UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

December 16, 2021

Mr. Matt Eales
Lucid Energy Group
3100 McKinnon Street #800
Dallas, Texas 75201

Re: Monitoring, Reporting and Verification (MRV) Plan for Red Hills Gas Processing Plant

Dear Mr. Eales:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for the Red Hills Gas Processing Plant as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Lucid Energy Delaware, LLC for the Red Hills Gas Processing Plant as the final MRV plan. The MRV Plan Approval Number is 1011064-1. This decision is effective December 21, 2021 and appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78.

If you have any questions regarding this determination, please write to ghgreporting@epa.gov and a member of the Greenhouse Gas Reporting Program will respond.

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Lucid Red Hills Gas Plant

December 2021

Contents

<u>**Appendices**</u>

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) Plan submitted by Lucid Energy Delaware, LLC (Lucid) for their acid gas injection (AGI) project at the Red Hills Gas Plant.

1 Overview of Project

As is described in the MRV Plan, the Lucid Red Hills Gas Plant is a treated acid gas (TAG) injection facility currently injecting TAG through an existing well (Red Hills (RH) AGI #1 (API 20-025-40448)). The Red Hills Gas Plant was originally built by Agave Energy Company (hereafter referred to as Agave) in 2012-2013 after they filed an application with the New Mexico Oil Conservation Division (NMOCD) to inject TAG into a Class II injection well (referred to as a TAG injection well in the MRV plan). Although Agave drilled RH AGI #1 in 2012-2013, the well was never completed or put into service because the plant was processing only sweet gas (no H_2S) at the time. Lucid purchased the plant from Agave in 2016 and completed the RH AGI #1 well.

Lucid is currently authorized to inject a total of up to 13 million standard cubic feet per day (MMSCF/D) of TAG into RH AGI #1 under the New Mexico Oil Conservation Commissions (NMOCC) Order R-13507 – 13507F. Recently, Lucid received authorization to construct an additional Class II 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. Authorization of RH AGI #2 provides increased capacity for the Red Hills Gas Plant expansion and accommodates the ability to inject additional volumes of TAG.

The NMOCC authorized RH AGI #2 to inject and 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 and at a maximum surface injection pressure of approximately 4,838 pounds per square inch gauge (psig). Thus, total injection capacity at Red Hills is 26 MMSCF/D (approximately 500,000 metric tons per year).

The Red Hills Gas Plant is located approximately 15 miles NNW of Jal in Lea County, New Mexico at the northern margin of the Delaware Basin, a sub-basin of the Permian Basin, which covers a large area of southeastern New Mexico and west Texas (see Figure 3.2-1 of the MRV plan). The Lucid Red Hills MRV plan provides detailed characterizations of the target injection zones, confining seals, and geologic setting of each injection well.

RH AGI #1's injection zone is the uppermost portion of the Cherry Canyon Formation. This formation is a part of the greater Permian Guadalupe Series, which is thought to be a submarine fan complex channel deposit. The Cherry Canyon deposit includes five high porosity sandstone units and has excellent cap rocks above, below, and between the individual sandstone units. The lack of structural features or faults and the high net porosity of the Cherry Canyon Formation indicate that the injected TAG will be easily contained close to the injection well.

The MRV plan details the geologic structural properties that would determine fluid migration throughout the injection zone. Figures 3.3-2 and 3.3-3 in the MRV plan reveal relatively horizontal formations 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. Fluid migration and the overall three-dimensional shape of the injected TAG plume will largely be controlled by local heterogeneities in permeability and porosity. The Cherry Canyon sands were deposited by turbidites and submarine fan complexes and, therefore, are encased in low porosity and low permeability fine-grained siliciclastics and mudstones with lateral continuity. The resulting preferred orientation for fluid and gas flow is south-to-north along the channel axis of deposition.

RH AGI #2's injection zone 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 saltwater disposal (SWD) wells in the region. The proposed injection zone includes several 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 occur throughout the section, most notably in the Fusselman Formation. The overlying Chester, Osage, and Woodford Formations provide over 1,000 feet of shale and intervening tight limestones, providing an effective seal on top of the injection zone. The proposed Devonian-Silurian injection zone for the RH AGI #2 well does not produce economic hydrocarbons within 15 miles of the well site. In addition, 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.

The Red Hills Gas Plant and existing RH AGI #1 well are in operation and 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) and comply with National Association of Corrosion Engineers (NACE) and other applicable standards that require they are constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the processing plant 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.

The MRV plan discusses protection from ground water contamination. There are 15 freshwater wells within a two-mile radius of either RH AGI wells, and only two 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 Quaternary alluvium and the Triassic red beds of the Santa Rosa Formation. RH AGI #1 and RH AGI #2 injection zones are located more than 6,000 and 15,350 feet, respectively, below these aquifers. The shallow freshwater aquifer is protected by the surface and intermediate casings and cement in the RH AGI wells (Figures 3.6-2 and 3.6-3).

The MRV plan notes that there are current well operations within a two-mile radius of the Red Hills Gas Plant. There are 129 wells (13 plugged and abandoned or temporarily plugged, 38 active, and the RH AGI#1 well, with the remaining wells listed as "New" horizontal wells). Three wells within the two-mile radius penetrate the proposed RH AGI #2 injection zone (deeper than 16,000 feet true vertical depth (TVD)). Two of these wells are plugged and abandoned. The third well (NGL Water Solutions Striker 6 SWD 002, API #3002544291) is currently active and lies 1.25 miles from the proposed RH AGI #2. Lucid stated in the MRV plan that 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 with the injected TAG in the injection zone. The active production wells within a one-mile radius of the Red Hills gas plant target the Bone Springs 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 these production 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.

The MRV plan provides a description of the project, including the site setting, processes, and plans for injection operations. The description of the project provides acceptable information as it relates to 40 CFR 98.448(a)(6). Lucid states in the MRV plan that it 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 United States Environmental Protection Agency (US EPA) or the State of New Mexico. Lucid states in the MRV plan that it intends to update the MRV plan after RH AGI #2 has been drilled and characterized.

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV Plan, the reporter must identify both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines the MMA as "the area that must be monitored under this regulation and is defined as 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." Subpart RR defines the AMA as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the AMA is established by superimposing two areas: (1) the area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) the area projected to contain the free phase CO_2 plume at the end of year t + 5." See 40 CFR 98.449.

Lucid has defined the AMA as the extent of modelled CO_2 plumes for each injection zone plus the required 0.5-mile radius buffer. Lucid has also similarly defined the MMA as the extent of modelled CO_2

plumes for each injection zone plus the required 0.5-mile buffer as required by 40 CFR §98.440-449 (subpart RR). Factors considered include: the extent of free-phase CO_2 within the Cherry Canyon and Siluro-Devonian formations, fluid pressure and management strategies to retain injected CO_2 within these units, and the geological structure of the units.

The reservoir characterization modeling described in section 3.9 of the MRV plan indicates that the free phase CO_2 plume will be contained within the NMOCD-approved Class II Area of Review (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 is required. Modeling shows that the pressure in the Siluro-Devonian does not change significantly as a result of the injection activities irrespective of fault transmissivity. 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 post-injection monitoring period as predicted by reservoir simulation. The modeled pressure profiles demonstrate the strong potential for safe injection into both target formations.

The MMA and AMA described in the MRV plan are clearly and explicitly delineated and are consistent with the definitions in 40 CFR 98.449. The delineations of the MMA and AMA are acceptable.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). Lucid identified the following as potential leakage pathways in their MRV plan that required consideration:

- Leakage from surface equipment;
- Approved, not yet drilled wells;
- Existing wells;
- Through fractures and faults;
- Through the confining/seal system;
- Due to natural and induced seismicity; and
- Lateral migration outside of the injection zone.

3.1 Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S within a sour gas stream, there is a potential for leakage from surface equipment at TAG injection facilities such as those at the Lucid Red Hills Gas Plant. Section 5.1 of the MRV plan details strategies that have been implemented at the Red Hills Gas Plant to reduce this potential for leakage, including following industry standards and regulatory requirements.

For example, NMAC Code R. § 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 comply with this requirement, Lucid states that they conduct regular inspections and maintenance of their surface equipment. Additionally, sections 6, 7, and 8 of the MRV plan describe several methods Lucid employs at the Red Hills Gas Plant to quickly detect, quantify, and respond to potential gas leaks at the surface.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from surface equipment.

3.2 Leakage through Approved, but not yet Drilled Wells

Approved wells in the vicinity of the Red Hills Gas Plant that have yet to be drilled include the proposed RH AGI #2 well and a number of horizontal wells. Further characterization of these wells is included in Appendix 3 and Figure 4.1-1 of the MRV plan. The drilling of new wells in the region surrounding the Red Hills Gas Plant is under the jurisdiction of the NMOCC as specified in the NMAC.

Relevant NMOCC and NMAC regulations, discussed in further detail in section 5.2 of the MRV plan, require 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." Moreover, New Mexico regulations require the use of "blowout preventers in areas of high pressure at or above the projected depth of the wells" to minimize the magnitude and duration (timing) of CO_2 leakage to the surface. Lucid notes that these requirements apply to any new well drilled within the MMA for this MRV plan.

Additionally, 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 #1 (API No. 30-025-40448) in the Delaware Mountain Group."

Lucid further notes in section 5.2 of the MRV plan that 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. These enhanced safety measures include using heavier than normal drilling mud, using loss control material at a higher rate than normal, monitoring H_2S concentrations at the surface, use of slower drilling processes, and more vigilant mud level monitoring than usual.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through approved but not yet drilled wells.

3.3 Leakage through Existing Wells

In section 5.3 of the MRV plan, Lucid states that there are 13 existing oil/gas related wells within the approved RH AGI #1 Class II AoR, which is nearly equivalent to the MMA as defined in section 4.1 of the MRV plan. Of these wells, only RH AGI #1 is completed in the Cherry Canyon formation. This well is constructed with multiple strings of casing which are all cemented to the surface. Injection of the TAG occurs through tubing with a permanent production packer set at 6,170 feet, 60 feet above the Cherry Canyon injection zone. The MRV plan claims this construction, coupled with continuous monitoring of operational parameters, minimizes the likelihood of CO_2 leakage along the borehole to the surface in these existing wells.

Six of the thirteen wells within the AoR are completed in the Bone Springs and Wolfcamp zones (as described in section 3.7.2 of the MRV plan); however, these zones lie at least 2,500 feet above the proposed RH AGI #2 injection zone and more than 2,000 feet below the RH AGI #1 injection zone. Construction of these wells includes surface casing cemented to the surface, as well as intermediate casing set at the top of the Bell Canyon through the Permian Ochoan. In the the MRV plan, Lucid states that these casings provide sufficient zonal isolation, preventing injected TAG from leaking upward along these boreholes in the event that the plume reaches them.

One of the wells within the AoR penetrated the Siluro-Devonian sequence, which is the proposed injection zone of RH AGI #2. This well was permanently plugged and abandoned in 2004, and the plugging and abandonment was approved by NMOCD in 2005. According to the MRV plan, 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.

The MRV plan notes that there are 15 ground water wells within a 2-mile radius of the RH AGI wells, and only 2 water wells within a 1-mile radius. The deepest of these ground water wells is 650 feet deep. Lucid states in the MRV plan that the evaporite sequence of the Permian Ochoan Salado and Castile Formations (see Section 3.2.2 of the MRV plan) provide an excellent seal between these ground water wells and the Cherry Canyon injection zone of the RH AGI #1 well. Therefore, the MRV plan states that it is unlikely that these two ground water wells are a potential pathway of CO_2 leakage to the surface.

Thus, the MRV plan provides an acceptable characterization of the likelihood of leakage through existing wells.

3.4 Leakage through Fractures and Faults

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

Simulation modeling presented in section 3.9 of the MRV plan addressed the possible existence of interpreted faults within the Silurian-Devonian injection zone for RH AGI #2. Simulation modeling concluded that even if these potential faults are fully transmissive, the TAG plume will not migrate outside of the MMA during the injection or post-injection period. However, there is no conclusive evidence that faults that occur or may occur in the vicinity of the Red Hills Gas Plant extend through the confining zone overlying the Silurian-Devonian injection zone for RH AGI #2. Furthermore, overpressure in the eastern Delaware Basin will act as a barrier restricting vertical migration of CO_2.

Thus, the MRV plan provides an acceptable characterization of the likelihood of leakage through fractures and faults.

3.5 Leakage through the Confining/Seal System

The injection zone for RH AGI #1 is overlain by a thick sequence of Permian Ochoan evaporites, limestone, and siltstones with no evidence of faulting, as described in sections 3.2.2 and 3.3.1 of the MRV plan. Therefore, Lucid concludes that it is unlikely that TAG injected into RH AGI #1 will leak through this confining zone to the surface. The MRV plans states that the injection pressure will also be limited to less than the fracture pressure of the confining zone, further minimizing the likelihood of CO_2 leakage through the confining seal of this reservoir.

The injection zone for RH AGI #2, described in section 3.3.2 of the MRV plan, is separated from the nearest overlying producing zone by 200 feet of Woodford shale, 550 feet of tight Osagean limestones, and nearly 350 feet of tight Chesterian shales and deep-water limestones. As discussed in section 3.2.3 of the MRV plan, faults have been interpreted as possible in this zone, but with little evidence. Additionally, these potential faults only penetrate up to the base of the lower Woodford shale immediately above the Siluro-Devonian injection zone. Over-pressuring in the overlying shale sequence will serve as a barrier to the vertical migration of CO_2. As with RH AGI #1, the MRV plan states that the injection pressure will be limited to less than the fracture pressure of the confining zone, further minimizing the likelihood of CO_2 leakage through the seal.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through the confining/seal system.

3.6 Leakage due to Natural/Induced Seismicity

The MRV plan claims that there have been no historical seismic events, natural or induced, within the MMA for this MRV plan. As concluded in section 3.5 of the MRV plan, faults considered in Lucid's assessment do not display significant potential for injection-induced slip. Additionally, the proposed RH AGI #2 is not predicted to contribute significantly to the total resultant pressure front according to fault slip potential modeling.

Lucid concluded 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 a seismic monitoring station or stations for the life of the project (described in more detail in section 7.6 of the MRV plan).

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected due to natural/induced seismic activity.

3.7 Leakage due to Lateral Migration

As described in section 3.3.1 of the MRV plan, the injection zone of RH AGI #1 is composed of channel turbidite sandstones deposited in submarine fan complexes. Due to the nature of their depositional environment, these sandstones are encased in low porosity and low permeability fine-grained siliciclastics and mudstones with lateral continuity. The regional depositional environment suggests a preferred north-south orientation for fluid flow along the channel axes, but the locally 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.

The potential for lateral migration of injected TAG out of the injection zone for RH AGI #2 was evaluated using reservoir modeling described in section 3.9 of the MRV plan. The results of that modeling indicate that the TAG is unlikely to laterally migrate beyond approximately ¾ mile within the injection zone.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from lateral migration.

4 Strategy for Detecting and Quantifying Surface Leakage of CO_2 and for Establishing Expected Baselines for Monitoring

40 CFR 98.448(a)(3) requires that an MRV Plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV Plan include a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Sections 6, 7, and 8 of the MRV plan outline Lucid's strategy for quantifying surface leakage of CO_2 and their strategy for establishing expected baselines to monitor against. Lucid's approach includes primarily surveillance of plant and well operations through an automated distributed control system (DCS), fixed gas monitors in-field, and personal hand-held gas monitors operated by field personnel. CO_2 records will be determined quarterly, consistent with requirements specified by 40 CFR §98.3(g). Section 11 of the MRV plan states that all data will be collected as generated and aggregated as required for reporting purposes under 40 CFR 98.3 (g) of Subpart A and 40 CFR 98.447 of Subpart RR of the GHGRP, and Lucid will maintain these records for at least three years.

The strategy for monitoring the potential leakage pathways was summarized in Table 6.1 in the MRV plan and is reproduced in Table 1 below.

Table 1 – Summary of Leak Detection Monitoring

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

4.1 Leakage from Surface Equipment

Lucid has implemented several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S and CO_2 sensors, and continual monitoring of operational parameters. As described in section 7 of the MRV plan, 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. These periodic inspections of surface equipment have afforded Lucid the opportunity to assess baseline concentrations of H_2S, a proxy for CO_2, at the Red Hills Gas Plant. Additionally, compositional analysis of Lucid's gas injectate at the Red Hills Gas Plant indicates a baseline concentration of approximately 12% H_2S. Deviation from these baseline conditions will trigger further investigation to determine if the issue poses a leak threat.

In addition to the handheld and in-field gas detection monitors described above, New Mexico Tech, through a DOE research grant, will assist Lucid in setting up a monitoring network for CO_2 leakage detection in the MMA/AMA as described in section 4.2 of the MRV plan. This monitoring will also consist of periodic well and atmospheric sampling from an area of 10-15 square miles around the injection wells. Lucid will assume the responsibility of monitoring, recording, and reporting data collected from the system for the duration of the project.

4.2 Leakage from Approved, Not Yet Drilled Wells

Lucid states in the MRV plan that 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 of the MRV plan 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.

The MRV Plan also states that wells within the MMA/AMA surrounding the Red Hills Gas Plant are subject to NMOCC regulations regarding casing construction, periodic mechanical integrity testing (MIT), and additional precautions taken while drilling or completing a well. These wells are required to be constructed with a cemented surface casing set at 1,375 feet and additional intermediate casing to provide zonal isolation where necessary. All Class II injection wells in the area, including the RH AGI #1 and proposed RH AGI #2, are required to undergo periodic testing and monitoring to ensure that the wells maintain mechanical integrity at all times. Additionally, any newly drilled wells in the area will be required to take special precautions including using heavier than normal drilling mud, vigilant monitoring of fluid returns using loss-control material at a higher-than-normal rate, and monitoring for any potential gas leaks.

4.3 Leakage from Existing Wells

As is explained in the MRV Plan, the DCS of the plant continuously monitors injection rates, pressures, and compositions for variance outside of the allowable windows. If a parameter is outside of the allowable window, plant engineering and operations are alerted, and an investigation is begun to determine if the issue poses a potential leak threat. Additionally, the RH AGI #1 well is equipped with two pressure and temperature gauges monitoring reservoir pressure and temperature as well as the pressure and temperature of the annular space between the tubing and long string casing. Data from these gauges is continuously monitored by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits.

4.4 Leakage from Fractures and Faults

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

4.5 Leakage through the Confining / Seal System

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

4.6 Leakage due to Natural / Induced Seismicity

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

4.7 Leakage due to Lateral Migration

The MRV plan states that 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. Further, the MRV plan notes that the CO_2 monitoring network described in Section 7.3 of the MRV plan, and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone.

The strategy for detecting and quantifying surface leakage of CO_2 and for establishing expected baselines for monitoring is determined to comply with 40 CFR 98.448(a)(3) and 40 CFR 98.448(a)(4). The strategies described in the MRV plan are clearly and explicitly delineated and are consistent with subpart RR requirements.

5 Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation

5.1 Calculation of Mass of CO_2 Received

Lucid proposes to use equation RR-2 per 40 CFR 98.443(a)(2) to calculate the amount of CO_2 received. The equation is:

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2p,r}}$$

Where:

$CO_{2T,r}$ = *CO_2 Received, the injected 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). Since all delivery to Red Hills is used within the facility, the quarterly flow redelivered, $S_{r,p}$ is zero ("0").*

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

$C_{CO2,p,r}$ = *Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (volume percent CO_2, expressed as a decimal fraction).*

p = *Quarter of the year.*

r = *Receiving flow meter (M_2, CO_2 concentration for M_2 is measured at M_1).*

Lucid provides an acceptable approach to calculating each of these variables in section 8.1 of the MRV Plan.

5.2 Calculation of Mass of CO_2 Injected

Section 8.2 of the MRV plan states that the mass of CO_2 injected into the subsurface at the Red Hills Gas Plant will be measured by using equation RR-5 to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will then be used to calculate the total annual mass of CO_2 injected into both RH AGI wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in equation RR-12.

Lucid's approach for calculating the total mass injected is acceptable for the subpart RR requirements.

5.3 Calculation of Mass of CO_2 Produced

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.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

For reporting of the total annual CO_2 mass sequestered under subpart RR, potential surface leaks must be accounted for in the mass balance equation. Pursuant to 40 CFR 98.448(a)(2), an MRV Plan must describe the likelihood, magnitude, and timing of surface leakage of CO_2 through potential pathways. Subpart RR also requires that the MRV plan identify a strategy for establishing a baseline for monitoring CO_2 surface leakage, pursuant to 40 CFR 98.448(a)(4). The MRV plan notes that Equation RR-10 would be used to calculate and report the mass of CO_2 emitted by surface leakage from the leakage pathways identified and evaluated in section 5 of the MRV plan.

The plan's approach, using techniques from subpart W of the GHGRP, is acceptable for estimating potential emissions from surface leakage given the likelihood, magnitude and timing of surface leakage as described in the MRV plan.

5.5 Calculation of Mass of 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. 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 factors listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Lucid proposes an acceptable approach for calculating the Mass of CO_2 Sequestered.

6 Summary of Findings

The subpart RR MRV plan for the Lucid Red Hills Gas Plant facility meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in Lucid's MRV Plan.

Subpart RR MRV Plan Requirement	**Lucid Red Hills Gas Plant MRV Plan**
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 4 of the MRV Plan describes the MMA and AMA. Lucid has defined the MMA as the extent of modelled CO_2 plumes for each injection zone plus the required 0.5-mile radius buffer and has defined the AMA as the same area as the MMA. This is consistent with the NMOCD-approved Class II AoR for the 30-year injection period plus the 5-year post injection monitoring period. The MMA and AMA delineations consider the extent of free-phase CO_2 within the Cherry

	Canyon and Siluro-Devonian formations, fluid pressure and management strategies to retain injected CO_2 within these units, and the geological structure of the units.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 5 of the MRV Plan identifies and evaluates potential surface leakage pathways. The MRV Plan identifies the following potential pathways: potential leakage from surface equipment, from not yet drilled wells, from existing wells, through fractures and faults, through the confining/seal system, due to natural/induced seismic activity, and due to lateral migration. The MRV Plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. Lucid determined that these leakage pathways are highly improbable to minimal at the Red Hills Gas Plant, and it is very unlikely that potential leakage conduits would result in significant loss of CO_2 to the atmosphere.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 6 of the MRV Plan describes how the facility would detect CO_2 leakage to the surface, such as monitoring of existing wells, field inspections, gas detection systems, and pressure/temperature monitoring. Sections 8 and 10 of the MRV Plan describe how surface leakage would be quantified.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 7 of the MRV Plan describes the baselines against which monitoring results will be compared to assess potential surface leakage.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site specific variables for the mass balance equation.	Section 8 of the MRV Plan describes Lucid's approach to determining the amount of CO_2 sequestered using the subpart RR mass balance equation, including as related to calculation of total annual mass emitted as equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for	Section 12 Appendix 1 in the MRV Plan provides well identification numbers for each applicable injection well. The MRV Plan specifies that all

the UIC permit (or the permit application) and the UIC permit class.	injection wells are permitted as UIC Class II wells. Lucid states in section 10.4 that they intend to update the MRV plan once RH AGI #2 has been drilled and characterized.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR12 of this subpart.	The MRV plan states, “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.”

Appendix A: Final MRV Plan

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).

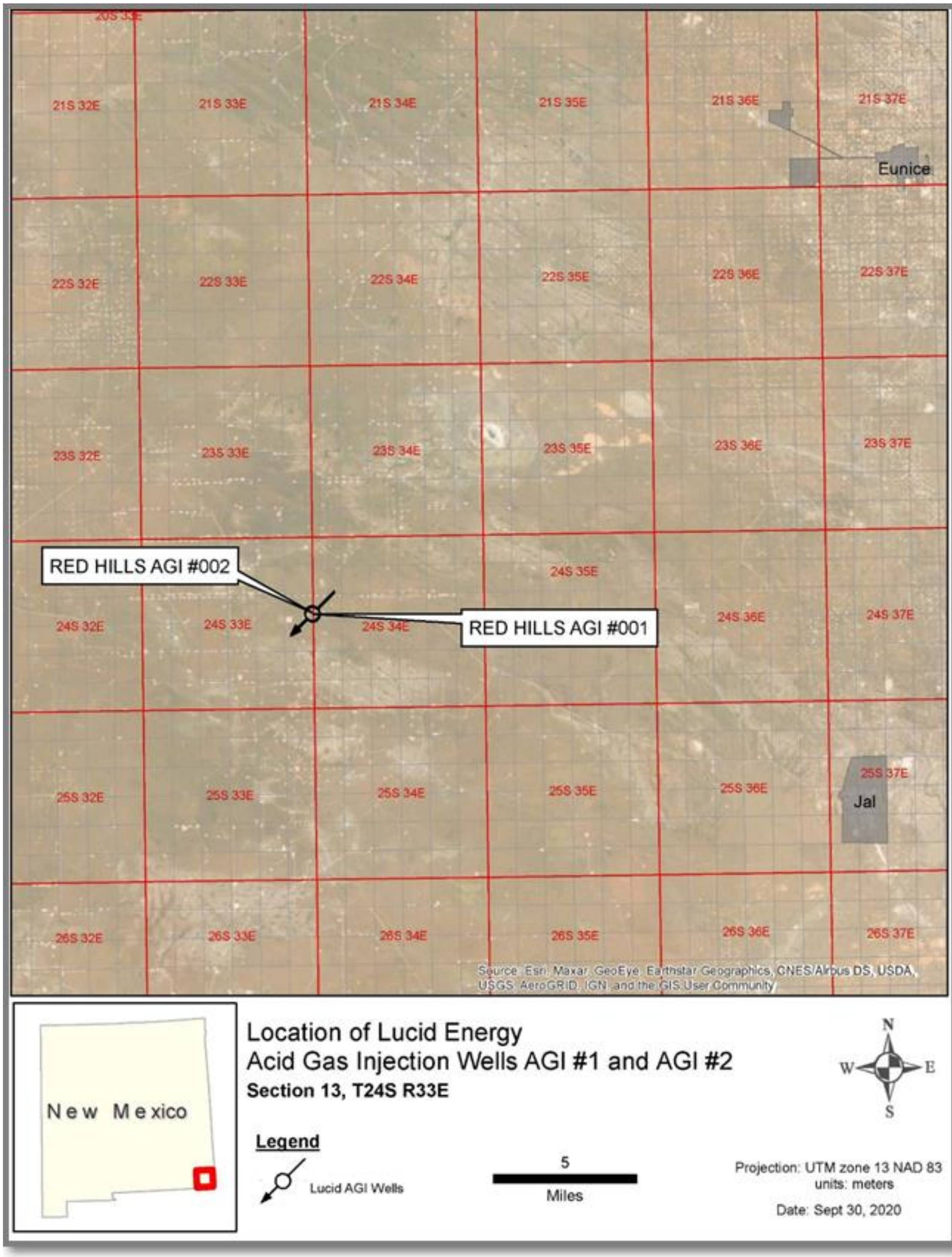


Figure 1-1 -- Location of the Red Hills Gas Plant and Wells – RH AGI #1 and RH AGI #2

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

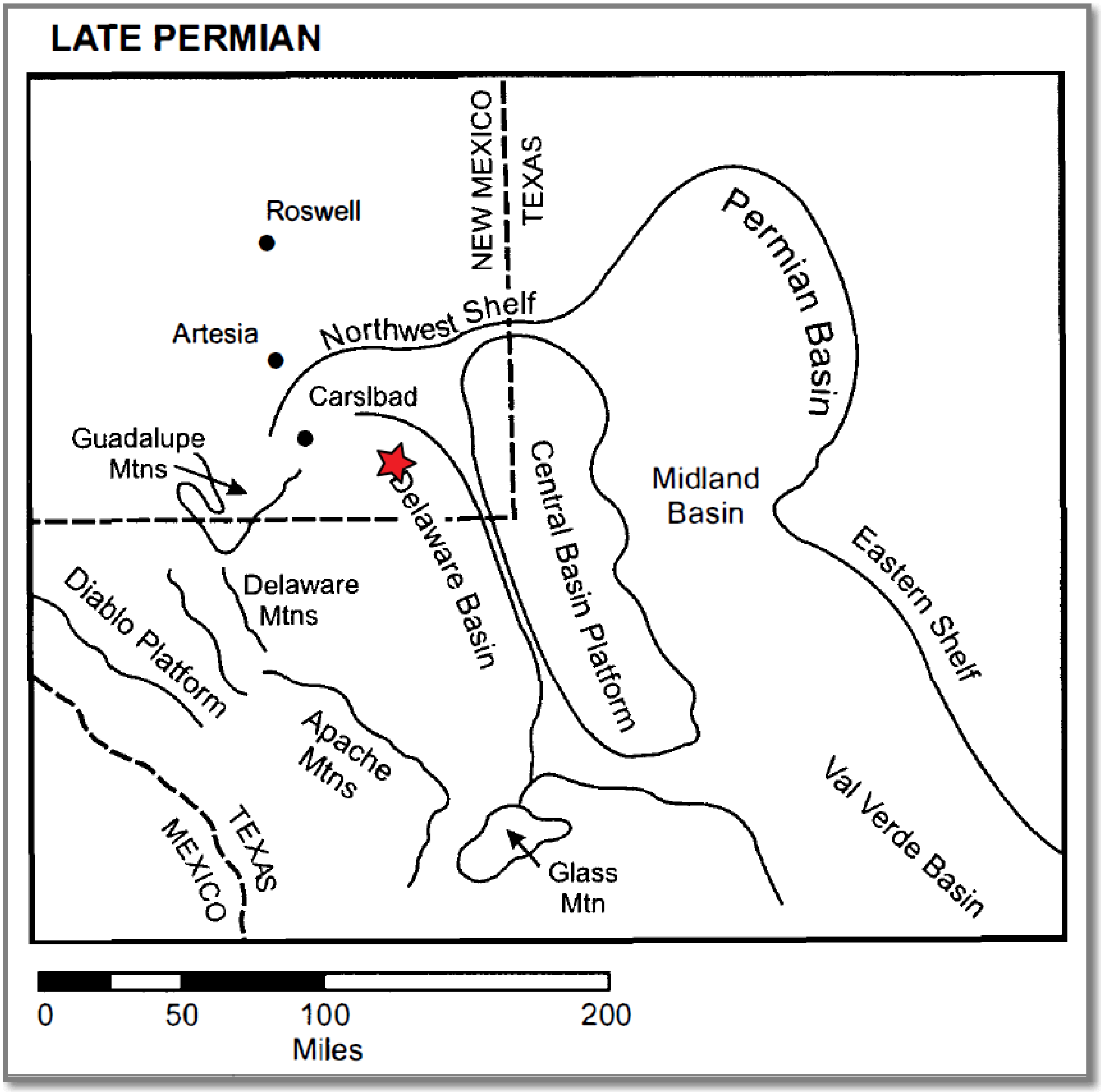


Figure 3.2-1 -- Structural features of the Permian Basin during the Late Permian. Location of the Lucid RH AGI wells is shown by the red star. (Modified from Ward, et al (1986))

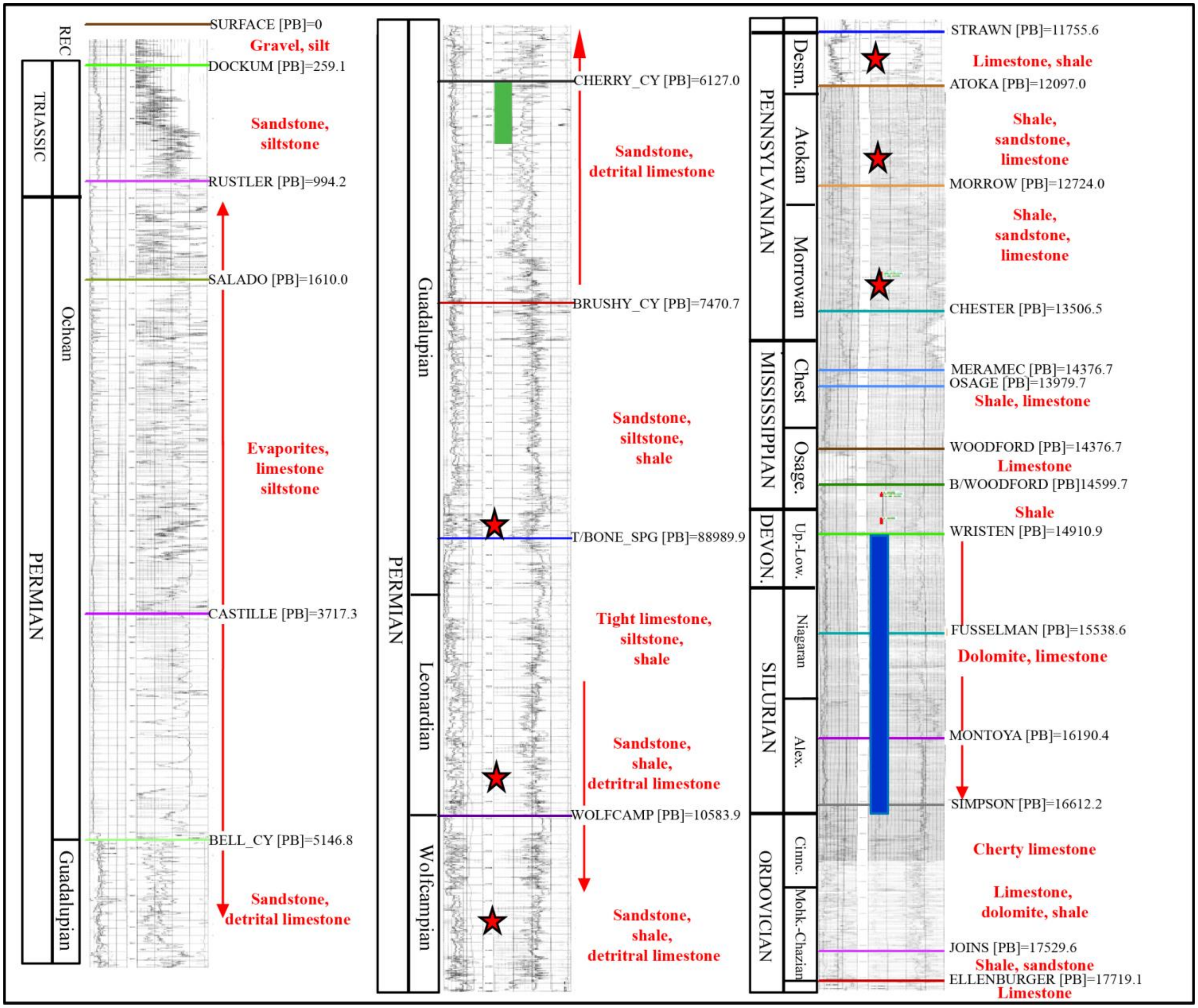


Figure 3.2-2 -- Stratigraphy and generalized lithologies of the formations underlying the Lucid RH AGI Wells.

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).

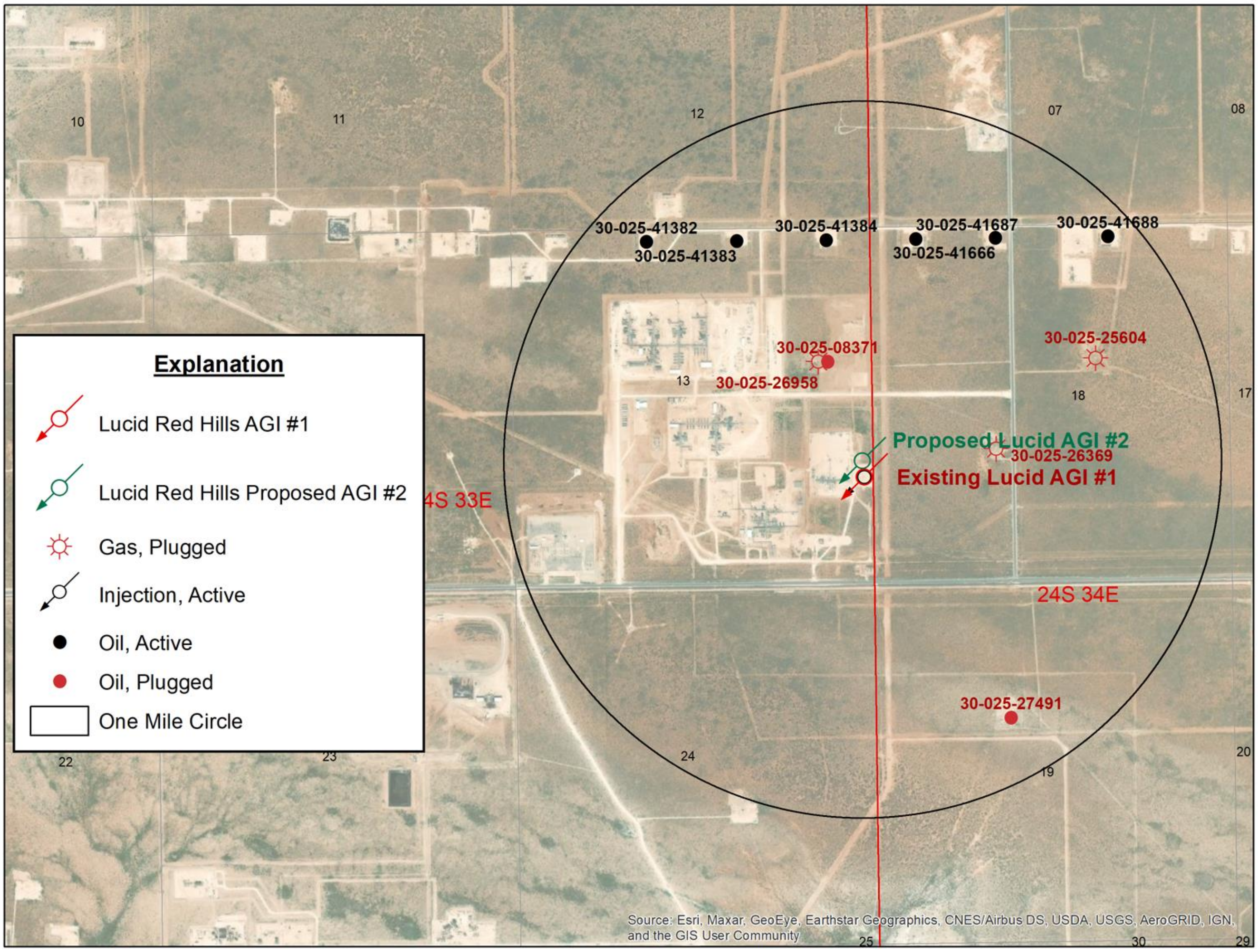


Figure 3.2-3 – Oil and gas production and saltwater (SWD) wells completed in the Siluro-Devonian in the vicinity of the RH AGI wells. The Class II one-mile radius AoR is also indicated.

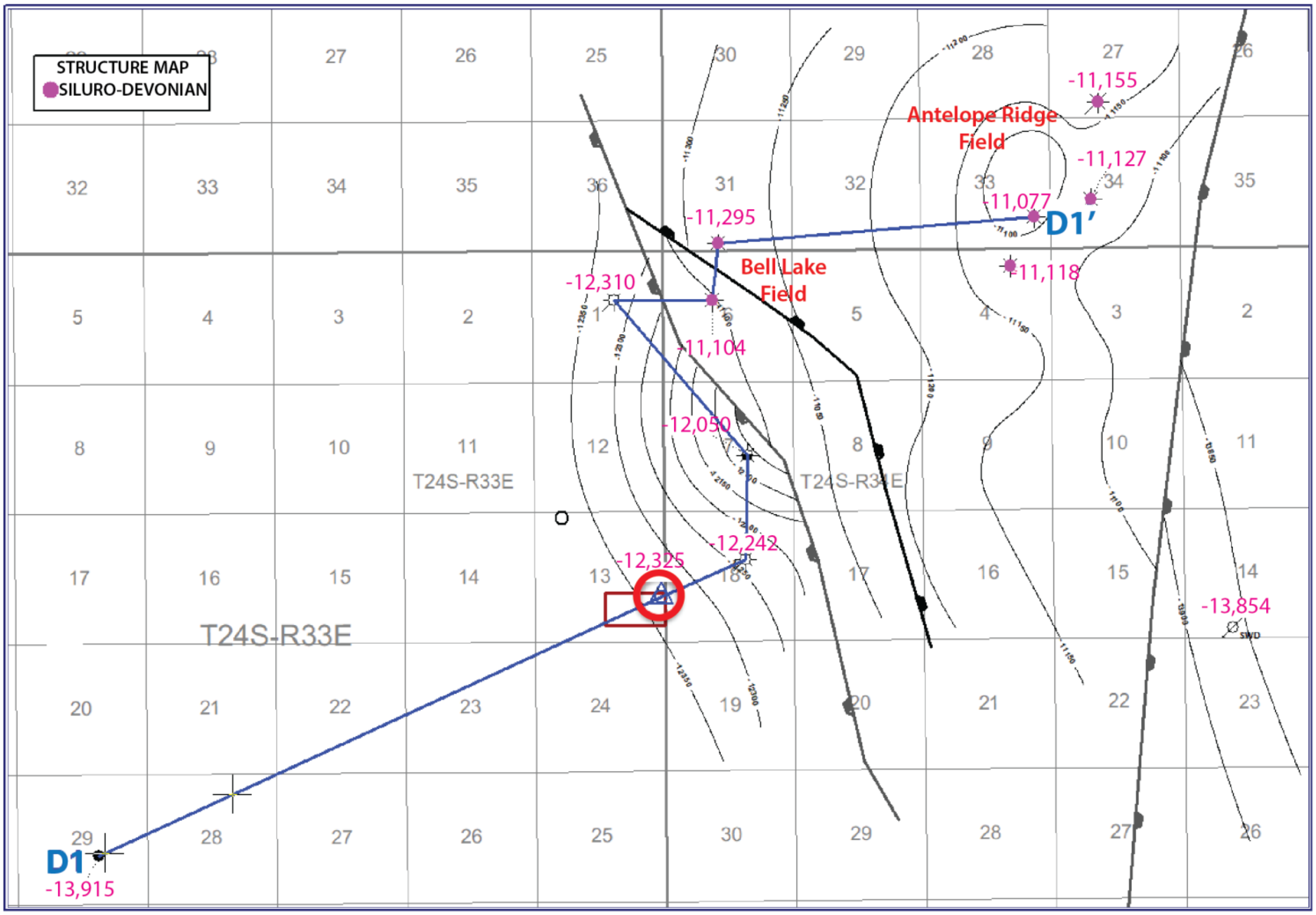


Figure 3.2-4 -- Structure on top of the Devonian and location of cross section D1-D1'

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.

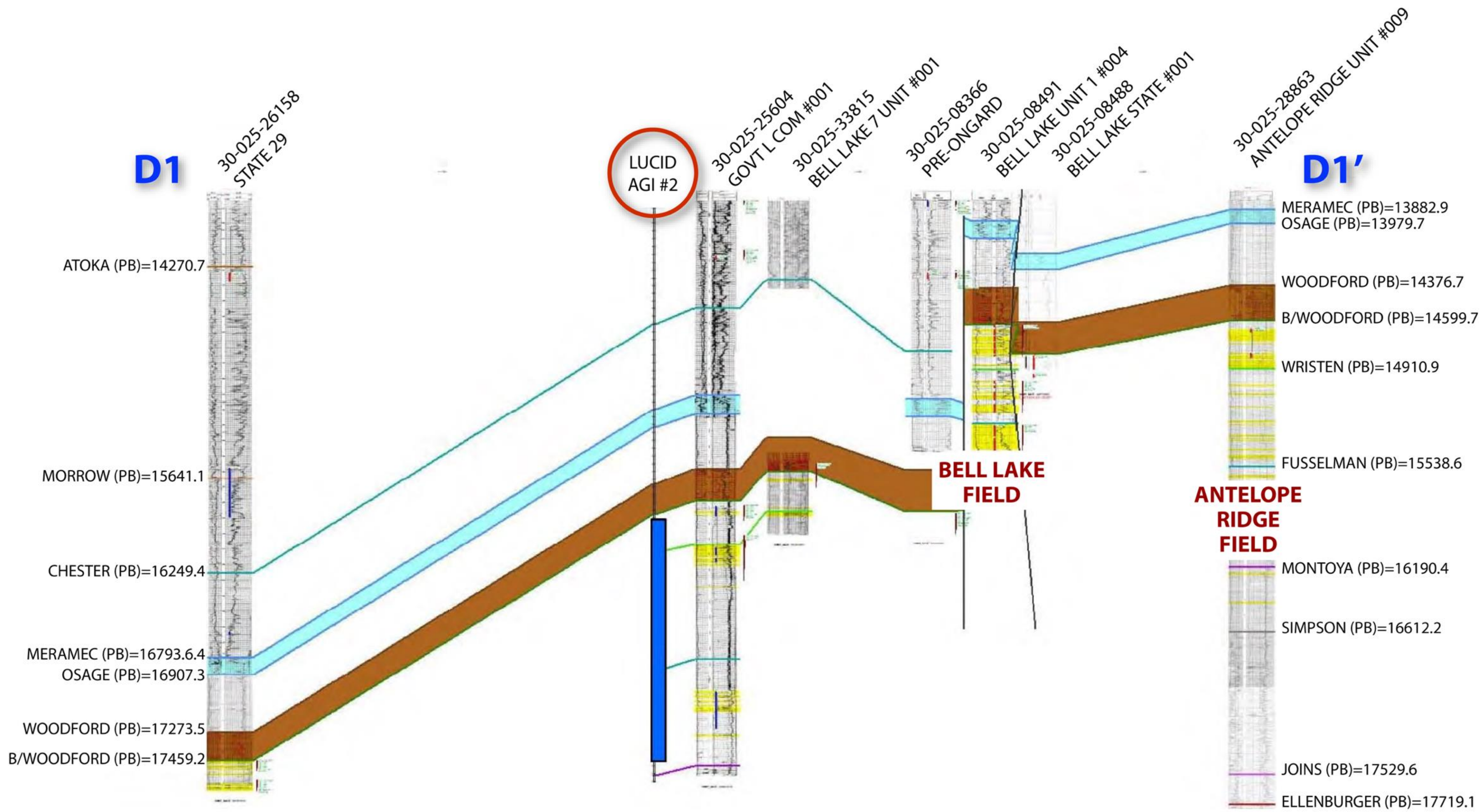


Figure 3.2-5 -- Structural cross section through the deeper horizons across the Red Hill Gas Plant Site

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

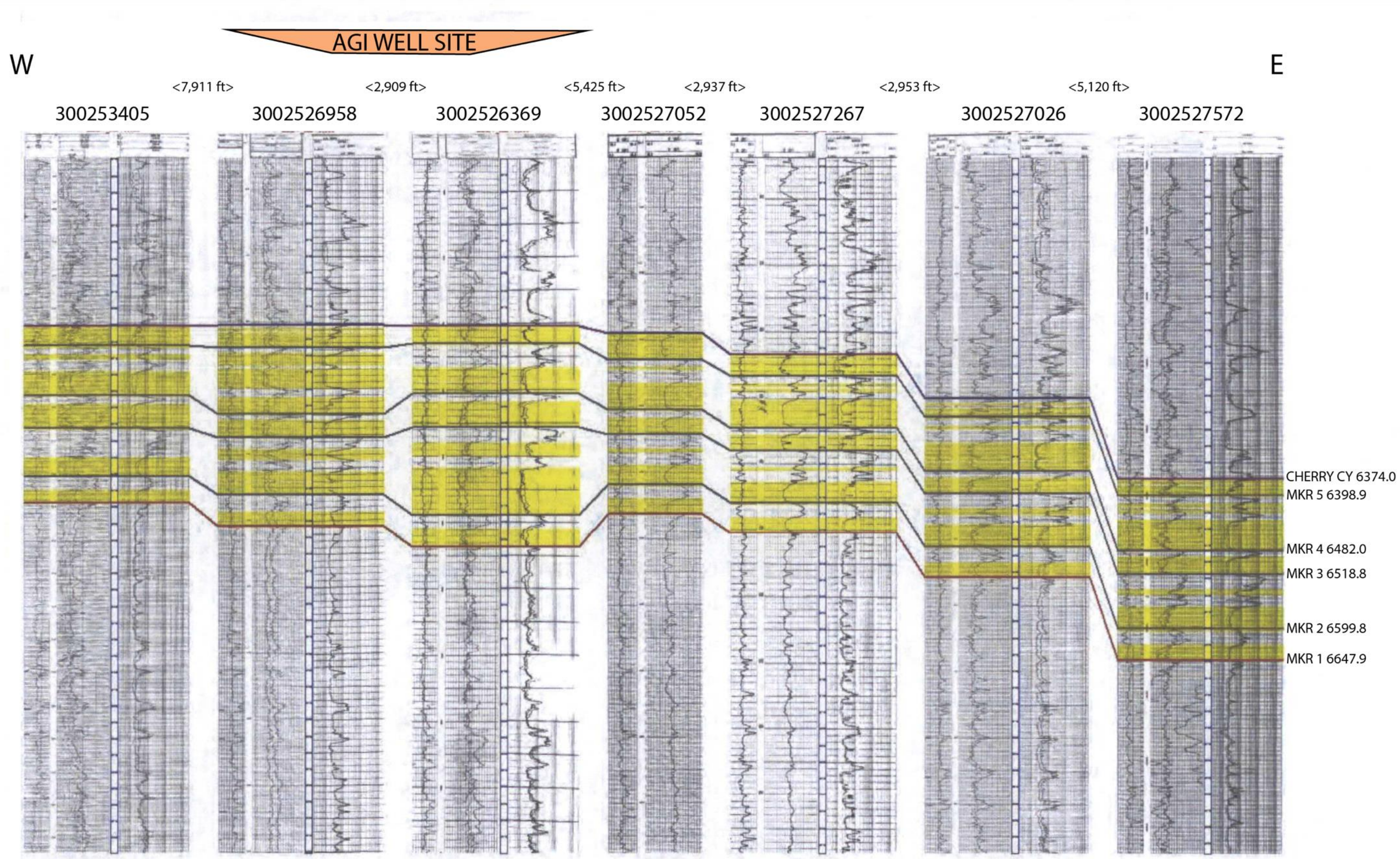


Figure 3.3-2 -- West – East cross section showing the 5 sand units of the Manzanita Zone of the Cherry Canyon Formation

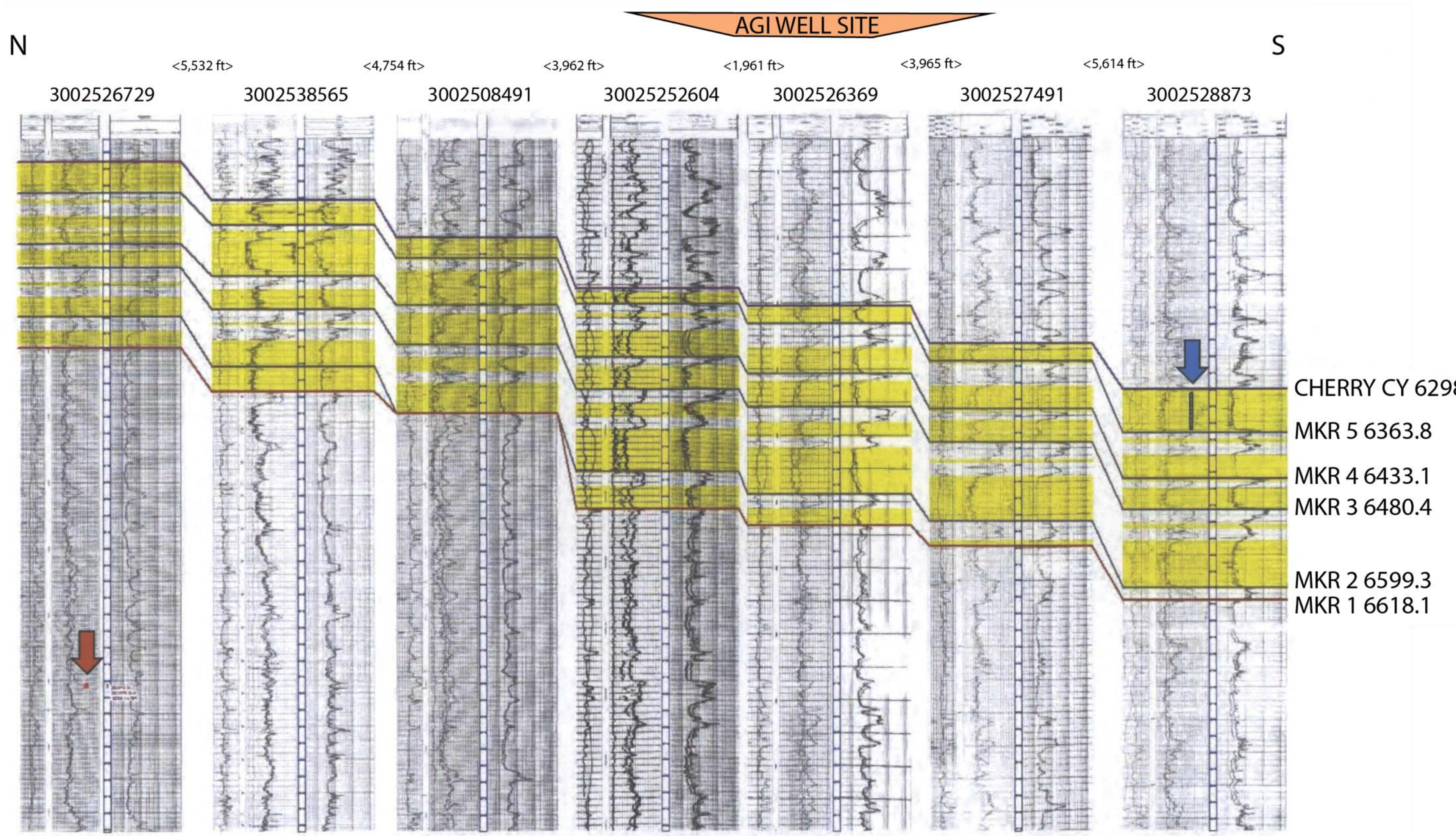


Figure 3.3-3 -- -- North - South cross-section showing the 5 sandstone units of the Manzanita Zone of the Cherry Canyon Formation

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.

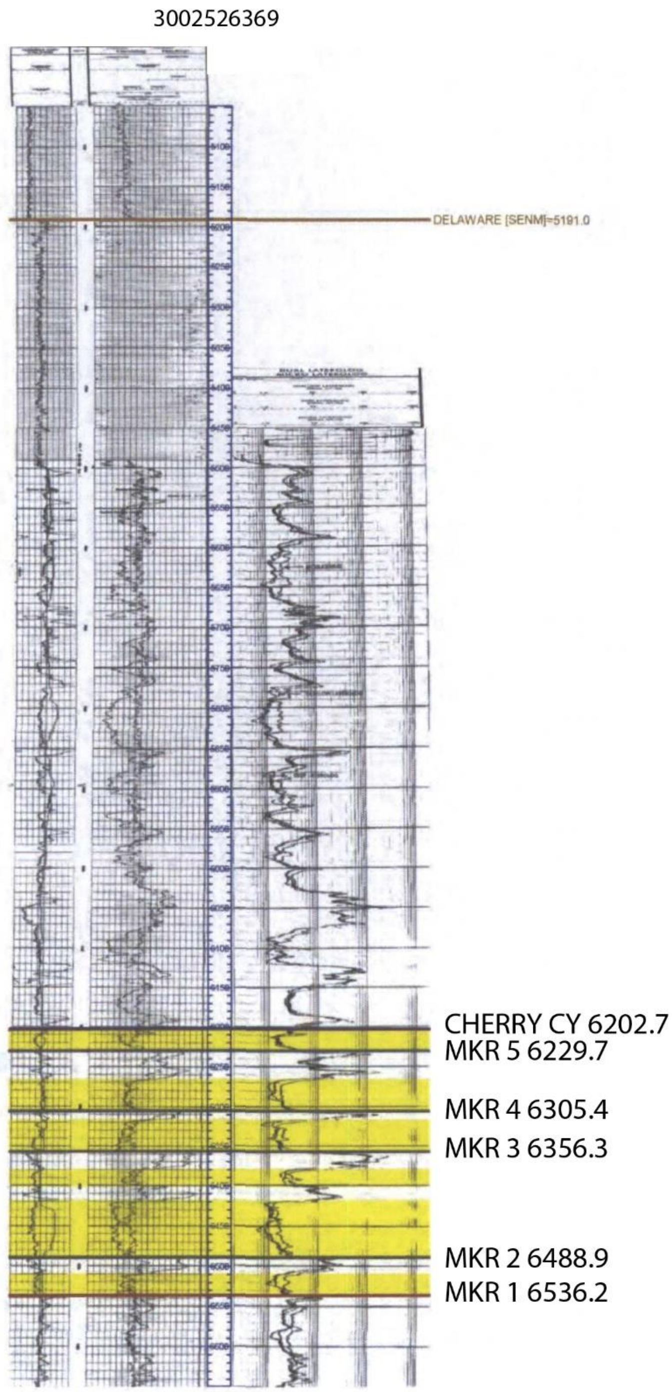


Figure 3.3-4 -- Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well

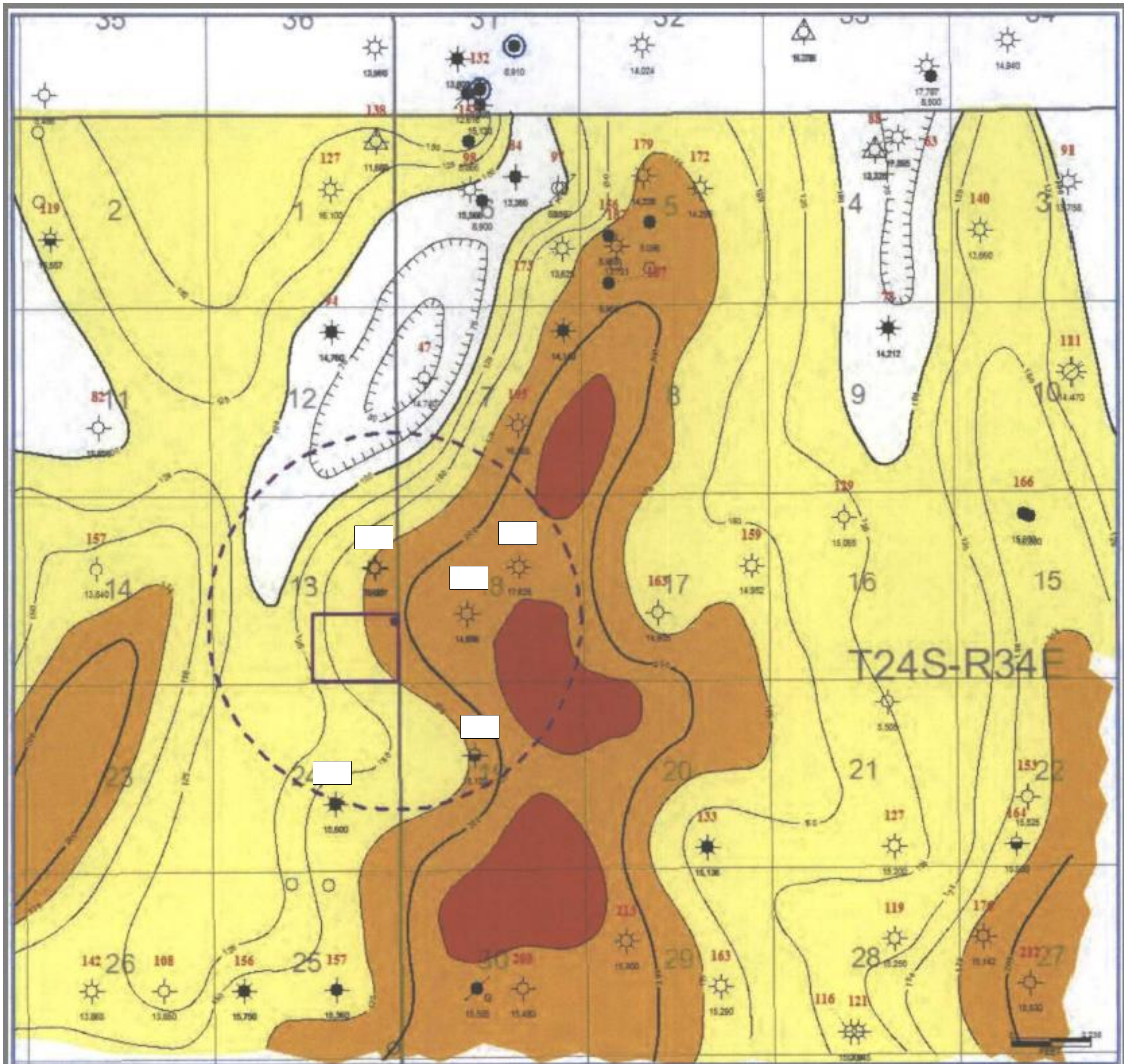


Figure 3.3-5 -- Map showing thickness of the clean sands in the Upper Cherry Canyon injection zone for RH AGI #1 and the one-mile radius AoR

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.

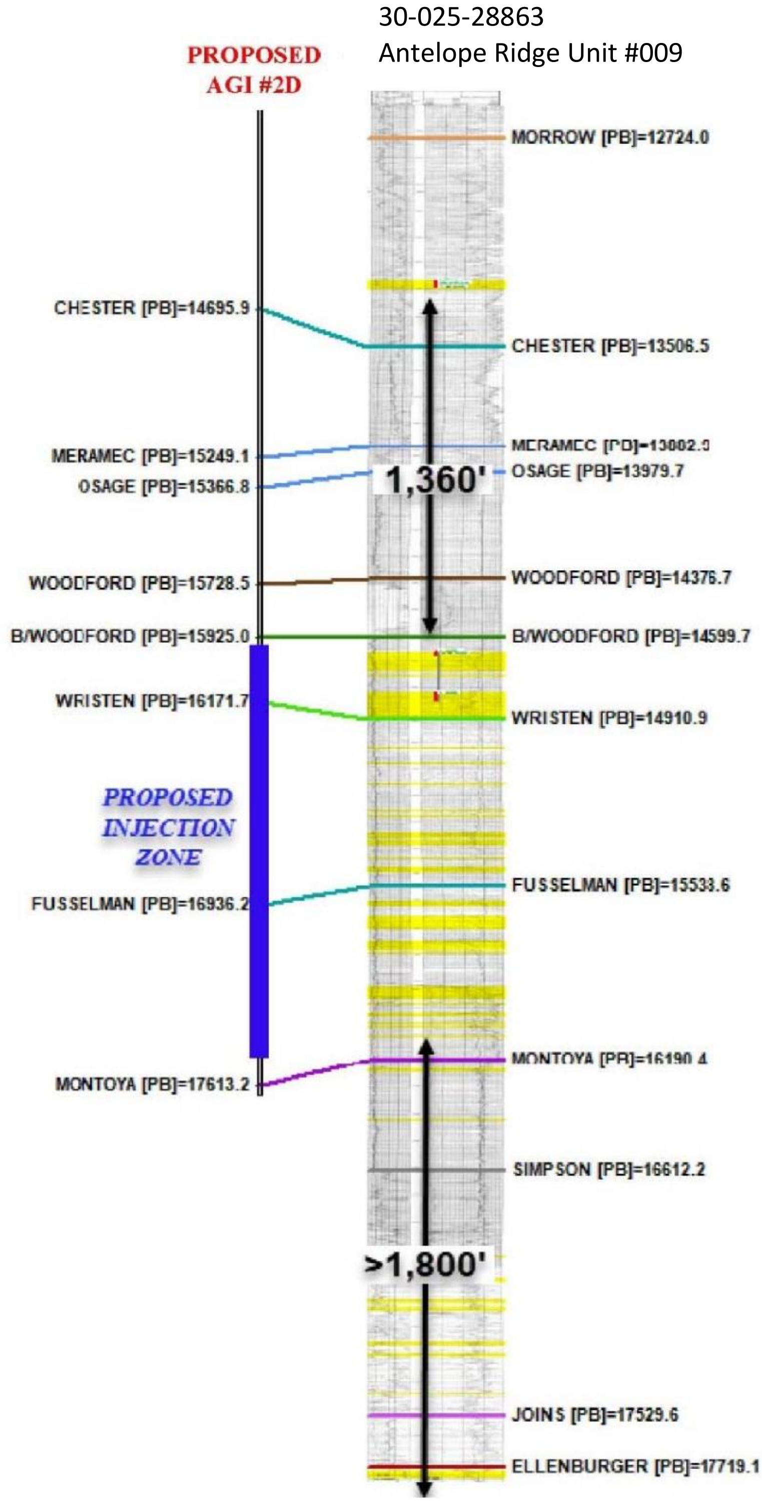


Figure 3.3-6 -- Porosity profile above and below proposed injection zone for RH AGI #2

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).

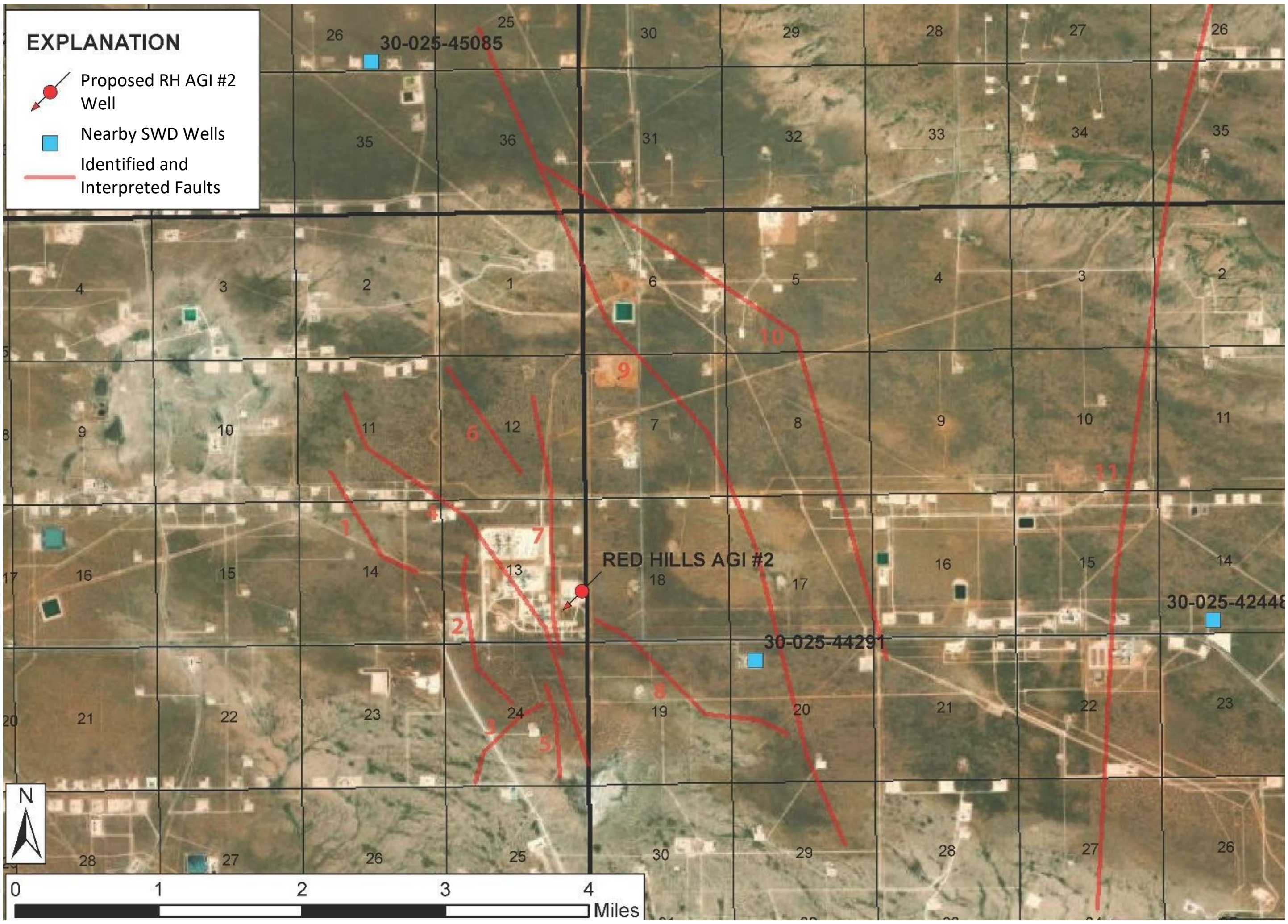


Figure 3.5-1 -- Map showing identified and interpreted faults in the area of the proposed RH AGI #2 well.

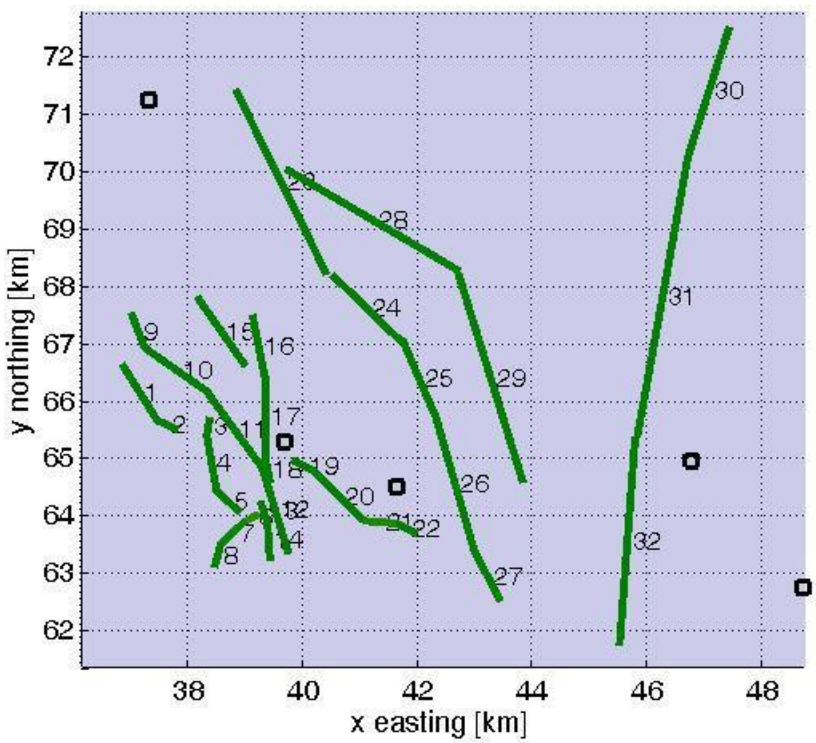


Figure 3.5-2 – Graphic showing 11 faults divided into 32 segments for FSP analysis.

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.

