AFMSS

U.S. Department of the Interior
Bureau of Land Management

Application for Permit to Drill

APD Package Report

Date Printed: 10/10/2025 09:38 AM

APD ID:	10400105339	Well Status:	AAPD
APD Received Date:	06/06/2025 08:35 AM	Well Name:	PEREGRINE 27 FED COM
Operator:	EOG RESOURCES INCORPORATED	Well Number:	502H

APD Package Report Contents

- Form 3160-3

- Operator Certification Report

- Application Report
- Application Attachments
  - -- Well Plat: 2 file(s)

- Drilling Plan Report
- Drilling Plan Attachments
  - -- Blowout Prevention Choke Diagram Attachment: 2 file(s)
  - -- Blowout Prevention BOP Diagram Attachment: 2 file(s)
  - -- Casing Design Assumptions and Worksheet(s): 10 file(s)
  - -- Hydrogen sulfide drilling operations plan: 2 file(s)
  - -- Proposed horizontal/directional/multi-lateral plan submission: 4 file(s)
  - -- Other Facets: 13 file(s)
  - -- Other Variances: 9 file(s)

- SUPO Report
- SUPO Attachments
  - -- Existing Road Map: 2 file(s)
  - -- New Road Map: 6 file(s)
  - -- Attach Well map: 2 file(s)
  - -- Production Facilities map: 11 file(s)
  - -- Water source and transportation map: 2 file(s)
  - -- Construction Materials source location attachment: 2 file(s)
  - -- Well Site Layout Diagram: 6 file(s)
  - -- Recontouring attachment: 2 file(s)
  - -- Surface use plan certification document: 2 file(s)
  - -- Other SUPO Attachment: 4 file(s)

- PWD Report
- PWD Attachments

-- None

- Bond Report
- Bond Attachments
  -- None

Form 3160-3
(October 2024)

FORM APPROVED
OMB No. 1004-0220
Expires: October 31, 2027

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No.
NMNM123534

6. If Indian, Allotee or Tribe Name

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

8. Lease Name and Well No.
PEREGRINE 27 FED COM
502H

1a. Type of work: ☑ DRILL ☐ REENTER
1b. Type of Well: ☑ Oil Well ☐ Gas Well ☐ Other
1c. Type of Completion: ☐ Hydraulic Fracturing ☑ Single Zone ☐ Multiple Zone

2. Name of Operator EOG RESOURCES INCORPORATED	9. API Well No. 30-025-55409
3a. Address 1111 BAGBY SKY LOBBY 2, HOUSTON, TX 77002 / 3b. Phone No. *(include area code)* (713) 651-7000	10. Field and Pool, or Exploratory RED HILLS/BONESPRING, EAST
4. Location of Well *(Report location clearly and in accordance with any State requirements.*)* At surface TR L / 1700 FSL / 159 FWL / LAT 32.1859549 / LONG -103.4658473 At proposed prod. zone TR E / 2528 FNL / 715 FWL / LAT 32.1598168 / LONG -103.4640044	11. Sec., T. R. M. or Blk. and Survey or Area SEC 27/T24S/R34E/NMP

14. Distance in miles and direction from nearest town or post office*	12. County or Parish	13. State
	LEA	NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any)	16. No of acres in lease	17. Spacing Unit dedicated to this well
100 feet		639.0

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft.	19. Proposed Depth	20. BLM/BIA Bond No. in file
33 feet	10972 feet / 21249 feet	FED: NMB106709157

21. Elevations (Show whether DF, KDB, RT, GL, etc.)	22. Approximate date work will start*	23. Estimated duration
3451 feet	06/04/2026	25 days

24. Attachments

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

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

25. Signature	Name *(Printed/Typed)*	Date
(Electronic Submission)	SHEA BAILEY / Ph: (713) 651-7000	06/06/2025
Title Regulatory Contractor		
Approved by *(Signature)* (Electronic Submission)	Name *(Printed/Typed)* CODY LAYTON / Ph: (575) 234-5959	Date 10/09/2025
Title Assistant Field Manager Lands & Minerals	Office Carlsbad Field Office	

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

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

APPROVED WITH CONDITIONS

(Continued on page 2)

*(Instructions on page 2)

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INSTRUCTIONS

GENERAL: This form is designed for submitting proposals to perform certain well operations, as indicated on Federal and Indian lands and leases for action by appropriate Federal agencies, pursuant to applicable Federal laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from local Federal offices.

ITEM I: If the proposal is to redrill to the same reservoir at a different subsurface location or to a new reservoir, use this form with appropriate notations. Consult applicable Federal regulations concerning subsequent work proposals or reports on the well.

ITEM 4: Locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local Federal offices for specific instructions.

ITEM 14: Needed only when location of well cannot readily be found by road from the land or lease description. A plat, or plats, separate or on the reverse side, showing the roads to, and the surveyed location of, the wen, and any other required information, should be furnished when required by Federal agency offices.

ITEMS 15 AND 18: If well is to be, or has been directionany drilled, give distances for subsurface location of hole in any present or objective productive zone.

ITEM 22: Consult applicable Federal regulations, or appropriate officials, concerning approval of the proposal before operations are started.

ITEM 24: If the proposal will involve hydraulic fracturing operations, you must comply with 43 CFR 3162.3-3, including providing information about the protection of usable water. Operators should provide the best available information about all formations containing water and their depths. This information could include data and interpretation of resistivity logs run on nearby wells. Information may also be obtained from state or tribal regulatory agencies and from local BLM offices.

NOTICES

The Privacy Act of 1974 and regulation in 43 CFR 2.48(d) provide that you be furnished the following information in connection with information required by this application.

AUTHORITY: 30 U.S.C. 181 et seq., 25 U.S.C. 396; 43 CFR 3160

PRINCIPAL PURPOSES: The information will be used to: (1) process and evaluate your application for a permit to drill a new oil, gas, or service wen or to reenter a plugged and abandoned well; and (2) document, for administrative use, information for the management, disposal and use of National Resource Lands and resources including (a) analyzing your proposal to discover and extract the Federal or Indian resources encountered; (b) reviewing procedures and equipment and the projected impact on the land involved; and (c) evaluating the effects of the proposed operation on the surface and subsurface water and other environmental impacts.

ROUTINE USE: Information from the record and/or the record win be transferred to appropriate Federal, State, and local or foreign agencies, when relevant to civil, criminal or regulatory investigations or prosecution, in connection with congressional inquiries and for regulatory responsibilities.

EFFECT OF NOT PROVIDING INFORMATION: Filing of this application and disclosure of the information is mandatory only if you elect to initiate a drilling or reentry operation on an oil and gas lease.

The Paperwork Reduction Act of 1995 requires us to inform you that:
The BLM conects this information to anow evaluation of the technical, safety, and environmental factors involved with drilling for oil and/or gas on Federal and Indian oil and gas leases. This information will be used to analyze and approve applications. Response to this request is mandatory only if the operator elects to initiate drilling or reentry operations on an oil and gas lease. The BLM would like you to know that you do not have to respond to this or any other Federal agency-sponsored information collection unless it displays a currently valid OMB control number.

BURDEN HOURS STATEMENT: Public reporting burden for this form is estimated to average 8 hours per response, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect of this form to U.S. Department of the Interior, Bureau of Land Management (1004-0137), Bureau Information Conection Clearance Officer (WO-630), 1849 C Street, N.W., Mail Stop 401 LS, Washington, D.C. 20240.

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Additional Operator Remarks

Location of Well

0. SHL: TR L / 1700 FSL / 159 FWL / TWSP: 24S / RANGE: 34E / SECTION: 27 / LAT: 32.1859549 / LONG: -103.4658473 (TVD: 0 feet, MD: 0 feet)
PPP: TR L / 2540 FSL / 715 FWL / TWSP: 24S / RANGE: 34E / SECTION: 27 / LAT: 32.1882605 / LONG: -103.4640556 (TVD: 10707 feet, MD: 10800 feet)
PPP: TR D / 0 FNL / 715 FWL / TWSP: 24S / RANGE: 34E / SECTION: 34 / LAT: 32.1812797 / LONG: -103.464043 (TVD: 10972 feet, MD: 13441 feet)
BHL: TR E / 2528 FNL / 715 FWL / TWSP: 25S / RANGE: 34E / SECTION: 3 / LAT: 32.1598168 / LONG: -103.4640044 (TVD: 10972 feet, MD: 21249 feet)

BLM Point of Contact

Name: SAMUEL J TRUJILLO
Title: Legal Instruments Examiner
Phone: (575) 234-5943
Email: STRUJILLO@BLM.GOV

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PECOS DISTRICT

SURFACE USE

CONDITIONS OF APPROVAL

OPERATOR'S NAME:	EOG Resources Incorporated
LEASE NO.:	NMNM 123534 and NMNM 016139
COUNTY:	Lea County, New Mexico

Wells:

The legal land description is in Lea County, New Mexico, and is described as follows:

Well Pad A

Peregrine 27 Fed Com 501H
Surface Hole Location: 1700 feet FSL and 126 feet FWL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 330 feet FWL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 502H
Surface Hole Location: 1700 feet FSL and 159 feet FWL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 715 feet FWL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 503H
Surface Hole Location: 1700 feet FSL and 192 feet FWL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 1100 feet FWL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 504H
Surface Hole Location: 1700 feet FSL and 225 feet FWL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2529 feet FNL and 1485 feet FWL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 591H
Surface Hole Location: 1760 feet FSL and 352 feet FWL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 330 feet FWL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 592H
Surface Hole Location: 1760 feet FSL and 385 feet FWL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 1100 feet FWL, Section 3, T. 25 S, R 34 E.

Well Pad C

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Peregrine 27 Fed Com 509H
Surface Hole Location: 1918 feet FSL and 1178 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 1485 feet FEL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 510H
Surface Hole Location: 1885 feet FSL and 1178 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 1100 feet FEL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 511H
Surface Hole Location: 1852 feet FSL and 1178 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 715 feet FEL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 512H
Surface Hole Location: 1819 feet FSL and 1178 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 330 feet FEL, Section 3, T. 25 S, R 34 E.

Well Pad D

Peregrine 27 Fed Com 505H
Surface Hole Location: 2006 feet FSL and 1914 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2529 feet FNL and 1870 feet FWL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 506H
Surface Hole Location: 2006 feet FSL and 1881 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2529 feet FNL and 330 feet FWL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 507H
Surface Hole Location: 2006 feet FSL and 1848 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2529 feet FNL and 2255 feet FEL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 508H
Surface Hole Location: 2006 feet FSL and 1815 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2528 feet FNL and 1870 feet FEL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 593H
Surface Hole Location: 2064 feet FSL and 1754 feet FEL, Section 27, T. 24 S., R. 34 E.
Bottom Hole Location: 2529 feet FNL and 1870 feet FWL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 594H

Surface Hole Location: 2064 feet FSL and 1721 feet FEL, Section 27, T. 24 S., R. 34 E.

Bottom Hole Location: 2528 feet FNL and 1870 feet FEL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 595H

Surface Hole Location: 2064 feet FSL and 1688 feet FEL, Section 27, T. 24 S., R. 34 E.

Bottom Hole Location: 2528 feet FNL and 1100 feet FEL, Section 3, T. 25 S, R 34 E.

Peregrine 27 Fed Com 596H

Surface Hole Location: 2064 feet FSL and 1655 feet FEL, Section 27, T. 24 S., R. 34 E.

Bottom Hole Location: 2528 feet FNL and 330 feet FEL, Section 3, T. 25

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1. GENERAL PROVISIONS

The failure of the operator to comply with these requirements may result in the assessment of liquidated damages or penalties pursuant to 43 CFR 3163.1 or 3163.2. A copy of these conditions of approval shall be present on the location during construction, drilling and reclamation activity. Any request for a variance shall be submitted to the Authorized Officer on Form 3160-5, Sundry Notices and Report on Wells.

1.1. ARCHAEOLOGICAL, PALEONTOLOGY & HISTORICAL SITES

Any cultural resource (historic or prehistoric site or object) discovered by the operator, or any person working on the operator's behalf, on the public or federal land shall be immediately reported to the Authorized Officer. The operator shall suspend all operations in the immediate area (within 100ft) of such discovery until written authorization to proceed is issued by the Authorized Officer. An evaluation of the discovery will be made by the Authorized Officer, in conjunction with a BLM Cultural Resource Specialist, to determine appropriate actions to prevent the loss of significant scientific values. The operator shall be responsible for the cost of evaluation and any decision as to the proper mitigation measures will be made by the Authorized Officer after consulting with the operator.

Traditional Cultural Properties (TCPs) are protected by NHPA as codified in 36 CFR 800 for possessing traditional, religious, and cultural significance tied to a certain group of individuals. Though there are currently no designated TCPs within the project area or within a mile of the project area, but it is possible for a TCP to be designated after the approval of this project. **If a TCP is designated in the project area after the project's approval, the BLM Authorized Officer will notify the operator of the following conditions and the duration for which these conditions are required.**

1. Temporary halting of all construction, drilling, and production activities to lower noise.
2. Temporary shut-off of all artificial lights at night.

The operator is hereby obligated to comply with procedures established in the Native American Graves Protection and Repatriation Act (NAGPRA), specifically NAGPRA Subpart B regarding discoveries, to protect human remains, associated funerary objects, sacred objects, and objects of cultural patrimony discovered during project work. If any human skeletal remains, funerary objects, sacred objects, or objects of cultural patrimony are discovered at any time during construction, all construction activities shall halt and a BLM-CFO Authorized Officer will be notified immediately. The BLM will then be required to be notified, in writing, within 24 hours of the discovery. The written notification should include the geographic location by county and state, the contents of the discovery, and the steps taken to protect said discovery. You must also include any potential threats to the discovery and a conformation that all activity within 100ft of the discovery has ceased and work will not resume until written certification is issued. All work on the entire project must halt for a minimum of 3 days and work cannot resume until an Authorized Officer grants permission to do so.

Any paleontological resource discovered by the operator, or any person working on the operator's behalf, on public or Federal land shall be immediately reported to the Authorized Officer. The operator shall suspend all operations in the immediate area of such discovery until written authorization to proceed is issued by the Authorized Officer. The operator will be responsible for the cost of evaluation and any decision as to the proper mitigation measures will be made by the Authorized Officer after consulting with the operator.

1.2. RANGELAND RESOURCES

1.2.1. **Cattleguards**

Where a permanent cattleguard is approved, an appropriately sized cattleguard(s) sufficient to carry out the project shall be installed and maintained at fence crossing(s). Any existing cattleguard(s) on the access road shall be repaired or replaced if they are damaged or have deteriorated beyond practical use. The operator shall be responsible for the condition of the existing cattleguard(s) that are in place and are utilized during lease operations. A gate shall be constructed on one side of the cattleguard and fastened securely to H-braces.

1.2.2. **Fence Requirement**

Where entry granted across a fence line, the fence must be braced and tied off on both sides of the passageway prior to cutting. Once the work is completed, the fence will be restored to its prior condition, or better. The operator shall notify the private surface landowner or the grazing allotment holder prior to crossing any fence(s).

1.2.3. **Livestock Watering Requirement**

Any damage to structures that provide water to livestock throughout the life of the well, caused by operations from the well site, must be immediately corrected by the operator. The operator must notify the BLM office (575-234-5972) and the private surface landowner or the grazing allotment holder if any damage occurs to structures that provide water to livestock.

1.3. NOXIOUS WEEDS

The operator shall be held responsible if noxious weeds become established within the areas of operations. Weed control shall be required on the disturbed land where noxious weeds exist, which includes the roads, pads, associated pipeline corridor, and adjacent land affected by the establishment of weeds due to this action. The operator shall consult with the Authorized Officer for acceptable weed control methods, which include following EPA, New Mexico Department of Agriculture, and BLM requirements and policies.

1.3.1 African Rue (Peganum harmala)

Spraying: The spraying of African Rue must be completed by a licensed or certified applicator. In order to attempt to kill or remove African Rue the proper mix of chemical is needed. The mix consists of 2% Arsenal (Imazapyr) and 2% Roundup (Glyphosate) along with a nonionic surfactant. Any other chemicals or combinations shall be approved by the BLM Noxious Weeds Coordinator prior to treatment. African Rue shall be sprayed in connection to any dirt working activities or disturbances to the site being sprayed. Spraying of African Rue shall be done on immature plants at initial growth through flowering and mature plants between budding and flowering stages. Spraying shall not be conducted after flowering when plant is fruiting. This will ensure optimal intake of chemical and decrease chances of developing herbicide resistance. After spraying, the operator or necessary parties must contact the Carlsbad Field Office to inspect the effectiveness of the application treatment to the plant species. No ground disturbing activities can take place until the inspection by the authorized officer is complete. The operator may contact the Environmental Protection Department or the BLM Noxious Weed Coordinator at (575) 234-5972 or BLM_NM_CFO_NoxiousWeeds@blm.gov.

Management Practices: In addition to spraying for African Rue, good management practices should be followed. All equipment should be washed off using a power washer in a designated containment area. The containment area shall be bermed to allow for containment of the seed to prevent it from entering any open areas of the nearby landscape. The containment area shall be excavated near or adjacent to the well pad at a depth of three feet and just large enough to get equipment inside it to be washed off. This will allow all seeds to be in a centrally located area that can be treated at a later date if the need arises.

1.4. LIGHT POLLUTION

1.4.1. **Downfacing**

All permanent lighting will be pointed straight down at the ground in order to prevent light spill beyond the edge of approved surface disturbance.

1.4.2. **Shielding**

All permanent lighting will use full cutoff luminaires, which are fully shielded (i.e., not emitting direct or indirect light above an imaginary horizontal plane passing through the lowest part of the light source).

1.4.3. **Lighting Color**

Lighting shall be 3,500 Kelvin or less (Warm White) except during drilling, completion, and workover operations. No bluish-white lighting shall be used in permanent outdoor lighting.

2. SPECIAL REQUIREMENTS

2.1. WATERSHED

The entire well pad(s) will be bermed to prevent oil, salt, and other chemical contaminants from leaving the well pad. The compacted berm shall be constructed at a minimum of 12 inches with impermeable mineral material (e.g. caliche). Topsoil shall not be used to construct the berm. No water flow from the uphill side(s) of the pad shall be allowed to enter the well pad. The integrity of the berm shall be maintained around the surfaced pad throughout the life of the well and around the downsized pad after interim reclamation has been completed. Any water erosion that may occur due to the construction of the well pad during the life of the well will be quickly corrected and proper measures will be taken to prevent future erosion. Stockpiling of topsoil is required. The topsoil shall be stockpiled in an appropriate location to prevent loss of soil due to water or wind erosion and not used for berming or erosion control. If fluid collects within the bermed area, the fluid must be vacuumed into a safe container and disposed of properly at a state approved facility.

2.1.1. **Tank Battery**

Tank battery locations will be lined and bermed. A 20-mil permanent liner will be installed with a 4 oz. felt backing to prevent tears or punctures. Secondary containment holding capacity must be large enough to contain 1 ½ times the content of the largest tank or 24-hourproduction, whichever is greater (displaced volume from all tanks within the berms MUST be subtracted from total volume of containment in calculating holding capacity). Automatic shut off, check valves, or similar systems will be installed for tanks to minimize the effects of catastrophic line failures used in production or drilling.

2.1.2. **Buried/Surface Line(s)**

When crossing ephemeral drainages, the pipeline(s) will be buried to a minimum depth of 48 inches from the top of pipe to ground level. Erosion control methods such as gabions and/or rock aprons must be placed on both up and downstream sides of the pipeline crossing. In addition, curled (weed free) wood/straw fiber wattles/logs and/or silt fences must be placed on the downstream side for sediment control during construction and maintained until soils and vegetation have stabilized. Water bars must be placed within the corridor to divert and dissipate surface runoff. A pipeline access road is not permitted to cross ephemeral drainages. Traffic must be diverted to a preexisting route. Additional seeding may be required in floodplains and drainages to restore energy dissipating vegetation.

Prior to pipeline installation/construction a leak detection plan will be developed. The method(s) could incorporate gauges to detect pressure drops, situating valves and lines so they can be visually inspected periodically or installing electronic sensors to alarm when a leak is present. The leak detection plan will incorporate an automatic shut off system that will be installed for proposed pipelines to minimize the effects of an undesirable event.

2.3 WILDLIFE

2.3.1 **Lesser Prairie Chicken**

2.3.1.1 Timing Limitation Stipulation/Condition of Approval for Lesser Prairie-Chicken:

Oil and gas activities including 3-D geophysical exploration, and drilling will not be allowed in lesser prairie-chicken habitat during the period from March 1st through June 15th annually. During that period, other activities that produce noise or involve human activity, such as the maintenance of oil and gas facilities, geophysical exploration other than 3-D operations, and pipeline, road, and well pad construction, will be allowed except between 3:00 am and 9:00 am. The 3:00 am to 9:00 am restriction will not apply to normal, around-the-clock operations, such as venting, flaring, or pumping, which do not require a human presence during this period. Additionally, no new drilling will be allowed within up to 200 meters of leks known at the time of permitting. Normal vehicle use on existing roads will not be

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restricted. Exhaust noise from pump jack engines must be muffled or otherwise controlled so as not to exceed 75 db measured at 30 ft. from the source of the noise.

2.3.1.2 Timing Limitation Exceptions:

The Carlsbad Field Office will publish an annual map of where the LPC timing and noise stipulations and conditions of approval (Limitations) will apply for the identified year (between March 1 and June 15) based on the latest survey information. The LPC Timing Area map will identify areas which are Habitat Areas (HA), Isolated Population Area (IPA), and Primary Population Area (PPA). The LPC Timing Area map will also have an area in red crosshatch. The red crosshatch area is the only area where an operator is required to submit a request for exception to the LPC Limitations. If an operator is operating outside the red crosshatch area, the LPC Limitations do not apply for that year and an exception to LPC Limitations is not required.

2.3.1.3 Ground-level Abandoned Well Marker to avoid raptor perching:

Upon the plugging and subsequent abandonment of the well, the well marker will be installed at ground level on a plate containing the pertinent information for the plugged well. For more installation details, contact the Carlsbad Field Office at BLM_NM_CFO_Construction_Reclamation@blm.gov.

2.3.2 **Raptor Nest Mitigation (includes Burrowing Owls)**

- A BLM Wildlife Biologist must be contacted by the operator prior to construction activities to determine if any raptor nests observed or detected are active. Raptor nest surveys are required prior to initiating construction of the project.
- Raptor nests on special, natural habitat features, such as trees, large brush, cliff faces and escarpments, will be protected by not allowing surface disturbance within up to 200 meters of nests or by delaying activity for up to 90 days, or a combination of both. Exceptions to this requirement for raptor nests will be considered if the nests expected to be disturbed are inactive, the proposed activity is of short duration (e.g. habitat enhancement projects, fences, pipelines), and will not result in continuing activity in proximity to the nest.
- Exhaust noise from pump jack engines, or other equipment, must be muffled or otherwise controlled so as not to exceed 75 db measured at 30 ft. from the source of the noise.

2.4 VISUAL RESOURCE MANAGEMENT

2.5.1 **VRM IV**

Above-ground structures including meter housing that are not subject to safety requirements are painted a flat non-reflective paint color, Shale Green from the BLM Standard Environmental Color Chart (CC-001: June 2008).

2.5.2 **VRM III Facility Requirement**

Above-ground structures including meter housing that are not subject to safety requirements are painted a flat non-reflective paint color, Shale Green from the BLM Standard Environmental Color Chart (CC-001: June 2008).

3. CONSTRUCTION REQUIRENMENTS

3.1 CONSTRCUTION NOTIFICATION

The BLM shall administer compliance and monitor construction of the access road and well pad. Notify the Carlsbad Field Office at BLM_NM_CFO_Construction_Reclamation@blm.gov at least 3 working days prior to commencing construction of the access road and/or well pad.

When construction operations are being conducted on this well, the operator shall have the approved APD and COAs on the well site and they shall be made available upon request by the Authorized Officer.

3.2 TOPSOIL

The operator shall strip the topsoil (the A horizon) from the entire well pad area and stockpile the topsoil along the edge of the well pad as depicted in the APD. No more than the top 6 inches of topsoil shall be removed. All the stockpiled topsoil will be redistributed over the interim reclamation areas. Topsoil shall not be used for berming the pad or facilities. For final reclamation, the topsoil shall be spread over the entire pad area for seeding preparation.

Other subsoil (the B horizon and below) stockpiles must be completely segregated from the topsoil stockpile. Large rocks or subsoil clods (not evident in the surrounding terrain) must be buried within the approved area for interim and final reclamation.

3.3 CLOSED LOOP SYSTEM

Tanks are required for drilling operations: No reserve pits will be used for drill cuttings. The operator shall properly dispose of drilling contents at an authorized disposal site.

3.4 FEDERAL MINERAL PIT

Payment shall be made to the BLM prior to removal of any federal mineral materials. Call the Carlsbad Field Office at (575) 234-5972.

3.5 WELL PAD & SURFACING

Any surfacing material used to surface the well pad will be removed at the time of interim and final reclamation.

3.6 EXCLOSURE FENCING (CELLARS & PITS)

The operator will install and maintain exclosure fencing for all open well cellars to prevent access to public, livestock, and large forms of wildlife before and after drilling operations until the well cellar is free of fluids and the operator initiates backfilling. (For examples of exclosure fencing design, refer to BLM's Oil and Gas Gold Book, Exclosure Fence Illustrations, Figure 1, Page 18.)

The operator will also install and maintain mesh netting for all open well cellars to prevent access to smaller wildlife before and after drilling operations until the well cellar is free of fluids and the operator. Use a maximum netting mesh size of 1 ½ inches. The netting must not have holes or gaps.

3.7 ON LEASE ACESS ROAD

3.7.1 **Road Width**

The access road shall have a driving surface that creates the smallest possible surface disturbance and does not exceed twenty-four (24) feet in width. The maximum width of surface disturbance, when constructing the access road, shall not exceed thirty (30) feet.

3.7.2 **Surfacing**

Surfacing material is not required on the new access road driving surface. If the operator elects to surface the new access road or pad, the surfacing material may be required to be removed at the time of reclamation.

Where possible, no improvements will be made on the unsurfaced access road other than to remove vegetation as necessary, road irregularities, safety issues, or to fill low areas that may sustain standing water.

The Authorized Officer reserves the right to require surfacing of any portion of the access road at any time deemed necessary. Surfacing may be required in the event the road deteriorates, erodes, road traffic increases, or it is determined to be beneficial for future field development. The surfacing depth and type of material will be determined at the time of notification.

3.7.3 Crowning

Crowning shall be done on the access road driving surface. The road crown shall have a grade of approximately 2% (i.e., a 1" crown on a 14' wide road). The road shall conform to Figure 1; cross section and plans for typical road construction.

3.7.4 Ditching

Ditching shall be required on both sides of the road.

3.7.5 Turnouts

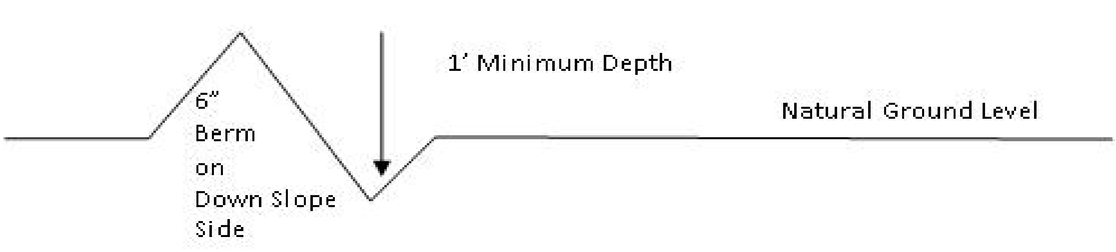
Vehicle turnouts shall be constructed on the road. Turnouts shall be intervisible with interval spacing distance less than 1000 feet. Turnouts shall conform to Figure 1; cross section and plans for typical road construction.

3.7.6 Drainage

Drainage control systems shall be constructed on the entire length of road (e.g. ditches, sidehill outsloping and insloping, leadoff ditches, culvert installation, and low water crossings).

A typical lead-off ditch has a minimum depth of 1 foot below and a berm of 6 inches above natural ground level. The berm shall be on the down-slope side of the lead-off ditch.

Cross Section of a Typical Lead-off Ditch



All lead-off ditches shall be graded to drain water with a 1 percent minimum to 3 percent maximum ditch slope. The spacing interval are variable for lead-off ditches and shall be determined according to the formula for spacing intervals of lead-off ditches, but may be amended depending upon existing soil types and centerline road slope (in %);

Formula for Spacing Interval of Lead-off Ditches

Example - On a 4% road slope that is 400 feet long, the water flow shall drain water into a lead-off ditch. Spacing interval shall be determined by the following formula:

400 foot road with 4% road slope: $\frac{400'}{4} + 100' = 200'$ lead-off ditch interval

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3.7.7 **Public Access**

Public access on this road shall not be restricted by the operator without specific written approval granted by the Authorized Officer.

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Construction Steps

1. Salvage topsoil
2. Construct road
3. Redistribute topsoil
4. Revegetate slopes

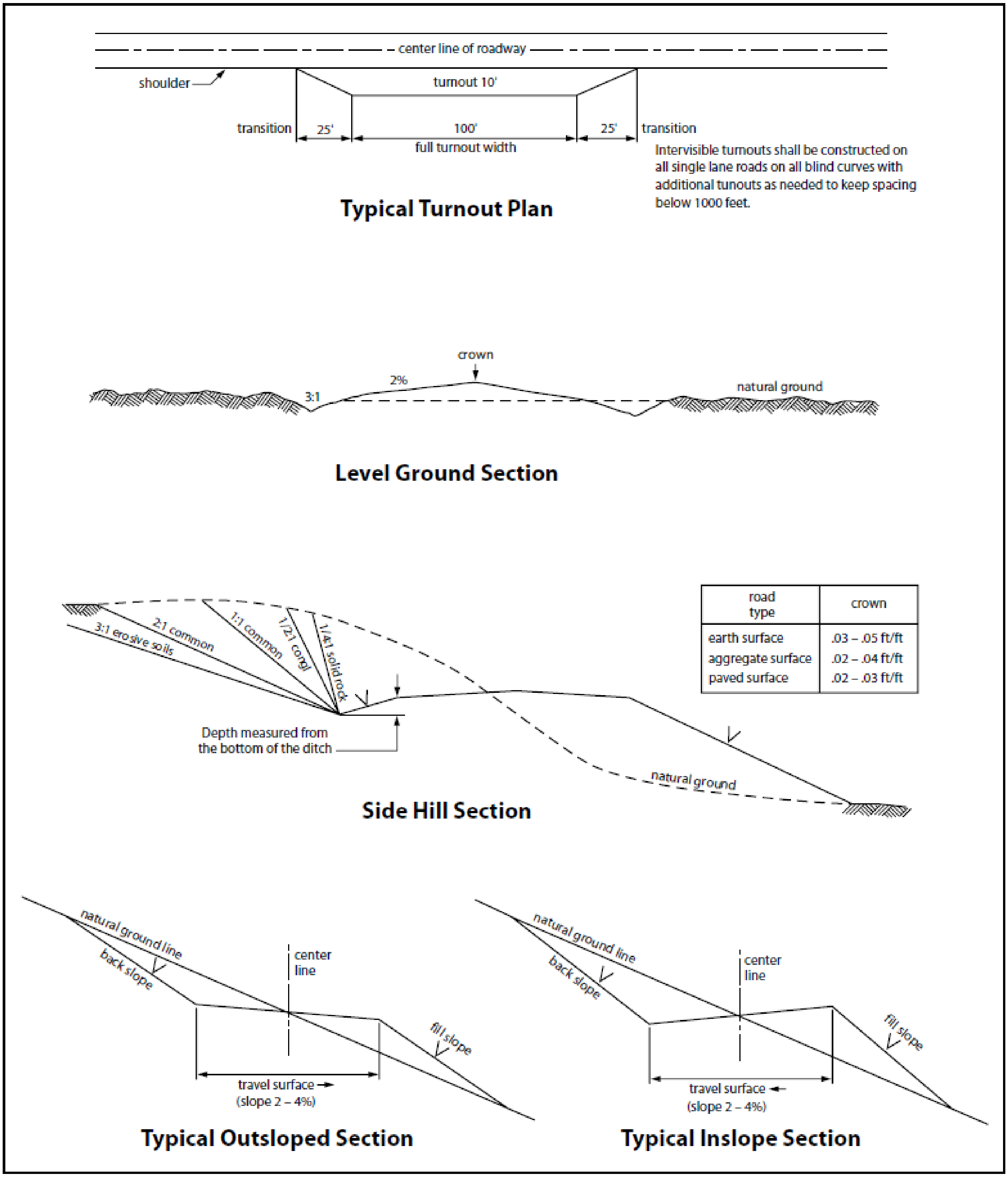

Figure 1. Cross-sections and plans for typical road sections representative of BLM resource or FS local and higher-class roads.

4. PIPELINES

- The BLM, Carlsbad Field Office, will be informed immediately if any subsurface drainage channels, passages, or voids are intersected by trenching, and no pipe will be laid in the trench at that point until clearance has been issued by the Authorized Officer.
- A leak detection plan **will be submitted to the BLM Carlsbad Field Office for approval** prior to pipeline installation. The method could incorporate gauges to detect pressure drops, situating values and lines so they can be visually inspected periodically or installing electronic sensors to alarm when a leak is present. The leak detection plan will incorporate an automatic shut off system that will be installed for proposed pipelines to minimize the effects of an undesirable event.
- Regular monitoring is required to quickly identify leaks for their immediate and proper treatment.
- All spills or leaks will be reported to the BLM immediately for their immediate and proper treatment.

4.1 BURIED PIPELINES

A copy of the application (APD, or Sundry Notice) and attachments, including conditions of approval, survey plat and/or map, will be on location during construction. BLM personnel may request a copy of your permit during construction to ensure compliance with all stipulations.

Operator agrees to comply with the following stipulations to the satisfaction of the Authorized Officer:

1. The Operator shall indemnify the United States against any liability for damage to life or property arising from the occupancy or use of public lands under this APD.

2. The Operator shall comply with all applicable Federal laws and regulations existing or hereafter enacted or promulgated. In any event, the operator shall comply with the Toxic Substances Control Act of 1976 as amended, 15 USC 2601 et seq. (1982) with regards to any toxic substances that are used, generated by or stored on the pipeline corridor or on facilities authorized under this APD. (See 40 CFR Part 702-799 and especially, provisions on polychlorinated biphenyls, 40 CFR 761.1-761.193.) Additionally, any release of toxic substances (leaks, spills, etc.) in excess of the reportable quantity established by 40 CFR Part 117 shall be reported as required by the Comprehensive Environmental Response, Compensation, and Liability Act, section 102b. A copy of any report required or requested by any Federal agency or State government as a result of a reportable release or spill of any toxic substances shall be furnished to the authorized officer concurrent with the filing of the reports to the involved Federal agency or State government.

3. The operator agrees to indemnify the United States against any liability arising from the release of any hazardous substance or hazardous waste (as these terms are defined in the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 42 U.S.C. 9601, et seq. or the Resource Conservation and Recovery Act, 42 U.S.C.6901, et seq.) on the Pipeline corridor (unless the release or threatened release is wholly unrelated to the operator's activity on the pipeline corridor), or resulting from the activity of the Operator on the pipeline corridor. This agreement applies without regard to whether a release is caused by the operator, its agent, or unrelated third parties.

4. If, during any phase of the construction, operation, maintenance, or termination of the pipeline, any oil or other pollutant is discharged from the pipeline system, impacting Federal lands, the control and total removal, disposal, and cleaning up of such oil or other pollutant, wherever found, shall be the responsibility of operator, regardless of fault. Upon failure of operator to control, dispose of, or clean up such discharge on or affecting Federal lands, or to repair all damages resulting therefrom, on the Federal lands, the Authorized Officer may take such measures as he deems necessary to control and clean up the discharge and restore the area, including where appropriate, the aquatic environment and

fish and wildlife habitats, at the full expense of the operator. Such action by the Authorized Officer shall not relieve operator of any responsibility as provided herein.

5. All construction and maintenance activity will be confined to the authorized pipeline corridor.

6. The pipeline will be buried with a minimum cover of 36 inches between the top of the pipe and ground level.

7. The maximum allowable disturbance for construction in this pipeline corridor will be 30 feet:

   - Blading of vegetation within the pipeline corridor will be allowed: maximum width of blading operations will not exceed **20** feet. The trench is included in this area. (*Blading is defined as the complete removal of brush and ground vegetation*.)

   - Clearing of brush species within the pipeline corridor will be allowed: maximum width of clearing operations will not exceed **30** feet. The trench and bladed area are included in this area. (*Clearing is defined as the removal of brush while leaving ground vegetation (grasses, weeds, etc.) intact. Clearing is best accomplished by holding the blade 4 to 6 inches above the ground surface.*)

   - The remaining area of the pipeline corridor (if any) shall only be disturbed by compressing the vegetation. (*Compressing can be caused by vehicle tires, placement of equipment, etc.*)

8. The operator shall stockpile an adequate amount of topsoil where blading is allowed. The topsoil to be stripped is approximately ___6___ inches in depth. The topsoil will be segregated from other spoil piles from trench construction. The topsoil will be evenly distributed over the bladed area for the preparation of seeding.

9. Vegetation, soil, and rocks left as a result of construction or maintenance activity will be randomly scattered on this pipeline corridor and will not be left in rows, piles, or berms, unless otherwise approved by the Authorized Officer. The entire pipeline corridor shall be recontoured to match the surrounding landscape. The backfilled soil shall be compacted, and a 6-inch berm will be left over the ditch line to allow for settling back to grade.

10. The pipeline will be identified by signs at the point of origin and completion of the pipeline corridor and at all road crossings. At a minimum, signs will state the operator's name, BLM serial number, and the product being transported. All signs and information thereon will be posted in a permanent, conspicuous manner, and will be maintained in a legible condition for the life of the pipeline.

11. The operator shall not use the pipeline route as a road for purposes other than routine maintenance as determined necessary by the Authorized Officer in consultation with the operator before maintenance begins. The operator will take whatever steps are necessary to ensure that the pipeline route is not used as a roadway. As determined necessary during the life of the pipeline, the Authorized Officer may ask the operator to construct temporary deterrence structures.

12. The operator shall be held responsible if noxious weeds become established within the areas of operations. Weed control shall be required on the disturbed land where noxious weeds exist, which includes associated roads, pipeline corridor and adjacent land affected by the establishment of weeds due to this action. The operator shall consult with the Authorized Officer for acceptable weed control methods, which include following EPA and BLM requirements and policies.

13. Escape Ramps - The operator will construct and maintain pipeline/utility trenches [that are not otherwise fenced, screened, or netted] to prevent livestock, wildlife, and humans from becoming entrapped. At a minimum, the operator will construct and maintain escape ramps, ladders, or other methods of avian and terrestrial wildlife escape in the trenches according to the following criteria:

a. Any trench left open for eight (8) hours or less is not required to have escape ramps; however, before the trench is backfilled, the contractor/operator shall inspect the trench for wildlife, remove all trapped wildlife, and release them alive at least 100 yards from the trench.
b. For trenches left open for eight (8) hours or more, earthen escape ramps (built at no more than a 30-degree slope and spaced no more than 500 feet apart) shall be placed in the trench. Before the trench is backfilled, the contractor/operator shall inspect the trench for wildlife, remove all trapped wildlife, and release them alive at least 100 yards from the trench.

4.2 SURFACE PIPELINES

A copy of the APD and attachments, including stipulations, survey plat(s) and/or map(s), shall be on location during construction. BLM personnel may request to review a copy of your permit during construction to ensure compliance with all stipulations.

Operator agrees to comply with the following stipulations to the satisfaction of the Authorized Officer:

1. Operator shall indemnify the United States against any liability for damage to life or property arising from the occupancy or use of public lands under this APD.

2. Operator shall comply with all applicable Federal laws and regulations existing or hereafter enacted or promulgated. In any event, Operator shall comply with the Toxic Substances Control Act of 1976 as amended, 15 USC § 2601 et seq. (1982) with regard to any toxic substances that are used, generated by or stored on the pipeline corridoror on facilities authorized under this APD (see 40 CFR, Part 702-799 and in particular, provisions on polychlorinated biphenyls, 40 CFR 761.1-761.193). Additionally, any release of toxic substances (leaks, spills, etc.) in excess of the reportable quantity established by 40 CFR, Part 117 shall be reported as required by the Comprehensive Environmental Response, Compensation, and Liability Act, section 102b. A copy of any report required or requested by any Federal agency or State government as a result of a reportable release or spill of any toxic substances shall be furnished to the Authorized Officer concurrent with the filing of the reports to the involved Federal agency or State government.

3. Operator agrees to indemnify the United States against any liability arising from the release of any hazardous substance or hazardous waste (as these terms are defined in the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 42 U.S.C. § 9601, et seq. or the Resource Conservation and Recovery Act, 42 U.S.C. 6901, et seq.) on the Pipeline corridor (unless the release or threatened release is wholly unrelated to activity of the Operator's activity on the Pipeline corridor), or resulting from the activity of the Operator on the pipeline corridor. This provision applies without regard to whether a release is caused by Operator, its agent, or unrelated third parties.

4. Operator shall be liable for damage or injury to the United States to the extent provided by 43 CFR Sec. 2883.1-4. Operator shall be held to a standard of strict liability for damage or injury to the United States resulting from pipe rupture, fire, or spills caused or substantially aggravated by any of the following within the pipeline corridor or permit area:

   a. Activities of Operator including, but not limited to: construction, operation, maintenance, and termination of the facility;

   b. Activities of other parties including, but not limited to:
      (1) Land clearing
      (2) Earth-disturbing and earth-moving work
      (3) Blasting
      (4) Vandalism and sabotage

   c. Acts of God.

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The maximum limitation for such strict liability damages shall not exceed one million dollars ($1,000,000) for any one event, and any liability in excess of such amount shall be determined by the ordinary rules of negligence of the jurisdiction in which the damage or injury occurred.

This section shall not impose strict liability for damage or injury resulting primarily from an act of war or from the negligent acts or omissions of the United States.

5. If, during any phase of the construction, operation, maintenance, or termination of the pipeline, any oil, salt water, or other pollutant is discharged from the pipeline system, impacting Federal lands, the control and total removal, disposal, and cleaning up of such oil, salt water, or other pollutant, wherever found, shall be the responsibility of Operator, regardless of fault. Upon failure of Operator to control, dispose of, or clean up such discharge on or affecting Federal lands, or to repair all damages resulting therefrom, on the Federal lands, the Authorized Officer may take such measures as they deem necessary to control and clean up the discharge and restore the area, including, where appropriate, the aquatic environment and fish and wildlife habitats, at the full expense of Operator. Such action by the Authorized Officer shall not relieve Operator of any responsibility as provided herein.

6. All construction and maintenance activity shall be confined to the authorized pipeline corridor width of 30-feet. If the pipeline route follows an existing road or buried pipeline corridor, the surface pipeline shall be installed no farther than 10 feet from the edge of the road or buried pipeline corridor. If existing surface pipelines prevent this distance, the proposed surface pipeline shall be installed immediately adjacent to the outer surface pipeline. All construction and maintenance activity shall be confined to existing roads or pipeline corridors.

7. No blading or clearing of any vegetation shall be allowed unless approved in writing by the Authorized Officer.

8. Operator shall install the pipeline on the surface in such a manner that will minimize suspension of the pipeline across low areas in the terrain. In hummocky of duney areas, the pipeline shall be "snaked" around hummocks and dunes rather than suspended across these features.

9. The pipeline shall be buried with a minimum of 6 inches under all roads, "two-tracks," and trails. Burial of the pipe will continue for 20 feet on each side of each crossing. The condition of the road, upon completion of construction, shall be returned to at least its former state with no bumps or dips remaining in the road surface.

10. The operator shall minimize disturbance to existing fences and other improvements on public lands. The operator is required to promptly repair improvements to at least their former state. Functional use of these improvements will be maintained at all times. The operator will contact the owner of any improvements prior to disturbing them. When necessary to pass through a fence line, the fence shall be braced on both sides of the passageway prior to cutting of the fence. No permanent gates will be allowed unless approved by the Authorized Officer.

11. In those areas where erosion control structures are required to stabilize soil conditions, the operator will install such structures as are suitable for the specific soil conditions being encountered and which are in accordance with sound resource management practices.

12. Excluding the pipe, all above-ground structures not subject to safety requirement shall be painted by the operator to blend with the natural color of the landscape. The paint used shall be a color which simulates "Standard Environmental Colors" – Shale Green, Munsell Soil Color No. 5Y 4/2; designated by the Rocky Mountain Five State Interagency Committee.

13. The pipeline will be identified by signs at the point of origin and completion of the pipeline corridor and at all road crossings. At a minimum, signs will state the operator's name, BLM serial number, and the product being transported. Signs will be maintained in a legible condition for the life of the pipeline.

14. The operator shall not use the pipeline route as a road for purposes other than routine maintenance as determined necessary by the Authorized Officer in consultation with the operator. The operator will take whatever steps are necessary to ensure that the pipeline route is not used as a roadway.

15. The operator shall be held responsible if noxious weeds become established within the areas of operations. Weed control shall be required on the disturbed land where noxious weeds exist, which includes the roads, powerline corridor, and adjacent land affected by the establishment of weeds due to this action. The operator shall consult with the Authorized Officer for acceptable weed control methods, which include following EPA and BLM requirements and policies.

16. Surface pipelines shall be less than or equal to 4 inches and a working pressure below 125 psi.

4.3 RANGELAND MITIGATION FOR PIPELINES

4.5.1 **Fence Requirement**

Where entry is granted across a fence line, the fence must be braced and tied off on both sides of the passageway with H-braces prior to cutting. Once the work is completed, the fence will be restored to its prior condition, or better. The operator shall notify the private surface landowner or the grazing allotment operator prior to crossing any fence(s).

4.5.2 **Cattleguards**

An appropriately sized cattleguard(s) sufficient to carry out the project shall be installed and maintained at road-fence crossing(s). Any existing cattleguard(s) on the access road shall be repaired or replaced if they are damaged or have deteriorated beyond practical use. The operator shall be responsible for the condition of the existing cattleguard(s) that are in place and are utilized during lease operations. A gate shall be constructed on one side of the cattleguard and fastened securely to H-braces.

4.5.3 **Livestock Watering Requirement**

Structures that provide water to livestock, such as windmills, pipelines, drinking troughs, and earthen reservoirs, will be avoided by moving the proposed action.

Any damage to structures that provide water to livestock throughout the life of the well, caused by operations from the well site, must be immediately corrected by the operator. The operator must notify the BLM office (575-234-5972) and the private surface landowner or the grazing allotment operator if any damage occurs to structures that provide water to livestock.

- Livestock operators will be contacted, and adequate crossing facilities will be provided as needed to ensure livestock are not prevented from reaching water sources because of the open trench.
- Wildlife and livestock trails will remain open and passable by adding soft plugs (areas where the trench is excavated and replaced with minimal compaction) during the construction phase. Soft plugs with ramps on either side will be left at all well-defined livestock and wildlife trails along the open trench to allow passage across the trench and provide a means of escape for livestock and wildlife that may enter the trench.
- Trenches will be backfilled as soon as feasible to minimize the amount of open trench. The Operator will avoid leaving trenches open overnight to the extent possible and open trenches that cannot be backfilled immediately will have escape ramps (wooden) placed at no more than 2,500 feet intervals and sloped no more than 45 degrees.

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5. PRODUCTION (POST DRILLING)

5.1 WELL STRUCTURES & FACILITIES

5.1.1 **Placement of Production Facilities**

Production facilities must be placed on the well pad to allow for maximum interim recontouring and revegetation of the well location.

