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

1a. Type of work: ☐ DRILL ☐ REENTER

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

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

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

8. Lease Name and Well No.

2. Name of Operator

9. API Well No.
30-015-55549

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.

Confidential

APPROVED WITH CONDITIONS

Approval Date: 09/23/2024

(Continued on page 2)

*(Instructions on page 2)

District I
1625 N. French Dr., Hobbs, NM 88240
PhonE: (575) 393-6161 Fax: (575) 393-0720
District II
811 S. First St., Artesia, NM 88210
PhonE: (575) 748-1283 Fax: (575) 748-9720
District III
1000 Rio Brazos Road, Aztec, NM 87410
PhonE: (505) 334-6178 Fax: (505) 334-6170
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505
PhonE: (505) 476-3460 Fax: (505) 476-3462

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

Form C-102
Revised August 1, 2011

Submit one copy to appropriate District Office

☐ AMENDED REPORT

WELL LOCATION AND ACREAGE DEDICATION PLAT

[1] API Number	[2] Pool Code	[3] Pool Name
30-015-55549	98357	WC 20S29E28; WOLFCAMP

[4] Property Code	[5] Property Name	[6] Well Number
336433	TAMBORA 36-35 FED COM	622H

[7] OGRID No.	[8] Operator Name	[9] Elevation
6137	DEVON ENERGY PRODUCTION COMPANY, L.P.	3284.0

[10] Surface Location

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
A	36	20-S	29-E	N/A	1253	NORTH	21	EAST	EDDY

[11] Bottom Hole Location If Different From Surface

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
L	35	20-S	29-E	N/A	2475	SOUTH	20	WEST	EDDY

[12] Dedicated Acres	[13] Joint or Infill	[14] Consolidation Code	[15] Order No.
640			Pending NSL

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.

[16]

TAMBORA 36-35 FED COM 622H

SURFACE HOLE LOCATION
1253' FNL & 21' FEL
EL: 3284.0
N: 558030.24
E: 637879.00
LAT: 32.5336933°
LON: -104.0200697°

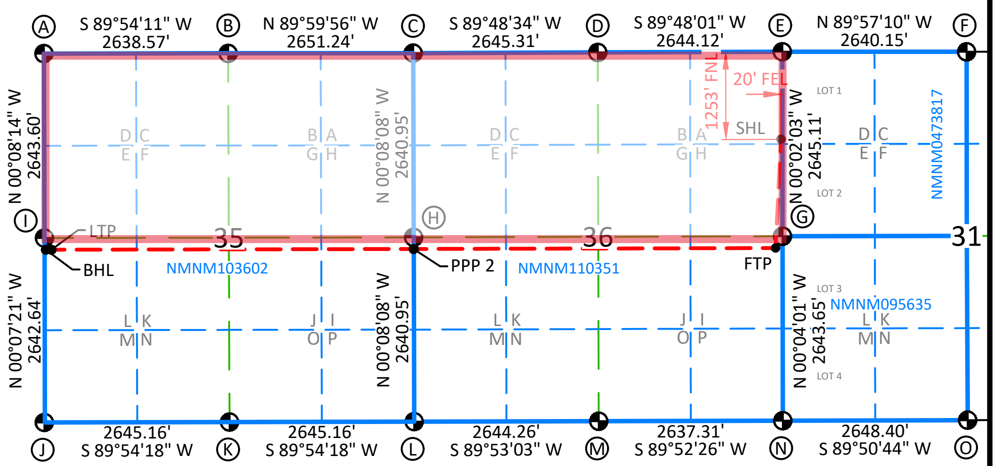
KICK OFF POINT
2475_F S L - __49___FE L
N: _32.5293_______ __
E: ___104.0203_ ___
LAT: __32.52931060
LON: -104.02025467

FIRST TAKE POINT (PPP 1)
2475' FSL - 100' FEL
N: 556469.38
E: 637800.52
LAT. 32.5294035°
LON. -104.0203392°

PPP 2
2475' FSL - 0' FEL
N: 556458.45
E: 632617.22
LAT. 32.5294142°
LON. -104.0371574°

LAST TAKE POINT
2475' FSL - 100' FWL
N: 556449.85
E: 627428.68
LAT. 32.5294291°
LON. -104.0539926°

BOTTOM HOLE LOCATION
2475' FSL - 20' FWL
N: 556449.72
E: 627348.70
LAT. 32.5294293°
LON. -104.0542521°



COORDINATE TABLE

A	N: 559260.26	E: 627322.02
B	N: 559264.72	E: 629959.96
C	N: 559264.68	E: 632610.58
D	N: 559273.48	E: 635255.24
E	N: 559282.69	E: 637898.72
F	N: 559280.52	E: 640538.24
G	N: 556638.20	E: 637900.30
H	N: 556624.36	E: 632616.82
I	N: 556617.29	E: 627328.34
J	N: 553975.28	E: 627334.00
K	N: 553979.66	E: 629978.53
L	N: 553984.04	E: 632623.07
M	N: 553989.38	E: 635266.70
N	N: 553995.18	E: 637903.38
O	N: 554002.32	E: 640551.15

LEGEND

- SECTION LINE
- 1/4 SECTION LINE
- 1/16 SECTION LINE
- WELL PATH
- LEASE LINE
- NM010101010 LEASE ID NUMBER
- FOUND USGLO B.C. ON 1"PIPE, "1916"

[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.

Chelsey Green 8/7/24

Signature Date

Arianna Evans

Printed Name

arianna.evans@dvn.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.

03/24/24

Date of Survey

Signature and Seal of Professional Surveyor:

JOHN E. ALLEN
NEW MEXICO
20250
PROFESSIONAL SURVEYOR

John E. Allen

Certificate No. 20250 John E. Allen

Drawn by: JEB	Checked by: JEA	Date: 03/25/24

NOTES:
1. BASIS OF BEARINGS, COORDINATES AND DISTANCES ARE A LAMBERT CONICAL PROJECTION OF THE NEW MEXICO COORDINATE SYSTEM, STATE PLANE GRID, NAD 83, NEW MEXICO EAST (3001) WITH A CONVERGENCE ANGLE OF -0°08'00.86" AND A COMBINED SCALE FACTOR OF 1.000236530 BASED ON CONTROL POINT STREET GLIDE AT N. 558290.968' E. 617876.978'.
2. DISTANCES SHOWN ARE GROUND DISTANCES IN U.S. SURVEY FEET.
3. ELEVATIONS SHOWN ARE EXISTING GROUND ELEVATIONS.

Intent [X] As Drilled [ ]

API #

Operator Name:	Property Name:	Well Number
DEVON ENERGY PRODUCTION COMPANY, L.P.	TAMBORA 36-35 FED COM	622H

Kick Off Point (KOP)

UL	Section	Township	Range	Lot	Feet	From N/S	Feet	From E/W	County
I	36	20S	29E		2475	SOUTH	49	EAST	EDDY

Latitude	Longitude	NAD
32.52931060	-104.02025467	83

First Take Point (FTP)

UL	Section	Township	Range	Lot	Feet	From N/S	Feet	From E/W	County
I	36	20-S	29-E	N/A	2475	SOUTH	100	EAST	EDDY

Latitude	Longitude	NAD
32.5294035°	-104.0203392°	83

Last Take Point (LTP)

UL	Section	Township	Range	Lot	Feet	From N/S	Feet	From E/W	County
L	35	20-S	29-E	N/A	2475	SOUTH	100	WEST	EDDY

Latitude	Longitude	NAD
32.5294291°	-104.0539926°	83

Is this well the defining well for the Horizontal Spacing Unit? NO

Is this well an infill well? YES

If infill is yes provide API if available, Operator Name and well number for Defining well for Horizontal Spacing Unit.

API #

Operator Name:	Property Name:	Well Number
DEVON ENERGY PRODUCTION COMPANY, L.P.	TAMBORA 36-35 FED COM	623H

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: DEVON ENERGY PRODUCTION COMPANY, LP **OGRID:** 6137 **Date:** 06 / 27 / 2023

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 attachment						

IV. Central Delivery Point Name: See attachment [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 attachment						

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.

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	Central Delivery Point Name:
TAMBORA 36-35 FED COM 621H		36-20S-30E	1137	FNL	145	FWL	(+/-)1245bopd	(+/-)2995mcfd	(+/-)3115bwpd	TAMBORA 36 CTB 2
TAMBORA 36-35 FED COM 331H		36-20S-30E	1167	FNL	145	FWL	(+/-)973bopd	(+/-)1295mcfd	(+/-)2965bwpd	TAMBORA 36 CTB 2
TAMBORA 36-35 FED COM 821H		36-20S-30E	1197	FNL	145	FWL	(+/-)626bopd	(+/-)6778mcfd	(+/-)2539bwpd	TAMBORA 36 CTB 2
TAMBORA 36-35 FED COM 622H		36-20S-30E	1227	FNL	145	FWL	(+/-)1245bopd	(+/-)2995mcfd	(+/-)3115bwpd	TAMBORA 36 CTB 2
TAMBORA 36-35 FED COM 332H		36-20S-29E	1243	FSL	815	FEL	(+/-)973bopd	(+/-)1295mcfd	(+/-)2965bwpd	TAMBORA 36 CTB 1
TAMBORA 36-35 FED COM 822H		36-20S-29E	1213	FSL	815	FEL	(+/-)626bopd	(+/-)6778mcfd	(+/-)2539bwpd	TAMBORA 36 CTB 1
TAMBORA 36-35 FED COM 623H		36-20S-29E	1183	FSL	815	FEL	(+/-)1245bopd	(+/-)2995mcfd	(+/-)3115bwpd	TAMBORA 36 CTB 1
TAMBORA 36-35 FED COM 823H		36-20S-29E	1153	FSL	815	FEL	(+/-)626bopd	(+/-)6778mcfd	(+/-)2539bwpd	TAMBORA 36 CTB 1
TAMBORA 36-35 FED COM 333H		36-20S-29E	1123	FSL	815	FEL	(+/-)973bopd	(+/-)1295mcfd	(+/-)2965bwpd	TAMBORA 36 CTB 1
TAMBORA 36-35 FED COM 624H		36-20S-29E	1093	FSL	815	FEL	(+/-)1245bopd	(+/-)2995mcfd	(+/-)3115bwpd	TAMBORA 36 CTB 1
TAMBORA 36-35 FED COM 824H		36-20S-29E	1106	FSL	814	FEL	(+/-)626bopd	(+/-)6778mcfd	(+/-)2539bwpd	TAMBORA 36 CTB 1

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
TAMBORA 36-35 FED COM 621H	n/a	6/4/2025	7/4/2025	11/1/2025	11/1/2025	11/1/2025
TAMBORA 36-35 FED COM 331H	n/a	6/25/2025	7/25/2025	11/22/2025	11/22/2025	11/22/2025
TAMBORA 36-35 FED COM 821H	n/a	7/6/2025	8/5/2025	12/3/2025	12/3/2025	12/3/2025
TAMBORA 36-35 FED COM 622H	n/a	7/29/2025	8/28/2025	12/26/2025	12/26/2025	12/26/2025
TAMBORA 36-35 FED COM 332H	n/a	7/19/2025	8/18/2025	12/16/2025	12/16/2025	12/16/2025
TAMBORA 36-35 FED COM 822H	n/a	8/19/2025	9/18/2025	1/16/2026	1/16/2026	1/16/2026
TAMBORA 36-35 FED COM 623H	n/a	6/10/2025	7/10/2025	11/7/2025	11/7/2025	11/7/2025
TAMBORA 36-35 FED COM 823H	n/a	7/8/2025	8/7/2025	12/5/2025	12/5/2025	12/5/2025
TAMBORA 36-35 FED COM 333H	n/a	5/4/2025	6/3/2025	10/1/2025	10/1/2025	10/1/2025
TAMBORA 36-35 FED COM 624H	n/a	6/12/2025	7/12/2025	11/9/2025	11/9/2025	11/9/2025
TAMBORA 36-35 FED COM 824H	n/a	6/7/2025	7/7/2025	11/4/2025	11/4/2025	11/4/2025

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

D 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;
(t) 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:	
Printed Name:	Jeff Walla
Title:	Surface Land and Regulatory Manager
E-mail Address:	
Date:	
Phone:	

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

devon

VI. Separation Equipment

Devon Energy Production Company, L.P. utilizes a "stage separation" process in which oil and gas separation is carried out through a series of separators operating at successively reduced pressures. Hydrocarbon liquids are produced into a high-pressure inlet separator, then carried through one or more lower pressure separation vessels before entering the storage tanks. The purpose of this separation process is to attain maximum recovery of liquid hydrocarbons from the fluids and allow maximum capture of produced gas into the sales pipeline. Devon utilizes a series of Low-Pressure Compression units to capture gas off the staged separation and send it to the sales pipeline. This process minimizes the amount of flash gas that enters the end-stage storage tanks that is subsequently vented or flared.

devon

VII. Operational Practices

Devon Energy Production Company, L. P. will employ best management practices and control technologies to maximize the recovery and minimize waste of natural gas through venting and flaring.

