Final Well Report
Zia AGI D #2

1893 FSL & 950 FWL
Section 19, T19S, R32E
Lea County, New Mexico
API: 30-025-42207

Volume 1 of 1
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GEOLEX INCORPORATED

dcp Midstream

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1.0 EXECUTIVE SUMMARY

On behalf of DCP Midstream LP (DCP), COG Operating LLC (Concho) and Scandrill Inc. (Scandrill) spudded and drilled the DCP Zia AGI D #2 well, API No. 30-025-42207, from November 2, 2016 through December 10, 2016. Geolex, Inc. ® (Geolex) provided all permitting, regulatory, and geologic oversight for the drilling and completion of the Zia AGI D #2. The final production casing was cemented on December 4, 2016. Geolex completed and tested the well beginning on December 15, 2016 and ending on January 25, 2017. Zia AGI D #2 is ready for injection of treated acid gas (TAG) from the DCP Zia II natural gas processing plant (the Plant). The Zia AGI D #2 well is located on the Plant in Section 19, T19S, R32E approximately 35 miles west of Hobbs in Lea County, New Mexico (Figure 1). The vertical well was drilled from the surface location at 1,893 feet from the south line (FSL) and 950 feet from the west line (FWL) (Figure 2).

Zia AGI D #2 was designed and drilled for the purpose of safely injecting up to 15 million standard cubic feet (MMSCF) per day of TAG produced from the Plant, for a design life of 30 years. Under normal operations the TAG will be primarily injected into Zia AGI D #2, with the existing Zia AGI #1 being maintained as a backup well to be used when Zia AGI D #2 is shut down for maintenance. The TAG stream will consist of approximately 90% carbon dioxide (CO_2) and 10% hydrogen sulfide (H_2S), with trace components of hydrocarbons (C_1 – C_6) and Nitrogen. The Zia AGI D #2 if running at capacity would permanently sequester approximately 820 tons of CO_2, and approximately 72 tons of H_2S per day.

The Zia AGI D #2 well pad was built during the construction of the Plant and Zia AGI #1 using the "best practices" approach to minimize storm-water runoff from the site, and was shown in the Bureau of Land Management's (BLM) approved application to permit and drill (APD). These best practices included liners, berms, and sumps to contain any runoff, and also to contain any potential release(s) of drilling fluids. No downsizing of the pad for Zia AGI D #2 is required due to its location at the Plant.

Drilling of the Zia AGI D #2 well began on November 2, 2016. Daily drilling and completion records can be found in Appendix A. Drilling activities were operated by Scandrill, and overseen by Concho and Geolex. A "closed-loop" drilling fluid system was used to minimize the amount of fluids required to complete the well and prevent any releases of fluids to the surface. A closed-loop drilling fluid system separates the drilling cuttings from the drilling mud and temporarily stores the drilling mud and drill cuttings in separate tanks.

The geology at Zia AGI D #2 was evaluated during the entire drilling process and the geologic interpretations were updated after reviewing the drilling gamma ray log, mud log, and geophysical logs as the project progressed from spudding through injection testing (Figures 5, 6, 7, 8, and 9).

The 30-inch diameter conductor casing was installed to a depth of 120 feet and cemented to the surface. The 20-inch surface casing was installed to a depth of 826 feet in a 26-inch borehole and cemented to the surface. The 13-3/8-inch 1st intermediate casing was installed in a 17½-inch borehole to a depth of 2,555 feet and cemented to the surface. The 9-5/8-inch 2nd intermediate casing was installed in a 12¼-inch borehole to a depth of 4,696 feet and cemented to the surface. The 7-inch production casing was installed in an 8¾-inch borehole to a depth of 13,622 feet and cemented to the surface. The final 6-inch open-hole injection zone was drilled from 13,622 to 14,750 feet. The final as-built well schematic is shown on Figure 3.

The acid gas injection (AGI) system is designed to be safe and robust. All tubing and equipment in contact with the TAG are constructed of materials resistant to the corrosive properties of the TAG. From the wellhead, TAG is carried to the production packer via the 3½-inch 9.3 pound BTS-8 L80 tubing that crosses over to the 3½-inch 9.2 pound VAMTOP Inconel G3 Nickel tubing. The production packer, set at

13,535 feet, is constructed from Incoloy 925 material and is set in a corrosion-resistant alloy (CRA) segment of the production casing (7-inch) from 13,298 to 13,622 feet. The final as-built injection tubing and equipment schematic is shown on Figure 4.

A nickel alloy retrievable subsurface safety valve (SSSV) was installed on the production tubing at a depth of 277 feet to prevent upward movement of the TAG in the event of a downhole upset or emergency. Prior to drilling the well, a comprehensive H_2S Contingency Plan (NMOCD Rule 11) was prepared, submitted and approved by New Mexico Oil and Gas Conservation Division (NMOCD) (Appendix B). The Contingency Plan addresses the Plant operations, H_2S monitoring and control, and emergency response activities that encompass both the Plant and all other facilities and residents within one mile of the well.

Geolex's review of the geophysical log results demonstrated the presence of sufficient cap rock with permeabilities and porosities low enough to serve as excellent caprock for permanent sequestration of TAG. Furthermore, units within the injection interval are separated by very tight limestone and dolomite of lower porosities and permeabilities. Finally, it was determined there was sufficient capacity to inject TAG into the Ordovician-Devonian Formations (Figures 8 and 9 and Appendix C).

The mudlog and sidewall core results indicate that the predominant lithologies over the open-hole injection zone are limestone and dolomite with permeabilities that widely range from 0.005 to 284 milidarcies (mD). The higher permeabilities are within the Wristen (137, 284 and 11 mD), Fusselman (2 mD), and Montoya (1, 6, 8, 38 and 131 mD). Caprock above the injection zone is composed of the highly impermeable Woodford shale. Sidewall core results and photographs are located in Appendix C.

Reservoir testing on the Zia AGI D #2 well consisted of a step-rate test (SRT), ten day fall-off test, ten day warm-back test, and reservoir fluid analysis (Appendix D). The reservoir tests findings indicate the injection reservoir will readily accept TAG at the designed injection pressures and rates that are within the maximum allowable operating pressure (MAOP) of 5,023 psig and 15 MMSCF per day.

The SRT was designed and overseen by Geolex and performed by Halliburton in order to assess the injectivity of the injection zone. The SRT was conducted on December 29, 2016, within the injection zone between 13,622 and 14,750 feet. Surface pressure measurements were recorded by Halliburton and recorded by Geolex. The maximum surface pressure achieved during the SRT was 1,613 psig at the maximum flow rate of 7.0 barrels per minute (bpm). Formation parting pressures were never achieved during this test, and surface pressure decreased from 1,608 psig to 229 psig within 19 minutes of shutting the well in. Temperature surveys (warm-back analysis) conducted during the ten-day fall-off test by Schlumberger revealed permeable zones between approximately 13,622 – 13,880 feet, 14,200 – 14,400 feet, and 14,530 – 14,630 feet.

The New Mexico Oil Conservation Commission (NMOCC) - approved MAOP for treated acid gas is 5,028 psig at the rate of 15 MMSCFD, which at bottom-hole pressure/temperature (P/T) conditions is approximately 4.4 bpm of liquid TAG. The anticipated pressure required to inject this volume is estimated to be between 1,400 and 1,800 psig. The SRT and ten-day fall-off tests fulfill the requirements of the BLM Conditions of Approval (COA) dated September 6, 2016 and NMOCC Order R-14207, and demonstrate the Zia AGI D #2 well can safely operate at pressures within the currently-approved MAOP.

2.0 ORGANIZATION OF THE END OF WELL REPORT

This is a final end of well report describing the permitting, design, installation, completion, testing, and current status of the DCP Zia AGI D #2 acid gas injection well. This report is presented in the following categories:

- A history of the Zia AGI D #2 project, including: A description of the Plant and the need for the AGI project; a summary of the project permitting history; a basic project design; and anticipated disposal volumes (Sections 3.0 and 4.0)
- A narrative discussing the rationale and technical aspects of the Zia AGI D #2 design, the drilling operations, and completion (Section 5.0)
- An evaluation of regional and local geology of the Zia AGI D #2 well (Section 6)
- A description of the rationale used to develop the selection of the injection zone and an evaluation of the reservoir testing (Sections 7.0 and 8.0)
- A synopsis of operations, maintenance, and training recommended for the Zia AGI D #2 (Section 9.0)

The downsizing of the drilling-pad stated by the BLM COA is not required due to the location of surface facilities and operations at the Plant. The land leased to DCP by the BLM to operate the Plant covers all drilling activities for both Zia AGI #1 and Zia AGI D #2.

In addition, this report includes the following supporting information:

Appendix A:	Daily Drilling and Completion Records
Appendix B:	H_2S Contingency Plan Approved for Zia II Gas Plant, July 2016
Appendix C:	Sidewall Coring Reports and Analyses of Core Samples
Appendix D:	Reservoir Tests
Appendix E:	NMOCD and BLM Regulatory Documents, Notifications and Submittals
Appendix F:	Notice Letters to Producers within One Mile
Appendix G:	Operation Design Specifications for the Subsurface Safety Valve, Halliburton BWD Permanent Packer, P/T gauge, and AGI System Training and Maintenance
Appendix H:	Mud Logs
Appendix I:	Open-Hole Geophysical Well Logs
Appendix J:	Casing and Tubing Tallies
Appendix K:	Cement Programs and Reports
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Appendix N:	Well Tree Schematic
Appendix O:	Oil and Gas Wells in the DCP Zia AGI D #2 Area of Review and Vicinity
Appendix P:	Concho Drilling and Completion Prognosis

3.0 PLANT DESCRIPTION AND PERMITTING HISTORY

On behalf of DCP, Geolex prepared and submitted revised and complete regulatory applications (C-108 and Application for Permit and Drill – APD) to drill, complete and operate an AGI system comprised of two combined AGI and CO_2 sequestration wells at the Plant. The Plant is located in Section 19, T19S R32E approximately 35 miles west of Hobbs in Lea County, New Mexico (Figure 1). The Plant gathers and processes produced natural gas from Lea and Eddy Counties, New Mexico. Once gathered at the Plant, the produced natural gas is compressed, dehydrated to remove water content, and processed to remove and recover natural liquids. The processed natural gas and recovered natural liquids are then sold and shipped to various customers.

The Plant needs to safely inject up to a maximum of 15 MMSCF per day of TAG for 30 years. Under normal operations the TAG will be injected into Zia AGI D #2. During scheduled or unanticipated maintenance on Zia AGI D #2, TAG injection will be transferred to Zia AGI #1. Geologic studies conducted for the selection of this location demonstrate that the injection zone is readily capable of accepting and containing the acid gas and CO_2 injection volumes well within the NMOCD recommended maximum injection pressures.

The original C-108 Application for Authorization to Inject for Zia AGI #2 was submitted on November 18, 2013 and approved under Order No.R-15528; which also included Zia AGI #1. After reviewing the reservoir capabilities that Zia AGI #1 is currently injecting into it was determined a new injection zone should be explored. The geology and reservoir properties of the deeper Devonian/Wristen/Fusselman/ Montoya Formations exhibited great potential as a new injection zone. After discussions with the BLM and NMOCD, a new C-108 Application for Authorization to Inject for Zia AGI D #2 was submitted on July 12, 2016 and approved under Order R-14207; on the condition that if the new injection zone is selected, the original Order will be obviated for Zia AGI #2. A new APD was submitted to the BLM on July 16, 2016 and approved with updated COA on September 7, 2016.

Zia AGI #1 was drilled at 2,100 feet from the south line (FSL) and 950 feet from the west line (FWL) of Section 19 (Figure 2). Zia AGI #1 was deviated approximately 16.2° to the north of the surface location to reach the bottom hole approximately 1,080 feet north of the surface location, placing the top of the injection zone at approximately 2,275 FNL and 875 FWL in Section 19. The final bottom-hole location for Zia AGI #1 is located at 2,099 FNL and 862 FWL. The surface and bottom-hole locations of Zia AGI #1, as well as the gas plant facility, are located within lands owned or leased by DCP.

During permitting, drilling and completion Geolex filed all BLM and NMOCD documents, notifications, sundries and submittals, which are located in Appendix E.

Pursuant to NMOCC Order R-14207 and BLM approval of the well completion, notifications of initiation of operation were sent to producers of wells within one mile of Zia AGI D #2 prior to initiation of injection. The purpose of these letters is to inform the producers that DCP will commence injection, including a map of the worst case scenario H_2S radius of exposure. The letters along with the certified mail receipts are included in Appendix F.

4.0 PURPOSE AND RATIONALE FOR ZIA AGI D #2

The Zia II Gas plant operations include gas compression, treating and processing of natural gas. Operation of the plant is dependent on the associated compression facility and the ability to inject acid gas. DCP needs to safely inject up to 15 MMSCF per day of TAG for 30 years. Zia AGI #1 was completed on January 31, 2015 to a measured depth of 6,360 feet within the Brushy Canyon and Lower Cherry Canyon. The injection zone proved to be inadequate to accept the permitted daily flow of TAG. However, this zone's reservoir characteristics and the fact that producers are interested in targets below this approved injection zone, caused DCP to evaluate alternative disposal zones for the AGI #2 well previously approved by NMOCC. Geolex then prepared, submitted, and obtained approval for an application for a well into the Devonian-Ordovician section in the area. This well was approved at the same location as previously approved for AGI#2 and the well was approved as a vertical well.

DCP drilled the Zia AGI D #2 to a total depth of approximately 14,750 feet and targeted the injection zone in the Devonian/Wristen/Fusselman/Montoya Formations. The injection reservoir selected and successfully implemented for Zia AGI D #2 is between approximately 13,622 and 14,750 feet. Analysis of the reservoir characteristics of this unit confirms that this zone is an excellent closed-system reservoir that should easily accommodate the future needs of DCP for disposal of acid gas and sequestration of H_2S and CO_2 from the Plant. This will allow for the operation to rely primarily on AGI D#2 for its acid gas disposal needs (in zones below all potential production) and to keep AGI#1 on standby status to use as needed at times when AGI D#2 may require service.

Without the ability to dispose of acid gas at the permitted flow rate by injection, the Plant would have to find alternative methods of disposal, including uneconomical and unproductive Sulphur reduction units that generate Sulphur and CO_2 byproducts. Safely injecting acid gas creates no byproducts, and decreases the risk of a plant shut down and producers being shut in due to disposal issues. Injecting acid gas provides an economical and environmental advantage to acid gas disposal. Based upon Geolex's detailed evaluation included in the C-108, DCP, NMOCD and NMOCC have determined that the AGI wells are a safe and environmentally-sound project for the disposal of acid gas. Furthermore, the project provides additional environmental benefit by permanently sequestering a significant volume of CO_2 which would otherwise be released to the atmosphere if H_2S was flared or if a sulfur reduction unit (SRU) were to be operated at the Plant.

5.0 SYNOPSIS OF WELL DESIGN, DRILLING, LOGGING, AND COMPLETION

Geolex was contracted by DCP to design, permit, oversee drilling, and oversee testing and completion and train DCP personnel in the operation of the Zia AGI #1 and Zia AGI D #2 wells at the Zia II Gas Processing Plant. Every effort was made to safely execute the planned project operations from the drilling, to completion, and to the operation of the well. Safety meetings were conducted daily in an onsite trailer manned by representatives of Concho, prior to the beginning of each shift. Scandrill conducted mandatory safety meetings to discuss safe procedures during each major service company's operations such as coring, logging, running casing, cementing, etc., and to answer any questions personnel had prior to each specific job. All personnel entering the site, located on the Plant, were required to watch DCP's safety video and to complete and pass a written test about operations of the Plant.

Concho's drilling and completion prognoses, which were organized prior to the drilling and completion of Zia AGI D #2, can be found in Appendix P.

H_2S monitors were placed near the wellhead, inside the wellhead cellar and on the drilling deck to monitor for any possible leaks of H_2S according to Concho's BLM-approved drilling H_2S Contingency Plan. In addition, all personnel on the site had personal H_2S monitors or were required to be in the company of a person with an H_2S monitor.

Geolex submitted well installation documentation to the BLM using the BLM's Form 3160-5 for spud notice and to document any changes to the drilling plans, each casing string, pressure tests, and completion details (Appendix E). Geolex submitted courtesy Form C-103s to the NMOCD for all drilling activities included in the BLMs Form 3160-5. These forms reported data for each casing string and any changes to drilling plans. No significant lost-circulation was encountered during drilling in the Capitan Reef; therefore, there was no need to notify the BLM. Daily Drilling and Completion Reports are included in Appendix A.

