MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and AGI #2

Lucid Energy Delaware, LLC (Lucid)

Version 3.0
September, 2021

Contents

1 Introduction

Lucid Energy Delaware, LLC (Lucid) is currently authorized to inject a total of up to 13 million standard cubic feet per day (MMSCF/D) of treated acid gas (TAG) in the currently-approved Red Hills (RH) AGI #1 well (API 30-025-40448) under the New Mexico Oil Conservation Commission (NMOCC) Orders R-13507 – 13507F at the Lucid Red Hills Gas Plant located approximately 15 miles NNW of Jal in Lea County, New Mexico (Figure 1-1).

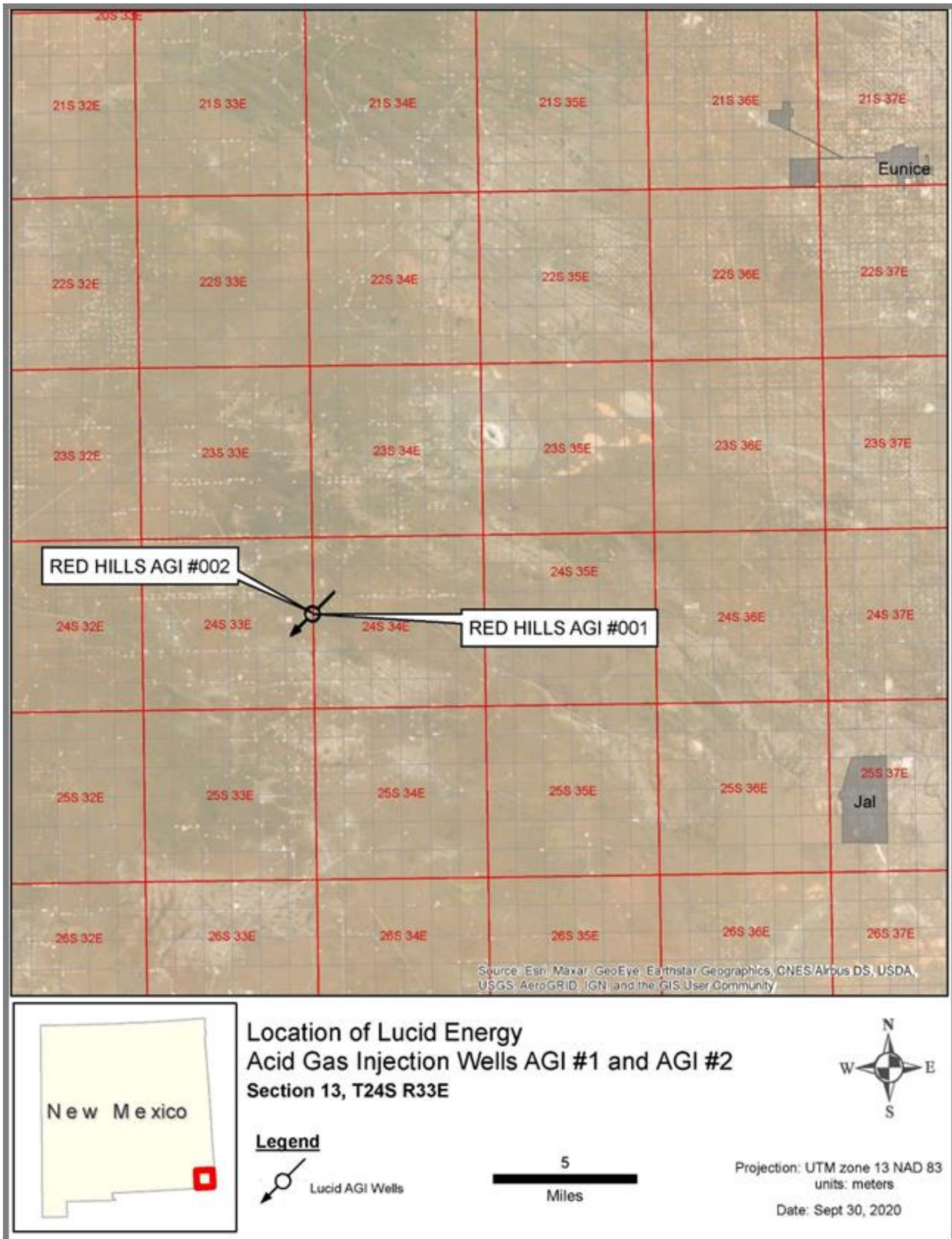


Figure 1-1 -- Location of the Red Hills Gas Plant and Wells – RH AGI #1 and RH AGI #2

Recently, Lucid received authorization to construct a redundant well, RH AGI #2 (API # not yet assigned) under NMOCC Order R-20916-H, which will be offset 200 feet to the north of RH AGI #1 and completed approximately 9,350 feet deeper than RH AGI #1. The newly permitted RH AGI #2 is authorized to inject to dispose of TAG at a maximum daily injection rate of 13 million standard cubic feet per day (MMSCF/D) into the Devonian and Upper Silurian Wristen and Fusselman Formations at depths of approximately 16,000 to 17,600 feet with a maximum surface injection pressure of approximately 4,838 pounds per square inch gauge (psig). Authorization of the second well, RH AGI #2, provides increased capacity for the Red Hills Gas Plant expansion and accommodates the ability to sequester additional significant amounts of CO_2.

Lucid has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to EPA for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Lucid intends to inject CO_2 for another 30 years.

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage.

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 11 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is **553798**

2.2 UIC injection well identification numbers

This MRV plan is for RH AGI #1 and RH AGI #2 (Appendix 1). The details of the injection process are provided in Section 3.8.

2.3 UIC permit class

For injection wells that are the subject of this MRV plan, the New Mexico Oil Conservation Division (NMOCD) has issued Underground Injection Control (UIC) Class II acid gas injection (AGI) permits under its State Rule 19.15.26 NMAC (see Appendix 2). All oil- and gas-related wells within the UIC Class II one-mile radius area of review (AoR) around the RH AGI wells, including both injection and production wells, are regulated by the NMOCD, which has primacy to implement the UIC Class II program.

3 Project Description

Much of the following project description has been taken from the Class II permit applications for the RH AGI #1 well prepared by Geolex, Inc. for Agave Energy Company, dated 20 July 2011, and for the RH AGI #2 well, also prepared by Geolex, Inc. for Lucid Energy Delaware, LLC, dated 8 August 2019. These two Class II applications required the delineation and characterization of the AoR which is occasionally referenced below. Both applications were submitted to the NMOCD for approval.

3.1 General Geologic Setting / Surficial Geology

The Lucid Red Hills Gas Plant is located in T 24 S R 33 E, Section 13, in Lea County, New Mexico, immediately adjacent to the two RH AGI wells. (Figure 3.1-1). The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. 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 plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

3.2 Bedrock Geology

3.2.1 Basin Development

The Red Hills Gas Plant and the RH AGI wells are located at the northern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (Figure 3.2-1), which covers a large area of southeastern New Mexico and west Texas.

3.2.2 Stratigraphy

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Red Hills Gas Plant and RH AGI wells site. The thick sequences of Permian through Ordovician rocks are described below. Because we are discussing two different injection wells and zones, we are providing a general description of the stratigraphy of the area that includes both injection zones and their caprocks and underlying seals. Note that formations and lithologies are different for other parts of the Permian Basin.

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent), Guadalupe, Leonard, and Wolfcamp (oldest) (Figure 3.2-2). Numerous oil and gas pools have been identified in these rocks. In the area of the RH AGI wells, the rocks consist predominately of clastic rocks – primarily sands, and shales with lesser carbonates. Producing reservoirs are concentrated in the high porosity sands. Local oil production is largely restricted to the Delaware Sands. There is some production from both the Cherry Canyon and from the Ramsey Sand member of the Bell Canyon which is approximately 1,000 feet above the top of the Cherry Canyon Formation of the Delaware Mountain Group to the northeast of the Cherry Canyon injection zone in the RH AGI #1. Gas production is dispersed through the deeper Bone Spring (also referred to as "Avalon" by some operators in the area) and Wolfcamp Formation. The rock units of the Permian series are discussed in more detail below.

Figure 3.1-1 -- Map showing location of Lucid Red Hills Gas Plant and RH AGI Wells in Section 13, T 24 S, R 33 E

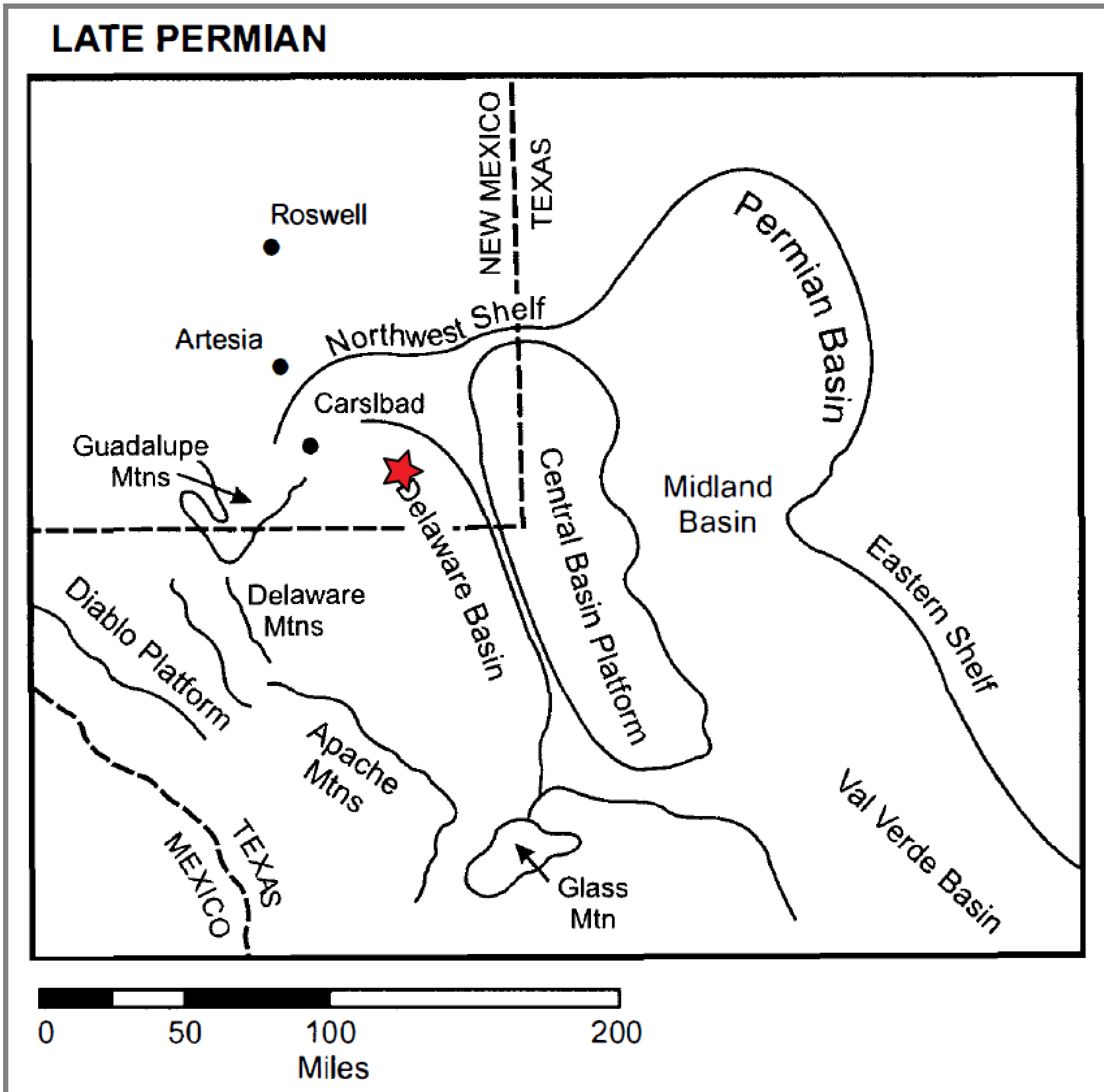


Figure 3.2-1 -- Structural features of the Permian Basin during the Late Permian. Location of the Lucid RH AGI wells is shown by the red star. (Modified from Ward, et al (1986))

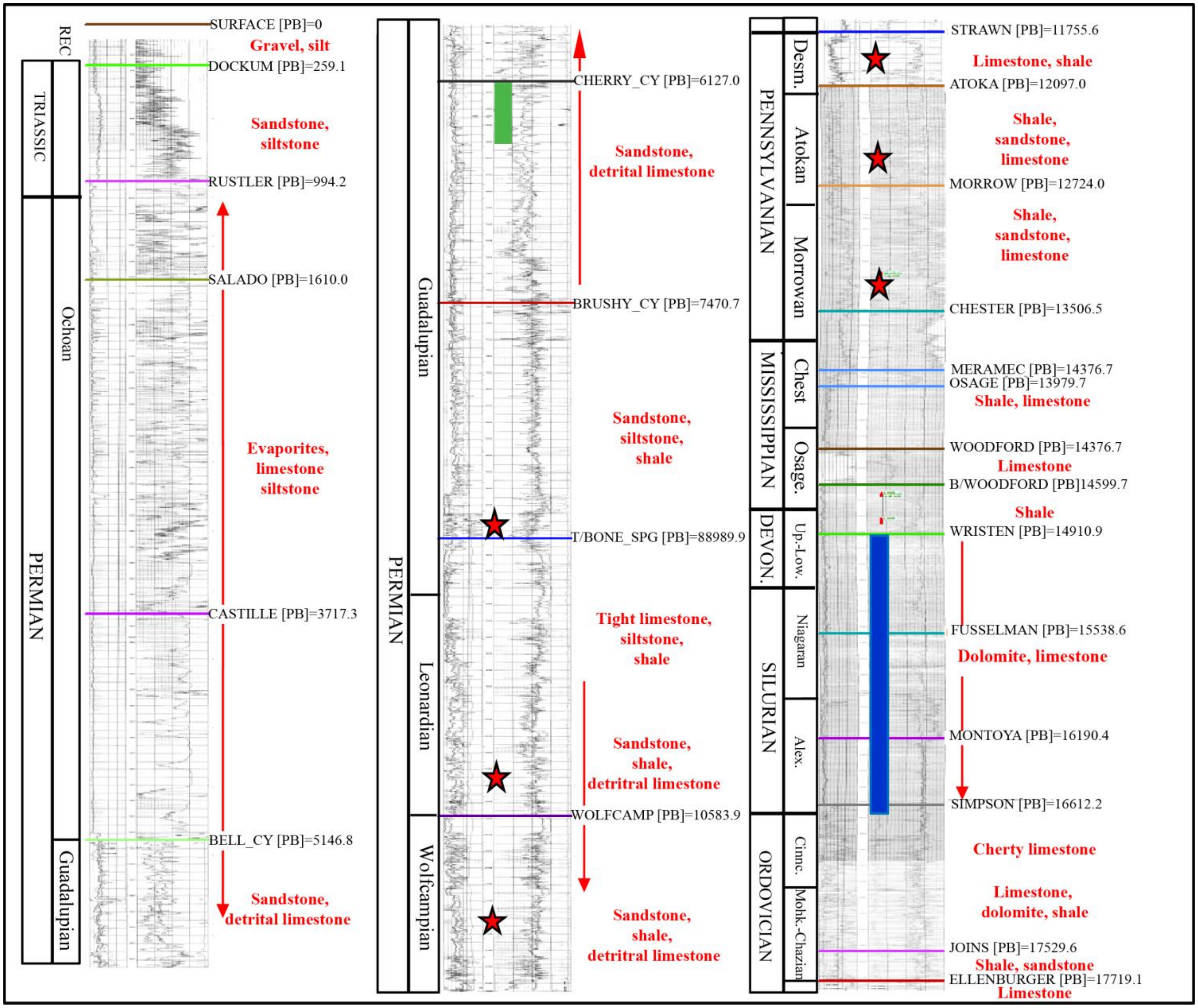


Figure 3.2-2 -- Stratigraphy and generalized lithologies of the formations underlying the Lucid RH AGI Wells.

Zones with active pay hydrocarbon production within the radii of investigation are shown by the red stars. The interval shown by the green bar is the injection zone for RH AGI #1. The injection interval for RH AGI #2, shown by the blue bar, includes the Devonian (Thirtyone Formation), and Silurian Wristen and Fusselman Formations, which contain intervals of karst-related solution enlarged and fracture porosity in dolomites that alternate with tight, dolomitic limestones. These formations are sufficiently isolated from the active pay zones by over 1,300 feet of tight, Mississippian (Chester through upper Woodford) limestones and shales.

CONFINING/SEAL ROCKS

Permian 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 supratidal and intertidal flats.

INJECTION ZONE FOR AGI #1

Permian Guadalupe Series. Sediments in the underlying Guadalupe 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 submarine fan complex channel deposits, resulting from density currents carrying sediments off the shelf through submarine canyons. The sandstones are interspersed with fine-grained siliciclastics 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. Collectively, the Bell Canyon, the Cherry Canyon and the Brushy Canyon formations are included in the Delaware Mountain Group. 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.

UNDERLYING CONFINING ZONE FOR AGI #1

Permian Leonard Series. The Leonard Series, located beneath the Guadalupe Series sediments, is characterized by basinal sediments similar to the Guadalupe although generally more carbonate rich. Locally, the Leonard Series consists exclusively of the Bone Spring Formation. The several, well-defined sand units within the Bone Spring 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.

Permian Wolfcamp Series. The Wolfcamp is extremely variable in lithology in response to changes in the environment of deposition. In the Red Hills area, it is composed of dark skeletal to fine-grained limestone, fine-grained sand to coarse silt, and shale in these basin facies. Horizontal wells are being drilled in the Bone Spring and Wolfcamp; however, most activity is primarily to the west of the Red Hills area.

Pennsylvanian. The Pennsylvanian is comprised of the Strawn, Atoka, Morrow, and Cisco-Canyon at the top of the pre-Permian section. Within this entire sequence, the Morrow is a major gas producing zone, with smaller contributions from the overlying Atoka and Strawn.

Mississippian. The Chester, Meramec, and Osage Formations comprise the Mississippian section. The Chester Formation consists of several hundred feet of shales and basinal limestones which are underlain by several hundred feet of Osage limestone. At the base of the Mississippian section and extending into the Upper Devonian is approximately 200 feet of Woodford Shale.

INJECTION ZONE FOR PROPOSED AGI #2

Devonian and Silurian. Underlying the Woodford Shale are the interbedded dolomites and dolomitic limestones of the Devonian Thirty-one Formation and the Silurian Wristen Formation, collectively often referred to as the Siluro-Devonian, and the Silurian Fusselman Formation. The proposed Devonian-Silurian injection zone for the RH AGI #2 well does not produce economic hydrocarbons closer than 15 miles away from the well site.

There have been no commercially significant deposits of oil or gas found in the Devonian or Silurian rocks in the vicinity of the RH AGI wells and there is no current or foreseeable production at these depths within the one-mile radius AoR (Figure 3.2-3). Adjacent wells have shown that these formations are primarily water-bearing and are routinely approved as produced-water disposal zones in this area.

UNDERLYING CONFINING ZONE FOR AGI #2

Ordovician. Below the Silurian Fusselman Formation lies about 400 feet of Ordovician Montoya cherty carbonates which overlies about 400 feet of Ordovician Simpson sandstones, shales, and tight limestones. These formations are underlain by the Ordovician Ellenburger Formation which is comprised of dolomites and limestones and is upward of 1,000 feet thick. The Ellenburger sits on the basement over a veneer of Early Ordovician sandstones and granite wash.

The entire lower Paleozoic interval (Ellenburger through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karst formation, most especially in the Ellenburger, Fusselman and Devonian. The result of this exposure was development of systems of karst-related secondary porosity, which included solution-enlargement of fractures and vugs, and development of small cavities and caves. Particularly in the Ellenburger and Fusselman, solution features from temporally distinct karst events became interconnected with each successive episode, so there could be some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability. The Ellenburger is well below either injection zone of interest, so it is unlikely to be affected by any proposed activity.

3.2.3 Faulting

In this immediate area of the Permian Basin, faulting is primarily confined to the lower Paleozoic section, where seismic data shows major faulting and ancillary fracturing-affected rocks only as high up as the base of the lower Woodford Shale (Figures 3.2-4 and 3.2-5). Faults that have been identified in the area are normal faults associated with Ouachita related movement along the western margin of the Central Platform to the east of the RH AGI well site. The closest identified fault lies approximately 1.5 miles east of the proposed site and has approximately 1,000 feet of down-to-the-west structural relief (Figure 3.2-4). During the public comment period for the Class II permit for the RH AGI #2 well, unsubstantiated claims were made of the existence of additional faults in the Siluro-Devonian underlying the Red Hill Gas Plant. Lacking evidence to verify this claim, Lucid chose to address the situation from a worst-case scenario. Section 3.5 presents a fault slip potential analysis considering the three faults shown in Figure 3.2-4 and the additional faults. Section 3.9 presents a simulation of the effects these faults may have on CO_2 plume extent. As stated above, Lucid sees no evidence that faults in the Siluro-Devonian extend upward through the confining zone (beginning with the Woodward Shale).

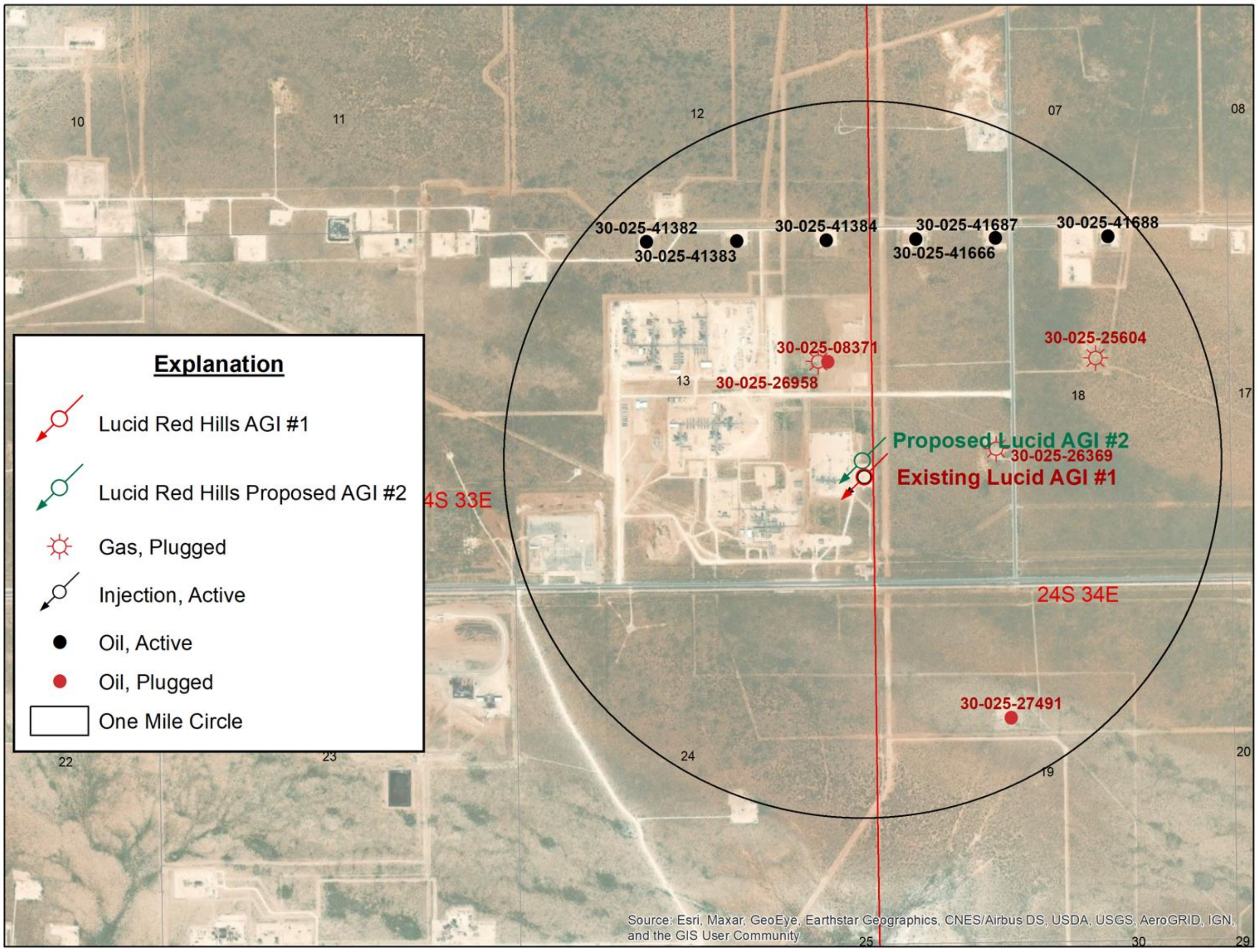


Figure 3.2-3 – Oil and gas production and saltwater (SWD) wells completed in the Siluro-Devonian in the vicinity of the RH AGI wells. The Class II one-mile radius AoR is also indicated.

