OKLAHOMA GAS & ELECTRIC
McCLAIN FACILITY
UIC CLASS I PERMIT RENEWAL APPLICATION
ATTACHMENT D – INJECTION OPERATION AND MONITORING PLAN

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D.1 INJECTION OPERATIONS

D.1.1 Maximum Instantaneous Rate of Injection

OG&E is not requesting any changes to the current permitted rate of 530 gpm. This rate limit is supported by the modeling presented in Attachment A.

D.1.2 Average and Maximum Daily Rate and Volume of Injection

OG&E anticipates that average cumulative daily flow to the injection well will be on the order of 16,650 gallons per day based on recent well usage. This equates to an average cumulative monthly volume of 516,200 gallons (31 days per month) and an annual average cumulative volume of 6,077,850 gallons (365 days per year).

Maximum daily flow to the injection well will be on the order of 763,200 gallons per day based on the permitted injection rate of 530 gpm. This equates to an maximum cumulative monthly volume of 23,659,200 gallons (31 days per month) and an annual maximum volume of 278,568,000 gallons (365 days per year). These values are consistent with the reservoir modeling presented in Attachment A.

D.1.3 Surface Injection Pressure

The maximum allowable surface injection pressure (MASIP) is the maximum surface pressure at which an injection well is allowed to inject fluid into the subsurface. According to Oklahoma Administrative Code, Subchapter 9 – §252:652-9-1(1)(B), the maximum total pressure gradient (applied injection pressure plus fluid pressure plus allowances for friction pressure loss) shall not exceed 0.65 psi/ft of depth from ground surface to the top of the disposal zone.

$$\text{MASIP} = (\text{Depth} \times 0.65\ \text{psi/ft}) - P_{hydro} + P_{friction}$$

$P_{friction}$ = 50 psi [calculated using a friction loss (pressure drop) calculator for Newtonian fluid flow through clean 6 5/8-inch tubing (ID = 5.761 inches) at 530 gpm]

$$\text{MASIP} = (4{,}566\ \text{ft.} \times 0.65\ \text{psi/ft}) - 2{,}018\ \text{psi} + 50\ \text{psi}$$

$$\text{MASIP} = 1{,}000\ \text{psi}$$

The MASIP allowed by Oklahoma Department of Environmental Quality (ODEQ) regulations (1,000 psi) is less than the calculated pressure required to fracture the formation from the surface (1,388 psi) (see Attachment A). Therefore, a maximum allowable surface injection pressure of 1,000 psi is requested for the Injection Well WDW1, per Oklahoma Administrative Code, Subchapter 9 – §252:652-9-1(1)(B).

D.1.4 Operation and Injection Procedures

OG&E operates and will continue to operate the Injection Well (WDW1) such that none of the permitted operating parameters are exceeded. Conservative Maximum Surface Injection Pressures (MASIP) have been defined in Section D.1.1.3, which ensure injection operations will not result in the fracturing of the subsurface. No injection operations will occur between the outermost casing and the USDW. Operating the well in this fashion will prevent the movement of fluids that could result in the pollution of a USDW and will prevent leaks from any of the subject injection wells into unauthorized zones.

Per 252:652-9-1(2)(a), the annulus pressure will be maintained at least 10 psi greater than the injection tubing pressure to prevent leaks from the well into unauthorized zones and to detect well malfunction.

OG&E will continually monitor operational parameters of the Injection Well and the monthly average and maximum instantaneous rates of injection, and annual and monthly volumes of injected fluids will not exceed limits specified by the ODEQ Permit. OG&E will ensure that all gauges, pressure sensing, and recording devices are tested and calibrated quarterly or as specified by the manufacturer.

Section D.6 of the application discusses the injected waste streams compatibility with the injection interval formation materials. The injected fluids with the injection interval sands have indicated that no adverse reactions with the formations, such as generating gases, have not developed over the historical operation of the wells and/or not expected. However, Lyondell has a program to ensure that the personnel that operate and maintain the Injection Well are trained in how to do so safely and within regulatory and facility requirements. The construction and operational procedures prevent potential pressure imbalances that could cause a backflow or blowout in a well.

