30-025-40420

MALJAMAR AGI#1 NINE POINT DRILLING PLAN FOR BLM APD

Frontier Field Services, LLC Maljamar Natural Gas Processing Plant

(Unit O, Section 21, Township 17 S, Range 32 E)

Revised 9/16/2011

Prepared For:

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MALJAMAR AGI#1 NINE POINT DRILLING PLAN FOR BLM APD

EXECUTIVE SUMMARY

On behalf of Frontier Field Services, LLC (Frontier), Geolex®, Inc. (Geolex) has prepared and is hereby submitting a completed Application for Permit to Drill (APD) a combined acid gas injection and CO_2 sequestration well (Maljamar AGI #1) adjacent to the Frontier Gas Plant which is located on approximately 19 acres near Maljamar in Lea County, New Mexico (Figure 1). This is the 9-point drilling plan supporting the APD.

NAME OF WELL: Maljamar AGI #1

LEGAL DESCRIPTION: Surface 130 FSL, 1813 FEL, Section 21, T17S, R32E, NMPM, Lea County, New Mexico (see well plat attached to APD form)

The Maljamar AGI #1 is anticipated to have a total depth of approximately 10,000 feet in the lower Leonard and Wolfcamp series along the northern margin of the Delaware Basin (Permian). The primary proposed injection zone will be within a porous debris and algal mound carbonate facies in the Wolfcamp with secondary potential targets in the lower Leonard. All of these zones are between 9,300 and 10,000 feet. Analysis of the reservoir characteristics of these units confirms that they act as excellent closed-system reservoirs that should easily accommodate the future needs of Frontier for disposal of acid gas and sequestration of CO_2 from the plant. Frontier needs to safely inject up to 2.0 million standard cubic feet (MMSCF) per day of treated acid gas (TAG) for 30 years. Geologic studies conducted for the selection of this location demonstrate that 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 that 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
VII. Testing, Coring, Logging
VIII. Pressures, Termperatures, LCZ's, H2S
IX. Other Aspects of the Proposal

I. ESTIMATED FORMATION TOPS

(See II. Below)

II. ZONES THAT CONTAIN OIL AND GAS, WATER AND OTHER MINERALS

The anticipated depths to formation tops and a resource inventory at the proposed well site are:

Table 1: Summary of Formation Tops and Resources

Formation	Estimated Top	Estimated Elevation	Resource
T/Alluvium/Ogallala	0	4,016 GL	Fresh Water
B/Alluvium/Ogallala	200	3,816	N/A
T/Dockum/Rustler	200	3,816	Water
T/ Salt	930	3,086	None
T/Yates/ 7Rivers/Queen	2,150	1,866	Oil/Gas
T/Grayburg	3,490	526	Oil/Gas
T/San Andres	3,880	136	Oil/Gas
T/Glorieta	5,380	-1,364	Oil/Gas
T/Tubbs	6,900	-2,884	Oil/Gas
T/Abo	7,580	-3,564	Oil/Gas
T/Lower Leonard	9,300	-5,284	Barren
T/Wolfcamp	9,550	-5,534	Barren
T/Pennsylvanian	10,000	-5,984	Barren
T/Cisco	10,400	-6,384	Oil/Gas
T/Strawn	11,400	-7,384	Oil/Gas
T/Morrow	11,990	-7,974	Oil/Gas
T/Mississippian	12,450	-8,434	Barren
T/Devonian	13,500	-9,484	Oil/Gas

Water Wells and Fresh Water Resources in the Vicinity

The only significant aquifer in the area is the Pliocene Ogallala Formation, which crops out in the Mescalero Ridge, a prominent landform seen near Maljamar, approximately 3 miles northeast of the Plant As seen in Figure 2, one water well is reported within one mile of the Plant, with a total depth of 158 feet. The nearest well for which groundwater analysis exists is in Section 3, T17S, R32E, approximately 3 miles north of the plant. This well is completed in the Ogallala Formation, and has a Total Dissolved Solids of approximately 500 mg/L. There are no reported natural bodies of surface water within 5 miles of the proposed well site.

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

A summary of potential oil and gas bearing zones in the area is included in Table 1 above. 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 (Figure 1-1, Table 1-1) and those within the one-mile radius area of review (Figure 1-2) of the proposed AGI disposal well. There are 565 recorded wells within two miles of the Plant, of which 351 are active and 214 are listed as plugged and abandoned. Within one mile of the plant, there are 201 wells, of which 139 are active and 62 are plugged and abandoned. These wells are shown in Figure 1-2.

