Pre-Operational Testing and Logging Plan

1.0 FACILITY INFORMATION

Facility Information

Facility name: NBU CCS Site

- NBU- CCS #1
- NBU- CCS #2

Facility contact: Ronald T. Evans, tevans@capturepointllc.com
1101 Central Expy S, Suite 150, Allen TX 75013
832-300-8225

Well location: Osage County, Oklahoma

- NBU- CCS #1: 36.8292741/ -96.7251231
- NBU- CCS #2: 36.8228557/ -96.7251776

1.1 INTRODCUTION

The testing activities at the NBU CCS site described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the "*Testing and Monitoring Plan*" (Module E), along with other non-well related pre-injection baseline activities such as geochemical monitoring.

CapturePoint Solutions, LLC plans to deepen an existing well (NBU 2212A), collect core, acquire fluid samples and run log suites. The purpose of this test well is to better characterize the local geology and provide data for areas with uncertainties.

Site specific information will also be collected during the drilling and installation of the injection wells. CapturePoint Solutions, LLC has designed this project using a total of 2 injection wells and one injection zone. Both injection wells will follow the 40 CFR 146.87(a), (b), (c), and (d) standards for logging and testing requirements. Coring will be developed based upon well spatial variability, core recovery, and core quality as each well is drilled. All wells will demonstrate mechanical integrity prior to authorization to inject. The data acquisition obtained in this plan will be used to update and validate the "*Area of Review and Corrective Action Plan*" (Module B), to define and reduce uncertainties with the site characterization, revise the "*Testing and Monitoring Plan*" (Module E), and determine final operational procedures and limits.

This Pre-Operational Logging and Testing strategy has been developed based upon the needs and requirements for the Injection Wells (Section 2.0) and for the in-zone monitoring well (Section 3.0).

2.0 INJECTION WELLS – TESTING STRATEGY

The following tests and logs will be conducted during drilling, casing installation, and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the "*Project Information Narrative*" (Module A). Borehole diagrams for the injection wells are detailed in the Project Information Tracking Narrative, "*Well Construction Plan*" (Module A).

A schedule of testing operations will be submitted to the UIC Director 30 days prior to commencing the operations. The UIC director will be provided the opportunity to witness all operations for the Injection Wells per the 40 CFR 146.87(f) standard.

2.1 DEVIATION CHECKS

Two injection wells will be drilled at the NBU site. There will be two pads spaced approximately 2,200 feet apart with one well located on each pad. The wells are planned to be installed as vertical completions. Deviation measurements will be collected at sufficiently frequent intervals during the drilling to develop robust deviation surveys.

2.2 LOGGING PROGRAM

The logging program will cover open hole and cased hole for all drilling stages of the injection wells. The logging program will meet all requirements set forth by the EPA Class VI standards and will be used to determine in-situ formation properties such as: thickness, porosity, permeability, lithology, formation fluid salinity and reservoir pressure [per 40 CFR 146.87].

A detailed mud logging program will be developed based upon the target depths for each injection well. Cuttings will be caught from surface to total depth, with increased interval samples through the proposed injection intervals. Gas sampling will also be employed and correlated across the cuttings and drilling for onsite analysis.

The following sections detail the approach for logging in the open and cased hole sections of each injection well for their corresponding completions. The injection wells have been designed with two phases: the surface and long string casings.

2.2.1 Surface String Logging Program

The surface hole will be analyzed using wireline logging techniques, with the following geophysical logs planned upon reaching casing point (~600 feet). The depth of the surface casing will be set below the lowermost freshwater zone and will be cemented to surface (Table 1).

Table 1. Well Log Details

Open Hole - 17 1/2"		
Well Log	**Measurement**	**Data Acquisition Profile**
Spontaneous Potential	Electrical Potential	Permeability and formation fluid salinity
Resistivity	Ohm-meters	Porosity, water saturation and the presence of hydrocarbons
Gamma Ray	API Units	Lithology
Open Hole Caliper	Inches	Borehole diameter and log correction. Account for washouts
Cased Hole – 9 5/8"		
Well Log	**Measurement**	**Data Acquisition Profile**

Cement Bond	Acoustic	Determine the integrity of the cement
Variable Density	Sonic	Well completion quality
Temperature	Degrees Fahrenheit	Develop temperature profile Establish Baseline

Note: Additional diagnostic logs may be run at the discretion of CapturePoint Solutions, LLC geological consultant or as directed by the authorized regulatory UIC Director.

