

ATTACHMENT C: TESTING AND MONITORING PLAN**Facility Information**

Facility name: One Carbon Partnership, LP
CCS1

Facility address: 1554 N. 600 E. Union City, IN 47390

Well Location: Section 17, Township 20 N, Range 15 E
40.1874°, -84.8646°

This Testing and Monitoring Plan describes how One Carbon Partnership will monitor the Project site pursuant to 40 C.F.R. § 146.90 and per Section N of this permit. One Carbon Partnership will use the monitoring data to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDWs). One Carbon Partnership will also use the monitoring data to validate and adjust the geological models used to predict the distribution of the carbon dioxide within the storage zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan in Attachment F of this permit.

Testing and Monitoring Schedule of Sampling

All testing and monitoring will be conducted in accordance with the requirements of this permit, and the procedures will adhere to the Quality Assurance and Surveillance Plan (QASP) in Attachment K.

The schedule of sampling is as follows:

1. Continuous: Data is continuously sampled and recorded per the frequencies presented in Table 2 of this attachment.
2. Quarterly: Sampling will take place within 5 days before the following dates each year: March 31st, June 30th, September 30th, December 31st.
3. Semi-annual: Sampling will take place within 5 days before June 30th and December 31st.
4. Annual: Sampling will take place within 45 days before January 1st of each year.
5. 5 Year: Sampling will take place every 5 years within 45 days before January 1st during injection and the PISC period.

Measurement, Monitoring and Verification (MMV) Technologies

Two key objectives of any risk assessment evaluation and the development of a viable MMV plan are to:

1. Ensure Conformance by demonstrating that storage performance aligns with expectations regarding injectivity, capacity, and carbon dioxide behavior inside the geologic storage reservoir.
2. Ensure Containment, which demonstrates security of carbon dioxide storage to protect human health, groundwater resources, hydrocarbon resources (if present), and the environment, and meets regulatory requirements.

Reporting procedures

One Carbon Partnership will report the results of all testing and monitoring activities to the EPA in compliance with this attachment, the requirements under 40 C.F.R. § 146.91, and Section O of this permit.

Carbon Dioxide Stream Analysis

One Carbon Partnership will analyze the carbon dioxide stream during the operation period with sufficient frequency to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 C.F.R. § 146.90(a). One Carbon Partnership will sample and analyze the carbon dioxide stream as presented below.

Analytical Parameters

One Carbon Partnership will collect samples of the CO₂ stream at quarterly intervals. Gas samples of the CO₂ stream will be obtained to analyze the components present in the injection stream. Samples of the CO₂ stream will be collected at a location in the system where the material is representative of the material injected (i.e., between the compression system and CCS1), using a ¼-inch sampling port in the flowline. Fittings will be consistent with those used by the contracted third-party laboratory who will be performing the analysis.

The CO₂ stream will flow from the flowline through an open ball valve, through a pressure reducer (regulator), and into the cylinder. The pressure regulator will reduce the pressure of the CO₂ stream to approximately 250 pound-force per square inch (psi) to ensure the CO₂ is in a gaseous state rather than a super-critical liquid.

A contracted third-party laboratory will analyze the CO₂ stream samples. The lab will specialize in gas analyses and routinely perform specialized analyses on CO₂ for industrial clients. The contracted laboratory will follow standard sample handling and chain-of custody guidance (EPA 540-R-09-03, or equivalent). The chemical composition of the CO₂ stream will be monitored downstream of the final compression unit and upstream of CCS1 (40 C.F.R. § 146.90(a)) for the following parameters:

Table 1: CO₂ Stream Analytical Parameters

Parameter	Analytical Method(s)
CO ₂ Purity	ISBT 2.0
Water (H ₂ O)	ISBT 3.0
Total Hydrocarbons as Methane	ISBT 10.0
Total Non-Methane Hydrocarbon (TNMHC)	ISBT 10.1
Carbon Monoxide (CO)	ISBT 5.0
Ammonia (NH ₃)	ISBT 6.0
Oxides of Nitrogen (NO _x)	ISBT 7.0
Nitrogen Dioxide (NO ₂)	ISBT 7.1
Nitric Oxide (NO)	ISBT 7.2
<u>Source Specific Parameters:</u>	
Hydrogen Cyanide (HCN)	ISBT 17.0
Vinyl Chloride (C ₂ H ₃ Cl)	ISBT 18.0
Phosphine (PH ₃)	ISBT 19.0
Ethylene Oxide (C ₂ H ₄ O)	ISBT 20.0

<u>Non-Condensable Gases:</u>	
Nitrogen (N ₂)	ISBT 4.0
Oxygen (O ₂)	ISBT 4.0
Argon (Ar)	ISBT 4.0
Hydrogen (H ₂)	ISBT 4.0
Helium (He)	ISBT 4.0
<u>Volatile Hydrocarbons:</u>	
	ISBT 10.1
Methane	ISBT 10.1
Ethylene	ISBT 10.1
Ethane	ISBT 10.1
Propylene	
Propane	
Isobutane	ISBT 10.1
n-Butane	ISBT 10.1
Butenes	ISBT 10.1
Isopentane	ISBT 10.1
n-Pentane	ISBT 10.1
Pentenes	ISBT 10.1
C6	ISBT 10.1
<u>Aromatic Hydrocarbons:</u>	
Benzene (AHC)	ISBT 12.0
Toluene	ISBT 12.0
Ethyl Benzene	ISBT 12.0
m+p Xylene	ISBT 12.0
o-Xylene	ISBT 12.0
<u>Volatile Sulfur Compounds:</u>	
Hydrogen Sulfide (H ₂ S)	ISBT 14.0
Carbonyl Sulfide (COS)	ISBT 14.0
Sulphur Dioxide (SO ₂)	ISBT 14.0
Methyl Mercaptan	ISBT 14.0
Ethyl Mercaptan	ISBT 14.0
Dimethyl Sulfide	ISBT 14.0
Carbon Disulfide	ISBT 14.0
i-Propyl Mercaptan	ISBT 14.0
t-Butyl Mercaptan	ISBT 14.0
n-Propyl Mercaptan	ISBT 14.0
Methyl Ethyl Sulfide	ISBT 14.0
sec-Butyl Mercaptan	ISBT 14.0
i-Butyl Mercaptan	ISBT 14.0
Dimethyl Disulfide	ISBT 14.0
n-Butyl Mercaptan	ISBT 14.0
Dimethyl Disulfide	ISBT 14.0
Other Sulfurs	ISBT 14.0
Total Sulfur Content (TSC)	ISBT 13.0
<u>Volatile Oxygenates:</u>	
Acetaldehyde (AA)	ISBT 11.0
Ethyl Oxide	ISBT 20.0