- During drilling operations, Devon will utilize flares and/or combustors to capture and control natural gas, where technically feasible. If flaring is deemed technically in-feasible, Devon will employ best management practices to minimize or reduce venting to the extent possible.
- During completions operations, Devon will utilize Green Completion methods to capture gas produced during well completions that is otherwise vented or flared. If capture is technically in-feasible, flares and/or combustors will be used to capture and control flow back fluids entering into frac tanks during initial flowback. Upon indication of first measurable hydrocarbon volumes, Devon will turn operations to onsite separation vessels and flow to the gathering pipeline.
- During production operations, Devon will take every practical effort to minimize waste of natural gas through venting and flaring by:
    - Designing and constructing facilities in a manner consistent to achieve maximum capture and control of hydrocarbon liquids & produced gas
    - Utilizing a closed-loop capture system to collect and route produced gas to sales line via low pressure compression, or to a flare/combustor
    - Flaring in lieu of venting, where technically feasible
    - Utilizing auto-ignitors or continuous pilots, with thermocouples connected to Scada, to quickly detect and resolve issues related to malfunctioning flares/combustors
    - Employ the use of automatic tank gauging to minimize storage tank venting during loading events
    - Installing air-driven or electric-driven pneumatics & combustion engines, where technically feasible to minimize venting to the atmosphere
    - Confirm equipment is properly maintained and repaired through a preventative maintenance and repair program to ensure equipment meets all manufacturer specifications
    - Conduct and document AVO inspections on the frequency set forth in Part 27 to detect and repair any onsite leaks as quickly and efficiently as is feasible

devon

VIII. Best Management Practices during Maintenance

Devon Energy Production Company, L.P. will utilize best management practices to minimize venting during active and planned maintenance activities. Devon is operating under guidance that production facilities permitted under NOI permits have no provisions to allow high pressure flaring and high pressure flaring is only allowed in disruption scenarios so long as the duration is less than eight hours. When technically feasible, flaring during maintenance activities will be utilized in lieu of venting to the atmosphere. Devon will work with third-party operators during scheduled maintenance of downstream pipeline or processing plants to address those events ahead of time to minimize venting. Actions considered include identifying alternative capture approaches or planning to temporarily reduce production or shut in the well to address these circumstances.

TAMBORA 36-35 FED COM 622H

1. Geologic Formations

TVD of target	9734	Pilot hole depth	N/A
MD at TD:	20386	Deepest expected fresh water	

Basin

Formation	Depth (TVD) from KB	Water/Mineral Bearing/Target Zone?	Hazards*
Rustler	167		
Salt	356		
Base of Salt	1569		
Capitan Reef Top	2036		
Delaware	3874		
Cherry Canyon	3964		
Brushy Canyon	4882		
1st Bone Spring Lime	6509		
Bone Spring 1st	7621		
Bone Spring 2nd	8355		
3rd Bone Spring Lime	8663		
Bone Spring 3rd	9403		
Wolfcamp	9830		

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

2. Casing Program (Primary Design)

Hole Size	Csg. Size	Wt (PPF)	Grade	Conn	Top (MD)	Bottom (MD)	Top (TVD)	Bottom (TVD)
17 1/2	13 3/8	54.5	J-55	BTC	0.0	192 MD	0	192 TVD
12 1/4	10 3/4	45.5	J-55	BTC SCC	0.0	1986 MD	0	1986 TVD
9 7/8	8 5/8	32.0	P110EC	Sprint FJ	0	3924 MD	0	3924 TVD
7 7/8	5 1/2	17.0	P110	DWC/C IS+	0	20386 MD	0	9734 TVD

• All casing strings will be tested in accordance with Onshore Oil and Gas Order #2 IILB.1.h Must have table for contingency casing.
• The Rustler top will be validated via drilling parameters (i.e. reduction in ROP), and the surface casing setting depth will be revised accordingly. In addition, surface casing will be set a minimum of 25' above the top of the salt.

3. Cementing Program (Primary Design)

Casing	# Sks	TOC	Wt. (lb/gal)	Yld (ft3/sack)	Slurry Description
Surface	177	Surf	13.2	1.44	Lead: Class C Cement + additives
Int	111	Surf	9	3.27	Lead: Class C Cement + additives
	101	1486	13.2	1.44	Tail: Class H / C + additives
Int 1	64	Surf	9	3.27	Lead: Class C Cement + additives
	225	2036	13.2	1.44	Tail: Class H / C + additives
Int 1 Intermediate Squeeze	84	Surf	9	1.44	Squeeze Lead: Class C Cement + additives
	64	Surf	9	3.27	Lead: Class C Cement + additives
	225	2036	13.2	1.44	Tail: Class H / C + additives
Production	441	1986	9	3.27	Lead: Class H /C + additives
	1434	9554	13.2	1.44	Tail: Class H / C + additives

Assuming no returns are established while drilling, Devon requests to pump a two stage cement job on the intermediate 1 casing string with the first stage being pumped conventionally with the calculated top of cement at the Capitan Reef and the second stage performed as a bradenhead squeeze with planned cement from the Capitan Reef to surface. The final cement top will be verified by Echo-meter. Devon will include theEcho-meter verified fluid top and the volume of displacement fluid above the cement slurry in the annulus in all post-drill sundries on wells utilizing this cement program.

Casing String	% Excess
Surface	50%
Intermediate and Intermediate 1	30%
Intermediate 1 (Two Stage)	25%
Prod	10%

4. Pressure Control Equipment (Four String Design)

<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></tr>
<tr><td rowspan="5">Int</td><td rowspan="5">13-5/8"</td><td rowspan="5">5M</td><td colspan="2">Annular</td><td>X</td><td>50% of rated working pressure</td></tr>
<tr><td colspan="2">Blind Ram</td><td>X</td><td rowspan="4">5M</td></tr>
<tr><td colspan="2">Pipe Ram</td><td></td></tr>
<tr><td colspan="2">Double Ram</td><td>X</td></tr>
<tr><td>Other*</td><td></td><td></td></tr>
<tr><td rowspan="5">Int 1</td><td rowspan="5">13-5/8"</td><td rowspan="5">5M</td><td colspan="2">Annular (5M)</td><td>X</td><td>100% of rated working pressure</td></tr>
<tr><td colspan="2">Blind Ram</td><td>X</td><td rowspan="4">5M</td></tr>
<tr><td colspan="2">Pipe Ram</td><td></td></tr>
<tr><td colspan="2">Double Ram</td><td>X</td></tr>
<tr><td>Other*</td><td></td><td></td></tr>
<tr><td rowspan="5">Production</td><td rowspan="5">13-5/8"</td><td rowspan="5">5M</td><td colspan="2">Annular (5M)</td><td>X</td><td>100% of rated working pressure</td></tr>
<tr><td colspan="2">Blind Ram</td><td>X</td><td rowspan="4">5M</td></tr>
<tr><td colspan="2">Pipe Ram</td><td></td></tr>
<tr><td colspan="2">Double Ram</td><td>X</td></tr>
<tr><td>Other*</td><td></td><td></td></tr>
<tr><td>N</td><td colspan="6">A variance is requested for the use of a diverter on the surface casing. See attached for schematic.</td></tr>
<tr><td>N</td><td colspan="6">A variance is requested to run a 5 M annular on a 10M system</td></tr>
</table>

5. Mud Program (Four String Design)

Section	Type	Weight (ppg)
Surface	WBM	8.5-9
Intermediate	DBE / Cut Brine	10-10.5
Intermediate 1	WBM	8.5-9
Production	OBM	10-10.5

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

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

6. Logging and Testing Procedures

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

Additional logs planned		Interval
	Resistivity	Int. shoe to KOP
	Density	Int. shoe to KOP
X	CBL	Production casing
X	Mud log	Intermediate shoe to TD
	PEX	

7. Drilling Conditions

Condition	Specfiy what type and where?
BH pressure at deepest TVD	5315
Abnormal temperature	No

Mitigation measure for abnormal conditions. Describe. Lost circulation material/sweeps/mud scavengers.

Hydrogren 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 Onshore Oil and Gas Order #6. 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

Is this a walking operation? Potentially

1. If operator elects, drilling rig will batch drill the surface holes and run/cement surface casing; walking the rig to next wells on the pad.
2. The drilling rig will then batch drill the intermediate sections and run/cement intermediate casing; the wellbore will be isolated with a blind flange and pressure gauge installed for monitoring the well before walking to the next well.
3. The drilling rig will then batch drill the production hole sections on the wells with OBM, run/cement production casing, and install TA caps or tubing heads for completions.

   NOTE: During batch operations the drilling rig will be moved from well to well however, it will not be removed from the pad until all wells have production casing run/cemented.

Will be pre-setting casing? Potentially

1. Spudder rig will move in and batch drill surface hole.
   a. Rig will utilize fresh water based mud to drill surface hole to TD. Solids control will be handled entirely on a closed loop basis.,
2. After drilling the surface hole section, the spudder rig will run casing and cement following all of the applicable rules and regulations (OnShore Order 2, all COAs and NMOCD regulations).
3. The wellhead will be installed and tested once the surface casing is cut off and the WOC time has been reached.
4. A blind flange with the same pressure rating as the wellhead will be installed to seal the wellbore. Pressure will be monitored with a pressure gauge installed on the wellhead.
5. Spudder rig operations is expected to take 4-5 days per well on a multi-well pa.
6. The NMOCD will be contacted and notified 24 hours prior to commencing spudder rig operations.
7. Drilling operations will be performed with drilling rig. A that time an approved BOP stack will be nipped up and tested on the wellhead before drilling operations commences on each well.
   a. The NMOCD will be contacted / notified 24 hours before the drilling rig moves back on to the pad with the pre-set surface casing.

Attachments

X	Directional Plan
	Other, describe

AFMSS
U.S. Department of the Interior
BUREAU OF LAND MANAGEMENT

Drilling Plan Data Report

09/24/2024

APD ID: 10400093682 **Submission Date:** 08/22/2023

Highlighted data reflects the most recent changes

Show Final Text

Operator Name: DEVON ENERGY PRODUCTION COMPANY LP

Well Name: TAMBORA 36 35 FED COM **Well Number:** 622H

Well Type: OIL WELL **Well Work Type:** Drill

Section 1 - Geologic Formations

Formation ID	Formation Name	Elevation	True Vertical	Measured Depth	Lithologies	Mineral Resources	Producing Formatio
14190754	RUSTLER	0	167	167	SANDSTONE	NONE	N
14190755	TOP SALT	-356	356	356	SALT	NONE	N
14190756	BASE OF SALT	-1569	1569	1569	SALT	NONE	N
14190757	LAMAR	-2036	2036	2036	SANDSTONE	NATURAL GAS, OIL	N
14190758	BELL CANYON	-3874	3874	3874	SANDSTONE	NATURAL GAS, OIL	N
14190759	CHERRY CANYON	-3964	3964	3964	SANDSTONE	NATURAL GAS, OIL	N
14190760	BRUSHY CANYON	-4882	4882	4882	SANDSTONE	NATURAL GAS, OIL	N
14190761	BONE SPRING 1ST	-6509	6509	6509	LIMESTONE	NATURAL GAS, OIL	N
14190762	AVALON SAND	-6625	6625	6625	SANDSTONE	NATURAL GAS, OIL	N
14190763	BONE SPRING 1ST	-7621	7621	7621	SANDSTONE	NATURAL GAS, OIL	N
14190764	BONE SPRING 2ND	-8355	8355	8355	SANDSTONE	NATURAL GAS, OIL	N
14190765	BONE SPRING 3RD	-8663	8663	8663	LIMESTONE	NATURAL GAS, OIL	N
14190766	BONE SPRING 3RD	-9403	9403	9403	SANDSTONE	NATURAL GAS, OIL	N
14190767	WOLFCAMP	-9830	9830	9830	SHALE	NATURAL GAS, OIL	Y

Section 2 - Blowout Prevention

devon

Commitment Runs Deep

Design Plan
Operation and Maintenance Plan
Closure Plan

SENM – Closed Loop Systems
June 2010

I. Design Plan

Devon uses MI SWACO closed loop system (CLS). The MI SWACO CLS is designed to maintain drill solids at or below 5%. The equipment is arranged to progressively remove solids from the largest to the smallest size. Drilling fluids can thus be reused and savings is realized on mud and disposal costs. Dewatering may be required with the centrifuges to insure removal of ultra fine solids.

The drilling location is constructed to allow storm water to flow to a central sump normally the cellar. This insures no contamination leaves the drilling pad in the event of a spill. Storm water is reused in the mud system or stored in a reserve fluid tank farm until it can be reused. All lubricants, oils, or chemicals are removed immediately from the ground to prevent the contamination of storm water. An oil trap is normally installed on the sump if an oil spill occurs during a storm.

A tank farm is utilized to store drilling fluids including fresh water and brine fluids. The tank farm is constructed on a 20 ml plastic lined, bermed pad to prevent the contamination of the drilling site during a spill. Fluids from other sites may be stored in these tanks for processing by the solids control equipment and reused in the mud system. At the end of the well the fluids are transported from the tank farm to an adjoining well or to the next well for the rig.

