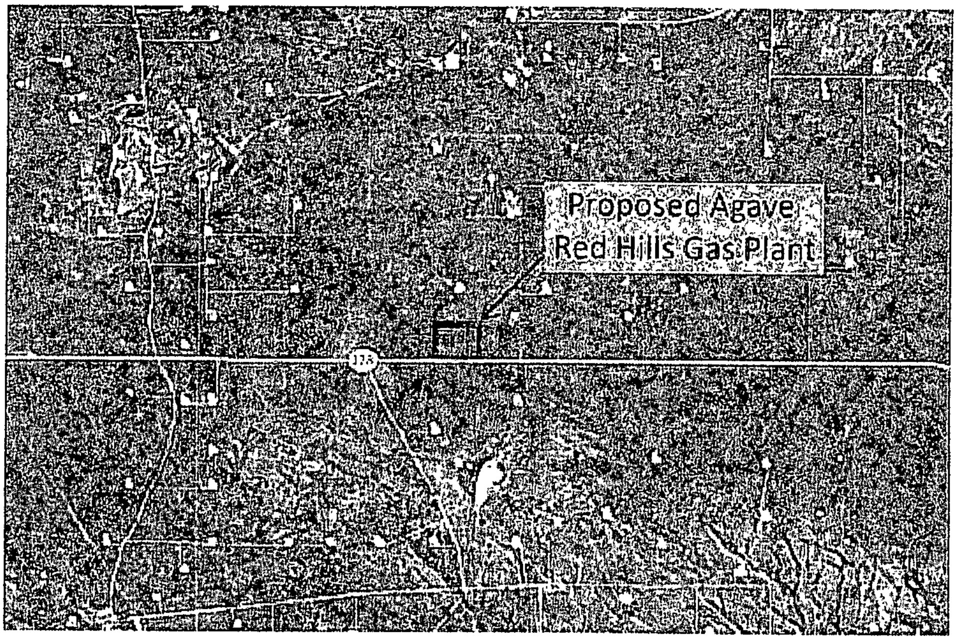
30-025-40448

GEOLEX
INCORPORATED

AGAVE ENERGY COMPANY

# RED HILLS AGI#1 NINE POINT DRILLING PLAN FOR BLM APD
# AGAVE ENERGY COMPANY PROPOSED NATURAL GAS PROCESSING PLANT

**(Unit I, Section 13, Township 24 S, Range 33 E)**




**August 15, 2011**

*Prepared For:*

**Agave Energy Company**
**105 S. Fourth Street**
**Artesia, NM 88210**

*Submitted To:*

**Bureau of Land Management, Carlsbad District**
**620 East Greene Street**
**Carlsbad NM 88220**

*Prepared By:*

**Geolex, Incorporated**
**500 Marquette Avenue, NE, Suite 1350**
**Albuquerque, New Mexico 87102**
**Telephone: (505) 842-8000**

FEB 20 2012

GEOLEX®
INCORPORATED

AGAVE ENERGY COMPANY

## TABLE OF CONTENTS



## LIST OF FIGURES



## LIST OF ATTACHMENTS

GEOLEX®
INCORPORATED

## AGAVE RED HILLS AGI#1 NINE POINT DRILLING PLAN FOR BLM APD

### EXECUTIVE SUMMARY

On behalf of Agave Energy Company (Agave), 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 (Red Hills AGI #1) at the proposed Agave Red Hills Gas Plant which is located approximately 20 miles west-northwest of Jal in Lea County, New Mexico (Figure 1). This is the 9-point drilling plan supporting the APD.

**NAME OF WELL: Agave Red Hills AGI #1**

**LEGAL DESCRIPTION: Unit I , Section 13, T24S, R33E, NMPM, at 150' FEL, 1,600' FSL, Lea County, New Mexico (see well plat attached to APD form).**

The proposed Agave Red Hills AGI #1 well is anticipated to have a total depth of approximately 6,550 feet in the Cherry Canyon Formation of the Delaware Basin (Permian). The proposed injection zone will be within five porous sandstone units of the upper Cherry Canyon, lying between approximate depths of 6,200 to 6,530 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 Agave for disposal of acid gas and sequestration of $CO_2$ from the proposed Red Hills Plant. Agave needs to safely inject up to 13 million standard cubic feet per day (MMSCFD) 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 New Mexico Oil Conservation Division's (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, Temperatures, 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/Ogalalla | 0 | 3,574 | Water |
| T/Dockum Group | 80 | 3,494 | Water |
| T/Rustler | 1,245 | 2,329 | None Identified |
| T/Salado | 1,620 | 1,954 | None Identified |
| T/Castile | 3,530 | 44 | None Identified |
| T/Bell Canyon | 5,190 | -1,616 | Oil |
| T/Cherry Canyon | 6,202 | -2,628 | None Identified |
| T/Brushy Canyon | 7,450 | -3,876 | None Identified |
| T/Bone Springs | 9,005 | -5,431 | Oil/Gas |
| T/Wolfcamp | 11,860 | -8,286 | Oil/Gas |
| T/Strawn | 12,956 | -9,382 | Oil/Gas |
| T/Atoka | 13,330 | -9,756 | Oil/Gas |
| T/Morrow | 14,115 | -10,541 | Oil/Gas |

