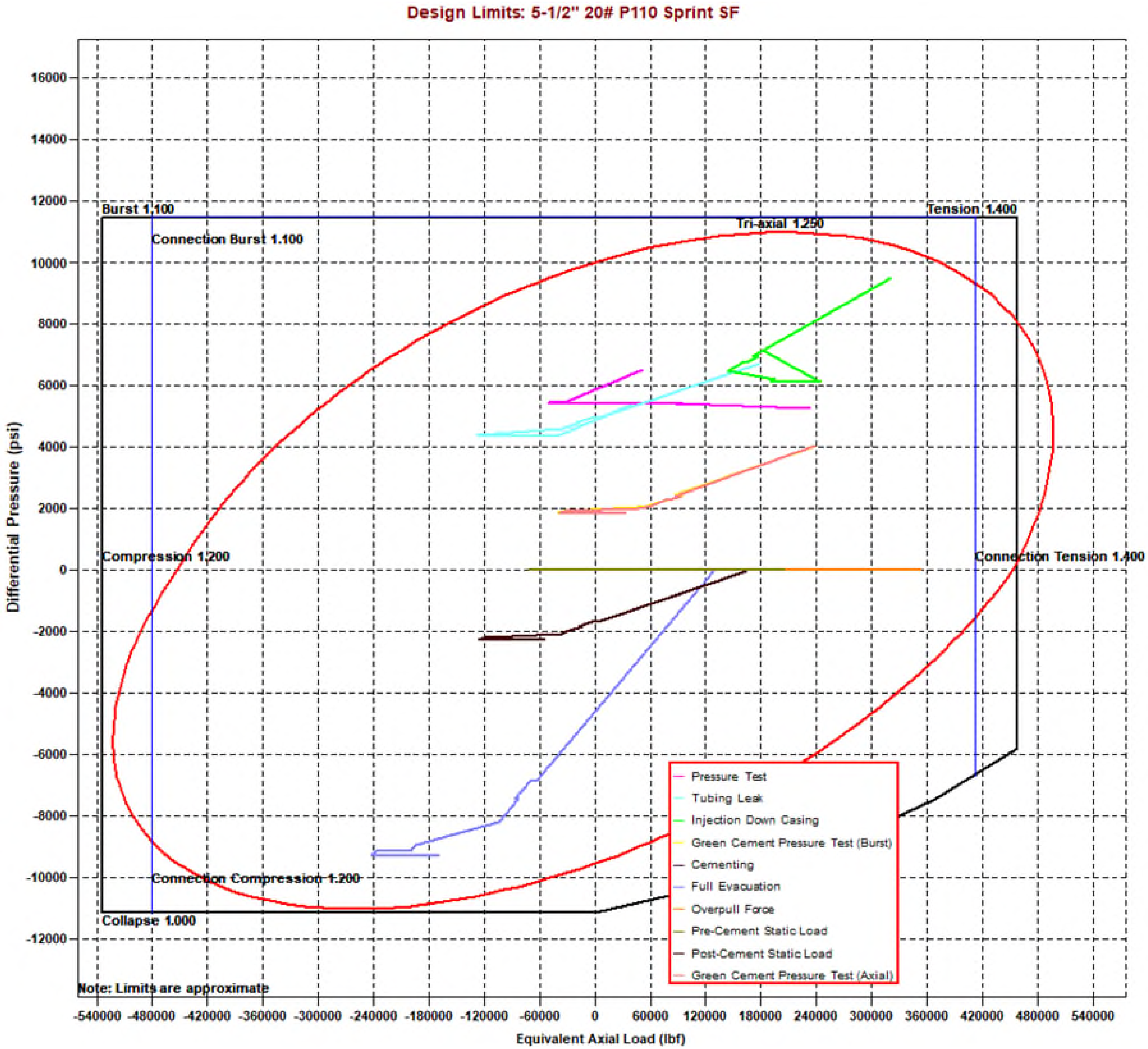
Oxy Bulk Design - Casing Design "A"



Oxy Bulk Design - Casing Design "A"



Oxy Bulk Design - Casing Design "A"



8. Landmark StressCheck Screenshots – Inputs for Intermediate CSG Load Cases

Burst Load Cases

General | 7 5/8" Intermediate Casing

Burst Loads Data	
Drilling Load:	**Lost Returns with Water**
Fracture at Shoe (MD= 13111.00 ft):	10591 psi
Mud/Water Interface, MD:	0.00 ft
Mud Weight	11.28 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Gas Kick Profile**
Influx Depth, MD:	23361.00 ft
Kick Volume:	50.0 bbl
Kick Intensity	0.50 ppg
Maximum Mud Weight:	13.50 ppg
Kick Gas Gravity:	0.55 (0.1159 psi/ft @ 182 °F & 9291 psi)
Fracture at Shoe (MD= 13111.00 ft):	10591 psi
Drill Pipe OD:	5.000 in
Collar OD:	5.500 in
Collar Length:	200.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Pressure Test**
Test Pressure:	3120 psi
Mud Weight:	10.00 ppg
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Green Cement Pressure Test**
Test Pressure:	2000 psi
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	25.00 ft
Lead Slurry Density:	13.30 ppg
Tail Slurry Density:	13.30 ppg
Tail Slurry Length:	5906.00 ft
Displacement Fluid Density:	10.00 ppg
Float Collar Depth, MD:	12800.00 ft
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	25.00 ft
Prior Shoe, MD:	1200.00 ft
Mud Weight Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	8.33 ppg
Wellhead Pressure:	13 psi
Pore Pressure In Open Hole:	Yes

Oxy Bulk Design - Casing Design "A"

Collapse Load Cases

General | 7 5/8" Intermediate Casing

Collapse Loads Data

Drilling Load:	**Cementing**
Mud Weight at Shoe:	10.00 ppg
TOC, MD:	25.00 ft
Lead Slurry Density:	13.30 ppg
Tail Slurry Density:	13.30 ppg
Tail Slurry Length:	5906.00 ft
Displacement Fluid Density:	10.00 ppg
Float Collar Depth, MD:	12800.00 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
Drilling Load:	**Lost Returns with Mud Drop**
Lost Returns Depth, MD:	13110.89 ft
Pore Pressure at Lost Returns Depth:	8183 psi
Pore Pressure Gradient at Lost Returns Depth:	12.33 ppg
Mud Weight:	13.50 ppg
Mud Drop Level, MD:	1106.39 ft
Assigned External Pressure:	Fluid Gradients (w/ Pore Pressure)
External Pressure:	**Fluid Gradients (w/ Pore Pressure)**
TOC, MD:	25.00 ft
Prior Shoe, MD:	1200.00 ft
Fluid Gradient Above TOC:	10.00 ppg
Fluid Gradient Below TOC:	10.00 ppg
Wellhead Pressure:	13 psi
Pore Pressure In Open Hole Below TOC:	No

Axial Load Cases

General | 7 5/8" Intermediate Casing

Axial Loads Data

Overpull Force:	100000 lbf
Pre-Cement Static Load:	Yes
Pickup Force:	0 lbf
Post-Cement Static Load:	Yes
Green Cement Pressure Test:	2000 psi
Service Loads:	Yes

Oxy Bulk Design - Casing Design "A"

9. Landmark StressCheck Screenshot – Int. Casing Triaxial Results Table (Pressure Test)

StressCheck - [Triaxial Results - Blanket Design A1 *]

File Edit Wellbore Tubular View Composer Tools Window Help

7 5/8" Intermediate Casing

Pressure Test

Triaxial Results

	Depth (MD) (ft)	Axial Force (lbf) Apparent (w/Bending)	Axial Force (lbf) Actual (w/o Bending)	Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor Triaxial	Absolute Safety Factor Burst	Absolute Safety Factor Collapse (V)	Absolute Safety Factor Axial	Temperature (°F)	Pressure (psi) Internal	Pressure (psi) External	Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (ft)
28	12300	-142410	-17423	-94936	16622.5	1.79	2.10	N/A	(4.09)	178	9505	6732		
29	12400	-149639	-24652	-100590	16622.5	1.87	2.25	N/A	(3.89)	179	9555	6970		
30	12400	-149640	-24653	-100591	16622.5	1.87	2.25	N/A	(3.89)	179	9555	6970		
31	12500	-156448	-31461	-105919	16622.5	1.95	2.42	N/A	(3.72)	180	9603	7193		
32	12500	-156449	-31462	-105920	16622.5	1.95	2.42	N/A	(3.72)	180	9603	7193		
33	12550	-159630	-34643	-108410	16622.5	1.99	2.50	N/A	(3.64)	180	9625	7298		
34	12550	-159631	-34644	-108411	16622.5	1.99	2.50	N/A	(3.64)	180	9625	7298		
35	12600	-162630	-37643	-110759	16622.5	2.03	2.59	N/A	(3.58)	180	9646	7396		
36	12600	-162631	-37644	-110760	16622.5	2.03	2.59	N/A	(3.58)	180	9646	7396		
37	12650	-165426	-40439	-112949	16622.5	2.07	2.67	N/A	(3.52)	181	9665	7488		
38	12650	-165427	-40440	-112950	16622.5	2.07	2.67	N/A	(3.52)	181	9665	7488		
39	12700	-167997	-43010	-114963	16622.5	2.10	2.76	N/A	(3.46)	181	9683	7573		
40	12700	-167998	-43011	-114963	16622.5	2.10	2.76	N/A	(3.46)	181	9683	7573		
41	12750	-170322	-45335	-116784	16622.5	2.13	2.84	N/A	(3.41)	181	9699	7649		
42	12750	-170323	-45336	-116785	16622.5	2.13	2.84	N/A	(3.41)	181	9699	7649		
43	12800	-172385	-47398	-118401	16622.5	2.16	2.91	N/A	(3.37)	181	9714	7717		
44	12800	-172386	-47399	-118401	16622.5	2.16	2.91	N/A	(3.37)	181	9714	7717		
45	12850	-174169	-49183	-119799	16622.5	2.19	2.98	N/A	(3.34)	182	9726	7775		
46	12850	-174170	-49183	-119800	16622.5	2.19	2.98	N/A	(3.34)	182	9726	7775		
47	12900	-175662	-50675	-120969	16622.5	2.21	3.04	N/A	(3.31)	182	9736	7824		
48	12950	-176851	-51864	-121901	16622.5	2.23	3.09	N/A	(3.29)	182	9745	7863		
49	13000	-177727	-52740	-122588	16622.5	2.24	3.13	N/A	(3.27)	182	9751	7892		
50	13000	-177728	-52741	-122588	16622.5	2.24	3.13	N/A	(3.27)	182	9751	7892		
51	13050	-178285	-53298	-123025	16622.5	2.25	3.15	N/A	(3.26)	182	9755	7910		
52	13111	-178527	-53540	-123214	16622.5	2.25	3.16	N/A	(3.26)	182	9756	7918		
53														
54														
55														
56														

( ) Compression
(V) Vector Collapse Safety Factor

Internal Pressure = Surface Pressure + Hydrostatic = 9756 psi
External Pressure = Fluid Gradient w/ Pore Pressure = 7918 psi
Burst SF = 3.16

NOTE: *Specific load case inputs for the pressure test can be seen in* ***Section 8*** *above. The test pressure does not exceed 70% of the minimum internal yield.*

10. Intermediate Non-API Casing Spec Sheet

AXIS PIPE AND TUBE

Technical Data Sheet

7 5/8" 26.40 lbs/ft. L80HC - Axis HT

Mechanical Properties			
Minimum Yield Strength	psi.	80,000	
Maximum Yield Strength	psi.	95,000	
Minimum Tensile Strength	psi.	95,000	
Dimensions		**Pipe**	**AXIS HT**
Outside Diameter	in.	7.625	8.500
Wall Thickness	in.	0.328	-
Inside Diameter	in.	6.969	-
Standard Drift	in.	6.844	6.844
Alternate Drift	in.	-	-
Plain End Weight	lbs/ft.	-	-
Nominal Linear Weight	lbs/ft.	26.40	-
Performance		**Pipe**	**AXIS HT**
Minimum Collapse Pressure	psi.	4,320	-
Minimum Internal Yield Pressure	psi.	6,020	6,020
Minimum Pipe Body Yield Strength	lbs.	602 x 1,000	-
Joint Strength	lbs.	-	635 x 1,000
Make-Up Torques		**Pipe**	**AXIS HT**
Optimum Make-Up Torque	ft/lbs.	-	8,000
Maximum Operational Torque	ft/lbs.	-	25,000

Oxy Bulk Design - Casing Design "A"

11. Production Non-API Casing Spec Sheets

Printed on: 11/09/2021

Tenaris

TenarisHydril Wedge 461 ® MS

Coupling	Pipe Body
Grade: P110-ICY	Grade: P110-ICY
Body: White	1st Band: White
1st Band: Pale Green	2nd Band: Pale Green
2nd Band: -	3rd Band: Pale Green
3rd Band: -	4th Band: -
	5th Band: -
	6th Band: -

Outside Diameter	5.500 in.	Wall Thickness	0.361 in.	Grade	P110-ICY
Min. Wall Thickness	87.50 %	Pipe Body Drift	API Standard	Type	Casing
Connection OD Option	MS				

Pipe Body Data

Geometry				Performance	
Nominal OD	5.500 in.	Wall Thickness	0.361 in.	Body Yield Strength	729 x1000 lb
Nominal Weight	20 lb/ft	Plain End Weight	19.83 lb/ft	Min. Internal Yield Pressure	14,360 psi
Drift	4.653 in.	OD Tolerance	API	SMYS	125,000 psi
Nominal ID	4.778 in.			Collapse Pressure	12,300 psi

Connection Data

Geometry	
Connection OD	6.050 in.
Coupling Length	7.714 in.
Connection ID	4.778 in.
Make-up Loss	3.775 in.
Threads per inch	3.40
Connection OD Option	Ms

Performance	
Tension Efficiency	100 %
Joint Yield Strength	729 x1000 lb
Internal Pressure Capacity	14,360 psi
Compression Efficiency	100 %
Compression Strength	729 x1000 lb
Max. Allowable Bending	104 °/100 ft
External Pressure Capacity	12,300 psi
Coupling Face Load	273,000 lb

Make-Up Torques	
Minimum	17,000 ft-lb
Optimum	18,000 ft-lb
Maximum	21,600 ft-lb

Operation Limit Torques	
Operating Torque	43,000 ft-lb
Yield Torque	51,000 ft-lb

Buck-On	
Minimum	21,600 ft-lb
Maximum	23,100 ft-lb

Notes

This connection is fully interchangeable with:
Wedge 441® - 5.5 in. - 0.304 / 0.361 in.
Wedge 461® - 5.5 in. - 0.304 / 0.415 / 0.476 in.
Connections with Dopeless® Technology are fully compatible with the same connection in its Standard version
In October 2019, TenarisHydril Wedge XP® 2.0 was renamed TenarisHydril Wedge 461™. Product dimensions and properties remain identical and both connections are fully interchangeable

For the lastest performance data, always visit our website: www.tenaris.com

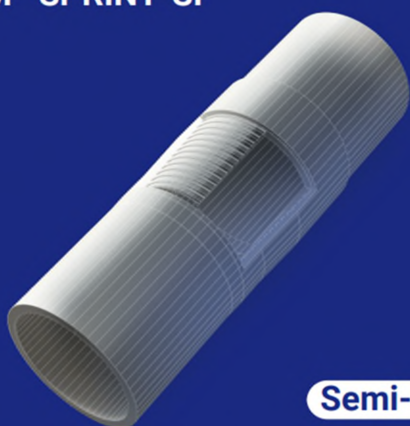
Oxy Bulk Design - Casing Design "A"

Generated on May 21, 2024

CONNECTION DATA SHEET

OD: **5.500 in.** Grade: **P110**
Weight: **20.00 lb/ft** Drift: **4.653 in. (API)**
Wall Th.: **0.361 in.**

VAM® SPRINT-SF



Semi-Flush

Field Torque Values

Make-up Torque (ft-lb)
- 20,000 MIN
- 22,500 OPTI
- 25,000 MAX

Torque with Sealability (ft-lb)
- 36,000 MTS

Locked Flank Torque (ft-lb)
- 4,500 MIN
- 15,750 MAX

(2) MTS: Maximum Torque with Sealability.

PIPE BODY PROPERTIES

Nominal OD	5.500	in.
Nominal ID	4.778	in.
Nominal Wall Thickness	0.361	in.
Minimum Wall Thickness	87.5	%
Nominal Weight (API)	20.00	lb/ft
Plain End Weight	19.83	lb/ft
Drift	4.653	in.
Grade Type	API 5CT	
Minimum Yield Strength	110	ksi
Maximum Yield Strength	140	ksi
Minimum Ultimate Tensile Strength	125	ksi
Pipe Body Yield Strength	641	klb
Internal Yield Pressure	12,640	psi
Collapse Pressure	11,100	psi

CONNECTION PROPERTIES

Connection Type	Semi-Premium Integral Semi-Flu	
Nominal Connection OD	5.783	in.
Nominal Connection ID	4.718	in.
Make-up Loss	5.965	in.
Tension Efficiency	90	% Pipe Body
Compression Efficiency	90	% Pipe Body
Internal Pressure Efficiency	100	% Pipe Body
External Pressure Efficiency	100	% Pipe Body

JOINT PERFORMANCES

Tension Strength	577	klb
Compression Strength	577	klb
Internal Pressure Resistance	12,640	psi
External Pressure Resistance	11,100	psi
Maximum Bending, Structural	78	°/100 ft
Maximum Bending, with Sealability(1)	30	°/100 ft

(1) Sealability rating demonstrated as per API RP 5C5 / ISO 13679

Oxy Bulk Design - Casing Design “A”

DWC/C-HT-IS

Connection Data Sheet

OD (in.)	WEIGHT (lbs./ft.)	WALL (in.)	GRADE	API DRIFT (in.)	RBW%	CONNECTION
5.500	Nominal: 20.00 Plain End: 19.83	0.361	‡VST P110MY	4.653	87.5	DWC/C-HT-IS

PIPE PROPERTIES		
Nominal OD	5.500	in.
Nominal ID	4.778	in.
Nominal Area	5.828	sq.in.
Grade Type		API 5CT
Min. Yield Strength	125	ksi
Max. Yield Strength	140	ksi
Min. Tensile Strength	135	ksi
Yield Strength	729	klb
Ultimate Strength	787	klb
Min. Internal Yield Pressure	14,360	psi
Collapse Pressure	12,090	psi

CONNECTION PROPERTIES		
Connection Type		Semi-Premium T&C
Connection OD (nom)	6.050	in.
Connection ID (nom)	4.778	in.
Make-Up Loss	4.125	in.
Coupling Length	9.250	in.
Critical Cross Section	5.828	sq.in.
Tension Efficiency	89.1%	of pipe
Compression Efficiency	88.0%	of pipe
Internal Pressure Efficiency	86.1%	of pipe
External Pressure Efficiency	100.0%	of pipe

CONNECTION PERFORMANCES		
Yield Strength	649	klb
Parting Load	729	klb
Compression Rating	641	klb
Min. Internal Yield Pressure	12,360	psi
External Pressure Resistance	12,090	psi
Maximum Uniaxial Bend Rating	91.7	°/100 ft
Reference String Length w 1.4 Design Factor	22,890	ft.

FIELD TORQUE VALUES		
Min. Make-up torque	16,600	ft.lb
Opti. Make-up torque	17,950	ft.lb
Max. Make-up torque	19,300	ft.lb
Min. Shoulder Torque	1,660	ft.lb
Max. Shoulder Torque	13,280	ft.lb
Max. Delta Turn	0.200	Turns
†Maximum Operational Torque	23,800	ft.lb
†Maximum Torsional Value (MTV)	26,180	ft.lb

† Maximum Operational Torque and Maximum Torsional Value only valid with Vallourec P110MY Material.
‡ P110MY - Coupling Min Yield Strength is 110ksi and Coupling Max Yield is 125ksi.

"VST = Vallourec Star as the mill source for the pipe, "P110EC" is the grade name"
Need Help? Contact: tech.support@vam-usa.com
For detailed information on performance properties, refer to DWC Connection Data Notes on following page(s).

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Oxy Bulk Design - Casing Design “A”

VAM USA
2107 CityWest Boulevard Suite 1300
Houston, TX 77042
Phone: 713-479-3200
Fax: 713-479-3234
VAM® USA Sales E-mail: VAMUSAsales@vam-usa.com
Tech Support Email: tech.support@vam-usa.com

DWC Connection Data Sheet Notes:

1. DWC connections are available with a seal ring (SR) option.
2. All standard DWC/C connections are interchangeable for a given pipe OD. DWC connections are interchangeable with DWC/C-SR connections of the same OD and wall.
3. Connection performance properties are based on nominal pipe body and connection dimensions.
4. DWC connection internal and external pressure resistance is calculated using the API rating for buttress connections. API Internal pressure resistance is calculated from formulas 31, 32, and 35 in the API Bulletin 5C3.
5. DWC joint strength is the minimum pipe body yield strength multiplied by the connection critical area.
6. API joint strength is for reference only. It is calculated from formulas 42 and 43 in the API Bulletin 5C3.
7. Bending efficiency is equal to the compression efficiency.
8. The torque values listed are recommended. The actual torque required may be affected by field conditions such as temperature, thread compound, speed of make-up, weather conditions, etc.
9. Connection yield torque is not to be exceeded.
10. Reference string length is calculated by dividing the joint strength by both the nominal weight in air and a design factor (DF) of 1.4. These values are offered for reference only and do not include load factors such as bending, buoyancy, temperature, load dynamics, etc.
11. DWC connections will accommodate API standard drift diameters.
12. DWC/C family of connections are compatible with API Buttress BTC connections. Please contact tech.support@vam-usa.com for details on connection ratings and make-up.

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Offline Cementing Variance Request

Oxy requests a variance to cement the 9.625" and/or 7.625" intermediate casing strings offline in accordance to the approved variance, EC Tran 461365.

1. Cement Program

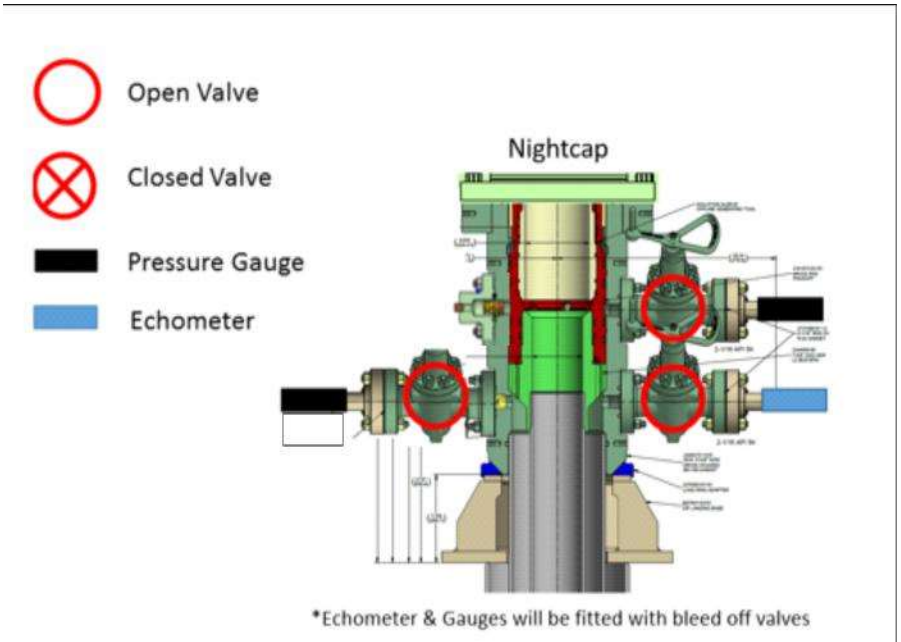
No changes to the cement program will take place for offline cementing.

2. Offline Cementing Procedure

The operational sequence will be as follows:

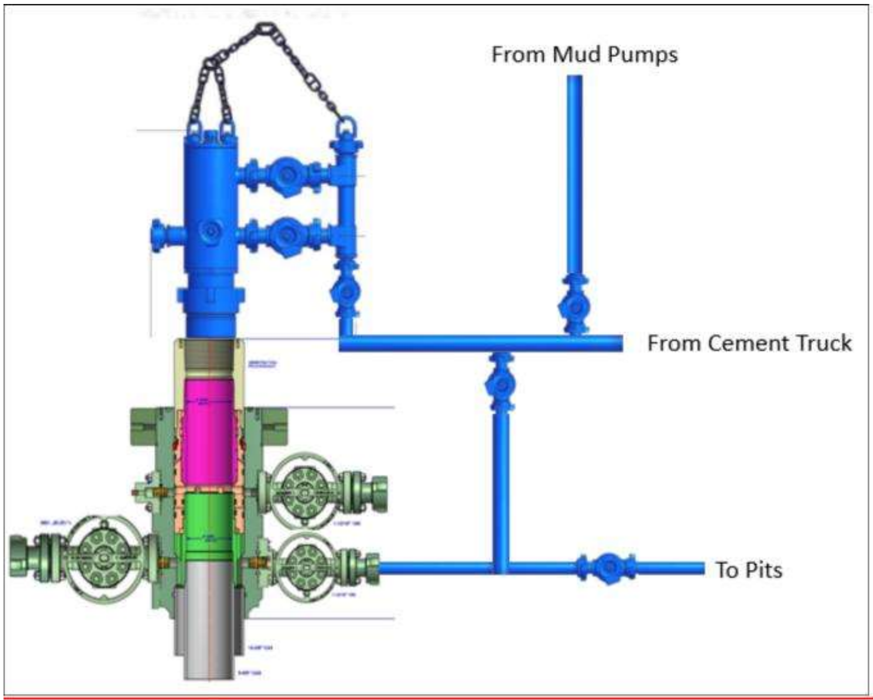
1. Run casing as per normal operations. While running casing, conduct negative pressure test and confirm integrity of the float equipment (float collar and shoe)
2. Land casing with mandrel
3. Fill pipe with kill weight fluid, do not circulate through floats and confirm well is static
4. Set annular packoff shown below and pressure test to confirm integrity of the seal. Pressure ratings of wellhead components and valves is 5,000 psi

Annular packoff with both external and internal seals



Wellhead diagram during skidding operations

5. After confirmation of both annular barriers and internal barriers, nipple down BOP and install cap flange.
    a. If any barrier fails to test, the BOP stack will not be nippled down until after the cement job is completed with cement 500ft above the highest formation capable of flow with kill weight mud above or after it has achieved 50 psi compressive strength if cannot be verified.
6. Skid rig to next well on pad.
7. Confirm well is static before removing cap flange, flange will not be removed and offline cementing operations will not commence until well is under control. If well is not static, 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 or nippling up for further remediation.
    a. Well Control Plan
        i. The Drillers Method will be the primary well control method to regain control of the wellbore prior to cementing, if wellbore conditions do not permit the drillers method other methods of well control may be used
        ii. Rig pumps or a 3rd party pump will be tied into the upper casing valve to pump down the casing ID
        iii. A high pressure return line will be rigged up to lower casing valve and run to choke manifold to control annular pressure
        iv. Once influx is circulated out of the hole, kill weight mud will be circulated
        v. Well will be confirmed static
        vi. Once confirmed static, cap flange will be removed to allow for offline cementing operations to commence
8. Install offline cement tool
9. Rig up cement equipment



Wellhead diagram during offline cementing operations

10. Circulate bottoms up with cement truck
    a. If gas is present on bottoms up, well will be shut in and returns rerouted through gas buster to handle entrained gas
    b. Max anticipated time before circulating with cement truck is 6 hrs
11. Perform cement job taking returns from the annulus wellhead valve
12. Confirm well is static and floats are holding after cement job
13. Remove cement equipment, offline cement tools and install night cap with pressure gauge for monitoring.

5M Annluar BOP Variance Request

Per BLM's Memorandum No. NM-2017-008: *Decision and Rationale for a Variance Allowing the Use of a 5M Annular Preventer with a 10M BOP Stack*, Oxy requests to employ a 5M annular with a 10M BOPE stack in the pilot and lateral sections of the well and will ensure that two barriers to flow are maintained at all times. Please see Well Control Plan below.

Oxy Well Control Plan

A. Component and Preventer Compatibility Table

The table below, which covers the drilling and casing of the >5M MASP portion of the well, outlines the tubulars and the compatible preventers in use. This table, combined with the mud program, documents that two barriers to flow can be maintained at all times, independent of the rating of the annular preventer.

Pilot hole and Lateral sections, 10M requirement

Component	OD	Preventer	RWP
Drillpipe	4-1/2"-5"	Lower 3-1/2 - 5-1/2" VBR Upper 3-1/2 - 5-1/2" VBR	10M
HWDP	4-1/2"-5"	Lower 3-1/2 - 5-1/2" VBR Upper 3-1/2 - 5-1/2" VBR	10M
Drill collars and MWD tools	4-3/4" – 5-1/2"	Lower 3-1/2 - 5-1/2" VBR Upper 3-1/2 - 5-1/2" VBR	10M
Mud Motor	4-3/4"	Lower 3-1/2 - 5-1/2" VBR Upper 3-1/2 - 5-1/2" VBR	10M
Production casing	5-1/2"	Lower 3-1/2 - 5-1/2" VBR Upper 3-1/2 - 5-1/2" VBR	10M
ALL	0" - 13-5/8"	Annular	5M
Open-hole	6-3/4"	Blind Rams	10M

VBR = Variable Bore Ram. Compatible range listed in chart.
HWDP = Heavy Weight Drill Pipe
MWD = Measurement While Drilling

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 drilling, tripping, running casing, pipe out of the hole (open hole), and moving the Bottom Hole Assembly (BHA) through the Blowout Preventers (BOP). The pressure at which control is swapped from the annular to another compatible ram will occur when the anticipated pressure is approaching or envisioned to exceed 70% of the 5M annular Rated Working Pressure (RWP) or 3500 PSI.

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. The Hydraulic Control Remote (HCR) valve and choke will already be in the closed position).
5. Confirm shut-in
6. Notify tool pusher/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 expected to reach 70% of the annular RWP during kill operations, crew will reconfirm spacing and swap to the upper pipe ram

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. The HCR and choke will already be in the closed position)
5. Confirm shut-in
6. Notify tool pusher/company representative
7. Read and record the following
    a. SIDPP and SICP
    b. Pit gain
    c. Time
    d. Regroup and identify forward plan
    e. If pressure has built or is anticipated during the kill to reach the RWP of the annular preventer, confirm spacing and swap to the upper pipe ram

General Procedure While Running 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. The HCR and choke will already be in the closed position).
5. Confirm shut-in
6. Notify tool pusher/company representative
7. Read and record the following:
    a. SIDPP and SICP
    b. Pit gain
    c. Time
    d. Regroup and identify forward plan.
    e. If pressure has built or is anticipated during the kill to reach the RWP of the annular preventer, confirm spacing and swap to compatible pipe ram.

