Chapter 1. Acid Gas Injection in the Permian and San Juan Basins: Recent Case Studies from New Mexico

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1.1. Abstract

Acid gas injection (AGI) is becoming an increasingly popular choice for the disposal of gas processing wastes and CO_2 sequestration in New Mexico. Four AGIs have been brought on-line and several additional projects have been successfully permitted in the last few years. The first AGI well in northwestern New Mexico has been successfully drilled and is being completed and tested in time for the initiation of operation by year end. AGI has proven to be a cost-effective and environmentally-beneficial alternative to traditional treatment systems. While New Mexico has an abundance of deep saline aquifers suitable for injection, site selection is complicated by extensive oil and gas production. In this paper we explore reservoir selection and characterization, permitting, design and completion of AGI wells using examples of wells in New Mexico. We also discuss ongoing efforts to register similar projects as permanent CO_2 sequestration sites and potentially obtain associated carbon credits.

Search Terms: Acid Gas Injection (AGI), AGI wells, AGI well design, dry injection, wet injection, injection reservoir selection, reservoir evaluation, carbon sequestration, CO_2 sequestration, New Mexico

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1.2. Background

New Mexico has a long history of oil and gas development and production in two primary sedimentary basins (Figure 1.1). The Permian Basin of west Texas extends westward into southeastern New Mexico and includes a portion of the Central Basin Platform and the Delaware sub-basin to the west. The San Juan Basin located in the north-central and northwestern portions of the state and is located on the Colorado Plateau. These basins produce oil and both sweet and sour gas. The increased demand for natural gas as a "clean" fossil fuel, combined with discovery of new reserves and increased pipeline capacity to these markets, have resulted in the construction of a large number of natural gas processing plants in these basins over the last 45 years.

New Mexico has thirteen natural gas processing plants that process sour gas, twelve in the Permian Basin and one in the San Juan Basin. Some of these plants have traditionally used Class II injection wells to dispose of wastewater associated with natural gas processing. The methodology of choice for addressing H_2S and CO2 in the treated waste acid gas (TAG) from the amine units at natural gas processing plants has been the use of sulfur recovery units (SRUs) to convert this waste stream into native sulfur, CO2 and H20 using the Claus process (1). In this process, the waste CO_2 from the acid gas stream is then released to the atmosphere along with additional CO_2 emissions from the combustion sources used to keep the SRUs at optimum operating temperature. Many of these units are now 30-40 years old, are expensive to maintain and often have upsets. These upsets require excess flaring of the waste gas stream and result in violations of air quality permits at these plants. In addition, many of these plants are bottle-necked in terms of processing capacity by the capacity of these aging SRUs. These factors, combined with the added pressure on companies to reduce greenhouse gas (GHG) emissions, provide powerful incentives to utilize acid gas injection (AGI) as an alternative to SRUs for treatment and disposal of the waste acid gas from plants which process sour gas. In addition, the GHG reporting rules which go into effect in 2010 (2) contribute to the already existing regulatory and economic drivers which encourage the use of AGI and geologic sequestration of CO_2 as a technology of choice for addressing both H_2S and CO_2 waste streams at these natural gas processing plants.

Geolex, Inc.® (Geolex) is an industry leader in providing comprehensive solutions to the natural gas processing industry in acid gas injection and CO_2 sequestration. Over the last decade we have developed specialized expertise and significant practical experience in planning and successfully permitting, designing and constructing AGI wells for the natural gas processing industry. These wells include both types of disposal and sequestration systems, TAG-only (dry gas injection) and combined TAG/wastewater (wet gas injection). While many of the same considerations go into the identification and characterization of adequate potential reservoirs for AGI and CO_2 sequestration, dry and wet gas configurations result in distinctly different equipment and material requirements along with operational considerations and limitations. This paper presents an overview of the critical factors involved in identifying and characterizing potential reservoirs for the geologic sequestration of these wastes and the steps involved in successfully planning, permitting, designing and executing both wet and dry gas injection projects. Three case studies have been selected to illustrate the process from initial planning through start-up and operation of both dry and wet gas injection systems. In addition, we provide a synopsis of important considerations and the current potential for registration of carbon credits resulting from the permanent geologic sequestration of CO_2 associated with both types of AGI projects.

1.3. AGI Project Planning and Implementation

The successful execution of an AGI project requires the implementation of a step-by-step process where the goals of the project and critical constraints are identified and evaluated in the context of specific regulatory requirements and operational limitations unique to each site (Figure 1.2). In addition to the design, permitting and construction of related surface compression facilities, our process for AGI projects includes the following six steps:

- Project Planning and Feasibility Study
- Reservoir/Cap Rock Identification and Regulatory Permitting
- Well Drilling and Testing
- Reservoir and Seal Evaluation
- Well Completion and Construction
- Documentation, System Start-up and Reporting

Each of these steps involves a multi-disciplinary team of professionals working together in close coordination with engineering and operational staff from the facility to ensure that relevant technical and regulatory goals are met on-schedule and within budget.

1.3.1. Project Planning and Feasibility Study

The project planning process begins with the definition of project goals and objectives, constraints, regulatory, economic and schedule considerations. This involves a determination of the amount and composition of the acid gas stream to be treated. The amount and composition of the acid gas stream varies with plant capacity and the field gas mix that is being processed at the facility. It is important to consider not only current plant capacity and field gas mix but, to the extent possible, the future potential for capacity expansion and changes in composition of the field gas. Often projects are designed and permitted to handle variable injection volumes over the projected life of a facility. Typical TAG compositions range from 75%-90% CO_2, 10%-25% H_2S and trace-2% hydrocarbons by volume.

In addition to volume and composition considerations, it is necessary to determine whether the specific facility requires an integrated solution to the disposal of associated wastewater (in the USA this is referred to as Class II wastewater (3) or whether only acid gas disposal is required. The higher material costs associated with wet vs. dry gas injection must be balanced with the costs associated with handling the two waste streams separately. Wet gas injection requires the use of more expensive materials in most of the well components due to the corrosive nature of the combined acid gas/wastewater stream. Another important consideration when deciding between wet and dry gas injection, is the availability of additional reservoir capacity required to accommodate the added volume of both acid gas and wastewater streams.

Once the ranges in volume and composition of the waste stream over the projected life of the facility have been determined, the reservoir requirements can be established. Obviously it is preferable to site the AGI well on or immediately adjacent to the plant; however, sometimes the geologic and regulatory constraints on a technically and economically-feasible sequestration reservoir may require an off-site well location. Most natural gas processing plants are located in established oil and gas provinces where there is a significant amount of subsurface geologic information available to evaluate potential reservoirs; however, it is necessary to consider the degree to which the integrity of the upper and lower seals (cap rock) of the potential reservoir may have been compromised by past or future oil and gas exploration and development. Another important consideration is the proximity to existing mineral, oil and gas reserves and drinking water reservoirs. While adequate sequestration targets are almost exclusively found at depths well below potable groundwater resources, in depleted oil and gas reservoirs or in saline aquifers, care must be taken to assure that these are not impacted by the proposed sequestration of acid gas or acid gas/wastewater. Therefore, the ideal reservoir is a geologic unit which is stratigraphically-located in a manner which it cannot be compromised by future exploration/exploitation of oil and gas resources, is located far below potable water resources and has not been significantly penetrated by plugged oil and gas wells whose integrity may be questionable. Also important in the evaluation of the potential reservoir are any natural geologic features such as faulting or fracturing that could create potential paths for the escape of acid gas from the reservoir.

As mentioned above, since most gas processing plants are located in developed oil and gas provinces, data required for reservoir/cap rock identification and evaluation are usually available in the form of drilling and geophysical logs from nearby wells, seismic data from previous exploration efforts, records of injection wells, published and unpublished regional geologic studies. These data sources include the US Department of Energy (USDOE), US Geological Survey (USGS), Geological Survey of Canada (GSC), state or provincial oil and gas agencies and well as commercial sources such as Petroleum Information Corporation. In addition to geologic data, production and well location data to evaluate the potential interference with existing oil and gas production is available from provincial or state oil and gas agencies. Domestic and industrial water well data are often available from state or provincial water or environmental agencies and from the Water Resources Division of the USGS and the GSC.

The elements of an AGI feasibility study include the gathering and processing of geological and production data to identify and evaluate potential reservoirs within the area of the natural gas processing facility as discussed above. In addition, economic data regarding the costs of well completion and associated above ground facilities and the permitting constraints which apply to the use of the selected reservoir(s) must be developed. Much of the data collected and analyzed for the feasibility study is also used to provide the basis for the permitting application for AGI from the applicable provincial or state agency as described in the following section.

1.3.2. Reservoir/Cap Rock Identification and Regulatory Permitting

The identification and preliminary characterization of the most attractive reservoir and associated cap rock is a critical component of the requirements for obtaining the necessary permits for an AGI project and for evaluating the technical and economic risks associated with the proposed project. The selected reservoir must have the necessary net porosity, permeability and extent necessary to contain the anticipated volume of acid gas or acid gas and wastewater for the entire life cycle of the project. The reservoir must be contained within a geologic structure or stratigraphic trap that is capable of permanently sequestering the injected volume of wastes. Geologic and production data associated with oil and gas wells in the vicinity of the project are used for the preliminary evaluation of the reservoir and the cap rock until it can be supplemented by site-specific data developed during the drilling and completion of the AGI well. These data are useful in the development of permitting documents required by state or provincial regulatory agencies in order to obtain the appropriate approvals and permits for the drilling, completion and operation of these wells.

While permitting procedures and requirements vary considerably with jurisdiction, the fundamental requirement is to demonstrate that the potential reservoir will be adequate to contain the projected volume of injected wastes and the cap and bottom seal rocks will not allow the escape of the acid gas or wastewater into potable groundwater aquifers or contaminate other existing or potential oil and gas producing zones. In addition to the technical demonstrations and regulatory considerations described above, every jurisdiction requires different procedures for the public notice and review of potential AGI projects.