5.1 WELL DESIGN

Due to the corrosive environment in which the Zia AGI D #2 is required to operate, special consideration was given to the metals used in its construction. The Plant will generate approximately 15 MMSCF per day of acid gases that are compressed to supercritical pressures (up to 2,227 pounds per square inch gauge-psig) prior to injection. The stream of H_2S (10%) and CO_2 (90%) is corrosive to wellheads, valves, packers, casing and tubing. Corrosion resistant alloys, or CRA's (chromium and nickel based), were thoroughly evaluated and included in the well design of all potentially impacted components in accordance with standards published by the National Association of Corrosion Engineers (NACE).

While the injected fluid will be dehydrated, the line that conveys the TAG to the well from the compression facilities is a stainless steel line, which provides added corrosion protection. The final design for the compression facilities and associated piping and layout of H_2S alarms and other safety equipment was incorporated into a H_2S Contingency Plan pursuant to the requirements 19.15.11 NMAC and was approved by the NMOCD on June 26, 2015 (Appendix B). The final as-built design for the Zia AGI D #2 well is shown on Figure 3.

Zia AGI D #2 is a vertical well located on property leased to DCP by the BLM. This location allows DCP access to the primary injection zone (Devonian). Zia AGI D #2 has four strings of telescoping casing, all cemented to the surface (Figure 3). Design and material considerations include: Quadruple casing through freshwater resources (Dockum and Rustler Groups); triple cased through the Permian Salt

Units (Salado Formation); double cased through the Yates Formation and Capitan Reef lost circulation zones to 4,696 feet; and corrosion resistant alloy and WellLock cement covering the Zia AGI #1 injection zone from 4,955 to 6,363 feet. The corrosion resistant alloy that covers the Zia AGI #1 injection zone adds further protection against any TAG that may come into contact with the Zia AGI D #2 well. Furthermore, the placement of the SSSV at 277 feet and the corrosion resistant packer at 13,535 feet add additional safety to injection operations.

A SSSV is installed on the production tubing to assure that fluid cannot flow back out of the well during an injection equipment failure event (SSSV Operation Manual and Design of Service is included in Appendix G). In addition, the annular space between the production tubing and casing is filled with corrosion-inhibited diesel fuel as a further safety measure, which is consistent with injection well designs previously approved by NMOCD for acid gas injection.

5.2 WELL DRILLING

Scandrill Freedom rig drilled Zia AGI D #2. The Freedom rig was equipped with a 5,000 psig blowout preventer and choke manifold to account for unforeseen downhole pressures. Drilling began on November 2, 2016. The drilling was completed at 14,750 feet on December 10, 2016. The original Zia AGI #2 well was to include three casing strings to a total vertical depth of 6,360 feet. As such, the 120-foot conductor pipe was only 20 inches in diameter. In order to accommodate the four casing strings of the Zia AGI D #2 well the original conductor pipe was plugged and the location moved seven feet to the south in order to install the 120-foot, 30-inch diameter conductor casing prior to the arrival of the Scandrill Freedom rig. A detailed description of the casing installed on Zia AGI D #2 is provided with the well schematic (Figure 3) and summarized below:

- 20-inch Surface Casing installed in a 26-inch Borehole to 826 feet
- 13-3/8-inch Upper (first) Intermediate Casing installed in a 17½-inch Borehole to 2,555 feet
- 9-5/8-inch Lower (second) Intermediate Casing installed in a 12¼-inch Borehole to 4,696 feet
- 7- and 7-5/8-inch Production Casing installed in an 8¾-inch Borehole to 13,622 feet with,
- Injection in a 6-inch diameter open hole from 13,622 to 14,750 feet.

5.3 WELL LOGGING

Logging of the Zia AGI D #2 consisted of mud logging and geophysical logging. Mud logging was performed by Selman and Associates, LTD. Mud logging started below the lower intermediate casing at 4,696 feet and continued to the total depth of the well. The mud log is included in Appendix H.

Open-hole geophysical logging was conducted by Schlumberger prior to installing the surface and upper intermediate casing (caliper log only). Schlumberger completed a suite of open-hole geophysical logs below the lower intermediate casing to total depth at 14,750 feet. Gamm ray logging was conducted by Integrity Directional Services during the entire active drilling process, where the gamma ray tool was located behind the bit. These logs were useful for immediate geologic analysis and selecting seating depths for casing. See Appendix I for a list of all logs for Zia AGI D #2, and the logs themselves.

5.4 WELL CASING INSTALLATIONS AND CEMENTING

The casing and tubing tallies for each casing string and the injection tubing are included in Appendix J. A schematic of the Zia AGI D #2 well design is presented in Figure 3. A schematic of the Zia AGI D #2 injection tubing and equipment is presented in Figure 4. Halliburton designed each cementing job and performed cementing activities for each casing string and provided recommendations for the cementing job. Cementing lab results and final cementing reports are included in Appendix K.

5.4.1 Surface Casing

The Zia AGI D #2 26-inch surface casing borehole was drilled into the top of the Magenta dolomite to 826 feet on November 3, 2016. The surface casing was installed on Friday, November 4, 2016, and was seated within a competent anhydritic dolomite of the Magenta Formation at the total depth of the borehole (826 feet), which was above the underlying Salado Formation (salt top) at 882 feet.

Cement volume for the surface casing was determined using a fluid caliper log. The casing was constructed with 19 joints of 20-inch, 106.5 lb/ft, J55, BTC casing (Appendix J). The total depth of the 26-inch borehole (826 feet) is the same as the length of the 20-inch casing with float collar and shoe. It was cemented in a single stage with 1,425 sacks (422 bbls) of Class C cement with a lead yield of 1.728 ft^3/sack and a tail yield of 1.364 ft^3/sack. 487 sacks (150 bbls) of cement were circulated to the surface. Minimum wait on cement (WOC) time was scheduled to be 14 hours, and actual WOC time was 36.5 hours.

A cement bond log (CBL) was run by Schlumberger, which indicated that the cement bond was effective (Appendix L). Following installation and testing of the blow out preventer (BOP) and blow out preventer equipment (BOPE) the surface casing was pressurized to 1,000 psi and held for 30 minutes with no loss of pressure (<10%) for a successful casing integrity test (CIT-Appendix M).

5.4.2 First Intermediate Casing

Drilling continued below the surface casing on November 6, 2016, in order to install the 13-3/8-inch first (upper) intermediate casing. The 17½-inch borehole was advanced through the salt section and into the Yates Formation. The total depth of this segment was reached on November 8, 2016, at 2,555 feet, which is approximately 205 feet above the Capitan Reef.

Cement volume for the first intermediate casing was determined using a Schlumberger open-hole caliper log. The casing was constructed with 51 joints of 13-3/8-inch, 61 lb/ft, J55, BTC casing and 6 joints of 13-3/8-inch, 68 lb/ft, J55, BTC casing (Appendix J). The total depth of the 17½-inch borehole (2,555 feet) is the same as the length of the 13-3/8-inch casing with float collar and shoe. It was cemented in a single stage with 1,950 sacks (584 bbls) of Class C cement with a lead yield of 1.732 ft^3/sack and a tail yield of 1.332 ft^3/sack. 428 sacks (132 bbls) of cement were circulated to the surface. Minimum WOC time was scheduled to be 14 hours, and actual WOC time was 17.5 hours.

A CBL was run by Schlumberger, which indicated that the cement bond was effective (Appendix L). Following installation and testing of the BOP/BOPE the first intermediate casing was pressurized to 1,000 psi and held for 30 minutes with no loss of pressure (<10%) for a successful CIT (Appendix M).

5.4.3 Second Intermediate Casing

Drilling continued below the first intermediate casing on November 11, 2016, in order to install the 9 5/8-inch second (lower) intermediate casing. The 12¼-inch borehole was advanced through the Capitan Reef and into the Goat Seep-Queen Formation. The total depth of this segment was reached on November 12, 2016, at 4,696 feet, which was approximately 83 feet above the Delaware Formation.

Cement volume for the second intermediate casing was determined using a fluid caliper log. The casing was constructed with 104 joints of 9-5/8-inch, 40 lb/ft, N80, BTC casing (Appendix J). The total depth of the 12¼-inch borehole (4,696 feet) is the same as the length of the 9-5/8-inch casing with deviation (DV) tool, float collar and shoe. It was cemented in two stages with the DV tool/external casing packer set at 2,608 to 2,633 feet. The first stage included 700 sacks (219 bbls) of Class C cement with a lead yield of 1.987 ft^3/sack and a tail yield of 1.333 ft^3/sack. 144 sacks (51 bbls) of cement were circulated to the surface. The second stage included 750 sacks (225 bbls) of Class C cement with a lead yield of 1.728 ft^3/sack and a tail yield of 1.332 ft^3/sack. 107 sacks (33 bbls) of cement were circulated to the surface. Minimum WOC time was scheduled to be 18 hours, and actual WOC time was 26 hours.

A CBL was run by Schlumberger, which indicated that the cement bond was effective (Appendix L). Following installation and testing of the BOP/BOPE the second intermediate casing was pressurized to 1,000 psi and held for 30 minutes with no loss of pressure (<10%) for a successful CIT (Appendix M). Approximately 8 feet of formation was drilled below the casing shoe and the casing was pressurized to 513 psi and held for 10 minutes, then 631 psi and held for 10 minutes for a successful formation integrity test (FIT) or mud equivalency test.

5.4.4 Production Casing

The Zia AGI D #2 production borehole was drilled to 13,622 feet on November 28, 2016. The production string was open-hole logged from below the lower intermediate casing (4,696 feet) to 13,622 feet. The open-hole geophysical logs, in combination with the mud log, were used to determine the reservoir cap-rock (Woodford shale and upper Devonian) in the lower portion of this section. This information is discussed in more detail in Sections 7 and 8.

The caliper log for the production (8¾-inch) borehole indicated a clean hole with no significant washouts from 4,696 feet to 13,622 feet (Appendix I). The Woodford shale caprock was determined to be at a depth of 13,499 feet. This caprock serves as an impermeable barrier above the injection zone that will inhibit upward migration of TAG. The borehole was advanced near the top of the Devonian, which is at 13,625 feet. These formation tops were determined using open-hole geophysical logs and the mud log (Appendices H and I).

Elevated H_2S detections (1.0 – 2.2 ppm) were encountered while drilling through the Cherry Canyon, Brushy Canyon, and Upper Bone Springs Limestone. These results are similar to what was encountered during drilling Zia AGI #1. Two elevated H_2S detections (1.1 and 1.8 ppm) were encountered in the lower Mississippian Lime (Osage Formation). Small H_2S detections (<1 ppm) were encountered during the drilling of the production borehole in nearly all formations. None of the H_2S concentrations exceeded 2.23 ppm, with an instrument H_2S detection limit between 0.01 and 100 ppm. H_2S concentrations are shown on the mud log in Appendix H.

The Zia AGI D #2 production casing was run on December 1, 2016, after completing the logging of the open borehole and laying down the drill string. The production casing shoe is set at 13,621 feet. The complex Zia AGI D #2 production casing is constructed from the top downward (from KB) starting with:

7 joints of 7-5/8-inch diameter 33.7 #/ft., HCP-110, LT&C casing to a depth of 302.4 feet;
1 cross-over of 7-5/8-inch diameter 33.7 #/ft., HCP-110, LT&C casing to a depth of 306.1 feet;
115 joints of 7-inch diameter 29 #/ft., HCP-110, LT&C casing to a depth of 4,925.8 feet;

1 cross-over of 7-inch diameter, 29#/ft. LTC Box by 7" 32#/ft. VAM TOP Pin to 4,955.4 feet;
48 joints of 7-inch diameter, 32 #/ft., SM2035-110 VAM TOP casing to a depth of 6,317.5 feet;
1 cross-over of 7-inch diameter, 32#/ft. VAM TOP Box by 7" 29#/ft. LTC pin to 6,345.5 feet;
DV Tool to 6,345.5
155 joints of 7-inch diameter, 29 #/ft., HCP-110, LT&C casing to a depth of 13,298.1 feet;
1 cross-over of 7-inch diameter, 29 #/ft. LTC Box by 32 #/ft VAM TOP Pin to 13,329.2 feet;
10 joints of 7-inch diameter, 32 #/ft., SM2035-110 VAM TOP casing to a depth of 13,622 feet

A detailed description of the production casing installed at the Zia AGI D #2 is provided with the well schematic (Figure 3).

The production casing for the Zia AGI D #2 was cemented in two stages. A DV tool was placed at a depth of 6,346 feet (see casing tally sheet-Appendix J). The first stage (bottom 13,622 feet - top 6,346 feet) required two types of cement including 770 sacks (289 bbl.) of Tuned Light™ 11.5 pounds per gallon (ppg), 2.11 yield, 11.18 gallons/sack (gal/sks) cement followed by 20 bbl. of WellLock 12 ppg resin cement. The DV tool dart was dropped, which opened the DVT and pushed 128 sacks (48 bbl.) of cement to the surface. Appendix K includes details and cementing reports for all cementing jobs.

The second stage (bottom 6,346 feet - top surface) also required two types of cement including 420 sacks (158 bbl.) of Tuned Light™ 11.5 ppg, 2.11 yield, 11.18 gal/sks cement followed by 80 bbl. of WellLock 12 ppg resin cement. The WellLock cement covers the Zia AGI #1 injection interval, and acts as another security measure to prevent corrosion from TAG that may come in contact with Zia AGI D #2. The DVT was closed and cement was pumped to the surface with 93 sacks (35 bbl.) returned to the surface. WOC was 32 hours, including both the first and second stage cement jobs. No fall back of cement was observed and the production casing remained cemented to surface. The cement returns were not witnessed by the BLM, but were photographed and submitted with the approved 3160-5 Form. The cement report is included in Appendix K.

A CBL was run by Schlumberger, 55 hours after setting the second stage cement, which indicated that the cement bond was effective (Appendix L). Halliburton CBL tools were run with no casing pressure applied at the surface in order to prepare an Advanced Cement Evaluation log and Peak Analysis of the CBL Waveform log. The logs required significant in-house processing in order to minimize the effects of the CRA pipe and resin-based cement. A few isolated questionable bonds are present between the 7-inch and 9-5/8-inch casing; however, these are countered by good bonds above and below these intervals and the overall bond of the production casing.

Following installation and testing of the BOP/BOPE, the production casing was pressurized to 1,000 psi and held for 30 minutes with no loss of pressure (<10%) for a successful CIT (Appendix M). Approximately 10 feet of formation was drilled below the casing shoe to perform a FIT by applying 440 psi of pressure for 30 minutes with no evidence of formation breakdown.

5.4.5 Open-Hole Section

The Zia AGI D #2 open-hole borehole was drilled from 13,622 feet to 14,750 feet on December 10, 2016. The open-hole borehole was logged form 13,635 to 14,750 feet. The open-hole geophysical logs, in conjunction with the mud log, were used to determine the best locations to sidewall core the reservoir. Sidewall cores are used to determine the injection reservoirs capabilities, and are also used to determine if recoverable hydrocarbons are present in this zone. This information is discussed in more detail in Sections 7 and 8.

The injection zone is characterized by the Devonian at 13,625 feet, Wristen at 13,797 feet, Fusselman at 13,972 feet, and Montoya at 14,371 feet, which are all primarily composed of limestones and dolomites (Figure 7 and Appendices H and I). Small isolated H_2S detections were encountered during drilling of the open-hole borehole, as the drill bit cut through the injection zone and during circulation. None of the H_2S detections exceeded 0.74 ppm (one at 14,325 feet). H_2S concentrations are shown on the mud log in Appendix H.

After completing the open-hole borehole Scandrill Freedom Rig was released. All results were reported to and approved by the BLM (online) and NMOCD (hand-delivered and e-mailed to Hobbs office) in the final production casing NOI sundry (Form 3160-5).

All of the components of the H_2S Contingency Plan remained in effect during the drilling, installation, and cementing of all casing strings. Geolex submitted copies of all casing tallies, surveys, casing specifications, cementing details and reports, cement lab results, CBLs, and FITs to the BLM using form 3160-5 online. Form C-103s with similar attachments were submitted to the NMOCD, Hobbs, NM office.

5.4.6 Packer and Tubing Equipment

A work-over rig (Aries Rig #46) and workover string were used to complete the work on Zia AGI D #2 starting December 15, 2016. The permanent packer placed in Zia AGI D #2 is built from Incoloy CRA components and was placed at 13,535 feet within the CRA 7-inch diameter casing. Just above the packer is a Halliburton HAL ROC® Pressure-Temperature (PT) gauge, located at a depth of 13,526 feet. Nine joints of Inconel G3 Nickel VAM TOP tubing followed by 411 joints of BTS-8 L80 tubing are present between the P-T gauge and surface. The SSSV is placed at a depth of 277 feet. The 3½-inch diameter 9.2 #/ft., VAMTOP Inconel G3 Nickel injection tubing was installed at a depth of approximately 13,200 feet to 13,518 feet (Appendix J). Above this special corrosion resistant tubing is the 3½-inch diameter 9.3 #/ft. BTS-8 L80 tubing to surface. The design of service for the Haliburton BWD Permanent Packer is included in Appendix G.

