1. GEOLOGICAL MARKERS & FORMATION TOP

The SMU 8-15-D will be a new drill from Pad Site #2 near Sheep Mountain in Huerfano County, CO. The objective of the 8-15-D is to target the Dakota and Entrada repeat sections of each block by drilling through faulted zones. A 13 3/8"surface casing string will be set in the top of the Pierre Shale at 1100 ft, with 9 5/8" intermediate casing above the 1st repeat section of the Dakota formation. Then an 8 ½" hole will be drilled to a TD point of 8900 ft MD (7784 ft TVD) with 7" casing run to bottom.

The names and depths of estimated formation tops are given below in the chart. The chart provides the formation tops for reservoir zones, including the repeat sections.

Formation Top	TVD
Pierre	1031
Greenhorn	2817
Dakota	3266
Entrada	3593
Fault 1	4519
Repeat Section 1 Dakota	4794
Repeat Section 1 Entrada	5413
Fault 2	5578
Repeat Section 2 Dakota	6339
Fault 3	6454
Repeat Section 3 Dakota	6643
Repeat Section 3 Entrada	6872
Fault 4	7299
TD	7784

Table 1: Formation Tops for SMU 8-15-D

2. ESTIMATED TOPS OF ANTICIPATED WATER, OIL, GAS, OR MINERALS

The cells highlighted in green in **Table 1** represent the formation tops of the zones containing CO_2. No other hydrocarbons or usable quality water zones are present in these formations. Casing and cementing will be designed to protect the CO_2 zones, lost circulation, and usable quality water zones.

3. THE OPERATORS MINIMUM SPECIFICATIONS FOR PRESSURE CONTROL

A schematic of the BOP is provided in Appendix A. The BOP setup complies with the regulations presented in the BLM Onshore Order #2 for a 10M system. The rated working pressure of the BOP stack is 10,000 psi. Rams are rated to 10,000 psi while the annular is rated to 5,000 psi. The BOP stack will be nippled up after surface casing has been cemented and the "A&B" sections of the wellhead installed. As indicated in Onshore Order #2, the ram type preventers will be tested to its

stack working pressure of 10,000 psi for 10 minutes along with its associated equipment. The annular preventer will be tested to 3400 psi, which meets the requirements of Onshore Order #2 as it exceeds the 50% rated working pressure for the annular. This test will also be conducted for 10 minutes. A low pressure test of 250 psi for 10 minutes will occur for all BOP equipment. All BOP tests are going to occur every 21 days as per Oxy's standard, and use clear water for the test.

A diagram of the choke manifold is presented in Appendix A.

4. PROPOSED CASING SETTING DEPTHS AND CEMENTING PROGRAM

The casing program for the SMU 8-15-D is outlined in the table below. The table contains specific details including weight, grades, and design ratings.

SMU 8-15-D Casing Program

String	Depth (ft) MD	OD (in)	ID (in)	Coupling OD (in)	Drift (in)	Weight (#/ft)	Grade	CXN	Burst (psi)	Collapse (psi)	Tension (k-lbs)
Surface	0 – 1100′	13.375	12.615	14.375	12.459	54.5	J-55	BTC	2,740	1,130	909
Intermediate	0 – 5321′	9.625	8.835	10.625	8.679	40	L-80	BTC	5,750	3,090	947
Production	0′– 8900′	7	6.276	7.656	6.151	26	L-80	BTC	7,250	5,410	641

Cement Program

Cement Design 13 3/8" Surface Casing								
Stage	Weight (ppg)	TOC (ft)	BOC (ft)	Hole Size (in)	% Open Hole Excess	Cement Volume (sacks)	Slurry Volume (bbls)	Remarks
Tail	13	Surface	1100	17.5	100%	780	279	Adjust if hole conditions change.