OG&E will maintain the mechanical integrity of Injection Well while the well is in active service. Should the mechanical integrity of the Injection Well be compromised, OG&E will notify the ODEQ before commencing any workover operation. The notification will be in writing and will include plans for the proposed work. OG&E will not commence any workover procedures until approval has been issued by the ODEQ. Should it be necessary to remove the Injection Well from service for longer than two years, OG&E will notify the ODEQ in writing 30 days prior to resuming operation of the well.

D.1.4.1 Injection Wellhead Monitoring Program

OG&E monitors the injection well to ensure compliance with the provisions specified or referenced by ODEQ in the final injection permit. The injection well and surface facilities are maintained in good working order. Pressure gauges installed at the injection wellhead, on the injection tubing and on the annulus between the injection tubing and the long-string casing are maintained in good working order at all times. Continuous recording devices installed at the wellhead or surface facilities record the following data:

- Injection tubing pressures
- Injection flow rates
- Injection fluid temperatures
- Tubing—long-string casing annulus pressure

All gauges, pressure sensing devices, and recording devices are tested and calibrated at least annually. Test and calibration records are maintained at the generating facility. All instruments are housed in weatherproof enclosures. Quarterly reports are submitted in accordance with 40 CFR 146.13(c) addressing the physical and chemical characteristics of injection fluids and data from the monitoring well consistent with 40 CFR 146.13(b). Monitoring taps as required by OAC 252:652-7-1(2) are located on the wellhead adjacent to the pressure monitoring equipment as shown in Figure X-3.

Pressure falloff tests are conducted annually (or at a frequency specified by ODEQ) with results reported to the ODEQ per 40 CFR 146.13(d). The resulting bottom hole pressure will be corrected for friction loss and compared to the modeled pressure. Annulus pressure tests are conducted by ODEQ personnel semi-annually per the requirements of OAC 252:652-9-1(4). Once each five years the well is tested for mechanical integrity by conducting a differential temperature survey as required by regulations (or alternate tests as specified by ODEQ). Results of this test are submitted to the ODEQ. ODEQ will be notified in advance of/and have an opportunity to witness all upcoming testing.

Mechanical integrity testing to meet the 5-Year test requirement was conducted in May 2007 and May 2011. Each testing date included a differential temperature survey run from the surface to total depth. The differential surveys confirmed there was no evidence of vertical fluid movement out of the permitted injection interval into an underground source of drinking water through vertical channels adjacent to the wellbore. A copy of the 2007 and 2011 testing data are included as Appendix D-1 and Appendix D-2, respectively, to this attachment.

Additionally, a flowmeter survey was run in conjunction with the 2011testing operations to document the flow profile within the wellbore. A copy of the flowmeter survey data and report are included as Appendix D-3.

Results of the wellhead-monitoring program are submitted quarterly to the ODEQ. These reports contain at a minimum the following.

- Monthly average injection pressure, flow rate, injection volume, and annular pressure
- Monthly maximum and minimum injection pressure, flow rate, injection volume, and annular pressure
- Results of any waste analysis sampling conducted and copies of any well work conducted during the quarter.

D.1.4.2 Injection Well Pressure Tests

To satisfy 40 CFR §146.8(b)(2), OG&E shuts in the Injection Well semi-annually and pressurizes the annulus for two hours. Test pressure is a minimum of 300 pounds per square inch or 125 % of the highest operating annulus pressure, whichever is greater, unless otherwise specified by the ODEQ. Pressure loss or gain exceeding - 5 % or + 10 % respectively, from initial test pressure, will require additional tests and/or immediate repairs to ensure the mechanical integrity of the well. These tests are administered by the ODEQ.

D.1.4.3 Injection Well Integrity Tests

To satisfy 40 CFR §146.8(a)(2), that requires that there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore, OG&E performs a temperature survey (40 CFR §146.8(c)(1)). Temperature surveys have been conducted in 2007 (Appendix D-1), 2011 (Appendix D-2), 2016 (Appendix D-4), and 2021 (Appendix D-5). These tests confirm that there is no significant fluid movement out of the Injection Zone or into an underground source of drinking water.

