1. FORMATION TOPS

The estimated tops of important geologic markers are as follows:

FORMATION	SUB-SEA TVD	KBTVD	MD
Rustler		800	
Castile		3480	
Lamar		4900	
Bell Canyon		4930	
Cherry Canyon		5970	
Brushy Canyon		7620	
Bone Spring Limestone		9090	
Upr. Avalon		9120	
Lateral TD (Upper Avalon)		9,300	14300

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		700
Water	Rustler	800
Water	Bell Canyon	4930
Water	Cherry Canyon	5970
Oil/Gas	Brushy Canyon	7620
Oil/Gas	Bone Spring Limestone	9090
Oil/Gas	Upr. Avalon	9120

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. Batch drilling of the surface, intermediate, and production will take place. A full BOP test will be performed unless approval from BLM is received otherwise.

Chevron requests a variance to use a FMC UH2 Multibowl wellhead, which will be run through the rig foor on surface casing. BOPE will be nippled 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	Hole Size	Csg Size	Weight	Grade	Thread	Condition
Surface	0'	800'	17-1/2"	13-3/8"	55 #	J55	STC	New
Intermediate	0'	4,790'	12-1/4"	9-5/8"	43.5#	HCK-L80	LTC	New
Production	0'	14,300'	8-1/2"	5-1/2"	20.0 #	P-110-ICY	TXP BTC	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: 850'
Intermediate Casing: 11,200' TVD
Production Casing: 23,000' MD/12,750' TVD (10,300' VS @ 90 deg inc)

Casing String	Min SF Burst	Min SF Collapse	Min SF Tension	Min SF Tri-Axial
Surface	1.36	3.12	3.17	1.70
Intermediate	1.12	1.44	1.93	1.37
Production	1.11	1.23	1.97	1.37

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, 13 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
Tail	Class C	0'	800'	14.8	1.33	50	650	6.57
Intermediate								
Conventional	Class C	0'	3900	11.9	2.39	100	1070	13.46
Conventional	Class C	3900	4900	14.8	1.33	25	89	6.35
Production								
1st Lead	Conventional	3,850'	8,508'	11.5	2.66	50	575	15.51
2nd Lead	Conventional	8,508'	13,300'	12.5	1.59	10	1145	9.64
Tail	SoluCem H	13,300'	14,300'	15	1.59	0	144	11.42

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 joint for the first 1000' from TD, then every other joint to EOB, and then every third 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'	800'	Spud Mud	8.3 - 8.7	32 - 34	NC - NC
800'	4,900'	Oil Based Mud	8.7-9.2	28 - 30	25-30
4,900'	9,000'	Oil Based Mud	8.7-9.3	70 - 75	25 - 30
9,000'	14,300'	Oil Based Mud	8.7-9.3	70 - 75	25 - 30

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	Int. and Prod. Hole	While Drilling	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: 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

Tenaris

Wed Jun 17 2015

Casing and Tubing Performance Dat

PIPE BODY DATA

GEOMETRY

Outside Diameter	9.625 in	Wall Thickness	0.435 in	API Drift Diameter	8.599 in
Nominal Weight	43.50 lbs/ft	Nominal ID	8.755 in	Alternative Drift Diameter	8.625 in
Plain End Weight	42.73 lbs/ft	Nominal cross section	12.559 in		

PERFORMANCE

Steel Grade	L80	Minimum Yield	80,000 psi	Minimum Ultimate	95,000 psi
Tension Yield	1,005,000 in	Internal Pressure Yield	6,330 psi	Collapse Pressure	3,810 psi
Available Seamless	Yes	Available Welded	No		

CONNECTION DATA

TYPE: LTC

GEOMETRY

Coupling Reg OD	10.625 in	Threads per in	8	Thread turns make up	3.5

PERFORMANCE

Steel Grade	L80	Coupling Min Yield	80,000 psi	Coupling Min Ultimate	95,000 psi
Joint Strength	813,000 lbs			Internal Pressure Resistance	6,330 psi

For the latest performance data, always visit our website: www.tenaris.com

June 17 2015

TenarisHydril

Size: 5.000 in.
Wall: 0.362 in.
Weight: 18.00 lbs/ft
Grade: P110-IC
Min. Wall Thickness: 87.5 %

