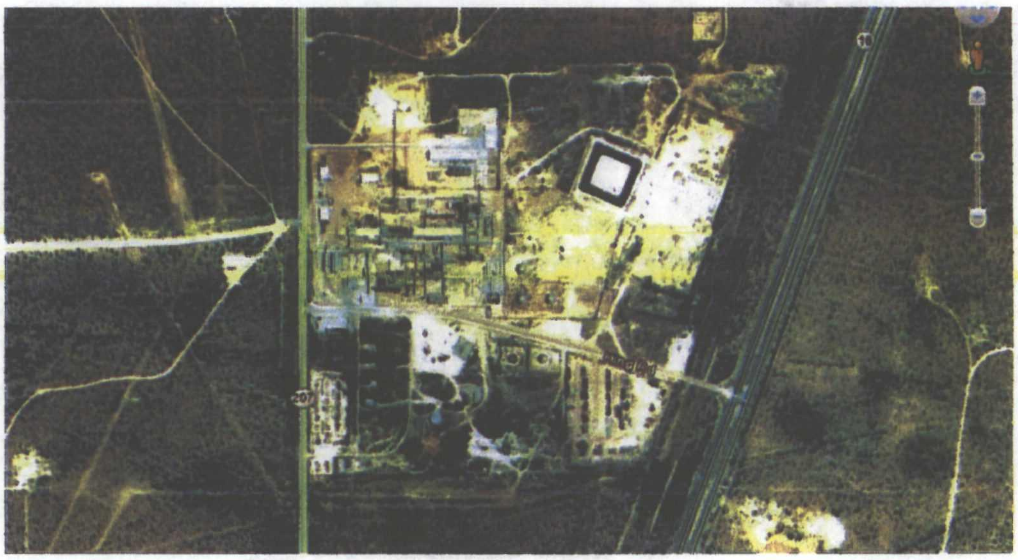
End of Well Report
Targa Eunice Gas Plant AGI/SWD #1
(2580 FSL & 1200 FWL, Unit L Section 27, Township 22 S, Range 37 E)



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TARGA™

GEOLEX® INCORPORATED

EXHIBIT 1

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1.0 EXECUTIVE SUMMARY AND WORK PERFORMED

On October 26, 1961 Skelly Oil Company spudded the Eunice Gasoline Plant Salt Water Disposal Well #1 (API # 3002521497), located 2,580 feet FSL, 1,200 feet FWL in Unit L, Section 27, T22S, R37E in Lea County, New Mexico. The well was permitted under Administrative Order SW-29, issued on September 21, 1961. The salt water disposal (SWD) well was completed on November 12, 1961 at a total depth of 4,550 feet in the Permian San Andres Formation.

The well was cased to 300 feet with 10 ¾ inch surface casing, and to 4,000 feet with 7 inch production casing, leaving a open hole interval of 550 feet. The well was subsequently operated by Getty Oil, Texaco Producing, and Dynergy Midstream before its acquisition by Targa Midstream Services Limited Partnership (Targa) in 2006. Available injection data (1994 to 2011) show that during that period the well received approximately 4.2 million barrels of salt water, or approximately 27,000 barrels per month during active months.

In September 2007 Targa received an NMOCD Order (R-12809) allowing the drilling and completion of a new acid gas injection (AGI) and SWD well 300 feet from the existing well. Although this order was extended until 2009, the well was never drilled. In September 2010 Targa retained Geolex, Inc. (Geolex) to prepare a new C-108 to permit the existing well as a combined AGI and SWD well.

In November 2010 Geolex submitted a C-108 to the New Mexico Oil Conservation Division (NMOCD), on the behalf of Targa, as operator for Versado Gas Processors, LLC to permit and recomplete the existing SDW as an AGI well. The proposed recompletion included redrilling the well to a new total depth of 4,950 feet, and setting new, 5 ½ inch production casing inside the existing 7 inch casing and open hole, to a total casing depth of 4,250 feet, allowing 700 feet of open hole for injection.

Following a hearing with New Mexico Oil Commission on December 9, 2010 and subsequent discussions, the Commission issued Order R-1289-C-1-HO on December 20, 2010. The Order allowed Targa to proceed with the proposed recompletion, but reduced the new total depth from 4,950 feet to 4,850 feet due to the Commission's concerns with potential migration of injected fluids into deeper formations.

The recompleted well will receive both wastewater and treated acid gasses (TAG) generated at the Targa Eunice Gas Plant, located in Eunice, New Mexico, approximately 5 miles north of the well. The TAG and wastewater will be transported in new low-pressure underground lines, and final compression and injection facilities are now in place at the well location.

The combined AGI/SWD well is designed and drilled for the purpose of safely injecting up to 5 million standard cubic feet per day (MMSCF/D) of TAG produced from the Targa Eunice Gas Plant, and up to 1,575 barrels of wastewater, for a design life of 30 years. The TAG stream will consist of approximately 84% carbon dioxide (CO_2), 14% hydrogen sulfide (H_2S) and approximately 2% light hydrocarbons (C_1 – C_7). Due to the relatively high percentage of CO_2 in the TAG, the well will effectively sequester up to 260 tons of carbon, and 30 tons of sulfur per day from the environment. The total injection rate, at surface compression pressures, will be 4,075 barrels per day (bbl/d). The TAG rate will be 2500 bbl/d (61%) and the wastewater rate will be 1,575 (39%) bbl/d.

The AGI system is designed to be safe and robust. The TAG generated at the Targa Eunice Gas Plant will be compressed to approximately 1300 pounds per square inch (psi) prior to mixing with the wastewater prior to injection to the well. All tubing and equipment in contact with the TAG is constructed of materials resistant to the corrosive properties of the gasses. From the wellhead, the TAG will be carried to the production packer via 2 ⅞ inch L-80 J-55 Duolined EUE tubing. The production packer, set at 4,190 feet, is constructed from Inconel® 725 material, and is set in a corrosion-resistant alloy segment of the production (5 ½ inch) casing. Below the packer, the 5 ½ inch casing ends at 4,258 feet, and the 6 ¼ inch open hole extends to 4,850 feet (TD).

A nickel alloy safety valve was installed on the production tubing at a depth of 250 feet to prevent upward movement of the fluid in the event of a downhole upset or emergency. Prior to drilling the well, a comprehensive Hydrogen Sulfide Contingency Plan (NMOCD Rule 11) was prepared and submitted. The Plan was approved by NMOCD in August 2011. 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.

Redrilling of the Eunice Gas Plant SWD/AGI #1 began on May 13, 2011. Drilling activities were supervised by Cambrian Management, and Geolex geologists oversaw the logging and coring. A "closed-loop" drilling fluid system was used, minimizing the amount of fluids required and preventing any releases of fluids to the surface. On May 18, 2011 the target depth of 4,850 feet was reached, and the well was conditioned prior to logging.

After conditioning the borehole, Halliburton arrived on May 19, 2011 and provided geophysical logging services, including natural gamma, self-potential, resistivity, gamma and neutron porosity, and caliper logs. A second run was used for collection XRMI™ logging, a high-resolution resistivity tool that images small bedding planes and fractures. This tool was used in the reservoir (open hole interval from 4,010 to 4,850 feet), and showed only minor, drilling-induced fractures in the San Andres.

After field evaluation of the geophysical logs, the 44 depth intervals were selected for side wall coring (4,044 to 4,826 feet), of which 31 were recovered. The cores were collected by Halliburton and were inspected by Geolex and analyzed by Weatherford Laboratories for porosity, permeability, water saturation and other reservoir characteristics.

On May 22, 2011 the "long string" of 5 ½ inch casing was installed to a depth of 4,258 feet, and the cementing program was started. The program involved a two-stage process, to emplace the corrosion-resistant CORROSACEM™ cement around the casing through the reservoir and the cap rock, and more conventional Halliburton Light Lead cement from the top of the CORROSACEM™ to the surface. The original cement job in 1961 circulated both the 300-foot 10 ¾ inch surface casing and the 4,000-foot 7 inch production casing to the surface, so the final cement job only involved the new, 5 ½ inch production casing.

A Diverter Valve (DV) was installed at a depth of 3,900 feet to separate the cement stages. In Stage 1, Halliburton installed approximately 50 sacks of CORROSACEM™ cement, and then dropped the "bomb" to activate the DV. In Stage 2, Halliburton pumped approximately 260 sacks of, and cement returns reached the surface. Following the cement job, the rig was released on May 23, 2011.

After cementing stopped, however, the cement level fell below the surface. A Cement Bond Log (CBL) run by Renegade on June 3, 2011 showed that the final top of the cement was at 1,059 feet, well within the existing initial production casing.

A Mechanical Integrity Test (MIT) was conducted on the production string on June 29 and was successful. Following the MIT, preparations were made to collect a baseline temperature profile, acidize the well, perform a step-rate test, conduct a transient falloff test, collect "warm-back" data, and conduct a radioactive tracer survey.

The step-rate test, transient falloff test, "warmback" data, and radioactive tracer survey were designed to:

1. Determine the injectivity of the formation, and determine if fracturing would occur at designed injection pressures (Step-Rate Test and Transient Fallback)
2. Locate the relatively permeable zones and their flow characteristics (Warmback),
3. Quantify the flow rates in the zones identified in the warmback (Radioactive Tracer Survey) and,
4. Provide a database for reservoir evaluation and modeling.

On June 29, 2011 Schlumberger installed a "goat head" adaptor on the well head to allow wireline tools to be left in the well during pumping operations, and lowered their Slickline Distributed Temperature Profile (SL-DTS) fiber optic temperature equipment to total depth for a thermal background profile. After the data were collected, the Schlumberger equipment was pulled out of the hole, and a second Schlumberger crew moved in and rigged up for the acid job. On June 30, 2011, the acid job was completed and the well shut in.