2.2.2 Long String Logging Program

The long-string casing will be analyzed using wireline logging techniques, with the following open and cased hole geophysical logs planned upon reaching total depth (~4,430 feet): The long string casing will be cemented to surface for all Injection Wells (Table 2).

Table 2. Well Log Details

Open Hole – 12 1/4”		
Well Log	**Measurement**	**Data Acquisition Profile**
Spontaneous Potential	Electrical Potential	Permeability and formation fluid salinity
Resistivity	Ohm-meters	Porosity, water saturation and the presence of hydrocarbons
Gamma Ray	API Units	Lithology
Open Hole Caliper	Inches	Borehole diameter and log correction. Account for washouts
Density/Neutron	Porosity (Phi)	Matrix Porosity
Fracture Finder	Image Log	Formation Imaging for breakouts and fractures
Dipole Sonic	Sonic Compressional and Shear	Porosity, Mechanical Properties
NMR	Nuclear Magnetic Resonance	Fluid Properties, Porosity, Permeability
Cased Hole – 9 5/8”		
Well Log	**Measurement**	**Data Acquisition Profile**
Cement Bond	Acoustic	Determine the integrity of the cement

Variable Density	Sonic	Well completion quality
Temperature	Degrees Fahrenheit	Develop temperature profile Establish Baseline

Note: Additional diagnostic logs may be run at the discretion of CapturePoint Solutions, LLC geological consultant or as directed by the authorized regulatory UIC Director.

2.2.3 Analysis and Reporting

After the open and cased hole logging has been completed, CapturePoint Solutions, LLC will prepare an interpretation of all the reports prepared by a knowledgeable log analyst [per 40 CFR 146.87(a)]. The report will include:

- The date and time of each test, the data of wellbore completion, and the data of installation of all casings and types of cements.
- Chart (graphical) results of each log and any supplemental data.
- The name of the logging company and log analyst and information on their qualifications.
- Interpretation of the well logs by the log analyst, including any assumptions, determination of porosity, permeability, lithology, thickness, depth, and formation fluid salinity of relevant geologic formations; and
- Any changes in interpretation of site stratigraphy based on formation testing logs.

Reports will be submitted to the authorized regulatory UIC Director.

2.3 CORE PROGRAM

Petrophysics is used in building a model, which is impacted by the amount of core data that is used to correlate properties with the log results. CapturePoint Solutions, LLC has developed a coring program to meet the standards outlined in 40 CFR 146.87(b).

A detailed coring program for whole core that is to be collected from the confining and injection zones has been developed for the proposed NBU Site (**Table 3**), core will be collected from the NBU 2212A well. Whole core collected from this well will be representative of the primary confining unit and injection zone conditions within the AoR. The goal is to collect approximately 630 feet of whole core representative of the primary confining layer and the injection zone. The site characterization indicates low dip rates, no structural impacts, and no faulting.

Table 3. Coring Details

Formation	Regulatory Intervals	Core Acquisition
Upper Mississippi		3,183 – 3,273
Lower Mississippi	Confining Zone	3,329 – 3,509
Upper Arbuckle	Injection Zone	3,663 – 3,753
Middle Arbuckle	Injection Zone	3,977 – 4,67
Lower Arbuckle	Injection Zone	4,210 – 4,390

The actual core points during the drilling of the well will be made available. If insufficient formation core is recovered in any core run, the core run may be repeated at the discretion of the geological consultant, or sidewall coring may be conducted to obtain the necessary formation samples. Core depths will be adjusted relative to actual drilling depths encountered.

However, if the UIC director determines that the core recovered from these wells is not sufficiently representative or if the core recovery and quality is poor, CapturePoint Solutions, LLC will develop an additional coring contingency program.