5.1.2 **Exclosure Netting (Open-top Tanks)**

Immediately following active drilling or completion operations, the operator will take actions necessary to prevent wildlife and livestock access, including avian wildlife, to all open-topped tanks that contain or have the potential to contain salinity sufficient to cause harm to wildlife or livestock, hydrocarbons, or Resource Conservation and Recovery Act of 1976-exempt hazardous substances. At a minimum, the operator will net, screen, or cover open-topped tanks to exclude wildlife and livestock and prevent mortality. If the operator uses netting, the operator will cover and secure the open portion of the tank to prevent wildlife entry. The operator will net, screen, or cover the tanks until the operator removes the tanks from the location or the tanks no longer contain substances that could be harmful to wildlife or livestock. Use a maximum netting mesh size of 1 ½ inches. The netting must not be in contact with fluids and must not have holes or gaps.

5.1.3. Chemical and Fuel Secondary Containment and Exclosure Screening

The operator will prevent all hazardous, poisonous, flammable, and toxic substances from coming into contact with soil and water. At a minimum, the operator will install and maintain an impervious secondary containment system for any tank or barrel containing hazardous, poisonous, flammable, or toxic substances sufficient to contain the contents of the tank or barrel and any drips, leaks, and anticipated precipitation. The operator will dispose of fluids within the containment system that do not meet applicable state or U. S. Environmental Protection Agency livestock water standards in accordance with state law; the operator must not drain the fluids to the soil or ground. The operator will design, construct, and maintain all secondary containment systems to prevent wildlife and livestock exposure to harmful substances. At a minimum, the operator will install effective wildlife and livestock exclosure systems such as fencing, netting, expanded metal mesh, lids, and grate covers. Use a maximum netting mesh size of 1 ½ inches.

5.1.4. Open-Vent Exhaust Stack Exclosures

The operator will construct, modify, equip, and maintain all open-vent exhaust stacks on production equipment to prevent birds and bats from entering, and to discourage perching, roosting, and nesting. (*Recommended exclosure structures on open-vent exhaust stacks are in the shape of a cone.*) Production equipment includes, but may not be limited to, tanks, heater-treaters, separators, dehydrators, flare stacks, in-line units, and compressor mufflers.

5.1.5. Containment Structures

Proposed production facilities such as storage tanks and other vessels will have a secondary containment structure that is constructed to hold the capacity of 1.5 times the largest tank, plus freeboard to account for precipitation, unless more stringent protective requirements are deemed necessary.

6. RECLAMATION

Stipulations required by the Authorized Officer on specific actions may differ from the following general guidelines

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6.1 ROAD AND SITE RECLAMATION

Any roads constructed during the life of the well will have the caliche removed or linear burial. If contaminants are indicated then testing will be required for chlorides and applicable contaminate anomalies for final disposal determination (disposed of in a manner approved by the Authorized Officer within Federal, State and Local statutes, regulations, and ordinances) and seeded to the specifications in sections 6.5 and 6.6.

6.2 EROSION CONTROL

Install erosion control berms, windrows, and hummocks. Windrows must be level and constructed perpendicular to down-slope drainage; steeper slopes will require greater windrow density. Topsoil between windrows must be ripped to a depth of at least 12”, unless bedrock is encountered. Any large boulders pulled up during ripping must be deep-buried on location. Ripping must be perpendicular to down-slope. The surface must be left rough in order to catch and contain rainfall on-site. Any trenches resulting from erosion cause by run-off shall be addressed immediately.

6.3 INTERIM RECLAMATION

During the life of the development, all disturbed areas not needed for active support of production operations must undergo interim reclamation in order to minimize the environmental impacts of development on other resources and uses.

Within six (6) months of well completion, operators must work with BLM surface protection specialists (BLM_NM_CFO_Construction_Reclamation@blm.gov) to devise the best strategies to reduce the size of the location. Interim reclamation must allow for remedial well operations, as well as safe and efficient removal of oil and gas.

During reclamation, the removal of caliche and any other surface material is required. Removed caliche that is free of contaminants may be used for road repairs, fire walls or for building other roads and locations. In order to operate the well or complete workover operations, it may be necessary to drive, park and operate on restored interim vegetation within the previously disturbed area. Disturbing revegetated areas for production or workover operations will be allowed. If there is significant disturbance and loss of vegetation, the area will need to be revegetated. Communicate with the appropriate BLM office for any exceptions/exemptions if needed.

All disturbed areas after they have been satisfactorily prepared need to be reseeded with the seed mixture provided in section 6.6.

Upon completion of interim reclamation, the operator shall submit a Sundry Notice, Subsequent Report of Reclamation (Form 3160-5).

6.4 FINAL ABANDONMENT & RECLAMATION

Prior to surface abandonment, the operator shall submit a Notice of Intent Sundry Notice and reclamation plan.

At final abandonment, well locations, production facilities, and access roads must undergo "final" reclamation so that the character and productivity of the land are restored.

Earthwork for final reclamation must be completed within six (6) months of well plugging. All pads, pits, facility locations and roads must be reclaimed to a satisfactory revegetated, safe, and stable condition, unless an agreement is made with the landowner or BLM to keep the road and/or pad intact.

After all disturbed areas have been satisfactorily prepared, these areas need to be revegetated with the seed mixture provided below. Seeding will be accomplished by drilling on the contour whenever practical or by other approved methods. Seeding may need to be repeated until revegetation is successful, as determined by the BLM. After earthwork and seeding is completed, the operator is required to submit a Sundry Notice, Subsequent Report of Reclamation.

Operators shall contact a BLM surface protection specialist prior to surface abandonment operations for site specific objectives (BLM_NM_CFO_Construction_Reclamation@blm.gov).

6.5 SEEDING TECHNIQUES

Seeds shall be hydro-seeded, mechanically drilled, or broadcast, with the broadcast-seeded area raked, ripped or dragged to aid in covering the seed. The seed mixture shall be evenly and uniformly planted over the disturbed area.

6.6 SOIL SPECIFIC SEED MIXTURE

The lessee/permitee shall seed all disturbed areas with the seed mixture listed below. The seed mixture shall be planted in the amounts specified in pounds of pure live seed (PLS)* per acre. There shall be no primary or secondary noxious weeds in the seed mixture. Seed will be tested and the viability testing of seed will be done in accordance with State law(s) and within nine (9) months prior to purchase. Commercial seed will be either certified or registered seed. The seed container will be tagged in accordance with State law(s) and available for inspection by the Authorized Officer.

Seed land application will be accomplished by mechanical planting using a drill equipped with a depth regulator to ensure proper depth of planting where drilling is possible. The seed mixture will be evenly and uniformly planted over the disturbed area. Smaller/heavier seeds tend to drop the bottom of the drill and are planted first; the operator shall take appropriate measures to ensure this does not occur. Where drilling is not possible, seed will be broadcast and the area shall be raked or chained to cover the seed. When broadcasting the seed, the pounds per acre are to be doubled. The seeding will be repeated until a satisfactory BLM or Soil Conservation

District stand is established as determined by the Authorized Officer. Evaluation of growth will not be made before completion of at least one full growing season after seeding or until several months of precipitation have occurred, enabling a full four months of growth, with one or more seed generations being establishe

Seed Mixture 2, for Sandy Site

Species to be planted in pounds of pure live seed* per acre:

Species	lb/acre
Sand dropseed (Sporobolus cryptandrus)	1.0
Sand love grass (Eragrostis trichodes)	1.0
Plains bristlegrass (Setaria macrostachya)	2.0

*Pounds of pure live seed:

Pounds of seed **x** percent purity **x** percent germination = pounds pure live seed

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	EOG Resources Incorporated
WELL NAME & NO.:	PEREGRINE 27 FED COM 502H
LOCATION:	Section 27, T.24 S., R.34 E.
COUNTY:	Lea County, New Mexico

COA

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

A. HYDROGEN SULFIDE

A Hydrogen Sulfide (H2S) Drilling Plan shall be activated AT SPUD. As a result, the Hydrogen Sulfide area must meet Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

B. CASING

The above well is approved for the primary design and 5 Designs listed in the "EOG BLM Variance 5a - Alternate Shallow Casing Designs" document. The casing set points and directional plans for the wells in the batch are within the boundary conditions reviewed in the blanket design. The COA is written for the deepest well on the pad. Operator is responsible to review the cement volumes based on the set points, design executed and to achieve the TOC requirements listed in the COA.

<u>Primary(Design E:)</u>

1. The **10-3/4** inch surface casing shall be set at approximately **1169 feet TVD** (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface.

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

2. The **8-5/8** inch intermediate casing shall be set at approximately **5283** feet **TVD**.
    a. Mud weight could brine up to 10.2ppg. Reviewed and OK
    b. Keep casing half full during run for collapse SF

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

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

3. The **6** inch **x 5.5** inch tapered production casing shall be set at approximately **21,249** feet. Operator has also proposed ONLY running **6** inch casing for the production string. Reviewed and is OK. The minimum required fill of cement behind the **5-1/2** inch production casing is:

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

<u>Shallow Design A:</u>

1. The **13-3/8** inch surface casing shall be set at approximately **1169 feet TVD** (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface.
    a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run

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to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.

b. Wait on cement (WOC) time for a primary cement job will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
d. If cement falls back, remedial cementing will be done prior to drilling out that string.

2. The **9-5/8** inch intermediate casing shall be set at approximately **5283** feet **TVD**.
   a. Mud weight could brine up to 10.2ppg. Reviewed and OK
   b. Keep casing half full during run for collapse SF

   The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:

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

3. The **5-1/2** inch production casing shall be set at approximately **21,249** feet. The minimum required fill of cement behind the **5-1/2** inch production casing is:

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

Shallow Design B:

1. The **10-3/4** inch surface casing shall be set at approximately **1169 feet TVD** (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface.

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

If cement falls back, remedial cementing will be done prior to drilling out that string.

2. The **8-5/8** inch intermediate casing shall be set at approximately **5283** feet **TVD**.
   a. **Mud weight could brine up to 10.2ppg. Reviewed and OK**
   b. **Keep casing half full during run for collapse SF**

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

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

3. The **5-1/2** inch production casing shall be set at approximately **21,249** feet. The minimum required fill of cement behind the **5-1/2** inch production casing is:

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

Shallow Design C:

1. The **13-3/8** inch surface casing shall be set at approximately **1169 feet TVD** (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface.

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

2. The **9-5/8** inch intermediate casing shall be set at approximately **5283** feet **TVD**.
   c. **Mud weight could brine up to 10.2ppg. Reviewed and OK**
   d. **Keep casing half full during run for collapse SF**

The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:

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

3. The **6** inch production casing shall be set at approximately **21,249** feet. The minimum required fill of cement behind the **6** inch production casing is:

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

<u>Shallow Design D:</u>

1. The **13-3/8** inch surface casing shall be set at approximately **1169 feet TVD** (a minimum of 25 feet (Lea County) into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface.

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

2. The **9-5/8** inch intermediate casing shall be set at approximately **5283** feet **TVD**.
    e. Mud weight could brine up to 10.2ppg. Reviewed and OK
    f. Keep casing half full during run for collapse SF

    The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:

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

3. The **6** inch x **5.5** inch tapered production casing shall be set at approximately **21,249** feet. The minimum required fill of cement behind the **6** inch x **5.5** inch tapered production casing is:

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

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C. PRESSURE CONTROL

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

2. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the **13-3/8** inch surface casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **5000 (5M)** psi. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 3500 (70% Working Pressure) psi.**

    a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
    b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
    c. Manufacturer representative shall install the test plug for the initial BOP test.
    d. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
    e. Whenever any seal subject to test pressure is broken, all the tests in OOGO2.III.A.2.i must be followed.

D. SPECIAL REQUIREMENT (S)

Communitization Agreement

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

(Note: For a minimum 5M BOPE or less (Utilizing a 10M BOPE system)
BOPE Break Testing Variance

- BOPE Break Testing is ONLY permitted for 5M BOPE or less. **(Annular preventer must be tested to a minimum of 70% of BOPE working pressure and shall be higher than the MASP)**
- BOPE Break Testing is NOT permitted to drilling the production hole section.

- Variance only pertains to the intermediate hole-sections and no deeper than the Bone Springs formation.
- While in transfer between wells, the BOPE shall be secured by the hydraulic carrier or cradle.
- Any well control event while drilling require notification to the BLM Petroleum Engineer **(575-706-2779)** prior to the commencement of any BOPE Break Testing operations.
- A full BOPE test is required prior to drilling the first deep intermediate hole section. If any subsequent hole interval is deeper than the first, a full BOPE test will be required. (200' TVD tolerance between intermediate shoes is allowable).
- The BLM is to be contacted (575-689-5981 Lea County) 4 hours prior to BOPE tests.
- As a minimum, a full BOPE test shall be performed at 21-day intervals.
- In the event any repairs or replacement of the BOPE is required, the BOPE shall test as per Onshore Oil and Gas Order No. 2.
- If in the event break testing is not utilized, then a full BOPE test would be conducted.

Casing Clearance:

- Variance in place for production interval as long as the 500' overlap into the previous casing meets the requirement
- Variance in place for salt interval clearance based on caliper data study

Offline Cementing

Operator is approved for offline cementing for surface and intermediate intervals. Notify the BLM prior to the commencement of any offline cementing procedure.

GENERAL REQUIREMENTS

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

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

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

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

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

a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
b. When the operator proposes to set surface casing with Spudder Rig
   - Notify the BLM when moving in and removing the Spudder Rig.
   - Notify the BLM when moving in the 2nd Rig. Rig to be moved in within 90 days of notification that Spudder Rig has left the location.
   - BOP/BOPE test to be conducted per **43 CFR part 3170 Subpart 3172** as soon as 2nd Rig is rigged up on well.

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

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

A. CASING

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

2. <u>Wait on cement (WOC) for Potash Areas:</u> After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi for all cement blends, 2) until cement has been in place at least <u>24 hours</u>. WOC time will be recorded in the driller's log. The casing intergrity test can be done (prior to the cement setting up) immediately after bumping the plug.

3. <u>Wait on cement (WOC) for Water Basin:</u> After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least <u>8 hours</u>.

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WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements. The casing integrity test can be done (prior to the cement setting up) immediately after bumping the plug.

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

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

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

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

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

B. PRESSURE CONTROL

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

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

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

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

    a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
    b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
    c. Manufacturer representative shall install the test plug for the initial BOP test.
    d. Whenever any seal subject to test pressure is broken, all the tests in **43 CFR part 3170 Subpart 3172** must be followed.
    e. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.

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

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

    b. In potash areas, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. For all casing strings, casing cut-off and BOP installation can be initiated at twelve hours after bumping the cement plug. The BOPE test can be initiated after bumping the cement plug with the casing valve open. (only applies to single stage cement jobs, prior to the cement setting up.)

    c. The tests shall be done by an independent service company utilizing a test plug not a cup or J-packer and can be initiated immediately with the casing valve open. The operator also has the option of utilizing an independent tester to test without a plug (i.e. against the casing) pursuant to **43 CFR part 3170 Subpart 3172** with the pressure not to exceed 70% of the burst rating for the casing. Any test against the casing must meet the WOC time for water basin (8 hours) or potash (24 hours) or 500 pounds compressive strength, whichever is greater, prior to initiating the test (see casing segment as lead cement may be critical item).

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

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

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

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

h. BOP/BOPE must be tested by an independent service company within 500 feet of the top of the Wolfcamp formation if the time between the setting of the intermediate casing and reaching this depth exceeds 20 days. This test does not exclude the test prior to drilling out the casing shoe as per **43 CFR part 3170 Subpart 3172**.

C. DRILLING MUD

Mud system monitoring equipment, with derrick floor indicators and visual and audio alarms, shall be operating before drilling into the Wolfcamp formation, and shall be used until production casing is run and cemented.

D. WASTE MATERIAL AND FLUIDS

All waste (i.e. drilling fluids, trash, salts, chemicals, sewage, gray water, etc.) created as a result of drilling operations and completion operations shall be safely contained and disposed of properly at a waste disposal facility. No waste material or fluid shall be disposed of on the well location or surrounding area.

Porto-johns and trash containers will be on-location during fracturing operations or any other crew-intensive operations.

KPI 9/3/2025

Approval Date: 10/09/2025

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:** 10/13/2025

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
PEREGRINE 27 FED COM 502H		L-27-24S-34E	1700' FSL & 159' FWL	+/- 1000	+/- 3500	+/- 3000

IV. Central Delivery Point Name: ___Peregrine 27 Fed Com 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
PEREGRINE 27 FED COM 502H		11/7/25	11/22/25	1/01/26	2/01/26	3/01/26

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: 11/3/2025
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.

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

- 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.

Midland

Lea County, NM (NAD 83 NME)
Peregrine 27 Fed Com
#502H

OH

Plan: Plan #0.1 RT

Standard Planning Report

03 October, 2024

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #502H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3477.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3477.0usft
Site:	Peregrine 27 Fed Com	**North Reference:**	Grid
Well:	#502H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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	Peregrine 27 Fed Com				
Site Position:		**Northing:**	431,580.00 usft	**Latitude:**	32° 11' 0.630 N
From:	Map	**Easting:**	810,070.00 usft	**Longitude:**	103° 27' 52.923 W
Position Uncertainty:	0.0 usft	**Slot Radius:**	13-3/16 "		

Well	#502H					
Well Position	**+N/-S**	0.0 usft	**Northing:**	432,467.00 usft	**Latitude:**	32° 11' 9.436 N
	+E/-W	0.0 usft	**Easting:**	809,708.00 usft	**Longitude:**	103° 27' 57.052 W
Position Uncertainty		0.0 usft	**Wellhead Elevation:**	usft	**Ground Level:**	3,451.0 usft
Grid Convergence:		0.46 °				

Wellbore OH

Magnetics	Model Name	Sample Date	Declination (°)	Dip Angle (°)	Field Strength (nT)
	IGRF2020	10/3/2024	6.10	59.77	47,137.27519209

Design Plan #0.1 RT

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	176.11

Plan Survey Tool Program **Date** 10/3/2024

	Depth From (usft)	Depth To (usft)	Survey (Wellbore)	Tool Name	Remarks
1	0.0	21,249.3	Plan #0.1 RT (OH)	EOG MWD+IFR1 MWD + IFR1	

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #502H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3477.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3477.0usft
Site:	Peregrine 27 Fed Com	**North Reference:**	Grid
Well:	#502H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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	
1,300.0	0.00	0.00	1,300.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,774.3	9.49	31.54	1,772.1	33.4	20.5	2.00	2.00	0.00	31.54	
7,656.5	9.49	31.54	7,573.9	859.6	527.5	0.00	0.00	0.00	0.00	
8,130.8	0.00	0.00	8,046.0	893.0	548.0	2.00	-2.00	0.00	180.00	
10,579.3	0.00	0.00	10,494.5	893.0	548.0	0.00	0.00	0.00	0.00	KOP(Peregrine 27 Fe
10,799.7	26.46	180.00	10,707.2	843.0	548.0	12.00	12.00	81.65	180.00	FTP(Peregrine 27 Fe
11,329.2	90.00	179.43	10,971.9	415.6	550.9	12.00	12.00	-0.11	-0.64	
13,440.9	90.00	179.43	10,972.0	-1,696.0	572.0	0.00	0.00	0.00	0.00	Fed Perf 1(Peregrine
17,402.1	90.00	179.47	10,972.0	-5,657.0	610.0	0.00	0.00	0.00	86.33	Fed Perf 2(Peregrine
21,249.3	90.00	179.43	10,972.0	-9,504.0	647.0	0.00	0.00	0.00	-93.45	PBHL(Peregrine 27 F

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #502H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3477.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3477.0usft
Site:	Peregrine 27 Fed Com	**North Reference:**	Grid
Well:	#502H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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	0.00	0.00	1,300.0	0.0	0.0	0.0	0.00	0.00	0.00
1,400.0	2.00	31.54	1,400.0	1.5	0.9	-1.4	2.00	2.00	0.00
1,500.0	4.00	31.54	1,499.8	5.9	3.6	-5.7	2.00	2.00	0.00
1,600.0	6.00	31.54	1,599.5	13.4	8.2	-12.8	2.00	2.00	0.00
1,700.0	8.00	31.54	1,698.7	23.8	14.6	-22.7	2.00	2.00	0.00
1,774.3	9.49	31.54	1,772.1	33.4	20.5	-31.9	2.00	2.00	0.00
1,800.0	9.49	31.54	1,797.5	37.0	22.7	-35.4	0.00	0.00	0.00
1,900.0	9.49	31.54	1,896.1	51.0	31.3	-48.8	0.00	0.00	0.00
2,000.0	9.49	31.54	1,994.8	65.1	39.9	-62.2	0.00	0.00	0.00
2,100.0	9.49	31.54	2,093.4	79.1	48.6	-75.7	0.00	0.00	0.00
2,200.0	9.49	31.54	2,192.0	93.2	57.2	-89.1	0.00	0.00	0.00
2,300.0	9.49	31.54	2,290.6	107.2	65.8	-102.5	0.00	0.00	0.00
2,400.0	9.49	31.54	2,389.3	121.3	74.4	-115.9	0.00	0.00	0.00
2,500.0	9.49	31.54	2,487.9	135.3	83.0	-129.4	0.00	0.00	0.00
2,600.0	9.49	31.54	2,586.5	149.4	91.7	-142.8	0.00	0.00	0.00
2,700.0	9.49	31.54	2,685.2	163.4	100.3	-156.2	0.00	0.00	0.00
2,800.0	9.49	31.54	2,783.8	177.5	108.9	-169.7	0.00	0.00	0.00
2,900.0	9.49	31.54	2,882.4	191.5	117.5	-183.1	0.00	0.00	0.00
3,000.0	9.49	31.54	2,981.1	205.6	126.1	-196.5	0.00	0.00	0.00
3,100.0	9.49	31.54	3,079.7	219.6	134.8	-209.9	0.00	0.00	0.00
3,200.0	9.49	31.54	3,178.3	233.6	143.4	-223.4	0.00	0.00	0.00
3,300.0	9.49	31.54	3,277.0	247.7	152.0	-236.8	0.00	0.00	0.00
3,400.0	9.49	31.54	3,375.6	261.7	160.6	-250.2	0.00	0.00	0.00
3,500.0	9.49	31.54	3,474.2	275.8	169.2	-263.7	0.00	0.00	0.00
3,600.0	9.49	31.54	3,572.9	289.8	177.9	-277.1	0.00	0.00	0.00
3,700.0	9.49	31.54	3,671.5	303.9	186.5	-290.5	0.00	0.00	0.00
3,800.0	9.49	31.54	3,770.1	317.9	195.1	-303.9	0.00	0.00	0.00
3,900.0	9.49	31.54	3,868.8	332.0	203.7	-317.4	0.00	0.00	0.00
4,000.0	9.49	31.54	3,967.4	346.0	212.3	-330.8	0.00	0.00	0.00
4,100.0	9.49	31.54	4,066.0	360.1	221.0	-344.2	0.00	0.00	0.00
4,200.0	9.49	31.54	4,164.7	374.1	229.6	-357.7	0.00	0.00	0.00
4,300.0	9.49	31.54	4,263.3	388.2	238.2	-371.1	0.00	0.00	0.00
4,400.0	9.49	31.54	4,361.9	402.2	246.8	-384.5	0.00	0.00	0.00
4,500.0	9.49	31.54	4,460.6	416.2	255.4	-397.9	0.00	0.00	0.00
4,600.0	9.49	31.54	4,559.2	430.3	264.1	-411.4	0.00	0.00	0.00
4,700.0	9.49	31.54	4,657.8	444.3	272.7	-424.8	0.00	0.00	0.00
4,800.0	9.49	31.54	4,756.5	458.4	281.3	-438.2	0.00	0.00	0.00
4,900.0	9.49	31.54	4,855.1	472.4	289.9	-451.7	0.00	0.00	0.00
5,000.0	9.49	31.54	4,953.7	486.5	298.5	-465.1	0.00	0.00	0.00
5,100.0	9.49	31.54	5,052.4	500.5	307.2	-478.5	0.00	0.00	0.00
5,200.0	9.49	31.54	5,151.0	514.6	315.8	-491.9	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #502H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3477.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3477.0usft
Site:	Peregrine 27 Fed Com	**North Reference:**	Grid
Well:	#502H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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	9.49	31.54	5,249.6	528.6	324.4	-505.4	0.00	0.00	0.00
5,400.0	9.49	31.54	5,348.3	542.7	333.0	-518.8	0.00	0.00	0.00
5,500.0	9.49	31.54	5,446.9	556.7	341.6	-532.2	0.00	0.00	0.00
5,600.0	9.49	31.54	5,545.5	570.8	350.3	-545.6	0.00	0.00	0.00
5,700.0	9.49	31.54	5,644.2	584.8	358.9	-559.1	0.00	0.00	0.00
5,800.0	9.49	31.54	5,742.8	598.8	367.5	-572.5	0.00	0.00	0.00
5,900.0	9.49	31.54	5,841.4	612.9	376.1	-585.9	0.00	0.00	0.00
6,000.0	9.49	31.54	5,940.1	626.9	384.7	-599.4	0.00	0.00	0.00
6,100.0	9.49	31.54	6,038.7	641.0	393.3	-612.8	0.00	0.00	0.00
6,200.0	9.49	31.54	6,137.3	655.0	402.0	-626.2	0.00	0.00	0.00
6,300.0	9.49	31.54	6,236.0	669.1	410.6	-639.6	0.00	0.00	0.00
6,400.0	9.49	31.54	6,334.6	683.1	419.2	-653.1	0.00	0.00	0.00
6,500.0	9.49	31.54	6,433.2	697.2	427.8	-666.5	0.00	0.00	0.00
6,600.0	9.49	31.54	6,531.9	711.2	436.4	-679.9	0.00	0.00	0.00
6,700.0	9.49	31.54	6,630.5	725.3	445.1	-693.4	0.00	0.00	0.00
6,800.0	9.49	31.54	6,729.1	739.3	453.7	-706.8	0.00	0.00	0.00
6,900.0	9.49	31.54	6,827.8	753.4	462.3	-720.2	0.00	0.00	0.00
7,000.0	9.49	31.54	6,926.4	767.4	470.9	-733.6	0.00	0.00	0.00
7,100.0	9.49	31.54	7,025.0	781.5	479.5	-747.1	0.00	0.00	0.00
7,200.0	9.49	31.54	7,123.6	795.5	488.2	-760.5	0.00	0.00	0.00
7,300.0	9.49	31.54	7,222.3	809.5	496.8	-773.9	0.00	0.00	0.00
7,400.0	9.49	31.54	7,320.9	823.6	505.4	-787.4	0.00	0.00	0.00
7,500.0	9.49	31.54	7,419.5	837.6	514.0	-800.8	0.00	0.00	0.00
7,600.0	9.49	31.54	7,518.2	851.7	522.6	-814.2	0.00	0.00	0.00
7,656.5	9.49	31.54	7,573.9	859.6	527.5	-821.8	0.00	0.00	0.00
7,700.0	8.62	31.54	7,616.9	865.5	531.1	-827.4	2.00	-2.00	0.00
7,800.0	6.62	31.54	7,716.0	876.7	538.0	-838.2	2.00	-2.00	0.00
7,900.0	4.62	31.54	7,815.5	885.1	543.1	-846.1	2.00	-2.00	0.00
8,000.0	2.62	31.54	7,915.3	890.5	546.4	-851.3	2.00	-2.00	0.00
8,100.0	0.62	31.54	8,015.2	892.9	547.9	-853.6	2.00	-2.00	0.00
8,130.8	0.00	0.00	8,046.0	893.0	548.0	-853.7	2.00	-2.00	0.00
8,200.0	0.00	0.00	8,115.2	893.0	548.0	-853.7	0.00	0.00	0.00
8,300.0	0.00	0.00	8,215.2	893.0	548.0	-853.7	0.00	0.00	0.00
8,400.0	0.00	0.00	8,315.2	893.0	548.0	-853.7	0.00	0.00	0.00
8,500.0	0.00	0.00	8,415.2	893.0	548.0	-853.7	0.00	0.00	0.00
8,600.0	0.00	0.00	8,515.2	893.0	548.0	-853.7	0.00	0.00	0.00
8,700.0	0.00	0.00	8,615.2	893.0	548.0	-853.7	0.00	0.00	0.00
8,800.0	0.00	0.00	8,715.2	893.0	548.0	-853.7	0.00	0.00	0.00
8,900.0	0.00	0.00	8,815.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,000.0	0.00	0.00	8,915.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,100.0	0.00	0.00	9,015.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,200.0	0.00	0.00	9,115.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,300.0	0.00	0.00	9,215.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,400.0	0.00	0.00	9,315.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,500.0	0.00	0.00	9,415.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,600.0	0.00	0.00	9,515.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,700.0	0.00	0.00	9,615.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,800.0	0.00	0.00	9,715.2	893.0	548.0	-853.7	0.00	0.00	0.00
9,900.0	0.00	0.00	9,815.2	893.0	548.0	-853.7	0.00	0.00	0.00
10,000.0	0.00	0.00	9,915.2	893.0	548.0	-853.7	0.00	0.00	0.00
10,100.0	0.00	0.00	10,015.2	893.0	548.0	-853.7	0.00	0.00	0.00
10,200.0	0.00	0.00	10,115.2	893.0	548.0	-853.7	0.00	0.00	0.00
10,300.0	0.00	0.00	10,215.2	893.0	548.0	-853.7	0.00	0.00	0.00
10,400.0	0.00	0.00	10,315.2	893.0	548.0	-853.7	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #502H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3477.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3477.0usft
Site:	Peregrine 27 Fed Com	**North Reference:**	Grid
Well:	#502H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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	10,415.2	893.0	548.0	-853.7	0.00	0.00	0.00
10,579.3	0.00	0.00	10,494.5	893.0	548.0	-853.7	0.00	0.00	0.00
10,600.0	2.49	180.00	10,515.2	892.5	548.0	-853.3	12.00	12.00	0.00
10,625.0	5.49	180.00	10,540.2	890.8	548.0	-851.5	12.00	12.00	0.00
10,650.0	8.49	180.00	10,565.0	887.8	548.0	-848.5	12.00	12.00	0.00
10,675.0	11.49	180.00	10,589.6	883.4	548.0	-844.2	12.00	12.00	0.00
10,700.0	14.49	180.00	10,614.0	877.8	548.0	-838.6	12.00	12.00	0.00
10,725.0	17.49	180.00	10,638.0	870.9	548.0	-831.7	12.00	12.00	0.00
10,750.0	20.49	180.00	10,661.6	862.8	548.0	-823.6	12.00	12.00	0.00
10,775.0	23.49	180.00	10,684.8	853.4	548.0	-814.2	12.00	12.00	0.00
10,799.7	26.46	180.00	10,707.2	843.0	548.0	-803.8	12.00	12.00	0.00
10,825.0	29.49	179.93	10,729.5	831.1	548.0	-792.0	12.00	12.00	-0.27
10,850.0	32.49	179.88	10,751.0	818.3	548.0	-779.2	12.00	12.00	-0.23
10,875.0	35.49	179.83	10,771.7	804.3	548.1	-765.2	12.00	12.00	-0.19
10,900.0	38.49	179.79	10,791.7	789.2	548.1	-750.2	12.00	12.00	-0.16
10,925.0	41.49	179.75	10,810.8	773.2	548.2	-734.2	12.00	12.00	-0.14
10,950.0	44.49	179.72	10,829.1	756.1	548.3	-717.2	12.00	12.00	-0.13
10,975.0	47.49	179.69	10,846.5	738.2	548.4	-699.2	12.00	12.00	-0.12
11,000.0	50.49	179.66	10,862.9	719.3	548.5	-680.4	12.00	12.00	-0.10
11,025.0	53.49	179.64	10,878.3	699.6	548.6	-660.7	12.00	12.00	-0.10
11,050.0	56.49	179.62	10,892.6	679.1	548.7	-640.3	12.00	12.00	-0.09
11,075.0	59.49	179.60	10,905.8	657.9	548.9	-619.1	12.00	12.00	-0.08
11,100.0	62.49	179.58	10,918.0	636.1	549.0	-597.3	12.00	12.00	-0.08
11,125.0	65.49	179.56	10,928.9	613.6	549.2	-574.9	12.00	12.00	-0.07
11,150.0	68.49	179.54	10,938.7	590.6	549.4	-551.9	12.00	12.00	-0.07
11,175.0	71.49	179.52	10,947.3	567.1	549.6	-528.5	12.00	12.00	-0.07
11,200.0	74.49	179.51	10,954.6	543.2	549.8	-504.6	12.00	12.00	-0.07
11,225.0	77.49	179.49	10,960.6	519.0	550.0	-480.4	12.00	12.00	-0.06
11,250.0	80.49	179.48	10,965.4	494.4	550.2	-455.9	12.00	12.00	-0.06
11,275.0	83.49	179.46	10,968.9	469.7	550.4	-431.2	12.00	12.00	-0.06
11,300.0	86.49	179.45	10,971.1	444.8	550.7	-406.3	12.00	12.00	-0.06
11,325.0	89.49	179.43	10,971.9	419.8	550.9	-381.4	12.00	12.00	-0.06
11,329.2	90.00	179.43	10,971.9	415.6	550.9	-377.2	12.00	12.00	-0.06
11,400.0	90.00	179.43	10,972.0	344.8	551.7	-306.5	0.00	0.00	0.00
11,500.0	90.00	179.43	10,972.0	244.8	552.7	-206.7	0.00	0.00	0.00
11,600.0	90.00	179.43	10,972.0	144.8	553.6	-106.9	0.00	0.00	0.00
11,700.0	90.00	179.43	10,972.0	44.8	554.6	-7.0	0.00	0.00	0.00
11,800.0	90.00	179.43	10,972.0	-55.2	555.6	92.8	0.00	0.00	0.00
11,900.0	90.00	179.43	10,972.0	-155.2	556.6	192.6	0.00	0.00	0.00
12,000.0	90.00	179.43	10,972.0	-255.2	557.6	292.5	0.00	0.00	0.00
12,100.0	90.00	179.43	10,972.0	-355.2	558.6	392.3	0.00	0.00	0.00
12,200.0	90.00	179.43	10,972.0	-455.2	559.6	492.1	0.00	0.00	0.00
12,300.0	90.00	179.43	10,972.0	-555.2	560.6	592.0	0.00	0.00	0.00
12,400.0	90.00	179.43	10,972.0	-655.2	561.6	691.8	0.00	0.00	0.00
12,500.0	90.00	179.43	10,972.0	-755.2	562.6	791.6	0.00	0.00	0.00
12,600.0	90.00	179.43	10,972.0	-855.1	563.6	891.5	0.00	0.00	0.00
12,700.0	90.00	179.43	10,972.0	-955.1	564.6	991.3	0.00	0.00	0.00
12,800.0	90.00	179.43	10,972.0	-1,055.1	565.6	1,091.1	0.00	0.00	0.00
12,900.0	90.00	179.43	10,972.0	-1,155.1	566.6	1,191.0	0.00	0.00	0.00
13,000.0	90.00	179.43	10,972.0	-1,255.1	567.6	1,290.8	0.00	0.00	0.00
13,100.0	90.00	179.43	10,972.0	-1,355.1	568.6	1,390.6	0.00	0.00	0.00
13,200.0	90.00	179.43	10,972.0	-1,455.1	569.6	1,490.4	0.00	0.00	0.00
13,300.0	90.00	179.43	10,972.0	-1,555.1	570.6	1,590.3	0.00	0.00	0.00
13,400.0	90.00	179.43	10,972.0	-1,655.1	571.6	1,690.1	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #502H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3477.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3477.0usft
Site:	Peregrine 27 Fed Com	**North Reference:**	Grid
Well:	#502H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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)
13,440.9	90.00	179.43	10,972.0	-1,696.0	572.0	1,730.9	0.00	0.00	0.00
13,500.0	90.00	179.43	10,972.0	-1,755.1	572.6	1,789.9	0.00	0.00	0.00
13,600.0	90.00	179.43	10,972.0	-1,855.1	573.6	1,889.8	0.00	0.00	0.00
13,700.0	90.00	179.43	10,972.0	-1,955.1	574.6	1,989.6	0.00	0.00	0.00
13,800.0	90.00	179.43	10,972.0	-2,055.1	575.6	2,089.4	0.00	0.00	0.00
13,900.0	90.00	179.43	10,972.0	-2,155.1	576.6	2,189.3	0.00	0.00	0.00
14,000.0	90.00	179.43	10,972.0	-2,255.1	577.5	2,289.1	0.00	0.00	0.00
14,100.0	90.00	179.44	10,972.0	-2,355.1	578.5	2,388.9	0.00	0.00	0.00
14,200.0	90.00	179.44	10,972.0	-2,455.1	579.5	2,488.8	0.00	0.00	0.00
14,300.0	90.00	179.44	10,972.0	-2,555.1	580.5	2,588.6	0.00	0.00	0.00
14,400.0	90.00	179.44	10,972.0	-2,655.1	581.5	2,688.4	0.00	0.00	0.00
14,500.0	90.00	179.44	10,972.0	-2,755.1	582.5	2,788.3	0.00	0.00	0.00
14,600.0	90.00	179.44	10,972.0	-2,855.1	583.4	2,888.1	0.00	0.00	0.00
14,700.0	90.00	179.44	10,972.0	-2,955.0	584.4	2,987.9	0.00	0.00	0.00
14,800.0	90.00	179.44	10,972.0	-3,055.0	585.4	3,087.7	0.00	0.00	0.00
14,900.0	90.00	179.44	10,972.0	-3,155.0	586.3	3,187.6	0.00	0.00	0.00
15,000.0	90.00	179.45	10,972.0	-3,255.0	587.3	3,287.4	0.00	0.00	0.00
15,100.0	90.00	179.45	10,972.0	-3,355.0	588.3	3,387.2	0.00	0.00	0.00
15,200.0	90.00	179.45	10,972.0	-3,455.0	589.2	3,487.1	0.00	0.00	0.00
15,300.0	90.00	179.45	10,972.0	-3,555.0	590.2	3,586.9	0.00	0.00	0.00
15,400.0	90.00	179.45	10,972.0	-3,655.0	591.2	3,686.7	0.00	0.00	0.00
15,500.0	90.00	179.45	10,972.0	-3,755.0	592.1	3,786.6	0.00	0.00	0.00
15,600.0	90.00	179.45	10,972.0	-3,855.0	593.1	3,886.4	0.00	0.00	0.00
15,700.0	90.00	179.45	10,972.0	-3,955.0	594.0	3,986.2	0.00	0.00	0.00
15,800.0	90.00	179.45	10,972.0	-4,055.0	595.0	4,086.0	0.00	0.00	0.00
15,900.0	90.00	179.46	10,972.0	-4,155.0	595.9	4,185.9	0.00	0.00	0.00
16,000.0	90.00	179.46	10,972.0	-4,255.0	596.9	4,285.7	0.00	0.00	0.00
16,100.0	90.00	179.46	10,972.0	-4,355.0	597.8	4,385.5	0.00	0.00	0.00
16,200.0	90.00	179.46	10,972.0	-4,455.0	598.8	4,485.4	0.00	0.00	0.00
16,300.0	90.00	179.46	10,972.0	-4,555.0	599.7	4,585.2	0.00	0.00	0.00
16,400.0	90.00	179.46	10,972.0	-4,655.0	600.7	4,685.0	0.00	0.00	0.00
16,500.0	90.00	179.46	10,972.0	-4,755.0	601.6	4,784.8	0.00	0.00	0.00
16,600.0	90.00	179.46	10,972.0	-4,855.0	602.5	4,884.7	0.00	0.00	0.00
16,700.0	90.00	179.46	10,972.0	-4,955.0	603.5	4,984.5	0.00	0.00	0.00
16,800.0	90.00	179.47	10,972.0	-5,055.0	604.4	5,084.3	0.00	0.00	0.00
16,900.0	90.00	179.47	10,972.0	-5,154.9	605.3	5,184.2	0.00	0.00	0.00
17,000.0	90.00	179.47	10,972.0	-5,254.9	606.3	5,284.0	0.00	0.00	0.00
17,100.0	90.00	179.47	10,972.0	-5,354.9	607.2	5,383.8	0.00	0.00	0.00
17,200.0	90.00	179.47	10,972.0	-5,454.9	608.1	5,483.6	0.00	0.00	0.00
17,300.0	90.00	179.47	10,972.0	-5,554.9	609.1	5,583.5	0.00	0.00	0.00
17,402.1	90.00	179.47	10,972.0	-5,657.0	610.0	5,685.4	0.00	0.00	0.00
17,500.0	90.00	179.47	10,972.0	-5,754.9	610.9	5,783.1	0.00	0.00	0.00
17,600.0	90.00	179.47	10,972.0	-5,854.9	611.8	5,883.0	0.00	0.00	0.00
17,700.0	90.00	179.47	10,972.0	-5,954.9	612.8	5,982.8	0.00	0.00	0.00
17,800.0	90.00	179.47	10,972.0	-6,054.9	613.7	6,082.6	0.00	0.00	0.00
17,900.0	90.00	179.47	10,972.0	-6,154.9	614.6	6,182.4	0.00	0.00	0.00
18,000.0	90.00	179.46	10,972.0	-6,254.9	615.5	6,282.3	0.00	0.00	0.00
18,100.0	90.00	179.46	10,972.0	-6,354.9	616.5	6,382.1	0.00	0.00	0.00
18,200.0	90.00	179.46	10,972.0	-6,454.9	617.4	6,481.9	0.00	0.00	0.00
18,300.0	90.00	179.46	10,972.0	-6,554.9	618.4	6,581.7	0.00	0.00	0.00
18,400.0	90.00	179.46	10,972.0	-6,654.9	619.3	6,681.6	0.00	0.00	0.00
18,500.0	90.00	179.46	10,972.0	-6,754.9	620.2	6,781.4	0.00	0.00	0.00
18,600.0	90.00	179.46	10,972.0	-6,854.9	621.2	6,881.2	0.00	0.00	0.00
18,700.0	90.00	179.46	10,972.0	-6,954.9	622.1	6,981.1	0.00	0.00	0.00

eog resources

Planning Report

Database:	PEDMB	**Local Co-ordinate Reference:**	Well #502H
Company:	Midland	**TVD Reference:**	kb = 26' @ 3477.0usft
Project:	Lea County, NM (NAD 83 NME)	**MD Reference:**	kb = 26' @ 3477.0usft
Site:	Peregrine 27 Fed Com	**North Reference:**	Grid
Well:	#502H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OH		
Design:	Plan #0.1 RT		

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)
18,800.0	90.00	179.46	10,972.0	-7,054.9	623.1	7,080.9	0.00	0.00	0.00
18,900.0	90.00	179.45	10,972.0	-7,154.9	624.0	7,180.7	0.00	0.00	0.00
19,000.0	90.00	179.45	10,972.0	-7,254.9	625.0	7,280.6	0.00	0.00	0.00
19,100.0	90.00	179.45	10,972.0	-7,354.9	625.9	7,380.4	0.00	0.00	0.00
19,200.0	90.00	179.45	10,972.0	-7,454.8	626.9	7,480.2	0.00	0.00	0.00
19,300.0	90.00	179.45	10,972.0	-7,554.8	627.9	7,580.0	0.00	0.00	0.00
19,400.0	90.00	179.45	10,972.0	-7,654.8	628.8	7,679.9	0.00	0.00	0.00
19,500.0	90.00	179.45	10,972.0	-7,754.8	629.8	7,779.7	0.00	0.00	0.00
19,600.0	90.00	179.45	10,972.0	-7,854.8	630.8	7,879.5	0.00	0.00	0.00
19,700.0	90.00	179.44	10,972.0	-7,954.8	631.7	7,979.4	0.00	0.00	0.00
19,800.0	90.00	179.44	10,972.0	-8,054.8	632.7	8,079.2	0.00	0.00	0.00
19,900.0	90.00	179.44	10,972.0	-8,154.8	633.7	8,179.0	0.00	0.00	0.00
20,000.0	90.00	179.44	10,972.0	-8,254.8	634.6	8,278.9	0.00	0.00	0.00
20,100.0	90.00	179.44	10,972.0	-8,354.8	635.6	8,378.7	0.00	0.00	0.00
20,200.0	90.00	179.44	10,972.0	-8,454.8	636.6	8,478.5	0.00	0.00	0.00
20,300.0	90.00	179.44	10,972.0	-8,554.8	637.6	8,578.3	0.00	0.00	0.00
20,400.0	90.00	179.44	10,972.0	-8,654.8	638.6	8,678.2	0.00	0.00	0.00
20,500.0	90.00	179.43	10,972.0	-8,754.8	639.6	8,778.0	0.00	0.00	0.00
20,600.0	90.00	179.43	10,972.0	-8,854.8	640.5	8,877.8	0.00	0.00	0.00
20,700.0	90.00	179.43	10,972.0	-8,954.8	641.5	8,977.7	0.00	0.00	0.00
20,800.0	90.00	179.43	10,972.0	-9,054.8	642.5	9,077.5	0.00	0.00	0.00
20,900.0	90.00	179.43	10,972.0	-9,154.8	643.5	9,177.3	0.00	0.00	0.00
21,000.0	90.00	179.43	10,972.0	-9,254.8	644.5	9,277.2	0.00	0.00	0.00
21,100.0	90.00	179.43	10,972.0	-9,354.8	645.5	9,377.0	0.00	0.00	0.00
21,200.0	90.00	179.43	10,972.0	-9,454.7	646.5	9,476.8	0.00	0.00	0.00
21,249.3	90.00	179.43	10,972.0	-9,504.0	647.0	9,526.0	0.00	0.00	0.00

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(Peregrine 27 Fed (- plan hits target center - Point	0.00	0.00	10,494.5	893.0	548.0	433,360.00	810,256.00	32° 11' 18.228 N	103° 27' 50.592 W
FTP(Peregrine 27 Fed C - plan hits target center - Point	0.00	0.00	10,707.2	843.0	548.0	433,310.00	810,256.00	32° 11' 17.733 N	103° 27' 50.596 W
Fed Perf 1(Peregrine 27 - plan hits target center - Point	0.00	0.00	10,972.0	-1,696.0	572.0	430,771.00	810,280.00	32° 10' 52.608 N	103° 27' 50.556 W
Fed Perf 2(Peregrine 27 - plan hits target center - Point	0.00	0.00	10,972.0	-5,657.0	610.0	426,810.00	810,318.00	32° 10' 13.411 N	103° 27' 50.486 W
PBHL(Peregrine 27 Fed - plan hits target center - Point	0.00	0.00	10,972.0	-9,504.0	647.0	422,963.00	810,355.00	32° 9' 35.342 N	103° 27' 50.417 W

eog resources

Lea County, NM (NAD 83 NME)

Peregrine 27 Fed Com #502H

Plan #0.1 RT

Azimuths to Grid North
True North: -0.46°
Magnetic North: 5.64°

Magnetic Field
Strength: 47137.3nT
Dip Angle: 59.77°
Date: 10/3/2024
Model: IGRF2020

To convert a Magnetic Direction to a Grid Direction, Add 5.64°
To convert a Magnetic Direction to a True Direction, Add 6.10° East
To convert a True Direction to a Grid Direction, Subtract 0.46°

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: #502H

3451.0
kb = 26' @ 3477.0usft

Northing	Easting	Latitude	Longitude
432467.00	809708.00	32° 11' 9.436 N	103° 27' 57.052 W