<u>Water Wells and Fresh Water Resources in the Vicinity</u>

The area surrounding the proposed injection wells is arid and there are no bodies of surface water within a five mile radius. Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are no freshwater wells located within a one mile radius of the Agave Red Hills AGI #1 well; the closest water well, as shown in Figure 2, is located 1.37 miles away. Available information shows that groundwater occurs at a depth of approximately 20 to 650 feet, and is hosted by the Ogallala and Santa Rosa Formations. All wells within a five mile radius are shallow, collecting water from about 20 to 650 feet depth. The wells were drilled primarily for stock and commercial purposes; there are two domestic water wells within five miles of the proposed Agave Red Hills AGI #1. The shallow freshwater aquifer is protected by the surface and intermediate casing in the proposed Agave Red Hills AGI #1 well, which extend to 1,245 feet and 5,190 feet, respectively.

<u>Oil and Gas Resources Agave Red Hills AGI #1 Area of Review and Vicinity</u>

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 18 recorded wells within two miles of the Plant, of which five are active, one is zone plugged (temporarily abandoned), and 12 are listed as plugged and abandoned. Within the one-mile area of review for the proposed well, there are six wells, of which one is active and five are plugged and abandoned. These wells are shown in Figure 1-2.

Status of Cherry Canyon-Penetrating Wells Within One Mile

As shown in the Table 2 below, and in the accompanying Figure 1-1 in Attachment 1, there are a total of five wells penetrating the Cherry Canyon ("deep wells") in the one mile area of review, one active and four plugged and abandoned. A review of the available data indicates that the one active well (Madera Ridge 24 001) is cased and cemented throughout the Cherry Canyon interval, and that the abandoned wells are properly plugged and effectively seal the Cherry Canyon formation, preventing any migration of injected fluids to deeper or shallower units.

**Table 2: Summary of Wells Penetrating Cherry Canyon within One Mile of Proposed Red Hills Gas Plant**

| API # | OPERATOR | SPUD DATE | PLUG DATE | TOTAL DEPTH | WELL NAME | WELL TYPE | STATUS | ZONE | DIST |
|---|---|---|---|---|---|---|---|---|---|
| 3002526958 | BOPCO, L.P. | 4/13/81 | 12/26/07 | 15007 | SIMS 001 | Gas | Plugged | Morrow | 0.35 |
| 3002526369 | EOG RESOURCES INC | 9/15/79 | 10/8/90 | 14698 | GOVERNMENT L COM 002 | Gas | Plugged | Atoka | 0.38 |
| 3002525604 | EOG RESOURCES INC | 10/3/77 | 12/30/04 | 17625 | GOVERNMENT L COM 001 | Gas | Plugged | Morrow | 0.72 |
| 3002527491 | SOUTHLAND ROYALTY CO | 10/19/81 | 8/10/86 | 15120 | SMITH FEDERAL 001 | Oil | Plugged | Morrow | 0.79 |
| 3002529008 | EOG RESOURCES INC | 11/7/84 | | 15600 | MADERA RIDGE 24 001 | Gas | Active | Bone Springs | 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 Red Hills 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

The blowout preventer for the 17-1/2" intermediate hole will consist of a 20" 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 13-3/8" intermediate casing spool will consist

## III. PRESSURE CONTROL *See COA

The blowout preventer for the 24" and the 17-1/2" sections of hole will consist of a 21 ¼" X 2000 psi Hydril annular preventer. The 12 ¼" hole will be drilled using a 13 3/8" by 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 13-3/8" intermediate casing spool will consist of a 13-3/8" 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.

OK

## IV. CASING

**All well tubulars which would potentially be exposed to $H_2S$ will meet or exceed NACE MR0175, latest edition. The well design shown on the attached well bore diagram comply with applicable industry and API standards including, but not limited to the use and design of the Inconel alloy containing SSV and packer**

See COA

| TYPE | INTERVAL (MD) | HOLE SIZE | PURPOSE | CONDITION |
|---|---|---|---|---|
| 26", 136.3#/ft, Sch. 20 | 0'-48' | 32" | Conductor | New |
| 20", 94 #/ft, H40, STC | 0'-1245' | 24" | Surface | New |
| 13-3/8", 54.5#/ft, J55, STC | 0'-5,190' | 17-1/2" | Intermediate | New |
| 7", 26 #/ft, L80 (1), FJ | 0'-6,550' | 12-1/4" | Production | New |

