

1. FORMATION TOPS

The estimated tops of important geologic markers are as follows:

FORMATION	SUB-SEA TVD	KBTVD	MD
Ground Elevation	3146	0	
Rustler	2496	650	
Castile	146	3000	
Lamar	-1554	4700	
Bell Canyon	-1834	4980	
Cherry Canyon	-2729	5875	
Brushy Canyon	-4279	7425	
Bone Spring Limestone	-5659	8805	
Upper Avalon	-5729	8875	
Lateral TD (Upper Avalon)	-5882	9028	13951

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		500
Water	Rustler	650
Water	Bell Canyon	4980
Water	Cherry Canyon	5875
Oil/Gas	Brushy Canyon	7425
Oil/Gas	Bone Spring Limestone	8805
Oil/Gas	Upper Avalon	8875

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 FMC UH2 Multibowl wellhead, which will be run through the rig floor on surface casing. BOPE will be nipped up and tested after cementing surface casing. Subsequent tests will be performed as needed, not to exceed 30 days. The field report from FMC and BOP test information will be provided in a subsequent report at the end of the well. Please see the attached wellhead schematic. An installation manual has been placed on file with the BLM office and remains unchanged from previous submittal.

4. CASING PROGRAM

a. The proposed casing program will be as follows:

Purpose	From	To	TVD	Hole Size	Csg Size	Weight	Grade	Thread	Condition
Surface	0'	650'	650'	17-1/2"	13-3/8"	54.5 #	J55	STC	New
Intermediate	0'	4,530'	4,485'	12-1/4"	9-5/8"	40 #	HCK-55	LTC	New
Production	0'	13,951'	9,028'	8-3/4"	5-1/2"	20.0 #	HCP-110	TXP BTC S	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 recalculated & 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: 850'
 Intermediate Casing: 4800'
 Production Casing: 22,000' MD/9,200' TVD (12,800' VS @ 90 deg inc)

Casing String	Min SF Burst	Min SF Collapse	Min SF Tension	Min SF Tri-Axial
Surface	1.40	1.92	2.40	1.75
Intermediate	1.21	3.02	2.15	1.48
Production	1.30	2.51	2.48	1.51

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	BBLs
Surface				(ppg)	(sx/cu ft)	Open Hole		gal/sk	
Tail	Class C	0'	650'	14.8	1.35	125	749	6.57	180
Intermediate									
Lead	50:50 Poz	0'	3,530'	11.9	2.43	150	1025	14.21	444
Tail	Class C	3,530'	4,530'	14.8	1.33	85	464	6.37	110
Production									
1st Lead	50:50 Poz	3,680'	8,610'	11.5	2.51	50	704	15.51	315
2nd Lead	TXI	8,610'	12,951'	12.5	1.62	35	921	9.64	266
Tail	Acid Soluble	12,951'	13,951'	15	2.18	0	116	11.42	45

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 centralizer on every joint for the first 1000' from TD, then every other joint to EOB, then every third joint to KOP, and then every forth joint to intermediate casing.

6. MUD PROGRAM

From	To	Type	Weight	F. Vis	Filtrate
0'	650'	Spud Mud	8.3 - 8.7	32 - 34	NC - NC
650'	4,530'	Brine	9.5 - 10.1	28 - 30	NC - NC
4,530'	8,610'	OBM	8.3 - 9.6	28 - 30	NC - NC
8,610'	9,359'	OBM	8.3 - 9.6	28 - 30	15 - 25
9,359'	13,951'	OBM	8.3 - 9.6	28 - 30	15 - 25

A closed system will be 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	Surface to TD	Drillout of Int Csg	TBD
LWD	MWD Gamma	Int. and Prod. Hole	While Drilling	TBD

- c. Conventional hole 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: 4500 psi
- b. Hydrogen sulfide gas is not anticipated. An H2S Contingency plan is attached with this APD in the event that H2S is encountered



H₂S Preparedness and Contingency Plan Summary

SD WE 15 FED P12 1H

SD WE 15 FED P12 3H

SD WE 15 FED P12 2H

SD WE 15 FED P12 4H

HOBBS OCD

FEB 13 2017

Training

MCBU Drilling and Completions H₂S 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 H₂S.