SECTION DETAILS

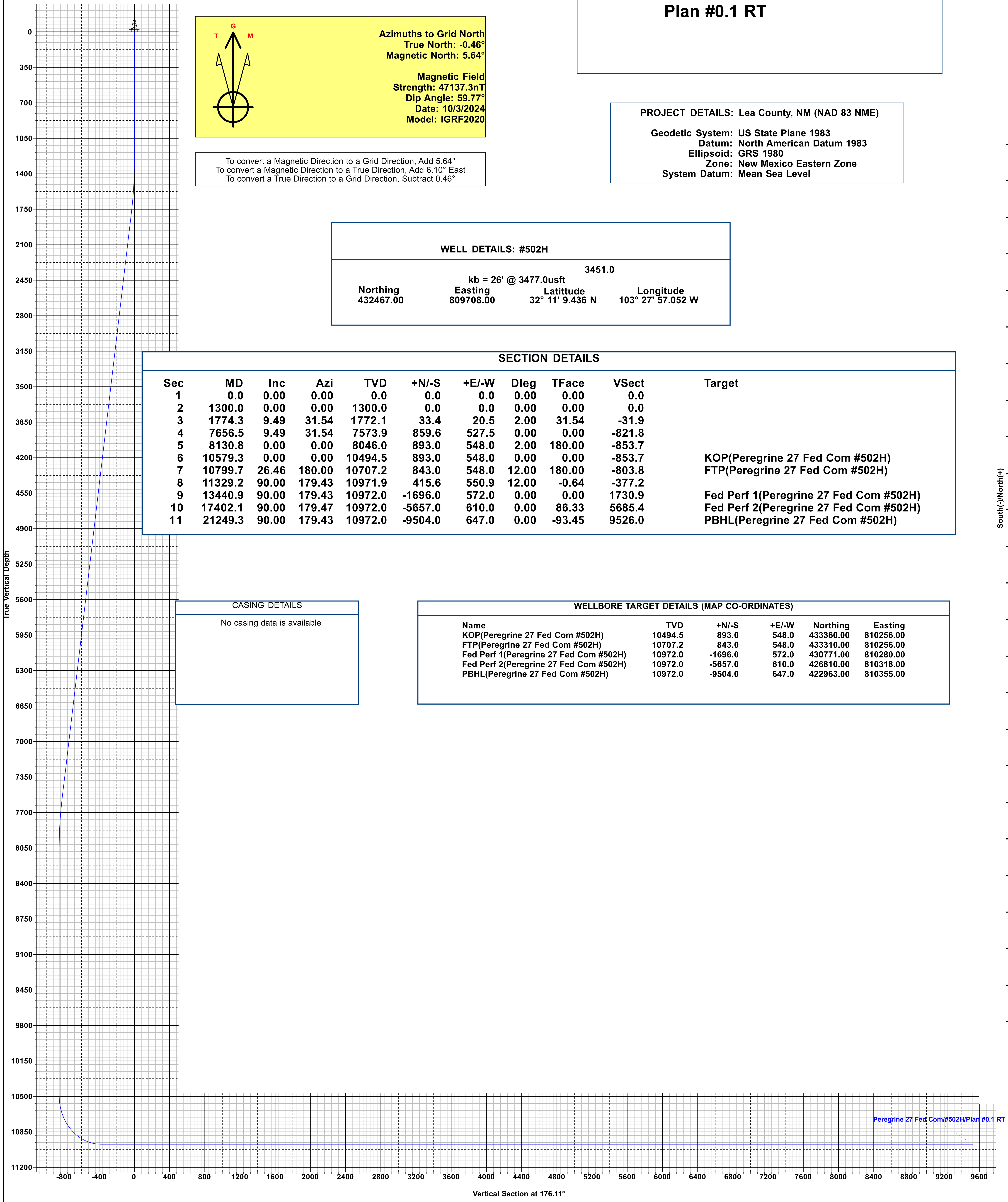
Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Target
1	0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.0	
2	1300.0	0.00	0.00	1300.0	0.0	0.0	0.00	0.00	0.0	
3	1774.3	9.49	31.54	1772.1	33.4	20.5	2.00	31.54	-31.9	
4	7656.5	9.49	31.54	7573.9	859.6	527.5	0.00	0.00	-821.8	
5	8130.8	0.00	0.00	8046.0	893.0	548.0	2.00	180.00	-853.7	
6	10579.3	0.00	0.00	10494.5	893.0	548.0	0.00	0.00	-853.7	KOP(Peregrine 27 Fed Com #502H)
7	10799.7	26.46	180.00	10707.2	843.0	548.0	12.00	180.00	-803.8	FTP(Peregrine 27 Fed Com #502H)
8	11329.2	90.00	179.43	10971.9	415.6	550.9	12.00	-0.64	-377.2	
9	13440.9	90.00	179.43	10972.0	-1696.0	572.0	0.00	0.00	1730.9	Fed Perf 1(Peregrine 27 Fed Com #502H)
10	17402.1	90.00	179.47	10972.0	-5657.0	610.0	0.00	86.33	5685.4	Fed Perf 2(Peregrine 27 Fed Com #502H)
11	21249.3	90.00	179.43	10972.0	-9504.0	647.0	0.00	-93.45	9526.0	PBHL(Peregrine 27 Fed Com #502H)

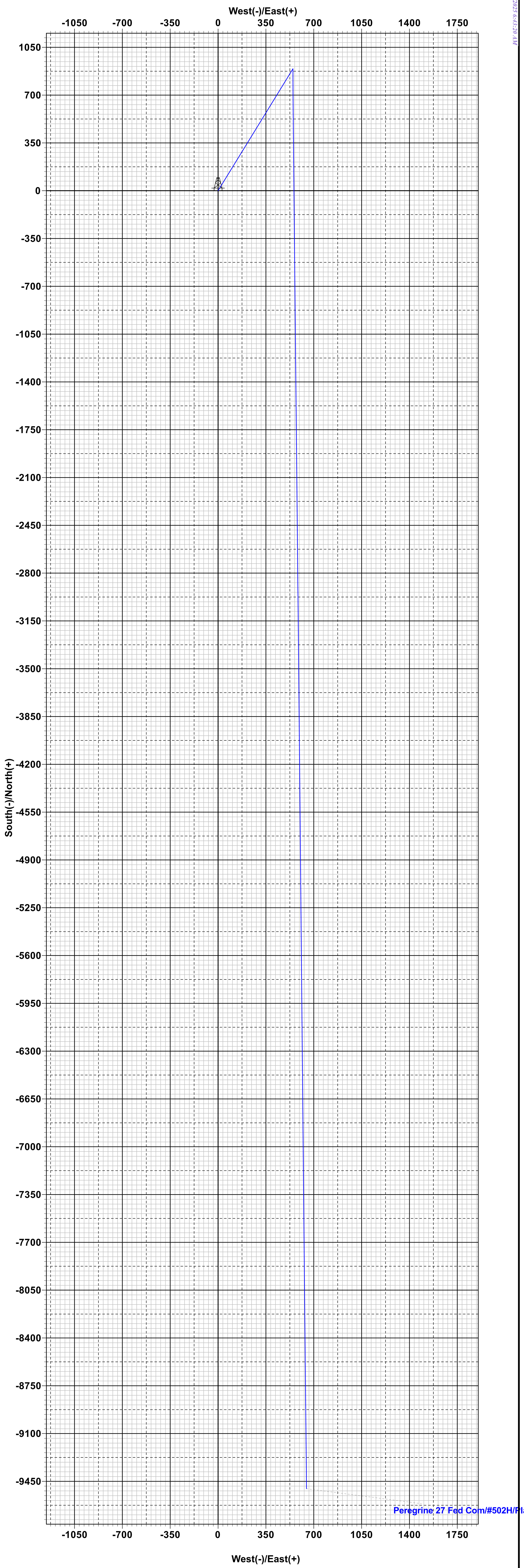
CASING DETAILS

No casing data is available

WELLBORE TARGET DETAILS (MAP CO-ORDINATES)

Name	TVD	+N/-S	+E/-W	Northing	Easting
KOP(Peregrine 27 Fed Com #502H)	10494.5	893.0	548.0	433360.00	810256.00
FTP(Peregrine 27 Fed Com #502H)	10707.2	843.0	548.0	433310.00	810256.00
Fed Perf 1(Peregrine 27 Fed Com #502H)	10972.0	-1696.0	572.0	430771.00	810280.00
Fed Perf 2(Peregrine 27 Fed Com #502H)	10972.0	-5657.0	610.0	426810.00	810318.00
PBHL(Peregrine 27 Fed Com #502H)	10972.0	-9504.0	647.0	422963.00	810355.00





Lea County, NM (NAD 83 NME)
Peregrine 27 Fed Com
#502H
OH
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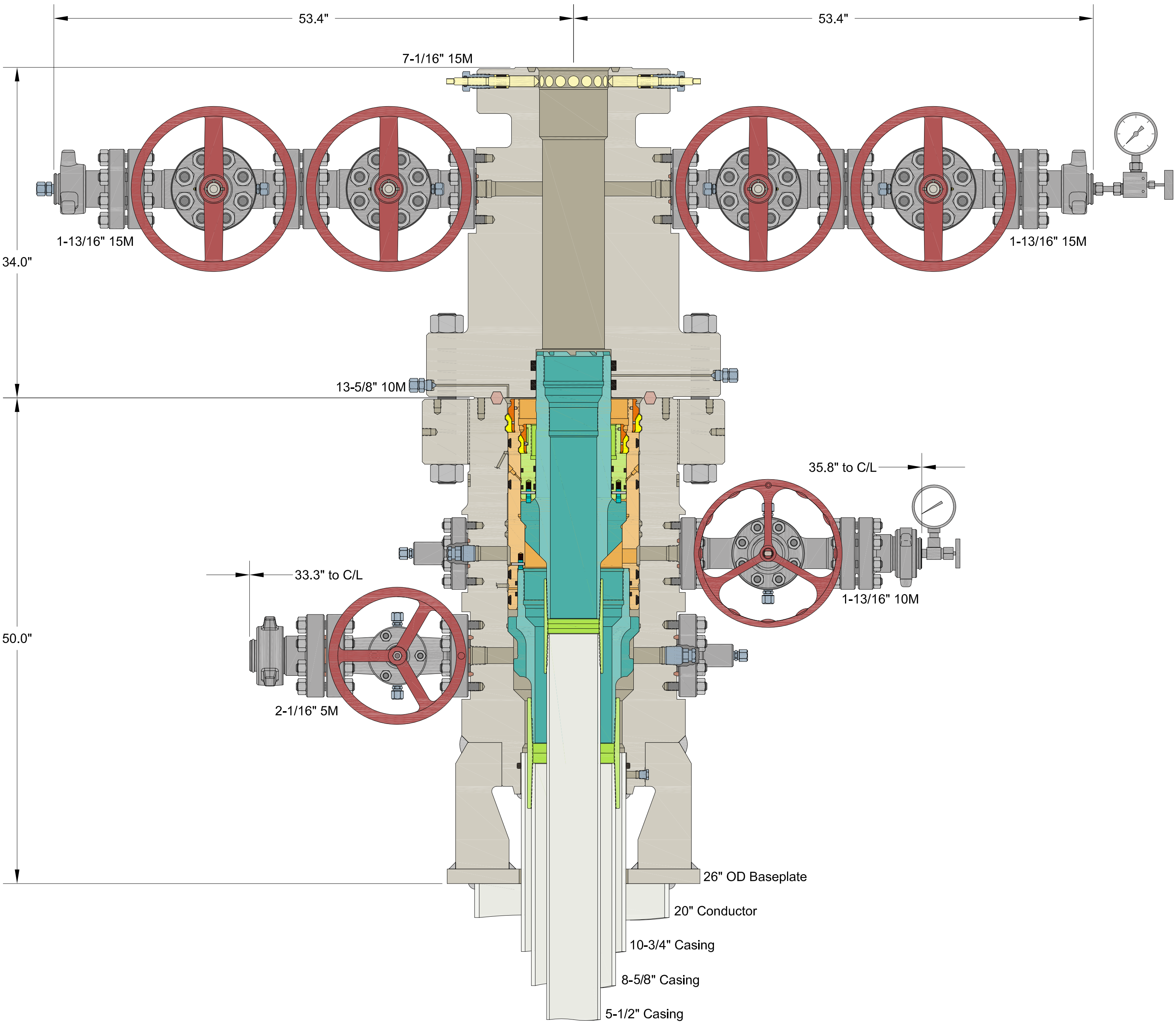


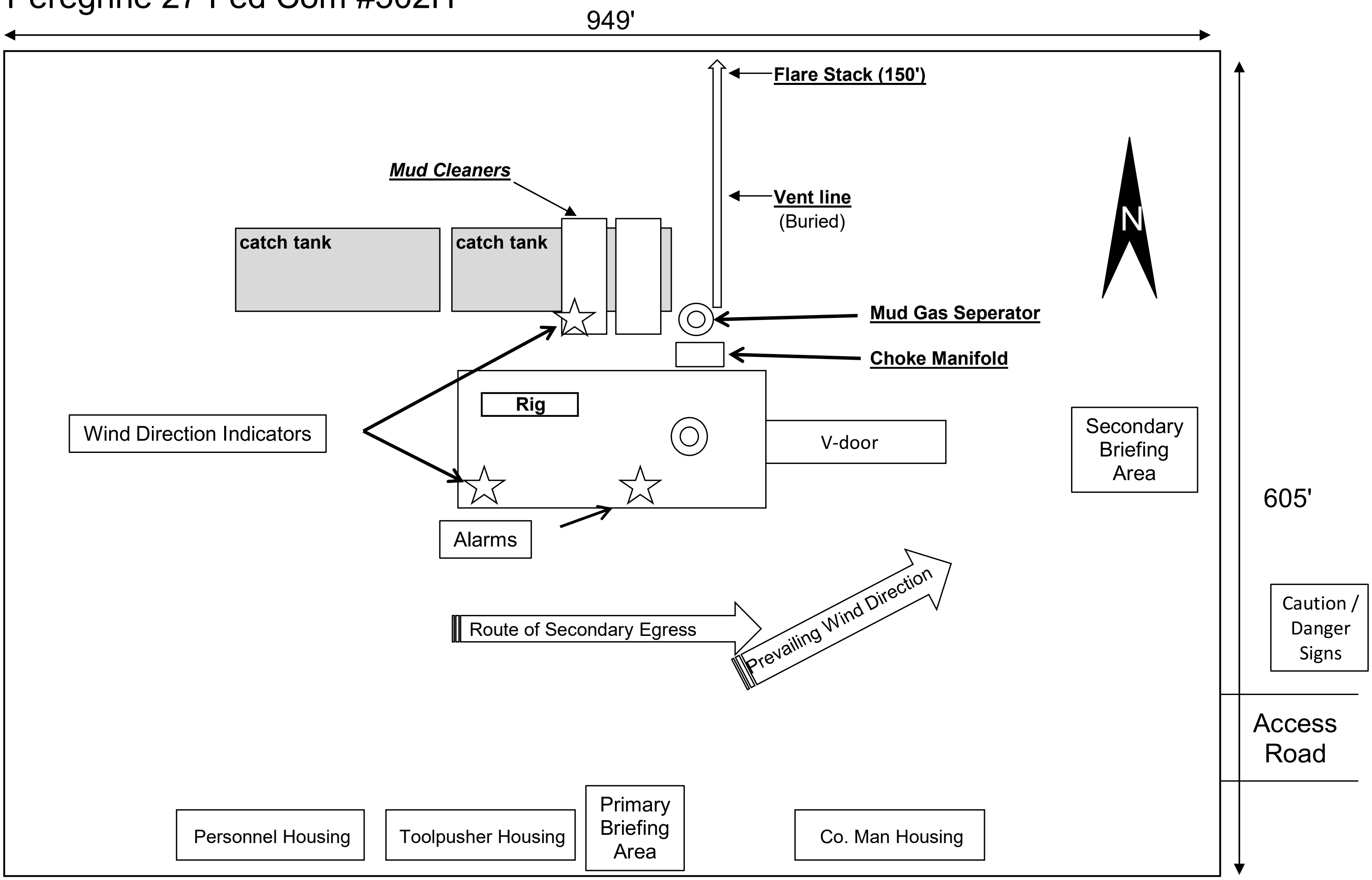
ALL DIMENSIONS APPROXIMATE

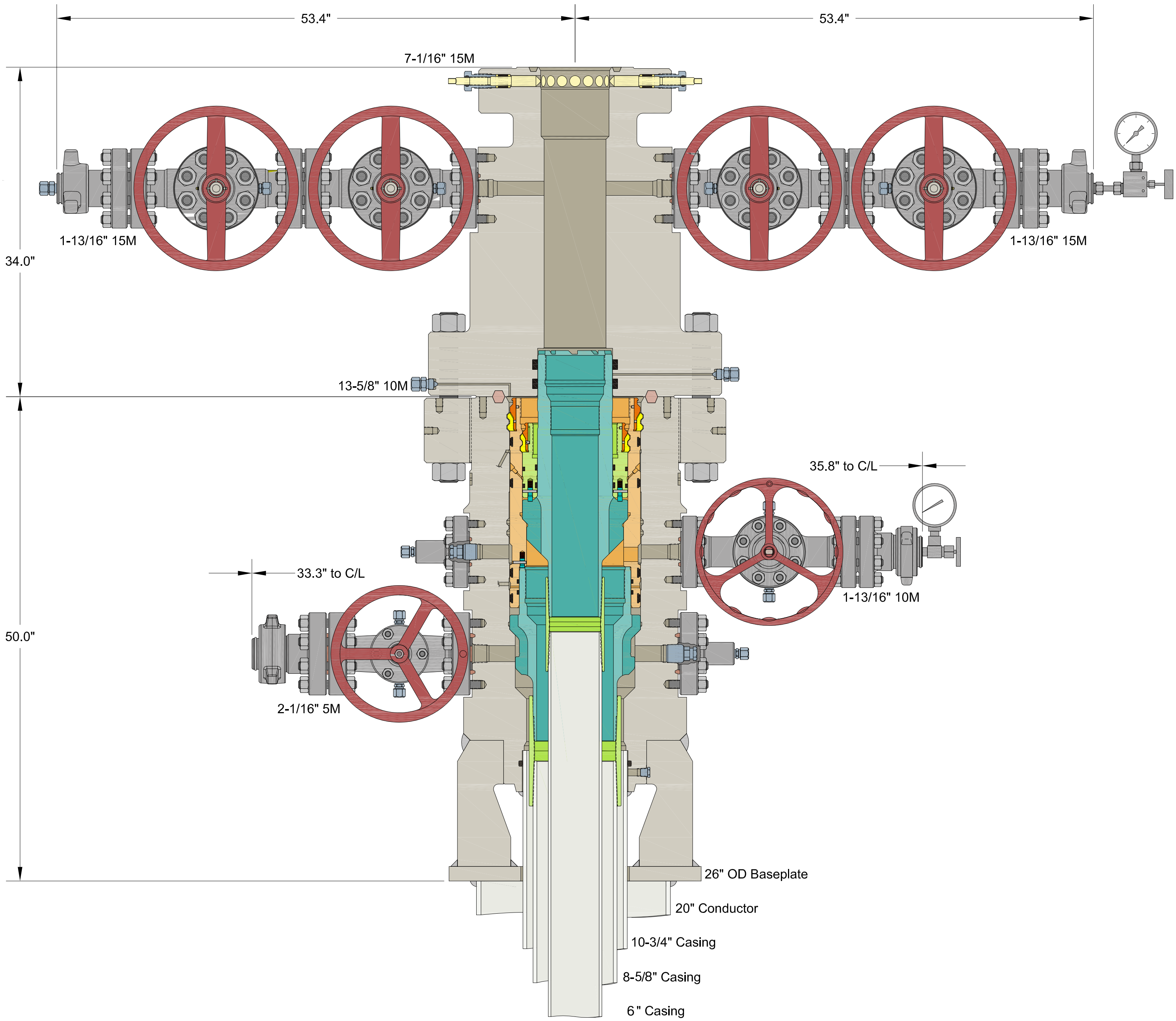
CACTUS WELLHEAD LLC	EOG RESOURCES		
10-3/4" x 8-5/8" x 5-1/2" MBU-3T-SF-SOW Wellhead System With 8-5/8" & 5-1/2" Pin Bottom Mandrel Casing Hangers And 13-5/8" 10M x 7-1/16" 15M CTH-DBLHPS Tubing Head	DRAWN	DLE	14APR21
	APPRV		
	DRAWING NO.	SDT-3141	

Exhibit 4

Well Site Diagram

EOG Resources
Peregrine 27 Fed Com #502H



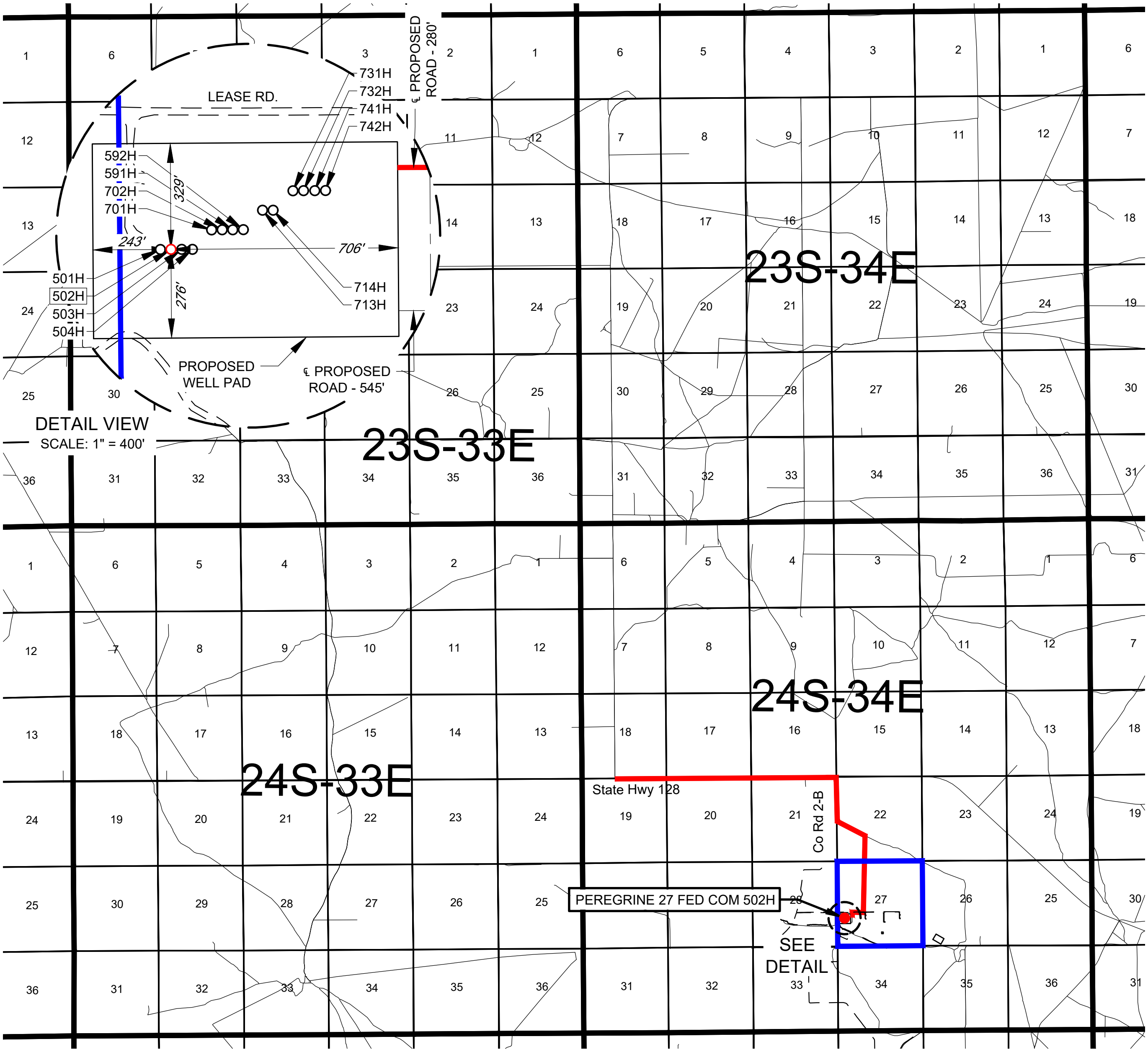


ALL DIMENSIONS APPROXIMATE

CACTUS WELLHEAD LLC	EOG RESOURCES		
10-3/4" x 8-5/8" x 5-1/2" MBU-3T-SF-SOW Wellhead System With 8-5/8" & 5-1/2" Pin Bottom Mandrel Casing Hangers And 13-5/8" 10M x 7-1/16" 15M CTH-DBLHPS Tubing Head	DRAWN	DLE	14APR21
	APPRV		
	DRAWING NO.	SDT-3141	

EXHIBIT 2

VICINITY MAP



eog resources, inc.

LEASE NAME & WELL NO.: PEREGRINE 27 FED COM 502H

SECTION 27 TWP 24-S RGE 34-E SURVEY N.M.P.M.

COUNTY LEA STATE NM

DESCRIPTION 1700' FSL & 159' FWL

-N-

SCALE: 1" = 10000'

0' 5000' 10000'

DISTANCE & DIRECTION

FROM INT. OF NM-128, & DELAWARE BASIN RD., GO EAST ON NM-128 ±2.6 MILES, THENCE SOUTH (RIGHT) ON COUNTY RD. 2-B ±1.8 MILES, THENCE WEST (RIGHT) ON A LEASE RD. ±0.1 MILES, THENCE SOUTH (LEFT) ON A PROPOSED RD. ±280 FEET TO A POINT ±749 FEET NORTHEAST OF THE LOCATION.

THIS EASEMENT/SERVITUDE LOCATION SHOWN HEREON HAS BEEN SURVEYED ON THE GROUND UNDER MY SUPERVISION AND PREPARED ACCORDING TO THE EVIDENCE FOUND AT THE TIME OF SURVEY, AND DATA PROVIDED BY EOG RESOURCES, INC. THIS CERTIFICATION IS MADE AND LIMITED TO THOSE PERSONS OR ENTITIES SHOWN ON THE FACE OF THIS PLAT AND IS NON-TRANSFERABLE. THIS SURVEY IS CERTIFIED FOR THIS TRANSACTION ONLY.

ALL BEARINGS, DISTANCES, AND COORDINATE VALUES CONTAINED HEREON ARE GRID BASED UPON THE NEW MEXICO COORDINATE SYSTEM OF 1983, EAST ZONE, U.S. SURVEY FEET.

TOPOGRAPHIC
LOYALTY INNOVATION LEGACY
481 WINSCOTT ROAD, Ste. 200 • BENBROOK, TEXAS 76126
TELEPHONE: (817) 744-7512 • FAX (817) 744-7554
2903 NORTH BIG SPRING • MIDLAND, TEXAS 79705
TELEPHONE: (432) 682-1653 OR (800) 767-1653 • FAX (432) 682-1743
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T-25-S, R-34-E
SECTION 3
LOT 1 - 39.68 ACRES
LOT 2 - 39.68 ACRES
LOT 3 - 39.68 ACRES
LOT 4 - 39.68 ACRES

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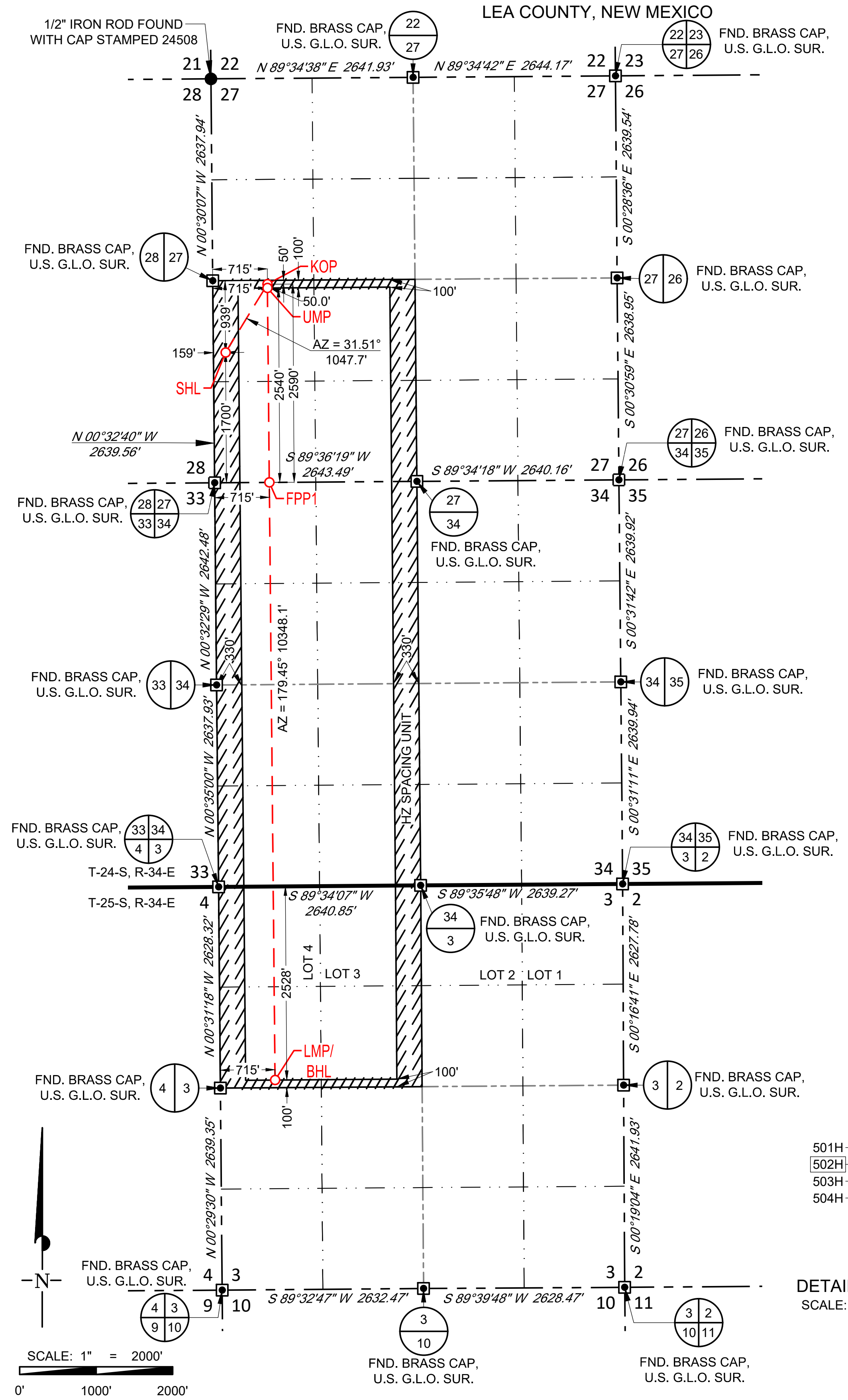
EXHIBIT 2A

SECTION 27, TOWNSHIP 24-S, RANGE 34-E, N.M.P.M.
LEA COUNTY, NEW MEXICO



SURFACE LOCATION (SHL)

NEW MEXICO EAST
NAD 1983
X=809708 Y=432467
LAT.: N 32.1859549
LONG.: W 103.4658473
1700' FSL 159' FWL

KICK OFF POINT (KOP)

NEW MEXICO EAST
NAD 1983
X=810256 Y=433360
LAT.: N 32.1883979
LONG.: W 103.4640543
2590' FSL 715' FWL

UPPER MOST PERF. (UMP)

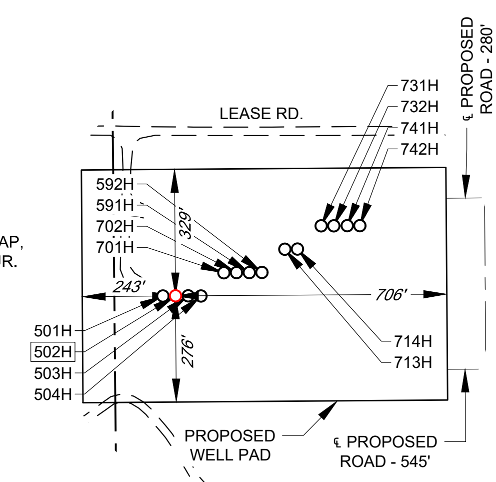
NEW MEXICO EAST
NAD 1983
X=810256 Y=433310
LAT.: N 32.1882605
LONG.: W 103.4640556
2540' FSL 715' FWL

FED PERF. POINT (FPP1)

NEW MEXICO EAST
NAD 1983
X=810280 Y=430771
LAT.: N 32.1812797
LONG.: W 103.4640430
0' FNL 715' FWL

LOWER MOST PERF. (LMP) BOTTOM HOLE LOCATION (BHL)

NEW MEXICO EAST
NAD 1983
X=810355 Y=422963
LAT.: N 32.1598168
LONG.: W 103.4640044
2528' FNL 715' FWL



DETAIL VIEW
SCALE: 1" = 400'

LEASE NAME & WELL NO.: PEREGRINE 27 FED COM 502H

SECTION 27 TWP 24-S RGE 34-E SURVEY N.M.P.M.
COUNTY LEA STATE NM
DESCRIPTION 1700' FSL & 159' FWL

DISTANCE & DIRECTION

FROM INT. OF NM-128, & DELAWARE BASIN RD., GO EAST ON NM-128 ±2.6 MILES, THENCE SOUTH (RIGHT) ON COUNTY RD. 2-B ±1.8 MILES, THENCE WEST (RIGHT) ON A LEASE RD. ±0.1 MILES, THENCE SOUTH (LEFT) ON A PROPOSED RD. ±280 FEET TO A POINT ±749 FEET NORTHEAST OF THE LOCATION.

RAMON DOMINGUEZ NEW MEXICO 24508 PROFESSIONAL SURVEYOR

9/5/2024 2:37:49 PM

Ramon A. Dominguez, P.S. No. 24508

ALL BEARINGS, DISTANCES, AND COORDINATE VALUES CONTAINED HEREON ARE GRID BASED UPON THE NEW MEXICO COORDINATE SYSTEM OF 1983, EAST ZONE, U.S. SURVEY FEET.

THIS EASEMENT/SERVITUDE LOCATION SHOWN HEREON HAS BEEN SURVEYED ON THE GROUND UNDER MY SUPERVISION AND PREPARED ACCORDING TO THE EVIDENCE FOUND AT THE TIME OF SURVEY, AND DATA PROVIDED BY EOG RESOURCES, INC. THIS CERTIFICATION IS MADE AND LIMITED TO THOSE PERSONS OR ENTITIES SHOWN ON THE FACE OF THIS PLAT AND IS NON-TRANSFERABLE. THIS SURVEY IS CERTIFIED FOR THIS TRANSACTION ONLY.

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Peregrine 27 Fed Com #502H

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:**
  - a. Breathing Apparatus:
    - i. Rescue Packs (SCBA) — 1 unit shall be placed at each breathing area, 2 shall be stored in the safety trailer.
    - ii. Work/Escape packs —4 packs shall be stored on the rig floor with sufficient air hose not to restrict work activity.
    - iii. Emergency Escape Packs —4 packs shall be stored in the doghouse for emergency evacuation.
  - b. Auxiliary Rescue Equipment:
    - i. Stretcher
    - ii. Two OSHA full body harness
    - iii. 100 ft 5/8 inch OSHA approved rope
    - iv. 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 System:**
  - 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.

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Peregrine 27 Fed Com #502H

- **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

Peregrine 27 Fed Com #502H

Emergency Assistance Telephone List

PUBLIC SAFETY:	911 or
Lea County Sheriff's Department	(575) 396-3611
Corey Helton	
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
U.S. Department of Labor	(575) 887-1174
Bureau of Land Management - Hobbs (Lea Co)	(575) 393-3612
PET On Call - Hobbs	(575) 706-2779
Bureau of Land Management - Carlsbad (Eddy Co)	(575) 234-5972
PET On Call - Carlsbad	(575) 706-2779
New Mexico Oil Conservation Division - Artesia	(575) 748-1283
Inspection Group South - Gilbert Gordero	(575) 626-0830

EOG Resources, Inc.	
EOG Midland	(432) 686-3600

Company Drilling Consultants:	
Jett Dueitt	(432) 230-4840
Blake Burney	

Drilling Engineers	
Stephen Davis	(432) 235-9789
Matt Day	(210) 296-4456

Drilling Managers	
Branden Keener	(210) 294-3729

Drilling Superintendents	
Lance Hardy	(432) 215-8152
Ryan Reynolds	(432) 215-5978
Steve Kelly	(210) 416-7894

H&P Drilling	
H&P Drilling	(432) 563-5757

Nabors Drilling	
Nabors Drilling	(432) 363-8180

Patterson UTI	
Patterson UTI	(432) 561-9382

EOG Safety	
Brian Chandler (HSE Manager)	(817) 239-0251

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Peregrine 27 Fed Com #502H

1. GEOLOGIC NAME OF SURFACE FORMATION:
Permian

2. ESTIMATED TOPS OF IMPORTANT GEOLOGICAL MARKERS:

Rustler	1,007'
Tamarisk Anhydrite	1,080'
Top of Salt	1,338'
Base of Salt	4,704'
Lamar	4,939'
Bell Canyon	4,958'
Cherry Canyon	5,919'
Brushy Canyon	7,318'
Bone Spring Lime	9,027'
Leonard (Avalon) Shale	9,108'
1st Bone Spring Sand	10,038'
2nd Bone Spring Shale	10,231'
TD	10,972'

3. ESTIMATED DEPTHS OF ANTICIPATED FRESH WATER, OIL OR GAS:

Upper Permian Sands	0- 400’	Fresh Water
Lamar	4,939'	Oil
Cherry Canyon	5,919'	Oil
Brushy Canyon	7,318'	Oil
Bone Spring Lime	9,027'	Oil
Leonard (Avalon) Shale	9,108'	Oil
1st Bone Spring Sand	10,038'	Oil
2nd Bone Spring Shale	10,231'	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 10-3/4" casing at 1,105' and circulating cement back to surface.

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Peregrine 27 Fed Com #502H

4. CASING PROGRAM

Hole	Interval MD		Interval TVD		Csg			
Size	From (ft)	To (ft)	From (ft)	To (ft)	OD	Weight	Grade	Conn
13"	0	1,105	0	1,105	10-3/4"	40.5#	J-55	STC
9-7/8"	0	5,127	0	5,039	8-5/8"	32#	J-55	BTC-SC
7-7/8"	0	10,479	0	10,395	6"	24.5#	P110-EC	VAM Sprint-TC
6-3/4"	10,479	21,249	10,395	10,972	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.

5. CEMENTING PROGRAM:

Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
1,110' 10-3/4"	260	13.5	1.73	Lead: Class C/H + additives (TOC @ Surface)
	120	14.8	1.34	Tail: Class C/H + additives (TOC @ 910')
5,230' 8-5/8"	310	12.7	2.22	Lead: Class C/H + additives + expansive additives (TOC @ Surface)
	140	14.8	1.32	Tail: Class C/H + additives + expansive additives (TOC @ 4102')
21,249' 6"	1000	14.8	1.32	Bradenhead squeeze: Class C/H + additives + expansive additives (TOC @ surface)
	1650	13.2	1.52	Tail: Class C/H + additives (TOC @ 7320')

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Peregrine 27 Fed Com #502H

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 6" and 5-1/2" production casing strings with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon (7,318') and the second stage performed as a bradenhead squeeze with planned cement from the Brushy Canyon to surface. If necessary, a top out consisting of Class C/H cement + additives (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.

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Peregrine 27 Fed Com #502H

6. MINIMUM SPECIFICATIONS FOR PRESSURE CONTROL:

Variance is requested to use a co-flex line between the BOP and choke manifold (instead of using a 4" OD steel line).

The minimum blowout preventer equipment (BOPE) shown in Exhibit #1 will consist of a single ram, mud cross and double ram-type (10,000 psi WP) preventer and an annular preventer (5,000-psi WP). Both units will be hydraulically operated and the ram-type will be equipped with blind rams on bottom and drill pipe rams on top. All BOPE will be tested in accordance with Onshore Oil & Gas order No. 2.

EOG will utilize wing unions on BOPE connections that can be isolated from wellbore pressure through means of a choke. All wing unions will be rated to a pressure that meets or exceeds the pressure rating of the BOPE system.

Variance is requested to use a 5,000 psi annular BOP with the 10,000 psi BOP stack.

Before drilling out of the surface casing, the ram-type BOP and accessory equipment will be tested to 10,000/ 250 psig and the annular preventer to 5,000/ 250 psig.

Pipe rams and blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets.

A hydraulically operated choke will be installed prior to drilling out of the intermediate casing shoe.

7. TYPES AND CHARACTERISTICS OF THE PROPOSED MUD SYSTEM:

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:

Depth	Type	Weight (ppg)	Viscosity	Water Loss
0 – 1,105'	Fresh - Gel	8.6-8.8	28-34	N/c
1,105' – 5,039'	Brine	9-10.5	28-34	N/c
5,039' – 21,249' 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.

8. AUXILIARY WELL CONTROL AND MONITORING EQUIPMENT:

(A) A kelly cock will be kept in the drill string at all times.

(B) A full opening drill pipe-stabbing valve (inside BOP) with proper drill pipe connections will be on the rig floor at all times.

(C) H2S monitoring and detection equipment will be utilized from surface casing point to TD.

9. LOGGING, TESTING AND CORING PROGRAM:

(A) Open-hole logs are not planned for this well.

(B) GR–CCL will be run in cased hole during completions phase of operations.

10. ABNORMAL CONDITIONS, PRESSURES, TEMPERATURES AND POTENTIAL HAZARDS:

The estimated bottom-hole temperature (BHT) at TD is 180 degrees F with an estimated maximum bottom-hole pressure (BHP) at TD of 5,135 psig and a maximum anticipated surface pressure of 2,721 psig (based on 9.0 ppg MW). No hydrogen sulfide or other hazardous gases or fluids have been encountered, reported or are known to exist at this depth in this area. Severe loss circulation is expected from 7,318' to intermediate casing point.

11. ANTICIPATED STARTING DATE AND DURATION OF OPERATIONS:

The drilling operation should be finished in approximately one month. If the well is productive, an additional 60-90 days will be required for completion and testing before a decision is made to install permanent facilities.

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.

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Peregrine 27 Fed Com #502H

12. WELLHEAD:

A multi-bowl wellhead system will be utilized.

After running the surface casing, a BOP/BOPE system with a minimum working pressure of 10,000 psi will be installed on the wellhead system and will be pressure tested to 250 psi low followed by a 10,000 psi pressure test. This pressure test will be repeated at least every 30 days, as per Title 43 CFR Part 3170.

The minimum working pressure of the BOP and related BOPE required for drilling below the surface casing shoe shall be 10,000 psi.

The multi-bowl wellhead will be installed by vendor's representative(s). A copy of the installation instructions for the Cactus Multi-Bowl WH system has been sent to the NM BLM office in Carlsbad, NM.

The wellhead will be installed by a third party welder while being monitored by WH vendor's representative.

All BOP equipment will be tested utilizing a conventional test plug. Not a cup or J-packer type. EOG Resources reserves the option to conduct BOPE testing during wait on cement periods provided a test plug is utilized.

A solid steel body pack-off will be utilized after running and cementing the intermediate casing. After installation the pack-off and lower flange will be pressure tested to 5000 psi.

Casing strings will be tested as per Title 43 CFR Part 3170 to at least 0.22 psi/ft or 1,500 psi, whichever is greater.

13. VARIANCE REQUESTS:

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

- EOG BLM Variance 3e - BOP Break-test and Offline Surface and Intermediate Cement
- EOG BLM Variance 3d - Production Offline Cement
- EOG BLM Variance 4a - Salt Section Annular Clearance
- EOG BLM Variance 5a - Alternate Shallow Casing Designs

14. 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.

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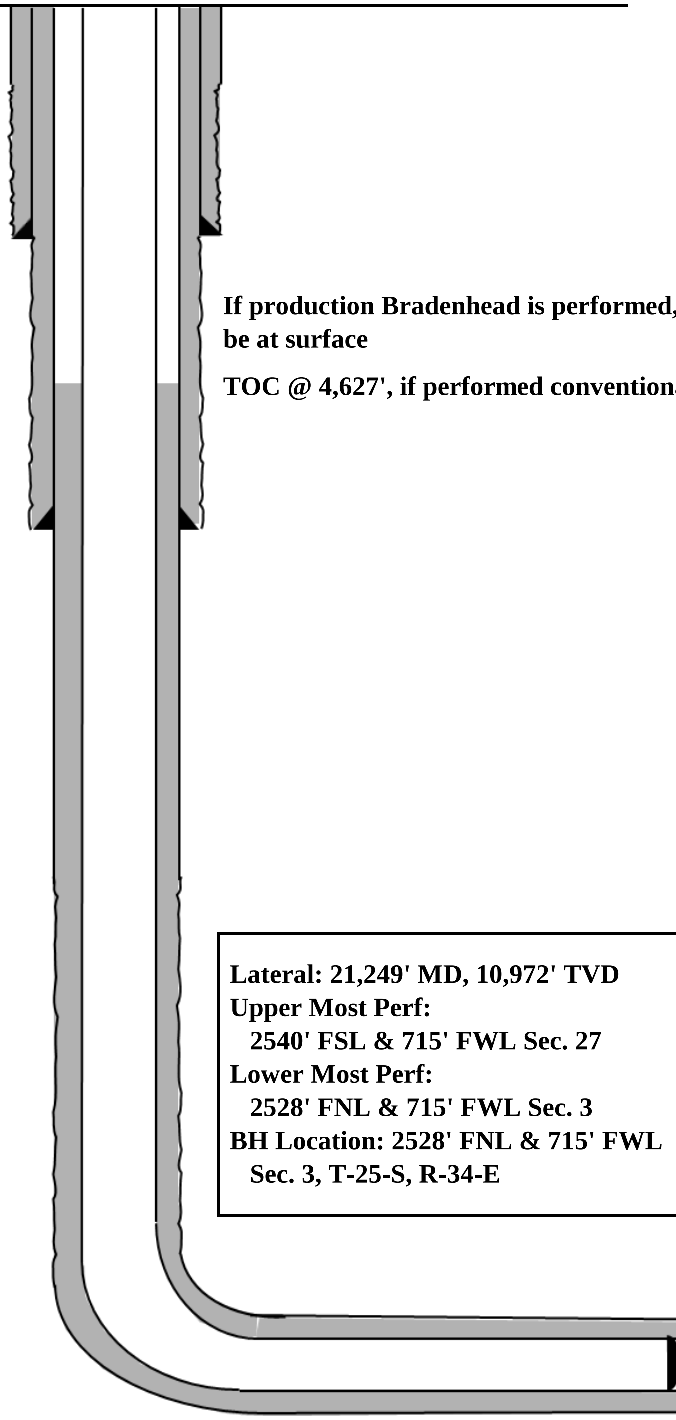
Peregrine 27 Fed Com #502H

1700' FSL
159' FWL
Section 27
T-24-S, R-34-E

Proposed Wellbore

API: 30-025-*****

KB: 3476'
GL: 3451'



Bit Size: 13''
10-3/4'', 40.5#, J-55, STC
@ 0' - 1,105' MD
@ 0' - 1,105' TVD

If production Bradenhead is performed, TOC will be at surface

TOC @ 4,627', if performed conventionally.

Bit Size: 9-7/8''
8-5/8'', 32.#, J-55, BTC-SC
@ 0' - 5,127' MD
@ 0' - 5,039' TVD

Lateral: 21,249' MD, 10,972' TVD
Upper Most Perf:
2540' FSL & 715' FWL Sec. 27
Lower Most Perf:
2528' FNL & 715' FWL Sec. 3
BH Location: 2528' FNL & 715' FWL
Sec. 3, T-25-S, R-34-E

Bit Size: 7-7/8''|Bit Size: 6-3/4''
6'', 24.5#, P110-EC, VAM Sprint-TC
@ 0' - 10,479' MD
@ 0' - 10,395' TVD

5-1/2'', 20.#, P110-EC, VAM Sprint SF
@ 10,479' - 21,249' MD
@ 10,395' - 10,972' TVD

KOP: 10,579' MD, 10,495' TVD
EOC: 11,329' MD, 10,972' TVD

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:	
	[X] Initial Submittal
	[ ] Amended Report
	[ ] As Drilled

WELL LOCATION AND ACREAGE DEDICATION PLAT

API Number	Pool Code	Pool Name
30-025-55409	97369	RED HILLS; BONESPRING, EAST

Property Code	Property Name	Well Number
325650	PEREGRINE 27 FED COM	502H

OGRID No.	Operator Name	Ground Level Elevation
7377	EOG RESOURCES, INC.	3451'

Surface Owner: [ ] State [X] Fee [ ] Tribal [ ] Federal | Mineral Owner: [ ] State [X] Fee [ ] Tribal [X] 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
L	27	24-S	34-E	-	1700' S	159' W	N 32.1859549	W 103.4658473	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
E	3	25-S	34-E	-	2528' N	715' W	N 32.1598168	W 103.4640044	LEA

Dedicated Acres	Infill or Defining Well	Defining Well API	Overlapping Spacing Unit (Y/N)	Consolidated Code
639.36	INFILL	30-025-49847	N	C

Order Numbers: PENDING COM AGREEMENT | 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
L	27	24-S	34-E	-	2590' S	715' W	N 32.1883979	W 103.4640543	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
L	27	24-S	34-E	-	2540' S	715' W	N 32.1882605	W 103.4640556	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
E	3	25-S	34-E	-	2528' N	715' W	N 32.1598168	W 103.4640044	LEA

Unitized Area or Area of Uniform Intrest	Spacing Unity Type	Ground Floor Elevation
COM AGREEMENT	[X] Horizontal [ ] Vertical	3476'

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.

