ATS-14-704

Form 3160-3
(August 2007)

OCD Hobbs OCD

OCT 27 2014

FORM APPROVED
OMB No. 1004-0137
Expires July 31, 2010

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER RECEIVED

1a. Type of work: ☑ DRILL ☐ REENTER Acid Gas Injection Well	5. Lease Serial No. ~~NMNM 77995 6~~ ~~NMLC0149956~~ NMLC 065863
1b. Type of Well: ☐ Oil Well ☐ Gas Well ☑ Other ☐ Single Zone ☑ Multiple Zone	6. If Indian, Allotee or Tribe Name N/A
2. Name of Operator DCP Midstream LP (36785)	7. If Unit or CA Agreement, Name and No. N/A
3a. Address 370 17th St, Suite 2500, Denver CO 80208-5406	8. Lease Name and Well No. Zia AGI #1 (313824)
3b. Phone No. *(include area code)* (303) 595-3331	9. API Well No. 30-025-42208
4. Location of Well *(Report location clearly and in accordance with any State requirements.*)* At surface 2100' FSL, 950' FWL Section 19, T19S, R32 E (32.64459881, -103.8111449) (L) At proposed prod. zone 2305' N ~~2,650~~' ~~FSL~~, 750' FWL Section 19, T19S, R32 E (~~32.645751~~, ~~-103.881764~~ (E)	10. Field and Pool, or Exploratory (98096) AGI; CHERRY CANYON-BRUSHY CANYON
	11. Sec., T. R. M. or Blk. and Survey or Area Section 19, T19S, R32 E NMPM
14. Distance in miles and direction from nearest town or post office* 15 MILES SOUTH OF MALJAMAR, NM POST OFFICE (88264)	12. County or Parish LEA — 13. State NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) Surface Loc: 950'FWL, 540'FNL NMCLO149966;	16. No. of acres in lease NMLC0149956: 40.77A	17. Spacing Unit dedicated to this well N/A
18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. BH: 345' S42E to #3002500911	19. Proposed Depth ~~6,135~~ MTV - 6200' ~~6,100~~ TVD - 6055'	20. BLM/BIA Bond No. on file NMB 001159
21. Elevations (Show whether DF, KDB, RT, GL, etc.) 3550 FT GL	22. Approximate date work will start* 10/01/2014	23. Estimated duration 45 DAYS

24. Attachments

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No.1, must be attached to this form:

1. Well plat certified by a registered surveyor.
2. A Drilling Plan.
3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO must be filed with the appropriate Forest Service Office).
4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification
6. Such other site specific information and/or plans as may be required by the BLM.

25. Signature [signature]	Name *(Printed/Typed)* James C. Hunter, RG	Date 08/11/2014
Title Senior Geologist - Consultant to DCP Midstream		
Approved by *(Signature)* **Steve Caffey**	Name *(Printed/Typed)*	Date OCT 2 2 2014
Title FIELD MANAGER	Office CARLSBAD FIELD OFFICE	

Application approval 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.
Conditions of approval, if any, are attached.

APPROVAL FOR TWO YEARS

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.

(Continued on page 2) *(Instructions on page 2)

Capitan Controlled Water Basin

KZ 10/27/24 R-13809

SEE ATTACHED FOR CONDITIONS OF APPROVAL

Approval Subject to General Requirements & Special Stipulations Attached

OCT 28 2014

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DCP MIDSTREAM ZIA AGI #1 NINE POINT DRILLING PLAN FOR BLM APD

EXECUTIVE SUMMARY

On behalf of DCP Midstream LP (DCP), Geolex®, Inc. (Geolex) has prepared and is hereby submitting a completed Application for Permit to Drill (APD) and Nine Point Drilling Plan for a combined acid gas injection and CO_2 disposal well (Zia AGI #1) at the proposed DCP Zia Gas Plant in Section 19, T19S, R32E approximately 35 miles west of Hobbs in Lea County, New Mexico (Figure 1). This well will be drilled as an acid gas disposal well for the proposed plant. This is the 9-point drilling plan supporting the APD which also contains the SUPO, and all other required attachments.

NAME OF WELL: Zia AGI #1

LEGAL DESCRIPTION:
Surface Location: 2100' FSL and 950' FWL of Section 19, T19S, R32E, NMPM, Lea County, New Mexico
Bottom Hole Location: 2,550' FSL and 750' FWL, Sec 19, T19S, R32E NMPM, Lea County, New Mexico.

Figure 2 shows the specific locations of the proposed well and the anticipated bottom-hole location.

The proposed well will be drilled, cased, cemented and complete using appropriate methods and materials. The proposed injection zone will be within two porous sandstone units of the lower Cherry Canyon, lying between approximate depths of 5,470 to 5,670 feet, and three porous sandstone units in the upper Brushy Canyon at depths of 5,670 to 6,070 feet (TVD).

The well will be advanced vertically to approximately 2,000 feet. The well will then be deviated at approximately 0.31°/100' DLS to 12.66° from vertical. The well will be completed at a true vertical depth (TVD) of approximately 6,100 feet, and a measured total depth (MTD) of approximately 6,135 feet. The bottom-hole location (BHL) will land approximately 460 feet northwest of the AGI #1 surface location.

Analysis of the reservoir characteristics of these units confirms the well and reservoir will act as excellent closed-system reservoirs and should easily accommodate the future needs of DCP for disposal of acid gas and sequestration of CO_2 from the plant.

DCP needs to safely inject up to a total 15 million standard cubic feet (MMSCF) per day of treated acid gas (TAG) for 30 years and cannot rely on one well to accept this volume of TAG for the 30 year period. Therefore, a second AGI well is being drilled to receive this capacity, as well as allow for maintenance on either well without shutting down the plant. The information on the second well (AGI #2) is described in an accompanying additional APD.

Geologic studies conducted for the selection of this location demonstrate the proposed injection zone is readily capable of accepting and containing the proposed acid gas and CO_2 injection volumes well within NMOCD's recommended maximum injection pressures and no hydrocarbons are present in the proposed injection zone (see Section IX of this plan).