D.2 AMBIENT MONITORING PROGRAM

Per the ambient monitoring requirements of OAC 252:652-7-1(4), OG&E drilled a monitoring well to monitor the lowest underground source of drinking water beneath the injection well site. The monitoring well is placed hydraulically down gradient from the injection well. Ground water from the monitoring well is analyzed for parameters specified in the permit at least once each month. The analysis and water levels shall be submitted as part of the quarterly report to the ODEQ. The construction and monitoring procedures are described in the following sections.

D.2.1 Monitoring Well Construction

OG&E received approval from ODEQ to drill a sampling well to obtain formation water samples from the lowermost USDW in response to questions raised during review of the original permit application. OG&E believed that the formation water sands at 910-feet to 960-feet were saline (total dissolved solids (TDS) greater than 10,000 mg/l) based on results of the well log review conducted during installation of the geologic test well. With this information, OG&E designed and drilled a sampling well (Sampling Well No. 1) to 1,000 feet and set casing to allow sampling of the 910 to 960-foot water sand. The results of the sampling of this water sand yielded a TDS of approximately 4,000 mg/l, which is below the 10,000 mg/l TDS limit that defines a USDW according to ODEQ regulation.

A second sampling well (Sampling Well No. 2) was designed and drilled to a total depth of 1,453 feet with casing set and cemented in place. OG&E then perforated and sampled successive potential water sands to determine the depth of the lowermost USDW. Sampling of the sand at 1,097 feet to 1,115 feet yielded a TDS below 10,000 mg/l, therefore this sand is determined to be the base of the USDW at the injection well. OG&E then received approval from ODEQ to convert Sampling Well No. 2 into the monitoring well for the facility through a minor modification of the construction permit. The original drilling and testing plan as well as complete details on the installation and sampling of each of the two sampling wells are attached as Appendix D-6 and Appendix D-7, respectively, to this attachment. Geophysical wireline logs from the drilling and installation of the two sampling wells are included as Appendix D-8.

The results of the sampling analysis are discussed in Attachment D of this Permit Application. The following section presents plans that were undertaken for completion of the monitoring well.

D.2.2 Monitoring Well Completion

The monitor well completion is shown in Figure D-1. The monitoring well is completed in a sand layer at a depth of 1,097 to 1,115 feet below ground. This sand layer is the lowermost USDW as determined from well logs gathered during the drilling of the deep test well (injection well) and the two USDW Sampling Wells. The choice of this zone as the base of the USDW was confirmed by laboratory analyses of recovered formation waters obtained from 6 sands located between 900 feet and 1,400 feet below ground.

The monitor well schematic shows casing information, casing depths, grout information, and completion details. The well is located approximately 95 feet southwest of the injection well (WDW-1), which is hydraulically down gradient of the proposed injection well. MIT is not required for monitoring wells per 40 CFR 144 and 146.

D.2.2.1Monitoring Well Completion Procedure

The following procedures were performed for the development and completion of Sampling Well No. 2 as the final monitoring well for the 1,097 to 1,115 foot sand at the OG&E facility in Newcastle, Oklahoma. These procedures included the removal of a small ring of cement located inside the casing just above the perforated zone, development of the perforated zone, installation of the sampling pump, and start-up/testing of the new monitoring well. A well schematic for the Monitoring Well is shown in Figure D-1.

1. A clean out of the small cement plug located at a depth of 1,083 feet below ground surface (bgs) was performed using brushes and other mechanical means.

2. The perforated zone (1,097 to 1,115 feet bgs) was developed by airlift and other applicable means to ensure that any potential debris, sand and silt content remaining in the casing has been removed. Due to low yield in formation at this depth, the well was repeatedly surged. Following surging, additional development using airlift or other applicable methods were performed on the well.

3. The sampling pump inlet is set at a depth of 1,090 feet bgs.

The total dissolved solids content of the samples from the 1,125-Foot Sand recovered from the Monitoring Well No. 1 are shown below.