Shea Bailey 6/3/25

Signature Date

Shea Bailey

Print Name

shea_bailey@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

9/5/2024 2:37:47 PM

Signature and Seal of Professional Surveyor Date

Certificate Number

Date of Survey

07/09/2024

S:\SURVEY\EOG_MIDLAND\PEREGRINE_27_FED_COM\FINAL_PRODUCTS\LO_PEREGRINE_27_FED_COM_502H_REV1.dwg ANDREW.HALL 9/5/2024 2:37 PM

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

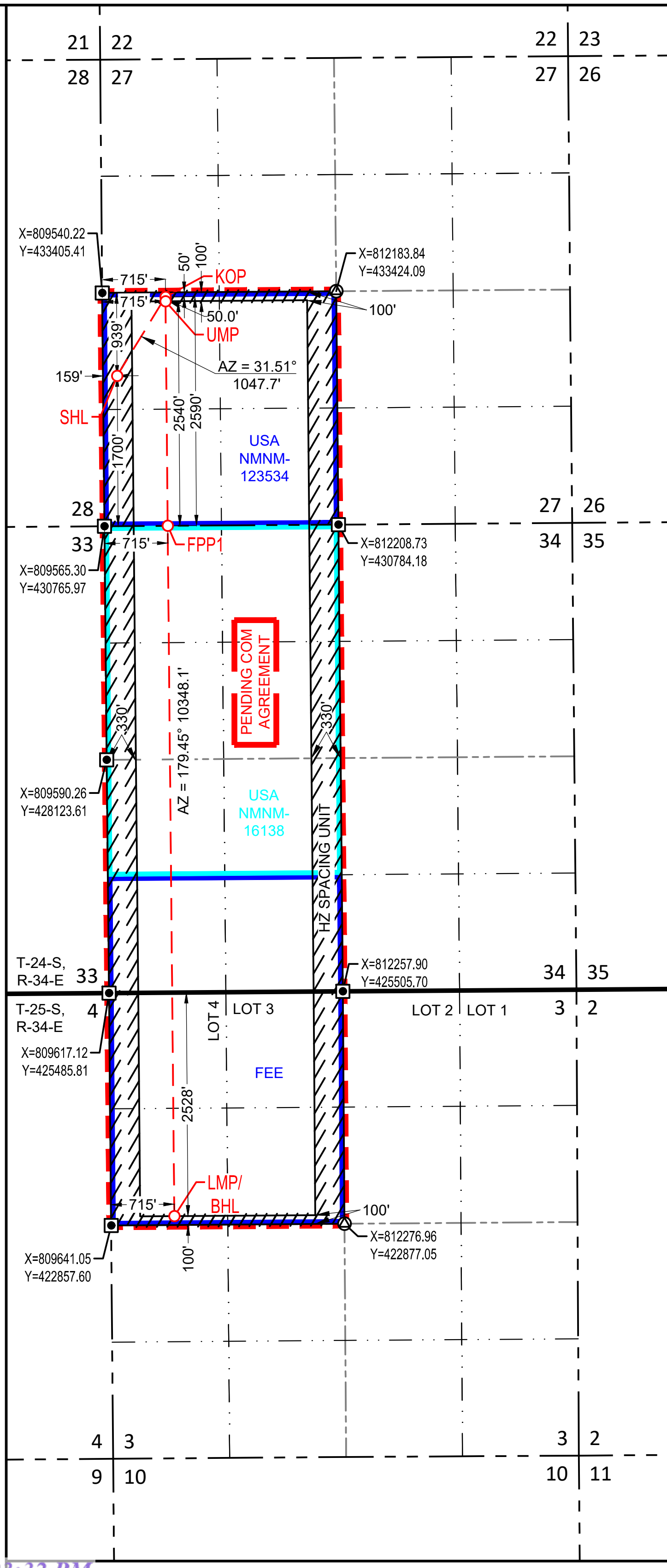
Property Name and Well Number

PEREGRINE 27 FED COM 502H

SURFACE LOCATION (SHL)
NEW MEXICO EAST
NAD 1983
X=809708 Y=432467
LAT.: N 32.1859549
LONG.: W 103.4658473
NAD 1927
X=768523 Y=432409
LAT.: N 32.1858302
LONG.: W 103.4653749
1700' FSL 159' FWL

KICK OFF POINT (KOP)
NEW MEXICO EAST
NAD 1983
X=810256 Y=433360
LAT.: N 32.1883979
LONG.: W 103.4640543
NAD 1927
X=769070 Y=433302
LAT.: N 32.1882732
LONG.: W 103.4635818
2590' FSL 715' FWL

UPPER MOST PERF. (UMP)
NEW MEXICO EAST
NAD 1983
X=810256 Y=433310
LAT.: N 32.1882605
LONG.: W 103.4640556
NAD 1927
X=769070 Y=433252
LAT.: N 32.1881357
LONG.: W 103.4635831
2540' FSL 715' FWL



FED PERF. POINT (FPP1)
NEW MEXICO EAST
NAD 1983
X=810280 Y=430771
LAT.: N 32.1812797
LONG.: W 103.4640430
NAD 1927
X=769095 Y=430712
LAT.: N 32.1811549
LONG.: W 103.4635710
0' FNL 715' FWL

LOWER MOST PERF. (LMP)
BOTTOM HOLE LOCATION (BHL)
NEW MEXICO EAST
NAD 1983
X=810355 Y=422963
LAT.: N 32.1598168
LONG.: W 103.4640044
NAD 1927
X=769169 Y=422905
LAT.: N 32.1596919
LONG.: W 103.4635337
2528' FNL 715' FWL

T-25-S, R-34-E
SECTION 3
LOT 1 - 39.68 ACRES
LOT 2 - 39.68 ACRES
LOT 3 - 39.68 ACRES
LOT 4 - 39.68 ACRES

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.

07/09/2024
Date of Survey
Signature and Seal of Professional Surveyor:

RAMON DOMINGUEZ NEW MEXICO 24508 PROFESSIONAL SURVEYOR

9/5/2024 2:37:47 PM

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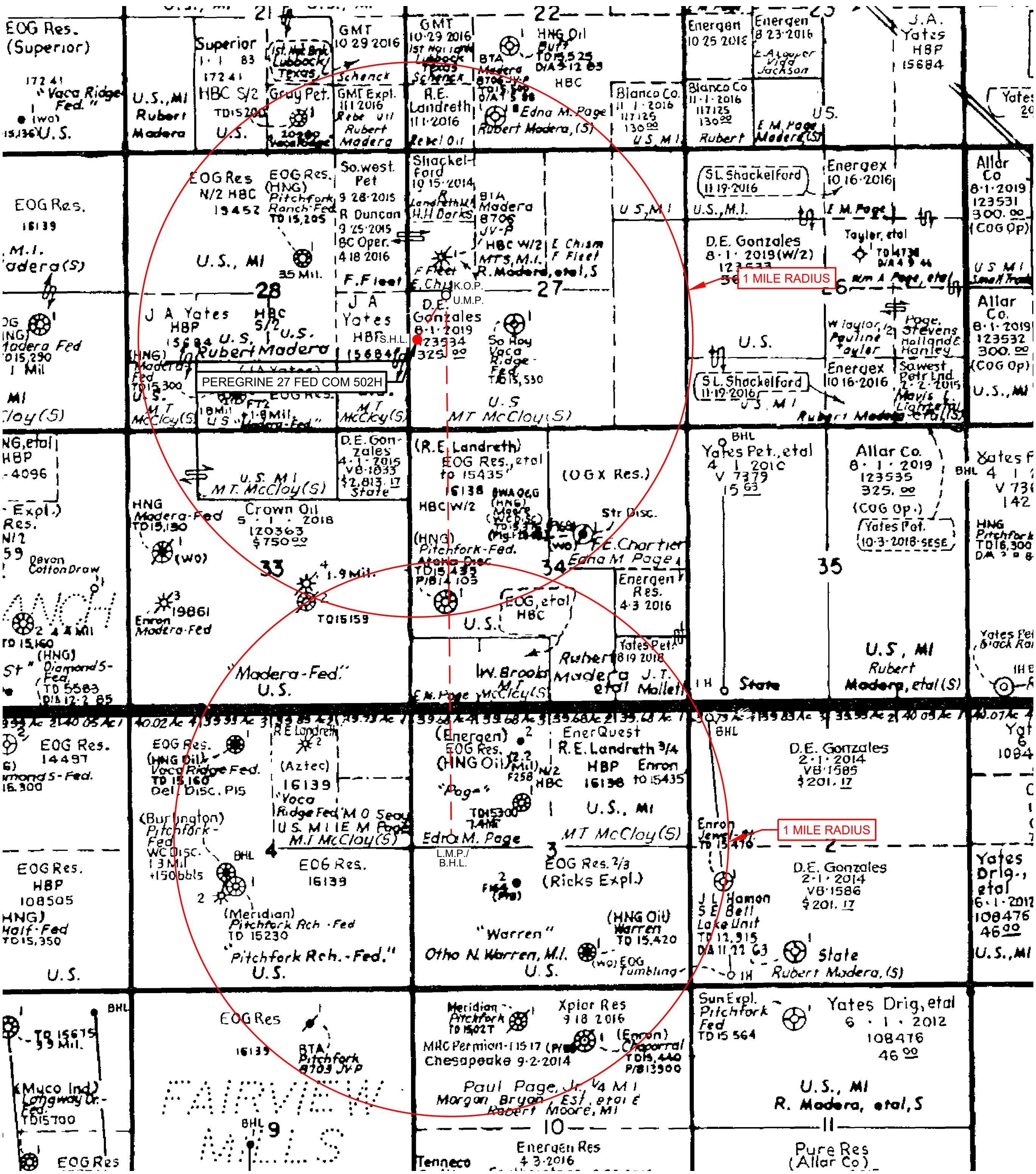
EXHIBIT 3

eog resources, inc.

SECTION 27, TOWNSHIP 24-S, RANGE 34-E, N.M.P.M.
LEA COUNTY, NEW MEXICO



LEASE NAME & WELL NO.: PEREGRINE 27 FED COM 502H

502H LATITUDE N 32.1859549 502H LONGITUDE W 103.4658473

SCALE: NTS

ALL BEARINGS, DISTANCES, AND COORDINATE VALUES CONTAINED HEREON ARE GRID BASED UPON THE NEW MEXICO COORDINATE SYSTEM OF 1983, EAST ZONE, U.S. SURVEY FEET.

THIS EASEMENT/SERVITUDE LOCATION SHOWN HEREON HAS BEEN SURVEYED ON THE GROUND UNDER MY SUPERVISION AND PREPARED ACCORDING TO THE EVIDENCE FOUND AT THE TIME OF SURVEY, AND DATA PROVIDED BY EOG RESOURCES, INC. THIS CERTIFICATION IS MADE AND LIMITED TO THOSE PERSONS OR ENTITIES SHOWN ON THE FACE OF THIS PLAT AND IS NON-TRANSFERABLE. THIS SURVEY IS CERTIFIED FOR THIS TRANSACTION ONLY.

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481 WINSCOTT ROAD, Ste. 200 • BENBROOK, TEXAS 76126
TELEPHONE: (817) 744-7512 • FAX (817) 744-7554
2903 NORTH BIG SPRING • MIDLAND, TEXAS 79705
TELEPHONE: (432) 682-1653 OR (800) 767-1653 • FAX (432) 682-1743
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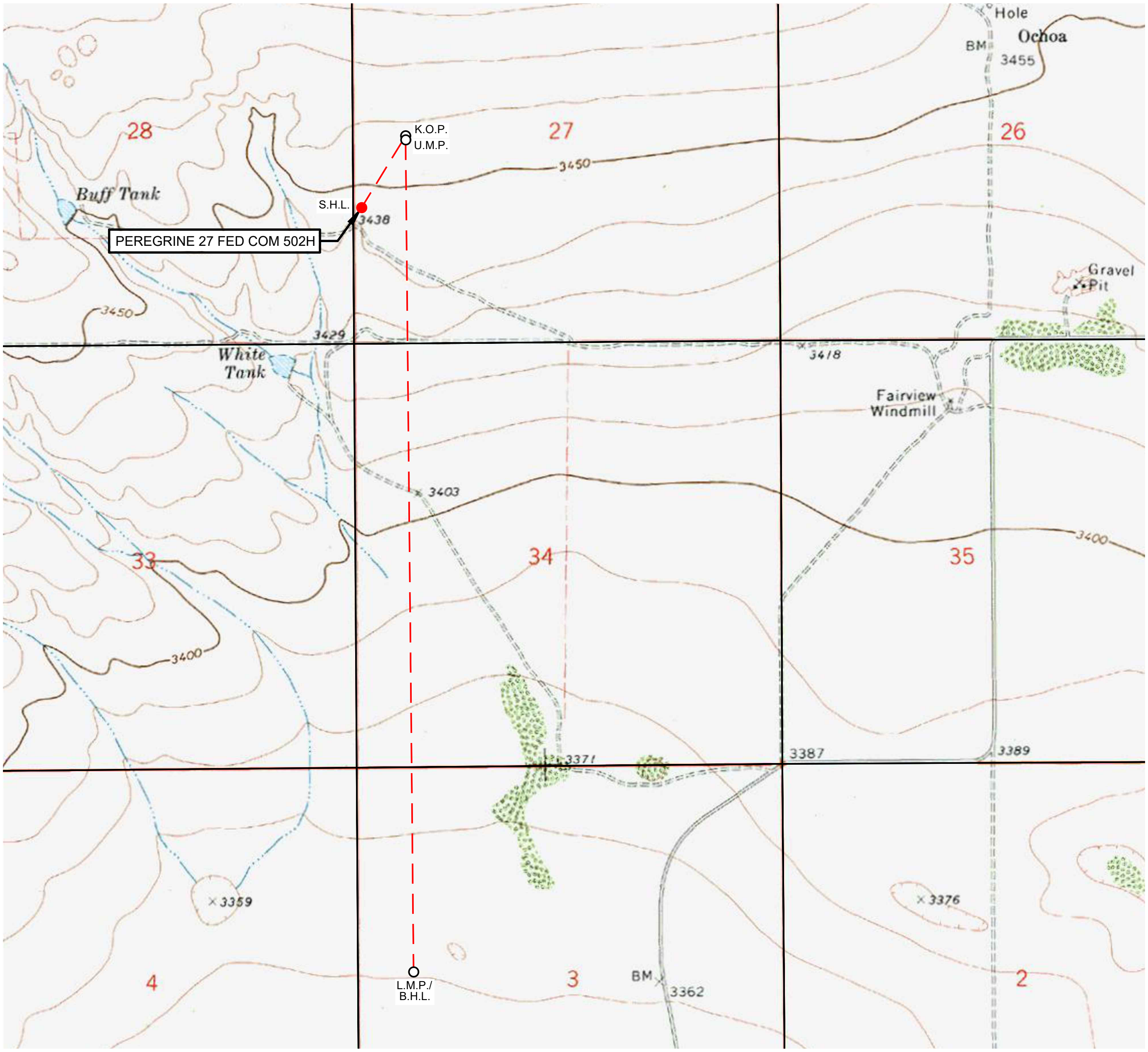
LOCATION & ELEVATION VERIFICATION MAP



eog resources, inc.

LEASE NAME & WELL NO.: PEREGRINE 27 FED COM 502H

SECTION 27 TWP 24-S RGE 34-E SURVEY N.M.P.M.
COUNTY LEA STATE NM ELEVATION 3451'
DESCRIPTION 1700' FSL & 159' FWL

LATITUDE N 32.1859549 LONGITUDE W 103.4658473

N

SCALE: 1" = 2000'
0' 1000' 2000'

THIS EASEMENT/SERVITUDE LOCATION SHOWN HEREON HAS BEEN SURVEYED ON THE GROUND UNDER MY SUPERVISION AND PREPARED ACCORDING TO THE EVIDENCE FOUND AT THE TIME OF SURVEY, AND DATA PROVIDED BY EOG RESOURCES, INC. THIS CERTIFICATION IS MADE AND LIMITED TO THOSE PERSONS OR ENTITIES SHOWN ON THE FACE OF THIS PLAT AND IS NON-TRANSFERABLE. THIS SURVEY IS CERTIFIED FOR THIS TRANSACTION ONLY.

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EXHIBIT 2B

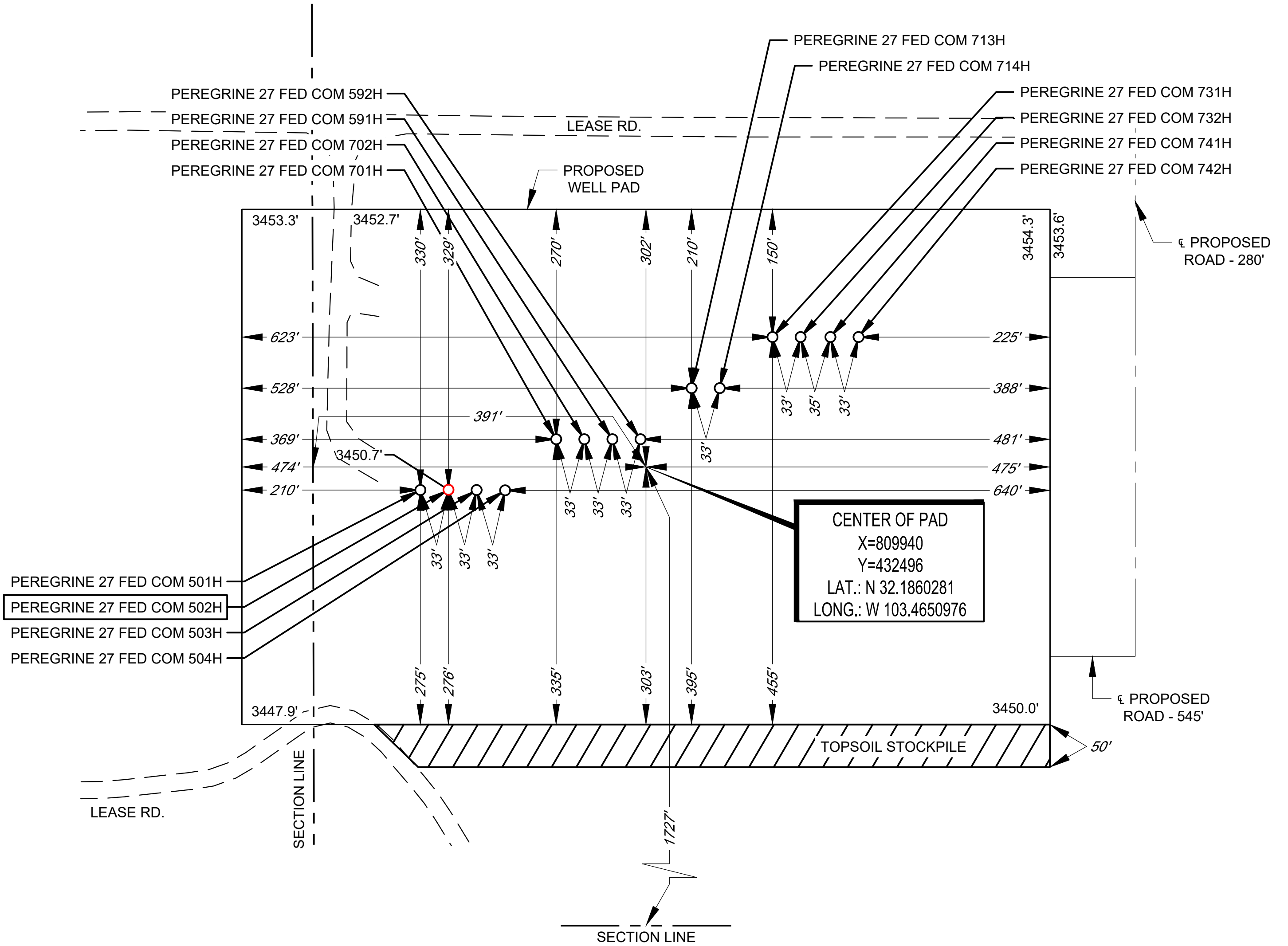
eog resources, inc.

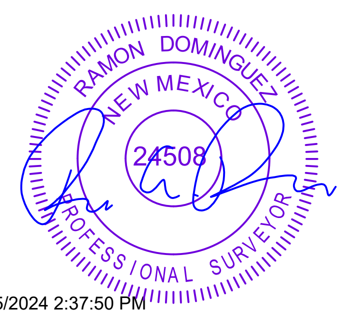
SECTION 27, TOWNSHIP 24-S, RANGE 34-E, N.M.P.M.
LEA COUNTY, NEW MEXICO

DETAIL VIEW
SCALE: 1" = 200'

LEGEND

SECTION LINE
PROPOSED ROAD
ROAD WAY





9/5/2024 2:37:50 PM

Ramon A. Dominguez, P.S. No. 24508

LEASE NAME & WELL NO.: PEREGRINE 27 FED COM 502H

502H LATITUDE N 32.1859549 502H LONGITUDE W 103.4658473

CENTER OF PAD IS 1727' FSL & 391' FWL

ALL BEARINGS, DISTANCES, AND COORDINATE VALUES CONTAINED HEREON ARE GRID BASED UPON THE NEW MEXICO COORDINATE SYSTEM OF 1983, EAST ZONE, U.S. SURVEY FEET. ELEVATIONS USED ARE NAVD88, OBTAINED THROUGH AN OPUS SOLUTION.

THIS PROPOSED PAD SITE LOCATION SHOWN HEREON HAS BEEN SURVEYED ON THE GROUND UNDER MY SUPERVISION AND PREPARED ACCORDING TO THE EVIDENCE FOUND AT THE TIME OF SURVEY, AND DATA PROVIDED BY EOG RESOURCES, INC. ONLY THE DATA SHOWN ABOVE IS BEING CERTIFIED TO, ALL OTHER INFORMATION WAS INTENTIONALLY OMITTED. THIS PLAT IS ONLY INTENDED TO BE USED FOR A PERMIT AND IS NOT A BOUNDARY SURVEY. THIS CERTIFICATION IS MADE AND LIMITED TO THOSE PERSONS OR ENTITIES SHOWN ON THE FACE OF THIS PLAT AND IS NON-TRANSFERABLE. THIS SURVEY IS CERTIFIED FOR THIS TRANSACTION ONLY.

ORIGINAL DOCUMENT SIZE: 8.5" X 11"

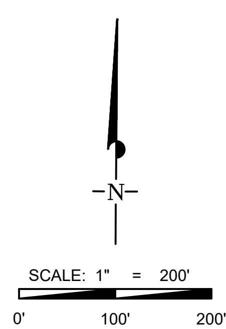


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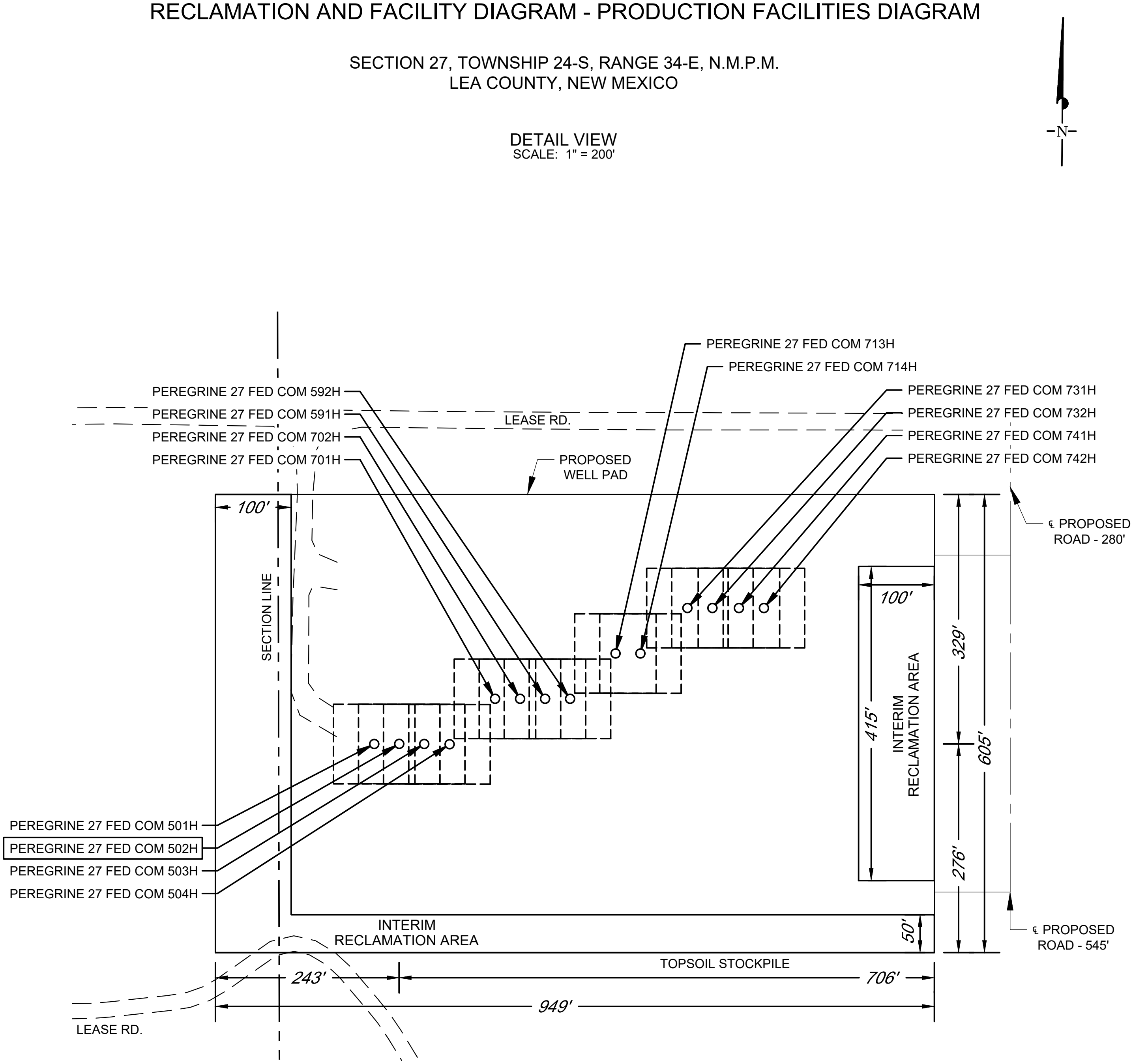
EXHIBIT 2C

RECLAMATION AND FACILITY DIAGRAM - PRODUCTION FACILITIES DIAGRAM

SECTION 27, TOWNSHIP 24-S, RANGE 34-E, N.M.P.M.
LEA COUNTY, NEW MEXICO

DETAIL VIEW
SCALE: 1" = 200'



LEASE NAME & WELL NO.: PEREGRINE 27 FED COM 502H

502H LATITUDE N 32.1859549 502H LONGITUDE W 103.4658473

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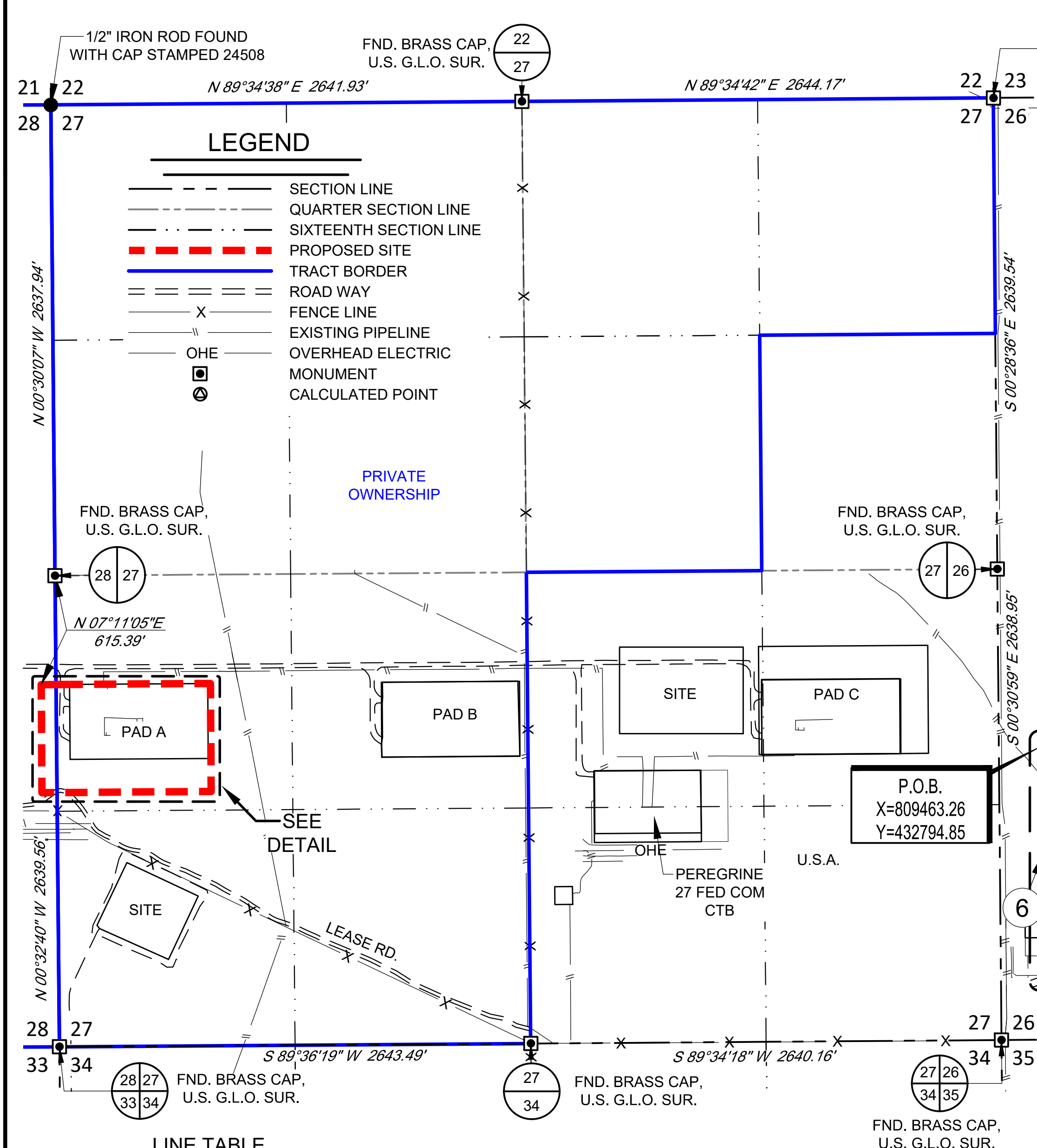
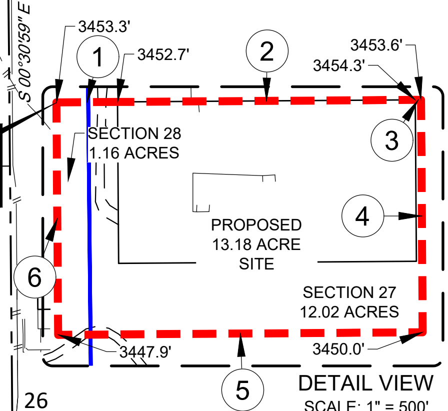
SCALE: 1" = 1000'
0' 500' 1000'

SECTION 27, TOWNSHIP 24-S, RANGE 34-E, N.M.P.M.
LEA COUNTY, NEW MEXICO





PAD A
PEREGRINE 27 FED COM 502H

Metes and Bounds Description of a proposed 13.18 acre pad site located within Sections 27 & 28, Township 24 South, Range 34 East, N.M.P.M., in Lea County, New Mexico.

BEGINNING at a point for the Northwest corner of this site, from whence a brass cap found for the West quarter corner of said Section 27, bears: N 07°11'05" E, a distance of 615.39 feet;

Thence N 89°35'45" E, a distance of 159.00 feet to a point on the North line of this site;

Thence N 89°35'42" E, a distance of 775.08 feet to a point on the North line of this site;

Thence N 89°36'22" E, a distance of 14.92 feet to a point for the Northeast corner of this site;

Thence S 00°24'18" E, a distance of 605.00 feet to a point for the Southeast corner of this site;

Thence S 89°35'42" W, a distance of 949.00 feet to a point for the Southwest corner of this site;

Thence N 00°24'17" W, a distance of 605.00 feet to the Point of Beginning.

Section 28 - 1.16 acres or 50,517 sq. ft.
Section 27 - 12.02 acres or 523,627 sq. ft.

LINE TABLE

LINE	BEARING	DISTANCE
1	N 89°35'45" E	159.00'
2	N 89°35'42" E	775.08'
3	N 89°36'22" E	14.92'
4	S 00°24'18" E	605.00'
5	S 89°35'42" W	949.00'
6	N 00°24'17" W	605.00'

RAMON DOMINGUEZ
NEW MEXICO
24508
PROFESSIONAL SURVEYOR

9/5/2024 2:37:50 PM

Ramon A. Dominguez, P.S. No. 24508

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PAD A
PEREGRINE 27 FED COM 502H

REVISION:	
INT	DATE

DATE: 07/22/24
FILE: LO_PEREGRINE_27_FED_COM_502H_REV1
DRAWN BY: MML
SHEET : 6 OF 9

NOTES:
1. ORIGINAL DOCUMENT SIZE: 8.5" X 11"
2. ALL BEARINGS, DISTANCES, AND COORDINATE VALUES CONTAINED HEREIN ARE GRID BASED UPON THE NEW MEXICO COORDINATE SYSTEM OF 1983, EAST ZONE, U.S. SURVEY FEET.
3. CERTIFICATION IS MADE ONLY TO THE LOCATION OF THIS EASEMENT, IN RELATION TO THE EVIDENCE FOUND DURING A FIELD SURVEY, MADE ON THE GROUND, UNDER MY SUPERVISION, AND USING DOCUMENTATION PROVIDED BY EOG RESOURCES, INC. ONLY UTILITIES/EASEMENTS THAT WERE VISIBLE ON THE DATE OF THIS SURVEY, WITHIN/ADJOINING THIS EASEMENT, HAVE BEEN LOCATED AS SHOWN HEREON OF WHICH I HAVE KNOWLEDGE. THIS CERTIFICATION IS LIMITED TO THOSE PERSONS OR ENTITIES SHOWN ON THE FACE OF THIS PLAT AND IS NON-TRANSFERABLE, AND MADE FOR THIS TRANSACTION ONLY.
4. P.O.B. = POINT OF BEGINNING
5. ADJOINER INFORMATION SHOWN FOR INFORMATIONAL PURPOSES ONLY.

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10,000 PSI BOP Annular
Variance Request (EOG Variance 1c)

EOG Resources request a variance to use a 5000 psi annular BOP with a 10,000 psi BOP stack. The component and compatibility tables along with the general well control plans demonstrate how the 5000 psi annular BOP will be protected from pressures that exceed its rated working pressure (RWP). The pressure at which the control of the wellbore is transferred from the annular preventer to another available preventer will not exceed 3500 psi (70% of the RWP of the 5000 psi annular BOP).

1. Component and Preventer Compatibility Tables

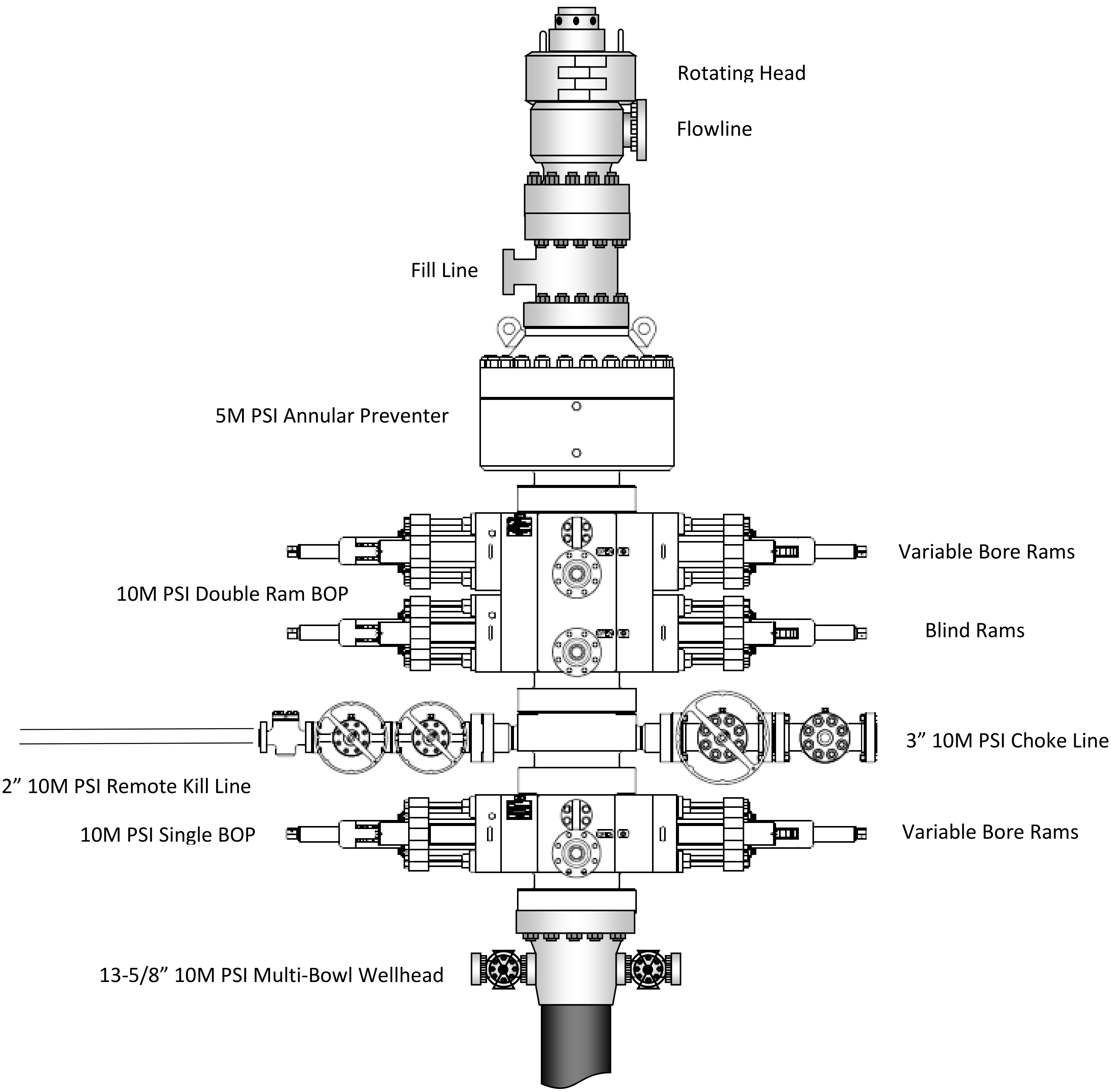
The tables below outlines the tubulars and the compatible preventers in use. This table, combined with the drilling fluid, documents that two barriers to flow will be maintained at all times.

12-1/4" Intermediate Hole Section 10M psi requirement					
Component	**OD**	**Primary Preventer**	**RWP**	**Alternate Preventer(s)**	**RWP**
Drillpipe	5.000" or 4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
HWDP	5.000" or 4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Jars	6.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
DCs and MWD tools	6.500" – 8.000"	Annular	5M	-	-
Mud Motor	8.000" – 9.625"	Annular	5M	-	-
1st Intermediate casing	9.625"	Annular	5M	-	-
Open-hole	-	Blind Rams	10M	-	-

8-3/4" Production Hole Section 10M psi requirement					
Component	**OD**	**Primary Preventer**	**RWP**	**Alternate Preventer(s)**	**RWP**
Drillpipe	5.000" or 4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
HWDP	5.000" or 4.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
Jars	6.500"	Annular	5M	Upper 3.5 - 5.5" VBR Lower 3.5 - 5.5" VBR	10M 10M
DCs and MWD tools	6.500" – 8.000"	Annular	5M	-	-
Mud Motor	6.750" – 8.000"	Annular	5M	-	-
2nd Intermediate casing	7.625"	Annular	5M	-	-
Open-hole	-	Blind Rams	10M	-	-

VBR = Variable Bore Ram

EOG Resources
13-5/8” 10M PSI BOP Stack



2. Well Control Procedures

Below are the minimal high-level tasks prescribed to assure a proper shut-in while drilling, tripping, running casing, pipe out of the hole (open hole), and moving the BHA through the BOPs. At least one well control drill will be performed weekly per crew to demonstrate compliance with the procedure and well control plan. The well control drill will be recorded in the daily drilling log. The type of drill will be determined by the ongoing operations, but reasonable attempts will be made to vary the type of drill conducted (pit, trip, open hole, choke, etc.). This well control plan will be available for review by rig personnel in the EOG Resources drilling supervisor's office on location, and on the rig floor. All BOP equipment will be tested as per Onshore O&G Order No. 2 with the exception of the 5000 psi annular which will be tested to 100% of its RWP.

General Procedure While Drilling

1. Sound alarm (alert crew)
2. Space out drill string
3. Shut down pumps (stop pumps and rotary)
4. Shut-in Well (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
   a. SIDPP and SICP
   b. Pit gain
   c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

General Procedure While Tripping

1. Sound alarm (alert crew)
2. Stab full opening safety valve and close
3. Space out drill string
4. Shut-in (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
   a. SIDPP and SICP
   b. Pit gain
   c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

General Procedure While Running Production Casing

1. Sound alarm (alert crew)
2. Stab crossover and full opening safety valve and close
3. Space out string
4. Shut-in (uppermost applicable BOP, typically annular preventer first. HCR and choke will already be in the closed position.)
5. Confirm shut-in
6. Notify toolpusher/company representative
7. Read and record the following:
    a. SIDPP and SICP
    b. Pit gain
    c. Time
8. Regroup and identify forward plan
9. If pressure has built or is anticipated during the kill to reach 70% or greater of the RWP of the annular preventer, confirm spacing and close the upper variable bore rams.

