HOBBS OCD

OCD Hobbs

SEP 0 8 2014

RECEIVED

Form 3160-5
(March 2012)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0137
Expires: October 31, 2014

5. Lease Serial No.
NMNM113418

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

6. If Indian, Allottee or Tribe Name

***SUBMIT IN TRIPLICATE** – Other instructions on page 2.*

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

1. Type of Well
☑ Oil Well ☐ Gas Well ☐ Other

8. Well Name and No.
MADERA 17 FEDERAL #1H

2. Name of Operator
CHEVRON MIDCONTINENT, L.P.

9. API Well No.
30-025-41199

3a. Address
15 SMITH ROAD
MIDLAND, TEXAS 79705

3b. Phone No. *(include area code)*
432-687-7375

10. Field and Pool or Exploratory Area
RED HILLS, BONE SPRING, NORTH

4. Location of Well *(Footage, Sec., T.,R.,M., or Survey Description)*
330' FNL, & 380' FEL, SEC 17, T-24S, R-34E, UL: A

11. County or Parish, State
LEA COUNTY, NM

12. CHECK THE APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☑ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Subsequent Report	☐ Casing Repair	☐ New Construction	☐ Recomplete	☑ Other CHANGES TO ORIGINAL APD
	☐ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
☐ Final Abandonment Notice	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation: Clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports must be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 must be filed once testing has been completed. Final Abandonment Notices must be filed only after all requirements, including reclamation, have been completed and the operator has determined that the site is ready for final inspection.)

PLEASE FIND ATTACHED, THE FOLLOWING DOCUMENTS FOR THE SUBJECT WELL, WHICH NOW BELONGS TO CHEVRON MIDCONTINENT, L.P., PREVIOUSLY SUBMITTED BY REGENERATION ENERGY CORPORATION

BLOWOUT PREVENTOR SCHEMATIC
CHOKE MANIFOLD SCHEMATIC
BOPE TESTING
HYDROSTATIC TEST CERTIFICATION
TEST CHART
PAD LAHOUT - ENSIGN 153
STANDARD PLANNING REPORT
DRILLING PLAN
WELLHEAD ASSEMBLY SCHEMATIC
H2S PLAN
PRESSURE CONTROL WELLHEAD EQUIPMENT RUNNING PROCEDURE

14. I hereby certify that the foregoing is true and correct. Name *(Printed/Typed)*
DENISE PINKERTON

Title REGULATORY SPECIALIST

Signature Denise Pinkerton

Date 02/24/2014

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by

Title FIELD MANAGER

Date

Conditions of approval, if any, are attached. Approval of this notice 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.

Office CARLSBAD FIELD OFFICE

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.

(Instructions on page 2)

SEP 1 2 2014

BLOWOUT PREVENTOR SCHEMATIC

Minimum Requirements

OPERATION : Intermediate and Production Hole Sections

Minimum System Pressure Rating : **5,000 psi**

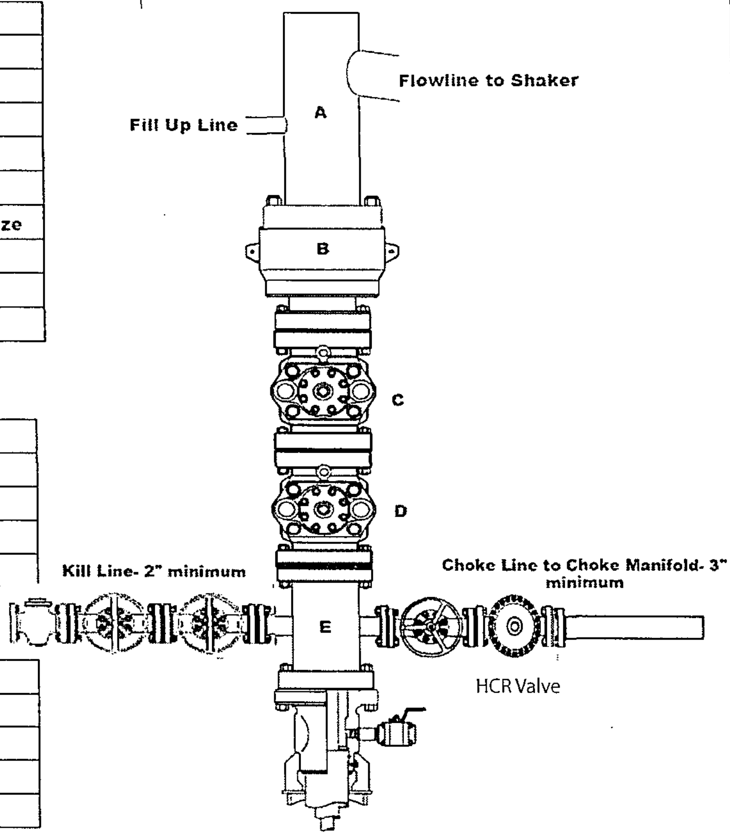
	SIZE	PRESSURE	DESCRIPTION
A		N/A	Bell Nipple
B	13 5/8"	5,000 psi	Annular
C	13 5/8"	5,000 psi	Pipe Ram
D	13 5/8"	5,000 psi	Blind Ram
E	13 5/8"	5,000 psi	Mud Cross
F			
DSA		As required for each hole size	
C-Sec			
B-Sec		13-5/8" 5K x 11" 5K	
A-Sec		13-3/8" SOW x 13-5/8" 5K	

Kill Line

SIZE	PRESSURE	DESCRIPTION
2"	5,000 psi	Gate Valve
2"	5,000 psi	Gate Valve
2"	5,000 psi	Check Valve

Choke Line

SIZE	PRESSURE	DESCRIPTION
3"	5,000 psi	Gate Valve
3"	5,000 psi	HCR Valve



Installation Checklist

The following item must be verified and checked off prior to pressure testing of BOP equipment.

- [ ] The installed BOP equipment meets at least the minimum requirements (rating, type, size, configuration) as shown on this schematic. Components may be substituted for equivalent equipment rated to higher pressures. Additional components may be put into place as long as they meet or exceed the minimum pressure rating of the system.
- [ ] All valves on the kill line and choke line will be full opening and will allow straight though flow.
- [ ] The kill line and choke line will be straight unless turns use tee blocks or are targeted with running tess, and will be anchored to prevent whip and reduce vibration.
- [ ] Manual (hand wheels) or automatic locking devices will be installed on all ram preventers. Hand wheels will also be installed on all manual valves on the choke line and kill line.
- [ ] A valve will be installed in the closing line as close as possible to the annular preventer to act as a locking device. This valve will remain open unless accumulator is inoperative.
- [ ] Upper kelly cock valve with handle will be available on rig floor along with safety valve and subs to fit all drill string connections in use.

After Installation Checklist is complete, fill out the information below and email to Superintendent and Drilling Engineer

Wellname: ______________________

Representative: ______________________

Date: ______________________

CHOKE MANIFOLD SCHEMATIC

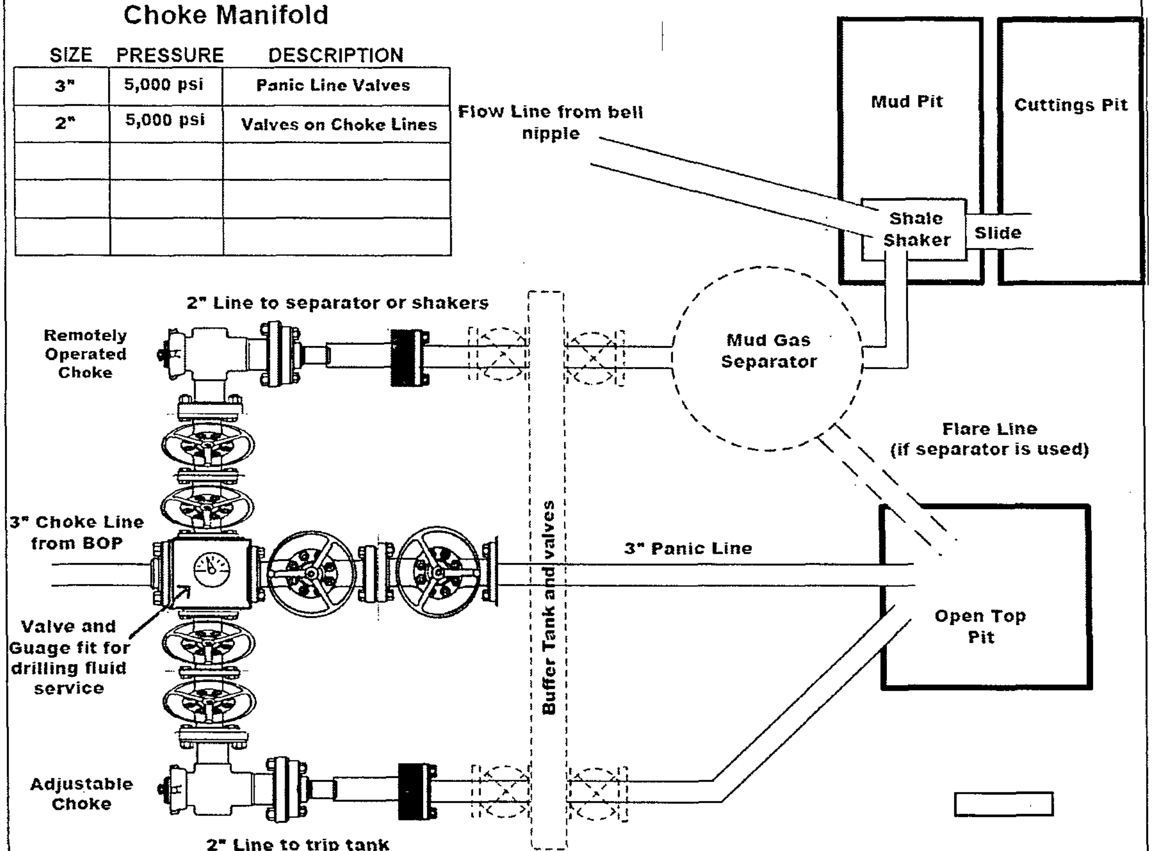
Minimum Requirements

OPERATION : Intermediate and Production Hole Sections

Minimum System Pressure Rating : 5,000 psi

Choke Manifold

SIZE	PRESSURE	DESCRIPTION
3"	5,000 psi	Panic Line Valves
2"	5,000 psi	Valves on Choke Lines



Installation Checklist

The following item must be verified and checked off prior to pressure testing of BOP equipment.

- ☐ The installed BOP equipment meets at least the minimum requirements (rating, type, size, configuration) as shown on this schematic. Components may be substituted for equivalent equipment rated to higher pressures. Additional components may be put into place as long as they meet or exceed the minimum pressure rating of the system.
- ☐ Adjustable Chokes may be Remotely Operated but will have backup hand pump for hydraulic actuation in case of loss of rig air pressure or power.
- ☐ Flare and Panic lines will terminate a minimum of 150' from the wellhead. These lines will terminate at a location as per approved APD.
- ☐ The choke line, kill line, and choke manifold lines will be straight unless turns use tee blocks or are targeted with running tess, and will be anchored to prevent whip and reduce vibration. This excludes the line between mud gas separator and shale shaker.
- ☐ All valves (except chokes) on choke line, kill line, and choke manifold will be full opening and will allow straight through flow. This excludes any valves between mud gas separator and shale shakers.
- ☐ All manual valves will have hand wheels installed.
- ☐ If used, flare system will have effective method for ignition
- ☐ All connections will be flanged, welded, or clamped (no threaded connections like hammer unions)
- ☐ If buffer tank is used, a valve will be used on all lines at any entry or exit point to or from the buffer tank.

After Installation Checklist is complete, fill out the information below and email to Superintendent and Drilling Engineer

Wellname: ______________________

Representative: ______________________

Date: ______________________

BOPE Testing

Minimum Requirements

Closing Unit and Accumulator Checklist

The following item must be performed, verified, and checked off at least once per well prior to low/high pressure testing of BOP equipment. This must be repeated after 6 months on the same well.

☐ **Precharge pressure for each accumulator bottle must fall within the range below. Bottles may be further charged with nitrogen gas only. Tested precharge pressures must be recorded for each individual bottle and kept on location through the end of the well. Test will be conducted prior to connecting unit to BOP stack.**

Check one that applies	Accumulator working pressure rating	Minimum acceptable operating pressure	Desired precharge pressure	Maximum acceptable precharge pressure	Minimum acceptable precharge pressure
☐	1500 psi	1500 psi	750 psi	800 psi	700 psi
☐	2000 psi	2000 psi	1000 psi	1100 psi	900 psi
☐	3000 psi	3000 psi	1000 psi	1100 psi	900 psi

☐ **Accumulator will have sufficient capacity to open the hydraulically-controlled choke line valve (if used), close all rams, close the annular preventer, and retain a minimum of 200 psi above the maximum acceptable precharge pressure (see table above) on the closing manifold without the use of the closing pumps. This test will be performed with test pressure recorded and kept on location through the end of the well**

☐ **Accumulator fluid reservoir will be double the usable fluid volume of the accumulator system capacity. Fluid level will be maintained at manufacturer's recommendations. Usable fluid volume will be recorded. Reservior capacity will be recorded. Reservoir fluid level will be recorded along with manufacturer's recommendation. All will be kept on location through the end of the well.**

☐ **Closing unit system will have two independent power sources (not counting accumulator bottles) to close the preventers.**

☐ **Power for the closing unit pumps will be available to the unit at all times so that the pumps will automatically start when the closing valve manifold pressure decreases to the pre-set level. It is recommended to check that air line to accumulator pump is "ON" during each tour change.**

☐ **With accumulator bottles isolated, closing unit will be capable of opening the hydraulically-operated choke line valve (if used) plus close the annular preventer on the smallest size drill pipe within 2 minutes and obtain a minimum of 200 psi above maximum acceptable precharge pressure (see table above) on the closing manifold. Test pressure and closing time will be recorded and kept on location through the end of the well.**

☐ **Master controls for the BOPE system will be located at the accumulator and will be capable of opening and closing all preventer and the choke line valve (if used)**

☐ **Remote controls for the BOPE system will be readily accessible (clear path) to the driller and located on the rig floor (not in the dog house). Remote controls will be capable of closing all preventers.**

☐ **Record accumulator tests in drilling reports and IADC sheet**

BOPE Test Checklist

The following item must be ckecked off prior to beginning test

☐ **BLM will be given at least 4 hour notice prior to beginning BOPE testing**

☐ **Valve on casing head below test plug will be open**

☐ **Test will be performed using clear water.**

The following item must be performed during the BOPE testing and then checked off

☐ **BOPE will be pressure tested when initially installed, whenever any seal subject to test pressure is broken, following related repairs, and at a minimum of 30 days intervals. Test pressure and times will be recorded by a 3rd party on a test chart and kept on location through the end of the well.**

☐ **Test plug will be used**

☐ **Ram type preventer and all related well control equipment will be tested to 250 psi (low) and 5,000 psi (high).**

☐ **Annular type preventer will be tested to 250 psi (low) and 3,500 psi (high).**

☐ **Valves will be tested from the working pressure side with all down stream valves open. The check valve will be held open to test the kill line valve(s)**

☐ **Each pressure test will be held for 10 minutes with no allowable leak off.**

☐ **Master controls and remote controls to the closing unit (accumulator) must be function tested as part of the BOP testing**

☐ **Record BOP tests and pressures in drilling reports and IADC sheet**

After Installation Checklist is complete, fill out the information below and email to Superintendent and Drilling Engineer <u>along with any/all BOP and accumulator test charts and reports from 3rd parties</u>.

Wellname: ______________________

Representative: ______________________

Date: ______________________

A Tomkins Company

Robsco, Inc.

OILFIELD RUBBER PRODUCTS

4749 Eastpark Drive
Houston, TX 77028
United States of America

Gates Corporation Authorized Rotary and Vibrator Hose Subcontracted Fabricator

Hydrostatic Test Certification

Robsco, Inc. certifies that the following hose assembly has been tested to the Gates Oilfield Roughneck Agreement/Specification requirements and passed the hydrostatic test per API Spec 7K, Fifth Edition, June 2010, Test pressure 9.6.7 and per Table 9 to 15,000 psi in accordance with this product number. Hose burst pressure 9.6.7.2 exceeds the minimum of 2.25 times the working pressure per Table 9.

Assembly Part Number	**Serial Number / Date Code**
36332R3-1/16HUB10K-LL-L	L32461102512R112712-5

		Chart Recorder Information	
Hose Size	**Testers**	**Serial Number**	**Calibration Date**
3.5IN X 32FT	OC CS	Recorder 22349	Oct. 19th 2012

Lloyd's Register Type Approved for Fire Test OD/1000/499 Rev 1

Hydrostatic Test: **Passed**
Visual Inspection: **Passed**

QA Representative Signature

11/28/2012 PS
Date & Initial

Shipper:
GHX - Robsco, Inc.
4749 Eastpark Drive

Houston, TX 77028
Rufus Dominguez 713-672-1777

Shipment Reference: 9415989
Consignee Reference: 491394-156JR
Total Weight: 1687
Total Shipment Pieces: 1

Label 1 of 1

Saia, Inc.
853-1923-A
11/29/2012

Special Instruction

DO NOT STAND CRATES ON END!!!!

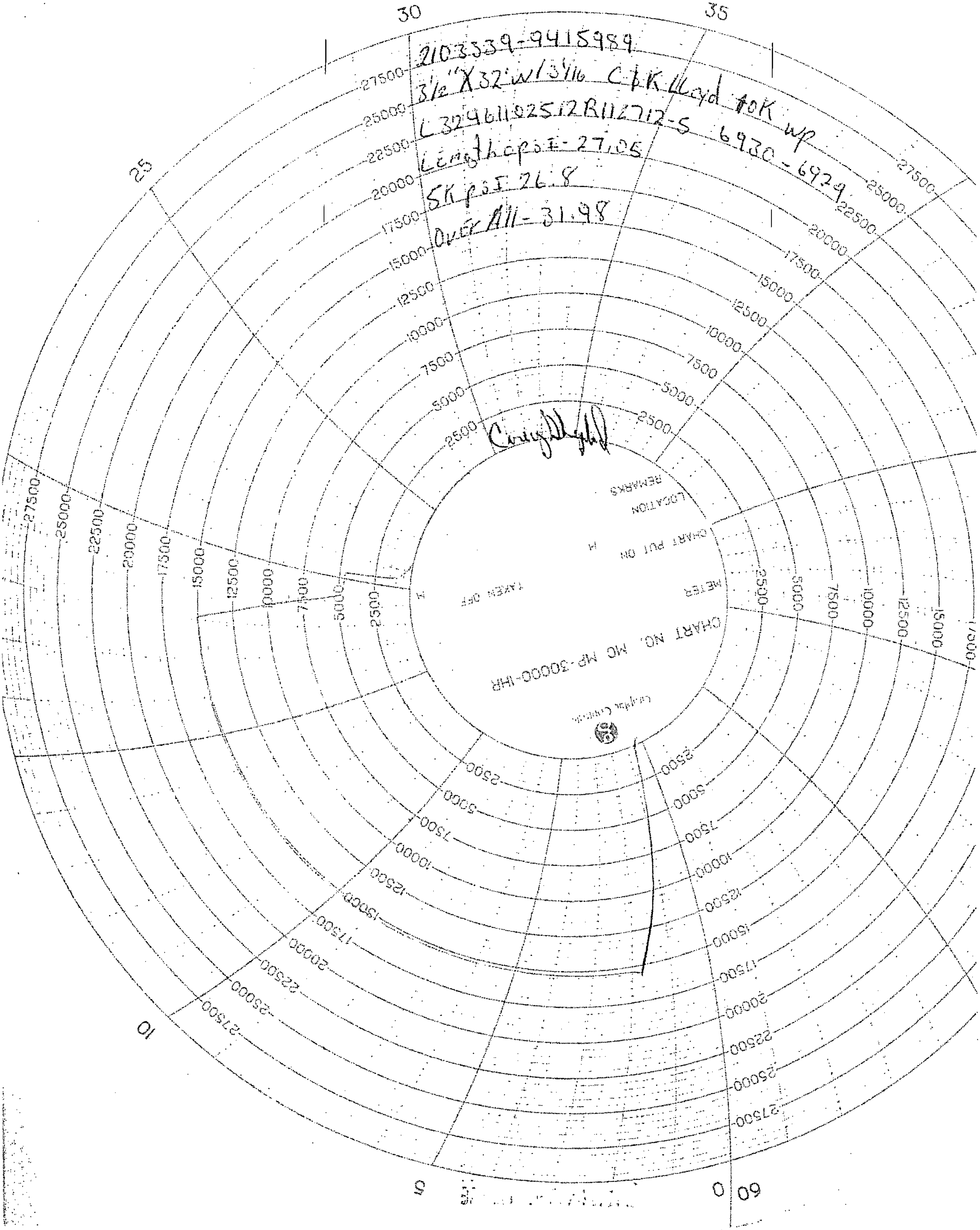
DIM Weight: 1105
qty: 1 (88 x 84 x 29)

00608423360 2

TOTAL SERVICE SUPPLY LP
1620 VICEROY

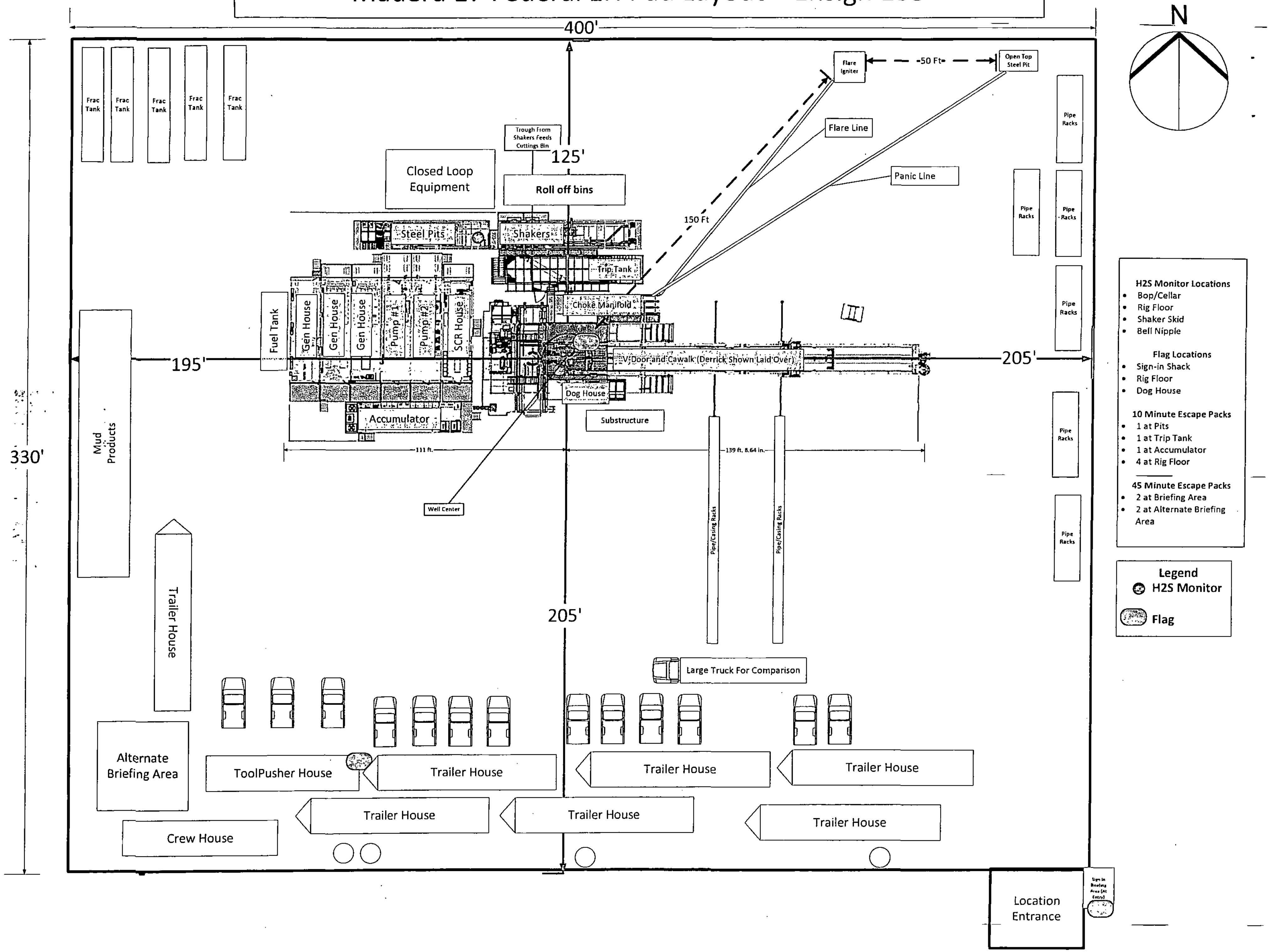
ODESSA, TX 79763
ATTN: BRUCE

(Fold Sheet Here)



2103339-9415989
3½" X 32' w/ 3 3/16 C.P.K. Lloyd 40K wp
L3246110251 2B112712-5 6930-6929
Length psi - 27.05
SK psi 26.8
Over All - 31.98
REMARKS
LOCATION
CHART PUT ON
TAKEN OFF
METER
CHART NO. MC MP-30000-1HR

Madera 17 Federal 1H Pad Layout – Ensign 153



Chevron

Lea County NM (NAD27 NME)
Madera 17 Federal
1H

WB1/Job #1410114

Plan: Plan #1 01-15-14

Standard Planning Report

15 January, 2014

Phoenix Technology Services

Planning Report

Database:	GCR DB	Local Co-ordinate Reference:	Well 1H
Company:	Chevron	TVD Reference:	KB @ 3585.50usft (Ensign 153)
Project:	Lea County NM (NAD27 NME)	MD Reference:	KB @ 3585.50usft (Ensign 153)
Site:	Madera 17 Federal	North Reference:	Grid
Well:	1H	Survey Calculation Method:	Minimum Curvature
Wellbore:	WB1/Job #1410114		
Design:	Plan #1 01-15-14		

Project Lea County NM (NAD27 NME)

Map System:	US State Plane 1927 (Exact solution)	**System Datum:**	Mean Sea Level
Geo Datum:	NAD 1927 (NADCON CONUS)		
Map Zone:	New Mexico East 3001		

Site Madera 17 Federal

Site Position:		**Northing:**	446,173.20 usft	**Latitude:**	32° 13' 25.66151 N
From:	Map	**Easting:**	762,588.30 usft	**Longitude:**	103° 29' 3.13581 W
Position Uncertainty:	0.00 usft	**Slot Radius:**	13-3/16 "	**Grid Convergence:**	0.45 °

Well 1H

Well Position	**+N/-S**	0.00 usft	**Northing:**	446,173.20 usft	**Latitude:**	32° 13' 25.66151 N
	+E/-W	0.00 usft	**Easting:**	762,588.30 usft	**Longitude:**	103° 29' 3.13581 W
Position Uncertainty		0.00 usft	**Wellhead Elevation:**		**Ground Level:**	3,561.00 usft

Wellbore WB1/Job #1410114

Magnetics	Model Name	Sample Date	Declination (°)	Dip Angle (°)	Field Strength (nT)
	IGRF2010_14	12/10/13	7.24	60.14	48,376

Design Plan #1 01-15-14

Audit Notes:					
Version:		**Phase:**	PLAN	**Tie On Depth:**	0.00

Vertical Section:	Depth From (TVD) (usft)	+N/-S (usft)	+E/-W (usft)	Direction (°)
	0.00	0.00	0.00	179.51

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
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
10,405.25	0.00	0.00	10,405.25	0.00	0.00	0.00	0.00	0.00	0.00	
11,144.41	88.70	179.51	10,882.59	-466.62	3.97	12.00	12.00	0.00	179.51	
15,297.42	88.70	179.51	10,976.81	-4,618.40	39.30	0.00	0.00	0.00	0.00	PBHL-Madera 17 Fed

Database:	GCR DB	Local Co-ordinate Reference:	Well 1H
Company:	Chevron	TVD Reference:	KB @ 3585.50usft (Ensign 153)
Project:	Lea County NM (NAD27 NME)	MD Reference:	KB @ 3585.50usft (Ensign 153)
Site:	Madera 17 Federal	North Reference:	Grid
Well:	1H	Survey Calculation Method:	Minimum Curvature
Wellbore:	WB1/Job #1410114		
Design:	Plan #1 01-15-14		