For example, for the case studies of projects in New Mexico discussed in this paper it was necessary to submit contingency plans for the potential release of H_2S as a result of worst case scenarios developed by the NM Oil Conservation Division (NMOCD) that meet their prescribed requirements. In addition, it is necessary to provide direct written notice by registered mail to all surface property and mineral owners or lessees within a one mile radius of the proposed well and of the required public hearing to evaluate the project permit application once the application has been deemed administratively complete by the regulatory agency. While the nuances of the permitting process are different for each state or province, the overall process can easily take from six months to a year from initial application to final approval by the agency. Approvals are then usually accompanied by periodic testing and reporting requirements as well as maximum flow rate and injection pressure constraints which are a function of the depth and characteristics of the individual reservoir. In addition, pressure monitoring requirements to assure well integrity are also typically included as part of the permit approval and operating constraints.

The following sections describe the specific design considerations of AGI wells and the detailed characterization of the reservoir and seal rocks which are conducted during the drilling and completion of the wells.

1.3.3. Well Drilling and Testing

A number of methods have been used to drill the AGI wells discussed in this paper, including conventional rotary drilling, use of down hole mud motors and directional devices, and top-drive double-joint rigs. Drilling companies and contractors are selected after a review of the potential companies' safety record, equipment, experience, estimated costs, and availability.

Following driller and subcontractor selection, a detailed prognosis is developed describing the schedule and sequence of the drilling program. The document identifies the location, equipment, materials, personnel, and a timeline for progress. Particular attention is paid to the programs for fluids, casing, cementing, coring and logging. A "pre-spud" meeting is held among all of the involved parties to review the plan, schedule, and safety requirements for the project.

Although drilling and casing operations are performed by the drilling contractor, specialized subcontractors are usually employed for fluid control, cementing, coring, logging and testing of the well.

Drilling fluid ("mud") programs are designed to maximize safe drilling progress, control downhole pressures, protect the target formation from excessive invasion, and to insure a stable borehole during logging and casing operations. Representatives of the mud companies regularly visit the site to test and maintain the fluid characteristics. Mud programs for AGI wells generally do not differ significantly from programs for conventional oil and gas wells in similar geological settings. However; in some circumstances, mud tracer materials are added to the mud in order to allow for the definitive determination that a subsequent formation water sample retrieved after swabbing is free from the influence of mud filtrate which enters the formation during drilling.

Although lined, excavated mud pits are still permitted for drilling wells in certain states, closed-loop systems of solids removal and fluid management are currently being used to avoid potential contamination of soils or groundwater with drilling fluid and costly close-out requirements for lined mud pits. These systems employ centrifuges to separate the solids from the drilling fluids and have significant advantages in controlling the mud's physical and chemical properties. This reduces water use, the net inventory of mud required during drilling operations, facilitating easy and economical removal and disposal of the solids, allowing some mud to be recycled for subsequent drilling operations. Additional non-drilling advantages of closed-loop drilling include a smaller pad footprint, reduced potential for soil and/or groundwater impacts and streamlined permitting with state or provincial oil and gas agencies (such as the C 144 CLEZ process in New Mexico).

The cement contractor installs the cement by pressure methods that force the cement into the annular space between the casing and the borehole. Following a period to allow the cement to set, the well head is capped and tested for prescribed pressures and periods before approval. All cement jobs and pressure tests must be documented and results are generally required to be submitted to the applicable state or provincial regulatory agency.

As seen in Figure 1.3, a typical AGI casing program involves a conductor, surface casing and production casing. The annular space surrounding each casing string is cemented to the surface, and the casing and cement integrity are determined by pressure testing following each cement completion.

The conductor is typically set into competent bedrock at depths of 50 to 150 feet. This initial casing element is used to support subsequent casings, and to provide a seal for attaching the BOP used during drilling.

Following the installation and testing of the conductor, drilling progresses with a smaller-diameter bit to the target depth for the surface casing. To protect drinking water resources, the surface casing depth is selected to exceed the locally known depth of potable groundwater or other shallow mineral resources such as aggregate or coal, commonly from 500 to 1300 feet. Cementing to the surface and pressure testing are also generally required at this stage.

Once the surface casing is installed, cemented and tested, the final bit size is used to advance the well to the target injection zone. As described below, logging while drilling (LWD) and mud logging are employed to determine accurate formation depths in preparation for coring. The coring program is critical for demonstrating the depth, thickness and integrity of the geological seal, and to provide samples to evaluate the physical and chemical properties of the reservoir.

After coring and drilling to the selected total depth is accomplished, the well is circulated and conditioned to prepare the borehole for geophysical logging. Following geophysical logging and initial interpretation, depths are selected for the installation of the production casing, preliminary perforation zones, and the location of a Corrosion Resistant Alloy (CRA) joint(s) of the casing. The CRA joint(s), typically 20 to 30 feet in length, is casing segment where the packer is seated. Ideally, the CRA is installed in the production casing section within the seal formation, above the uppermost injection zone, and is designed to prevent acid gas from migrating up the borehole from the injection zone. An additional safety factor is provided by the use of special acid and corrosion-resistant cement in the annulus through the seal formation.

1.3.4. Well Completion and Construction

After coring and logging are completed as described below, the production casing is installed, cemented and tested and temporarily capped, the drilling rig is released and a smaller workover rig is mobilized for the final completion tasks. Completion includes logging of the cement-bond (and remediation cementation if necessary), perforation of the injection zone(s), collection of formation water samples, injection testing (using fresh water or brine compatible with the target formation), installation of the production packer and injection tubing, emplacement of the subsurface safety valve (SSV) (to isolate any TAG in the tubing in the event of a failure upstream), and the installation of the production "Christmas tree" that was designed and constructed using appropriate corrosion-resistant alloys. The annulus of the well is now filled with an inert fluid (dry gas only injection-diesel; combined gas/wastewater injection-brine) to prevent corrosion and assist in detecting potential tubing leaks. Once all submissions are made to the appropriate regulatory agencies and final approval is obtained for the completed well, it is now ready to be connected to the aboveground facilities and put on line for injection.

1.3.5. Reservoir and Seal Evaluation

Throughout the initial geological feasibility study, detailed prospect evaluation, permitting and well design phases, great care is taken to accurately model the depths, thicknesses and properties of the targeted seal and reservoir system. Although geophysical, driller or mud logs are usually available from nearby reference wells, representative core samples are commonly unavailable, and publically-available geophysical logs may not provide the necessary parameters for reservoir and seal determinations.

To provide convincing and assuring data on the properties of the seal and reservoir, it is critical to collect cores that span the interval between these units. Because coring is expensive and time-consuming, and since a core cannot be collected once a zone has been drilled, it is imperative that the core point be selected at the correct stratigraphic interval.

Before drilling begins, careful examination of existing reference well logs is used to estimate the anticipated depths and thicknesses of distinct formations and/or marker beds to identify the core point in the location of the proposed AGI well. As drilling progresses, an experienced mud logger and the project geologist continuously monitor the chip returns, drilling rates, and Logging While Drilling (LWD) gamma ray readings to provide an ongoing orientation in the stratigraphic section.

For projects where there are no wells within a mile which penetrate the injection zone (such as during drilling of the Pathfinder AGI #1, where the nearest wells penetrating the targeted system were from 3.5 to 5 miles away), LWD tools provide significant advantages in picking core points as observed depths and thicknesses of the relevant formations may depart significantly from the anticipated levels. In the case of the Pathfinder AGI #1 referenced above, correlation of the LWD gamma ray readings with the closest reference wells permitted selection of a core point which resulted in the successful collection of a representative sample of the entire upper seal rock (Wanakah Fm.) and the majority of the reservoir (Entrada Fm.).

Immediately after the cores are recovered from the well, the project geologist supervises the visual logging and sampling of the cores. The cores are typically removed from the coring assembly in the aluminum tube lining in the core barrel. This method protects the core from damage and contamination, and preserves the formation fluids in the material. The original cores, thirty feet in length, are cut into three to 6 feet sections while in the tubes, and capped and stored for shipping to the core laboratory. During the cutting process, short (1 to 4 inches) samples are collected for field logging. Selected core segments used for detailed formation fluid studies are refrigerated for preservation.

At the laboratory, core analyses include the determination of mineralogy, porosity, permeability, formation fluid versus injection fluid interactions, and general petrology. These tests are selected to determine the initial and long-term performance of the seal and the reservoir during the anticipated life of the injection project.

After the total depth is reached, the borehole is cleaned and conditioned for geophysical logging and the drilling string is tripped out of the hole. Then a suite of open hole geophysical logs is run to provide additional information on the *in situ* properties of the seal and the reservoir. The initial logging includes caliper, natural gamma, resistivity, litho density porosity and neutron porosity. The data is provided in both analog and digital electronic formats. Gamma and resistivity logs are used for lithology determination and correlation. The formation density and neutron porosity logs are critical in modeling the porosity volume and reservoir capacity and the litho density photo electric absorption index (Pe) is useful in identifying mineralogy differences. Caliper data is used to generate a borehole volume calculation that is very useful in refining the cement program planning.

The zone spanning the interval from below the reservoir to the top of the seal is then logged using a Formation Micro Imaging (FMI) logging tool. This tool uses an array of six circumferential micro-resistance sensing pads to detect very fine-scaled features related to bedding planes and fractures. These logs are used to evaluate the presence and extent of any fractures that might either enhance the permeability of the reservoir, or, conversely, damage the effectiveness of the seal.

After the final evaluation and interpretation of the core analyses and the geophysical logging, a comprehensive model of the reservoir – seal system is developed. This model is used to select the final injection zones to be perforated, determine if any well treatment is needed prior to injection and the optimum pressures and flow rates for injection.

1.3.6. Documentation, System Start-up and Reporting

Although documentation and reporting differ in various jurisdictions, the general process is described below giving examples specific to the NM case studies.

The permitting process typically begins with the submittal of an application for injection (Form C-108 in NM) to the applicable regulatory agency. Following agency review, a public hearing is usually required and scheduled at which any of the potentially impacted parties identified and notified may attend and raise any relevant questions and/or objections to the proposed project. Following the hearing, the appropriate state or provincial agency can accept, modify or deny the application. The final decision will usually be published as a formal order.

Following the approved order, the applicants are usually required to follow well drilling permit requirements similar to those for other types of oil and gas or injection wells (Forms C-101 and C-102 in NM)then provide a Form C-101 (Application for Permit to Drill, Re-Enter, Deepen, Plug back or Add a Zone). This application usually summarizes the operators, location, depths, and casing programs for the well.

