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

General Information
Phone: (505) 629-6116

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

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

Form C-101
August 1, 2011

Permit 380616

APPLICATION FOR PERMIT TO DRILL, RE-ENTER, DEEPEN, PLUGBACK, OR ADD A ZONE

1. Operator Name and Address EOG RESOURCES INC 5509 Champions Drive Midland, TX 79706		2. OGRID Number 7377 3. API Number 30-025-54213
4. Property Code 317298	5. Property Name MAGNOLIA 15	6. Well No. 751H

7. Surface Location

UL - Lot	Section	Township	Range	Lot Idn	Feet From	N/S Line	Feet From	E/W Line	County
D	15	26S	33E		425	N	826	W	Lea

8. Proposed Bottom Hole Location

UL - Lot	Section	Township	Range	Lot Idn	Feet From	N/S Line	Feet From	E/W Line	County
M	15	26S	33E	M	100	S	330	W	Lea

9. Pool Information

SANDERS TANK;UPPER WOLFCAMP	98097

Additional Well Information

11. Work Type New Well	12. Well Type OIL	13. Cable/Rotary	14. Lease Type State	15. Ground Level Elevation 3293
16. Multiple N	17. Proposed Depth 17906	18. Formation Wolfcamp	19. Contractor	20. Spud Date 1/22/2024
Depth to Ground water		Distance from nearest fresh water well		Distance to nearest surface water

☒ **We will be using a closed-loop system in lieu of lined pits**

21. Proposed Casing and Cement Program

Type	Hole Size	Casing Size	Casing Weight/ft	Setting Depth	Sacks of Cement	Estimated TOC
Surf	12.25	9.625	36	1076	380	0
Int1	8.75	7.625	29.7	12502	1880	0
Prod	6.75	5.5	17	17906	540	11970

Casing/Cement Program: Additional Comments

EOG respectfully requests the option to use the casing and cement program described in Design B of the drill plan. The NMOCD will be notified of EOG's election at spud.

22. Proposed Blowout Prevention Program

Type	Working Pressure	Test Pressure	Manufacturer
Double Ram	5000	3000	

23. I hereby certify that the information given above is true and complete to the best of my knowledge and belief. **I further certify I have complied with 19.15.14.9 (A) NMAC ☒ and/or 19.15.14.9 (B) NMAC ☒, if applicable.** Signature:		**OIL CONSERVATION DIVISION**	
Printed Name:	Electronically filed by Patricia Donald	Approved By:	Ward Rikala
Title:	Regulatory Specialist	Title:	Petroleum Specialist Supervisor
Email Address:	Patricia_Donald@eogresources.com	Approved Date: 1/8/2025	Expiration Date: 1/8/2027
Date: 1/2/2025	Phone: 432-488-7684	Conditions of Approval Attached	

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

WELL LOCATION AND ACREAGE DEDICATION PLAT

API Number	Pool Code	Pool Name
30-025- 54213	98097	Sanders Tank; Upper Wolfcamp

Property Code	Property Name	Well Number
317298	MAGNOLIA 15	751H

OGRID No.	Operator Name	Ground Level Elevation
7377	EOG RESOURCES, INC.	3293'

Surface Owner: ☐ State ☒ Fee ☐ Tribal ☐ Federal | Mineral Owner: ☐ State ☒ Fee ☐ Tribal ☐ Federal

Surface Location

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
D	15	26-S	33-E	-	425' N	826' W	N 32.0495724	W 103.5660602	LEA

Bottom Hole Location

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
M	15	26-S	33-E	-	100' S	330' W	N 32.0364968	W 103.5676512	LEA

Dedicated Acres	Infill or Defining Well	Defining Well API	Overlapping Spacing Unit (Y/N)	Consolidated Code
160	INFILL	30-025-43555	N	-

Order Numbers: N/A | Well Setbacks are under Common Ownership: ☐ Yes ☐ No

Kick Off Point (KOP)

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
D	15	26-S	33-E	-	50' N	330' W	N 32.0506040	W 103.5676625	LEA

First Take Point (FTP)

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
D	15	26-S	33-E	-	100' N	330' W	N 32.0504665	W 103.5676623	LEA

Last Take Point (LTP)

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the N/S	Feet from the E/W	Latitude	Longitude	County
M	15	26-S	33-E	-	100' S	330' W	N 32.0364968	W 103.5676512	LEA

Unitized Area or Area of Uniform Intrest	Spacing Unity Type	Ground Floor Elevation
-	☒ Horizontal ☐ Vertical	3318'

S:\SURVEY\EOG_MIDLAND\MAGNOLIA_15_FED_COM\FINAL_PRODUCTS\LO_MAGNOLIA_15_751H_C102.dwg SAMANTHA.ROGERS 12/17/2024 3:18 PM

OPERATOR CERTIFICATION

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

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

Star L Harrell — 1/2/2025

Signature | Date

Star L Harrell

Print Name

star_harrell@eogresources.com

E-mail Address

SURVEYORS CERTIFICATION

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true and correct to the best of my belief.

RAMON DOMINGUEZ
NEW MEXICO
24508
PROFESSIONAL SURVEYOR

Signature and Seal of Professional Surveyor | Date

12/17/2024 3:18:10 PM

Certificate Number | Date of Survey

12/08/2024

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

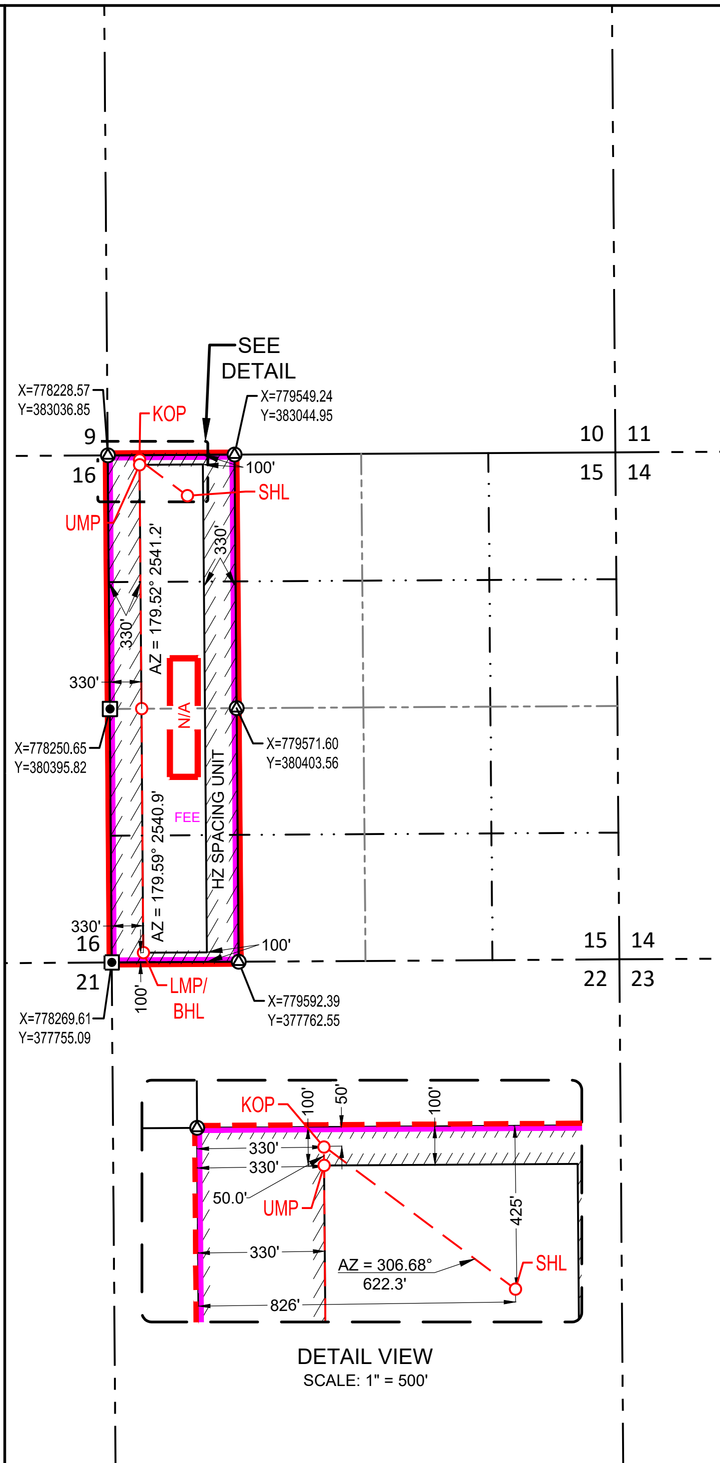
Property Name and Well Number

MAGNOLIA 15 751H

SURFACE LOCATION (SHL)
NEW MEXICO EAST
NAD 1983
X=779058 Y=382617
LAT.: N 32.0495724
LONG.: W 103.5660602
NAD 1927
X=737871 Y=382560
LAT.: N 32.0494474
LONG.: W 103.5655929
425' FNL 826' FWL

KICK OFF POINT (KOP)
NEW MEXICO EAST
NAD 1983
X=778559 Y=382989
LAT.: N 32.0506040
LONG.: W 103.5676625
NAD 1927
X=737372 Y=382932
LAT.: N 32.0504789
LONG.: W 103.5671950
50' FNL 330' FWL

UPPER MOST PERF. (UMP)
NEW MEXICO EAST
NAD 1983
X=778559 Y=382939
LAT.: N 32.0504665
LONG.: W 103.5676623
NAD 1927
X=737372 Y=382882
LAT.: N 32.0503414
LONG.: W 103.5671948
100' FNL 330' FWL



LOWER MOST PERF. (LMP)
BOTTOM HOLE LOCATION (BHL)
NEW MEXICO EAST
NAD 1983
X=778599 Y=377857
LAT.: N 32.0364968
LONG.: W 103.5676512
NAD 1927
X=737411 Y=377800
LAT.: N 32.0363717
LONG.: W 103.5671846
100' FSL 330' FWL

SURVEYORS CERTIFICATION

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true and correct to the best of my belief.

12/08/2024
Date of Survey
Signature and Seal of Professional Surveyor:

12/17/2024 3:18:11 PM

S:\SURVEYEOG_MIDLAND\MAGNOLIA_15_FED_COM\FINAL_PRODUCTS\LO_MAGNOLIA_15_751H_C102.dwg SAMANTHA ROGERS 12/17/2024 3:18 PM

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

General Information
Phone: (505) 629-6116

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

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

Form APD Conditions

Permit 380616

PERMIT CONDITIONS OF APPROVAL

Operator Name and Address:	API Number:
EOG RESOURCES INC [7377] 5509 Champions Drive Midland, TX 79706	30-025-54213
	Well: MAGNOLIA 15 #751H

OCD Reviewer	Condition
ward.rikala	Notify the OCD 24 hours prior to casing & cement.
ward.rikala	File As Drilled C-102 and a directional Survey with C-104 completion packet.
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.
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.
ward.rikala	Cement is required to circulate on both surface and intermediate1 strings of casing.
ward.rikala	A [C-103] Sub. Drilling (C-103N) is required within (10) days of spud.
ward.rikala	If cement does not circulate on any string, a Cement Bond Log (CBL) is required for that string of casing.

eog resources

EOG Batch Casing

Pad Name: Magnolia 15 Fed Com DEEP
SHL: Section 15, Township 26-S, Range 33-E, LEA County, NM

Well Name	API #	Surface		Intermediate		Production	
		MD	TVD	MD	TVD	MD	TVD
Magnolia 15 #741H	30-025-*****	1,076	1,076	12,487	12,473	17,892	12,950
Magnolia 15 #751H	30-025-*****	1,076	1,076	12,502	12,473	17,906	12,950
Magnolia 15 Fed Com #721H (205H)	30-025-49069	1,076	1,076	12,354	12,323	17,759	12,800
Magnolia 15 Fed Com #742H (204H)	30-025-49068	1,076	1,076	12,486	12,473	17,891	12,950
Magnolia 15 Fed Com #752H (404H)	30-025-49229	1,076	1,076	12,739	12,673	18,143	13,150
Magnolia 15 Fed Com #753H (305H)	30-025-49225	1,076	1,076	12,712	12,673	20,755	13,150

EOG Batch Casing

Variances

EOG requests the additional variance(s) in the attached document(s):

- EOG BLM Variance 2a - Intermediate Bradenhead Cement
- EOG BLM Variance 3d - Production Offline Cement
- EOG BLM Variance 2b - Wolfcamp Intermediate Casing Setpoint
- EOG BLM Variance 3a_b - BOP Break-test and Offline Intermediate Cement

eog resources

EOG Batch Casing

GEOLOGIC NAME OF SURFACE FORMATION:

Permian

ESTIMATED TOPS OF IMPORTANT GEOLOGICAL MARKERS:

Rustler	972'
Tamarisk Anhydrite	1,051'
Top of Salt	1,273'
Base of Salt	4,801'
Lamar	5,059'
Bell Canyon	5,077'
Cherry Canyon	6,098'
Brushy Canyon	8,064'
Bone Spring Lime	9,174'
Leonard (Avalon) Shale	9,244'
1st Bone Spring Sand	10,134'
2nd Bone Spring Shale	10,301'
2nd Bone Spring Sand	10,691'
3rd Bone Spring Carb	11,137'
3rd Bone Spring Sand	11,772'
Wolfcamp	12,217'

ESTIMATED DEPTHS OF ANTICIPATED FRESH WATER, OIL OR GAS:

Upper Permian Sands	0- 400’	Fresh Water
Bell Canyon	5,077'	Oil
Cherry Canyon	6,098'	Oil
Brushy Canyon	8,064'	Oil
Leonard (Avalon) Shale	9,244'	Oil
1st Bone Spring Sand	10,134'	Oil
2nd Bone Spring Shale	10,301'	Oil
2nd Bone Spring Sand	10,691'	Oil

No other Formations are expected to give up oil, gas or fresh water in measurable quantities. Surface fresh water sands will be protected by setting surface casing at 1,080' and circulating cement back to surface.

Intermediate Bradenhead Cement:
EOG requests variance from minimum standards to pump a two stage cement job on the intermediate casing string with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon and the second stage performed as 1000 sack bradenhead squeeze with planned cement from the Brushy Canyon to surface. If necessary, a top out consisting of Class C cement + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (2.30 yld, 12.91 ppg) will be executed as a contingency. Top of cement will be verified by Echo-meter.

EOG 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.

EOG will report to the BLM the volume of fluid (limited to 5 bbls) used to flush intermediate casing valves following backside cementing procedures.

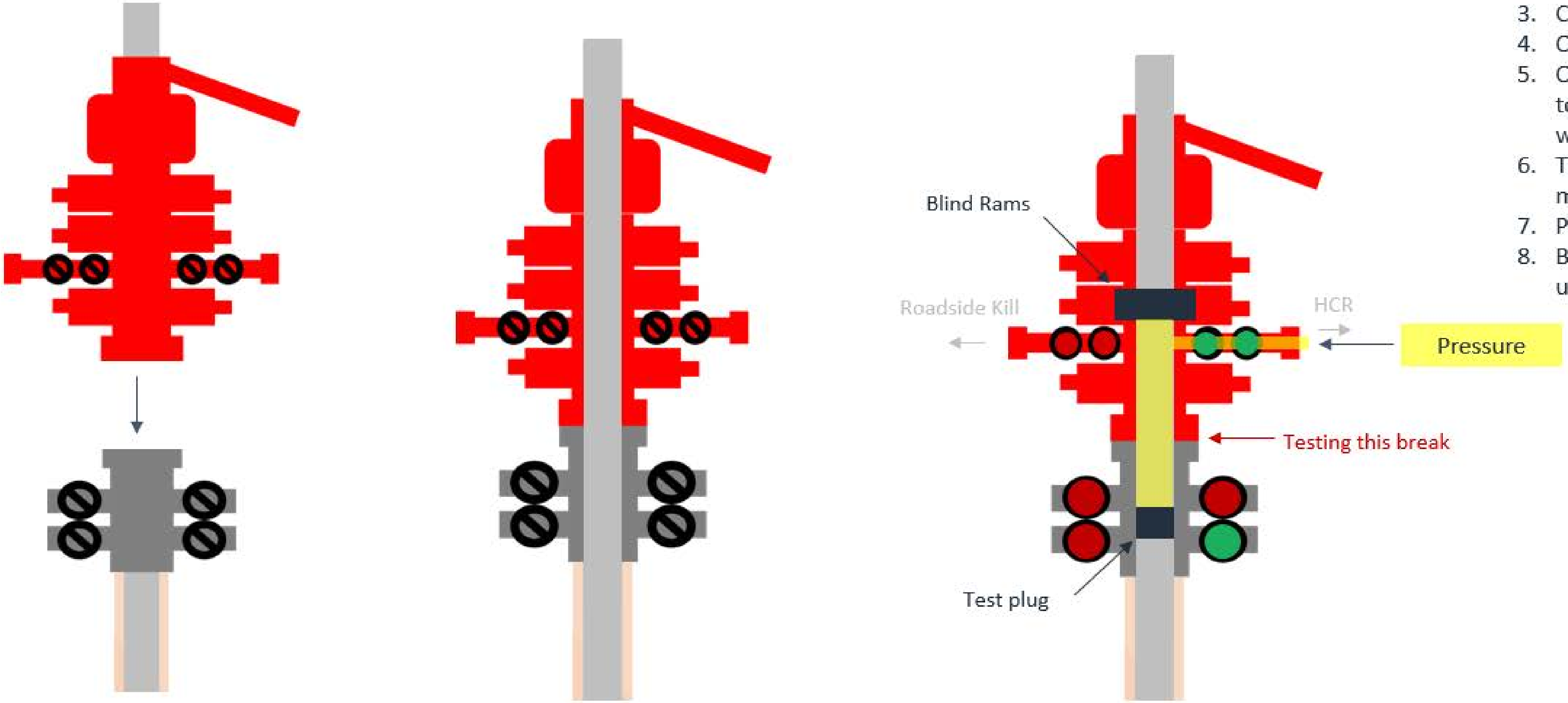
eog resources

Break-test BOP & Offline Cementing:

EOG Resources Inc. (EOG) respectfully requests a variance from the minimum standards for well control equipment testing of ECFR Title 43 Part 3172.6(b)(9)(iv) to allow a testing schedule of the blow out preventer (BOP) and blow out prevention equipment (BOPE) along with Batch Drilling & Offline cement operations to include the following:

- Full BOPE test at first installation on the pad.
- Full BOPE test every 21 days.
- This test will be conducted for 5M rated hole intervals only.
- Each rig requesting the break-test variance is capable of picking up the BOP without damaging components using winches, following API Standard 53, Well Control Equipment Systems for Drilling Wells (Fifth edition, December 2018, Annex C. Table C.4) which recognizes break testing as an acceptable practice.
- Function tests will be performed on the following BOP elements:
    - Annular à during each full BOPE test
    - Upper Pipe Rams à On trip ins where FIT required
    - Blind Rams à Every trip
    - Lower Pipe Rams à during each full BOPE test
- Break testing BOP and BOPE coupled with batch drilling operations and option to offline cement and/or remediate (if needed) any surface or intermediate sections, according to attached offline cementing support documentation.
- After the well section is secured, the BOP will be disconnected from the wellhead and walked with the rig to another well on the pad.
- TA cap will also be installed per Wellhead vendor procedure and pressure inside the casing will be monitored via the valve on the TA cap as per standard batch drilling ops.

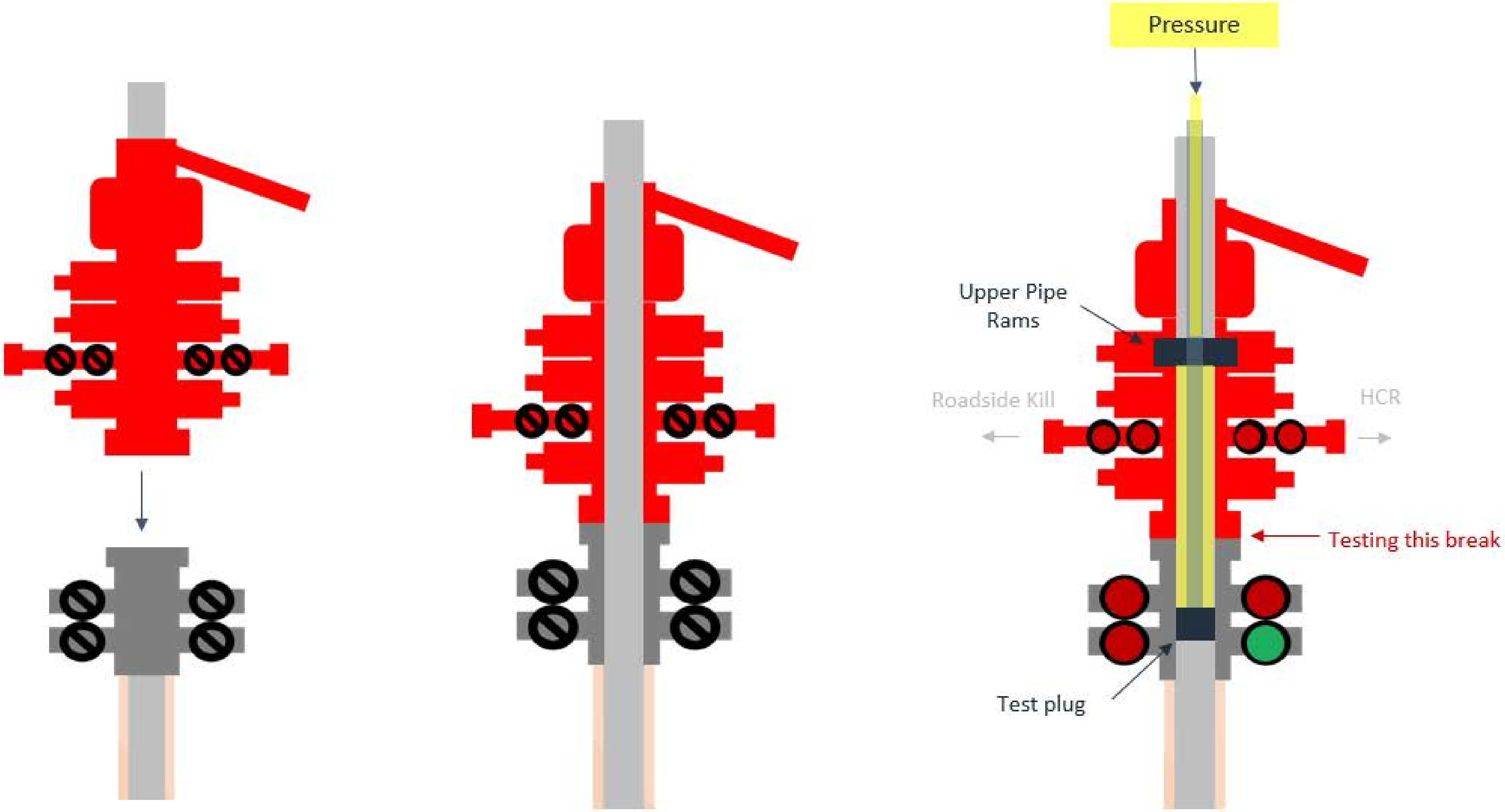
Break Test Diagram (HCR valve)



Steps

1. Set plug in wellhead (lower barrier)
2. Close Blind Rams (upper barrier)
3. Close roadside kill
4. Open HCR (pressure application)
5. Open wellhead valves below test plug to ensure if leak past test plug, pressure won't be applied to wellbore
6. Tie BOP testers high pressure line to main choke manifold crown valve
7. Pressure up to test break
8. Bleed test pressure from BOP testing unit

Break Test Diagram (Test Joint)



Steps

1. Set plug in with test joint wellhead (lower barrier)
2. Close Upper Pipe Rams (upper barrier)
3. Close roadside kill
4. Close HCR
5. Open wellhead valves below test plug to ensure if leak past test plug, pressure won't be applied to wellbore
6. Tie BOP testers high pressure line to top of test joint
7. Pressure up to test break
8. Bleed test pressure from BOP testing unit

Cement Program

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

Summarized Operational Procedure for Intermediate Casing

1. Run casing as per normal operations. While running casing, conduct negative pressure test and confirm integrity of the float equipment back pressure valves.
    a. Float equipment is equipped with two back pressure valves rated to a minimum of 5,000 psi.
2. Land production casing on mandrel hanger through BOP.
    a. If casing is unable to be landed with a mandrel hanger, then the **casing will be cemented online**.
3. Break circulation and confirm no restrictions.
    a. Ensure no blockage of float equipment and appropriate annular returns.
    b. Perform flow check to confirm well is static.
4. Set pack-off
    a. If utilizing a fluted/ported mandrel hanger, ensure well is static on the annulus and inside the casing by filling the pipe with kill weight fluid, remove landing joint, and set annular packoff through BOP. Pressure test to 5,000 psi for 10 min.
    b. If utilizing a solid mandrel hanger, ensure well is static on the annulus and inside the casing by filling the pipe with kill weight fluid. Pressure test seals to 5,000 psi for 10 min. Remove landing joint through BOP.
5. After confirmation of both annular barriers and the two casing barriers, install TA plug and pressure test to 5,000 psi for 10 min. Notify the BLM with intent to proceed with nipple down and offline cementing.
    a. Minimum 4 hrs notice.
6. With the well secured and BLM notified, nipple down BOP and secure on hydraulic carrier or cradle.
    a. Note, if any of the barriers fail to test, the BOP stack will not be nippled down until after the cement job has concluded and both lead and tail slurry have reached 500 psi.
7. Skid/Walk rig off current well.
8. Confirm well is static before removing TA Plug.
    a. Cementing operations will not proceed until well is under control. (If well is not static, notify BLM and proceed to kill)
    b. Casing outlet valves will provide access to both the casing ID and annulus. Rig or third party pump truck will kill well prior to cementing.
    c. Well control plan can be seen in Section B, Well Control Procedures.
    d. If need be, rig can be moved back over well and BOP nippled back up for any further remediation.

   e. Diagram for rig positioning relative to offline cementing can be seen in Figure 4.

9. Rig up return lines to take returns from wellhead to pits and rig choke.
   a. Test all connections and lines from wellhead to choke manifold to 5,000 psi high for 10 min.
   b. If either test fails, perform corrections and retest before proceeding.
   c. Return line schematics can be seen in Figure 3.
10. Remove TA Plug from the casing.
11. Install offline cement tool.
    a. Current offline cement tool schematics can be seen in Figure 1 (Cameron) and Figure 2 (Cactus).
12. Rig up cement head and cementing lines.
    a. Pressure test cement lines against cement head to 80% of casing burst for 10 min.
13. Break circulation on well to confirm no restrictions.
    a. If gas is present on circulation, well will be shut in and returns rerouted through gas buster.
    b. Max anticipated time before circulating with cement truck is 6 hrs.
14. Pump cement job as per plan.
    a. At plug bump, test casing to 0.22 psi/ft or 1500 psi, whichever is greater.
    b. If plug does not bump on calculated, shut down and wait 8 hrs or 500 psi compressive strength, whichever is greater before testing casing.
15. Confirm well is static and floats are holding after cement job.
    a. With floats holding and backside static:
       i. Remove cement head.
    b. If floats are leaking:
       i. Shut-in well and WOC (Wait on Cement) until tail slurry reaches 500 psi compressive strength and the casing is static prior to removing cement head.
    c. If there is flow on the backside:
       i. Shut in well and WOC until tail slurry reaches 500 psi compressive strength. Ensure that the casing is static prior to removing cement head.
16. Remove offline cement tool.
17. Install night cap with pressure gauge for monitoring.
18. Test night cap to 5,000 psi for 10 min.

Example Well Control Plan Content

A. Well Control Component Table

The table below, which covers the cementing of the **5M MASP (Maximum Allowable Surface Pressure) portion of the well**, outlines the well control component rating in use. This table, combined with the mud program, documents that two barriers to flow can be maintained at all times, independent of the BOP nippled up to the wellhead.

Intermediate hole section, 5M requirement

Component	RWP
Pack-off	10M
Casing Wellhead Valves	10M
Annular Wellhead Valves	5M
TA Plug	10M
Float Valves	5M
2” 1502 Lo-Torque Valves	15M

B. Well Control Procedures

Well control procedures are specific to the rig equipment and the operation at the time the kick occurs. Below are the minimal high-level tasks prescribed to assure a proper shut-in while circulating and cementing through the Offline Cement Adapter.

General Procedure While Circulating

1. Sound alarm (alert crew).
2. Shut down pumps.
3. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
4. Confirm shut-in.
5. Notify tool pusher/company representative.

6. Read and record the following:
    a. SICP (Shut in Casing Pressure) and AP (Annular Pressure)
    b. Pit gain
    c. Time
    d. Regroup and identify forward plan to continue circulating out kick via rig choke and mud/gas separator. Circulate and adjust mud density as needed to control well.

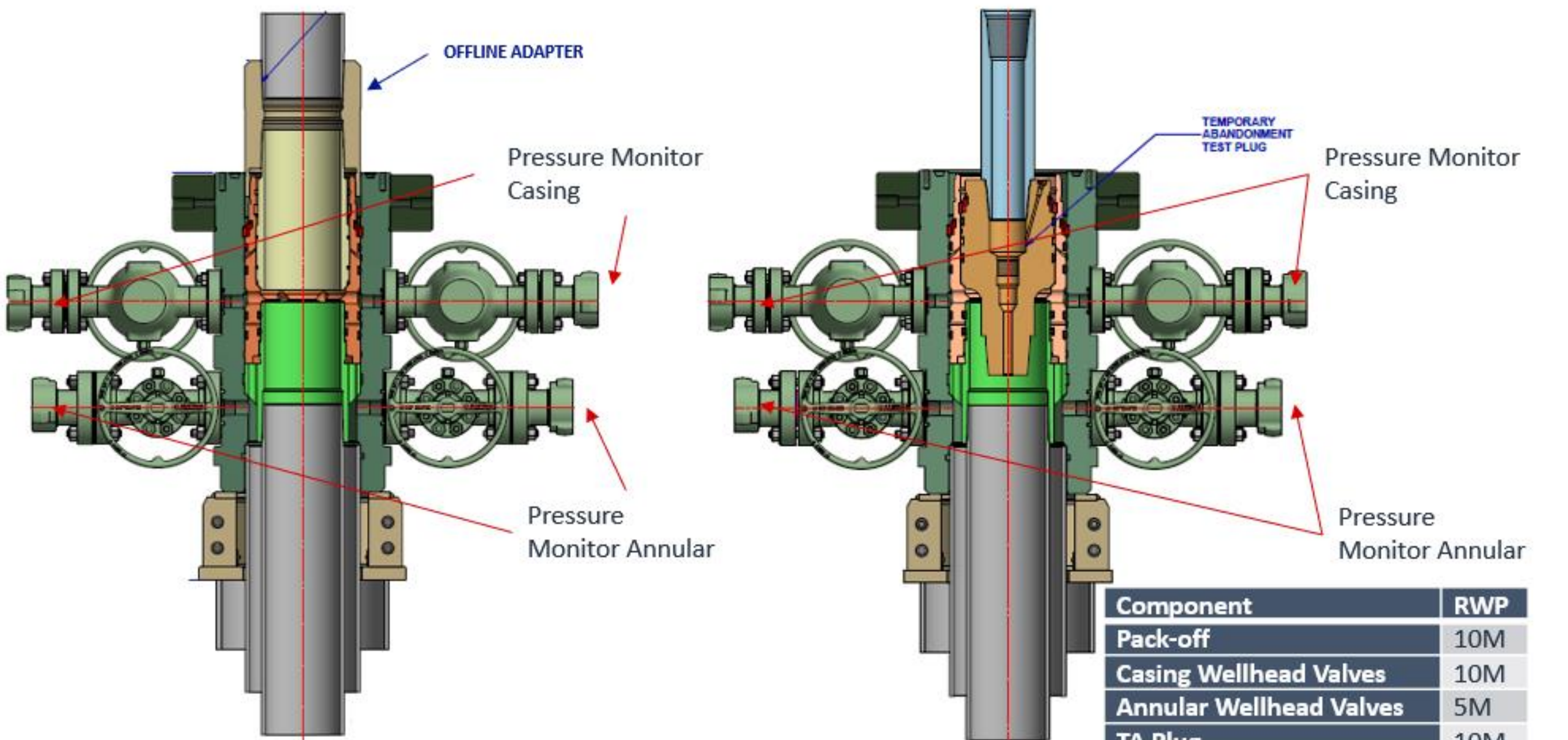
<u>General Procedure While Cementing</u>

1. Sound alarm (alert crew).
2. Shut down pumps.
3. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
4. Confirm shut-in.
5. Notify tool pusher/company representative.
6. Open rig choke and begin pumping again taking returns through choke manifold and mud/gas separator.
7. Continue to place cement until plug bumps.
8. At plug bump close rig choke and cement head.
9. Read and record the following
    a. SICP and AP
    b. Pit gain
    c. Time
    d. Shut-in annulus valves on wellhead