A review of the available NMOCD data regarding the wells within one mile of the proposed AGI well shows that of the 201 total wells, only 12 intersect and/or penetrate the proposed injection zone in the Wolfcamp. Of the total 201 wells, 148 (74%) are less than 6,000 feet deep. These wells are or were targeted into the San Andres/Grayburg, Glorieta/Paddock zones. An additional 41 wells are drilled between 6,000 feet and 8,933 feet, targeting the Yeso and/or Abo formations. All of these wells' total depths are well above the Wolfcamp, which lies from 9,100 to 9,300 feet in this area. Zones which contain potentially economic minerals or oil and gas in the area of review include: San Andres, Grayburg, Glorieta/Paddock and Abo Formations above the targeted injection zone and the Cisco, Strawn, Morrow and Devonian below the targeted injection zone.

Status of Wolfcamp-Penetrating Wells Within One Mile

As shown in the Table 2, below, and in Figure 1-3 of Attachment 1 there are a total of 12 wells penetrating the Wolfcamp "deep wells" in the one mile area of review. Information on the wells in the one mile area of review (see Table 2 below) includes their total depth, production or injection interval and current status. A review of the available data on these wells indicates that they are cased and cemented throughout the Wolfcamp interval, effectively sealing that formation and preventing any migration of injected fluids to deeper or shallower units.

Table 2: Summary of Wells Penetrating Wolfcamp within One Mile of Frontier Gas Plant

API #	OPERATOR	SPUD DATE	PLUG DATE	TOTAL DEPTH	WELL NAME	WELL TYPE	STATUS	Producing/Target/ Injection Zone	Miles From Plant
3002500751	CONOCOPHILLIPS COMPANY	9/20/1948	9/17/2004	10,005	QUEEN B 036 (Baish B 36)	Oil	Plugged	Wolfcamp (Dry Hole)	0.37
3002521951	PAN AMERICAN PETROLEUM CORP	12/20/1966	2/15/1968	13,735	BAISH B FEDERAL 002	Oil	Plugged	Wolfcamp (Dry Hole)	0.40
3002500622	CONOCO INC	11/12/1958	3/7/1986	13,670	BAISH A 008	Oil	Plugged	Cisco/Abo (plugged back)	0.57
3002535252	COG OPERATING LLC	11/17/2000	na	15,026	MC FEDERAL 006	Gas	Active	Devonian	0.68
3002500745	CONOCOPHILLIPS COMPANY	8/8/1961	na	9,680	MCA UNIT 382	Oil	Active	San Andres (plugged back)	0.70
3002500614	CONOCO INC	11/1/1993	3/3/1993	12,778	MCA UNIT 355	Injection	Plugged	Abo/Grayburg (plugged back)	0.73
3002500634	CONOCO INC	4/26/1951	1/11/1991	13,573	BAISH B 005	Oil	Plugged	Devonian	0.81
3002527068	COG OPERATING LLC	10/14/1980	na	12,992	FEDERAL BI 001	Salt Water Disposal	Active	Wolfcamp (plugged back)	0.86
3002508053	CONOCO INC	10/28/1959	9/5/1996	13,965	MCA UNIT 303	Injection	Plugged	Grayburg (plugged back)	0.92
3002520647	COG OPERATING LLC	10/25/1964	na	9,958	MC FEDERAL 007	Oil	Active	Paddock (plugged back)	0.94
3002534647	COG OPERATING LLC	6/16/1999	na	14,912	MC FEDERAL COM 001	Gas	Active	McKee	0.99
3002520568	CONOCOPHILLIPS COMPANY	11/22/1963	na	13,717	BAISH A 012	Oil	Active	Abo (plugged back)	0.99

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 Maljamar 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 date, 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.

Additional cross sections and maps which demonstrate the lack of hydrocarbons present in the proposed injection zones are included in Section IX. of this plan.

III. PRESSURE CONTROL * See COA

The blowout preventer for the 12-1/4" intermediate hole will consist of a 13-5/8" X 5,000 psi dual ram BOP with mud cross, choke manifold, chokes and hydril per Figure 3 (5,000 psi WP). The BOP stack, choke, kill lines, kelly cocks, inside BOP, etc., when installed on the surface casing head will be hydro-tested to 300 psig and 2,000 psig. The BOPE when rigged up on the 8-5/8" intermediate casing spool will consist of a 13-5/8 X 5,000 psi annular, pipe and blind rams with choke manifold and chokes as in Figure 3 and will be tested to 300 psig and 3,000 psig. Hydril will be tested to 2,500 psig. These tests will be performed upon installation, after any component changes and as required by well conditions. A function test to insure that the preventers are operating correctly will be performed on each trip.