Connection: Wedge 521™
Casing/Tubing: CAS

PIPE BODY DATA

GEOMETRY

Nominal OD	**5.000** in.	Nominal Weight	**18.00** lbs/ft	Standard Drift Diameter	**4.151** in.
Nominal ID	**4.276** in.	Wall Thickness	**0.362** in.	Special Drift Diameter	**N/A**
Plain End Weight	**17.95** lbs/ft				

PERFORMANCE

Body Yield Strength	**580** x 1000 lbs	Internal Yield	**13940** psi	SMYS	**110000** psi
Collapse	**14840** psi				

WEDGE 521™ CONNECTION DATA

GEOMETRY

Connection OD	**5.359** in.	Connection ID	**4.226** in.	Make-Up Loss	**3.620** in.
Critical Section Area	**3.891** sq. in.	Threads per in.	**3.36**		

PERFORMANCE

Tension Efficiency	**73.8** %	Joint Yield Strength	**428** x 1000 lbs	Internal Pressure Capacity	**13940** psi
Compression Strength	**514** x 1000 lbs	Compression Efficiency	**88.7** %	Bending	**75** °/100 ft
External Pressure Capacity	**14840** psi				

MAKE-UP TORQUES

Minimum	**6100** ft-lbs	Optimum	**7300** ft-lbs	Maximum (*)	**10700** ft-lbs

OPERATIONAL LIMIT TORQUES

Operating Torque	**17300** ft-lbs	Yield Torque	**26000** ft-lbs		

BLANKING DIMENSIONS

Blanking Dimensions

* If you need to use torque values that are higher than the maximum indicated, please contact a local Tenaris technical sales representative.

Tenaris

Data Sheet

TH DS-16.0370 11 ago 16
Rev 00

5" 18.00 ppf P110-ICY - TenarisXP® BTC (min wt 90%) (USC Units)

PIPE BODY DATA					
GEOMETRY					
Nominal OD	5.000 in.	Nominal Weight	18.00 lbs/ft	Standard Drift Diameter	4.151 in.
Nominal ID	4.276 in.	Wall Thickness	0.362 in.	Special Drift Diameter	-
Plain End Weight	17.95 lbs/ft				
PERFORMANCE					
Body Yield Strength	659 x 1000 lbs	Internal Yield [4]	16290 psi	Collapse	14840 psi

CONNECTION DATA					
Regular OD	5.720 in.	Coupling Length	9.325 in.	Connection ID	4.264 in.
Critical Section Area	5.275 sq. in.	Threads per in.	5	Make-Up Loss	4.141 in.
PERFORMANCE					
Tension Efficiency	100.0 %	Joint Yield Strength	659 x 1000 lbs	Internal Pressure Capacity [1] [4]	16290 psi
Structural Compression Efficiency	100.0 %	Structural Compression Rating	659 x 1000 lbs	External Pressure Capacity	14840 psi
Structural Bending [2]	115°/100 ft				
MAKE-UP TORQUES [3]					
Minimum	11480 ft-lbs	Target	12750 ft-lbs	Maximum	14030 ft-lbs
Operating Torque	15800 ft-lbs	Yield Torque	17700 ft-lbs		

(1) Internal Yield pressure related to structural resistance only. Internal pressure leak resistance as per section 10.3 API 5C3 / ISO 10400 - 2007.

(2) Structural rating, pure bending to yield (i.e no other loads applied)

(3) Torque values calculated for API Modified thread compounds with Friction Factor=1. For other thread compounds please contact us at licensees@oilfield.tenaris.com.

(4) Minimum wall thickness 90% of nominal

For the latest performance data, always visit our website: www.tenaris.com

January 18 2016

Tenaris

Connection: TenarisXP® BTC
Casing/Tubing: CAS
Coupling Option: REGULAR

Size: 5.500 in.
Wall: 0.361 in.
Weight: 20.00 lbs/ft
Grade: P110-ICY
Min. Wall Thickness: 87.5 %

PIPE BODY DATA

GEOMETRY

Nominal OD	**5.500** in.	Nominal Weight	**20.00** lbs/ft	Standard Drift Diameter	**4.653** in.
Nominal ID	**4.778** in.	Wall Thickness	**0.361** in.	Special Drift Diameter	**N/A**
Plain End Weight	**19.83** lbs/ft				

PERFORMANCE

Body Yield Strength	**729** x 1000 lbs	Internal Yield	**14360** psi	SMYS	**125000** psi
Collapse	**12100** psi				

TENARISXP® BTC CONNECTION DATA

GEOMETRY

Connection OD	**6.100** in.	Coupling Length	**9.450** in.	Connection ID	**4.766** in.
Critical Section Area	**5.828** sq. in.	Threads per in.	**5.00**	Make-Up Loss	**4.204** in.