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)
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
100.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00
200.00	0.00	0.00	200.00	0.00	0.00	0.00	0.00	0.00	0.00
300.00	0.00	0.00	300.00	0.00	0.00	0.00	0.00	0.00	0.00
400.00	0.00	0.00	400.00	0.00	0.00	0.00	0.00	0.00	0.00
500.00	0.00	0.00	500.00	0.00	0.00	0.00	0.00	0.00	0.00
600.00	0.00	0.00	600.00	0.00	0.00	0.00	0.00	0.00	0.00
700.00	0.00	0.00	700.00	0.00	0.00	0.00	0.00	0.00	0.00
800.00	0.00	0.00	800.00	0.00	0.00	0.00	0.00	0.00	0.00
900.00	0.00	0.00	900.00	0.00	0.00	0.00	0.00	0.00	0.00
1,000.00	0.00	0.00	1,000.00	0.00	0.00	0.00	0.00	0.00	0.00
1,100.00	0.00	0.00	1,100.00	0.00	0.00	0.00	0.00	0.00	0.00
1,200.00	0.00	0.00	1,200.00	0.00	0.00	0.00	0.00	0.00	0.00
1,300.00	0.00	0.00	1,300.00	0.00	0.00	0.00	0.00	0.00	0.00
1,400.00	0.00	0.00	1,400.00	0.00	0.00	0.00	0.00	0.00	0.00
1,500.00	0.00	0.00	1,500.00	0.00	0.00	0.00	0.00	0.00	0.00
1,600.00	0.00	0.00	1,600.00	0.00	0.00	0.00	0.00	0.00	0.00
1,700.00	0.00	0.00	1,700.00	0.00	0.00	0.00	0.00	0.00	0.00
1,800.00	0.00	0.00	1,800.00	0.00	0.00	0.00	0.00	0.00	0.00
1,900.00	0.00	0.00	1,900.00	0.00	0.00	0.00	0.00	0.00	0.00
2,000.00	0.00	0.00	2,000.00	0.00	0.00	0.00	0.00	0.00	0.00
2,100.00	0.00	0.00	2,100.00	0.00	0.00	0.00	0.00	0.00	0.00
2,200.00	0.00	0.00	2,200.00	0.00	0.00	0.00	0.00	0.00	0.00
2,300.00	0.00	0.00	2,300.00	0.00	0.00	0.00	0.00	0.00	0.00
2,400.00	0.00	0.00	2,400.00	0.00	0.00	0.00	0.00	0.00	0.00
2,500.00	0.00	0.00	2,500.00	0.00	0.00	0.00	0.00	0.00	0.00
2,600.00	0.00	0.00	2,600.00	0.00	0.00	0.00	0.00	0.00	0.00
2,700.00	0.00	0.00	2,700.00	0.00	0.00	0.00	0.00	0.00	0.00
2,800.00	0.00	0.00	2,800.00	0.00	0.00	0.00	0.00	0.00	0.00
2,900.00	0.00	0.00	2,900.00	0.00	0.00	0.00	0.00	0.00	0.00
3,000.00	0.00	0.00	3,000.00	0.00	0.00	0.00	0.00	0.00	0.00
3,100.00	0.00	0.00	3,100.00	0.00	0.00	0.00	0.00	0.00	0.00
3,200.00	0.00	0.00	3,200.00	0.00	0.00	0.00	0.00	0.00	0.00
3,300.00	0.00	0.00	3,300.00	0.00	0.00	0.00	0.00	0.00	0.00
3,400.00	0.00	0.00	3,400.00	0.00	0.00	0.00	0.00	0.00	0.00
3,500.00	0.00	0.00	3,500.00	0.00	0.00	0.00	0.00	0.00	0.00
3,600.00	0.00	0.00	3,600.00	0.00	0.00	0.00	0.00	0.00	0.00
3,700.00	0.00	0.00	3,700.00	0.00	0.00	0.00	0.00	0.00	0.00
3,800.00	0.00	0.00	3,800.00	0.00	0.00	0.00	0.00	0.00	0.00
3,900.00	0.00	0.00	3,900.00	0.00	0.00	0.00	0.00	0.00	0.00
4,000.00	0.00	0.00	4,000.00	0.00	0.00	0.00	0.00	0.00	0.00
4,100.00	0.00	0.00	4,100.00	0.00	0.00	0.00	0.00	0.00	0.00
4,200.00	0.00	0.00	4,200.00	0.00	0.00	0.00	0.00	0.00	0.00
4,300.00	0.00	0.00	4,300.00	0.00	0.00	0.00	0.00	0.00	0.00
4,400.00	0.00	0.00	4,400.00	0.00	0.00	0.00	0.00	0.00	0.00
4,500.00	0.00	0.00	4,500.00	0.00	0.00	0.00	0.00	0.00	0.00
4,600.00	0.00	0.00	4,600.00	0.00	0.00	0.00	0.00	0.00	0.00
4,700.00	0.00	0.00	4,700.00	0.00	0.00	0.00	0.00	0.00	0.00
4,800.00	0.00	0.00	4,800.00	0.00	0.00	0.00	0.00	0.00	0.00
4,900.00	0.00	0.00	4,900.00	0.00	0.00	0.00	0.00	0.00	0.00
5,000.00	0.00	0.00	5,000.00	0.00	0.00	0.00	0.00	0.00	0.00
5,100.00	0.00	0.00	5,100.00	0.00	0.00	0.00	0.00	0.00	0.00
5,200.00	0.00	0.00	5,200.00	0.00	0.00	0.00	0.00	0.00	0.00
5,300.00	0.00	0.00	5,300.00	0.00	0.00	0.00	0.00	0.00	0.00

Phoenix Technology Services
Planning Report

Database:	GCR DB	Local Co-ordinate Reference:	Well 1H
Company:	Chevron	TVD Reference:	KB @ 3585.50usft (Ensign 153)
Project:	Lea County NM (NAD27 NME)	MD Reference:	KB @ 3585.50usft (Ensign 153)
Site:	Madera 17 Federal	North Reference:	Grid
Well:	1H	Survey Calculation Method:	Minimum Curvature
Wellbore:	WB1/Job #1410114		
Design:	Plan #1 01-15-14		

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)
5,400.00	0.00	0.00	5,400.00	0.00	0.00	0.00	0.00	0.00	0.00
5,500.00	0.00	0.00	5,500.00	0.00	0.00	0.00	0.00	0.00	0.00
5,600.00	0.00	0.00	5,600.00	0.00	0.00	0.00	0.00	0.00	0.00
5,700.00	0.00	0.00	5,700.00	0.00	0.00	0.00	0.00	0.00	0.00
5,800.00	0.00	0.00	5,800.00	0.00	0.00	0.00	0.00	0.00	0.00
5,900.00	0.00	0.00	5,900.00	0.00	0.00	0.00	0.00	0.00	0.00
6,000.00	0.00	0.00	6,000.00	0.00	0.00	0.00	0.00	0.00	0.00
6,100.00	0.00	0.00	6,100.00	0.00	0.00	0.00	0.00	0.00	0.00
6,200.00	0.00	0.00	6,200.00	0.00	0.00	0.00	0.00	0.00	0.00
6,300.00	0.00	0.00	6,300.00	0.00	0.00	0.00	0.00	0.00	0.00
6,400.00	0.00	0.00	6,400.00	0.00	0.00	0.00	0.00	0.00	0.00
6,500.00	0.00	0.00	6,500.00	0.00	0.00	0.00	0.00	0.00	0.00
6,600.00	0.00	0.00	6,600.00	0.00	0.00	0.00	0.00	0.00	0.00
6,700.00	0.00	0.00	6,700.00	0.00	0.00	0.00	0.00	0.00	0.00
6,800.00	0.00	0.00	6,800.00	0.00	0.00	0.00	0.00	0.00	0.00
6,900.00	0.00	0.00	6,900.00	0.00	0.00	0.00	0.00	0.00	0.00
7,000.00	0.00	0.00	7,000.00	0.00	0.00	0.00	0.00	0.00	0.00
7,100.00	0.00	0.00	7,100.00	0.00	0.00	0.00	0.00	0.00	0.00
7,200.00	0.00	0.00	7,200.00	0.00	0.00	0.00	0.00	0.00	0.00
7,300.00	0.00	0.00	7,300.00	0.00	0.00	0.00	0.00	0.00	0.00
7,400.00	0.00	0.00	7,400.00	0.00	0.00	0.00	0.00	0.00	0.00
7,500.00	0.00	0.00	7,500.00	0.00	0.00	0.00	0.00	0.00	0.00
7,600.00	0.00	0.00	7,600.00	0.00	0.00	0.00	0.00	0.00	0.00
7,700.00	0.00	0.00	7,700.00	0.00	0.00	0.00	0.00	0.00	0.00
7,800.00	0.00	0.00	7,800.00	0.00	0.00	0.00	0.00	0.00	0.00
7,900.00	0.00	0.00	7,900.00	0.00	0.00	0.00	0.00	0.00	0.00
8,000.00	0.00	0.00	8,000.00	0.00	0.00	0.00	0.00	0.00	0.00
8,100.00	0.00	0.00	8,100.00	0.00	0.00	0.00	0.00	0.00	0.00
8,200.00	0.00	0.00	8,200.00	0.00	0.00	0.00	0.00	0.00	0.00
8,300.00	0.00	0.00	8,300.00	0.00	0.00	0.00	0.00	0.00	0.00
8,400.00	0.00	0.00	8,400.00	0.00	0.00	0.00	0.00	0.00	0.00
8,500.00	0.00	0.00	8,500.00	0.00	0.00	0.00	0.00	0.00	0.00
8,600.00	0.00	0.00	8,600.00	0.00	0.00	0.00	0.00	0.00	0.00
8,700.00	0.00	0.00	8,700.00	0.00	0.00	0.00	0.00	0.00	0.00
8,800.00	0.00	0.00	8,800.00	0.00	0.00	0.00	0.00	0.00	0.00
8,900.00	0.00	0.00	8,900.00	0.00	0.00	0.00	0.00	0.00	0.00
9,000.00	0.00	0.00	9,000.00	0.00	0.00	0.00	0.00	0.00	0.00
9,100.00	0.00	0.00	9,100.00	0.00	0.00	0.00	0.00	0.00	0.00
9,200.00	0.00	0.00	9,200.00	0.00	0.00	0.00	0.00	0.00	0.00
9,300.00	0.00	0.00	9,300.00	0.00	0.00	0.00	0.00	0.00	0.00
9,400.00	0.00	0.00	9,400.00	0.00	0.00	0.00	0.00	0.00	0.00
9,500.00	0.00	0.00	9,500.00	0.00	0.00	0.00	0.00	0.00	0.00
9,600.00	0.00	0.00	9,600.00	0.00	0.00	0.00	0.00	0.00	0.00
9,700.00	0.00	0.00	9,700.00	0.00	0.00	0.00	0.00	0.00	0.00
9,800.00	0.00	0.00	9,800.00	0.00	0.00	0.00	0.00	0.00	0.00
9,900.00	0.00	0.00	9,900.00	0.00	0.00	0.00	0.00	0.00	0.00
10,000.00	0.00	0.00	10,000.00	0.00	0.00	0.00	0.00	0.00	0.00
10,100.00	0.00	0.00	10,100.00	0.00	0.00	0.00	0.00	0.00	0.00
10,200.00	0.00	0.00	10,200.00	0.00	0.00	0.00	0.00	0.00	0.00
10,300.00	0.00	0.00	10,300.00	0.00	0.00	0.00	0.00	0.00	0.00
10,400.00	0.00	0.00	10,400.00	0.00	0.00	0.00	0.00	0.00	0.00
10,405.25	0.00	0.00	10,405.25	0.00	0.00	0.00	0.00	0.00	0.00
KOP, 12°/100' Build									

Phoenix Technology Services

Planning Report

Database:	GCR DB	Local Co-ordinate Reference:	Well 1H
Company:	Chevron	TVD Reference:	KB @ 3585.50usft (Ensign 153)
Project:	Lea County NM (NAD27 NME)	MD Reference:	KB @ 3585.50usft (Ensign 153)
Site:	Madera 17 Federal	North Reference:	Grid
Well:	1H	Survey Calculation Method:	Minimum Curvature
Wellbore:	WB1/Job #1410114		
Design:	Plan #1 01-15-14		

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)
10,500.00	11.37	179.51	10,499.38	-9.37	0.08	9.37	12.00	12.00	0.00
10,600.00	23.37	179.51	10,594.64	-39.17	0.33	39.17	12.00	12.00	0.00
10,700.00	35.37	179.51	10,681.63	-88.12	0.75	88.13	12.00	12.00	0.00
10,800.00	47.37	179.51	10,756.54	-154.09	1.31	154.10	12.00	12.00	0.00
10,900.00	59.37	179.51	10,816.10	-234.19	1.99	234.20	12.00	12.00	0.00
11,000.00	71.37	179.51	10,857.69	-324.93	2.76	324.94	12.00	12.00	0.00
11,100.00	83.37	179.51	10,879.52	-422.33	3.59	422.34	12.00	12.00	0.00
11,144.20	88.67	179.51	10,882.58	-466.40	3.97	466.42	12.00	12.00	0.00
TL 10872' TVD @ 0' VS w/88.7° Inc									
11,144.41	88.70	179.51	10,882.59	-466.61	3.97	466.63	12.00	12.00	0.00
LP, Hold 88.7° Inc									
11,200.00	88.70	179.51	10,883.85	-522.19	4.44	522.20	0.00	0.00	0.00
11,300.00	88.70	179.51	10,886.12	-622.16	5.29	622.18	0.00	0.00	0.00
11,400.00	88.70	179.51	10,888.39	-722.13	6.14	722.15	0.00	0.00	0.00
11,500.00	88.70	179.51	10,890.66	-822.10	7.00	822.13	0.00	0.00	0.00
11,600.00	88.70	179.51	10,892.93	-922.07	7.85	922.10	0.00	0.00	0.00
11,700.00	88.70	179.51	10,895.19	-1,022.04	8.70	1,022.08	0.00	0.00	0.00
11,800.00	88.70	179.51	10,897.46	-1,122.01	9.55	1,122.05	0.00	0.00	0.00
11,900.00	88.70	179.51	10,899.73	-1,221.98	10.40	1,222.02	0.00	0.00	0.00
12,000.00	88.70	179.51	10,902.00	-1,321.95	11.25	1,322.00	0.00	0.00	0.00
12,100.00	88.70	179.51	10,904.27	-1,421.92	12.10	1,421.97	0.00	0.00	0.00
12,200.00	88.70	179.51	10,906.54	-1,521.89	12.95	1,521.95	0.00	0.00	0.00
12,300.00	88.70	179.51	10,908.81	-1,621.86	13.80	1,621.92	0.00	0.00	0.00
12,400.00	88.70	179.51	10,911.08	-1,721.83	14.65	1,721.90	0.00	0.00	0.00
12,500.00	88.70	179.51	10,913.34	-1,821.80	15.50	1,821.87	0.00	0.00	0.00
12,600.00	88.70	179.51	10,915.61	-1,921.77	16.35	1,921.84	0.00	0.00	0.00
12,700.00	88.70	179.51	10,917.88	-2,021.74	17.20	2,021.82	0.00	0.00	0.00
12,800.00	88.70	179.51	10,920.15	-2,121.72	18.05	2,121.79	0.00	0.00	0.00
12,900.00	88.70	179.51	10,922.42	-2,221.69	18.91	2,221.77	0.00	0.00	0.00
13,000.00	88.70	179.51	10,924.69	-2,321.66	19.76	2,321.74	0.00	0.00	0.00
13,100.00	88.70	179.51	10,926.96	-2,421.63	20.61	2,421.71	0.00	0.00	0.00
13,200.00	88.70	179.51	10,929.23	-2,521.60	21.46	2,521.69	0.00	0.00	0.00
13,300.00	88.70	179.51	10,931.49	-2,621.57	22.31	2,621.66	0.00	0.00	0.00
13,400.00	88.70	179.51	10,933.76	-2,721.54	23.16	2,721.64	0.00	0.00	0.00
13,500.00	88.70	179.51	10,936.03	-2,821.51	24.01	2,821.61	0.00	0.00	0.00
13,600.00	88.70	179.51	10,938.30	-2,921.48	24.86	2,921.59	0.00	0.00	0.00
13,700.00	88.70	179.51	10,940.57	-3,021.45	25.71	3,021.56	0.00	0.00	0.00
13,800.00	88.70	179.51	10,942.84	-3,121.42	26.56	3,121.53	0.00	0.00	0.00
13,900.00	88.70	179.51	10,945.11	-3,221.39	27.41	3,221.51	0.00	0.00	0.00
14,000.00	88.70	179.51	10,947.38	-3,321.36	28.26	3,321.48	0.00	0.00	0.00
14,100.00	88.70	179.51	10,949.64	-3,421.33	29.11	3,421.46	0.00	0.00	0.00
14,200.00	88.70	179.51	10,951.91	-3,521.30	29.96	3,521.43	0.00	0.00	0.00
14,300.00	88.70	179.51	10,954.18	-3,621.28	30.82	3,621.41	0.00	0.00	0.00
14,400.00	88.70	179.51	10,956.45	-3,721.25	31.67	3,721.38	0.00	0.00	0.00
14,500.00	88.70	179.51	10,958.72	-3,821.22	32.52	3,821.35	0.00	0.00	0.00
14,600.00	88.70	179.51	10,960.99	-3,921.19	33.37	3,921.33	0.00	0.00	0.00
14,700.00	88.70	179.51	10,963.26	-4,021.16	34.22	4,021.30	0.00	0.00	0.00
14,800.00	88.70	179.51	10,965.53	-4,121.13	35.07	4,121.28	0.00	0.00	0.00
14,900.00	88.70	179.51	10,967.79	-4,221.10	35.92	4,221.25	0.00	0.00	0.00
15,000.00	88.70	179.51	10,970.06	-4,321.07	36.77	4,321.23	0.00	0.00	0.00
15,100.00	88.70	179.51	10,972.33	-4,421.04	37.62	4,421.20	0.00	0.00	0.00
15,200.00	88.70	179.51	10,974.60	-4,521.01	38.47	4,521.17	0.00	0.00	0.00
15,297.42	88.70	179.51	10,976.81	-4,618.40	39.30	4,618.57	0.00	0.00	0.00

Database:	GCR DB	Local Co-ordinate Reference:	Well 1H
Company:	Chevron	TVD Reference:	KB @ 3585.50usft (Ensign 153)
Project:	Lea County NM (NAD27 NME)	MD Reference:	KB @ 3585.50usft (Ensign 153)
Site:	Madera 17 Federal	North Reference:	Grid
Well:	1H	Survey Calculation Method:	Minimum Curvature
Wellbore:	WB1/Job #1410114		
Design:	Plan #1 01-15-14		

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)
TD at 15297.42 - PBHL-Madera 17 Fed #1H									

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
PBHL-Madera 17 Fed # - plan hits target center - Point	0.00	0.01	10,976.81	-4,618.40	39.30	441,554.80	762,627.60	32° 12' 39.95796 N	103° 29' 3.10314 W

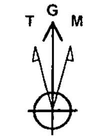
Formations

Measured Depth (usft)	Vertical Depth (usft)	Name	Lithology	Dip (°)	Dip Direction (°)
11,144.20	10,882.58	TL 10872' TVD @ 0' VS w/88.7° Inc		1.30	179.51

Plan Annotations

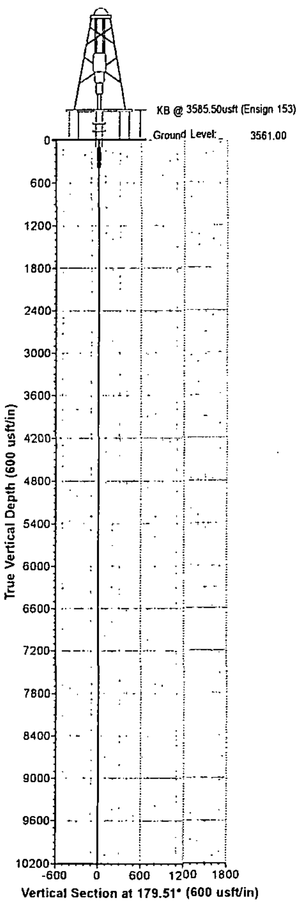
Measured Depth (usft)	Vertical Depth (usft)	Local Coordinates +N/-S (usft)	+E/-W (usft)	Comment
10,405.25	10,405.25	0.00	0.00	KOP, 12°/100' Build
11,144.41	10,882.59	-466.61	3.97	LP, Hold 88.7° Inc
15,297.42	10,976.81	-4,618.40	39.30	TD at 15297.42

Project: Lea County NM (NAD27 NME)
Site: Madera 17 Federal
Well: 1H
Wellbore: WB1/Job #1410114
Design: Plan #1 01-15-14
Rig: Ensign 153



Azimuths to Grid North
True North: -0.45°
Magnetic North: 6.79°

Magnetic Field
Strength: 48375.6snT
Dip Angle: 60.14°
Date: 12/10/2013
Model: IGRF2010_14



WELL DETAILS

Ground Level: 3561.00

+N/-S	+E/-W	Northing	Easting	Latittude	Longitude
0.00	0.00	446173.20	762588.30	32° 13' 25.66150 N	103° 29' 3.13581 W

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Target	Annotation
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
2	10405.25	0.00	0.00	10405.25	0.00	0.00	0.00	0.00	0.00		KOP, 12°/100' Build
3	11144.41	88.70	179.51	10882.59	-466.62	3.97	12.00	179.51	466.63		LP, Hold 88.7° Inc
4	15297.42	88.70	179.51	10976.81	-4618.40	39.30	0.00	0.00	4618.57	PBHL-Madera 17 Fed #1H	TD at 15297.42

DESIGN TARGET DETAILS

Name	TVD	+N/-S	+E/-W	Northing	Easting	Latitude	Longitude	Shape
PBHL-Madera 17 Fed #1H	10976.81	-4618.40	39.30	441554.80	762627.60	32° 12' 39.95796 N	103° 29' 3.10314 W	Point

- plan hits target center

Map System: US State Plane 1927 (Exact solution)
Datum: NAD 1927 (NADCON CONUS)
Ellipsoid: Clarke 1866
Zone Name: New Mexico East 3001

Local Origin: Well 1H, Grid North

Latitude: 32° 13' 25.66150 N
Longitude: 103° 29' 3.13581 W

Grid East: 762588.30
Grid North: 446173.20
Scale Factor: 1.000

Geomagnetic Model: IGRF2010_14
Sample Date: 10-Dec-13
Magnetic Declination: 7.24°
Dip Angle from Horizontal: 60.14°
Magnetic Field Strength: 48376

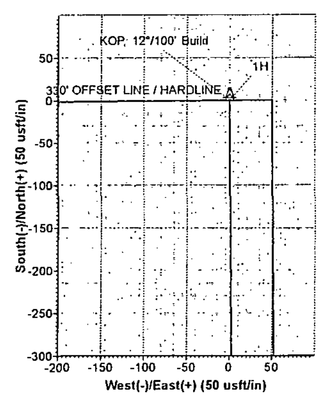
To convert a Magnetic Direction to a Grid Direction, Add 6.79°
To convert a Magnetic Direction to a True Direction, Add 7.24° East
To convert a True Direction to a Grid Direction, Subtract 0.45°

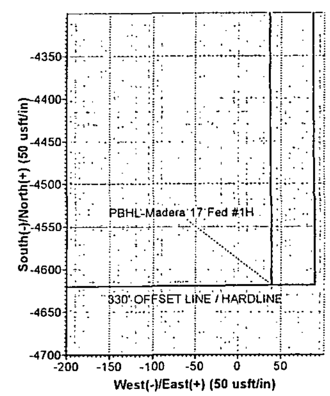
FORMATION TOP DETAILS

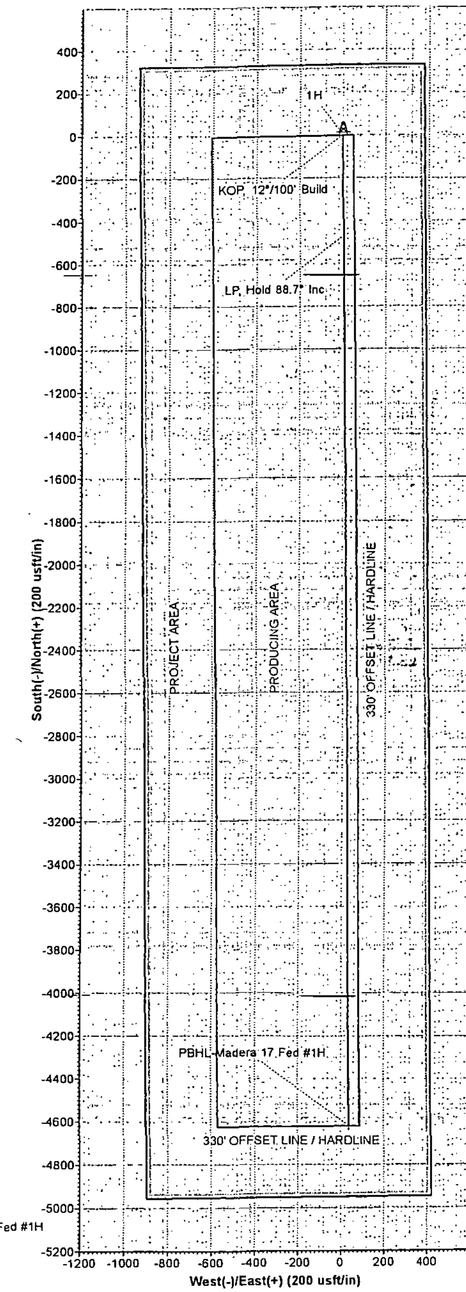
TVDPath	MDPath	Formation	DipAngle	DipDir
10882.58	11144.20	TL 10872' TVD @ 0' VS w/88.7° Inc	1.30	179.51

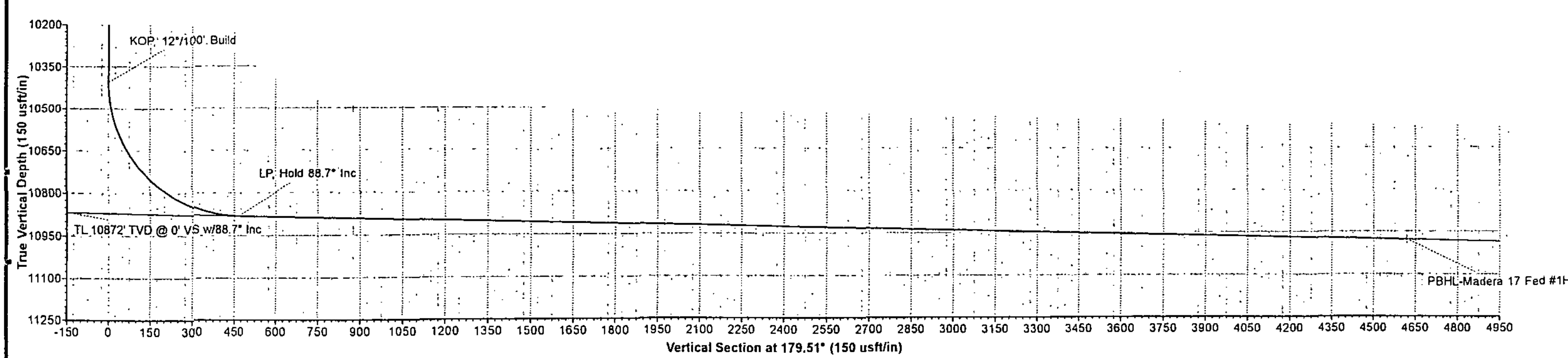
LEGEND

——— Plan #1 01-15-14









Created By: Julio Piña Date: 17:54, January 15 2014

OHSORE OIL & GAS ODER NO. 1
Approval of Operations on Onshore
Federal and Indian Oil and Gas Leases

All lease and/or unit operations are to be conducted in such a manner that full compliance is made with the applicable laws, regulations (CFR 43, Part 3160) and the approved Application for Permit to Drill. The operator is considered fully responsible for the actions of his subcontractors. A copy of the approved APD must be on location during construction, drilling and completion operations.

Approval of this application 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.

1. **FORMATION TOPS**

The estimated tops of important geologic markers are as follows:

FORMATION	SUB-SEA	KBTVD	MD
Rustler	2431	1155	
Magenta Dolomite	2361	1225	
Salado	1922	1664	
Castile	-225	3811	
Lamar	-1753	5339	
Bell Canyon	-1771	5357	
Cherry Canyon	-2650	6236	
Brushy Canyon	-4036	7622	
Bone Spring Limestone	-5418	9004	
1st Bone Spring	-6350	9936	
2nd Bone Spring	-6955	10541	
Landing Point (2nd Bone Spring)	-7296	10882	11144
Lateral TD (2nd Bone Spring)	-7390	10976	15297

Note: Planned target line is 88.7 deg inc.