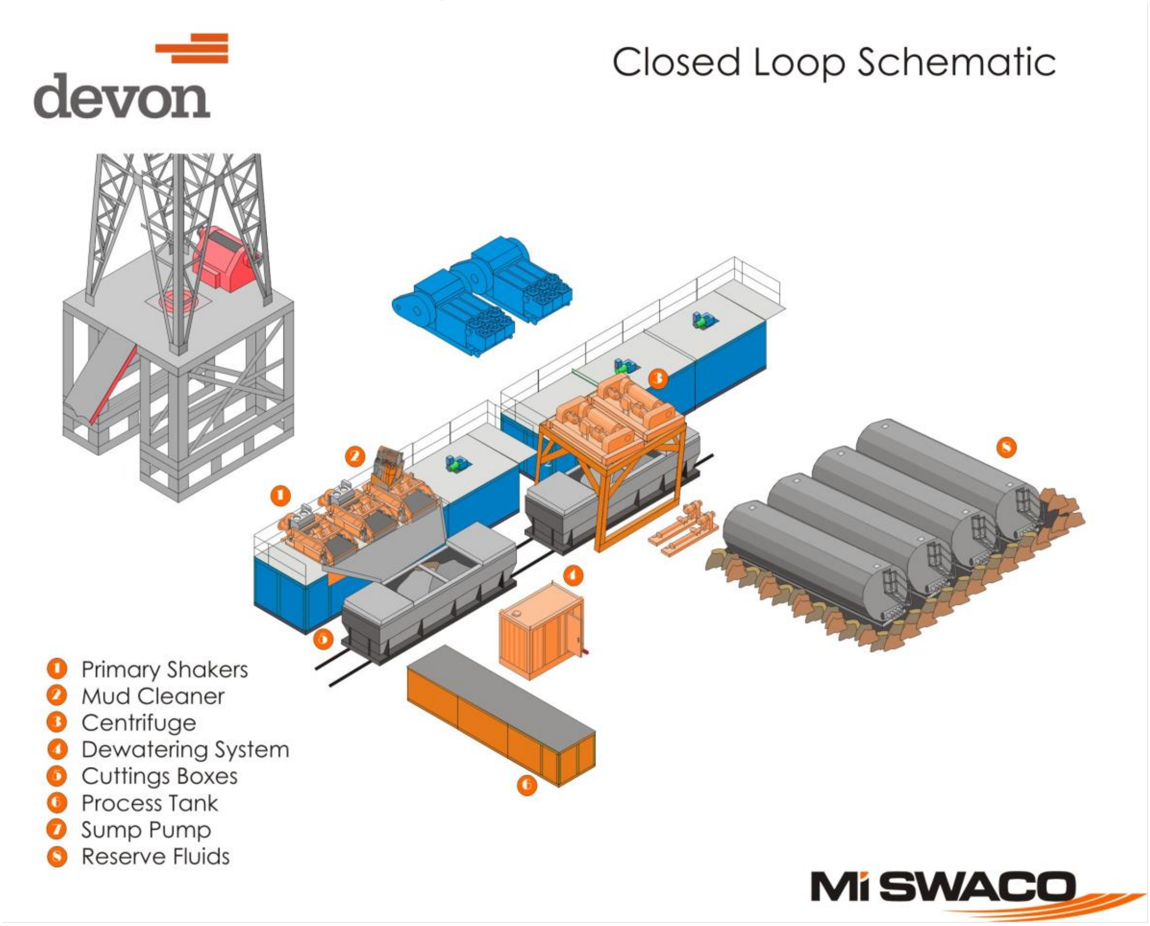
Prior to installing a closed-loop system on site, the topsoil, if present, will be stripped and stockpiled for use as the final cover or fill at the time of closure.

Signs will be posted on the fence surrounding the closed-loop system unless the closed-loop system is located on a site where there is an existing well, that is operated by Devon.

II. Operations and Maintenance Plan

Primary Shakers: The primary shakers make the first removal of drill solids from the drilling mud as it leaves the well bore. The shakers are sized to handle maximum drilling rate at optimal screen size. The shakers normally remove solids down to 74 microns.

Mud Cleaner: The Mud Cleaner cleans the fluid after it leaves the shakers. A set of hydrocyclones are sized to handle 1.25 to 1.5 times the maximum circulating rate. This ensures all the fluid is being processed to an average cut point of 25 microns. The wet discharged is dewatered on a shaker equipped with ultra fine mesh screens and generally cut at 40 microns.



Centrifuges: The centrifuges can be one or two in number depending on the well geometry or depth of well. The centrifuges are sized to maintain low gravity solids at 5% or below. They may or may not need a dewatering system to enhance the removal rates. The centrifuges can make a cut point of 8-10 microns depending on bowl speed, feed rate, solids loading and other factors.

The centrifuge system is designed to work on the active system and be flexible to process incoming fluids from other locations. This set-up is also dependant on well factors.

Dewatering System: The dewatering system is a chemical mixing and dosing system designed to enhance the solids removal of the centrifuge. Not commonly used in shallow wells. It may contain pH adjustment, coagulant mixing and dosing, and polymer mixing and dosing. Chemical flocculation binds ultra fine solids into a mass that is within the centrifuge operating design. The dewatering system improves the centrifuge cut point to infinity or allows for the return of clear water or brine fluid. This ability allows for the ultimate control of low gravity solids.

Cuttings Boxes: Cuttings boxes are utilized to capture drill solids that are discarded from the solids control equipment. These boxes are set upon a rail system that allows for the removal and replacement of a full box of cuttings with an empty one. They are equipped with a cover that insures no product is spilled into the environment during the transportation phase.

Process Tank: (Optional) The process tank allows for the holding and process of fluids that are being transferred into the mud system. Additionally, during times of lost circulation the process tank may hold active fluids that are removed for additional treatment. It can further be used as a mixing tank during well control conditions.

Sump and Sump Pump: The sump is used to collect storm water and the pump is used to transfer this fluid to the active system or to the tank for to hold in reserve. It can also be used to collect fluids that may escape during spills. The location contains drainage ditches that allow the location fluids to drain to the sump.

Reserve Fluids (Tank Farm): A series of frac tanks are used to replace the reserve pit. These are steel tanks that are equipped with a manifold system and a transfer pump. These tanks can contain any number of fluids used during the drilling process. These can include fresh water, cut brine, and saturated salt fluid. The fluid can be from the active well or reclaimed fluid from other locations. A 20 ml liner and berm system is employed to ensure the fluids do not migrate to the environment during a spill.

If a leak develops, the appropriate division district office will be notified within 48 hours of the discovery and the leak will be addressed. Spill prevention is accomplished by maintaining pump packing, hoses, and pipe fittings to insure no leaks are occurring. During an upset condition the source of the spill is isolated and repaired as soon as it is discovered. Free liquid is removed by a diaphragm pump and returned to the mud system. Loose topsoil may be used to stabilize the spill and the contaminated soil is excavated and placed in the cuttings boxes. After the well is finished and the rig has moved, the entire location is scrapped and testing will be performed to determine if a release has occurred.

All trash is kept in a wire mesh enclosure and removed to an approved landfill when full. All spent motor oils are kept in separate containers and they are removed and sent to an approved recycling center. Any spilled lubricants, pipe dope, or regulated chemicals are removed from soil and sent to landfills approved for these products.

These operations are monitored by Mi Swaco service technicians. Daily logs are maintained to ensure optimal equipment operation and maintenance. Screen and chemical use is logged to maintain inventory control. Fluid properties are monitored and recorded and drilling mud volumes are accounted for in the mud storage farm. This data is kept for end of well review to insure performance goals are met. Lessons learned are logged and used to help with continuous improvement.

A MI SWACO field supervisor manages from 3-5 wells. They are responsible for training personnel, supervising installations, and inspecting sites for compliance of MI SWACO safety and operational policy.

III. Closure Plan

A maximum 340' X 340' caliche pad is built per well. All of the trucks and steel tanks fit on this pad. All fluid cuttings go to the steel tanks to be hauled by various trucking companies to an agency approved disposal.

Devon Energy
APD VARIANCE DATA

OPERATOR NAME: Devon Energy

1. SUMMARY OF Variance:

Devon Energy respectfully requests approval for the following additions to the drilling plan:

1. Potential utilization of a spudder rig to pre-set surface casing.

2. Description of Operations

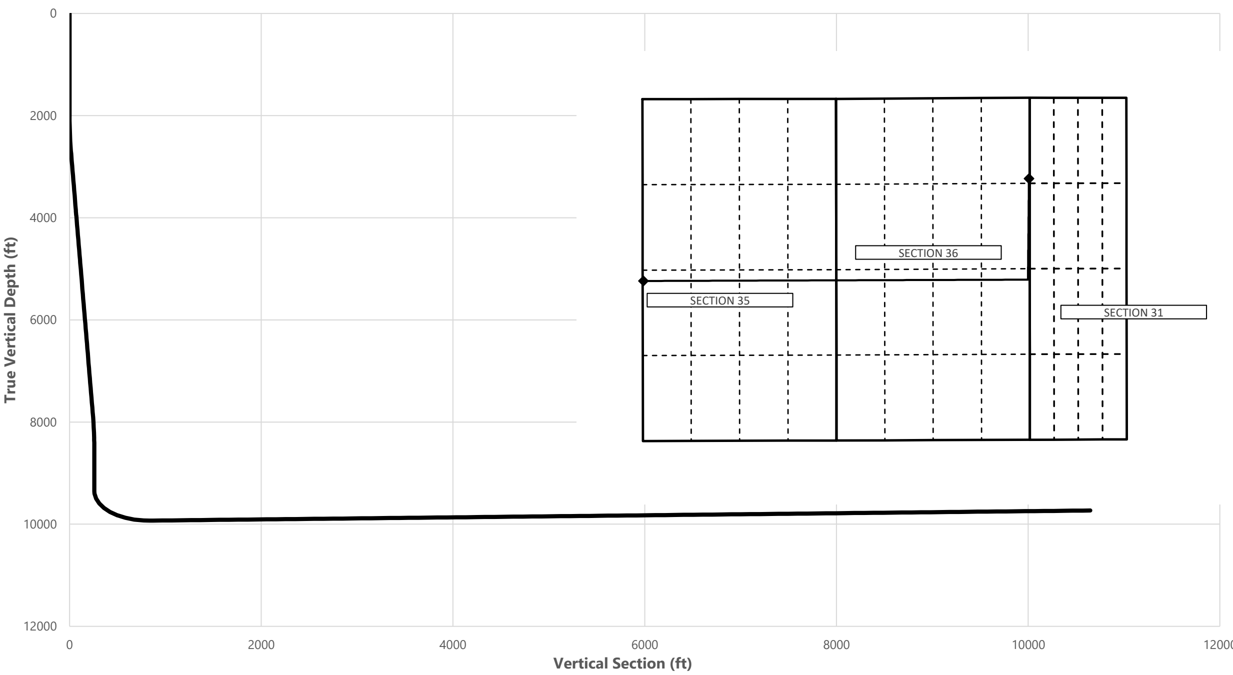
1. A spudder rig contractor may move in their rig to drill the surface hole section and pre-set surface casing on this well.
    a. After drilling the surface hole section, the rig will run casing and cement following all of the applicable rules and regulations (OnShore Order 2, all COAs and NMOCD regulations).
    b. Rig will utilize fresh water based mud to drill surface hole to TD.
2. The wellhead will be installed and tested once the surface casing is cut off and the WOC time has been reached.
3. A blind flange with 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. The BLM will be contacted and notified 24 hours prior to commencing spudder rig operations.
5. Drilling operation will be performed with the big rig. At that time an approved BOP stack will be nippled up and tested on the wellhead before drilling operations commences on each well.
    a. The BLM will be contacted / notified 24 hours before the big rig moves back on to the pad with the pre-set surface casing.
6. Devon Energy will have supervision on the rig to ensure compliance with all BLM and NMOCD regulations and to oversee operations.
7. Once the rig is removed, Devon Energy will secure the wellhead area by placing a guard rail around the cellar area.

devon

Well: TAMBORA 36-35 FED COM 622H
County: Eddy
Wellbore: Permit Plan
Design: Permit Plan #1

Geodetic System: US State Plane 1983
Datum: North American Datum 1927
Ellipsoid: Clarke 1866
Zone: 3001 - NM East (NAD83)

MD (ft)	INC (°)	AZI (°)	TVD (ft)	NS (ft)	EW (ft)	VS (ft)	DLS (°/100ft)	Comment
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	SHL
2000.00	0.00	181.00	2000.00	0.00	0.00	0.00	0.00	Start Tangent
2750.00	15.00	181.00	2741.46	-97.60	-1.70	16.17	2.00	Hold Tangent
8025.36	15.00	181.00	7837.06	-1462.76	-25.53	242.36	0.00	Drop to Vertical
8775.36	0.00	181.00	8578.53	-1560.36	-27.24	258.53	2.00	Hold Vertical
9553.99	0.00	269.89	9357.16	-1560.36	-27.24	258.53	0.00	KOP
10465.42	91.14	269.89	9930.00	-1561.48	-611.63	836.62	10.00	Landing Point
20386.09	91.14	269.89	9732.00	-1580.52	-10530.30	10648.25	0.00	BHL