In preparing this Drilling Plan, Geolex conducted a detailed evaluation of the nine points that BLM's Onshore Oil and Gas Order #1 outlines as required for submission of such a plan. These include:

I.	Estimated Formation Tops
II.	Depth to Zones that Contain Water, Oil, Gas and/or Mineral Bearing Formations
III.	Pressure Control
IV.	Casing
V.	Cement
VI.	Circulation Medium (Mud Program)
VII.	Testing, Coring, Logging
VIII.	Pressures, Temperatures, LCZ's, H2S
IX.	Other Aspects of the Proposal
X.	Hydrogen Sulfide Contingency Plan
XI.	Closed Loop System

I. ESTIMATED FORMATION TOPS

Formation	Vertical Depth to Top (ft)
Alluvium/Ogallala	0
Dockum/Rustler	760
Salado (salt)	925
B/Salt	2,205
Yates	2,440
Seven Rivers	2,667
Capitan Reef	2,761
Delaware	4,570
Cherry Canyon	5,014
Brushy Canyon	6,072
Est. Total Depth	~~6,100~~ 6200

II. DEPTHS TO ZONES THAT CONTAIN OIL AND GAS, WATER AND/OR MINERAL BEARING FORMATIONS

In the area of the proposed Zia Gas Plant, the surficial deposits are relatively thin layers of aeolian sands and both active and stabilized dunes. These materials are described in the United States Department of Agriculture on-line soil survey data (http://websoilsurvey.nrcs.usda.gov/app/WebSoilSurvey.aspx) as the Maljamar and Palomas Fine Sands. The dune sands are locally stabilized with shin oak, mesquite and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the Plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The surface casing will be set in the Magenta dolomite or its equivalent in the Rustler formation to isolate all potable fresh water. The intermediate casing will protect usable water in the Capitan Aquifer.

Under these sandy deposits lie the "redbeds" of the Triassic Dockum Group, in which groundwater locally occurs in sandier beds of the mudrocks characterizing the Dockum. Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are four freshwater wells located within a one mile radius of the DCP Zia AGI well; the closest water well is located 0.6 miles away. All wells within the one mile radius are shallow, collecting water from about 250 to 350 feet depth, in the Triassic redbeds. These wells were drilled for exploratory purposes by Phillips Petroleum in 1982, and do not produce any consumed water. The shallow freshwater aquifer is protected by the surface and intermediate casing in the proposed DCP Zia AGI #1, which extend to 785 feet and 4,710 feet, respectively.

The anticipated vertical and measured depths to formations tops and kick-off point (KOP) are shown on Table 1 below. Depths are shown as vertical depths and as well as measured depths since well AGI #1 will be drilled vertically to a kick-off point depth at approximately 2,000 feet. The hole angle will begin at kick-off in the intermediate hole section and continue after intermediate casing is set until hole angle is built to 12.66°. Final BHL coordinates plan for a total horizontal distance of 460 feet at 6,100' TVD 6,135' MTD (Table 1). All depths are estimated and are subject to change based on geological information obtained at the time of drilling.

Figure 3 shows the site area geology in more detail. Note the proposed injection zone (shown in blue) is separated from any active production zones. Figure 4 shows the locations of the cross-sections shown in Figures 5 and 6. These cross sections show in detail the continuous low-permeability beds isolating the proposed injection zone from overlying and underlying strata.

TABLE 1
Depths to Formation Tops and Other Important and Relevant Depths

Formation	Vertical Depth to Top (ft)	Measured Depth to Top (ft)	Resource
Alluvium/Ogallala	0	0	Fresh Water
Dockum/Rustler	760	760	Freshwater
Salado (salt)	925	925	None
KICK OFF POINT	**2,000**	**2,000**	None
B/Salt	2,205	2,205	None
Yates	2,440	2,441	None
Seven Rivers	2,667	2,668	None
Capitan Reef	2,761	2,762	None
Delaware	4,570	4,562	Oil/Gas
Cherry Canyon	5,014	5,027	None
Brushy Canyon	6,072	6,106	None
Est. Total Depth	~~6,100~~ 6200	6,135	None

Water Wells and Fresh Water Resources in the Vicinity

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are four freshwater wells located within a one mile radius of the DCP Zia AGI #1; the closest water well is located 0.6 miles away (Figure 7; Table 2). All wells within the one mile radius are shallow, collecting water from about 250 to 350 feet depth, in the Triassic redbeds. These wells were drilled for exploratory purposes by Phillips Petroleum in 1982, and do not produce any consumed water. The shallow freshwater aquifer is protected by the surface and intermediate casing in the proposed DCP Zia AGI #1, which extend to 785 feet and 4,710 feet, respectively. The area surrounding the proposed injection wells is arid and there are no bodies of surface water within a five mile radius.

Table 2: Water Wells Identified by the New Mexico State Engineer's Files within One Mile of the Proposed Zia AGI Well #1

POD Number	Owner	Use	UTME*	UTMN*	Distance (m)	Depth Well (ft)	Depth Water (ft)
CP 00642 EXPL	PHILIP PETROLEUM COMPANY	Exploration	611025	3611657	973	250	na
CP 00640 EXPL	PHILIP PETROLEUM COMPANY	Exploration	612621	3613280	1342	260	102
CP 00639 EXPL	PHILIP PETROLEUM COMPANY	Exploration	613029	3612880	1540	350	345
CP 00563 EXPL	PHILIP PETROLEUM COMPANY	Exploration	612118	3613376	1064		na

- UTM coordinated from NM State Engineer's files are calculated from PLSS locations, not surveyed.

Oil and Gas Resources in the AGI #1 Area of Review and Vicinity

A summary of potential area oil and gas bearing resource zones is included in Table 1. Attachment 1 contains a complete list based on NMOCD records of all active, temporarily abandoned, abandoned and plugged oil and gas wells within two miles (Attachment 1: Table A). There are 188 recorded wells within two miles of the Plant, of which 87 penetrate the proposed injection zone. The wells are shown in Figure 8 and summarized in Table 3 below.

