UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

January 19, 2017

Mr. Dean Frommelt
Archer Daniels Midland Company
4666 Faries Parkway
Decatur, IL 62521

Re: Monitoring, Reporting and Verification (MRV) Plan for Illinois Industrial Carbon Capture and Sequestration project (CCS #2)

Dear Mr. Frommelt:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted by Archer Daniels Midland Company for the Illinois Industrial Carbon Capture and Sequestration project (CCS #2) as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Archer Daniels Midland for CCS #2 as the final MRV plan. The MRV Plan Approval Number is 1005661-1. This decision is effective January 24, 2017 and appealable to EPA's Environmental Appeals Board under 40 CFR Part 78.

If you have any questions regarding this determination, please write to ghgreporting@epa.gov and a member of the Greenhouse Gas Reporting Program will respond.

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for Archer Daniels Midland Illinois Industrial Carbon Capture and Storage Project

January 2017

Contents

This report summarizes the U.S Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) Plan submitted by Archer Daniels Midland (ADM) for the Illinois Industrial Carbon Capture and Sequestration Project (IL-ICCS).

1 Overview of Project

The IL-ICCS project is located at ADM's Decatur, IL, ethanol plant. ADM will capture CO_2 at the plant, compress it to a supercritical state, and inject it into the Mt. Simon deep saline formation via a single injection well, CCS #2. The CO_2 will be transported from the ethanol plant to the injection well via an approximately 5,000-foot pipeline. ADM received an Underground Injection Control (UIC) Class VI permit for CCS #2 in September 2014 (permit no. IL-115-6A-0001). Due to new information obtained during well construction and pre-injection testing, the existing UIC permit, first issued in 2014, was modified to incorporate the new information. ADM constructed the well and performed required pre-operational testing in 2015, and then submitted updated information to EPA in its revised permit application.[1]

[1] Specifically, modifications to ADM's Class VI permit are related to: (1) the size of the Area of Review (the AoR, the region surrounding the well that ADM and EPA examined to ensure the protection of underground sources of drinking water), (2) the final injection and monitoring well construction; (3) the injection start-up procedures, and (4) other administrative edits for clarity.

The MRV Plan references the approved Class VI permit for CCS #2. The information in the permit and attachments to the permit provides an acceptable, comprehensive description of the project, including the site setting, processes, and plans for injection operations.

The IL-ICCS project is the second geologic sequestration project at this location. The other project is the Illinois Basin Decatur Project (IBDP) which completed its goal of injecting 1 million metric tons of CO2 over a three-year period from November 2011 to November 2014. A map showing the IL-ICCS project is provided as Figure 1 of the MRV Plan.

As specified in the MRV Plan, ADM plans to inject up to 3,300 metric tons of CO_2 per day for a 5-year injection phase, followed by 10-years of post-injection site care (PISC). The total amount of CO_2 expected to be injected over the 5-year period is 5.5 million metric tons.

The description of the project is determined to be reasonable and provided appropriate information to comply with 40 CFR 98.448(a)(6). Under 40 CFR 98.448(a)(6), if a well is permitted under the UIC program, for each injection well, the facility must provide the well identification number used for the UIC permit and the UIC permit class. The MRV Plan clearly provides the well identification number (permit no. IL-115-6A-0001) and states that the injection well is permitted as UIC Class VI.

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV Plan, the reporter must identify the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines the MMA as “the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile.” Subpart RR defines the AMA as “the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the AMA is established by superimposing two areas: (1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) The area projected to contain the free phase CO_2 plume at the end of year t + 5.” See 40 CFR 98.449.

ADM has defined the MMA as the area of review (AoR) determined in its Class VI permit, plus a 0.5-mile buffer. The AoR for Class VI is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data as set forth in 40 CFR 146.84. The three dimensional (3-D) geologic model developed for the initial injection simulations was based on the interpretation of a diverse collection of geological, geophysical, and petrophysical data acquired throughout the construction of the IBDP wells (CCS#1 and VW#1). Structurally, the model is also based on the interpretation of both two dimensional (2-D) and 3-D seismic survey data in conjunction with dip-meter log data acquired from the IBDP wells. Petrophysical and transport properties based on the interpreted well log data and the analysis of core samples recovered from the IBDP wells were then distributed throughout each layer in the geo-cellular model. Following the collection of testing and logging data during construction and pre-operational testing of CCS#2 and VW#2, the geologic model was updated pursuant to 40 CFR 146.82(c)(1).

The MMA, defined in the MRV Plan as the AoR plus a 0.5-mile buffer, is consistent with Subpart RR requirements because the defined AoR accounts for the free phase CO_2 plume and the resulting pressure front. The Subpart RR requirement is defined as the free phase CO_2 plume plus a 0.5 mile or greater buffer, therefore the MMA defined by the MRV Plan meets the requirements for Subpart RR.

ADM has defined the AMA as the Class VI AoR. The MRV Plan notes that the AMA will remain constant throughout the 5-year injection period and the 10-year post-injection site care period. Monitoring within the AMA should encompass a sufficient area to detect any potential surface leaks. The computational modeling used to delineate the Class VI AoR, as described in ADM's Class VI permit, accounts for the existing operational and subsurface conditions at the site and supports a high level of confidence that monitoring over a sufficient area will be performed. Therefore, the process for the delineation of the AMA as the Class VI AoR is a reasonable approach. The delineation of the MMA and AMA is determined to be in compliance with 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV Plan are clearly and explicitly delineated and, respectively, cover the maximum monitoring area and active monitoring area that is defined at 40 CFR 98.449.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV Plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). In Section 4 of the MRV Plan, ADM identified the following as potential leakage pathways in their MRV Plan:

- Surface components (pipeline and wellhead)
- Abandoned oil and gas wells
- Faults, fractures, and bedding plane partings
- Leakage through the confining zone
- Leakage through the injection well or monitoring wells.

Leakage from Surface Components

The MRV Plan states that the most probable potential for leakage of CO_2 to the surface is from surface components of the injection system: the 5,000-foot pipeline that transports CO_2 to the injection well and the wellhead itself. The MRV Plan states that leakage would most likely be the result of aging and use of the surface components over time, most likely at flanged connection points. The MRV Plan states that leakage could also occur as ventilation from relief valves to dissipate over-pressure in the pipeline.

Additionally, the MRV Plan states that leakage may occur as the result of an accident or natural disaster which damages the surface components and allows CO_2 to be released.

Although ADM concludes that the risk of leakage through this pathway is possible, it finds that the magnitude of such a leak would be relatively small compared to the amount of CO_2 being injected. The MRV Plan notes that the magnitude of such a leak will depend on the particular circumstance. ADM concludes that a sudden break or rupture would have the potential to allow several thousand pounds of CO_2 to be released to the atmosphere almost immediately, while a slowly deteriorating seal at a flanged connection may release only a few pounds of CO_2 to the atmosphere over the course of several hours or days. ADM finds that leakage or venting from surface components will be a risk only during the 5-year injection phase of the project; following the injection phase, surface components will not store or transport CO_2 and will therefore no longer be a surface leakage risk.

These appear to be a reasonable estimate of the likelihood of and the volume of a leak that could be expected from surface components.

Leakage through Abandoned Oil and Gas Wells

According to the MRV Plan, leakage through abandoned oil and gas wells is almost impossible (and, according to the MRV Plan, “should in fact be zero”) because no abandoned wells penetrate the confining zone (the Eau Claire) (at least within 17 miles of the site). This is a reasonable statement, as the absence of abandoned wells has been corroborated by analyses performed to support ADM’s Class VI permit application and Corrective Action Plan. Wells that do penetrate the confining zone were constructed in accordance with UIC Class VI requirements and will be actively monitored for integrity on a regular basis. No other wells in the AoR have a depth greater than approximately 2,500 feet below ground surface, which is roughly 3,000 feet above the top of the injection zone (Mt. Simon Sandstone).

The MRV Plan states that although leakage through abandoned wells will not occur as a primary pathway, it is possible that leakage that has migrated through the confining zone and into the more recent geologic strata may enter an abandoned well and migrate through the well to the surface. ADM determined that such leakage is expected to be detected by other monitoring methods (such as groundwater monitoring), as discussed in Section 5 of the ADM MRV Plan.

Leakage through Fractures, Faults, and Bedding Plane Partings

ADM considers leaks through folds or faults to be highly improbable to nearly impossible because 2-D and 3-D seismic surveys in the area show no evidence of these geologic features. The MRV Plan also states that the risk of a significant seismic event in the project area is highly unlikely. This determination is reasonable because both lines of evidence are consistent with ADM’s assertion of low probability of CO_2 leakage through structural conduits. The MRV Plan notes that if an undiscovered fault were activated, it could potentially cause leakage; ADM states that, depending on the magnitude of such an event, up to the entire mass of injected CO_2 could potentially be released to the surface. The timing of such a leak would occur over the course of several months or years. This is a reasonable estimate of the likelihood of this type of leak, and the lack of transmissive faults is corroborated by site characterization associated with ADM's Class VI permit application.

Leakage through Confining Zones

The MRV Plan provides details on the confining unit, the Eau Claire Formation: the lack of penetrations through that unit (not including the Class VI compliant IBDP and IL-ICCS wells), the minimal dip of the formation (<1 degree), the low permeability of the Eau Claire, and its large lateral extent. Following these lines of evidence, ADM considers leaks through the confining layer to be highly improbable to nearly impossible. If such a leak were to occur, ADM determined that it would likely be "very small" and that "the timing of such a leak to the surface may be extremely slow (e.g., over the course of decades or longer)." Moreover, any such leak would likely be contained within the low permeability secondary seal strata (Makoqueta Shale and the New Albany Shale).

The estimate of the size of this type of leak is reasonable based on the information provided in the MRV Plan. Furthermore, the ability of the Eau Claire to confine the CO_2 is corroborated by the site characterization and computational modeling associated with ADM's Class VI permit application and supporting analyses (United States Environmental Protection Agency Underground Injection Control Permit: Class VI, Permit #: IL-115-6A-0001).

Leakage through Injection or Monitoring Wells

The MRV Plan specifies that the only wells in the MMA that currently penetrate the injection zone (Mt. Simon Sandstone) and/or the confining zone (Eau Claire Formation) are the existing Class VI injection wells (CCS#1 and CCS#2) and the associated monitoring wells, which are subject to ADM's Class VI Testing and Monitoring Plan and other Class VI Rule requirements. Due to the rigorous construction, maintenance and monitoring standards applied to the Class VI wells, ADM reasonably concludes that leaks through the injection well and monitoring wells are highly improbable. No other wells in the MMA have a depth greater than approximately 2,500 feet below ground surface, which is roughly 3,000 feet above the top of the injection zone (Mt. Simon Sandstone). A table of well depths, ages, and construction standards for wells in the AoR is provided in the MRV Plan. The MRV Plan states that, should such a leak occur, the magnitude of the leak is likely to be on the order of several hundred to several thousand pounds, and that early detection is anticipated because injection zone wells are continuously monitored.

4 Strategy for Detecting and Quantifying Surface Leakage of CO_2 and for Establishing Expected Baselines for Monitoring

ADM's proposed strategy for leakage detection is described in Section 5 of its MRV Plan and summarized in Table 2 of the MRV Plan. For review purposes, these are expanded in

Leakage Pathway	Detection Monitoring Program	Spatial Coverage of Monitoring Program	Monitoring Timeline
Surface components	Visual Inspection	From flow meter to injection wellhead	N/A
	Injection Well Monitoring	Annulus pressure (at surface) and Injection well temperature (at surface, at depth)	Prior to Injection Activities. The average of these values will be used as the baseline for these parameters. Baseline pressure and temperature data for CCS#2 was collected on September 30, 2015.
Abandoned Oil & Gas Wells	Groundwater	Groundwater monitoring locations	Prior to Injection Activities. Shallow groundwater will be sampled 2 years prior to injection on a quarterly basis. All other baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.
Fractures & Faults	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	Prior to Injection Activities. Baseline reservoir saturation measurement (RST) measurements were collected for CCS#1 - 12/10/2014, CCS#2 - 09/30/2015, VW#1 - 12/11/2014, and VW#2 – 11/01/2012).
	Groundwater	Groundwater monitoring locations	Prior to Injection Activities. Shallow groundwater will be sampled 2 years prior to injection on a quarterly basis. All other baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.
Injection or Monitoring Wells	MIT	Injection well (from surface to injection formation)	Prior to Injection Activities. Cement evaluation, pressure data, temperature log (DTS), pulse neutron log

Table (Baseline Monitoring) and Table 2 (Injection and Post-Injection Monitoring) below.

Table 1. Baseline Leakage Detection Monitoring Activities Described in ADM's MRV Plan

Leakage Pathway	Detection Monitoring Program	Spatial Coverage of Monitoring Program	Monitoring Timeline
Surface components	Visual Inspection	From flow meter to injection wellhead	N/A
	Injection Well Monitoring	Annulus pressure (at surface) and Injection well temperature (at surface, at depth)	Prior to Injection Activities. The average of these values will be used as the baseline for these parameters. Baseline pressure and temperature data for CCS#2 was collected on September 30, 2015.
Abandoned Oil & Gas Wells	Groundwater	Groundwater monitoring locations	Prior to Injection Activities. Shallow groundwater will be sampled 2 years prior to injection on a quarterly basis. All other baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.
Fractures & Faults	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	Prior to Injection Activities. Baseline reservoir saturation measurement (RST) measurements were collected for CCS#1 - 12/10/2014, CCS#2 - 09/30/2015, VW#1 - 12/11/2014, and VW#2 – 11/01/2012).
	Groundwater	Groundwater monitoring locations	Prior to Injection Activities. Shallow groundwater will be sampled 2 years prior to injection on a quarterly basis. All other baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.
Injection or Monitoring Wells	MIT	Injection well (from surface to injection formation)	Prior to Injection Activities. Cement evaluation, pressure data, temperature log (DTS), pulse neutron log

Table 2. Injection and Post-Injection Phase Leakage Detection Monitoring Activities Described in ADM's MRV Plan

Leakage Pathway	Detection Monitoring Program	Spatial Coverage of Monitoring Program	Injection Phase and Post-Injection Monitoring Timeline
Surface Components	Visual Inspection	From flow meter to injection wellhead	Monthly for duration of injection (5 years)
		Injection well (from surface to injection formation)	For duration of injection (5 years)
	Injection Well Monitoring & Mechanical Integrity Tests (MITs)		
Abandoned Oil & Gas Wells	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
			During injection: Quarterly in years 1-2, semi-annual years 3-5. Post Injection: annual sampling.
	Groundwater Quality Monitoring	Groundwater monitoring locations	
Fractures & Faults	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
			Quarterly to annual during injection (5 years)
	Groundwater Quality Monitoring	Groundwater monitoring locations	
Confining Zone Limitations	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
			Quarterly to annual during injection (5 years)
	Groundwater Quality Monitoring	Groundwater monitoring locations	
Injection or Monitoring Wells	Injection Well Monitoring & MITs	Injection well (from surface to injection formation)	For duration of injection (5 years)

40 CFR 98.448(a)(3) requires that an MRV Plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV Plan include a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. ADM's MRV Plan describes both a strategy for detecting and quantifying any surface leakage of CO_2 based on the identification of potential leakage risks, as wells as establishing baselines for monitoring against which potential suspected leaks can be identified, evaluated, and, if necessary, quantified.

The monitoring frequencies/timeline in the MRV Plan are the same as in the Class VI Testing and Monitoring Plan. The Testing and Monitoring Plan calls for quarterly sampling in years 1-2 of the injection phase, semi-annual sampling in years 3-5 of the injection phase, and annual sampling during the 10-year post-injection site care period.

For surface components, controlled or planned emissions are listed as potential sources of CO_2 leaks due to maintenance requirements. If planned CO_2 emissions occur, the amount vented would be estimated and reported as "leakage". For unplanned leaks, visual sighting of clouds of ice crystals is a reasonable way to detect leaks of pressurized supercritical CO_2, provided the observer is in place to notice the cloud when the leak occurs.

In the MRV Plan, monthly visual monitoring of surface components is planned to monitor for CO_2 leaks. Leakage from the pipeline or wellhead would be detected visually by ice crystal formation (due to the temperature reduction associated with release of supercritical CO_2 to the atmosphere) around the leakage point. A portion of the pipeline is underground that cannot be visually monitored. ADM notes that no valves or flanges exist along the length of underground pipeline to act as potential leakage sources. ADM will utilize an annual well shut-in for pressure monitoring as a method of leak detection for this surface component.

The MRV Plan outlines that subsurface leaks will be detected by initial and final seismic surveys, annual ground water monitoring, and temperature and pulse neutron logs conducted twice during the injection period, distributed temperature sensing, and micro-seismic monitoring.

This is determined to be a reasonable array of monitoring methods to detect subsurface leakage because it will address site-specific conditions as well as provide early warning of CO_2 movement.

Pressure and temperature monitoring of injection wells, along with monitoring data determining the baseline, is an established way to detect leaks in the injection wells. This monitoring method may also be able to detect leaks through abandoned wells or faults by comparing the monitoring results to modeled predictions. The MRV Plan states that leaks from wells will be detected by continuous injection pressure and temperature monitoring at the wells. Mechanical Integrity Tests (MITs) are also an established way to detect leaks along wellbores, which is another method listed in the MRV Plan, with MITs to be performed prior to injection, annually during injection, and after the injection period. The proposed well monitoring methods are consistent with the Class VI requirements, and are suitable to detect leaks in the casing, tubing, or packer or fluid movement behind the casing.

The MRV Plan outlines monitoring strategies designed to detect anomalous results outside of the predicted ranges, baselines, or expected observations. ADM will compare monitoring results from the 5-year injection phase of the project with baselines collected prior to injection or during the first year of injection. The MRV Plan states that if results exceed the statistical baseline values, the potential of the abnormal values being caused by a leak will be investigated. In all cases where monitoring data suggest a leak, data verification procedures will be followed to eliminate the possibility of a “false positive” leak. If it is determined that a “false positive” is not responsible for the anomalous values, ADM states that corrective action responses will be implemented in accordance with Area of Review and Corrective Action Plan and/or the Emergency and Remedial Response Plan in its Class VI permit.

If a leak is detected, it will be quantified using a method chosen at the time depending on the nature of the leak. ADM proposes that the methods used for quantification will generally involve either models or mass balance equations. Along with the leak estimate, the MRV Plan states that statistical uncertainty of calculated leak volumes will be provided. This is a reasonable approach to calculating leak rates, while acknowledging uncertainties in possible leak scenarios, and complies with Subpart RR.

5 Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation

A reporter who is not producing oil or natural gas is required to calculate the amount of CO_2 sequestered using equation RR-12 per 40 CFR 98.443(f)(2), which ADM appropriately proposes to use. The equation is:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 is the total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} is the total annual CO_2 mass injected (metric tons) in the well or group of wells covered by subpart RR in the reporting year.

CO_{2E} is the total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} is the total CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W.

ADM explains its approach to calculating each of these variables in Section 8 of the MRV Plan.

5.1 Calculation of Total Annual Mass Injected

ADM will determine the amount of CO_2 injected by using a Coriolis mass meter to measure the total mass rate flowing through n the injection pipeline. ADM proposes to use Equation RR-4 for this calculation. ADM notes that flow rate is measured on a mass basis (kg/hr). Annual mass will be calculated based on the quarterly mass flow rate measurements multiplied by the quarterly CO_2 concentrations for CCS#2.

ADM's proposed approach for calculating the total annual mass injected is acceptable for the Subpart RR requirements.

5.2 Calculation of Total Annual Mass Emitted by Surface Leakage

For reporting of the total annual CO_2 mass sequestered under Subpart RR, potential surface leaks must be accounted for in the mass balance equation. Pursuant to 40 CFR 98.448(a)(2), an MRV Plan must describe the likelihood, magnitude, and timing of surface leakage of CO_2 through potential pathways. Subpart RR also requires that the MRV Plan identify a strategy for establishing a baseline for monitoring CO_2 surface leakage, pursuant to 40 CFR 98.448(a)(4).

ADM reasonably proposes to use Equation RR-10 for the calculation of annual surface leakage. ADM's strategy for the quantification of potential leakage for each pathway, as discussed above in Section 4, is in compliance with Subpart RR.

5.3 Calculation of Total Annual Mass Emitted as Equipment Leakage or Vented Emissions

According to the MRV Plan, the parameters CO2E and CO2FI will be measured using the leakage quantification procedure described in Section 5.3. ADM identified five pressure relief valves that could vent CO_2 to the atmosphere. As noted in the MRV Plan, ADM will estimate the mass of CO_2 emitted from relief valves or leakage points based on operating conditions at the time of the release – pipeline pressure and flow rate, set point of relief valves, the size of the valve opening or leakage point opening, and the estimated length of time that the emission occurred. The MRV plan states that this estimation method may have a large margin of error; therefore, ADM is proposing to include a statistical estimate of the calculation error to document the likely range of the emitted quantity.

This approach is reasonable for calculating vented emissions.

Summary of Findings

The Subpart RR MRV Plan for the IL-ICCS project meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV Plans, are summarized below, along with a summary of relevant provisions in ADM's MRV Plan.

Subpart RR MRV Plan Requirement	ADM MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV Plan describes the MMA and AMA. The MMA is delineated as the AoR plus a 0.5-mile-radius buffer and the AMA is the boundary of the AoR. The MMA and AMA delineations take into account site characterization and reservoir modeling along with pressure management considerations.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV Plan identifies and evaluates potential surface leakage pathways. The MRV Plan identifies the following potential pathways: surface components (pipeline and wellhead); abandoned oil and gas wells; faults, fractures, and bedding plane partings; leakage through the confining zone; leakage through the injection well or monitoring wells. l The MRV Plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. ADM determined that leakage pathways are highly improbable to minimal at the Decatur facility and it is very unlikely that potential leakage conduits would result in significant loss of CO_2 to the atmosphere.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 5 of the MRV Plan describes how the facility would detect CO_2 leakage to the surface, such as monitoring of existing wells, field inspections, and pressure modeling and monitoring. The monitoring strategy is summarized in Table 2 of the MRV Plan. Section 5 of the MRV Plan also describes how surface leakage would be quantified.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV Plan describes the baselines against which monitoring results will be compared to assess potential surface leakage.

40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 7 of the MRV Plan describes ADM's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equation, including as related to calculation of total annual mass injected, calculation of total annual mass produced, and calculation of total annual mass emitted as equipment leakage or vented emissions.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Table 1 in the MRV Plan provides well identification numbers for each well. The MRV Plan specifies that injection well is permitted as UIC Class VI.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	The MRV Plan projects that baseline data collection will be completed by January 31, 2016. ADM anticipates that the MRV Plan will be implemented at the start of the injection process.

