CLASS VI PERMIT TESTING AND MONITORING PLAN

[40 CFR 146.90]

NATURAL STATE RENEWABLES, INC.
Nimbus ARCCS, Inc.
Ouachita County, Arkansas

Prepared By:
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1.0 FACILITY INFORMATION

Facility/project Name:	Natural State Renewables Inc. Nimbus ARCCS Inc. Class VI Injection Well Nos. 1-4
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Well Locations:	Ouachita County, Arkansas PBI [redacted]

This Testing and Monitoring Plan (TMP) describes how Natural State Renewables (NSR) Nimbus ARCCS will monitor the sequestration project pursuant to 40 CFR §146.90 at the Nimbus ARCCS site in Ouachita County, Arkansas. The monitoring data will be used to demonstrate that the injection wells are operating as expected, the carbon dioxide plume and pressure front are moving as predicted, and there is no endangerment to Underground Sources of Drinking Water (USDW). Additionally, the data will be used to validate and guide any required adjustments to the geologic and dynamic models in future re-evaluations and support a non-endangerment demonstration. The following testing and monitoring plan includes a detection plan to monitor and account for any movement of the carbon dioxide outside of the storage complex.

In accordance with 40 CFR §146.90(j), the TMP will be re-evaluated every 5 years (at a minimum), within one year of an AoR evaluation, following any significant changes to the operations, or more frequently at the direction of the Underground Injection Control (UIC) Program Director. The review process will evaluate whether the current plan will require an amendment. All amendments will be approved by the UIC Program Director and incorporated into the currently authorized operating permit.

Monitoring well locations are presented in Figure 1 and the modeling strategy with the wells are laid out in Figure 2.

Results of the testing and monitoring activities described below may also trigger responsive actions according to the Emergency and Remedial Response Plan [40 CFR 146.94(a)].

2.0 OVERALL STRATEGY AND APPROACH

This TMP is adapted for the Nimbus ARCCS site and considers the following site-specific strategy and approach:

- The design principle is risk-based and adaptive to provide the optimum monitoring results. The risk assessment will be concurrently reviewed and updated along with the regular AoR and TMP updates.
- The Injection Zones targeted for this project are made up of the Hosston, Cotton Valley (A and B) and Upper Smackover Formations. The Cotton Valley and Hosston formations are comprised of stacked packages of porous and permeable sandstone that are separated by local clay/shale baffles. The Smackover formation is comprised of an oolitic to chalky porous Limestone in the upper member and a dense argillaceous limestone and dark calcareous shale in the lower member. The four injection zones function as separate flow units.
- The delineated AoR is bound by a two sealing faults that run east-west (strike) to the project site. The two minor faults are located north and south. The faults are a dynamic barrier to flow and pressure dissipation, as discussed in the computational modeling reports (**Module B** – *"Area of Review and Corrective Action Plan"*).
- In the Ouachita County area, the multiple shallow sandstones of the Upper Cretaceous contain hydrocarbons. The proximal hydrocarbon production areas are located north, west, and south of the immediate project area. However, most of these wells are less than 3,000 feet in depth and do not penetrate the Injection Zone.
- The upper Confining Zone for the sequestration complex is comprised of the Rodessa/Pine Island/Sligo and is located between the Hosston and the Upper Cretaceous Unconformity which lies at the base of the Upper Cretaceous section. For this Class VI application, this group of strata is referred to as the Lower Cretaceous Sequence Boundary (LCSB) and this unit is of regional extent and is geologically suited to contain injected CO_2. See **Module A** – "*Project Narrative*" for additional information.

- The Tokio Formation, directly overlaying the LCSB Confining Zone, is a blanket sandstone unit. This formation in the project area is saline and serves as a buffer aquifer situated between the top of the Sequestration Complex and the USDW.
- The Wilcox Formation is defined as the lowermost USDW. It is separated from the underlying Cretaceous section by the Midway Shale, an extensive, regional shale that extends throughout the Gulf Coast area. A fluid sample prior to injection operations will be obtained from this formation to establish a geochemical baseline of the lowermost USDW. This baseline will be used against samples collected during and post operational periods. There are no known water wells or uses of the Wilcox aquifer in the area.
- As part of the site-specific TMP regional seismicity will be monitored annually using public sources for any change in occurrence or frequency of seismic events. Only if a change in frequency of seismic events occurs, will additional site-specific monitoring of local events be undertaken by NSR.
- The four proposed injection wells will create a composite carbon dioxide plume and an area of elevated pressures surrounding the injection wells. Both the carbon dioxide plume and the AoR perimeter will be reviewed throughout the lifetime of the project to account for the potential to intersect additional existing (legacy) wells. Monitoring activities will provide:
    a) validation of the magnitude and area of pressure increase during injection, and
    b) documentation of the extent of the carbon dioxide plume during injection and subsequent stabilization during the post-injection monitoring period.

2.1 IN-ZONE (IZ) MONITORING

The in-zone monitoring system is built around four Deep Monitoring (DM) wells, which will be completed into the injection zones to directly and indirectly monitor the pressure and plume front. Locations of the proposed DM wells (red circles) are presented on Figure 1 and are positioned north (up dip) of the project site. Three DM wells (DM-1, DM-2, and DM-3) are on the south side of the north fault, and DM-4 is on the north side of the fault.

2.1.1 Direct Monitoring

Nimbus DM-1, DM-2, DM-3, and DM-4 will penetrate and monitor each of the targeted intervals within Injection Zone. Permanent casing sensor array (temperature and pressure) will be installed on the protection casing string and cemented in place. Sensors will be spaced out and installed in each of the injection zones (*i.e.*, Smackover, Cotton Valley A, Cotton Valley B, Hosston). Up to 40 real-time sensors will be placed across the casing. This sensor array will collect real-time, continuous data to assess reservoir response to injection.

- Monitoring the injection wells will evaluate the plume and pressure extent within the subsurface storage intervals within the Injection Zone.
- Real-time, continuous in-zone pressure-monitoring will be performed once the wells are constructed and will record changes in the reservoir once injection commences at the Injection Wells. As shown in Figure 1, the in-zone monitoring wells will be placed in the up-dip direction near the northeastern property boundary. Initial pressures recorded, prior to injection operations, will establish static (baseline) pressure measurements.
- One in-zone monitoring well (Nimbus DM-4) will be located on the northern side of the fault to establish the sealing nature of the fault and validate the model assumptions.

The in-zone monitoring wells will provide direct measurement of the sequestered plume, when or if the sequestered carbon dioxide plume ever reaches the monitoring well location(s). Pressure and temperature will be continuously measured con-currently in all formations (at each well) using a fiber-optic monitoring array (gauges) permanently installed downhole.

Native formation fluids will be sampled from each injection zone (*i.e.*, Smackover, Cotton Valley, and the Hosston) during the drilling of Nimbus DM-1, DM-2, DM-3, and DM-4. These initial fluids samples will establish reference baseline values if fluid sampling is required.

The direct monitoring program will be enhanced with the addition of unique injection zone tracers to assess intra-zone flow communication. (See Section 9.1.1.). The selected tracers will be foreign to the system, inert, non-flammable and non-toxic, and are classified as non-dangerous goods. The targeted tracer concentration within the CO_2 stream has been designed at 10 parts per billion (ppb). This way, the provenance of a CO_2 sample can be determined. The tracers provide insight into origin (injection zone) of the sampled CO_2. The absence of a tracer in a CO_2 sample indicates the CO_2 is from outside the project injection wells.

2.1.2 Indirect Monitoring

- Indirect plume monitoring will be employed in the injection wells and in Nimbus DM-2 (directly north of the facility) to define the location, extent, and thickness of the sequestered carbon dioxide. Pulsed neutron capture logs will also be used to monitor carbon dioxide saturation in the injection wells and in Nimbus DM-2. Saturation logging in Nimbus DM-2 will help in the five-year re-evaluation of the AoR and potential amendments to the TMP.
- The areal distribution of the carbon dioxide plume in the Injection Zones will be determined using a time-lapse ray path seismic technique. Substitution of carbon dioxide for brine within sandstones and limestones at similar project depths is well documented to produce a strong change in acoustic impedance (Vasco et al., 2019). Leading-edge techniques for time-lapse imaging of carbon dioxide plumes were developed during implementation of the Regional DOE Partnership projects include time-lapse vertical seismic profiling (Daley and Korneev, 2006; Gupta, et al., 2020), azimuthal vertical seismic profiling (Gordon, et al., 2016), and sparse array walk-away surveys or scalable, automated, semipermanent seismic array "SASSA" (Roach, et al., 2015; Burnison, et al., 2016; Livers, 2017; Adams, et al., 2020).

  NSR is proposing deployment of an autonomous, real-time permanent source and receiver seismic array within and beyond the expected dimensions of the carbon dioxide plume. The system will use one or more permanent surface sources and an autonomous receiver array with the receivers emplaced underground. The receivers will be used to monitor ray paths that will allow for dense sampling over time. System flexibility allows for sensors and/or source geometry to be optimally redeployed further away from the injection wells as the plume gets larger. Baseline and subsequent time-lapse surveys will be processed using a technique that will resolve the differences between the surveys, which will be mapped to show the change in plume extent over time. The seismic array will monitor a grid of several 10's of different X, Y locations, resembling a grid of 'pseudo-monitoring well locations' in the form of a single seismic trace per X,Y location repeated over time, aimed at detecting the moment a plume reaches an X,Y location.

2.2 ABOVE CONFINING ZONE (ACZ) MONITORING

ACZ monitoring will occur in a shallow well drilled and completed in the basal Tokio Formation and referred to as the Nimbus SM-1 well. The well will be drilled and completed into the Tokio Formation, which is the first permeable layer overlaying the LCSB Confining Zone. Nimbus SM-1 will be located on the well pad with the four Injection Wells, near the point of injection, where elevated formation pressure would be the greatest.