Table 3: Summary of Well Status within Two Miles of Proposed Zia AGI Well #1

	Active	Plugged	Temp Abandoned	New (Not Drilled)	**TOTALS**
Deep (Penetrating Injection Zone)	87	49	2		**138**
Shallow (Above Injection Zone)	10	28			**38**
Not Drilled				12	**12**
TOTALS	**97**	**77**	**2**	**12**	**188**

Status of Injection-Zone-Penetrating Wells Within One-Half Mile

During the preparation of the New Mexico Oil Conservations Division Application for Authorization to Inject (Form C-108), calculations were made to determine the area of influence of the proposed injection well, using both the anticipated injection rate of 7.5 MMSCFD, and a safety factor of 100% factor (15 MMSCFD). These calculations indicated an influence radius ranging from 0.26 miles (7.5 MMSCFD) to 0.37 miles (15 MMSCFD). The projected areas are shown in Figure 9, along with the one-half mile radii of the well.

Within the one-half mile radius of interest, there are only 9 wells penetrating the injection zone, of which 7 are active and 2 are plugged and abandoned (Table 4). Records for these wells are included in Attachment 2. A review of the plugging and completion reports indicates that the injection zone is properly isolated by all of the plugged wells within 0.37 mile calculated radius of injection of the proposed AGI well.

Figure 9 shows the locations of the 9 wells within the area of interest, and Table 4 below summarizes the relevant information for those wells. As seen in Figure 9, only 5 wells are within the calculated areas of injection for the proposed AGI well, and 4 wells lie outside this area.

TABLE 4: Wells Penetrating the Injection Zone within One Half Mile of the Proposed AGI Well

Map Number	API Number	OPERATOR	DEPTH (ft)	WELL NAME	STATUS	Distance (Miles)*
35	3002520247	EL PASO NATURAL GAS	11432	LUSK DEEP UNIT 006	Plugged	0.29
100	3002535291	COG OPERATING LLC	12718	LUSK DEEP UNIT A 021	Active	0.29
94	3002534573	COG OPERATING LLC	12540	LUSK DEEP UNIT A 014	Active	0.30
45	3002520876	TOM R CONE	11223	GULF FEDERAL 003	Active	0.31
32	3002520122	COG OPERATING LLC	12554	LUSK DEEP UNIT A 005	Active	0.40
148	3001510382	PHILLIPS PETROLEUM CO	11540	LUSK DEEP UNIT 008	Plugged	0.43
28	3002520025	CHISOS, LTD	11286	DELHI FEDERAL 001	Active	0.54
123	3002540863	COG OPERATING LLC	13660	LUSK DEEP UNIT A 024H	Active	0.55
108	3002539441	COG OPERATING LLC	9580	SL DEEP FEDERAL 003	Active	0.59

Completion and plugging information for these wells is included in Attachment 2. Available data shows none of these wells are likely to create migratory paths between the injection zone and deeper/shallower formations; however, NMOCC will require the four wells highlighted above will be addressed due to questions regarding their cementing around the proposed injection zone. In the case of the active wells, the injection zone will be cemented by an approved squeezing method when 1) the well is scheduled to be plugged and abandoned, 2) when the well is opened by the operator for workover maintenance, or 3) after 15 years of the initiation of injection, whichever occurs first. An effort will be attempted to re-enter and squeeze the injection zone in the plugged well within 15 years of the initiation of injection. These are conditions required by NMOCC and included in the final Order approving this project, anticipated to be signed in March 2014.

As part of the work performed to support this application, a detailed investigation of the structure, stratigraphy and hydrogeology of the area surrounding the proposed Zia AGI #1 injection well has been performed. The investigation included the analysis of available geologic data and hydrogeologic data from wells and literature identified in Sections 3, 4 and 5 of the C-108 application including related appendices. Based on this investigation and analysis of these data, it is clear that there are no open fractures, faults or other structures which could potentially result in the communication of proposed injection zone with any known sources of drinking water in the vicinity as described above. The proposed injection zone is a closed system and over 4,000 vertical feet from fresh water-bearing zones.

Our analysis of the reservoir indicates the fluids in the permeable zones (see Figures 3, 5 and 6) are saline water and contain no economical hydrocarbons. Available well records shown in these Figures do not report any shows in the proposed injection zone.

Geolex's analysis of the impact of TAG injection from the proposed AGI #1 completed in the Cherry Canyon and Brushy Basin porosity zones will not negatively impact the production of any economic hydrocarbons within a 1-mile radius of the AGI #1 injection zone. This opinion is based upon test and production results, seismic identification of porosity zone limits, experience with the depositional systems of the lower Permian rocks, and local structure. Any injected fluid will be confined to an area significantly less than a 1-mile radius away from the well, and will be unlikely to break-through to any producing wells up-dip of the site.

III. PRESSURE CONTROL

SPECIFICATIONS FOR PRESSURE CONTROL EQUIPMENT: SEE COA

A 21-1/4" annular BOP will be installed on the 20' conductor prior to drilling the surface hole. After running the 13-3/8" surface casing, a 13-3/8" 5,000# WP double BOP stack will be installed on the 13-3/8", 9-5/8" and 7" casings (Figure 11). Pressure tests will be conducted prior to drilling out under all casing strings. BOP controls will be installed prior to drilling under surface casing and will remain in use until completion of drilling operations. BOP's will be inspected and operated as recommended in Onshore Order #2. A Kelly cock and a sub equipped with a full opening valve sized to fit the drill pipe and collars will be available on the rig floor in the open position when the Kelly is not in use. The annular diverter will not be tested. The 13-3/8", 9-5/8" and 7" BOP's will be tested to 5,000# and the annular to 1,500# using a third party testing company prior to drilling below each shoe. If operations last more than 30 days from 1st test, the BOPE will be tested again per BLM Onshore Oil & Gas Order #2. The preventer rams will be function tested daily (when possible) and on each trip to ensure preventers are functioning properly. See COA

Figure 12 is a schematic of the manifold system between the BOP/BOPE, the mud separator and the close-loop mud control system.

IV. CASING

A schematic of the proposed Zia AGI #1 is shown in Figure 10. The casing specifications for Zia AGI #1 were specially developed to be more resistant to the anticipated TAG stream. There are two lines of defense against TAG corrosion. The first line of defense is supplied by 300 feet of CRA casing surrounded with TAG resistant cement (CORROSACHEM or equivalent) (Tables 5, 6, and 7). The second line of defense against corrosion is the acid resistant fiberglass lined 3- 1/2" production tubing which should protect the metal interior against the effects of TAG. Both of these material upgrades will aid in reducing corrosion and add additional life to the well.