Appendix A: Final MRV Plan

LIST OF CONTROLLED COPIES, LOCATION, AND RESPONSIBILITY:

Copy #	Location	Responsibility
Original	DCS/DMS – (180-SQL)	Environmental Manager

APPROVALS:

Plant Manager

Environmental Manager

SUMMARY OF CURRENT REVISION:

Date	Version	Author	Reason(s) for revision
01/09/2017	3.0	Outzen	Modified Reference 1. Removed References 3, 4, and 5. Updated figure 2 to reflect current Active Monitoring Area. Updated Table 1. Update Section 9.1.2.4 to reflect current monitoring practice. Updated Section 10 to reflect current practice. Updated Section 12 to reflect current implementation schedule. Minor formatting and grammar corrections.

1.0 PURPOSE

This Monitoring, Reporting, and Verification (MRV) Plan has been prepared by the Archer Daniels Midland Company (ADM) for Carbon Capture and Sequestration well #2 (CCS #2) located in Decatur, Illinois, for the United States Environmental Protection Agency (USEPA). The MRV Plan was developed in accordance with the regulations at 40 CFR 98, Subparts RR (Geologic Sequestration of Carbon Dioxide) and UU (Injection of Carbon Dioxide).

2.0 SCOPE

This procedure is applicable to:

Archer Daniels Midland Company (ADM)
Permit Number: IL-115-6A-0001 (UIC Class VI)
Facility Name:CCS#2
UNDERGROUND INJECTION CONTROL PERMIT – CLASS VI
PERMIT NO. IL-115-6A-0001 (FACILITY NAME: CCS#2)

A map showing the ADM facility is provided as Figure 1.

3.0 DEFINITIONS

None

4.0 PRINCIPLE

None

5.0 SAFETY

There are no specific safety guidelines associated with this procedure.

6.0 PROJECT DESCRIPTION

ADM will capture carbon dioxide gas from their fuel ethanol production unit and compress the gas into a dense-phase liquid for injection into the Mt. Simon Sandstone approximately 7,000 feet below the ground surface. This project is identified as the Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) project.

The IL-ICCS project plans to inject up to 3,300 metric tons of carbon dioxide (CO2) daily, or 5.5 million metric tons over a five (5) year period.

The IL-ICCS project is the second carbon sequestration project at the Decatur facility. The Illinois State Geological Survey (ISGS) manages the Illinois Basin Decatur Project (IBDP) which completed its goal of injecting 1 million metric tons of CO2 over a three-year period from November 2011 to November 2014.

Further information can be found in the following documents which are referenced throughout this MRV Plan:

Reference 1 – USEPA Underground Injection Control Permit, Class VI, for ADM CCS#2, Permit No. IL-115-6A-0001, proposed modification published November 22, 2016, including Attachments A, B, C (with Quality Assurance & Surveillance Plan), D, E, F, G, H, and I

Reference 2 – ADM Permit Application for Underground Injection Control Permit, July 2011, including Appendices A-H (Permit Application)

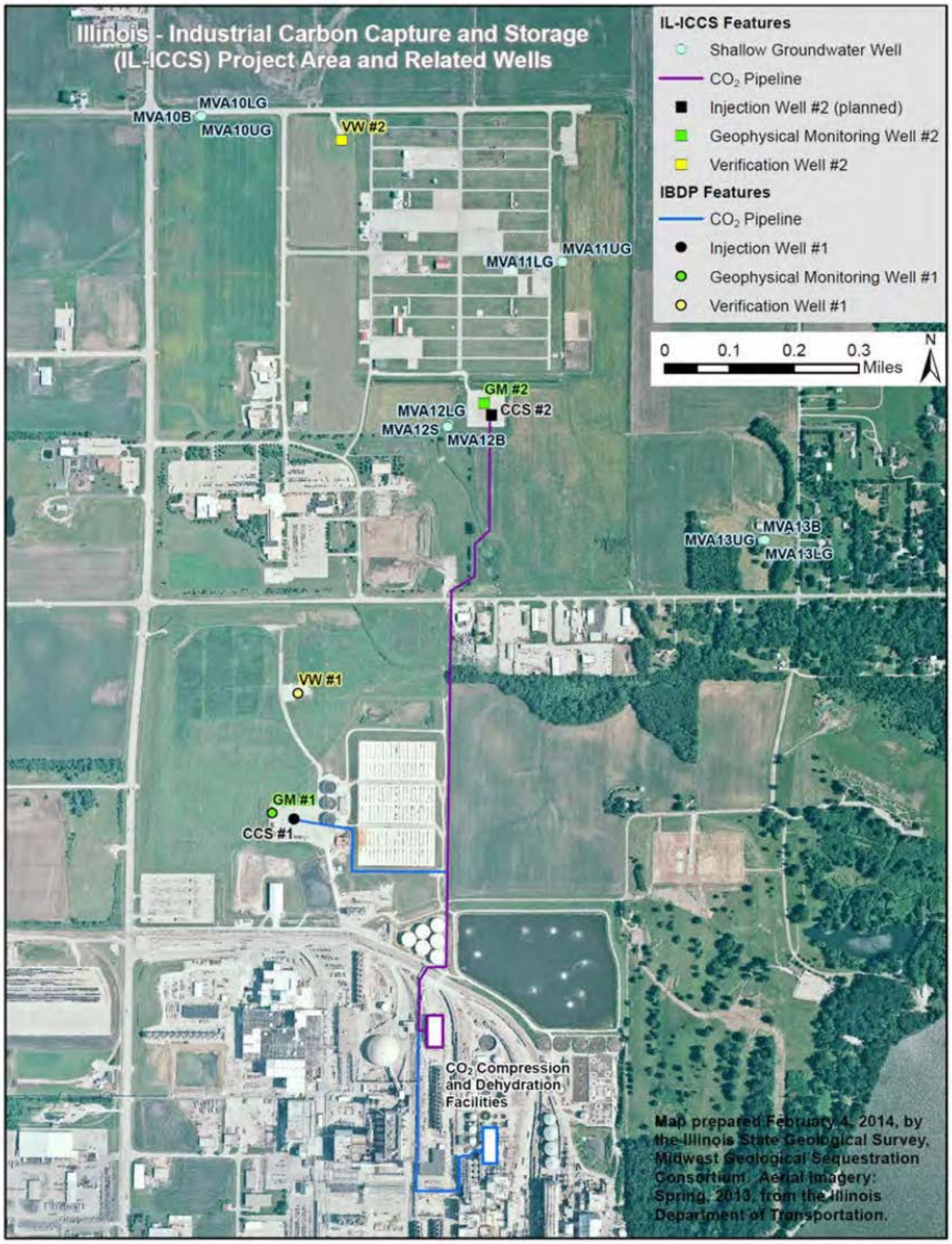

Figure 1. Aerial Photographic Map of ADM CCS#2 Facilities.

7.0 Delineation of Monitoring Areas

The area to be monitored is the Area of Review (AOR) identified in Reference 1, Section G.1 and Attachment B. Based on the predicted area of the CO2 plume as estimated using the reservoir flow model, ADM will use the AOR as shown in Reference 1, Attachment B, Figure 7, plus a one-half mile buffer, as the maximum monitoring area (MMA).

The active monitoring area (AMA) is defined in 40 CFR 98.449 as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) The area projected to contain the free phase CO2 plume at the end of year t+5."

For CCS#2, the AMA will remain constant throughout the 5-year injection period and the 10-year post-injection site care (PISC) period, and will consist of the AOR as shown in Attachment B of Reference 1. Figure 2 shows the extent of the AMA.

The AMA will incorporate, as described in the Testing and Monitoring Plan (Reference 1, Attachment C):

- Continuous monitoring of injection pressure, annulus pressure, and temperature monitoring at the injection well;
- Groundwater quality monitoring in the local drinking water strata, the lowermost underground source of drinking water (USDW), and the strata immediately above the Eau Claire confining zone;
- External mechanical integrity testing (MIT) and pressure fall-off testing at the injection well;
- Plume and pressure front monitoring in the Mt. Simon using direct and indirect methods (i.e., brine geochemical monitoring, pulse neutron / RST logs, VSP and 3D seismic surveys).

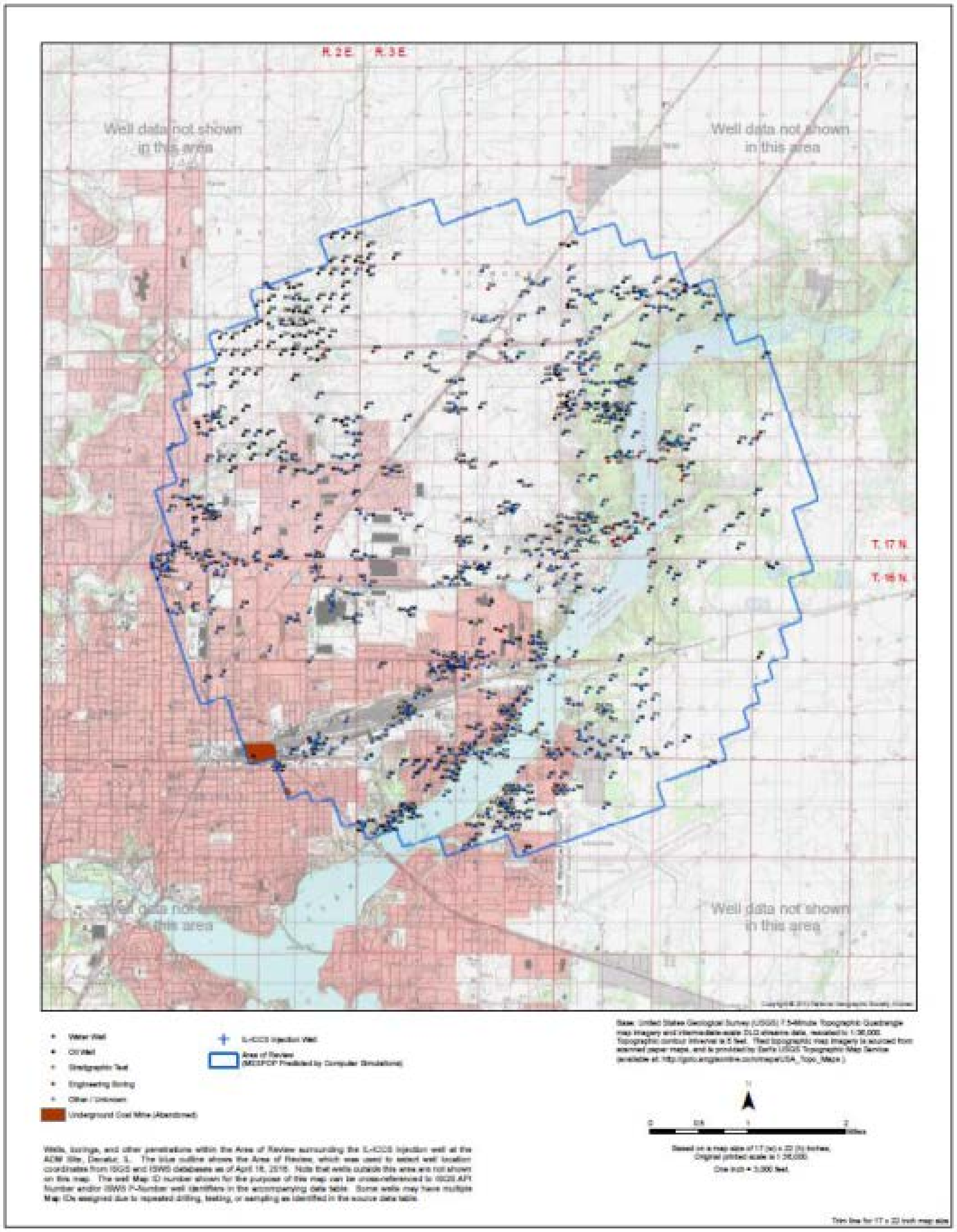

Figure 2. Active Monitoring Area (AMA) consists of the AoR (green outline) shown above.

8.0 EVALUATION OF LEAKAGE PATHWAYS

ADM has defined the potential leakage pathways within the AOR as:

1. Leakage from surface components (pipeline and wellhead)
2. Leakage through abandoned oil & gas wells
3. Leakage through fractures, faults, and bedding plane partings
4. Leakage through confining zone limitations
5. Leakage through injection well or monitoring wells

A qualitative evaluation of each potential leakage pathways is described in the below paragraphs. Risk estimates utilize the qualitative descriptions found in the geosphere risk assessment described for the Weyburn CO2 storage site in Canada[1].

8.1 Leakage from Surface Components

The most probable potential for leakage of CO2 to the surface is from surface components of the injection system: the pipeline that transports CO2 to the injection well (approximately 5,000 feet in length), and the wellhead itself. Leakage is most likely to be the result of aging and use of the surface components over time, most likely at flanged connection points. Leakage could also occur as ventilation from relief valves to dissipate over-pressure in the pipeline. Additionally, leakage may occur as the result of an accident or natural disaster which damages the surface components and allows CO2 to be released.

As a result, we conclude that the risk of leakage through this pathway is possible. The magnitude of such a leak will vary, depending on the failure mode of the component: a sudden break or rupture has the potential to allow several thousand pounds of CO2 to be released to the atmosphere almost immediately; a slowly deteriorating seal at a flanged connection may release only a few pounds of CO2 to the atmosphere over the course of several hours or days. Leakage or venting from surface components will be a risk only during the operation phase of injection (5 year period); following the injection phase, surface components will not store or transport CO2 and will therefore no longer be a leakage risk.

[1] "Geosphere risk assessment conducted for the IEAGHG Weyburn-Midale CO2 Monitoring and Storage Project," Bowden, A.R., Pershke, D. F., Chalaturnyk, R. International Journal of Greenhouse Gas Control 16S (2013) S276–S290. Reference Table 4, p. S284.

8.2 Leakage through Abandoned Oil & Gas Wells

As discussed in Attachment B of Reference 1, the only wells that currently penetrate the confining zone (Eau Claire Formation) are the IBDP injection and verification wells, and the IL-ICCS injection and verification wells, all of which were constructed in accordance with UIC Class VI requirements and are actively or will be monitored for **integrity on a** regular basis. No other wells in the AOR have a depth greater than approximately 2,500 feet below ground surface, which is roughly 3,000 feet above the top of the injection zone (Mt. Simon Sandstone).

As a result, we conclude that the risk of leakage through this pathway is almost impossible (and should in fact be zero) since no abandoned wells penetrate the confining zone. The magnitude and timing of such a leak are therefore not estimated.

Although leakage through abandoned wells will not occur as a primary pathway, it is possible that leakage that has migrated through the confining zone and into the more recent geologic strata may enter an abandoned well and migrate through the well to the surface; however, such leakage is expected to be detected by other monitoring methods (such as groundwater monitoring) as discussed in Section 5 of this MRV Plan.

8.3 Leakage through Fractures, Faults, and Bedding Plane Partings

As discussed in Section 2.2 of Reference 2, there are no regional faults or folds mapped within a 15-mile radius of the proposed IL-ICCS site. 2D and 3D seismic survey data collected and analyzed as part of the IBDP and IL-ICCS projects confirm the lack of faults or folds. Also as discussed in Section 2.2 of Reference 2, the risk of a significant seismic event in the IL-ICCS project area (which could open fractures in the confining zone and overlying geologic strata and allow leakage from the injection zone) is minimal.

As a result, we conclude that the risk of leakage through this pathway is highly improbable to nearly impossible. The magnitude and timing of such a leak, if it were to occur, would be dependent on the magnitude of the seismic event. If such an event were to occur during the injection period or after, it is possible that entire mass of CO2 that was injected into the reservoir up to that time may eventually be released to the surface; the timing of such a leak would occur over the course of several months to years following the seismic event

8.4 Leakage through Confining Zone Limitations

As discussed in Sections 2.2 and 2.5 of Reference 2, the Eau Claire Formation does not have any known penetrations (save for IBDP and IL-ICCS wells) within a 17-mile radius of the project site, has a laterally extensive shale component, and has only a slight dip (<1 degree). The type of leakage event through a confining zone limitation is conceived as an undiscovered local anomaly in the Eau Claire Formation, small in size, which would allow CO2 to leak through the confining zone into overlying strata.

As a result, we conclude that the risk of leakage through this pathway is highly improbable to nearly impossible. The magnitude of such a leak, if it were to occur, is likely to be very small, due to the known low permeability of the Eau Claire and the overlying secondary seal strata (Makoqueta Shale and New Albany Shale) that are also low permeability geologic units. For the same reason, it is believed that the timing of such a leak to the surface may be extremely slow (e.g., over the course of decades or longer), as the leak must pass upward through the confining zone, the secondary confining strata, and other geologic units.

8.5 Leakage through Injection or Monitoring Wells

As discussed in Sections I,K, L, and M of Reference 1 and further detailed in Attachments C (Testing and Monitoring Plan) and G (Well Construction) of Reference 1, design, construction, operation, maintenance, and monitoring plans for the injection-zone wells have been developed in accordance with UIC Class VI standards to minimize the potential for loss of well integrity. Additionally, the IBDP project at the ADM Decatur facility has provided prior experience in well construction, operations and maintenance, and monitoring that has been applied in the IL-ICCS project to further reduce the risk of a leakage pathway.

As a result, we conclude that the risk of leakage through this pathway is highly improbable. If a leak were to occur through this pathway, the magnitude of the leak is likely to be on the order of several hundred to several thousand pounds of CO2, depending on the location of the leak relative to the surface and the complexity of logistics required to seal the leak; since injection-zone wells are continuously monitored, early detection of a leak is anticipated, with resulting operations to be shut down and the well shut in to minimize the mass of CO2 leakage. The timing of CO2 release to the surface would be dependent on the location of the leak relative to the surface, and the resulting geologic strata into which the CO2 is released.

Table 1 shows IL-ICCS project injection and monitoring wells, with well depth, age, and construction information.

TABLE 1. IL-ICCS PROJECT WELL DATA

WELL ID	DEPTH	AGE	CONSTRUCTION
MVA 10LG	101 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 11LG	135 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 12LG	95 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 13LG	140 feet	3 years	Per Illinois Dept. of Public Health regulations
CCS#1	7,236 feet KB	6 years	Per UIC Class VI regulations
GM#1	3,496 feet KB	6 years	Per UIC Class VI regulations
VW#1	7,272 feet KB	6 years	Per UIC Class VI regulations

CCS#2	7,200 feet KB	1 year	Per UIC Class VI regulations
GM#2	3,555 feet KB	3 years	Per UIC Class VI regulations
VW#2	7,237 feet KB	1 year	Per UIC Class VI regulations

9.0 Detection, Verification, and Quantification of Leakage

9.1 Leakage Detection

Leakage detection for the IL-ICCS project will incorporate several monitoring programs: visual inspection of the pipeline to the injection well, injection well monitoring and MIT, CO2 plume / pressure front monitoring, and groundwater quality monitoring. Table 2 provides general information on the leakage pathways, monitoring programs to detect such leakage, spatial coverage of the monitoring program, and the monitoring timeline. Further details are provided in Reference 1, Attachment C (Testing and Monitoring Plan).

TABLE 2. LEAKAGE DETECTION MONITORING

Leakage Pathway	Detection Monitoring Program	Spatial Coverage of Monitoring Program	Monitoring Timeline
Surface Components	Visual Inspection	From flow meter to injection wellhead	Monthly for duration of injection (5 years)
	Injection Well Monitoring & MIT	Injection well (from surface to injection formation)	For duration of injection (5 years)
Abandoned Oil & Gas Wells	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality Monitoring	Groundwater monitoring locations (see Figure 1)	Quarterly to annual during injection (5 years)
Fractures & Faults	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality Monitoring	Groundwater monitoring locations (see Figure 1)	Quarterly to annual during injection (5 years)
Confining Zone Limitations	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality Monitoring	Groundwater monitoring locations (see Figure 1)	Quarterly to annual during injection (5 years)
Injection or Monitoring Wells	Injection Well Monitoring & MIT	Injection well (from surface to injection formation)	For duration of injection (5 years)

9.1.1 Surface Leakage Detection

Controlled or planned emissions from maintenance would occur when a section of a pipe containing CO_2 is isolated and vented so that a part can be maintained or repaired. Examples include replacement of instruments and valves as well as replacement of gaskets in the event of a leaking flange. Planned emissions due to maintenance will be limited to the extent possible. Controlled emissions will be tracked and reported as "leakage" (as the CO_2 will be vented rather than injected).

Unintentional (fugitive) emissions could arise from leakage of CO_2 at flanges and seals, at defects or cracks in the casing wall, or at pressure relief valves along the pipeline. Leakage from the pipeline or wellhead would be detected visually by ice crystal formation (due to the temperature reduction associated with release of supercritical CO_2 to the atmosphere) around the leakage point. Visual monitoring for these emissions will be performed monthly to detect fugitive emissions.

Visual inspection will not be possible for the one segment of pipeline that is underground. This section of the pipeline is 100% welded with no valves or flanges that could act as a leakage source; therefore, the potential for leakage in this segment is very low. Leak detection for this segment of pipeline would be limited to observation of abnormal pressure drop during a period of well shut-in and there is an absence of leakage detected in the aboveground pipeline. Well shut-in will be planned to occur on an annual basis.

9.1.2 Subsurface Leakage Detection

Leakage from the subsurface would be detected by one or more of the monitoring systems in the form of multiple measurements that are outside of the statistical baseline values (see Section 10,) are persistent over a time period (i.e., not a one-time anomalous measurement), and cannot be explained by a variation in injection operations or unanticipated conditions in the injection formation.

In all cases where monitoring data suggest a leak, data verification procedures will be followed as outlined in the Quality Assurance and Surveillance Plan (QASP, located in Reference 1, Attachment C, Appendix A). Data verification efforts should eliminate the possibility that a "false positive" leak detection occurs.

Injection Well Monitoring and MIT. Injection well monitoring will include pressure and temperature monitoring, and the use of one or more approved methods for MIT as described in the Final Permit (Reference 1). The injection well monitoring methods are briefly described below; further information on testing and monitoring procedures can be found in Reference 1, Attachment C.

1. Injection Well Pressure and Temperature. Pressure and temperature will be continuously monitored during injection operations, at the surface (wellhead), at the injection zone, and in the well annulus. Anomalous measurements will trigger further investigation, and if not attributable to operational or injection zone conditions, such measurements could indicate CO_2 leakage.