<u>General Procedure After Cementing</u>

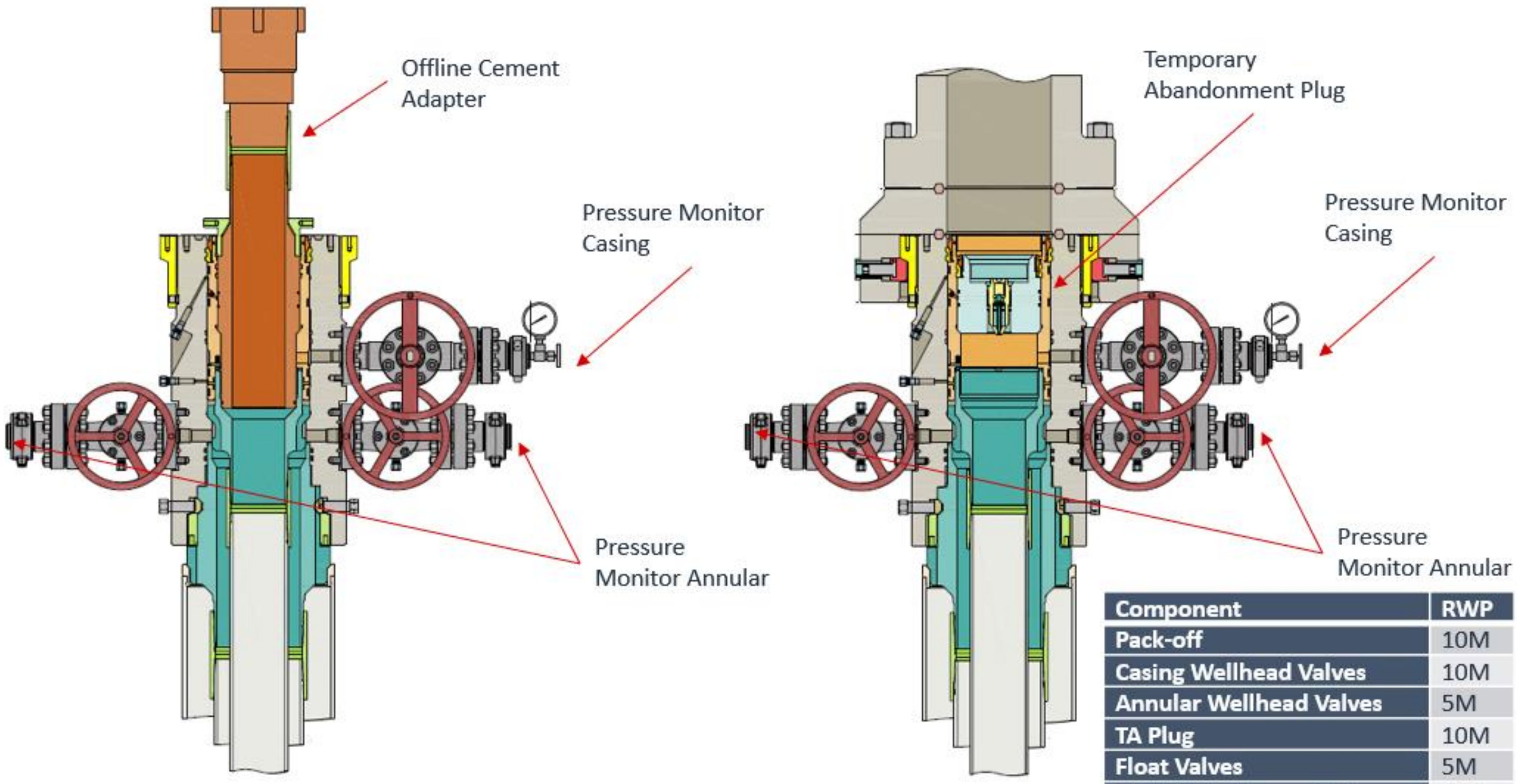
1. Sound alarm (alert crew).
2. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
3. Confirm shut-in.
4. Notify tool pusher/company representative.
5. Read and record the following:
    a. SICP and AP
    b. Pit gain
    c. Time
    d. Shut-in annulus valves on wellhead

Figure 1: Cameron TA Plug and Offline Adapter Schematic



Component	RWP
Pack-off	10M
Casing Wellhead Valves	10M
Annular Wellhead Valves	5M
TA Plug	10M
Float Valves	5M
2" 1502 Lo-Torque Valves	15M

Figure 2: Cactus TA Plug and Offline Adapter Schematic



Component	RWP
Pack-off	10M
Casing Wellhead Valves	10M
Annular Wellhead Valves	5M
TA Plug	10M
Float Valves	5M
2" 1502 Lo-Torque Valves	15M

Figure 3: Back Yard Rig Up

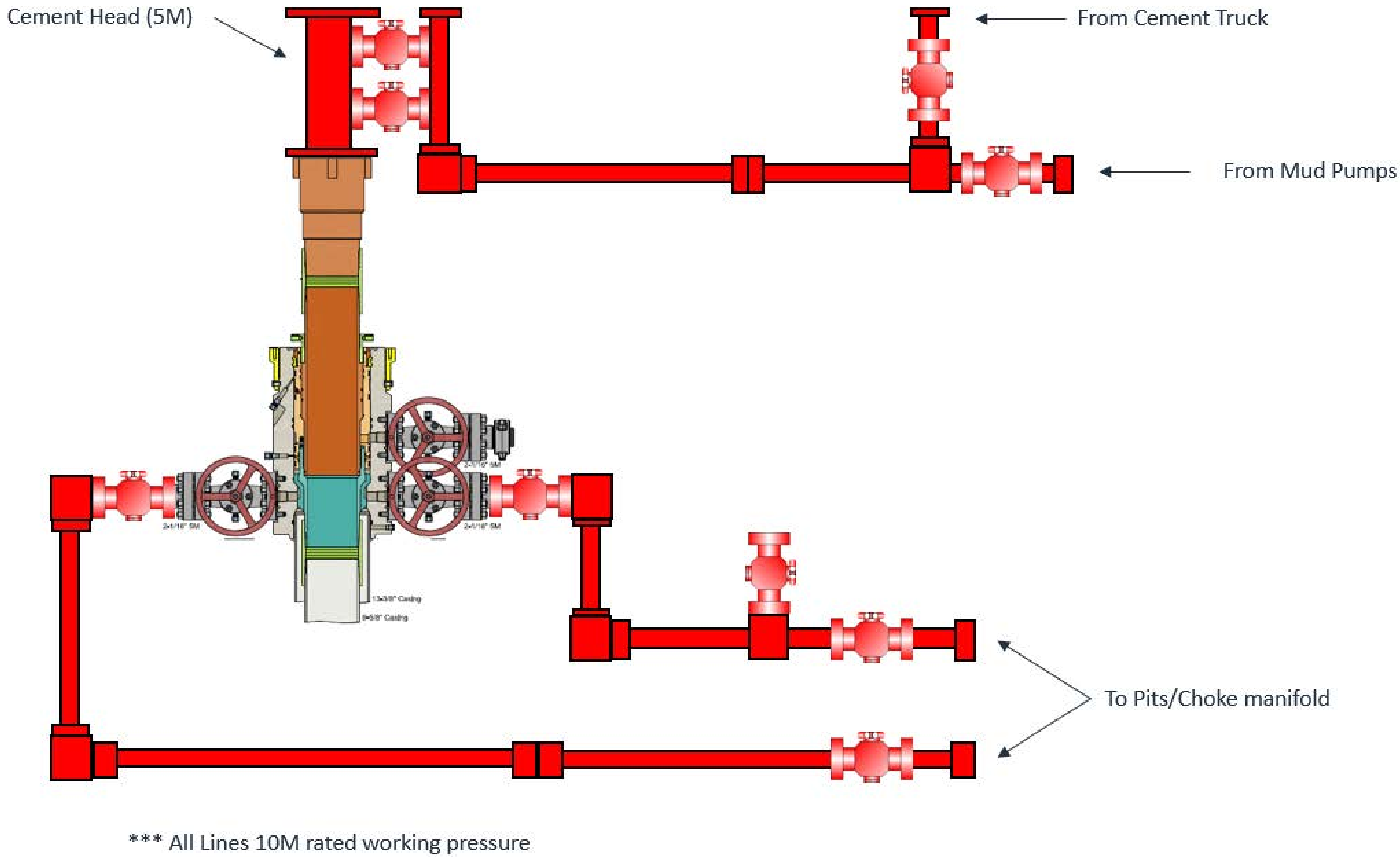
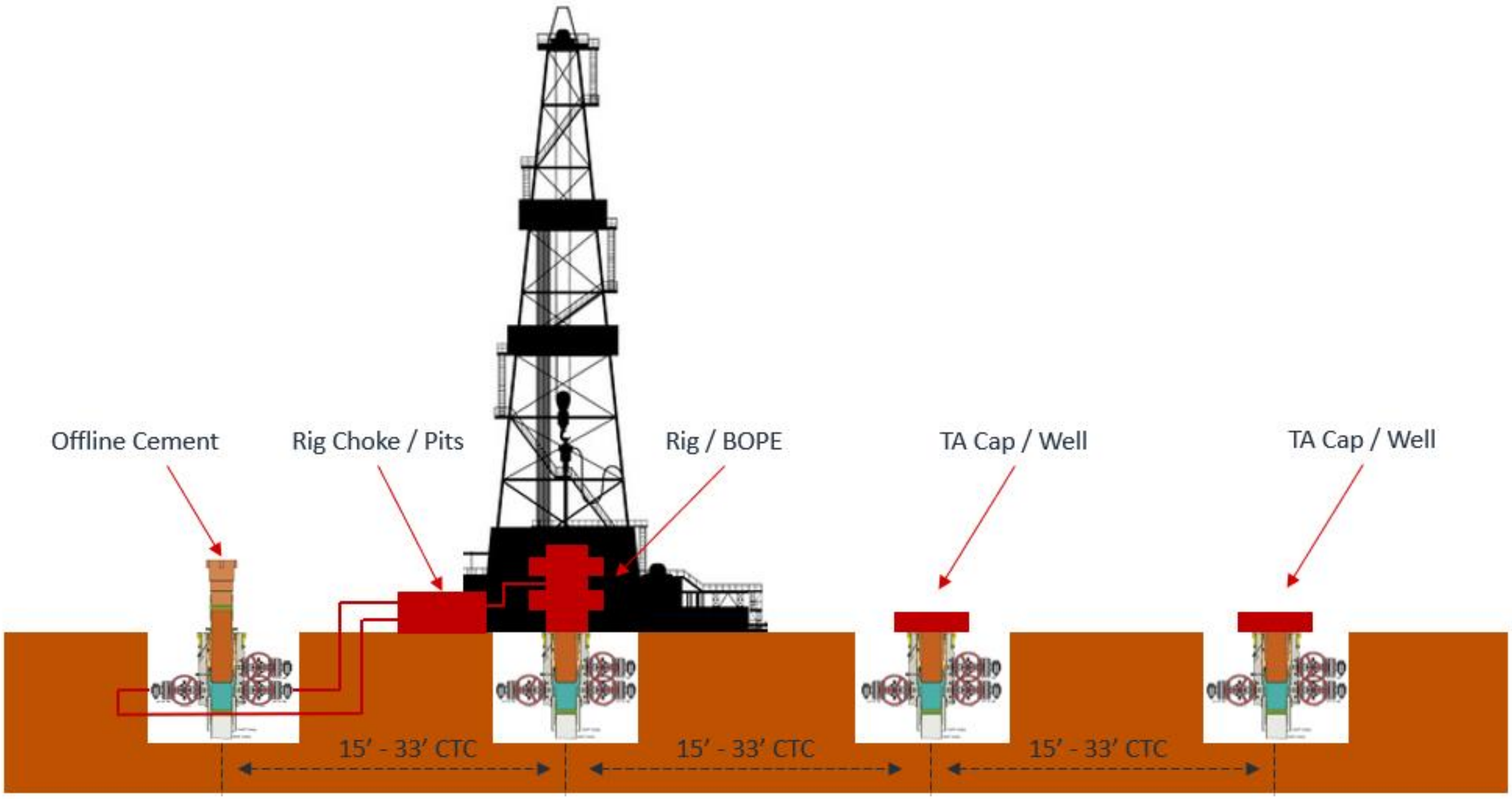


Figure 4: Rig Placement Diagram



eog resources

Shallow Target Offline Bradenhead:

EOG Resources Inc. (EOG) respectfully requests a variance from the minimum standards to allow for offline bradenhead cementing of the production string after primary cementing operations have been completed. The primary cement job will be pumped conventionally (online) to top of the Brushy Canyon and will cover the target production intervals, and after production pack-off is set and tested, bradenhead will be pumped through casing valves between the production and intermediate casings (offline). For the bradenhead stage of production cementing, the barriers remain the same for offline cementing compared to performing it online.

The bradenhead will be the primary option for production cementing. EOG also requests to have the conventional option in place to accommodate for logistical or wellbore conditions. The tie back requirements will be met if the cement is pumped conventionally, and cement volumes will be adjusted accordingly. TOC will be verified by CBL.

eog resources

Offline Production Cement Variance

EOG Offline Production Checklist

Offline Checklist

All items below must be met. If not, the production cement will be done online.

1. Offline production cement jobs must be above the Atoka formation.
2. Nothing out of the ordinary observed during drilling, tripping or casing running operations in the Production Hole Section.
3. Casing must be landed with Hanger.
4. EOG Company Man and Superintendent with Well Control certification must be present to monitor returns.
5. EOG Cement Advisor must be present to oversee the Cement Job.
6. Rig Manager is responsible for walking the rig to the next well.
7. The BOP will ***NOT*** be nippled down if:
    1. **ANY** barrier fails to test.
    2. **ANY** offset frac operations are observed within 1 mile and within the same producing horizon.
8. After all barriers test and the BLM has been notified, the BOP may be nippled down to proceed with offline operations.
9. EOG will not Drill out of the next well until Cement Operations have concluded on the offline well.

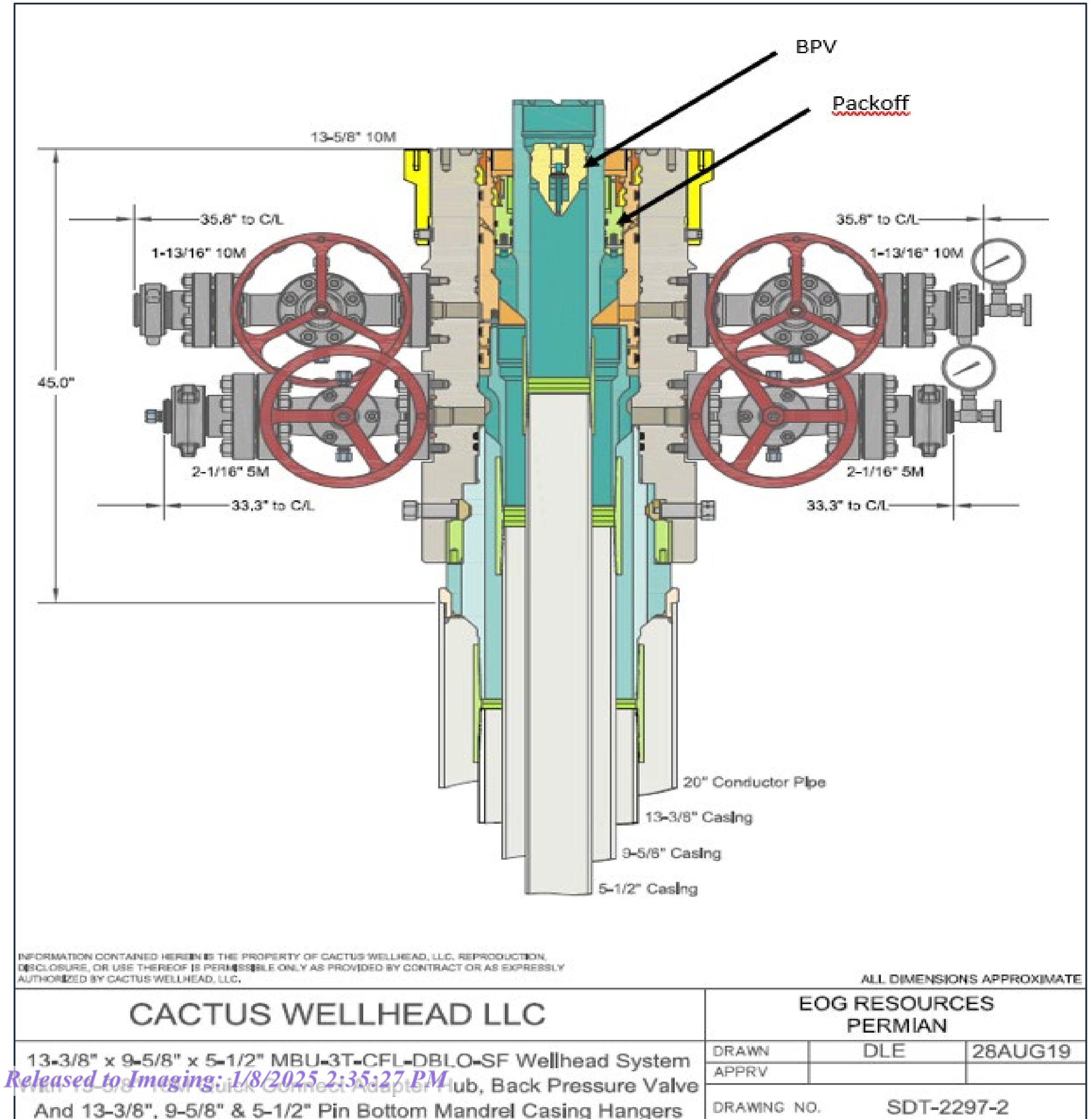
Offline Procedure

1. Run casing as per normal operations. Review EOG Offline Requirements Checklist, if the well is a candidate for Offline Cement on the Production continue following this procedure. Conduct negative pressure test while running casing and confirm integrity of the float equipment back pressure valves.
   a. Float equipment is equipped with two back pressure valves rated to 15,000 psi.
2. Land production casing on mandrel hanger.
   a. If casing is unable to be landed with a mandrel hanger, then the casing will be cemented online.
   b. If utilizing a fluted/ported mandrel hanger, ensure well is static on the annulus and inside the casing by filling the pipe with kill weight fluid, remove landing joint, and set annular packoff rated to 10,000 psi. Pressure test same to 10,000 psi.
   c. If utilizing a solid mandrel hanger, ensure well is static on the annulus and inside the casing by filling the pipe with kill weight fluid. Pressure test seals to 10,000 psi. Remove landing joint.
3. Install back pressure valve in the casing for a 3rd casing barrier.
   a. Back pressure valve rated to a minimum of 10,000 psi.
4. With the well Secured and BLM notified; Nipple down BOP and secure on hydraulic carrier or cradle and Skid/Walk rig to next well on pad.
   a. Note, if any of the barriers fail to test, the BOP stack will not be nippled down until after the cement job has concluded.
   b. Note, EOG Company Man and Cement Advisor will oversee Cementing Operations while Rig Manager walks the rig and nipples up the BOP.
   c. Note, EOG will not drill out of the subsequent well until after plug bump.
5. Install 10M Gate Valve, with Wellhead Adapter.
   a. This creates an additional barrier on the annulus and inside the casing.
   b. Gate valve rated to a minimum of 10,000 psi.
6. Test connection between Wellhead Adapter seals against hanger neck and ring gasket to 10,000 psi.
7. Remove backpressure valve from the casing.
8. Rig up cement head and cementing lines.
9. After rig up of cement head and cement lines, and confirmation of the annular barriers and casing barriers, notify the BLM with intent to proceed offline cementing.
10. Perform cement job.
11. *Note* – Procedure continued on the next page.

Offline Procedure

12. If an influx is noted during the Cement Job:
    a. It is the Company Man and Superintendent's responsibility to maintain well control.
    b. The aux manifold will be redirected to the rig's chokes.
    c. Backpressure will be held on the well with the chokes to ensure well control is maintained through the remainder of the cement job while circulating out the influx.
    d. If annular surface pressure approaches 90% tested pressure of the manifold or if circulating the influx out with the cementing pumps is not feasible, the well can be secured by closing the casing valves (10M).
    e. Once cement is in place, we will close the casing valves and confirm the well is static and floats are holding.
    f. If the floats fail, the gate valve (10M) or cement head (10M) can be closed to secure the well.
13. Confirm well is static and floats are holding after cement job.
14. Remove cement head.
15. Install back pressure valve.
16. Remove 10M Gate Valve and Wellhead Adapter.
17. Install night cap with pressure gauge for monitoring.
18. Test night cap to 5,000 psi.

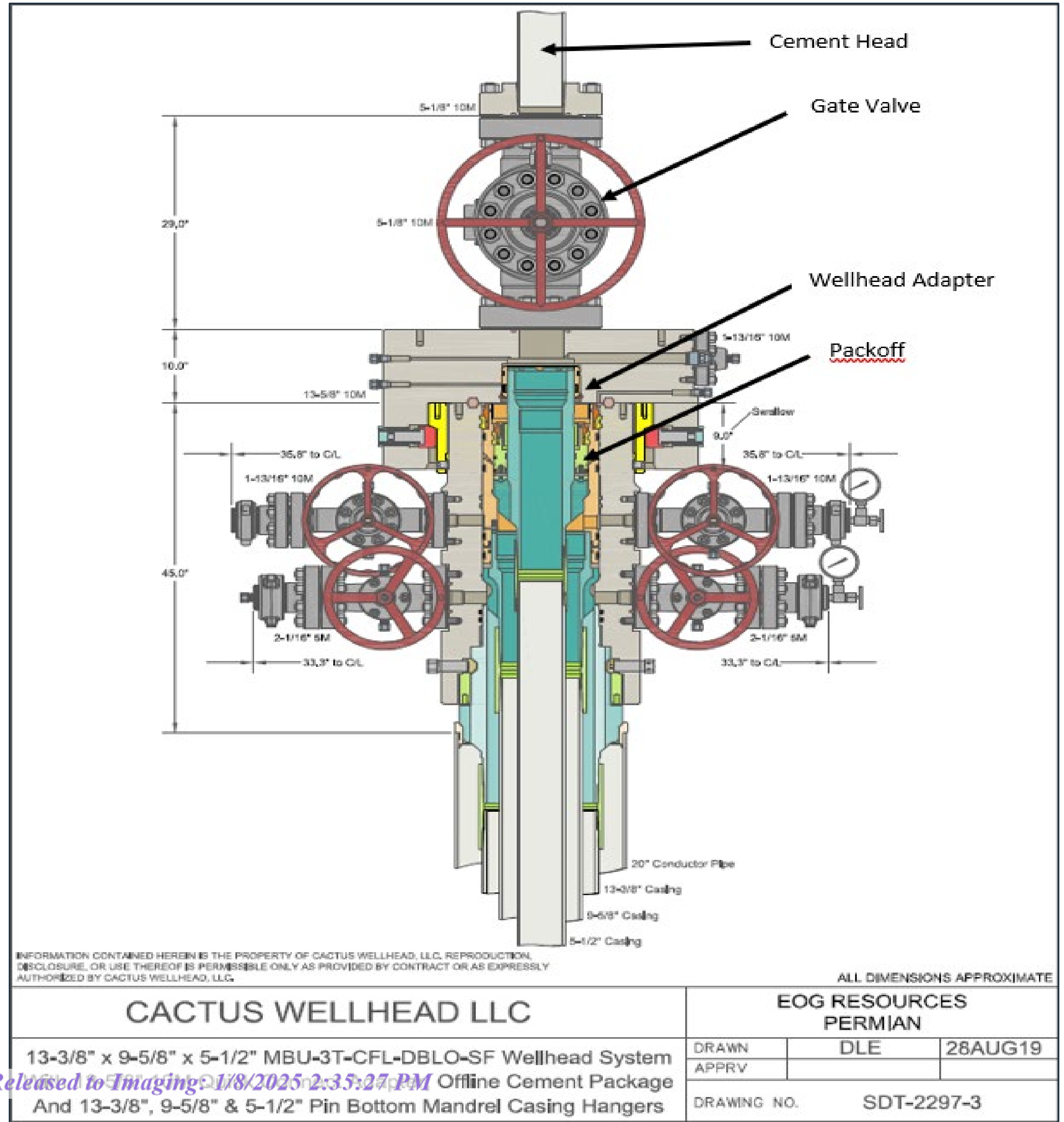
Offline Barrier Overview



Barriers in Place during removal of BOP		
Operation	Casing	Annulus
Nippling Down BOP	1. BPV 2. Hydrostatic Barrier 3. Float Valves	1. Hydrostatic Barrier 2. Mechanical 10M Packoff

Barriers in Place during Offline Cementing of Production Casing		
Operation	Casing	Annulus
Pull BPV	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical Packoff 3. 10M Wellhead Adapter
Install Cement Head	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Cement Job	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve 4. Cement Head	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Remove Cement Head	1. Float Valves 2. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Install BPV	1. Float Valves 2. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Remove 10M Gate Valve	1. Float Valves 2. BPV	1. Hydrostatic Barrier 2. Mechanical 10M Packoff
Nipple Up TA Cap	1. Float Valves 2. BPV	1. Hydrostatic Barrier 2. Mechanical 10M Packoff

Offline Barrier Overview



Barriers in Place during removal of BOP		
Operation	Casing	Annulus
Nippling Down BOP	1. BPV 2. Hydrostatic Barrier 3. Float Valves	1. Hydrostatic Barrier 2. Mechanical 10M Packoff

Barriers in Place during Offline Cementing of Production Casing		
Operation	Casing	Annulus
Pull BPV	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical Packoff 3. 10M Wellhead Adapter
Install Cement Head	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Cement Job	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve 4. Cement Head	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Remove Cement Head	1. Float Valves 2. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Install BPV	1. Float Valves 2. 10M Gate Valve	1. Hydrostatic Barrier 2. Mechanical 10M Packoff 3. 10M Wellhead Adapter
Remove 10M Gate Valve	1. Float Valves 2. BPV	1. Hydrostatic Barrier 2. Mechanical 10M Packoff
Nipple Up TA Cap	1. Float Valves 2. BPV	1. Hydrostatic Barrier 2. Mechanical 10M Packoff

More Control: Meeting/Exceeding Barrier Requirements

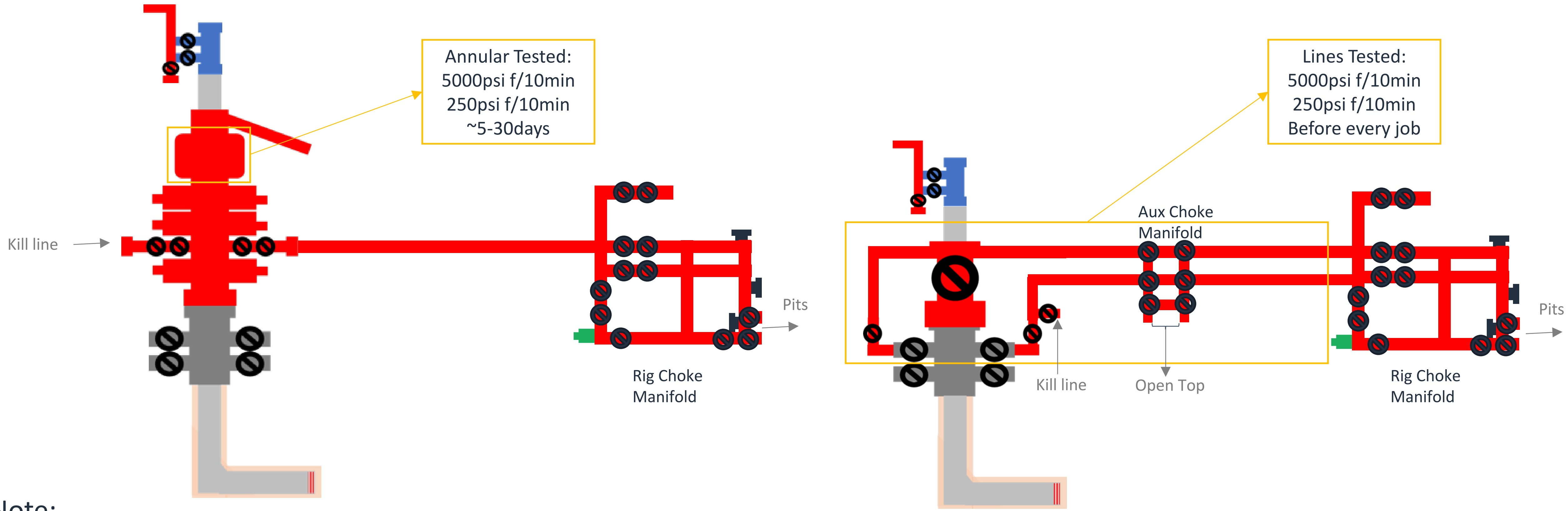
Casing Barriers – Online vs Offline		
Operation	Online	Offline
Install Cement Head	1. Hydrostatic Barrier 2. Float Valves	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve ✓
Cement Job	1. Hydrostatic Barrier 2. Float Valves 3. Cement Head	1. Hydrostatic Barrier 2. Float Valves 3. 10M Gate Valve 4. Cement Head ✓
Remove Cement Head	1. Float Valves	1. Float Valves 2. 10M Gate Valve ✓
Install BPV & Nipple Down BOP / Offline Adapter	1. Float Valves	1. Float Valves 2. BPV ✓
Nipple Up TA Cap	1. Float Valves	1. Float Valves 2. BPV ✓

Annulus Barriers – Online vs Offline		
Operation	Online	Offline
Install Cement Head	1. Hydrostatic Barrier 2. Annular 3. VBR	1. Hydrostatic Barrier 2. Mechanical Pack-off 3. 10M Wellhead Adapter ✓
Cement Job	1. Hydrostatic Barrier 2. Annular 3. VBR	1. Hydrostatic Barrier 2. Mechanical Pack-off 3. 10M Wellhead Adapter ✓
Remove Cement Head	1. Hydrostatic Barrier 2. Annular 3. VBR	1. Hydrostatic Barrier 2. Mechanical Pack-off 3. 10M Wellhead Adapter ✓
Install BPV & Nipple Down BOP / Offline Adapter	1. Hydrostatic barrier 2. Mechanical Pack-off	1. Hydrostatic Barrier 2. Mechanical Pack-off ✓
Nipple Up TA Cap	1. Hydrostatic barrier 2. Mechanical Pack-off	1. Hydrostatic Barrier 2. Mechanical Pack-off ✓

Return Rig Up Diagram

Online

Offline



Note:

1) Have the Rig's same Well Control Capabilities as Online
2) Have more flexibility with Gate Valve than with a Landing Joint through BOP
3) Never had to circulate out a kick during Offline

Received by OCD: 1/2/2025 12:45:07 PM

Salt Section Annular Clearance Variance Request

Daniel Moose

Released to Imaging: 1/8/2025 2:35:27 PM

Current Design (Salt Strings)

0.422” Annular clearance requirement

> - Casing collars shall have a minimum clearance of 0.422 inches on all sides in the hole/casing annulus, with recognition that variances can be granted for justified exceptions.