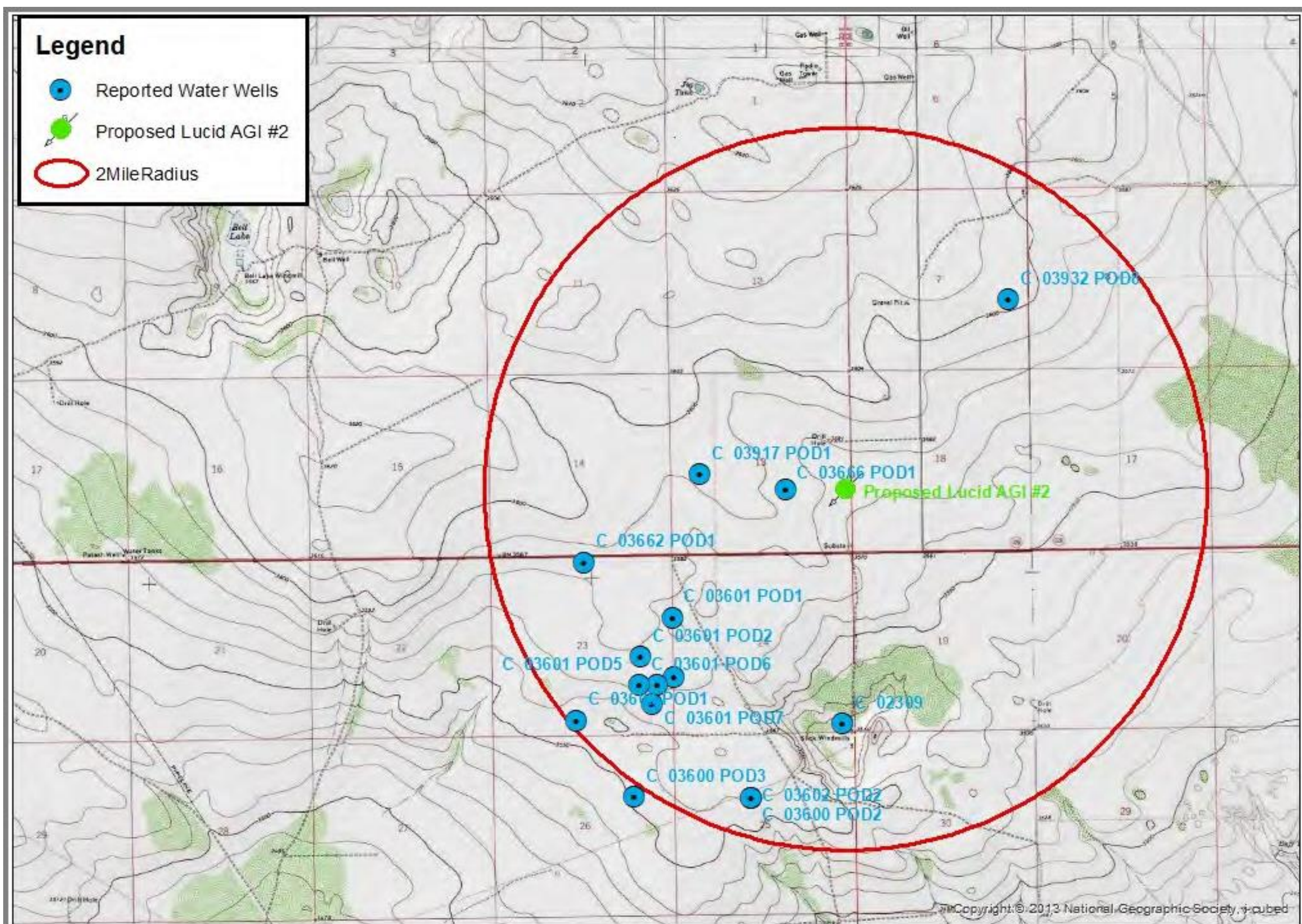


Figure 3.6-1 -- Reported Water Wells within 2-mile Radius of Proposed Lucid AGI #2

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			

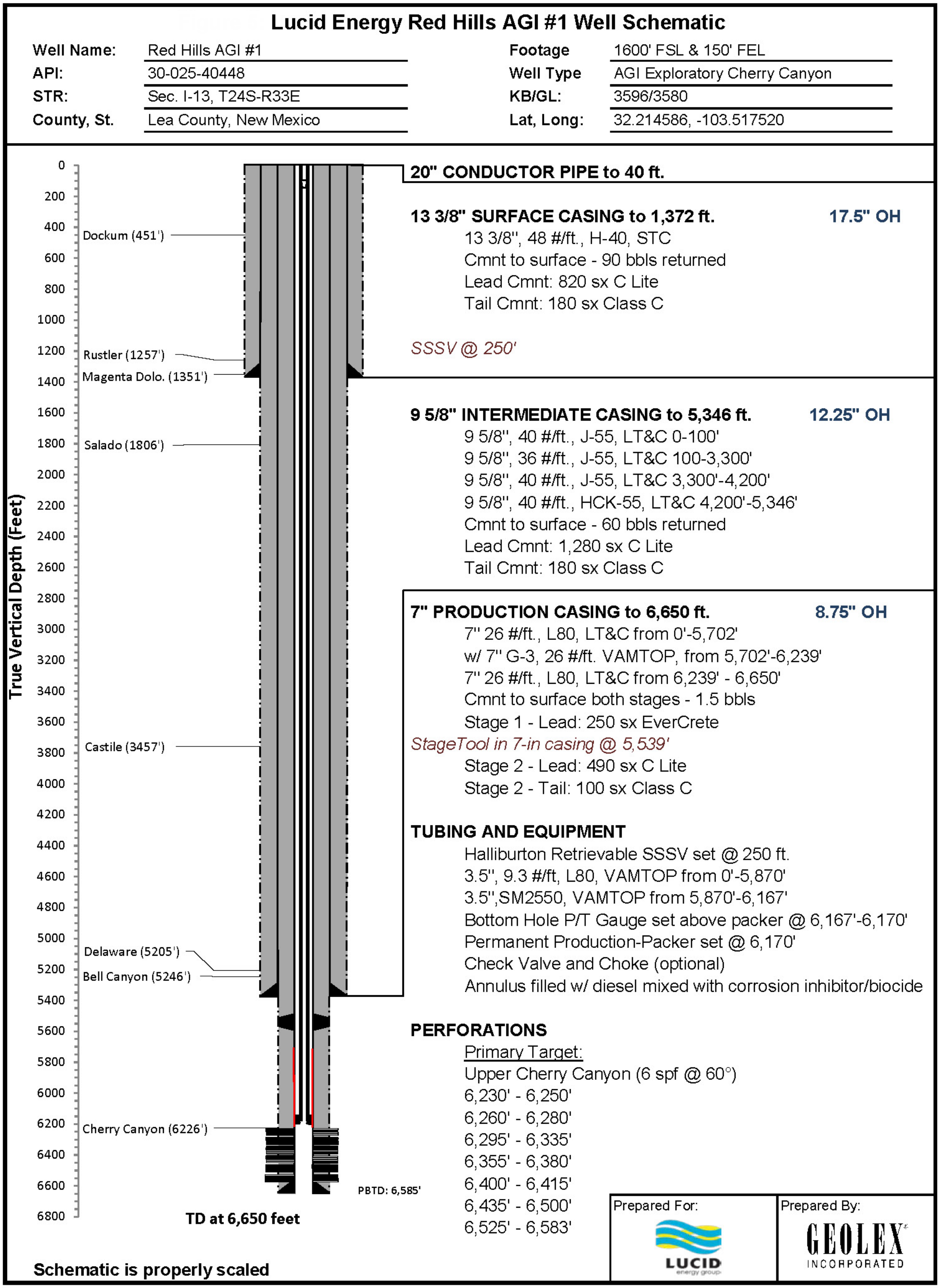


Figure 3.6-2 -- Schematic of RH AGI #1

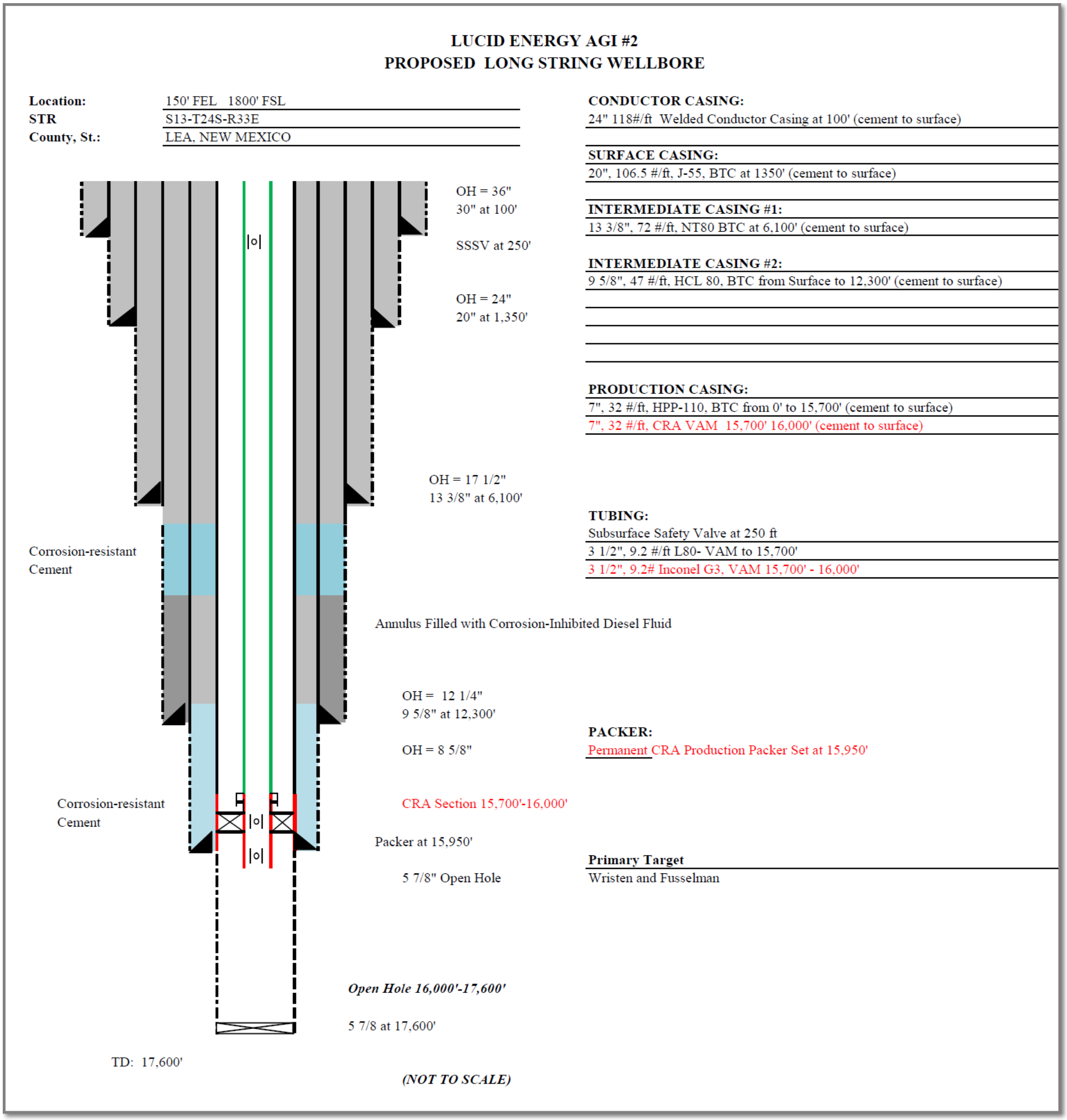


Figure 3.6-3 -- Schematic of Proposed RH AGI #2 (Option 2). Red text refers to completion parameters for the injection zone.

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.

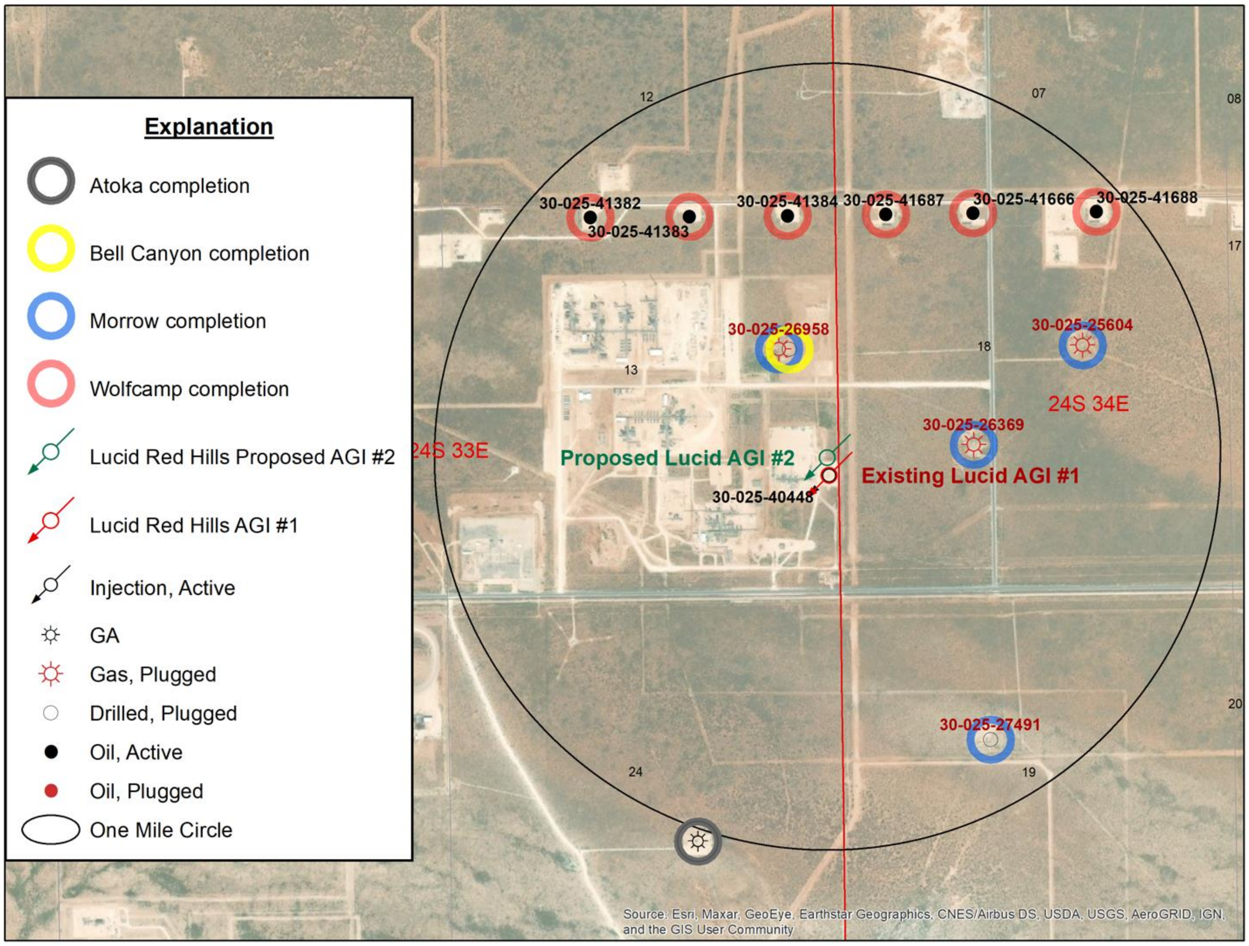


Figure 3.7-1 – Location of all oil- and gas-related wells within a 1-mile radius of the RH AGI wells

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

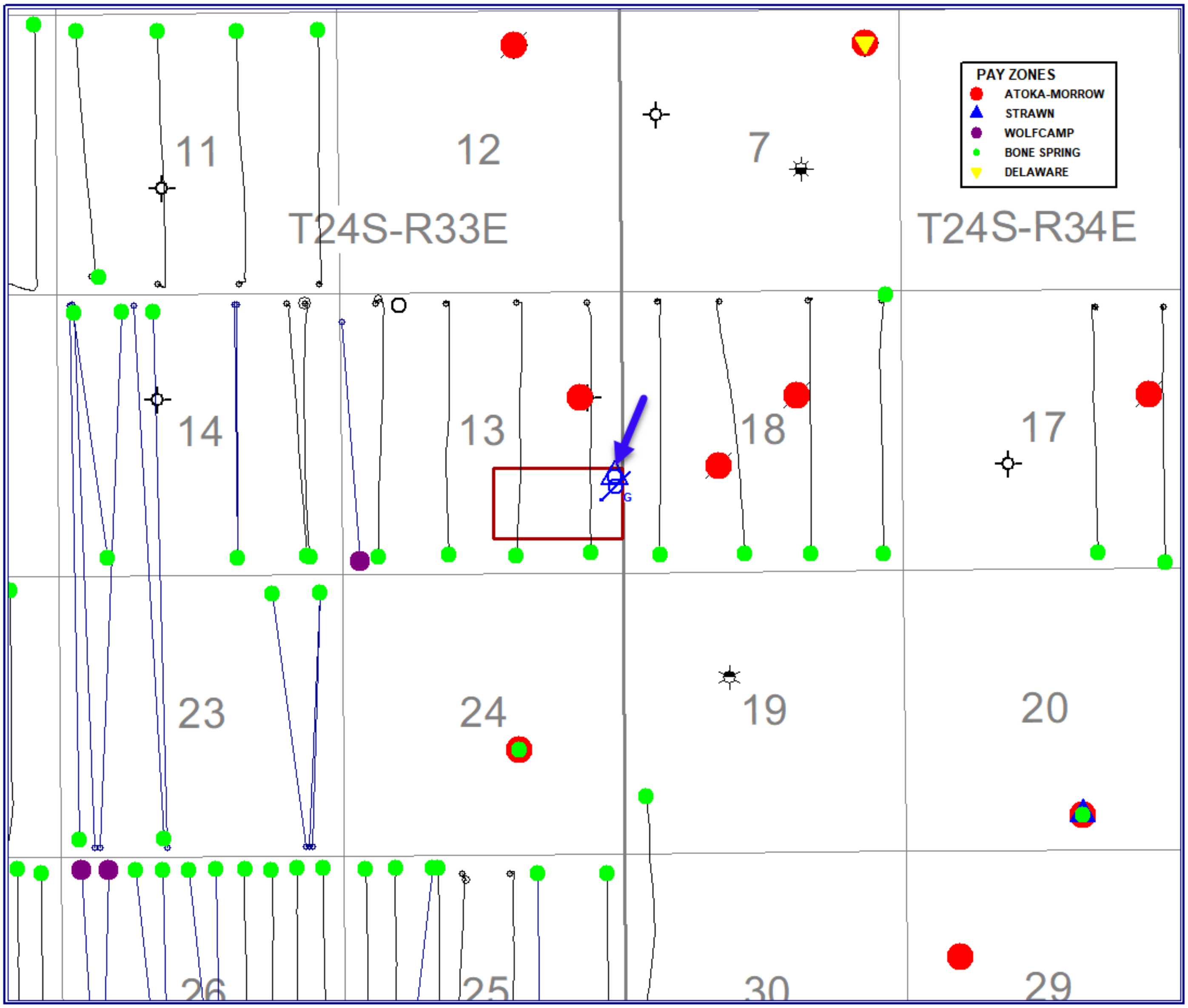


Figure 3.7-2 -- Producing wells in the area of the Red Hill Gas Plant.

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.

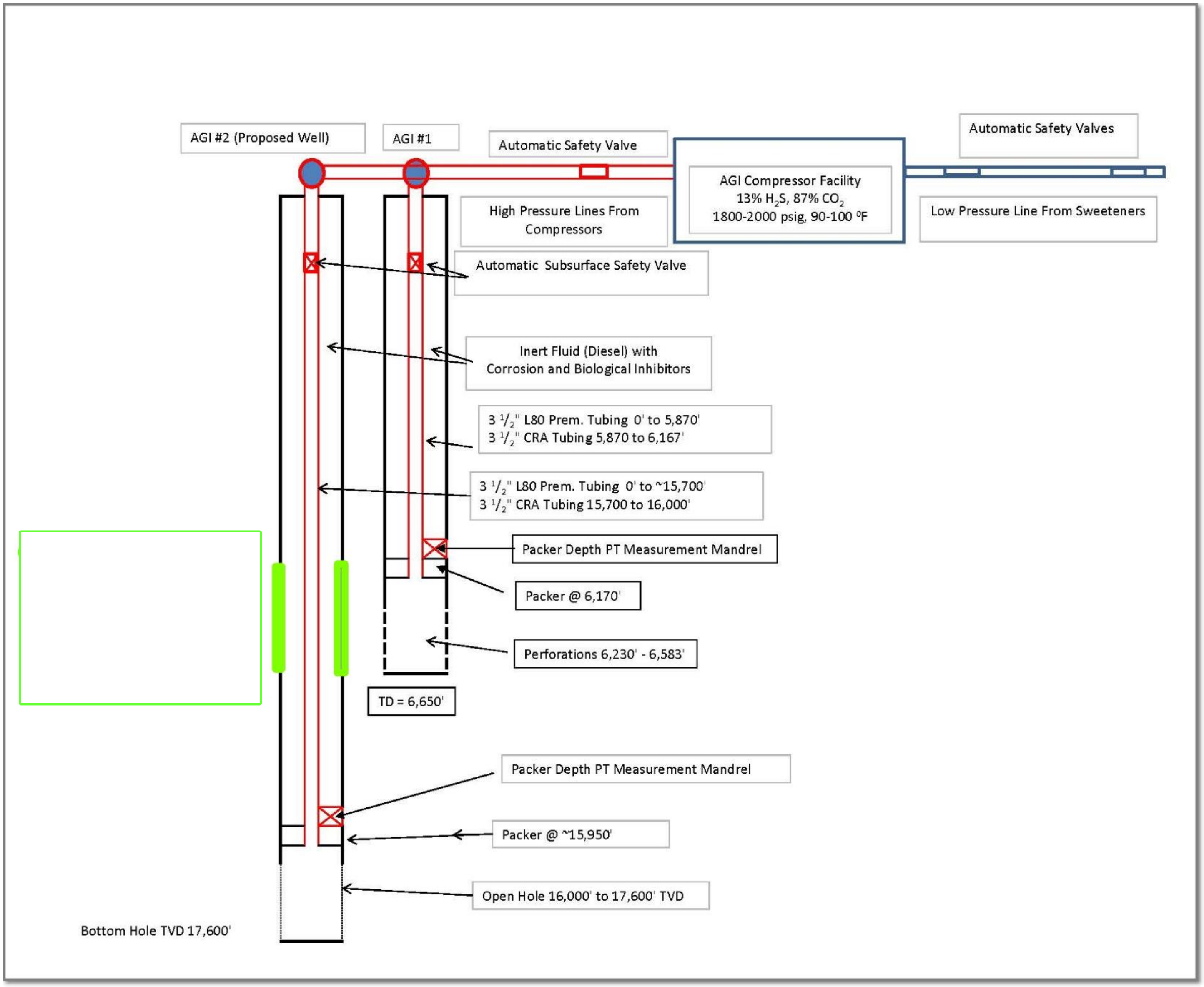


Figure 3.8-1 -- Schematic of surface facilities and RH AGI wells at the Red Hills Gas Plant

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).

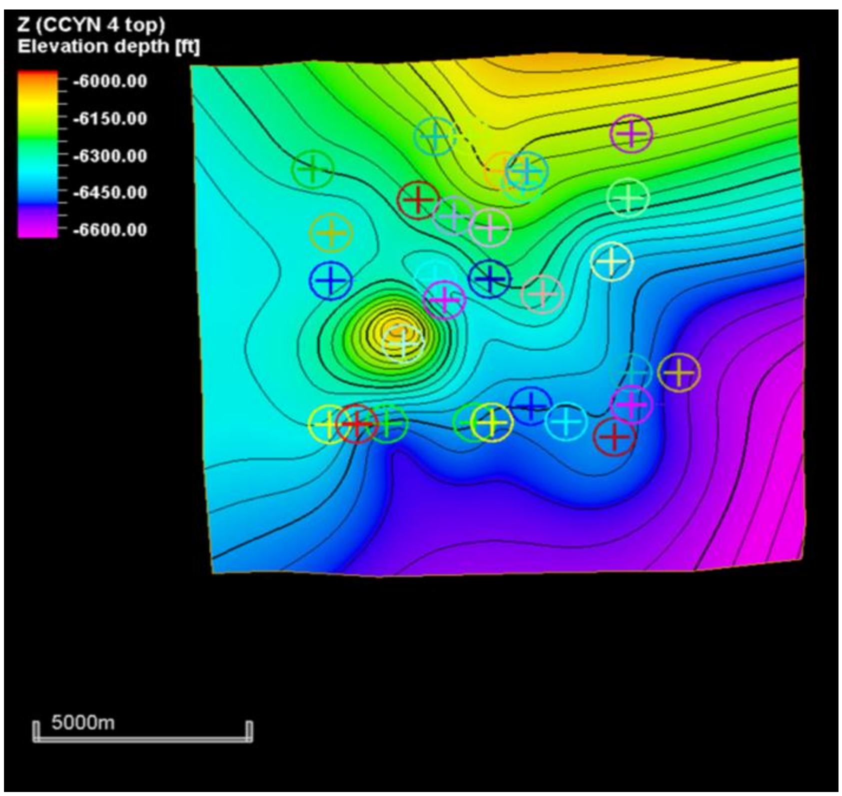


Figure 3.9-1 – Structural surface for top of Layer 4 of the Manzanita Zone of the Cherry Canyon Formation within the geological model.

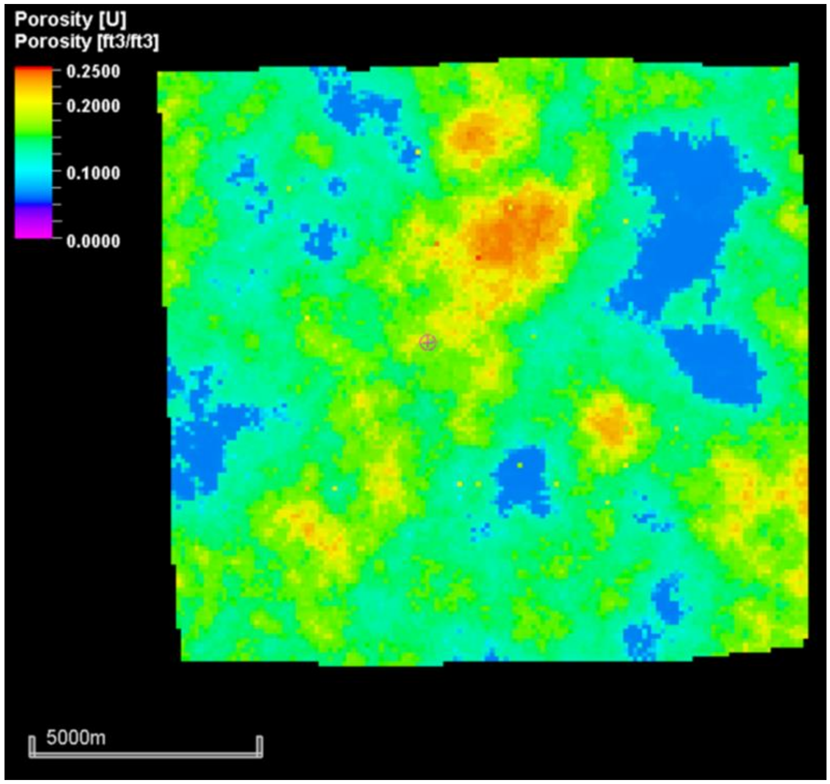


Figure 3.9-2 – Graphic showing the distribution of porosity in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation. Plan view.

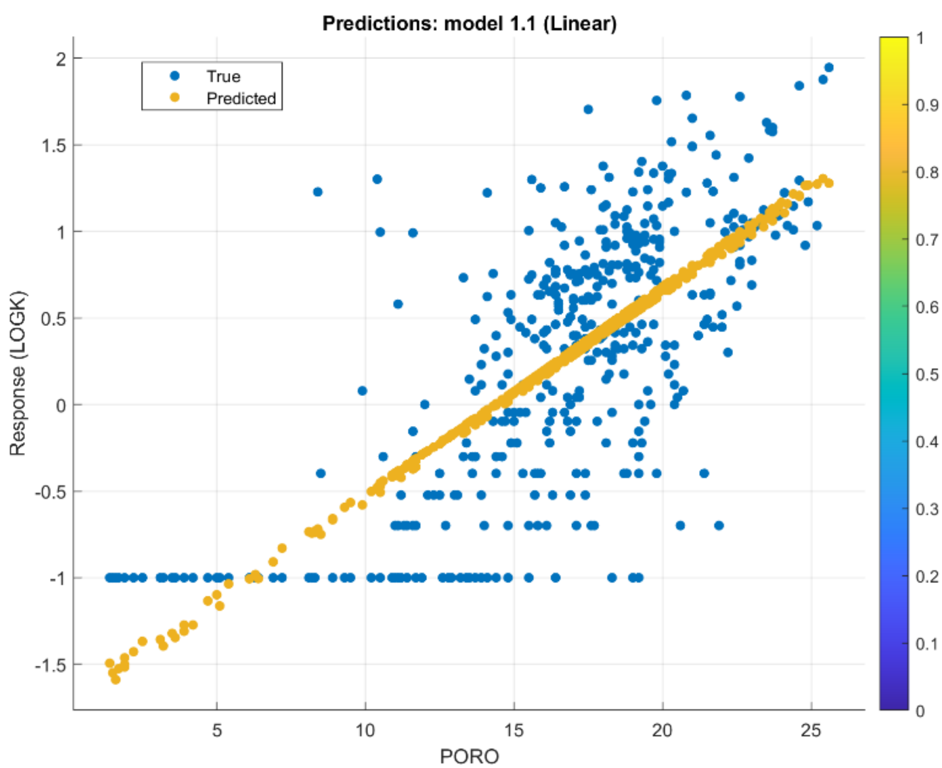


Figure 3.9-3 -- Porosity-permeability relationship for Layer 4 of the Manzanita Zone of the Cherry Canyon Formation.

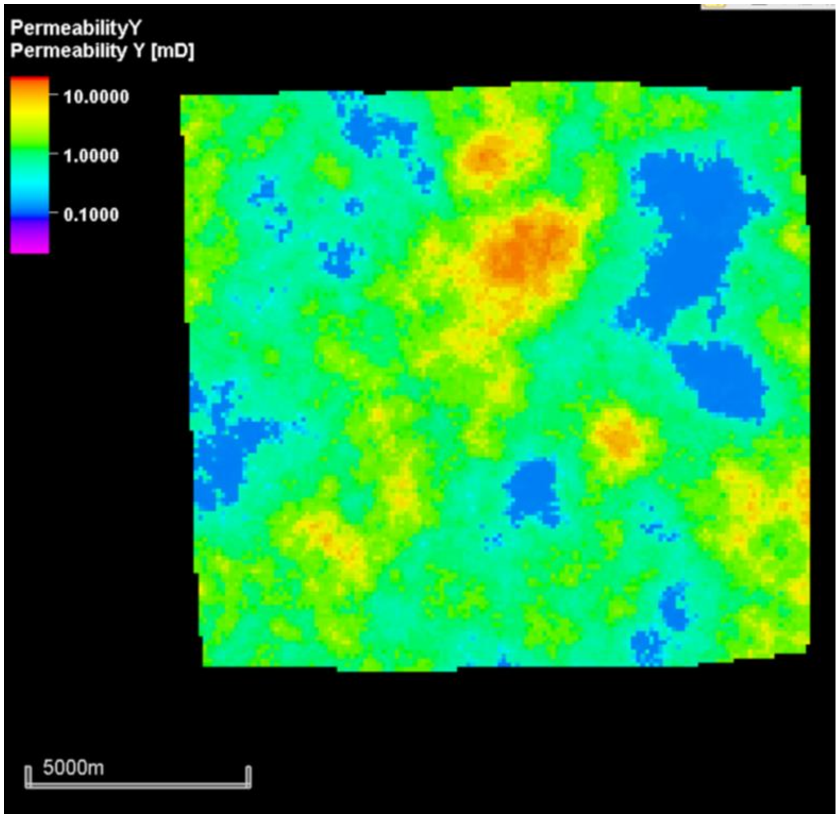


Figure 3.9-4 – Graphic showing the permeability distribution in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation. Plan view.

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.

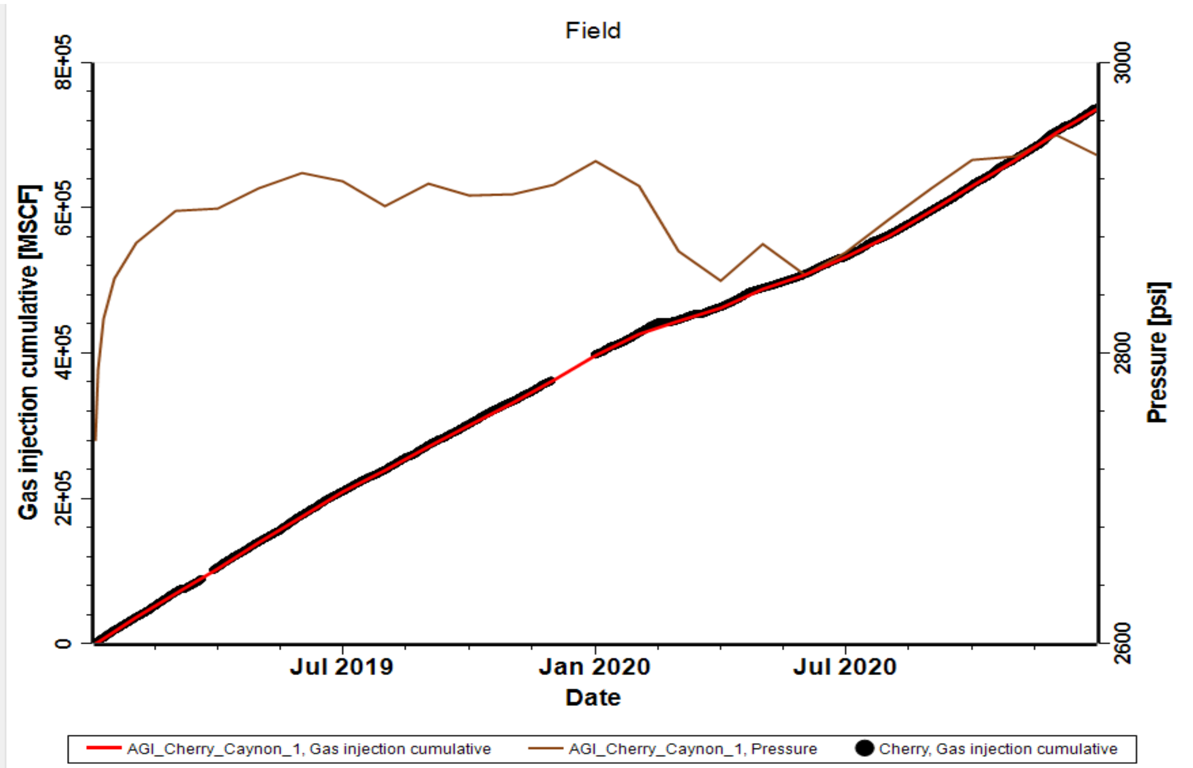


Figure 3.9-5 – Graph showing the calibrated cumulative gas injection and field pressure profile in the Cherry Canyon

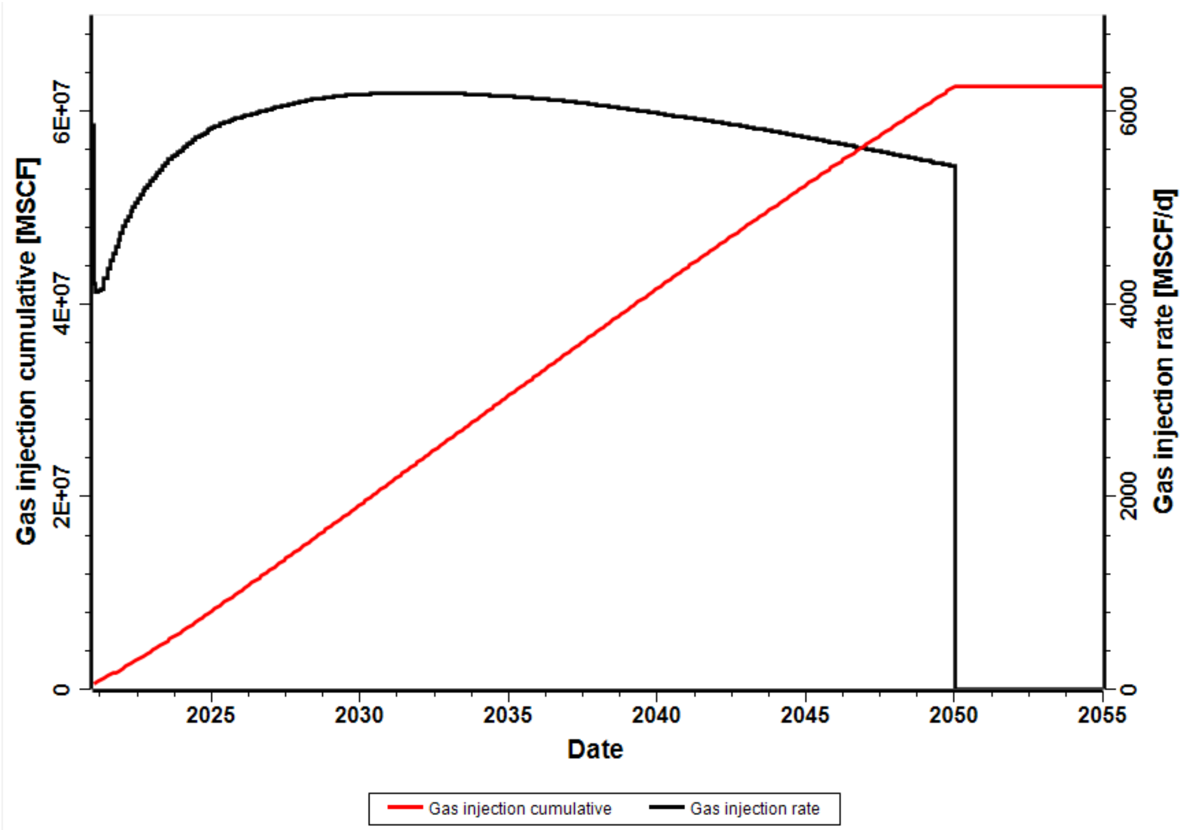


Figure 3.9-6 – Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period

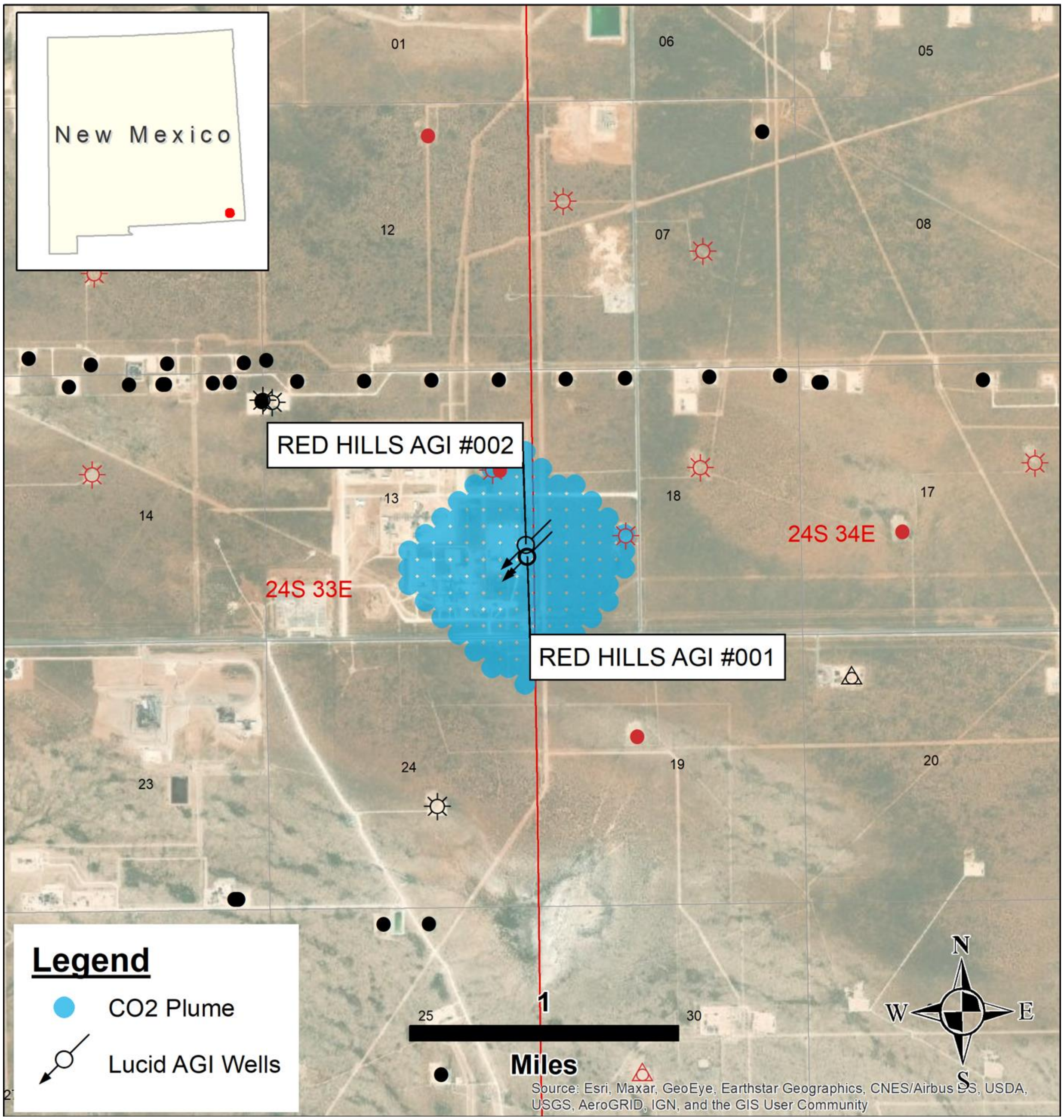


Figure 3.9-7 -- Map showing the largest lateral extent of the TAG plume within the Cherry Canyon

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.

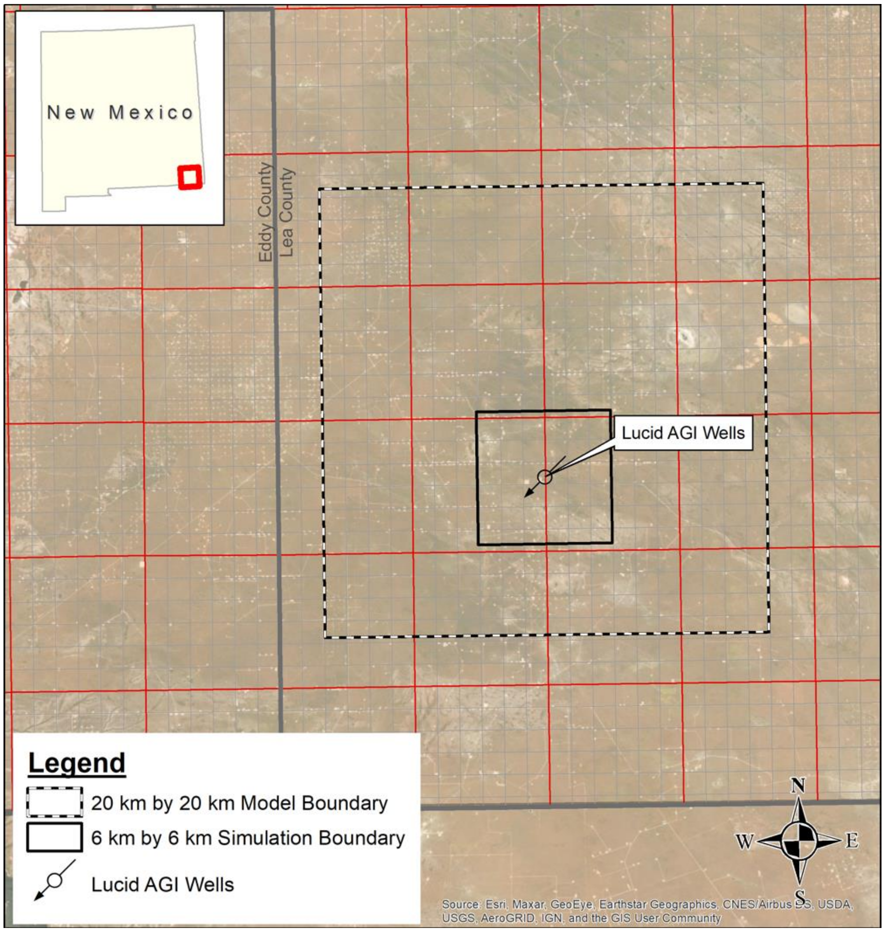


Figure 3.9-8 -- Map showing the top view of the geological and simulation model boundaries for the Siluro-Devonian injection zone.

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

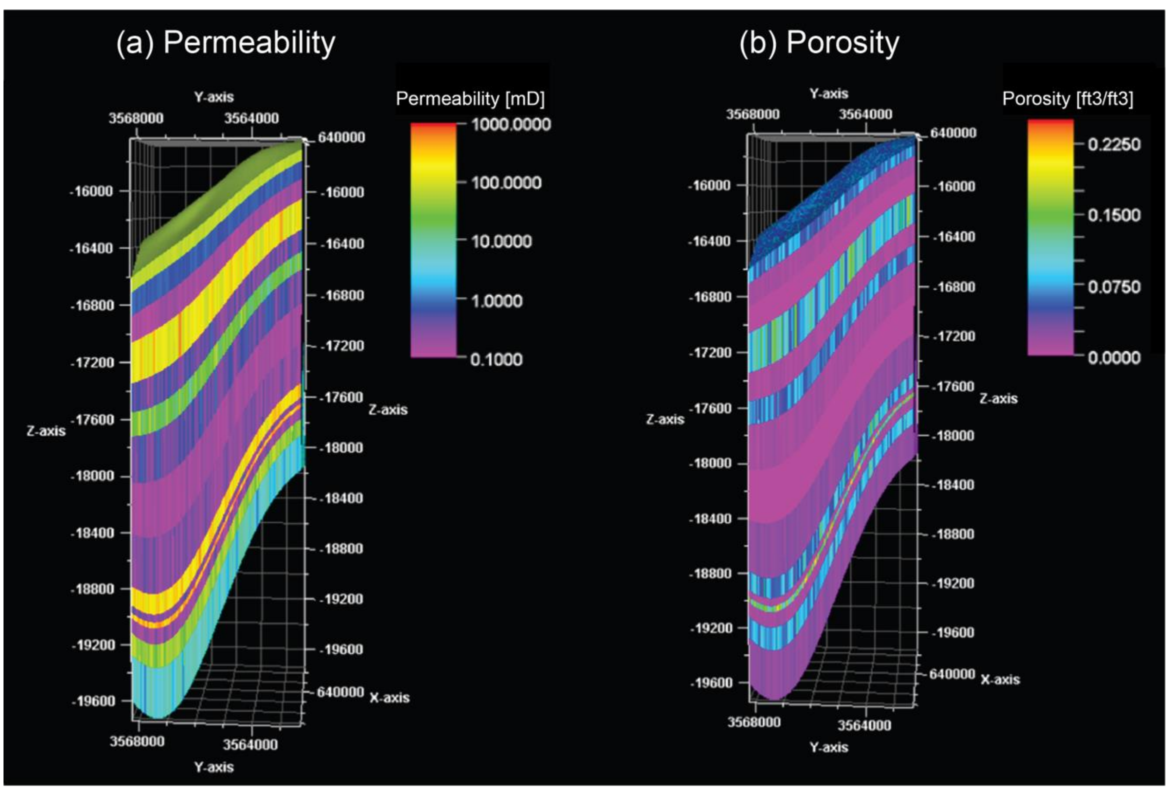


Figure 3.9-9 -- A 3D view of Siluro-Devonian modeled permeability (a) and porosity (b) distributions.

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.

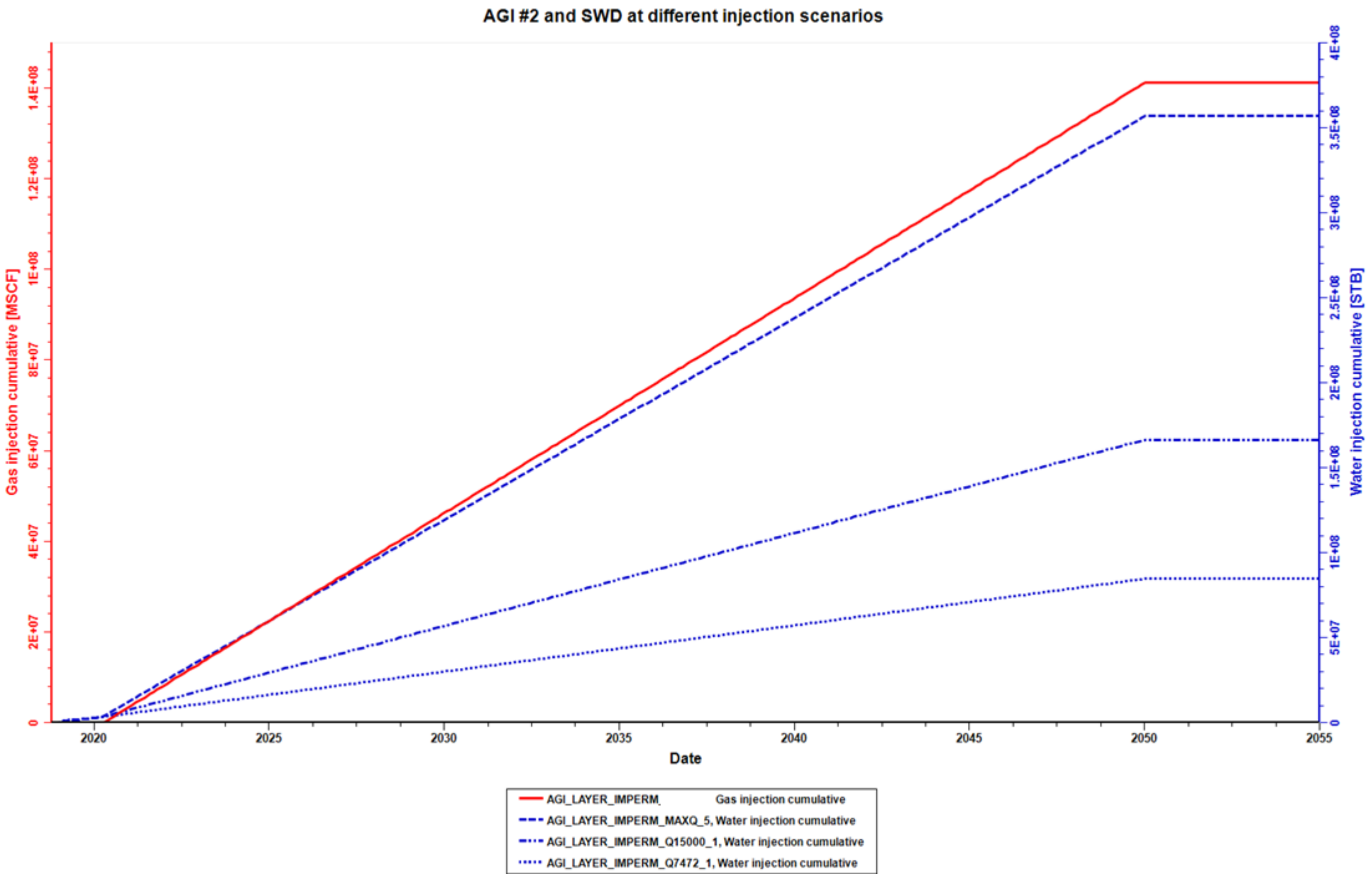


Figure 3.9-10 -- Graph showing the injection profile of the RH AGI #2 and the Striker well at different injection scenarios.

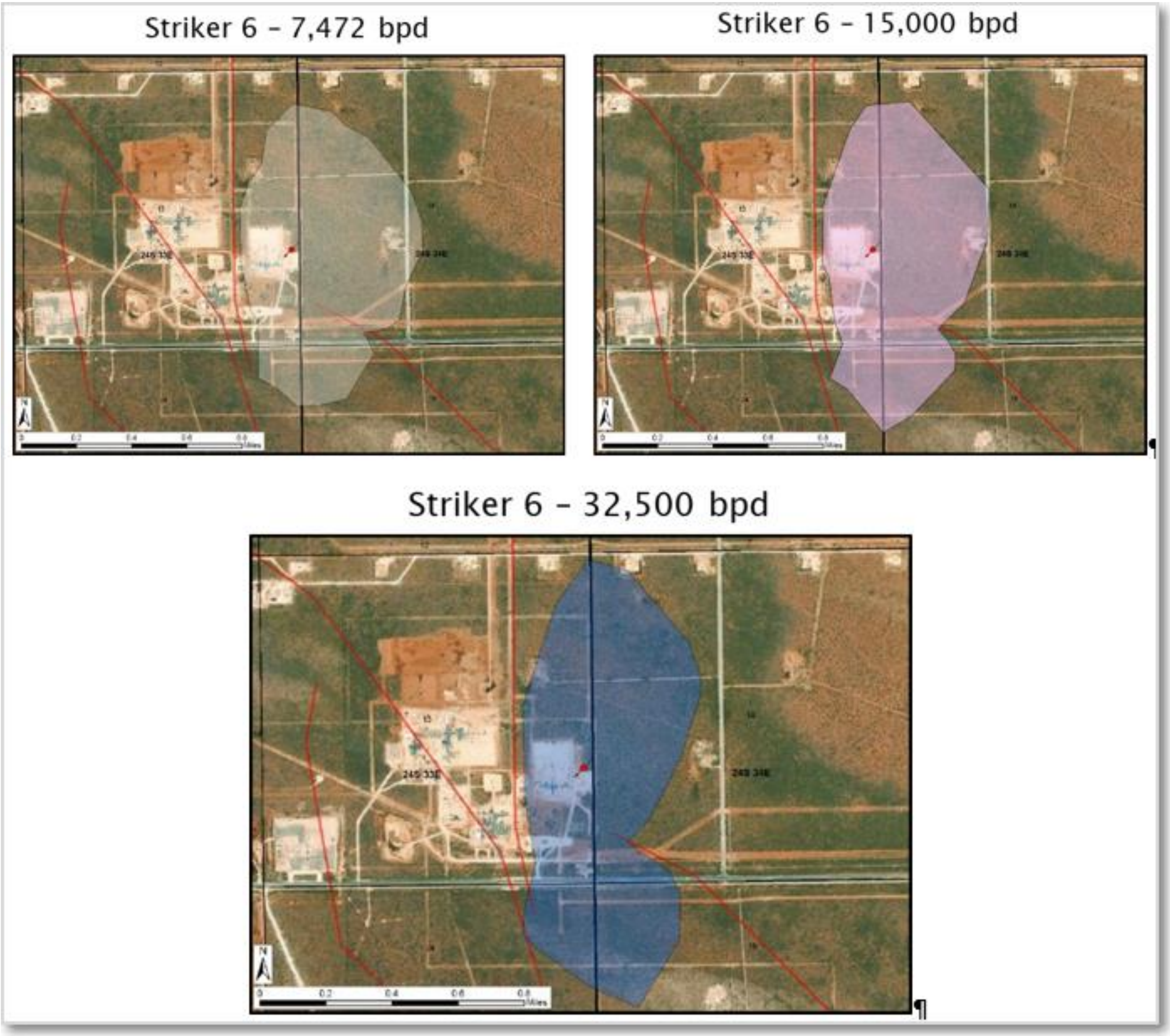


Figure 3.9-11 – Maps showing the largest lateral extent of the TAG when the interpreted faults are non-transmissive. The Striker 6 well injects into the Siluro-Devonian injection interval for RH AGI #2.

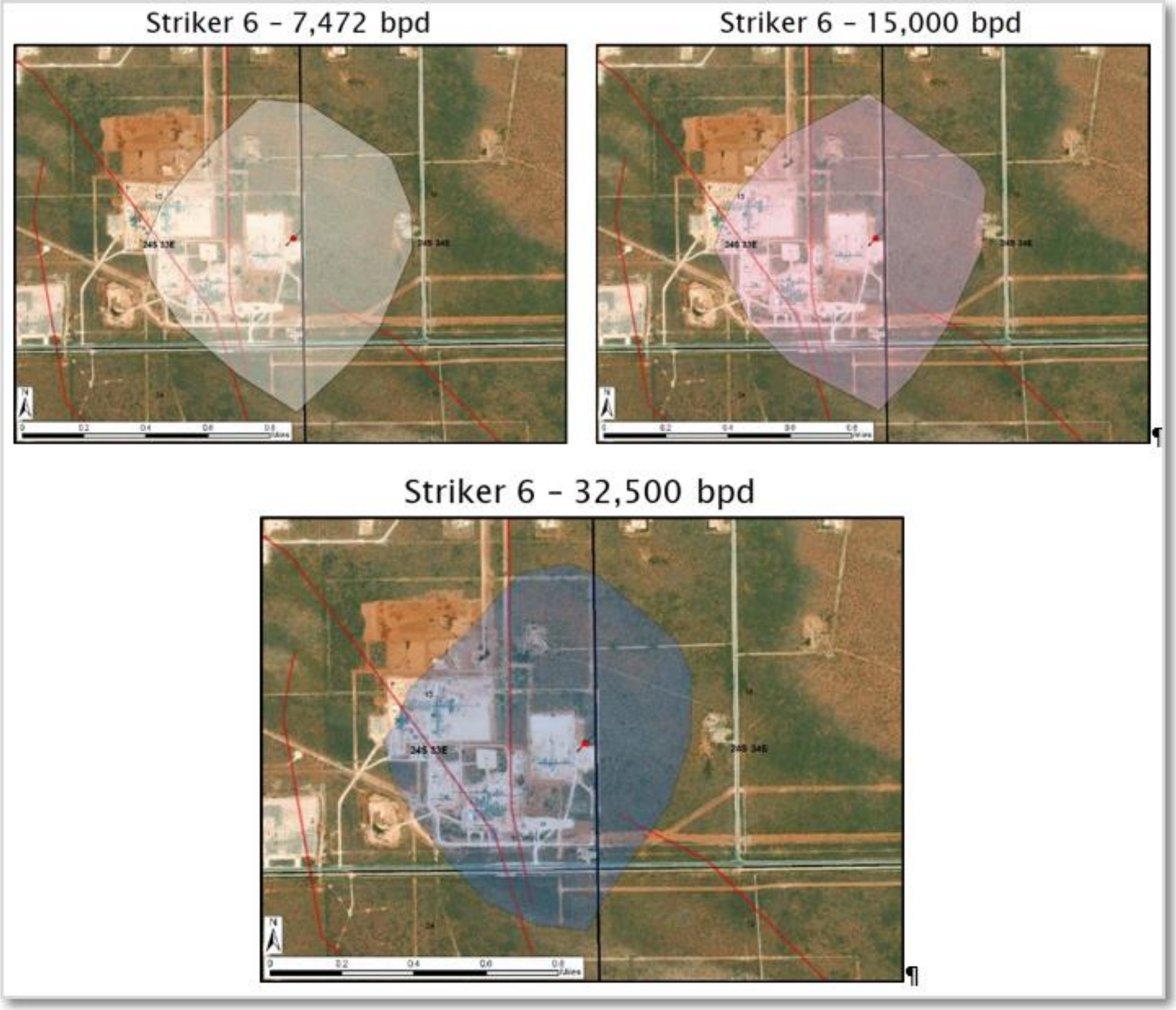


Figure 3.9-12 -- Maps showing the largest lateral extent of the TAG when the interpreted faults are transmissive. The Striker 6 well injects into the Siluro-Devonian injection interval for RH AGI #2.

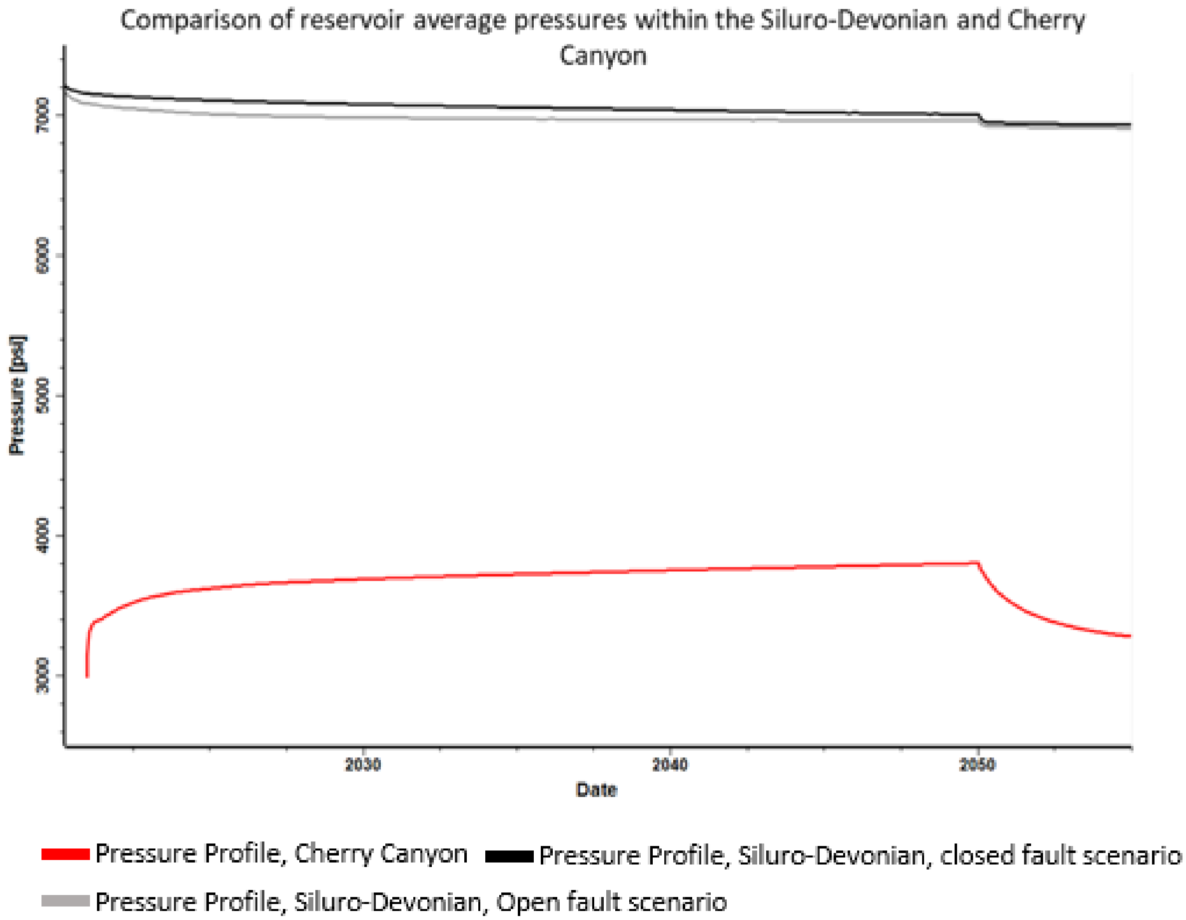


Figure 3.9-13 – Comparison of reservoir average pressure within the Siluro-Devonian and Cherry Canyon during injection and during the post-injection period

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.

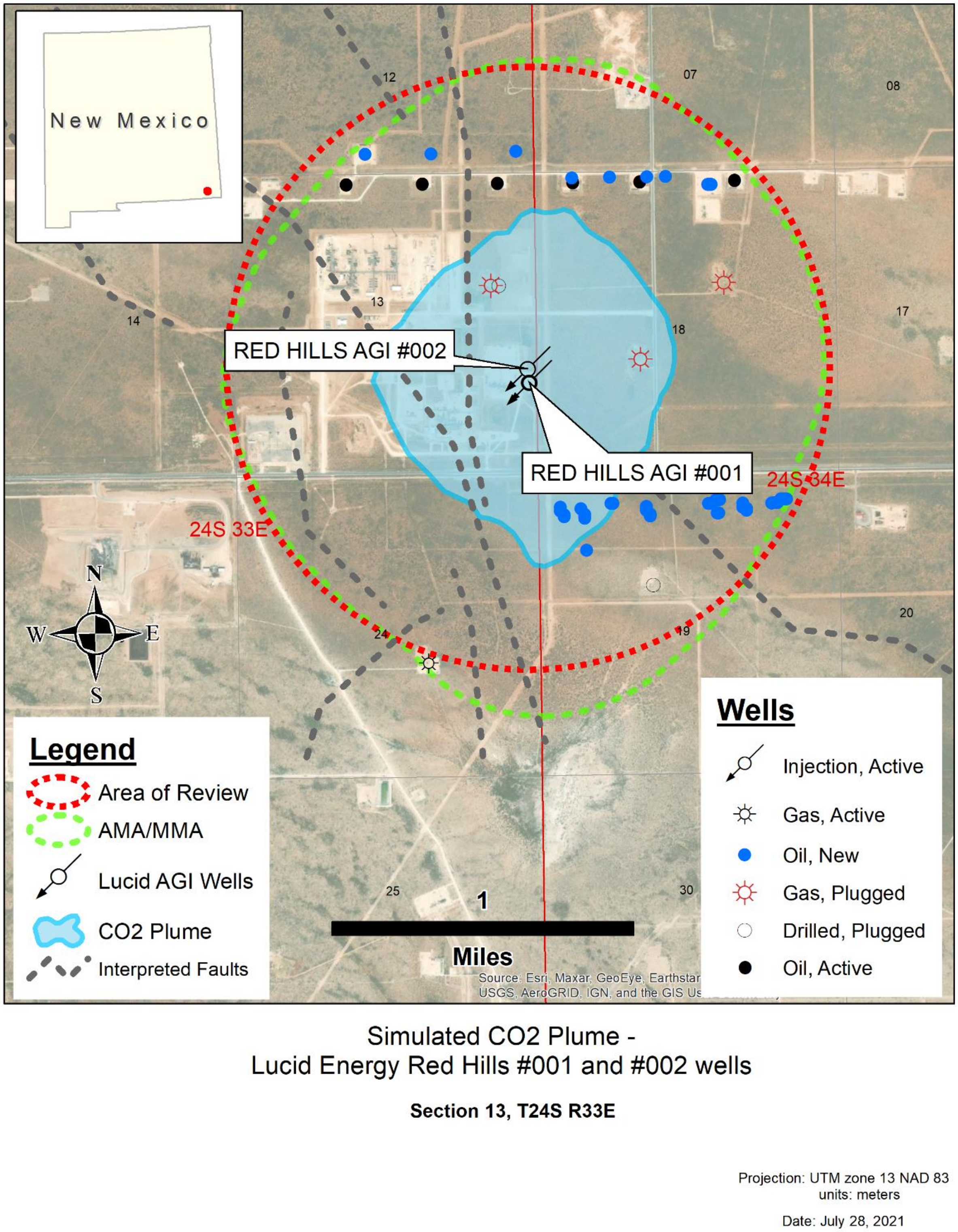


Figure 4.1-1 -- Maximum monitoring area (MMA) and active monitoring area (AMA) for Lucid Red Hill RH AGI #1 and RH AGI #2 Wells. The Class II Area of Review (AoR) is also shown.

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.

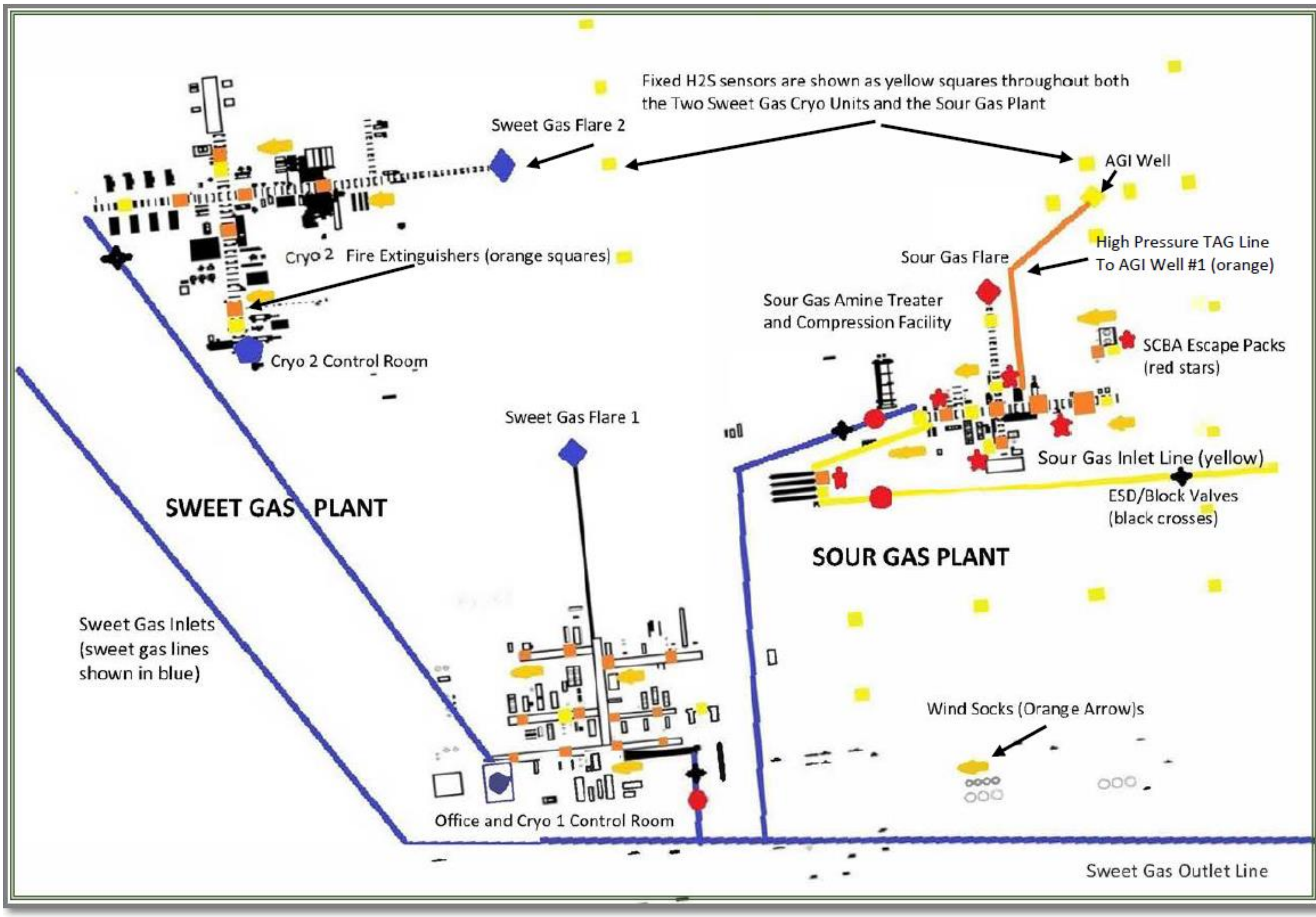


Figure 5.1-1 -- Red Hill Gas Plant plot plan showing location of major process units (taken from the H_2S Contingency Plan for Red Hills). The yellow squares indicate the location of fixed H_2S sensors.

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.

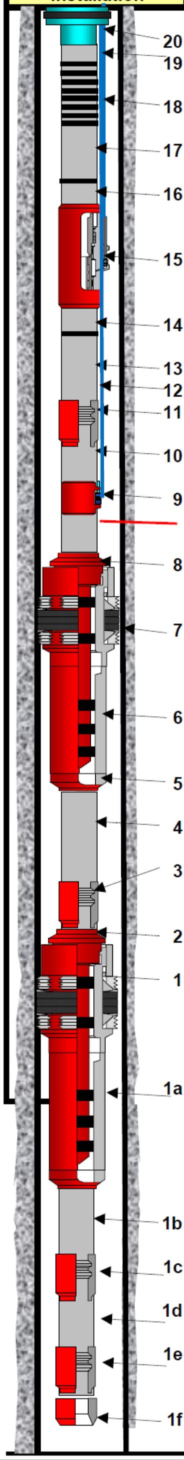
HALLIBURTON

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



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) Ran Eight Subs 8', 8', 6', 6',4', 4', 2', 2'	3.500	3.035
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 13.49' Length Includes Line Items 10, 11 & 12	3.540	2.959
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 7.51' Length Includes Line Items 8 & 9	4.470	2.959
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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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
7. If Unit or CA/Agreement, Name and/or No.
8. Well Name and No. **Government "L" Com #1**
9. API Well No. **30-025-~~[illegible]~~ 25604**
10. Field and Pool, or Exploratory Area **Bell Lake, South Morrow**
11. County or Parish, State **Lea, New Mexico**

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

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other
2. Name of Operator **EOG Resources, Inc**
3a. Address **P.O. Box 2267, Midland, TX, 79702**
3b. Phone No. *(include area code)* **432-561-8600**
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

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

Appendix B: Submissions and Responses to Requests for Additional Information

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).