RECEIVED

Awareness Level

Employees and visitors to MCBU Drilling and Completions locations that have known concentrations of H₂S, who are not required to perform work in H₂S areas, will be provided with an awareness level of H₂S training prior to entering any H₂S areas. At a minimum, awareness level training will include:

1. Physical and chemical properties of H₂S
2. Health hazards of H₂S
3. Personal protective equipment
4. Information regarding potential sources of H₂S
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 H₂S Training

Employees and contractors required to work in areas that may contain H₂S will be provided with Advanced Level H₂S training prior to initial assignment. In addition to the Awareness Level requirements, Advanced Level H₂S training will include:

1. H₂S safe work practice procedures;
2. Emergency contingency plan procedures;
3. Methods to detect the presence or release of H₂S (e.g., alarms, monitoring equipment), including hands-on training with direct reading and personal monitoring H₂S equipment.
4. Basic overview of respiratory protective equipment suitable for use in H₂S 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 H₂S training;
6. Proficiency examination covering all course material.

Advanced H₂S training courses will be instructed by personnel who have successfully completed an appropriate H₂S train-the-trainer development course (ANSI/ASSE Z390.1-2006) or who possess significant past experience through educational or work-related background.



H₂S Training Certification

All employees and visitors will be issued an H₂S training certification card (or certificate) upon successful completion of the appropriate H₂S training course. Personnel working in an H₂S environment will carry a current H₂S 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 upwind from the well at all times. Upon recognition of an emergency situation, all personnel should assemble at the designated upwind briefing areas for instructions.

H₂S 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.

H₂S Detection and Monitoring System

- a) H₂S 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.

H₂S Preparedness and Contingency Plan Summary



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

<u>Agency</u>	<u>Telephone Number</u>
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