Key Depths	MD (ft)	TVD (ft)
Rustler	167.00	167.00
Salt	356.00	356.00
Base of Salt	1569.00	1569.00
Capitan Reef Top	2036.00	2036.00
Delaware	3922.49	3874.00
Cherry Canyon	4015.66	3964.00
Brushy Canyon	4966.05	4882.00
1st Bone Spring Lime	6650.44	6509.00
Bone Spring 1st	7801.67	7621.00
Bone Spring 2nd	8551.60	8355.00
3rd Bone Spring Lime	8859.83	8663.00
Bone Spring 3rd	9599.88	9403.00
Wolfcamp / Point of Penetration	10110.14	9830.00
exit	20306.09	9733.61

	MD (ft)	TVD (ft)	Lat (°)	Long (°)	Section Footages
SHL	0.00	0.00	32.5336	-104.0202	1253' FNL, 21' FEL of Sec 36 in T20S, R29E
KOP	9553.99	9357.16	32.5293	-104.0203	2475' FSL, 49' FEL of Sec 36 in T20S, R29E
Point of Penetration	10110.14	9830.00	32.5294	-104.0203	2475' FSL, 100' FEL of Sec 36 in T20S, R29E
Exit	20306.09	9733.61	32.5294	-104.0540	2475' FSL, 100' FWL of Sec 35 in T20S, R29E
BHL	20386.09	9732.00	32.5293	-104.0543	2475' FSL, 20' FWL of Sec 35 in T20S, R29E

	Y	X
KOP	556469.9	637852

devon

Well: TAMBORA 36-35 FED COM 622H
County: Eddy
Wellbore: Permit Plan
Design: Permit Plan #1

Geodetic System: US State Plane 1983
Datum: North American Datum 1927
Ellipsoid: Clarke 1866
Zone: 3001 - NM East (NAD83)

MD (ft)	INC (°)	AZI (°)	TVD (ft)	NS (ft)	EW (ft)	VS (ft)	DLS (°/100ft)	Comment
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	SHL
100.00	0.00	181.00	100.00	0.00	0.00	0.00	0.00	
167.00	0.00	181.00	167.00	0.00	0.00	0.00	0.00	Rustler
200.00	0.00	181.00	200.00	0.00	0.00	0.00	0.00	
300.00	0.00	181.00	300.00	0.00	0.00	0.00	0.00	
356.00	0.00	181.00	356.00	0.00	0.00	0.00	0.00	Salt
400.00	0.00	181.00	400.00	0.00	0.00	0.00	0.00	
500.00	0.00	181.00	500.00	0.00	0.00	0.00	0.00	
600.00	0.00	181.00	600.00	0.00	0.00	0.00	0.00	
700.00	0.00	181.00	700.00	0.00	0.00	0.00	0.00	
800.00	0.00	181.00	800.00	0.00	0.00	0.00	0.00	
900.00	0.00	181.00	900.00	0.00	0.00	0.00	0.00	
1000.00	0.00	181.00	1000.00	0.00	0.00	0.00	0.00	
1100.00	0.00	181.00	1100.00	0.00	0.00	0.00	0.00	
1200.00	0.00	181.00	1200.00	0.00	0.00	0.00	0.00	
1300.00	0.00	181.00	1300.00	0.00	0.00	0.00	0.00	
1400.00	0.00	181.00	1400.00	0.00	0.00	0.00	0.00	
1500.00	0.00	181.00	1500.00	0.00	0.00	0.00	0.00	
1569.00	0.00	181.00	1569.00	0.00	0.00	0.00	0.00	Base of Salt
1600.00	0.00	181.00	1600.00	0.00	0.00	0.00	0.00	
1700.00	0.00	181.00	1700.00	0.00	0.00	0.00	0.00	
1800.00	0.00	181.00	1800.00	0.00	0.00	0.00	0.00	
1900.00	0.00	181.00	1900.00	0.00	0.00	0.00	0.00	
2000.00	0.00	181.00	2000.00	0.00	0.00	0.00	0.00	Start Tangent
2036.00	0.72	181.00	2036.00	-0.23	0.00	0.04	2.00	Capitan Reef Top
2100.00	2.00	181.00	2099.98	-1.74	-0.03	0.29	2.00	
2200.00	4.00	181.00	2199.84	-6.98	-0.12	1.16	2.00	
2300.00	6.00	181.00	2299.45	-15.69	-0.27	2.60	2.00	
2400.00	8.00	181.00	2398.70	-27.88	-0.49	4.62	2.00	
2500.00	10.00	181.00	2497.47	-43.52	-0.76	7.21	2.00	
2600.00	12.00	181.00	2595.62	-62.59	-1.09	10.37	2.00	
2700.00	14.00	181.00	2693.06	-85.08	-1.48	14.10	2.00	
2750.00	15.00	181.00	2741.46	-97.60	-1.70	16.17	2.00	Hold Tangent
2800.00	15.00	181.00	2789.76	-110.54	-1.93	18.32	0.00	
2900.00	15.00	181.00	2886.35	-136.42	-2.38	22.60	0.00	
3000.00	15.00	181.00	2982.94	-162.30	-2.83	26.89	0.00	
3100.00	15.00	181.00	3079.54	-188.17	-3.28	31.18	0.00	
3200.00	15.00	181.00	3176.13	-214.05	-3.74	35.47	0.00	
3300.00	15.00	181.00	3272.72	-239.93	-4.19	39.75	0.00	
3400.00	15.00	181.00	3369.31	-265.81	-4.64	44.04	0.00	
3500.00	15.00	181.00	3465.91	-291.69	-5.09	48.33	0.00	
3600.00	15.00	181.00	3562.50	-317.56	-5.54	52.62	0.00	
3700.00	15.00	181.00	3659.09	-343.44	-5.99	56.90	0.00	
3800.00	15.00	181.00	3755.68	-369.32	-6.45	61.19	0.00	
3900.00	15.00	181.00	3852.28	-395.20	-6.90	65.48	0.00	
3922.49	15.00	181.00	3874.00	-401.02	-7.00	66.44	0.00	Delaware
4000.00	15.00	181.00	3948.87	-421.07	-7.35	69.77	0.00	
4015.66	15.00	181.00	3964.00	-425.13	-7.42	70.44	0.00	Cherry Canyon
4100.00	15.00	181.00	4045.46	-446.95	-7.80	74.06	0.00	
4200.00	15.00	181.00	4142.05	-472.83	-8.25	78.34	0.00	
4300.00	15.00	181.00	4238.65	-498.71	-8.70	82.63	0.00	
4400.00	15.00	181.00	4335.24	-524.59	-9.16	86.92	0.00	
4500.00	15.00	181.00	4431.83	-550.46	-9.61	91.21	0.00	
4600.00	15.00	181.00	4528.42	-576.34	-10.06	95.49	0.00	
4700.00	15.00	181.00	4625.02	-602.22	-10.51	99.78	0.00	
4800.00	15.00	181.00	4721.61	-628.10	-10.96	104.07	0.00	
4900.00	15.00	181.00	4818.20	-653.98	-11.41	108.36	0.00	
4966.05	15.00	181.00	4882.00	-671.07	-11.71	111.19	0.00	Brushy Canyon
5000.00	15.00	181.00	4914.80	-679.85	-11.87	112.64	0.00	
5100.00	15.00	181.00	5011.39	-705.73	-12.32	116.93	0.00	
5200.00	15.00	181.00	5107.98	-731.61	-12.77	121.22	0.00	
5300.00	15.00	181.00	5204.57	-757.49	-13.22	125.51	0.00	
5400.00	15.00	181.00	5301.17	-783.37	-13.67	129.80	0.00	
5500.00	15.00	181.00	5397.76	-809.24	-14.12	134.08	0.00	
5600.00	15.00	181.00	5494.35	-835.12	-14.58	138.37	0.00	
5700.00	15.00	181.00	5590.94	-861.00	-15.03	142.66	0.00	
5800.00	15.00	181.00	5687.54	-886.88	-15.48	146.95	0.00	
5900.00	15.00	181.00	5784.13	-912.76	-15.93	151.23	0.00	
6000.00	15.00	181.00	5880.72	-938.63	-16.38	155.52	0.00	
6100.00	15.00	181.00	5977.31	-964.51	-16.83	159.81	0.00	

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Well: TAMBORA 36-35 FED COM 622H
County: Eddy
Wellbore: Permit Plan
Design: Permit Plan #1

Geodetic System: US State Plane 1983
Datum: North American Datum 1927
Ellipsoid: Clarke 1866
Zone: 3001 - NM East (NAD83)

MD (ft)	INC (°)	AZI (°)	TVD (ft)	NS (ft)	EW (ft)	VS (ft)	DLS (°/100ft)	Comment
6200.00	15.00	181.00	6073.91	-990.39	-17.28	164.10	0.00	
6300.00	15.00	181.00	6170.50	-1016.27	-17.74	168.38	0.00	
6400.00	15.00	181.00	6267.09	-1042.15	-18.19	172.67	0.00	
6500.00	15.00	181.00	6363.68	-1068.02	-18.64	176.96	0.00	
6600.00	15.00	181.00	6460.28	-1093.90	-19.09	181.25	0.00	
6650.44	15.00	181.00	6509.00	-1106.95	-19.32	183.41	0.00	1st Bone Spring Lime
6700.00	15.00	181.00	6556.87	-1119.78	-19.54	185.54	0.00	
6800.00	15.00	181.00	6653.46	-1145.66	-19.99	189.82	0.00	
6900.00	15.00	181.00	6750.05	-1171.54	-20.45	194.11	0.00	
7000.00	15.00	181.00	6846.65	-1197.41	-20.90	198.40	0.00	
7100.00	15.00	181.00	6943.24	-1223.29	-21.35	202.69	0.00	
7200.00	15.00	181.00	7039.83	-1249.17	-21.80	206.97	0.00	
7300.00	15.00	181.00	7136.42	-1275.05	-22.25	211.26	0.00	
7400.00	15.00	181.00	7233.02	-1300.92	-22.70	215.55	0.00	
7500.00	15.00	181.00	7329.61	-1326.80	-23.16	219.84	0.00	
7600.00	15.00	181.00	7426.20	-1352.68	-23.61	224.12	0.00	
7700.00	15.00	181.00	7522.80	-1378.56	-24.06	228.41	0.00	
7800.00	15.00	181.00	7619.39	-1404.44	-24.51	232.70	0.00	
7801.67	15.00	181.00	7621.00	-1404.87	-24.52	232.77	0.00	Bone Spring 1st
7900.00	15.00	181.00	7715.98	-1430.31	-24.96	236.99	0.00	
8000.00	15.00	181.00	7812.57	-1456.19	-25.41	241.28	0.00	
8025.36	15.00	181.00	7837.06	-1462.76	-25.53	242.36	0.00	Drop to Vertical
8100.00	13.51	181.00	7909.41	-1481.13	-25.85	245.41	2.00	
8200.00	11.51	181.00	8007.03	-1502.78	-26.23	249.00	2.00	
8300.00	9.51	181.00	8105.35	-1521.01	-26.55	252.02	2.00	
8400.00	7.51	181.00	8204.24	-1535.80	-26.81	254.47	2.00	
8500.00	5.51	181.00	8303.59	-1547.13	-27.01	256.35	2.00	
8551.60	4.48	181.00	8355.00	-1551.62	-27.08	257.09	2.00	Bone Spring 2nd
8600.00	3.51	181.00	8403.28	-1554.99	-27.14	257.65	2.00	
8700.00	1.51	181.00	8503.18	-1559.36	-27.22	258.37	2.00	
8775.36	0.00	181.00	8578.53	-1560.36	-27.24	258.53	2.00	Hold Vertical
8800.00	0.00	269.89	8603.17	-1560.36	-27.24	258.54	0.00	
8859.83	0.00	269.89	8663.00	-1560.36	-27.24	258.54	0.00	3rd Bone Spring Lime
8900.00	0.00	269.89	8703.17	-1560.36	-27.24	258.54	0.00	
9000.00	0.00	269.89	8803.17	-1560.36	-27.24	258.54	0.00	
9100.00	0.00	269.89	8903.17	-1560.36	-27.24	258.54	0.00	
9200.00	0.00	269.89	9003.17	-1560.36	-27.24	258.54	0.00	
9300.00	0.00	269.89	9103.17	-1560.36	-27.24	258.54	0.00	
9400.00	0.00	269.89	9203.17	-1560.36	-27.24	258.54	0.00	
9500.00	0.00	269.89	9303.17	-1560.36	-27.24	258.54	0.00	
9553.99	0.00	269.89	9357.16	-1560.36	-27.24	258.53	0.00	KOP
9599.88	4.59	269.89	9403.00	-1560.36	-29.07	260.35	10.00	Bone Spring 3rd
9600.00	4.60	269.89	9403.12	-1560.36	-29.08	260.36	10.00	
9700.00	14.60	269.89	9501.60	-1560.39	-45.74	276.84	10.00	
9800.00	24.60	269.89	9595.68	-1560.46	-79.25	309.99	10.00	
9900.00	34.60	269.89	9682.52	-1560.55	-128.58	358.79	10.00	
10000.00	44.60	269.89	9759.47	-1560.67	-192.24	421.76	10.00	
10100.00	54.60	269.89	9824.20	-1560.82	-268.30	497.00	10.00	
10110.14	55.62	269.89	9830.00	-1560.84	-276.62	505.23	10.00	Wolfcamp / Point of Penetration
10200.00	64.60	269.89	9874.74	-1560.99	-354.44	582.22	10.00	
10300.00	74.60	269.89	9909.55	-1561.17	-448.05	674.81	10.00	
10400.00	84.60	269.89	9927.57	-1561.35	-546.29	771.99	10.00	
10465.42	91.14	269.89	9930.00	-1561.48	-611.63	836.62	10.00	Landing Point
10500.00	91.14	269.89	9929.31	-1561.54	-646.20	870.82	0.00	
10600.00	91.14	269.89	9927.31	-1561.74	-746.18	969.72	0.00	
10700.00	91.14	269.89	9925.32	-1561.93	-846.16	1068.62	0.00	
10800.00	91.14	269.89	9923.32	-1562.12	-946.14	1167.52	0.00	
10900.00	91.14	269.89	9921.33	-1562.31	-1046.12	1266.43	0.00	
11000.00	91.14	269.89	9919.33	-1562.51	-1146.10	1365.33	0.00	
11100.00	91.14	269.89	9917.34	-1562.70	-1246.08	1464.23	0.00	
11200.00	91.14	269.89	9915.34	-1562.89	-1346.06	1563.13	0.00	
11300.00	91.14	269.89	9913.34	-1563.08	-1446.04	1662.03	0.00	
11400.00	91.14	269.89	9911.35	-1563.28	-1546.02	1760.93	0.00	
11500.00	91.14	269.89	9909.35	-1563.47	-1646.00	1859.83	0.00	
11600.00	91.14	269.89	9907.36	-1563.66	-1745.98	1958.73	0.00	
11700.00	91.14	269.89	9905.36	-1563.85	-1845.96	2057.63	0.00	
11800.00	91.14	269.89	9903.37	-1564.04	-1945.94	2156.53	0.00	
11900.00	91.14	269.89	9901.37	-1564.24	-2045.92	2255.44	0.00	
12000.00	91.14	269.89	9899.37	-1564.43	-2145.90	2354.34	0.00	
12100.00	91.14	269.89	9897.38	-1564.62	-2245.88	2453.24	0.00	

