2.0 INTRODUCTION AND ORGANIZATION OF THIS C-108 APPLICATION

The completed NMOCD Form C-108 is included before the Table of Contents of this document and references appropriate sections where data required to be submitted are included herein.

This application organizes and details all of the information required by NMOCD and NMOCC to evaluate and approve the submitted Form C-108 – Application for Authorization to Inject. This information is presented in the following categories:

- A detailed description of the location, construction and operation of the proposed injection well (Section 3.0);
- A summary of the regional and local geology, the hydrogeology, and the location of drinking water wells within the area of review (Section 4.0);
- The identification, location, status, production zones, and other relevant information on oil and gas wells within the area of review (Section 5.0);
- The identification and required notification for operators and surface land owners that are located within the area of review (Section 6.0);
- An affirmative statement, based on the analysis of geological conditions at the site, that there is no hydraulic connection between the proposed injection zone and any known sources of drinking water (Section 7.0).

In addition, this application includes the following supporting information:

- Appendix A: Well Logs for Existing Wells within One Mile of Proposed Linam AGI #2 that Penetrate the Lower Bone Springs;
- Appendix B: Well Completion and Plugging Design for Deep Wells within One Mile of Proposed Linam AGI #2 that Penetrate the Lower Bone Springs Injection Reservoir;
- Appendix C: Maps and Spreadsheets Identifying Operators, Lessees, Surface Owners and Other Interested Parties for Notices, Copies of Notice Letters and Certified Mail Receipts.

It is anticipated that this application shall be the subject of a NMOCC hearing in December 2012.

3.0 PROPOSED CONSTRUCTION AND OPERATION OF LINAM AGI #2 WELL

The proposed injection well will be drilled near Linam AGI #1 in Unit K, 2,120 feet from the south line and 2,120 feet from the west line of Section 30, T18S, and R37E. Figure 2 shows the proposed location of the new well.

3.1 CALCULATED MAXIMUM INJECTION PRESSURE

The well will be designed and constructed such that it will serve as a redundant injection conduit for a stream of treated acid gas. The stream of treated acid gas (TAG) will be of approximately the following composition:

- 81.6% CO_2
- 18.4% H_2S
- Trace Components of $C_1 - C_7$

These concentrations are entered into Table 1 which are derived from the most recent data collected from the Linam AGI #1 and are used to calculate pressure and volume for TAG under current maximum Linam Plant capacity of 225 MMCFD and measured inlet gas concentrations. The TAG specific gravity is the average of the top and bottom specific gravity as calculated by Aqualibrium™ software and included in the table.

The total volume of TAG to be injected under this scenario will be approximately 2,886 barrels per day (bpd) at 7 MMSCFD, under reservoir conditions. Pressure reduction valves will be incorporated, as needed, to assure that maximum surface injection pressure allowed by NMOCD will not be exceeded.

The calculated maximum allowable injection pressure is approximately 2,599 psig (depending on specific gravity of final TAG stream). We have used the following method approved by NMOCD to calculate the preliminary proposed maximum injection pressure. The final maximum permitted surface injection pressure should be based on the final specific gravity of the injection stream according to the following formula:

$IP_{max} = PG\ (D_{top})$ where: IP_{max} = maximum surface injection pressure (psig)
PG = pressure gradient of mixed injection fluid (psig/foot)
D_{top} = depth at top of perforated interval of injection zone (feet)

and $PG = 0.2 + 0.433\ (1.04 - SG_{tag})$ where:

SG_{tag} = specific gravity of treated acid gas and it is pressure and temperature dependent. It is calculated using the measured surface conditions of 120 F and 1,437 psig and bottom hole conditions of 122 F and 3,376 psig to determine conditions in the reservoir at equilibrium (see Table 1 for details). The reservoir conditions at equilibrium are 124 F and 3,376 psig resulting in an SG_{tag} of 0.81.