IV. CASING

See COA

TYPE	COLLAR TYPE	INTERVAL (MD)	HOLE SIZE	PURPOSE	CONDITION
20"	STC	0' – 50'	24"	Conductor	Contractor Discretion
13-3/8", 48#/ft, H40	STC	0' – ~~550'~~	17 ½"	Surface	New
8-5/8", 24#/ft, J55	STC	0' - 4,200'	12 ¼"	Intermediate	New
5-1/2", 15.5#/ft, L80	~~STC~~ LTC	0' – 10,000'	7 7/8 "	Production	New

CASING DESIGN SAFETY FACTORS

TYPE	TENSION	COLLAPSE	BURST
13-3/8" , 48#/ft, H40	7.88	4.63	3.72
8-5/8", 24#/ft, J55	1.59	2.19	1.01
5-1/2", 15.5#/ft, L80	1.28	4.22	1.54

DESIGN CRITERIA AND CASING LOADING ASSUMPTIONS * See COA

The operator intends to keep the casing liquid filled during emplacement to the greatest degree possible and no less than 75% full. This is taken into consideration in the casing design and loading assumptions as expressed below and results in the safety factors calculated above using the design factors described below.

SURFACE CASING – (13-3/8")

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 (0.47 psi/ft) and effects of axial load considered.

Burst A 1.1 design factor with a surface pressure equal to the fracture gradient at setting depth. 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 – (8-5/8")

Tension A 1.8 design factor utilizing the effects of buoyancy (10.2 ppg).

Collapse A 1.125 design factor with 25% internal evacuation and a collapse force equal to the mud gradient in which the casing will be run (0.53 psi/ft).

Burst A 1.1 design factor with an internal burst force at the shoe equal to the fracture pressure at that depth. Back pressure will be formation pore pressure. The effects of tension on burst will not be utilized.

PRODUCTION CASING – (5-1/2")

Tension A 1.8 design factor utilizing the effects of buoyancy (9.0 ppg).

Collapse A 1.125 design factor with 25% internal evacuation and a collapse force equal to the mud gradient in which the casing will be run (0.48 psi/ft). The effects of axial load on collapse are considered.

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

V. CEMENT *See COA

INTERVAL	AMOUNT (sx)	FEET	EXCESS	TYPE	ADDITIVES	GALS/SX	PPG	FT³/SX
Surface	1,000	550	100%	Class C	2% CaCl	6.39	14.8	1.35
Intermediate	1,250	3,700	50%	Class C (Lead)	2% CaCl	10 19	12.8	1.90
	200	500	25%	Class C (Tail)	2% CaCl	6.39	14.8	1.35
Production				H See COA			ok	
5000' Stage 1	950	4,500	50%	Class ~~C~~ (Lead)	1lb/sx Pheno Seal (Lost Circ additive)	15 39	11.7	1.30 rev for Class H
(10,000 - 5,000)	150	500	25%	CorrosaCem (Tail)	none	3.44	15	0 91
5000' Stage 2	925	4,200	50%	Class C (Lead)	1lb/sx Pheno Seal (Lost Circ additive)	15 39	11.7	1 30
(5,000 - Surface)	160	800	25%	Class C (Tail)	2% CaCl	6.39	14.8	1.35

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See COA

The borehole for the surface casing will be drilled with a 17 ½ inch bit to a depth of approximately 550 feet, and 13 $^{3}/_{8}$ inch, 48.0 ppf, H40, STC casing will be installed and cemented to the surface with approximately 600 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 4,200 feet. There an 8 $^{5}/_{8}$ inch, 24.0 ppf, J55, STC ~~surface~~ casing string will be run and cemented to surface with approximately 1,400 sacks of cement (or amount adequate to circulate the cement to the surface). Visual inspections of cement returns to the surface will be noted in both the surface and intermediate pipe casing jobs. Casing and cement integrity will be demonstrated by pressure-testing after each cement job.

* See COA

The cementing of the Production string will be accomplished in two stages. The first stage will seal the annular space from total depth (approximately 10,000 feet) to a level well above the Corrosion Resistant Alloy joint at approximately 9500 ft. This stage will employ acid-resistant cement (CORROSACEM™ or equivalent). For the second stage, a DV Tool previously inserted in the casing (at approximately 5,000) feet will be used to pump the remaining cement to the surface.

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. The C-144 describing this system is included as Attachment 2 to this drilling plan.

See COA

DEPTH	MUD TYPE	WEIGHT	FV	PV	YP	FL	pH
0' – 550'	FW Spud Mud	8.5 – 9.2	38-70	NC	NC	NC	10.0
550' - 4,200'	Brine	9.8 – 10.2	28-30	NC	NC	NC	9.5-10.5
4,200'–10,000"	FW/Gel	8.7 - 9.0	28-36	NC	NC	NC	9.5-10.0

May increase viscosity for logging and hole conditioning purposes only

VII. TESTING, CORING, LOGGING

See COA

Mud logging will commence at approximately 1,000 ft. The proposed open hole logging suite for the TD run consists of a Dual Induction, Density-Neutron-Gamma Ray Porosity and Fracture Matrix Identification (FMI) log in the lower Leonard and the Wolfcamp and a portion of the caprock and basal seal formations, with rotary sidewall cores in the Wolfcamp. A conventional core will be collected from the Wolfcamp zone to evaluate the permeability of this caprock. Additional sidewall cores may also be obtained from the Wolfcamp to allow more detailed reservoir analysis.