Dimethyl Ether	ISBT 11.0
Methyl Ethyl Ether	ISBT 11.0
Methanol (MeOH)	ISBT 9.0
Propionaldehyde	ISBT 11.0
Acetone	ISBT 11.0
Ethanol	ISBT 11.0
Isopropanol	ISBT 11.0
Ethyl Acetate	ISBT 11.0
t-Butanol	ISBT 11.0
n-Propanol	ISBT 11.0
2-Butanol	ISBT 11.0
Isobutanol	ISBT 11.0
n-Butanol	ISBT 11.0
Isoamyl Alcohol	ISBT 11.0
Isoamyl Acetate	ISBT 11.0

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

If at any time this monitoring reveals a substantive change from expected for the carbon dioxide stream, process troubleshooting will begin to determine the root cause of the carbon dioxide quality deviation. If carbon dioxide purity falls below 98.75%, the anomaly will be investigated and AoR re-modeling will be initiated, if appropriate.

Continuous Recording of Operational Parameters

One Carbon Partnership will install and use continuous recording devices to monitor injection pressure, mass flow rate, and volume (calculated); the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added or produced; and the temperature of the carbon dioxide stream. (40 C.F.R. §§ 146.90(b), 146.88(e)(1), and 146.89(b)).

System Operation Monitoring

One Carbon Partnership will perform the activities identified in this attachment (Testing and Monitoring Plan) and Attachment K (QASP) to continuously monitor operational parameters listed in Attachment A and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in Table 2.

Table 2: Sampling devices, locations, and frequencies for continuous monitoring

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure at Wellhead	Pressure Gauge	Wellhead	Every 10 sec.	Every 10 sec.
Injection rate	Orifice Meter	Wellhead	Every 10 sec.	Every 10 sec.
Injection Volume (calculated)	Volumetric Flow meter & Flow computer	CO ₂ Delivery Flowline	Every 10 sec.	Every 10 sec.
Annular pressure	Pressure Gauge	Wellhead	Every 10 sec.	Every 10 sec.
Annulus fluid level	Level Transmitter	Wellhead	Every 1 min.	Every 1 min.
CO ₂ stream temperature	Electronic Thermocouple	Wellhead	Every 10 sec.	Every 10 sec.

Injection pressure at Formation	Pressure Gauge	Downhole Gauge	Every 10 sec.	Every 10 sec.
Temperature at Formation	Temperature Sensor	Above Packer (Depth TBD)	Every 10 sec.	Every 10 sec.

Notes:

- 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.
- 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.

System Monitoring details

Injection operations will be monitored through a range of continuous, daily, and quarterly techniques as detailed in Attachment A. All the data recorded on a continuous basis will be connected to the main facility through a supervisory control and data acquisition (SCADA) system to record the operations data, control injection rates, or initiate system shutdown, if needed. The SCADA system can also be used to adjust the volume of annular fluid, and thereby pressure, in the annular space to meet the operational and regulatory objectives.

Continuous recording devices will monitor wellhead injection pressure, temperature, and mass flow rate (40 C.F.R. § 146.90(b)). The injection flow rate will be directly measured at the surface to calculate the cumulative mass of injected CO₂ and ensure compliance with the permit injection limits. The injection volume will be calculated using the mass flow rate combined with the pressure and temperature conditions in the injection zone. The calculated injection volumes will, in turn, be used to update the computational models at regular intervals throughout the injection phase of the project as detailed in Attachment B.

The annular pressure between the tubing and the injection casing strings as well as the annular fluid volumes will also be monitored on a continuous basis (40 C.F.R. § 146.90(b)). The volume of the annulus fluid between the injection tubing and the long-string casing will be measured using the accumulator levels and the brine reservoir level on the well control system. The accumulator and brine reservoir levels will be measured using a level transmitter. The transmitters will be connected to the well control system and to the SCADA system. A significant change in the fluid volume in the accumulator or brine reservoir (i.e., fluid is being pumped from the reservoir to the annulus or fluid being pushed out of the annular space) during routine injection operations may be an indication of well integrity problems, as the fluid volumes would normally remain relatively constant, and will require further investigation.

Pressure differential between the annulus and the tubing at the depth of the packer will be calculated by the operator.

Injection Rate and Pressure Monitoring

The CO₂ injection pressure will be monitored on a continuous basis at the wellhead and downhole to ensure that injection pressures do not exceed the maximum allowable injection pressure (MAIP), based, in part, on 90% of the fracture pressure of the injection zone pursuant to 40 C.F.R. § 146.88(a). If

the injection pressure exceeds 5% less than maximum allowable injection pressure at any point, then the injection process will be automatically shut down per Attachments A and F of the permit. To assist with the proper hydrostatic gradient evaluations, permanent downhole gauges will be used. The data gathered from the downhole gauges will be used to calculate corresponding surface pressure readings. The CO₂ injection rate and density will vary under actual injection operations, and the downhole gauges will be used to establish a calibration curve incorporating injection rate, fluid properties, frictional pressure drop, and downhole pressure. Establishing this correlation is important during the early stages of injection as rates ramp up and flow conditions stabilize. Once EPA agrees that the relationship between injection rate, CO₂ fluid properties, and downhole pressure has been determined, the calibration curve may be evaluated for use in the absence of downhole data to ensure operations remain at or below 90% of the injection zone fracture pressure.