2. Wireline Temperature Log. Temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided.

   Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

3. Temperature Log using Distributed Temperature Sensing (DTS). CCS#2 is equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string. The DTS line is used for real time temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity.

   Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. This data can be continuously monitored to provide real time MIT surveillance.

4. Pulse Neutron Logging. Logging data will be recorded across the wellbore from the surface down to primary caprock.

   Data analysis will identify the mobilization of CO_2 or differences in the salinity of the reservoir fluids in the observation zone above the Eau Claire Shale seal. Differences between the measured and baseline value(s) may indicate the movement of fluids in the annulus or behind the casing.

Groundwater Quality and Geochemical Monitoring. The groundwater quality monitoring network, which includes both injection-zone monitoring and monitoring above the primary confining zone, is designed to detect unforeseen leakage from the Mt. Simon as soon after the first occurrence as possible.

Three aquifers above the primary confining zone are monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone: these include the aquifer immediately above the confining zone (Ironton/Galesville Sandstone), the St. Peter Sandstone, which is considered to be the lowermost USDW at the site (direct monitoring of the lowermost USDW aquifer is required by the EPA's UIC Program for CO_2 geologic sequestration), and the local source of drinking water, Quaternary / Pennsylvania strata (shallow groundwater). Shallow groundwater samples will be collected on a quarterly basis in years 1-2 of injection, semi-annual sampling for years 3-5 of injection, and annual sampling during post-injection; deep groundwater quality samples will be collected on an annual basis (see Reference 1, Attachment C for further detail on monitoring frequency).

In addition to direct monitoring specifically for the presence of CO_2, wells monitoring the deeper formations (St. Peter and Ironton/Galesville) are monitored for changes in geochemical and isotopic signatures that provide indication of CO_2 and/or brine leakage.

Plume and Pressure Front Monitoring. Direct and indirect methods will be utilized to monitor the CO_2 plume and pressure front. The plume will be directly monitored via annual fluid sampling in the Mt. Simon using VW#1 and VW#2. Indirect monitoring will consist of pulse neutron logging / reservoir saturation testing in VW#1, VW#2, CCS#1, and CCS#2 every two years during the injection phase, and seismic surveys / monitoring (reference Attachment C of Reference 1 for details).

Time lapse–vertical seismic profile (VSP) surveys were conducted annually using GM#1 in 2013, 2014, and 2015. The extent of the VSP survey is limited to approximately 30 acres in the vicinity of CCS #1. A baseline 3D seismic survey was conducted over the full AOR in January 2011, and a subsequent 3D survey conducted after the completion of the IBDP's injection period, in January 2015. These 3D surveys extended roughly 3,000 acres, centered near the location of CCS#2, and provided fold image coverage of roughly 2,000 acres.

Reduced-scale 3D surveys (roughly 2,000 acres, with fold image coverage of roughly 650 acres), with a focus on the vicinity north of CCS#2, will be conducted in years 1 and 10 following the conclusion of injection operations (i.e., scheduled for 2020 and 2030).

Seismic survey data interpretations should detect any faults or fractures in the subsurface strata that may indicate leakage or the potential for leakage, and will provide information on the extent of the CO_2 plume within the Mt. Simon.

Additionally, ADM will maintain a network of seismic monitoring stations (USGS will also maintain a similar seismic monitoring network) to detect seismic events greater than magnitude-1.0 (M1.0) within an 8-mile radius of the CCS#2 site, which could indicate activation of pre-existing planes of weakness (faults) that could compromise the seal formation.

Monitoring systems are anticipated to have a high capability to detect leakage that occurs. The monitoring program criteria and objectives are detailed in Section A.4 of the QASP

9.2 Leakage Verification

Once potential leakage has been detected, the following steps will be used to verify the potential location and source of leakage. Concurrent actions to minimize the detected leak (e.g., isolating the pipeline, shutting down injection operations) will be implemented.

If leakage is detected and verified, corrective action responses will be implemented in accordance with Area of Review and Corrective Action Plan (Reference 1, Attachment B) and/or the Emergency and Remedial Response Plan (Reference 1, Attachment F).

9.2.1 Surface Leakage

9.2.1.1 Obtain photographic documentation of the leakage point. (Visual signs of ice buildup or a plume are evidence of a leak.)

9.2.1.2 Identify and document the leak location on a map and/or P&I diagram of the pipeline.

9.2.2 Subsurface Leakage

If leakage is detected via surface or subsurface monitoring, and the quality assurance process has confirmed anomalous data readings:

9.2.2.1 Well Pressure / Temperature Monitoring

a. Identify and document the location (depth) of the anomalous readings.
b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.

9.2.2.2 Mechanical Integrity Testing

a. Identify and document the location (depth) of the anomalous readings.
b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.

9.2.2.3 Groundwater Quality / Geochemical Monitoring

a. Identify and document the aquifer in which the anomalous readings were measured.
b. Collect confirmation sample(s) and/or additional data in accordance with the QASP to verify result(s).

c. Use spatial and/or temporal analyses of available data (e.g., water quality, well measurements, reservoir flow model) to estimate the location and timing of the leakage.

9.2.2.4 Plume / Pressure Front Monitoring:

a. Determine whether injection formation characteristics (e.g., unanticipated conditions or heterogeneity) or model uncertainty are the cause of the anomalous data.
b. If step 9.2.2.4a does not determine the cause of the anomalous data, then it will be assumed that CO_2 leakage has been verified.

9.3 Leakage Quantification

9.3.1 Surface Leakage

The leakage rate from a pinhole, crack, or other defect in the pipeline or wellhead will be estimated once leakage has been detected and confirmed, using a methodology selected by ADM. Leakage estimating methods may potentially consist of either a form of mass balance equation or models. The selected method will be based on known data such as the size of the opening and the measured pressure, density, and temperature of CO_2 in the conduit at the time the leak was discovered.

Once a leakage rate has been estimated, the quantity (mass) of leakage may be estimated by calculating the approximate length of time that leakage occurred (e.g., based on time that leak was discovered and prior time that pipeline integrity was last verified). It is understood that this quantification method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

9.3.2 Subsurface Leakage

The ease with which leakage rate from the subsurface may be quantified will depend on the monitoring system that detected the leak. For example, leakage that is detected from pressure/temperature readings or MIT results may be more easily quantified (due to its location close to the injection source) than leakage that is detected from groundwater quality monitoring or from measurements of the CO_2 plume / pressure front.

Should leakage be detected and verified based on pressure/temperature readings or MIT results, ADM will select an estimation method to quantify leakage. One potential method under consideration is to use a form of mass balance equation; as with pipeline or wellhead leakage estimates, this method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

Similarly, should leakage be detected and verified based on groundwater monitoring data or plume / pressure front monitoring, ADM will select a method to estimate the quantity of leakage. One potential estimation method is to use the reservoir model to simulate a leak, use observed data to calibrate the "leaky" model. Once calibrated, the resulting model should provide a reasonably accurate estimate of the leakage quantity. ADM reserves the right to utilize other estimation methods (e.g., groundwater data evaluation) to evaluate leakage quantities.

9.3.3 Leakage Emitted to Surface

Mass balance calculations (see Section 11) require the estimation of leakage emitted to the surface / atmosphere. In the case of surface leakage (from pipeline or wellhead), the entire quantity of CO_2 that has leaked will be released to the atmosphere. For subsurface leakage, ADM will initially assume that the entire estimated quantity of CO_2 that has leaked will eventually reach the surface, unless modeling or other analysis is used to demonstrate that some portion of the leak will remain within the subsurface strata and will not reach the surface.

10.0 DETERMINATION OF EXPECTED BASELINES

Baseline data will consist of the following:, groundwater quality and geochemistry, MIT data, injection well pulse neutron & temperature logs, injection well DTS profile, seismic and pressure front data

10.1 Injection Well Monitoring

The following data will be collected over an established timeframe determined by ADM prior to injection operations:

1. Injection well pulse neutron and temperature logs (surface to confining zone)
2. Injection well DTS temperature profile (surface to confining zone) during well shut-in.

The average of these values will be used as the baseline for these parameters. Baseline logs for CCS#2 were collected on September 30, 2015. The baseline injection well DTS temperature profile during well shut-in was completed on December 31, 2016.

Anticipated annulus pressure as noted in Reference 1, Attachment A & C is discussed as follows:

1. The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) during injection.
2. During period of well shut down, the surface annulus pressure will be kept at a minimum of 100 psi.
3. At all times, 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 (higher pressure) and below (lower pressure) the injection tubing packer set at 6,320 feet below Kelly Bushing (KB).

[Note: Surface annulus pressure downhole annulus/tubing differential pressure and injection pressure measurements are not considered baseline parameters. Injection pressure (at surface and at depth) measurements will be collected continuously once CO_2 injection starts. Injection pressure will be a function of the mass flow rate, density, and pressure of the delivered CO_2; thus, the baseline injection pressure range will be based on the anticipated range of the mass flow rate, density, and pressure of the delivered CO_2. Injection pressure will be used for comparison against other baseline data and model predictions. Maximum injection pressure at the surface is limited to 2,284 psig.]

10.2 Groundwater Quality and Geochemical Change Monitoring

Groundwater quality and geochemistry will consist of the following data collection:

Shallow groundwater monitoring (4 sites)

- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density

Lowermost USDW (St. Peter Sandstone)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Lowermost aquifer above confining zone (Ironton-Galesville Sandstone)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Further details on testing and monitoring may be found in Reference 1, Attachment C.

Baseline groundwater quality and geochemistry will be developed in accordance with approved USEPA statistical methods using software (e.g., USEPA's ProUCL) to calculate the accepted range of data values (e.g., data within the 95% confidence limit). Data values collected during injection and post-injection periods that are outside of the accepted range will be an indicator that leakage may have occurred, subject to data verification per the QASP. Baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.

10.3 Mechanical Integrity Testing

Baseline MIT data will be collected following installation of CCS#2 and VW#2, and will consist of logged data from the well (e.g., cement evaluation, pressure data, or other logging type as described in Section 5.1). Baseline MIT data will be compared to subsequent MIT data (collection frequency as noted in Reference 1, Attachment C) to evaluate whether well integrity has been compromised. Baseline MIT data were collected from CCS#2 on (05/31/2015, 06/10/2015, 07/06/2015, 07/25/2015, 09/29/2015, & 09/30/2015), and from VW#2 on (11/01/2012 & 09/10/2015), and consisted of running a cement evaluation log and temperature log on CCS#2, pressure testing the casing & annulus on CCS#2, running a cement evaluation log on VW#2, and pressure testing the annulus on VW#2..

10.4 Plume and Pressure Front Monitoring

Baseline pulse neutron logging measurements will be collected in VW#1, VW#2, CCS#1, and CCS#2. Logged data will indicate, at minimum, CO_2 saturation within the Mt. Simon. Baseline data will be compared to data collected during Years 2 and 4 of injection operations. Baseline RST values for CCS#1 - 12/10/2014, CCS#2 - 09/30/2015, VW#1 - 12/11/2014, and VW#2 – 11/30/2016) were collected

Baseline 3D VSP and surface seismic surveys have been completed (performed in 2011 and 2015). Seismic data collected in 2020 and 2030 (post-injection) will be compared to baseline surveys to evaluate plume location and configuration relative to the reservoir model prediction.

Data from seismic event monitors in the vicinity of the IL-ICCS project will be used to compare seismicity during and following injection operations with pre-injection seismicity. Increased seismicity, while not directly correlating to a leak, may provide additional information in the event of a leak detected from other monitoring data.

11.0 SITE SPECIFIC MODIFICATIONS TO THE MASS BALANCE EQUATIONS

40 CFR 98, Subpart RR requires greenhouse gas (GHG) reporting for geologic sequestration (GS) of carbon dioxide. 40 CFR 98.442 through 98.447 details the data calculations, monitoring, estimating, reporting and recordkeeping requirements for GS projects. This section describes how ADM will calculate the mass of CO_2 injected, emitted, and sequestered.

The mass (in metric tons, MT) of CO_2 sequestered in the Mt. Simon will consist of the following components (equations referenced from Subpart RR of 40 CFR 98):

- Annual mass of CO_2 injected (CO2I, Equation RR-4)

  Parameter CO2I will be measured using flow meter FE006 (Coriolis meter) as referenced in P&ID No. 1041-PD-13 in Appendix C of Reference 2. Flow rate is measured on a mass basis (kg/hr). Annual mass will be calculated based on the quarterly mass flow rate measurements multiplied by the quarterly CO_2 concentrations provided to USEPA by ADM for CCS#2.

- Annual mass of CO_2 emitted by surface leakage (CO2E, Equation RR-10)

- Annual mass of CO_2 emitted from equipment leaks and vented emissions (CO2FI,)

Equipment that may emit CO_2 to the atmosphere include three thermal pressure relief valves along the pipeline (TRV-001, TRV-002, and TRV-003), and two pressure relief valves (PSV101 and MOV101) located on the annulus head tank. Process & instrumentation diagrams (P&ID) 1041-PD-13, 1041-PD-40, and 1041-PD-50 illustrate the location of these valves.

- Annual mass of CO_2 sequestered = CO2I – CO2E – CO2FI (Equation RR-12)

Parameters CO2E and CO2FI will be measured using the leakage quantification procedure described in Section 5.3. ADM will estimate the mass of CO_2 emitted from relief valves or leakage points based on operating conditions at the time of the release – pipeline pressure and flow rate, set point of relief valves, the size of the valve opening or leakage point opening, and the estimated length of time that the emission occurred. It is noted that this estimation method may have a large margin of error; therefore, ADM may include a statistical estimate of the calculation error to document the likely range of the emitted quantity.

12.0 ESTIMATED SCHEDULE FOR IMPLIMENTATION

The anticipated date for injection operations to begin at CCS#2 is 1st Quarter 2017. At that time, ADM will begin implementation of the leakage detection process. Also by that time, ADM expects to begin data collection for the purpose of calculating the total amount of CO_2 sequestered in the Mt. Simon formation.

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13.0 QUALITY ASSURANCE PROGRAM

Quality assurance procedures for the IL-ICCS project are provided in the Quality Assurance and Surveillance Plan (QASP) found in Reference 1, Attachment C, Appendix A.

- Section A of the QASP details project organization, project reasoning and regulatory information, project description, quality objectives and criteria, training and certification requirements, and project documentation/ recordkeeping.
- Section B details acquisition and generation of project data: sampling design, methods, handling and custody; sample analytical methods; quality control; instrument/equipment inspection, testing, calibration, operation and maintenance; use of indirect measurements; and data management.
- Section C details project assessments, corrective actions, and internal reporting.
- Section D discusses data validation and use.

14.0 RECORDS RETENTION

ADM will maintain and submit records required under Section N of the Final Permit issued by USEPA. Reports will be maintained in electronic format at the ADM Decatur facility unless the USEPA Director is otherwise notified by ADM.

SUMMARY OF PREVIOUS REVISIONS:

Date	Version	Author	Reason(s) for revision
01/06/2016	1.0	Outzen	New Document
01/07/2016	2.0	Outzen	Minor Formatting changes.

Appendix B: Submissions and Responses to Requests for Additional Information

Monitoring, Reporting, and Verification Plan CCS#2			
Date Issued 01/09/2017	**Document #** 180.60.ENV.309	**Version** 3.0	**Page** 1 of 22

LIST OF CONTROLLED COPIES, LOCATION, AND RESPONSIBILITY:

Copy #	Location	Responsibility
Original	DCS/DMS – (180-SQL)	Environmental Manager

APPROVALS:

Plant Manager

Environmental Manager

SUMMARY OF CURRENT REVISION:

Date	Version	Author	Reason(s) for revision
01/09/2017	3.0	Outzen	Modified Reference 1. Removed References 3, 4, and 5. Updated figure 2 to reflect current Active Monitoring Area. Updated Table 1. Update Section 9.1.2.4 to reflect current monitoring practice. Updated Section 10 to reflect current practice. Updated Section 12 to reflect current implementation schedule. Minor formatting and grammar corrections.

1.0 PURPOSE

This Monitoring, Reporting, and Verification (MRV) Plan has been prepared by the Archer Daniels Midland Company (ADM) for Carbon Capture and Sequestration well #2 (CCS #2) located in Decatur, Illinois, for the United States Environmental Protection Agency (USEPA). The MRV Plan was developed in accordance with the regulations at 40 CFR 98, Subparts RR (Geologic Sequestration of Carbon Dioxide) and UU (Injection of Carbon Dioxide).

2.0 SCOPE

This procedure is applicable to:

Archer Daniels Midland Company (ADM)
Permit Number: IL-115-6A-0001 (UIC Class VI)
Facility Name: CCS#2
UNDERGROUND INJECTION CONTROL PERMIT – CLASS VI
PERMIT NO. IL-115-6A-0001 (FACILITY NAME: CCS#2)

A map showing the ADM facility is provided as Figure 1.

3.0 DEFINITIONS

None

4.0 PRINCIPLE

None

5.0 SAFETY

There are no specific safety guidelines associated with this procedure.

6.0 PROJECT DESCRIPTION

ADM will capture carbon dioxide gas from their fuel ethanol production unit and compress the gas into a dense-phase liquid for injection into the Mt. Simon Sandstone approximately 7,000 feet below the ground surface. This project is identified as the Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) project.

The IL-ICCS project plans to inject up to 3,300 metric tons of carbon dioxide (CO2) daily, or 5.5 million metric tons over a five (5) year period.

The IL-ICCS project is the second carbon sequestration project at the Decatur facility. The Illinois State Geological Survey (ISGS) manages the Illinois Basin Decatur Project (IBDP) which completed its goal of injecting 1 million metric tons of CO2 over a three-year period from November 2011 to November 2014.

Further information can be found in the following documents which are referenced throughout this MRV Plan:

Reference 1 – USEPA Underground Injection Control Permit, Class VI, for ADM CCS#2, Permit No. IL-115-6A-0001, proposed modification published November 22, 2016, including Attachments A, B, C (with Quality Assurance & Surveillance Plan), D, E, F, G, H, and I

Reference 2 – ADM Permit Application for Underground Injection Control Permit, July 2011, including Appendices A-H (Permit Application)

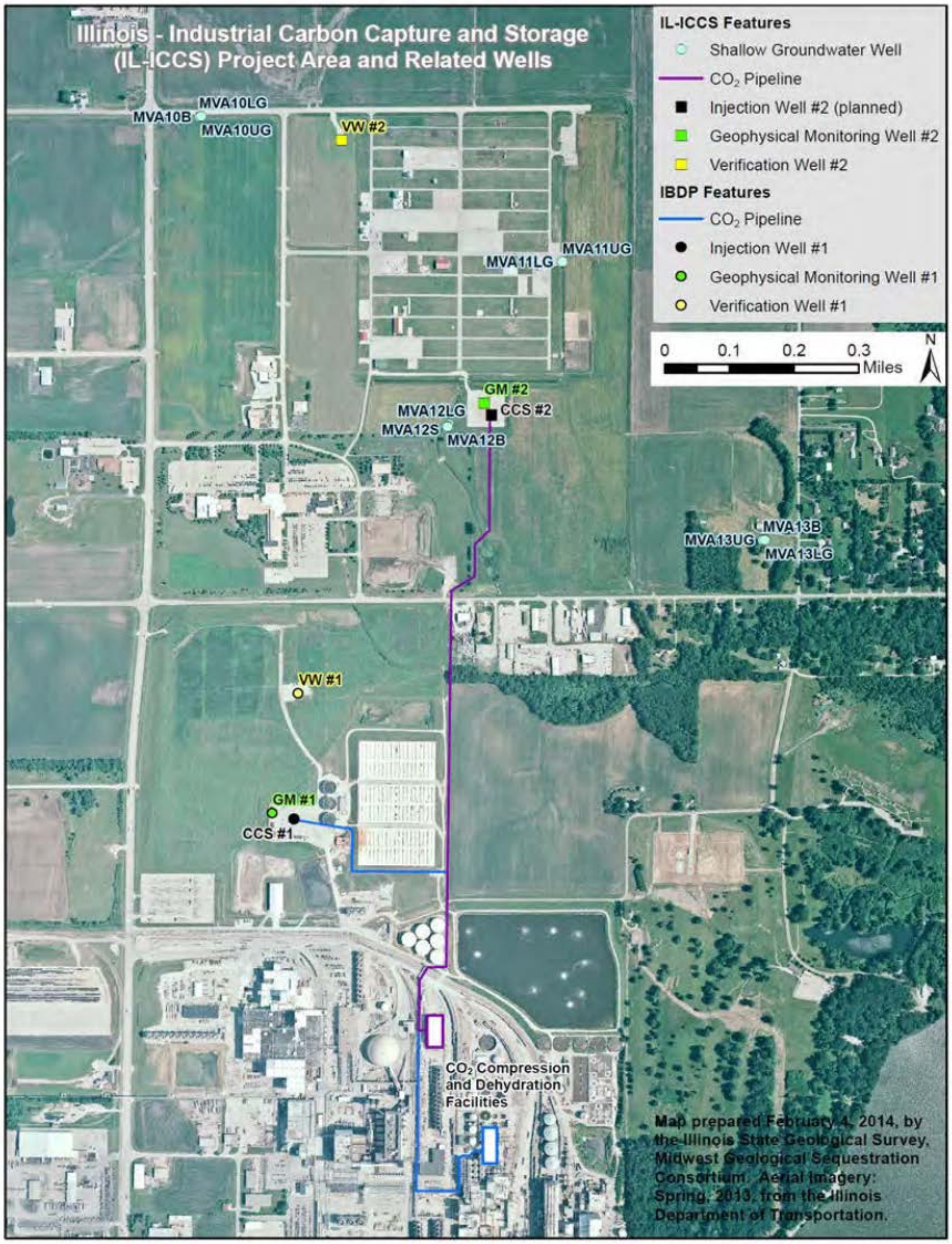

Figure 1. Aerial Photographic Map of ADM CCS#2 Facilities.

7.0 Delineation of Monitoring Areas

The area to be monitored is the Area of Review (AOR) identified in Reference 1, Section G.1 and Attachment B. Based on the predicted area of the CO2 plume as estimated using the reservoir flow model, ADM will use the AOR as shown in Reference 1, Attachment B, Figure 7, plus a one-half mile buffer, as the maximum monitoring area (MMA).

The active monitoring area (AMA) is defined in 40 CFR 98.449 as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) The area projected to contain the free phase CO2 plume at the end of year t+5."