On January 21, 2017, 20 bbls of WG-19 gel spacer mixed with red dye were placed in the tubing/casing annulus. Following the gel spacer were 500 bbls of red diesel packer fluid mixed with 1% (5 bbls) Baker CRO 381 corrosion inhibitor down the tubing/casing annulus. The CRO 381 corrosion inhibitor contains quaternary amines which also function as a biocide. Once the diesel with the dyed gel spacer was circulated out of the tubing/casing annulus, and clean diesel appeared at the surface, pumping ceased.

The tubing was landed in the tubing hanger and into the tubing head, and the annular space was sealed off. The two Inconel control lines (P-T gauge and SSSV control line) were placed through the tubing head and dressed out on the termination blocks. The final P/T connections were made and the Christmas tree was installed. The well tree is comprised of equipment shown in Appendix N. The wellhead/tree adapter flange and tie-in control fitting components were installed and pressure-tested to 5,000 psi for 15 minutes. On January 25, 2016, a mechanical integrity test (MIT) was successfully performed and witnessed by a BLM and NMOCD representative (Appendix M).

6.0 REGIONAL AND LOCAL GEOLOGY AND HYDROGEOLOGY

6.1 GENERAL GEOLOGIC SETTING/SURFICIAL GEOLOGY

The Zia II Gas Plant is located in Section 19, T 19 S, R 32 E, in Lea County, New Mexico, about 35 miles west of Hobbs (Figure 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 redbeds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater. The thick sequences of Permian through Ordovician rocks that underlie these deposits are generally described below.

6.2 BEDROCK GEOLOGY

The Plant and the well are located at the northern margin of the Delaware Basin, a sub-basin of the larger encompassing Permian Basin (Figure 5), 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 Basin, Midland Basin, Central Basin Platform and North Platform) 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 was gradually filled by large quantities of clastic sediments while carbonates were deposited on the surrounding shelves, and was further deepened by basin subsidence.

Figure 6 is a generalized stratigraphic column showing the formations that underlie the well site. The entire lower Paleozoic interval (Ordovician through Devonian) was periodically subjected to subaerial exposure and prolonged periods of karsting, most especially in the Fusselman and Devonian. The result of this exposure was development of karst-related secondary porosity systems, that included solution-enlargement of fractures and vugs, and development of small cavities and caves. Particularly in the Fusselman, solution features from temporally-distinct karst events became interconnected with each successive episode. This may have caused some degree of vertical continuity in parts of the Fusselman section that could lead to enhanced vertical and horizontal permeability.

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 that truncate up against the Woodford shale (Figures 6 and 9). Faulting higher in the section that is related to the Hercynian orogeny is more prevalent closer to the Central Basin Platform margins and the northern margins of the Northwest Shelf (Figure 5).

The sub-Woodford Paleozoic rocks extend down to the Ordovician age Ellenburger Formation, which sits on the basement over a veneer of Early Ordovician sandstones and granite wash. The Ellenburger is comprised of dolomites and limestones, and is up to several hundred feet thick. It is overlain by about 400 feet of Ordovician Simpson sandstones and tight limestones, in turn overlain by about 400 feet of Montoya cherty carbonates.

The Silurian age Fusselman and Wristen and Devonian age Thirty-one Formations overlie the Montoya, and are comprised of interbedded dolomites and dolomitic limestones that are capped by the Woodford Shale (Figure 6). The Woodford shale is overlain by approximately 570 feet of Osagean limestone, which is overlain by approximately 381 feet of shales and basinal limestones of the Upper Mississippian Chester Formation. The Pennsylvanian Morrow, Atoka and Strawn, and a starved section of Cisco-Canyon complete the pre-Permian section. Within this entire sequence, the Morrow is a major gas producing zone, with smaller contributions from the Atoka and Strawn. The Ordo-Devonian injection zone does not produce economic hydrocarbons for more than 15 miles away from the well site.

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent), Guadalupe, Leonard, and Wolfcamp (oldest) (Figure 6). Numerous oil and gas pools have been identified in these rocks. In the area of the Zia AGI D #2 well, 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 pool, and gas production is dispersed through the deeper Bone Spring (the “Avalon”) and Wolfcamp. Figure 7 provides tops of the major formations encountered in the drilling of AGI D#2.

There have been no commercially significant deposits of oil or gas found in the Ordovician, Silurian, or Devonian rocks (the injection zone), in the vicinity of the well. 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 of review (Figure 10). In fact, these zones are routinely approved as produced-water disposal zones in this area.

6.3 LITHOLOGIC AND RESERVOIR CHARACTERISTICS OF THE ORDO-DEVONIAN FORMATIONS

The correlation section with the nearest adjacent well of similar depth and log characteristics of both wells are shown in Figures 8 and 9. The injection interval includes the Devonian age Thirty-one Formation, Silurian age Wristen and Fusselman Formations, and Ordovician age Montoya Formation, collectively referred to here as the Ordo-Devonian (Figure 9). Based on the geologic analyses of the subsurface at the Zia II Gas Plant, acid gas injection and CO_2 sequestration was recommended in the Ordo-Devonian Formations. The 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. In addition, the porous zones are separated by tight limestones and dolomites.

The Ordo-Devonian interval has excellent cap rocks above, below and between the individual porous carbonate units. There are no producing zones within or below the Ordo-Devonian in the area of the well, and the injection interval is separated from the nearest producing zone (Morrow) by 126 feet of Woodford shale, 570 feet of tight Osagean limestones, and nearly 381 feet of tight Chesterian shales and deep water limestones (Figures 8 and 9). The injection interval is a minimum of approximately 1,200 feet above the Precambrian crystalline basement. Faults that have been identified in the area truncate up against the base of the Woodford Shale, and would not serve as potential vertical conduits because of the thick tight cap rock above (Woodford Shale). The relatively high net porosity of the injection zone indicates that the injected H_2S and CO_2 will be easily contained close to the injection well.

Figure 11 shows the cross section of the injection zone portraying continues thick cap rocks that overlie the Ordo-Devonian section. These logs clearly show that the cap rocks are continuous across the area, and that any migration of fluids along faults would be confined to the sub-Woodford injection zone.

The available geophysical logs were examined for all wells penetrating beneath the Woodford Shale within a three-mile radius of the DCP Zia AGI D #2 well. Existing well control to these depths is limited to three wells, two of which are salt water disposal wells that inject into the open-hole interval from the base of the Woodford through the Fusselman or upper Montoya Formations. The third and closest deep penetration is the Lusk Deep Unit #2, a plugged Morrow producer that is approximately 4,800 feet northeast of the injection well (Figure 11).

Working with Devon Energy, who owns a proprietary 3D seismic volume that covers the area around the location, Geolex was able to observe deep structures and produce a generalized subsea structure map drawn on top of the Devonian (base of Woodford) that was based on synthetic seismograms generated from the sonic logs and well tops of the Lusk Deep #2 and the Magnum Pronto SWD #31-1 (two miles southeast of the location) wells.

These seismic and log analyses were used to define a porosity “fairway” (encompassing at least 400 acres), shown in Figure 12. This interpretation is supported by cross-sections of the overlying stratigraphy that reveal relatively horizontal contacts between the units (Figure 11). Only one fault was observed in the area, which penetrates only up to the base of the Woodford Shale. This fault runs northwest to southeast through the Zia plant site. Local heterogeneities in permeability and porosity affect fluid migration and the overall three-dimensional shape of the injected gas plume.

The porosity of the units in the area were evaluated using amplitude attribute analysis of the Devon 3D seismic volume, and geophysical logs collected from three nearby wells penetrating the sub-Woodford section. Amplitude anomalies indicative of porosity formation in the Ordo-Devonian section were identified on the 3D seismic volume and the extent of observed anomalies were mapped. The major amplitude anomaly was found in the upper Fusselman, and covers an area of 400 to 600 acres under and in the vicinity of the Plant; another anomaly, identified in the lower Devonian, is at least 80 acres in size and extends below the Plant. Geolex had a restricted view of the Devon seismic volume, but the Fusselman anomaly extends further to the west and could be as large as 600 acres, and the Devonian anomaly at least 30% larger than what was observable (Figure 12).

Full modern logging suites through the entire Ordo-Devonian section were available from the BOPCO Hackberry 34 SWDW #1 (Sec. 34-19S-31E) and Concho Oil & Gas Magnum Pronto SWD #32 #1 (Sec. 32-19S-32E) wells, and a sonic and old induction electric log through the upper Fusselman were available in the El Paso Natural Gas Lusk Deep #2 (Sec. 18-19S-32E). Primary porosity was counted from the neutron/density cross-plot log in the Hackberry and Magnum Pronto wells, but it was not possible to count secondary porosity from solution-enlarged fractures and vugs/cavities in any of the wells. The micrulog resistivity logs in the two disposal wells, which inject salt water into the Ordo-Devonian interval, show a number of solution-enlarged and primary fractures throughout the Ordo-Devonian section that could have porosities in excess of 15%. Primary porosity ranges up to 10% in each well. The sonic log from the Lusk Deep Unit #2 shows porosities up to 14% or more, in the Devonian and the Fusselman, which reflects some of the secondary porosity in that wellbore. The two disposal wells show more primary and widespread fractured/solution-enlarged porosity in the Fusselman than in the Wristen and Devonian, and less tight rock intervening between porous zones.

The Lusk Deep Unit #2 shows about the same amount of porosity in the Devonian-Wristen and upper Fusselman (the lower Fusselman was not logged in this well) than in the other two wells. The upper

Devonian in the Lusk Deep and Magnum Pronto wells appears generally to be tight, but is more heavily fractured in the Hackberry SWD well. Primary porosity in the two disposal wells average from 4-5%, without taking into consideration the porosity "plumbing" or interconnection of the primary porosity with the fracture and solution-enlarged porosity. The COG Magnum Pronto well is currently injecting up to 2.5 bpm at an injection pressure of less than 300 psi, showing that the formation is very permeable and capable of accepting higher volumes of fluid. This suggests that secondary porosity plays a key role in transmissivity.

6.4 GROUNDWATER HYDROLOGY IN THE VICINITY OF THE INJECTION WELL

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are four freshwater wells located within a one-mile radius of the DCP Zia AGI D #2 well; the closest water well is located 0.6 miles away (Figure 13; Table 1). All wells within the one-mile radius are shallow, collecting water from about 250 to 350 feet depth, in the Triassic redbeds. These wells were drilled for exploratory purposes by Phillips Petroleum in 1982, and do not produce any consumed water. The shallow freshwater aquifer is protected by four strings of casing in the DCP Zia AGI D #2 well, which extend to 826 feet, 2,555, 4,696, and 13,622 feet, respectively.

Table 1: Water Wells Identified by the New Mexico State Engineer's Files Within One Mile of Zia AGI D #2 Well

POD Number	Owner	Use	UTME	UTMN	Distance (m)	Depth Well (ft)	Depth Water (ft)
CP 00642 EXPL	PHILLIPS PETROLEUM COMPANY	Exploration	611025	3611657	973	250	N/A
CP 00640 EXPL	PHILLIPS PETROLEUM COMPANY	Exploration	612621	3613280	1342	260	102
CP 00639 EXPL	PHILLIPS PETROLEUM COMPANY	Exploration	613029	3612880	1540	350	345
CP 00563 EXPL	PHILLIPS PETROLEUM COMPANY	Exploration	612118	3613376	1064	N/A	N/A

The area surrounding the injection well is arid and there are no bodies of surface water within a five mile radius. Our analysis confirms that the well poses no risk of contaminating groundwater in the area. Furthermore, there are no potential conduits that would allow migration of injected fluids to fresh-water zones.

6.5 OIL AND GAS WELLS IN THE DCP ZIA AGI AREA OF REVIEW AND VICINITY

Within a two-mile radius of the Zia AGI D #2 location, NMOCD records identify a total of 192 wells (80 plugged and abandoned or temporarily plugged and 101 active). There are also 11 well applications approved and awaiting drilling (including the permitted Zia AGI D #2). Except for the Lusk Deep Unit well noted below, there are no known wells (current or proposed) that penetrate the injection zone (see Appendix O).

Fifty-five wells were identified in the one-mile radius of the AGI location, of which 29 are active, 24 are plugged, and 2 are pending (Figure 10 and Appendix O). There is no current production in the injection zone in this area. The single well penetrating the injection zone (API 3002500900; Lusk Deep Unit 002) reached a total vertical depth of 13,974 feet at a location 0.88 miles northeast of Zia AGI D #2 in 1961, and was plugged and abandoned in September 1971. Well data and a plugging diagram are included in Appendix O. All of the wells identified are listed in Appendix O, which includes the locations, depths, status, operators and distances of the wells from the AGI well locations. Figure 10 identifies all wells within a one-mile radius, including the single well penerating the injection zone.

Within the one-half mile radius of interest, there are only 20 wells, of which 12 are active and 7 are plugged and abandoned, and one drilled well in the Ordo-Devonian (Zia AGI D #2). A complete list of oil and gas wells within the one-half, one and two mile radii are included in Appendix O. A review of the plugging and completion reports indicate that none of the wells within one-half mile penetrate the injection zone (Appendix O). Table 2 below identifies all wells within a one-half mile radius of the Zia AGI D #2 well. The locations of these wells are shown on Figure 14.

Table 2: Wells within One-half Mile of Zia AGI D #2

API #	**OPERATOR**	**PLUG DATE**	**SPUD DATE**	**TVD**	**STATUS**	**To AGI D #2 (mi)**
3002542207	DCP MIDSTREAM, LP				Permitted, not drilled	0.0
3002542208	DCP MIDSTREAM, LP		12/23/2014	6192	Active	0.04
3002500911	SIMMS & REESE OIL CO	12/30/1959	12/7/1959	2640	Plugged	0.09
3002500904	CARPER DRILLING CO	3/1/1943	12/19/1942	2862	Plugged	0.17
3002520247	EL PASO NATURAL GAS	10/25/1971	12/10/1963	11432	Plugged	0.24
3002535291	COG OPERATING LLC		4/24/2001	12718	Active	0.26
3001505790	PLAINS PROD CO	8/18/1947	1/20/1946	2876	Plugged	0.28
3002500902	REMNANT OIL PROPERTIES, LLC		10/12/1942	2634	Active	0.29
3002500909	TOM R CONE		8/31/1958	2490	Active	0.29
3001542914	COG OPERATING LLC		2/2/2015	9210	Active	0.31
3002542750	COG OPERATING LLC	9/25/2015	9/1/2015	4370	Plugged	0.32
3002542858	COG OPERATING LLC		10/22/2015	9241	Active	0.32
3002534573	COG OPERATING LLC		12/17/1999	12540	Active	0.34
3002520876	TOM R CONE		11/6/1964	11223	Active	0.35
3002500910	TOM R CONE		8/3/1961	2500	Active	0.36
3002500907	KELLY G STOUT	3/24/1958	10/1/1957	2552	Plugged	0.37
3001510382	PHILLIPS PETROLEUM CO	10/17/1994	4/26/1964	11540	Plugged	0.40
3002520122	COG OPERATING LLC		4/16/1963	12554	Active	0.42
3001505785	REMNANT OIL PROPERTIES, LLC		10/8/1941	2470	Active	0.43
3002500906	TOM R CONE		1/2/1957	2715	Active	0.50

7.0 SELECTION OF INJECTION ZONE

During drilling, Geolex, DCP, and their contractors performed mud logging, sidewall coring, and geophysical logging of the well. Based on the geologic analyses of the data collected during drilling, Geolex recommends acid gas injection and CO_2 sequestration in the Devonian, Wristen, Fusselman, and Montoya Formations. The injection interval from 13,622 feet to 14,750 feet includes good porous limestone and dolomite units that have excellent low porosity caps above and between the individual porous units. These relatively high porosity intervals cover the entire injection zone as shown on the geophysical log in Figure 9.

Geolex utilized sidewall cores produced during the drilling of Zia AGI D #2 to help with correlations and injectivity interpretations between 13,622 feet and 14,750 feet (Appendix C). Sidewall cores were not collected above or below this interval. Core measured carbonate porosities within the open-hole injection zone range from 1.3% to 12.6 %, and measured permeabilities range between 0.0048 and 283.5 millidarcies (mD). The results of this analysis provide evidence for the location of the Ordo-Devonian at depth, which were correlated with the suite of geophysical logs. Furthermore, this analysis shows good porosity and significant permeability within the injection zone that will allow for the transport of TAG throughout the reservoir. Since, the injection zone within the well is an open-hole; there was no need to select perforation intervals.

7.1 GEOPHYSICAL LOGGING ANALYSIS

Schlumberger open-hole logged below the 2nd intermediate casing (4,696 feet) to the bottom of the open-hole borehole (14,750 feet). Gamma ray logging was conducted by Integrity Directional Services during the entire drilling process, where the gamma ray tool was located behind the bit. These logs were useful for immediate geologic analysis and selecting seating depths for casing. Schlumberger provided logs consisting of spontaneous potential, natural gamma, resistivity, neutron porosity, sonic porosity, and 360^{o} caliper with integrated borehole volume. All geophysical logs are included in Appendix I.

