OXY USA Inc. - Mesa Verde 17-8 Federal Com 14H – Amended Drilling Plan

1. Geologic Formations

TVD of target	12000'	Pilot Hole Depth	14127'
MD at TD:	21929'	Deepest Expected fresh water:	875'

Delaware Basin

Formation	TVD - RKB	Expected Fluids
Rustler	875	
Salado	1200	
Lamar/Delaware	4713	Oil/Gas
Bell Canyon	4757	Water/Oil/Gas
Cherry Canyon	5508	Oil/Gas
Brushy Canyon	6898	Oil/Gas
Bone Spring	8593	Oil/Gas
1st Bone Spring	9672	Oil/Gas
2nd Bone Spring	9839	Oil/Gas
3rd Bone Spring	10692	Oil/Gas
Wolfcamp (Lateral)	**11905**	**Oil/Gas**
Penn	12297	Oil/Gas
Strawn (Pilot)	**13976**	**Oil/Gas**

*H2S, water flows, loss of circulation, abnormal pressures, etc.

2. Casing Program

Hole Size (in)	Casing Interval		Csg. Size (in)	Weight (lbs)	Grade	Conn.	SF Collapse	SF Burst	Buoyant Body SF Tension	Buoyant Joint SF Tension
	From (ft)	To (ft)								
17.5	0	926	13.375	54.5	J55	BTC	4.83	1.34	2.46	2.63
12.25	0	7500	9.625	43.5	HCL-80	BTC	1.22	1.58	2.05	2.15
12.25	7500	11305	9.625	47	HCL-80	BTC	1.29	1.85	3.83	4.16
8.5	11205	21926	5.5	20	P-110	DQX	2.10	1.20	2.26	2.48

All casing strings will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.h
*OXY requests the option to set casing shallower yet still below the salts if losses or hole conditions require this. Cement volumes may be adjusted if casing is set shallower and a DV tool will be run in case a contingency second stage is required for cement to reach surface. If cement circulated to surface during first stage we will drop a cancelation cone and not pump the second stage.

	Y or N
Is casing new? If used, attach certification as required in Onshore Order #1	Y
Does casing meet API specifications? If no, attach casing specification sheet.	Y
Is premium or uncommon casing planned? If yes attach casing specification sheet.	Y
Does the above casing design meet or exceed BLM's minimum standards? If not provide justification (loading assumptions, casing design criteria).	Y
Will the intermediate pipe be kept at a minimum 1/3 fluid filled to avoid approaching the collapse pressure rating of the casing?	Y

Is well located within Capitan Reef?	N
If yes, does production casing cement tie back a minimum of 50' above the Reef?	
Is well within the designated 4 string boundary.	
Is well located in SOPA but not in R-111-P?	N
If yes, are the first 2 strings cemented to surface and 3rd string cement tied back 500' into previous casing?	
Is well located in R-111-P and SOPA?	N
If yes, are the first three strings cemented to surface?	
Is 2nd string set 100' to 600' below the base of salt?	
Is well located in high Cave/Karst?	N
If yes, are there two strings cemented to surface?	
(For 2 string wells) If yes, is there a contingency casing if lost circulation occurs?	
Is well located in critical Cave/Karst?	N
If yes, are there three strings cemented to surface?	

3. Cementing Program

Casing	# Sks	Wt. lb/ gal	Yld ft3/ sack	H20 gal/sk	500# Comp. Strength (hours)	Slurry Description
Surface	597	14.2	1.68	6.53	6:50	Class C Cement, Accelerator
Production Casing	696	10.2	3.05	15.63	15:07	Pozzolan Cement, Retarder
	239	13.2	1.65	8.45	12:57	Class H Cement, Retarder, Dispersant, Salt
DV/ECP Tool @ 4764' (We request the option to cancel the second stage if cement is circulated to surface during the first stage of cement operations)						
2nd Stage	1171	12.9	1.85	9.86	12:44	Class C Cement, Accelerator, Retarder
	207	14.8	1.33	6.34	6:31	Class C Cement
Production Liner	1734	13.2	1.631	8.37	15:15	Class H Cement, Retarder, Dispersant, Salt

Casing String	Top of Lead (ft)	Bottom of Lead (ft)	Top of Tail (ft)	Bottom of Tail (ft)	% Excess Lead	% Excess Tail
Surface	N/A	N/A	0	926	N/A	50%
Production Casing	4664	10305	10305	11305	20%	20%
2nd Stage Prodution Casing	0	4264	4264	4764	75%	75%
Production Liner	N/A	N/A	11205	21926	N/A	15%

Cement Top and Liner Overlap

a. Oxy is requesting permission to have minimum fill of cement behind the 5-1/2" production liner to be 100 ft into previous casing string.The reason for this is so that we can come back and develop shallower benches from the same 9.625" mainbore in the future
b. Our plan is to use a whipstock for our exit through the mainbore. Based on our future lateral target, we are planning a whipstock cased/hole exit so that kick-off point will allow for roughly 10deg/100' doglegs needed for the curve.
c. Cement will be brought to the top of this liner hanger.

Pilot hole depth: 14127'
KOP: 11405'

Plug top	Plug Bottom	% Excess	No. Sacks	Wt. lb/gal	Yld ft3/sack	Water gal/sk	Slurry Description and Cement Type
13,527' MD	14,127' MD	10	252	15	1.032	4.13	NeoCem TM
12,957' MD	13,527' MD	10	252	15	1.032	4.13	NeoCem TM
12,357' MD	12,957' MD	10	252	15	1.032	4.13	NeoCem TM
11,757' MD	12,357' MD	10	252	15	1.032	4.13	NeoCem TM
11,157' MD	11,757' MD	10	270	17.5	0.952	3.51	Class H Cement, Retarder

Note: The first through fifth plugs are designed to be 600' in length to isolate the high pressure zones in the Pilot Hole from the KOP. The sixth plug is designed to be 600' in length and 248' above KOP to provide a strong foundation to sidetrack at the KOP.