For CCS#2, the AMA will remain constant throughout the 5-year injection period and the 10-year post-injection site care (PISC) period, and will consist of the AOR as shown in Attachment B of Reference 1. Figure 2 shows the extent of the AMA.

The AMA will incorporate, as described in the Testing and Monitoring Plan (Reference 1, Attachment C):

- Continuous monitoring of injection pressure, annulus pressure, and temperature monitoring at the injection well;
- Groundwater quality monitoring in the local drinking water strata, the lowermost underground source of drinking water (USDW), and the strata immediately above the Eau Claire confining zone;
- External mechanical integrity testing (MIT) and pressure fall-off testing at the injection well;
- Plume and pressure front monitoring in the Mt. Simon using direct and indirect methods (i.e., brine geochemical monitoring, pulse neutron / RST logs, VSP and 3D seismic surveys).

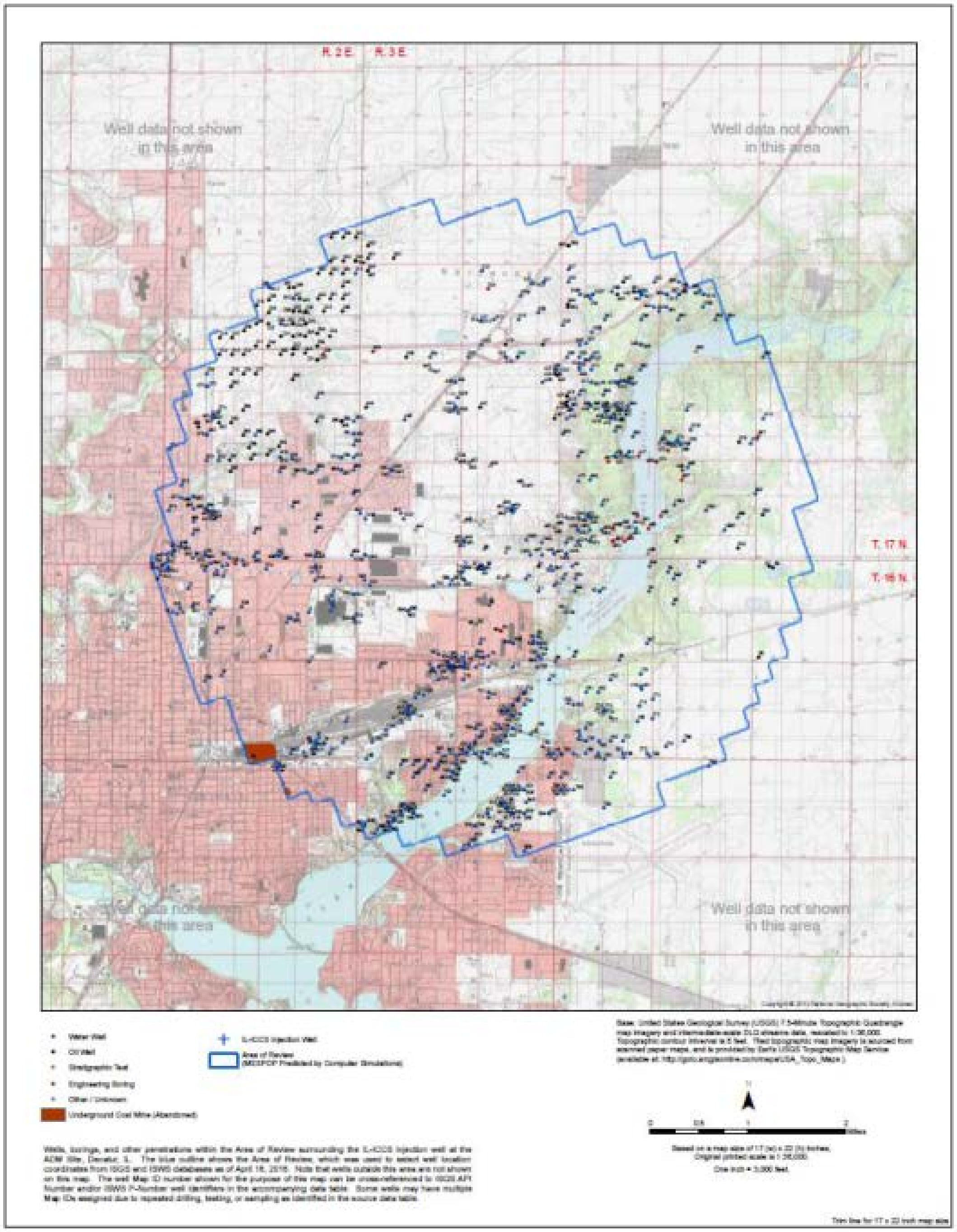

Figure 2. Active Monitoring Area (AMA) consists of the AoR (green outline) shown above.

8.0 EVALUATION OF LEAKAGE PATHWAYS

ADM has defined the potential leakage pathways within the AOR as:

1. Leakage from surface components (pipeline and wellhead)
2. Leakage through abandoned oil & gas wells
3. Leakage through fractures, faults, and bedding plane partings
4. Leakage through confining zone limitations
5. Leakage through injection well or monitoring wells

A qualitative evaluation of each potential leakage pathways is described in the below paragraphs. Risk estimates utilize the qualitative descriptions found in the geosphere risk assessment described for the Weyburn CO2 storage site in Canada[1].

8.1 Leakage from Surface Components

The most probable potential for leakage of CO2 to the surface is from surface components of the injection system: the pipeline that transports CO2 to the injection well (approximately 5,000 feet in length), and the wellhead itself. Leakage is most likely to be the result of aging and use of the surface components over time, most likely at flanged connection points. Leakage could also occur as ventilation from relief valves to dissipate over-pressure in the pipeline. Additionally, leakage may occur as the result of an accident or natural disaster which damages the surface components and allows CO2 to be released.

As a result, we conclude that the risk of leakage through this pathway is possible. The magnitude of such a leak will vary, depending on the failure mode of the component: a sudden break or rupture has the potential to allow several thousand pounds of CO2 to be released to the atmosphere almost immediately; a slowly deteriorating seal at a flanged connection may release only a few pounds of CO2 to the atmosphere over the course of several hours or days. Leakage or venting from surface components will be a risk only during the operation phase of injection (5 year period); following the injection phase, surface components will not store or transport CO2 and will therefore no longer be a leakage risk.

[1] "Geosphere risk assessment conducted for the IEAGHG Weyburn-Midale CO2 Monitoring and Storage Project," Bowden, A.R., Pershke, D. F., Chalaturnyk, R. International Journal of Greenhouse Gas Control 16S (2013) S276–S290. Reference Table 4, p. S284.

8.2 Leakage through Abandoned Oil & Gas Wells

As discussed in Attachment B of Reference 1, the only wells that currently penetrate the confining zone (Eau Claire Formation) are the IBDP injection and verification wells, and the IL-ICCS injection and verification wells, all of which were constructed in accordance with UIC Class VI requirements and are actively or will be monitored for **integrity on a** regular basis. No other wells in the AOR have a depth greater than approximately 2,500 feet below ground surface, which is roughly 3,000 feet above the top of the injection zone (Mt. Simon Sandstone).

As a result, we conclude that the risk of leakage through this pathway is almost impossible (and should in fact be zero) since no abandoned wells penetrate the confining zone. The magnitude and timing of such a leak are therefore not estimated.

Although leakage through abandoned wells will not occur as a primary pathway, it is possible that leakage that has migrated through the confining zone and into the more recent geologic strata may enter an abandoned well and migrate through the well to the surface; however, such leakage is expected to be detected by other monitoring methods (such as groundwater monitoring) as discussed in Section 5 of this MRV Plan.

8.3 Leakage through Fractures, Faults, and Bedding Plane Partings

As discussed in Section 2.2 of Reference 2, there are no regional faults or folds mapped within a 15-mile radius of the proposed IL-ICCS site. 2D and 3D seismic survey data collected and analyzed as part of the IBDP and IL-ICCS projects confirm the lack of faults or folds. Also as discussed in Section 2.2 of Reference 2, the risk of a significant seismic event in the IL-ICCS project area (which could open fractures in the confining zone and overlying geologic strata and allow leakage from the injection zone) is minimal.

As a result, we conclude that the risk of leakage through this pathway is highly improbable to nearly impossible. The magnitude and timing of such a leak, if it were to occur, would be dependent on the magnitude of the seismic event. If such an event were to occur during the injection period or after, it is possible that entire mass of CO2 that was injected into the reservoir up to that time may eventually be released to the surface; the timing of such a leak would occur over the course of several months to years following the seismic event

8.4 Leakage through Confining Zone Limitations

As discussed in Sections 2.2 and 2.5 of Reference 2, the Eau Claire Formation does not have any known penetrations (save for IBDP and IL-ICCS wells) within a 17-mile radius of the project site, has a laterally extensive shale component, and has only a slight dip (<1 degree). The type of leakage event through a confining zone limitation is conceived as an undiscovered local anomaly in the Eau Claire Formation, small in size, which would allow CO2 to leak through the confining zone into overlying strata.

As a result, we conclude that the risk of leakage through this pathway is highly improbable to nearly impossible. The magnitude of such a leak, if it were to occur, is likely to be very small, due to the known low permeability of the Eau Claire and the overlying secondary seal strata (Makoqueta Shale and New Albany Shale) that are also low permeability geologic units. For the same reason, it is believed that the timing of such a leak to the surface may be extremely slow (e.g., over the course of decades or longer), as the leak must pass upward through the confining zone, the secondary confining strata, and other geologic units.

8.5 Leakage through Injection or Monitoring Wells

As discussed in Sections I,K, L, and M of Reference 1 and further detailed in Attachments C (Testing and Monitoring Plan) and G (Well Construction) of Reference 1, design, construction, operation, maintenance, and monitoring plans for the injection-zone wells have been developed in accordance with UIC Class VI standards to minimize the potential for loss of well integrity. Additionally, the IBDP project at the ADM Decatur facility has provided prior experience in well construction, operations and maintenance, and monitoring that has been applied in the IL-ICCS project to further reduce the risk of a leakage pathway.

As a result, we conclude that the risk of leakage through this pathway is highly improbable. If a leak were to occur through this pathway, the magnitude of the leak is likely to be on the order of several hundred to several thousand pounds of CO2, depending on the location of the leak relative to the surface and the complexity of logistics required to seal the leak; since injection-zone wells are continuously monitored, early detection of a leak is anticipated, with resulting operations to be shut down and the well shut in to minimize the mass of CO2 leakage. The timing of CO2 release to the surface would be dependent on the location of the leak relative to the surface, and the resulting geologic strata into which the CO2 is released.

Table 1 shows IL-ICCS project injection and monitoring wells, with well depth, age, and construction information.

TABLE 1. IL-ICCS PROJECT WELL DATA

WELL ID	DEPTH	AGE	CONSTRUCTION
MVA 10LG	101 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 11LG	135 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 12LG	95 feet	3 years	Per Illinois Dept. of Public Health regulations
MVA 13LG	140 feet	3 years	Per Illinois Dept. of Public Health regulations
CCS#1	7,236 feet KB	6 years	Per UIC Class VI regulations
GM#1	3,496 feet KB	6 years	Per UIC Class VI regulations
VW#1	7,272 feet KB	6 years	Per UIC Class VI regulations

CCS#2	7,200 feet KB	1 year	Per UIC Class VI regulations
GM#2	3,555 feet KB	3 years	Per UIC Class VI regulations
VW#2	7,237 feet KB	1 year	Per UIC Class VI regulations

9.0 Detection, Verification, and Quantification of Leakage

9.1 Leakage Detection

Leakage detection for the IL-ICCS project will incorporate several monitoring programs: visual inspection of the pipeline to the injection well, injection well monitoring and MIT, CO2 plume / pressure front monitoring, and groundwater quality monitoring. Table 2 provides general information on the leakage pathways, monitoring programs to detect such leakage, spatial coverage of the monitoring program, and the monitoring timeline. Further details are provided in Reference 1, Attachment C (Testing and Monitoring Plan).

TABLE 2. LEAKAGE DETECTION MONITORING

Leakage Pathway	Detection Monitoring Program	Spatial Coverage of Monitoring Program	Monitoring Timeline
Surface Components	Visual Inspection	From flow meter to injection wellhead	Monthly for duration of injection (5 years)
	Injection Well Monitoring & MIT	Injection well (from surface to injection formation)	For duration of injection (5 years)
Abandoned Oil & Gas Wells	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality Monitoring	Groundwater monitoring locations (see Figure 1)	Quarterly to annual during injection (5 years)
Fractures & Faults	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality Monitoring	Groundwater monitoring locations (see Figure 1)	Quarterly to annual during injection (5 years)
Confining Zone Limitations	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality Monitoring	Groundwater monitoring locations (see Figure 1)	Quarterly to annual during injection (5 years)
Injection or Monitoring Wells	Injection Well Monitoring & MIT	Injection well (from surface to injection formation)	For duration of injection (5 years)

9.1.1 Surface Leakage Detection

Controlled or planned emissions from maintenance would occur when a section of a pipe containing CO_2 is isolated and vented so that a part can be maintained or repaired. Examples include replacement of instruments and valves as well as replacement of gaskets in the event of a leaking flange. Planned emissions due to maintenance will be limited to the extent possible. Controlled emissions will be tracked and reported as “leakage” (as the CO_2 will be vented rather than injected).

Unintentional (fugitive) emissions could arise from leakage of CO_2 at flanges and seals, at defects or cracks in the casing wall, or at pressure relief valves along the pipeline. Leakage from the pipeline or wellhead would be detected visually by ice crystal formation (due to the temperature reduction associated with release of supercritical CO_2 to the atmosphere) around the leakage point. Visual monitoring for these emissions will be performed monthly to detect fugitive emissions.

Visual inspection will not be possible for the one segment of pipeline that is underground. This section of the pipeline is 100% welded with no valves or flanges that could act as a leakage source; therefore, the potential for leakage in this segment is very low. Leak detection for this segment of pipeline would be limited to observation of abnormal pressure drop during a period of well shut-in and there is an absence of leakage detected in the aboveground pipeline. Well shut-in will be planned to occur on an annual basis.

9.1.2 Subsurface Leakage Detection

Leakage from the subsurface would be detected by one or more of the monitoring systems in the form of multiple measurements that are outside of the statistical baseline values (see Section 10,) are persistent over a time period (i.e., not a one-time anomalous measurement), and cannot be explained by a variation in injection operations or unanticipated conditions in the injection formation.

In all cases where monitoring data suggest a leak, data verification procedures will be followed as outlined in the Quality Assurance and Surveillance Plan (QASP, located in Reference 1, Attachment C, Appendix A). Data verification efforts should eliminate the possibility that a “false positive” leak detection occurs.

Injection Well Monitoring and MIT. Injection well monitoring will include pressure and temperature monitoring, and the use of one or more approved methods for MIT as described in the Final Permit (Reference 1). The injection well monitoring methods are briefly described below; further information on testing and monitoring procedures can be found in Reference 1, Attachment C.

1. Injection Well Pressure and Temperature. Pressure and temperature will be continuously monitored during injection operations, at the surface (wellhead), at the injection zone, and in the well annulus. Anomalous measurements will trigger further investigation, and if not attributable to operational or injection zone conditions, such measurements could indicate CO_2 leakage.

2. Wireline Temperature Log. Temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided.

   Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

3. Temperature Log using Distributed Temperature Sensing (DTS). CCS#2 is equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string. The DTS line is used for real time temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity.

   Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. This data can be continuously monitored to provide real time MIT surveillance.

4. Pulse Neutron Logging. Logging data will be recorded across the wellbore from the surface down to primary caprock.

   Data analysis will identify the mobilization of CO_2 or differences in the salinity of the reservoir fluids in the observation zone above the Eau Claire Shale seal. Differences between the measured and baseline value(s) may indicate the movement of fluids in the annulus or behind the casing.

Groundwater Quality and Geochemical Monitoring. The groundwater quality monitoring network, which includes both injection-zone monitoring and monitoring above the primary confining zone, is designed to detect unforeseen leakage from the Mt. Simon as soon after the first occurrence as possible.

Three aquifers above the primary confining zone are monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone: these include the aquifer immediately above the confining zone (Ironton/Galesville Sandstone), the St. Peter Sandstone, which is considered to be the lowermost USDW at the site (direct monitoring of the lowermost USDW aquifer is required by the EPA's UIC Program for CO_2 geologic sequestration), and the local source of drinking water, Quaternary / Pennsylvania strata (shallow groundwater). Shallow groundwater samples will be collected on a quarterly basis in years 1-2 of injection, semi-annual sampling for years 3-5 of injection, and annual sampling during post-injection; deep groundwater quality samples will be collected on an annual basis (see Reference 1, Attachment C for further detail on monitoring frequency).

In addition to direct monitoring specifically for the presence of CO_2, wells monitoring the deeper formations (St. Peter and Ironton/Galesville) are monitored for changes in geochemical and isotopic signatures that provide indication of CO_2 and/or brine leakage.

Plume and Pressure Front Monitoring. Direct and indirect methods will be utilized to monitor the CO_2 plume and pressure front. The plume will be directly monitored via annual fluid sampling in the Mt. Simon using VW#1 and VW#2. Indirect monitoring will consist of pulse neutron logging / reservoir saturation testing in VW#1, VW#2, CCS#1, and CCS#2 every two years during the injection phase, and seismic surveys / monitoring (reference Attachment C of Reference 1 for details).

Time lapse–vertical seismic profile (VSP) surveys were conducted annually using GM#1 in 2013, 2014, and 2015. The extent of the VSP survey is limited to approximately 30 acres in the vicinity of CCS #1. A baseline 3D seismic survey was conducted over the full AOR in January 2011, and a subsequent 3D survey conducted after the completion of the IBDP's injection period, in January 2015. These 3D surveys extended roughly 3,000 acres, centered near the location of CCS#2, and provided fold image coverage of roughly 2,000 acres.

Reduced-scale 3D surveys (roughly 2,000 acres, with fold image coverage of roughly 650 acres), with a focus on the vicinity north of CCS#2, will be conducted in years 1 and 10 following the conclusion of injection operations (i.e., scheduled for 2020 and 2030).

Seismic survey data interpretations should detect any faults or fractures in the subsurface strata that may indicate leakage or the potential for leakage, and will provide information on the extent of the CO_2 plume within the Mt. Simon.

Additionally, ADM will maintain a network of seismic monitoring stations (USGS will also maintain a similar seismic monitoring network) to detect seismic events greater than magnitude-1.0 (M1.0) within an 8-mile radius of the CCS#2 site, which could indicate activation of pre-existing planes of weakness (faults) that could compromise the seal formation.

Monitoring systems are anticipated to have a high capability to detect leakage that occurs. The monitoring program criteria and objectives are detailed in Section A.4 of the QASP

9.2 Leakage Verification

Once potential leakage has been detected, the following steps will be used to verify the potential location and source of leakage. Concurrent actions to minimize the detected leak (e.g., isolating the pipeline, shutting down injection operations) will be implemented.

If leakage is detected and verified, corrective action responses will be implemented in accordance with Area of Review and Corrective Action Plan (Reference 1, Attachment B) and/or the Emergency and Remedial Response Plan (Reference 1, Attachment F).

9.2.1 Surface Leakage

9.2.1.1 Obtain photographic documentation of the leakage point. (Visual signs of ice buildup or a plume are evidence of a leak.)

9.2.1.2 Identify and document the leak location on a map and/or P&I diagram of the pipeline.

9.2.2 Subsurface Leakage

If leakage is detected via surface or subsurface monitoring, and the quality assurance process has confirmed anomalous data readings:

9.2.2.1 Well Pressure / Temperature Monitoring

a. Identify and document the location (depth) of the anomalous readings.
b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.

9.2.2.2 Mechanical Integrity Testing

a. Identify and document the location (depth) of the anomalous readings.
b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.

9.2.2.3 Groundwater Quality / Geochemical Monitoring

a. Identify and document the aquifer in which the anomalous readings were measured.
b. Collect confirmation sample(s) and/or additional data in accordance with the QASP to verify result(s).

c. Use spatial and/or temporal analyses of available data (e.g., water quality, well measurements, reservoir flow model) to estimate the location and timing of the leakage.

9.2.2.4 Plume / Pressure Front Monitoring:

a. Determine whether injection formation characteristics (e.g., unanticipated conditions or heterogeneity) or model uncertainty are the cause of the anomalous data.
b. If step 9.2.2.4a does not determine the cause of the anomalous data, then it will be assumed that CO_2 leakage has been verified.

9.3 Leakage Quantification

9.3.1 Surface Leakage

The leakage rate from a pinhole, crack, or other defect in the pipeline or wellhead will be estimated once leakage has been detected and confirmed, using a methodology selected by ADM. Leakage estimating methods may potentially consist of either a form of mass balance equation or models. The selected method will be based on known data such as the size of the opening and the measured pressure, density, and temperature of CO_2 in the conduit at the time the leak was discovered.

Once a leakage rate has been estimated, the quantity (mass) of leakage may be estimated by calculating the approximate length of time that leakage occurred (e.g., based on time that leak was discovered and prior time that pipeline integrity was last verified). It is understood that this quantification method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

9.3.2 Subsurface Leakage

The ease with which leakage rate from the subsurface may be quantified will depend on the monitoring system that detected the leak. For example, leakage that is detected from pressure/temperature readings or MIT results may be more easily quantified (due to its location close to the injection source) than leakage that is detected from groundwater quality monitoring or from measurements of the CO_2 plume / pressure front.

Should leakage be detected and verified based on pressure/temperature readings or MIT results, ADM will select an estimation method to quantify leakage. One potential method under consideration is to use a form of mass balance equation; as with pipeline or wellhead leakage estimates, this method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

Similarly, should leakage be detected and verified based on groundwater monitoring data or plume / pressure front monitoring, ADM will select a method to estimate the quantity of leakage. One potential estimation method is to use the reservoir model to simulate a leak, use observed data to calibrate the "leaky" model. Once calibrated, the resulting model should provide a reasonably accurate estimate of the leakage quantity. ADM reserves the right to utilize other estimation methods (e.g., groundwater data evaluation) to evaluate leakage quantities.

9.3.3 Leakage Emitted to Surface

Mass balance calculations (see Section 11) require the estimation of leakage emitted to the surface / atmosphere. In the case of surface leakage (from pipeline or wellhead), the entire quantity of CO_2 that has leaked will be released to the atmosphere. For subsurface leakage, ADM will initially assume that the entire estimated quantity of CO_2 that has leaked will eventually reach the surface, unless modeling or other analysis is used to demonstrate that some portion of the leak will remain within the subsurface strata and will not reach the surface.