In addition to the conventional logs used, Schlumberger performed Fullbore Formation MicroImager (FMI) logging for the injection, caprock, and above-caprock zones. FMI logs show highly detailed contrasts in porosity and the locations and orientations of beds, faults, fractures, and unconformities. Schlumberger performed a detailed analysis of the FMI log, which is included as a presentation in Appendix D. The final interpreted FMI log is labeled as the Borehole Image Interpretation and is included in Appendix I.

The interpreted logs classify fractures as conductive continuous-fractures, conductive lithology-bound-fractures, conductive part-resistive-fractures, and resistive-fractures. Conductive fractures are open pathways for fluid to migrate through, whereas resistive fractures are closed or healed fractures that may inhibit fluid migration. Conductive, continuous-fractures completely and continuously transect the wellbore. Conductive, part-resistive-fractures conversely are partially healed or do not completely transects the wellbore. Conductive, lithology-bound-fractures terminate at an observable lithology contrast. Resistive, continuous-fractures completely and continuously transect the wellbore.

Analyses of the FMI log from 12,675 feet (Chester Formation) to 13,625 feet (base of Woodford Formation) showed an overall low bed boundary dip of approximately 6 degrees toward the west and west-southwest direction. The overall sedimentary bedding (layers within each formation) has a low dip of approximately 5 degrees to the west-southwest direction. No faults were observed on the FMI log across this section. 0 conductive, continuous-fractures, 5 conductive, lithology-bound-fractures, and 6 conductive, part-resistive-fractures were identified within this interval (12,675 – 13,625 feet). The dominate strike orientation of these fractures is northeast-southwest. The few natural open lithology-bound-fractures identified are mainly within the Chester Formation. 1 resistive, continuous-fracture and 15 resistive, lithology-bound fractures were identified within the interval from 12,675 feet to 13,625 feet. The dominate strike orientation of these fractures is northeast-southwest.

0 conductive, continuous-fractures, 4 conductive, lithology-bound-fractures, and 5 conductive, part-resistive-fractures were identified within the Chester from 12,548 feet to 12,765 feet. 0 conductive, continuous-fractures, 0 conductive, lithology-bound-fractures, and 0 conductive, part- resistive fractures were identified within the Barnett interval from 12,765 feet to 12,929 feet. 0 conductive continuous-fractures, 1 conductive, lithology- bound-fracture, and 0 conductive, part-resistive-fractures were identified within the Osage interval from 12,929 feet to 13,499 feet. Analysis of the Woodford shale caprock identified 0 conductive, continuous-fractures, 0 conductive, lithology-bound-fractures, and 1 conductive, part-resistive-fracture from 13,499 feet to 13,625 feet.

Analyses of the FMI log from 13,622 feet (Devonian) to 14,750 feet (Montoya) showed an overall low sedimentary bedding dip of approximately 8 degrees toward the southwest direction. The maximum horizontal stress is the preferential direction for fracture stimulation (i.e. fracture orientation). The dominant strike of the horizontal stress is northeast-southwest (58 %) with a minor (26%) north-northeast to south-southwest orientation. Across this entire interval (13,622 – 14,750 feet) there were 3 conductive, continuous-fractures, 224 conductive, lithology-bound-fractures, and 0 conductive, part- resistive-fractures identified. The dominant strike orientation of these fractures is east-northeast to west-southwest. There were no faults identified on the FMI log across this interval.

0 conductive, continuous-fractures, 4 conductive, lithology-bound-fractures, and 0 conductive, part-resistive-factures were identified within the Devonian interval from 13,622 feet to 13,797 feet. The dominate strike orientations within the Devonian are north-northwest to south-southeast (50%) and west-northwest to east-southeast (50%). 0 conductive, continuous-fractures, 45 conductive, lithology-bound-fractures, and 0 conductive, part-resistive-fractures were identified within the Wristen interval from 13,797 feet to 13,972 feet. The dominate strike orientation of fractures within the Wristen is east-northeast to west-southwest. 1 conductive, continuous-fracture, 48 conductive, lithology-bound-fractures, and 0 conductive, part-resistive-fractures were identified within the Fusselman interval from 13,927 feet to 14,371 feet. The dominate strike orientation within the Fusselman is northeast to southwest. 2 conductive, continuous-fractures, 127 conductive, lithology- bound-fractures, and 0 conductive, part-resistive-fractures were identified within the Montoya interval from 14,371 feet to 14,750 feet. The dominate strike orientation within the Montoya is east-northeast to west-southwest.

The FMI log interpretation has shown that the intervals above the injection zone are completely isolated from the injection reservoir. There are no pathways for TAG to migrate up from the injection zone to these upper intervals. Furthermore, the tight shale of the Woodford creates an impermeable barrier to upward movement of TAG. The FMI log interpretation has shown that the injection zone is highly fractured, with open and continuous fractures, and secondary vug and karst porosity. The majority of these fractures are within the Wristen, Fusselman, and Montoya. These structural and diagenetic (i.e. secondary porosity) features ultimately allow for the safe disposal of TAG into the Ordo-Devonian injection zone.

As discussed below, the log interpretations were used to select 50 sidewall core points to verify the lithologies, porosity, and permeability inferred from the logs.

7.2 SIDEWALL CORING ANALYSIS

Geolex selected 50 sidewall cores to be collected from the open-hole injection zone between 13,622 feet and 14,750 feet. These were selected based off of the density and neutron porosity geophysical logs. Schlumberger was able to retrieve 43 one-inch diameter sidewall cores, which were analyzed by Weatherford Laboratories (Appendix C). The sidewall cores prove the major lithology of the injection zone to be limestone and dolomite with a cherty layer near the bottom. The sidewall cores also provide empirical evidence that quantifies permeable units within the injection zone.

There are zones with relatively high porosity (4.3 %), yet low permeable (0.005 mD) which may prevent TAG flow. However, zones with relatively moderate-high porosity (2.9% and 8 %) and relatively moderate-high permeability (131 mD and 10.8 mD), respectively, may promote acceptance of TAG. These sidewall core results demonstrate that one order of magnitude difference in porosity, and more importantly permeable, can create enough connecting space within the injection zone to accept TAG at the designated injection pressures. Therefore, it is crucial to have good porosity attached to good permeability within the injection zone. Figure 15 shows permeability versus porosity from sidewall cores collected across the injection zone.

Units within the injection zone of notable porosity and permeability are at 13,847 feet (11.1 % and 136.9 mD), 13,853 feet (8.3% and 283.5 mD), 13,895 feet (10.9% and 0.3 mD), 13,903 feet (8% and 10.8 mD), 14,319 feet (7.8% 1.6 mD), 14,514 (2.9% and 131.4 mD), 14,682 feet (9.5% and 6.0 mD), 14,695 feet (7.5% and 7.9 mD), 14,712 feet (9.3% and 38.0 mD), and 14,722 feet (12.6% and 1.1 mD). This data demonstrates there are units across the entire injection zone of good porosity and permeability that will accept TAG. It appears the Wristen and Montoya Formations contain the majority of these high porosity and permeability units, with minor units in the Fusselman. Furthermore, these sidewall cores were sampled at small points across the injection zone, where there may be zones of high porosity and permeably that were not sampled, and vice versa.

8.0 RESERVOIR CHARACTERISTICS

8.1 FORMATION FLUID CHEMISTRY

Following the drilling of the 6-inch open-hole section the injection zone was swabbed and 10 samples were sent to Cardinal Laboratories in Hobbs, NM. The laboratory report and analysis, along with a summary table of the results that depict the concentrations of all analytes is included in Appendix D. The average concentrations for major constituents within the formation water in the entire injection interval are as follows:

Chloride: 23,700 mg/L
TDS: 42,750 mg/L
Diesel Range Organics: 5.7 mg/L
Extended Range Organics: 2.7 mg/L
pH: 6.5
Total Alkalinity: 613 mg/L

The maximum concentrations for major constituents within the formation water in the entire injection interval are as follows:

Chloride: 27,000 mg/L
TDS: 44,700 mg/L
Diesel Range Organics: 20.5 mg/L
Extended Range Organics: 5.6 mg/L
pH: 6.7
Total Alkalinity: 670 mg/L

The results of the formation water analysis support and confirm the conclusions presented from the geophysical logs, mud log, and sidewall cores that the injection zone clearly does not contain recoverable hydrocarbons. Included in Appendix D is Geolex's No Recoverable Hydrocarbon Summary report, which was required by the BLMs COA, and submitted to the BLM and NMOCD.

8.2 RESERVOIR TESTING

Reservoir testing on the Zia AGI D #2 included acidizing, SRT, and ten-day pressure fall-off and temperature warm-back tests across the entire open-hole injection interval. The FMI log (discussed above in Section 7.1) was used in conjunction with these tests in order to accurately determine which units in the injection zone will accept TAG. These reservoir tests findings indicate the injection reservoir will accept TAG at the designed rates and injection pressures over an extended period.

After the well was drilled to 14,750, and formation swabbed, it was then stimulated with 40,000 gallons of double inhibited NE Fe 20% hydrochloric (HCl) acid (inhibited for 200 ºF bottom hole standard temperature) plus 4,000 lbs graded salt in gelled brine at approximately 7-10 bpm. HCl acid was injected into the open-hole to stimulate the injection zone and remove as much "skin" as possible prior to the SRT and injection. Initially the injection zone appeared open to accept TAG as evidence by the sidewall coring and geophysical logging results. The acid further opened potential fractures and secondary porosity zones (vugs in the limestone). After all the acid was pumped it was followed by 1,000 bbls of freshwater at an average rate of 7.4 bpm and average surface pressure of 1,740 psi. This relatively high average pumping rate (7.4 bpm) and low average surface pressure (1,740 psi) indicates the reservoir gave little resistance to accepting fluids.

The distributed temperature sensing (DTS) slickline was placed in the hole for 10 days to capture the exothermic reaction data from the acid job and temperature warm-back data post-SRT (Appendix D). The DTS warm-back data clearly shows acid reacting with the formations at multiple zones. These zones are also high porosity and permeable zones as indicated by cooler anomalies on the DTS curve and sidewall core results. The DTS warm-back data demonstrates the majority of the fluids were taken by porous/permeable intervals in the upper portions (approximately 13,840 feet – 13,856 feet) of the injection zone. Additionally, porous/permeable zones between approximately 14,280 feet – 14,410 feet and 14,600 feet – 14,650 feet are shown as cool anomalies on the DTS data, and appear to accept fluids.

Following the acid wash, Aries Rig #46 and Halliburton conducted a SRT on Zia AGI D #2 starting at 14:11 on December 29, 2016, within the injection interval between 16,322 and 14,750 feet (Figures 16 and 17). Surface pressure measurements were recorded by Halliburton and witnessed by Geolex (Appendix D). Formation pressures were measured by Schlumberger using a retrievable pressure bomb set at 14,662 feet, which was recovered after the 10-day fall off test. The BLM was notified 24 hours prior to the test and they opted not to be onsite to witness it. The NMOCD Hobbs District office was also notified as a courtesy and elected not to observe.

The SRT design pumping rates were 0.25, 0.5, 1.0, 1.5, 2.0, 3.0, 4.0, 5.0, 6.0, and 7.0 barrels/minute (Appendix D). The SRT was stopped at 19:13 on December 29, 2016. A total of approximately 918 bbls were pumped during the SRT. Table 3 below shows the rate, volume, maximum surface pressure at each step, average surface pressure at each step, average formation pressure at each step, and duration for each step.

Table 3: Step Rate Test Data

Step #	Rate (bbls/min)	Volume (bbls)	Max Surface Pressure (psig)	Avg. Surface Pressure (psig)	Avg. Formation Pressure (psig)	Duration (min)
1	0.25	7.5	86	86	6,483	30
2	0.5	15.0	101	100	6,497	30
3	1.0	30.0	152	142	6,528	30
4	1.5	45.0	211	199	6,567	30
5	2.0	60.0	279	273	6,609	30
6	3.0	90.0	453	439	6,688	30
7	4.0	120.0	662	644	6,778	30
8	5.0	160.0	927	885	6,850	32
9	6.0	180.0	1253	1,229	6,998	30
10	7.0	210.0	1613	1,558	7,129	30

The observed surface pressure was 86 psig prior to the initiation of pumping step 1 at 0.25 bpm using 8.35 lb/gal fresh water. Maximum surface pressures of 662 psig and 927 psig respectively were observed in the 7th and 8th steps at rates of 4.0 and 5.0 bpm bracketing the maximum permitted injection rate of 4.4 bpm. Three additional steps, of greater injection rate, were conducted following the maximum permitted injection rate of 4.4 bpm. These additional steps were used to help evaluate injection potential of the reservoir and to reach the break-over conditions of the formations. A maximum surface pressure was recorded at 1,613 psig in the tenth step at a target rate of 7.0 bpm with fluids filing the natural fractures and porosity in the carbonates of the injection zone with no indication of vertical fracturing.

The SRT did not reach a break-over point, which demonstrates the formation parting pressure was never reached during the test; even at the highest pumping rate well above the maximum permitted injection rate. This is confirmed by the fitting of a linear relationship whose slope does not change over the entire population of observed surface or formation pressures, and has a linear fit correlation coefficient in excess of 0.98 (Figure 17). The NMOCD-approved maximum allowable operating pressure (MAOP) for treated acid gas is 5,028 psig at the rate of 15.0 MMSCFD, which at bottom-hole P/T conditions is approximately 4.4 bpd of liquid TAG. The anticipated pressure required to inject this volume is estimated to be between 1,400 and 1,800 psig.

This SRT fulfilled the requirement of the BLM COA for DCP Zia AGI D #2 dated September 7, 2016 and completion COA dated December 15, 2016, and NMOCC Order R-14207. The SRT demonstrated the Zia AGI D #2 well could be safely operated at pressures well below the currently approved MAOP. DCP did not request an MAOP increase for this well during this time. Since, this well will be completed with continuous surface and bottom-hole pressure monitoring, as required by the NMOCC Order R-14207, DCP can assure that fracture pressure is never exceeded during injection operations.

8.3 PRESSURE TRANSIENT ANALYSIS AND DISTRIBUTED TEMPERATURE SENSING REVIEW

Geolex and Schlumberger analyzed available data to determine the injectivity of the Montoya, Fusselman, Wristen, and Devonian (i.e. injection reservoir) at the recently-completed Zia AGI D #2. The open-hole injection zone covers a vertical depth of approximately 1,128 feet (from 14,750 feet to 13,622 feet) and is composed of carbonates with secondary porosity features including vugs, karst, and structural features including fractures and faults. One fault was observed in the area, which only penetrates the injection zone terminating in the base of the Woodford shale caprock. This fault is to the east of the well and runs NE-SW deep beneath the Zia plant.

After reviewing the pressure transient analysis (PTA) and DTS data prior to initiating TAG injection it was confirmed this zone will accept TAG at the maximum allowable daily rate of 15 MMSCF for at least 30 years, if not significantly more, within the designated MAOP of 5,023 psig and below the maximum AGI system operating pressure of 2,600 psig.

This reservoir testing was accomplished using a PTA derived from a pressure gauge set at 13,526 feet and a DTS that covered the entire length of the injection zone. These provide a baseline for reservoir pressures and evidence for permeable zones within the injection reservoir that will accept TAG. Furthermore, the step rate test (SRT) reached a maximum rate of 7 barrels per minute (bpm) with maximum surface and formation pressures of 1,613 psi and 7,165 psi, respectively, without fracturing the formation. The bottom hole TAG injection pressures have remained below 4,220 psi after eight days of injection beginning on February 2, 2017, indicating an open and unrestricted reservoir which takes flow into open fractures, vugs and karst features with rapid bleed-off into a porous matrix.

Schlumberger has provided the attached detailed report on the analysis of the reservoirs pressure and thermal properties during and after the SRT (see attached Schlumberger report). Geolex and Schlumberger agree on an interpretation of a triple porosity reservoir system based on the pressure fall-off data and FMI log interpretation. A graph of this ternary system is shown on the pressure vs. time graph on Figure 1. The green line on Figure 1 shows the pressure curve of a single system. The red line shows a derivative of the actual pressure curve. The red line was compared to a triple porosity system model and matches it closely. A detailed explanation of this reservoir behavior is presented on page 24 of the Schlumberger report.

The first system (takes initial injection) is comprised of the secondary porosity of the carbonate units, vug and karst deposits, and fractures that accept the fluid linearly and radially from the wellbore. The second system is the connectivity of the vugs and karst deposits that are further connected to fractures that extend vertically and horizontally beyond the well bore, but do not intersect the wellbore. The third system is the eastern fault zone that also appears to partially behave as a conduit for fluids to invade additional area of the reservoir. A simplified step-by-step approach to the triple porosity system with respect to injected fluid is explained:

1. Secondary porosity units and fractures within the wellbore are filled with fluid followed by,
2. Fractures and secondary porosity units connecting away from the wellbore being filled with fluid followed by,
3. Fractures and secondary porosity units that connect to, and are a part of, the eastern fault zone being filled with fluids which are redistributed and bled off into the high porosity matrix.