- The ACZ monitoring will utilize wireline deployed sensors located in the tubing string to continuously monitor downhole pressure/temperature. Formation fluid samples will be taken during well construction (including testing for dissolved gases) for baseline characterization purposes for the Tokio formation. Once the well is installed, baseline sampling of the fluids will be sampled on a quarterly basis before injection operations commence.
- Following initiation of injection, fluid sampling in Nimbus SM-1 will continue on a quarterly cycle for three years, to determine if there are any changes in water quality and composition, as well as test for the presence of an injected tracer. After the initial three years of testing, frequency will decrease to an annual fluid sample.
- A baseline (static) pressure and initial temperature will be measured at time of well construction.
- Pressure and temperature trends will be continuously monitored and averaged over 30-day periods. Major deviations from the trends will trigger fluid sampling in Nimbus SM-1. Since unique tracers will be used for each Injection Zone, the fluid samples will be tested for the presence or absence of the tracer and to compare the sampled geochemical analysis to the baseline. Sampling will occur weekly for 30 days.
- If sampling after 30 days determines that there is no presence of CO_2 or tracer associated with the CO_2 stream, operations will continue as normal, and pressure and temperature trends will be re-valuated and potentially redefined. Sampling will return to an annual frequency.
- If the presence of CO_2 is determined, by detection of tracer, operations at the facility will immediately cease and follow the protocol in *"E.4 – Emergency and Remedial Response Plan"* of this application. This would also trigger fluid sampling of the lowermost USDW

(Wilcox Formation) to determine the extent of the vertical leakage for presence or absence of tracers.

2.3 UNDERGROUND SOURCES OF DRINKING WATER (USDW) MONITORING

The lowermost USDW is located with the Wilcox Formation, directly overlying the regionally extensive Midway Shale. Approximate depth to the lowermost USDW at the project site is approximately 850 ft, with the site-specific depth confirmed with the drilling of the injection and SM-1 wells at the project site. Three water supply wells will be drilled at the Nimbus ARCCS site at time of construction. These wells will be drilled down into the USDW and be used as sampling points for the TMP. Well locations will be within the facility boundaries and specific locations will be determined from the facility construction plans. Initial fluid samples (baselines) will be collected at time of the water well construction. Fluid samples will be collected quarterly prior to injection operations at the facility, quarterly for the first 3 years of injection, and then revert to annual sampling thereafter. These wells will also be sampled if tracers or the presence of CO_2 is determined from sampling in SM-1.

2.4 SAMPLES AND DATA COLLECTION

NSR will sample and record injection and monitoring operations using a SCADA distributive control system (or similar). Operations will be monitored in a central control room and data will be recorded in real time. An archiver may be used to reduce the data stream size for long term data storage. To ensure that permit limits are not exceeded, the distributive control system will consist of safe-set controls and alarms that are set to a value safely below the permitted regulatory requirement. All gauges and equipment related to injection and monitoring operations will be calibrated to each manufacturer's specifications and the calibration records will be maintained at the facility.

2.5 REPORTING PROCEDURES

NSR will report the results of all testing and monitoring activities to the UIC Program Director in compliance with the requirements under 40 CFR §146.91. The following Table 1 is an overview of the monitoring and reporting frequency program discussed within this plan.

Table 1: Testing and Monitoring Reporting Overview

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
Carbon Dioxide Stream Analysis [40 CFR §146.90(a)]		
Chemical and physical composition of CO_2 Stream	Compositional analysis of the injected CO_2 stream using non-destructive chromatographic detector	Quarterly or as process changes or additional sources are included in the injection stream. Semi-annual reporting.
Continuous Recording of Operational Procedures [40 CFR §146.88(e)(1), §146.89(b), and §146.90(b)]		
Injection Parameter Monitoring	Pressure and temperature gauge, mass flow meter with alarms for measurements outside of the normal operating conditions	Continuous monitoring. Summary monthly statistics prepared. Semi-annual reporting.
Annulus Pressure Monitoring	Annulus pressure gauge	
	Annular Fluid Volume Measurements	
Corrosion Monitoring [40 CFR §146.90(c)]		
Coupon Testing	Flow-through corrosion coupon using injection well construction materials. Utilize corrosion inhibitors in all fluids during well workovers.	Quarterly analysis during injection operations. Additionally, as new sources added to stream. Semi-annual reporting.
Above Confining Zone Monitoring [40 CFR §146.90(d)]		
Nimbus SM-1 *(Tokio Formation)*	Downhole temperature and pressure	Continuous real time temperature and pressure monitoring for all phases of the project. Semi-annual reporting.

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
	Fluid analyses from the Tokio.	Pre-injection: Quarterly. Injection: Quarterly for initial 3 years of injection. After 3 years, annual frequency, unless triggered by a pressure or temperature event Post-Injection: Annually, unless triggered by a pressure or temperature event
USDW Monitoring [40 CFR §146.90(d)]		
Water Supply Wells (Wilcox Formation)	Fluid analyses from the Wilcox	Baseline: Quarterly Injection: Quarterly for initial 3 years of injection. After, annual frequency, unless triggered by the presence of CO_2 in the SM-1 fluid sample. Post-Injection: Annually; unless triggered by the presence of CO_2 in the SM-1 fluid sample.
External Mechanical Integrity [40 CFR §146.90(e)]		
Well Integrity	Temperature Survey and/or Noise Survey, annual external mechanical integrity test	At least annually After well workover operations that change well configuration. Report submitted within 30 days of test completion.
Pressure Falloff Test [40 CFR §146.90(f)]		
Reservoir transmissivity and pressure.	Pressure Falloff Test	Baseline: test after injection well completion. Every 5 years thereafter. Report submitted within 30 days of test completion.
CO_2 Pressure and Plume Front [40 CFR §146.90(g)]		
Nimbus ARCCS injection well One IZ monitoring well(s)	Direct Pressure Monitoring	Continuous

Parameters Monitored	Monitoring Program	Monitoring & Reporting Frequency [a]
Injection wells Pulsed Neutron Logging. Repeat Seismic	Indirect Monitoring	A base line pulsed neutron and every 5 years thereafter. Seismic via permanently installed array.

[a] *Data archiver may be used to reduce data streams.*

2.6 QUALITY ASSURANCE PROCEDURES

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 40 CFR §146.90(k), is provided in Appendix 1 – Quality Assurance and Surveillance Plan (QASP) to this TMP.

3.0 CARBON DIOXIDE STREAM ANALYSIS

NSR will analyze the composite carbon dioxide stream during the operational period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR §146.90(a). A baseline sample of the carbon dioxide stream will be evaluated and tested prior to initiation of injection operations at the facility.

3.1 CARBON DIOXIDE SAMPLING LOCATION AND FREQUENCY

The injected carbon dioxide will be continuously monitored at the surface for pressure, temperature, and flow volumes. Sampling will be performed upstream or downstream of the flowmeter to analyze the gas composition. Sampling procedures will follow protocols to ensure the sample is representative of the injected carbon dioxide stream.

The frequency of carbon dioxide sampling will be conducted on a quarterly basis commencing with the initiation of injection operations. This equates to a schedule as follows:

1. Sample No. 1: 3 months after start of injection
2. Sample No. 2: 6 months after start of injection
3. Sample No. 3: 9 months after start of injection
4. Sample No. 4: 12 months after start of injection

The schedule will then repeat using this quarterly sample cycle. When known changes to the injected stream occur (*i.e.*, source changes and/or additions/deletions to the existing stream), sampling will also be performed for verification of the chemical and physical properties of the modified stream. This will determine if there are changes to the stream that need to be accounted and tested to update and compare to the baseline conditions. The proposed sample frequency is sufficient to characterize the carbon dioxide stream and account for any potential changes to representative data.

Density measurements will be performed at the mass flow meter. The isotopic composition of carbon in CO_2 will be measured for baseline and fingerprinting of the injected stream. This will also be measured again if new sources are added to the stream.

3.2 CARBON DIOXIDE ANALYTICAL PARAMETERS

NSR will contract a Vendor to analyze the carbon dioxide for the constituents identified in Table 2 using the methods listed (or equivalent). If the constituents are not found in initial analysis or are screened out at the source prior to injection, this will be documented and with the prior approval of the UIC Program Director, they will be removed from the list of analytical parameters.

Table 2: Summary of potential analytical parameters for CO_2 stream

Parameter	Analytical Method(s)[1]
Carbon Dioxide (CO_2)	ISBT[2] 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
Oxygen (O_2)	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen (N_2)	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide (CO)	ISBT 5.0 Colorimetric, ISBT 4.0 (GC/DID)
Hydrogen Sulfide (H_2S)	ISBT 14.0 (GC/SCD)
Nitrogen Oxides (NOx)	ISBT 7.0 Colormetric
Sulfur dioxide (SO_2)	ISBT 14.1 (GC/FID)
Methane (CH_4)	ISBT 10.1 (GC/FID)

Parameter	**Analytical Method(s)**[1]
Total hydrocarbons (C_2H_6, C_3H_8+)	ISBT 10.0 THA (FID)
Hydrogen (H_2)	ISBT 4.0 (GC/DID) GC/TCD
Carbon Isotopes (δ13C and 14C of CO_2)	Measured once and when a significant new source is added. Used for attribution during monitoring
Surface Pressure	Permanent Surface Gauge
Surface Temperature	Permanent Surface Gauge

[1] An equivalent method may be employed with the prior approval of the UIC Program Director, such as ASTM Standards

[2] International Society of Beverage Technologists (ISBT) Carbon Dioxide Guidelines MBAA TQ vol. 39, no. 1, 2002, pp. 32-35 as cited in ISO/TR 27921: 2020(en). Carbon dioxide capture, transportation, and geological storage — Cross Cutting Issues — CO_2 stream composition

3.3 CARBON DIOXIDE SAMPLING METHODS

The sampling will be performed from a tap located upstream or downstream of the flowmeter and will follow protocols to ensure the sample is representative of the injected carbon dioxide stream. Sample collection procedures will be provided in detail by a certified laboratory Vendor, who will be determined prior to injection authorization. Sampling methods and equipment will meet the standards and limits provided within the attached QASP (Appendix 1).