- 12.25” Hole x 9.625”40# J55/HCK55 LTC Casing
  - 1.3125” Clearance to casing OD
  - 0.8125” Clearance to coupling OD
- 9.875” Hole x 8.75” 38.5# P110 Sprint-SF Casing
  - 0.5625” Clearance to casing OD
  - 0.433” Clearance to coupling OD

Annular Clearance Variance Request

EOG request permission to allow deviation from the 0.422” annulus clearance requirement for the intermediate (salt) section from Onshore Order #2 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues

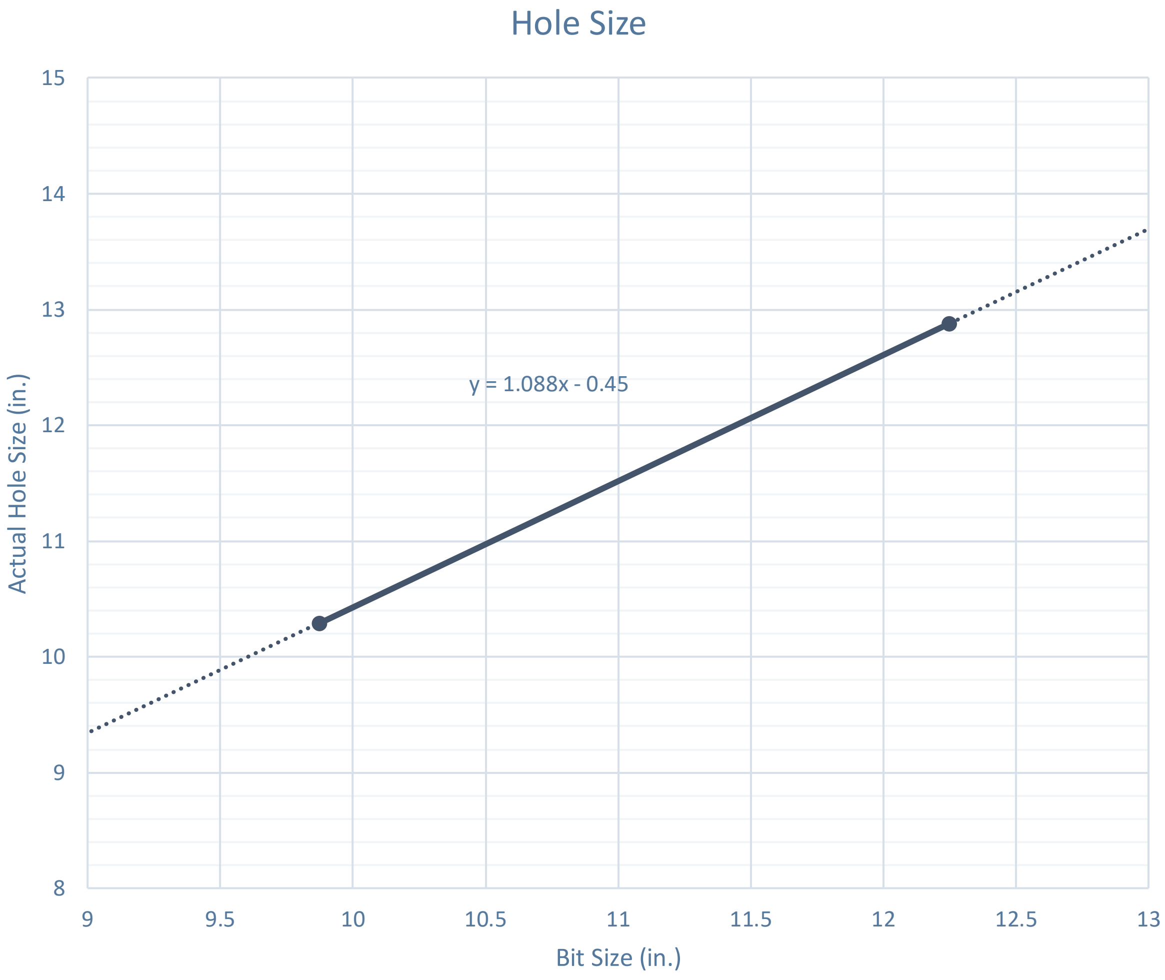
Volumetric Hole Size Calculation

Hole Size Calculations Off Cement Volumes

- Known volume of cement pumped
- Known volume of cement returned to surface
- Must not have had any losses
- Must have bumped plug

Average Hole Size

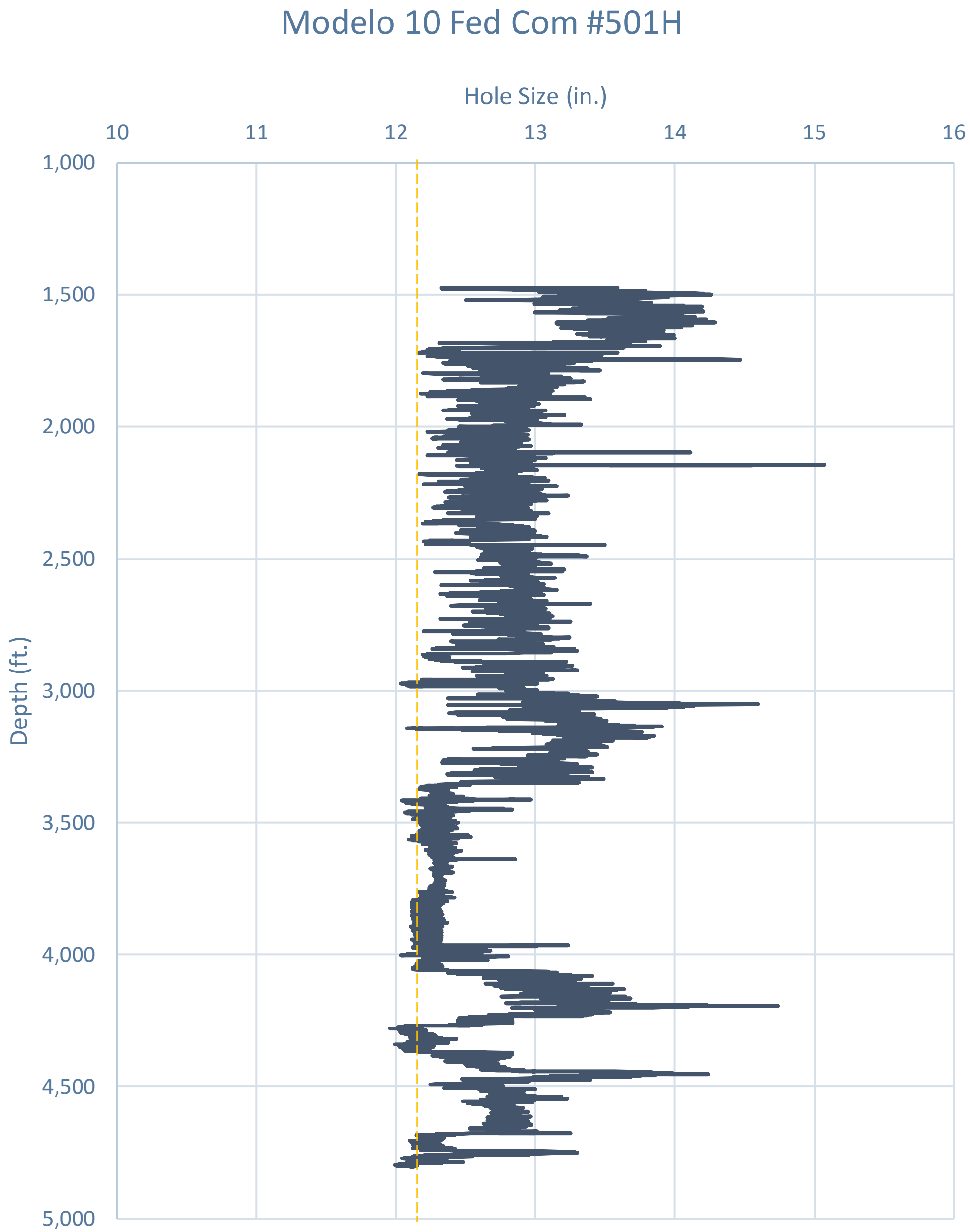
- 12.25” Hole
  - 12.88” Hole
    - 5.13% diameter increase
    - 10.52% area increase
  - 0.63” Average enlargement
  - 0.58” Median enlargement
  - 179 Well Count
- 9.875” Hole
  - 10.30” Hole
    - 4.24% diameter increase
    - 9.64% area increase
  - 0.42” Average enlargement
  - 0.46” Median enlargement
  - 11 Well Count



Caliper Hole Size (12.25”)

Average Hole Size

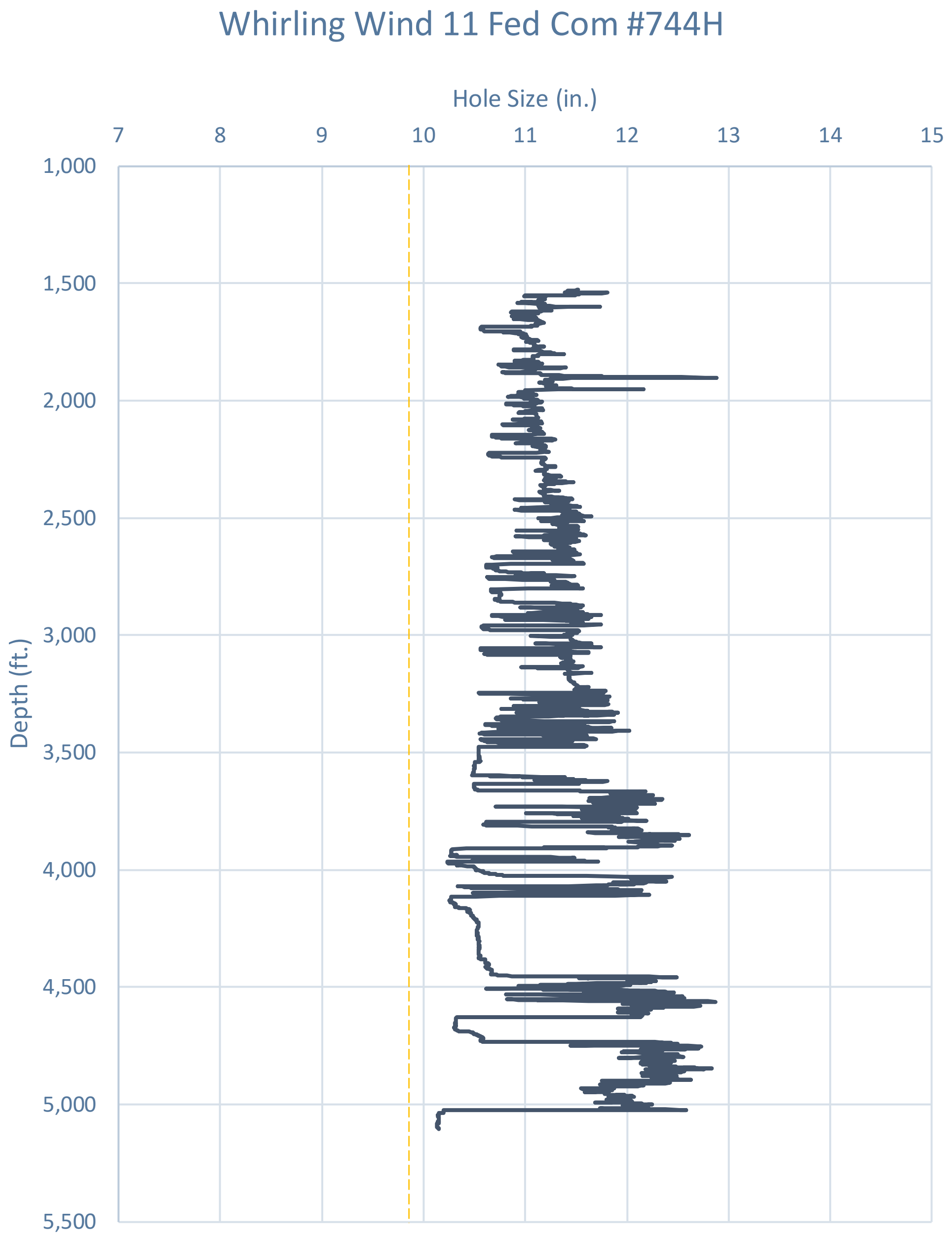
- 12.25” Bit
  - 12.76” Hole
    - 4.14% diameter increase
    - 8.44% area increase
  - 0.51” Average enlargement
  - 0.52” Median enlargement
  - Brine



Caliper Hole Size (9.875”)

Average Hole Size

- 9.875” Hole
  - 11.21” Hole
    - 13.54% diameter increase
    - 28.92% area increase
  - 1.33” Average enlargement
  - 1.30” Median enlargement
  - EnerLite



Design A

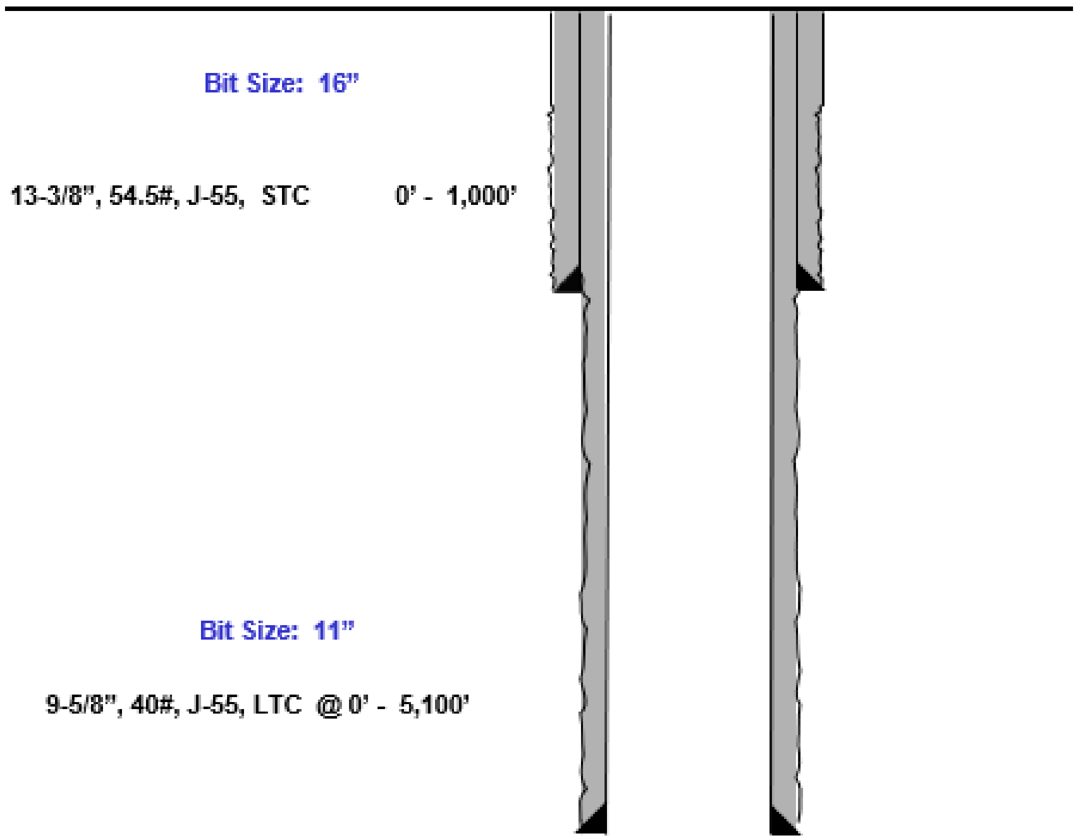
Proposed 11" Hole with 9.625" 40# J55/HCK55 LTC Casing

- 11" Bit + 0.52" Average hole enlargement = 11.52" Hole Size
  - 0.9475" Clearance to casing OD

    $= \frac{11.52 - 9.625}{2}$
  - 0.4475" Clearance to coupling OD

    $= \frac{11.52 - 10.625}{2}$
- Previous Shoe – 13.375" 54.5# J55 STC
  - 0.995" Clearance to coupling OD (~1,200' overlap)

    $= \frac{12.615 - 10.625}{2}$



Design B

Proposed 9.875" Hole with 8.625" 32# J55/P110 BTC-SC Casing

- 9.875" Bit + 0.42" Average hole enlargement = 10.295" Hole Size
    - 0.835" Clearance to casing OD

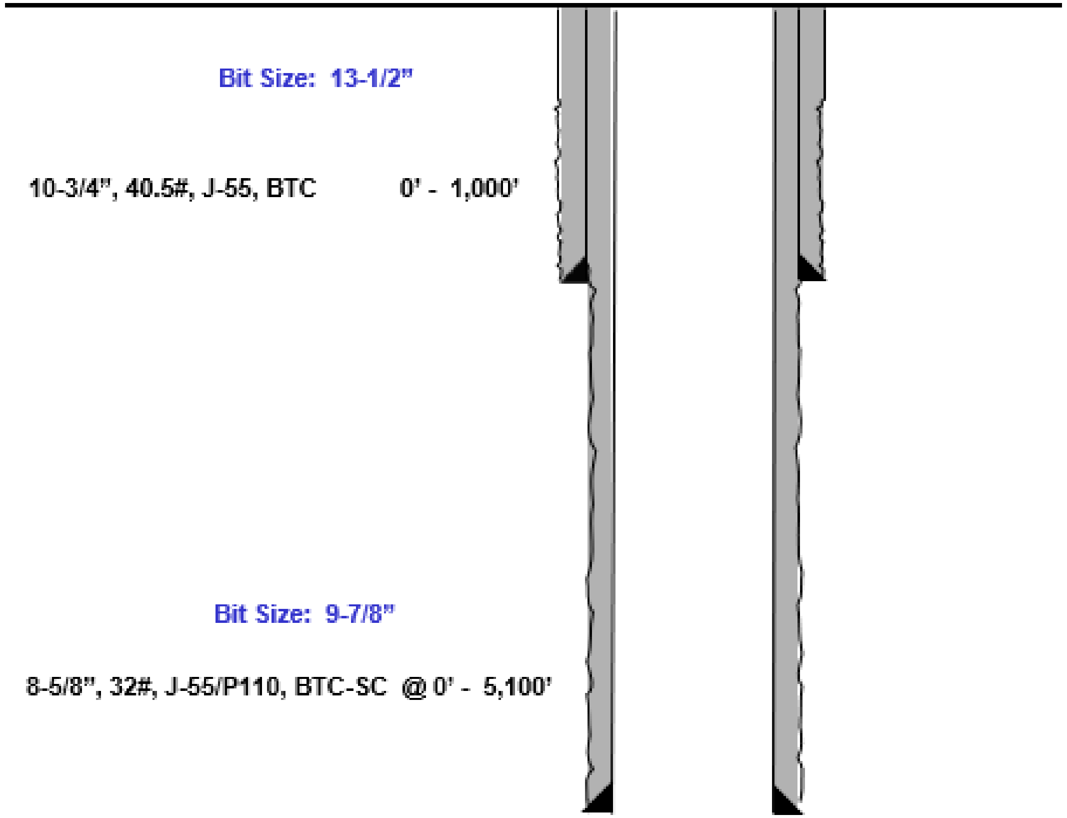
      $$= \frac{10.295 - 8.625}{2}$$

    - 0.585" Clearance to coupling OD

      $$= \frac{10.295 - 9.125}{2}$$

- Previous Shoe – 10.75" 40.5# J55 STC
    - 0.4625" Clearance to coupling OD (~1,200' overlap)

      $$= \frac{10.05 - 9.125}{2}$$



eog resources

Index

Casing Spec Sheets

PERFORMANCE DATA

API LTC
Technical Data Sheet

9.625 in | 40.00 lbs/ft | K55 HC

Tubular Parameters

Size	9.625	in	Minimum Yield	55	ksi
Nominal Weight	40.00	lbs/ft	Minimum Tensile	95	ksi
Grade	K55 HC		Yield Load	629	kips
PE Weight	38.94	lbs/ft	Tensile Load	1088	kips
Wall Thickness	0.395	in	Min. Internal Yield Pressure	3,950	psi
Nominal ID	8.835	in	Collapse Pressure	3600	psi
Drift Diameter	8.750	in			
Nom. Pipe Body Area	11.454	in²			

Connection Parameters

Connection OD	10.625	in
Coupling Length	10.500	in
Threads Per Inch	8	tpi
Standoff Thread Turns	3.50	turns
Make-Up Loss	4.750	in
Min. Internal Yield Pressure	3,950	psi

Pipe Body and API Connections Performance Data

13.375 54.50/0.380 J55

PDF

New Search »

« Back to Previous List

USC Metric

6/8/2015 10:04:37 AM

Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	**Pipe**	**BTC**	**LTC**	**STC**	
Outside Diameter	13.375	14.375	--	14.375	in.
Wall Thickness	0.380	--	--	--	in.
Inside Diameter	12.615	12.615	--	12.615	in.
Standard Drift	12.459	12.459	--	12.459	in.
Alternate Drift	--	--	--	--	in.
Nominal Linear Weight, T&C	54.50	--	--	--	lbs/ft
Plain End Weight	52.79	--	--	--	lbs/ft
Performance	**Pipe**	**BTC**	**LTC**	**STC**	
Minimum Collapse Pressure	1,130	1,130	--	1,130	psi
Minimum Internal Yield Pressure	2,740	2,740	--	2,740	psi
Minimum Pipe Body Yield Strength	853.00	--	--	--	1000 lbs
Joint Strength	--	909	--	514	1000 lbs
Reference Length	--	11,125	--	6,290	ft
Make-Up Data	**Pipe**	**BTC**	**LTC**	**STC**	
Make-Up Loss	--	4.81	--	3.50	in.
Minimum Make-Up Torque	--	--	--	3,860	ft-lbs
Maximum Make-Up Torque	--	--	--	6,430	ft-lbs

Casing Spec Sheets

Pipe Body and API Connections Performance Data

10.750 40.50/0.350 J55

PDF

New Search »

« Back to Previous List

USC Metric

6/8/2015 10:14:05 AM

Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	**Pipe**	**BTC**	**LTC**	**STC**	
Outside Diameter	10.750	11.750	--	11.750	in.
Wall Thickness	0.350	--	--	--	in.
Inside Diameter	10.050	10.050	--	10.050	in.
Standard Drift	9.894	9.894	--	9.894	in.
Alternate Drift	--	--	--	--	in.
Nominal Linear Weight, T&C	40.50	--	--	--	lbs/ft
Plain End Weight	38.91	--	--	--	lbs/ft
Performance	**Pipe**	**BTC**	**LTC**	**STC**	
Minimum Collapse Pressure	1,580	1,580	--	1,580	psi
Minimum Internal Yield Pressure	3,130	3,130	--	3,130	psi
Minimum Pipe Body Yield Strength	629.00	--	--	--	1000 lbs
Joint Strength	--	700	--	420	1000 lbs
Reference Length	--	11,522	--	6,915	ft
Make-Up Data	**Pipe**	**BTC**	**LTC**	**STC**	
Make-Up Loss	--	4.81	--	3.50	in.
Minimum Make-Up Torque	--	--	--	3,150	ft-lbs
Maximum Make-Up Torque	--	--	--	5,250	ft-lbs

vallourec

API 5CT, 10th Ed. Connection Data Sheet

O.D. (in)	WEIGHT (lb/ft)	WALL (in)	GRADE	*API DRIFT (in)	RBW %
8.625	Nominal: 32.00 Plain End: 31.13	0.352	J55	7.796	87.5

Material Properties (PE)	
Pipe	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi
Coupling	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi

Pipe Body Data (PE)	
Geometry	
Nominal ID:	7.92 inch
Nominal Area:	9.149 in^2
*Special/Alt. Drift:	7.875 inch
Performance	
Pipe Body Yield Strength:	503 kips
Collapse Resistance:	2,530 psi
Internal Yield Pressure: (API Historical)	3,930 psi

API Connection Data Coupling OD: 9.625"	
STC Performance	
STC Internal Pressure:	3,930 psi
STC Joint Strength:	372 kips
LTC Performance	
LTC Internal Pressure:	3,930 psi
LTC Joint Strength:	417 kips
SC-BTC Performance - Cplg OD = 9.125"	
BTC Internal Pressure:	3,930 psi
BTC Joint Strength:	503 kips

API Connection Torque

STC Torque (ft-lbs)

Min:	2,793	Opti:	3,724	Max:	4,655

LTC Torque (ft-lbs)

Min:	3,130	Opti:	4,174	Max:	5,217

BTC Torque (ft-lbs)

follow API guidelines regarding positional make up

*Alt. Drift will be used unless API Drift is specified on order.

**If above API connections do not suit your needs, VAM® premium connections are available up to 100% of pipe body ratings.

Rev 3, 7/30/2021 10/21/2022 15:24

eog resources

EOG Blanket Casing Design Variance

EOG respectfully requests the drill plans in the attached document 'EOG Alternate Casing Designs – BLM APPROVED' be added to the COA's for this well. These designs have been approved by the BLM down to the TVDs listed below and will allow EOG to run alternate casing designs for this well if necessary.

The designs and associated details listed are the "worst case scenario" boundaries for design safety factors. Location and lithology have NOT been accounted for in these designs. The specific well details will be based on the APD/Sundry package and the information listed in the COA.

The mud program will not change from the original design for this well. Summary of the mud programs for both shallow and deep targets are listed at the end of this document. If the target is changing, a sundry will be filed to update the casing design and mud/cement programs.

Cement volumes listed in this document are for reference only. The cement volumes for the specific well will be adjusted to ensure cement tops meet BLM requirements as listed in the COA and to allow bradenhead cementing when applicable.

This blanket document only applies to wells with three string designs outside of Potash and Capitan Reef boundaries.

Shallow Design Boundary Conditions

	Deepest MD (ft)	Deepest TVD (ft)	Max Inc (deg)	Max DLS (°/100usft)
Surface	2030	2030	0	0
Intermediate	7793	5650	40	8
Production	28578	12000	90	25

eog resources

Shallow Design A

4. CASING PROGRAM

Hole Size	Interval MD From (ft)	Interval MD To (ft)	Interval TVD From (ft)	Interval TVD To (ft)	Csg OD	Weight	Grade	Conn
16"	0	2,161	0	2,030	13-3/8"	54.5#	J-55	STC
11"	0	7,951	0	5,650	9-5/8"	40#	J-55	LTC
6-3/4"	0	29,353	0	12,000	5-1/2"	20#	P110-EC	DWC/C IS MS

Hole will be full during casing run for well control and tensile SF factor. Casing will be kept at least half full during run for this design to meet BLM collapse SF requirement. External pressure will be reviewed prior to conducting casing pressure tests to ensure that 70% of the yield is not exceeded.

Variance is requested to waive the centralizer requirements for the 9-5/8" casing in the 11" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 11" hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive any centralizer requirements for the 5-1/2" casing in the 6-3/4" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 6-3/4" hole interval to maximize cement bond and zonal isolation.

EOG requests permission to allow deviation from the 0.422’’ annulus clearance requirement for the intermediate (salt) section from Title 43 CFR Part 3170 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues.

5. CEMENTING PROGRAM:

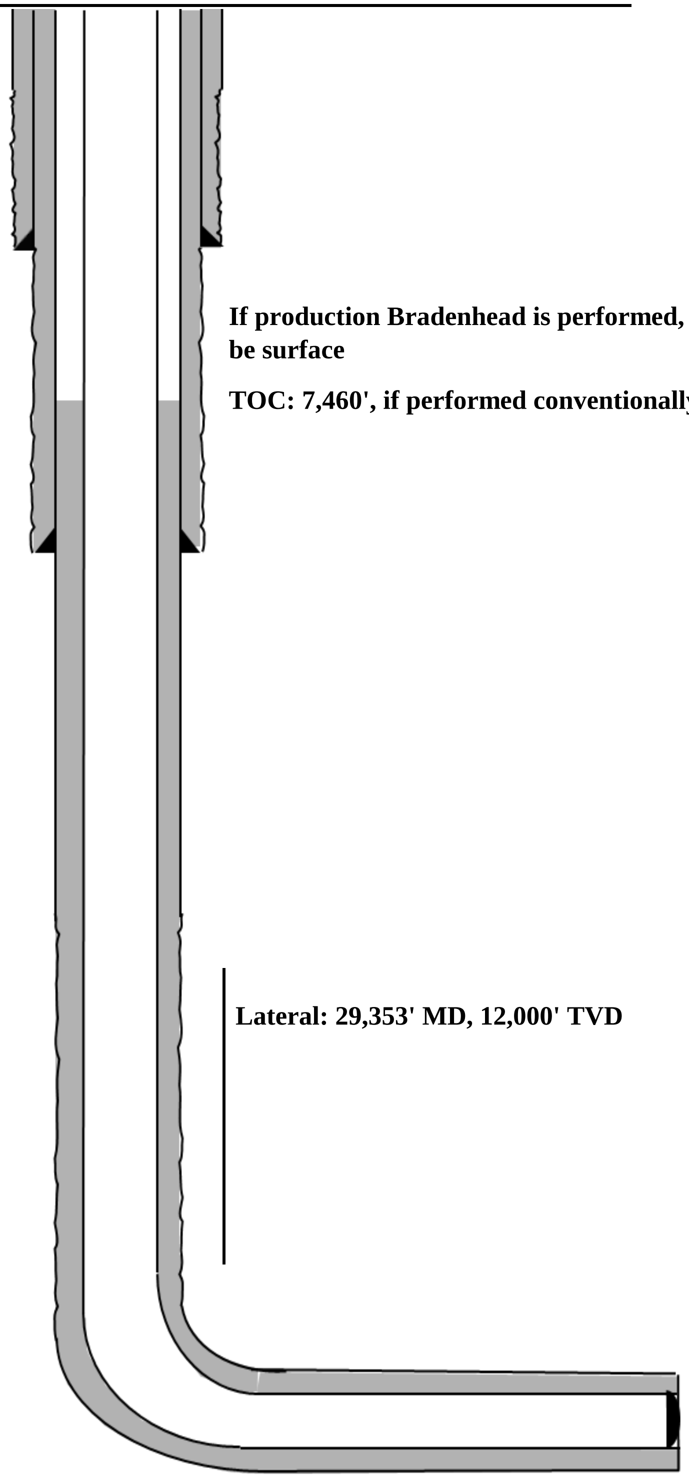
Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 13-3/8''	570	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	160	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830’)
8,050' 9-5/8''	760	12.7	2.22	Lead: Class C/H + 10% NaCl + 6% Bentonite Gel + 3% MagOx (TOC @ Surface)
	250	14.8	1.32	Tail: Class C/H + 10% NaCL + 3% MagOx (TOC @ 6360')
29,353' 5-1/2''	1000	14.8	1.32	Bradenhead squeeze: Class C/H + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
	1480	13.2	1.52	Tail: Class C/H + 5% NEX-020 + 0.2% NAC-102 + 0.15% NAS-725 + 0.5% NFL-549 + 0.2% NFP-703 + 1% NBE-737 + 0.3% NRT-241 (TOC @ Top of Brushy)

eog resources

Shallow Design A

Proposed Wellbore

KB: 3558'
GL: 3533'



Bit Size: 16''
13-3/8'', 54.5#, J-55, STC
@ 0' - 2,030'

If production Bradenhead is performed, TOC will be surface

TOC: 7,460', if performed conventionally.

Bit Size: 11''
9-5/8'', 40.#, J-55, LTC
@ 0' - 7,960'

Lateral: 29,353' MD, 12,000' TVD

Bit Size: 6-3/4''
5-1/2'', 20.#, P110-EC, DWC/C IS MS
@ 0' - 29,353'

KOP: 13,378' MD, 11,771' TVD
EOC: 13,738' MD, 12,000' TVD

Bit Size: 6-3/4''

StressCheck - [Triaxial Results - Shallow 3.0 Mile - Big Hole 1]

File Edit Wellbore Tubular View Composer Tools Window Help

9 5/8" Intermediate Casing

Pressure Test

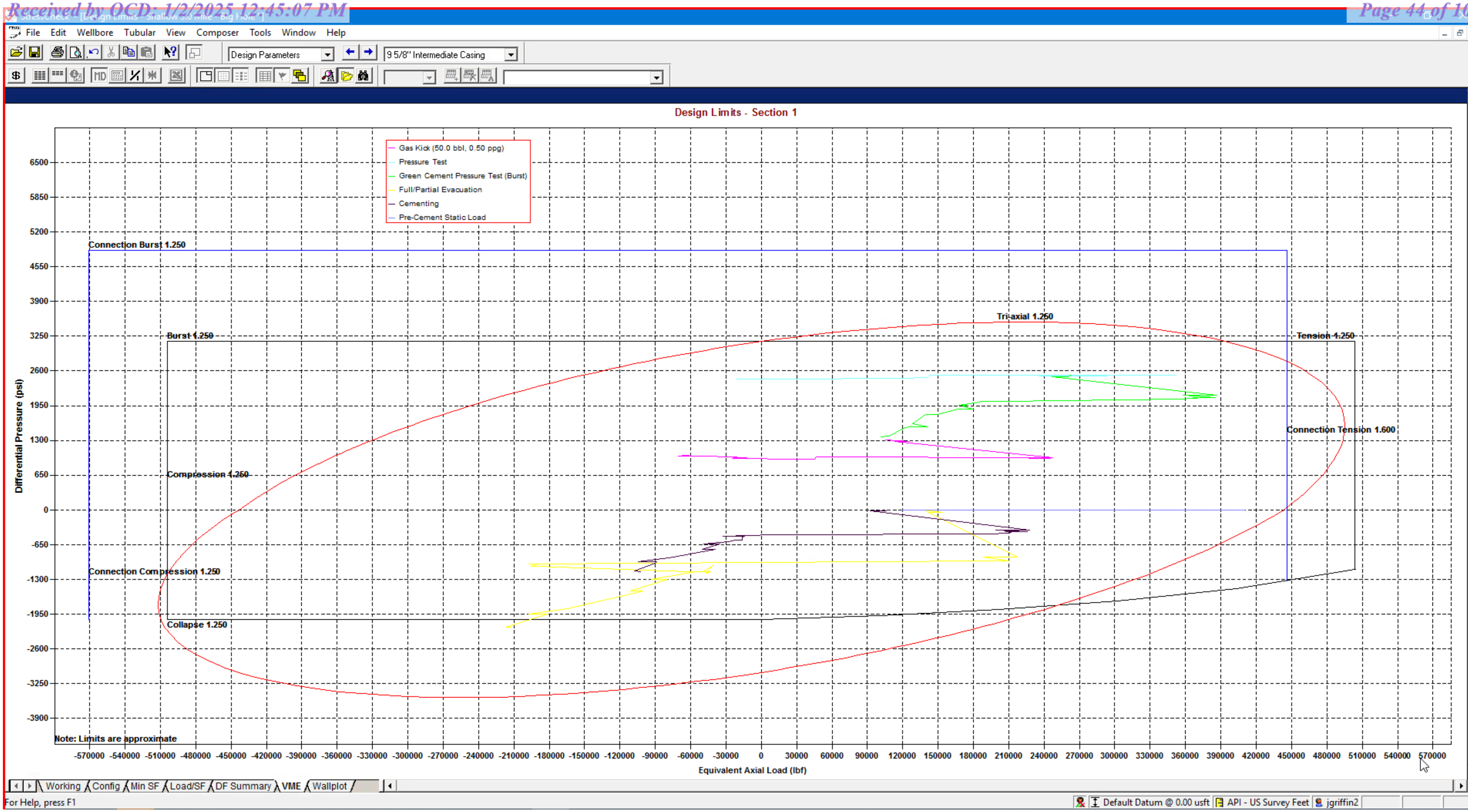
Triaxial Results

	Depth (MD) (usft)	Axial Force (lbf) Apparent (w/Bending)	Axial Force (lbf) Actual (w/o Bending)	Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor Triaxial	Absolute Safety Factor Burst	Absolute Safety Factor Collapse (V)	Absolute Safety Factor Axial	Temperature (°F)	Pressure (psi) Internal	Pressure (psi) External	Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (usft)
1	0	252987	228954	253140	2098.2	1.69	1.58	N/A	2.82 F	70.00	2500.00	0.00	N/A	N/A
2	100	247735	223702	248466	2098.2	1.69	1.58	N/A	2.88 F	71.10	2543.63	43.63		
3	100	234996	223701	235716	986.2	1.71	1.58	N/A	3.04 F	71.10	2543.64	43.64		
4	1700	341565	139667	352253	17627.2	1.53	1.57	N/A	2.09 F	88.70	3241.64	741.64		
5	1700	312979	139666	323488	15131.5	1.58	1.57	N/A	2.28 F	88.70	3241.65	741.65		
6	1850	336881	132027	348440	17885.2	1.51	1.57	N/A	2.12 F	90.29	3305.05	805.05		
7	1850	318549	132027	329984	16284.8	1.54	1.57	N/A	2.24 F	90.29	3305.06	805.06		
8	1950	320468	127243	332475	16869.9	1.52	1.57	N/A	2.23 F	91.30	3344.87	844.87		
9	1950	312802	127243	324756	16200.7	1.53	1.57	N/A	2.28 F	91.30	3344.87	844.87		
10	2050	307858	122773	320295	16159.3	1.52	1.57	N/A	2.32 F	92.23	3381.89	881.89		
11	2050	303560	122772	315965	15784.1	1.53	1.57	N/A	2.35 F	92.23	3381.89	881.89		
12	2300	151294	112633	163658	3375.4	1.71	1.57	N/A	4.72 F	94.35	3466.13	966.13		
13	2300	132741	112633	144956	1755.6	1.72	1.57	N/A	5.38 F	94.35	3466.14	966.14		
14	2370	129966	109858	142452	1755.6	1.72	1.57	N/A	5.49 F	94.94	3489.28	989.28		
15	2370	127909	107800	140922	1755.6	1.75	1.60	N/A	5.58 F	94.94	3489.29	1036.40		
16	2700	105515	94232	119785	985.1	1.75	1.60	N/A	6.77 F	97.73	3599.97	1152.35		
17	2700	111680	94231	126006	1523.4	1.75	1.60	N/A	6.39 F	97.73	3599.97	1152.35		
18	3100	110766	77783	126839	2879.6	1.71	1.60	N/A	6.44 F	101.11	3734.23	1293.00		
19	3100	97392	77783	113331	1712.1	1.73	1.60	N/A	7.33 F	101.11	3734.23	1293.01		
20	3700	71565	53303	89806	1594.4	1.70	1.61	N/A	9.97 F	106.15	3934.24	1502.54		
21	3700	60887	53302	79004	662.3	1.71	1.61	N/A	11.72 F	106.16	3934.25	1502.55		
22	4650	34671	14219	56495	1785.6	1.64	1.61	N/A	20.59 F	114.20	4253.37	1836.86		
23	4900	44595	4828	67626	3472.0	1.59	1.61	N/A	16.01 F	116.32	4337.37	1924.87		
24	4900	28975	4828	51775	2108.2	1.62	1.61	N/A	24.64 F	116.32	4337.38	1924.87		
25	5029	22103	34	45340	1926.8	1.61	1.61	N/A	32.30 F	117.40	4380.40	1969.94		
26	5029	22102	33	45339	1926.8	1.61	1.61	N/A	32.30 F	117.40	4380.41	1969.95		
27	5600	-45329	-21341	-20805	2094.3	1.57	1.62	N/A	(13.67)	122.23	4572.11	2170.78		
28	5650	-40465	-23210	-15657	1506.5	1.58	1.62	N/A	(15.31)	122.66	4588.87	2188.34		
29														
30	F	Conn Fracture												
31	( )	Compression												
32	(V)	Vector Collapse Safety Factor												
33														