Any anomalies outside of the normal operating specifications may indicate that an issue has occurred within the well, such as a loss of mechanical integrity or blockage in the tubing or may be caused by a change in injection flow rate. Anomalous pressure measurements will trigger further investigation by One Carbon Partnership of the cause of the change. The wellhead and downhole injection pressures will also be used to calibrate the computational modeling throughout the injection phase and PISC phase of the project.

The SCADA system will limit the bottomhole pressure to the MAIP listed in Attachment A of this permit. NOTE: The injection pressure limit may be changed if the Fracture Gradient is significantly different during subsequent well testing during the drilling of the injection well(s). All injection operations will be continuously monitored and controlled by One Carbon Partnership operations staff using the SCADA system. This system will continuously monitor, control, record, and will alarm and shutdown if specified control parameters exceed their normal operating range. The initial operating conditions, parameters, limits, and alarm set points are as follows:

Table 3: Injection Well Permitted Operating Conditions, Parameters, and Limits:

PARAMETER/CONDITION	PERMITTED LIMITATION	UNIT
Maximum Injection Pressure - Surface	2,015	psi
Maximum Injection Pressure - Injection Zone at 3,100 feet BGL	2,325	psi
Minimum Annulus Pressure	100	psi
Minimum Annulus Pressure above Tubing Differential (directly above and across packer)	100	psi
Carbon Dioxide Purity	98.75	percent
Maximum Injection Rate	450,000	metric tons/year

Table 4. Operational emergency shut down set points

ALARM TYPE		SET POINT	UNIT
Maximum Injection Pressure, Surface	Shutdown point: 5% less than maximum allowable injection pressure (MAIP)	1,910	PSI
Maximum Injection Pressure, Bottomhole	Shutdown point: 5% less than maximum allowable bottomhole flowing pressure (BHFP)	2,200	PSI
Annulus Pressure	High alarm	1,250	PSI
	Shutdown point: Maximum	1,500	PSI

	Low alarm	300	PSI
	Shutdown point: Minimum	100	PSI
	Shutdown point: Less than minimum allowable annulus over tubing differential	100	PSI

The set point values of 5% less than maximum allowable pressures may need to be adjusted after the injection well is constructed and the startup testing has been conducted. The final alarm set points will be included in the startup report submitted to EPA.

More specifically, all critical system parameters, e.g., pressure, temperature, and flow rate will have continuous electronic monitoring with signals transmitted back to a master control system. Operators will monitor the status of the entire system from the main operations control room.

Calculation of Injection Volumes

The injection volume into the reservoir will be calculated on a continuous basis based on the injection mass and the pressure and temperature conditions in the injection zone. The volumetric flow rate of CO₂ injected into the well will be measured by a volumetric flow meter and flow computer. The flow computer will have a digital output. The flow meter will be connected to the SCADA system for continuous monitoring and control of the CO₂ injection rate into the well. The flow meter will be calibrated at the frequency recommended by the manufacturer. The volume of carbon dioxide injected will be calculated from the mass flow rate obtained from the volumetric flow meter and flow computer. The mass flow rate will be calculated based on the pressure differential, temperature, and pressure data. This flow meter will be placed on the CO₂ delivery line downstream of the compressor.

Continuous Monitoring of Annular Pressure

One Carbon Partnership will use the procedures below to monitor annular pressure. The following procedures will be used to limit the potential for any unpermitted fluid movement into or out of the annulus:

1. The annulus between the tubing and the long string of casing will be filled with brine. The brine will have a specific gravity and a density that meets the requirements of the downhole conditions. The final values will be determined after the construction of the injection well.
2. The surface annulus pressure will be kept at a minimum of 100 pounds per square inch (psi) during injection. (This is subject to changes based upon actual conditions encountered at the injection site.)
3. During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of at least 100 psi between the annular fluid directly above (lower pressure) and below (higher pressure) the injection tubing packer set at 3,144 ft BGL. (The packer setting depth is subject to change based on actual depths obtained during the drilling and completion of the wells and the packer setting depths will be reported after the wells are completed and prior to obtaining pre-injection authorization.)
4. The pressure within the annular space, over the interval above the packer to the confining layer, will be greater than the pressure of the injection zone formation at all times.
5. The pressure in the annular space directly above the packer will be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

Casing-Tubing Pressure Monitoring

One Carbon Partnership will monitor the casing-tubing pressure on a continuous basis. During the injection timeframe of the project, the casing-tubing pressure will be monitored and recorded in real time. Surface pressure of the casing-tubing annulus is anticipated to be from 100 – 1,500 psi. As detailed in the Emergency and Remedial Response Plan, significant changes in the casing-tubing annular pressure will be investigated.

In addition to the annulus pressure test (APT), the annular pressure will be continuously monitored throughout the operational period in conjunction with the annular pressure monitoring and control system. The pressure on the annulus between the injection tubing and the long-string casing will be measured by an electronic pressure transducer with analog output that is mounted on the wing valve/annular fluid line connected to the wellhead of CCS1. The transmitter will be connected to the well control system and the SCADA system to regulate the annular pressure. Sudden changes in the annular pressure during routine injection operations are a sign of potential tubing or tubing packer integrity issues that will trigger further investigation through mechanical integrity testing.

Corrosion Monitoring

To meet the requirements of 40 C.F.R. § 146.90(c) and Section N(6) of this permit, One Carbon Partnership must monitor well materials during the operational period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

Monitoring location and frequency

This monitoring will occur quarterly, in accordance with Section N and Attachment A of this permit. One Carbon Partnership will monitor corrosion using a Corrosion Coupon Method and collect samples according to the description below.

Sample description

Samples of material used in the construction of the compression equipment, flowline, and injection well which come into contact with the carbon dioxide stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 5 below. Each coupon will be weighed, measured, and photographed prior to initial exposure (see “Sample Handling and Monitoring” below).