Additionally, permeable formations above the injection zones may be sampled. This could add quantitative value to the "*Testing and Monitoring Plan*" (Module E) over the lifetime of the project. This will be determined based upon the evaluated needs of the project at the time of drilling the injection wells.

2.3.1 Analysis

Detailed core analyses will be done by a certified laboratory (to be determined) to characterize both the injection and confining zones. The samples will cover the range of rock properties found in the zones and will cover petrology and mineralogy; petrophysical properties like porosity and permeability, and capillary pressure (**Table 4**). The prescribed analysis of the collected core and fluid samples will be used to refine and enhance site characterization per 40 CFR 146.82(a). Geomechanical tests will be run on both the confining and injection zones to determine reservoir fracture gradient and pore volume compressibility.

Data acquired from the analysis will be used to reduce uncertainties within the model. The results will assist in "fine-tuning". Whole core collection in the stratigraphic test well is expected to be representative of conditions of the injection site.

Data acquired from the core results will be used to verify and "fine-tune" input parameters in the Model. Site specific information will validate caprock seal integrity and help determine facility operational procedures for injection.

At a minimum, a lithologic core description, thin sections, XRD, and XRF will be performed to reduce uncertainties that impact the depositional and flow environments. Additional special core analysis such as electrical property measurements and relative permeability measurements will be determined based upon quality of the core samples and the evaluated needs for the injection operations.

Table 4. Core Analysis Details

Parameter	Measurement	Units
Porosity	Total Porosity Diffuse Porosity	Percent
Permeability	Vertical Permeability Horizontal Permeability	mD
Relative Permeability	Relative Gas Permeability Relative Aqueous Permeability	mD
Saturation	Fluid Saturation Residual Aqueous Saturation Residual Gas Saturation	Percent
Resistivity		Ohm-meters
Compressibility	Bulk Compressibility Pore Compressibility	1/Pa
Physical Properties	Rock Strength Ductility Elastic Properties	UCS % Pa
Lithology	Description	
Rock/Soil Type	Petrology	SEM

Parameter	Measurement	Units
	Mineralogy	Thin sections
Capillary Pressure		P_c

2.3.2 Reporting

CapturePoint Solutions, LLC will submit a report prepared by a log analyst the details on the core results [per 40 CFR 146.87(b)]. It will include information on collection and testing method, specifics on the samples and calibration of instrumentation as appropriate, results in tabular or graphic form, and photographs as appropriate. The report will be submitted to the UIC Director.

2.4 FORMATION PRESSURE AND FLUID SAMPLING

Formation brines will be collected from the injection zone (Arbuckle) using a wireline reservoir sampling tool and then tested for temperature, pH, conductivity, and static fluid pressures [per 40 CFR 146.87 (c)].

Fluids will be sent to a certified laboratory (to be determined) for determination of the physical and chemical properties of the formation fluids. Drilling mud contamination will be considered but expected to be low. Results from the gathered fluid analysis will be used to assess compatibility of the injected CO_2 with the formation fluid(s).

Additionally, initial downhole pressure conditions for each injection interval will be collected during the drilling and completion of the injection wells. Measurements will be collected using wireline gauges and sensors. The collected information will be used to assess injection rates and volumes. Details of the formation tests are in **Table 8**. Pressures will be collected from each injection well for their prospective injection interval.

2.4.1 Analysis

Geochemical testing will be performed on all fluids collected from the injection interval to determine physical and chemical properties. **Table 5** shows the parameters to be employed and measured.

Table 5. Physical and Chemical Testing Parameters

Parameter	Methodology
Reservoir Pressure	Downhole gauges
Fluid Temperature	Thermocouple
pH	pH electrode
Conductivity	APHA 2510
Fracture Pressure	Step-rate test,core analysis, MDT, log analysis
Static Fluid Level	Fluid level ultrasonic transmitter

Additionally, solubility and compatibility tests will be performed for:

1. Salinity determination
2. Reduce uncertainties in the viscosity calculation
3. Compatibility of the CO_2 injectate with the formation fluids
4. Compatibility of the formation fluids with the injection well materials.

The formation fluid samples will also establish baselines for the injection interval. This initial data will be imperative for monitoring changes and integrity with the reservoirs during injection operations and for post-injection site closure.