TAIL SLURRY	
Cement Type:	VARICEM
Additive:	0.125lb/sk Poly-E-Flake (Lost Circulation Additive)
Mix Water	10.80 Gal/sk
Slurry Density:	13 ppg
Yield:	2.011 ft^3/sack

Detailed Pumping Schedule – 13 3/8" Surface Casing				
Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Volume bbl
1	Spacer	Fresh Water	10.5	50
2	Cement	Tail Cement	13	279
DROP PLUG				
4	Spacer	Displacement Fluid	8.0	163.77

Cement Design 9 5/8" Intermediate Casing								
Stage	Weight (ppg)	TOC (ft)	BOC (ft)	Hole Size (in)	% Open Hole Excess	Cement Volume (sacks)	Slurry Volume (bbls)	Remarks
Lead	12.6	2400	3250	12.25	50%	210	71.12	Adjust if hole conditions change.
Tail	13.5	3250	5321	12.25	50%	560	179.65	Adjust if hole conditions change.

LEAD SLURRY	
Cement Type:	ECONOCEM
Mix Water	10.22 gal/sack
Slurry Density:	12.6 ppg
Yield:	1.944 ft^3/sack
TAIL SLURRY	
Cement Type:	FRACCEM SYSTEM
Mix Water	8.63 Gal/sk
Slurry Density:	13.5 ppg
Yield:	1.814 ft^3/sack

Detailed Pumping Schedule – 9 5/8" Intermediate Casing				
Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Volume bbl
1	Spacer	Tuned Spacer	9	50
2	Cement	Lead Cement	12.6	71.12

Detailed Pumping Schedule – 9 5/8" Intermediate Casing				
Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Volume bbl
3	Cement	Tail Cement	13.5	174.89
DROP PLUG				
4	Spacer	Displacement Fluid	8.0	397.11

Cement Design 7" Production Casing								
Stage	Weight (ppg)	TOC (ft)	BOC (ft)	Hole Size (in)	% Open Hole Excess	Cement Volume (sacks)	Slurry Volume (bbls)	Remarks
Tail	10	4900	8900	8.50	50%	340	137.50	Adjust if hole conditions change.

TAIL SLURRY	
Cement Type:	TUNED LIGHT SYSTEM
Mix Water	8.49 gal/sack
Slurry Density:	10 ppg
Yield:	2.28 ft^3/sack

Detailed Pumping Schedule – 7" Production Casing				
Fluid #	Fluid Type	Fluid Name	Surface Density lbm/gal	Volume bbl
1	Spacer	Tuned Spacer	9.0	30
2	Cement	Tuned Light Cement	10.0	140
DROP PLUG				
4	Spacer	Displacement Fluid	8.3	340

5. MUD PROGRAM

Mud specifications are provided in the table below. The properties will be followed, but may change depending on hole conditions. Materials to control a lost circulation event or well control will be on site, too. These products are contained in sacks and delivered to the rigs on a pallet wrapped in plastic. The drilling operation will have a closed looped system with all returns going through a shale shaker and back into the rig's mud pit system. All cuttings will be removed via the cuttings disposal procedure and hauled off to a designated disposal site.

Hole Size (in)	Depth Interval (ft)	Fluid Type	Mud Weight (ppg)	Funnel Visc (s/qt)	PV	YP	Drill Solids (%)
17 ½"	0 - 1100	FW spud mud	8.4 – 9.2	28-34	10-15	12-15	<8
12 ¼"	1100 – 5321	OBM*	7.9 – 8.5	35 – 40	8 – 12	6 – 10	< 5
8 ½"	5321 – 8900	OBM*	7.9 – 8.5	35 – 40	8 – 12	6 – 10	< 5

**The OBM will contain an oil/water ratio of 80/20 – to 85/15.*

6. LOGGING PROGRAM

When drilling the 12 ¼" intermediate hole section, a gamma tool will be run in conjunction with the drilling assembly. Once the 9 5/8" casing is set and cemented, a CBL will be run to identify the top of cement. The current cement design plans for the top of cement to be 1,400 ft above the Dakota, which is the topmost zone containing potential hydrocarbons, or in this case, CO_2.