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Zone: 3001 - NM East (NAD83)

MD (ft)	INC (°)	AZI (°)	TVD (ft)	NS (ft)	EW (ft)	VS (ft)	DLS (°/100ft)	Comment
12200.00	91.14	269.89	9895.38	-1564.81	-2345.86	2552.14	0.00	
12300.00	91.14	269.89	9893.39	-1565.01	-2445.84	2651.04	0.00	
12400.00	91.14	269.89	9891.39	-1565.20	-2545.82	2749.94	0.00	
12500.00	91.14	269.89	9889.40	-1565.39	-2645.80	2848.84	0.00	
12600.00	91.14	269.89	9887.40	-1565.58	-2745.78	2947.74	0.00	
12700.00	91.14	269.89	9885.40	-1565.78	-2845.76	3046.64	0.00	
12800.00	91.14	269.89	9883.41	-1565.97	-2945.74	3145.54	0.00	
12900.00	91.14	269.89	9881.41	-1566.16	-3045.72	3244.44	0.00	
13000.00	91.14	269.89	9879.42	-1566.35	-3145.70	3343.35	0.00	
13100.00	91.14	269.89	9877.42	-1566.55	-3245.68	3442.25	0.00	
13200.00	91.14	269.89	9875.43	-1566.74	-3345.66	3541.15	0.00	
13300.00	91.14	269.89	9873.43	-1566.93	-3445.64	3640.05	0.00	
13400.00	91.14	269.89	9871.43	-1567.12	-3545.62	3738.95	0.00	
13500.00	91.14	269.89	9869.44	-1567.31	-3645.60	3837.85	0.00	
13600.00	91.14	269.89	9867.44	-1567.51	-3745.58	3936.75	0.00	
13700.00	91.14	269.89	9865.45	-1567.70	-3845.56	4035.65	0.00	
13800.00	91.14	269.89	9863.45	-1567.89	-3945.54	4134.55	0.00	
13900.00	91.14	269.89	9861.46	-1568.08	-4045.52	4233.45	0.00	
14000.00	91.14	269.89	9859.46	-1568.28	-4145.50	4332.36	0.00	
14100.00	91.14	269.89	9857.46	-1568.47	-4245.48	4431.26	0.00	
14200.00	91.14	269.89	9855.47	-1568.66	-4345.46	4530.16	0.00	
14300.00	91.14	269.89	9853.47	-1568.85	-4445.44	4629.06	0.00	
14400.00	91.14	269.89	9851.48	-1569.05	-4545.42	4727.96	0.00	
14500.00	91.14	269.89	9849.48	-1569.24	-4645.40	4826.86	0.00	
14600.00	91.14	269.89	9847.49	-1569.43	-4745.38	4925.76	0.00	
14700.00	91.14	269.89	9845.49	-1569.62	-4845.36	5024.66	0.00	
14800.00	91.14	269.89	9843.49	-1569.81	-4945.34	5123.56	0.00	
14900.00	91.14	269.89	9841.50	-1570.01	-5045.32	5222.46	0.00	
15000.00	91.14	269.89	9839.50	-1570.20	-5145.30	5321.36	0.00	
15100.00	91.14	269.89	9837.51	-1570.39	-5245.28	5420.27	0.00	
15200.00	91.14	269.89	9835.51	-1570.58	-5345.26	5519.17	0.00	
15300.00	91.14	269.89	9833.52	-1570.78	-5445.23	5618.07	0.00	
15400.00	91.14	269.89	9831.52	-1570.97	-5545.21	5716.97	0.00	
15500.00	91.14	269.89	9829.52	-1571.16	-5645.19	5815.87	0.00	
15600.00	91.14	269.89	9827.53	-1571.35	-5745.17	5914.77	0.00	
15700.00	91.14	269.89	9825.53	-1571.55	-5845.15	6013.67	0.00	
15800.00	91.14	269.89	9823.54	-1571.74	-5945.13	6112.57	0.00	
15900.00	91.14	269.89	9821.54	-1571.93	-6045.11	6211.47	0.00	
16000.00	91.14	269.89	9819.55	-1572.12	-6145.09	6310.37	0.00	
16100.00	91.14	269.89	9817.55	-1572.32	-6245.07	6409.28	0.00	
16200.00	91.14	269.89	9815.56	-1572.51	-6345.05	6508.18	0.00	
16300.00	91.14	269.89	9813.56	-1572.70	-6445.03	6607.08	0.00	
16400.00	91.14	269.89	9811.56	-1572.89	-6545.01	6705.98	0.00	
16500.00	91.14	269.89	9809.57	-1573.08	-6644.99	6804.88	0.00	
16600.00	91.14	269.89	9807.57	-1573.28	-6744.97	6903.78	0.00	
16700.00	91.14	269.89	9805.58	-1573.47	-6844.95	7002.68	0.00	
16800.00	91.14	269.89	9803.58	-1573.66	-6944.93	7101.58	0.00	
16900.00	91.14	269.89	9801.59	-1573.85	-7044.91	7200.48	0.00	
17000.00	91.14	269.89	9799.59	-1574.05	-7144.89	7299.38	0.00	
17100.00	91.14	269.89	9797.59	-1574.24	-7244.87	7398.29	0.00	
17200.00	91.14	269.89	9795.60	-1574.43	-7344.85	7497.19	0.00	
17300.00	91.14	269.89	9793.60	-1574.62	-7444.83	7596.09	0.00	
17400.00	91.14	269.89	9791.61	-1574.82	-7544.81	7694.99	0.00	
17500.00	91.14	269.89	9789.61	-1575.01	-7644.79	7793.89	0.00	
17600.00	91.14	269.89	9787.62	-1575.20	-7744.77	7892.79	0.00	
17700.00	91.14	269.89	9785.62	-1575.39	-7844.75	7991.69	0.00	
17800.00	91.14	269.89	9783.62	-1575.59	-7944.73	8090.59	0.00	
17900.00	91.14	269.89	9781.63	-1575.78	-8044.71	8189.49	0.00	
18000.00	91.14	269.89	9779.63	-1575.97	-8144.69	8288.39	0.00	
18100.00	91.14	269.89	9777.64	-1576.16	-8244.67	8387.29	0.00	
18200.00	91.14	269.89	9775.64	-1576.35	-8344.65	8486.20	0.00	
18300.00	91.14	269.89	9773.65	-1576.55	-8444.63	8585.10	0.00	
18400.00	91.14	269.89	9771.65	-1576.74	-8544.61	8684.00	0.00	
18500.00	91.14	269.89	9769.65	-1576.93	-8644.59	8782.90	0.00	
18600.00	91.14	269.89	9767.66	-1577.12	-8744.57	8881.80	0.00	
18700.00	91.14	269.89	9765.66	-1577.32	-8844.55	8980.70	0.00	
18800.00	91.14	269.89	9763.67	-1577.51	-8944.53	9079.60	0.00	
18900.00	91.14	269.89	9761.67	-1577.70	-9044.51	9178.50	0.00	
19000.00	91.14	269.89	9759.68	-1577.89	-9144.49	9277.40	0.00	
19100.00	91.14	269.89	9757.68	-1578.09	-9244.47	9376.30	0.00	

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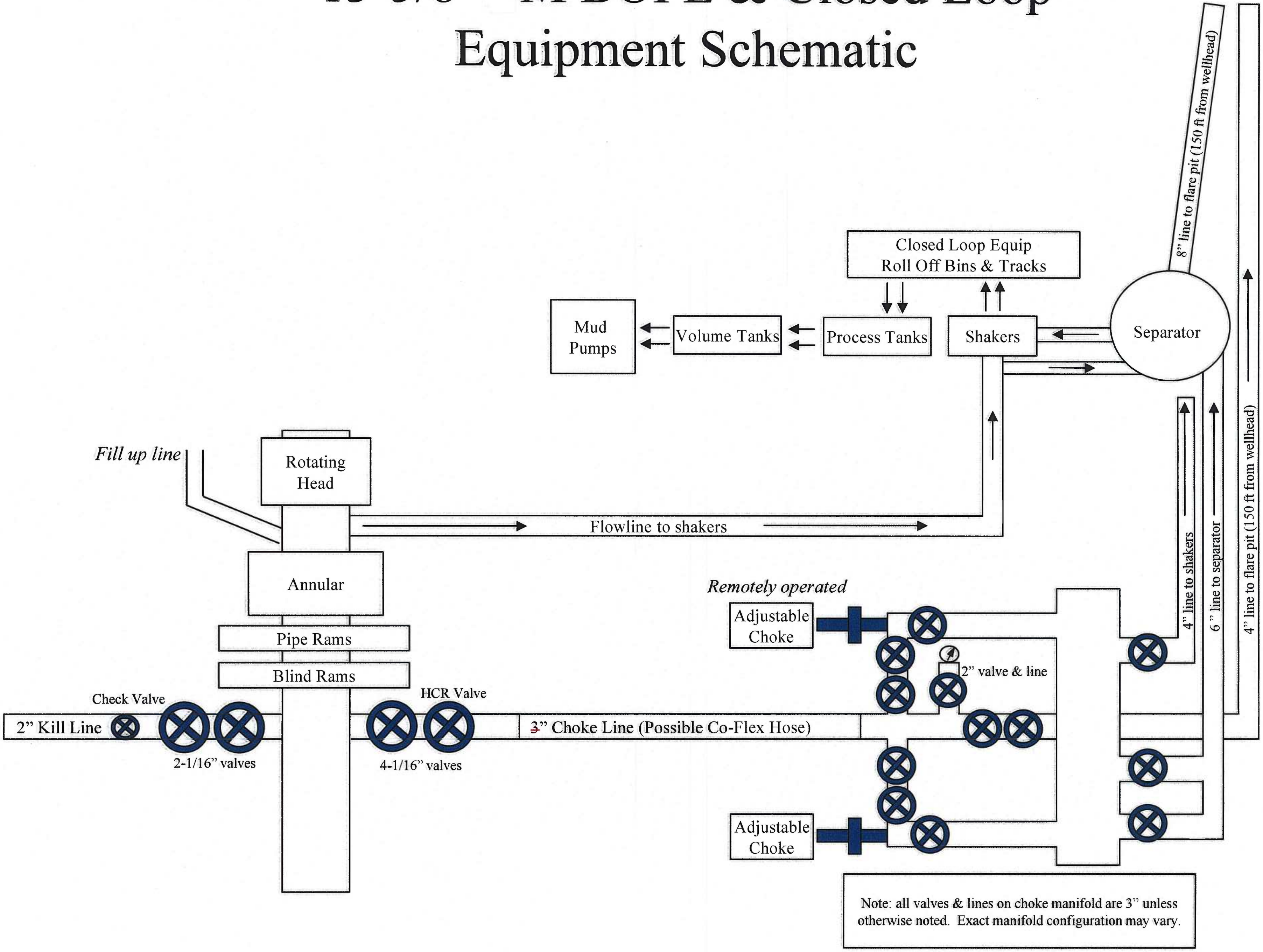
19200.00	91.14	269.89	9755.68	-1578.28	-9344.45	9475.21	0.00	
19300.00	91.14	269.89	9753.69	-1578.47	-9444.43	9574.11	0.00	
19400.00	91.14	269.89	9751.69	-1578.66	-9544.41	9673.01	0.00	
19500.00	91.14	269.89	9749.70	-1578.86	-9644.39	9771.91	0.00	
19600.00	91.14	269.89	9747.70	-1579.05	-9744.37	9870.81	0.00	
19700.00	91.14	269.89	9745.71	-1579.24	-9844.35	9969.71	0.00	
19800.00	91.14	269.89	9743.71	-1579.43	-9944.33	10068.61	0.00	
19900.00	91.14	269.89	9741.71	-1579.62	-10044.31	10167.51	0.00	
20000.00	91.14	269.89	9739.72	-1579.82	-10144.29	10266.41	0.00	
20100.00	91.14	269.89	9737.72	-1580.01	-10244.27	10365.31	0.00	
20200.00	91.14	269.89	9735.73	-1580.20	-10344.25	10464.22	0.00	
20300.00	91.14	269.89	9733.73	-1580.39	-10444.23	10563.12	0.00	
20306.09	91.14	269.89	9733.61	-1580.41	-10450.32	10569.14	0.00	exit
20386.09	91.14	269.89	9732.00	-1580.52	-10530.30	10648.25	0.00	BHL

13-5/8" 5M BOPE & Closed Loop Equipment Schematic



Devon Energy Annular Preventer Summary

1. Component and Preventer Compatibility Table

The table below, which covers the drilling and casing of the 10M 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.

