AFMSS

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

Sundry Print Report

05/24/2022

Well Name: BURTON FLAT 26-28 FED STATE COM

Well Location: T20S / R28E / SEC 26 / SESW /

County or Parish/State: /

Well Number: 623H

Type of Well: OIL WELL

Allottee or Tribe Name:

Lease Number: NMNM108513

Unit or CA Name: BURTON FLAT DEEP-EXPL

Unit or CA Number: NMNM70798X

US Well Number: 3001549256

Well Status: Drilling Well

Operator: DEVON ENERGY PRODUCTION COMPANY LP

Notice of Intent

Sundry ID: 2663401

Type of Submission: Notice of Intent

Type of Action: Casing

Date Sundry Submitted: 03/23/2022

Time Sundry Submitted: 06:52

Date proposed operation will begin: 02/09/2022

Procedure Description: Devon Energy Production Company, L.P. respectfully requests approval for optional intermediate casing/drilling plan of 10-3/4" intermediate casing inside of 13-1/2" intermediate hole at previously permitted set depths. Devon Energy Production Company, L.P. will circulate class C cement to surface behind the 10-3/4'' casing.

Surface Disturbance

Is any additional surface disturbance proposed?: No

NOI Attachments

Procedure Description

BURTON_FLAT_26_28_FED_COM_623H_final_drill_plan_20220513102927.pdf

MB_Wellhd_10M_4S_20_10.75_8.625_20220323065150.pdf

MB_Wellhd_10M_4S_20_13.375_9.625_20220323065150.pdf

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Conditions of Approval

Specialist Review

26_20_28_N_Sundry_ID_2663401_Burton_Flat_26_28_Fed_State_Com_623H_Eddy_NM108513_13_22c_10_26_2021_LV_Alt_20220513111259.pdf

26_20_28_N_Sundry_ID_2663401_Burton_Flat_26_28_Fed_State_Com_623H_Eddy_NM108513_13_22c_10_26_2021_LV_Primary_20220513111259.pdf

Burton_Flat_26_28_Fed_Com_623H_Dr_COA_Sundry_ID_2663401_20220513111259.pdf

Operator

I certify that the foregoing is true and correct. Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction. Electronic submission of Sundry Notices through this system satisfies regulations requiring a

Operator Electronic Signature: CHELSEY GREEN

Signed on: MAY 13, 2022 10:30 AM

Name: DEVON ENERGY PRODUCTION COMPANY LP

Title: Regulatory Compliance Professional

Street Address: 333 West Sheridan Avenue

City: Oklahoma City **State:** OK

Phone: (405) 228-8595

Email address: Chelsey.Green@dvn.com

Field

Representative Name:

Street Address:

City: **State:** **Zip:**

Phone:

Email address:

BLM Point of Contact

BLM POC Name: CHRISTOPHER WALLS

BLM POC Title: Petroleum Engineer

BLM POC Phone: 5752342234

BLM POC Email Address: cwalls@blm.gov

Disposition: Approved

Disposition Date: 05/20/2022

Signature: Chris Walls

Burton Flat 26-28 Fed State Com 623H

20		surface csg in a	26	inch hole.		Design Factors				Surface		
Segment	#/ft	Grade		Coupling	Joint	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	94.00		j 55	stc	22.21	2.97	3.73	375	13	6.25	5.60	35,250
"B"				stc				0				0
	w/8.4#/g mud, 30min Sfc Csg Test psig:		1,313		Tail Cmt	does not	circ to sfc.	Totals:	375			35,250

Comparison of Proposed to Minimum Required Cement Volumes

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
26	1.5053	800	1152	565	104	9.00	338	2M	2.50

Site plat (pipe racks S or E) as per O.O.1.III.D.4.i. not found.

Proposed

10 3/4		casing inside the	20			Design Factors				Int 1		
Segment	#/ft	Grade		Coupling	Joint	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	40.50		h 40	stc	7.47	2.46	0.57	1,038	4	1.08	4.11	42,039
"B"								0				0
	w/8.4#/g mud, 30min Sfc Csg Test psig:						Totals:	1,038				42,039
		The cement volume(s) are intended to achieve a top of			0	ft from	surface or a	375				overlap.
Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE				Min Dist Hole-Cplg
13 1/2	0.3637	375	906	753	20	10.50	2115	3M				0.88

Class 'C' tail cmt yld > 1.35

Burst Frac Gradient(s) for Segment(s): A, B, C, D = 2.2, b, c, d All > 0.70, OK.