3.4 CARBON DIOXIDE ANALYSIS PROCEDURES AND CHAIN OF CUSTODY

Samples will be analyzed by an accredited laboratory or the International Organization for Standardization (ISO) using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Detection limits will be dependent on equipment facilitated for the analytical methods by the selected qualified Vendor. However, all Vendors will meet the minimum levels set forth in the QASP (Appendix 1).

The sample chain-of-custody procedures will be dependent on Vendor selection as they will assume custody of the samples. The procedures will document and track the sample transfer to laboratory, to the analyst, to testing, to storage and to disposal (at a minimum). A sample chain of custody procedures is contained in the QASP (Appendix 1).

4.0 CONTINUOUS RECORDING OF OPERATIONAL PROCEDURES

NSR will install and use continuous recording devices to monitor injection pressure, injection rate (mass flow), and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the carbon dioxide stream, as required at 40 CFR §146.88(e)(1), §146.89(b), and §146.90(b).

Injection rates and pressures will be monitored such that they do not exceed the values set by the permit. All aspects of the injection process will be monitored, recorded, and if necessary, shut down in the event the normal operating range is exceeded. Surface pressure and temperature will be measured continuously. The injected volume will be determined from a mass flow meter for each well that will be installed on the injection supply line.

4.1 MONITORING LOCATION AND FREQUENCY

NSR will perform the activities identified in Table 3 to monitor operational parameters and verify internal mechanical integrity of the injection wells. All monitoring will take place at the locations and frequencies shown below.

Table 3: Sampling devices, locations, and frequencies for continuous monitoring

Parameter	Device(s)	Location	Min. Sampling[1] Frequency	Min. Recording[2] Frequency
Injection Pressure (surface)	Pressure Gauge	Wellhead/Flowline	1 minute	30 minutes
Injection Pressure (downhole)	Quartz Pressure Gauge	Above injection packer	1 minute	30 minutes
Injection Rate	Mass Flow Meter/Computer	Flowline	1 minute	30 minutes
Injection Volume	Mass Flow Meter/Computer	Flowline	1 minute	30 minutes
Annulus pressure	Pressure Gauge	Wellhead	1 minute	30 minutes
Annulus fluid volume	Fluid Level Measure	Annulus Tank	1 minute	Daily
CO_2 stream temperature	Mass Flow Meter/Computer	Wellhead/Flowline	1 minute	30 minutes

Parameter	Device(s)	Location	Min. Sampling[1] Frequency	Min. Recording[2] Frequency
Downhole Temperature	Temperature Gauge	Above injection packer	1 minute	30 minutes
Deployed on Injection Wells				
Changes in *Rayleigh* scattering resulting from distributed strain indicative of wave arrival	optical fiber	Installed on outside of casing or tubing	As designed for acoustic survey	As designed for acoustic survey
Changes in *Rayleigh* scattering indicates temperature change	optical fiber	Installed on outside of casing or tubing	Hourly	Daily

[1] Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. for example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.

[2] Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). for example, the data from the injection pressure transducer might be recorded to a hard drive once every minute. Note: A data archiver may be used to reduce data stream size for long term storage.

Continuously recorded injection parameters will be reviewed and interpreted on a regular basis, to evaluate the injection stream parameters against permit requirements. Trend analysis will also help evaluate the performance (*e.g.,* drift) of the instruments, suggesting the need for maintenance or calibration.

Basic calibration standards, precision, formulas, conversion factors, and tolerances for measuring devices and analysis are included in the QASP (Appendix 1) but will be dependent on specific qualified Vendor selection. Calibrations will be per manufacturers specifications and frequency.

4.2 MONITORING DETAILS

For each of the parameters that are required to be continuously monitored, such as injection pressure, injection rate, injection volume, annular pressure, annulus fluid volume, and carbon dioxide stream temperature, these will be monitored and recorded using a SCADA distributive control system (DCS) or similar. Results of the monitoring activities will be submitted to the UIC Program Director in a semi-annual report for each of the following parameters:

- Monthly average, maximum, and minimum values for injection pressure, flow rate, and volume [40 CFR §146.91(a)(2)].
- Monthly average, maximum, and minimum values for annulus pressure, in compliance with 40 CFR §146.91(a)(2).
- A description of any event that exceeds operating parameters for annular pressure or injection pressure specified in the permit, in compliance with 40 CFR §146.91(a)(3).
- A description of any event that triggers a shut-off device required pursuant to 40 CFR §146.88(e) and the response taken.
- The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and volume injected cumulatively over the life of the project [40 CFR §146.91(a)(5)].
- Monthly annulus fluid volume added or gained [40 CFR §146.91(a)(6)].

Automatic alarm and automatic shutoff systems will be designed and installed to trigger an audible alarm in the event that pressures, flow rates, or other parameters, designated by the Executive Director, exceed the normal operating range specified in the injection permit per 40 CFR §146.88(e)(2). If an alarm or shutdown is triggered, NSR will immediately investigate and identify the cause of the alarm or shutoff (Please see the "*E.4-Emergency and Remedial Response Plan"* [40 CFR §146.94 (a)] submitted in Module E for details).

4.2.1 Injection Rate, Volume, and Pressure Monitoring

Injection rates, volumes, and pressures will be set and limited to safe operating values below those specified in the authorized permit. All gauges, pressure sensing devices, and recording devices will be tested and calibrated as specified by the manufacturer. Test and calibration records will be maintained at the facility. All instruments will be housed in weatherproof enclosures, where appropriate, to limit damage from outside elements and events. The flow meters and pressure gauges will continuously record data that will be sent to a distributive control system.

Downhole flowing pressures into the reservoir will be monitored by a gauge installed near the perforations in the injection well, above the injection packer. Gauges will be referenced to ground level at each well. Downhole pressure monitoring will protect the Injection Zone against over-injection as the carbon dioxide becomes denser. If a retrievable gauge is used, pressure gauge(s) will be periodically calibrated according to the manufacturer's instructions and corrected for drift.

If permanent unretrievable downhole gauges are used, those gauges will be calibrated by comparison to a wireline deployed gauge and run to the same depth during mechanical integrity testing events. Static gradient stops will be made with the wireline deployed gauge to verify fluid column density for pressure to depth corrections. Downhole pressure gauge data will provide real-time information for verification of model predictions and AoR reevaluations.

4.2.2 Annulus System Monitoring

NSR plans to maintain pressure on the annulus that exceeds the operating injection pressure. This applied annulus pressure is currently anticipated to be set at a minimum of 100 psig over injection pressure. If the annulus pressure exceeds fracture pressure, NSR will contact the UIC Program Director for approval to reduce annular pressure to protect well integrity. The purpose of the annulus system is to maintain a positive pressure on the tubing through the casing annulus. This will limit fluid movement from the tubing out into the casing which will prevent contamination of freshwater sands in the event of well casing or injection tubing failure. During the project's construction phase, direct and indirect measurements of the Confining Zone's fracture pressure will be determined. The maximum allowable injection pressure and subsequent annulus pressure will be determined from the data acquired at this time.

The integrity of the well's annulus system is achieved by monitoring the annulus system at the wellhead. Annulus monitoring equipment used for the injection wells includes an annulus tank, an annulus pump (small volume/high pressure), well flow meters, pressure monitoring cells, and pressure control valves. Alternate annulus construction may use a pressurized nitrogen system to maintain a constant pressure on the annulus. The annulus pressure will be monitored continuously. Deviations from expected changes could indicate a potential loss of mechanical integrity in the well annulus system. Observed deviations will initiate a well shutdown protocol and investigation to determine the root cause of the observed deviation. Details are contained in the "*E.4-Emergency and Remedial Response Plan*" [40 CFR §146.94(a)] of this application.

Annulus brine tank fluid levels (and volumes) will be monitored for indications of system losses/gains and recorded daily.

5.0 CORROSION MONITORING

Per the requirements of 40 CFR §146.90(c), NSR will monitor injection well materials of construction during the operational period. This will be accomplished by using corrosion coupons of well construction materials, which will be monitored for loss of mass and thickness, and will be visually inspected for evidence of cracking, pitting, and other signs of corrosion. The coupon monitoring program is described in the following sections.

5.1 MONITORING LOCATION AND FREQUENCY

Coupon samples of the well construction materials (well casing, tubing, and any other well parts in contact with carbon dioxide, such as the packer and wellhead) will be mounted in a tray located in the common flowline to the injection well, upstream of the flow distribution header. The tray of coupons will be in contact with the carbon dioxide stream during all injection operations. This will ensure that the tray location will provide representative exposure of the samples to the carbon dioxide composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal for testing.