The Directional Plan is included as Attachment 3.

TABLE 5
Casing Design Specifications

TYPE	COLLAR TYPE	INTERVAL (MD)	HOLE SIZE	PURPOSE	CONDITION
20", Grade B, 0.25" wall thickness	Welded	0' – 120'	24"	Conductor	New
13-3/8", 48#/ft, H40	STC	0' –785'	17 ½"	Surface	New
9-5/8", 40#/ft, J55	LTC	0' – 4,710'	12 ¼"	Intermediate	New
7", 26#/ft, HCL80	LTC	0' – 5,225' 5,525' – 6,135'	8 3/4 "	Production	New
7", 26#/ft, SM 2535 or equivalent	USF	5,225' – 5,525'	8 3/4 "	Production	New

The design criteria and casing loading assumptions are shown in Table 6 and discussed below for each casing string.

TABLE 6
Casing Design Safety Factors (PSI)

TYPE	TENSION	COLLAPSE	BURST
13-3/8" , 48#/ft, H40	8.55	2.01	1.73
9-5/8", 40#/ft, J55	2.76	2.08	2.79
7", 26#/ft, HCL80 (Sect 1)	4.03	3.13	1.45
7", 26#/ft, SM2535 (Sect 2)	3.82	2.33	1.99
7", 26#/ft, HCL80 (Sect 3)	3.55	2.67	1.45

The casing design criteria and assumptions are as follows:

SURFACE CASING – (13-3/8")

Tension A 1.8 design factor in air.

Collapse A 1.125 design factor with full internal evacuation and a collapse force equal to the mud gradient in which the casing will be run (0.488 psi/ft). The effects of axial load on collapse will not be considered.

Burst A 1.1 design factor with a surface pressure equal to the fracture gradient at setting depth, or 1,000 psi test pressure, whichever is greater. Internal burst force at the shoe will be cement hydrostatic pressure at that depth. No backup pressure or effects of tension on burst are utilized.

INTERMEDIATE CASING – (9-5/8")

Tension A 1.8 design factor in air. See COA

Collapse A 1.125 design factor with 50% internal evacuation and a collapse force equal to the mud gradient in which the casing will be run (0.51 psi/ft).

Burst A 1.1 design factor with an internal burst force at the shoe equal to the fracture pressure at that depth, or an inside cmt column hydrostatic, whichever is greater. Back pressure will be formation pore pressure. The effects of tension on burst will not be utilized.

PRODUCTION CASING – (7") (Even though the section from 5,225' – 5,525' is CRA 28#/ft has higher strength, the entire string was designed using HCL-80 26#/ft specifications.)

Tension A 1.8 design factor utilizing the effects of buoyancy (9.2 ppg).

Collapse A 1.125 design factor with full internal evacuation and a collapse force equal to the mud gradient in which the casing will be run (0.48 psi/ft) at TVD. The effects of axial load on collapse are not considered.

Burst A 1.1 design factor with an anticipated maximum tubing pressure (MASP -5,000 psig) on top of the maximum anticipated packer fluid (diesel) gradient (0.37 psi/ft), and considering an outside cement column offset with inside water column. Back pressure on production string will be formation pore pressure (0.433 psi/ft) evaluating MASP. The effects of tension on burst will not be utilized.

V. CEMENT See COA

The borehole for the surface casing will be drilled with a 17 ½ inch bit to a depth of approximately 785 feet, and 13 $^3/_8$ inch, 48.0 ppf, H40, STC casing will be installed and cemented to the surface with approximately 675 sacks of cement (or amount adequate to circulate the cement to the surface).

The intermediate hole will be drilled with a 12 ¼ inch bit to a depth of approximately 4,700 feet and 9 $^5/_8$ inch, 40.0 ppf, J55, LTC casing string run and cemented to surface in two stages (Table 7). The first stage will seal the annular space to the cement diverter tool at 2,000' with approximately 565 sacks of cement. The second stage will bring use 530 sacks of cement to from 2,000' to surface. Cement returns will be observed during both the surface & intermediate jobs and losses noted. Casing and cement integrity will be demonstrated by pressure-testing after each cement job.

The production hole will be drilled with a 8 1/2 inch bit to a depth of approximately 6,135 feet and 7 inch, 26.0 ppf, HCL & SM2535 (or equivalent) casing run and cemented to surface in two stages (Table 7) with 945 sx of cement. The first stage will seal the annular space from TD (~6,135 feet) to 4,500' (~ 210 feet into the intermediate casing and 725' above the upper most Corrosion Resistant Alloy joint) where a cement diverter tool will be located. Stage 1 cement will be 355 sx acid-resistant (CORROSACEM™ or equivalent). The second stage will be 390 sx light-weight lead cement followed with 200 sx Class C tail cement (Table 7) bringing cement to surface. To help ensure good cement bonding and filling throughout the inclined section of the production casing, centralizers & turbolizers will be installed on the casing string as recommended by the centralizer company.

TABLE 7
Cement Program Design Specifications

See COA

INTERVAL	AMOUNT (sx)	FEET	EXCESS	TYPE	ADDITIVES	GALS/SX	PPG	FT^3/SX
Surface (Single Slurry)	675	785	100%	Class C	2% CaCl + 4%Gel+0.25 pps FlexfiberA+0.25 pps Celloflake+0.1% CF4P	8.44	13.7	1.62
Intermediate								
Stage 1 (Lead) DV @ 2,000'	365	2,300	10%	C-NACL	6% Gel+5% Salt + 2 pps EC-10 + 0.25 pps Celloflake + 0.1% CF-41P	10.94	12.6	2.01
Stage 1 (Tail)	200	400	100%	Class C	1% CaCl + 0.1% CF-41P	6.17	14.8	1.34
Stage 2 (Lead)	330	1,600	25%	Class C	6% Gel+5% Salt + 2 pps EC-10 + 0.25 pps Celloflake + 0.1% CF-41P	9.36	13.5	1.78
Stage 2 (Tail)	200	400	100%	Class C	1% CaCl + 0.1% CF-41P	6.17	14.8	1.34
Production								
Stage 1 (4,500' – 6,135') DV @ 4,500'	355	1,800	10%	EverCrete	1% LAP-1 + 0.5% CFR-3 + 1 pps D-AIR +0.3% HaladR-344 + 0.2% HR-800	3.478	16.06	1.12
Stage 2 Lead (Surf – 4,500')	390	4,524	25%	C	5% Salt +5lb/sx Kol Seal + 0.1% HR-800	9.36	13.5	1.78
Stage 2 Tail (Surf – 4,500')	200	890	25%	Class C	0.1% HR-800	6.17	14.8	1.34

VI. CIRCULATING MEDIUM (MUD PROGRAM)

A closed loop system for the handling of drilling fluids and cuttings will be utilized in the drilling of this well. This system is included as Attachment 4 to this drilling plan. Drilled solids will be hauled to an approved site and disposed of according to state and federal guidelines.