8 5/8		casing inside the	10 3/4			Design Factors				Int 2		
Segment	#/ft	Grade		Coupling	Joint	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	32.00		p 110	tlw	3.94	1.06	1.79	8,544	2	3.01	2.00	273,408
"B"								0				0
	w/8.4#/g mud, 30min Sfc Csg Test psig:		1,880				Totals:	8,544				273,408
		The cement volume(s) are intended to achieve a top of			838	ft from	surface or a	200				overlap.
Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE				Min Dist Hole-Cplg
9 7/8	0.1261	760	1735	976	78	9.00	2971	3M				0.44
		Setting Depths for D V Tool(s):	1088				sum of sx	Σ CuFt				Σ%excess
	% excess cmt by stage:	84	1854				1135	2425				149

Class 'C' tail cmt yld > 1.35

Tail cmt

5 1/2		casing inside the	8 5/8			Design Factors				Prod 1		
Segment	#/ft	Grade		Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	17.00		p 110	btc	3.52	1.5	2.14	22,182	2	3.58	2.52	377,094
"B"								0				0
	w/8.4#/g mud, 30min Sfc Csg Test psig:		2,008				Totals:	22,182				377,094
		The cement volume(s) are intended to achieve a top of			8344	ft from	surface or a	200				overlap.
Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE				Min Dist Hole-Cplg
7 7/8	0.1733	1909	2963	2398	24	10.50						0.91

Class 'H' tail cmt yld > 1.20 Capitan Reef est top XXXX.

Burton Flat 26-28 Fed State Com 623H

20 surface csg in a **26** inch hole. — **Design Factors** — **Surface**

Segment	#/ft	Grade	Coupling	Joint	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	94.00	j 55	stc	22.21	2.97	3.73	375	13	6.25	5.60	35,250
"B"			stc				0				0

w/8.4#/g mud, 30min Sfc Csg Test psig: 1,313 — Tail Cmt does not circ to sfc. — Totals: 375 — 35,250

Comparison of Proposed to Minimum Required Cement Volumes

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
26	1.5053	800	1152	565	104	9.00	338	2M	2.50

Site plat (pipe racks S or E) as per O.O.1.III.D.4.i. not found.

Proposed

13 3/8 casing inside the **20** — **Design Factors** — **Int 1**

Segment	#/ft	Grade	Coupling	Joint	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	48.00	h 40	stc	6.46	1.36	1.24	1,038	3	2.34	2.28	49,824
"B"							0				0

w/8.4#/g mud, 30min Sfc Csg Test psig: — Totals: 1,038 — 49,824

The cement volume(s) are intended to achieve a top of 0 ft from surface or a 375 overlap.

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
17 1/2	0.6946	802	1433	843	70	10.50	739	2M	1.56

Class 'C' tail cmt yld > 1.35

9 5/8 casing inside the **13 3/8** — **Design Factors** — **Int 2**

Segment	#/ft	Grade	Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	40.00	j 55	btc	5.27	1.84	0.79	2,987	3	1.33	3.48	119,480
"B"							0				0

w/8.4#/g mud, 30min Sfc Csg Test psig: 1,462 — Totals: 2,987 — 119,480

The cement volume(s) are intended to achieve a top of 838 ft from surface or a 200 overlap.

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
12 1/4	0.3132	491	985	686	44	9.00	2971	3M	0.81

Class 'C' tail cmt yld > 1.35

Burst Frac Gradient(s) for Segment(s): A, B, C, D = 1.32, b, c, d All > 0.70,

5 1/2 casing inside the **9 5/8** — **Design Factors** — **Prod 1**

Segment	#/ft	Grade	Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	17.00	p 110	btc	3.52	1.5	2.14	22,182	2	3.58	2.52	377,094
"B"							0				0

w/8.4#/g mud, 30min Sfc Csg Test psig: 2,008 — Totals: 22,182 — 377,094

The cement volume(s) are intended to achieve a top of 2787 ft from surface or a 200 overlap.