For the 8 ½" interval, the logging program will consist of a quad combo log, which includes Gamma Ray, Formation Density, Neutron, and Sonic. A CBL is planned to be run in the 7" casing once the drilling rig has moved off the site.

A mud logger will be onsite through the duration of the well collecting mud samples and keeping track of all formation intervals.

7. ANTICIPATED PRESSURES AND TEMPERATURES

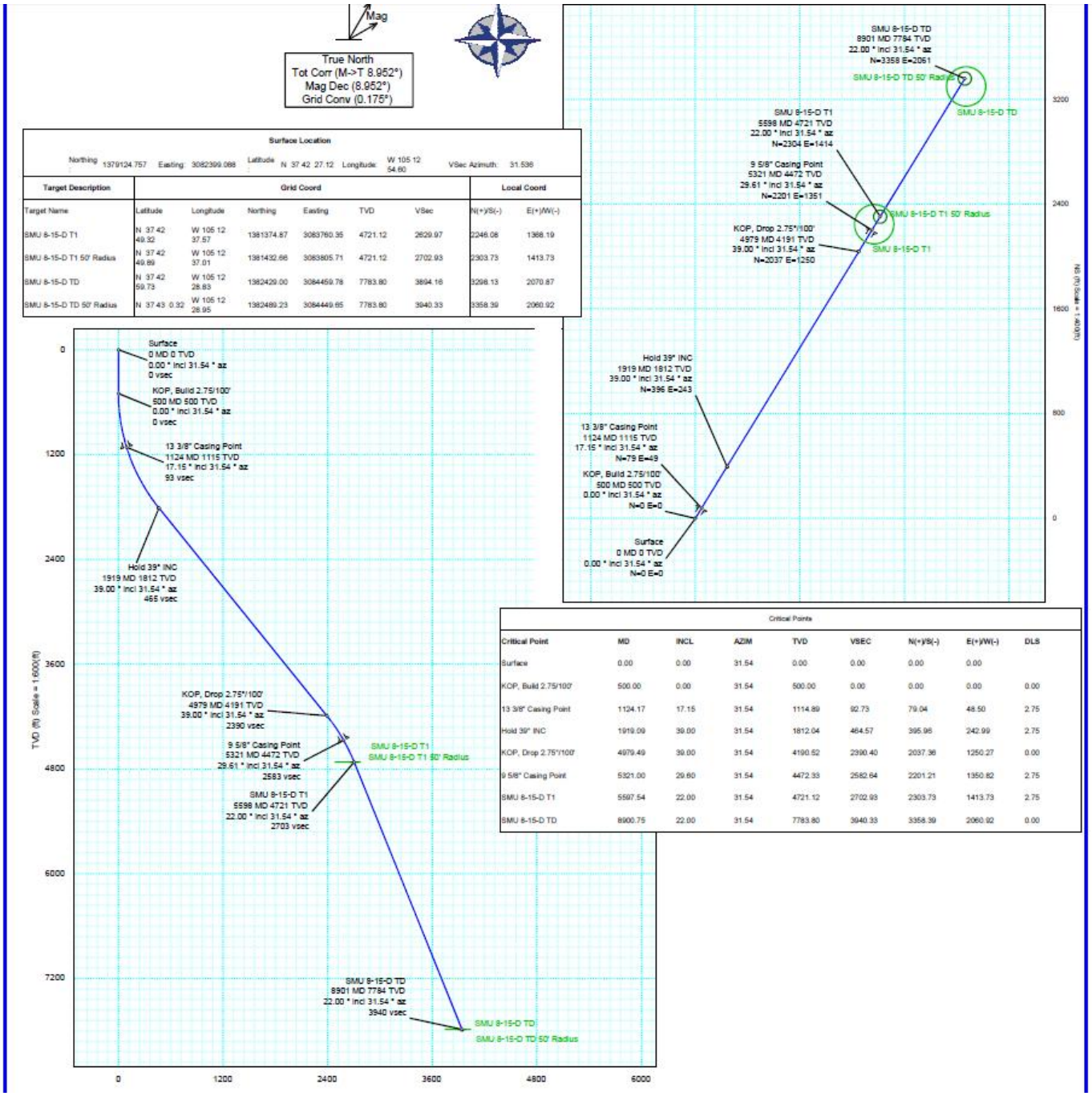
The Dakota and Entrada formations are prone to lost circulation. The repeat sections of both the Dakota and Entrada are predicted to have higher reservoir pressures than the first Dakota/Entrada zones, but still may be prone to lost circulation. The Dakota pressure gradient has been estimated at 0.38 psi/ft and the Entrada at 0.35 psi/ft.