The frequency of corrosion coupon collection and testing will be conducted on a quarterly basis per 40 CFR §146.90(c). Baseline measurements on all coupon samples will be made prior to initiation of injection of carbon dioxide. Commencing with the initiation of injection operations, the initial monitoring event will occur at the end of the first calendar quarter (even if less than 3 months). Subsequent monitoring will occur at the end of each calendar quarter. This equates to a schedule as follows:

- March 31 – End of Calendar 1st Quarter
- June 30 – End of Calendar 2nd Quarter
- September 31 – End of Calendar 3rd Quarter
- December 31 – End of Calendar 4th Quarter

The schedule will then repeat using this quarterly sample cycle for the lifetime of the injection operations. Coupon compositions and details will be specified as part of conveyance pipeline and final well design.

5.2 SAMPLE DESCRIPTION

NSR is proposing that a corrosion coupon (weight loss) technique will be used for monitoring purposes, as it is the best known and simplest of all corrosion monitoring techniques (the alternative is to use flow line loops). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (*i.e.*, at the beginning of the flow distribution header to the injection well). This will allow for monitoring at a single location for the injection well. Corrosion coupons representative of the well construction materials (Table 4) will be inspected, photographed, and weighed prior to placement into the flowline to establish a baseline. Prior to installation of the corrosion monitoring system, the following information will be recorded:

1) Coupon Serial Number.
2) Installation date.
3) Identification of the location of the Corrosion Coupon System.
4) Orientation of the coupon holder.

The coupon method involves exposing a specimen sample of material (the coupon) to a process environment for a given duration, then removing the specimen for analysis. The corrosion monitoring plan will be implemented following the initial installation of the test coupons in the flowline, as follows:

1) Consult maintenance schedule to determine when to remove test coupons from corrosion monitoring holders (coincident with end of calendar quarter).

2) Remove and inspect coupons on a calendar quarterly basis and quantitatively evaluate for corrosion according to ASTM G1 – 03 (2017) or NACE Standard RP0775-2005 Item No. 21017 standards guidelines.

3) Place coupons in proper receptacle for safe transport to measurement and weighing equipment.

4) Photograph each coupon as received. Visually inspect each corrosion coupon for any pitting, stress corrosion cracking or scale buildup. Analyze corrosion coupons by weighing each coupon (to the nearest 0.0001 gram) and measuring the length, the width, and the height of the coupon (to the nearest 0.0001 inch).

5) Record information for each coupon including the date of measurement, the coupon identity (coupon number and metal grade), and the coupon weight in grams, and include any observations of excessive weight loss or pitting, stress corrosion cracking, or scale buildup.

6) Determine if the current corrosion coupon can be returned to the monitoring test holder, if so, make a note of the coupon return; if not, make a note of the installation of a new coupon.

Table 4: List of equipment coupon with material of construction

Equipment Coupon	**Material of Construction**
Injection Wells	
Surface Piping	"As built" material in contact with CO_2
Wellhead	Chrome alloy, or "as built" trim material in contact with CO_2
Long string casing *(above injection zone)*	L-80
Long string casing *(below injection zone)*	13Cr80
Injection Tubing	13Cr80
Packer	13Cr80
Monitoring Wells	

Equipment Coupon	**Material of Construction**
Long string casing *(above injection zone)*	L-80
Long string casing *(below injection zone)*	13Cr80

Samples will be collected by trained and authorized personnel and submitted to a third-party analytical laboratory for analysis. Results of the analysis will be compared to the pre-project baseline of the coupons and measured for loss of mass and/or thickness, which would represent corrosion. The coupons will also be inspected visually for pitting and cracking that could also indicate corrosion.

Basic details regarding the laboratory analysis are explained in the attached QASP, however, specific details will be provided and updated by the selected corrosion laboratory Vendor. Results will be submitted in semi-annual reports. The UIC Program Director will independently assess the results of the corrosion monitoring program to assess the integrity of the injection well.

5.3 ALTERNATIVE TESTS

In accordance with 40 CFR §146.90, NSR may run a casing inspection log to determine the presence, or absence, of corrosion in the protection (longstring) casing whenever the tubing is pulled from the well, or at the request of the UIC Program Director. Proposed casing inspection logs may include multi-finger caliper, ultrasonic imaging, magnetic flux leakage, and electromagnetic imaging tools, as they are the industry standard for determining casing thickness and for identifying internal and external corrosion. The log will be compared to those run during the initial construction of the well (40 CFR §146.87). Additional inspection logging programs may be implemented, should the coupons show undue corrosion in excess of the design-life criteria.

Alternative testing, other than those listed above, may be conducted with the written approval of the UIC Program Director. To obtain approval for alternative testing, ahead of any proposed testing, NSR will submit a written request to the UIC Program Director setting forth the proposed test and all technical data supporting its use.

6.0 ABOVE CONFINING ZONE (ACZ) MONITORING

6.1 ACZ MONITORING – TOKIO FORMATION

NSR will monitor pressure and temperature in the first permeable layer above the Confining Zone, which is identified as the Tokio Formation. This will allow for early detection of any out-of-zone movement of either carbon dioxide or intraformational fluids above the Confining Zone. The Tokio Formation is a blanket sandstone, which is laterally extensive across the AoR. The formation will be monitored in a dedicated ACZ monitor well (Nimbus SM-1) located on the NSR property, near the Nimbus ARCCS injection wells. The well will be engineered for continuous monitoring and set up for fluid sampling.

The well will be fitted with a real-time, continuously recording downhole pressure/temperature gauge for the Tokio Formation. The gauge will be referenced to ground level. Native formation water from the Tokio Formation will be sampled initially upon well construction (including a quantification of dissolved native gases) for baseline characterization purposes. Changes in water composition are not expected; however, the Nimbus SM-1 will provide direct measurement if there is vertical leakage out of zone.

6.1.1 Monitoring Location and Frequency

Per Standard 40 CFR §146.90(d), geochemical and water quality will be monitored within the lower sandstone of the Tokio Formation. Table 5 shows the planned monitoring methods, locations, and frequencies for direct and indirect monitoring of groundwater quality and geochemistry for SM-1.

Table 5: Monitoring of groundwater in the Tokio Formation (Nimbus SM-1)

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Tokio Formation	Downhole pressure & temperature monitoring	Nimbus SM-1	Near the point of CO_2 injection	Real time daily read out.
	Baseline geochemical sampling			Baseline Sample prior to injection.
	Additional Sampling			Only if pressure or temperature event is observed
	Fluid Sampling			Pre-injection: Quarterly. Injection: Quarterly for the 1st 2 years of injection into each zone, annually thereafter; adaptive, if triggered Post-Injection: Annually; adaptive, if triggered

Baseline sampling will be performed prior to initiation of sequestration injection and sampled on a quarterly basis in the well prior to the project authorization to inject. Fluid samples will then be collected on a quarterly basis during the first 3 years of injection and then will revert to annual samples thereafter.

Modeling shows that pressure monitoring is a more robust and more diagnostic leakage detection method in deep confined saline aquifers. Under typical low flow gradients in saline formations, a carbon dioxide pressure signal is unlikely to propagate far from the leakage point and would be chemically undetectable. Leakage of brine from one formation to another is also unlikely to be chemically diagnostic. If ambient methane or carbon dioxide is present in the system, carbon dioxide may not be chemically diagnostic either.

NSR will measure bottomhole pressures and temperatures in Nimbus SM-1, which will be continuously monitored. If the long-term data exhibits trends which indicate changes in the Tokio (deviations from reference temperature or pressure), this will trigger additional fluid sample and monitoring from SM-1.

The event triggered fluid samples in SM-1 will be collected and analyzed weekly for 1 month period to establish the absence or presence of the CO_2 via geochemical analysis and/or the detection of the unique tracers that are planned to be injected along with the stream. Field sampling work will be conducted by a qualified Vendor and the selected analytical laboratory will be compliant with the Laboratory Accreditation Program.

NSR will also monitor ground water quality and geochemical changes in the Tokio Formation above during the post-operational period to meet the requirements of 40 CFR §146.90(d). Sufficient volumes will be collected to complete all the specified analyses in Table 6.

Chain-of-custody will be documented using a standardized form from the analytical laboratory and will be retained and archived to allow tracking of sample status. This will include any required duplicates collected and appropriate field and trip blanks included for quality assurance. Completing the field chain-of-custody form will be the responsibility of groundwater sampling personnel.

If pressure and sample analyses confirm potential leakage into the strata overlying the Confining Zone, then injection operations will cease and will trigger the procedures set out in the "*E.4-Emergency Remedial and Response Plan"* contained in this application. Sampling of the lowermost USDW (Wilcox Formation) will then be initiated as part of the response, to define the impact and reach of the potential leakage above the Confining Zone.

6.1.2 Analytical Procedures

Table 6: Summary of potential analytical and field parameters for the Tokio Formation (Nimbus SM-1)

Parameters	Analytical Methods
Lab Parameters	
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Cd, Co, Cr, Cu, Mn, Mo, Nim Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	EPA Method 200.8
Total and Dissolved Metals: B, Ca, Fe, K, Li, Mg, Na, Si, Sr, Ti	EPA Method 200.7
Anions: Br, Cl, F, NO_3, and SO_4	Ion chromatography EPA Method 300.0
Alkalinity (total and bicarbonate)	Standard Method 2320B
Total Dissolved Solids (TDS)	EPA Method 160.1
Water density (lab)	Standard Method 2710F
pH (lab)	Standard Method 4500 H+B
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS
$\delta^{13}C$ of DIC*	GasBench/CF-IRMS
^{14}C of DIC*	AMS
Dissolved Inorganic Carbon (DIC)	Standard Method 5310C
Dissolved Organic Carbon (DOC)	Standard Method 5310C
Dissolved CO_2	Method B - ASTM D513-06
Volatile Organic Compounds (VOC)	Method 8260D (SW-846)
$\delta^{13}C$ of dissolved methane, ethane, propane, and CO_2, $\delta^{2}H$ of methane*	High precision (offline) analysis via dual inlet IRMS
Field Parameters	
pH (field)	Standard Method 4500-H+ B-2000
Specific conductance (field)	Standard Method 2510 B
Temperature (field)	Thermistor, Standard Method 2550 B-2000
Turbidity (field)	EPA Method 180.1
Oxidation-Reduction Potential (field)	Standard Method 2580
Dissolved oxygen (field)	ASTM Method D888-09 (C)

* *Analytical parameters to be included during the baseline phase, and only as needed during* the *injection and post-injection phases of the project.*

The initial parameters identified in Table 6 may be revised to include additional components for testing, depending on the initial geochemical evaluation. When the fluid samples are collected, then they will be sent to a third-party accredited laboratory or ISO for analysis.