6-3/4" Production hole section, 10M requirement

Component	OD	Preventer	RWP
Drillpipe	4.5"	Fixed lower 4.5" Upper 4.5-7" VBR	10M
HWDP	4.5"	Fixed lower 4.5" Upper 4.5-7" VBR	10M
Drill collars and MWD tools	4.75"	Upper 4.5-7" VBR	10M
Mud Motor	4.75"	Upper 4.5-7" VBR	10M
Production casing	5.5"	Upper 4.5-7" VBR	10M
ALL	0-13-5/8"	Annular	5M
Open-hole	-	Blind Rams	10M

VBR = Variable Bore Ram. Compatible range listed in chart.

2. 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 BHA through the BOPs. The pressure at which control is swapped from the annular to another compatible ram is variable, but the operator will document in the submission their operating pressure limit. The operator may chose an operating pressure less than or equal to RWP, but in no case will it exceed the RWP of the annular preventer.

<u>General Procedure While Drilling</u>

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

Devon Energy Annular Preventer Summary

General Procedure While Tripping

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

Devon Energy Annular Preventer Summary

General Procedures While Pulling BHA thru Stack

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

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

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

Section 2 - Blowout Preventer Testing Procedure

Variance Request

Devon Energy requests to only test BOP connection breaks after drilling out of surface casing and while skidding between wells which conforms to API Standard 53 and industry standards. This test will include the Top Pipe Rams, HCR, Kill Line Check Valve, QDC (quick disconnect to wellhead) and Shell of the 10M BOPE to 5M for 10 minutes. If a break to the flex hose that runs to the choke manifold is required due to repositioning from a skid, the HCR will remain open during the shell test to include that additional break. The variance only pertains to intermediate hole-sections and no deeper than the Bone Springs Formation where 5M BOP tests are required. The initial BOP test will follow OOGO2.III.A.2.i, and subsequent tests following a skid will only test connections that are broken. The annular preventer will be tested to 100% working pressure. This variance will meet or exceed OOGO2.III.A.2.i per the following: Devon Energy will perform a full BOP test per OOGO2.III.A.2.i before drilling out of the intermediate casing string(s) and starting the production hole, before starting any hole section that requires a 10M test, before the expiration of the allotted 14-days for 5M intermediate batch drilling or when the drilling rig is fully mobilized to a new well pad, whichever is sooner. We will utilize a 200' TVD tolerance between intermediate shoes as the cutoff for a full BOP test. The BLM will be contacted 4hrs prior to a BOPE test. The BLM will be notified if and when a well control event is encountered. Break test will be a 14 day interval and not a 30 day full BOPE test interval. <u>If in the event break testing is not utilized, then a full BOPE test would be conducted.</u>

1. Well Control Response:

1. Primary barrier remains fluid
2. In the event of an influx due to being underbalanced and after a realized gain or flow, the order of closing BOPE is as follows:
   a) Annular first
   b) If annular were to not hold, Upper pipe rams second (which were tested on the skid BOP test)
   c) If the Upper Pipe Rams were to not hold, Lower Pipe Rams would be third

A multibowl wellhead may be used. The BOP will be tested per Onshore Order #2 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.

Devon proposes using a multi-bowl wellhead assembly. This assembly will only be tested when installed on the surface casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be 5000 (5M) psi.

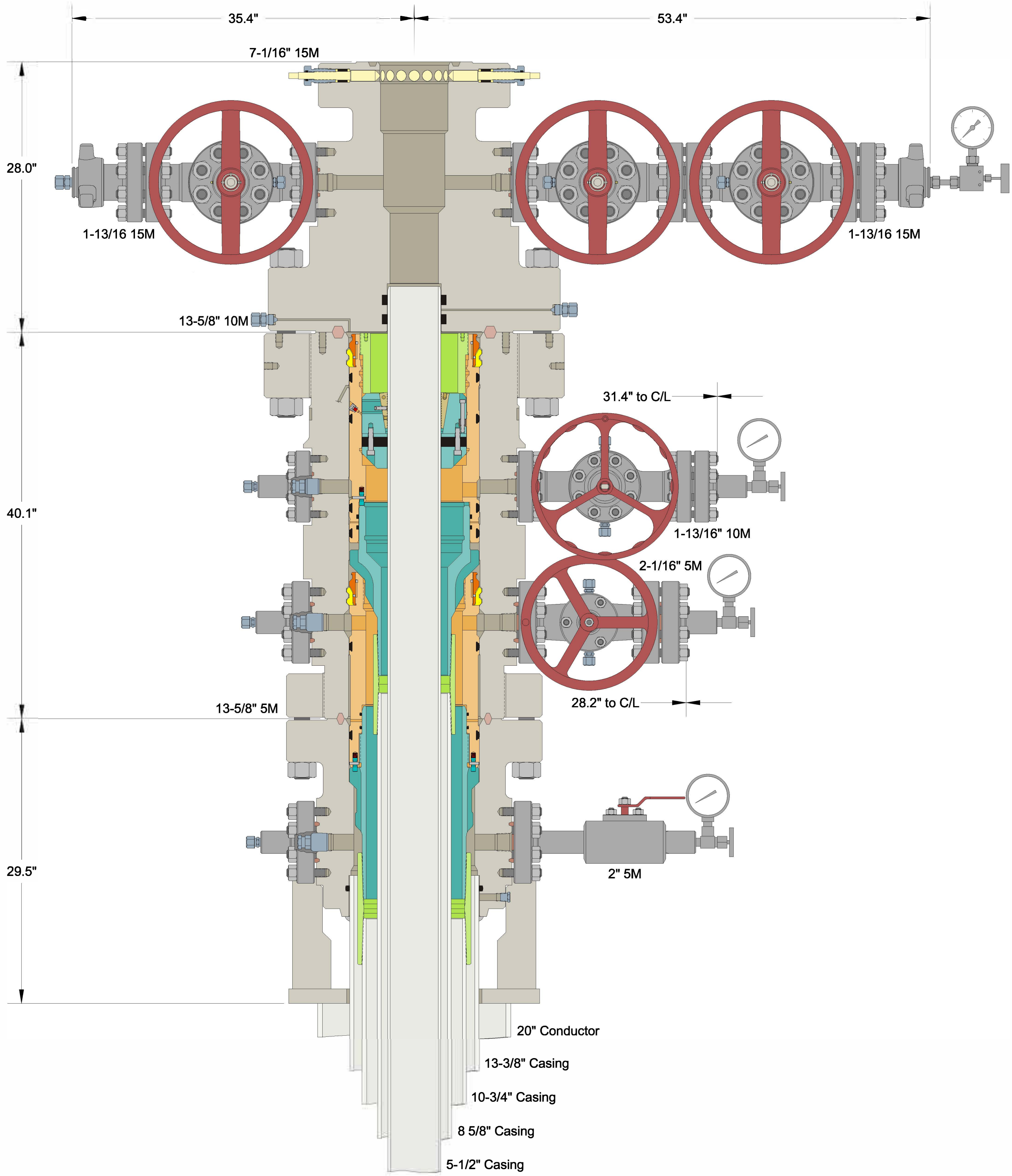
- Wellhead will be installed by wellhead representatives.
- If the welding is performed by a third party, the wellhead representative will monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
- Wellhead representative will install the test plug for the initial BOP test.
- Wellhead company will install a solid steel body pack-off to completely isolate the lower head after cementing intermediate casing. After installation of the pack-off, the pack-off and the lower flange will be tested to 5M, as shown on the attached schematic. Everything above the pack-off will not have been altered whatsoever from the initial nipple up. Therefore the BOP components will not be retested at that time.
- If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head will be cut and top out operations will be conducted.
- Devon will pressure test all seals above and below the mandrel (but still above the casing) to full working pressure rating.
- Devon will test the casing to 0.22 psi/ft or 1500 psi, whichever is greater, as per Onshore Order #2.

After running the surface casing, a 13-5/8" BOP/BOPE system with a minimum rating of 5M will be installed on the wellhead system and will undergo a 250 psi low pressure test followed by a 5,000 psi high pressure test. The 5,000 psi high and 250 psi low test will cover testing requirements a maximum of 30 days, as per Onshore Order #2. If the well is not complete within 30 days of this BOP test, another full BOP test will be conducted, as per Onshore Order #2.

After running the intermediate casing with a mandrel hanger, the 13-5/8" BOP/BOPE system with a minimum rating of 5M will already be installed on the wellhead.

The pipe rams will be operated and checked each 24 hour period and each time the drill pipe is out of the hole. These tests will be logged in the daily driller’s log. A 2” kill line and 3” choke line will be incorporated into the drilling spool below the ram BOP. In addition to the rams and annular preventer, additional BOP accessories include a kelly cock, floor safety valve, choke lines, and choke manifold rated at 5,000 psi WP.

Devon’s proposed wellhead manufactures will be FMC Technologies, Cactus Wellhead, or Cameron.



ALL DIMENSIONS APPROXIMATE

CACTUS WELLHEAD LLC	DEVON ENERGY CORPORATION DELAWARE BASIN		
20" x 13-3/8" x 10-3/4" x 8-5/8" x 5-1/2" MBU-4T-SOW Wellhead With 13-5/8" 10M x 7-1/16" 15M CTH-DBLHPS Tubing Head, 10-3/4" & 8-5/8" Mandrel Hangers And 5-1/2" Slip Casing Hanger	DRAWN	DLE	09AUG19
	APPRV		
	DRAWING NO.	HBE0000156	

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	**Devon Energy Production Company LP**
LEASE NO.:	**NMNM110351**
LOCATION:	Section 36, T.20 S., R.29 E., NMPM
COUNTY:	Eddy County, New Mexico

WELL NAME & NO.:	**Tambora 36-35 Fed Com 622H**
BOTTOM HOLE FOOTAGE	2475'/S & 20'/W
ATS/API ID:	**ATS-24-396**
APD ID:	**10400093682**
Sundry ID:	**N/a**

WELL NAME & NO.:	**Tambora 36-35 Fed Com 821H**
BOTTOM HOLE FOOTAGE	660'/N & 20'/W
ATS/API ID:	**ATS-24-911**
APD ID:	**10400094064**
Sundry ID:	**N/a**

Approval Date: 09/23/2024

COA

H2S	No		
Potash	Secretary	None	
Cave/Karst Potential	Medium		
Cave/Karst Potential	☐ Critical		
Variance	○ None	● Flex Hose	○ Other
Wellhead	Conventional and Multibowl		
Other	☑ 4 String	Capitan Reef Int 2	☐ WIPP
Other	Pilot Hole None	☐ Open Annulus	
Cementing	Contingency Squeeze None	Echo-Meter Int 2	Primary Cement Squeeze None
Special Requirements	☐ Water Disposal/Injection	☑ COM	☐ Unit
Special Requirements	☐ Batch Sundry	Waste Prevention None	
Special Requirements Variance	☑ Break Testing	☐ Offline Cementing	☐ Casing Clearance

A. HYDROGEN SULFIDE

Hydrogen Sulfide (H2S) monitors shall be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the Hydrogen Sulfide area shall meet **43 CFR part 3170 Subpart 3176**, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, provide measured values and formations to the BLM.

B. CASING

1. The **13-3/8** inch surface casing shall be set at approximately **267 feet** (a minimum of **70 feet (Eddy County)** into the Rustler Anhydrite and above the salt when present, and below usable fresh water) and cemented to the surface. The surface hole shall be **17 1/2** inch in diameter.

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

Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.