2. **ESTIMATED DEPTH OF WATER, OIL, GAS & OTHER MINERAL BEARING FORMATIONS**

The estimated depths at which the top and bottom of the anticipated water, oil, gas, or other mineral bearing formations are expected to be encountered are as follows:

Substance	Formation	Depth
Deepest Expected Base of Fresh Water		1253
Water	Rustler	1155
Water	Bell Canyon	1225
Water	Cherry Canyon	6236
Oil/Gas	Brushy Canyon	7622
Oil/Gas	Bone Spring Limestone	9004
Oil/Gas	1st Bone Spring	9936
Oil/Gas	2nd Bone Spring	10541

All shows of fresh water and minerals will be reported and protected.

3. **BOP EQUIPMENT**

Will have a minimum of a 5000 psi rig stack (see proposed schematic) for drill out below surface casing. Stack will be tested as specified in the attached testing requirements. Chevron requests a variance to use A coflex hose with a metal protective covering that will be utilized between the BOP and Choke manifold. Please see the attached testing and certification information.

Chevron requests a variance to use a GE/Vetco SH-2 Multibowl wellhead, which will be run through the rig foor on surface casing. BOPE will be nippled up and test after cementing surface casing. Subsequent tests will be performed as needed, not to exceed 30 days. The field report from GE/Vetco and BOP test information will be provided in a subsequent report at the end of the well. Please see the attached wellhead schematic and installation manual.

4. **CASING PROGRAM**

a. The proposed casing program will be as follows:

Purpose	From	To	Hole Size	Csg Size	Weight	Grade	Thread	Condition
Surface	0'	1,288'	17-1/2"	13-3/8"	48 #	H-40	STC	New
Shallow Intermediate	0'	5,200'	12-1/4"	9-5/8"	40 #	J-55	LTC	New
Production	0'	15,297'	8-3/4"	5-1/2"	17.0 #	HCP-110	CDC	New

b. Casing design subject to revision based on geologic conditions encountered.

c. *****A "Worst Case" casing design for wells in a particular area is used below to calculate the Casing Safety Factors. If for any reason the casing design for a particular well requires setting casing deeper than the following "worst case" design, then the Casing Safety Factors will be recalcuated & sent to the BLM prior to drilling.**

d. **Chevron will fill casing at a minimum of every 20 jts (840') while running for intermediate and production casing in order to maintain collapse SF.**

SF Calculations based on the following "Worst Case" casing design.
Surface Casing: 1500'
Intermediate Casing: 5200'
Production Casing: 16,500' MD/11,500' TVD (5000' VS @ 90 deg inc)

Casing String	Min SF Burst	Min SF Collapse	Min SF Tension
Surface	1.28	1.14	1.6
Shallow Intermediate	1.28	1.25	1.6
Production	1.34	1.65	1.6

Min SF is the smallest of a group of safety factors that include the following considerations:

	Surf	Int	Prod
Burst Design			
Pressure Test- Surface, Int, Prod Csg P external: Water P internal: Test psi + next section heaviest mud in csg	X	X	X
Displace to Gas- Surf Csg P external: Water P internal: Dry Gas from Next Csg Point	X		
Frac at Shoe, Gas to Surf- Int Csg P external: Water P internal: Dry Gas, 15 ppg Frac Gradient		X	
Stimulation (Frac) Pressures- Prod Csg P external: Water P internal: Max inj pressure w/ heaviest injected fluid			X
Tubing leak- Prod Csg (packer at KOP) P external: Water P internal: Leak just below surf, 8.7 ppg packer fluid			X
Collapse Design			
Full Evacuation P external: Water gradient in cement, mud above TOC P internal: none	X	X	X
Cementing- Surf, Int, Prod Csg P external: Wet cement P internal: water	X	X	X
Tension Design			
100k lb overpull	X	X	X

5. **CEMENTING PROGRAM**

Slurry	Type	Top	Bottom	Weight	Yield	%Excess	Sacks	Water
Surface				(ppg)	(sx/cu ft)	Open Hole		gal/sk
Lead	C + 4% Gel+2%CaCl	0'	988'	13.5	1.75	150	933	9.18
Tail	Class C+2%CaCl	988'	1,288'	14.8	1.36	150	441	6.39
Intermediate								
Lead	65C/35Poz +6%Gel +5%Salt	0'	4,600'	12.9	1.87	100	1369	9.72
Tail	Class C	4,600'	5,200'	14.8	1.33	100	311	6.24
Production								
Lead	50% Class H+ 50% Silicalite +2% Gel	4,700'	9,883'	12.5	1.81	75	1216	9.62
Tail	Class H (Premium)	9,883'	15,297'	15.6	1.19	75	2016	5.38

1. Final cement volumes will be determined by caliper.
2. Surface casing shall have at least one centralizer installed on each of the bottom three joints starting with the shoe joint.
3. Production casing will have one horizontal type centralizer on every other joint for the first 1000' from TD, then every third joint to EOB, and then every other joint to KOP. Bowspring type centralizers will be run from KOP to intermediate casing.

6. **MUD PROGRAM**

From	To	Type	Weight	F. Vis	Filtrate
0'	1,288'	Spud Mud	8.3 - 8.7	32 - 34	NC - NC
1,288'	5,200'	Brine	9.5 - 10.1	28 - 29	NC - NC
5,200'	10,383'	FW/Cut Brine	8.3 - 9.5	28 - 29	NC - NC
10,383'	11,122'	Cut Brine	8.3 - 9.5	28 - 30	15 - 25
11,122'	15,297'	FW/Cut Brine	8.3 - 9.5	28 - 29	15 - 25

A closed system will by utilized consisting of above ground steel tanks. All wastes accumulated during drilling operations will be contained in a portable trash cage and removed from location and deposited in an approved sanitary landfill. Sanitary wastes will be contained in a chemical porta-toilet and then hauled to an approved sanitary landfill.

All fluids and cuttings will be disposed of in accordance with New Mexico Oil Conservation Division rules and regulations.

A mud test shall be performed every 24 hours after mudding up to determine, as applicable: density, viscosity, gel strength, filtration, and pH.

Visual mud monitoring equipment shall be in place to detect volume changes indicating loss or gain of circulating fluid volume. When abnormal pressures are anticipated -- a pit volume totalizer (PVT), stroke counter, and flow sensor will be used to detect volume changes indicating loss or gain of circulating fluid volume.

A weighting agent and lost circulating material (LCM) will be onsite to mitigate pressure or lost circulation as hole conditions dictate.

7. **TESTING, LOGGING, AND CORING**

The anticipated type and amount of testing, logging, and coring are as follows:

a. Drill stem tests are not planned.
b. The logging program will be as follows:

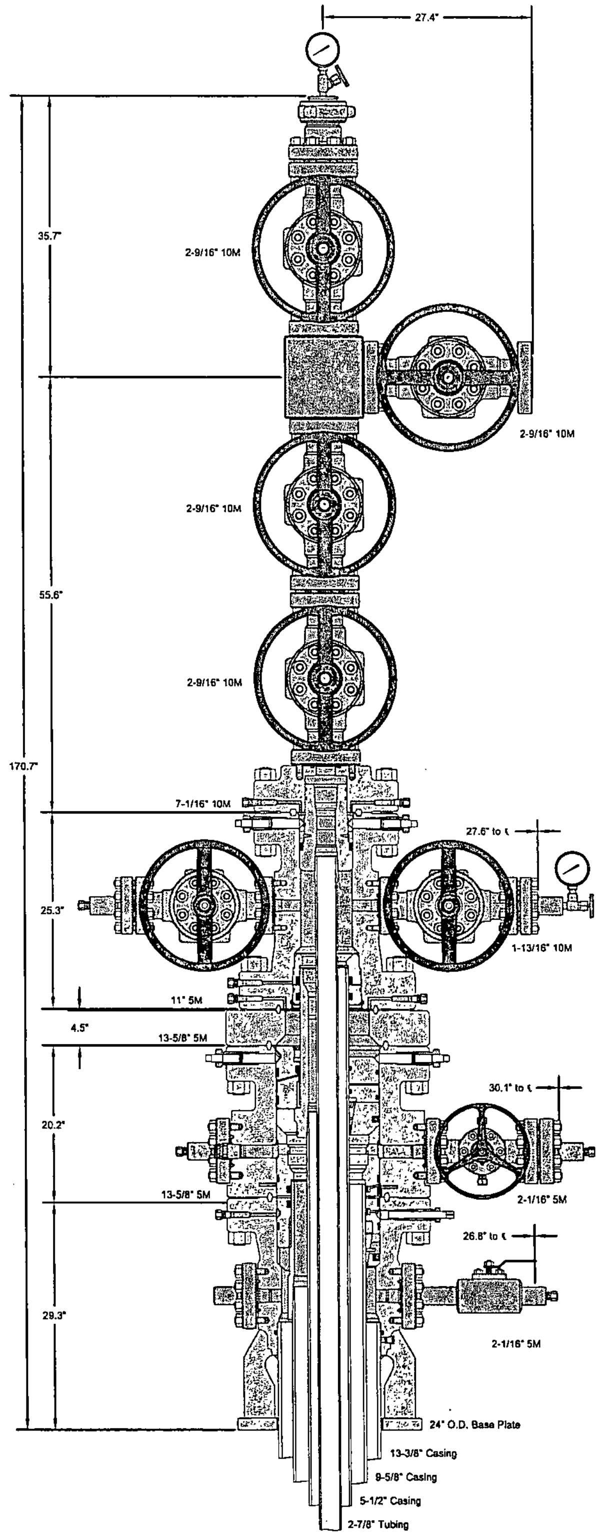
TYPE	Logs	Interval	Timing	Vendor
Mudlogs	2 man mudlog	Int Csg to TD	Drillout of Int Csg	TBD
LWD	MWD Gamma	Curve and Lateral	While Drilling	TBD
Wireline	Triple Combo	KOP to Surf	After reaching KOP.	TBD
-	-	-	-	-
-	-	-	-	-

c. Conventional whole core samples are not planned.
d. A Directional Survey will be run.

8. **ABNORMAL PRESSURES AND HYDROGEN SULFIDE**

a. No abnormal pressures or temperatures are expected. Estimated BHP is: 4842 psi
b. Hydrogen sulfide gas is not anticipated. An H2S Contingency plan is attached with this APD in the event that H2S is encountered

GE Oil & Gas



CHEVRON USA, INC.
DELAWARE BASIN

13-3/8" x 9-5/8" x 5-1/2" x 2-7/8" 10M SH2/Conventional Wellhead Assembly, With DSA, T-EBS-F Tubing Head, T-EN Tubing Hanger and A5PEN Adapter Flange

DRAWN	VJK	19MAR13
APPRV	KN	19MAR13
FOR REFERENCE ONLY		
DRAWING NO.	AE23705	

H_2S Preparedness and Contingency Plan Summary

Madera 17 Federal 1H

Training

MCBU Drilling and Completions H_2S training requirements are intended to define the minimum level of training required for employees, contractors and visitors to enter or perform work at MCBU Drilling and Completions locations that have known concentrations of H_2S.

Awareness Level

Employees and visitors to MCBU Drilling and Completions locations that have known concentrations of H_2S, who are not required to perform work in H_2S areas, will be provided with an awareness level of H_2S training prior to entering any H_2S areas. At a minimum, awareness level training will include:

1. Physical and chemical properties of H_2S
2. Health hazards of H_2S
3. Personal protective equipment
4. Information regarding potential sources of H_2S
5. Alarms and emergency evacuation procedures

Awareness level training will be developed and conducted by personnel who are qualified either by specific training, educational experience and/or work-related background.

Advanced Level H_2S Training

Employees and contractors required to work in areas that may contain H_2S will be provided with Advanced Level H_2S training prior to initial assignment. In addition to the Awareness Level requirements, Advanced Level H_2S training will include:

1. H_2S safe work practice procedures;
2. Emergency contingency plan procedures;
3. Methods to detect the presence or release of H_2S (e.g., alarms, monitoring equipment), including hands-on training with direct reading and personal monitoring H_2S equipment.
4. Basic overview of respiratory protective equipment suitable for use in H_2S environments. Note: Employees who work at sites that participate in the Chevron Respirator User program will require separate respirator training as required by the MCBU Respiratory Protection Program;
5. Basic overview of emergency rescue techniques, first aid, CPR and medical evaluation procedures. Employees who may be required to perform "standby" duties are required to receive additional first aid and CPR training, which is not covered in the Advanced Level H_2S training;
6. Proficiency examination covering all course material.

Advanced H_2S training courses will be instructed by personnel who have successfully completed an appropriate H_2S train-the-trainer development course (ANSI/ASSE Z390.1-2006) or who possess significant past experience through educational or work-related background.

H_2S Training Certification

All employees and visitors will be issued an H_2S training certification card (or certificate) upon successful completion of the appropriate H_2S training course. Personnel working in an H_2S environment will carry a current H_2S training certification card as proof of having received the proper training on their person at all times.

Briefing Area

A minimum of two briefing areas will be established in locations that at least one area will be up-wind from the well at all times. Upon recognition of an emergency situation, all personnel should assemble at the designated upwind briefing areas for instructions.

H_2S Equipment

Respiratory Protection

a) Six 30 minute SCBAs – 2 at each briefing area and 2 in the Safety Trailer.

b) Eight 5 minute EBAs – 5 in the dog house at the rig floor, 1 at the accumulator, 1 at the shale shakers and 1 at the mud pits.

Visual Warning System

a) One color code sign, displaying all possible conditions, will be placed at the entrance to the location with a flag displaying the current condition.

b) Two windsocks will be on location, one on the dog house and one on the Drill Site Manager's Trailer.

H_2S Detection and Monitoring System

a) H_2S monitoring system (sensor head, warning light and siren) placed throughout rig.

- Drilling Rig Locations: at a minimum, in the area of the Shale shaker, rig floor, and bell nipple.
- Workover Rig Locations: at a minimum, in the area of the Cellar, rig floor and circulating tanks or shale shaker.

Well Control Equipment

a) Flare Line 150' from wellhead with igniter.

b) Choke manifold with a remotely operated choke.

c) Mud / gas separator

Mud Program

In the event of drilling, completions, workover and well servicing operations involving a hydrogen sulfide concentration of 100 ppm or greater the following shall be considered:

1. Use of a degasser
2. Use of a zinc based mud treatment
3. Increasing mud weight

Public Safety - Emergency Assistance

Agency	Telephone Number
Lea County Sheriff's Department	575-396-3611
Fire Department:	
Carlsbad	575-885-3125
Artesia	575-746-5050
Lea County Regional Medical Center	575-492-5000
Jal Community Hospital	505-395-2511
Lea County Emergency Management	575-396-8602
Poison Control Center	800-222-1222

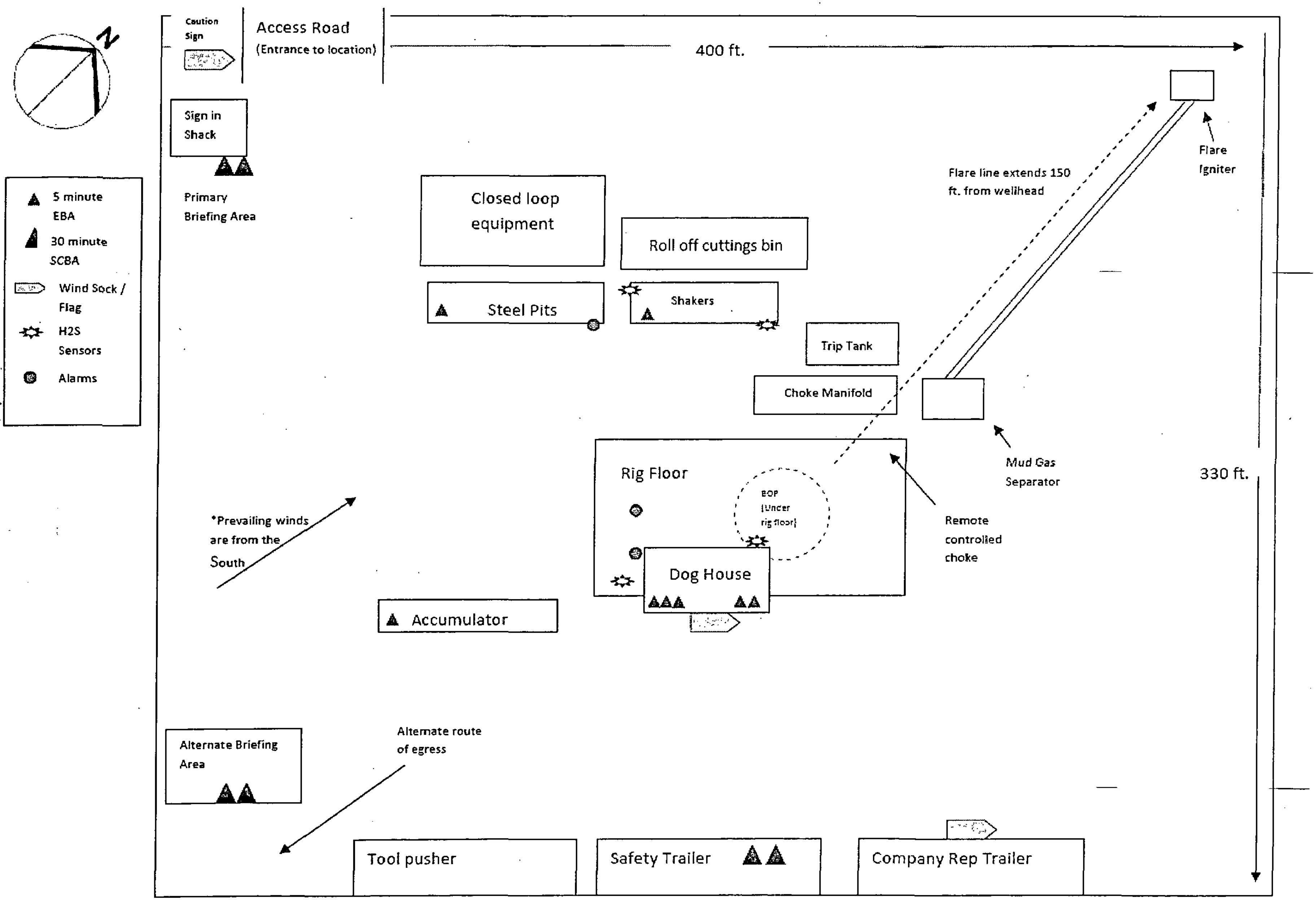
Chevron

Chevron MCBU D&C Emergency Notifications

Below are lists of contacts to be used in emergency situations.

	Name	Title	Office Number	Cell Phone
1.	Kyle Johnson	Drilling Engineer	(713) 372-6514	(832) 714-0670
2.	Dan Jovanovic	Superintendent	(713) 372-1402	(832) 319-4079
5.	Kim McHugh	Drilling Manager	(713) 372-7591	(713) 204- 8550
6.	Darrell Hammonds	Operations Manager	(713) 372-5747	(281) 352 2302
7.	Andrea Calhoun	D&C HES	(713) 372-7586	(832) 588-0100
8.	Andrew Espinoza	Completion Engineer	(713) 372-7587	(713) 294-9534

H_2S Preparedness and Contingency Plan Summary



GE Oil & Gas
Drilling & Production

Pressure Control Wellhead Equipment Running Procedure For:

Chevron

13-3/8" x 9-5/8" x 5-1/2" x 2-7/8" 10M SH2/SH2-R Wellhead Assembly

Publication # RP-2072
June, 2012

GE

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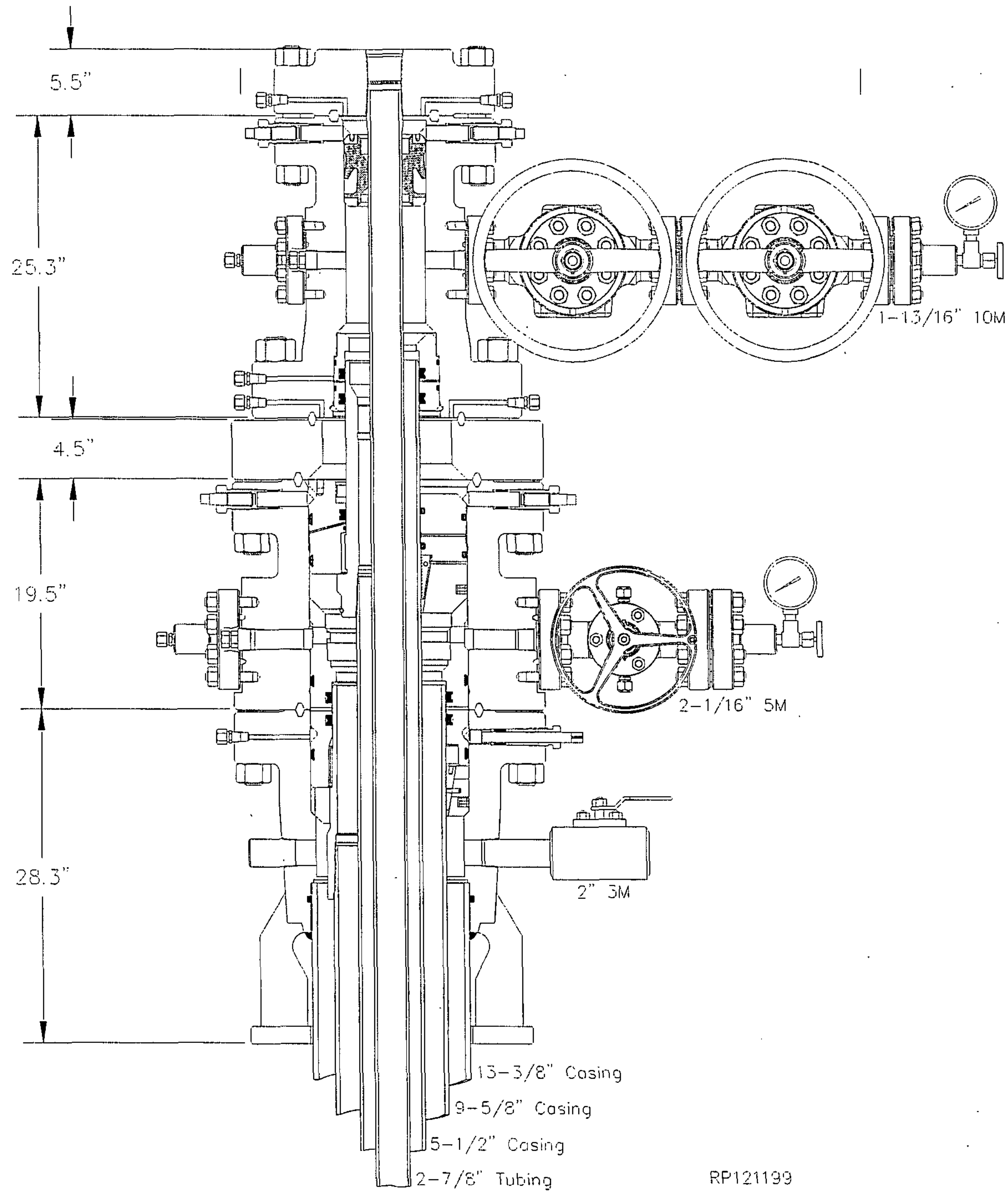
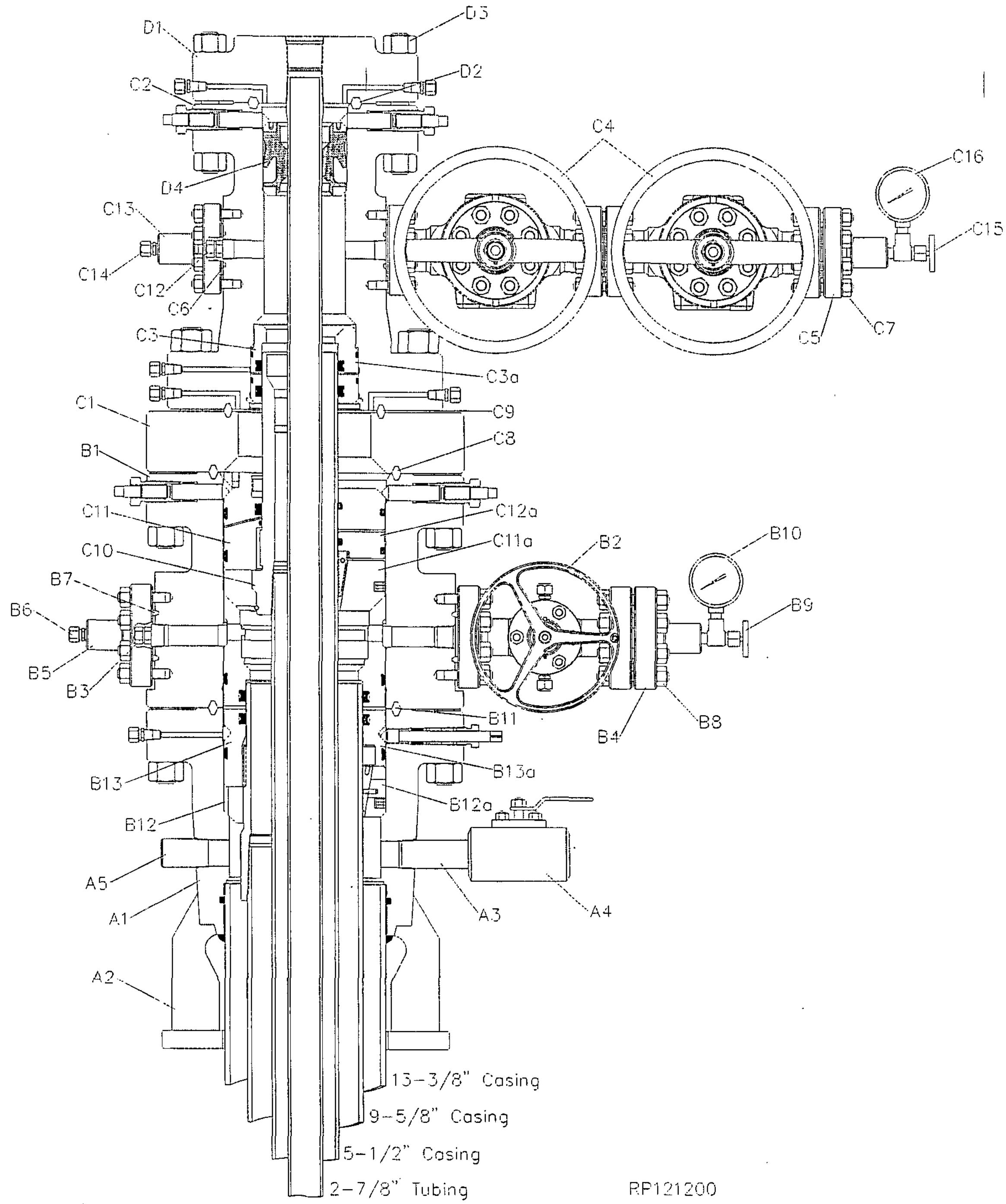
System Drawing



Bill of Materials



LOWER SH2 ASSEMBLY

Item	Qty	Description
A1	1	Housing, SH2-LWR, 13-5/8" 5M x 13-3/8" SOW, o-ring, with two 2" line pipe outlets Part # 3315122
A2	1	Baseplate Kit, 24" OD x 14" ID x 1.50" thick, with six #1 gussets and two 2-1/2" grout slots, (for 13-5/8" casing head) Part # 342693
A3	1	Nipple, 2" line pipe x 6" long, XXH with 1.50" bore Part # NI6
A4	1	Ball Valve, KF, CFH, 2 RP 3M, threaded, 2LP, carbon steel, with CS Trim Part # BV2-3
A5	1	Bull Plug, solid, 2" line pipe x 1/2" line pipe, 4" long Part # BPS-API

UPPER SH2 ASSEMBLY

Item	Qty	Description
B1	1	Housing, SH2-UPR, 13-5/8" 5M studded x 13-5/8" 5M with two 2-1/16" 5M studded outlets, integral lockscrews and seal test port Part # 376846
B2	1	Gate Valve, WG, 1000, 2-1/16" 3/5M, flanged, 6A-PU-AA-1-2 Part # 327693
B3	1	Valve Removal Plug, 1-1/2" sharp vee, with 1-1/4" hex, API Part # 329570
B4	2	Companion Flange, 2-1/16" 5M x 2" line pipe, 6A-PU-EE-NL-1 Part # 317865
B5	2	Bull Plug, tapped, 2" line pipe x 1/2" npt Part # BPT-API
B6	1	Fitting, grease/vent, 1/2" NPT 10M, SVC 1215 Part # A025-001
B7	3	Ring Gasket, R-24, Carbon Steel, Plated, AISI 1005/1020, API 6A PSL 1-4 Part # R24
B8	8	Stud, with two nuts, plated, 7/8" x 6-1/2, B7/2H Part # 331062
B9	1	Needle Valve, angled, 1/2" npt Part # NVA
B10	1	Pressure Gauge, 0-5000 PSI, Dual Gage, 75% liquid filled, 4" min. O.D. face, 1/2" NPT, SS Case, Poly Carbonite face, Crimped Bezel, Temp -40 to 220F Part # PG5
B11	1	Ring Gasket, BX-160, carbon steel, plated, API 6A PSL 1-4 Part # BX160
B12	1	Casing Hanger, SH2, 13-5/8" x 9-5/8" (36.0# - 40.0#) LC box bottom x 10.125" -4 ACME left hand pin, minimum bore 8.785", 6A-U-AA-1-2 Part # 336028
B13	1	Packoff Support Bushing, SH2E, 13-5/8" x 9-5/8" for use with mandrel hanger, 6A-PU-AA-1-2 Part # 348027