CASING DESIGN SAFETY FACTORS

| TYPE | TENSION | COLLAPSE | BURST |
|---|---|---|---|
| 20", 94#/ft, H40 | 3.21 | 1.40 | 1.17 |
| 13-3/8", 54.5 #/ft, J55 | 1.20 | 1.32 | 2.30 |
| 7", 26#/ft, L80 (1) | 1.93 | 1.56 | 1.36 |

See Revision Recieved on 2/7/2012

DESIGN CRITERIA AND CASING LOADING ASSUMPTIONS *See COA

**The operator commits to keeping the casing liquid-filled to the greatest degree possible while running casing and cementing.**

SURFACE CASING – (20")

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

## IV. CASING

**All well tubulars which would potentially be exposed to $H_2S$ will meet or exceed NACE MR0175, latest edition. The well design shown on the attached well bore diagram complies with applicable industry and API standards including, but not limited to the use and design of the Inconel alloy containing SSV and packer.**

| TYPE | INTERVAL (MD) | HOLE SIZE | PURPOSE | CONDITION |
|---|---|---|---|---|
| 26", 136.5 #/ft, Sch. 20 | 0'-48' | 32" | Conductor | New |
| 20", 106.5 #/ft, J-55, STC | 0'-1,355' | 24" | Surface | New |
| 13-3/8", 68 #/ft, J-55, STC | 0'-5,190' | 17-1/2" | Intermediate | New |
| 7", 26 #/ft, L-80, LTC | 0'-6,550' | 12-1/4" | Production | New |

CASING DESIGN SAFETY FACTORS

| TYPE | TENSION | COLLAPSE | BURST |
|---|---|---|---|
| 20", 106.5 #/ft, J-55, STC | 6.33 | 1.19 | 0.88 |
| 13-3/8", 68 #/ft, J-55, STC | 1.91 | 1.42 | 1.13 |
| 7", 26 #/ft, L-80, LTC | 3.00 | 1.76 | 2.36 |

DESIGN CRITERIA AND CASING LOADING ASSUMPTIONS * See COA

**The operator commits to keeping the casing liquid-filled to the greatest degree possible while running casing and cementing.**

SURFACE CASING – (20")

Tension A minimum 1.8 safety factor utilizing the effects of mud buoyancy (9.2 ppg).

Collapse A minimum 1.125 safety factor with full internal evacuation inside the casing string and a collapse force equal to the mud gradient in which the casing will be run (0.48 psi/ft).

Burst A minimum safety factor with an internal burst force at the shoe equal to the mud hydrostatic pressure at the next casing depth. No backup pressure is utilized. Safety factor of 0.88 has been discussed with BLM.

INTERMEDIATE CASING – (13-3/8") — See COA

Tension A minimum 1.8 safety factor utilizing the effects of mud buoyancy (10.2 ppg).

*See COA Collapse A minimum 1.125 safety factor with 50% internal evacuation inside the casing string and a collapse force equal to the mud gradient in which the casing will be run (0.53 psi/ft).

Burst A minimum 1.0 safety factor with an internal burst force at the shoe equal to the mud hydrostatic pressure at the next casing depth. No backup pressure is utilized.

PRODUCTION CASING – (7")

Tension A minimum 1.8 safety factor utilizing the effects of mud buoyancy (9.0 ppg).

| | |
|---|---|
| Collapse | A minimum 1.125 safety factor with full internal evacuation inside the casing string and a collapse force equal to the mud gradient in which the casing will be run (0.47 psi/ft). |
| Burst | A minimum 1.0 safety factor with an internal burst force at the shoe equal to the mud hydrostatic pressure at that depth. No backup pressure is utilized. |

## V. CEMENT

**The cementing program is summarized in the table below:**

| INTERVAL | AMOUNT (SACKS) | FT OF FILL | EXCESS | TYPE | ADDITIVES | GALS/SX | PPG | FT³/SX |
|---|---|---|---|---|---|---|---|---|
| **Surface** | 2,000 | 1,355 | 100% | Class C | 2% CaCl | 6.39 | 14.8 | 1.35 |
| **Intermediate** | 2,600 | 4,190 | 50% | Class C (Lead) | 2%CaCl | 10.19 | 12.8 | 1.90 |
| | 650 | 1,000 | 25% | Class C (Tail) | | 6.39 | 14.8 | 1.35 |
| **Production** (See COA) | | | | | | | | |
| Stage 1 (6,550-5,550) | 760 | 1,000 | 25% | CorrosaCem (Tail) | 0.5% $Fe_2$ (Buffer) | 3.44 | 15.0 | 0.91 |
| Stage 2 (5,550-Surface) | 2,950 | 4,200 | 50% | Class C (Lead) | 1 lb/sx Pheno Seal (Lost Circ additive) | 15.39 | 11.7 | 1.30 |
| | 1,500 | 1,350 | 25% | Class C (Tail) | 2% CaCl | 6.39 | 14.8 | 1.35 |