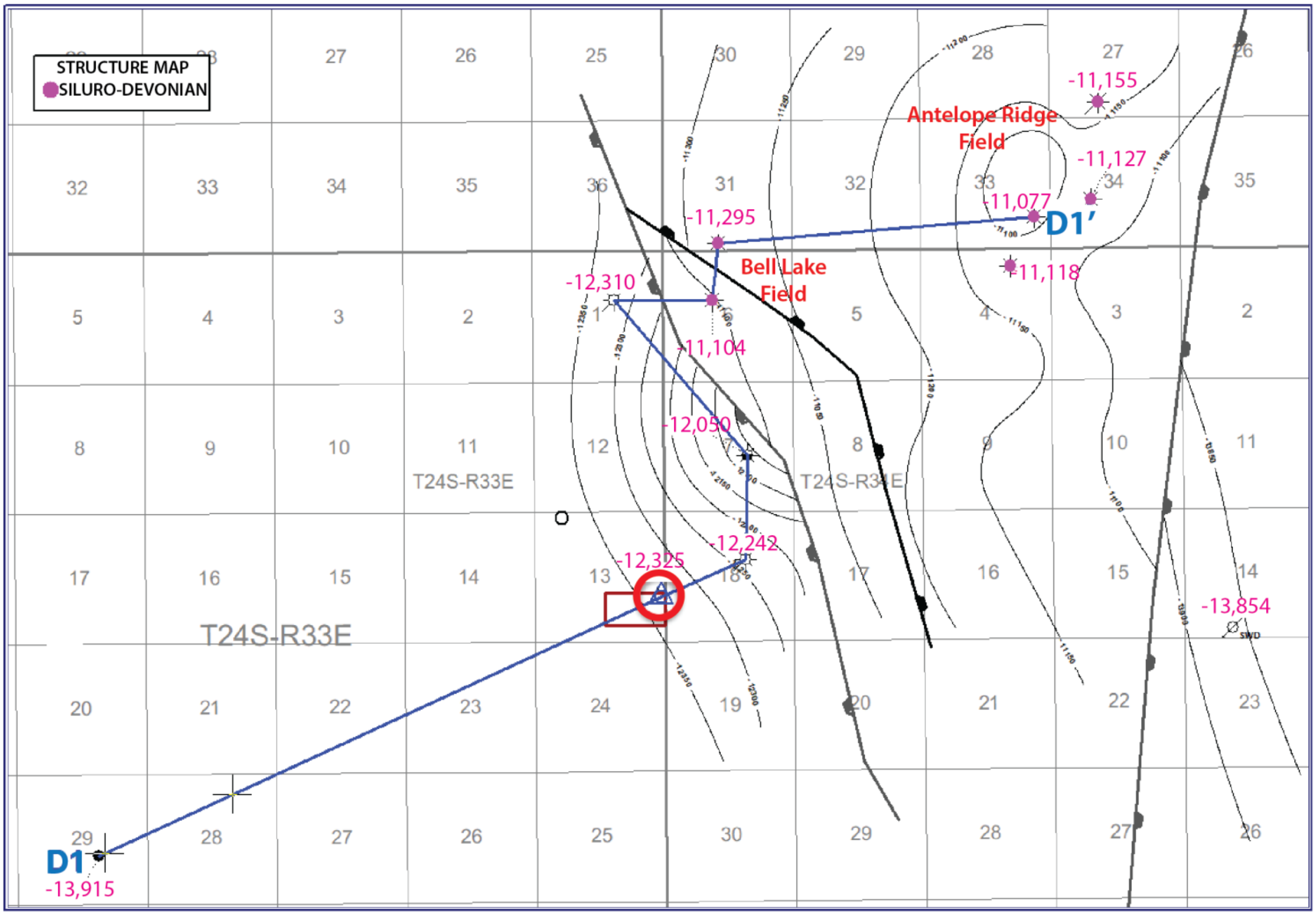


Figure 3.2-4 -- Structure on top of the Devonian and location of cross section D1-D1'

Map showing the only wells that penetrated below the Woodford shale in the area of the Lucid Red Hills AGI Wells (circled in red). Because of the sparsity of deep well control, the map was drawn from extension of the structural trend coming off the cluster of wells to the NNE. These limited number of control wells seem to indicate steep dip to the WSW. It has been suggested there is a high likelihood that faults are cutting the section as it comes off the Central Basin Platform margin to the east. The faults could only be estimated from the irregular spacing of the well control. Cross-section D1-D1' is discussed on Figure 3.2-5.

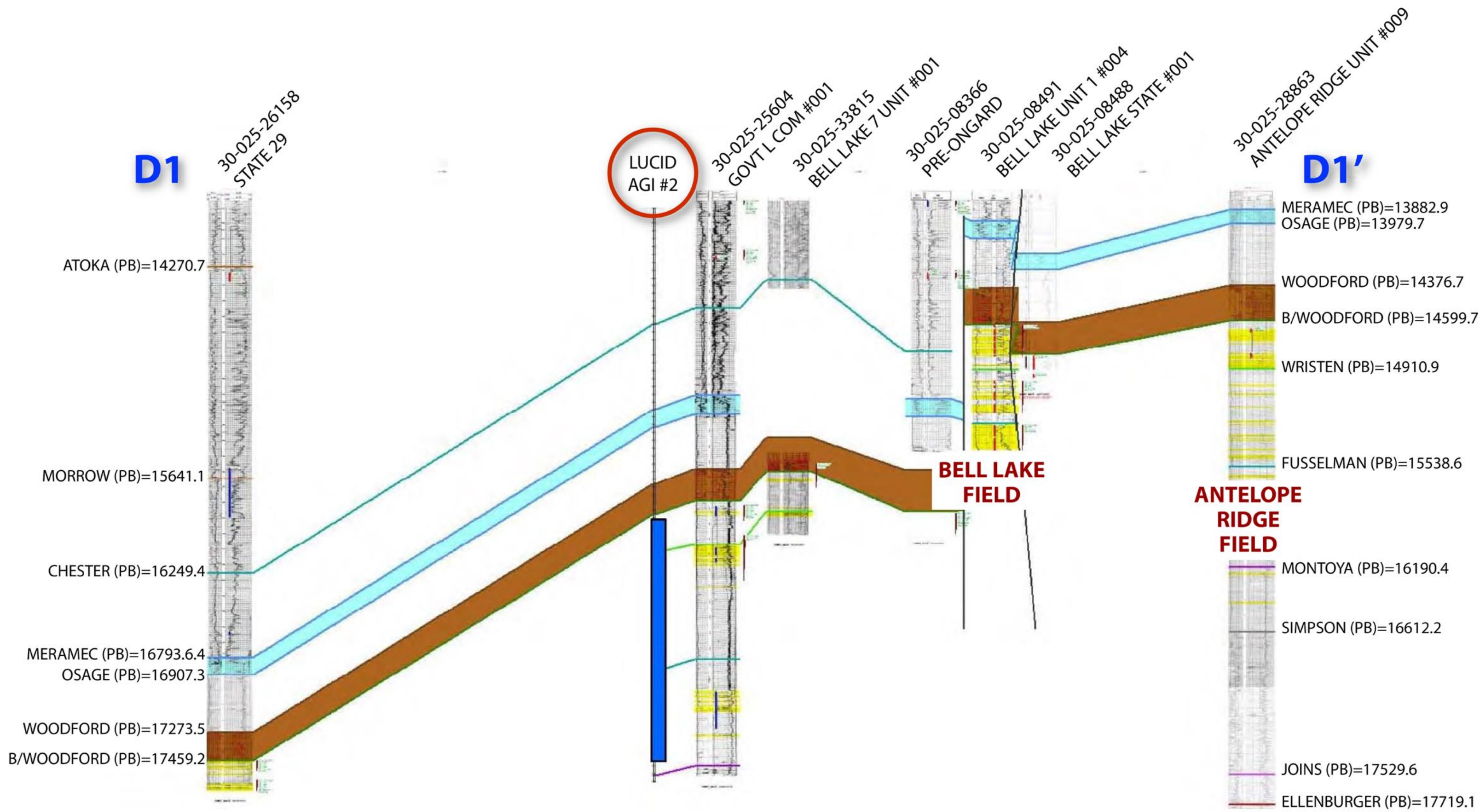


Figure 3.2-5 -- Structural cross section through the deeper horizons across the Red Hill Gas Plant Site

Yellow shading denotes porosity in the Siluro-Devonian section of 5% or greater, where it could be determined from porosity logs. Porosity is present in thin to thickly bedded sequences that are separated by tight and/or fractured carbonates. The proposed injection interval (blue bar) for the proposed RH AGI #2 would extend to the base of the Fusselman. The Siluro-Devonian interval is approximately 1,200 feet below the closest producing formation (Morrow) in the area.

3.3 Lithologic and Reservoir Characteristics

3.3.1 RH AGI #1 - Permian Cherry Canyon Formation

Based on the geologic analyses of the subsurface at the proposed Red Hills Gas Plant, the uppermost portion of the Cherry Canyon Formation was chosen for acid gas injection and CO_2 sequestration. This interval includes five high porosity sandstone units (sometimes referred to as the Manzanita) and has excellent caps above, below and between the individual sandstone units. There is no local production in the overlying Delaware Sands pool of the Bell Canyon Formation. There are no structural features or faults that would serve as potential vertical conduits. The high net porosity of the RH AGI #1 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 RH AGI #1 well. Figure 3.3-1 shows the location of two cross-sections through the Cherry Canyon Formation intersecting less than ½ mile east of the RH AGI #1 well. The cross-sections in Figures 3.3-2 and 3.3-3 reveal relatively horizontal contacts in the vicinity of the RH AGI #1 well between the units in a West-East direction and an approximately 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. Local heterogeneities in permeability and porosity will exercise significant control over fluid migration and the overall three-dimensional shape of the injected TAG. As these sands were deposited by turbidites in channels in submarine fan complexes, each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. As a result of their depositional environment, the preferred orientation for fluid and gas flow would be south-to-north along the channel axis.

The porosity was evaluated using geophysical logs from nearby wells penetrating the Cherry Canyon Formation. Figure 3.3-4 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) are targets for injection. Ten percent was the minimum cut-off considered for adequate porosity for injection. The sand units are separated by lime mudstone beds with lateral continuity. 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 RH AGI #1. There is an average of 177 feet (Figure 3.3-5) with an irreducible water (S_{wir}) of 0.54 (see Table 1 of the RH AGI #1 permit application). Many of the sands are very porous (average porosity of > 22%) and it is anticipated that for these more porous sands, the S_{wir} may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the estimated porosity feet (PhiH) of approximately 15.4 porosity-feet should be considered to be a minimum. 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.

Figure 3.3-1 – Map showing locations of W-E and N-S (Figures 3.3-2 and 3.3-3, respectively) cross-sections through the Cherry Canyon Formation and the one-mile radius AoR

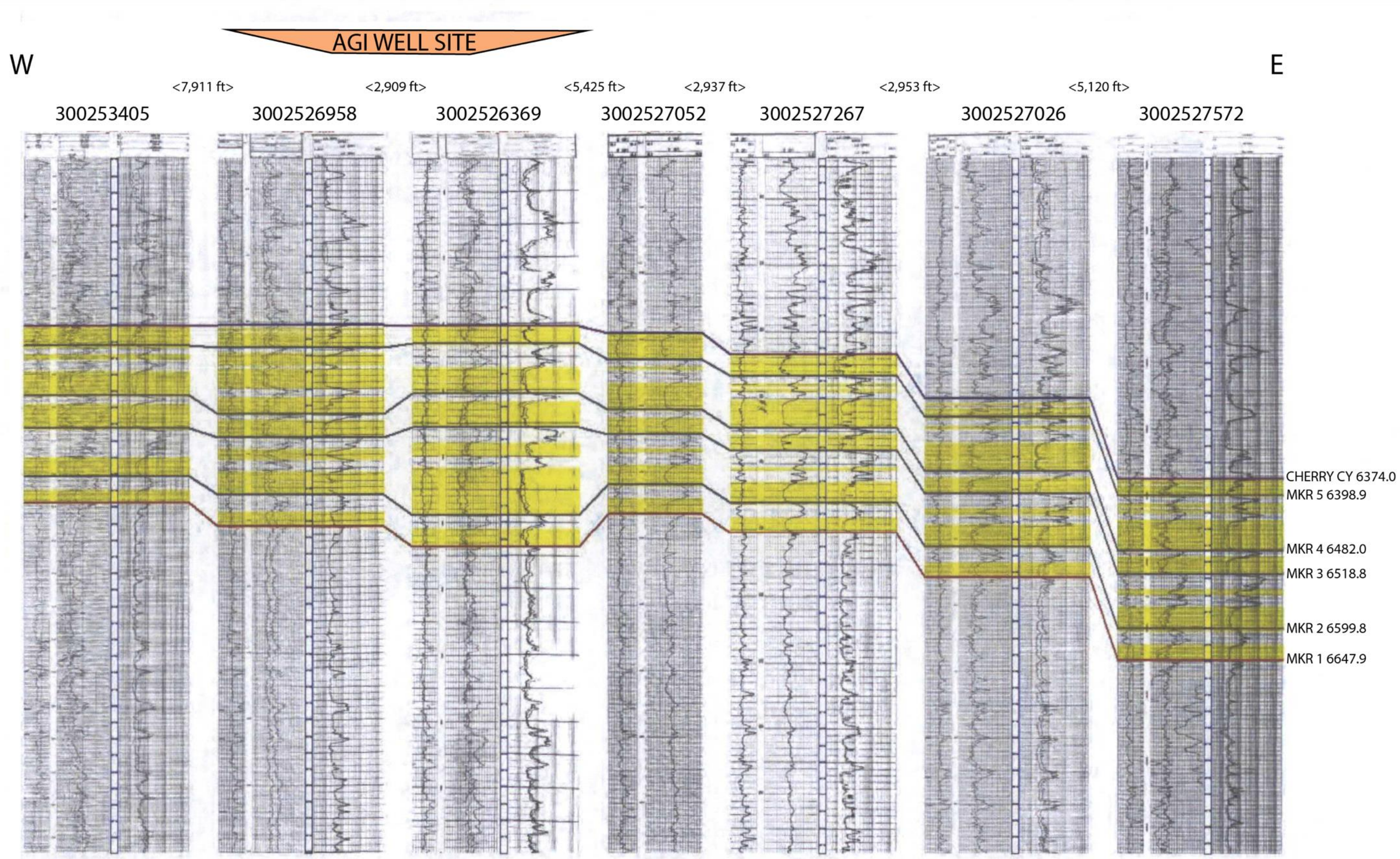


Figure 3.3-2 -- West – East cross section showing the 5 sand units of the Manzanita Zone of the Cherry Canyon Formation

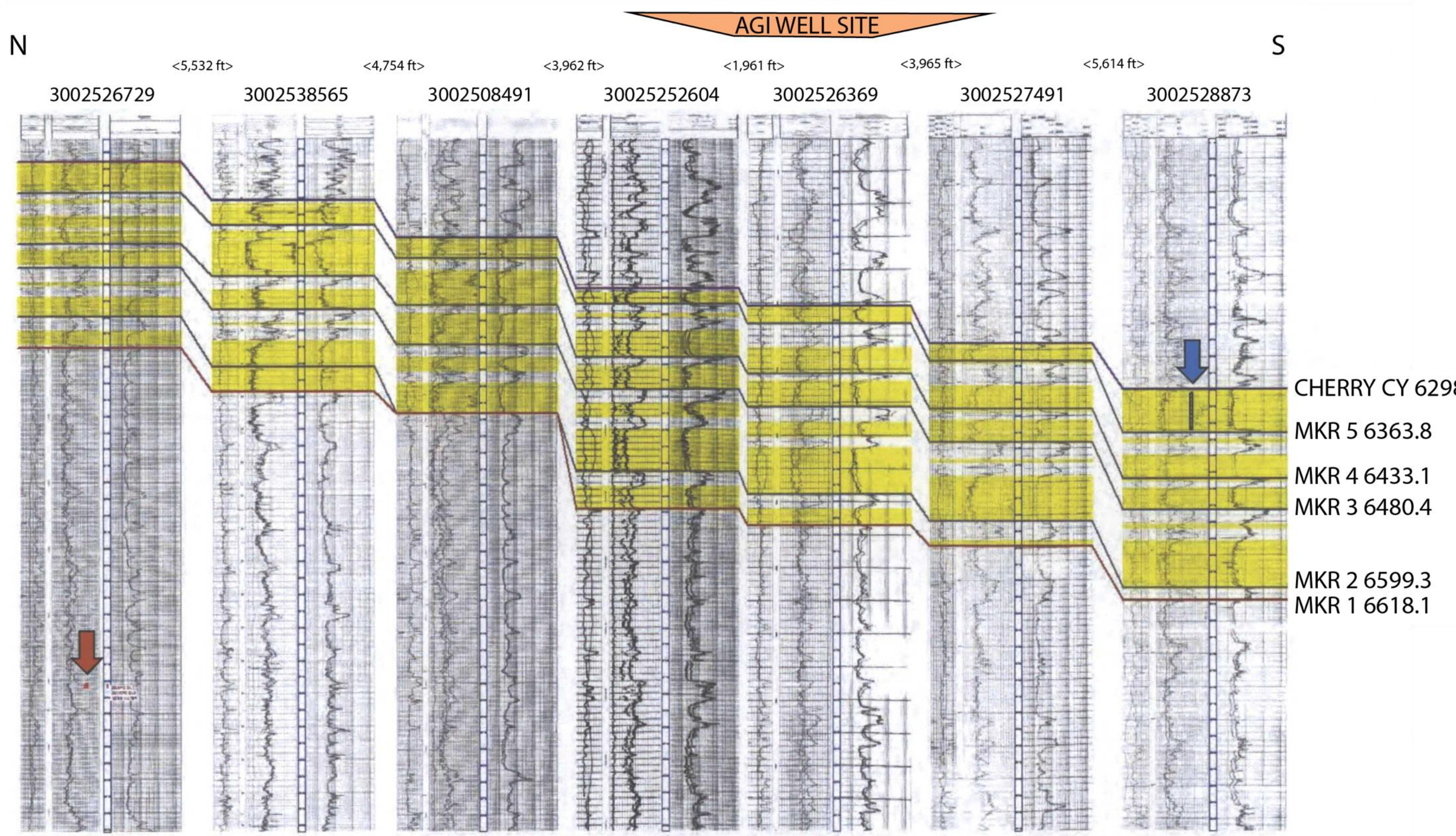


Figure 3.3-3 -- -- North - South cross-section showing the 5 sandstone units of the Manzanita Zone of the Cherry Canyon Formation

Note: Blue arrow shows injection interval of closest SWD well. Red arrow shows location of Cherry Canyon production within 2 wells located more than 2.5 miles to the north.

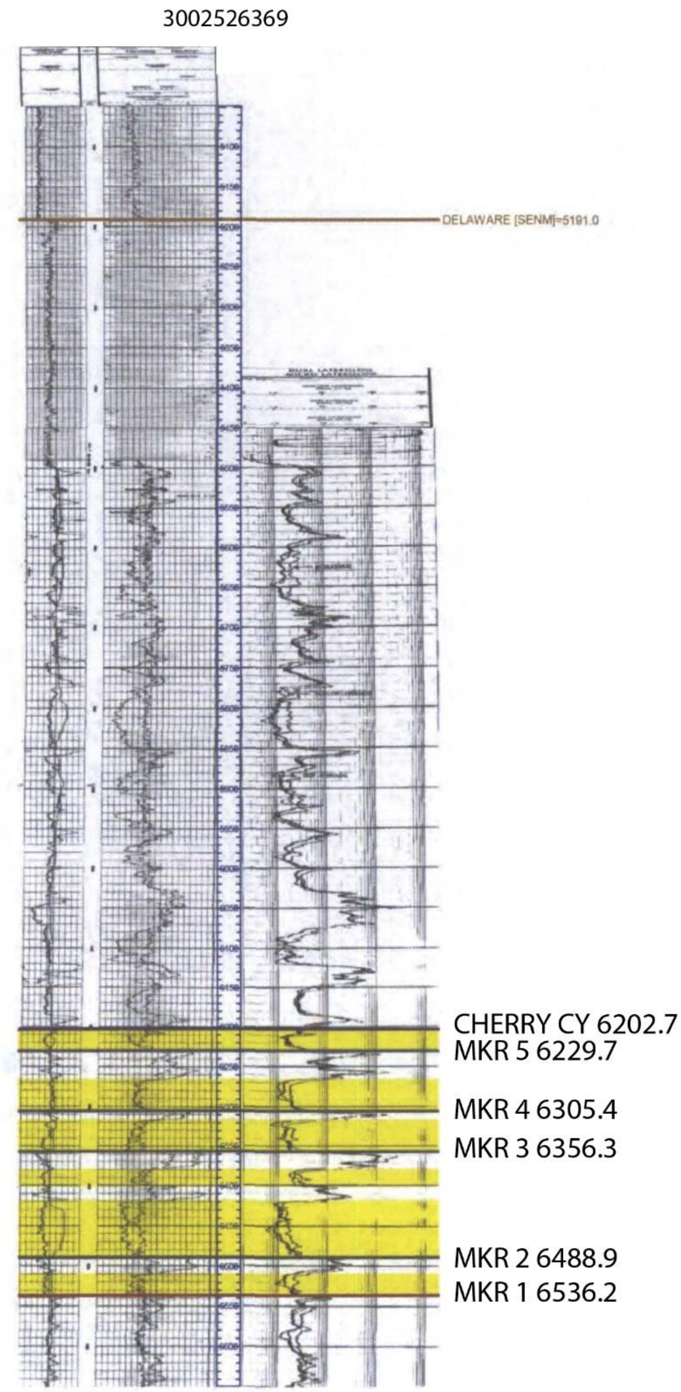


Figure 3.3-4 -- Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well

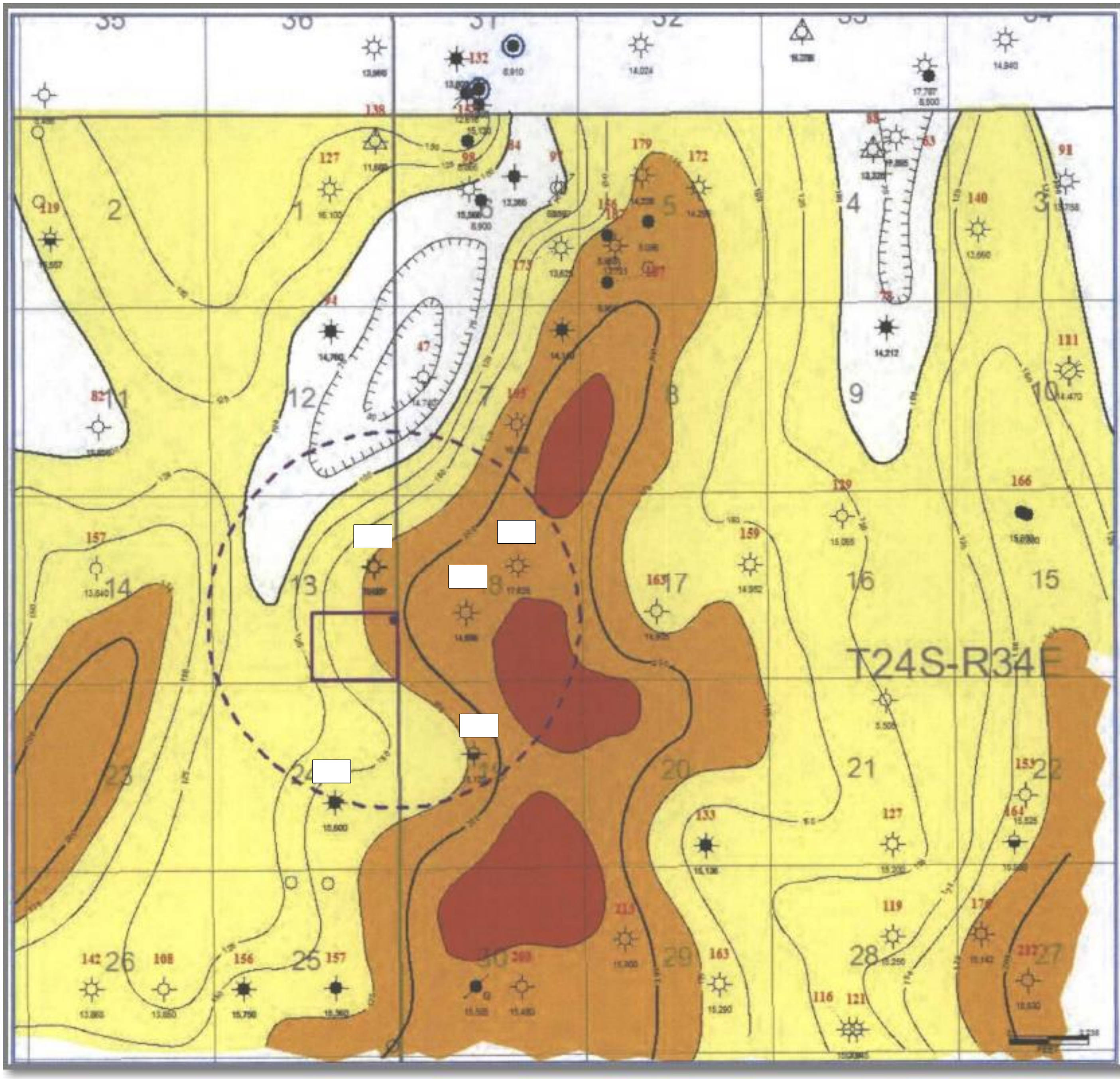


Figure 3.3-5 -- Map showing thickness of the clean sands in the Upper Cherry Canyon injection zone for RH AGI #1 and the one-mile radius AoR

Dark brown to light brown to yellow indicates thicker to thinner sequence of clean sands in the Upper Cherry Canyon.

3.3.2 RH AGI #2 - Siluro-Devonian Formations

The proposed injection interval for RH AGI #2 includes the Devonian Thirty-one and Silurian Wristen Formations, collectively referred to as the Siluro-Devonian and Silurian Fusselman Formation. These formations are common targets for SWD wells in the region. The proposed injection zone includes a number of intervals of dolomite and dolomitic limestones with moderate to high primary porosity, and secondary, solution-enlarged porosity that is related to karst events that periodically occurred throughout the section, most notably in the Fusselman Formation. These karst events produced solution cavities and enlarged fractures throughout the section, which can be substantial enough to provide additional permeability that is not readily apparent on well logs. The porous zones are separated by tight limestones and dolomites.

The Siluro-Devonian interval has excellent cap rocks above, below and between the individual porous carbonate units. There are no producing zones within or below the Siluro-Devonian in the area of the proposed RH AGI #2 well, and the injection interval is separated from the nearest producing zone (Morrow) by 200 feet of Woodford shale, 550 feet of tight Osagean limestones, and nearly 350 feet of tight Chesterian shales and deep-water limestones (Figure 3.3-6). The Siluro-Devonian interval is a minimum of 1,200 feet above the Precambrian basement.

The overlying Chester, Osage and Woodford Formations provide over 1,000 feet of shale and intervening tight limestones, providing an effective seal on the top of the injection zone. The proposed injection interval is located more than 1,000 feet below the Morrow Formation, which is the deepest potential pay zone in the area. There are no pay zones below the RH AGI #2 injection zone in the area (see Figures 3.2-2).

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 zone will be logged and cored in the RH AGI #2 well to obtain site-specific porosity and permeability data.