TUBING HEAD ASSEMBLY

Item	Qty	Description
C1	1	DSA, 13-5/8" 5M x 11" 5M, 6A-PU-EE-NL-1 Part # 332394
C2	1	Tubing Head, WG, T-EBS-F, 9", 11" 5M x 7-1/16" 10M, with two 1-13/16" 10M studded outlets Part # 350994
C3	1	Secondary Seal, WG, EBS-F, 9" x 7" Part # 350850
C4	2	Gate Valve, manual, 2200T, 1-13/16" 10M, flanged Part # 373740
C5	2	Companion Flange, 1-13/16" 10M x 2" line pipe, (5000 max wp) 6A-KX-EE-NL-1 Part # 351855
C6	4	Ring Gasket, BX-151, carbon steel, API 6A PSL 1-4 Part # BX151-SS
C7	16	Studs, with two nuts each, black, 3/4" x 5.50" long, stud A193-GR B7, nuts A194-GR 2H Part # 802029
C8	1	Ring Gasket, BX-160, carbon steel, API 6A PSL 1-4 Part # BX160
C9	1	Ring Gasket, R-54, PSL4 Part # R54
C10	1	Casing Hanger, SH2-R-UPR, 13-5/8" 5M x 5-1/2" LC box bottom x 7.375" -4 ACME left hand pin top, with 5" BPV prep Part # 397222
C11	1	Packoff, SH2E-R-LWR, 13-5/8" x 7" for mandrel hanger, arranged for test port in upper housing Part# 397224
C12	1	Valve Removal Plug, 1-1/4" sharp vee, with 1-1/4" hex, API Part # 329569
C13	2	Bull Plug, tapped, 2" line pipe x 1/2" npt Part # BPT-API
C14	1	Fitting, grease/vent, 1/2" NPT 10M Part # A025001
C15	1	Needle Valve, angled, 1/2" npt Part # NVA
C16	1	Pressure Gauge, 0-5000 PSI, Dual Gage, 75% liquid filled, 4" min. O.D. face, 1/2" NPT, SS Case, Poly Carbonite face, Crimped Bezel Part # PG5

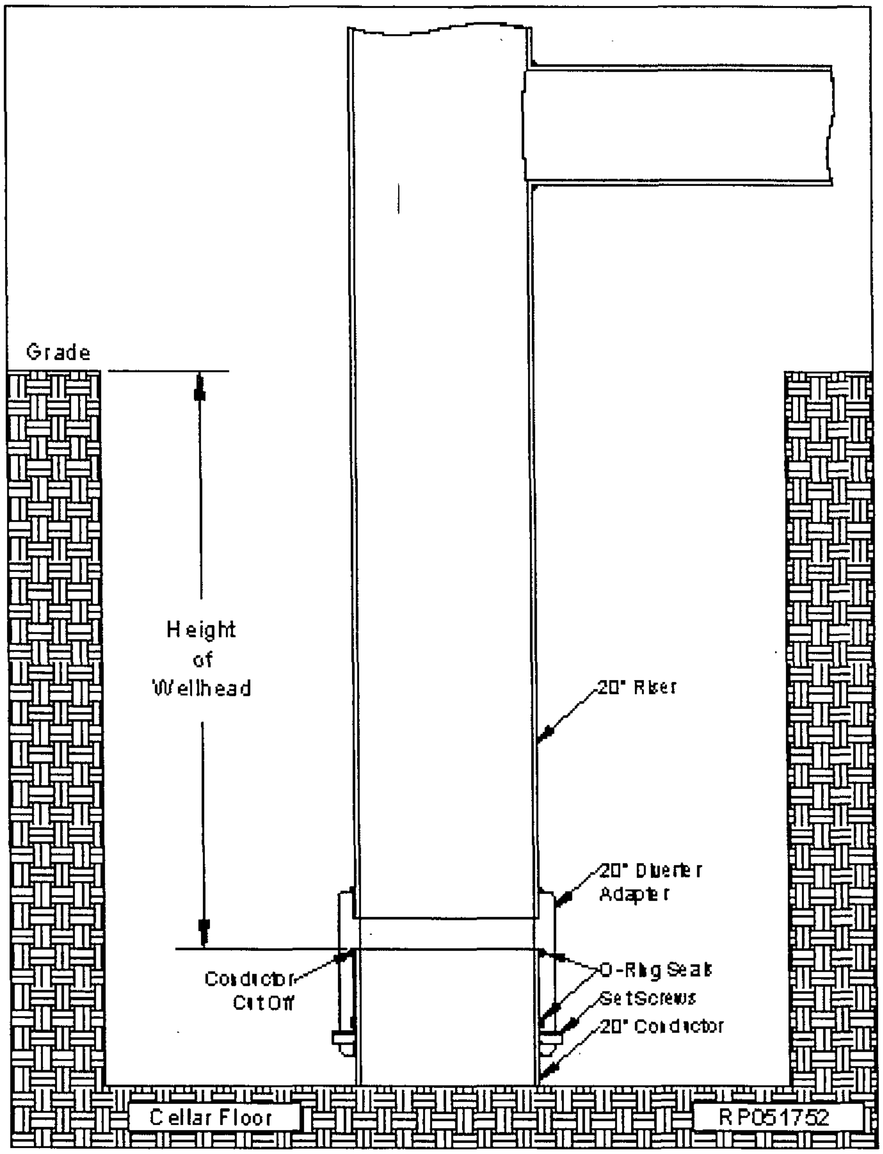
CHRISTMAS TREE ASSEMBLY		
Item	Qty	Description
D1	1	Adapter, WG, B5, 7-1/16" 10M x 2-7/8" EU box bottom and top, 5M psi max Part # TBE-NWH
D2	1	Ring Gasket, BX-156, carbon steel, API 6A PSL 1-4 Part # BX156-SS
D3	12	Studs, with two nuts, PLT, 1-1/2" x 11-3/4" stud A193-GR B7, nut A194-GR 2H Part # 325237
D4	1	Stripper Rubber, TC, 7-1/16" x 2-7/8" Part # 318028

RECOMMENDED SERVICE TOOLS		
Item	Qty	Description
ST1	1	Diverter connector, SRC, 20" SOW x 20" Part # 307158
ST2	1	Lift Flange, 13-5/8" 5M x 13-3/8" Csg box, with 1.5" deep counter bore Part # 344520
ST3	1	Isolation bushing, SH2, WG, 13-5/8" x 13-3/8" ID x 28.5" long Part # 344552S
ST4	1	Test Plug/Retrieving Tool, WG-22, 13-5/8" nominal x 4-1/2" IF box x box Part # 301607
ST5	1	Test Plug/Retrieving Tool, SL, 13-5/8" nominal x 4-1/2" IF box top and bottom with 1-1/4" line pipe bypass and spring loaded dogs Part # 332044
ST6	1	Wear Bushing, WG, SH2-SL, 13-5/8" nominal x 12.36" I.D. x 33 long, with silt barrier Part # 345899
ST7	1	Casing Hanger Running Tool, SH2, 9-5/8" LCSG box top x 10.125"-4-2G left hand internal running threads Part # 300511
ST8	1	Running Tool, WG-SH2 packoff support bushing, 13-5/8" nominal x 4-1/2" IF pin x box Part # 301454
ST9	1	Wear Bushing, SH2-SL, 13-5/8" nominal x 12.62" ID x 13.6" long Part # 334035S
ST10	1	Casing Hanger Running Tool, SH2-R, 7" x 5-1/2" LC box x 7.375"-4-2G left hand internal running threads, 26.5" long Part # 397226
ST11	1	Packoff Running Tool, SH2E-R-LWR, 7.375" 4 Stub Acme LH pin top x 8.750" 4 Stub Acme RH pin bottom, 16.5" long Part # 397387

EMERGENCY EQUIPMENT		
Item	Qty	Description
B12a	1	Casing Hanger, WG-SH1, 13-5/8" x 9-5/8", for high capacity, also for multi bowl Part # 359031
B13a	1	Packoff Support Bushing, WG-SH2S, Emergency, 13-5/8", with 9-5/8" double 'EBS' Seals Part # 348029
C3a	1	Secondary Seal, WG, EBS-F, 9" x 5-1/2" Part # 350848
C110a	1	Casing Hanger, WG, SH1-UPR, 13-5/8" x 5-1/2", for use with test port Part # 397263
C11a	1	Primary Seal, H-SH2, 13-5/8" x 5-1/2", for use with test port, arranged for emergency Part # TBE-NWH

Stage 1 — Installing the 20" Diverter Riser Assembly

1. Drill 20" rat hole and set 20" conductor pipe.
2. Cut the conductor pipe off at the correct height to accommodate the installation of the SH2 Wellhead Assembly and grind stub level.
3. Move rig on location and rig up as required.
4. Examine the ***20" Diverter Adapter (Item ST1)***. Verify the following:
   - 20" riser pipe is properly welded in place and is in good condition
   - all internal seals are in place and in good condition
   - 1" set screws are in place and fully retracted
5. Calculate the distance from the top of the 20" conductor pipe stub to the location of the diverter flowline.
6. Using the calculated dimension, locate and weld in-place, the flowline outlet of the diverter riser.
7. Thoroughly clean and lightly lubricate the I.D. seals of the Diverter Adapter with clean light grease.
8. Remove all old grease, scale and any sharp edges from the O.D. of the conductor stub and then lightly lubricate the stub with clean light grease.
9. Pick up the Diverter Riser Assembly, orientate the flowline outlet as required, and then carefully lower the assembly over the conductor stub until the stub contacts the inner stop shoulder.
10. While balancing the Diverter weight, run in all 1" set screws in an alternating cross pattern. Tighten screws securely.
11. Slack off all weight and secure Diverter Riser as required with necessary tie down lines.
12. Drill and condition hole for 13-3/8" casing.



13. Prior to running the 13-3/8" casing the Diverter Riser must be removed.
14. Remove as much fluid as possible from the Diverter Riser.
15. Fully retract all 1" set screws and remove tie down lines.
16. Attach a suitable lifting device to the Diverter Riser and retrieve with a straight vertical lift.

Stage 2 — Install Split Speed Head With Riser Assembly

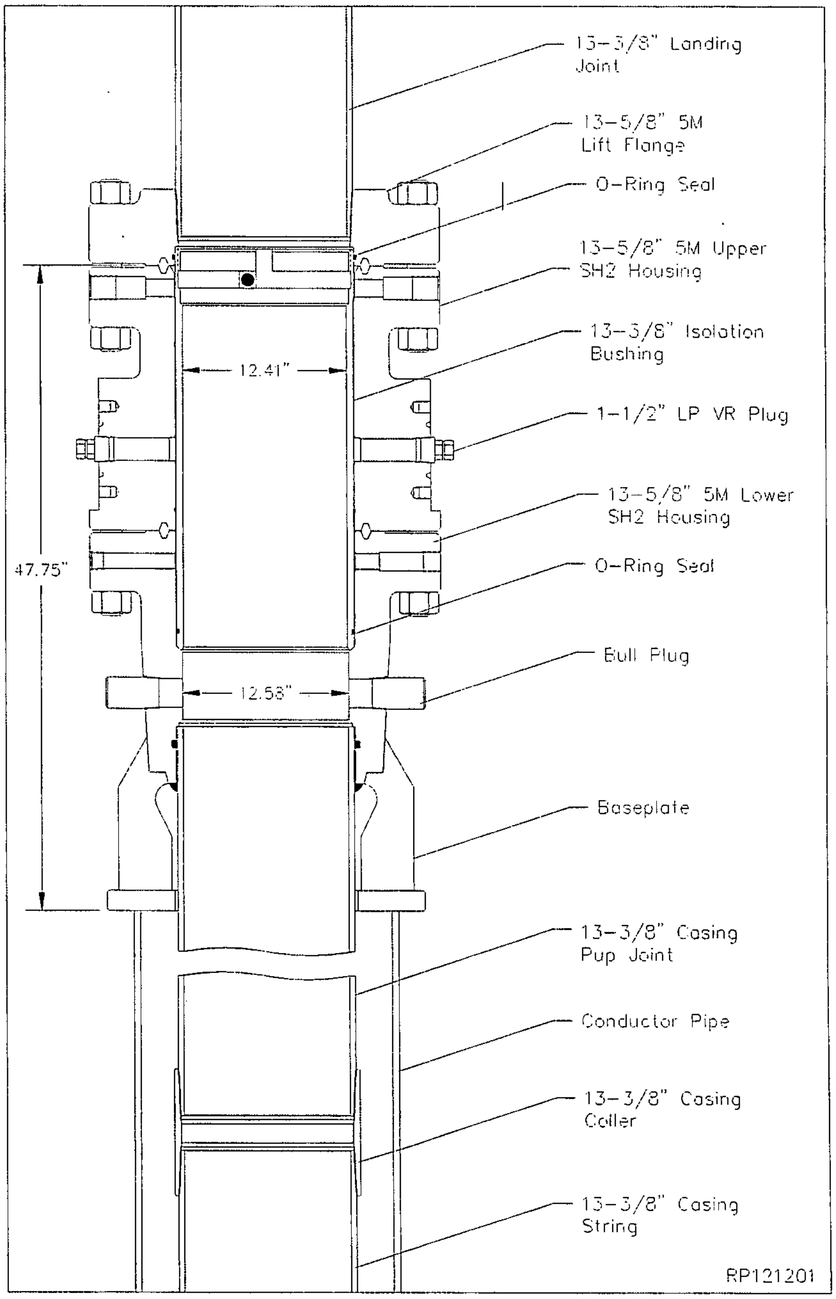
1. Drill and condition hole for surface casing.
2. Cut the conductor pipe off at the correct height above the cellar floor and grind stub level.

Note: The SH2 Riser Assembly is pre-assembled and tested prior to being shipped to location. The assembly is made up of a full length landing joint with flange, upper and lower SH2 housings, and a 10' long pup joint.

3. Examine the ***13-5/8" 5M x 13-3/8" SOW SH2 Speed Head/Riser Assembly (Items A1 & B1)***. Verify the following:
   - 10' pup joint is properly welded in place and casing threads are clean and in good condition
   - all outlet equipment has been removed including all studs and nuts, and valves
   - VR plugs are in place and tight
   - base plate is intact and properly welded to the casing head
   - isolation bushing is in place and properly retained with landing flange
   - landing flange with landing joint are in place and connection is properly made up

Note: Lockscrews are removed to clear 27-1/2" rotary.

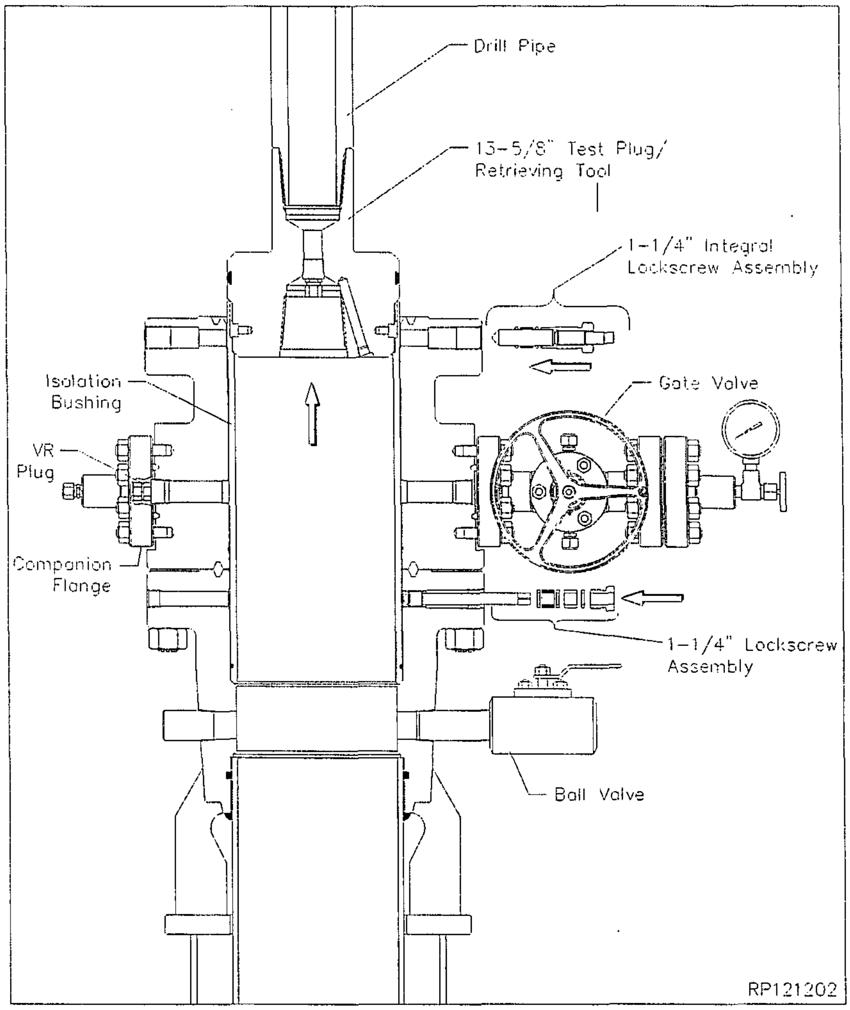
4. Run the surface casing to the required depth and then set the last joint of casing run in the floor slips.
5. Pick up the SH2 Riser Assembly and make up the assembly in the casing string, tightening the thread connection to the thread manufacturers optimum make up torque.
6. Pick up the casing string and remove the floor slips and rotary bushings.
7. Slowly and carefully lower the assembly through the rotary table until the baseplate contacts the conductor pipe stub. Slack off all weight.
8. Rig up the cement head and cement the surface casing string as per program, taking returns through the circulation ports in the baseplate.
9. After the cement job is completed, bleed off and remove the cement head.
10. Remove the landing flange with landing joint and set aside.



11. Examine the ***13-5/8" 22 Test Plug/Retrieving Tool (Item ST4)***. Verify the following:
    - elastomer seals, lift lugs, and plugs are intact and in good condition
    - drill pipe threads are clean and in good condition
11. Orient the retrieving tool with elastomer up and lift lugs down. Make up a joint of drill pipe to the tool.
12. Slowly lower the tool into the Isolation Bushing.

Stage 2 — Install Split Speed Head With Riser Assembly

13. Rotate the tool clockwise until the drill pipe drops approximately 2". This indicates the lugs have aligned with the bushing slots.
14. Slack off all weight to make sure the tool is down and then rotate the tool clockwise 1/4 turn to fully engage the lugs in the bushing.
15. Retrieve the bushing with a straight vertical lift, and remove it and the tool from the drill string.
16. Remove the duct tape from the O.D. of both the upper and lower flanges of the assembly and lightly grease all threaded lockscrew holes.
17. Locate the (six) 1-1/4" and the (twelve) 1-1/4" lockscrew assemblies.
18. Install the 1-1/4" integral lockscrew assemblies in the upper flange and the 1-1/4" assemblies in the lower flange as indicated. (Ref. Dwg. RP121202)



Installing the Outlet Equipment

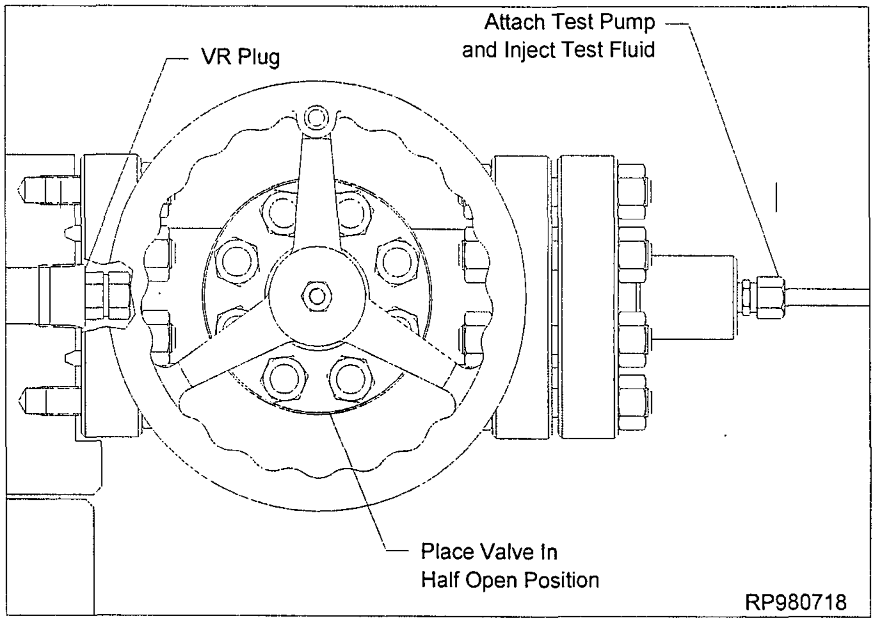
Note: All outlet valves, test and injection fittings, and pad studs are shipped to location loose on a pallet.

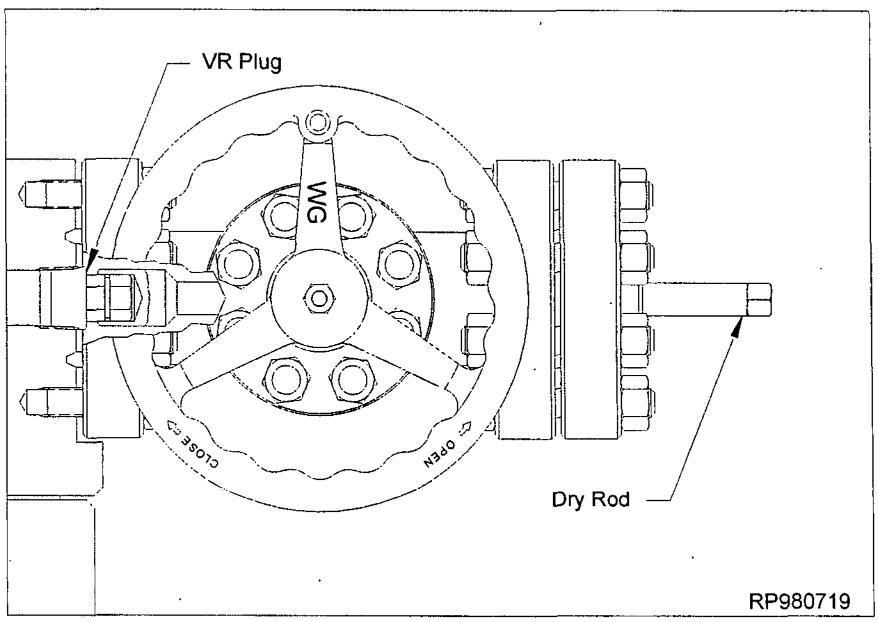
1. Examine all loose equipment. Verify the following:
   - exposed valve and flange ring grooves are clean and in good condition
   - companion flange is made up on valve and flange bolting is tightened securely
   - all fittings are present and in good condition
   - all bull plug and nipple threads are clean and in good condition
   - all pad studs (16) are clean and in good condition
2. Remove all bull plugs, test port, and injection port plugs and set aside.
3. Using a high pressure fresh water hose, thoroughly wash out the entire bore, lockscrew threads and all ports until SH2 assembly is free of all cement debris.
4. Install all test port and injection port fittings as required and tighten securely.
5. Install the ***2" LP, 3M WP Ball Valve, with 2" LP x 6" Long Nipple*** in the open port of the lower speed head and tighten connection securely.
6. Thoroughly clean the 2-1/16" 5M outlet ring grooves, removing all old grease and dirt.
7. Install the 7/8" x 4-1/2" pad studs (8 per outlet) in the side of the upper housing and tighten securely.
8. Place a new ***R-24 Ring Gasket*** in the appropriate outlet ring groove and then install the ***2-1\16" 5M x 2" LP Companion Flange with 2" LP Tapped Bull Plug***. Tighten flange bolting in an alternating cross pattern until a flange standoff of approximately 3/16" is achieved. Tighten bull plug securely.
9. Place a new ***R24 Ring Gasket*** in the opposite outlet ring groove and then install the ***2-1\16" 5M Gate Valve, 2-1\16" 5M x 2" LP Companion Flange and 2" LP, 1/2" NPT Tapped Bull Plug***. Tighten valve flange bolting in an alternating cross pattern until a flange standoff of approximately 3/16" is achieved. Tighten bull plug securely.

Stage 2 — Install Split Speed Head With Riser Assembly

Testing the Valve/Speed Head Connection

10. Place the valve in the half open position.
11. Attach a hand test pump to the open 1/2" NPT port of the bull plug and inject test fluid into the valve until a test pressure of 5,000 psi. is attained. Hold test for 10 minutes or as required by drilling supervisor.
12. After a satisfactory test is achieved, bleed off test pressure, remove test pump and bull plug and drain valve.
13. Fully open the gate valve.
14. Locate the 1-3/8" hex VR plug dry rod and pass the rod through the valve bore and engage it to the 1-3/8" hex of the VR plug.
15. Remove the VR plug from the split speed head by rotating the dry rod to the left until the plug comes free of the VR threads in the speed head.
16. Retrieve the VR plug from the valve bore and fully close the valve.
17. Nipple up BOP stack as required.





Stage 3 — Test the BOP Stack

1. Examine the ***13-5/8" Test Plug/Retrieving Tool (Item ST5)***. Verify the following:
   - elastomer seals, lift lugs, and plugs are intact and in good condition
   - drill pipe threads are clean and in good condition
2. Install a spare Ring Gasket in the ring groove of the Upper Housing and make up the BOP stack.

Immediately after making up the BOP stack and periodically during the drilling of the hole for the next casing string, the BOP stack (connections and rams) must be tested.

3. Orient the Test Plug with elastomer down and lift lugs up. Make up a joint of drill pipe to the Test Plug.

WARNING: Make sure the **elastomer is down** and the **lift lugs are up**.

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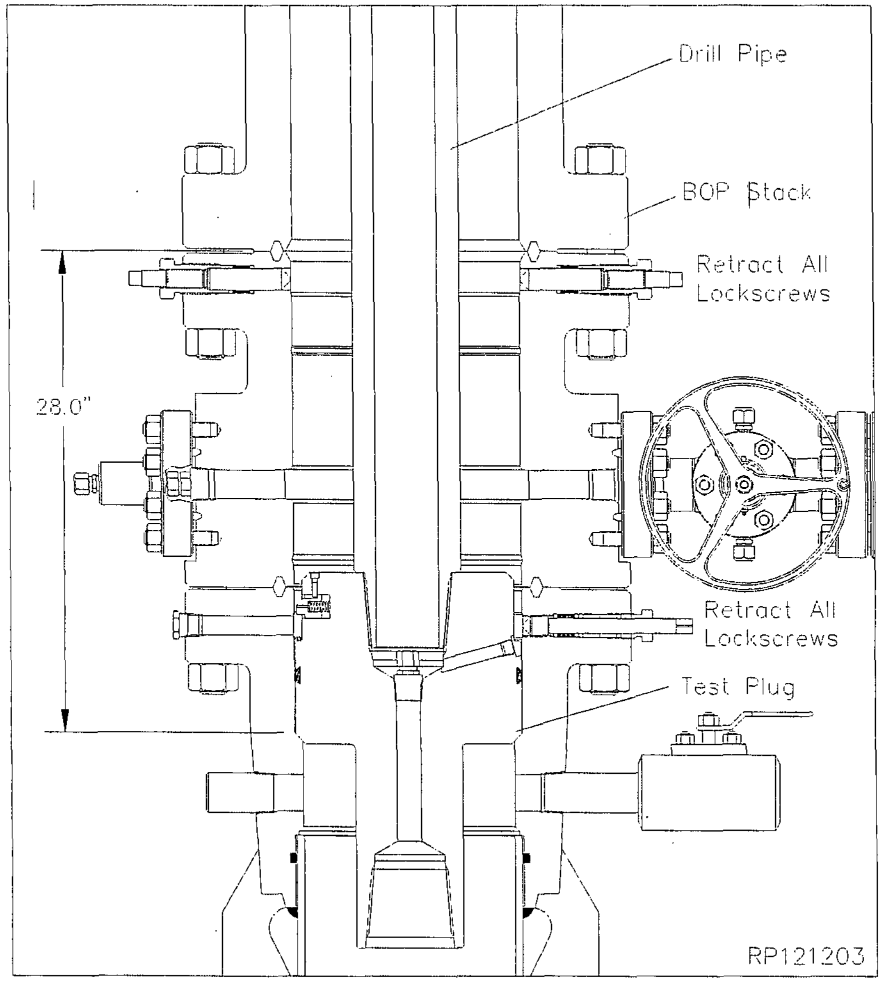
4. Remove 1/2" NPT pipe plug if pressure is to be supplied through the drill pipe.
5. Fully retract all lockscrews in the entire Speed Head Assembly.
6. Lubricate the elastomer seal of the Test Plug with a light oil or grease.
7. Lower the Test Plug through the BOP and into the Speed Head Assembly until it lands on the load shoulder in the Casing Head.
8. Open the Lower speed Head side outlet valve to monitor any leakage past the test plug seal.
9. Close the BOP rams on the drill pipe and test to 5,000 psi. or as required by drilling supervisor.
10. After a satisfactory test, release pressure, and open the rams.
11. Remove as much fluid from the BOP stack as possible.
12. Retrieve the Test Plug Assembly slowly to avoid damage to the seal.
13. Repeat steps 7 - 12 as required during the drilling of the hole.