Working / Config / Min SF / Load/SF / DF Summary / VME / Wallplot

For Help, press F1 | Default Datum @ 0.00 usft | API - US Survey Feet | jqriffin2

9-5/8" Intermediate Casing Pressure Test:
Internal Profile based off Surface Pressure + Hydrostatic: 4589 psi
External Profile based off Pore Pressure: 2188 psi

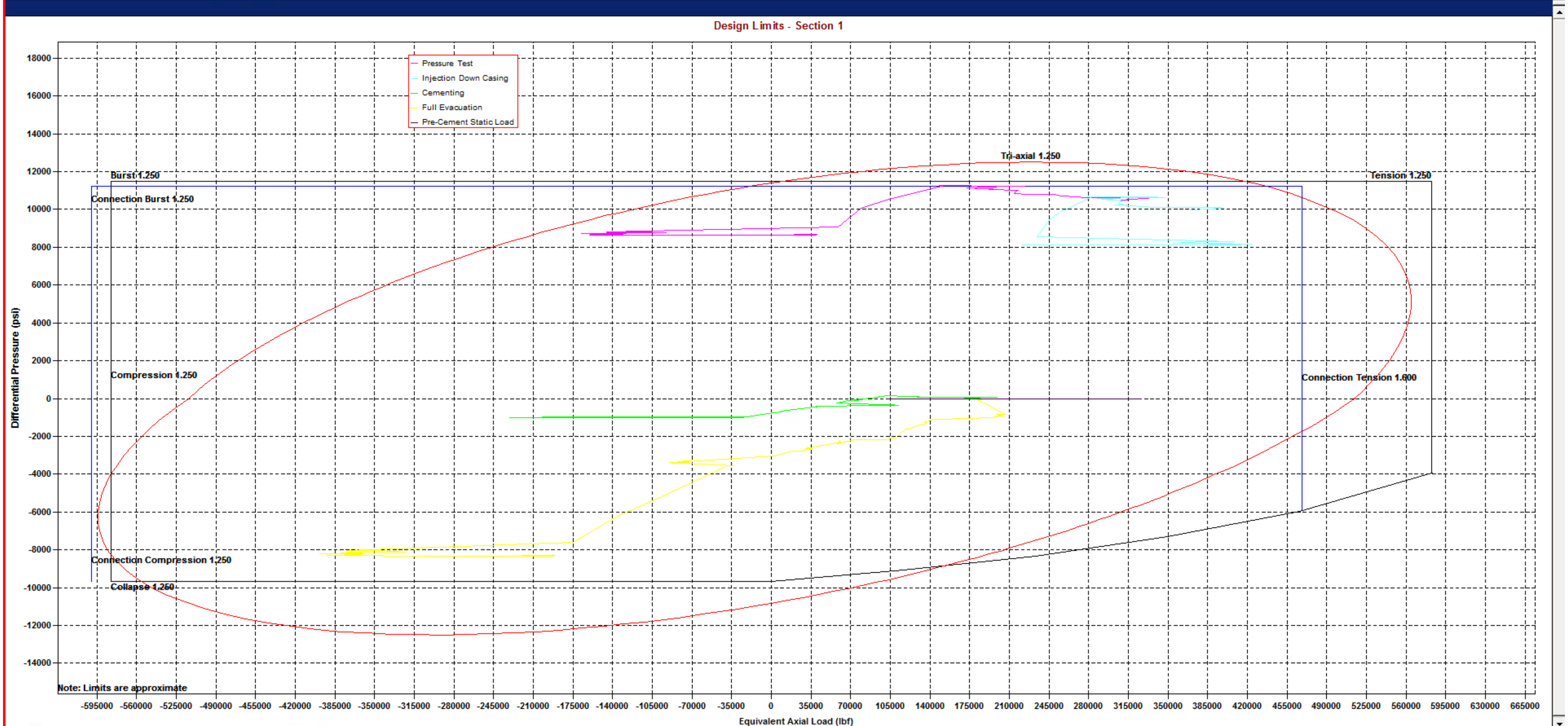


StressCheck - [String Summary - Shallow 3.0 Mile - Big Hole *]

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs) Burst	Collapse (V)	Axial	Triaxial	Design Cost ($)
1	Intermediate Casing	9 5/8", 40.000 ppf, J-55	BTC, J-55	0.0-5650.0	8.750 A	1.57	1.59	1.80 F	1.35	98,141
2										Total = 98,141
3										
4	F Conn Fracture									
5	A Alternate Drift									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 9-5/8" 40# Intermediate Casing. Passes all Burst, Collapse and Tensile design criteria.



StressCheck - [String Summary - Shallow 3.0 Mile]

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs) Burst	Collapse (V)	Axial	Triaxial	Design Cost ($)
1	Production Casing	5 1/2", 20.000 ppf, P110 ICY	BTC, P110 ICY	0.0-28578.0	4.653	1.27	1.47	1.90 F	1.35	446,902
2										Total = 446,902
3										
4	F Conn Fracture									
5	( ) Compression									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 5-1/2" 20# Production Casing with a 125ksi Control Yield. Passes all Burst, Collapse and Tensile design criteria.

eog resources

Shallow Design B

4. CASING PROGRAM

Hole Size	Interval MD From (ft)	Interval MD To (ft)	Interval TVD From (ft)	Interval TVD To (ft)	Csg OD	Weight	Grade	Conn
13-1/2"	0	2,161	0	2,030	10-3/4"	40.5#	J-55	STC
9-7/8"	0	7,951	0	5,650	8-5/8"	32#	J-55	BTC-SC
6-3/4"	0	29,353	0	12,000	5-1/2"	20#	P110-EC	DWC/C IS MS

Hole will be full during casing run for well control and tensile SF factor. Casing will be kept at least half full during run for this design to meet BLM collapse SF requirement. External pressure will be reviewed prior to conducting casing pressure tests to ensure that 70% of the yield is not exceeded.

Variance is requested to waive the centralizer requirements for the 8-5/8" casing in the 9-7/8" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 9-7/8" hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive any centralizer requirements for the 5-1/2" casing in the 6-3/4" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 6-3/4" hole interval to maximize cement bond and zonal isolation.

EOG requests permission to allow deviation from the 0.422’’ annulus clearance requirement for the intermediate (salt) section from Title 43 CFR Part 3170 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues.

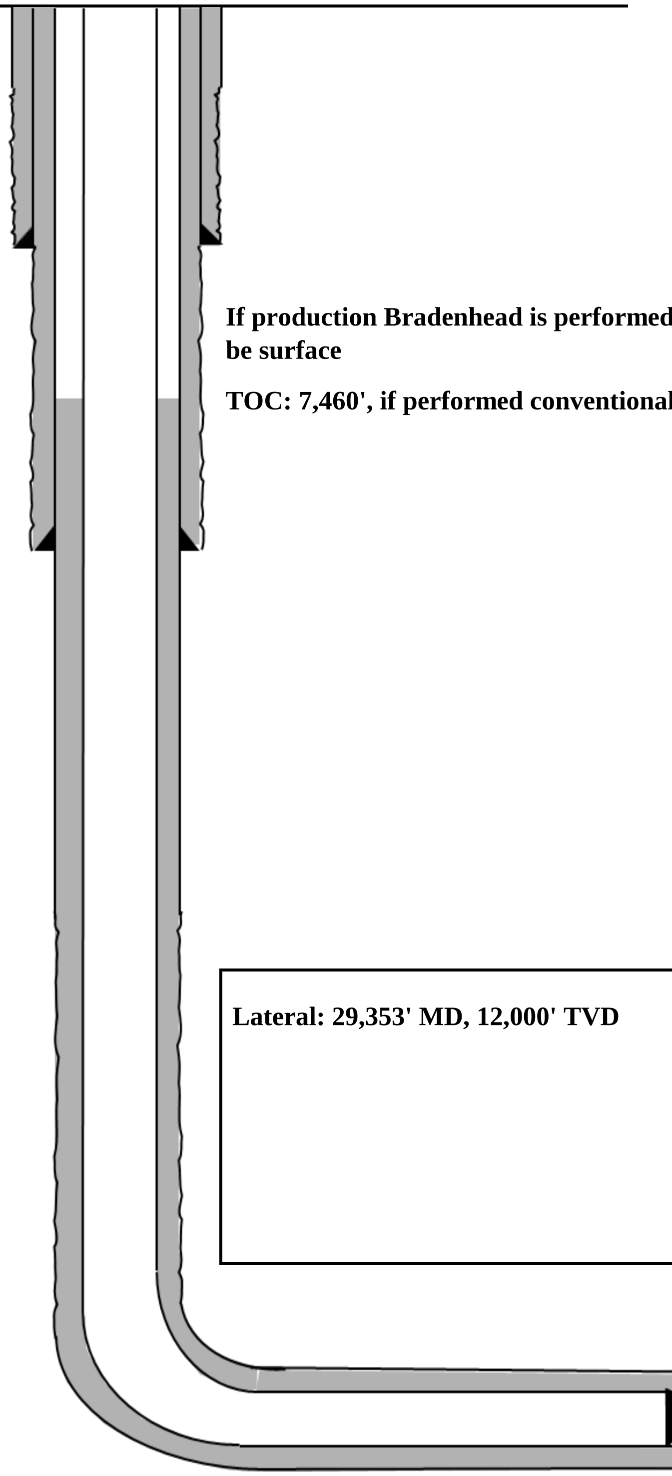
5. CEMENTING PROGRAM:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 10-3/4"	530	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	140	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830’)
8,050' 8-5/8"	470	12.7	2.22	Lead: Class C/H + 10% NaCl + 6% Bentonite Gel + 3% MagOx (TOC @ Surface)
	210	14.8	1.32	Tail: Class C/H + 10% NaCL + 3% MagOx (TOC @ 6360')
29,353' 5-1/2"	1000	14.8	1.32	Bradenhead squeeze: Class C/H + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
	1480	13.2	1.52	Tail: Class C/H + 5% NEX-020 + 0.2% NAC-102 + 0.15% NAS-725 + 0.5% NFL-549 + 0.2% NFP-703 + 1% NBE-737 + 0.3% NRT-241 (TOC @ Top of Brushy)

Shallow Casing Design B

Proposed Wellbore

KB: 3558'
GL: 3533'



Bit Size: 13-1/2''
10-3/4'', 40.5#, J-55, STC
@ 0’ - 2,030'

If production Bradenhead is performed, TOC will be surface

TOC: 7,460', if performed conventionally.

Bit Size: 9-7/8''
8-5/8'', 32.#, J-55, BTC-SC
@ 0’ - 7,960'

Lateral: 29,353' MD, 12,000' TVD

Bit Size: 6-3/4''
5-1/2'', 20.#, P110-EC, DWC/C IS MS
@ 0’ - 29,353'

KOP: 13,378' MD, 11,771' TVD
EOC: 13,738' MD, 12,000' TVD

Bit Size: 6-3/4''

StressCheck - [Triaxial Results - Shallow 3.0 Mile *]

File Edit Wellbore Tubular View Composer Tools Window Help

Burst Design | 8 5/8" Intermediate Casing | Pressure Test

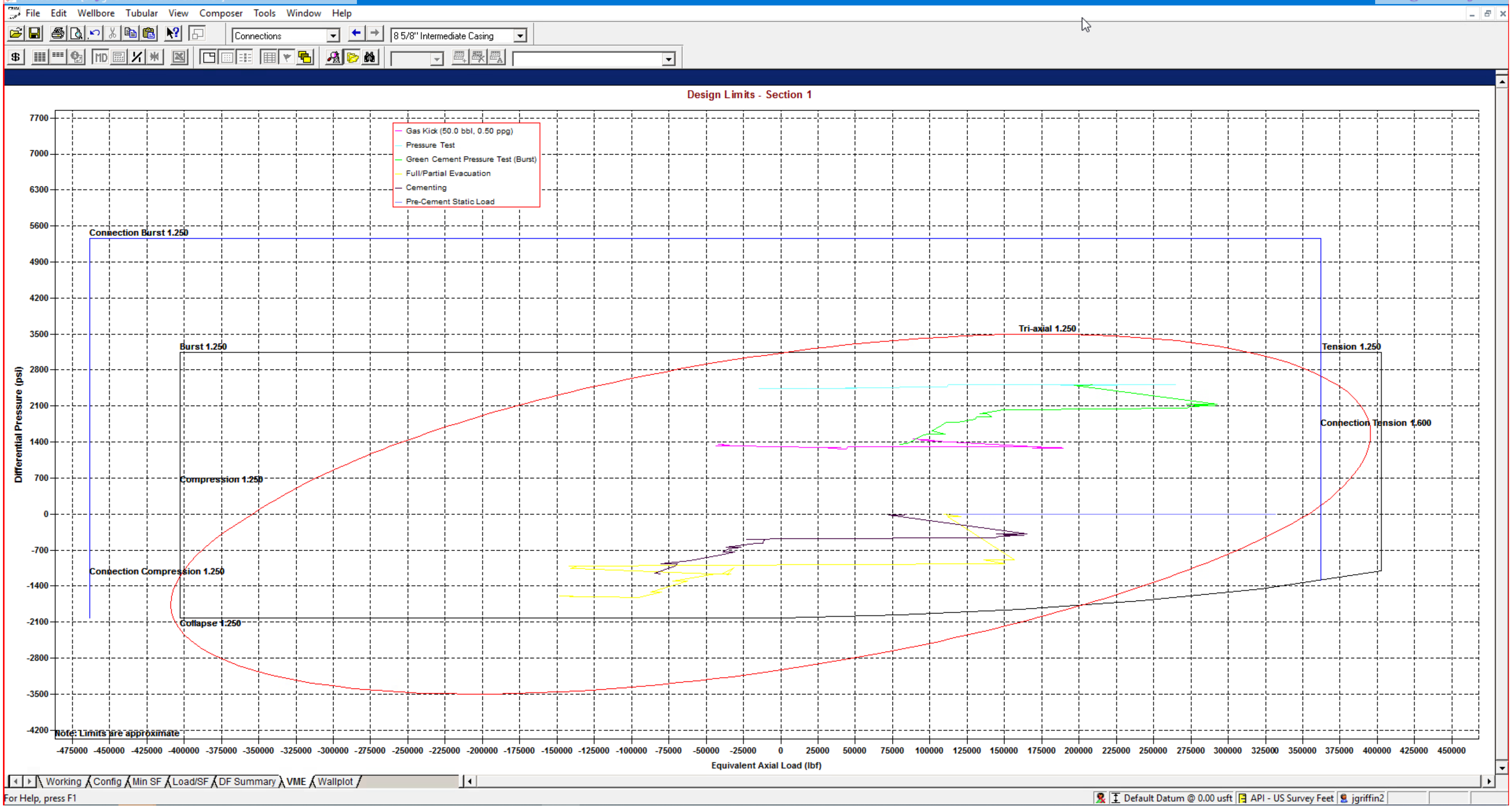
Triaxial Results

	Depth (MD) (usft)	Axial Force (lbf) Apparent (w/Bending)	Axial Force (lbf) Actual (w/o Bending)	Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor Triaxial	Absolute Safety Factor Burst	Absolute Safety Factor Collapse (V)	Absolute Safety Factor Axial	Temperature (°F)	Pressure (psi) Internal	Pressure (psi) External	Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (usft)
1	0	200426	183224	200546	1880.2	1.68	1.57	N/A	2.89 F	70.00	2500.00	0.00	N/A	N/A
2	100	196229	179028	196812	1880.2	1.69	1.57	N/A	2.95 F	71.10	2543.63	43.63		
3	100	187111	179027	187686	883.7	1.70	1.57	N/A	3.10 F	71.10	2543.64	43.64		
4	1700	256401	111891	264835	15795.8	1.56	1.56	N/A	2.26 F	88.70	3241.64	741.64		
5	1700	235940	111891	244247	13559.4	1.60	1.56	N/A	2.45 F	88.70	3241.65	741.65		
6	1850	252413	105788	261533	16027.0	1.54	1.56	N/A	2.29 F	90.29	3305.05	805.05		
7	1850	239292	105787	248323	14592.9	1.56	1.56	N/A	2.42 F	90.29	3305.06	805.06		
8	1950	240267	101966	249748	15117.2	1.54	1.56	N/A	2.41 F	91.30	3344.87	844.87		
9	1950	234781	101965	244223	14517.5	1.56	1.56	N/A	2.47 F	91.30	3344.87	844.87		
10	2050	230871	98395	240694	14480.4	1.55	1.56	N/A	2.51 F	92.23	3381.89	881.89		
11	2050	227794	98394	237594	14144.2	1.55	1.56	N/A	2.54 F	92.23	3381.89	881.89		
12	2300	117966	90294	127818	3024.7	1.70	1.56	N/A	4.91 F	94.35	3466.13	966.13		
13	2300	104686	90293	114432	1573.2	1.71	1.56	N/A	5.53 F	94.35	3466.14	966.14		
14	2370	102469	88077	112431	1573.2	1.71	1.56	N/A	5.65 F	94.94	3489.28	989.28		
15	2370	100817	86424	111200	1573.2	1.75	1.59	N/A	5.75 F	94.94	3489.29	1036.40		
16	2700	83660	75583	95052	882.8	1.74	1.59	N/A	6.92 F	97.73	3599.97	1152.35		
17	2700	88072	75583	99504	1365.1	1.74	1.59	N/A	6.58 F	97.73	3599.97	1152.35		
18	3100	86049	62442	98863	2580.4	1.71	1.59	N/A	6.73 F	101.11	3734.23	1293.00		
19	3100	76477	62441	89195	1534.2	1.72	1.59	N/A	7.57 F	101.11	3734.23	1293.01		
20	3700	55953	42882	70509	1428.8	1.69	1.60	N/A	10.35 F	106.15	3934.24	1502.54		
21	3700	48311	42881	62778	593.5	1.71	1.60	N/A	11.99 F	106.16	3934.25	1502.55		
22	4000	41458	33043	56865	919.9	1.69	1.60	N/A	13.97 F	108.69	4034.82	1607.91		
23	4650	26293	11655	43706	1600.1	1.63	1.60	N/A	22.03 F	114.20	4253.37	1836.86		
24	4900	32619	4156	50970	3111.2	1.59	1.60	N/A	17.76 F	116.32	4337.37	1924.87		
25	4900	21439	4155	39625	1889.2	1.61	1.60	N/A	27.02 F	116.32	4337.38	1924.87		
26	5039	15822	26	34389	1726.6	1.61	1.61	N/A	36.61 F	117.49	4383.77	1973.48		
27	5039	15822	26	34388	1726.6	1.61	1.61	N/A	36.61 F	117.49	4383.78	1973.49		
28	5600	-33912	-16743	-14286	1876.7	1.57	1.61	N/A	(14.60)	122.23	4572.11	2170.78		
29	5650	-30585	-18235	-10742	1350.0	1.58	1.61	N/A	(16.18)	122.66	4588.87	2188.34		
30														
31	F	Conn Fracture												
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												
34														

Working | Config | Min SF | Load/SF | DF Summary | VME | Wallplot

For Help, press F1 | Default Datum @ 0.00 usft | API - US Survey Feet | jgriffin2

8-5/8" Intermediate Casing Pressure Test:
Internal Profile based off Surface Pressure + Hydrostatic: 4589 psi
External Profile based off Pore Pressure: 2188 psi

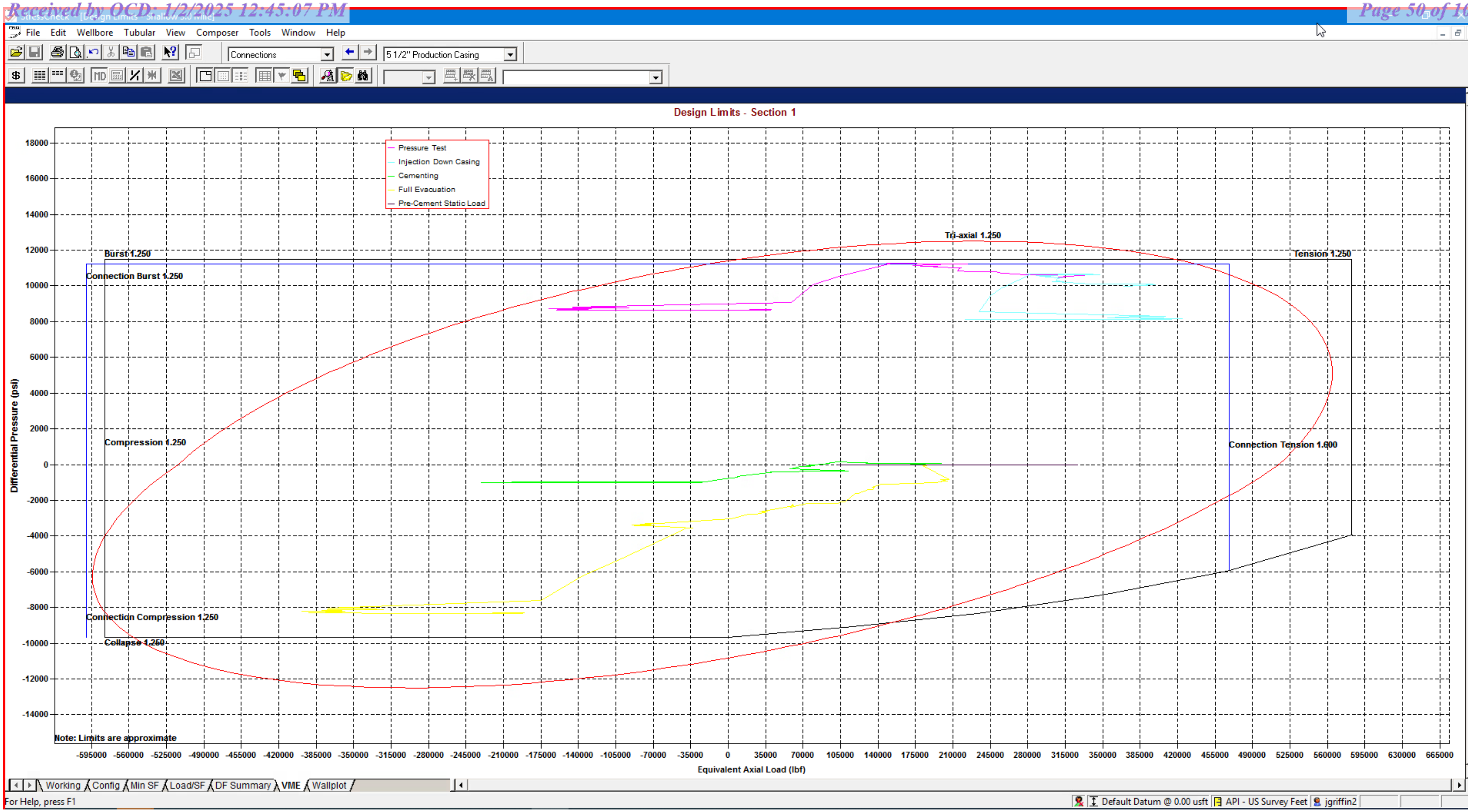


StressCheck - [String Summary - Shallow 3.0 Mile *]

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs) Burst	Collapse (V)	Axial	Triaxial	Design Cost ($)
1	Intermediate Casing	8 5/8", 32.000 ppf, J-55	BTC, J-55	0.0-5650.0	7.875 A	1.56	1.57	1.81 F	1.34	80,117
2										Total = 80,117
3										
4	F Conn Fracture									
5	A Alternate Drift									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 8-5/8" 32# Intermediate Casing. Passes all Burst, Collapse and Tensile design criteria.



StressCheck - [String Summary - Shallow 3.0 Mile]

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs) Burst	Collapse (V)	Axial	Triaxial	Design Cost ($)
1	Production Casing	5 1/2", 20.000 ppf, P110 ICY	BTC, P110 ICY	0.0-28578.0	4.653	1.27	1.47	1.90 F	1.35	446,902
2										Total = 446,902
3										
4	F Conn Fracture									
5	( ) Compression									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 5-1/2" 20# Production Casing with a 125ksi Control Yield. Passes all Burst, Collapse and Tensile design criteria.

eog resources

Shallow Design C

4. CASING PROGRAM

Hole Size	Interval MD From (ft)	Interval MD To (ft)	Interval TVD From (ft)	Interval TVD To (ft)	Csg OD	Weight	Grade	Conn
16"	0	2,161	0	2,030	13-3/8"	54.5#	J-55	STC
11"	0	7,951	0	5,650	9-5/8"	40#	J-55	LTC
7-7/8"	0	29,353	0	12,000	6"	24.5#	P110-EC	VAM Sprint-SF

Hole will be full during casing run for well control and tensile SF factor. Casing will be kept at least half full during run for this design to meet BLM collapse SF requirement. External pressure will be reviewed prior to conducting casing pressure tests to ensure that 70% of the yield is not exceeded.

Variance is requested to waive the centralizer requirements for the 9-5/8" casing in the 11" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 11" hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive any centralizer requirements for the 6" casing in the 7-7/8" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 7-7/8" hole interval to maximize cement bond and zonal isolation.

EOG requests permission to allow deviation from the 0.422’’ annulus clearance requirement for the intermediate (salt) section from Title 43 CFR Part 3170 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues.

5. CEMENTING PROGRAM:

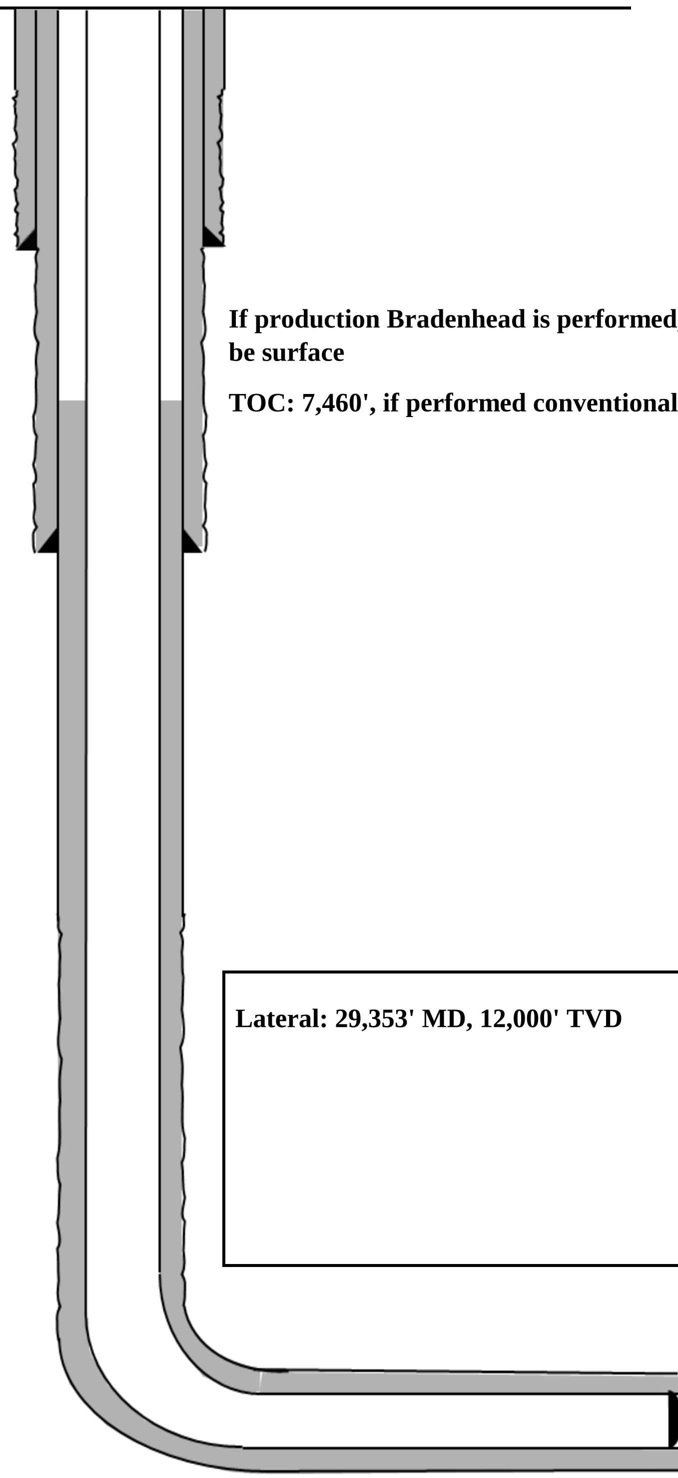
Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 13-3/8''	570	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	160	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830’)
8,050' 9-5/8''	760	12.7	2.22	Lead: Class C/H + 10% NaCl + 6% Bentonite Gel + 3% MagOx (TOC @ Surface)
	250	14.8	1.32	Tail: Class C/H + 10% NaCL + 3% MagOx (TOC @ 6360')
29,353' 6''	1000	14.8	1.32	Bradenhead squeeze: Class C/H + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
	2500	13.2	1.52	Tail: Class C/H + 5% NEX-020 + 0.2% NAC-102 + 0.15% NAS-725 + 0.5% NFL-549 + 0.2% NFP-703 + 1% NBE-737 + 0.3% NRT-241 (TOC @ Top of Brushy)

eog resources

Shallow Design C

Proposed Wellbore

KB: 3558'
GL: 3533'



Bit Size: 16''
13-3/8'', 54.5#, J-55, STC
@ 0' - 2,030'

If production Bradenhead is performed, TOC will be surface

TOC: 7,460', if performed conventionally.