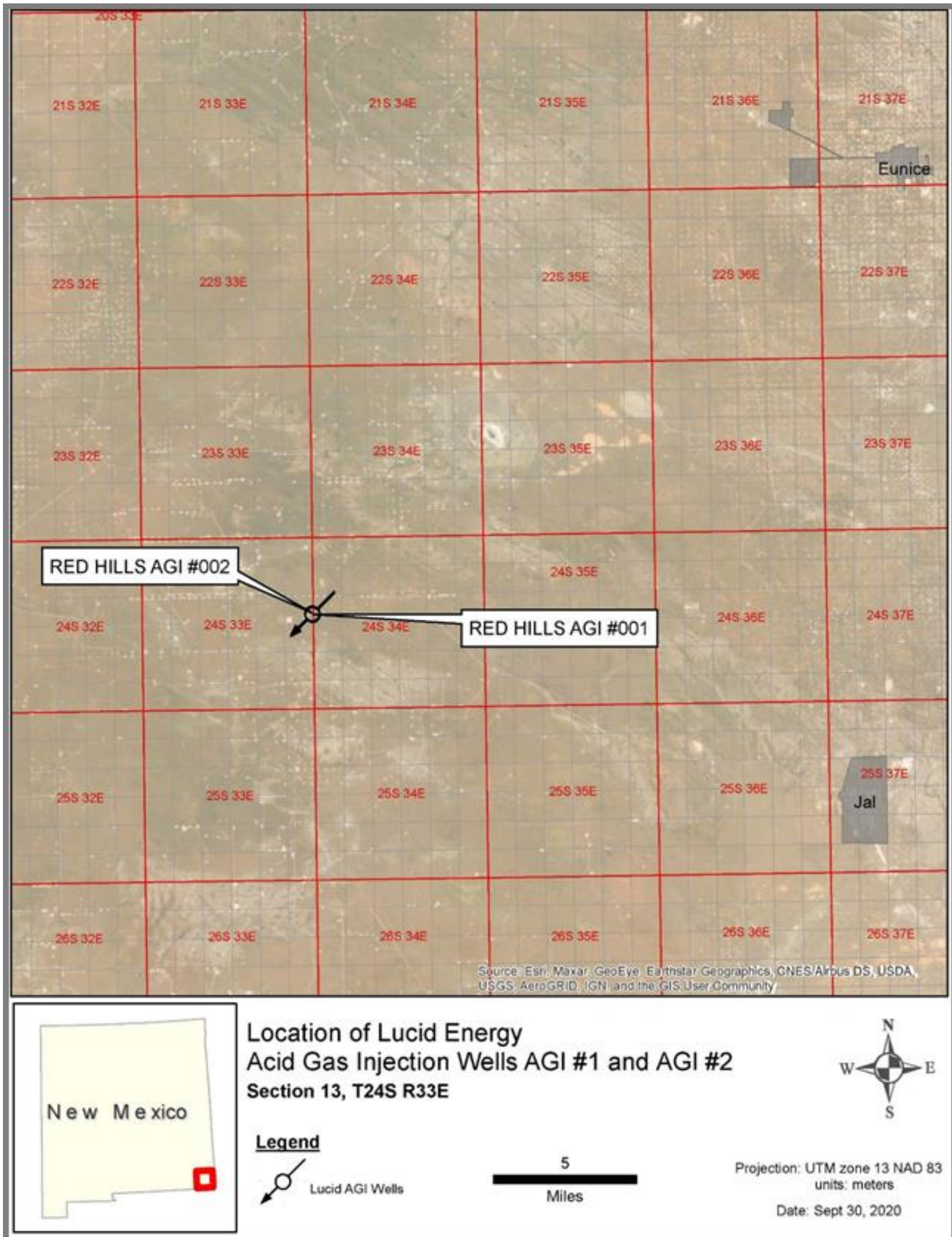


Figure 1-1 -- Location of the Red Hills Gas Plant and Wells – RH AGI #1 and RH AGI #2

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

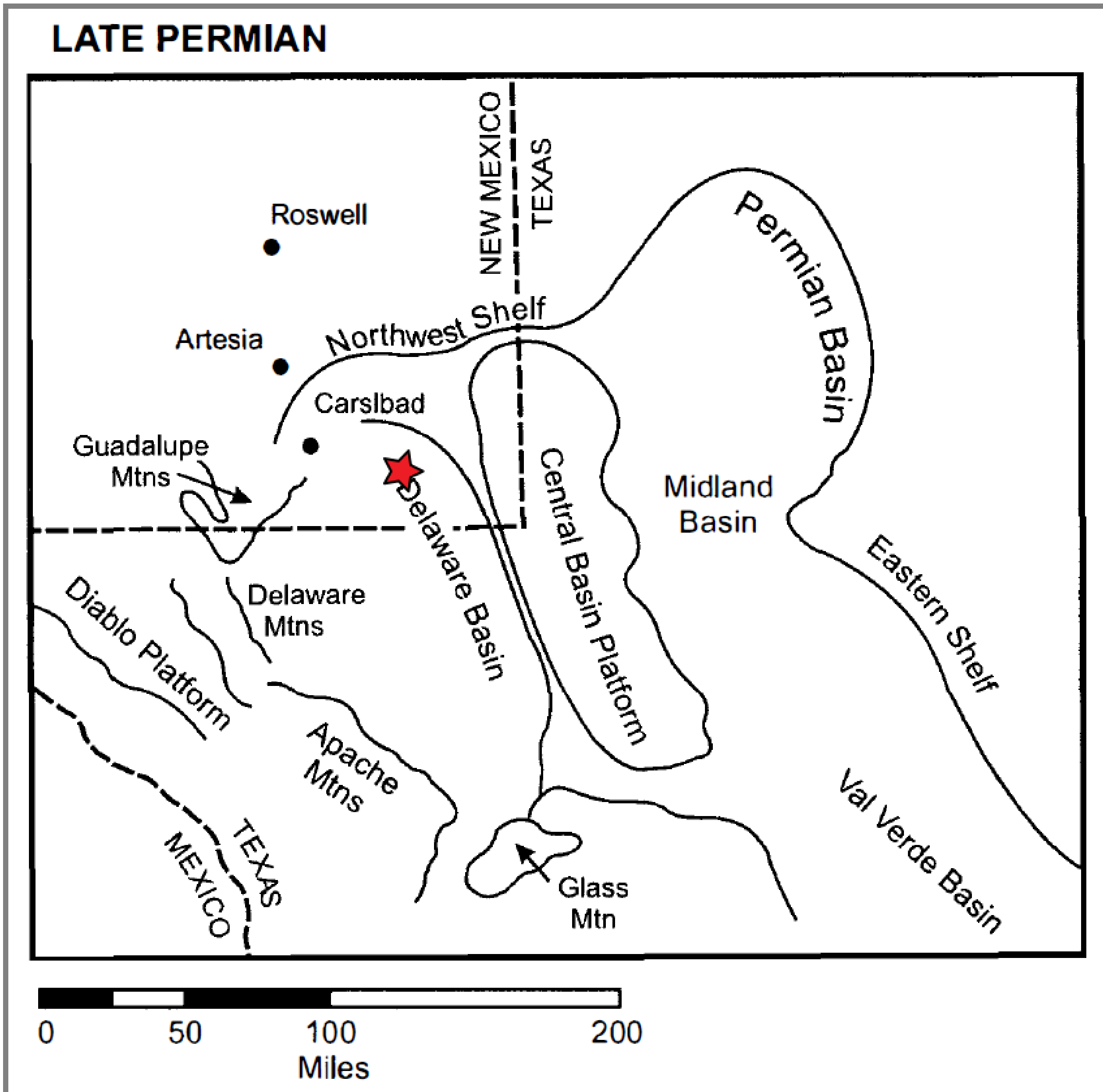


Figure 3.2-1 -- Structural features of the Permian Basin during the Late Permian. Location of the Lucid RH AGI wells is shown by the red star. (Modified from Ward, et al (1986))

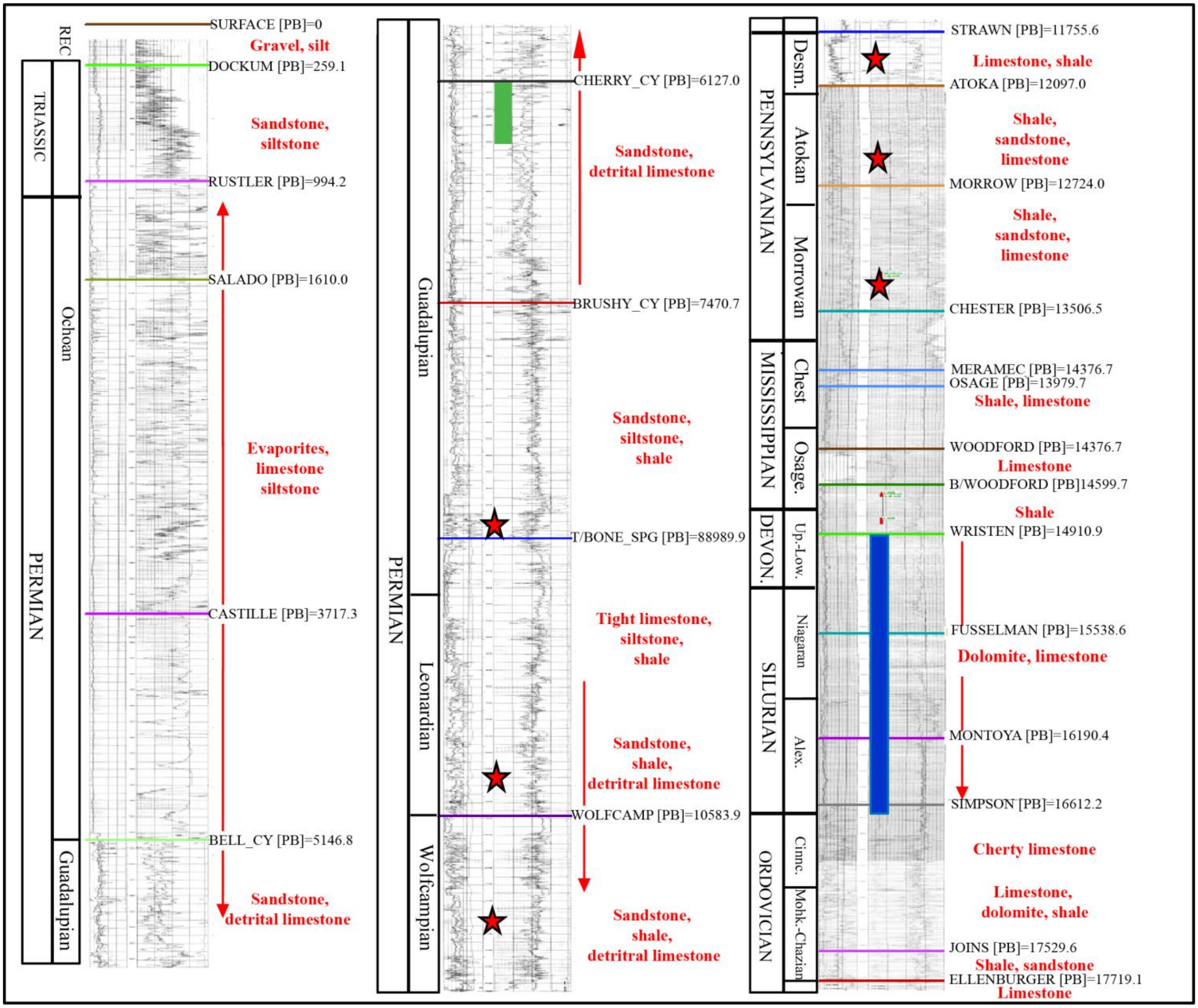


Figure 3.2-2 -- Stratigraphy and generalized lithologies of the formations underlying the Lucid RH AGI Wells.

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).

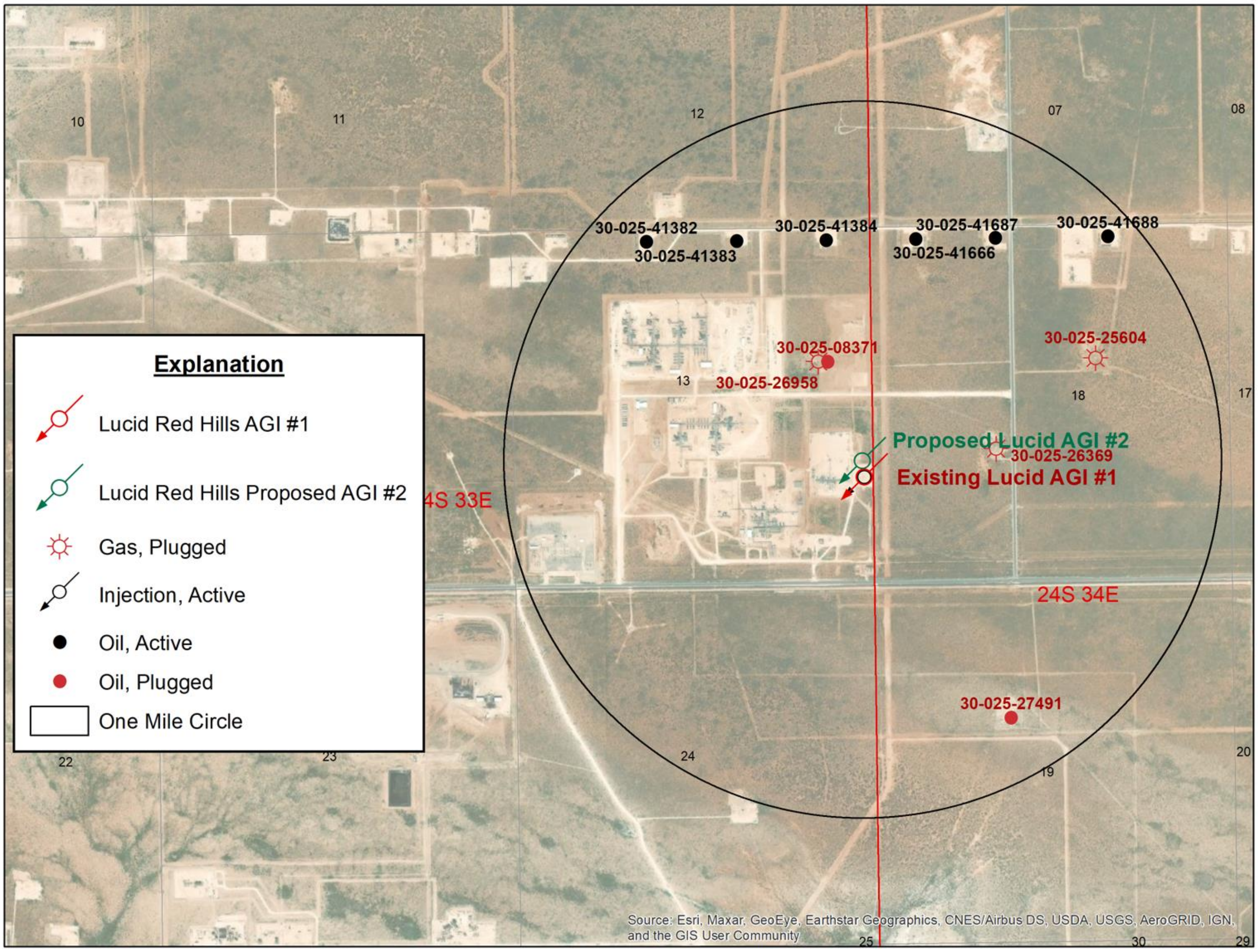


Figure 3.2-3 – Oil and gas production and saltwater (SWD) wells completed in the Siluro-Devonian in the vicinity of the RH AGI wells. The Class II one-mile radius AoR is also indicated.

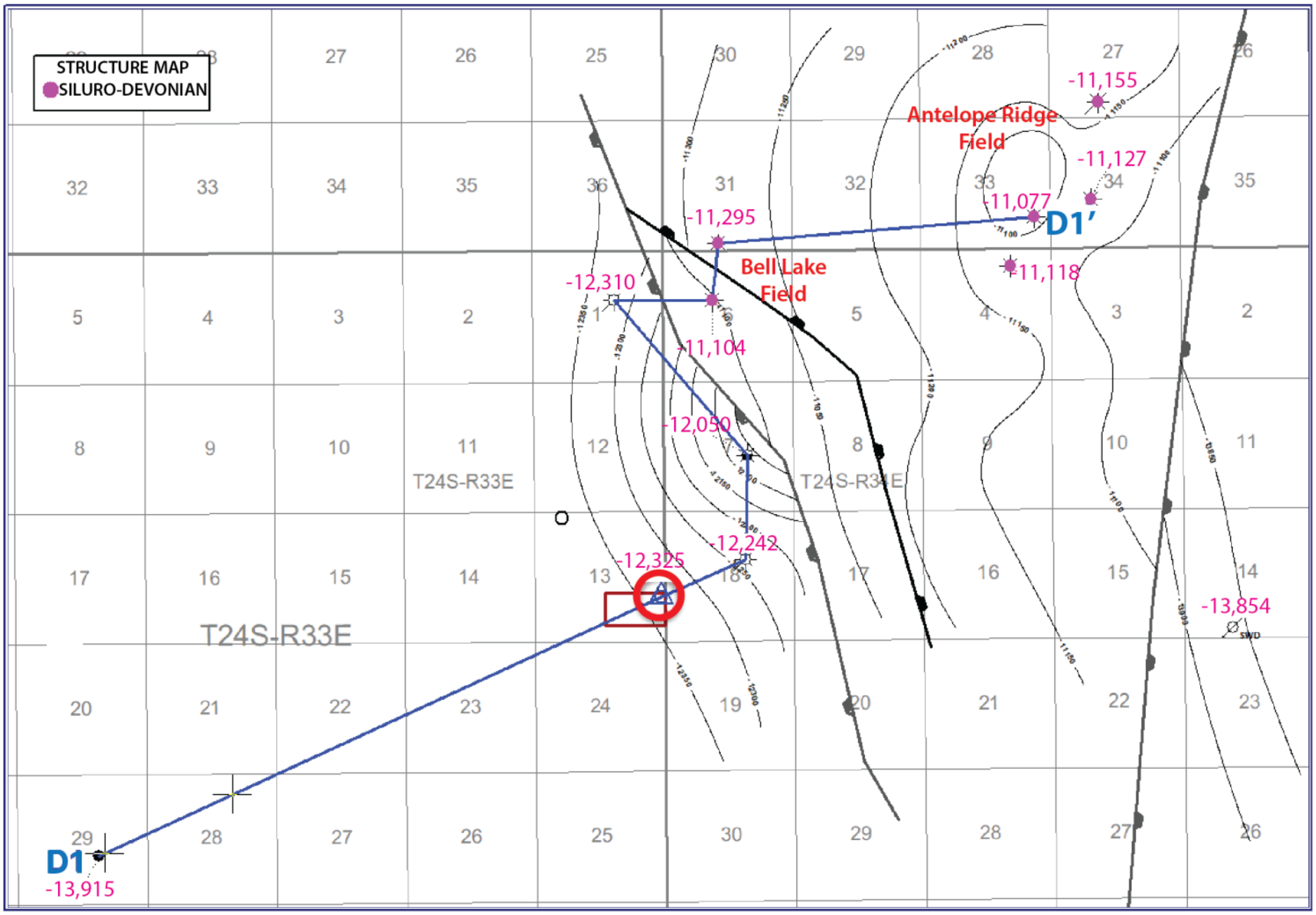


Figure 3.2-4 -- Structure on top of the Devonian and location of cross section D1-D1'

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.

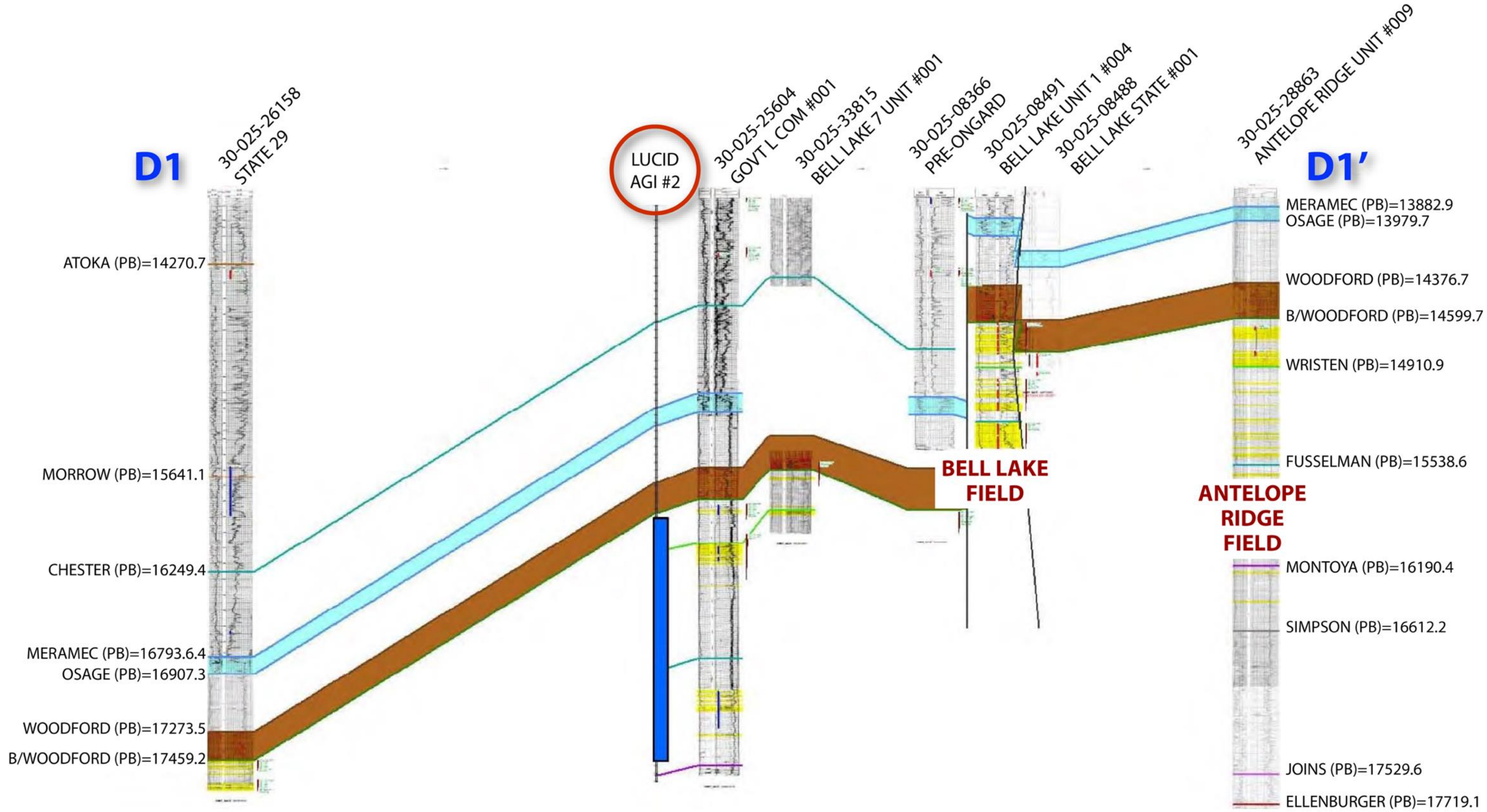


Figure 3.2-5 -- Structural cross section through the deeper horizons across the Red Hill Gas Plant Site

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

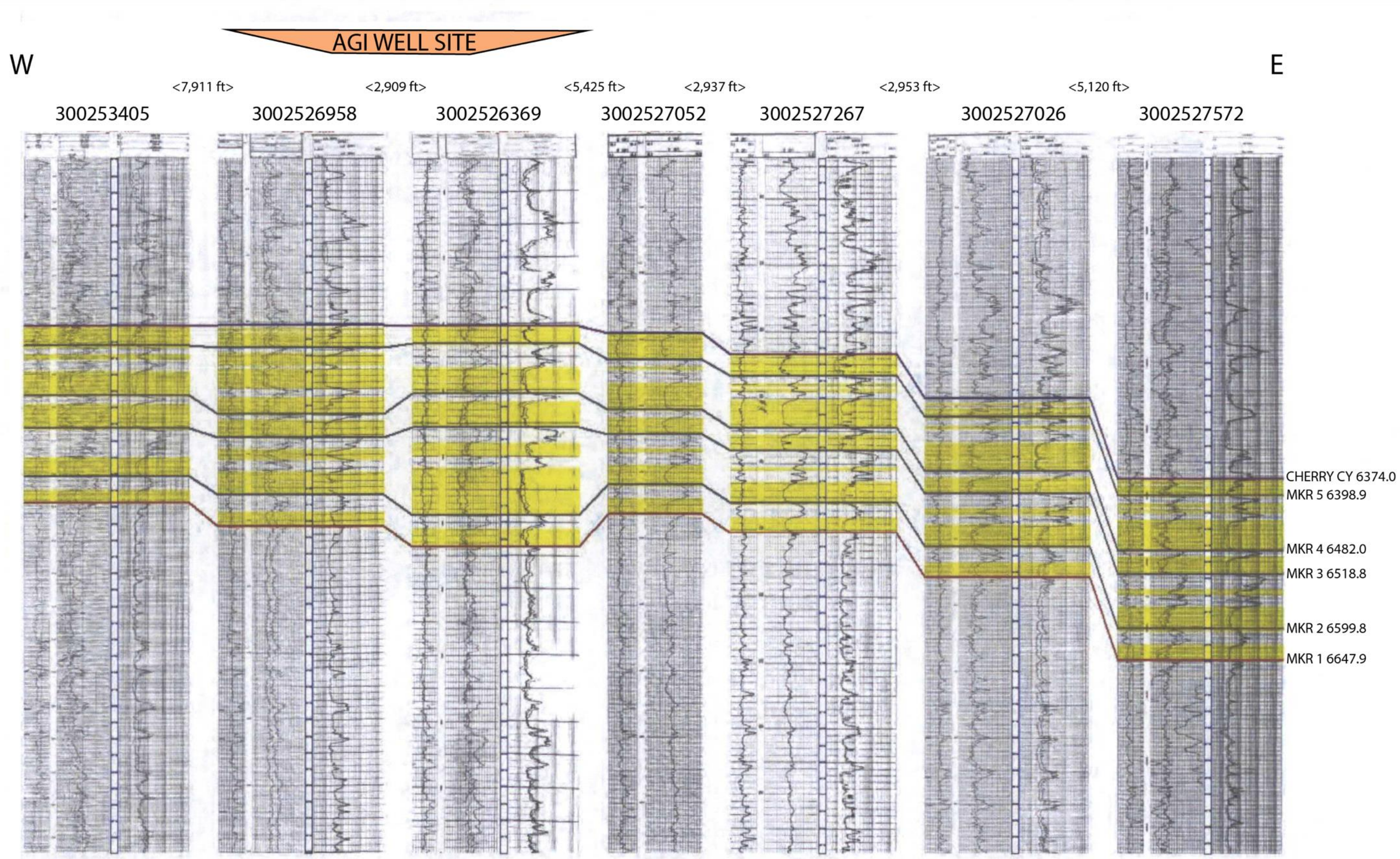


Figure 3.3-2 -- West – East cross section showing the 5 sand units of the Manzanita Zone of the Cherry Canyon Formation

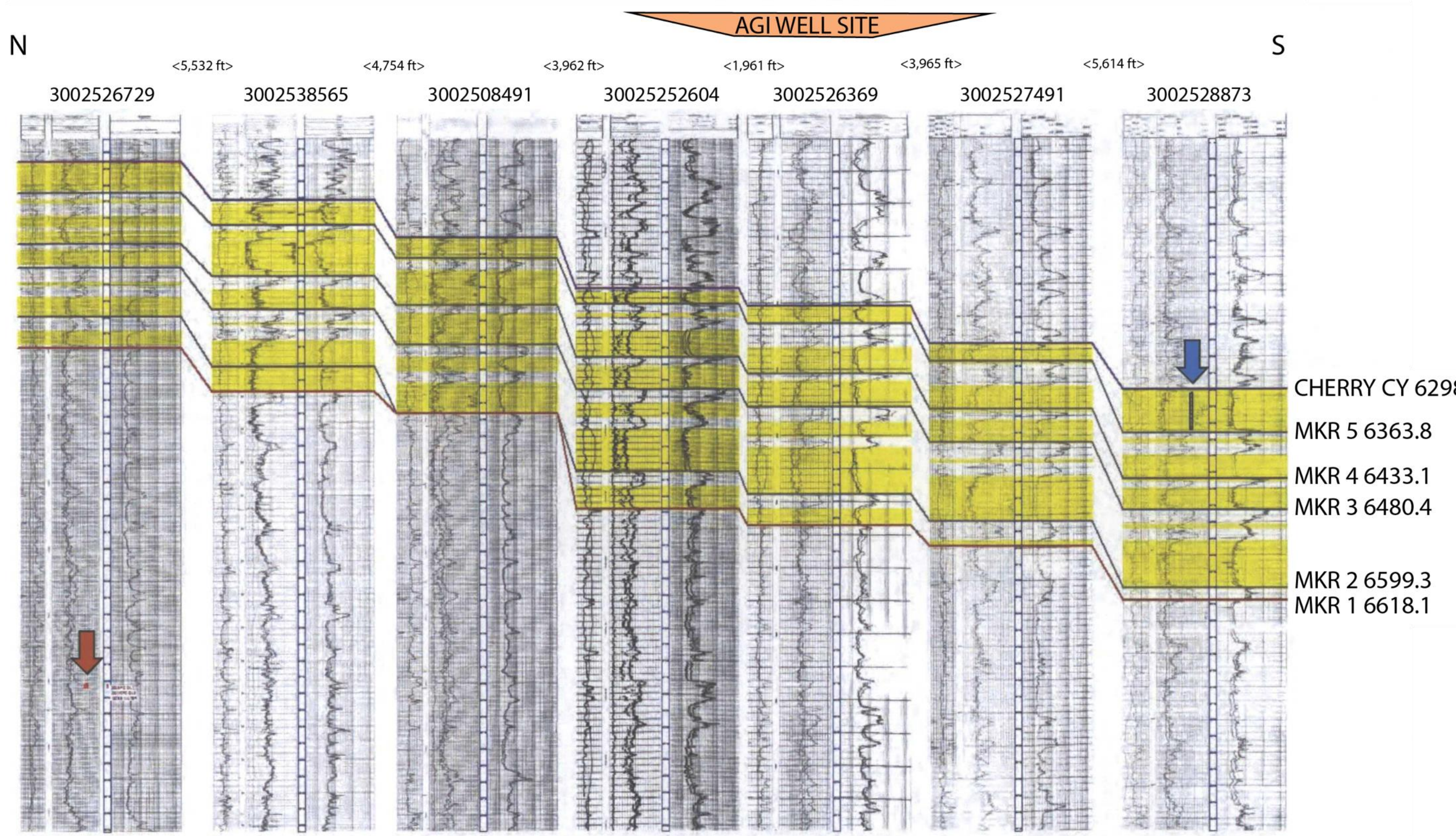


Figure 3.3-3 -- -- North - South cross-section showing the 5 sandstone units of the Manzanita Zone of the Cherry Canyon Formation

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.

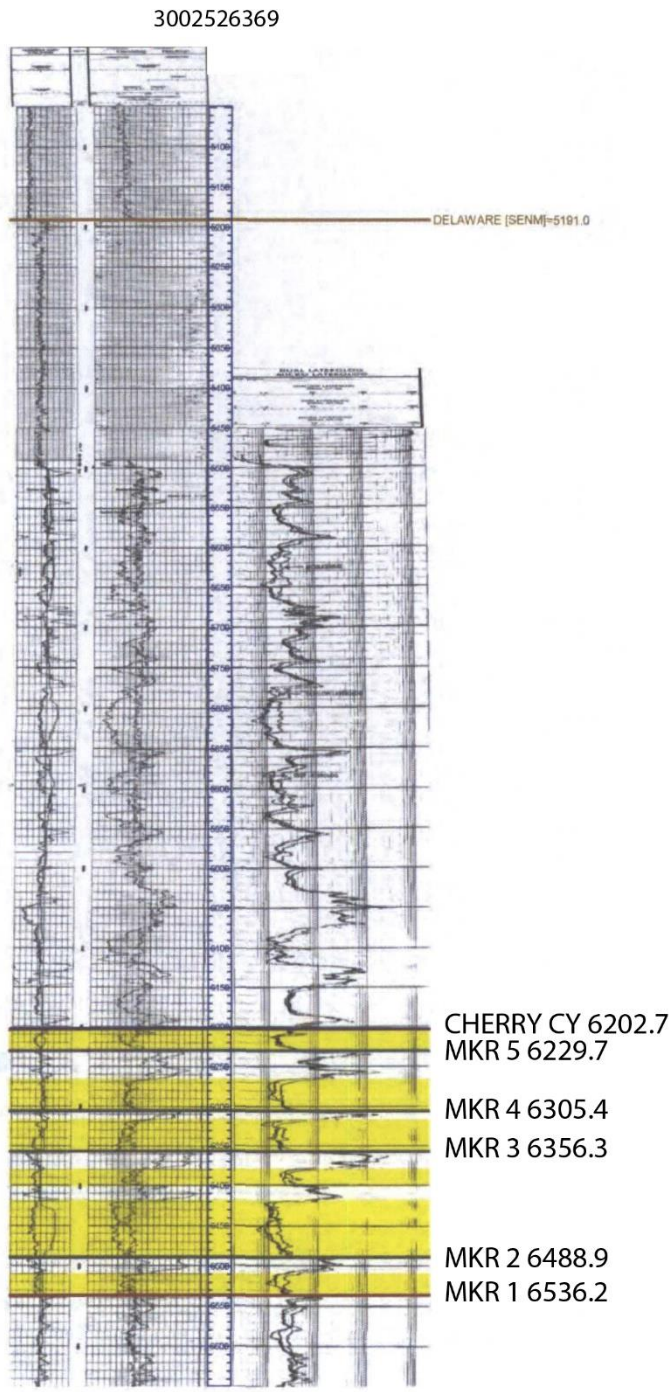


Figure 3.3-4 -- Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well

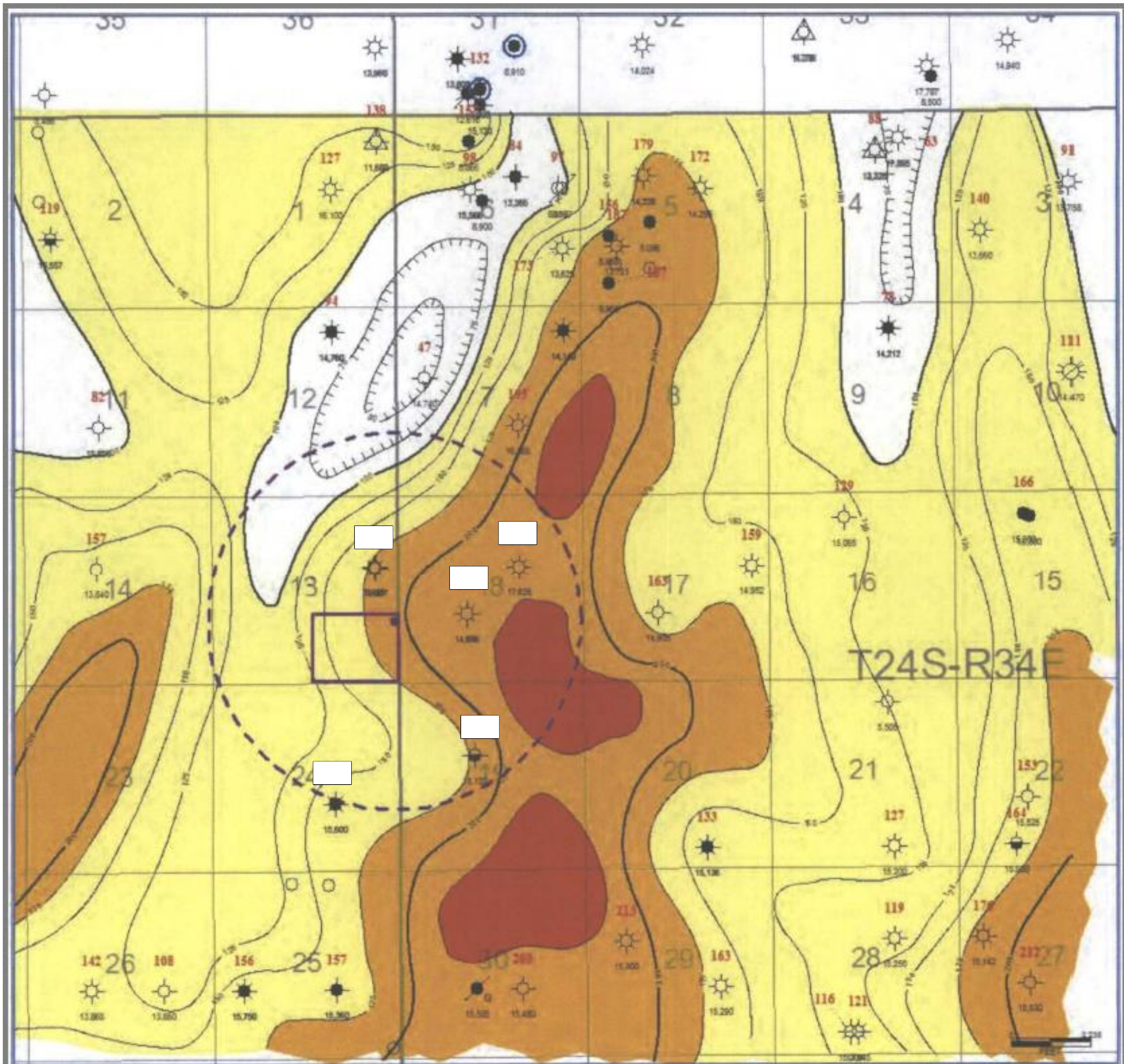


Figure 3.3-5 -- Map showing thickness of the clean sands in the Upper Cherry Canyon injection zone for RH AGI #1 and the one-mile radius AoR

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.

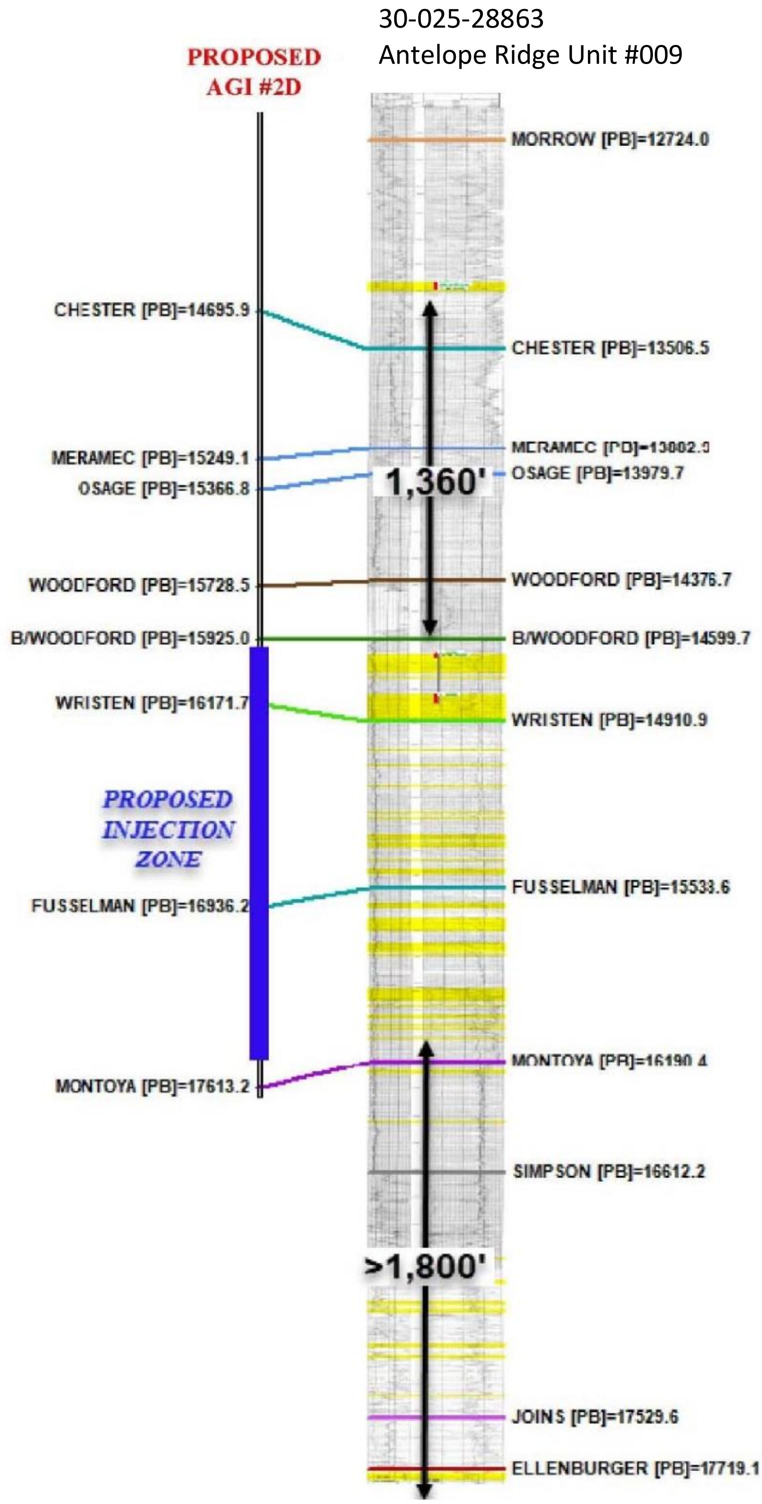


Figure 3.3-6 -- Porosity profile above and below proposed injection zone for RH AGI #2

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).

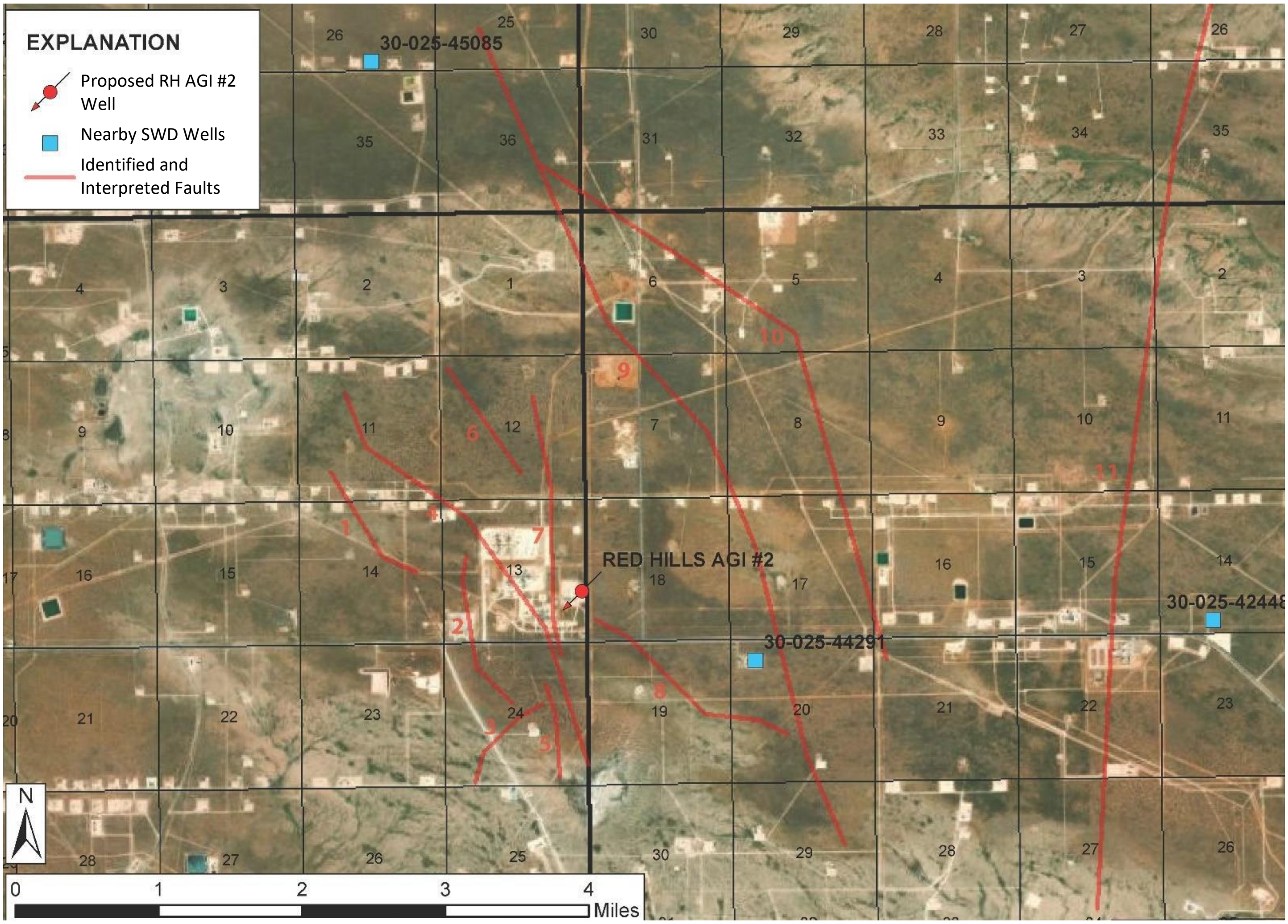


Figure 3.5-1 -- Map showing identified and interpreted faults in the area of the proposed RH AGI #2 well.

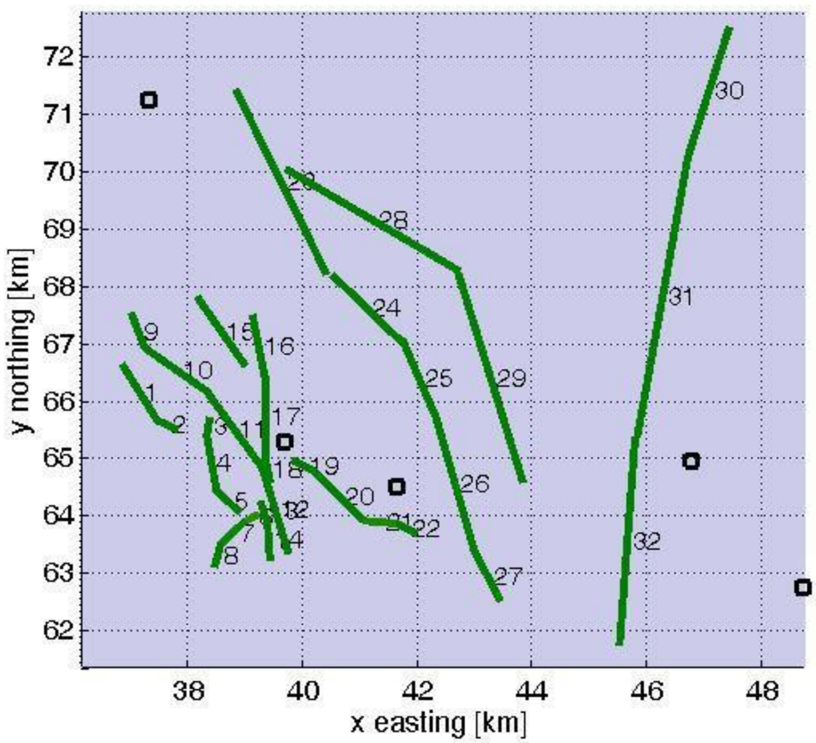


Figure 3.5-2 – Graphic showing 11 faults divided into 32 segments for FSP analysis.

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.

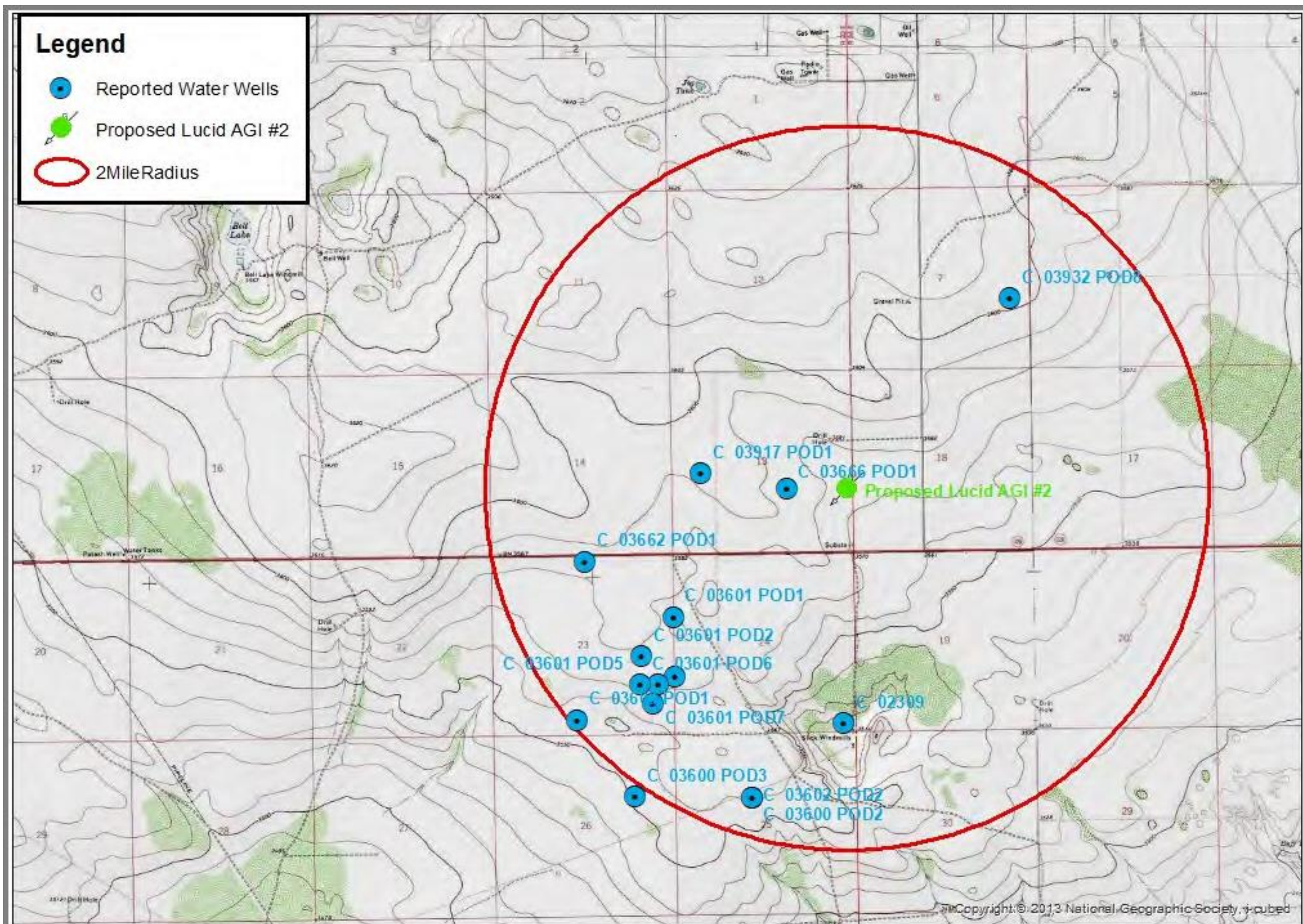


Figure 3.6-1 -- Reported Water Wells within 2-mile Radius of Proposed Lucid AGI #2

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			

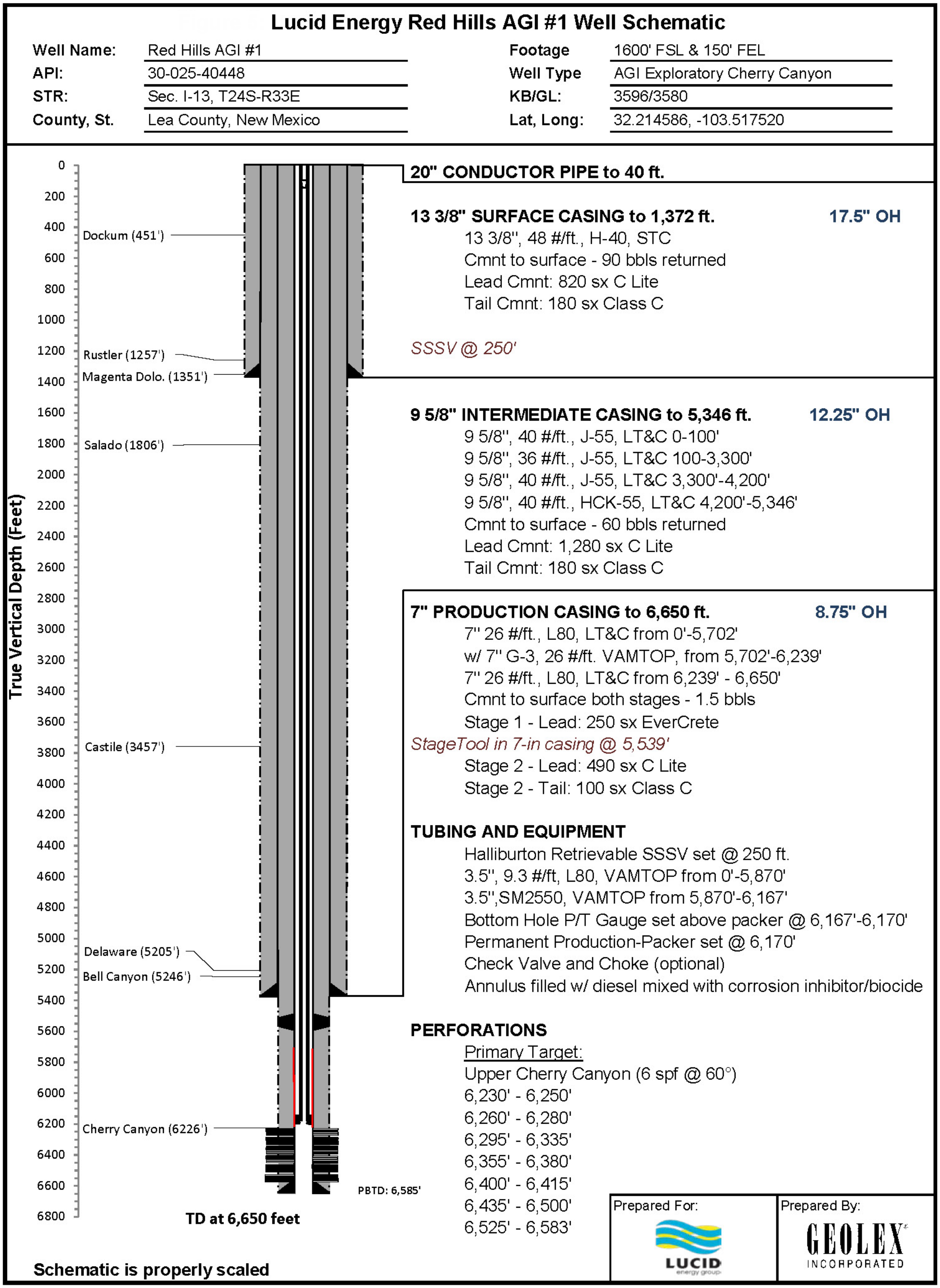


Figure 3.6-2 -- Schematic of RH AGI #1

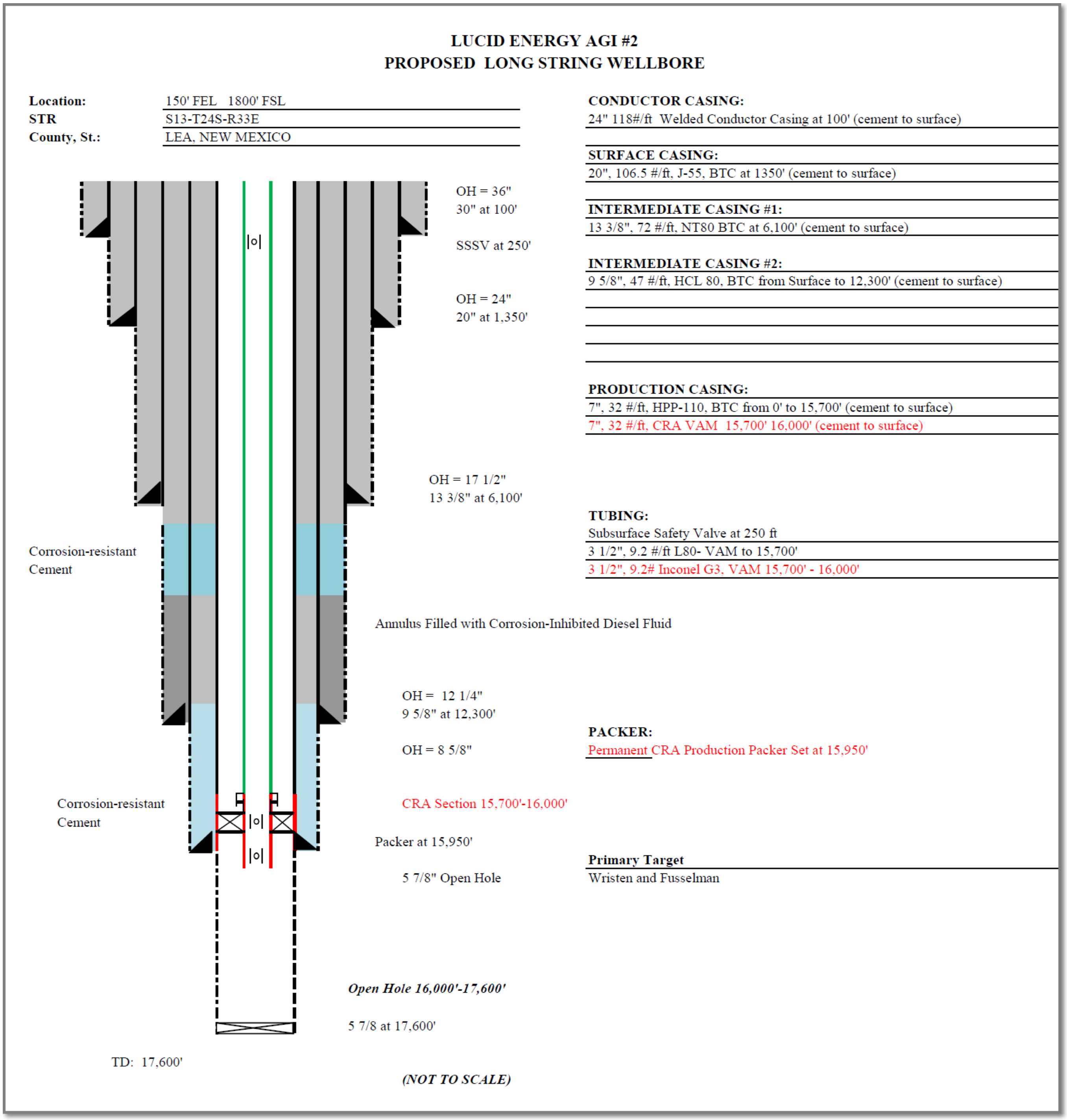


Figure 3.6-3 -- Schematic of Proposed RH AGI #2 (Option 2). Red text refers to completion parameters for the injection zone.

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.

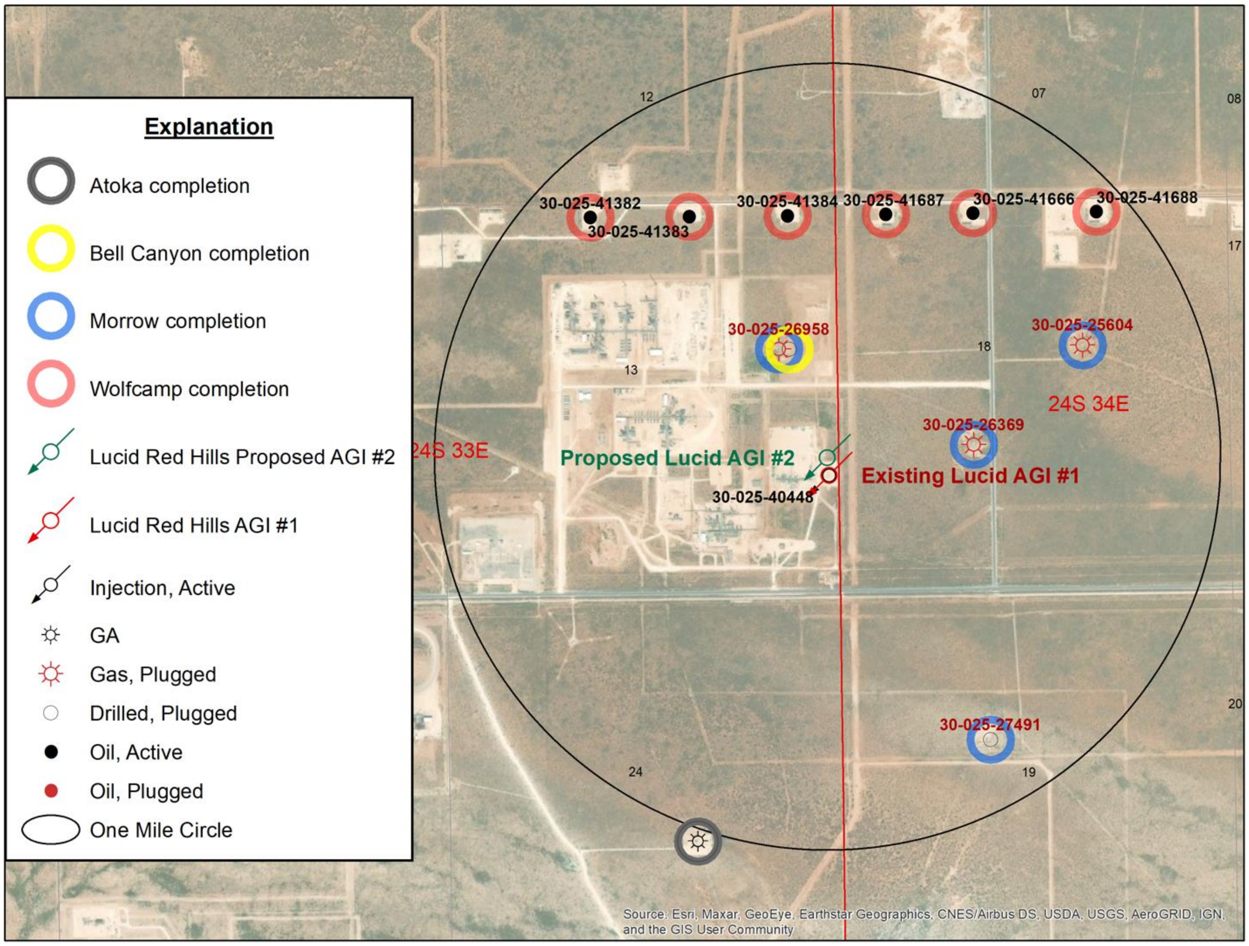


Figure 3.7-1 – Location of all oil- and gas-related wells within a 1-mile radius of the RH AGI wells

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

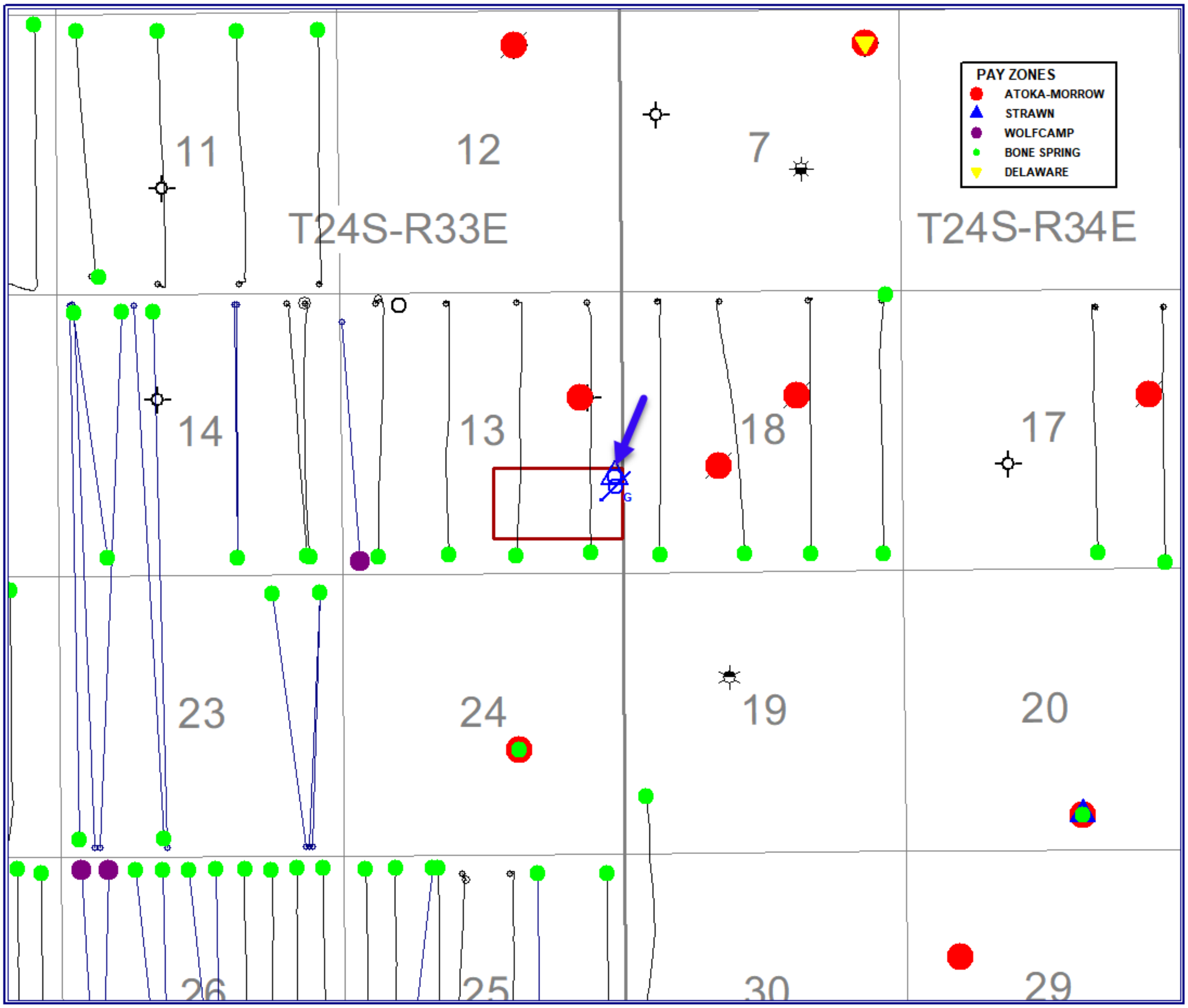


Figure 3.7-2 -- Producing wells in the area of the Red Hill Gas Plant.

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.

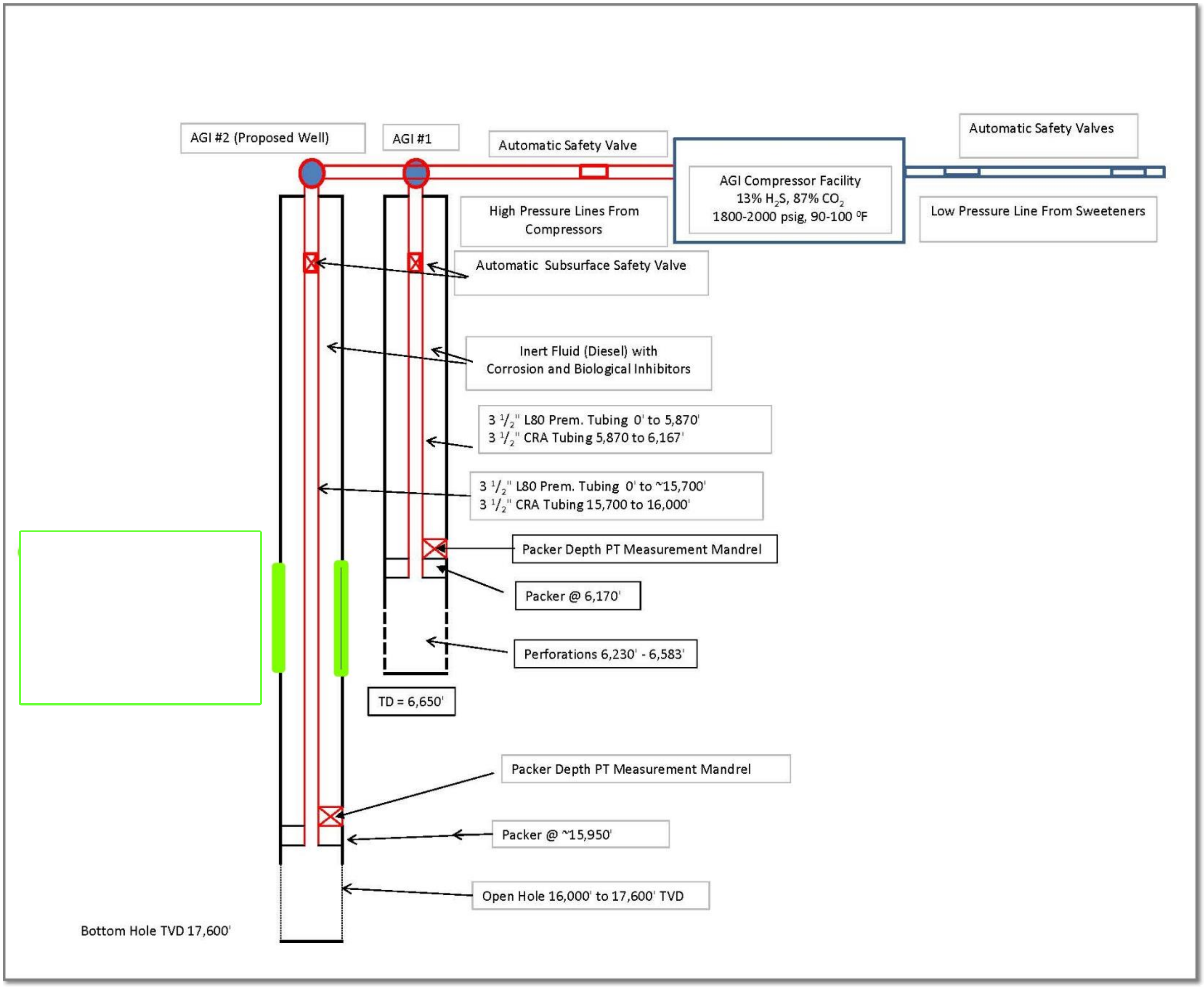


Figure 3.8-1 -- Schematic of surface facilities and RH AGI wells at the Red Hills Gas Plant

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).

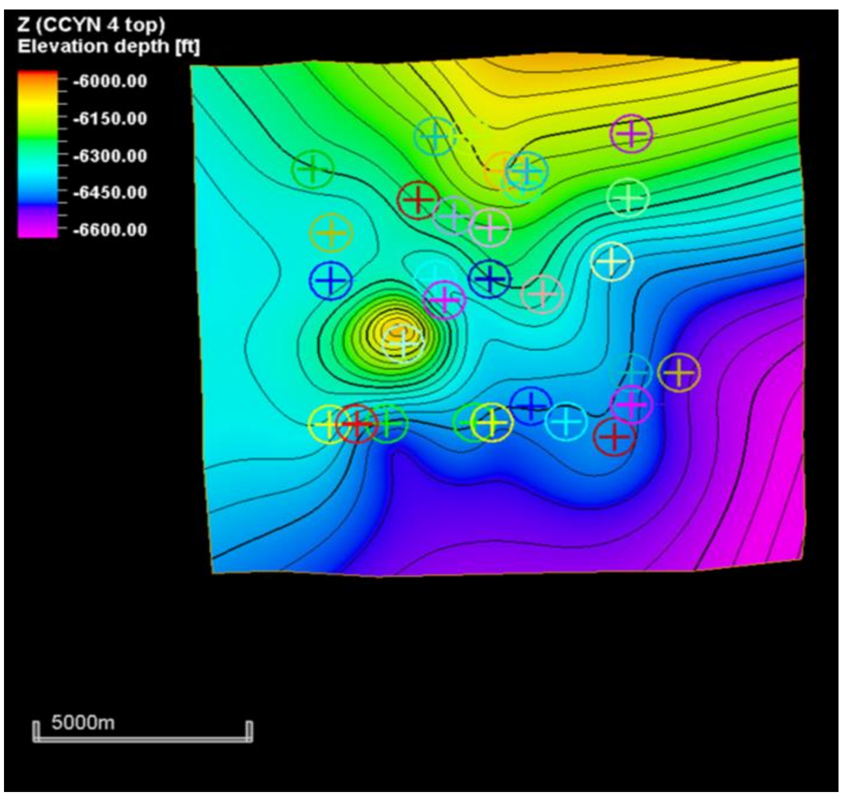


Figure 3.9-1 – Structural surface for top of Layer 4 of the Manzanita Zone of the Cherry Canyon Formation within the geological model.

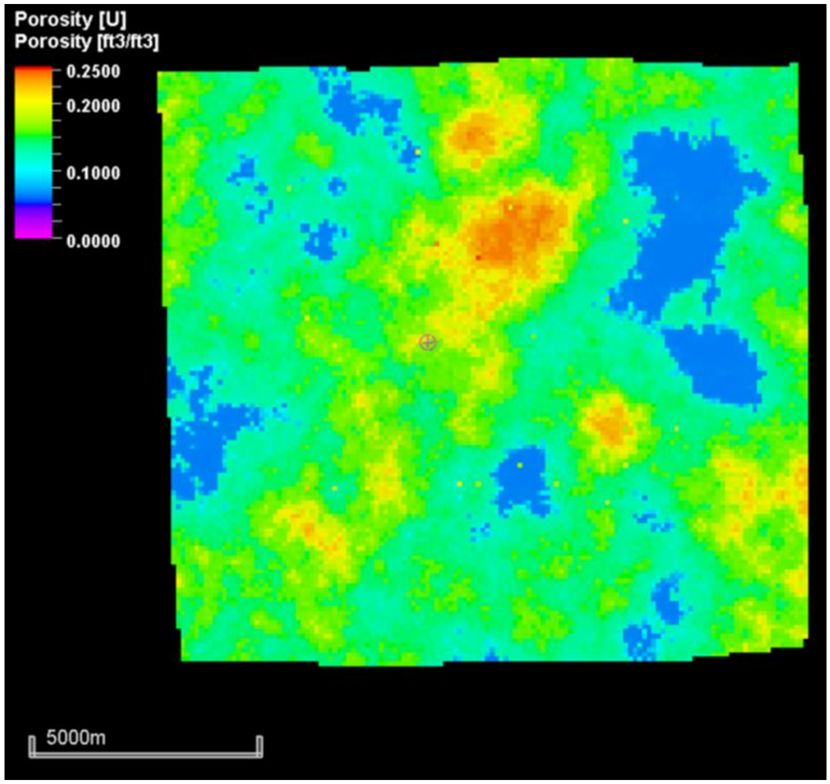


Figure 3.9-2 – Graphic showing the distribution of porosity in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation. Plan view.

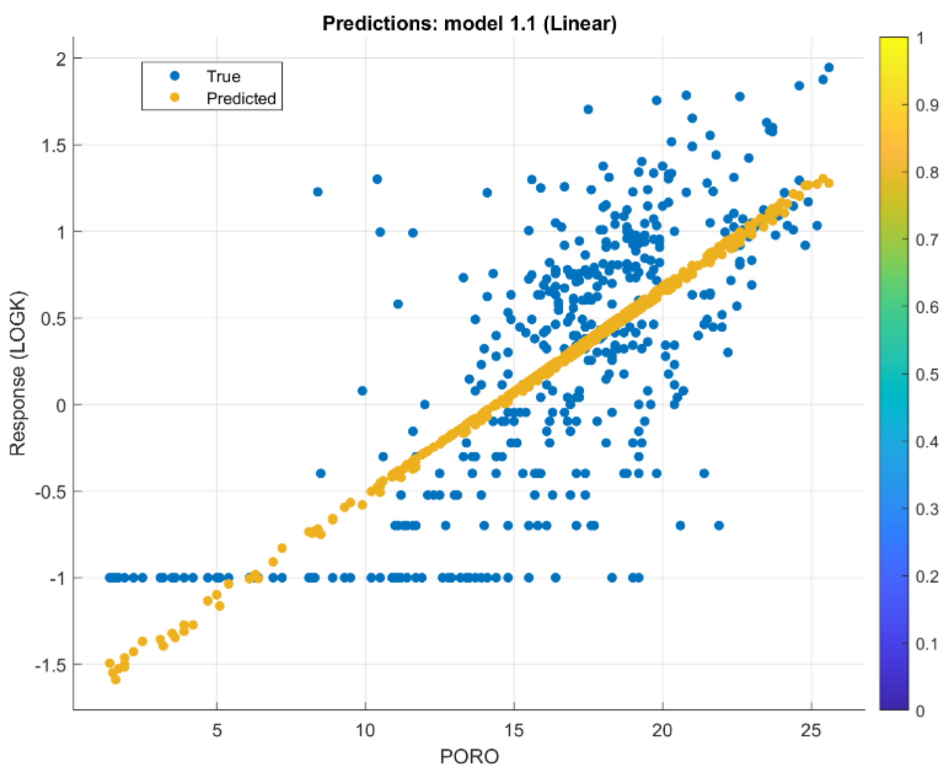


Figure 3.9-3 -- Porosity-permeability relationship for Layer 4 of the Manzanita Zone of the Cherry Canyon Formation.