The Morrison shale can lead to wellbore instability and may be seen while drilling through the faulted zones.

Maximum bottom hole temperature will be less than 150°F. The maximum bottom hole pressure is anticipated to be 3,000 psi.

8. DIRECTIONAL PROGRAM

The directional plan consists of an S-shaped 2D well trajectory with a maximum inclination planned for 40° in the tangent section, which is shown below in the drawing.



Surface Location

Northing	Easting	Latitude	Longitude	VSec Azimuth
1379124.757	3082399.088	N 37 42 27.12	W 105 12 54.60	31.536

Target Description	Grid Coord						Local Coord	
Target Name	Latitude	Longitude	Northing	Easting	TVD	VSec	N(+)/S(-)	E(+)/W(-)
SMU 8-15-D T1	N 37 42 49.32	W 105 12 37.57	1381374.87	3083760.35	4721.12	2629.97	2246.08	1368.19
SMU 8-15-D T1 50' Radius	N 37 42 49.89	W 105 12 37.01	1381432.66	3083805.71	4721.12	2702.93	2303.73	1413.73
SMU 8-15-D TD	N 37 42 59.73	W 105 12 28.83	1382429.00	3084459.78	7783.80	3894.16	3298.13	2070.87
SMU 8-15-D TD 50' Radius	N 37 43 0.32	W 105 12 28.95	1382489.23	3084449.65	7783.80	3940.33	3358.39	2060.92