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
8 3/4	0.2526	3280	5947	4901	21	10.50			1.35

Class 'H' tail cmt yld > 1.20 — Capitan Reef est top XXXX.

BURTON FLAT 26-28 FED COM 623H

1. Geologic Formations

TVD of target	9128	Pilot hole depth	N/A
MD at TD:	22182	Deepest expected fresh water	

Basin

Formation	Depth (TVD) from KB	Water/Mineral Bearing/Target Zone?	Hazards*
Rustler	85		
Salt	241		
Base of Salt	500		
Lamar	616		
Capitan Reef Top	1088		
Delaware	3012		
Cherry Canyon	3202		
Brushy Canyon	3849		
1st Bone Spring Lime	5399		
Bone Spring 1st	6583		
Bone Spring 2nd	7263		
3rd Bone Spring Lime	7615		
Bone Spring 3rd	8544		
Wolfcamp	8949		

*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)
26	20	94.0	J-55	STC	0.0	375 MD	0	375 TVD
13 1/2	10 3/4	40.5	H40	STC	0.0	1038 MD	0	1038 TVD
9 7/8	8 5/8	8.6	P110	TLW	0	8544 MD	0	8544 TVD
7 7/8	5 1/2	17.0	P110	BTC	0	22182 MD	0	9128 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.

2. Casing Program (Contingency Design)

Hole Size	Csg. Size	Wt (PPF)	Grade	Conn	Top (MD)	Bottom (MD)	Top (TVD)	Bottom (TVD)
26	20	94.0	J-55	STC	0.0	375 MD	0	375 TVD
17 1/2	13 3/8	48.0	H40	STC	0.0	1038 MD	0	1038 TVD
12 1/4	9 5/8	40	J-55	BTC	0	2987 MD	0	2987 TVD
8 3/4	5 1/2	17.0	P110	BTC	0	22182 MD	0	9128 TVD

• This contingency design will be used IF full returns thru the Delaware are experienced on the initial well on the pad

3. Cementing Program (Primary Design)

Casing	# Sks	TOC	Wt. (lb/gal)	Yld (ft3/sack)	Slurry Description
Surface	800	Surf	13.2	1.44	Lead: Class C Cement + additives
Int	200	Surf	9	3.27	Lead: Class C Cement + additives
	175	500' above shoe	13.2	1.44	Tail: Class H / C + additives
Int 1	350	Surf	9	3.27	Lead: Class C Cement + additives
	410	5000'	13.2	1.44	Tail: Class H / C + additives
Int 1 Intermediate Squeeze	200	Surf	9	1.44	Squeeze Lead: Class C Cement + additives
	350	Surf	9	3.27	Lead: Class C Cement + additives
	410	5000'	13.2	1.44	Tail: Class H / C + additives
Production	117	6639	9	3.27	Lead: Class H /C + additives
	1792	8639	13.2	1.44	Tail: Class H / C + additives

3. Cementing Program (Contingency Design)

Casing	# Sks	TOC	Wt. (lb/gal)	Yld (ft3/sack)	Slurry Description
Surface	800	Surf	13.2	1.44	Lead: Class C Cement + additives
Int	152	Surf	9	3.27	Lead: Class C Cement + additives
	650	500' above shoe	13.2	1.44	Tail: Class H / C + additives
Int 1	242	Surf	9	3.27	Lead: Class C Cement + additives
	154	2000' above shoe	13.2	1.44	Tail: Class H / C + additives
Int 1 Intermediate Squeeze	235	Surf	9	1.44	Squeeze Lead: Class C Cement + additives
	152	Surf	9	3.27	Lead: Class C Cement + additives
	339	2000' above shoe	13.2	1.44	Tail: Class H / C + additives
Production	669	50' above Capitan	9	3.27	Lead: Class H /C + additives
	2611	8639	13.2	1.44	Tail: Class H / C + additives

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

3. Cementing Program (Primary Design)

Assuming no returns are established while drilling, Devon requests to pump a two stage cement job on the 8-5/8'' intermediate casing string with the first stage being pumped conventionally with the calculated top of cement at the Capitan Reef (1088') and the second stage performed as a bradenhead squeeze with planned cement from the Capitan Reef to surface. If necessary, a top out consisting of 175 sacks of Class C cement + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (2.30 yld, 12.91 ppg) will be executed as a contingency. The final cement top will be verified by Echo-meter. Devon will include the Echo-meter verified fluid top and the volume of displacement fluid above the cement slurry in the annulus in all post-drill sundries on wells utilizing this cement program.