Table 5: List of equipment coupon with material of construction

Equipment Coupon	Material of Construction
Flowline	Stainless Steel
Long String Casing	13Cr85 Steel Alloy
Long String Casing	25Cr125
Injection Tubing	Standard Carbon Steel with TK-15XT Coating (Tuboscope)
Wellhead	Xylan coated iron
Packer	Nickel coated steel, nitrile

Monitoring details

Corrosion monitoring of well materials will be conducted using coupons placed in the CO₂ flowline. The coupons will be made of the same materials as the well components and CO₂-delivery flowline that are listed in Table 5. Coupons will be analyzed on a quarterly basis for signs of corrosion and loss of mass that may be indicative of future potential well integrity issues (40 C.F.R. § 146.90(c)).

If the coupons show evidence of corrosion, CCS1 and OBS1 will be assessed for signs of corrosion using commercially available logging or other inspection tools. The frequency of running these inspection logs will be contingent on the corrosion data from the coupon monitoring program and at a frequency acceptable to the Director.

Sample handling and monitoring

Prior to placement of the corrosion coupons in the CO₂ stream, they will be weighed and measured for thickness, width, and length as a baseline measurement. Corrosion coupons will be evaluated from sampling points within the injection line within the compression building.

The coupons will be removed quarterly after injection commences and assessed for corrosion using American Society for Testing and Materials (ASTM) G1-03: Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM G1-03, 2017). This method measures the corrosivity of steel to both aqueous and non-aqueous liquid wastes.

Upon removal, coupons will be photographed and inspected visually for evidence of corrosion, which may include pitting, cracking, and loss of mass or thickness NACE Standard RP0775 (2005). The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed and compared to the baseline measurements. Corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

Above Confining Zone Groundwater Monitoring

One Carbon Partnership will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 C.F.R. § 146.90(d) and Section N(4) of this permit. One Carbon Partnership will also monitor groundwater quality and geochemical changes in the lowermost USDW (USDW1) and shallow groundwater wells, as well as pressure above the confining zone (ACZ1). ACZ1 will be used to take fluid samples and monitor pressure changes in the selected saline formation.

Pressures in the ACZ monitoring interval will be monitored at the wellhead. Migration of CO₂ or brine into the ACZ saline formation would likely first be identified through pressure changes in the formation. An increasing pressure trend in the ACZ monitoring zone would suggest that leakage across the confining zone has occurred. Any increasing trend in pressure will be evaluated, and an increase in pressure that deviates more than 5% above baseline values will warrant additional monitoring and inspections to rule out the possibility of fluid leakage out of the injection zone. Such a change in pressure will initiate more frequent fluid sampling and analysis for aqueous geochemistry from the ACZ monitoring zone as well as additional external well integrity investigations in CCS1 or OBS1. Anomalous pressure, anomalous geochemical, and well integrity testing results may require One Carbon Partnership to acquire a time-lapse 3D surface seismic survey before scheduled surveys to characterize any potential leakage accumulations during the operations phase of the project. Anomalous pressure

or geochemical changes may also trigger the need for additional well integrity testing in both CCS1 and OBS1. Anomalous changes above the confining zone may also trigger the emergency response actions found in the Emergency and Remedial Response Plan in Attachment F.

If anomalous changes in aqueous geochemistry, such as pH, alkalinity, or dissolved solids, are observed in the ACZ monitoring interval or the lowermost USDW, One Carbon Partnership will obtain new samples from the affected formation to verify the changes. Changes of greater than 25% in the value of the above parameters, not attributable to natural or seasonal fluctuations, will require One Carbon Partnership to acquire new samples. Changes in these parameters may also trigger the need for analyses of isotopic compositions.

The shallow groundwater monitoring program will use twelve shallow groundwater wells spatially distributed within the AoR in near surface groundwater aquifers, and one dedicated groundwater monitoring well that will be drilled into the lowermost USDW (40 C.F.R. § 146.90(d)).

Throughout the injection and PISC phases of the project, the results of the aqueous geochemistry analyses will be compared to the baseline conditions for any indication of CO₂ or brine migration into the shallow groundwater aquifers or a USDW. If indications of CO₂ or brine are found in the shallow groundwater aquifer, it will trigger the emergency response actions found in the Emergency and Remedial Response Plan in Attachment F. If collected water samples during monitoring show anomalous changes in geochemical parameters, such as pH, alkalinity, or dissolved solids, the samples will be further analyzed for a change in isotopic composition.

Monitoring location and frequency

ACZ1 will be drilled into the first deep saline aquifer formation above the confining zone for the project. It is expected that this will be below the Knox Formation unconformity based on regional geology; however, a final determination will be made after the first deep well for the project has been drilled. The ACZ1 well location will be adjacent to CCS1 to monitor a deep saline formation immediately above the confining layer assuming that fluid migration from the injection zone is most likely to occur along a wellbore.

The lowermost USDW is expected to be located at a depth of approximately 450 ft below ground level (BGL) based on local well log data. The USDW1 well will be drilled relatively close to CCS1 to be able to properly monitor the fluids in the lowermost USDW.

It is expected that the lowermost USDW will be at 450 ft BGL based on nearby well data and reports from the Indiana Department of Natural Resources. The lowermost USDW will be verified when USDW1 is drilled as per Attachment G.

Table 6 lists the groundwater sample well locations, and Figure 1 shows the distribution of the groundwater wells within the AoR including the proposed location of USDW1. Baseline shallow groundwater samples will be collected from existing shallow groundwater wells within the AoR on a quarterly schedule following the effective date of the permit in order to characterize the seasonal variations in groundwater quality within the AoR. The project will have surface access rights to the land to sample the shallow groundwater wells as part of the landowner leases for the project.

During the injection phase of the project, fluids from these wells will be sampled biannually to identify any changes to parameters for aqueous geochemistry.

Pressure in the ACZ monitoring zone will be monitored from the wellhead. The gauge will record and transmit data to the SCADA system once every 10 seconds. The gauge will be installed on the wellhead at least three months prior to any injection to ensure that a sufficient baseline is established.