10.0 DETERMINATION OF EXPECTED BASELINES

Baseline data will consist of the following:, groundwater quality and geochemistry, MIT data, injection well pulse neutron & temperature logs, injection well DTS profile, seismic and pressure front data

10.1 Injection Well Monitoring

The following data will be collected over an established timeframe determined by ADM prior to injection operations:

1. Injection well pulse neutron and temperature logs (surface to confining zone)
2. Injection well DTS temperature profile (surface to confining zone) during well shut-in.

The average of these values will be used as the baseline for these parameters. Baseline logs for CCS#2 were collected on September 30, 2015. The baseline injection well DTS temperature profile during well shut-in was completed on December 31, 2016.

Anticipated annulus pressure as noted in Reference 1, Attachment A & C is discussed as follows:

1. The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) during injection.
2. During period of well shut down, the surface annulus pressure will be kept at a minimum of 100 psi.
3. At all times, 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 (higher pressure) and below (lower pressure) the injection tubing packer set at 6,320 feet below Kelly Bushing (KB).

[Note: Surface annulus pressure downhole annulus/tubing differential pressure and injection pressure measurements are not considered baseline parameters. Injection pressure (at surface and at depth) measurements will be collected continuously once CO_2 injection starts. Injection pressure will be a function of the mass flow rate, density, and pressure of the delivered CO_2; thus, the baseline injection pressure range will be based on the anticipated range of the mass flow rate, density, and pressure of the delivered CO_2. Injection pressure will be used for comparison against other baseline data and model predictions. Maximum injection pressure at the surface is limited to 2,284 psig.]

10.2 Groundwater Quality and Geochemical Change Monitoring

Groundwater quality and geochemistry will consist of the following data collection:

Shallow groundwater monitoring (4 sites)

- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density

Lowermost USDW (St. Peter Sandstone)

- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Lowermost aquifer above confining zone (Ironton-Galesville Sandstone)

- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Further details on testing and monitoring may be found in Reference 1, Attachment C.

> Baseline groundwater quality and geochemistry will be developed in accordance with approved USEPA statistical methods using software (e.g., USEPA's ProUCL) to calculate the accepted range of data values (e.g., data within the 95% confidence limit). Data values collected during injection and post-injection periods that are outside of the accepted range will be an indicator that leakage may have occurred, subject to data verification per the QASP. Baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.

10.3 Mechanical Integrity Testing

Baseline MIT data will be collected following installation of CCS#2 and VW#2, and will consist of logged data from the well (e.g., cement evaluation, pressure data, or other logging type as described in Section 5.1). Baseline MIT data will be compared to subsequent MIT data (collection frequency as noted in Reference 1, Attachment C) to evaluate whether well integrity has been compromised. Baseline MIT data were collected from CCS#2 on (05/31/2015, 06/10/2015, 07/06/2015, 07/25/2015, 09/29/2015, & 09/30/2015), and from VW#2 on (11/01/2012 & 09/10/2015), and consisted of running a cement evaluation log and temperature log on CCS#2, pressure testing the casing & annulus on CCS#2, running a cement evaluation log on VW#2, and pressure testing the annulus on VW#2..

10.4 Plume and Pressure Front Monitoring

Baseline pulse neutron logging measurements will be collected in VW#1, VW#2, CCS#1, and CCS#2. Logged data will indicate, at minimum, CO_2 saturation within the Mt. Simon. Baseline data will be compared to data collected during Years 2 and 4 of injection operations. Baseline RST values for CCS#1 - 12/10/2014, CCS#2 - 09/30/2015, VW#1 - 12/11/2014, and VW#2 – 11/30/2016) were collected

Baseline 3D VSP and surface seismic surveys have been completed (performed in 2011 and 2015). Seismic data collected in 2020 and 2030 (post-injection) will be compared to baseline surveys to evaluate plume location and configuration relative to the reservoir model prediction.

Data from seismic event monitors in the vicinity of the IL-ICCS project will be used to compare seismicity during and following injection operations with pre-injection seismicity. Increased seismicity, while not directly correlating to a leak, may provide additional information in the event of a leak detected from other monitoring data.

11.0 SITE SPECIFIC MODIFICATIONS TO THE MASS BALANCE EQUATIONS

40 CFR 98, Subpart RR requires greenhouse gas (GHG) reporting for geologic sequestration (GS) of carbon dioxide. 40 CFR 98.442 through 98.447 details the data calculations, monitoring, estimating, reporting and recordkeeping requirements for GS projects. This section describes how ADM will calculate the mass of CO_2 injected, emitted, and sequestered.

The mass (in metric tons, MT) of CO_2 sequestered in the Mt. Simon will consist of the following components (equations referenced from Subpart RR of 40 CFR 98):

- Annual mass of CO_2 injected (CO2I, Equation RR-4)

  Parameter CO2I will be measured using flow meter FE006 (Coriolis meter) as referenced in P&ID No. 1041-PD-13 in Appendix C of Reference 2. Flow rate is measured on a mass basis (kg/hr). Annual mass will be calculated based on the quarterly mass flow rate measurements multiplied by the quarterly CO_2 concentrations provided to USEPA by ADM for CCS#2.

- Annual mass of CO_2 emitted by surface leakage (CO2E, Equation RR-10)

- Annual mass of CO_2 emitted from equipment leaks and vented emissions (CO2FI,)

Equipment that may emit CO_2 to the atmosphere include three thermal pressure relief valves along the pipeline (TRV-001, TRV-002, and TRV-003), and two pressure relief valves (PSV101 and MOV101) located on the annulus head tank. Process & instrumentation diagrams (P&ID) 1041-PD-13, 1041-PD-40, and 1041-PD-50 illustrate the location of these valves.

- Annual mass of CO_2 sequestered = CO2I – CO2E – CO2FI (Equation RR-12)

Parameters CO2E and CO2FI will be measured using the leakage quantification procedure described in Section 5.3. ADM will estimate the mass of CO_2 emitted from relief valves or leakage points based on operating conditions at the time of the release – pipeline pressure and flow rate, set point of relief valves, the size of the valve opening or leakage point opening, and the estimated length of time that the emission occurred. It is noted that this estimation method may have a large margin of error; therefore, ADM may include a statistical estimate of the calculation error to document the likely range of the emitted quantity.

12.0 ESTIMATED SCHEDULE FOR IMPLIMENTATION

The anticipated date for injection operations to begin at CCS#2 is 1st Quarter 2017. At that time, ADM will begin implementation of the leakage detection process. Also by that time, ADM expects to begin data collection for the purpose of calculating the total amount of CO_2 sequestered in the Mt. Simon formation.

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13.0 QUALITY ASSURANCE PROGRAM

Quality assurance procedures for the IL-ICCS project are provided in the Quality Assurance and Surveillance Plan (QASP) found in Reference 1, Attachment C, Appendix A.

- Section A of the QASP details project organization, project reasoning and regulatory information, project description, quality objectives and criteria, training and certification requirements, and project documentation/ recordkeeping.
- Section B details acquisition and generation of project data: sampling design, methods, handling and custody; sample analytical methods; quality control; instrument/equipment inspection, testing, calibration, operation and maintenance; use of indirect measurements; and data management.
- Section C details project assessments, corrective actions, and internal reporting.
- Section D discusses data validation and use.

14.0 RECORDS RETENTION

ADM will maintain and submit records required under Section N of the Final Permit issued by USEPA. Reports will be maintained in electronic format at the ADM Decatur facility unless the USEPA Director is otherwise notified by ADM.

SUMMARY OF PREVIOUS REVISIONS:

Date	Version	Author	Reason(s) for revision
01/06/2016	1.0	Outzen	New Document
01/07/2016	2.0	Outzen	Minor Formatting changes.

Request for Additional Information: ADM Subpart RR MRV Plan
December 19, 2016

Instructions: Please enter responses into this table. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. Supplemental information may also be provided in a resubmitted MRV plan.

<table>
<tr><th rowspan="2">No.</th><th colspan="2">MRV Plan</th><th rowspan="2">EPA Questions</th><th rowspan="2">Responses</th></tr>
<tr><th>Section</th><th>Page</th></tr>
<tr><td>1.</td><td>2. Project Description</td><td>1, 3</td><td>MRV Plan: “Further information can be found in the following documents which are referenced throughout this MRV Plan:

Reference 1 – USEPA Underground Injection Control Permit, Class VI, for ADM CCS#2, Permit No. IL-115-6A-0001, effective December 1, 2014, including Attachments A, B, C (with Quality Assurance & Surveillance Plan), D, E, F, G, H, and I (Final Permit)

Reference 2 – ADM Permit Application for Underground Injection Control Permit, July 2011, including Appendices A-H (Permit Application)

Reference 3 – ADM Response to USEPA Request for Additional Information, January 2012 (Supplement #1)

Reference 4 – ADM Update to Area of Review and CO2 Plume Model, June 2012 (Model Update)

Reference 5 – ADM Response to USEPA Request for Additional Information, November 2012 (Supplement #2).”

Please reference the proposed permit modification.</td><td>Reference 1 was changed to reference the proposed modification published November 22, 2016.

Deleted References 3-5.

Changes also made throughout document to update citations to each reference.</td></tr>
</table>

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
2.	7. Delineation of Monitoring Areas	5	MRV Plan: “For CCS#2, the AMA will remain constant throughout the 5-year injection period and the 10-year post-injection site care (PISC) period, and will consist of the AOR as shown in Attachment B of Reference 1. Figure 2 shows the extent of the AMA.” Please provide an updated version of Figure 2 (i.e., AMA) to reflect the AoR in the proposed permit modification.	Updated the AOR figure 2.
3.	12. Estimated Schedule for Implementation	22	MRV Plan: “Determination of baseline data is anticipated to be complete by January 31, 2016. At that time, ADM anticipates having collected all of the initial baseline data, determined the range of acceptable values for the data, and established the “alarm” values which may signal anomalous conditions and will trigger further evaluation. The anticipated date for injection operations to begin at CCS#2 is 1st Quarter 2015. At that time, ADM will begin implementation of the leakage detection process. Also by that time, ADM expects to begin data collection for the purpose of calculating the total amount of CO_2 sequestered in the Mt. Simon formation.” If necessary, please update.	Updated anticipated date for injection operations to begin at CCS#2 to 1st Quarter 2017. Deleted anticipated date and discussion for reviewing baseline data as this is complete. Plan updated to incorporate this review as follows: • Section 9.1.2.: Replaced previous items 4-Wireline Noise Logging and 5-Wireline Oxygen Activation Logging with new item 4 Pulse Neutron Logging. • Section 9.1.2: In paragraph discussing seismic survey data interpretations, deleted last sentence stating “Leakage would be detected as CO2 migration above the confining zone.” • Section 10.1: Updated language to reflect final baseline information and adjust to be consistent with edits for Section 9.1.2. • Section 10.3: Deleted second slide as additional baseline data using RST logs will not be obtained as of this date. • Corrected section 10.4 by replacing RST with pulse neutron logging and corrected date for VW#2.

ADM also update Section 8.5 updated “Age” for several wells in Table 1.

Monitoring, Reporting, and Verification Plan CCS#2			
Date Issued 01/07/2016	**Document #** 180.60.ENV.309	**Version** 2.0	**Page** 1 of 23

LIST OF CONTROLLED COPIES, LOCATION, AND RESPONSIBILITY:

Copy #	Location	Responsibility
Original	DCS/DMS – (180-SQL)	Environmental Manager

APPROVALS:

Plant Manager

Environmental Manager

SUMMARY OF CURRENT REVISION:

Date	Version	Author	Reason(s) for revision
01/07/2016	2.0	Outzen	Minor Formatting changes.

UNCONTROLLED COPY PRINTED ON: 01/08/2016 11:44 AM

1.0 PURPOSE

This Monitoring, Reporting, and Verification (MRV) Plan has been prepared by the Archer Daniels Midland Company (ADM) for Carbon Capture and Sequestration well #2 (CCS #2) located in Decatur, Illinois, for the United States Environmental Protection Agency (USEPA). The MRV Plan was developed in accordance with the regulations at 40 CFR 98, Subparts RR (Geologic Sequestration of Carbon Dioxide) and UU (Injection of Carbon Dioxide).

2.0 SCOPE

This procedure is applicable to:

Archer Daniels Midland Company (ADM)
Permit Number: IL-115-6A-0001 (UIC Class VI)
Facility Name:CCS#2
UNDERGROUND INJECTION CONTROL PERMIT – CLASS VI
PERMIT NO. IL-115-6A-0001 (FACILITY NAME: CCS#2)

A map showing the ADM facility is provided as Figure 1.

3.0 DEFINITIONS

None

4.0 PRINCIPLE

None

5.0 SAFETY

There are no specific safety guidelines associated with this procedure.

6.0 PROJECT DESCRIPTION

ADM will capture carbon dioxide gas from their fuel ethanol production unit and compress the gas into a dense-phase liquid for injection into the Mt. Simon Sandstone approximately 7,000 feet below the ground surface. This project is identified as the Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) project.

The IL-ICCS project plans to inject up to 3,300 metric tons of carbon dioxide (CO2) daily, or 5.5 million metric tons over a five (5) year period.

The IL-ICCS project is the second carbon sequestration project at the Decatur facility. The Illinois State Geological Survey (ISGS) manages the Illinois Basin Decatur Project (IBDP) which completed its goal of injecting 1 million metric tons of CO2 over a three-year period from November 2011 to November 2014.

Further information can be found in the following documents which are referenced throughout this MRV Plan:

Reference 1 – USEPA Underground Injection Control Permit, Class VI, for ADM CCS#2, Permit No. IL-115-6A-0001, effective December 1, 2014, including Attachments A, B, C (with Quality Assurance & Surveillance Plan), D, E, F, G, H, and I (Final Permit)

Reference 2 – ADM Permit Application for Underground Injection Control Permit, July 2011, including Appendices A-H (Permit Application)

Reference 3 – ADM Response to USEPA Request for Additional Information, January 2012 (Supplement #1)

Reference 4 – ADM Update to Area of Review and CO2 Plume Model, June 2012 (Model Update)

Reference 5 – ADM Response to USEPA Request for Additional Information, November 2012 (Supplement #2)

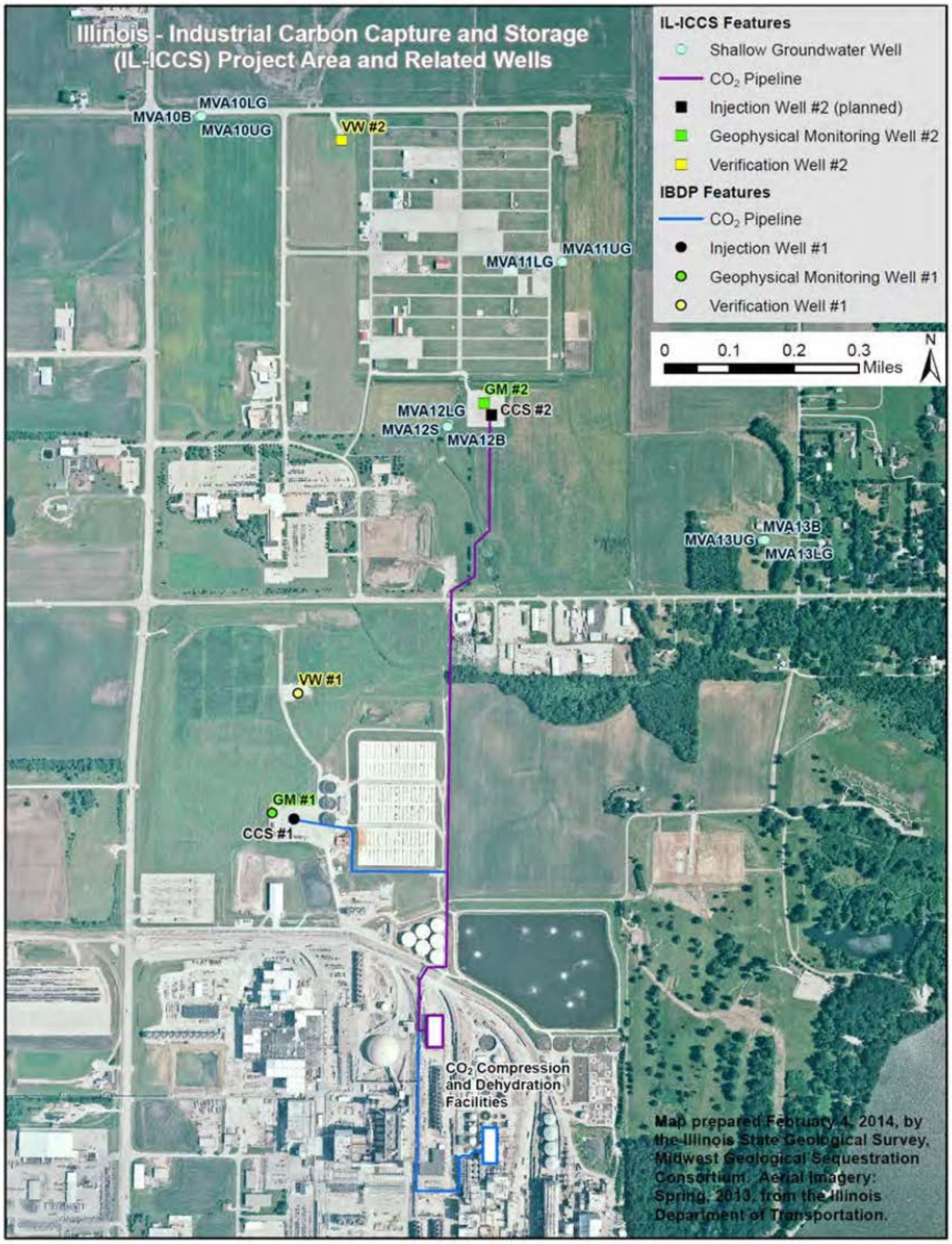

Figure 1. Aerial Photographic Map of ADM CCS#2 Facilities.

7.0 Delineation of Monitoring Areas

The area to be monitored is the Area of Review (AOR) identified in Reference 1, Section G.1 and Attachment B. Based on the predicted area of the CO2 plume as estimated using the reservoir flow model, ADM will use the AOR as shown in Reference 1, Attachment B, Figure 7, plus a one-half mile buffer, as the maximum monitoring area (MMA).

The active monitoring area (AMA) is defined in 40 CFR 98.449 as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) The area projected to contain the free phase CO2 plume at the end of year t+5."

For CCS#2, the AMA will remain constant throughout the 5-year injection period and the 10-year post-injection site care (PISC) period, and will consist of the AOR as shown in Attachment B of Reference 1. Figure 2 shows the extent of the AMA.

The AMA will incorporate, as described in the Testing and Monitoring Plan (Reference 1, Attachment C):

- Continuous monitoring of injection pressure, annulus pressure, and temperature monitoring at the injection well;
- Groundwater quality monitoring in the local drinking water strata, the lowermost underground source of drinking water (USDW), and the strata immediately above the Eau Claire confining zone;
- External mechanical integrity testing (MIT) and pressure fall-off testing at the injection well;
- Plume and pressure front monitoring in the Mt. Simon using direct and indirect methods (i.e., brine geochemical monitoring, pulse neutron / RST logs, VSP and 3D seismic surveys).

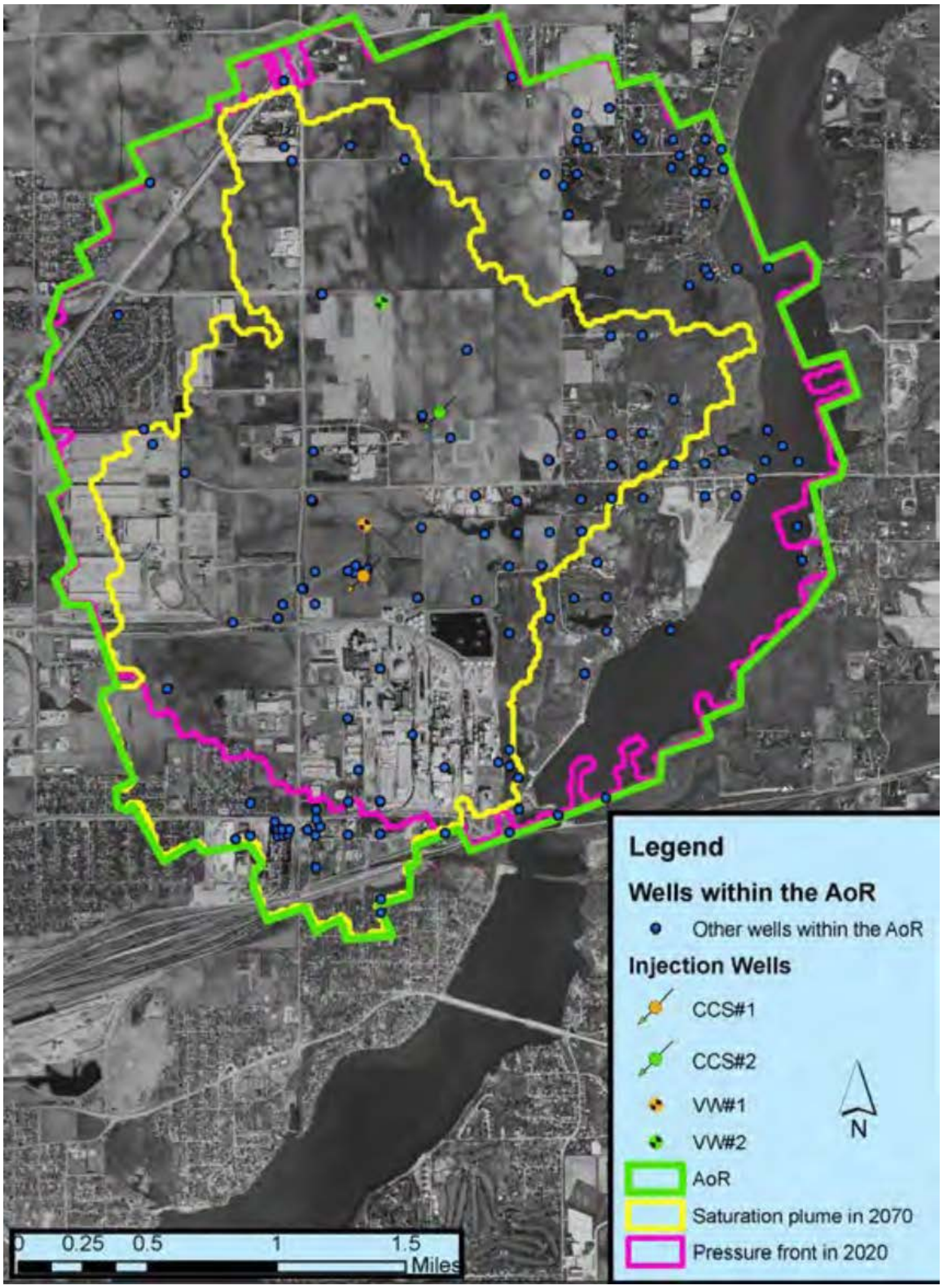

Figure 2. Active Monitoring Area (AMA) consists of the AoR (green outline) shown above.