The DTS warm-back analysis showed the Wristen, Montoya and Fusselman Formations are the primary accepters of fluid. During the SRT, at 2 bpm injection 75% of the flow was going into the Wristen with 20% going into Fusselman and 5% to the Montoya. At 7 bpm injection 81% of the flow was going into the Wristen with 18% going into the Montoya and 1% going into the Fusselman. The increased injection rate may be opening fractures within the Montoya facilitating the increased flow. The primary injection interval is within the Wristen, where a high permeability zone (13,840 feet to 13,856 feet) is indicated by conductive fractures on the FMI log.

This baseline reservoir analysis clearly demonstrates that the Zia AGI D #2 will readily accept TAG at anticipated maximum rates (15MMSCFD) for 30 years within the permit restrictions on MAOP and operational restrictions on compression. Further reservoir analyses should be conducted after injecting for one year to help characterize the injection reservoir and assess any deviations from this baseline study. In conjunction with ongoing analyses of injection data and parameters, these analyses will be invaluable to provide the data required for authorizing continued injection into the well every 10 years as required by NMOCC orders and permit conditions.

9.0 MONITORING AND MAINTENANCE

The routine operation, training, and maintenance of the Zia AGI D #2 well are detailed in the H_2S Contingency Plan in Appendix B, and in the Operation Design Specifications for the SSSV and Haliburton BWD Permanent Packer in Appendix G. It is not unusual for the annular pressure (space between the 7-inch casing and 3½-inch tubing) to fluctuate seasonally and with different TAG pressures and temperatures. However, the annular pressure will be constantly monitored by a gas control center so that any pressure anomalies can be addressed immediately, if the need arises.

Tubing injection pressure and volume will be monitored and archived for input into reservoir modeling software. It is important that any changes in injection pressure be analyzed with regard to anticipated reservoir performance. There is a slight possibility that oxygen within the TAG may cause sulfur precipitation within the reservoir pore throats; therefore, unexpected pressure increases could mean some remedial action may have to be taken to overcome this potential resistance.

The hydraulic pressure at the SSSV control panel will be constantly monitored, and alarms will sound when anomalies arise. Regular function tests for the SSSV will be scheduled every six months to verify proper functioning of the sliding sleeve within the SSSV. A review of the Operation Manual and Design Specifications for the SSSV is included in Appendix G. In conjunction with the SSSV, DCP Midstream has installed an emergency shutdown (ESD) system at the Zia II Plant and AGI wells. The ESD system is a fail-safe hardwired system that provides logic solving via a Foxboro Ticonex Safety System. Twenty ESD manual pull stations are placed throughout the Plant. Operators in consultation with Incident Command (IC) will determine if an H_2S release situation warrants ESD of the Plant. More details of the EDS system and monitoring are in Appendix G.

The mechanical condition of the wellhead and Christmas tree will be visually inspected regularly and if any leaks are detected, the wellhead company will be called to inspect and repair as necessary.

Current State guidelines mandate a MIT of the annular space must be conducted annually. By having the annular pressure monitored constantly by the gas control center, regular MIT tests can be conducted in a routine manner, efficiently and economically, on an as needed bases without the need to cease injection. These tests will be coordinated by Geolex, Inc. and will be planned at times when injection pressures and temperatures are steady and will provide an adequate baseline for conducting the MIT.

Ongoing documentation requirements that must be performed by DCP, which are included in the NMOCC Order No. R-14207, are as follows:

1) Analyze and report injection parameters (injection rates and pressures) to the Engineering Bureau in the NMOCD's Santa Fe Office and to the NMOCD's Hobbs District 1 Office quarterly.
2) Conduct an MIT annually.
3) Review the immediate notification parameters with the Division annually.
4) Complete a report that compares the actual injection results to the original reservoir analysis predictions every 10 years.

The baseline data for the initial report on the reservoir in this well is provided by the geophysical logging analyses, core analyses, step-rate testing, and temperature warm-back analyses which are described above.

FIGURES

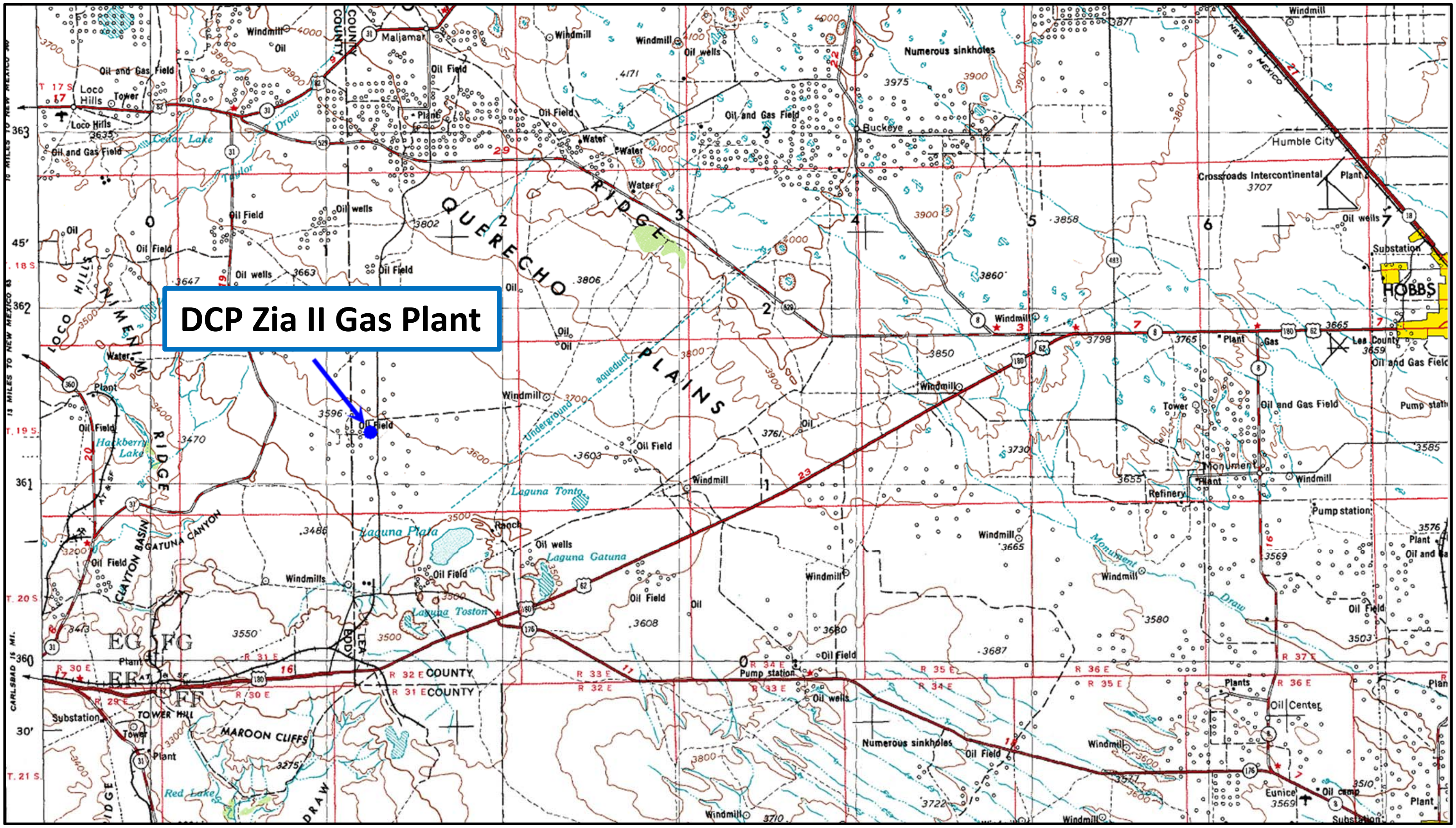

FIGURE 1: Location of the DCP Zia II Gas Plant.
(USGS 1:250,000)

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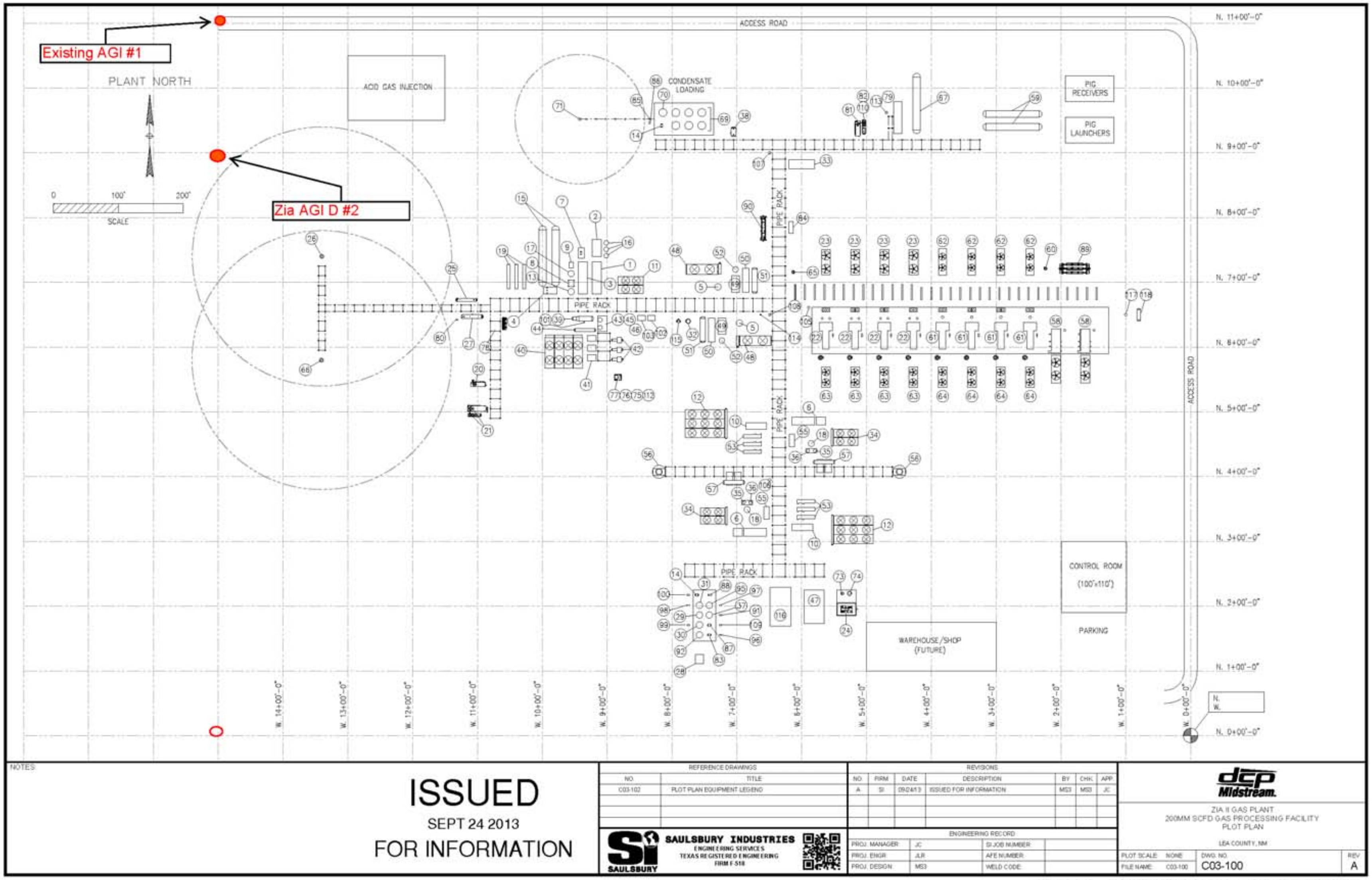

FIGURE 2: Surface location for Zia AGI D #2 and Zia AGI #1 relative to the Plant

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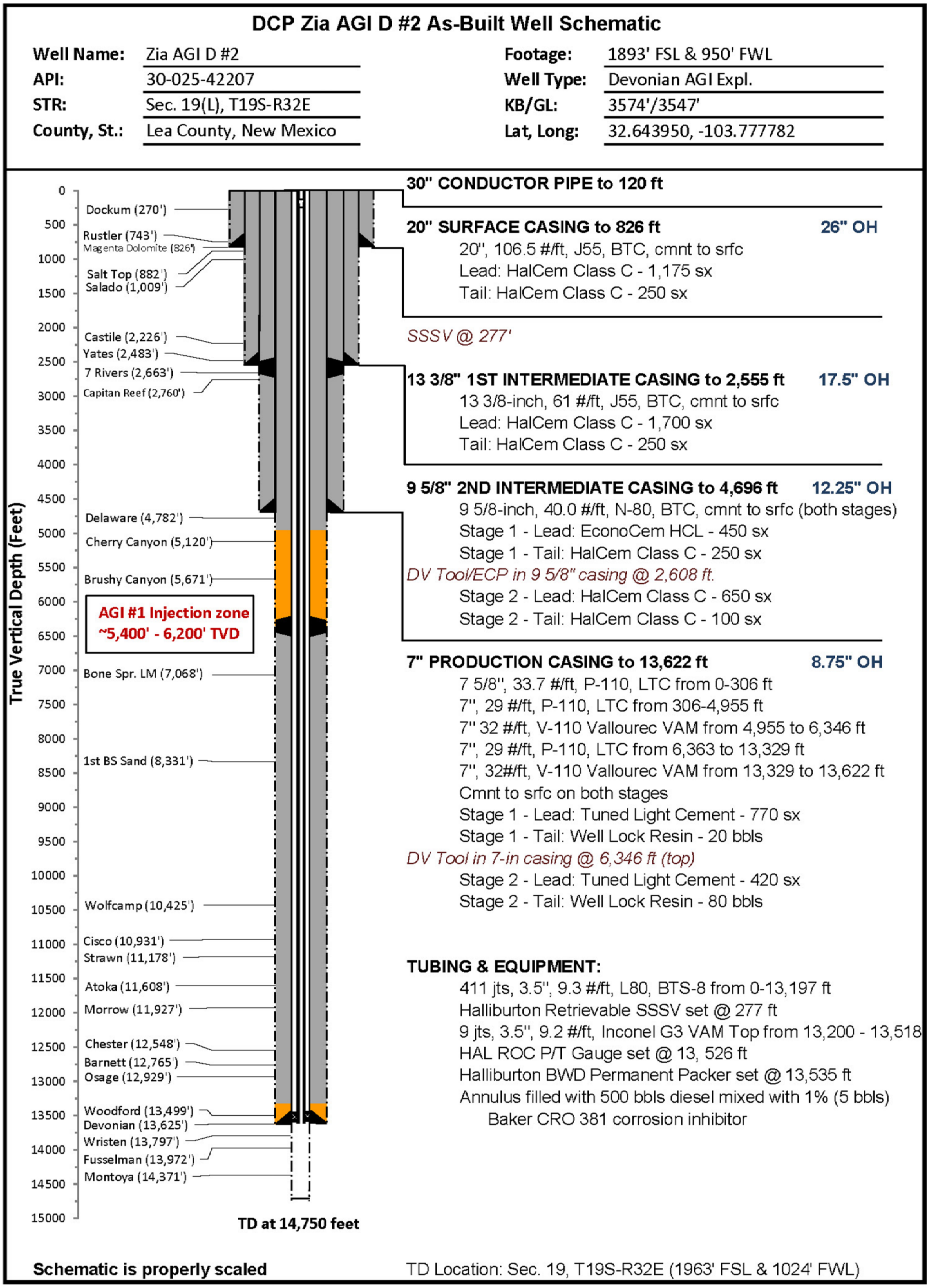


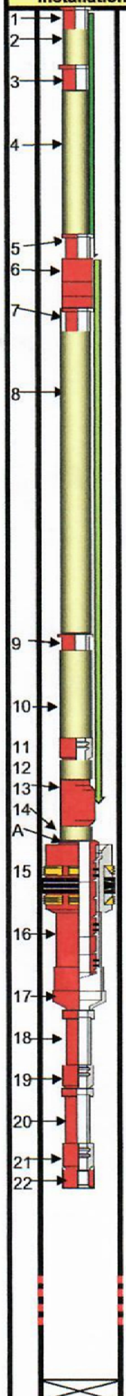
FIGURE 3: Zia AGI D #2 as-built well schematic

HALLIBURTON ENERGY SERVICES

DCP MIDSTREAM
ZIA AGI #2
LEA COUNTY, NEW MEXICO
1/22/17

Company Rep.	GARY HENRICH
Tool Specialist	SCOTT WALTON
Office	ODESSA
SAP No.	903711839