An additional certification usually addresses the operation and removal of drilling fluids. This is the Form C-144/C-144 CLEZ (Closed-Loop System Permit or Closure Plan Application) in NM. This submission usually describes the methods that will be used for either closed-loop drilling (where no subgrade excavated pits will be used), or excavated pits, where a detailed plan for closure, verification and restoration.

Following the submittal and approval of the above forms, state or provincial agencies usually require notice prior to "spudding", or initiating drilling operations.

Once drilling begins, additional regulatory submissions are usually required following drilling milestones such as casing and cementing, testing, completions, etc. These forms include copies or original documentation on work performed.

Internal documents include daily summary reports from the drilling supervisor ("Company Man"), project geologist, mud logger, contractors, and coring and logging specialists. These reports are copied to owner, operator and consultants.

Following the completion of the well, the operator is usually required to submit a well completion report (Form C-105 in NM) detailing the final configurations of the well, and identifying the depths of formations encountered during drilling. Copied of geophysical logs and mud logs may also be required in this submittal.

Once injection commences, operators are usually required to submit periodic reports (C-115, monthly in NM) to provide the details on the volumes and pressures observed during injection.

Regulators also typically require continuous monitoring or periodic pressure testing of the casing between the surface and the packer to assure the integrity of the injection system.

Following the final completion, approval and operation of the well, a detailed End of Well Report is prepared. This report documents the well's history from initial design to completion, including copies of all regulatory correspondence and submittals, internal reports, logs, contractor reports, and budget documents.

1.4. AGI Projects in New Mexico

There are currently four AGI wells in operation in New Mexico, the oldest of which was installed in 2002. All of these AGI wells are located in the Permian Basin (Figure 1.1; Table 1.1). A fifth AGI well is scheduled to begin operations in December 2010, and it will be the first in the San Juan Basin. The AGI wells and associated compression facilities represent a range of designs and injection conditions reflecting: both dry injection (TAG only) and combined TAG/wastewater injection. Injection depths range from approximately 4400 feet to over 11,000 feet. This section provides details from three recent Geolex AGI projects (Linam AGI #1, Jal 3 AGI #1, and Pathfinder AGI#1) in order to illustrate the range of AGI projects and the characteristics of successful projects with varying constraints and in different geologic environments.

1.4.1. Permian Basin

The Permian Basin of west Texas and southeastern New Mexico is one of the major oil producing areas of the US; it also contains significant accumulations of natural gas. In 2009, the New Mexico portion of the Permian Basin produced close to 500 MMCF of natural gas (4). This portion of the basin consists primarily of Paleozoic carbonates that were deposited on the basin shelf. The climate at the time of deposition was arid and resulted in limited fluvial runoff. This contributed to the growth of carbonate banks and reefs and the coincident development of dune fields during episodic subaerial exposure of the shallow marine carbonates. The carbonates are capped by a regional evaporite and thick red beds.

Oil and gas pools are found throughout almost the entire stratigraphy of the Permian Basin, including: the Tansill; Yates; Seven Rivers; Queen; Grayburg; San Andres; Yeso; Bone Springs; Abo; Lower Bone Springs; Atoka; Devonian; Ellenburger; and others (Figure 1.4; 5). Production from these formations is localized and depends on the proximity to source rocks, local structural geology, and variations in permeability and porosity. Where hydrocarbons are absent, these zones form extensive reservoirs for saline brines. Tighter, less permeable and less porous units, bound these reservoirs and inhibit vertical migration.

Linam AGI #1

During the early through mid 2000s, the Linam Processing Plant in Hobbs (Figure 1.1), operated by DCP Midstream LP (DCP), experienced numerous problems with its SRU. In order to help reduce the pollution levels and eliminate the need for the SRU, Geolex and DCP designed and installed an AGI well during October-December 2007. A two-mile long LP pipeline was constructed to transport TAG from the plant to the AGI well. Following completion of the pipeline in early 2009, the well was reentered and completed. The AGI system has been in operation since September 2009.

The feasibility study for the Linam plant found that due to local faulting, there was no reservoir beneath the plant capable of accepting the target injection of 5 MMCFD of TAG. The geology of the surrounding area was examined and a suitable site was found about 1.5 miles away. Design TAG (20% H_2S and 80% $C0_2$) compressed at the plant to 15-20 PSI, piped to well where the TAG was compressed at the wellhead 1400 PSI prior to injection. Injected through 3 1/2” carbon-steel tubing set in an Inconel packer with an Inconel-clad Christmas tree. The TAG is then injected into the Lower Bone Springs formation. A SSV located at about 260 feet depth prevents the upwards migration of TAG in the case of an emergency. The facility has been designed to inject up to 5 MMCFD over a 30 year lifespan.

Two target reservoirs were originally selected for the Linam project, the Brushy Canyon (top found to be at 5023 ft) and the Lower Bone Springs (top found to be at 8696 ft). The Brushy Canyon formation (sandstone) was eliminated as a choice, in part due to its low permeability found by an open hole Drill Stem Test (DST). An analysis of sidewall core samples and open hole logs revealed two promising zones in the Lower Bone Springs, one at 8710-9085 feet and the other at 8445-8538 feet zones (Figure 1.5). The Lower Bone Springs is composed of a mixed calcite and dolomite packstone. The secondary calcite cement is vuggy, fractured and has dissolution porosities measured up to 15%. Permeabilities of around 100 mD and greater were measured. It was decided to perforate the deeper of the two Lower Bone Springs zones and to save the shallower zone for future injection potential. Based on the porosity logs, the deeper zone has a net porosity of about 73 feet.

The Linam AGI #1 was spudded on October 21, 2007 and reached a TD of 9212 ft on November 16, 2007. Three casing strings (13 3/8" casing to 580 feet, 9 5/8" casing to 4217, and 7" casing to TD) were installed and cemented to the surface (Figure 1.6). The cement was drilled out to 9137 feet depth. It was decided to perforate and test the deeper portion of the Lower Bone Springs first to ascertain whether it would accept the required 5.0 MMSCFD of TAG at less than the maximum expected surface pressure of 2800 psi. If the lower zone performed adequately, the upper zone would be reserved for future injection potential because perforating the casing to test (and then abandoning it later) would cause unnecessary casing integrity issues. This process was accomplished by installing temporary tubing and a retrievable packer and then using Tubing Conveyed Perforating (TCP) guns. The objective in using the TCP guns was to perforate with a slightly underbalanced hydrostatic pressure and then immediately flow the well through the tubing string into a measuring tank at the surface. Upon firing of the guns, no significant blow or flow at the surface was noticed. It was discovered that only the top 85 ft of guns had shot and that the top 45 (net) ft of perforations had opened up a zone that took fluids on a vacuum; an encouraging sign for injection potential. New guns were run in the hole and the missed shots were run. Following swabbing and an extensive acid job on the perforations, several injection tests were performed.

An injection test performed at an injection rate of 7.25 MMSCFD (above the maximum anticipated 5.0 MMSCFD injection rate) for 6 hours exhibited only a slight gain in surface pressure from 250 PSI to 300 PSI. As a result a flow choke was considered in order to hold enough back pressure on the flow stream to keep the surface injection pressure above critical pressure at approximately 1,000 PSI.

Following completion of the low pressure pipeline and aboveground facilities (the AGI compression facility and pressure regulating devices) in July 2009, the hole was reopened and the permanent packer was installed at 8650 feet. Carbon-steel 3 1/2" production tubing with a subsurface safety valve was inserted downhole and the casing annulus was filled with diesel. The well was put into operation in September 2009 and is currently injecting 2.5-3.5 MMSCFD of dry gas at about 1100-1300 PSI, well below the maximum allowed pressure of 2644 PSI.

Jal 3 AGI #1

By mid-2007 the SRU at the Jal 3 gas processing plant (Figure 1.1) had reached its processing limit and the operator, Southern Union Gas Services (SUGS), had to potentially curtail gas production and processing at the plant. Following a favorable feasibility study, it was decided to pursue the installation of an AGI well at the plant to reduce the overall GHG emissions at the plant and with the eventual goal of replacing the SRU entirely by injecting the entire stream which was processed by the former SRU and eliminating associated combustion sources. The Jal 3 AGI #1 was drilled during June 25-July 14, 2008 and completed during December 1-10, 2008. It has been in operation since March 2009, following the completion of the aboveground facilities.

The Jal 3 AGI #1 was designed to inject a mixed TAG (78%CO_2, 20% H_2S, and 2% C_1-C_7) and wastewater stream. Field gas at the plant contains significant water that had previously been disposed of using an SWD located at the plant. At this installation TAG is compressed to 1,600 PSI and then mixed with the Class II plant wastewater. The mixed TAG and wastewater is then choked down from 1,600 PSI to 980 PSI and injected into the AGI well through 3 ½ inch fiberglass-lined tubing set in an Inconel® (a corrosion resistant nickel alloy) clad packer, and then, through perforations into the San Andres formation. An automatic subsurface safety valve (SSV) placed on the injection tubing approximately 260 feet below the surface will prevent the injected acid gas from migrating upwards in case of an upset or emergency. The facility has been designed to inject 2,300 to 7,930 barrels per day of mixed wastewater and dissolved TAG (with an approximate ratio of 3:1 wastewater to TAG) over a lifespan of 30 years.

The Permian San Andres formation was chosen as the injection reservoir, in part since the majority of oil and gas production within this area is restricted to the shallower Yates-Queen interval. The only other well that penetrated the San Andres formation was the plant SWD that was plugged and abandoned prior to the injection of TAG through the AGI well. The primary local fresh water Tertiary-Quaternary Ogallala formation aquifer (<200 feet depth) has been safeguarded by surface casing extending more than 1000 feet below this zone to include any possible freshwater in the red beds of the Triassic Dockum group.

The suitability of the San Andres as the injection reservoir collected sidewall and traditional core samples and open hole well logs (Figure 1.7). The analysis identified an injection interval of 600 net feet with an approximate average porosity of 7.85%, resulting in a calculated 47 feet of effective porosity at this location. The interval is highly fractured and permeable, as indicated by an FMI analysis and demonstrated by twenty years of successful injection of wastewater in the adjacent salt water disposal well which was plugged and abandoned prior to putting the new combined TAG/wastewater well into service. The overlying Grayburg formation and the upper portion of the San Andres form an impermeable barrier (significant sections with a measured vertical permeability of <0.1 milliDarcy (mD) and no conductive fracturing) above the injection zone, while a salt-rich, low porosity, low permeability layer (1.8 % porosity and 0.01 mD permeability) near the base of the San Andres forms a barrier beneath the injection zone. No faults have been identified through the section indicating that the injection interval is well confined. In addition, the injection well is located within a structural trough that should constrain the injected fluid to an area of <240 acres, forming an ellipse extending <2800 ft from the well in a NE-SW direction. The entire sequence is composed of carbonates that will neutralize the acidity of the injected fluids and lead to long-term sequestration of the CO_2 and sulfur species.