4. Pressure Control Equipment

BOP installed and tested before drilling which	Size?	Min. Required WP	Type	✓	Tested to:
13.5" 1st Intermediate	13-5/8"	2M	Annular	✓	70% of working pressure
			Blind Ram	✓	250/2,000 psi
		2M	Upper Pipe Ram		
			Double Ram	✓	
			Lower Pipe Ram		
9.875" 2nd Intermediate Hole	13-5/8"	5M	Annular	✓	70% of working pressure
		5M	Blind Ram	✓	250/5,000 psi
			Upper Pipe Ram Double Ram	✓	
			Lower Pipe Ram	✓	
6.75" Pilot Hole	13-5/8"	10M	Annular	✓	70% of working pressure
		10M	Blind Ram	✓	250/10,000 psi
			Upper Pipe Ram	✓	
			Double Ram		
			Lower Pipe Ram	✓	

*Specify if additional ram is utilized.

BOP/BOPE will be tested by an independent service company to 250 psi low and the high pressure indicated above per Onshore Order 2 requirements. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested.

Pipe rams will be operationally checked each 24 hour period. Blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets. Other accessories to the BOP equipment will include a Kelly cock and floor safety valve (inside BOP) and choke lines and choke manifold. See attached schematics.

	Formation integrity test will be performed per Onshore Order #2. On Exploratory wells or on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.i.
	A variance is requested for the use of a flexible choke line from the BOP to Choke Manifold. See attached for specs and hydrostatic test chart.
	Y Are anchors required by manufacturer?
	A multibowl or a unionized multibowl wellhead system will be employed. The wellhead and connection to the BOPE will meet all API 6A requirements. The BOP will be tested per Onshore Order #2 after installation on the surface casing which will cover testing requirements for a maximum of 30 days. If any seal subject to test pressure is broken the system must be tested. We will test the flange connection of the wellhead with a test port that is directly in the flange. We are proposing that we will run the wellhead through the rotary prior to cementing surface casing as discussed with the BLM on October 8, 2015. See attached schematics.

5. Mud Program

Pilot

Depth		Type	Weight (ppg)	Viscosity	Water Loss
From (ft)	To (ft)				
0	926	Water-Based Mud	8.4-8.6	40-60	N/C
926	4764	Brine	9.8-10.0	35-45	N/C
4764	11305	Water-Based Mud	8.8-9.6	38-50	N/C
11305	14127	Water-Based Mud	10.0-13.0	38-50	N/C

Lateral

Depth		Type	Weight (ppg)	Viscosity	Water Loss
From (ft)	To (ft)				
11305	21926	Oil-Based Mud	8.8-9.6	35-50	N/C

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept on location at all times. The following is a general list of products: Barite, Bentonite, Gypsum, Lime, Soda Ash, Caustic Soda, Nut Plug, Cedar Fiber, Cotton Seed Hulls, Drilling Paper, Salt Water Clay, CACL2. Oxy will use a closed mud system.

OXY proposes to drill out the 13-3/8" surface casing shoe with a saturated brine system from 926-4764', which is the base of the salt system. At this point we will swap fluid systems to a fully saturated brine direct emulsion system. We will drill with this system to the production casing TD @ 11305'.

What will be used to monitor the loss or gain of fluid?	PVT/MD Totco/Visual Monitoring

6. Logging and Testing Procedures

Logs Planned		Interval
Yes	Triple Combo	Triple Combo with Spectral Gamma, Dipole Sonic, CMR Int CSG – TD
Yes	Mud Log	Surface Casing Shoe - TD

7. Drilling Conditions

Condition	Specify what type and where?
BH Pressure at deepest TVD	9550 psi (Pilot) 3350 psi (Lateral)
Abnormal Temperature	No
BH Temperature at deepest TVD	176°F

Pump high viscosity sweeps as needed for hole cleaning. The mud system will be monitored visually/manually as well as with an electronic PVT. The necessary mud products for additional weight and fluid loss control will be on location at all times. Appropriately weighted mud will be used to isolate potential gas, oil, and water zones until such time as casing can be cemented into place for zonal isolation.

Hydrogen Sulfide (H2S) monitors will be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the operator will comply with the provisions of Onshore Oil and Gas Order #6. If Hydrogen Sulfide is encountered, measured values and formations will be provided to the BLM.	
N	H2S is present
Y	H2S Plan attached

8. Other facets of operation

	Yes/No
Will the well be drilled with a walking/skidding operation? If yes, describe. • We plan to drill the two well pad in batch by section: all surface sections, intermediate sections and production sections. The wellhead will be secured with a night cap whenever the rig is not over the well.	Yes
Will more than one drilling rig be used for drilling operations? If yes, describe.	No

Total estimated cuttings volume: 2943.3 bbls.

9. Company Personnel

Name	Title	Office Phone	Mobile Phone
Philippe Haffner	Drilling Engineer	713-985-6379	832-767-9047
Diego Tellez	Drilling Engineer Supervisor	713-350-4602	713-303-4932
Simon Benavides	Drilling Superintendent	713-522-8652	281-684-6897
John Willis	Drilling Manager	713-366-5556	713-259-1417