**Note: The number of sacks of cement included in the table above accounts for the excess based on calculated hole volumes. During actual cementing operations, hole caliper logs will be used to determine actual hole volumes, and the additional 25-100% excess will be added as required to achieve the desired excess amounts.**

## VI. MUD PROGRAM

| DEPTH | MUD TYPE | WEIGHT | FV | PV | YP | FL | Ph |
|---|---|---|---|---|---|---|---|
| 0'-1,355' | FW Spud Mud | 8.5-9.2 | 38-70 | NC | NC | NC | 10.0 |
| 1,355'-5,190' | Brine Water | 9.8-10.2 | 28-30 | NC | NC | NC | 9.5-10.5 |
| 5,190'-6,550' | FW/Gel | 8.7-9.0 | 28-36 | NC | NC | NC | 9.5-10.0 |

The borehole for the surface casing will be drilled with a 24" bit to a depth of 1,355 ft, and 20", 106.5 #/ft, J-55, STC surface casing will be installed and cemented to the surface with approximately ~~1,800~~ 2,000 sacks of cement including 100% excess (or amount adequate to circulate the cement to the surface). The intermediate hole will be drilled with a 17-1/2" bit to a depth of 5,190 ft. A 13-3/8", 68 #/ft, J-55, STC intermediate casing string will be run and cemented to surface with approximately 3,250 sacks of cement (or amount adequate to circulate the cement to the surface). Visual inspections of cement returns to the

* See COA

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.

* The cementing of the 7", 26 #/ft, L-80, LTC production string will be accomplished in two stages. The first stage will seal the annular space from total depth (6,550 feet) to a level well above the Corrosion Resistant Alloy joint at approximately 6,170 ft. This stage will employ acid resistant cement (CORROSACEM$^{TM}$ or equivalent). For the second stage, a DV Tool previously inserted in the casing will be used to pump the remaining cement to the surface.

See COA

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.

The cementing of the production string will be accomplished in two stages. The first stage will seal the annular space from total depth (approximately 6,550 feet) to a level well above the Corrosion Resistant Alloy (CRA) joint at approximately 6,170 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 3,000) feet will be used to pump the remaining cement to the surface.

OK

## 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 Bell Canyon and the Cherry Canyon. A conventional core will be collected from the tight zone near the base of the Bell Canyon into the upper Cherry Canyon target reservoir sands. Representative core samples will be analyzed in the laboratory to determine caprock and reservoir permeability and porosity.

See COA

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 CRA 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.

See COA

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.

## VIII. PRESSURES, TEMPERATURES, LOST CIRCULATION ZONES, H2S

The conditions in the reservoir are anticipated to be a reservoir pressure of approximately 2,600 psi with a bottom hole temperature of approximately 112° F. There are no anticipated lost circulations zones or $H_2S$ 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 Red Hills 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 approximately 175 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 6,550 feet of 3-1/2 inch, 9.3 ppf, L80 ULTRA FX premium thread tubing, and an SSV will be run into the well. A ¼ inch 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 CRA 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

Suitability of Proposed Injection Zone and Demonstration of Lack of Hydrocarbons

Based on the geologic analyses of the subsurface at the proposed Red Hills Gas Plant, we recommend acid gas injection and $CO_2$ sequestration in the uppermost Cherry Canyon Formation. The proposed injection interval includes five high porosity sandstone units and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool of Bell Canyon Formation (Figure 8). There are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the proposed injection zone indicates that the injected $H_2S$ and $CO_2$ will be easily contained close to the injection well.

The geophysical logs were examined for all wells penetrating the Cherry Canyon Formation within a three-mile radius of the proposed Agave Red Hills AGI #1 well. Using the formation tops from more than 70 wells, a contour map was constructed for the top of the Cherry Canyon Formation in the vicinity of the well. This map reveals an approximate 1.0° dip to the south, with no visible faulting or offsets that might influence fluid migration, suggesting that injected fluid would spread radially from the point of injection with a small elliptical component to the south. This interpretation is supported by cross-sections of the overlying stratigraphy that reveal relatively horizontal contacts between the units (Figures 9-10). Local heterogeneities in permeability and porosity will exercise significant control over fluid migration and the overall three-dimensional shape of the injected gas plume.

A geological analysis confirms that the upper Cherry Canyon Formation as the most promising injection zone in the vicinity of the proposed Agave Red Hills AGI #1 well. This preliminary analysis is confirmed by Geolex's detailed geological analysis, including the analysis of the geophysical logs collected from nearby wells. The zone has the requisite high porosity and permeability and is bounded by tight limestones, shales, and calcic siltstones rocks in the Bell Canyon above and the lower Cherry Canyon and Brushy Canyon below. These are ideal $H_2S$ and $CO_2$ sequestration conditions.

**Ochoa Series.** The youngest of the Permian sediments are referred to as the Ochoa Series. These sediments were deposited in arid to semi-arid conditions, near the shore of the sea filling the Delaware Basin. Red beds of terrigenous sands in the Rustler Formation resulted from Eolian sediment transport. These red beds grade downwards into evaporates of the Salado and Castile Formations that were deposited in supra and intertidal flats.