The Jal 3 AGI #1 was spudded on June 25, 2008 and TD was reached at 5245 feet on July 11th. The well was constructed with three casing strings: 16” conductor casing to 51 feet; 9 5/8” surface casing to 1247 feet; and 7” production casing to TD (Figure 1.6). All three casing strings were cemented to the surface, with the lower portion of the 7" casing cemented using Halliburton's special acid resistant ThermaLock™ cement. Completion of the well began on December 1, 2008. Based on the evaluation of the injection reservoir, the production casing was perforated from 4,430 feet to 4,970 feet bgs and the packer was set at 4,355 feet bgs. The injection tubing and SSV were inserted downhole and the casing annulus was filled with saltwater. Following connection of the Christmas and testing of the safety devices, a temporary flow line from the plant SWD was installed, connected to the completed well and a test injection performed. That night the new well pressured up and flow was redirected back to the SWD. The perforations were cleaned with an acid job the next day and the injection pressure dropped to 280 PSI at 5 bbl/min. Flow of plant waste water was then returned to the Jal 3 AGI #1 well.

Injection of mixed TAG and wastewater into the AGI well commenced on March 26, 2009, shortly after completion of the aboveground facilities (the AGI compression facility, pressure regulating devices, and the new gas/wastewater mixing chamber). The plant is currently injecting an average of 2.5 MMSCFD of TAG mixed with 2500 bbls/day of wastewater with a resulting injection pressure of 1300 PSI (Table 1.1).

1.4.2. San Juan Basin

The San Juan Basin accounts for roughly two thirds of the New Mexico's natural gas production (937 MMCF of natural gas was produced in the San Juan Basin of New Mexico in 2009; 4). The Basin, located in northwestern New Mexico and southern Colorado, was filled by numerous cycles of is the result of marine and non-marine deposition that began in the Pennsylvanian and continued through the Tertiary. The marine deposits are characterized by a range silicic sediments (shale to sandstone) and limestone. The non-marine rocks include sandstones originally deposited as aeolian dunes and or deposited by rivers and streams. During the Late Cretaceous, shoreline migration along the large inland seaway resulted in swamps and coastal plain conditions that produced significant coal deposits. The most notable of the coal deposits is the Fruitland Formation, which is the most prolific coal bed-methane field in the United States (6).

Although the Cretaceous coal beds now account for the majority of natural gas produced in the San Juan Basin, numerous deeper oil and gas pools have been produced in the past. These deeper pools are found in marine through subaerial sandstones in the Mesa Verde, Gallup and the Dakota (Figure 1.4). The Entrada sandstone has also seen limited production. These sandy units serve as reservoirs to saline brines and are separated by thick units of shale and mudstones in the Lewis, Mancos, Morrison, and Chinle.

Pathfinder AGI #1

Field gas processed at the San Juan River Gas Plant operated by WGR (Figure 1.1) is sourced primarily from the Barker Dome area and has a high CO_2 content. The high CO_2 content in the inlet gas results in a lower than optimal operating temperature and reduced effectiveness of the SRU. In order to eliminate all GHG emissions associated with the SRU and its combustion sources, the stream currently going to the SRU (90% CO_2, 10% H_2S, trace C_1-C_7) will be injected using the Pathfinder AGI #1 . This well was drilled in August 2010 to a total depth of 6610 feet.

The proposed injection zone for the Pathfinder AGI #1 will be within the Jurassic Entrada Sandstone for all of its thickness of approximately 140 feet in this location (6352-6492 feet). The preliminary core analysis and geophysical logs show that the Entrada in this area consists of friable, well-sorted sandstone with porosities up to 25% (average about 17%) and a net porosity of 23.5 feet (Figure 1.8). Although reservoir tests have not yet been performed, the friable nature of the sandstone indicates that the Entrada should be very permeable. The Entrada is effectively sealed on top by the overlying Todilto Limestone and Beclabito siltstones of the Jurassic Wanakah Formation and below by the underlying shales and mudstones of the Triassic Chinle Formation.

Based on the value of 23.5 feet of net porosity, a thirty-year period of injection at an average of about 2.5 MMSCF per day (1000 barrels of compressed TAG) would occupy an area of approximately 60 acres, covering a radius of approximately 910 feet around the AGI well. At a maximum rate of 5 MMSCF per day (2000 barrels of compressed TAG), the area would be approximately 120 acres, enclosed within a radius of about 1290 feet from the well. There are currently four permitted and operating salt water disposal (SWD) wells completed in the Entrada in the general area of the plant, but the closest well (Salty Dog #5) is approximately 3.7 miles southeast, well outside the one-mile radius of evaluation within the proposed injection zone and the area of review required for the MNOCD C-108 application. According to NMOCD files, these four SWD wells currently accept from 800 to over 2000 barrels of fluids per day, at pressures below their permitted levels. Based on these data, we have concluded that the Entrada provides ample porosity, permeability and volume to serve Anadarko's injection needs.

Since the Pathfinder well has not yet been completed, no samples are available for the injection reservoir. The most representative analysis of fluids from the Entrada was collected in December 2005 from the Salty Dog #5 SWD well, approximately 3.5 miles southeast from the proposed AGI well. These analyses showed that the formation water had a Total Dissolved Solids of 25,624 mg/L. The primary cation was sodium, and the principal anions were chlorides, sulfate, and bicarbonates (Table 1.2).

Three casing strings were installed in the Pathfinder AGI #1: 13 3/8" conductor casing to 134 feet; 8 5/8" surface casing to 1108 feet; and 5" production casing to TD at 6610 feet (Figure 1.6). The length of the surface casing was chosen to ensure double casing through the Lewis Shale and the Pictured Cliffs, to protect the Fruitland Coal Formation. Both of these formations are considered fresh water aquifers and the Fruitland is an active coal mining and natural gas producing zone. TD reached nearly 150 feet into the Triassic Chinle Formation allowing characterization of the basal cap and ensuring access to full injection zone. Casing was cemented pursuant to applicable requirements.

Completion of the well is scheduled for October 2010 and will begin with the cement bond log and the perforation of the production casing. The 2 7/8" 6.5ppf L80 tubing string will be set into an Inconel packer and CRA joint situated in the Wanakah, just above the Entrada injection zone. An SSV (subsurface safety valve) also be constructed of Inconel, will be installed on the production tubing to assure that fluid cannot flow back out of the well in the event of a failure of the injection equipment.. In addition, the annular space between the projection tubing and the well bore will be filled with an inert fluid such as diesel fuel. The gates, bonnets and valve stems within the Christmas tree will be nickel coated, while the remainder of the Christmas tree will be made of standard carbon steel components. The Christmas tree will be outfitted with annular pressure gauges that report operating pressure conditions in real time to a gas control center located remotely from the wellhead. In the case of abnormal pressures or any other situation requiring immediate action, the acid gas injection process can be stopped at the compressor and the wellhead shut in using a hydraulically operated wing valve on the Christmas tree. Due to the corrosive nature of the injected fluid, the line that will convey the TAG to the well from the compression facilities will be a 3" stainless steel line.

1.5. AGI and the Potential for Carbon Credits

Since 80 to 90 percent of the acid gas stream that comes out of amine units is CO_2, significant amounts of CO_2 production can be reduced or eliminated through geologic sequestration of GHG using AGI. For example, a 5 MMSCFD acid gas stream with 80% CO_2 results in 77,000 metric tons of CO_2 per year, as demonstrated in Figure 1.9. In sharp contrast to the carbon capture challenge presented by traditional coal-fired power plants, natural gas processing facilities afford a ready opportunity for geologic sequestration of GHG because the waste gas stream from amine units does not contain a significant fraction of non-GHG which would have to be separated or compressed prior to injection/sequestration. In addition, the significantly lower volumes of CO_2 produced from natural gas processing plants relative to coal-fired power plants make these facilities ideal candidates for practical and economical sequestration projects. Unlike many industrialized nations which have signed on to the Kyoto Protocol, the US has not yet implemented cap and trade legislation or formal rules to regulate the release of GHG. However, reporting requirements for GHG emissions go into effect this year in the US, and legislation to regulate CO_2 and other GHG emissions remains a high priority of the Obama administration.

In the absence of federal legislation to regulate GHG emissions, a number of states and regions have formed voluntary coalitions to reduce and regulate GHG emissions, including CO_2. These include such organizations/coalitions as the Western Climate Initiative (WCI), the Regional Greenhouse Gas Initiative (RGGI) and others. The advent of the reporting requirements taking effect this year and the anticipation of potential legislative regulation of GHG emissions are bringing increased visibility to the whole area of GHG emissions from gas processing plants. As environmental legislation is implemented, geologic sequestration of CO_2 from these facilities may prove to be "low hanging fruit" for gas producers because gas processing plants have a distinct advantage over other GHG emitters such as coal-fired power plants in terms of CO_2 capture and sequestration as described above because gas plants already separate and capture CO_2 as a part of their amine process. Therefore, geologic sequestration of CO_2, from either sour or sweet gas processing is a viable and economical alternative for the gas processing industry now, unlike the coal-fired utility industry.

Obtaining carbon credits for CO_2 reductions is a purely voluntary process in the United States at the present time. One credit can be obtained for each metric ton of CO_2 reduction. Although there is some market for these credits in the US (approximately $71 million of these credits were traded in US markets in 2006), the real value of these credits in US markets remains to be established when binding GHG legislation comes into effect in this country. In European markets, where that regulation already exists, billions of dollars a year of carbon trading is taking place. Carbon credits can be obtained in a variety of ways, including the purchase of reforestation and planting projects. Clearly, verifying and quantifying the CO_2 offsets from these sorts of projects is a much less precise process than in the gas processing business where measurement and verification can be done directly at the well head. AGI provides a GHG reduction method for obtaining carbon credits that is both directly measurable and easily verifiable.