Date of Sample	Total Dissolved Solids (mg/L)
September 17, 2001	8,530 9,410 (duplicate)
November 14, 2001	12,400
December 4, 2001	12,200 11,600 (duplicate

D.3 WASTE COMPATIBILITY AND CORROSION MONITORING

D.3.1 Well Materials Compatibility

The well materials must also be compatible with annular fluids, formation fluids, soil, and other elements of the well's environment. Most injection wells are constructed with metallic materials for structural reasons. Non-metallic materials may be used in specific areas where metals are not adequate. Corrosion of the metallic materials and/or degradation of the non-metallic materials are the chief causes of premature failure in injection wells.

D.3.1.1Types of Corrosion

Corrosion can be defined as the destruction of metal by chemical or electrochemical reaction with its environment (Larrabee, 1946). At the corroding metal surface, two types of reactions occur simultaneously: anodic reaction, in which metal atoms are dissolved to form positively-charged ions and electrons (corrosion); and cathodic reaction, where specific ions in the electrolyte (fluids such as acids, alkalis, and salt solutions) accept the electrons.

Although there are several types of corrosion, they may be grouped into two main forms: general and localized. General corrosion is the uniform or near-uniform thinning of metal. The corrosive environment penetrates the passive film over the entire surface area of the metal and the anodic and cathodic sites on the metal surface switch continuously, resulting in a relatively uniform metal loss. If the rate of general corrosion is tolerable, an adequate life span can be built into the well construction materials by adding a corrosion allowance to the design thickness. If the general corrosion rate is too high, the material should not be used.

Localized corrosion consists of several forms of attack (pitting and crevice corrosion) that can lead to failure of the equipment before the designed corrosion allowance is used up. The corrosive environment penetrates the passive film at only a few points, making them anodic in nature. This causes the rate of corrosion to be greater in some areas than others. Failure may arise from the development of a leak, from mechanical failure caused by localized thinning, or from crack formation and propagation.

Another form of corrosion that may be important in injection wells is galvanic corrosion. This occurs when two electrically dissimilar metals are in contact with one another in an electrolytic solution. The more active metal will be anodic to the other and will give up metal to the solution, thereby corroding the metal.

When non-metallic materials are exposed to a hostile environment, they may also degrade. This type of degradation is generally physiochemical rather than electrochemical in nature. The degradation of non-metallic materials may exhibit a variety of forms: blistering, crazing, swelling, softening, and de-lamination. All degradation leads to the loss of structural properties and possible failure. One method of checking the applicability of non-metallic materials is to remove samples at regular intervals during exposure and to measure the loss of mechanical properties, such as flexural strength. If the degradation is limited to an acceptable value, the material is usually considered suitable.

D.3.2 Factors Influencing Corrosiveness of Injection Well Environments

The potential for an injection well to experience corrosion depends on the materials of construction, the nature of the hydrologic and geologic environments, and the operating conditions.

Temperature and flow velocities can have a pronounced effect on corrosion. Increasing the temperature usually increases the corrosion rate (generally doubling for each additional 18°F), as do increased-flow velocities. For example, concentrated sulfuric acid is not corrosive to carbon steel at ambient temperatures because it is strongly oxidizing, therefore, causing passivation (the formation of a protective film). However, if the temperature is raised or the velocity of flow is increased, concentrated sulfuric acid becomes extremely corrosive to carbon steel since the increased temperatures cause the protective film to dissolve, and the increased velocities cause the protective film to be mechanically removed. Increasing temperature also increases the opportunity for the occurrence of localized corrosion, such as pitting or stress corrosion cracking.

Alloys which easily passivate, such as stainless steels and titanium, act in an opposite manner to carbon steel, and have better corrosion resistance under aerated (containing dissolved oxygen) or flowing conditions. They are more likely to be attacked when oxygen concentration is low, as in places of fluid stagnation such as joints or cracks.

The presence of aggressive species will alter corrosion behavior. The chloride ions, for example, may easily penetrate the passive film on stainless steel and cause deep localized pitting. Also, the presence of dissolved gases such as oxygen, carbon dioxide, hydrogen sulfide, and methane in fluids increase corrosion rates.

Since the discharge of hydrogen ions takes place in most corrosion reactions, the hydrogen ion concentration (pH) is a useful indicator of corrosiveness for certain alloy systems. Acidic (low pH) solutions are, as a general rule, more corrosive than neutral (pH 7), or alkaline (high pH) solutions. In the case of ordinary iron and steel, the dividing line between rapid corrosion in acid solutions and moderate or slow corrosion in nearly neutral or alkaline solutions occurs at a pH of about 4.5. With atmospheric metals, such as aluminum and zinc, highly alkaline (high pH) solutions may be more corrosive than acid solutions.