PERFORMANCE

Tension Efficiency	**100** %	Joint Yield Strength	**729** x 1000 lbs	Internal Pressure Capacity(1)	**14360** psi
Structural Compression Efficiency	**100** %	Structural Compression Strength	**729** x 1000 lbs	Structural Bending(2)	**104** °/100 ft
External Pressure Capacity	**12100** psi				

ESTIMATED MAKE UP TORQUES(3)

Minimum	**11540** ft-lbs	Optimum	**12820** ft-lbs	Maximum	**14100** ft-lbs

OPERATIONAL LIMIT TORQUES

Operating Torque	**22700** ft-lbs	Yield Torque	**25250** ft-lbs		

BLANKING DIMENSIONS

Blanking Dimensions

(1) Internal Pressure Capacity related to structural resistance only. Internal pressure leak resistance as per section 10.3 API 5C3 / ISO 10400 - 2007.

(2) Structural rating, pure bending to yield (i.e no other loads applied)

(3) Torque values calculated for API Modified thread compounds with Friction Factor=1. For other thread compounds please contact us at licensees@oilfield.tenaris.com. Torque values may be further reviewed.

For additional information, please contact us at contact-tenarishydril@tenaris.com

BLOWOUT PREVENTOR SCHEMATIC

Minimum Requirements

OPERATION : Intermediate and Production Hole Sections

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

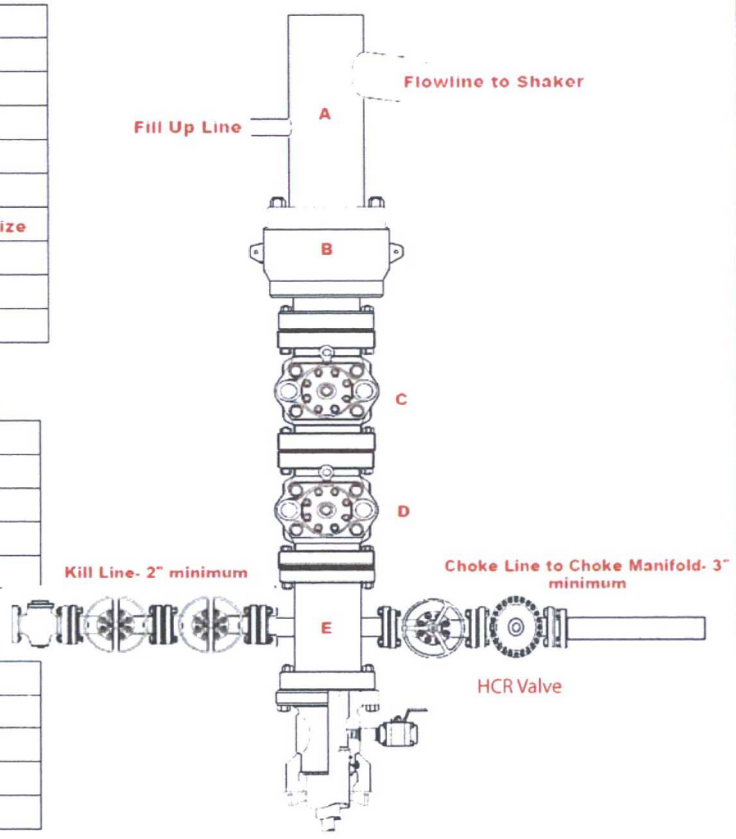
	SIZE	PRESSURE	DESCRIPTION
A		N/A	Bell Nipple
B	13 5/8"	5,000 psi	Annular
C	13 5/8"	5,000 psi	Pipe Ram
D	13 5/8"	5,000 psi	Blind Ram
E	13 5/8"	5,000 psi	Mud Cross
F			
DSA		As required for each hole size	
C-Sec			
B-Sec		13-5/8" 5K x 11" 5K	
A-Sec		13-3/8" SOW x 13-5/8" 5K	