H₂S Preparedness and Contingency Plan Summary

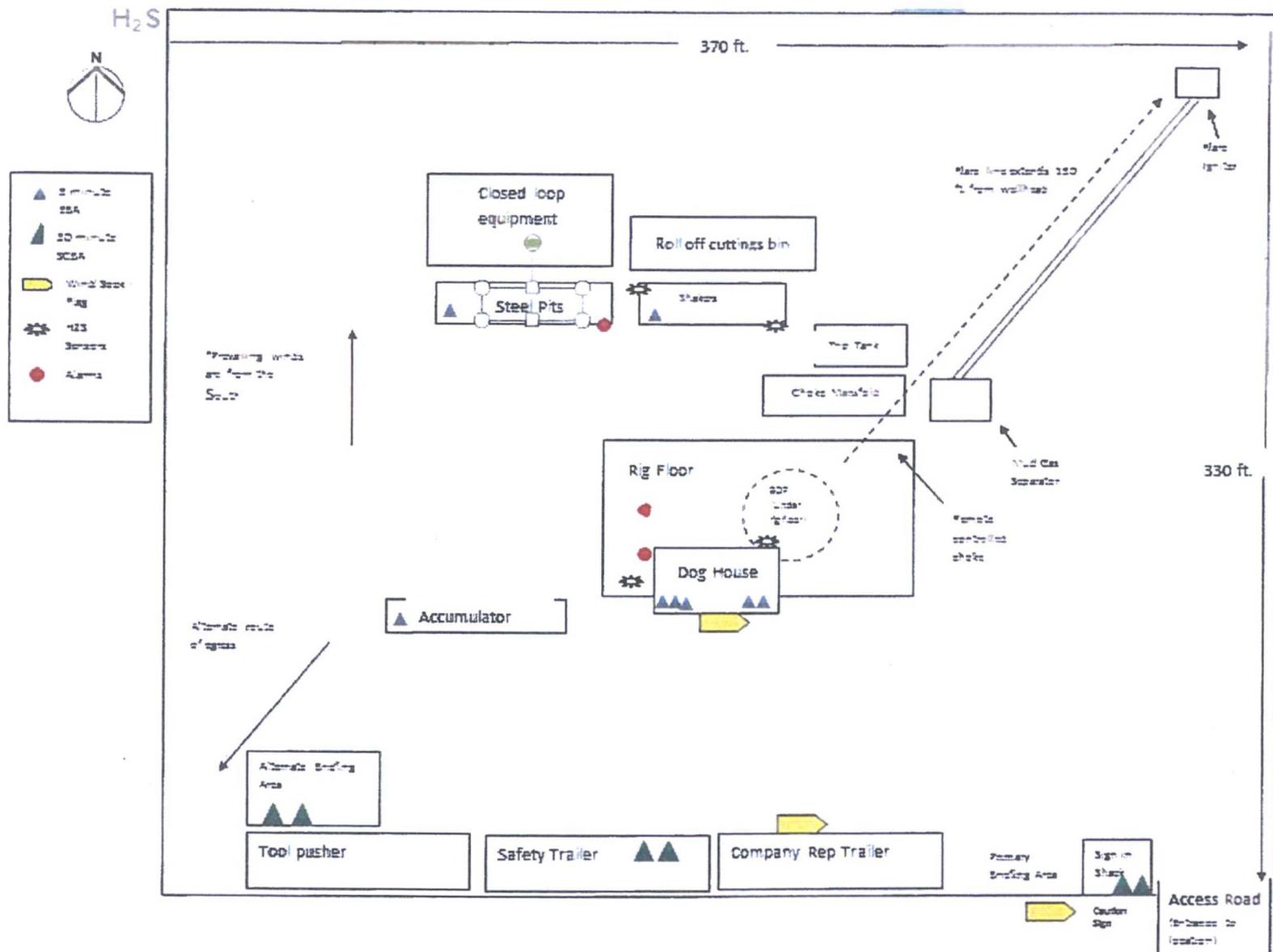


Chevron MCBU D&C Emergency Notifications

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

	Name	Title	Office Number	Cell Phone
1.	Kenneth Hodges	Drilling Engineer	(713) 372-2154	(832) 470-3579
2.	Elmo Cecchetti	Superintendent	(713) 372-1235	(412) 719-7885
5.	Ikenna Chukwumaeze	Drilling Manager	(713) 372-7591	(281) 615-0701
6.	Scott Nash	Operations Manager	(713) 372-5747	(281) 814-9713
7.	Luke Meaux	D&C HES	(432) 687-7133	(432) 208-3572
8.	Brendan Gustus	Completion Engineer	(713) 372-1309	(432) 530-6158

H₂S Preparedness and Contingency Plan Summary



BLOWOUT PREVENTOR SCHEMATIC

Minimum Requirements

OPERATION : Intermediate and Production Hole Sections

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

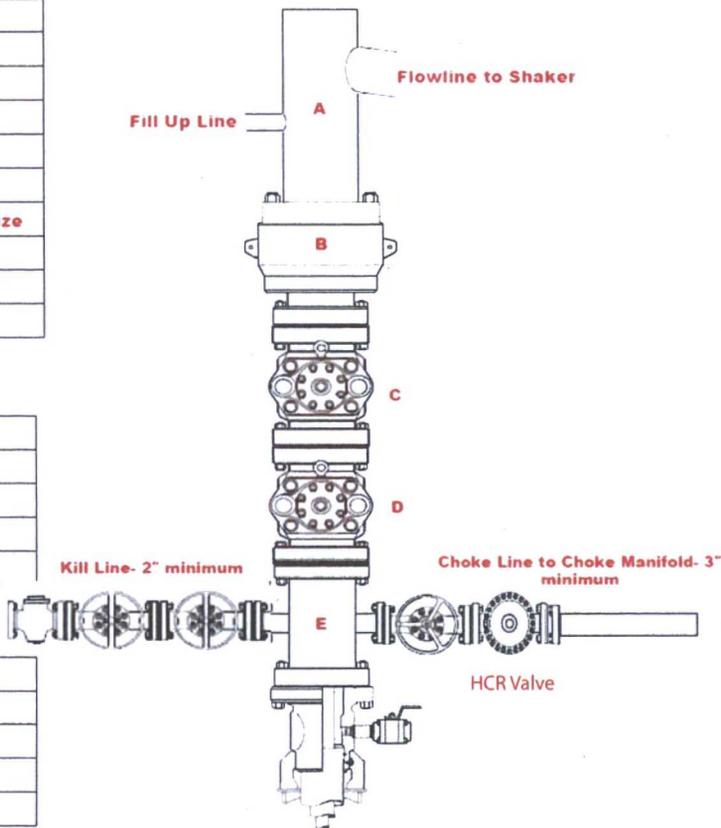
	SIZE	PRESSURE	DESCRIPTION
A		N/A	Bell Nipple
B	13 5/8"	5,000 psi	Annular
C	13 5/8"	5,000 psi	Pipe Ram
D	13 5/8"	5,000 psi	Blind Ram
E	13 5/8"	5,000 psi	Mud Cross
F			
DSA	As required for each hole size		
C-Sec			
B-Sec	13-5/8" 5K x 11" 5K		
A-Sec	13-3/8" SOW x 13-5/8" 5K		

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 through flow.
- The kill line and choke line will be straight unless turns use tee blocks or are targeted with running tress, 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