On July 1, 2011 the Schlumberger SL-DTS equipment was again run into the well and a pressure truck from Lobo Services rigged up for the step-rate test. Equipment problems stopped the test before the planned rate of 5 barrels per minute (bbl/min) was achieved. The test was rescheduled for the following week. The SL-DTS remained in the well.

On July 6, 2011 a pump truck from Cudd Energy Services rigged up and the step-rate test was successfully completed. The surface pressure rose to a final level of 2206 psi at 5 bbls/min, and a total injection of 549 barrels of water. Analysis of the step rate test indicates that fracturing or parting developed during the test, and that well can safely accept fluids at pressures well above the permitted 1300 psi.

The Schlumberger slickline equipment, including a bottom-hole pressure recorder, was left in the well from July 6 until July 13, 2011. On July 14, 2011 Cardinal Surveys conducted the radioactive tracer tests.

Data from the geophysical logs, sidewall cores, step rate test, warmback and tracer tests were analyzed by Geolex to develop an integrated analytical model of the San Andres reservoir, and to predict the behavior of the injected material over the 30-year projected life of the project. The model shows that there is ample pore space within one half mile of the well to receive the anticipated injection volumes, with a reasonable safety factor.

In the area of the well, the San Andres Formation can be described as a silty, dolomitic carbonate, with irregular porosity patterns primarily derived from post-depositional diagenesis. In a very broad sense, the San Andres can be divided into an upper (4,050 to 4,500 feet) zone with porosity up to 20%, and a lower (4,500 to 4,850 feet) with much lower porosity. These porosity trends can be seen in the geophysical logs, the sidewall cores, and the formation's response in the warmback and tracer tests. In the upper zone the porosity is vuggy in nature, but in the lower zone the vugs are small or not present and porosity is commonly plugged with secondary calcite and/or anhydrite.

Although this general vertical porosity pattern is seen in the area, the distribution of diagenesis is very irregular and small-scale porosity zones seen in this well cannot be correlated with porous zones seen in any nearby wells. Also, comparisons among the geophysical logs, the sidewall cores, and the warmback and tracer tests show that although the porosity and permeability are related, they are not reliably correlated. This is clearly seen in the lower zone, where the porosity seen in the geophysical logs is poorly interconnected, and does not allow significant permeability.

This small-scale complexity in the distribution of porosity and permeability of the San Andres prevents modeling the migration of injection fluids in any simple, stacked-layer model. In the discontinuous, interfingering porous zones, injected fluids will migrate into the preferentially permeable layers until these layers pinch out. Then the fluids will spread vertically and/or horizontally, filling the available pore space, until they reach another more permeable pathway. Over distance and time, the migration front will be "smeared" in geometry consistent with the large-scale average porosity and permeability of the formation.

This stochastic behavior of the fluids in the formation allows the use of a long-term "average reservoir" model to calculate the behavior of the injected fluids. Our model is based on:

- A total net injection zone of approximately 300 feet (from tracer and temperature surveys), with an average effective porosity of 11% (from geophysical logs and sidewall core testing)
- An effective residual water ratio of 0.353, from sidewall core analysis, and
- A net pore space of 457 million cubic feet within one half mile of the well.

From the bottomhole pressure and temperatures recorded during the well testing, Geolex modeled the physical properties of the injected fluids at reservoir conditions. This shows us that, at the maximum rate of roughly 3 bbl/min of combined TAG and wastewater:

- At reservoir temperatures and pressures, the 5 MMSCF/D TAG will be compressed to 1,980 bbl/d,
- The 1,575 bbl/d of waste water (essentially incompressible) will retain the same volume,
- The net injection fluid will be 3,555 bbl/d, and
- This rate of injection will yield approximately 220 million cubic feet of injection fluids over 30 years.

Over an injection period of 30 years at the maximum daily rate, the injected fluid will occupy a volume equivalent to approximately 48% of the available pore space within one half mile of the well. This would encompass approximately 240 acres of footprint, with a radius of 0.35 miles. These calculations are based on conservative values of porosity and residual formation water, which tend to over predict the volume of reservoir that will be affected.

Following the completion of the tests described above, the well has been temporarily shut in. Targa is currently completing the compressor equipment and pipeline connections, and anticipates fully activating the well in September 2011.

2.0 ORGANIZATION OF END OF WELL REPORT

This is a final well report describing the design, installation, completion, testing and current status of the Eunice Gas Plant SWD #1 acid gas injection well. This report is presented in the following categories:

- A history of the Eunice Gas Plant SWD #1 project, including: a description of the Targa Eunice natural gas processing plant and the need for the AGI project; a summary of the project permitting history; a basic project design and anticipated disposal volumes; and a review of nearby wells and potential interactions (Section 3.0),
- A synopsis of the technical aspects of the Eunice Gas Plant SWD #1 design, the drilling operations, and completion (Section 4.0),
- An evaluation of the local subsurface geology and the suitability of the San Andres Formation as an injection reservoir (Section 5.0), and
- A characterization of the reservoir and its response to injection, including an evaluation of the area that will be impacted by injection (Section 6.0).

In addition, this report includes the following supporting information:

- Appendix A: Records for Original Eunice Gas Plant SWD #1
- Appendix B: Summary of Injection (C-115) Records for Eunice Gas Plant SWD #1 Prior to Recompletion
- Appendix C: Previous NMOCD Orders for Eunice Gas Plant SWD #1
- Appendix D: NMOCD Orders, Permits, Filings and Bond for Recompleted Well
- Appendix E: Recompletion Plans and Specifications
- Appendix F: Open-Hole Geophysical and XRMI Well logs
- Appendix G: Cement Bond Logs
- Appendix H: Coring Plan and Core Data
- Appendix I: CCL Depth Logs
- Appendix J: Compliance Documentation
- Appendix K: Reservoir Stimulation, Tests and Analysis
- Appendix L: Summary of Injection (C-115) Records for Eunice Gas Plant SWD #1 Post Recompletion
- Appendix M: Re-Plugging of Langlie Mattix PSU-252

3.0 EUNICE GAS PLANT SWD #1 – DESIGN AND PRELIMINARY WORK

3.1 SUMMARY PLANT DESCRIPTION

The Eunice Gas Plant SWD #1 well is located at the Targa Eunice Gas Plant, an unused former natural gas treatment and processing plant near Eunice in Lea, New Mexico. This plant occupies approximately 80 acres in the northern half of the southeastern quarter of Section 27, Township 22 South, Range 37 East, one mile north of the junction of Highways 207 and 18 (Figure 1). The TAG and wastewater to the well is supplied from the Targa Eunice Middle Gas Plant, located approximately 5 miles north of the AGI site

Natural gas is supplied to the Middle Gas Plant from numerous wells in the Permian Basin of SE New Mexico. The natural gas stream is treated in an amine sweetening unit to remove acid gas, and the resulting TAG consists of approximately 84% CO_2, 14% H_2S, and 2% of C_1-C_7. The sweetened gas is then dehydrated in a glycol dehydrator and processed to separate residual gas, primarily methane, from liquids, including the higher carbon number hydrocarbons.

3.2 DRILLING, CONSTRUCTION AND OPERATION OF EUNICE GAS PLANT SWD #1

On September 21, 1961 Skelly Oil Company was granted a permit (SWD-29) to operate the now-recompletion well as a salt water disposal well. The well was spudded on October 26, 1961 and completed on November 12 of that year. The well was subsequently operated by Getty Oil (early 1980's), Texaco Producing, Inc. (1990's), and Dynergy Midstream from 1998 until 2006 when it was acquired by Targa. Available NMOCD documents regarding the original well are included in Appendix A.

In 2000, Dynergy submitted a successful application for an administrative amendment to the existing SWD-1161 (Amended Order SW-29, May 30, 2000). The amendment changed the designation of the injection zone from the San Andres to the San Andres and the Grayburg. This change did not incorporate any changes in the well or its operations. It was submitted after Dynergy informed the NMOCD that the well in fact penetrated part of the Grayburg, and NMOCD required an amendment to reflect the actual formations in which the well was injecting. Through 2007, the well was operated as an SWD, and injection records (NMOCD Form C-115) are included as Appendix B.

3.3 PERMITTING HISTORY OF AGI WELL

On September 14, 2007 Targa received an NMOCD Order (R-12809), approving the application, prepared by Geolex, Inc., to permit the drilling and completion of a new combined AGI and SWD well. This well was to be located approximately 300 feet south of the existing Eunice Gas Plant SWD #1. A second Order (R-12809-B) dated August 8, 2008 extended the period to drill the new well until September 14, 2009. However, this well was never drilled (Appendix C).

In September 2008, Geolex was retained by Targa to design and permit the existing SWD well at the Eunice Gas Plant as a combined AGI and SWD well. In accordance with the agreement, Geolex prepared a detailed C-108 application meeting the requirements for a successful application for an AGI well from the NMOCD. In February 2009, Geolex applied to NMOCD for an approval to transfer Order R-12809 from the permitted (but never drilled) new well to the existing, permitted SWD. The application also incorporated re-completion of the well, casing it to 4,450 feet, and deepening it to 4,950 feet. This application was approved with minor modifications on February 23, 2009, as Order SW-1161 (Appendix C).

On August 12, 2010 NMOCD informed Targa that their permit to inject into the existing Eunice Gas Plant SWD #1 well had expired, and that a new C-108 Application would be required.

Geolex was retained in September 2010 to prepare and present a new Application. The C-108 "Application for approval to drill and inject" was submitted on November 9, 2010 and a subsequent "H_2S Contingency Plan" complying with Division Rule 11 was provided by Targa in October 2010, and was approved in August 2011.