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

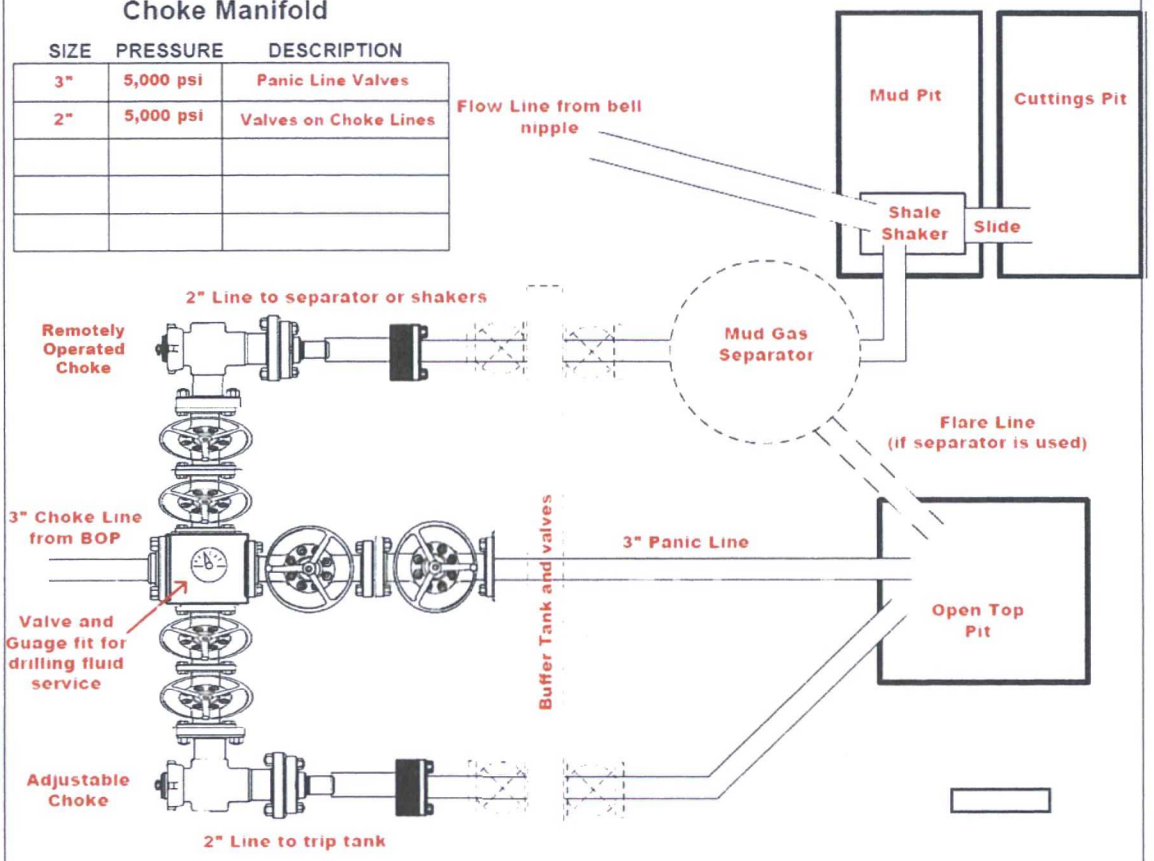
Minimum Requirements

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 along with any/all BOP and accumulator test charts and reports from 3rd parties.