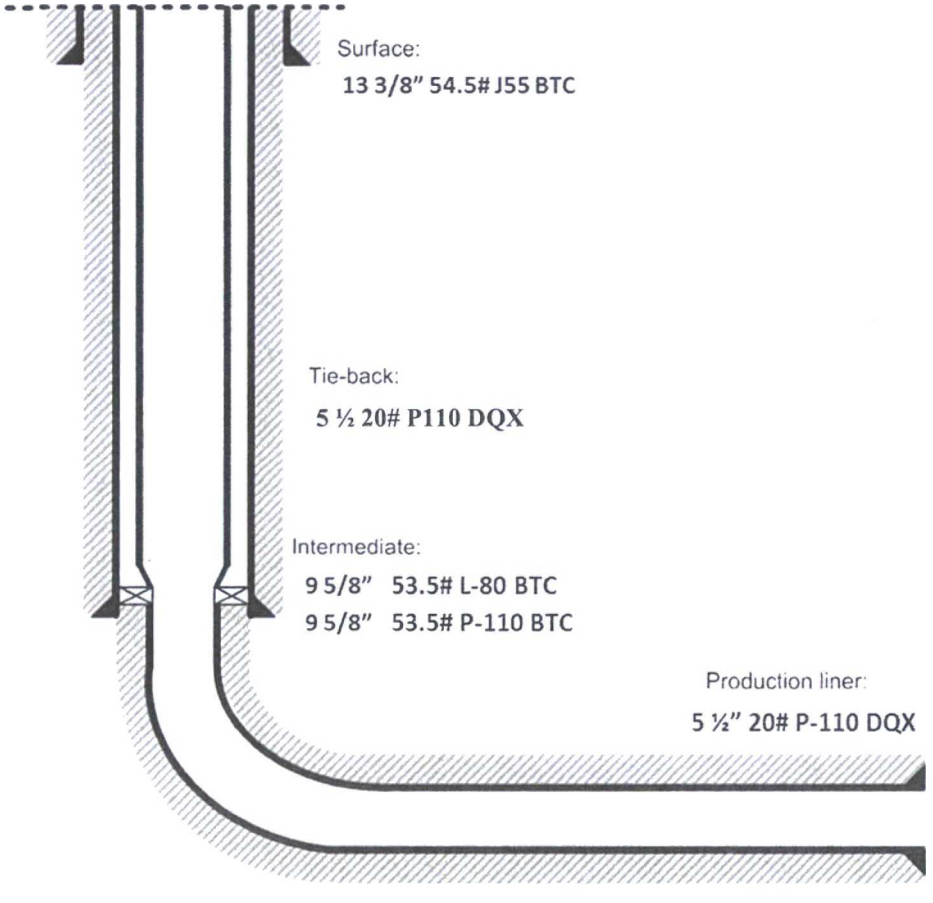
OXY USA WTP LP
Mesa Verde 17-8 Federal Com 14H

Below is a summary that describes the general operational steps to drill and complete the well.

- Drill 17-1/2" hole x 13-3/8" casing for surface section. Cement to surface.
- Drill 12-1/4" hole x 9-5/8" casing for intermediate section. Cement to surface.
- Drill 8-1/2" hole x 5-1/2" liner for production section. Cement to top of liner, 100' inside 9-5/8" shoe.
- Release drilling rig from location.
- Move in workover rig and run a 5-1/2" 20# P110 DQX tie-back frack string and seal assembly (see connection specs below). Tie into liner hanger Polished Bore Receptacle (PBR) with seal assembly.
- Pump hydraulic fracture job.
- Flowback and produce well.

When a decision is made to develop a secondary bench from this wellbore, a workover rig will be moved to location. The workover rig will then retrieve the tie-back frack string and seal assembly before temporarily abandoning the initial lateral.

General well schematic:



5 ½" 20# P110 DQX Tie-back string specifications:

PERFORMANCE DATA

TMK UP DQX
Technical Data Sheet

5.500 in | 20.00 lbs/ft | P-110

Tubular Parameters

Size	5.500	in	Minimum Yield	110,000	psi
Nominal Weight	20.00	lbs/ft	Minimum Tensile	125,000	psi
Grade	P-110		Yield Load	641,000	lbs
PE Weight	19.41	lbs/ft	Tensile Load	729,000	lbs
Wall Thickness	0.361	in	Min Internal Yield Pressure	12,640	psi
Nominal ID	4.778	in	Collapse Pressure	11,100	psi
Drift Diameter	4.653	in			
Nom. Pipe Body Area	5.708	in²			

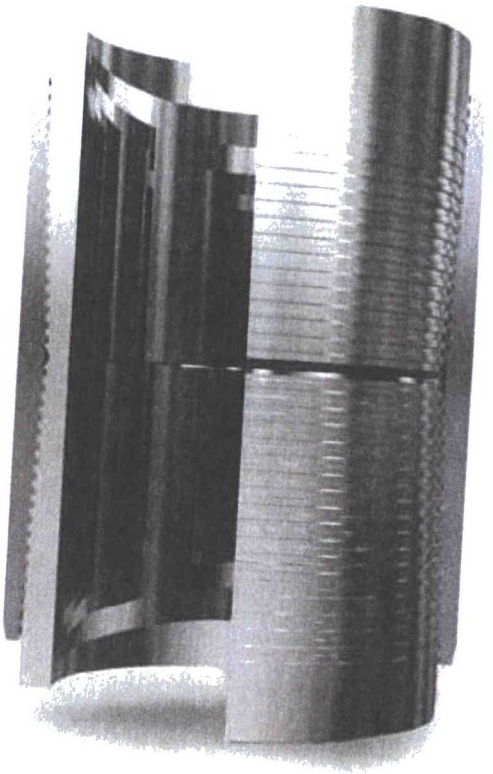
Connection Parameters

Connection OD	6.000	in
Connection ID	4.778	in
Make-Up Loss	4.122	in
Critical Section Area	5.333	in²
Tension Efficiency	100.0	%
Compression Efficiency	100.0	%
Yield Load In Tension	641,000	lbs
Min Internal Yield Pressure	12,640	psi
Collapse Pressure	11,100	psi