8.0 EVALUATION OF LEAKAGE PATHWAYS

ADM has defined the potential leakage pathways within the AOR as:

1. Leakage from surface components (pipeline and wellhead)
2. Leakage through abandoned oil & gas wells
3. Leakage through fractures, faults, and bedding plane partings
4. Leakage through confining zone limitations
5. Leakage through injection well or monitoring wells

A qualitative evaluation of each potential leakage pathways is described in the below paragraphs. Risk estimates utilize the qualitative descriptions found in the geosphere risk assessment described for the Weyburn CO2 storage site in Canada[1].

8.1 Leakage From Surface Components

The most probable potential for leakage of CO2 to the surface is from surface components of the injection system: the pipeline that transports CO2 to the injection well (approximately 5,000 feet in length), and the wellhead itself. Leakage is most likely to be the result of aging and use of the surface components over time, most likely at flanged connection points. Leakage could also occur as ventilation from relief valves to dissipate over-pressure in the pipeline. Additionally, leakage may occur as the result of an accident or natural disaster which damages the surface components and allows CO2 to be released.

As a result, we conclude that the risk of leakage through this pathway is possible. The magnitude of such a leak will vary, depending on the failure mode of the component: a sudden break or rupture has the potential to allow several thousand pounds of CO2 to be released to the atmosphere almost immediately; a slowly deteriorating seal at a flanged connection may release only a few pounds of CO2 to the atmosphere over the course of several hours or days. Leakage or venting from surface components will be a risk only during the operation phase of injection (5 year period); following the injection phase, surface components will not store or transport CO2 and will therefore no longer be a leakage risk.

[1] "Geosphere risk assessment conducted for the IEAGHG Weyburn-Midale CO2 Monitoring and Storage Project," Bowden, A.R., Pershke, D. F., Chalaturnyk, R. International Journal of Greenhouse Gas Control 16S (2013) S276–S290. Reference Table 4, p. S284.

8.2 Leakage through Abandoned Oil & Gas Wells

As discussed in Attachment B of Reference 1, the only wells that currently penetrate the confining zone (Eau Claire Formation) are the IBDP injection and verification wells, and the IL-ICCS injection and verification wells, all of which were constructed in accordance with UIC Class VI requirements and are actively or will be monitored for **integrity on a** regular basis. No other wells in the AOR have a depth greater than approximately 2,500 feet below ground surface, which is roughly 3,000 feet above the top of the injection zone (Mt. Simon Sandstone).

As a result, we conclude that the risk of leakage through this pathway is almost impossible (and should in fact be zero) since no abandoned wells penetrate the confining zone. The magnitude and timing of such a leak are therefore not estimated.

Although leakage through abandoned wells will not occur as a primary pathway, it is possible that leakage that has migrated through the confining zone and into the more recent geologic strata may enter an abandoned well and migrate through the well to the surface; however, such leakage is expected to be detected by other monitoring methods (such as groundwater monitoring) as discussed in Section 5 of this MRV Plan.

8.3 Leakage through Fractures, Faults, and Bedding Plane Partings

As discussed in Section 2.2 of Reference 3, there are no regional faults or folds mapped within a 15-mile radius of the proposed IL-ICCS site. 2D and 3D seismic survey data collected and analyzed as part of the IBDP and IL-ICCS projects confirm the lack of faults or folds. Also as discussed in Section 2.2 of Reference 3, the risk of a significant seismic event in the IL-ICCS project area (which could open fractures in the confining zone and overlying geologic strata and allow leakage from the injection zone) is minimal.

As a result, we conclude that the risk of leakage through this pathway is highly improbable to nearly impossible. The magnitude and timing of such a leak, if it were to occur, would be dependent on the magnitude of the seismic event. If such an event were to occur during the injection period or after, it is possible that entire mass of CO2 that was injected into the reservoir up to that time may eventually be released to the surface; the timing of such a leak would occur over the course of several months to years following the seismic event

8.4 Leakage through Confining Zone Limitations

As discussed in Sections 2.2 and 2.5 of Reference 3, the Eau Claire Formation does not have any known penetrations (save for IBDP and IL-ICCS wells) within a 17-mile radius of the project site, has a laterally extensive shale component, and has only a slight dip (<1 degree). The type of leakage event through a confining zone limitation is conceived as an undiscovered local anomaly in the Eau Claire Formation, small in size, which would allow CO2 to leak through the confining zone into overlying strata.

As a result, we conclude that the risk of leakage through this pathway is highly improbable to nearly impossible. The magnitude of such a leak, if it were to occur, is likely to be very small, due to the known low permeability of the Eau Claire and the overlying secondary seal strata (Makoqueta Shale and New Albany Shale) that are also low permeability geologic units. For the same reason, it is believed that the timing of such a leak to the surface may be extremely slow (e.g., over the course of decades or longer), as the leak must pass upward through the confining zone, the secondary confining strata, and other geologic units.

8.5 Leakage through Injection or Monitoring Wells

As discussed in Attachment G of Reference 1, Section 3A of Reference 2, and Section 3B of Reference 5, design, construction, operation, maintenance, and monitoring plans for the injection-zone wells have been developed in accordance with UIC Class VI standards to minimize the potential for loss of well integrity. Additionally, the IBDP project at the ADM Decatur facility has provided prior experience in well construction, operations and maintenance, and monitoring that has been applied in the IL-ICCS project to further reduce the risk of a leakage pathway.

As a result, we conclude that the risk of leakage through this pathway is highly improbable. If a leak were to occur through this pathway, the magnitude of the leak is likely to be on the order of several hundred to several thousand pounds of CO2, depending on the location of the leak relative to the surface and the complexity of logistics required to seal the leak; since injection-zone wells are continuously monitored, early detection of a leak is anticipated, with resulting operations to be shut down and the well shut in to minimize the mass of CO2 leakage. The timing of CO2 release to the surface would be dependent on the location of the leak relative to the surface, and the resulting geologic strata into which the CO2 is released.

Table 1 shows IL-ICCS project injection and monitoring wells, with well depth, age, and construction information.

TABLE 1. IL-ICCS PROJECT WELL DATA			
WELL ID	DEPTH	AGE	CONSTRUCTION
MVA 10LG	101 feet	<1 year	Per Illinois Dept. of Public Health regulations
MVA 11LG	135 feet	<1 year	Per Illinois Dept. of Public Health regulations
MVA 12LG	95 feet	<1 year	Per Illinois Dept. of Public Health regulations
MVA 13LG	140 feet	<1 year	Per Illinois Dept. of Public Health regulations

CCS#1	7,236 feet KB	6 years	Per UIC Class VI regulations
GM#1	3,496 feet KB	6 years	Per UIC Class VI regulations
VW#1	7,272 feet KB	6 years	Per UIC Class VI regulations
CCS#2	7,200 feet KB	<1 year	Per UIC Class VI regulations
GM#2	3,555 feet KB	<1 year	Per UIC Class VI regulations
VW#2	7,237 feet KB	<1 year	Per UIC Class VI regulations

9.0 Detection, Verification, and Quantification of Leakage

9.1 Leakage Detection

Leakage detection for the IL-ICCS project will incorporate several monitoring programs: visual inspection of the pipeline to the injection well, injection well monitoring and MIT, CO2 plume / pressure front monitoring, and groundwater quality monitoring. Table 2 provides general information on the leakage pathways, monitoring programs to detect such leakage, spatial coverage of the monitoring program, and the monitoring timeline. Further details are provided in Reference 1, Attachment C (Testing and Monitoring Plan).

TABLE 2. LEAKAGE DETECTION MONITORING

Leakage Pathway	Detection Monitoring Program	Spatial Coverage of Monitoring Program	Monitoring Timeline
Surface Components	Visual Inspection	From flow meter to injection wellhead	Monthly for duration of injection (5 years)
	Injection Well Monitoring & MIT	Injection well (from surface to injection formation)	For duration of injection (5 years)
Abandoned Oil & Gas Wells	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality Monitoring	Groundwater monitoring locations (see Figure 1)	Quarterly to annual during injection (5 years)
Fractures & Faults	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality Monitoring	Groundwater monitoring locations (see Figure 1)	Quarterly to annual during injection (5 years)
Confining Zone Limitations	Plume / Pressure Front Monitoring	From injection wellhead to edge of AMA	For duration of injection (5 years); and in Years 1 and 10 following injection
	Groundwater Quality	Groundwater monitoring	Quarterly to annual during

	Monitoring	locations (see Figure 1)	injection (5 years)
Injection or Monitoring Wells	Injection Well Monitoring & MIT	Injection well (from surface to injection formation)	For duration of injection (5 years)

9.1.1 Surface Leakage Detection

Controlled or planned emissions from maintenance would occur when a section of a pipe containing CO_2 is isolated and vented so that a part can be maintained or repaired. Examples include replacement of instruments and valves as well as replacement of gaskets in the event of a leaking flange. Planned emissions due to maintenance will be limited to the extent possible. Controlled emissions will be tracked and reported as "leakage" (as the CO_2 will be vented rather than injected).

Unintentional (fugitive) emissions could arise from leakage of CO_2 at flanges and seals, at defects or cracks in the casing wall, or at pressure relief valves along the pipeline. Leakage from the pipeline or wellhead would be detected visually by ice crystal formation (due to the temperature reduction associated with release of supercritical CO_2 to the atmosphere) around the leakage point. Visual monitoring for these emissions will be performed monthly to detect fugitive emissions.

Visual inspection will not be possible for the one segment of pipeline that is underground. This section of the pipeline is 100% welded with no valves or flanges that could act as a leakage source; therefore, the potential for leakage in this segment is very low. Leak detection for this segment of pipeline would be limited to observation of abnormal pressure drop during a period of well shut-in and there is an absence of leakage detected in the aboveground pipeline. Well shut-in will be planned to occur on an annual basis.

9.1.2 Subsurface Leakage Detection

Leakage from the subsurface would be detected by one or more of the monitoring systems in the form of multiple measurements that are outside of the statistical baseline values (see Section 10,) are persistent over a time period (i.e., not a one-time anomalous measurement), and cannot be explained by a variation in injection operations or unanticipated conditions in the injection formation.

In all cases where monitoring data suggest a leak, data verification procedures will be followed as outlined in the Quality Assurance and Surveillance Plan (QASP, located in Reference 1, Attachment C, Appendix A). Data verification efforts should eliminate the possibility that a "false positive" leak detection occurs.

Injection Well Monitoring and MIT. Injection well monitoring will include pressure and temperature monitoring, and the use of one or more approved methods for MIT as described in the Final Permit (Reference 1). The injection well monitoring methods are briefly described below; further information on testing and monitoring procedures can be found in Reference 1, Attachment C.

1. Injection Well Pressure and Temperature. Pressure and temperature will be continuously monitored during injection operations, at the surface (wellhead), at the injection zone, and in the well annulus. Anomalous measurements will trigger further investigation, and if not attributable to operational or injection zone conditions, such measurements could indicate CO_2 leakage.

2. Wireline Temperature Log. Temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided.

   Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

3. Temperature Log using Distributed Temperature Sensing (DTS). CCS#2 is equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string. The DTS line is used for real time temperature monitoring and, like a conventional temperature log, can be used for early

detection of temperature changes that may indicate a loss of well mechanical integrity.

Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. This data can be continuously monitored to provide real time MIT surveillance.

4. Wireline Noise Logging. Logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging will be carried out while injection is occurring.

   The base noise level in the well (dead well level) will be determined, and the log analyzed to identify departures from this level. (An increase in noise near the surface due to equipment operating at the surface is to be expected in many situations.)

5. Wireline Oxygen Activation (OA) Logging. Logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging will be carried out while injection is occurring.

   Data analysis will identify any differences in the activated water's measured gamma ray count-rate profile versus the expected count-rate profile for a static environment. Differences between the measured and expected value(s) may indicate flow in the annulus or behind the casing.

Groundwater Quality and Geochemical Monitoring. The groundwater quality monitoring network, which includes both injection-zone monitoring and monitoring above the primary confining zone, is designed to detect unforeseen leakage from the Mt. Simon as soon after the first occurrence as possible.

Three aquifers above the primary confining zone are monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone: these include the aquifer immediately above the confining zone (Ironton/Galesville Sandstone), the St. Peter Sandstone, which is considered to be the lowermost USDW at the site (direct monitoring of the lowermost USDW aquifer is required by the EPA's UIC Program for CO_2 geologic sequestration), and the local source of drinking water, Quaternary / Pennsylvania strata (shallow groundwater). Shallow groundwater samples will be collected on a quarterly basis in years 1-2 of injection, semi-annual sampling for years 3-5 of injection, and annual sampling during post-injection; deep groundwater quality samples will be collected on an annual basis (see Reference 1, Attachment C for further detail on monitoring frequency).

In addition to direct monitoring specifically for the presence of CO_2, wells monitoring the deeper formations (St. Peter and Ironton/Galesville) are monitored for changes in geochemical and isotopic signatures that provide indication of CO_2 and/or brine leakage.

Plume and Pressure Front Monitoring. Direct and indirect methods will be utilized to monitor the CO_2 plume and pressure front. The plume will be directly monitored via annual fluid sampling in the Mt. Simon using VW#1 and VW#2. Indirect monitoring will consist of pulse neutron logging / reservoir saturation testing in VW#1, VW#2, CCS#1, and CCS#2 every two years during the injection phase, and seismic surveys / monitoring (reference Attachment C of Reference 1 for details).

Time lapse–vertical seismic profile (VSP) surveys were conducted annually using GM#1 in 2013, 2014, and 2015. The extent of the VSP survey is limited to approximately 30 acres in the vicinity of CCS #1. A baseline 3D seismic survey was conducted over the full AOR in January 2011, and a subsequent 3D survey conducted after the completion of the IBDP's injection period, in January 2015. These 3D surveys extended roughly 3,000 acres, centered near the location of CCS#2, and provided fold image coverage of roughly 2,000 acres.

Reduced-scale 3D surveys (roughly 2,000 acres, with fold image coverage of roughly 650 acres), with a focus on the vicinity north of CCS#2, will be conducted in years 1 and 10 following the conclusion of injection operations (i.e., scheduled for 2020 and 2030).

Seismic survey data interpretations should detect any faults or fractures in the subsurface strata that may indicate leakage or the potential for leakage, and will provide information on the extent of the CO_2 plume within the Mt. Simon. Leakage would be detected as CO_2 migration above the confining zone.

Additionally, ADM will maintain a network of seismic monitoring stations (USGS will also maintain a similar seismic monitoring network) to detect seismic events greater than magnitude-1.0 (M1.0) within an 8-mile radius of the CCS#2 site, which could indicate activation of pre-existing planes of weakness (faults) that could compromise the seal formation.

Monitoring systems are anticipated to have a high capability to detect leakage that occurs. The monitoring program criteria and objectives are detailed in Section A.4 of the QASP

9.2 Leakage Verification

Once potential leakage has been detected, the following steps will be used to verify the potential location and source of leakage. Concurrent actions to minimize the detected leak (e.g., isolating the pipeline, shutting down injection operations) will be implemented.

If leakage is detected and verified, corrective action responses will be implemented in accordance with Area of Review and Corrective Action Plan (Reference 1, Attachment B) and/or the Emergency and Remedial Response Plan (Reference 1, Attachment F).

9.2.1 Surface Leakage

9.2.1.1 Obtain photographic documentation of the leakage point. (Visual signs of ice buildup or a plume are evidence of a leak.)

9.2.1.2 Identify and document the leak location on a map and/or P&I diagram of the pipeline.

9.2.2 Subsurface Leakage

If leakage is detected via surface or subsurface monitoring, and the quality assurance process has confirmed anomalous data readings:

9.2.2.1 Well Pressure / Temperature Monitoring

a. Identify and document the location (depth) of the anomalous readings.
b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.

9.2.2.2 Mechanical Integrity Testing

a. Identify and document the location (depth) of the anomalous readings.
b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.

9.2.2.3 Groundwater Quality / Geochemical Monitoring

a. Identify and document the aquifer in which the anomalous readings were measured.
b. Collect confirmation sample(s) and/or additional data in accordance with the QASP to verify result(s).
c. Use spatial and/or temporal analyses of available data (e.g., water quality, well measurements, reservoir flow model) to estimate the location and timing of the leakage.

9.2.2.4 Plume / Pressure Front Monitoring:

a. Determine whether injection formation characteristics (e.g., unanticipated conditions or heterogeneity) or model uncertainty are the cause of the anomalous data.
b. If step 9.2.2.4a does not determine the cause of the anomalous data, then it will be assumed that CO_2 leakage has been verified.

9.3 Leakage Quantification

9.3.1 Surface Leakage

The leakage rate from a pinhole, crack, or other defect in the pipeline or wellhead will be estimated once leakage has been detected and confirmed, using a methodology selected by ADM. Leakage estimating methods may potentially consist of either a form of mass balance equation or models. The selected method will be based on known data such as the size of the opening and the measured pressure, density, and temperature of CO_2 in the conduit at the time the leak was discovered.

Once a leakage rate has been estimated, the quantity (mass) of leakage may be estimated by calculating the approximate length of time that leakage occurred (e.g., based on time that leak was discovered and prior time that pipeline integrity was last verified). It is understood that this quantification method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

9.3.2 Subsurface Leakage

The ease with which leakage rate from the subsurface may be quantified will depend on the monitoring system that detected the leak. For example, leakage that is detected from pressure/temperature readings or MIT results may be more easily quantified (due to its location close to the injection source) than leakage that is detected from groundwater quality monitoring or from measurements of the CO_2 plume / pressure front.

Should leakage be detected and verified based on pressure/temperature readings or MIT results, ADM will select an estimation method to quantify leakage. One potential method under consideration is to use a form of mass balance equation; as with pipeline or wellhead leakage estimates, this method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

Similarly, should leakage be detected and verified based on groundwater monitoring data or plume / pressure front monitoring, ADM will select a method to estimate the quantity of leakage. One potential estimation method is to use the reservoir model to simulate a leak, use observed data to calibrate the “leaky” model. Once calibrated, the resulting model should provide a reasonably accurate estimate of the leakage quantity. ADM reserves the right to utilize other estimation methods (e.g., groundwater data evaluation) to evaluate leakage quantities.

9.3.3 Leakage Emitted to Surface

Mass balance calculations (see Section 11) require the estimation of leakage emitted to the surface / atmosphere. In the case of surface leakage (from pipeline or wellhead), the entire quantity of CO_2 that has leaked will be released to the atmosphere. For subsurface leakage, ADM will initially assume that the entire estimated quantity of CO_2 that has leaked will eventually reach the surface, unless modeling or other analysis is used to demonstrate that some portion of the leak will remain within the subsurface strata and will not reach the surface.

10.0 DETERMINATION OF EXPECTED BASELINES

Baseline data will consist of the following: annulus pressure (at surface), injection well temperature (at surface, at depth), groundwater quality and geochemistry, MIT data, CO_2 saturation, seismic and pressure front data.

10.1 Injection Well Monitoring

The following data will be collected over an established timeframe determined by ADM prior to injection operations:

1. Annulus pressure (at surface)
2. Injection well temperature (at surface, at depth)

The average of these values will be used as the baseline for these parameters. Baseline pressure and temperature data for CCS#2 was collected on September 30, 2015.

Anticipated annulus pressure as noted in Reference 1, Attachment C is as follows:

1. The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) during injection.
2. 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 (higher pressure) and below (lower pressure) the injection tubing packer set at 6,320 feet below Kelly Bushing (KB).
3. 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.

4. 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.

[Note: Injection pressure is not considered a baseline parameter. Injection pressure (at surface and at depth) measurements will be collected continuously once CO_2 injection starts. Injection pressure will be a function of the mass flow rate, density, and pressure of the delivered CO_2; thus, the baseline injection pressure range will be based on the anticipated range of the mass flow rate, density, and pressure of the delivered CO_2. Injection pressure will be used for comparison against other baseline data and model predictions. Maximum injection pressure at the surface is limited to 2,284 psig.]

10.2 Groundwater Quality and Geochemical Change Monitoring

Groundwater quality and geochemistry will consist of the following data collection:

Shallow groundwater monitoring (4 sites)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density

Lowermost USDW (St. Peter Sandstone)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Lowermost aquifer above confining zone (Ironton-Galesville Sandstone)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity

- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Further details on testing and monitoring may be found in Reference 1, Attachment C.

Baseline groundwater quality and geochemistry will be developed in accordance with approved USEPA statistical methods using software (e.g., USEPA's ProUCL) to calculate the accepted range of data values (e.g., data within the 95% confidence limit). Data values collected during injection and post-injection periods that are outside of the accepted range will be an indicator that leakage may have occurred, subject to data verification per the QASP. Baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.

10.3 Mechanical Integrity Testing

Baseline MIT data will be collected following installation of CCS#2 and VW#2, and will consist of logged data from the well (e.g., cement evaluation, pressure data, or other logging type as described in Section 5.1). Baseline MIT data will be compared to subsequent MIT data (collection frequency as noted in Reference 1, Attachment C) to evaluate whether well integrity has been compromised. Baseline MIT data were collected from CCS#2 on (05/31/2015, 06/10/2015, 07/06/2015, 07/25/2015, 09/29/2015, & 09/30/2015), and from VW#2 on (11/01/2012 & 09/10/2015), and consisted of running a cement evaluation log and temperature log on CCS#2, pressure testing the casing & annulus on CCS#2, running a cement evaluation log on VW#2, and pressure testing the annulus on VW#2..

Additional baseline data may also be obtained using pulse neutron capture / reservoir saturation measurement (RST) logs, which are already planned to monitor changes in reservoir fluid composition including detection and measurement of CO_2 saturation within the reservoir. RST logs are effective and accurate tools to monitor for changes in reservoir fluid composition and determining the presence of near-wellbore CO_2 within the Mt. Simon.