**Guadalupe Series.** Sediments in the underlying Guadelupe Series are marine and were deposited within the basin at depths that varied due to numerous changes in sea-level. The sediments are predominately quartz-rich and terrigenous in origin. The quartz-rich sands are fine grained and poorly cemented. They have been interpreted to be channel deposits, resulting from density currents carrying sediments of the shelf through submarine canyons. The sandstones are interspersed with fine-grained rocks and limestones that taper with distance from the shelf. The limestones consist of laminated micrites and result from the transport of carbonate from the shelf in suspension. Limited amounts of coarse carbonate detritus have been attributed to density currents from shallow water on the shelf. The top of the Guadalupe Series is locally marked by the Lamar Limestone, which is the source of hydrocarbons found directly beneath it in the Delaware Sand (an upper member of the Bell Canyon Formation). The Bell Canyon, Cherry Canyon, and lowermost Brushy Canyon are all characterized by alternating units of channel sands with limestones and fine-grained sediments. The Cherry Canyon has notably more discrete units than the Brushy Canyon. The relatively fine-grained sands coarsen towards the base of the Brushy Canyon.

**Leonard Series.** The Leonard Series, located beneath the Guadalupe Series sediments, is characterized by basinal sediments similar to the Guadalupe. Locally, the Leonard Series consists exclusively of the Bone Springs Formation. The Bone Springs has less terrigenous material (sands) and more carbonates than the Guadalupe Series. The several, well defined sand units were deposited by sediments transported by density currents through submarine canyons. These sand units are associated with periods of high sea levels, while the thick intervening carbonate units are associated with lower sea levels.

The porosity of the units in the area were evaluated using geophysical logs collected from nearby wells penetrating the Cherry Canyon Formation. Figure 11 shows the Resistivity (Res) and Thermal Neutron Porosity (TNPH) logs from 5,050 feet to 6,650 feet and includes the proposed injection interval. Five clean sands (>10% porosity and <60 API gamma units) separated by limestone beds mapable units demonstrating lateral continuity of units. The sand units exhibit an average porosity of about 18.9%; taken over the average thickness of the clean sand units within ½ mile of the proposed Agave Red Hills AGI #1 of 177 feet (Figure 12) and irreducible water ($S_{wir}$) of 0.54. This results in an effective porosity of approximately 15.4 feet after considering $S_{wir}$. The overlying Bell Canyon Formation has 900 feet of sands and intervening tight limestones, shales, and calcitic siltstones with porosities as low as 4%, consistent with an effective seal on the injection zone. The proposed injection interval is located more than 2,650 feet above the Bone Spring Formation (Avalon zone), which is the next possible pay in the area.

Calculated Areas of Fluid Injection

No direct measurements have been made of the injection zone porosity or permeability. However, satisfactory injectivity of the injection zone can be inferred from the porosity logs described above. The good injectivity of the zone is supported by the performance of nearby SWD wells. Four SWD wells are located within a 7.5-mile radius, injecting into the same zone; the closest is about 2.0 miles away (Vaca Ridge 30 Federal 001; Figure 5). The Vaca Ridge 30 Federal 001 has been injecting since 1994 on vacuum (no recorded injection pressure) at rates of up to 5,000 bbl/day.

A maximum allowable surface injection pressure was calculated for the proposed AGI well following the NMOCD approved formula: $IP_{max} = PG (D_{top})$, where $IP_{max}$ is the maximum allowed surface injection pressure (psi), PG is the pressure gradient of the injected fluid (psi/ft), and $D_{top}$ is the depth to the top of the perforated zone (ft). Using the proposed depth to the perforated zone in the Red Hill AGI #1 well (6,230 ft) and TAG as the injection fluid, the maximum allowable injection pressure would be approximately 2,085 psi. This value is significantly higher than the maximum allowable injection pressure for saltwater (approximately 1,240 psig), due to the lower specific gravity of TAG.

The reservoir pressure and temperature have been estimated by plotting data from nearby wells. A plot of bottomhole temperatures (Figure 6a) reveals a consistent trend with depth, indicating that the reservoir temperature in the proposed well would be approximately 112° F. A plot of reservoir pressures using successful Drill Stem Tests (DSTs) show some scatter, but indicates that the reservoir pressure in the proposed well would be about 1,600 psi (Figure 6b).

Using the total porosity determined from well logs, combined with an allowance for $S_{wir}$ of 0.54, it is possible to estimate the area of injection over a 30-year life span for an AGI well at the proposed Red Hills Gas Plant. The anticipated TAG composition for this well will be 95% $CO_2$ and 5% $H_2S$. Assuming a maximum injection rate of 13 MMSCFD (7,343 bbl/day of compressed TAG at well head conditions equates to approximately 5,692 bbl/day at reservoir conditions), acid gas would spread to cover an area of approximately 532 acres or a circle with a radius of approximately 0.51 miles (Figure 7). This maximum injection rate is roughly equivalent with the Vaca Ridge 30 Federal 001 injecting into the same zone two miles away.