For the maximum requested injection volume (7 MMSCF/Day) it is assumed that:

$$SG_{tag} = 0.81$$
$$D_{top} = 8{,}710 \text{ feet}$$

Therefore:

$$PG = 0.2 + 0.433\ (1.04 - 0.81) = 0.298$$
$$IP_{max} = PG(D_{top}) = 0.298 \times 8{,}710 = 2{,}599 \text{ psig}$$

Based on the performance of the existing injection well, it is anticipated that the average injection pressure will not exceed 2,599 psig but will be approximately 1,500 psig under normal operations. Based on the above calculations, DCP is requesting approval of a Maximum Allowable Operating Pressure (MOAP) of 2,599 psig at the surface.

Table 1: Pressure and Volume Calculations for TAG, Linam under Current Maximum Plant Capacity of 225 MMCFD and Measured Inlet Gas Concentrations

PROPOSED INJECTION STREAM CHARACTERISTICS

TAG	H_2S	CO_2	H_2S	CO_2	TAG
Gas vol MMSCFD	conc. mol %	conc. mol %	inject rate lb/day	inject rate lb/day	inject rate lb/day
7	18.4	81.6	122260	700156	822416

CONDITIONS AT WELL HEAD

Well Head Conditions		TAG							
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
120	1437	7	82:18	822416	456.66	0.46	3.81	28834	5136

CONDITIONS AT BOTTOM OF WELL

Injection Zone Conditions					TAG				
Temp F	Pressure[3] psi	$Depth_{top}$ ft	$Depth_{bottom}$ ft	Thickness[4] ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
122	3376	8710	9137	427.00	818.98	0.82	6.84	16078	2864

CONDITIONS IN RESERVOIR AT EQUILIBRIUM

Injection Reservoir Conditions					TAG				
Temp[5] F	Pressure[3] psi	Ave. Porosity[6] %	Swr	Porosity ft	Density[1] kg/m^3	SG[2]	density lb/gal	volume ft^3	volume bbl
124	3376	6.0	0.45	14.0	812.70	0.81	6.79	16202	2886

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 MAXIMUM INJECTION PRESSURE LIMITATION

SG_{TAG}	0.81
$PG = 0.2 + 0.433\,(1.04 - SG_{TAG})$	0.298 psi/ft
$IP_{max} = PG * Depth$	2599 psi

Where: SG_{TAG} is specific gravity of TAG; PG is calculated pressure gradient; and IP_{max} is calculated maximum injection pressure.

CALCULATION OF 30 YEAR AREA OF INJECTION

Cubic Feet/day (5.6146 ft^3/bbl)	16202 ft^3/day
Cubic Feet/30 years	177535382 ft^3/30 years
Area = V/Net Porosity (ft)	12638211 ft^2/30 years
Area = V/Net Porosity (ft) (43560 ft^2/acre)	290.1 acres/30 years
Radius =	2006 ft
Radius =	0.38 miles

[1] Density calculated using AQUAlibrium software
[2] Specific gravity calculated assuming a constant density for water
[3] PP is taken from well tests of Linam AGI #1
[4] Thickness is the net thinckness of the perforated intervals
[5] Reservoir temp. is extrapolated from bottomhole temp. measured in logs
[6] Porosity is estimated using geophysical logs from nearby wells

Note that total Mass of H2S remains constant -- for this reason ROE in H2S Contingency Plan Remains the Same

Calculations presented in Table 1 (incorporating the compressibility of the TAG at reservoir conditions) show that, given a more detailed calculation of well pressure over 30 years, a daily injection volume of 7 MMSCF/Day of TAG will occupy approximately 177.6 million cubic feet in the reservoir. As discussed in Section 4.3, a calculated gross net porosity of 25.6 feet in the reservoir is reduced to an effective net porosity of 14.0 feet after correcting for a residual water content of 45%. Based on a net porosity of 14.0 feet, we calculate that the 30-year injection volume will occupy approximately 290.1 acres of the reservoir, with a radius of 0.38 miles centered around the Linam AGI #1 and #2.