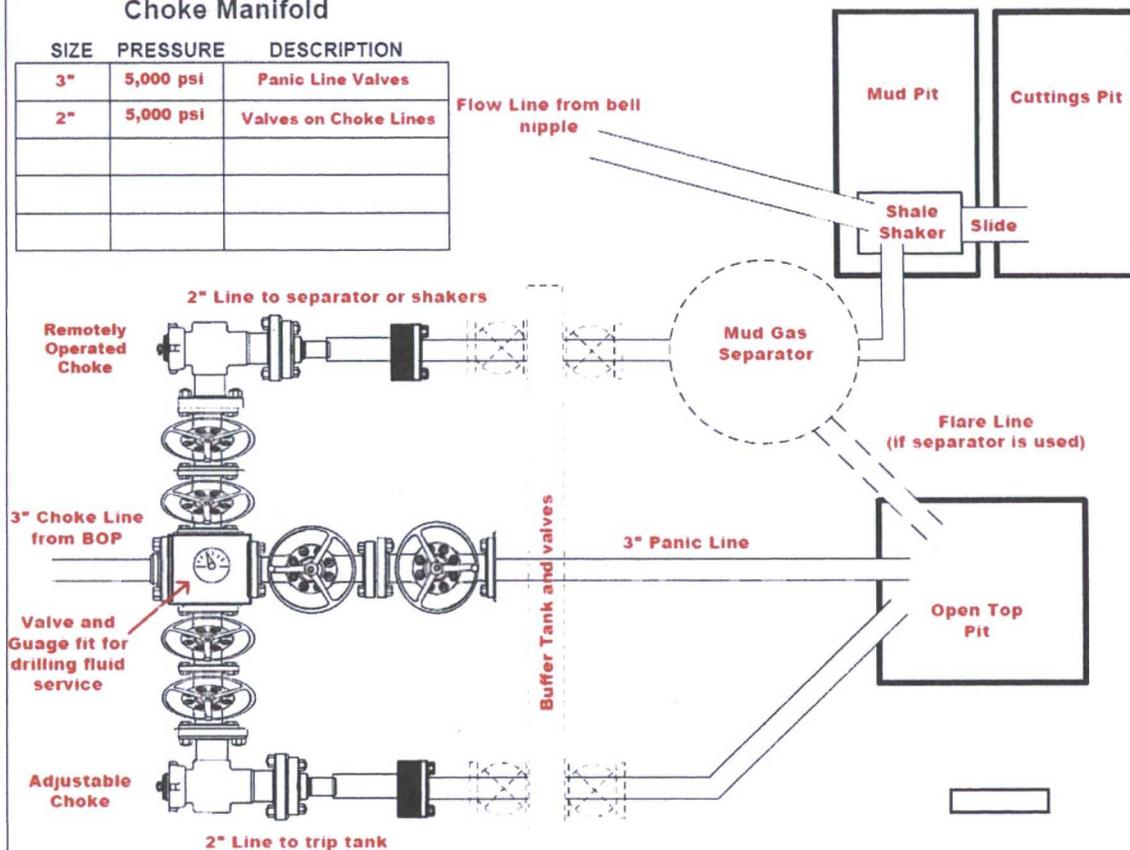
Minimum Requirements

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 items 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 tress, 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
<input type="checkbox"/>	1500 psi	1500 psi	750 psi	800 psi	700 psi
<input type="checkbox"/>	2000 psi	2000 psi	1000 psi	1100 psi	900 psi
<input type="checkbox"/>	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. Reservoir 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 checked 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