Formation pressures recovered at this point may not be representative of static conditions, due to impacts from drilling operations. However, this will be resolved during formation testing of the intervals for each injection well following well completion and is described in Section 2.7. The initial downhole formation pressures will be representative of static (or initial) reservoir pressures, that will be used establish baseline conditions. Initial pressures will be used to monitored pressures increases over injection and post-injection operations.

2.4.2 Reporting

After the fluid samples have been collected and analyzed, a report will be prepared regarding the formation fluid sample information [per 40 CFR 146.87(b)]. The report will include:

- Type of sampling equipment used and field procedure.
- If the sample was pumped, flow rate, type of pump, location of the pump, and geochemical. modeling results indicating the likely geochemical makeup of the fluids at downhole conditions.
- Data for field measurements (pH, conductivity, temperature, pressure)
- Laboratory results, including quality assurance samples; and
- Notes on any anomalous data.

Reports will be submitted to the authorized regulatory UIC Director.

2.5 FRACTURE PRESSURE

The fracture pressure of the confining and injection zones must be determined or calculated per 40 CFR 146.87(d)(1). This information is used (along with pore pressures in the injection zone) to determine appropriate injection pressures for the wells. CapturePoint Solutions, LLC will utilize density logs run in each well to determine the vertical stress (Sv). This will be in conjunction with the fracture finder logs (image logs) that will identify any borehole breakouts or fractures.

Reservoir pressure and fracture pressure will also be determined from log and core analysis. This information will be used to verify injection rates and pressures with respect to the determined fracture pressure of the injection zone(s). Using a pressure gradient of 0.75 psi/ft and a depth of 3,400 feet, the calculated fracture pressure at the top of the Arbuckle is ~2,550 psi.

2.6 DEMONSTRTION OF INJECTION WELL MECHANICAL INTEGRITY

Below is a summary of the Mechanical Integrity Tests (MITs) to be performed on the injection wells at the NBU site, after installation and prior to commencing CO_2 injection operations. Tests conducted to ensure mechanical integrity of the wells are described in **Table 6**. The tests will include a pressure test using fluid or gas to ensure there are no leaks in the well. Additionally, a tracer survey or noise log will be run to ensure there is no movement of fluid behind pipe. The purpose of these tests is to ensure that the well's mechanical integrity is sound and that there is no migration of formation fluid along the wellbore. If a well fails to demonstrate mechanical integrity, the well will be repaired prior to advancing to the next phase of drilling and construction.

Table 6. Mechanical Integrity Testing

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT – Internal	Pressure test using liquid or gas to determine that there is no significant leak in the casing, tubing or packer	After construction
40 CFR 146.87(a)(4) **40 CFR 146.87(a)(4)**	MIT – External MIT – External	Pressure test using liquid or gas and a casing inspection log to demonstrate the internal and external mechanical integrity of the well	
40 CFR 146.87(e)(1)	Testing prior to operating	Pressure fall-off test, pump test and injectivity test to verify the hydrogeologic characteristics of the injection zone	Prior to operation

CapturePoint Solutions, LLC will notify EPA or regulatory UIC Director least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notice and the opportunity to witness the test/log shall be provided to EPA or regulatory UIC Director at least 48 hours in advance of a given test/log. The following wireline logs will be run (**Table 7**).

Table 7. Wireline Logs and Description

Test	Description
Casing Inspection Log (Internal MIT)	To detect deformation, physical wear and or corrosion
Cement Bond Log (External MIT)	To evaluate integrity of cement job between the casing and the formation
Tracer Survey (Oxygen Activation Log)	To detect the movement of fluid behind pipe
Temperature or Noise Log (External MIT)	To detect thermal anomalies that deviate from the baseline gradient

In addition to running logs, an Annulus Pressure Test (APT) will be run to verify the well integrity. The test will be run after well completion and prior to injection operations. A successful APT consists of holding a positive annulus pressure of at least 500 psig for a minimum of 60 minutes, with a loss or buildup of less than 5 percent of the starting annulus pressure. A minimum annulus differential pressure of 100 psi will be maintained throughout the test.