Devon will report to the BLM the volume of fluid (limited to 1 bbls) used to flush intermediate casing valves following backside cementing procedures.

4. Pressure Control Equipment (Four String Design)

BOP installed and tested before drilling which hole?	Size?	Min. Required WP	Type		✓	Tested to:
Int			Annular			N/A
			Blind Ram			500psi
			Pipe Ram			
			Double Ram			
			Other*	Diverter	X	
Int 1	13-5/8"	5M	Annular (5M)		X	100% of rated working pressure
			Blind Ram		X	5M
			Pipe Ram			
			Double Ram		X	
			Other*			
Production	13-5/8"	5M	Annular (5M)		X	100% of rated working pressure
			Blind Ram		X	5M
			Pipe Ram			
			Double Ram		X	
			Other*			

By definition, the diverter will only be used to divert flow from the well and not to shut in the well. Prior to drilling out, the diverter will be tested to 250 PSI to ensure functionality.

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	4984
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 nippled 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

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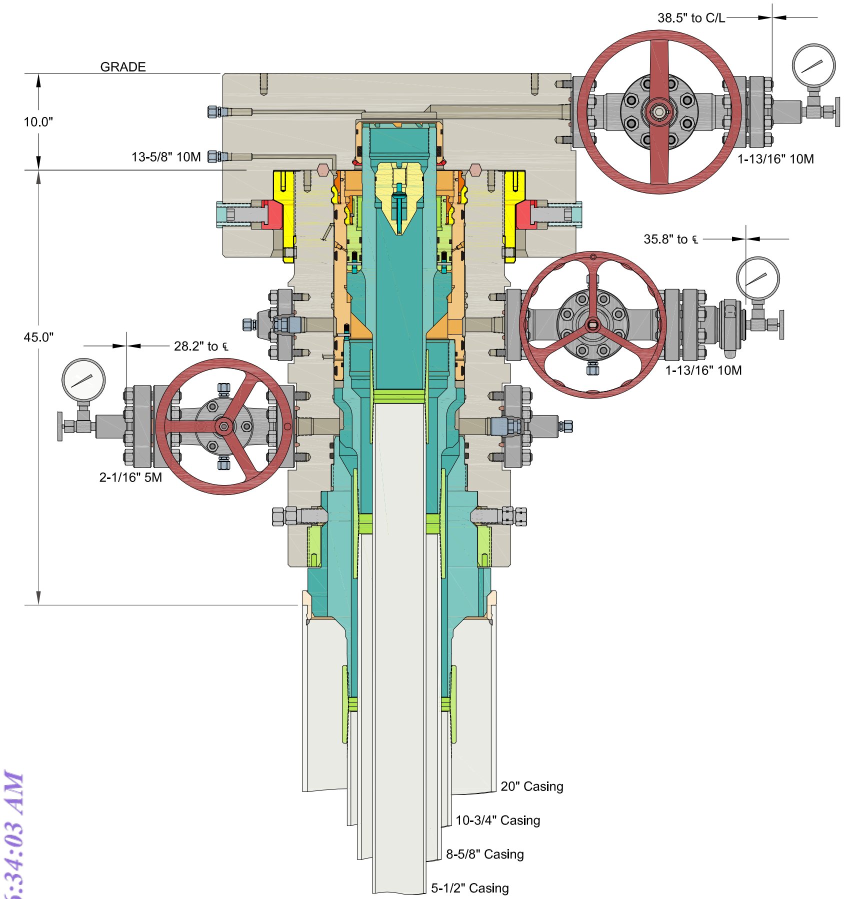