3.2 WELL DESIGN

The Linam AGI #2 is intended to provide redundancy in case there is ever a problem that the Linam AGI #1 has to be shut in for repairs or upgrades. Since the Linam AGI #2 will be within 250 feet of the Linam AGI #1, the depth intervals of the injection zone are anticipated to be approximately same as for the Linam AGI #1. The Final End of Well Report, DCP Midstream LP, Linam AGI #1, September 30, 2011 contains the geophysical log suite and side wall core data. It demonstrates that the Linam AGI #1 and AGI #2 will be in the same geologic environment with nearly identical formation depths and reservoir characteristics. Therefore, the Linam AGI #2 is designed to inject TAG into the Lower Bone Springs from approximately 8,710 to 9,137 feet below ground surface.

While the injected fluid will be dehydrated, the line that will convey the TAG to the well from the compression facilities will be a 3 inch steel line (304 or 316) to provide added corrosion protection. The compression facilities and associated piping and layout of H_2S alarms and other safety equipment will remain the same with the exception of additional H_2S monitors placed along the TAG line to the well and around the Linam AGI #2 wellhead. Based on this, only a minor revision of the Rule 11 Plan is required. This revision will be completed prior to placing the Linam AGI #2 into service. The schematic of the new AGI facilities and tie-in to the existing Linam Plant are shown in Figure 2, and the preliminary design for the injection well is shown in Figure 3.

The proposed well (Linam AGI #2) will be a vertical well, spudded on property leased by DCP. The well will be drilled vertically to the approved Lower Bone Springs injection zone to a final total depth of approximately 9,137 feet.

The well will have each string of the telescoping casing cemented to the surface and will include a subsurface safety valve (SSV) on the production tubing to assure that fluid cannot flow back out of the well in the event of a failure of the injection equipment. The annular space between the projection tubing and the well bore will be filled with corrosion inhibited diesel fuel as a further safety measure which is consistent with injection well designs which have been previously approved by NMOCD for acid gas injection and the updated construction of the Linam AGI #1 after the May 2012 workover. In addition, the well drilling plan and design address the lost circulation problems that were encountered while drilling the Linam AGI #1 and the presence of acid gas in the Lower Bone Springs in the vicinity of the Linam AGI #1.

Design and materials considerations include: placement of SSV and the packer, double casing through freshwater resources and shallow production zones (Dockum and Rustler Group (groundwater), Artesia Group and San Andres-Grayburg (oil and gas production)), characterization of the zone of injection, and a total depth (TD) ensuring identification of the reservoirs. Four casing strings are proposed (Figure 3):

1. Surface casing to approximately 500 feet to protect the fresh water.
2. Intermediate casing (upper) to approximately 3,200 feet to isolate the Permian Salt Units (Salado and Castile) and the productive units in the Artesia Group (Yates and Queen).
3. Intermediate casing (lower) to approximately 8,600 feet in the Grayburg to isolate all lost circulation zones and allow for well control when penetrating the lower Bone Springs reservoir.
4. Production casing extending down to the final total depth (TVD approximately 9,100 feet).
5. Corrosion resistant (CRA) joints to be placed in production casing string at the packer seating depth.
6. CRA tubing to prevent potential tubing corrosion due to TAG pressure/temperature fluctuations.
7. Corrosion resistant cement will be utilized for cementing the production casing in the stage that includes the injection zone and caprock.

A suitable drilling rig will be chosen for the job that will include a 5,000 psi blowout preventer (minimum) and choke manifold for any unforeseen pressures encountered. The borehole for the surface casing will be drilled with a 26 inch bit to a depth of approximately 500 feet, and 20 inch, 94.0 ppf, J-55, BTC casing will be installed and cemented to the surface (approximately 753 cubic feet). The upper intermediate hole will be drilled with a 17 ½ inch bit to a depth of approximately 3,200 feet. There, a 13 3/8 inch, 68.0 ppf, J55, STC intermediate casing string will be run and cemented to surface (approximately 2,386 cubic feet). The lower intermediate hole will be drilled with a 12 ¼ inch bit to a depth of approximately 8,600 feet. There, an 9 $^5/_8$ inch, 47.0 ppf, HCL-80, LTC intermediate casing string will be run and cemented to surface (approximately 2,764 cubic feet). Visual inspections of cement returns to the surface will be noted in both the conductor and surface pipe casing jobs. Casing and cement integrity will be demonstrated by pressure-testing after each cement job.