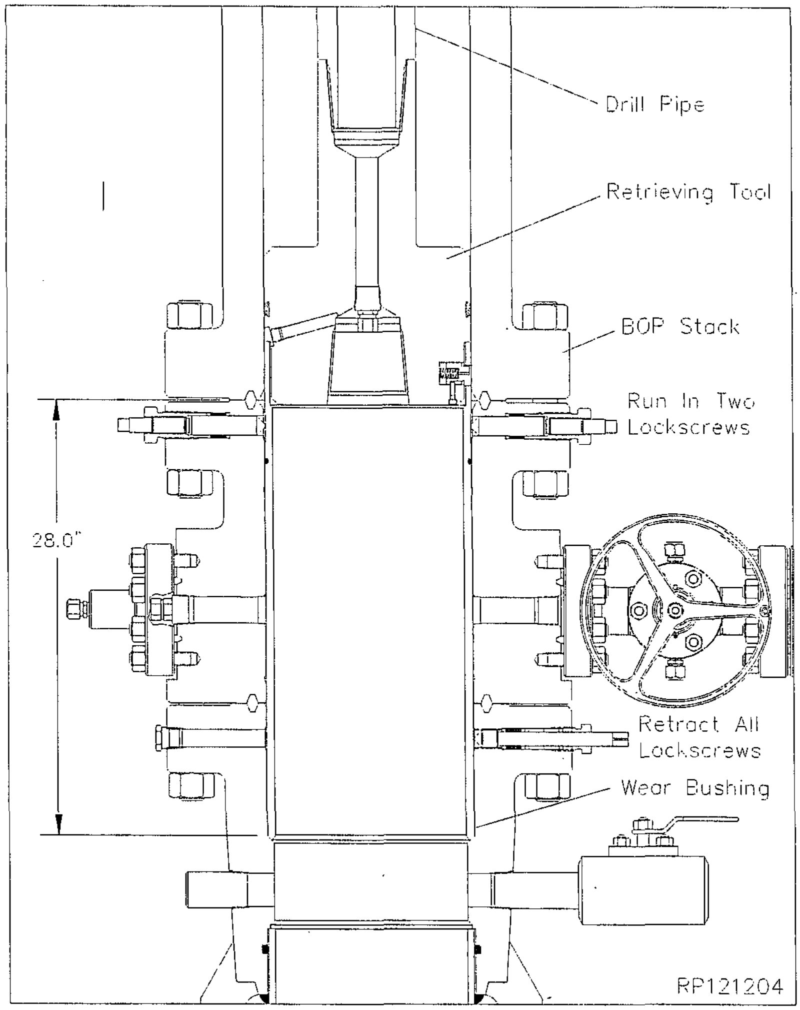


Stage 4 — Run the Long Wear Bushing

Note: Always use a Wear Bushing while drilling to protect the load shoulders and seal area from damage by the drill bit or rotating drill pipe. The Wear Bushing **must be retrieved** prior to running the casing.

Note: Locate two opposing lockscrews of the Upper Housing, that are convenient and paint both screws **RED.**

1. Examine the ***13-5/8" Nominal Long Wear Bushing (Item ST6)***. Verify the internal bore is clean and undamaged.
2. Examine the ***13-5/8" Test Plug/Retrieving Tool (Item ST5)***. Verify the following:
   - drill pipe threads are clean and undamaged
   - lift lugs function as required



Run the Wear Bushing Before Drilling

WARNING: Make sure the **lift lugs are down** and the **elastomer is up** when latching into the Wear Bushing.

3. Attach the Tool to a joint of drill pipe.
4. Align the retractable lift lugs of the tool with the retrieval holes of the bushing and then carefully lower the tool into the Wear Bushing until the lugs snap into place.

Note: If the lugs did not align with the holes, rotate the tool in either direction until they snap into place.

5. Apply a heavy coat of grease, not dope, to the O.D. of the bushing.
6. Ensure all lockscrews are fully retracted and then slowly lower the Tool/Bushing Assembly through the BOP stack and land it on the load shoulder in the lower Housing.

WARNING: When operating integral lockscrews, the gland nut is at no time to be backed off to operate the lockscrew.

7. Holding a backup on the Glandnut, ***run in the two Red Painted lockscrews of the Upper Housing*** until the lockscrews just contact the O.D. of the Bushing.
8. Drill as required.

Note: It is highly recommended to retrieve, clean, inspect, grease, and reset the wear bushing each time the hole is tripped during the drilling of the hole section.

Retrieve the Wear Bushing After Drilling

9. Make up the Retrieving Tool to the drill pipe with the lift lugs down and the elastomer up.
10. Slowly lower the Tool into the Wear Bushing.
11. Rotate the Tool clockwise until a positive stop is felt. This indicates the lugs have snapped into the holes in the bushing.
12. Fully retract the red painted lockscrews only and the retrieve the Wear Bushing using the elevators if possible, and remove it and the Tool from the drill string.
13. Thoroughly clean and inspect the Wear Bushing and report any damage to the Drilling Supervisor immediately.

Stage 5 — Hang Off the 9-5/8" Casing

1. Run the 9-5/8" casing as required and space out appropriately for the mandrel casing hanger.

2. Examine the ***13-5/8" x 9-5/8" WG-SH2 Mandrel Casing Hanger (Item B12)***. Verify the following:
   - internal bore and threads are clean and in good condition
   - neck seal area is clean and undamaged

   Examine the ***13-5/8" x 9-5/8" WG-SH2 Mandrel Casing Hanger Running Tool (Item ST7)***. Verify the following:
   - internal bore and threads are clean and in good condition
   - o-rings are clean and undamaged

3. Thread the Hanger onto the last joint of casing to be run and torque connection to thread manufacturer's optimum make up torque.

4. Make up a landing joint to the top of the Running Tool and torque connection to thread manufacturer's maximum make up torque.

5. Liberally lubricate the O.D. of the Hanger neck and I.D. of the Running Tool o-rings with a light oil or grease.

6. ***Using chain tongs only***, thread the Running Tool onto the Hanger, with left hand rotation, until it bottoms out on the Hanger body.

WARNING: Do Not apply torque to the Hanger/Tool connection.

Note: If steps 1 through 5 where done prior to being shipped to location, the running tool should be backed off and made back up to ensure it will back off freely.

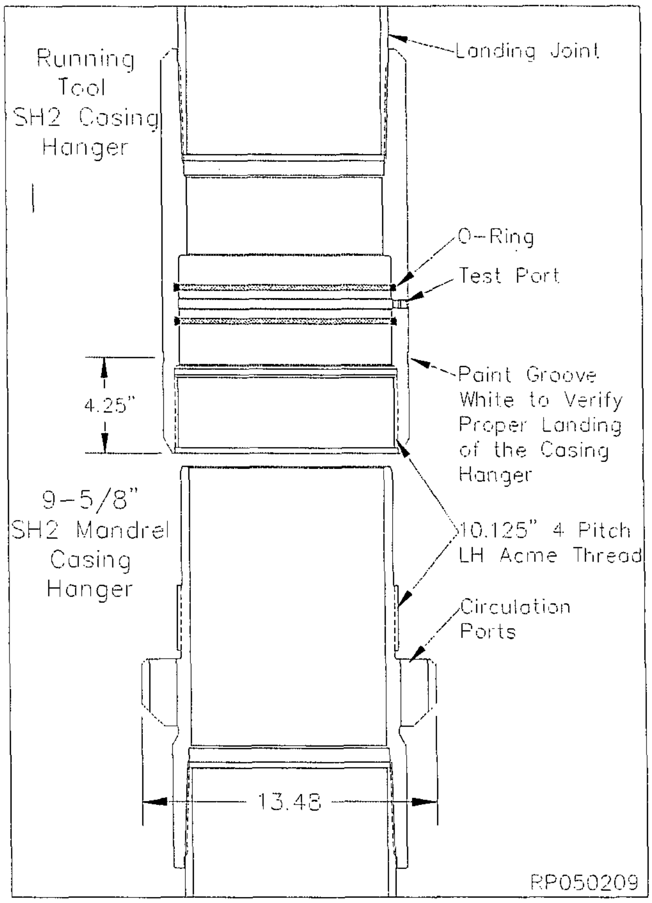
7. Remove the 1/8" LP flush fitting Allen head pipe plug from the O.D. of the running tool and attach a test pump.

8. Apply hydraulic test pressure to ***5,000 psi*** and hold for 5 minutes or as required by drilling supervisor.

9. Upon completion of a successful test, bleed off pressure through the test pump and remove the pump. Reinstall the pipe plug in the open port and tighten securely.

10. Locate the indicator groove machined in the O.D. of the Running tool and paint the groove with white paint.

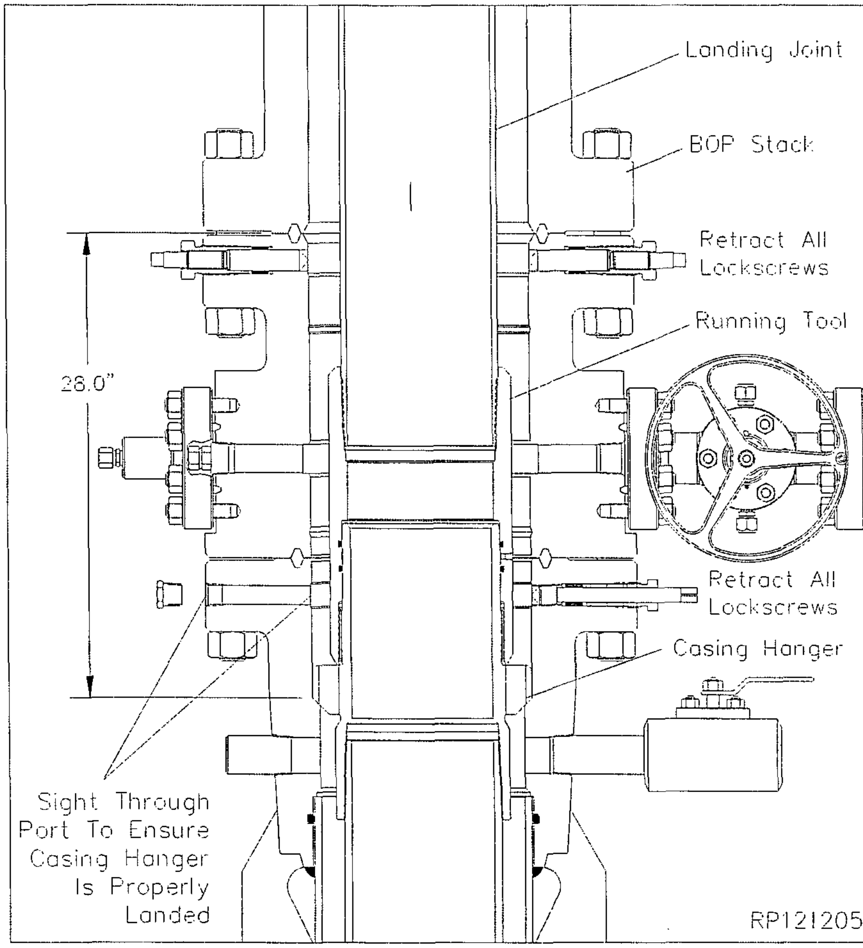
Note: If there is no groove present on the running tool, place a paint mark on the Running Tool as indicated.



Stage 5 — Hang Off the 9-5/8" Casing

11. Verify all lockscrews in the SH2 Assembly are fully retracted.
12. Calculate the total landing dimension by adding the previously attained rig floor to ground level dimension and 28.0", the depth of the wellhead.
13. Starting at the top of the 45° angle load shoulder of the casing hanger measure up 5 feet and place a horizontal paint mark on the landing joint and write 5 next to the mark.
14. Using the 5 foot stick, slowly and carefully lower the Hanger through the BOP, marking the landing joint at five foot increments until you come to the calculated total landing dimension. Place a paint mark on the landing joint at that dimension and write the landing dimension next to the mark.
15. Continue carefully lowering the hanger through the BOP stack and land it on the load shoulder in the lower Housing, 28.0" below the top of the upper Housing.
16. Slack off all weight on the casing and verify that the landing dimension paint mark has aligned with the rig floor.
17. If conditions exist or the paint mark has not aligned with the rig floor, verify through the inspection port that the Hanger has landed properly:
    a) Ensure well is stable and no pressure buildup or mud flow is occurring.
    b) Drain BOP stack through the casing head side outlet valve
    c) Remove the 1" pipe plug from the casing head flange port marked inspection port.
    d) Check to ensure that the groove on the Running Tool is in the center of the port.
    e) Reinstall the 1" pipe plug and tighten securely.
18. Place a vertical paint mark on the landing joint level to verify if the casing string rotates during the cementing process.
19. Cement the casing as required.

Note: Returns may be taken through the circulation ports and out the BOP or out the side outlets on the Casing Head.



Note: If the casing is to be reciprocated during cementing, it is advisable to pick up the casing hanger a minimum of the length of the pup joint below the hanger plus 4 feet above the landing point. Place a mark on the landing joint level with the rig floor and then reciprocate above that point. If at any time resistance is felt, re-land the casing hanger **immediately**.

20. ***Using Chain Tongs Only, located 180° apart***, retrieve the Running Tool and landing joint by rotating the landing joint to the right 12 full turns.

WARNING: The rig floor tong may be used to break the connection but **under no circumstances is the top drive to be used to rotate or remove the casing hanger running tool.**

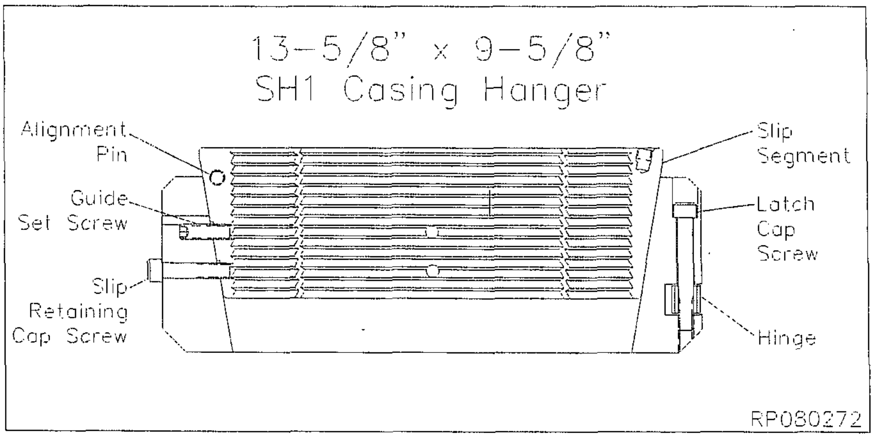
Stage 5A — Hang Off the 9-5/8" Casing (Emergency)

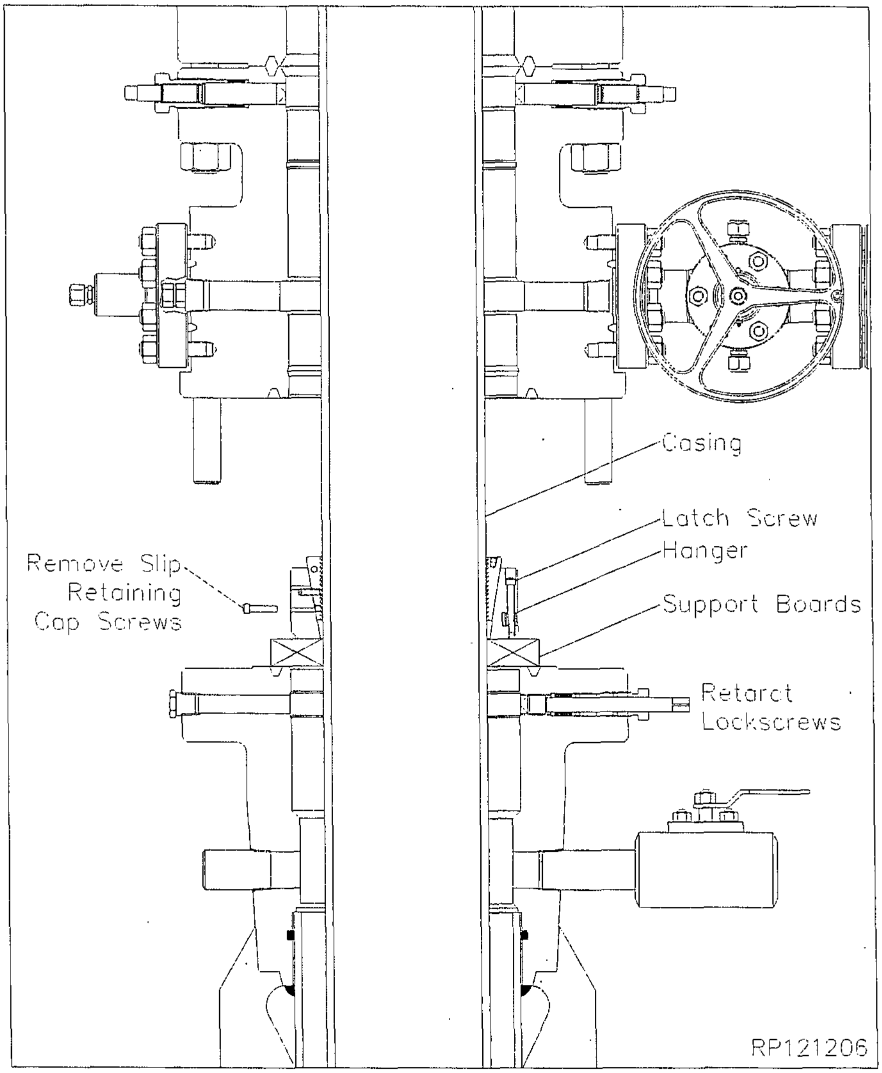
Note: The following procedure should be followed **ONLY** if the 9-5/8" casing should become stuck in the hole. If the casing did not get stuck and is hung off with the Mandrel Casing Hanger, skip this stage.

1. Cement the hole as required.
2. Drain the lower housing bowl through the side outlet.
3. Separate the upper housing from the lower housing.
4. Pull up on the upper housing and suspend it above the lower housing high enough to install the Slip Casing Hanger.
5. Washout as required.
6. Examine the ***13-5/8" x 9-5/8" WG-SH1 Slip Casing Hanger (Item B12a)***. Verify the following:
   - slips and internal bore are clean and in good condition
   - all screws are in place
7. Remove the latch screw to open the Hanger.
8. Place two boards on the lower housing flange against the casing to support the Hanger.
9. Wrap the Hanger around the casing and replace the latch screw.
10. Prepare to lower the Hanger into the lower housing bowl.

WARNING: Do Not Drop the Casing Hanger!

11. Grease the Casing Hanger's body and remove the slip retaining screws.





Stage 5A — Hang Off the 9-5/8" Casing (Emergency)

12. Remove the boards and allow the Hanger to slide into the lower housing bowl.

13. When the Hanger is down, pull tension on the casing to the desired hanging weight and then slack off.

Note: A sharp decrease on the weight indicator will signify that the Hanger has taken weight and at what point. If this does not occur, pull tension again and slack off once more.

14. Rough cut the casing approximately 8" above the top flange and move the excess casing out of the way.

15. Final cut the casing at 2" ± 1/8" above the casing head flange.

16. Grind the casing stub level and then place a 3/16" x 3/8" bevel on the O.D. and a I.D. chamfer to match the minimum bore of the support bushing to be installed.

Note: There **must not** be any rough edges on the casing or the seals of the Packoff Support Bushing seals will be damaged.

17. Remove and discard the used ring gasket from the lower housing.

18. Clean the mating ring grooves of the Upper and Lower SH2 Housings and wipe lightly with oil or grease.

WARNING: Excessive oil or grease may prevent a good seal from forming!

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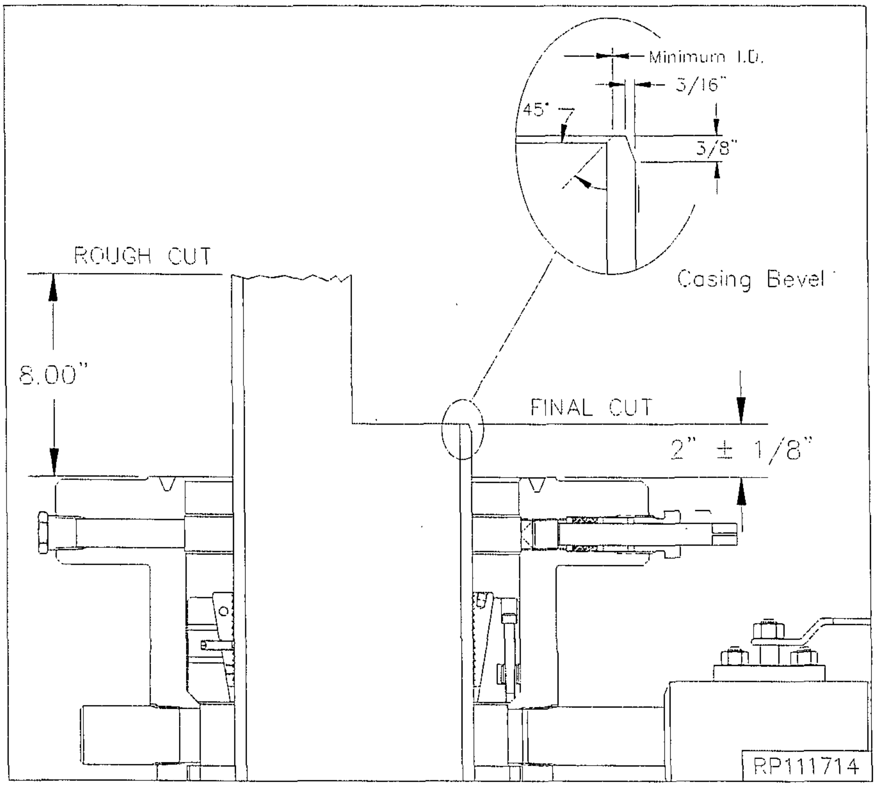
19. Install the new ***BX-160 Ring Gasket (Item B11)*** in the lower housing ring groove.

20. Reconnect the upper housing to the lower housing and loosely make up the connection.

Note: The upper and lower housing connection will be fully tightened after the Packoff Support Bushing is run and proper setting location is verified.



Stage 6 — Install Packoff Support Bushing, Drill Pipe

The following steps detail the installation of the WG-SH2E and SH2S Packoff Support Bushing. The installation procedure is identical for both the intended Packoff Support Bushing and the emergency Packoff Support Bushing.

1. Determine which Packoff Support Bushing to use:

If the casing has been run normally and is hung off with the Mandrel Casing Hanger, then use the ***13-5/8" x 9-5/8" SH2E Mandrel Packoff Support Bushing (Item B13).***

If the casing became stuck and the Slip Casing Hanger is hanging off the casing, then use the ***13-5/8" x 9-5/8" SH2S Emergency Packoff Support Bushing (Item B13a).***

2. Examine the appropriate Packoff Support Bushing. Verify the following:
   - all elastomer seals are in place and undamaged
   - internal bore, and ports, are clean and in good condition
   - paint the lockscrew relief groove white
3. Lubricate the I.D. of the EBS seals and the O.D. of the dovetail seals liberally with a light oil or grease.
4. Examine the ***Packoff Support Bushing Running Tool (Item ST8).*** Verify the following:
   - lift lugs are in place and in good condition
5. Make up a landing joint to the Running Tool and rack back assembly.
6. Carefully run two or three stands of drill pipe or collars in the hole and set in floor slips.

Note: Use heavy weight drill pipe or drill collars. Weight required to pull support bushing into head is approximately 3500 lbs. per O.D. seal.

WARNING: When lowering the drill collars into the well, extreme caution must be taken not to damage the top of the casing stub with the end of the drill pipe. It is recommended that the drill pipe be held centralized as closely as possible when entering the casing.

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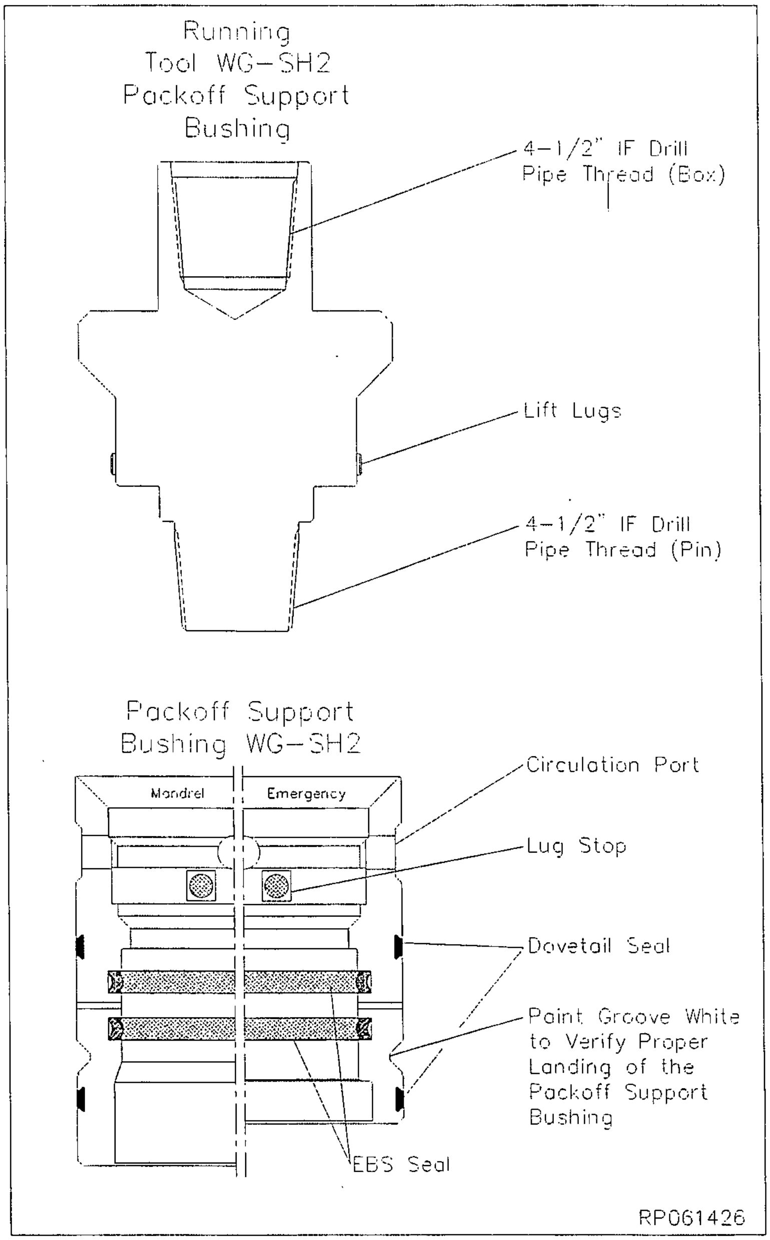
7. Carefully lower the support bushing over the drill pipe and set down on top of the floor slips.
8. Make up the landing joint/Running Tool assembly to the drill pipe suspended in the floor slips.
9. Carefully pick up the support bushing and slide the bushing over the lift lugs of the running tool and then rotate the bushing to the left 1/4 turn to secure the bushing on the running tool.