Following public notice, a hearing on the application was held on December 9, 2010 in Santa Fe, New Mexico before the New Mexico Oil Conservation Commission, and information regarding the proposed AGI was presented by Geolex. The application was approved by Order R-1289-C-HO on December 20, 2010 (see Appendix D).

Testing and recompletion of the Eunice Gas Plant SWD #1 were finished on July 14, 2010 and the well is now shut in pending final construction and connections with the "topside" compressor and control facilities. All NMOCD notifications and permits required in association with drilling the AGI well have been filed and approved (see Table 1 and Appendices D and L).

This report forms the basis for the presentation required by the current NMOCC order (R-1289-C-HO) that Targa perform well testing and reservoir analysis to establish an appropriate time period and maximum value for injection to be presented to NMOCC in a hearing within one year.

Table 1. Timeline of reports and permits

No.	Form	Submitted	Approved	Notes
1	C-108 – approval to drill & inject	November 9, 2010	December 20, 2010 Order #R-1289-C-HO	Hearing December 9, 2010 submission not included Order - Appendix D
2	Rule 11 H_2S Contingency Plan	October 10, 2010	August 11, 2011	Approval letter in Appendix D
3	O & G Plugging bond	na	na	Blanket Bond 6407032 Appendix D
4	Plugging for API# 3002510499	June 8, 2011	June 10, 2011	Appendix M
5	C-101/102 – permit to drill	January 1, 2011	April 21, 2011	Appendix D
6	C-144 – Closed Loop Form	Sept. 16, 2010	March 29, 2011	Appendix D
7	C-103 – spud & Cond. casing	May 17, 2011	May 25, 2011	Appendix D
8	C-103 – Long casing	May 23, 2011	June 1, 2011	Appendix D
9	C-103 – Logging program	Sept. 16, 2011	Sept. 23, 2011	Appendices D, I
10	C-103 – Intent to Perform Testing	Pending	Pending	Appendix D
11	C-103 – Report on Step-Rate Test	Pending	Pending	Appendix D
12	C-105 – Well completion	July 15, 2011	June 20, 2011	Appendix D

3.4 AGI PROJECT DESIGN AND DISPOSAL VOLUMES

The Eunice Gas Plant SWD #1 is located on Targa-owned land situated immediately north of the compressor facilities (Figure 2). Figure 3 is a schematic diagram of the connection layout for the surface facilities and the well. The proposed design of the surface injection facilities was included in the approved Rule 11 H_2S contingency plan.

The AGI well is fitted with a corrosion-resistant well tree which includes pressure regulating and injection control equipment. Below this, each string of casing has been cemented to the surface. The 2-⅞ inch J-55 Duo-Line production tubing has been fitted with a subsurface safety valve to assure that fluid cannot flow back out of the well in the event of a failure of the injection equipment (Figure 3). The annular space between this production tubing and the 5 ½ inch L-80 LTC production casing has been filled with packer fluid, as approved by NMOCD. The lower segment of the production casing was cemented using Halliburton's CORROSACEM™ cement that is both CO_2 and acid resistant.

The initial plan for the injection of acid gas is to inject approximately 5.0 MMSCF/D (2,500 bbl/d at the surface at operating injection pressure) and 1,575 bbl/d of wastewater, for a total of 4,075 bbl/d, or roughly 3 barrels per minute of combined TAG and wastewater for a period of 30 yrs or when the volume of injected fluid reaches the maximum daily rate injection over 30 yrs, whichever comes last.

The Order established a maximum surface injection pressure of 1300 psig, based on a formula provided by NMOCD that estimates the parting pressure of the formation, using the lithostatic pressure of the formation and the hydraulic pressure of the injection fluid. The NMOCC Order allows modifications of the maximum allowable operating pressure (MAOP) based on formation responses to step-rate tests. As described in detail in Section 6.0, a step rate test indicates that the MAOP can be safely increased to 1,615 psi (at the proposed maximum injection mixture).

3.5 POTENTIAL IMPACTS ON NEARBY WELLS

Information on the wells in the one mile area of review (see Table 2) includes their total depth, production or injection interval and current status. Only two wells, completed in the Wantz/Abo (Santa Rita 002 and 012), penetrate the proposed injection zone within one half mile of the well (Figure 4). There is no potential impact on these wells from the Eunice Gas Plant SWD #1 well, as the production casings of these Wantz/Abo wells extend and are cemented through the proposed injection zone.

Table 2: Wells Penetrating San Andres Within One Mile of Targa Eunice Gas Plant SWD #1

API	OPERATOR	DEPTH	WELL NAME	TYPE	STATUS	DISTANCE (mi)	ZONE
3002521497	TARGA	4850	EUNICE GAS PLANT SWD 001	S	Active	0.00	San Andres
3002536825	BURLESON	7250	SANTA RITA 002	O	Active	0.47	Wantz/Abo
3002536482	BURLESON	7200	SANTA RITA 012	O	Active	0.49	Wantz/Abo
3002510486	YARBROUGH	6429	J V BAKER 011	O	Plugged	0.59	Drinkard
3002536027	BURLESON	7218	SANTA RITA 011	O	Active	0.63	Wantz/Abo
3002510568	ELDER	6550	T O MAY 001	O	Plugged	0.64	Drinkard
3002537387	BURLESON	7220	SANTA RITA 003	O	Active	0.66	Wantz/Abo
3002510415	BURLESON	6450	J V BAKER 009	O	Active	0.67	Drinkard
3002526480	OXY USA INC	7200	LAURA J MAY 001	O	Active	0.69	Blinebry
3002534497	ENCORE	7360	SARAH JOHNSTON 001	O	Active	0.76	Drinkard
3002510485	TEXACO	6458	J V BAKER 010	O	Plugged	0.80	Drinkard
3002510500	KEY	6797	CHRISTMAS 003	S	Active	0.80	San Andres
3002535883	BURLESON	7180	SANTA RITA 001	O	Active	0.81	Wantz/Abo
3002534715	ENCORE	7425	HSOG 002	O	Active	0.83	Silurian
3002525412	LEGACY	6700	A L CHRISTMAS 001	S	Active	0.87	San Andres
3002534611	ENCORE	7475	SARAH JOHNSTON 002	O	Active	0.87	Drinkard
3002539376	RANGE	7052	CHRISTMAS 28 005	O	Active	0.89	Blinebry
3002510411	HENDRIX	7130	WILL CARY 006	O	Active	0.90	Montoya
3002510403	EXXON	8190	W B FARRELL 003	O	Plugged	0.93	Drinkard
3002510413	HENDRIX	7500	WILL CARY 008	O	Active	0.94	Drinkard
3002525264	CHEVRON	6704	MANDA B TR C 001	O	Plugged	0.95	Blinebry
3002534808	HENDRIX	7400	SHIRLEY BOYD 001	O	Active	0.95	Silurian
3002510463	HENDRIX	6487	BAKER A 001	O	Plugged	0.97	Drinkard
3002510467	TEXACO	6450	BAKER A 005	O	Plugged	0.97	Blinebry
3002539049	RANGE	6995	CHRISTMAS 28 004	O	Active	0.98	Blinebry

During the C-108 review and hearing, NMOCD raised questions regarding the potential for migration from the injection activities in the San Andres through a currently active well, the Legacy Resources Operating LC Langlie-Mattix Penrose Sand Unit 25-002 (3002410499; see Figure 4). This well was originally drilled to a total depth of 4066 feet (to the base of the Greyburg - top of the San Andres) in 1937 and lies approximately 0.35 miles northwest of the Eunice Gas Plant SWD #1 well. At that time, water flow was observed and the well was plugged back to 3,692 feet with gravel, 10 sacks of cement, and 600 pounds of lead wool. This plugging operation was reported as successful in stopping the water flow.

After producing for 27 years, the well was shut in 1964 pending proposed reuse as a waterflood well. Pursuant to NMOCD Order WFX No. 333 of January 23, 1970, this well was approved for waterflood operations. The well is currently operated as an injection well in the Langlie-Mattix zone, receiving approximately 40,000 barrels of water in 2009.

Following discussions with NMOCD, and contingent on final approval from Legacy, Targa proposed to re-enter the well, drill out the approximately 375 feet of original plugging (3,692 to 4,066 feet) and plug that zone in accordance with current plugging practices, in a manner that preserves the well's utility as an injection well in Legacy's waterflood program. This proposal was accepted by NMOCD and incorporated into the Order, and the work completed in June 2011. A copy of the plugging report and NMOCD approval is included in Appendix M.

A detailed reservoir analysis was performed combining geophysical logs, sidewall cores, and reservoir tests (see Section 6). This analysis enabled us to determine the likely area to be impacted by the fluid injected into the Eunice Gas Plant SWD #1 at the maximum proposed injection rate (4,075 bbls/day) over the anticipated injection period of approximately 30 years (Table 3). This evaluation focuses on the displacement of existing formation fluid. While it is clear that at the displacement front there will be interaction between the injected TAG and wastewater mixture with the formation fluid, this chemical diffusion is significantly slower than the dominant advective movement of the injection stream. The radius of the reservoir affected by this total volume of injection over the entire 30 years of injection is approximately 0.35 miles, which lies well inside the ½ mile radius of the Eunice Gas Plant SWD #1 well (Figure 5).

Table 3: Summary of Calculations of Reservoir Areas Affected by Injection	
Barrels per Day at Wellhead	3,931
Barrels per Day in Reservoir	3,555
Cubic Feet/Day (5.61 Cubic Feet per Barrel)	19,962
Cubic Feet/Year (365.25 Days)	7,291,009
Cubic Feet in 30 Years	218,730,272
Effective Porosity in Feet = 20.9 feet (Corrected for Residual Water (0.353))	20.9
Net Area Consumed (Sq. Ft.)	10,475,588
Net Area in Acres (43560 Sq. Ft./Acre)	240.5
Radius in feet (R = Square Root of (Area/pi))	**1,826**
Radius in Miles	**0.35**

This calculation demonstrates that there is a considerable safety factor between the anticipated radius of injection (0.35 miles) and the nearest well penetrating the San Andres (0.47 miles).