2. The minimum required fill of cement behind the **10-3/4** inch intermediate casing shall be set at approximately **1986 feet** is:

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

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3. The minimum required fill of cement behind the **8-5/8** inch intermediate casing is:

<u>Option 1 (Single Stage):</u>

- Cement should tie-back at least **50 feet** on top of Capitan Reef top **or 500 feet** into the previous casing, whichever is greater and may be lower than USGS Marker Bed No. 126. Operator must run a CBL from TD of the production casing to surface to verify top of cement. Submit results to the BLM. If cement does not circulate see B.1.a, c-d above.
  Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst, potash or capitan reef.

<u>Option 2:</u>

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 **Capitan Reef at 2036'.**

b. Second stage:

   - Operator will perform bradenhead squeeze from the top of **Capitan Reef** to at least **50 feet** on top of the Capitan Reef top **or 500 feet** into the previous casing, whichever is greater and may be lower than USGS Marker Bed No. 126. If cement does not meet the minimum tie-back requirement, the appropriate BLM office shall be notified. **(Squeeze 84 sxs Class C.)**
     Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst, potash or capitan reef.

Operator has proposed to pump down **13-3/8**" X **10-3/4**" annulus after primary cementing stage. <u>Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the **10-3/4**" casing to surface after the second stage BH to verify TOC.</u>
Submit results to the BLM. Operator must run one CBL per Well Pad. Operator may conduct a negative and positive pressure test during completion to remediate sustained casing pressure.

❖ In <u>Medium Cave/Karst Areas</u> if cement does not circulate to surface on the first two casing strings, the cement on the 3rd casing string must come to surface.

❖ In <u>Secretary Potash Areas</u> if cement does not circulate to surface on the first two casing strings, the cement on the 3rd casing string must come to surface.

- ❖ In Capitan Reef Areas if cement does not circulate to surface on the first two casing strings, the cement on the 3rd casing string must come to surface.

4. The minimum required fill of cement behind the **5-1/2** inch production casing is:

    - Cement should tie-back **500 feet** into the previous casing and may be lower than USGS Marker Bed No. 126. Operator must run a CBL from TD of the production casing to surface to verify top of cement. Submit results to the BLM.
    Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst, potash or capitan reef. Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.

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.

Option 1:

a. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **3000 (3M)** psi. **Annular which shall be tested to 2100 (70% Working Pressure) psi.**

b. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **10-3/4** intermediate casing shoe shall be **3000 (3M)** psi. **Annular which shall be tested to 2100 (70% Working Pressure) psi.**

c. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **8-5/8** inch intermediate casing shoe shall be **5000 (5M)** psi. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 5000 (5M) psi.**

Option 2:

a. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the **13-3/8** inch surface casing. Minimum working pressure of the blowout preventer (BOP) and related equipment

(BOPE) required for drilling below the surface casing shoe shall be **5000 (5M)** psi.

a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
c. Manufacturer representative shall install the test plug for the initial BOP test.
d. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
e. Whenever any seal subject to test pressure is broken, all the tests in 43 CFR 3172.6(b)(9) must be followed.

D. SPECIAL REQUIREMENT (S)

Communitization Agreement

- The operator will submit a Communitization Agreement to the Santa Fe Office, 301 Dinosaur Trail Santa Fe, New Mexico 87508, at least 90 days before the anticipated date of first production from a well subject to a spacing order issued by the New Mexico Oil Conservation Division. The Communitization Agreement will include the signatures of all working interest owners in all Federal and Indian leases subject to the Communitization Agreement (i.e., operating rights owners and lessees of record), or certification that the operator has obtained the written signatures of all such owners and will make those signatures available to the BLM immediately upon request.
- The operator will submit an as-drilled survey well plat of the well completion, but are not limited to, those specified in **43 CFR part 3170 Subpart 3171**
- If the operator does not comply with this condition of approval, the BLM may take enforcement actions that include, but are not limited to, those specified in 43 CFR 3163.1.
- In addition, the well sign shall include the surface and bottom hole lease numbers. When the Communitization Agreement number is known, it shall also be on the sign.

BOPE Break Testing Variance (Approved)

- 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 **43 CFR part 3170 Subpart 3172**.
- If in the event break testing is not utilized, then a full BOPE test would be conducted.

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GENERAL REQUIREMENTS

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

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

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

1. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval.

    a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
    b. When the operator proposes to set surface casing with Spudder Rig
        - Notify the BLM when moving in and removing the Spudder Rig.
        - 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.
        - BOP/BOPE test to be conducted per **43 CFR part 3170 Subpart 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.

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

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if the changes are substantial (i.e. Multistage tool, ECP, etc.). The initial wellhead installed on the well will remain on the well with spools used as needed.

2. Wait on cement (WOC) for Potash Areas: After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi for all cement blends of both lead and tail cement, 2) until cement has been in place at least 8 hours. WOC time will be recorded in the driller's log. The casing integrity test can be done (prior to the cement setting up) immediately after bumping the plug.

3. Wait on cement (WOC) for Water Basin: After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least 8 hours. WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements. The casing integrity test can be done (prior to the cement setting up) immediately after bumping the plug.

4. Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string. Have well specific cement details onsite prior to pumping the cement for each casing string.

5. No pea gravel permitted for remedial or fall back remedial without prior authorization from the BLM engineer.

6. On that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.

7. If hardband drill pipe is rotated inside casing, returns will be monitored for metal. If metal is found in samples, drill pipe will be pulled and rubber protectors which have a larger diameter than the tool joints of the drill pipe will be installed prior to continuing drilling operations.

8. Whenever a casing string is cemented in the R-111-P potash area, the NMOCD requirements shall be followed.

B. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in **43 CFR part 3170 Subpart 3172** and **API STD 53 Sec. 5.3**.

2. If a variance is approved for a flexible hose to be installed from the BOP to the choke manifold, the following requirements apply: The flex line must meet the requirements of API 16C. Check condition of flexible line from BOP to choke manifold, replace if exterior is damaged or if line fails test. Line to be as straight as possible with no hard bends and is to be anchored according to Manufacturer's requirements. The flexible hose can be exchanged with a hose of equal size and equal or greater pressure rating. Anchor requirements, specification sheet and hydrostatic pressure test certification matching the hose in service, to be onsite for review. These documents shall be posted in the company man's trailer and on the rig floor.

3. 5M or higher system requires an HCR valve, remote kill line and annular to match. The remote kill line is to be installed prior to testing the system and tested to stack pressure.

4. If the operator has proposed a multi-bowl wellhead assembly in the APD. The following requirements must be met:

    a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
    b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
    c. Manufacturer representative shall install the test plug for the initial BOP test.
    d. Whenever any seal subject to test pressure is broken, all the tests in 43 CFR 3172.6(b)(9) must be followed.
    e. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.

5. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.

    a. In a water basin, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. The casing cut-off and BOP installation can be initiated four hours after installing the slips, which will be approximately six hours after bumping the plug. For those casing strings not using slips, the minimum wait time before cut-off is eight hours after bumping the plug. BOP/BOPE testing can begin after cut-off or once cement reaches 500 psi compressive strength (including lead 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).

    b. In potash areas, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. For all casing strings, casing cut-off and BOP installation can be initiated at twelve hours after bumping the 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.)

c. 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 part 3170 Subpart 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).

d. The test shall be run on a 5000 psi chart for a 2-3M BOP/BOP, on a 10000 psi chart for a 5M BOP/BOPE and on a 15000 psi chart for a 10M BOP/BOPE. If a linear chart is used, it shall be a one hour chart. A circular chart shall have a maximum 2 hour clock. If a twelve hour or twenty-four hour chart is used, tester shall make a notation that it is run with a two hour clock.

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

f. All tests are required to be recorded on a calibrated test chart. A copy of the BOP/BOPE test chart and a copy of independent service company test will be submitted to the appropriate BLM office.

g. The BOP/BOPE test shall include a low pressure test from 250 to 300 psi. The test will be held for a minimum of 10 minutes if test is done with a test plug and 30 minutes without a test plug. This test shall be performed prior to the test at full stack pressure.

h. BOP/BOPE must be tested by an independent service company within 500 feet of the top of the Wolfcamp formation if the time between the setting of the intermediate casing and reaching this depth exceeds 20 days. This test does not exclude the test prior to drilling out the casing shoe as per **43 CFR part 3170 Subpart 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.

Long Vo (LVO) 8/23/2024

Approval Date: 09/23/2024

Devon Energy Center
333 West Sheridan Avenue
Oklahoma City, Oklahoma 73102-5015

Hydrogen Sulfide (H_2S) Contingency Plan

For

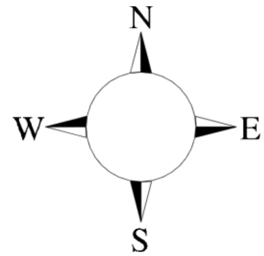
Tambora 36-35 Fed Com 622H

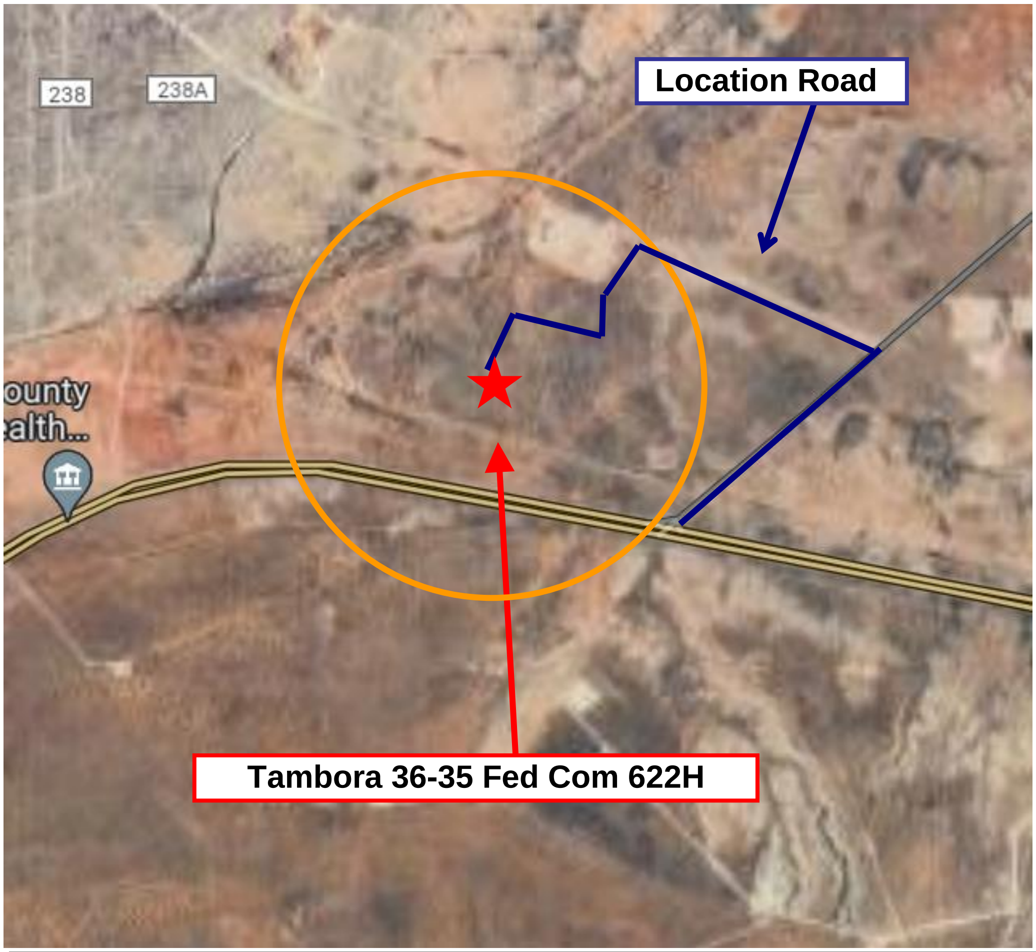
Sec-36 T-20S R-29E
1253' FNL & 21' FEL
LAT. = 32.5336933º N (NAD83)
LONG = 104.0200697º W

Eddy County NM

Tambora 36-35 Fed Com 622H

This is an open drilling site. H_2S monitoring equipment and emergency response equipment will be used within 500' of zones known to contain H_2S, including warning signs, wind indicators and H_2S monitor.





Assumed 100 ppm ROE = 3000' (Radius of Exposure)
100 ppm H2S concentration shall trigger activation of this plan.

Escape
Crews shall escape upwind of escaping gas in the event of an emergency release of gas. Escape can be facilitated from the location entrance road. Crews should then block the entrance to the location from the lease road so as not to allow anyone traversing into a hazardous area. The blockade should be at a safe distance outside of the ROE. There are no homes or buildings in or near the ROE.

Assumed 100 ppm ROE = 3000'

100 ppm H_2S concentration shall trigger activation of this plan.