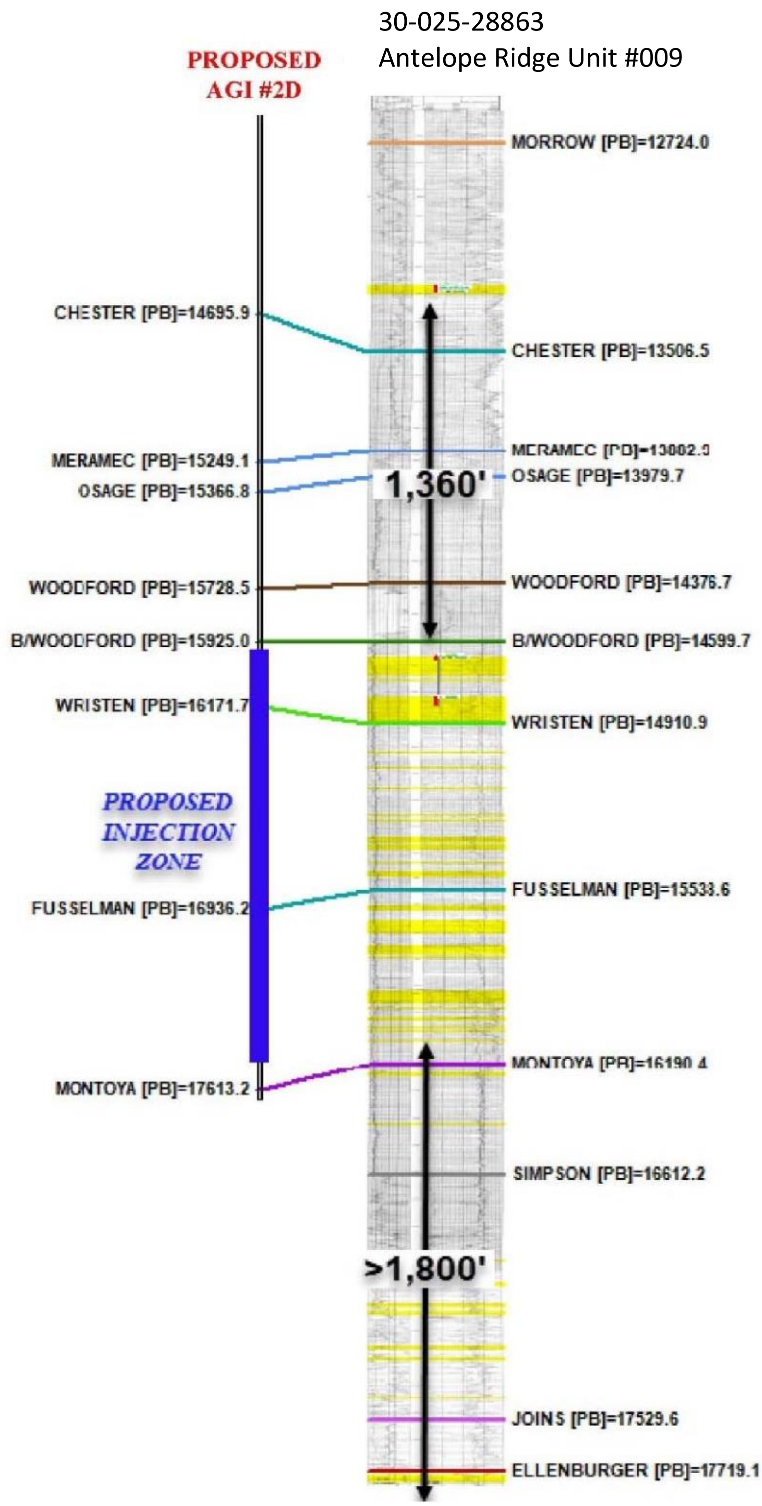


Figure 3.3-6 -- Porosity profile above and below proposed injection zone for RH AGI #2

3.4 Formation Fluid Chemistry

3.4.1 Cherry Canyon Formation

A chemical analysis (Table 3.4-1) of water from Federal 30 Well No. 2 (API 30-025-29069), approximately 3.9 miles away, indicates that the formation waters are highly saline (180,000 ppm NaCl) and compatible with the proposed injection.

Table 3.4-1 – Formation fluid analysis for Cherry Canyon Formation from Federal 30 Well No. 2

Sp. Gravity	1.125 @ 74°F	Resistivity	0.07 @ 74°F
pH	7	Sulfate	1,240
Iron	Good/Good	Bicarbonate	2,135
Hardness	45,000	Chloride	110,000
Calcium	12,000	NaCl	180,950
Magnesium	3,654	Sod. & Pot.	52,072

Table extracted from C-108 Application to Inject by Ray Westall Associated with SWD-1067 – API 30-025-24676. Water analysis for formation water from Federal 30 #2 Well (API 30-025-29069), depth 7,335-7,345 feet, located 3.9 miles from Red Hill AGI #1

3.4.2 Siluro-Devonian

A review of formation waters from the U.S. Geological Survey National Produced Waters Geochemical Database v2.1 (10/16/2014) identified 10 wells with analyses from drill stem test fluids collected from the Devonian, Silurian-Devonian, or Fusselman Formations, in wells within approximately 12 miles of the proposed RH AGI #2 (Townships 18 to 20 South and Ranges 30 to 33 East).

These analyses showed Total Dissolved Solids (TDS) values ranging from 20,669 to 40,731 milligrams per liter (mg/l) with an average of 28,942 mg/l. The primary anion is chloride, and the concentrations range from 11,176 to 23,530 mg/l with an average of 16,170 mg/l.

An attempt will be made to sample formation fluids during drilling or completion of the RH AGI #2 well to provide more site-specific fluid properties.

3.5 RH AGI #2 – Assessment of Potential for Induced Seismicity in Siluro-Devonian

During the site characterization for the RH AGI #2 well, Geolex identified three faults within the proposed Siluro-Devonian injection zone that may have potential for induced seismic activity in response to injected fluids. As described in Section 3.2.3, additional faults in the Siluro-Devonian were suggested by nearby operators but they provided Lucid with no evidence to verify this claim. It was decided to include these additional faults in the assessment of the potential for induced seismicity in order to consider a worst-case scenario. Figure 3.5-1 shows the eleven (11) potential faults identified and interpreted to be present within the Siluro-Devonian in the area around the RH AGI wells. These faults were then divided into 32 fault segments to characterize more accurately their non-linear expression (Figure 3.5-2).

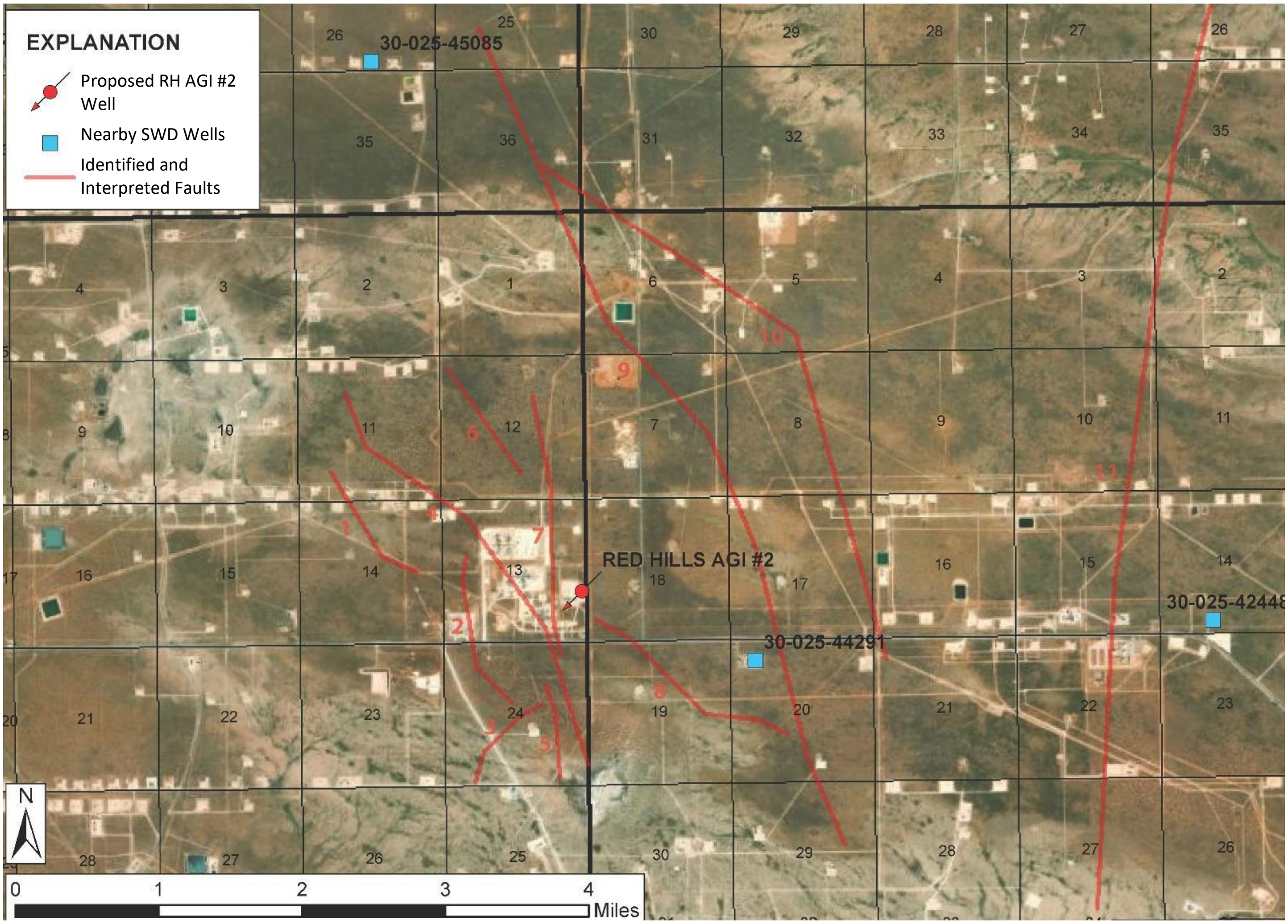


Figure 3.5-1 -- Map showing identified and interpreted faults in the area of the proposed RH AGI #2 well.

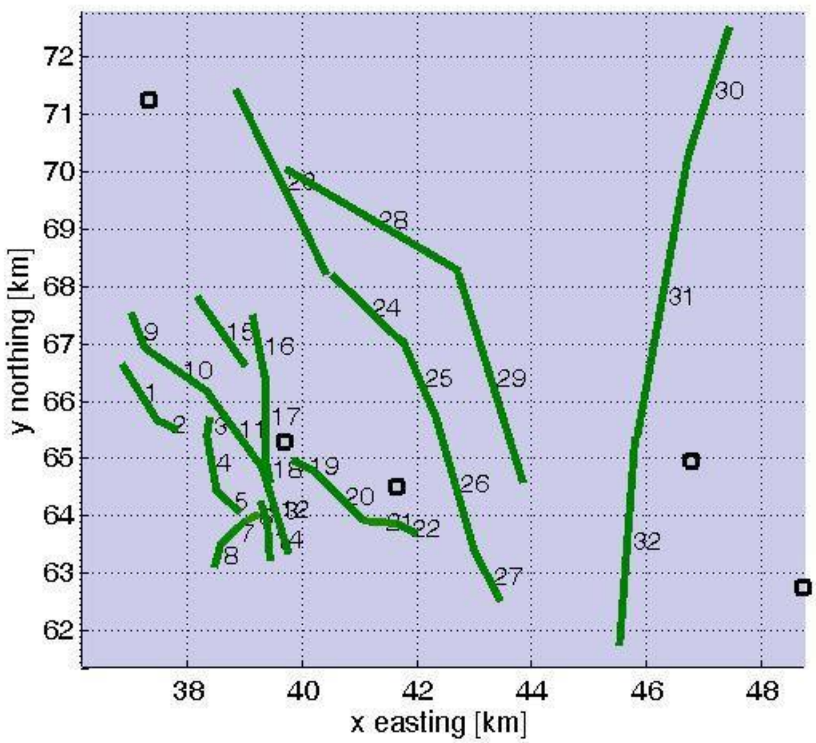


Figure 3.5-2 – Graphic showing 11 faults divided into 32 segments for FSP analysis.

To evaluate the potential for induced seismicity, Geolex conducted an induced-seismicity risk assessment utilizing the Stanford Center for Induced and Triggered Seismicity's (SCITS) Fault Slip Potential (FSP) modeling package. This assessment modeled the impact of all sixteen (16) SWD wells (Table 3.5-1) located within ten (10) miles of the RH AGI #2 well over a 30-year period and estimates the fault-slip probability associated with the anticipated injection scenario. Thirteen of these sixteen SWD wells are located approximately 6 miles or greater from the proposed RH AGI #2 well. The Striker SWD #2 well is the nearest SWD well located approximately 1.3 miles from the proposed well. To ensure a conservative assessment of fault slip potential, all SWD wells were simulated at their maximum permitted daily injection rate as documented in their respective C-108 Class II permit applications. As indicated in Table 3.5-1, the daily injection volume for each SWD well simulated except RH AGI #2 ranged from 20,000 to 50,000 barrels per day. By comparison, the proposed daily injection volume for the RH AGI #2 well is 6,000 barrels per day, less than 1.2% of the total of all the other SWD wells. The actual calculated maximum operational volume (13 MMSCF/D) of compressed TAG at anticipated reservoir conditions of 225 °F and 7,500 psig is 5,285 barrels per day. This value was rounded up to 6,000 barrels per day in the FSP analysis providing another measure of conservativeness to the analysis.

Table 3.5-1 – Sixteen (16) SWD wells included in the FSP analysis

Well #	API	Well Name	Volume (bbls/day)	Start (year)	End (year)
1	-	Red Hills AGI #2	6000	2020	2050
2	3002544291	Striker 6 SWD #2	32500	2018	2050
3	3002545085	Brininstool SWD #4	31500	2020	2050
4	3002542448	Madera SWD #1	20000	2016	2050
5	3002544661	Moomaw SWD #1	30000	2019	2050
6	3002546109	McCloy Central #1	50000	2020	2050
7	3002545427	Sidewinder SWD #1	50000	2019	2050
8	3002545363	Mr Belding State #1	40000	2020	2050
9	3002544000	Brininstool SWD #3	25000	2020	2050
10	3002545514	Gold Coast 26 Fed #3	25000	2020	2050
11	3002523895	Vaca Draw Fed #1	40000	2017	2050
12	3002546685	Cyclone Fed #1	50000	2020	2050
13	3002545151	Breckinridge State #1	40000	2020	2050
14	3002543908	Solaris Brininstool #1	25000	2020	2050
15	3002542947	McCloy SWD #2	20000	2017	2050
16	3002545605	R Wallman State #1	45000	2020	2050

The FSP model utilized input parameters describing fault geometry, orientation, and local stress conditions to estimate the pressure increase required to induce motion along the feature. Multiple model simulations were performed by varying fault dip angles to account for uncertainty in the true orientation of the faults. Table 3.5-2 shows the FSP simulation results for the 7 of the total 32 modeled fault segments with the lowest differential pressure required to initiate slip.

Table 3.5-2 – FSP simulation results for the 7 segments with the lowest differential pressure required to initiate slip

Segment #	Predicted ΔPP (PSI)	Predicted ΔPP NO AGI (PSI)	ΔPP Required to Slip (PSI)	Probability of Slip	Probability (No AGI)	ΔPP Required to Slip (PSI)	Probability of Slip	Probability (No AGI)	ΔPP Required to Slip (PSI)	Probability of Slip	Probability (No AGI)
ALL CASES			CASE #1 DIP = 80° ± 10			CASE #2 DIP = 75° ± 10			CASE #3 DIP = 70° ± 10		
2	234	216	1513	0.01	0	1418	0.02	0.02	1363	0.03	0.03
6	259	238	1340	0.05	0.04	823	0.16	0.15	422	0.29	0.27
7	250	231	1147	0.03	0.02	938	0.06	0.07	776	0.10	0.10
19	293	260	1707	0.01	0	1636	0.01	0.01	1603	0.01	0.02
21	343	326	1166	0.06	0.05	800	0.14	0.14	506	0.28	0.23
22	339	324	1707	0.01	0.01	1636	0.02	0.02	1603	0.03	0.02
28	186	176	1985	0	0	1935	0	0	1923	0	0.01

Geolex summarized the results of their fault slip potential analysis as follows:

- Operation of the proposed RH AGI #2 is not predicted by the FSP model to contribute significantly to the total risk for injection-induced slip
- Multiple case simulations were completed to address uncertainty of fault-dip magnitudes and demonstrate that slip potential increases as dip angles become more shallow
- Maximum slip probabilities of high-angle fault conditions range from 0.03 to 0.06 and the shallowest fault conditions exhibit a probability range of 0.10 to 0.29 (highlighted in yellow in Table 3.5-2)
- Though simulated at their maximum anticipated daily injection rate to assure a conservative assessment of slip probability, the most proximal Striker 6 SWD #2 and Red Hills AGI #2 well are not anticipated to operate at this capacity for the full 30-year injection duration

- Striker 6 SWD #2 –Average reported daily injection volume of approximately 7,500 bpd
- Red Hills AGI #2 –Intended to split total 13 MMSCF/D with existing Red Hills AGI #1

- In summary, operation of the proposed RH AGI #2 is not anticipated to contribute significantly to the total potential for injection-induced fault slip and the historic volume contributions of relevant SWD combined with the anticipated operational parameters of the proposed AGI demonstrate that acid gas can be injected as proposed while maintaining minimal risk of induced seismicity

3.6 Groundwater Hydrology in the Vicinity of the Red Hills Gas Plant

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are 15 freshwater wells located within a two-mile radius of the RH AGI wells, and only 2 water wells within one mile; the closest water well is located 0.31 miles away and has a total depth of 650 feet (Figure 3.6-1; Table 3.6-1). All water wells within the two-mile radius are shallow, collecting water from about 60 to 650 feet depth, in Alluvium and the Triassic redbeds. The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the RH AGI wells (Figures 3.6-2 and 3.6-3). While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

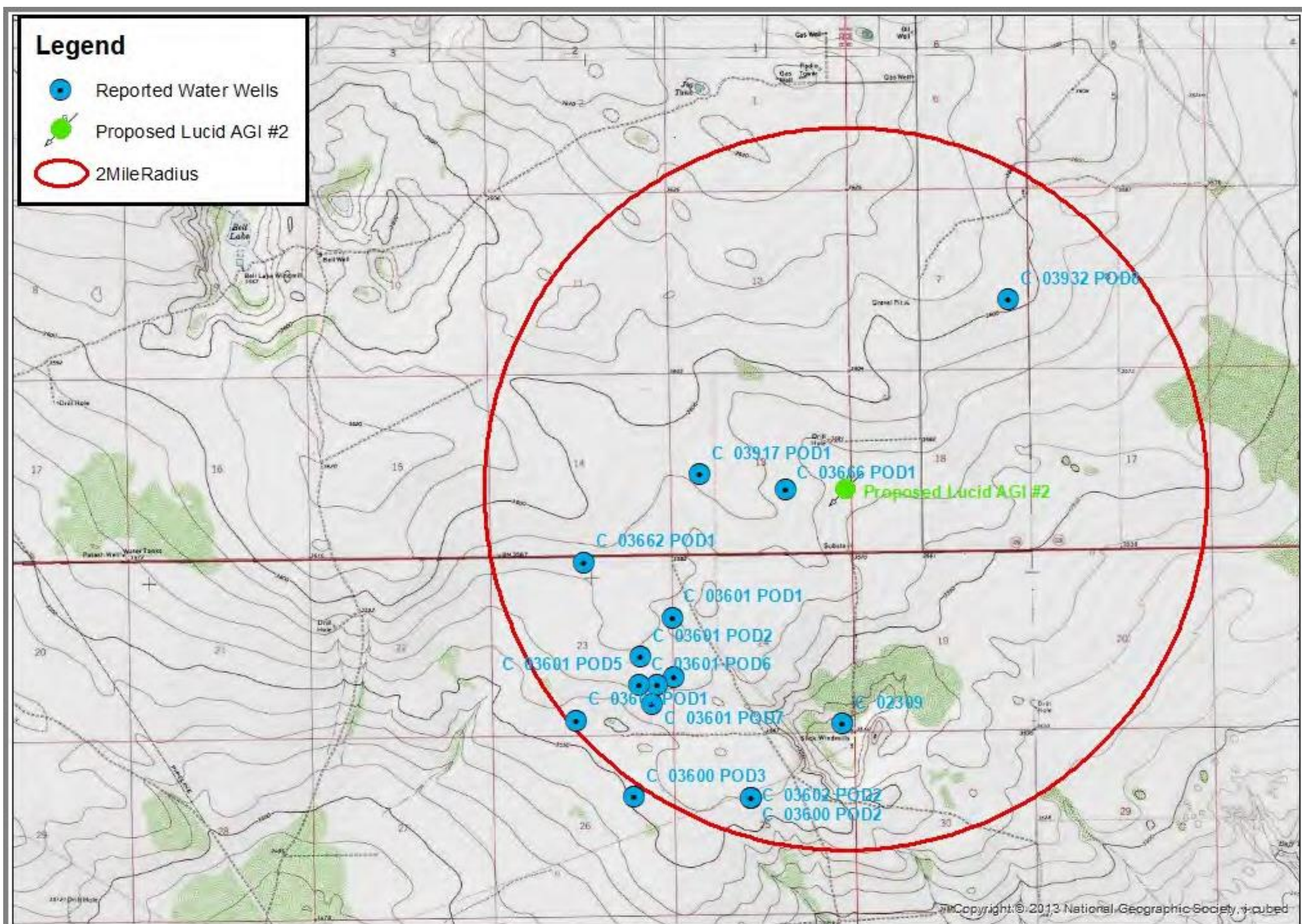


Figure 3.6-1 -- Reported Water Wells within 2-mile Radius of Proposed Lucid AGI #2

Table 3.6-1 -- Water wells identified by the New Mexico State Engineer's files within two miles of the proposed RH AGI wells; water wells within one mile are highlighted in yellow.

POD Number	County	Sec	Tws	Rng	UTME	UTMN	Distance (mi)	Depth Well (ft)	Depth Water (ft)	Water Column (ft)
C 03666 POD1	LE	13	24S	33E	639132	3565078	0.31	650	390	260
C 03917 POD1	LE	13	24S	33E	638374	3565212	0.79	600	420	180
C 03601 POD1	LE	23	24S	33E	638124	3563937	1.17			
C 02309	LE	25	24S	33E	639638	3562994	1.29	60	30	30
C 03601 POD3	LE	24	24S	33E	638142	3563413	1.38			
C 03932 POD8	LE	7	24S	34E	641120	3566769	1.40	72		
C 03601 POD2	LE	23	24S	33E	637846	3563588	1.44			
C 03662 POD1	LE	23	24S	33E	637342	3564428	1.48	550	110	440
C 03601 POD5	LE	23	24S	33E	637988	3563334	1.48			
C 03601 POD6	LE	23	24S	33E	637834	3563338	1.55			
C 03601 POD7	LE	23	24S	33E	637946	3563170	1.58			
C 03600 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03602 POD2	LE	25	24S	33E	638824	3562329	1.78			
C 03600 POD1	LE	26	24S	33E	637275	3563023	1.94			
C 03600 POD3	LE	26	24S	33E	637784	3562340	2.05			

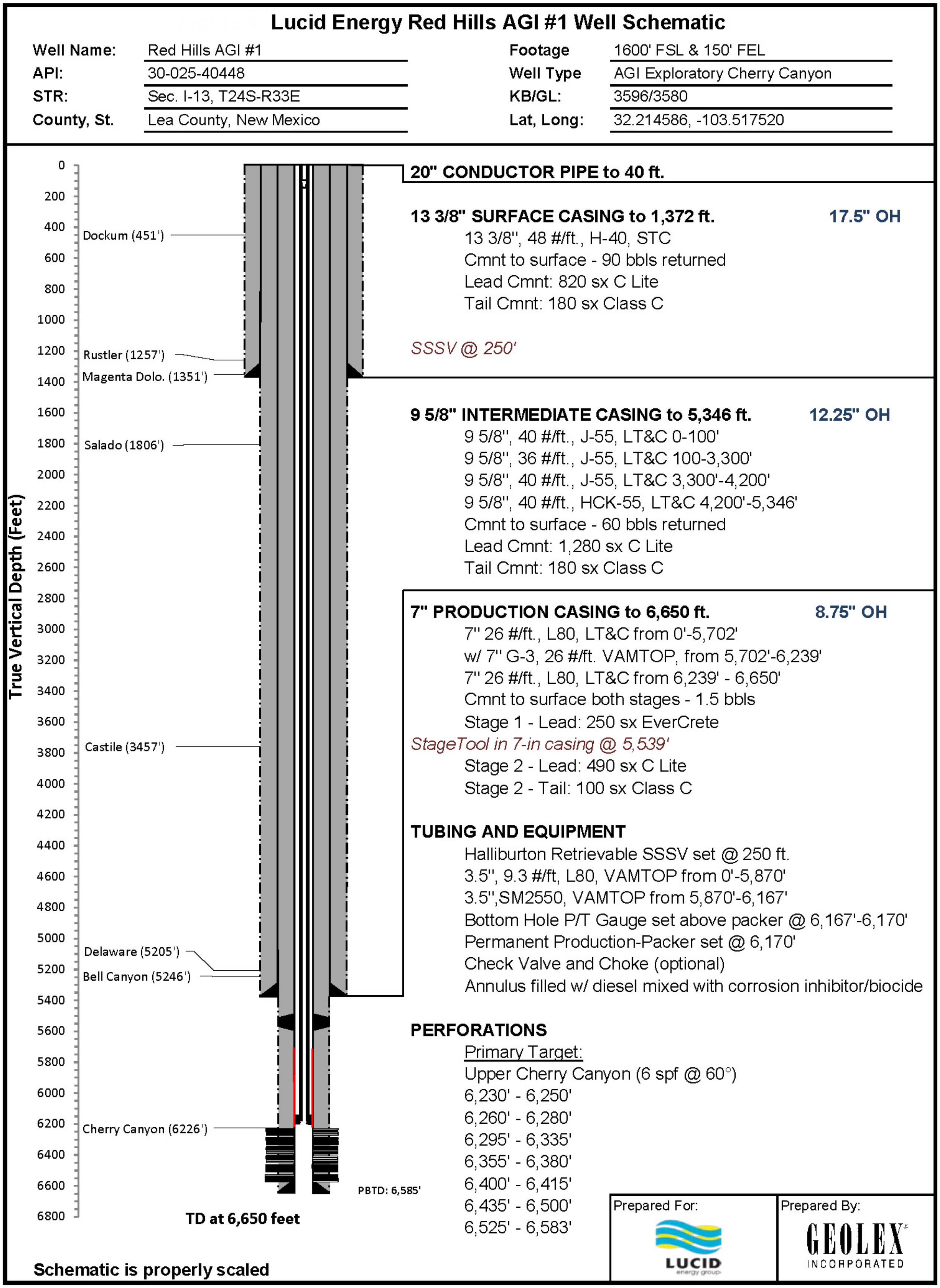


Figure 3.6-2 -- Schematic of RH AGI #1

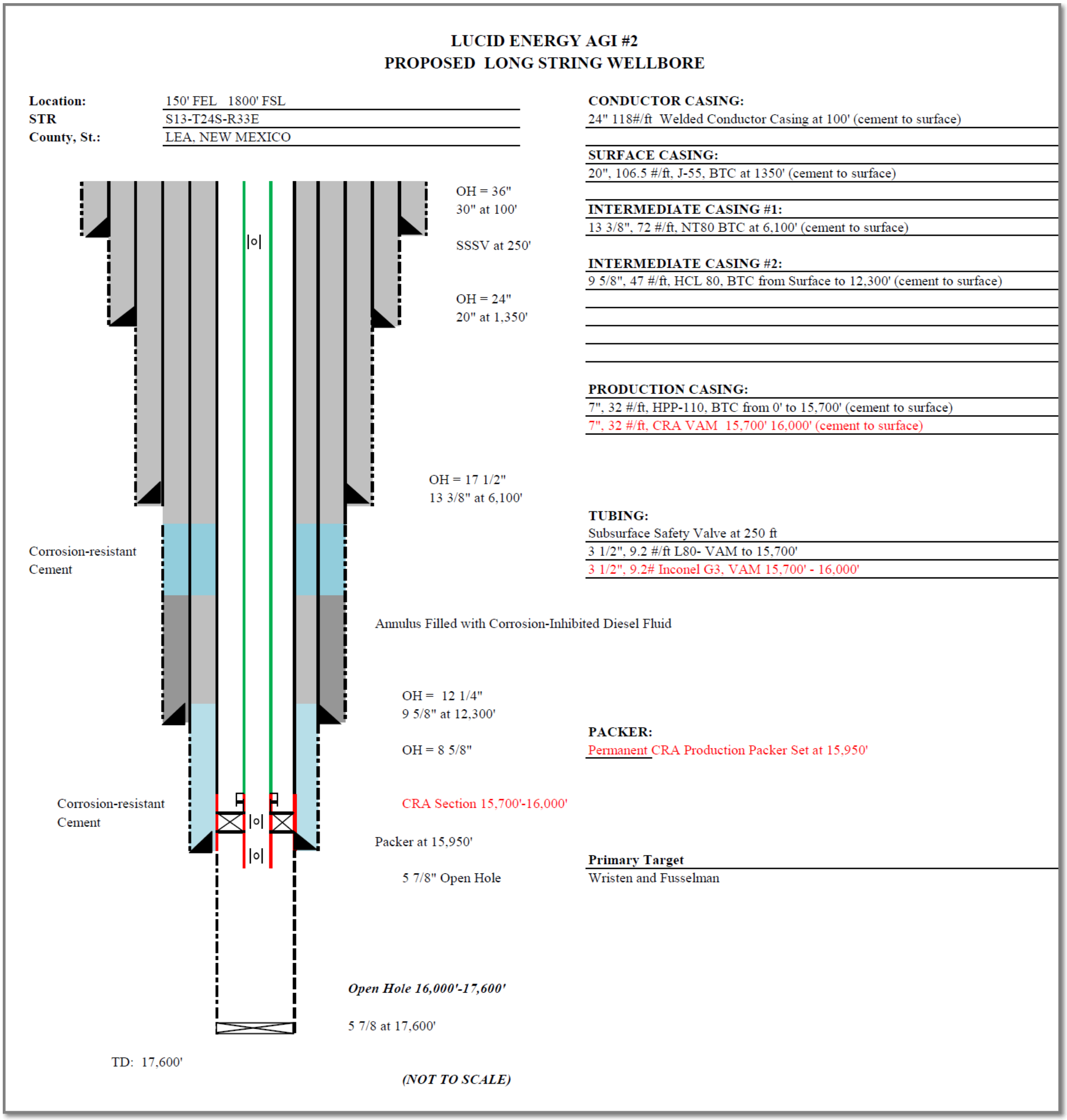


Figure 3.6-3 -- Schematic of Proposed RH AGI #2 (Option 2). Red text refers to completion parameters for the injection zone.