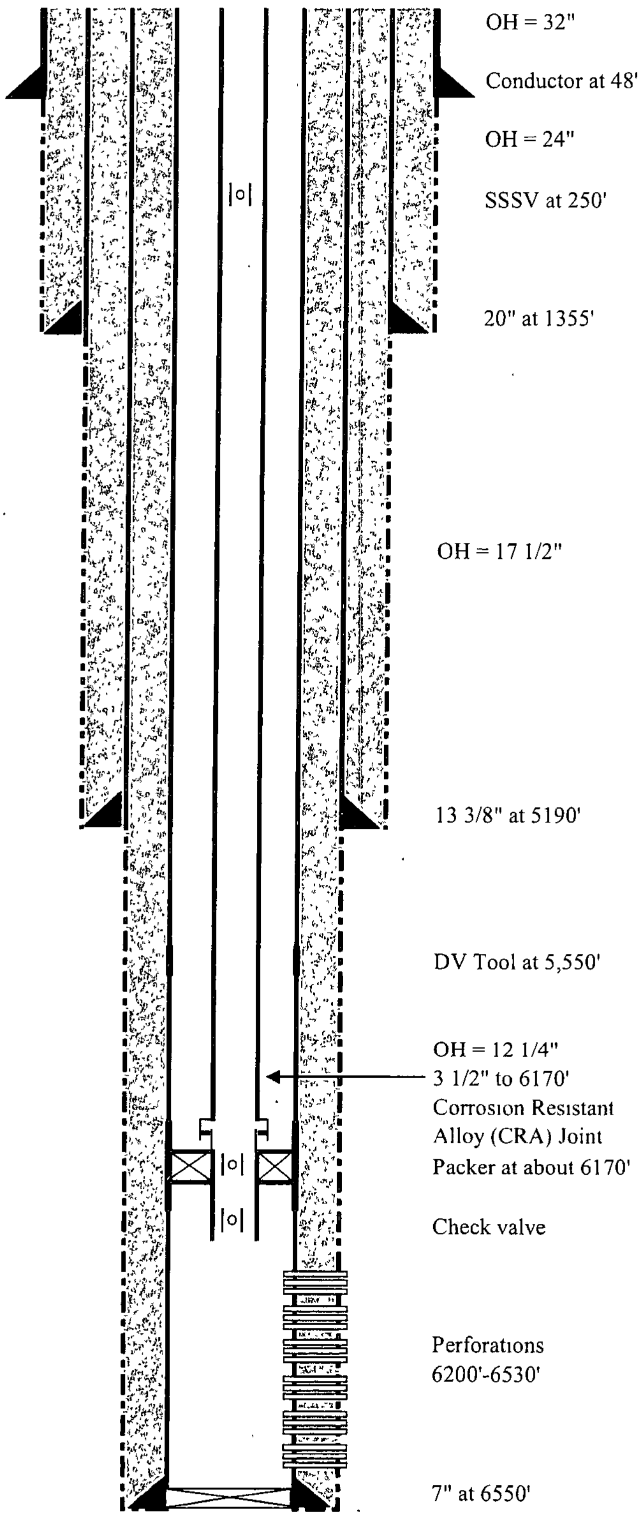
**Table 3: Calculations of Area and Volume of Reservoir Affected by Proposed Injection**

| | Maximum Injection Rate – 13 MMSCFD of TAG |
|---|---|
| Barrels per Day at Reservoir Conditions | 5,692 |
| Cubic Feet/Day (5.6146 Cubic Feet per Barrel) | 31,957 |
| Cubic Feet/ Year (365.25 Days) | 11,672,385 |
| Cubic Feet in 30 Years | 350,171,549 |
| Effective Porosity in Feet = 15.4 feet | |
| Net Area Consumed (Volume/eff. porosity) (ft) | 22,791,369 |
| Net Area in Acres (43,560 Sq. feet/acre) | 523 |
| | |
| Radius in feet | 2,693 |
| Radius in miles | 0.51 |

* See COA for Completion Sundry

# AGAVE RED HILLS AGI #1
# PROPOSED WELLBORE

**Location:** RED HILLS PLANT
**STR** S13-T24S-R33E
**County, St.:** LEA, NEW MEXICO




TD: 6550'

**CONDUCTOR PIPE**
26", 136.5 #/ft, Sch. 20 at ~48'

**SURFACE CASING**
20", 106.5 #/ft, J55, STC at top of Rustler ~ 1355'

**INTERMEDIATE CASING:**
13 3/8", 68 #/ft, J55, STC at base of salt ~ 5190'

**PRODUCTION CASING:**
7", 26 #/ft, L80, LTC at 6550'

**TUBING:**
Subsurface Safety Valve at 250 ft

3 1/2", 9 3#/ft, L80, Premium thread at 6170'