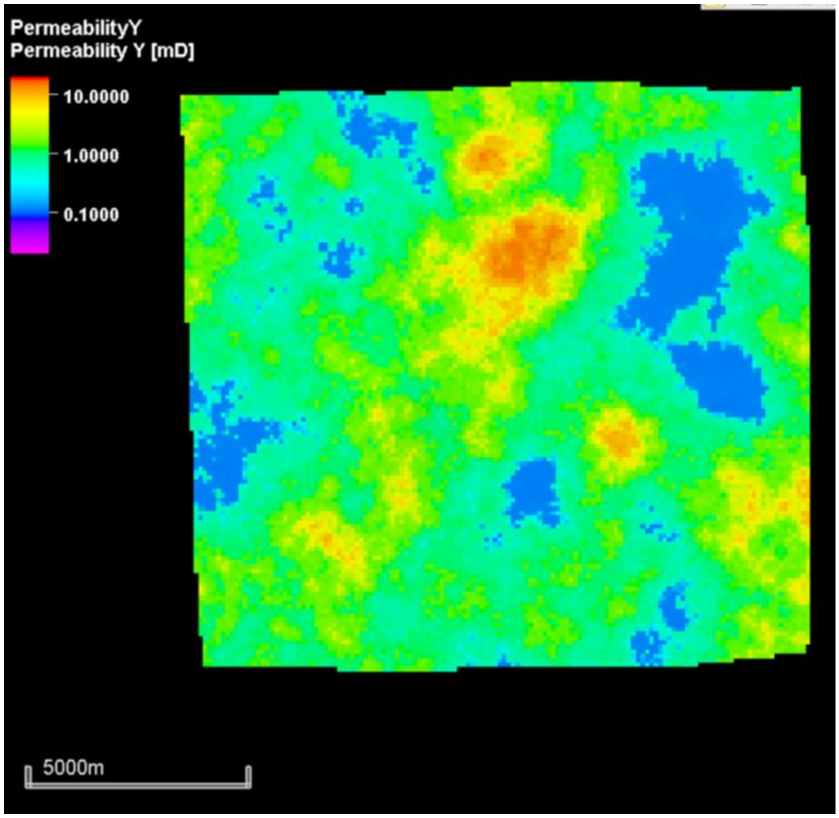


Figure 3.9-4 – Graphic showing the permeability distribution in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation. Plan view.

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.

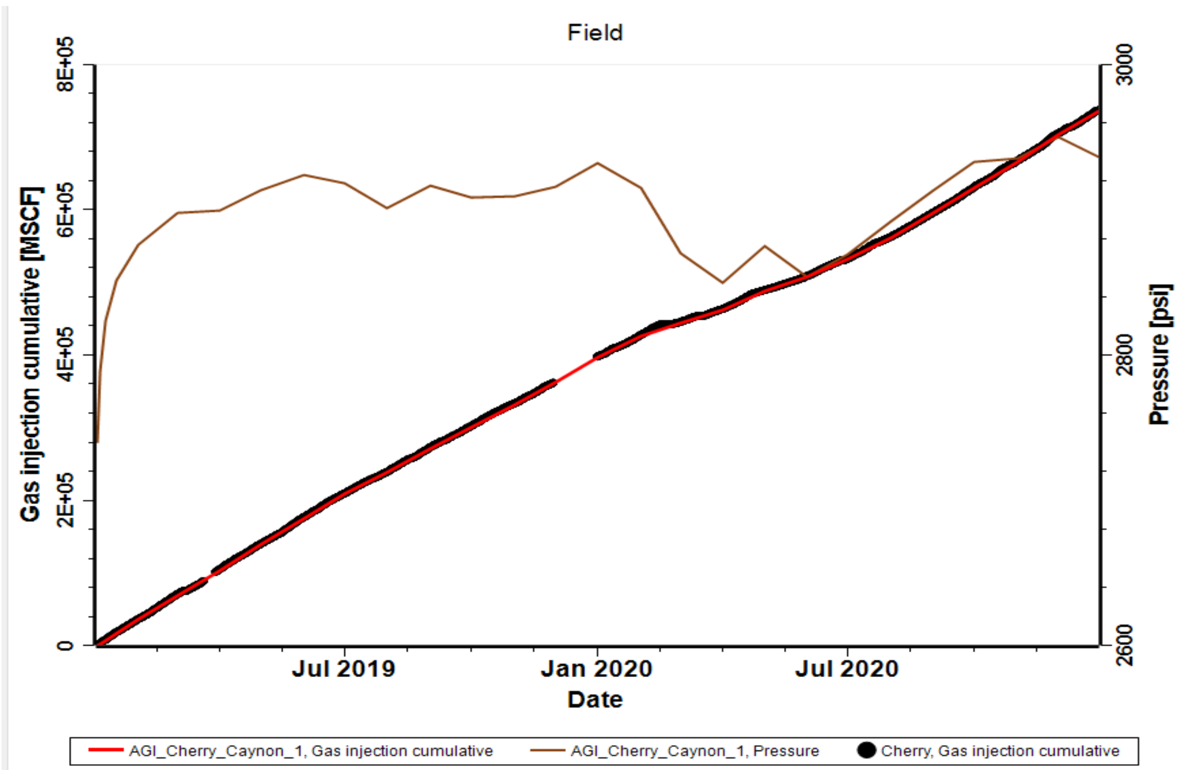


Figure 3.9-5 – Graph showing the calibrated cumulative gas injection and field pressure profile in the Cherry Canyon

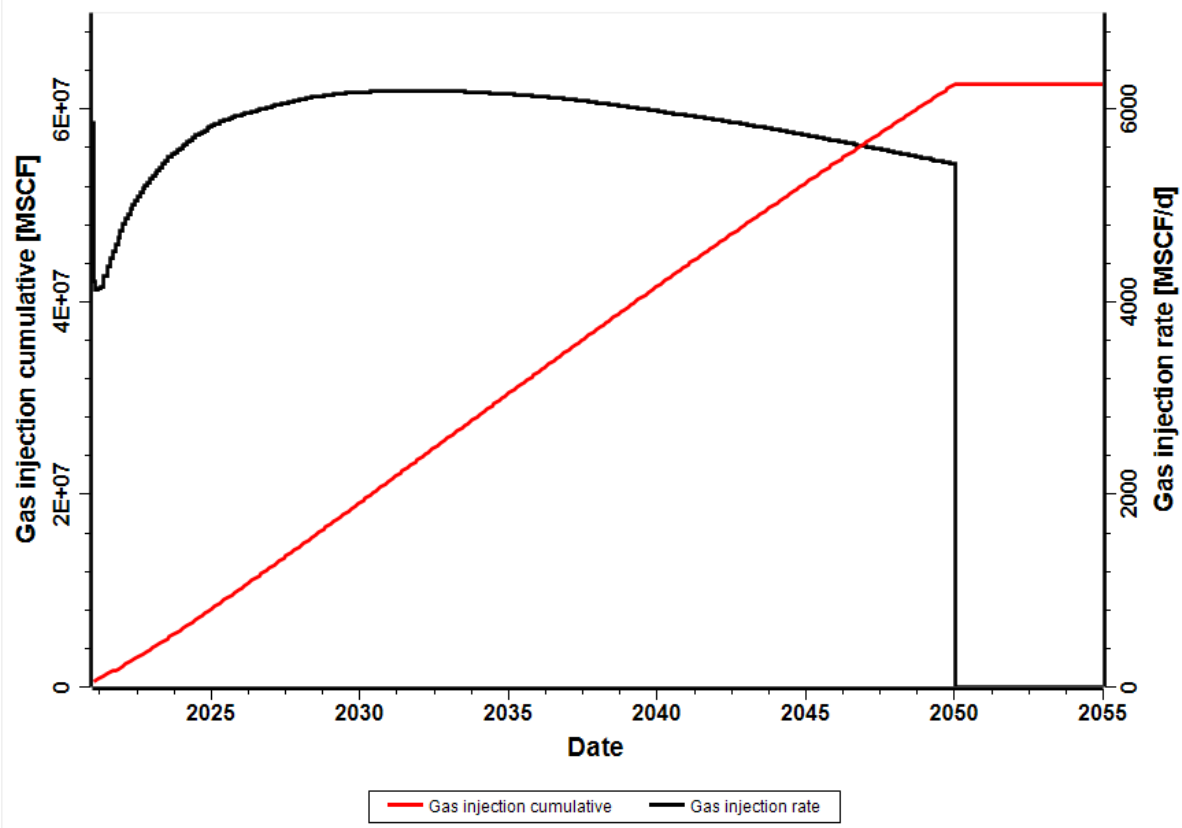


Figure 3.9-6 – Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period

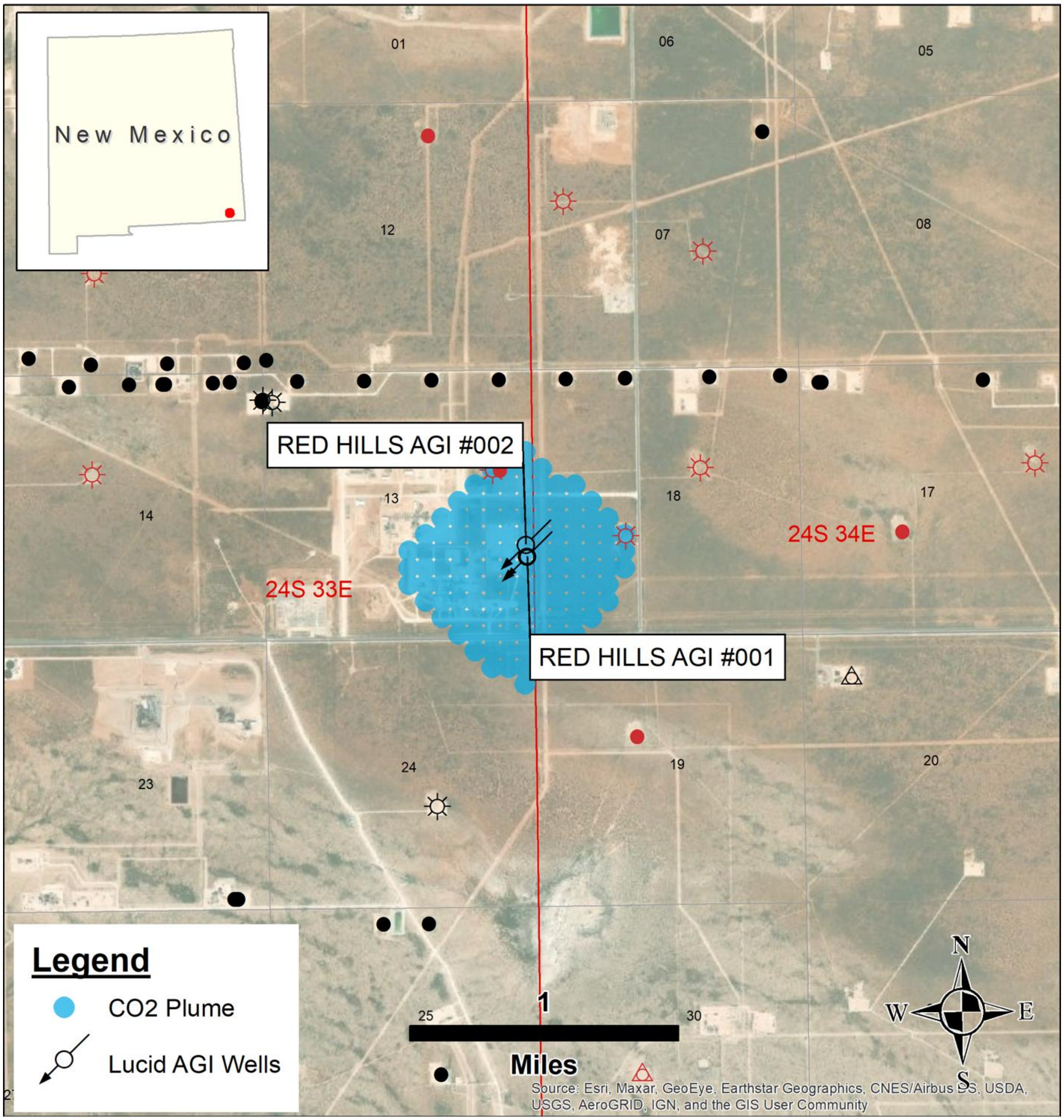


Figure 3.9-7 -- Map showing the largest lateral extent of the TAG plume within the Cherry Canyon

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.

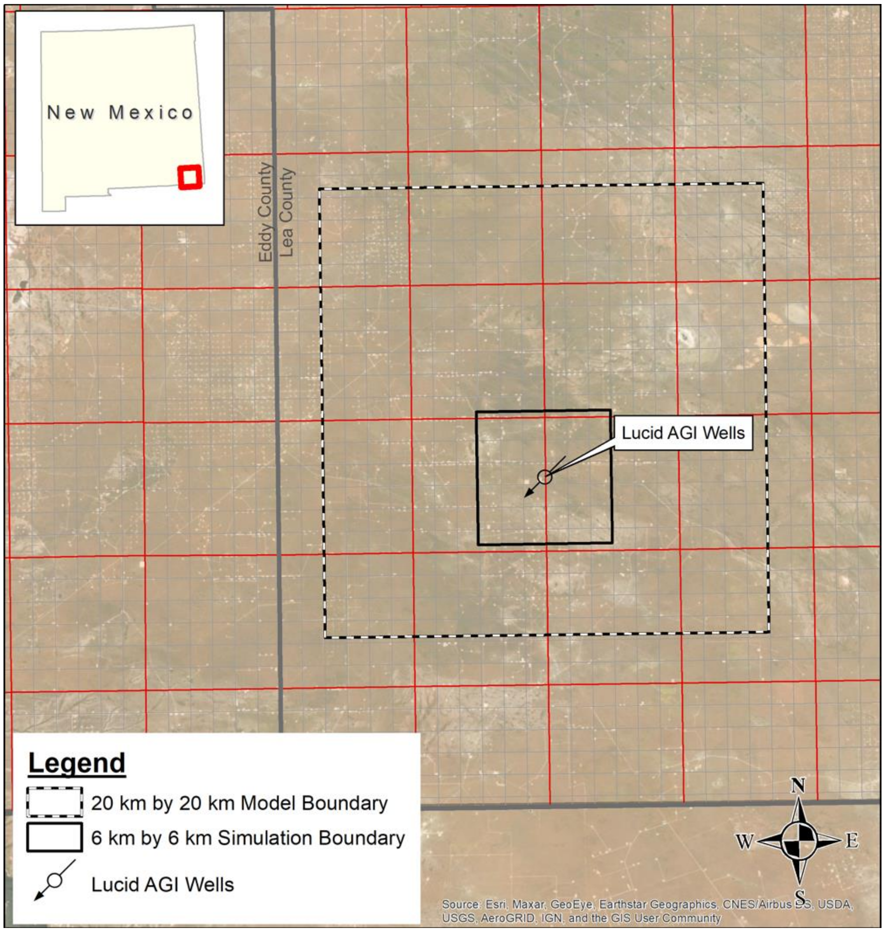


Figure 3.9-8 -- Map showing the top view of the geological and simulation model boundaries for the Siluro-Devonian injection zone.

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

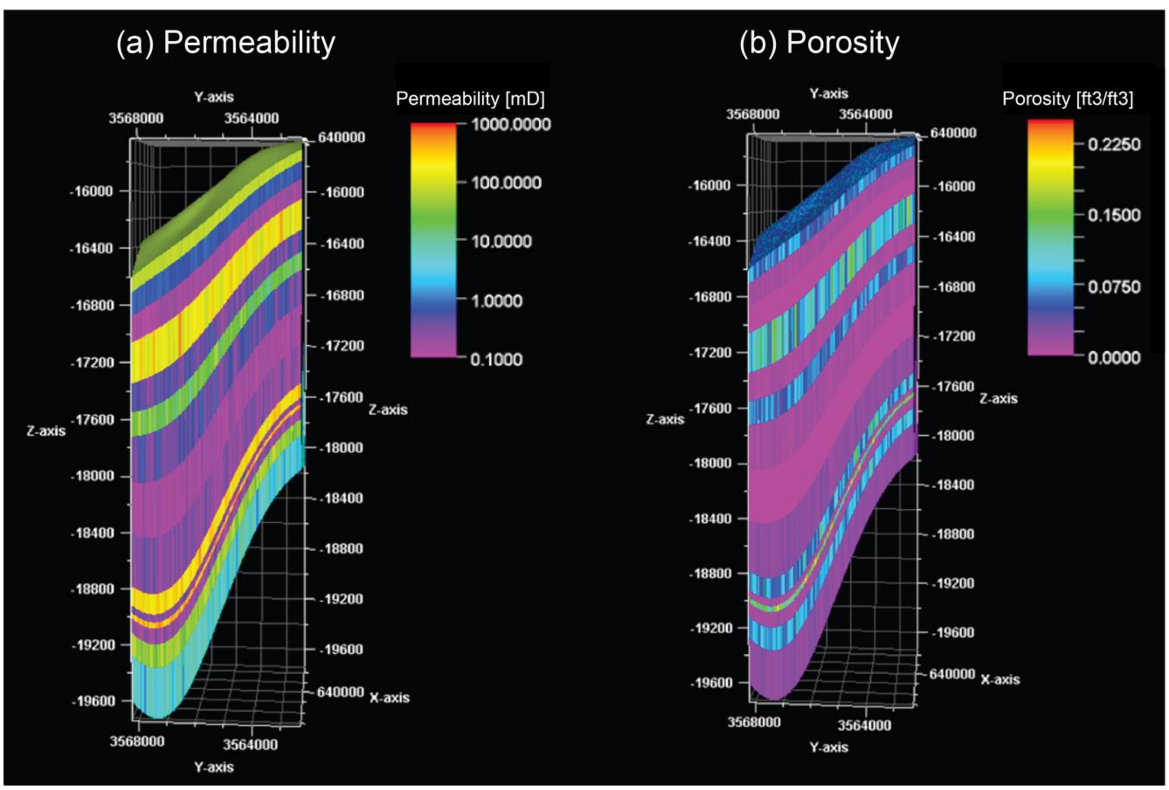


Figure 3.9-9 -- A 3D view of Siluro-Devonian modeled permeability (a) and porosity (b) distributions.

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.

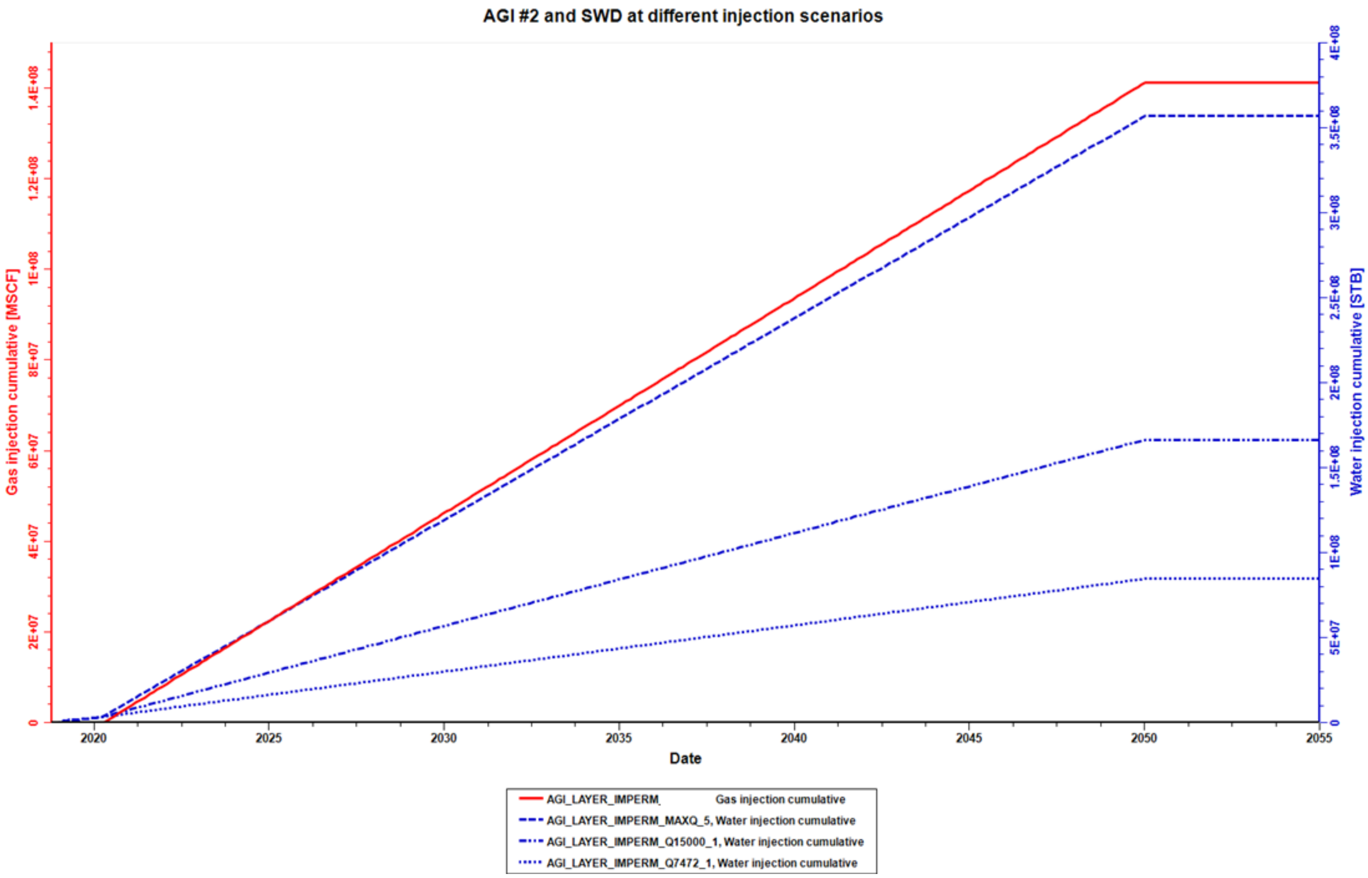


Figure 3.9-10 -- Graph showing the injection profile of the RH AGI #2 and the Striker well at different injection scenarios.

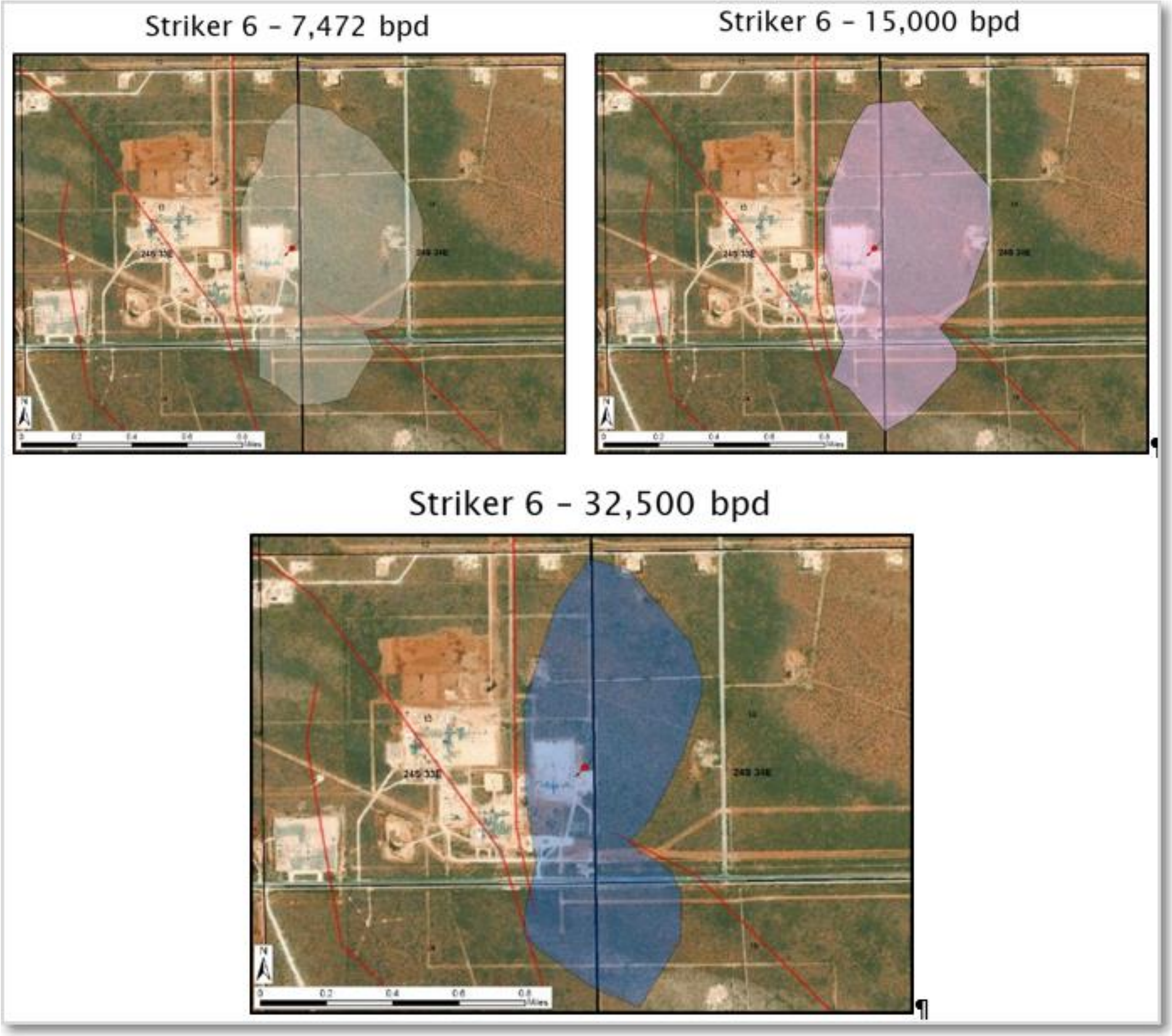


Figure 3.9-11 – Maps showing the largest lateral extent of the TAG when the interpreted faults are non-transmissive. The Striker 6 well injects into the Siluro-Devonian injection interval for RH AGI #2.

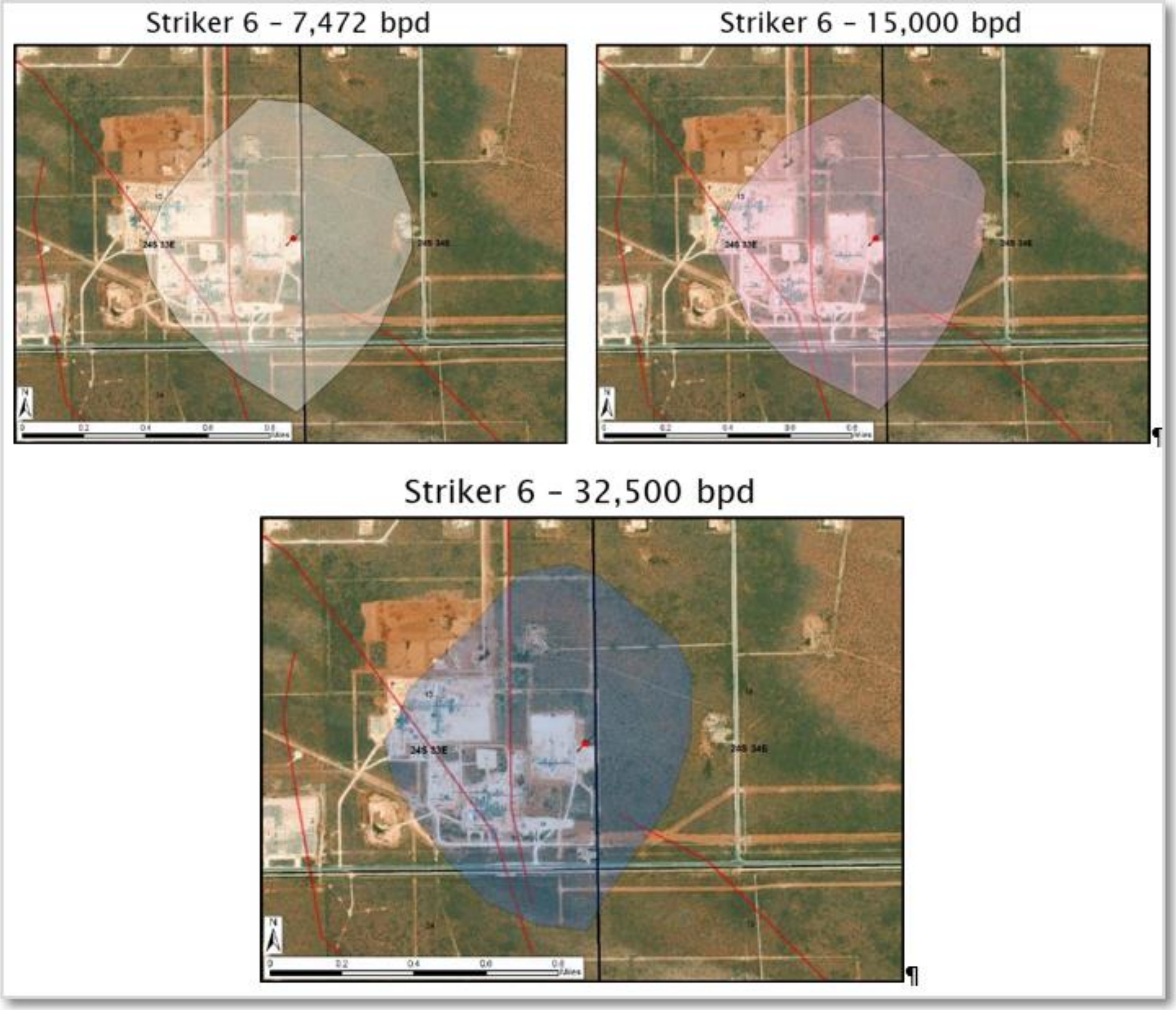


Figure 3.9-12 -- Maps showing the largest lateral extent of the TAG when the interpreted faults are transmissive. The Striker 6 well injects into the Siluro-Devonian injection interval for RH AGI #2.

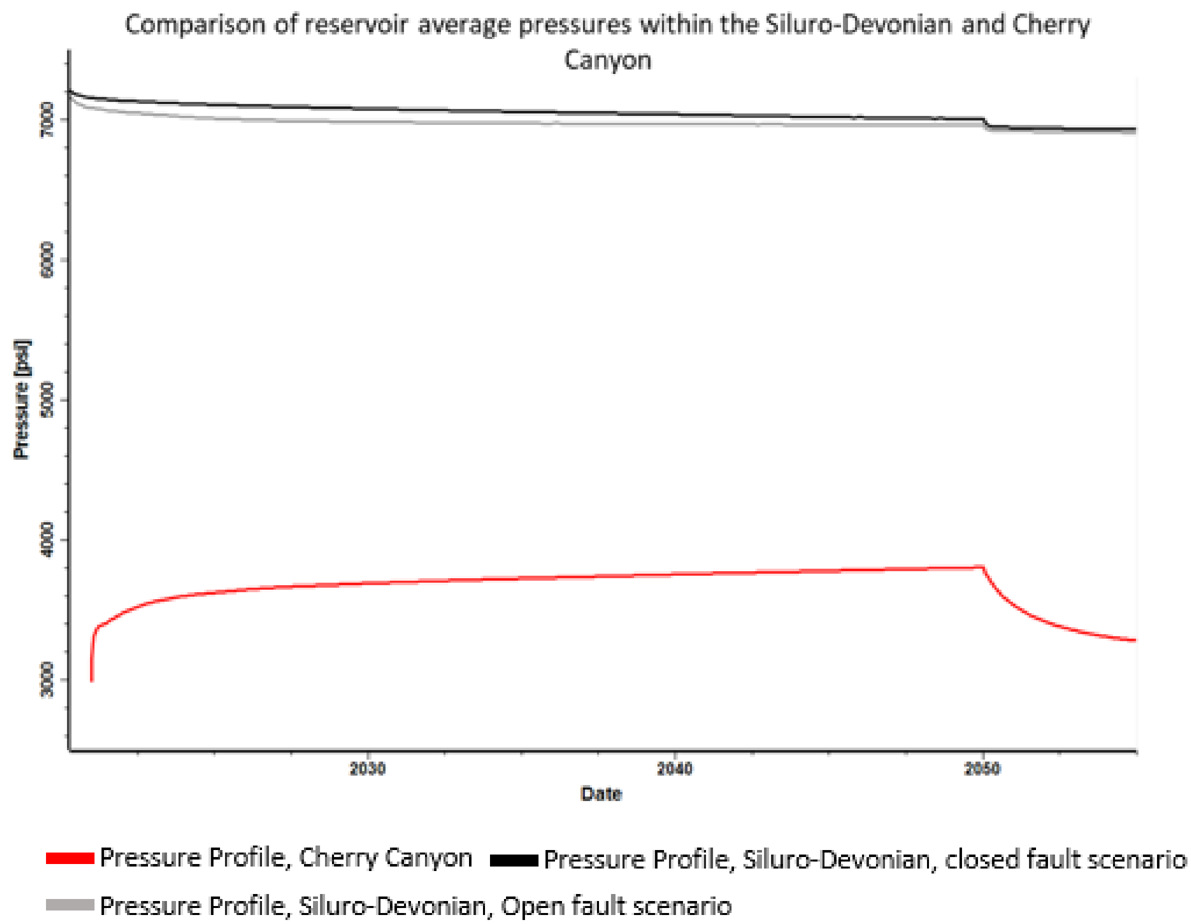


Figure 3.9-13 – Comparison of reservoir average pressure within the Siluro-Devonian and Cherry Canyon during injection and during the post-injection period

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.

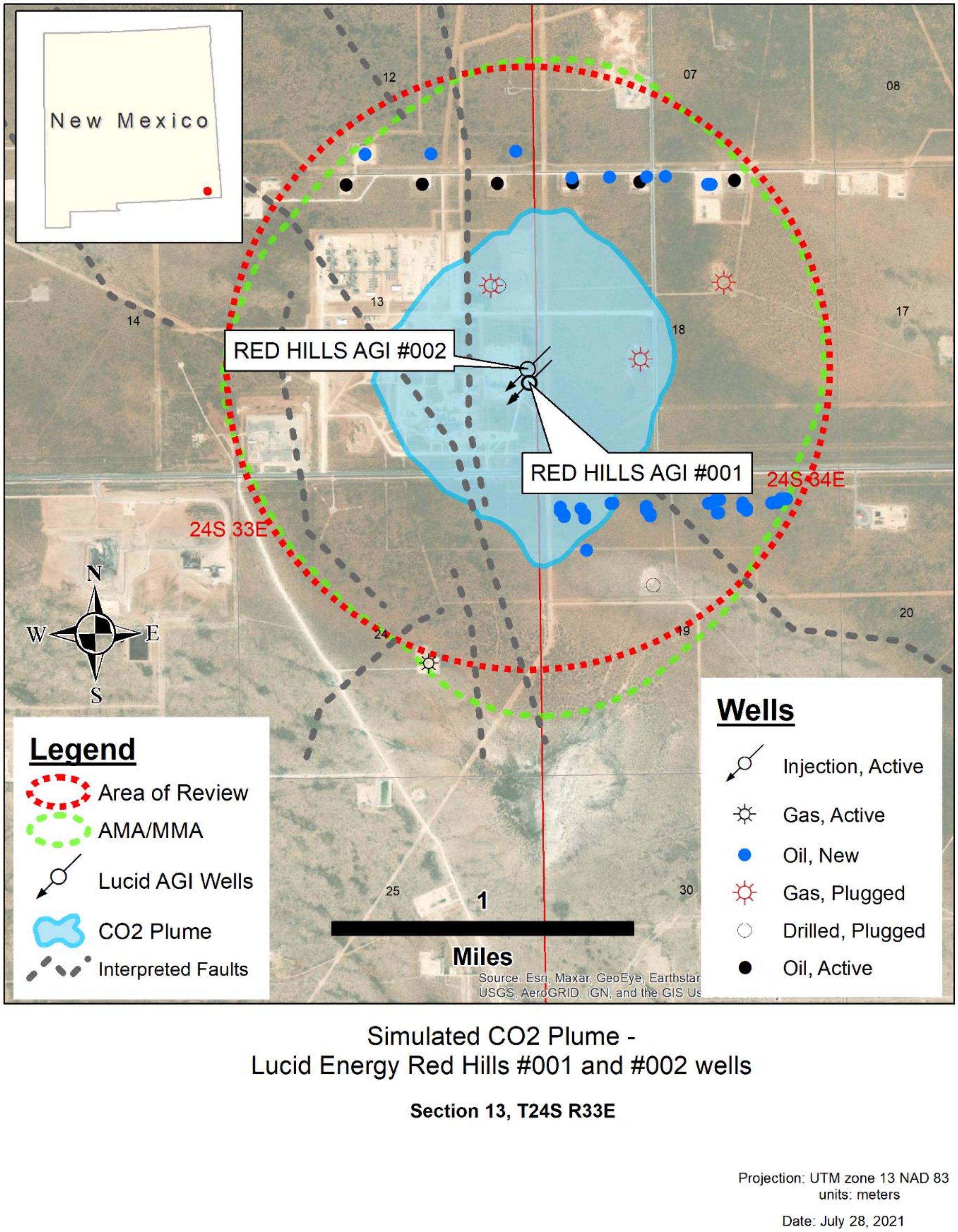


Figure 4.1-1 -- Maximum monitoring area (MMA) and active monitoring area (AMA) for Lucid Red Hill RH AGI #1 and RH AGI #2 Wells. The Class II Area of Review (AoR) is also shown.

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.

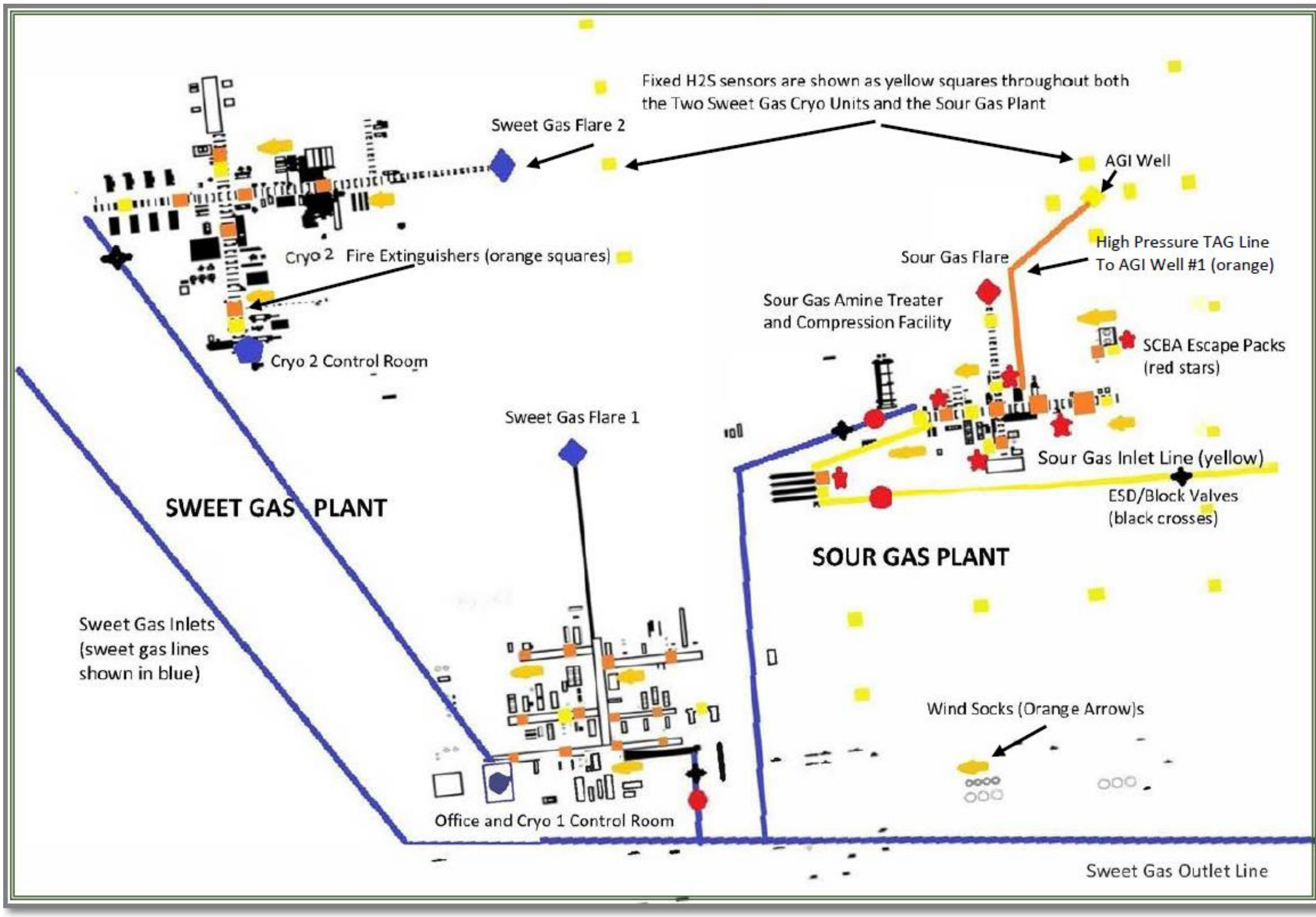


Figure 5.1-1 -- Red Hill Gas Plant plot plan showing location of major process units (taken from the H_2S Contingency Plan for Red Hills). The yellow squares indicate the location of fixed H_2S sensors.

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.

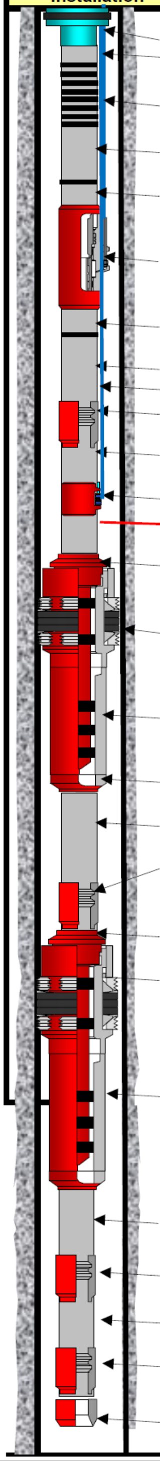
HALLIBURTON

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

Madalyn S. Blondes, Kathleen D. Gans, James J. Thordsen, Mark E. Reidy, Burt Thomas, Mark A. Engle, Yousif K. Kharaka, and Elizabeth L. Rowan, 2014. U.S. Geological Survey National Produced Waters Geochemical Database v2.1, *http://energy.usgs.gov/EnvironmentalAspects/EnvironmentalAspectsofEnergyProductionandUse/ProducedWaters.aspx*

Boyle, T.B., Carroll, J.J., 2002. Study determines best methods for calculating acid-gas density. *Oil and Gas Journal* 100 (2): 45-53.

H_2S Contingency Plan, Lucid Energy, April 2018, Red Hills Gas Processing Plant, Lea County, NM

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Luo, Ming; Baker, Mark R.; and LeMone, David V.; 1994, *Distribution and Generation of the Overpressure System, Eastern Delaware Basin, Western Texas and Southern New Mexico*, AAPG Bulletin, V.78, No. 9 (September 1994) p. 1386-1405.

Nicholson, A., Jr., Clebsch, A., Jr., 1961. *Geology and ground-water conditions in southern Lea County, New Mexico.* New Mexico Bureau of Mines and Mineral Resources, Ground-Water Report 6, 123 pp., 2 Plates.

Powers, D.W., Lambert, S. J., Shafer, S., Hill, L. R. and Weart, W. D., 1978., *Geological Characteristic Report, Waste Isolation Pilot Plant (WIPP) Site, Southeastern New Mexico (SAND78-1596)*, Department 4510, Waste Management Technology, Sandia Laboratories, Albuquerque, New Mexico

Silver, B.A., Todd, R.G., 1969. Permian cyclic strata, northern Midland and Delaware Basins, west Texas and southeastern New Mexico, *The American Association of Petroleum Geologists Bulletin* 53: 2223- 2251.

Walsh, R., Zoback, M.D., Pasi, D., Weingarten, M. and Tyrrell, T., 2017, FSP 1.0: A Program for Probabilistic Estimation of Fault Slip Potential Resulting from Fluid Injection, User Guide from the Stanford Center for Induced and Triggered Seismicity, available from SCITS.Stanford.edu/software

Ward, R.F., Kendall, C.G.St.C., Harris, P.M., 1986. Upper Permian (Guadalupian) facies and their association with hydrocarbons – Permian Basin, west Texas and New Mexico. *The American Association of Petroleum Geologists Bulletin* 70: 239-262

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

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 5.4092×10^{-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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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.

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

5. Lease Serial No. **NM-17446**
6. If Indian, Allottee or Tribe Name
7. If Unit or CA/Agreement, Name and/or No.
8. Well Name and No. **Government "L" Com #1**
9. API Well No. **30-025-~~05070~~ 25604**
10. Field and Pool, or Exploratory Area **Bell Lake, South Morrow**
11. County or Parish, State **Lea, New Mexico**

1. Type of Well ☐ Oil Well ☑ Gas Well ☐ Other
2. Name of Operator **EOG Resources, Inc**
3a. Address **P.O. Box 2267, Midland, TX, 79702**
3b. Phone No. *(include area code)* **432-561-8600**
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

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

Request for Additional Information: Red Hills AGI #1 and AGI #2 - Lucid Energy Delaware, LLC (Lucid)
September 9, 2021

Instructions: Please enter responses into this table. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. Supplemental information may also be provided in a resubmitted MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	Throughout the majority of the MRV plan the two wells owned by Lucid at Red Hills are referred to as "RH AGI #1" and "RH AGI #2"; however, there are several occasions where they are referred to as "RH AGI#1" and "RH AGI#2", respectively. We recommend editing these occurrences to increase the uniformity of the document.	All occurrences of "RH AGI#1" have been revised to read "RH AGI #1"; all occurrences of "RH AGI#2" have been revised to read "RH AGI #2"
2.	1	4	"…in the currently-approved Red Hills (RH) AGI #1 (API 30-025-40448) …" We recommend adding the word "well" to the above phrase for clarity.	"well" has been added after AGI #1"
3.	1	5	"The newly authorized RH AGI #2 is authorized…." We recommend removing the repeated use of authorized in the phrase above to reduce redundancy.	This sentence as been edited as follows: "The newly permitted RH AGI #2 is authorized to inject…"
4.	1	5	"…into the Devonian and Upper Silurian Wristen and Fusselman formations at depths of approximately 16,000 to 17,600 feet **and** a maximum surface injection pressure of…" We recommend changing "and" in the phrase above to "with" to improve clarity.	The recommended change has been made.
5.	3.2.2	6	"There is some production from both the Cherry Canyon and from the Ramsey Sand member of the Bell Canyon approximately **1000** feet above" It appears there is a typo, please correct it if so.	The sentence has been revised as follows: "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"…

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	3.2.2	9	"The interval shown by the blue bar includes the…" In the phrase above it is unclear if the interval shown by the blue bar is the injection interval for RH AGI #2. We suggest editing this phrase to improve clarity.	The sentence has been revised as follows: "*The injection interval for RH AGI #2, shown by the blue bar, includes the Devonian..*"
7.	3.2.2	11	"These formations are underlain by the Ordovician Ellenburger Formation comprised of dolomites and limestones and is upward of **1000** feet thick" It appears there is a typo, please correct it if so.	This sentence has been revised as follows: ´ These formations are underlain by the Ordovician Ellenburger Formation which is comprised of dolomites and limestones and is upward of 1,000 feet thick."
8.	3.2.3	13	"Map showing the only wells that penetrated below the Woodford shale in the area of the Lucid **Red Hill** AGI…" It appears there is a typo, please correct it if so.	This sentence has been revised as follows: "*Map showing the only wells that penetrated below the Woodford shale in the area of the Lucid Red Hills AGI Wells (circled in red).*"
9.	3.2, 3.3	12, 18	The abbreviation Saltwater Disposal (SWD) is used in the captions of Figures 3.2-3 and 3.3-3 before it is defined in the text. Please correct this error.	SWD was first defined in the caption of Figure 3.2-3. The definition on page 21 was removed.
10.	3.3.2	21	"**It** lies a minimum of 1,200 feet above the Precambrian basement." In the phrase above it is unclear what is being referenced by 'It'. We suggest clarifying what 'It' is.	The sentence has been revised as follows: "The Siluro-Devonian interval lies a minimum of 1,200 feet above the Precambrian basement."
11.	3.4.2	23	"These analyses showed Total Dissolved **Solids(TDS)**…" Throughout the rest of the document there is a space between parenthesis and the preceding word. We recommend editing the above phrase to maintain uniformity.	Space inserted.
12.	3.5	26	"Multiple model simulations were **performed varying** fault dip angles to account for uncertainty in the true orientation of the faults." It appears there is a missing word, please correct if so.	The sentence has been revised as follows: "Multiple model simulations were performed by varying fault dip angles to account for uncertainty in the true orientation of the faults."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
13.	3.9	34	"Schlumberger **Petrel, version 2020.4** was used" "Eclipse Compositional **E300, version 2020.1** was used" The commas in the above phrase are extraneous and unnecessary. We recommend removing them.	These sentences have been revised as follows: "Schlumberger's Petrel (Version 2020.4) 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."
14.	3.9.1	35	"The geologic model boundary focused on a 13.5 km X 12.8 km (8.39 miles X 7.95 miles) area with **grid cell dimensions** of 141 X 132 X 7 equaling a total of 130,284 cells. The **grid dimension** is 100 m X 100 m" It appears that the terms "grid cell dimensions" and "grid dimension" have been applied incorrectly here and should be switched. If this is the case, then please correct the error.	Terms switched.
15.	3.9.2	37	"There are no known SWD wells in the simulation study area and therefore none **was** included in the modeling efforts within this target injection zone." It appears there is a typo, please correct it.	The sentence has been revised as follows: "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."
16.	3.9.2	37	"An estimated maximum bottomhole pressure (BHP) gradient of 0.65psi/ft (**4225** psi @ **6500** feet)" It appears there are missing commas in the above quote, please add them.	This sentence has been revised as follows: "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."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
17.	3.9.2	37/38	"A forecasting model was performed for a period of approximately 28 years in addition to 5 years of monitoring." It is unclear whether the above phrase is referencing a 28-year period and an additional 5-year monitoring period, or if the 5 years of monitoring is included in the 28-year period. We suggest editing this for clarity. Also, the period of injection is not consistent with the rest of the MRV plan. Several sections reference 30 years of injection. Please clarify and revise the MRV plan accordingly.	This apparent discrepancy was addressed as follows: "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."
18.	3.9.2	38	"…injection rate recorded was approximately **6200** thousand standard cubic feet per day (MSCF/D)." It appears there is a missing comma in the above quote, please add it.	Comma added.
19.	3.9.3	40	"The simulation model has **grid cell dimensions** of 119 x 119 x 15 for a total of 212,415 cells." Similar to the previous question regarding 3.9.1, are these the grid cell dimensions or the dimensions of the entire grid?	The sentence has been revised as follows: "The simulation model has a grid dimension of 119 x 119 x 15 for a total of 212,415 cells."
20.	3.9.3	42	"Figure 3.9-9 -- A 3D view of Siluro-Devonian modeled **permeability (a) and porosity (b) distributions**" The caption for this figure contains references to image labels, but no such labels exist on the figure itself. While it can be inferred that the one on the left is (a) and the one on the right is (b), we recommend adding these labels to the image.	The figure has been edited to show more clearly that (a) is for permeability and (b) is for porosity.
21.	3.9.4	46, 47	While it is stated in the body of the MRV plan, Figures 3.9-11 and 3.9-12 are not clear as to which formation the Striker 6 well is injecting into. We recommend adding this information to the captions or titles of these figures.	The following sentence was added to the caption for each of these figures: "The Striker 6 well injects into the Siluro-Devonian injection interval for RH AGI #2."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
22.	3.9.4	43	"Scenarios investigated impacts of **a** high, medium, and low injection **volumes**…" It appears there is a typo, please correct.	This sentence has been revised as follows: "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."
23.	3.9.4	43	"The figure shows clearly that the Devonian **is has** the capacity to store all volumes injected into both wells for all scenarios." It appears there is a typo, please correct.	This sentence has been revised as follows: "The figure shows clearly that the Devonian has the capacity to store all volumes injected into both wells for all scenarios. "
24.	5.2.2	52	"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 CO2 leakage to the surface." Please provide further explanation in the MRV plan as to who is requiring the special precautions and what the special precautions are.	The following additional sentence was added: "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."
25.	5.3.3	52	"This well was drilled to a **TD** of 17,625 feet on March 5, 1978…." The acronym 'TD' in the phrase above is not referenced anywhere else in the MRV plan; if this is an error then please correct it.	This sentence has been revised as follows: "This well was drilled to a total depth of 17,625 feet on March 5, 1978,.."
26.	5.3.3	52	"…this well will be a pathway for CO2 leakage to the surface from **either injection zones**." It appears there is a typo, please correct it if so.	This sentence has been revised as follows: "..zone minimizing the likelihood that this well will be a pathway for CO_2 leakage to the surface from either injection zone."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
27.	5.6	54	Section 5.6 provides adequate characterization of the potential for leakage due to induced seismicity, but offers no information regarding the likelihood of potential leakage due to natural seismicity. Even if the potential for leakage due to natural seismicity is low, this needs to be explicitly stated and evidenced in the MRV plan.	The potential for natural seismicity is addressed as follows: "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."
28.	5.6	54	"Nevertheless, the NMOCC Order…" It is unclear which NMOCC Order is being referenced in the above phrase. Please provide further explanation.	This sentence has been revised as follows: "Nevertheless, the NMOCC Order No. R-20916-H requires Lucid to.."
29.	6	54	"Monitoring will occur for the duration of injection." Will monitoring not also occur post-injection? If this is an error, then please correct it.	This sentence has been modified as follows: ". Monitoring will occur for the duration of injection and the 5-year post-injection period."
30.	6.1	55	"Fixed Monitors….' Starting the quote containing the description of gas detection equipment on the last line of a page is slightly confusing. We suggest a slight tweak to the formatting of this section to remedy the issue.	The document has been revised to ensure the introductory sentence appears on the same page as the quote containing the description of the gas detection equipment.
31.	7.7	59	"New Mexico Tech, through the same DOE research grant described in Section 7.2 above…" The DOE research grant is described in Section 7.3, not Section 7.2. Please correct this error.	Correction made.
32.	8	60	There is an inconsistency in the usage of **"CO2"** vs. **"CO_2"** on this page of the MRV plan. We suggest you correct these errors and examine the remainder of the MRV plan for similar errors.	All uses of "CO2" have been changed to "CO_2"

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
33.	10.1.1	61	"Measurement of CO2 Volume – All measurements of CO2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP" Reference to Equation RR-8 can be removed since Red Hills will not be producing CO_2.	Reference to RR-8 has been removed.
34.	11	63	"(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams." Most references to CO_2 produced have been removed; however, this subsection is still appearing in v2. If there is no CO_2 production at the site, we recommend removing this reference.	Deleted.
35.	11	63	"**(12)** Annual records of information used to calculate the CO2 emitted from equipment leaks and vented emissions of CO2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead. **(14)** Any other records as specified for retention in this EPA-approved MRV plan." It appears there is a typo, please correct it.	The numbering has been corrected.
36.	Appendix 7	76	Appendix 7 - Lucid Red Hills AGI Wells - Subpart RR Equations for Calculating CO2 Geologic Sequestration Reference is made to Equations RR-7, RR-8 and RR-9 Although this is not necessary since this is a summary of Subpart RR Equations, references to Equations RR-7, RR-8, and RR-9 can be removed from the Appendix since CO_2 will not be produced at the Red Hills site.	As stated, Appendix 7 is a summary of the Subpart RR equations. The introductory paragraph to Section 8 of the MRV plan states that " 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."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
37.	Appendix 8	80-81	Appendix 8 - Subpart RR Equations for Calculating Annual Mass of CO2 Sequestered RR-7 for Calculating Mass of CO2 Produced / Recycled from a Gas-Liquid Separator through Mass Flow Meters RR-8 for Calculating Mass of CO2 Produced / Recycled from a Gas-Liquid Separator through Volumetric Flow Meters RR-9 for Summation of Mass of CO2 Produced / Recycled through Multiple Gas Liquid Separators Although this is not necessary since this is a summary of Subpart RR Equations, references to Equations RR-7, RR-8, and RR-9 can be removed from the Appendix since CO_2 will not be produced at the Red Hills site.	As stated, Appendix 8 is a summary of the Subpart RR equations. The introductory paragraph to Section 8 of the MRV plan states that " 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."

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and AGI #2

Lucid Energy Delaware, LLC (Lucid)

Version 2.0
August, 2021

Table of 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 (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).

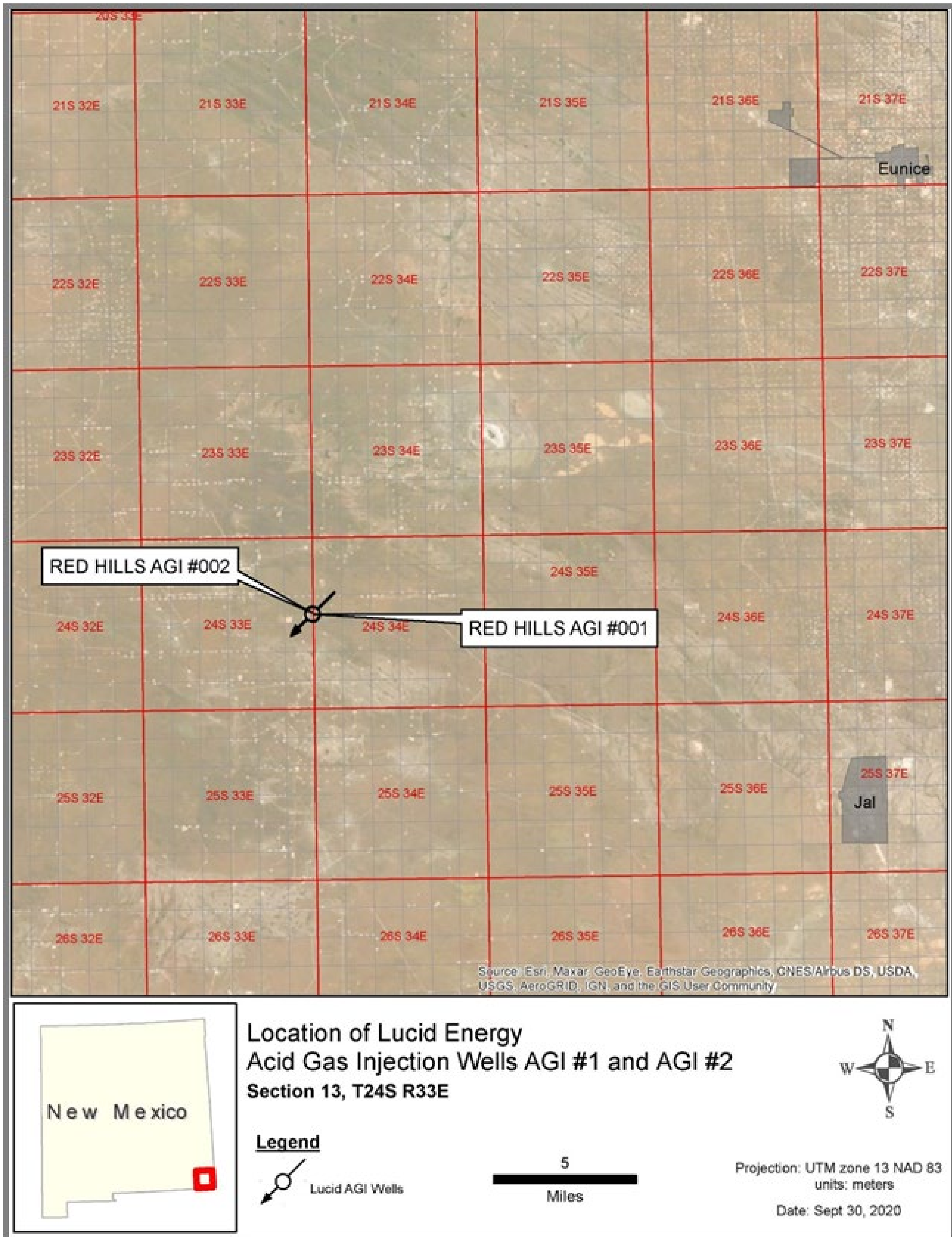


Figure 1-1 -- Location of the Red Hills Gas Plant and Wells – RH AGI #1 and RH AGI #2

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 authorized 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 and 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 approximately 1000 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 and 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

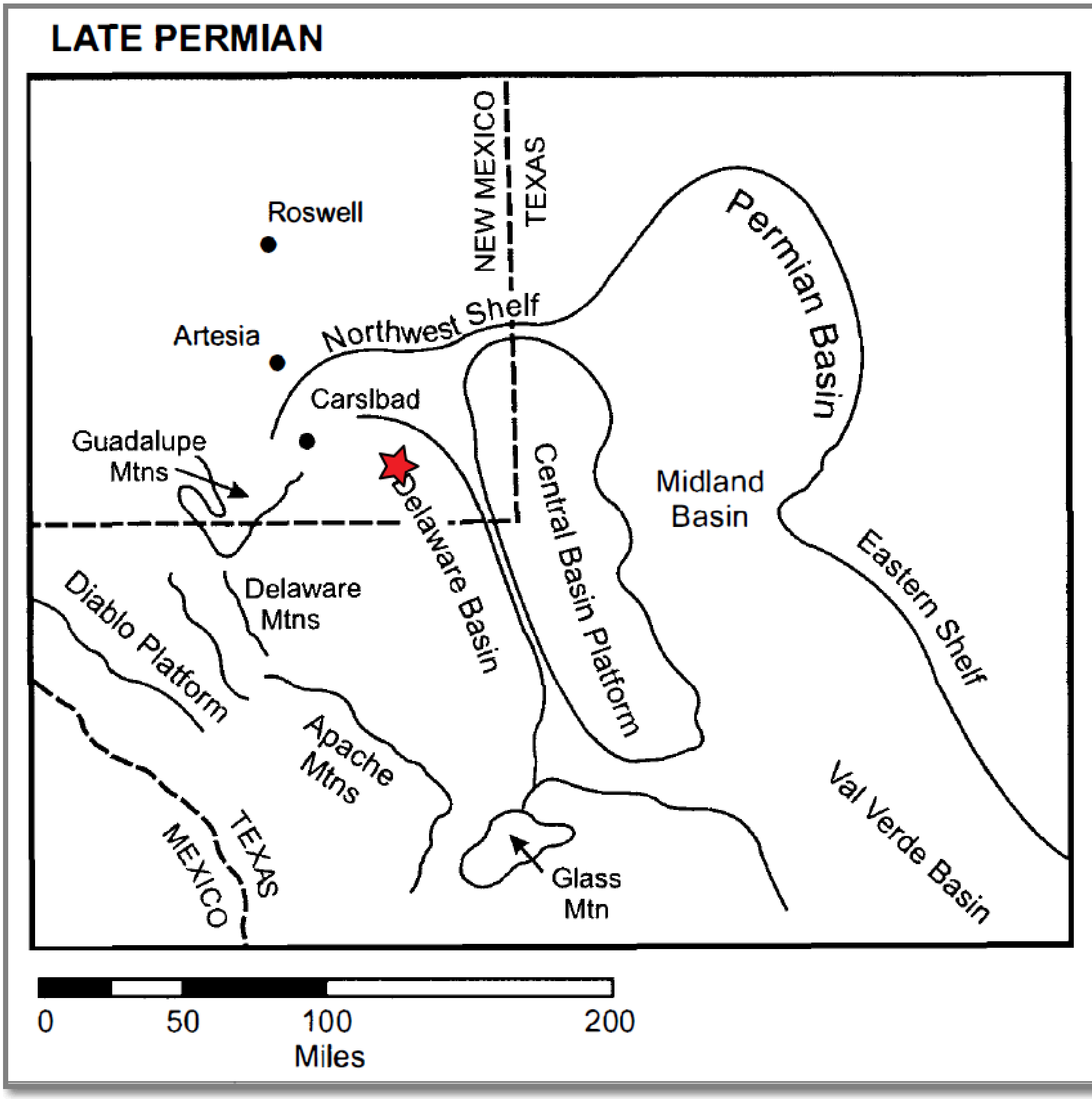


Figure 3.2-1 -- Structural features of the Permian Basin during the Late Permian. Location of the Lucid RH AGI wells is shown by the red star. (Modified from Ward, et al (1986))

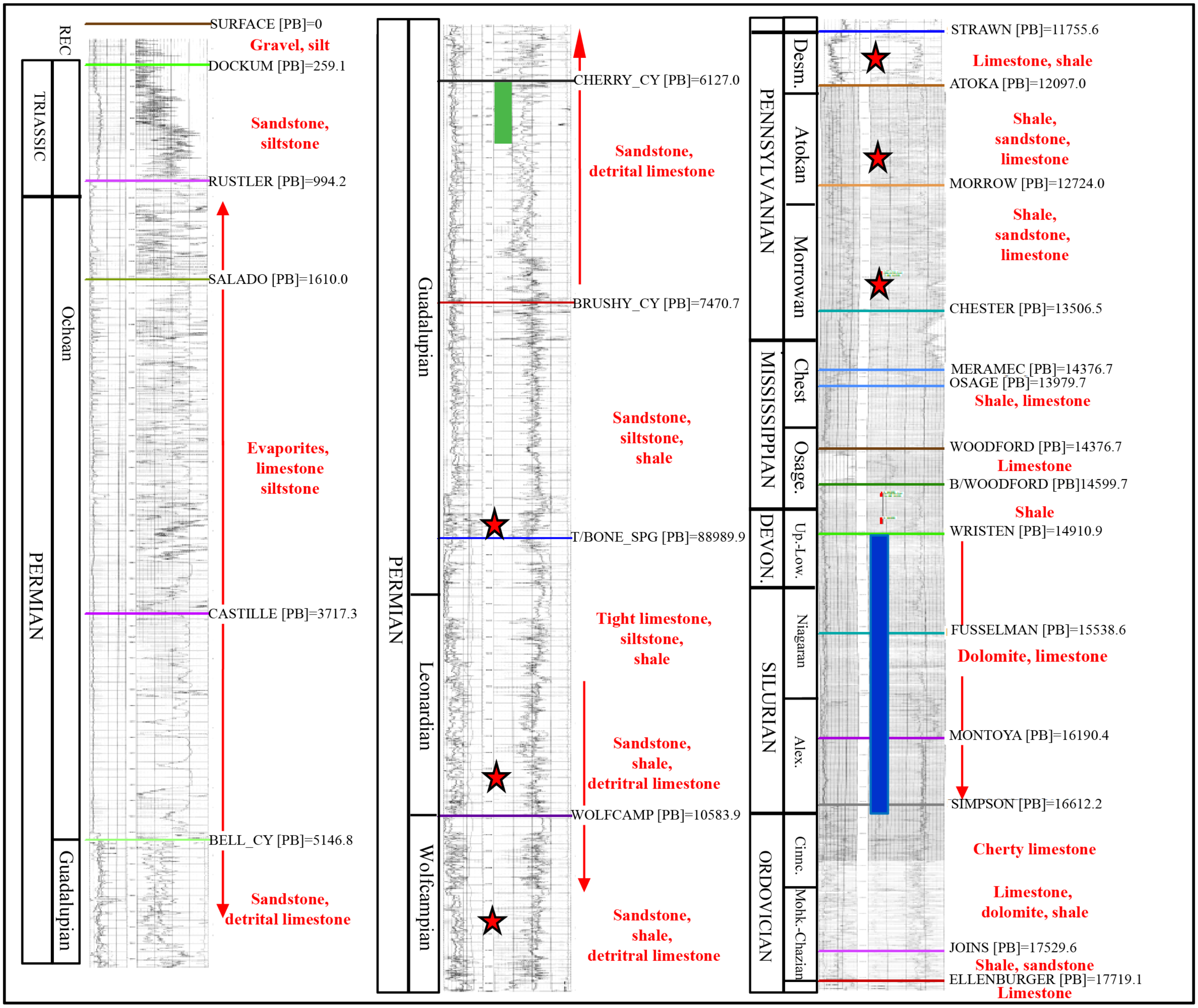


Figure 3.2-2 -- Stratigraphy and generalized lithologies of the formations underlying the Lucid RH AGI Wells.

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 interval 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 comprised of dolomites and limestones and is upward of 1000 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).

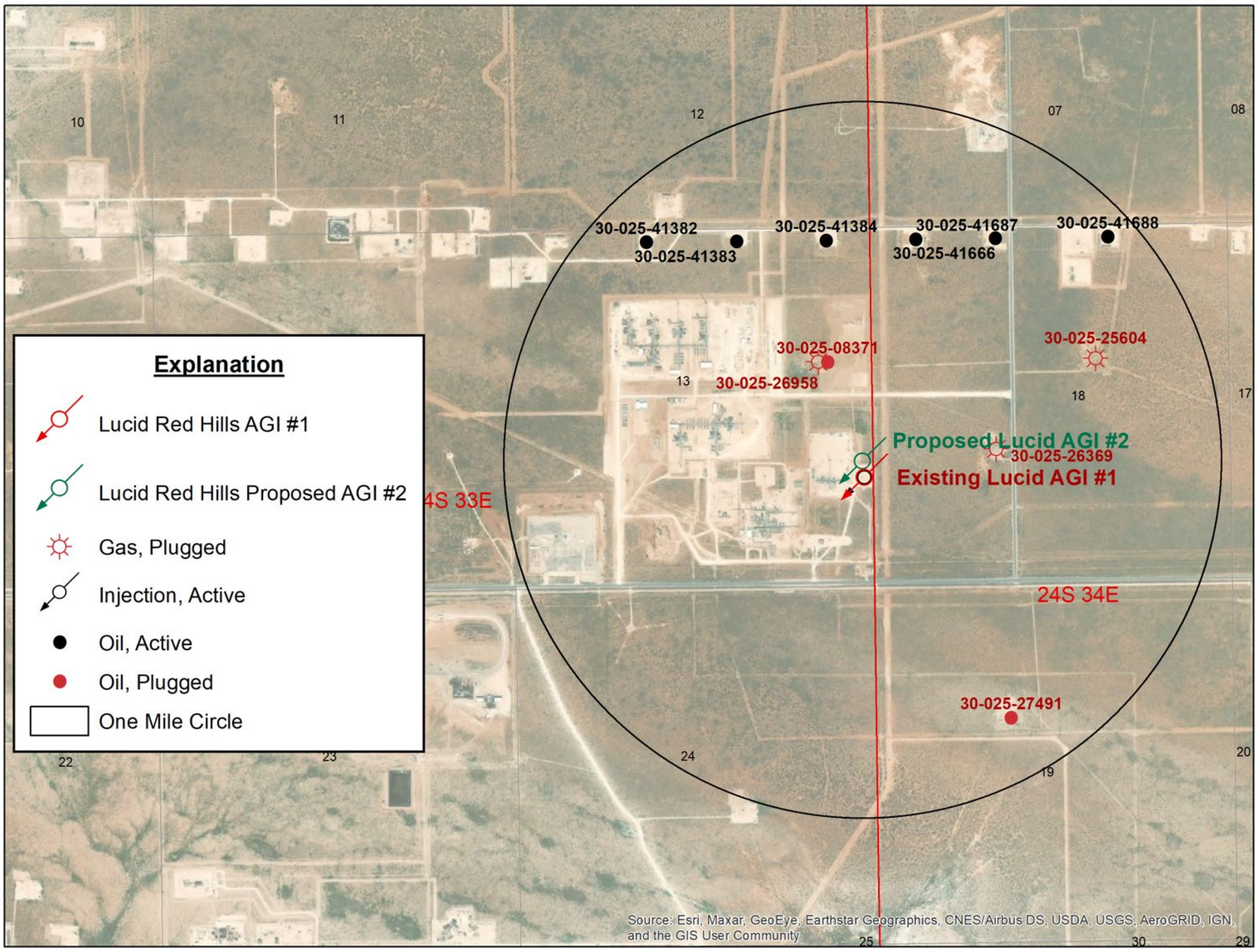


Figure 3.2-3 – Oil and gas production and SWD wells completed in the Siluro-Devonian in the vicinity of the RH AGI wells. The Class II one-mile radius AoR is also indicated.