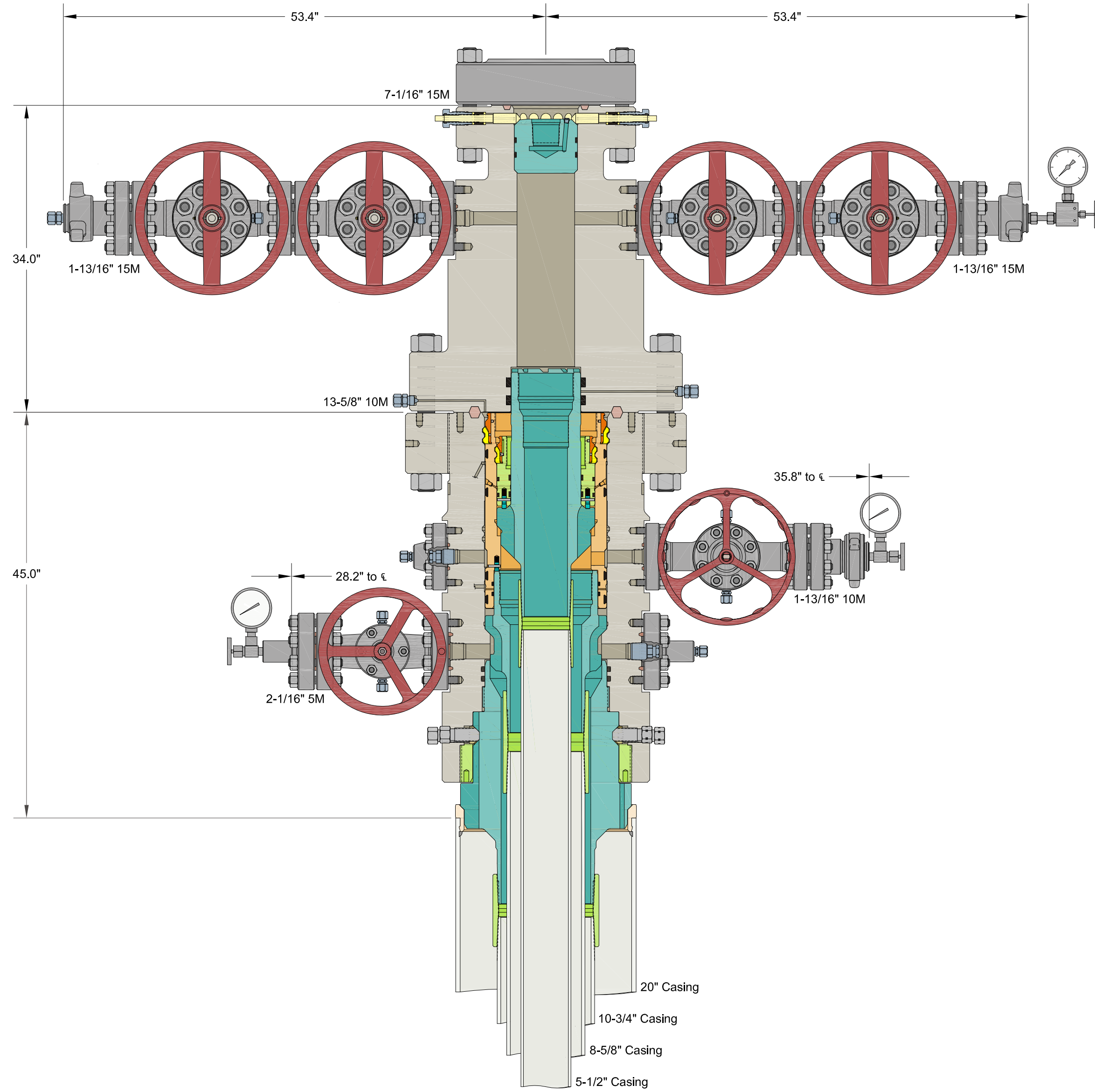

ALL DIMENSIONS APPROXIMATE

CACTUS WELLHEAD LLC	DEVON ENERGY CORPORATION DELAWARE BASIN		
10-3/4" x 8-5/8" x 5-1/2" 10M MBU-3T-CFL-R-DBLO Wellhead Sys. With 8-5/8" And 5-1/2" Mandrel Casing Hangers And 13-5/8" 10M x 7-1/16" 15M CTH-DBLHPS Tubing Head	DRAWN	DLE	16SEP21
	APPRV		
	DRAWING NO.	HBE0000595	