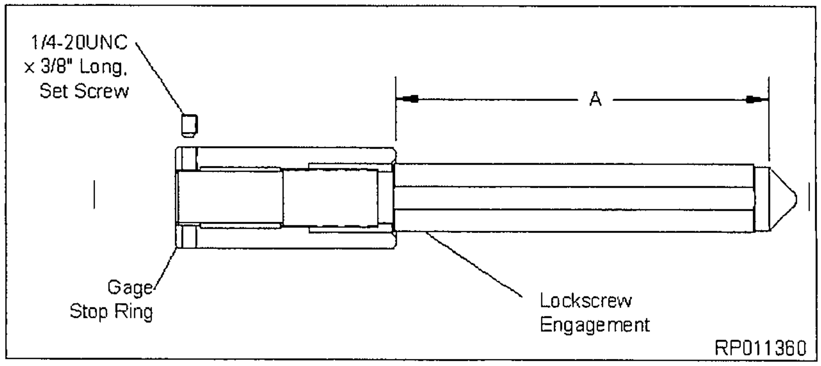


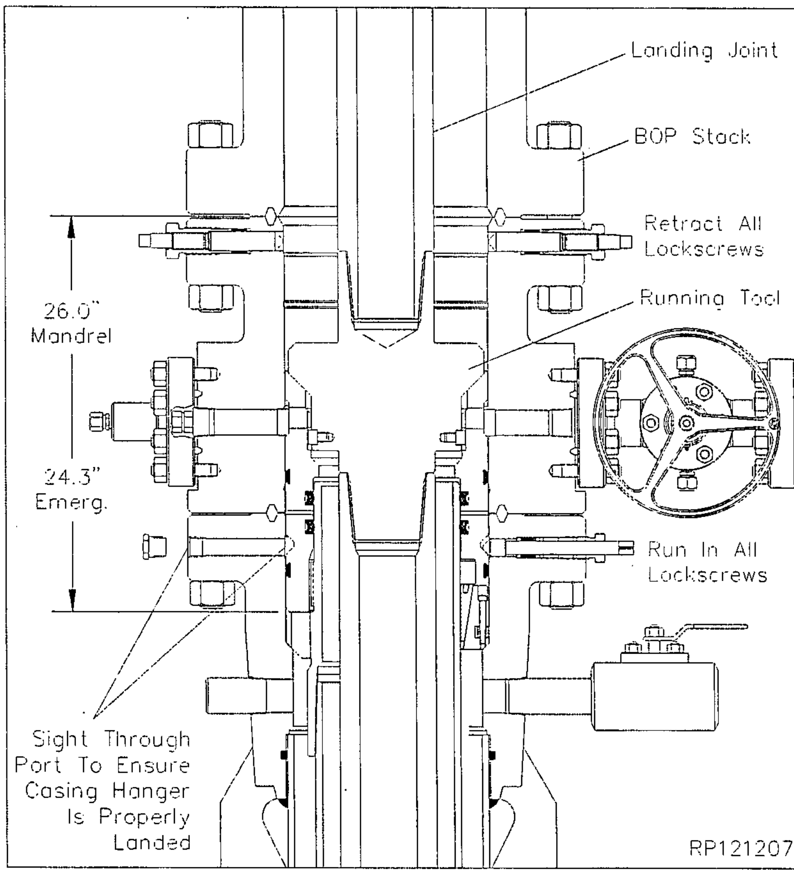
Stage 6 — Install Packoff Support Bushing, Drill Pipe

10. Drain BOP stack through the Lower Housing side outlet valve.
11. Using a high pressure water hose, thoroughly wash out the BOP stack and SH2 housing until returns are clear and no debris is visible on top of the Casing Hanger landing shoulder which would cause the Packoff to not properly set.
12. Lower the assembly through the BOP stack and Wellhead Assembly until the Packoff lands on the Casing Hanger.
13. Verify through the inspection port that the Packoff has landed properly:
    a) Ensure well is stable and no pressure buildup or mud flow is occurring.
    b) Drain BOP stack through the Lower Housing side outlet valve
    c) Remove the 1" pipe plug from the Lower Housing flange port marked inspection port.
    d) Verify through the inspection port the lockscrew relief of the Packoff, painted white, is visible.
    e) Stenciled next to the inspection port is the cross sectional dimension of the Lower Housing. Using the given dimension, adjust the gage stop ring on the lockscrew engagement tool to achieve that measurement as dimension 'A' from the start of the lockscrew nose. Tighten the 1/4" set screw to maintain the setting.
    f) Slide the Engagement Tool into the inspection port until either the gage stop ring contacts the flange O.D. or the nose of the Engagement Tool contacts the Packoff.

- If the gage stop ring contacts the flange O.D., the Packoff is properly set.
- If the nose of the Engagement Tool contacts the Packoff and a gap is visible between the flange OD and the gage stop ring, the Packoff is not properly seated.

1 Remove the Support Bushing from the wellhead.
2 Inspect the bushing and seals for any damage and repair as necessary
3 Thoroughly wash the area of the hanger until returns are clean and free of all debris. Ensure that there is no cement or debris on top of the casing hanger landing shoulder.
4 Reinstall the Packoff and check for proper setting position using the Engagement Tool as previously described.





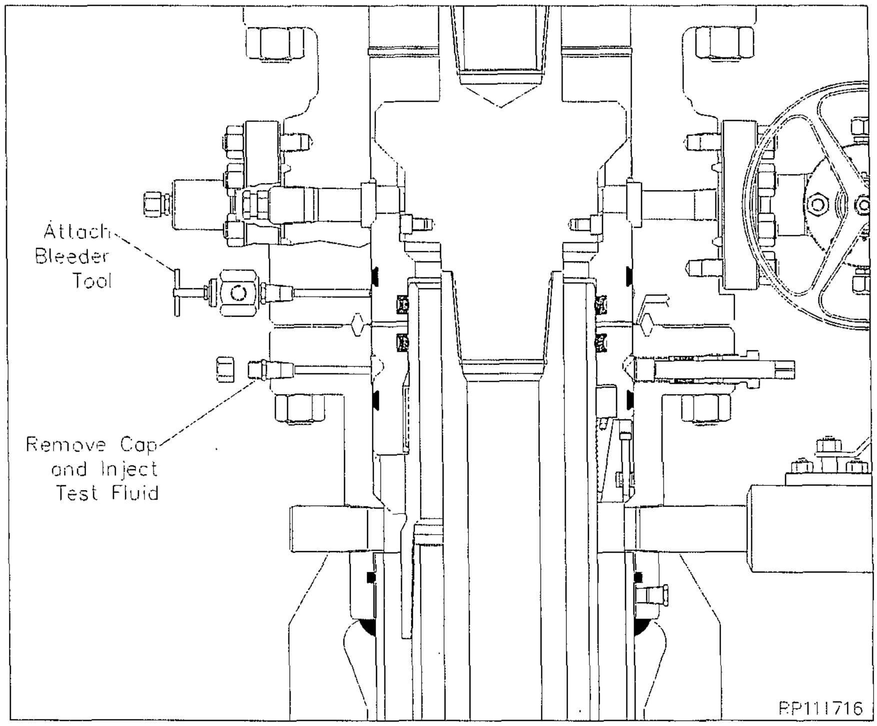
    g) With the proper setting position confirmed, reinstall the 1" pipe plug and tighten securely.

14. Fully make up the Lower and Upper Housing connection. Tighten all the studs in an alternating cross pattern until the flanges come face to face.
15. Run in the Lower Housing lockscrews to 100 ft lbs and verify the standoff is at 3.2" from the O.D. of the flange.

Stage 6 — Install Packoff Support Bushing, Drill Pipe

Flange and Seal Test

1. Locate the test fittings on the upper and lower housings as indicated and remove the dust cap from each fitting.
2. Attach a Bleeder Tool to the upper fitting and open the Tool.
3. Attach a Hydraulic Test Pump to the lower fitting and pump clean test fluid into the flange connection until a continuous stream flows from the Bleeder Tool.
4. Close the Bleeder Tool and continue pumping test fluid to ***5,000 psi. Do Not exceed 80% of casing collapse.***
5. Hold the test pressure for fifteen (15) minutes or as desired by the drilling supervisor.
6. If pressure drops a leak has developed. Take the appropriate action in the adjacent table.
7. Repeat this procedure until a satisfactory test is achieved.
8. When a satisfactory test is achieved, remove Test Pump and Bleeder Tool, drain test fluid, and reinstall the dust cap on each fitting.
9. Retighten the Lower Housing lockscrews to 100 ft lbs and verify the standoff is at 3.2" from the O.D. of the flange.
10. Paint the exposed end of the lockscrews RED to signify the lockscrews are not to be tampered with.
11. ***Using only chain tongs located 180° apart, rotate the landing joint clockwise to a positive stop.***
12. Retrieve the Packoff Running Tool to the rig floor with a straight vertical lift.



Leak Location	Appropriate Action
Into Spool Bore or Casing Annulus - Packoff Seals are Leaking	Retrieve Packoff and Replace Seals as Required.
Between Flanges - Ring gasket is Leaking	Further Tighten Connection.
Around Lockscrew - Lockscrew Packing is Leaking	Further Tighten Glandnut.

Stage 7 — Re-Testing the BOP Stack

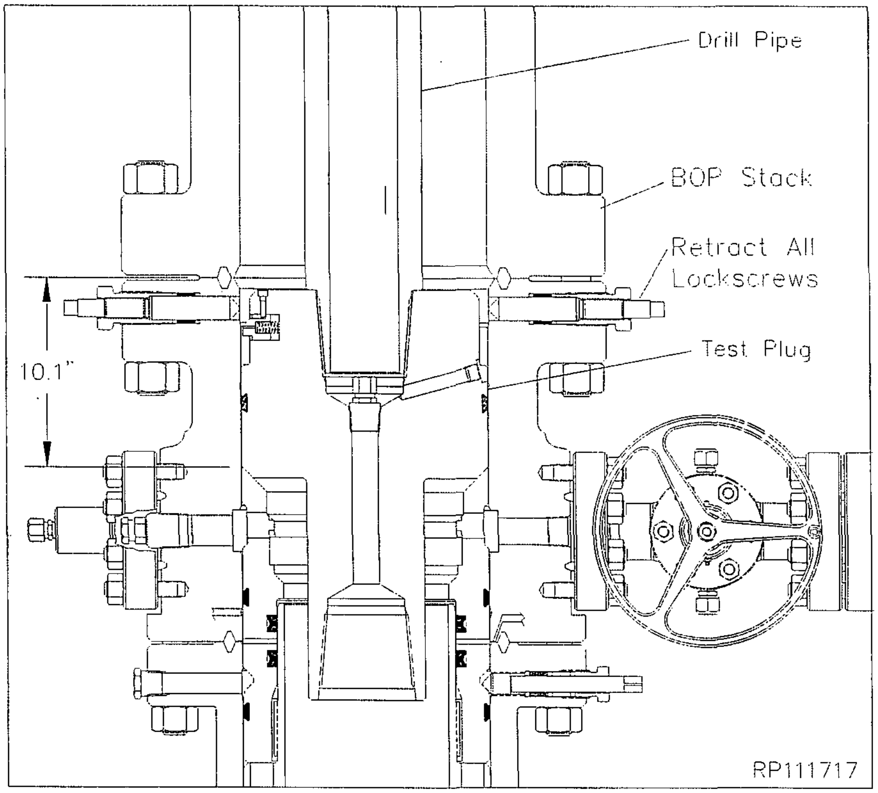
1. Examine the **13-5/8" *Nominal x 4-1/2" IF SL Test Plug/Retrieving Tool (Item ST5)***. Verify the following:
   - elastomer seals, lift lugs, and plugs are intact and in good condition
   - drill pipe threads are clean and in good condition

Immediately after testing the support bushing seals, and periodically during the drilling of the hole for the next casing string, the BOP stack (connections and rams) must be tested.

2. Orient the Test Plug with elastomer down and lift lugs up. Make up a joint of drill pipe to the Test Plug.

WARNING: Make sure the **elastomer is down** and the **lift lugs are up**.

3. Remove 1/2" NPT pipe plug if pressure is to be supplied through the drill pipe.
4. Fully retract all lockscrews in the upper SH2 Housing .
5. Lubricate the elastomer seal of the Test Plug with a light oil or grease.
6. Lower the Test Plug through the BOP and into the SH2 Housing Assembly until it lands on top of the Packoff Support Bushing, 10.1" below the top of the SH2 Housing Assembly.
7. Close the BOP rams on the drill pipe and test to ***5,000 psi.*** or as required by drilling supervisor.
8. After a satisfactory test, release pressure, and open the rams.



Note: Any leakage past the test plug seal will be monitored at the open side outlet valve.

9. Remove as much fluid from the BOP stack as possible.
10. Retrieve the Test Plug Assembly slowly to avoid damage to the seal.

Note: If the blind rams are to be tested, run in the hole with a minimum of two joints of drill pipe with the appropriate size pin x pin crossover prior to running the test plug. This will ensure the test plug remains firmly seated when disconnecting from it.

Failure to do this may cause severe damage to the wellhead.

11. Repeat steps 6 - 11 as required prior to running the completion.

Stage 8 — Run the Short Wear Bushing

Note: Always use a Wear Bushing while drilling to protect the load shoulders and seal area from damage by the drill bit or rotating drill pipe. The Wear Bushing **must be retrieved** prior to running the casing.

Note: Locate two opposing lockscrews of the upper Housing, that are convenient and paint both screws **RED**.

1. Examine the ***13-5/8" nominal Short Wear Bushing (Item ST9)***. Verify the internal bore is clean and undamaged
2. Examine the ***13-5/8" Test Plug/Retrieving Tool (Item ST5)***. Verify the following:
   - drill pipe threads are clean and undamaged
   - lift lugs function as required

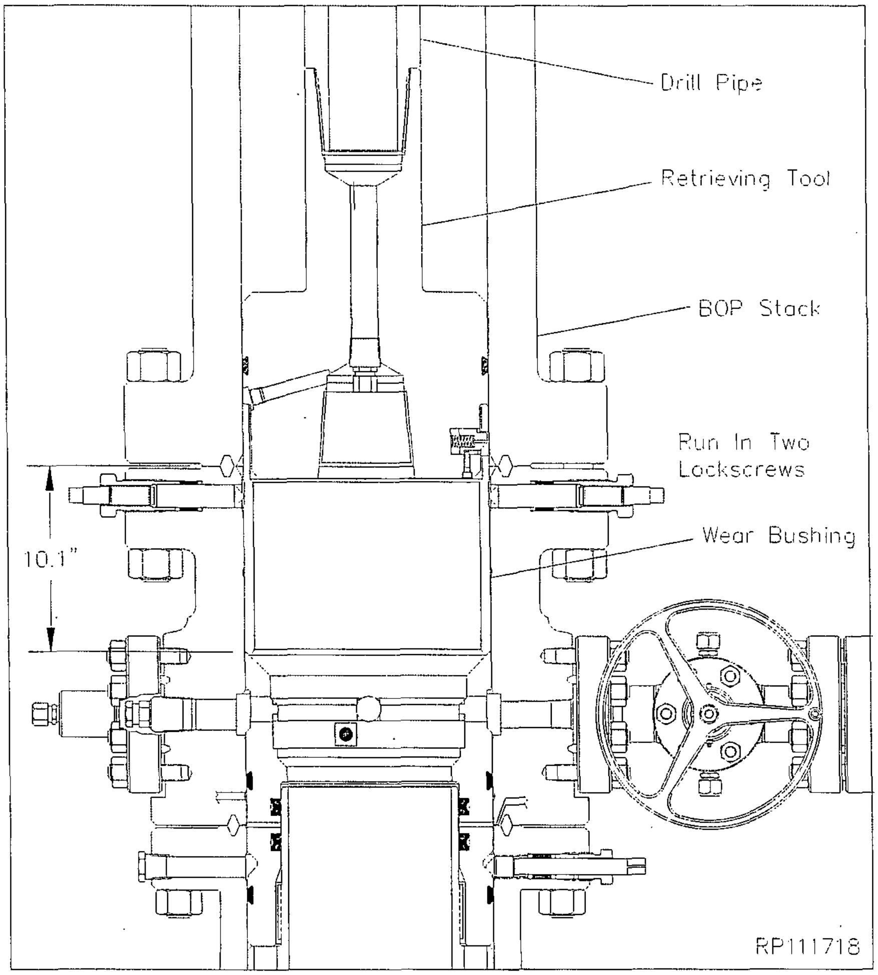
Run the Wear Bushing Before Drilling

WARNING: Make sure the **lift lugs are down** and the **elastomer is up** when latching into the Wear Bushing.

3. Attach the Tool to a joint of drill pipe.
4. Align the retractable lift lugs of the tool with the retrieval holes of the bushing and then carefully lower the tool into the Wear Bushing until the lugs snap into place.

Note: If the lugs did not align with the holes, rotate the tool in either direction until they snap into place.

5. Apply a heavy coat of grease, not dope, to the O.D. of the bushing.
6. Ensure all lockscrews are fully retracted and then slowly lower the Tool/Bushing Assembly through the BOP stack and land it on the load shoulder in the lower Housing.
7. Remove the Tool from the Wear Bushing by rotating the drill pipe counter clockwise 1/4 turn and lifting straight up.
8. Drill as required.



Note: It is highly recommended to retrieve, clean, inspect, grease, and reset the wear bushing each time the hole is tripped during the drilling of the hole section.

Retrieve the Wear Bushing After Drilling

9. Make up the Retrieving Tool to the drill pipe with the lift lugs down and the elastomer up.
10. Slowly lower the Tool into the Wear Bushing.
11. Rotate the Tool clockwise until a positive stop is felt. This indicates the lugs have snapped into the holes in the bushing.
12. Fully retract the ***RED*** painted lockscrews and the retrieve the Wear Bushing using the elevators if possible, and remove it and the Tool from the drill string.
13. Thoroughly clean and inspect the Wear Bushing and report any damaged to the Drilling Supervisor immediately.

Stage 9 — Hang Off the 5-1/2" Casing

1. Run the 5" casing as required and space out appropriately for the mandrel casing hanger.

Note: If the 5" casing becomes stuck and the mandrel casing hanger can not be landed, Refer to **Stage 9A** for the emergency procedure.

2. Examine the ***13-5/8" x 5-1/2" WG-SH2 Upper Mandrel Casing Hanger (Item C10).*** Verify the following:
   - internal bore and threads are clean and in good condition
   - neck seal area is clean and undamaged

   Examine the ***7" x 5-1/2" WG-SH2-R Upper Mandrel Casing Hanger Running Tool (Item ST10).*** Verify the following:
   - internal bore and threads are clean and in good condition
   - o-rings are clean and undamaged

3. Thread the Hanger onto the last joint of casing to be run and torque connection to thread manufacturer's optimum make up torque.

4. Make up a landing joint to the top of the Running Tool and torque connection to thread manufacturer's maximum make up torque.

5. Liberally lubricate the OD of the Hanger neck and ID of the Running Tool o-rings with a light oil or grease.

6. ***Using chain tongs only***, thread the Running Tool onto the Hanger, with left hand rotation, until it bottoms out on the Hanger body.

WARNING: Do Not apply torque to the Hanger/Tool connection.

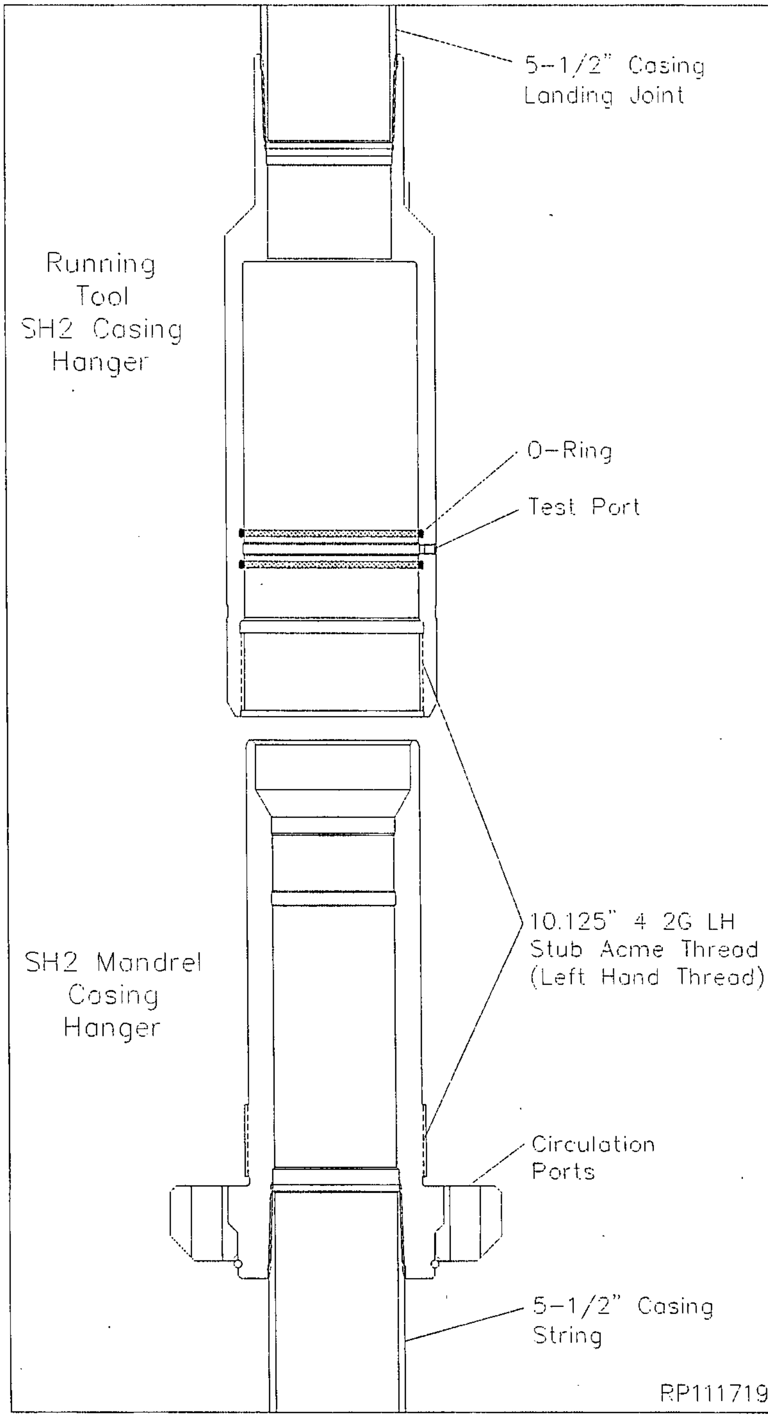
Note: If steps 1 through 5 where done prior to being shipped to location, the running tool should be backed off 1 turn and made back up to ensure it will back off freely.

7. Remove the 1/8" LP flush fitting Allen head pipe plug from the O.D. of the running tool and attach a test pump.

8. Apply hydraulic test pressure to 5,000 psi. and hold for 5 minutes or as required by drilling supervisor.

9. Upon completion of a successful test, bleed off pressure through the test pump and remove the pump. Reinstall the pipe plug in the open port and tighten securely.

10. Locate the indicator groove machined in the O.D. of the Running tool and paint the with white paint.

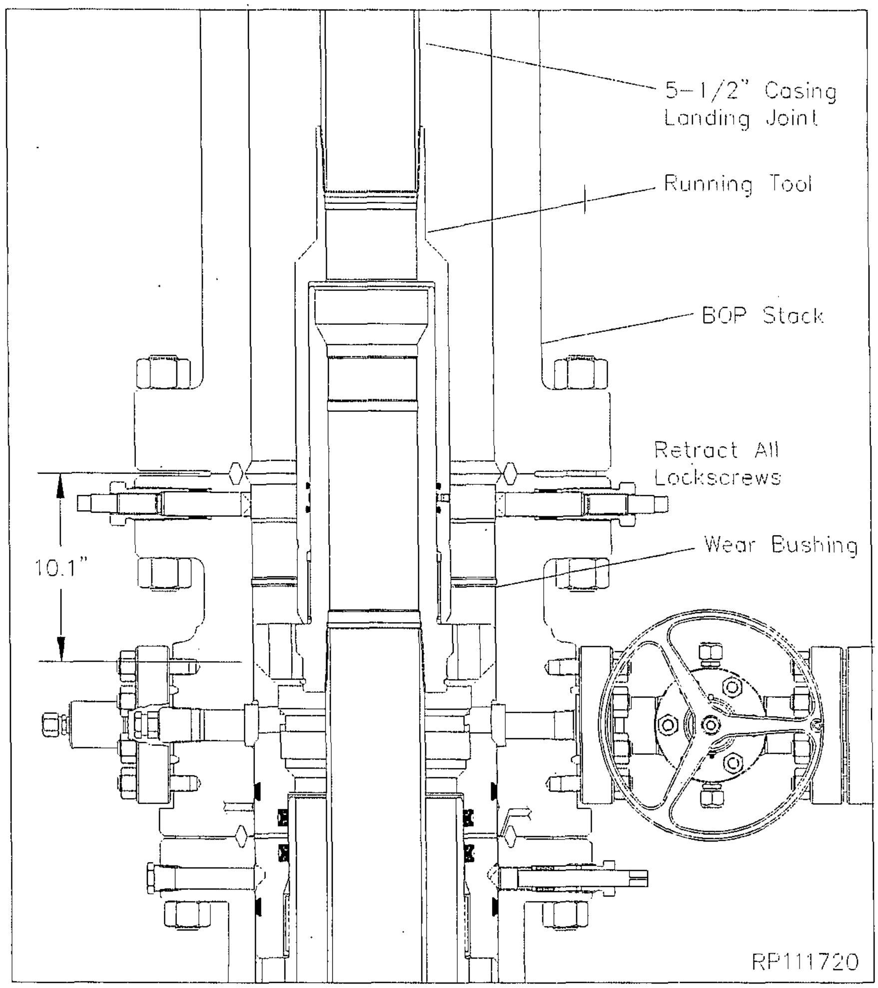


Note: If there is no groove present on the running tool, place a paint mark on the Running Tool as indicated.

11. Verify all lockscrews in the Upper SH2 Housing are fully retracted.
12. Calculate the total landing dimension by adding the previously attained RKB dimension and 10.1", the depth of the wellhead.
13. Starting at the top of the 45° angle load shoulder of the casing hanger measure up 5 feet and place a horizontal paint mark on the landing joint and write 5 next to the mark.
14. Using the 5 foot stick, slowly and carefully lower the Hanger through the BOP, marking the landing joint at five foot increments until you come to the calculated total landing dimension. Place a paint mark on the landing joint at that dimension and write the landing dimension next to the mark.
15. Continue carefully lowering the hanger through the BOP stack and land it on top of the 9-5/8" packoff support bushing, 10.1" below the top of the wellhead assembly.
16. Slack off all weight on the casing and verify that the landing dimension paint mark has aligned with the rig floor.
17. Place a vertical paint mark on the landing joint to verify if the casing string rotates during the cementing process.
18. Cement the casing as required.

Note: Returns may be taken through the circulation ports and out the BOP or out the side outlets on the Casing Head.

Note: If the casing is to be reciprocated during cementing, it is advisable to pick up the casing hanger a minimum of the length of the pup joint below the hanger plus 4 feet above the landing point. Place a mark on the landing joint level with the rig floor and then reciprocate above that point. If at any time resistance is felt, re-land the casing hanger **immediately**.