Wellname: _____

Representative: _____

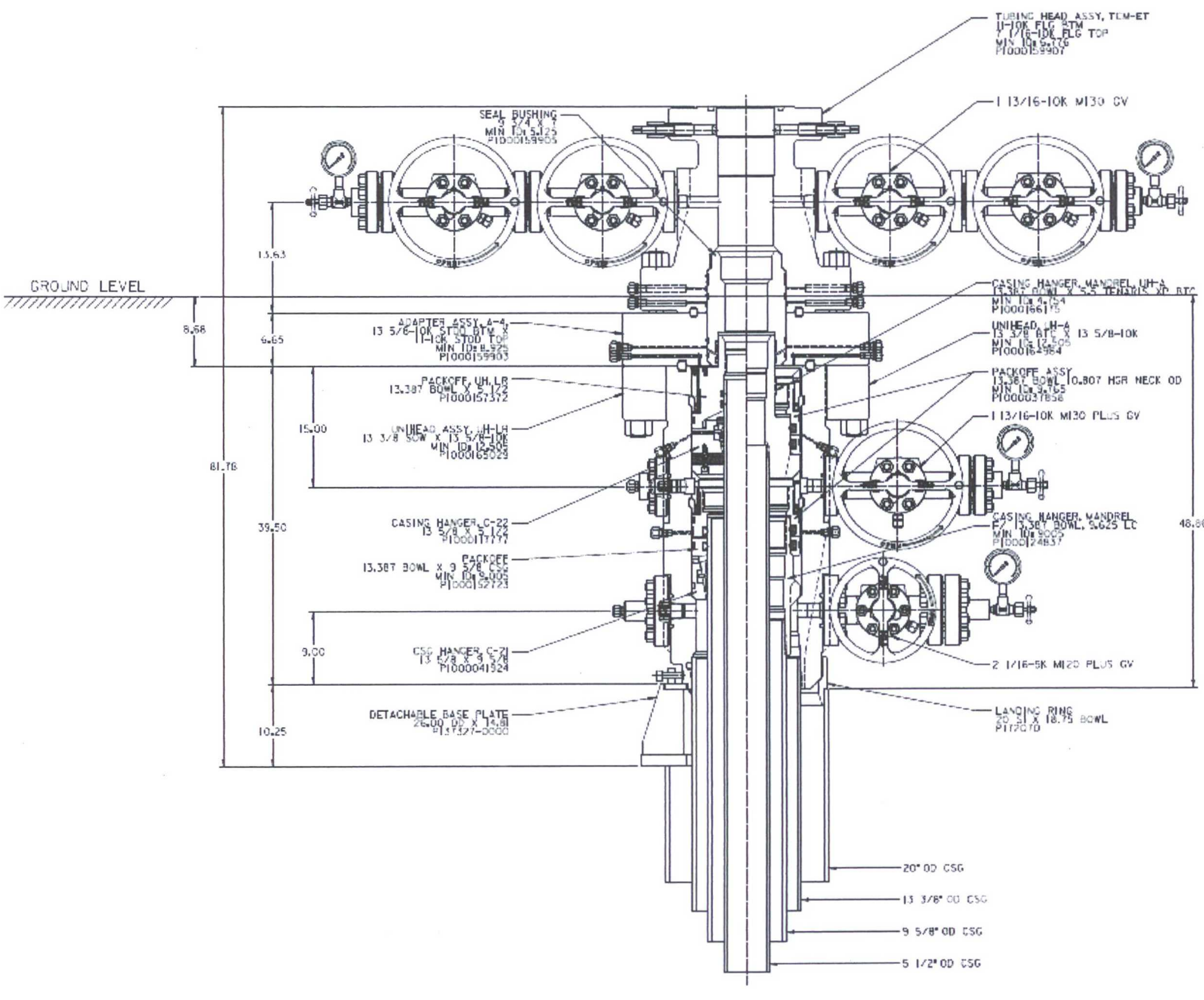
Date: _____

Continental

ContiTech

Hose Data Sheet

CRI Order No.	538332
Customer	ContiTech Oil & Marine Corp.
Customer Order No	4500412631 CBC544771, CBC544769, CBC544767, CBC544763, CBC544768, CBC544745, CBC544744, CBC544746
Item No.	1
Hose Type	Flexible Hose
Standard	**API SPEC 16 C**
Inside dia in inches	3
Length	45 ft
Type of coupling one end	FLANGE 4.1/16" 10KPSI API SPEC 17D SV SWIVEL FLANGE SOURC/W BX155 ST/ST INLAID R.GR.
Type of coupling other end	FLANGE 4.1/16" 10KPSI API SPEC 17D SV SWIVEL FLANGE SOUR C/W BX155 ST/ST INLAID R.GR.
H2S service NACE MR0175	Yes
Working Pressure	10 000 psi
Design Pressure	10 000 psi
Test Pressure	15 000 psi
Safety Factor	2,25
Marking	USUAL PHOENIX
Cover	NOT FIRE RESISTANT
Outside protection	St.steel outer wrap
Internal stripwound tube	No
Lining	OIL + GAS RESISTANT SOUR
Safety clamp	Yes
Lifting collar	Yes
Element C	Yes
Safety chain	Yes
Safety wire rope	No
Max.design temperature [°C]	100
Min.design temperature [°C]	-20
Min. Bend Radius operating [m]	0,90
Min. Bend Radius storage [m]	0,90
Electrical continuity	The Hose is electrically continuous
Type of packing	WOODEN CRATE ISPM-15


TUBING HEAD ASSY, TCM-ET
11-10K FLG BTM
7 1/16-10K FLG TOP
MIN ID: 6.176
P1000159907
1 13/16-10K M130 GV
SEAL BUSHING
9 3/4 X 7
MIN ID: 5.125
P1000159905
GROUND LEVEL
13.63
8.68
6.65
15.00
81.78
39.50
9.00
10.25
48.86