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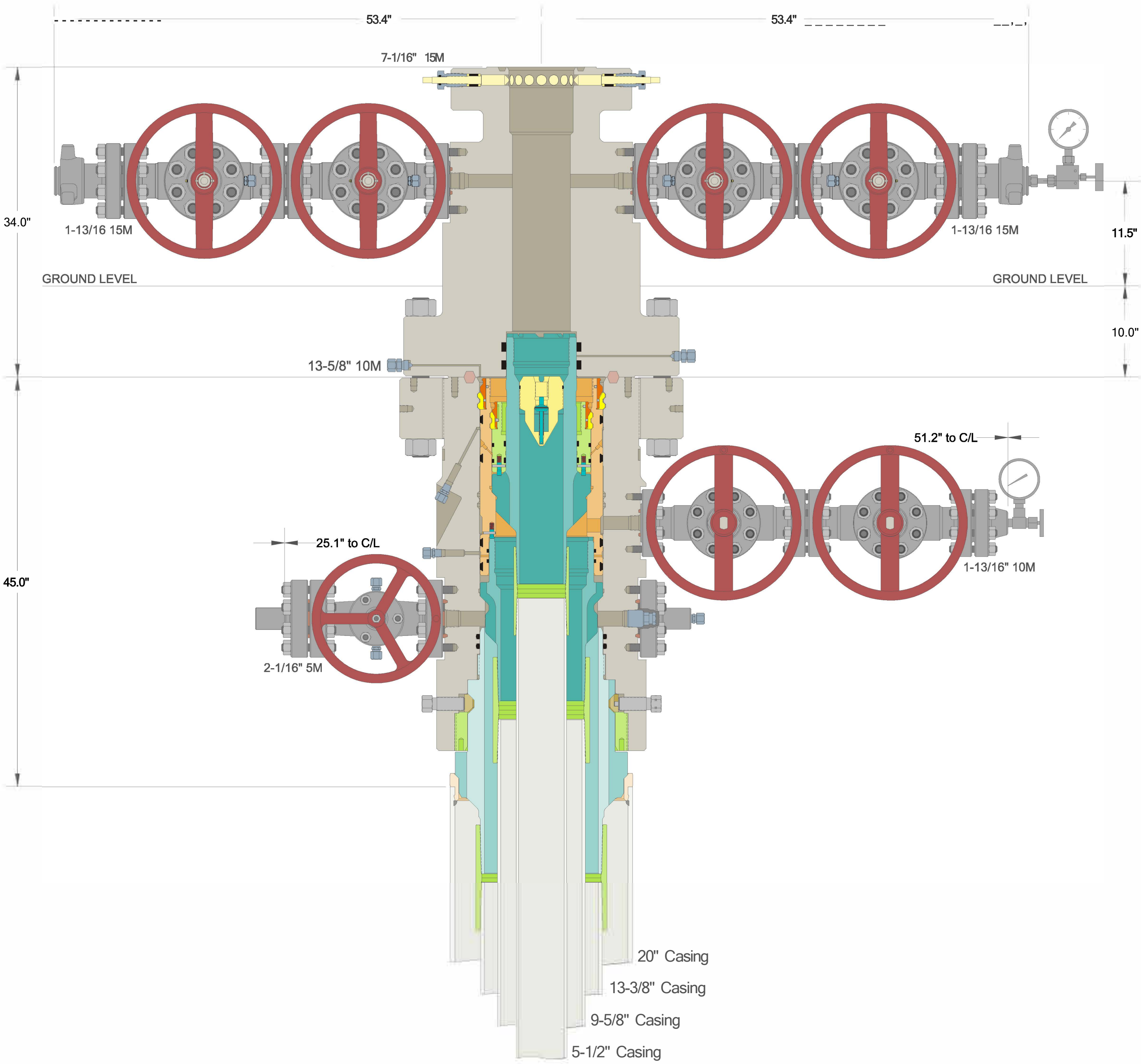

ALL DIMENSIONS APPROXIMATE

CACTUS WELLHEAD LLC	DEVON ENERGY CORPORATION ANADARKO BASIN/ STACK		
20" x 13-3/8" x 9-5/8" x 5-1/2" 15M MBU-3T-CFL-R-DBLO System With 13-3/8", 9-5/8" & 5-1/2" MBU-3T Mandrel Casing Hangers And 13-5/8" 10M x 7-1/16" 15M CTH-DBLHPS Tubing Head	DRAWN	DLE	13DEC18
	APPRV		
	DRAWING NO.	SDT-1815	

