

1. Geologic Formations

TVD of target	12,504'	Pilot hole depth	N/A
MD at TD:	22,161'	Deepest expected fresh water:	794'

Basin

Formation	Depth (TVD) from KB	Water/Mineral Bearing/ Target Zone?	Hazards*
RUSTLER	794		
TOP SALT	1149		
BASE OF SALT	5024		
DELAWARE	5279		
LOWER BRUSHY CANYON 8A	9339		
BONE SPRING LIME	9549		
FIRST BONE SPRING SAND	10444		
2ND BONE SPRING LIME	10674		
BONE SPRING 2ND	11039		
BONE SPRING 3RD	11499		
BONE SPRING 3RD	12119		
WOLFCAMP	12554		
WOLFCAMP	12754		

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

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2. Casing Program

Hole Size	Casing Interval		Csg. Size	Weight (lbs)	Grade	Conn.	SF Collapse	SF Burst	SF Tension
	From	To							
14.75"	0	900'	10.75"	40.5	J-55	STC	1.125	1.25	1.6
9.875"	0	9200'	7.625"	29.7	P110	BTC	1.125	1.25	1.6
8.75"	9200'	12,650'	7.625"	29.7	P110	Flushmax III	1.125	1.25	1.6
6.75"	0	12,450'	5.5"	20	P110	VamTop HT	1.125	1.25	1.6
6.75"	12,450'	22,161'	5.5"	20	P110	Vam SG	1.125	1.25	1.6

All casing strings will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.h

Rustler top will be validated via drilling parameters (i.e. reduction in ROP) and surface casing setting depth revised accordingly if needed.

A variance is requested to wave the centralizer requirement for the 7-5/8" flush casing in the 8-3/4" hole and the 5-1/2" SF/Flush casing in the 6-3/4" hole.

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

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If yes, are there three strings cemented to surface?	
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3. Cementing Program

Casing	# Sk	Wt. lb/ gal	H ₂ O gal/sk	Yld ft ³ / sack	Slurry Description
10-3/4" Surface	529	14.8	6.34	1.34	Tail: Class C Cement + 1% Calcium Chloride
	311	9	13.5	3.27	Lead: Tuned Light® Cement
7-5/8" Int	430	14.5	5.31	1.2	Tail: (50:50) Class H Cement: Poz (Fly Ash) + 0.5% bwoc HALAD-344 + 0.4% bwoc CFR-3 + 0.2% BWOC HR-601 + 2% bwoc Bentonite
	122	10.9	20.6	3.31	1 st Stage Lead: (50:40:10) Class C: Silicalite: Enhancer 923 + 10% BWOC Bentonite + 0.05% BWOC SA-1015 + 0.3% BWOC HR-800 + 0.2% BWOC FE-2 + 0.125 lb/sk Pol-E-Flake + 0.5 lb/sk D-Air 5000
7-5/8" Int Two Stage	430	14.5	5.31	1.2	1 st Stage Tail: (50:50) Class H Cement: Poz (Fly Ash) + 0.5% bwoc HALAD-344 + 0.4% bwoc CFR-3 + 0.2% BWOC HR-601 + 2% bwoc Bentonite
	230	10.9	20.6	3.31	2 nd Stage Lead: (50:40:10) Class C: Silicalite: Enhancer 923 + 10% BWOC Bentonite + 0.05% BWOC SA-1015 + 0.3% BWOC HR-800 + 0.2% BWOC FE-2 + 0.125 lb/sk Pol-E-Flake + 0.5 lb/sk D-Air 5000
	30	14.8	6.32	1.33	2 nd Stage Tail: Class C Cement + 0.125 lbs/sack Poly-E-Flake
	1450	14.8	6.32	1.32	Class C Cement + 0.125 lbs/sack Poly-E-Flake
7-5/8" Intermediate Squeeze	84	9	13.5	3.27	Class H Cement: Poz (Fly Ash) + 6% BWOC Bentonite + 0.25% BWOC HR-601 + 0.125 lbs/sack Poly-E-Flake
	430	14.5	5.31	1.2	Tail: (50:50) Class H Cement: Poz (Fly Ash) + 0.5% bwoc HALAD-344 + 0.4% bwoc CFR-3 + 0.2% BWOC HR-601 + 2% bwoc Bentonite
5-1/2" Production	750	14.8	6.32	1.33	Tail: Class C Cement + 0.125 lbs/sack Poly-E-Flake