Make-Up Torques

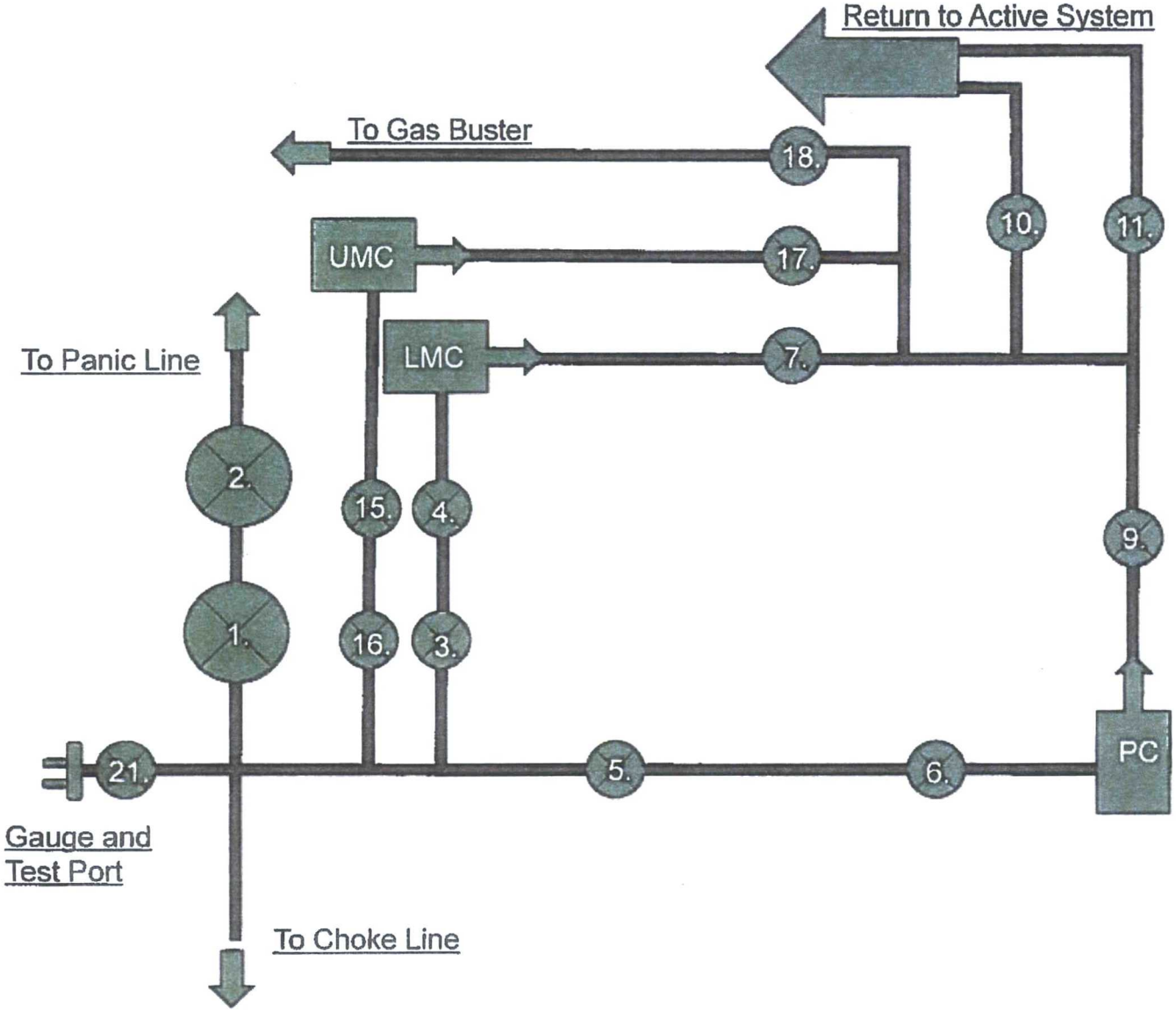
Min. Make-Up Torque	11,600	ft-lbs
Opt. Make-up Torque	12,900	ft-lbs
Max. Make-up Torque	14,200	ft-lbs
Yield Torque	23,600	ft-lbs

Printed on: July-29-2014



TMK IPSCO

10M Choke Panel



1. Choke Manifold Valve
2. Choke Manifold Valve
3. Choke Manifold Valve
4. Choke Manifold Valve
5. Choke Manifold Valve
6. Choke Manifold Valve
7. Choke Manifold Valve
8. PC – Power Choke
9. Choke Manifold Valve
10. Choke Manifold Valve
11. Choke Manifold Valve
12. LMC – Lower Manual Choke
13. UMC – Upper manual choke

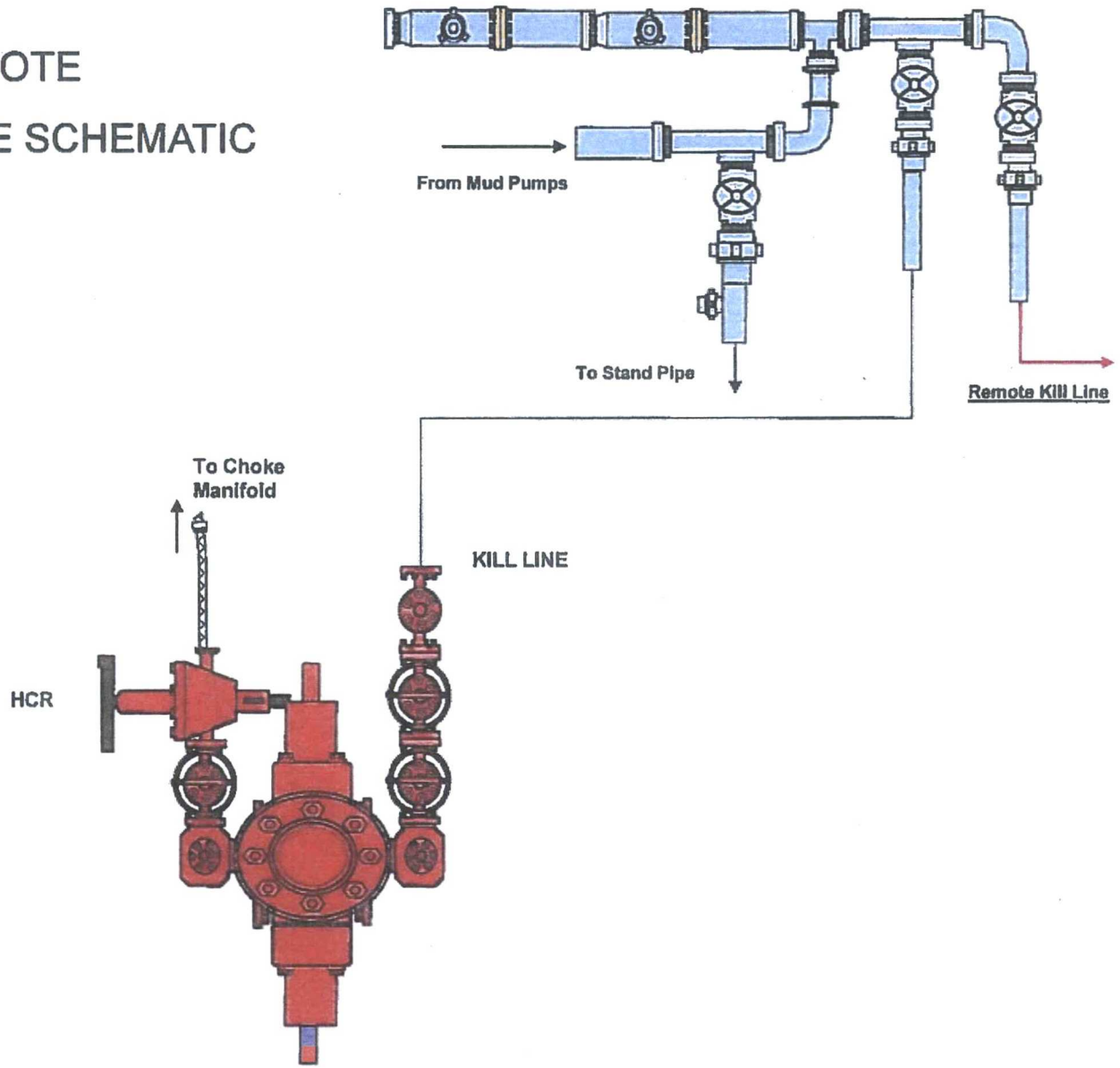
15. Choke Manifold Valve
16. Choke Manifold Valve
17. Choke Manifold Valve
18. Choke Manifold Valve