The actual registration of voluntary carbon credits (with the issuance of Renewable Energy Certificates) is presently fairly well defined by Federal regulation, and there are several groups in the United States that provide certification and verification of these credits—these include the Chicago Climate Exchange (CCX), American Carbon Registry (ACR) and others. The process for registration of carbon offsets or credits in these voluntary markets consists of three basic steps. Initially, the calculation of tons per year of CO_2 sequestered must be made; then a formal application must be submitted (project protocols); and subsequently, verification of the carbon reduction must be obtained from an independent entity. This whole process can cost between US$50 to $100 thousand per project, depending on the size and complexity of the project. The direct economic benefit of registration of offset credits into voluntary programs is not clear at the present time. The motivation for obtaining formal offset reduction credits at the present time lies more in the potential public relations benefit of such actions in terms of enhancing a "green" corporate image and in terms of positioning the companies for a favorable regulatory review.

There may also be some potential direct monetary advantage in the early registration of credits if early offset provisions are implemented in forthcoming legislation. However, the definition of the monetary value of voluntary early offset credits in pending federal legislation is very much a moving target at present. In spite of the lack of quantifiable advantages for early offset credits, and the absence of current definitive regulatory legislation, the fact remains that the regulation of CO_2 and other GHG in the US is inevitable, and natural gas producers should begin thinking about how compliance with these regulations will affect their operations. Geologic sequestration of GHG and H_2S through AGI is the best currently-available technology and it has been demonstrated to be a viable and cost-effective methodology for achieving compliance with future mandatory GHG reduction requirements.

As geologic sequestration of GHG and related natural gas processing wastes expands in the US, there are numerous legal and regulatory issues which will need to be addressed. One of the most significant of these issues is ownership of pore space in potential reservoirs targeted for geologic sequestration projects. Most states in the US do not define who owns the pore space into which the acid gas will be injected. In contrast, as an example, Wyoming became the only state in the US to legislatively define ownership of pore space. Under Wyoming law, the surface owner is also the owner of underlying pore space, and leases for the anticipated use of pore space must be obtained from those owners in a similar manner that oil and gas leases must now be obtained from mineral owners (7). Similar legislation is anticipated in other oil and gas producing states. Another regulatory issue being examined relative to sequestration projects is whether the unitization process currently implemented in many oil and gas producing regions for secondary and tertiary recovery operations might be adapted to AGI/CO_2 reservoirs. Also under consideration is whether the federal, provincial or state governments might assume liability associated with these AGI/CO_2 injection projects.

An evolving technical and regulatory issue has to do with the actual monitoring of the injected gas plume and verification that the plume is being contained by the overlying and underlying caprocks and within the boundaries of the leased reservoir. No specific regulatory requirements have yet been developed at the state or national level to standardize methods of acceptable monitoring of these projects and verification of the longevity of carbon credits arising from these projects. The EPA, however, has developed some proposed regulations for Class VI injection wells under its underground injection control program (UIC) program. These regulations seek to standardize the construction and installation of injection wells. Although there is no specific time table for implementation of these regulations, they will be an important factor governing the technical and economic constraints on future AGI projects and should be considered in constructing projects which seek to generate future carbon credits from GHG sequestration as an added benefit to the use of this technology for disposal of acid gas.

1.6. Conclusions

AGI has been demonstrated to be an effective means for disposing of TAG from natural gas processing plants and is well suited to New Mexico and other areas with large reservoirs of saline brine. Building on its experience in AGI, Geolex has developed a structured process for AGI development and identified the following key points in the successful development and implementation of these systems:

1. Identification of a suitable injection reservoir and cap rock is critical.
2. Well design is largely dependent on choice of wet vs. dry injection and characteristics of injection reservoir and cap rocks.
3. Close communication with regulatory agencies at all stages of the process is important.
4. Proper monitoring of drilling and completion is necessary to ensure that completion of the project is successful, timely and within budget.
5. The accurate characterization of reservoir and caprock (determining capacity and demonstrating isolation) is essential for obtaining regulatory agency approval and for future registration of carbon credits.

Since TAG predominantly consists of CO_2, AGI represents an increasingly popular method of carbon sequestration that can be readily monitored. The combination of AGI and carbon sequestration produce environmental benefits and cost savings for operating companies now and will most certainly produce additional economic benefits as the regulation of GHG emissions becomes more stringent and companies seek to enhance their image as green energy producers.

1.7. References

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2. U.S. Federal Government, *Federal Register* , Vol. 74, No. 209, pp. 56250-56519, Friday, October 30, 2009.

3. U.S. Federal Government, 40 CFR Parts 144 and 146, *Underground Injection Control Program*.

4. EMNRD, *New Mexico Energy, Minerals and Natural Resources Department 2009 Annual Report*, 2009.

5. E.E. Kinney and F.L. Schatz, *The Oil and Gas Fields of Southeastern New Mexico – A Symposium*, Roswell Geological Society, p. 220, 1967.

6. US Energy Information Administration, *New Mexico State Energy Profile*, <http://www.eia.doe.gov/state/state_energy_profiles.cfm?sid=NM>, last updated August 26, 2010.