Pressures will be recorded on a time-drive recorder for at least 60 minutes in duration and the chart or digital printout of times and pressures will be certified as true and accurate. The pressure scale on the chart will be low enough to readily show a 5 percent change from the starting pressure. In general, the test procedure will be as follows:

1. Connect a high-resolution pressure transducer to the annulus and increase annulus pressure to at least 500 psig or 100 psi over the tubing pressure. Conduct Annulus Pressure Test (APT) by holding annular pressure a minimum of 100 psi above the well's maximum permitted surface injection pressure for a minimum of 60 minutes. A minimum annulus differential pressure of 100 psi will be maintained throughout the test.

2. At the conclusion of the APT, annular pressure will be lowered to the well's normal, safe differential pressure value and pressure recording equipment will be removed from the well system.

A successful pressure test will "PASS" if the pressure holds. **IF** the well isn't able to hold pressure for a selected time period, then the test will be considered a "FAIL" and the construction of the well may have lost its integrity. Continuous monitoring of the annulus system will be reviewed to identify if there are any data that may lead to a potential leak and assist in diagnosing potential issues with the annulus.

2.7 FORMATION TESTING

Before injection can begin, a hydrogeologic test must be done in the injection well. Potential tests are a pressure fall-off test and an injectivity test. Inputs for the test are porosity, permeability, and connectivity, which will have already been measured during the initial site characterization. After the casing is cemented and formation is perforated, a straddle packer will be set in the well within the cased hole and prior to performing the tests.

The following sections outline the potential steps associated for each test. Please note, well specific tests will be designed based upon final completion and injection interval. These will be designed and submitted to EPA or the regulatory UIC Director 30 days prior to performing the procedures.

2.7.1 Ambient Pressure Fall-off Testing

A short-term injection/fall-off test will be performed to analyze reservoir permeability, determine injection potential, and evaluate skin damage (completion efficiency) of the wellbore for each well after construction and prior to injection [per 40 CFR 146.87(e)(1)]. The initial test will provide a baseline standard for each well to measures the effects of CO_2 injection into the near wellbore.

A fall-off test is conducted by a long period of injection, followed by a long period of well shut in. Pressures are monitored prior to injection, during injection, and the observed drop of time period until the formation reaches the initial static pressures. The test will be designed in accordance with the "*USEPA Region 6 UIC Pressure Fall-off Testing Guidance* (*Third Revision – August 8, 2002*)". The wells will be shut-in for a sufficient period to allow for static conditions (*i.e* no injection prior to test). Two gauges will be installed downhole at a pre-determined depth for each injection interval to obtain the initial bottomhole pressure at static conditions.

After collection of static pressures, continuous injection will occur at a steady pre-defined rate for an acceptable duration to produce a measurable pressure transient that will produce a fall-off test for each injection interval. The gauges downhole will monitor the flowing bottomhole pressures. The well will be shut-in at the wellhead (to minimize wellbore storage effects). The pressure fall-off will be monitored until the well reaches radial flow (pressure response for the reservoir) and a final bottomhole pressure is measured. Note, no injection will occur from offset wells during the pressure fall-off tests. The injection will be isolated to the well and interval that is actively being tested.

In performing a fall-off test analysis, a series of plots and calculations will be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. It will also be used to compare formation characteristics such as transmissivity and skin factor of the near wellbore for changes over time. Skin effects due to drilling and completion (possible damage from perforation) will be assessed for the wells injectivity and potential well cleanouts in the future. These tests can also measure drops in pressure due to potential damage/leakage over time. In CO2, it is anticipated that pressure drops may indicate multiple fluid phases. The analysis will be designed to consider all parameters.

Reports will be submitted to the EPA within 30 days of the test [40 CFR 146.91 (e) and 146.91 (b)(3)].

2.7.2 Step-Rate Test

A Step-rate test will be used to determine the Maximum Surface Injection Pressure (MASIP), which should be less than (90 percent) the measured fracture closure pressure of the injection interval. A step-rate test will be developed for each well and their specific injection interval completion. Injection rates will be developed to span the initial pressures (minimum rate) and an estimated fracture pressure (maximum rate).