General Procedure With No Pipe In Hole (Open Hole)

1. Sound alarm (alert crew)
2. Shut-in with blind rams or BSR. (The HCR and 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
   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 drill pipe thru the stack.
   a. Perform flow check, 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 pipe ram
   e. Shut-in using upper pipe ram. (The HCR and choke will already be in the closed position)
   f. Confirm shut-in
   g. Notify tool pusher/company representative
   h. Read and record the following:
      i. SIDPP and SICP
      ii. Pit gain
      iii. Time
      iv. 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 compatible pipe ram
   d. Shut-in using compatible pipe ram. (The HCR and choke will already be in the closed position.)
   e. Confirm shut-in
   f. Notify tool pusher/company representative
   g. Read and record the following:
      i. SIDPP and SICP
      ii. Pit gain
      iii. Time
      iv. 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 drill pipe, and full opening safety valve and close
e. Space out drill string with tool joint just beneath the upper pipe ram
f. Shut-in using upper pipe ram. (The HCR and choke will already be in the closed position)
g. Confirm shut-in
h. Notify tool pusher/company representative
i. Read and record the following:
    i. SIDPP and SICP
    ii. Pit gain
    iii. Time

j. Regroup and identify forward plan

Bradenhead Cement CBL Variance Request

Oxy requests permission to adjust the CBL requirement after bradenhead cement jobs, on 7-5/8" intermediate casings, as per the agreement reached in the OXY/BLM meeting on September 5, 2019.

Three string wells:

- CBL will be required on one well per pad
- If the pumped volume of cement is less than permitted in the APD, BLM will be notified and a CBL may be run
- Echometer will be used after bradenhead cement job to determine TOC before pumping top-out cement

Four string wells:

- CBL is not required
- If the pumped volume of cement is less than permitted in the APD, BLM will be notified and a CBL may be run
- Echometer will be used after bradenhead cement job to determine TOC before pumping top-out cement

BOP Break Testing Request

Oxy requests permission to adjust the BOP break testing requirements as per the agreement reached in the OXY/BLM meeting on September 5, 2019.

BOP break test under the following conditions:
- After a full BOP test is conducted
- When skidding to drill an intermediate section where ICP is set into the third Bone Spring or shallower.
- When skidding to drill a production section that does not penetrate into the third Bone Spring or deeper.

If the kill line is broken prior to skid, two tests will be performed.
1) Wellhead flange, co-flex hose, kill line connections and upper pipe rams
2) Wellhead flange, HCR valve, check valve, upper pipe rams

If the kill line is not broken prior to skid, only one test will be performed.
1)Wellhead flange, co-flex hose, check valve, upper pipe rams

See supporting information below:

Subject: Request for a Variance Allowing Break Testing of a Blowout Preventer Stack

OXY USA Inc. (OXY) requests a variance to allow break testing of the Blowout Preventer (BOP) stack when skidding a drilling rig between wells on multi-well pads. This practice entails retesting only the connections of the **BOP** stack that have been disconnected during this operation and not a complete **BOP** test.

Background

43 CFR part 3170 Subpart 3172 states that a **BOP** test must be performed whenever any seal subject to test pressure is broken. The current interpretation of the Bureau of Land Management (BLM) is this requires a complete **BOP** test and not just a test of the affected component. 43 CFR part 3170 Subpart 3172, Section I.D.2. states, "Some situations may exist either on a well-by-well basis or field-wide basis whereby it is commonly accepted practice to vary a particular minimum standard(s) established in this Order. This situation can be resolved by requesting a variance...". OXY feels the practice of break testing the **BOP** stack is such a situation. Therefore, as per 43 CFR part 3170 Subpart 3172, Section IV., OXY submits this request for the variance.

Supporting Rationale

43 CFR part 3170 Subpart 3172 became effective on December 19, 1988, and has remained the standard for regulating BLM onshore drilling operations for almost 30 years. During this time there have been significant changes in drilling technology. **BLM** continues to use the variance request process to allow for the use of modern technology and acceptable engineering practices that have arisen since 43 CFR part 3170 Subpart 3172 was originally released. The drilling rig fleet OXY utilizes in New Mexico was built with many modern upgrades. One of which allows the rigs to skid between wells on multi-well pads. A part of this rig package is a hydraulic winch system which safely installs and removes the BOP from the wellhead and carries it during skidding operations. This technology has made break testing a safe and reliable procldure.

American Petroleum Institute (API) standards, specifications and recommended practices are considered industry standards and are consistently utilized and referenced by the industry. 43 CFR part 3170 Subpart 3172 recognized API Recommended Practices (RP) 53 in its original development. API Standard 53, *Blowout Prevention Equipment Systems for Drilling Wells* (Fourth Edition, November 2012, Addendum 1, July 2016) recognizes break testing as an acceptable practice. Specifically, API Standard 53, Section 6.5.3.4.1.b states "Pressure tests on the well control equipment shall be conducted after the disconnection or repair of any pressure containment seal in the **BOP** stack, choke line, kill line, choke manifold, or wellhead assembly but limited to the affected component."

The Bureau of Safety and Environmental Enforcement (BSEE), Department of Interior, has also utilized the API standards, specifications and best practices in the development of its offshore oil and gas regulations and incorporates them by reference within its regulations. BSEE issued new offshore regulations under 30 CFR Part 250, *Oil and Gas and Sulphur Operations in the Outer Continental Shelf - Blowout Preventer Systems and Well Control,* which became effective on July 28, 2016. Section 250.737(d.1) states "Follow the testing requirements of API Standard 53". In addition, Section 250.737(d.8) has adopted language from **API** Standard 53 as it states "Pressure test affected **BOP** components following the disconnection or repair of any well-pressure containment seal in the wellhead or **BOP** stack assembly".

Break testing has been approved by the BLM in the past. See the Appendix for a Sundry Notice that was approved in 2015 by the Farmington Field Office. This approval granted permission for the operator to break test when skidding its Aztec 1000 rig on multi-well pads.

Oxy feels break testing and our current procedures meet the intent of 43 CFR part 3170 Subpart 3172 and often exceed it. We have not seen any evidence that break testing results in more components failing tests than seen on full BOP tests. As skidding operations take place within the 30-day full BOPE test window, the BOP shell and components such as the pipe rams and check valve get tested to the full rated working pressure more often. Therefore, there are more opportunities to ensure components are in good working order. Also, Oxy's standard requires complete BOP tests more often than that of 43 CFR part 3170 Subpart 3172. In addition to function testing the annular at least weekly and the pipe and blind rams on each trip, Oxy also performs a choke drill prior to drilling out every casing shoe. As a crew's training is a vital part of well control, this procedure to simulate step one of the Driller's Method exceeds the requirements of 43 CFR part 3170 Subpart 3172.

<u>Procedures</u>

1) OXY to submit the break testing plan in the APD or Sundry Notice (SN) and receive approval prior to implementing (See Appendix for examples)
2) OXY would perform BOP break testing on multi-well pads where multiple intermediate sections can be drilled and cased within the 30-day BOP test window
3) After performing a complete BOP test on the first well and drilling and casing the hole section, three breaks would be made on the BOP.
   - Between the check valve and the kill line
   - Between the HCR valve and the co-flex hose or the co-flex hose and the manifold
   - Between the BOP flange and the wellhead
4) The BOP is then lifted and removed from the wellhead by the hydraulic winch system
5) After skidding to the next well, the BOP is moved to the wellhead by the hydraulic winch system and installed
6) The choke line and kill line are reconnected
7) A test plug is installed in the wellhead with a joint of drill pipe and the internal parts of the check valve are removed
8) A shell teit is performed against the upper pipe rams testing all thl-ee breaks
9) The internal parts of the check valve are reinstalled and the HCR valve is closed. A second test is performed on them
10) These tests consist of a 250 psi low test and a high test to the value submitted in the APD or SN (e.g., 5000 psi)
11) Perform a function test of components not pressure tested to include the lower pipe rams, the blind rams and the annular
12) If this were a three well pad, the same three breaks on the BOP would be made and steps 4 through 11 would be repeated
13) A second break test would only be done if the third hole section could be completed within the 30-day BOP test window
14) If a second break test is performed, additional components that were not tested on the initial break test will be tested on this break test

Notes:

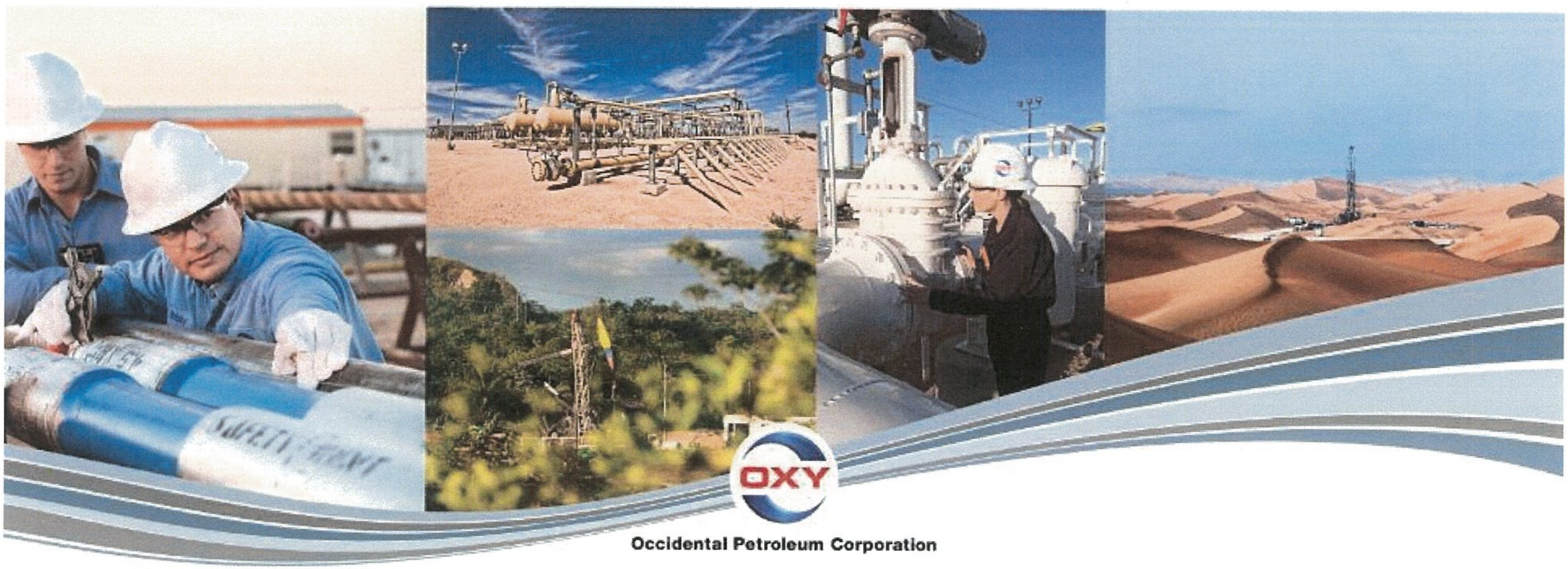
a. If any parts of the BOP are changed out or any additional breaks are made during the skidding operation, these affected components would also be tested as in step 10.
b. As the choke manifold remains stationary during the skidding operation and the only break to the manifold is tested in step 8 above, no further testing of the manifold is done until the next full BOP test.

Summary

OXY requests a variance to allow break testing of the BOP stack when skidding drilling rigs between wells on multi-well pads. API standards, specifications and recommended practices are considered industry standards and are consistently utilized and referenced by the industry and the BLM. API Standard 53 recognizes break testing as an acceptable practice and BSEE adopted language from this standard into its newly created 30 CFR Part 250 which also supports break testing. Due to this, OXY feels this request meets the intent of 43 CFR part 3170

REQUEST FOR A VARIANCE TO BREAK TEST THE BOP

Permian Resources New Mexico



Request for Variance

OXY USA Inc. (OXY) requests a variance to allow break testing of the Blowout Preventer (BOP) stack when skidding a drilling rig between wells on multi-well pads

- This practice entails retesting only the connections of the BOP stack that have been disconnected during this operation and not a complete BOP test.
- As the choke manifold remains stationary during the skidding operation and the only break to the manifold is tested, no further testing of the manifold is done until the next full BOP test.
- This request is being made as per Section IV of the *Onshore Oil and Gas Order (OOGO) No. 2*

Rationale for Allowing BOP Break Testing

American Petroleum Institute (API) standards, specifications and recommended practices are considered industry standards and are consistently utilized and referenced by the industry

- API Standard 53, *Blowout Prevention Equipment Systems for Drilling Wells* (Fourth Edition, November 2012, Addendum 1, July 2016) recognizes break testing as an acceptable practice.
- Specifically, API Standard 53, Section 6.5.3.4.1.b states "Pressure tests on the well control equipment shall be conducted after the disconnection or repair of any pressure containment seal in the BOP stack, choke line, kill line, choke manifold, or wellhead assembly but limited to the affected component."

Rationale for Allowing BOP Break Testing

The Bureau of Safety and Environmental Enforcement (BSEE), Department of Interior, has also utilized the API standards, specifications and best practices in the development of its offshore oil and gas regulations and incorporates them by reference within its regulations.

- BSEE issued new offshore regulations in July 2016 under 30 CFR Part 250, *Oil and Gas and Sulphur Operations in the Outer Continental Shelf - Blowout Preventer Systems and Well Control.* Within these regulations is language adopted from API Standard 53 which also supports break testing.
- Specifically, Section 250.737(d.8) states "Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly."

Rationale for Allowing BOP Break Testing

Break testing has been approved by the BLM in the past

- The Farmington Field Office approved a Sundry Notice (SN) to allow break testing in 2015
- This SN granted permission for the operator to break test when skidding its Aztec 1000 rig on multi-well pads

Oxy feels break testing and our current procedures meet or exceed the intent of OOGO No. 2

- As skidding operations take place within the 30-day full BOPE test window, the BOP shell and components such as the pipe rams and check valve get tested to the full rated working pressure more often
- Oxy's standard requires complete BOP tests more often than that of OOGO No. 2
- Oxy performs a choke drill prior to drilling out every casing shoe. As a crew's training is a vital part of well control, this procedure to simulate step one of the Driller's Method exceeds the requirements of OOGO No. 2

Break Testing Procedures

1) OXY to submit the break testing plan in the APD or Sundry Notice (SN) and receive approval prior to implementing

2) OXY would perform BOP break testing on multi-well pads where multiple intermediate sections can be drilled and cased within the full BOP test window

3) After performing a complete BOP test on the first well and drilling and casing the hole section, three breaks would be made on the BOP.
   - Between the check valve and the kill line
   - Between the HCR valve and the co-flex hose or the co-flex hose and the manifold
   - Between the BOP flange and the wellhead

4) The BOP is then lifted and removed from the wellhead by the hydraulic winch system

5) After skidding to the next well, the BOP is moved to the wellhead by the hydraulic winch system and installed

6) The choke line and kill line are reconnected

7) A test plug is installed in the wellhead with a joint of drill pipe and the internal parts of the check valve are removed

Break Testing Procedures

8) A shell test is performed against the upper pipe rams testing all three breaks

9) The internal parts of the check valve are reinstalled and the HCR valve is closed. A second test is performed on them

10) These tests consist of a 250 psi low test and a high test to the value submitted in the APD or SN (e.g., 5000 psi)

11) Perform a function test of components not pressure tested to include the lower pipe rams, the blind rams and the annular

12) If this were a three well pad, the same three breaks on the BOP would be made and steps 4 through 11 would be repeated

13) A second break test would only be done if the third hole section could be completed within the 30-day BOP test window

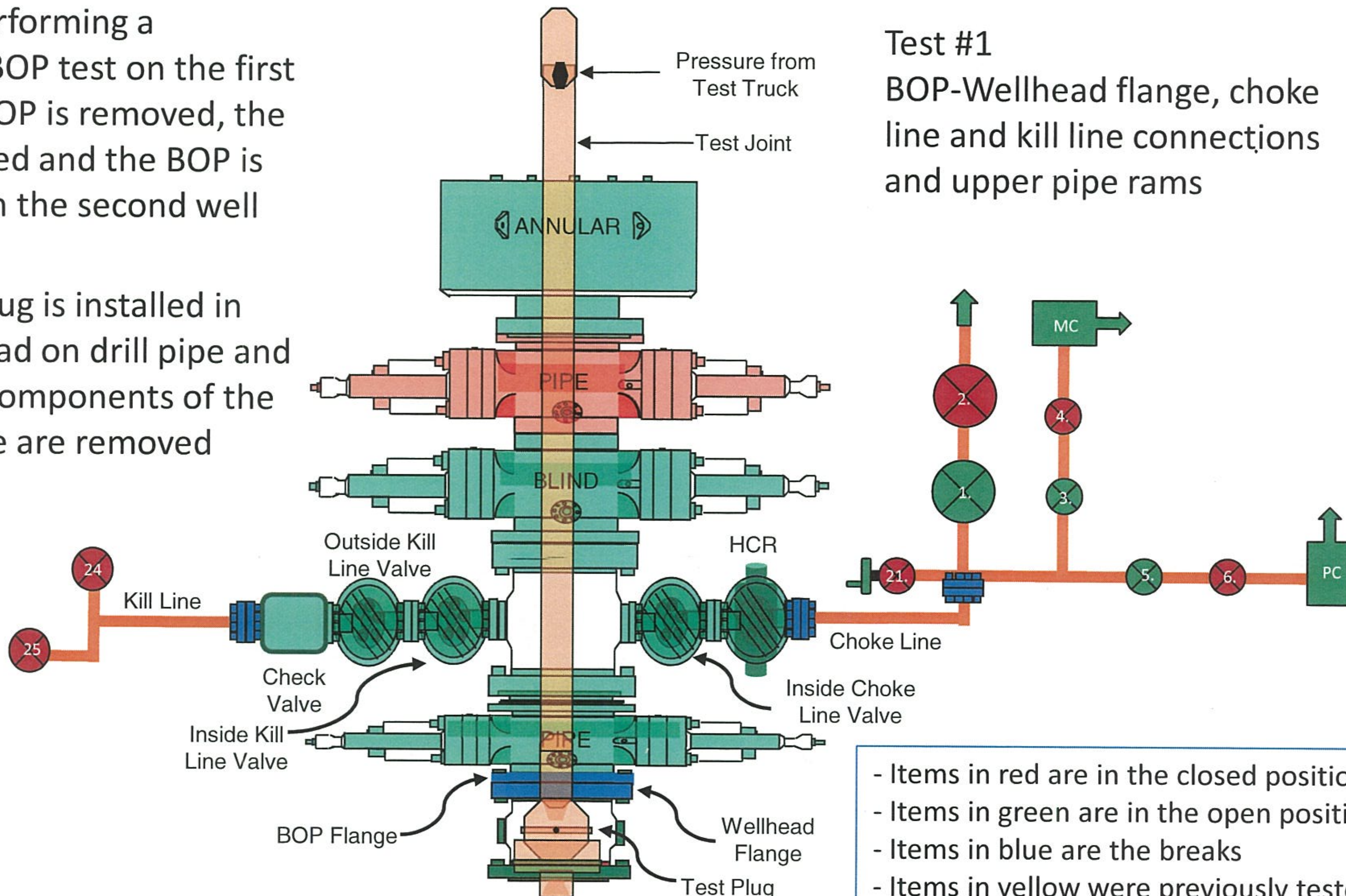
14) If a second break test is performed, additional components that were not tested on the first break test will be tested

Break Testing Procedures and Tests

1. After performing a complete BOP test on the first well, the BOP is removed, the rig is skidded and the BOP is installed on the second well

2. A test plug is installed in the wellhead on drill pipe and the inner components of the check valve are removed

Test #1
BOP-Wellhead flange, choke line and kill line connections and upper pipe rams

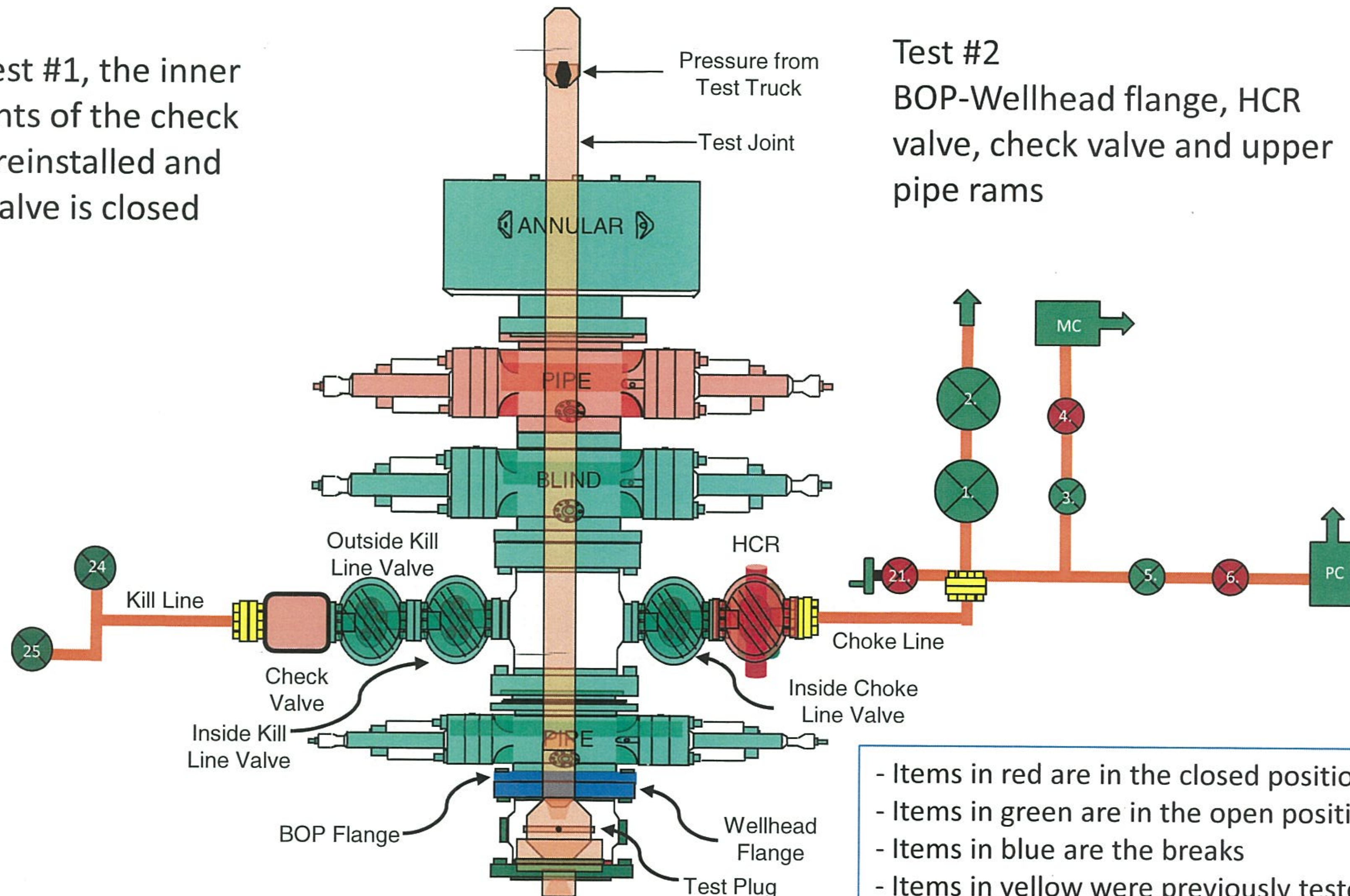


- Items in red are in the closed position
- Items in green are in the open position
- Items in blue are the breaks
- Items in yellow were previously tested

Break Testing Procedures and Tests

3. After Test #1, the inner components of the check valve are reinstalled and the HCR valve is closed

Test #2
BOP-Wellhead flange, HCR valve, check valve and upper pipe rams



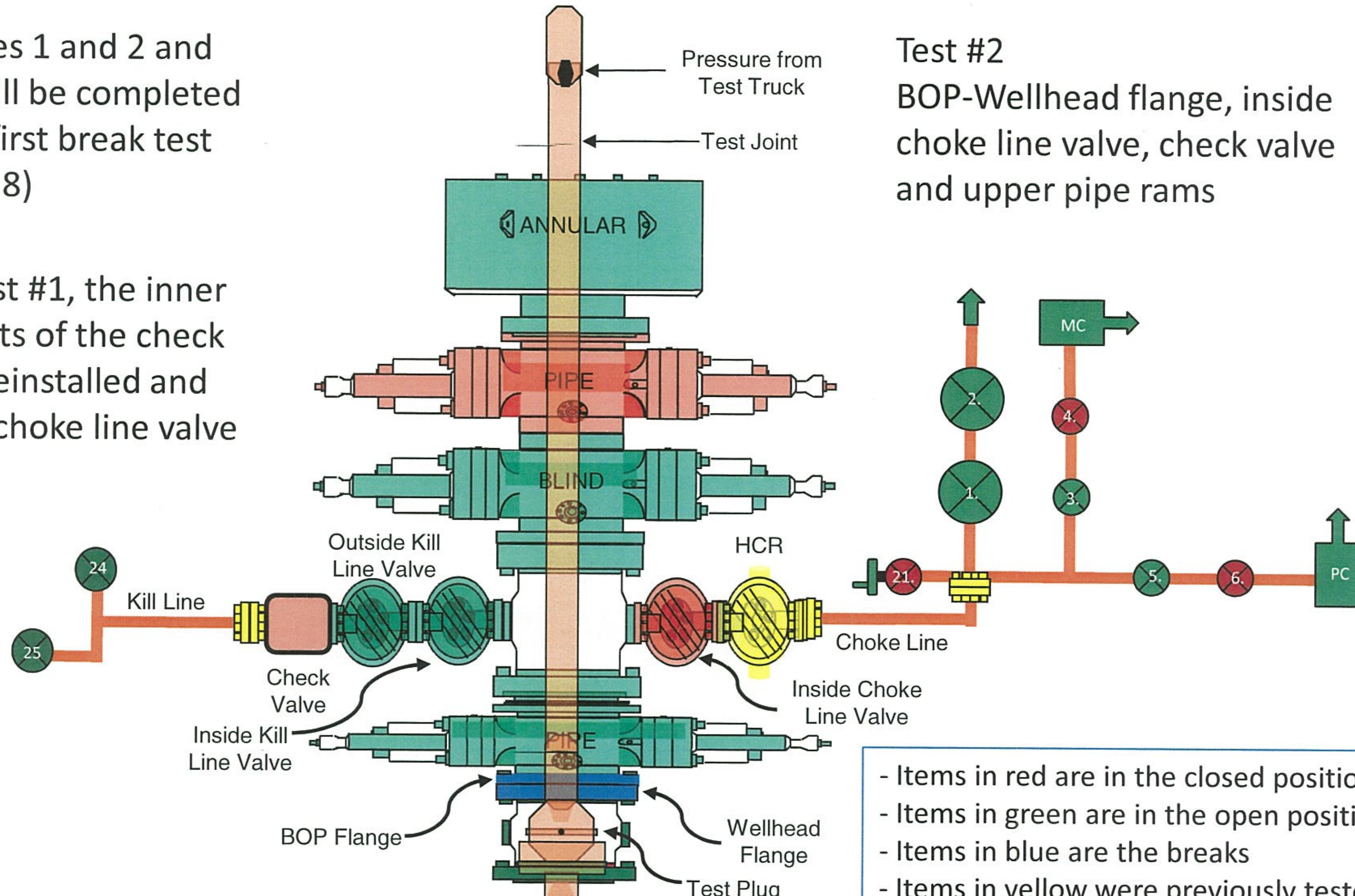
- Items in red are in the closed position
- Items in green are in the open position
- Items in blue are the breaks
- Items in yellow were previously tested

Second Break Testing Procedures and Tests

Procedures 1 and 2 and Test #1 will be completed as in the first break test (see slide 8)

3. After Test #1, the inner components of the check valve are reinstalled and the inside choke line valve is closed

Test #2
BOP-Wellhead flange, inside choke line valve, check valve and upper pipe rams



- Items in red are in the closed position
- Items in green are in the open position
- Items in blue are the breaks
- Items in yellow were previously tested

BOP Handling System

Hydraulic winch system which moves the BOP from its carrier to the wellhead

BOP standing in its carrier

BOP Handling System

Hydraulic winch system moving the BOP over to the wellhead

Wellhead

Summary for Variance Request for Break Testing

- API standards, specifications and recommended practices are considered industry standards
  - *OOGO No. 2* recognized API Recommended Practices (RP) 53 in its original development
  - API Standard 53 recognizes break testing as an acceptable practice
  - The Bureau of Safety and Environmental Enforcement has utilized API standards, specifications and best practices in the development of its offshore oil and gas regulations
  - API Standard 53 recognizes break testing as an acceptable practice

- OXY feels break testing meets the intent of *OOGO No. 2* to protect public health and safety and the environment

OXY

PRD NM DIRECTIONAL PLANS (NAD 1983)
Tuna Nut 24_13 Fed Com
Tuna Nut 24_13 Fed Com 311H

Wellbore #1

Plan: Permitting Plan

Standard Planning Report

22 November, 2022

OXY

Planning Report

Database:	HOPSPP	**Local Co-ordinate Reference:**	Well Tuna Nut 24_13 Fed Com 311H
Company:	ENGINEERING DESIGNS	**TVD Reference:**	RKB=25' @ 3790.00ft
Project:	PRD NM DIRECTIONAL PLANS (NAD 1983)	**MD Reference:**	RKB=25' @ 3790.00ft
Site:	Tuna Nut 24_13 Fed Com	**North Reference:**	Grid
Well:	Tuna Nut 24_13 Fed Com 311H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	Wellbore #1		
Design:	Permitting Plan		

Project	PRD NM DIRECTIONAL PLANS (NAD 1983)		
Map System:	US State Plane 1983	**System Datum:**	Mean Sea Level
Geo Datum:	North American Datum 1983		
Map Zone:	New Mexico Eastern Zone		Using geodetic scale factor