7. Wyoming State Legislature, Wyoming Statutes WS 34-1-152, *Ownership of Pore Space Underlying Surfaces*, July 1, 2008.

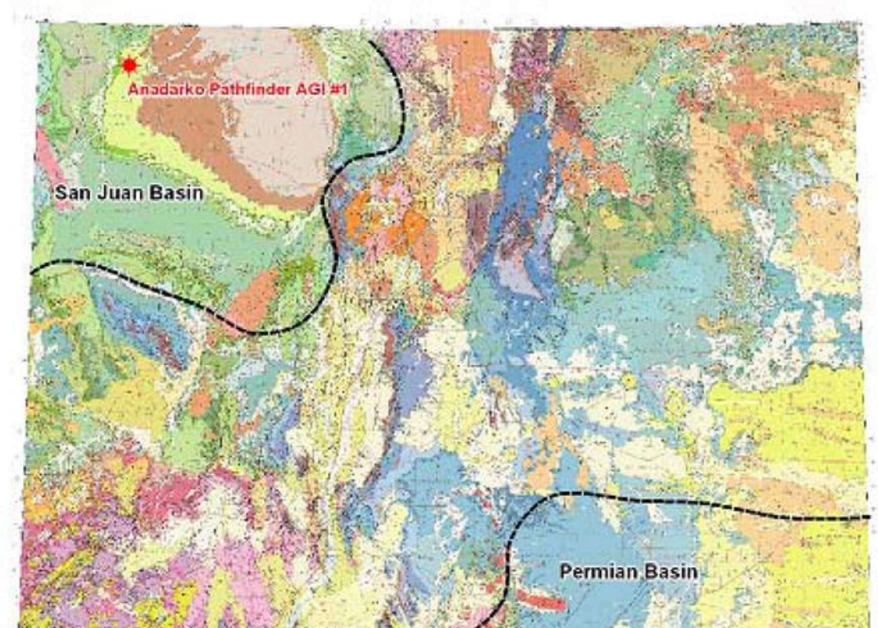
List of Tables

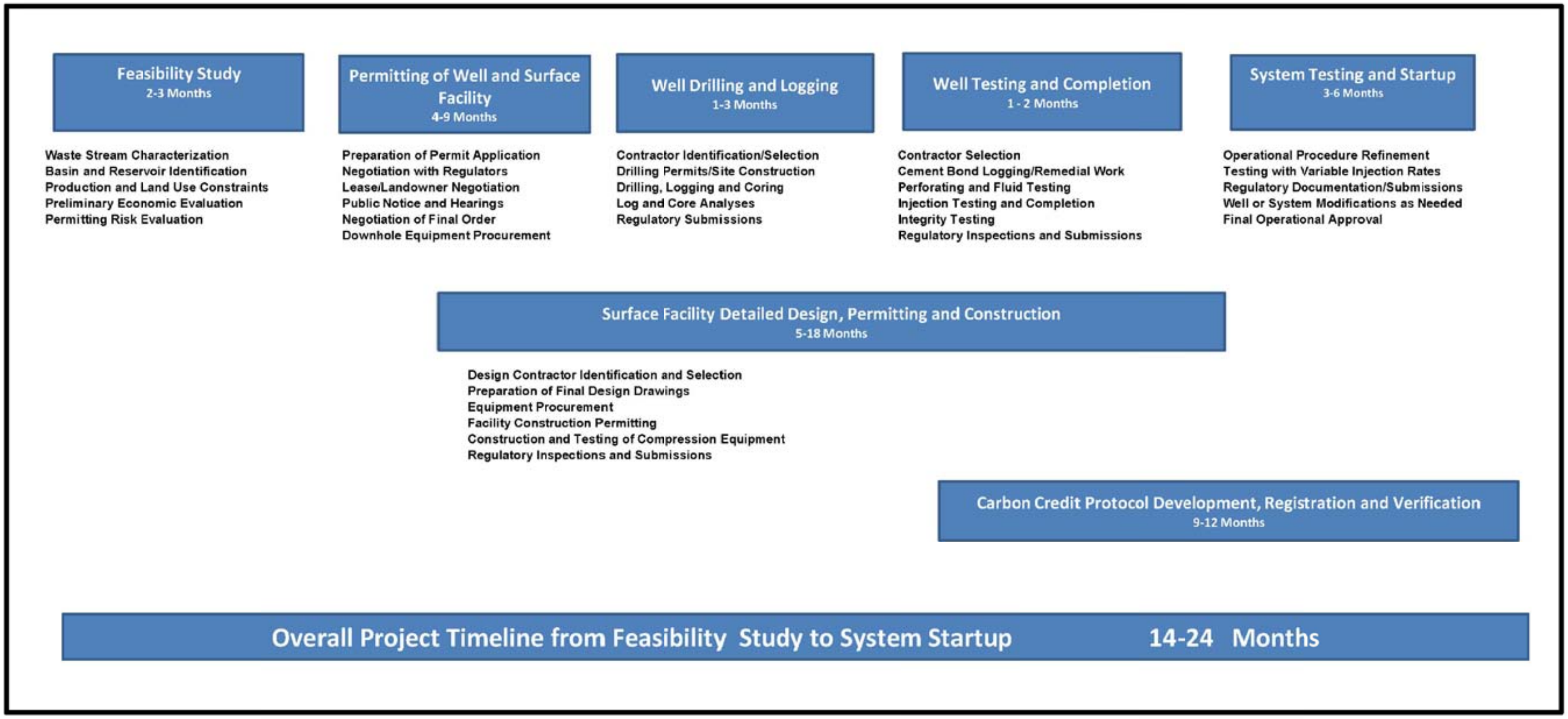
List of Figures

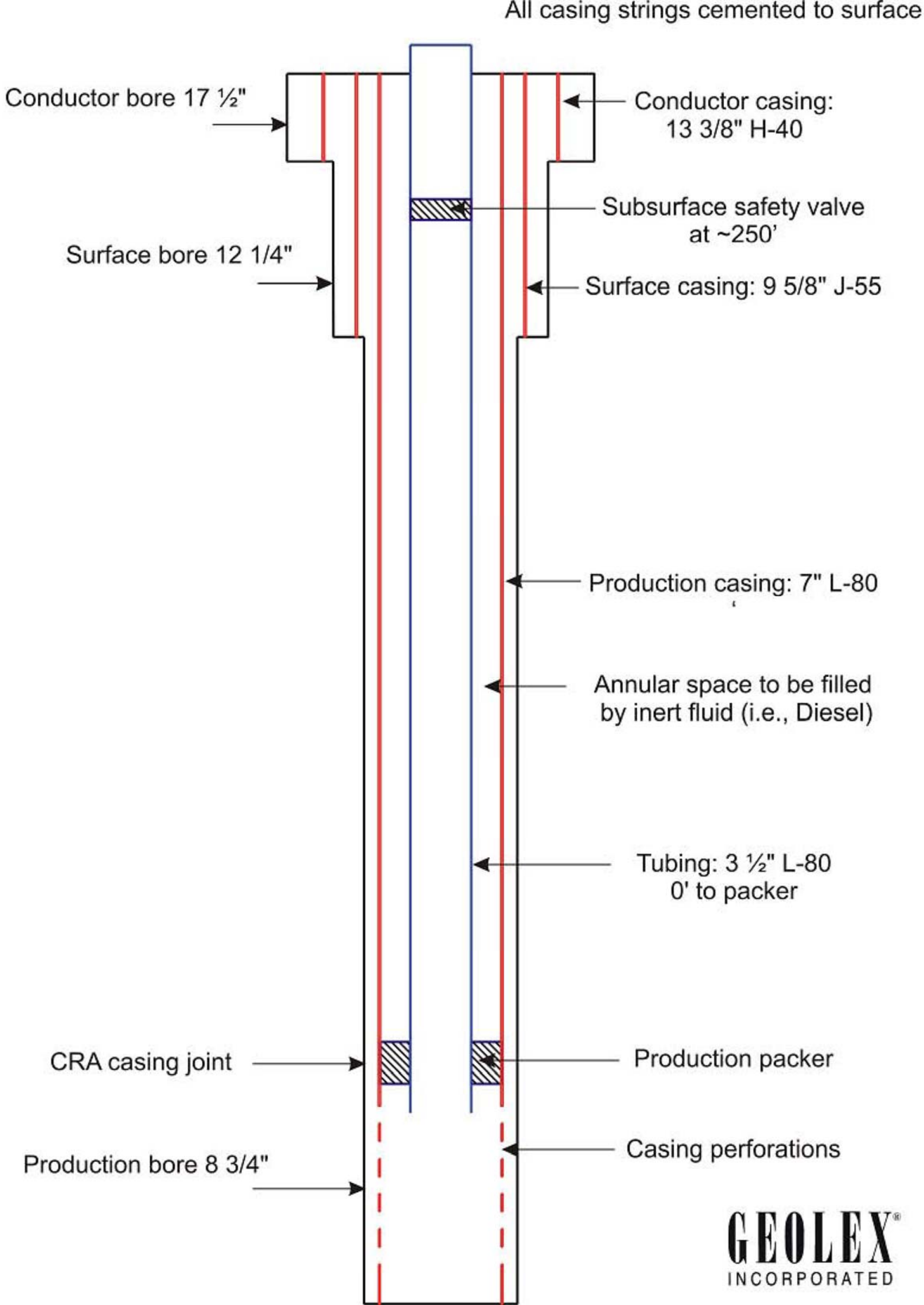
Well Information		Reservoir Characterization					TAG Composition	Injection Characteristics				
Operator	Well Name	TD (feet)	Reservoir Name	Injection Depth feet	Net Porosity feet	Cap Rock	Percentage CO_2:H_2S:C_1-C_7	Injection type TAG:WW	Injection Rate MMSCFD (TAG)	Reported Injection Press. PSI	Max. Rate MMSCFD (TAG)	Permited Max. Press. (PSI)
Marathon	Agave Metropolis AZL St #1	11600	Devonian Ellenburger	9900-11400	n/a	Woodford	75:25:00	1:2500	0.3	1800	0.5	1980
DCP Midstream	Duke AGI #1	11472	Devonian	11207-11412	14	Woodford	75:25:00	Dry	0.8	1850	1	3240
DCP Midstream	Linam AGI#1	9212	Lower Bone Springs	8700-9100	73	Abo	75:25:00	Dry	2.5-3.5	1200	5	2644
SUGS	Jal 3 AGI #1	5144	San Andres	4375-5000	47	Grayburg	78:20:02	1:2.5	2.5	1300	5	1600
WGR	Pathfinder AGI #1	6610	Entrada	6355-6550	24	Wanakah/Todilto	90:10:00	Dry	n/a	n/a	3.8	1985

Well	Formation	Location	Na mg/L	Ca mg/L	Mg mg/L	K mg/L	Fe mg/L	Sr mg/L	Zn mg/L	T-Alk mg/L	Cl- mg/L	SO_4 mg/L	HCO_3 mg/L	TDS mg/L	pH	Conduct uS/cm
Permian Basin																
Linam AGI #1	L. Bone Spr.	Linam AGI #1	24,909	1,760	424	535	67	93	0	324	40,000	4,145	395	73,412	7	94,800
Littman[a]	San Andres	Approx. 15 Miles NE of Jal 3 AGI #1	30,900	5,240	2,527	N/A	0	N/A	N/A	N/A	62,000	2,080	N/A	93,400	N/A	N/A
San Juan Basin																
Salty Dog #5	Entrada	Approx. 3.5 Miles E of Anadarko Pathfinder	8,809	160	146	N/A	1	N/A	N/A	400	9,000	5,800	1,708	25,624	7	N/A

[a] from A. Nicholson, Jr., and A. Clebsch, Jr., Geology and Ground-Water Conditions in Southern Lea County, New Mexico, U.S. Geological Survey Ground-Water Report 6, p. 123, 1961.


Anadarko Pathfinder AGI #1
San Juan Basin
Permian Basin
Duke AGI #1
Agave Metropolis AZL St. #1
Linam AGI #1
Jal 3 AGI #1
GEOLEX
INCORPORATED
Miles
0 25 50 100 150