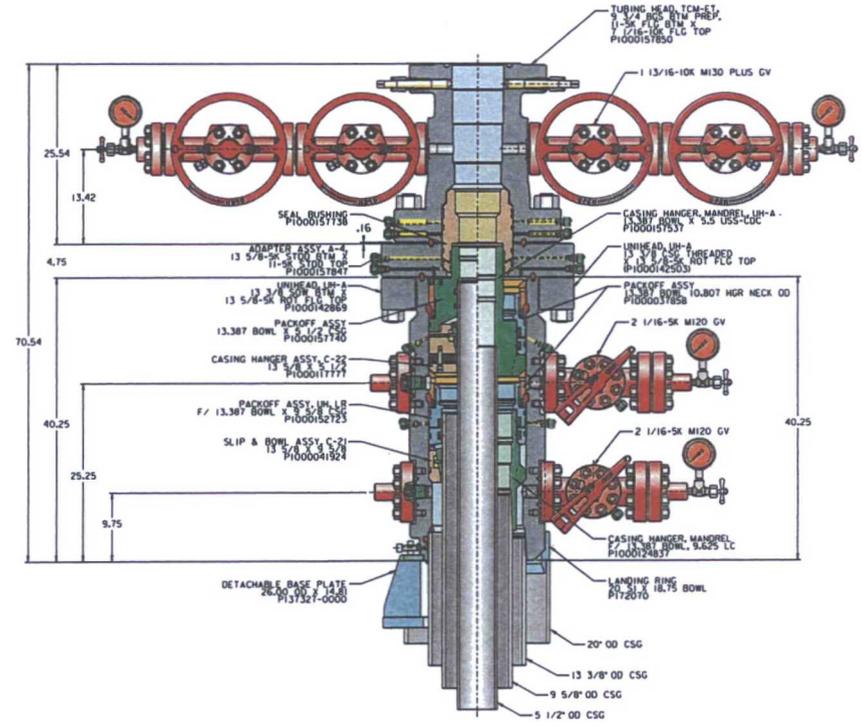
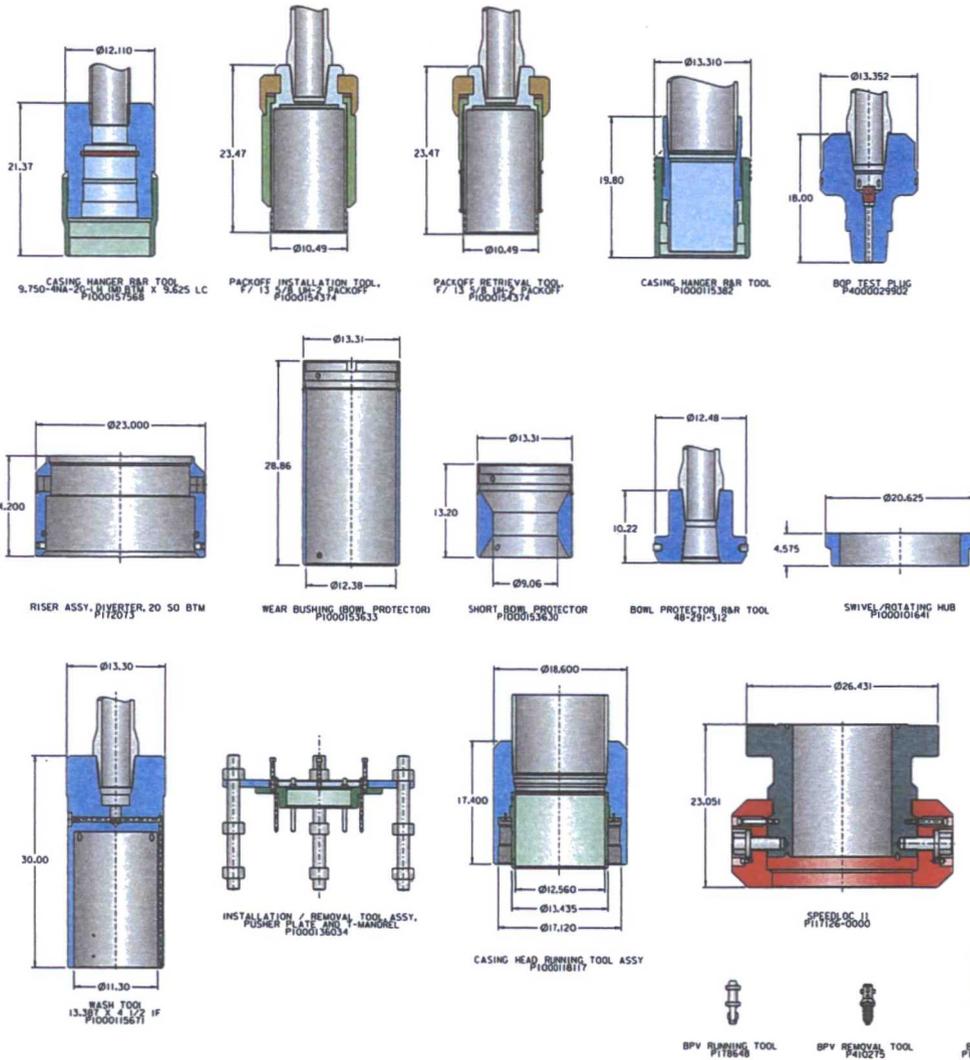
- BOPE will be pressure tested when initially installed, whenever any seal subject to test pressure is broken, following related repairs, and at a minimum of 30 days intervals. **Test pressure and times will be recorded by a 3rd party on a test chart and kept on location through the end of the well.**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

Wellname: _____

Representative: _____

Date: _____



20 X 13 3/8 X 9 5/8 X 5 1/2

UH-2 Unihead

Odessa
13" Single Piece

FMC Technologies
We put you first.
And keep you ahead.