Site	Tuna Nut 24_13 Fed Com				
Site Position:		**Northing:**	497,414.86 usft	**Latitude:**	32.365515
From:	Map	**Easting:**	757,769.29 usft	**Longitude:**	-103.632352
Position Uncertainty:	2.00 ft	**Slot Radius:**	13.200 in		

Well	Tuna Nut 24_13 Fed Com 311H					
Well Position	**+N/-S**	0.00 ft	**Northing:**	497,414.86 usf	**Latitude:**	32.365515
	+E/-W	0.00 ft	**Easting:**	757,769.29 usf	**Longitude:**	-103.632352
Position Uncertainty		2.00 ft	**Wellhead Elevation:**	ft	**Ground Level:**	3,765.00 ft
Grid Convergence:		0.38 °				

Wellbore Wellbore #1

Magnetics	Model Name	Sample Date	Declination (°)	Dip Angle (°)	Field Strength (nT)
	HDGM_FILE	11/21/2022	6.32	59.98	47,689.80000000

Design Permitting Plan

Audit Notes:

Version:		**Phase:**	PROTOTYPE	**Tie On Depth:**	0.00

Vertical Section:	Depth From (TVD) (ft)	+N/-S (ft)	+E/-W (ft)	Direction (°)
	0.00	0.00	0.00	358.15

Plan Survey Tool Program **Date** 11/22/2022

	Depth From (ft)	Depth To (ft)	Survey (Wellbore)	Tool Name	Remarks
1	0.00	22,717.61	Permitting Plan (Wellbore #1)	B001Mb_MWD+HRGM OWSG MWD + HRGM	

Plan Sections

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Turn Rate (°/100ft)	TFO (°)	Target
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
4,985.00	0.00	0.00	4,985.00	0.00	0.00	0.00	0.00	0.00	0.00	
6,184.56	12.00	346.29	6,175.82	121.55	-29.66	1.00	1.00	0.00	346.29	
11,498.30	12.00	346.29	11,373.53	1,194.46	-291.44	0.00	0.00	0.00	0.00	
12,272.84	89.12	359.58	11,830.00	1,746.64	-317.41	10.00	9.96	1.72	13.62	FTP (Tuna Nut
22,717.61	89.12	359.58	11,990.00	12,189.91	-393.37	0.00	0.00	0.00	0.00	PBHL (Tuna Nut

OXY

Planning Report

Database:	HOPSPP	**Local Co-ordinate Reference:**	Well Tuna Nut 24_13 Fed Com 311H
Company:	ENGINEERING DESIGNS	**TVD Reference:**	RKB=25' @ 3790.00ft
Project:	PRD NM DIRECTIONAL PLANS (NAD 1983)	**MD Reference:**	RKB=25' @ 3790.00ft
Site:	Tuna Nut 24_13 Fed Com	**North Reference:**	Grid
Well:	Tuna Nut 24_13 Fed Com 311H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	Wellbore #1		
Design:	Permitting Plan		

Planned Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Turn Rate (°/100ft)
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
100.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00
200.00	0.00	0.00	200.00	0.00	0.00	0.00	0.00	0.00	0.00
300.00	0.00	0.00	300.00	0.00	0.00	0.00	0.00	0.00	0.00
400.00	0.00	0.00	400.00	0.00	0.00	0.00	0.00	0.00	0.00
500.00	0.00	0.00	500.00	0.00	0.00	0.00	0.00	0.00	0.00
600.00	0.00	0.00	600.00	0.00	0.00	0.00	0.00	0.00	0.00
700.00	0.00	0.00	700.00	0.00	0.00	0.00	0.00	0.00	0.00
800.00	0.00	0.00	800.00	0.00	0.00	0.00	0.00	0.00	0.00
900.00	0.00	0.00	900.00	0.00	0.00	0.00	0.00	0.00	0.00
1,000.00	0.00	0.00	1,000.00	0.00	0.00	0.00	0.00	0.00	0.00
1,100.00	0.00	0.00	1,100.00	0.00	0.00	0.00	0.00	0.00	0.00
1,200.00	0.00	0.00	1,200.00	0.00	0.00	0.00	0.00	0.00	0.00
1,300.00	0.00	0.00	1,300.00	0.00	0.00	0.00	0.00	0.00	0.00
1,400.00	0.00	0.00	1,400.00	0.00	0.00	0.00	0.00	0.00	0.00
1,500.00	0.00	0.00	1,500.00	0.00	0.00	0.00	0.00	0.00	0.00
1,600.00	0.00	0.00	1,600.00	0.00	0.00	0.00	0.00	0.00	0.00
1,700.00	0.00	0.00	1,700.00	0.00	0.00	0.00	0.00	0.00	0.00
1,800.00	0.00	0.00	1,800.00	0.00	0.00	0.00	0.00	0.00	0.00
1,900.00	0.00	0.00	1,900.00	0.00	0.00	0.00	0.00	0.00	0.00
2,000.00	0.00	0.00	2,000.00	0.00	0.00	0.00	0.00	0.00	0.00
2,100.00	0.00	0.00	2,100.00	0.00	0.00	0.00	0.00	0.00	0.00
2,200.00	0.00	0.00	2,200.00	0.00	0.00	0.00	0.00	0.00	0.00
2,300.00	0.00	0.00	2,300.00	0.00	0.00	0.00	0.00	0.00	0.00
2,400.00	0.00	0.00	2,400.00	0.00	0.00	0.00	0.00	0.00	0.00
2,500.00	0.00	0.00	2,500.00	0.00	0.00	0.00	0.00	0.00	0.00
2,600.00	0.00	0.00	2,600.00	0.00	0.00	0.00	0.00	0.00	0.00
2,700.00	0.00	0.00	2,700.00	0.00	0.00	0.00	0.00	0.00	0.00
2,800.00	0.00	0.00	2,800.00	0.00	0.00	0.00	0.00	0.00	0.00
2,900.00	0.00	0.00	2,900.00	0.00	0.00	0.00	0.00	0.00	0.00
3,000.00	0.00	0.00	3,000.00	0.00	0.00	0.00	0.00	0.00	0.00
3,100.00	0.00	0.00	3,100.00	0.00	0.00	0.00	0.00	0.00	0.00
3,200.00	0.00	0.00	3,200.00	0.00	0.00	0.00	0.00	0.00	0.00
3,300.00	0.00	0.00	3,300.00	0.00	0.00	0.00	0.00	0.00	0.00
3,400.00	0.00	0.00	3,400.00	0.00	0.00	0.00	0.00	0.00	0.00
3,500.00	0.00	0.00	3,500.00	0.00	0.00	0.00	0.00	0.00	0.00
3,600.00	0.00	0.00	3,600.00	0.00	0.00	0.00	0.00	0.00	0.00
3,700.00	0.00	0.00	3,700.00	0.00	0.00	0.00	0.00	0.00	0.00
3,800.00	0.00	0.00	3,800.00	0.00	0.00	0.00	0.00	0.00	0.00
3,900.00	0.00	0.00	3,900.00	0.00	0.00	0.00	0.00	0.00	0.00
4,000.00	0.00	0.00	4,000.00	0.00	0.00	0.00	0.00	0.00	0.00
4,100.00	0.00	0.00	4,100.00	0.00	0.00	0.00	0.00	0.00	0.00
4,200.00	0.00	0.00	4,200.00	0.00	0.00	0.00	0.00	0.00	0.00
4,300.00	0.00	0.00	4,300.00	0.00	0.00	0.00	0.00	0.00	0.00
4,400.00	0.00	0.00	4,400.00	0.00	0.00	0.00	0.00	0.00	0.00
4,500.00	0.00	0.00	4,500.00	0.00	0.00	0.00	0.00	0.00	0.00
4,600.00	0.00	0.00	4,600.00	0.00	0.00	0.00	0.00	0.00	0.00
4,700.00	0.00	0.00	4,700.00	0.00	0.00	0.00	0.00	0.00	0.00
4,800.00	0.00	0.00	4,800.00	0.00	0.00	0.00	0.00	0.00	0.00
4,900.00	0.00	0.00	4,900.00	0.00	0.00	0.00	0.00	0.00	0.00
4,985.00	0.00	0.00	4,985.00	0.00	0.00	0.00	0.00	0.00	0.00
5,000.00	0.15	346.29	5,000.00	0.02	0.00	0.02	1.00	1.00	0.00
5,100.00	1.15	346.29	5,099.99	1.12	-0.27	1.13	1.00	1.00	0.00
5,200.00	2.15	346.29	5,199.95	3.92	-0.96	3.95	1.00	1.00	0.00
5,300.00	3.15	346.29	5,299.84	8.41	-2.05	8.47	1.00	1.00	0.00

OXY

Planning Report

Database:	HOPSPP	**Local Co-ordinate Reference:**	Well Tuna Nut 24_13 Fed Com 311H
Company:	ENGINEERING DESIGNS	**TVD Reference:**	RKB=25' @ 3790.00ft
Project:	PRD NM DIRECTIONAL PLANS (NAD 1983)	**MD Reference:**	RKB=25' @ 3790.00ft
Site:	Tuna Nut 24_13 Fed Com	**North Reference:**	Grid
Well:	Tuna Nut 24_13 Fed Com 311H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	Wellbore #1		
Design:	Permitting Plan		

Planned Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Turn Rate (°/100ft)
5,400.00	4.15	346.29	5,399.64	14.59	-3.56	14.70	1.00	1.00	0.00
5,500.00	5.15	346.29	5,499.31	22.47	-5.48	22.64	1.00	1.00	0.00
5,600.00	6.15	346.29	5,598.82	32.03	-7.82	32.27	1.00	1.00	0.00
5,700.00	7.15	346.29	5,698.15	43.29	-10.56	43.60	1.00	1.00	0.00
5,800.00	8.15	346.29	5,797.25	56.22	-13.72	56.63	1.00	1.00	0.00
5,900.00	9.15	346.29	5,896.12	70.83	-17.28	71.35	1.00	1.00	0.00
6,000.00	10.15	346.29	5,994.70	87.11	-21.25	87.75	1.00	1.00	0.00
6,100.00	11.15	346.29	6,092.98	105.07	-25.64	105.84	1.00	1.00	0.00
6,184.56	12.00	346.29	6,175.82	121.55	-29.66	122.44	1.00	1.00	0.00
6,200.00	12.00	346.29	6,190.92	124.67	-30.42	125.58	0.00	0.00	0.00
6,300.00	12.00	346.29	6,288.74	144.86	-35.34	145.92	0.00	0.00	0.00
6,400.00	12.00	346.29	6,386.55	165.05	-40.27	166.26	0.00	0.00	0.00
6,500.00	12.00	346.29	6,484.37	185.24	-45.20	186.60	0.00	0.00	0.00
6,600.00	12.00	346.29	6,582.18	205.43	-50.12	206.94	0.00	0.00	0.00
6,700.00	12.00	346.29	6,680.00	225.62	-55.05	227.28	0.00	0.00	0.00
6,800.00	12.00	346.29	6,777.82	245.81	-59.98	247.62	0.00	0.00	0.00
6,900.00	12.00	346.29	6,875.63	266.00	-64.90	267.96	0.00	0.00	0.00
7,000.00	12.00	346.29	6,973.45	286.20	-69.83	288.30	0.00	0.00	0.00
7,100.00	12.00	346.29	7,071.27	306.39	-74.76	308.64	0.00	0.00	0.00
7,200.00	12.00	346.29	7,169.08	326.58	-79.68	328.98	0.00	0.00	0.00
7,300.00	12.00	346.29	7,266.90	346.77	-84.61	349.32	0.00	0.00	0.00
7,400.00	12.00	346.29	7,364.72	366.96	-89.53	369.66	0.00	0.00	0.00
7,500.00	12.00	346.29	7,462.53	387.15	-94.46	390.00	0.00	0.00	0.00
7,600.00	12.00	346.29	7,560.35	407.34	-99.39	410.34	0.00	0.00	0.00
7,700.00	12.00	346.29	7,658.16	427.54	-104.31	430.68	0.00	0.00	0.00
7,800.00	12.00	346.29	7,755.98	447.73	-109.24	451.02	0.00	0.00	0.00
7,900.00	12.00	346.29	7,853.80	467.92	-114.17	471.36	0.00	0.00	0.00
8,000.00	12.00	346.29	7,951.61	488.11	-119.09	491.70	0.00	0.00	0.00
8,100.00	12.00	346.29	8,049.43	508.30	-124.02	512.04	0.00	0.00	0.00
8,200.00	12.00	346.29	8,147.25	528.49	-128.95	532.38	0.00	0.00	0.00
8,300.00	12.00	346.29	8,245.06	548.68	-133.87	552.72	0.00	0.00	0.00
8,400.00	12.00	346.29	8,342.88	568.88	-138.80	573.06	0.00	0.00	0.00
8,500.00	12.00	346.29	8,440.70	589.07	-143.73	593.40	0.00	0.00	0.00
8,600.00	12.00	346.29	8,538.51	609.26	-148.65	613.74	0.00	0.00	0.00
8,700.00	12.00	346.29	8,636.33	629.45	-153.58	634.08	0.00	0.00	0.00
8,800.00	12.00	346.29	8,734.14	649.64	-158.50	654.41	0.00	0.00	0.00
8,900.00	12.00	346.29	8,831.96	669.83	-163.43	674.75	0.00	0.00	0.00
9,000.00	12.00	346.29	8,929.78	690.02	-168.36	695.09	0.00	0.00	0.00
9,100.00	12.00	346.29	9,027.59	710.21	-173.28	715.43	0.00	0.00	0.00
9,200.00	12.00	346.29	9,125.41	730.41	-178.21	735.77	0.00	0.00	0.00
9,300.00	12.00	346.29	9,223.23	750.60	-183.14	756.11	0.00	0.00	0.00
9,400.00	12.00	346.29	9,321.04	770.79	-188.06	776.45	0.00	0.00	0.00
9,500.00	12.00	346.29	9,418.86	790.98	-192.99	796.79	0.00	0.00	0.00
9,600.00	12.00	346.29	9,516.68	811.17	-197.92	817.13	0.00	0.00	0.00
9,700.00	12.00	346.29	9,614.49	831.36	-202.84	837.47	0.00	0.00	0.00
9,800.00	12.00	346.29	9,712.31	851.55	-207.77	857.81	0.00	0.00	0.00
9,900.00	12.00	346.29	9,810.12	871.75	-212.70	878.15	0.00	0.00	0.00
10,000.00	12.00	346.29	9,907.94	891.94	-217.62	898.49	0.00	0.00	0.00
10,100.00	12.00	346.29	10,005.76	912.13	-222.55	918.83	0.00	0.00	0.00
10,200.00	12.00	346.29	10,103.57	932.32	-227.48	939.17	0.00	0.00	0.00
10,300.00	12.00	346.29	10,201.39	952.51	-232.40	959.51	0.00	0.00	0.00
10,400.00	12.00	346.29	10,299.21	972.70	-237.33	979.85	0.00	0.00	0.00
10,500.00	12.00	346.29	10,397.02	992.89	-242.25	1,000.19	0.00	0.00	0.00
10,600.00	12.00	346.29	10,494.84	1,013.08	-247.18	1,020.53	0.00	0.00	0.00
10,700.00	12.00	346.29	10,592.65	1,033.28	-252.11	1,040.87	0.00	0.00	0.00

OXY

Planning Report

Database:	HOPSPP	**Local Co-ordinate Reference:**	Well Tuna Nut 24_13 Fed Com 311H
Company:	ENGINEERING DESIGNS	**TVD Reference:**	RKB=25' @ 3790.00ft
Project:	PRD NM DIRECTIONAL PLANS (NAD 1983)	**MD Reference:**	RKB=25' @ 3790.00ft
Site:	Tuna Nut 24_13 Fed Com	**North Reference:**	Grid
Well:	Tuna Nut 24_13 Fed Com 311H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	Wellbore #1		
Design:	Permitting Plan		

Planned Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Turn Rate (°/100ft)
10,800.00	12.00	346.29	10,690.47	1,053.47	-257.03	1,061.21	0.00	0.00	0.00
10,900.00	12.00	346.29	10,788.29	1,073.66	-261.96	1,081.55	0.00	0.00	0.00
11,000.00	12.00	346.29	10,886.10	1,093.85	-266.89	1,101.89	0.00	0.00	0.00
11,100.00	12.00	346.29	10,983.92	1,114.04	-271.81	1,122.23	0.00	0.00	0.00
11,200.00	12.00	346.29	11,081.74	1,134.23	-276.74	1,142.57	0.00	0.00	0.00
11,300.00	12.00	346.29	11,179.55	1,154.42	-281.67	1,162.91	0.00	0.00	0.00
11,400.00	12.00	346.29	11,277.37	1,174.62	-286.59	1,183.25	0.00	0.00	0.00
11,498.30	12.00	346.29	11,373.53	1,194.46	-291.44	1,203.24	0.00	0.00	0.00
11,500.00	12.16	346.48	11,375.19	1,194.81	-291.52	1,203.59	10.00	9.72	11.18
11,600.00	22.01	352.66	11,470.66	1,223.71	-296.39	1,232.63	10.00	9.85	6.18
11,700.00	31.95	355.12	11,559.67	1,268.76	-301.04	1,277.81	10.00	9.94	2.46
11,800.00	41.91	356.50	11,639.51	1,328.62	-305.35	1,337.77	10.00	9.97	1.38
11,900.00	51.89	357.42	11,707.75	1,401.44	-309.17	1,410.68	10.00	9.98	0.93
12,000.00	61.87	358.12	11,762.32	1,485.03	-312.39	1,494.33	10.00	9.98	0.70
12,100.00	71.86	358.71	11,801.55	1,576.84	-314.91	1,586.17	10.00	9.99	0.58
12,200.00	81.85	359.22	11,824.27	1,674.08	-316.66	1,683.42	10.00	9.99	0.52
12,272.84	89.12	359.58	11,830.00	1,746.64	-317.41	1,755.97	10.00	9.99	0.49
12,300.00	89.12	359.58	11,830.42	1,773.79	-317.61	1,783.11	0.00	0.00	0.00
12,400.00	89.12	359.58	11,831.95	1,873.78	-318.34	1,883.07	0.00	0.00	0.00
12,500.00	89.12	359.58	11,833.48	1,973.76	-319.06	1,983.03	0.00	0.00	0.00
12,600.00	89.12	359.58	11,835.01	2,073.75	-319.79	2,082.98	0.00	0.00	0.00
12,700.00	89.12	359.58	11,836.54	2,173.73	-320.52	2,182.94	0.00	0.00	0.00
12,800.00	89.12	359.58	11,838.08	2,273.72	-321.25	2,282.90	0.00	0.00	0.00
12,900.00	89.12	359.58	11,839.61	2,373.71	-321.97	2,382.86	0.00	0.00	0.00
13,000.00	89.12	359.58	11,841.14	2,473.69	-322.70	2,482.81	0.00	0.00	0.00
13,100.00	89.12	359.58	11,842.67	2,573.68	-323.43	2,582.77	0.00	0.00	0.00
13,200.00	89.12	359.58	11,844.20	2,673.66	-324.15	2,682.73	0.00	0.00	0.00
13,300.00	89.12	359.58	11,845.73	2,773.65	-324.88	2,782.68	0.00	0.00	0.00
13,400.00	89.12	359.58	11,847.27	2,873.63	-325.61	2,882.64	0.00	0.00	0.00
13,500.00	89.12	359.58	11,848.80	2,973.62	-326.34	2,982.60	0.00	0.00	0.00
13,600.00	89.12	359.58	11,850.33	3,073.61	-327.06	3,082.56	0.00	0.00	0.00
13,700.00	89.12	359.58	11,851.86	3,173.59	-327.79	3,182.51	0.00	0.00	0.00
13,800.00	89.12	359.58	11,853.39	3,273.58	-328.52	3,282.47	0.00	0.00	0.00
13,900.00	89.12	359.58	11,854.93	3,373.56	-329.24	3,382.43	0.00	0.00	0.00
14,000.00	89.12	359.58	11,856.46	3,473.55	-329.97	3,482.38	0.00	0.00	0.00
14,100.00	89.12	359.58	11,857.99	3,573.53	-330.70	3,582.34	0.00	0.00	0.00
14,200.00	89.12	359.58	11,859.52	3,673.52	-331.43	3,682.30	0.00	0.00	0.00
14,300.00	89.12	359.58	11,861.05	3,773.50	-332.15	3,782.25	0.00	0.00	0.00
14,400.00	89.12	359.58	11,862.59	3,873.49	-332.88	3,882.21	0.00	0.00	0.00
14,500.00	89.12	359.58	11,864.12	3,973.48	-333.61	3,982.17	0.00	0.00	0.00
14,600.00	89.12	359.58	11,865.65	4,073.46	-334.34	4,082.13	0.00	0.00	0.00
14,700.00	89.12	359.58	11,867.18	4,173.45	-335.06	4,182.08	0.00	0.00	0.00
14,800.00	89.12	359.58	11,868.71	4,273.43	-335.79	4,282.04	0.00	0.00	0.00
14,900.00	89.12	359.58	11,870.24	4,373.42	-336.52	4,382.00	0.00	0.00	0.00
15,000.00	89.12	359.58	11,871.78	4,473.40	-337.24	4,481.95	0.00	0.00	0.00
15,100.00	89.12	359.58	11,873.31	4,573.39	-337.97	4,581.91	0.00	0.00	0.00
15,200.00	89.12	359.58	11,874.84	4,673.38	-338.70	4,681.87	0.00	0.00	0.00
15,300.00	89.12	359.58	11,876.37	4,773.36	-339.43	4,781.83	0.00	0.00	0.00
15,400.00	89.12	359.58	11,877.90	4,873.35	-340.15	4,881.78	0.00	0.00	0.00
15,500.00	89.12	359.58	11,879.44	4,973.33	-340.88	4,981.74	0.00	0.00	0.00
15,600.00	89.12	359.58	11,880.97	5,073.32	-341.61	5,081.70	0.00	0.00	0.00
15,700.00	89.12	359.58	11,882.50	5,173.30	-342.33	5,181.65	0.00	0.00	0.00
15,800.00	89.12	359.58	11,884.03	5,273.29	-343.06	5,281.61	0.00	0.00	0.00
15,900.00	89.12	359.58	11,885.56	5,373.27	-343.79	5,381.57	0.00	0.00	0.00
16,000.00	89.12	359.58	11,887.10	5,473.26	-344.52	5,481.52	0.00	0.00	0.00

OXY
Planning Report

Database:	HOPSPP	**Local Co-ordinate Reference:**	Well Tuna Nut 24_13 Fed Com 311H
Company:	ENGINEERING DESIGNS	**TVD Reference:**	RKB=25' @ 3790.00ft
Project:	PRD NM DIRECTIONAL PLANS (NAD 1983)	**MD Reference:**	RKB=25' @ 3790.00ft
Site:	Tuna Nut 24_13 Fed Com	**North Reference:**	Grid
Well:	Tuna Nut 24_13 Fed Com 311H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	Wellbore #1		
Design:	Permitting Plan		

Planned Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Turn Rate (°/100ft)
16,100.00	89.12	359.58	11,888.63	5,573.25	-345.24	5,581.48	0.00	0.00	0.00
16,200.00	89.12	359.58	11,890.16	5,673.23	-345.97	5,681.44	0.00	0.00	0.00
16,300.00	89.12	359.58	11,891.69	5,773.22	-346.70	5,781.40	0.00	0.00	0.00
16,400.00	89.12	359.58	11,893.22	5,873.20	-347.42	5,881.35	0.00	0.00	0.00
16,500.00	89.12	359.58	11,894.75	5,973.19	-348.15	5,981.31	0.00	0.00	0.00
16,600.00	89.12	359.58	11,896.29	6,073.17	-348.88	6,081.27	0.00	0.00	0.00
16,700.00	89.12	359.58	11,897.82	6,173.16	-349.61	6,181.22	0.00	0.00	0.00
16,800.00	89.12	359.58	11,899.35	6,273.15	-350.33	6,281.18	0.00	0.00	0.00
16,900.00	89.12	359.58	11,900.88	6,373.13	-351.06	6,381.14	0.00	0.00	0.00
17,000.00	89.12	359.58	11,902.41	6,473.12	-351.79	6,481.10	0.00	0.00	0.00
17,100.00	89.12	359.58	11,903.95	6,573.10	-352.51	6,581.05	0.00	0.00	0.00
17,200.00	89.12	359.58	11,905.48	6,673.09	-353.24	6,681.01	0.00	0.00	0.00
17,300.00	89.12	359.58	11,907.01	6,773.07	-353.97	6,780.97	0.00	0.00	0.00
17,400.00	89.12	359.58	11,908.54	6,873.06	-354.70	6,880.92	0.00	0.00	0.00
17,500.00	89.12	359.58	11,910.07	6,973.04	-355.42	6,980.88	0.00	0.00	0.00
17,600.00	89.12	359.58	11,911.61	7,073.03	-356.15	7,080.84	0.00	0.00	0.00
17,700.00	89.12	359.58	11,913.14	7,173.02	-356.88	7,180.79	0.00	0.00	0.00
17,800.00	89.12	359.58	11,914.67	7,273.00	-357.61	7,280.75	0.00	0.00	0.00
17,900.00	89.12	359.58	11,916.20	7,372.99	-358.33	7,380.71	0.00	0.00	0.00
18,000.00	89.12	359.58	11,917.73	7,472.97	-359.06	7,480.67	0.00	0.00	0.00
18,100.00	89.12	359.58	11,919.26	7,572.96	-359.79	7,580.62	0.00	0.00	0.00
18,200.00	89.12	359.58	11,920.80	7,672.94	-360.51	7,680.58	0.00	0.00	0.00
18,300.00	89.12	359.58	11,922.33	7,772.93	-361.24	7,780.54	0.00	0.00	0.00
18,400.00	89.12	359.58	11,923.86	7,872.92	-361.97	7,880.49	0.00	0.00	0.00
18,500.00	89.12	359.58	11,925.39	7,972.90	-362.70	7,980.45	0.00	0.00	0.00
18,600.00	89.12	359.58	11,926.92	8,072.89	-363.42	8,080.41	0.00	0.00	0.00
18,700.00	89.12	359.58	11,928.46	8,172.87	-364.15	8,180.37	0.00	0.00	0.00
18,800.00	89.12	359.58	11,929.99	8,272.86	-364.88	8,280.32	0.00	0.00	0.00
18,900.00	89.12	359.58	11,931.52	8,372.84	-365.60	8,380.28	0.00	0.00	0.00
19,000.00	89.12	359.58	11,933.05	8,472.83	-366.33	8,480.24	0.00	0.00	0.00
19,100.00	89.12	359.58	11,934.58	8,572.81	-367.06	8,580.19	0.00	0.00	0.00
19,200.00	89.12	359.58	11,936.12	8,672.80	-367.79	8,680.15	0.00	0.00	0.00
19,300.00	89.12	359.58	11,937.65	8,772.79	-368.51	8,780.11	0.00	0.00	0.00
19,400.00	89.12	359.58	11,939.18	8,872.77	-369.24	8,880.06	0.00	0.00	0.00
19,500.00	89.12	359.58	11,940.71	8,972.76	-369.97	8,980.02	0.00	0.00	0.00
19,600.00	89.12	359.58	11,942.24	9,072.74	-370.69	9,079.98	0.00	0.00	0.00
19,700.00	89.12	359.58	11,943.77	9,172.73	-371.42	9,179.94	0.00	0.00	0.00
19,800.00	89.12	359.58	11,945.31	9,272.71	-372.15	9,279.89	0.00	0.00	0.00
19,900.00	89.12	359.58	11,946.84	9,372.70	-372.88	9,379.85	0.00	0.00	0.00
20,000.00	89.12	359.58	11,948.37	9,472.69	-373.60	9,479.81	0.00	0.00	0.00
20,100.00	89.12	359.58	11,949.90	9,572.67	-374.33	9,579.76	0.00	0.00	0.00
20,200.00	89.12	359.58	11,951.43	9,672.66	-375.06	9,679.72	0.00	0.00	0.00
20,300.00	89.12	359.58	11,952.97	9,772.64	-375.78	9,779.68	0.00	0.00	0.00
20,400.00	89.12	359.58	11,954.50	9,872.63	-376.51	9,879.64	0.00	0.00	0.00
20,500.00	89.12	359.58	11,956.03	9,972.61	-377.24	9,979.59	0.00	0.00	0.00
20,600.00	89.12	359.58	11,957.56	10,072.60	-377.97	10,079.55	0.00	0.00	0.00
20,700.00	89.12	359.58	11,959.09	10,172.58	-378.69	10,179.51	0.00	0.00	0.00
20,800.00	89.12	359.58	11,960.62	10,272.57	-379.42	10,279.46	0.00	0.00	0.00
20,900.00	89.12	359.58	11,962.16	10,372.56	-380.15	10,379.42	0.00	0.00	0.00
21,000.00	89.12	359.58	11,963.69	10,472.54	-380.88	10,479.38	0.00	0.00	0.00
21,100.00	89.12	359.58	11,965.22	10,572.53	-381.60	10,579.33	0.00	0.00	0.00
21,200.00	89.12	359.58	11,966.75	10,672.51	-382.33	10,679.29	0.00	0.00	0.00
21,300.00	89.12	359.58	11,968.28	10,772.50	-383.06	10,779.25	0.00	0.00	0.00
21,400.00	89.12	359.58	11,969.82	10,872.48	-383.78	10,879.21	0.00	0.00	0.00
21,500.00	89.12	359.58	11,971.35	10,972.47	-384.51	10,979.16	0.00	0.00	0.00

OXY

Planning Report

Database:	HOPSPP	**Local Co-ordinate Reference:**	Well Tuna Nut 24_13 Fed Com 311H
Company:	ENGINEERING DESIGNS	**TVD Reference:**	RKB=25' @ 3790.00ft
Project:	PRD NM DIRECTIONAL PLANS (NAD 1983)	**MD Reference:**	RKB=25' @ 3790.00ft
Site:	Tuna Nut 24_13 Fed Com	**North Reference:**	Grid
Well:	Tuna Nut 24_13 Fed Com 311H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	Wellbore #1		
Design:	Permitting Plan		