Fluid will be injected in steps, plotting the injection pressure versus the injection rate (unconsolidated formations may require a tubing/packer setup). Injection will be held constant for each step for equal length of time. Injection steps will be designed with a minimum of 5 steps with 20 percent rate increases. However, injection steps will be tailored to each well to optimize data collection and may result in more steps and a lower percent increase over time.

Rates and pressures will be recorded downhole and at surface. Injection rates and pressures will be plotted at the end of each step and analyzed for either a constant slope or a decrease in slope (which identifies when the formation fractures and loses the pressure held). In general, the test procedure will be as follows:

1. Shut-in well for a period such that bottom hole pressure has stabilized
2. Inject at successively higher rates. Each injection period should last for the same amount of time. Each injection rate and corresponding pressure response will be recorded using a pressure gauge at the wellhead. The recorded surface pressure readings shall be adjusted to account for friction loss.
3. Injection rates should be controlled with a constant flow regulator that has been tested prior to use
4. Flow rates should be measured with a calibrated turbine flowmeter and recorded
5. Measure bottomhole pressure with a down hole pressure bomb.
6. A plot of injection rates and corresponding stabilized pressure values are to be plotted graphically represented by a constant slope and extended to a point at which the formation fracture pressure is reached.
7. Stop injection and allow the pressure to bleed off into the injection zone and stabilize. Record the instantaneous shut-in pressure drop (ISIP). The ISIP is the minimum pressure required to hold open a fracture in the well
8. If a fracture pressure is not obtained at the maximum test injection pressure results may indicate that the formation is accepting fluids without fracturing.

Reports will be submitted to the EPA within 30 days of the test [40 CFR 146.91 (e) and 146.91 (b)(3)].

3.0 MONITORING WELL – TESTING STRATEGY

CapturePoint Solutions, LLC plans to drill an in-zone monitoring well equipped with bottom hole and surface gauges and sensors designed to simultaneously monitor pressure and temperature in the injection zone. This well will also be used to measure and verify the site characterization properties for the Confining and Injection Zones.

Although EPA does not require the same level of testing for monitoring wells, CapturePoint Solutions, LLC has developed a strategy to assist in reducing uncertainties and insufficient data and help establish baseline parameters. The following sections provide information on the logging and testing program for the in-zone monitoring well.

The test well will be designed and constructed in a manner that permits testing and the use of downhole tools and workover equipment within the well casing, that the well's mechanical integrity can be assessed. Open and cased hole logging and formation testing will occur in phases depending on the final well design.

3.1 DEVIATION CHECKS

The above-zone monitoring well will be drilled between the two proposed injection wells at of the proposed injection site. The well is planned as a vertical drilling and completion, with minimum to no deviations. Measurements will be conducted at sufficiently frequent intervals during the drilling of each phase.

An in-zone monitoring well will be drilled approximately 2 miles east of the injection site. The well is planned as a vertical drilling and completion, with minimum to no deviations. Measurements will be conducted at sufficiently frequent intervals during the drilling of each phase.

3.2 LOGGING PROGRAM

The logging program has been designed to optimize site characterization across the confining and injection zones. The logging suite is similar to those to be performed for the Injection Wells (**Section 2.2 and Table 8**) and will be comprised of a combination of the following logging run types. Note: this table is not comprehensive but is an example of logs that CapturePoint, LLC may run and is dependent on the immediate needs of the project to pursue the permit to construct for the injection wells.

Table 8. Scheduled Logging Suites

Logging Run	Logging tools	Data Acquisition
Triple Combo	Gamma Ray (GR), Caliper, Spontaneous Potential (SP), Resistivity, Density, Neutron	Correlation, Porosity, Saturations, Hole Size, Resistive Anisotropy
Dipole Sonic	Sonic compressional and shear	Porosity, Mechanical Properties
Formation Images	Formation Micro-Imager borehole images	Structure, Env. Deposition, Fractures
Magnetic Resonance	Magnetic Resonance	Porosity, free and bound fluids, Permeability
Elemental Spectroscopy	Elemental Capture Spectroscopy	Lithology
Natural Gamma Ray Spectroscopy	Spectral GR	Clay Minerals
MDT Tool	Modular formation dynamics tester	*In situ* Fracture Pressure Fluid Samples
Sidewall Cores	Sidewall Coring Tool	Porosity, Permeability
Temperature Survey	Temperature Log	Geothermal Gradient Baseline for Fluid Migration
VSP	Vertical Seismic Profile	Tie in to 2D regional profile or be used for future monitoring techniques (if applicable)
CBL/VDL, CCL	Cement Bond Log, Variable Density Log, Casing Collar Locator	Casing cement integrity