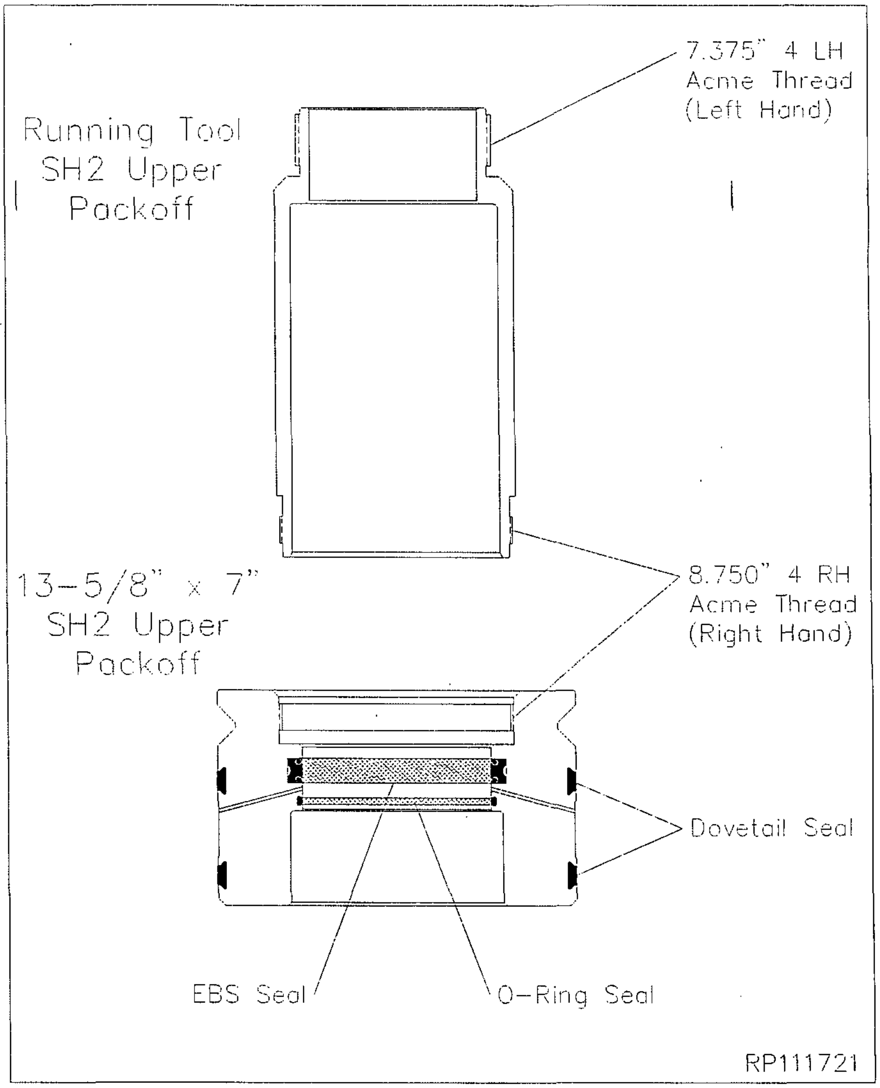
19. ***Using Chain Tongs Only located 180° apart***, retrieve the Running Tool and landing joint by rotating the landing joint to the right 12 full turns.

WARNING: The rig floor tong may be used to break the connection but **under no circumstances is the top drive to be used to rotate or remove the casing hanger running tool.**

Stage 9 — Hang Off the 5-1/2" Casing

Install Packoff

1. Examine the ***13-5/8" Nominal x 5" SH2 Upper Packoff (Items C11)***. Verify the following:
   - all elastomer seals are in place and undamaged
   - internal bore is clean and in good condition
2. Liberally lubricate the packoff ID o-ring seals, the OD dovetail seals with oil or a light grease.
3. Examine the ***Packoff Running Tool (Items ST11)***. Verify the following:
   - bore is clean and free of debris
   - all threads are clean and undamaged
4. Thoroughly clean and lightly lubricate the mating Acme threads of the packoff and running tool with oil or a light grease.
5. Carefully thread the running tool into the packoff with right hand rotation to a positive stop.
6. Pick up the casing hanger running tool with landing joint with casing elevators and suspend above the packoff.
7. Thoroughly clean and lightly lubricate the mating Acme threads of the packoff and hanger running tools with oil or a light grease.
8. Carefully lower the casing hanger running tool over the packoff tool and thread them together with left hand rotation to a positive stop.



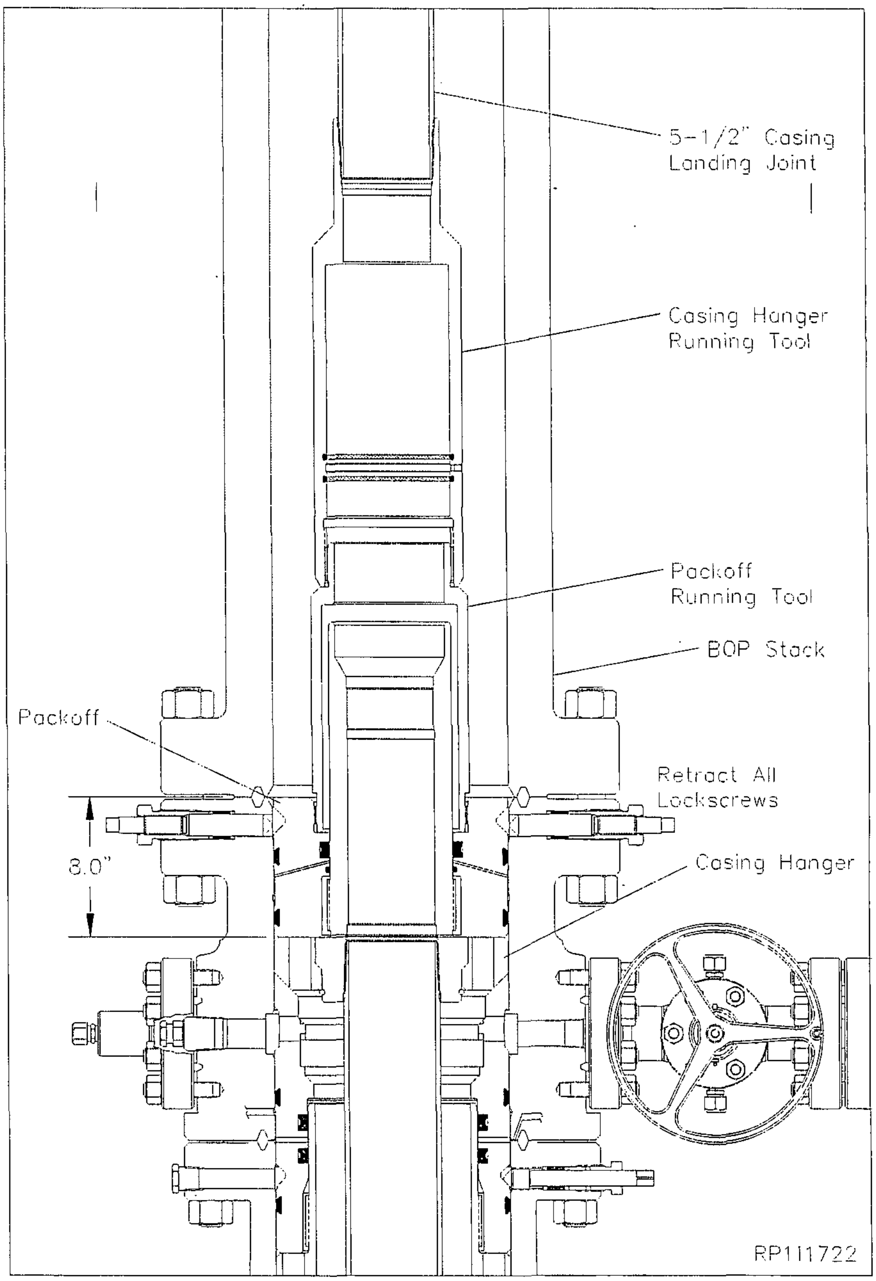
Stage 9 — Hang Off the 5-1/2" Casing

9. Drain BOP stack through the Upper Housing side outlet valve
10. Thoroughly washout the Housing using a high pressure water hose until returns from the open outlet valve on the Upper Housing are clean and free of debris.
11. Calculate the total landing dimension by adding the previously attained RKB dimension and 8.0", the depth of the wellhead.
12. Starting at the bottom of the packoff and measure up 5 feet and place a horizontal paint mark on the landing joint and write 5 next to the mark.
13. Using the 5 foot stick, slowly and carefully lower the Packoff through the BOP, marking the landing joint at five foot increments until you come to the calculated total landing dimension. Place a paint mark on the landing joint at that dimension and write the landing dimension next to the mark.
14. Continue lower the packoff into the wellhead until the packoff paint mark aligns with the rig floor and a positive stop is felt.

Note: It may be necessary to use the weight of the blocks or top drive unit to push the Packoff into position.

Note: The mark on the landing joint will be level with the rig floor when the Packoff is properly landed. This may be used as secondary identification while running the Packoff. The Packoff location should always be verified by removing one of the upper housing lockscrew assemblies and sighting through the hole to verify. The white painted lockscrew rap of the packoff will be clearly visible through the open hole.

15. Reinstall the lockscrew assembly.



Stage 9 — Hang Off the 5-1/2" Casing

16. Locate the test fitting on the upper SH2 housing upper flange marked "SEAL TEST" and remove the dust cap from the fitting.
17. Attach a hydraulic test pump to the open fitting and inject test fluid between the packoff seals until a pressure of 5,000 psi is attained.
18. Hold test pressure for 15 minutes or as required by drilling supervisor.
19. After a satisfactory test is achieved, bleed off test pressure and remove test pump.
20. Reinstall the dust cap on the open fitting.

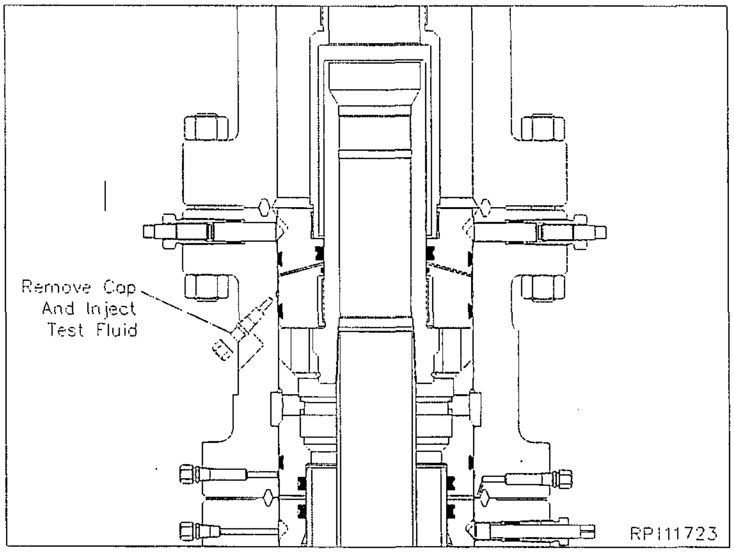
Note: Prior to operating lockscrews, refer to the procedure in the back of this manual for proper lockscrew operating procedures.

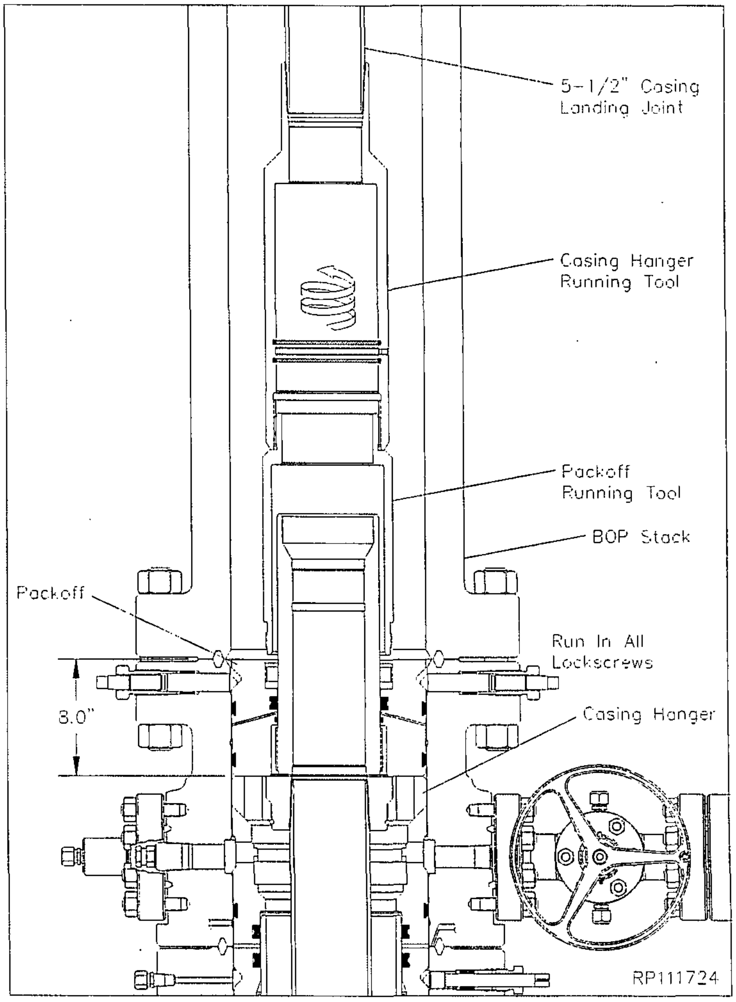
21. Holding a backup wrench on the lockscrew gland nuts, fully run in all of the Upper Housing lockscrews in an alternating cross pattern to approximately 100 ft lbs. When fully made up the lockscrews will protrude approximately 2.69" from the O.D. of the upper housing flange.

Note: Lockscrews are to be operated by Pressure Control personnel only.

22. Remove the running tool by rotating the landing joint 8 turns to the left or until it comes free of the packoff.
23. Retrieve the Running Tool assembly to the rig floor with a straight lift.
24. Install a 5" BPV.
25. Nipple down and remove BOP stack.

WARNING: Ensure all valves are in the closed position prior



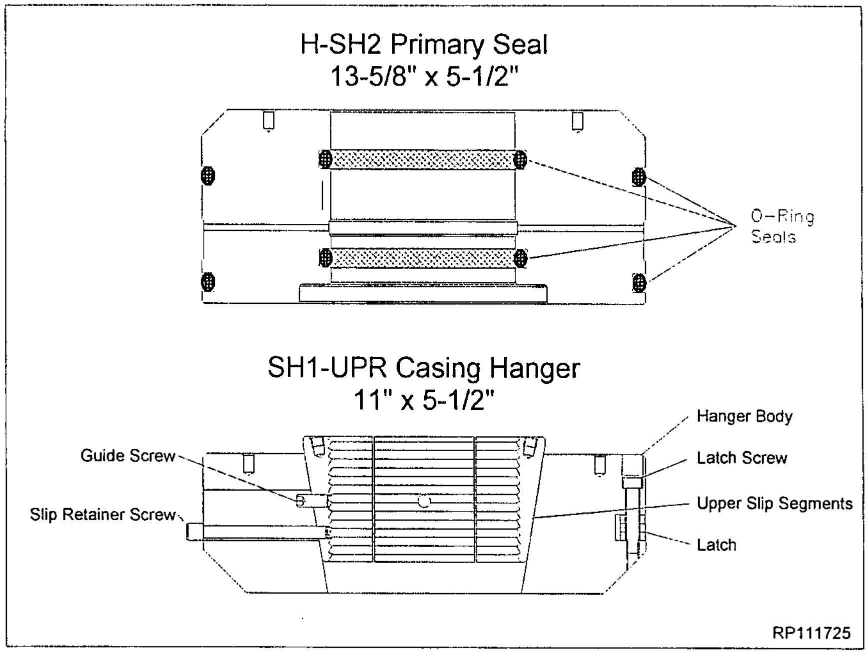


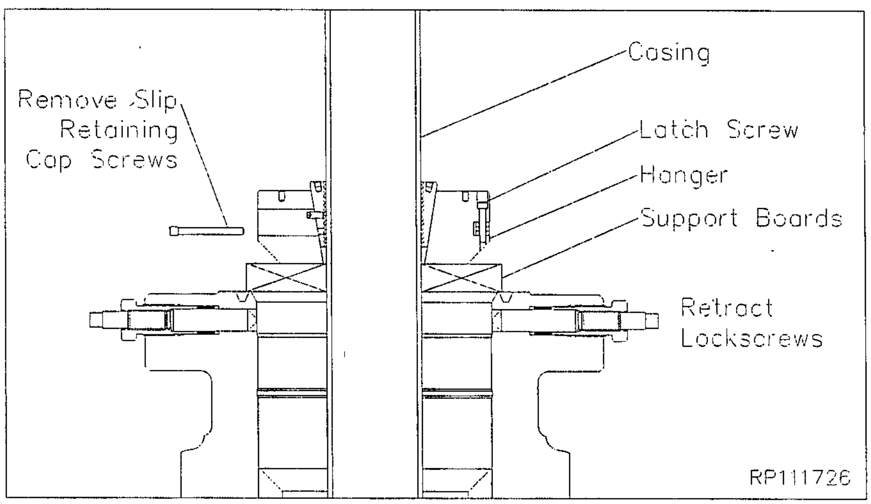
Stage 9A — Hang Off the 5-1/2" Casing (Emergency)

1. Run the 5" casing string as required and cement in place.
2. Drain the SH2 Upper Housing bowl through the side outlet and ensure the lockscrews are fully retracted from the bore.
3. Examine the ***13-5/8" x 5-1/2" SH1-UPR Casing Hanger (Item C10a)***. Verify the following:
   - slips and internal bore are clean and undamaged
   - slip retainer screws are in place
4. Examine the ***13-5/8" x 5-1/2" H-SH2 Primary Seal (Item C11a)***. Verify the following:
   - bore is clean and free of debris
   - seals are properly installed, clean and undamaged
5. Separate the BOP from the Upper Housing and lift the BOP approximately 12" to 16" above the Housing and secure BOP with safety slings.
6. Using a fresh water hose, thoroughly wash out the bowl.

Note: The side outlet valve to remain open while setting the Hanger.

7. Remove the latch screw and open the Hanger
8. Place two boards across the flange against the casing to support the Hanger.
9. Place the Hanger on the support boards and wrap the around the casing and replace the latch screw.
10. Remove all of the slip retainer screws from the of the Hanger.
11. Wipe the OD of the Hanger with a coat of oil or grease.
12. Remove the boards and allow the Hanger to slide into the bowl.





Stage 9A – Hang Off the 5-1/2" Casing (Emergency)

13. Pull tension on the casing to the desired hanging weight and then slack off.

Note: A sharp decrease on the weight indicator will signify that the Hanger has taken weight and at what point, If this does not occur, pull tension again and slack off once more.

WARNING: Because of the potential fire hazard and the risk of loss of life and property, It is highly recommended to check the casing annulus and pipe bore for gas with an approved sensing device prior to cutting off the casing. If gas is present, do not use an open flame torch to cut the casing. It will be necessary to use a air driven mechanical cutter which is spark free.

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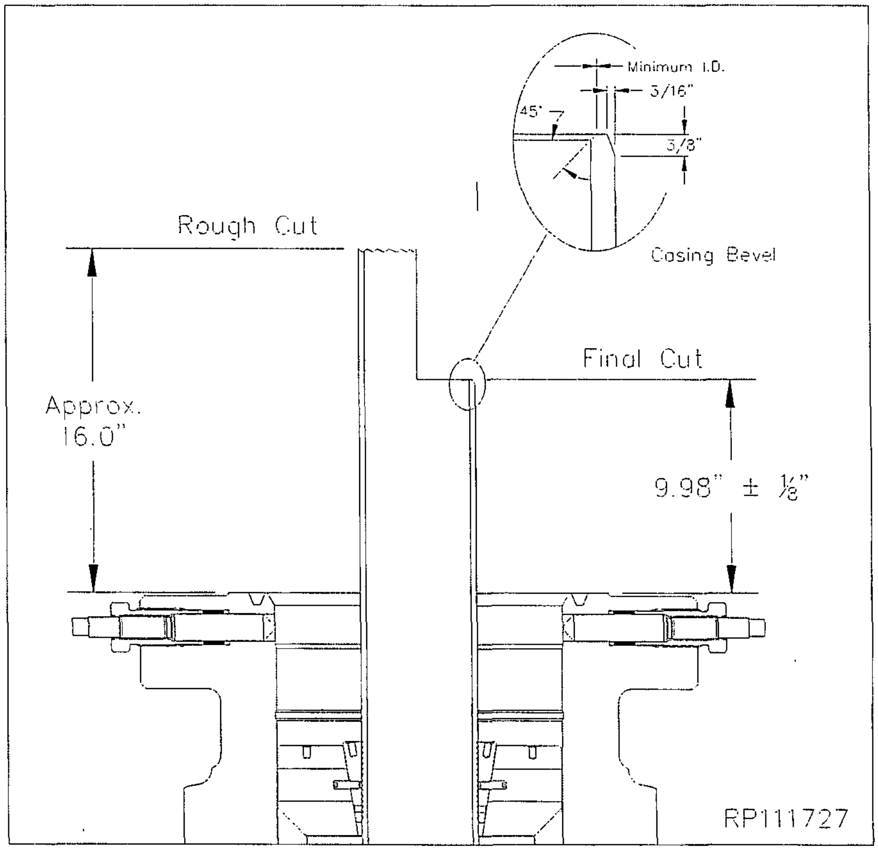
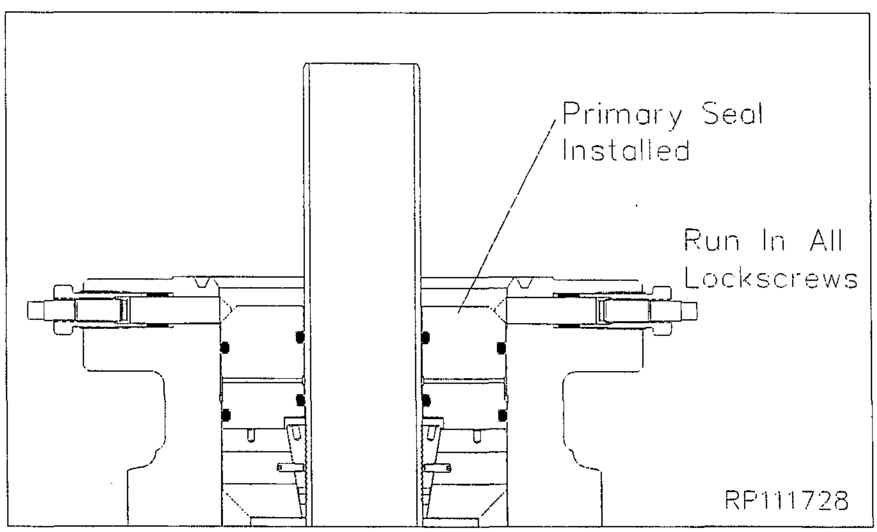
14. Rough cut the casing approximately 12" above the top of the Housing and move the excess casing and BOP out of the way.
15. Final cut the casing at 9.98" ± 1/8" above the top flange of the Housing.
16. Grind the casing stub level and place a 3/16" x 3/8" bevel on the casing stub.
17. Using a high pressure water hose, thoroughly clean the top of the Housing, Casing Hanger, and casing stub and blow dry with compressed air. Ensure all cutting debris are removed.
18. Install the Primary Seal over the casing stub and land it on the top of the Casing Hanger.
19. Run in all of the lockscrews in an alternating cross fashion to approximately 100 ft lbs.





Stage 9A — Hang Off the 5-1/2" Casing (Emergency)

20. Locate the test fitting on the upper SH2 housing upper flange marked "SEAL TEST" and remove the dust cap from the fitting.
21. Attach a hydraulic test pump to the open fitting and inject test fluid between the packoff seals until a pressure of 5,000 psi is attained.
22. Hold test pressure for 15 minutes or as required by drilling supervisor.
23. After a satisfactory test is achieved, bleed off test pressure and remove test pump.
24. Reinstall the dust cap on the open fitting.

Note: Prior to operating lockscrews, refer to the procedure in the back of this manual for proper lockscrew operating procedures.

25. Holding a backup wrench on the lockscrew gland nuts, fully run in all of the Upper Housing lockscrews in an alternating cross pattern to approximately 100 ft lbs. When fully made up the lockscrews will protrude approximately 2.61" from the O.D. of the upper housing flange.

Note: Lockscrews are to be operated by Pressure Control personnel only.

WARNING: Ensure all valves are in the closed position prior to leaving location after completion of job.

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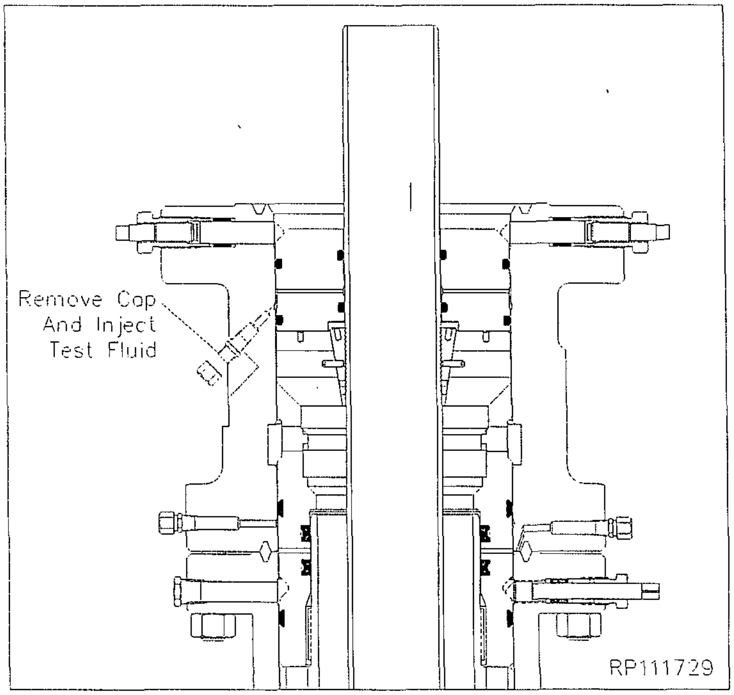
26. Fill the void above the Seal with clean test fluid to the top of the Housing flange.

WARNING: Do Not over fill the void with test fluid - trapped fluid under the ring gasket may prevent a good seal from forming.



Stage 10 — Install the Tubing Head Assembly

1. Examine the ***13-5/8" 5M x 11" 5M DSA (Item C1)***. Verify the following:
   - bore is clean and free of debris
   - all studs are in place and properly made up
   - ring grooves are clean and free of debris
2. Thoroughly clean the mating ring grooves of the DSA and LSH housing, removing all old grease and debris.
3. Lightly wipe both grooves with a light oil.
4. Place the ***BX-160 Ring Gasket (Item C8)*** in the ring groove of the LSH housing.
5. Pick up the DSA and position it above the housing.
6. Orientate the DSA to a proper Two Hole position and then carefully lower it over the casing stub and land it on the ring gasket.

WARNING: Two Hole position is when two studs straddle the center line of the DSA. This position is attainable in only four equally spaced locations. Improper two holing will result in the tubing head to be miss aligned with the LSH housing.

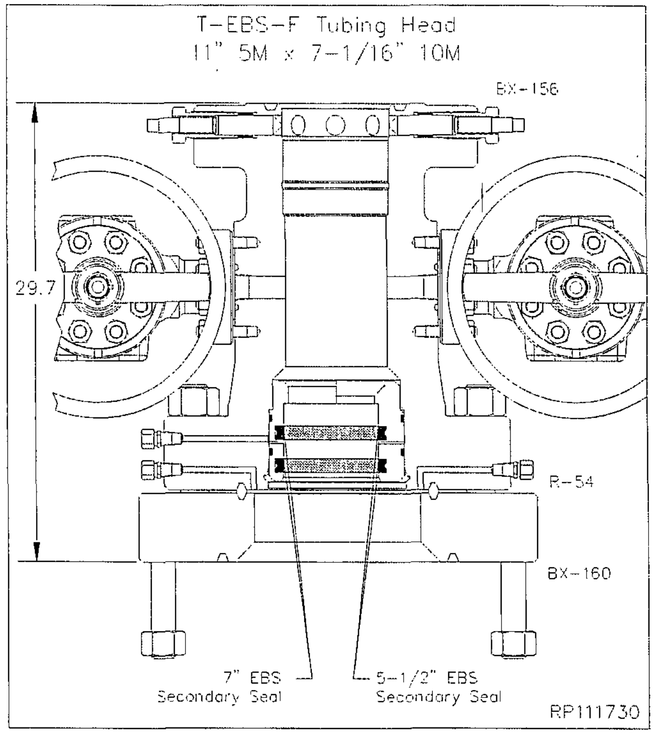
7. Examine the ***11" 5M x 7-1/16" 10M T-EBS-F Tubing Head Assembly (Item C2)***. Verify the following:
   - seal area and bore are clean and in good condition
   - ***EBS-F Secondary Seal Bushing (Item C3 or C3a)*** is in place and properly retained with square snap wire
   - all peripheral equipment is intact and undamaged
8. Clean the mating ring grooves of the Tubing Head and DSA.
9. Lightly lubricate the ID of the EBS seals and the casing stub with a light grease.