The Linam AGI #1 experienced lost mud returns at approximately 3,000 feet and at approximately 5,000 feet. It was necessary to add significant loss circulation material, increase mud weight and increase viscosity to minimize mud loss. Similar conditions will be encountered in the Linam AGI #2. In addition, the Linam AGI #1 experienced lost mud returns at approximately 5,800 feet. The drilling contractor will have LCM pills on hand and will be ready to pump to minimize lost returns and maintain circulation. H_2S and CO_2 influxes are expected in the Lower Bone Springs interval in the Linam AGI #2 based on actual experience during the completion of the Linam AGI #1. This is the reason for an additional intermediate string of casing down to just above the target injection zone. Furthermore, H_2S and CO_2 levels will be carefully monitored and mud weight will be adjusted accordingly to control the acid gas influx.

After verifying the intermediate casing (upper and lower), the well will be drilled to the projected TD of approximately 9,100 feet using an 8 ½ inch bit. All drilling fluids will be managed and contained in a closed-loop system, to be documented in an approved NMOCD C-144-CLEZ form. All drilling water will be disposed of at a permitted facility.

The proposed open hole logging suite for the TD run consists of a Dual Induction, Density-Neutron-Gamma Ray Porosity log. No additional logging or coring will be performed since the well is essentially a twin of the Linam AGI #1, which has been exhaustively logged and tested.

After the logs have been evaluated, the production casing consisting of approximately 9,100 feet of 7 inch, 26 ppf, HCL-80, Premium casing grade will be run and cemented to the surface (approximately 1,299 cubic feet of cement). A 30 foot section of Corrosion Resistant Alloy (CRA) material will be inserted into the string at the packer setting depth to provide a corrosion resistant seat for the packer later in the job. The cementing of the long string will be accomplished in two stages. The first stage will seal the annular space from total depth (approximately 9100 feet) to a level well above the CRA joint in the caprock. This stage will employ acid-resistant cement (CORROSACEM™ or equivalent). For the second stage, a DV Tool previously inserted in the casing (at approximately 5,000) feet will be used to pump the remaining cement to the surface.

Once the cement has set up, the tubing adaptor for the wellhead will be welded on the wellhead and the rig will be released. A casing integrity (pressure test) will be performed to test the casing just prior to releasing the rig. Following successful testing and release of the drilling rig, a workover rig will be used and a cement bond log will be run to ascertain the quality of the cement bond of the production casing. It is important that a good bond be established around the injection interval as well as below the CRA joint to ensure that acid gas mixed with formation water does not travel up the outside of the casing and negatively impact the integrity of the casing job.

Once the integrity of the cement job has been confirmed, the selected injection intervals will be perforated with approximately four shots per foot. At this location a total of approximately 427 feet of injection zone may be perforated. A temporary string of removable packer and tubing will be run, and injection tests (step tests) will be performed to confirm that injection pressures and volumes mirror the Linam AGI #1. Once the reservoirs have been tested, the final tubing string including a permanent packer, approximately 9,120 feet of 3 ½ inch, 6.5 ppf, L80 ULTRA FX premium thread tubing, and an SSV will be run into the well. A ¼ inch Inconel steel line will connect the SSV to a hydraulic panel at the surface.

The National Association of Corrosion Engineers (NACE) issues guidelines for metals exposed to various corrosive gases like the ones in this well. For a H_2S/CO_2 stream of acid gas that is de-watered at the surface through successive stages of compression, downhole components such as the SSV and packer need to be constructed of Inconel 925. The CRA joint will be constructed of a similar alloy from a manufacturer such as Sumitomo. A product like SM2550 (with 50% nickel content) will likely be used. The gates, bonnets and valve stems within the Christmas tree will also be nickel coated and corrosion resistant.

The rest of the Christmas tree will be outfitted with annular pressure gauges that report operating pressure conditions in real time to a gas control center located remotely from the wellhead. In the case of abnormal pressures or any other situation requiring immediate action, the acid gas injection process can be stopped at the compressor and the wellhead shut-in using a hydraulically operated wing valve on the Christmas tree. The SSV provides a redundant safety feature to shut in the well in case the wing valve does not close properly.