Final Installation



Installation	Length	Depth	Description	OD	ID
	25.00	7.52	KB CORRECTION		
	0.50	32.52	TUBING HANGER		
1	3.62	33.02	DOUBLE PIN ADAPTER	3.500	2.925
2	31.41	36.64	1 JOINT 3.5" 9.3# L-80 BTS8 TUBING	3.500	2.925
3	17.48	68.05	3.5" 9.3# L80 BTS8- TUBING SUBS(9.73, 7.75)	3.500	2.925
4	188.39	85.53	6 JOINT 3.5" 9.3# L-80 BTS8 TUBING	3.500	2.925
5	3.72	273.92	3.5" 9.3# X-OVER SUB BTS8 BOX X AB-TC-II PIN	3.940	2.910
6	4.40	277.64	HALLIBURTON TUBING RETRIEVABLE SAFETY VALVE 3.5" 9.2# AB-TC-II BOX X PIN 478HRE18 102588547 SN-0003667054-2 NICKLE ALLOY 925 15,000# PRESSURE RATING 750 PSI CLOSING 2300 PSI OPENING 2.813 'R' PROFILE IN TOP OF VALVE.	5.290	2.813
7	3.75	282.04	3.5" 9.3# X-OVER SUB AB-TC-II BOX X BTS8 PIN	3.940	2.910
8	12911.35	285.79	411 JOINTS 3.5" 9.3# L80 BTS8 TUBING	3.500	2.684
9	3.75	13,197.14	X-OVER PUP JOINT 3.5" 9.3# BTS8 box X 3.5" 9.3# VAMTOP pin	3.930	2.684
10	317.56	13,200.89	9 JOINTS 3.5" 9.3# VAMTOP SM2550 NICKELTUBING	3.500	2.992
11	1.33	13,518.45	HALLIBURTON 2.562 X 3.5# 9.3# L-80 VAM TOP LANDING NIPPLE (811R25635)(102204262)(SN-0003744132-3) NICKEL ALLOY 925	3.940	2.562
12	6.35	13,519.78	3.5" 9.2# G3-125 VAMTOP BOX X PIN SUB (COUPLING ON BTM)	3.930	2.992
13	4.32	13,526.13	HALLIBURTON ROC GAUGE MANDREL 3.5" VAMTOP PXP 102329817 SN-ATM-16-106669-1 ROC GAUGE ROC16K175C 101863926 WD#9381-6034 ADDRESS 094 SN-ROC004482	4.670	2.950
14	3.75	13,530.45	3.5" 9.2# G3-125 VAMTOP BOX X PIN SUB	3.930	2.992
A			HALLIBURTON SEAL ASSEMBLY		
a-1	1.73	13,534.20	STRAIGHT SLOT LOCATOR 3.5" VAMTOP X 3.5" 10.2# VAMINSIDE INCOLOY 925 (212S4042-D)(102351212)(SN-G3362241-1)	4.460	2.886
a-2	4.33	13,535.93	EXTENSION 3.5" 10.2# VAMINSIDE NICKEL ALLOY 925 (212X38814-D) (158726)(SN-G3362256-1)	3.860	2.902
a-3	4.33	13,540.26	EXTENSION 3.5" 10.2# VAMINSIDE NICKEL ALLOY 925 (212X38814-D) (158726)(SN-G3362256-1)	3.860	2.902
a-4	5.00	13,544.59	5 -SEAL UNITS 4" X 3.5" 10.2 VAM TOP NICKEL ALLOY 925 MOLDED AFLAS SEALS 4.07 OD, 8000 PSI (812MSA40003-D)(102133617)(SN-0003744129-1 0003744129-4) (0003744129-3 0003744129-2 0003744129-5) (METAL OD 3.95") (TOP 2 SEAL ARE FLOUREL BOTTOM 3 SEALS ARE AFLAS)	4.050	2.883
a-5	0.54	13,549.59	MULE SHOE GUIDE 3.5" 10.2# VAMINSIDE NICKEL ALLOY 925 (812G40137-D) (102133560)(SN-3744130) LAND HANGER WITH 26,000# COMPRESSION PUTS 20,000# COMPRESSION ON PACKER PICK UP WEIGHT IS 132,000# SLACK OFF IS 120,000#	3.950	2.980
			HALLIBURTON PACKER ASSEMBLY		
15	3.11	13,535.00	HALLIBURTON 7" 26-32# BWD PERMANENT PACKER WITH 4" BORE, 4.75" 8UN BOX THREAD, INCOLOY 925 (212BWD70412-D)(101303583)(SN C3774119) WAS RUN ON W/L AND TOP @ 13535' ELEMENTS @ 13533.21'	5.880	4.000
16	11.41	13,538.11	SEAL BORE EXTENSION 4" X 8' INCOLOY 925 4.75 8UN PXP (PN212C7674)(120051359)(SN-0003744131-1)	5.030	4.000
17	0.83	13,549.52	X-OVER 4 75" 8UN BOX X 3.5" 9.3# VAM INCOLOY 925 (212N100131)(101719647)(SN-0003744131-1)	5.680	2.963
18	5.76	13,550.35	PUP JOINT 3.5" 9.3# VAM TOP INCOLOY 925 WITH COUPLING	3.520	2.940
19	1.33	13,556.11	HALLIBURTON 2.562'"R' X 3.5" VAMTOP LANDING NIPPLE (811X25635) (102204262) (SN- 0003744132-1) NICKEL ALLOY 925	3.940	2.562
20	5.76	13,557.44	PUP JOINT 3.5" 9.3# VAM INCOLOY 925 WITH COUPLING	3.520	2.930
21	1.33	13,563.20	HALLIBURTON 2.562" X 3.5" VAMTOP LANDING NIPPLE (811X25635) (102204262) (SN- 0003744132-2) NICKEL ALLOY 925	3.940	2.562
22	0.73	13,564.53	WIRELINE RE-ENTRY GUIDE 3.5" 9.3# VAM INCOLOY 925	3.970	3.000
		13,565.26	BOTTOM OF ASSEMBLY		

EOC @ 13,622'
TD @ 14,750'

DIESEL USED FOR PACKER FLUID

Filename:

FIGURE 4: Zia AGI D #2 as-built injection tubing and equipment schematic

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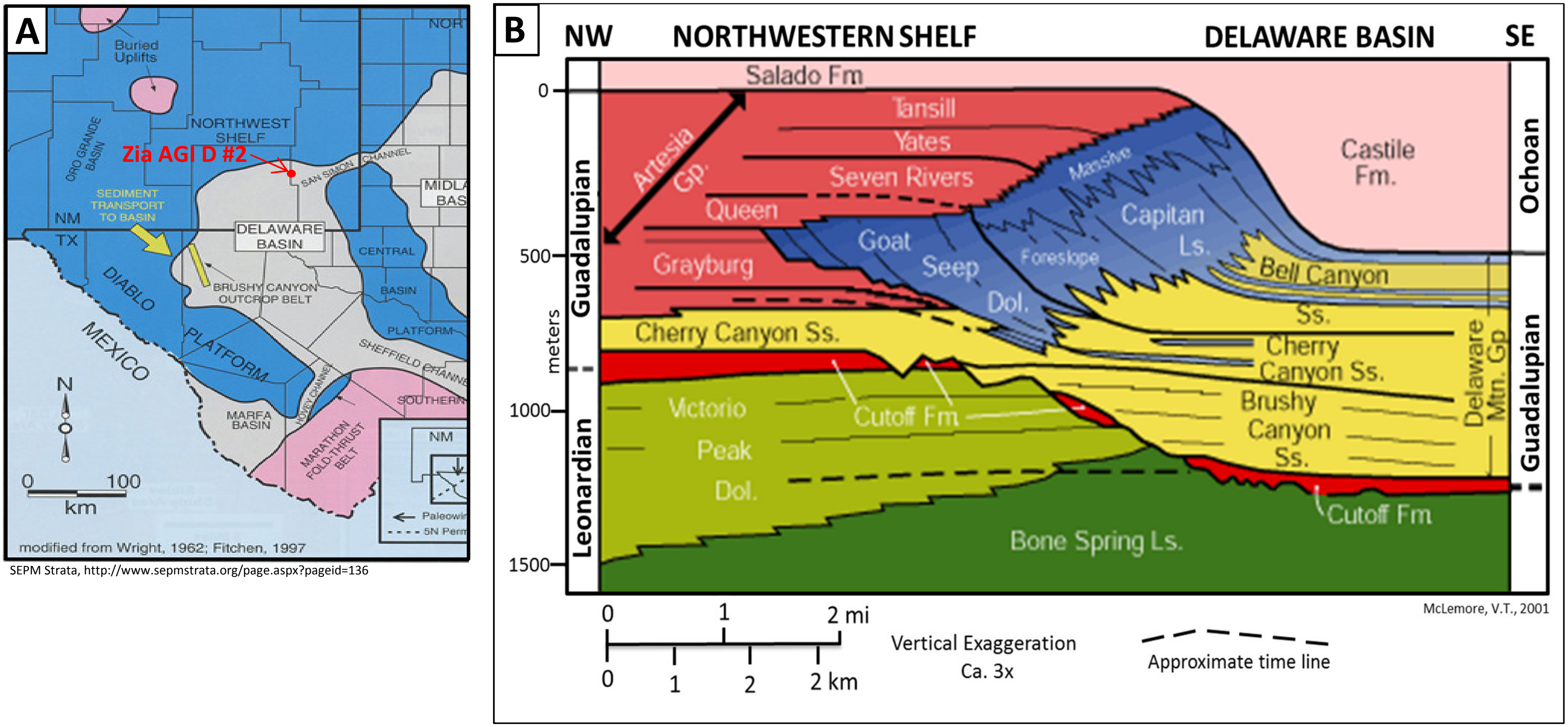

SEPM Strata, http://www.sepmstrata.org/page.aspx?pageid=136

FIGURE 5: Structural setting of the Permian Basin(A) and General Stratigraphy of the Northwest Shelf and Delaware Sub-Basin(B)

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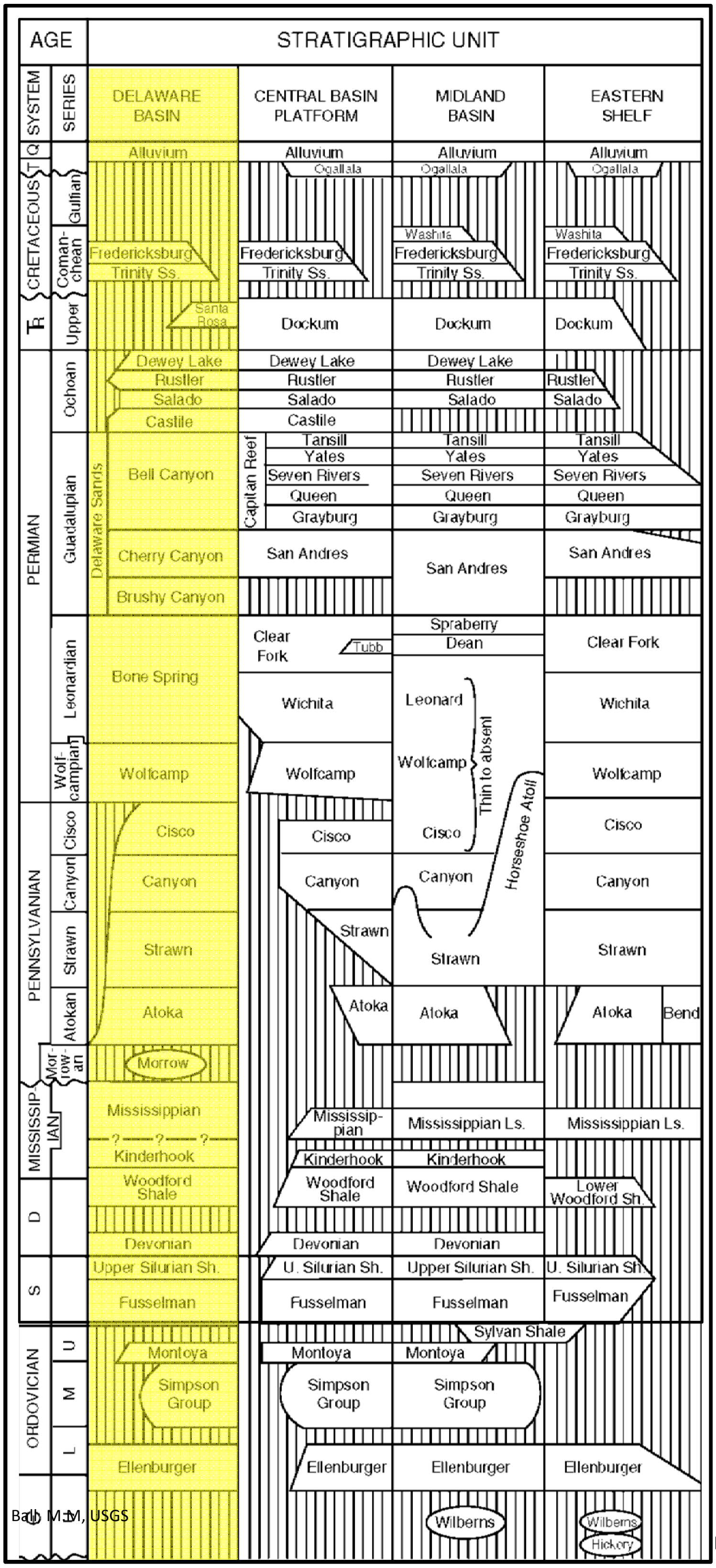

Ball, 1995

FIGURE 6: General Stratigraphy of the Permian Basin.
Delaware Sub-Basin highlighted in yellow

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Formation Name	**Top (Feet)**	**Above/Below Sea level (Feet)**
Dockum	270	3306
Rustler	743	2833
Magenta Dolomite	826	2750
Salado	1009	2567
Tansill	2343	1233
Capitan Reef	2760	816
Yates	2483	1093
7 Rivers	2663	913
Castile	2226	1350
Delaware	4782	-1206
Lamar Limestone	4825	-1249
Cherry Canyon	5120	-1544
Brushy Canyon	5671	-2095
Bone Springs	7068	-3492
Bone Springs 1	8331	-4755
Bone Springs 2	9082	-5506
Bone Springs 3	9895	-6319
Wolfcamp	10425	-6849
Cisco	10931	-7355
Strawn	11178	-7602
Atoka	11608	-8032
Atoka Lime	11811	-8235
Morrow	11927	-8351
Morrow Clastic	12171	-8595
Chester	12548	-8972
Barnett	12765	-9189
Osage	12929	-9353
Woodford	13499	-9923
Devonian	13625	-10049
Wristen	13797	-10221
Fusselman	13972	-10396
Montoya	14371	-10795
Kelly Bush Elevation (Feet):	**3576**	

FIGURE 7: Zia AGI D #2 Formation Top Depths.