A cement bond log will be run to ascertain the quality of the cement bond of the production casing. 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 do 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 establish the injection parameters for final design of the surface facilities.

JN

VIII. PRESSURES, TEMPERATURES, LOST CIRCULATION ZONES, H2S

The conditions in the reservoir are anticipated to be a reservoir pressure of approximately 3,400 psi with a bottom hole temperature of approximately 130 ° F. There are no anticipated lost circulations zones or H2S bearing formations in the area to the total proposed depth.

IX. OTHER ASPECTS OF THE PROPOSAL

Additional information relative to the proposed completion of the proposed Maljamar AGI#1 which relates to its proposed use as an acid gas injection and CO2 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.

Additional Completion Information *See COA

Once the integrity of the cement job has been determined, the selected injection intervals will be perforated with approximately four shots per foot. At this location a total of 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 9300 feet of 2 $^7/_8$ inch, 6.5 ppf, L80 ULTRA FX premium thread 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 925. The CORROSION RESISTANT joint will be constructed of a similar alloy from a manufacturer such as Sumitomo. A product like SM2550 (with 50% nickel content) will likely be used. The gates, bonnets and valve stems within the Christmas tree will be nickel coated 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 Frontier AGI well.

Calculated Areas of Fluid Injection

Based on the geology described in Section 4.4 of the C-108 application, anticipated range of injection volumes, and the injection pressures and temperatures in the reservoir (see Section 3.1 and Table 1of the

C-108 application) we have calculated the range of injection areas for the anticipated ranges of injection volume, over an estimated 30-year life of the AGI well. These calculations are shown in Table 3 below, and in Figure 5.

As calculated in Section 3.1 of the C-108 application, each standard million cubic feet (MMSCF) of TAG at the surface will be compressed to approximately 425 barrels of supercritical fluid at reservoir pressures and temperature. Hence, a 30-year lifetime of injection will result in 4.6 million barrels in the reservoir per MMSCFD of TAG. As shown in the Table below, the Wolfcamp zone alone is capable of holding up to 5 times the anticipated injection rate for 30 years.

As shown in Figure 5, the proposed maximum injection rate of 2.0 MMSCFD will generate a "footprint" with an area of approximately 73 acres after considering the effect of irreducible water. This footprint will not impact any of the nearby wells.

Table 3: Calculated Volumes and Areas of TAG in Wolfcamp Reservoir

Daily TAG Injection Volume (MMSCF)	Daily Volume of TAG in Reservoir (BBLS/D)	Total TAG Volume in Reservoir after 30 Years (BBLS)	Calculated Reservoir Volume in Wolfcamp (BBLS)	Percentage of Reservoir Occupied	Calculated Radii of Affected Area of Reservoir (Miles)	Affected Area of Reservoir (Acres)
2.0	850	9.3 Million	24 Million	38.8%	0.19	72.8

Suitability of Proposed Injection Zone and Demonstration of Lack of Hydrocarbons

On June 23, 2011, a NMOCD hearing was held to consider the proposed Maljamar AGI #1 acid gas injection (AGI) well in the immediate vicinity of the Frontier Maljamar Plant. At the hearing the C-108 Application was explained in full including the use of 3D seismic data to map key horizons in and immediately adjacent to the lower Leonard (sub-Abo) and underlying Wolfcamp formation intervals. The data identified three areally-limited porosity zones; two in the lower Leonard and one in the lower Wolfcamp. Currently, there is no production from the lower Leonard in the vicinity of the proposed AGI site, and limited waning production updip in the Wolfcamp, northeast of the proposed site. However, the Wolfcamp porosity zone that was mapped on 3D seismic was shown to be a discrete body (mound or near-shelf detrital) with an eastern and northern limit that is stratigraphically isolated from productive zones that are updip to the northeast. The Wolfcamp zone is also the largest of the three identified features, and is most accessible from the proposed AGI well site. The attached seismic structure map shows the location of the three features, and their relationship to Wolfcamp structure and the nearby Wolfcamp wells. There are no active Wolfcamp wells within a ½ mile radius of the proposed site, and only one active well almost 1 mile to the northeast of the site. That well (Continental Baish A #012, in the NE4/NE4 of section 21), was completed from another lower Wolfcamp carbonate mound in January, 1993, and is currently (as of April 1) making 9 BO + 10 BWPD. It is at least 150 feet updip of the proposed well, as mapped on the seismic structure map. Two other wells in the NW4 section 22 are plugged back from the Wolfcamp, defining an apparent current Wolfcamp productive limit as shown on the map.