3.7 Historical Operations

3.7.1 Red Hills Site

On July 20, 2010, Agave Energy Company (Agave) filed an application with NMOCD to inject treated acid gas into an acid gas injection well. Agave built the Red Hills Gas Processing Plant and drilled RH AGI #1 in 2012-13. However, the well was never completed and never put into service because the plant was processing only sweet gas (no H_2S). Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well.

3.7.2 Operations within a 2 Mile Radius of the Red Hills Site

Within a two-mile radius of the proposed Red Hills Gas Plant location, NMOCD records identify a total of 129 wells (13 plugged and abandoned or temporarily plugged, 38 active, 1 is the RH AGI #1 well). The remaining wells are listed as “New” horizontal wells (see Appendix 3).

Three wells within the 2-mile radius penetrate the proposed RH AGI #2 injection zone (deeper than 16,000 feet true vertical depth (TVD)):

- EOG Resources Government L Com 001 (P&A), API #3002525604, TVD = 17,625 feet, 0.72 miles from proposed RH AGI #2
- NGL Water Solutions Striker 6 SWD 002, (Active), API #3002544291 (hereafter, “the Striker well”), TVD = 17,765 feet, 1.25 miles from proposed RH AGI #2
- EOG Resources Bell Lake 7 Unit 001 (P&A), API #3002533815, TVD = 16,085 feet, 1.31 miles from proposed RH AGI #2

NGL Water Solutions has agreed to limit their injection rate in the Striker well to 20,000 barrels per day, reducing the potential for pressure interference in the injection zone.

The EOG Resources Government Com 001 well (API #3002525604) penetrated the Devonian zone during initial drilling in March 1978. Testing showed that there were no economical hydrocarbons in this zone, and the well’s liner and production casing were cemented and plugged back to 14,590 feet (over 1,000 feet above the 16,000 foot top of the proposed injection zone) in May of 1978. The well was completely plugged and abandoned in December of 2004. The plugging conditions and the distance of this well from the RH AGI wells indicate that this well poses no hazard for TAG migration to shallower zones.

Figure 3.7-1 shows the locations of 13 wells, including RH AGI #1, within a one-mile radius of the RH AGI wells, and Table 3.7-1 summarizes the relevant information for those wells.

Figure 3.7-2 shows the geometry of producing wells in the general area of the Red Hills Gas Plant. All active production in this area is targeted for the Bone Spring and Wolfcamp zones, at depths of 8,900 to 11,800 feet, the Strawn (11,800 to 12,100 feet) and the Morrow (12,700 to 13,500 feet). All of these productive zones lie at least 2,500 feet above the proposed RH AGI #2 injection zone at 16,000 feet and more than 2,000 feet below the RH AGI #1 injection zone.

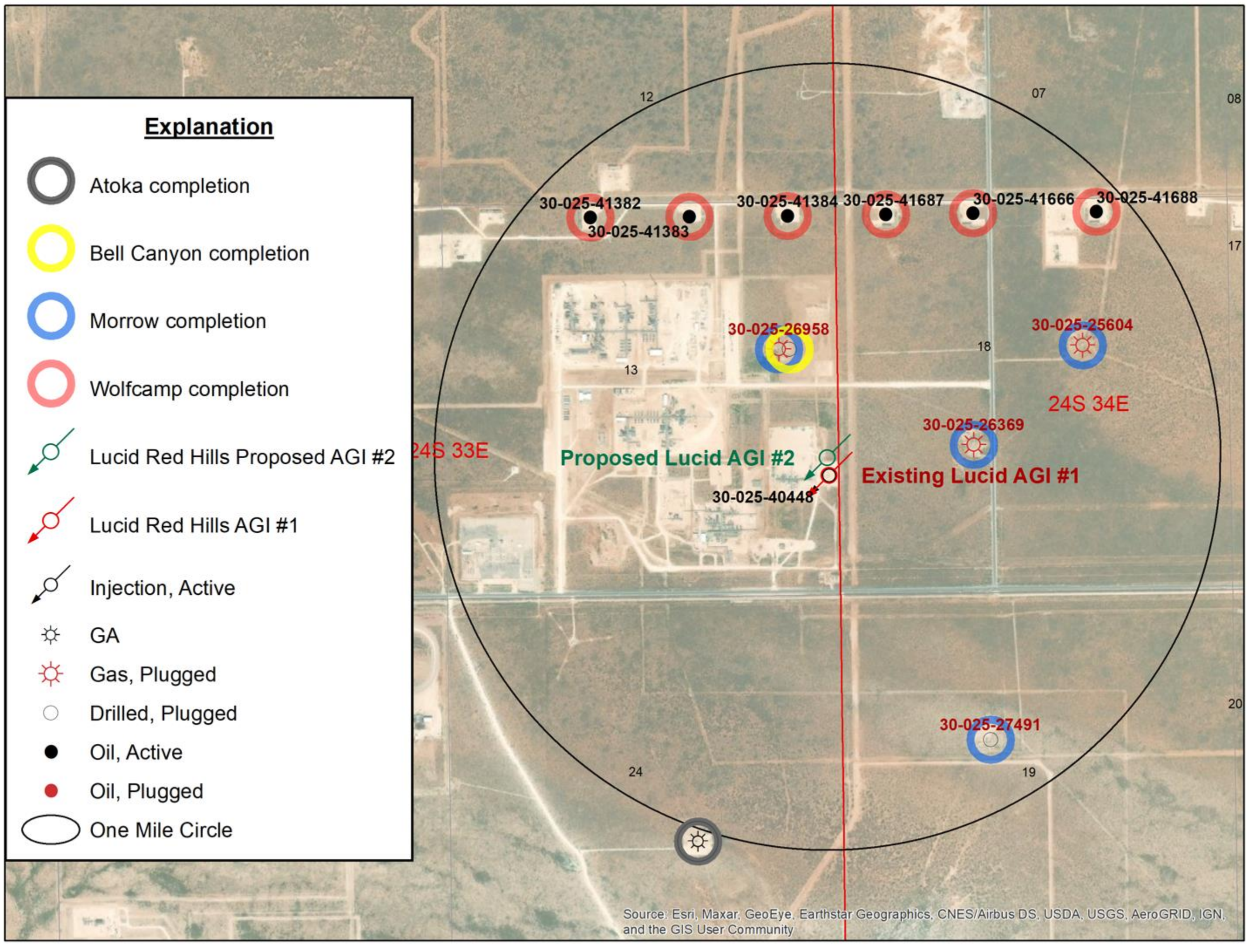


Figure 3.7-1 – Location of all oil- and gas-related wells within a 1-mile radius of the RH AGI wells

Table 3.7-1 – Oil- and gas-related wells within 1-mile radius of the RH AGI Wells

API	OPERATOR	WELLNAME	SPUDDATE	PLUGDATE	TVDDEPTH	STATUS	DIST(Miles)
3002540448	LUCID ENERGY DELAWARE, LLC	RED HILLS AGI 001	23-Oct-13		6650	Active	0.00
3002508371	BYARD BENNETT	J L HOLLAND ETAL 001	24-Feb-61	8-Mar-61	5425	Plugged	0.33
3002526958	BOPCO, L.P.	SIMS 001	4/13/1981	26-Dec-07	15007	Plugged	0.34
3002526369	EOG RESOURCES INC	GOVERNMENT L COM 002	15-Sep-79	8-Oct-90	14698	Plugged	0.38
3002541384	COG OPERATING LLC	DECKARD FEDERAL COM 004H	1-Jun-14		11103	Active	0.67
3002541687	COG OPERATING LLC	SEBASTIAN FEDERAL COM 001H	1-Feb-15		10944	Active	0.68
3002525604	EOG RESOURCES INC	GOVERNMENT L COM 001	3-Oct-77	30-Dec-04	17625	Plugged	0.72
3002541383	COG OPERATING LLC	DECKARD FEDERAL COM 003H	30-Aug-14		11162	Active	0.75
3002541666	COG OPERATING LLC	SEBASTIAN FEDERAL COM 002H	24-Feb-15		10927	Active	0.76
3002527491	SOUTHLAND ROYALTY CO	SMITH FEDERAL 001	19-Oct-81	10-Aug-86	15120	Plugged	0.80
3002541382	COG OPERATING LLC	DECKARD FEDERAL COM 002H	3-Jun-14		11067	Active	0.88
3002541688	COG OPERATING LLC	SEBASTIAN FEDERAL COM 003H	3-Aug-14		11055	Active	0.93
3002529008	EOG RESOURCES INC	MADERA RIDGE 24 001	7-Nov-84		15600	Active	1.00

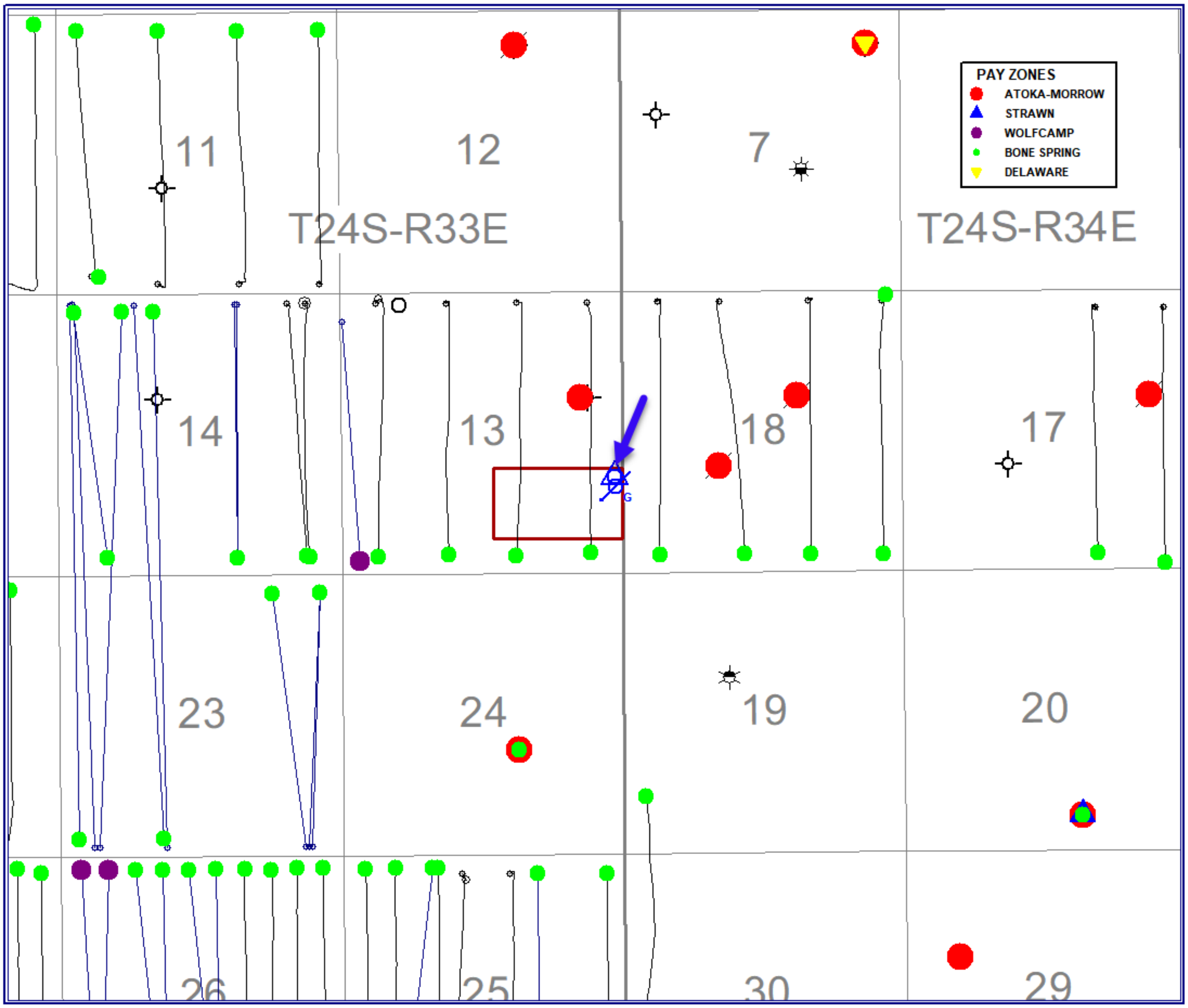


Figure 3.7-2 -- Producing wells in the area of the Red Hill Gas Plant.

The RH AGI Wells (arrow) are in an area that is within an active Bone Spring and Wolfcamp (Permian) horizontal play. Lines are approximate horizontal well paths. There are no Devonian producing wells within this map area.

3.8 Description of Injection Process

The Red Hills Gas Plant and existing RH AGI #1 well are in operation and are manned 24-hours-a-day, 7-days-a week. The plant operations include gas compression, treating and processing. The plant gathers and processes produced natural gas from Lea and Eddy Counties in New Mexico. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility, located west of the well head. Compressed TAG is then routed to the wells via high-pressure rated lines. Figure 3.8-1 is a schematic of the AGI facilities.

The approximate composition of the TAG stream is: 83% CO_2, 17% H_2S, 1% Trace Components of $C_1 – C_6$ and Nitrogen.

The anticipated duration of injection is 30 years.

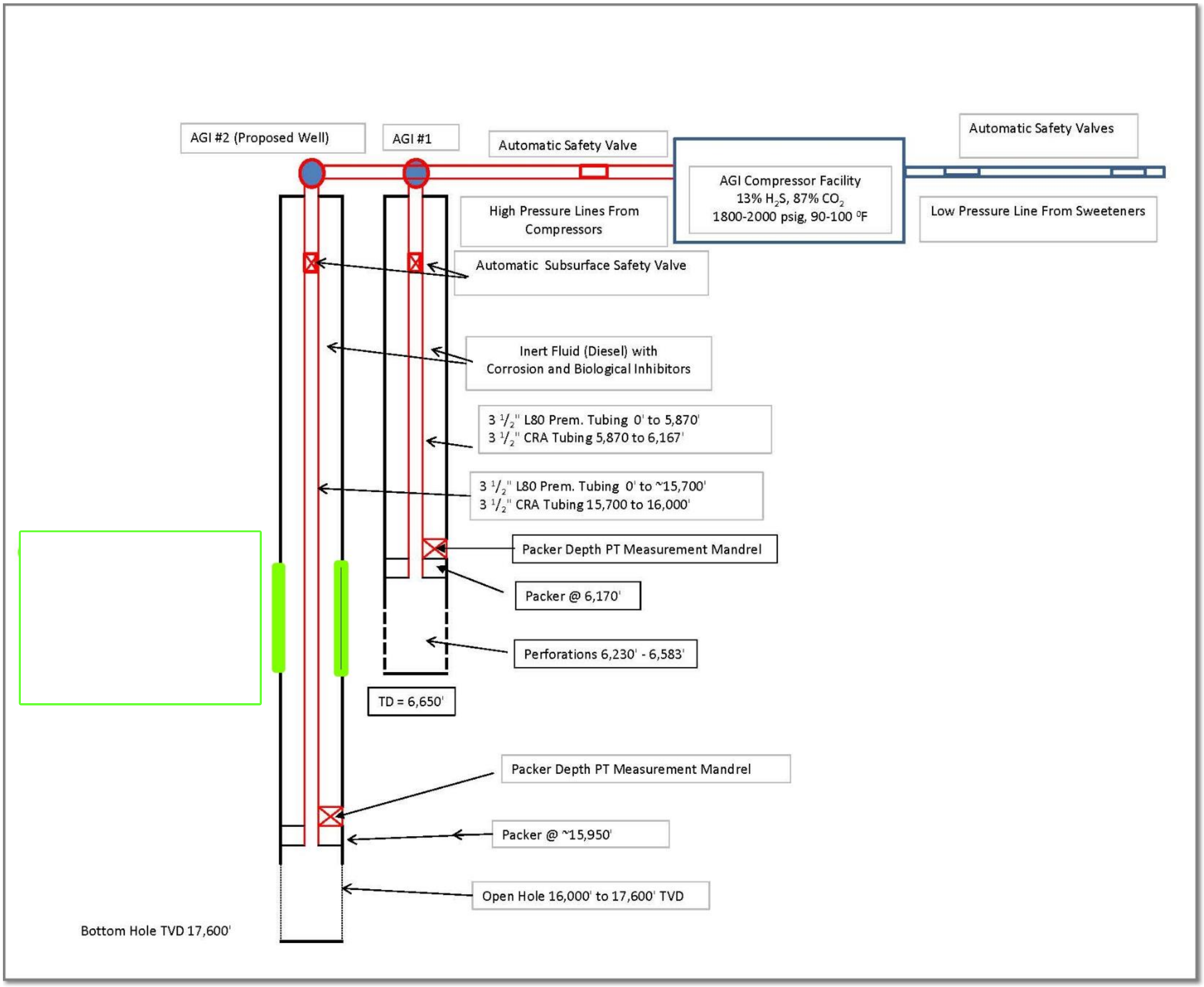


Figure 3.8-1 -- Schematic of surface facilities and RH AGI wells at the Red Hills Gas Plant

3.9 Reservoir Characterization Modeling

There are two main target formations for the Red Hills injection project. The RH AGI #1 well penetrates and is completed in the Cherry Canyon Formation. The proposed RH AGI #2 well is planned to be completed in Devonian rocks. The characterization and modeling for injection targets will be described separately below.

Schlumberger's Petrel (Version 2020.4) software was used to construct the geological models used in this work. Schlumberger's simulation software Eclipse Compositional E300 (Version 2020.1) was used in the reservoir simulations presented in this MRV plan. The model simulates solubility trapping of the injected TAG in the formation water and/or the portion of the TAG that can exist in a supercritical phase. The modeling did not consider CO_2 storage attributed to mineral and geomechanical trapping mechanisms. Also, the model did not implicitly model storage attributed to residual trapping because insufficient information was available to develop the hysteresis effects.

Though the two AGI wells were modeled separately, similar constraints were used for both models. The reservoir is assumed to be at hydrostatic equilibrium and initially saturated with 100% brine. The injection gas has two components, H_2S and CO_2, with a mole fraction of 17% and 83%, respectively. Both acid gas components are assumed to be soluble into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for the gas/water system. The external boundary conditions are specified to be open boundary.

3.9.1 Cherry Canyon- RH AGI #1 Injection Characterization and Modeling

Formation tops were picked from 33 well logs available for the area and mapped to construct the structural surfaces for the Cherry Canyon injection zone. The geologic model boundary focused on a 13.5 km X 12.8 km (8.39 miles X 7.95 miles) area with a grid dimension of 141 X 132 X 7 equaling a total of 130,284 cells. The grid cell dimension is 100 m X 100 m, and there are eight (8) vertical units within the target zone. Figure 3.9-1 shows the structural surface for Cherry Canyon layer 4 within the geological model. No significant structures such as faults were identified in the studied area within the Cherry Canyon. Porosity data derived from the 33 well logs were used to populate the model porosity values (Figure 3.9-2). The Cherry Canyon Formation has an average porosity of 19.2% with a standard deviation of 2.5%. The maximum and minimum values are 25% and 15% respectively. There are permeability core data available for some wells in the study area in addition to other wells within the region. A porosity-permeability relationship was established to develop a correlation to populate 3D distribution of permeability (Figure 3.9-3). The permeability distribution signifies a fairly tight formation with an average of 4 millidarcies (md) with a maximum value of 19 md. Figure 3.9-4 shows the permeability distribution in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation (see Section 3.3.1).

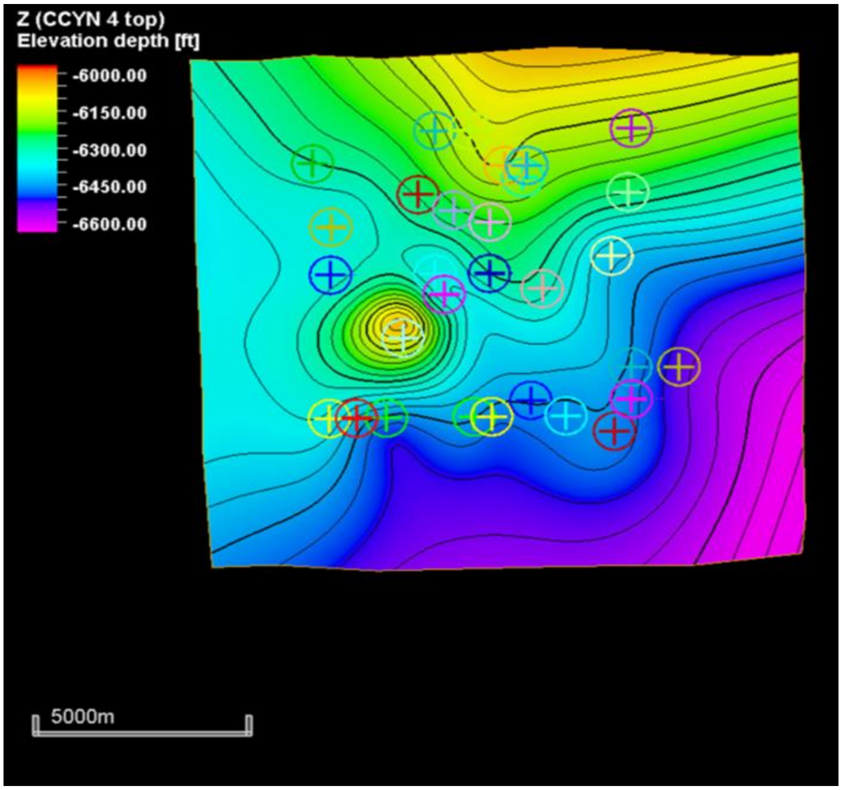


Figure 3.9-1 – Structural surface for top of Layer 4 of the Manzanita Zone of the Cherry Canyon Formation within the geological model.

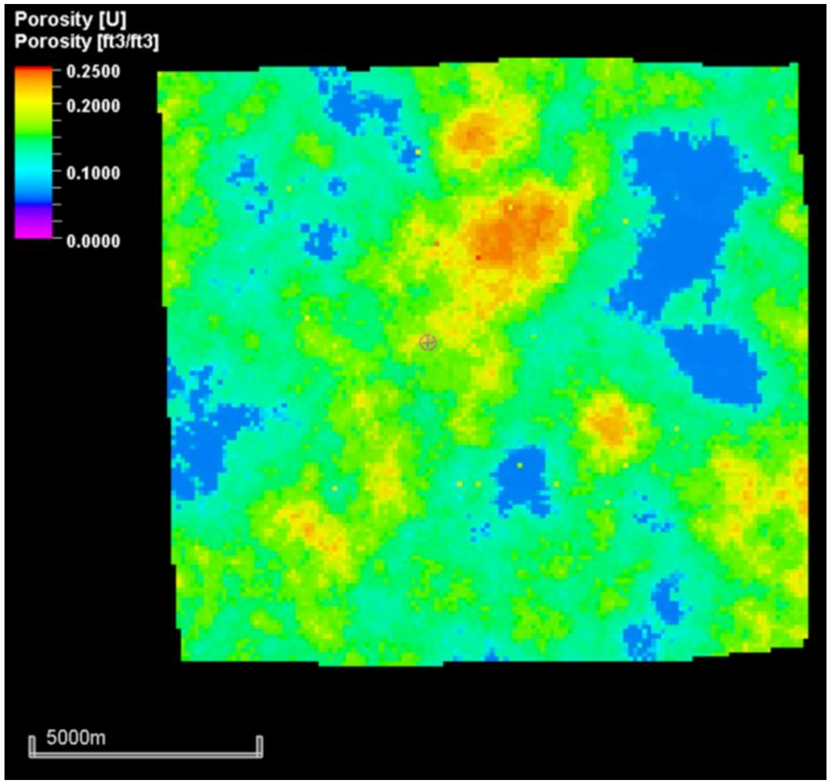


Figure 3.9-2 – Graphic showing the distribution of porosity in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation. Plan view.