General Procedure With No Pipe In Hole (Open Hole)

1. Sound alarm (alert crew)
2. Shut-in with blind rams. (HCR and choke will already be in the closed position.)
3. Confirm shut-in
4. Notify toolpusher/company representative
5. Read and record the following:
    a. SICP
    b. Pit gain
    c. Time
6. Regroup and identify forward plan

General Procedures While Pulling BHA thru Stack

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

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

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

EOG Blanket Casing Design Variance

EOG respectfully requests the drill plans in the attached document 'EOG BLM Variance 5a - Alternate Shallow Casing Designs' 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:

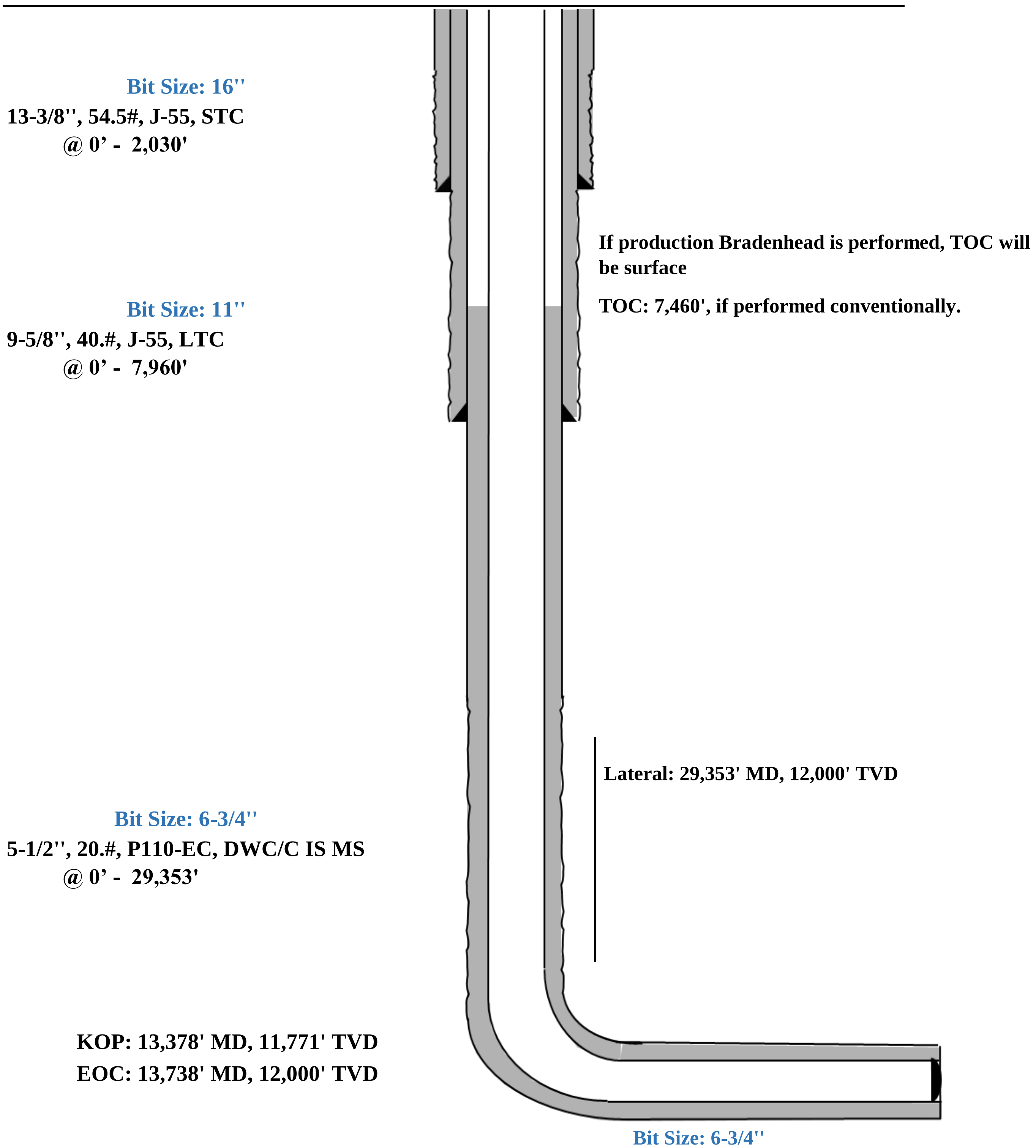
Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 13-3/8''	570	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	160	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830')
8,050' 9-5/8''	760	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'



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

File Edit Wellbore Tubular View Composer Tools Window Help

9 5/8" Intermediate Casing

Pressure Test

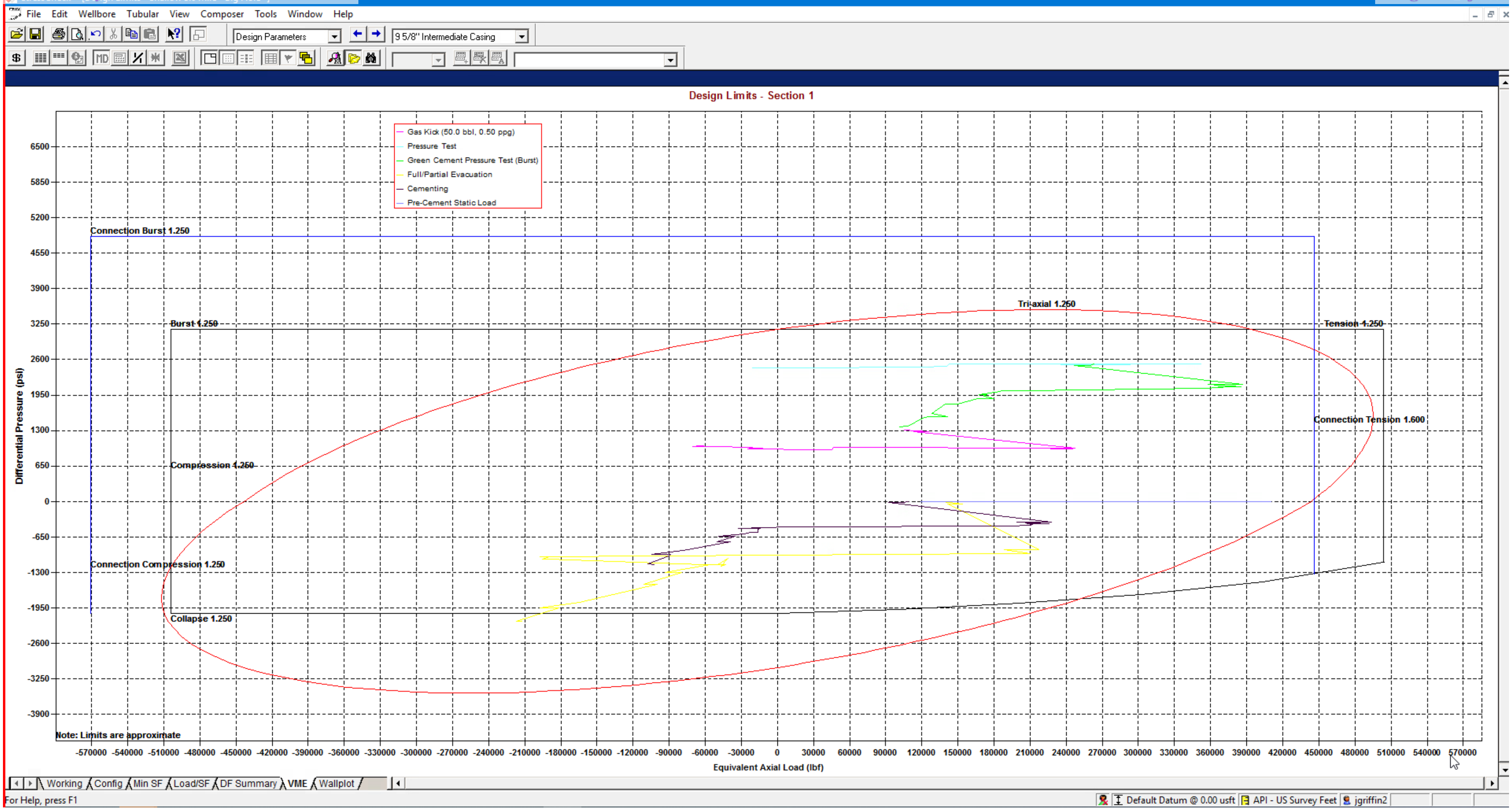
Triaxial Results

	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

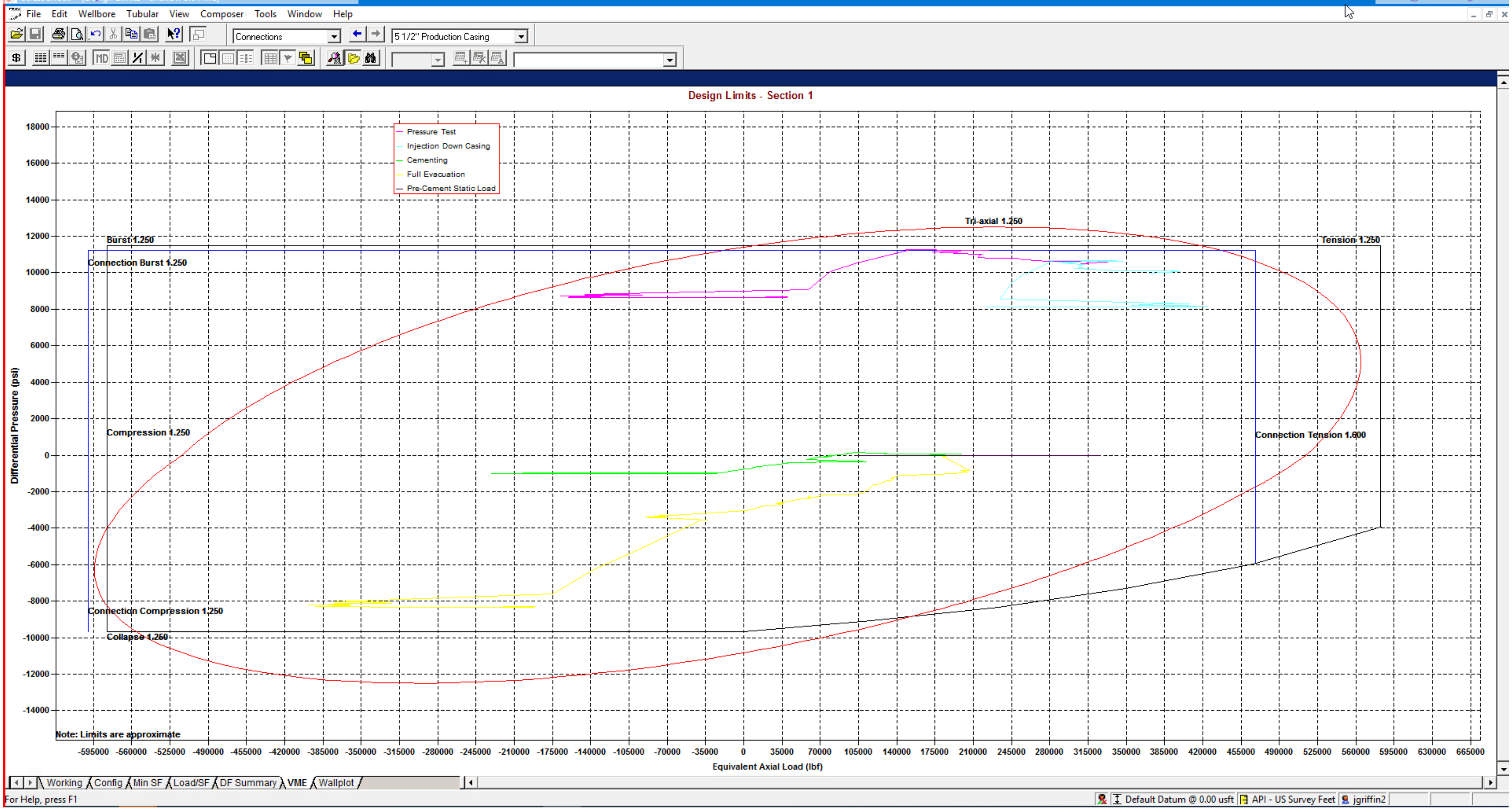


StressCheck - [String Summary - Shallow 3.0 Mile - Big Hole *]

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)				Design Cost ($)
						Burst	Collapse (V)	Axial	Triaxial	
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:

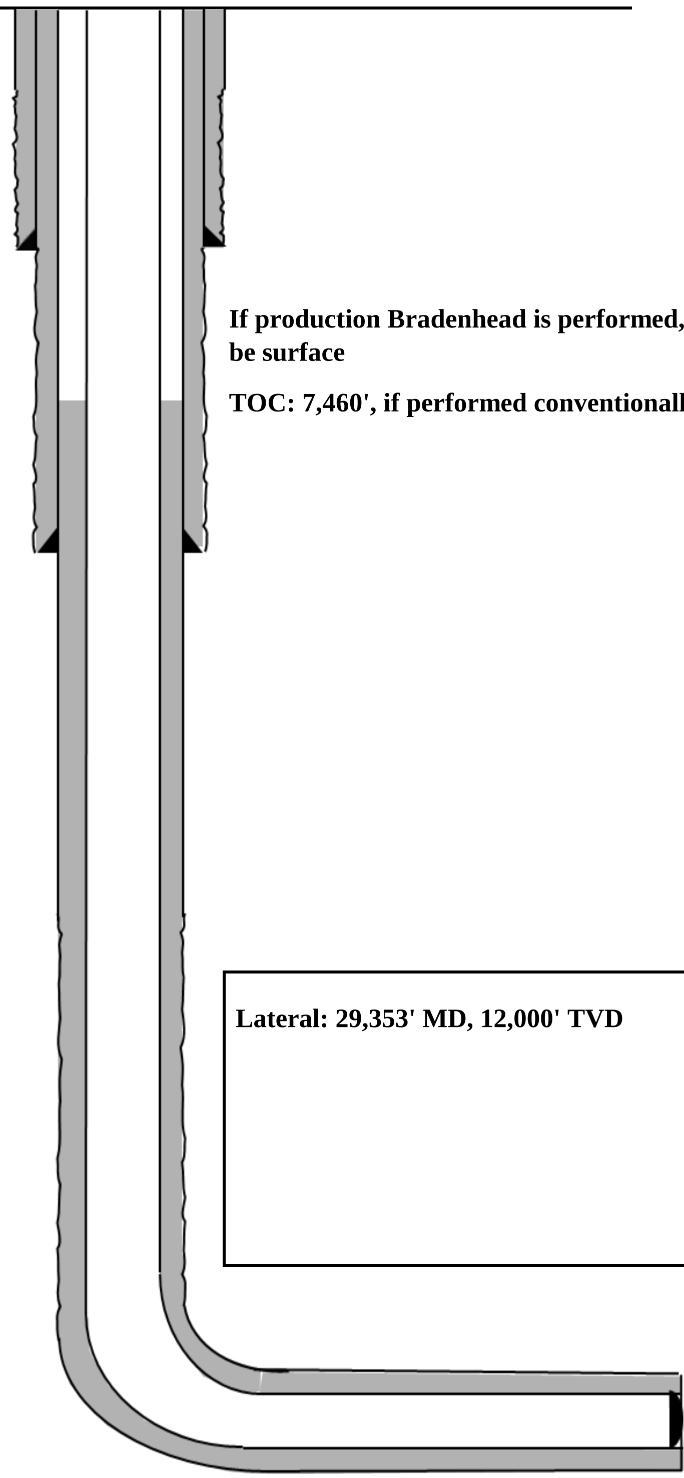
Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 10-3/4''	530	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	140	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830')
8,050' 8-5/8''	470	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)

eog resources

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

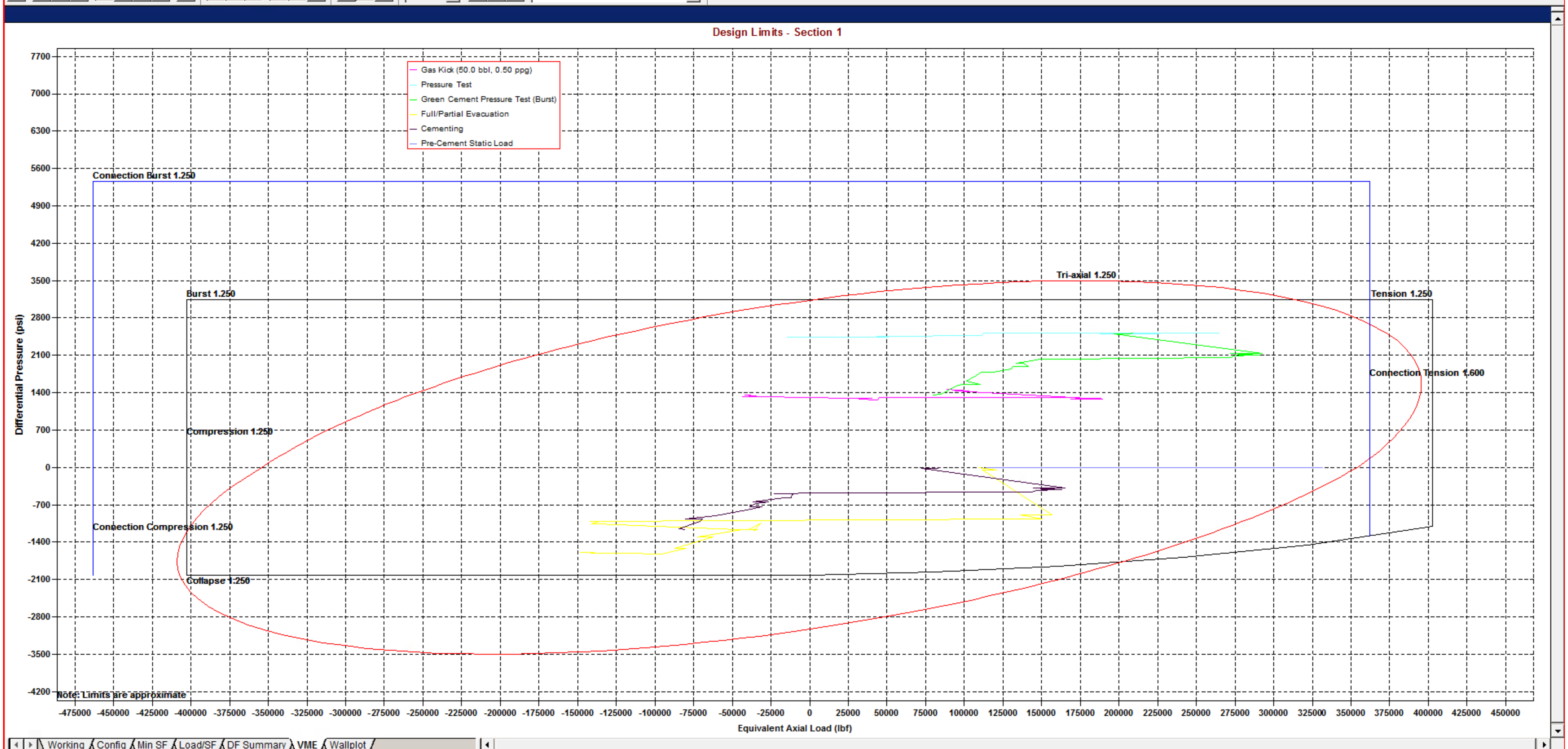
Triaxial Results

	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

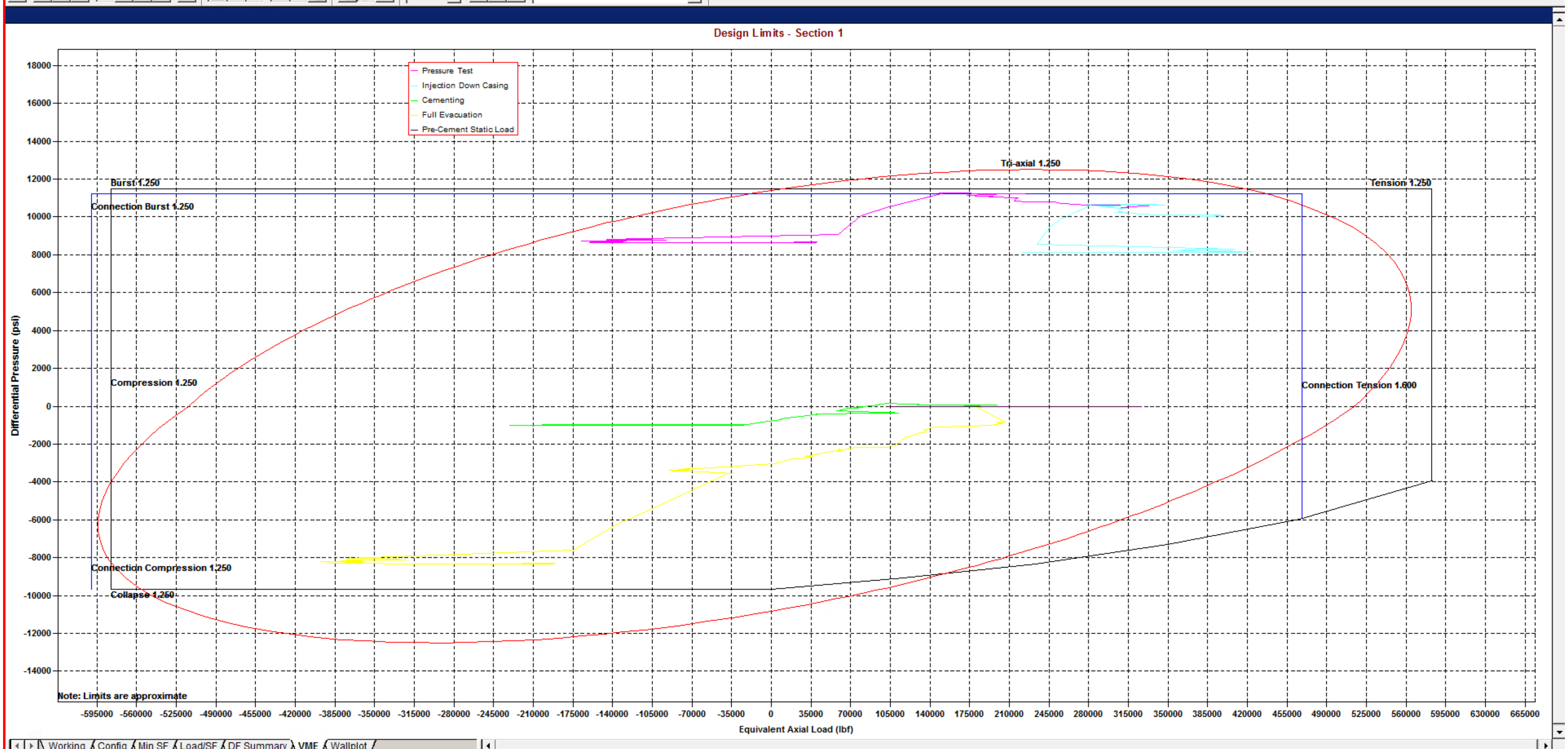


StressCheck - [String Summary - Shallow 3.0 Mile *]

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:

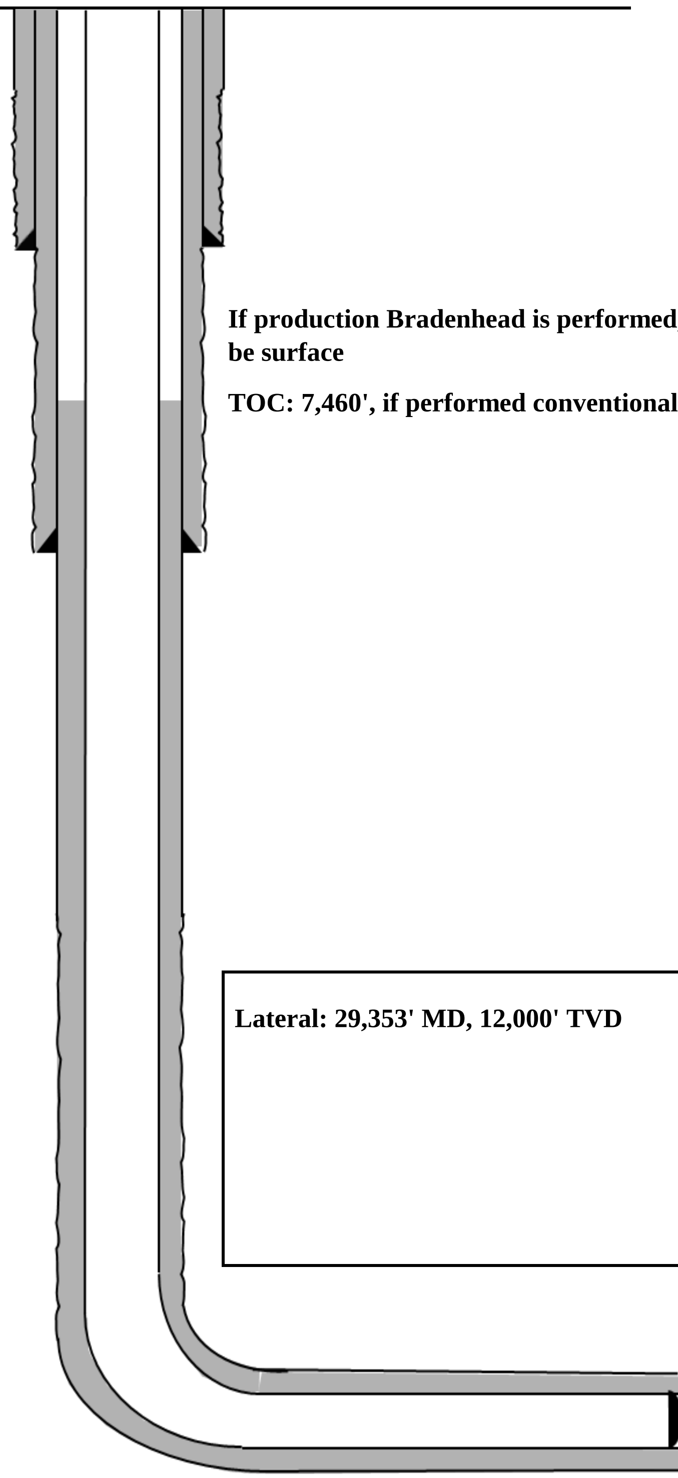
Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 13-3/8''	570	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	160	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830')
8,050' 9-5/8''	760	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

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

TOC: 7,460', if performed conventionally.

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''

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)		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														

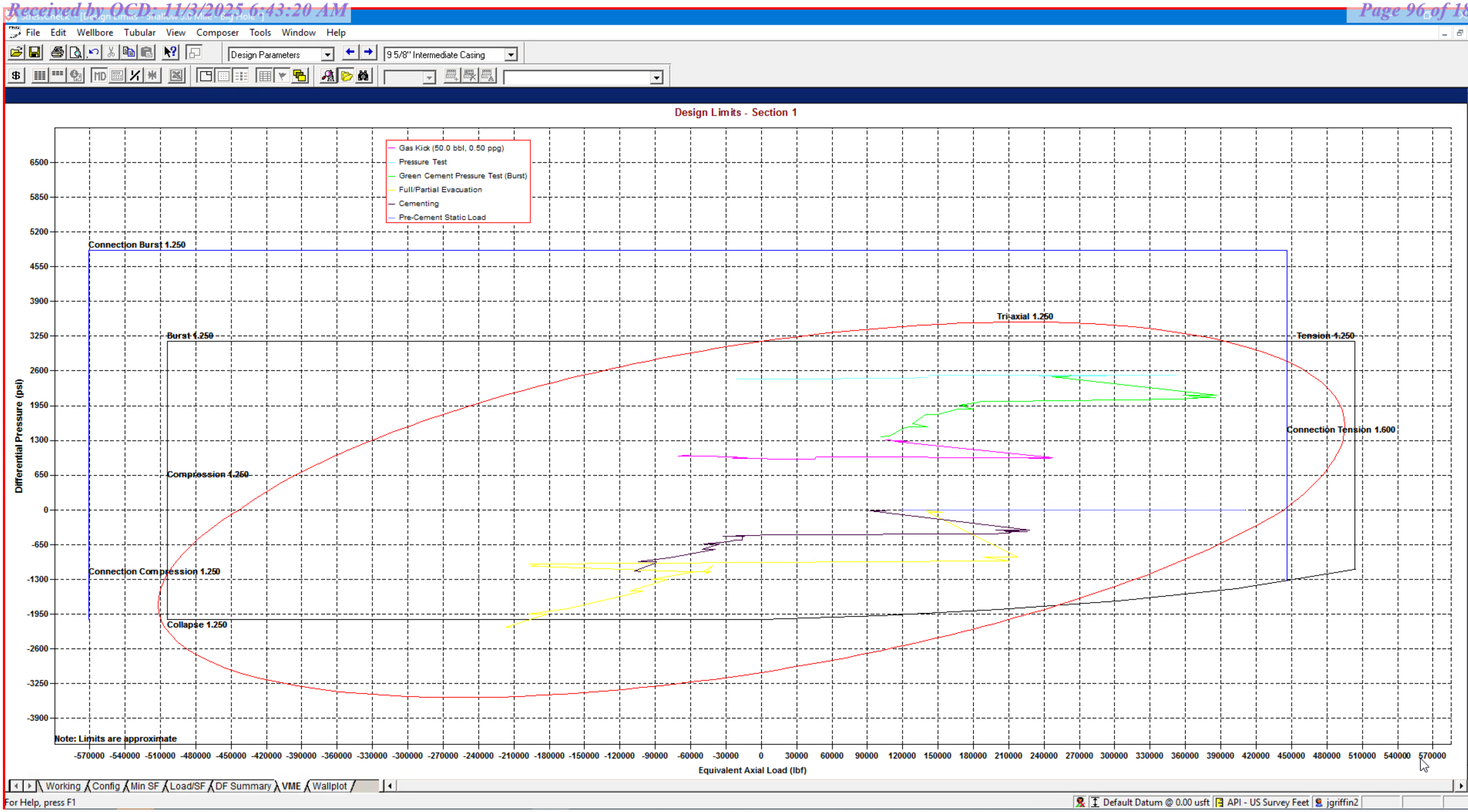
Working Config Min SF Load/SF DF Summary VME Wallplot

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

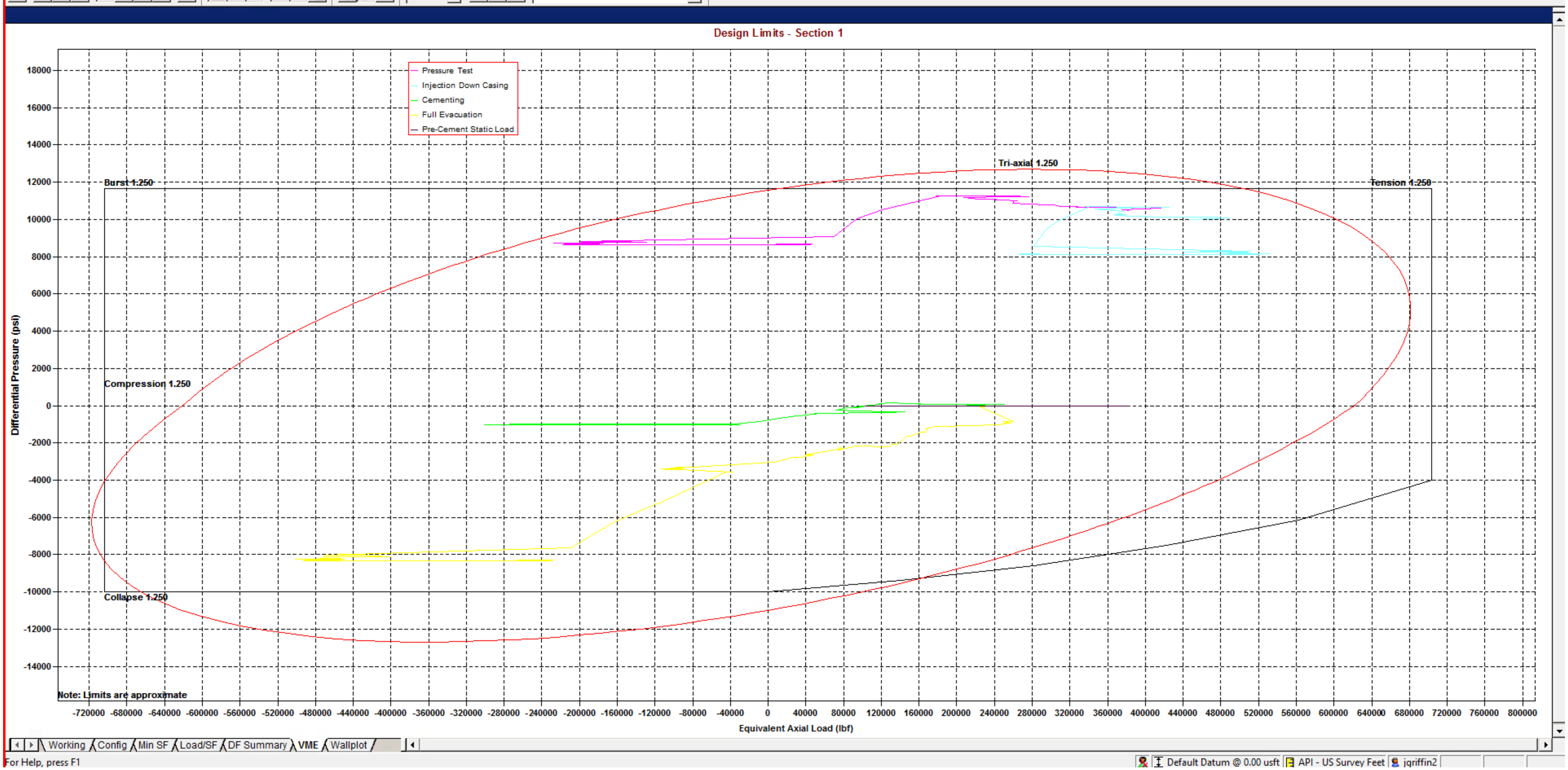


StressCheck - [String Summary - Shallow 3.0 Mile - Big Hole *]

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 - 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	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.

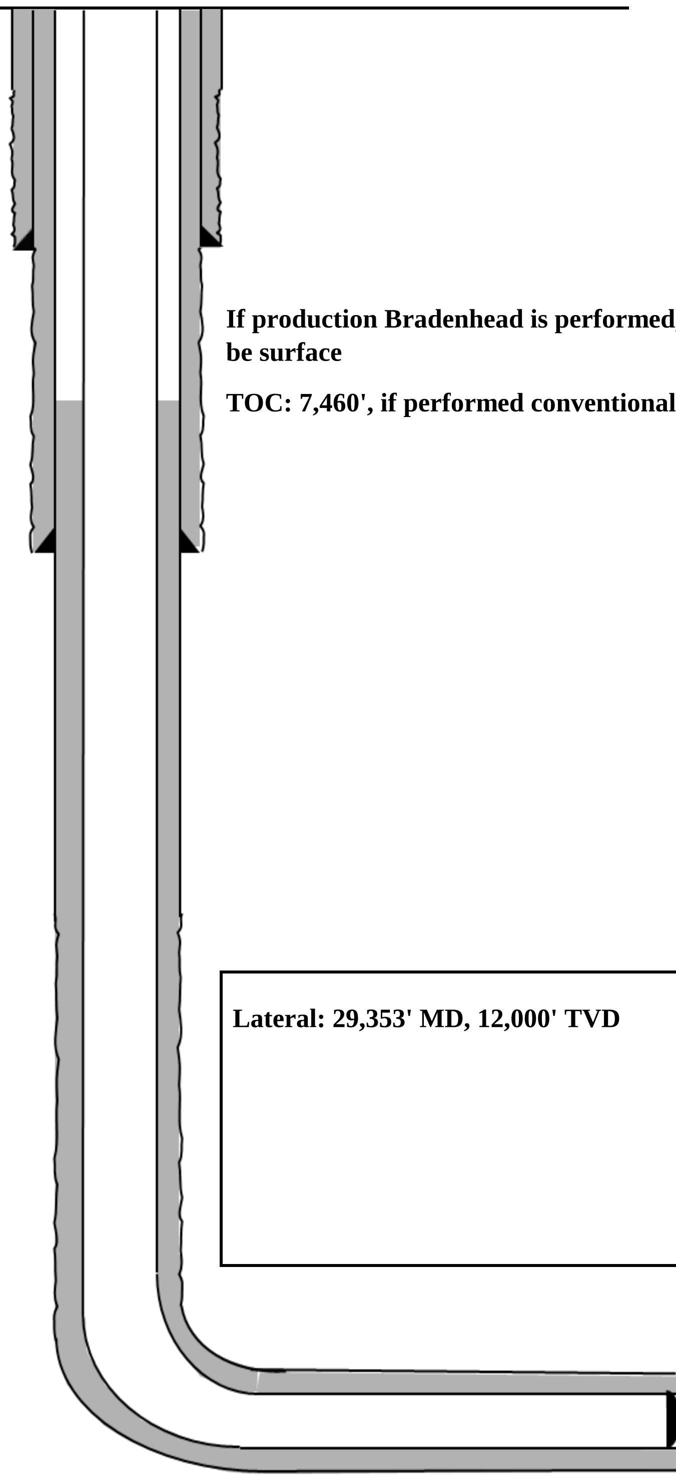
5. CEMENTING PROGRAM:

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

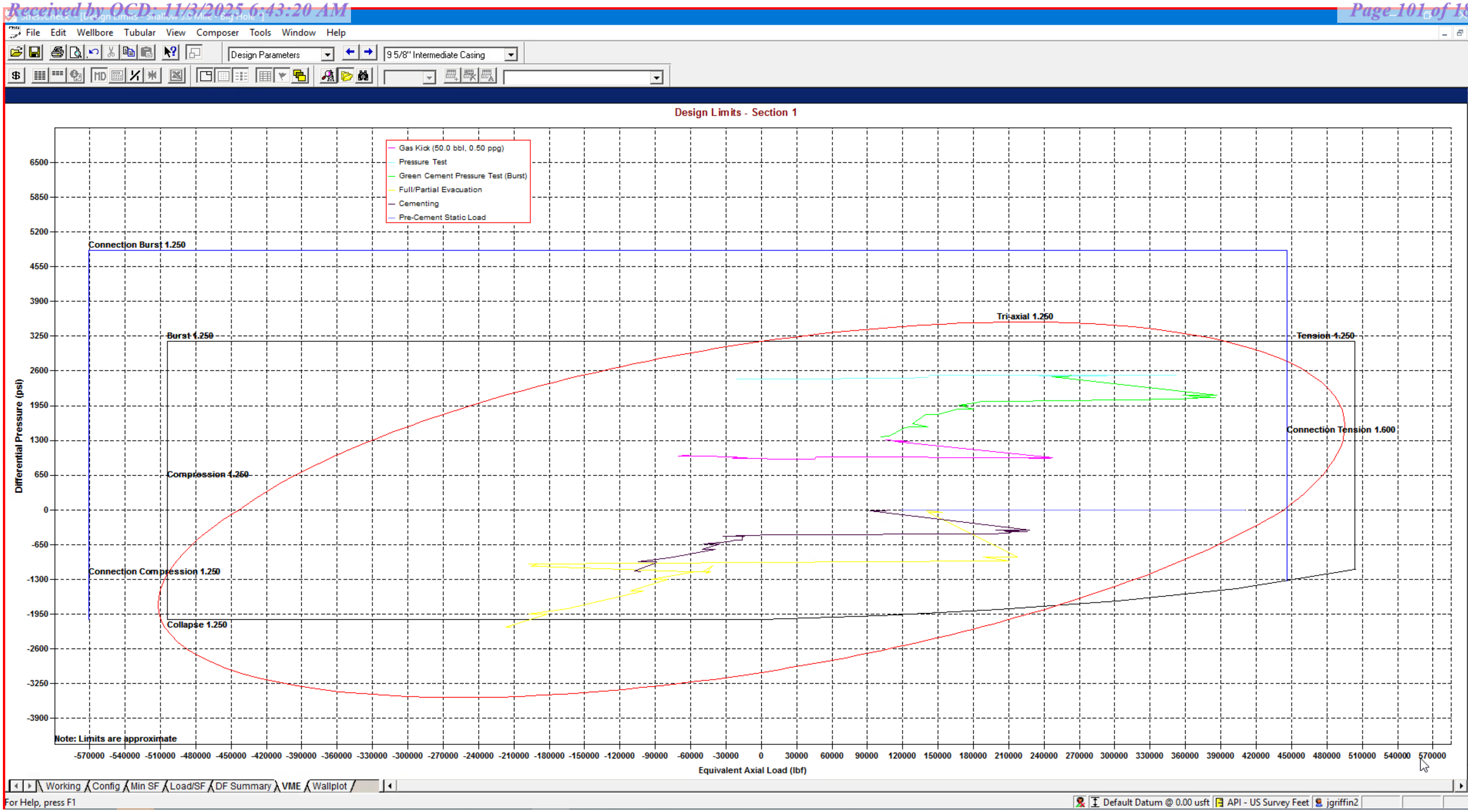
Triaxial Results

	Depth (MD) (usft)	Axial Force (lbf) 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

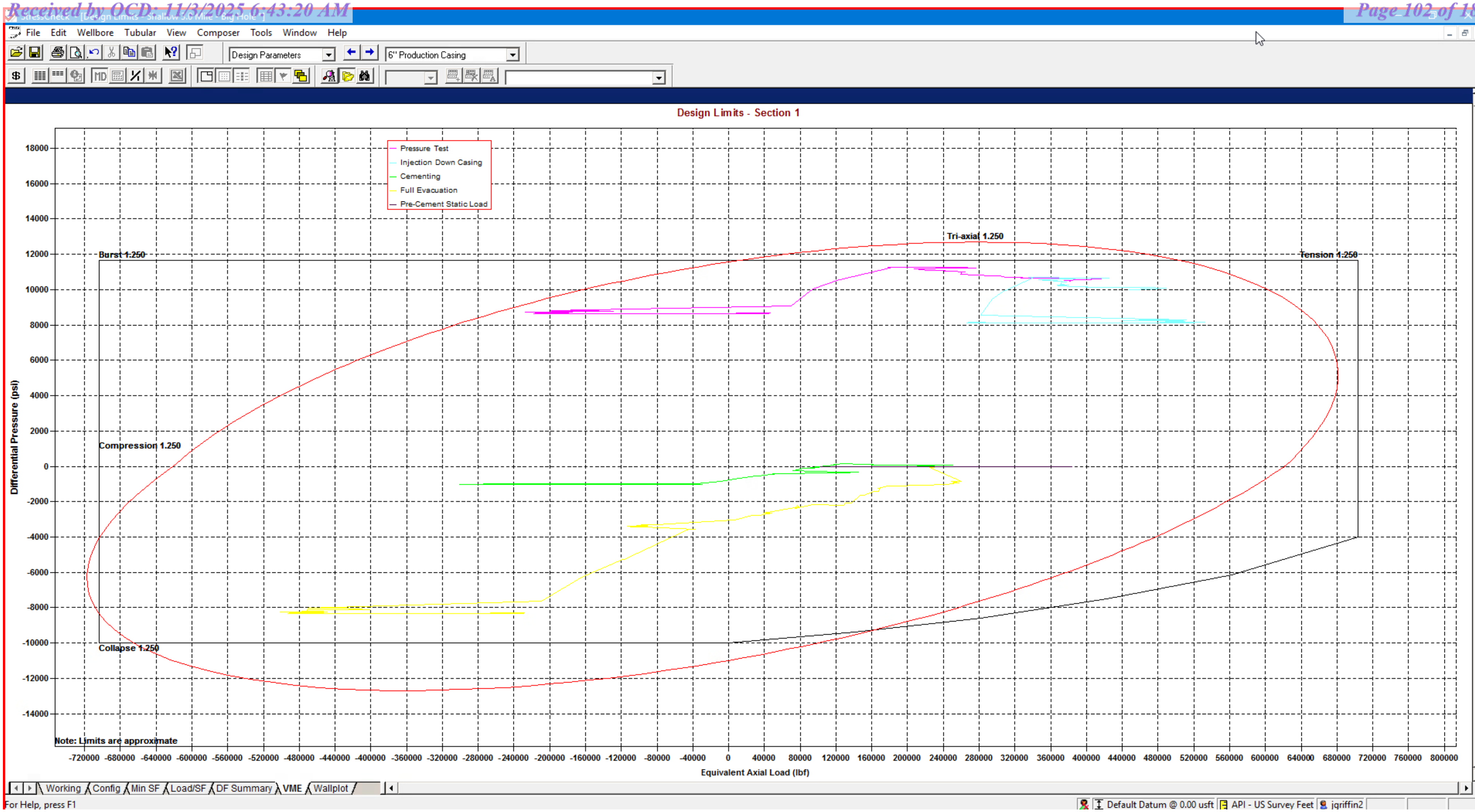


StressCheck - [String Summary - Shallow 3.0 Mile - Big Hole *]

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										

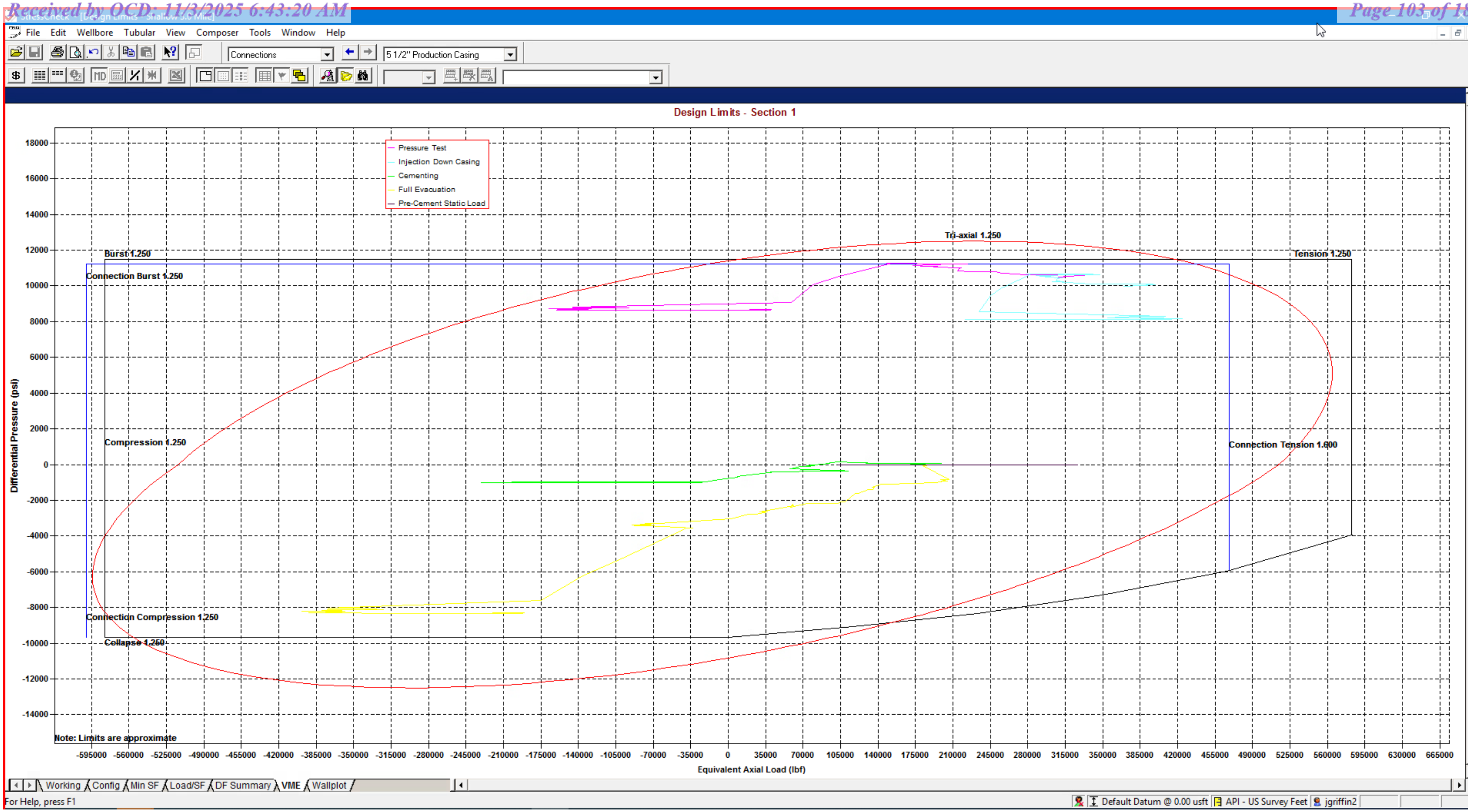
*Modelling done with 9-5/8" 40# Intermediate Casing. Passes all Burst, Collapse and Tensile design criteria.



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.