21. Vertical Choke Manifold Valve

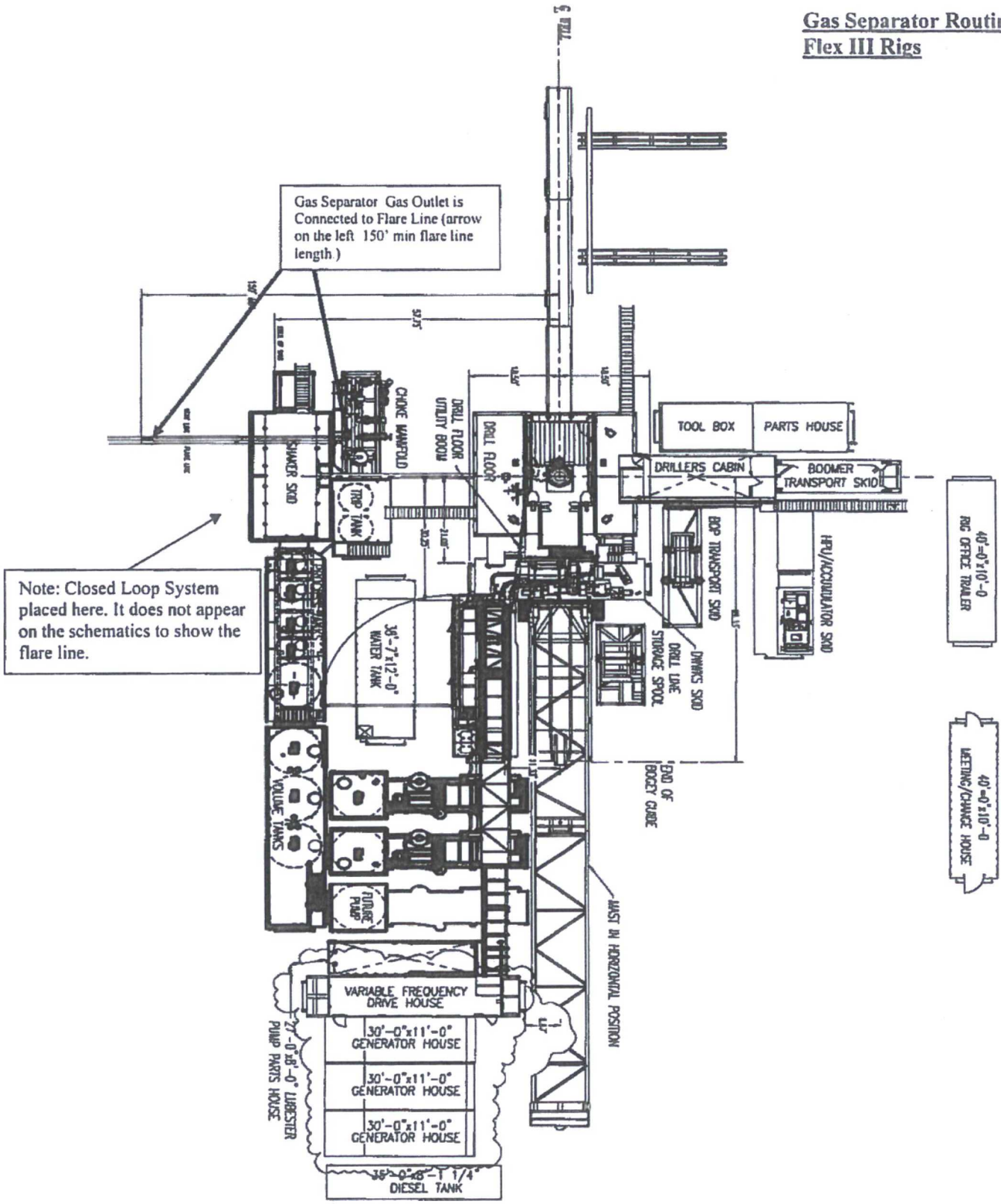
***All Valves 3" minimum**

10M REMOTE

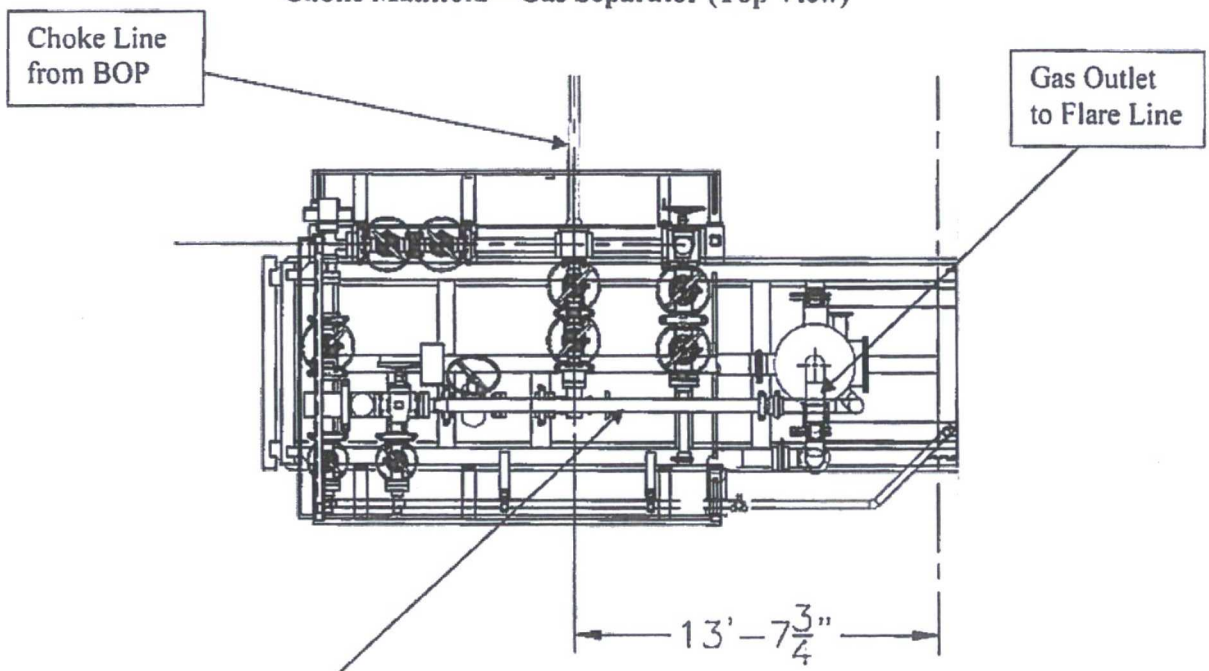
KILL LINE SCHEMATIC