After the AGI well is drilled and tested (without using acid gas) to ensure that it will be able to accept the volume of injection fluid, it will be completed with the approved injection equipment for the acid gas stream. The Rule 11 Plan will be modified when the well connection design is complete and will be submitted for NMOCD review and approval prior to commencement of TAG injection into the Linam AGI #2 well. The current AGI facility at Linam operates under an approved Rule 11 Plan dated November 9, 2009. The new plan is anticipated to have an ROE essentially identical to the existing plan because the new well, the Linam AGI #2, is simply being located 250 feet to the northeast of the Linam AGI #1. There is no change in the total capacity or stream composition from what is already approved for the Linam AGI #1. The Linam AGI #1 and proposed Linam AGI #2 will operate as redundant injection points to the NMOCC-approved Lower Bone Springs injection reservoir.

4.0 REGIONAL AND LOCAL GEOLOGY AND HYDROGEOLOGY

The Linam Gas Plant is located in the NE 1/4 of Section 6, T 19 S, R 37 E, in Lea County, New Mexico. This Section (4.0) is based on the collection and analysis of data generated in the design and installation of Linam AGI #1. Linam AGI #2 will be located approximately 250 feet northeast of the Linam AGI #1(Figure 1). The regional and local geology and hydrogeology are not expected to be significantly different within this short distance.

4.1 GENERAL GEOLOGIC SETTING

The Linam AGI #1 and proposed Linam AGI #2 are located on the north end of the Central Basin Platform, a buried structural high in the Permian Basin (Figure 4). The persistent relief of this platform throughout the deposition of Permian sediments in the larger basin greatly influenced the stratigraphy and local structure of the surrounding formations. Originally overlain by Ordovician and Mississippian deposits, the platform was draped by younger Pennsylvanian and Permian rocks, and was faulted along generally northwest-southeast and northeast-southwest normal faults. These faults continued to grow during lower (Wolfcamp and Leonardian) time, before being buried by the younger Guadeloupian and Ochoan series.

4.2 BEDROCK GEOLOGY

The Bone Springs Group (Leonardian) was deposited in this area along relatively steep slopes of the northern end of the Central Platform, and consists of relatively porous and permeable clastic carbonates, commonly in the form of debris fans from the adjacent, shallow-water Abo Reef (Figure 4).

As seen in Figure 5, the Abo Reef closely parallels the trend of the Central Platform, forming a narrow "fairway" west of the Linam Gas Plant. In contrast, the Bone Springs facies found west and north of the platform (in the Delaware Basin and the San Simon Channel) are not productive. This is due in part to the fact that the Bone Springs Formation is below the oil-water contact, easily seen in the trend of the Abo Reef play (Figure 5).

The depths to formation tops in the Linam AGI #1 and anticipated for the Linam AGI #2 are:

Table 2: Estimated Formation Tops in the Area of Proposed Linam AGI #2

Formation	Depth (feet)
Anhydrite	1,542
Salt	1,653
Salt (bottom)	2,683
Yates	2,841
7 Rivers	3,150
Queen	3,783
Grayburg	4,167
San Andres	4,655
Brushy Canyon	5,023
Glorieta	5,536
Victorio Peak	5,939
Upper Bone Springs	6,125
Abo	7,641
Lower Bone Springs	8,104
Wolfcamp	9,045
TD	9,213
From Linam AGI #1 Well Log	

4.3 LITHOLOGIC AND RESERVOIR CHARACTERISTICS OF THE LOWER BONE SPRINGS

Figure 5 also includes isopach contours on the Bone Springs. The net thickness falls to zero beneath the plant, but thickens to over 100 feet in Section 30, approximately one mile north of the plant. Note that there are two north-dropping normal faults between the plant and the target area. Seismic data indicate that these faults were active during the deposition of the Bone Springs, and enhanced the accumulation of the detrital material that formed the reservoir. There is no indication that these faults penetrate the formation overlying the Bone Springs.