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 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:

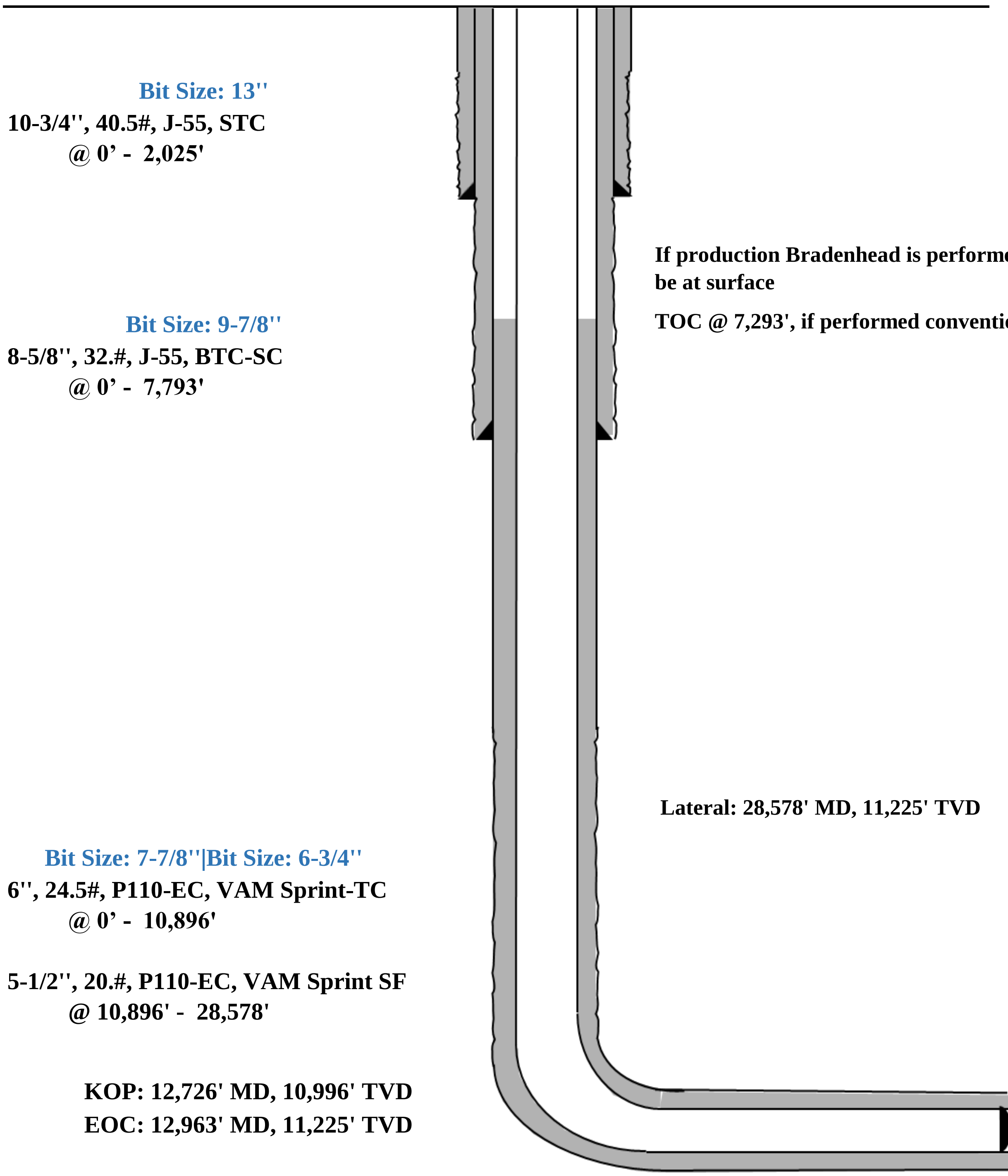
Depth	No. Sacks	Wt. ppg	Yld Ft3/sk	Slurry Description
2,030' 10-3/4"	450	13.5	1.73	Lead: Class C/H + 4.0% Bentonite Gel + 0.5% CaCl2 + 0.25 lb/sk Cello-Flake (TOC @ Surface)
	120	14.8	1.34	Tail: Class C/H + 0.6% FL-62 + 0.25 lb/sk Cello-Flake + 0.2% Sodium Metasilicate (TOC @ 1830')
7,890' 8-5/8"	460	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-*****



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)	Actual (w/o Bending)	Equivalent Axial Load (lbf)	Bending Stress at OD (psi)	Absolute Safety Factor Triaxial	Burst	Collapse (V)	Axial	Temperature (°F)	Pressure (psi) Internal	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														

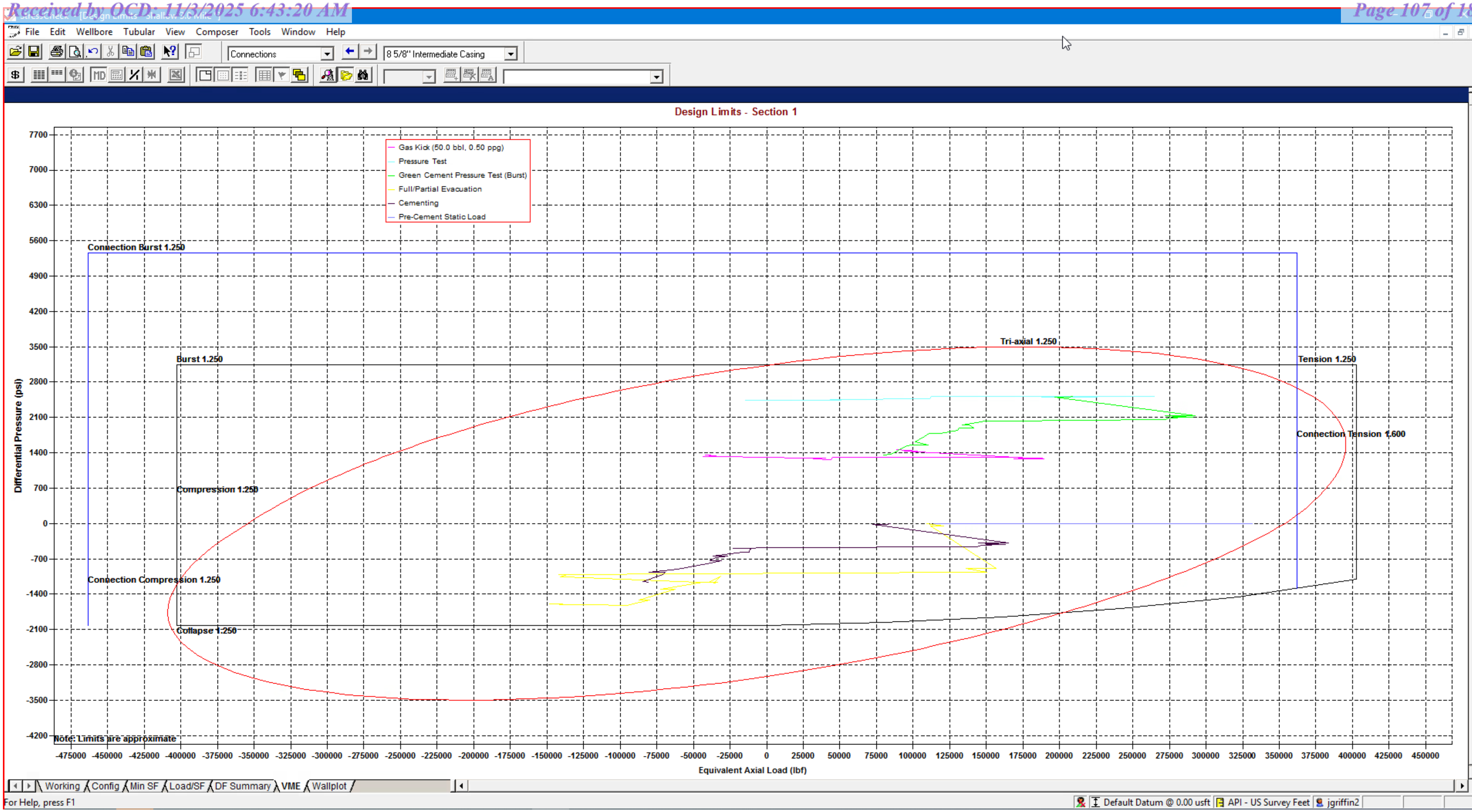
Working | Config | Min SF | Load/SF | DF Summary | VME | Wallplot

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



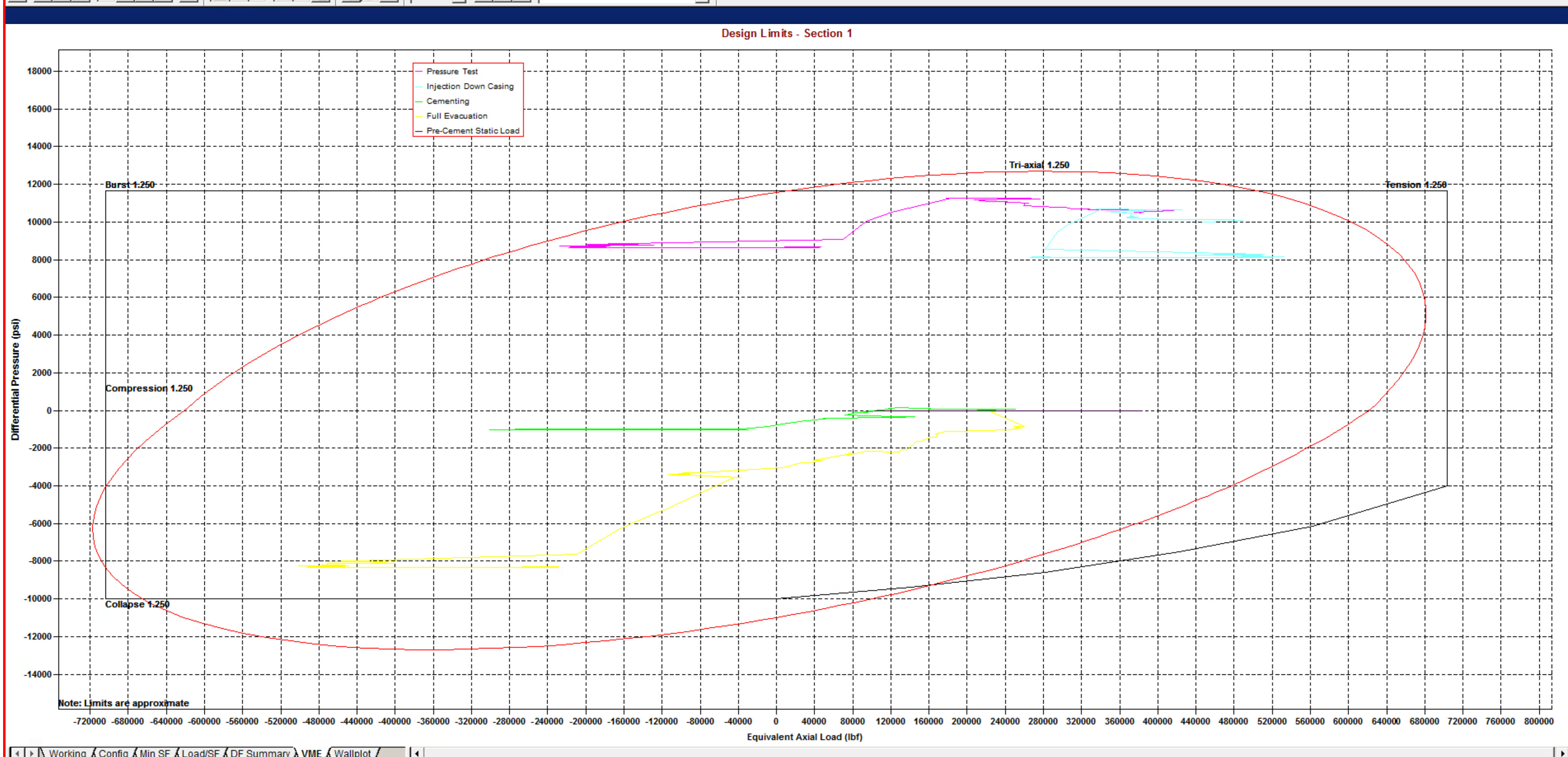
StressCheck - [String Summary - Shallow 3.0 Mile *]

File Edit Wellbore Tubular View Composer Tools Window Help

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										

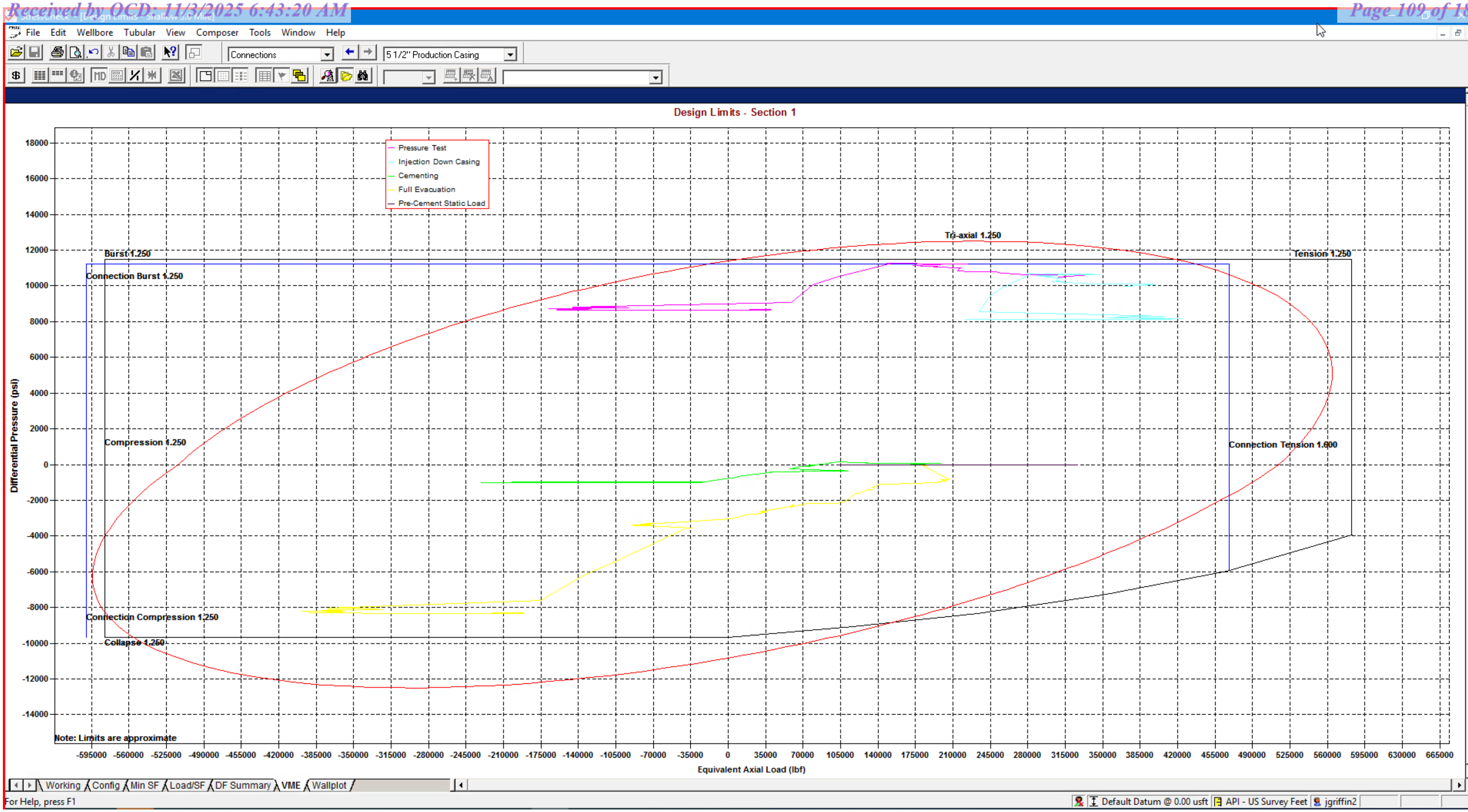
*Modelling done with 8-5/8" 32# Intermediate Casing. Passes all Burst, Collapse and Tensile design criteria.



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	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 »

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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

Pipe Body and API Connections Performance Data

9.625 40.00/0.395 J55

PDF

New Search »

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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

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

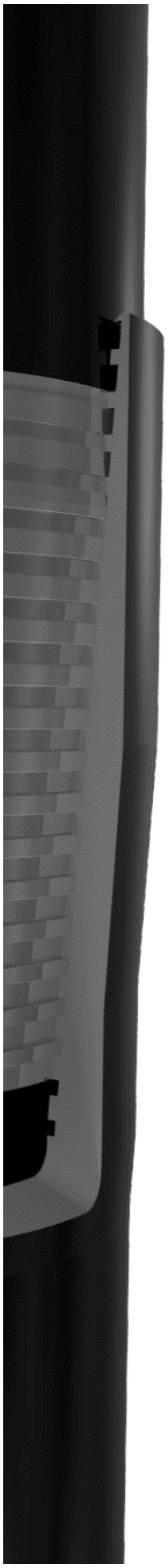
LTC Torque (ft-lbs)					
Min:	3,130	Opti:	4,174	Max:	5,217

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

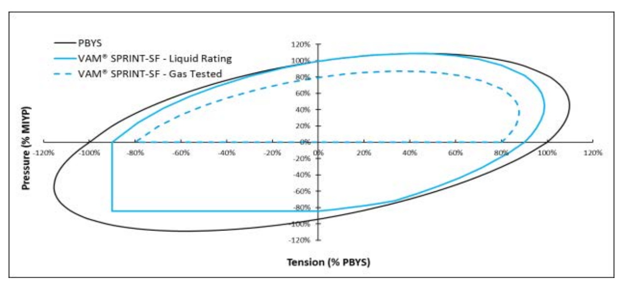
CONNECTION PROPERTIES		
Connection Type	Integral Semi-Flush	
Connection OD (nom):	6.277	in.
Connection ID (nom):	5.146	in.
Make-Up Loss	5.386	in.
Critical Cross Section	6.417	sqin.
Tension Efficiency	91.0	% of pipe
Compression Efficiency	91.0	% of pipe
Internal Pressure Efficiency	100	% of pipe
External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

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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

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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.

CONFIDENTIAL

THIRD ANGLE	DESIGNED IN INCHES DIMENSIONAL UNITS INCHES [MILLIMETERS]	MACHINING TOLERANCES UNLESS OTHERWISE SPECIFIED	SURFACE TREATMENT	DO NOT SCALE	CAMERON A Schlumberger Company — SURFACE SYSTEMS
MACHINED FILLET RADII .015-.050 [0.38-1.27]. BREAK ALL SHARP EDGES .01-.03 [0.2-0.8] RADII OR 45°. SURFACE FINISH IN MICRO (μ) INCHES (Ra). INTERPRET DRAWING PER ASME Y14.5, ASME Y14.36, AND AWS A2.4 STANDARDS. SEE B/M FOR MATERIAL AND SPECIAL REQUIREMENTS. ITEM NUMBERS NOT APPEARING ON B/M DO NOT APPLY.	.X [0.] ± = [] .XX [0.X] ± = [] .XXX [0.XX] ± = []	ANGLES ± ° RA ON ALL MACHINED SURFACES	MATERIAL & HEAT TREAT	DRAWN BY: KEN REED — DATE 6 Nov 18 CHECKED BY: PA — DATE 6 Nov 18 APPROVED BY: APPROVER NAME — DATE 6 Nov 18	EOG RESOURCES, INC 13-5/8" 10K MN-DS WELLHEAD 13-3/8" X 9-5/8" X 5-1/2"
			ESTIMATED WEIGHT: 8147.2 LBS 3695.5 KG	INITIAL USE B/M: EWR:650353762	SHEET 1 OF 1 — SD-052491-19-07 — REV: 01

INVENTOR - D

American Petroleum Institute

2018-151

Certificate of Authority to use the Official API Monogram

License Number: 7K-0519 **ORIGINAL**

The American Petroleum Institute hereby grants to

GATES ENGINEERING AND SERVICES
7603 Prairie Oak Drive, Suite 190
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United States

the right to use the Official API Monogram® on manufactured products under the conditions in the official publications of the American Petroleum Institute entitled API Spec Q1® and **API-7K** and in accordance with the provisions of the License Agreement.

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The American Petroleum Institute reserves the right to revoke this authorization to use the Official API Monogram for any reason satisfactory to the Board of Directors of the American Petroleum Institute.

The scope of this license includes the following: High Pressure Mud and Cement Hoses at FSL 0, at FSL 1, at FSL 2

QMS Exclusions: No Exclusions Identified as Applicable

Effective Date: OCTOBER 24, 2024
Expiration Date: DECEMBER 18, 2027

Anchal Liddar

Senior Vice President of Global Industry Services

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2018-151

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QMS Exclusions: No Exclusions Identified as Applicable

Effective Date: OCTOBER 24, 2024
Expiration Date: DECEMBER 18, 2027

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American Petroleum Institute

REGISTRATION NO. Q1-3650

Certificate of Registration

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United States

has been assessed by the American Petroleum Institute and found to be in conformance with the following:

API Spec Q1, 9th Edition

The scope of this registration and the approved quality management system applies to the

Assembly and Pressure Test of High Pressure Mud and Cement Hoses, Flexible Choke and Kill Lines and General Rubber Hydraulic Hose Assemblies

API approves the organization's justification for excluding

No Exclusions Identified as Applicable

Effective Date:	**OCTOBER 24, 2024**
Expiration Date:	**DECEMBER 18, 2027**
Registered Since:	**DECEMBER 18, 2018**

Q1 API Spec Q1 Registered ®

Anchal Liddar

Senior Vice President of Global Industry Services

This certificate is valid for the period specified herein. The registered organization must continually meet all requirements of API Spec Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry,* and the requirements of the Registration Agreement. Registration is maintained and regularly monitored through annual full system audits. This certificate has been issued from API offices located at 200 Massachusetts Avenue, NW Suite 1100, Washington, DC 20001-5571, U.S.A. It is the property of API and must be returned upon request.
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Houston, TX. 77086

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

CERTIFICATE OF CONFORMANCE

This is to verify that all Parts and/or Materials included in this shipment have been manufactured and/or processed in Conformance with applicable drawings and specifications, and that Records of Required Tests are on file and subject to examination. The following items were purchased via **Gates Engineering & Services North America** facilities in Houston, TX, USA. This hose assembly was designed and manufactured to meet requirements of API Spec 16C, 3rd Edition.

CUSTOMER:	HELMERICH & PAYNE INTERNATIONAL DRILLING CO.
CUSTOMER P.O.#:	740399823 (TAG WITH H&P I.D # 88076545 &H&P P.O. # 740399823 (UK S/O 34557))
CUSTOMER P/N:	3.035.016C4116FX-FLTSSA
PART DESCRIPTION:	3" X 35 FT GATES API 16C CHOKE & KILL FSL 3 TEMP B HOSE ASSEMBLY WITH STAINLESS STEEL ARMOR C/W 4 1/16" 10K H2S SUITED FLOAT X FLOAT FLANGES WITH BX 155 RING GROOVE SUPPLIED WITH SAFETY CLAMPS/LIFT EYE CLAMPS
SALES ORDER #:	525112
QUANTITY:	1
SERIAL #:	SN 139321 HOSE BATCH 139244

SIGNATURE: ______________________

TITLE: QUALITY ASSURANCE

DATE: 2/10/2023

Gates Engineering & Services UK Ltd		CERTIFICATE OF CONFORMITY	Gates
Doc. Ref.	Form-056		
Revision	4		

Gates SO No. 34557	**Customer Name & Address:** Gates Engineering & Services NA Inc Accounts payable 7N GESNA 1144 Fifteenth Street, Suite 1400 Denver, CO 80202 USA
Customer PO No: 1803964/ 1	
Description: 3" 10K API 16C CHOKE & KILL HOSE ASSEMBLY X 35FT OAL (QTY 5)	

This is to certify that the components listed below have been supplied in accordance with API 16C & the above referenced order number. The assemblies listed below have been manufactured and tested in the UK.

SPECIFICATION

ITEM	DESCRIPTION	BATCH NUMBER	QTY
1	3" 10K API 16C CHOKE & KILL HOSE ASSEMBLY X 35FT OAL PART NO: HA34539-001 END A: 4.1/16" 10K API SPEC 6A TYPE FLANGE WITH BX155 RING GROOVE END B: 4.1/16" 10K API SPEC 17D SV SWIVEL FLANGE WITH BX155 RING GROOVE EACH END HAS AN INCONEL 625 INLAID RING GROOVE HOSE METALLIC PARTS MEET NACE-MR-0175 LATEST EDITION REQUIREMENTS WORKING PRESSURE: 10,000 PSI TEST PRESSURE: 15,000 PSI STANDARD: API 16C FSL3 MONOGRAMMED, 3RD EDITION EXTERNAL PROTECTION: STAINLESS STEEL ARMOUR INCLUDED FIRE RATED: API 16C STANDARD SECTION B.12.4 (704° FOR 30 MINS) H2S SERVICE SUITABLE TEMPERATURE CLASS B(-25 TO 100°C) HIGH TEMPERATURE EXPOSURE / SURVIVAL @ 177°C (INTERNAL IN A KICK SITUATION) SAFETY EQUIPMENT: INCLUDED 2 X HOSE SAFETY CLAMPS 2 X 3.6T SHACKLES 2 X 10MM OD X 6FT PCP COATED CHAINS HOSE ASSEMBLYY WORKS ORDERS NUMBERS: 139051 139052 139053 139054 139321	139062 139063 139064 139065 139244	5
	SAFETY/LIFTER CLAMP 195MM 1.7T PART NO: HCC108	MYB59483	10
	SAFETY CHAIN 10MM C/S PCP 6FT PART NO: CHC001	ACU59481	10

QA JW J. Hawkins 06 DEC 2022

Accepted by.. for and on behalf of Gates Engineering & Services UK Ltd

CR 240

Gates Engineering & Services UK Ltd		PRESSURE TEST CERTIFICATE
Doc. Ref.	Form-051	
Revision	9	

			Certificate No:
☐ BURST	☑ HYDROSTATIC	☐ CYCLIC	PTC-139321

Product:	CK03F	Hose WO/Batch:	139244
Assembly WO:	139321	Length:	35FT
SO No:	34557	Date:	25/11/22
Customer:	Gates Engineering & Services NA Inc	Customer Reference:	PO 1803964/ 1

Inner Diameter:	3	Inch		
Working Pressure:	10000	Psi	690	bar
Test Pressure:	15000	Psi	1034	bar
Burst Pressure:	22500	Psi	1551	bar

Hose Description:	3" 10K API 16C CHOKE & KILL HOSE ASSEMBLY X 35FT OAL END A: 4.1/16" 10K API SPEC 6A TYPE FLANGE WITH BX155 RING GROOVE END B: 4.1/16" 10K API SPEC 17D SV SWIVEL FLANGE WITH BX155 RING GROOVE		
Item No	**Qty**	**Part Code**	**Customer Tag No (if applicable)**
1	1	HA34539-001	N/A

Details of Test:	Pressure tested with water at ambient temperature for a minimum of **60** minutes at test pressure **1034 BAR** Pressure Transducer S/N: 131203 (CH1) Chart Recorder S/N: S5VB14523 Calibration Certificate No: IKMCERTU823
Results:	Pressure Loss: **8.43 BAR** Acceptance Criteria: Pressure loss not to exceed **500 PSI (34.47 BAR)**

GESUK Ltd	Third Party
QA JW J. Walker 06 DEC 2022	

CR 374

1/1

File Message	: CH1 139321
Device Type	: GX20
Serial No.	: S5VB14523
Print Groups	: GROUP 1
Print Range	: 2022/11/25 00:53:50.000 - 2022/11/25 03:53:20.000 (UTC+08:00)

Start Time	: 2022/11/25 00:53:50.000 (UTC+08:00)
Stop Time	: 2022/11/25 03:53:20.000 (UTC+08:00)

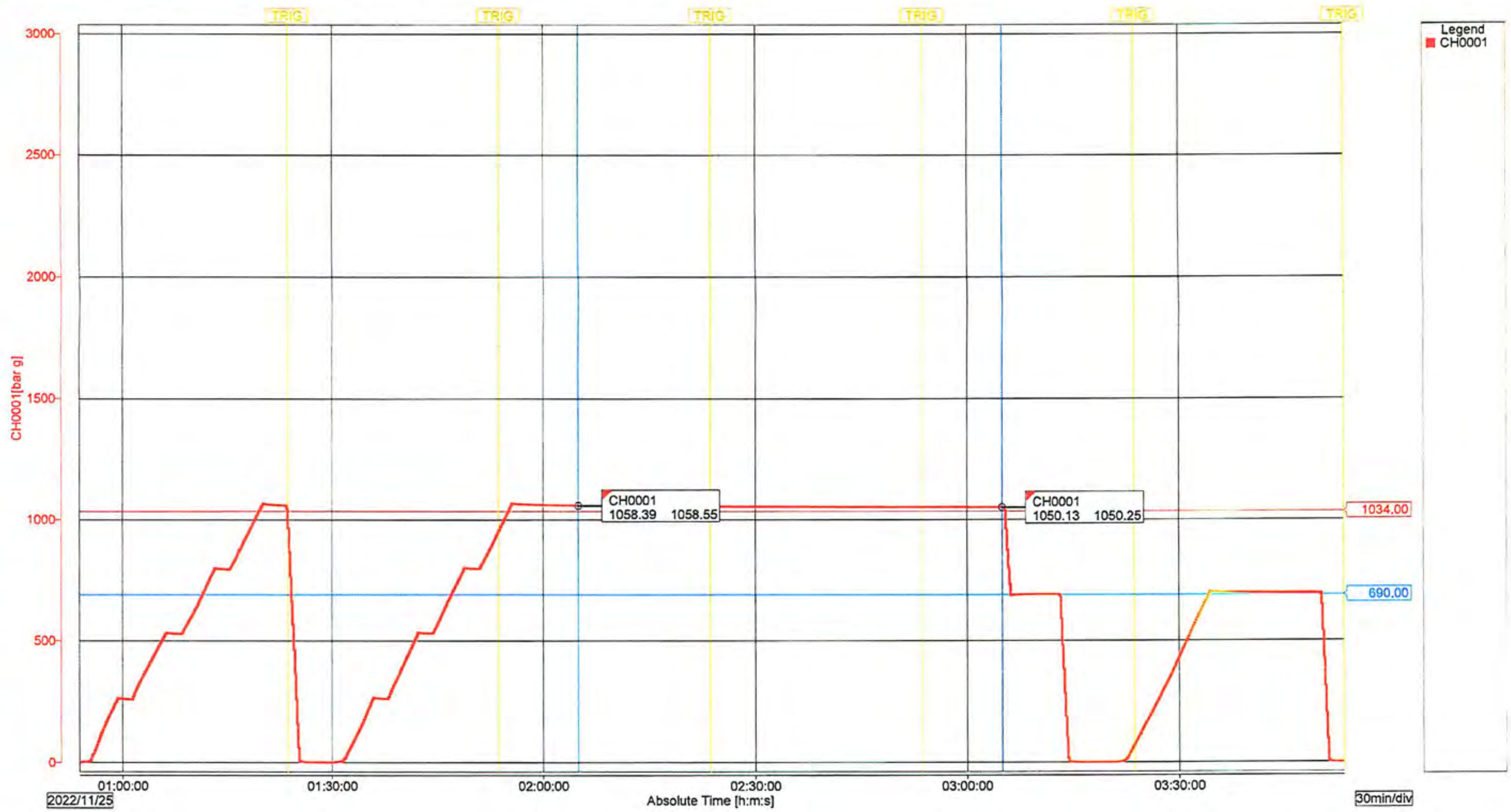
QA
JW

J. Wilkins

06 DEC 2022

Section 427 - 787 2022/11/25 02:05:00.000 - 2022/11/25 03:05:00.000

Channel	MIN	MAX	P-P	Mean	RMS
CH0001[bar g]	1050.12	1058.55	8.43	1053.28	1053.28



Master Variance Document

Table of Contents

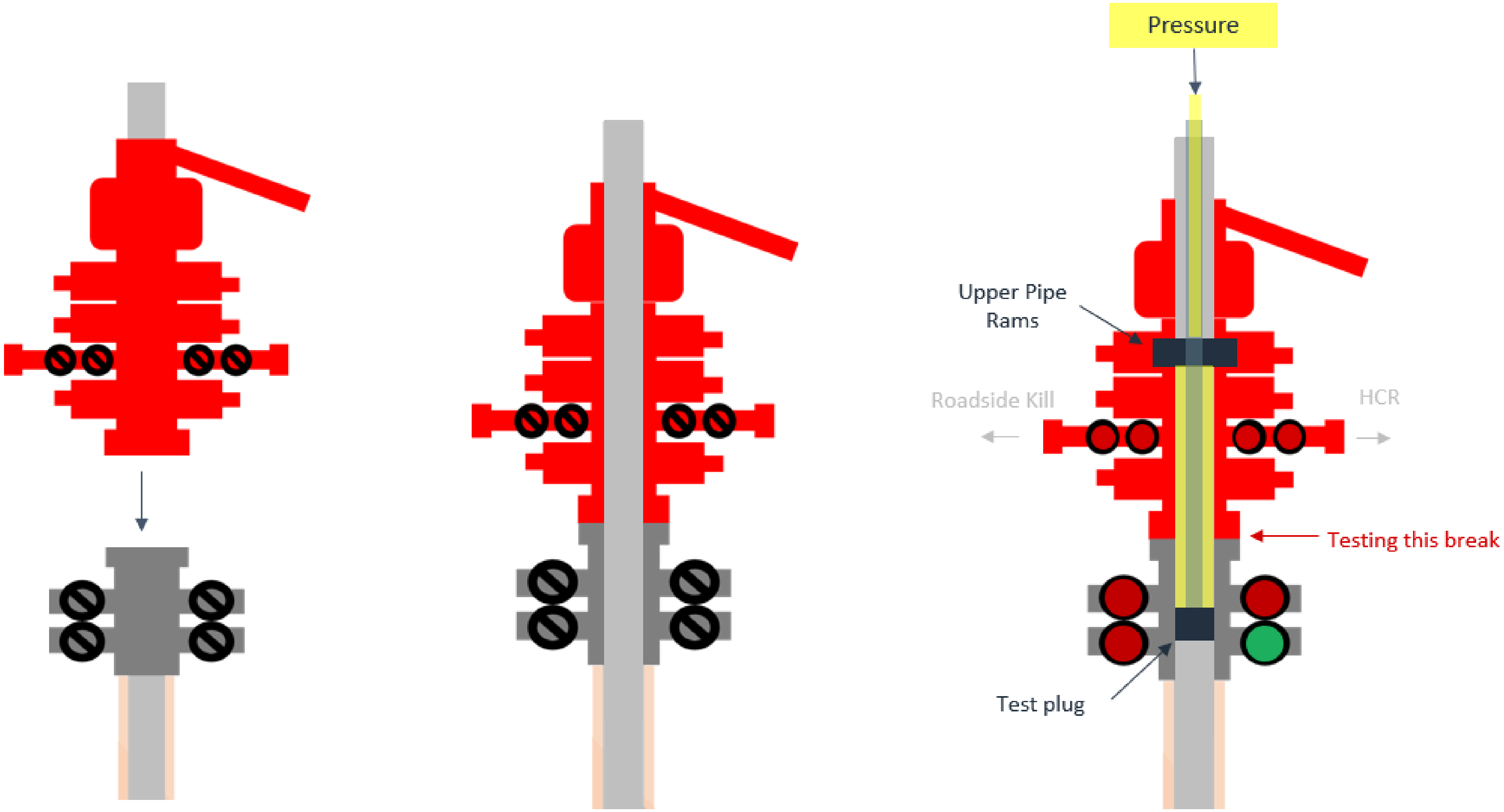
BOPE Break Test Variance

EOG BOPE Break Test Variance (Intervals 5M MASP or less)

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.**
- **Break-test only available for the Base of the Wolfcamp or shallower**
    - If anything out of the ordinary is observed during drilling, tripping or casing running operations in the production hole section, break testing will not be performed in the subsequent well's production hole section.
    - Furthermore, break testing in the production hole section will not be performed if offset frac operations are observed within 1 mile and within the same producing horizon.
- **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 → during each full BOPE test and at least weekly
    - Pipe Rams → Every trip and on trip ins where FIT required
    - Blind Rams → Every trip
- **Break testing BOP and BOPE coupled with batch drilling operations and option to offline cement and/or remediate (if needed) any surface, intermediate or production 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 (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

Offline Surface + Intermediate Variance

Offline Surface + Intermediate Cement

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.

Offline Surface + Intermediate Cement

   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.

Offline Surface + Intermediate Cement

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.

Offline Surface + Intermediate Cement

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.

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

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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.

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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.

Offline Surface + Intermediate Cement

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>

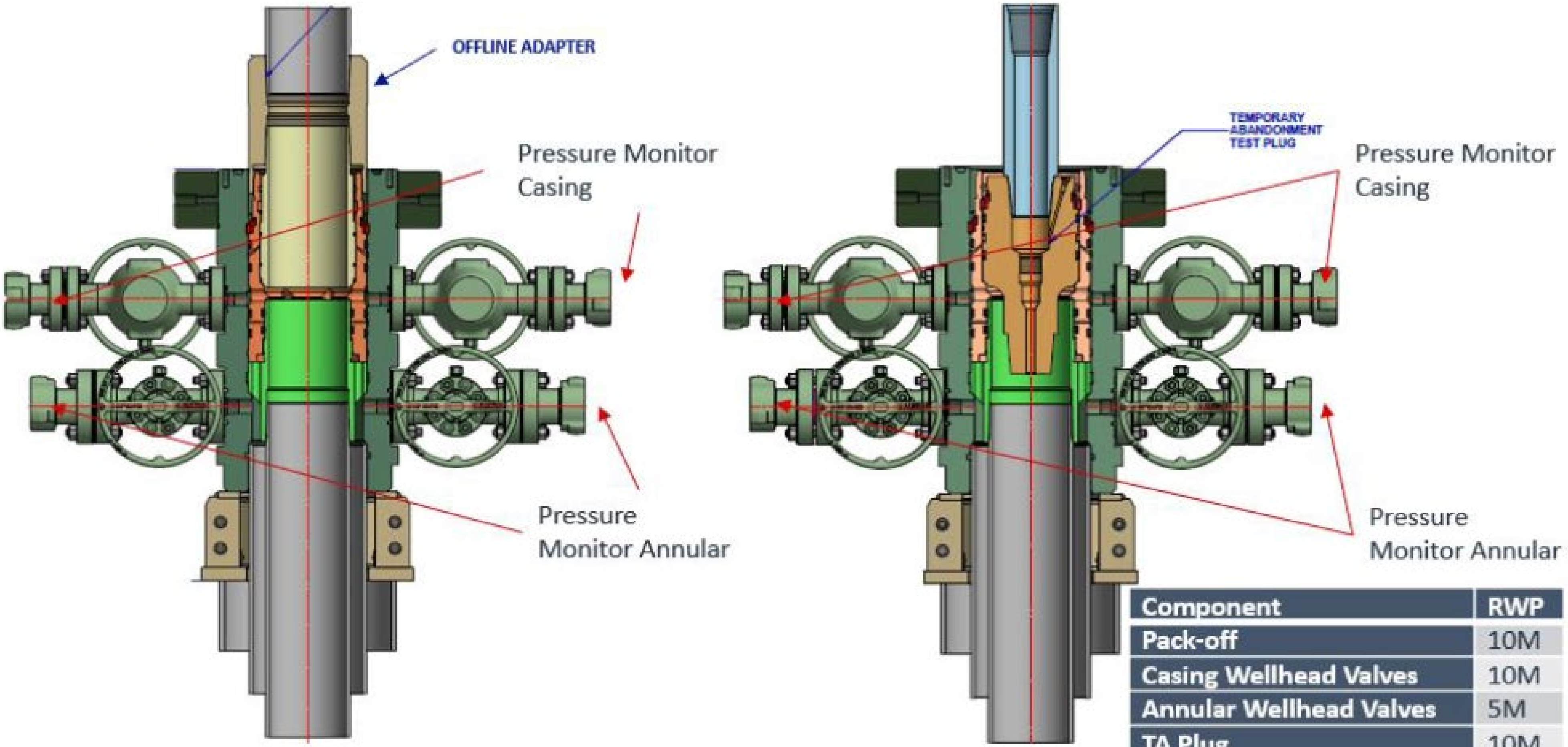
1. Sound alarm (alert crew).
2. Shut down pumps.
3. Shut-in Well (close valves to rig pits and open valve to rig choke line. Rig choke will already be in the closed position).
4. Confirm shut-in.
5. Notify tool pusher/company representative.
6. Open rig choke and begin pumping again taking returns through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

Offline Surface + Intermediate Cement

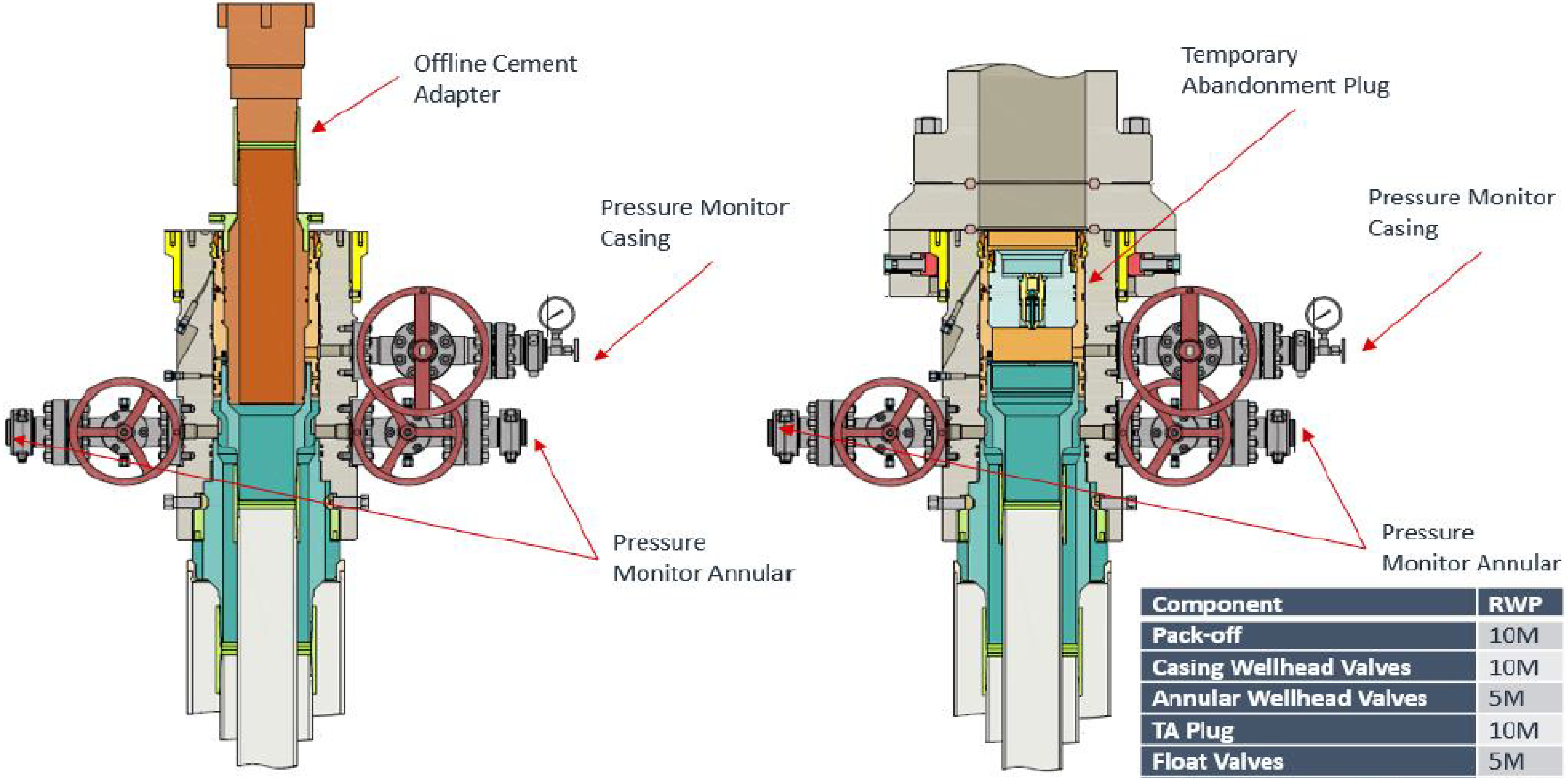
Figure 1: Cameron TA Plug and Offline Adapter Schematic



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

Offline Surface + Intermediate Cement

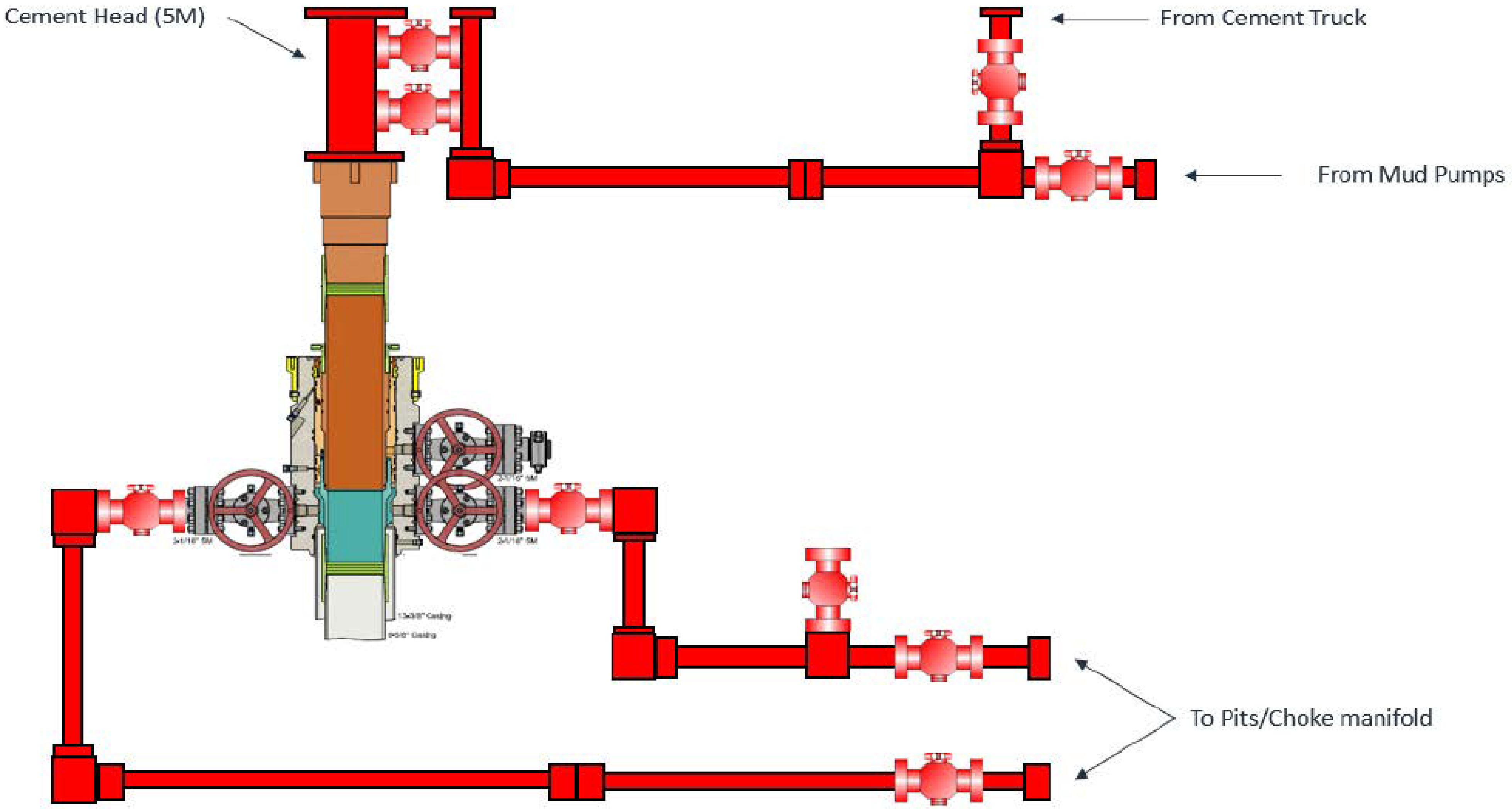
Figure 2: Cactus TA Plug and Offline Adapter Schematic



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

Offline Surface + Intermediate Cement

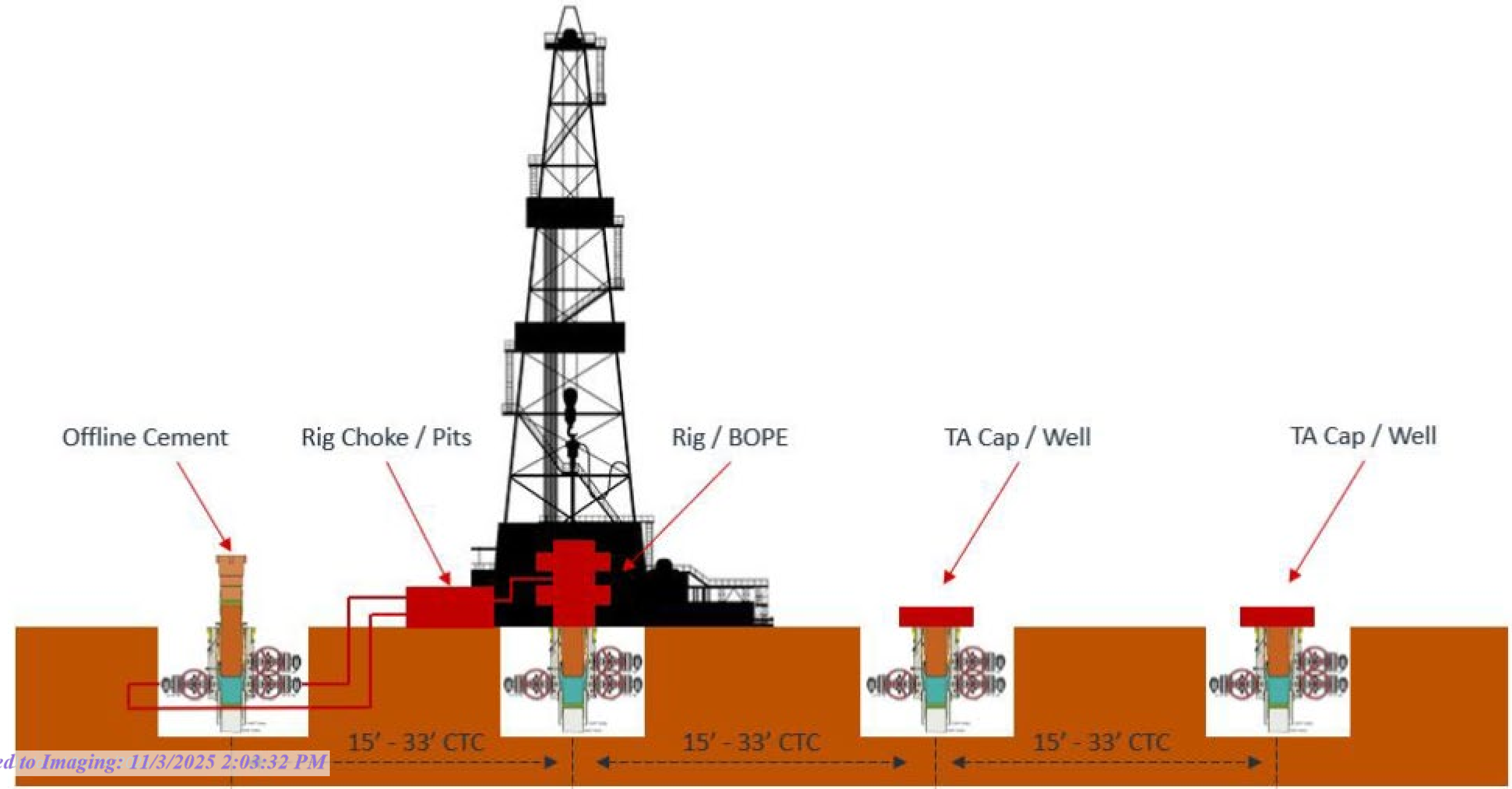
Figure 3: Back Yard Rig Up



*** All Lines 10M rated working pressure

Offline Surface + Intermediate Cement

Figure 4: Rig Placement Diagram



Intermediate Bradenhead Cement Variance

Intermediate Bradenhead Cement

Deep Target Intermediate Bradenhead:

EOG requests variance from minimum standards to pump a two stage cement job on the intermediate casing string when set below the Delaware Mountain Group with the first stage being pumped conventionally with the calculated top of cement at the Brushy Canyon and the second stage bradenhead squeezed to be performed at a minimum of 50% of OH excess (typically increased to ~1,000 sacks) with planned cement from the Brushy Canyon to surface. If necessary, a top out consisting of Class C/H cement + additives (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.