6.1.3 Sampling Methods

The sampling system used to sample and quantify dissolved gases and the aqueous phases in equilibrium with those gases will be supplied by a third-party Vendor (Schlumberger, Expro, or equivalent Vendor using downhole PVT sampler or equivalent tool). Bottomhole samples are preferred, however, surface samples may be used for expediency.

The sampling protocol will be similar to the following:

1) Purge the casing volume to bring fresh fluids that have not reacted with casing and tubing to the sample point within the wellbore.
2) Deploy commercial downhole sampler on slickline to collect a fluid sample at pressure and then close to retain gas phases as sample is transported to the surface.
3) Conserve gas volumes as samples are stepped to atmospheric pressure for shipping and analysis.
4) Filter and preserve samples following protocols for brine sampling.
5) All sample containers will be labeled with durable labels and indelible markings.
6) A unique sample identification number and the sampling date will be recorded on each sample container; and
7) The sample container will be sealed and sent to an authorized third-party accredited laboratory.

Repeat sampling and frequency to be determined based on results.

6.1.4 Analysis Procedures and Chain of Custody

Samples will be analyzed by a third-party accredited laboratory or ISO using standardized procedures for gas, major, minor and trace element compositions. Detection limits will be dependent on equipment used for the analytical methods by the selected qualified Vendor and meet the minimum levels set forth in the QASP.

The sample chain-of-custody procedures will be dependent on Vendor selection as they will assume custody of the samples. The procedures will document and track the sample transfer to laboratory, to the analyst, to testing, to storage, to disposal (at a minimum). A sample chain-of-custody procedure is illustrated in Appendix 1.

6.2 USDW MONITORING – WILCOX FORMATION

The primary goal of the USDW monitoring program is to confirm protection of groundwater that can potentially be used as a drinking water resource. Within the project area, this is defined as the Wilcox Formation.

6.2.1 Monitoring Location and Frequency

Three shallow water supply wells are planned for the NSR Fuels facility site. These wells will be drilled to depths of approximately 850 ft (into the Wilcox formation). Groundwater samples will be collected for water quality testing to establish baseline measurements. Table 7 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring of the Wilcox Formation.

Table 7: Monitoring of the lowermost USDW – Wilcox Formation

Target Formation	Monitoring Phase	Suggested Monitoring Location(s)	Spatial Coverage	Frequency
Wilcox Formation	Baseline	Water Supply Wells	Facility Property	Quarterly prior to injection operations
	Injection			After, annual frequency, unless triggered by the presence of CO_2 in the SM-1 fluid sample.
	Post-Injection			Annually, unless triggered by the presence of CO_2 in the SM-1 fluid sample.

USDW groundwater samples will be collected on a quarterly basis during the baseline phase prior to commencement of injection operations or for at least 1 year. During injection operations, quarterly monitoring will be conducted during the first 3 years. This equates to a schedule as follows:

- March 31 – End of Calendar 1st Quarter
- June 30 – End of Calendar 2nd Quarter
- September 31 – End of Calendar 3rd Quarter
- December 31 – End of Calendar 4th Quarter

Following the first 3 years of injection, sampling will reduce to a frequency of once a year. For post-injection closure sampling, the frequency of sampling will continue to be performed on an annual basis for a determined post-site care closure timeframe.

Additional frequency of sampling will be triggered if detection of CO_2 or a unique tracer is found during the fluid sampling of SM-1. If this were to occur, a sampling frequency schedule and plan will be developed with the EPA as part of the procedures presented in the "*E.4-Emergency Remedial and Response Plan*" contained in this application.

6.2.2 Analytical Procedures

USDW monitoring programs can entail an array of analytical components, some of which may be prone to false-positive indications of carbon dioxide leakage. These false positives often reflect the natural variability in groundwater geochemistry in space and time, which are unrelated to carbon dioxide injection and storage activities. As such, this USDW monitoring program has been designed to improve the ability to discern natural vs anthropogenic sources of carbon dioxide based on the geochemical patterns observed before, during, and after the injection operations. Table 8 identifies the parameters to be monitored and the analytical methods that NSR will use for USDW groundwater sampling and testing.

Table 8: Summary of potential analytical and field parameters for the lowermost USDW – Wilcox Formation

Parameters	Analytical Methods
Lab Parameters	
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Cd, Co, Cr, Cu, Mn, Mo, Nim Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	EPA Method 200.8
Total and Dissolved Metals: B, Ca, Fe, K, Li, Mg, Na, Si, Sr, Ti	EPA Method 200.7
Anions: Br, Cl, F, NO_3, and SO_4	Ion chromatography EPA Method 300.0
Alkalinity (total and bicarbonate)	Standard Method 2320B
Total Dissolved Solids (TDS)	EPA Method 160.1
Water density (lab)	Standard Method 2710F
pH (lab)	Standard Method 4500 H+B
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS
$\delta^{13}C$ of DIC*	GasBench/CF-IRMS
^{14}C of DIC*	AMS
Dissolved Inorganic Carbon (DIC)	Standard Method 5310C
Dissolved Organic Carbon (DOC)	Standard Method 5310C
Dissolved CO_2	Method B - ASTM D513-06
Volatile Organic Compounds (VOC)	Method 8260D (SW-846)
$\delta^{13}C$ of dissolved methane, ethane, propane, and CO_2, $\delta^{2}H$ of methane*	High precision (offline) analysis via dual inlet IRMS
Field Parameters	
pH (field)	Standard Method 4500-H+ B-2000
Specific conductance (field)	Standard Method 2510 B
Temperature (field)	Thermistor, Standard Method 2550 B-2000
Turbidity (field)	EPA Method 180.1
Oxidation-Reduction Potential (field)	Standard Method 2580
Dissolved oxygen (field)	ASTM Method D888-09 (C)

* *Analytical parameters to be included during the baseline phase, and only as needed during the injection and post-injection phases of the project.*

At the conclusion of baseline monitoring, the range of naturally occurring groundwater conditions during the baseline timeframe will be characterized, and protocols for carbon dioxide leakage detection during the injection phase (*e.g.*, the initiation of adaptive sampling when certain threshold concentrations are exceeded) will be developed. Shallow formations have natural slight variations over time due to mineralogy and movement of fluid. The samples will be analyzed for the tracers used in the CO_2 injection stream to confirm the absence or presence of the CO_2.

An anomalous detection of carbon dioxide above background levels in the USDW "does not necessarily demonstrate that USDWs have been endangered, but it may indicate that a leakage pathway or conduit exists" (EPA, 2013b). The addition of tracer to the injected CO_2 will also aid in the evaluation of whether the CO_2 is natural or part of the sequestered plume.

The elements of the USDW monitoring program may be modified throughout the baseline, injection, and post-injection operational phases of the project, as needed, and with approval of the UIC Program Director, as more data and information become available for the Nimbus ARCCS site.

6.2.3 Sampling Methods

Groundwater sampling will be conducted in general accordance with operating procedures set forth in EPA Method SESDPROC-301-R4 (EPA, 2017). Groundwater samples will be collected into appropriate lab-supplied, method-specific sample containers, properly preserved (as needed), and shipped within 24 hours of collection for laboratory analysis. Groundwater samples for the analysis of cations will be field-filtered utilizing a 0.45 µm flow-through filter cartridge and preserved using appropriate techniques. Prior to sample collection, filters will be purged with a minimum of 100 mL of well water (or more if required by the filter manufacturer). All sample containers will be labeled with durable labels and indelible markings, and a unique sample identification number and sampling date will be recorded on the sample containers.

6.2.4 Analysis Procedures and Chain of Custody

Groundwater samples will be submitted for various geochemical and isotopic analyses by a third-party accredited laboratory or ISO using standardized procedures. Detection limits will be dependent on equipment facilitated for the analytical methods by the selected qualified Vendor and meet the minimum levels set forth in Appendix 1.

The sample chain-of-custody procedures will be dependent on Vendor selection as they will assume custody of the samples. The procedures will document and track the sample transfer to laboratory, to the analyst, to testing, to storage, to disposal (at a minimum). A sample chain-of-custody procedure is contained in the attached QASP (Appendix 1). Sample chain-of-custodies will include any required duplicates collected and appropriate field and trip blanks included for quality assurance.

The initial parameters identified in Table 8 may be revised and include additional components for testing dependent on the initial geochemical evaluation.

7.0 EXTERNAL MECHANICAL INTEGRITY TESTING (MIT)

To verify external mechanical integrity of the injection wells (Nimbus INJ-1, Nimbus INJ-2, Nimbus-INJ-3 and Nimbus INJ-4), NSR will conduct the tests presented in Table 9. These tests pertain to the active injection period (e.g., 20 years), as required by 40 CFR 146.89(c) and 146.90(e). Testing will follow the frequency indicated in Table 9. A demonstration of mechanical integrity will be done at least once a year during injection operations and either an approved tracer survey or temperature/noise log.