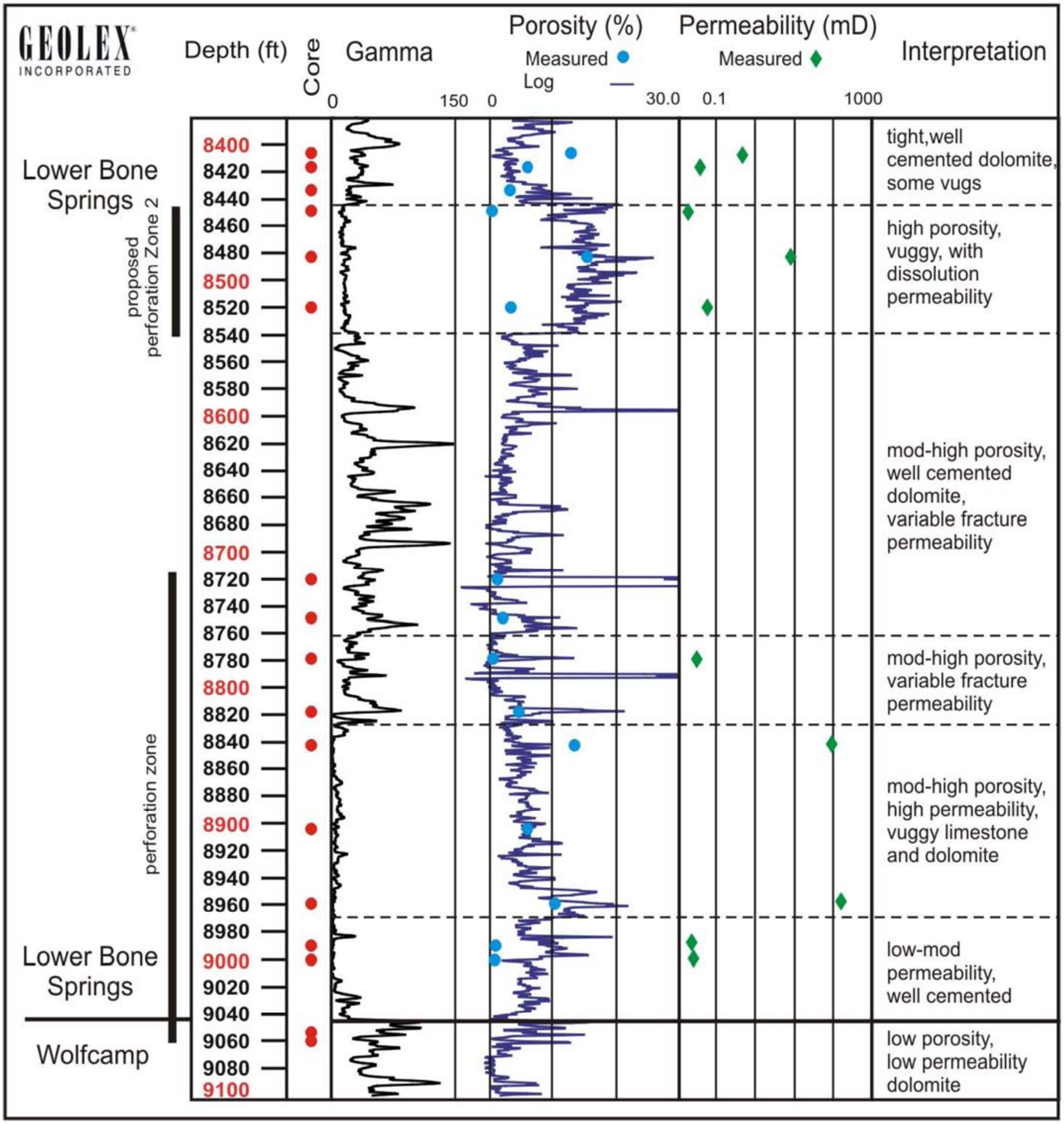

Feasibility Study
2-3 Months
Waste Stream Characterization
Basin and Reservoir Identification
Production and Land Use Constraints
Preliminary Economic Evaluation
Permitting Risk Evaluation
Permitting of Well and Surface Facility
4-9 Months
Preparation of Permit Application
Negotiation with Regulators
Lease/Landowner Negotiation
Public Notice and Hearings
Negotiation of Final Order
Downhole Equipment Procurement
Well Drilling and Logging
1-3 Months
Contractor Identification/Selection
Drilling Permits/Site Construction
Drilling, Logging and Coring
Log and Core Analyses
Regulatory Submissions
Well Testing and Completion
1 - 2 Months
Contractor Selection
Cement Bond Logging/Remedial Work
Perforating and Fluid Testing
Injection Testing and Completion
Integrity Testing
Regulatory Inspections and Submissions
System Testing and Startup
3-6 Months
Operational Procedure Refinement
Testing with Variable Injection Rates
Regulatory Documentation/Submissions
Well or System Modifications as Needed
Final Operational Approval
Surface Facility Detailed Design, Permitting and Construction
5-18 Months
Design Contractor Identification and Selection
Preparation of Final Design Drawings
Equipment Procurement
Facility Construction Permitting
Construction and Testing of Compression Equipment
Regulatory Inspections and Submissions
Carbon Credit Protocol Development, Registration and Verification
9-12 Months
Overall Project Timeline from Feasibility Study to System Startup
14-24 Months



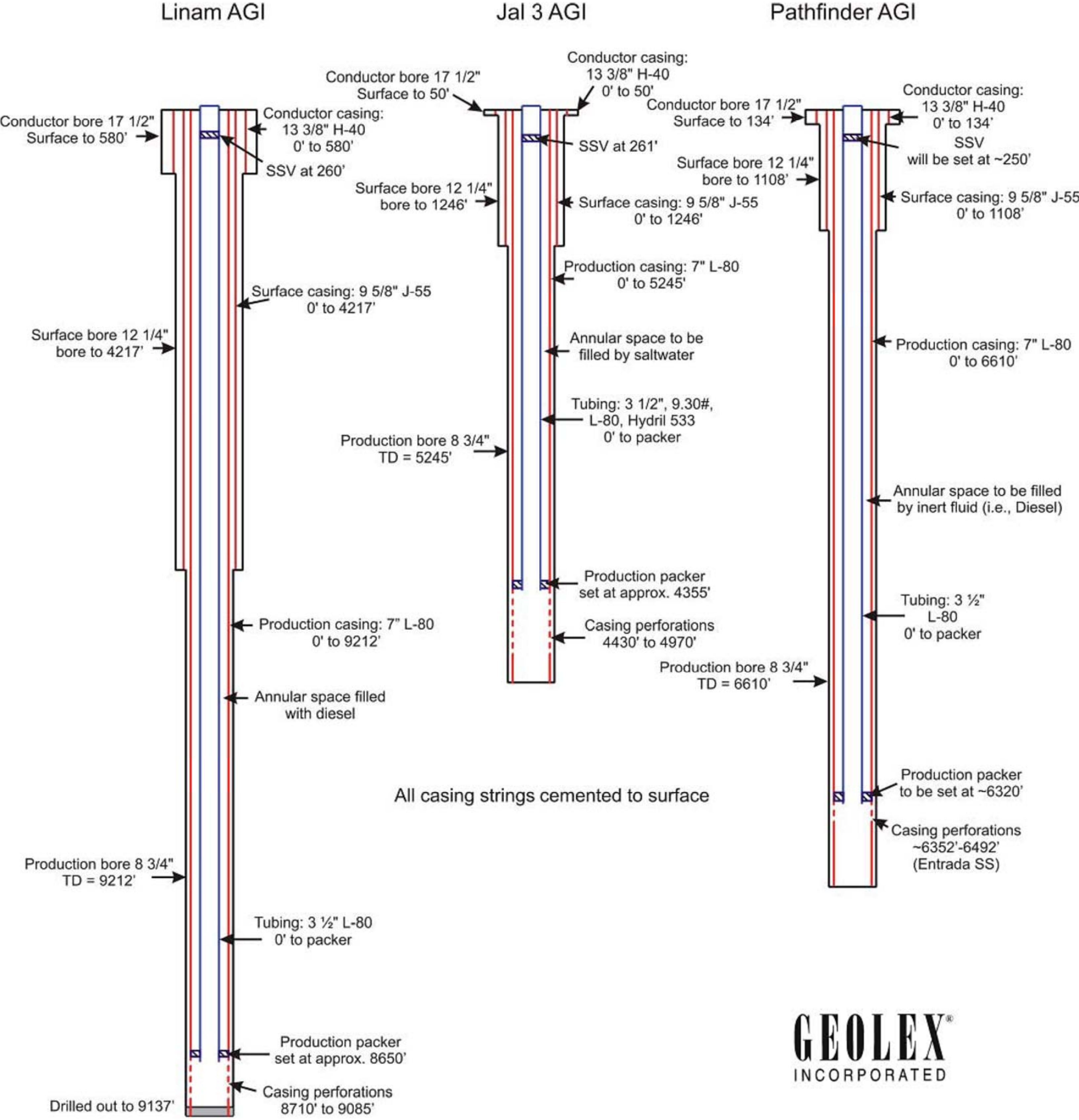
GEOLEX®
INCORPORATED

AGE	Permian Basin		San Juan Basin
Quaternary	Alluvium		Alluvium
Tertiary	Ogallala		
Cretaceous	Fredericksburg Trinity Ss.		Kirtland Shale Fruitland Fm. Pictured Cliffs Ss. Lewis Shale Upper Mancos Shale Gallup Ss. Greenhorn Ls. Graneros Sh. Dakota Fm.
Jurrasic			Morrison Fm. Wanakah Fm. Todilto Ls. Entrada Ss.
Triassic	Santa Rosa Dewey Lake		Chinle fm.
Permian	Dewey Lake Rustler Salado Castile Bell Canyon Greyburg San Andres Cherry Canyon Bone Springs Wolfcamp/Abo		Cutler Fm.
Pennsylvanian	Cisco Canyon Strawn Atoka		Honaker Trail Fm. Paradox Fm. Pinkerton Trail Fm. Molas Fm.
Mississippian	Woodford		Leadville Ls.
Devonian	Woodford		Elbert Fm.
Silurian	Fussleman		
Ordivician	Montoya Simpson Group Ellenburger		
Cambrian	Ellenburger		Ignacio Qtz.
preCambrian	Undifferentiated Basement Rocks		Undifferentiated Basement Rocks

Linam AGI #1

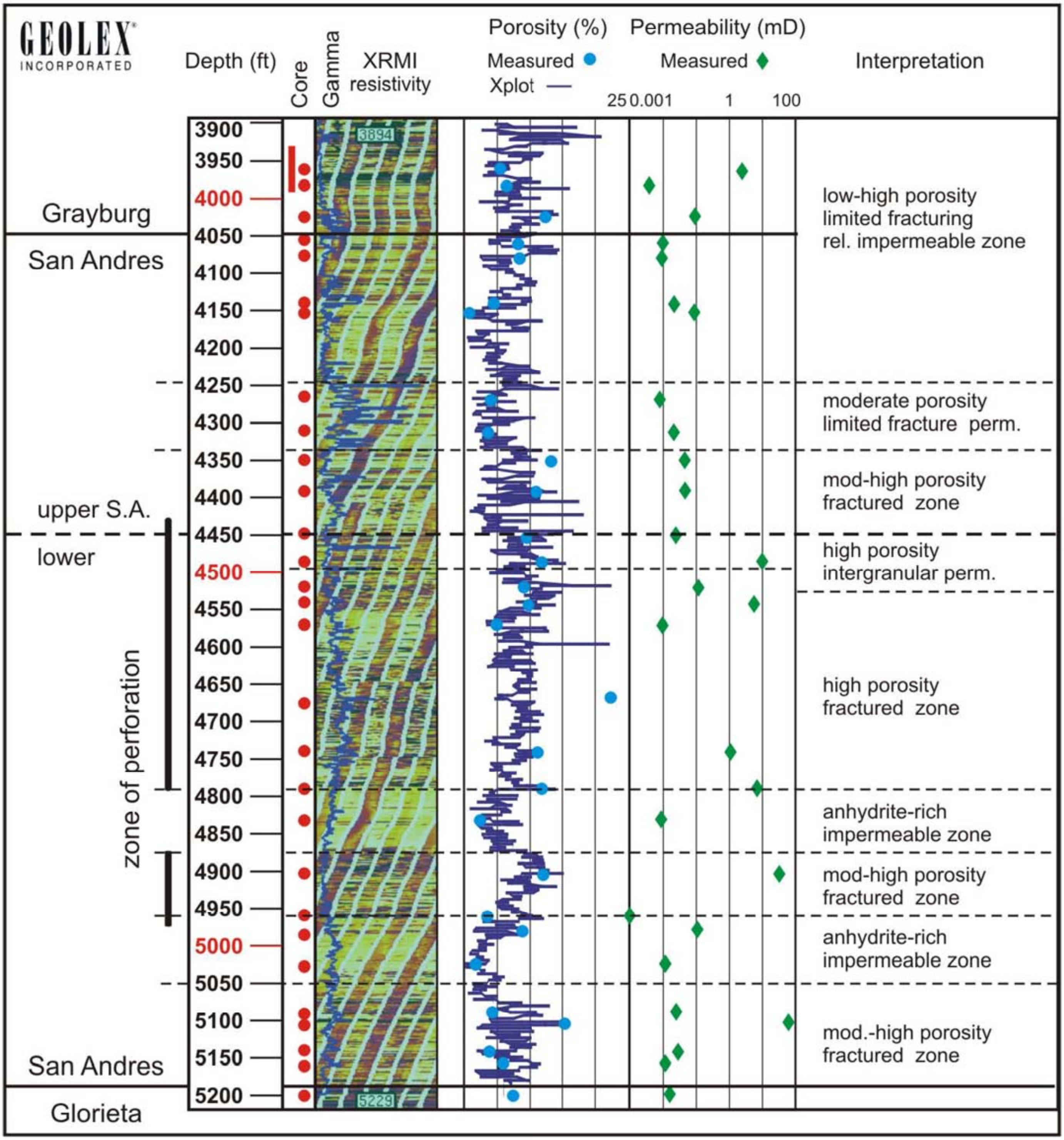


GEOLEX
INCORPORATED
Depth (ft)
Core
Gamma
Porosity (%)
Measured
Log
Permeability (mD)
Measured
Interpretation
0
150
0
30.0
0.1
1000
Lower Bone Springs
proposed perforation Zone 2
perforation zone
Lower Bone Springs
Wolfcamp
8400
8420
8440
8460
8480
8500
8520
8540
8560
8580
8600
8620
8640
8660
8680
8700
8720
8740
8760
8780
8800
8820
8840
8860
8880
8900
8920
8940
8960
8980
9000
9020
9040
9060
9080
9100
tight,well cemented dolomite, some vugs
high porosity, vuggy, with dissolution permeability
mod-high porosity, well cemented dolomite, variable fracture permeability
mod-high porosity, variable fracture permeability
mod-high porosity, high permeability, vuggy limestone and dolomite
low-mod permeability, well cemented
low porosity, low permeability dolomite