Wolfcamp Intermediate Casing Setpoint

Intermediate Bradenhead Cement

EOG Resources Inc. (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 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 are applicable for the Base of the Wolfcamp or shallower.**
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 nipped down if:**
   - **a)** **ANY** barrier fails to test.
   - **b)** **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 nipped 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.**

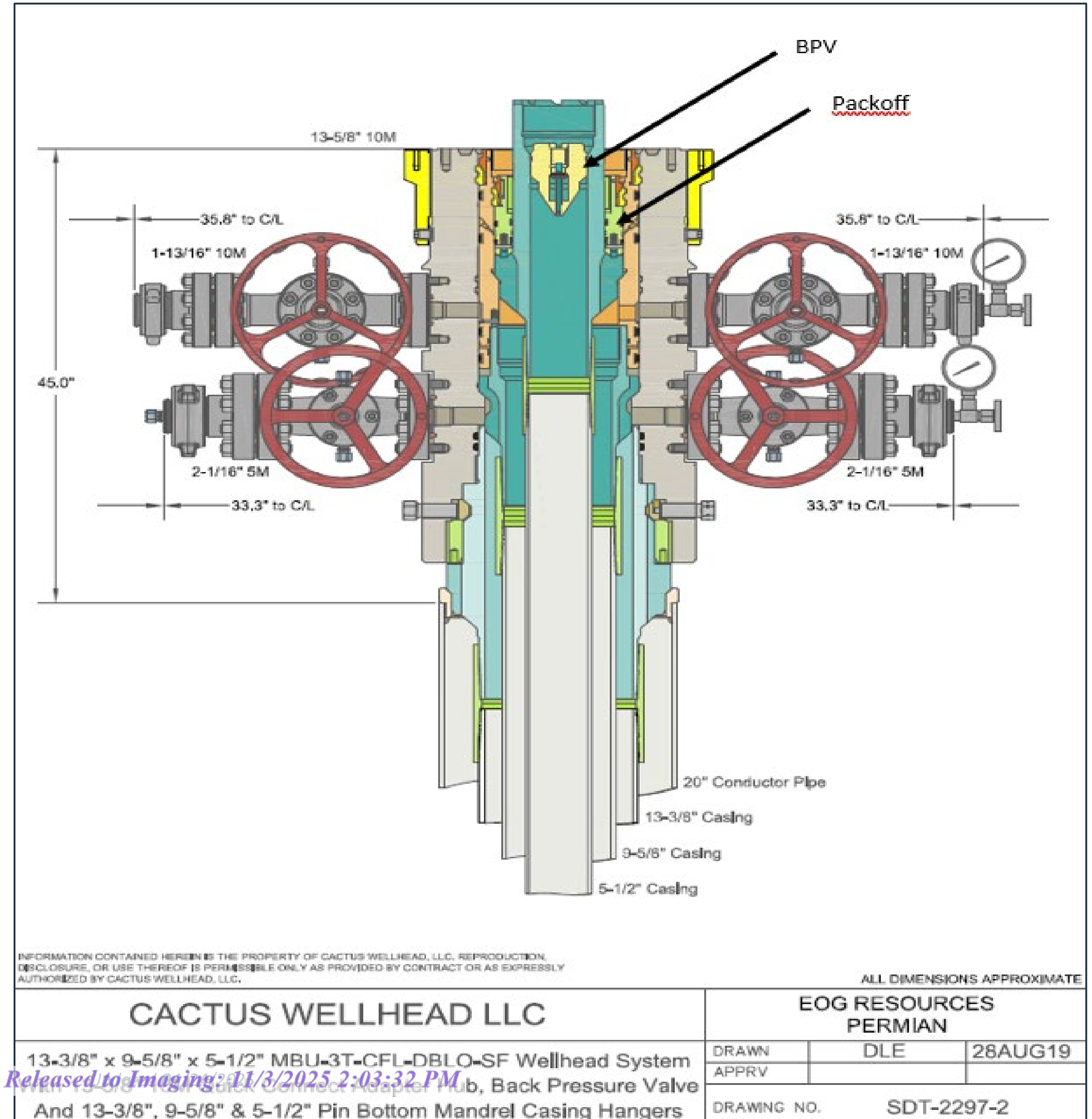
Offline Procedure

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.

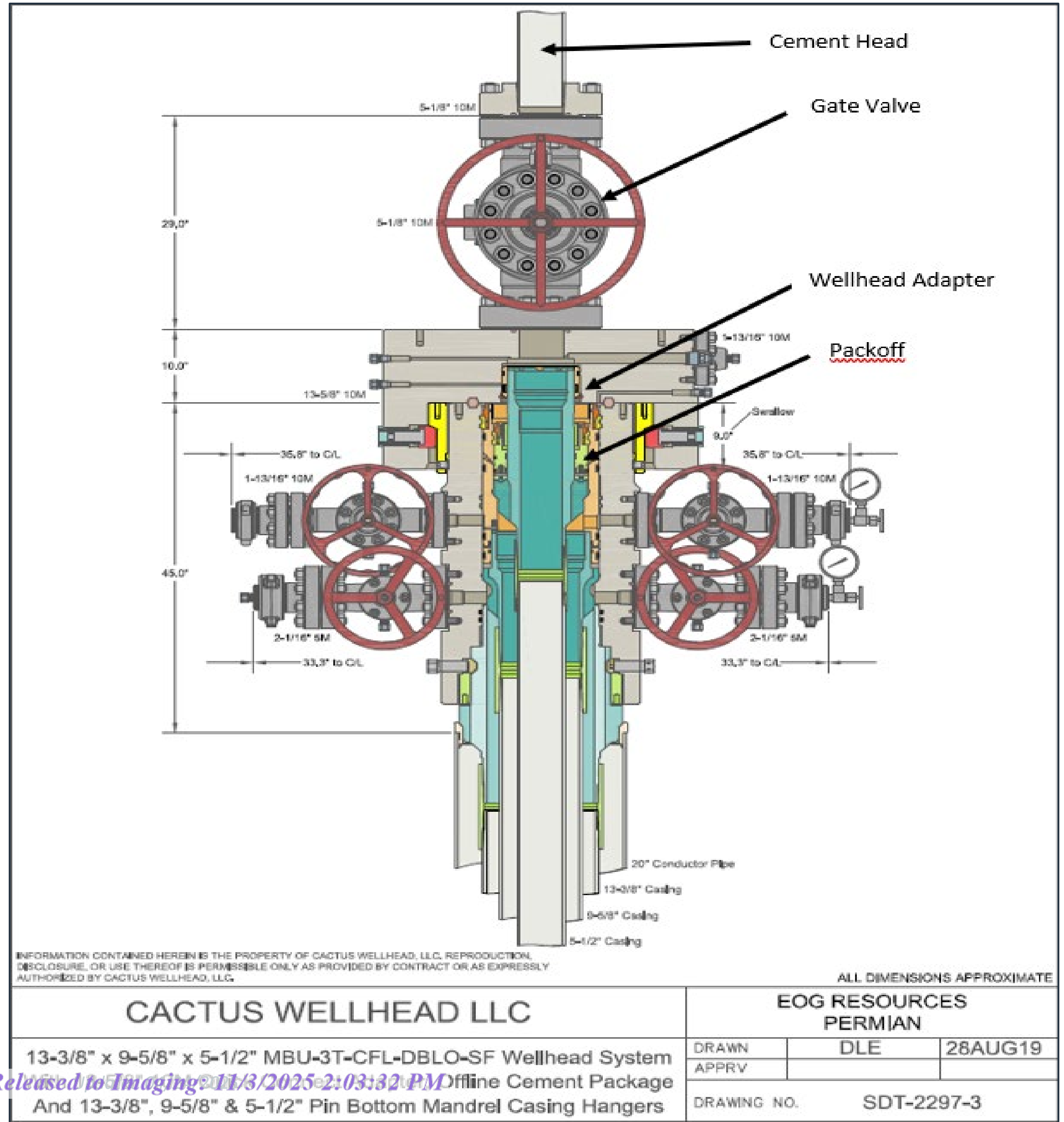
Offline Barrier Overview



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

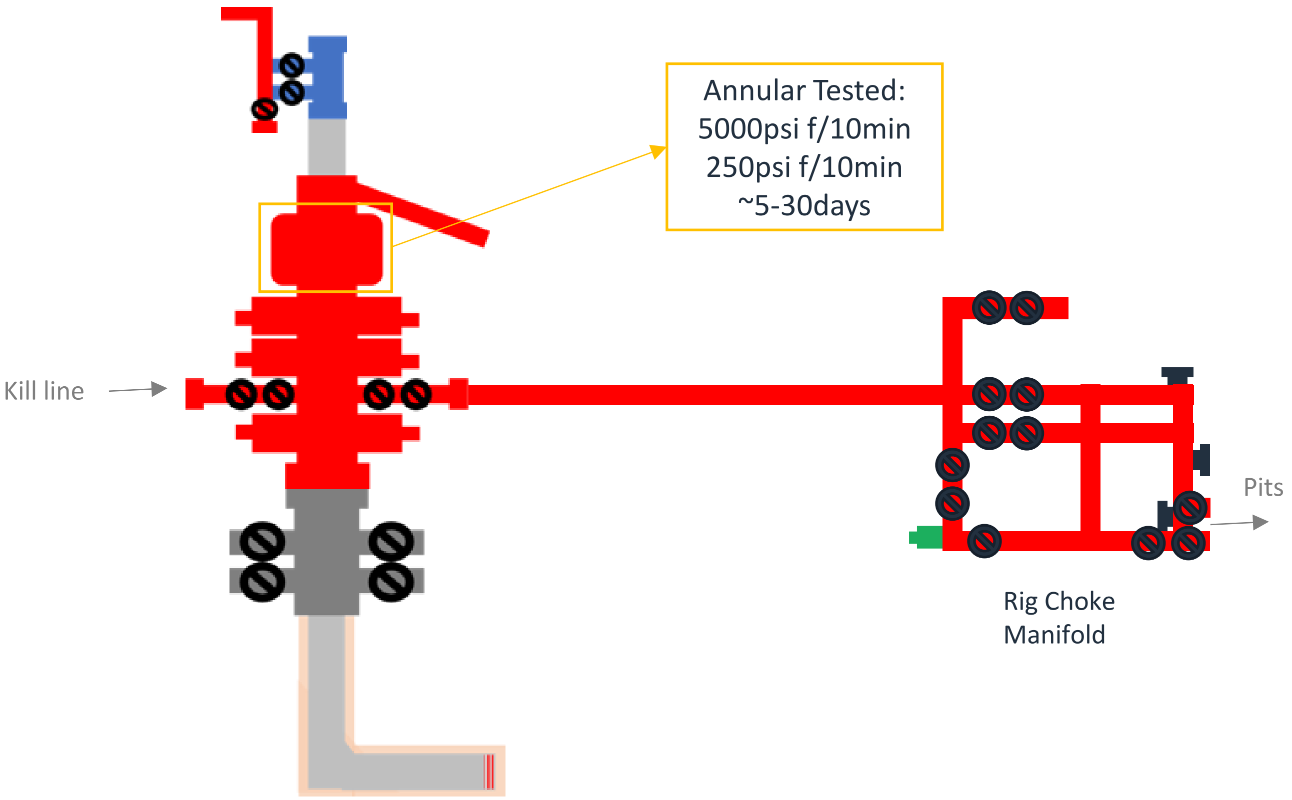
More Control: Meeting/Exceeding Barrier Requirements

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 ✓

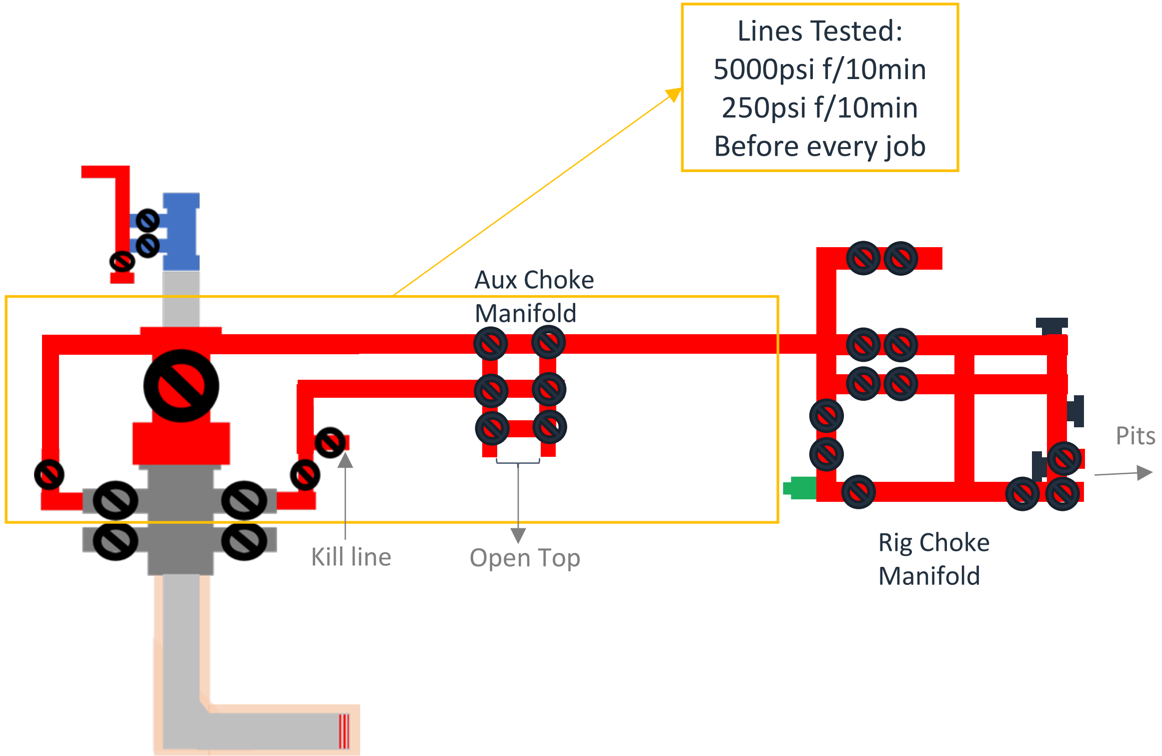
Annulus Barriers – Online vs Offline		
Operation	Online	Offline
Install Cement Head	1. Hydrostatic Barrier 2. Annular 3. VBR	1. Hydrostatic Barrier 2. Mechanical Pack-off 3. 10M Wellhead Adapter ✓
Cement Job	1. Hydrostatic Barrier 2. Annular 3. VBR	1. Hydrostatic Barrier 2. Mechanical Pack-off 3. 10M 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

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Production Bradenhead Cement Variance

Production Bradenhead Cement

Shallow Target Production 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.

Salt Section Annular Clearance

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

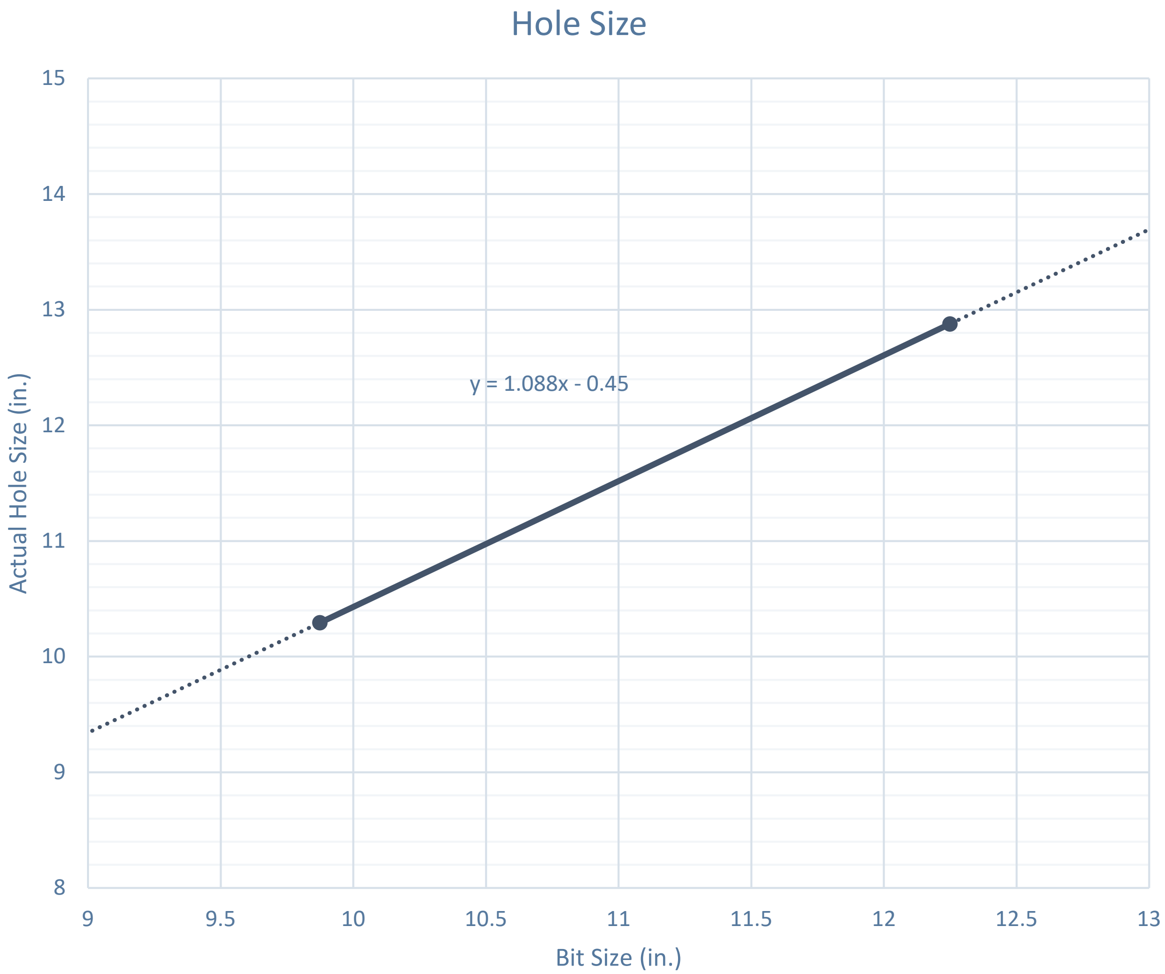
Volumetric Hole Size Calculation

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

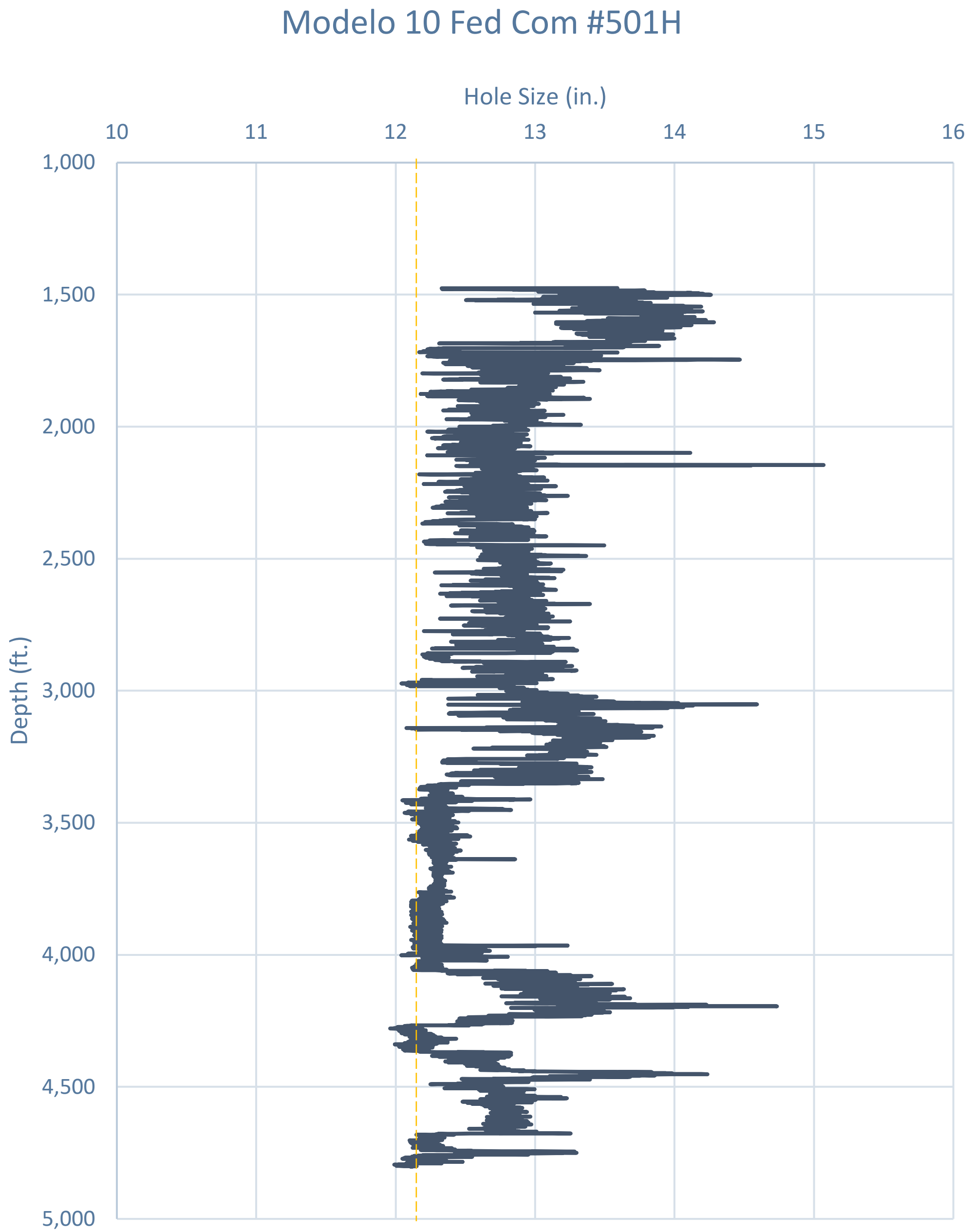
- 12.25” Hole
  - 12.88” Hole
    - 5.13% diameter increase
    - 10.52% area increase
  - 0.63” Average enlargement
  - 0.58” Median enlargement
  - 179 Well Count
- 9.875” Hole
  - 10.30” Hole
    - 4.24% diameter increase
    - 9.64% area increase
  - 0.42” Average enlargement
  - 0.46” Median enlargement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



Caliper Hole Size (12.25”)

Average Hole Size

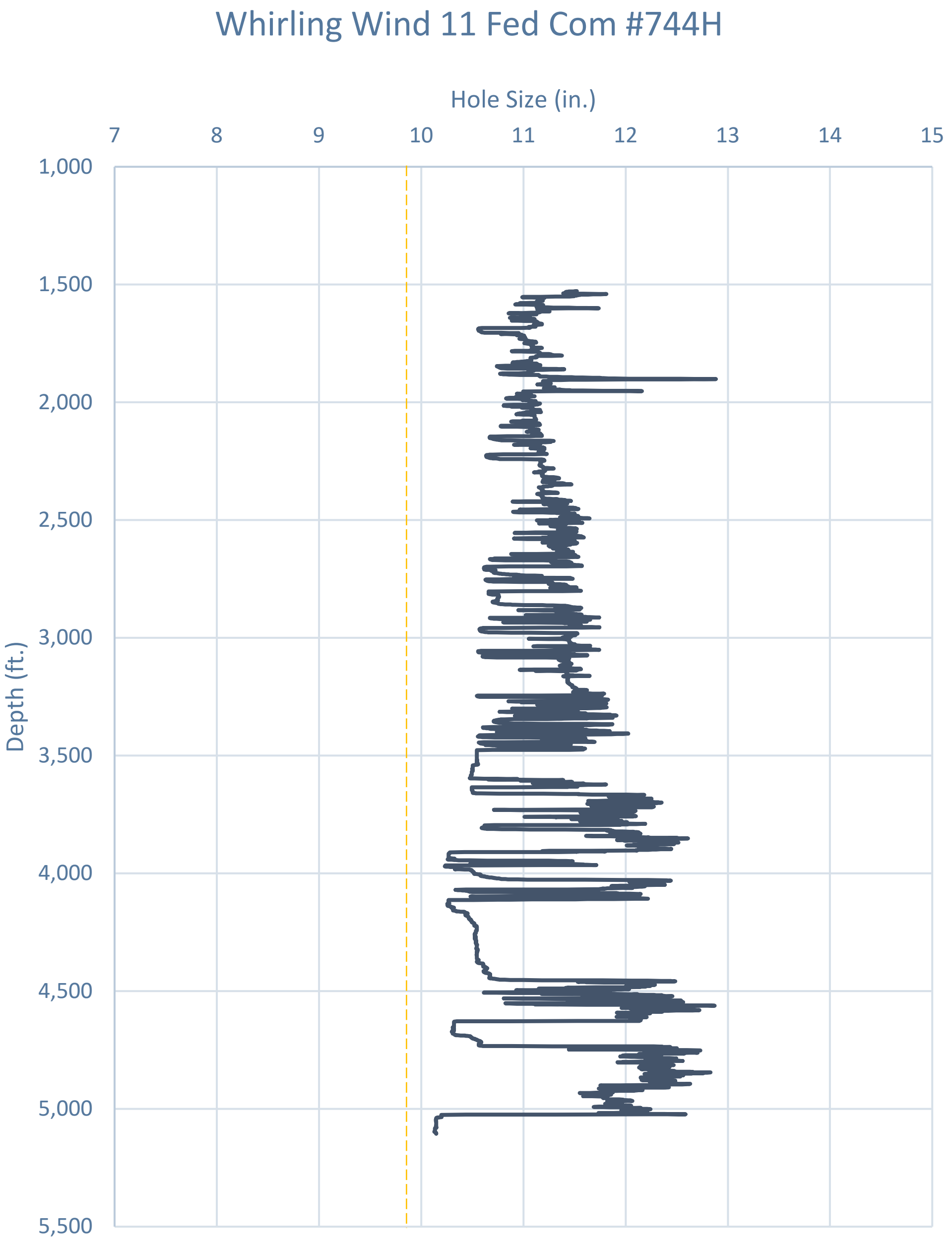
- 12.25” Bit
  - 12.76” Hole
    - 4.14% diameter increase
    - 8.44% area increase
  - 0.51” Average enlargement
  - 0.52” Median enlargement
  - Brine



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

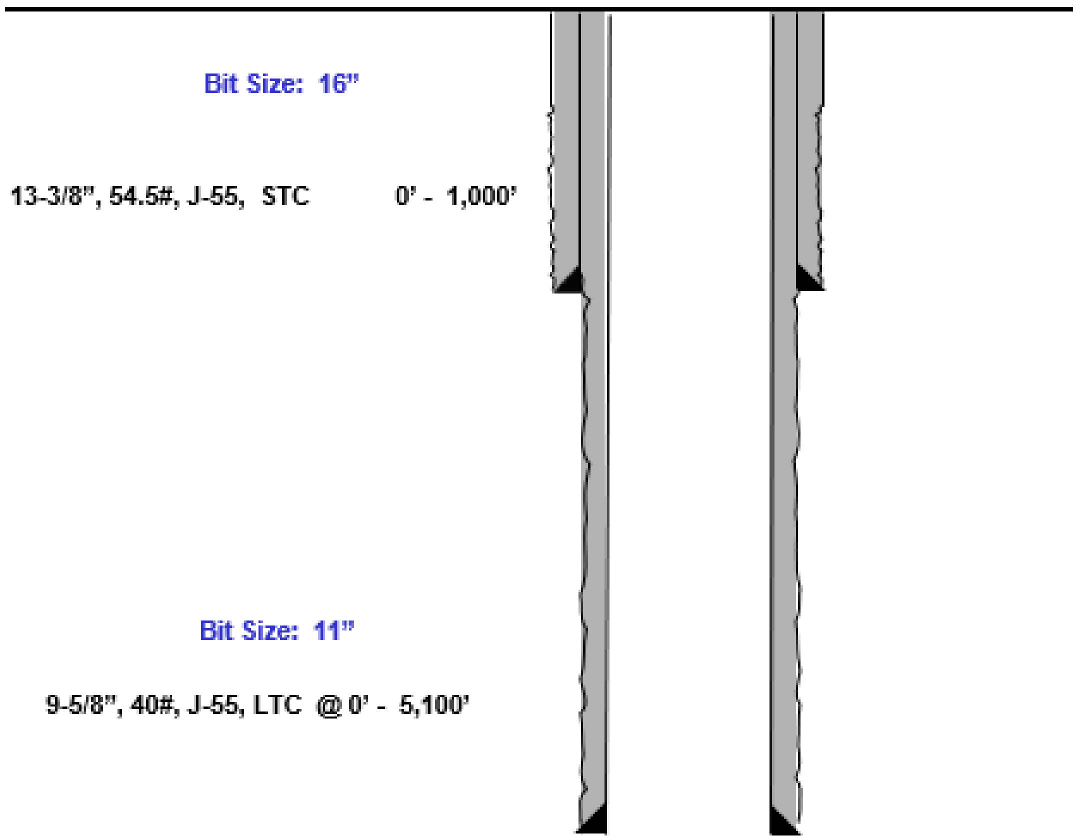
      $$= \frac{11.52 - 9.625}{2}$$

    - 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)

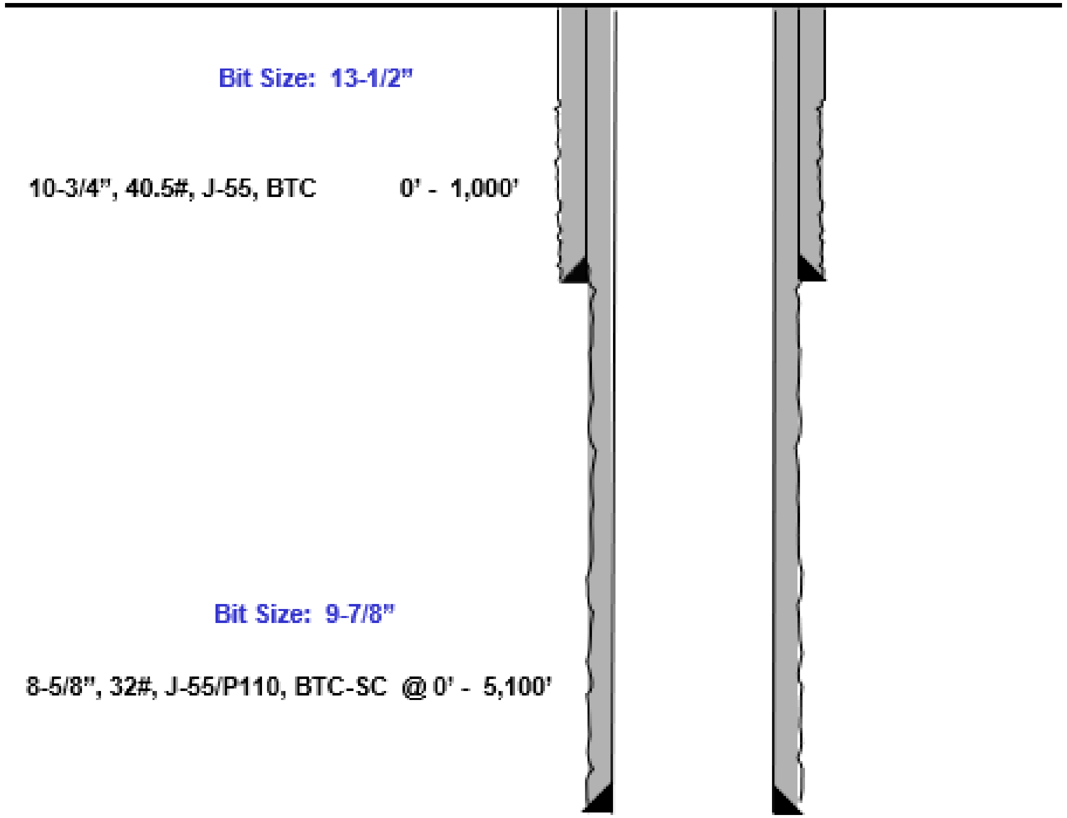
      $$= \frac{12.615 - 10.625}{2}$$



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



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Casing Spec Sheets

PERFORMANCE DATA

API LTC 9.625 in 40.00 lbs/ft K55 HC
Technical Data Sheet

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 »

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USC Metric

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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 »

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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 WO# 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:	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)

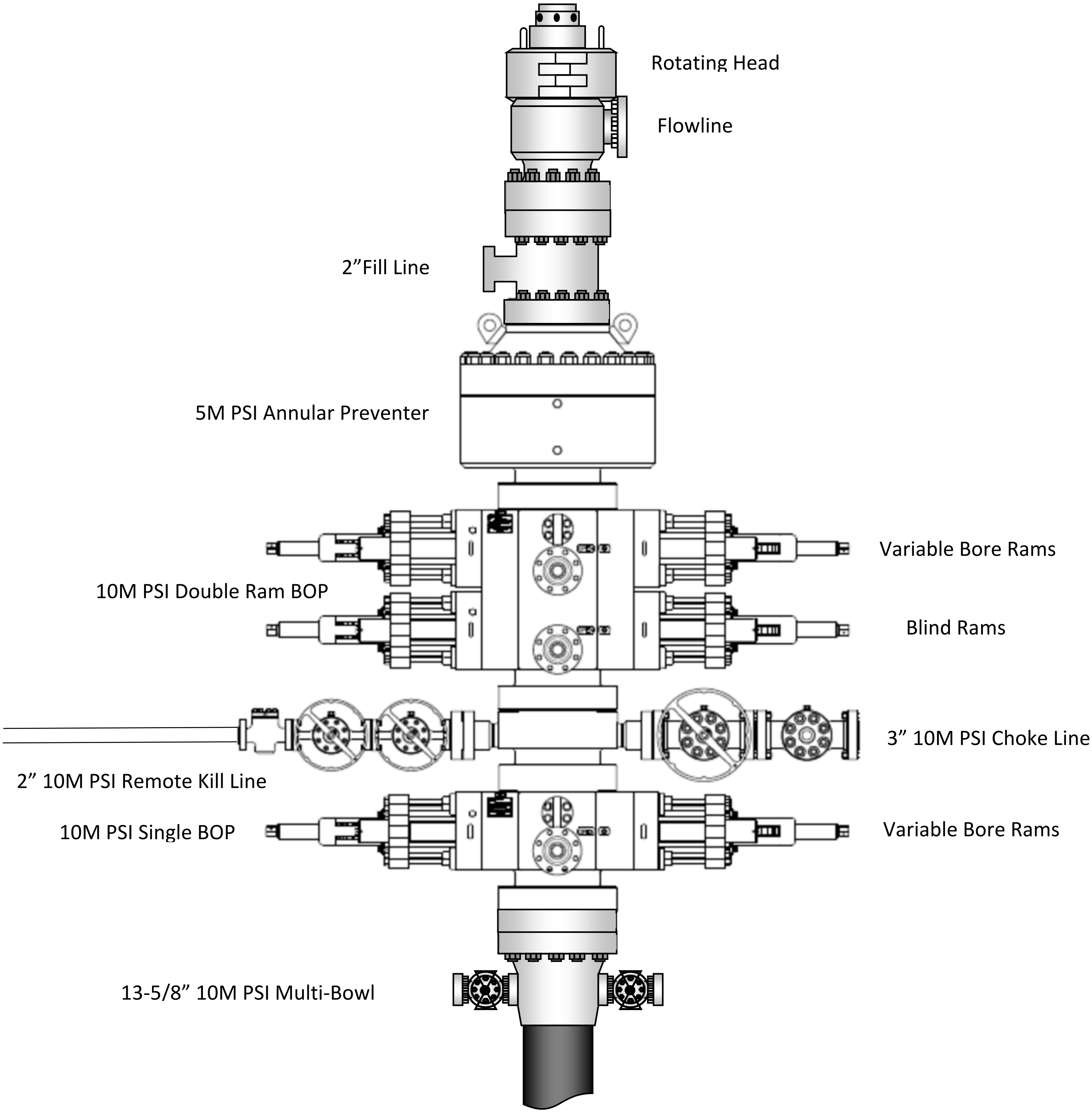
follow API guidelines regarding positional make up

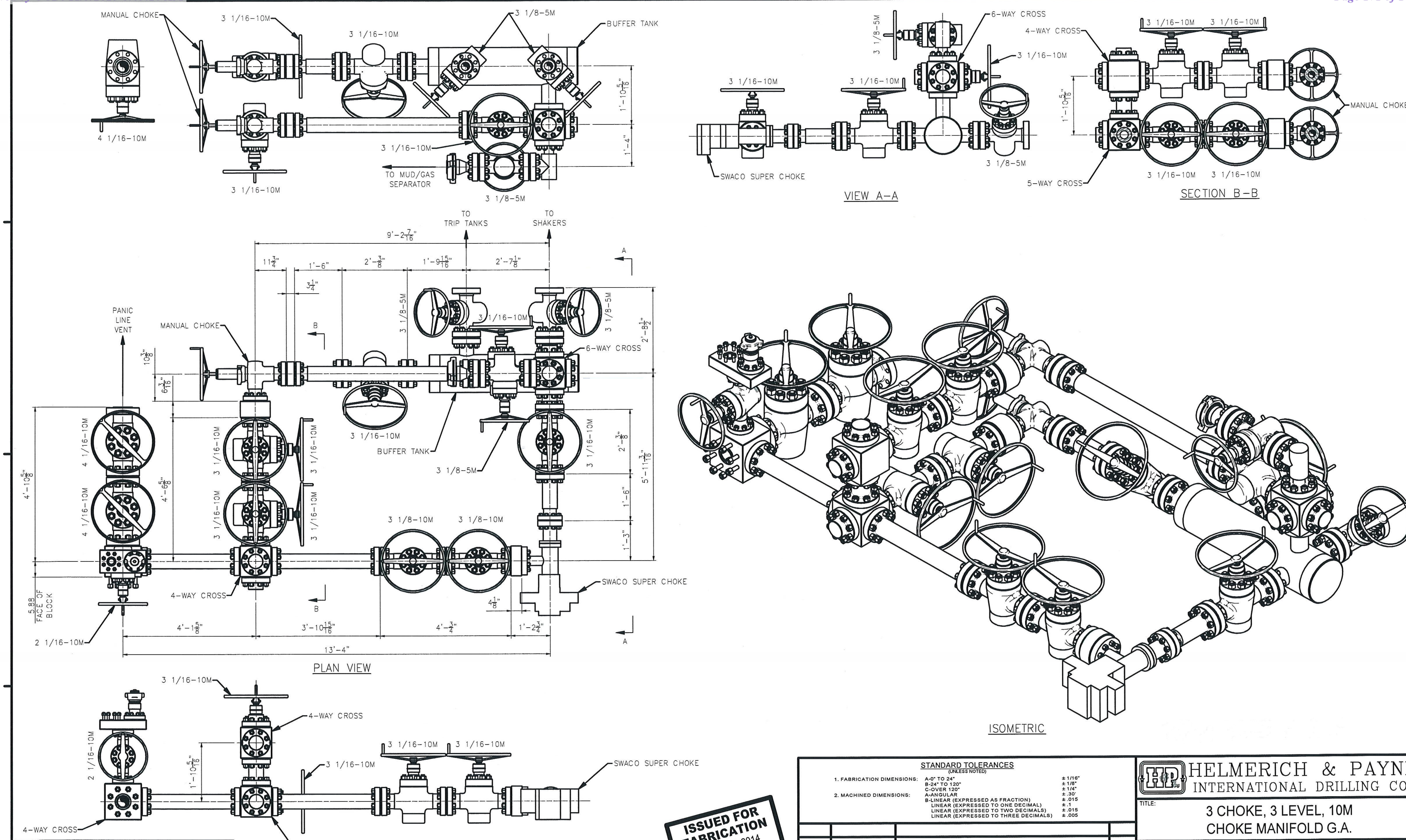
*Alt. Drift will be used unless API Drift is specified on order.

**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

Exhibit 1
EOG Resources
13-5/8" 10M PSI BOP Stack





STANDARD TOLERANCES
(UNLESS NOTED)

1. FABRICATION DIMENSIONS:
   - A-0" TO 24" ± 1/16"
   - B-24" TO 120" ± 1/8"
   - C-OVER 120" ± 1/4"
2. MACHINED DIMENSIONS:
   - A-ANGULAR ± .30'
   - B-LINEAR (EXPRESSED AS FRACTION) ± .015
   - LINEAR (EXPRESSED TO ONE DECIMAL) ± .1
   - LINEAR (EXPRESSED TO TWO DECIMALS) ± .015
   - LINEAR (EXPRESSED TO THREE DECIMALS) ± .005

REV	DATE	DESCRIPTION	BY
—			

ISSUED FOR FABRICATION
February-10-2014
DRAFTSMAN MWL
ENGINEER BRC

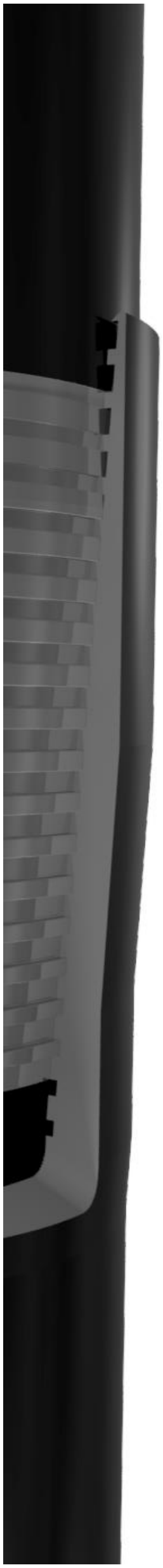
HELMERICH & PAYNE
INTERNATIONAL DRILLING CO.

TITLE: 3 CHOKE, 3 LEVEL, 10M CHOKE MANIFOLD G.A.

CUSTOMER: H&P

PROJECT:

DRAWN: MWL	DATE: 2/10/2014	DWG. NO.: HP-D1254	REV: —
SCALE: 3/4"=1'-0"	SHEET: 1 OF 1		



Issued on: 08 Jul. 2020 by Wesley Ott

VAM® SPRINT-SF
Connection Data Sheet

OD	Weight	Wall Th.	Grade	API Drift:	Connection
5 1/2 in.	20.00 lb/ft	0.361 in.	P110EC	4.653 in.	VAM® SPRINT-SF

PIPE PROPERTIES		
Nominal OD	5.500	in.
Nominal ID	4.778	in.
Nominal Cross Section Area	5.828	sqin.
Grade Type	High Yield	
Min. Yield Strength	125	ksi
Max. Yield Strength	140	ksi
Min. Ultimate Tensile Strength	135	ksi

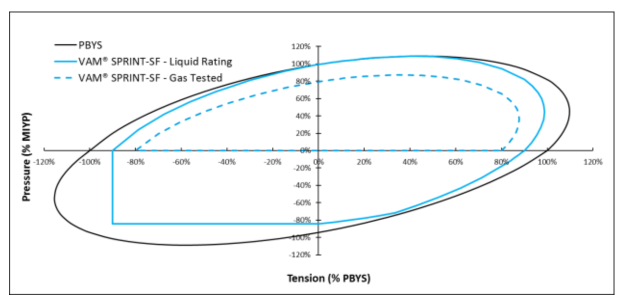
CONNECTION PROPERTIES		
Connection Type	Semi-Premium Integral Semi-Flush	
Connection OD (nom):	5.783	in.
Connection ID (nom):	4.717	in.
Make-Up Loss	5.965	in.
Critical Cross Section	5.244	sqin.
Tension Efficiency	90.0	% of pipe
Compression Efficiency	90.0	% of pipe
Internal Pressure Efficiency	100	% of pipe
External Pressure Efficiency	100	% of pipe

CONNECTION PERFORMANCES		
Tensile Yield Strength	656	klb
Compression Resistance	656	klb
Internal Yield Pressure	14,360	psi
Collapse Resistance	12,080	psi
Max. Structural Bending	89	°/100ft
Max. Bending with ISO/API Sealability	30	°/100ft

* 87.5% RBW

TORQUE VALUES		
Min. Make-up torque	20,000	ft.lb
Opt. Make-up torque	22,500	ft.lb
Max. Make-up torque	25,000	ft.lb
Max. Torque with Sealability (MTS)	40,000	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.