MUD PROGRAM:

Drill 17-1/2" surface hole with **fresh water (8.4 to 8.7 ppg)** to a depth of approx 785'. Control lost circulation with paper and LCM pills. Viscosity 28-55, no fluid loss control. Fresh water gel sweeps.

Drill 12-1/4" hole from 785' to 4,700' with **Brine or Cut Brine (9.2 to 10.0 ppg)**. Watch for potential lost circulation in Capitan Aquifer. Control lost circulation with paper and LCM pills. Viscosity 28-30, no fluid loss control. Salt water gel sweeps.

Drill 8 1/2" production hole from 4,700' to **6,135'** (6,100 TVD) with **fresh water (8.4 to 8.7 ppg)**. Control lost circulation with paper and LCM pills. From 5,200' to TD, control filtrate with starch and water loss additives. Clean hole with pre-hydrated freshwater gel sweeps, as necessary. System properties: viscosity 34-40, fluid loss <20 ml/30min.

All necessary mud products for weight addition and fluid loss control will be on location at all times. Mud program subject to change due to hole conditions.

Mud monitoring system: Mud will be maintained and checked daily for mud weight, viscosity, API water loss, pH, etc. Additional electronic monitoring will include a pit volume totalizer to monitor mud volume in active system, pump rate, and mud return flow percentage. H2S monitors and alarms will be located on rig floor, shale shakers, and mud tanks (see rig plat). Gas chromatograph with monitor hydrocarbon gas content of mud from 4,600' to TD. A third-party corrosion company will utilize H2S/oxygen scavengers to monitor for corrosion and limit damage to tubulars.

Auxiliary Equipment

A. A Kelly cock will be in the drill string at all times. BOP and fittings must be in good condition with minimum of 2,000 psi working pressure on 13-3/8" casing and 5000 psi working pressure on 9-5/8" and 7" casing. Accumulator will be at least 40 gallon capacity with 2 independent sources of pressure on closing unit and meet all other API specifications.

B. A full opening drill pipe stabbing valve having the appropriate connections will be on the rig floor at all times with 5,000 psi working pressure.

C. Hydrogen Sulfide detection equipment will be in operation before drilling out the 13 3/8" casing shoe until the 7" casing is run/set and rigging down operations have begun.

TESTING, LOGGING & CORING PROGRAM:

a. Testing: No DST's are expected.
b. Open hole logs are planned at TD of surface, intermediate, & production holes, w/ side wall cores included in production hole.
c. Mud logging will take place from 120 ft to TD 10ft samples

POTENTIAL HAZARDS:

No significant hazards are expected to TD, no abnormal pressures or temperatures are expected. Lost circulation may occur. No H_2S is expected but may occur in the Yates, so the operator will utilize a 3[rd] party H_2S monitoring package from 785' to TD. If H_2S is encountered the operator will comply with the provisions of Onshore Oil & Gas Order #6, and the Contingency Plan included in Section X. All personnel will be familiar with all aspects of safe operation of equipment being used to drill this well.

TABLE 8
Mud Program Specifications

DEPTH	MUD TYPE	WEIGHT	FV	PV	YP	FL	pH
0' – 785'	FW Spud Mud	8.5 – 9.0	32-34	2-6	1-10	NC	9.0-9.5
785'- 4,710'	Brine/CBW	9.5 – 10.0	28-30	1-2	1-2	NC	10.0-10.5
4,710'–5,400"	CBW/Gel	8.7 - 9.2	28-36	1-2	1-2	NC	9.5-10.0
5,400'-6,135'TD	CBW/Gel	8.8 - 9.2	32-36	2-4	4-8	<15cc	10

VII. TESTING, CORING, LOGGING

Mud logging will commence at approximately 120 feet. The proposed open hole logging suites for all logging runs consists of a Dual Induction, Density-Neutron-Gamma Ray Porosity (triple combo w/4 arm caliper). A Fracture Matrix Identification (FMI) log may be run in the production hole in the caprock and basal seal formations. Rotary sidewall coring will be performed in AGI #1. The cores from AGI #1 should provide the necessary information to evaluate the caprock and proposed injection zone for both wells.

A 360° radial cement bond log will be run to ascertain the quality of the cement bond of each casing and a casing evaluation log will also be run to establish a new casing baseline for future casing corrosion evaluation. It is important that a good bond be established around the injection interval as well as below the corrosion resistant joint to assure that acid gas mixed with formation water does not travel up the outside of the casing and negatively impact the integrity of the casing job.

A comprehensive injection and step rate testing program will be conducted after perforation in order to evaluate the reservoir in the injection zone and establish the injection parameters for final design of the surface facilities.

VIII. PRESSURES, TEMPERATURES, LOST CIRCULATION ZONES, H_2S

Expected pressure gradient will be 0.35 psi/ft, estimated BHP is approximately 2,175 psi at TVD of 6,135 ft, and Estimated BHT is 120° F, estimated from static pressure test conducted on nearby wells. A potential for lost circulation exists in the Capitan Aquifer and appropriate precautions, including the availability of appropriate LCM materials and additives, will be available as described above in the mud program. In addition, occasional occurrences of H_2S have been reported from the Yates Formation and appropriate precautions for handling potential H_2S in mud are also described above in Section VI and in Section X.