4.0 SYNOPSIS OF WELL DESIGN, DRILLING AND COMPLETION

Geolex was contracted by Targa to permit, oversee coring, logging and testing of the Eunice Gas Plant SWD #1 at the Eunice Gas Plant, and to provide reservoir analyses. Based on Geolex's recommendations, a Drilling Prognosis and AFE were prepared by Cambrian Management, Inc. in October 2010 and subsequently approved by Targa. The completed well schematic is shown in Figure 6 and the drilling plan is included in Appendix E.

4.1 PLANNING AND WELL DESIGN

Metallurgy. Due to the corrosive environment in which the well would be required to operate, special consideration had to be given to the metals used in its construction. The Eunice Middle Gas Plant generates approximately 5.0 MMSCF/D of acid gases that will be compressed to supercritical pressures (approximately 1300 psig) prior to injection. The stream of H_2S (14%) and CO_2 (84%) can impact wellheads, valves, packers, casing and tubing. Corrosion resistant alloys, or CRA's (chromium and nickel based) were evaluated thoroughly prior to their selection for inclusion in the well design.

After evaluation of the alternatives, it was determined that although carbon steel is resistant to the acid gases, it was necessary to upgrade the metallurgy for critical components with Inconel® 725 (or 625+) alloys for certain components in the Christmas Tree, the Subsurface Safety Valve (SSSV), the packer, and two joints of casing surrounding the depth where the packer was to be placed.

L80 grade casing and J-55 Duo-Line tubing were chosen for their resistance to H_2S environments. The casing in the area of the perforations will most likely undergo severe corrosion during operation. By placing the packer in a specially made CRA joint, the packer seat as well as the casing above the packer will be adequately protected by the acid resistant alloys (as well as the acid resistant cement – Halliburton CORROSACEM™, used around the casing string – see below.)

Drilling. A number of design considerations were implemented in the drilling planning for the Eunice Gas Plant SWD #1 well. Metallurgy requirements had to be incorporated into the wellhead design, including a tubing hanger fabricated with Inconel® 625+, as well as Inconel® cladding and hard faced trims on the valve stems and bonnets. The SSSV placed 250 feet below ground level has a hydraulic control line connected to it that passes through the wellhead at the surface.

A closed-loop drilling mud system was incorporated into the planning from project initiation. This environmentally-safe drilling mud circulation system is fully contained in steel tanks and thus avoids excavating earthen pits that have the potential to leak into shallow fresh water zones. By using centrifuges to separate the drilling mud from the cuttings, Key Energy Services could minimize the net inventory of mud on the site as well as better controlling the weight and other properties of the fluids, and maintain the mud in good enough condition to be recycled for future drilling. The system collected the cuttings in a dumpster, from which the material was removed by an excavator and a dump truck (Figure 7).

Cambrian Management began operations by rigging up a pulling unit, installing a blowout preventer, and removing the existing tubing and packer. After cleaning and testing the existing casing, the pulling unit was released and the rotary drilling rig (Key No. 115) was moved in. After connecting the Closed-Loop mud system, a 6 ¼ inch hole was advanced from the original depth of 4,550 feet to the new total depth of 4,850 feet.

Cementing. The planned cement program included Halliburton's special acid resistant CORROSACEM™ cement in the lower portion of the 6 ¼ inch hole around the injection interval (Appendix E). This special cement has been field tested by Halliburton to withstand years of acidic environments such as those encountered with long term injection of CO_2 and H_2S into a reservoir. Fifty sacks of this cement were emplaced from the bottom of the production casing (4,258 feet) to the Diverter Valve at 3,900 feet. Conventional Class C cement (270 sacks) was used for the remainder of the long string.

Completion. After cementing and testing, the well was completed by emplacing a Halliburton TWB Perma-Series packer at 4,190 feet, connected with 2 ⅞ inch J-55 Duo-Line tubing to 4,219 feet. The SSSV was installed at 250 feet, along with a stainless-steel control line to actuate the valve manually if necessary.

Safety. Every effort was made to execute the planned safe operation from the drilling, to completion, to the operation of the well. A pre-spud meeting was held prior to drilling operations to familiarize the drilling and service company personnel with plant safety rules, and a Company Safety representative will monitor compliance. During major service company operations like coring, logging, running casing, cementing, perforating, etc. mandatory safety meetings were held to discuss safe procedures and answer any questions personnel might have prior to each job.

As approved by NMOCD in the Rule 11 plan for the site, H_2S monitors are located near the wellhead and inside the wellhead cellar to monitor for any possible leaks of H_2S. The SSSV installed at 250 feet below the surface is designed to fail "closed" if constant hydraulic pressure applied to it through the control line is ever interrupted. In other words, if something as drastic as the wellhead being sheared off at the surface ever occurred, the SSSV would shut itself in automatically, sealing off the injected zone from the surface.

4.2 DRILLING

The well recompletion was spudded on May 13, 2011 following removal of the existing tubing and packer. After rigging the BOP, drilling advanced using a 6 ¼ inch bit. Conventional rotary drilling was used, and the total depth was reached by May 18, 2011.

After conditioning the borehole, Halliburton arrived on May 19 and provided geophysical logging services, including natural gamma, self-potential, resistivity, gamma and neutron porosity, and caliper logs. A second run was used for collection XRMI™ logging, a high-resolution resistivity tool that images small bedding planes and fractures. This tool was used in the reservoir (open hole interval from 4,258 to 4,850 feet), and showed only minor fractures in the San Andres; no faults or microfaults were detected.

Sidewall coring was provided by Halliburton, who provided the equipment and personnel for the coring, retrieval and packing. After reviewing the geophysical logs, Geolex selected a total of 44 depth intervals for side wall coring (4,044 to 4,826 feet), of which 32 were recovered. The cores were inspected by Geolex and analyzed by Weatherford Laboratories in Houston for porosity, permeability, water saturation and other reservoir characteristics.

4.3 FINAL CEMENTING AND TESTING

The cementing program for the long string (Appendix E) involved a two-stage process. This program was designed to emplace the acid-resistant first-stage CORROSACEM™ cement in the annulus surrounding the San Andres and the overlying cap rock, and the more conventional Halliburton EconoCem C (lead) and Halliburton HalCEm C (tail) in the second stage.

On May 22, 2011, Halliburton mobilized to the site and began cementing operations. The first stage was successful, and 50 sacks of CORROSACEM™ were emplaced. The "bomb" to open the DV at 3900 feet was dropped and pressured up to open the DV, and circulation was attempted as planned. Returns to the surface were observed from cementing of Stage 1 of the production casing.

Halliburton then completed the second stage, with a combined amount of 270 sacks. Although cement returns were observed at the surface, the cement column subsided below the surface after cement pumping ceased. A Cement Bond Log (CBL) run by Renegade on June 3, 2011 showed that the final top of the cement was at 1,059 feet, well within the existing initial production casing (Appendix G).

Following site cleanup and rig down tasks, the rig was released on May 23, 2011.

4.4 COMPLETION

As designed, the well was completed by emplacing a Halliburton TWB Perma-Series packer at 4,190 feet, connected with 2 ⅞ inch J-55 Duo-Line tubing to 4,219 feet. The SSSV was installed at 250 feet, along with a stainless-steel control line to actuate the valve manually if necessary.

On June 30, 2011 a Mechanical Integrity Test (MIT) was conducted to test the pressure stability between the tubing and the production casing. The test, witnessed by Mark Whitaker of NMOCD, involved pressuring the annulus at 500 psi for 30 minutes. The test was successful. The next MIT will be required in June of 2013.

4.5 MONITORING AND MAINTENANCE

It is not unusual for annular pressures (5 ½ inch casing x 2 ⅞ inch tubing) to fluctuate 100 to 200 psi seasonally and with different TAG pressures and temperatures. However, the annular pressure will be constantly monitored by Gas Control Operations at the plant 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 mechanical condition of the wellhead and Christmas tree will be visually inspected regularly and if any leaks are noticed, the wellhead company will be called to inspect and repair as necessary.

The NMOCC Order requires an MIT of the annular space every two years. By having the annular pressures monitored constantly by Gas Control, regular MIT tests can be conducted in a routine manner.

4.6 CURRENT WELL STATUS

Following completion, the topside compression facilities were connected to the well. Mixed acid gas and wastewater injection commenced on August 24, 2011, as stated in an August 29, 2011 letter to NMOCD providing notification (Appendix D). The composition and daily volumes of the injection fluid have been quite variable during the first few months of operation, with 5,099 barrels of mixed acid gas and wastewater injected into the well in August and 11,895 barrels of pure wastewater injected in September. Injection volumes and pressures have been reported to using the required C-115 filing system (Appendix L).

5.0 REGIONAL AND LOCAL GEOLOGY AND HYDROGEOLOGY

5.1 GENERAL GEOLOGIC SETTING

The overall regional model (Figure 7) shows that the South Eunice Gas Plant is located on the northwestern corner of the Central Basin Platform of the Permian Basin. In this geological setting, lower to upper Permian strata lie upon a truncated lower Paleozoic surface. Truncation of the older beds by erosion occurred during the emergence of the Central Basin Platform as a structural entity. This emergence took place along a series of down-to-basin faults to all sides of the Platform. Beneath the study area, lower Permian Abo carbonates sit directly upon Devonian (Woodford) and older beds. The lower Paleozoic beds are at depths averaging about 7400-7600 feet and deeper below the surface in the vicinity of the plant. This portion of Lea County has had oil and gas production dating back to the 1930s, and has and is still producing from a variety of formations, including the Abo, Blinebry/Tubb/Drinkard, Queen and Seven Rivers.