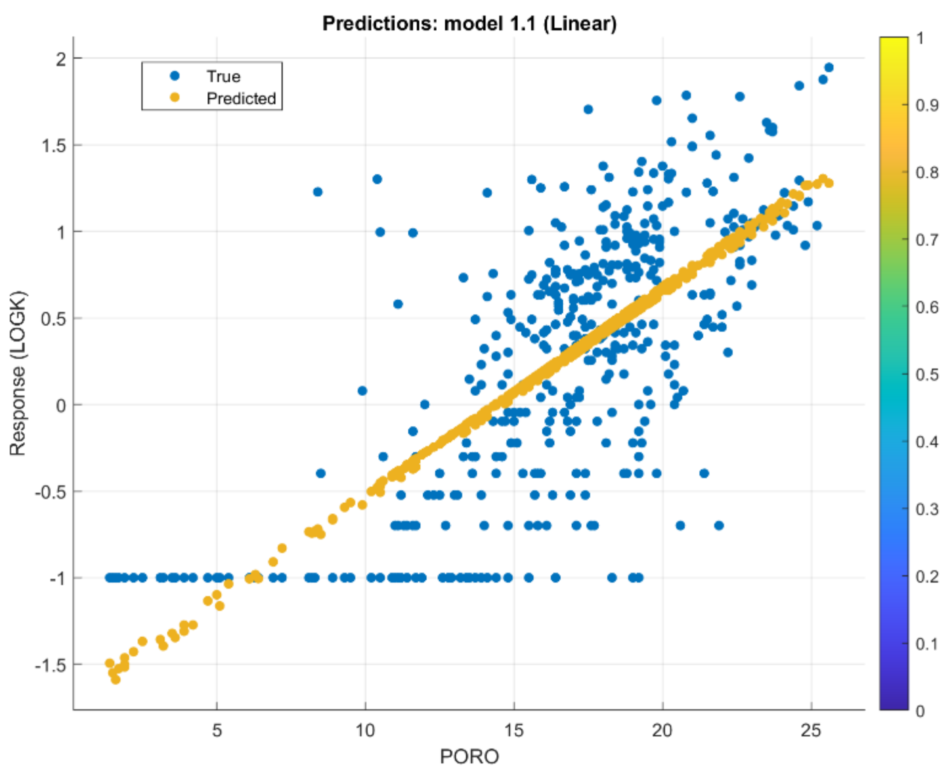


Figure 3.9-3 -- Porosity-permeability relationship for Layer 4 of the Manzanita Zone of the Cherry Canyon Formation.

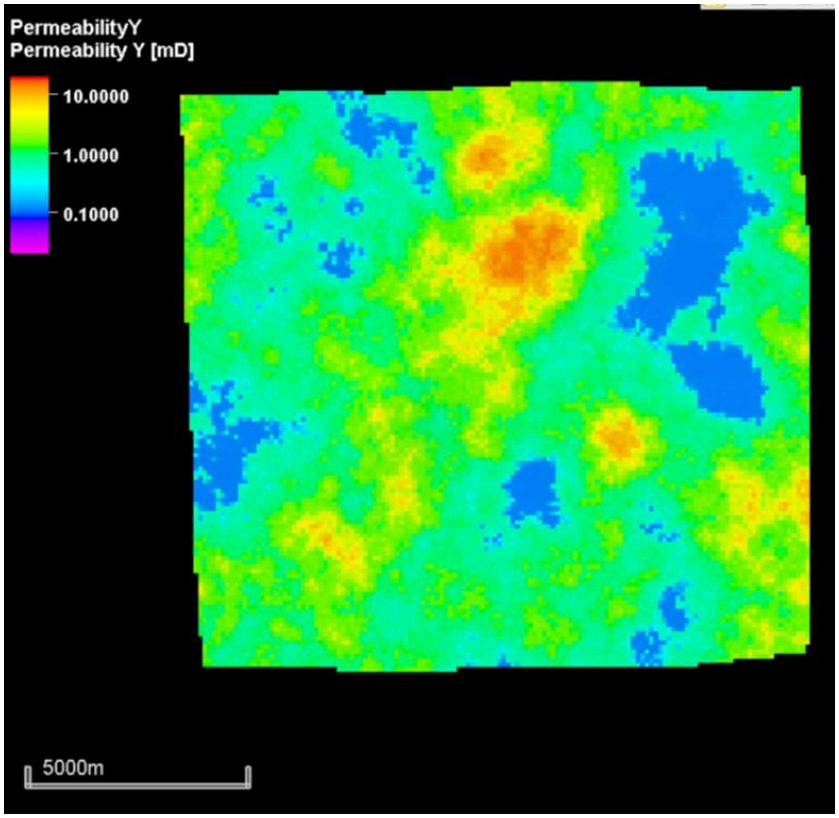


Figure 3.9-4 – Graphic showing the permeability distribution in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation. Plan view.

3.9.2 Simulation Modeling for RH AGI #1

Once the geological model was established, numerical modeling was performed to:

1) perform calibration of injection history to model specifically considering measured bottomhole pressure and injection rate
2) assess the storage capacity of the Cherry Canyon Formation
3) assess the maximum injection rate with respect to estimated maximum bottomhole pressure to ensure safe operation
4) estimate the modeled extent of the injected TAG after 30-year injection period and 5-year post injection monitoring period

The reservoir is assumed to be initially saturated with 100% brine and exhibit hydrostatic equilibrium. The injection gas has two components of H_2S and CO_2 with a mole fraction of 17% and 83%, respectively. Both of the two acid gas components are assumed to be able to dissolve into the aqueous phase. An irreducible water saturation of 0.17 is used to generate the relative permeability curves for gas/water system. The external boundary conditions are specified to be open boundary. An estimated maximum bottomhole pressure (BHP) gradient of 0.65 psi/ft (4,225 psi @ 6,500 feet) corresponded to the fracture pressure gradient imposed on the RH AGI #1 injection well to ensure safe injection operations. The BHP constraint was more prominent in the injection forecasting period. During the calibration period (January 1, 2019 – December 31, 2020), the measured BHP from the field was used as the control constraint to allow the historical injection rate to be matched. Figure 3.9-5 shows the calibrated cumulative gas injection and field pressure profile within the Cherry Canyon Formation. There are no known SWD wells in the simulation study area and therefore none were included in the modeling efforts within this target injection zone. An injection forecast model was performed for a period of approximately 28 years. The RH AGI #1 well had 2 years of historical injection data. Together, this accounts for a total of 30 years of injection. An additional 5 years of post-injection modeling was performed to ascertain fluid movement and pressure evolution. Figure 3.9-6 shows the injection profile for the forecasting period which showed the maximum injection rate recorded was approximately 6,200 thousand standard cubic feet per day (MSCF/D). This could be a result of low permeability within the modeled area. There was an increase in pressure close to the injection vicinity at the time of injection, but the build-up dissipated after the 5-year monitoring period even though the TAG front did not change with a maximum radius of 400 meters away from the AGI #1 injection well. The model showed that all the injected gas remained in the reservoir and there was no change in the size of the TAG extent compared at the end of injection and 5-year post injection period within the Cherry Canyon Formation. Figure 3.9-7 shows the largest lateral extent of the supercritical (free phase) TAG after comparing all the injection layers in the Cherry Canyon Formation.

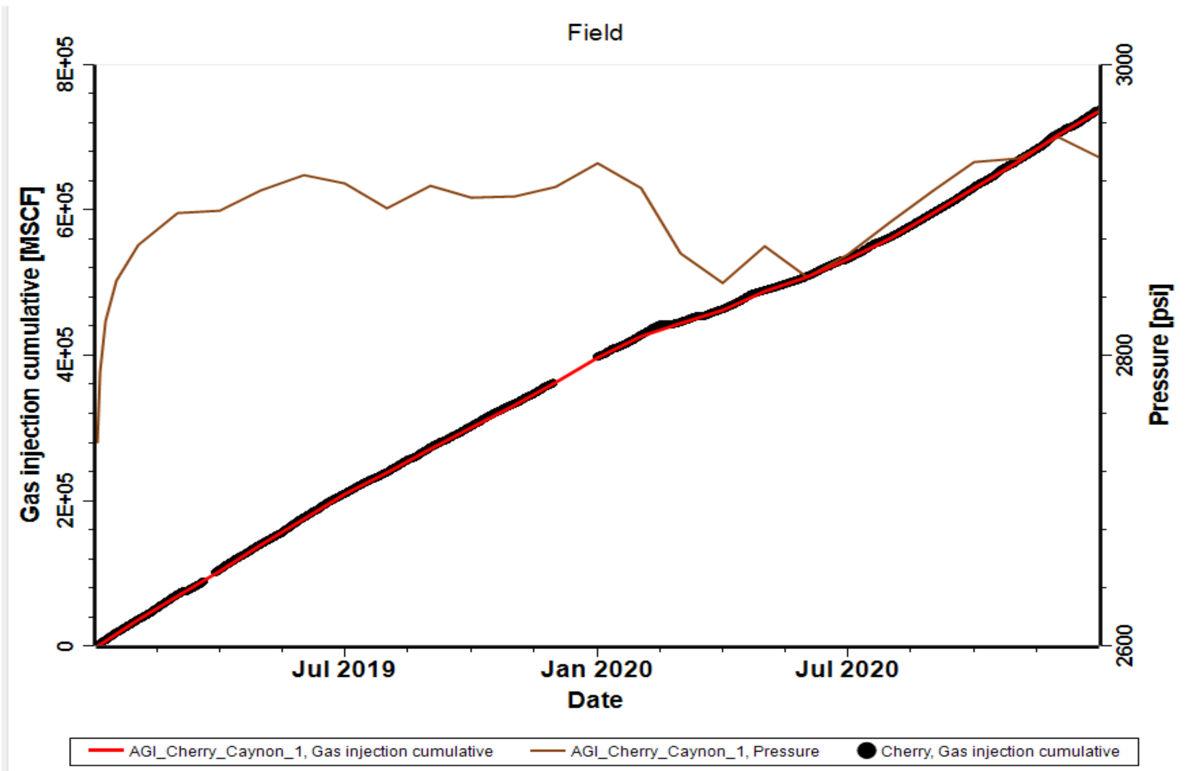


Figure 3.9-5 – Graph showing the calibrated cumulative gas injection and field pressure profile in the Cherry Canyon

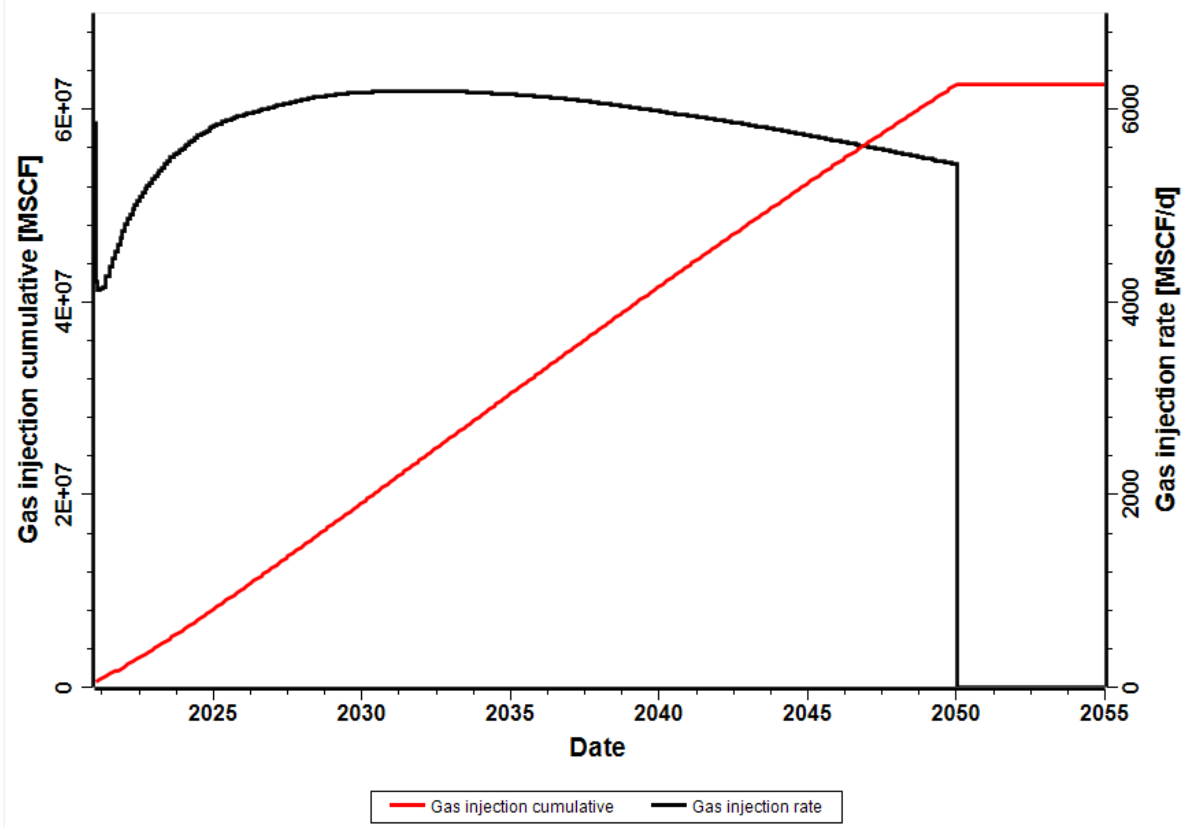


Figure 3.9-6 – Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period

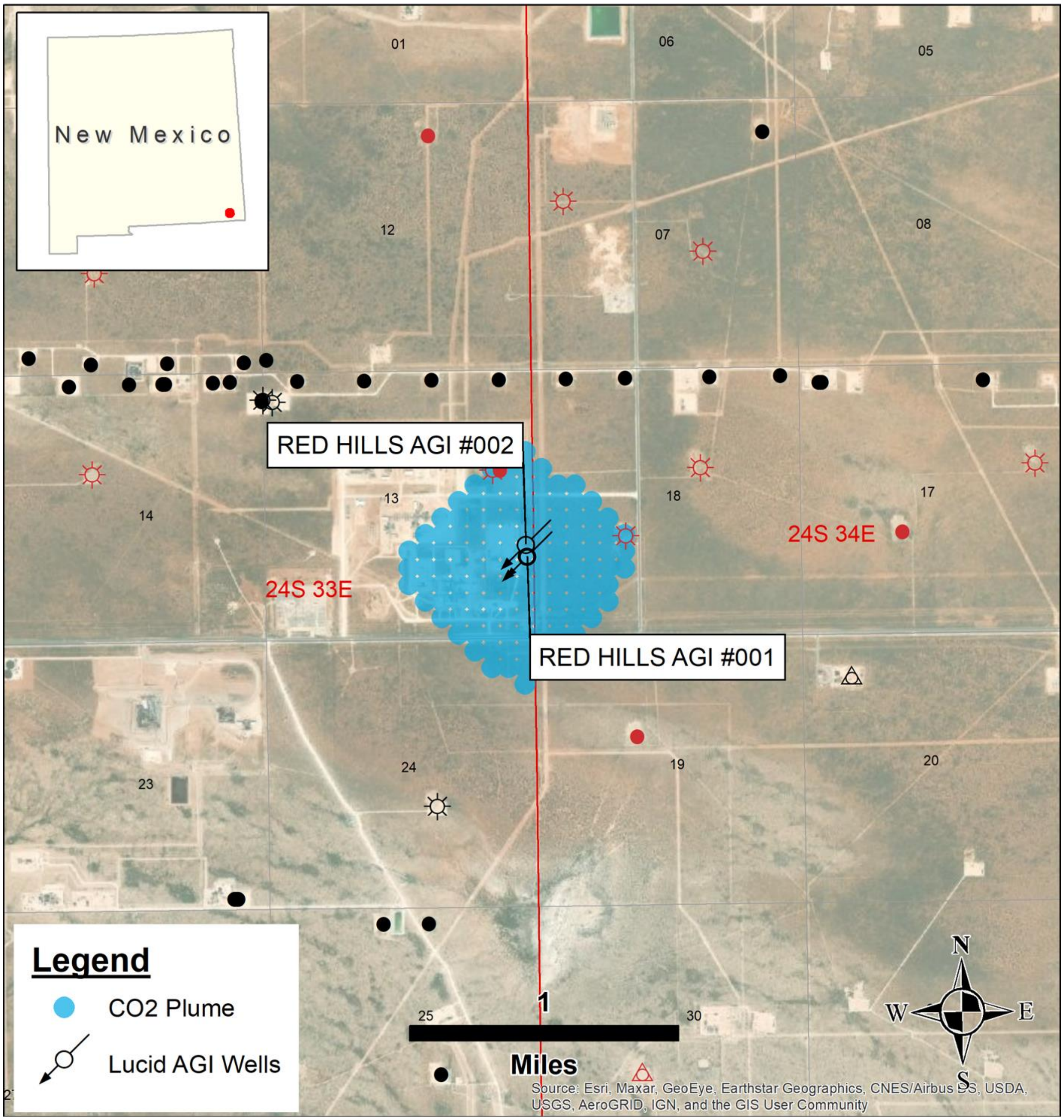


Figure 3.9-7 -- Map showing the largest lateral extent of the TAG plume within the Cherry Canyon

3.9.3 Siluro-Devonian- RH AGI #2 Injection Well Characterization and Modeling

A total of 10 wells that penetrated through Siluro-Devonian reservoir were utilized to map the geological structural surfaces for the RH AGI #2 well. These wells covered a 20 km by 20 km (12.4 X 12.4 miles) area for the geological model. The simulation model focused on a 6 km by 6 km (3.7 X 3.7 miles) area centered on the proposed RH AGI #2 injection well. In the simulation boundary, three SWD wells: the Trident, the Striker and the Deep Thirsty are included, but only the Striker well is currently injecting wastewater and its effect on the acid gas injection was analyzed. Figure 3.9-8 shows the geological and simulation model boundaries. The simulation model has a grid dimension of 119 x 119 x 15 for a total of 212,415 cells. Table 3.9-1 shows the various zones, depths, porosity, and permeability ranges used in populating rock properties onto the 3D simulation grid. Each zone is assigned different permeability and porosity distributions, using the recommended mean, minimum and maximum values. Pseudo-random numbers are generated following log-normal distributions to populate the spatial porosity and permeability distributions of the zones. Figure 3.9-9 shows the porosity and permeability distributions.

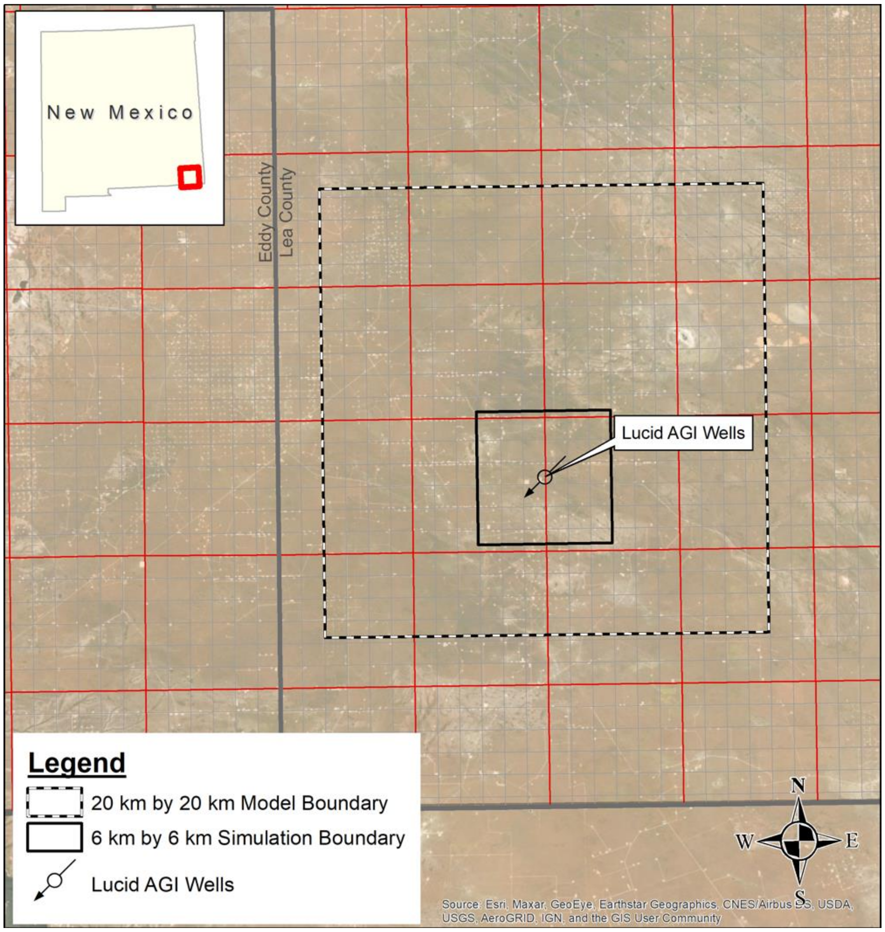


Figure 3.9-8 -- Map showing the top view of the geological and simulation model boundaries for the Siluro-Devonian injection zone.

Table 3.9-1 -- Geological zones and ranges of the properties for the Siluro-Devonian geologic model

Zone	Depth, ft	Porosity, %		Permeability, md	
		Range	Mean	Range	Mean
ZONE 1	A. 15964 - 16020	1-10%	7%	1-100 md	80 md
	B. 16020 - 16110	0-2%	1%	0.1- 1.0 md	0.75 md
ZONE 2	16110 - 16208	0-0.5%	0%	0.1-0.3 md	0.15 md
ZONE 3	16208 - 16357	4-20%	10%	75-700 md	150 md
ZONE 4	A. 16357- 16464	0-2%	1%	0.1 to 1 md	0.4 md
	B. 16464 - 16566	0-10%	7%	1-100 md	30 md
ZONE 5	16566 - 16744	0-2%	1%	0.1-1 md	0.5 md
ZONE 6	16744 - 16936	0- 0.5%	0%	0.1 to 0.3 md	0.15 md
ZONE 7	16936 - 17149	0-3%	2%	0.1 to 5 md	.025 md
ZONE 8	A. 17149 - 17194	0-15%	8%	10- 700 md	250 md
	B. 17194 - 17215	0-2%	1%	0.1 to 1 md	0.3 md
	C. 17215 - 17280	10-25%	14%	100-700 md	400 md
ZONE 9	A. 17280 - 17360	0-2%	1%	0.1 to 0.5 md	0.2 md
	B. 17360 - 17441	2 -14%	8%	1.0 to 100 md	50 md
ZONE 10	17441 - 17628	0 - 3%	2%	1 to 10 md	0.5 md

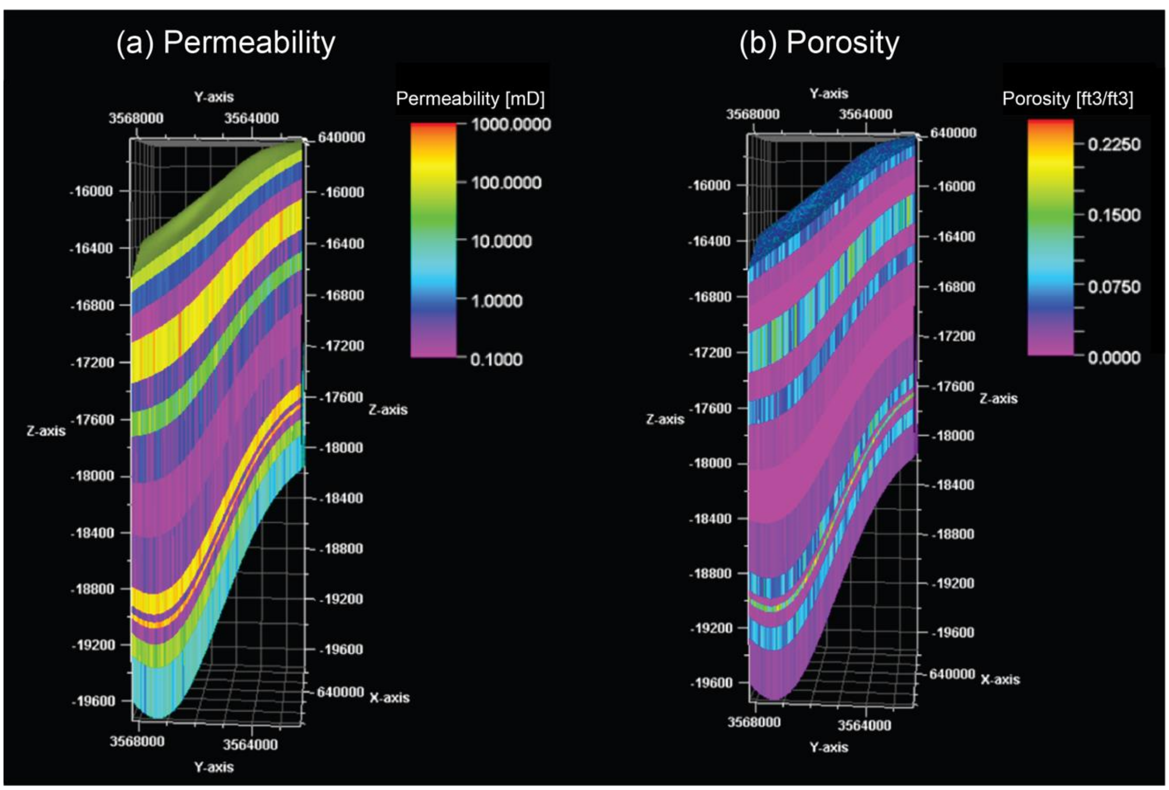


Figure 3.9-9 -- A 3D view of Siluro-Devonian modeled permeability (a) and porosity (b) distributions.

3.9.4 Simulation Modeling for proposed RH AGI # 2

Once the geological model was established, numerical modeling was performed to:

1) perform calibration of injection history for the SWD wells to ascertain the current subsurface conditions prior to injection of TAG into RH AGI #2
2) assess the storage potential within the Siluro-Devonian formation with and without the presence of faults discussed in Section 3.2.3
3) assess the storage potential in the presence of the Striker well operating at different rates
4) estimate the TAG extent considering above listed scenarios

An initial history match of the Striker well was performed from October 2018 and continued with the acid gas injection into the RH AGI #2 well for 30 years ending in 2050. The gas injection rate target was 13 MMSCF/D. After the calibration period, several scenarios were performed for the Striker well to ascertain potential impacts on the RH AGI #2 well. Several scenarios were investigated to show the impacts of high, medium, and low injection volumes for the Striker well: a maximum injection target of 32,500 stock tank barrels per day (Stb/d), a medium volume of injection rate at 15,000 Stb/d and a minimum injection volume at 7,472 Stb/d. The bottomhole injection pressure gradient based on the potential fracture pressure was constrained to 0.629 psi/foot. For all the injection scenarios modeled, injection of TAG in RH AGI #2 into the Siluro-Devonian zone was successfully demonstrated for the target injection rate of 13 MMSCF/D for the 30-year injection period. The TAG distribution remained the same at the end of the 5-year post-injection period. Note on the use of different injection rate units: "Stock tank barrels per day" is equivalent to "barrels per day" when referring to water, but the use of "stock tank barrels per day" is more standard as it reflects surface conditions. "Million standard cubic feet per day" is the appropriate unit when referring to injection of gas.

Figure 3.9-10 shows injection profiles of the AGI #2 well modeled at a target rate of 13 MMSCF/D with respect to three different injection target scenarios for the Striker well. The figure shows clearly that the Devonian has the capacity to store all volumes injected into both wells for all scenarios. Modeling showed that a slightly elevated pressure increase was mostly attributed to the water injection. The existing faults did not impede on the proposed injection strategy.

Figure 3.9-11 shows the furthest lateral extent of the gas saturation, stacking all the layers, when faults are closed to fluid flow. The injected TAG is far from reaching the edge of the model boundary. Non-transmissive faults combined with the Striker well pressure effects promote TAG dispersion in the north and south direction. Increasing the Striker well injection volume contribution progressively restricts dispersion in the eastern direction resulting in increasingly north-south elongation of the TAG plume. The TAG is predicted to extend a maximum of 1.17 km (0.73 miles) from the AGI wellbore.