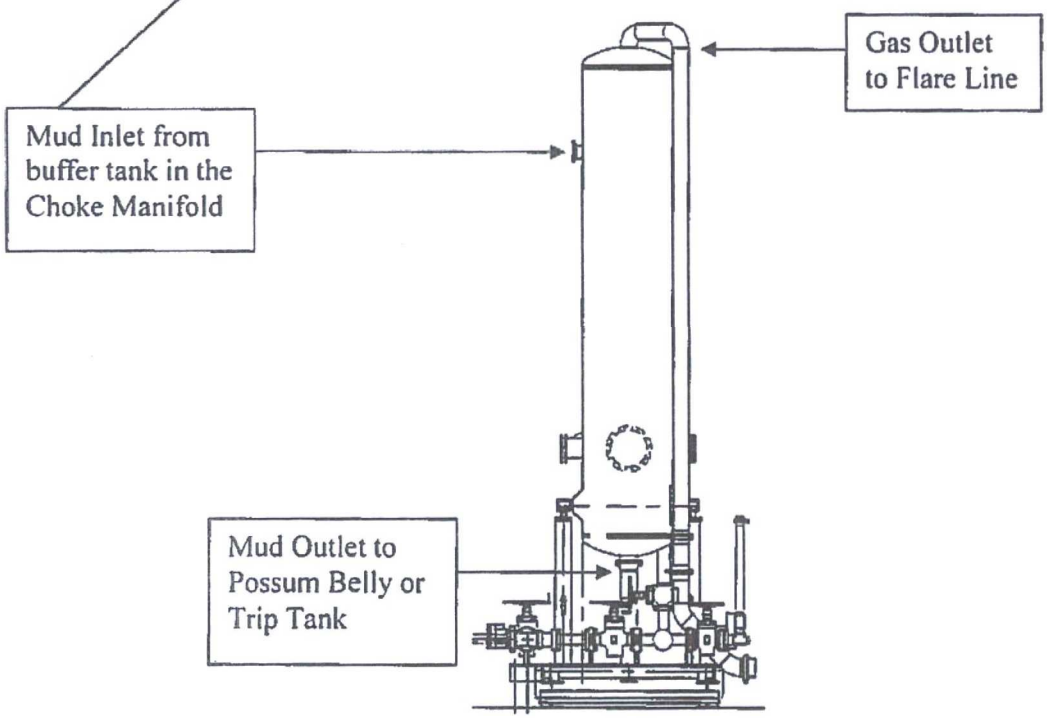
Gas Separator Routing
Flex III Rigs



Choke Manifold – Gas Separator (Top View)



Choke Manifold – Gas Separator (Side View)