The synergistic effect of corrosive mixtures must also be considered. Combinations of chemicals, which alone are relatively non-corrosive, may be extremely aggressive towards specific alloys. For example, injection streams containing dilute nitric acid or dilute flowing sodium chloride are usually not corrosive towards stainless steel. However, if the two streams are combined, severe pitting of stainless steel may result.

To summarize, a variety of factors will affect the corrosiveness of an injection well environment. These include the characteristics of the alloy, the presence of aggressive species, the pH, the temperature, and velocity or turbulence of the flowing streams. It is also important to know whether chemical combinations present in the injection stream increase or decrease corrosion.

D.3.2.1 Corrosion Detection and Measurement

Tubing and casing materials should be compatible with the injection operation, as well as the fluids to be injected, and the environment in which the well is constructed. To determine proper construction materials, it may be desirable to test the corrosiveness of the injection fluid in the laboratory. Despite the consideration given to corrosion control during well design, there is often a need to recognize corrosive environments during well construction and to detect and measure corrosion during injection operations. Before initiating a corrosion-prevention program, it is necessary to determine if corrosion will occur, the cause of corrosion, and the rate and severity of corrosion. To determine the effectiveness of a corrosion-prevention program, the rate and effects of corrosion should be measured before and after application of preventative measures.

There are five commonly used methods to detect and measure corrosion. The most common is the use of weight-loss coupons. By inserting a sample of the material with a known weight into the injection stream for a defined period of time, corrosion rates may be determined.

Other methods include the use of corrosion loops, which are smaller diameter pipes installed parallel to the injection tubing, which may be valved off and removed for inspection. Electrical resistance probes that measure changes in the resistance of a metal as it corrodes, polarization resistance probes, caliper surveys, and other well logging methods may also be used for corrosion detection and measurement.

D.3.2.2Corrosion Control

Corrosion can be minimized by the application of a number of different design considerations and operating techniques. The use of construction materials known to be resistant to the potentially corrosive environment is effective (Driscoll, 1986). The corrosive environment, as well as the physical requirements of the system, affects the choice of metals. Carbon steels are resistant to sulfide cracking, while stainless steel alloys or titanium are more suitable to acidic environments.

Altering the environment can make appreciable differences in the corrosion of metals. Changes in the oxygen concentration, temperature, velocity, and pH of the injection or annular fluids can help reduce corrosion.

The application of nonmetallic corrosion-resistant materials to well construction is limited to certain types of plastics. Other nonmetallic materials do not possess the characteristics necessary for injection tubing. The most extensively used nonmetallic tubular goods are constructed from fiberglass reinforced with epoxy resins. The material is highly resistant to corrosive fluids. It also affords good resistance to attack by corrosive acids and alkalis, although it has a relatively poor resistance to attack by organic solvents and dissolved chlorine. Polyvinyl chloride (PVC) and other plastic pipe also offer this corrosion-resistant capability, but have lower strength and temperature ratings.

Protective coatings that separate the tubing from the corrosive environment and cathodic protection (connecting a metal lower in the galvanic series electrically to the metal to be protected) are other corrosion-prevention measures. Operational measures such as de-gasification and/or neutralization of the injection stream or the addition of corrosion inhibitors and bactericides also protect the construction materials from corrosion.

D.3.2.3Corrosion and Injection Fluids

EPA conducted an inventory of Class I waste wells in the United States. The data collected have provided a database for determining the composition of the most generally injected waste fluids. For most Class I injection wells, pH neutralizers, cathodic, and protective coatings are probably the most effective methods for preventing corrosion.

The effluent stream is mostly water with a few dissolved metals and organics present in low concentrations. The pH of the effluent is within the neutral range and is only mildly corrosive to carbon steel. Therefore, carbon steel is an appropriate material for construction of the well.