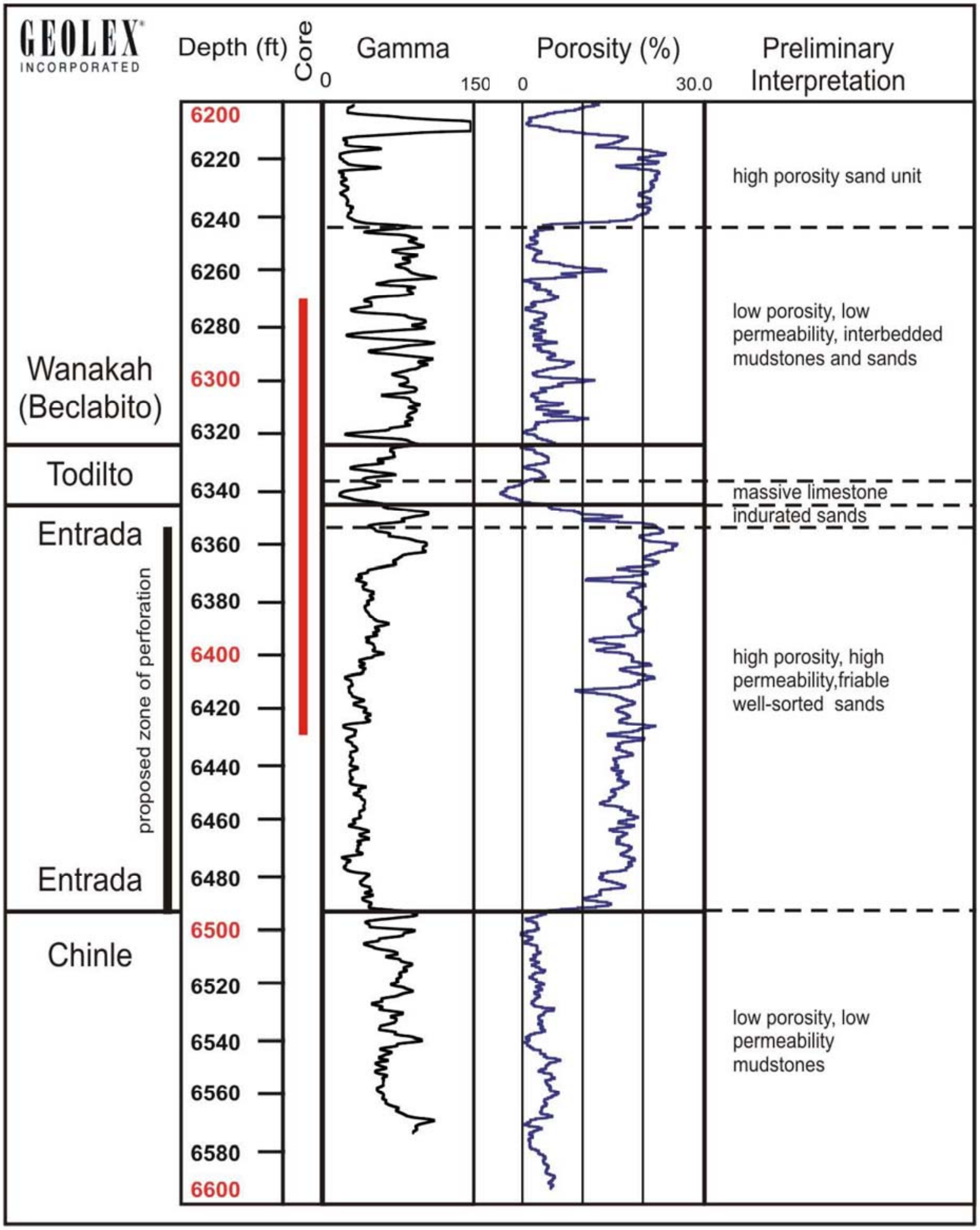
GEOLEX®
INCORPORATED

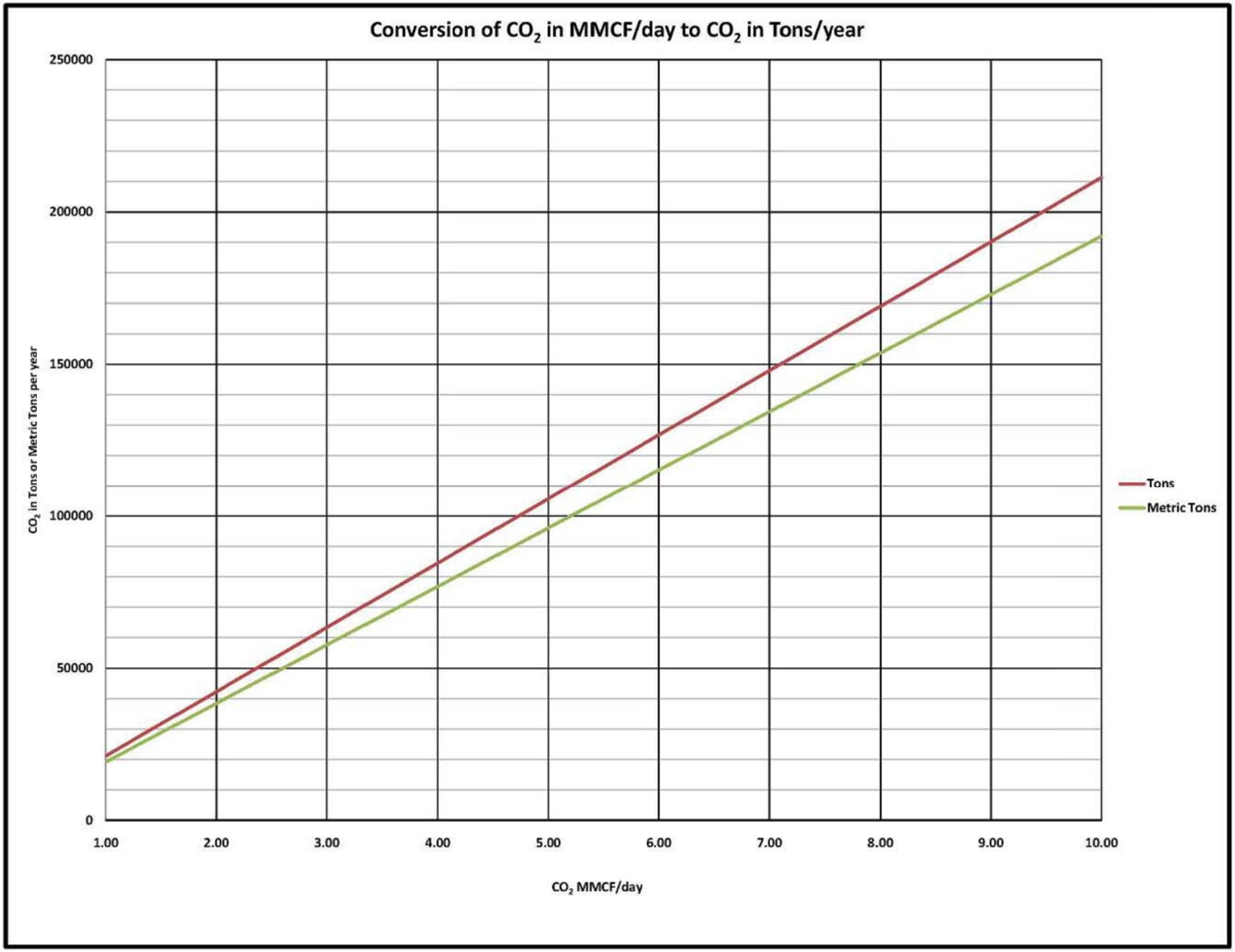
Jal 3 AGI #1



GEOLEX INCORPORATED
Depth (ft)
Core
Gamma
XRMI resistivity
Porosity (%)
Measured
Xplot
25
Permeability (mD)
Measured
0.001
1
100
Interpretation
Grayburg
San Andres
upper S.A.
lower
zone of perforation
San Andres
Glorieta
3900
3950
4000
4050
4100
4150
4200
4250
4300
4350
4400
4450
4500
4550
4600
4650
4700
4750
4800
4850
4900
4950
5000
5050
5100
5150
5200
3894
5229
low-high porosity limited fracturing rel. impermeable zone
moderate porosity limited fracture perm.
mod-high porosity fractured zone
high porosity intergranular perm.
high porosity fractured zone
anhydrite-rich impermeable zone
mod-high porosity fractured zone
anhydrite-rich impermeable zone
mod.-high porosity fractured zone

Pathfinder AGI #1




Conversion of CO_2 in MMCF/day to CO_2 in Tons/year
CO_2 in Tons or Metric Tons per year
250000
200000
150000
100000
50000
0
1.00
2.00
3.00
4.00
5.00
6.00
7.00
8.00
9.00
10.00
CO_2 MMCF/day
Tons
Metric Tons