Emergency Procedures

In the event of a release of gas containing H_2S, the first responder(s) must

- **Isolate the area and prevent entry by other persons into the 100 ppm ROE.**
- **Evacuate any public places encompassed by the 100 ppm ROE.**
- **Be equipped with H_2S monitors and air packs in order to control the release.**
- **Use the "buddy system" to ensure no injuries occur during the response**
- **Take precautions to avoid personal injury during this operation.**
- **Contact operator and/or local officials to aid in operation. See list of phone numbers attached.**
- **Have received training in the**
  - **Detection of H_2S, and**
  - **Measures for protection against the gas,**
  - **Equipment used for protection and emergency response.**

Ignition of Gas Source

Should control of the well be considered lost and ignition considered, take care to protect against exposure to Sulfur Dioxide (SO_2). Intentional ignition must be coordinated with the NMOCD and local officials. Additionally the NM State Police may become involved. NM State Police shall be the Incident Command on scene of any major release. Take care to protect downwind whenever there is an ignition of the gas

Characteristics of H_2S and SO_2

Common Name	Chemical Formula	Specific Gravity	Threshold Limit	Hazardous Limit	Lethal Concentration
Hydrogen Sulfide	H_2S	1.189 Air = 1	10 ppm	100 ppm/hr	600 ppm
Sulfur Dioxide	SO_2	2.21 Air = 1	2 ppm	N/A	1000 ppm

Contacting Authorities

Devon Energy Corp. personnel must liaison with local and state agencies to ensure a proper response to a major release. Additionally, the OCD must be notified of the release as soon as possible but no later than 4 hours. Agencies will ask for information such as type and volume of release, wind direction, location of release, etc. Be prepared with all information available. The following call list of essential and potential responders has been prepared for use during a release. Devon Energy Corp. Company response must be in coordination with the State of New Mexico's 'Hazardous Materials Emergency Response Plan' (HMER)

Hydrogen Sulfide Drilling Operation Plan

I. HYDROGEN SULFIDE (H_2S) 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 this well:

1. The hazards and characteristics of hydrogen sulfide (H_2S)

2. The proper use and maintenance of personal protective equipment and life support systems.

3. The proper use of H_2S detectors, alarms, warning systems, briefing areas, evacuation procedures, and prevailing winds.

4. The proper techniques for first aid and rescue procedures.

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

1. The effects of H_2S metal components. If high tensile tubulars are to be used, personnel will be trained in their special maintenance requirements.

2. Corrective action and shut-in procedures when drilling or reworking a well and blowout prevention and well control procedures.

3. The contents and requirements of the H_2S Drilling Operations Plan.

There will be weekly H_2S and well control drills for all personnel in each crew.

II. HYDROGEN SULFIDE TRAINING

Note: All H_2S safety equipment and systems will be installed, tested, and operational when drilling reaches a depth of 500 feet above, or three days prior to penetrating the first zone containing or reasonably expected to contain H_2S.

1. **Well Control Equipment**

   A. Flare line

   B. Choke manifold – Remotely Operated

   C. Blind rams and pipe rams to accommodate all pipe sizes with properly sized closing unit

   D. Auxiliary equipment may include if applicable: annular preventer and rotating head.

   E. Mud/Gas Separator

2. **Protective equipment for essential personnel:**

   30-minute SCBA units located at briefing areas, as indicated on well site diagram, with escape units available in the top doghouse. As it may be difficult to communicate audibly while wearing these units, hand signals shall be utilized.

3. **H_2S detection and monitoring equipment:**

   Portable H_2S monitors positioned on location for best coverage and response. These units have warning lights which activate when H_2S levels reach 10 ppm and audible sirens which activate at 10 ppm. Sensor locations:

   - **Bell nipple**
   - **Rig floor**
   - **Cellar**
   - **Possum Belly/Shale shaker**
   - **Choke manifold**

   Visual warning systems:

   A. Wind direction indicators as shown on well site diagram

   B. Caution/ Danger signs shall be posted on roads providing direct access to locations. Signs will be painted a high visibility yellow with black lettering of sufficient size to be reasonable distance from the immediate location. Bilingual signs will be used when appropriate.

4. **Mud program:**

   The mud program has been designed to minimize the volume of H_2S circulated to surface. Proper mud weight, safe drilling practices and the use of H_2S scavengers will minimize hazards when penetrating H_2S bearing zones.

5. **Metallurgy:**

   A. All drill strings, casings, tubing, wellhead, blowout preventer, drilling spool, kill lines, choke manifold lines, and valves shall be H_2S trim.

   B. All elastomers used for packing and seals shall be H_2S trim.

6. **Communication:**

   A. Company personnel have/use cellular telephones in the field.

   B. Land line (telephone) communications at the Office

7. **Well testing:**

   A. Drill stem testing will be performed with a minimum number of personnel in the immediate vicinity, which are necessary to safety and adequately conduct the test. The drill stem testing will be conducted during daylight hours and formation fluids will not be flowed to the surface. All drill-stem-testing operations conducted in an H_2S environment will use the closed chamber method of testing.

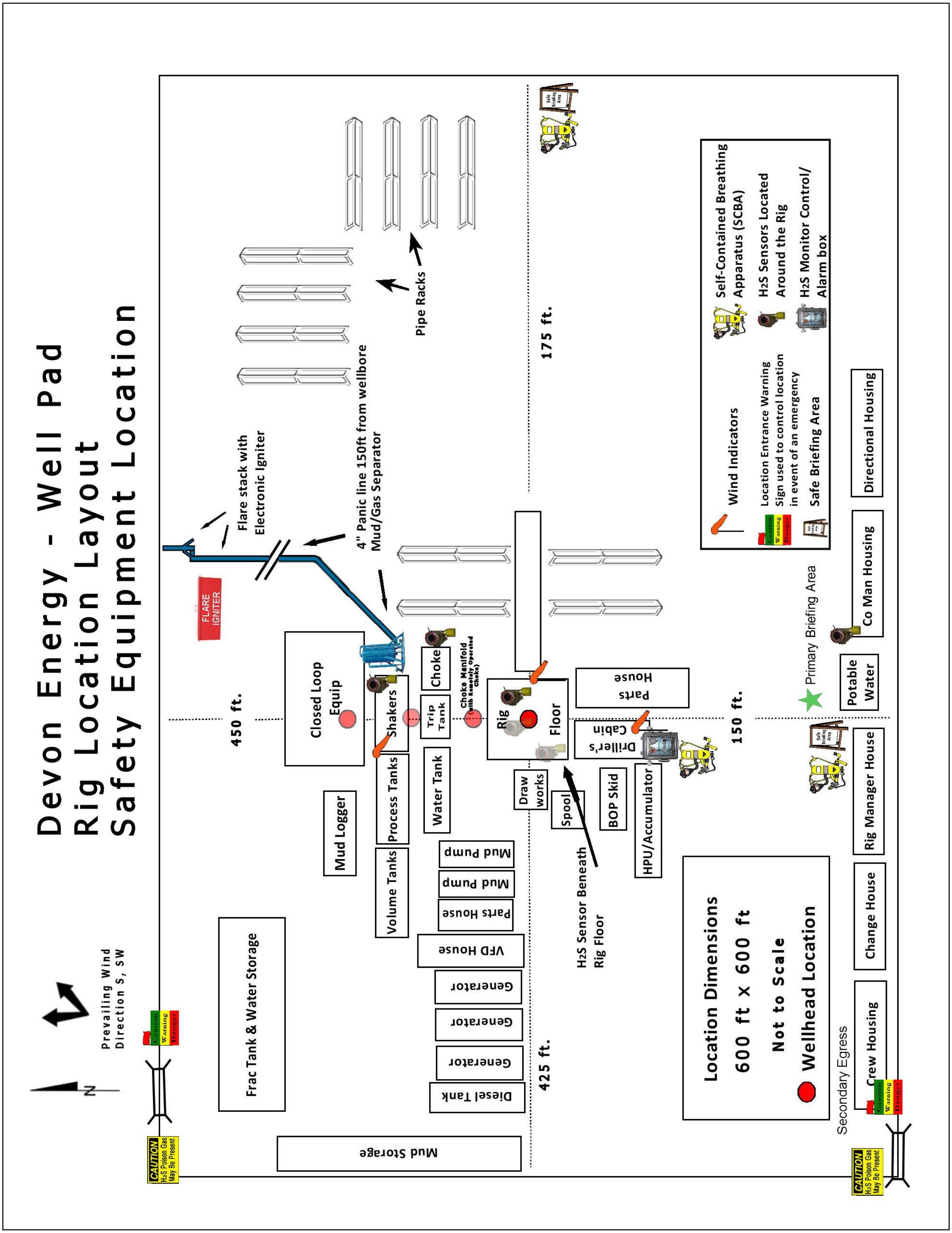
   B. There will be no drill stem testing.

Devon Energy Corp. Company Call List

Employee/Company Contact Representative	Position	Phone Number	After Hours Number
Jonathan Fisher (North)	Drilling Manager	832-967-7912	
Jason Hildebrand (South)	Drilling Manager	405-552-6514	
Rich Downey	Drilling VP	405-228-2415	
Josh Harvey	EHS Manager	405-228-2440	918-500-5536
Laura Wright	EHS Supervisor	405-552-5334	832-969-8145
Robert Glover	EHS Professional	575-703-5712	575-703-5712
Lane Frank	Lead EHS	580-579-7052	580-579-7052
Rickey Porter	Lead EHS	903-720-8315	903-720-8315
Ronnie Handy	Lead EHS	918-839-2046	918-839-2046
Brock Vise	Lead EHS	918-413-3291	918-413-3291

Agency Call List			
Lea County (575)	**Hobbs**		
	Lea County Communication Authority		397-9265
	State Police		885-3138
	City Police		397-9265
	Sheriff's Office		396-3611
	Ambulance		**911**
	Fire Department		397-9308
	LEPC (Local Emergency Planning Committee)		393-2870
	NMOCD		393-6161
	US Bureau of Land Management (Closed)		393-0002
Eddy County (575)	**Carlsbad**		
	State Police		885-3137
	City Police		885-2111
	Sheriff's Office		887-7551
	Ambulance		**911**
	Fire Department		885-3125
	LEPC (Local Emergency Planning Committee)		887-3798
	US Bureau of Land Management		234-5972
	NM Emergency Response Commission (Santa Fe)		(505) 476-9600
	24 HR		(505) 827-9126
	National Emergency Response Center		(800) 424-8802
	National Pollution Control Center: Direct		(703) 872-6000
	For Oil Spills		(800) 280-7118
	Emergency Services		
	Wild Well Control		(281) 784-4700
	Cudd Pressure Control	(915) 699-0139	(915) 563-3356
	Halliburton		(575) 746-2757
	B. J. Services		(575) 746-3569
Give GPS position:	Native Air – Emergency Helicopter – Hobbs		(575) 347-9836
	For Air Ambulance - **Eddy County** Dispatch		(575)-616-7155
	For Air Ambulance - **Lea County** (LCCA)		(575)-397-9265
	Poison Control (24/7)		(800) 222-1222
	Oil & Gas Pipeline 24 Hour Service		(800) 364-4366
	NOAA – Website - www.nhc.noaa.gov		
	National Pollution Control Center		202-795-6958
	NPCC – Oil Spills		800-280-7118

Prepared in conjunction with
Dave Small


Devon Energy - Well Pad
Rig Location Layout
Safety Equipment Location
Prevailing Wind Direction S, SW
Flare stack with Electronic Igniter
FLARE IGNITER
4" Panic line 150ft from wellbore Mud/Gas Separator
Pipe Racks
450 ft.
175 ft.
425 ft.
150 ft.
Frac Tank & Water Storage
Mud Storage
Diesel Tank
Generator
Generator
Generator
VFD House
Parts House
Mud Pump
Mud Pump
Mud Logger
Volume Tanks
Process Tanks
Water Tank
Closed Loop Equip
Shakers
Trip Tank
Choke
Choke Manifold (with Remotely Operated Choke)
Rig Floor
Draw works
Spool
BOP Skid
HPU/Accumulator
Driller's Cabin
Parts House
H2S Sensor Beneath Rig Floor
Location Dimensions
600 ft x 600 ft
Not to Scale
Wellhead Location
Wind Indicators
Location Entrance Warning Sign used to control location in event of an emergency
Safe Briefing Area
Self-Contained Breathing Apparatus (SCBA)
H2S Sensors Located Around the Rig
H2S Monitor Control/ Alarm box
Primary Briefing Area
Secondary Egress
Potable Water
Co Man Housing
Directional Housing
Rig Manager House
Change House
Crew Housing
CAUTION H2S Poison Gas May Be Present
Caution Warning Danger

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

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

CONDITIONS

Action 387666

CONDITIONS

Operator:	
DEVON ENERGY PRODUCTION COMPANY, LP 333 West Sheridan Ave. Oklahoma City, OK 73102	OGRID: 6137
	Action Number: 387666
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

CONDITIONS

Created By	Condition	Condition Date
ward.rikala	Notify OCD 24 hours prior to casing & cement	10/23/2024
ward.rikala	Will require a File As Drilled C-102 and a Directional Survey with the C-104	10/23/2024
ward.rikala	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	10/23/2024
ward.rikala	Cement is required to circulate on both surface and intermediate1 strings of casing	10/23/2024
ward.rikala	If cement does not circulate on any string, a CBL is required for that string of casing	10/23/2024
ward.rikala	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	10/23/2024