Data collected during the drilling of the well will provide additional site data for the confining and injection zones and used to update "*Area of Review and Corrective Action Plan*" contained in Module B.

3.3 CORE PROGRAM

Coring is described above in Section 2.3.

3.4 FORMATION FLUID SAMPLES

Formation fluid samples will be collected using a wireline sample chamber for each of the targeted injection zones. This procedure will occur as each well for the project is drilled.

3.5 FORMATION TESTING

Due to the design and engineering of this well, no formation testing will occur at this location.

3.6 DEMONSTRATION OF WELL MECHANICAL INTEGRITY

Below is a summary of the Mechanic Integrity Tests (MITs) to be performed to ensure mechanical integrity of the well are described in Table 9. The tests will include a pressure test using fluid or gas to ensure there are no leaks in the well. Additionally, a tracer survey or noise log will be run to ensure there is no movement of fluid behind pipe. The purpose of these tests is to ensure that the well's mechanical integrity is sound and that there is no migration of formation fluid along the wellbore. If a well fails to demonstrate mechanical integrity, the well will be repaired prior to advancing to the next phase of drilling and construction.

Table 9. Mechanical Integrity Tests

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT – Internal	Pressure test using liquid or gas to determine that there is no significant leak in the casing, tubing or packer	After construction
40 CFR 146.87(a)(4)	MIT – External	Pressure test using liquid or gas and a casing inspection log to demonstrate the internal and external mechanical integrity of the well	
40 CFR 146.87(a)(4)	MIT – External		
40 CFR 146.87(e)(1)	Testing prior to operating	Pressure fall-off test, pump test and injectivity test to verify the hydrogeologic characteristics of the injection zone	Prior to operation

The following wireline logs will be run (**Table 10**).

Table 10. Wireline Logging

Test	Description
Casing Inspection Log (Internal MIT)	To detect deformation, physical wear and or corrosion
Cement Bond Log (External MIT)	To evaluate integrity of cement job between the casing and the formation
Tracer Survey (Oxygen Activation Log)	To detect the movement of fluid behind pipe
Temperature or Noise Log (External MIT)	To detect thermal anomalies that deviate from the baseline gradient

In addition to running logs, an Annulus Pressure Test (APT) will be run to verify the monitoring well integrity. The test will be run after well completion. A successful APT consists of holding a positive annulus pressure of at least 500 psig for a minimum of 60 minutes, with a loss or buildup of less than 5 percent of the starting annulus pressure. A minimum annulus differential pressure of 100 psi will be maintained throughout the test.

Pressures will be recorded on a time-drive recorder for at least 60 minutes in duration and the chart or digital printout of times and pressures will be certified as true and accurate. The pressure scale on the chart will be low enough to readily show a 5 percent change from the starting pressure. In general, the test procedure will be as follows:

1. Connect a high-resolution pressure transducer to the annulus and increase annulus pressure to at least 500 psig or 100 psi over the tubing pressure. Conduct Annulus Pressure Test (APT) by holding annular pressure a minimum of 100 psi above the well's maximum permitted surface injection pressure for a minimum of 60 minutes. A minimum annulus differential pressure of 100 psi will be maintained throughout the test.
2. At the conclusion of the APT, annular pressure will be lowered to the well's normal, safe differential pressure value and pressure recording equipment will be removed from the well system.

A successful pressure test will "PASS" if the pressure holds. **IF** the test is nott able to hold pressure for a selected time period, then the test will be considered a "FAIL" and the construction of the well may have lost its integrity. Continuous monitoring of the annulus system will be reviewed to identify if there are any data that may lead to a potential leak and assist in diagnosing potential issues with the annulus.