Planned Survey

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Vertical Section (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Turn Rate (°/100ft)
21,600.00	89.12	359.58	11,972.88	11,072.46	-385.24	11,079.12	0.00	0.00	0.00
21,700.00	89.12	359.58	11,974.41	11,172.44	-385.97	11,179.08	0.00	0.00	0.00
21,800.00	89.12	359.58	11,975.94	11,272.43	-386.69	11,279.03	0.00	0.00	0.00
21,900.00	89.12	359.58	11,977.48	11,372.41	-387.42	11,378.99	0.00	0.00	0.00
22,000.00	89.12	359.58	11,979.01	11,472.40	-388.15	11,478.95	0.00	0.00	0.00
22,100.00	89.12	359.58	11,980.54	11,572.38	-388.87	11,578.91	0.00	0.00	0.00
22,200.00	89.12	359.58	11,982.07	11,672.37	-389.60	11,678.86	0.00	0.00	0.00
22,300.00	89.12	359.58	11,983.60	11,772.35	-390.33	11,778.82	0.00	0.00	0.00
22,400.00	89.12	359.58	11,985.13	11,872.34	-391.06	11,878.78	0.00	0.00	0.00
22,500.00	89.12	359.58	11,986.67	11,972.33	-391.78	11,978.73	0.00	0.00	0.00
22,600.00	89.12	359.58	11,988.20	12,072.31	-392.51	12,078.69	0.00	0.00	0.00
22,700.00	89.12	359.58	11,989.73	12,172.30	-393.24	12,178.65	0.00	0.00	0.00
22,717.61	89.12	359.58	11,990.00	12,189.91	-393.37	12,196.25	0.00	0.00	0.00

Design Targets

Target Name - hit/miss target - Shape	Dip Angle (°)	Dip Dir. (°)	TVD (ft)	+N/-S (ft)	+E/-W (ft)	Northing (usft)	Easting (usft)	Latitude	Longitude
FTP (Tuna Nut 24_13 - plan hits target center - Point	0.00	0.00	11,830.00	1,746.64	-317.41	499,161.43	757,451.89	32.370322	-103.633343
PBHL (Tuna Nut - plan hits target center - Point	0.00	0.00	11,990.00	12,189.91	-393.37	509,604.29	757,375.94	32.399027	-103.633368

Formations

Measured Depth (ft)	Vertical Depth (ft)	Name	Lithology	Dip (°)	Dip Direction (°)
1,041.00	1,041.00	RUSTLER			
1,687.00	1,687.00	SALADO			
3,468.00	3,468.00	CASTILE			
4,905.00	4,905.00	DELAWARE			
4,996.00	4,996.00	BELL CANYON			
5,791.66	5,789.00	CHERRY CANYON			
7,120.17	7,091.00	BRUSHY CANYON			
8,795.76	8,730.00	BONE SPRING			
9,927.48	9,837.00	BONE SPRING 1ST			
10,629.81	10,524.00	BONE SPRING 2ND			
11,808.78	11,646.00	BONE SPRING 3RD			

OXY

Planning Report

Database:	HOPSPP	**Local Co-ordinate Reference:**	Well Tuna Nut 24_13 Fed Com 311H
Company:	ENGINEERING DESIGNS	**TVD Reference:**	RKB=25' @ 3790.00ft
Project:	PRD NM DIRECTIONAL PLANS (NAD 1983)	**MD Reference:**	RKB=25' @ 3790.00ft
Site:	Tuna Nut 24_13 Fed Com	**North Reference:**	Grid
Well:	Tuna Nut 24_13 Fed Com 311H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	Wellbore #1		
Design:	Permitting Plan		

Plan Annotations

Measured Depth (ft)	Vertical Depth (ft)	Local Coordinates +N/-S (ft)	Local Coordinates +E/-W (ft)	Comment
4,985.00	4,985.00	0.00	0.00	Build 1°/100'
6,184.56	6,175.82	121.55	-29.66	Hold 12° Tangent
11,498.30	11,373.53	1,194.46	-291.44	KOP, Build & Turn 10°/100'
12,272.84	11,830.00	1,746.64	-317.41	Landing Point
22,717.61	11,990.00	12,189.91	-393.37	TD at 22717.61' MD

PROJECT DETAILS: NM DIRECTIONAL PLANS (NAD 1983)

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

System Datum: Mean Sea Level

Project: PRD NM DIRECTIONAL PLANS (NAD 1983)
Site: Tuna Nut 24_13 Fed Com
Well: Tuna Nut 24_13 Fed Com 311H
Wellbore: Wellbore #1
Design: Permitting Plan

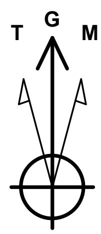
WELL DETAILS: Tuna Nut 24_13 Fed Com 311H

3765.00

+N/-S	+E/-W	Northing	Easting	Latittude	Longitude
0.00	0.00	497414.86	757769.29	32.365515	-103.632352

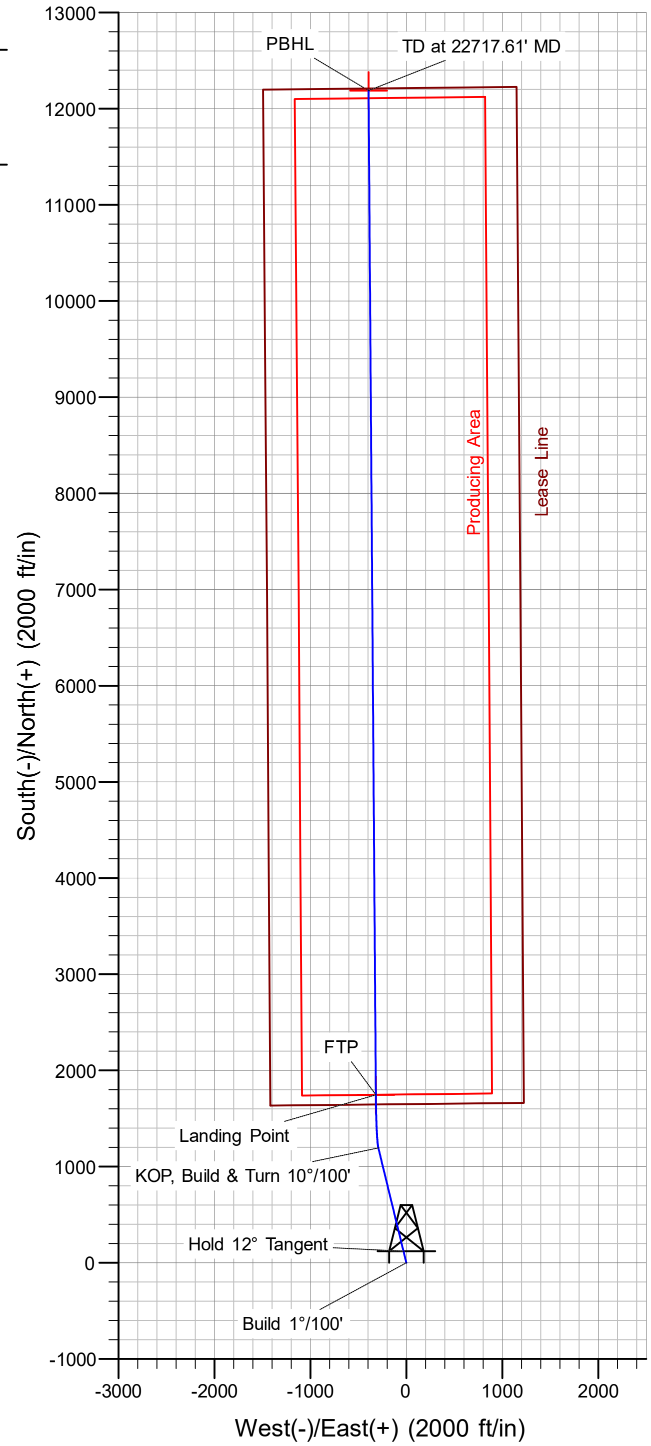
SECTION DETAILS

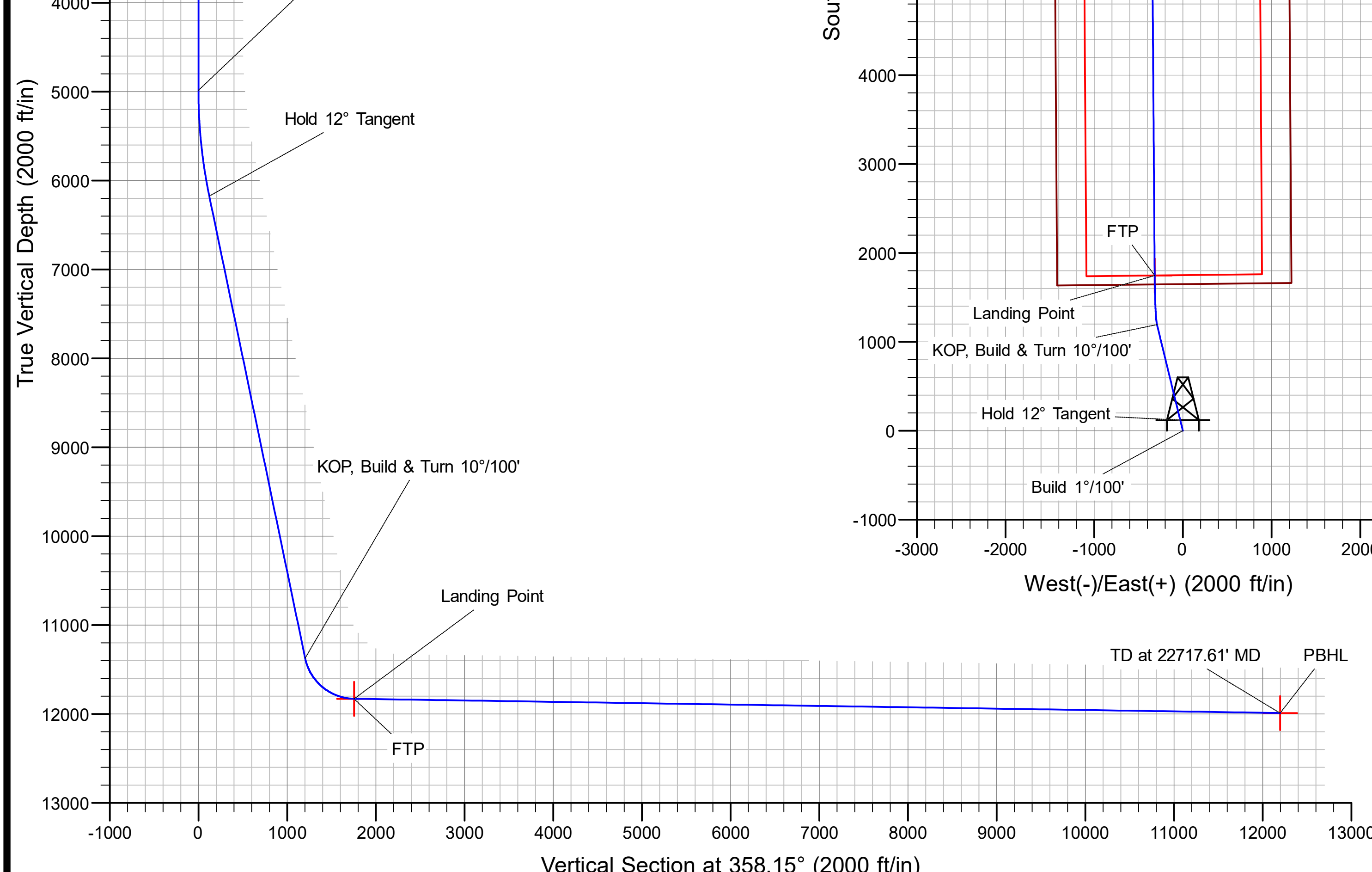
MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Annotation
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
4985.00	0.00	0.00	4985.00	0.00	0.00	0.00	0.00	0.00	Build 1°/100'
6184.56	12.00	346.29	6175.82	121.55	-29.66	1.00	346.29	122.44	Hold 12° Tangent
11498.30	12.00	346.29	11373.53	1194.46	-291.44	0.00	0.00	1203.24	KOP, Build & Turn 10°/100'
12272.84	89.12	359.58	11830.00	1746.64	-317.41	10.00	13.62	1755.97	Landing Point
22717.61	89.12	359.58	11990.00	12189.91	-393.37	0.00	0.00	12196.25	TD at 22717.61' MD



Azimuths to Grid North
True North: -0.38°
Magnetic North: 5.94°

Magnetic Field
Strength: 47689.8nT
Dip Angle: 59.98°
Date: 11/21/2022
Model: HDGM_FILE





PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	OXY USA INCORPORATED
WELL NAME & NO.:	TUNA NUT 25_13 FED COM 311H
LOCATION:	Section 25, T.22 S., R.32 E.
COUNTY:	Lea County, New Mexico

COA

H2S	◉ Yes	○ No	
Potash	◉ None	○ Secretary	○ R-111-P
Cave/Karst Potential	◉ Low	○ Medium	○ High
Cave/Karst Potential	○ Critical		
Variance	○ None	◉ Flex Hose	○ Other
Wellhead	○ Conventional	◉ Multibowl	○ Both
Wellhead Variance	○ Diverter		
Other	☐ 4 String	☐ Capitan Reef	☐ WIPP
Other	☐ Fluid Filled	☐ Pilot Hole	☐ Open Annulus
Cementing	☐ Contingency Cement Squeeze	☐ EchoMeter	☑ Primary Cement Squeeze
Special Requirements	☐ Water Disposal	☑ COM	☐ Unit
Special Requirements	☐ Batch Sundry		
Special Requirements Variance	☑ Break Testing	☑ Offline Cementing	☑ 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 Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

B. CASING

Both A1 and A2 designs in Blanket Designs approved. Parameters of the pad within boundary conditions. Please contact BLM Engineering if 4 string design is needed and sundry as needed. Please review cement volumes to ensure tieback is achieved as required below(25% excess required.)

Primary Casing Design:

1. The **13-3/8** inch surface casing shall be set at approximately **1104** 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.
   BLM Geology Note: The operator purposes to set surface casing at 919 feet, which may not adequately protect usable water zones. BLM suggests to set the surface casing at a depth of 930' to protect the usable water zones. If the Salt is encountered, set casing at least 25 feet above the Salt Formation.

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

2. The **7-5/8** inch intermediate casing shall be set at approximately **11,398** feet TVD. **KEEP CASING 1/2 FULL FOR COLLAPSE SF. PRESSURE TEST NEEDS EXTERNAL PRESSURE REVIEW AS WELL.** The minimum required fill of cement behind the **7-5/8** inch intermediate casing is:

   Option 1 (Single Stage):

   - Cement to surface. If cement does not circulate see B.1.a, c-d above.

   Option 2 (Bradenhead):

   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 will perform bradenhead squeeze and top-out. Cement to surface. If cement does not reach surface, the appropriate BLM office shall be notified

3. The **5-1/2** inch production casing shall be set at approximately **22,718** feet. The minimum required fill of cement behind the **5-1/2** inch production casing is:

Option 1 (Single Stage):

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

Alternate Casing Design:

1. The **10-3/4** inch surface casing shall be set at approximately **1104** 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.

   e. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
   f. Wait on cement (WOC) time for a primary cement job will be a minimum of **24 hours in the Potash Area** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
   g. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
   h. If cement falls back, remedial cementing will be done prior to drilling out that string.

2. The **7-5/8** inch intermediate casing shall be set at approximately **11,398** feet. **KEEP CASING 1/2 FULL FOR COLLAPSE SF. PRESSURE TEST NEEDS EXTERNAL PRESSURE REVIEW AS WELL.** The minimum required fill of cement behind the **7-5/8** inch intermediate casing is:

Option 1 (Single Stage):

- Cement to surface. If cement does not circulate see B.1.a, c-d above.

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.

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c. First stage: Operator will cement with intent to reach the top of the **Brushy Canyon**

d. Second stage:

- Operator will perform bradenhead squeeze and top-out. Cement to surface. If cement does not reach surface, the appropriate BLM office shall be notified

❖ In Secretary Potash 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.

Operator has proposed to pump down 10-3/4" X 7-5/8" annulus. Operator must top out cement after the bradenhead squeeze and verify cement to surface. Operator can also check TOC with Echo-meter. CBL must be run from TD of the 7-5/8" casing to surface if confidence is lacking on the quality of the bradenhead squeeze cement job. Submit results to BLM.

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.

Bradenhead squeeze in the production interval is only as an edge case remediation measure and is NOT approved in this COA. If production cement job experiences losses and a bradenhead squeeze is needed for tie-back, BLM Engineering should be notified prior to job with volumes and planned wellbore schematic. CBL will be needed when this occurs.

3. The **5-1/2** inch production casing shall be set at approximately **22,718** feet. The minimum required fill of cement behind the **5-1/2** inch production casing is:

Option 1 (Single Stage):

- Cement should tie-back at least **500 feet** into previous casing string. Operator shall provide method of verification.

C. PRESSURE CONTROL

1. Variance approved to use flex line from BOP to choke manifold. Manufacturer's specification to be readily available. No external damage to flex line. Flex line to be installed as straight as possible (no hard bends).'

2. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on 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)

<u>**Communitization Agreement**</u>

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

<u>**(Note: For a minimum 5M BOPE or less (Utilizing a 10M BOPE system)**</u>
<u>**BOPE Break Testing Variance**</u>

- 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 (575-361-2822 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 Onshore Oil and Gas Order No. 2.
- If in the event break testing is not utilized, then a full BOPE test would be conducted.

Offline Cementing
Offline cementing OK for surface and intermediate intervals. Notify the BLM prior to the commencement of any offline cementing procedure.

Casing Clearance
Overlap clearance OK

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

Contact Lea County Petroleum Engineering Inspection Staff:
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.

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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. <u>Wait on cement (WOC) for Potash Areas:</u> 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 <u>8 hours</u>. 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. <u>Wait on cement (WOC) for Water Basin:</u> 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 <u>8 hours</u>. 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 11/24/2024

Approval Date: 11/25/2024

Permian Drilling
Hydrogen Sulfide Drilling Operations Plan
New Mexico

Scope

This contingency plan establishes guidelines for the public, all company employees, and contract employees who's work activities may involve exposure to hydrogen sulfide (H2S) gas.
While drilling this well, it is possible to encounter H2S bearing formations. At all times, the first barrier to control H2S emissions will be the drilling fluid, which will have a density high enough to control influx.

Objective

1. Provide an immediate and predetermined response plan to any condition when H2S is detected. All H2S detections in excess of 10 parts per million (ppm) concentration are considered an Emergency.

2. Prevent any and all accidents, and prevent the uncontrolled release of hydrogen sulfide into the atmosphere.

3. Provide proper evacuation procedures to cope with emergencies.

4. Provide immediate and adequate medical attention should an injury occur.

Discussion

Implementation:	This plan with all details is to be fully implemented before drilling to commence.
Emergency response Procedure:	This section outlines the conditions and denotes steps to be taken in the event of an emergency.
Emergency equipment Procedure:	This section outlines the safety and emergency equipment that will be required for the drilling of this well.
Training provisions:	This section outlines the training provisions that must be adhered to prior to drilling.
Drilling emergency call lists:	Included are the telephone numbers of all persons to be contacted should an emergency exist.
Briefing:	This section deals with the briefing of all people involved in the drilling operation.
Public safety:	Public safety personnel will be made aware of any potential evacuation and any additional support needed.
Check lists:	Status check lists and procedural check lists have been included to insure adherence to the plan.
General information:	A general information section has been included to supply support information.

Hydrogen Sulfide Training

All personnel, whether regularly assigned, contracted, or employed on an unscheduled basis, will receive training from a qualified instructor in the following areas prior to commencing drilling operations on the well:

1. The hazards and characteristics of H2S.
2. Proper use and maintenance of personal protective equipment and life support systems.
3. H2S detection.
4. Proper use of H2S detectors, alarms, warning systems, briefing areas, evacuation procedures and prevailing winds.
5. Proper techniques for first aid and rescue procedures.
6. Physical effects of hydrogen sulfide on the human body.
7. Toxicity of hydrogen sulfide and sulfur dioxide.
8. Use of SCBA and supplied air equipment.
9. First aid and artificial respiration.
10. Emergency rescue.

In addition, supervisory personnel will be trained in the following areas:

1. The effects of H2S on metal components. If high tensile strength tubular is to be used, personnel will be trained in their special maintenance requirements.
2. Corrective action and shut-in procedures when drilling a well, blowout prevention and well control procedures.
3. The contents and requirements of the H2S Drilling Operations Plan.

H2S training refresher must have been taken within one year prior to drilling the well. Specifics on the well to be drilled will be discussed during the pre-spud meeting. H2S and well control (choke) drills will be performed while drilling the well, at least on a weekly basis. This plan shall be available in the well site. All personnel will be required to carry the documentation proving that the H2S training has been taken.

Service company and visiting personnel

A. Each service company that will be on this well will be notified if the zone contains H2S.

B. Each service company must provide for the training and equipment of their employees before they arrive at the well site.

C. Each service company will be expected to attend a well site

Emergency Equipment Requirements

1. Well control equipment

   The well shall have hydraulic BOP equipment for the anticipated pressures. Equipment is to be tested on installation and follow Oxy Well Control standard, as well as 43 CFR part 3170 Subpart 3172.

   Special control equipment:

   A. Hydraulic BOP equipment with remote control on ground.
   Remotely operated choke.
   B. Rotating head
   C. Gas buster equipment shall be installed before drilling out of surface pipe.

2. Protective equipment for personnel

   A. Four (4) 30-minute positive pressure air packs (2 at each briefing area) on location.

   B. Adequate fire extinguishers shall be located at strategic locations.

   C. Radio / cell telephone communication will be available at the rig.

      - Rig floor and trailers.
      - Vehicle.

3. Hydrogen sulfide sensors and alarms

   A. H2S sensor with alarms will be located on the rig floor, at the bell nipple, and at the flow line. These monitors will be set to alarm at 10 ppm with strobe light, and audible alarm.
   B. Hand operated detectors with tubes.
   C. H2S monitor tester (to be provided by contract Safety Company.)
   D. There shall be one combustible gas detector on location at all times.

4. Visual Warning Systems

   A. One sign located at each location entrance with the following language:

   Caution – potential poison gas
   Hydrogen sulfide
   No admittance without authorization

Wind sock – wind streamers:

A. One 36” (in length) wind sock located at protection center, at height visible from rig floor.
B. One 36” (in length) wind sock located at height visible from pit areas.

Condition flags

A. One each condition flag to be displayed to denote conditions.

green – normal conditions
yellow – potential danger
red – danger, H2S present

B. Condition flag shall be posted at each location sign entrance.

5. Mud Program

The mud program is designed to minimize the risk of having H2S and other formation fluids at surface. Proper mud weight and safe drilling practices will be applied. H2S scavengers will be used to minimize the hazards while drilling. Below is a summary of the drilling program.

Mud inspection devices:

Garrett gas train or hatch tester for inspection of sulfide concentration in mud system.

6. Metallurgy

A. Drill string, casing, tubing, wellhead, blowout preventers, drilling spools or adapters, kill lines, choke manifold, lines and valves shall be suitable for the H2S service.
B. All the elastomers, packing, seals and ring gaskets shall be suitable for H2S service.

7. Well Testing

No drill stem test will be performed on this well.

8. Evacuation plan

Evacuation routes should be established prior to well spud for each well and discussed with all rig personnel.

9. Designated area

A. Parking and visitor area: all vehicles are to be parked at a predetermined safe distance from the wellhead.
B. There will be a designated smoking area.
C. Two briefing areas on either side of the location at the maximum allowable distance from the well bore so they offset prevailing winds perpendicularly, or at a 45-degree angle if wind direction tends to shift in the area.

Emergency procedures

A. In the event of any evidence of H2S level above 10 ppm, take the following steps:

1. The Driller will pick up off bottom, shut down the pumps, slow down the pipe rotation.

2. Secure and don escape breathing equipment, report to the upwind designated safe briefing / muster area.

3. All personnel on location will be accounted for and emergency search should begin for any missing, the Buddy System will be implemented.

4. Order non-essential personnel to leave the well site, order all essential personnel out of the danger zone and upwind to the nearest designated safe briefing / muster area.

5. Entrance to the location will be secured to a higher level than our usual "Meet and Greet" requirement, and the proper condition flag will be displayed at the entrance to the location.

6. Take steps to determine if the H2S level can be corrected or suppressed and, if so, proceed as required.

B. If uncontrollable conditions occur:

1. Take steps to protect and/or remove any public in the down-wind area from the rig – partial evacuation and isolation. Notify necessary public safety personnel and appropriate regulatory entities (i.e. BLM) of the situation.

2. Remove all personnel to the nearest upwind designated safe briefing / muster area or off location.

3. Notify public safety personnel of safe briefing / muster area.

4. An assigned crew member will blockade the entrance to the location. No unauthorized personnel will be allowed entry to the location.

5. Proceed with best plan (at the time) to regain control of the well. Maintain tight security and safety procedures.

C. Responsibility:

1. Designated personnel.

a. Shall be responsible for the total implementation of this plan.
b. Shall be in complete command during any emergency.
c. Shall designate a back-up.

All personnel:	1.	On alarm, don escape unit and report to the nearest upwind designated safe briefing / muster area upw
	2.	Check status of personnel (buddy system).
	3.	Secure breathing equipment.
	4.	Await orders from supervisor.
Drill site manager:	1.	Don escape unit if necessary and report to nearest upwind designated safe briefing / muster area.
	2.	Coordinate preparations of individuals to return to point of release with tool pusher and driller (using the buddy system).
	3.	Determine H2S concentrations.
	4.	Assess situation and take control measures.
Tool pusher:	1.	Don escape unit Report to up nearest upwind designated safe briefing / muster area.
	2.	Coordinate preparation of individuals to return to point of release with tool pusher drill site manager (using the buddy system).
	3.	Determine H2S concentration.
	4.	Assess situation and take control measures.
Driller:	1.	Don escape unit, shut down pumps, continue

rotating DP.
2. Check monitor for point of release.
3. Report to nearest upwind designated safe briefing / muster area.
4. Check status of personnel (in an attempt to rescue, use the buddy system).
5. Assigns least essential person to notify Drill Site Manager and tool pusher by quickest means in case of their absence.
6. Assumes the responsibilities of the Drill Site Manager and tool pusher until they arrive should they be absent.

Derrick man Floor man #1 Floor man #2	1.	Will remain in briefing / muster area until instructed by supervisor.
Mud engineer:	1.	Report to nearest upwind designated safe briefing / muster area.
	2.	When instructed, begin check of mud for ph and H2S level. (Garett gas train.)
Safety personnel:	1.	Mask up and check status of all personnel and secure operations as instructed by drill site manager.

Taking a kick

When taking a kick during an H2S emergency, all personnel will follow standard Well control procedures after reporting to briefing area and masking up.

Open-hole logging

All unnecessary personnel off floor. Drill Site Manager and safety personnel should monitor condition, advise status and determine need for use of air equipment.

Running casing or plugging

Following the same "tripping" procedure as above. Drill Site Manager and safety personnel should determine if all personnel have access to protective equipment.

Ignition procedures

The decision to ignite the well is the responsibility of the operator (Oxy Drilling Management). The decision should be made only as a last resort and in a situation where it is clear that:

1. Human life and property are endangered.
2. There is no hope controlling the blowout under the prevailing conditions at the well.

Instructions for igniting the well

1. Two people are required for the actual igniting operation. They must wear self-contained breathing units and have a safety rope attached. One man (tool pusher or safety engineer) will check the atmosphere for explosive gases with the gas monitor. The other man is responsible for igniting the well.
2. Primary method to ignite: 25 mm flare gun with range of approximately 500 feet.
3. Ignite upwind and do not approach any closer than is warranted.
4. Select the ignition site best for protection, and which offers an easy escape route.
5. Before firing, check for presence of combustible gas.
6. After lighting, continue emergency action and procedure as before.
7. All unassigned personnel will remain in briefing area until instructed by supervisor or directed by the Drill Site Manager.

Remember: After well is ignited, burning hydrogen sulfide will convert to sulfur dioxide, which is also highly toxic. **Do not assume the area is safe after the well is ignited.**

Status check list

Note: All items on this list must be completed before drilling to production casing point.

1. H2S sign at location entrance.
2. Two (2) wind socks located as required.
3. Four (4) 30-minute positive pressure air packs (2 at each Briefing area) on location for all rig personnel and mud loggers.
4. Air packs inspected and ready for use.
5. Cascade system and hose line hook-up as needed.
6. Cascade system for refilling air bottles as needed.
7. Condition flag on location and ready for use.
8. H2S detection system hooked up and tested.
9. H2S alarm system hooked up and tested.
10. Hand operated H2S detector with tubes on location.
11. 1 – 100' length of nylon rope on location.
12. All rig crew and supervisors trained as required.
13. All outside service contractors advised of potential H2S hazard on well.
14. No smoking sign posted and a designated smoking area identified.
15. Calibration of all H2S equipment shall be noted on the IADC report.

Checked by: ________________________ Date:

Procedural check list during H2S events

Perform each tour:

1. Check fire extinguishers to see that they have the proper charge.

2. Check breathing equipment to ensure that it in proper working order.

3. Make sure all the H2S detection system is operative.

Perform each week:

1. Check each piece of breathing equipment to make sure that demand or forced air regulator is working. This requires that the bottle be opened and the mask assembly be put on tight enough so that when you inhale, you receive air or feel air flow.

2. BOP skills (well control drills).

3. Check supply pressure on BOP accumulator stand by source.

4. Check breathing equipment mask assembly to see that straps are loosened and turned back, ready to put on.

5. Check pressure on breathing equipment air bottles to make sure they are charged to full volume. (Air quality checked for proper air grade “D” before bringing to location)

6. Confirm pressure on all supply air bottles.

7. Perform breathing equipment drills with on-site personnel.

8. Check the following supplies for availability.

   A. Emergency telephone list.
   B. Hand operated H2S detectors and tubes.

General evacuation plan

1. When the company approved supervisor (Drill Site Manager, consultant, rig pusher, or driller) determines the H2S gas cannot be limited to the well location and the public will be involved, he will activate the evacuation plan.

2. Drill Site Manager or designee will notify local government agency that a hazardous condition exists and evacuation needs to be implemented.

3. Company or contractor safety personnel that have been trained in the use of H2S detection equipment and self-contained breathing equipment will monitor H2S concentrations, wind directions, and area of exposure. They will delineate the outer perimeter of the hazardous gas area. Extension to the evacuation area will be determined from information gathered.