Critical Points

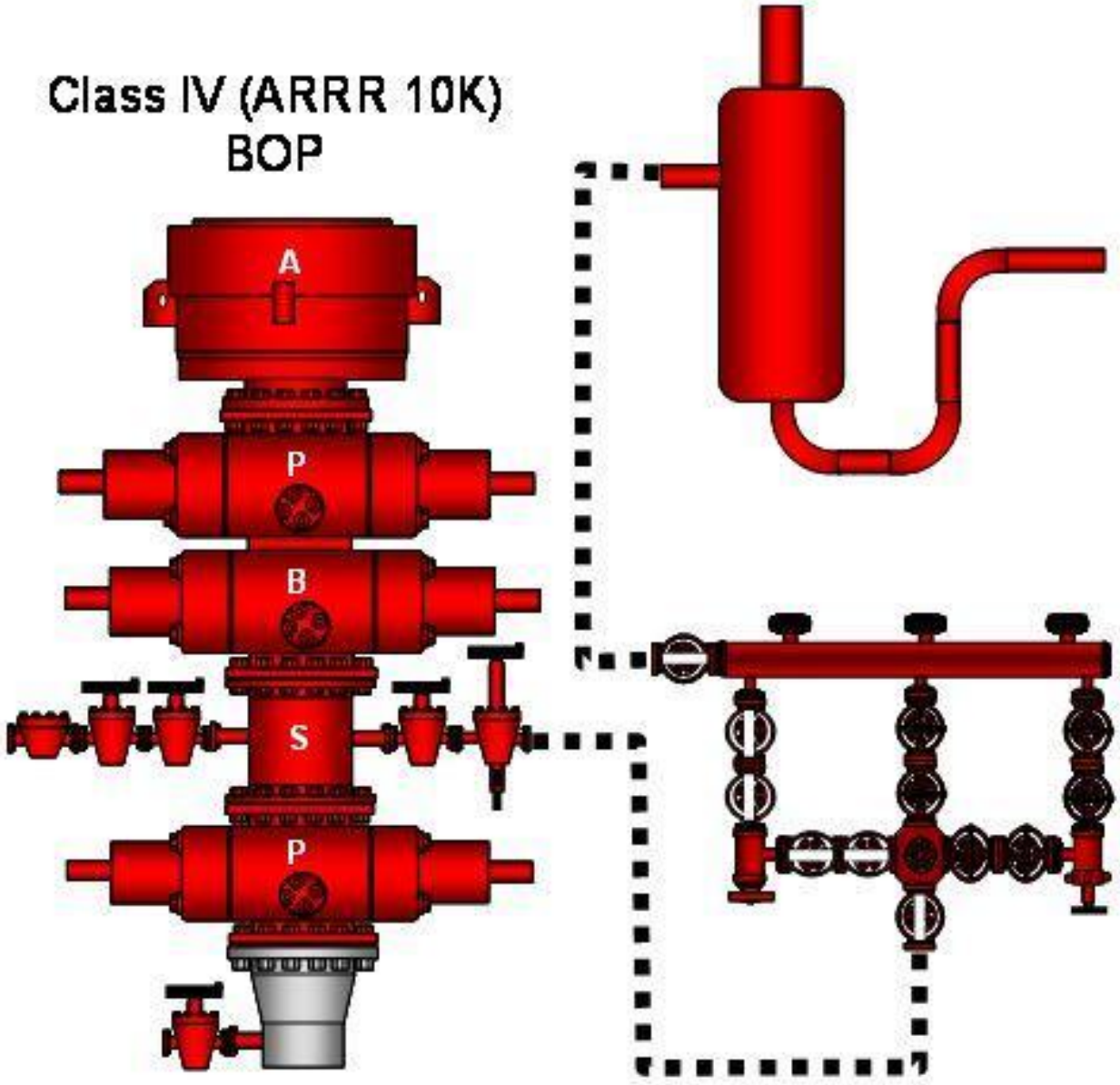
Critical Point	MD	INCL	AZIM	TVD	VSEC	N(+)/S(-)	E(+)/W(-)	DLS
Surface	0.00	0.00	31.54	0.00	0.00	0.00	0.00	
KOP, Build 2.75/100'	500.00	0.00	31.54	500.00	0.00	0.00	0.00	0.00
13 3/8" Casing Point	1124.17	17.15	31.54	1114.89	92.73	79.04	48.50	2.75
Hold 39° INC	1919.09	39.00	31.54	1812.04	464.57	395.96	242.99	2.75
KOP, Drop 2.75*/100'	4979.49	39.00	31.54	4190.52	2390.40	2037.36	1250.27	0.00
9 5/8" Casing Point	5321.00	29.60	31.54	4472.33	2582.64	2201.21	1350.82	2.75
SMU 8-15-D T1	5597.54	22.00	31.54	4721.12	2702.93	2303.73	1413.73	2.75
SMU 8-15-D TD	8900.75	22.00	31.54	7783.80	3940.33	3358.39	2060.92	0.00