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Figure 8: Log Composite of All Formations Encountered While Drilling Zia AGI D #2

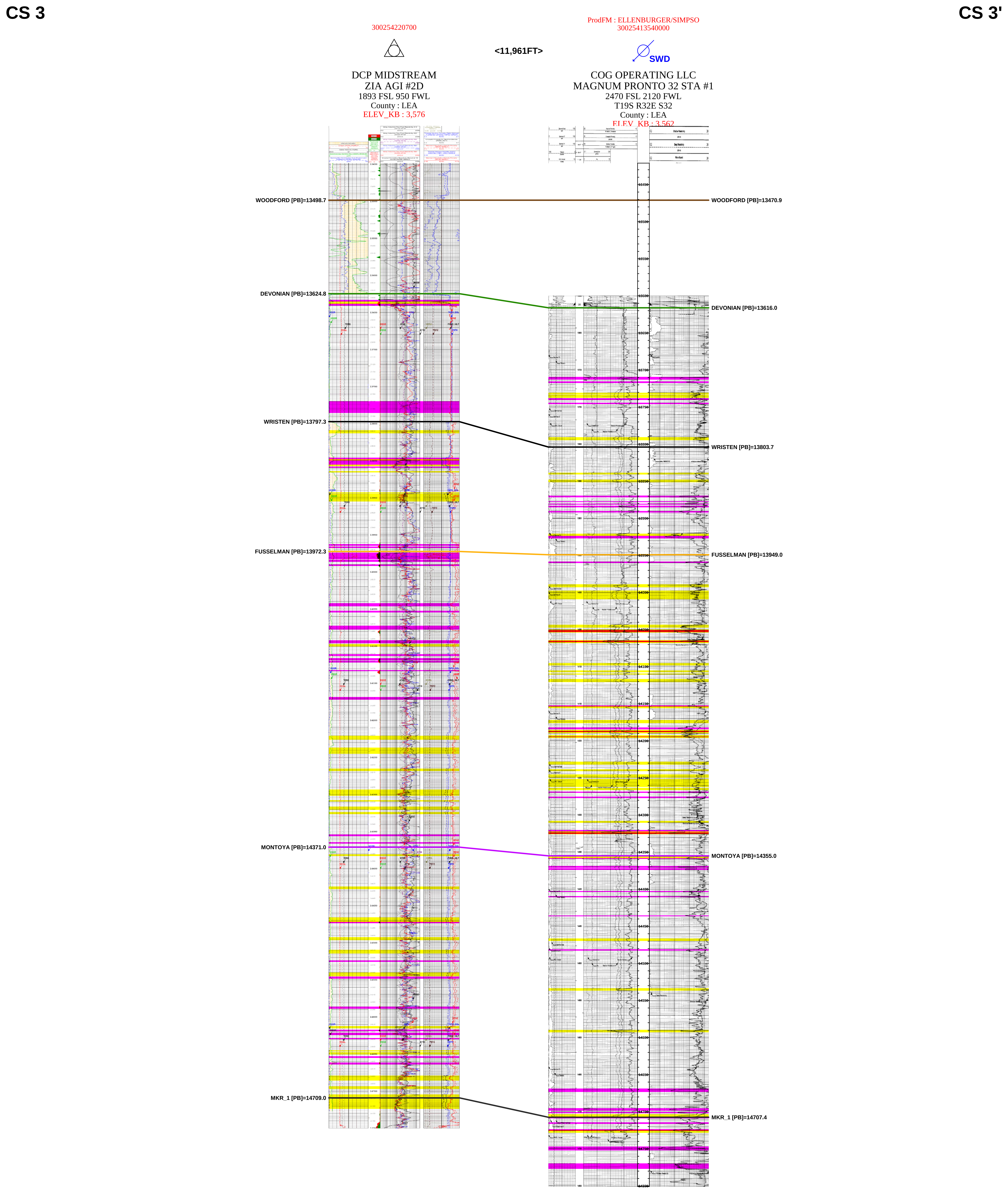

Figure 9: Detailed log composite through the Ordo-Devonian injection zone. Yellow highlights indicate high porosity intervals. Pink Highlights indicate tight intervals

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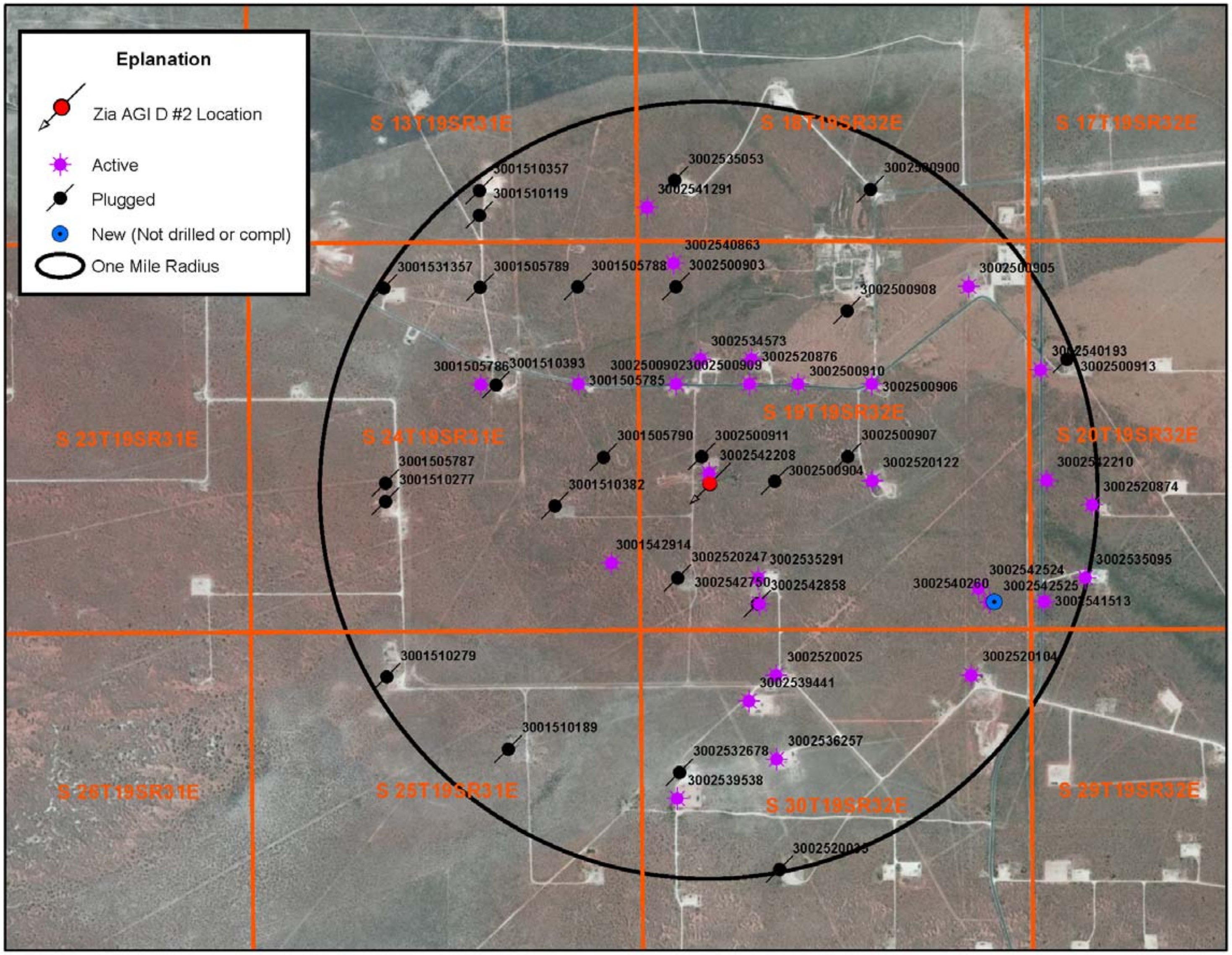

FIGURE 10: Wells Identified within a One Mile Radius of Zia AGI D #2

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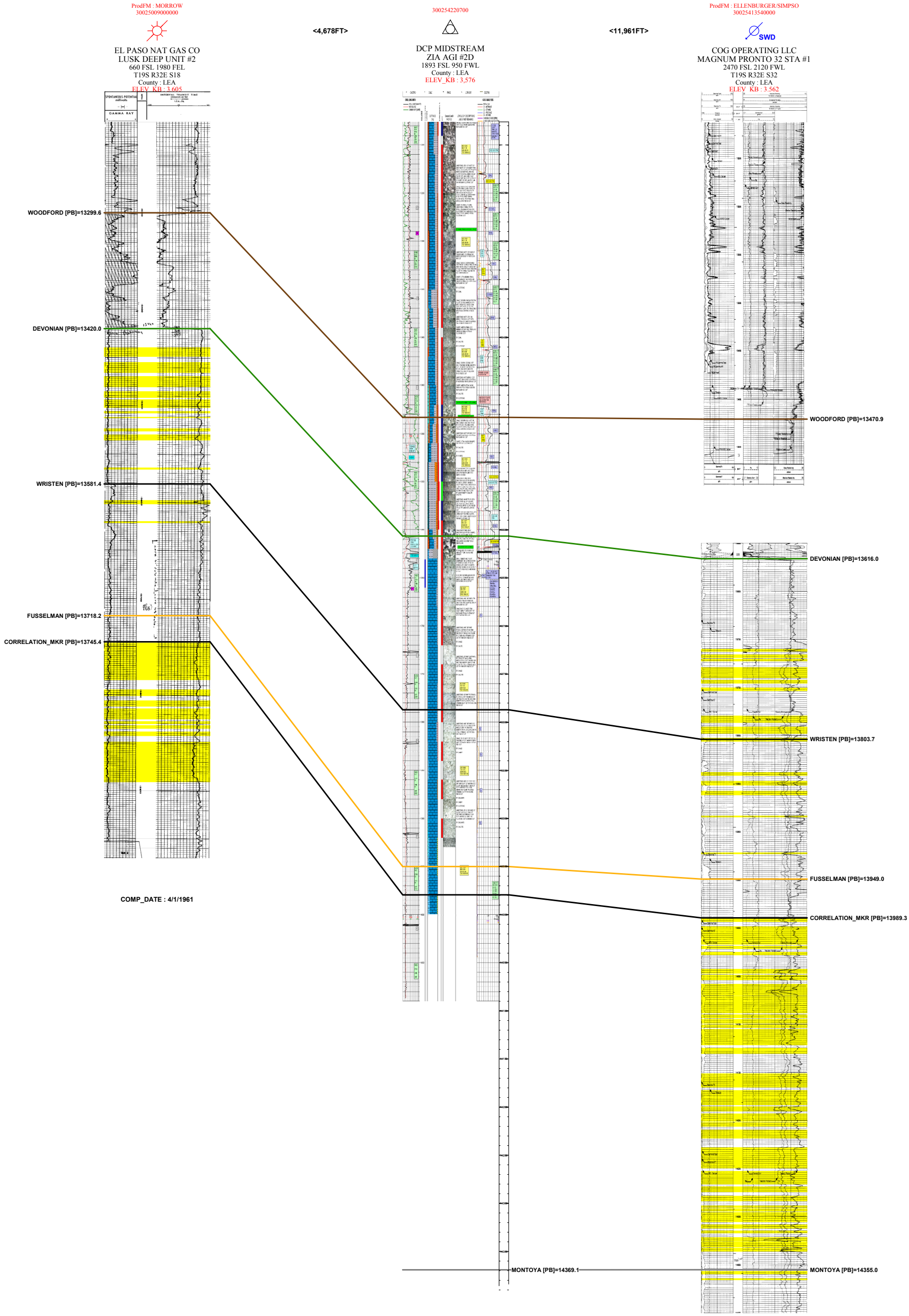

Figure 11: Cross section of the Ordo-Devonian injection zone and overlying Woodford shale caprock. Yellow highlights indicate high porosity.

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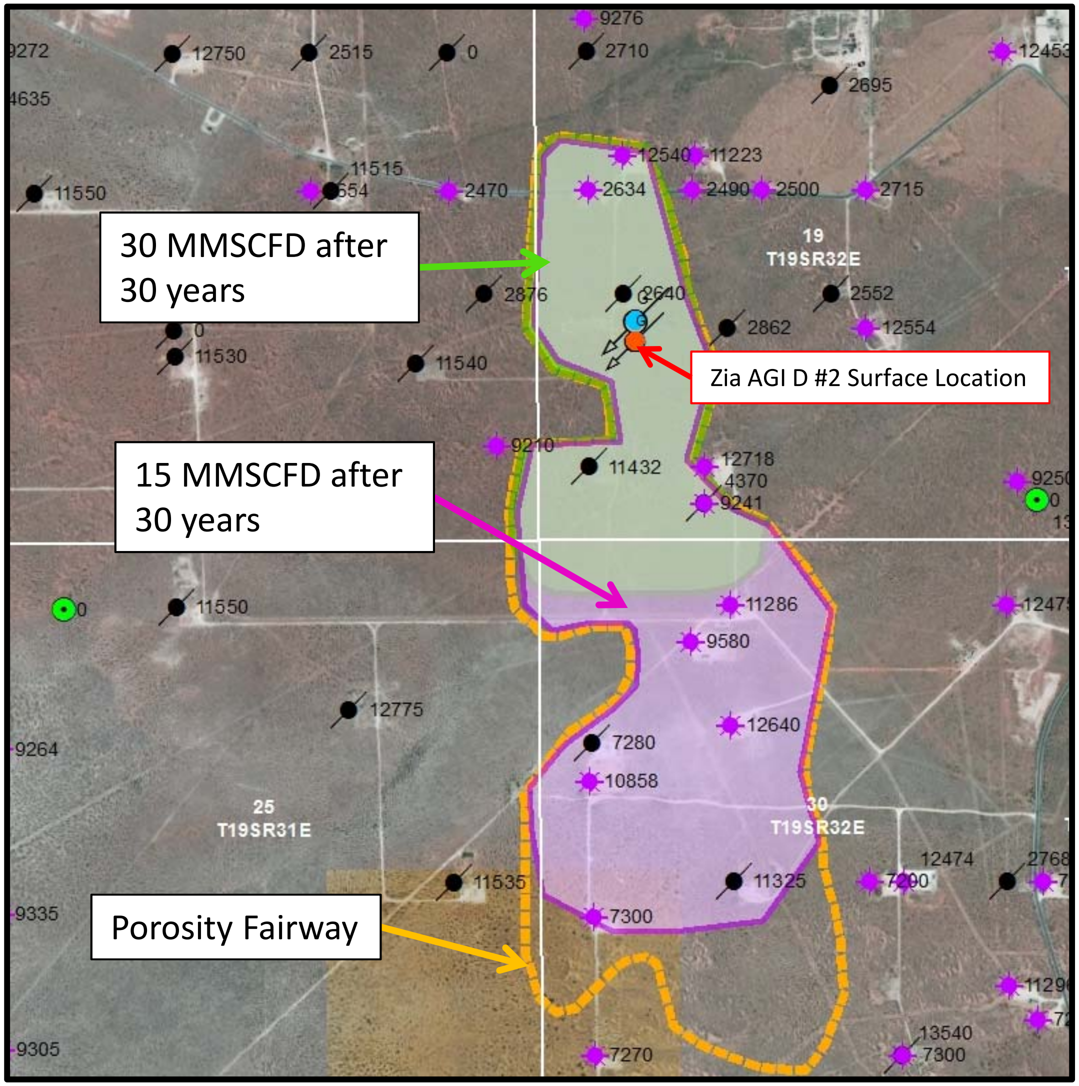

FIGURE 12: Porosity fairway in the Ordo-Devonian injection zone depicting migration of TAG plume after 30 years of injection

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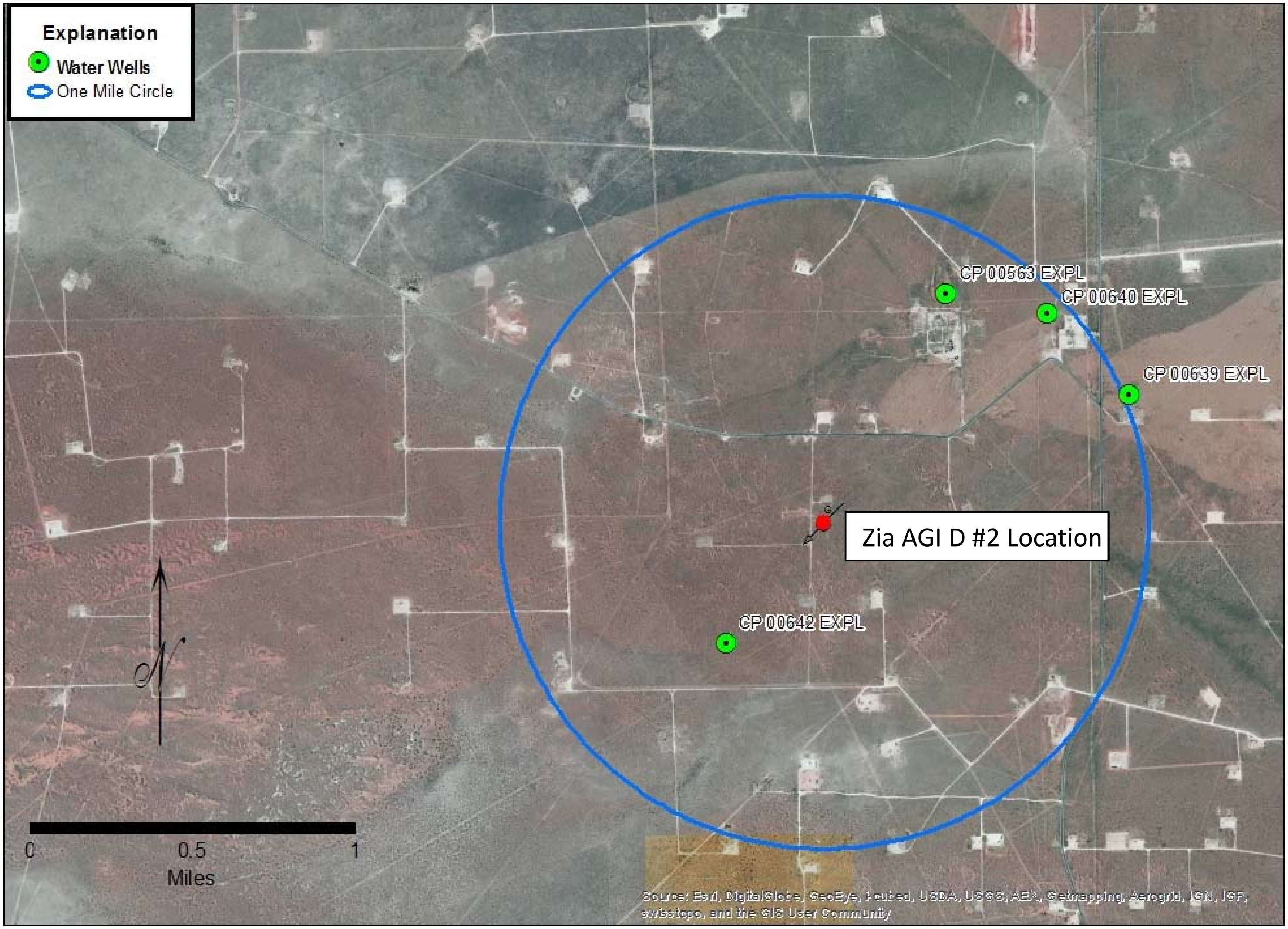