4. Law enforcement personnel (state police, police dept., fire dept., and sheriff's dept.) Will be called to aid in setting up and maintaining road blocks. Also, they will aid in evacuation of the public if necessary.

5. After the discharge of gas has been controlled, company safety personnel will determine when the area is safe for re-entry.

Important: Law enforcement personnel will not be asked to come into a contaminated area. Their assistance will be limited to uncontaminated areas. Constant radio contact will be maintained with them.

Emergency actions

Well blowout – if emergency

1. Evacuate all personnel to "Safe Briefing / Muster Areas" or off location if needed.

2. If sour gas – evacuate rig personnel.

3. If sour gas – evacuate public within 3000 ft radius of exposure.

4. Don SCBA and shut well in if possible using the buddy system.

5. Notify Drilling Superintendent and call 911 for emergency help (fire dept and ambulance) if needed.

6. Implement the Blowout Contingency Plan, and Drilling Emergency Action Plan.

6. Give first aid as needed.

Person down location/facility

1. If immediately possible, contact 911. Give location and wait for confirmation.

2. Don SCBA and perform rescue operation using buddy system.

Toxic effects of hydrogen sulfide

Hydrogen sulfide is extremely toxic. The acceptable ceiling concentration for eight-hour exposure is 10 ppm, which is .001% by volume. Hydrogen sulfide is heavier than air (specific gravity – 1.192) and colorless. It forms an explosive mixture with air between 4.3 and 46.0 percent by volume. Hydrogen sulfide is almost as toxic as hydrogen cyanide and is between five and six times more toxic than carbon monoxide. Toxicity data for hydrogen sulfide and various other gases are compared in table i. Physical effects at various hydrogen sulfide exposure levels are shown in table ii.

Table i
Toxicity of various gases

Common name	Chemical formula	Specific gravity (sc=1)	Threshold limit (1)	Hazardous limit (2)	Lethal concentration (3)
Hydrogen Cyanide	Hcn	0.94	10 ppm	150 ppm/hr	300 ppm
Hydrogen Sulfide	H2S	1.18	10 ppm	250 ppm/hr	600 ppm
Sulfur Dioxide	So2	2.21	5 ppm	-	1000 ppm
Chlorine	Cl2	2.45	1 ppm	4 ppm/hr	1000 ppm
Carbon Monoxide	Co	0.97	50 ppm	400 ppm/hr	1000 ppm
Carbon Dioxide	Co2	1.52	5000 ppm	5%	10%
Methane	Ch4	0.55	90,000 ppm	Combustible above 5% in air	

1) threshold limit – concentration at which it is believed that all workers may be repeatedly exposed day after day without adverse effects.

2) hazardous limit – concentration that will cause death with short-term exposure.

3) lethal concentration – concentration that will cause death with short-term exposure.

Toxic effects of hydrogen sulfide

Table ii
Physical effects of hydrogen sulfide

Concentration			Physical effects
Percent (%)	Ppm	Grains 100 std. Ft3*	
0.001	<10	00.65	Obvious and unpleasant odor.

0.002	10	01.30	Safe for 8 hours of exposure.
0.010	100	06.48	Kill smell in 3 – 15 minutes. May sting eyes and throat.
0.020	200	12.96	Kills smell shortly; stings eyes and throat.
0.050	500	32.96	Dizziness; breathing ceases in a few minutes; needs prompt artificial respiration.
0.070	700	45.36	Unconscious quickly; death will result if not rescued promptly.
0.100	1000	64.30	Unconscious at once; followed by death within minutes.

*at 15.00 psia and 60’f.

Use of self-contained breathing equipment (SCBA)

1. Written procedures shall be prepared covering safe use of SCBA's in dangerous atmosphere, which might be encountered in normal operations or in emergencies. Personnel shall be familiar with these procedures and the available SCBA.

2 SCBA's shall be inspected frequently at random to insure that they are properly used, cleaned, and maintained.

3. Anyone who may use the SCBA's shall be trained in how to insure proper face-piece to face seal. They shall wear SCBA's in normal air and then wear them in a test atmosphere. (note: such items as facial hair {beard or sideburns} and eyeglasses will not allow proper seal.) Anyone that may be reasonably expected to wear SCBA's should have these items removed before entering a toxic atmosphere. A special mask must be obtained for anyone who must wear eyeglasses or contact lenses.

4. Maintenance and care of SCBA's:

   a. A program for maintenance and care of SCBA's shall include the following:
      1. Inspection for defects, including leak checks.
      2. Cleaning and disinfecting.
      3. Repair.
      4. Storage.

   b. Inspection, self-contained breathing apparatus for emergency use shall be inspected monthly.
      1. Fully charged cylinders.
      2. Regulator and warning device operation.
      3. Condition of face piece and connections.
      4. Rubber parts shall be maintained to keep them pliable and prevent deterioration.

   c. Routinely used SCBA's shall be collected, cleaned and disinfected as frequently as necessary to insure proper protection is provided.

5. Persons assigned tasks that requires use of self-contained breathing equipment shall be certified physically fit (medically cleared) for breathing equipment usage at least annually.

6. SCBA's should be worn when:

   A. Any employee works near the top or on top of any tank unless test reveals less than 10 ppm of H_2S.

B. When breaking out any line where H2S can reasonably be expected.

C. When sampling air in areas to determine if toxic concentrations of H2S exists.

D. When working in areas where over 10 ppm H2S has been detected.

E. At any time there is a doubt as to the H2S level in the area to be entered.

Rescue
First aid for H2S poisoning

Do not panic!

Remain calm – think!

1. Don SCBA breathing equipment.

2. Remove victim(s) utilizing buddy system to fresh air as quickly as possible. (go up-wind from source or at right angle to the wind. Not down wind.)

3. Briefly apply chest pressure – arm lift method of artificial respiration to clean the victim's lungs and to avoid inhaling any toxic gas directly from the victim's lungs.

4. Provide for prompt transportation to the hospital, and continue giving artificial respiration if needed.

5. Hospital(s) or medical facilities need to be informed, before-hand, of the possibility of H2S gas poisoning – no matter how remote the possibility is.

6. Notify emergency room personnel that the victim(s) has been exposed to H2S gas.

Besides basic first aid, everyone on location should have a good working knowledge of artificial respiration.

Revised CM 6/27/2012

Permian Drilling
Hydrogen Sulfide Drilling Operations Plan

Open drill site. No homes or buildings are near the proposed location.

1. Escape

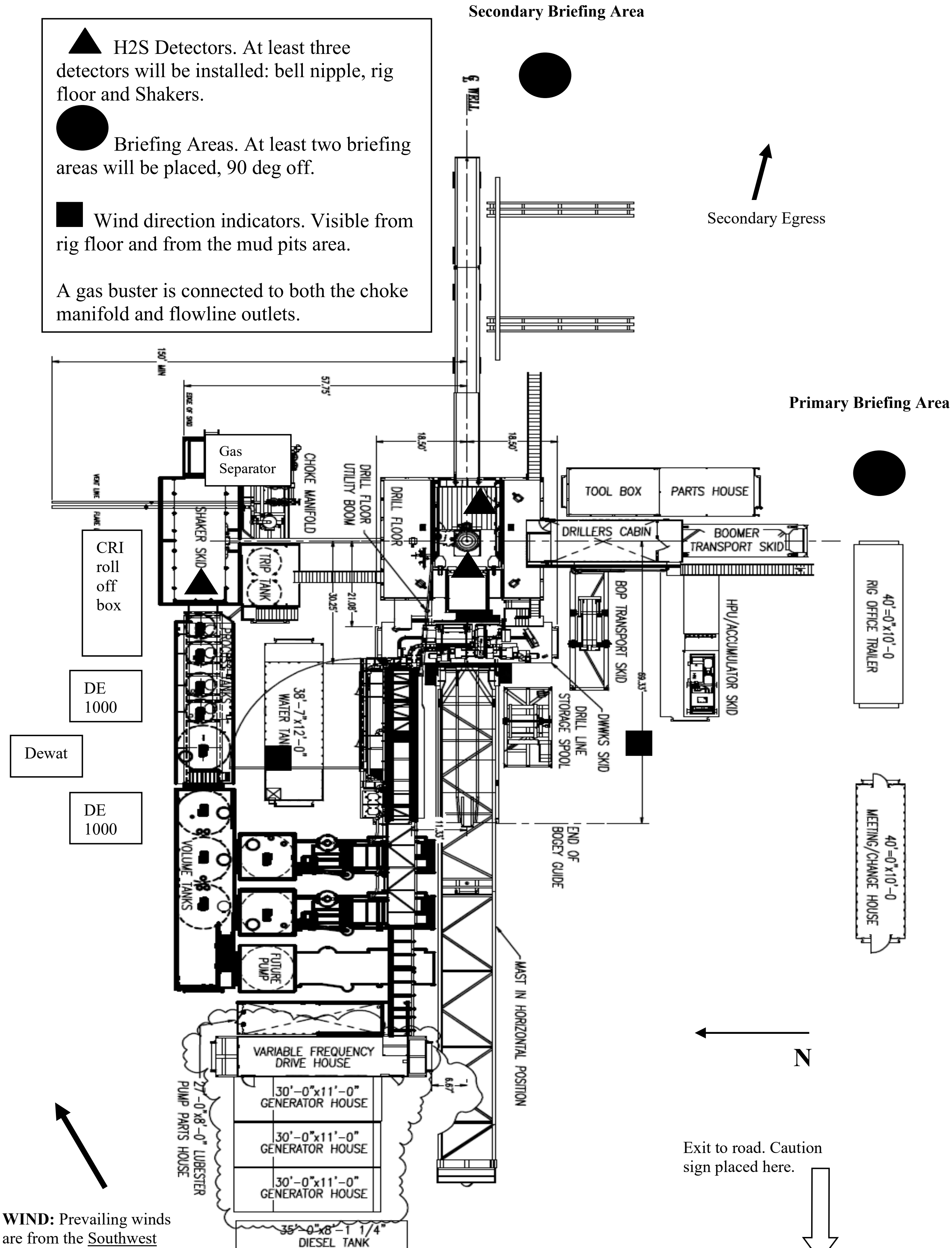
   Personnel shall escape upwind of wellbore in the event of an emergency gas release. Escape can take place through the lease road on the Southeast side of the location. Personnel need to move to a safe distance and block the entrance to location. If the primary route is not an option due to the wind direction, then a secondary egress route should be taken.

H2S Detectors. At least three detectors will be installed: bell nipple, rig floor and Shakers.

Briefing Areas. At least two briefing areas will be placed, 90 deg off.

Wind direction indicators. Visible from rig floor and from the mud pits area.

A gas buster is connected to both the choke manifold and flowline outlets.



SITE PLAN

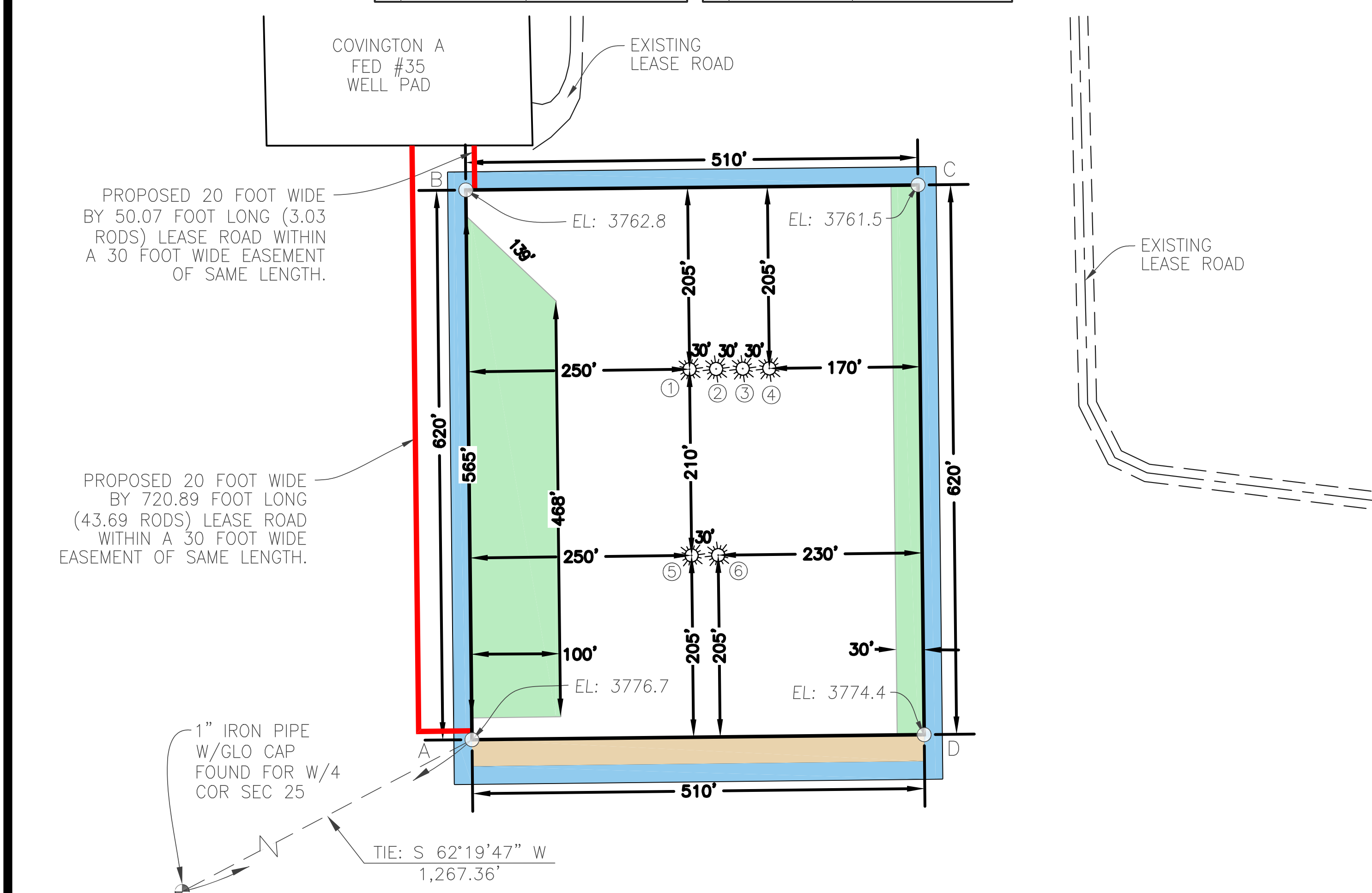
REDTNK_T22SR32E_2505
SEC. 25 TWP. 22-S RGE. 32-E
SURVEY: N.M.P.M.
COUNTY: LEA
OPERATOR: OXY USA, INC.
U.S.G.S. TOPOGRAPHIC MAP: BOOTLEG RIDGE, N.M.
FAA PERMIT NEEDED: NO

TANK BATTERY
RECLAMATION
30' TOP SOIL
20' DISTURBANCE AREA

100' 0' 100' 200'
SCALE: 1" = 200'

NAD 83		
A	E:(X)757493.94 N:(Y)496996.76	LAT:32.36437086 LON:–103.63325239
B	E:(X)757487.02 N:(Y)497616.73	LAT:32.36607504 LON:–103.63326165
C	E:(X)757996.99 N:(Y)497622.42	LAT:32.36608150 LON:–103.63160994
D	E:(X)758003.90 N:(Y)497002.45	LAT:32.36437732 LON:–103.63160070

NAD 27		
A	E:(X)716311.21 N:(Y)496936.51	LAT:32.36424765 LON:–103.63276715
B	E:(X)716304.31 N:(Y)497556.46	LAT:32.36595186 LON:–103.63277637
C	E:(X)716814.28 N:(Y)497562.15	LAT:32.36595831 LON:–103.6311269
D	E:(X)716821.17 N:(Y)496942.20	LAT:32.36425411 LON:–103.63111554



10/18/2021	10/26/2021
DATE SURVEYED	DATE DRAWN

REV.	DATE	BY

NOVEMBER 12, 2021

DAVID W. MYERS NEW MEXICO 11403 PROFESSIONAL SURVEYOR

DAVID W. MYERS 11403

BASIS OF BEARING
ALL BEARINGS AND COORDINATES REFER TO NAD 83, NEW MEXICO STATE PLANE COORDINATE SYSTEM, EAST ZONE, U.S. SURVEY FEET. (ALL BEARINGS, DISTANCES, COORDINATES AND AREAS ARE GRID MEASUREMENTS UTILIZING A COMBINED SCALE FACTOR OF 0.99975697 CONVERGENCE ANGLE OF 0.07066669°.)

LEGEND
EXISTING ROAD
PROPOSED ROAD
SURFACE SITE EDGE
EXIST. PIPELINE
MONUMENT
QUARTER SPLIT
OHP OVERHEAD POWER
FENCE
SECTION LINE
PROPERTY LINE
W WATER LINE
SWD SALT WATER LINE
EDGE OF ROAD

SHEET 1 OF 2
PREPARED BY:
R-SQUARED GLOBAL, LLC
510 TRENTON ST. UNIT B
WEST MONROE, LA 71291
318-323-6900 OFFICE
JOB No. R4195_004

SITE PLAN

REDTNK_T22SR32E_2505
SEC. 25 TWP. 22-S RGE. 32-E
SURVEY: N.M.P.M.
COUNTY: LEA
OPERATOR: OXY USA, INC.
U.S.G.S. TOPOGRAPHIC MAP: BOOTLEG RIDGE, N.M.
FAA PERMIT NEEDED: NO

WELL 1
TUNA NUT 24_13 FED COM 31H
OXY USA, INC.
1650' FNL 1375' FWL, SECTION 25
NAD 83, SPCS NM EAST
X:757739.29' / Y:497414.53'
LAT:32.36551473N / LON:103.63244893W
NAD 27, SPCS NM EAST
X:716556.58' / Y:497354.26'
LAT:32.36539153N / LON:103.63196369W
ELEVATION = 3765'

WELL 2
TUNA NUT 24_13 FED COM 311H
OXY USA, INC.
1650' FNL 1405' FWL, SECTION 25
NAD 83, SPCS NM EAST
X:757769.29' / Y:497414.86'
LAT:32.36551511N / LON:103.63235177W
NAD 27, SPCS NM EAST
X:716586.57' / Y:497354.60'
LAT:32.36539191N / LON:103.63186653W
ELEVATION = 3765'

WELL 3
TUNA NUT 24_13 FED COM 32H
OXY USA, INC.
1650' FNL 1435' FWL, SECTION 25
NAD 83, SPCS NM EAST
X:757799.29' / Y:497415.20'
LAT:32.36551549N / LON:103.63225461W
NAD 27, SPCS NM EAST
X:716616.57' / Y:497354.93'
LAT:32.36539229N / LON:103.63176937W
ELEVATION = 3765'

WELL 4
TUNA NUT 24_13 FED COM 33H
OXY USA, INC.
1650' FNL 1465' FWL, SECTION 25
NAD 83, SPCS NM EAST
X:757829.29' / Y:497415.53'
LAT:32.36551587N / LON:103.63215745W
NAD 27, SPCS NM EAST
X:716646.57' / Y:497355.27'
LAT:32.36539267N / LON:103.63167222W
ELEVATION = 3764'

WELL 5
TUNA NUT 24_13 FED COM 41H
OXY USA, INC.
1860' FNL 1376' FWL, SECTION 25
NAD 83, SPCS NM EAST
X:757741.63' / Y:497204.54'
LAT:32.36493751N / LON:103.63244580W
NAD 27, SPCS NM EAST
X:716558.91' / Y:497144.28'
LAT:32.36481431N / LON:103.63196057W
ELEVATION = 3768'

WELL 6
TUNA NUT 24_13 FED COM 42H
OXY USA, INC.
1860' FNL 1406' FWL, SECTION 25
NAD 83, SPCS NM EAST
X:757771.63' / Y:497204.88'
LAT:32.36493789N / LON:103.63234864W
NAD 27, SPCS NM EAST
X:716588.91' / Y:497144.62'
LAT:32.36481469N / LON:103.63186342W
ELEVATION = 3768'

10/18/2021	10/26/2021
DATE SURVEYED	DATE DRAWN

REV.	DATE	BY

NOVEMBER 12, 2021

DAVID W. MYERS
NEW MEXICO
11403
PROFESSIONAL SURVEYOR

DAVID W. MYERS 11403

BASIS OF BEARING
ALL BEARINGS AND COORDINATES REFER TO NAD 83, NEW MEXICO STATE PLANE COORDINATE SYSTEM, EAST ZONE, U.S. SURVEY FEET. (ALL BEARINGS, DISTANCES, COORDINATES AND AREAS ARE GRID MEASUREMENTS UTILIZING A COMBINED SCALE FACTOR OF 0.99975697 CONVERGENCE ANGLE OF 0.07066669°.)

LEGEND
EXISTING ROAD
PROPOSED ROAD
SURFACE SITE EDGE
EXIST. PIPELINE
MONUMENT
QUARTER SPLIT
OHP — OVERHEAD POWER
x — FENCE
SECTION LINE
PL — PROPERTY LINE
W — WATER LINE
SWD — SALT WATER LINE

SHEET 2 OF 2
PREPARED BY:
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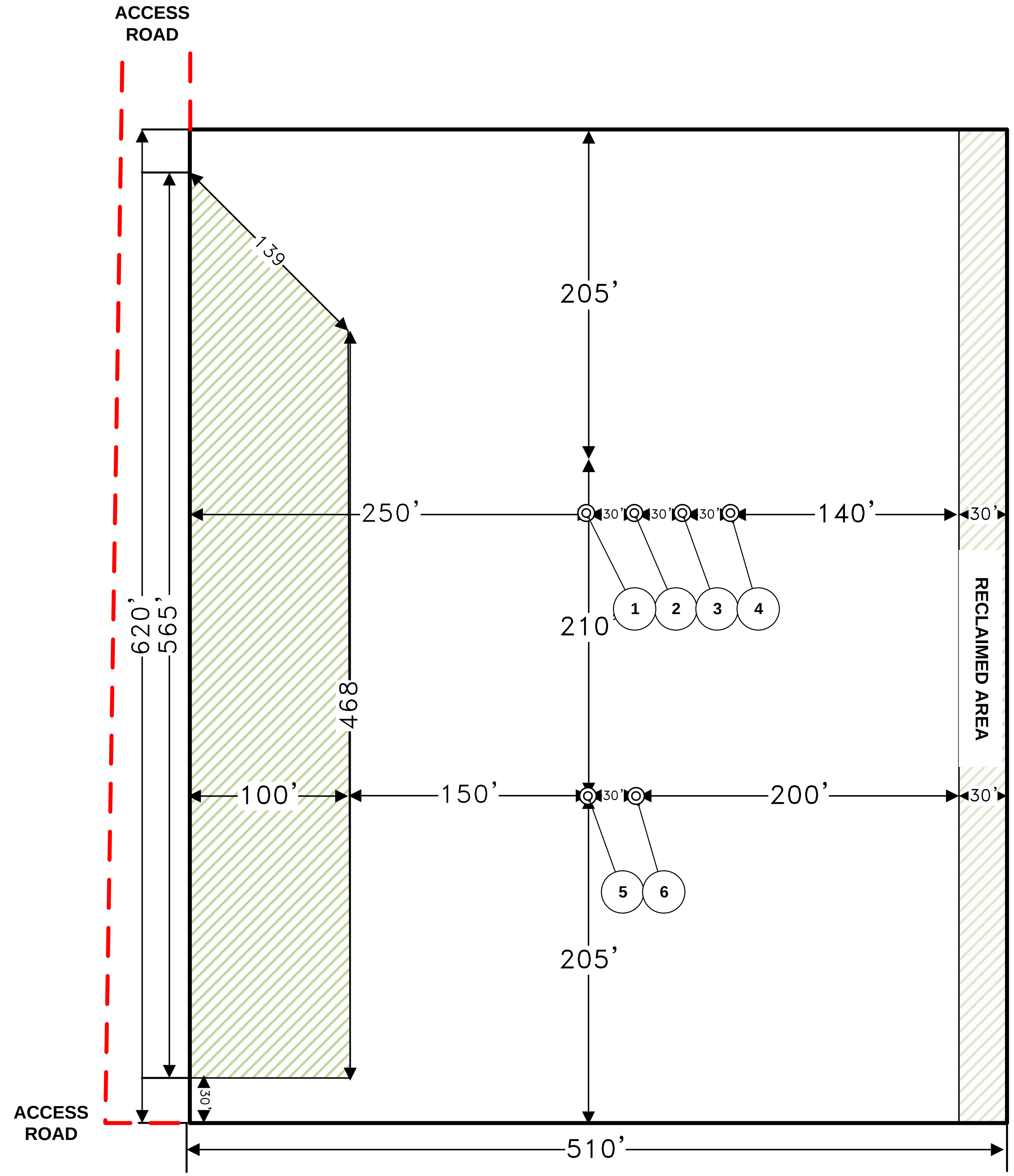
510 TRENTON ST. UNIT B
WEST MONROE, LA 71291
318-323-6900 OFFICE
JOB No. R4195_004



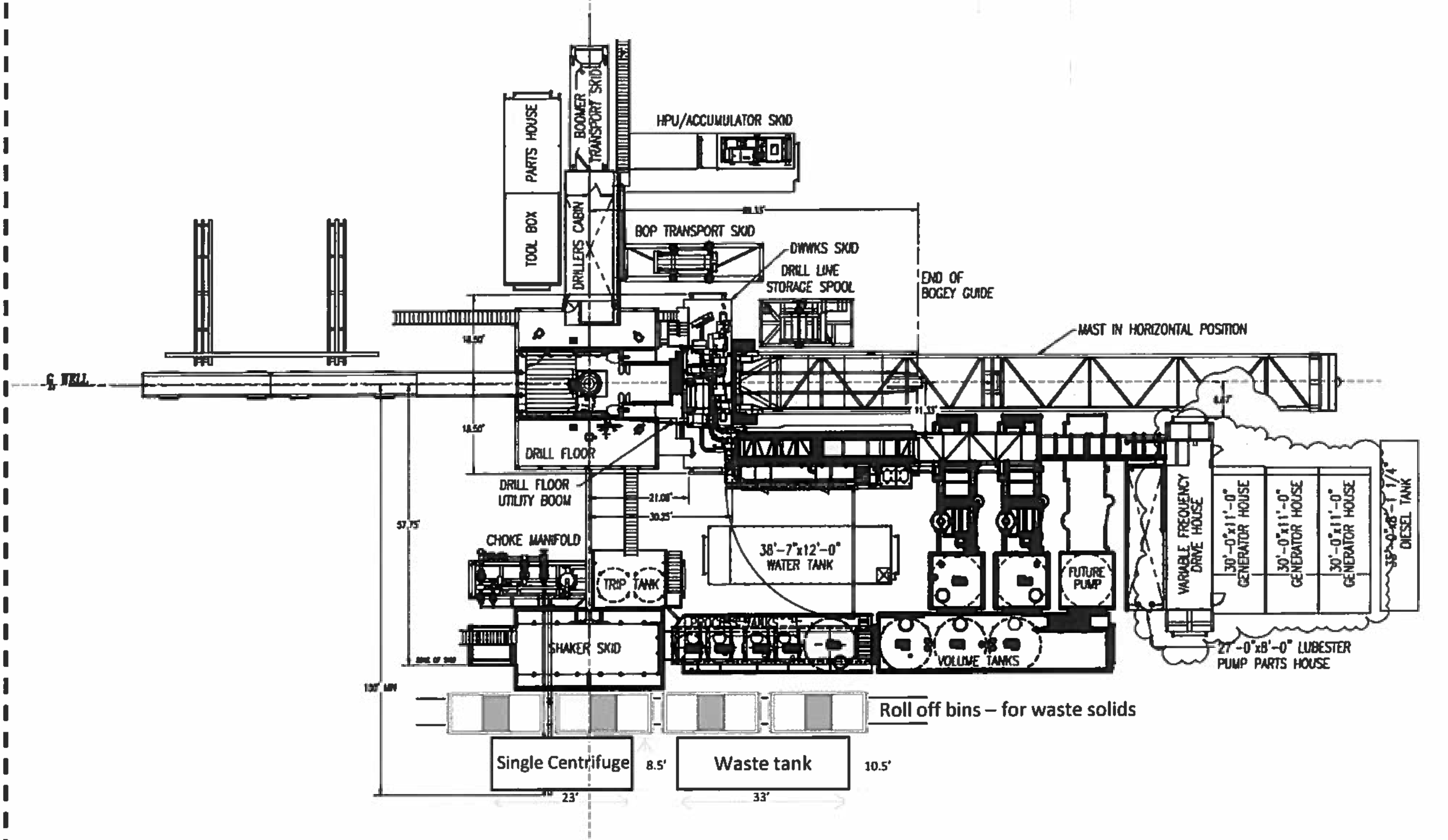
NORTH

1. TUNA NUT 25-36 FED COM 31H
2. TUNA NUT 25-36 FED COM 311H
3. TUNA NUT 25-36 FED COM 32H
4. TUNA NUT 25-36 FED COM 33H
5. TUNA NUT 25-36 FED COM 41H
6. TUNA NUT 25-36 FED COM 42H