5.2 BEDROCK GEOLOGY

Figure 8 is a cross-section that illustrates the structure and stratigraphy in the study area. All of the units of interest in this area are very uniform in thickness, have very gentle dips, and there is no evidence of faults, folds or other structures in this area. The primary producing zones in the area are the Queen-Seven Rivers (Langlie-Mattix) and Glorieta-Yeso (Blinebry), as well as underlying Abo horizons to the west (not shown here). The cross-section incorporates wells in the study area that were perforated in the San Andres either for production or salt water disposal. Most of the wells in the study area that tested the San Andres are now plugged, but three wells continue to be used for water disposal purposes. These wells (shown in Figure 7) include the A.L. Christmas 001, the Christmas 003, and the existing Eunice Gas Plant SWD #1 (also shown on the cross-section, Figure 8).

5.3 LITHOLOGIC AND RESERVOIR CHARACTERISTICS OF THE SAN ANDRES

The San Andres in the study area is composed of approximately 1000 feet of dolomitic carbonate that was deposited in shallow water environments. During Guadalupian time, the depositional environment of the San Andres can be characterized as a relatively shallow marine shelf, locally called the Northwestern Basin, adjacent to the deeper Delaware Basin to the south. The San Andres represents the highstand of the Guadalupian marine sequence, and the San Andres was subsequently overlain by the more clastic and evaporitic deposits of the Artesia Group. The final Ochoan sequence of the Permian period deposited the Salado evaporites, and the clastic Rustler and Dewey Lake beds.

Although this area of the Permian Basin has been tectonically quiet since its deposition, there have been numerous phases of diagenetic changes involving the carbonate facies. Diagenetic events in the San Andres in this area show significant heterogeneity in their three-dimensional patterns. This architecture results in discreet porous "reservoir rocks" adjacent to and vertically constrained by relatively impermeable seal rocks.

In a general sense, in the area of the Eunice Gas Plant SWD #1, porosity is better developed in the upper half of the San Andres, and is generally aligned along a N10W strike (Figure 9). It is important to note that although large-scale porosity trends do exist, there are no small-scale porosity zones than can be correlated among wells at scales of less than one mile.

Diagenetic processes can cause both increases and decreases in primary porosity. This is part of the reason for the differences between the porous upper portion and less porous lower zone of the San Andres. In the upper zone, secondary vuggy porosity is well developed and preserved. In the lower zone, porosity has subsequently been partially plugged by calcite and/or anhydrite. This process has both reduced the overall porosity of the formation, and greatly reduced the permeability in that zone.

5.4 FORMATION FLUID CHEMISTRY

Although there are no published formation fluid analyses for wells in the immediate area of the Eunice Gas Plant SWD #1, a study by the Texas Water Development Board (Robert E. Mace, et. al, Report 366, April 2006) shows that fluids in the San Andres exhibit total dissolved solids ranging from 10,000 mg/l to 400,000 mg/l, with an average value of 82,000 mg/l. Values of pH range from 6 to 9, and the waters' constituents are primarily sodium and chloride.

5.5 GROUNDWATER HYDROLOGY IN THE VICINITY OF THE PROPOSED INJECTION WELL

The New Mexico State Engineer's Office lists 22 water wells within one mile of the Eunice Gas Plant SWD #1, and their locations are shown in Figure 10. All of these wells are shallow, and completed in the surficial alluvium at depths of less than 200 feet. Furthermore, the SWD well's 300 ft of surface casing cemented to the surface is fully protective of this shallow groundwater resource. There is no potential for impacts from the proposed injection in the San Andres, over 4500 feet below surface. There are no natural bodies of surface water within one mile of the Eunice Gas Plant SWD #1.

6.0 RESERVOIR CHARACTERIZATION AND MODELING

Extensive reservoir characterization and testing were performed on the Eunice Gas Plant SWD #1 well during May-July 2011 in order to better evaluate the impact of the planned AGI to the reservoir. The work performed included: geophysical logs, XRMI, sidewall coring and lab analysis, step rate test, transient pressure test, warm back test, and tracer and temperature surveys. Below we describe the results of this work and present a refined model of the reservoir in the vicinity of the Eunice Gas Plant SWD #1 well. This refined model was then used to calculate a best estimate for the area that will be impacted over the life of the AGI well, as required by the NMOCC in Order R-1289-C-1-HO. These results will be presented at the subsequent NMOCC hearing and are intended to aid in the NMOCC in determining injection limits for the Eunice Gas Plant SWD #1 well.

6.1 GEOPHYSICAL LOGS AND XRMI

On May 19, 2011, Halliburton logged the open hole from 4,050 feet depth to just above TD at 4,850 feet using a full suite of geophysical tools, including gamma ray, self potential, resistivity, compensated neutron and density porosity, caliper logs and XRMI. The geophysical logs are included in Appendix F; selected data are included in Figure 11.

The evaluated portion of the San Andres can be divided into four zones based on the porosity logs. The two zones with the highest porosity (up to 20%), from 4,010 to 4,100 feet (above the injection zone) and 4,320 to 4,520 feet, reveal significant vertical heterogeneity. The remaining two zones (from 4,100 to 4,320 feet and below 4,520 feet) exhibit little variability and lower values of porosity (averages of 14% and 7%, respectively). In general, the upper half of the San Andres (above 4,520 feet) has relatively high porosities (>14%) and low resistivity values, consistent with the presence of saline water. The lower half of the San Andres (below 4,520 feet) has relatively low porosities (~7 %) and high resistivity.

XRMI logs use high-resolution, oriented resistivity measurements to detect structural and depositional features in the country rock. An evaluation of the XRMI data (Appendix F) reveals the absence of faults and microfaults in the open hole section. The upper half of the San Andres is interpreted to be vuggy, poorly bedded carbonate, with well developed interparticular and secondary porosities. The lower half of the San Andres is interpreted as tighter, more bedded carbonate, with limited interparticular porosity and few vugs. A relatively large number of conductive fractures were identified in these tighter carbonates, but these showed no preferential orientation. The upper, higher porosity portion of the San Andres had very few conductive fractures, but did have several small E-W oriented, high-angle, drilling-induced fractures.

6.2 SIDEWALL CORING

Using the initial geophysical logs as a guide, Geolex selected sidewall core sample points from the open hole portion of the Eunice Gas Plant SWD #1 well. On May 19th, Halliburton successfully collected 32 core samples. An additional 6 sidewall cores were attempted, but had no recovery. The samples were visually inspected and described and then sent to Weatherford Laboratories to be analyzed for porosity, air permeability, water and oil content and fluorescence. Three representative samples were selected and analyzed for water and CO_2 permeability and for irreducible water. All core sample descriptions and analyses are included in Appendix H.

Inspection of the core samples indicate that the San Andres Formation locally consists of silty, mixed limestone/dolomite carbonate. Samples from the upper half of the section were notably vuggy and had well developed pin point (interparticular) porosity. Above about 4,320 feet, the vugs were somewhat smaller and secondary calcite filled some of the visible pores. Between 4,320 feet and 4,550 feet, sample return was poor and many samples were fractured. No secondary calcite was visible in these samples.

The injection of remediation water by the Eunice Gas Plant SWD #1 well into the reservoir above 4,550 feet is reflected by the presence of black, weathered, odoriferous hydrocarbon material within the vugs in many of the samples from the upper half of the San Andres. This material was also identified in the laboratory analyses of oil saturation, gas content and % fluorescence.

Samples collected from the lower half of the San Andres had poorly developed porosity that was partially filled by secondary calcite. Numerous gypsum inclusions were also observed. Below 4,610 feet, visible porosity improved with presence of some small vugs and pin point porosity. Samples were largely intact and exhibited few fractures.

Sample porosities and permeabilities were measured in the laboratory (Appendix H; Figure 11). Porosities measured in the upper half of the San Andres ranged from around 4% to around 39%, but were generally lower than estimated using the porosity logs. This disparity is due in part to sample bias related to poor recovery from the highest porosity portions of the section. Additionally, samples that were observed to have large vugs that were filled with hydrocarbons had surprisingly low measured porosities (i.e., samples 4324 and 4430 had visibly high porosity and yet had measured porosities of < 5%), possibly due to retention of hydrocarbons during porosity measurements. In contrast, porosities measured in the lower half of the San Andres (around 2% to 9%) where no hydrocarbons were observed were very consistent with the porosity logs. As a result, we feel that the most representative porosities for the San Andres at the Eunice Gas Plant SWD #1 are the cross plot porosities calculated using the compensated neutron porosity and density porosity logs (both use a limestone matrix; Figure 12).

Permeability measurements ranged from 0.003 mD to 9.5 mD, with the majority of samples having permeabilities below 0.1 mD. The highest permeabilities were measured in the upper half of the section, but may not be representative of the true formation permeability since poor recovery from the high porosity zones and fragmentary samples has resulted in sample bias towards lower permeabilities. Using the quality of recovery for high permeability reveals zones of high permeability above 4,250 feet and from 4,330 to 4,550 feet (Figure 11).

Three samples considered to be representative of the portions of the reservoir with the highest injectivity, as determined by the tracer survey described below, were chosen for analyses of water and CO_2 permeabilities and for irreducible water (see Appendix H for results). The irreducible water for the sample collected at 4457 feet was measured to be 0.320, this value was used to characterize the section above 4500 feet. Samples from 4730 and 4770 feet had irreducible water values of 0.555 and 0.636, respectively; the average 0.596 was used to characterize the section below 4500 feet.