IX. OTHER ASPECTS OF THE PROPOSAL

Additional information relative to the proposed completion of the proposed Zia AGI #1 which relates to its proposed use as an acid gas injection and CO_2 sequestration well is included in the C-108 application that was submitted to the NMOCD and BLM. Some of this information has been summarized and included in this section of the 9-point drilling plan for easy reference.

The full C-108 was the subject of a NMOCC Hearing held on February 13, 2014 which was unopposed and during which the NMOCC approved the two-well project with conditions. A copy of the NMOCC Order is included as Attachment 5 to this plan, and the Operator Certification is included as Attachment 6.

<u>Additional Completion Information</u>

Once the integrity of the cement job has been determined, the selected injection intervals will be perforated with approximately six shots per foot. At this location a total of up to 500 feet of target areas may be perforated. A temporary string of removable packer and tubing will be run, and injection tests (step tests) will be performed to determine the final injection pressures and volumes. Once the reservoirs have been tested, the final tubing string including a permanent packer, approximately 5,475 feet of 3 $^1/_2$ inch, 9.3 ppf, L80 Hydril Fiber Glass Lined tubing, and an SSV will be run into the well. A ¼ inch Inconel steel line will connect the SSV to a hydraulic panel at the surface.

The National Association of Corrosion Engineers (NACE) issues guidelines for metals exposed to various corrosive gases like the ones in this well. For a H_2S/CO_2 stream of acid gas that is de-watered at the surface through successive stages of compression, downhole components such as the SSV and packer need to be constructed of Inconel 625, 925, or equivalent. The corrosion resistant joint will be constructed of a similar alloy from a manufacturer such as Sumitomo. A product like SM2535 (with 50% nickel content) will likely be used. The gates, bonnets and valve stems within the Christmas tree will be internally nickel-clad as well.

The rest of the Christmas tree will be made of standard carbon steel components and outfitted with annular pressure gauges that report operating pressure conditions in real time to a gas control center located remotely from the wellhead. In the case of abnormal pressures or any other situation requiring immediate action, the acid gas injection process can be stopped at the compressor and the wellhead shut-in using a hydraulically operated wing valve on the Christmas tree. The SSV provides a redundant safety feature to shut in the well in case the wing valve does not close properly.

After the AGI well is drilled and tested to assure that it will be able to accept the volume of injection fluid (without using acid gas), it will be completed with the approved injection equipment for the acid gas stream. The Rule 11 Plan will be finalized when the compression facility design and well connection design is complete and will be submitted for NMOCD review and approval prior to commencement of TAG injection into the Zia AGI well.

Calculated Areas of Fluid Injection

The range of injection areas for the anticipated ranges of injection volume over an estimated 30-year life of the AGI well are calculated based on the geology, anticipated range of injection volumes, and the injection pressures and temperatures in the reservoir. These calculations are shown in Table 9, and the results of the calculations are plotted on Figure 9.

TABLE 9
Calculations for Area of Injection at Estimated Rate of 15 MMSCFD (Anticipated Normal Injection Rate, Both Wells Included)

PROPOSED INJECTION STREAM CHARACTERISTICS

TAG Gas vol MMSCFD	H_2S conc. mol %	CO_2 conc. mol %	H_2S inject rate lb/day	CO_2 inject rate lb/day	TAG inject rate lb/day
15	11	89	156622	1636394	1793016

CONDITIONS AT WELL HEAD

Well Head Conditions		TAG							
Temp F	Pressure psi	Gas vol MMSCFD	Comp CO_2:H_2S	Inject Rate lb/day	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
100	1200	15	89:11	1793016	689.00	0.48	5.75	41666	7421

CONDITIONS AT BOTTOM OF WELL

Injection Zone Conditions					TAG				
Temp F	Pressure[3] psi	$Depth_{top}$ ft	$Depth_{bottom}$ ft	Thickness[4] ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
120	3315	5500	5903	403	826.00	0.83	6.90	34755	6190

CONDITIONS IN RESERVOIR AT EQUILIBRIUM

Injection Reservoir Conditions					TAG				
Temp[5] F	Pressure[3] psi	Ave. Porosity[6] %	Swr	Porosity ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
120	2400	15.0	0.41	35.6655	726.00	0.73	6.06	39542	7043

CONSTANTS

	SCF/mol	
Molar volume at STD	0.7915	
	g/mol	lb/mol
Molar weight of H_2S	34.0809	0.0751
Molar weight of CO_2	44.0096	0.0970
Molar weight of H_2O	18.015	0.0397

[1] Density calculated using AQUAlibrium software
[2] Specific gravity calculated assuming a constant density for water
[3] PP is extrapolated using successful Drill Stem Tests at nearby wells
[4] Thickness is the average total thickness of coarse sand units in the reservoir zone
[5] Reservoir temp. is extrapolated from bottomhole temp. measured at nearby wells
[6] Porosity is estimated using geophysical logs from nearby wells

CALCULATION OF MAXIMUM INJECTION PRESSURE LIMITATION

SG_{TAG}	0.66	
PG = 0.2 + 0.433 (1.04-SG_{TAG})	0.367	psi/ft
IP_{max} = PG *Depth	2017	psi

Where: SG_{TAG} is specific gravity of TAG; PG is calculated pressure gradient; and IP_{max} is calculated maximum injection pressure.

CALCULATION OF 30 YEAR AREA OF INJECTION

Cubic Feet/day (5.6146 ft^3/bbl)	39542	ft^3/day
Cubic Feet/30 years	433282411	ft^3/30 years
Area = V/Net Porosity (ft)	12148502	ft^2/30 years
Area = V/Net Porosity (ft) (43560 ft^2/acre)	278.9	acres/30 years
Radius =	1966	ft
Radius =	0.37	miles

Each standard million cubic feet (MMSCF) of TAG at the surface will be compressed to approximately 7,043 cubic feet of supercritical fluid at reservoir pressures and temperature. Hence, a 30-year lifetime of injection will result in 433 million cubic feet in the reservoir per MMSCFD of TAG (Figure 9, Table 9).

As shown in Figure 9, the proposed maximum injection rate of 15.0 MMSCFD (7.5 MMSCFD per well) will generate a "footprint" with an area of approximately 138 acres around each well after considering the effect of irreducible water. This footprint will not impact any of the nearby active wells.