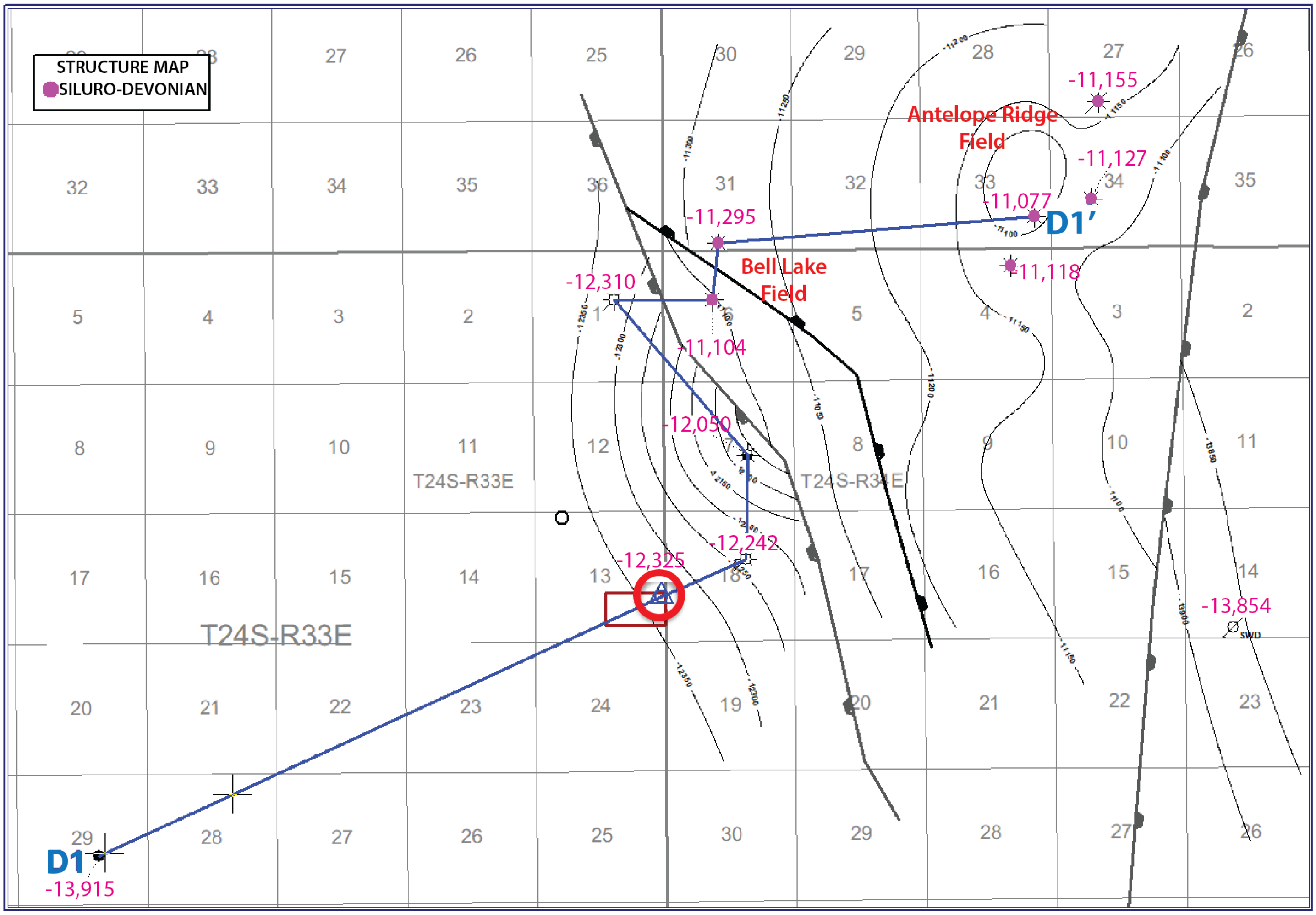


Figure 3.2-4 -- Structure on top of the Devonian and location of cross section D1-D1'

Map showing the only wells that penetrated below the Woodford shale in the area of the Lucid Red Hill 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.

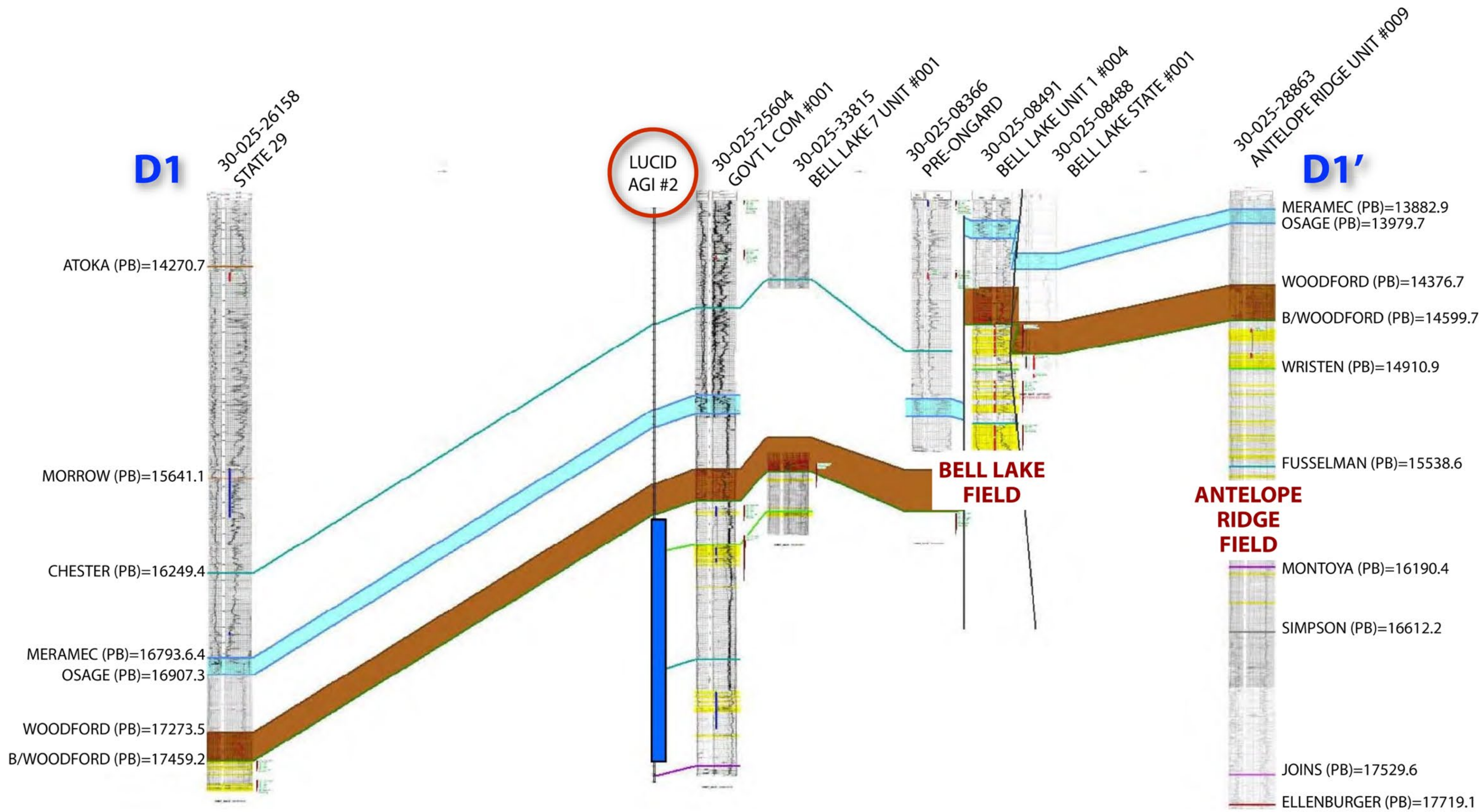


Figure 3.2-5 -- Structural cross section through the deeper horizons across the Red Hill Gas Plant Site

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

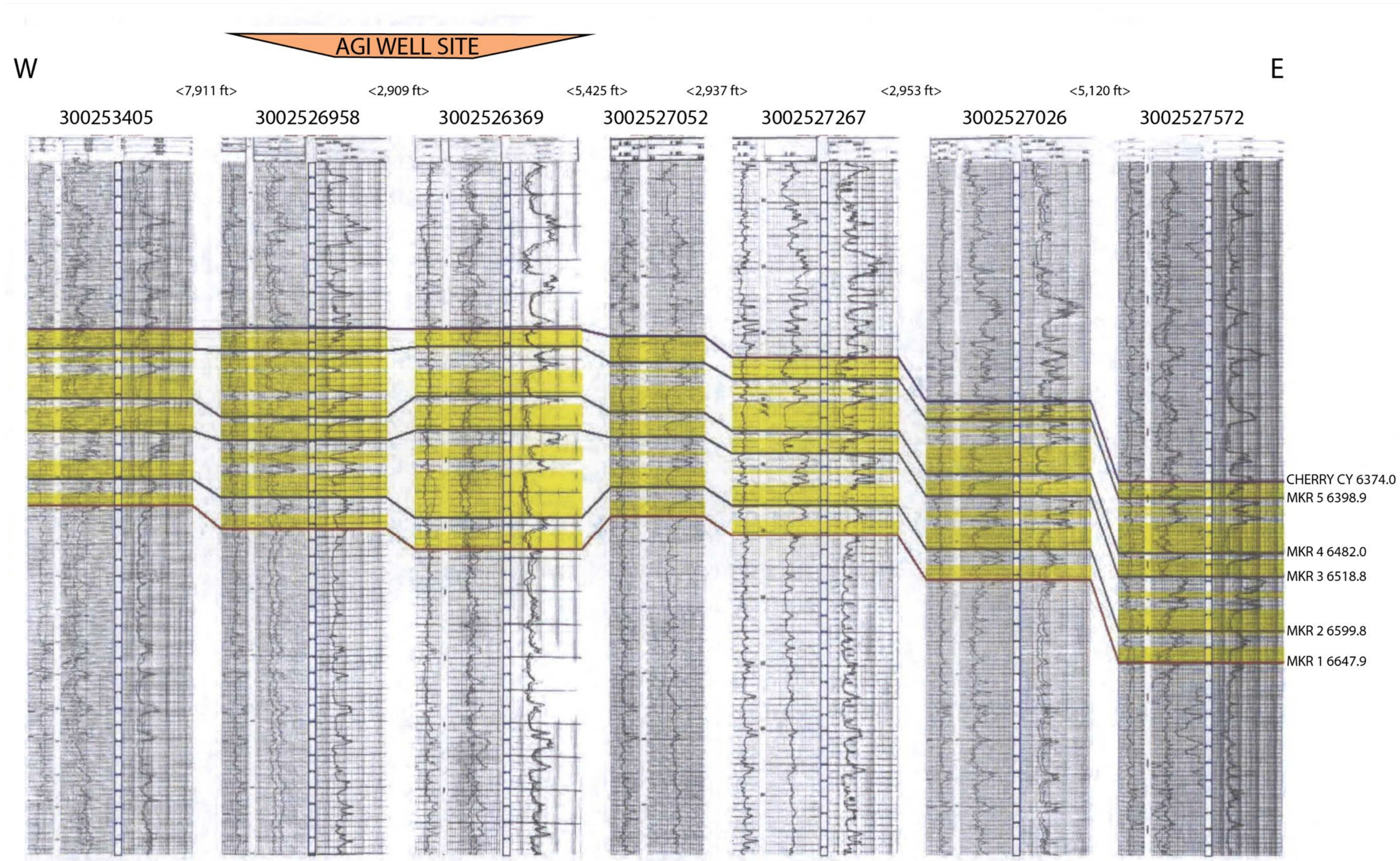


Figure 3.3-2 -- West – East cross section showing the 5 sand units of the Manzanita Zone of the Cherry Canyon Formation

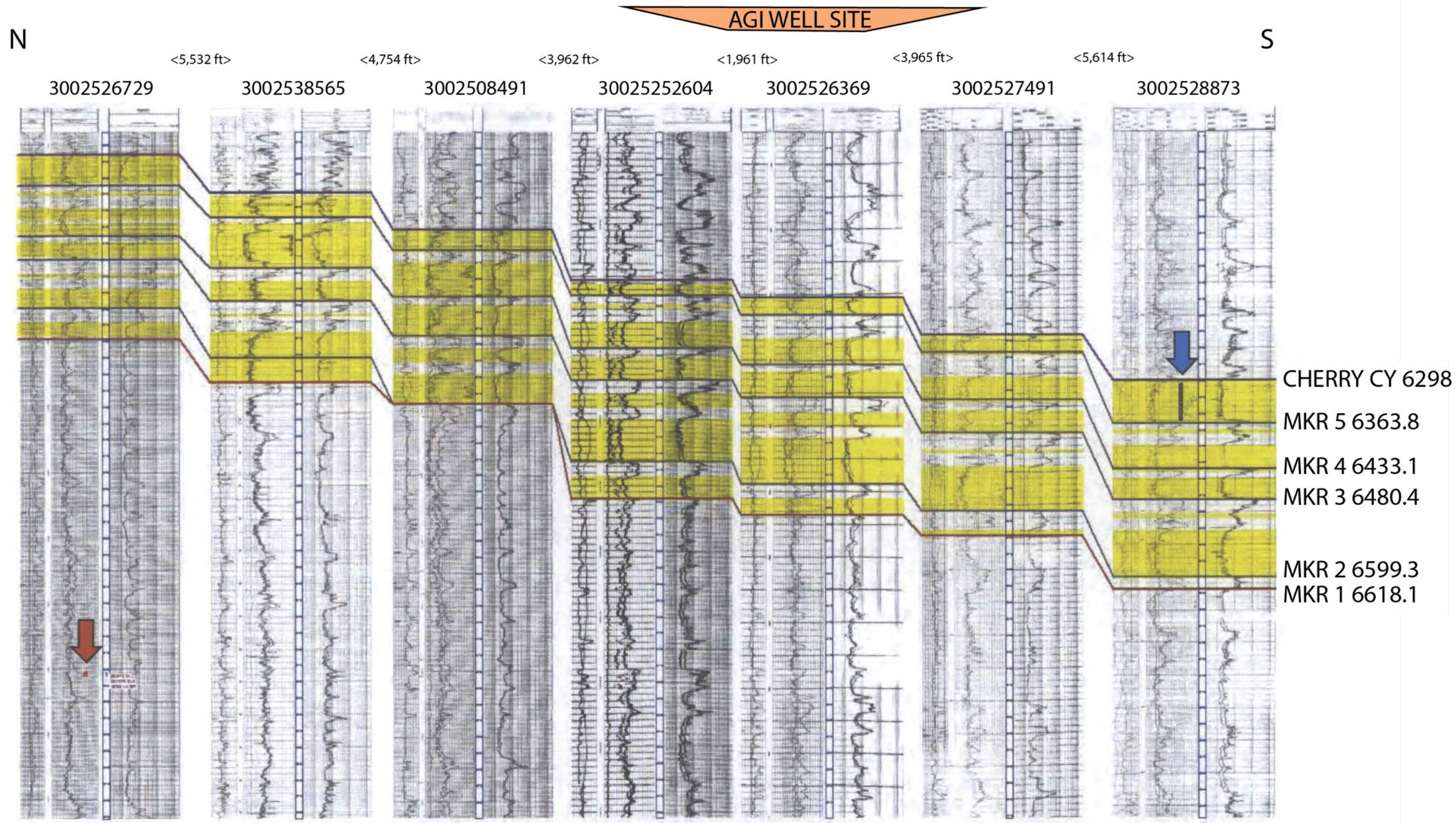


Figure 3.3-3 -- -- North - South cross-section showing the 5 sandstone units of the Manzanita Zone of the Cherry Canyon Formation

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.

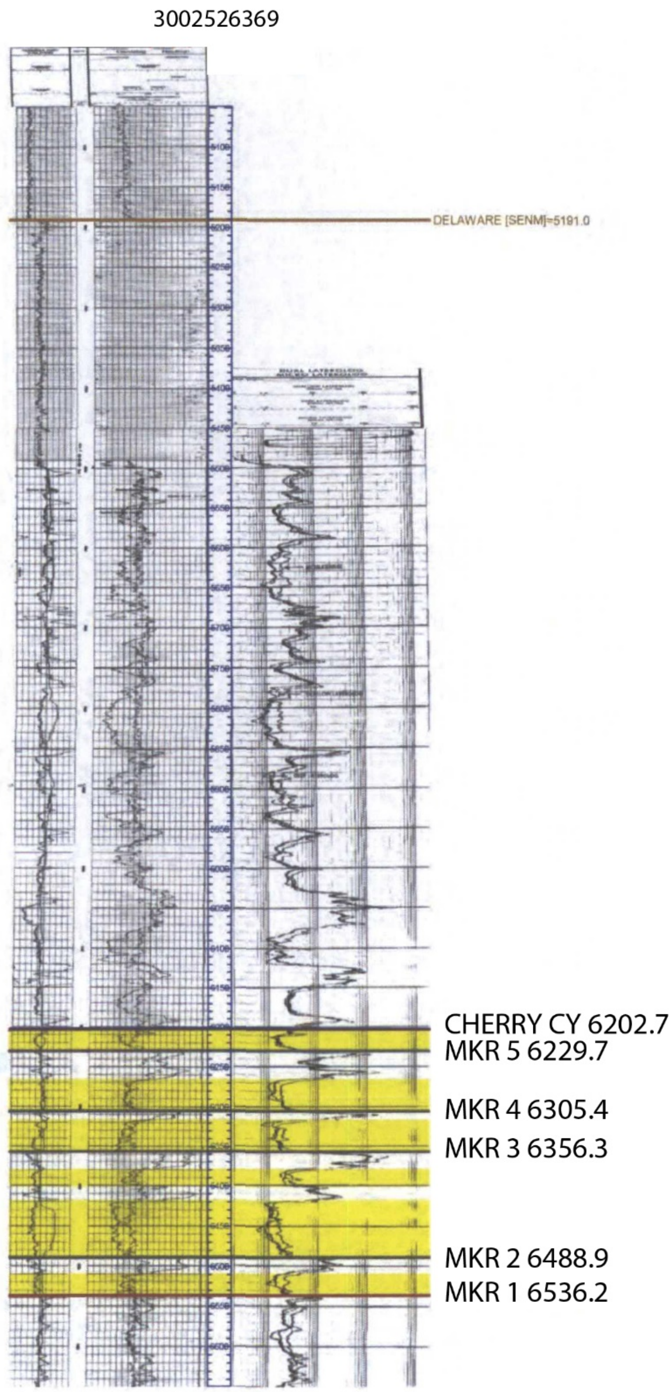


Figure 3.3-4 -- Geophysical logs from the Bell Canyon and the Upper Cherry Canyon from the Government L Com #002 well, located 0.38 miles from the RH AGI #1 Well

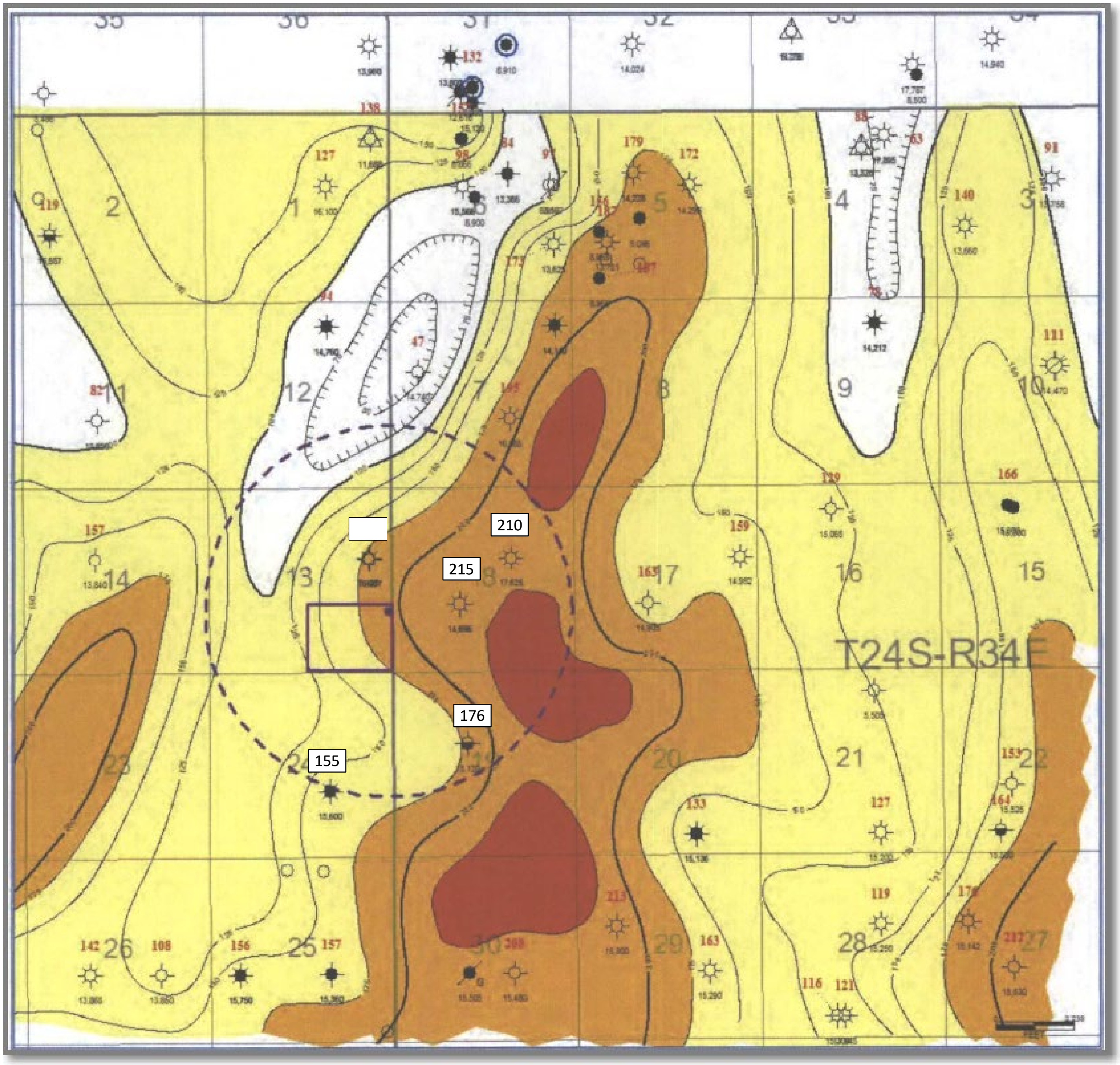


Figure 3.3-5 -- Map showing thickness of the clean sands in the Upper Cherry Canyon injection zone for RH AGI #1 and the one-mile radius AoR

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 saltwater disposal (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). It lies 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.

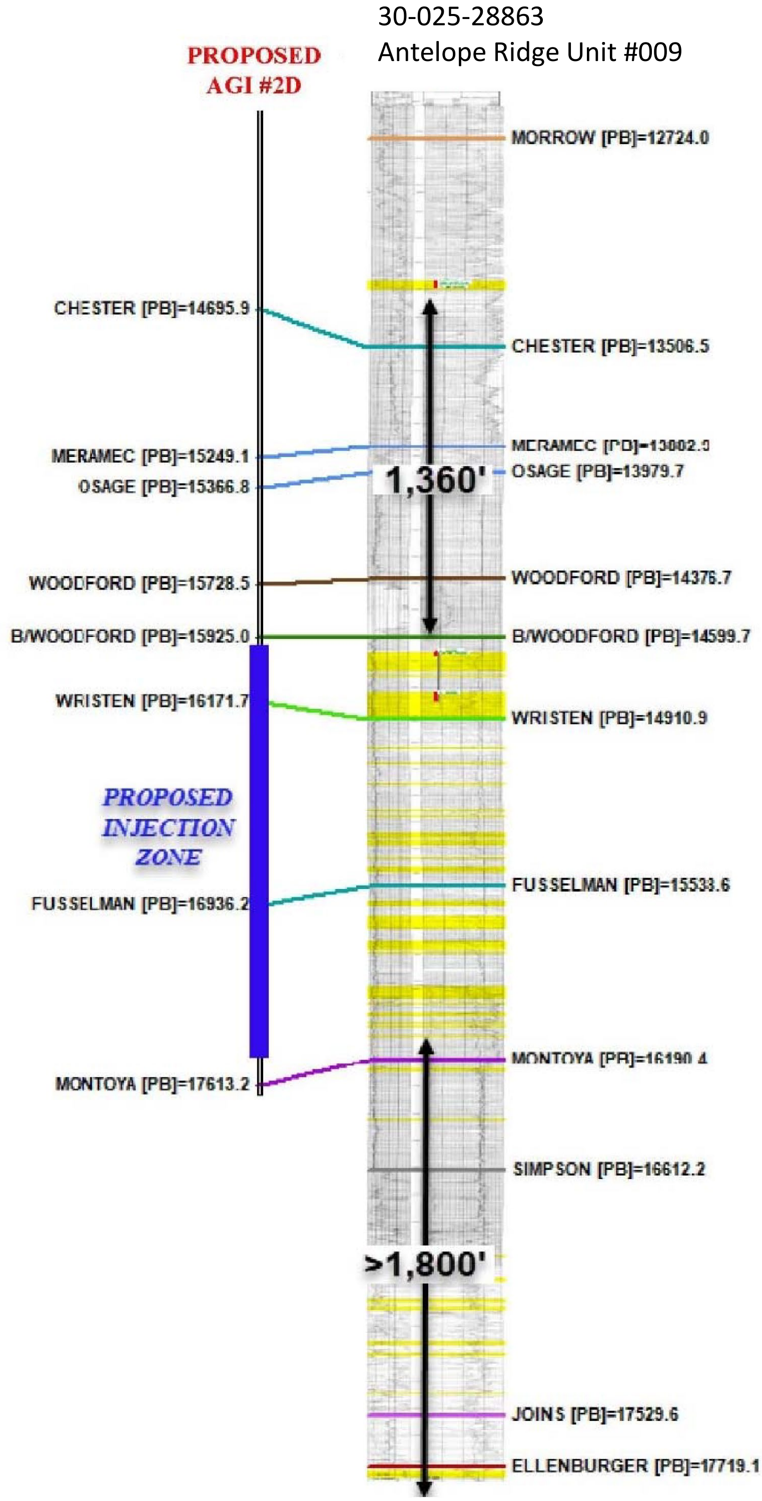


Figure 3.3-6 -- Porosity profile above and below proposed injection zone for RH AGI #2

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).

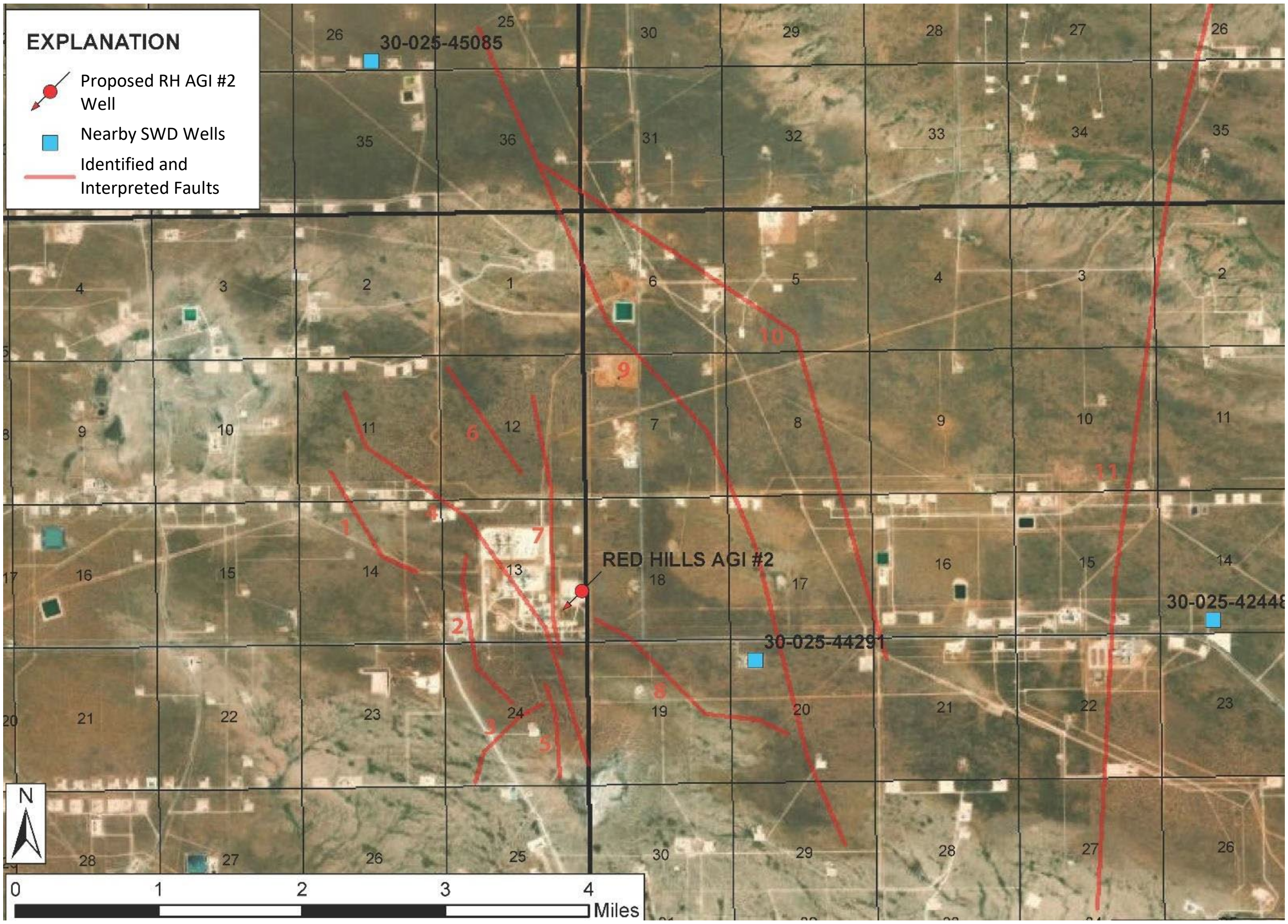


Figure 3.5-1 -- Map showing identified and interpreted faults in the area of the proposed RH AGI #2 well.

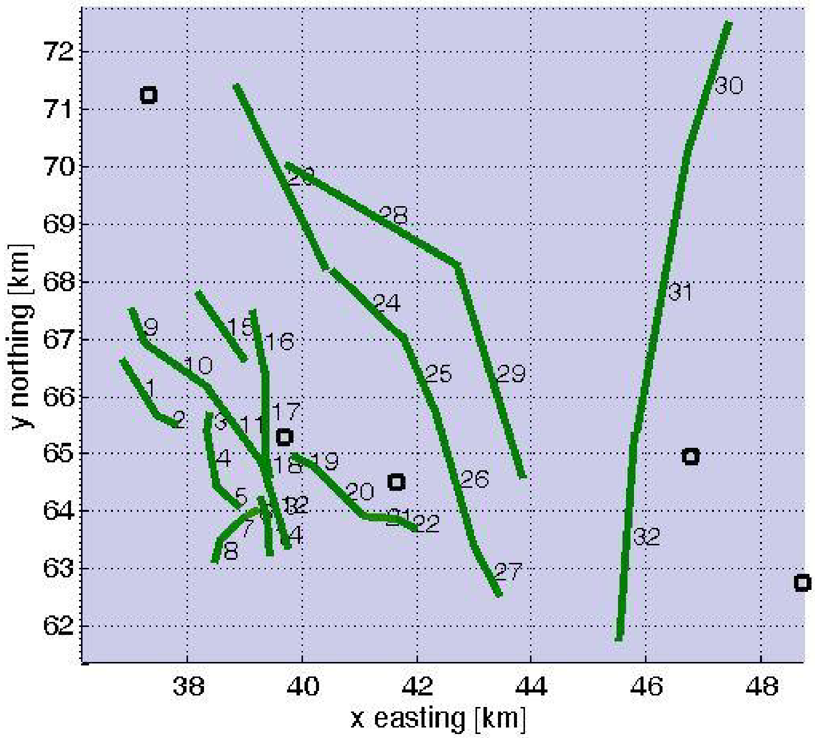


Figure 3.5-2 – Graphic showing 11 faults divided into 32 segments for FSP analysis.

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 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.

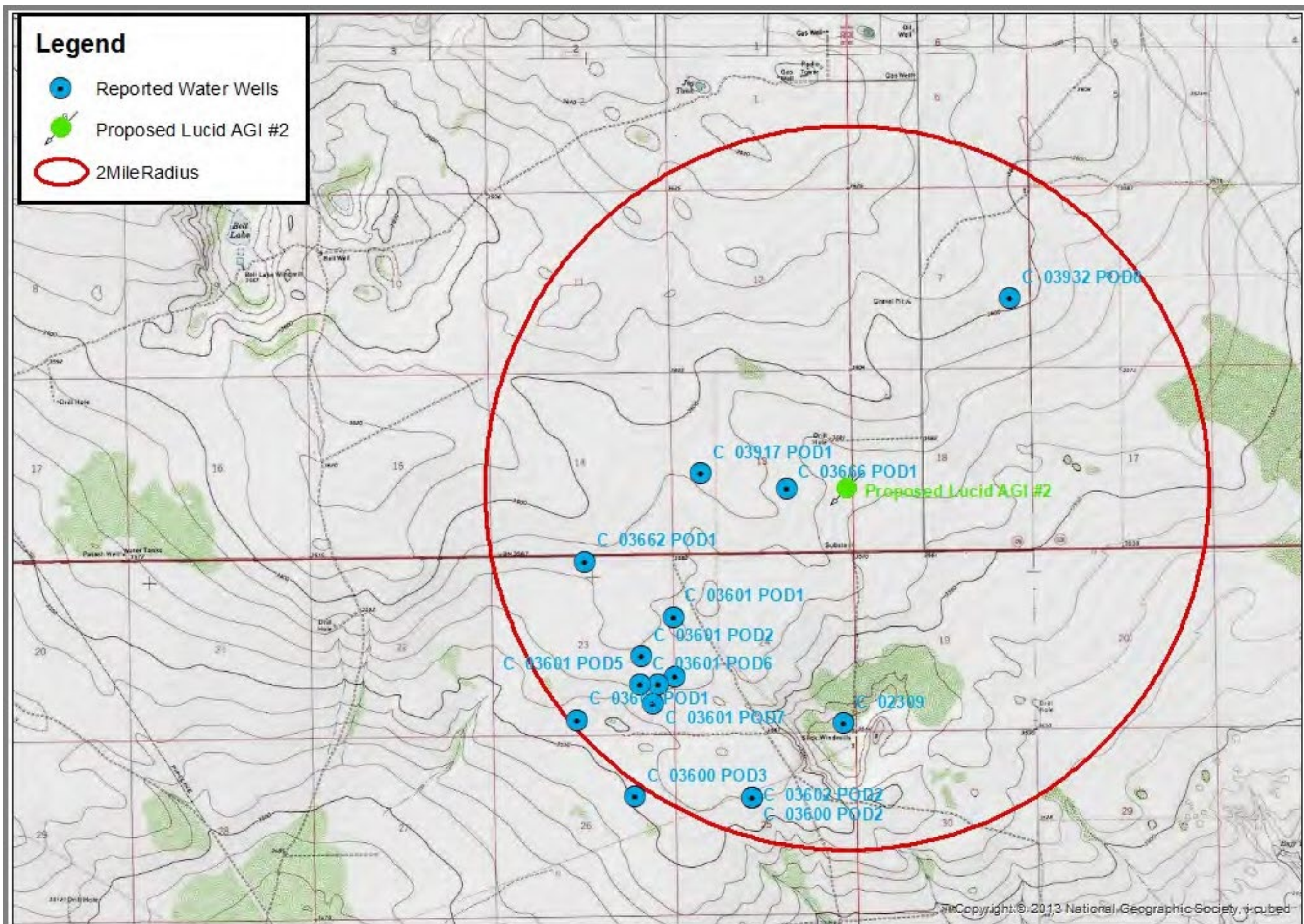


Figure 3.6-1 -- Reported Water Wells within 2-mile Radius of Proposed Lucid AGI #2

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			

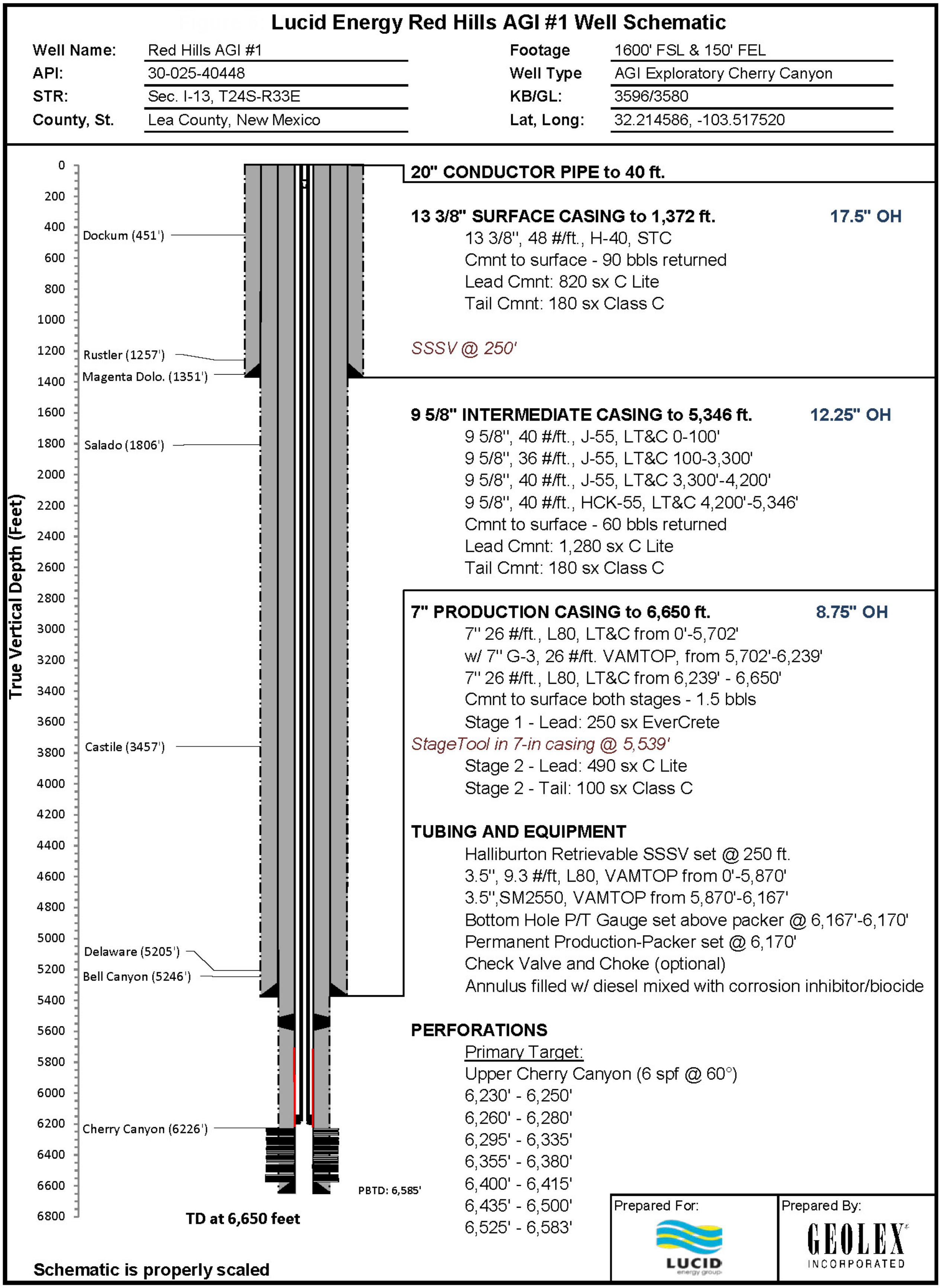


Figure 3.6-2 -- Schematic of RH AGI #1

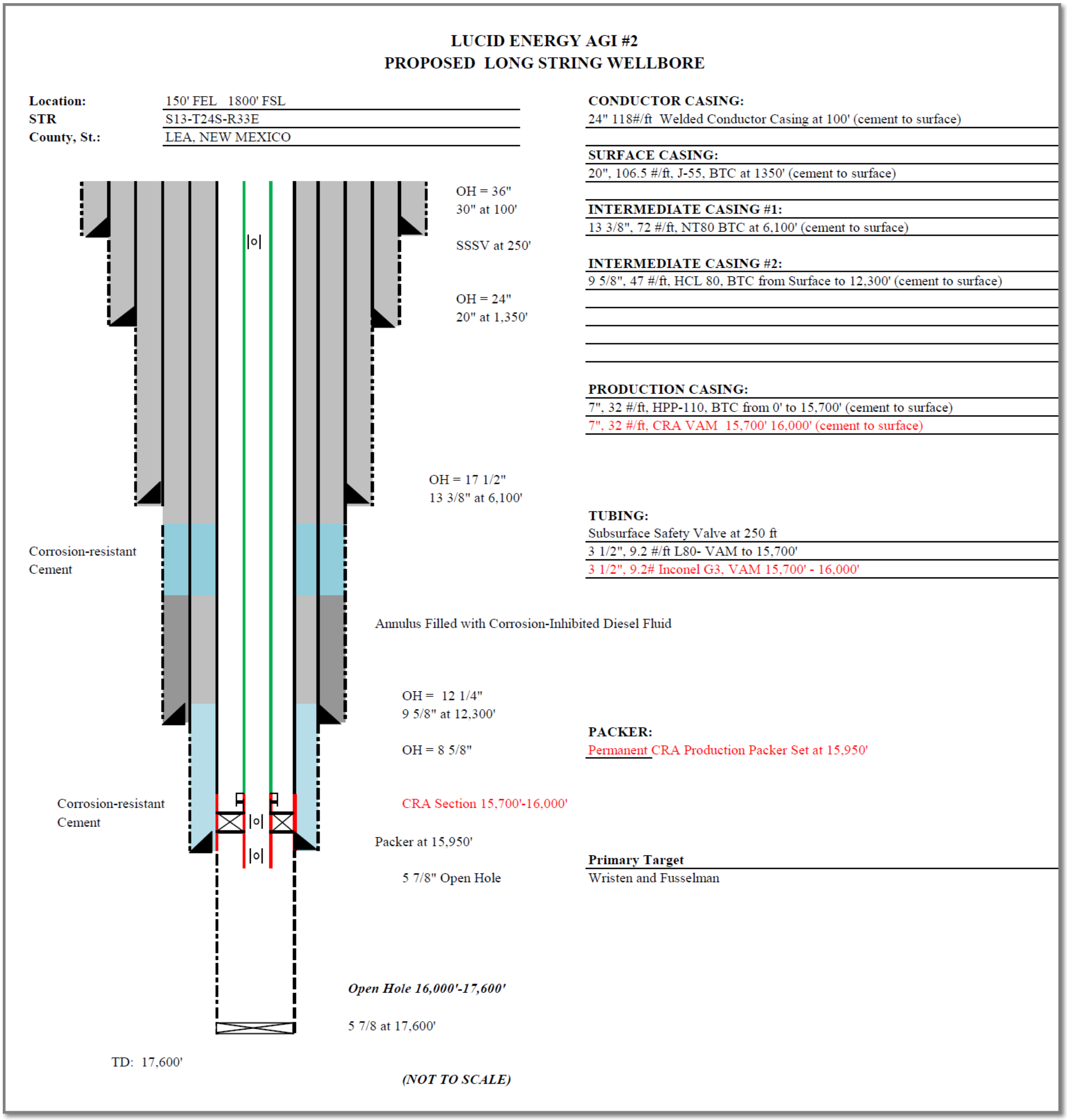


Figure 3.6-3 -- Schematic of Proposed RH AGI #2 (Option 2). Red text refers to completion parameters for the injection zone.

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.

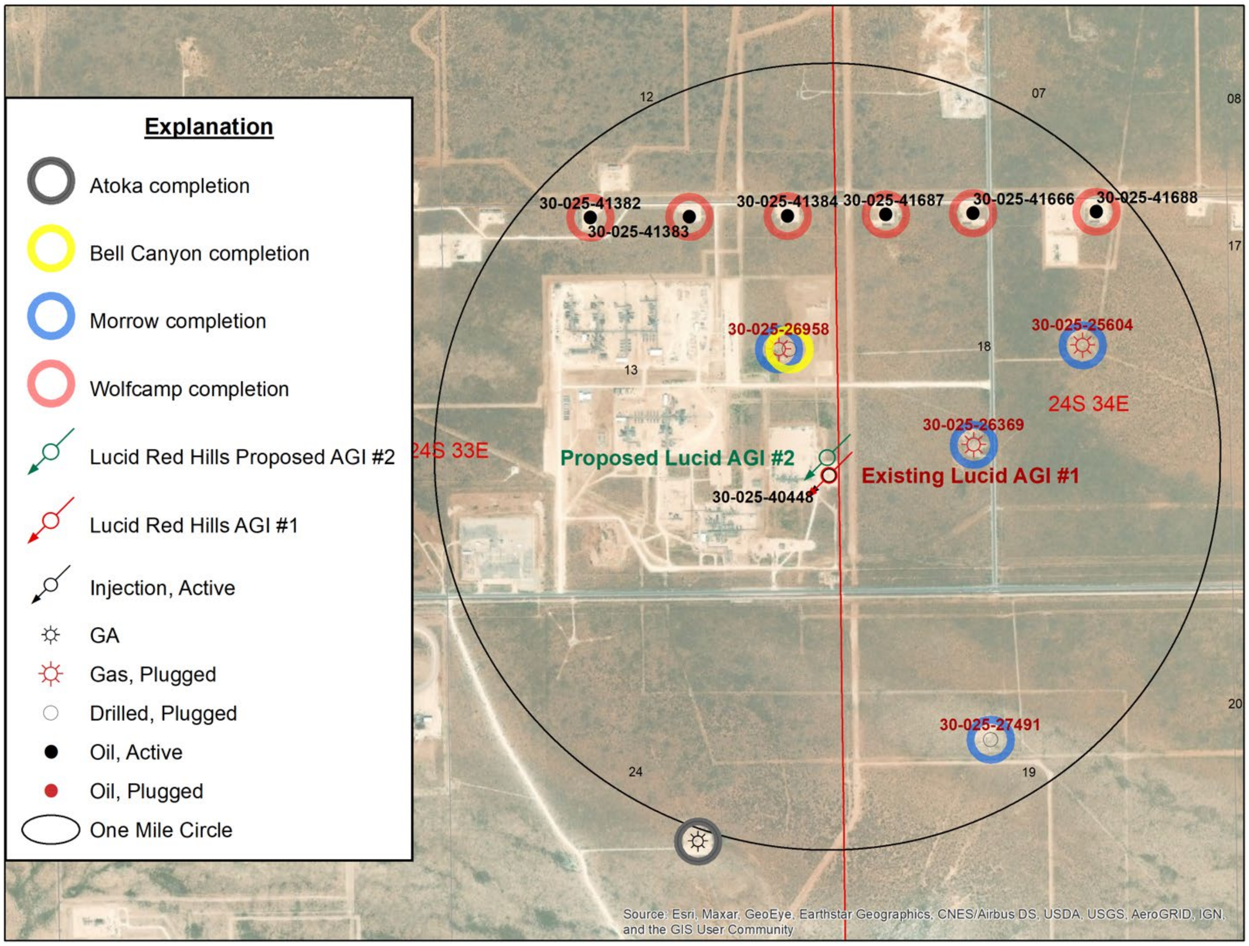


Figure 3.7-1 – Location of all oil- and gas-related wells within a 1-mile radius of the RH AGI wells

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

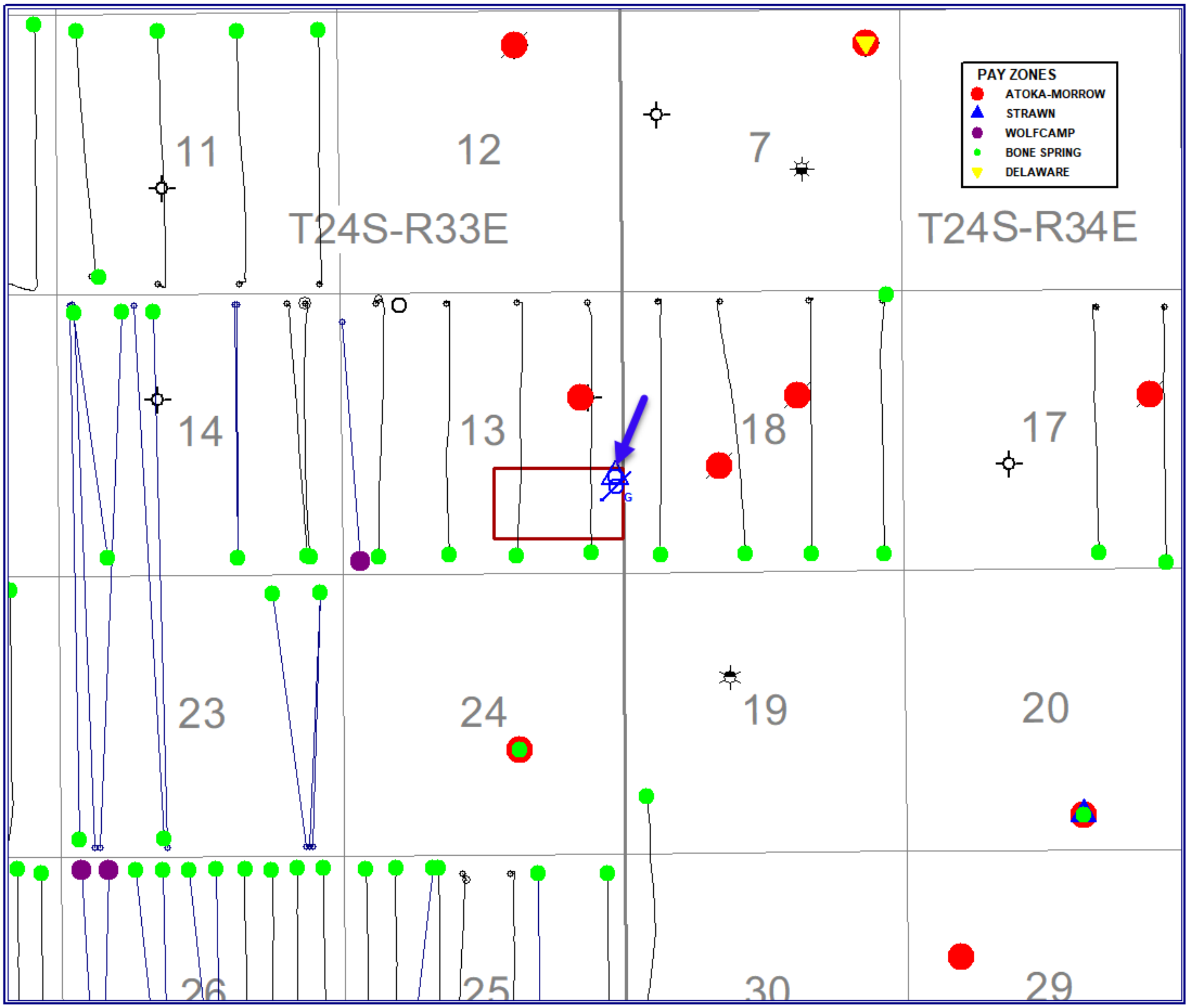


Figure 3.7-2 -- Producing wells in the area of the Red Hill Gas Plant.

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.

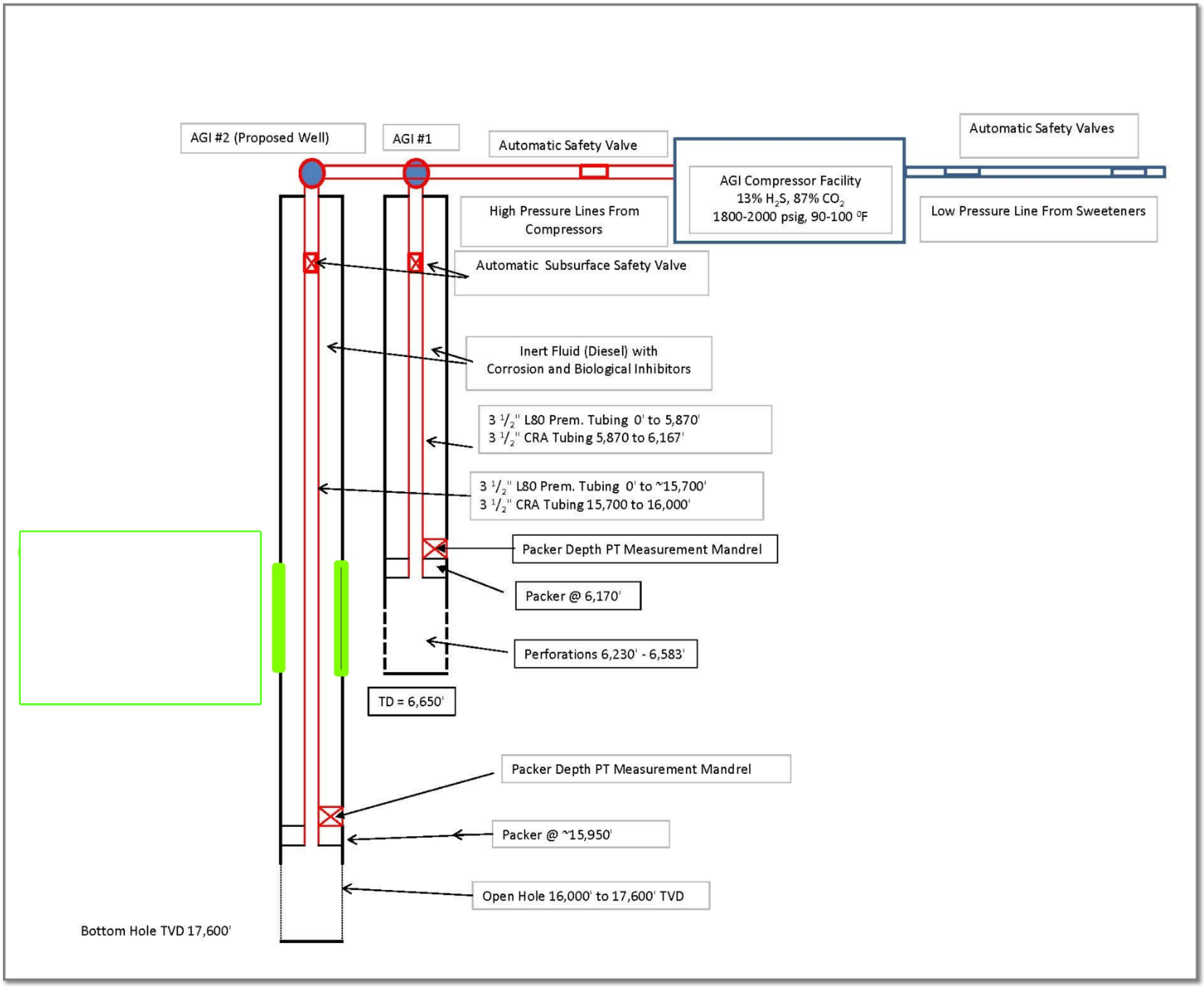


Figure 3.8-1 -- Schematic of surface facilities and RH AGI wells at the Red Hills Gas Plant

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 Petrel, version 2020.4 was used to construct geological models used in this work. Schlumberger 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- 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 grid cell dimensions of 141 X 132 X 7 equaling a total of 130,284 cells. The grid 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).

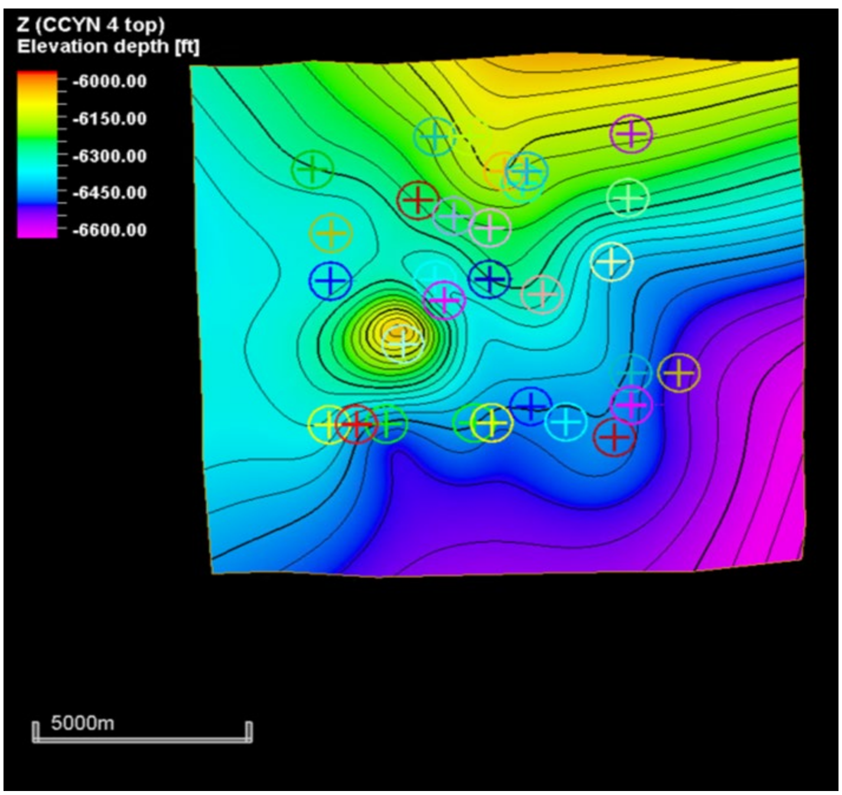


Figure 3.9-1 – Structural surface for top of Layer 4 of the Manzanita Zone of the Cherry Canyon Formation within the geological model.

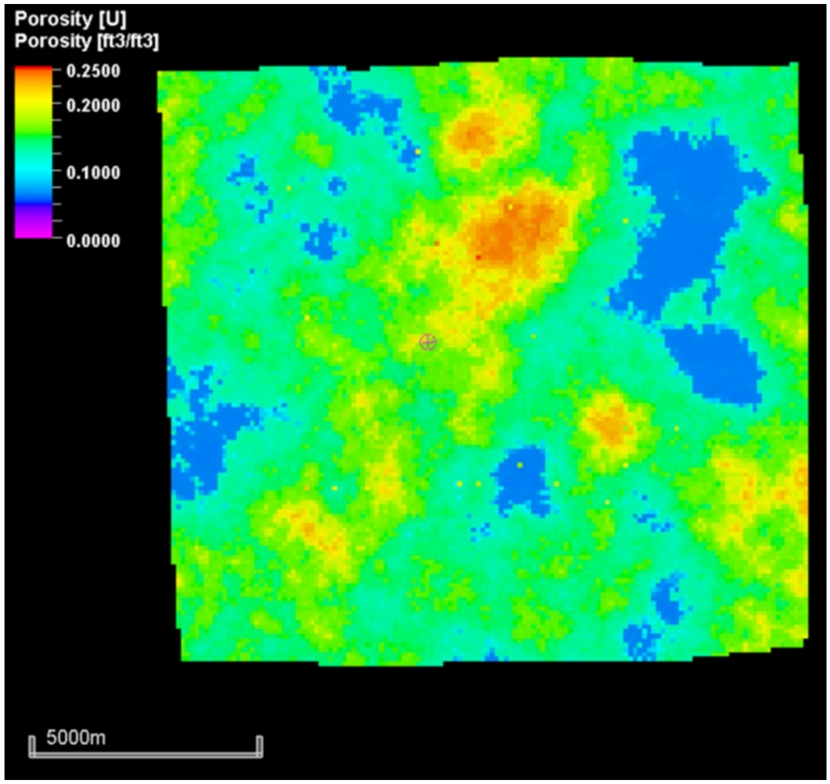


Figure 3.9-2 – Graphic showing the distribution of porosity in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation. Plan view.

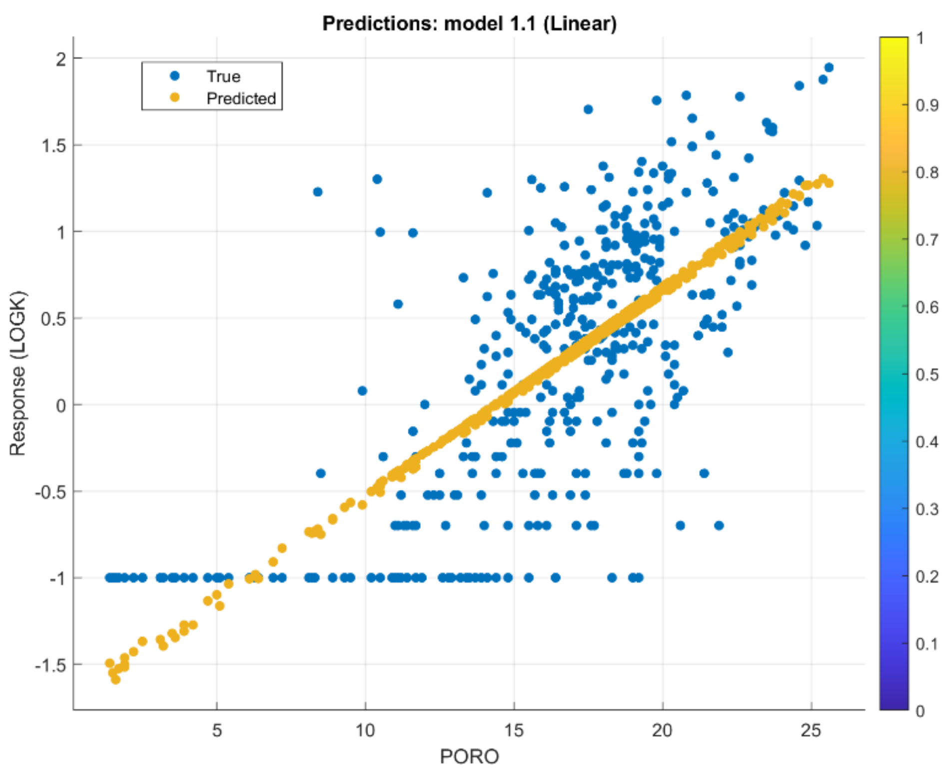


Figure 3.9-3 -- Porosity-permeability relationship for Layer 4 of the Manzanita Zone of the Cherry Canyon Formation.

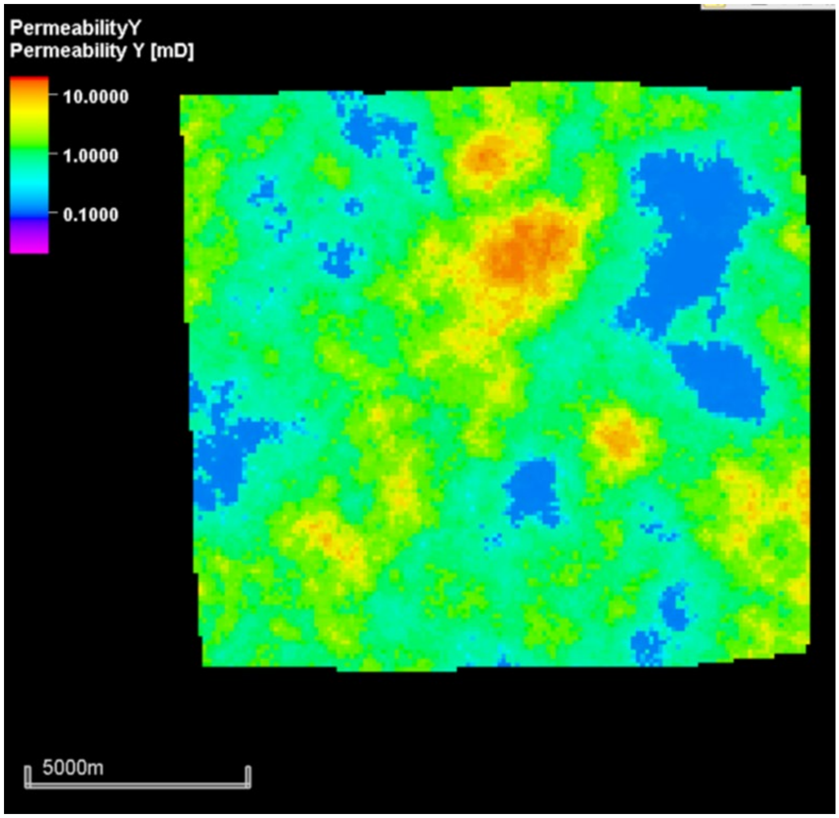


Figure 3.9-4 – Graphic showing the permeability distribution in Layer 4 of the Manzanita Zone of the Cherry Canyon Formation. Plan view.

3.9.2 Simulation Modeling for 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 0.65psi/ft (4225 psi @ 6500 feet) corresponded to the fracture pressure gradient imposed on the 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 was included in the modeling efforts within this target injection zone. A forecasting model was performed for a period of approximately 28 years in addition to 5 years of monitoring. Figure 3.9-6 shows the injection profile for the forecasting period which showed the maximum injection rate recorded was approximately 6200 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.

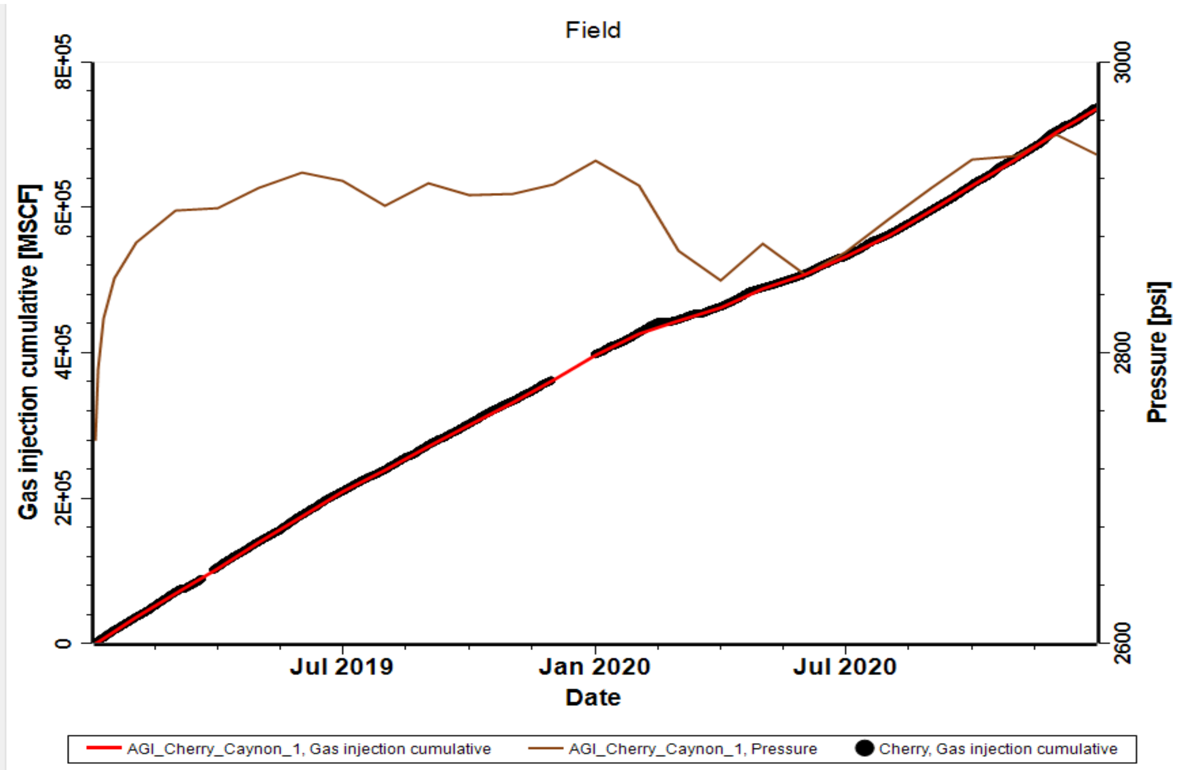


Figure 3.9-5 – Graph showing the calibrated cumulative gas injection and field pressure profile in the Cherry Canyon

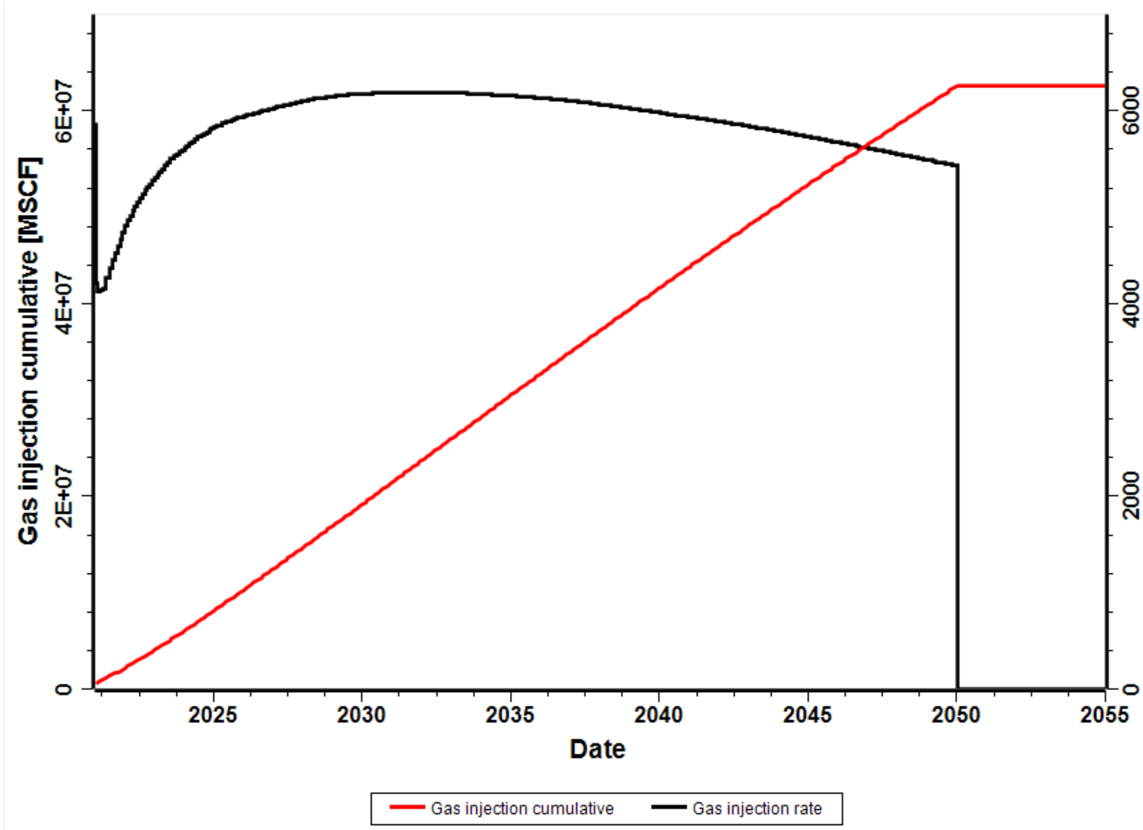


Figure 3.9-6 – Graph showing the forecast profile for the injection rate and cumulative injection volume over the simulated period

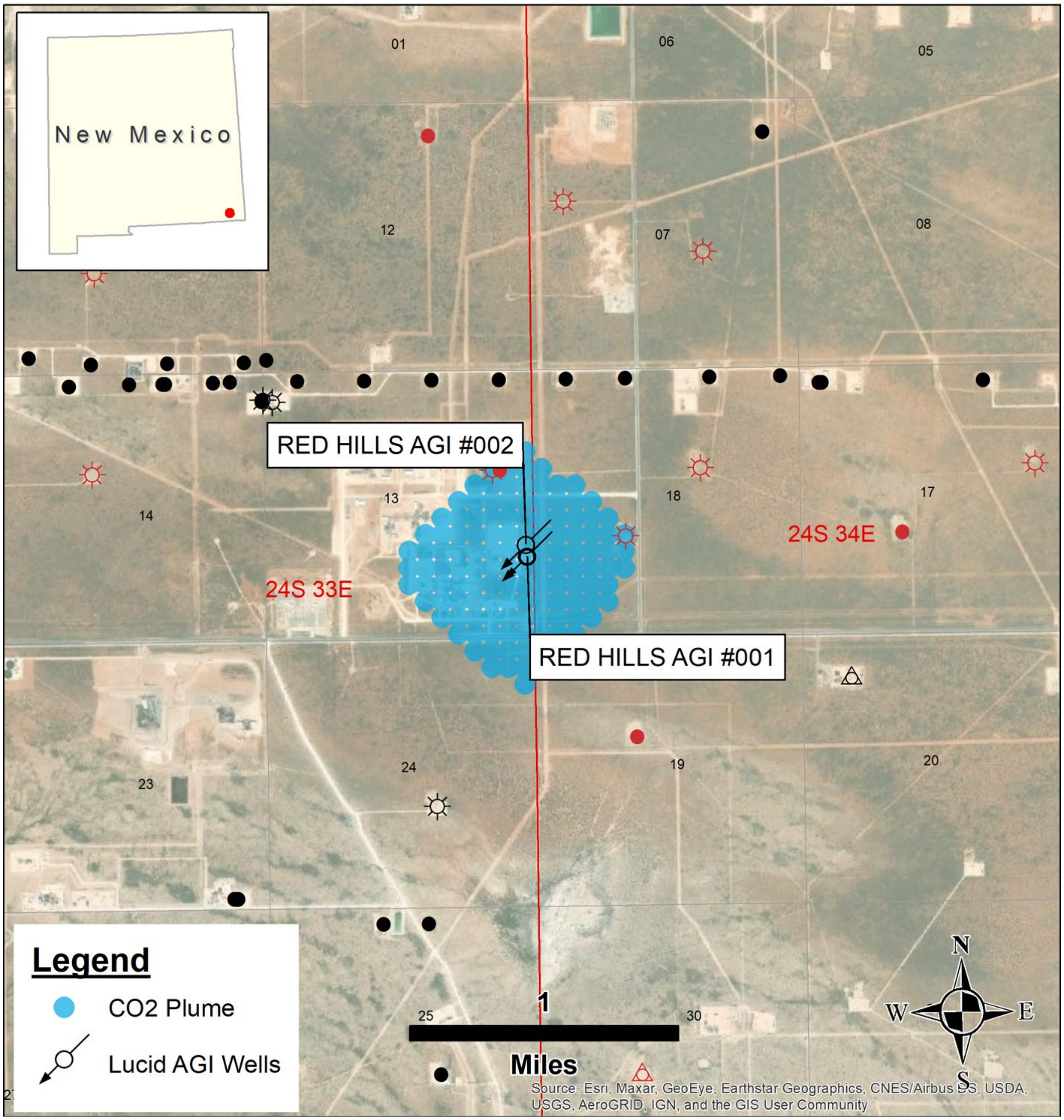


Figure 3.9-7 -- Map showing the largest lateral extent of the TAG plume within the Cherry Canyon

3.9.3 Siluro-Devonian- 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 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 grid cell dimensions 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.