**PACKER:**
Permanent Production Packer

Check valve (optional)

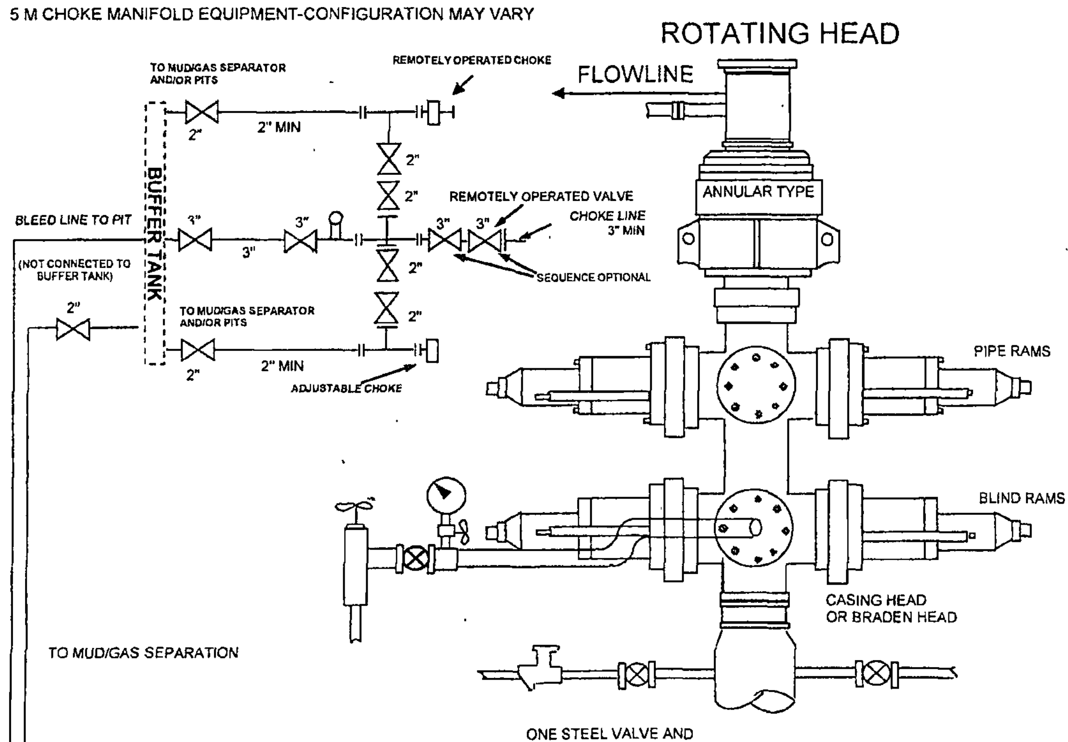
**PERFORATIONS:**

| Primary Target | Secondary Target |
|---|---|
| Upper Cherry Canyon Fm | |
| at approx. (6200'-6530' | |

# 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 sufffficient 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.