7.1 TESTING LOCATION AND FREQUENCY

The integrity of the long-string casing, the injection tubing, and the annular seal shall be tested by means of an approved pressure test. The integrity of the bottom-hole cement may be tested by means of a temperature survey or an approved tracer survey. Alternatively, a noise log may be run in the well to demonstrate containment within the permitted Injection Zones. Pulsed neutron logging will be run to verify the mechanical integrity of the near-well area behind the casing of the injection wells.

Table 9: External Mechanical Integrity Testing – Injection Well

Test Description	Location	Frequency
Temperature/Noise Log or Tracer Survey	Injection Well	Annually
Pulsed Neutron Log	Injection Well	Once every 5 years

External Mechanical Integrity Tests (MITs) will be run after the initial construction of the well, prior to the initiation of injection operations. An initial Annulus Pressure Test (APT) will be run on the well at this time, followed by continuous monitoring of this parameter during injection (See section 4.2.2).

Annual external mechanical integrity testing will be performed within 45 days of the anniversary of the preceding year's test and the results will be submitted to the UIC Program Director within 30 days of completion. NSR will notify the UIC Program Director 30 days prior to commencing testing.

NSR shall notify the UIC Program Director in writing 30 days in advance of any well workover. Following the well workover and prior to placing the well back into service, NSR shall conduct an external MIT. The results of the external MIT shall be submitted to the UIC Program Director within 30 days of completion. If at any time, a well fails to maintain integrity, NSR will cease injection into the well and report to the UIC Program Director within 24 hours as required by 40 CFR 146.91(c)(4).

7.2 TESTING DETAILS

Prior to running an external MIT, the wellbore may be displaced with water or brine. In either case, the well will be allowed to thermally stabilize prior to all testing operations. It is recommended that the well be shut-in for 36 hours to allow temperature effects to dissipate. The external MIT logs will be run in the injection wells.

7.2.1 Temperature Survey

A baseline differential temperature survey will be run in the well after allowing the well a period of time to reach approximate static conditions. The temperature log will be one of the approved logs for detecting fluid movement outside of the well pipe. A baseline survey will be run during completion operations, which will provide an initial baseline temperature curve for future comparisons. The log will include both an absolute temperature curve and a differential temperature curve. The well should be shut-in for at least 36 hours to allow temperature stabilization of the well prior to running the temperature survey.

If a distributed temperature sensing fiber is run in the injection well, the fiber will be used for the temperature testing; otherwise, a wireline truck will be used. Wireline temperature surveys will be conducted in lieu of relying on the DTS data for the initial annual temperature surveys.

When wireline operations are conducted, the temperature will be logged from the surface down to the total depth of the well. Recommended line speed for the logging operations is 30 to 40 feet per minute. A correlation log(s) will be presented in Track 1, and the two temperature curves will be presented in Tracks 2 and 3. The temperature log tracks will be scaled to approximately 20° F per track. The differential curve will be scaled in a manner appropriate to the logging equipment design but will be sensitive enough to readily indicate temperature anomalies. In general, the procedure for wireline operations will be as follows:

1) Attach a temperature probe and casing collar locator (CCL) to the wireline.

2) After a minimum of 36 hours of well static conditions, begin the temperature survey. The tools will be lowered into the well at 30 to 40 feet/minute, recording the temperature in wellbore. The temperature survey will be run to the deepest attainable depth (top of solids fill) in the wellbore. The wireline may be flagged, if needed, to assist in depth correlation.

3) Following completion of the survey, the wireline tools will be retrieved from the wellbore.

A temperature log run will be considered successful if there are no unexplained temperature anomalies observed outside of the permitted injection zone.

If temperature anomalies are observed outside of the permitted zone, additional logging may be conducted to determine whether a loss of mechanical integrity or loss of containment has occurred. Depending on the nature of the suspected movement, radioactive tracer, noise, oxygen activation, or other logs approved by the UIC Program Director may be required to further define the nature of the fluid movement or to diagnose a potential leak.

7.2.2 Radioactive Tracer Survey

A Radioactive Tracer Survey (RTS) may be run as an alternative to a temperature survey. The tool consists of a gamma ray detector above an ejector port and one or two gamma ray detectors below the ejector port. In order to run the RTS, the wellbore annulus will need to be flushed with brine. Therefore, the test will be conducted using brine to convey the radioactive tracer material down the well. The tool will continuously record the gamma ray API units during tracer fluid injection. The upper detector will be recorded in Track 1 at a scale of 0 to 100 or 150 API units, and the lower detector(s) will be recorded in Tracks 2 and 3 at a higher (less sensitive) scale, typically 0 to 1,000 API units.

Prior to testing, an initial gamma ray baseline log will be recorded from at least 100 feet above the injection tubing packer to the total depth of the well. The initial gamma ray survey can be conducted under low flow conditions or static well conditions.

For depth correlation, a concurrent casing collar locator log will be run on the wireline tool string. Two, five (5) minute drive, statistical checks will be run prior to the ejection of tracer fluid. One of the statistical checks will be run in the confining unit immediately above the uppermost perforation in the well. The second check will be run at the depth of the Injection Zone. The baseline log and the statistical checks will be used to determine the baseline background radiation prior to the ejection of the tracer fluid.

Brine injection will be initiated or increased during testing operations. During the survey, brine injection rates will be set at the rate at which the fluid will be under laminar flow conditions, while remaining within the maximum permitted operating parameters anticipated for the well. The volume of the tracer fluid slug will be sufficient to cause a gamma curve deflection on the order of 25x background reading as the ejected slug passes the lower detector(s). This would typically be a full-scale deflection.

A constant injection (moving) survey will be run from above the packer down to the perforations to check for leaks between those two points. This survey will consist of ejecting a tracer slug above the packer, verifying the tracer slug ejection, dropping the tool down through the slug, and logging up through the slug to above where the slug was first ejected. Then, the tool will be successively dropped down through the slug again and logging will continue upward to above where the slug was encountered on the previous pass. This process will be repeated a minimum of two times, until the slug flows out into the formation. If necessary, the injection rate may be adjusted to accomplish this test.

A stationary survey will be run approximately 20 feet or less above the top of the perforated interval to check for upward fluid migration outside of the cemented casing. The flow during the stationary survey will be at sufficient rates to approximate the normal operating conditions anticipated for the well. The stationary survey procedure consists of setting the tool and logging on time drive, ejecting a slug, verifying the ejection, and waiting an appropriate amount of time to allow the slug to exit the wellbore and return through channels outside of the pipe, if present. The time spent at the station will vary but should be at least twice the time estimated to detect the tracer fluid if channeling exists, or 15 minutes, whichever is greater. If tracer fluid is detected channeling outside of the pipe at any time during the stationary survey, the survey may be stopped, and the movement of the tracer fluid will be documented by logging up on depth drive, until the tracer exits the channel. The stationary survey will be repeated at least once.

Additional stationary or moving surveys may be required, depending upon well construction, test results, or to investigate known problem conditions. At least two repeatable logs of every tracer survey, moving and stationary, should be run. On completion of the tracer surveys, a final background gamma log will be run to compare to the initial background log. In general, the test procedure will be as follows:

1) Attach radioactive tracer tools, including the casing collar locator (CCL), the gamma ray detectors, and the ejector modules to the wireline. Lower the tools into wellbore to the deepest attainable depth (top of solids fill). Record the depth of solids fill in the

well, if any. Correlate the tools to depth with the injection packer and any other cased-hole log(s) that are run in the well.

2) A baseline gamma log will be run from the deepest attainable depth to approximately 100 feet above the packer. Statistical tool checks will be conducted 10 feet above the set depth of the injection packer and approximately 15 feet above the top perforation. (*Specific depths will be identified and updated after injection well completion*).

3) With the tool set a minimum of 100 feet above the packer, start injecting brine fluid at approximately 50 gallons per minute (gpm) or the defined acceptable rate. Eject a slug of tracer material and verify ejection.

4) Lower the tool through the slug and log up through the slug. Repeat the slug-tracking sequence, following the slug down the tubing and into the Injection Zone until the slug has been dissipated.

Note: It is desired to achieve a minimum of three or more passes below the injection packer before the radioactive slug exits the perforations. Adjust or reduce injection rate, if needed, to achieve this objective.

5) Repeat Steps 3 and 4.

6) Position the RTS tool's lower detector approximately 15 feet above the top perforation. Initiate and maintain injection at approximately 250 gpm or the defined acceptable rate.

7) Eject a slug of tracer material and record on-time drive for a minimum of 15 minutes to determine if upward flow around the casing occurs.

8) Repeat Step 7.

9) Cease pumping, lower the tool to the deepest attainable depth, and run a repeat baseline gamma ray log to verify that the radiation level has returned to baseline background radiation levels.

10) Dump the remaining radioactive tracer material from the tool and pump the remaining test fluid to flush the tracer material from the wellbore.

11) Retrieve the wireline tools from the wellbore and rig down wireline unit.

A successful pressure test will "PASS" if the radioactive iodine material stays within the Injection Zone(s) and within the sequestration complex.

If the radioactive anomalies are observed outside of the permitted zones, this would represent a "Fail" of the test. This could be presented as detecting the radioactive material moving upwards of the formation. If this is encountered, the tool will be moved upwards with a time drive until the material cannot be detected anymore, to analyze the material's maximum extent of movement.

Additional logging will then be conducted to determine whether a loss of mechanical integrity or containment has occurred. Depending on the nature of the suspected movement, a temperature, oxygen activation, or other logs approved by the UIC Program Director may be required to further define the nature of the fluid movement or to diagnose a potential leak.