10.4 Plume and Pressure Front Monitoring

Baseline RST measurements will be collected in VW#1, VW#2, CCS#1, and CCS#2. Logged data will indicate, at minimum, CO_2 saturation within the Mt. Simon. Baseline data will be compared to data collected during Years 2 and 4 of injection operations. Baseline RST values for CCS#1 - 12/10/2014, CCS#2 - 09/30/2015, VW#1 - 12/11/2014, and VW#2 – 11/01/2012) were collected.

Baseline 3D VSP and surface seismic surveys have been completed (performed in 2011 and 2015). Seismic data collected in 2020 and 2030 (post-injection) will be compared to baseline surveys to evaluate plume location and configuration relative to the reservoir model prediction.

Data from seismic event monitors in the vicinity of the IL-ICCS project will be used to compare seismicity during and following injection operations with pre-injection seismicity. Increased seismicity, while not directly correlating to a leak, may provide additional information in the event of a leak detected from other monitoring data.

11.0 SITE SPECIFIC MODIFICATIONS TO THE MASS BALANCE EQUATIONS

40 CFR 98, Subpart RR requires greenhouse gas (GHG) reporting for geologic sequestration (GS) of carbon dioxide. 40 CFR 98.442 through 98.447 details the data calculations, monitoring, estimating, reporting and recordkeeping requirements for GS projects. This section describes how ADM will calculate the mass of CO_2 injected, emitted, and sequestered.

The mass (in metric tons, MT) of CO_2 sequestered in the Mt. Simon will consist of the following components (equations referenced from Subpart RR of 40 CFR 98):

- Annual mass of CO_2 injected (CO2I, Equation RR-4)

  Parameter CO2I will be measured using flow meter FE006 (Coriolis meter) as referenced in P&ID No. 1041-PD-13 in Appendix C of Reference 2. Flow rate is measured on a mass basis (kg/hr). Annual mass will be calculated based on the quarterly mass flow rate measurements multiplied by the quarterly CO_2 concentrations provided to USEPA by ADM for CCS#2.

- Annual mass of CO_2 emitted by surface leakage (CO2E, Equation RR-10)

- Annual mass of CO_2 emitted from equipment leaks and vented emissions (CO2FI,)

Equipment that may emit CO_2 to the atmosphere include three thermal pressure relief valves along the pipeline (TRV-001, TRV-002, and TRV-003), and two pressure relief valves (PSV101 and MOV101) located on the annulus head tank. Process & instrumentation diagrams (P&ID) 1041-PD-13, 1041-PD-40, and 1041-PD-50 illustrate the location of these valves.

- Annual mass of CO_2 sequestered = CO2I – CO2E – CO2FI (Equation RR-12)

Parameters CO2E and CO2FI will be measured using the leakage quantification procedure described in Section 5.3. ADM will estimate the mass of CO_2 emitted from relief valves or leakage points based on operating conditions at the time of the release – pipeline pressure and flow rate, set point of relief valves, the size of the valve opening or leakage point opening, and the estimated length of time that the emission occurred. It is noted that this estimation method may have a large margin of error; therefore, ADM may include a statistical estimate of the calculation error to document the likely range of the emitted quantity.

12.0 ESTIMATED SCHEDULE FOR IMPLIMENTATION

Determination of baseline data is anticipated to be complete by January 31, 2016. At that time, ADM anticipates having collected all of the initial baseline data, determined the range of acceptable values for the data, and established the “alarm” values which may signal anomalous conditions and will trigger further evaluation.

The anticipated date for injection operations to begin at CCS#2 is 1st Quarter 2015. At that time, ADM will begin implementation of the leakage detection process. Also by that time, ADM expects to begin data collection for the purpose of calculating the total amount of CO_2 sequestered in the Mt. Simon formation.

13.0 QUALITY ASSURANCE PROGRAM

Quality assurance procedures for the IL-ICCS project are provided in the Quality Assurance and Surveillance Plan (QASP) found in Reference 1, Attachment C, Appendix A.

- Section A of the QASP details project organization, project reasoning and regulatory information, project description, quality objectives and criteria, training and certification requirements, and project documentation/ recordkeeping.
- Section B details acquisition and generation of project data: sampling design, methods, handling and custody; sample analytical methods; quality control;

instrument/equipment inspection, testing, calibration, operation and maintenance; use of indirect measurements; and data management.

- Section C details project assessments, corrective actions, and internal reporting.
- Section D discusses data validation and use.

14.0 RECORDS RETENTION

ADM will maintain and submit records required under Section N of the Final Permit issued by USEPA. Reports will be maintained in electronic format at the ADM Decatur facility unless the USEPA Director is otherwise notified by ADM.

SUMMARY OF PREVIOUS REVISIONS:

Date	Version	Author	Reason(s) for revision
01/06/2016	1.0	Outzen	New Document

Request for Additional Information: ADM Subpart RR MRV Plan
January 4, 2016

Instructions: Please enter responses into this table. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. Supplemental information may also be provided in a resubmitted MRV plan.

No.	MRV Plan Section	MRV Plan Page	EPA Questions	Responses
1.	5.1 – Leakage Detection	10	MRV Plan: "Shallow groundwater samples will be collected on a quarterly basis; deep groundwater quality samples will be collected on an annual basis (see Reference 1, Attachment C for further detail on monitoring frequency)." For the shallow Quaternary/Pennsylvanian zones, the Subpart RR MRV plan notes that groundwater samples will be collected on a quarterly basis. However, ADM's Class VI testing and monitoring plan, which is referenced by the MRV plan, calls for quarterly sampling in years 1-2 of injection, semi-annual sampling for years 3-5 of injection, and annual sampling during post-injection. Please clarify or edit.	ADM intended the sampling frequencies to be the same as that required by the UIC Permit, Attachment C. The plan draft has been modified as indicated in the attached file to specify the same frequency as the permit for sampling.
2.	7 – Site Specific Modifications to the Mass Balance Equation	16	MRV Plan: "The mass (in metric tons, MT) of CO_2 sequestered in the Mt. Simon will consist of the following components (equations referenced from Subpart RR of 40 CFR 98): Annual mass of CO_2 injected (CO_{2I}, Equation RR-4 or RR-5)." Because a mass flow meter is used to measure the flow of the injected CO_2 stream, one would expect Equation RR-4 to be used for the Subpart RR mass balance equation and not Equation RR-5. Please clarify or edit.	Equation RR-4 will be used with the mass flow meter specified in the plan. ADM will delete "or RR-5". As indicated in the attached file.

MONITORING, REPORTING AND VERIFICATION PLAN
ARCHER DANIELS MIDLAND COMPANY, DECATUR, ILLINOIS
UNDERGROUND INJECTION CONTROL PERMIT – CLASS VI
PERMIT NO. IL-115-6A-0001 (FACILITY NAME: CCS#2)

This Monitoring, Reporting, and Verification (MRV) Plan has been prepared by the Archer Daniels Midland Company (ADM) for Carbon Capture and Sequestration well #2 (CCS #2) located in Decatur, Illinois, for the United States Environmental Protection Agency (USEPA). The MRV Plan was developed in accordance with the regulations at 40 CFR 98, Subparts RR (Geologic Sequestration of Carbon Dioxide) and UU (Injection of Carbon Dioxide).

1) FACILITY INFORMATION

Archer Daniels Midland Company (ADM)
Permit Number: IL-115-6A-0001 (UIC Class VI)
Facility Name: CCS#2

A map showing the ADM facility is provided as Figure 1.

2) PROJECT DESCRIPTION

ADM will capture carbon dioxide gas from their fuel ethanol production unit and compress the gas into a dense-phase liquid for injection into the Mt. Simon Sandstone approximately 7,000 feet below the ground surface. This project is identified as the Illinois Industrial Carbon Capture and Sequestration (IL-ICCS) project.

The IL-ICCS project plans to inject up to 3,300 metric tons of carbon dioxide (CO_2) daily, or 5.5 million metric tons over a five (5) year period.

The IL-ICCS project is the second carbon sequestration project at the Decatur facility. The Illinois State Geological Survey (ISGS) manages the Illinois Basin Decatur Project (IBDP) which completed its goal of injecting 1 million metric tons of CO_2 over a three-year period from November 2011 to November 2014.

Further information can be found in the following documents which are referenced throughout this MRV Plan:

Reference 1 – USEPA Underground Injection Control Permit, Class VI, for ADM CCS#2, Permit No. IL-115-6A-0001, effective December 1, 2014, including Attachments A, B, C (with Quality Assurance & Surveillance Plan), D, E, F, G, H, and I (Final Permit)

Reference 2 – ADM Permit Application for Underground Injection Control Permit, July 2011, including Appendices A-H (Permit Application)

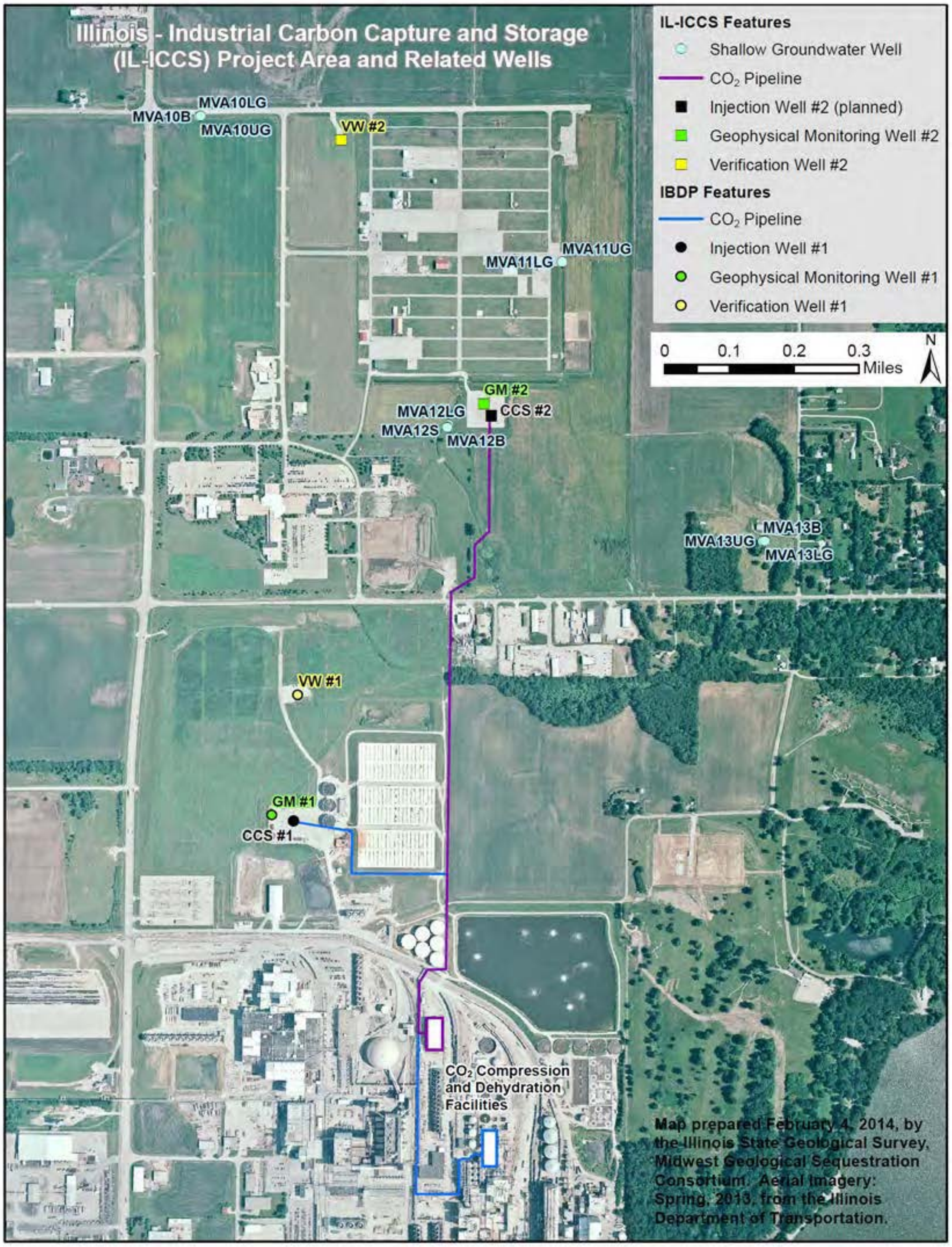

Figure 1. Aerial Photographic Map of ADM CCS#2 Facilities.

Reference 3 – ADM Response to USEPA Request for Additional Information, January 2012 (Supplement #1)

Reference 4 – ADM Update to Area of Review and CO_2 Plume Model, June 2012 (Model Update)

Reference 5 – ADM Response to USEPA Request for Additional Information, November 2012 (Supplement #2)

3) DELINEATION OF MONITORING AREAS

The area to be monitored is the Area of Review (AOR) identified in Reference 1, Section G.1 and Attachment B. Based on the predicted area of the CO_2 plume as estimated using the reservoir flow model, ADM will use the AOR as shown in Reference 1, Attachment B, Figure 7, plus a one-half mile buffer, as the maximum monitoring area (MMA).

The active monitoring area (AMA) is defined in 40 CFR 98.449 as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) The area projected to contain the free phase CO_2 plume at the end of year t+5."

For CCS#2, the AMA will remain constant throughout the 5-year injection period and the 10-year post-injection site care (PISC) period, and will consist of the AOR as shown in Attachment B of Reference 1. Figure 2 shows the extent of the AMA.

The AMA will incorporate, as described in the Testing and Monitoring Plan (Reference 1, Attachment C):

- Continuous monitoring of injection pressure, annulus pressure, and temperature monitoring at the injection well;
- Groundwater quality monitoring in the local drinking water strata, the lowermost underground source of drinking water (USDW), and the strata immediately above the Eau Claire confining zone;
- External mechanical integrity testing (MIT) and pressure fall-off testing at the injection well;
- Plume and pressure front monitoring in the Mt. Simon using direct and indirect methods (i.e., brine geochemical monitoring, pulse neutron / RST logs, VSP and 3D seismic surveys).

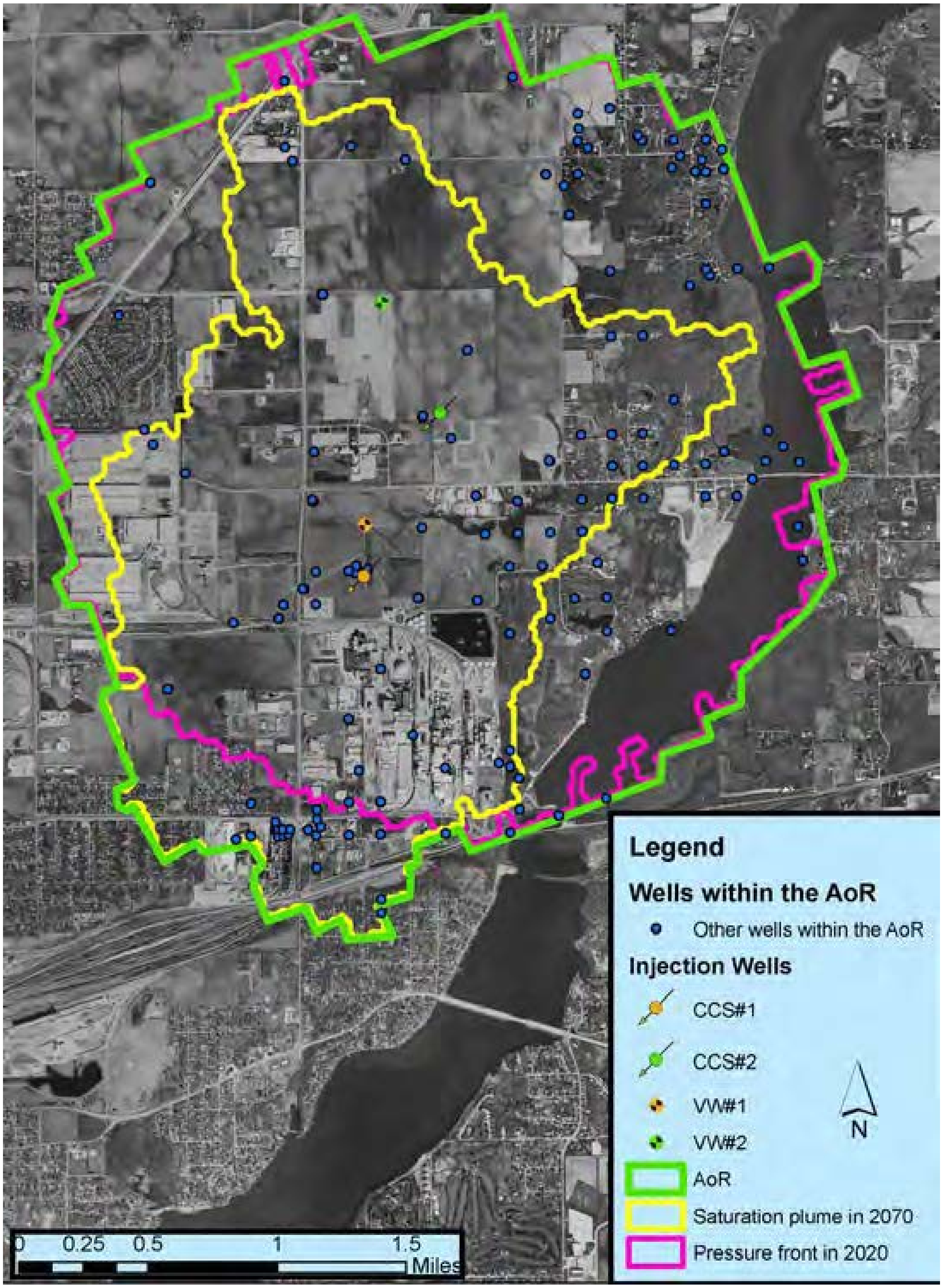

Figure 2. Active Monitoring Area (AMA) consists of the AoR (green outline) shown above.

4) EVALUATION OF LEAKAGE PATHWAYS

ADM has defined the potential leakage pathways within the AOR as:

1. Leakage from surface components (pipeline and wellhead)
2. Leakage through abandoned oil & gas wells
3. Leakage through fractures, faults, and bedding plane partings
4. Leakage through confining zone limitations
5. Leakage through injection well or monitoring wells

A qualitative evaluation of each potential leakage pathways is described in the below paragraphs. Risk estimates utilize the qualitative descriptions found in the geosphere risk assessment described for the Weyburn CO_2 storage site in Canada[1].

4.1 Leakage From Surface Components

The most probable potential for leakage of CO_2 to the surface is from surface components of the injection system: the pipeline that transports CO_2 to the injection well (approximately 5,000 feet in length), and the wellhead itself. Leakage is most likely to be the result of aging and use of the surface components over time, most likely at flanged connection points. Leakage could also occur as ventilation from relief valves to dissipate over-pressure in the pipeline. Additionally, leakage may occur as the result of an accident or natural disaster which damages the surface components and allows CO_2 to be released.

As a result, we conclude that the risk of leakage through this pathway is **possible**. The magnitude of such a leak will vary, depending on the failure mode of the component: a sudden break or rupture has the potential to allow several thousand pounds of CO_2 to be released to the atmosphere almost immediately; a slowly deteriorating seal at a flanged connection may release only a few pounds of CO_2 to the atmosphere over the course of several hours or days. Leakage or venting from surface components will be a risk only during the operation phase of injection (5 year period); following the injection phase, surface components will not store or transport CO_2 and will therefore no longer be a leakage risk.

4.2 Leakage Through Abandoned Oil & Gas Wells

As discussed in Attachment B of Reference 1, the only wells that currently penetrate the confining zone (Eau Claire Formation) are the IBDP injection and verification wells, and the IL-ICCS injection and verification wells, all of which were constructed in accordance with UIC Class VI requirements and are actively or will be monitored for integrity on a regular basis. No other wells in the AOR have a depth greater than approximately 2,500 feet below ground surface, which is roughly 3,000 feet above the top of the injection zone (Mt. Simon Sandstone).

[1] "Geosphere risk assessment conducted for the IEAGHG Weyburn-Midale CO2 Monitoring and Storage Project," Bowden, A.R., Pershke, D. F., Chalaturnyk, R. International Journal of Greenhouse Gas Control 16S (2013) S276–S290. Reference Table 4, p. S284.

As a result, we conclude that the risk of leakage through this pathway is **almost impossible** (and should in fact be zero) since no abandoned wells penetrate the confining zone. The magnitude and timing of such a leak are therefore not estimated.

Although leakage through abandoned wells will not occur as a primary pathway, it is possible that leakage that has migrated through the confining zone and into the more recent geologic strata may enter an abandoned well and migrate through the well to the surface; however, such leakage is expected to be detected by other monitoring methods (such as groundwater monitoring) as discussed in Section 5 of this MRV Plan.

4.3 Leakage Through Fractures, Faults, and Bedding Plane Partings

As discussed in Section 2.2 of Reference 3, there are no regional faults or folds mapped within a 15-mile radius of the proposed IL-ICCS site. 2D and 3D seismic survey data collected and analyzed as part of the IBDP and IL-ICCS projects confirm the lack of faults or folds. Also as discussed in Section 2.2 of Reference 3, the risk of a significant seismic event in the IL-ICCS project area (which could open fractures in the confining zone and overlying geologic strata and allow leakage from the injection zone) is minimal.

As a result, we conclude that the risk of leakage through this pathway is **highly improbable to nearly impossible**. The magnitude and timing of such a leak, if it were to occur, would be dependent on the magnitude of the seismic event. If such an event were to occur during the injection period or after, it is possible that entire mass of CO_2 that was injected into the reservoir up to that time may eventually be released to the surface; the timing of such a leak would occur over the course of several months to years following the seismic event.

4.4 Leakage Through Confining Zone Limitations

As discussed in Sections 2.2 and 2.5 of Reference 3, the Eau Claire Formation does not have any known penetrations (save for IBDP and IL-ICCS wells) within a 17-mile radius of the project site, has a laterally extensive shale component, and has only a slight dip (<1 degree). The type of leakage event through a confining zone limitation is conceived as an undiscovered local anomaly in the Eau Claire Formation, small in size, which would allow CO_2 to leak through the confining zone into overlying strata.

As a result, we conclude that the risk of leakage through this pathway is **highly improbable to nearly impossible**. The magnitude of such a leak, if it were to occur, is likely to be very small, due to the known low permeability of the Eau Claire and the overlying secondary seal strata (Makoqueta Shale and New Albany Shale) that are also low permeability geologic units. For the same reason, it is believed that the timing of such a leak to the surface may be extremely slow (e.g., over the course of decades or longer), as the leak must pass upward through the confining zone, the secondary confining strata, and other geologic units.