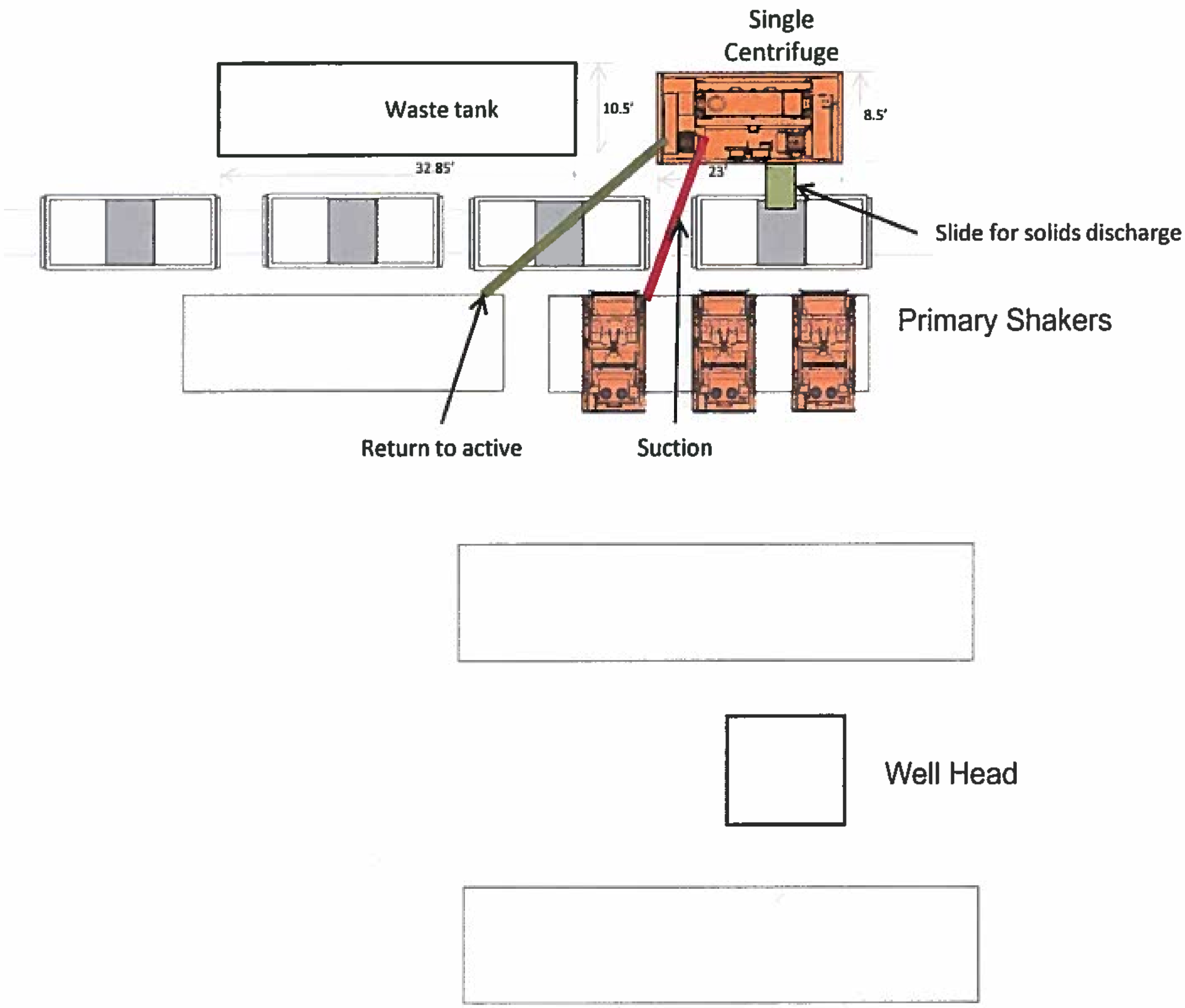
REVISION BLOCK						ENGINEERING RECORD		RIG DIAGRAM V-DOOR SOUTHWEST PAD REDTNK-2402 TUNA NUT 25-36 FED COM 31H, 311H, 32H, 33H, 41H, 42H SECTION 24, TOWNSHIP 22S, RANGE 32E LEA COUNTY, NEW MEXICO
NO.	DATE	DESCRIPTION	BY	CHK	APP	BY	DATE	
						LP	12/13/2021	

Oxy Single Centrifuge Closed Loop System – New Mexico Flex III

May 28, 2013

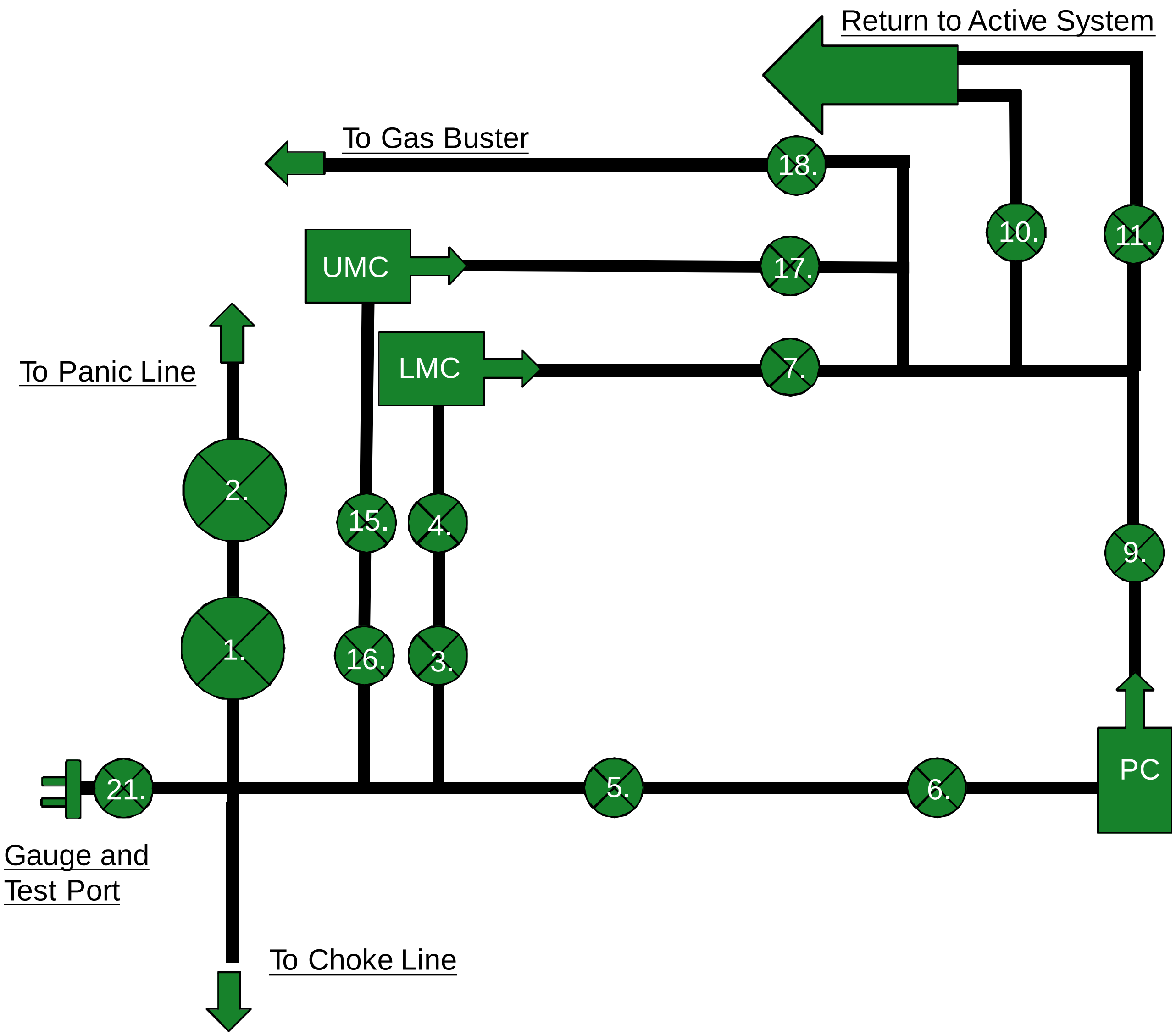


Oxy



Oxy Single Centrifuge Closed Loop System – New Mexico Flex III
May 28, 2013

10M Choke Panel



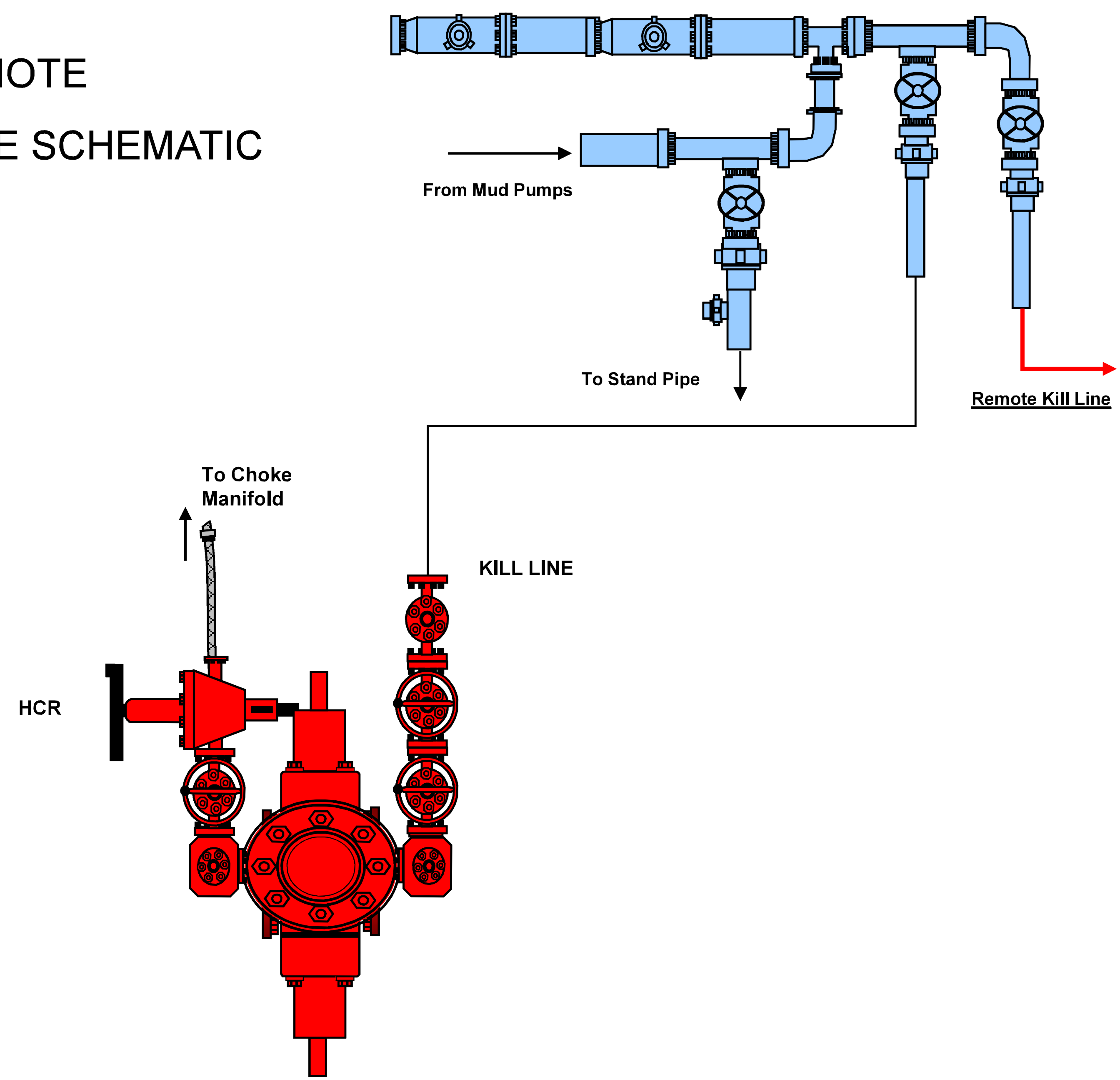
1. Choke Manifold Valve
2. Choke Manifold Valve
3. Choke Manifold Valve
4. Choke Manifold Valve
5. Choke Manifold Valve
6. Choke Manifold Valve
7. Choke Manifold Valve
8. PC – Power Choke
9. Choke Manifold Valve
10. Choke Manifold Valve
11. Choke Manifold Valve
12. LMC – Lower Manual Choke
13. UMC – Upper manual choke

15. Choke Manifold Valve
16. Choke Manifold Valve
17. Choke Manifold Valve
18. Choke Manifold Valve

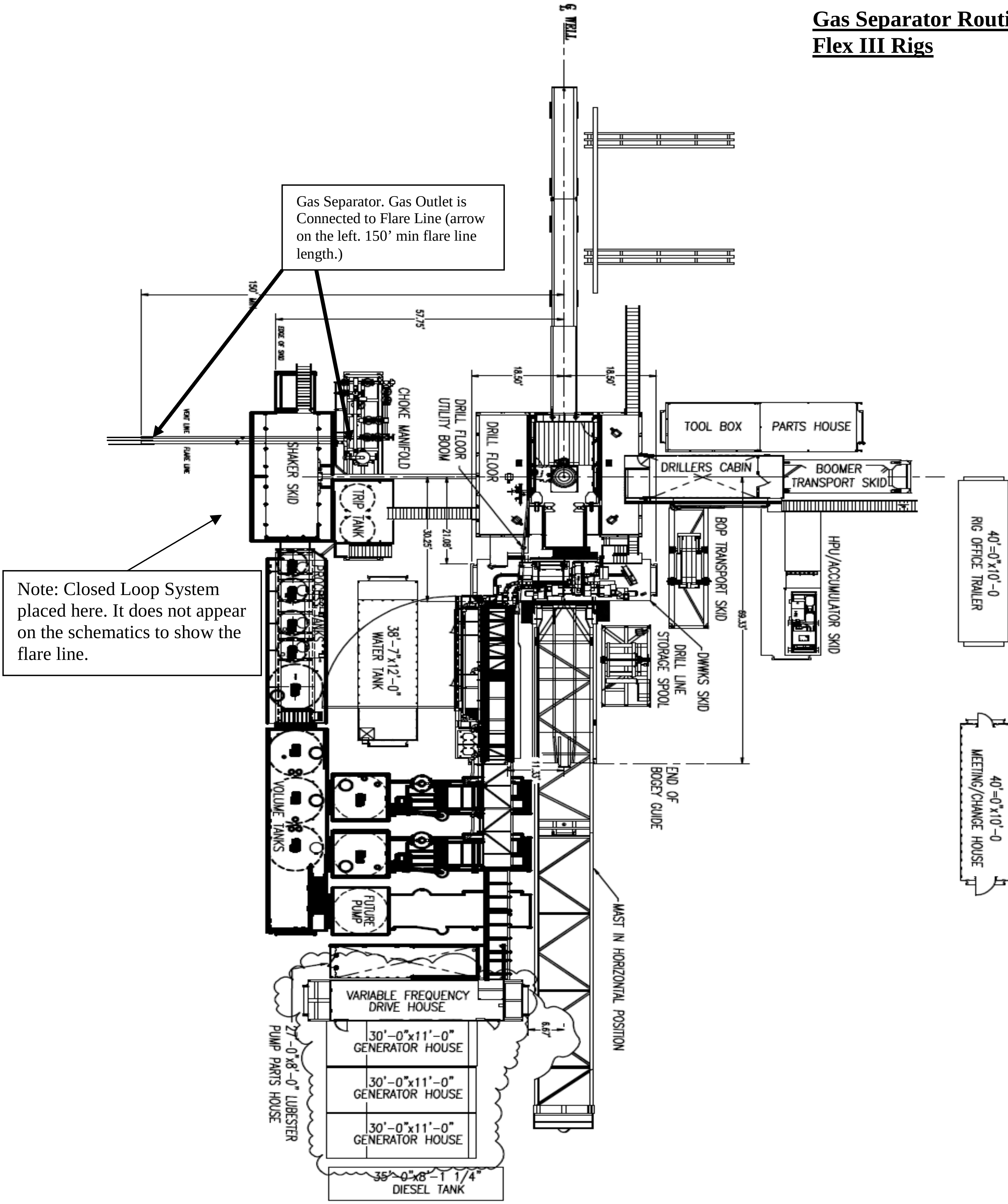
21. Vertical Choke Manifold Valve

***All Valves 3" minimum**

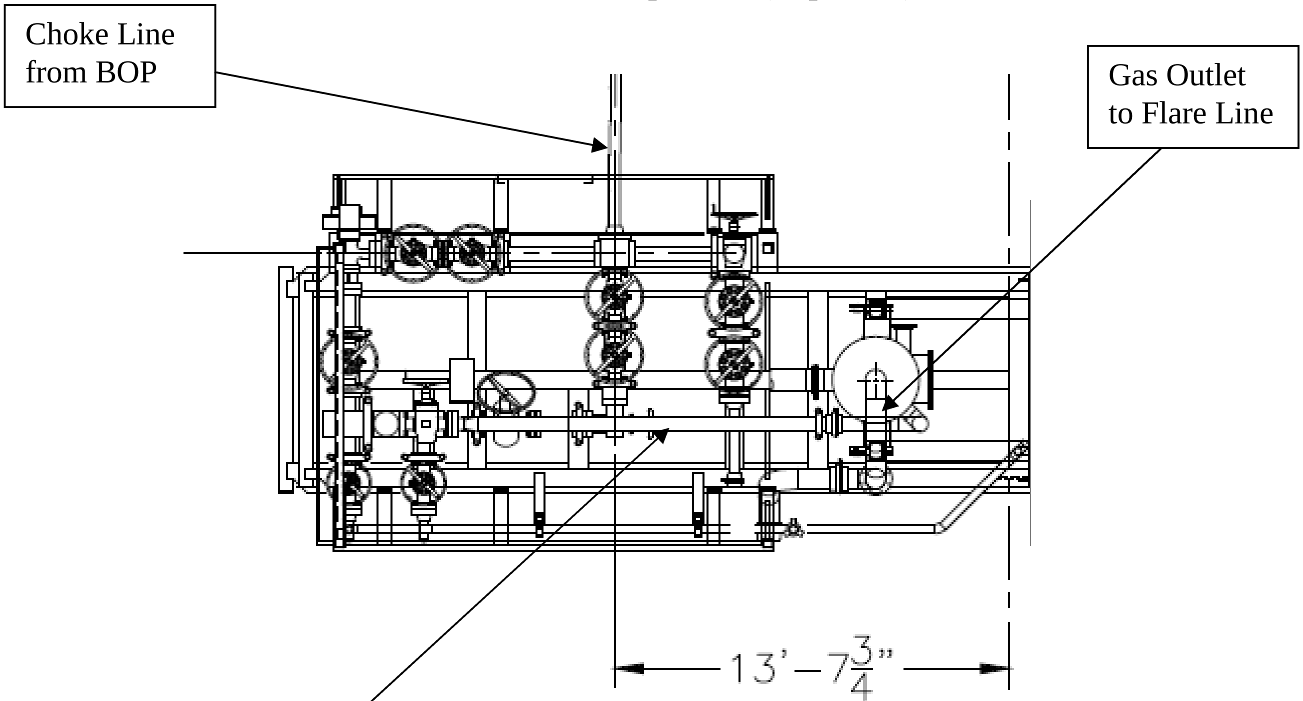
10M REMOTE
KILL LINE SCHEMATIC



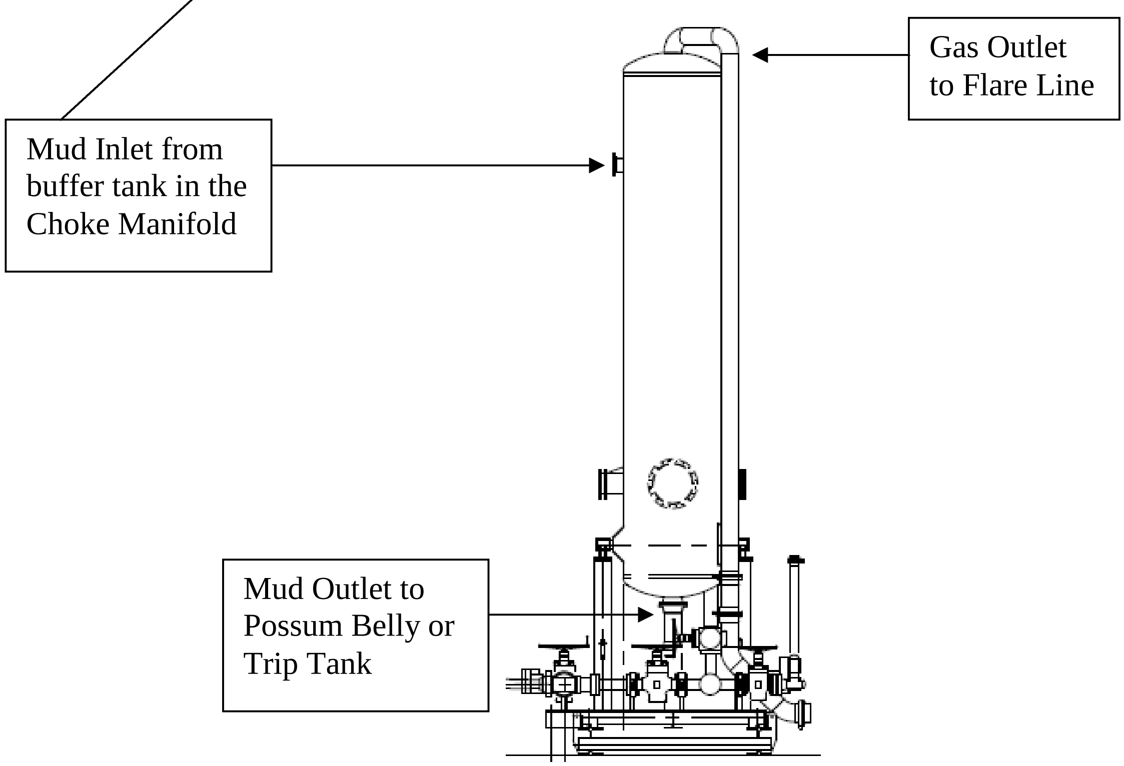
Gas Separator Routing
Flex III Rigs



Choke Manifold – Gas Separator (Top View)



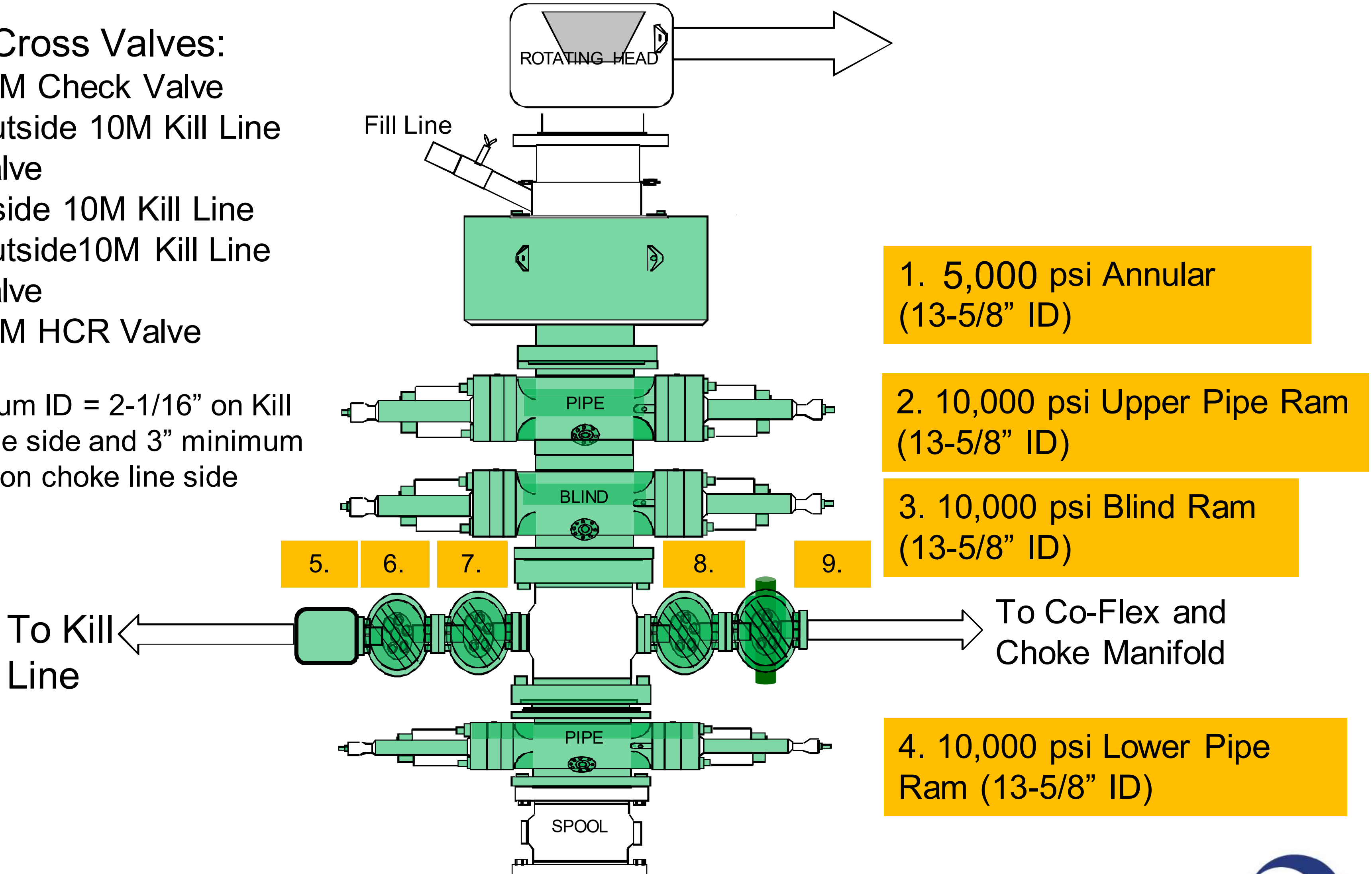
Choke Manifold – Gas Separator (Side View)



5/10M BOP Stack

Mud Cross Valves:
5. 10M Check Valve
6. Outside 10M Kill Line Valve
7. Inside 10M Kill Line
8. Outside10M Kill Line Valve
9. 10M HCR Valve

*Minimum ID = 2-1/16” on Kill Line side and 3” minimum ID on choke line side



Certificate of Conformity

Continental
ContiTech

Certificate Number	COM Order Reference	Customer Name & Address
H100161	1429702	HELMERICH & PAYNE DRILLING CO 1434 SOUTH BOULDER AVE TULSA, OK 74119 USA
Customer Purchase Order No:	740382384	
Project:		

Test Center Address	Accepted by COM Inspection	Accepted by Client Inspection
ContiTech Oil & Marine Corp. 11535 Brittmoore Park Drive Houston, TX 77041 USA	Signed: Gerson Mejia-Lazo Date: 06/27/22	

We certify that the items detailed below meet the requirements of the customer's Purchase Order referenced above, and are in conformance with the specifications given below.

Item	Part No.	Description	Qnty	Serial Number	Specifications
30	RECERTIFICATION	3" ID 10K Choke and Kill Hose x 35ft OAL	1	70024	ContiTech Standard

Hydrostatic Test Certificate

ContiTech

Certificate Number	COM Order Reference	Customer Name & Address
H100161	1429702	HELMERICH & PAYNE DRILLING CO 1434 SOUTH BOULDER AVE TULSA, OK 74119 USA
Customer Purchase Order No:	740382384	
Project:		

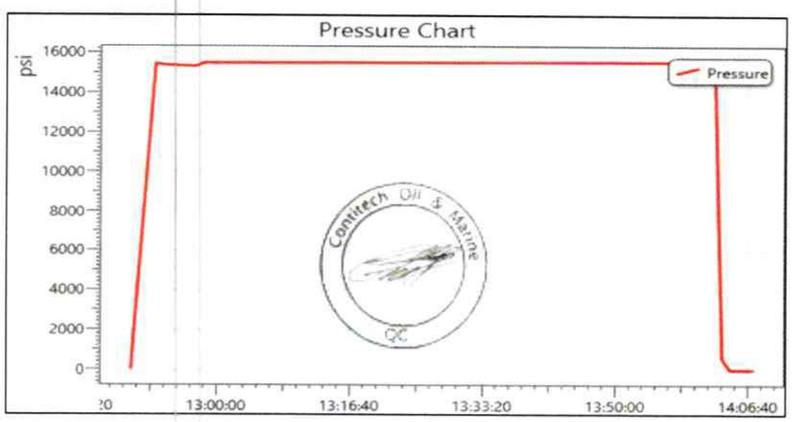
Test Center Address	Accepted by COM Inspection		Accepted by Client Inspection
ContiTech Oil & Marine Corp. 11535 Brittmoore Park Drive Houston, TX 77041 USA	Signed: Date:	Gerson Mejia-Lazo 06/27/22	

We certify that the goods detailed hereon have been inspected as described below by our Quality Management System, and to the best of our knowledge are found to conform the requirements of the above referenced purchase order as issued to ContiTech Oil & Marine Corporation.

Item	Part No.	Description	Qnty	Serial Number	Work. Press. (psi)	Test Press. (psi)	Test Time (minutes)
30	RECERTIFICATION	3" ID 10K Choke and Kill Hose x 35ft OAL	1	70024	10,000	15,000	60

Record Information	
Start Time	6/8/2022 12:49:19
End Time	6/8/2022 14:07:25
Interval	00:01:00
Number	79
MaxValue	15762
MinValue	-7
AvgValue	14395
RecordName	70024-sh
RecordNumber	235

Gauge Information	
Model	ADT680
SN	21817380014
Range	(0-40000)psi
Unit	psi



THIS GONE DEC 23/22
IN USE A.S.

@Rig NOV 21 2019 CHOKE HOSE

Gates Engineering & Services North America
7603 Prairie Oak Dr.
Houston, TX. 77086
PHONE : (281) 602-4119
FAX:
EMAIL: Troy.Schmidt@gates.com

CERTIFICATE OF CONFORMANCE

This is to certify that all parts and materials included in this shipment have manufactured and/or processed in accordance with various Gates and API assembly and test specifications. Records of required tests are on-file and subject to examination. Test reports and subsequent test graphs have been made available with this shipment. Additional supporting documentation related to materials, welding, weld inspections, and heat-treatment activities are available upon request.

CUSTOMER:	A-7 AUSTIN INC DBA AUSTIN HOSE
CUSTOMERS P.O.#:	4128128 (RIG 1 PO 002773)
CUSTOMER P/N:	10KFR3.012.0CK411610KFIXXFLT SSA SC LE
PART DESCRIPTION:	3" X 12 FT GATES CHOKE & KILL HOSE ASSEMBLY WITH STAINLESS STEEL ARMOR C/W 4 1/16 10K FIX X FLOAT H2S SUITED FLANGES WITH BX 155 RING GROOVE SUPPLIED WITH SAFETY CLAMPS & SLINGS & LIFT EYE CLAMPS
SALES ORDER #:	516982
QUANTITY:	1
SERIAL #:	H2-112019-4

SIGNATURE: Norma Cabo

TITLE: QUALITY ASSURANCE

DATE: 11/20/2019

GATES ENGINEERING & SERVICES NORTH AMERICA
7603 Prairie Oak Dr.
Houston, TX 77086

PHONE: (281) 602 - 4119
FAX:
EMAIL: Troy.Schmidt@gates.com
WEB: www.gates.com

PRESSURE TEST CERTIFICATE

Customer:	A-7 AUSTIN INC DBA AUSTIN HOSE	Test Date:	11/20/2019
Customer Ref.:	4128128 (RIG 1 PO 002773)	Hose Serial No.:	H2-112019-4
Invoice No.:	516982	Created By:	Norma Cabrera

Product Description:	3" X 12 FT GATES CHOKE & KILL HOSE ASSEMBLY WITH STAINLESS STEEL ARMOR C/W 4 1/16 10K FIX X FLOAT H2S SUITED FLANGES WITH BX 155 RING GROOVE SUPPLIED WITH SAFETY CLAMPS & SLINGS & LIFT EYE CLAMPS

End Fitting 1:	4 1/16 10K FLANGES FIXED	End Fitting 2:	4 1/16 10K FLANGES FLOAT
Oracle Star No.:	68903010-9879429	Assembly Code:	L41242 113018
CUSTOMER P/N:	10KFR3.012.0CK411610KFIXXFLT SSA SC LE	Test Pressure:	15,000 PSI.
		Working Pressure:	10,000 PSI.