In order to further document that injection into the (preferred) lower Wolfcamp porosity zone would not affect or in any way impede on the potential production of economic hydrocarbons within the area of the proposed AGI well site (Figure 6), additional cross-sections were constructed that incorporate every well within a 1-mile radius of the site, that penetrated at least through the upper Wolfcamp. These cross-sections are labeled WC1-WC1' (N-S), WC2-WC2' (N-S), and WC3-WC3' (W-E). Prior to construction of the cross-sections, water saturation calculations were performed on 12 wells, inside and just outside of the 1-mile radius of the site that had appropriate porosity-resistivity log suites. Calculations were performed using the Archie's Equation and formation factors based on vuggy carbonates, which is the usual mode of occurrence in both formations in this area. Lithologies varied from dolomite to dolomitic limestones. The results of those calculations were inconclusive as to whether a zone would produce hydrocarbons or water, as Sw values overlapped between producing zones and zones that tested water on either drillstem or production tests. The fundamental reason for this overlap is the chemical nature of native waters in the two formations. Results of production and drillstem tests that recovered formation water show them to be sulfurous salt water, which would make formation resistivities (Rt) appear fresher (i.e., more resistive) than they would for non-sulfurous salt water. These generally higher Rt values, which are used in the Archie Equation, would tend to make Sw values look optimistically productive, even in zones that are proven to be wet.

Figure 6 shows the locations of three cross-sections which evaluate the potential impact of injection into any of the three zones identified on the 3D seismic. Sw values are shown on cross-section wells that had log suites that enabled calculations to be run. Section WC1-WC1' (Figure 7) starts with the one active Wolfcamp well and tracks downdip through the proposed site, and to one of two Wolfcamp salt water injection wells to the south. Drillstem test results, production of water in the Queen B #036 well (which is located in the Zone 3 seismic feature), and the presence of the water injection well all point to the absence of producible hydrocarbons downdip of the producing well, as well as in the lower Leonard porosity zones. Porosity trends in the lower Wolfcamp pay zone of the Baish A #012 cannot be correlated continuously across the section, as previously proven by the seismic mapping.

Similar observations can be made on the other dip section, WC2-WC2' (Figure 8), which clearly shows a lack of porosity continuity of the Baish A #012 pay zone to a well just to the north of the seismic porosity feature (second well from left), and thin-bedded porosity just starting to develop on the north edge of the Zone 3 porosity feature (third well from the left). The west-east section, WC3-WC3' (Figure 9), very clearly demonstrates that the proposed AGI site is in a structural low and is surrounded by wells that exhibit water-bearing (or non-economic) porosity in the Wolfcamp and lower Leonard.

Geolex's analysis of the impact of injection of TAG from a proposed AGI well placed immediately east of the Frontier Maljamar Plant and completed in the lower Wolfcamp and/or other lower Leonard porosity zones would not negatively impact the production of any economic hydrocarbons within a 1 mile radius of the AGI well site. 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 Wolfcamp structure. Any injected fluid would be confined to an area significantly less than a 1-mile radius away from the well, and would be unlikely to break through to any producing wells updip of the site.

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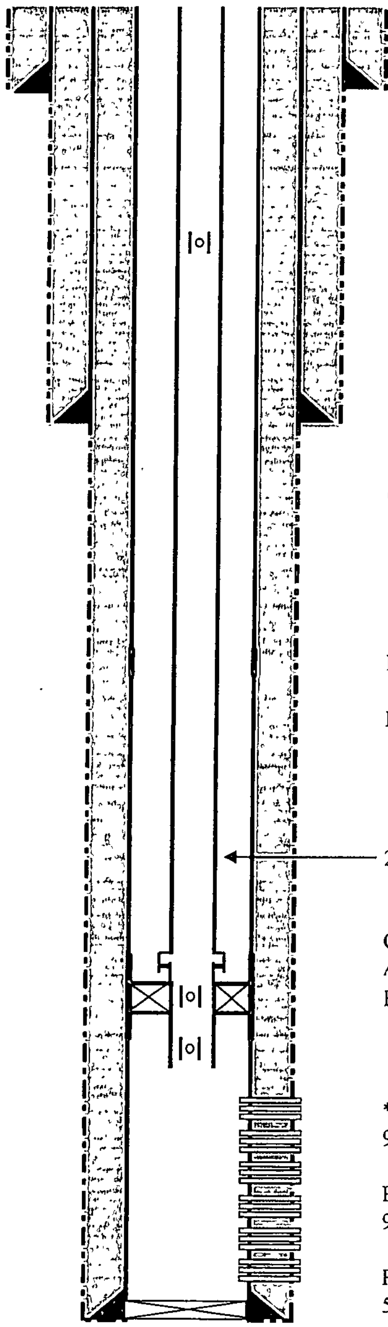
FIGURE 4: MALJAMAR AGI #1 WELL DESIGN