Figure 3.9-12 shows the largest modelled lateral extent of the TAG, resulting from allowing faults to be fully transmissive in addition to allowing variable water injection targets in the Striker well. The simulation predicted an approximate radial dispersion pattern of acid gas within the area of the proposed AGI #2. With increasing injection volume contributions from the Striker well, eastern dispersion becomes increasingly restricted, and the TAG is displaced in a western direction. Maximum lateral distance from AGI wellbore after the 5-year post injection period is approximately 0.9 km (0.56 miles).

Modeling shows resultant TAG extent is highly dependent on operating conditions of the nearby Striker well, which exhibits the greatest potential to influence pressure conditions within the target reservoir. Pressure build-up in the Siluro-Devonian target reservoir from the Striker well is dependent on the saltwater disposal rate. Modeling demonstrates that the higher the injection rate, the higher the pressure differential, particularly near the wellbore. However, modeling responses showed that even if the Striker well is operated at a maximum allowable injection rate and volume, RH AGI #2 is well situated to safely inject the proposed target of 13 MMSCF/D regardless of any fault transmissibility.

Figures 3.9-11 and 3.9-12 show results from the sensitivity analysis performed assuming faults are either transmissive to flow or non-transmissive to flow and corresponding effects on the injected TAG subsurface movement and/or plume size. The TAG injection rate is 13 MMSCF/D for all three scenarios, and low, medium, and high injection rates are used for the Striker well. Figure 3.9-11 shows the supercritical TAG phase with the largest lateral footprint within the Devonian injection zone with respect to corresponding saltwater injection within the Striker well. This scenario assumes that the faults are non-transmissive to fluid flow along and across the faults (a fault transmissibility of zero (0)). The shape and the direction of the plume movement is affected by fault locations and the saltwater injection rate in the Striker well. The minimum and the average saltwater injection rates did not change the plume size much compared to the maximum potential saltwater injection rate. Figure 3.9-12 shows the largest plume size of the supercritical TAG for the modeled scenarios which assumed the mapped faults are open to fluid flow across and along the faults (a fault transmissibility of one (1)). The shape of the plume appears more radial especially for the scenarios involving minimum and average saltwater injection rates as compared with the results shown in Figure 3.9-11.

Figure 3.9-13 shows pressure profiles for injection into RH AGI #1 in the Cherry Canyon and RH AGI #2 in the Siluro-Devonian injection zone. The pressure in the Siluro-Devonian does not change significantly as a result of the injection activities irrespective of fault transmissivity. There is a slightly higher pressure for the non-transmissive fault scenario. There is a pressure drop which is expected during the 5-year shut-in monitoring period. With regards to the Cherry Canyon, due to the slightly lower permeability of the formation, there was, as expected, pressure build-up throughout the 30-year injection period and a reduction during the 5-year monitoring period. The pressure profiles demonstrate the strong potential for safe injection into both target formations.

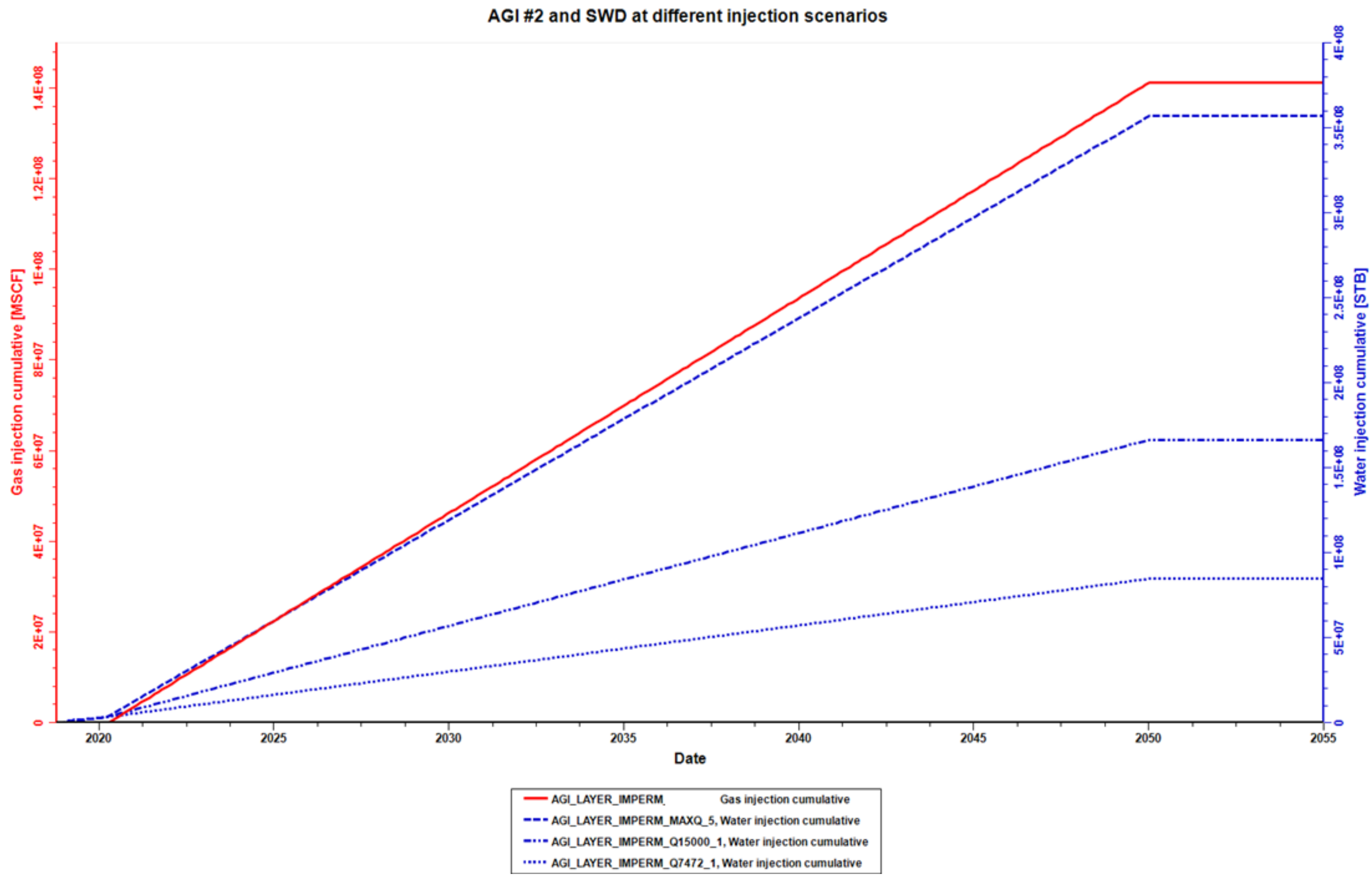


Figure 3.9-10 -- Graph showing the injection profile of the RH AGI #2 and the Striker well at different injection scenarios.

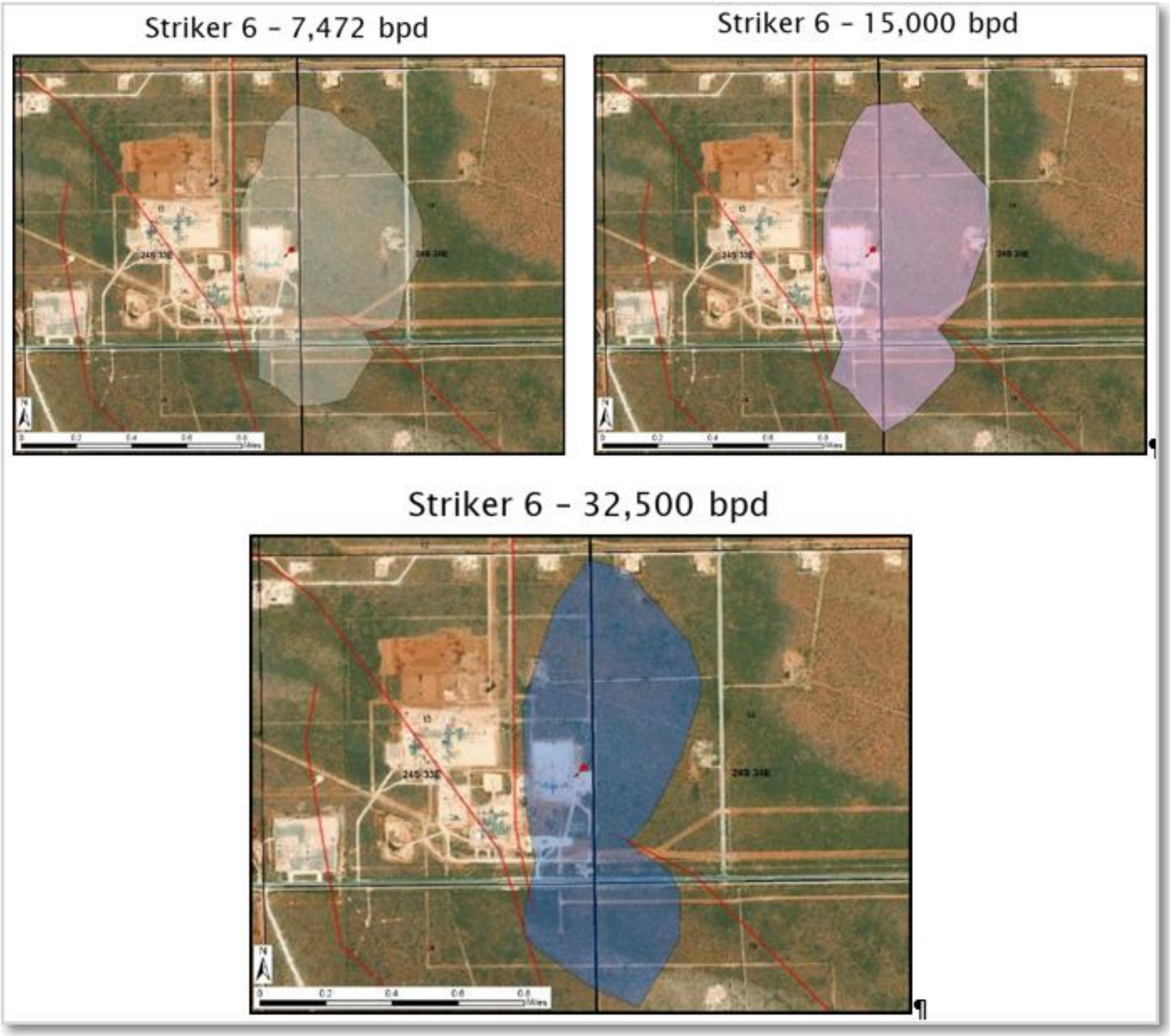


Figure 3.9-11 – Maps showing the largest lateral extent of the TAG when the interpreted faults are non-transmissive. The Striker 6 well injects into the Siluro-Devonian injection interval for RH AGI #2.

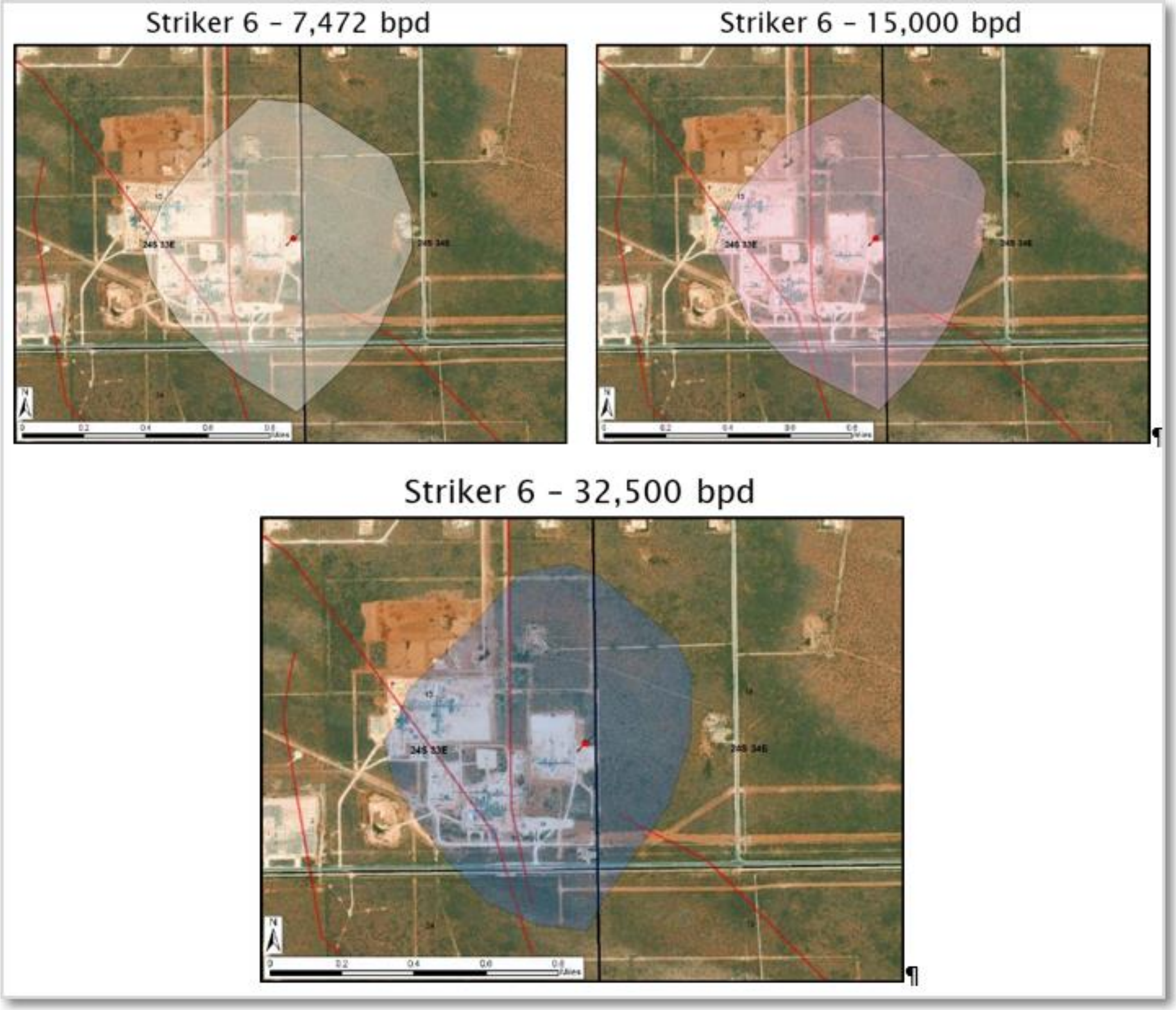


Figure 3.9-12 -- Maps showing the largest lateral extent of the TAG when the interpreted faults are transmissive. The Striker 6 well injects into the Siluro-Devonian injection interval for RH AGI #2.

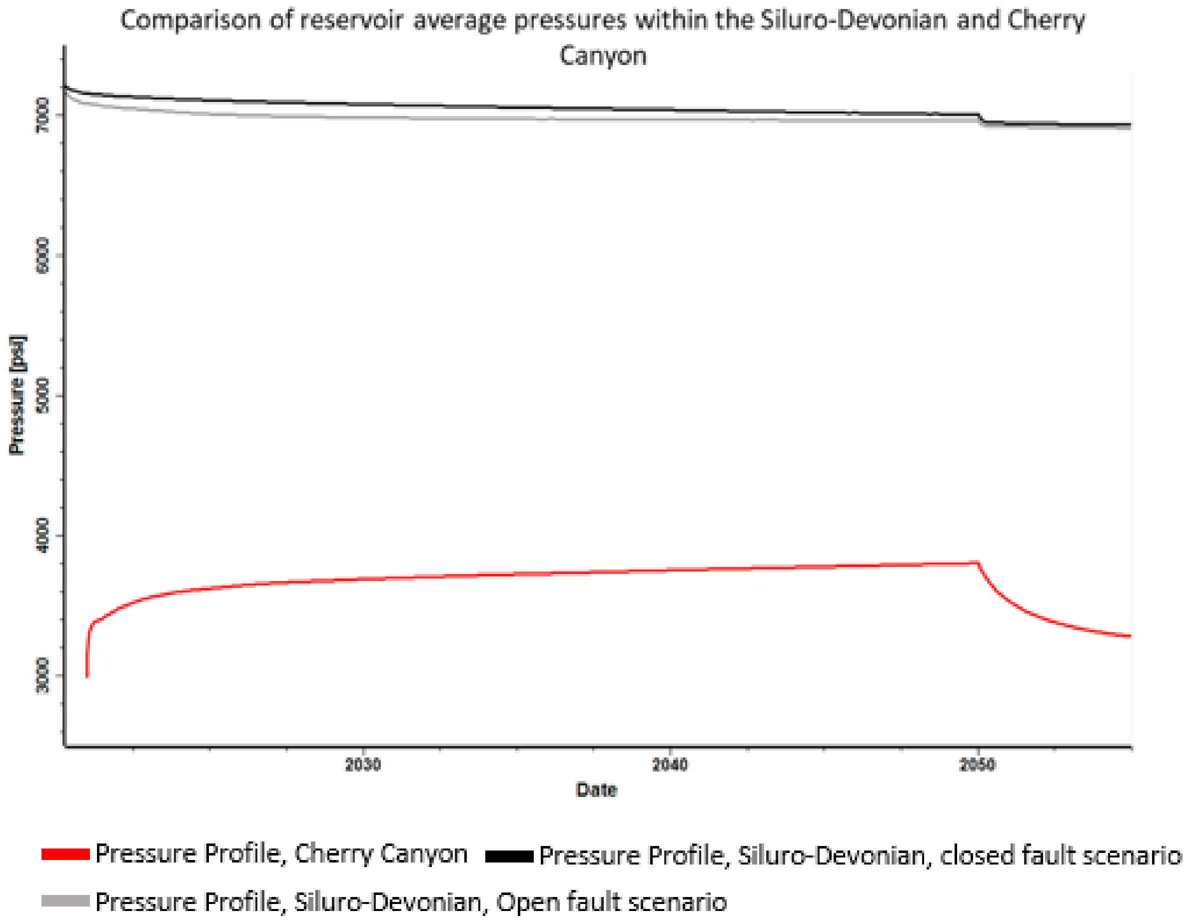


Figure 3.9-13 – Comparison of reservoir average pressure within the Siluro-Devonian and Cherry Canyon during injection and during the post-injection period

4 Delineation of the Monitoring Areas

In delineating the maximum monitoring area (MMA) and the active monitoring area (AMA), Lucid began by assessing the information provided in the UIC Class II permit application, particularly that pertaining to the 1-mile radius AoR. The modeling described in Section 3.9 indicates that the free phase CO_2 plume will be contained within the Class II AoR for the 30-year injection period plus the 5-year post injection monitoring period. This supports the conclusion that the site characterization required by the Class II permit application is sufficient in delineating the monitoring areas for this MRV plan and no additional site characterization was required.

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the MMA is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The plume extent for this MRV plan is comprised of the modeled extent in the:

- Cherry Canyon for RH AGI #1 as shown in Figure 3.9-7, and
- Siluro-Devonian for RH AGI #2 for the scenario in which faults were modeled as non-transmissive and the Striker well injection rates were 7,472 and 15,000 barrels per day (Figure 3.9-11), and
- Siluro-Devonian for RH AGI #2 for the scenario in which faults were modeled as transmissive and the Striker well injection rates were 7,472 and 15,000 barrels per day (Figure 3.9-12).

Figure 4.1-1 shows the MMA defined by the superposition of these modeled plumes plus a ½ mile buffer.

4.2 AMA – Active Monitoring Area

Lucid intends to define the AMA as the same area as the MMA.

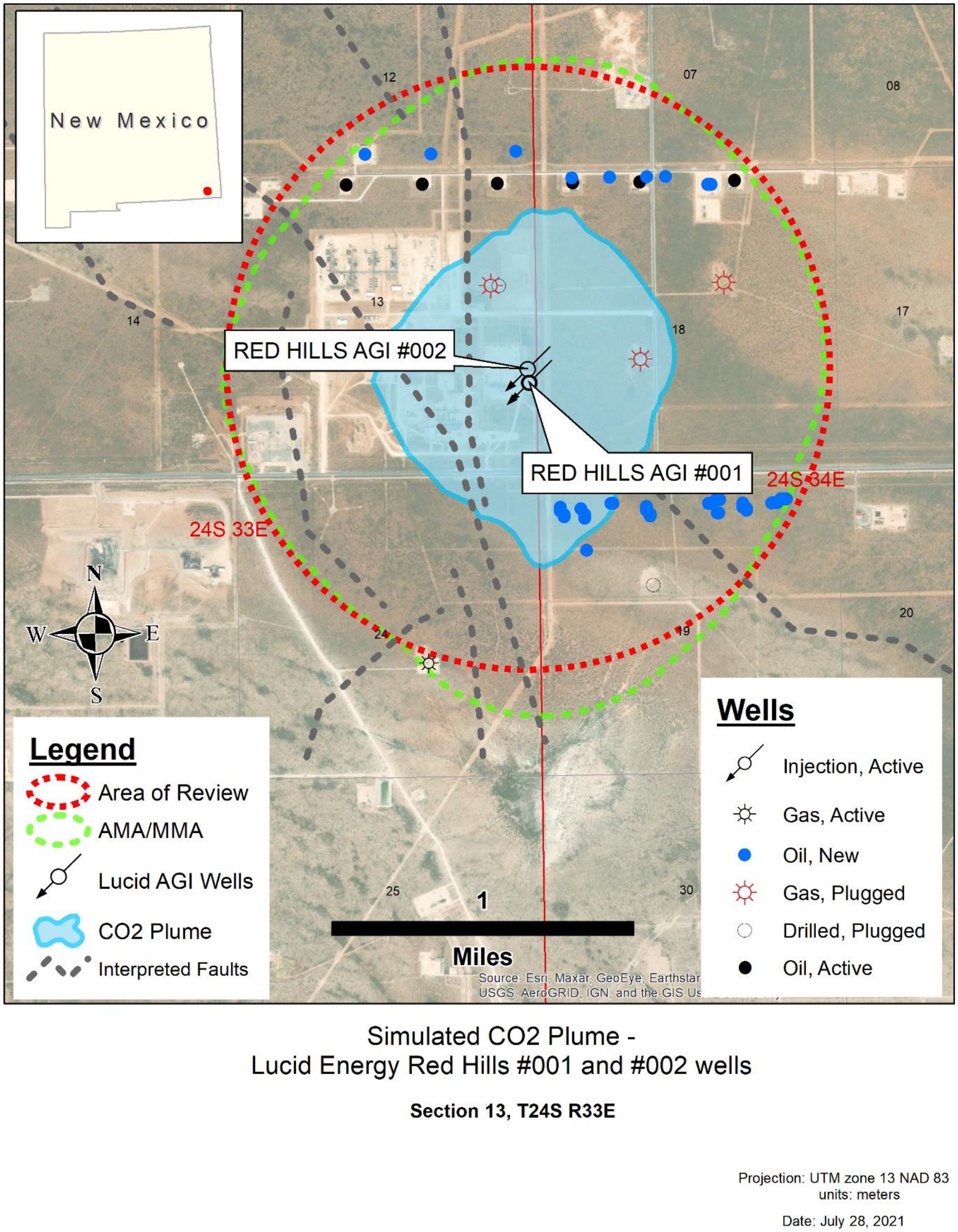


Figure 4.1-1 -- Maximum monitoring area (MMA) and active monitoring area (AMA) for Lucid Red Hill RH AGI #1 and RH AGI #2 Wells. The Class II Area of Review (AoR) is also shown.

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

Subpart RR at 40 CFR 448(a)(2) requires the identification of potential surface leakage pathways for CO_2 in the MMA and the evaluation of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways.

Through the site characterization required by the NMOCD C-108 application process for Class II injection wells and the reservoir modeling described in Section 3.9, Lucid has identified and evaluated the following potential CO_2 leakage pathways to the surface.

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. To minimize this potential for leakage, the construction, operation, and maintenance of gas plants follows industry standards and relevant regulatory requirements. Additionally, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills."

To further minimize the likelihood of surface leakage of CO_2 from surface equipment, Lucid implements a schedule for regular inspection and maintenance of surface equipment. To further minimize the magnitude and duration (timing) of detected gas leaks to the surface, Lucid implements several methods for detecting gas leaks at the surface. Detection is followed up by immediate response. These methods are described in more detail in sections 6 and 7.

Figure 5.1-1 is a schematic (taken from the Red Hills H_2S Contingency Plan) of the surface equipment at the Red Hills Gas Plant showing the location of the fixed H_2S monitors, the number of which is greater in the vicinity of the sour gas plant, the sour gas pipeline, and the RH AGI wells.

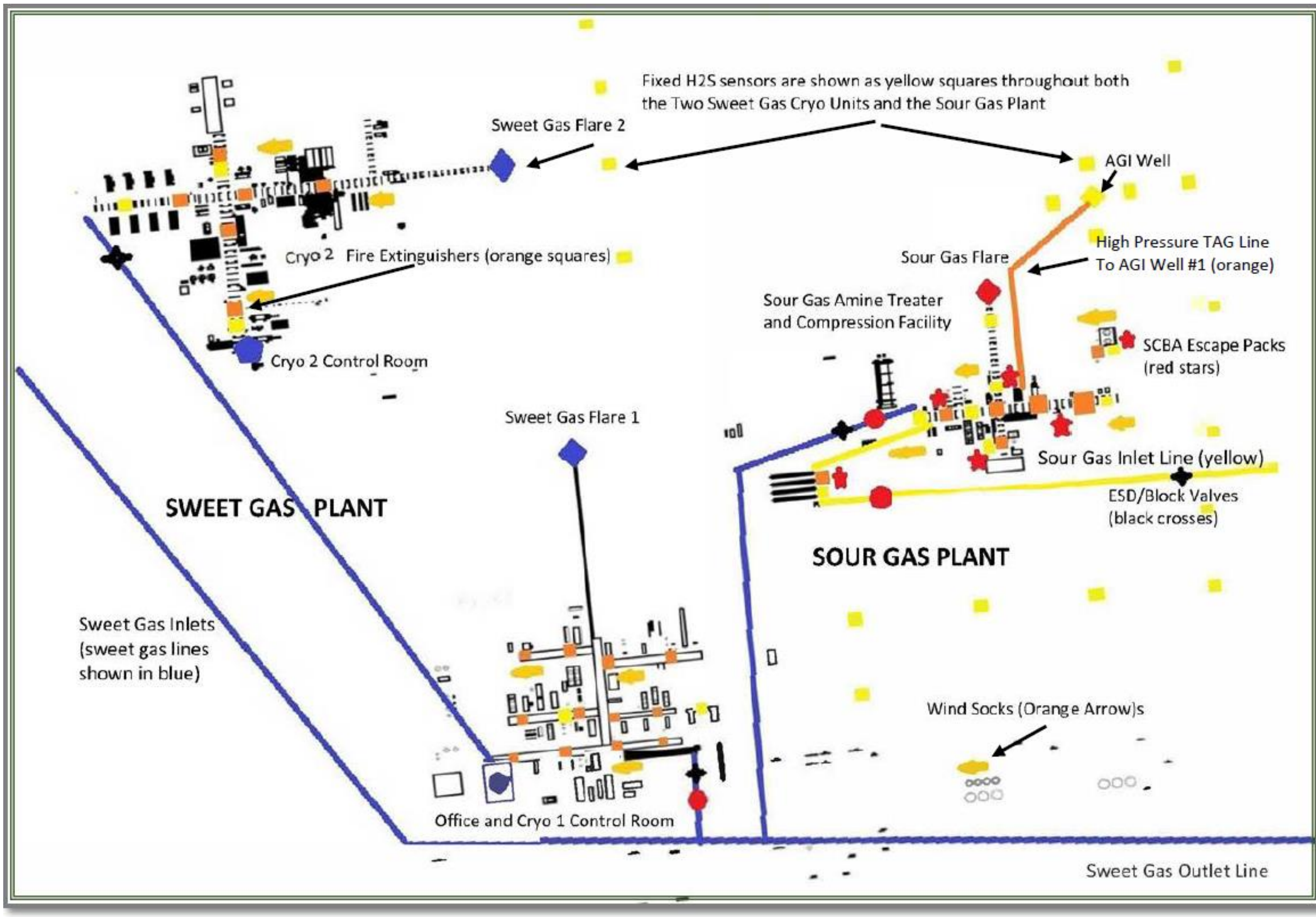


Figure 5.1-1 -- Red Hill Gas Plant plot plan showing location of major process units (taken from the H_2S Contingency Plan for Red Hills). The yellow squares indicate the location of fixed H_2S sensors.