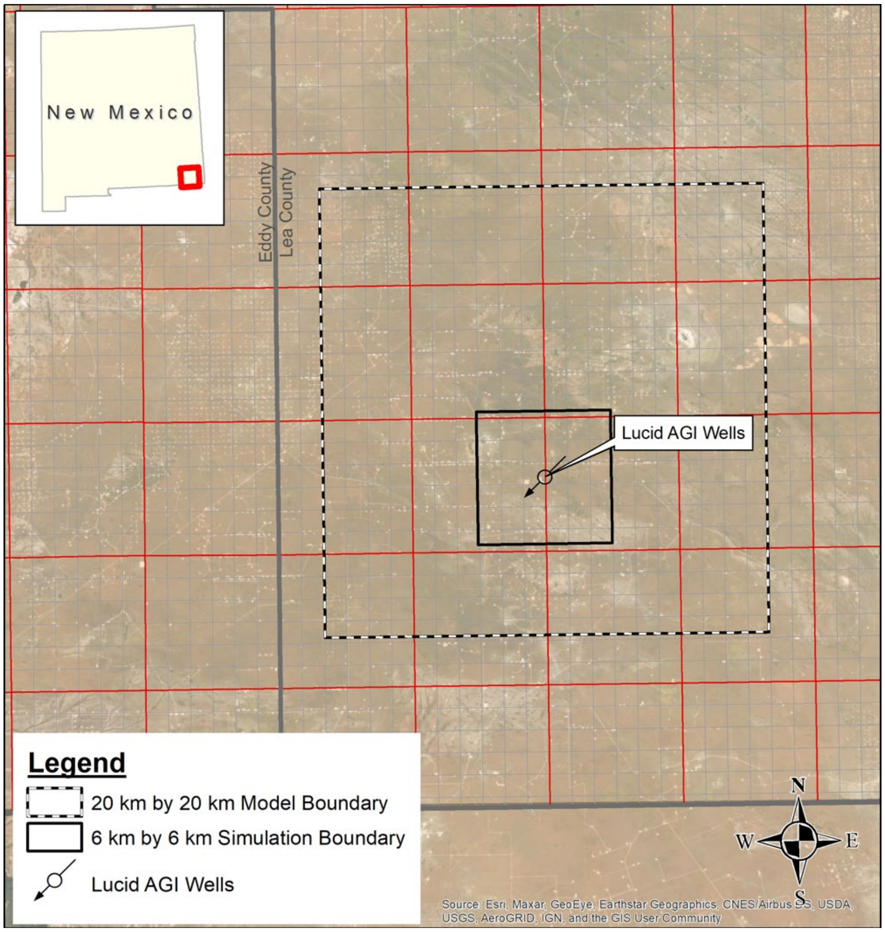


Figure 3.9-8 -- Map showing the top view of the geological and simulation model boundaries for the Siluro-Devonian injection zone.

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

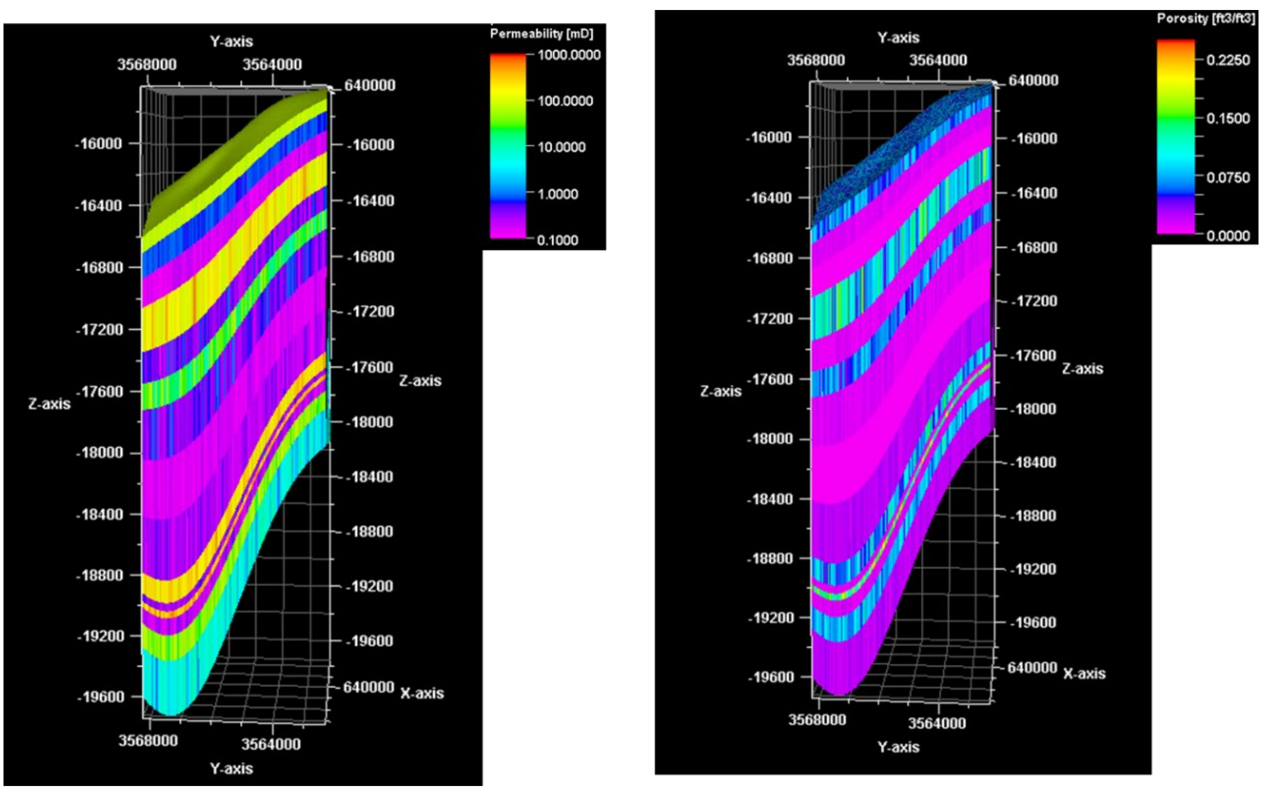


Figure 3.9-9 -- A 3D view of Siluro-Devonian modeled permeability (a) and porosity (b) distributions.

3.9.4 Simulation Modeling for proposed 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 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. Scenarios investigated impacts of a 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 is 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.

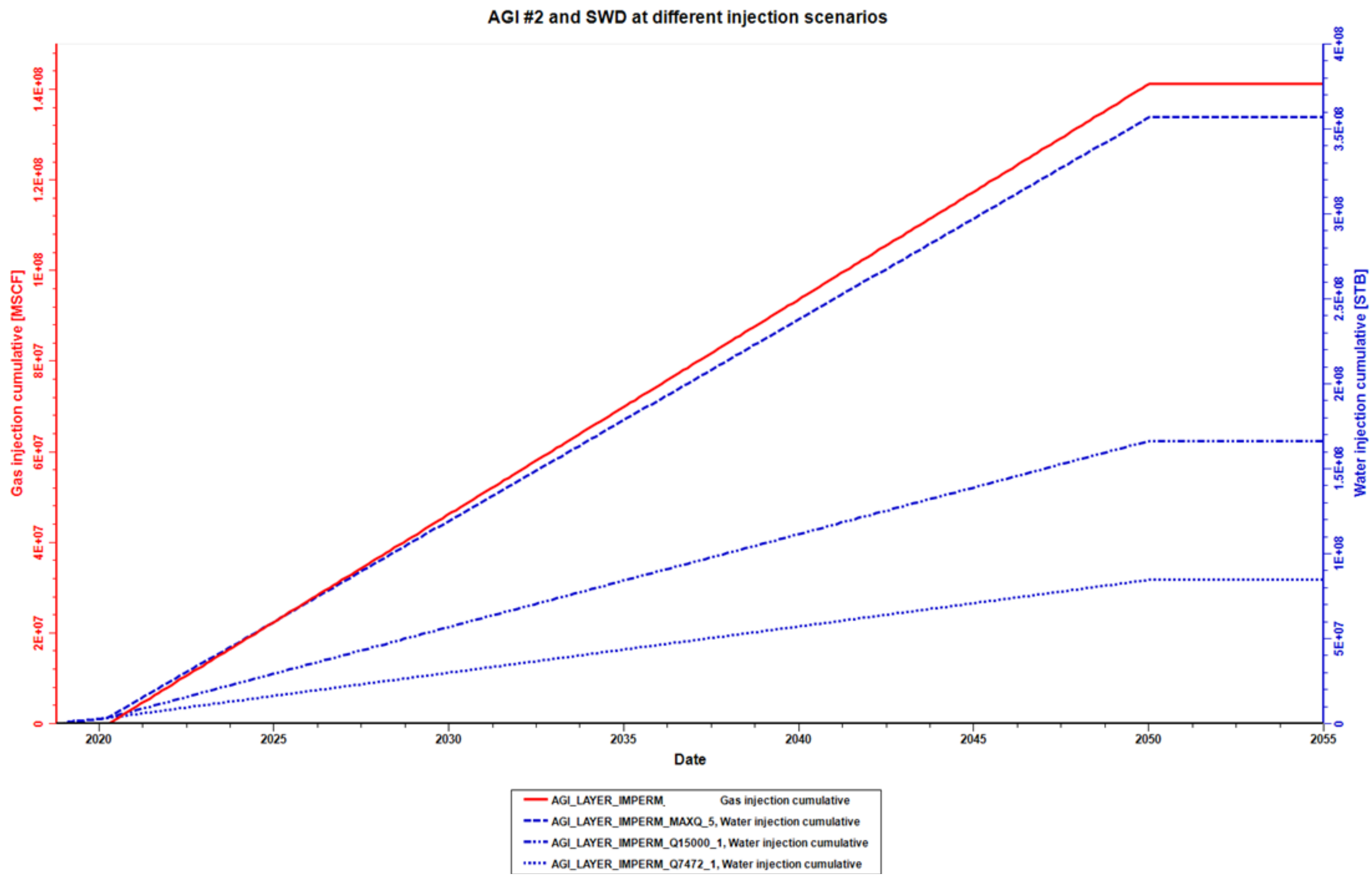


Figure 3.9-10 -- Graph showing the injection profile of the RH AGI #2 and the Striker well at different injection scenarios.

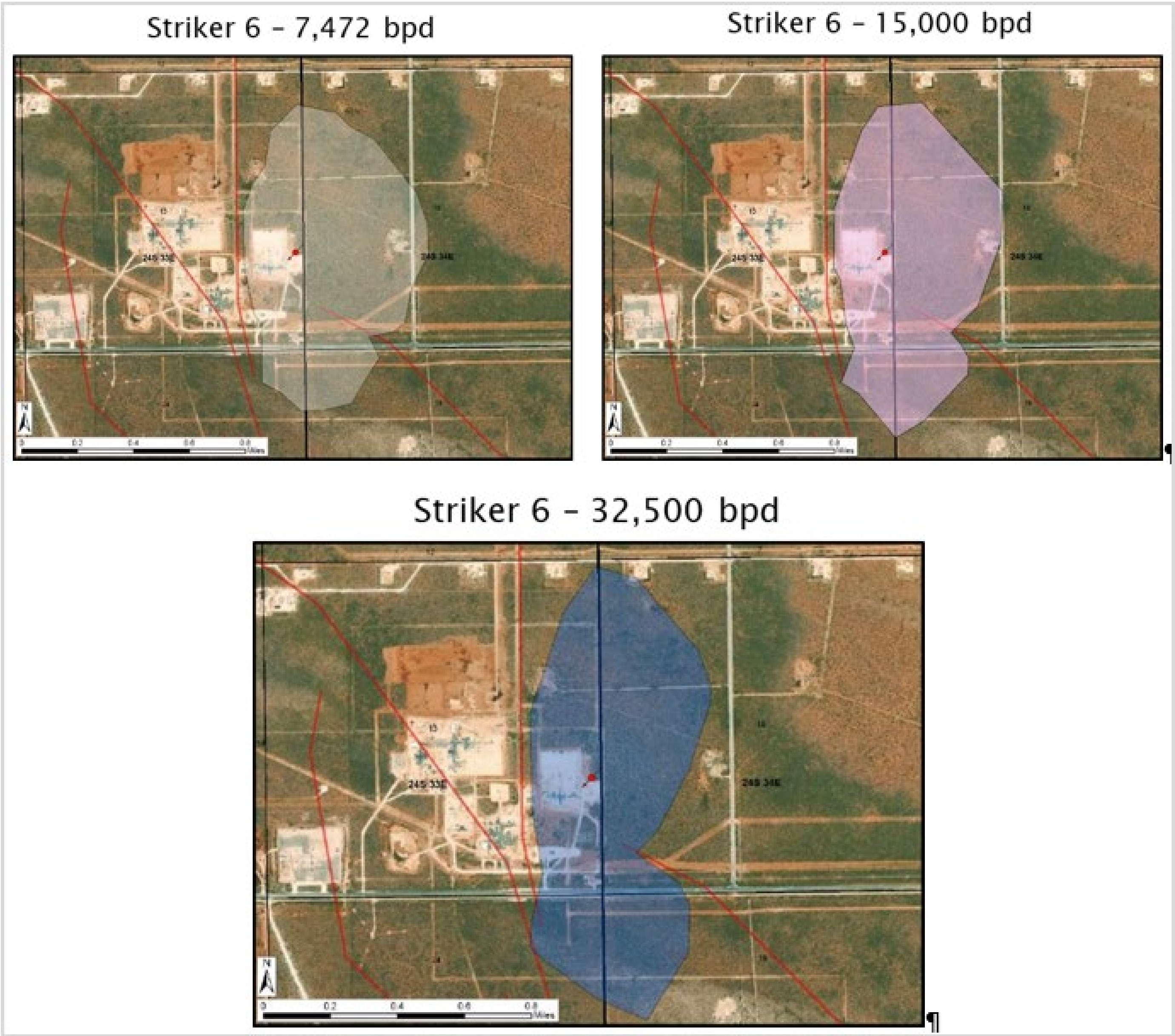


Figure 3.9-11 – Maps showing the largest lateral extent of the TAG when the interpreted faults are non-transmissive

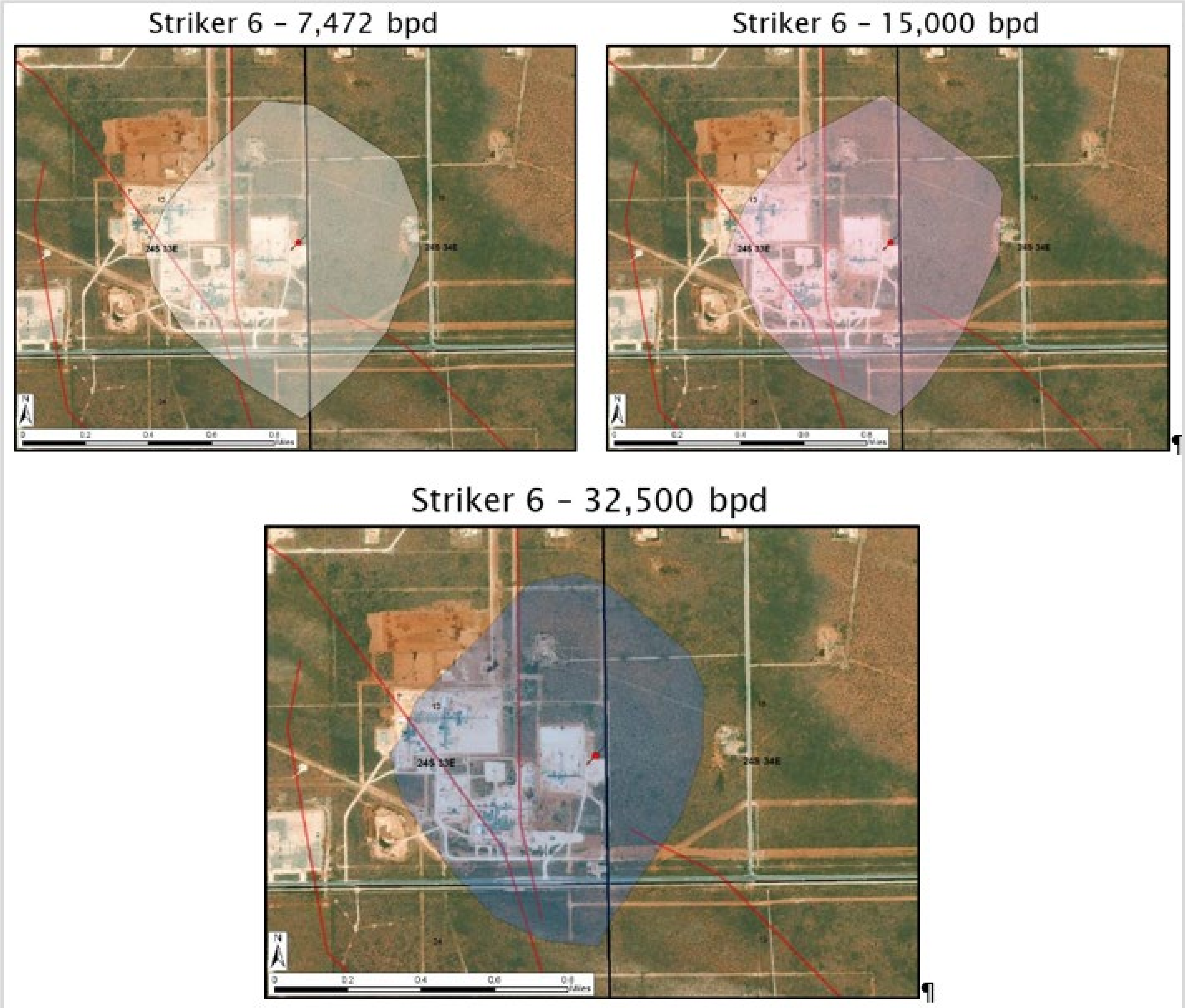


Figure 3.9-12 -- Maps showing the largest lateral extent of the TAG when the interpreted faults are transmissive

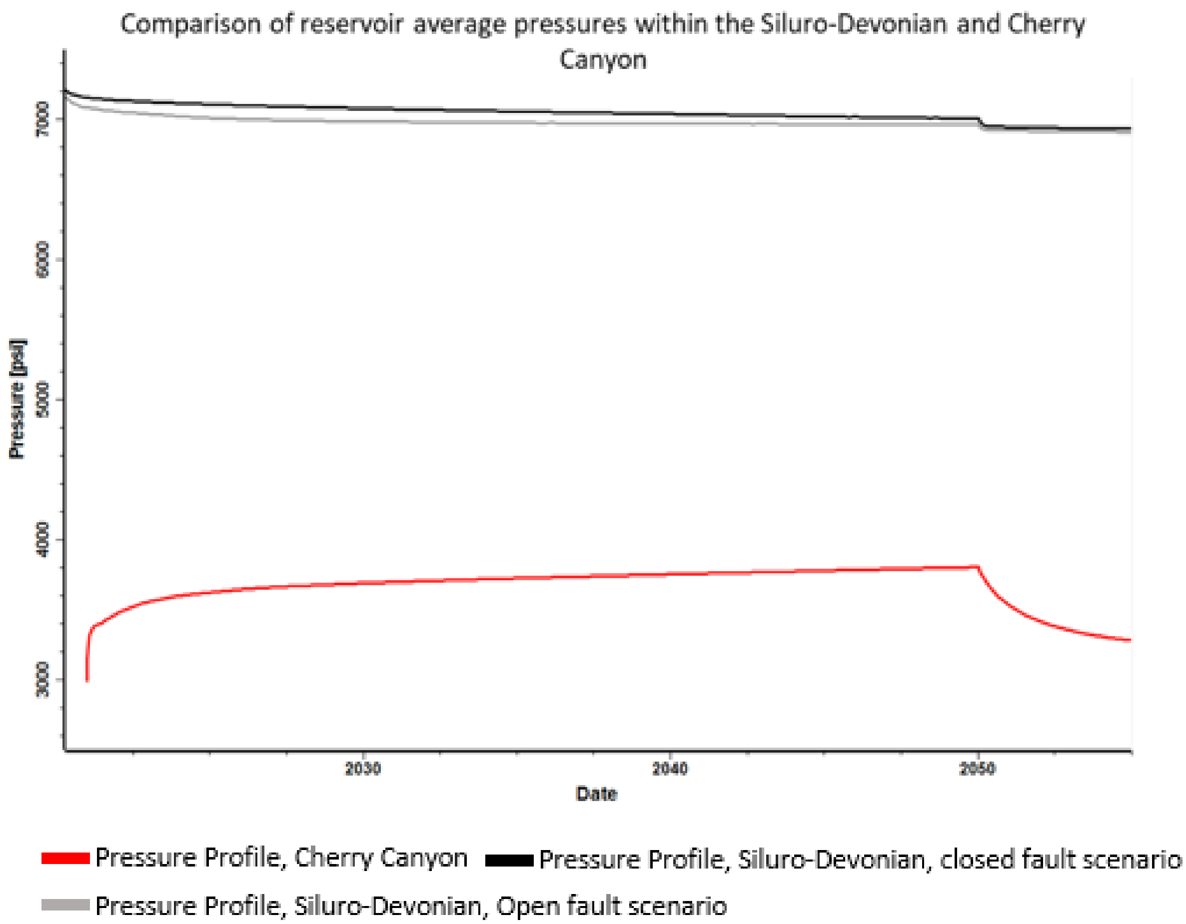


Figure 3.9-13 – Comparison of reservoir average pressure within the Siluro-Devonian and Cherry Canyon during injection and during the post-injection period

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.

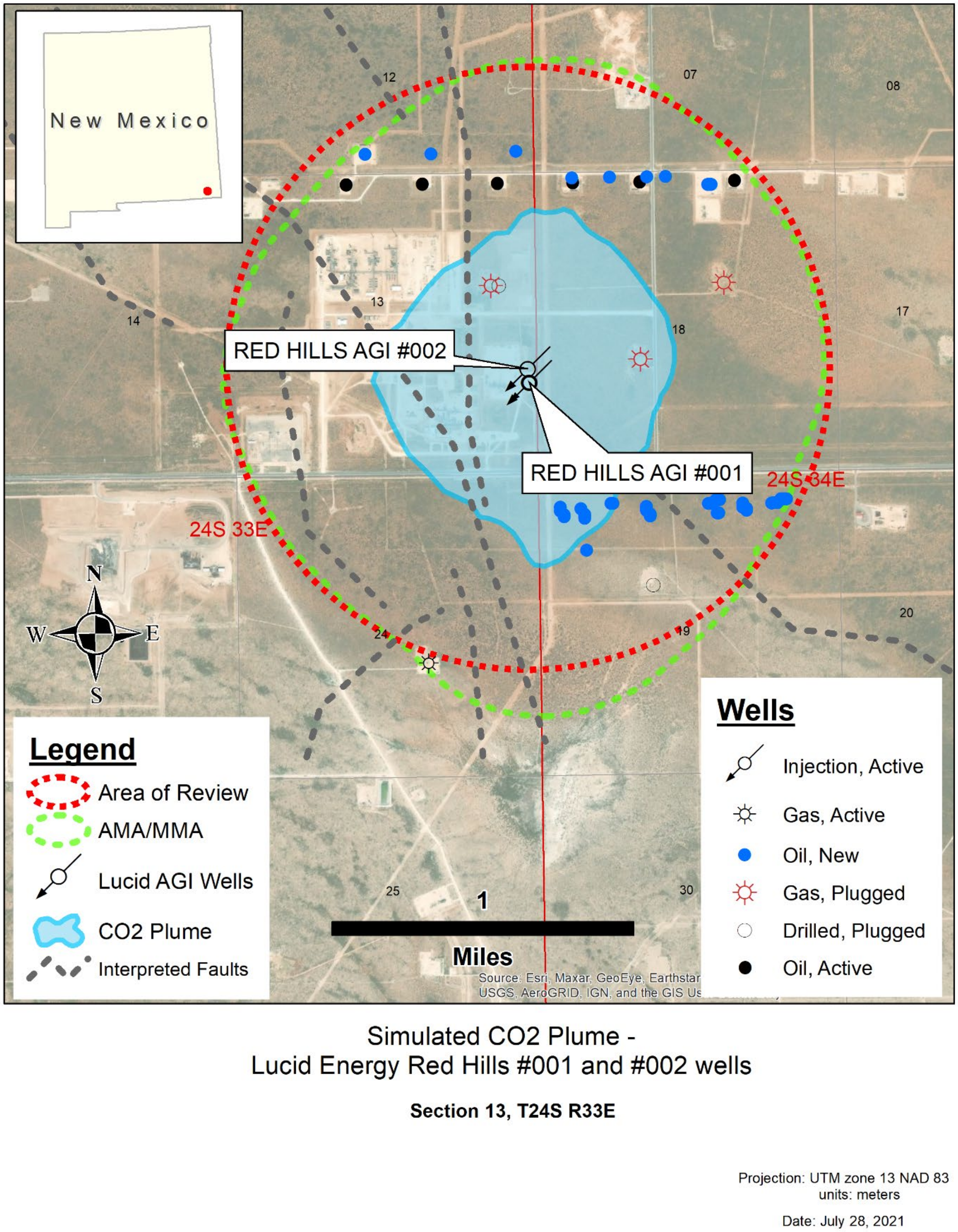


Figure 4.1-1 -- Maximum monitoring area (MMA) and active monitoring area (AMA) for Lucid Red Hill RH AGI #1 and RH AGI #2 Wells. The Class II Area of Review (AoR) is also shown.

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.

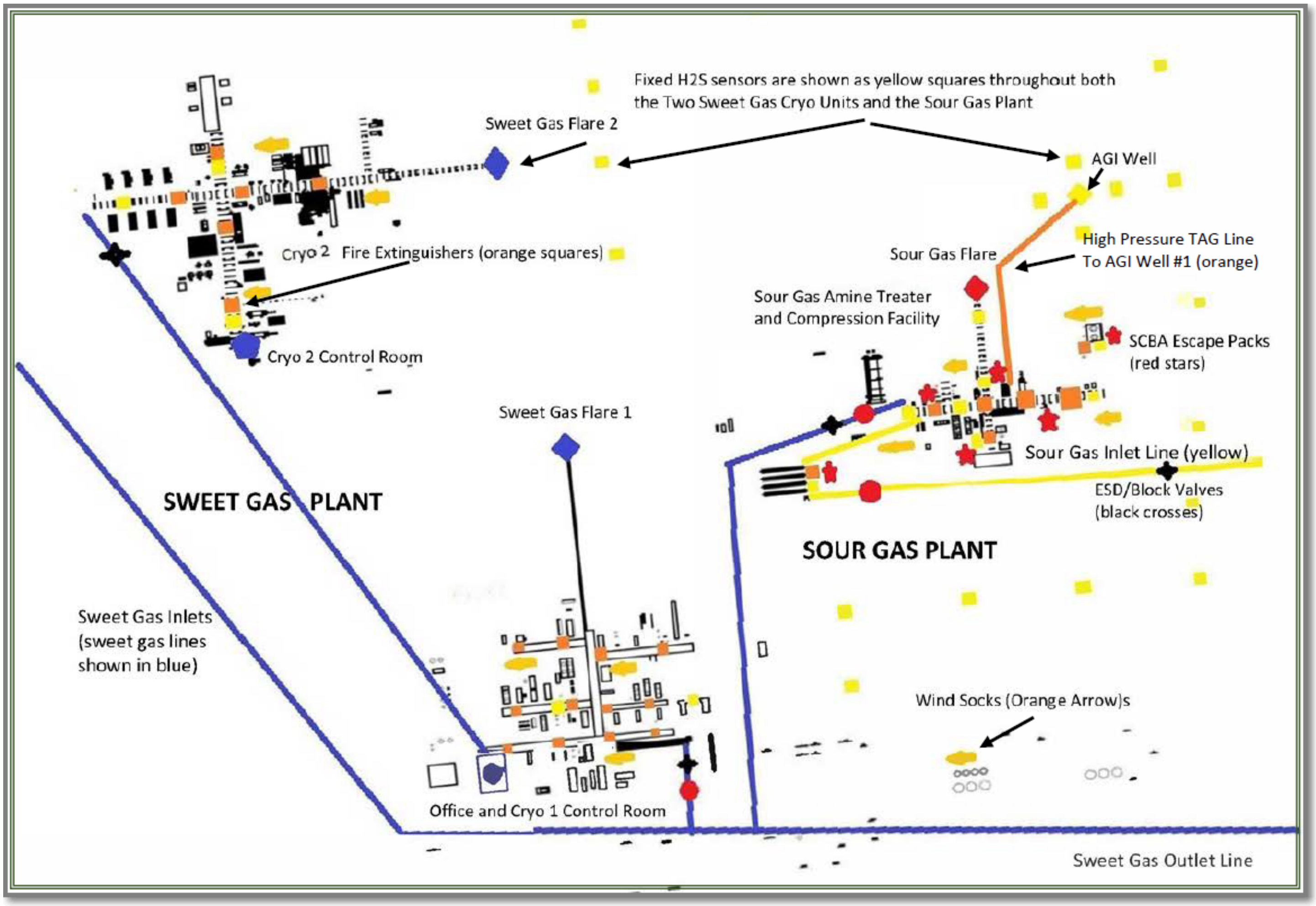


Figure 5.1-1 -- Red Hill Gas Plant plot plan showing location of major process units (taken from the H_2S Contingency Plan for Red Hills). The yellow squares indicate the location of fixed H_2S sensors.

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.

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 TD 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 zones.

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 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.

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.

Table 6.1 – Summary of Leak Detection Monitoring

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

Leakage Pathway	Detection Monitoring
	• 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.

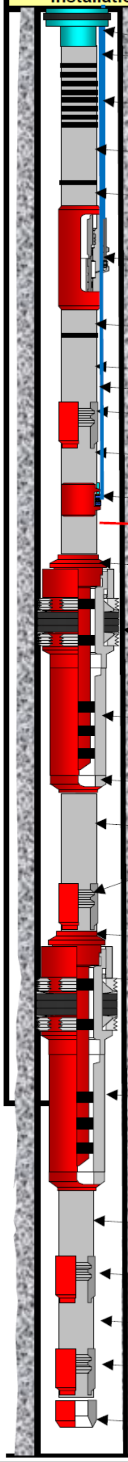
HALLIBURTON

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 7.2 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 CO2 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 CO2 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, RR-5, and RR-8 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 CO2 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 CO2 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 CO2 produced.

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

10.1.5 CO2 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 produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) 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.

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

(12) 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.

(14) 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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Boyle, T.B., Carroll, J.J., 2002. Study determines best methods for calculating acid-gas density. *Oil and Gas Journal* 100 (2): 45-53.

H_2S Contingency Plan, Lucid Energy, April 2018, Red Hills Gas Processing Plant, Lea County, NM

Lambert, S.J., 1992. Geochemistry of the Waste Isolation Pilot Plant (WIPP) site, southeastern New Mexico, U.S.A. *Applied Geochemistry* 7: 513-531.

Luo, Ming; Baker, Mark R.; and LeMone, David V.; 1994, *Distribution and Generation of the Overpressure System, Eastern Delaware Basin, Western Texas and Southern New Mexico*, AAPG Bulletin, V.78, No. 9 (September 1994) p. 1386-1405.

Nicholson, A., Jr., Clebsch, A., Jr., 1961. *Geology and ground-water conditions in southern Lea County, New Mexico.* New Mexico Bureau of Mines and Mineral Resources, Ground-Water Report 6, 123 pp., 2 Plates.

Powers, D.W., Lambert, S. J., Shafer, S., Hill, L. R. and Weart, W. D., 1978., *Geological Characteristic Report, Waste Isolation Pilot Plant (WIPP) Site, Southeastern New Mexico (SAND78-1596)*, Department 4510, Waste Management Technology, Sandia Laboratories, Albuquerque, New Mexico

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Ward, R.F., Kendall, C.G.St.C., Harris, P.M., 1986. Upper Permian (Guadalupian) facies and their association with hydrocarbons – Permian Basin, west Texas and New Mexico. *The American Association of Petroleum Geologists Bulletin* 70: 239-262

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

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 CO2 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 CO2 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 CO2 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 CO2 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

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

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

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

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

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

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

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

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

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

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 CO2 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 CO2 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-~~05070~~ 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

(Instructions on page 2)

GWW

Request for Additional Information: Lucid Red Hills MRV Plan
July 15, 2021

Instructions: Please enter responses into this table. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. Supplemental information may also be provided in a resubmitted MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	9 10.4	19 21	This section states, "Lucid expects to begin implementing the approved MRV plan on June 1, 2021. The RH AGI #2 will be drilled in late summer / early fall of 2021. At that time, Lucid will reevaluate the MRV and update it to reflect any necessary modifications." It appears that "plan" is missing after MRV. Please add.	"plan" was added after "MRV" in all instances.
2.	N/A	N/A	We recommend placing important figures and tables in the body of text to facilitate EPA review and improve the public understanding of the document when posted to EPA's website. For example, Table 6.1-1 should be reproduced in the main document as it contains key MRV plan information related to leak detection monitoring.	Figures and tables have been embedded in the narrative. One large table was included as an Appendix.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	N/A	N/A	Some of the figures have poor resolution and/or other legibility issues. We recommend using the original versions of the figures submitted in your Class II application, rather than copying and pasting the figures because the resolution degrades with each copy. We also recommend reviewing the figures to ensure that legend text is legible, that symbols are clear, and that key parts of the figure are not obstructed. Specifically, we recommend reviewing the following figures: Figure 3.2-3 Figure 3.2-4 Figure 3.2-5 Figure 3.3-1 Figure 3.3-2 Figure 3.3-3 Figure 3.3-4 Figure 3.3-5 Figure 3.3-6 Figure 3.7-1 Figure 3.8-1 Figure 3.9-7 Figure 3.9-8	All figures in the MRV plan were reviewed for resolution, clarity, and legibility. Figures found wanting in these qualities were re-created.
4.	N/A	N/A	It is unclear whether certain tables and graphics apply to AGI #1/Cherry Canyon storage target or apply to AGI #2/Siluro-Devonian storage target. We recommend reviewing the provided tables/graphics to ensure it is clear which wells they refer to.	Captions for such tables and figures were changed to explicitly state which RH AGI well or injection zone is being addressed.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	N/A	N/A	There are multiple units of measurement related to injection estimates used throughout the document. We recommend reviewing the document and ensuring consistency.	Barrels per day (Bbls/d) and stock tank barrels per day (Stb/d) are the units used when referring to liquid injection rates. Stock tank barrels are equal to barrels when referring to water. The use of 'stock tank barrels' is more standard as it reflects surface conditions. Million standard cubic feet per day (MMSCF/D) is the unit used when referring to gas injection rates. These 3 units will continue to be used throughout the MRV plan but their relationship, as described above, will be included at first use.
6.	1	5	"…under NMOCC Orders R-13507…" An explanation of the acronym "NMOCC" is not provided in the main text of the MRV plan. While the explanation is given in the appendix, we recommend fully writing the acronym out the first time it is used to aid in understanding of the MRV plan.	The entire document was edited to identify first use of all acronyms, abbreviations, and units. At first use, they were fully defined and added to Appendix 5 – Abbreviations and Acronyms.
7.	3.3.1	9	"The sands within the zone have the requisite high porosity and permeability and is bounded by tight limestones, shales, and calcic **siltstones rocks** in the Bell Canyon above and the lower Cherry Canyon and Brushy Canyon below." It appears there is a typo; please correct.	The paragraph including this sentence was deleted as it was deemed redundant.
8.	3.3.1	9	"Although 10% is used as a cutoff, 10% is considered to be too low for **oil classic production**, where a cutoff of 13-15% is often used." It appears there is a typo; please correct.	The sentence was deleted and replaced with the following: "Ten percent was the minimum cut-off considered for adequate porosity for injection.".
9.	3	6-10	The MRV plan contains a detailed summary of basin-level and regional geology, but much of this information is not directly relevant to the proposed injection zones or confining formations, which is only discussed at a high-level overview. We recommend providing discussion of geology related to what is relevant to the project, and ensuring that the injection zones and confining formations are adequately characterized.	Section 3 was edited to summarize those parts that discussed basin-level and regional geology and to call out those sections that discussed the confining/seal and injection zones for both RH AGI wells.

No.	MRV Plan		EPA Questions	Responses
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10.	3	10-11	Saltwater Disposal (SWD) is first used as an abbreviation on page 10, but there is no explanation of the acronym until page 11. Please include the full explanation of the acronym the first time it is used in the plan.	The entire document was edited to identify first use of all acronyms, abbreviations, and units. At first use, they were fully defined and added to Appendix 5 – Abbreviations and Acronyms.
11.	3.5	11	"To ensure a conservative fault-slip probability estimate, the proposed RH AGI #2 well was modeled utilizing the characteristics of a **SWD**" It appears there is a typo; please correct it. Specifically, SWD is defined as "saltwater disposal" in the sentence before this quote. We suggest changing the above to "SWD well" or an equivalent phrase.	Section 3.5 - RH AGI #2 – Assessment of Potential for Induced Seismicity in Siluro-Devonian has been re-written to present the more current fault slip potential assessment presented at the August 2020 NMOCC hearing for the RH AGI #2 well.
12.	3.7.2	11 12	The acronym "TVD" is used several times on pages 11 and 12 but is never defined in the main text of the MRV plan or in Appendix 5. Please provide a definition of this acronym.	The entire document was edited to identify first use of all acronyms, abbreviations, and units. At first use, they were fully defined and added to Appendix 5 – Abbreviations and Acronyms.
13.	3.7.2	12	"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)." It appears there is a typo; please correct.	The decimal point in "12.100" was replaced with a comma. "12,100"
14.	3.9	12	"There are two main target **formation** for the Red Hills injection project." It appears there is a typo; please correct.	The sentence was changed to: "…two main target formations…"
15.	3.9	12	"The AGI#1 well penetrates and completed in the Cherry Canyon formation." It appears there is a typo; please correct.	The sentence was changed to: "…and is completed in…"

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
16.	3.9.1	13	"A total of 33 well **logs** formation tops in addition to porosity logs were interpreted and mapped to construct the structural surfaces for the Cherry Canyon injection formation." It appears there is a typo; please correct. We suggest changing the wording to "well logs' formation tops".	The sentence was changed to: "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
17.	3.9.1	13	"The model boundary was focused on **13.5 km X 12.8 km with a grid cells** of 141 X 132 X 7 totaling 130,284 cells." It appears there is a typo; please correct.	The sentence was changed to: "The geologic model boundary focused on a 13.5 km X 12.8 km area with grid cell dimensions of 141 X 132 X 7 equaling a total of 130,284 cells."
18.	3.9.2	13	"Once the geological model was established, **a numerical modeling** was performed to:" It appears there is a typo; please correct.	The sentence was changed to: "…was established, numerical modeling was…"
19.	3.9.3	14	"A simulation model focused on a **6km by 6 km** centered on the proposed AGI#2 injection well." It appears there is a typo; please correct.	The sentence was changed to: "The simulation model focused on a 6 km by 6 km area centered on…"
20.	3.9.3	14	"The simulation model **has a grid cells** of 119 x 119 x 15 with a total cell of 212,415." It appears there is a typo; please correct.	The sentence was changed to: "The simulation model has grid cell dimensions of 119 x 119 x 15 equaling a total of 212,415 cells."
21.	3.9.4	14	"Once the geological model was established, **a numerical modeling** was performed to:" It appears there is a typo; please correct.	The sentence was changed to: "Once the geological model was established, numerical modeling…"
22.	3.9.4	14	"perform calibration of injection history for the SWD wells to ascertain the **current conditions subsurface** prior to injection of TAG into AGI#2;" It appears there is a typo; please correct.	The sentence was changed to: "…for the SWD wells to ascertain the current subsurface conditions prior to…"

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
23.	3.9.4	14	"The reservoir is initially saturated with 100 % of brine and **exhibit** hydrostatic equilibrium." It appears there is a typo; please correct.	The sentence was changed to: "…100% brine and exhibits hydrostatic…"
24.	3.9.4	14	"An irreducible water saturation of 0.17 is used to generate the relative permeability curves **for gas/water system**." It appears there is a typo; please correct.	The sentence was changed to: "…relative permeability curves for the gas/water system."
25.	3.9.4	14	"The Striker 6 SWD well after the calibration period, several scenarios were performed to ascertain their impact on the AGI#2 well if operated at maximum injection target of 32,500 Stb/d, medium volume of injection rate at 15,000 Stb/d and lastly a minimum injection volume at 7472 Stb/d." It appears there are typos; please correct.	This sentence was changed to: "After the calibration period, several scenarios were performed for the Striker well to ascertain potential impacts on the RH AGI#2 well. Scenarios investigated impacts if the Striker well is operated at 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 lastly a minimum injection volume at 7,472 Stb/d."
26.	3.9.4	14	"The bottomhole injection pressure gradient based on the potential fracture pressure was **constraint** at 0.629 psi/ft." It appears there is a typo; please correct.	The sentence was changed to: "The bottomhole injection pressure gradient based on the potential fracture pressure was constrained to 0.629 psi/foot."
27.	3.9.4	14	"In all the scenarios performed, the **Siluro-Devonian formation was able to successfully inject** the set injection target of 13 MMScf/d for over 30-years and the TAG distribution remained the same even after 5-years of monitoring." It appears there is a typo; please correct. Specifically, the Siluro-Devonian formation is not doing the injection.	The sentence was changed to: "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."
28.	3.9.4	14	"The figures show clearly that the Devonian is able to store all the volumes injected both into both wells." It appears there is a typo; please correct.	The sentence was changed to: "The figure shows clearly that the Devonian is has the capacity to store all volumes injected into both wells for all scenarios."

No.	MRV Plan		EPA Questions	Responses
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29.	3.9.4	14	"Figure 3.9-11 shows the corresponding TAG results from the furthest lateral **extend** of the gas saturation stacking all the layers when faults are closed to fluid flow" It appears there is a typo; please correct.	The sentence was changed to: "Figure 3.9-11 shows the corresponding TAG results from the furthest lateral extent of the gas saturation, stacking all the layers, when faults are closed to fluid flow."
30.	3.9.4	15	"Resultant TAG extent is highly dependent on operating conditions of nearby Striker 6 SWD #2, which exhibits the greatest potential to influence pressure conditions within the target reservoir. The modeling responses showed that even at the maximum injection strategy for the SWD well, the AGI#2 is well situated to inject the target of 13 MMScf/d with or without faults safely without causing any hazard." Please provide further explanation as to how the injection of fluids via Striker 6 SWD#2 will influence the pressure conditions within the target reservoir of AGI#2.	Further explanation was added.
31.	4	15	Subpart RR at 40 CFR 98.449 defines the maximum monitoring area (MMA) as "equal to or greater than the area expected to contain the free phase CO2 plume until the CO2 plume has stabilized plus an all-around buffer zone of at least one-half mile." Note that MMA definition is not identical to that of the area of review for a Class II permit. In the MRV plan, the MMA appears to be based on the area of review (AOR) in the Class II well application and is not a result of the plume modeling. Please ensure that the MMA reflects the area expected to contain the free phase CO2 plume and required buffer, and/or provide further explanation as to how the MMA was determined.	Section 4 was re-written including an explanation of the correlation between the Class II AoR and the MMA which was delineated by superimposing the maximum modeled extent of the CO_2 plumes in the Cherry Canyon Formation and the Siluro-Devonian and adding a ½ mile buffer.
32.	4	15	It is not obvious, though quite possible, that the CO2 plume will stay within the Class II AOR, but this inference must be explicitly made in the MRV plan.	Section 4 was re-written including an explanation of the correlation between the Class II AoR and the delineation of the MMA for the MRV plan. Figure 4.1-1 shows the CO_2 plume will stay within the Class II AoR.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
33.	4	15	Figure 3.9-7 displays the largest lateral extent of the treated acid gas (TAG) within the Cherry Canyon Formation, but there is no explanation as to how this CO2 plume model was constructed. Please provide further detail on the modeling software used, the modeling approach, key assumptions made, etc.	A paragraph was added under the main Section 3.9 heading describing the modeling software used and the CO_2 trapping mechanisms modeled. The specific modeling details for each injection zone are presented in Sections 3.9.1 – 3.9.4.
34.	4	15	Please provide a figure that shows the MMA/AMA with the modelled CO2 plumes, faults, etc. to provide a better explanation as to the characterization of the MMA in the project area.	Figure 4.1-1 has been revised to show the superposition of the modeled 30-year TAG plume in the Cherry Canyon and in the Siluro-Devonian assuming transmissive and non-transmissive character of interpreted faults and injection rates into a nearby SWD well of 7,472 and 15,000 barrels per day.
35.	4	15-16	It is not clear what is meant to be communicated in the later CO2 plume models, seen in Figures 3.9-11 and 3.9-12. Please provide further detail.	Further explanation was provided in Section 3.9.4.
36.	5	N/A	Subpart RR at 40 CFR 448(a)(2) requires the "Identification of potential surface leakage pathways for CO2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO2 through these pathways." Section 3.2.3 makes reference to "major tectonic activity" that occurred "only as high up as the base of the lower Woodford Shale"; it appears that the proposed injection zone for the AGI #2 well coincides with the referenced area where seismic data shows major faulting. Please address whether natural seismic activity is a potential leakage pathway and, if so, characterize the likelihood, magnitude, and timing of leakage due to natural seismic activity.	Section 5 was re-written to include a subsection – Potential Leakage due to Natural / Induced Seismicity – to explain the likelihood, magnitude, and timing of leakage due to natural / induced seismicity. This re-written section references the revised Section 3.5 (see response to item 11 above).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
37.	5	16	Subpart RR at 40 CFR 448(a)(2) requires the "Identification of potential surface leakage pathways for CO_2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways." Given the apparent potential for drilling to occur near the injection area (see "New" wells in table 3.7-1), please address whether drilling through the CO_2 injection area is a potential leakage pathway and, if so, characterize the likelihood, magnitude, and timing of surface leakage.	Section 5.2 – Potential Leakage from New Wells - was added to address the likelihood, magnitude, and timing of surface leakage due to drilling of the proposed RH AGI #2 well or any other new wells within the MMA.
38.	5.2	16	Please elaborate in the MRV plan on the evaluation of the wells in their potential for acting as conduits for vertical migration out of the injection zones. What factors led to the conclusion that all wells within the 2-mile radius area of the RH #1 and #2 AGI do not pose a potential for vertical leakage of CO_2 to the surface?	The newly numbered section 5.3 – Potential Leakage from Existing Wells - was expanded to explain likelihood, magnitude, and timing of leakage through existing wells within the MMA.
39.	5.3	16	"Modeling presented in Section 3.9 indicates that the extent of the TAG after 30 years of injection does not reach the faults discussed." The sentence above appears to contradict Figures 3.9-11 and 3.9-12 where the TAG plume appears to intersect the mapped faults. Please provide further explanation and clarification as to this apparent contradiction.	The MRV plan was edited to update Section 3.2.3 – Faulting – to include a discussion on the claims of additional faults made by nearby operators.
40.	5.5	16	Please provide more information on the potential for inducing seismicity within the two injection zones. There is evidence of induced seismicity in nearby areas from deep disposal wells from multiple earthquake trackers. The figures and their descriptions in the MRV plan are not clear in explaining this potential leakage pathway (see Figure 3.5.2).	Section 5.5 references Section 3.5 which describes the updated assessment of the potential for induced seismicity.
41.	5.6	16	How do the geological characteristics of the injection zones impact the potential for lateral migration of CO_2 out of the intended areas?	Section 5.7 discusses the influence of geologic characteristics of each of injection zone on lateral migration of the injected TAG plume.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
42.	5,6,7	15-18, 31	Subpart RR at 40 CFR 448(a)(2) requires the "Identification of potential surface leakage pathways for CO2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO2 through these pathways", and at 40 CFR 448(a)(3) requires "A strategy for detecting and quantifying any surface leakage of CO2." Strategies for detecting and quantifying leakage of CO2 should be included for each potential leakage pathway even if the likelihood is determined to be low. Sections 5, 6, and 7 should be revised/expanded to ensure all leakage pathways are adequately addressed. For example, Table 6.1-1 should describe leakage monitoring plans/programs for all identified potential pathways that have a likelihood of potential surface leakage. Furthermore, we recommend expanding the discussion for the existing leakage pathways to ensure there is adequate evidence supporting the characterizations regarding likelihood, magnitude and timing of leakage.	Sections 5 was revised to address potential pathways discussed in previous sections of the MRV plan including the likelihood, magnitude, and timing of surface leakage from each of the identified pathways. Section 6 was revised to detail the strategy for the detection and quantification of surface leakage of CO_2 from each of the potential pathways identified in Section 5 including descriptions of equipment in place or to be put in place to monitor for surface leakage of CO_2. Section 7 was revised to provide additional detail on monitoring equipment.
43.	7.3	18	"In addition to the handheld gas detection monitors described above, New Mexico Tech, through a DOE research grant, will monitor for CO2 leakage in the AMA as defined in Section 4.2." Details of this grant, such as the applicable term of the grant and how it relates to the timescale of the project, and other information about the grant that is relevant to the MRV plan are not described in Section 4.2, nor elsewhere in the MRV plan. Please elaborate.	Section 7.3 was revised to include the portions of the scope of work for the DOE project that are relevant to the establishment of the CO_2 monitoring network around the two RH AGI wells.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
44.	10.1.5	20 21	10.1.5, paragraph 1: Reference in paragraph 1 of the section is made to measuring emissions and leaks **from equipment between the flow meter used to measure production quantity and the production wellhead**. 10.1.5, paragraph 2: Paragraph 2 of the section states, "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, including recycle CO2 stream, **for facilities that conduct EOR operations**. The default emission factors for **production equipment** are applied to CCUS injection operations reporting under Subpart RR. The site is previously described in the MRV plan as injection only, and this is confirmed in Sections 8.3 and 8.5 where the MRV plan notes that "Lucid does not produce oil or gas or any other liquid at its Red Hills Gas Plant so there is no CO2 produced or recycled" and that it will use Equation RR-12 to calculate the quantity of CO2 sequestered. This is further noted in subsection 10.1.4. However, references in subsection 10.1.5 of Section 10, GHG Monitoring and Quality Assurance Program, note CO2 production. Please clarify whether there is any CO2 production at the site, and if applicable, remove references to CO2 production.	References to EOR operations and production equipment were added in error and have been deleted. Paragraphs under Section 10.1.5 have been changed to: "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."
45.	10.3	21	The text, which applies to missing data procedures, references the **quarterly quantity of CO2 produced** from subsurface geologic formations that is missing would be estimated using a representative quantity of CO2 produced from the nearest previous period of time. As was requested in a previous item, please clarify whether there is any production of CO2 at the site. If this sentence was intended to refer to surface leakage, please revise it.	The fifth bullet under Section 10.3 was added in error. It has been deleted.

No.	MRV Plan		EPA Questions	Responses
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46.	10.3	21	"When estimating the amount of CO2 (due to an interruption in data collection, mechanical failure of a meter, mechanical failure of other equipment, or otherwise), the amount of CO2 is to be estimated by using the most recent periodic (i.e. daily) volume of CO2 associated with the meter or equipment and calculating the proportionate volume of "missing" CO2 based on the number of hours involved in the data gap or until meter/equipment repair." It is unclear what this is intended to address since the first five bullets address missing data procedures for reported data for quarterly CO2 flow rates and concentration for CO2 received, equipment leaks and presumably surface leaks, and CO2 injected. Please clarify.	This bullet was meant to address the loss of CO_2 measurement data due to a failure in data collection, of mechanical failure of a meter or other equipment, or otherwise. However, upon reconsideration Lucid recognizes that this final bullet point is redundant as the phrase "or using a representative value from the nearest previous time period" in the previous bullets also applies to that situation. Therefore, the final bullet point was deleted.
47.	10.4	21	Lucid will revise the MRV Plan as needed to reflect changes in **production processes**, 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. Following on previous comments, the MRV plan describes the site as injection-only with no CO2 production. Please clarify and/or remove the reference to production.	"Production processes" was added in error. The first sentence of Section 10.4 was changed to: "Lucid will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures...."
48.	11	22	"(13) Annual records of information used to calculate the CO2 emitted from equipment leaks and vented emissions of CO2from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity." Following on previous comments, the MRV plan describes the site as injection-only with no CO2 production. Please clarify and/or remove the reference to production.	Item 13 on page 22 of the MRV plan was added in error. It has been deleted.

No.	MRV Plan		EPA Questions	Responses
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49.	12	24	Table 3.4-1 displays seven SWD wells injecting into the Delaware Mountain Group within 10 miles of AGI #1. However, upon review of state data we have found approximately 98 injection and disposal wells within 10 miles, and 45 of these wells are potentially injecting into the Delaware Mountain Group. Furthermore, Table 3.7-2 displays 13 wells, but our review indicates there are over 100 wells within the 1-mile radius of AGI #1. Please provide further explanation of this apparent inconsistency, and/or update the MRV plan as necessary.	Lucid conducted a new search of the New Mexico databases to develop a list of all oil and gas-related wells within a 2-mile radius and a 1-mile radius around the RH AGI wells. Section 3.7 – Historical Operations and the tables supporting this section were revised to focus on the more immediate area around the RH AGI wells. Furthermore, relevant to well numbers, many wells that are listed in NM OCD databases are locations with approved permits that have not yet (and may never be) been drilled. Others have cancelled permits.
50.	13	64	"Figure 3.9-13 - shows pressure profile for both Cherry Canyon and Siluro-Devonian formation during injection and monitoring periods." Please provide further detail and explanation for the referenced figure, including a more legible legend and updated description.	This figure was revised for clarity and with more explanation in the narrative that discusses it.

MONITORING, REPORTING, AND VERIFICATION PLAN

Red Hills AGI #1 and AGI #2

Lucid Energy Delaware, LLC (Lucid)

Version 1.0
June, 2021

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1 Introduction

Lucid Energy Delaware, LLC (Lucid) is currently authorized to inject a total of up to 13 million standard cubic feet per day (MMSCFD) of treated acid gas (TAG) in the currently-approved Red Hills (RH) AGI #1 (API 30-025-40448) under 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).

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 by 200' north of RH AGI #1 and completed approximately 9,350' deeper than RH AGI #1. The newly authorized RH AGI #2 is authorized to inject to dispose of TAG at a maximum daily injection rate of 13 MMSCFD into the Devonian and Upper Silurian Wristen and Fusselman formations at depths of approximately 16,000 to 17,600 feet and a maximum surface injection pressure of 2,085 psig. Authorization of the second well, RH AGI #2, provides increased capacity for the Red Hills 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 fourteen 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.

Section7 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 all the tables referenced in the narrative of the MRV Plan numbered according to the subsection in which they first appeared.

Section 13 includes all the figures referenced in the narrative of the MRV Plan numbered according to the subsection in which they first appeared.

Section 14 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 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 wells within a one-mile radius 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.

2.3 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.

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. Both applications were submitted to the New Mexico Oil Conservation Division 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 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. The Permian Basin lies within the area of the larger, ancestral (pre- Mississippian) Tabosa Basin, which covered an area that included the entire present-day Permian Basin area and beyond. The Tabosa Basin was a shallow sub-tropical basin throughout the period between the Ordovician and early Mississippian (Osagean). The Permian Basin as we know it today began to take form during the Middle to Late Mississippian, with various segments (Delaware and Midland Basins, Central Basin Platform, North Platforms) arising from the ancestral Tabosa Basin. The Delaware Basin was subsequently deepened by periodic deformation during the Hercynian orogeny of the Pennsylvanian through Early Permian. Following the orogeny, the Delaware Basin was structurally stable and gradually was filled by large quantities of clastic sediments while carbonates were deposited on the surrounding shelves and was further deepened by basin subsidence.

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.

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 ~1000' 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 and gas production is dispersed through the deeper Bone Springs (the "Avalon") and Wolfcamp Formation. The rock units of the Permian series are discussed in more detail below.

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 supra and intertidal flats.

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.

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

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 primarily to the west of the Red Hills area.

Pennsylvanian. The Pennsylvanian is comprised of the Strawn, Atoka, Morrow, and a starved section of 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.

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. Adjacent wells have shown that these formations are "wet," and there is no current or foreseeable production at these depths within the one-mile radius (Figure 3.2-3) area of review. In fact, these zones are routinely approved as produced-water disposal zones in this area.

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 comprised of dolomites and limestones and is upward of 1000' 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.

3.2.3 Faulting

In this immediate area of the Permian Basin, major tectonic activity was 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). Faulting higher in the section that is related to the Ouachita orogeny is more prevalent closer to the Central Basin Platform margins and the southern margin of the Northwest Shelf. Modeling presented in Section 3.9 indicates that faults do not pose a risk of surface leakage from the injected CO_2.

3.3 Lithologic and Reservoir Characteristics

3.3.1 Permian Cherry Canyon Formation

Based on the geologic analyses of the subsurface at the proposed Red Hills Gas Plant, the uppermost Cherry Canyon Formation was chosen for acid gas injection and $C0_2$ 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 Bell Canyon Formation (Figure 3.3-1). 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 $C0_2$ 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. Using the formation tops from more than 70 wells, a contour map was constructed for the top of the Cherry Canyon Formation (Figure 3.3-2) in the vicinity of the well. This map reveals an approximate 1.0° dip to the south, with no visible faulting or offsets that might influence fluid migration, suggesting that injected fluid would spread radially from the point of injection with a small elliptical component to the south. This interpretation is supported by cross-sections of the overlying stratigraphy that reveal relatively horizontal contacts between the units (Figures 3.3-3 and 3.3-4). 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. As a result, the preferred orientation for fluid and gas flow would be south-to-north along the channel axis.

A geological analysis confirmed that the upper Cherry Canyon Formation was the most promising injection zone in the vicinity of the RH AGI #1 well. This preliminary analysis was confirmed by Geolex's detailed geological analysis, including the analysis of the geophysical logs collected from nearby wells. The sands within the zone have the requisite high porosity and permeability and is bounded by tight limestones, shales, and calcic siltstones rocks in the Bell Canyon above and the lower Cherry Canyon and Brushy Canyon below. These are ideal H_2S and $C0_2$ sequestration conditions.

The porosity of the units in the area were evaluated using geophysical logs collected from nearby wells penetrating the Cherry Canyon Formation. Figure 3.3-5 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. Although 10% is used as a cutoff, 10% is considered to be too low for oil classic production, where a cutoff of 13-15% is often used. The sand units are separated by mapable 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 3.3-6) with an irreducible water (Swir) 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 Swir may be too high. The effective porosity (Total Porosity – Clay Bound Water) would therefore also be higher. As a result, the 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.

3.3.2 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. Based on the geologic analyses of the subsurface at the Lucid Gas Plant, acid gas injection and CO_2 sequestration in the Siluro-Devonian Formations was recommended. The proposed injection interval includes a number of intervals of dolomites 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 3.3-7). It lies a minimum of 1,200 feet above the Precambrian basement.

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 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). This is well away from the simulated 30-year extent of the injected CO_2 (see Section 3.9).

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 injection zone in the area (see Figures 3.2-2 and 3.3-7).

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.

3.4 Formation Fluid Chemistry

3.4.1 Cherry Canyon Formation

There are four SWD wells injecting into the Cherry Canyon Formation within a 10-mile radius of the RH AGI #1, the injection zone (Table 3.4-1). The closest of these wells is located approximately 2.0 miles from the RH AGI #1. A chemical analysis (Table 3.4-2) 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.

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 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 Potential for Induced Seismicity in the Area

To evaluate the potential for seismic events in response to injected fluids, Geolex conducted an induced-seismicity risk assessment in the area of the proposed RH AGI #2. This assessment models the impact of eight waste disposal wells over a 30-year period and estimates the fault-slip probability associated with the anticipated injection scenario. The analysis was completed utilizing the Stanford Center for Induced and Triggered Seismicity's (SCITS) Fault Slip Potential (FSP) modeling package.

In review of the proposed RH AGI #2 location, Geolex identified three faults within the Siluro-Devonian injection interval that may have the potential for induced-seismic activity (Figure 3.5-1). For inclusion in the FSP model, these features (Faults 1, 2, and 3) were separated into ten fault segments (Faults 1-5, 6-7, and 8-10, respectively), which allows the model to assess non-linear features. To calculate the fault-slip probability for this injection scenario, input parameters characterizing the local stress field, reservoir characteristics, sub-surface features, and injected fluids are required. Parameters utilized and their sources for this study are included in Table 3.5-1. Additionally, Table 3.5-2 details the injection volume characteristics and locations of the disposal wells modeled in this scenario.

Two proposed SWD wells in the area that Lucid originally objected to are the Permian Oilfield Partners Deep Thirst and the NGL Water Solutions Trident well. Even though these wells are not currently approved, NGL and Permian Oilfield Partners agreed with Lucid that if the injection rates at these locations would be limited to 20,000 BPD, Lucid would remove their objections. Since Lucid has dropped their objection to these wells, if held to 20,000 BPD, we have included them in our Induced Seismicity Model, as shown in this section.

For this study, limitations of the FSP model required a conservative approach be taken in determining the fault-slip probability of the injection scenario. Specifically, the FSP model is only capable of considering a single set of fluid characteristics and this study aims to model an injection scenario that includes saltwater disposal (SWD) and acid gas injection (AGI) systems. To ensure a conservative fault-slip probability estimate, the proposed RH AGI #2 well was modeled utilizing the characteristics of a SWD. This approach yields a more conservative probability prediction as water displays greater density, dynamic viscosity, and is significantly less compressible than acid gas. Characteristics of acid gas at reservoir conditions, as modeled by AQUAlibrium, are shown in Table 3.5-1.

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. Only fault 6 shows any observable increase in slip probability (0.03) throughout the 30-year modeled scenario (Figure 3.5-2). Table 3.5-3 summarizes the predicted pressure change along each fault and suggests that no features within the area display an increased risk of slip in response to injection. Furthermore, subsequent simulations in which injection from the proposed RH AGI #2 well is excluded suggest minimal change in the model-derived fault-slip probability as shown in Table 3.5-3.

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 Lucid 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 in the Lucid RH AGI wells (Figures 3.6-2 and 3.6-3). The area surrounding the injection wells is arid and there are no bodies of surface water within a five-mile radius. Our analysis confirms that the wells pose no risk of contaminating groundwater in the area. There are no potential conduits that would allow migration of injected fluids to fresh-water zones.

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. 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 50 wells (12 plugged and abandoned or temporarily plugged, 29 active). There are also 9 well applications approved and awaiting drilling (see Table 3.7-1).

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

- EOG Resources Government Com 001 (P&A), API #3002525604, TVD = 17,625', 0.72 miles from proposed RH AGI #2

- NGL Water Solutions Striker 6 SWD 002, (Active), API #3002544291, TVD = 17,765', 1.25 miles from proposed RH AGI #2
- EOG Resources Bell Lake 7 Unit 001 (P&A), API #3002533815, TVD = 16,085', 1.31 miles from proposed RH AGI #2

None of these three wells potentially impact the injection zone's simulated 30-year extent (see Section 3.9). NGL Water Solutions has agreed to limit their injection rate in the Striker 6 SWD 002 to 20,000 barrels per day, further reducing the potential for pressure interference in the injection zone.

The EOG Resources Government Com 001 well (P&A), API #3002525604) penetrated the Devonian zone during initial completion in May 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' (over 1,000 feet above the 16,000' top of the proposed injection zone) in May of 1978. The well was completely plugged and abandoned in December of 2003. 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 the 13 wells within a one-mile radius of the RH AGI wells, and Table 3.7-2 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.

3.8 Description of Injection Process

The existing RH AGI #1 well is located at 1600 feet from the south line (FSL) and 150 feet from the east line (FEL) of Section 13, T24S, R33E. The proposed RH AGI #2 well will be drilled at 1,800 feet from the south line (FSL) and 150 feet from the east line (FEL) of Section 13 T24S, R33E (Figure 3.8-1).

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 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 DOT, 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 3.8-2 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.

3.9 Reservoir Characterization Modeling

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

3.9.1 Cherry Canyon- AGI#1 Injection Characterization and Modeling

A total of 33 well logs formation tops in addition to porosity logs were interpreted and mapped to construct the structural surfaces for the Cherry Canyon injection formation. There are no geological structures such as faults available in the studied area. There are eight (8) vertical units within the target zone. The model boundary was focused on 13.5 km X 12.8 km with a grid cells of 141 X 132 X 7 totaling 130,284 cells. The grid dimension is 100ft X 100ft. Figure 3.9-1 shows the structural surface for a layer within the geological model. The porosity logs available for the 33 wells were utilized to perform geostatistical analysis to distribute the property in 3D. Figure 3.9-2 shows the distribution of porosity in a layer view. The porosity within the model for the Cherry Canyon formation has an average 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 md with a maximum value of 19 md. Figure 3.9-4 shows the permeability distribution in a layer within the Cherry Canyon formation.

3.9.2 Simulation Modeling for AGI#1

Once the geological model was established, a 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;
3) assess the maximum injection rate with respect to estimated maximum bottomhole pressure;
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 0.65psi/ft (4225 psi @ 6500ft) corresponded to the fracture pressure gradient imposed on the 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 saltwater disposal (SWD) wells in the study area and therefore none was included in the modeling efforts within this target formation. A forecasting model was performed for a period of ~28 years in addition to 5 years of monitoring. Figure 3.9-6 shows the injection profile for the forecasting period which showed the maximum injection rate recorded was ~ 6200 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 m 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 TAG within the Cherry Canyon.

3.9.3 Siluro-Devonian- 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. These wells covered a 20 km by 20 km geological boundary. A simulation model focused on a 6km by 6 km centered on the proposed AGI#2 injection well. In the simulation boundary, three SWD wells: Trident, Striker 6 and Deep Thirsty are included, but only Striker 6 is currently injecting wastewater and its effect on the acid gas injection was analyzed. Figure 3.9-8 show the top view of the geological and simulation model boundaries. The simulation model has a grid cells of 119 x 119 x 15 with a total cell of 212,415. 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 with different permeability and porosity distributions, using the recommended mean, min and max 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.

3.9.4 Simulation Modeling for proposed AGI# 2

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

1) perform calibration of injection history for the SWD wells to ascertain the current conditions subsurface prior to injection of TAG into AGI#2;
2) assess the storage potential within the Siluro-Devonian formation with and without the presence of faults;
3) assess the storage potential in the presence of Striker 6 SWD well operating at different rates;
4) estimate the TAG extent considering above listed scenarios.

The reservoir is initially saturated with 100 % of brine and exhibit hydrostatic equilibrium. The injection gas has two components of H_2S and CO_2 with molar fractions of 17% and 83%, respectively. Both of the two acid gas components are able to dissolve into 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. Initial history match of Striker well was performed from October 2018 and continued the acid gas injection into the AGI #2 well for 30-years ending at 2050. The gas injection rate target was 13 MMSCF/d. The Striker 6 SWD well after the calibration period, several scenarios were performed to ascertain their impact on the AGI#2 well if operated at maximum injection target of 32,500 Stb/d, medium volume of injection rate at 15,000 Stb/d and lastly a minimum injection volume at 7472 Stb/d. The bottomhole injection pressure gradient based on the potential fracture pressure was constraint at 0.629 psi/ft. In all the scenarios performed, the Siluro-Devonian formation was able to successfully inject the set injection target of 13 MMScf/d for over 30-years and the TAG distribution remained the same even after 5-years of monitoring.

Figure 3.9-10 shows the injection profile 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 6 SWD well assuming the potential existing faults are closed to fluid flow across and along the faults. The figures show clearly that the Devonian is able to store all the volumes injected both into both wells. From the modeling, it showed that slightly alleviated pressure increase was mostly attributed to the water injection. The existing faults did not impede on the injection strategy.

Figure 3.9-11 shows the corresponding TAG results from the furthest lateral extend of the gas saturation stacking all the layers when faults are closed to fluid flow. The figure also illustrates that the injected TAG is still far from reaching the edge of the 6 km by 6 km boundary. Non-transmissive faults combined with Striker 6 SWD pressure affects promote TAG dispersion in the north and south direction. Increasing Striker 6 SWD injection contribution progressively restricts dispersion in the eastern direction resulting in increasingly

N-S elongation of the TAG plume. The TAG is predicted to extend a maximum of 0.73 miles from the AGI wellbore.

Figure 3.9-12 shows the largest lateral extent of the TAG when the faults mapped are assumed to be fully transmissive to fluid flow across and along the faults in addition to variable water injection targets in the Striker 6 SWD 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 Striker SWD #2, eastern dispersion becomes increasingly restricted and the TAG is displaced in a western direction. Maximum lateral distance from AGI wellbore after 5-year post injection is approximately 0.56 miles.

Resultant TAG extent is highly dependent on operating conditions of nearby striker 6 SWD #2, which exhibits the greatest potential to influence pressure conditions within the target reservoir. The modeling responses showed that even at the maximum injection strategy for the SWD well, the AGI#2 is well situated to inject the target of 13 MMScf/d with or without faults safely without causing any hazard.

Figure 3.9-13 shows pressure profiles for both injections into AGI#1 in Cherry Canyon and AGI#2 Siluro-Devonian formation. The pressure in the Siluro-Devonian does not change significantly as a result of the injection activities irrespective of faults been transmissive or non-transmissive. There is a slightly higher pressure for 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 low 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 continue to signify a potential safe injection operation into both target formations.

4 Delineation of the monitoring areas

NMOCD requires the delineation of a ½ mile radius area of review around each injection well, referred to as the '1 mile area of review' in the permit application.

4.1 MMA – Maximum Monitoring Area

As defined in Subpart RR, the maximum monitoring area (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 modeling described in Section 3.9 indicates that the majority of the CO_2 will remain in the reservoir. Therefore, Lucid is defining the MMA as the boundary of the 1-mile radius area of review (AoR) plus an additional one-half mile buffer zone, the minimum required by Subpart RR, because the site characterization of the AoR did not reveal any leakage pathways that would allow free-phase CO2 to migrate laterally thereby warranting a buffer zone greater than one-half mile. This will allow for operational expansion for the next 30 years, the anticipated life of the project. Figure 4.1-1 shows the 1-mile radius AoR / MMA, the one-half mile buffer, and the maximum extent of the injected CO2 after 30 years of injection based on the modeling simulation presented in Section 3.9.

4.2 AMA – Active Monitoring Area

Lucid intends to define the active monitoring area (AMA) as the same area as the MMA.

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

Lucid has identified and evaluated the following potential CO_2 leakage pathways to the surface.

5.1 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, construction, operation, and maintenance of gas plants follow industry standards and relevant regulatory requirements. Additionally, several tiers of monitoring for leakage are implemented including frequent periodic visual inspection of surface equipment, use of fixed and personal H_2S (proxy for CO_2) sensors, and continual monitoring of operational parameters.

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.

5.2 Existing Wells

As required by the NMOCD C-108 application for Class II injection wells, Lucid identified all wells within a 2-mile radius of the RH AGI #1 and #2 wells (see Section 3.7.2). All wells were evaluated in terms of their potential for acting as conduits for vertical migration of TAG out of the injection zones for both RH AGI wells. Lucid concludes that the wells within the 2-mile radius area around the RH AGI wells do not pose a potential for vertical leakage of CO_2 to the surface.

5.3 Fractures and Faults

Fractures and faults identified during the preparation of the NMOCD C-108 applications for both RH AGI wells were evaluated and discussed in Sections 3.2.3, 3.3, and 3.5 above. Modeling presented in Section 3.9 indicates that the extent of the TAG after 30 years of injection does not reach the faults discussed. Lucid concludes that the identified faults do not pose a potential for vertical leakage of CO_2 to the surface.

5.4 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. Modeling presented in Section 3.9 indicates the characteristics of the confining zones are sufficient to contain the injected TAG.

5.5 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 potential for the creation and/or opening of vertical conduits for CO_2 leakage to the surface due to induced seismicity is low.

5.6 Lateral Migration

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 conduits to the surface.

6 Detection, Verification, and Quantification of Leakage

6.1 Detection of Leakage

Lucid employs the same monitoring techniques and methodologies for detecting leaks during operations as it uses in determining the CO_2 baseline described in Section 7.0.

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.

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. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

Leaks from the RH AGI wells are detected by implementing several monitoring programs including distributed control system (DCS) surveillance, visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and personal H_2S monitors. Table 6.1-1 summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection.

6.2 Verification of Leakage

Lucid's internal operational documents and protocols detail the steps to be taken to verify leaks of H_2S, a surrogate for CO_2.

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 ft 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.

6.3 Quantification of 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. See Section 8.4 for additional information regarding the quantification of leaks from surface equipment.

7 Determination of Expected Baselines

Lucid uses existing automatic data collection systems to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. The following describes Lucid's approach to 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 surrogate for CO_2, at the Red Hills Gas Plant.

7.2 Fixed, 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 RH AGI Wells contained within the plant and documents procedures that would be followed in case of such an event.