FIGURE 13: Water wells identified by the NM State Engineer's files within one mile of Zia AGI D #2

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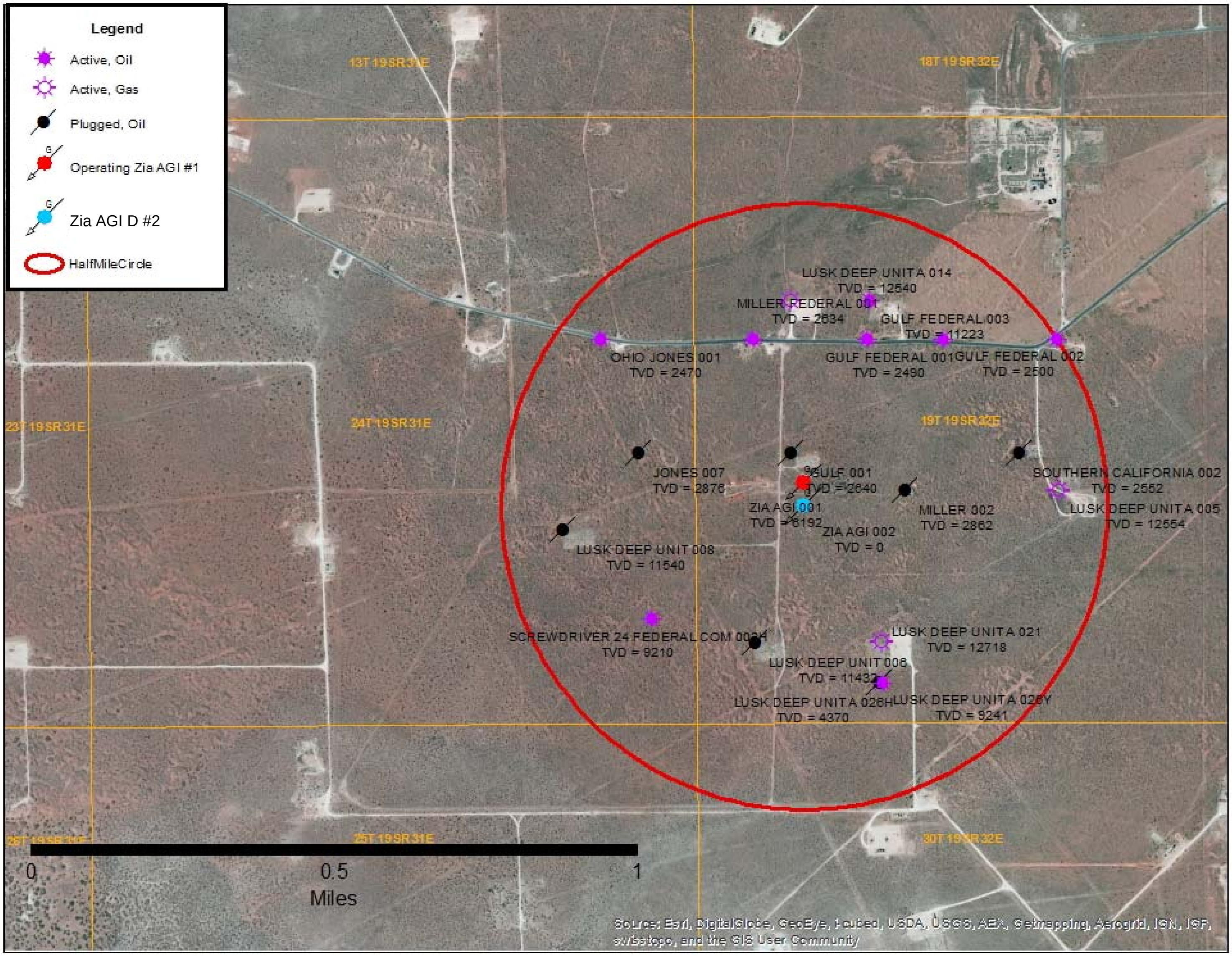

FIGURE 14: Wells identified within one-half mile of Zia AGI D #2

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Porosity	*Perm*	Sample ID
11.1	136.9229	9
8.3	283.5097	10
10.9	0.3249	11
8.0	10.8433	12
1.3	0.0074	15
3.0	0.0258	16
4.3	0.0048	17
6.3	0.0310	20
7.8	1.6367	27
3.5	0.0392	30
7.2	0.0354	31
2.9	131.3879	32
2.5	0.0876	34
4.2	0.0247	35
4.9	0.0282	37
4.5	0.0205	38
9.5	5.9943	39
7.5	7.8688	40
9.3	37.9700	42
12.6	1.0858	43

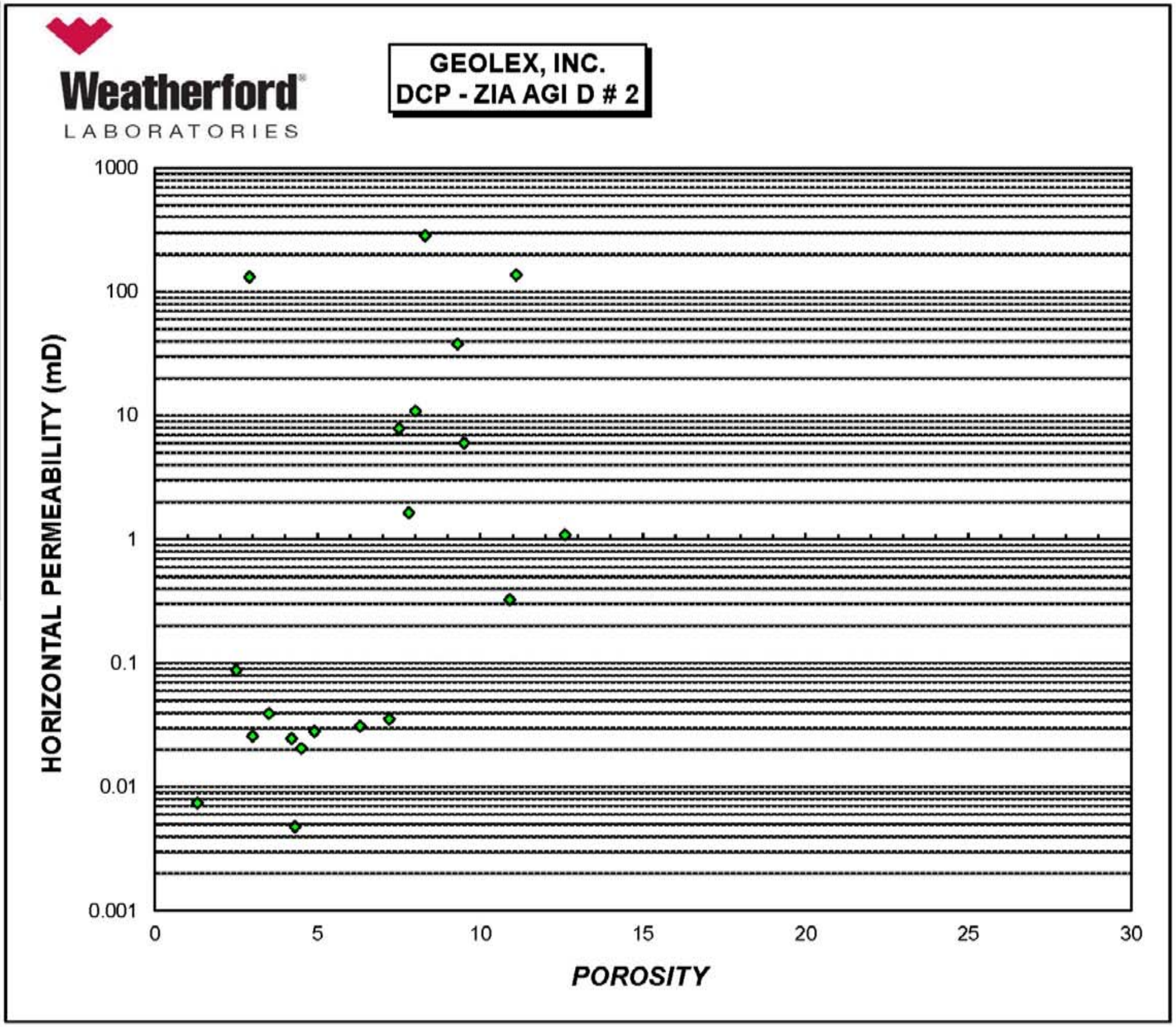

Figure 15: Porosity versus permeability from sidewall cores within the injection zone

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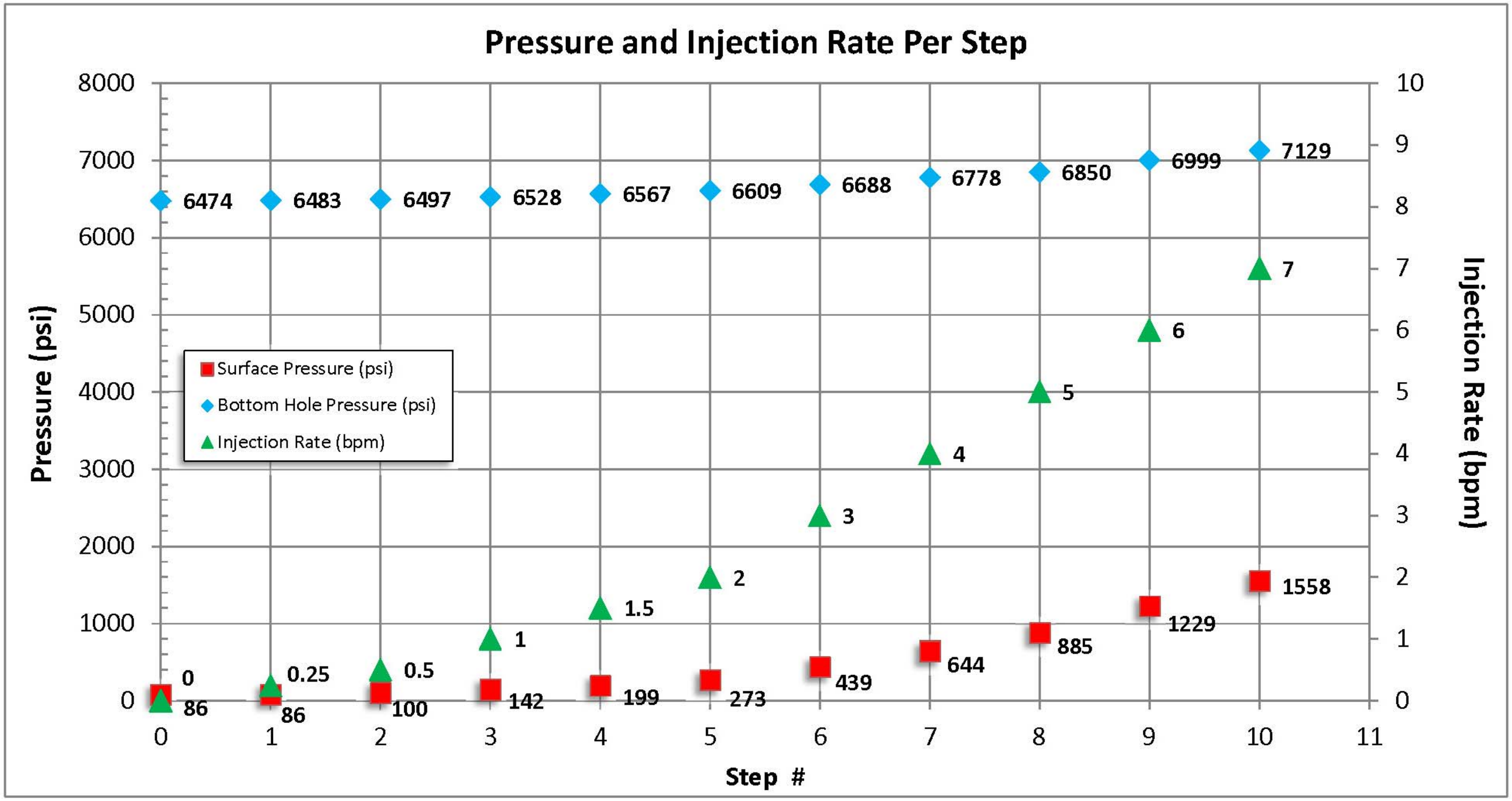

FIGURE 16: Summary of step rate test, Zia AGI D #2, December 29, 2016

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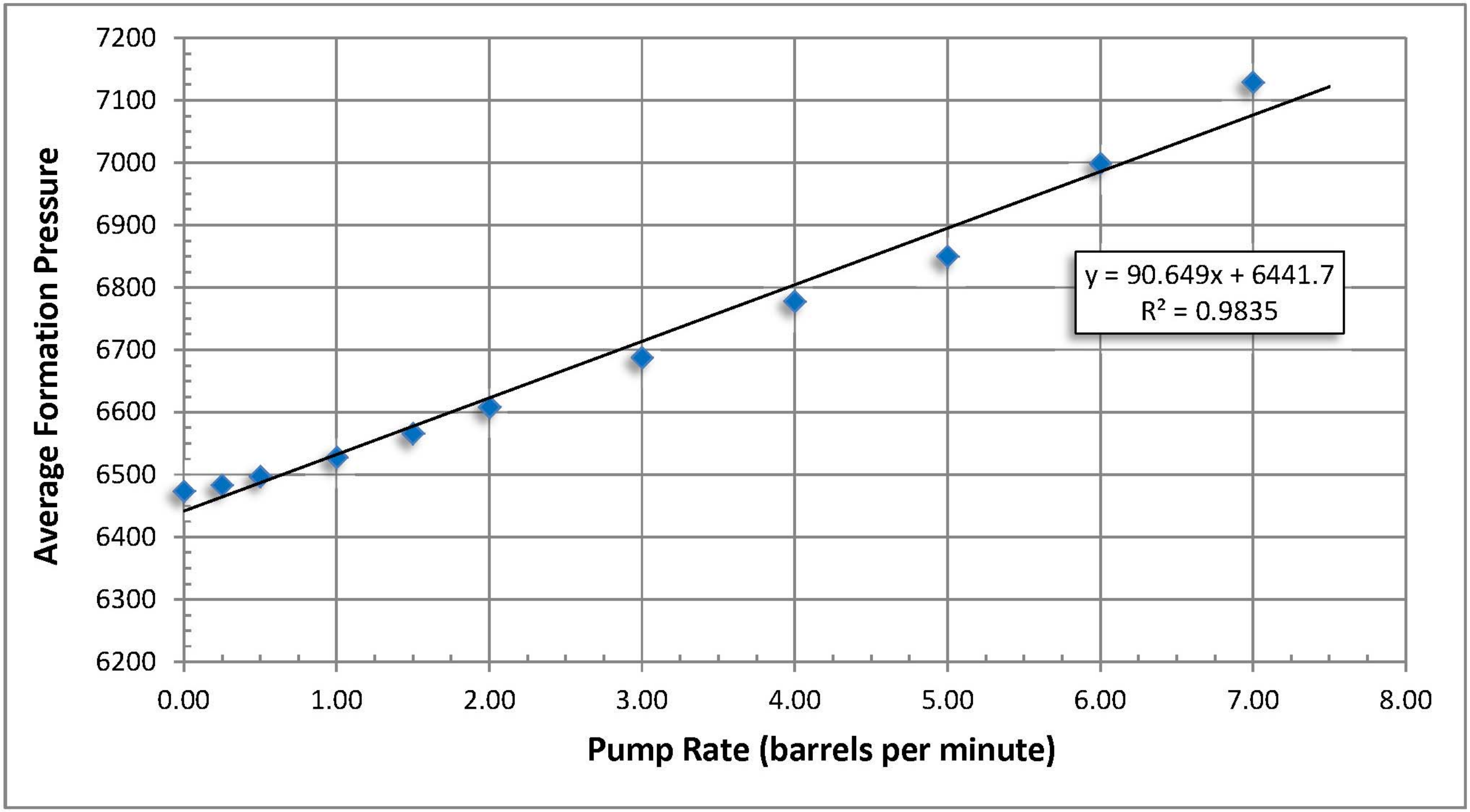

FIGURE 17: Formation Pressure at each step showing no break-over point, or parting pressure being reached within the injection zone.

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