5.2 Potential Leakage from Approved, Not Yet Drilled Wells

5.2.1 RH AGI #2

The only new well Lucid plans to drill within the MMA is the proposed RH AGI #2 well. To minimize the likelihood of leaks from new wells, NMAC 19.15.26.9 regarding the casing and cementing of injection wells requires operators to case injection wells "with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string." Additionally, the NMOCC Order No. R-20916-H for the proposed RH AGI #2 well requires "the use of corrosion-resistant casing or cement in the proposed injection interval in the Silurian-Devonian formations and the existing injection interval for the Red Hills AGI No. 1 (API No. 30-025-40448) in the Delaware Mountain Group." To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, NMAC 19.15.16.12 requires the use of "blowout preventers in areas of high pressure at or above the projected depth of the well." These requirements apply to any other new well drilled within the MMA for this MRV plan.

Lucid realizes that when they drill the RH AGI #2, they will be drilling through a reservoir in which they have been injecting H_2S and CO_2 for many years. Therefore, for safety purposes, they will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 escapes to the surface during the drilling of RH AGI #2. Enhanced measures include:

- Using a heavier-than-normal drilling mud to keep weight pushing from inside the borehole to the outside thereby minimizing the chance of any gas from entering the wellbore
- Using LCM (loss control material) at a higher-than-normal rate to fill in the pockets of the wellbore thereby minimizing the chance of gas from entering the wellbore while drilling
- Monitoring H_2S at surface at many points to assure operators that we are successfully keeping any possible gas pressures from impacting the drilling operation
- Employing a high level of caution and care while drilling through a known H_2S injection zone, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling through the RH AGI #1 injection zone

5.2.2 Horizontal Wells

The table in Appendix 3 and Figure 4.1-1 shows a number of horizontal wells in the area, many of which have approved permits to drill but which are not yet drilled. If any of these wells are drilled through the Cherry Canyon injection zone for RH AGI #1, they will be required to take special precautions to prevent leakage of TAG minimizing the likelihood of CO_2 leakage to the surface. This requirement will be made by NMOCD in regulating applications for permit drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation.

5.3 Potential Leakage from Existing Wells

As shown in Figure 3.7-1 and detailed in Table 3.7-1, there are 13 existing oil- and gas-related wells within the Class II 1-mile radius AoR which is nearly equivalent to the MMA in area (Figure 4.1-1).

5.3.1 Well Completed in the Cherry Canyon Formation

The only well completed in the Cherry Canyon Formation within the MMA is the RH AGI #1 well. Figure 3.6-2 is a schematic of the well construction showing multiple strings of casing which were all cemented to surface. Injection of TAG occurs through tubing with a permanent production packer set at 6,170 feet, 60 feet above the Cherry Canyon injection zone. This construction minimizes the likelihood that leakage of CO_2 along the borehole to the surface will occur. Furthermore, the continuous monitoring of operational parameters and immediate response when these parameters fall outside acceptable ranges (see Section 6.3.1) minimizes the magnitude and timing of CO_2 leaks that may be associated with the operation of the well.

5.3.2 Wells Completed in the Bone Spring / Wolfcamp Zones

Six of the 13 wells are completed in the Bone Spring and Wolfcamp zones as described in Section 3.7.2. These productive zones lie at least 2,500 feet above the proposed RH AGI #2 injection zone at 16,000 feet and more than 2,000 feet below the RH AGI #1 injection zone minimizing the likelihood of communication between the injection zones and the Bone Spring / Wolfcamp production zones. Construction of these wells includes surface casing set at 1,375 feet and cemented to surface and intermediate casing set at the top of the Bell Canyon at depths of from 5,100 to 5,200 feet and cemented through the Permian Ochoan evaporites, limestone and siltstone (Figure 3.2-2) providing zonal isolation preventing TAG injected into the Cherry Canyon Formation through RGH AGI #1 from leaking upward along the borehole in the event the TAG plume were to reach these wellbores. Figure 4.1-1 shows that the modeled TAG plume extent after 30 years of injection and 5 years of post-injection stabilization does not extend to these well boreholes thereby indicating that these well are not likely to be pathways for CO_2 leakage to the surface.

5.3.3 Wells Completed in the Siluro-Devonian Zone

One well penetrated the Devonian within the MMA - EOG Resources, Government Com 001, API #3002525604, TVD = 17,625 feet, 0.72 miles from proposed RH AGI #2. This well was drilled to a total depth of 17,625 feet on March 5, 1978, but plugged back to 14,590 feet, just below the Morrow, in May of 1978. Subsequently, this well was permanently plugged and abandoned on December 30, 2004, and approved by

NMOCD on January 4, 2005 (see Appendix 9). The approved plugging provides zonal isolation for both the Siluro-Devonian injection zone and the Cherry Canyon Formation injection zone minimizing the likelihood that this well will be a pathway for CO_2 leakage to the surface from either injection zone.

5.3.4 Groundwater Wells

Figure 3.6-1 shows 15 water wells within a 2-mile radius of the RH AGI wells, only 2 of which are within a 1-mile radius of the RH AGI wells. The deepest ground water well is 650 feet deep (Table 3.6-1). The evaporite sequence of the Permian Ochoan Salado and Castile Formations (see Section 3.2.2) provide an excellent seal between these groundwater wells and the Cherry Canyon injection zone of the RH AGI #1 well. Therefore, it is unlikely that these two groundwater wells are a potential pathway of CO_2 leakage to the surface. Nevertheless, the CO_2 surface monitoring and groundwater monitoring described in Sections 6 and 7 will provide early detection of CO_2 leakage followed by immediate response thereby minimizing the magnitude of CO_2 leakage volume via this potential pathway.

5.4 Potential Leakage through Fractures and Faults

5.4.1 RH AGI #1

No faults were identified in the confining zone above the Cherry Canyon injection zone for RH AGI #1. Therefore, leakage of CO_2 from this injection zone to the surface via faults is very unlikely.

5.4.2 RH AGI #2

Simulation modeling presented in Section 3.9 addressed the possible existence of interpreted faults discussed in Sections 3.2.3 and 3.5 and their possible impact on TAG plume migration within the Siluro-Devonian injection zone for RH AGI #2. However, there is no evidence that faults that occur or may occur in the lower Paleozoic section extend through the nearly 200 feet of Woodford Shale, the lowermost unit of the RH AGI #2 confining zone, in the immediate area around the Red Hills Gas Plant, although such an interpretation was made to account for the steep dip in the section in a cluster of wells several miles to the north-northeast of the Red Hill Gas Plant (Figures 3.2-4 and 3.2-5). Furthermore, overpressure in the eastern Delaware Basin associated with Mississippian, Pennsylvanian, and Permian shale sequences (Luo et al., 1994) will act as a barrier restricting vertical migration of CO_2.

5.5 Potential Leakage through the Confining / Seal System

Subsurface lithologic characterization at the Red Hills Gas Plant (see Section 3.3) reveals excellent upper and lower confining zones for the injection zones for RH AGI #1 and for RH AGI #2.

5.5.1 RH AGI #1

The site characterization for the injection zone of the RH AGI #1 well described in Sections 3.2.2 and 3.3.1 indicates a thick sequence of Permian Ochoan evaporites, limestone, and siltstones (Figure 3.2-2) above the Cherry Canyon Formation and no evidence of faulting. Therefore, it is unlikely that TAG injected into the Cherry Canyon Formation will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface. Section 6.3.1 describes operational monitoring in place to prevent CO_2 leakage from the RH AGI #1 well.

5.5.2 RH AGI #2

As described in Section 3.3.2, the confining zone above the Siluro-Devonian injection zone has excellent cap rocks above, below and between the individual porous carbonate units. The injection zone is separated from the nearest overlying producing zone (Morrow) by 200 feet of Woodford shale, 550 feet of tight Osagean limestones, and nearly 350 feet of tight Chesterian shales and deep-water limestones. Furthermore, the faulting as described in Section 3.2.3 is primarily confined to the lower Paleozoic section where fracture-affected rocks extend only up to the base of the lower Woodford Shale immediately above the Siluro-Devonian injection zone. This combination of a sequence of tight overlying formations and the restriction of faulting to within the lower Paleozoic section minimizes the likelihood of leakage of CO_2 through the confining zone. Again, overpressure in the overlying shale sequences will serve as a barrier to vertical migration of CO_2. Limiting the injection pressure to less than the fracture pressure of the confining zone will further minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

5.6 Potential Leakage due to Natural / Induced Seismicity

The potential for leaks initiated by induced seismicity was addressed in Section 3.5. It was concluded that generally, faults considered in this assessment do not display significant potential for injection-induced slip and the proposed RH AGI #2 is not predicted by the FSP model to contribute significantly to the total resultant pressure front. Lucid concludes that the likelihood for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced seismicity is low. Nevertheless, the NMOCC Order No. R-20916-H requires Lucid to install, operate, and monitor for the life of the project a seismic monitoring station or stations described in more detail in Section 7.6.

Additionally, there have been no seismic events, natural or induced, detected within the MMA for this MRV plan. Therefore, Lucid concludes that the likelihood, magnitude, and timing of natural seismicity is minimal.

5.7 Potential Leakage due to Lateral Migration

5.7.1 RH AGI #1

The characterization of the sand layers in the Cherry Canyon Formation described in Section 3.3.1 states that these sands were deposited by turbidites in channels in submarine fan complexes, each sand is encased in low porosity and permeability fine-grained siliciclastics and mudstones with lateral continuity. Regional consideration of their depositional environment suggests a preferred orientation for fluid and gas flow would be south-to-north along the channel axis. However, locally the high net porosity of the RH AGI #1 injection zone indicates adequate storage capacity such that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA due to a preferred regional depositional orientation.

5.7.2 RH AGI #2

Lateral migration of the injected TAG was addressed in the simulation modeling detailed in Section 3.9. The results of that modeling indicate the TAG is unlikely to migrate laterally beyond approximately ¾ mile within the injection zone to encounter any conduits to the surface.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO_2. Lucid will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. Lucid considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage. Table 6-1 summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection and the 5-year post-injection period.

Table 6.1 – Summary of Leak Detection Monitoring

Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections

Leakage Pathway	Detection Monitoring
	• Inline inspections • Fixed in-field gas monitors/CO_2 monitoring network • Personal and hand-held gas monitors
New RH AGI Well	• Vigilant monitoring of fluid returns during drilling • Multiple gas monitoring points around drilling operations – personal and hand-held gas monitors
New Other Operator Wells	• Vigilant monitoring of fluid returns during drilling • Multiple gas monitoring points around drilling operations – personal and hand-held gas monitors
Existing RH AGI Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 monitoring network • Personal and hand-held gas monitors • In-well P/T sensors
Existing Other Operator Active Wells	• Monitoring of well operating parameters • Visual inspections • MITs
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO2 monitoring network
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO2 monitoring network
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO2 monitoring network

6.1 Leakage from Surface Equipment

Lucid implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters.

Leaks from surface equipment are detected by Lucid field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events. Lucid also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the distributed control system (DCS) housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

The following description of the gas detection equipment at the Red Hills Gas Processing Plant was extracted from the H_2S Contingency Plan:

> "**Fixed Monitors**
> The Red Hills Plant has numerous ambient hydrogen sulfide detectors placed strategically throughout the Plant to detect possible leaks. Upon detection of hydrogen sulfide at 10 ppm at any detector, visible beacons are activated, and an alarm is sounded. Upon detection of hydrogen sulfide at 90 ppm at any detector, an evacuation alarm is sounded throughout the Plant at which time all personnel will proceed immediately to a designated evacuation area. The Plant utilizes fixed-point monitors to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the Distributed Control System (DCS). The monitors are equipped with amber beacons. The beacon is activated at 10 ppm. The plant and AGI Well horns are activated with a continuous warbling alarm at 10 ppm and a siren at 90 ppm. All monitoring equipment is Red Line brand. The Control Panel is a 24 Channel Monitor Box, and the fixed point H_2S Sensor Heads are model number RL-101.
>
> The Plant will be able to monitor concentrations of H_2S via H_2S Analyzers in the following locations:
> - Inlet gas of the combined stream from Winkler and Limestone
> - Inlet sour liquid downstream of the slug catcher
> - Outlet Sweet Gas to Red Hills 1
> - Outlet Sweet Liquid to Red Hills Condensate Surge
>
> The AGI system monitors can also be viewed on the PLC displays located at the Plant. These sensors are all shown on the plot plan (see Figure 5.1-1). This requires immediate action for any occurrence or malfunction. All H_2S sensors are calibrated monthly.
>
> **Personal and Handheld H2S Monitors**
> All personnel working at the Plant wear personal H_2S monitors. The personal monitors are set to alarm and vibrate at 10 ppm. Handheld gas detection monitors are available at strategic locations around the Plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and carbon dioxide (CO_2)."

Lucid's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S.

Quantification of CO_2 emissions from surface equipment and components will be estimated according to the requirements of 98.448 (d) of Subpart RR as discussed in Sections 8.4 and 10.4.

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones as described in Section 5.2.1 for RH AGI #2 including more frequent monitoring during drilling operations. This applies to Lucid and other operators drilling new wells through the RH AGI injection zones.

6.3 Leakage from Existing Wells

6.3.1 RH AGI Wells

As part of ongoing operations, Lucid continuously monitors and collects flow, pressure, temperature, and gas composition data in the data collection system. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

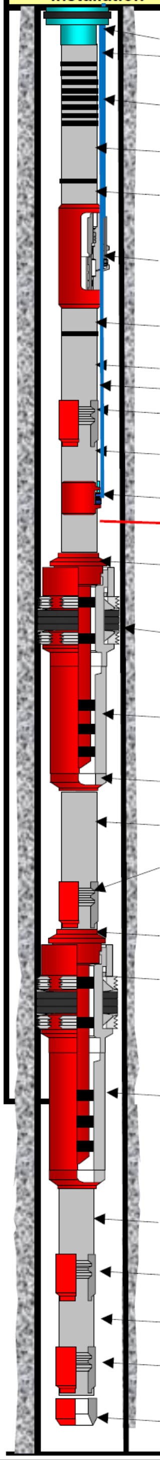
To monitor leakage and wellbore integrity, two pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) were deployed in Lucid's AGI #1 well. One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing. (Figure 6.2-1). A leak is indicated when both gauges start reading the same pressure. DTS is clamped to the tubing, and it monitors the temperature profiles of the annulus from 6,159 feet to surface. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical analysis.

HALLIBURTON

Installation

Lucid
Red Hills AGI 1
Lea County New Mexico
2/3/21 - 2/28/21

WSP - Troy Gillen / Michael Forrier
Sales Rep - Lynn Talley (432) 631-4626
Tool Specialists: Carey Lehmann, Jonathan Phillips, Jose Vargas



Installation	Depth	Length	Jts.	Description	OD	ID
	18.50	18.50		KB		
20	22.90	4.40		20) Hanger Sub 3 1/2" 9.2# CRA VAMTOP x 7.7# VAM Ace Pin	7.000	3.000
19	64.05	41.15	1	19) 3 1/2" 7.7# VAM ACE 125K G3 Tubing (Slick Joint)	3.500	3.035
				Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'		
18	103.97	39.92		18) 3 1/2" 7.7# VAM ACE 125K G3 Spaceout Subs	3.500	3.035
17	235.95	131.98	3	17) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.035
16	241.95	6.00		16) 6' x 3 1/2" 7.7# CRA VAM ACE Box x 9.2# VAMTOP Pin	3.540	2.959
15	246.30	4.35		15) 3 1/2" NE HES SSSV Nickel Alloy 925 w/Alloy 825 Control Line 3 1/2" 9.2# VAMTOP Box x Pin	5.300	2.813
14	252.29	5.99		14) 6' x 3 1/2" 9.2# CRA VAMTOP Box x 7.7# VAM ACE Pin	3.540	2.959
13	6,140.23	5,887.94	134	13) 3 1/2" 7.7# VAM ACE 125K G3 Tubing	3.500	3.305
12				12) 3 1/2" 7.7# VAM ACE Box x 9.2# VAMTOP Pin CRA Crossover	3.830	2.959
11				11) 2.813" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925	4.073	2.813
10	6,153.72	13.49		10) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy G3 Sub	3.540	2.959
				13.49' Length Includes Line Items 10, 11 & 12		
9	6,159 Tubing	P/T		9) Baker PT Sensor Mandrel 3 1/2" 9.2# VAMTOP Box x Pin 6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl	5.200	2.992
	6,162.6 Annular	P/T				
8	6,161.23	7.51		8) 4.00" BWS Landed Seal Asmbly 9.2# VAM TOP Nickel Alloy 925	4.470	2.959
				7.51' Length Includes Line Items 8 & 9		
7	6,164.55	3.32		7) 7" 26-32# x 4.00" BWS Packer Nickel Alloy 925 Casing Collar @ 6,160.6' WL Measurement	5.875	4.000
6	6,172.05	7.5		6) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.032	4.000
5	6,172.88	0.83		5) 4.00" PBR Adapter x 9.2# VAMTOP BxP Nickel Alloy 925	5.680	2.959
4	6,181.19	8.31		4) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub Nickel Alloy G3	3.540	2.959
3	6,182.52	1.33		3) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel Alloy 925 #102204262	4.073	2.562
2	6,184.29	1.77		2) Straight Slot Locator Seal Assembly Above Top Of Packer	4.450	2.880
1		6,186.06		1) BWD Permanent Packer. WL Measured Depth Previously 6189'	5.875	4.000
1a				1a) 4.00" x 8' PBR Nickel Alloy 925 4 3/4"-8 UN 2A Pin x Pin	5.660	2.965
1b				1b) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1c				1c) 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel,	2.920	2.562
1d				1d) 8' x 3 1/2" 9.2# VAMTOP BxP Tbg Sub , 925	3.520	2.989
1e				1e) 2.562" RN Nipple 3 1/2" 9.2# VAMTOP Box x Pin Nickel	3.920	2.321
1f				1f) Re-Entry Guide / POP	3.950	3.000

Figure 6.2-1 -- Well Schematic for RH AGI #1 showing installation of P/T sensors

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage.

6.4 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults. Continuous operational monitoring of the RH AGI wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone.

6.5 Leakage through the Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the RH AGI wells, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone.

6.6 Leakage due to Natural / Induced Seismicity

Continuous operational monitoring of the RH AGI wells, described in Sections 6.3 and 7.5 coupled with a detection of a seismic event by the seismic stations described in Section 7.6 will provide an indicator if CO_2 leaks out of the injection zone due to a seismic event.

6.7 Leakage due to Lateral Migration

Continuous operational monitoring of the RH AGI wells during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The CO_2 monitoring network described in Section 7.3, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

Lucid uses the existing automatic distributed control system to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. Lucid considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to establish baselines for monitoring CO_2 surface leakage. The following describes Lucid's strategy for collecting baseline information.

7.1 Visual Inspection

Lucid field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the Red Hills Gas Plant.

7.2 Fixed In-Field, Handheld, and Personal H_2S Monitors

Compositional analysis of Lucid's gas injectate at the Red Hills Gas Plant indicates an approximate H_2S concentration of 12% thus requiring Lucid to develop and maintain an H_2S Contingency Plan (Plan) according to the NMOCD Hydrogen Sulfide Gas Regulations, Rule 11 (19.15.11 NMAC). Lucid considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated RH AGI Wells and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

The Red Hills Gas Plant utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS. Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of hydrogen sulfide at 90 ppm at any monitor, an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

7.2.2 Handheld and Personal H_2S Monitors

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and CO_2.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant (DE-FE0031837 – Carbon Utilization and Storage Project of the Western USA (CUSP)), will assist Lucid in setting up a monitoring network for CO_2 leakage detection in the AMA as defined in Section 4.2. The scope of work for the DOE project includes field sampling activities to monitor CO_2/H_2S at the two RH AGI wells. These activities include periodic well (groundwater and gas) and atmospheric sampling from an area of 10 – 15 square miles around the injection wells. Once the network is set up, Lucid will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS, and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat. Also, see Section 6.2 for continuous monitoring of P/T in the well.

7.5 Well Surveillance

Lucid adheres to the requirements of NMOCC Rule 26 governing the construction, operation and closing of an injection well under the Oil and Gas Act. Rule 26 also includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, NMOCC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. Lucid’s Routine Operations and Maintenance Procedures for the RH AGI wells ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic Monitoring Stations

Lucid will purchase a model TCH120-1 Trillium Compact Horizon Seismometer and a model CTR4-3S Centaur Digital Recorder to monitor for and record data for any seismic event at the Red Hills Gas Plant. The seismic station will meet the requirements of the NMOCC Order No. R-20916-H to “install, operate, and monitor for the life of the [Class II AGI] permit a seismic monitoring station or stations as directed by the Manager of the New Mexico Tech Seismological Observatory (“state seismologist”) at the New Mexico Bureau of Geology and Mineral Resources.”

7.7 Groundwater Monitoring

New Mexico Tech, through the same DOE research grant described in Section 7.3 above, will monitor groundwater wells for CO_2 leakage which are located within the AMA as defined in Section 4.2.

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

Appendix 7 summarizes the twelve Subpart RR equations used to calculate the mass of CO_2 sequestered annually. Appendix 8 includes the twelve equations from Subpart RR. Not all of these equations apply to Lucid’s current operations at the Red Hills Gas Plant but are included in the event Lucid's operations change in such a way that their use is required.

8.1 CO_2 Received

Currently, Lucid receives gas to its Red Hills Gas Plant through six pipelines: Gut Line, Winkler Discharge, Red Hills 24" Inlet Loop, Greyhound Discharge, Limestone Discharge, and the Plantview Loop. Lucid will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3.

Although Lucid does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When Lucid begins to receive CO_2 in containers, Lucid will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Lucid will adhere to the requirements in 40 CFR 98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

8.2 CO_2 Injected

Lucid injects CO_2 into the existing RH AGI #1. Upon its completion, Lucid will commence injection into RH AGI #2. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12.

8.3 CO_2 Produced / Recycled

Lucid does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

As required by 98.448 (d) of Subpart RR, Lucid will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12.

8.5 CO_2 Sequestered

Since Lucid does not actively produce oil or natural gas or any other fluid at its Red Hills Gas Plant, Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead.

9 Estimated Schedule for Implementation of MRV Plan

Lucid will implement this MRV plan as soon as it is approved by EPA. After RH AGI #2 is drilled, Lucid will reevaluate the MRV plan and update it to reflect any necessary modifications.

10 GHG Monitoring and Quality Assurance Program

Lucid will meet the monitoring and QA/QC requirements of 40 CFR 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40 CFR 98.444 (d).

10.1 GHG Monitoring

As required by 40 CFR 98.3(g)(5)(i), Lucid's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR 98.444(a)(3).

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2 and RR-5, of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 15.025 psia (Appendix 6). Lucid will adhere to the American Gas Association (AGA) Report #3 – Orifice Metering.

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the RH AGI #1 and #2 wells using accepted flow calculations for CO_2 according to the AGA Report #3.

10.1.4 CO_2 produced.

Lucid does not produce CO_2 at the Red Hills Gas Plant.

10.1.5 CO_2 emissions from equipment leaks and vented emissions of CO_2.

As required by 98.444 (d), Lucid will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

As required by 98.444 (d) of Subpart RR, Lucid will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used.

10.1.6 Measurement devices.

As required by 40 CFR 98.444(e), Lucid will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards

organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

Lucid will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

10.3 Estimating Missing Data

Lucid will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in Subpart RR, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

10.4 Revisions of the MRV Plan

Lucid will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of New Mexico. Lucid intends to update the MRV plan after RH AGI #2 has been drilled and characterized.

11 Records Retention

Lucid will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, Lucid will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:

(i) The GHG emissions calculations and methods used

(ii) Analytical results for the development of site-specific emissions factors, if applicable

(iii) The results of all required analyses

(iv) Any facility operating data or process information used for the GHG emission calculations

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, Lucid will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A copy of the most recent revision of this MRV Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(12) Any other records as specified for retention in this EPA-approved MRV plan.