If a DV tool is used, depth(s) will be adjusted based on hole conditions and cement volumes will be adjusted proportionally. DV tool will be set a minimum of 50 feet below previous casing and a minimum of 200 feet above current shoe. Lab reports with the 500 psi compressive strength time for the cement will be onsite for review.

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Casing String	TOC	% Excess
10-3/4" Surface	0'	50%
7-5/8" Intermediate	0'	30%
7-5/8" Intermediate Two Stage Option	1 st Stage = 4900' / 2 nd Stage = 0'	30%
5-1/2" Production Casing	12,450'	25%

4. Pressure Control Equipment

N	A variance is requested for the use of a diverter on the surface casing. See attached for schematic.
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BOP installed and tested before drilling which hole?	Size?	Min. Required WP	Type	✓	Tested to:
9-7/8" & 8-3/4"	13-5/8"	5M	Annular	X	50% of rated working pressure
			Blind Ram	X	
			Pipe Ram	X	5M
			Double Ram	X	
			Other*		
6-3/4"	13-5/8"	10M	Annular (5M)	X	70% of rated working pressure
			Blind Ram	X	10M
			Pipe Ram	X	
			Double Ram	X	
			Other*		
			Annular		
			Blind Ram		
			Pipe Ram		
			Double Ram		
			Other*		

*Specify if additional ram is utilized.

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BOP/BOPE will be tested by an independent service company to 250 psi low and the high pressure indicated above per Onshore Order 2 requirements. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested.

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

Y	<p>Formation integrity test will be performed per Onshore Order #2.</p> <p>On Exploratory wells or on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.i.</p>
Y	<p>A variance is requested for the use of a flexible choke line from the BOP to Choke Manifold. See attached for specs and hydrostatic test chart.</p>
Y	<p>Are anchors required by manufacturer?</p>
Y	<p>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.</p> <p>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.</p> <ul style="list-style-type: none"> • 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 3M, 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.

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After running the 10-3/4" 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 7-5/8" intermediate casing with a mandrel hanger, the 13-5/8" BOP/BOPE system with a minimum rating of 10M will 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 3,000 psi WP.

Devon's proposed wellhead manufacturers will be FMC Technologies, Cactus Wellhead, or Cameron.

Devon requests a variance to use a flexible line with flanged ends between the BOP and the choke manifold (choke line). The line will be kept as straight as possible with minimal turns.

5. Mud Program

Depth		Type	Weight (ppg)	Viscosity	Water Loss
From	To				
0	1000'	FW Gel	8.6-8.8	28-34	N/C
1000'	12,650'	OBM/Cut Brine	8.6-10	34-65	N/C - 6
12,650'	22,161'	Oil Based Mud	9.5-12	45-65	N/C - 6

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
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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 Report and submitted to the BLM.
	No Logs are planned based on well control or offset log information.
	Drill stem test? If yes, explain

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	Coring? If yes, explain
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	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	Specify what type and where?
BH Pressure at deepest TVD	7200 psi
Abnormal Temperature	No

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

Hydrogen Sulfide (H2S) monitors will be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the operator will comply with the provisions of 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? Yes

1. In the event the spudder rig is unable to drill the surface holes the 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 with either OBM or cut brine 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.

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Will be pre-setting casing? Yes

1. Spudder rig will move in and drill surface hole.
 - a. Rig will utilize fresh water based mud to drill 14 3/4" 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 10-3/4" 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 pad.
6. The NMOCD will be contacted and notified 24 hours prior to commencing spudder rig operations.
7. Drilling operations will be performed with the drilling rig. At 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

- Directional Plan
 Other, describe