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	**Devon Energy Production Company LP**
LEASE NO.:	**NMNM108513**
LOCATION:	Section 26, T.20 S., R.28 E., NMPM
COUNTY:	Eddy County, New Mexico
Sundry ID:	**2663401**

WELL NAME & NO.:	**Burton Flat 26-28 Fed State Com 623H**
SURFACE HOLE FOOTAGE:	866'/S & 2438'/W
BOTTOM HOLE FOOTAGE	1870'/S & 20'/W

COA

H2S	☒ Yes	☐ No	
Potash	☒ None	☐ Secretary	☐ R-111-P
Cave/Karst Potential	☐ Low	☐ Medium	☒ High
Cave/Karst Potential	☐ Critical		
Variance	☐ None	☒ Flex Hose	☐ Other
Wellhead	☐ Conventional	☐ Multibowl	☐ Both
Wellhead Variance	☒ Diverter		
Other	☒ 4 String	☒ Capitan Reef	☐ WIPP
Other	☒ Fluid Filled	☐ Pilot Hole	☐ Open Annulus
Cementing	☒ Cement Squeeze	☒ EchoMeter	
Special Requirements	☐ Water Disposal	☒ COM	☐ Unit
Special Requirements Variance	☐ Break Testing	☐ Offline Cementing	

A. HYDROGEN SULFIDE

A Hydrogen Sulfide (H2S) Drilling Plan shall be activated 500 feet prior to drilling into the **Delaware and Wolfcamp** formation. As a result, the Hydrogen Sulfide area must meet Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

B. CASING

Primary Casing Design:

1. The **20** inch surface casing shall be set at approximately **375 feet** (a minimum of **70 feet (Eddy County)** into the Rustler Anhydrite and above the salt) and cemented to the surface.

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

2. The minimum required fill of cement behind the **10-3/4** inch intermediate casing shall be set at approximately **1038 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.**

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

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

   Option 1 (Single Stage):

   - Cement should tie-back at least **50 feet** on top of Capitan Reef top **or 200 feet** into the previous casing, whichever is greater. 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.

   Option 2:

   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.

   b. Second stage:

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

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

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

Operator has proposed to pump down 10-3/4" X 8-5/8" annulus after primary cementing stage. Operator must run Echo-meter to verify Cement Slurry/Fluid top in the annulus Or operator shall run a CBL from TD of the 8-5/8" casing to surface after the second stage BH to verify TOC.
Submit results to the BLM. No displacement fluid/wash out shall be utilized at the top of the cement slurry between second stage BH and top out. Operator must run one CBL per Well Pad.

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

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

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

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

Alternate Casing Design:

1. The **20** inch surface casing shall be set at approximately **375 feet** (a minimum of **70 feet (Eddy County)** into the Rustler Anhydrite and above the salt) and cemented to the surface.

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

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

2. The minimum required fill of cement behind the **13-3/8** inch intermediate casing shall be set at approximately **1038 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.**

3. The minimum required fill of cement behind the **9-5/8** inch intermediate casing shall be set at approximately **2987 feet** is:

   - Cement should tie-back at least **50 feet** on top of Capitan Reef top **or 200 feet** into the previous casing, whichever is greater. 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.
     Cement excess is less than 25%, more cement might be required.

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

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

Operator has proposed to pump down 13-3/8" X 9-5/8" annulus after primary cementing stage. Operator must run a CBL from TD of the 9-5/8" casing to surface. Submit results to the BLM.

If cement does not tie-back into the previous casing shoe, a third stage remediation BH may be performed. The appropriate BLM office shall be notified.

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

   - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.
     Cement excess is less than 25%, more cement might be required.

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.

Primary Design:

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 tested to **500** psi. A Diverter system is approved as a variance to drill the **10-3/4** inch intermediate casing in a **13-1/2** inch hole.

b. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **10-3/4** inch intermediate casing shoe shall be **3000 (3M)** 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.