9. WELLHEAD SCHEMATIC

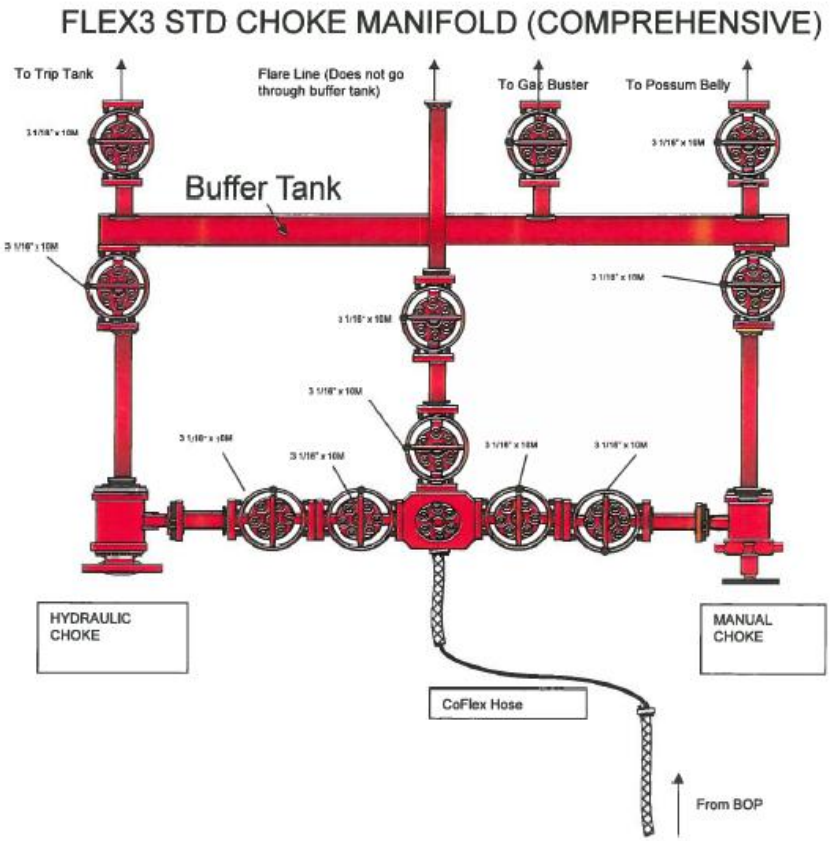
The wellhead will be a multi-bowl system consisting of a 13-3/8" x 9-5/8" x 7" 5M design. A drawing of the wellhead can be found in Appendix A.