ADAPTER ASSY, A-4,
13 5/8-10K STDD BTM X
11-10K STDD TOP
MIN ID: 8.925
P1000159903
PACKOFF, UH, LR
13.387 BOWL X 5 1/2
P1000157372
UNIHEAD ASSY, UH-LH
13 3/8 SOW X 13 5/8-10K
MIN ID: 12.505
P1000165029
CASING HANGER, C-22
13 5/8 X 5 1/2
P1000117777
PACKOFF
13.387 BOWL X 9 5/8 CSG
MIN ID: 9.005
P1000152723
CSG HANGER, C-21
13 5/8 X 9 5/8
P1000041924
DETACHABLE BASE PLATE
26.00 OD X 14.81
P137327-0000
CASING HANGER, MANDREL, UH-A
13.387 BOWL X 5.5 TENARIS XP BTC
MIN ID: 4.754
P1000166175
UNIHEAD, UH-A
13 3/8 BTC X 13 5/8-10K
MIN ID: 12.505
P1000164964
PACKOFF ASSY
13.387 BOWL 10.807 HGR NECK OD
MIN ID: 9.765
P1000037856
1 13/16-10K M130 PLUS GV
CASING HANGER, MANDREL
F/ 13.387 BOWL, 9.625 LC
MIN ID: 9005
P1000124837
2 1/16-5K M120 PLUS GV
LANDING RING
20 S1 X 18.75 BOWL
P1170TD
20" OD CSG
13 3/8" OD CSG
9 5/8" OD CSG
5 1/2" OD CSG

QUALITY CONTROL INSPECTION AND TEST CERTIFICATE

CERT. N°: 594

PURCHASER:	ContiTech Oil & Marine Corp.	P.O. N°:	4500412631
CONTITECH ORDER N°:	538332	HOSE TYPE: 3" ID	Choke & Kill Hose
HOSE SERIAL N°:	67349	NOMINAL / ACTUAL LENGTH:	13,72 m / 13,85 m

W.P.	68,9	MPa	10000	psi	T.P. 103,4	MPa	15000	psi

Duration: 60 min.

Pressure test with water at ambient temperature

See attachment. (1 page)

↑ 10 mm = 10 Min.

→ 10 mm = 25 MPa

COUPLINGS Type	Serial N°	Quality	Heat N°
3" coupling with	1435 1436	AISI 4130	A1258U
4 1/16" 10K API Swivel Flange end		AISI 4130	034939
Hub		AISI 4130	A1045N