Option 2:

a. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be tested to **500** psi. A Diverter system is approved as a variance to drill the **10-3/4** inch intermediate casing in a **13-1/2** inch hole.

b. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the **10-3/4** inch intermediate casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the intermediate 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 OOGO2.III.A.2.i must be followed.

Alternate Design:

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 tested to **500** psi. A Diverter system is approved as a variance to drill the **13-3/8** inch intermediate casing in a **17-1/2** inch hole.

b. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **13-3/8** inch intermediate casing shoe shall be **2000 (2M)** psi.

c. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **9-5/8** inch intermediate casing shoe shall be **5000 (5M)** psi.

Option 2:

a. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be tested to **500** psi. A Diverter system is approved as a variance to drill the **13-3/8** inch intermediate casing in a **17-1/2** inch hole.

b. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the **13-3/8** inch intermediate casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the intermediate 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 OOGO2.III.A.2.i must be followed.

D. SPECIAL REQUIREMENT (S)

Communitization Agreement

- The operator will submit a Communitization Agreement to the Santa Fe Office, 301 Dinosaur Trail Santa Fe, New Mexico 87508, at least 90 days before the anticipated date of first production from a well subject to a spacing order issued by the New Mexico Oil Conservation Division. The Communitization Agreement will include the signatures of all working interest owners in all Federal and Indian leases subject to the Communitization Agreement (i.e., operating rights owners and lessees of record), or certification that the operator has obtained the written signatures of all such owners and will make those signatures available to the BLM immediately upon request.
- 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.

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
Call the Carlsbad Field Office, 620 East Greene St., Carlsbad, NM 88220, (575) 361-2822

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

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

    a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
    b. When the operator proposes to set surface casing with Spudder Rig
        - 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 Onshore Oil and Gas Order No. 2 as soon as 2nd Rig is rigged up on well.

2. Floor controls are required for 3M or Greater systems. These controls will be on the rig floor, unobstructed, readily accessible to the driller and will be operational at all times during drilling and/or completion activities. Rig floor is defined as the area immediately around the rotary table; the area immediately above the substructure on which the draw works are located, this does not include the dog house or stairway area.

3. The record of the drilling rate along with the GR/N well log run from TD to surface (horizontal well – vertical portion of hole) shall be submitted to the BLM office as well as all other logs run on the borehole 30 days from completion. If available, a digital copy of the logs is to be submitted in addition to the paper copies. The Rustler top and top and bottom of Salt are to be recorded on the Completion Report.

A. CASING

1. Changes to the approved APD casing program need prior approval if the items substituted are of lesser grade or different casing size or are Non-API. The Operator can exchange the components of the proposal with that of superior strength (i.e. changing from J-55 to N-80, or from 36# to 40#). Changes to the approved cement program need prior approval if the altered cement plan has less volume or strength or if the changes are substantial (i.e. Multistage tool, ECP, etc.). The initial wellhead installed on the well will remain on the well with spools used as needed.

2. Wait on cement (WOC) for Potash Areas: After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi for all cement blends, 2) until cement has been in place at least 24 hours. WOC time will be recorded in the driller's log. The casing intergrity 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 intergrity 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 Onshore Oil and Gas Order No. 2 and API RP 53 Sec. 17.

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 OOGO2.III.A.2.i 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 when specified), 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 plug. However, **no tests** shall commence until the cement has had a minimum of 24 hours setup time, except the casing pressure test can be initiated immediately after bumping the plug (only applies to single stage cement jobs).

c. The tests shall be done by an independent service company utilizing a test plug not a cup or J-packer. The operator also has the option of utilizing an independent tester to test without a plug (i.e. against the casing) pursuant to Onshore Order 2 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 water basin (8 hours) or potash (24 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 Onshore Order No. 2.

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.

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

COMMENTS

Action 109667

COMMENTS

Operator:	
DEVON ENERGY PRODUCTION COMPANY, LP 333 West Sheridan Ave. Oklahoma City, OK 73102	OGRID: 6137
	Action Number: 109667
	Action Type: [C-103] NOI Change of Plans (C-103A)

COMMENTS

Created By	Comment	Comment Date
jagarcia	Approved, John Garcia, Petroleum Engineer	8/22/2022

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State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
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CONDITIONS

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CONDITIONS

Created By	Condition	Condition Date
jagarcia	None	8/22/2022