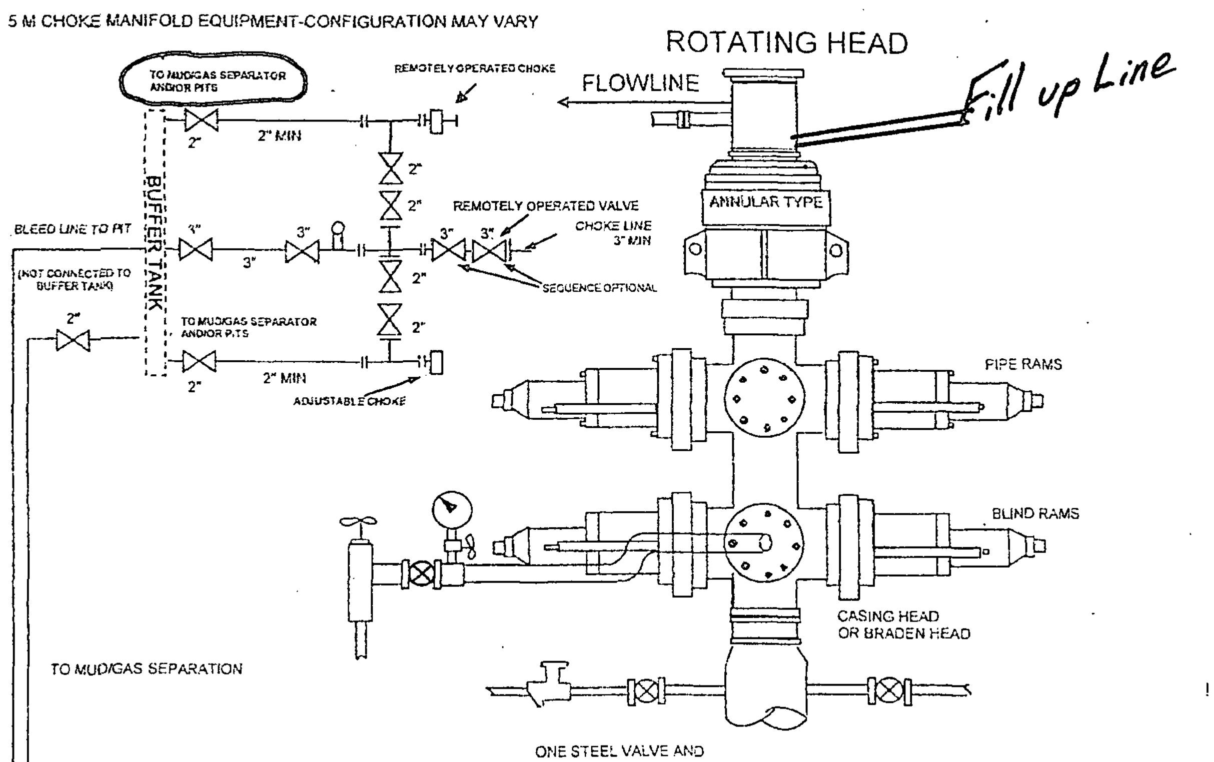
Formation Fluid Chemistry

There is little available public information on the formation fluids in the Cherry Canyon and Brushy Canyon Formations. One report (Powers, *et. al.*, 1978) notes that the waters in these units have chloride levels ranging from 50,000 to 150,000 milligrams per liter. An attempt will be made to sample formation fluids during drilling or completion of the well to provide site-specific fluid properties.