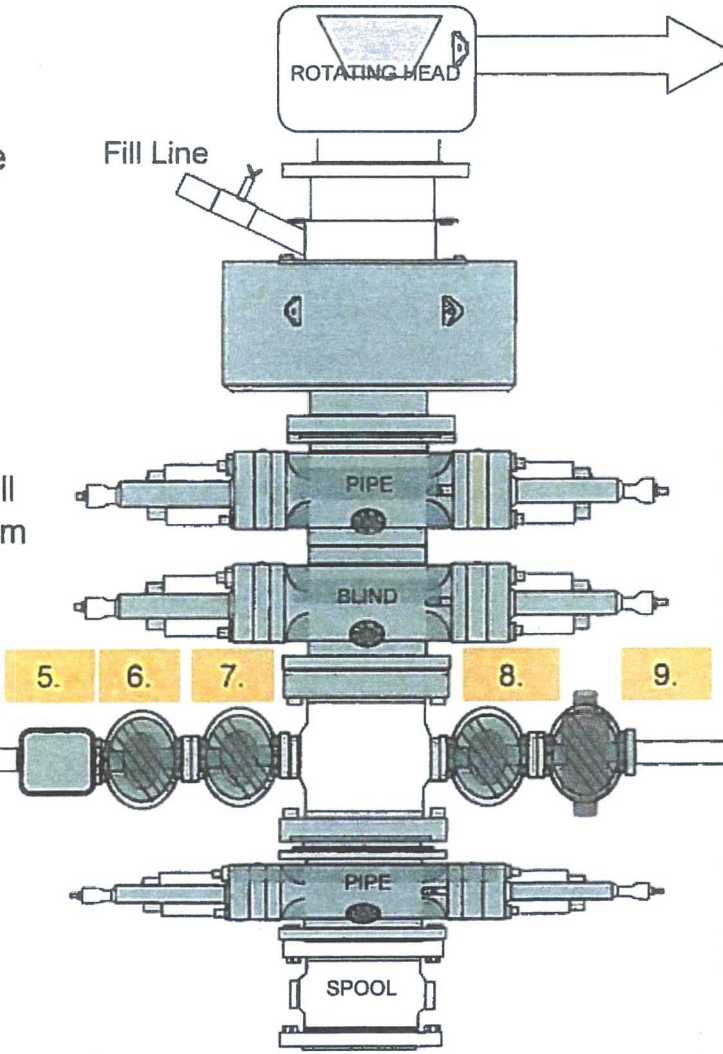


10M BOP Stack

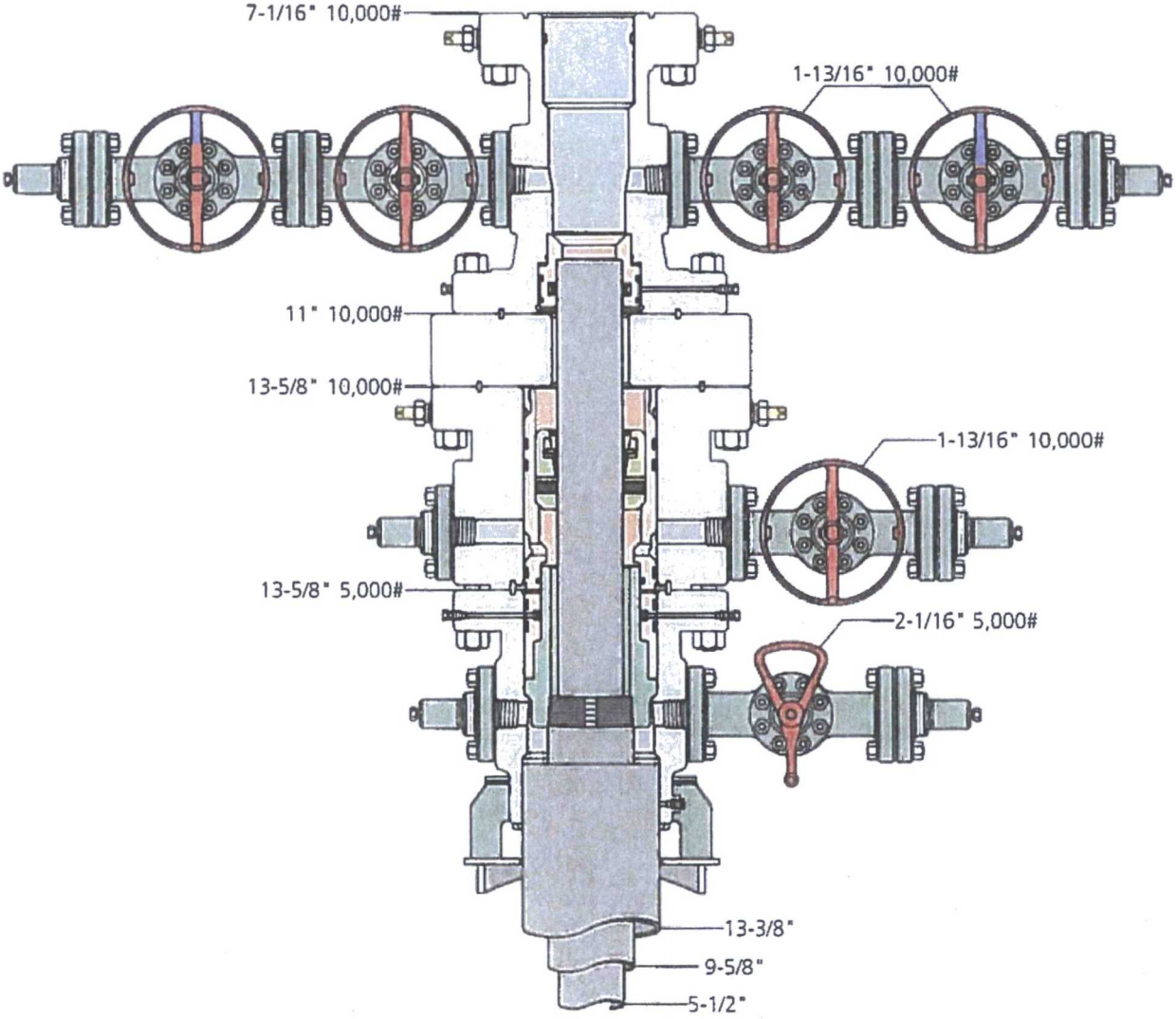
Mud Cross Valves:

5. 10M Check Valve
6. Outside 10M Kill Line Valve
7. Inside 10M Kill Line
8. Outside10M Kill Line Valve
9. 10M HCR Valve