Bit Size: 11''
9-5/8'', 40.#, J-55, LTC
@ 0' - 7,960'

Lateral: 29,353' MD, 12,000' TVD

Bit Size: 7-7/8''
6'', 24.5#, P110-EC, VAM Sprint-SF
@ 0' - 29,353'

KOP: 13,378' MD, 11,771' TVD
EOC: 13,738' MD, 12,000' TVD

Bit Size: 7-7/8''

File Edit Wellbore Tubular View Composer Tools Window Help

9 5/8" Intermediate Casing

Pressure Test

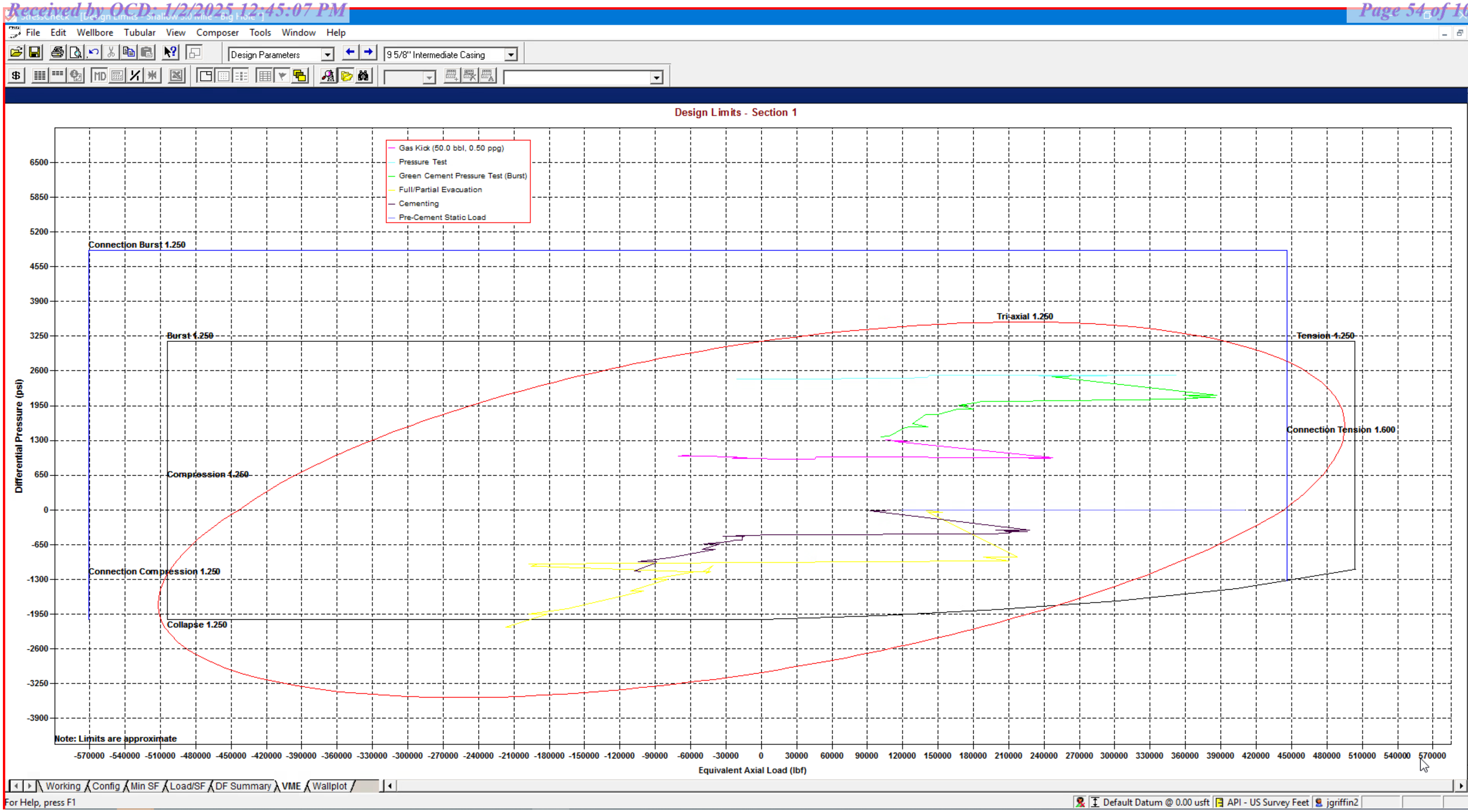
Triaxial Results

	Depth (MD) (usft)	Axial Force (lbf) Apparent (w/Bending)	Axial Force (lbf) Actual (w/o Bending)	Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor Triaxial	Absolute Safety Factor Burst	Absolute Safety Factor Collapse (V)	Absolute Safety Factor Axial	Temperature (°F)	Pressure (psi) Internal	Pressure (psi) External	Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (usft)
1	0	252987	228954	253140	2098.2	1.69	1.58	N/A	2.82 F	70.00	2500.00	0.00	N/A	N/A
2	100	247735	223702	248466	2098.2	1.69	1.58	N/A	2.88 F	71.10	2543.63	43.63		
3	100	234996	223701	235716	986.2	1.71	1.58	N/A	3.04 F	71.10	2543.64	43.64		
4	1700	341565	139667	352253	17627.2	1.53	1.57	N/A	2.09 F	88.70	3241.64	741.64		
5	1700	312979	139666	323488	15131.5	1.58	1.57	N/A	2.28 F	88.70	3241.65	741.65		
6	1850	336881	132027	348440	17885.2	1.51	1.57	N/A	2.12 F	90.29	3305.05	805.05		
7	1850	318549	132027	329984	16284.8	1.54	1.57	N/A	2.24 F	90.29	3305.06	805.06		
8	1950	320468	127243	332475	16869.9	1.52	1.57	N/A	2.23 F	91.30	3344.87	844.87		
9	1950	312802	127243	324756	16200.7	1.53	1.57	N/A	2.28 F	91.30	3344.87	844.87		
10	2050	307858	122773	320295	16159.3	1.52	1.57	N/A	2.32 F	92.23	3381.89	881.89		
11	2050	303560	122772	315965	15784.1	1.53	1.57	N/A	2.35 F	92.23	3381.89	881.89		
12	2300	151294	112633	163658	3375.4	1.71	1.57	N/A	4.72 F	94.35	3466.13	966.13		
13	2300	132741	112633	144956	1755.6	1.72	1.57	N/A	5.38 F	94.35	3466.14	966.14		
14	2370	129966	109858	142452	1755.6	1.72	1.57	N/A	5.49 F	94.94	3489.28	989.28		
15	2370	127909	107800	140922	1755.6	1.75	1.60	N/A	5.58 F	94.94	3489.29	1036.40		
16	2700	105515	94232	119785	985.1	1.75	1.60	N/A	6.77 F	97.73	3599.97	1152.35		
17	2700	111680	94231	126006	1523.4	1.75	1.60	N/A	6.39 F	97.73	3599.97	1152.35		
18	3100	110766	77783	126839	2879.6	1.71	1.60	N/A	6.44 F	101.11	3734.23	1293.00		
19	3100	97392	77783	113331	1712.1	1.73	1.60	N/A	7.33 F	101.11	3734.23	1293.01		
20	3700	71565	53303	89806	1594.4	1.70	1.61	N/A	9.97 F	106.15	3934.24	1502.54		
21	3700	60887	53302	79004	662.3	1.71	1.61	N/A	11.72 F	106.16	3934.25	1502.55		
22	4650	34671	14219	56495	1785.6	1.64	1.61	N/A	20.59 F	114.20	4253.37	1836.86		
23	4900	44595	4828	67626	3472.0	1.59	1.61	N/A	16.01 F	116.32	4337.37	1924.87		
24	4900	28975	4828	51775	2108.2	1.62	1.61	N/A	24.64 F	116.32	4337.38	1924.87		
25	5029	22103	34	45340	1926.8	1.61	1.61	N/A	32.30 F	117.40	4380.40	1969.94		
26	5029	22102	33	45339	1926.8	1.61	1.61	N/A	32.30 F	117.40	4380.41	1969.95		
27	5600	-45329	-21341	-20805	2094.3	1.57	1.62	N/A	(13.67)	122.23	4572.11	2170.78		
28	5650	-40465	-23210	-15657	1506.5	1.58	1.62	N/A	(15.31)	122.66	4588.87	2188.34		
29														
30	F	Conn Fracture												
31	( )	Compression												
32	(V)	Vector Collapse Safety Factor												
33														

Working Config Min SF Load/SF DF Summary VME Wallplot

For Help, press F1 Default Datum @ 0.00 usft API - US Survey Feet jgriffin2

9-5/8" Intermediate Casing Pressure Test:
Internal Profile based off Surface Pressure + Hydrostatic: 4589 psi
External Profile based off Pore Pressure: 2188 psi



StressCheck - [String Summary - Shallow 3.0 Mile - Big Hole *]

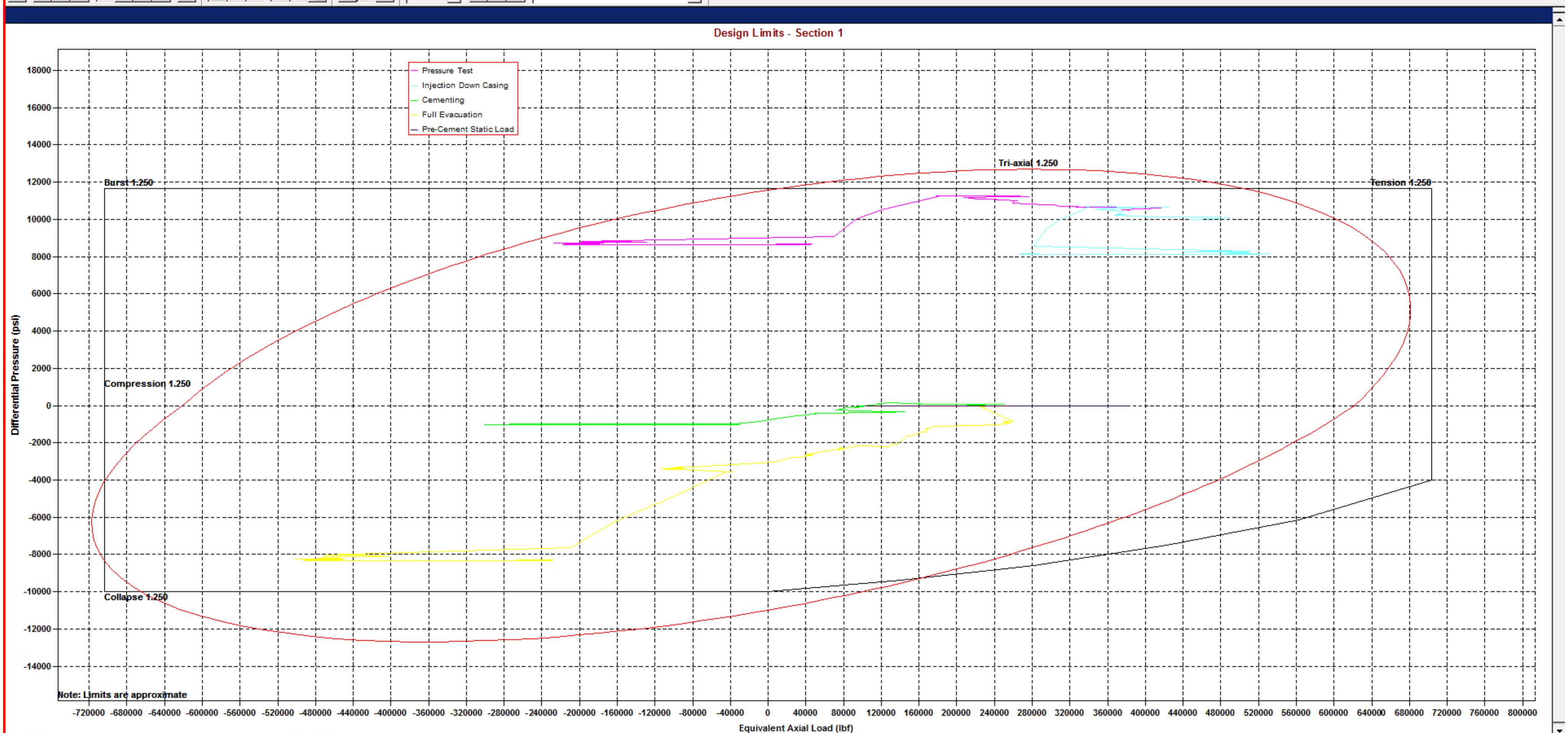
File Edit Wellbore Tubular View Composer Tools Window Help

Collapse Loads | 9 5/8" Intermediate Casing

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs) Burst	Collapse (V)	Axial	Triaxial	Design Cost ($)
1	Intermediate Casing	9 5/8", 40.000 ppf, J-55	BTC, J-55	0.0-5650.0	8.750 A	1.57	1.59	1.80 F	1.35	98,141
2										Total = 98,141
3										
4	F Conn Fracture									
5	A Alternate Drift									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 9-5/8" 40# Intermediate Casing. Passes all Burst, Collapse and Tensile design criteria.



String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V)	Axial	Triaxial	
1	Production Casing	6", 24.500 ppf, P110 ICY	BTC, P110 ICY	0.0-28578.0	5.075	1.29	1.52	(1.75)	1.37	541,493
2										Total = 541,493
3										
4	( ) Compression									
5	(V) Vector Collapse Safety Factor									
6										

*Modelling done with 6" Production Casing with a 125ksi Control Yield. Passes all Burst, Collapse and Tensile design criteria.

eog resources

Shallow Design D

4. CASING PROGRAM

Hole Size	Interval MD From (ft)	Interval MD To (ft)	Interval TVD From (ft)	Interval TVD To (ft)	Csg OD	Weight	Grade	Conn
16"	0	2,161	0	2,030	13-3/8"	54.5#	J-55	STC
11"	0	7,951	0	5,650	9-5/8"	40#	J-55	LTC
7-7/8"	0	13,278	0	11,671	6"	22.3#	P110-EC	DWC/C IS
6-3/4"	13,278	29,353	11,671	12,000	5-1/2"	20#	P110-EC	DWC/C IS MS

Hole will be full during casing run for well control and tensile SF factor. Casing will be kept at least half full during run for this design to meet BLM collapse SF requirement. External pressure will be reviewed prior to conducting casing pressure tests to ensure that 70% of the yield is not exceeded.

Variance is requested to waive the centralizer requirements for the 9-5/8" casing in the 11" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 11" hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive any centralizer requirements for the 6" and 5-1/2" casings in the 7-7/8" and 6-3/4" hole sizes. An expansion additive will be utilized in the cement slurry for the entire length of the 7-7/8" and 6-3/4" hole intervals to maximize cement bond and zonal isolation.

EOG requests permission to allow deviation from the 0.422'' annulus clearance requirement for the intermediate (salt) section from Title 43 CFR Part 3170 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues.

5. CEMENTING PROGRAM:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 13-3/8''	570	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	160	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830')
8,050' 9-5/8''	760	12.7	2.22	Lead: Class C/H + 10% NaCl + 6% Bentonite Gel + 3% MagOx (TOC @ Surface)
	250	14.8	1.32	Tail: Class C/H + 10% NaCL + 3% MagOx (TOC @ 6360')
29,353' 6''	1000	14.8	1.32	Bradenhead squeeze: Class C/H + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
	2500	13.2	1.52	Tail: Class C/H + 5% NEX-020 + 0.2% NAC-102 + 0.15% NAS-725 + 0.5% NFL-549 + 0.2% NFP-703 + 1% NBE-737 + 0.3% NRT-241 (TOC @ Top of Brushy)

Shallow Design D

Proposed Wellbore

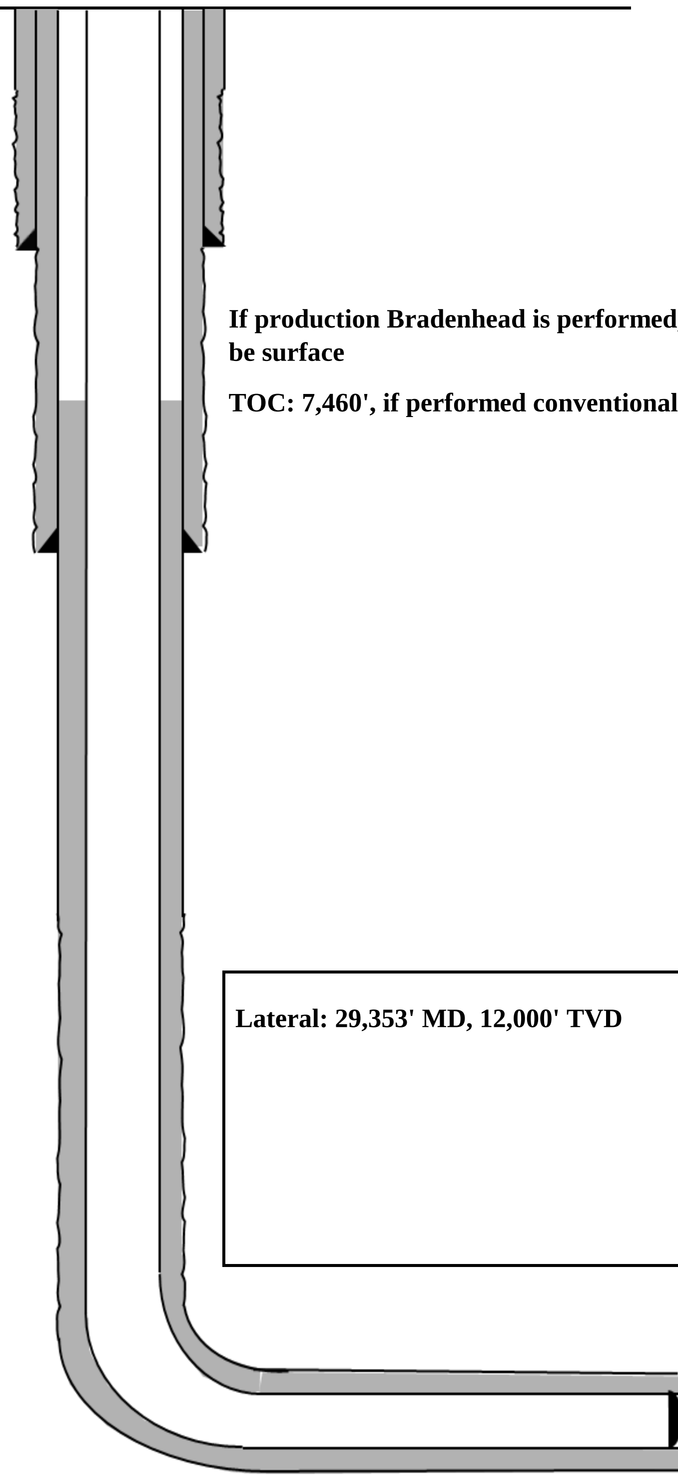
KB: 3558'
GL: 3533'

Bit Size: 16''
13-3/8'', 54.5#, J-55, STC
@ 0' - 2,030'

If production Bradenhead is performed, TOC will be surface

TOC: 7,460', if performed conventionally.

Bit Size: 11''
9-5/8'', 40.#, J-55, LTC
@ 0' - 7,960'



Lateral: 29,353' MD, 12,000' TVD

Bit Size: 7-7/8''|Bit Size: 6-3/4''
6'', 22.3#, P110-EC, DWC/C IS
@ 0' - 11,671'

5-1/2'', 20.#, P110-EC, DWC/C IS MS
@ 11,671' - 29,353'

KOP: 13,378' MD, 11,771' TVD
EOC: 13,738' MD, 12,000' TVD

File Edit Wellbore Tubular View Composer Tools Window Help

9 5/8" Intermediate Casing | Pressure Test

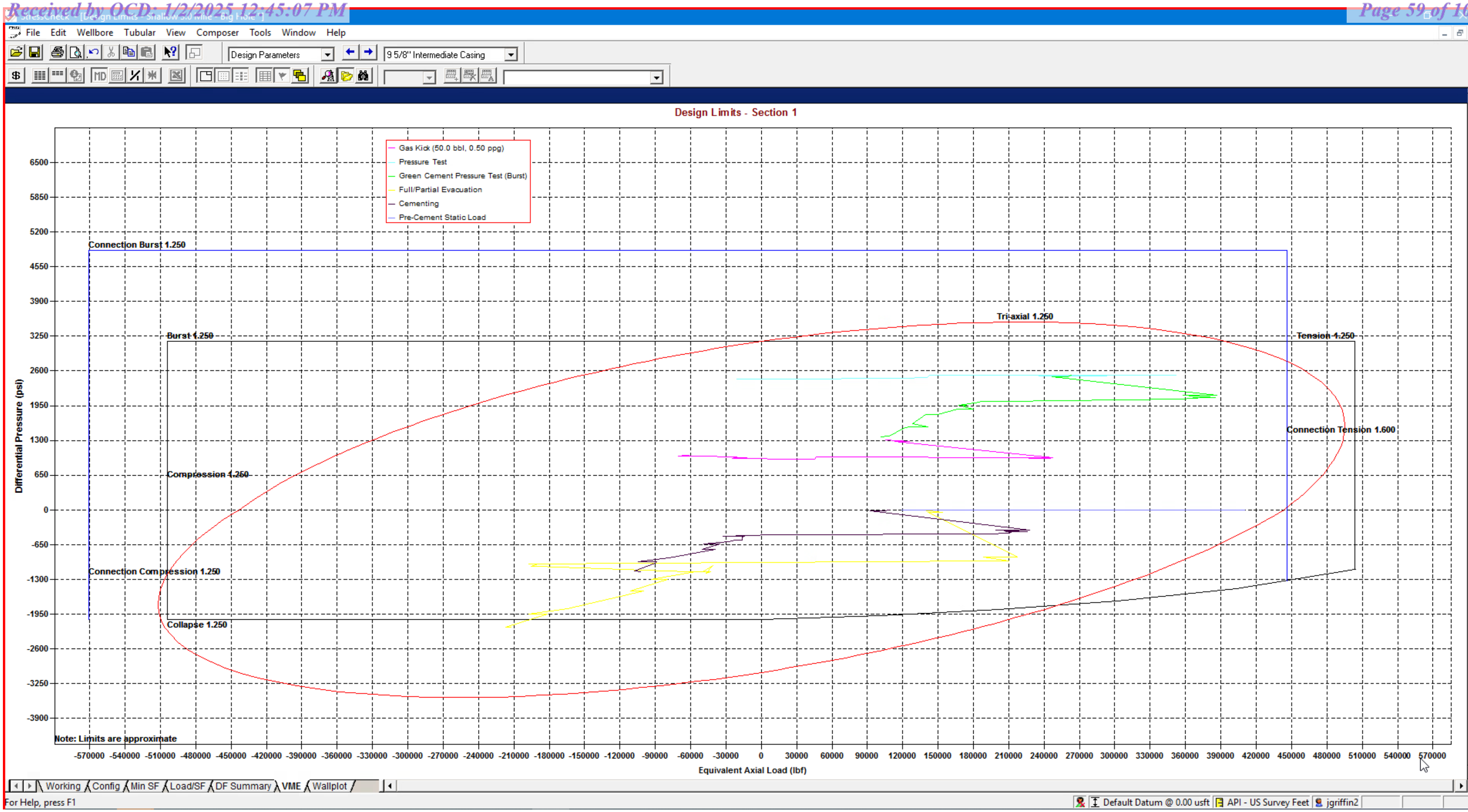
Triaxial Results

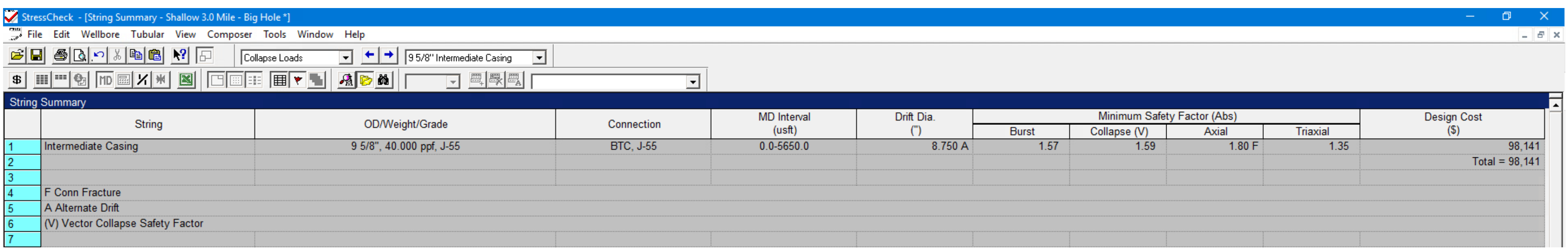
	Depth (MD) (usft)	Axial Force (lbf)		Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor				Temperature (°F)	Pressure (psi)		Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (usft)
		Apparent (w/Bending)	Actual (w/o Bending)			Triaxial	Burst	Collapse (V)	Axial		Internal	External		
1	0	252987	228954	253140	2098.2	1.69	1.58	N/A	2.82 F	70.00	2500.00	0.00	N/A	N/A
2	100	247735	223702	248466	2098.2	1.69	1.58	N/A	2.88 F	71.10	2543.63	43.63		
3	100	234996	223701	235716	986.2	1.71	1.58	N/A	3.04 F	71.10	2543.64	43.64		
4	1700	341565	139667	352253	17627.2	1.53	1.57	N/A	2.09 F	88.70	3241.64	741.64		
5	1700	312979	139666	323488	15131.5	1.58	1.57	N/A	2.28 F	88.70	3241.65	741.65		
6	1850	336881	132027	348440	17885.2	1.51	1.57	N/A	2.12 F	90.29	3305.05	805.05		
7	1850	318549	132027	329984	16284.8	1.54	1.57	N/A	2.24 F	90.29	3305.06	805.06		
8	1950	320468	127243	332475	16869.9	1.52	1.57	N/A	2.23 F	91.30	3344.87	844.87		
9	1950	312802	127243	324756	16200.7	1.53	1.57	N/A	2.28 F	91.30	3344.87	844.87		
10	2050	307858	122773	320295	16159.3	1.52	1.57	N/A	2.32 F	92.23	3381.89	881.89		
11	2050	303560	122772	315965	15784.1	1.53	1.57	N/A	2.35 F	92.23	3381.89	881.89		
12	2300	151294	112633	163658	3375.4	1.71	1.57	N/A	4.72 F	94.35	3466.13	966.13		
13	2300	132741	112633	144956	1755.6	1.72	1.57	N/A	5.38 F	94.35	3466.14	966.14		
14	2370	129966	109858	142452	1755.6	1.72	1.57	N/A	5.49 F	94.94	3489.28	989.28		
15	2370	127909	107800	140922	1755.6	1.75	1.60	N/A	5.58 F	94.94	3489.29	1036.40		
16	2700	105515	94232	119785	985.1	1.75	1.60	N/A	6.77 F	97.73	3599.97	1152.35		
17	2700	111680	94231	126006	1523.4	1.75	1.60	N/A	6.39 F	97.73	3599.97	1152.35		
18	3100	110766	77783	126839	2879.6	1.71	1.60	N/A	6.44 F	101.11	3734.23	1293.00		
19	3100	97392	77783	113331	1712.1	1.73	1.60	N/A	7.33 F	101.11	3734.23	1293.01		
20	3700	71565	53303	89806	1594.4	1.70	1.61	N/A	9.97 F	106.15	3934.24	1502.54		
21	3700	60887	53302	79004	662.3	1.71	1.61	N/A	11.72 F	106.16	3934.25	1502.55		
22	4650	34671	14219	56495	1785.6	1.64	1.61	N/A	20.59 F	114.20	4253.37	1836.86		
23	4900	44595	4828	67626	3472.0	1.59	1.61	N/A	16.01 F	116.32	4337.37	1924.87		
24	4900	28975	4828	51775	2108.2	1.62	1.61	N/A	24.64 F	116.32	4337.38	1924.87		
25	5029	22103	34	45340	1926.8	1.61	1.61	N/A	32.30 F	117.40	4380.40	1969.94		
26	5029	22102	33	45339	1926.8	1.61	1.61	N/A	32.30 F	117.40	4380.41	1969.95		
27	5600	-45329	-21341	-20805	2094.3	1.57	1.62	N/A	(13.67)	122.23	4572.11	2170.78		
28	5650	-40465	-23210	-15657	1506.5	1.58	1.62	N/A	(15.31)	122.66	4588.87	2188.34		
29														
30	F	Conn Fracture												
31	( )	Compression												
32	(V)	Vector Collapse Safety Factor												
33														

Working | Config | Min SF | Load/SF | DF Summary | VME | Wallplot

For Help, press F1 | Default Datum @ 0.00 usft | API - US Survey Feet | jgriffin2

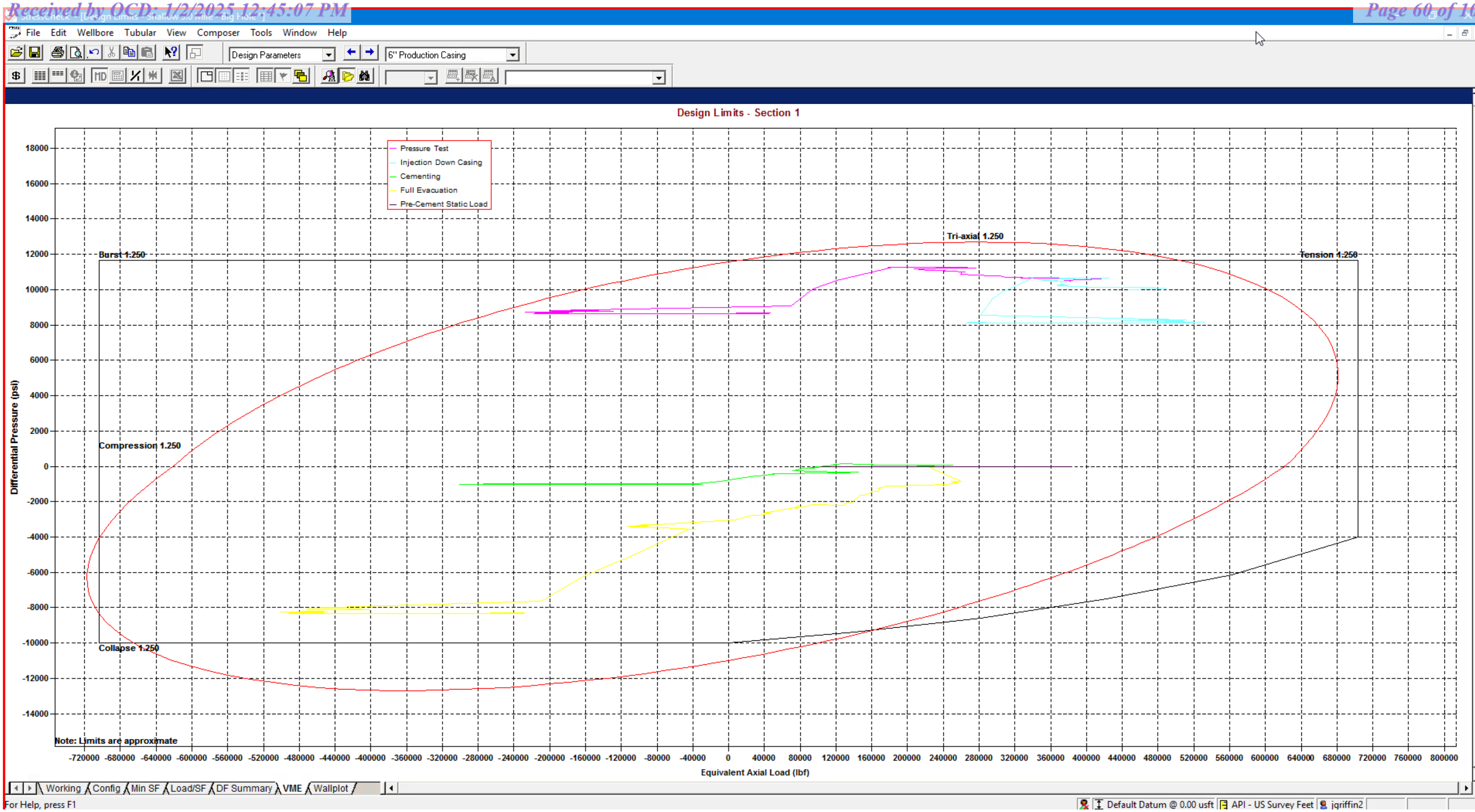
9-5/8" Intermediate Casing Pressure Test:
Internal Profile based off Surface Pressure + Hydrostatic: 4589 psi
External Profile based off Pore Pressure: 2188 psi





	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V)	Axial	Triaxial	
1	Intermediate Casing	9 5/8", 40.000 ppf, J-55	BTC, J-55	0.0-5650.0	8.750 A	1.57	1.59	1.80 F	1.35	98,141
2										Total = 98,141
3										
4	F Conn Fracture									
5	A Alternate Drift									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 9-5/8" 40# Intermediate Casing. Passes all Burst, Collapse and Tensile design criteria.



StressCheck - [String Summary - Shallow 3.0 Mile - Big Hole *]

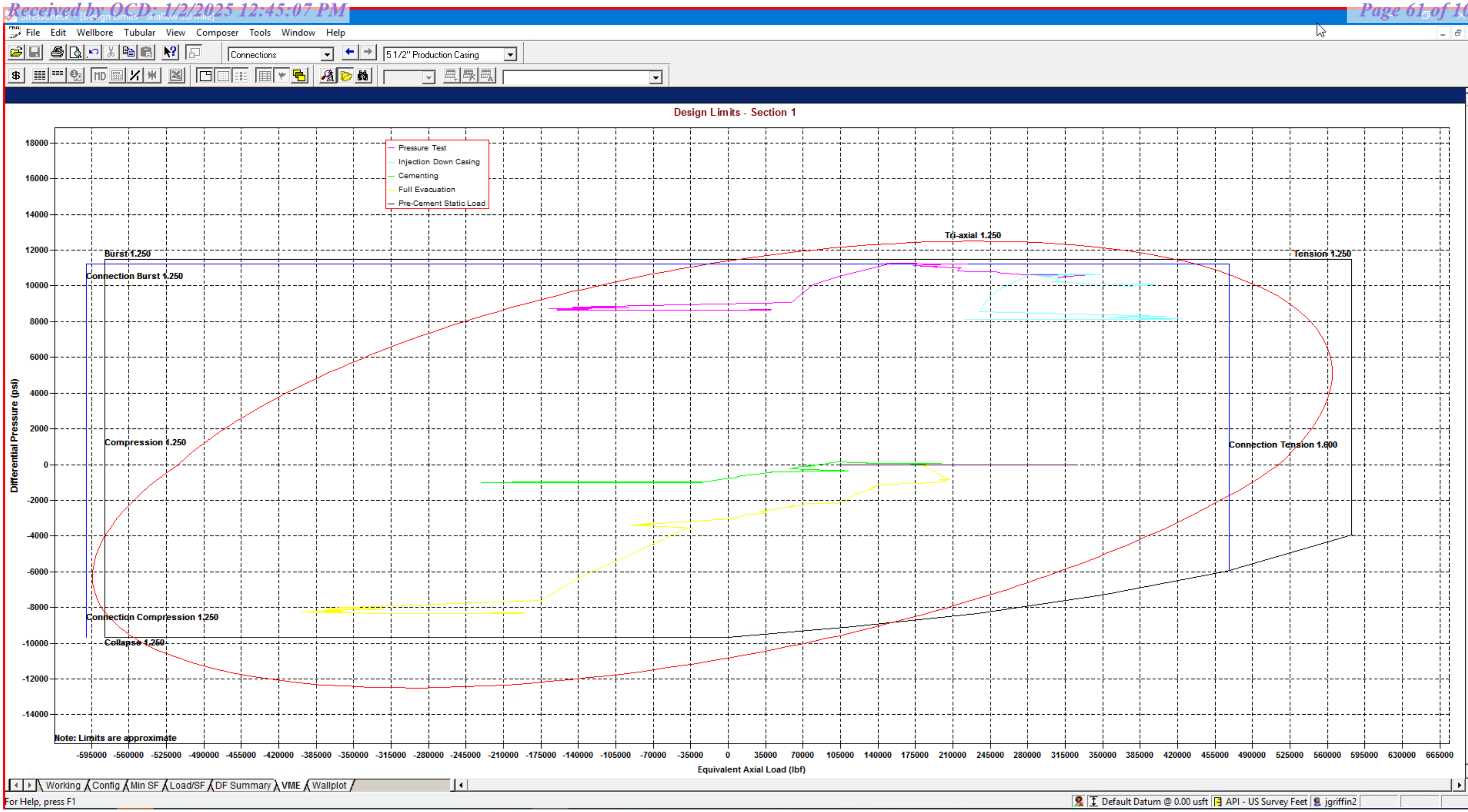
File Edit Wellbore Tubular View Composer Tools Window Help

Design Parameters | 6" Production Casing

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V)	Axial	Triaxial	
1	Production Casing	6", 24.500 ppf, P110 ICY	BTC, P110 ICY	0.0-28578.0	5.075	1.29	1.52	(1.75)	1.37	541,493
2										Total = 541,493
3										
4	( ) Compression									
5	(V) Vector Collapse Safety Factor									
6										

*Modelling done with 6" Production Casing with a 125ksi Control Yield. Passes all Burst, Collapse and Tensile design criteria.