Gates Engineering & Services North America certifies that:

The following hose assembly has successfully passed all pressure testing requirements set forth in Gates specifications: GTS-04-052 (for 5K assemblies) or GTS-04-053 (10K assemblies), which include reference to Specification API 16C (2nd Edition); sections 7.5.4, 7.5.9, and 10.8.7. A test graph will accompany this test certificate to illustrate conformity to test requirements. This hose assembly was pressure tested using equipment and instrumentation that has been calibrated in accordance with the requirements set-forth in the GESNA management system.

Quality:	QUALITY	Production:	PRODUCTION
Date :	11/20/2019	Date :	11/20/2019
Signature :	Norma Cabrera	Signature :	

F-PRD-005

Revision 1_022819

H2-1987

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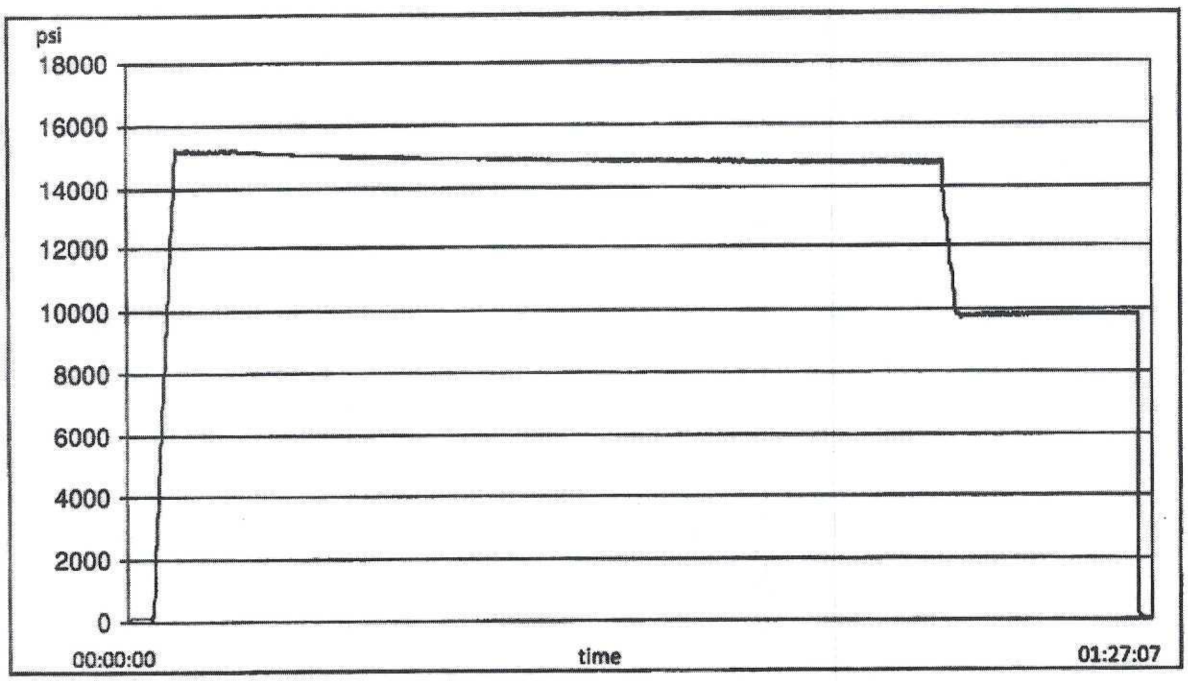
TEST REPORT

CUSTOMER			TEST OBJECT		
Company:	Austin Hose		Serial number:	H2-112019-4	
			Lot number:	L41242113018	
Production description:			Description:		
Sales order #:	516982				
Customer reference:			Hose ID:	3.0 10k MS C&K	
			Part number:		
TEST INFORMATION					
Test procedure:	GTS-04-053		Fitting 1:	3.0 x 4-1/16 10K	
Test pressure:	15000.00	psi	Part number:		
Test pressure hold:	3600.00	sec	Description:		
Work pressure:	9750.00	psi			
Work pressure hold:	900.00	sec	Fitting 2:	3.0 x 4-1/16 10K	
Length difference:	0.00	%	Part number:		
Length difference:	0.24	inch	Description:		
Visual check:			Length:	12	feet
Pressure test result:	PASS				
Length measurement result:					
Test operator:	Roderick Shambra				



Filename: D:\Certificates\Report_112019-H2-112019-4.pdf

H2-1987

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TEST REPORT

GAUGE TRACEABILITY

Description	Serial number	Calibration date	Calibration due date
S-25-A-W	110AMCL0	2019-03-17	2020-03-15
S-25-A-W	110AP02K	2019-04-16	2020-04-14

Comment

Filename: D:\Certificates\Report_112019-H2-112019-4.pdf

Certificate of Conformance

COPY

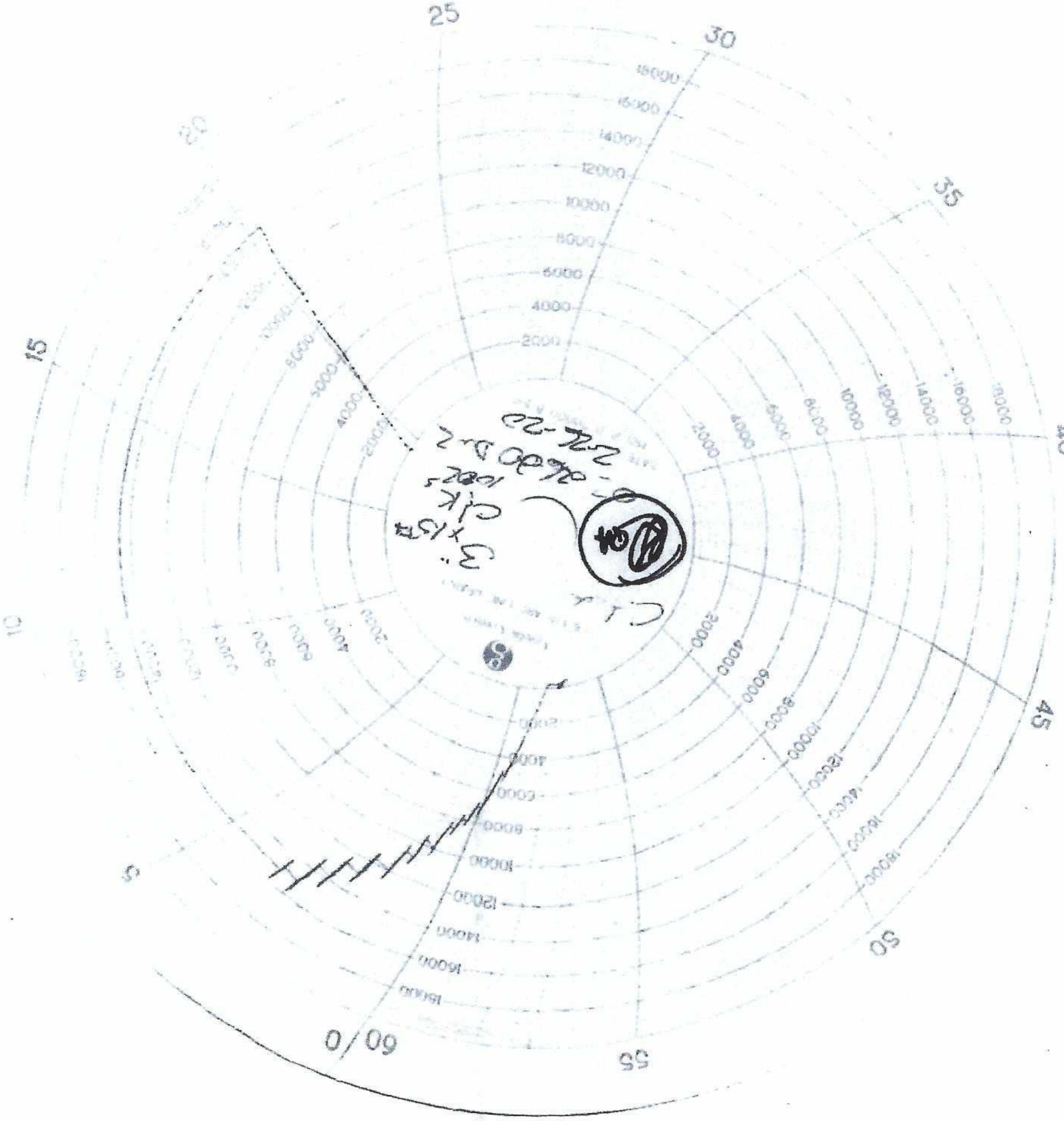
DW INDUSTRIES INC.
6287 Long Drive
Houston, TX 77087
Tel. 713 644-8372 Fax 713-644-4947

Customer Name:	CITADEL DRILLING		Customer Contact:	PAUL HOFFMAN 432-241-5360	
Purchase Order Information	Customer Purchase Order Number:	CONTACT PAUL HOFFMAN FOR INFO		DW Industries Work Order Number:	20020163
	DW Industries Part Number:	OA-5640-4815-1002-4		Serial Number:	022620DW-2
	QTY Ordered:	1		Assembly Date:	02/26/2020
	Customer Part Number:	OA-5640-4815-1002-4	Part Description:	3" 10,000 psi WP CHOKE HOSE M X F 4" 1002 HAMMER UNIONS C/W CLAMPS	

I DO HEREBY CERTIFY, AS THE AUTHORIZED REPRESENTATIVE OF DW INDUSTRIES, THAT THE PRODUCT LISTED ABOVE ARE OF THE QUALITY SPECIFIED AND CONFORM TO ALL REQUIREMENTS OF THE PURCHASE ORDER, INCLUDING: QUALITY CONTROL CLAUSES, DESIGN SPECIFICATIONS, DRAWINGS, PRESERVATION, PACKAGING, PACKING, MARKING, AND PHYSICAL IDENTIFICATION REQUIREMENTS AND HAS BEEN PROCESSED IN ACCORDANCE WITH ISO-9001:2015, API Q1 AND API SPEC 7K.

Certificate Issue Date: 2/27/2020

Garrett Crawford, Director of Quality
DW Industries Inc.



COPY

Certificate of Conformance

COPY

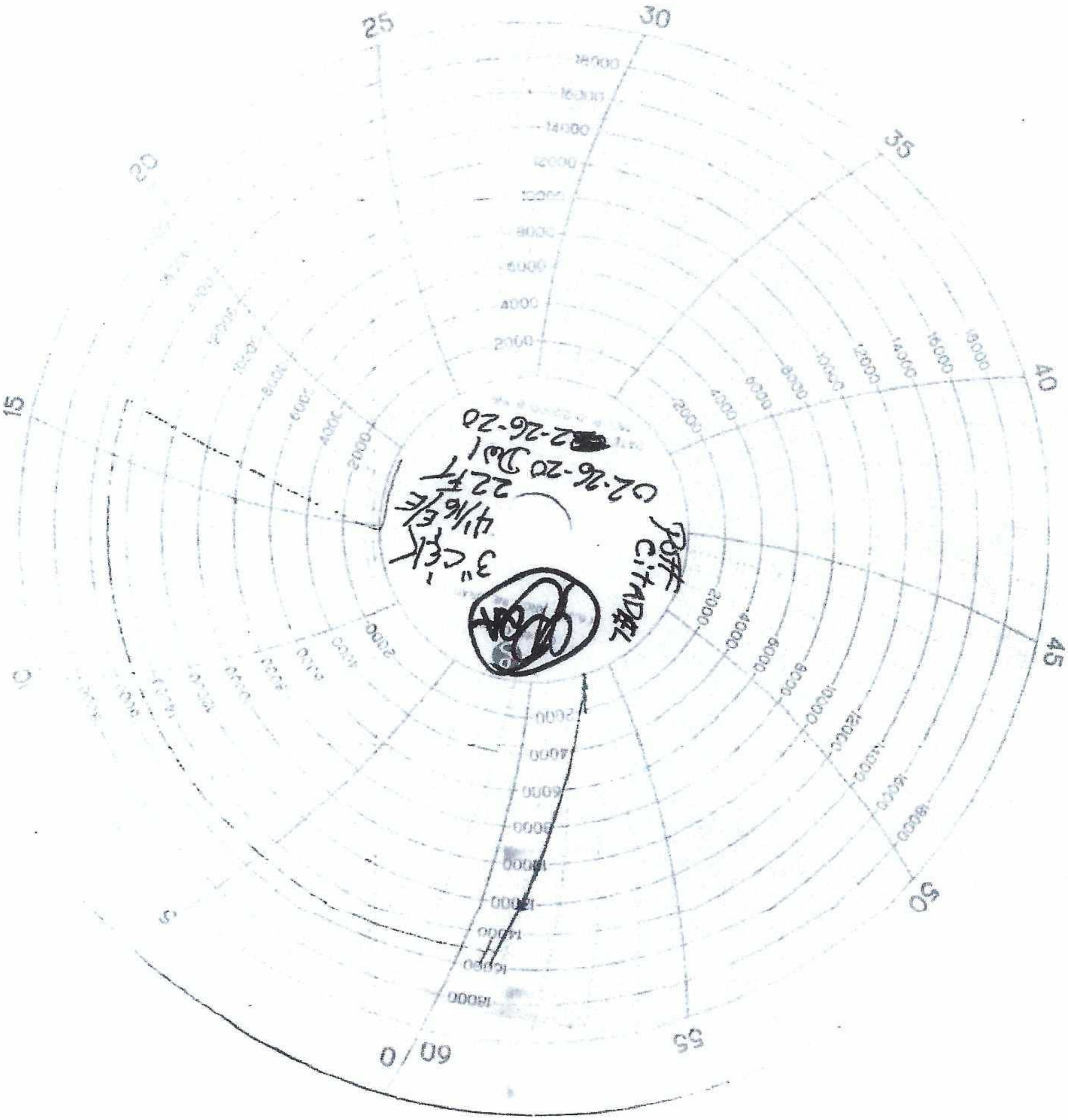
DW INDUSTRIES INC.
6287 Long Drive
Houston, TX 77087
Tel. 713 644-8372 Fax 713-644-4947

Customer Name:	CITADEL DRILLING		Customer Contact:	PAUL HOFFMAN 432-241-5360	
Purchase Order Information	Customer Purchase Order Number:	CONTACT PAUL HOFFMAN FOR INFO		DW Industries Work Order Number:	20020164
	DW Industries Part Number:	OA-5640-4822-4-1/16FXFL-ALE		Serial Number:	022620DW-1
	QTY Ordered:	1		Assembly Date:	02/26/2020
	Customer Part Number:	OA-5640-4822-4-1/16FXFL-ALE	Part Description:	3" 10,000 psi WP CHOKE HOSE 4-1/16" FIXED BY FLOAT FLANGES C/W SS ARMOR & LIFTING EYES	

I DO HEREBY CERTIFY, AS THE AUTHORIZED REPRESENTATIVE OF DW INDUSTRIES, THAT THE PRODUCT LISTED ABOVE ARE OF THE QUALITY SPECIFIED AND CONFORM TO ALL REQUIREMENTS OF THE PURCHASE ORDER, INCLUDING: QUALITY CONTROL CLAUSES, DESIGN SPECIFICATIONS, DRAWINGS, PRESERVATION, PACKAGING, PACKING, MARKING, AND PHYSICAL IDENTIFICATION REQUIREMENTS AND HAS BEEN PROCESSED IN ACCORDANCE WITH ISO-9001:2015, API Q1 AND API SPEC 7K.

Certificate Issue Date: 2/27/2020

Garrett Crawford, Director of Quality
DW Industries Inc.



COPY

Certificate of Conformance

DW INDUSTRIES INC.
6287 Long Drive
Houston, TX 77087
Tel. 713 644-8372 Fax 713-644-4947

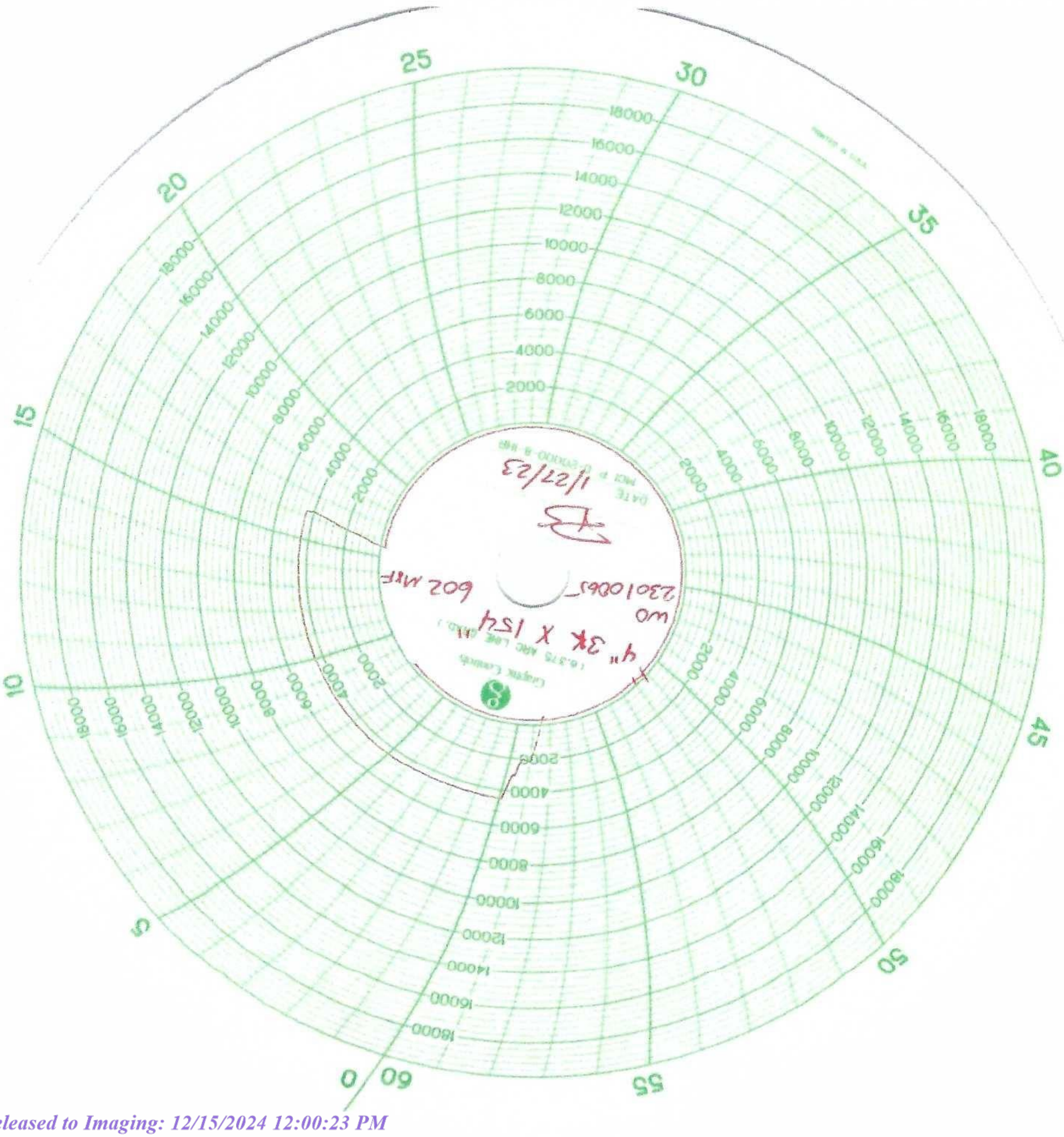
Customer Name:	ASUTIN HOSE		Customer Contact:	JUDY LOERA
Purchase Order Information	Customer Purchase Order Number:	00704977	DW Industries Work Order Number:	23010065
	DW Industries Part Number:	OA-PS5038-64154"-602	Serial Number:	23010065
	QTY Ordered:	1	Assembly Date:	1/27/2023
	Customer Part Number:		Part Description:	4"X154" 3K W/4" FIG 602 MXF

I DO HEREBY CERTIFY, AS THE AUTHORIZED REPRESENTATIVE OF DW INDUSTRIES, THAT THE PRODUCT LISTED ABOVE ARE OF THE QUALITY SPECIFIED AND CONFORM TO ALL REQUIREMENTS OF THE PURCHASE ORDER, INCLUDING: QUALITY CONTROL CLAUSES, DESIGN SPECIFICATIONS, DRAWINGS, PRESERVATION, PACKAGING, PACKING, MARKING, AND PHYSICAL IDENTIFICATION REQUIREMENTS AND HAS BEEN PROCESSED IN ACCORDANCE WITH ISO-9001:2015, API Q1 AND API SPEC 7K.

Certificate Issue Date: 1/27/2023

Quality Assurance,
DW Industries, Inc.

QF-018-OF, Rev New
Rev Date: 12/17/2019


1/27/23
WO
2301006
602 MRF
4" 3K X 154

IN SERVICE
12-20-21

Gates BLACK GOLD®

GATES ENGINEERING & SERVICES NORTH AMERICA
7603 Prairie Oak Dr. Suite 190
Houston, TX. 77086

PHONE: +1 (281) 602-4100
FAX: +1 (281) 602-4147
EMAIL: gesna.quality@gates.com
WEB: www.gates.com/oilandgas

PRESSURE TEST CERTIFICATE

Customer:	A-7 AUSTIN INC DBA AUSTIN HOSE	Test Date:	10/15/2021
Customer Ref.:	00595477	Hose Serial No.:	H3-101521-2
Invoice No.:	521925	Created By:	Micky Mhina

Product Description:	3" X 35' GATES FIRE RATED CHOKE & KILL HOSE ASSEMBLY SUITED FOR H2S SERVICE C/W 4 1/16 10K FIXED X FLOAT HEAT TREATED FLANGES SUPPLIED WITH STAINLESS STEEL ARMOR SAFETY CLAMPS & LIFT EYES

End Fitting 1:	4 1/16 10K FIXED FLANGE	End Fitting 2:	4 1/16 10K FLOAT HEAT TREATED FLANGES
Oracle Star No.:	68703010-10074881	Assembly Code:	L41975 091719
CUSTOMER P/N:	10K3.035.0CK411610KFIXXFLTW/SSA/SC/LE	Test Pressure:	15,000 PSI.
		Working Pressure:	10,000 PSI.

Gates Engineering & Services North America certifies that:

The following hose assembly has successfully passed all pressure testing requirements set forth in Gates specifications: GTS-04-052 (for 5K assemblies) or GTS-04-053 (10K assemblies) or GTS-04-048 (15K assemblies), which include reference to Specification API 16C (2nd Edition); sections 7.5.4, 7.5.9, and 10.8.7. A test graph will accompany this test certificate to illustrate conformity to test requirements. This hose assembly was pressure tested using equipment and instrumentation that has been calibrated in accordance with the requirements set-forth in the GESNA management system.

Quality:	QUALITY	Production:	PRODUCTION
Date :	10/15/2021	Date :	10/15/2021
Signature :	Micky Mhina	Signature :	

F-PRD-005B

Revision 6_05032021

BLACK GOLD®

GATES ENGINEERING & SERVICES NORTH AMERICA
7603 Prairie Oak Dr.
Houston, TX. 77086

PHONE: +1 (281) 602-4100
FAX: +1 (281) 602-4147
EMAIL: gesna.quality@gates.com
WEB: www.gates.com/oilandgas

CERTIFICATE OF CONFORMANCE

This is to certify that all parts and materials included in this shipment have manufactured and/or processed in accordance with various Gates and API assembly and test specifications. Records of required tests are on-file and subject to examination. Test reports and subsequent test graphs have been made available with this shipment. Additional supporting documentation related to materials, welding, weld inspections, and heat-treatment activities are available upon request.

CUSTOMER:	A-7 AUSTIN INC DBA AUSTIN HOSE
CUSTOMER P.O.#:	00595477
CUSTOMER P./N.#:	10K3.035.0CK411610KFIXXFLTW/SSA/SC/LE
PART DESCRIPTION:	3" X 35' GATES FIRE RATED CHOKE & KILL HOSE ASSEMBLY SUITED FOR H2S SERVICE C/W 4 1/16 10K FIXED X FLOAT HEAT TREATED FLANGES SUPPLIED WITH STAINLESS STEEL ARMOR SAFETY CLAMPS & LIFT EYES
SALES ORDER #:	521925
QUANTITY:	1
SERIAL #:	H3-101521-2

SIGNATURE: Mialye Wilner

TITLE: QUALITY ASSURANCE

DATE: 10/15/2021

H3-6963

10/15/2021 10:15:57 AM

TEST REPORT

CUSTOMER

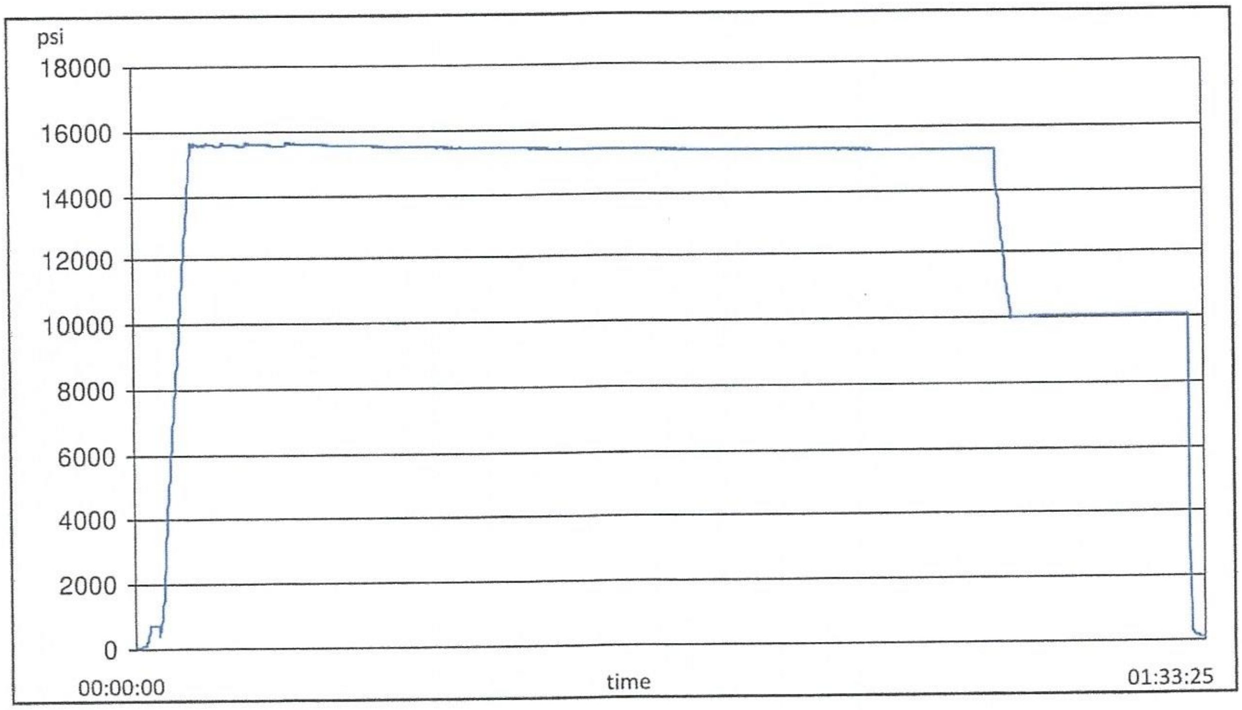
Company:	Austin Distributing
Production description:	
Sales order #:	521925
Customer reference:	

TEST INFORMATION

Test procedure:	GTS-04-053	
Test pressure:	15000.00	psi
Test pressure hold:	3600.00	sec
Work pressure:	10000.00	psi
Work pressure hold:	900.00	sec
Length difference:	0.00	%
Length difference:	0.00	inch
Visual check:		
Pressure test result:	PASS	
Length measurement result:		
Test operator:	francisco	

TEST OBJECT

Serial number:	H3-101521-2	
Lot number:	L41975091719	
Description:		
Hose ID:	3" 10k ck	
Part number:		
Fitting 1:	3.0 x 4-1/16 10K	
Part number:		
Description:		
Fitting 2:	3.0 x 4-1/16 10K	
Part number:		
Description:		
Length:	35	feet



H3-6963

10/15/2021 10:15:57 AM

TEST REPORT

GAUGE TRACEABILITY

Description	Serial number	Calibration date	Calibration due date
S-25-A-W	110AQA1S	2021-02-24	2022-02-24
S-25-A-W	110D3PHQ	2021-03-11	2022-03-11

Comment

Continental

ContiTech

Hydrostatic Test Certificate

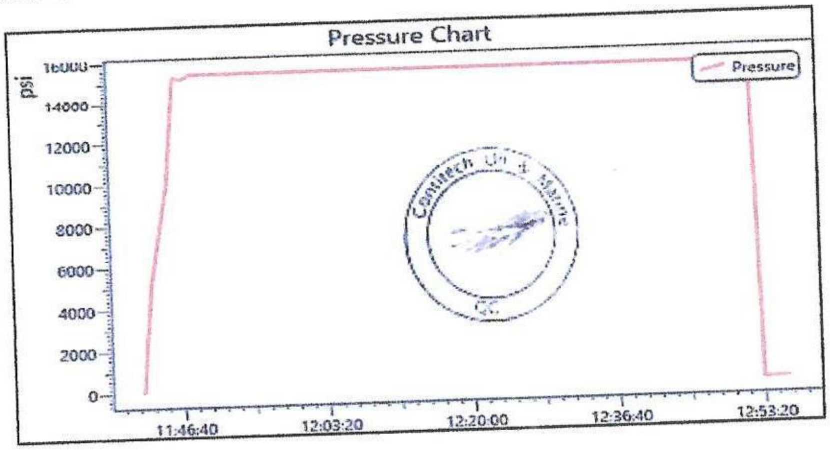
Certificate Number H100163	**COM Order Reference** 1429702	**Customer Name & Address** HELMERICH & PAYNE DRILLING CO 1434 SOUTH BOULDER AVE TULSA, OK 74119 USA
Customer Purchase Order No:	740382384	
Project:		
Test Center Address	**Accepted by COM Inspection**	**Accepted by Client Inspection**
ContiTech Oil & Marine Corp. 11535 Brittmoore Park Drive Houston, TX 77041 USA	Signed: Gerson Mejia-Lazo Date: 07/14/22	

We certify that the goods detailed hereon have been inspected as described below by our Quality Management System, and to the best of our knowledge are found to conform the requirements of the above referenced purchase order as issued to ContiTech Oil & Marine Corporation.