Figure 3 BOP Diagram

* See COA

5-M WP BOPE WITH 5-M WP ANNULAR



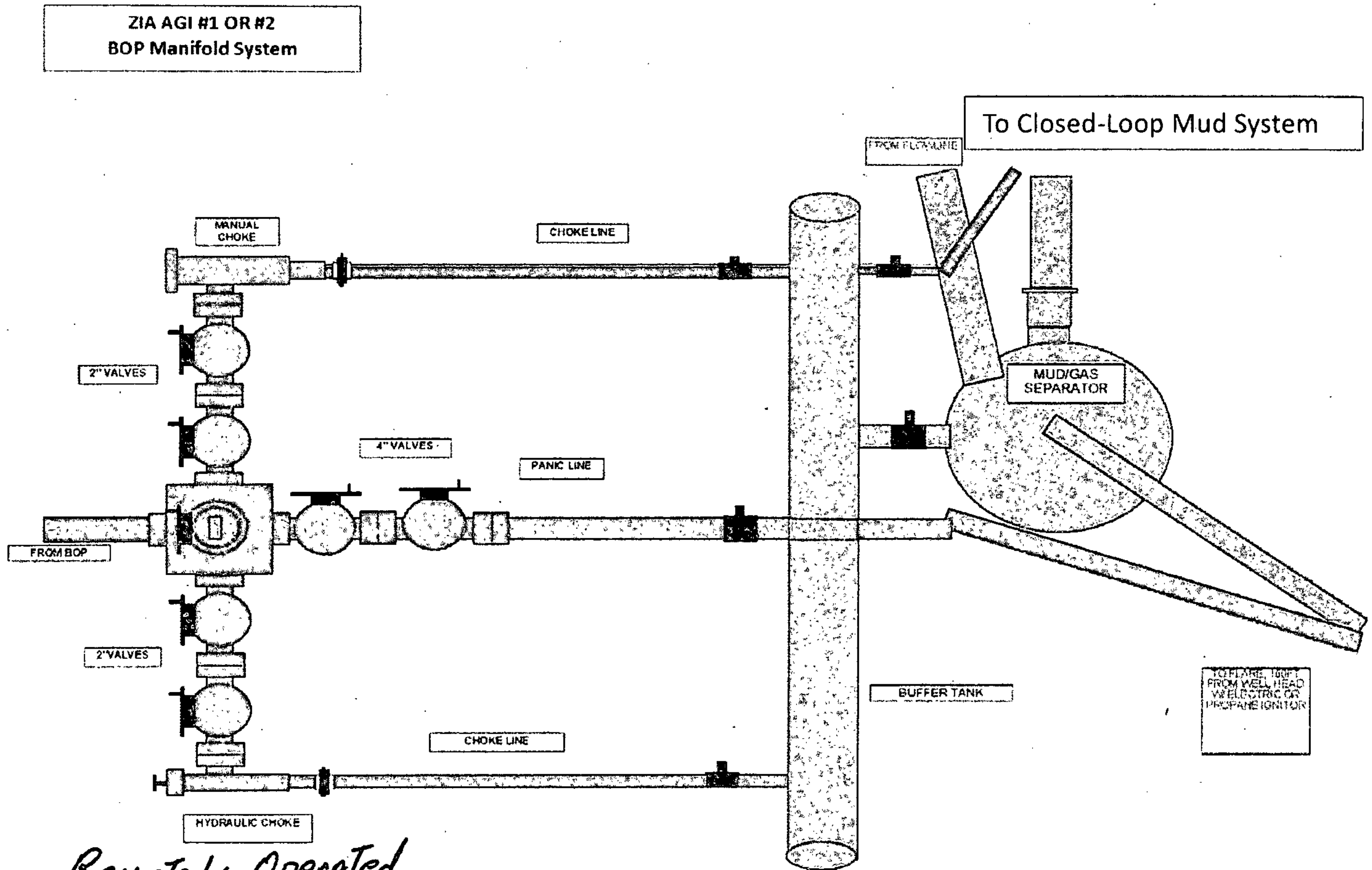
THE FOLLOWING CONSTITUTE MINIMUM BLOWOUT PREVENTER REQUIREMENTS

A. One double gate Blowout preventer with lower pipe rams and upper blind rams, all hydraulically controlled.
B. Opening on preventers between rams to be flanged, studded or clamped and at least two inches in diameter.
C. All connections from operating manifold to preventers to be all steel hose or tube a mininum of one inch in diameter.
D. The available closing pressure shall be at least 15% in excess of that required with suffficient volume to operate (close, open, and re-close) the preventers.
E. All connections to and from preventers to have a pressure rating equivalent to that of the BOPs.
F. Manual controls to be installed before drilling cement plug.
G. Valve to control flow through drill pipe to be located on rig floor.
H. Chokes must be adjustable. Choke spool may be used between rams.

mud/gas separator See COA
Onshore Order 6

TO STEEL MUD TANKS 75 feet

BLEED LINE TO FLARE PIT OR 180 feet



Remotely Operated

5M

Figure 12: BOP Manifold Schematic

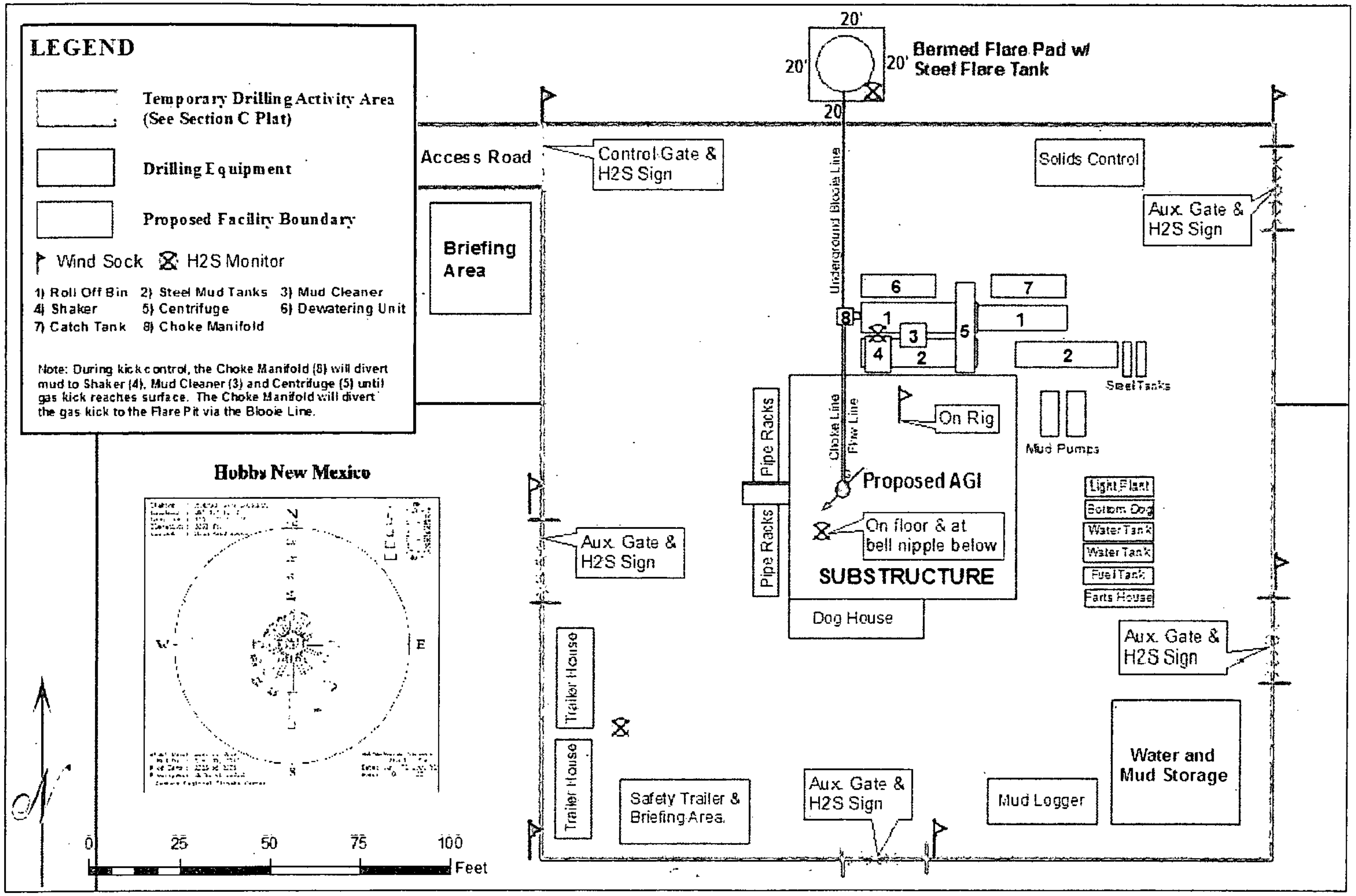


Figure 13: Site Plat Showing H2S Safety Features and Closed Loop System