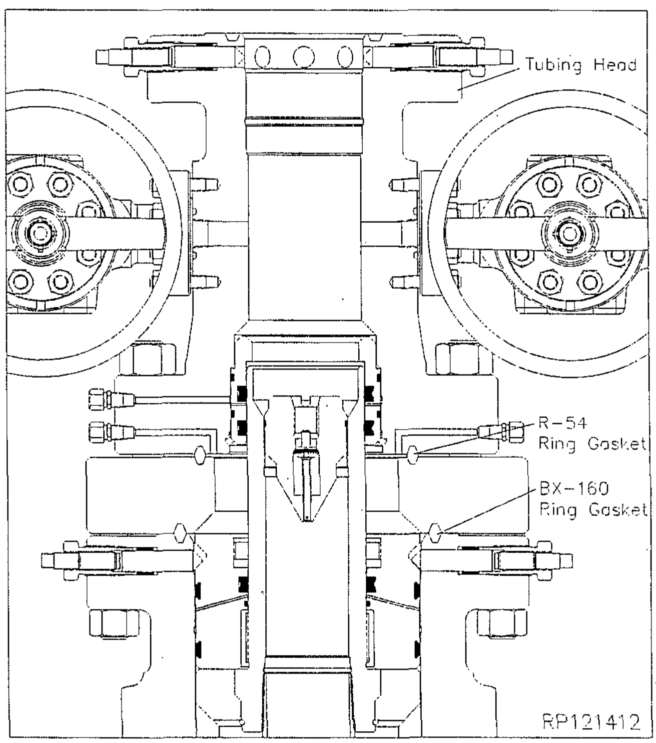
Note: Excessive grease may prevent a good seal from forming!

10. Install a new ***R-54 Ring Gasket (Item C9)*** in the ring groove of the DSA.
11. Orientate the outlets to aline with the casing head outlets then carefully lower the Tubing Head Assembly over the casing stub or hanger neck and land it on the ring gasket.

WARNING: Do Not damage the EBS Seal elements or their sealing ability will be impaired!

12. Make up both flange connections using the DSA studs and nuts, tightening them in an alternating cross pattern.

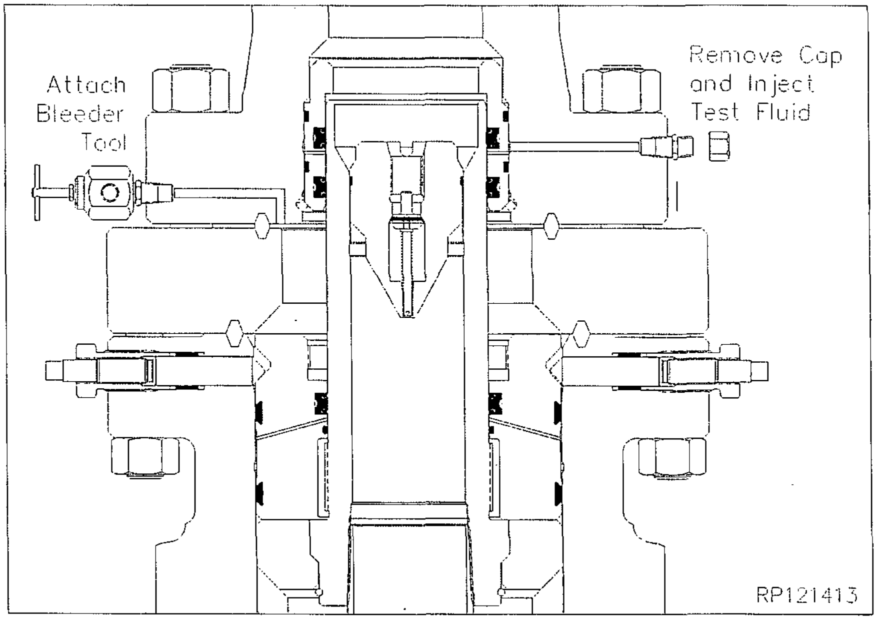




Stage 10 — Install The Tubing Head Assembly

Seal Test

1. Locate the "SEAL TEST" fitting and one "FLG TEST" fitting on the tubing head lower flange and remove the dust cap from both fittings.
2. Attach a Bleeder Tool to one of the open "FLG TEST" fitting and open the Tool.
3. Attach a Hydraulic Test Pump to the "SEAL TEST" fitting and pump clean test fluid between the EBS Seals until a test pressure of ***10,000 psi. or 80% of casing collapse pressure - whichever is less.***
4. Hold the test pressure for fifteen (15) minutes or as desired by the drilling supervisor.
5. If pressure drops a leak has developed. Take the appropriate action in the table below.
7. Repeat steps 1 - 6 until a satisfactory test is achieved.
8. When a satisfactory test is achieved, remove Test Pump, drain test fluid, and reinstall the dust cap on the open "SEAL TEST" fitting.

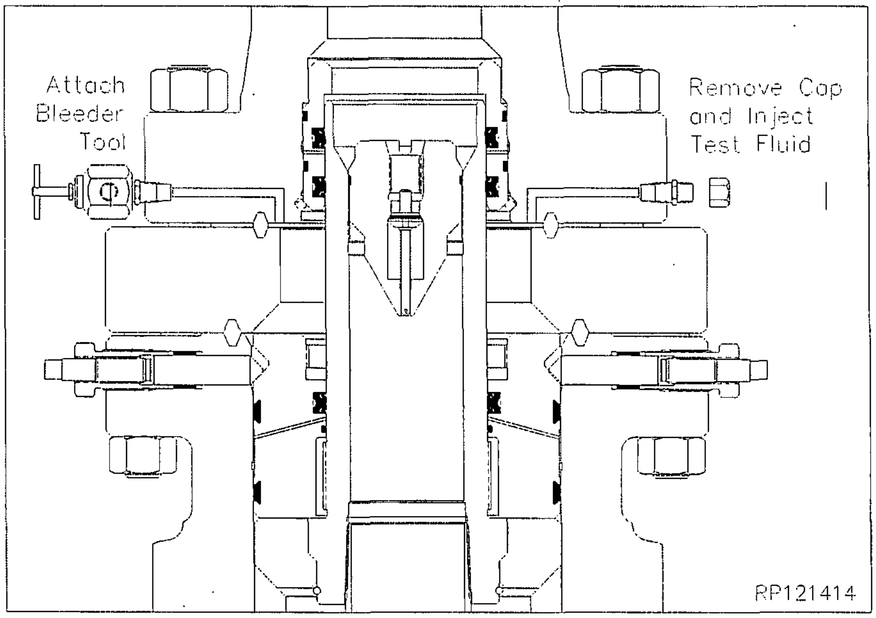


Leak Location	Action
Tubing Head bore - Upper EBS seal leaking	Remove tubing head and replace leaking seal.
Flange Test Bleeder Tool - Lower EBS seal leaking	Remove tubing head and replace leaking EBS seal.

Stage 10 — Install The Tubing Head Assembly

Flange Test

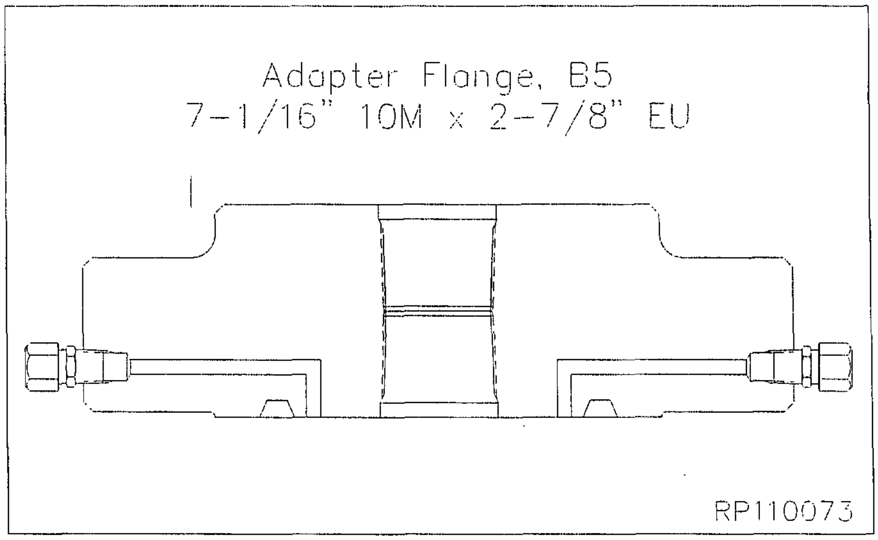
1. Locate the remaining FLG TEST fitting on the tubing head lower flange and remove the dust cap from the fitting.
2. Attach a test pump to the open FLG TEST fitting and inject test fluid into the flange connection until a continuous stream flows from the opposite FLG TEST bleeder tool.
3. Close the FLG TEST bleeder tool and continue to inject test fluid to ***5,000 psi. or 80% of casing collapse — whichever is less***.
4. Hold the test pressure for fifteen (15) minutes or as desired by the drilling supervisor.
5. If pressure drops a leak has developed. Take the appropriate action from the adjacent chart.
6. Repeat this procedure until a satisfactory test is achieved.
7. Once a satisfactory test is achieved, remove the test pump and bleeder tool, drain all test fluid, and reinstall the dust caps.

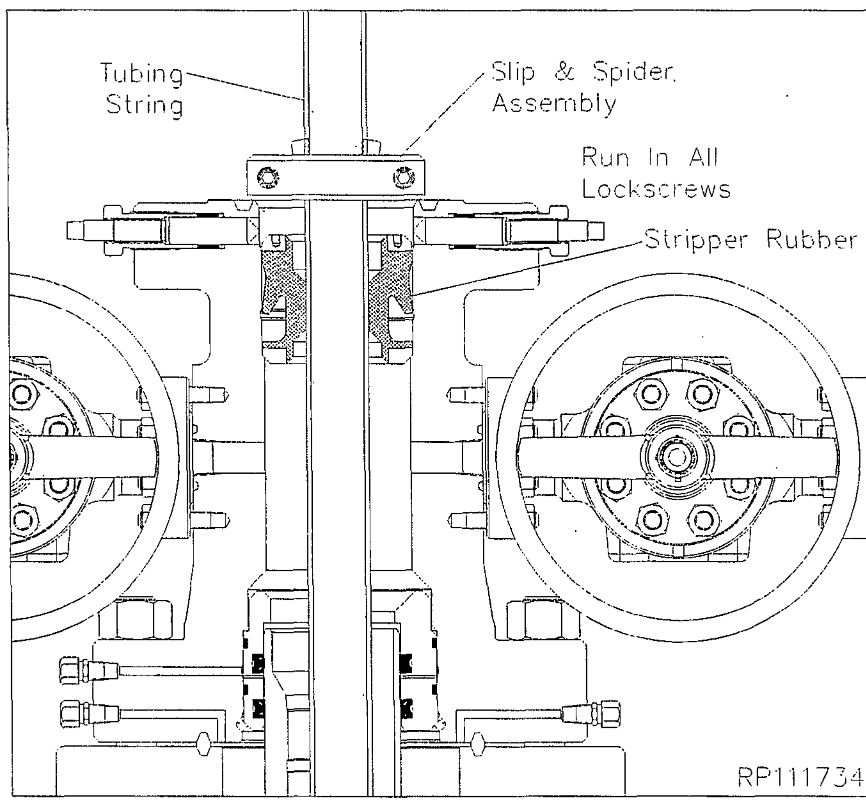


Leak Location	Action
Around lockscrews - Lockscrew packing leaking	Further tighten Glandnut.
Between Flanges - Ring Gasket leaking	Further tighten connection.
Casing Annulus - Hanger seal leaking	Remove tubing head and further tighten slip hanger cap nuts.

Stage 11 — 2-7/8" Tubing Completion

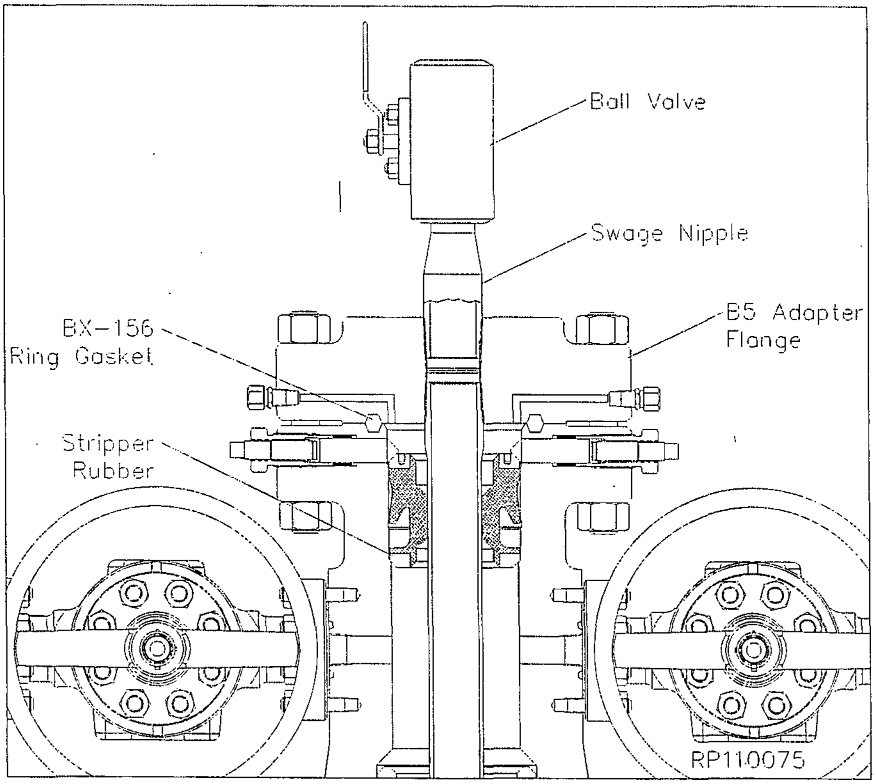
1. Thoroughly clean the top of the tubing head and bowl, removing all old grease and debris.
2. Examine the ***7-1/16" Nominal x 2-7/8" TC Stripper Rubber (Item D4)***. Verify the following:
   - ID and OD seal rubber is intact and undamaged
3. Thoroughly clean the entire stripper rubber, removing all old grease and packaging debris.
4. Lightly lubricate the ID and OD of the stripper rubber with a light grease.
5. Ensure all tubing head lockscrews are fully retracted and then push the stripper rubber into the tubing head bowl until it bottoms on the load shoulder.
6. Run in all the tubing head lockscrews until they make firm contact with the lockscrew rap on the stripper rubber.
7. Place a suitable flange protector on top of the tubing head and rig up the slip and spider assembly.
8. Pick up the first joint of tubing and push it through the stripper rubber.
9. Continue running tubing to the required depth.
10. Engage tubing anchor and then set the tubing in the slip and spider.
11. Remove the coupling from the last joint ran.
12. Pass the ***BX-156 Ring Gasket (Item D2)*** over the tubing and set it on top of the spider assembly.
13. Examine the ***7-1/16" 10M x 2-7/8" EU B5 Adapter Flange (Item D1)***. Verify that:
    - ID threads are clean and in good condition
    - ring groove is clean and free of defects
14. Thoroughly clean the entire flange,



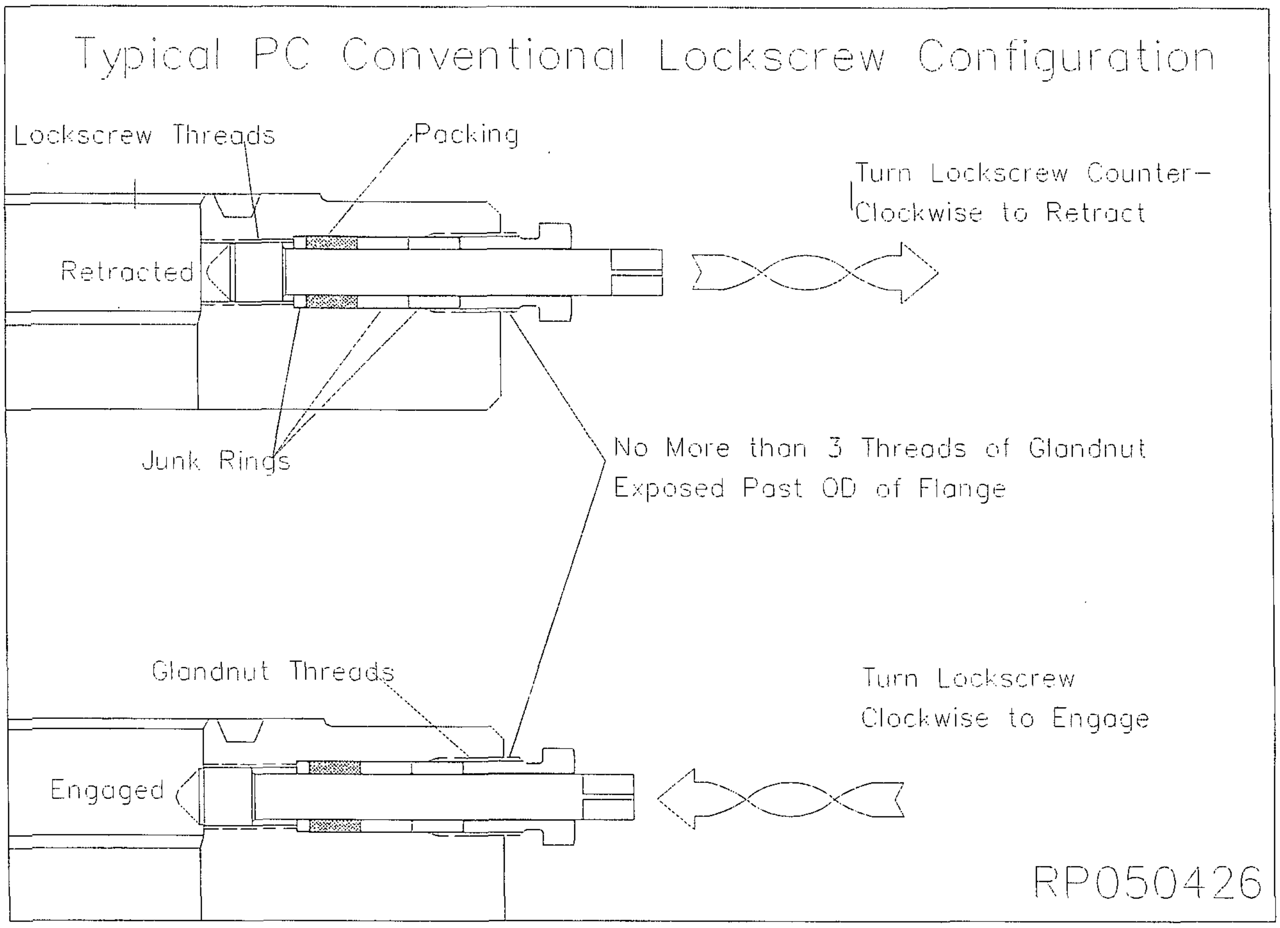


removing all old grease and debris.

15. Make up the appropriate length handling joint to the top of the flange and tighten connection to thread manufacturer's minimum make up torque.
16. Apply approved pipe thread sealant to the mating threads of the flange and the tubing string.
17. Carefully make up the flange to the tubing string and torque connection to thread manufacturer's optimum make up torque.
18. Pick up on the tubing string and ring gasket and remove the slip and spider assembly.
19. Place the ring in the ring groove of the tubing head and then carefully lower the tubing into the well and land the flange on the ring gasket.
20. Make up the flange connection using the appropriate size ***studs and nuts***, tightening them in an alternating cross pattern.
21. Remove handling joint and install Swedge Nipple and Ball Valve.
23. Run in all the lockscrews in an alternating cross pattern as required.



Conventional Lockscrew Operation



Lockscrew Operation Instructions

These instructions are applicable to ONLY Pressure Control "Conventional" style lockscrews. This procedure does not cover lockscrews manufactured or installed in wellhead equipment not supplied by Pressure Control.

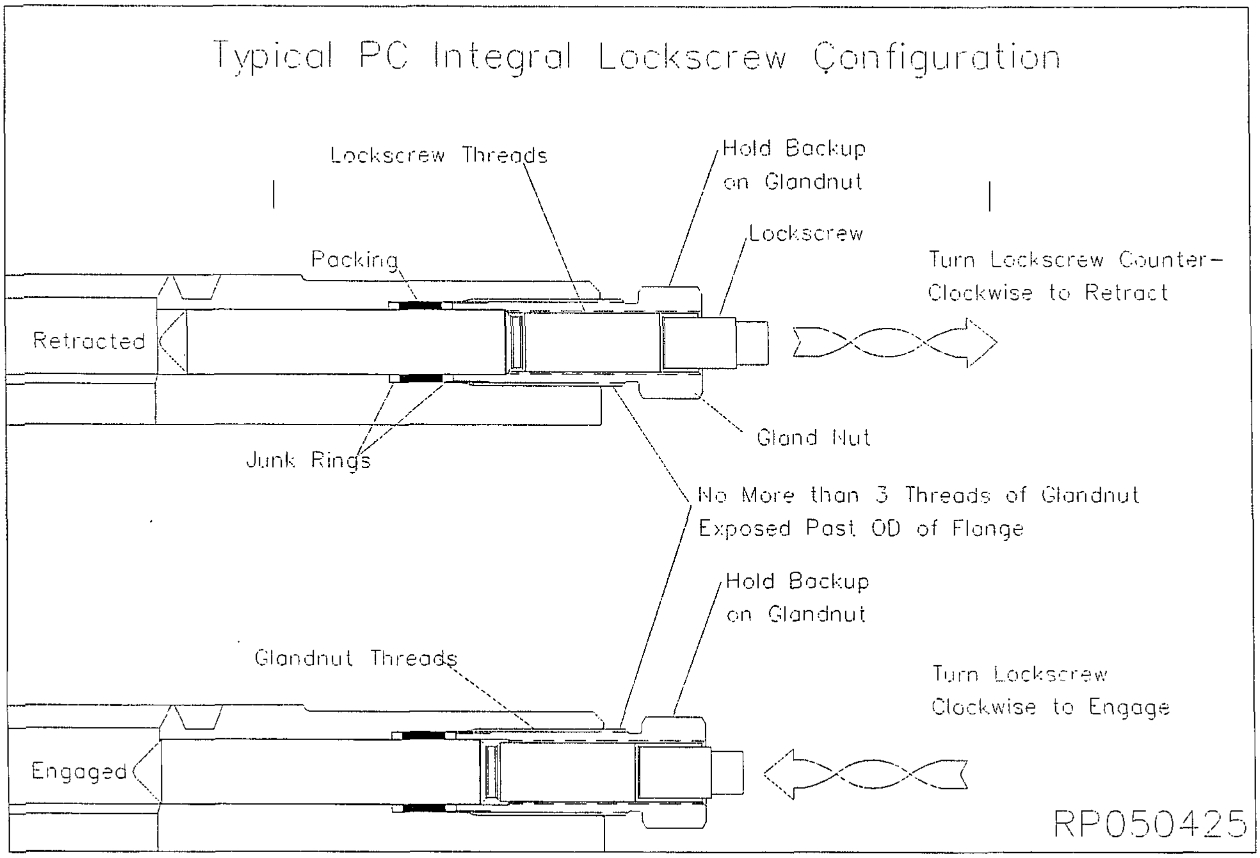
1. The Conventional lockscrew is threaded into the wellhead or flange with enough thread to back out clear of the bowl or to extend into the bowl. This will not disturb the seal/packing around the lockscrew shaft.
2. The seal around the shaft is a compression type with metal Junk Rings. The Packing is energized with the Glandnut on the outside diameter of the flange.
3. The lockscrew is normally backed out of the bowl. The lockscrews are extended into the bowl only after a hanger has been installed. The lockscrew must be backed out prior to removing the hanger.
4. To properly operate the lockscrew it is advised to first backoff (Counterclockwise) the Glandnut no more the one full turn and while holding a backup wrench on the Glandnut, rotate the lockscrew in or out as required. Retighten the Glandnut. The Glandnut, when properly installed, should not expose more than 3 external threads past the OD of the wellhead.

Under a pressure situation the Glandnut should remain tight and the lockscrew rotated as required.

Always use the appropriate size wrench to rotate the Lockscrew. Do not use a pipe wrench.

For lockscrew or lockscrew packing replacement instruction, refer to OM-044.

Integral Lockscrew Operation



Lockscrew Operation Instructions

These instructions are applicable to ONLY Pressure Control "Integral" style lockscrews. This procedure does not cover lockscrews manufactured or installed in wellhead equipment not supplied by Pressure Control.

1. The Integral Lockscrew is threaded into the Glandnut of the assembly with enough thread to back out clear of the bowl or to extend into the bowl. This will not disturb the seal/packing around the lockscrew shaft.
2. The seal around the shaft is a compression type with metal Junk Rings. The Packing is energized with the Glandnut on the outside diameter of the flange and isolates the lockscrew threads from the well bore.
3. The lockscrew is normally backed out of the bowl. The lockscrews are extended into the bowl only after a hanger has been installed. The lockscrew must be backed out prior to removing the hanger.
4. To properly operate the lockscrew it is required to place a backup wrench on the Glandnut, rotate the lockscrew in or out as required. In new installations the Glandnut torque is preset and should not be backed off to operate the lockscrew. The Glandnut, when properly installed, should not expose more than 3 external threads past the OD of the wellhead.
5. When replacing the lockscrew assembly, the junk rings and packing are to be placed in the lockscrew prep as indicated followed by the lockscrew/Glandnut assembly. The Glandnut is then torqued as required. Once the Glandnut torque is met, the Lockscrew may be operated as required.

Under no circumstances is the Glandnut to be backed off to operate the lockscrew.

Always use the appropriate size box wrench or socket to rotate the Lockscrew. Do not use a pipe wrench.

For lockscrew or lockscrew packing replacement instruction, refer to OM-044.

Conditions of Approval

Chevron Midcontinent, L.P.
Madera 17 Fed 1H
API 30-025-41199

I. DRILLING

A. DRILLING OPERATIONS 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)

☒ **Lea County**
Call the Hobbs Field Station, 414 West Taylor, Hobbs NM 88240,
(575) 393-3612

1. **Hydrogen Sulfide has been reported as a hazard in formations deeper than the proposed depth. It is recommended that monitoring equipment be onsite for potential Hydrogen Sulfide. If Hydrogen Sulfide is encountered, report measurements and formations to the BLM.**

2. 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. **If the drilling rig is removed without approval – an Incident of Non-Compliance will be written and will be a "Major" violation.**

3. 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 is located, this does not include the dog house or stairway area.

4. **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.**

B. CASING

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.).
Centralizers required on surface casing per Onshore Order 2.III.B.1.f.

Wait on cement (WOC) time prior to drilling out for a primary cement job will be a minimum 18 hours for a water basin, 24 hours in the potash area, or 500 pounds compressive strength, whichever is greater for all casing strings. DURING THIS WOC TIME, NO DRILL PIPE, ETC. SHALL BE RUN IN THE HOLE. Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string. IF OPERATOR DOES NOT HAVE THE WELL SPECIFIC CEMENT DETAILS ONSITE PRIOR TO PUMPING THE CEMENT FOR EACH CASING STRING, THE WOC WILL BE 30 HOURS. See individual casing strings for details regarding lead cement slurry requirements.

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

Possibility of water and brine flows in the Salado and Castile.
Possibility of lost circulation in the Rustler, Bell Canyon, Cherry Canyon, and Brushy Canyon.

1. The **13-3/8** inch surface casing shall be set at approximately **1288** feet (a minimum of 25 feet into the Rustler Anhydrite and above the salt) and cemented to the surface. **If salt is encountered, set casing at least 25 feet above the salt.**

    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 is to include the lead cement slurry.**

    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.

Formation below the 13-3/8" shoe to be tested according to Onshore Order 2.III.B.1.i. Test to be done as a mud equivalency test using the mud weight necessary for the pore pressure of the formation below the shoe and the mud weight for the bottom of the hole. Report results to BLM office.

Intermediate casing shall be kept fluid filled while running into hole to meet BLM minimum collapse requirements.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing, which shall be set at approximately **5200** feet, is:

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

Formation below the 9-5/8" shoe to be tested according to Onshore Order 2.III.B.1.i. Test to be done as a mud equivalency test using the mud weight necessary for the pore pressure of the formation below the shoe (not the mud weight required to prevent dissolving the salt formation) and the mud weight for the bottom of the hole. Report results to BLM office.

Centralizers approved as written.

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

   ☒ Cement should tie-back at least 500 feet into previous casing string. Operator shall provide method of verification.

4. 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.

C. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in Onshore Oil and Gas Order No. 2 and API RP 53 Sec. 17.

2. Variance approved to use flex line from BOP to choke manifold. 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.** If the BLM inspector questions the straightness of the hose, a BLM engineer will be contacted and will review in the field or via picture supplied by inspector to determine if changes are required (operator shall expect delays if this occurs).

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

    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. **Operator shall perform the intermediate casing integrity test to 70% of the casing burst. This will test the multi-bowl seals.**
    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.**

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

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

    b. The tests shall be done by an independent service company utilizing a test plug **not a cup or J-packer**.

    c. 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.

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

e. 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.**

f. 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.

D. DRILL STEM TEST

If drill stem tests are performed, Onshore Order 2.III.D shall be followed.

E. 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.

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