7.2.3 Pulsed Neutron Logging

Pulsed neutron logging will be utilized to verify the mechanical integrity of the near-wellbore area behind the casing in the injection wells. A baseline Pulse neutron logging survey will be run during completion operations to provide an initial baseline log for future comparisons. Should the downhole well completion change at any time, a new baseline log will be run. The pulsed neutron survey will be run from the Wilcox Formation below a depth of 2,400 feet below ground down to the total depth of the well and will be run in gas-sigma-hydrogen mode. The sigma measurement is used to determine porosity, differentiate between saline water and carbon dioxide, and calculate formation saturation in the Injection Zones. NSR will run the Pulsed Neutron log every 5 years throughout the life of the injection wells. The UIC Program Director may require more frequent monitoring to further define the nature of potential fluid movement along the casing-borehole wall or to diagnose potential leaks.

8.0 TRANSIENT PRESSURE FALLOFF TEST

NSR will perform pressure falloff tests during the injection phase, to meet the requirements of 40 CFR §146.90(f). Pressure falloff testing will be conducted upon the completion of the injection well to characterize the baseline formation properties and to determine the near-well reservoir conditions that may impact the injection of carbon dioxide.

8.1 FALLOFF TESTING LOCATION AND FREQUENCY

NSR will perform an initial (baseline) pressure falloff test in the injection well using either formation brine or municipal water mixed with a clay stabilizer (to avert clay swelling). This will provide the baseline characterization of the transmissibility of fluid into the Injection Zone(s). The pressure falloff test will be repeated using carbon dioxide within the first 60 days of initiation of injection operations. This will allow for a comparison to the baseline fluid-to-fluid test with the changes in the injection fluid from brine water to carbon dioxide.

A pressure falloff test will be performed at least once every five years (within +/-45 days of the anniversary of the previous test) for the lifetime of injection operations. Periodic testing is expected to provide insight into the performance of the storage complex and potentially aid in assessing the dimensions of the expanding carbon dioxide plume, based on the expected lateral change from supercritical carbon dioxide near the wellbore and native formation brine beyond the plume. The UIC Program Director may request more frequent testing, which will be dependent on test results or other variables. A final pressure falloff test will be run at the end of active injection.

8.2 FALLOFF TESTING DETAILS

Testing procedures will follow the methodology detailed in "*EPA Region 6 UIC Pressure Falloff Testing Guideline-Third Revision (August 8, 2002)"*. Bottomhole pressure measurements near the perforations are preferred due to phase changes within the column of carbon dioxide in the tubing. A surface pressure gauge may also serve as a monitoring tool for tracking the progress of the falloff test.

The pressure gauge can be either installed as part of the completion or can be deployed via a wireline truck. If a wireline truck deployed gauge will be used, the wireline should be corrosion resistant, and the deployed gauges should consist of a surface read-out gauge with a memory backup. Examples of standard gauge specifications are presented in Table 10.

Table 10: Wireline Pressure Gauge specification examples

Pressure Gauge	Property	Value
Surface Readout Pressure Gauge	Range Resolution	0 – 10, 000 psi/356 °F +/-0.01 psi/0.01 °F
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 °F)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual
Memory Pressure Gauge	Range Resolution	0 – 10, 000 psi/356 °F +/-0.01 psi/0.01 °F
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 °F)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual

The general testing procedure is as follows and presumes that a wireline truck deployed unit is used for the testing: NOTE: a dedicated downhole monitoring gauge may be used if they provide data of sufficient quality:

1) Mobilize the wireline unit to the injection well and rig up on the wellhead.
2) Rig up a wireline lubricator that contains a calibrated downhole surface-readout pressure gauge (SRO) and that has a memory gauge installed in the tool string as a backup to the adapter above the crown valve. Each gauge should have an operating range of 0 - 10,000 psi. Reference the elevation of gauge to both kelly bushing (KB) elevation and elevation above ground level.
3) Open the crown valve, record the surface injection pressure. While maintaining a constant rate of injection, run the wireline with the SRO down the well to just above the shallowest perforations in the completion. Steady rates of injection should be maintained for at least 24 hours ahead of the planned shut-in of the injection well. Any offset injection well(s) should be either shut-in ahead of the testing or should maintain

a constant rate of injection for the entire duration of the testing. This will minimize cross-well interference effects.

4) With the SRO positioned just above the perforations, monitor the bottom-hole injection pressure response for ±1 hour to allow the gauge to stabilize to wellbore temperature and pressure conditions. Ensure that the injection rate and pressure are stable.

5) Cease injection as rapidly as possible (controlled quick shut-in). Starting with the valve closest to the wellhead, close the control valve and the manual flowline valve at the well site (so that wellbore storage effect in early time is minimized, the order of closing is important). Conduct the pressure falloff test for approximately 24 hours, or until bottomhole pressures have stabilized.

6) Lock out all valves on the injection annulus pressure system to ensure that the annulus pressure cannot be changed during the falloff test period. Ensure that the valves located on the flow line to the injection well are closed and locked out to prevent flow to the well during the falloff test period.

7) After 24 hours, download the pressure data and make a preliminary field analysis of the falloff test data using computer-aided transient test software to estimate if, or when, radial flow conditions might be reached. If sufficient data acquisition is confirmed the falloff test will be terminated. If additional data is required, extend the falloff test until radial flow conditions are confirmed. After the confirmation of sufficient data acquisition, end the falloff test.

8) Pull the SRO tool up the well by 1,000 feet and stop to allow the gauge to stabilize (5 minutes each stop). Record stabilized temperature and pressure. Repeat the process to collect stabilized pressure data (5-minute stops) at 1,000-foot intervals and in the lubricator.

In performing a falloff test analysis, a series of plots and calculations will be prepared to QA/QC the test, to identify flow regimes, and to 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 well's injectivity and for potential well cleanouts in the future. These tests can also measure drops in pressure due to potential damage/leakage over time. With CO_2 injection, it is anticipated that drops in pressure may indicate multiple fluid phases. The analysis will be designed to consider all parameters.

8.3 TEST ANALYSIS AND REPORTING

In order to make the proper assessment, multi-phase flow conditions will be considered. Results of the pressure fall-off test may trigger a reevaluation of the AoR. Testing methods, results, and interpretation will be submitted electronically within 30 days of the test per 40 CFR 146.91(e) and 146.91(b)(3)

Each submission will include the following.

1) Location, test name and the date and time of the shut-in period.
2) Bottom hole pressure and temperature depths.
3) Records of gauges.
4) Raw test data in a tabular format (if required by the UIC Program Director).
5) Measured injection rates and pressure data from the test well and any off-set wells completed in the same zone and including data prior to the shut-in period.
6) Pressure gauge information (make, model, manufacturer, etc.).
7) Diagnostic curves of test results, noting any flow regimes.
8) Description of quantitative analysis of pressure-test results, type of software used and any multi-phase effects.
9) Calculated parameter values such as transmissivity, permeability, and skin factor.
10) Analysis and comparison of calculated parameter values to previous testing values.
11) Identification of data gaps if any exist; and
12) Identified necessary changes to the project and the TMP to ensure continued protection of USDWs.

Testing procedures, testing equipment, tolerances and specifications, and calibration details are included in the QASP, which is contained in Appendix 1.

9.0 CARBON DIOXIDE PLUME AND PRESSURE FRONT TRACKING

NSR will employ both direct (Table 11) and indirect (Table 12) methods to track the geometry and extent of the carbon dioxide plume with time and the areal distribution in pressures within and above the sequestration complex to meet the requirements of 40 CFR 146.90(g).

Table 11: Pressure-Front and Plume-Front Monitoring - Direct

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
PRESSURE-FRONT MONITORING-DIRECT				
Injection Zone - Hosston - Cotton Valley - Smackover	Downhole Pressure & Temperature	*Injection Wells* Nimbus INJ-1, INJ-2, INJ-3, INJ-4 *Monitor Wells* Nimbus DM-1, DM-2, DM-3, DM-4	Injection Well Field & Up dip of injection wells.	Continuous
ACZ -Tokio Formation	Downhole Pressure & Temperature	Nimbus SM-1	Near point of injection	Continuous
PLUME-FRONT MONITORING-DIRECT				
Injection Zone - Hosston - Cotton Valley - Smackover	Fluid Sampling	*Monitor Wells* Nimbus DM-1, DM-2, DM-3, DM-4	Up dip of injection wells	Injection: Quarterly for the first 3 years, annually thereafter; adaptive, if triggered Post-Injection: Annually; adaptive, if unless triggered by a pressure or temperature event

Table 12: Pressure Front and Plume Front Monitoring - Indirect

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
PRESSURE-FRONT MONITORING-INDIRECT				
Sequestration Complex	Time-lapse Seismic	Surface Array	CO_2 Plume	If applicability can be demonstrated after one year of injection: Pre-injection: At least one baseline survey Injection: Once a month or more. Post Injection: annually; adaptive if triggered
PLUME-FRONT MONITORING-INDIRECT				
Injection Zone - Hosston - Cotton Valley - Smackover	Pulsed Neutron Log	*Injection Wells* Nimbus INJ-1, INJ-2, INJ-3, INJ-4 *Monitor Wells* Nimbus DM-1, DM-2, DM-3, DM-4	Injection Well Field & Up dip of injection wells.	Every 5 years in Injection Wells. Adaptive, if pressure/temperature event is triggered at monitor well.
Sequestration Complex	Time-lapse Seismic	Surface Array	Lateral extent of the CO_2 Plume	Pre-injection: At least one baseline survey Injection: annually Post Injection: annually; adaptive if triggered

9.1 PLUME FRONT MONITORING

9.1.1 Direct Monitoring Details

The Deep Monitor wells (Nimbus DM-1, DM-2, DM-3, and DM-4) will be completed with pressure/temperature sensors cemented on the outside of the casing. Each in-zone monitor will continuously record wellhead and annulus pressure(s).