Not Designed For Well Testing **API Spec 16 C**

Tag No.: 66 – 1198 **Temperature rate:"B"**

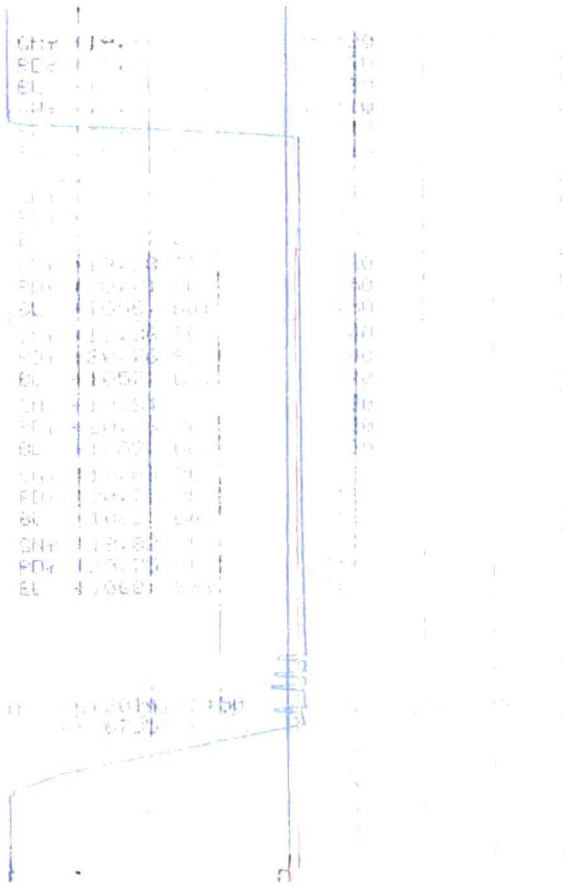
All metal parts are flawless

WE CERTIFY THAT THE ABOVE HOSE HAS BEEN MANUFACTURED IN ACCORDANCE WITH THE TERMS OF THE ORDER INSPECTED AND PRESSURE TESTED AS ABOVE WITH SATISFACTORY RESULT.

STATEMENT OF CONFORMITY: We hereby certify that the above items/equipment supplied by us are in conformity with the terms, conditions and specifications of the above Purchaser Order and that these items/equipment were fabricated inspected and tested in accordance with the referenced standards, codes and specifications and meet the relevant acceptance criteria and design requirements.

Date:	Inspector	Quality Control
03. April 2014.		ContiTech Rubber Industrial Kft. Quality Control Dept. (1)

ATTACHMENT OF QUALITY CONTROL INSPECTION AND TEST CERTIFICATE *No: 594, 596, 597*



CordTech Rubber
Industrial Kft.
Quality Control Dept.
(1)

BLOWOUT PREVENTOR SCHEMATIC

Minimum Requirements

OPERATION : Intermediate and Production Hole Sections

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

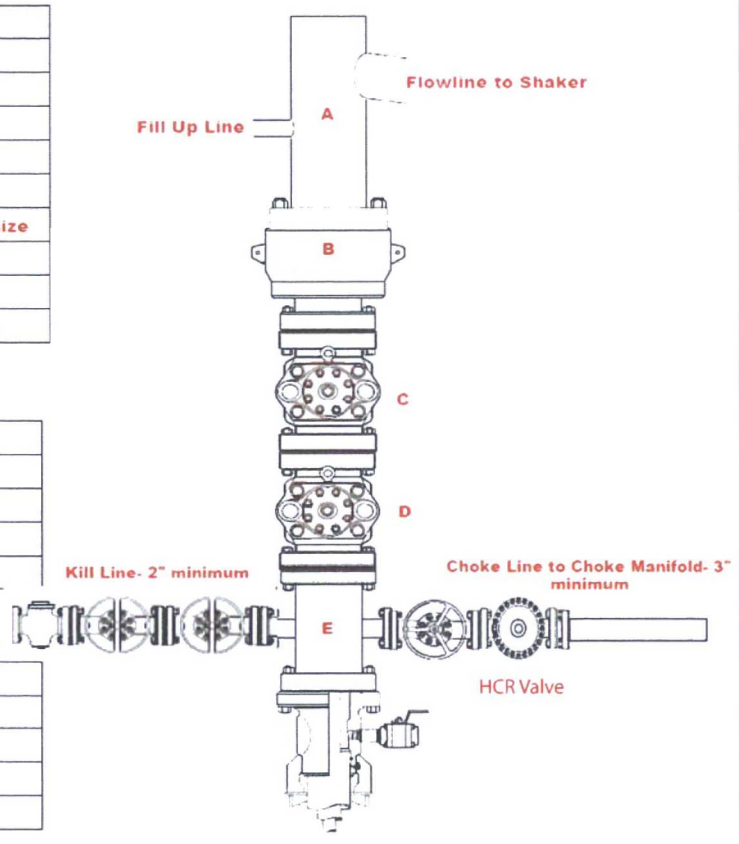
	SIZE	PRESSURE	DESCRIPTION
A		N/A	Bell Nipple
B	13 5/8"	5,000 psi	Annular
C	13 5/8"	5,000 psi	Pipe Ram
D	13 5/8"	5,000 psi	Blind Ram
E	13 5/8"	5,000 psi	Mud Cross
F			
DSA		As required for each hole size	
C-Sec			
B-Sec		13-5/8" 5K x 11" 5K	
A-Sec		13-3/8" SOW x 13-5/8" 5K	