6.3 RESERVOIR TESTING

Reservoir testing was performed on the Eunice Gas Plant SWD #1 well during the period of June 29 to July 13, 2011. Downhole temperatures and bottomhole pressures were monitored for the entire period (except during the acid job on June 30, 2011) by Schlumberger using a fiber optic Slick-line Distributed Temperature Survey String (SL-DTS String) and a pressure bomb. After the baseline reservoir conditions were determined, the well was stimulated using two stages of 15% hydrochloric acid. A step rate test and transient pressure test were performed and surface conditions were monitored by Cudd Energy Services. Following the injection tests, the well was shut in and a warmback test was performed to evaluate the reservoir recovery. All of the reservoir test data and analysis performed by Schlumberger are included in Appendix K.

Baseline Reservoir Temperatures. Baseline reservoir temperatures were measured at the Eunice Gas Plant SWD #1 on June 29, 2011, prior to the described injection tests. Measurements were performed by Schlumberger using the SL-DTS String, which is considered to be the most accurate of the techniques employed at the well for measuring temperatures. The measured temperatures ranged from 79°F at the top of the injection interval (4,258 feet) to 88°F near the bottom of the open hole (TD 4,850 feet) (Appendix K).

Acid Treatment. After the baseline temperature measurements were performed, the SL-DTS String was removed from the well and on June 30, 2011 the open hole was stimulated by Schlumberger using 5,000 gal of 15% HCl. Rock salt was used as a diverter to ensure that the entire injection interval was stimulated. The SL-DTS String was reinserted downhole and the warm back temperature traces were collected (Appendix K). Warming of the reservoir results from the exothermic reaction between the acid and the carbonate reservoir rock.

Notable heating was measured between 4,297 feet and 4,368 feet and below 4,503 feet. Less pronounced heating was measured between 4,368 feet and 4,503 feet. The observed warming is consistent with effective placement of the acid at 4,297-4,368 feet and below 4,503 feet. Changes in the limestone content of the San Andres Formation may also have influenced the observed warming.

Step Rate Test. The step rate test (SRT) was conducted on July 6, 2011 at the Eunice Gas Plant SWD #1 well (after appropriate notice was made to Mark Whittaker at the NMOCD district office in Hobbs as required by NMOCC Order #12809) to examine the behavior of the San Andres Formation during injection. The test was performed following completion of the well, injecting water through the corrosion-resistant 2 ⅞ inch production tubing and the packer set at 4,201 feet. Fluid was injected Cudd Energy Services into the San Andres Formation through the open hole from 4,258 to 4,850 feet. Injection rates during the SRT ranged from 1.2 to 5.0 bbl/min, with 0.5 bbl/min steps (the first step from 1.2 to 1.5 bbl/min was smaller), each lasting 20 minutes. The surface injection pressure and bottom hole pressures down the tubing were recorded, the former by Cudd Energy Services and the latter by Schlumberger using the bottom hole pressure bomb set at 4,810 feet. A maximum bottom hole pressure 3,348 psig was recorded during the SRT at an injection rate of 5.0 bbl/min (Figure 13). Since the SRT was performed following completion of the well with the actual operational equipment, no corrections associated with changes in tubing diameter or packer placement are required. The data are included in Appendix K.

The results of the SRT are shown in Figure 14 in a plot of injection rate versus measured injection pressures. A notable increase in injectivity was observed at about 2.5 bbl/min, as indicated by an inflection in the bottom hole pressure curve at 3,340 psig and in the surface pressure curve at about 1,400 psig. The observed change in injectivity is consistent with a formation parting pressure (P_p) of about 3,300 psig. The theoretical parting pressure can be calculated using the equation:

$$P_p = P_{RES} + (\nu/(1-\nu)) * (P_{OB} - P_{RES}),$$

where P_{RES} is the reservoir pressure , P_{OB} is the overburden pressure, and ν is the Poisson 's ratio for the reservoir rock.

At the Eunice Gas Plant SWD #1 well, the reservoir pressure was determined to be 1,980 psig during the July 6, 2011 injection test and the overburden pressure was calculated to be 4,810 psig at the test gauge depth. Using these observed values and the parting pressure estimated from the SRT results, the Poisson's ratio can be calculated for the San Andres Formation. The resultant value, 0.325, is well within the range of values for carbonates (Poisson's Ratios for carbonates range from 0.10-0.35; Gercek, 2007. Poisson's ratio values for rocks. International Journal of Rock Mechanics and Mining Science, 44: 1-13).

A comparison of the July 6, 2011 SRT with historical records of a 1983 pump-in injection test on the original Eunice Gas Plant SWD #1 (NMOCD Order No. R-12809-C), suggest that the behavior of the injection reservoir may have changed over time. The 1983 injection test reached an injection rate of 10 bbl/min into the open hole interval of 4,010 feet to 4,550 feet at a maximum bottom hole pressure of 3,000 psig without showing any apparent evidence of fracturing. During the 2011 test, the formation parting pressure was found to be 3,340 psig, consistent with the 1983 test, but this was achieved at an injection rate of roughly 2.5 bbl/min. Although the initial test included the open hole interval from 4,010 to 4,258 feet, the geophysical logs and core data indicate that this interval should not have been significantly different from the interval from 4,258 to 4,500 feet included in the 2011 test. More likely, the injection of remediation water containing hydrocarbons has plugged up the porosity close to the wellbore, resulting in some reduction in permeability. This is consistent with the low permeabilities measured in core samples containing weathered hydrocarbons (Section 6.2). Based on the well documented ability of supercritical CO_2 to flush hydrocarbons during Enhanced Oil Recovery (EOR), we anticipate that the continued injection of supercritical TAG will clean out the clogged porosity and improve the reservoir permeability and injectivity over time.

Transient Pressure and Pressure Fall off Test. After the completion of the SRT on July 6, 2011,a transient pressure test was performed on the Eunice Gas Plant SWD #1 well. During the test, Cudd Energy Services injected 162 barrels of water over a period of 110 minutes (1.5 bbl/min), followed by 291 barrels over a period of 92 minutes (3.0 bbl/min). The well was shut in and pressure fall off was monitored by Schlumberger from July 6 until July 13, 2011 using the downhole pressure bomb. An earlier pressure fall off test had been performed following an injection well test on July 1st that was aborted due to insufficient water supply. The initial test involved two hours of injection, the well was then shut in and the pressure fall off was monitored from July 1 to July 6, 2011.

Schlumberger analysts were not able to satisfactorily fit the pressure data (Appendix K). They postulate that the pressure measurements were affected by the wellbore dynamics, such as possible fluid movement (vertical flow) between layers after shut in. The skin effect and effective permeability (k) for the injection zone were determined by modeling the fall off curves. The modeled k was 0.745 mD, or a transmissivity of 447 mD-ft for the entire injection interval.

Warm Back and Thermal Profile Analysis. Downhole temperature profiles were collected by Schlumberger using the SL-DTS String from July 1 to July 13, 2011. This period included injection tests on July 1 and July 6, 2011 and warm back periods when the well was shut in on July 1 to July 6, 2011 and July 6 to July 13, 2011. The temperature measurements are included in Appendix K.

The injection tests resulted in a general cooling of the reservoir. By measuring the changes in temperature using the SL-DST String, it was possible to detect and track the injection velocities in the tubing and open hole (Figure 15).

During the initial injection phase of the SRT, the calculated fluid velocity decreased from 1.5 bbl/min in the tubing to 1.0 bbl/min at the 5 ½ inch casing shoe indicating a loss of up to 0.5 bbl/min (33.3% of the injected fluid) at the casing shoe suggesting a leak zone or highly permeable zone directly behind the shoe. An additional fluid velocity decrease below 4350 feet indicated a loss of about 0.73 bbl/min (48.67% of the injected fluid) at 4350 feet. At that injection rate, the injection front (base of injection) was located at 4,420 feet. Increasing the injection rate and the associated pressure caused the injection front to move down hole from 4,420 to 4,750 feet and beyond. At an injection rate of 3.0 bbl/min, as much as 0.4 bbl/min (13.3%) was injected to 4,750 feet.

6.4 TRACER AND TEMPERATURE SURVEYS

Radioactive tracer and temperature surveys were conducted at the Eunice Gas Plant SWD #1 well on July 14, 2011 to examine the response of the well to injection and to determine which zones were taking up fluid. The surveys were performed by Cardinal Surveys, with Cudd Energy Services controlling the water injection rate and monitoring the injection surface pressures. An initial tracer survey was performed at an injection rate of 1.5 bbl/min, followed by a second survey at a rate of 3.0 bbl/min, representative of the planned injection into the well. Temperature surveys were performed before and after the tracer surveys to determine the background conditions and to examine the response of the reservoir to injection. All of the survey results and interpretations from Cardinal Surveys are included in Appendix K.

Tracer surveys are performed by releasing a small amount of radioactive iodine, a radioactive tracer, into the tubing. As the tracer is forced down the tubing and into the open hole portion of the well by the injection water, a detector is lowered through the water column to measure the position of the tracer front. By plotting the change in the tracer front position over time, it is possible to measure the velocity of the fluid in the well and to calculate the amount water lost to (injected into) the surrounding reservoir rocks.

The results of the tracer surveys indicate that the upper portion of the reservoir has the highest injectivity (Figure 11; Appendix K). At an injection rate of 1.5 bbl/min, flow was stagnant below 4,475 feet indicating minimal injection below that depth. The majority of injection (76.2%) occurred in a zone from 4,340 to 4,442 feet; the remainder occurred in the vicinity of the casing shoe (15.6 %) and below 4,442 feet (8.2%). At the higher injection rate of 3.0 bbl/min, the zone of injection is extended to greater depth. Although the majority of injection (82.7%) still occurs at depths of less than 4,450 feet (75.7% between 4,356 feet and 4,451 feet and 7% near the casing shoe), a zone below 4,653 feet opens up and takes 11.9% of the injected fluid. The base of this lower injection zone is shown to be 4,790 feet based on the temperature surveys.