7.2.1 Fixed H_2S Monitors

The Red Hills 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 hydrogen sulfide 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, will monitor for CO_2 leakage in the AMA as defined in Section 4.2.

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 Groundwater Monitoring

New Mexico Tech, through a DOE research grant, 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

Table 8-1 summarizes the twelve Subpart RR equations used to calculate the mass of CO2 sequestered annually. Appendix 6 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 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 CO2 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 CO2 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 expects to begin implementing the approved MRV plan on **June 1, 2021**. The RH AGI #2 will be drilled in late summer / early fall of 2021. At that time, Lucid will reevaluate the MRV 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 (GSA) 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, RR-5, and RR-8 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 5). 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 and between the flow meter used to measure production quantity and the production wellhead.

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, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to CCUS injection operations reporting under Subpart RR.

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_2injected 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.
- The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.
- When estimating the amount of CO_2 (due to an interruption in data collection, mechanical failure of a meter, mechanical failure of other equipment, or otherwise), the amount of CO_2 is to be estimated by using the most recent periodic (i.e. daily) volume of CO_2 associated with the meter or equipment and calculating the proportionate volume of “missing” CO_2 based on the number of hours involved in the data gap or until meter/equipment repair.

10.4 Revisions of the MRV Plan

Lucid will revise the MRV Plan as needed to reflect changes in production processes, 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. Specifically, Lucid intends to update the MRV Plan after RH AGI #2 has been drilled and characterized. The well will be drilled in late summer / early fall of 2021.

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 produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) 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.

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

(12) 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.

(13) 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 production wellhead and the flow meter used to measure production quantity.

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

12 Tables

Table 3.4-1 – Saltwater Disposal Wells Injecting Into the Delaware Mountain Group Within 10 Miles of RH AGI #1

API	OPERATOR	SPUD	TD	WELL NAME	DIST	TOP	BOT	ZONE
3002528873	EOG RESOURCES INC	9/12/84	15505	VACA RIDGE 30 FEDERAL 001	1.97	5424	6360	CHERRY CANYON
3002524916	CHESAPEAKE OPER, INC.		14238	ANTELOPE RIDGE UNIT 005	3.84	5167	6134	BELL CANYON
3002508489	KAISER-FRANCIS OIL CO		13044	BELL LAKE UNIT 002	3.84	5185	7060	BELL/CHERRY CANYON
3002524676	ENDURANCE RES LLC	2/14/74	8710	FEDERAL 19 001	5.64	6670	6883	CHERRY CANYON
3002524003	SIANA OPERATING LLC	12/28/71	13500	CURRY FEDERAL 002	5.88	5240	6160	BELL CANYON
3002524432	PRIMAL ENERGY CORP	6/7/73	5204	INGRAM O STATE 002	5.99	5012	5033	BELL CANYON
3002524771	CONOCO INC	1/2/00	13589	BELL LAKE UNIT 4 015	7.21	5060	6520	BELL/CHERRY CANYON

Table 3.4-2 – Formation Fluid Analysis for Cherry Canyon Formation

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 7335-45 feet, located 3.9 miles from Red Hill AGI #1

Table 3.5-1 -- Input parameters and source material for FSP simulations

Modeled Parameter	Input Value	Variability (+/-)	UOM	Source
Stress				
Vertical Stress Gradient	1.05	0.105	psi ft^{-1}	Nearby well estimate
Max Horizontal Stress Direction	N75E	5	Deg.	Lund Snee & Zoback, 2018
Reference Depth	17,030		ft	Nearby well evaluation
Initial Res. Pressure Gradient	0.43	0.043	psi ft^{-1}	Lund Snee & Zoback, 2018
A_Φ Parameter	0.6	0.06	-	Lund Snee & Zoback, 2018
Reference Friction Coefficient (μ)	0.6	0.06	-	Standard Value
Hydrologic				
Aquifer Thickness	700	10	ft	Nearby well evaluation
Porosity	3	0.5	%	Nearby well evaluation
Permeability	10	5	mD	Nearby well evaluation
Material properties				
Density (Water)	1000	50	kg m^{-3}	Standard Value
Dynamic Viscosity (Water)	0.0008	0.0001	Pa.s	Standard Value
Fluid Compressibility (water)	3.6×10^{-10}	0	Pa^{-1}	Standard Value
Rock Compressibility	1.08×10^{-9}	0	Pa^{-1}	Standard Value
Acid gas @ 210 °F, 6,700 psi				
Density	811.00	-	kg m^{-3}	AQUAlibrium™
Dynamic Viscosity	0.0000787	-	Pa.s	AQUAlibrium™

Table 3.5-2 -- Location and characteristics of injection wells modeled in FSP assessment.

#	API	Well Name	Latitude	Longitude	Volume (bbls/day)	Start (year)	End (year)
1	TBD	Red Hills AGI #2	32.215378	-103.518021	6,000	2020	2050
2	30-025-44291	Striker 6 SWD #2	32.208049	-103.49742	32,500	2018	2050
3	30-025-45085	Brininstool SWD #4	32.269289	-103.542198	31,500	2020	2050
4	30-025-42448	Madera SWD #1	32.211484	-103.442864	20,000	2016	2050
5	30-025-44661	Moomaw SWD #1	32.191228	-103.422569	30,000	2019	2050
6	TBD	Trident SWD (proposed)	32.2218	-103.5338	20,000	2020	2050
7	30-025-44387	Leviathan State SWD #1	32.313965	-103.500200	30,000	2020	2050
8	TBD	Deep Thirst (proposed)	32.2076	-103.3816	20,000	2020	2050

Table 3.5-3 -- Summary of model-simulation results showing the required pressure change to induce fault slip, actual pressure change as predicted by the FSP model, probability of fault slip at the end of the 30-year injection scenario, and fault slip probability when proposed AGI is excluded

Fault #	Δ Pressure necessary to induce fault slip	Actual Δ Pressure at fault midpoint at year 2050	Fault Slip Potential at year 2050	Fault Slip Potential excluding AGI
1	6,010 psi	766 psi	0.00	0.00
2	3,353 psi	905 psi	0.00	0.00
3	6,373 psi	1,209 psi	0.00	0.00
4	6,948 psi	2,047 psi	0.00	0.00
5	5,830 psi	1,022 psi	0.00	0.00
6	1,920 psi	663 psi	0.03	0.02
7	6,906 psi	1,023 psi	0.00	0.00
8	3,136 psi	144 psi	0.00	0.00
9	4,100 psi	470 psi	0.00	0.00
10	4,925 psi	899 psi	0.00	0.00

Table 3.6-1 – Water Wells Identified by the New Mexico State Engineer's Files within One Mile of the Proposed RH AGI #2 Well

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			

Table 3.7-1 - List of Reported Wells within Two Miles of Lucid RH AGI Wells #1 and #2

API	OPERATOR	WELLNAME	TOWNSHIP	RANGE	SECTION	SPUDDATE	PLUGDATE	TVDDEPTH	WELLTYPE	COMPLSTAT	DIST(Mi)
3002540448	LUCID ENERGY DELAWARE, LLC	RED HILLS AGI 001	24.0S	33E	13	23-Oct-13		6650	I	Active	0.00
3002508371	BYARD BENNETT	J L HOLLAND ETAL 001	24.0S	33E	13	24-Feb-61	8-Mar-61	5425	O	Plugged	0.33
3002526958	BOPCO, L.P.	SIMS 001	24.0S	33E	13	4/13/1981	26-Dec-07	15007	G	Plugged	0.34
3002526369	EOG RESOURCES INC	GOVERNMENT L COM 002	24.0S	34E	18	15-Sep-79	8-Oct-90	14698	G	Plugged	0.38
3002541384	COG OPERATING LLC	DECKARD FEDERAL COM 004H	24.0S	33E	13	1-Jun-14		11103	O	Active	0.67
3002541687	COG OPERATING LLC	SEBASTIAN FEDERAL COM 001H	24.0S	34E	18	1-Feb-15		10944	O	Active	0.68
3002525604	EOG RESOURCES INC	GOVERNMENT L COM 001	24.0S	34E	18	3-Oct-77	30-Dec-04	17625	G	Plugged	0.72
3002541383	COG OPERATING LLC	DECKARD FEDERAL COM 003H	24.0S	33E	13	30-Aug-14		11162	O	Active	0.75
3002541666	COG OPERATING LLC	SEBASTIAN FEDERAL COM 002H	24.0S	34E	18	24-Feb-15		10927	O	Active	0.76
3002527491	SOUTHLAND ROYALTY CO	SMITH FEDERAL 001	24.0S	34E	19	19-Oct-81	10-Aug-86	15120	O	Plugged	0.80
3002541382	COG OPERATING LLC	DECKARD FEDERAL COM 002H	24.0S	33E	13	3-Jun-14		11067	O	Active	0.88
3002541688	COG OPERATING LLC	SEBASTIAN FEDERAL COM 003H	24.0S	34E	18	3-Aug-14		11055	O	Active	0.93
3002529008	EOG RESOURCES INC	MADERA RIDGE 24 001	24.0S	33E	24	7-Nov-84		15600	G	Active	1.00
3002540914	COG OPERATING LLC	DECKARD FEE 001H	24.0S	33E	13	15-Mar-13		11034	O	Active	1.07
3002543532	MATADOR PRODUCTION COMPANY	LEO THORSNESS 13 24 33 211H	24.0S	33E	13	10-Dec-17		12383	G	Active	1.13
3002541689	COG OPERATING LLC	SEBASTIAN FEDERAL COM 004H	24.0S	34E	18	2-Jul-14		10877	O	Active	1.13
3002544442	MATADOR PRODUCTION COMPANY	STRONG 14 24 33 AR 214H	24.0S	33E	14	31-Jul-18		12499	G	Active	1.13
3002544918	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL 211H	24.0S	34E	17			0	O	New (Not drilled or compl)	1.24
3002544936	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL 121H	24.0S	34E	17			0	O	New (Not drilled or compl)	1.24
3002544937	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL 125H	24.0S	34E	17			0	O	New (Not drilled or compl)	1.25
3002544291	NGL WATER SOLUTIONS PERMIAN, LLC	STRIKER 6 SWD 002	24.0S	34E	20	1/20/2018		17705	S	Active	1.25
3002544917	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL 101H	24.0S	34E	17			0	O	New (Not drilled or compl)	1.25
3002544919	MATADOR PRODUCTION COMPANY	CARL MOTTEK FEDERAL 215H	24.0S	34E	17			0	O	New (Not drilled or compl)	1.26
3002541334	COG OPERATING LLC	ROY BATTY FEDERAL COM 004H	24.0S	33E	11	26-Dec-13		10899	O	Active	1.27
3002541026	COG OPERATING LLC	TYRELL FEE 001H	24.0S	33E	14	24-Apr-13		10951	O	Active	1.28
3002533815	EOG RESOURCES INC	BELL LAKE 7 UNIT 001	24.0S	34E	7	12-Jun-97	10-Sep-97	16085	G	Plugged	1.31
3002535504	EOG RESOURCES INC	BELL LAKE UNIT 008	24.0S	34E	7	24-Apr-01	13-Jun-01	14500	G	Plugged	1.32
3002542789	COG OPERATING LLC	TYRELL FEE 002H	24.0S	33E	14	4-Nov-15		9359	O	Active	1.33
3002543152	KAISER-FRANCIS OIL CO	BELL LAKE UNIT 7 001C	24.0S	34E	7			0	G	New (Not drilled or compl)	1.36
3002527052	SUPERIOR OIL CO	GOVERNMENT M 001	24.0S	34E	17	14-Dec-80	8-Nov-82	14905	O	Plugged	1.41
3002539716	COG OPERATING LLC	RED RAIDER BKS STATE 002H	24.0S	33E	25	1-Apr-10		9455	O	Active	1.42
3002539560	EOG RESOURCES INC	FALCON 25 FEDERAL 001	24.0S	33E	25	30-Nov-09		9444	O	Active	1.47
3002542933	DEVON ENERGY PRODUCTION COMPANY, LP	BOOMSLANG 14 23 FEDERAL 004H	24.0S	33E	14	5-Jul-17		11274	O	Active	1.49
3002542920	DEVON ENERGY PRODUCTION COMPANY, LP	BOOMSLANG 14 23 FEDERAL 001H	24.0S	33E	14	28-Jul-17		9517	O	Active	1.50
3002541333	COG OPERATING LLC	ROY BATTY FEDERAL COM 003H	24.0S	33E	11	28-Nov-13		11116	O	Active	1.51
3002526257	KAISER-FRANCIS OIL CO	BELL LAKE UNIT 019	24.0S	33E	12	25-Mar-79	12-Jul-11	14760	O	Plugged	1.60
3002534050	EOG RESOURCES INC	LELA MAE STEVENS FEDERAL COM 001	24.0S	33E	14	23-Oct-97	13-Mar-02	13840	G	Plugged	1.64
3002543238	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL 004H	24.0S	33E	23	21-Jun-17		11130	O	Active	1.66
3002543239	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL 006H	24.0S	33E	23	26-Jun-17		9408	O	Active	1.67
3002543237	DEVON ENERGY PRODUCTION COMPANY, LP	BLUE KRAIT 23 FEDERAL 003H	24.0S	33E	23	1-Jul-17		9399	O	Active	1.67
3002541332	COG OPERATING LLC	ROY BATTY FEDERAL COM 002H	24.0S	33E	11	1-Nov-13		11101	O	Active	1.77
3002524910	CONOCO INC	BELL LAKE UNIT 5 016	24.0S	34E	7	31-Jan-75		14140	G	Active	1.81
3002543308	DEVON ENERGY PRODUCTION COMPANY, LP	BOOMSLANG 14 23 FEDERAL 002H	24.0S	33E	14	18-Aug-17		9485	O	Active	1.81
3002541957	CHEVRON MIDCONTINENT, L.P.	PRODIGAL SUN 17 24 34 001H	24.0S	34E	17	12-Aug-14		10865	O	Active	1.82
3002534246	DEVON ENERGY PRODUCTION COMPANY, LP	STEVENS 11 001	24.0S	33E	11	20-Jan-98	1-Nov-02	15250	G	Plugged	1.92
3002527267	MOBIL PROD TX & NM	GOVERNMENT M 002	24.0S	34E	17	28-Mar-81	21-Feb-89	14942	G	Plugged	1.93
3002545296	MATADOR PRODUCTION COMPANY	CHARLES LING FEDERAL COM 134H	24.0S	33E	11			0	O	New (Not drilled or compl)	1.98
3002545300	MATADOR PRODUCTION COMPANY	CHARLES LING FEDERAL COM 204H	24.0S	33E	11			0	O	New (Not drilled or compl)	1.98
3002545083	MATADOR PRODUCTION COMPANY	CHARLES LING FEDERAL COM 214H	24.0S	33E	11			0	O	New (Not drilled or compl)	1.98
3002541099	COG OPERATING LLC	ROY BATTY FEDERAL COM 001H	24.0S	33E	11	24-Jun-13		10700	O	Active	1.99

Table 3.7-2 - Wells within One-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

Table 3.9-1 - Geological zones and ranges of the properties.

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

Table 6.1-1 -- Leak Detection Monitoring

Leakage Pathway	Detection Monitoring Program
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Fixed Gas Monitors Personal H_2S Monitors
RH AGI Wells	DCS Surveillance Visual Inspections Mechanical Integrity Tests Fixed Gas Monitors around Wellheads Personal H_2S Monitors In-Well P/T Sensors
Fractures and Faults	*
Confining Zone / Seal	*
Induced Seismicity	*
Lateral Migration	*

* These potential leakage pathways have been evaluated and are not considered to pose a threat for surface leakage of CO2.

Table 8-1 -- Subpart RR Equations for Calculating CO2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO2 received and measurement of CO2 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 CO2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO2 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 CO2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO2 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 CO2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO2 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 CO2 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 CO2 received in containers for injection.

13 Figures

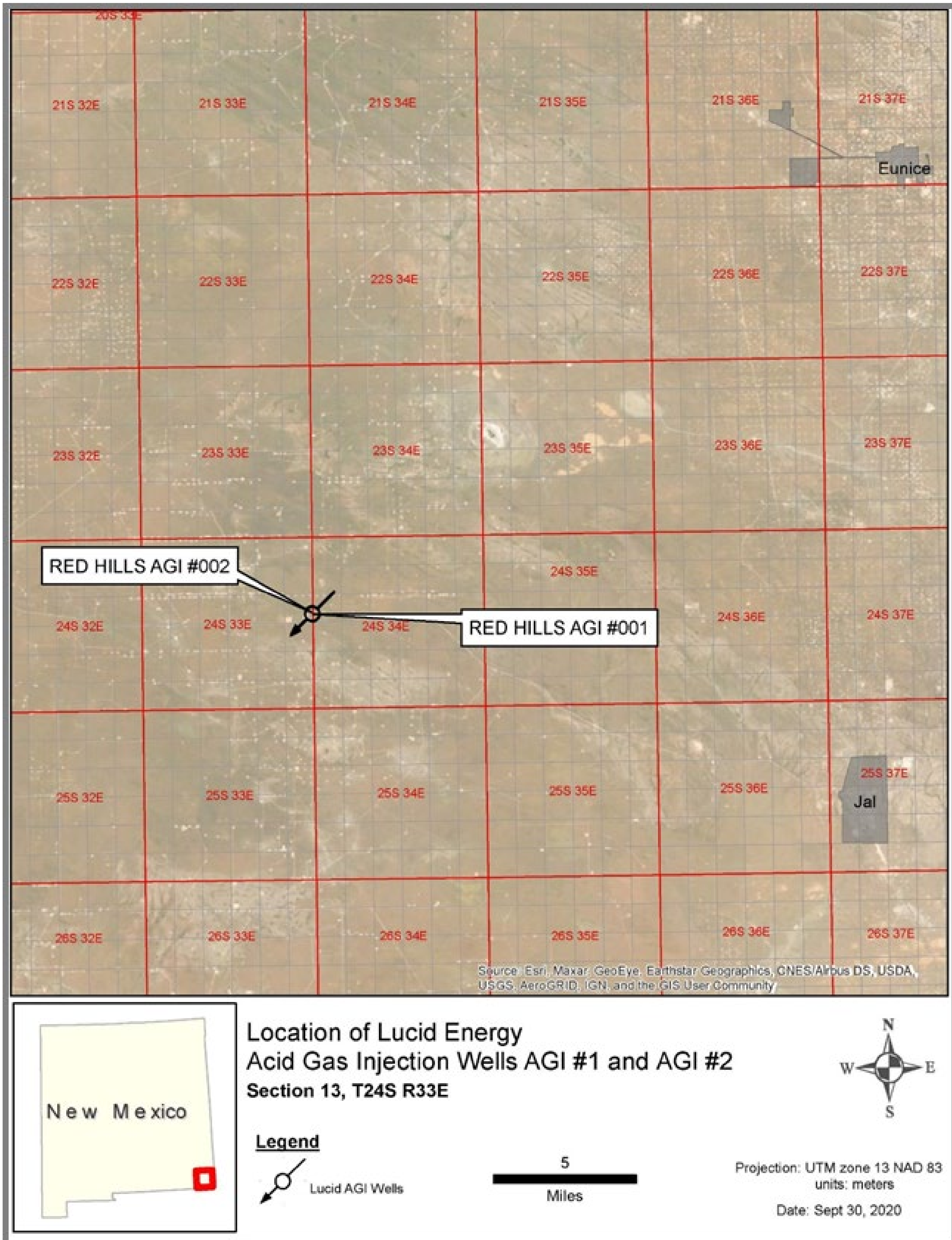


Figure 1-1 -- Location of Red Hills Gas Plant and Wells – RH AGI #1 and RH AGI #2

Figure 3.1-1 – Map Showing Location of RH AGI Wells and Gas Plant in Section 13, T 24 S, R 33 E

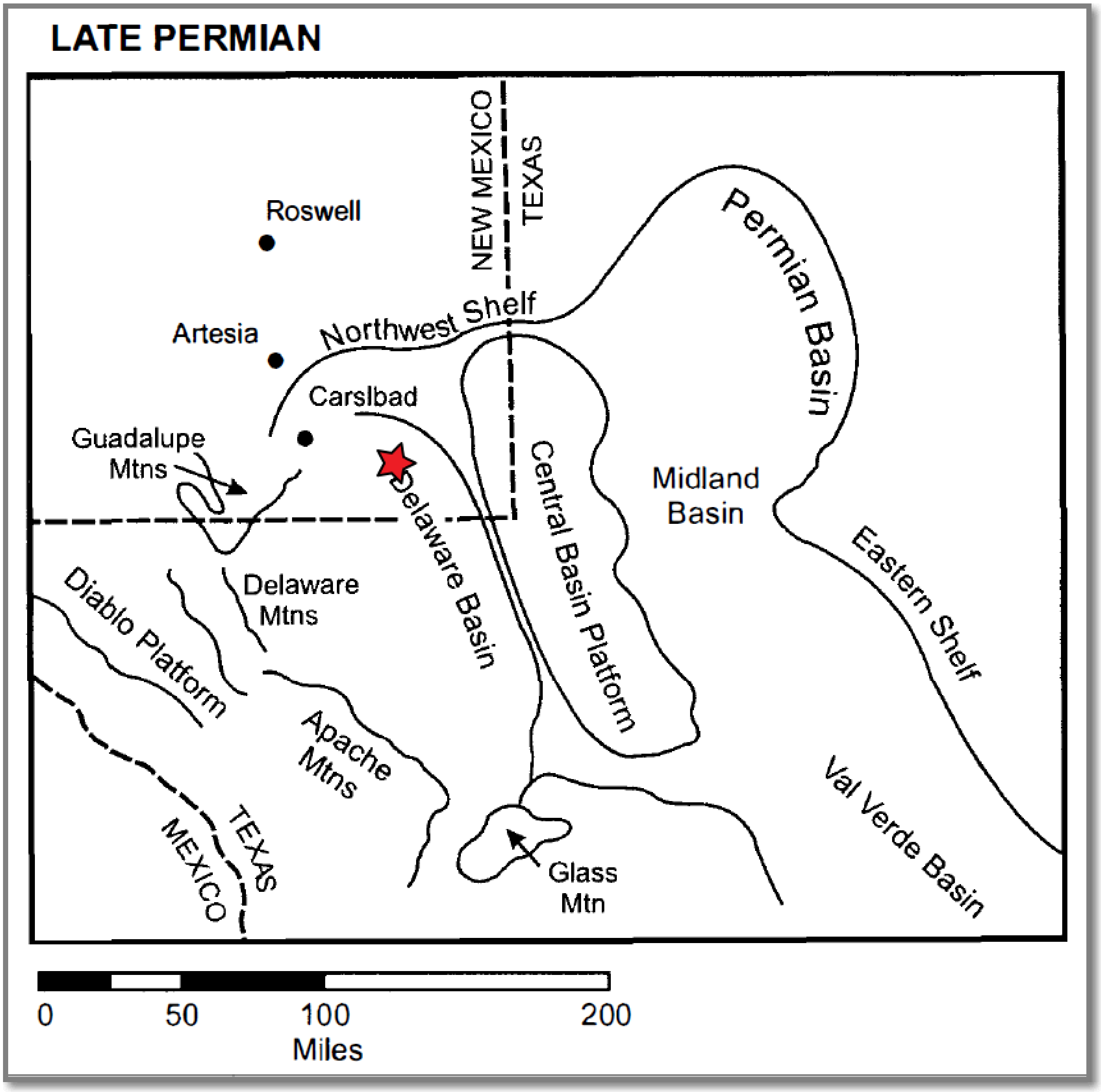


Figure 3.2-1 -- Structural features of the Permian Basin during the Late Permian. Location of the Lucid RH AGI wells is shown by the red star. (Modified from Ward, et al (1986))

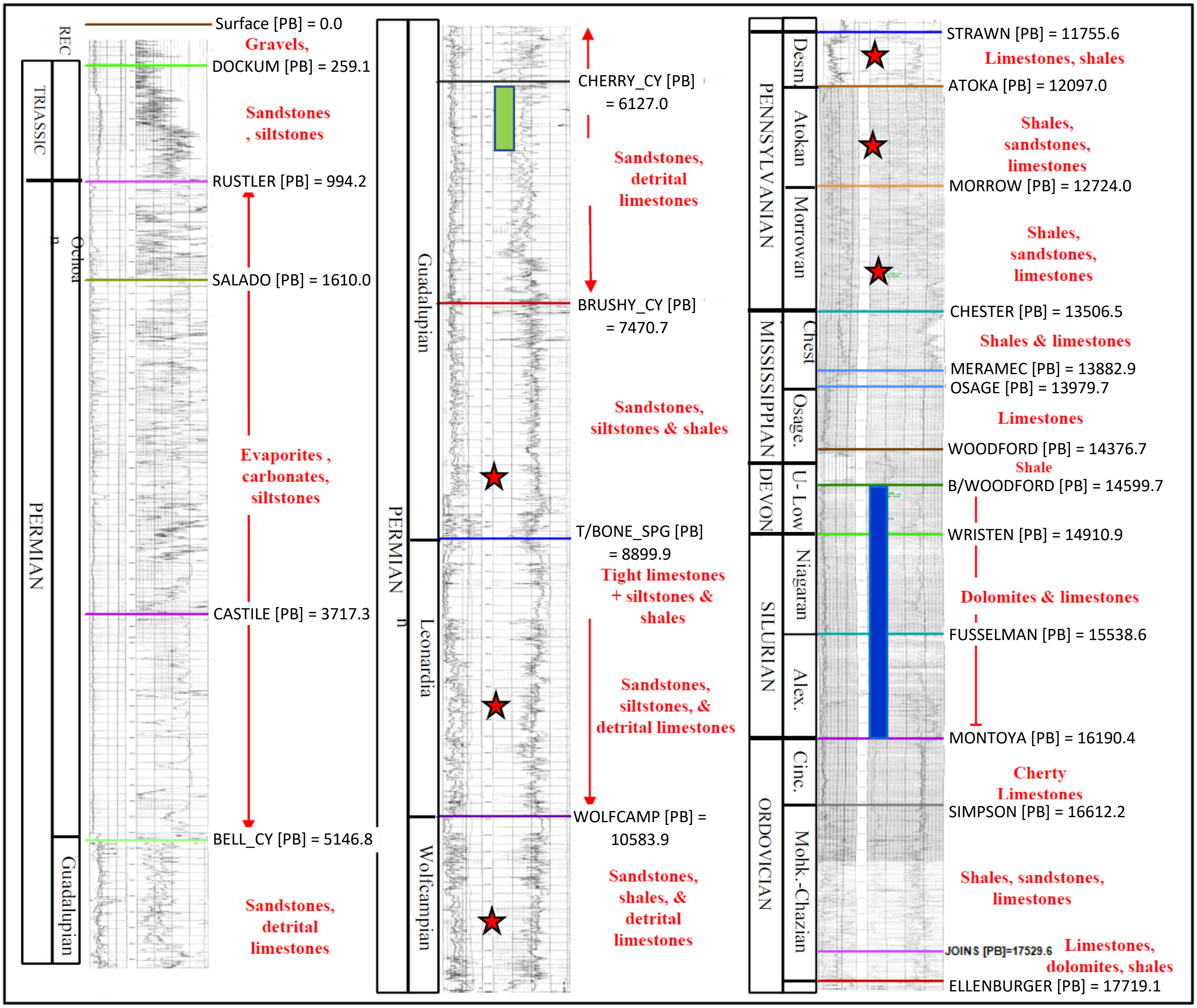


Figure 3.2-2 -- Stratigraphy and Generalized Lithologies of the Subsurface Formations underlying the Lucid RH AGI Wells.

Zones with active pay 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 interval 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.

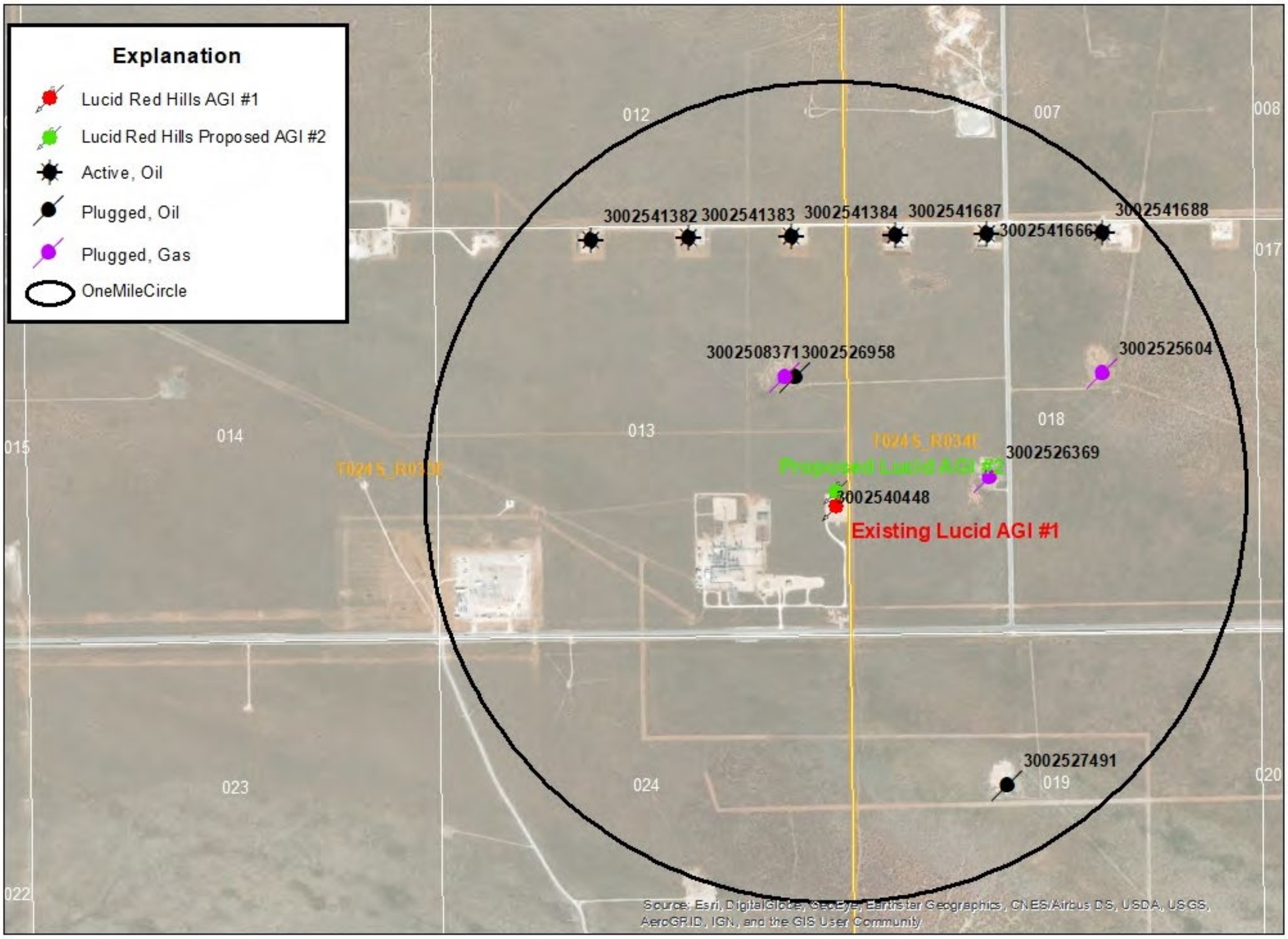


Figure 3.2-3 – Identified Oil and Gas Wells within One Mile Radius of Lucid RH AGI Wells

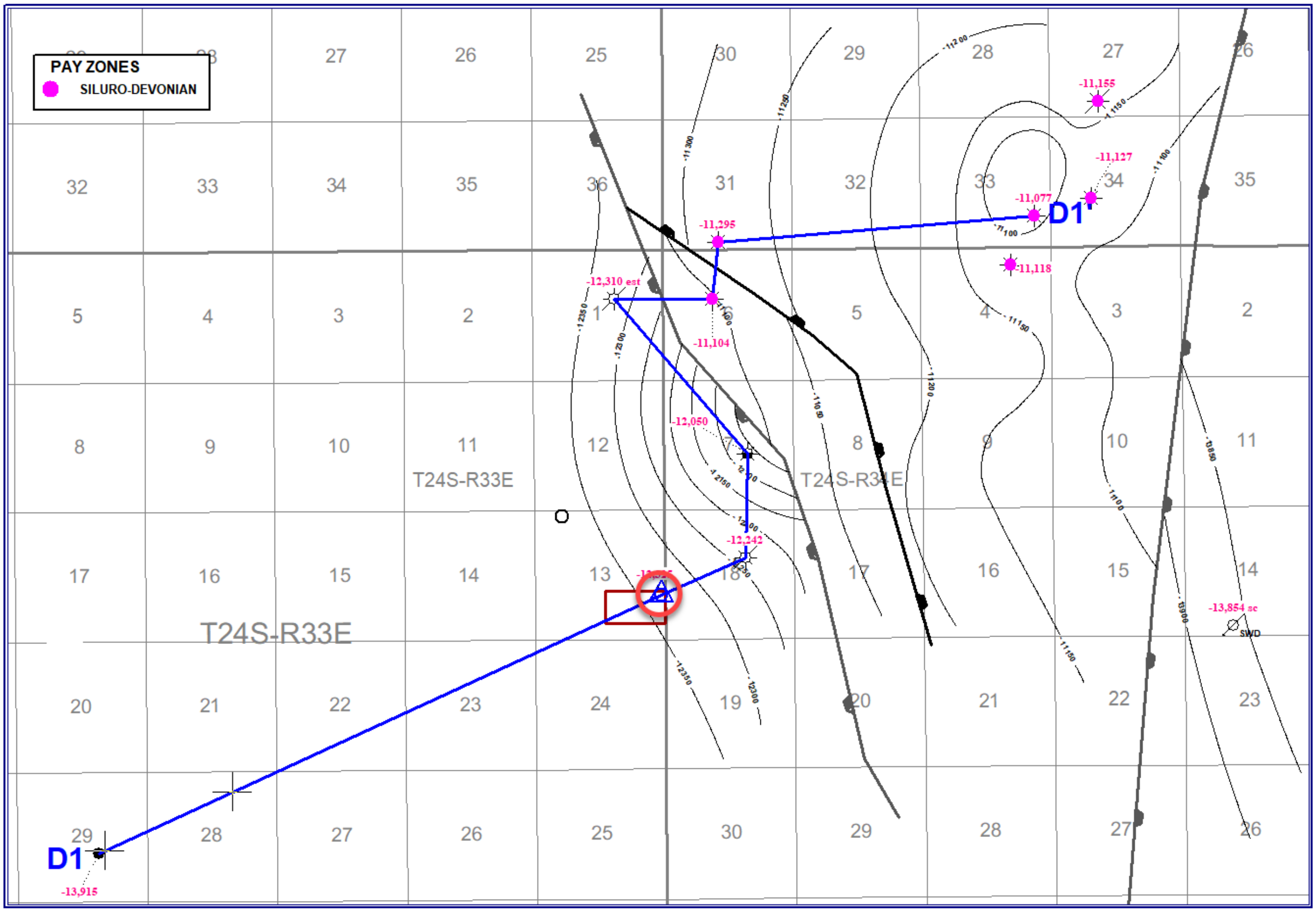


Figure 3.2-4 -- Structure on Top of the Devonian and Location of Cross Section D1

Map showing the only wells that penetrated below the Woodford shale in the area of the Lucid Red Hill 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, and there are no doubt faults 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.

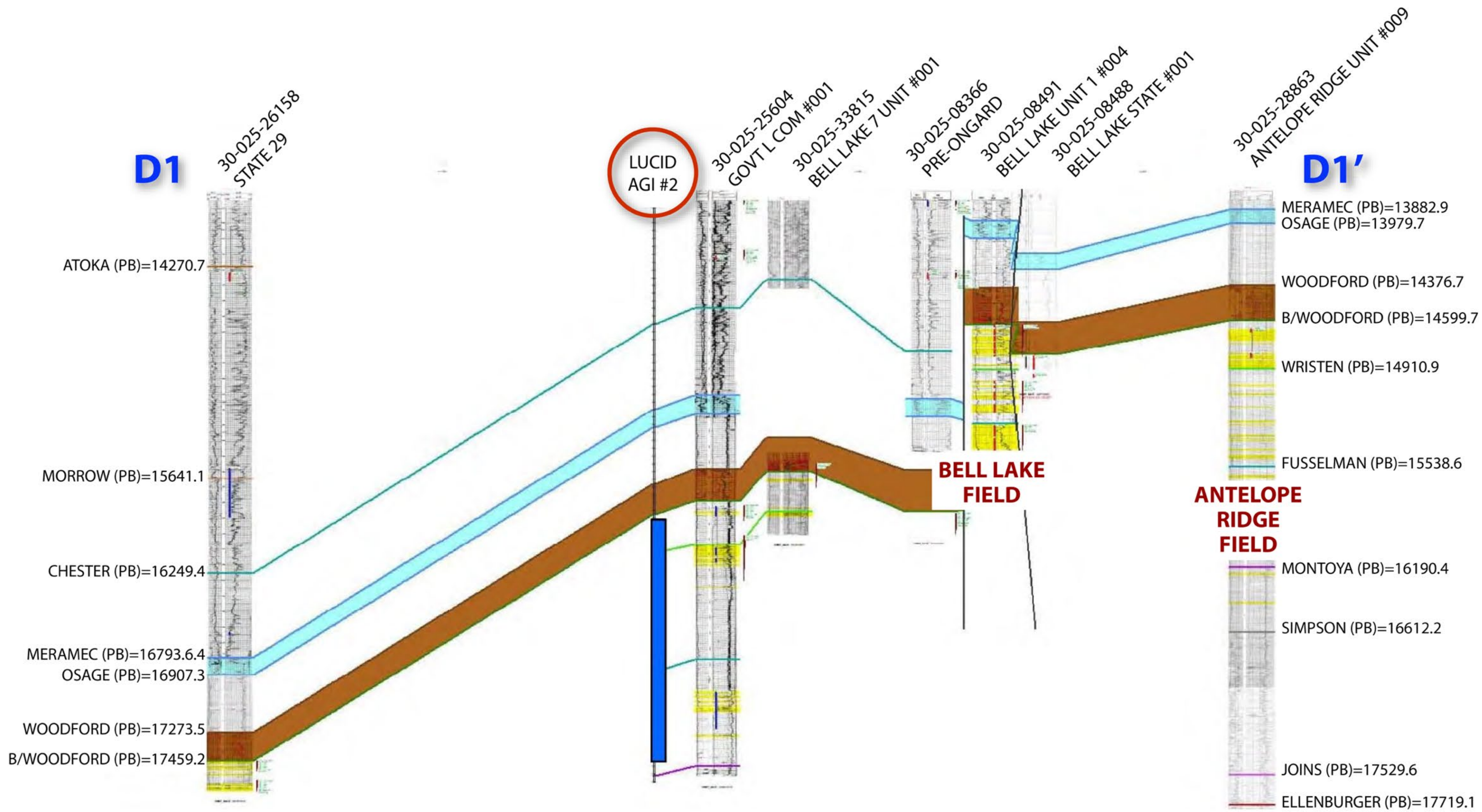


Figure 3.2-5 -- Structural Cross Section through the Deeper Horizons across the Red Hill Gas Plant Site

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) 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, although there are no active producing Morrow wells within or immediately outside the one-mile radius around the proposed well.

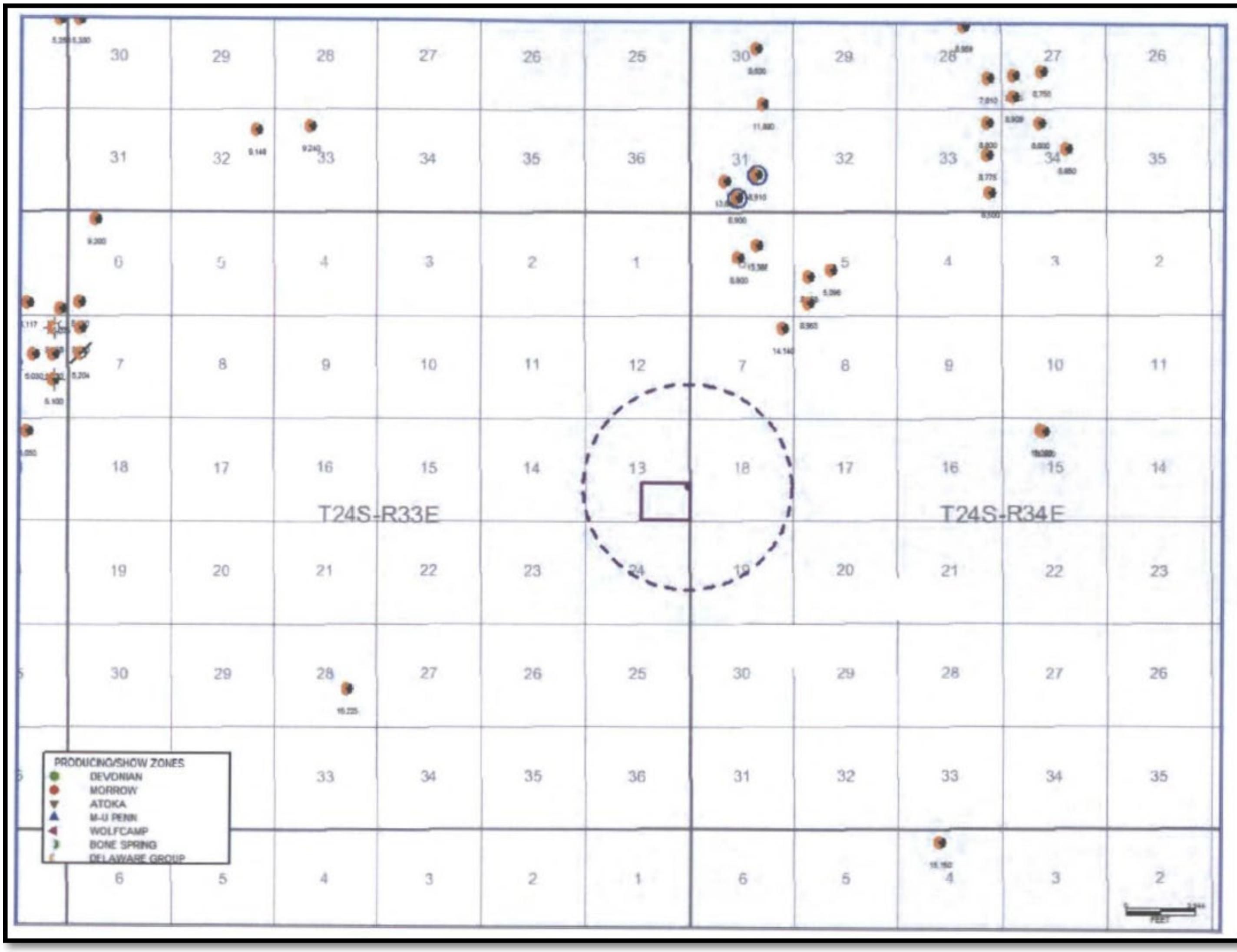


Figure 3.3-1 -- Oil and Gas Production Well in the Delaware Mountain Group (Bell Canyon, Cherry Canyon and Brushy Canyon Formations) in the Vicinity of the Red Hills Gas Plant Showing One Mile Radius Area of Review.

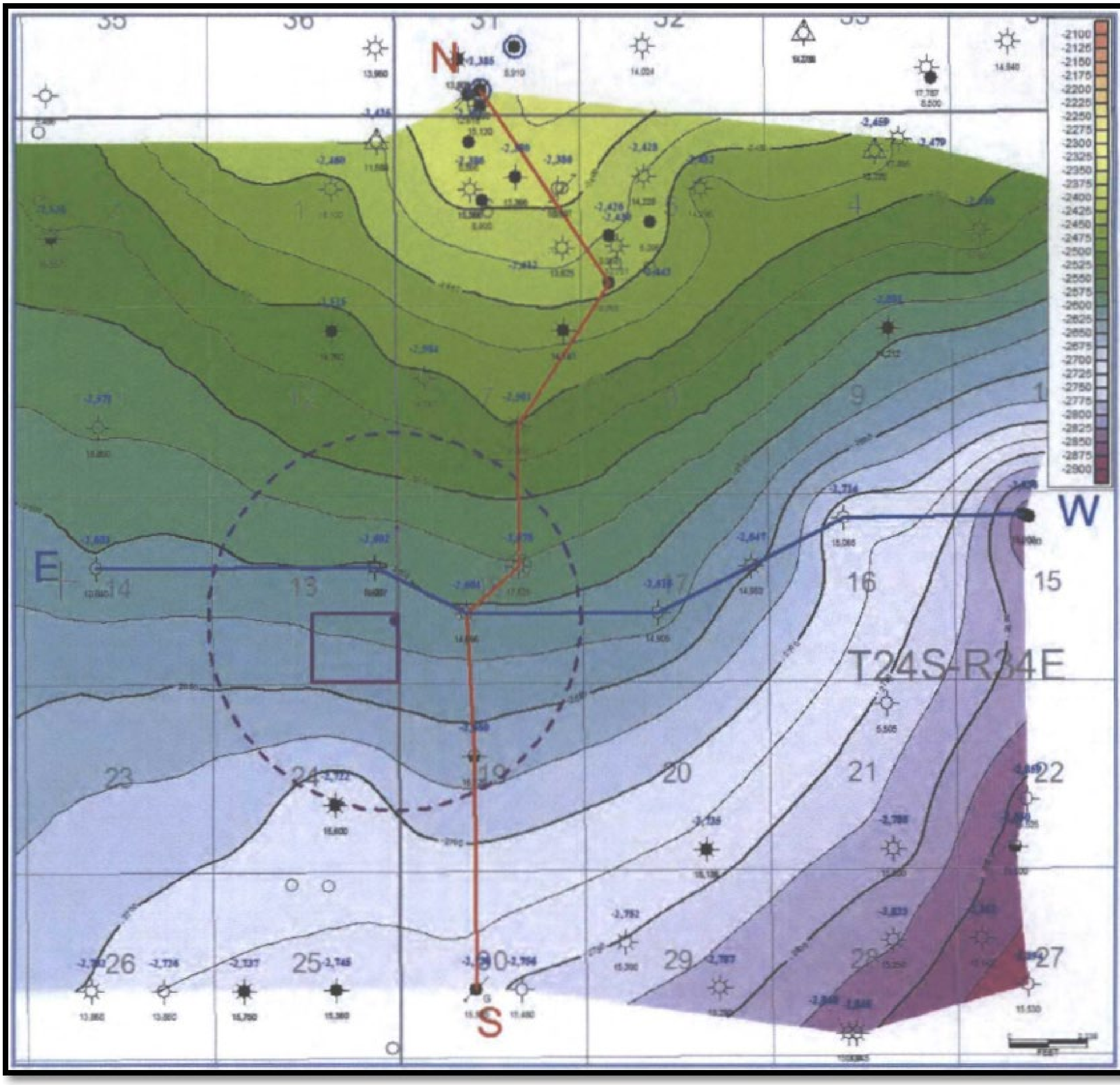


Figure 3.3-2 -- Structure on Top of the Cherry Canyon Formation Showing the Locations of Cross-Sections and the One Mile Radius Area of Review

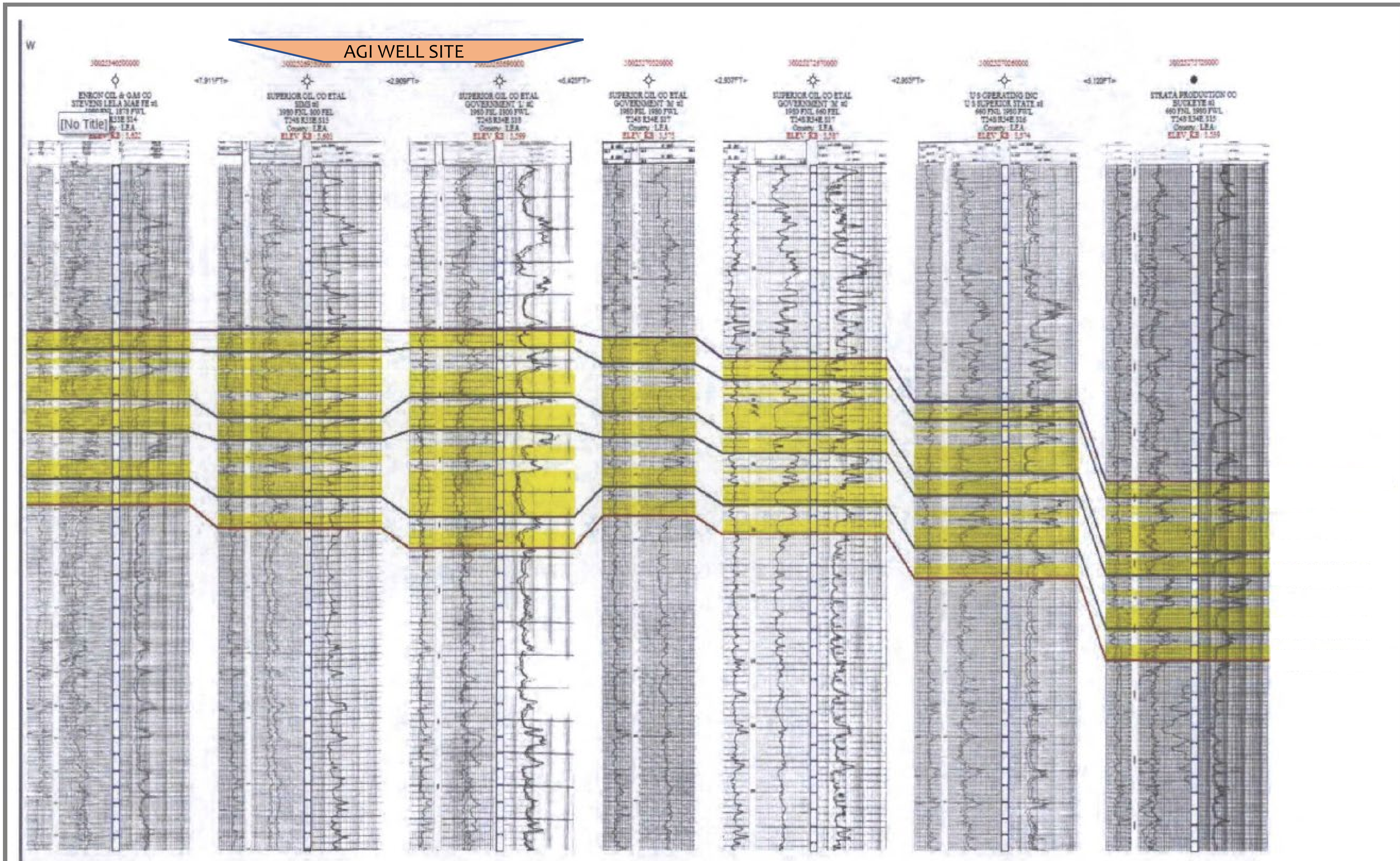


Figure 3.3-3 -- West – East Cross Section showing Cherry Canyon Formation

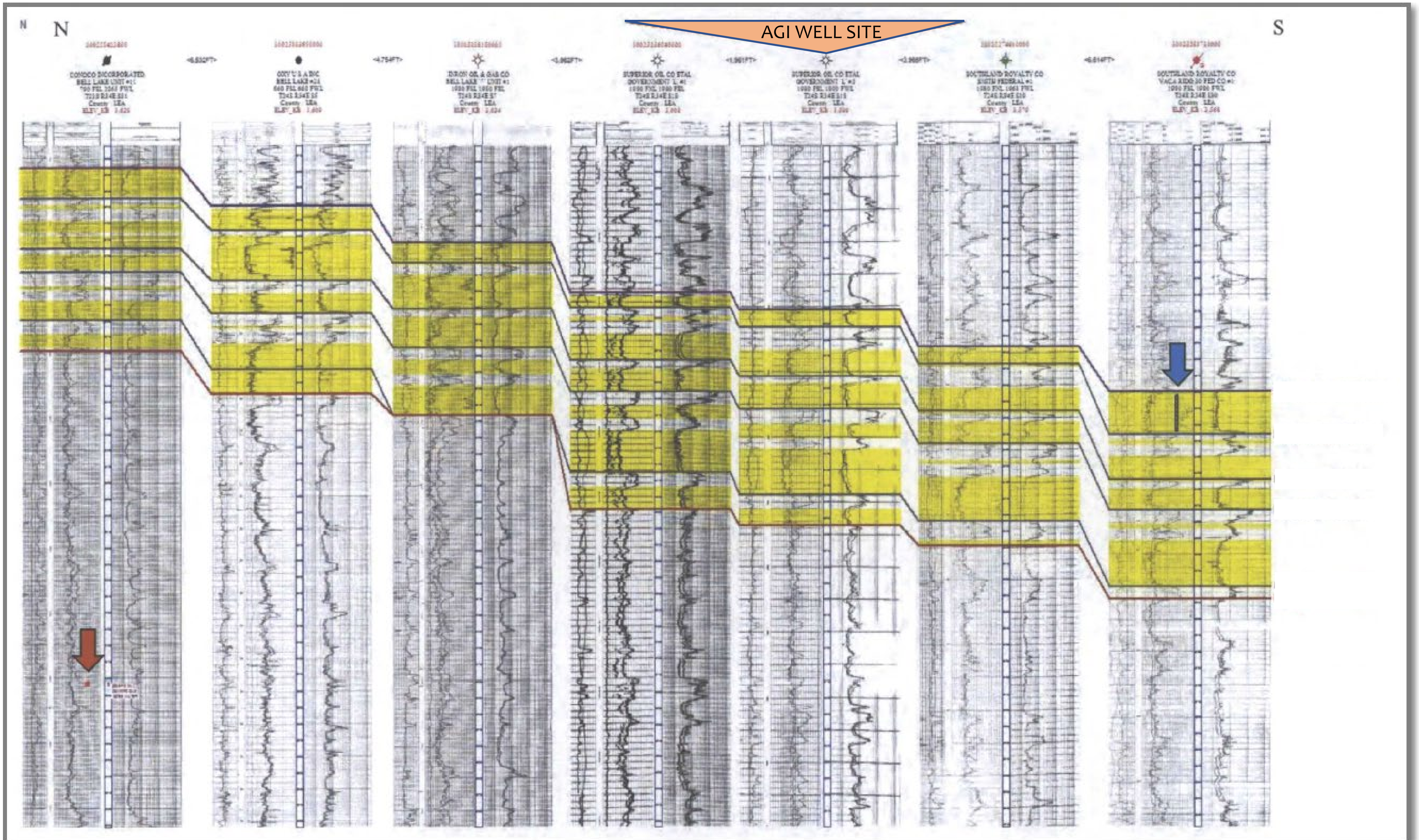


Figure 3.3-4 -- North - South Cross Section showing Cherry Canyon Formation.

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.

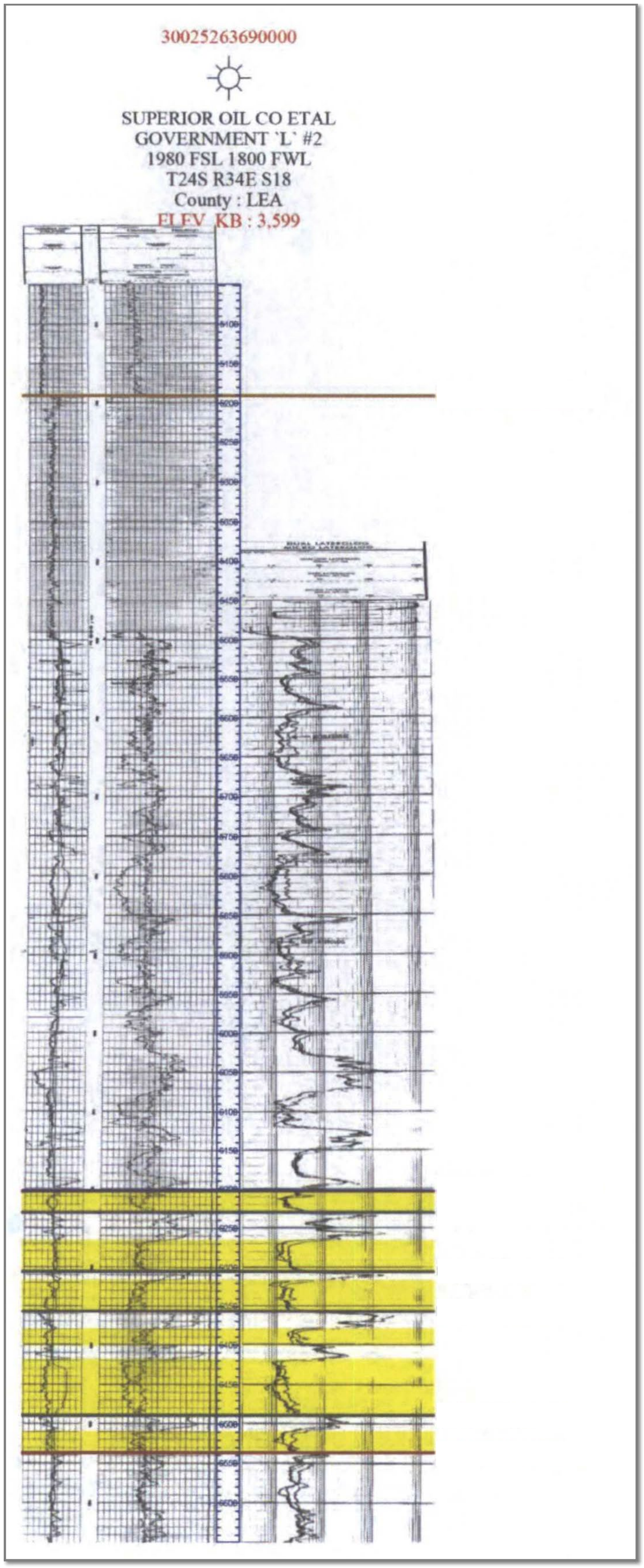


Figure 3.3-5 -- Geophysical Logs from the Bell Canyon and the Upper Cherry Canyon from the Government 'L' #2 Well, Located 0.38 Miles from the RH AGI #1 Well

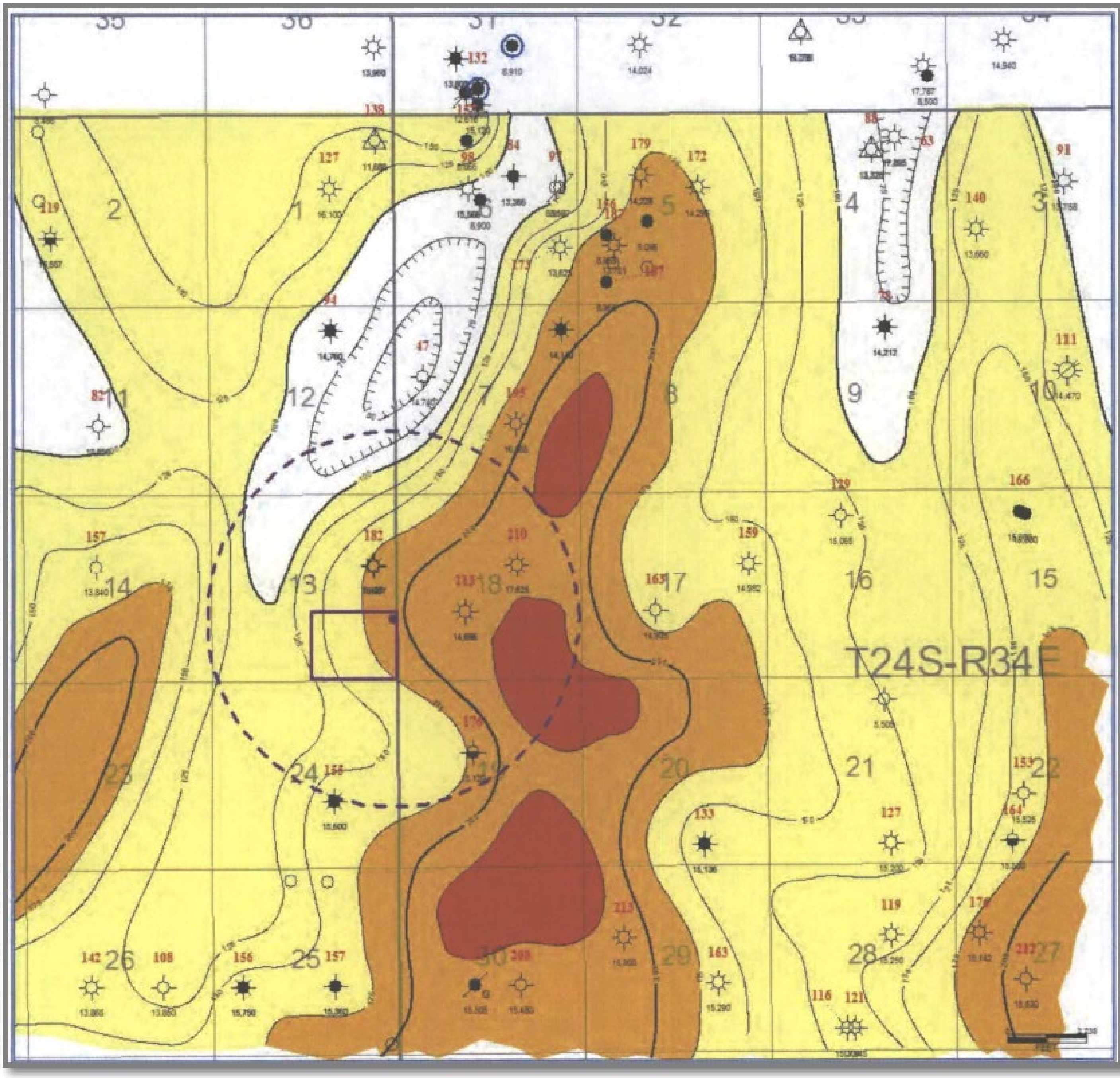


Figure 3.3-6 -- Map Showing Thickness of the Clean Sands in the Upper Cherry Canyon Injection Interval and the One Mile Radius Area of Review

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

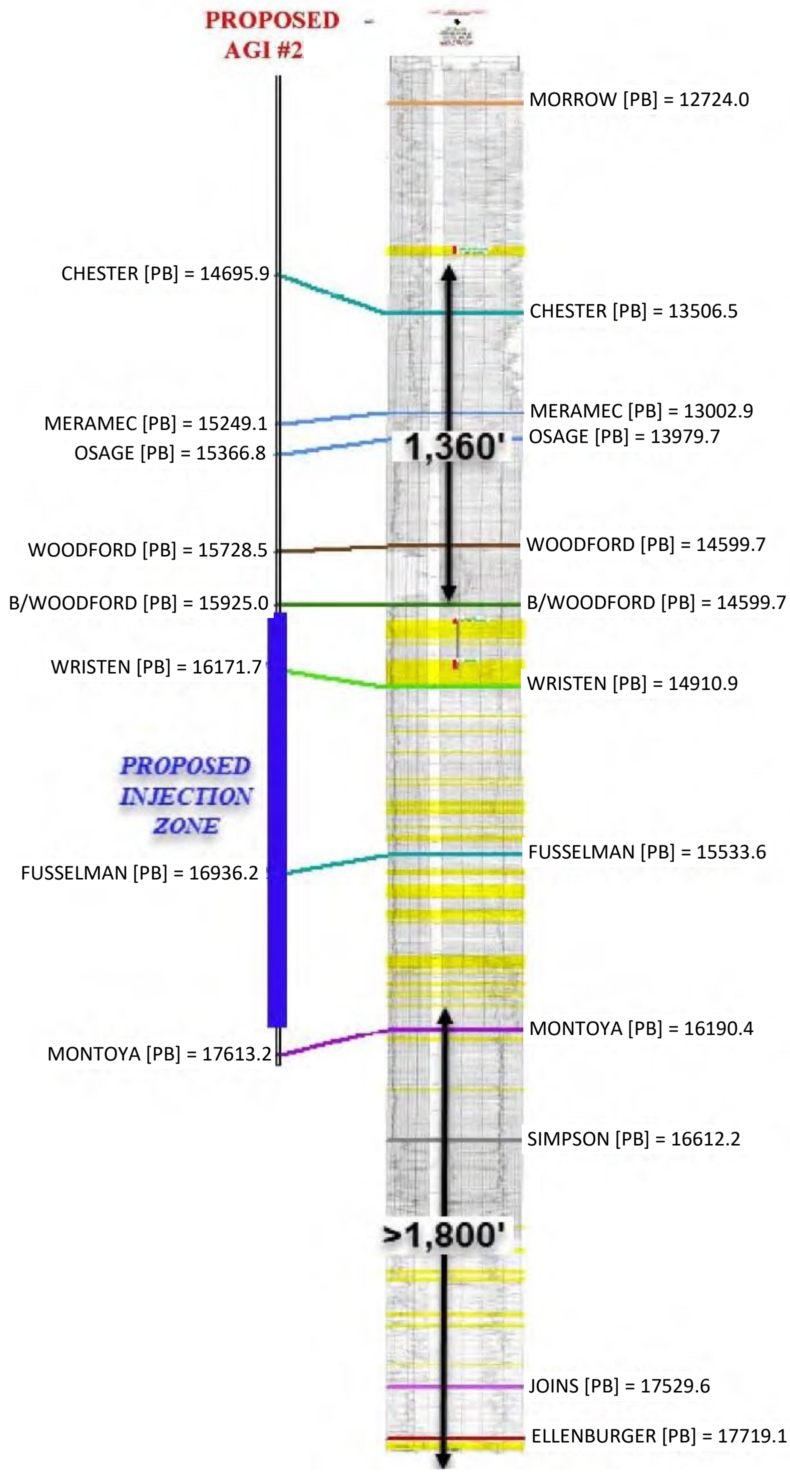


Figure 3.3-7 -- Porosity Profile Above and Below Proposed Injection Zone for RH AGI #2

Section is hung on base of the Woodford Shale. Yellow shading shows porosity; no shading indicates tight rock. The closest producing zone to the injection target within the area of investigation is over 1,300 feet above in the Morrow. Between the Devonian and Morrow is primarily tight limestones and shales. There are no producing horizons below the Fusselman in this area. The basement is over 1,800 below the base of the proposed injection zone.

The lack of any porosity between the top of the proposed injection zone and the nearest Morrow producing zone demonstrates that there is adequate caprock above the intended injection interval, and there is more than adequate tight rock between the base of the injection interval and the basement.