Table 6: Groundwater sample wells

GW Sample ID	IDNR Well Number	Latitude	Longitude
GW 001	None	40.184784	-84.884018
GW 002	136443	40.188255	-84.881041
GW 003	3402	40.170229	-84.858527
GW 004	316789	40.169993	-84.856949
GW 005	273410	40.176733	-84.855598
GW 006	22685	40.180825	-84.839696
GW 007	239110	40.189625	-84.840591
GW 008	3400	40.213672	-84.862153
GW 009	136388	40.168401	-84.888939
GW 010	136383	40.164637	-84.865454
GW 011	239156	40.180047	-84.835199
GW 012	48833	40.200224	-84.852014

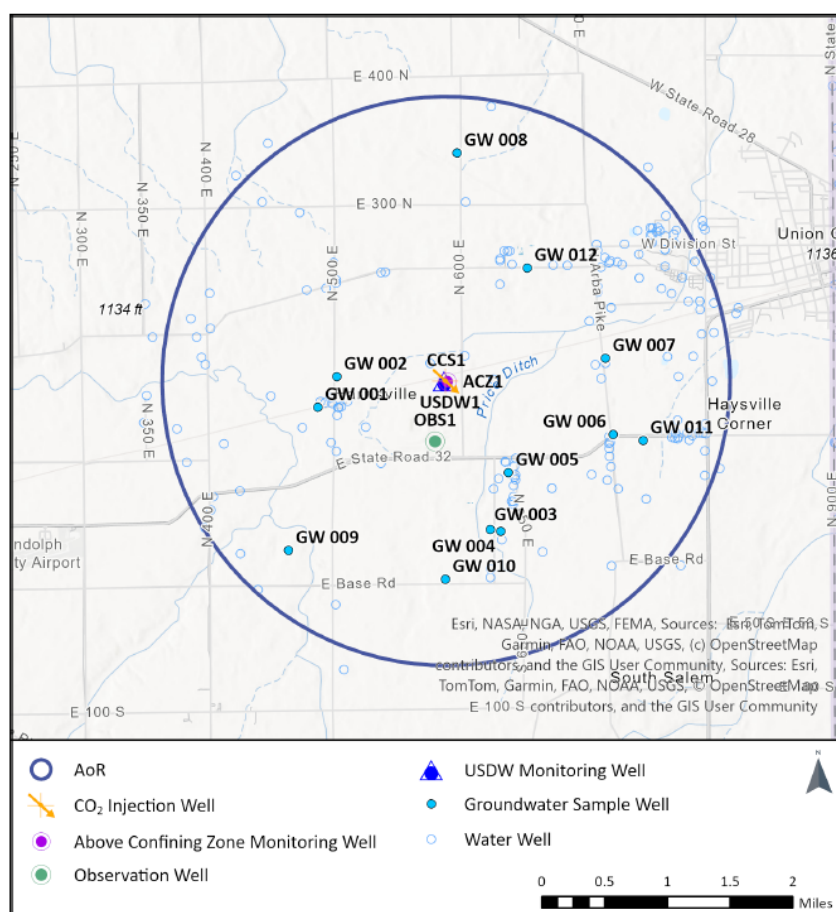


Figure 1. Groundwater sample wells and shallow groundwater wells within the AoR.

Table 7: Monitoring of groundwater quality and geochemical changes above the confining zone

Designated Well(s)	Target Formation	Monitoring Activity	Spatial Coverage	Frequency
Existing Wells ²	Glacial Drift	Aqueous Geochemistry	<300 ft BGL	Biannual ¹
USDW1	Maquoketa shale	Aqueous Geochemistry	~600 ft BGL	Biannual ¹
ACZ1	Knox Formation (TBD)	Wellhead Pressure	Surface	Continuous
		Aqueous Geochemistry	(TBD)	Biannual ¹

¹ Every 6 Months

² Wells Listed in Table 6

Analytical parameters**Table 8: Summary of analytical and field parameters for groundwater samples**

Parameters	Analytical Methods
Formation: Glacial Drift	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO ₃ , and SO ₄	Ion Chromatography EPA Method 300.0
Dissolved carbon dioxide	Coulometric Titration ASTM D513-11
Total Dissolved Solids	Gravimetry APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Formation: Maquoketa Shale	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO ₃ , and SO ₄	Ion Chromatography EPA Method 300.0
Dissolved carbon dioxide	Coulometric Titration

	ASTM D513-11
Isotopes: $\delta^{13}\text{C}$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Formation: Knox	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO_3 , and SO_4	Ion Chromatography EPA Method 300.0
Dissolved carbon dioxide	Coulometric Titration ASTM D513-11
Isotopes: $\delta^{13}\text{C}$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Once the project has established baseline conditions, One Carbon Partnership may submit a request to the Director to reduce monitoring to a subset of analytes that are most likely to change as a result of interactions with CO_2 . Upon the Director's approval, that subset of analytes supplant the analytes listed in Table 8.

Sampling methods

During pre-operational testing, the carbon isotopic composition of the CO_2 stream, the USDWs, and the fluids of the ACZ zone, will be measured to determine baseline values. If there are sufficient differences among their carbon isotopic compositions, carbon isotopes may provide a unique indication of the presence of injected CO_2 in the ACZ interval or USDWs.

For ACZ fluid sampling, a bailer system will be used to collect the water samples. Prior to sample collection the well will be flushed to remove stagnant water from the well and ensure representative water is collected from the formation. The fluid removed from the well will be

monitored for the field parameters listed in Table 8. Once these parameters stabilize, it will be an indication that representative formation fluid is in the well at the time the sample is collected.

Sampling will be performed as described in Section 4 of the QASP, Attachment K, which describes the groundwater sampling methods to be employed, including sampling SOPs (Section 4.2.1) and sample preservation (Section 4.2.6).

Sample handling and custody will be performed as described in Section 4.3 of the QASP. Quality Control (QC) will be ensured using the methods described in Section 4.5 of the QASP.

Laboratory to be used/chain of custody procedures

Final laboratory selection has not been made at this time. The laboratory selected will meet all requirements set forth in the Testing and Monitoring Plan and the QASP. The Chain-of-Custody procedures will follow the requirements of Section 4.3.5 and Appendix A of the QASP. Section 3.4 of the QASP, Quality Objectives and Criteria, provides the detection limits and analytical methods to be employed during the testing and monitoring of all critical parameters of the project.