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

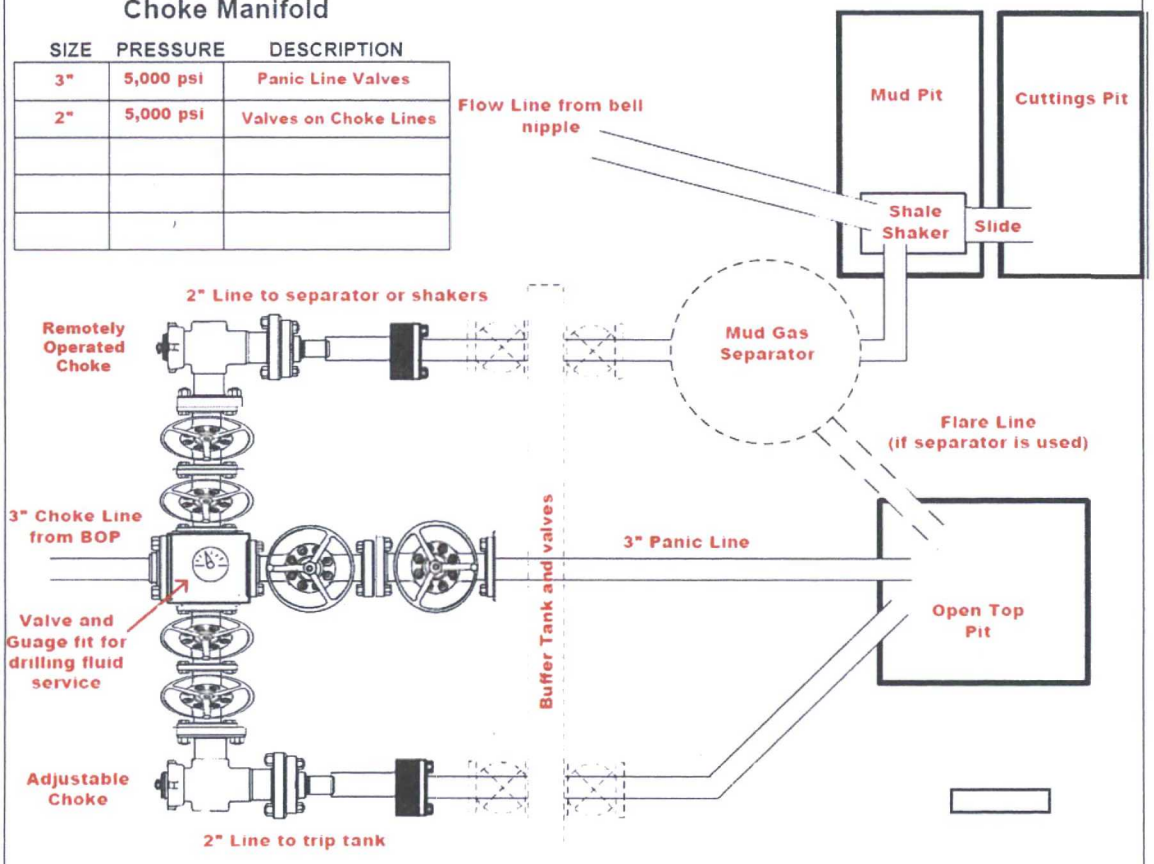
Minimum Requirements

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 along with any all BOP and accumulator test charts and reports from 3rd parties.

Wellname: _____

Representative: _____

Date: _____