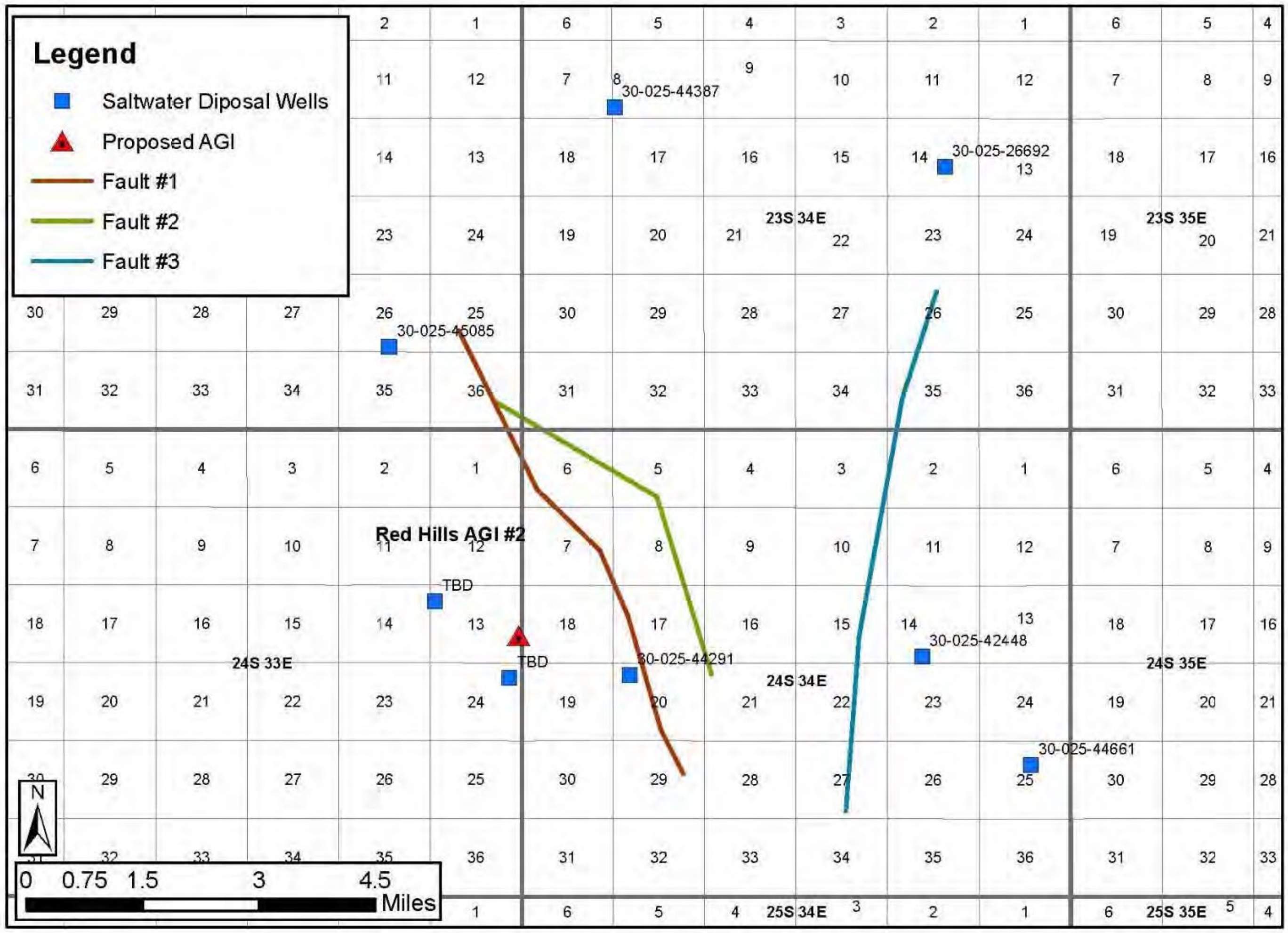


Figure 3.5-1 -- Location Map Showing Saltwater Disposal Wells and Observed Faults within the Area of Proposed RH AGI #2

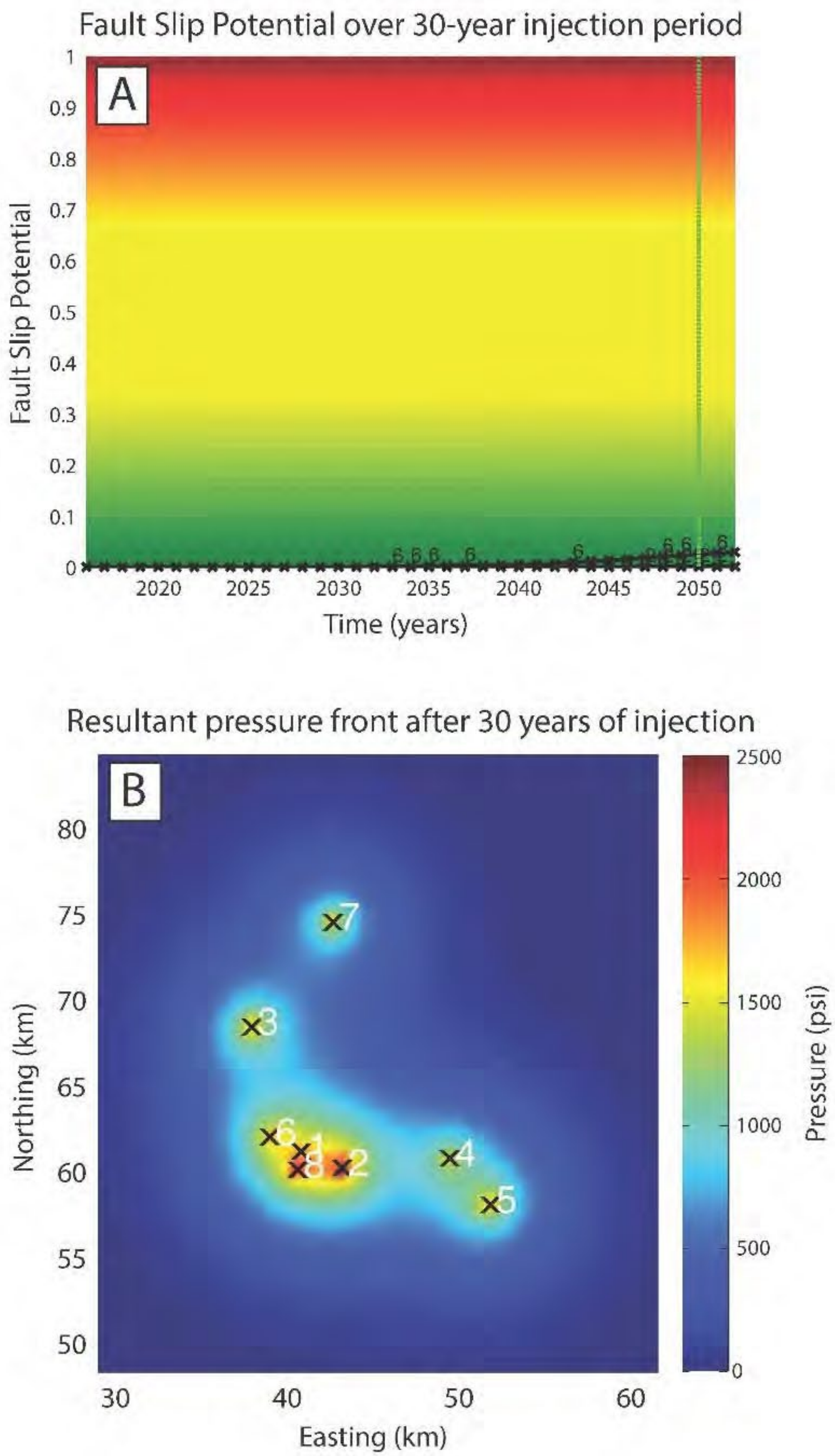


Figure 3.5-2 -- Model Predicted Fault Slip Potential over 30 Years (Panel A) and Resultant Pressure Front at Year 2050 (Panel B)

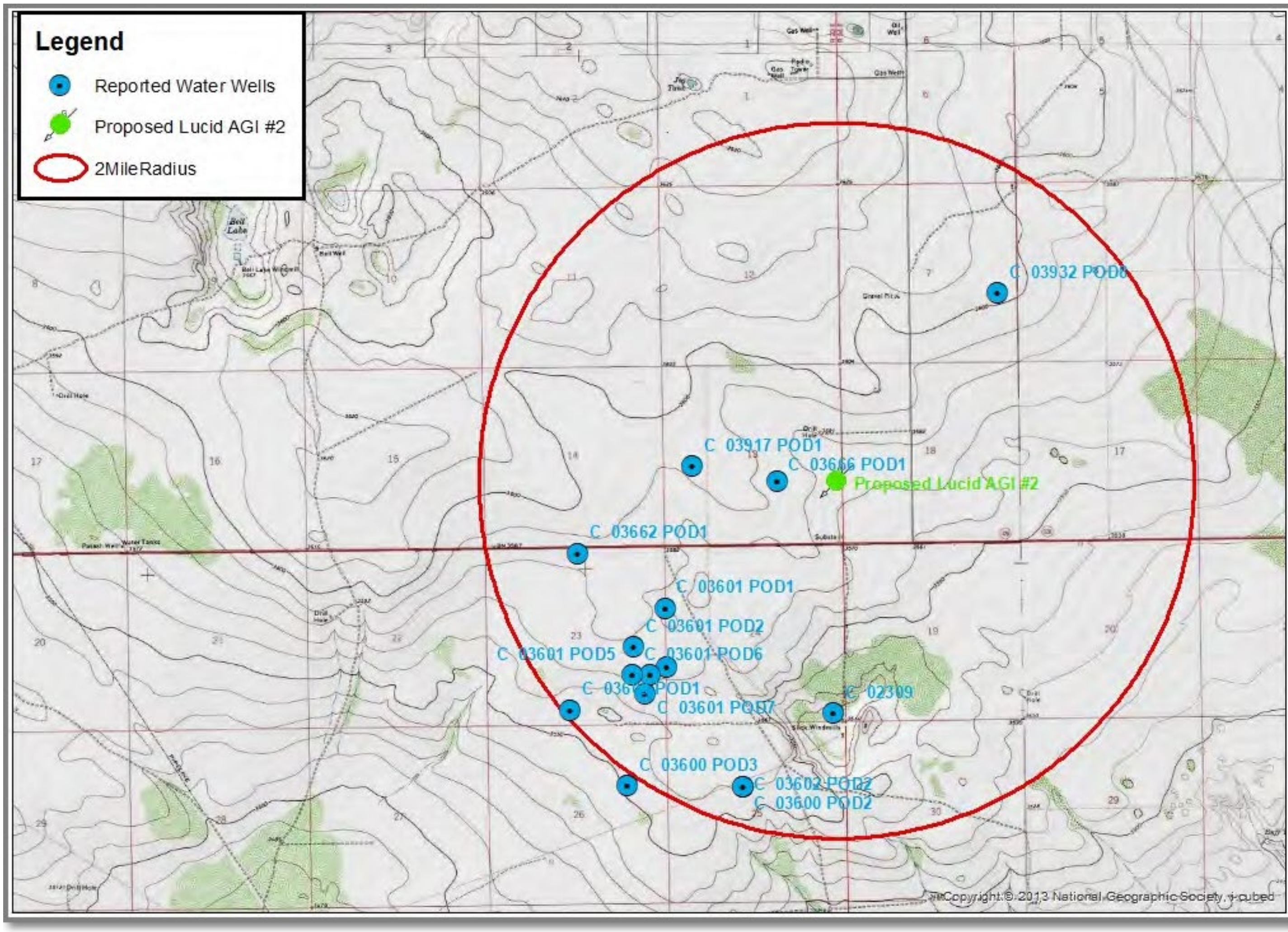


Figure 3.6-1 -- Reported Water Wells within 2-mile Radius of Proposed Lucid AGI #2

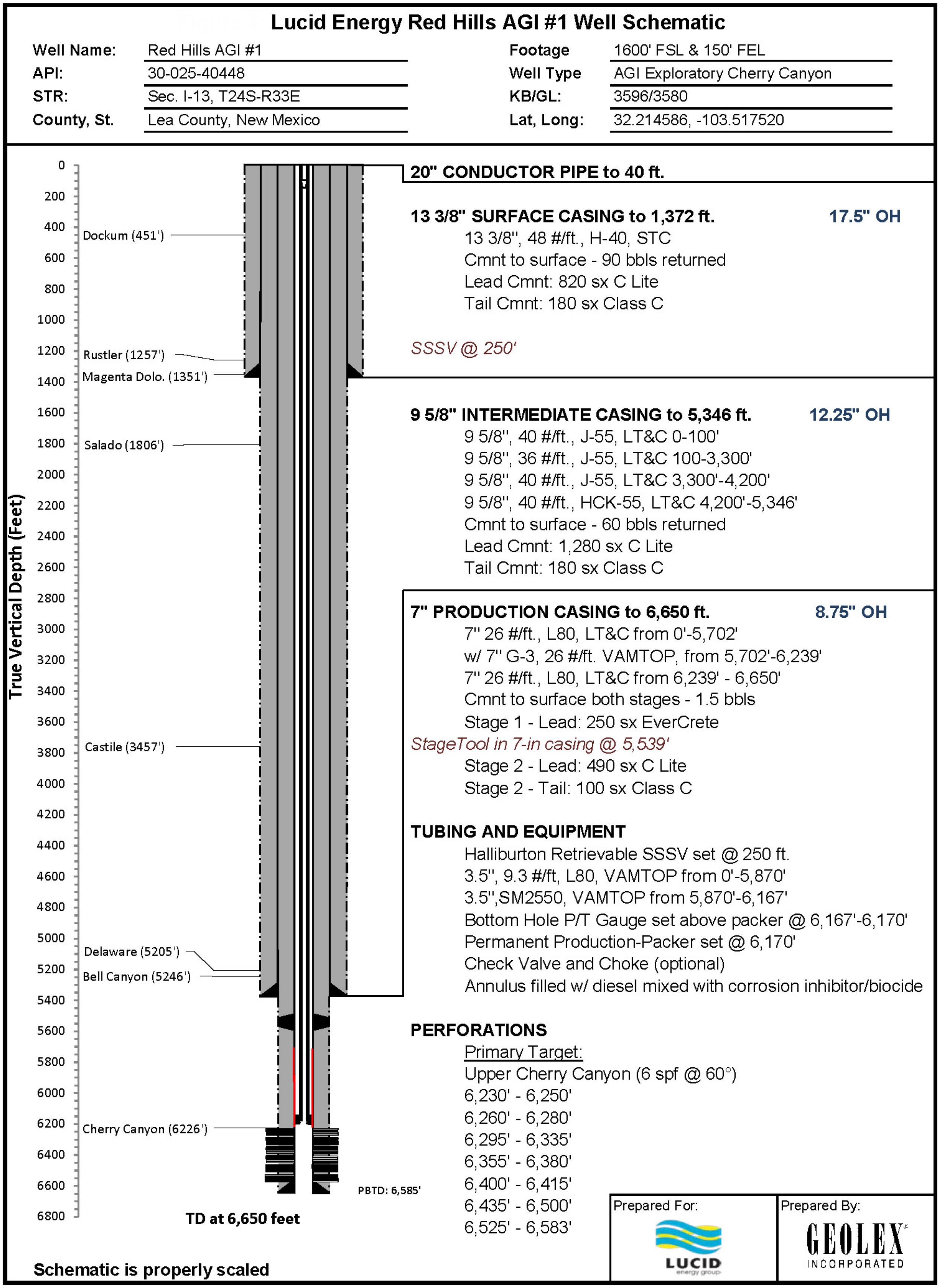


Figure 3.6-2 – Schematic of RH AGI #1

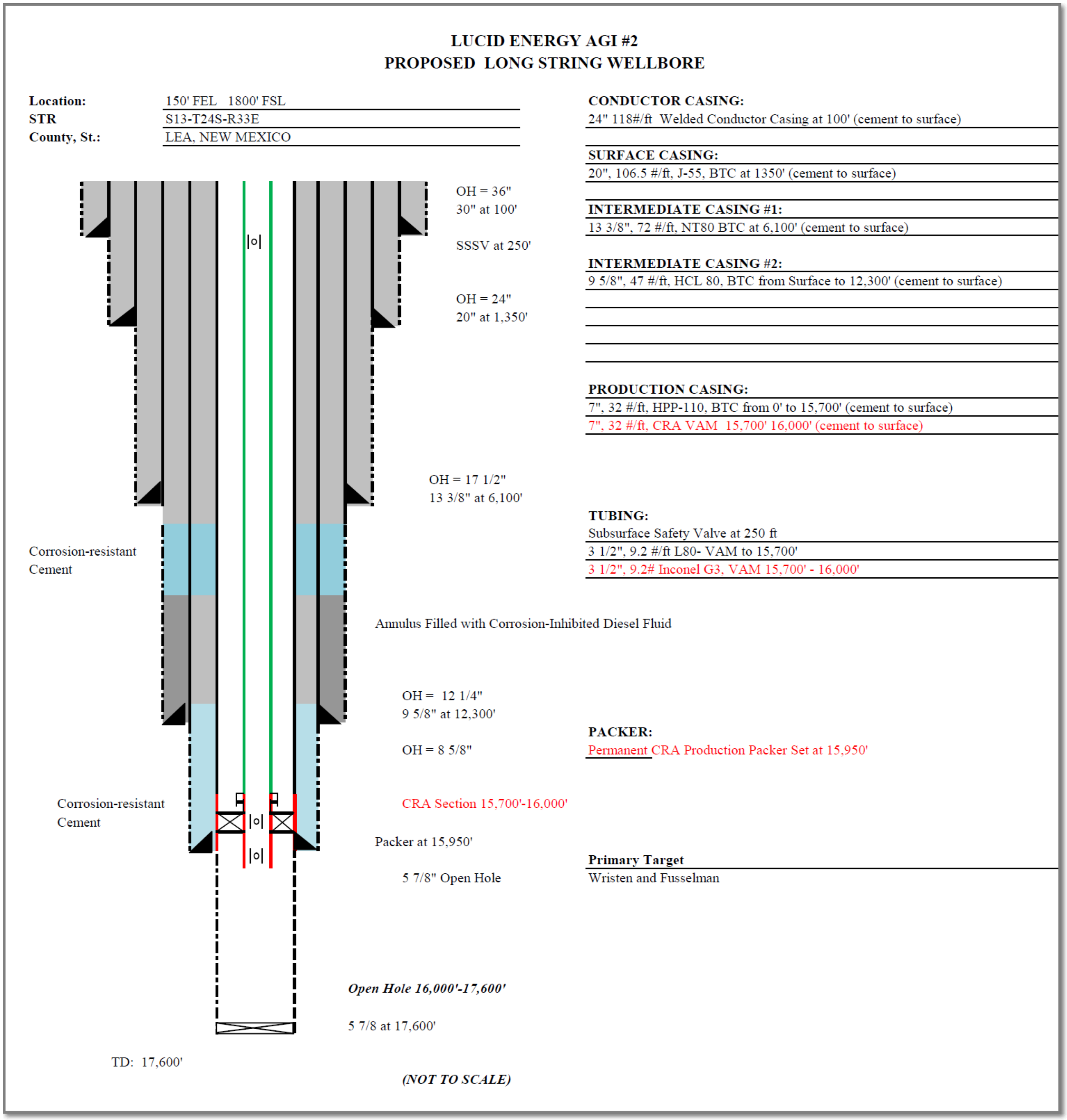


Figure 3.6-3 – Schematic of Proposed RH AGI #2 (Option 2)

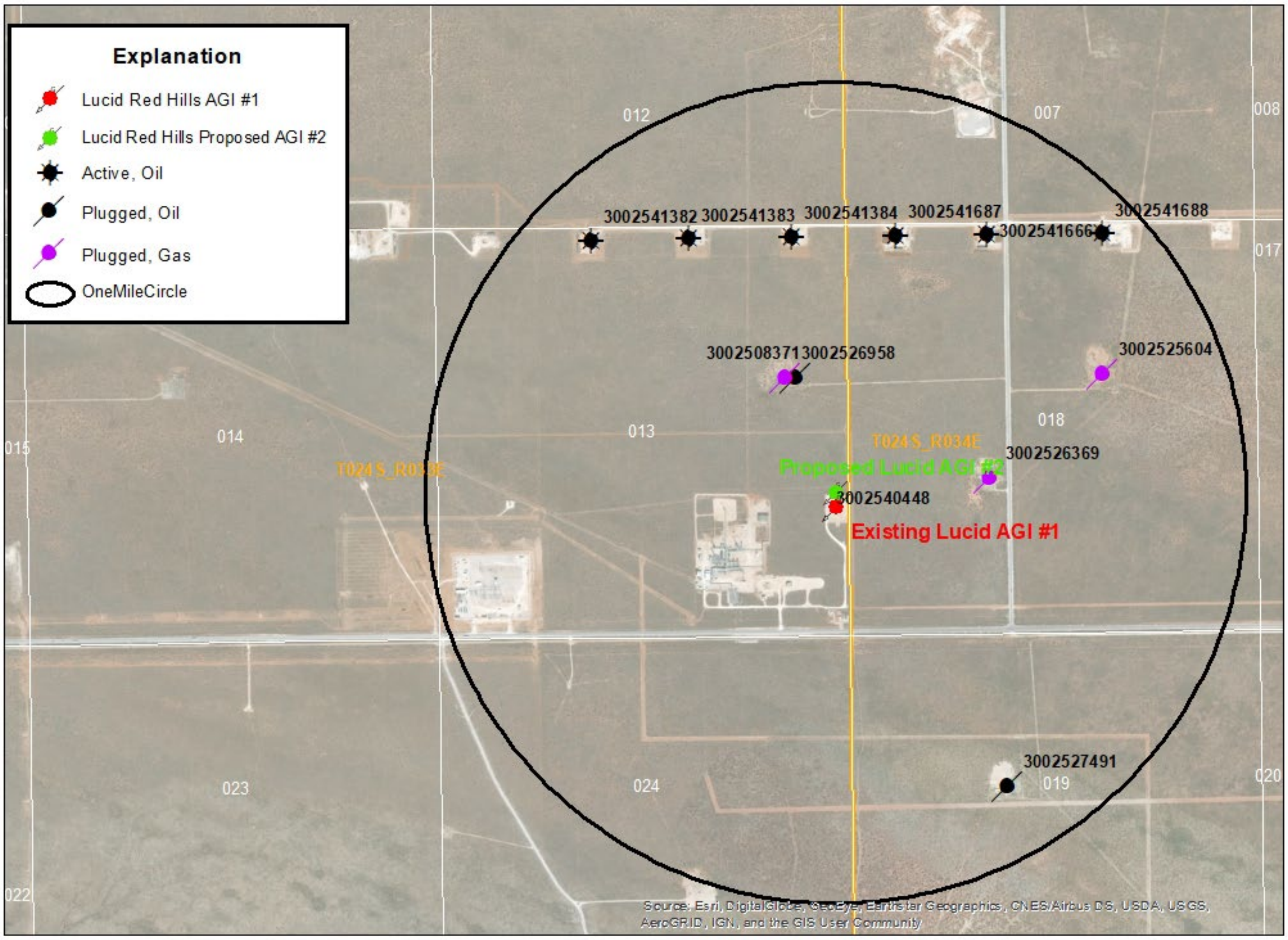


Figure 3.7-1 – Location of Oil and Gas Wells within a One-Mile Radius of the RH AGI Wells

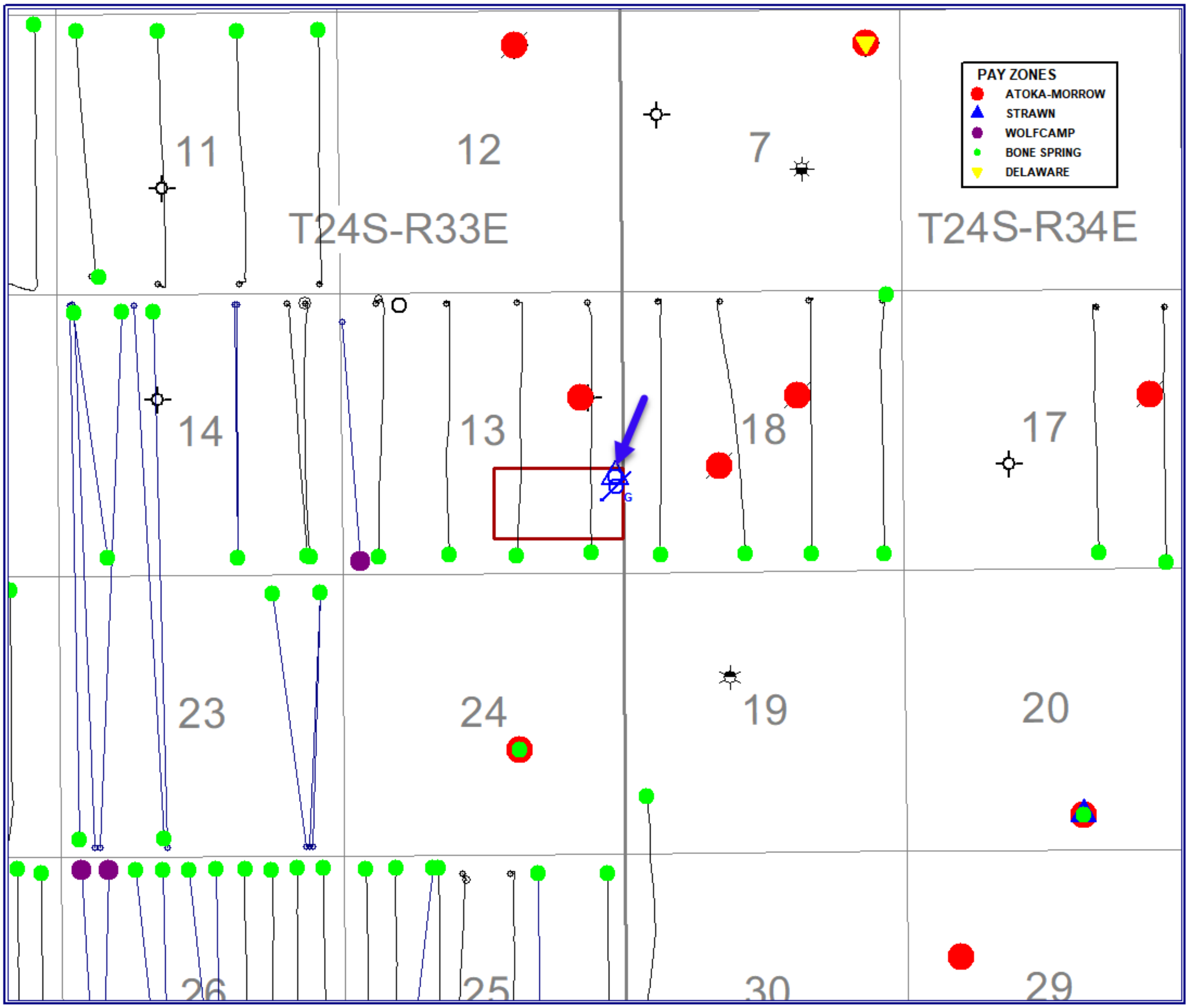


Figure 3.7-2 – Producing Well in the Area of the Red Hill Gas Plant.

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

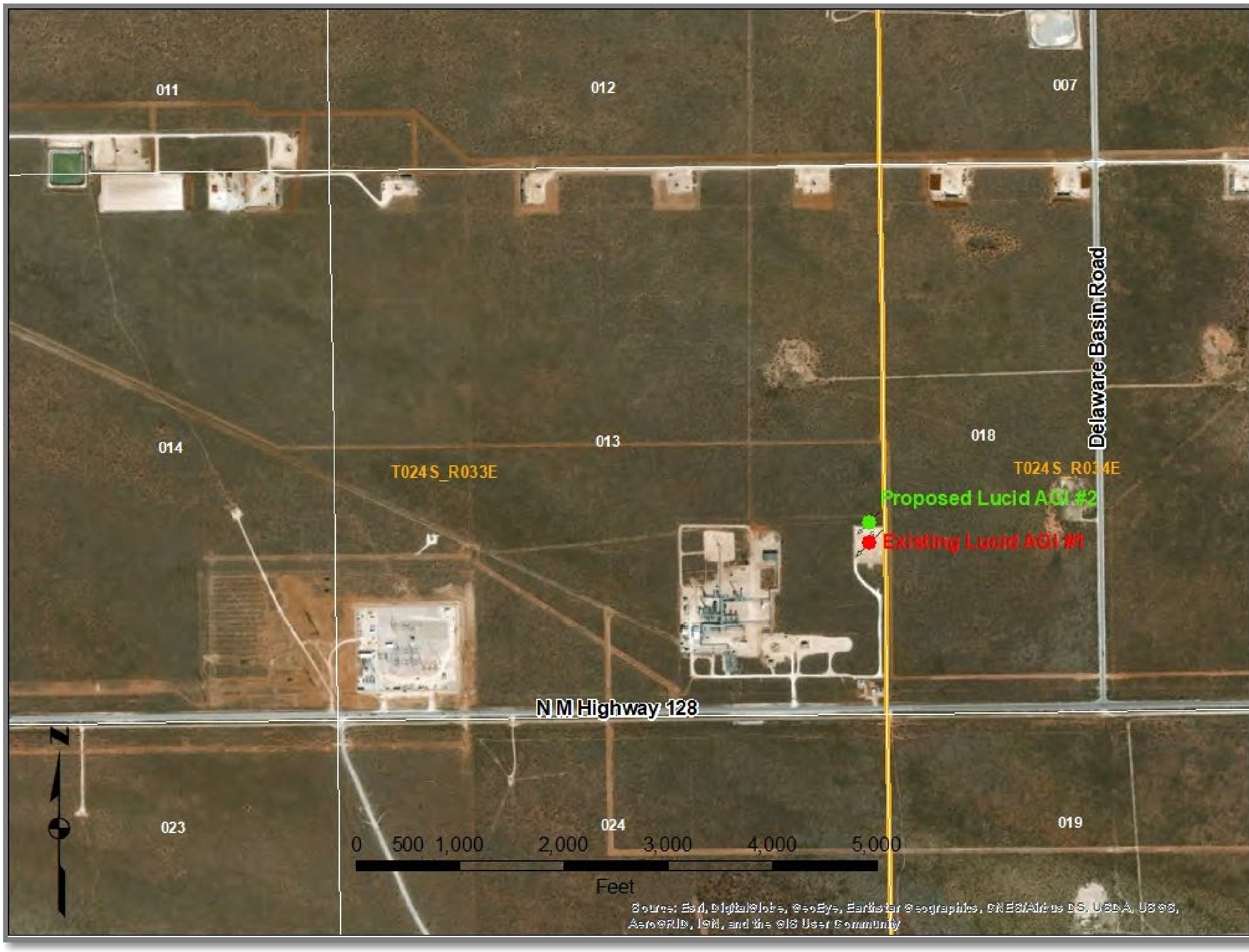


Figure 3.8-1 – Detailed Location of Lucid Energy Existing RH AGI #1 Well and Proposed RH AGI #2 Well

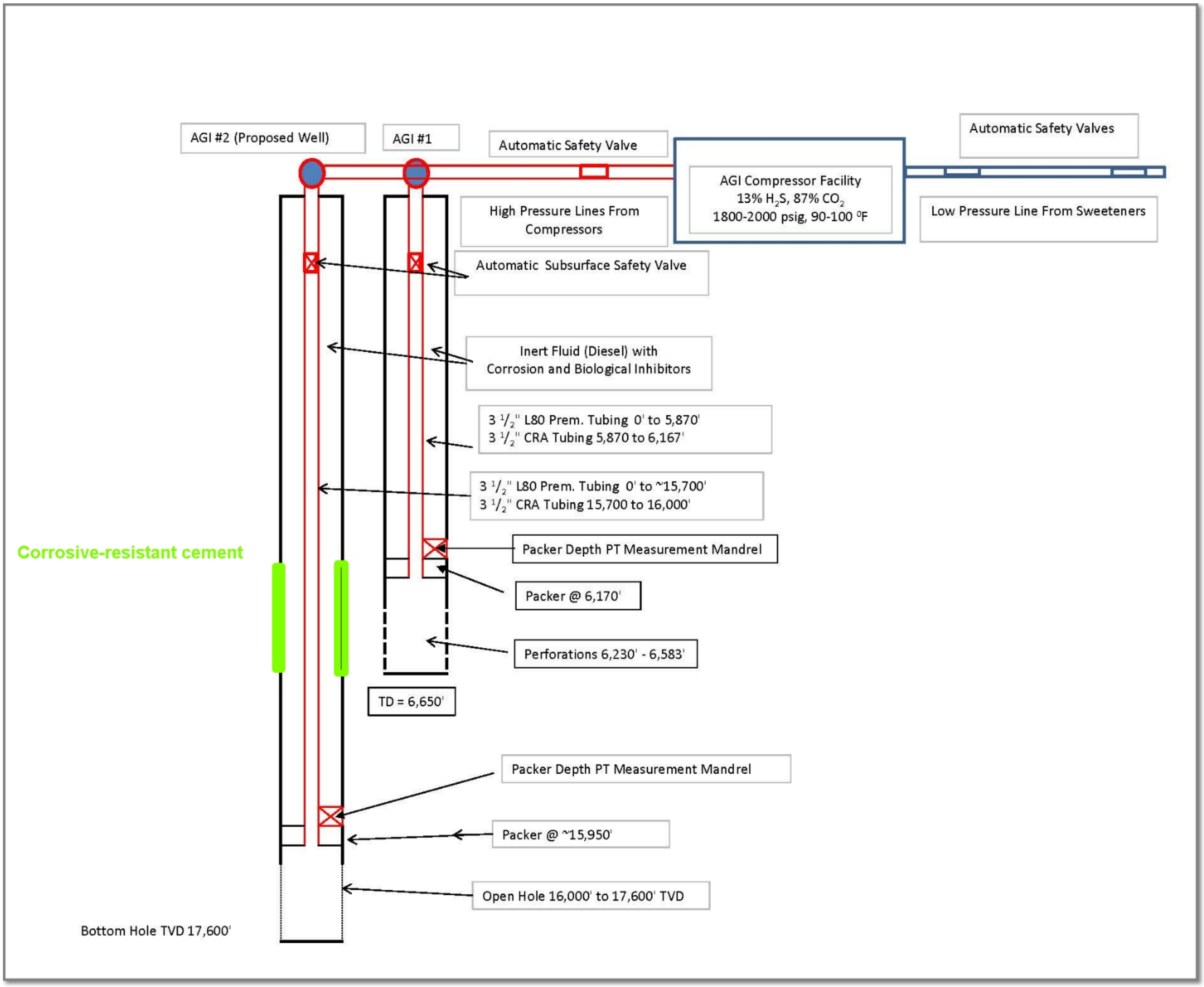


Figure 3.8-2 -- Schematic of Surface Facilities and Wells, Lucid Hills Gas Plant

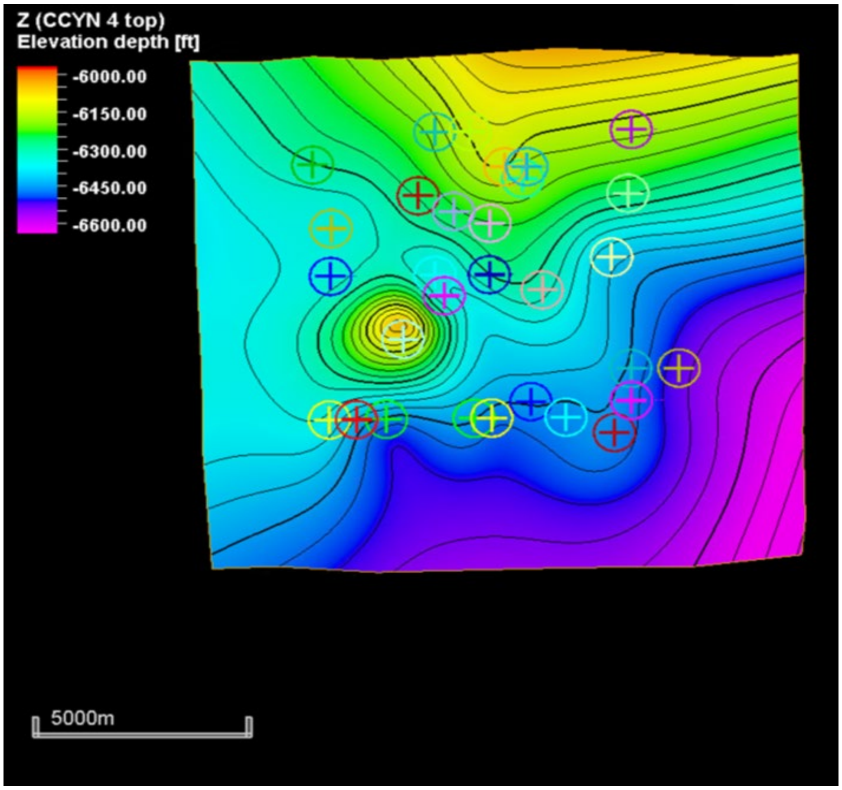


Figure 3.9-1 - shows the structural surface for a layer within the geological model.

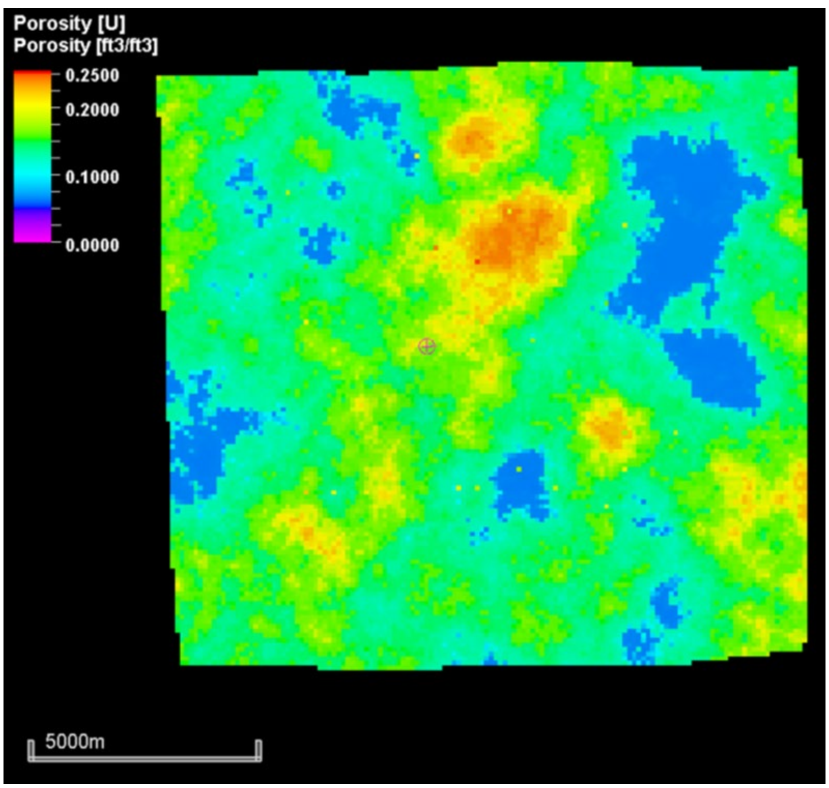


Figure 3.9-2 - shows the distribution of porosity in a layer view for the Cherry Canyon.

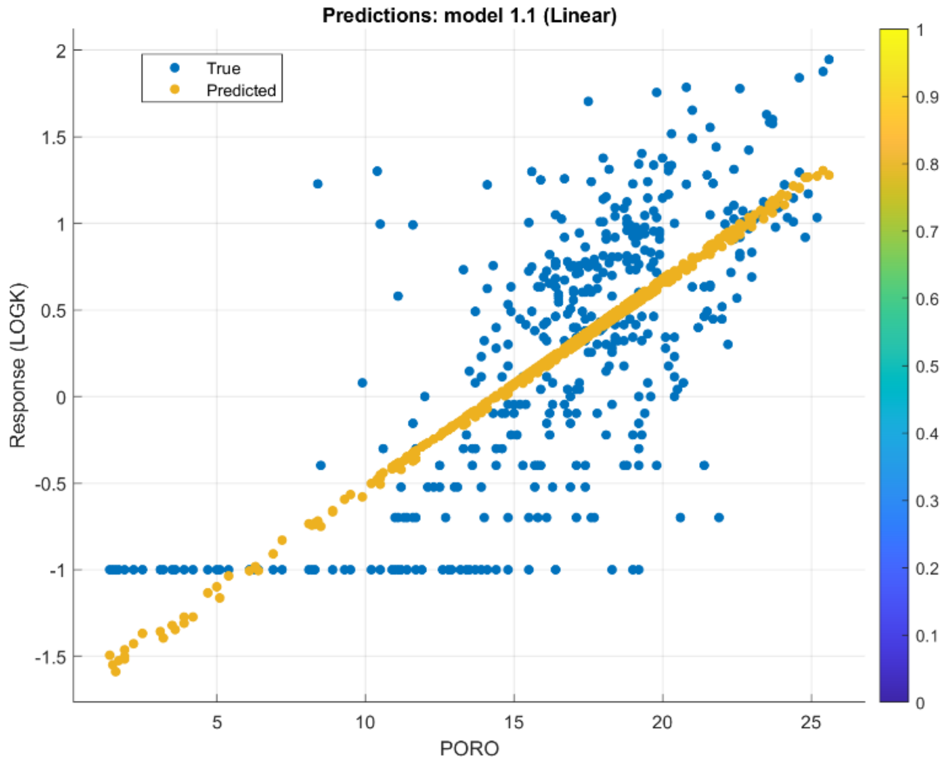


Figure 3.9-3 – porosity-permeability relationship for the Cherry Canyon formation.

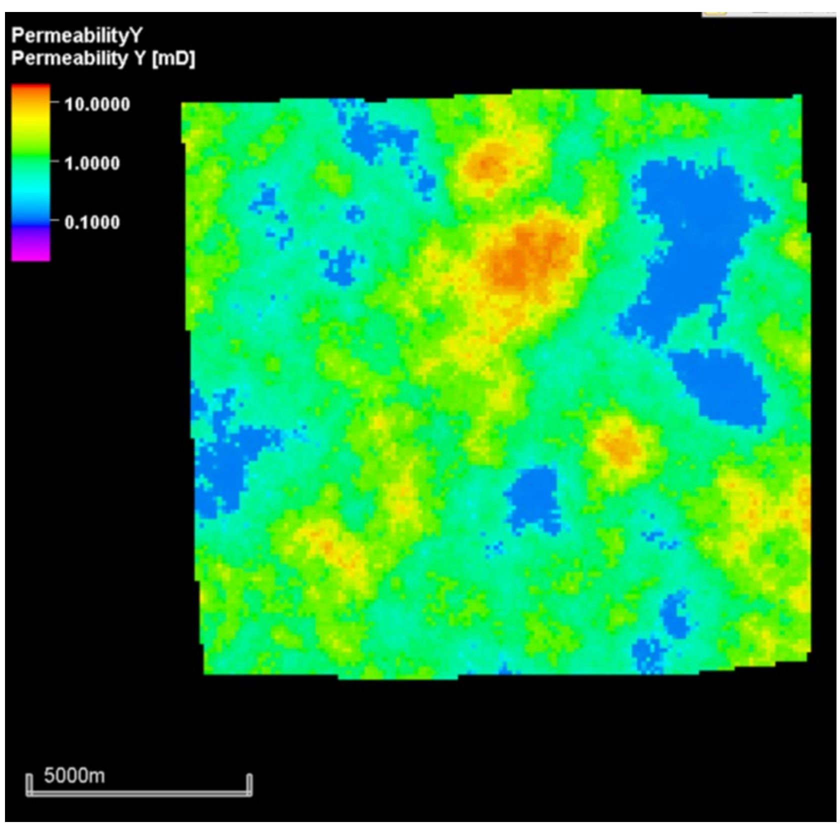


Figure 3.9-4 - shows the permeability distribution.

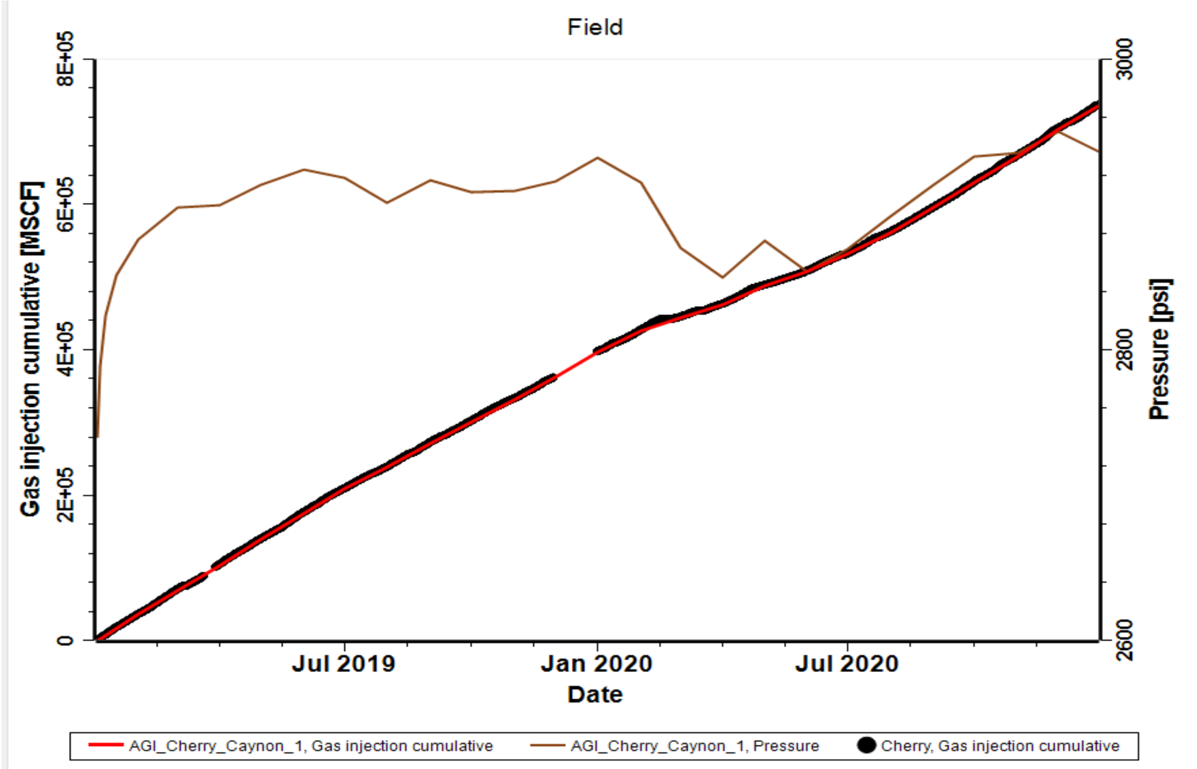


Figure 3.9-5 - shows the calibrated cumulative gas injection and field pressure profile.

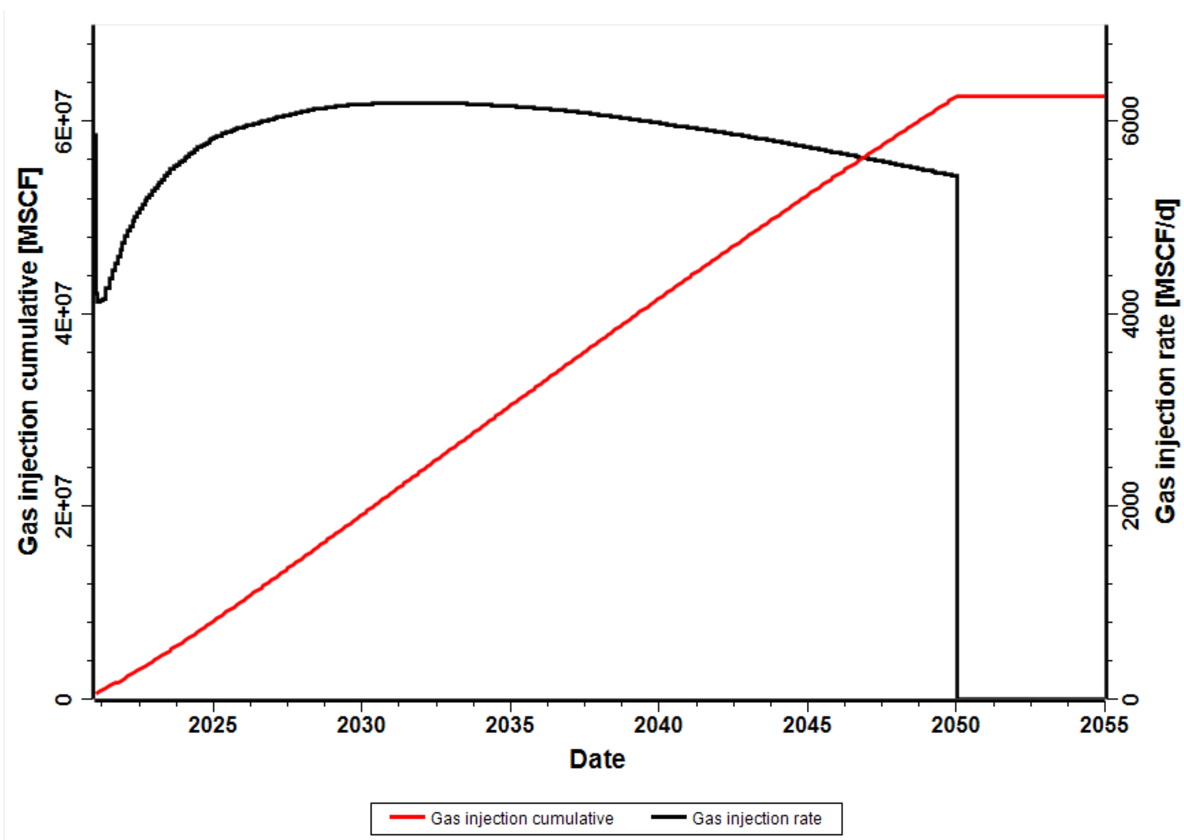


Figure 3.9- 6 - shows the forecast profile for the injection rate and cumulative injection volume over the simulated period.

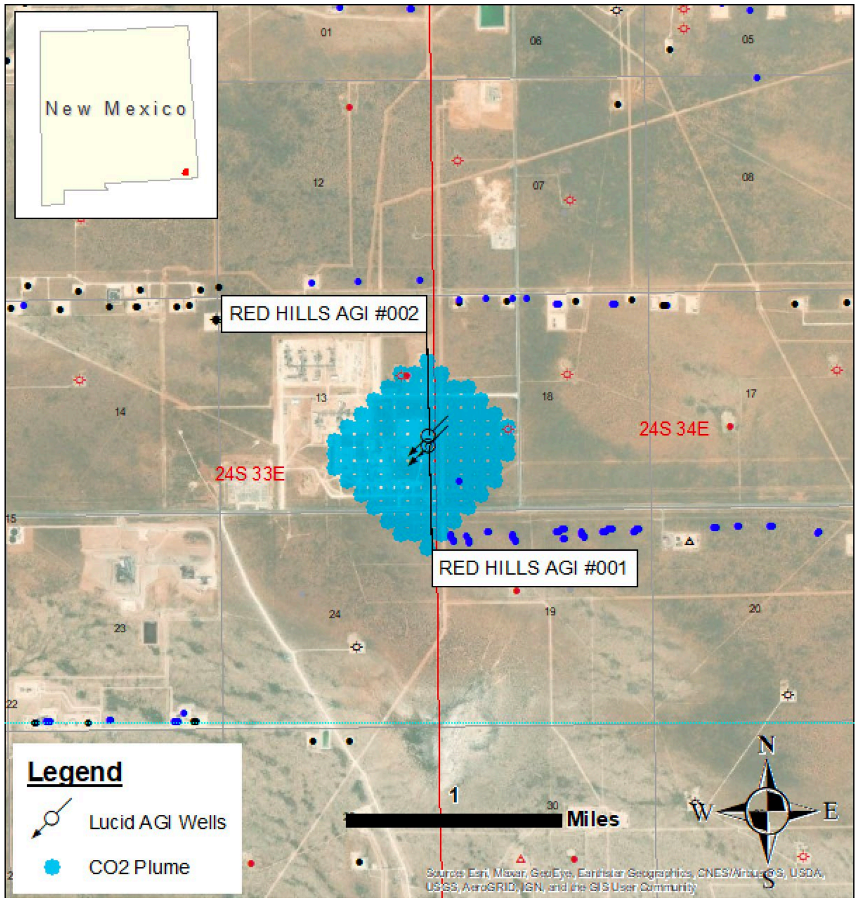


Figure 3.9-7 - shows the largest lateral extent of the TAG within the Cherry Canyon.

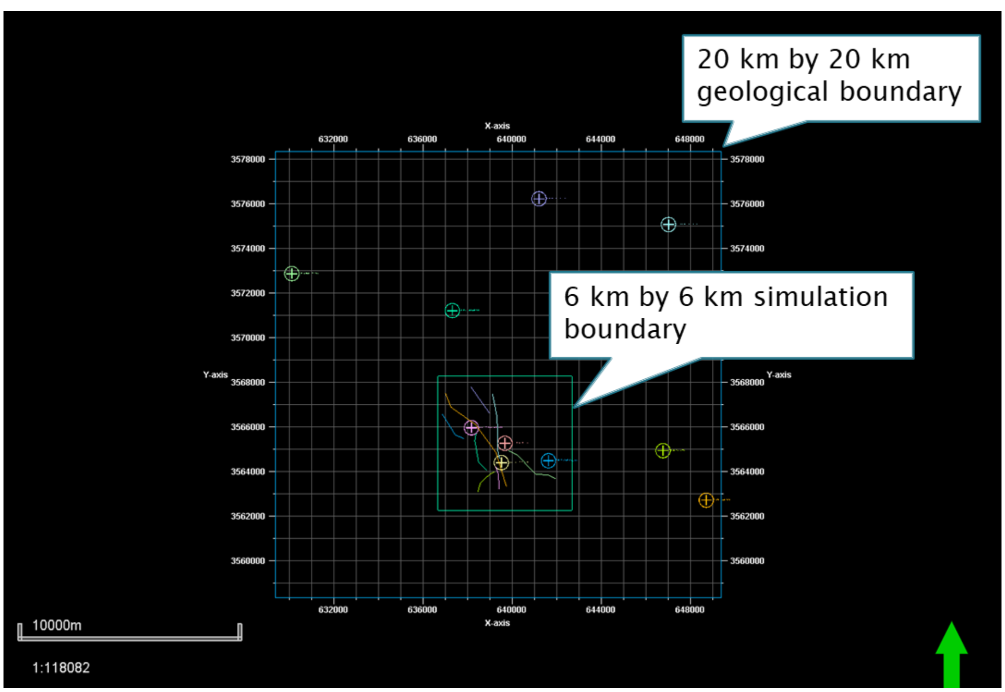


Figure 3.9-8 - shows the top view of the geological and simulation model boundaries.

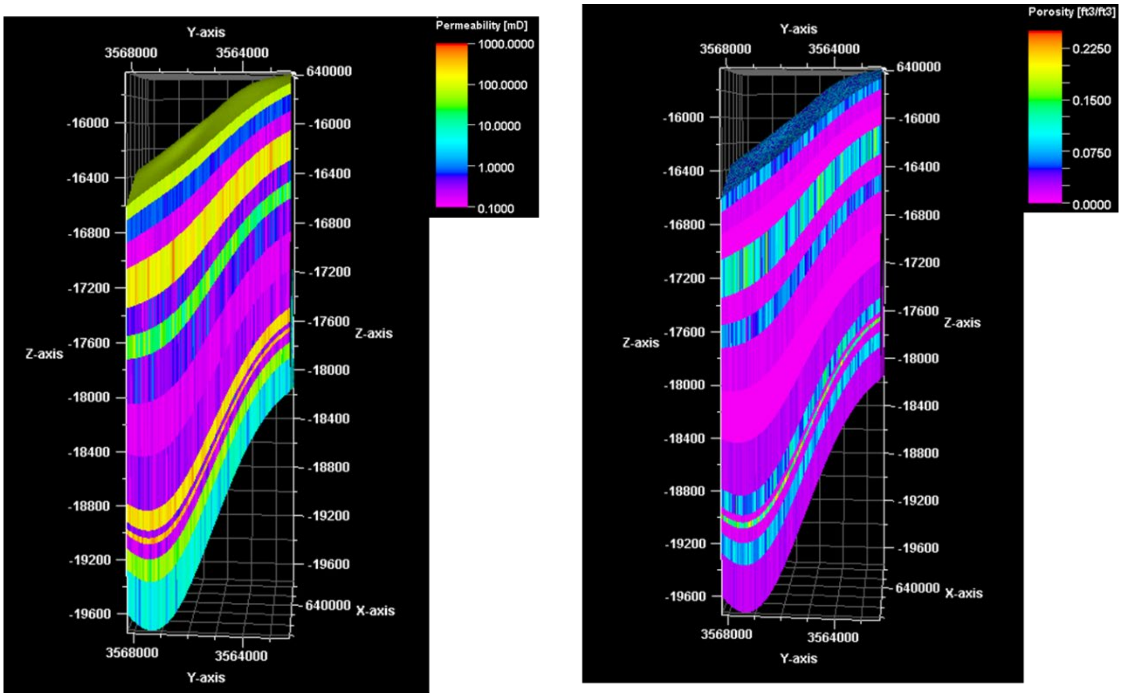


Figure 3.9-9 - A 3D view of Siluro-Devonian modeled permeability (a) and porosity (b) distributions.

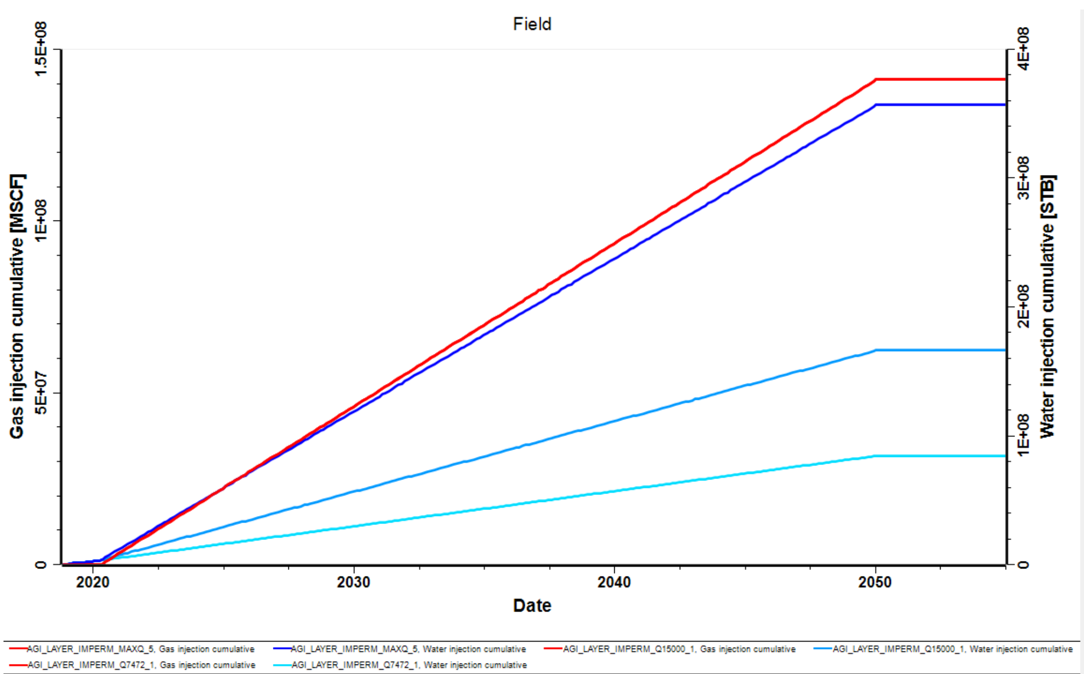
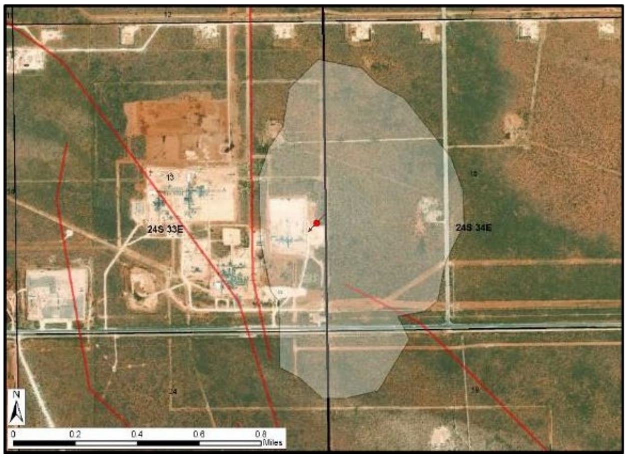
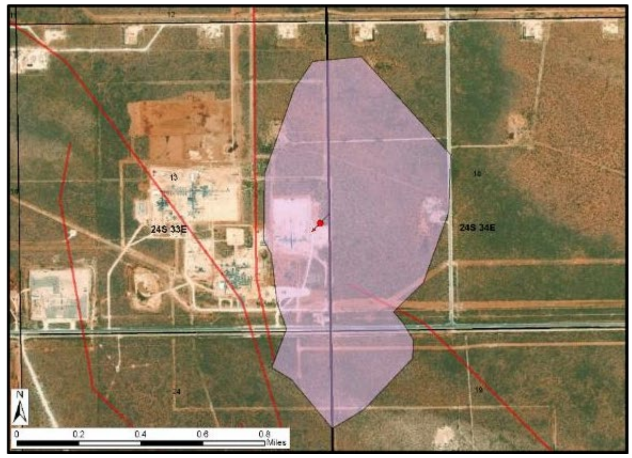


Figure 3.9-10 - shows the injection profile of the AGI #2 and SWD at different injection scenarios.

Striker 6 – 7,472 bpd



Striker 6 – 15,000 bpd



Striker 6 – 32,500 bpd

Figure 3.9-11 - shows the corresponding extent of the TAG results from the furthest lateral extend-closed.

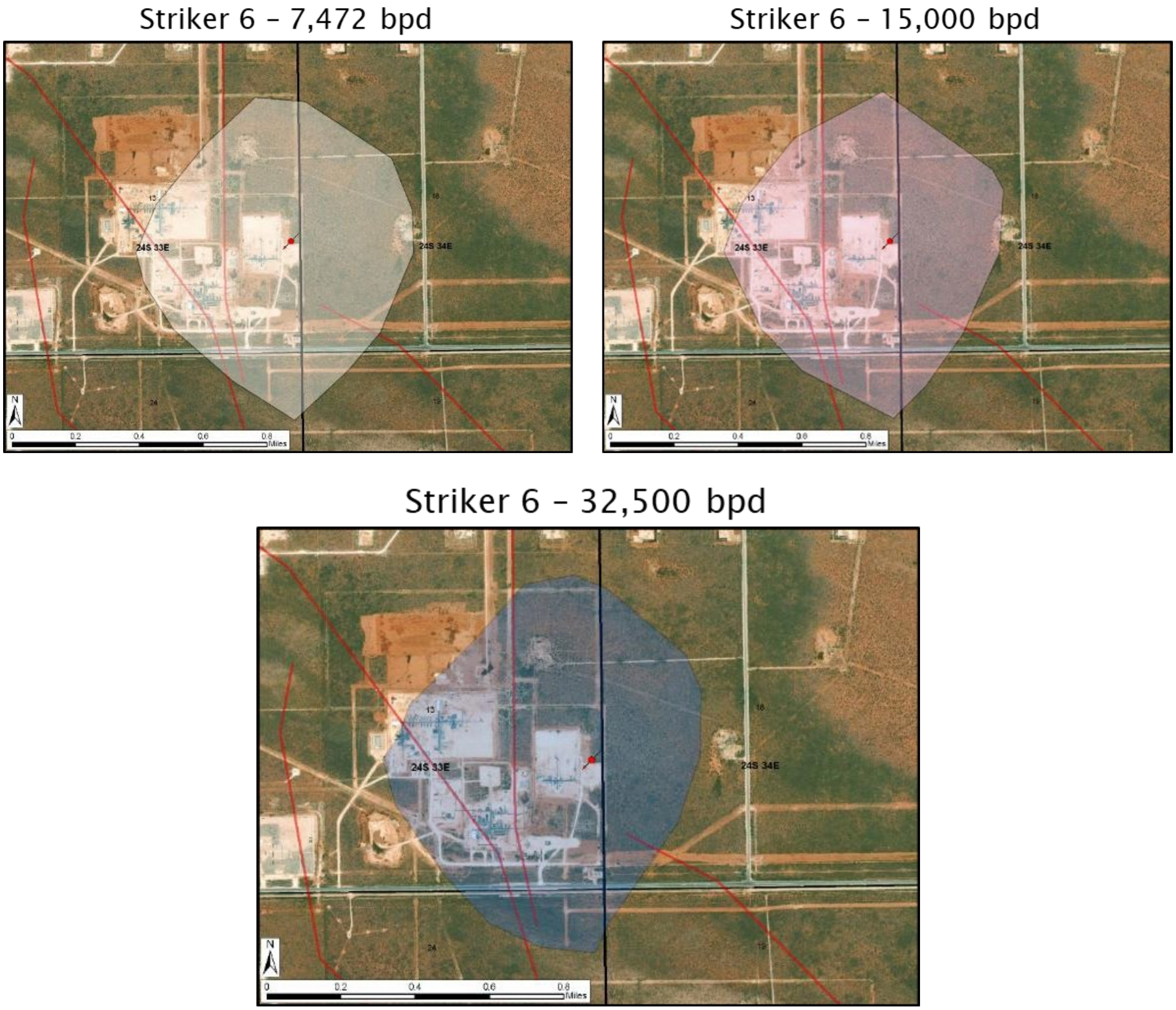


Figure 3.9-12 - shows the largest lateral extent of the TAG when the faults mapped- transmissive.

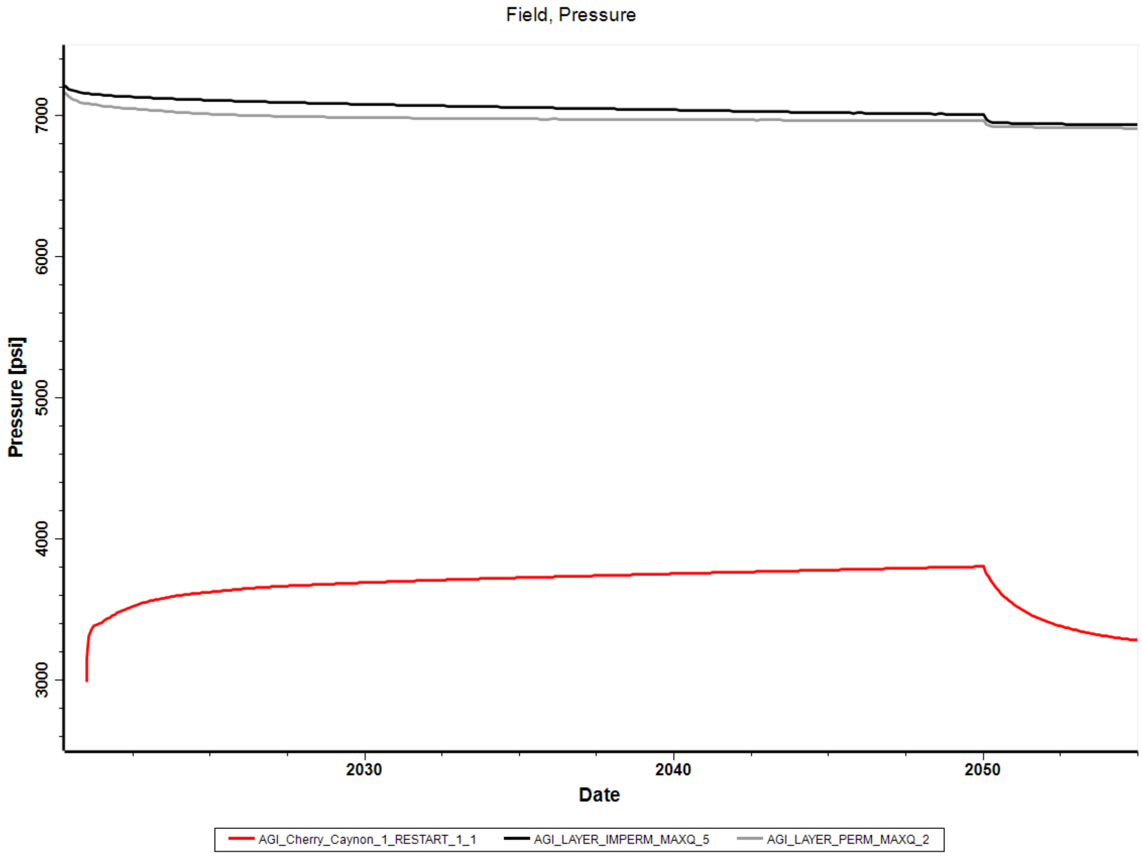


Figure 3.9-13 - shows pressure profile for both Cherry Canyon and Siluro-Devonian formation during injection and monitoring periods.

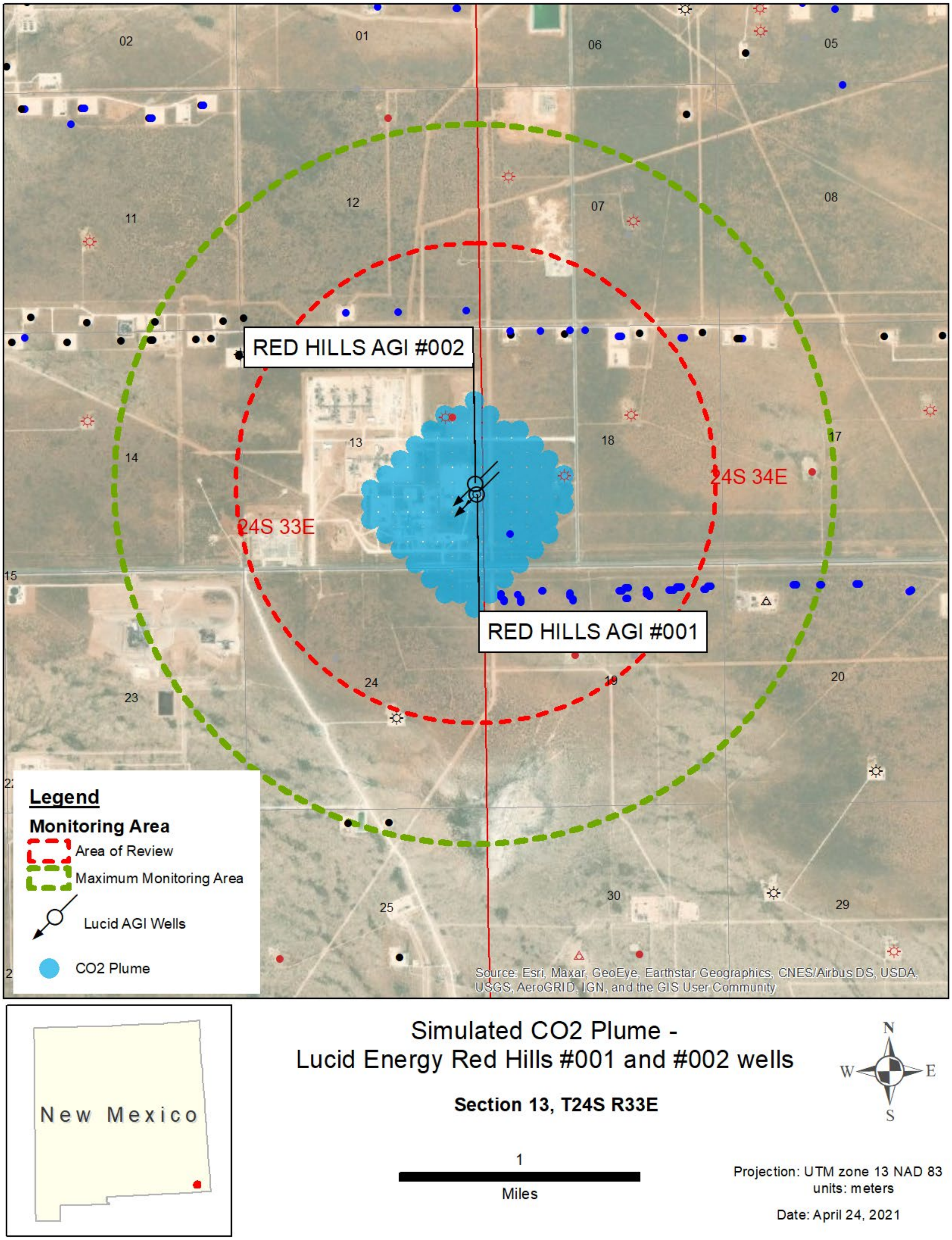


Figure 4.1-1 -- Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA) for Lucid Red Hill RH AGI #1 and RH AGI #2 Wells

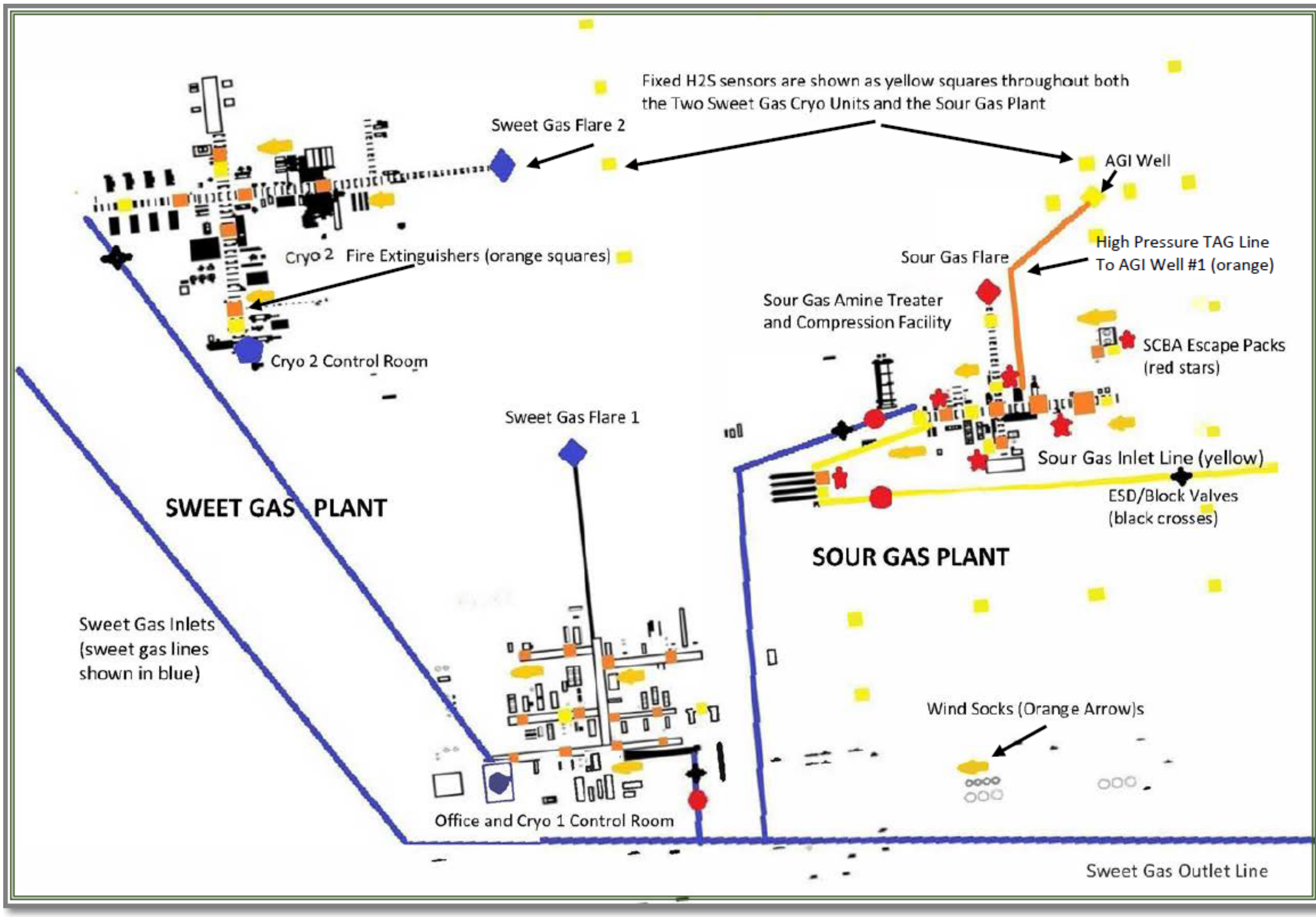


Figure 5.1-1 – Red Hill Gas Plant Plot Plan Showing Location of Major Process Units (taken from the H_2S Contingency Plan for Red Hills) The yellow squares indicate the location of fixed H_2S sensors.

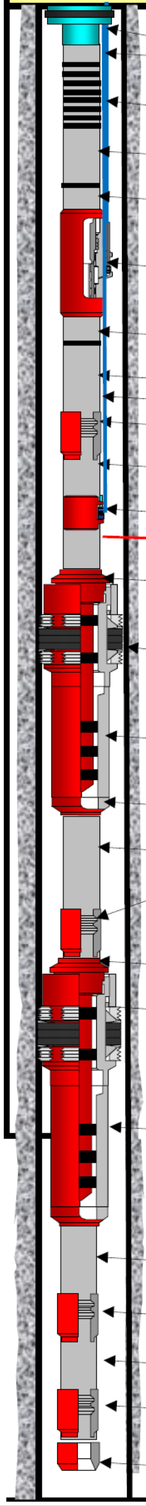
HALLIBURTON

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



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	5.200	2.992
	6,162.6 Annular	P/T		6' VAMTOP 9.2# CRA Tubing Sub Above & Below Gauge Mdl		
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

14 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 - 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

Madalyn S. Blondes, Kathleen D. Gans, James J. Thordsen, Mark E. Reidy, Burt Thomas, Mark A. Engle, Yousif K. Kharaka, and Elizabeth L. Rowan, 2014. U.S. Geological Survey National Produced Waters Geochemical Database v2.1, *http://energy.usgs.gov/EnvironmentalAspects/EnvironmentalAspectsofEnergyProductionandUse/ProducedWaters.aspx*

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H_2S Contingency Plan, Lucid Energy, April 2018, Red Hills Gas Processing Plant, Lea County, NM

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Nicholson, A., Jr., Clebsch, A., Jr., 1961. *Geology and ground-water conditions in southern Lea County, New Mexico.* New Mexico Bureau of Mines and Mineral Resources, Ground-Water Report 6, 123 pp., 2 Plates.

Powers, D.W., Lambert, S. J., Shafer, S., Hill, L. R. and Weart, W. D., 1978., *Geological Characteristic Report, Waste Isolation Pilot Plant (WIPP) Site, Southeastern New Mexico (SAND78-1596)*, Department 4510, Waste Management Technology, Sandia Laboratories, Albuquerque, New Mexico

Silver, B.A., Todd, R.G., 1969. Permian cyclic strata, northern Midland and Delaware Basins, west Texas and southeastern New Mexico, *The American Association of Petroleum Geologists Bulletin* 53: 2223- 2251.

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Ward, R.F., Kendall, C.G.St.C., Harris, P.M., 1986. Upper Permian (Guadalupian) facies and their association with hydrocarbons – Permian Basin, west Texas and New Mexico. *The American Association of Petroleum Geologists Bulletin* 70: 239-262

Appendix 4 - Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
BMT – billion metric tonnes
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
cf – cubic feet
cm – centimeter(s)
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
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
HC – hydrocarbon
HFU – hydrocarbon flow unit
m – meter(s)
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
Mscf – thousand standard cubic feet
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRRW B – Morrow B
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MMT – Thousand metric tonnes
MT -- Metric tonne

NG—Natural Gas
NGLs – Natural Gas Liquids
NIST - National Institute of Standards and Technology
NMOCC – New Mexico Oil Conservation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SCITS - Stanford Center for Induced and Triggered Seismicity
SEM – scanning electron microscope
ST – Short Ton
SWP - Southwest Regional Partnership on Carbon Sequestration
TAG – Treated Acid Gas
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USEPA – U.S. Environmental Protection Agency
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

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 temperature 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 6 - Subpart RR Equations for Calculating Annual Mass of CO2 Sequestered

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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}}$$ (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

$$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}}$$ (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

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

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

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

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

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

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

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

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

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

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 CO2 Sequestered for Operators Actively Producing Oil or Natural Gas or Any Other Fluid

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

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 CO2 Sequestered for Operators NOT Actively Producing Oil or Natural Gas or Any Other Fluid

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

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.