Mechanical Integrity Testing

One Carbon Partnership will conduct the tests presented in Table 9 during the injection and post-injection phase to verify mechanical integrity as required at 40 C.F.R. §§ 146.89 and 146.90(e) and Sections L and N(7) of this permit. One Carbon Partnership will perform annual temperature logs to demonstrate external mechanical integrity per 40 C.F.R. §§ 146.89(c) and 146.90(e), and annular pressure tests in addition to continuous annulus pressure monitoring to demonstrate internal mechanical integrity per 40 C.F.R. § 146.89(b).

Table 9: Mechanical Integrity Tests

Test Description	Location	Depth Range (MD ft)	Frequency
Temperature Log	CCS1	Surface to Well TD ¹	Annual*
	OBS1	Surface to Well TD	Annual*
Annulus Pressure Test (APT)	CCS1 Wellhead	Surface to Well TD	Annual* & after completion or workover
	OBS1 Wellhead	Surface to Well TD	
Annular Pressure Monitoring	CCS1	Surface to Well TD	Continuous
	OBS1	Surface to Well TD	Continuous
¹ Total Depth (TD)			
*Every 12 Months			

Test Procedures

The following testing procedures are testing protocols expected to be used by One Carbon Partnership. The following procedures are approved by the Director for use per Section L of this

permit. Any deviation from the methods and procedures below will require approval by the Director at least 30 days prior to conducting the test and must comply with the witnessing requirements of Section L(5) of this permit.

Temperature Logging

Temperature logging is used to establish a temperature profile of the well and make year-to-year comparisons to determine if any unexpected variations are present. Each year, multiple temperature log runs will be made to monitor the temperature decay after injection has stopped.

Temperature logs will be run using a tool assembly which utilizes (at minimum) the following components:

- Casing collar locator,
- Gamma ray tool, and
- Temperature tool.

To initiate the logging sequence, the well will be shut-in, and a baseline temperature log will be run as per the schedule in Table 10. This will allow for four temperature curves to be plotted for each year that temperature logs will be performed. Temperature logs will be acquired from the bottom up.

Table 10: Temperature logging schedule for well integrity

Temperature Logging Run	Time Increment from Shut-in (hours)
Baseline	Shut-in
Second	1
Third	3
Fourth	6

In situations where injection has not, or will not occur, a baseline temperature log will be performed to use for year-to-year comparison.

The data from each annual logging event will be compared to the baseline log to determine if there are any inconsistencies between the logs. If inconsistencies appear, One Carbon Partnership will determine the cause of the deviations and perform additional logs over the entire depth of the well to substantiate results of the mechanical integrity test (MIT) logging.

Annulus Pressure Testing

Annulus Pressure Tests (APT) will be performed annually to demonstrate mechanical integrity, or any time a component of the internal seals, detailed above, are broken or altered. The test will be performed consistent with approved and accepted EPA guidance and regulations. In addition, One Carbon Partnership will perform an APT following an emergency shut-in due to a

high-high or low-low annulus alarm when the cause of the alarm cannot be easily correlated to a change in temperature.

The APT will then be performed by pressuring up the annulus after the well has reached thermal equilibrium. Once this has occurred, the annulus will be pressured up to 1,500 psi. A calibrated digital gauge will be installed on the annulus, and the pressure will be monitored for a period no less than 60 minutes.

The following procedures will be followed for all APTs:

1. Ensure well is in thermal equilibrium. Thermal equilibrium will be assumed under the following circumstances:
 - a. Injection has not occurred for approximately 24 hours, or sufficient data indicates the wellbore temperature is static. The scenario constitutes a static APT.
 - b. Injection is occurring at a constant rate ($\pm 5\%$), often referred to as a dynamic APT.
2. Install calibrated digital gauge on the casing-tubing annulus. Note initial pressures.
3. Increase annulus pressure to 1,500 psi. Note the fluid level in the system prior to increasing the annulus pressure.
4. Disconnect annulus system and ensure the annulus is isolated.
5. Monitor the annulus and tubing pressure for a period of one hour, taking readings every 10 minutes.
6. Once the test has concluded, reconnect the annulus system.
7. Blow the pressure down to the normal operating pressure.
8. Note the fluid level in the system.

Annulus Pressure Monitoring

The annular pressure will be continuously monitored throughout the operational period in conjunction with the annual annulus pressure tests to ensure internal mechanical integrity. Once injection operations commence, injection pressure, annular pressure, and annular fluid volumes will be monitored continuously in order to ensure that internal well integrity and proper annular pressure is maintained.

If a change in the annular pressure or annular fluid volume was not the result of temperature or injection rate alteration, One Carbon Partnership will investigate the cause of the change.

Pressure Fall-Off Testing

A pressure fall-off test (FOT) will be conducted in the Mt. Simon Sandstone in CCS1 after it is drilled to establish the hydrogeologic characteristics of the injection zone (see Attachment G). One Carbon Partnership will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 C.F.R. § 146.90(f) and Section N(8) of this permit. Pressure fall-off testing will be performed on CCS1 during system operation every 5 years. The formation characteristics obtained through the FOT will be compared to the results

from previous tests to identify any changes over time, and they will be used to calibrate the computational models.