Item	Part No.	Description	Qnty	Serial Number	Work. Press. (psi)	Test Press. (psi)	Test Time (minutes)
50	RECERTIFICATION	3" ID 10K Choke and Kill Hose x 35ft OAL	1	70025	10,000	15,000	60

Record Information	
Start Time	6/14/2022 11:42:08
End Time	6/14/2022 12:56:14
Interval	00:01:00
Number	75
MaxValue	15888
MinValue	-8
AvgValue	14184
RecordName	70025-sh
RecordNumber	237

Gauge Information	
Model	ADT680
SN	21817380014
Range	(0-40000)psi
Unit	psi



Continental

Certificate of Conformity

ContiTech

Certificate Number H100163	**COM Order Reference** 1429702	**Customer Name & Address** HELMERICH & PAYNE DRILLING CO 1434 SOUTH BOULDER AVE TULSA, OK 74119 USA
Customer Purchase Order No:	740382384	
Project:		
Test Center Address	**Accepted by COM Inspection**	**Accepted by Client Inspection**
ContiTech Oil & Marine Corp. 11535 Brittmoore Park Drive Houston, TX 77041 USA	Signed: Gerson Mejia-Lazo Date: 07/14/22	

We certify that the items detailed below meet the requirements of the customer's Purchase Order referenced above, and are in conformance with the specifications given below.

Item	Part No.	Description	Qnty	Serial Number	Specifications
50	RECERTIFICATION	3" ID 10K Choke and Kill Hose x 35ft OAL	1	70025	ContiTech Standard

ARMORED CHOKE HOSE

Installed

4-29-22

Continental

ContiTech

CONTITECH RUBBER Industrial Kft.	No: QC-DB- 120 / 2019
	Page: 16 / 91

QUALITY CONTROL INSPECTION AND TEST CERTIFICATE

QUALITY CONTROL INSPECTION AND TEST CERTIFICATE				CERT. N°:	75819
PURCHASER:	ContiTech Oil & Marine Corp.			P.O. N°:	4501225327
CONTITECH RUBBER order N°:	1127442	HOSE TYPE:	3" ID	Choke and Kill Hose	
HOSE SERIAL N°:	75819	NOMINAL / ACTUAL LENGTH:		10,67 m / 10,68 m	
W.P. 69,0 MPa 10000 psi		T.P. 103,5 MPa 15000 psi		Duration: 60 min.	

Pressure test with water at ambient temperature

See attachment (1 page)

COUPLINGS Type	Serial N°	Quality	Heat N°
3" coupling with	6026	AISI 4130	A0607J
4 1/16" 10K API Swivel Flange end		AISI 4130	040841
Hub		AISI 4130	54194
3" coupling with	6016	AISI 4130	A0607J
4 1/16" 10K API b.w. Flange end		AISI 4130	040431

Not Designed For Well Testing

API Spec 16 C 2nd Edition– FSL2

Temperature rate: "B"

All metal parts are flawless

WE CERTIFY THAT THE ABOVE HOSE HAS BEEN MANUFACTURED IN ACCORDANCE WITH THE TERMS OF THE ORDER INSPECTED AND PRESSURE TESTED AS ABOVE WITH SATISFACTORY RESULT.

STATEMENT OF CONFORMITY: We hereby certify that the above items/equipment supplied by us are in conformity with the terms, conditions and specifications of the above Purchaser Order and that these items/equipment were fabricated inspected and tested in accordance with the referenced standards, codes and specifications and meet the relevant acceptance criteria and design requirements.

COUNTRY OF ORIGIN HUNGARY/EU

Date:	Inspector	Quality Control
08. April 2019.		ContiTech Rubber Industrial Kft. Quality Control Dept. (1)

ContiTech Rubber Industrial Kft. | Budapesti út 10. H-6728 Szeged | H-6701 P.O.Box 152 Szeged, Hungary
Phone: +36 62 566 737 | e-mail: info@fluid.contitech.hu | Internet: www.contitech-rubber.hu; www.contitech-oil-gas.com
The Court of Csongrád County as Registry Court | Registry Court No: Cg.06-09-002502 | EU VAT No: HU11087209
Bank data Commerzbank Zrt., Budapest | 14220108-26830003

Hose Assembly Evaluation Sheet

Prepared by	Cristian Rivera	Date:	8/27/2022		QIN:	N/A
Customer:	HELMERICH & PAYNE, INC	Location:	H&P INT'L DRILLING CO 210 MAGNOLIA DR GALENA PARK,TX,77547-2738			
User contact:	MITCH MCKINNIS	Phone:			e-mail:	mitch.mckinnis@hpinc.com

	Parameters	Hose Details	Test Status
Application Information	PO	740398454 (88000240 | SN:70035)	PASS
	Gates SO	525035	
	Serial #:	88000240 | SN:70035	
	As Tested Serial:	H2-082722-1 RE-TEST	
	Hose ID:	3 IN	
	Hose type:	INSPECT AND RETEST CUSTOMER HOSE 3IN X 35FT CHOKE & KILL ASSEMBLY C/W 4-1/16 FLANGES BX155 RING GROOVE EACH END	
	Working pressure:	10000 PSI.	

1. Visual Examination

An API 16C, IN X 35FT CHOKE & KILL ASSEMBLY C/W 4-1/16 FLANGES BX155 RING GROOVE EACH END received from HELMERICH & PAYNE, INC for inspection, testing and external cosmetic repairs. The hydrostatic pressure testing was requested to 15000 PSI., by the customer HELMERICH & PAYNE, INC

Visual inspection and examination of external hose assembly showed some cosmetic dents and repairabledamages to the external armor at distance 32ft 9in. from EF2. (Need to fix a part of the hose.)

Both external & internal hose body and couplings of the hose were examined. Visual Inspection photos are in Table 2, while post inspection/testing pictures are in Table 4.

The hose was hydrostatically tested at 15000 PSI. test pressure with an hour-long hold. On completion of hydrostatic testing, an internal baroscopic examination was carried out, to check the condition of internal hose areas, mainly hose tube and coupling hose interface.

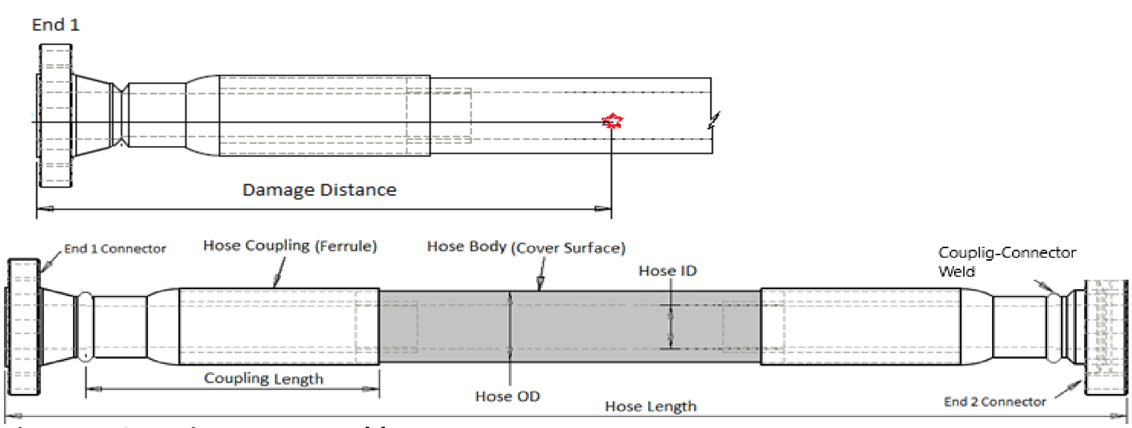


Figure 1: Generic Hose Assembly

Hose Assembly Evaluation Sheet

1.0 Observations and comments

	Comments
1	 **Photos: ID.**
2	 **Photo: Damaged armor areas**

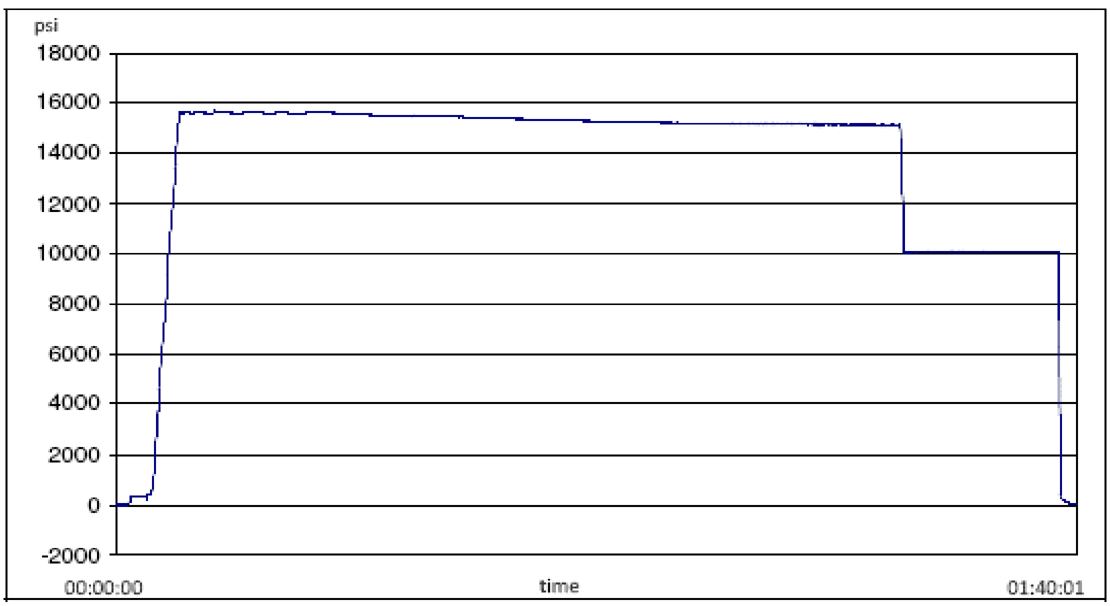
Hose Assembly Evaluation Sheet

3	 **Photos: At Shipping.**
4	 **Photos: Armor and Engraving.**

Hose Assembly Evaluation Sheet

5	 Photo: In the Crate

2. Hydro Static Pressure test



2.1 Hydrostatic Pressure test Procedures

	Hose Type	Test Specification	Test Date	Technician
1	IN X 35FT CHOKE & KILL ASSEMBLY C/W 4-1/16	3 10K C&K	2022-08-27	Martin Orozco

2.2 Gates Hydrostatic Pressure tester

	Test Equipment	Serial No	Last Cal Date	Cal Due Date
1	S-25-A-W	110AMCLO	2022-01-10	2023-01-10
2	S-25-A-W	110BSEUZ	2022-03-09	2023-03-09

Hose Assembly Evaluation Sheet

2.3 Hydro Static Test Pressure results

	Details	Results	
1	Hydrostatic Test Results (1)	Pass	~~Fail~~
2	Failure Mode	None	
3	Hose Dispatched to the customer?	Yes	~~No~~

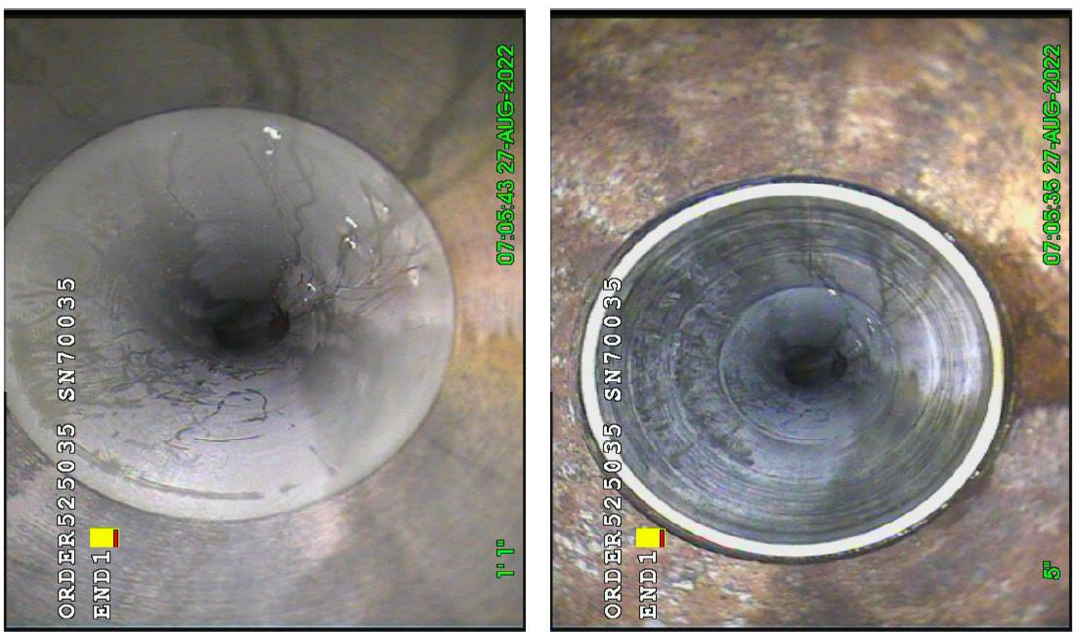
Note:

1. Hydrostatic Pressure report is given in Appendix 1

3. Hose borescope inspection

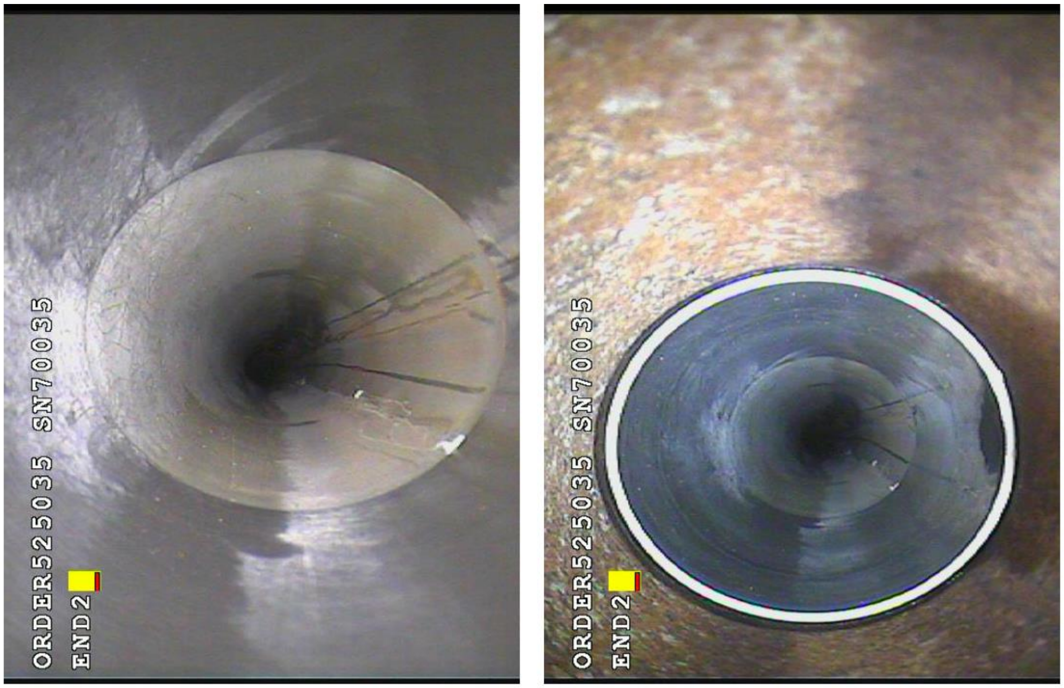
3.2 Internal Failure Details

	Type of Failure	Location of Defect	Ref. Photo	Defect Details
1	Liner breach/ collapse	None		None
2	Bulges/ Blisters	None		None
3	Other breach/failures	None		None



Photos: Liner/Coupling Interface END 1

Hose Assembly Evaluation Sheet



Photos: Liner/Coupling Interface END 2

Note

Borescope completed? *Yes*

4. Summary

Hose assembly successfully tested to requested test pressure of 15000 PSI. with an hour hold. It was then serialized and stamped, as H2-082722-1 RE-TEST. The bore scope showed no blisters or delamination in the internal lining/tube area. External damages were repaired as agreed with the customer.

Hose Assembly Evaluation Sheet

APPENDIX 1:
Pressure Chart

H2-8316

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TEST REPORT

CUSTOMER

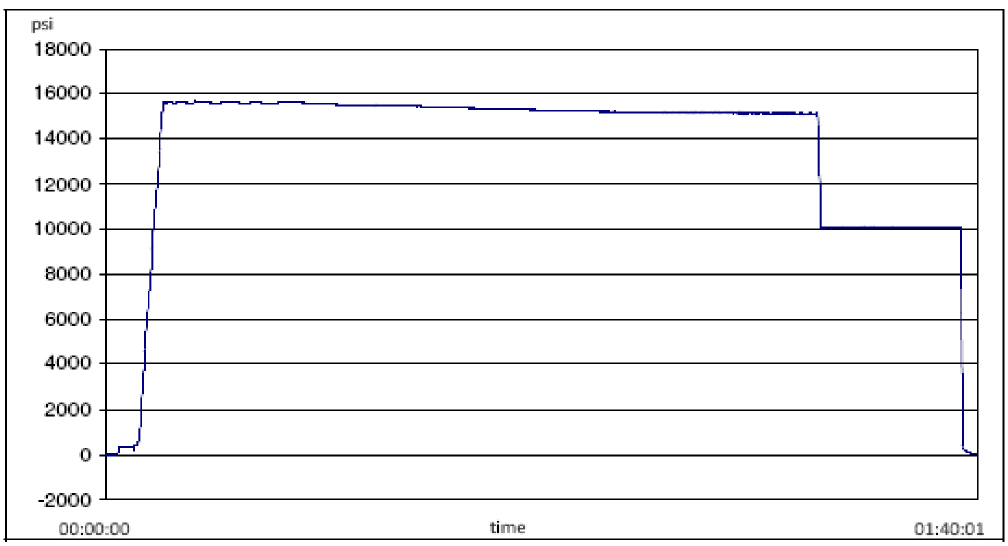
Company:	
Production description:	
Sales order #:	525035
Customer reference:	740398454 (88000240 | SN:70035)

TEST OBJECT

Serial number:	H2-082722-1
Lot number:	
Description:	
Hose ID:	3 10k C&K
Part number:	
Fitting 1:	3.0 x 4-1/16 10K
Part number:	
Description:	
Fitting 2:	3.0 x 4-1/16 10K
Part number:	
Description:	
Length:	35 feet

TEST INFORMATION

Test procedure:	3 10K C&K	
Test pressure:	15000.00	psi
Test pressure hold:	3600.00	sec
Work pressure:	10000.00	psi
Work pressure hold:	900.00	sec
Length difference:	0.00	%
Length difference:	0.00	inch
Visual check:		
Pressure test result:	PASS	
Length measurement result:		
Test operator:	Martin	



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TEST REPORT

GAUGE TRACEABILITY

Description	Serial number	Calibration date	Calibration due date
S-25-A-W	110AMCLO	2022-01-10	2023-01-10
S-25-A-W	110BSEUZ	2022-03-09	2023-03-09

Comment

APPENDIX 2:
Certificate of Conformance

BLACK GOLD®

GATES ENGINEERING & SERVICES NORTH AMERICA
7603 Prairie Oak Dr.
Houston, TX. 77086

PHONE: +1 (281) 602-4100
FAX: +1 (281) 602-4147
EMAIL: gesna.quality@gates.com
WEB: www.gates.com/oilandgas

CERTIFICATE OF CONFORMANCE

This is to verify that the items detailed below meet the requirements of the Customer's Purchase Order referenced herein, and are in Conformance with applicable specifications, and that Records of Required Tests are on file and subject to examination. The following items were inspected and hydrostatically tested at **Gates Engineering & Services North America** facilities in Houston, TX, USA.

CUSTOMER:	HELMERICH & PAYNE, INC
CUSTOMER P.O.#:	740398454 (88000240 | SN:70035)
CUSTOMER P/N:	88000240 | SN:70035
PART DESCRIPTION:	INSPECT AND RETEST CUSTOMER HOSE 3IN X 35FT CHOKE & KILL ASSEMBLY C/W 4-1/16 FLANGES BX155 RING GROOVE EACH END
SALES ORDER #:	525035
QUANTITY:	1
SERIAL #:	H2-082722-1 RE-TEST

SIGNATURE: Ojavarc

TITLE: QUALITY ASSURANCE

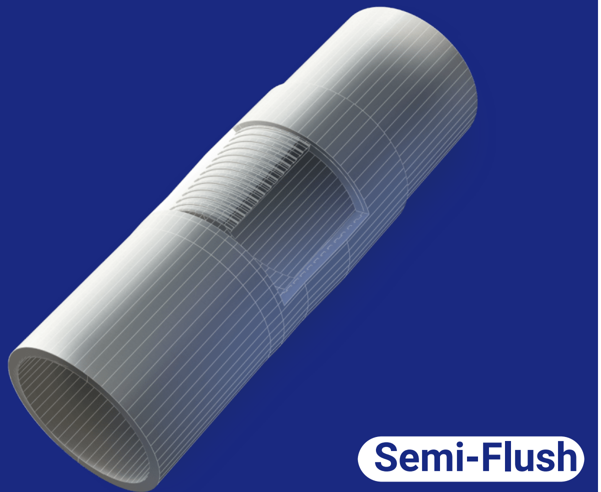
DATE: 8/27/2022

Generated on April 25, 2024

CONNECTION DATA SHEET

OD: **5.500 in.** Grade: **P110 RY**
Weight: **20.00 lb/ft** Drift: **4.653 in. (API)**
Wall Th.: **0.361 in.**

VAM® SPRINT-SF



Field Torque Values

Make-up Torque (ft-lb)
- 20,000 **MIN**
- 22,500 **OPTI**
- 25,000 **MAX**

Torque with Sealability (ft-lb)
- 36,000 **MTS**

Locked Flank Torque (ft-lb)
- 4,500 **MIN**
- 15,750 **MAX**

(2) MTS: Maximum Torque with Sealability.

PIPE BODY PROPERTIES

Nominal OD	5.500	*in.*
Nominal ID	4.778	*in.*
Nominal Wall Thickness	0.361	*in.*
Minimum Wall Thickness	87.5	*%*
Nominal Weight (API)	20.00	*lb/ft*
Plain End Weight	19.83	*lb/ft*
Drift	4.653	*in.*
Grade Type	Controlled Yield	
Minimum Yield Strength	110	*ksi*
Maximum Yield Strength	125	*ksi*
Minimum Ultimate Tensile Strength	140	*ksi*
Pipe Body Yield Strength	641	*klb*
Internal Yield Pressure	12,640	*psi*
Collapse Pressure	11,110	*psi*

CONNECTION PROPERTIES

Connection Type	Semi-Premium Integral Semi-Flu	
Nominal Connection OD	5.783	*in.*
Nominal Connection ID	4.718	*in.*
Make-up Loss	5.965	*in.*
Tension Efficiency	90	*% Pipe Body*
Compression Efficiency	90	*% Pipe Body*
Internal Pressure Efficiency	100	*% Pipe Body*
External Pressure Efficiency	100	*% Pipe Body*

JOINT PERFORMANCES

Tension Strength	577	*klb*
Compression Strength	577	*klb*
Internal Pressure Resistance	12,640	*psi*
External Pressure Resistance	11,110	*psi*
Maximum Bending, Structural	78	*°/100 ft*
Maximum Bending, with Sealability(1)	30	*°/100 ft*

(1) Sealability rating demonstrated as per API RP 5C5 / ISO 13679

OXY's Minimum Design Criteria

Burst, Collapse, and Tensile SF are calculated using Landmark's Stress Check (Casing Design) software. A sundry will be requested if any lesser grade or different size casing is substituted.

1) Casing Design Assumptions

a) Burst Loads

CSG Test (Surface)

- Internal: Displacement fluid + pressure required to comply with regulatory casing test pressures. This will comply with both 43 CFR part 3170 Subpart 3172 and 19.15.16 of the OCD Rules.
- External: Pore pressure in open hole.

CSG Test (Intermediate)

- Internal: Displacement fluid + pressure required to comply with regulatory casing test pressures. This will comply with both 43 CFR part 3170 Subpart 3172 and 19.15.16 of the OCD Rules.
- External: Mud Weight to TOC, cement mix water gradient (8.4 ppg) below TOC, and pore pressure in open hole.

CSG Test (Production)

- Internal:
  - For Drilling: Displacement fluid + pressure required to comply with regulatory casing test pressures. This will comply with both 43 CFR part 3170 Subpart 3172 and 19.15.16 of the OCD Rules.
  - For Production: The design pressure test should be the greater of (1) the planned test pressure prior to stimulation down the casing. (2) the regulatory test pressure, and (3) the expected gas lift system pressure. The design test fluid should be the fluid associated with pressure test having the greatest pressure.
- External:
  - For Drilling: Mud Weight to TOC, cement mix water gradient (8.4 ppg) below TOC, and pore pressure in open hole.
  - For Production: Mud base-fluid density to TOC, cement mix water gradient (8.4 ppg) below TOC, and pore pressure in open hole.

Gas Column (Surface)

- Internal: Assumes a full column of gas in the casing with a Gas/Oil Gradient of 0.1 psi/ft in the absence of better information. It is limited to the controlling pressure based on the fracture pressure at the shoe or the maximum expected pore pressure within the next drilling interval, whichever results in a lower surface pressure.
- External: Fluid gradient below TOC, pore pressure from the TOC to the Intermediate CSG shoe (if applicable), and MW of the drilling mud that was in the hole when the CSG was run from Intermediate CSG shoe to surface.

Bullheading (Surface / Intermediate)

- Internal: The string must be designed to withstand a pressure profile based on the fracture pressure at the casing shoe with a column of water above the shoe plus an additional surface pressure (in psi) of 0.02 X MD of the shoe to account for pumping friction pressure.
- External: Mud weight to TOC, cement mix water gradient (8.4 ppg) below TOC, and pore pressure in open hole.

Gas Kick (Intermediate)

- The string must be designed to at least a gas kick load case unless the rig is unable to detect a kick. For the gas kick load case, the internal pressure profile must be based on a minimum volume of 50 bbl or the minimum kick detection capability of the rig, whichever is greater, and a kick intensity of 2.0 ppg for Class 1, 1.0 ppg of Class 2, and 0.5 ppg for Class 3 and 4 wells.
- Internal: Influx depth of the maximum pore pressure of 0.55 “gas kick gravity” of gas to surface while drilling the next hole section.
- External: Mud weight to the TOC, cement mix water gradient below TOC, and pore pressure in open hole.

Tubing Leak Near Surface While Producing (Production)

- Internal: SITP plus a packer fluid gradient to the shoe or top of packer.
- External: Mud base-fluid density to TOC, cement mix water gradient (8.4 ppg) below TOC, and pore pressure in open hole.

Tubing Leak Near Surface While Stimulating (Production)

- Internal: Surface pressure or pressure-relief system pressure, whichever is lower plus packer fluid gradient.
- External: Mud base-fluid density to TOC, cement mix water gradient (8.4 ppg) below TOC, and pore pressure in open hole.

Injection / Stimulation Down Casing (Production)

- Internal: Surface pressure plus injection fluid gradient.
- External: Mud base-fluid density to TOC, cement mix water gradient (8.4 ppg) below TOC, and pore pressure in open hole.

b) Collapse Loads

Lost Circulation (Surface / Intermediate)

- Internal: Lost circulation at the TD of the next hole section, and the fluid level falls to a depth where the hydrostatic of the mud equals pore pressure at the depth of the lost circulation zone.
- External: MW of the drilling mud that was in the hole when the casing was

  run. Cementing (Surface / Intermediate / Production)

- Internal: Displacement fluid density.
- External: Mud weight from TOC to surface and cement slurry weight from TOC to casing shoe.

Full Evacuation (Production)

- Internal: Full void pipe.
- External: MW of drilling mud in the hole when the casing was run.

c) Tension Loads

Running Casing (Surface / Intermediate / Production)

- Axial: Buoyant weight of the string plus the lesser of 100,000 lb or the string weight in air.

Green Cement (Surface / Intermediate / Production)

- Axial: Buoyant weight of the string plus cement plug bump pressure load.

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 408237

CONDITIONS

Operator:	
OXY USA INC P.O. Box 4294 Houston, TX 772104294	OGRID: 16696
	Action Number: 408237
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

CONDITIONS

Created By	Condition	Condition Date
guthries	Cement is required to circulate on both surface and intermediate1 strings of casing.	12/3/2024
guthries	If cement does not circulate on any string, a Cement Bond Log (CBL) is required for that string of casing.	12/3/2024
pkautz	Administrative order required for non-standard spacing unit prior to production.	12/15/2024
pkautz	File As Drilled C-102 and a directional Survey with C-104 completion packet.	12/15/2024
pkautz	Once the well is spud, to prevent ground water contamination through whole or partial conduits from the surface, the operator shall drill without interruption through the fresh water zone or zones and shall immediately set in cement the water protection string.	12/15/2024
pkautz	Oil base muds are not to be used until fresh water zones are cased and cemented providing isolation from the oil or diesel. This includes synthetic oils. Oil based mud, drilling fluids and solids must be contained in a steel closed loop system.	12/15/2024