StressCheck - [String Summary - Shallow 3.0 Mile]

File Edit Wellbore Tubular View Composer Tools Window Help

Connections | 5 1/2" Production Casing

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs) Burst	Collapse (V)	Axial	Triaxial	Design Cost ($)
1	Production Casing	5 1/2", 20.000 ppf, P110 ICY	BTC, P110 ICY	0.0-28578.0	4.653	1.27	1.47	1.90 F	1.35	446,902
2										Total = 446,902
3										
4	F Conn Fracture									
5	( ) Compression									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 5-1/2" 20# Production Casing with a 125ksi Control Yield. Passes all Burst, Collapse and Tensile design criteria.

eog resources

Shallow Casing Design E

1. CASING PROGRAM

Hole Size	Interval MD From (ft)	Interval MD To (ft)	Interval TVD From (ft)	Interval TVD To (ft)	Csg OD	Weight	Grade	Conn
13"	0	2,025	0	2,025	10-3/4"	40.5#	J-55	STC
9-7/8"	0	7,793	0	5,645	8-5/8"	32#	J-55	BTC-SC
7-7/8"	0	12,626	0	10,896	6"	24.5#	P110-EC	VAM Sprint-TC
6-3/4"	12,626	28,578	10,896	11,225	5-1/2"	20#	P110-EC	VAM Sprint SF

**For highlighted rows above, variance is requested to run entire string of either 6'' or 5-1/2'' casing string above due to availablility.

Hole will be full during casing run for well control and tensile SF factor. Casing will be kept at least half full during run for this design to meet BLM collapse SF requirement. External pressure will be reviewed prior to conducting casing pressure tests to ensure that 70% of the yield is not exceeded.

Variance is requested to waive the centralizer requirements for the 8-5/8" casing in the 9-7/8" hole size. An expansion additive will be utilized, in the cement slurry, for the entire length of the 9-7/8" hole interval to maximize cement bond and zonal isolation.

Variance is also requested to waive any centralizer requirements for the 6" and 5-1/2" casings in the 7-7/8" and 6-3/4" hole sizes. An expansion additive will be utilized in the cement slurry for the entire length of the 7-7/8" and 6-3/4" hole intervals to maximize cement bond and zonal isolation.

EOG requests permission to allow deviation from the 0.422'' annulus clearance requirement for the intermediate (salt) section from Title 43 CFR Part 3170 under the following conditions:

- The variance is not applicable within the Potash Boundaries or Capitan Reef areas.
- Operator takes responsibility to get casing to set point in the event that the clearance causes stuck pipe issues.

2. CEMENTING PROGRAM:

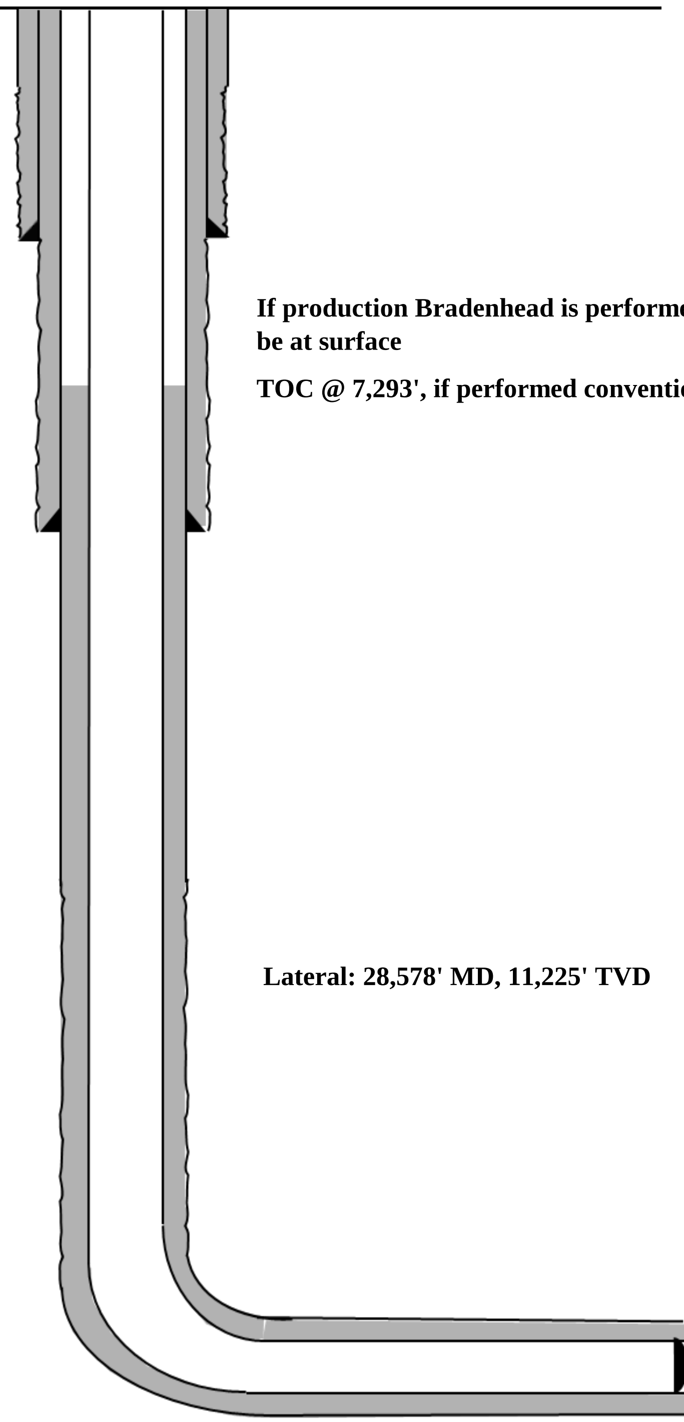
Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 10-3/4"	450	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	120	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830')
7,890' 8-5/8"	460	12.7	2.22	Lead: Class C/H + 10% NaCl + 6% Bentonite Gel + 3% MagOx (TOC @ Surface)
	210	14.8	1.32	Tail: Class C/H + 10% NaCL + 3% MagOx (TOC @ 6234')
28,578' 6"	1000	14.8	1.32	Bradenhead squeeze: Class C/H + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (TOC @ surface)
	2410	13.2	1.52	Tail: Class C/H + 5% NEX-020 + 0.2% NAC-102 + 0.15% NAS-725 + 0.5% NFL-549 + 0.2% NFP-703 + 1% NBE-737 + 0.3% NRT-241 (TOC @ 8140')

Shallow Casing Design E

Proposed Wellbore

KB: 3558'
GL: 3533'

API: 30-025-***



Bit Size: 13''
10-3/4'', 40.5#, J-55, STC
@ 0' - 2,025'

If production Bradenhead is performed, TOC will be at surface

TOC @ 7,293', if performed conventionally.

Bit Size: 9-7/8''
8-5/8'', 32.#, J-55, BTC-SC
@ 0' - 7,793'

Lateral: 28,578' MD, 11,225' TVD

Bit Size: 7-7/8''|Bit Size: 6-3/4''
6'', 24.5#, P110-EC, VAM Sprint-TC
@ 0' - 10,896'

5-1/2'', 20.#, P110-EC, VAM Sprint SF
@ 10,896' - 28,578'

KOP: 12,726' MD, 10,996' TVD
EOC: 12,963' MD, 11,225' TVD

StressCheck - [Triaxial Results - Shallow 3.0 Mile *]

Burst Design | 8 5/8" Intermediate Casing | Pressure Test

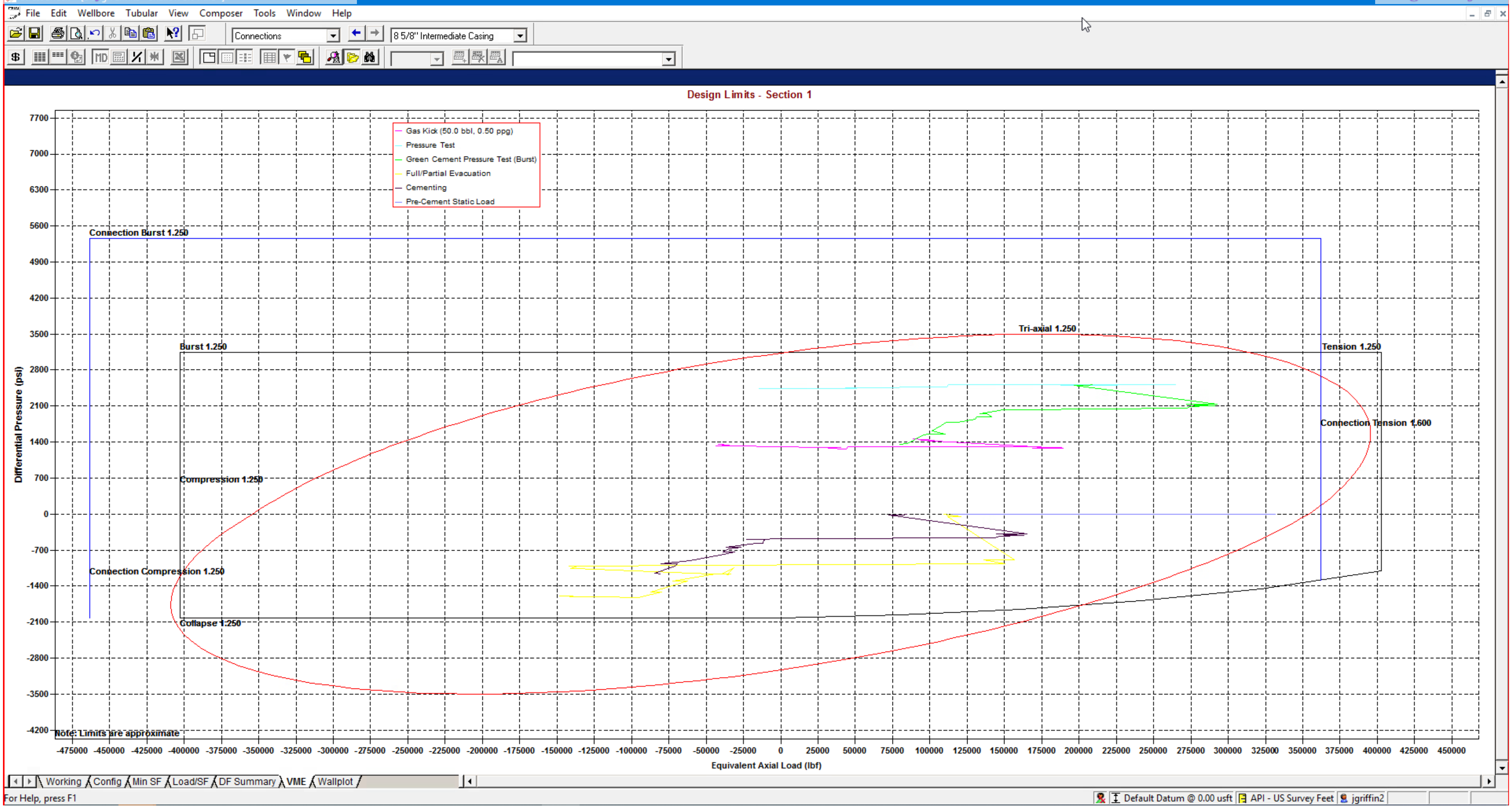
Triaxial Results

	Depth (MD) (usft)	Axial Force (lbf) Apparent (w/Bending)	Axial Force (lbf) Actual (w/o Bending)	Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor Triaxial	Absolute Safety Factor Burst	Absolute Safety Factor Collapse (V)	Absolute Safety Factor Axial	Temperature (°F)	Pressure (psi) Internal	Pressure (psi) External	Addt'l Pickup To Prevent Buck. (lbf)	Buckled Length (usft)
1	0	200426	183224	200546	1880.2	1.68	1.57	N/A	2.89 F	70.00	2500.00	0.00	N/A	N/A
2	100	196229	179028	196812	1880.2	1.69	1.57	N/A	2.95 F	71.10	2543.63	43.63		
3	100	187111	179027	187686	883.7	1.70	1.57	N/A	3.10 F	71.10	2543.64	43.64		
4	1700	256401	111891	264835	15795.8	1.56	1.56	N/A	2.26 F	88.70	3241.64	741.64		
5	1700	235940	111891	244247	13559.4	1.60	1.56	N/A	2.45 F	88.70	3241.65	741.65		
6	1850	252413	105788	261533	16027.0	1.54	1.56	N/A	2.29 F	90.29	3305.05	805.05		
7	1850	239292	105787	248323	14592.9	1.56	1.56	N/A	2.42 F	90.29	3305.06	805.06		
8	1950	240267	101966	249748	15117.2	1.54	1.56	N/A	2.41 F	91.30	3344.87	844.87		
9	1950	234781	101965	244223	14517.5	1.56	1.56	N/A	2.47 F	91.30	3344.87	844.87		
10	2050	230871	98395	240694	14480.4	1.55	1.56	N/A	2.51 F	92.23	3381.89	881.89		
11	2050	227794	98394	237594	14144.2	1.55	1.56	N/A	2.54 F	92.23	3381.89	881.89		
12	2300	117966	90294	127818	3024.7	1.70	1.56	N/A	4.91 F	94.35	3466.13	966.13		
13	2300	104686	90293	114432	1573.2	1.71	1.56	N/A	5.53 F	94.35	3466.14	966.14		
14	2370	102469	88077	112431	1573.2	1.71	1.56	N/A	5.65 F	94.94	3489.28	989.28		
15	2370	100817	86424	111200	1573.2	1.75	1.59	N/A	5.75 F	94.94	3489.29	1036.40		
16	2700	83660	75583	95052	882.8	1.74	1.59	N/A	6.92 F	97.73	3599.97	1152.35		
17	2700	88072	75583	99504	1365.1	1.74	1.59	N/A	6.58 F	97.73	3599.97	1152.35		
18	3100	86049	62442	98863	2580.4	1.71	1.59	N/A	6.73 F	101.11	3734.23	1293.00		
19	3100	76477	62441	89195	1534.2	1.72	1.59	N/A	7.57 F	101.11	3734.23	1293.01		
20	3700	55953	42882	70509	1428.8	1.69	1.60	N/A	10.35 F	106.15	3934.24	1502.54		
21	3700	48311	42881	62778	593.5	1.71	1.60	N/A	11.99 F	106.16	3934.25	1502.55		
22	4000	41458	33043	56865	919.9	1.69	1.60	N/A	13.97 F	108.69	4034.82	1607.91		
23	4650	26293	11655	43706	1600.1	1.63	1.60	N/A	22.03 F	114.20	4253.37	1836.86		
24	4900	32619	4156	50970	3111.2	1.59	1.60	N/A	17.76 F	116.32	4337.37	1924.87		
25	4900	21439	4155	39625	1889.2	1.61	1.60	N/A	27.02 F	116.32	4337.38	1924.87		
26	5039	15822	26	34389	1726.6	1.61	1.61	N/A	36.61 F	117.49	4383.77	1973.48		
27	5039	15822	26	34388	1726.6	1.61	1.61	N/A	36.61 F	117.49	4383.78	1973.49		
28	5600	-33912	-16743	-14286	1876.7	1.57	1.61	N/A	(14.60)	122.23	4572.11	2170.78		
29	5650	-30585	-18235	-10742	1350.0	1.58	1.61	N/A	(16.18)	122.66	4588.87	2188.34		
30														
31	F	Conn Fracture												
32	( )	Compression												
33	(V)	Vector Collapse Safety Factor												
34														

Working | Config | Min SF | Load/SF | DF Summary | VME | Wallplot

For Help, press F1 | Default Datum @ 0.00 usft | API - US Survey Feet | jgriffin2

8-5/8” Intermediate Casing Pressure Test:
Internal Profile based off Surface Pressure + Hydrostatic: 4589 psi
External Profile based off Pore Pressure: 2188 psi

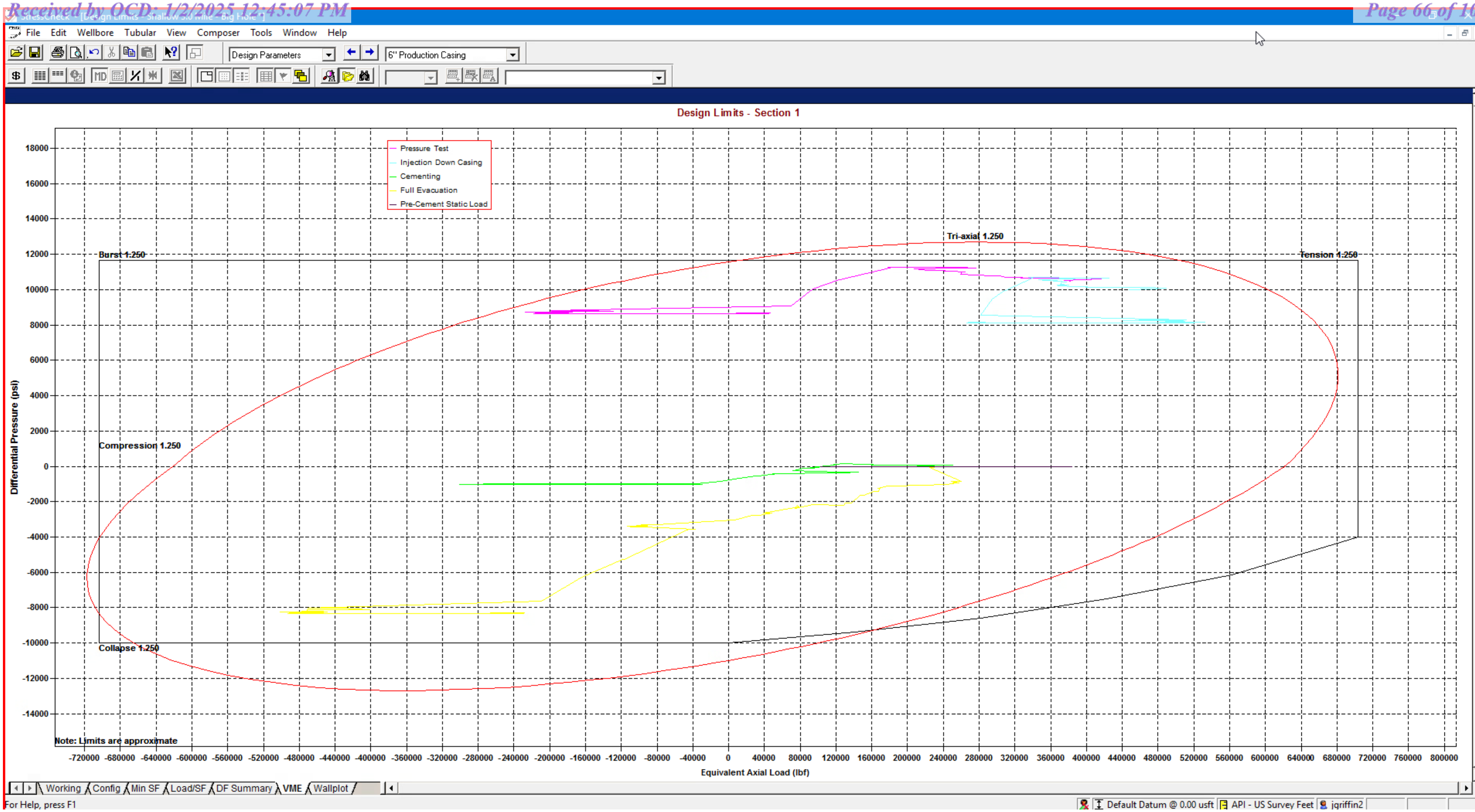


StressCheck - [String Summary - Shallow 3.0 Mile *]

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V)	Axial	Triaxial	
1	Intermediate Casing	8 5/8", 32.000 ppf, J-55	BTC, J-55	0.0-5650.0	7.875 A	1.56	1.57	1.81 F	1.34	80,117
2										Total = 80,117
3										
4	F Conn Fracture									
5	A Alternate Drift									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 8-5/8” 32# Intermediate Casing. Passes all Burst, Collapse and Tensile design criteria.

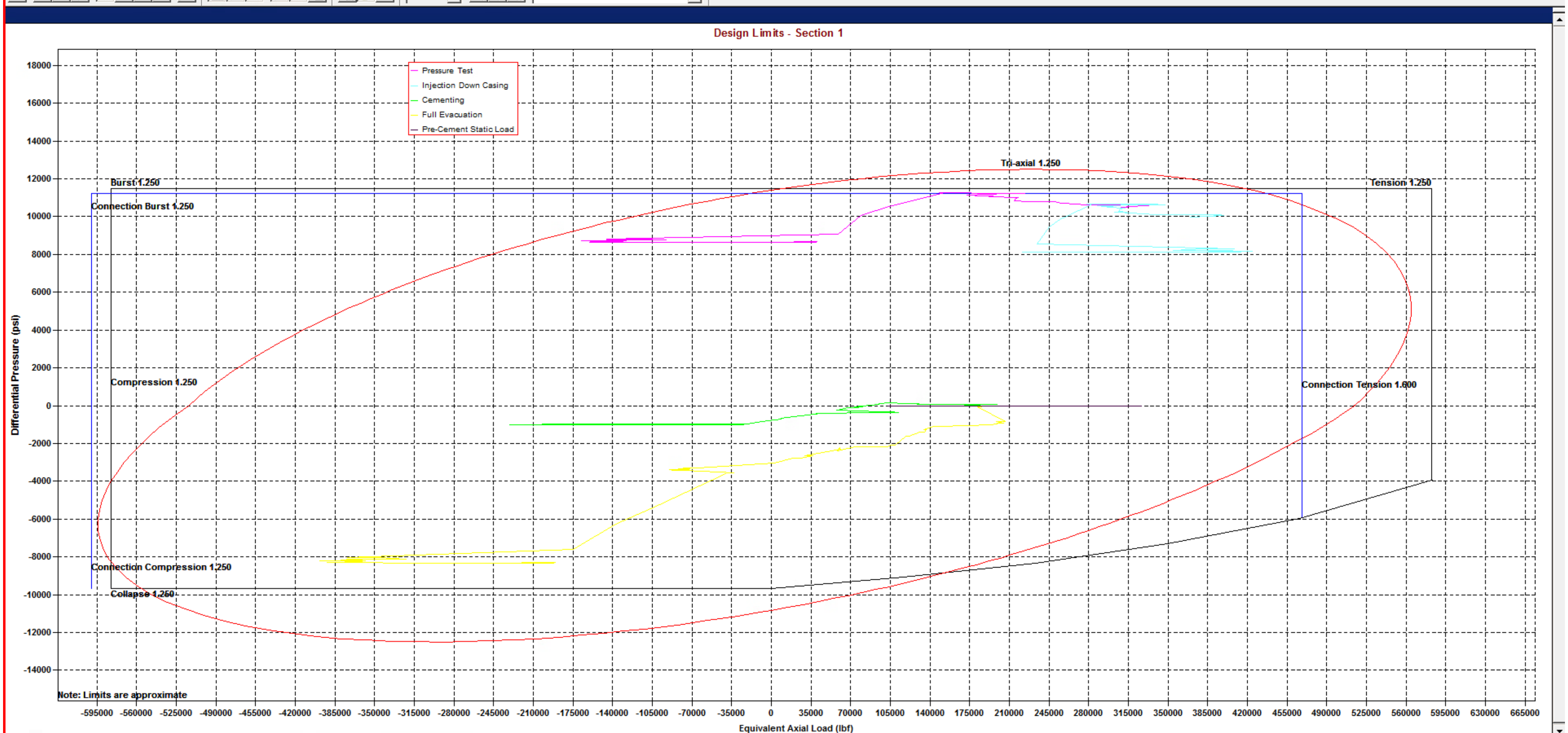


StressCheck - [String Summary - Shallow 3.0 Mile - Big Hole *]

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs)				Design Cost ($)
						Burst	Collapse (V)	Axial	Triaxial	
1	Production Casing	6", 24.500 ppf, P110 ICY	BTC, P110 ICY	0.0-28578.0	5.075	1.29	1.52	(1.75)	1.37	541,493
2										Total = 541,493
3										
4	( ) Compression									
5	(V) Vector Collapse Safety Factor									
6										

*Modelling done with 6" Production Casing with a 125ksi Control Yield. Passes all Burst, Collapse and Tensile design criteria.



StressCheck - [String Summary - Shallow 3.0 Mile]

String Summary

	String	OD/Weight/Grade	Connection	MD Interval (usft)	Drift Dia. (")	Minimum Safety Factor (Abs) Burst	Collapse (V)	Axial	Triaxial	Design Cost ($)
1	Production Casing	5 1/2", 20.000 ppf, P110 ICY	BTC, P110 ICY	0.0-28578.0	4.653	1.27	1.47	1.90 F	1.35	446,902
2										Total = 446,902
3										
4	F Conn Fracture									
5	( ) Compression									
6	(V) Vector Collapse Safety Factor									
7										

*Modelling done with 5-1/2" 20# Production Casing with a 125ksi Control Yield. Passes all Burst, Collapse and Tensile design criteria.

eog resources

Shallow Casing Design 501H

Additive	Purpose
Bentonite Gel	Lightweight/Lost circulation prevention
Calcium Chloride	Accelerator
Cello-flake	Lost circulation prevention
Sodium Metasilicate	Accelerator
MagOx	Expansive agent
Pre-Mag-M	Expansive agent
Sodium Chloride	Accelerator
FL-62	Fluid loss control
Halad-344	Fluid loss control
Halad-9	Fluid loss control
HR-601	Retarder
Microbond	Expansive Agent

Cement integrity tests will be performed immediately following plug bump.

Note: Cement volumes based on bit size plus at least 25% excess in the open hole plus 10% excess in the cased-hole overlap section.

EOG requests variance from minimum standards to pump a two stage cement job on the production casing string with the first stage being pumped conventionally with the calculated top of cement at the top of the Brushy Canyon and the second stage performed as a 1000 sack bradenhead squeeze with planned cement from the Brushy Canyon to surface. If necessary, a top out consisting of 400 sacks of Class C cement + 3% Salt + 1% PreMag-M + 6% Bentonite Gel (1.32 yld, 14.8 ppg) will be executed as a contingency. Top will be verified by Echo-meter.

Bradenhead will be the primary option for production cementing. EOG also requests to have the conventional option in place to accommodate for logistical or wellbore conditions. The tie back requirements will be met if the cement is pumped conventionally, and cement volumes will be adjusted accordingly. TOC will be verified by CBL.

eog resources

MUD PROGRAM:

During this procedure we plan to use a Closed-Loop System and haul contents to the required disposal. The applicable depths and properties of the drilling fluid systems are as follows:

Measured Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 2,030'	Fresh - Gel	8.6-8.8	28-34	N/c
2,030' – 7,793'	Brine	9-10.5	28-34	N/c
5,450' – 28,578' Lateral	Oil Base	8.8-9.5	58-68	N/c - 6

An electronic pit volume totalizer (PVT) will be utilized on the circulating system, to monitor pit volume, flow rate, pump pressure and stroke rate.

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

Appendix A - Spec Sheets

Pipe Body and API Connections Performance Data

13.375 54.50/0.380 J55

PDF

New Search »

« Back to Previous List

USC Metric

6/8/2015 10:04:37 AM

Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	**Pipe**	**BTC**	**LTC**	**STC**	
Outside Diameter	13.375	14.375	--	14.375	in.
Wall Thickness	0.380	--	--	--	in.
Inside Diameter	12.615	12.615	--	12.615	in.
Standard Drift	12.459	12.459	--	12.459	in.
Alternate Drift	--	--	--	--	in.
Nominal Linear Weight, T&C	54.50	--	--	--	lbs/ft
Plain End Weight	52.79	--	--	--	lbs/ft
Performance	**Pipe**	**BTC**	**LTC**	**STC**	
Minimum Collapse Pressure	1,130	1,130	--	1,130	psi
Minimum Internal Yield Pressure	2,740	2,740	--	2,740	psi
Minimum Pipe Body Yield Strength	853.00	--	--	--	1000 lbs
Joint Strength	--	909	--	514	1000 lbs
Reference Length	--	11,125	--	6,290	ft
Make-Up Data	**Pipe**	**BTC**	**LTC**	**STC**	
Make-Up Loss	--	4.81	--	3.50	in.
Minimum Make-Up Torque	--	--	--	3,860	ft-lbs
Maximum Make-Up Torque	--	--	--	6,430	ft-lbs

9.625 40.00/0.395 J55

PDF

New Search »

« Back to Previous List

USC Metric

6/8/2015 10:23:27 AM

Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	**Pipe**	**BTC**	**LTC**	**STC**	
Outside Diameter	9.625	10.625	10.625	10.625	in.
Wall Thickness	0.395	--	--	--	in.
Inside Diameter	8.835	8.835	8.835	8.835	in.
Standard Drift	8.679	8.679	8.679	8.679	in.
Alternate Drift	8.750	8.750	8.750	8.750	in.
Nominal Linear Weight, T&C	40.00	--	--	--	lbs/ft
Plain End Weight	38.97	--	--	--	lbs/ft
Performance	**Pipe**	**BTC**	**LTC**	**STC**	
Minimum Collapse Pressure	2,570	2,570	2,570	2,570	psi
Minimum Internal Yield Pressure	3,950	3,950	3,950	3,950	psi
Minimum Pipe Body Yield Strength	630.00	--	--	--	1000 lbs
Joint Strength	--	714	520	452	1000 lbs
Reference Length	--	11,898	8,665	7,529	ft
Make-Up Data	**Pipe**	**BTC**	**LTC**	**STC**	
Make-Up Loss	--	4.81	4.75	3.38	in.
Minimum Make-Up Torque	--	--	3,900	3,390	ft-lbs
Maximum Make-Up Torque	--	--	6,500	5,650	ft-lbs

VAM USA

DWC/C-IS MS™

Connection Data Sheet

OD (in.)	WEIGHT (lbs./ft.)	WALL (in.)	GRADE	API DRIFT (in.)	RBW%	CONNECTION
5.500	Nominal: 20.00 Plain End: 19.83	0.361	VST P110EC	4.653	87.5	DWC/C-IS MS

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

CONNECTION PROPERTIES		
Connection Type	Semi-Premium T&C	
Connection O.D. (nom)	6.115	in.
Connection I.D. (nom)	4.778	in.
Make-Up Loss	4.125	in.
Coupling Length	9.250	in.
Critical Cross Section	5.828	sq.in.
Tension Efficiency	100.0%	of pipe
Compression Efficiency	100.0%	of pipe
Internal Pressure Efficiency	100.0%	of pipe
External Pressure Efficiency	100.0%	of pipe

CONNECTION PERFORMANCES		
Yield Strength	729	klb
Parting Load	787	klb
Compression Rating	729	klb
Min. Internal Yield	14,360	psi
External Pressure	12,090	psi
Maximum Uniaxial Bend Rating	104.2	°/100 ft
Reference String Length w 1.4 Design Factor	26,040	ft

FIELD END TORQUE VALUES		
Min. Make-up torque	16,100	ft.lb
Opti. Make-up torque	17,350	ft.lb
Max. Make-up torque	18,600	ft.lb
Min. Shoulder Torque	1,610	ft.lb
Max. Shoulder Torque	12,880	ft.lb
Min. Delta Turn	-	Turns
Max. Delta Turn	0.200	Turns
Maximum Operational Torque	21,100	ft.lb
Maximum Torsional Value (MTV)	23,210	ft.lb

Need Help? Contact: tech.support@vam-usa.com

Reference Drawing: 8136PP Rev.01 & 8136BP Rev.01

Date: 12/03/2019

Time: 06:19:27 PM

For detailed information on performance properties, refer to DWC Connection Data Notes on following page(s).

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

DWC Connection Data Sheet Notes:

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

Pipe Body and API Connections Performance Data

10.750 40.50/0.350 J55

PDF

New Search »

« Back to Previous List

USC Metric

6/8/2015 10:14:05 AM

Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	**Pipe**	**BTC**	**LTC**	**STC**	
Outside Diameter	10.750	11.750	--	11.750	in.
Wall Thickness	0.350	--	--	--	in.
Inside Diameter	10.050	10.050	--	10.050	in.
Standard Drift	9.894	9.894	--	9.894	in.
Alternate Drift	--	--	--	--	in.
Nominal Linear Weight, T&C	40.50	--	--	--	lbs/ft
Plain End Weight	38.91	--	--	--	lbs/ft
Performance	**Pipe**	**BTC**	**LTC**	**STC**	
Minimum Collapse Pressure	1,580	1,580	--	1,580	psi
Minimum Internal Yield Pressure	3,130	3,130	--	3,130	psi
Minimum Pipe Body Yield Strength	629.00	--	--	--	1000 lbs
Joint Strength	--	700	--	420	1000 lbs
Reference Length	--	11,522	--	6,915	ft
Make-Up Data	**Pipe**	**BTC**	**LTC**	**STC**	
Make-Up Loss	--	4.81	--	3.50	in.
Minimum Make-Up Torque	--	--	--	3,150	ft-lbs
Maximum Make-Up Torque	--	--	--	5,250	ft-lbs

VALLOUREC STAR 8.625 32# J55 S S2L2 DA 7.875 W/O# SLN # PO# MADE IN USA FT LB

vallourec

API 5CT, 10th Ed. Connection Data Sheet

O.D. (in)	WEIGHT (lb/ft)	WALL (in)	GRADE	*API DRIFT (in)	RBW %
8.625	Nominal: 32.00 Plain End: 31.13	0.352	J55	7.796	87.5

Material Properties (PE)

Pipe	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi
Coupling	
Minimum Yield Strength:	55 ksi
Maximum Yield Strength:	80 ksi
Minimum Tensile Strength:	75 ksi

Pipe Body Data (PE)

Geometry	
Nominal ID:	7.92 inch
Nominal Area:	9.149 in^2
*Special/Alt. Drift:	7.875 inch
Performance	
Pipe Body Yield Strength:	503 kips
Collapse Resistance:	2,530 psi
Internal Yield Pressure: (API Historical)	3,930 psi

API Connection Data

Coupling OD: 9.625"

STC Performance	
STC Internal Pressure:	3,930 psi
STC Joint Strength:	372 kips
LTC Performance	
LTC Internal Pressure:	3,930 psi
LTC Joint Strength:	417 kips
SC-BTC Performance - Cplg OD = 9.125"	
BTC Internal Pressure:	3,930 psi
BTC Joint Strength:	503 kips

API Connection Torque

STC Torque (ft-lbs)

Min:		Opti:		Max:	
Min:	2,793	Opti:	3,724	Max:	4,655

LTC Torque (ft-lbs)

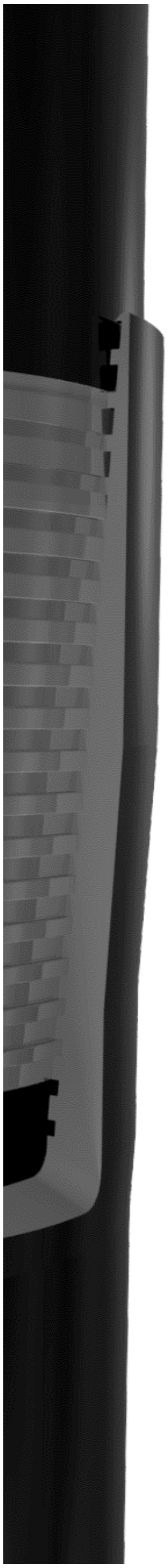
Min:	3,130	Opti:	4,174	Max:	5,217

BTC Torque (ft-lbs)

follow API guidelines regarding positional make up

*Alt. Drift will be used unless API Drift is specified on order.