FRONTIER

* See COA For Completion Sondry

Location:	130' FSL & 1831' FEL
STR	S22-T17S-R32E
County, St.:	LEA COUNTY, NEW MEXICO



CONDUCTOR CASING
13 3/8", 48.00#/ft, H40, STC at ~550'

SURFACE CASING:
8 5/8", 24.0 #/ft, J55, STC at ~4,200'

PRODUCTION CASING:
5 1/2", 17 #/ft, L80, STC at ~10,000'

ANNULAR FLUID:
Diesel Fuel from top of packer to surface

TUBING:
Subsurface Safety Valve at ~250 ft

2 7/8", 6.5#/ft, L80, Premium thread at ~9,300'

PACKER:
Permanent Production Packer
Adj. Choke (if needed, placed in nipple below packer)
Check valve (if needed, placed in nipple below packer)

PERFORATIONS:

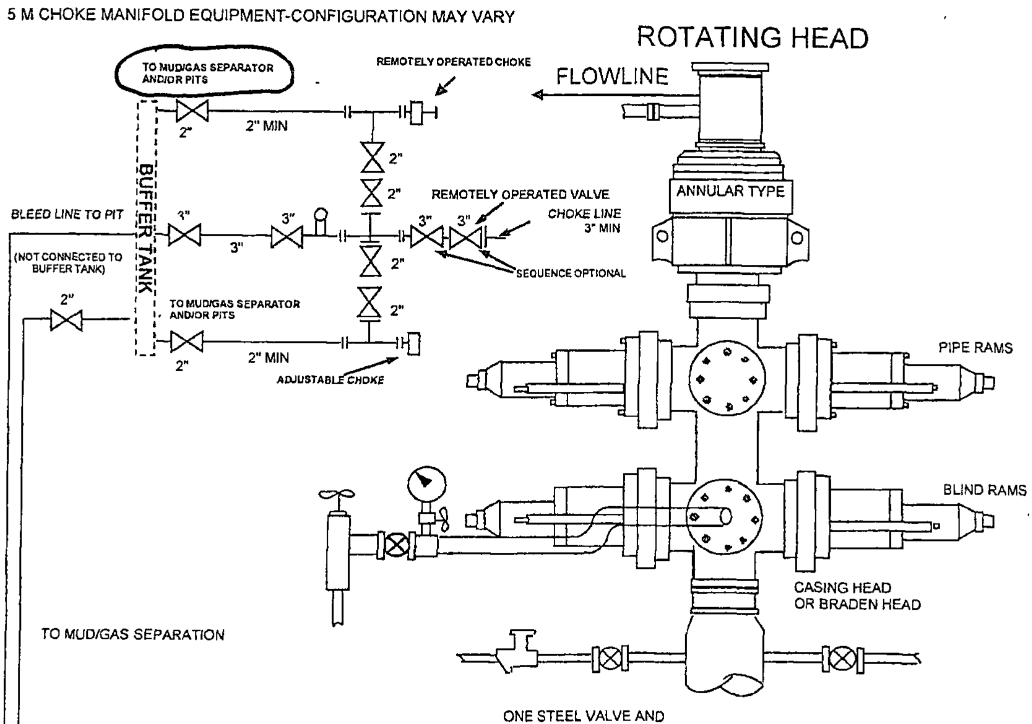
Primary Target	**Secondary Target***
Lower Wolfcamp	Lower Leonard #1
9,800' - 10,000'	9,300' - 9,400'
	Lower Leonard #2
	9,450' - 9,550'

* Depending on logging and coring results

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

Closed Loop System Design Plan (pursuant to 19.15.17.11 NMAC):

The closed loop design does not incorporate any temporary pits or below-grade tanks. The plan uses above-ground tanks suitable to contain the fluids and cuttings generated during the drilling operations. The volumes of all tank(s) will be suitable to contain all anticipated fluids with an adequate freeboard for periodic removal of cuttings and fluids.

The fluids and cuttings will be held in temporary steel tanks, allowing setting of the cuttings and recycling of the drilling fluids. Following completion of drilling operations, the fluids and cuttings will be removed to a permitted disposal facility in Lea County (Controlled Recovery, Inc.).

The grading and operation of the drilling pad will maintained to minimize and control on-run and off-run from storm water.