A total of 19 side wall cores were collected from the Bone Springs in AGI #1. Analyses of these cores (see Final End of Well Report, DCP Midstream LLC, Linam AGI #1, September 30, 2011) show porosity ranging from 0.4 to 15.8 percent, and permeability from 0.013 to 165 milliDarcies. The lithology was primarily dolomite, locally grading into dolomitic limestone. Fossil fragments were abundant, and the major porosity was vuggy in nature, developed by diagenetic dissolution of secondary calcite.

Analyses of the geophysical logs (see Final End of Well Report, DCP Midstream LLC, Linam AGI #1, September 30, 2011) showed porosities of 2 to 10 percent in the target interval. Based on the log analyses, 8 intervals between 8,710 and 9,085 feet were perforated in the Linam AGI #1 with a total of 750 shots.

The perforated intervals total 280 feet in an overall injection reservoir that is 375 feet thick, in which an average porosity of 6 % was calculated. The gross net porosity (427 ft. x 0.06) is 25.6 feet. Correcting for a residual water ratio (Swr) of 0.45, the available net porosity is 14.0 feet.

Reservoir testing on the Linam AGI #1 included injection-falloff and step-rate tests in the Bone Springs (see Linam AGI #1 End of Well Report, DCP Midstream LLC, Linam AGI #1, September 30, 2011). The injection and fall-off test, operated and analyzed by MHA Petroleum Consultants, began with a 9.5 hour period of injecting water at 2 barrels per minute, followed by a 221 hour fall off. Pressure was continuously recorded at the surface and by a bottom-hole probe. The analysis indicated a permeability of 2220 milliDarcy-feet, and possible intersecting barriers at 1800 and 2000 feet from the well. The fall-off test analysis further concluded that the reservoir has a minimum pore volume of 47 to 55 million barrels, and that only a 1000 psig increase in the reservoir would allow over 230 million barrels of compressed TAG.

The step-rate test on the Linam AGI #1 involved pumping water into the well at rates of 1 to 9 barrels per minute, using 30-minute intervals for each step. Injection rates, surface and bottom pressures were continuously recorded. Following the final injection step, pressure was monitored for fall back. The step test final surface pressure was 3600 psig. After 25 minutes, the pressure had fallen to 589 psig and was essentially zero the following day.

The very rapid decay of well head pressure after cessation of injection in both the fall-off and step-rate tests on Linam AGI #1 indicates that the reservoir has excellent injectivity, and adequate volume for the anticipated injection volumes. As discussed above, a capacity of 230 million barrels at a reservoir pressure increase of 1000 psig would compare very favorably versus the anticipated 30-year injection volume of approximately 75 million barrels, at the surface rate of 7.0 MMSCFD.

The step test (Figure 6) shows that there was no inflection or "breakdown" in the pressure/rate curve over the range tested. The area determined by the estimated injection pressures and projected range of injection rates is well below the maximum pressure set by Order R-12546. The well has a large capacity for additional injection before reaching the allowed maximum pressure.

During the April/May 2012 workover of the Linam AGI #1, it was noted that the reservoir went on vacuum when the well was killed with brine in preparation for tubing removal. This clearly demonstrates that the injection reservoir for the Linam AGI #1 (and proposed for Linam AGI #2) is an excellent reservoir that has shown no pressure increase after three years of operation. This makes the conservative cylindrical displacement model to anticipate the effect of injection in the reservoir in Section 3.0 more likely than not to over predict the extent of the effect of injection in the reservoir.

4.4 FORMATION FLUID CHEMISTRY

In January 2008, samples of the Bone Springs formation fluid were collected from AGI #1and analyzed. The formation fluid is sodium chloride-rich brine with total dissolved solids of 73,412 milligrams per liter. A complete copy of the analyses is included in the Final End of Well Report, DCP Midstream LLC, Linam AGI #1, September 30, 2011. The formation fluid has been further impacted by the injection of acid gas via the Linam AGI #1 over the last three and one-half years. The areas at and around the wellhead will be continuously monitored for H_2S. Escape packs and 30 minute working packs will be readily available to workers in the event of an H_2S release during drilling and well completion. A wind sock will be installed and continuously monitored so that the safest evacuation route is always known. In addition, injection tubing will have a subsurface safety valve installed at approximately 250 feet and a check valve will be installed below the permanent packer.