VAM USA

Pipe Body and API Connections Performance Data

10.750 40.50/0.350 J55

PDF

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USC Metric

6/8/2015 10:14:05 AM

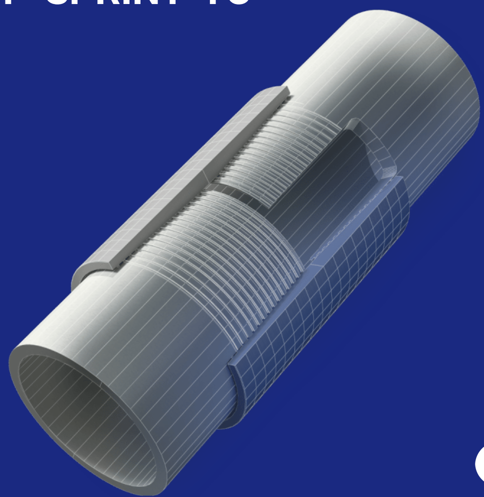
Mechanical Properties	Pipe	BTC	LTC	STC	
Minimum Yield Strength	55,000	--	--	--	psi
Maximum Yield Strength	80,000	--	--	--	psi
Minimum Tensile Strength	75,000	--	--	--	psi
Dimensions	**Pipe**	**BTC**	**LTC**	**STC**	
Outside Diameter	10.750	11.750	--	11.750	in.
Wall Thickness	0.350	--	--	--	in.
Inside 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

Generated on November 28, 2023

CONNECTION DATA SHEET

OD: **6.000 in.** Grade: **P110 EC**
Weight: **24.50 lb/ft** Drift: **5.075 in. (API)**
Wall Th.: **0.400 in.**

VAM® SPRINT-TC



T&C

Field Torque Values

Make-up Torque (ft-lb)
- 25,000 MIN
- 26,000 OPTI
- 27,000 MAX

Torque with Sealability (ft-lb)
- 52,600 MTS

Locked Flank Torque (ft-lb)
- 1,300 MIN
- 18,200 MAX

(2) MTS: Maximum Torque with Sealability.
Note: Thread compound must be applied as a thin even layer

PIPE BODY PROPERTIES

Nominal OD	6.000	in.
Nominal ID	5.200	in.
Nominal Wall Thickness	0.400	in.
Minimum Wall Thickness	87.5	%
Nominal Weight (API)	24.50	lb/ft
Plain End Weight	23.95	lb/ft
Drift	5.075	in.
Grade Type	High Yield	
Minimum Yield Strength	125	ksi
Maximum Yield Strength	140	ksi
Minimum Ultimate Tensile Strength	135	ksi
Pipe Body Yield Strength	880	klb
Internal Yield Pressure	14,580	psi
Collapse Pressure	12,500	psi

CONNECTION PROPERTIES

Connection Type	Semi-Premium Threaded & Coup	
Nominal Connection OD	6.525	in.
Nominal Connection ID	5.267	in.
Make-up Loss	4.283	in.
Coupling Length	8.831	in.
Tension Efficiency	100	% Pipe Body
Compression Efficiency	100	% Pipe Body
Internal Pressure Efficiency	100	% Pipe Body
External Pressure Efficiency	100	% Pipe Body

JOINT PERFORMANCES

Tension Strength	880	klb
Compression Strength	880	klb
Internal Pressure Resistance	14,580	psi
External Pressure Resistance	12,500	psi
Maximum Bending, Structural	95	°/100 ft
Maximum Bending, with Sealability(1)	30	°/100 ft
Maximum Load on Coupling Face	373	klb

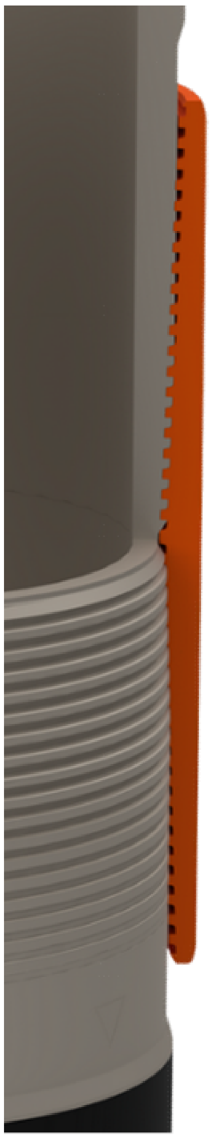
(1) Sealability rating demonstrated as per API RP 5C5 / ISO 13679

GBCONNECTIONS
ENGINEERING THE RIGHT CONNECTIONS

GB Connection Performance Properties Sheet

Rev. 0 (11/22/2024)

E N G I N E E R I N G   T H E   R I G H T   C O N N E C T I O N S



Casing: 8.625 OD, 32 ppf
Casing Grade: Borusan HSCY P110 (95% RBW)
Connection: GB CD Slim Hole 9.000
Coupling Grade: API P-110

PIPE BODY GEOMETRY					
Nominal OD (in.)	8 5/8	Wall Thickness (in.)	0.352	Drift Diameter (in.)	7.796
Nominal Weight (ppf)	32.00	Nominal ID (in.)	7.921	API Alternate Drift Dia. (in.)	7.875
Plain End Weight (ppf)	31.13	Plain End Area (in.^{2})	9.149	Plain End Area OD Turn (in.^{2})	7.936

PIPE BODY PERFORMANCE**					
Material Specification	usan HSCY P110 (95% R	Min. Yield Str. (psi)	125,000	Min. Ultimate Str. (psi)	130,000
Collapse		Tension		Pressure	
API (psi)	3,470	Pl. End Yield Str. (kips)	1,144	Min. Int. Yield Press. **(psi)	9,690
High Collapse** (psi)	4,530	Torque		Bending	
		Yield Torque (ft-lbs)	189,540	Build Rate to Yield (°/100 ft)	66.4

GB CD Slim Hole 9.000 COUPLING GEOMETRY			
Coupling OD (in.)	9.000	Makeup Loss (in.)	5.0000
Coupling Length (in.)	10.000	Critical Cross-Sect. (in.^{2})	8.704

GB CD Slim Hole 9.000 CONNECTION PERFORMANCE RATINGS/EFFICIENCIES						
Material Specification	API P-110	Min. Yield Str. (psi)		110,000	Min. Ultimate Str. (psi)	125,000
Tension		Efficiency			Bending	
			Gas	Liquid***		
Tension OD Turn (kips)	992	Internal Pressure (%)	80%	100%	Build Rate to Yield (°/100 ft)	52.4
Thread Str. (kips)	948	External Pressure (%)	100%		Yield Torque	
Min. Tension Yield (kips)	910	Tension (%)	90%		Yield Torque (ft-lbs)	60,200
Min. Tension Ult. (kips)	1,034	Compression (%)	90%			
Joint Str. (kips)	948	Ratio of Areas (Cplg/Pipe)	0.95			
		Ratio of Areas (Cplg/OD Turn)	1.10			

MAKEUP TORQUE					
Min. MU Tq. (ft-lbs)	10,000	Max. MU Tq. (ft-lbs)	20,000	Running Tq. (ft-lbs)	See GBC RP
				Max. Operating Tq. (ft-lbs)*	57,190

Units: US Customary (lbm, in., °F, lbf)
1 kip = 1,000 lbs
* See Running Procedure for description and limitations.
See attached: Notes for GB Connection Performance Properties.
GBC Running Procedure (GBC RP): www.gbconnections.com/resources/running-procedures/
Blanking Dimensions: www.gbconnections.com/resources/documentation/#blanking-dimensions
Connection yield torque rating based on physical testing or extrapolation therefrom
** Casing properties applicable to Borusan HSCY P110 (95% RBW) grade with min. yield 125 ksi.
***Liquid Sealability for operational (frac) loading
GB CD Slim Hole US Patent Pending

GBCONNECTIONS
ENGINEERING THE RIGHT CONNECTIONS

GB Connections LLC - Notes for Connection Performance Properties

Rev. 3 (Feb. 2024)

ENGINEERING THE RIGHT CONNECTIONS™

1. The data provided in GB Connections LLC ("GBC") - Notes for Connection Performance Properties ("Notes"), and in GBC - Running Procedures for Casing ("Running Procedures"), are for general informational purposes only and do not constitute professional advice. The GBC Notes and Running Procedures and are intended to be, and should be, supplemented with the professional judgment of qualified personnel selected by the Buyer and/or User ("Customer") for specific applications. These Notes should not be relied upon for any specific application, including those applications in which the Customer requires modifications to GBC's standard product specifications.
2. The professional judgment of qualified personnel selected by the Customer should be utilized for all aspects of a specific application, including but not limited to, the well design, selection of suitable materials for site-specific well conditions, field handling, deployment, and all other well operations, including any casing and/or connection related issues that may occur during and after rotating operations.
3. GBC Terms and Conditions of Sale are incorporated herein by reference and may be accessed at: www.gbconnections.com/pdf/Terms-and-Conditions.pdf. These Notes do not negate or otherwise modify GBC Terms and Conditions of Sale, including those Warranties found in Paragraph 10 ("Warranty; Disclaimer").
4. All dimensions shown are nominal. Plain end weight is calculated in accordance with API TR 5C3. Performance properties are empirical, based on nominal dimensions, minimum material yield and ultimate strengths, and calculated in general accordance with industry standard formula(s) assuming uniaxial loading. All properties are calculated with material strengths at room temperature. **NOTE: Material properties change with temperature.**
5. Joint strength is the lesser of pipe thread strength and minimum coupling tension as calculated in accordance with API TR 5C3. Tensile efficiency is calculated using coupling strength based on ultimate material strength per API TR 5C3 divided by plain end yield strength of the casing. **Minimum Coupling Tension based on material yield strength is provided for information only**. Performance values presented for tension do not account for failure by pull-out (which can occur unexpectedly under certain circumstances), effects of internal and external pressure, thermally induced axial loads, casing curvature (bending), and/or other static and dynamic loads that may occur singularly or in combination during downhole deployment and with subsequent well operations.
6. Drift diameters are based on Standard and Alternate drift sizes per API 5CT. Drift diameters are not specified for API 5L pipe. Drift diameters shown on the Performance Property Sheets for GBC connection products represent the diameter of the drift mandrel used for end-drifting after coupling buck on. When shown, the alternate drift diameter is used for end drifting. Drift testing is performed in accordance with currently applicable API Specifications.
7. Minimum Internal Yield Pressure Performance values for Casing (API 5CT), Line Pipe (API 5L), and mill casing proprietary grades are based on API TR 5C3 formulas and assume 87.5% minimum wall thicknesses unless otherwise noted. Minimum Internal Yield Pressure efficiency for GBC is the lesser of the Minimum Internal Yield Pressure of the coupling and Leak Resistance divided by pipe body Minimum Internal Yield Pressure (all based on API TR 5C3 formulas). GBC products typically demonstrate pressure resistance exceeding the mating pipe body with a pressure efficiency > 100%. Certain casing size, weight, grade, and connection combinations may have gas pressure efficiency < 100% and will be so noted. Pressure efficiency can only be achieved when connections are properly assembled in strict accordance with GBC Running Procedures, which may be accessed at: www.gbconnections.com/pdf/RP-GB-DWC-Connections.pdf.
8. Compression efficiency of the Casing/Connection combinations does not consider the axial load that causes pipe body buckling. The compressive load that causes buckling is usually less than the pipe body compressive yield strength and is dependent on many factors including, but not limited to, string length (or slenderness ratio; L/D), thermally induced axial loads, and annular clearance that may (or may not) lend side support to the casing string.
9. Bending values assume a constant radius of curvature where the casing is in uniformly intimate contact with the wall of the wellbore (i.e. when the upset at the coupling OD is small compared with wellbore wall irregularities). When the radius of curvature is not constant due to large wellbore wall irregularities or where there is not uniformly intimate contact with the wellbore wall, varying trajectory, micro doglegs, wash-outs, rock ledges, and other downhole conditions, unpredictable and unquantifiable excessive bending stresses can occur that may be detrimental to casing and connection performance.
10. Fatigue failures are a function of material properties, stress range, and number of stress reversal cycles. API 5CT, API 5L, and mill proprietary casing/coupling materials have a finite fatigue life. Higher stress ranges yield lower fatigue life. So, as a general rule of thumb, casing should never be rotated at higher RPMs than needed for task accomplishment. For the same stress range, casing rotated at 25 RPMs will generally last 4 times longer (more rotating hours) than casing rotated at 100 RPMs. However, with fatigue, there are opportunities for unexpected higher stress reversal levels (cycles) associated with vibration, thermally induced axial loads, and bending (see above) in addition to all other stress reversals imparted during running, rotating, reciprocating, pressure testing, pumping, etc. The extent and quality of the cement job is also a factor. Under aggressive, high-volume, multi-stage hydraulic fracturing operations, the casing string (including the connections) is severely taxed such that local stress range(s) and actual number of applied cycles cannot be precisely determined without full string instrumentation.
11. External pressure efficiency (expressed in percent) is the ratio of the lesser of Minimum Internal Yield Pressure and Leak Resistance for coupling (calculated per API TR 5C3) divided by the API collapse rating of the casing. External pressure efficiency has not been verified by testing and does not consider other applied loads. External pressure efficiency does not account for any high collapse rating that may be shown on GBC Performance Property Sheets.
12. **Maximum Makeup Torque is provided for guidance only**. Customer assumes all risks associated with casing and connection related issues that occur during and after rotating operations and should rely upon the professional judgment of qualified personnel to address casing and connection related issues that occur during and after rotating operations for specific applications. This value is not the same as the Connection Yield Torque shown. Connection Yield Torque is the lowest yield torque rating for the critical cross-section of pipe body, connector body, pin nose, and the threadform load flank bearing area. Connection Yield Torque does not consider radial buckling of the pipe or connection due to excessive jaw pressure during torque application. Torque in connections can increase or decrease over that applied at makeup (connection tightening/loosening) with rotating and stimulation operations due to slip-stick, shock loads, bending, tight spots, vibration(s), temperature, and other downhole factors that may occur individually or in combination.
13. **Every GBC connection requires the proper amount and distribution of thread compound to all pin and coupling threads and careful field make up in strict accordance with GBC Running Procedures to provide expected levels of performance in service**. GBC Running Procedures may be accessed at: www.gbconnections.com/pdf/RP-GB-DWC-Connections.pdf.
14. Reactions among water, drilling muds and other fluids, and chemicals introduced by Customer with downhole formation fluids may result in an environment detrimental to casing and connection performance. Customer should carefully consider all aspects of the string design including material compatibility with respect to possible corrosion, sour conditions, possible reaction(s) among user introduced water and chemicals (liquids and solids) with in situ geochemistry and other factors that may result in unexpected casing and/or connection failure at or below published ratings.
15. These Notes and the Performance Properties described herein, as well as the Running Procedures and the information contained therein, are subject to change without notice. The Notes and the Running Procedures are not controlled documents. These Notes are provided on an "as is" basis, no warranty, express or implied, is given, and GBC does not assume any liability or responsibility for the information contained herein. Anyone making use of the information contained in the Notes or Running Procedures does so at their own risk and assumes any and all liability from such use.
16. Customer is advised to obtain the current GBC Performance Property Sheet for each GBC connection product purchased, which are available on a product-by-product basis, at GBC's website: www.gbconnections.com.

Limitations:

All sales made by GBC are subject to its Terms and Conditions of Sale, which are incorporated herein by reference, and may be accessed at: www.gbconnections.com/pdf/Terms-and-Conditions.pdf. By using the GBC Notes and/or the GBC Running Procedures, or upon the purchase of any GBC product(s), Customer warrants, represents and agrees that it has utilized its own knowledge, skill, and judgment, and determined that the GBC product(s) purchased is fit for its intended service, purpose, and use. Customer warrants, represents and agrees that it has read and understands the GBC Terms and Conditions of Sale and agrees to be bound thereby.

GBCONNECTIONS ENGINEERING THE RIGHT CONNECTIONS	Running Procedure for Casing with GB *Drilling with Casing* Connections	February 13, 2024
		Rev. 15

OVERVIEW

This field running procedure applies to makeup of **GB *Drilling with Casing*** (GB DwC) Connections which include GB CD, GB CDE, GB CD RDB, GB CD RDB WS, GB CD EHTQ and GB CD Slim Hole Connections with GB Butt (Buttress), GB 4P, and GB 3P thread forms. All GBC Connections are suitable for ***Running*** (standard casing applications), ***Rotating*** (to aid string advancement), ***Drilling*** (Drilling with Casing/Drilling with Liners), and with a special mandrel, ***Driving***. This procedure also applies to the legacy GB Connections known as GB Butt and GB 3P.

Numerous factors impact the makeup torque of Buttress (GB Butt) and Modified Buttress Threads (such as GB 4P and GB 3P). Some of these factors include but are not limited to: allowable threading tolerances, joint characteristics (OD, straightness, hooked ends, and weight), vertical alignment (derrick, top drive, and elevator alignment relative to rotary table), thread compound (type, amount, and distribution), snub line (location and orientation), distance between tongs and backups, temperature/weather, equipment type, efficiencies (electrical, hydraulic, and mechanical), grips/dies (type, condition, orientation, location, contact area, and grip distribution), measurement equipment, gauge calibration, personnel, etc. The nature of these types of connections makes it impossible to provide makeup torque values that will yield proper power tight makeup on every rig under all circumstances with the wide variety of existing connection makeup equipment.

This procedure has been designed to determine the ***Running Torque*** required for proper power tight makeup of GB Connections under the circumstances and with the actual equipment, set up conditions, weather, etc. that exist at the time of running. With proper execution of this procedure, GB Connections will be properly and consistently assembled.

LIMITATIONS

GB Connections LLC ("GBC") provides the data and information in this Running Procedure for general informational purposes only in order to provide the User with basic recommended practices. This GBC Running Procedure does not constitute professional advice. This GBC Running Procedure is intended to be, and should be, supplemented with the professional judgment of qualified personnel selected by the Buyer and/or User for specific applications, including the observation of actual makeups throughout the casing run. **<u>Every GBC Connection requires the proper amount and distribution of thread compound to all pin and coupling threads and careful field make up in strict accordance with this Running Procedure to provide expected levels of performance in service</u>**

No structural component can perform satisfactorily if not properly prepared and assembled prior to placing it in service in a downhole environment. In the field, the USER has complete control over proper application of thread compound and field makeup. Therefore, the USER is ultimately responsible for the resulting performance downhole if the User does not follow the professional judgment of qualified personnel, the designer/manufacturer procedures, and/or basic industry best-practices on the rig floor.

The GBC Terms and Conditions of Sale are incorporated herein by reference and may be accessed at: www.gbconnections.com/pdf/Terms-and-Conditions.pdf. This Running Procedure does not negate or otherwise modify GBC Terms and Conditions of Sale. All sales made by GBC are subject to its Terms and Conditions of Sale, which are incorporated herein by reference, and may be accessed at: www.gbconnections.com/pdf/Terms-and-Conditions.pdf. By using this GBC Running Procedure, Buyer and/or User warrants, represents and agrees that it has utilized its own knowledge, skill, and judgment and determined that the GBC product(s) is fit for its intended service, purpose, and use. Buyer and/or User warrants, represents and agrees that it has read and understands the GBC Terms and Conditions of Sale and agrees to be bound thereby.

DEFINITIONS

1. Minimum Makeup (MU) Torque: Connections must have at least this amount of torque applied and clearly exhibit shoulder engagement with a delta torque spike.
2. Shoulder Torque: MU torque required to achieve shoulder engagement.
3. Running Torque: Developed at start of casing run per GBC Running Procedure and once established, used for the rest of the joints in the string, using data established with progression of the casing run. The ***Running Torque*** may be adjusted during the casing run as needed to stay within parameters defined here. The ***Running Torque*** will likely vary with each job due to the factors listed in the Overview section.
4. Delta Torque: Difference between ***Shoulder Torque*** and final makeup (or dump) torque.

5. Maximum Makeup (MU) Torque: **Maximum Makeup Torque provided herein is for guidance only.** Customer should rely upon the professional judgment of its qualified personnel to address casing and connection related issues that occur during and after rotating operations for specific applications. This value is not the same as the Connection Yield Torque shown. Connection Yield Torque is the lower yield torque rating for the critical cross-section of pipe body, connector body, pin nose, and the threadform load flank bearing area. Connection Yield Torque does not consider radial buckling of the pipe or connection due to excessive jaw pressure during torque application. Torque in connections can increase or decrease over that applied at makeup (connection tightening/loosening) with rotating and stimulation operations due to slip-stick, shock loads, bending, tight spots, vibration(s), temperature, and other downhole factors that may occur individually or in combination. Final assembly torque including shoulder engagement shall not exceed the ***Maximum MU Torque*** shown on size, weight, and grade-specific GB Performance Property Sheets at the beginning of a casing run when establishing the ***Running Torque***. In the unlikely event that ***Running Torque*** determined by the procedure meets or exceeds the ***Maximum MU Torque***, call GB Connections for assistance.
6. Yield Torque: Torque that causes yielding in the connection (usually yielding of the pin nose). ***Yield Torque*** rating does **NOT** consider the torque that may radially buckle the pipe body at the grip points. ***Yield Torque*** values for the pipe body and connection are based on nominal dimensions and minimum material yield strength.
7. Maximum Operating Torque: The ***Maximum Operating Torque*** shown on the GB Connections Performance Property Sheets includes a 5% safety factor on ***Yield Torque***. As such, it represents the ***limiting torque spike*** that can be applied to the connection during rotating operations. The ***Maximum Operating Torque*** is **NOT** the ***Maximum MU Torque*** and **MAY NOT BE** a sustainable rotating torque. Operating at the ***Maximum Operating Torque*** for any length of time may damage connections due to likely random, unexpected torque spikes that occur during rotating operations. USER should carefully consider this value to determine if a higher Safety Factor on ***Yield Torque*** is more suitable for the project-specific application.

   As a general rule of thumb, rotating RPMs and Torque should be *"walked up"* to determine the minimum needed for task accomplishment. Additional information on best practices for rotating casing can be found at http://www.gbconnections.com/pdf/White-Paper-Rotating-Casing.pdf.

KEY INFORMATION

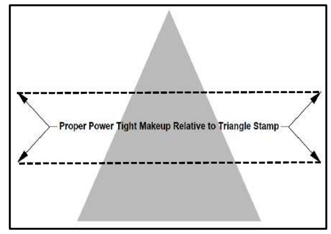
Thread Compound: Best-O-Life 2000, Best-O-Life 2000 Arctic Grade (AG), API Modified, API Modified Hi-Pressure, or any industry recognized equivalent to these products. Thread compound may also be referred to as "dope". User should avoid products that include Metal Free (MF) in the product name. Tool joint compounds are **expressly forbidden** for makeup of any GBC Connections. **Thread compound shall be applied to all pin and box threads** as described here.

Torque Values: ***Minimum and Maximum MU Torque*** values are provided on individual GB Connections Performance Property Sheets available at the following link: http://www.gbconnections.com

Continuous Makeup: Makeup of GB Connections **SHALL START AND CONTINUE WITHOUT STOPPING** until full power tight makeup is achieved.

Makeup Speed: Use of high gear at **no more than 40 RPMs** is permissible once proper starting thread engagement has occurred. **THE FINAL TWO (2) FULL TURNS, AT A MINIMUM, SHALL BE COMPLETED IN LOW GEAR AT LESS THAN 10 RPMS**.

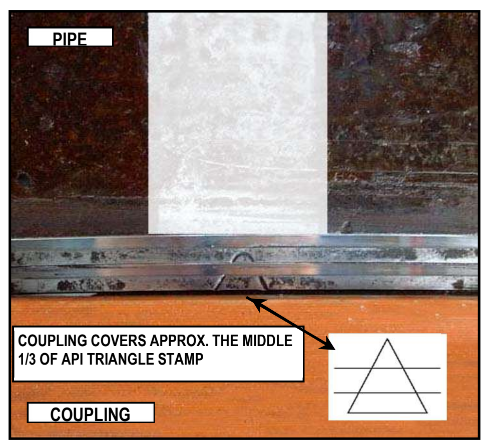
Pin Nose Engagement: Pin nose engagement is indicated by a spike on an analog torque gauge or a sharp vertical spike on a torque vs. turn plot. As a secondary check, proper power tight makeup is achieved when the coupling covers approximately the **middle third of the API Triangle Stamp** on the pin (see graphic). The triangle will be stamped on the pin member and indicated by a white locator stripe.



Acceptance Criteria: All GB Connections must exhibit shoulder engagement (achieve pin-to-pin or pin-to-shoulder engagement) with a: (1) ***Delta Torque*** ranging between 10% and 50% of majority of the previously recorded ***Shoulder Torques*** and (2) final torque not exceeding the ***Running Torque*** as established in this procedure. Outlier joints that require additional attention would be an exception to ***Maximum MU Torque*** limit as discussed under Comments, Troubleshooting.

It is imperative that the following procedure be executed carefully at the beginning of every casing run to determine the ***Running Torque*** (torque to be used for the rest of the string). Torque values established on an individual casing run are never transferrable to other runs.

The ***Running Torque*** is determined while running the first 10 joints after joints assembled with threadlocking compounds are made up. Sometimes more than the first 10 joints will be needed to establish the ***Running Torque*** due to erratic results and/or other run-specific conditions. The ***Running Torque*** may have to be re-established or adjusted during the casing run under certain conditions[1] and observations. Use the size-specific GBC Connections Performance Property Sheets (http://www.gbconnections.com) for the ***Minimum*** and ***Maximum MU Torque*** values.



Connections shall be made up until shoulder engagement with ***Delta Torque*** between 10% and 50% of the ***Shoulder Torque*** (not to exceed the ***Maximum MU Torque***, see procedure below) using the ***Running Torque*** value established in this procedure. The ***Maximum MU Torque*** at the beginning of the casing run for establishing the ***Running Torque*** shall be limited to the value shown on the applicable GBC Connections Performance Property Sheet. The ***Running Torque*** shall be used thereafter and throughout the run as the limiting makeup torque value. The ***Maximum MU Torque*** on the GBC Performance Property Sheet value is given as a practical limit for avoidance of thread galling, connection damage, and possible tube damage due to excessive jaw pressure that can occur with application of extreme makeup torque. Contact GB

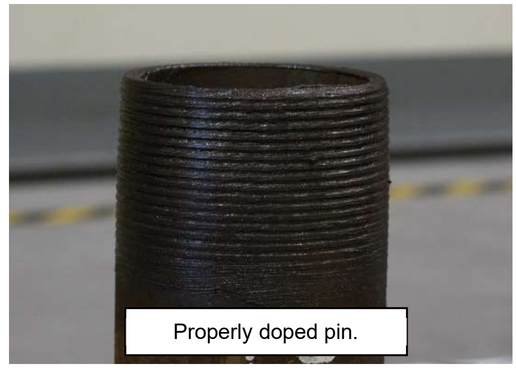
[1] Examples include but are not limited to more than an occasional low or high ***Delta Torque***, string of mixed mills, equipment change, large temperature change, and wobbling or noticeable vibration when joint is turning.

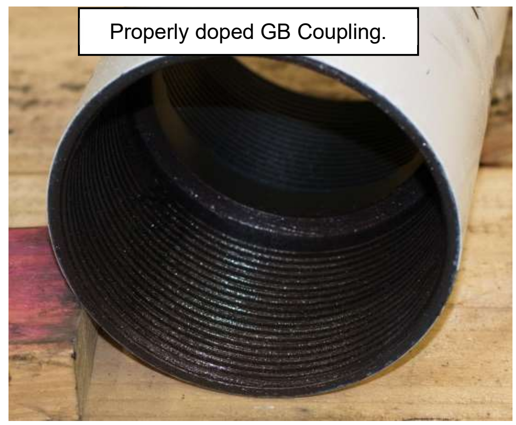
Connections if more than the ***Maximum MU Torque*** value is required for shoulder engagement and/or final makeup, or if torque exceeding the ***Maximum Operating Torque*** value is required for the intended service.

PROCEDURE FOR ESTABLISHING AND USING THE ***RUNNING TORQUE***

1. Remove coupling thread protectors only after casing is set in V-Door.
2. ***Always apply fresh thread compound to coupling threads and internal shoulder (where applicable).*** See Comment No. 1 (below) for discussion on proper amount of thread compound.
3. Remove pin thread protectors only after joint is raised in the derrick. Visually inspect pin threads for sufficient thread compound as described in Comment No. 1; ***add fresh compound to pin threads and pin nose***.
4. Fresh thread compound should **NEVER** be added on top of dope contaminated with dust, dirt, and/or debris. Threads observed to have contaminated thread compound shall be thoroughly cleaned and dried before applying fresh thread compound.
5. Stab the pin carefully into the coupling of the joint hanging in the rotary table. A stabbing guide is recommended to protect the pin nose and leading thread from physical damage that may contribute to thread galling. Make up each connection until shoulder engagement plus ***Delta Torque***. Record the ***Shoulder Torque*** observed for the first 10 joints (excluding threadlocked accessory joints). The ***Running Torque*** is (a) the ***Minimum MU Torque*** shown on the GB Connections Performance Property Sheets ***or*** (b) the ***Maximum Shoulder Torque*** recorded from the first 10 makeups + 20%, ***whichever is higher*** (rounded to the next highest 500 ft-lbs.) ***Delta Torque*** should Primarily be between 10% and 50% of the ***Shoulder Torque. Running Torque*** shall not exceed the ***Maximum MU Torque.*** When making up the initial joints for establishing the ***Running Torque*** carefully watch the torque gauge for the ***Shoulder Torque*** and try to manually shut down the tongs before reaching ***Maximum MU Torque*** shown on the GB Connections Performance Property Sheets. Alternately, the dump valve should be set to 80% of the ***Maximum MU Torque*** during this initial process.
6. After the first 10 makeups (more if necessary due to conditions at the time of the run), use the ***"Running Torque"*** established in Step 5 for the remainder of the string. A dump valve is strongly recommended to stop makeup once the established ***Running Torque*** is achieved.
7. All connections made up with the established ***Running Torque*** should achieve shoulder engagement with the reasonable amount of ***Delta Torque***. Carefully watch for the spike on the torque gauge during each make up to verify shoulder engagement. As a ***secondary*** verification, randomly check the makeup position relative to the API Triangle Stamp during the run. Proper power tight makeup position is achieved when the coupling covers the middle 1/3 of the API Triangle Stamp on the pin (see accompanying photo).
8. All connections should achieve shoulder engagement with at least 10% ***Delta Torque*** before the ***Maximum MU Torque*** is achieved.

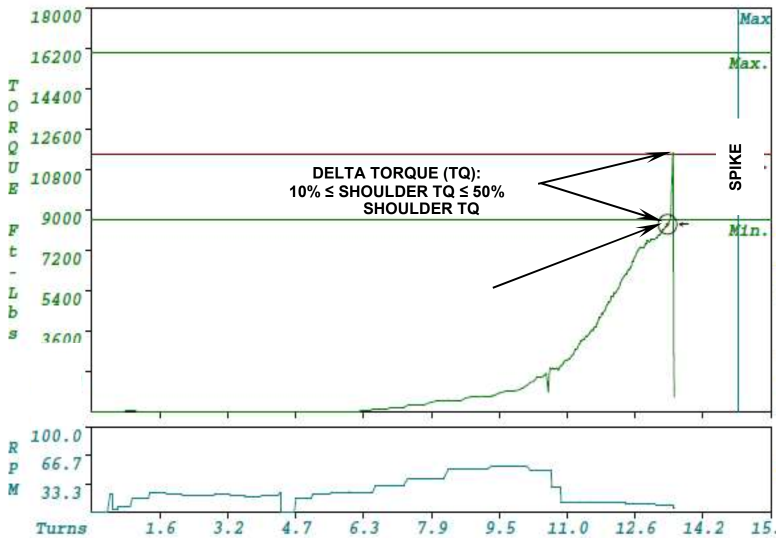
COMMENTS, TROUBLESHOOTING


Properly doped pin.


Properly doped GB Coupling.

1. GB Connections are thread compound friendly. Thread compounds shall be handled, mixed, and applied in strict accordance with the manufacturer's instructions. **THREAD COMPOUND SHALL BE APPLIED TO BOTH PIN AND COUPLING THREADS AND OPPOSING PIN NOSE OR SHOULDER AREA OF EVERY CONNECTION**. Thread compound "transfer" between pin and coupling will not provide proper sealing mechanism for the connection to function properly. Sufficient thread compound has been applied when all threads (pin and coupling), pin nose, and coupling ID surfaces are completely covered **WITH NO GAPS OR BARE SPOTS**. The thread form should be discernible beneath the compound, i.e. when the thread valleys appear half full. Be generous with the thread compound; but avoid over-doping to the point where ***excessive*** amounts are squeezed out during assembly. Use of a mustache brush is the preferred method for applying and distributing thread compounds to GB Connections.
2. If threads are cleaned on racks, new dope shall be applied in a light, even coat to both pin and coupling threads. See Comment No. 1 above for description of sufficient thread compound. Clean thread protectors shall be re-applied to freshly doped pin and coupling threads unless the casing run is imminent (no more than a few hours) to avoid contaminating exposed thread compound.
3. All connections should achieve shoulder engagement before reaching the "***Running Torque***" value determined by this procedure. Any connection that does not achieve a clear spike/shoulder engagement at the established "***Running Torque***" value shall be visually inspected for position relative to the API Triangle Stamp.
   a) If the coupling is shy of the API Triangle Stamp Base, the connection shall be broken out, cleaned and inspected visually for thread damage, re-doped, and made-up again (or laid down if threads are damaged). Connections **SHALL NEVER** be backed up a couple of turns and remade. They shall be completely broken out, cleaned and inspected as described above.
   b) If the coupling is at or covers the API Triangle base but does not land in approximately the middle third of the API Triangle Stamp, add additional torque to achieve shouldering and finish the makeup. It is common to see high torque (possibly exceeding the ***Maximum MU Torque***) to initiate connection turning. This is acceptable as long as the torque drops off once movement starts and then spikes with shoulder engagement. If acceptable makeup doesn't occur with one additional torque application, the connection shall be broken out (as described in 3a above).
   c) Any connection not properly assembled (i.e. not meeting the acceptance criteria) in two (2) attempts (provided threads pass a visual inspection each time) is reject and shall be laid down.

4. At the established ***Running Torque***, the connections will generally shoulder with ***Delta Torque*** between 10% and 50%. High interference connections will tend to have a higher ***Shoulder Torque*** and less ***Delta Torque*** (at least 10% of the ***Shoulder Torque*** is required). Low interference connections will tend to have lower ***Shoulder Torque*** and more ***Delta Torque***. In general, GB Connections makeup consistently but will vary due to any of the factors enumerated in the second paragraph of the Overview section of this procedure. However, wide variability on more than a few joints should be investigated for a root cause and, if necessary, a new ***Running Torque*** should be adjusted as described below.



If a connection appears to have shouldered but doesn't have at least 10% ***Delta Torque***, the position relative to the API Triangle Stamp should be checked. In just about every instance, the position will have covered the triangle base, so additional torque can be added to complete the makeup as discussed in 3.b) above. Expect an instantaneous spike with showing more than 50% ***Delta Torque*** with application of additional torque. Under this condition, this makeup is acceptable.

Similarly, random connections here and there with more than 50% ***Delta Torque*** is generally not cause for concern. However, if overshooting the 50% maximum ***Delta Torque*** target occurs frequently, then the established ***Running Torque*** value should be walked down in 500 ft-lbs. to 1,000 ft-lbs. increments until connection makeup routinely falls in line with the stated acceptance criteria.

5. ***Torque vs. Turn monitoring systems are recommended for field makeup of GB Connections.*** While Torque vs. Turn plots provide good information about makeup, they **SHALL NOT BE SUBSTITUTED FOR DIRECT VISUAL OBSERVATION OF THE CONNECTION DURING ASSEMBLY**. There is no second chance to watch field assembly of a connection. Torque vs. Turn plots can always be viewed for verification purposes once a makeup is finished. When available, torque vs. turn plots shall finish with a clearly defined spike as shown in the graphic above. The general character of torque vs. turn plots for good makeups will become evident after the first ten (10) makeups (again, more may be necessary due to rig and/or equipment-specific conditions). Any makeup that results in a plot that is "out-of-character"[2] when compared with most plots from previous good makeups should be checked carefully. Torque vs. Time is not recommended unless it supplements the Torque vs. Turn Data.

When using Torque vs. Turn monitoring equipment, GB recommends setting a reference torque value of 500 ft-lbs. or 10% of the minimum makeup torque (whichever is lower) to help normalize the turns-to-power-tight variability in the Tq-Tn graphs. Setting a reference torque normalizes field stab variability resulting in more consistency in the Tq-Tn data. Plot scales should be set so data spans at least 2/3 of the turns scale on each plot (15 turns will usually be sufficient at the start and can be reduced based on data from the first few joints). **UNDER NO CIRCUMSTANCE SHOULD MAKEUP BE STARTED UNTIL THE MONITORING SYSTEM IS READY TO RECORD DATA**.

6. Occasionally the mill side of a GB Connection may turn during field makeup. When observed, the makeup should continue without stopping per this procedure. It may be helpful to scribe a vertical line across the coupling-pipe

[2] An "out-of-character" plot may initiate with a high torque, show significantly steeper slope from the start of makeup, wide torque undulations as makeup progresses, no clearly defined spike, insufficient/inconsistent turns, etc.

interface to aid estimation of mill side turning if it is observed with some frequency. The amount of mill side turn should be carefully observed and estimated. If the mill side turns less than ½ turn and all other aspects of the makeup are good, the connection is acceptable. If the mill side turns more than ½ turn, troubleshooting should be initiated. Pay particular attention to amount and distribution of thread compound, vertical alignment, weight of joint, hooked end on pipe, and other possible factors that may contribute to possible high torque during field makeup. Counting turns can help to estimate if coupling will need to be stopped to avoid over rotation. It should be noted that mill side turning during field makeup occurs occasionally and should not be concerning. Frequent or persistent mill side turning is a symptom that needs troubleshooting and appropriate corrective action.

7. A double wrap of the pick-up sling should be used when raising casing into the derrick when lifting subs, single joint, side-door, or slip elevators are not being used.
8. Higher torque may be needed to achieve proper connection position when threadlock compounds are applied. User is advised to carefully follow the manufacturer's instructions with respect to mixing, application, temperature, and time. Torque ranges with threadlock compounds cannot be estimated due to many variables including but not limited to temperature, time, connection tolerances, and surface finish. In these cases, carefully monitor makeup to be sure shouldering occurs. The only exception to proper positioning is with float equipment (float shoe and float collar) that will be assembled with a threadlocking compound. In this case, makeup close to the base of API Triangle Stamp is considered satisfactory.
9. Manual and automated dump valves can overshoot the established ***Running Torque*** due to several factors. Slightly overshooting the ***Running Torque*** is not cause for concern as long as the final "dump" torque is not excessive, and the equipment used is generally consistent joint-to-joint. Overshooting the ***Running Torque*** with a final makeup speed greater than 10 RPMs is risky and potentially harmful to the connection as discussed below.
10. Attached is a "Worksheet for determining GB Connections ***Running Torque*** at the beginning of a Casing Run" for use at the start of any casing run using GB Connections. GB recommends that this worksheet be filled out and maintained with the casing run records.

MAKEUP SPEED

To reiterate: Use of high gear at no more than 40 RPMs is permissible once proper starting thread engagement has occurred. **<u>THE FINAL TWO (2) FULL TURNS, AT A MINIMUM, SHALL BE COMPLETED IN LOW GEAR AT LESS THAN 10 RPMS</u>**. Be sure that the final 2 turns occur after the tong speed has slowed completely to less than 10 RPMs.

Making up connections at RPM exceeding those listed above may result in unsatisfactory connection performance downhole. Risks associated with excessive makeup RPMs are common for any connection with internal pin nose engagement. High speed makeup can:

1. Impart an unnecessary impulse load at nose contact. Certain materials are more susceptible to cracking under sudden or instantaneously applied loads.
2. Inhibit efficient movement of and trap thread compound under high pressure causing additional and unquantifiable high hoop stresses in the connection.
3. Result in significant overshoot of established dump torque value due to equipment latency between signal and equipment shut down resulting in higher but unknown actual final torque value. Excessive overshoot can result in pin nose yielding.

PROCEDURE SUMMARY

1. Remove coupling protectors after casing is set in V-Door and apply fresh thread compound to coupling threads.

2. Raise joint in derrick, remove pin protectors, and apply fresh thread compound to pin threads and pin nose.
3. Carefully stab pin into coupling and makeup to pin nose engagement. Try to stop makeup without exceeding the ***Maximum MU Torque*** (shown on GB Connections Performance Property Sheets). Carefully watch for and note the ***Shoulder Torque***.
4. Record ***Shoulder Torque*** and Final Torque values, and position relative to API Triangle Stamp for first ten (10) connections, more if necessary due to run/rig-specific conditions.
5. The ***Running Torque*** is (a) the ***Minimum MU Torque*** shown on the GB Connections Performance Property Sheet or (b) the maximum torque required for shoulder engagement + 20% ***Delta Torque*** determined from the first 10 makeups, ***whichever is higher***. Use the attached Worksheet to record this data and determine the ***Running Torque***.
6. Make up the rest of the string at the ***Running Torque*** determined in the previous step verifying each connection has shouldered with between 10% and 50% ***Delta Torque***. Small incremental adjustments to the established Running Torque (500 to 1,000 ft-lbs) are advised if delta torques routinely fall short of the 10% requirement or routinely exceed the 50% requirement.

NOTES:

- *This procedure summary is not a substitute for the comprehensive procedure provided above and does not apply to threadlock connections.*

DO's and DONT's

1. **DO** check vertical alignment.
2. **DO** apply thread compound to all pin and coupling threads, pin nose and coupling shoulder area.
3. **DO** establish the ***Running Torque*** in accordance with GB Procedures.
4. **DO** make adjustments to ***Running Torque*** if indicated by inconsistent makeups during the casing run.
5. **DO** check every makeup for a clear indication of shouldering with a minimum ***Delta Torque*** ≥ 10% of the ***Shoulder Torque***.
6. **DO** reject any coupling that is not properly made up after two (2) attempts.
7. **DO** carefully stab pins into coupling (use a stabbing guide for casing smaller than 9 5/8” OD).
8. **DO** finish the makeup with at least two (2) full turns in low gear at 10 RPMs or less.
9. **DO** make up every connection continuously to pin nose engagement without stopping.
10. **DO** make note of anything that occurs with any connection makeup such as backup grips slipped, connection inspected and remade, etc.
11. **Do** check out every connection that appears out of character relative to the population. An example would be a connection that is completed with significantly fewer turns than most others. Check the triangle stamp and record position and take corrective action if needed.
12. **DO** add torque to any connection that appears to achieve pin nose engagement but not 10% delta torque.

13. **DO** adjust the ***Running Torque*** up or down in increments to achieve consistent ***Delta Torque*** between 10% and 50%.
14. **Do** make note of any anomaly during any connection makeup, such as backups slipped, mill side turned, etc.
15. **DO** minimize the weight on the connection, i.e. weight neutral, during break out as much as possible to minimize thread galling.
16. **Do** Reduce RPM's on any join racking around in the derrick during make up. Erratic joint movement wile rotating may contribute or cause thread galling during make-up.
17. **DO NOT** over dope.
18. **DO NOT** exceed the ***Maximum MU Torque*** as shown on the GB Connections Performance Property Sheets during assembly.
19. **DO NOT** make up any misaligned connection.
20. **DO NOT** exceed 40 RPMs in high gear and 10 RPMs in low gear for the final two (2) full turns.
21. **DO NOT** remove pin thread protectors until pipe is hanging in the derrick.
22. **DO NOT** ever back a connection up a couple of turns and remake. Any connection requiring this type of attention **SHALL** be broken out completely, cleaned, visually inspected, and if OK, re-doped and remade.
23. **DO NOT** hesitate to contact GB Connections with questions before and during any casing run.

RECOMMENDED EQUIPMENT

- Stabbing Guide
- Mustache Brush
- Torque vs. Turn Monitoring Equipment or Dump Valve

Worksheet for determining GB Connection Running Torque at the beginning of a Casing Run

Ignore joints that are assembled with threadlock compounds. See "Addendum Procedure for GB Connections Assembled with Threadlocking Compounds" available at www.gbconnections.com.

Pertinent Excerpt from GB Running Procedure

5. Stab the pin carefully into the coupling of the joint hanging in the rotary table. A stabbing guide is recommended to protect the pin nose and leading thread from physical damage that may contribute to thread galling. Make up each connection until shoulder engagement plus Delta Torque. Record the Shoulder Torque observed for the first 10 joints (excluding threadlocked accessory joints). The Running Torque is (a) the Minimum MU Torque shown on the GB Connections Performance Property Sheets or (b) the Maximum Shoulder Torque recorded from the first 10 makeups + 20%, whichever is higher (rounded to the next highest 500 ft-lbs.) Delta Torque should be between 10% and 50% of the Shoulder Torque. Running Torque shall not exceed the Maximum MU Torque. When making up the initial joints for establishing the Running Torque carefully watch the torque gauge for the Shoulder Torque and try to manually shut down the tongs before reaching Maximum MU Torque shown on the GB Connections Performance Property Sheets. Alternately, the dump valve should be set to **80% of the Maximum MU Torque** during this initial process.

6. After the first 10 makeups (more if necessary due to conditions at the time of the run), use the “Running Torque" established in Step 5 for the remainder of the string. A dump valve is strongly recommended to stop makeup once the established Running Torque is achieved.

Casing Data		Comment
OD (in)		See GBC Performance Property Sheet
Weight (ppf)		See GBC Performance Property Sheet
Grade		See GBC Performance Property Sheet
Min MU Torque (ft-lbs)		See GBC Performance Property Sheet
Max MU Torque (ft-lbs)		See GBC Performance Property Sheet
Max Operating Torque (ft-lbs)		The Maximum Operating Torque is **NOT** the Maximum Makeup Torque and is **NOT** a sustainable rotating torque. Operating at the Maximum Operating Torque for any length of time will likely damage the connection.

Notes	Joint No.	Shoulder Torque (ft-lbs)	Final Torque (ft-lbs)	Triangle Stamp Position Sketch (△)
Required	1			
Required	2			
Required	3			
Required	4			
Required	5			
Required	6			
Required	7			
Required	8			
Required	9			
Required	10			
Optional	11			
Optional	12			
Optional	13			
Optional	14			
Optional	15			
Max. Shoulder Torque				
A Max. Shoulder Torque + 20%				
B Min. Makeup Torque (from GB Conn. Data Sheet)				
Running Torque (ft-lbs)		-	**A** or **B**, whichever is **greater**.	

Optional joints should be added if there is wide variability in shoulder torques recorded during the initial 10 joints. Judgement should be used to determine if more than 10 joints are needed for the purpose of establishing the Running Torque and, if so, how many more should be added.

Wide variations in Shoulder Torque during the first ten (10) joints suggest other issues requiring attention such as poor alignment, improper amount and distribution of thread compound, etc. Refer to 2nd paragraph of GB Running Procedure for possible contributing factors to aid troubleshooting.

GB Connections
950 Threadneedle, Suite 130
Houston TX 77079
Toll Free: 1-888-245-3848
Main: 713-465-3585
Fax: 713-984-1529

For Techincal Information, contact:

Gene Mannella
gmannella@gbconnections.com

Qing Lu
qlu@gbconnections.com

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jkies@gbconnections.com
Cell 713-562-0050

SOP-12-F05
Performance Data Sheet

API 5CT Casing Performance Data Sheet
8 5/8" 32.00 lb/ft P110 HSCY

P110 HSCY (High Strength Controlled Yield) is a BPU proprietary ERW casing grade for deep well applications. It is not intended for sour condansate wells. Product properties are based on the requirements of API 5CT 11th edition for ERW P110, with increased minimum yield strength to meet the minimum yield strength requirement of Q125 grade. P110 HSCY is provided with an API monogram for P110 grade.

Grade	P110 HSCY

	Sizes and Weights
OD	8.625 in
Nominal Wall Thickness	0.352 in
Nominal Weight, T&C	32.00 lb/ft
Nominal Weight, PE	31.13 lb/ft
Nominal ID	7.921 in
Standard Drift	7.796 in
Alternate Drift	7.875 in

	Pipe Body Mechanical Properties
Minimum Yield Strength	125,000 psi
Maximum Yield Strength	140,000 psi
Minimum Tensile Strength	130,000 psi
Maximum Hardness	N/A

	Minimum Performance
Collapse Pressure	4,530 psi
Minimal Internal Pressure Yield	9,693 psi
Pipe body Tension Yield	1,143,577 lbs
Joint Strength STC/LTC Connections	1,092,021 psi
Joint Strength BTC Connections	1,092,021 psi
Joint Strength BTC SCC Connections	856,665 psi

	Inspection and Testing
Visual	OD Longitudinal and independent 3rd party SEA
NDT	Independent 3rd party full body EMI and weldline UT after hydrotest. Calibration notch sensitivity (% of specified wall thickness): 5% UTWL, Pipe Body K.9 for SR16

	Color code
Pipe ends	One white and two gold bands
Couplings	White

Revision: 2
Revision date: 10/16/2024

Reviewed by: Quality Manager
Approved by: VP of QA

Data Collector:
Quality Manager

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

ACKNOWLEDGMENTS

Action 522321

ACKNOWLEDGMENTS

Operator:	OGRID: 7377
EOG RESOURCES INC 5509 Champions Drive Midland, TX 79706	Action Number: 522321
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

ACKNOWLEDGMENTS

☑	I hereby certify that no additives containing PFAS chemicals will be added to the completion or recompletion of this well.

Sante Fe Main Office
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State of New Mexico
Energy, Minerals and Natural Resources
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1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 522321

CONDITIONS

Operator:	
EOG RESOURCES INC 5509 Champions Drive Midland, TX 79706	OGRID: 7377
	Action Number: 522321
	Action Type: [C-101] BLM - Federal/Indian Land Lease (Form 3160-3)

CONDITIONS

Created By	Condition	Condition Date
sharrell1	Cement is required to circulate on both surface and intermediate1 strings of casing.	11/3/2025
sharrell1	If cement does not circulate on any string, a Cement Bond Log (CBL) is required for that string of casing.	11/3/2025
matthew.gomez	If an alteration to the setting depth of the intermediate casing shoe is desired a form C-103A must be approved prior to the change being made.	11/3/2025
matthew.gomez	Notify the OCD 24 hours prior to casing & cement.	11/3/2025
matthew.gomez	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.	11/3/2025
matthew.gomez	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.	11/3/2025
matthew.gomez	File As Drilled C-102 and a directional Survey with C-104 completion packet.	11/3/2025