6.5 INTERPRETATION AND IMPLICATIONS

The geophysical logs, core samples and reservoir tests described above provide a consistent picture of the San Andres injection reservoir at the Eunice Gas Plant SWD #1 well. The San Andres is composed of silty carbonate that can locally be lithologically divided into a porous and relatively permeable upper portion (4,010 feet to 4,550 feet; note that the current open hole interval begins at 4,258 feet) and a less porous and relatively impermeable lower portion (4,550 feet to 4,850 feet). The vuggy porosity in the upper portion has become partially filled by weathered hydrocarbons associated with the injection of remediation water, somewhat reducing the effective permeability. The lower portion has secondary calcite filling much of the porosity and also contains abundant anhydrite inclusions. The San Andres is relatively unbedded and variations in porosity and permeability are largely controlled by diagenetic effects (dissolution) rather than depositional features (grainsize). No faults or microfaults were identified in the section.

The process of dissolution in the San Andres has been highly irregular, resulting in significant lateral and vertical variability. Although the general differences noted between the upper and lower portions of the section (greater porosity in the upper and anhydrite in the lower) are regional in nature, finer scale variations in porosity and permeability and highly localized and are not recognizable in logs from nearby wells (i.e., Santa Rita #012 API 30-025-36482, located 0.49 miles away, the closest well penetrating the injection zone). Zones of high permeability and preferential fluid flow pinch out or interfinger with zones of higher or lower permeability.

As a result of the lateral and vertical variability of San Andres Formation, it is not appropriate to model it as a stack of layers with well-defined characteristics. Fluids will migrate preferentially through permeable units and then slow and back up as the permeabilities decline and units pinch out. Fluids will then spread, vertically and laterally, filling the surrounding pore space until they find another more permeable unit and establish another preferential pathway. Over time this will result in a smearing of the flow distribution.

In addition to providing information regarding the injectivity of the San Andres Formation, the reservoir testing has provided measurements of the reservoir conditions. The measured reservoir temperature (83°F) is colder than our original estimate and the reservoir pressure (1980 psi) is somewhat lower. The density of TAG in the reservoir will increase as the reservoir pressure increases and ultimately decline as reservoir returns to background conditions. The SG of TAG in the reservoir should stabilize at 0.84 and occupy a significantly smaller volume than in our original calculations that used an SG of 0.67 (Table 4).

6.6 RESERVOIR MODEL AND AREA OF IMPACT

Due to the heterogeneity of the San Andres Formation it is difficult to know the precise reservoir characteristics away from the well bore. However, it is reasonable to assume that the sequence evaluated at the well is representative of the San Andres within a reasonable distance of the well (i.e., less than ½ mile). Therefore, we have used the test data to calculate the "average" reservoir characteristics for the San Andres. This assumes that at any given point, the thickness of the sequence accepting fluid will be roughly the same and the net porosity will be roughly the same. At the Eunice Gas Plant SWD #1 and at 3.0 bbl/min of injection, the sequence accepting fluid was 302 feet thick and had an average porosity of ~11% (Table 5). Taking the irreducible water of the formation into account (~0.353), we have calculated that a representative average net porosity for the San Andres would be 20.88 feet (Table 6). Using this net porosity, we calculate that the available pore space within ½ miles of the Eunice Gas Plant SWD #1 would be approximately 457 million cubic feet.

The proposed injection volume for the Eunice Gas Plant SWD #1 can be calculated using the planned injection rates and the SGs for TAG and wastewater at the reservoir conditions (Table 4). The planned maximum injection rate for TAG is 5.0 MMSCFD which equates to 1,980 bbl/day at reservoir conditions. Wastewater is essentially incompressible; therefore the maximum injection rate into the reservoir will be the same as the injection rate at the surface, 1,575 bbl/day. Using the combined volumes (3,555 bbl/day), we calculate that roughly 220 million cubic feet (122 million cubic feet of TAG and 97 million cubic feet of waste water) would be injected over a 30 year lifespan for the well. This injection volume would account for 48% of the calculated volume available within a ½ mile radius of the well (457 million cubic feet). Since no faults or microfaults have been identified that would result in a preferential flow direction and since we are assuming that the formation heterogeneities will result in an averaging of the flow characteristics, a radial distribution for the injected fluid is reasonable. We calculate that the radius of the injected fluid over a 30-year lifespan would be approximately 0.35 miles. The time required to fill the entire ½ mile radius around the well would be approximately 62.7 years. These are very conservative estimates, since the actual volume injected will likely be smaller than the maximum permitted.

Tabl[illegible]essure and Volume Calculations for TAG and Wastewater, Eun[illegible]s Plant SWD #1

PROPOSED INJECTION STREAM CHARACTERISTICS

TAG	H_2S	CO_2	H_2S	CO_2	TAG	Waste Water (WW)			Mixed TAG + WW	
Gas vol MMSCFD	conc. mol %	conc. mol %	inject rate lb/day	inject rate lb/day	inject rate lb/day	inject rate bbl/day	Density kg/m^3	inject rate lb/day	comp TAG:H_2O	inject rate lb/day
5	14.5	83.8	68819	513595	582414	1575	1010	552018	31:69	1134432

CONDITIONS AT WELL HEAD

Well Head Conditions		TAG								WW	Mixed	
Temp F	Pressure psi	Gas vol MMSCFD	Comp CO_2:H_2S	Inject Rate lb/day	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl	volume bbl	volume bbl	volume bbl/30yr
95	1500	5	84:15	582414	705.02	0.71	5.89	13226	2356	1575	3931	43070696

CONDITIONS AT BOTTOM OF WELL

Injection Zone Conditions					TAG					WW	Mixed	
Temp F	Pressure[4] psi	$Depth_{top}$ ft	$Depth_{bottom}$ ft	Avail. Thick.[3] ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl	volume bbl	volume bbl	volume bbl/30yr
95	1980	4258	4850	302	784.75	0.78	6.55	11883	2116	1575	3691	40448166

CONDITIONS IN RESERVOIR AT EQUILIBRIUM

Injection Reservoir Conditions					TAG					WW	Mixed	
Temp[5] F	Pressure4 psi	Ave. Porosity[6] %	S_{wir}[7]	Porosity[8] ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl	volume bbl	volume bbl	volume bbl/30yr
83	1980	11.0	0.353	20.88	838.67	0.84	7.00	11119	1980	1575	3555	38957410

CONSTANTS

	SCF/mol	
Molar volume at STD	0.7915	
	g/mol	lb/mol
Molar weight of H_2S	34.0809	0.0751
Molar weight of CO_2	44.0096	0.0970
Molar weight of H_2O	18.015	0.0397

CALCULATION OF 30 YEAR AREA OF INJECTION

Barrels/day	3555	bbl/day
Cubic Feet/day (5.6146 ft^3/bbl)	19962	ft^3/day
Cubic Feet/30 years	218730272	ft^3/30 years
Area = V/Net Porosity (ft)	10475588	ft^2/30 years
Area = V/Net Porosity (ft) (43560 ft^2/acre)	240.5	acres/30 years
Radius =	1826	ft
Radius =	0.35	miles

[1] Density calculated using AQUAlibrium software

[2] Specific gravity calculated assuming a constant density for water

[3] Available thickness corresponds to the thickness of the zone accepting fluid during the tracer survey (Table 6)

[4] Reservoir pressure measured during reservoir testing

[5] Reservoir temp. measured during reservoir testing

[6] Ave. Porosity is estimated using geophysical logs for well for zones accepting fluid during tracer survey (Table 6)

[7] S_{wir} is based on laboratory measurements of representative samples (Table 6)

[8] Net Porosity is estimated using the available thickness, average porosity and Swir (Table 6)

Table 5. Calculation of the Average Net Porosity for the Interval Accepting Fluid in the San Andres Formation Based on the July 14, 2011 Tracer Survey, Eunice Gas Plant SWD #1 Well

	Segment	Fluid Injection Into Segment % Total Injection	Top ft depth	Bottom ft depth	Thickness ft	Porosity Neutron (L) %	Porosity Density (L) %	Porosity XPlot %	S_{wir} Lab	Porosity Net ft
Top half of injection reservoir	1	7.0	4258	4284	26	20.2	5.9	13.0	0.320	2.3
	2	38.3	4355	4398	43	25.0	14.2	19.5	0.320	5.7
	3	10.9	4398	4418	20	16.0	10.1	13.0	0.320	1.8
	4	14.1	4418	4431	13	22.4	11.1	16.5	0.320	1.5
	5	12.4	4431	4451	20	25.1	13.1	19.0	0.320	2.6
	6	4.0	4451	4482	31	20.6	13.1	16.5	0.320	3.5
	7	1.4	4482	4494	12	19.2	8.4	13.5	0.320	1.1
Bottom half	8	11.9	4653	4790	137	11.1	-3.3	4.5	0.596	2.5
					Average			**11.0**	**0.353**	
					Total for Zone Accepting Fluid					**20.88**

6.7 STEP-RATE TEST AND REQUEST FOR INCREASED MAOP

As described in Section 6.3, the SRT at the Eunice Gas Plant SWD #1 well revealed that the formation parting pressure for the San Andres injection reservoir is 3340 psig. This equated to a surface injection pressure of 1425 psig for an injection stream of water. Due to the density difference between the planned mixed injection fluid (compressed TAG and wastewater) and the water with which the test was performed, a greater injection pressure is required to cause a similar change in reservoir pressure. The difference in injection pressure can be calculated using the specific gravities and ratios for TAG and wastewater at the relevant temperatures and pressures (Table 6).