**If above API connections do not suit your needs, VAM® premium connections are available up to 100% of pipe body ratings.



Issued on: 10 Feb. 2021 by Wesley Ott

VAM SPRINT-SF
Connection Data Sheet

OD	Weight (lb/ft)	Wall Th.	Grade	API Drift:	Connection
6 in.	Nominal: 24.50 Plain End: 23.95	0.400 in.	P110EC	5.075 in.	**VAM® SPRINT-SF**

PIPE PROPERTIES		
Nominal OD	6.000	in.
Nominal ID	5.200	in.
Nominal Cross Section Area	7.037	sqin.
Grade Type	High Yield	
Min. Yield Strength	125	ksi
Max. Yield Strength	140	ksi
Min. Ultimate Tensile Strength	135	ksi

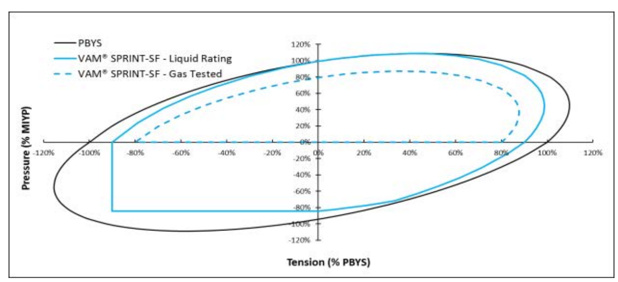
CONNECTION PROPERTIES		
Connection Type	Integral Semi-Flush	
Connection OD (nom):	6.277	in.
Connection ID (nom):	5.146	in.
Make-Up Loss	5.386	in.
Critical Cross Section	6.417	sqin.
Tension Efficiency	91.0	% of pipe
Compression Efficiency	91.0	% of pipe
Internal Pressure Efficiency	100	% of pipe
External Pressure Efficiency	100	% of pipe

CONNECTION PERFORMANCES		
Tensile Yield Strength	801	klb
Compression Resistance	801	klb
Internal Yield Pressure	14,580	psi
Collapse Resistance	12,500	psi
Max. Structural Bending	83	°/100ft
Max. Bending with ISO/API Sealability	30	°/100ft

* 87.5% RBW

TORQUE VALUES		
Min. Make-up torque	21,750	ft.lb
Opt. Make-up torque	24,250	ft.lb
Max. Make-up torque	26,750	ft.lb
Max. Torque with Sealability (MTS)	53,000	ft.lb

VAM® SPRINT-SF is a semi-flush connection innovatively designed for extreme shale applications. Its high tension rating and ultra high torque capacity make it ideal to run a fill string length as production casing in shale wells with extended horizontal sections and tight clearance requirements.



Do you need help on this product? - Remember no one knows VAM® like VAM®

canada@vamfieldservice.com
usa@vamfieldservice.com
mexico@vamfieldservice.com
brazil@vamfieldservice.com

uk@vamfieldservice.com
dubai@vamfieldservice.com
nigeria@vamfieldservice.com
angola@vamfieldservice.com

china@vamfieldservice.com
baku@vamfieldservice.com
singapore@vamfieldservice.com
australia@vamfieldservice.com

Over 140 VAM® Specialists available worldwide 24/7 for Rig Site Assistance

VAM® USA

DWC/C-IS™

Connection Data Sheet

OD (in.)	WEIGHT (lbs./ft.)	WALL (in.)	GRADE	API DRIFT (in.)	RBW%	CONNECTION
6.000	Nominal: 22.30 Plain End: 21.70	0.360	VST P110EC	5.155	92.5	DWC/C-IS

PIPE PROPERTIES

Nominal OD	6.000	in.
Nominal ID	5.280	in.
Nominal Area	6.379	sq.in.
Grade Type	API 5CT	
Min. Yield Strength	125	ksi
Max. Yield Strength	140	ksi
Min. Tensile Strength	135	ksi
Yield Strength	797	klb
Ultimate Strength	861	klb
Min. Internal Yield Pressure	13,880	psi
Collapse Pressure	9,800	psi

CONNECTION PROPERTIES

Connection Type	Semi-Premium T&C	
Connection OD (nom)	6.650	in.
Connection ID (nom)	5.280	in.
Make-Up Loss	4.313	in.
Coupling Length	9.625	in.
Critical Cross Section	6.379	sq.in.
Tension Efficiency	100.0%	of pipe
Compression Efficiency	100.0%	of pipe
Internal Pressure Efficiency	100.0%	of pipe
External Pressure Efficiency	100.0%	of pipe

CONNECTION PERFORMANCES

Yield Strength	797	klb
Parting Load	861	klb
Compression Rating	797	klb
Min. Internal Yield	13,880	psi
External Pressure	9,800	psi
Maximum Uniaxial Bend Rating	47.7	°/100 ft
Reference String Length w 1.4 Design Factor	25,530	ft.

FIELD END TORQUE VALUES

Min. Make-up torque	17,000	ft.lb
Opti. Make-up torque	18,250	ft.lb
Max. Make-up torque	19,500	ft.lb
Min. Shoulder Torque	1,700	ft.lb
Max. Shoulder Torque	13,600	ft.lb
Min. Delta Turn	-	Turns
Max. Delta Turn	0.200	Turns
Maximum Operational Torque	24,200	ft.lb
Maximum Torsional Value (MTV)	26,620	ft.lb

Need Help? Contact: tech.support@vam-usa.com

Reference Drawing: 8135PP Rev.02 & 8135BP Rev.02

Date: 07/30/2020

Time: 07:50:47 PM

For detailed information on performance properties, refer to DWC Connection Data Notes on following page(s).

VAM® USA

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

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

VAM USA

eog resources

Magnolia 15 #751H
LEA County, New Mexico
Proposed Wellbore
Design A

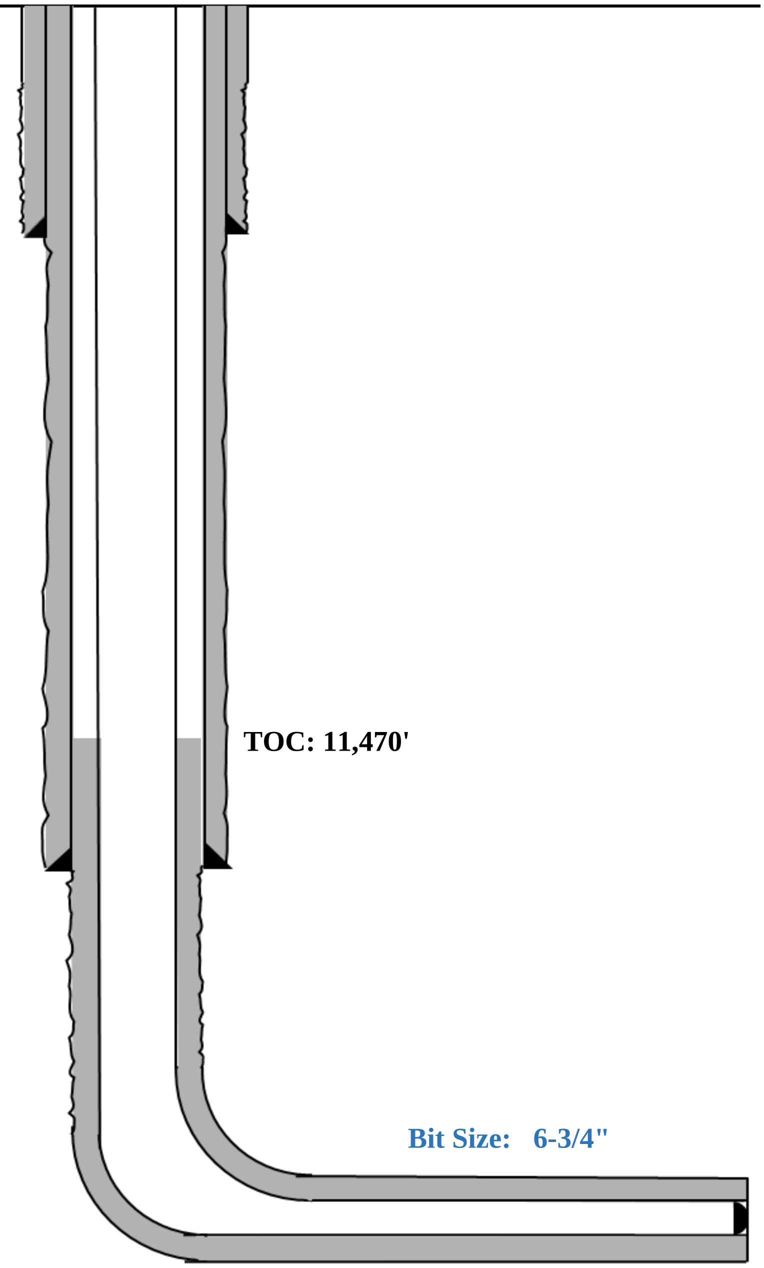
425' FNL
826' FWL
Section 15
T-26-S, R-33-E

KB: 3318'
GL: 3293'

API: 30-025-***

Bit Size: 12-1/4"
9-5/8'', 36#, J-55, LTC
@ 0' - 1,076'

Bit Size: 8-3/4"
7-5/8'', 29.7#, ICYP-110, MO FXL
@ 0' - 12,500'



TOC: 11,470'

Bit Size: 6-3/4"
5-1/2'', 17#, HCP-110, LTC
@ 0' - 17,906'

Bit Size: 6-3/4"

KOP: 12,501' MD, 12,473' TVD
EOC: 13,251' MD, 12,950' TVD

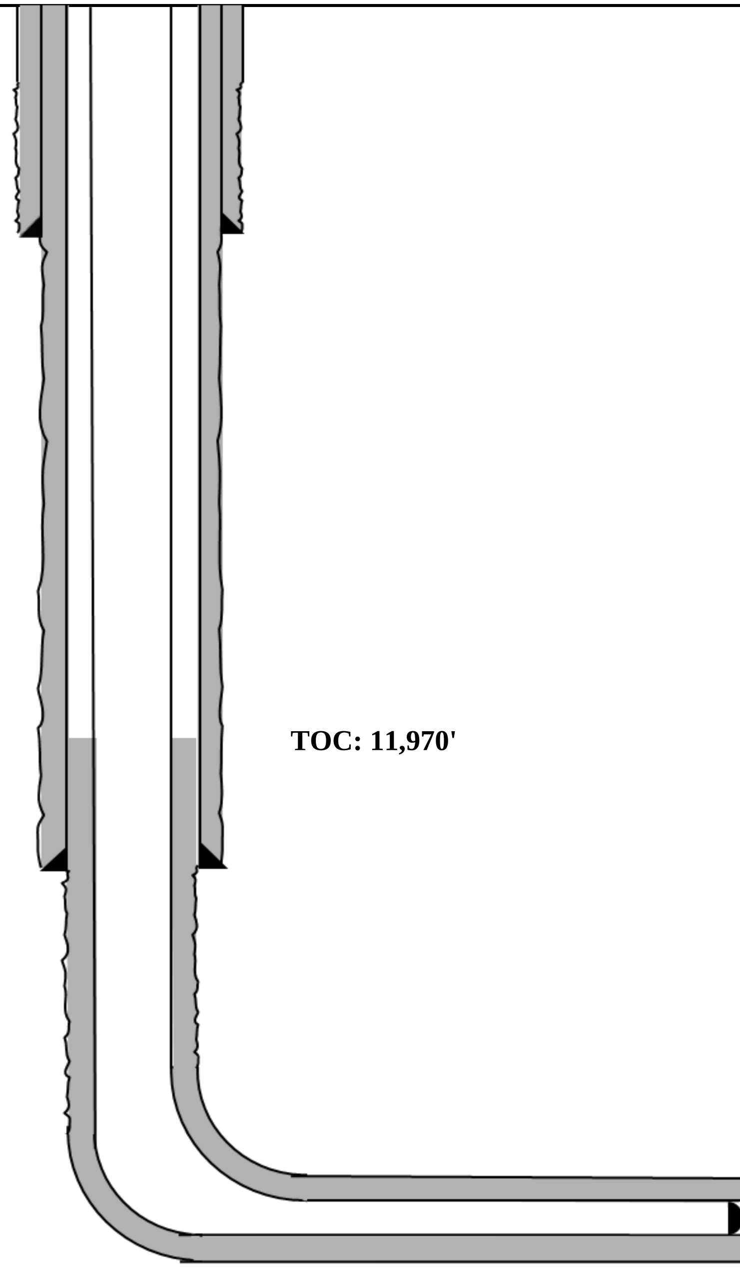
Lateral: 17,906' MD, 12,950' TVD
BH Location: 100' FSL & 330' FWL
Sec. 15
T-26-S R-33-E

Magnolia 15 #751H
LEA County, New Mexico
Proposed Wellbore
Design B

425' FNL
826' FWL
Section 15
T-26-S, R-33-E

KB: 3318'
GL: 3293'

API: 30-025-***



Bit Size: 13"
10-3/4'', 40.5#, J-55, STC,
@ 0' - 1,076'

Bit Size: 9-7/8"
8-3/4'' 38.5#, P110-EC, VAM Sprint-SF,
@ 0' - 12,502'

Bit Size: 7.875|6-3/4''
6'', 22.3#, P110-EC, DWC/C IS,
@ 0' - 12,601'
5-1/2'', 20#, P110-EC, DWC/C IS MS,
@ 12,601' - 17,906'

KOP: 12,501' MD, 12,473' TVD
EOC: 13,251' MD, 12,950' TVD

Lateral: 17,906' MD, 12,950' TVD
BH Location: 100' FSL & 330' FWL
Sec. 15
T-26-S R-33-E

eog resources

Magnolia 15 #751H

Permit Informati
Well Name: Magnolia 15 #751H

Location:
SHL: 425' FNL & 826' FWL, Section 15, T-26-S, R-33-E, LEA Co., N.M.
BHL: 100' FSL & 330' FWL, Section 15, T-26-S, R-33-E, LEA Co., N.M.

Design A

Casing Program:

Hole Size	Interval MD From (ft)	Interval MD To (ft)	Interval TVD From (ft)	Interval TVD To (ft)	Csg OD	Weight	Grade	Conn
12-1/4"	0	1,076	0	1,076	9-5/8"	36#	J-55	LTC
8-3/4"	0	12,502	0	12,473	7-5/8"	29.7#	ICYP-110	MO FXL
6-3/4"	0	17,906	0	12,950	5-1/2"	17#	HCP-110	LTC

Cement Program:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,076'	300	13.5	1.73	Class C/H + additives (TOC @ Surface)
	80	14.8	1.34	Class C/H + additives
12,470'	540	14.2	1.11	1st Stage (Tail): Class C/H + additives (TOC @ 7,864')
	1340	14.8	1.5	2nd Stage (Bradenhead squeeze): Class C/H + additives + expansion additives (TOC @ surface)
17,906'	540	13.2	1.31	Class C/H + additives (TOC @ 11,970')

Mud Program:

Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 1,076'	Fresh - Gel	8.6-8.8	28-34	N/c
1,076' – 12,470'	Brine	10.0-10.2	28-34	N/c
12,470’ – 12,501'	Water - Gel	8.7-9.4	58-68	N/c - 6
12,501’ – 17,906’ Lateral	Oil Base	10.0-14.0	58-68	4 - 6

eog resources

Magnolia 15 #751H

Design B

CASING PROGRAM

Hole Size	Interval MD From (ft)	Interval MD To (ft)	Interval TVD From (ft)	Interval TVD To (ft)	Csg OD	Weight	Grade	Conn
13"	0	1,076	0	1,080	10-3/4"	40.5#	J-55	STC
9-7/8"	0	12,502	0	12,473	8-3/4"	38.5#	P110-EC	VAM Sprint-SF
7-7/8"	0	12,601	0	12,573	6"	22.3#	P110-EC	DWC/C IS
6-3/4"	0	17,906	0	12,950	5-1/2"	20#	P110-EC	DWC/C IS MS

**For highlighted rows above, variance is requested to run entire string of either 6" or 5-1/2" casing string above.

Cementing Program:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,076' 10-3/4"	280	13.5	1.73	Lead: Class C/H + additives (TOC @ Surface)
	70	14.8	1.34	Tail: Class C/H + additives (TOC @ 876')
12,473' 8-3/4"	1630	14.2	1.11	1st Stage (Tail): Class C/H + additives (TOC @ 7,864')
	1000	14.8	1.5	2nd Stage (Bradenhead squeeze): Class C/H + additives + expansion additives (TOC @ surface)
17,906' 6"	850	13.2	1.31	Lead: Class C/H + additives (TOC @ 11,973')

EOG requests a variance to set the intermediate casing shoe in the Bone Spring formation OR the Wolfcamp formation, depending on depletion in the area and well conditions. EOG will monitor the well and ensure the well is static before casing operations begin.

EOG requests variance from minimum standards to pump a two stage cement job on the 8-3/4" intermediate casing string with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon (8,064') and the second stage performed as a 1000 sack bradenhead squeeze with planned cement from the Brushy Canyon to surface. If necessary, a top out consisting of 100 sacks of Class C/H cement + additives + expansion additives (2.30 yld, 12.91 ppg) will be executed as a contingency.

Mud Program:

Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 1,076'	Fresh - Gel	8.6-8.8	28-34	N/c
1,076' – 4,901'	Brine	10.0-10.2	28-34	N/c
4,901' – 12,470'	Water - Gel	8.7-9.4	58-68	N/c - 6
12,470’ – 17,906’ Lateral	Oil Base	10.0-14.0	58-68	4 - 6

eog resources

Magnolia 15 751H

TUBING REQUIREMENTS

EOG respectively requests an exception to the following NMOCD rule:

- 19.15.16.10 Casing AND TUBING RQUIREMENTS:
  J (3): "The operator shall set tubing as near the bottom as practical and tubing perforations shall not be more than 250 feet above top of pay zone."

With horizontal flowing and gas lifted wells an end of tubing depth placed at or slightly above KOP is a conservative way to ensure the tubing stays clean from debris, plugging, and allows for fewer well interventions post offset completion. The deeper the tubulars are run into the curve, the higher the probability is that the tubing will become stuck in sand and or well debris as the well produces over time. An additional consideration for EOT placement during artificial lift installations is avoiding the high dog leg severity and inclinations found in the curve section of the wellbore to help improve reliability and performance. Dog leg severity and inclinations tend not to hamper gas lifted or flowing wells, but they do effect other forms of artificial lift like rod pump or ESP (electric submersible pump). Keeping the EOT above KOP is an industry best practice for those respective forms of artificial lift.

eog resources

Magnolia 15 #751H

Hydrogen Sulfide Plan Summary

A. All personnel shall receive proper H2S training in accordance with Onshore Order III.C.3.a.

B. Briefing Area: two perpendicular areas will be designated by signs and readily accessible.

C. Required Emergency Equipment:

■ Well control equipment
a. Flare line 150’ from wellhead to be ignited by flare gun.
b. Choke manifold with a remotely operated choke.
c. Mud/gas separator

■ Protective equipment for essential personnel.
Breathing apparatus:
a. Rescue Packs (SCBA) — 1 unit shall be placed at each breathing area, 2 shall be stored in the safety trailer.
b. Work/Escape packs —4 packs shall be stored on the rig floor with sufficient air hose not to restrict work activity.
c. Emergency Escape Packs —4 packs shall be stored in the doghouse for emergency evacuation.

Auxiliary Rescue Equipment:
a. Stretcher
b. Two OSHA full body harness
c. 100 ft 5/8 inch OSHA approved rope
d. 1-20# class ABC fire extinguisher

■ H2S detection and monitoring equipment:
The stationary detector with three sensors will be placed in the upper dog house if equipped, set to visually alarm @ 10 ppm and audible @ 14 ppm. Calibrate a minimum of every 30 days or as needed. The sensors will be placed in the following places: Rig floor / Bell nipple / End of flow line or where well bore fluid is being discharged.
(Gas sample tubes will be stored in the safety trailer)

■ Visual warning systems.
a. One color code condition sign will be placed at the entrance to the site reflecting the possible conditions at the site.
b. A colored condition flag will be on display, reflecting the current condition at the site at the time.
c. Two wind socks will be placed in strategic locations, visible from all angles.

eog resources

Magnolia 15 #751H

- Mud program:
  The mud program has been designed to minimize the volume of H2S circulated to surface. The operator will have the necessary mud products to minimize hazards while drilling in H2S bearing zones.

- Metallurgy:
  All drill strings, casings, tubing, wellhead, blowout preventer, drilling spool, kill lines, choke manifold and lines, and valves shall be suitable for H2S service.

- Communication:
  Communication will be via cell phones and land lines where available.

eog resources

Magnolia 15 #751H

Emergency Assistance Telephone List

PUBLIC SAFETY:			911 or
Lea County Sheriff's Department			(575) 396-3611
	Rod Coffman		
Fire Department:			
	Carlsbad		(575) 885-3125
	Artesia		(575) 746-5050
Hospitals:			
	Carlsbad		(575) 887-4121
	Artesia		(575) 748-3333
	Hobbs		(575) 392-1979
Dept. of Public Safety/Carlsbad			(575) 748-9718
Highway Department			(575) 885-3281
New Mexico Oil Conservation			(575) 476-3440
NMOCD Inspection Group - South			(575) 626-0830
U.S. Dept. of Labor			(575) 887-1174
EOG Resources, Inc.			
EOG / Midland		Office	(432) 686-3600
Company Drilling Consultants:			
David Dominque		Cell	(985) 518-5839
Mike Vann		Cell	(817) 980-5507
Drilling Engineer			
Stephen Davis		Cell	(432) 235-9789
Matt Day		Cell	(432) 296-4456
Drilling Manager			
Branden Keener		Office	(432) 686-3752
		Cell	(210) 294-3729
Drilling Superintendent			
Ryan Reynolds		Cell	(432) 215-5978
Steve Kelly		Cell	(210) 416-7894
H&P Drilling			
H&P Drilling		Office	(432) 563-5757
H&P 651 Drilling Rig		Rig	(903) 509-7131
Tool Pusher:			
Johnathan Craig		Cell	(817) 760-6374
Brad Garrett			
Safety:			
Brian Chandler (HSE Manager)		Office	(432) 686-3695
		Cell	(817) 239-0251

Midland

Lea County, NM (NAD 83 NME)
Magnolia 15
751H

OH

Plan: Plan #0.1

Standard Planning Report

30 December, 2024

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well 751H
Company:	Midland	**TVD Reference:**	25 @ 3318.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	25 @ 3318.0usft
Site:	Magnolia 15	**North Reference:**	Grid
Well:	751H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1		

Project	Lea County, NM (NAD 83 NME)		
Map System:	US State Plane 1983	**System Datum:**	Mean Sea Level
Geo Datum:	North American Datum 1983		
Map Zone:	New Mexico Eastern Zone		

Site	Magnolia 15				
Site Position:		**Northing:**	378,055.00 usft	**Latitude:**	32° 2' 13.337 N
From:	Map	**Easting:**	778,760.00 usft	**Longitude:**	103° 34' 1.656 W
Position Uncertainty:	0.0 usft	**Slot Radius:**	13-3/16 "		

Well	751H					
Well Position	**+N/-S**	0.0 usft	**Northing:**	382,617.00 usft	**Latitude:**	32° 2' 58.459 N
	+E/-W	0.0 usft	**Easting:**	779,058.00 usft	**Longitude:**	103° 33' 57.818 W
Position Uncertainty		0.0 usft	**Wellhead Elevation:**	usft	**Ground Level:**	3,293.0 usft
Grid Convergence:		0.41 °				

Wellbore OH

Magnetics	Model Name	Sample Date	Declination (°)	Dip Angle (°)	Field Strength (nT)
	IGRF2020	12/30/2024	6.11	59.62	47,022.98844005

Design Plan #0.1

Audit Notes:

Version:		**Phase:**	PLAN	**Tie On Depth:**	0.0

Vertical Section:	Depth From (TVD) (usft)	+N/-S (usft)	+E/-W (usft)	Direction (°)
	0.0	0.0	0.0	185.51

Plan Survey Tool Program **Date** 12/30/2024

	Depth From (usft)	Depth To (usft)	Survey (Wellbore)	Tool Name	Remarks
1	0.0	17,906.1	Plan #0.1 (OH)	EOG MWD+IFR1 MWD + IFR1	

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well 751H
Company:	Midland	**TVD Reference:**	25 @ 3318.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	25 @ 3318.0usft
Site:	Magnolia 15	**North Reference:**	Grid
Well:	751H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1		

Plan Sections

Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)	TFO (°)	Target
0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,200.0	0.00	0.00	1,200.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,469.6	5.39	306.70	1,469.2	7.6	-10.2	2.00	2.00	0.00	306.70	
7,823.3	5.39	306.70	7,794.8	364.4	-488.8	0.00	0.00	0.00	0.00	
8,092.9	0.00	0.00	8,064.0	372.0	-499.0	2.00	-2.00	0.00	180.00	
12,501.4	0.00	0.00	12,472.5	372.0	-499.0	0.00	0.00	0.00	0.00	KOP(MAG 15 #751H)
12,721.9	26.46	180.00	12,685.2	322.0	-499.0	12.00	12.00	81.65	180.00	FTP(MAG 15 #751H)
13,251.4	90.00	179.54	12,949.9	-105.5	-496.6	12.00	12.00	-0.09	-0.52	
17,906.1	90.00	179.54	12,950.0	-4,760.0	-459.0	0.00	0.00	0.00	0.00	PBHL(MAG 15 #751H

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well 751H
Company:	Midland	**TVD Reference:**	25 @ 3318.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	25 @ 3318.0usft
Site:	Magnolia 15	**North Reference:**	Grid
Well:	751H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1		

Planned Survey

Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Vertical Section (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)
0.0	0.00	0.00	0.0	0.0	0.0	0.0	0.00	0.00	0.00
100.0	0.00	0.00	100.0	0.0	0.0	0.0	0.00	0.00	0.00
200.0	0.00	0.00	200.0	0.0	0.0	0.0	0.00	0.00	0.00
300.0	0.00	0.00	300.0	0.0	0.0	0.0	0.00	0.00	0.00
400.0	0.00	0.00	400.0	0.0	0.0	0.0	0.00	0.00	0.00
500.0	0.00	0.00	500.0	0.0	0.0	0.0	0.00	0.00	0.00
600.0	0.00	0.00	600.0	0.0	0.0	0.0	0.00	0.00	0.00
700.0	0.00	0.00	700.0	0.0	0.0	0.0	0.00	0.00	0.00
800.0	0.00	0.00	800.0	0.0	0.0	0.0	0.00	0.00	0.00
900.0	0.00	0.00	900.0	0.0	0.0	0.0	0.00	0.00	0.00
1,000.0	0.00	0.00	1,000.0	0.0	0.0	0.0	0.00	0.00	0.00
1,100.0	0.00	0.00	1,100.0	0.0	0.0	0.0	0.00	0.00	0.00
1,200.0	0.00	0.00	1,200.0	0.0	0.0	0.0	0.00	0.00	0.00
1,300.0	2.00	306.70	1,300.0	1.0	-1.4	-0.9	2.00	2.00	0.00
1,400.0	4.00	306.70	1,399.8	4.2	-5.6	-3.6	2.00	2.00	0.00
1,469.6	5.39	306.70	1,469.2	7.6	-10.2	-6.6	2.00	2.00	0.00
1,500.0	5.39	306.70	1,499.5	9.3	-12.5	-8.0	0.00	0.00	0.00
1,600.0	5.39	306.70	1,599.0	14.9	-20.0	-12.9	0.00	0.00	0.00
1,700.0	5.39	306.70	1,698.6	20.5	-27.5	-17.8	0.00	0.00	0.00
1,800.0	5.39	306.70	1,798.1	26.1	-35.1	-22.6	0.00	0.00	0.00
1,900.0	5.39	306.70	1,897.7	31.7	-42.6	-27.5	0.00	0.00	0.00
2,000.0	5.39	306.70	1,997.3	37.4	-50.1	-32.4	0.00	0.00	0.00
2,100.0	5.39	306.70	2,096.8	43.0	-57.7	-37.2	0.00	0.00	0.00
2,200.0	5.39	306.70	2,196.4	48.6	-65.2	-42.1	0.00	0.00	0.00
2,300.0	5.39	306.70	2,295.9	54.2	-72.7	-47.0	0.00	0.00	0.00
2,400.0	5.39	306.70	2,395.5	59.8	-80.3	-51.9	0.00	0.00	0.00
2,500.0	5.39	306.70	2,495.0	65.4	-87.8	-56.7	0.00	0.00	0.00
2,600.0	5.39	306.70	2,594.6	71.1	-95.3	-61.6	0.00	0.00	0.00
2,700.0	5.39	306.70	2,694.2	76.7	-102.9	-66.5	0.00	0.00	0.00
2,800.0	5.39	306.70	2,793.7	82.3	-110.4	-71.3	0.00	0.00	0.00
2,900.0	5.39	306.70	2,893.3	87.9	-117.9	-76.2	0.00	0.00	0.00
3,000.0	5.39	306.70	2,992.8	93.5	-125.5	-81.1	0.00	0.00	0.00
3,100.0	5.39	306.70	3,092.4	99.1	-133.0	-85.9	0.00	0.00	0.00
3,200.0	5.39	306.70	3,191.9	104.8	-140.5	-90.8	0.00	0.00	0.00
3,300.0	5.39	306.70	3,291.5	110.4	-148.1	-95.7	0.00	0.00	0.00
3,400.0	5.39	306.70	3,391.1	116.0	-155.6	-100.5	0.00	0.00	0.00
3,500.0	5.39	306.70	3,490.6	121.6	-163.1	-105.4	0.00	0.00	0.00
3,600.0	5.39	306.70	3,590.2	127.2	-170.7	-110.3	0.00	0.00	0.00
3,700.0	5.39	306.70	3,689.7	132.8	-178.2	-115.1	0.00	0.00	0.00
3,800.0	5.39	306.70	3,789.3	138.5	-185.7	-120.0	0.00	0.00	0.00
3,900.0	5.39	306.70	3,888.8	144.1	-193.3	-124.9	0.00	0.00	0.00
4,000.0	5.39	306.70	3,988.4	149.7	-200.8	-129.7	0.00	0.00	0.00
4,100.0	5.39	306.70	4,088.0	155.3	-208.3	-134.6	0.00	0.00	0.00
4,200.0	5.39	306.70	4,187.5	160.9	-215.9	-139.5	0.00	0.00	0.00
4,300.0	5.39	306.70	4,287.1	166.5	-223.4	-144.3	0.00	0.00	0.00
4,400.0	5.39	306.70	4,386.6	172.2	-230.9	-149.2	0.00	0.00	0.00
4,500.0	5.39	306.70	4,486.2	177.8	-238.5	-154.1	0.00	0.00	0.00
4,600.0	5.39	306.70	4,585.8	183.4	-246.0	-158.9	0.00	0.00	0.00
4,700.0	5.39	306.70	4,685.3	189.0	-253.5	-163.8	0.00	0.00	0.00
4,800.0	5.39	306.70	4,784.9	194.6	-261.1	-168.7	0.00	0.00	0.00
4,900.0	5.39	306.70	4,884.4	200.2	-268.6	-173.5	0.00	0.00	0.00
5,000.0	5.39	306.70	4,984.0	205.9	-276.1	-178.4	0.00	0.00	0.00
5,100.0	5.39	306.70	5,083.5	211.5	-283.7	-183.3	0.00	0.00	0.00
5,200.0	5.39	306.70	5,183.1	217.1	-291.2	-188.1	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well 751H
Company:	Midland	**TVD Reference:**	25 @ 3318.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	25 @ 3318.0usft
Site:	Magnolia 15	**North Reference:**	Grid
Well:	751H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1		