*Minimum ID = 2-1/16" on Kill Line side and 3" minimum ID on choke line side



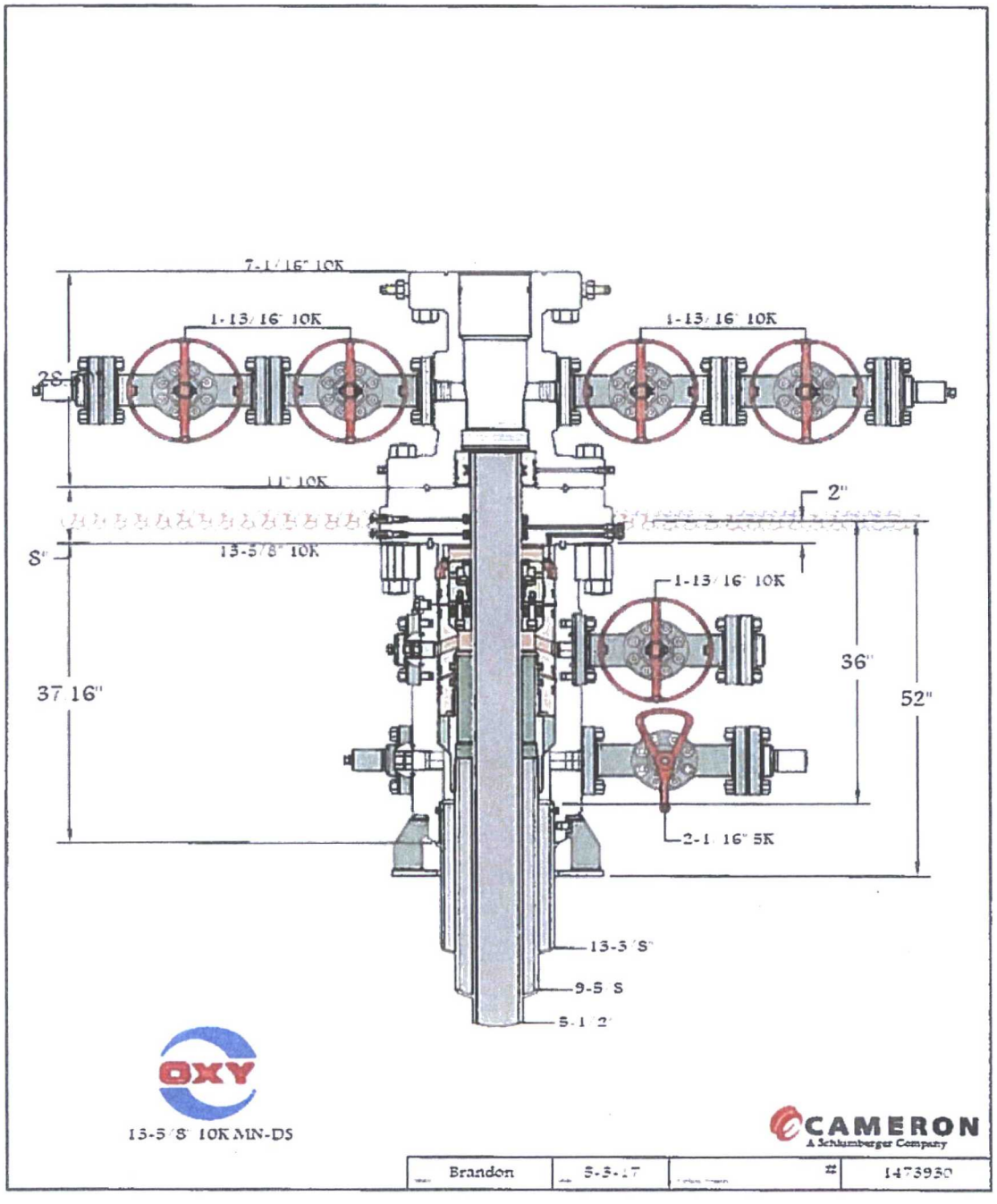
1. 10,000 psi Annular (13-5/8" ID)
2. 10,000 psi Upper Pipe Ram (13-5/8" ID)
3. 10,000 psi Blind Ram (13-5/8" ID)
4. 10,000 psi Lower Pipe Ram (13-5/8" ID)



13" 10K MBS SL2 Wellhead

CAMERON
A Schlumberger Company

Jeanette	7-5-16	#	J-9786-2


7-1/16" 10K
1-13/16" 10K
1-13/16" 10K
28"
11" 10K
2"
8"
13-5/8" 10K
1-13/16" 10K
36"
37 16"
52"
2-1 16" 5K
13-3 S"
9-5 S
5-1 2"
OXY
13-5 S" 10K MN-DS
CAMERON
A Schlumberger Company
Brandon
5-3-17
#
1473930

OXY USA Inc
APD ATTACHMENT: SPUDDER RIG DATA

OPERATOR NAME / NUMBER: OXY USA Inc

1. SUMMARY OF REQUEST:

Oxy USA respectfully requests approval for the following operations for the surface hole in the drill plan:

1. Utilize a spudder rig to pre-set surface casing for time and cost savings.

2. Description of Operations

1. Spudder rig will move in to drill the surface hole and pre-set surface casing on the well.
    a. After drilling the surface hole section, the spudder rig will run casing and cement following all of the applicable rules and regulations (OnShore Order 2, all COAs and NMOCD regulations).
    b. The spudder rig will utilize fresh water-based mud to drill the surface hole to TD. Solids control will be handled entirely on a closed loop basis. No earth pits will be used.
2. The wellhead will be installed and tested as soon as the surface casing is cut off and the WOC time has been reached.
3. A blind flange at the same pressure rating as the wellhead will be installed to seal the wellbore. Pressure will be monitored with needle valves installed on two wingvalves.
    a. A means for intervention will be maintained while the drilling rig is not over the well.
4. Spudder rig operations are expected to take 2-3 days per well on the pad.
5. The BLM will be contacted and notified 24 hours prior to commencing spudder rig operations.
6. Drilling operations will begin with a larger rig and a BOP stack equal to or greater than the pressure rating that was permitted will be nippled up and tested on the wellhead before drilling operations resume on each well.
    a. The larger rig will move back onto the location within 90 days from the point at which the wells are secured and the spudder rig is moved off location.
    b. The BLM will be contacted / notified 24 hours before the larger rig moves back on the pre-set locations.
7. Oxy will have supervision on the rig to ensure compliance with all BLM and NMOCD regulations and to oversee operations.
8. Once the rig is removed, Oxy will secure the wellhead area by placing a guard rail around the cellar area.

Spudder Rig Layout