Pressure Fall-off Test Procedure

1. Injection of normal injectate at the normal rate is preferred.
2. The injection period should be at least 50% longer than the planned shut-in time, or at minimum as long as operationally possible. During this time, injection will be at a rate that is representative of the injection rate for normal operations, at a constant rate $\pm 5\%$.
3. The pressure gauge utilized for the pressure transient test shall have been calibrated no more than one year prior to the test date.
5. The permanent downhole pressure gauges set above the packer will be used for the FOT. Surface monitoring equipment will be used to monitor injection data for the test.
6. Following at least one hour of pressure data collection during injection, the well will be shut-in at the wellhead, as quickly as possible.
7. Collect data at a frequency of at least one data point every 10 seconds for at least the first five minutes after shut-in; between five and 30 minutes at no less than one reading every 30 seconds; and the operator can reduce frequency as required after 30 minutes.
7. End pressure measurements when pressure is relatively stable, when operational necessity dictates, when sufficient radial flow dominated data has been collected to allow evaluation of kh and extrapolation of pressure to infinite shut-in time is possible, or if boundary effects are observed.
8. The test shall include a written report by a knowledgeable well test analyst. Such report must explain any anomalies shown in the results.
9. The test report shall include an up-to-date well schematic, a copy of the dated calibration certificate for the gauge utilized, and digital pressure data on CD/flash drive/email in a spreadsheet format.
10. The test report shall include a tabulation of values for the following background parameters: EPA permit number, porosity, net thickness (ft), viscosity (cp), formation compressibility (per psi), long string casing inner diameter (in), open hole diameter (in), and Kelly bushing elevation (ft). The test report shall also include a tabulation of values for the following test specific parameters: test start date/time, test end date/time, test length (hrs), depth reference (Kelly bushing or ground level), specific gravity of test fluid, test fluid compressibility (per psi), gauge depth (ft), gauge calibration date, pressure required to maintain tubing fluid to the surface (psi), final tubing fluid level (ft), final flow rate immediately prior to shut-in (gpm), cumulative volume injected since last pressure equalization (gal), permeability- thickness (md-ft), skin factor, radius of investigation (ft), final measured flowing pressure (psi), final measured shut-in pressure (psi), and p^* pressure (psi). Pressure gauge units (psia or psig) shall be specified.
11. The test must conclusively demonstrate its objectives and satisfy the Director to be considered a completed test.

Carbon Dioxide Plume and Pressure Front Tracking

One Carbon Partnership will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 C.F.R. § 146.90(g) and Section N(5) of this permit. The primary location for in-formation tracking of the carbon dioxide plume and pressure front will be the Knox, Eau Claire, and Mt. Simon formations at CCS1, OBS1, and ACZ1. The primary location for indirect tracking of the carbon dioxide plume and pressure front will be the entire formation from surface to total depth via time-lapse 3D seismic survey taken at the surface, sufficient to image an 8.97 square mile plume. OBS1 will have an offset of 2,600 ft south of CCS1. The final monitoring intervals will be determined after CCS1 has been drilled and the well logs have been analyzed (see Attachment G). The bottomhole pressure and temperature will be measured continuously in the OBS1 well. These gauges will continuously record these data and transmit them to surface. OBS1 has been located to account for the physical characteristics of the subsurface (dip). The placement of OBS1 places it on the upslope of the dip, to properly monitor the advancement of the carbon dioxide plume and pressure front to the predicted furthest distance from the injection well. Based on the prediction from the AoR modeling, the carbon dioxide plume is expected to reach the formation monitoring well within the first 3 years of injection. The variations in the pressure and temperature data will be used to calibrate and verify the computational modeling through the pre-operational, injection, and PISC phases of the project (40 C.F.R. § 146.90(g)).

If during the reassessment of the AoR during the injection phase of the project, the AoR is shown to have grown, the Testing and Monitoring Plan will be reassessed (see Attachment B).

Plume monitoring location and frequency

One Carbon Partnership will deploy temperature sensors to directly monitor the CO₂ plume. Indirect plume monitoring will employ pulsed neutron logging (PNL) to monitor carbon dioxide saturation and 3D seismic profiles. Baseline PNL logs will be acquired in CCS1, OBS1 and ACZ1 prior to the start of injection operations. Once injection starts, PNL logs will be acquired in CCS1 and OBS1 once each year. Once the near wellbore region of CCS1 becomes fully saturated with CO₂, routine logging over the injection interval will be suspended but will continue through the ACZ monitoring interval. Logging in OBS1 will continue for the duration of the injection phase of the project.

A baseline 3D surface seismic survey will be acquired. Subsequent time-lapse 3D surface seismic surveys will be acquired every five years in Q1 or Q4 after injection operations commence.

The baseline measurements collected during the Pre-Operational Testing program and the monitoring data collected during operations will be integrated to predict the development of the CO₂ plume and pressure front during operations and through the PISC phase of the project to site closure. This integration and evaluation of data will occur no less frequently than the five-year period required for re-evaluation of AoR per 40 C.F.R. § 146.84(e). The purpose of this

integration and evaluation of data is to provide a temporal and spatial prediction of CO₂ plume evolution and the trapping mechanisms involved pursuant to 40 C.F.R. § 146.84(c)(1).

Plume monitoring details

Pulsed neutron logging (PNL) will be run in the CCS1 and OBS1 to monitor CO₂ saturations and vertical plume development adjacent to the wellbores. The PNL data will be used to verify when the leading edge of the CO₂ plume reaches the observation well. This logging can also be used to identify the presence of CO₂ above the confining zone should there be leakage along the wellbore.

The PNL logs will be received as LAS files and interpreted products that can be imported into the static model. This logging data will be used to monitor the distribution and saturation of CO₂ adjacent to the wellbores in CCS1 and OBS1. The logs will be acquired through the Mt. Simon Sandstone to confirm the absence of CO₂ accumulations along the wellbore above the confining zone in the ACZ monitoring zone.

3D seismic data will be used to image the developing carbon dioxide plume for indirect plume monitoring. Surface seismic data is delivered in a variety of formats including acquisition and processing reports and SEG-Y data files from a variety of points in the processing flow. In the context of time-lapse analysis, an assessment will be provided about the differences between the baseline and time-lapse surveys as well as data files that can be incorporated into the static model. Once a data processing company is selected for the surface seismic processing, detailed information can be provided on their processing flows; however, it is expected that the company will use industry standard processing flows for noise attenuation, demultiple, pre-stack migration, and time-lapse analysis. The injection of CO₂ and expansion of the CO₂ plume is expected to change the acoustic impedance and travel times of the seismic waves through the Mt. Simon Sandstone, and these changes will be used to track CO₂ plume development over time. The time-lapse surface seismic data will also be monitored for changes that may suggest that CO₂ has migrated past the confining zone and into the overlying formation(s).