The injection zones penetrated by the deep monitor (DM) wells will not be perforated, therefore, fluid sampling in the DM wells is not planned.

The Nimbus DM-2 well is the most likely to encounter CO_2 plume extent. The DM-2 well is directly north, and up dip, from the injection site; see Figure 2 for the location of Nimbus DM-2 and other wells.

DM-1 is northwest of the site, and south of the northern fault. DM-1 will encounter the pressure front but is not expected to encounter CO_2 plume. DM-3 is northeast of the site, and south of the northern fault. DM-3 will also encounter the pressure front but is also not expected to encounter CO_2 plume.

DM-4 is due north of the site and located to the northern side of the fault. Pressure monitoring in DM-4 will confirm the sealing nature of the northern fault. Module B provides a discussion of the expected pressure and saturation response in each of the DM wells.

Although DM wells will not incorporate fluid sampling, the monitoring program will employee unique injection zone tracers. The tracers will be useful should CO_2 be detected anywhere within the AoR. The tracers are injected at the wellhead, or flow line, at each DM well and each tracer will have a distinct signature. The presence of the tracer in a CO_2 sample will help identify where the sample originated (Well and Zone). The tracers do not interact with each other and multiple tracer IDs in the same sample can be identified. The targeted tracer concentration within the CO_2 stream will be 10 parts per billion (ppb).

The tracer is inert, non-flammable and non-toxic. Hydraulic pumping systems are typically used to deliver the tracer into the flow system. Options are available for gas or electrically driven hydraulic pumps for continuous delivery or pulsed injection. Pumps will be integrated with the control DCS system and pump characteristics can be adapted to the conditions needed for each injection well.

Detection of CO_2 at surface sampling locations will utilize vapor sampling. The vapor samples are collected in activated charcoal tubes using an air sampling device that yields consistent air sample volume. The CO_2 and tracer identification rely upon thermal desorption to release the CO_2 and constituents. Gas Chromatography, coupled with Mass Spectrometry, will identify the presence of tracer. These units will be calibrated to detect 1 part per trillion of tracer material. Downhole samples taken from fluid in ACZ and USDW monitor wells will be processed to collect the liberated gas which will be collected and analyzed in a similar manner to identify the presence of CO_2 and tracer.

9.1.2 Indirect Monitoring Details

Indirect plume monitoring in the Injection Zones will include pulsed neutron capture logging to monitor the lateral and vertical saturation in carbon dioxide in the Injection Wells and in the in-zone monitor wells. The tool incorporates a pulsed neutron generator and a dual-detector spectrometry system to measure elemental concentrations, including carbon and oxygen, and the formation neutron-capture cross section (sigma) during a single trip in the well. The sigma measurement is used to determine porosity and differentiate between saline water and other fluids to calculate formation saturations. Fluid samples captured at the time of drilling monitor wells will verify brine salinity in the injection zones. However, where formation water is fresh or of unknown salinity, saturation is determined from the C/O ratio measurement, which is salinity independent. Schedule for running pulsed neutron tools in the wells is included in "*Section 7.2.3 - Pulsed Neutron Logging.*"

NSR is also considering the use of certain time-lapse seismic techniques for indirect monitoring. The displacement of brine by injected carbon dioxide within sedimentary strata at similar project depths is well documented to produce a strong negative change in acoustic impedance (Vasco et al., 2019). This change in impedance can be detected by many time-lapse seismic methods. Leading-edge techniques for time-lapse imaging of carbon dioxide plumes include time-lapse vertical seismic profiling (Daley and Korneev, 2006; Gupta, et al., 2020), azimuthal vertical seismic profiling (Gordon, et al., 2016), sparse array walk-away surveys or scalable, automated, semipermanent seismic array "SASSA" (Roach, et al., 2015; Burnison, et al., 2016; Livers, 2017; Adams, et al., 2020).

Permanent seismic monitoring techniques are robust and documented in monitoring plume growth and less invasive from a surface footprint (Harvey et al., 2021). NSR is anticipating deployment of an autonomous, real-time permanent source and receiver array within and beyond the dimensions of the carbon dioxide plume. The system will use one or more permanent surface sources and an autonomous receiver array with the receivers emplaced underground. The receivers will be to monitor ray paths that will allow for dense sampling over time. System flexibility allows for sensors and/or source geometry to be optimally redeployed further away from the injection wells as the plume gets larger. Baseline and subsequent time-lapse surveys will be processed using a technique that will resolve the differences between the surveys, which will be mapped to show the change in plume extent over time.

9.2 PRESSURE FRONT MONITORING

Quality assurance procedures for these methods are presented in Appendix 1.

Direct pressure monitoring in the Injection Zones will be used to measure the injection induced pressure buildup with time in the sequestration complex. Pressure monitoring will be conducted in each active injection well using a permanent installed cable system with up to 40 sensors (gauges) downhole, vertically across the Injection Zone. These monitor points will be used to evaluate the pressure buildup with time within the injection well field. Additionally, direct pressure and temperature monitoring will be conducted in the in-zone monitoring wells (Nimbus DM-1, DM-2, DM-3, and DM-4) located up dip of the injection wells and facility. Real-time, continuous pressure and temperature monitoring will be performed using the permanent sensor array system. The four in-zone deep monitor wells will be used to evaluate the rate and magnitude of pressure decay with distance away from the injection wells located at the Nimbus ARCCS site.

NSR is not aware of the existence of any quantitative indirect subsurface pressure measurement technologies. Large changes in pressure can sometimes be qualitatively detected using time lapse seismic (Wang and Nur, 1989). Given the subsurface pressure changes because of the CO_2 injection are relatively small, an indirect pressure response might not be observed. Nevertheless, during the first year of injection NSR will evaluate if the onsite permanent seismic CO_2 plume monitoring array can detect pressure induced reflectivity changes as well. In addition, during the first year of injection NSR will activate the array for permanent passive seismicity monitoring. At the end of the year NSR will compare in a qualitative manner the active and passive seismic observations with the direct pressure measurements in the in-zone monitoring wells and the simulation model. The results will be presented to the UIC Program Director. If a reasonable correlation can be obtained between the direct pressure measurements and seismic observations, NSR will continue the indirect pressure measurements for the remainder of the injection phase of the project in annual increments.

These measured pressures from the injection wells and the offset monitor locations will be used to assess the performance of the Injection Zone to ensure that the project is operating as permitted and will form the basis for the periodic re-evaluation of the extent of the AoR. Recorded pressures at the injection wells and at the monitor locations will be compared to model predictions to determine if actual data deviate from baseline predictions. Significant departures of actual pressure data above model predictions will be used to trigger an adaptive re-assessment of the AoR, in addition to the minimum 5-year re-assessment time frame specified for periodic review. In addition to the assessment of the AoR, real-time data from the overlying monitoring will also be re-evaluated to ensure continued containment of the injected carbon dioxide within the sequestration complex.

The locations of the Nimbus ARCCS injection wells and the in-zone monitoring wells are shown in Figure 1. The anticipated plume geometry and the AoR Pressure Front with time are presented in the "*Area of Review and Corrective Action Plan*" submitted in this application.

The downhole pressure and temperature data will be transmitted to the distributed control system for evaluation and storage. A data archiver may be used to permanently store data sets for later recovery.

10.0 SEISMICITY MONITORING

Natural seismicity in the project area is low and of low magnitude (https://earthquake.usgs.gov/earthquakes/search/).

Induced seismicity risk is also considered low. Injection rates and pressures will be maintained at 90 percent of (or less than) the fracture pressure. Previous measurements of induced seismicity in Department of Energy supported research projects along the Gulf Coast (the Mississippi Cranfield Project, for example), have not detected induced seismicity events resulting from the injection of large volumes of carbon dioxide.

No seismic events have been recorded in Ouachita County since 1900. Regional and local seismicity are discussed in the Project Narrative Report – Section 2.5 of this application.

However, as part of the monitoring program NSR will continue to check the regional and local seismicity annually for events through the United States Geological Society (USGS) National Earthquake Database. This provides data on location and depth of events in real time. NSR will search for events greater than 2.0 within a 100-mile radius (160 Km) annually. If it is found that any seismic events have occurred within Ouachita County, NSR will evaluate their location and depth.

If more than two events, with magnitudes greater than 2.5, occur within the county (during injection operations), NSR will increase the frequency of monitoring the National Earthquake database on a quarterly basis. If no events occur within 2 years, NSR will revert to an annual monitoring system basis.

Only if a seismic event with a magnitude of 2.5 or greater occurs within a two-mile radius of the injection wells, will additional site-specific monitoring of seismicity be undertaken by NSR. The planned permanent seismic CO_2 plume monitoring array can also measure passive seismicity. In the scenario of a magnitude 2.5 event, the array will be activated for a period of 2 years following the event, for permanent passive seismicity monitoring, except during periods of active seismic CO_2 plume measurements and periods of array maintenance.

Annually NSR will provide a report to the UIC Program Director detailing all events with a magnitude greater than 1.5, measured by the on-site passive seismicity monitoring. If within the 2-year period a seismic event takes place with a magnitude of 2.5 or greater within a two-mile radius of the injection wells the onsite passive seismicity monitoring will be extended by another 2 years, from the date of the occurrence of the seismic event.

11.0 APPENDIX: QUALITY ASSURANCE AND SURVEILLANCE PLAN

The Quality Assurance Plan (QASP) is in Appendix 1 of this Testing and Monitoring Plan (TMP).

12.0 REFERENCES

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