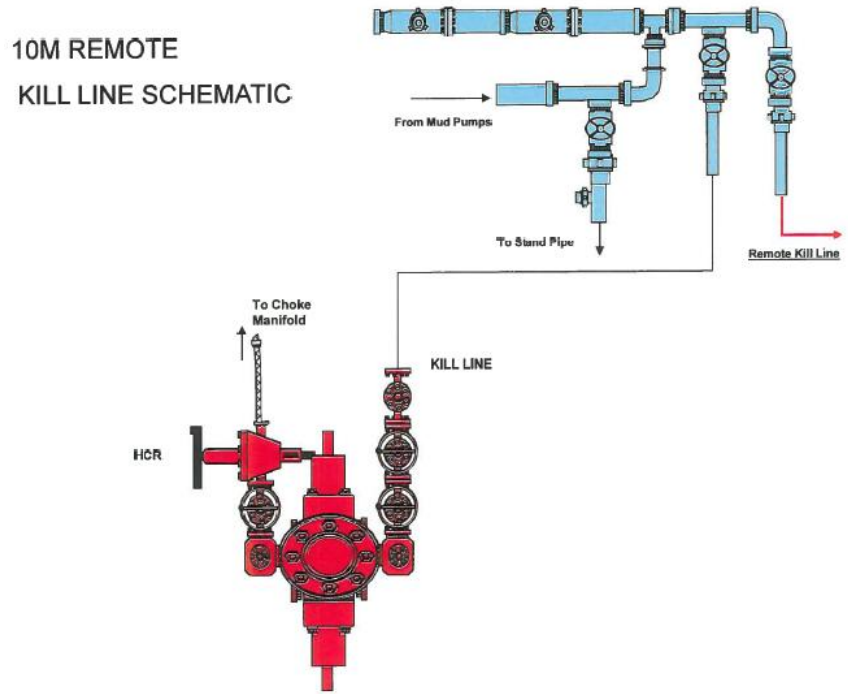
10. APPENDIX A

a) BOP Diagram

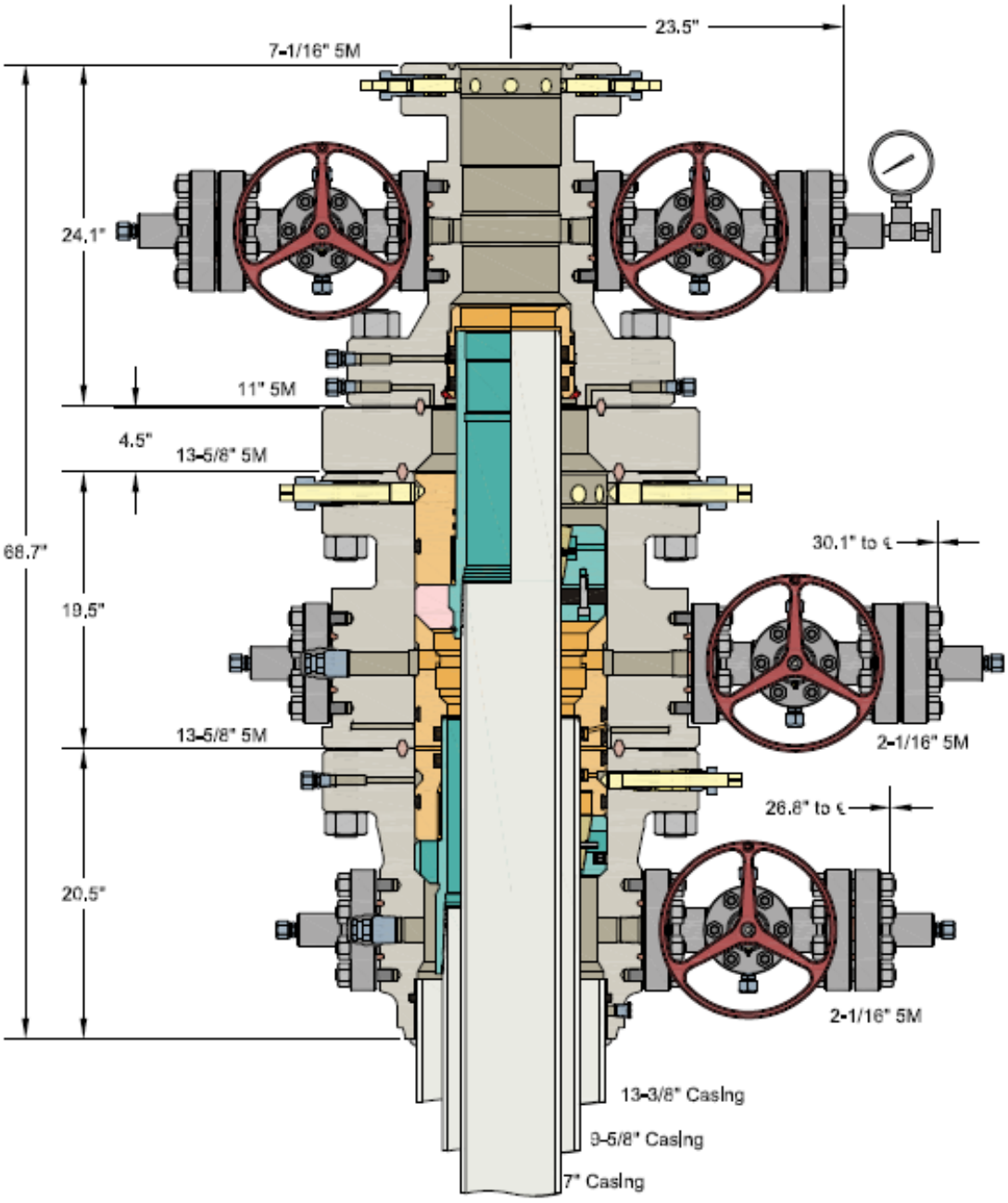


b) Choke Manifold





c) Wellhead


23.5"
7-1/16" 5M
24.1"
11" 5M
4.5"
13-5/8" 5M
68.7"
19.5"
30.1" to ℄
2-1/16" 5M
13-5/8" 5M
26.8" to ℄
20.5"
2-1/16" 5M
13-3/8" Casing
9-5/8" Casing
7" Casing