Closed Loop Operations and Maintenance Plan (pursuant to 19.15.17.12 NMAC):
:

1. Any free liquids will be recovered and reused, disposed of at the Controlled Recovery, Inc. facility (Permit # NM-1-006), or relocated for use in other permitted drilling operations.
2. Drill solids will be periodically removed from the site and transported to the Controlled Recovery facility for disposal, as required to maintain a safe freeboard on the tanks. No on-site disposal or burial of cuttings will occur.
3. All drilling materials and trash will be stored and disposed of in an appropriate manner.
4. The NMOCD and BLM will be notified within 48 hours of the discovery of any compromised integrity of the closed loop containment. Any required repairs will commence immediately.

Close Loop Closure Plan (pursuant to 19.15.17.9 NMAC and 19.15.17.13 NMAC):

1. Following the completion of drilling operations, the temporary fluid tanks will be cleaned and the final residues hauled and disposed of by Controlled Recovery, Inc. facility (Permit # NM-1-006).
2. The site will be re-graded as necessary to maintain drainage control and minimize erosion. Since the drilling site is owned by the Operator (Frontier Field Services, LLC), there will be no impacts to Federal lands or any other property owner.
3. Appropriate fencing, signage and other security measures will be installed after well completion and installation of the surface injection facilities.

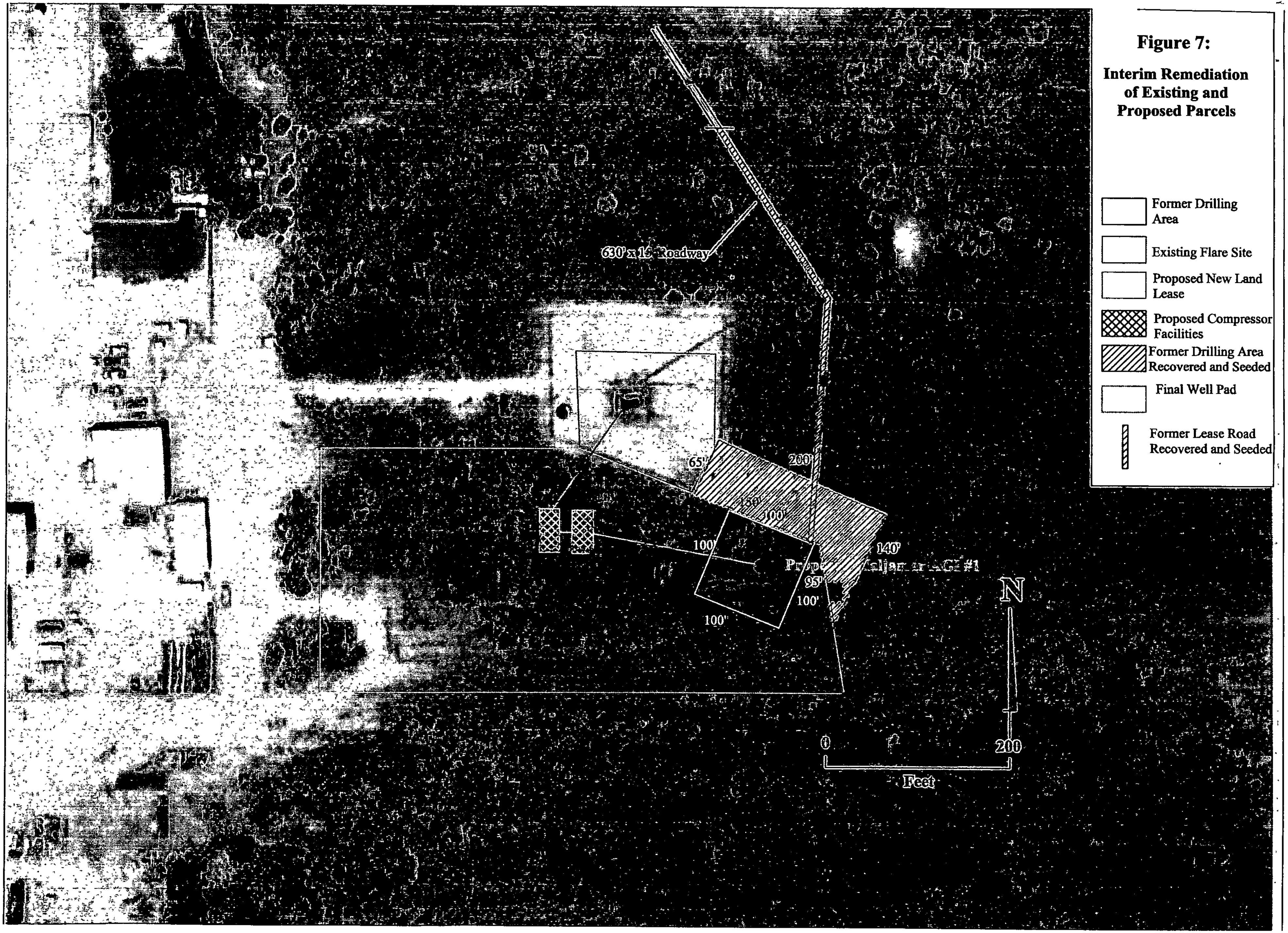
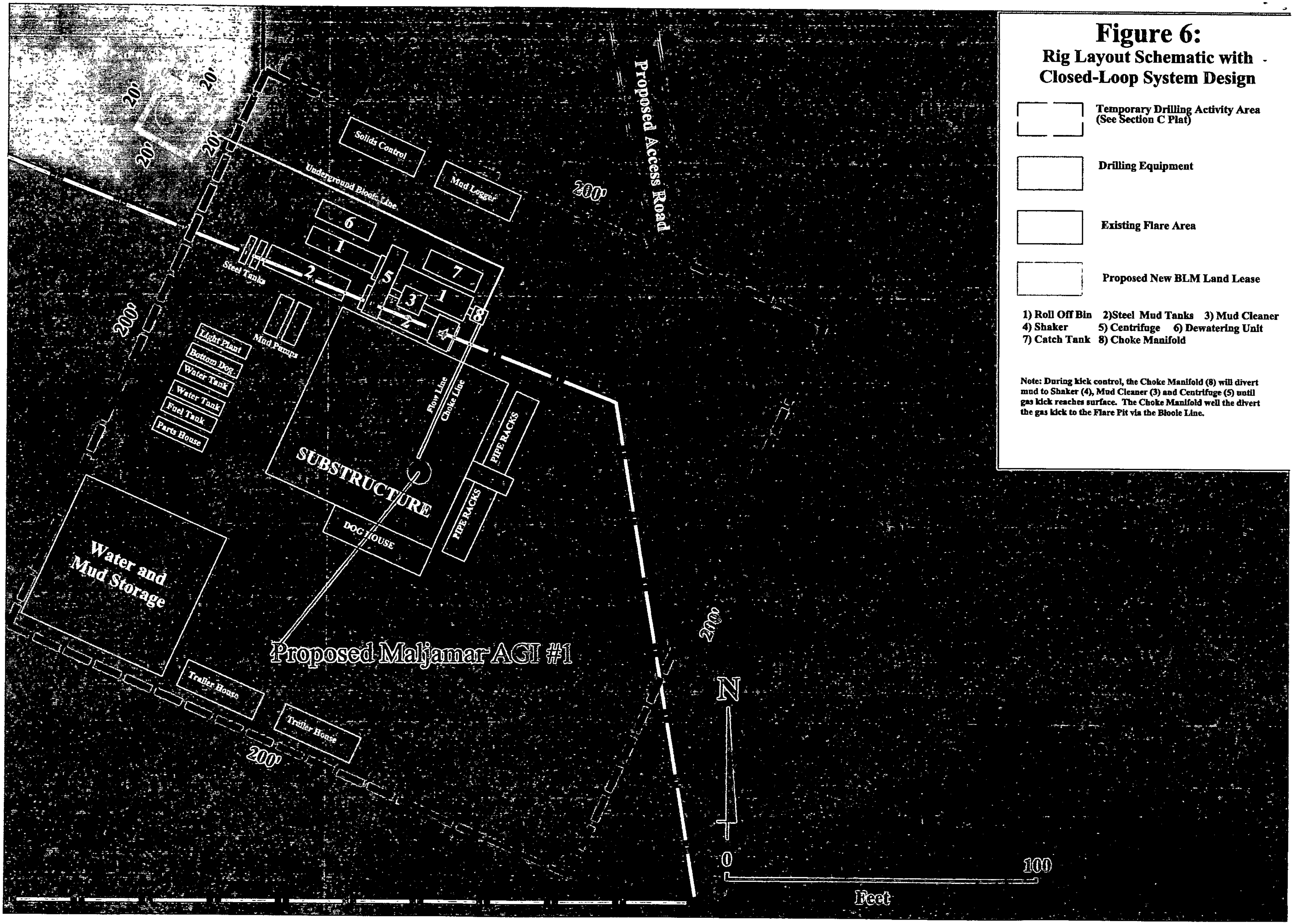


Figure 7:

Interim Remediation of Existing and Proposed Parcels

Figure 6:
Rig Layout Schematic with Closed-Loop System Design



Note: During kick control, the Choke Manifold (8) will divert mud to Shaker (4), Mud Cleaner (3) and Centrifuge (5) until gas kick reaches surface. The Choke Manifold well the divert the gas kick to the Flare Pit via the Bloole Line.