At the permitted maximum injection rates (5.0 MMSCFD TAG and 1575 bbl/day wastewater) and at the calculated formation parting pressure, the injection fluid mixture has a TAG fraction – F_{TAG} – of roughly 0.6. Using the calculated correction factor of 204 psig (Table 6), the corresponding surface injection pressure is 1629 psig (Figure 16), more than 300 psi greater than the approved MAOP for the well. In contrast, an injection of pure TAG (F_{TAG} = 1.0) has a correction factor of 335 psig and a corresponding surface injection pressure of approximately 1760 psig (Figure 16). Due to the changing operational constraints of the plant, we request that a NMOCC approve a mixture dependent MAOP – an MAOP that more accurately reflects the actual injection conditions.

We request that the MAOP be approved with four simple mixture thresholds of F_{TAG} = 0.4, 0.6, 0.8, and 1.0 (pure TAG). Mixtures with F_{TAG} of 0.0 (pure wastewater) to 0.4 would be limited to an MAOP of 1410 psig; mixtures with F_{TAG} of 0.4 to 0.6 would be limited to an MAOP of 1550 psig; mixtures with F_{TAG} of 0.6 to 0.8 would be limited to an MAOP of 1615 psig; mixtures with F_{TAG} of 0.8 to 1.0 would be limited to an MAOP of 1690 psig; and mixtures of pure TAG (F_{TAG} = 1.0) would be limited to an MAOP of 1745 psig. Operationally these mixtures would be achieved by controlling the amount of wastewater added to the injection stream. For example, when operating under the 1615 psig MAOP, the F_{TAG} would not be allowed to drop below 0.6. For an injection rate of 2.5 MMSCFD of TAG, the maximum wastewater injection rate would be 770 bbl/day or 22.4 gpm. This information would be provided to the operator in the form of a Table (i.e., Table 7). If the operator wanted to increase the amount of wastewater injected to greater than 770 bbl/day, he would have to operate with the MAOP of 1550 psig. The proposed mixture dependent MAOP is shown graphically in Figure 17.

6.8 REQUEST FOR APPROVAL TO INCREASE INJECTION INTERVAL BY 40 FEET

During recompletion, the Eunice Gas Plant SWD #1 well was deepened from 4550 to 4850 feet, primarily to compensate for the loss of the injection interval from 4050-4250 feet that was cased off as a requirement of Order R-1289-C-1-HO. However, the tracer and temperature surveys performed at the well indicate only limited injectivity below 4550 feet. In order to improve the quality of the injection reservoir, we request permission to perforate from 4210 to 4250 feet and to inject into that interval (Figure 18). As shown in the completion diagram, the packer was set at 4190 feet. Perforating from 4210 would add 48 feet of quality injection reservoir as indicated by prior injection and the open hole geophysical surveys and would still provide a buffer of more than 200 feet between the overlying Grayburg Formation. Using the average porosity for this interval as indicated by the geophysical logs (10.5%), and the S_{wir} measured in the laboratory (0.32), we calculate that this interval would add 3.43 feet of effective porosity (an additional 16%). The addition of this interval would have the dual benefit of improving the overall injectivity and providing additional pore space for storing acid gas. The pore volume within the ½ mile radius would be increased to roughly 532 million cubic feet. Thirty years of injection at the maximum permitted injection rate would occupy only 41% of this volume, and the radius of impact (assuming a cylindrical distribution) would be 0.32 miles (Figure 19; Table 8).

Table 6: Calculations Correcting Results of Step-Rate Test Performed with Salt Water Injection to Mixed TAG and Wastewater Injection, Eunice Gas Plant SWD #1. Note: Maximum Permitted Injection Mixture of 5.0 MMSCFD TAG and 1575 Bbl/D Wastewater is Roughly Equivalent to a TAG Fraction of 0.6.

Fraction		Surface		Bottomhole		Average		Injection Fluid			Max Injection
TAG (F_{TAG})[1]	Temp[2]	Pressure[3]	SG_{TAG}[3]	Pressure[4]	SG_{TAG}[3]	SG_{TAG}[5]	SG_{WW}	SG_{IF}[6]	Density	SRT corr.[7]	Pressure
	F	psi		Psi					psi/ft	psi	psi
1.0	95	1760	0.75	3340	0.90	0.83	1.01	0.829	0.36	334.73	1760
0.9	95	1727	0.75	3340	0.90	0.83	1.01	0.846	0.37	302.47	1727
0.8	95	1695	0.74	3340	0.90	0.82	1.01	0.864	0.37	269.68	1695
0.7	95	1662	0.74	3340	0.90	0.82	1.01	0.882	0.38	236.85	1662
0.6	95	1629	0.73	3340	0.90	0.82	1.01	0.900	0.39	203.59	1629
0.5	95	1595	0.72	3340	0.90	0.82	1.01	0.918	0.40	170.13	1595
0.4	95	1561	0.72	3340	0.90	0.81	1.01	0.936	0.40	136.35	1561
0.3	95	1527	0.71	3340	0.90	0.81	1.01	0.954	0.41	102.48	1527
0.2	95	1493	0.70	3340	0.90	0.80	1.01	0.973	0.42	68.40	1493
0.1	95	1455	0.69	3340	0.90	0.80	1.01	0.994	0.43	29.97	1455
0.0	95	1425	0.69	3340	0.90	0.80	1.01	1.010	0.44	0.00	1425

1 Volumetric fraction of TAG at surface injection conditions
2 Temperature of surface injection and bottomhole injection assumed to be equal.
3 Pressure and specific gravity of TAG are determined by iterative process using AquaLibrium 3.0 software to model compression of TAG
4 Bottomhole pressure is the formation parting pressure determined during the Step-Rate Test (SRT)
5 Average specific gravity in tubing string is determined by averaging TAG specific gravity at surface and at the bottom of the tubing strong
6 Specific gravity of injection fluid is determined using volumetric fraction of TAG, the average specific gravity of TAG, and the specific gravity of wastewater
7 the correction factor to the SRT is calculated difference between the hydrostatic head of the column of water injected during the SRT and a column of injection fluid with the specific gravity determined for the relevant fraction of TAG

Table 7: Injection Volumes Permitted Under the Mixture Dependent MAOP Model, Eunice Gas Plant SWD #1

MAOP = 1410 psig F_{TAG} = 0.0-0.4				MAOP = 1550 psig F_{TAG} = 0.4-0.6				MAOP = 1615 psig F_{TAG} = 0.6-0.8				MAOP = 1690 psig F_{TAG} = 0.8-1.0				MAOP = 1745 psig F_{TAG} = 1.0			
TAG		WW_{max}		TAG		WW_{max}		TAG		WW_{max}		TAG		WW_{max}		TAG		WW_{max}	
MMSCFD	bbl/d[1]	bbl/d[2]	gpm	MMSCFD	bbl/d[1]	bbl/d[2]	gpm	MMSCFD	bbl/d[1]	bbl/d[2]	gpm	MMSCFD	bbl/d[1]	bbl/d[2]	gpm	MMSCFD	bbl/d[1]	bbl/d[2]	gpm
0.5	246	1575	45.9	0.5	235	353	10.3	0.5	231	154	4.5	0.5	227	57	1.7	0.5	224	0	0.0
1.0	492	1575	45.9	1.0	470	706	20.5	1.0	462	308	9.0	1.0	455	114	3.3	1.0	448	0	0.0
1.5	738	1575	45.9	1.5	706	1059	30.8	1.5	693	462	13.5	1.5	682	171	5.0	1.5	673	0	0.0
2.0	984	1575	45.9	2.0	941	1411	41.1	2.0	924	616	17.9	2.0	910	227	6.6	2.0	897	0	0.0
2.5	1230	1575	45.9	2.5	1176	1575	45.9	2.5	1155	770	22.4	2.5	1137	284	8.3	2.5	1121	0	0.0
3.0	1476	1575	45.9	3.0	1411	1575	45.9	3.0	1386	924	26.9	3.0	1364	341	9.9	3.0	1345	0	0.0
3.5	1721	1575	45.9	3.5	1647	1575	45.9	3.5	1617	1078	31.4	3.5	1592	398	11.6	3.5	1570	0	0.0
4.0	1967	1575	45.9	4.0	1882	1575	45.9	4.0	1849	1232	35.9	4.0	1819	455	13.3	4.0	1794	0	0.0
4.5	2213	1575	45.9	4.5	2117	1575	45.9	4.5	2080	1386	40.4	4.5	2046	512	14.9	4.5	2018	0	0.0
5.0	2459	1575	45.9	5.0	2352	1575	45.9	5.0	2311	1540	44.8	5.0	2274	568	16.6	5.0	2242	0	0.0

[1] Volumetric injection rate of TAG at surface conditions: 95°F and proposed mixture dependent MAOP
[2] Maximum allowable wastewater injection rate calculated using the TAG volumetric injection rate and TAG fraction. Note: 1575 bbl/d is the maximum wastewater injection rate permitted for well

Table 8: Summary of Calculations of Reservoir Areas Affected by Injection Including Additional Injection Interval

Net area in ½ mile radius in square feet	21,895,644 ft^2
Effective porosity of injection zone in feet Corrected for residual water = 0.353	24.31 ft
Available volume in ½ mile radius in cubic feet	**532,217,419 ft^3**
Max. allowable injection volume in cubic feet/day (in barrels per day)	19,962 ft^3/day (3555 bbl/day)
Injection Volume in cubic feet/year	7,291,009 ft^3
Duration to fill ½ mile radius	**73.0 years**
Max. allowable 30 year injection volume in cubic feet	218,730,272 ft^3
Percentage of available volume in ½ mile radius	41%
Area consume in square feet (vol./effective porosity) (in acres)	
Radius of area in feet (assuming cylindrical distribution) (in miles)	**1,826 ft (0.32 miles)**