High resolution time-lapse 3D surface seismic data will be used to qualitatively monitor the CO₂ plume development and calibrate the computational modeling results over time. The time-lapse 3D surface seismic data will also be used to verify CO₂ containment within the injection zone, as any CO₂ accumulations in the overburden would result in seismic anomalies that would differ from the baseline seismic data. Source and receiver spacing and line intervals, and the resulting trace density will be designed to deliver full offset, full azimuth baseline data of sufficient resolution to image the target horizons. The microseismic monitoring will be used to monitor for any induced seismic events within an 8 mi radius of CCS1 that might indicate potential impacts to containment.

The results of the PNL and time-lapse 3D surface seismic data will be integrated to develop a comprehensive understanding of the CO₂ plume development over time. The logging and time-lapse 3D surface seismic data can be incorporated into the static model for comparison to the

computational modelling predictions at different points in time. The data can be used to constrain the computational modelling results and produce better CO₂ plume predictions over the course of the project. The subsequent PNLs will be used to identify the arrival of the CO₂ at OBS1, and subsequently to characterize the vertical development of the CO₂ plume within the injection zone over time at a distance from CCS1. The logging data will be used to calibrate the computational modelling on a yearly basis and provide information on the vertical and horizontal CO₂ plume development. It will also provide more detailed and direct measurement of CO₂ saturations than indirect seismic methods.

The time-lapse 3D surface seismic data will be used to update the models every five years. The subsequent 3D seismic surveys will provide additional data that addresses injection zone heterogeneity and will determine the temporal and spatial development of the CO₂ plume. If the CO₂ plume monitoring data diverges significantly from the modelled CO₂ plume predictions, it may result in a reassessment of the AoR (Attachment B). If anomalous pressure and geochemical results are obtained in the ACZ monitoring interval, or well integrity issues are identified in CCS1 or OBS1, a time-lapse 3D surface seismic survey maybe be triggered before the scheduled five-year acquisition cycle.

For information concerning the type and specification of gauges used for monitoring of the plume, please see the QASP in Attachment K.

Table 11: Plume monitoring activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Plume Monitoring				
Mt Simon Sandstone	Downhole Temperature	CCS1 OBS1	Downhole, just above the packer	Continuous
Indirect Plume Monitoring				
Mt Simon Sandstone	PNL	CCS1 OBS1	ACZ monitoring interval to TD	Once/year until fully saturated with CO ₂ (CCS1) Once/year (OBS1)
Entire formation (0-TD)	Time-lapse 3D Surface Seismic Data	Area sufficient to image an 8.97 square mile plume	Imaging of CO ₂ plume and overburden	Every 5 years (Q1 or Q4)

Pressure-front monitoring location and frequency

Table 11 lists the methods that One Carbon Partnership will use to monitor the position of the pressure front, including the activities, locations, and frequencies One Carbon Partnership will employ.

The downhole pressure gauge will be set at the bottom of the injection string, just above the packer, at approximately 3,142 ft BGL and will be programmed to continuously record the pressure and transmit it to surface.

The microseismic monitoring array will have a minimum of five surface stations. One station will be located adjacent to CCS1, and four stations will be distributed around the AoR. The physical locations of these stations will be optimized through a design process once the data from CCS1 and OBS1 have been analyzed. The local array will be complemented with the addition of any relevant regional seismometer stations that are available through the Incorporated Research Institutions for Seismology (IRIS) to aid in positioning events from outside the AoR.

Quality assurance procedures for these methods are presented in the QASP in Attachment K.

Pressure-front monitoring details

Pressure-front monitoring will occur via continuous monitoring of conditions in the injection interval of the Mt Simon Formation at CCS1 and OBS1 (final depth to be determined during the pre-operational logging phase). For information concerning the type and specification of gauges used for the continuous monitoring of the pressure front, please see the QASP in Attachment K.

One Carbon Partnership must collect baseline data from surface stations in the Eau Claire and Mt. Simon Formations before the start of injection activities. The project will start recording pressures in the Mt. Simon Sandstone during the quarter before injection operations commence. This baseline data will be used to generate comparative data between the baseline case of the predictive model and expected rate of change in the formation conditions. As measured pressures and temperatures change, the data will be compared to the predicted data from the model. The continuous, far field pressure measurements from OBS1 will be used to calibrate the computational modeling during the operations phase of the project. As appropriate, One Carbon Partnership must conduct re-evaluation of the model, or further investigation of the downhole conditions to ensure that no major deviation from the expected behavior of the pressure front occurs.

Microseismic data will also be recorded on a continuous basis. This data will be sent to a cloud-based service via a cellular connection for data processing and archive. Baseline microseismic data will be acquired for four to six months prior to the start of injection operations. Each standalone station will consist of a seismometer, digitizer, solar with battery backup, and a cell modem/antenna. Triggered data will be processed to provide magnitude and location error ellipsoids on a real-time basis and results will be reviewed by a data processor, and event data can be received by the project daily. Automatic notifications will be sent for events over a certain size.

The event locations will be incorporated into the static model. Some induced microseismicity may occur in the Precambrian basement once injection commences, and the pressure front related to the CO₂ injection expands. Microseismic activity will provide qualitative information

on the spatial extent of the pressure front over time. Clusters of microseismic activity in the confining zone may be an indication of loss of containment that will require further investigation.

Table 12: Pressure-front monitoring activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
Mt Simon Sandstone	Downhole Pressure	CCS1 OBS1	TBD (above packer) TBD (Injection zone)	Continuous
Indirect Pressure-Front Monitoring				
Eau Claire Formation Mt. Simon Sandstone	Microseismic Monitoring	Minimum of 5 Surface Stations	Events within an 8 mi radius of CCS1	Continuous

The integration of the testing and monitoring and subsequent computational modeling will help to track the pressure front and CO₂ plume development and predict how CO₂ trapping mechanisms will evolve over time. This information will enable accurate estimates of the injection zone behavior post-injection including the stabilization of the CO₂ plume and reduction in pressure that will lead to site closure.