*Possible Mud/gas Separator Onshore Order #6*

TO STEEL MUD TANKS 75 feet

BLEED LINE TO FLARE PIT OR 180 feet

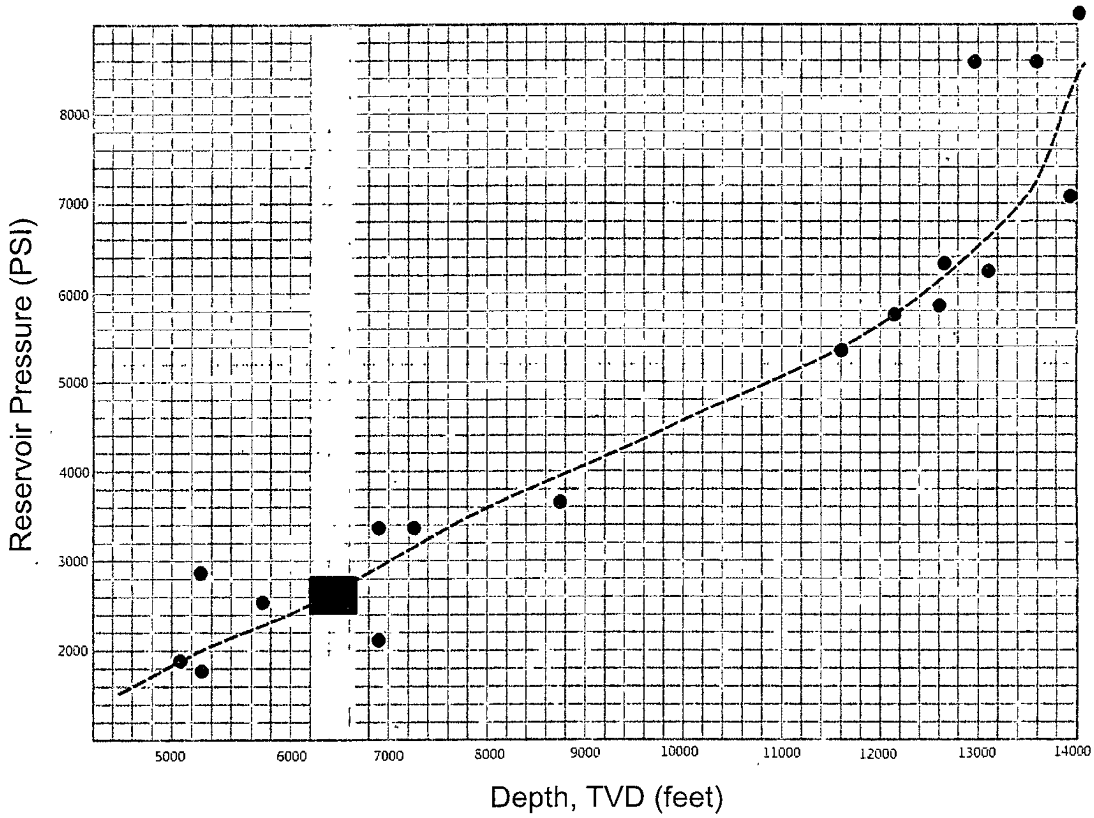



Figure 6a Plot of Reservoir Temperatures as a Function of Depth at Wells in the Vicinity of the Proposed Red Hills AGI #1. Yellow Bar Indicates the Planned Injection Depth for the Well.

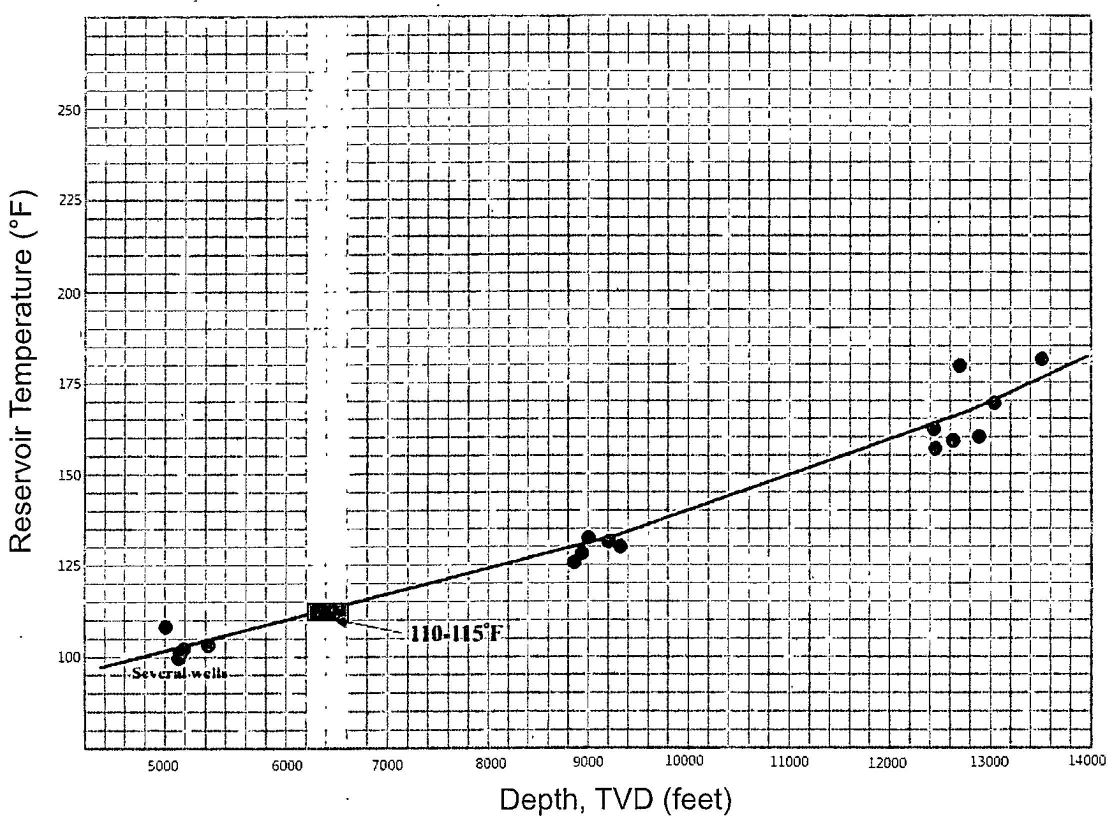



Figure 6b Plot of Reservoir Pressures Measured During Drill Stem Tests (DSTs) at Wells in the Vicinity of the Proposed Red Hills AGI #1. Yellow Bar Indicates the Planned Injection Depth for the Well.

ATTACHMENT C

HYDROGEN SULFIDE DRILLING OPERATIONS PLAN, MALJAMAR AGI #1