Planned Survey

Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Vertical Section (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)
5,300.0	5.39	306.70	5,282.7	222.7	-298.7	-193.0	0.00	0.00	0.00
5,400.0	5.39	306.70	5,382.2	228.3	-306.3	-197.9	0.00	0.00	0.00
5,500.0	5.39	306.70	5,481.8	233.9	-313.8	-202.7	0.00	0.00	0.00
5,600.0	5.39	306.70	5,581.3	239.6	-321.3	-207.6	0.00	0.00	0.00
5,700.0	5.39	306.70	5,680.9	245.2	-328.9	-212.5	0.00	0.00	0.00
5,800.0	5.39	306.70	5,780.4	250.8	-336.4	-217.3	0.00	0.00	0.00
5,900.0	5.39	306.70	5,880.0	256.4	-343.9	-222.2	0.00	0.00	0.00
6,000.0	5.39	306.70	5,979.6	262.0	-351.5	-227.1	0.00	0.00	0.00
6,100.0	5.39	306.70	6,079.1	267.6	-359.0	-231.9	0.00	0.00	0.00
6,200.0	5.39	306.70	6,178.7	273.3	-366.5	-236.8	0.00	0.00	0.00
6,300.0	5.39	306.70	6,278.2	278.9	-374.1	-241.7	0.00	0.00	0.00
6,400.0	5.39	306.70	6,377.8	284.5	-381.6	-246.5	0.00	0.00	0.00
6,500.0	5.39	306.70	6,477.3	290.1	-389.1	-251.4	0.00	0.00	0.00
6,600.0	5.39	306.70	6,576.9	295.7	-396.7	-256.3	0.00	0.00	0.00
6,700.0	5.39	306.70	6,676.5	301.3	-404.2	-261.1	0.00	0.00	0.00
6,800.0	5.39	306.70	6,776.0	307.0	-411.7	-266.0	0.00	0.00	0.00
6,900.0	5.39	306.70	6,875.6	312.6	-419.3	-270.9	0.00	0.00	0.00
7,000.0	5.39	306.70	6,975.1	318.2	-426.8	-275.7	0.00	0.00	0.00
7,100.0	5.39	306.70	7,074.7	323.8	-434.3	-280.6	0.00	0.00	0.00
7,200.0	5.39	306.70	7,174.2	329.4	-441.9	-285.5	0.00	0.00	0.00
7,300.0	5.39	306.70	7,273.8	335.0	-449.4	-290.3	0.00	0.00	0.00
7,400.0	5.39	306.70	7,373.4	340.6	-456.9	-295.2	0.00	0.00	0.00
7,500.0	5.39	306.70	7,472.9	346.3	-464.5	-300.1	0.00	0.00	0.00
7,600.0	5.39	306.70	7,572.5	351.9	-472.0	-305.0	0.00	0.00	0.00
7,700.0	5.39	306.70	7,672.0	357.5	-479.5	-309.8	0.00	0.00	0.00
7,800.0	5.39	306.70	7,771.6	363.1	-487.1	-314.7	0.00	0.00	0.00
7,823.3	5.39	306.70	7,794.8	364.4	-488.8	-315.8	0.00	0.00	0.00
7,900.0	3.86	306.70	7,871.2	368.1	-493.8	-319.0	2.00	-2.00	0.00
8,000.0	1.86	306.70	7,971.1	371.1	-497.8	-321.6	2.00	-2.00	0.00
8,092.9	0.00	0.00	8,064.0	372.0	-499.0	-322.4	2.00	-2.00	0.00
8,100.0	0.00	0.00	8,071.1	372.0	-499.0	-322.4	0.00	0.00	0.00
8,200.0	0.00	0.00	8,171.1	372.0	-499.0	-322.4	0.00	0.00	0.00
8,300.0	0.00	0.00	8,271.1	372.0	-499.0	-322.4	0.00	0.00	0.00
8,400.0	0.00	0.00	8,371.1	372.0	-499.0	-322.4	0.00	0.00	0.00
8,500.0	0.00	0.00	8,471.1	372.0	-499.0	-322.4	0.00	0.00	0.00
8,600.0	0.00	0.00	8,571.1	372.0	-499.0	-322.4	0.00	0.00	0.00
8,700.0	0.00	0.00	8,671.1	372.0	-499.0	-322.4	0.00	0.00	0.00
8,800.0	0.00	0.00	8,771.1	372.0	-499.0	-322.4	0.00	0.00	0.00
8,900.0	0.00	0.00	8,871.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,000.0	0.00	0.00	8,971.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,100.0	0.00	0.00	9,071.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,200.0	0.00	0.00	9,171.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,300.0	0.00	0.00	9,271.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,400.0	0.00	0.00	9,371.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,500.0	0.00	0.00	9,471.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,600.0	0.00	0.00	9,571.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,700.0	0.00	0.00	9,671.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,800.0	0.00	0.00	9,771.1	372.0	-499.0	-322.4	0.00	0.00	0.00
9,900.0	0.00	0.00	9,871.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,000.0	0.00	0.00	9,971.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,100.0	0.00	0.00	10,071.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,200.0	0.00	0.00	10,171.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,300.0	0.00	0.00	10,271.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,400.0	0.00	0.00	10,371.1	372.0	-499.0	-322.4	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well 751H
Company:	Midland	**TVD Reference:**	25 @ 3318.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	25 @ 3318.0usft
Site:	Magnolia 15	**North Reference:**	Grid
Well:	751H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1		

Planned Survey

Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Vertical Section (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)
10,500.0	0.00	0.00	10,471.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,600.0	0.00	0.00	10,571.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,700.0	0.00	0.00	10,671.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,800.0	0.00	0.00	10,771.1	372.0	-499.0	-322.4	0.00	0.00	0.00
10,900.0	0.00	0.00	10,871.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,000.0	0.00	0.00	10,971.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,100.0	0.00	0.00	11,071.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,200.0	0.00	0.00	11,171.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,300.0	0.00	0.00	11,271.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,400.0	0.00	0.00	11,371.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,500.0	0.00	0.00	11,471.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,600.0	0.00	0.00	11,571.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,700.0	0.00	0.00	11,671.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,800.0	0.00	0.00	11,771.1	372.0	-499.0	-322.4	0.00	0.00	0.00
11,900.0	0.00	0.00	11,871.1	372.0	-499.0	-322.4	0.00	0.00	0.00
12,000.0	0.00	0.00	11,971.1	372.0	-499.0	-322.4	0.00	0.00	0.00
12,100.0	0.00	0.00	12,071.1	372.0	-499.0	-322.4	0.00	0.00	0.00
12,200.0	0.00	0.00	12,171.1	372.0	-499.0	-322.4	0.00	0.00	0.00
12,300.0	0.00	0.00	12,271.1	372.0	-499.0	-322.4	0.00	0.00	0.00
12,400.0	0.00	0.00	12,371.1	372.0	-499.0	-322.4	0.00	0.00	0.00
12,501.4	0.00	0.00	12,472.5	372.0	-499.0	-322.4	0.00	0.00	0.00
12,525.0	2.83	180.00	12,496.1	371.4	-499.0	-321.8	12.00	12.00	0.00
12,550.0	5.83	180.00	12,521.0	369.5	-499.0	-319.9	12.00	12.00	0.00
12,575.0	8.83	180.00	12,545.8	366.3	-499.0	-316.8	12.00	12.00	0.00
12,600.0	11.83	180.00	12,570.4	361.9	-499.0	-312.3	12.00	12.00	0.00
12,625.0	14.83	180.00	12,594.7	356.1	-499.0	-306.6	12.00	12.00	0.00
12,650.0	17.83	180.00	12,618.7	349.1	-499.0	-299.6	12.00	12.00	0.00
12,675.0	20.83	180.00	12,642.3	340.8	-499.0	-291.3	12.00	12.00	0.00
12,700.0	23.83	180.00	12,665.4	331.3	-499.0	-281.9	12.00	12.00	0.00
12,721.9	26.46	180.00	12,685.2	322.0	-499.0	-272.6	12.00	12.00	0.00
12,725.0	26.83	179.99	12,688.0	320.6	-499.0	-271.2	12.00	12.00	-0.24
12,750.0	29.83	179.94	12,710.0	308.7	-499.0	-259.4	12.00	12.00	-0.21
12,775.0	32.83	179.89	12,731.4	295.7	-499.0	-246.5	12.00	12.00	-0.18
12,800.0	35.83	179.86	12,752.0	281.6	-498.9	-232.4	12.00	12.00	-0.15
12,825.0	38.83	179.82	12,771.9	266.5	-498.9	-217.4	12.00	12.00	-0.13
12,850.0	41.83	179.79	12,790.9	250.3	-498.8	-201.3	12.00	12.00	-0.12
12,875.0	44.83	179.77	12,809.1	233.1	-498.8	-184.2	12.00	12.00	-0.10
12,900.0	47.83	179.75	12,826.4	215.1	-498.7	-166.2	12.00	12.00	-0.09
12,925.0	50.83	179.72	12,842.7	196.1	-498.6	-147.3	12.00	12.00	-0.08
12,950.0	53.83	179.71	12,857.9	176.3	-498.5	-127.6	12.00	12.00	-0.08
12,975.0	56.83	179.69	12,872.2	155.8	-498.4	-107.2	12.00	12.00	-0.07
13,000.0	59.83	179.67	12,885.3	134.5	-498.3	-86.0	12.00	12.00	-0.07
13,025.0	62.83	179.66	12,897.3	112.5	-498.2	-64.2	12.00	12.00	-0.06
13,050.0	65.83	179.64	12,908.1	90.0	-498.0	-41.8	12.00	12.00	-0.06
13,075.0	68.83	179.63	12,917.7	66.9	-497.9	-18.8	12.00	12.00	-0.06
13,100.0	71.83	179.61	12,926.1	43.4	-497.7	4.6	12.00	12.00	-0.05
13,125.0	74.83	179.60	12,933.3	19.5	-497.6	28.4	12.00	12.00	-0.05
13,150.0	77.83	179.59	12,939.2	-4.8	-497.4	52.5	12.00	12.00	-0.05
13,175.0	80.83	179.57	12,943.8	-29.4	-497.2	77.0	12.00	12.00	-0.05
13,200.0	83.83	179.56	12,947.2	-54.2	-497.0	101.6	12.00	12.00	-0.05
13,225.0	86.83	179.55	12,949.2	-79.1	-496.8	126.4	12.00	12.00	-0.05
13,251.4	90.00	179.54	12,949.9	-105.5	-496.6	152.6	12.00	12.00	-0.05
13,300.0	90.00	179.54	12,949.9	-154.1	-496.2	201.0	0.00	0.00	0.00
13,400.0	90.00	179.54	12,949.9	-254.1	-495.4	300.4	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well 751H
Company:	Midland	**TVD Reference:**	25 @ 3318.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	25 @ 3318.0usft
Site:	Magnolia 15	**North Reference:**	Grid
Well:	751H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1		

Planned Survey

Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Vertical Section (usft)	Dogleg Rate (°/100usft)	Build Rate (°/100usft)	Turn Rate (°/100usft)
13,500.0	90.00	179.54	12,949.9	-354.1	-494.6	399.9	0.00	0.00	0.00
13,600.0	90.00	179.54	12,950.0	-454.1	-493.8	499.4	0.00	0.00	0.00
13,700.0	90.00	179.54	12,950.0	-554.0	-493.0	598.8	0.00	0.00	0.00
13,800.0	90.00	179.54	12,950.0	-654.0	-492.2	698.3	0.00	0.00	0.00
13,900.0	90.00	179.54	12,950.0	-754.0	-491.4	797.7	0.00	0.00	0.00
14,000.0	90.00	179.54	12,950.0	-854.0	-490.6	897.2	0.00	0.00	0.00
14,100.0	90.00	179.54	12,950.0	-954.0	-489.8	996.6	0.00	0.00	0.00
14,200.0	90.00	179.54	12,950.0	-1,054.0	-488.9	1,096.1	0.00	0.00	0.00
14,300.0	90.00	179.54	12,950.0	-1,154.0	-488.1	1,195.6	0.00	0.00	0.00
14,400.0	90.00	179.54	12,950.0	-1,254.0	-487.3	1,295.0	0.00	0.00	0.00
14,500.0	90.00	179.54	12,950.0	-1,354.0	-486.5	1,394.5	0.00	0.00	0.00
14,600.0	90.00	179.54	12,950.0	-1,454.0	-485.7	1,493.9	0.00	0.00	0.00
14,700.0	90.00	179.54	12,950.0	-1,554.0	-484.9	1,593.4	0.00	0.00	0.00
14,800.0	90.00	179.54	12,950.0	-1,654.0	-484.1	1,692.8	0.00	0.00	0.00
14,900.0	90.00	179.54	12,950.0	-1,754.0	-483.3	1,792.3	0.00	0.00	0.00
15,000.0	90.00	179.54	12,950.0	-1,854.0	-482.5	1,891.8	0.00	0.00	0.00
15,100.0	90.00	179.54	12,950.0	-1,954.0	-481.7	1,991.2	0.00	0.00	0.00
15,200.0	90.00	179.54	12,950.0	-2,054.0	-480.9	2,090.7	0.00	0.00	0.00
15,300.0	90.00	179.54	12,950.0	-2,154.0	-480.1	2,190.1	0.00	0.00	0.00
15,400.0	90.00	179.54	12,950.0	-2,254.0	-479.2	2,289.6	0.00	0.00	0.00
15,500.0	90.00	179.54	12,950.0	-2,354.0	-478.4	2,389.0	0.00	0.00	0.00
15,600.0	90.00	179.54	12,950.0	-2,454.0	-477.6	2,488.5	0.00	0.00	0.00
15,700.0	90.00	179.54	12,950.0	-2,554.0	-476.8	2,588.0	0.00	0.00	0.00
15,800.0	90.00	179.54	12,950.0	-2,654.0	-476.0	2,687.4	0.00	0.00	0.00
15,900.0	90.00	179.54	12,950.0	-2,754.0	-475.2	2,786.9	0.00	0.00	0.00
16,000.0	90.00	179.54	12,950.0	-2,854.0	-474.4	2,886.3	0.00	0.00	0.00
16,100.0	90.00	179.54	12,950.0	-2,954.0	-473.6	2,985.8	0.00	0.00	0.00
16,200.0	90.00	179.54	12,950.0	-3,054.0	-472.8	3,085.2	0.00	0.00	0.00
16,300.0	90.00	179.54	12,950.0	-3,154.0	-472.0	3,184.7	0.00	0.00	0.00
16,400.0	90.00	179.54	12,950.0	-3,254.0	-471.2	3,284.2	0.00	0.00	0.00
16,500.0	90.00	179.54	12,950.0	-3,354.0	-470.4	3,383.6	0.00	0.00	0.00
16,600.0	90.00	179.54	12,950.0	-3,454.0	-469.6	3,483.1	0.00	0.00	0.00
16,700.0	90.00	179.54	12,950.0	-3,554.0	-468.7	3,582.5	0.00	0.00	0.00
16,800.0	90.00	179.54	12,950.0	-3,653.9	-467.9	3,682.0	0.00	0.00	0.00
16,900.0	90.00	179.54	12,950.0	-3,753.9	-467.1	3,781.4	0.00	0.00	0.00
17,000.0	90.00	179.54	12,950.0	-3,853.9	-466.3	3,880.9	0.00	0.00	0.00
17,100.0	90.00	179.54	12,950.0	-3,953.9	-465.5	3,980.4	0.00	0.00	0.00
17,200.0	90.00	179.54	12,950.0	-4,053.9	-464.7	4,079.8	0.00	0.00	0.00
17,300.0	90.00	179.54	12,950.0	-4,153.9	-463.9	4,179.3	0.00	0.00	0.00
17,400.0	90.00	179.54	12,950.0	-4,253.9	-463.1	4,278.7	0.00	0.00	0.00
17,500.0	90.00	179.54	12,950.0	-4,353.9	-462.3	4,378.2	0.00	0.00	0.00
17,600.0	90.00	179.54	12,950.0	-4,453.9	-461.5	4,477.7	0.00	0.00	0.00
17,700.0	90.00	179.54	12,950.0	-4,553.9	-460.7	4,577.1	0.00	0.00	0.00
17,800.0	90.00	179.54	12,950.0	-4,653.9	-459.9	4,676.6	0.00	0.00	0.00
17,906.1	90.00	179.54	12,950.0	-4,760.0	-459.0	4,782.1	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well 751H
Company:	Midland	**TVD Reference:**	25 @ 3318.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	25 @ 3318.0usft
Site:	Magnolia 15	**North Reference:**	Grid
Well:	751H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1		

Design Targets

Target Name - hit/miss target - Shape	Dip Angle (°)	Dip Dir. (°)	TVD (usft)	+N/-S (usft)	+E/-W (usft)	Northing (usft)	Easting (usft)	Latitude	Longitude
KOP(MAG 15 #751H) - plan hits target center - Point	0.00	0.00	12,472.5	372.0	-499.0	382,989.00	778,559.00	32° 3' 2.175 N	103° 34' 3.585 W
FTP(MAG 15 #751H) - plan hits target center - Point	0.00	0.00	12,685.2	322.0	-499.0	382,939.00	778,559.00	32° 3' 1.681 N	103° 34' 3.589 W
PBHL(MAG 15 #751H) - plan hits target center - Point	0.00	0.00	12,950.0	-4,760.0	-459.0	377,857.00	778,599.00	32° 2' 11.389 N	103° 34' 3.543 W

Lea County, NM (NAD 83 NME)

Magnolia 15   751H

Plan #0.1

T G M

Azimuths to Grid North
True North: -0.41°
Magnetic North: 5.70°

Magnetic Field
Strength: 47023.0nT
Dip Angle: 59.62°
Date: 12/30/2024
Model: IGRF2020

To convert a Magnetic Direction to a Grid Direction, Add 5.70°
To convert a Magnetic Direction to a True Direction, Add 6.11° East
To convert a True Direction to a Grid Direction, Subtract 0.41°

PROJECT DETAILS: Lea County, NM (NAD 83 NME)

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

WELL DETAILS: 751H

3293.0
25 @ 3318.0usft

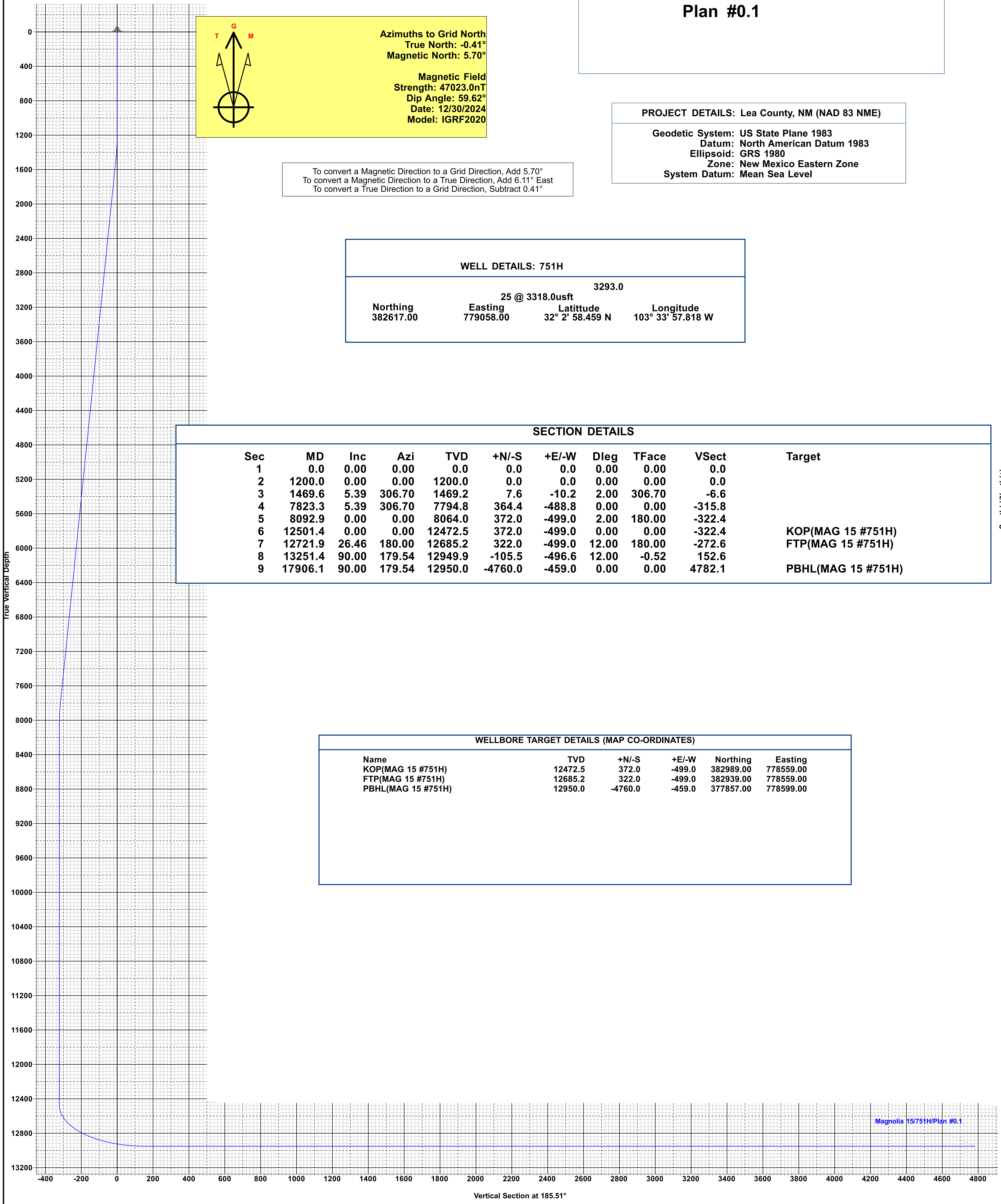
Northing	Easting	Latittude	Longitude
382617.00	779058.00	32° 2' 58.459 N	103° 33' 57.818 W

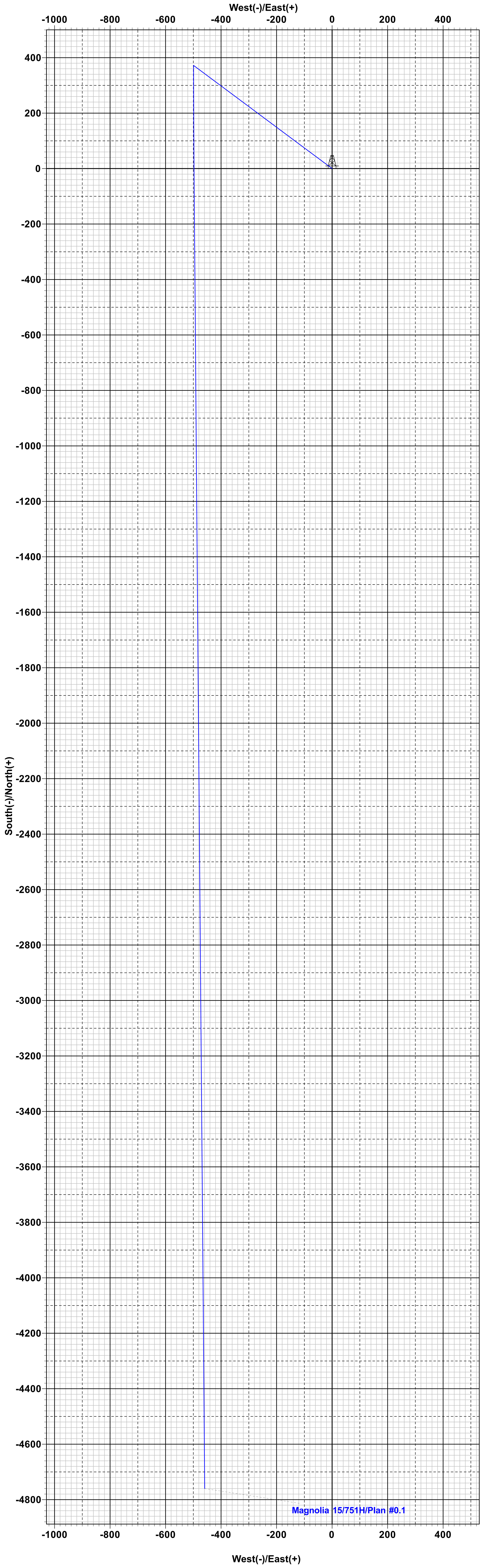
SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Target
1	0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.0	
2	1200.0	0.00	0.00	1200.0	0.0	0.0	0.00	0.00	0.0	
3	1469.6	5.39	306.70	1469.2	7.6	-10.2	2.00	306.70	-6.6	
4	7823.3	5.39	306.70	7794.8	364.4	-488.8	0.00	0.00	-315.8	
5	8092.9	0.00	0.00	8064.0	372.0	-499.0	2.00	180.00	-322.4	
6	12501.4	0.00	0.00	12472.5	372.0	-499.0	0.00	0.00	-322.4	KOP(MAG 15 #751H)
7	12721.9	26.46	180.00	12685.2	322.0	-499.0	12.00	180.00	-272.6	FTP(MAG 15 #751H)
8	13251.4	90.00	179.54	12949.9	-105.5	-496.6	12.00	-0.52	152.6	
9	17906.1	90.00	179.54	12950.0	-4760.0	-459.0	0.00	0.00	4782.1	PBHL(MAG 15 #751H)

WELLBORE TARGET DETAILS (MAP CO-ORDINATES)

Name	TVD	+N/-S	+E/-W	Northing	Easting
KOP(MAG 15 #751H)	12472.5	372.0	-499.0	382989.00	778559.00
FTP(MAG 15 #751H)	12685.2	322.0	-499.0	382939.00	778559.00
PBHL(MAG 15 #751H)	12950.0	-4760.0	-459.0	377857.00	778599.00





Lea County, NM (NAD 83 NME)
Magnolia 15
751H
OH
Plan #0.1
14:05, December 30 2024

Magnolia 15 751H API #: 30-025-*** Variances**

EOG respectfully requests the below variances to be applied to the above well:

- Variance is requested to waive the centralizer requirements for the intermediate casing in the intermediate hole. An expansion additive will be utilized, in the cement slurry, for the entire length of the intermediate interval to maximize cement bond and zonal isolation.
- Variance is also requested to waive the centralizer requirements for the production casing in the production hole. An expansion additive will be utilized, in the cement slurry, for the entire length of the production interval to maximize cement bond and zonal isolation.
- EOG requests a variance to set the intermediate casing shoe in the Bone Spring formation or the Wolfcamp formation, depending on depletion in the area and well conditions. EOG will monitor the well and ensure the well is static before casing operations begin.

- Variance is requested to use a co-flex line between the BOP and choke manifold (instead of using a 4” OD steel line).
- Variance is requested to use a 5,000 psi annular BOP with the 10,000 psi BOP stack.
- EOG Resources requests the option to contract a Surface Rig to drill, set surface casing, and Cement on the subject well. After WOC 8 hours or 500 psi compressive strength (whichever is greater), the Surface Rig will move off so the wellhead can be installed. A welder will cut the casing to the proper height and weld on the wellhead (both “A” and “B” sections). The weld will be tested to 1,500 psi. All valves will be closed and a wellhead cap will be installed (diagram attached). If the timing between rigs is such that EOG Resources would not be able to preset the surface, the Primary Rig will MIRU and drill the well in its entirety per the APD.

EOG requests the additional variance(s) in the attached document(s):

- EOG BLM Variance 2a - Inermediate Bradenhead Cement
- EOG BLM Variance 3a_b - BOP Break-test and Offline Intermediate Cement

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: ___EOG Resources, Inc.________ **OGRID:** _____7377___________________ **Date:** 1/2/2025

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
MAGNOLIA 15 751H		D-15-26S-33E	425' FNL & 826' FWL	+/- 1000	+/- 3500	+/- 3000

IV. Central Delivery Point Name: ___Magnolia 15 CTB_______________________ [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
MAGNOLIA 15 751H		1/30/25	2/15/25	5/01/25	6/01/25	7/01/25

VI. Separation Equipment: ☒ Attach a complete description of how Operator will size separation equipment to optimize gas capture.

VII. Operational Practices: ☒ Attach a complete description of the actions Operator will take to comply with the requirements of Subsection A through F of 19.15.27.8 NMAC.

VIII. Best Management Practices: ☒ Attach a complete description of Operator's best management practices to minimize venting during active and planned maintenance.

Section 2 – Enhanced Plan
EFFECTIVE APRIL 1, 2022

Beginning April 1, 2022, an operator that is not in compliance with its statewide natural gas capture requirement for the applicable reporting area must complete this section.

☒ Operator certifies that it is not required to complete this section because Operator is in compliance with its statewide natural gas capture requirement for the applicable reporting area.

IX. Anticipated Natural Gas Production:

Well	API	Anticipated Average Natural Gas Rate MCF/D	Anticipated Volume of Natural Gas for the First Year MCF

X. Natural Gas Gathering System (NGGS):

Operator	System	ULSTR of Tie-in	Anticipated Gathering Start Date	Available Maximum Daily Capacity of System Segment Tie-in

XI. Map. ☐ Attach an accurate and legible map depicting the location of the well(s), the anticipated pipeline route(s) connecting the production operations to the existing or planned interconnect of the natural gas gathering system(s), and the maximum daily capacity of the segment or portion of the natural gas gathering system(s) to which the well(s) will be connected.

XII. Line Capacity. The natural gas gathering system ☐ will ☐ will not have capacity to gather 100% of the anticipated natural gas production volume from the well prior to the date of first production.

XIII. Line Pressure. Operator ☐ does ☐ does not anticipate that its existing well(s) connected to the same segment, or portion, of the natural gas gathering system(s) described above will continue to meet anticipated increases in line pressure caused by the new well(s).

☐ Attach Operator's plan to manage production in response to the increased line pressure.

XIV. Confidentiality: ☐ Operator asserts confidentiality pursuant to Section 71-2-8 NMSA 1978 for the information provided in Section 2 as provided in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and attaches a full description of the specific information for which confidentiality is asserted and the basis for such assertion.

Section 3 - Certifications

Effective May 25, 2021

Operator certifies that, after reasonable inquiry and based on the available information at the time of submittal:

☒ Operator will be able to connect the well(s) to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced from the well(s) commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system; or

☐ Operator will not be able to connect to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced from the well(s) commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system. ***If Operator checks this box, Operator will select one of the following:***

Well Shut-In. ☐ Operator will shut-in and not produce the well until it submits the certification required by Paragraph (4) of Subsection D of 19.15.27.9 NMAC; or

Venting and Flaring Plan. ☐ Operator has attached a venting and flaring plan that evaluates and selects one or more of the potential alternative beneficial uses for the natural gas until a natural gas gathering system is available, including:

- **(a)** power generation on lease;
- **(b)** power generation for grid;
- **(c)** compression on lease;
- **(d)** liquids removal on lease;
- **(e)** reinjection for underground storage;
- **(f)** reinjection for temporary storage;
- **(g)** reinjection for enhanced oil recovery;
- **(h)** fuel cell production; and
- **(i)** other alternative beneficial uses approved by the division.

Section 4 - Notices

1. If, at any time after Operator submits this Natural Gas Management Plan and before the well is spud:

(a) Operator becomes aware that the natural gas gathering system it planned to connect the well(s) to has become unavailable or will not have capacity to transport one hundred percent of the production from the well(s), no later than 20 days after becoming aware of such information, Operator shall submit for OCD's approval a new or revised venting and flaring plan containing the information specified in Paragraph (5) of Subsection D of 19.15.27.9 NMAC; or

(b) Operator becomes aware that it has, cumulatively for the year, become out of compliance with its baseline natural gas capture rate or natural gas capture requirement, no later than 20 days after becoming aware of such information, Operator shall submit for OCD's approval a new or revised Natural Gas Management Plan for each well it plans to spud during the next 90 days containing the information specified in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and shall file an update for each Natural Gas Management Plan until Operator is back in compliance with its baseline natural gas capture rate or natural gas capture requirement.

2. OCD may deny or conditionally approve an APD if Operator does not make a certification, fails to submit an adequate venting and flaring plan which includes alternative beneficial uses for the anticipated volume of natural gas produced, or if OCD determines that Operator will not have adequate natural gas takeaway capacity at the time a well will be spud.

I certify that, after reasonable inquiry, the statements in and attached to this Natural Gas Management Plan are true and correct to the best of my knowledge and acknowledge that a false statement may be subject to civil and criminal penalties under the Oil and Gas Act.

Signature: Star L Harrell
Printed Name: Star L Harrell
Title: Regulatory Advisor
E-mail Address: Star_Harrell@eogresources.com
Date: 1/2/2025
Phone: (432) 848-9161

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

Natural Gas Management Plan
Items VI-VIII

VI. Separation Equipment: Attach a complete description of how Operator will size separation equipment to optimize gas capture.

- Separation equipment will be sized to provide adequate separation for anticipated rates.
- Adequate separation relates to retention time for Liquid – Liquid separation and velocity for Gas-Liquid separation.
- Collection systems are appropriately sized to handle facility production rates on all (3) phases.
- Ancillary equipment and metering is selected to be serviced without flow interruptions or the need to release gas from the well.

VII. Operational Practices: Attach a complete description of the actions Operator will take to comply with the requirements of Subsection A through F 19.15.27.8 NMAC.

Drilling Operations

- All flare stacks will be properly sized. The flare stacks will be located at a minimum 100' from the nearest surface hole location on the pad.
- All natural gas produced during drilling operations will be flared, unless there is an equipment malfunction and/or to avoid risk of an immediate and substantial adverse impact on safety and the environment, at which point the gas will be vented.

Completions/Recompletions Operations

- New wells will not be flowed back until they are connected to a properly sized gathering system.
- The facility will be built/sized for maximum anticipated flowrates and pressures to minimize waste.
- For flowback operations, multiple stages of separation will be used as well as excess VRU and blowers to make sure waste is minimized off the storage tanks and facility.
- During initial flowback, the well stream will be routed to separation equipment.
- At an existing facility, when necessary, post separation natural gas will be flared until it meets pipeline specifications, at which point it will be turned into a collection system.
- At a new facility, post separation natural gas will be vented until storage tanks can safely function, at which point it will be flared until it meets pipeline spec.

Production Operations

- Weekly AVOs will be performed on all facilities.
- All flares will be equipped with auto-ignition systems and continuous pilot operations.
- After a well is stabilized from liquid unloading, the well will be turned back into the collection system.
- All plunger lift systems will be optimized to limit the amount of waste.
- All tanks will have automatic gauging equipment installed.
- Leaking thief hatches found during AVOs will be cleaned and properly re-sealed.

Performance Standards

- Production equipment will be designed to handle maximum anticipated rates and pressure.
- All flared gas will be combusted in a flare stack that is properly sized and designed to ensure proper combustion.
- Weekly AVOs will be performed on all wells and facilities that produce more than 60 Mcfd.

Measurement & Estimation

- All volume that is flared and vented that is not measured will be estimated.
- All measurement equipment for flared volumes will conform to API 14.10.
- No meter bypasses with be installed.

- When metering is not practical due to low pressure/low rate, the vented or flared volume will be estimated.

VIII. Best Management Practices: Attach a complete description of Operator's best management practices to minimize venting during active and planned maintenance.

- During downhole well maintenance, EOG will use best management practices to vent as minimally as possible.
- Prior to the commencement of any maintenance, the tank or vessel will be isolated from the rest of the facilities.
- All valves upstream of the equipment will be closed and isolated.
- After equipment has been isolated, the equipment will be blown down to as low a pressure as possible into the collection system.
- If the equipment being maintained cannot be relieved into the collection system, it shall be released to a tank where the vapor can either be captured or combusted if possible.
- After downhole well maintenance, natural gas will be flared until it reaches pipeline specification.