12 Appendices

Appendix 1 - Lucid Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Red Hills AGI #1	30-025-40448	1600’ FSL, 150’ FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	10/23/2013	6,650’	6,170’
Red Hills AGI #2	Not yet assigned	1800’ FSL, 150’ FEL Sec. 13, T24S, R33E, NMPM	Lea, NM	Not Drilled Yet	17,600’	15,950’

Appendix 2 - Referenced Regulations

U.S. Code > Title 26. INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1. NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits > Section 45Q - Credit for carbon oxide sequestration

New Mexico Administrative Code (NMAC) > Title 19 – Natural resources > Chapter 15 – Oil and Gas

CHAPTER 15 - OIL AND GAS

19.15.1 NMAC	GENERAL PROVISIONS AND DEFINITIONS [REPEALED]
19.15.2 NMAC	GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS
19.15.3 NMAC	RULEMAKING
19.15.4 NMAC	ADJUDICATION
19.15.5 NMAC	ENFORCEMENT AND COMPLIANCE
19.15.6 NMAC	TAX INCENTIVES
19.15.7 NMAC	FORMS AND REPORTS
19.15.8 NMAC	FINANCIAL ASSURANCE
19.15.9 NMAC	WELL OPERATOR PROVISIONS
19.15.10 NMAC	SAFETY
19.15.11 NMAC	HYDROGEN SULFIDE GAS
19.15.12 NMAC	POOLS
19.15.13 NMAC	COMPULSORY POOLING
19.15.14 NMAC	DRILLING PERMITS
19.15.15 NMAC	WELL SPACING AND LOCATION
19.15.16 NMAC	DRILLING AND PRODUCTION
19.15.17 NMAC	PITS, CLOSED-LOOP SYSTEMS, BELOW-GRADE TANKS AND SUMPS
19.15.18 NMAC	PRODUCTION OPERATING PRACTICES
19.15.19 NMAC	NATURAL GAS PRODUCTION OPERATING PRACTICE
19.15.20 NMAC	OIL PRORATION AND ALLOCATION
19.15.21 NMAC	GAS PRORATION AND ALLOCATION
19.15.22 NMAC	HARDSHIP GAS WELLS
19.15.23 NMAC	OFF LEASE TRANSPORT OF CRUDE OIL OR CONTAMINANTS
19.15.24 NMAC	ILLEGAL SALE AND RATABLE TAKE
19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES
19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33

19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3 - Oil and Gas Wells within 2-mile Radius of the RH AGI Site

API	OPERATOR	WELL NAME	T	R	S	SPUD DATE	PLUG DATE	TVD DEPTH	WELL TYPE	COMPL STATUS	DIST (MI)
30-025-34246	DEVON ENERGY PRODUCTION COMPANY, LP	STEVENS 11 #001	24S	33E	11	20-Jan-98		15250	G	Plugged	1.90
30-025-41099	COG OPERATING LLC	ROY BATTY FEDERAL COM #001H	24S	33E	11	24-Jun-13		10700	O	Active	1.98
30-025-34050	EOG RESOURCES INC	LELA MAE STEVENS FEDERAL COM #001	24S	33E	14	23-Oct-97	13-Mar-02	13840	G	Plugged	1.64
30-025-41332	COG OPERATING LLC	ROY BATTY FEDERAL COM #002H	24S	33E	11	1-Nov-13		11101	O	Active	1.75
30-025-43032	DEVON ENERGY PRODUCTION COMPANY, LP	BOOMSLANG 14 23 FEDERAL #009H	24S	33E	14	13-Aug-17		10658	O	Active	1.59
30-025-43308	DEVON ENERGY PRODUCTION COMPANY, LP	BOOMSLANG 14 23 FEDERAL #002H	24S	33E	14	18-Aug-17		9485	O	Active	1.80
30-025-42920	DEVON ENERGY PRODUCTION COMPANY, LP	BOOMSLANG 14 23 FEDERAL #001H	24S	33E	14	28-Jul-17		9517	O	Active	1.48
30-025-42933	DEVON ENERGY PRODUCTION COMPANY, LP	BOOMSLANG 14 23 FEDERAL #004H	24S	33E	14	5-Jul-17		11274	O	Active	1.47
30-025-41333	COG OPERATING LLC	ROY BATTY FEDERAL COM #003H	24S	33E	11	28-Nov-13		11116	O	Active	1.50
30-025-45083	MATADOR PRODUCTION COMPANY	CHARLES LING FEDERAL COM #214H	24S	33E	11	4-Dec-18		12278	O	Active	1.95
30-025-42789	COG OPERATING LLC	TYRELL FEE #002H	24S	33E	14	4-Nov-15		9359	O	Active	1.31
30-025-41026	COG OPERATING LLC	TYRELL FEE #001H	24S	33E	14	24-Apr-13		10951	O	Active	1.26
30-025-43237	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL #003H	24S	33E	23	1-Jul-17		9399	O	Active	1.71
30-025-43239	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL #006H	24S	33E	23	26-Jun-17		9408	O	Active	1.71
30-025-43238	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL #004H	24S	33E	23	21-Jun-17		11130	O	Active	1.70
30-025-44469	EOG RESOURCES INC	NEPTUNE 10 STATE COM #206H	24S	33E	10	31-Dec-99		9630	O	Active	1.19
30-025-45300	MATADOR PRODUCTION COMPANY	CHARLES LING FEDERAL COM #204H	24S	33E	11	31-Dec-99		0	O	New	1.94
30-025-45296	MATADOR PRODUCTION COMPANY	CHARLES LING FEDERAL COM #134H	24S	33E	11	31-Dec-99		0	O	New	1.94
30-025-41334	COG OPERATING LLC	ROY BATTY FEDERAL COM #004H	24S	33E	11	26-Dec-13		10899	O	Active	1.25
30-025-43532	MATADOR PRODUCTION COMPANY	LEO THORSNESS 13 24 33 #211H	24S	33E	13	10-Dec-17		12383	G	Active	1.08
30-025-46930	EOG RESOURCES INC	YUKON 20 FEDERAL COM #702H	24S	34E	20	31-Dec-99		0	O	New	1.87
30-025-27267	PRE-ONGARD WELL OPERATOR	PRE-ONGARD WELL #002	24S	34E	17	1-Jan-00	1-Jan-00	14942	G	Plugged	1.92
30-025-41957	CHEVRON MIDCONTINENT, L.P.	PRODIGAL SUN 17 24 34 #001H	24S	34E	17	12-Aug-14		10865	O	Active	1.81
30-025-40914	COG OPERATING LLC	DECKARD FEE #001H	24S	33E	13	15-Mar-13		11034	O	Active	1.05
30-025-41382	COG OPERATING LLC	DECKARD FEDERAL COM #002H	24S	33E	13	3-Jun-14		11067	O	Active	0.86
30-025-44442	MATADOR PRODUCTION COMPANY	STRONG 14 24 33 AR #214H	24S	33E	14	31-Jul-18		12499	G	Active	1.12
30-025-26257	KAISER-FRANCIS OIL CO	BELL LAKE UNIT #019	24S	33E	12	25-Mar-79	12-Jul-11	14760	O	Plugged	1.57
30-025-39716	COG OPERATING LLC	RED RAIDER BKS STATE #002H	24S	33E	25	1-Apr-10		9455	O	Active	1.46
30-025-08371	PRE-ONGARD WELL OPERATOR	PRE-ONGARD WELL #001	24S	33E	13	1-Jan-00	1-Jan-00	5425	O	Plugged	0.29
30-025-26958	BOPCO, L.P.	SIMS #001	24S	33E	13	31-Dec-99	26-Dec-07	15007	G	Plugged	0.30
30-025-41384	COG OPERATING LLC	DECKARD FEDERAL COM #004H	24S	33E	13	1-Jun-14		11103	O	Active	0.62
30-025-39560	EOG RESOURCES INC	FALCON 25 FEDERAL #001	24S	33E	25	30-Nov-09		9444	O	Active	1.51
30-025-29008	EOG RESOURCES INC	MADERA RIDGE 24 #001	24S	33E	24	7-Nov-84		15600	G	Active	1.03
30-025-29141	COG OPERATING LLC	RED RAIDER BKS STATE #001	24S	33E	25	29-Mar-85		15360	O	Active	2.00
30-025-41383	COG OPERATING LLC	DECKARD FEDERAL COM #003H	24S	33E	13	30-Aug-14		11162	O	Active	0.71
30-025-35504	EOG RESOURCES INC	BELL LAKE UNIT #008	24S	34E	07	24-Apr-01		14500	G	Plugged	1.29
30-025-40448	LUCID ENERGY DELAWARE, LLC	RED HILLS AGI #001	24S	33E	13	23-Oct-13		0	I	Active	0.05
30-025-41687	COG OPERATING LLC	SEBASTIAN FEDERAL COM #001H	24S	34E	18	1-Feb-15		10944	O	Active	0.64
30-025-26369	EOG RESOURCES INC	GOVERNMENT L COM #002	24S	34E	18	15-Sep-79	8-Oct-90	14698	G	Plugged	0.37

API	OPERATOR	WELL NAME	T	R	S	SPUD DATE	PLUG DATE	TVD DEPTH	WELL TYPE	COMPL STATUS	DIST (MI)
30-025-41666	COG OPERATING LLC	SEBASTIAN FEDERAL COM #002H	24S	34E	18	24-Feb-15		10927	O	Active	0.72
30-025-28873	EOG RESOURCES INC	VACA RIDGE 30 FEDERAL #001	24S	34E	30	12-Sep-84	11-Jul-19	15505	S	Plugged	2.01
30-025-27491	PRE-ONGARD WELL OPERATOR	PRE-ONGARD WELL #001	24S	34E	19	1-Jan-00	1-Jan-00	15120	O	Plugged	0.83
30-025-33815	EOG RESOURCES INC	BELL LAKE 7 UNIT #001	24S	34E	07	12-Jun-97	10-Sep-97	16085	G	Plugged	1.28
30-025-41688	COG OPERATING LLC	SEBASTIAN FEDERAL COM #003H	24S	34E	18	3-Aug-14		11055	O	Active	0.93
30-025-25604	EOG RESOURCES INC	GOVERNMENT L COM #001	24S	34E	18	3-Oct-77	30-Dec-04	17625	G	Plugged	0.71
30-025-24910	KAISER-FRANCIS OIL CO	BELL LAKE UNIT #016	24S	34E	07	31-Jan-75		14140	O	Active	1.77
30-025-41689	COG OPERATING LLC	SEBASTIAN FEDERAL COM #004H	24S	34E	18	2-Jul-14		10877	O	Active	1.14
30-025-44936	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL #121H	24S	34E	17	25-Nov-18		10080	O	Active	1.25
30-025-44918	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL #211H	24S	34E	17	19-Dec-18		12212	O	Active	1.25
30-025-44919	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL #215H	24S	34E	17	31-Dec-99		0	O	New	1.27
30-025-44291	NGL WATER SOLUTIONS PERMIAN, LLC	STRIKER 6 SWD #002	24S	34E	20	20-Jan-18		17692	S	Active	1.31
30-025-44917	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL #101H	24S	34E	17	31-Dec-99		0	O	New	1.26
30-025-44937	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL #125H	24S	34E	17	8-Nov-18		10783	O	Active	1.26
30-025-27052	PRE-ONGARD WELL OPERATOR	PRE-ONGARD WELL #001	24S	34E	17	1-Jan-00	1-Jan-00	14905	O	Plugged	1.40
30-025-46282	MATADOR PRODUCTION COMPANY	LEO THORSNESS 13 24 33 AR #135H	24S	33E	14	24-Aug-19		12073	O	Active	1.12
30-025-46464	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 14 FEDERAL #028H	24S	33E	23	31-Dec-99		0	O	New	1.98
30-025-46466	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 14 FEDERAL #037H	24S	33E	23	31-Dec-99		0	O	New	1.77
30-025-46517	BC OPERATING, INC.	BROADSIDE 13 W FEDERAL COM #001H	24S	33E	12	31-Dec-99		0	O	New	0.89
30-025-46518	BC OPERATING, INC.	BROADSIDE 13 W FEDERAL COM #002H	24S	33E	12	31-Dec-99		0	O	New	0.78
30-025-46519	BC OPERATING, INC.	BROADSIDE 13 W FEDERAL COM #003H	24S	33E	12	31-Dec-99		0	O	New	0.72
30-025-46832	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL #038H	24S	33E	23	28-Feb-20		0	O	New	1.76
30-025-46154	MATADOR PRODUCTION COMPANY	LEO THORSNESS 13 24 33 #221H	24S	33E	14	13-Aug-19		12871	O	Active	1.12
30-025-46463	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 14 FEDERAL #027H	24S	33E	23	31-Dec-99		0	O	New	1.98
30-025-46540	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 14 FEDERAL #033H	24S	33E	23	29-Feb-20		0	O	New	1.77
30-025-46857	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL #021H	24S	33E	23	31-Dec-99		0	O	New	1.71
30-025-46970	EOG RESOURCES INC	YUKON 20 FEDERAL COM #701H	24S	34E	20	31-Dec-99		0	O	New	1.87
30-025-46971	EOG RESOURCES INC	YUKON 20 FEDERAL COM #705H	24S	34E	20	31-Dec-99		0	O	New	1.65
30-025-46972	EOG RESOURCES INC	YUKON 20 FEDERAL COM #706H	24S	34E	20	31-Dec-99		0	O	New	1.64
30-025-46973	EOG RESOURCES INC	YUKON 20 FEDERAL COM #707H	24S	34E	20	31-Dec-99		0	O	New	1.50
30-025-46974	EOG RESOURCES INC	YUKON 20 FEDERAL COM #708H	24S	34E	20	31-Dec-99		0	O	New	1.50
30-025-46975	EOG RESOURCES INC	YUKON 20 FEDERAL COM #709H	24S	34E	20	31-Dec-99		0	O	New	1.40
30-025-46984	COG OPERATING LLC	SEBASTIAN FEDERAL COM #601H	24S	34E	18	31-Dec-99		0	O	New	1.06
30-025-46985	COG OPERATING LLC	SEBASTIAN FEDERAL COM #703H	24S	34E	18	31-Dec-99		0	O	New	0.86
30-025-46986	COG OPERATING LLC	SEBASTIAN FEDERAL COM #602H	24S	34E	18	31-Dec-99		0	O	New	0.86
30-025-46987	COG OPERATING LLC	SEBASTIAN FEDERAL COM #701H	24S	34E	18	31-Dec-99		0	O	New	1.06
30-025-46988	COG OPERATING LLC	SEBASTIAN FEDERAL COM #704H	24S	34E	18	31-Dec-99		0	O	New	0.85
30-025-46989	COG OPERATING LLC	SEBASTIAN FEDERAL COM #702H	24S	34E	18	31-Dec-99		0	O	New	1.05
30-025-47030	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL #034H	24S	33E	23	31-Dec-99		0	O	New	1.76
30-025-47111	EOG RESOURCES INC	YUKON 20 FEDERAL COM #704H	24S	34E	20	31-Dec-99		0	O	New	1.66
30-025-46791	DEVON ENERGY PRODUCTION COMPANY, LP	SEA SNAKE 35 STATE #016H	23S	33E	35	31-Dec-99		0	O	New	1.97

API	OPERATOR	WELL NAME	T	R	S	SPUD DATE	PLUG DATE	TVD DEPTH	WELL TYPE	COMPL STATUS	DIST (MI)
30-025-47170	EOG RESOURCES INC	YUKON 20 FEDERAL COM #703H	24S	34E	20	31-Dec-99		0	O	New	1.87
30-025-47187	EOG RESOURCES INC	YUKON 20 FEDERAL COM #711H	24S	34E	20	31-Dec-99		0	O	New	1.39
30-025-47194	EOG RESOURCES INC	YUKON 20 FEDERAL COM #710H	24S	34E	20	31-Dec-99		0	O	New	1.40
30-025-47476	MARATHON OIL PERMIAN LLC	NED PEPPER 18 TB FEDERAL COM #001H	24S	34E	18	31-Dec-99		0	O	New	0.25
30-025-47477	MARATHON OIL PERMIAN LLC	NED PEPPER 18 TB FEDERAL COM #004H	24S	34E	18	31-Dec-99		0	O	New	0.75
30-025-47478	MARATHON OIL PERMIAN LLC	NED PEPPER 18 WA FEDERAL COM #002H	24S	34E	18	31-Dec-99		0	O	New	0.65
30-025-47479	MARATHON OIL PERMIAN LLC	NED PEPPER 18 WA FEDERAL COM #009H	24S	34E	18	31-Dec-99		0	O	New	0.79
30-025-47480	MARATHON OIL PERMIAN LLC	NED PEPPER 18 WXY FEDERAL COM #006H	24S	34E	18	31-Dec-99		0	O	New	0.69
30-025-47869	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #501H	24S	34E	19	31-Dec-99		0	O	New	0.53
30-025-47870	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #502H	24S	34E	19	31-Dec-99		0	O	New	0.52
30-025-47871	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #503H	24S	34E	19	31-Dec-99		0	O	New	0.52
30-025-47872	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #504H	24S	34E	19	31-Dec-99		0	O	New	0.75
30-025-47873	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #505H	24S	34E	19	31-Dec-99		0	O	New	0.75
30-025-47874	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #506H	24S	34E	19	31-Dec-99		0	O	New	0.76
30-025-47875	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #507H	24S	34E	19	31-Dec-99		0	O	New	0.92
30-025-47876	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #508H	24S	34E	19	31-Dec-99		0	O	New	0.93
30-025-47877	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #509H	24S	34E	19	31-Dec-99		0	O	New	0.93
30-025-47878	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #510H	24S	34E	19	31-Dec-99		0	O	New	0.94
30-025-47908	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #601H	24S	34E	19	31-Dec-99		0	O	New	0.52
30-025-47909	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #605H	24S	34E	19	31-Dec-99		0	O	New	1.07
30-025-47910	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #702H	24S	34E	19	31-Dec-99		0	O	New	0.50
30-025-47911	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #705H	24S	34E	19	31-Dec-99		0	O	New	0.77
30-025-47912	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #707H	24S	34E	19	31-Dec-99		0	O	New	0.86
30-025-47913	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #708H	24S	34E	19	31-Dec-99		0	O	New	0.86
30-025-48056	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #602H	24S	34E	19	31-Dec-99		0	O	New	0.53
30-025-48057	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #603H	24S	34E	19	31-Dec-99		0	O	New	0.79
30-025-48058	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #604H	24S	34E	19	31-Dec-99		0	O	New	0.79
30-025-48059	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #704H	24S	34E	19	31-Dec-99		0	O	New	0.76
30-025-48060	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #706H	24S	34E	19	31-Dec-99		0	O	New	0.77
30-025-48061	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #709H	24S	34E	19	31-Dec-99		0	O	New	1.06
30-025-48062	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #710H	24S	34E	19	31-Dec-99		0	O	New	1.07
30-025-48224	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #201H	24S	34E	19	31-Dec-99		0	O	New	0.47
30-025-48225	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #202H	24S	34E	19	31-Dec-99		0	O	New	0.63
30-025-48226	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #203H	24S	34E	19	31-Dec-99		0	O	New	0.48
30-025-48227	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #204H	24S	34E	19	31-Dec-99		0	O	New	0.60
30-025-48228	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #205H	24S	34E	19	31-Dec-99		0	O	New	0.61
30-025-48229	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #206H	24S	34E	19	31-Dec-99		0	O	New	0.61
30-025-48230	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #207H	24S	34E	19	31-Dec-99		0	O	New	0.94
30-025-48231	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #208H	24S	34E	19	31-Dec-99		0	O	New	0.95
30-025-48232	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #209H	24S	34E	19	31-Dec-99		0	O	New	0.96
30-025-48233	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #210H	24S	34E	19	31-Dec-99		0	O	New	0.96

API	OPERATOR	WELL NAME	T	R	S	SPUD DATE	PLUG DATE	TVD DEPTH	WELL TYPE	COMPL STATUS	DIST (MI)
30-025-48234	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #301H	24S	34E	19	31-Dec-99		0	O	New	0.50
30-025-48235	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #302H	24S	34E	19	31-Dec-99		0	O	New	0.51
30-025-48236	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #303H	24S	34E	19	31-Dec-99		0	O	New	0.63
30-025-48237	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #304H	24S	34E	19	31-Dec-99		0	O	New	0.63
30-025-48238	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #305H	24S	34E	19	31-Dec-99		0	O	New	0.85
30-025-48239	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #306H	24S	34E	19	31-Dec-99		0	O	New	0.84
30-025-48240	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #307H	24S	34E	19	31-Dec-99		0	O	New	1.05
30-025-48241	EOG RESOURCES INC	JUPITER 19 FEDERAL COM #308H	24S	34E	19	31-Dec-99		0	O	New	1.06

Note – a completion status of "New" indicates that an Aplication for Permit to Drill has been filed and approved but the well has not yet been completed. Likewise, a spud date of 31-Dec-99 is actually 12-31-9999, a date used by NMOCD databases to indicate work not yet reported.

Appendix 4 - References

Application for Authorization to Inject via Proposed Red Hills AGI #1 Well, Agave Energy Red Hills Gas Plant, Lea County, New Mexico; July 20, 2011; prepared by Geolex, Inc. for Agave Energy Company

Application for a Redundant Class II AGI Well, Lucid Energy Delaware, LLC; Red Hills AGI #2; August 8, 2019, prepared by Geolex, Inc. for Lucid Energy Delaware, LLC

Case No. 20779, Notice Regarding Hearing Exhibits, Application of Lucid Energy Delaware, LLC for Authorization to Inject, Lea County, New Mexico

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Appendix 5 - Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
CFR – Code of Federal Regulations
CO_2 – carbon dioxide
DCS – distributed control system
EOS – Equation of State
EPA – US Environmental Protection Agency, also USEPA
FSP - Fault Slip Potential modeling package of the Stanford Center for Induced and Triggered Seismicity
ft – foot (feet)
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCF– thousand standard cubic feet
MSCF/D– thousand standard cubic feet per day
MMSCF – million standard cubic feet
MMSCF/D – million standard cubic feet per day
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NG—Natural Gas
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
NMOCD - New Mexico Oil Conservation Division
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
SCITS - Stanford Center for Induced and Triggered Seismicity
ST – Short Ton
Stb/d – stock tank barrel per day
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TSD – Technical Support Document
TVD – True Vertical Depth
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

XRD – x-ray diffraction

Appendix 6 - Conversion Factors

Lucid reports CO_2 at standard conditions of temperature and pressure as defined in the State of New Mexico - 60°F and 15.025 psia (NMAC 19.15.2.7 (C)(16))

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

http://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperatures and pressures.

At State of New Mexico standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.0027097 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.0027097$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.4092\ x\ 10^{-5}\frac{MT}{ft^3}\ \ or\ \ 5.4092\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.4092 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix 7 - Lucid Red Hills AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP.

* All measurements must be made in accordance with 40 CFR 98.444 – Monitoring and QA/QC Requirements.

** If you measure the mass of contents of containers summed quarterly using weigh bill, scales, or load cells (40 CFR 98.444(a)(2)(i)), use RR-1 for Containers to calculate CO_2 received in containers for injection.

*** If you determine the volume of contents of containers summed quarterly (40 CFR 98.444(a)(2)(ii)), use RR-2 for Containers to calculate CO_2 received in containers for injection.

Appendix 8 - Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

RR-1 for Calculating Mass of CO_2 Received through Pipeline Mass Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Equation RR-1 for Pipelines)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving mass flow meter.

RR-1 for Calculating Mass of CO_2 Received in Containers by Measuring Mass in Container

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Equation RR-1 for Containers)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass of contents in containers r redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Containers.

RR-2 for Calculating Mass of CO_2 Received through Pipeline Volumetric Flow Meters

$$CO_{2T,r} = \sum_{p=1}^{4}\left(Q_{r,p} - S_{r,p}\right) * D * C_{CO_{2,p,r}} \quad \text{(Equation RR-2 for Pipelines)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving volumetric flow meter.

RR-2 for Calculating Mass of CO_2 Received in Containers by Measuring Volume in Container

$$CO_{2T,r} = \sum_{p=1}^{4}\left(Q_{r,p} - S_{r,p}\right) * D * C_{CO_{2,p,r}} \quad \text{(Equation RR-2 for Containers)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volume of contents in containers r redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 received in containers at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Container.

RR-3 for Summation of Mass of CO_2 Received through Multiple Flow Meters for Pipelines

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \qquad \text{(Equation RR-3 for Pipelines)}$$

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2,T.r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.

r = Receiving flow meter.

RR-4 for Calculating Mass of CO_2 Injected through Mass Flow Meters into Injection Well

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \qquad \text{(Equation RR-4)}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

$C_{CO_{2,p,u}}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Mass flow meter.

RR-5 for Calculating Mass of CO_2 Injected through Volumetric Flow Meters into Injection Well

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \qquad \text{(Equation RR-5)}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Volumetric flow meter.

RR-6 for Summation of Mass of CO_2 Injected into Multiple Wells

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,x} \quad \text{(Equation RR-6)}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) though all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as calculated in Equation RR-4 or RR-5 for flow meter u.

u = Flow meter.

RR-7 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Mass Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * C_{CO_{2,p,w}} \quad \text{(Equation RR-7)}$$

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas mass flow rate measurement for separator w in quarter p (metric tons).

$C_{CO_{2,p,w}}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Gas / Liquid Separator.

RR-8 for Calculating Mass of CO_2 Produced / Recycled from a Gas-Liquid Separator through Volumetric Flow Meters

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO_{2,p,w}} \quad \text{(Equation RR-8)}$$

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas volumetric flow rate measurement for separator w in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Gas / Liquid Separator.

RR-9 for Summation of Mass of CO_2 Produced / Recycled through Multiple Gas Liquid Separators

$$CO_{2P} = (1 + X) * \sum_{w=1}^{W} CO_{2,w} \qquad \text{(Equation RR-9)}$$

where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) though all separators in the reporting year.

X = Entrained CO_2 in produced oil or other liquid divided by the CO_2 separated through all separators in the reporting year (wt. percent CO_2 expressed as a decimal fraction).

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year as calculated in Equation RR-7 or RR-8 .

w = Flow meter.

RR-10 for Calculating Annual Mass of CO_2 Emitted by Surface Leakage

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{(Equation RR-10)}$$

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

RR-11 for Calculating Annual Mass of CO_2 Sequestered for Operators Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad \text{(Equation RR-11)}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

CO_{2FP} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of the GHGRP.

RR-12 for Calculating Annual Mass of CO_2 Sequestered for Operators NOT Actively Producing Oil or Natural Gas or Any Other Fluid

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Equation RR-12)}$$

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of the GHGRP.

Appendix 9 - Plugging and Abandonment Record for Government Com 001, API #3002525604

New Mexico Oil Conservation Division, District I
1625 N. French Drive
Hobbs, NM 88240

Form 3160-5
(April 2004)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OM B No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

5. Lease Serial No. **NM-17446**

6. If Indian, Allottee or Tribe Name

***SUBMIT IN TRIPLICATE**- Other instructions on reverse side.*

7. If Unit or CA/Agreement, Name and/or No.

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other

8. Well Name and No. **Government "L" Com #1**

2. Name of Operator **EOG Resources, Inc**

9. API Well No. **30-025-~~[illegible]~~ 25604**

3a. Address **P.O. Box 2267, Midland, TX, 79702**

3b. Phone No. *(include area code)* **432-561-8600**

10. Field and Pool, or Exploratory Area **Bell Lake, South Morrow**

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Unit Letter G, 1980 FNL, 1980 FEL
Section 18, Township 24-S, Range 34-E

11. County or Parish, State **Lea, New Mexico**

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☑ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☐ Change Plans	☑ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

1. **Notified Jim McCormick w/BLM 24 hrs prior to MI and RU.**
2. **Cut 3 1/2' tbg at 11500, spot 50sx CLass "H" cmt, plug from 11500-11400, WOC Tag at 11389.**
3. **Circ hole w/MLF.**
4. **Perf 4 holes at 9050, press up to 2000 PSI, spot 75sx, plug from 9100-8950, WOC Tag @ 8938.**
5. **Perf 4 holes at 7000, press up to 2000 PSI, spot 75sx, plug from 7050-6900, WOC Tag at 6855.**
6. **Cut 10 3/4" csg at 5450, L/D csg, spot 150sx, plug from 5500-5350, WOC Tag at 5336.**
7. **Spot 75sx, plug from 1300-1200 (T-Salt) WOC Tag at 1143.**
8. **Spot 150sx, plug from 650-450 (20" Shoe) WOC Tag at 423.**
9. **Spot 20sx, plug from 30-Surf.**
10. **Clean location. Install dry hole marker 12-30-04.**

P&A Complete 12-30-04

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

APPROVED
JAN 4 2005
GARY GOURLEY
PETROLEUM ENGINEER

14. I hereby certify that the foregoing is true and correct
Name *(Printed/Typed)* **Jimmy Bagley** Title **Consultant**

Signature Date **12/30/2004**

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by ______ Title ______ Date ______

Conditions of approval, if any, are attached. Approval of this notice 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. Office

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.

(Instructions on page 2)

GWW