4.5 Leakage Through Injection or Monitoring Wells

As discussed in Attachment G of Reference 1, Section 3A of Reference 2, and Section 3B of Reference 5, design, construction, operation, maintenance, and monitoring plans for the injection-zone wells have been developed in accordance with UIC Class VI standards to minimize the potential for loss of well integrity. Additionally, the IBDP project at the ADM Decatur facility has provided prior experience in well construction, operations and maintenance, and monitoring that has been applied in the IL-ICCS project to further reduce the risk of a leakage pathway.

As a result, we conclude that the risk of leakage through this pathway is **highly improbable**. If a leak were to occur through this pathway, the magnitude of the leak is likely to be on the order of several hundred to several thousand pounds of CO_2, depending on the location of the leak relative to the surface and the complexity of logistics required to seal the leak; since injection-zone wells are continuously monitored, early detection of a leak is anticipated, with resulting operations to be shut down and the well shut in to minimize the mass of CO_2 leakage. The timing of CO_2 release to the surface would be dependent on the location of the leak relative to the surface, and the resulting geologic strata into which the CO_2 is released.

Table 1 shows IL-ICCS project injection and monitoring wells, with well depth, age, and construction information.

TABLE 1. IL-ICCS PROJECT WELL DATA

WELL ID	DEPTH	AGE	CONSTRUCTION
MVA 10LG	101 feet	<1 year	Per Illinois Dept. of Public Health regulations
MVA 11LG	135 feet	<1 year	Per Illinois Dept. of Public Health regulations
MVA 12LG	95 feet	<1 year	Per Illinois Dept. of Public Health regulations
MVA 13LG	140 feet	<1 year	Per Illinois Dept. of Public Health regulations
CCS#1	7,236 feet KB	6 years	Per UIC Class VI regulations
GM#1	3,496 feet KB	6 years	Per UIC Class VI regulations
VW#1	7,272 feet KB	6 years	Per UIC Class VI regulations
CCS#2	7,200 feet KB	<1 year	Per UIC Class VI regulations
GM#2	3,555 feet KB	<1 year	Per UIC Class VI regulations
VW#2	7,237 feet KB	<1 year	Per UIC Class VI regulations

5) DETECTION, VERIFICATION, AND QUANTIFICATION OF LEAKAGE

5.1 Leakage Detection.

Leakage detection for the IL-ICCS project will incorporate several monitoring programs: visual inspection of the pipeline to the injection well, injection well monitoring and MIT, CO_2 plume / pressure front monitoring, and groundwater quality monitoring. Table 2 provides general information on the leakage pathways, monitoring programs to detect such leakage, spatial coverage of the monitoring program, and the monitoring timeline. Further details are provided in Reference 1, Attachment C (Testing and Monitoring Plan).

TABLE 2. LEAKAGE DETECTION MONITORING			
Leakage Pathway	**Detection Monitoring Program**	**Spatial Coverage of Monitoring Program**	**Monitoring Timeline**
Surface Components	Visual Inspection Injection Well Monitoring & MIT	From flow meter to injection wellhead Injection well (from surface to injection formation)	Monthly for duration of injection (5 years) For duration of injection (5 years)
Abandoned Oil & Gas Wells	Plume / Pressure Front Monitoring Groundwater Quality Monitoring	From injection wellhead to edge of AMA Groundwater monitoring locations (see Figure 1)	For duration of injection (5 years); and in Years 1 and 10 following injection Quarterly to annual during injection (5 years)
Fractures & Faults	Plume / Pressure Front Monitoring Groundwater Quality Monitoring	From injection wellhead to edge of AMA Groundwater monitoring locations (see Figure 1)	For duration of injection (5 years); and in Years 1 and 10 following injection Quarterly to annual during injection (5 years)
Confining Zone Limitations	Plume / Pressure Front Monitoring Groundwater Quality Monitoring	From injection wellhead to edge of AMA Groundwater monitoring locations (see Figure 1)	For duration of injection (5 years); and in Years 1 and 10 following injection Quarterly to annual during injection (5 years)
Injection or Monitoring Wells	Injection Well Monitoring & MIT	Injection well (from surface to injection formation)	For duration of injection (5 years)

<u>Surface Leakage Detection</u>

Controlled or planned emissions from maintenance would occur when a section of a pipe containing CO_2 is isolated and vented so that a part can be maintained or repaired. Examples include replacement of instruments and valves as well as replacement of gaskets in the event of a leaking flange. Planned emissions due to maintenance will be limited to the extent possible. Controlled emissions will be tracked and reported as "leakage" (as the CO_2 will be vented rather than injected).

Unintentional (fugitive) emissions could arise from leakage of CO_2 at flanges and seals, at defects or cracks in the casing wall, or at pressure relief valves along the pipeline. Leakage from the pipeline or wellhead would be detected visually by ice crystal formation (due to the temperature reduction associated with release of supercritical CO_2 to the atmosphere) around the leakage point. Visual monitoring for these emissions will be performed monthly to detect fugitive emissions.

Visual inspection will not be possible for the one segment of pipeline that is underground. This section of the pipeline is 100% welded with no valves or flanges that could act as a leakage source; therefore, the potential for leakage in this segment is very low. Leak detection for this segment of pipeline would be limited to observation of abnormal pressure drop during a period of well shut-in and there is an absence of leakage detected in the aboveground pipeline. Well shut-in will be planned to occur on an annual basis.

<u>Subsurface Leakage Detection</u>

Leakage from the subsurface would be detected by one or more of the monitoring systems in the form of multiple measurements that are outside of the statistical baseline values (see Section 6), are persistent over a time period (i.e., not a one-time anomalous measurement), and cannot be explained by a variation in injection operations or unanticipated conditions in the injection formation.

In all cases where monitoring data suggest a leak, data verification procedures will be followed as outlined in the Quality Assurance and Surveillance Plan (QASP, located in Reference 1, Attachment C, Appendix A). Data verification efforts should eliminate the possibility that a "false positive" leak detection occurs.

Injection Well Monitoring and MIT. Injection well monitoring will include pressure and temperature monitoring, and the use of one or more approved methods for MIT as described in the Final Permit (Reference 1). The injection well monitoring methods are briefly described below; further information on testing and monitoring procedures can be found in Reference 1, Attachment C.

1. Injection Well Pressure and Temperature. Pressure and temperature will be continuously monitored during injection operations, at the surface (wellhead), at the injection zone, and in the well annulus. Anomalous measurements will trigger further investigation, and if not attributable to operational or injection zone conditions, such measurements could indicate CO_2 leakage.

2. Wireline Temperature Log. Temperature data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided.

   Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

3. Temperature Log using Distributed Temperature Sensing (DTS). CCS#2 is equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string. The DTS line is used for real time temperature monitoring and, like a conventional temperature log, can be used for

early detection of temperature changes that may indicate a loss of well mechanical integrity.

Data interpretation involves comparing the time lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity; i.e. tubing leak or movement of fluid behind the casing. The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real time. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. This data can be continuously monitored to provide real time MIT surveillance.

4. Wireline Noise Logging. Logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging will be carried out while injection is occurring.

   The base noise level in the well (dead well level) will be determined, and the log analyzed to identify departures from this level. (An increase in noise near the surface due to equipment operating at the surface is to be expected in many situations.)

5. Wireline Oxygen Activation (OA) Logging. Logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging will be carried out while injection is occurring.

   Data analysis will identify any differences in the activated water's measured gamma ray count-rate profile versus the expected count-rate profile for a static environment. Differences between the measured and expected value(s) may indicate flow in the annulus or behind the casing.

Groundwater Quality and Geochemical Monitoring. The groundwater quality monitoring network, which includes both injection-zone monitoring and monitoring above the primary confining zone, is designed to detect unforeseen leakage from the Mt. Simon as soon after the first occurrence as possible.

Three aquifers above the primary confining zone are monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone: these include the aquifer immediately above the confining zone (Ironton/Galesville Sandstone), the St. Peter Sandstone, which is considered to be the lowermost USDW at the site (direct monitoring of the lowermost USDW aquifer is required by the EPA's UIC Program for CO_2 geologic sequestration), and the local source of drinking water, Quaternary / Pennsylvania strata (shallow groundwater). Shallow groundwater samples will be collected on a quarterly basis; deep groundwater quality samples will be collected on an annual basis (see Reference 1, Attachment C for further detail on monitoring frequency).

In addition to direct monitoring specifically for the presence of CO_2, wells monitoring the deeper formations (St. Peter and Ironton/Galesville) are monitored for changes in geochemical and isotopic signatures that provide indication of CO_2 and/or brine leakage.

Plume and Pressure Front Monitoring. Direct and indirect methods will be utilized to monitor the CO_2 plume and pressure front. The plume will be directly monitored via annual fluid sampling in the Mt. Simon using VW#1 and VW#2. Indirect monitoring will consist of pulse neutron logging / reservoir saturation testing in VW#1, VW#2, CCS#1, and CCS#2 every two years during the injection phase, and seismic surveys / monitoring (reference Attachment C of Reference 1 for details).

Time lapse-vertical seismic profile (VSP) surveys were conducted annually using GM#1 in 2013, 2014, and 2015. The extent of the VSP survey is limited to approximately 30 acres in the vicinity of CCS #1. A baseline 3D seismic survey was conducted over the full AOR in January 2011, and a subsequent 3D survey conducted after the completion of the IBDP's injection period, in January 2015. These 3D surveys extended roughly 3,000 acres, centered near the location of CCS#2, and provided fold image coverage of roughly 2,000 acres.

Reduced-scale 3D surveys (roughly 2,000 acres, with fold image coverage of roughly 650 acres), with a focus on the vicinity north of CCS#2, will be conducted in years 1 and 10 following the conclusion of injection operations (i.e., scheduled for 2020 and 2030).

Seismic survey data interpretations should detect any faults or fractures in the subsurface strata that may indicate leakage or the potential for leakage, and will provide information on the extent of the CO_2 plume within the Mt. Simon. Leakage would be detected as CO_2 migration above the confining zone.

Additionally, ADM will maintain a network of seismic monitoring stations (USGS will also maintain a similar seismic monitoring network) to detect seismic events greater than magnitude-1.0 (M1.0) within an 8-mile radius of the CCS#2 site, which could indicate activation of pre-existing planes of weakness (faults) that could compromise the seal formation.

Monitoring systems are anticipated to have a high capability to detect leakage that occurs. The monitoring program criteria and objectives are detailed in Section A.4 of the QASP.

5.2 Leakage Verification

Once potential leakage has been detected, the following steps will be used to verify the potential location and source of leakage. Concurrent actions to minimize the detected leak (e.g., isolating the pipeline, shutting down injection operations) will be implemented.

If leakage is detected and verified, corrective action responses will be implemented in accordance with Area of Review and Corrective Action Plan (Reference 1, Attachment B) and/or the Emergency and Remedial Response Plan (Reference 1, Attachment F).

Surface Leakage

1. Obtain photographic documentation of the leakage point. (Visual signs of ice buildup or a plume are evidence of a leak.)
2. Identify and document the leak location on a map and/or P&I diagram of the pipeline.

Subsurface Leakage

If leakage is detected via surface or subsurface monitoring, and the quality assurance process has confirmed anomalous data readings:

1. Well Pressure / Temperature Monitoring
    a. Identify and document the location (depth) of the anomalous readings.
    b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.
2. Mechanical Integrity Testing
    a. Identify and document the location (depth) of the anomalous readings.
    b. Collect and document confirmation readings and/or additional data (e.g., DTS temperature log) in accordance with the QASP to locate the source.
3. Groundwater Quality / Geochemical Monitoring
    a. Identify and document the aquifer in which the anomalous readings were measured.
    b. Collect confirmation sample(s) and/or additional data in accordance with the QASP to verify result(s).
    c. Use spatial and/or temporal analyses of available data (e.g., water quality, well measurements, reservoir flow model) to estimate the location and timing of the leakage.
4. Plume / Pressure Front Monitoring:
    a. Determine whether injection formation characteristics (e.g., unanticipated conditions or heterogeneity) or model uncertainty are the cause of the anomalous data.
    b. If step 4a does not determine the cause of the anomalous data, then it will be assumed that CO_2 leakage has been verified.

5.3 Leakage Quantification

Surface Leakage

The leakage rate from a pinhole, crack, or other defect in the pipeline or wellhead will be estimated once leakage has been detected and confirmed, using a methodology selected by ADM. Leakage estimating methods may potentially consist of either a form of mass balance equation or models. The selected method will be based on known data such as the size of the opening and the measured pressure, density, and temperature of CO_2 in the conduit at the time the leak was discovered.

Once a leakage rate has been estimated, the quantity (mass) of leakage may be estimated by calculating the approximate length of time that leakage occurred (e.g., based on time that leak was discovered and prior time that pipeline integrity was last verified). It is understood that this quantification method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

Subsurface Leakage

The ease with which leakage rate from the subsurface may be quantified will depend on the monitoring system that detected the leak. For example, leakage that is detected from pressure/temperature readings or MIT results may be more easily quantified (due to its location close to the injection source) than leakage that is detected from groundwater quality monitoring or from measurements of the CO_2 plume / pressure front.

Should leakage be detected and verified based on pressure/temperature readings or MIT results, ADM will select an estimation method to quantify leakage. One potential method under consideration is to use a form of mass balance equation; as with pipeline or wellhead leakage estimates, this method may have a large margin of error; therefore, ADM will include a statistical estimate of the calculation error to document the likely range of the leakage quantity.

Similarly, should leakage be detected and verified based on groundwater monitoring data or plume / pressure front monitoring, ADM will select a method to estimate the quantity of leakage. One potential estimation method is to use the reservoir model to simulate a leak, use observed data to calibrate the "leaky" model. Once calibrated, the resulting model should provide a reasonably accurate estimate of the leakage quantity. ADM reserves the right to utilize other estimation methods (e.g., groundwater data evaluation) to evaluate leakage quantities.

Leakage Emitted to Surface

Mass balance calculations (see Section 7) require the estimation of leakage emitted to the surface / atmosphere. In the case of surface leakage (from pipeline or wellhead), the entire quantity of CO_2 that has leaked will be released to the atmosphere. For subsurface leakage, ADM will initially assume that the entire estimated quantity of CO_2 that has leaked will eventually reach the surface, unless modeling or other analysis is used to demonstrate that some portion of the leak will remain within the subsurface strata and will not reach the surface.

6) DETERMINATION OF EXPECTED BASELINES

Baseline data will consist of the following: annulus pressure (at surface), injection well temperature (at surface, at depth), groundwater quality and geochemistry, MIT data, CO_2 saturation, seismic and pressure front data.

6.1 Injection Well Monitoring

The following data will be collected over an established timeframe determined by ADM prior to injection operations:

1. Annulus pressure (at surface)
2. Injection well temperature (at surface, at depth)

The average of these values will be used as the baseline for these parameters. Baseline pressure and temperature data for CCS#2 was collected on September 30, 2015.

Anticipated annulus pressure as noted in Reference 1, Attachment C is as follows:

1. The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) during injection.
2. 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 (higher pressure) and below (lower pressure) the injection tubing packer set at 6,320 feet below Kelly Bushing (KB).
3. 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.
4. 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.

[Note: Injection pressure is not considered a baseline parameter. Injection pressure (at surface and at depth) measurements will be collected continuously once CO_2 injection starts. Injection pressure will be a function of the mass flow rate, density, and pressure of the delivered CO_2; thus, the baseline injection pressure range will be based on the anticipated range of the mass flow rate, density, and pressure of the delivered CO_2. Injection pressure will be used for comparison against other baseline data and model predictions. Maximum injection pressure at the surface is limited to 2,284 psig.]

6.2 Groundwater Quality and Geochemical Change Monitoring

Groundwater quality and geochemistry will consist of the following data collection:

Shallow groundwater monitoring (4 sites)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density

Lowermost USDW (St. Peter Sandstone)
- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS

- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Lowermost aquifer above confining zone (Ironton-Galesville Sandstone)

- Cations: Al, As, Ba, Ca, Cd, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, Sb, Se, Si, Tl
- Anions: Br, Cl, F, NO_3, SO_4
- Dissolved CO_2
- TDS
- Alkalinity
- Field pH, specific conductance, temperature, and water density
- $\delta^{13}C$ of dissolved inorganic carbon (DIC)

Further details on testing and monitoring may be found in Reference 1, Attachment C.

Baseline groundwater quality and geochemistry will be developed in accordance with approved USEPA statistical methods using software (e.g., USEPA's ProUCL) to calculate the accepted range of data values (e.g., data within the 95% confidence limit). Data values collected during injection and post-injection periods that are outside of the accepted range will be an indicator that leakage may have occurred, subject to data verification per the QASP. Baseline groundwater quality and geochemistry data collection was completed on 08/09/2015.

6.3 Mechanical Integrity Testing

Baseline MIT data will be collected following installation of CCS#2 and VW#2, and will consist of logged data from the well (e.g., cement evaluation, pressure data, or other logging type as described in Section 5.1). Baseline MIT data will be compared to subsequent MIT data (collection frequency as noted in Reference 1, Attachment C) to evaluate whether well integrity has been compromised. Baseline MIT data were collected from CCS#2 on (05/31/2015, 06/10/2015, 07/06/2015, 07/25/2015, 09/29/2015, & 09/30/2015), and from VW#2 on (11/01/2012 & 09/10/2015), and consisted of running a cement evaluation log and temperature log on CCS#2, pressure testing the casing & annulus on CCS#2, running a cement evaluation log on VW#2, and pressure testing the annulus on VW#2..

Additional baseline data may also be obtained using pulse neutron capture / reservoir saturation measurement (RST) logs, which are already planned to monitor changes in reservoir fluid composition including detection and measurement of CO_2 saturation within the reservoir. RST logs are effective and accurate tools to monitor for changes in reservoir fluid composition and determining the presence of near-wellbore CO_2 within the Mt. Simon.

6.4 Plume and Pressure Front Monitoring

Baseline RST measurements will be collected in VW#1, VW#2, CCS#1, and CCS#2. Logged data will indicate, at minimum, CO_2 saturation within the Mt. Simon. Baseline data will be compared to data collected during Years 2 and 4 of injection operations. Baseline RST values for CCS#1 - 12/10/2014, CCS#2 - 09/30/2015, VW#1 - 12/11/2014, and VW#2 – 11/01/2012) were collected.

Baseline 3D VSP and surface seismic surveys have been completed (performed in 2011 and 2015). Seismic data collected in 2020 and 2030 (post-injection) will be compared to baseline surveys to evaluate plume location and configuration relative to the reservoir model prediction.

Data from seismic event monitors in the vicinity of the IL-ICCS project will be used to compare seismicity during and following injection operations with pre-injection seismicity. Increased seismicity, while not directly correlating to a leak, may provide additional information in the event of a leak detected from other monitoring data.

7) SITE SPECIFIC MODIFICATIONS TO THE MASS BALANCE EQUATION

40 CFR 98, Subpart RR requires greenhouse gas (GHG) reporting for geologic sequestration (GS) of carbon dioxide. 40 CFR 98.442 through 98.447 details the data calculations, monitoring, estimating, reporting and recordkeeping requirements for GS projects. This section describes how ADM will calculate the mass of CO_2 injected, emitted, and sequestered.

The mass (in metric tons, MT) of CO_2 sequestered in the Mt. Simon will consist of the following components (equations referenced from Subpart RR of 40 CFR 98):

- Annual mass of CO_2 injected (CO2I, Equation RR-4 or RR-5)

  Parameter CO2I will be measured using flow meter FE006 (Coriolis meter) as referenced in P&ID No. 1041-PD-13 in Appendix C of Reference 2. Flow rate is measured on a mass basis (kg/hr). Annual mass will be calculated based on the quarterly mass flow rate measurements multiplied by the quarterly CO_2 concentrations provided to USEPA by ADM for CCS#2.

- Annual mass of CO_2 emitted by surface leakage (CO2E, Equation RR-10)

- Annual mass of CO_2 emitted from equipment leaks and vented emissions (CO2FI,)

  Equipment that may emit CO_2 to the atmosphere include three thermal pressure relief valves along the pipeline (TRV-001, TRV-002, and TRV-003), and two pressure relief valves (PSV101 and MOV101) located on the annulus head tank. Process & instrumentation diagrams (P&ID) 1041-PD-13, 1041-PD-40, and 1041-PD-50 illustrate the location of these valves.

- Annual mass of CO_2 sequestered = CO2I – CO2E – CO2FI (Equation RR-12)

Parameters CO2E and CO2FI will be measured using the leakage quantification procedure described in Section 5.3. ADM will estimate the mass of CO_2 emitted from relief valves or leakage points based on operating conditions at the time of the release – pipeline pressure and flow rate, set point of relief valves, the size of the valve opening or leakage point opening, and the estimated length of time that the emission occurred. It is noted that this estimation method may have a large margin of error; therefore, ADM may include a statistical estimate of the calculation error to document the likely range of the emitted quantity.

8) ESTIMATED SCHEDULE FOR IMPLEMENTATION

Determination of baseline data is anticipated to be complete by December 31, 2015. At that time, ADM anticipates having collected all of the initial baseline data, determined the range of acceptable values for the data, and established the "alarm" values which may signal anomalous conditions and will trigger further evaluation.

The anticipated date for injection operations to begin at CCS#2 is 1st Quarter 2015. At that time, ADM will begin implementation of the leakage detection process. Also by that time, ADM expects to begin data collection for the purpose of calculating the total amount of CO_2 sequestered in the Mt. Simon formation.

9) QUALITY ASSURANCE PROGRAM

Quality assurance procedures for the IL-ICCS project are provided in the Quality Assurance and Surveillance Plan (QASP) found in Reference 1, Attachment C, Appendix A.

- Section A of the QASP details project organization, project reasoning and regulatory information, project description, quality objectives and criteria, training and certification requirements, and project documentation/ recordkeeping.
- Section B details acquisition and generation of project data: sampling design, methods, handling and custody; sample analytical methods; quality control; instrument/equipment inspection, testing, calibration, operation and maintenance; use of indirect measurements; and data management.
- Section C details project assessments, corrective actions, and internal reporting.
- Section D discusses data validation and use.

10) RECORDS RETENTION

ADM will maintain and submit records required under Section N of the Final Permit issued by USEPA. Reports will be maintained in electronic format at the ADM Decatur facility unless the USEPA Director is otherwise notified by ADM.