D.3.3 Corrosion Monitoring

Corrosion monitoring of well materials is conducted annually. Test materials are constructed of the same material as used in the wellhead, injection tubing, packer, and protection casing.. The test materials have been carefully prepared, weighed, and are exposed continuously to the effluent fluids with the exception of when the well is taken out of service.

The test materials are periodically removed from the system samples and sent to a certified laboratory for analysis. After removal from the system, the materials are examined, cleaned, and reweighed. The corrosivity and fouling characteristics of the effluent are determined form the difference in weight, the depth, and distribution of pits, and the weight and characteristics of the foreign matter on the coupons.

Corrosion analysis results from the 20 years of injection services demonstrate the compatibility of the well materials with the plant effluent. No significant corrosion of the well materials has been recorded.

D.4 WASTE CHARACTERISTICS DESCRIPTION

The effluent stream for injection comes from the cooling tower reject water system at the OG&E McClain Energy Facility. Table D-1 provides ranges of values from recent quarterly sampling of the waste stream for the required parameters listed in the UIC permit. The samples are obtained from a sampling port immediately downstream of the injection pumps.

TABLE D-1

Waste Stream Quarterly Samples

Specific Gravity	0.9991 – 1.0056
Total Dissolved Solids	3,660 – 4,500 mg/l
Total Suspended Solids	10.0 – 52.0 mg/l
Conductivity	4940 – 6520 umhos/cm
Lead	Less than detection limit

D.4.1 Waste Stream pH and Maximum Specific Gravity

The pH of the effluent stream typically neutral ranges from 6.9 to 7.2 standard units. The specific gravity of the effluent stream is expected to be, on average, 1.00. However, to be conservative, a maximum specific gravity limitation of 1.05 is requested in this permit application and has been used in the applicable engineering analysis.

D.5 WASTE ANALYSIS PLAN

The effluent for the OG&E injection facility is non-hazardous. Table D-2 lists the waste analysis plan for testing the injection stream, per 40 CFR 146.68(a). These tests characterize the effluent for various chemical constituents and physical properties. Test results are submitted in accordance with 40 CFR 146.13(c).

TABLE D-2

Waste Analysis Plan

Sampling Location	Sampling Method	Frequency	Parameter

TABLE D-2

Waste Analysis Plan

Sampling Location	Sampling Method	Frequency	Parameter
	Probe	Continuous	pH
	Grab	Monthly	Specific Gravity
	Grab	Monthly	Total Dissolved Solids
	Grab	Monthly	Total Suspended Solids
	Grab	Monthly	Specific Conductance
	Grab	Monthly	Lead

D.6 WASTE COMPATIBILITY WITH FORMATION AND FORMATION FLUID

The injection stream has been evaluated and compared to the makeup of the Pawhuska Formation and the native Pawhuska formation fluid. This analysis has determined that the proposed injectate is compatible with the formation and the formation fluid. Mr. Dan Anderson (chemist with CH2M Hill) prepared the following analysis of the interaction of the injection fluid with the formation fluid in the original permit application:

> *The analytical data for the effluent stream demonstrate that the water samples will be acceptable for injection. The water buffering capacity will resist any significant pH changes; consequently, the sample pH should remain neutral (i.e., pH 6-8). The inorganic analytes (e.g., calcium, sodium, etc) will be stable in this neutral solution and no precipitates are expected. Injection of this waste stream into the Pawhuska Formation waters will not cause any reactions that could cause precipitates to form.*

OMNI Labs reviewed the potential for injection fluid to react with the Pawhuska Formation or the confining zone materials. OMNI conducted a scanning electron microscope study of the core samples to determine the type and amount of clays in the formations. Clays which might react with the injection fluid were a concern due to the potential for clay swelling and reduced injection. The clays in the Pawhuska were determined to be non-reactive and there is no concerns for reaction with the injection fluid. Long-term operability of the well with minimal interventions or stimulations demonstrates the macro-compatibility of the injection operations on the subsurface.

REFERENCES

Driscoll, F. G. *Groundwater and Wells*. 2nd ed. Johnson Division, St. Paul, Minnesota. 1986. Pp. 58-665.

Larrabee, C. P. *Effect of Composition and Environment on Corrosion of Iron and Steel: Corrosion of Metals*. 1946. Pp. 30-50.